CLASS VI PERMIT
PRE-OPERATIONAL TESTING PLAN

40 CFR §146.87

Caliche Beaumont Sequestration Project
Beaumont, Jefferson County, Texas

Claimed as PBI

[redacted]

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1.0 FACILITY INFORMATION AND INTRODUCTION

<table>
<tr><td>Facility/Project Name:</td><td>Caliche Beaumont Sequestration Project</td></tr>
<tr><td>Facility/Project Contact:</td><td>W. Graham Payne, Director of Energy Transition
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(832) 500-7590 / Claimed as PBI [redacted]</td></tr>
<tr><td>Well Locations:</td><td>Beaumont, Jefferson County, Texas
Injection Well Nos. 1, 2, and 3
<table><tr><td>Well ID</td><td>Latitude</td><td>Longitude</td></tr><tr><td>Injection Well 1</td><td>Claimed as PBI [redacted]</td><td>[redacted]</td></tr><tr><td>Injection Well 2</td><td>Claimed as PBI [redacted]</td><td>[redacted]</td></tr><tr><td>Injection Well 3</td><td>Claimed as PBI [redacted]</td><td>[redacted]</td></tr></table></td></tr>
<tr><td>SIC Code(s):</td><td>4923</td></tr>
<tr><td>Entity Type:</td><td>Private</td></tr>
<tr><td>Indian Lands:</td><td>No</td></tr>
</table>

Per 40 CFR §146.87 and the California Air Resources Board (CARB) Low-Carbon Fuel Standard (LCFS) Subsection C.3.2, this Pre-Operational Testing Plan (”Pre-Op Test Plan”) describes how Caliche will obtain data from the drilling and completion of the proposed injection and monitoring wells at the Caliche Beaumont Sequestration Project Site. Three injection wells (Injection Well Nos. 1, 2, and 3) and eight deep monitoring wells (four in-zone (IZ) and four above confining zone (ACZ)) are proposed to meet the injection and storage needs for the Caliche Beaumont Sequestration Project. Results of the site-specific *in-situ* data collected during the drilling of these wells will be used to validate the final modeled Area of Review (AoR) and will be provided to the United States Environmental Protection Agency (USEPA) Region 6 and CARB Executive Officer prior to authorization to inject.

1.1 Introduction

This Pre-Op Test Plan contains a comprehensive pre-operational data acquisition strategy across the confining and injection zones (i.e., the Sequestration Complex) at the Caliche Beaumont Sequestration Project Site located in Beaumont, Jefferson County, Texas. These site-specific data will be used to evaluate the modeled injection rates and volumes, to assist with final surface facility design, and to revalidate (and update, if needed) the static and dynamic models and the AoR.

Caliche is proposing to inject supercritical CO_2 (CO_2(sc)) into the “Green,” “Yellow,” and/or “Gold” Sands of the Upper Frio Formation (i.e., the Upper Frio Sand injection zone), as listed below and detailed in *Module A - Section 2.1 Local Geology* and *Module B – Area of Review and Corrective Action Plan*.

- Upper Frio Green Sand Claimed as PBI [redacted] feet *approximate*)
- Upper Frio Yellow Sand Claimed as PBI [redacted] feet *approximate*)
- Upper Frio Gold Sand Claimed as PBI [redacted] feet *approximate*)

Actual sand depths and thicknesses will be updated for each of the three injection wells after the open hole logging analysis across the intervals.

As discussed in *Module A – Section 2.2 Local Geology*, the primary Upper Confining Zone is the regionally extensive Anahuac Shale, which is predominantly a marine shale that exhibits extremely low porosity and permeability. The Anahuac is approximately Claimed as PBI [redacted] thick within the greater injection area (see **Figure A.2.34** of *Module A – Section 2.2 Local Geology*). In addition, shale dominant layers within the Upper Frio Formation between the Upper Frio Green and Frio "Orange" and within the Lower Oakville Formation provide additional containment. These three shale zones are collectively referred to as the "Upper Confining System." The primary Lower Confining Zone is the Upper Hackberry shales immediately below the Upper Frio Gold Sand.

During the drilling and construction of the injection wells, Caliche will run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under 40 CFR §146.86 and to establish accurate baseline data against which future measurements may be compared. Caliche will submit to the UIC Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests.

Caliche is proposing three injection wells, and four IZ and four ACZ monitoring wells to be completed into the Upper Frio Sand injection zone, as described above. All injection wells will follow the standards for logging and testing requirements found at 40 CFR §146.87(a)-(d) and CARB LCFS Subsections C.3.2(a)-(e) standards for logging and testing requirements. Coring will be adaptive and based upon well spatial variability, wellbore conditions, core recovery, and core quality as each injection well will be drilled. All wells will demonstrate mechanical integrity prior to receiving authorization to sequester CO_2(sc). The data obtained in this plan will be used to validate and update, if necessary, the *Module B - Area of Review and Corrective Action Plan*, to define and reduce uncertainties with the *Module A - Site Characterization*, revise the *Module E.1-Testing and Monitoring Plan*, and determine final operational procedures and appropriate permit limits and conditions.

This pre-operational logging and testing strategy has been developed based upon the needs and requirements for the three injection wells (Section 2.0) and for the proposed IZ and ACZ monitoring well(s) (Section 3.0).

2.0 INJECTION WELLS – 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 federal standards outlined under 40 CFR §146.87(a)-(d) and CARB LCFS Subsections C.3.2(a)-(e). The tests and procedures are described below and in the *Proposed Injection Well Construction Information* section of the *Module A – Project Narrative*.

Pursuant to 40 CFR §146.87(a), the logs and tests will include:

- Deviation checks during drilling, as applicable;
- Resistivity, spontaneous potential, and caliper logs before the surface casing is installed;

- Cement bond and variable density log to evaluate cement quality radially, and a temperature log after surface casing is set and cemented;
- Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the long string casing is installed;
- A cement bond and variable density log, and a temperature log after the long string casing is set and cemented;
- Internal and external mechanical integrity tests, which may include:
    - A pressure test with liquid or gas;
    - A tracer survey such as oxygen-activation logging;
    - A temperature or noise log; and
    - A casing inspection log.

Caliche will record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone according to the requirements of 40 CFR §146.87(c). Caliche will determine or calculate fracture pressure, other physical and chemical characteristics of the formation fluids in the injection and confining zones, and physical and chemical characteristics of the formation fluids in the injection zone in accordance with 40 CFR §146.87(d). Upon completion, but prior to operation, Caliche will conduct a pressure fall-off test and either a pump test or injectivity test to verify hydrogeologic characteristics of the injection zone, per 40 CFR §146.87(e).

All logging and well testing plans will be submitted to the UIC Program Director and CARB Executive Officer 30 days prior to commencing such activities. Any changes to the testing schedule will be submitted 30 days prior to the next scheduled test. The UIC Program Director and CARB Executive Officer 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) and CARB LCFS Subsections C.3.2(g) standards.

2.1 Injection Well Design

Claimed as PBI [redacted]

- Claimed as PBI [redacted]
- [redacted]

2.2 Deviation Checks

Three injection wells will be drilled and completed in the Upper Frio Sand injection zone on the City of Beamont Lease in Beaumont, Jefferson County, Texas. The wells are planned to be installed as vertical completions. Wellbore deviation measurements will be conducted on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method at sufficiently frequent intervals (+/-500-foot increments) during the drilling of each section of the wells, per 40 CFR §146.87 (a)(1) and CARB LCFS Subsection C.3.2(c)(1). After completing each well, a final deviation/gyroscopic survey will be conducted from total depth back to the surface.

2.3 Logging Program

The well logging program will cover both open and cased hole for all drilling/installation stages for the three injection wells. The logging program will meet all requirements set forth by the USEPA Class VI standards and CARB LCFS requirements to determine *in-situ* formation properties such as: thickness, porosity, permeability, lithology, formation fluid salinity and reservoir pressure, per 40 CFR §146.87 and CARB LCFS Subsection C.3.2(a).

A detailed mud logging program will be developed based upon the target depths for each injection well. Drill cuttings will be collected from surface to total depth Claimed as PBI [redacted], with adaptive whole-core sampling methodologies, through the proposed Upper Confining System and Upper Frio Sand injection zone. Gas chromatograph sampling will also be employed to monitor in-situ gases.

Table D.2.1 below provides information on potential logging run types that may be selected and the data that each run may provide.

Table D.2.1. Potential Logging Runs and Data.

Claimed as PBI [redacted]

Claimed as PBI [redacted]

The following sections detail the approach for logging in the open and cased hole sections of each injection well and their corresponding completions**.** The injection wells have been designed with two phases: surface hole and protection hole, as further discussed below.

2.3.1 Surface Hole Logging Program

The surface hole will be analyzed using wireline logging techniques (see **Table D.2.2** below), with the following geophysical logs planned upon reaching casing point Claimed as PBI [redacted]. Casing will be set into shales of the Pleistocene Formation. The depth of the surface casing will be set below the lowermost USDW (Lower Chicot Aquifer) and will be cemented to surface.

Table D.2.2. Surface Hole Logging Runs and Data – Injection Wells Nos. 1, 2, and 3.

Claimed as PBI [redacted]

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

2.3.2 Protection Hole Logging Program

The protection hole will be analyzed using wireline logging techniques (**Table D.2.3**), with the following open and cased hole geophysical logs planned upon reaching total depth Claimed as PBI. The protection hole casing will be cemented to surface for all injection wells.

Table D.2.3. Protection Hole Logging Runs and Data – Injection Wells Nos. 1, 2, and 3.

Claimed as PBI

[redacted]

Note: Additional diagnostic logs (**Table D.2.1**) may be run at the discretion of Caliche's geological staff and/or consultants or as directed by the authorized regulatory UIC Program Director or CARB Executive Officer.

Note[1] Schlumberger nomenclature used for convenience only.

2.3.3 Analysis and Reporting

After the open and cased hole logging program has been completed, Caliche will prepare an evaluation and interpretation of all the logs prepared by a knowledgeable log analyst, per 40 CFR §146.87(a) and CARB LCFS Subsections C.3.2(c). The report will include:

- The date and time of each test, wellbore completion data, and the data of installation of all casings and cement types;
- 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 and CARB Executive Officer. The data acquired will be used to validate and/or reduce uncertanties presented in the *Module B - Area of Review and Corrective Action Plan*.

2.4 Injection Well Coring program

Pursuant to 40 CFR §146.87(b), Caliche will take both whole cores and sidewall cores as described herein of the injection zone and confining system and formation fluid samples from the injection zone and will submit to the UIC Program Director a detailed report prepared by a log analyst that includes well log analyses (including well logs), core analyses, and formation fluid sample information.

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 each injection well will be used in support of the local geology and future interactions of the static model and the dynamic simulations for the Caliche Beaumont Sequestration Project.

The coring program strategy (see **Table D.2.4** below) developed in this Pre-Op Testing Plan accounts for the remaining sampling objectives, defines lateral variabilities, and has been developed specifically for the injection wells to meet the standards outlined in 40 CFR §146.87(b) and CARB LCFS Subsection C.2.3.1(f)(1).

Table D.2.4. Whole Core Sampling Intervals.

Core Run and Proposed Top Depths (feet)	Formation	Regulatory Intervals	Core Acquisition
Claimed as PBI [redacted]			

The whole core will be collected in the injection wells from the Anahuac and Upper Frio shales using drilling fluids designed to reduce the swelling of formation clays and improve the quality of the retrieved core. Whole cores will also be cut and recovered from the Upper Frio Sand injection zone for characterization purposes and model verification. The whole core program will be adaptive, with the acquisition of additional cores contingent upon the recoveries from initial core attempt in each zone and/or to address spatial variability.

The depth at which each whole core will be cut will be projected prior to drilling and then further determined on-site by the company's wellsite geologist. During the drilling of each well, the correlative analysis of the lithologies penetrated and the rate of drill bit penetration with that of offset open hole geophysical well logs and mud logs will be conducted. Core attempts will be contingent upon acceptable drilling parameters and hole conditions. If insufficient formation core is determined to have been recovered in any core run, an additional core may be cut and recovered at the discretion of the company's wellsite geologist. Alternatively, if insufficiently cored material is recovered in the well, other intervals may be subsequently evaluated with rotary sidewall coring techniques. Additional wells may also be cored. Whole core depth intervals (as well as mud log depth intervals) will be adjusted (depth-shifted) to be equivalent to open-hole logging depths.

Each injection well may have rotary sidewall cores collected from other 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. These data will be used to characterize the mitigation potential of overlying and underlying geologic formations (Upper and Lower Confining Zones) to retract and/or prevent fluid movement. It is anticipated that the rotary sidewall coring program will be adaptive, based upon whole core recovery, and the evaluated needs of the project.

2.4.1 Core Laboratory Analysis

Detailed core analyses will be performed at one or more well-respected, experienced industry core laboratory(s), 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 at the time of coring. Analyses will cover the range of rock properties found in the Upper Frio Sand injection zone and the Upper Confining System, including:

1) Petrology, grain size, and mineralogy

2) Geomechanical properties
3) Petrophysical properties:
    a. porosity and permeability
    b. relative permeability to CO_2
    c. capillary pressure and pore throat sizing
    d. fluid compatibility
    e. wettability
    f. pore volume compressibility

At a minimum, routine core analyses (porosity, permeability, and bulk density) will be performed on a distribution of samples characterizing differing lithologies. The sample interval may be programmatic (i.e., every foot, etc.) or based on observed lithology changes in the recovered core. 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 and quantity of the recovered core and needs for reducing uncertainty and risk in the dynamic modeling.

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) and CARB LCFS Subsection C.1.1.2. Specific analyses that are to be conducted are listed in **Table D.2.5** below. The actual core analysis program will depend on the amount and quality of core recovered from each injection well.

Table D.2.5. Whole Core Analytical Program.

Claimed as PBI

[redacted]

Data acquired from the core analyses will be used to reduce uncertainties within the model and detail spatial variability in the various parameters. These testing results will enable “fine-tuning” of the static and dynamic geologic models.

2.4.2 Reporting

Caliche 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). The report will include information on data collection and testing methods employed, specific reports on the core intervals that were recovered, identification of 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.

2.5 Formation Fluid Analysis

The downhole system used to sample and retain free and dissolved gases and the aqueous phases in equilibrium with such gasses will be supplied by a third-party vendor (Schlumberger, Expro, or an equivalent vendor using a downhole pressure-volume-temperature (PVT) sampler or equivalent tool). Note that most deep sampling is designed for hydrocarbons; however, this testing will focus on all sampled formation gasses and fluids. Downhole samples retained under pressure are preferred; however, based on subsurface and well conditions, surface samples may be collected for expediency.

The anticipated fluid sampling protocol will be as follows:

1. Purge the well casing volume to bring fresh fluids that have not reacted with drilling muds, completion fluids, or casing and tubing to the sample point within the wellbore (swab, nitrogen back-lift, etc.). If several well volumes are removed from the well, monitor fluid parameters at surface until properties stabilize (e.g., pH, temperature, specific conductance).
2. Deploy a commercial downhole sampler on slickline to collect an *in-situ* 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.
3. Preserve fluid and gas volumes in preparation for shipping and analysis.
4. 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, accredited by the Texas Commission on Environmental Quality (TCEQ) or alternative methods (e.g., ASTM Methods or Standard Methods) using standardized procedures.

Repeat sampling and frequency for baseline characterization (adaptive program) will be determined based on initial sampling and analysis results.

2.5.1 Fluid Analysis

At least one initial baseline fluid sample will be collected from the Upper Frio Sand injection zone during completion activities in each of the injection wells. These samples will assist in providing the baseline measurements for formation fluids and document any spatial variability. **Table D.2.6** identifies the parameters to be monitored and the analytical methods Caliche will employ.

Table D.2.6. Summary of Analytical and Field Parameters for Formation Fluid Samples – Injection Wells Nos. 1, 2, and 3.

Claimed as PBI

[redacted]

Notes:

1. AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; IRMS = isotope ratio mass spectrometry; MS = mass spectrometry; SM = standard method.
2. * = Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the project.

The initial parameters identified in **Table D.2.6** may be revised or include additional components for testing dependent on the initial geochemical evaluation. The fluid samples will be sent to a third-party laboratory accredited by the TCEQ or alternative methods (e.g., ASTM Methods or Standard Methods) using standardized procedures.

2.5.2 Reporting

Caliche will submit a report prepared by a specialist for the details on the fluid sampling results, per 40 CFR §146.87(b) and CARB LCFS Subsection C.2.3.1(f)(1). The report will include information pertaining to sample collection and analytical 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 and CARB Executive Officer.

2.6 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) and CARB LCFS Subsection C.3.2(e)(1). This information will be used (along with measured pore pressures in the injection zone) to determine appropriate, safe injection pressures for the injection wells. Caliche will utilize density and dipole sonic logs run in each 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 each injection well. Evaluation of the formation micro-imager will also aid in the identification of any borehole breakouts or open fractures.

Pursuant to CARB LCFS Subsections C 2.3(a)(3)(A) and C.2.3.1(h), the fracture/parting pressure of the target injection zone and the primary Upper Confining Layer and the corresponding fracture gradients determined via step rate or leak-off tests may be performed in each injection well. These testing and logging activities may be undertaken during the drilling of each injection to determine the state of stress of the injection zone and the primary Upper Confining Layer. In general, mini-frac testing conducted on wireline is less invasive and less destructive on the test interval as opposed to propagating a large fracture out into the formation, as would occur during bull-head step-rate well testing. Experience has demonstrated that fractured half-wing lengths can extend hundreds of feet out into the formation, compromising the future integrity of the well completion across the injection zone as well as the Upper Confining Zone.

Immediately following the drilling and logging of the injection wells, 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 in the injection zone and the Upper Confining Zone. These mini-frac operations will be performed using the MDT set in dual-packer tool configuration.

Mini-frac 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 Upper Confining Zone, the tested interval must first be determined to have no pre-existing structural weaknesses, such as natural fractures. Proposed 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 to prevent packer by-pass. The proposed procedure is described below:

Procedure

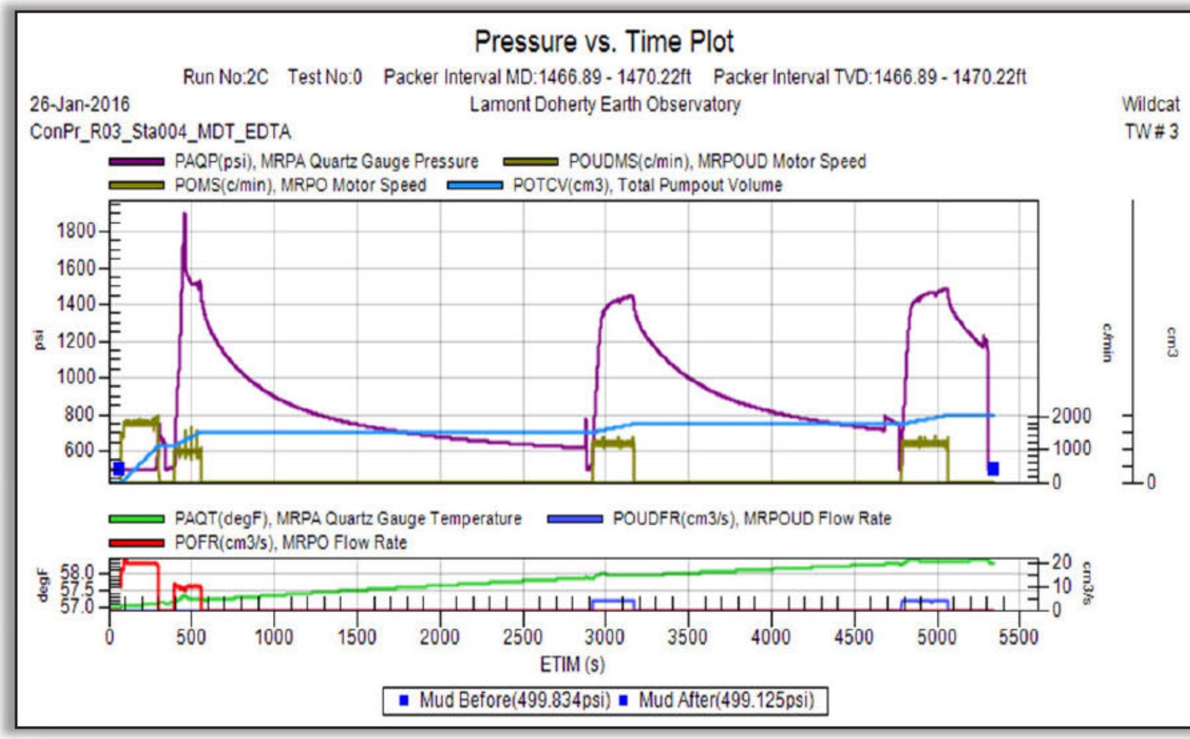
1. Rig up modular dynamics tool string for straddle-packer pressure testing.
2. Once the tool is ready, run the hole with the tool and run a baseline testing gamma ray strip. Match current baseline gamma ray strip in the well to the initial open-hole logging run.
3. Straddle the lowermost test interval and inflate the dual packers.
4. Attempt to perform an initial pre-test. If the interval is acceptable for mini-frac formation testing (i.e., rate will exceed matrix injection capacity).
    a. Initiate injection and ramp up rate in discrete rate steps, if needed, until formation breakdown is achieved;
    b. Continue to pump at a constant rate to propagate the fracture;
    c. Shut off the pump and record the pressure recovery;
    d. Repeat the injection/shut-in cycles at least two more times.
5. Complete testing of other intervals and pull tool from well.

Option:

6. Rig up Formation Micro-imager Tool and run in well for a final imaging pass.
7. Run tool below the lowest formation breakdown testing location and set tool for logging.
8. Extend pads and log image data upward across all the formation breakdown depths, recording log data at normal logging speeds.
9. Once the Formation Micro-imager Tool of above the top of uppermost breakdown point, retract pads and pull tool to surface.
10. Break down Formation Micro-imager Tool and retrieve from well.
11. Demobilize wireline unit.

The analysis procedure for mini-frac testing is presented below in Section 2.6.1. An example pressure versus time plot of a mini-frac test is provided below in **Exhibit D.2.1**.

Exhibit D.2.1. Time-Pressure Plot of a Mini-Frac Test.



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. 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, depending on the permeability of the test interval. 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 0.1 to 0.001 psi gauge resolution is recommended).

3. Load wellbore with water (potassium chloride 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 be commenced. 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.

2.6.1 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.

$$\Delta p_{net} = \text{ISIP} - \text{Closure Pressure}$$

- 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.

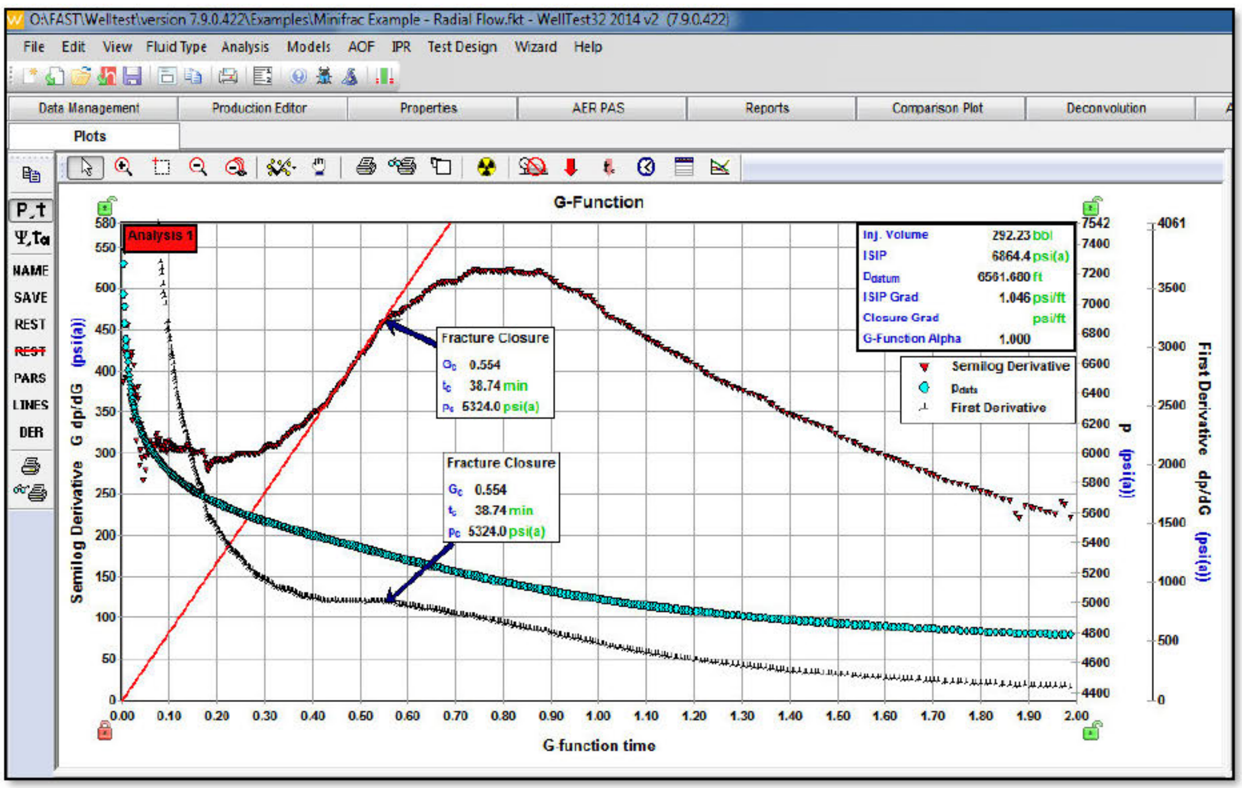
- Formation leak-off characteristics and fluid loss coefficients.
- Fracture closure pressure (pc).

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, 2021).

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 (**Exhibit D.2.2**; IHS, 2021).

Exhibit D.2.2. Example G-Function Derivative Prior to Closure.

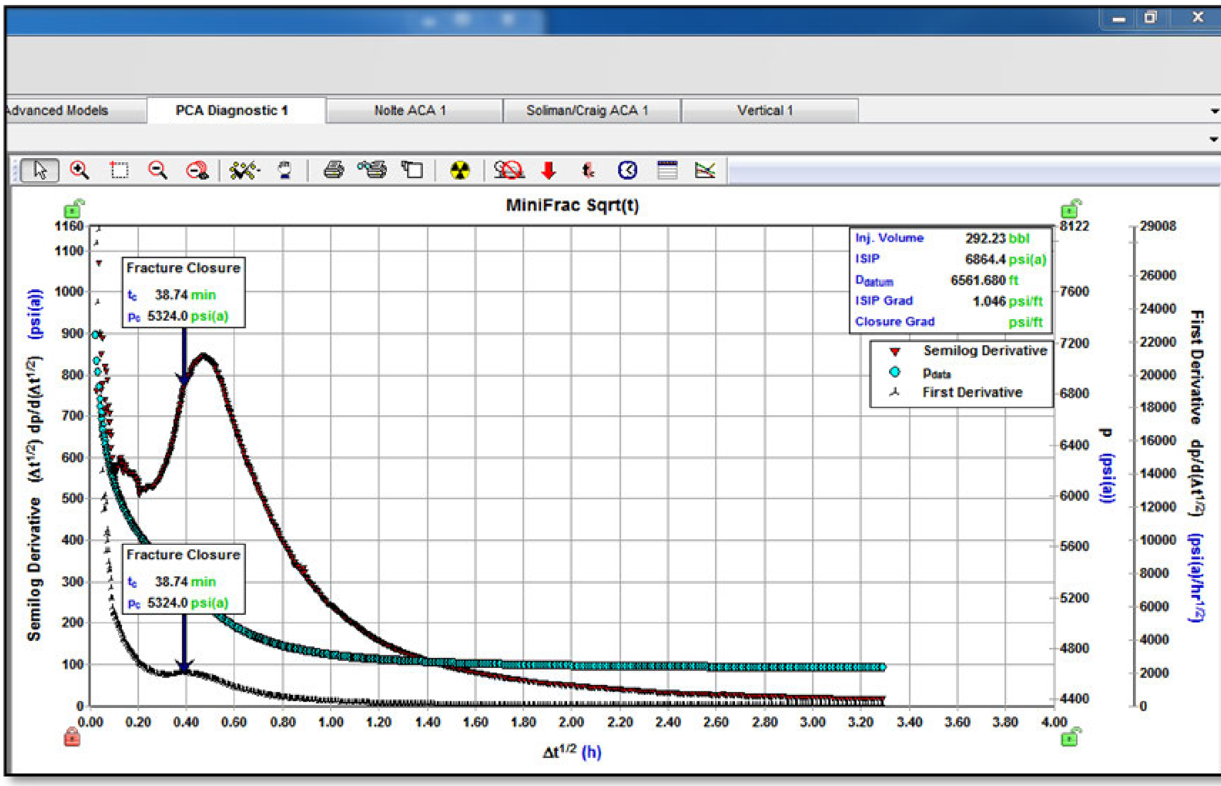


SOURCE: IHS, 2021.

Square Root Time Analysis

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 (**Exhibit D.2.3**; IHS, 2021).

Exhibit D.2.3. Example Fracture Closure.



SOURCE: IHS, 2021.

2.6.2 Reporting

Caliche will submit a report prepared by a specialist for the details on the formation fracture testing results, per 40 CFR §146.87(b) and CARB LCFS Subsection C.3.2(c). 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 and CARB Executive Officer.

2.7 Demonstration of Injection Well Mechanical Integrity

Tabulated below is a summary of the Mechanic Integrity Tests (MITs) to be performed on each injection well at the Caliche Beaumont Sequestration Project Site, which will be run after installation but before commencing injection operations. A list of the MITs for the injection wells is presented below in **Table D.2.7**.

As shown, MITs will include a pressure test of the well annulus using fluid or gas to ensure there are no significant 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 (USEPA, 2013, p. 10). If a well fails to demonstrate mechanical integrity, the well will be repaired prior to advancing to the next phase of drilling and construction.

Table D.2.7. Summary of Mechanical Integrity Testing – Injection Wells Nos. 1, 2, and 3.

Class VI Rule / CARB LCFS Citations	Description	Test Description	Program Period
40 CFR §146.89(a)(1) / Subsection C.4.2(b)(3)(A)	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) / Subsection C.4.2(b)(3)(A)	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(a)(4) / Subsection C.4.2(b)(4)	MIT – External		
40 CFR §146.87(e)(1) / Subsection C.2.3.1(i)	Testing prior to operating	Pressure fall-off test, pump test and injectivity test to verify the hydrogeologic characteristics of the injection zone	Prior to operation

<u>Radioactive Tracer Test Procedure</u>

The recommended technique for the Radioactive Tracer Survey (RTS) is to use a logging tool with a gamma detector above the ejector port and one or two detectors below it. The tool should be able to continuously record during tracer fluid ejection. The upper detector should be recorded in track 1 at a scale of 0 to 100 or 150 API units. The lower detector(s) should be recorded in tracks 2 and 3 at a higher scale, typically 0 to 1,000 API units.

1. Rig up a wireline unit with lubricator to the wellhead. Check tool and open crown valve. Run log in hole to test depth.
2. An initial gamma ray base log should be recorded from at least 100 feet above the injection tubing packer to total depth or plugged-back total depth (TD/PBTD) of the well, or as agreed between the well operator and the UIC Program Director / CARB Executive Officer:
    a. at least 100 feet below the lowest perforated interval, or
    b. the top of the screen, if present, or
    c. the top of fill or obstructions,

    whichever is deepest. A concurrent casing collar locator log for depth correlation is recommended.
3. Two 5-minute time drive statistical checks should also be run prior to the ejection of tracer fluid. These logs and statistical checks are run to determine background radiation prior to tracer fluid ejection. Recommend that checks be located above the packer and above the completion perforations.
4. Set the injection flow rates at a rate at which the fluid will be under laminar flow, while remaining within the maximum permitted operating parameters. The volume of the tracer

fluid slug should be sufficient to cause a gamma curve deflection of at least 25x background reading as the ejected slug passes the lower detector(s). This would typically be a full-scale deflection.

5. A constant injection (moving) survey should be run from, at least, above the packer to the perforations or screen to check for leaks between those two points. This survey should consist of ejecting a slug above the packer, verifying the ejection, and then dropping down through the slug, and then logging up through the slug to above where the slug was first ejected. The tool should then be dropped down through the slug again and logging should continue upward to above where the slug was encountered on the previous pass. This process should be repeated a minimum of two times, until the slug passes out into the formation. If necessary, the injection rate may be decreased to accomplish this test.
6. A stationary survey should be run approximately 20 feet or less above the top of the perforated interval or screen to check for upward fluid migration outside the cemented casing. If this depth cannot be reached due to fill or obstructions, the log should be run at the lowest possible depth. Flow during the stationary surveys should be at sufficient rates to approximate normal operating conditions in the well. As a guideline, this rate can be determined by dividing the total volume injected by the total hours the well is/was operated for the previous year (not the total number of hours in a year unless the well was operated non-stop).The procedure consists of logging on time drive, ejecting a slug, verifying the ejection, and waiting an appropriate amount of time to allow the slug to exit the wellbore and return through channels outside pipe. The time spent at the station will vary but should be at least twice the time estimated to detect the tracer fluid if channeling existed, or for a minimum of 15 minutes, whichever is greater. If tracer fluid is detected channeling outside of the pipe at any time during the stationary survey, then the survey may be stopped and the tracer fluid's movement should be documented by logging up on depth drive, until the tracer exits the channel.
7. Other stationary or moving surveys may be required, depending upon well construction, test results, or to investigate previously known problem conditions. At least two repeatable logs of every tracer survey, moving and stationary, should be run.
8. On completion of the tracer surveys, a final background gamma log should be run for comparison with the initial background log.
9. Unload iodine from the tool and pump away tracer material. Pull out of hole with the tool.

Interpretation of RTS

Where a measurable amount of tracer material leaks from the tubing, it will be observed as a small area of increased radioactivity after the slug has passed. If an area of elevated radioactivity is observed, additional runs should clarify what becomes of the slug material. This will demonstrate whether only the tubing is leaking, or if both the tubing and casing lack integrity. In most cases, if a well's casing has integrity but a tubing leak exists, pressure equalization and cessation of leaking will occur until a change in injection pressure allows the leak to resume. This is why it is important to ensure a pressure differential between the injection tubing and the annulus.

If annulus pressure is lower than injection pressure and both the tubing and casing are leaking, any tracer material that leaks out of the tubing will generally move toward and out through the casing leak. This is because the annulus pressure normally will be higher than the hydrostatic pressures within adjacent formations at all depths. If only the tubing is leaking, the tracer material will remain near the leak, spreading slowly both up and down from the leak location.

Adherence of tracer material to the tubing can be differentiated from a tubing leak because any material adhering to the tubing will eventually be washed away with no movement evident.

If no evidence of leaking is observed, the well has demonstrated part 1 of MIT. Be aware that demonstrations of MIT using the RTS will be examined very closely, and any conditions which threaten the ability to interpret them accurately must be removed.

Differential Temperature Survey (DTS) Procedure

The temperature log is one of the USEPA-approved logs for detecting fluid movement outside pipe. It should include both an absolute temperature curve and a differential temperature curve. The well should be shut-in at least 36 hours (USEPA, 2013, p. 21) to allow for temperature stabilization, though a shorter time period may be used with concurrence of the UIC Program Director and CARB Executive Officer. The log should be run over the entire interval of cemented casing, logging down from the surface to total obtainable well depth.

1. Rig up a wireline unit with lubricator to the wellhead. Calibrate the log if at all possible. This can be done by comparing measurements made using the tool in any two liquids to the known temperatures of those liquids. For instance, both a thermometer and the thermistor to be used for the logging may be used to measure the temperature of water at ambient conditions and a bucket of ice water. Even a single measurement made in a well-mixed bucket of ice water may be very useful.
2. Log the well from the surface downward, lowering the tool at a rate of no more than 30 feet to 40 feet per minute. The 30 to 40 feet per minute limitation is a practical balance between the tool response time and normal time constraints, slower speeds provide increasing detail. Time coding of the log, either a tick or gap in the log grid at 1-minute intervals or a logging speed trace, should be used to confirm the tool speed.
3. If the well has not been shut-in for at least 36 hours before the log is run, comparison with either a second log run six hours before the time the log of record is started or a log from another well at the same site showing no anomalies should be available to demonstrate normal patterns of temperature change.
4. The log digital data in either LAS or ASCII format is needed for ease of interpretation. A gamma ray log, made at the time of logging, or from a previous logging, and correlated to the temperature data is needed for accurate interpretation.
5. Once at total depth, logging is complete, pull out of hole with the tool.

The absolute temperature curve should be scaled no larger than 20ºF and recorded in API track 3 or 4. The differential temperature curve may be scaled in any manner appropriate to the specific logging vendor’s software, but it must be sensitive enough to readily indicate anomalies and should be recorded in API track 3 or 4. A correlation log(s) should be recorded in track 1, and the two temperature curves recorded in tracks 2 and 3. The temperature log should be scaled at or about 20°F or 10°C degrees per track. The differential curve may be scaled in any manner appropriate to the logging equipment design, but it must be sensitive enough to readily indicate anomalies.

Interpretation of DTS

Confirm the validity of the log at the well site by comparing logs made at or near the same site. When lithology and injectate characteristics are similar, then thermal effects along the wellbore should also be very similar. After the temperature effects caused by casing joints, packers, well diameter, casing string differences, and cement have dissipated, the temperature profiles should be similar, although not identical. If construction features are evident, a longer shut-in period is probably needed.

Note that testing in this section consists of collection of baseline data. The MIT during active operations and the post-injection period is detailed in *Module E.1 - Testing and Monitoring Plan*. The initial log can also be compared to temperature logs in other nearby wells if such logs exist. Lithologic effects which show up on one log should show up similarly in other wells at the same site. Failure of logs to compare coherently that are made at the same site under conditions which should result in thermal stability constitutes an anomaly.

If there are no logs suitable for comparison, then deviations from a predictable geothermal gradient are anomalies. These may take the form of a nearly constant temperature between reservoir strata. When more than one temperature log is run, these anomalies are likely to grow (be left behind) as the profile returns toward the natural geothermal while relative differences between the traces elsewhere decrease. In addition, areas with active flow will reach a stable temperature more quickly than other areas. If the movement is not related to injection, this temperature should be that of the natural geothermal gradient at the depth of the source reservoir.

If there are anomalies, a failure of initial mechanical integrity may be indicated. In such a case, a repeat log may be necessary to show whether forms apparent on the log just made are evolving toward the forms established on the log from another well. Comparison of these two new logs should show increasing parallelism along the cased wellbore, if not, then there may be flow along a channel adjacent to the well bore. If this flow results in the movement of liquid into unauthorized zones including USDWs, then the well does not have mechanical integrity. In the event that there are unresolved anomalies that might indicate an absence of mechanical integrity, another approved method (radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Program Director and CARB Executive Officer) must be used to confirm the absence of flow into unauthorized zones.

Noise Log (if run)

Channels along wellbores are very rarely uniform. When flow is occurring, irregularities in channel cross section usually result in generation of some turbulence which occurs in the audible range. Sonic energy travels for considerable distances through solids, allowing sensitive microphones to detect the effects of turbulent fluid flow at considerable distances. Different types of turbulence result in sounds having different frequencies. Single phase turbulence results in low frequency sounds, while two phase turbulence usually results in high frequency sounds. High pass filters are used to determine the intensity of detected noise within various frequency ranges.

Procedure for Noise Log (if run)

Noise logging may be carried out while injection is occurring in many wells because flow restriction caused by the logging tool is often insufficient to cause turbulence. It is especially desirable to log while injecting when looking for flow resulting from pressure increase near the top of the injection zone. If ambient noise while injecting is greater than 10 mv, injection should be halted. Logging procedures should include the following steps:

1. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.
2. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.
3. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection zone and at intervals of 20 feet within the 100-foot intervals containing:
    - the base of the lowermost bleed-off zone (i.e., first transmissive zone above the confining zone) above the injection zone;
    - the base of the lowermost USDW; and
    - in the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval.
4. Additional measurements may be made to pinpoint depths at which noise is produced.
5. Use a vertical scale of 1 or 2 inches per 100 feet.

Interpretation of Noise Log (if run)

The interpretation of noise logs for the purpose of demonstrating mechanical integrity is quite straightforward. The following steps are used:

1. Determine the base noise level in the well (dead well level).
2. Identify departures from this level which may indicate channeling (i.e., flow). An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations.
3. Attempt to determine the extent of any movement vertically through noise peaks/departures; this may be difficult when there are few flow constrictions.
4. If flow is into or between USDWs, a lack of mechanical integrity is indicated. If flow is from the injection zone of a hazardous-waste disposal well into or above the confining zone, failure of containment is indicated.

If the log measurements are ambiguous, the determination should be confirmed using another method.

Oxygen Activation Log (if run)

The oxygen activation method is based on the ability of the tool to convert oxygen into nitrogen$_{16}$ (N_{16}) within a short distance of the tool. This is accomplished by emitting high energy neutrons from the tool's neutron source. N_{16} is an unstable isotope of nitrogen which is referred to as “activated oxygen.” The half-life of activated oxygen is just 7.13 seconds, and the release of gamma rays as the activated oxygen decays into oxygen can be measured. If the tool is stationary and oxygen is activated, detectors placed near the activator device will detect increased gamma radiation. The intensity of the additional radiation will be inversely proportional to the square of the distance of the activated oxygen from the detector. Much of the oxygen near the tool occurs in water. If water containing activated oxygen moves, the measured intensity of radiation will be greater if the slug of activated oxygen moves closer to the detector, and less if it moves away. By comparison of intensity of gamma radiation measured as a result of activation at two detectors, the direction and velocity of water movement can be determined. Studies under controlled conditions have shown that water velocities between two and 120 feet per minute can be measured.

Procedure for Oxygen Activation Log (if run)

All measurements should be taken for periods of at least five minutes with the well injecting at the maximum normal rate. At least 15 minutes of measurement time is required at each station. This total time may be accumulated in one, two, or three episodes. If open hole caliper logs are available, care should be taken to obtain all readings at depths where the wellbore is in gauge. The method for obtaining measurements shall conform to optimum procedures contained in the operator's manual for the tool being used. The following steps are recommended for demonstrating mechanical integrity using the oxygen activation log:

1. Secure a log for lithology determination. If no such log is available, run a gamma ray-neutron log to identify porous intervals;
2. If required for tool calibration, background checks will be run with no injection occurring in an interval where no flow is thought to occur. Background calibration should be run for each interval of varying well construction;
3. Take measurements at stations at least 10 feet above the open injection interval;
4. Take measurements at the top of the confining zone and at two or three formation changes between the confining zone and the base of the USDW;
5. Take measurements within 50 feet below the base of each USDW, within 50 feet of the top of the first underlying aquifer, and at least one measurement between these two points;
6. If anomalies are found, additional readings, including readings made while the well is injecting if the original measurements were made while not injecting, or not injecting if the original measurements were made while injecting, should be made above and below the depth of the anomaly to confirm the anomalous reading and discover the extent of fluid movement; and
7. If flow is indicated, another log may be used to confirm the measurement and define the extent of flow. The choice for the confirmation log should be based on all wellbore and environmental factors, and the tool choice must be approved by the UIC Program Director and CARB Executive Officer prior to commencing testing operations.

Interpretation for Oxygen Log (if run)

A ratio of the short-spaced flow indicator results to standard deviation of 3 to 4:1 indicates flow. Indicated water-flow velocities should be in excess of two feet per minute, lower values should be viewed with skepticism. Velocities near and above two feet per minute have been measured at several depths at several sites; however, other logs did not indicate flow. In some cases, the occurrences were repeatable, at least during the period of one logging episode. Although the cause of the false measurements is not known, it is assumed that the logging tool was not properly calibrated for the interval being tested.

To minimize false positives, it is recommended that all measurements be confirmed at several nearby depths and/or measurements be taken under a minimum of 3 varying injection rates, i.e., at 75%, 50%, and 25% of maximum permitted injection rates. Before costly measures are taken to remedy problems, their existence should be confirmed using another approved log.

Caliche will notify the UIC Program Director and CARB Executive Officer at least 30 days prior to conducting any MIT 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 UIC Program Director and CARB Executive Officer at least 48 hours in advance of a given test/log. The wireline logs that will be performed during such MITs are listed below (**Table D.2.8**).

Table D.2.8. Mechanical Integrity Test Logging Summary.

Test	Description
Casing Inspection Log (Internal MIT)	To detect deformation, physical wear and or corrosion
Cement Bond Log (External MIT)	To evaluate integrity of cement job between the casing and the formation
Tracer Survey (Oxygen Activation Log)	To detect the movement of fluid behind pipe
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

Annulus Pressure Test (APT) Procedure

Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test. This may be achieved by filling the annulus with liquid and either ceasing injection or maintaining stabilized injection (i.e., continuous injection at a constant rate and constant injection fluid temperature) before and through the test (dynamic APT test). 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 block-off the surface annulus system. Increase annulus pressure to at least 200 psig over the permitted maximum tubing/injection pressure. Allow pressure to stabilize. Conduct APT by holding annular pressure a minimum of 100 psi 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 decreased 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 test pressure. **IF** the test indicated that the wellbore is not able to hold pressure for a selected period of time, 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 phase will be remediated prior to initiation of injection operations.

2.7.1 Reporting

Caliche will submit a descriptive report to the UIC Program Director and CARB Executive Officer, prepared by an experienced log analyst that includes the results of any mechanical integrity test with the application for 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 than 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.

2.8 Formation Testing

Caliche will perform pressure falloff tests during the injection phase as described below to meet the requirements of 40 CFR §146.87(e)(1), 40 CFR §146.90(f). Pressure falloff testing will be conducted upon completion of each injection well to characterize baseline formation properties, as well as determine near wellbore/reservoir conditions that may impact the injection of CO_2.

2.8.1 Ambient Pressure Falloff Testing

Caliche will perform an initial (baseline) pressure falloff test in each injection well 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 the sands of the Upper Frio injection zone. The initial pressure falloff testing will be repeated using CO_2 within the first 60 days following initiation of injection operations. This will allow for comparison to the baseline fluid-to-fluid test with the change in the injection fluid from brine water to CO_2.

A pressure falloff test will be performed at the minimum every 5 years (within approximately +/- 45 days of the fifth anniversary of the previous test) for the lifetime of injection operations, per 40 CFR §146.90(f) and CARB LCFS Subsection C.4.3.1.5. Periodic testing is expected to provide insight into the performance of the Storage Complex and potentially aid in assessing the dimensions of the expanding carbon dioxide plume, based on the expected lateral transition from CO_2(sc) near the wellbore and to native formation brine beyond the plume. The UIC Program Director or CARB Executive Officer may request more frequent testing which will be dependent on test results. A final pressure falloff test will be run after the cessation of injection into each injection well.

Test Details

Testing procedures will follow the methodology detailed in "*USEPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002)*"[1]. Bottomhole pressure measurements near the perforations are preferred due to phase changes within the column of CO_2 in the tubing. A surface pressure gauge may also serve as a monitoring tool for tracking the test progress.

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 (such as MP-35 line), and the deployed gauges should consist of a surface read-out gauge with a memory backup. Gauge specifications should be as follows or similar (**Table D.2.9**):

Table D.2.9. 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). A dedicated downhole monitoring gauge may be used if installed on each of the injection wells.

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 reference (KBR) elevation as well as the elevation above ground level.

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

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.

   NOTE: Rates from offset well may be superpositioned out of the test well data during analysis should an anomaly be observed: implications that may be attributed to significant rate change in an offset well. Rate information may also provide a reason for the final pressure being higher due to pressure buildup from the offset well and will be considered in the final interpretation of the test.

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 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 annulus pressure cannot be changed during the falloff period. Ensure that valves on 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 (5 minutes 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. If the well goes on a vacuum, the static fluid level will also be recorded.

In performing a fall-off test analysis, a series of plots and calculations will be prepared to quality assurance / quality control (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 activities (due to possible damage from well perforation) will be assessed for the wells injectivity and potential well cleanouts in the future. Data reduction and analyses will follow USEPA Region 6's *UIC Pressure Falloff Testing Guidelines – Third Revision* (https://www.epa.gov/sites/default/files/2015-07/documents/guideline.pdf). 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 UIC Program Director within 60 days of the test (per 40 CFR §146.91(e)) and to the CARB Executive Officer within 30 days of the test (per CARB LCFS Subsection C.4.3.1.5(d)).

3.0 MONITORING WELLS – TESTING STRATEGY

The following tests and log acquisitions will be conducted during drilling, casing installation, and after casing installation in the monitoring wells. As such, similar information to the injection wells may be gathered in the monitoring wells. The project currently anticipates that there will be four IZ monitoring wells drilled inside and outside the modeled AoR (see **Exhibit D.3.1** below) and will monitor the downhole conditions of the storage reservoir. Additionally, Caliche is planning for four ACZ monitoring wells, which have been designed to monitor the first transmissive zone above the primary Upper Confining Zone, which is sands of the Lower Oakville Formation.

Exhibit D.3.1. Location Caliche Proposed Injection Wells and Deep Monitoring Wells.

Claimed as PBI

[redacted]

3.1 Logging Program

The well logging program in the monitor 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 for baseline data acquisition. 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 and CARB LCFS Subsection C.2.3.1. The logging program for the monitoring wells will be defined based on the final well design and the logging requirements to establish a baseline to track the CO_2 plume and pressure movement. The data gathered will also comply with the requirements of 40 CFR §146.87 and CARB LCFS Subsection C.3.2(a). **Table D.3.1** below shows an example of a typical logging program for a monitoring well. Additional data may be gathered as needed. Spontaneous Potential Log acquisition will be dependent of the mud type and may not be possible in synthetic/diesel/oil-based mud systems.

Table D.3.1. Potential Logging Runs – IZ and ACZ Monitoring Wells.

Claimed as PBI

[redacted]

Notes:

1. Items: OH = Open Hole; WL = Wireline; CH = Cased Hole.
2. Data types: SP = Spontaneous Potential; GR = Gamma Ray; Res = Resistivity; Temp = Temperature; Den = Density; Neu = Neutron; Cali = Caliper; RSWC = Rotary Sidewall Cores; CBL = Cement Bond Log; VDL = Variable Density Log; MIT = Mechanical Integrity Test.

Caliche may perform additional logging during the monitoring well construction phase to establish a baseline to track the CO_2 using direct and direct monitoring methods for the pressure and plume front tracking discussed in the *Module E.1 – Testing and Monitoring Plan*.

3.2 Monitoring Well Coring Program

In addition to the whole core obtained from the injection wells, Caliche may opt to collect rotary sidewall core samples from the planned IZ and ACZ monitoring wells. These optional data may be collected if initial core acquisition is problematic or if spatial variation in parameters is expected. Specific rotary sidewall core acquisition for these wells will be dependent on logging results and future needs of the Caliche Beaumont Sequestration Project.

These data, if acquired, may be used to characterize the mitigation potential of overlying and/or underlying geologic formations to retract and/or prevent fluid movement. It is anticipated that the rotary sidewall coring program will be adaptive, based upon whole core recovery, and the evaluated needs of the Caliche Beaumont Sequestration Project.

3.3 Formation Pressure and Fluid Analysis

Caliche may acquire original static formation pressure and mobility data in the ACZ and IZ monitoring wells. These data will be used as a baseline for reservoir pressures before commencement of injection operations. These baseline pressures will be compared to project model pressures to monitor the effectiveness of the primary seal and understand connectivity between the formations laterally and vertically. Pressure gauges will be run in downhole of the completed wells to acquire baseline data.

Caliche will acquire baseline fluid samples for the Miocene and Oligocene saline formations in the ACZ and IZ monitoring wells, respectively, to evaluate the effectiveness of the primary seal and establish baseline characteristics. Subsequent fluid samples will also be acquired to track the CO_2 pressure and plume front. Additionally, Caliche will acquire baseline samples of the lowermost USDW (Lower Chicot aquifer).

The downhole system used to sample and retain free and dissolved gases and the aqueous phases in equilibrium with such gasses will be supplied by a third-party vendor (Schlumberger, Expro, or an equivalent vendor using a downhole PVT sampler or equivalent tool). Note that most deep sampling is designed for hydrocarbons; however, this testing will focus on all sampled formation gasses and fluids. Downhole samples retained under pressure are preferred; however, based on subsurface and well conditions, surface samples may be collected for expediency.

The anticipated fluid sampling protocol will be as follows:

1. Purge the well casing volume to bring fresh fluids that have not reacted with drilling muds, completion fluids, or casing and tubing to the sample point within the wellbore (swab, nitrogen back-lift, etc.). If several well volumes are removed from the well, monitor fluid parameters at surface until properties stabilize.
2. Deploy a commercial downhole sampler on slickline to collect a fluid sample at formation pressure at the targeted depth. Upon completion, close the sampler tool to retain the collected fluid and gas as it is pulled out of hole.
3. Preserve fluid and gas volumes in preparation for shipping and analysis.
4. 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, accredited by the TCEQ or alternative methods (e.g., ASTM Methods or Standard Methods) using standardized procedures.

Repeat sampling and frequency (adaptive program) are discussed in the *Module E.1 – Testing and Monitoring Plan*. An initial baseline fluid sample will be collected from the Miocene-aged Lower Oakville Formation in the ACZ monitoring well and within the Oligocene-aged sands of the Upper Frio Sand injection zone in the IZ monitoring wells. Sampling and analysis will be completed prior to injection operations. These fluid samples will provide the baseline measurements for formation fluids and document any spatial variability. The initial parameters identified in **Table D.3.2** will be analyzed for those fluid samples. However, this analytical program may be revised or include additional components for testing dependent on the initial geochemical evaluation.

Table D.3.2. Summary of potential analytical parameters for groundwater samples (IZ and ACZ Monitoring Wells).

Claimed as PBI

[redacted]

Notes:

1. AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; IRMS = isotope ratio mass spectrometry; MS = mass spectrometry; SM = standard method.
2. * = Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the project.

3.4 Demonstration of Monitor Well Mechanical Integrity

A baseline Pulsed Neutron Tool will be run in cased hole in each IZ and ACZ monitoring well after installation and prior to commencement of injection operations to establish initial conditions. Thereafter, an adaptive program of repeat surveys will be performed if indications of CO_2 approaching the monitoring locations are indicated on the in-zone 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 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

Caliche may opt to perform baseline pressure falloff tests during the IZ monitoring well construction phase. These tests, if conducted, would be used to quantify spatial variability of transmissibility (and by default permeability) within the sands of the Upper Frio Sand injection zone at a planned distance from the injection wells. It may also provide details of the lateral and vertical connectivity of the intervals. If conducted, the pressure falloff tests for the IZ monitoring well(s) will follow a similar procedure as discussed in Section 2.8 above. Falloff testing is not required for the ACZ monitoring well(s).

4.0 CITED REFERENCES

IHS, 2021, Minifrac Test Analyses, website: https://www.ihsenergy.ca/support/documentation_ca/WellTest/2019_1/content/html_files/analysis_types/minifrac_test_analyses/minifrac_test_analyses.htm. Accessed on 23 April 2024.

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