CLASS VI PERMIT TESTING AND MONITORING PLAN

40 CFR 146.90

SHELL U.S. POWER AND GAS
ST. HELENA PARISH SITE

Prepared By:
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1.0 FACILITY INFORMATION

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Two Class VI Injection Wells

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[redacted]

SOTERRA IT 2-1
[redacted]

This Testing and Monitoring Plan (TMP), which is risk-based and adaptive, describes how Shell U.S. Power and Gas (Shell) will monitor the sequestration project at the St. Helena Parish Site pursuant to USEPA 40 CFR §146.90. In addition to demonstrating that the injection wells are operating as expected, that the carbon dioxide plume and pressure front are moving as predicted, and there is no endangerment to Underground Sources of Drinking Water (USDWs), the monitoring data will be used to validate and guide any required adjustments to the geologic and dynamic models used to predict the distribution of carbon dioxide within the storage complex, supporting Area of Review (AoR) evaluations and a non-endangerment demonstration. Additionally, the testing and monitoring components include a leak detection plan to monitor and account for any movement of the carbon dioxide outside of the storage complex.

In accordance with 40 CFR §146.90(j), this testing and monitoring plan will be re-evaluated every 5 years (at a minimum) or more frequently at the direction of the Underground Injection Control (UIC) Program Director. The review process will evaluate whether the current plan will require an amendment. All amendments will be approved by the UIC Program Director and incorporated into the currently authorized operating permit.

Results of the testing and monitoring activities described below may also trigger response actions according to the Emergency and Remedial Response Plan [40 CFR 146.94(a)].

2.0 <u>OVERALL STRATEGY AND APPROACH</u>

This TMP is adapted for the Shell St. Helena Parish Site and considers the following site-specific strategy and approach:

- The design principle is risk-based and adaptive. The risk assessment will be concurrently reviewed and updated along with the regular AoR and TMP updates.
- The Injection Zones targeted for this project are made up of the Frio, Wilcox, and Lower Tuscaloosa Formations. These formations consist of stacked packages of porous and permeable sandstone that are separated by local to regional shale layers. The three Injection Zones act as separate flow units and are separated by approximately 400 feet, 1,300 feet and 2,200 feet regional seals for Frio, Wilcox, and Lower Tuscaloosa zones, respectively, at the storage site location.
- There is no evidence of faults or subsurface structures within the delineated AoR of the project site. However, two minor faults are interpreted in the broader local area, one to the north and another to the south of the AoR. While included in these sector models, the fault(s) interpretation has a high degree of uncertainty with respect to continuity and amount of throw at the Lower Tuscaloosa level and the fault(s) appear not to be present or have no offset at shallower Frio and Wilcox levels. The faults are not considered to be a dynamic barrier to flow or pressure dissipation, as discussed in the computational modeling reports (**Module B** – *"Area of Review and Corrective Action Plan"*).
- The Frio Confining Zone forms the Primary Upper Confining Zone for the sequestration complex. The Frio Confining Zone is of regional extent and is geologically suited to contain injected CO_2. Within the project area, the Frio Confining Zone is approximately 400 feet thick and has lithologic properties that would limit vertical fracturing in the subsurface (to be confirmed via site appraisal). See permit **Module A** – "*Project Narrative*" for additional information.
- The Lower Miocene Formation, directly overlaying the Frio Confining Zone, is composed of approximately 1,820 feet of sandstones that are interbedded with regional mudstone seals and local mudstone baffles. The Lower Miocene in the project area is saline and

serves as a series of alternating buffer aquifers situated between the top of the Sequestration Complex and the USDW. The formation provides ultimate protection of the USDW through these additional barriers to vertical fluid movement and potential for pressure dissipation, although migration through the Frio Confining Zone into the saline Miocene is not expected. Note that the Lower Miocene is used for Class II injection of saltwater within the Parish.

- In the project area, the main source of water for domestic use comes from the Upland Terrace Aquifer (Chicot Equivalent Aquifer System). The target CO_2 Injection Zones are deeper than the base of the lowermost USDW by more than 2,000 feet.
- Natural seismicity in the area is exceedingly low. The closest recorded earthquake occurred in 2010, which was recorded as a 3.0 magnitude earthquake, at a relatively shallow depth of 0.4 km. It was located at the western border of the St. Helena Parish, approximately 10.9 miles west of Greensburg, St Helena Parish, Louisiana.
- The induced seismicity risk is evaluated to be low due to the lack of any nearby significant faults and because of high transmissivity within the Injection Zones. Previous measurements of induced seismicity by the Department of Energy (DOE) supported research projects along the Gulf Coast (Mississippi Cranfield Project, for example), have not detected events resulting from injection of large volumes of carbon dioxide. Regional seismicity will be monitored annually using public sources for any change in occurrence or frequency of seismic events.
- The proposed injection wells will create a composite carbon dioxide plume and an area of elevated pressures surrounding the injection wells. Both the carbon dioxide plume and the AoR perimeter will be reviewed throughout the lifetime of the project to account for the potential to intersect additional existing (legacy) wells. The injected CO_2 is not expected to migrate to any legacy well that could permit vertical migration of CO_2. Key monitoring activities will provide:

    a) validation of the magnitude and area of pressure increase during injection, and

    b) documentation of the extent of the carbon dioxide plume during injection and subsequent stabilization during the post-injection monitoring period.

The proposed monitoring network for the project is composed of the following elements, listed from deepest and closest to injection wells, to the furthest away and shallowest. The overall concept for the monitoring well locations are shown in **Figure 1.**

<u>In-Zone (IZ) Monitoring</u>

<u>Direct Monitoring</u>

- IZ monitoring at the injection wells will confirm that the wells are performing as intended; delivering the carbon dioxide to the subsurface storage intervals only (Injection Zones), do not exceed safe injection pressures, and measure the pressure response in the reservoir intervals (a key model match parameter). Downhole pressure gauges and injection logging in the constructed injection wells will be used for data collection.

- Additional IZ pressure monitoring wells may be considered, located away from the injection site, which could validate future iteration of the dynamic model. Downhole pressure gauges and injection logging in the constructed monitoring wells will be used to collect real-time, continuous data. Potential additional monitoring wells will be located outside of the carbon dioxide plume and will monitor the pressure changes due to the developing pressure front.

- In addition to the pressure gauges, the IZ injection and monitoring well(s) will also be fitted with a downhole temperature gauge (gauge will be referenced to ground level).

- The IZ monitoring well will be located up-dip of the injector(s) such that the developing plume may intersect the well during the project injection and post-injection monitoring period. The IZ monitor well will provide direct measurement, when or if, the sequestered carbon dioxide plume reaches the well location. Should the well indicate the potential presence of carbon dioxide an adaptive fluid sampling program will be triggered in the to confirm presence or absence of CO_2. Fluid sampling will be conducted by a qualified vendor and the selected analytical laboratory will be compliant with the Louisiana Environmental Laboratory Accreditation Program[1].

[1] https://deq.louisiana.gov/page/la-lab-accreditation

- Native formation fluid will be sampled during the IZ monitoring well drilling campaign (for each injection zone) for pre-injection site characterization.

Indirect Monitoring

- Indirect monitoring will also be applied to assess the performance of the project to ensure that it is operating as intended and calibrate the AoR model. Indirect plume monitoring will be employed in the monitoring wells to define the location, extent, and thickness of the sequestered carbon dioxide.

- The areal distribution of the carbon dioxide plume in the Injection Zones will be determined using time-lapse seismic techniques during the injection and post-closure monitoring phases. It is well documented that the substitution of carbon dioxide for brine within sandstones, such as the Lower Tuscaloosa Formation, at similar project depths will produce a strong change in acoustic impedance (Vasco et al., 2019). Leading-edge techniques for time-lapse imaging of carbon dioxide plumes developed during implementation of the Regional DOE Partnership projects include time-lapse vertical seismic profiling (Daley and Korneev, 2006; Gupta, et al., 2020), azimuthal vertical seismic profiling (Gordon, et al., 2016), and sparse array walk-away surveys or scalable, automated, semipermanent seismic array "SASSA" (Roach, et al., 2015; Burnison, et al., 2016; Livers, 2017; Adams, et al., 2020), in addition to other traditional methods (*e.g.* repeat three-dimensional seismic surveys). Because three-dimensional seismic surveys have large on-the-ground footprints, a less invasive method will be selected for the St. Helena Parish site where possible.

- At a minimum, during acquisition of walk-away vertical seismic profiling and sparse array walk-away surveys, the array of acoustic source sites will be designed to optimize the plume image. The orientation for the next survey will be adjusted following the previous survey results. It is expected that for time-lapse profiling and sparse array walk-away techniques, frequency will be an initial baseline survey, followed by repeat surveys at the end of one year and three years after commencement of injection operations. Note: dates will be adjusted in response to data collected during the testing of the injection wells. After these initial surveys, the timing (and area) of each subsequent survey will be dependent on the recalibrated prediction of plume growth (based on previous survey and other monitoring data) and updated risk assessment (adaptive program). Data acquisition will be timed to ensure timely identification of potential issues that could trigger additional monitoring activities or change to project operations. The seismic monitoring method will be chosen to meet the risk assessment objectives of the survey (areal coverage and resolution).

Above-Confining Zone Monitoring Interval

- Monitoring of the Above Confining Zone Monitoring (ACZM) interval will occur in dedicated monitoring wells drilled on the well pads in close proximity to the Injection Wells. The initial ACZM zone for the sequestration project will be a permeable sandstone (directly overlying the Confining Zone) within the Lower Miocene Formation (exact sand will be identified following appraisal drilling). The ACZM well(s) are located near the point of carbon dioxide injection, where elevated formation pressure within the storage project is expected to be the greatest.
- The ACZM wells will be completed with a real-time, continuously recording downhole pressure/temperature gauge. The gauge will be referenced to ground level. Native formation fluid will be sampled during the ACZM well drilling campaign for pre-injection site characterization. Fluid sampling events during the injection phase, will primarily be triggered by project performance and evaluation of other TMP data, such as pressure from the ACZM wells.

Underground Sources of Drinking Water (USDW) Monitoring

- Aquifers in the area are part of the regional Southern Hills Aquifer System (SHAS), which has been designated as a sole-source aquifer for the region. The SHAS is comprised of three main aquifer subsystems known as the Upland Terrace (Chicot Equivalent), Evangeline Equivalent, and Jasper Equivalent Aquifer Systems. In the project area, the main source of water for domestic use comes from the Upland Terrace Aquifer (Chicot Equivalent Aquifer System). The target CO_2 Injection Zones are deeper than the base of the lowermost USDW by more than 2,000 feet.

- Shallow groundwater wells will be drilled and completed on the proposed injection well pads as part of the appraisal campaign. These wells will be sampled pre-injection to provide baseline water quality data and will provide accessible sampling points (if needed) during the injection phase.
- The project will investigate the opportunity to get access data from the Louisiana Department of Health, which routinely monitors for constituents in the drinking water according to Federal and State laws. This data will supplement monitoring data acquired by the project.
- During pre-injection monitoring activities, additional water sampling and analysis on existing water wells located around the St. Helena Parish site could also be performed to provide sufficient spatial and temporal data coverage for a comprehensive water quality baseline.
- An adaptive fluid sampling program is proposed for the USDW. Primarily sampling events and locations will be triggered following the pre-injection site characterization activities to investigate anomalous project performance and other TMP data (from ACZM Wells, for example), and to confirm no contamination of the USDW as a result of project activities.

2.1 REPORTING PROCEDURES

Shell will report the results of all testing and monitoring activities to the UIC Program Director in compliance with the requirements under 40 CFR §146.91. **Table 1** is an overview of the monitoring and reporting frequency program discussed within this plan.

Table 1: Testing and Monitoring Reporting Overview

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
Carbon Dioxide Stream Analysis [40 CFR §146.90(a)]		
Chemical and Physical Composition of CO_2 Stream	Compositional analysis of the injected CO_2 stream	Quarterly or as source changes
Continuous Recording of Operational Parameters [40 CFR §146.88(e)(1), §146.89(b), and §146.90(b)]		
Injection Parameter Monitoring	Pressure and temperature gauges; mass flow meter with alarms for	Continuous monitoring.

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
	measurements outside of the normal operating conditions	Summary of monthly statistics prepared and reported semi-annually.
Annulus Pressure Monitoring	Annulus pressure gauge	
	Annular Fluid Volume Measurements	
Corrosion Monitoring [40 CFR §146.90(c)]		
Coupon Testing	Flow-through corrosion coupon using injection well construction materials Utilize corrosion inhibitors in all fluids during well workovers	Quarterly analysis during injection operations. Additionally, as new sources added to stream
Above Confining Zone Monitoring ACZM - [40 CFR §146.90(d)]		
Lower Miocene Formation	Downhole Temperature and Pressure Groundwater sampling for laboratory geochemical analysis	Continuous real-time Pressure Monitoring (downhole) Pre-injection phase: discrete one-time sampling event Injection phase: sampling event dependent upon project performance and evaluation of other TMP data, such as pressure from the ACZM wells Semi-annual reporting
USDW Monitoring [40 CFR §146.90(d)]		
USDW Wells	Groundwater sampling of lowermost USDW within the AoR for laboratory geochemical analysis (baseline only) Groundwater sampling of commonly used USDW within the AoR for laboratory geochemical analysis. Groundwater sampling from project shallow groundwater wells	Pre-injection phase: discrete sampling events of shallow USDW during at least one year (frequency to be determined). Deep USDW baseline samples acquired during drilling. Injection phase: sampling events dependent upon project performance and evaluation of other TMP data, such as

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
	on pad and potentially landowner wells where needed & accessible.	anomalous pressure at the ACZM wells. Semi-annual reporting
External Mechanical Integrity [40 CFR §146.89(c) and §146.90]		
Well Integrity	Annulus Pressure Tests, Radioactive Tracer Survey, Temperature Survey	Annually and after all well workover operations that change well configuration.
Pressure Falloff Test [40 CFR §146.90(f)]		
Reservoir transmissivity and pressure.	Pressure Falloff Test, Static and Flowing Bottomhole Pressures	Baseline test after well completion. Every 5-years thereafter.
CO_2 Pressure and Plume Front [40 CFR §146.90(g)]		
Injection Wells and In-zone Monitoring wells	Direct Pressure and Temperature Monitoring with downhole gauges	Continuous parameter monitoring
VSP in ACZM well	Indirect Monitoring	Initial Baseline. Repeat at 1 year and 3 years after start of injection. Adaptive timing for subsequent surveys in response to AoR model, risk assessment and other TMP data

[a] Data archiver may be used to reduce data streams

2.2 QUALITY ASSURANCE PROCEDURES

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to §146.90(k), is provided in **Appendix 1 – QASP** to this TMP.

3.0 CARBON DIOXIDE STREAM ANALYSIS

Shell will analyze the composite carbon dioxide stream during the operational period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR §146.90(a) and LAC §3625.A.1 (State of Louisiana). A baseline sample of the carbon dioxide stream will be evaluated and tested prior to initiation of injection operations at the facility.

3.1 CARBON DIOXIDE SAMPLING LOCATION AND FREQUENCY

The injected carbon dioxide will be continuously monitored at the surface for pressure, temperature, and flow volumes. Sampling will be performed upstream or downstream of the flowmeter to analyze the gas composition. Sampling procedures will follow protocols to ensure the sample is representative of the injected carbon dioxide stream.

The frequency of carbon dioxide sampling will be conducted on a quarterly basis commencing with the initiation of injection operations. This equates to a schedule as follows:

1. Sample No. 1: 3 months after start of injection
2. Sample No. 2: 6 months after start of injection
3. Sample No. 3: 9 months after start of injection
4. Sample No. 4: 12 months after start of injection

The schedule will then repeat using this quarterly sample cycle. When known changes to the injected stream occur (*e.g.*, source changes and/or additions/deletions to the existing stream), sampling will also be performed for verification of the chemical and physical properties of the modified stream. This will determine if there are changes to the stream that need to be accounted and tested for to update and compare to the baseline conditions. The proposed sample frequency is sufficient to characterize the carbon dioxide stream and account for any potential changes to a representative data.

3.2 CARBON DIOXIDE ANALYTICAL PARAMETERS

Shell will contract a vendor to analyze the carbon dioxide for the potential constituents identified in **Table 2** using the methods listed (or equivalent). The final table of analytical parameters will be adjusted to contain only the actual constituents detected in the initial analysis of the CO_2 stream with the approval of the UIC Program Director. This table may be amended to account for a change in CO_2 source.

Table 2: Summary of potential analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)[1]
Carbon Dioxide (CO_2)	ISBT[2] 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
Oxygen (O_2)	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen (N_2)	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide (H_2S)	ISBT 14.0 (GC/SCD)
Sulfur dioxide (SO_2)	ISBT 10.1 (GC/FID)
Methane (CH_4)	ISBT 10.1 (GC/FID)
Total hydrocarbons (C_2H_6, C_3H_8+)	ISBT 10.0 THA (FID)
Hydrogen (H_2)	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide (CO)	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Nitrogen Oxides (any (NO_x)	ISBT 7.0 Colorimetric
Carbon isotopic composition $\delta^{13}C$	Measured once and when a significant new source is added.

Note 1: *An equivalent method may be employed with the prior approval of the UIC Program Director, such as ASTM Standards*

Note 2. *International Society of Beverage Technologists (ISBT) Carbon Dioxide Guidelines MBAA TQ vol. 39, no. 1, 2002, pp. 32-35 as cited in ISO/TR 27921:2020(en). Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — CO_2 stream composition*

3.3 CARBON DIOXIDE SAMPLING METHODS

Samples will be taken at the inlet or outlet of the flowmeter that will be on the pipeline entering to the sequestration site. The collection will follow protocols to ensure the sample is representative of the injected carbon dioxide stream. Sample collection procedures will be provided in detail by a certified laboratory vendor to be determined prior to injection authorization. Sampling methods and equipment will meet the standards and limits provided within the attached QASP (**Appendix** 1).

3.4 CARBON DIOXIDE ANALYSIS PROCEDURES AND CHAIN OF CUSTODY

Samples will be analyzed by a third party laboratory accredited by the Louisiana Department of Environmental Quality (https://internet.deq.louisiana.gov/portal/divisions/lelap/accredited-laboratories) using standardized procedures such as: gas chromatography, mass spectrometry, detector tubes, and photo ionization. Detection limits will be dependent on equipment facilitated for the analytical methods by the selected qualified vendor. However, all vendors will meet the minimum levels set forth in the QASP (**Appendix 1**).

The sample chain-of-custody procedures will be dependent on vendor selection as they will assume the custody of the samples. The procedures will document and track the sample transfer to the laboratory, to the analyst, to testing, to storage, and to disposal (at a minimum). A sample chain of custody procedure is contained in the QASP (**Appendix 1**).

4.0 CONTINUOUS RECORDING OF OPERATIONAL PROCEDURES

Shell will install and use continuous recording devices to monitor injection pressure, injection rate (mass flow), and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the carbon dioxide stream, as required at 40 CFR §146.88(e)(1), §146.89(b), and §146.90(b) (State of Louisiana Guidance - §3621.A.6.a, 3627.A.2, and 3625.A.2).

Injection rates and pressures will be set and monitored such that they do not exceed the values set by the permit. All aspects of the injection process will be monitored, recorded, and if necessary, shut down in the event the normal operating range is exceeded. Surface pressure and temperature will be measured continuously. The injected volume will be determined from a mass flow meter for each well that will be installed on the injection supply line.

4.1 MONITORING LOCATION AND FREQUENCY

Shell will perform the activities identified in **Table 3** to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies as presented below.

Table 3: Sampling devices, locations, and frequencies for continuous monitoring

Parameter	Device(s)	Location	Min. Sampling[1] Frequency	Min. Recording[2] Frequency
Injection Pressure (surface)	Pressure Gauge	Wellhead	I minute	1 minute
Injection Temperature (surface)	Temperature Gauge	Wellhead	I minute	1 minute
Injection Pressure (downhole)	Pressure Gauge	Downhole near perforations	1 minute	1 minute
Injection Rate	Flow meter per well	Wellhead	1 minute	1 minute
Injection Volume	From rate data	Flowline	1 minute	1 minute
Annulus pressure	Pressure Gauge	Wellhead	1 minute	1 minute

Parameter	Device(s)	Location	Min. Sampling[1] Frequency	Min. Recording[2] Frequency
Annulus fluid volume	Fluid Level Measure Calculate from bleed down and top up operations	Annulus Tank	N.A.	N.A.
Downhole Temperature	Temperature Gauge	Downhole, near perforations	1 minute	1 minute

[1] Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.

[2] Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute. Note a data archiver may be used to reduce data stream size for long term storage.

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements. Trend analysis will also help evaluate the performance (*e.g.*, drift) of the instruments, suggesting the need for maintenance or calibration.

Basic calibration standards, precision, formulas, conversion factors, and tolerances for measuring devices and analysis are included in the QASP (**Appendix 1**) but will be dependent on specific qualified vendor selection. Calibrations will be per manufacturers specifications and frequency.

4.2 MONITORING DETAILS

Semi-annual reports will be submitted to the UIC Program Director for each injection well, and will contain the following information:

- Monthly average, maximum, and minimum values for injection pressure, flow rate, and volume [40 CFR §146.91(a)(2)].
- Monthly average, maximum, and minimum values for annulus pressure [40 CFR §146.91(a)(2)].
- A description of any event that exceeds operating parameters for annular pressure or injection pressure specified in the permit, in compliance with [40 CFR §146.91(a)(3)].

- A description of any event that triggers a shut-off device required pursuant to [40 CFR §146.88(e)] and the response taken [40 CFR §146.91(a)(4)].
- The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and volume injected cumulatively over the life of the project [40 CFR §146.91(a)(5)].
- Monthly annulus fluid volume added [40 CFR §146.91(a)(6)].

Automatic alarm and automatic shutoff systems will be designed and installed to trigger an audible alarm in the event that pressures, flow rates, or other parameters, designated by the Executive Director, exceed the normal operating range specified in the injection permit per 40 CFR §146.88(e)(2). If an alarm or shutdown is triggered, Shell will immediately investigate and identify the cause of the alarm or shutoff (Please see the "*E.4 -Emergency and Remedial Response Plan*" [40 CFR §146.94 (a)] submitted in **Module E** for details).

4.2.1 Injection Rate, Volume, and Pressure Monitoring

Injection rates, volumes, and pressures will be set and limited to safe operating values below those specified in the authorized permit. All gauges, pressure sensing devices, and recording devices will be tested and calibrated as specified by the manufacturer. Test and calibration records will be maintained at the facility. All instruments will be housed in weatherproof enclosures, where appropriate, to limit damage from outside elements and events.

Downhole conditions (pressure and temperature) and flowline data (pressure, temperature, rate) will be gathered in real time and will provide information for verification of model predictions and AoR reevaluations. Any measured datapoint that exceeds a pre-determined trigger point (which will be set based on the well operating envelope) will create an automated response (such as a well shut-in) to ensure that operations remain safe. In addition, gathered data can be visualized and analyzed in the office in real time, which may prompt further action. Finally, a Well Integrity Monitoring System (WIMS) will be in place to ensure well integrity and the timely execution of preventative maintenance work.

4.2.2 Annulus System Monitoring

The purpose of the annulus system is to maintain a positive pressure on the tubing by the casing annulus of at least 100 psi in excess of the tubing pressure. This will prevent fluid movement from the tubing out into the casing, which will prevent contamination of freshwater sands in the event of well casing or injection tubing failure.

Integrity of the well's annulus system is achieved by monitoring of the annulus system at the wellhead. Annulus monitoring equipment used for each injection well includes an annulus tank, an annulus pump (small volume/high pressure), well flow meters, pressure monitoring cells, and pressure control valves. Alternate annulus construction may use a pressurized nitrogen system to maintain a constant pressure on the annulus. Annulus pressures will be monitored continuously. Deviations from expected changes could indicate a potential loss of mechanical integrity in the well annulus system. Observed deviations will initiate a well shutdown and investigation to determine the root cause of the observed deviation. Details are contained in the "*E.4 -Emergency and Remedial Response Plan*" [40 CFR §146.94(a)] in **Module E.**

Annulus brine tank fluid levels (and volumes) will be monitored for indications of system losses/gains and recorded daily.

5.0 CORROSION MONITORING

Per requirements of 40 CFR §146.90(c) and LAC §3625.A.3, Shell will monitor well materials during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. The coupon monitoring program is described below.

5.1 MONITORING LOCATION AND FREQUENCY

Coupon samples of the well construction materials (well casing, tubing, and any other well parts in contact with carbon dioxide such as the packer and wellhead) will be mounted in a tray located in the common flowline to the injection wells, upstream of the flow distribution header. The tray of coupons will be in contact with the carbon dioxide stream during all injection operations. This will ensure that the tray location will provide representative exposure of the samples to the carbon dioxide composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal for testing.

Corrosion coupon collection and testing will be conducted on a quarterly basis per 40 CFR §146.90(c). Baseline measurements on all coupon samples will be made prior to initiation of injection of carbon dioxide. Commencing with the initiation of injection operations, the initial monitoring event will occur at the end of the first calendar quarter (even if less than 3 months). Subsequent monitoring will occur at the end of each calendar quarter. This equates to a schedule as follows:

1. March 31 – End of Calendar 1st Quarter
2. June 30 – End of Calendar 2nd Quarter
3. September 30 – End of Calendar 3rd Quarter
4. December 31 – End of Calendar 4th Quarter

The schedule will then repeat using this quarterly sample cycle for the lifetime of the injection operations. Coupon compositions and details will be specified as part of conveyance pipeline and final well design.

5.2 SAMPLE DESCRIPTION

Shell is proposing that a corrosion coupon (weight loss) technique be used for monitoring purposes, as it is the best known and simplest of all corrosion monitoring techniques (the alternative is to use flow line loops). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (*i.e.*, at the beginning of the flow distribution header to the injection wells). This will allow for monitoring at a single location for each of the operating injection wells. Corrosion coupons representative of the well construction materials (**Table 4**) will be inspected, photographed, and weighed prior to placement into the flowline establish a baseline. Prior to installation of the corrosion monitoring system, the following information will be recorded:

1. Coupon Serial Number;
2. Installation date;
3. Identification of the location of the system; and
4. Orientation of the coupon holder.

The coupon method involves exposing a specimen sample of material (the coupon) to a process environment for a given duration, then removing the specimen for analysis. The Corrosion Monitoring Plan will be implemented following initial installation of the test coupons in the flowline, as follows:

- Consult maintenance schedule to determine when to remove test coupons from corrosion monitoring holders (coincident with end of calendar quarter);
- Remove and inspect coupons on a calendar quarterly basis and quantitatively evaluate for corrosion according to ASTM G1 – 03 (2017) or NACE Standard RP0775-2005 Item No. 21017 standards guidelines;
- Place coupons in proper receptacle for safe transport to measurement and weighing equipment;
- Photograph each coupon as received. Visually inspect each corrosion coupon for any pitting, stress corrosion cracking or scale buildup. Analyze corrosion coupons by weighing each coupon (to nearest 0.0001 gm) and measuring length, width, and height of the coupon (to nearest 0.0001 inch);

- Record information for each coupon including date of measurement, coupon identity (coupon number and metal grade), coupon weight in grams, and include any observations of excessive weight loss or pitting, stress corrosion cracking or scale buildup;
- Determine if current corrosion coupon can be returned to the monitoring test holder, make a note of coupon return, or if not make a note of installation of a new coupon.

Table 4: List of equipment coupon with material of construction

Equipment Coupon	Material of Construction
Surface Piping	"as built" material in contact with CO_2
Wellhead	Chrome14, or "as built" trim material in contact with CO_2
Injection Tubing	Chrome14, or "as built" material in contact with CO_2
Packer	Chrome14, or "as built" trim material in contact with CO_2

Samples will be collected by trained and authorized personnel and submitted to a third-party analytical laboratory for analysis. Results of the analysis will be compared to the pre-project baseline of the coupons. Basic details regarding the laboratory analysis are explained in the QASP (**Appendix 1**), however, specific details will be provided and updated by the selected corrosion laboratory vendor. Results will be submitted semi-annually through the Geological Sequestration Data Tool (GSDT). The UIC Program Director will independently assess the results of the corrosion monitoring for the integrity of the injection well.

5.3 ALTERNATIVE TESTS

Per 40 CFR §146.90, Shell may run a tubing/casing inspection log(s) to determine the presence or absence of corrosion in the protection (longstring) casing whenever the tubing is pulled from the well, or at the request of the UIC Program Director. Proposed inspection logs may include multi-finger caliper, ultrasonic imaging, magnetic flux leakage, and electromagnetic imaging tools as they are industry standard for determining casing thickness and identifying internal and external corrosion. The log(s) will be compared to those run during the initial construction of the well (40 CFR §146.87). Additional inspection logging programs may be implemented should the coupons show undue corrosion in excess of the design-life criteria.

Alternative testing other than those listed above may be conducted, with the written approval of the UIC Program Director. To obtain approval for alternative testing, Shell will submit a written request to the UIC Program Director setting forth the proposed alternative test and all technical data supporting its use for authorization.

6.0 ABOVE CONFINING ZONE MONITORING (ACZM)

6.1 ACZM – LOWER MIOCENE FORMATION

Shell will monitor the first permeable formation (saline Lower Miocene sand) above the confining zone, with the objective to detect changes that may be a result of loss of containment to meet 40 CFR 146.90.

The project proposes to drill two dedicated ACZM wells (one for each well pad) which will continuously monitor the pressure and temperature and will also be designed to allow fluid sampling if needed. These wells will also be equipped to perform indirect geophysical monitoring of the plume (see Section 9.1).

The exact Lower Miocene sand to be monitored will be selected after the data acquisition in the injection wells, which will include collection of pressure points and a compressive suite of logs across the formation. One or more transmissive sands may be identified as the best fit target for monitoring during the appraisal campaign. Higher sensitivity to leakage is obtained by selecting sandstones that have smaller areal continuity but are stratigraphically thinner.

The Lower Miocene formation, directly overlaying the Frio Confining Zone, is composed of approximately 2,000 feet of sandstones that are interbedded with regional mudstone seals and local mudstone baffles. The Lower Miocene in the project area is saline. There is no expectation that CO_2 or brine from the injection zones will migrate into the Miocene. However, were such a containment breach to occur, the Miocene formation provides additional protection for the USDW, with the alternating buffer aquifers offering pressure dissipation, and baffles providing additional barriers to vertical fluid movement.

The Lower Miocene formation is occasionally used for Saltwater Disposal (SWD) operations by Class II wells. Shell will monitor the SONRIS (Strategic Online Natural Resources Information System) website for any new Class II injection wells or status changes in the existing saltwater injection wells within a five-mile radius of the proposed injection wells.

6.1.1 Monitoring Location and Frequency

The ACZM 'Lower Miocene' wells will be completed with a real-time, continuously recording downhole pressure/temperature gauge. Native formation fluid will be sampled during the monitor well drilling campaign for pre-injection site characterization. Fluid sampling events during the injection phase, will depend upon project performance and evaluation of other TMP data, such as pressure from the ACZM wells.

Figure 1 shows the location of the planned wells and **Table 5** outlines the planned monitoring methods, locations, and frequencies. Shell proposes two ACZM wells, which will be located near the point of carbon dioxide injection (located on the injection well pads), where elevated formation pressure in the reservoirs is expected to be greatest combined with the presence of injected CO_2 for the entire injection and post-closure monitoring phase.

Modeling shows that pressure is a more robust and more diagnostic leakage detection method in deep confined saline aquifers (Nogues et al., 2011). Leakage of brine from one formation to another is also unlikely to be chemically detectable in most circumstances. Shell will instead primarily rely on an 'early warning' leak detection system based on bottom hole pressure measurements from the onsite ACZM wells, which will be continuously monitored and completed near the point of injection. If leakage trends are detected, follow up testing, logging, or geochemical measurements (as appropriate) will be conducted to investigate the cause and impact of the change in signal (adaptive monitoring).

Table 5: Monitoring of ground water above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Lower Miocene	Downhole Pressure/Temperature Monitoring	2 dedicated monitoring wells (one per an injection well pad)	Near point of injection	Continuous data
	Pre-injection phase fluid sampling for laboratory analysis			Discrete one-time sampling event prior to project start.
	Injection phase fluid sampling for laboratory analysis as needed based on project performance			Sampling events dependent upon project performance and evaluation of other TMP data, such as pressure from the ACZM wells
Lowermost USDW - sands within the Jasper Equivalent Aquifer System	Pressure and fluid sampling	To be determined after completion of appraisal campaign; potentially landowner wells	To be determined. Aim is to get areal coverage across AoR	Pre-injection phase: discrete sampling events for at least one year prior to injection (frequency to be determined) Injection phase: sampling event dependent upon project performance and evaluation of other TMP data, such as pressure from the ACZM wells
Commonly used USDW within the AoR – Upland Terrace Aquifer	Pressure and fluid sampling	To be determined after completion of appraisal campaign; potentially landowner wells where needed & accessible.	To be determined. Aim is to get areal coverage across AoR	
USDW - Upland Terrace Aquifer	Pressure and fluid sampling	groundwater wells installed during appraisal campaign on proposed injection well pads	Near point of Injection	

6.1.2 Analytical Procedures

If a pressure anomaly (triggers and thresholds to be defined post-appraisal) is detected in the monitoring well pressure gauge, the anomaly will be evaluated. If it is determined that the anomaly appears to be real and related to project performance following the evaluation, this may trigger formation fluid sampling for geochemical analysis. Samples from the onsite monitoring wells would be collected from the Lower Miocene formation. If pressure and fluid sample analysis confirm leakage into the strata overlying the Confining Zone, the procedures set out in the "*E.4 - Emergency Remedial and Response Plan*" submitted in **Module E** will be implemented.

Pre-injection phase fluid sampling and analysis is an integral part of the site characterization activities prior to start of the injection project and provides a basis to assess data gathered during the injection and post-closure monitoring phases of the project when such a need is identified based on project performance / triggers.

6.1.3 Sampling Methods

To ensure defensible data are generated during water sampling programs, best management practices / industry standard operating procedures will be employed (*e.g.* as per ISO 5667-11:2009, or EPA/240/B-06/001). Sample containers will be new and of an appropriate material and size for the analyte. Sufficient volumes will be collected to ensure selected analyses can be performed. Further details on Quality Assurance/Quality Control (QA/QC) procedures can be found in **Appendix 1**.

The sampling system for collecting formation fluid sample from the ACZM well will be supplied by a qualified third-party vendor offering a downhole pressure-volume-temperature (PVT) sampler or equivalent tool. Bottom hole samples are preferred; however, surface samples may be used for expediency.

The protocol for collecting bottom hole or surface samples will follow industry standard guidance. In general terms, casing volume will be purged to bring fresh fluids that have not reacted with casing and tubing to the sample point within the wellbore. In case of bottom-hole samples, a commercial downhole sampler will be deployed on a slickline to collect a fluid sample at pressure and then close to retain gas phases as sample is transported to the surface. The gas volumes will be conserved as samples stepped to atmospheric pressure for shipping and analysis. The samples will be filtered and conserved 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. Alternate sampling methodology may be adopted in alignment with final monitor well design, to be confirmed post-appraisal.

6.1.4 Analysis Procedures and Chain of Custody

Tables 6 and 7 provide an overview of potential analytes that might be considered for sample analysis during the pre-injection and injection phases monitoring activities.

Appropriate Standard Operating Procedures (SOPs) will be followed for sample collection to ensure sample integrity, as outlined in the QASP. Samples will be analyzed by a third party laboratory accredited by the Louisiana Department of Environmental Quality (https://internet.deq.louisiana.gov/portal/divisions/lelap/accredited-laboratories) using standardized procedures for gas in addition to major, minor and trace element compositions.

The sample chain-of-custody procedures will be implemented. The procedures will document and track the sample transfer to the laboratory, to the analyst, to testing, to storage and to disposal (at a minimum). A sample chain-of-custody procedure is provided in **Appendix 1.**

Table 6: Overview of *potential* analytical and field parameters. Analyses will be performed by a laboratory accredited by the Louisiana Department of Environmental Quality.

Parameters	Analytical Methods
Dissolved CO_2 gas by headspace	Gas Chromatography (GC)
Dissolved CH_4 gas by headspace	Gas Chromatography (GC)
Hydrocarbons	Gas Chromatography (GC)
Dissolved inorganic carbon (DIC)	Standard Methods: 5310B, or comparable method depending upon contract laboratory
Bicarbonate	Titration
Cations: Al, As, B, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Ti, Zn,	As listed in LDEQ ASSET (Aquifer Sampling and Assessment Program)'s Analytical Parameter List (https://deq.louisiana.gov/assets/docs/Water/Aquifer-ASSET_PARAM_LIST.pdf), or comparable method depending upon contract laboratory; or 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, CO_3	As listed in LDEQ ASSET (Aquifer Sampling and Assessment Program)'s Analytical Parameter List (https://deq.louisiana.gov/assets/docs/Water/Aquifer-ASSET_PARAM_LIST.pdf), or comparable method depending upon contract laboratory; or Ion Chromatography, EPA Method 300.8, ASTM 4327

Parameters	Analytical Methods
Total Dissolved Solids	As listed in LDEQ ASSET (Aquifer Sampling and Assessment Program)'s Analytical Parameter List (https://deq.louisiana.gov/assets/docs/Water/Aquifer-ASSET_PARAM_LIST.pdf), or comparable method depending upon contract laboratory; or EPA 160.1, ASTM D5907-10
Alkalinity	As listed in LDEQ ASSET (Aquifer Sampling and Assessment Program)'s Analytical Parameter List (https://deq.louisiana.gov/assets/docs/Water/Aquifer-ASSET_PARAM_LIST.pdf), or comparable method depending upon contract laboratory; or EPA 310.1
pH (field, lab)	EPA Method 150.1; ASTM D1293, or comparable method depending upon contract laboratory
Specific Conductance (field)	EPA 120.1, ASTM 1125
Temperature (field)	Thermocouple
Hardness	As listed in LDEQ ASSET (Aquifer Sampling and Assessment Program)'s Analytical Parameter List (https://deq.louisiana.gov/assets/docs/Water/Aquifer-ASSET_PARAM_LIST.pdf), or comparable method depending upon contract laboratory; or ASTM D1126
Turbidity (field)	As listed in LDEQ ASSET (Aquifer Sampling and Assessment Program)'s Analytical Parameter List (https://deq.louisiana.gov/assets/docs/Water/Aquifer-ASSET_PARAM_LIST.pdf), or comparable method depending upon contract laboratory; or EPA 180.1
Specific Gravity	Modified ASTM 4052
Density	Modified ASTM 4052

6.2 USDW MONITORING

Aquifers in the area are part of the regional Southern Hills Aquifer System (SHAS), which has been designated as a sole-source aquifer for the region. The SHAS is comprised of three main aquifer subsystems known as the Upland Terrace (Chicot Equivalent), Evangeline Equivalent, and Jasper Equivalent Aquifer Systems. In the project area, the main source of water for domestic use comes from the Upland Terrace Aquifer (Chicot Equivalent Aquifer System). The Injection Zones are deeper than the base of the lowermost USDW by more than 2,000 feet. The Louisiana Department of Health routinely monitors for constituents in the drinking water according to Federal and State laws. Depending on project performance and evaluation of other TMP data (*e.g.* from ACZM Wells), an adaptive fluid sampling program might be initiated for USDW.

6.2.1 Monitoring Location and Frequency

Pre-injection phase geochemical data will be collected from the deepest USDW, the commonly used USDW within the AoR, and from the shallow groundwater wells completed on the proposed injection well pads as part of the appraisal campaign. Frequency of sampling during the pre-injection phase will depend upon depth of sample collection. For the lowest USDW, where significant seasonal variation is not expected, only one sampling event is expected at any location during drilling of the deep monitor wells, whereas the shallow groundwater wells on the proposed injection well pads will be sampled at least bi-annually for one year. The number and distribution of sampling locations (wells and sands sampled) will be selected to provide sufficient spatial and vertical coverage given potential variation of water quality, within the limits of accessibility. The project puts an emphasis upon establishing a comprehensive dataset for site characterization related to the USDW zone prior to start of injection.

During the injection phase, the project does not propose regular monitoring of the lowest USDW zone and is not planning to drill any dedicated monitor wells for this zone initially. An emphasis is placed upon monitoring activities that enable the operator to identify early warning signs that indicate loss of containment before any CO_2 or displaced brine reaches the lowest USDW, which would then trigger additional monitoring or remediation activities (if needed, based on investigation). For instance, the Lower Miocene ACZM wells will provide the early warning for any vertical fluid movement through the top of the storage complex. Hence, during the injection phase, the timing of groundwater sampling event(s) will be primarily dependent upon project performance and evaluation of other TMP data, such as pressure from the ACZM wells or geophysical monitoring.

Table 5 outlines the planned monitoring methods, locations, and frequencies for gathering data on USDW.

6.2.2 Analytical Procedures

If a pressure anomaly is detected (triggers and thresholds to be defined post-appraisal) in the ACZM well pressure gauge, the anomaly will be evaluated. If it is determined that the anomaly appears to be real and related to project performance following the evaluation, this may trigger formation fluid sampling for geochemical analysis from the Lower Miocene formation from the

ACZM well(s). If pressure and fluid sample analysis confirm leakage into the strata overlying the Confining Zone, the procedures set out in the "*E.4-Emergency Remedial and Response Plan*" submitted in **Module E** will be implemented. In addition, dependent upon outcome of data evaluation, this may trigger collection and analysis of fluid samples from the USDW zone, along with other potential monitoring and remediation activities as appropriate.

Hence, in the unlikely event of loss of containment being detected and confirmed (*e.g.* ACZM wells or geophysical monitoring), all necessary steps will be taken to protect USDW. By prioritizing monitoring for early detection of containment issues at deeper zones immediately above the storage complex, pro-active measures can be more rapidly implemented to prevent endangering the USDW.

6.2.3 Sampling Methods

To ensure defensible data are generated during water sampling programs, best management practices / industry standard operating procedures will be employed (*e.g.* as per ISO 5667-11:2009, or EPA/240/B-06/001). Sample containers will be new and of an appropriate material and size for the analyte. Sufficient volumes will be collected to ensure selected analyses can be performed. Further details on QA/QC procedures can be found in **Appendix 1.**

The sampling system for collecting formation fluid sample from wells completed within the USDW will depend upon depth and setup of the well. Hence, sampling methods could range from using a downhole PVT sampler or equivalent tool, to deploying a pump within a well for sampling at surface or using an existing outlet of an active domestic use well. An appropriate sampling method will be chosen, on a well type of basis, when specific wells have been identified for sampling.

6.2.4 Analysis Procedures and Chain of Custody

Please refer to **Table 6** (see Section 6.1.4) for an overview of potential analytes that might be considered during pre-injection phase monitoring activities (final list still to be determined) and the analytical methods Shell may select to employ. The table of potential analytes will be finalized prior to authorization to inject.

Samples will be analyzed by a third party laboratory accredited by the Louisiana Department of Environmental Quality (https://internet.deq.louisiana.gov/portal/divisions/lelap/accredited-laboratories) using standardized procedures for gas, major, minor and trace element compositions.

The sample chain-of-custody procedures will be implemented. The procedures will document and track the sample transfer to the laboratory, to the analyst, to testing, to storage, to disposal (at a minimum). A sample chain-of-custody procedure is provided in **Appendix 1.**

7.0 EXTERNAL MECHANICAL INTEGRITY TESTING (MIT)

Shell will conduct at least one of the tests presented in **Table 7** periodically during the injection phase to verify external mechanical integrity in each injection well as required by §146.89(c) and §146.90, LAC §3627.A.3 and 3625.A (State of Louisiana). A demonstration of mechanical integrity will be made at least once a year during injection operations.

7.1 TESTING LOCATION AND FREQUENCY

The integrity of the long-string casing, injection tubing, and annular seal shall be tested by means of an approved pressure test for all injection wells. The integrity of the bottom-hole cement may be tested by means of a temperature survey or an approved tracer survey. Alternatively, a noise log may be run in the well to demonstrate containment within permitted injection zones. Pulsed neutron logging will be run to verify the mechanical integrity of the near-well area behind the casing.

Table 7. Mechanical Integrity Testing – Injection Wells

Test Description	Location
Temperature Survey **OR** Tracer Survey	Each Injection Well
	Each Injection Well
Pulsed Neutron Log	Each Injection Well
Annulus Pressure Test	Each Injection Well

Mechanical Integrity Tests (MIT's) will be run after the initial construction of the well prior to the initiation of injection operations. During injection operations the MITs will be performed on an annual basis within 45 days of the anniversary of the preceding year's test. Shell will notify the UIC Program Director ahead of testing. This schedule will repeat during the lifetime of the well during injection operations and prior to plugging operations. Should the well require a workover, a MIT will also be performed prior to placing the well back into service.

7.2 TESTING DETAILS

Prior to running an MIT, the wellbore annulus may be displaced with water or brine, in either case, the well will be allowed to thermally stabilize prior to all testing operations. It is recommended that the well be shut in for least 36 hours to allow temperature effects to dissipate. The external MIT logs will be run on all injection wells.

7.2.1 Temperature Survey

A baseline differential temperature survey will be run in the well after allowing the well a period of time to reach approximate static conditions. The temperature log is one of the approved logs for detecting fluid movement outside pipe. A baseline survey will be run during completion operations and will provide an initial baseline temperature curve for future comparisons. The log will include both an absolute temperature curve and a differential temperature curve. The well should be shut in at least 36 hours to allow for temperature stabilization prior to running the temperature survey.

If a distributed temperature sensing fiber is run in the injection wells, the fiber will be used for the temperature testing; otherwise, a wireline truck will be used.

If wireline operations are conducted, the temperature will be logged down from the surface to total depth in the well. Recommended line speed for the logging operations is 30 to 40 feet per minute. A correlation log(s) will be presented in Track 1, and the two temperature curves will be presented in Tracks 2 and 3. The temperature log will be scaled at or about 20° F (or 10° C degrees) per track. The differential curve will be scaled in a manner appropriate to the logging equipment design but will be sensitive enough to readily indicate temperature anomalies. In general, the procedure for wireline operations will be as follows:

1. Attach a temperature probe and casing collar locator (CCL) to the wireline.
2. After a minimum of 36 hours of well static conditions, begin the temperature survey. The tools will be lowered into well at 30 to 40 feet/minute, recording temperature in wellbore. The temperature survey will be run to the deepest attainable depth (top of solids fill) in the wellbore. The wireline may be flagged, if needed, to assist in depth correlation.

3. Following completion of the survey, the wireline tools will be retrieved from the wellbore.

A temperature log run will be considered successful if there are no unexplained temperature anomalies observed outside of the permitted injection zone.

If temperature anomalies are observed outside of the permitted zone, additional logging may be conducted to determine whether a loss of mechanical integrity or containment has occurred. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

7.2.2 Radioactive Tracer Survey

A Radioactive Tracer Survey (RTS) may be run as an alternative to the temperature survey. The tool consists of a gamma detector above the ejector port and one or two detectors below the ejector port. In order to run the RTS, the wellbore annulus will need to be flushed with brine and the test will be conducted using brine to convey the radioactive iodine tracer material. The tool will continuously record gamma ray API units during tracer fluid ejection. The upper detector will be recorded on Track 1 at a scale of 0 to 100 or 150 API units, and the lower detector(s) will be recorded on Tracks 2 and 3 at a higher (less sensitive) scale, typically 0 to 1,000 API units.

Prior to testing, an initial gamma ray baseline log will be recorded from at least 100 feet above the injection tubing packer to total depth of the well. The initial gamma ray survey can be made under low flow conditions or with the well in static conditions.

A concurrent casing collar locator log for depth correlation will be run on the wireline tool string. Two five (5) minute time drive statistical checks will be run prior to the ejection of tracer fluid. One of the statistical checks will be run in a confining unit immediately above the uppermost perforation in the well. The second check should be run within the injection zone sandstone. The baseline log and statistical checks will be run to determine background radiation prior to tracer fluid ejection.

Brine injection will be initiated or increased during testing operations. During the survey, brine injection rates will be set at the rate at which the fluid will be under laminar flow conditions, while remaining within the maximum permitted operating parameters anticipated for the well. The volume of the tracer fluid slug will be sufficient to cause a gamma curve deflection on the order of 25x background reading as the ejected slug passes the lower detector(s). This would typically be a full-scale deflection.

A constant injection (moving) survey will be run from above the packer to the perforations to check for leaks between those two points. This survey will consist of ejecting a tracer slug above the packer, verifying the tracer ejection, dropping down through the slug, and then logging up through the slug to above where the slug was first ejected. The tool will be successively dropped down through the slug again, and logging will continue upward to above where the slug was encountered on the previous pass. This process will be repeated a minimum of two times, until the slug flows out into the formation. If necessary, the injection rate may be adjusted to accomplish this test.

A stationary survey will be run approximately 20 feet or less above the top of the perforated interval to check for upward fluid migration outside the cemented casing. Flow during the stationary surveys will be at sufficient rates to approximate normal operating conditions anticipated for the well. The procedure consists of setting the tool and logging on time drive, ejecting a slug, verifying the ejection, and waiting an appropriate amount of time that would allow the slug to exit the wellbore and return through channels outside pipe, if present. 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 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 will be documented by logging up on depth drive, until the tracer exits the channel. The stationary survey should be repeated at least one time.

Additional stationary or moving surveys may be required, depending upon well construction, test results, or to investigate known problem conditions. At least two repeatable logs of every tracer survey, moving and stationary, should be run. On completion of the tracer surveys, a final background gamma log will be run for comparison with the initial background log. In general, the test procedure will be as follows:

1. Attach radioactive tracer tools, including casing collar locator (CCL), gamma ray detectors and ejector modules to the wireline. Lower tools in wellbore to total depth. Record the depth of solids fill in the well, if any. Correlate tools on depth with the injection packer and any other cased-hole log(s) run in the well.

2. A baseline gamma log will be run from deepest attainable depth to approximately at least 100 feet above the packer. Statistical tool checks will be conducted 10 feet above the set depth of the injection packer and approximately 15 feet above the top perforation. (*Specific depths will be identified ad updated after injection well(s) completion*).

3. With the tool set a minimum of 100 feet above the packer, start injecting brine fluid at approximately 50 gpm (or defined acceptable rate). Eject a slug of tracer material and verify ejection.

4. Lower the tool through the slug and log up through the slug. Repeat slug-tracking sequence, following the slug down the tubing and into the injection zone until the slug is dissipated.

Note: It is desired to achieve a minimum of three or more passes below the injection packer before the radioactive slug exits the perforations. Adjust or reduce injection rate if needed to achieve this objective.

5. Repeat Steps 3 and 4.

6. Position lower detector of RTS tool at approximately 15 feet above the top perforation. Initiate and maintain injection at approximately 250 gpm (or defined acceptable rate).

7. Eject a slug of tracer material and record on time drive for a minimum of 15 minutes to determine if upward flow around the casing occurs.

8. Repeat Step 7.

9. Cease pumping, lower the tool to the deepest attainable depth, and run a repeat baseline gamma ray log to verify that the radiation level has returned to background.

10. Dump remaining tracer material from the tool and pump remaining test fluid to flush the tracer material from the wellbore.

11. Retrieve the wireline tools from the wellbore and rig down wireline unit.

A successful pressure test will "PASS" if the radioactive iodine material stays within the Injection Zone and within the sequestration complex.

7.2.3 Pulsed Neutron Logging

Pulsed neutron logging will be run to verify the mechanical integrity of the near-wellbore area behind the casing in the injection wells. A baseline survey will be run during completion operations (with the well in completion configuration) and will provide an initial baseline log for future comparisons. Should the downhole well completion change at any time, a new baseline log will be run. The pulsed neutron survey will be run from the top of the confining zone, down to the total depth of the well and will be run in gas-sigma-hydrogen mode. The sigma measurement is used to determine porosity, differentiate between saline water and carbon dioxide, and calculate formation saturation in the Injection Zone(s). Shell may choose to run the Pulsed Neutron log annually for the first five years, and then every 5 years after that throughout the life of the wells.

7.2.4 Annulus Pressure Test

In conjunction with annual mechanical integrity testing, an annulus pressure test of the casing by tubing annulus will be made. 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 200 psig over the permitted maximum tubing/injection pressure. Conduct Annulus Pressure Test (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 lowered to the well's normal, safe differential pressure value and pressure recording equipment will be removed from the well system.

A successful pressure test will "PASS" if the pressure holds to +/-5 percent of the starting pressure. IF the test 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.

8.0 TRANSIENT PRESSURE FALLOFF TEST

Shell will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR §146.90(f) and LAC §3625.A.6 (State of Louisiana). Pressure fall-off testing will be conducted upon completion of each injection well to characterize baseline formation properties, as well as determine near well/reservoir conditions that may impact the injection of carbon dioxide.

8.1 FALLOFF TESTING LOCATION AND FREQUENCY

Shell will perform an initial (baseline) pressure fall-off 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 Injection Zone(s). The initial pressure fall-off testing will be repeated using carbon dioxide within the first 60 days of 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 carbon dioxide.

A pressure fall-off test will be performed at least once every five years (within approximately +/- 45 days of the anniversary of the previous test) for the lifetime of injection operations. Periodic testing is expected to provide insight into performance of the storage complex and potentially aid in assessing the dimensions of the expanding carbon dioxide plume, based on the expected lateral change from supercritical carbon dioxide near the wellbore and native formation brine beyond the plume. The UIC Program Director may request more frequent testing which will be dependent on test results. A final pressure fall-off test will be run after the cessation of injection into each injection well.

8.2 FALLOFF TESTING DETAILS

Testing procedures will follow the methodology detailed in "*EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002)*"[2]. Bottomhole pressure and temperature measurements near the perforations are 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

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

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. Examples of standard gauge specifications are contained in **Table 8**.

Table 8: Wireline Pressure Gauge Specification Examples

Pressure Gauge	Property	Value
Surface Readout Pressure Gauge	Range Resolution	0 – 10,000 psi/356 ºF +/-0.01 psi/0.01 ºF
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 ºF)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Readout Pressure Gauge	Range Resolution	0 – 10,000 psi/356 ºF +/-0.01 psi/0.01 ºF
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 ºF)
	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 (as proposed per injector) may be used if these provide data of sufficient quality:

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 pressure gauge (SRO) 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 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 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 fall-off test until radial flow conditions are confirmed. After confirmation of sufficient data acquisition, end fall-off test.

8. Pull SRO tool up out of the well at 1,000-foot increments and allow the gauge to stabilize (5 minutes each stop). Record 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; however, the analysis will be designed to consider all parameters and phases.

8.3 TEST ANALYSIS AND REPORTING

In order to make the proper assessment, multi-phase flow conditions will be considered. Results of the pressure fall-off test may trigger a reevaluation of the AoR. Testing methods, results, and interpretation will be submitted electronically within 30 days of the test per 40 CFR 146.91(e) and 146.91(b)(3)

Each submission will include the following.

1. Location, test name and the date and time of the shut-in period
2. Bottom hole pressure and temperature depths
3. Records of gauges
4. Raw test data in a tabular format (if required by the UIC Program Director)
5. Measured injection rates and pressure data from the test well and any off-set wells completed in the same zone and including data prior to the shut-in period
6. Pressure gauge information (make, model, manufacturer, *etc.)*
7. Diagnostic curves of test results, noting any flow regimes
8. Description of quantitative analysis of pressure-test results, type of software used and any multi-phase effects
9. Calculated parameter values such as transmissivity, permeability, and skin factor
10. Analysis and comparison of calculated parameter values to previous testing values
11. Identification of data gaps if any exist
12. Identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs

Testing procedures, testing equipment, tolerances and specifications, and calibration details are included in the QASP, which is contained in **Appendix 1.**

9.0 CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING.

Shell will employ both direct and indirect methods to track the geometry and extent of the carbon dioxide plume with time and the areal distribution in pressures within and above the sequestration complex to meet the requirements of 40 CFR §146.90(g) and LAC §3625.A.7 (State of Louisiana).

Table 9: Pressure-front and Plume-front Monitoring – Direct Monitoring Plan

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PRESSURE-FRONT MONITORING-DIRECT				
Frio Formation Injection Zone	Downhole Pressure and Temperature	Injection Well	Point of Injection	Continuous
Wilcox Formation Injection Zone*	Downhole Pressure and Temperature	Injection Well	Point of Injection	Continuous
Lower Tuscaloosa Formation Injection Zone	Downhole Pressure and Temperature	Injection Well	Point of Injection	Continuous
Lower Miocene Formation Above Confining Zone	Downhole Pressure and Temperature	2 above confining zone monitoring wells	Near point of injection	Continuous
IZ Monitoring Well**	Downhole Pressure and Temperature	North IZ Monitor Well	AoR – Updip of injection operations	Continuous
PLUME-FRONT MONITORING-DIRECT				
Lower Miocene Formation Above Confining Zone	Fluid Sampling	2 above confining zone monitoring wells	Near point of injection	Baseline: Adaptive, if triggered
IZ Monitoring Well**	Fluid Sampling	North IZ Monitor Well	AoR – Up dip of injection operations	Baseline: Adaptive, if triggered

**future injection in subsequent Class VI application.*

*** monitor well design not yet finalized. intent to monitor pressure of all injection targets (Frio, Wilcox & Lower Tuscaloosa) at a location offset from the injection location; sampling and logging capability will be installed where technically feasible; completion zones and functionality prioritized in-line with post-appraisal risk assessment. Additional (overburden) monitoring zones may be considered.*

Table 10: Pressure-front and Plume-front Monitoring - Indirect

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PRESSURE-FRONT MONITORING-INDIRECT				
NONE				

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PLUME-FRONT MONITORING-INDIRECT				
Frio, Wilcox, and Lower Tuscaloosa Formations	Repeat seismic method designed for plume tracking. May also detect overburden fluid changes	Well-based surveys focused on Injection Wells and potentially at Monitor Wells. DAS Fiber Optic Installation to be confirmed.	Azimuthal coverage of the plumes	Baseline, 1 year and 3-year repeats. Timing of subsequent repeats to be determined adaptively based on AoR model, risk assessment and other TMP data.
		Surface seismic as required over wider plume area (away from project well locations)	Adapted to plume extent and location (AoR model).	Baseline survey. Timing and area of any repeat survey dependent on plume prediction, risk assessment and survey objectives.

9.1 PLUME FRONT

Tables 9 and 10 summarizes the methods that Shell has proposed to employ to directly and indirection to monitor the migration of the sequestered carbon dioxide plume, including the activities, locations, and frequencies that will be employed. The parameters to be analyzed as part establishing a baseline for fluid samples and associated analytical methods are presented in **Table 6**. Quality assurance procedures for these methods are presented in **Appendix 1**.

9.1.1 Direct Monitoring Details

Direct monitoring of the CO_2 plume at distance away from the point of injection will be monitored with an In-Zone (IZ) monitor well up dip of injection operations (**Figure 1):**

Continuous pressure monitoring will be performed in the IZ monitoring well, and if an anomalous pressure response is detected then additional monitoring activities, such as cased hole logging or fluid sampling will be performed. Fluid samples would then be compared against the baseline analysis and to plume projections from the model to confirm plume arrival (or not). The well will be outfitted with continuous pressure gauges and will be completed to allow for fluid sampling of specific injection zones (Frio, Wilcox, or Lower Tuscaloosa) as applicable and feasible.

The IZ monitoring well will also have a transmitter gauge at surface to continuously record tubing pressure. Experience shows, such as at the Frio BEG Project, that carbon dioxide will rapidly evacuate the wellbore fluids in a monitoring well that is open to CO_2 in the Injection Zone. This will result in increased wellhead pressures due to the lighter column of gas replacing the brine fluid column.

Additional IZ monitoring wells may be considered if there is elevated pressure and/or if the injected volume rate increases. The monitor well design has not been finalized. Sampling and/or logging capability will be installed where feasible, and the functionality per injection zone in each well will be prioritized in-accordance with the post-appraisal risk assessment.

9.1.2 Indirect Monitoring Details

For indirect monitoring methods, Shell is proposing to use repeatable time-lapse seismic techniques, as the substitution of CO_2 for brine within sandstones at similar project depths is well documented to produce a strong change in acoustic impedance (Vasco et al., 2019). The goal of indirectly monitoring the Injection Zones is to constrain the geometry and size of the advancing carbon dioxide plume, and confirm that rate and direction of movement will not lead to future endangerment of the USDW (*e.g.* calibrate the plume model and confirm it is not expected to reach anything that might be a potential CO_2 leak risk). These monitor points provide site-specific and immediate data on the presence of carbon dioxide in the subsurface.

Leading-edge techniques for time-lapse imaging of the carbon dioxide plume include time-lapse walk away vertical seismic profiling, azimuthal vertical seismic profiling, and/or sparce array walk-away surveys.

At a minimum, the acoustic source sites will be oriented along the maximum and minimum orientations of the modeled plume and will be adjusted following each survey results. Distributed acoustic sensing (DAS) fiber may be installed in the monitoring wells, which will facilitate data acquisition activities. Baseline and subsequent time-lapse surveys will be processed using a technique that will resolve differences between surveys, which will be mapped to show the change in plume extent over time.

In addition, the use of fiber will allow very wide aperture of the acoustic array and so include surveillance of the Lower Miocene strata above the CO_2 plume to provide evidence that no out-of-zone CO_2 migration is occurring in this area.

The adaptive plume monitoring strategy will acquire two initial repeat surveys during the early injection phase. Years 1 and 3 are initially proposed, although this is subject to update post-appraisal when the pre-injection calibrated AoR model will confirm expected plume size versus time. These initial snapshots will be used to recalibrate the plume prediction model (also incorporating other TMP data) and reassess the risk assessment associated with the expanding plume area. The plume migration risk will be re-assessed using the updated model, and the timing of the next survey proposed to ensure timely identification on any unfavorable outcome *i.e.* the next survey will be acquired before the plume can reach any identified containment risk given the uncertainty range of the dynamic model. Hence, the results of each survey (along with the update of the AoR model and containment risk assessment) will inform the timing of the subsequent survey.

The timing of each subsequent survey will allow time for the operator to analyze the new data and take any remediation actions required to ensure protection of the USDW. A repeat survey might also be triggered by anomalous monitoring data (*e.g.* injection well integrity concerns) to confirm the injected CO_2 location and look for indications of CO_2 out of zone.

The survey area will be selected to meet the monitoring objectives of the data acquisition, and the seismic technique applied will be selected to deliver the scale and resolution requirements to deliver those objectives.

9.2 PRESSURE FRONT MONITORING

Table 10 presents the direct method that Shell has proposed to use to monitor the position of the pressure front, including the activities, locations, and frequencies that the St. Helena Parish site will employ.

Shell proposes to directly measure the injection pressure buildup in the Injection Zones in each of the installed facility wells. Additionally direct monitoring of the pressure buildup at an offset location away from the point of injection will be monitored with the IZ monitor well up dip of injection operations **(Figure 1):**

The IZ monitor well will be completed across the Lower Miocene formation (above Frio Confining Zone), as well as across all injection intervals, Frio, Wilcox, and Lower Tuscaloosa Formations. This in-zone monitoring point will also be used to evaluate the pressure decay with distance away from the injection well field.

These measured pressures from the injection wells and the offset monitor locations will be used to assess the performance of each injection zone to ensure that the project is operating as permitted and will form the basis for the periodic re-evaluation of the extent of the AoR. Recorded pressures at the injection wells and the monitor locations will be compared to model predictions to determine if actual data deviate from baseline predictions. Significant departures of actual pressure data compared to model predictions will be used to trigger an adaptive re-assessment of the AoR, in addition to the minimum 5-year re-assessment time frame specified for periodic review. In addition to a re-assessment of the AoR, deviations might trigger an investigative assessment of real-time data from the ACZM wells, and the TMP data, to ensure continued containment of carbon dioxide within the Sequestration Complex. Additional monitoring activities might also be triggered to confirm containment and USDW protection as necessary (Please see the "*E.4 -Emergency and Remedial Response Plan*" [40 CFR §146.94 (a)] submitted in **Module E** for details).

Quality assurance procedures for these methods are presented in **Appendix 1.**

10.0 SEISMICITY MONITORING

Natural seismicity in the project area is exceedingly low, with no recorded earthquakes in either St. Helena Parish or the immediately adjacent parishes (https://earthquake.usgs.gov/earthquakes/search/). Seismic risk of the area if detailed in Section 2.5 of the Site Characterization contained in **Module A.**

Induced seismicity risk is also low because of high transmissivity of the targeted Injection Zone(s) and the injection rates and pressure to be maintained at 90% of the fracture pressure or lower. Previous measurements of induced seismicity in the DOE supported research projects along the Gulf Coast (the Mississippi Cranfield Project, for example), have not detected induced seismicity events resulting from the injection of large volumes of carbon dioxide.

Therefore, the regional and local seismicity will be monitored annually for any change in frequency through the United States Geological Survey (USGS) National Earthquake Database (real time data available). If a change in frequency occurs, additional site-specific monitoring of local events be undertaken by Shell.

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FIGURES

THIS FIGURE HAS BEEN SUBMITTED CONFIDENTIAL BUSINESS

SHELL US GAS & POWER, LLC

FIGURE 1: Monitoring Well Network Layout
St. Helena Parish Site

ST. HELENA PARISH, LOUISIANA

GEODETIC DATUM: NAD27 SP LA S PROJECTION: LAMBERS CONFORMAL CONIC GRID UNITS: FEET	SCALE INFO: (IF APPLICABLE)

DATE: 11/22/2022	PROJECT NAME: 220017SEL	BY: GKS CHECK BY: SHELL	SHEET 1 OF 1

Geostock Sandia

Appendix 1: Quality Assurance and Surveillance Plan (QASP)

Appendix 1: Quality Assurance and Surveillance Plan (QASP) Submitted under the Appendices and Supporting Matierals Upload