TESTING AND MONITORING PLAN
40 CFR 146.90 (LAC 43:XVII.3625)

Venture Global CCS Cameron, LLC CO_2 Sequestration Project

Facility Information

Facility Name: Venture Global CCS Cameron, LLC CO_2 Sequestration Project

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Well Location: West Cameron Block 5, CS004 Well 001, Cameron Parish, Louisiana
[redacted]

This Testing and Monitoring Plan describes how Venture Global CCS Cameron, LLC (Venture Global) will monitor the Venture Global CCS Cameron, LLC CO2 Sequestration Project (Project) site pursuant to 40 CFR 146.90 (LAC 43:XVII.3625). In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are behaving as predicted, and that there is no endangerment to underground sources of drinking water (USDWs), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO2 within the storage zone to support area of review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to Module 6 Emergency and Remedial Response Plan.

1 Overall Strategy and Approach for Testing and Monitoring

The operating plans for the proposed CS004 Well 001 include robust testing and monitoring programs designed to satisfy the requirements of 40 CFR 146.90 [LAC 43:XVII.3625.A]. This section discusses the key details of the testing and monitoring program as well as the reporting requirements.

The depositional environment and offshore location of the proposed CO_2 injection well limit the effectiveness of in-zone monitoring wells. As such, alternative technologies are proposed for monitoring plume growth and behavior.

For direct monitoring as required by 40 CFR 146.90(g)(1) [LAC 43:XVII.3625.A.7.a], continuous acquisition of subsurface pressure and temperature will be documented and evaluated to define and monitor reservoir conditions. Indirect monitoring as required by 40 CFR 146.90(g)(2) [LAC

43:XVII.3625.A.7.b] to track the extent of the carbon dioxide plume and the pressure front, vertical seismic profile (VSP) surveys will be conducted around the CO_2 injection well. The VSP surveys will identify density changes within the various injection intervals between survey efforts.

Per 40 CFR 146.90(j) [LAC 43:XVII.3625.A.10], the testing and monitoring plan will be reviewed and revised as needed, but no less than once every five years. Plan amendments or demonstration of continued applicability of the existing plan will be submitted as follows:

- within one year of an AoR reevaluation per 40 CFR 146.84(e) [LAC 43:XVII.3615.C.2];
- following any significant facility changes, such as addition of monitoring wells or newly permitted injection wells within the AoR, on a schedule determined by the Director; or
- when required by the Director.

1.1 Area of Review and Associated Risks

The AoR is defined by the EPA as the superposition of the maximum extent of the separate-phase plume (pore occupancy plume) and the pressure front where the pressure buildup is of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW. Both parts of this definition were analyzed for the Project AoR. The Equation-of-State (EoS) reservoir simulator GEM was utilized to model the injectivity of CO_2 from the [redacted] planned injection stages of the proposed CS004 Well 001 into the Miocene sands of the Gulf Coast depositional environment and the subsequent plume migration away from the well through time. This modeling delineated the CO_2 plume and pressure front depth from [redacted].

The testing and monitoring strategy is site-specific to the regional site characterization and identified risks. The high permeability Middle and Lower Miocene sandstones are overlain by a vertically and laterally thick marine shale identified as a sealing interval in the Offshore CO_2 Storage Resource Assessment by the U.S. Department of Energy National Energy Technology Laboratory (Trevino and Meckel, 2019). This natural barrier provides an ideal trap for long-term CO_2 storage. The region is a geomechanically stable low stress domain in an area of low seismic risk.

Legacy wells within the modeled AoR were evaluated for their completions, plugging strategies, and construction materials to assess their risk to long-term CO_2 storage. [redacted]. A detailed corrective action plan for reentering and additional plugging operations is provided in Module 2 Area of Review and Corrective Action Plan of this permit application (Application). The planned engineered barrier to the risk of leakage to CO_2 into the USDW for these [redacted] wells is a combination of acid resistant cement (ARC), corrosive resistant alloys (CRA), and thermite plugs that will be used to seal the wellbores and fuse the casing/plugging material with the surrounding formation. The location of these [redacted] wells and the details of this corrective action are provided in Module 2 Area of Review and Corrective Action Plan.

Offshore Louisiana is susceptible to major storm events that have the potential risk of temporarily limiting access to the well site; however, thorough planning of the platform design, including requirements for wind loads and independent power for safety and emergency systems, and weather monitoring procedures will mitigate this risk.

Although the plume is modeled to remain offshore, the unlikely event of leakage could have a negative effect on nearby shallow marine ecosystems. Details of the emergency identification and response actions to be undertaken in the unlikely event of leakage are provided in Module 6 Emergency and Remedial Response Plan of this Application.

As set out in Module 8 Pre-Operation Testing Program, a rigorous testing and logging program will be conducted during drilling, casing installation, and after casing installation. These baseline cased hole tests and logging measurements will be compared to identical tests and logging measurements made at scheduled intervals and at recompletion during the injection phase as per 40 CFR 146.87(d)(1) [LAC 43:XVII.3617.B.4.a], 40 CFR 146.87(e)(3) [LAC 43:XVII.3617.B.5.c], 40 CFR 146.89(d) [LAC 43:XVII.3627.A.4], and 40 CFR 146.90(a) [LAC 43:XVII.3625.A.1]. Further, data recorded by the continuous monitoring technologies during initial injection will be verified by baseline measurements where applicable. During the period of sustained injection, the scheduled tests and logging will be assessed to confirm plume migration extent and timing are consistent with predictions.

Table 1 is a summary of the site-specific storage risks and their rating using the standard stoplight hazard color scheme shown in the legend. The identified risk ranking details for well integrity, site characterization, fluid reactions, fracture and fault stability, surface facilities, and environment are provided in Appendix A.

[redacted]

Qualitative Risk Matrix
Definitions (Likelihood)

VENTURE GLOBAL LNG

	Definition
E Likely	This event can reasonably be expected to occur several times during the life of the facility
D Probable	This event can reasonably be expected to occur at least once during the life of the facility
C Possible	This event might occur once during the life of the facility
B Unlikely	This event is not expected to occur during the life of the facility
A Rare	This event has occurred at least once within industry OR is not normally considered a credible event

Qualitative Risk Matrix
Definitions (Severity)

VENTURE GLOBAL LNG

	Health and Safety Impact	Environmental Impact	Reputational Impact *	Project, Asset, & Production Loss *
5 Catastrophic	• *Workforce*: Multiple Permanent Total Disabilities or Multiple Fatalities ***OR*** • *Public*: One or More Fatalities	• Extensive damage. • Major loss of containment with severe escape to the environment. • A spill or release causing major and sustained pollution external to the site.	• Major international impact. • Potential to severely impact future business.	• *Project*: >3 months delay • *Operations*: > 30 Days Equivalent Production
4 Severe	• *Workforce: Permanent Total Disability or Single Fatality* ***OR*** • *Public: Permanent Partial or Total Disability, or Days Away from Work Case*	• Major damage. • Loss of containment with severe escape to the environment. • A spill or release causing significant pollution offsite.	• Major national impact. • Numerous complaints. • Extensive negative attention in local media. • National press and TV coverage.	• *Project*: 2–3 months delay • *Operations*: > 10 Days Equivalent Production
3 Significant	• *Workforce*: Permanent Partial Disability or Days Away from Work Case ***OR*** • *Public*: Medical Treatment or Restricted Work Case	• Local damage. • Loss of containment with significant escape to the environment. • A spill or release with the potential to cause moderate onsite pollution and some offsite pollution (but of a limited extent in area/duration) requiring remediation work.	• Considerable impact. • Regional public concern. • Numerous complaints received. • Extensive negative attention in local and regional media.	• *Project*: 1–2 months delay • *Operations*: > 5 days Equivalent Production
2 Minor	• *Workforce*: Medical Treatment or Restricted Work Case ***OR*** • *Public*: First Aid Case	• Minor damage. • Loss of containment with minor escape to the environment.	• Limited space. • Some local public concern. • Some complaints received. • Slight coverage by media.	• *Project*: > 1 week – 1 month delay • *Operations*: > 1 Day Equivalent Production
1 Negligible	• *Workforce*: First Aid Case ***AND*** • *Public*: No Impact	• No damage to slight damage. • Loss of containment with no escape to the environment.	• No impact to slight impact. • Little public awareness of the incident. • There is not public concern. • No media reaction.	• *Project*: < 1 week delay • *Operations*: < 1 Day Equivalent Production

** Note: Reputational Impacts and Project, Asset, and Production Loss are not to be correlated to HSE Impacts*

1.2 Quality assurance procedures

Venture Global will implement Quality Assurance / Quality Control (QA/QC) measures for fluid sampling procedures, such as collection of duplicate samples or trip blanks. These measures will be used to validate test results and ensure samples were not contaminated. Similarly, QA/QC methods will be provided for all wellbore testing and logging operations, VSP seismic data acquisition, and for data recorded continuously via fiber optic cable. Venture Global has provided a Quality Assurance and Surveillance Plan (QASP) per 40 CFR 146.90 [LAC 43:XVII.3625] and addresses the foregoing in Section B.2 of that plan.

1.3 Reporting procedures

Venture Global will report the results of all testing and monitoring activities to the Director in compliance with the requirements under 40 CFR 146.91 [LAC 43:XVII.3629]. The content and frequency of these reports is summarized below:

Per 40 CFR 146.91(c) [LAC 43:XVII.3629.A.3], Report, within 24 hours:

- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW.
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.
- Any triggering of a shut-off system (i.e., downhole or at the surface).
- Any failure to maintain mechanical integrity.
- For surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of CO_2 to the atmosphere or biosphere.

Per 40 CFR 146.91(b) [LAC 43:XVII.3629.A.2], Reports to be submitted within thirty (30) days after the following events:

- Periodic tests of mechanical integrity.
- Any well workover.

Any other test of the injection well, if required by the Director, per 40 CFR 146.91(a) [LAC 43:XVII.3629.A.1], Semi-annual Reports:

- Physical, chemical, and other relevant characteristics of injection fluids.
- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure.
- Monthly volume and/or mass of the CO_2 stream injected over the reporting period and the volume injected cumulatively over the life of the project.
- Monthly annulus fluid volume added.
- Results of any monitoring as described in *40 CFR 146.90* ***[LAC 43:XVII.3625]***.
- Groundwater quality monitoring

- Plume and pressure front tracking

Per 40 CFR 146.91(d) [LAC 43:XVII.3629.A.4], Notification to the Director, in writing, thirty (30) days of advance of:

- Any planned workover.
- Any planned stimulation activities, other than stimulation for formation testing conducted under 40 CFR 146.82 [LAC 43:XVII.3607.A].
- Any other planned test of the injection well.

Venture Global will submit all reports, submittals, and notifications to both the EPA and LDNR, and will ensure that all records are retained throughout the life of the project as required by regulation. Per 40 CFR 146.91(f) [LAC 43:XVII.3629.A.4], records (all data collected under 40 CFR 146.82 [LAC 43:XVII.3607.A], such as injected fluid data, including nature and composition, well-plugging reports, post-injection site care data and the site closure report) will also be maintained for a ten (10)-year period after site closure, except for monitoring data which will be retained for ten (10) years post-collection. The records can be delivered to the Director upon request.

1.4 Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

Per 40 CFR 146.90(a) [LAC 43:XVII.3625.A.1] requirements, Venture Global will acquire samples of the CO_2 injection stream and evaluate any potential interactions of CO_2 and other injectate components. Venture Global will sample and analyze the CO_2 stream as presented below.

1.4.1 Sampling Location and Frequency

CO_2 stream samples will be collected from the CO_2 pipeline in a location representative of injection conditions. A sampling station will be connected to the pipeline at a sampling manifold, and sample cylinders will be purged with the injectate gas to expel laboratory-added gas and confirm a quality sample collection.

CO_2 injection stream samples will be taken quarterly for chemical analysis of the parameters listed in Table 2, in addition to continuous pressure and temperature analysis. The sampling will be conducted by the following dates each year:

- Three (3) months after the date of authorization of injection,
- Six (6) months after the date of authorization of injection,
- Nine (9) months after the date of authorization of injection, and
- Twelve (12) months after the date of authorization of injection.

1.4.2 Analytical parameters

Venture Global will analyze the CO_2 for the constituents identified in Table 2 using the methods listed.

[redacted]

1.4.3 Sampling methods

CO_2 stream sampling will occur in the compression facility after the last stage of compression. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the authorized laboratory.

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.

1.4.4 Laboratory to be used/chain of custody and analysis procedures

Samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of-custody procedures described in Section B.3 of the QASP will be employed.

2 Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 40 CFR 146.89(b) and 40 CFR 146.90(b)]

Venture Global will use continuous recording devices to ensure that continuous monitoring of the injection pressure, rate and volume, and annulus pressure are in compliance with 40 CFR 146.88(e)(1) [LAC 43:XVII.3621.A.6], 40 CFR 146.89(b) [LAC 43:XVII.3627.A.2], and 40 CFR 146.90(b) [LAC 43:XVII.3625.A.2] requirements.

A Supervisory Control and Data Acquisition system (SCADA) will be installed at the CO_2 injection well site to facilitate the operational data collection, monitoring, and reporting. Continuous monitoring of the injected carbon dioxide stream pressure and temperature will be performed using digital pressure and temperature gauges installed in the CO_2 pipeline near the pipeline-wellhead interface.

An on-site SCADA system will be connected to the pipeline, and a Coriolis mass flow transmitter used to measure the injected CO_2 mass flow rate will be installed on the injection well platform. It will be connected to the SCADA system at the CO_2 storage site control room to ensure continuous monitoring and control of the CO_2 injection rate and computation of injected volume.

The flowmeter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The flowmeter will be calibrated for the entire expected range of flow rates. The flowmeter will be equipped with a totalizer providing a running total of CO_2 volume (the amount of CO_2 that has passed by the sensor as a function of time).

Fiber-optic distributed temperature sensing (DTS) and fiber-optic distributed acoustic sensing (DAS) will be installed behind the casing for real time conveyance of DTS/DAS sensor data from total depth to the location of the SCADA system.

Pressure and temperature gauges will be installed (and cemented) outside the [redacted] casing (and ported to the inside) in each injection interval to provide real time bottom hole injection pressure and temperature. An additional gauge will be installed above the packer and ported to the annulus to provide real time measurements of annular pressure.

2.1 Monitoring location and frequency for internal mechanical integrity

Venture Global will perform the activities identified in Table 3 to verify internal mechanical integrity of the injection well and monitor operational parameters injection pressure, rate, volume, and annular pressure as required at 40 CFR 146.88(e)(1) [LAC 43:XVII.3621.A.6], 40 CFR 146.89(b) [LAC 43:XVII.3627.A.2], and 40 CFR 146.90(b) [LAC 43:XVII.3625.A.2]. All monitoring will take place at the locations and frequencies shown in the table. All monitoring will be continuous for the duration of the operation period, and at the locations shown in the table. The injection well will have pressure/temperature gauges at the surface and along the casing at the injection zones and at the packer housed within fiber optic/TEC monitoring cable.

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

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure		Surface	[redacted]	[redacted]
Annular Pressure		Surface	[redacted]	[redacted]
Temperature		Surface	[redacted]	[redacted]
Injection rate	Coriolis mass flowmeter	Surface	[redacted]	[redacted]
Injection volume	Coriolis mass flowmeter	Surface	[redacted]	[redacted]
Annular pressure	Downhole Pressure Temperature Gauge	Installed outside the [redacted] casing above the packer and ported to the annulus	[redacted]	[redacted]
Annulus fluid volume	Downhole Pressure Temperature Gauge	Installed outside the [redacted] casing above the packer and ported to the annulus	[redacted]	[redacted]
Injection pressure	Downhole Pressure Temperature Gauge	Installed outside the [redacted] casing and ported to the inside in each injection interval	[redacted]	[redacted]
CO_2 stream temperature	Downhole Pressure Temperature Gauge	Installed outside the [redacted] casing and ported to the inside in each injection interval	[redacted]	[redacted]

Notes:

- 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.
- 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.

2.2 Monitoring details

Above-ground pressure and temperature instruments shall be calibrated annually over the full operational range using ANSI or other recognized standards. To demonstrate the accuracy of the downhole gauges, on an annual basis, a second pressure gauge, with current certified calibration, will be lowered into the well to the same depth as the permanent downhole gauge. Pressure transducers will be considered accurate with a drift stability of less than 1 psi over the operational period of the instrument and an accuracy of ± 5 psi. [redacted]

[redacted] Temperature sensors will be accurate to within one degree Celsius. [redacted].

2.2.1 *Injection Rate Pressure Monitoring*

All critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system.

Venture Global will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination for trends to help determine any need for equipment maintenance or additional calibration, and semi-annual reports of the monitoring data will be submitted pursuant to 40 CFR 146.91(a) [LAC 43:XVII.3629.A.1].

2.2.2 *Calculation of Injection Volumes*

Flow rate is measured on a mass basis (kg/hr). The downhole pressure and temperature data will be used to perform the injectate density calculation.

The volume of carbon dioxide injected will be calculated from the mass flow rate obtained from the mass flow meter installed on the injection line. The mass flow rate will be divided by density and multiplied by injection time to determine the volume injected as follows:

Volume basis (m^3/hr) = Mass basis (kg/hr) / density (kg/m^3)

2.2.3 *Continuous Monitoring of Annular Pressure*

The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus for perforation Stage 1:

1. The annulus between the tubing and the long string of casing will be filled with brine. [redacted] The brine will contain a corrosion inhibitor.
2. The surface annulus pressure will be kept at a minimum of [redacted] psi during injection.
3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least [redacted] psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer set at [redacted] ft TVDSS.
4. The pressure within the annular space, in the fluid column from the packer to the confining layer, will be always greater than the pressure of the injection zone formation.
5. The pressure in the annular space directly above the packer will be maintained at least [redacted] psi higher than the adjacent tubing pressure during injection.

The annular monitoring system consists of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen or CO_2.

The predicted annulus pressures are given in Table 4 for each perforation stage and injection interval. The annulus pressure will be maintained between approximately [redacted] psi for Stage [redacted] and monitored by the control system gauges. The annulus head tank pressure will be controlled by pressure regulators–one set of regulators to maintain pressure above [redacted] psi by adding compressed nitrogen or CO_2 and the other to relieve pressure above [redacted] psi by venting gas off the annulus head tank. The same procedure will be followed for each stage and injection intervals using predicted annulus pressures and maximum wellhead injection pressures.

Table 4: Predicted Annulus Pressures for Each Perforation Stage and Injection Interval

Perforation Stage	Injection Interval (TVDSS)	Net Injection Interval, (ft)	Max Wellhead Injection Pressure (psi)	Max Bottomhole Pressure (psi)	Start of CO_2 Injection (@ static condition)		During CO_2 Injection	
					Annular Pressure (psi) (surface)	Annular Pressure (psi) (@ packer)	Annular Pressure (psi) (surface)	Annular Pressure (psi) (@ packer)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Any changes to the composition of annular fluid will be reported in the next report submitted to the Director.

Average annular pressure and annulus tank fluid level monitoring will be continuous and recorded daily. The volume of fluid added or removed from the system will be recorded. There will be full redundancy in communication between the onshore control center and offshore platform Programmable Logic Controller (PLC). The loss of the primary signal does not affect the injection operation on the offshore platform as long as the second signal is still functioning. If the primary signal does not recover, personnel will be dispatched to the platform for diagnosis and repair. In the case that the redundant communication is lost, the PLC on the platform will initiate the system shutdown by closing the emergency shutdown valve within a specified time, the tree valves, and then venting of hydraulic circuits. If the redundant communication does not recover within 24 hours, the Surface Controlled Subsurface Safety Valve (SCSSV) will be closed. A detailed emergency shutdown logic and timing will be developed in the detailed design phase.

2.2.4 Casing-Tubing Pressure Monitoring

Venture Global will monitor the casing-tubing pressure for each injection stage described in Module 7 Construction Details as presented below.

During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. Surface pressure of the casing-tubing annulus is anticipated to be from [redacted] psi. As detailed in Module 6 Emergency and Remedial Response Plan to this Application, significant changes in the casing-tubing annular pressure attributed to well mechanical integrity will be investigated.

Collection and recording of monitoring data will occur at the frequencies described in Table 5. Venture Global will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination for trends to help determine any need for equipment maintenance or calibration, and semi-annual reports of the monitoring data will be submitted.

Table 5: Sampling and Recording Frequencies for Continuous Monitoring.

Well Condition	Minimum sampling frequency: once every (1)(4)	Minimum recording frequency: once every (2)(4)
For continuous monitoring of the injection well when operating:	[redacted]	[redacted]
For the injection well when shut-in:	[redacted]	[redacted]

Note 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.

Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Note 3: This can be an average of the sampled readings over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified over that recording interval.

Note 4: DTS sampling frequency is once every 10 seconds and recorded on an hourly basis.

3 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c) [LAC 43:XVII.3625.A.3], Venture Global will monitor well materials during the operation 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.

Venture Global will monitor corrosion using Corrosion Coupons and collect samples according to the description below.

3.1 Monitoring location and frequency

Corrosion coupon monitoring will occur quarterly, by the following dates each year:

- Three (3) months after the date of authorization of injection,
- Six (6) months after the date of authorization of injection,
- Nine (9) months after the date of authorization of injection, and
- Twelve (12) months after the date of authorization of injection.

This quarterly evaluation of a corrosion coupon monitoring system will be performed in addition to the examination of casing inspection logs conducted every five (5) years with permit renewal.

3.2 Sample description

Corrosion coupons, comprising the same material as the construction of the compression equipment, injection tubing, and long-string casing, will be placed in the CO_2 injection pipeline. The samples consist of those items listed in Table 6.

Table 6: List of Equipment Coupon with Material of Construction.

Equipment Coupon	Material of Construction
Pipeline	[redacted]
Long String Casing (Surface – [redacted]')	[redacted]
Long String Casing ([redacted]' – TD)	[redacted]
Injection Tubing	[redacted]
Wellhead	[redacted]
Packers	[redacted]

3.3 Monitoring details

3.3.1 Sample Exposure

Each sample will be attached to an individual holder designed to be inserted in a flow-through pipe corrosion coupon rack to provide side stream monitoring. The corrosion monitoring will be located at the beginning of the CO_2 injection pipeline to the wellhead downstream of all process compression/dehydration/pumping equipment. This location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. A parallel stream of high-pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring and will allow for continuation of injection during sample removal. The configuration and location of the corrosion monitoring system will be included in the pipeline design.

3.3.2 Sample Handling and Monitoring

The coupons will be handled and assessed for corrosion on a quarterly basis using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons will be photographed, visually inspected with a minimum of 10x power, dimensionally measured (to within 0.0001 inch), and weighed (to within 0.0001 gram). The corrosion rate will be estimated by applying a weight loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

To augment the quarterly inspection of the pipe material, casing inspection logs will be performed every five (5) years or at recompletion, providing the condition of the casing to verify corrosion coupon monitoring method. An ultrasonic pulse echo casing evaluation tool employing a rotating transducer for 360-degree assessments will be used to deliver high-resolution measurements to detect casing problems including drill wear, ovality, and corrosion. The casing inspection log will be used to determine the thickness, external condition, and internal condition of the long string casing for its entire length.

4 Above Confining Zone Monitoring

Venture Global will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d) [LAC 43:XVII.3625.A.4].

A groundwater monitoring well, CS004 Monitor Well 001, will be drilled offshore within the AoR perforating into the lowermost sand above the Upper Confining Interval (UCI) (Figure 1). The location of the above zone monitoring well was selected such that its platform is optimally sited for the possible construction of an additional deeper in-zone monitoring well to monitor plume saturation post injection (see Figure 3). The bottomhole location and the arrangement and depth location of permanent sensors in this optional monitoring well will be determined prior to construction.

Pre-completion, open hole logging of CS004 Monitor Well 001 will be performed over the interval [redacted] ft to ensure the perforation location is in the first reasonably permeable formation above the confining zone (i.e., the first formation from which fluids can be extracted at appreciable volumes for sampling and analysis). Post-completion, cased hole logging will be performed over the intervals [redacted] ft to provide baseline measurements for subsequent additional logging as necessary.

Groundwater samples will be routinely collected from this depth to monitor for signs of CO_2 leakage. This vertical monitoring well is located within the projected plume extent. In addition to enabling wireline deployed sampling of water groundwater for water chemistry analysis, this well will continuously monitor pressure of the first mappable sand identified above the UCI. Any deviations from baseline pressures will initiate additional investigations in the area.

[redacted]

4.1 Monitoring location and frequency

Table 7 shows the planned monitoring methods, locations, and frequencies for groundwater quality geochemical and pressure monitoring above the confining zone.

Table 7: Direct Monitoring of Groundwater Quality and Geochemical Changes above the Confining Zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
First mappable sand identified above the Upper Confining Interval (UCI)	Fluid chemistry sampling	CS004 Monitor Well 001	[redacted]	Baseline Year 1-2: Quarterly Year 3-30: Semi- Annual
First mappable sand identified above the Upper Confining Interval (UCI)	Downhole pressure/temperature gauge	CS004 Monitor Well 001	1 point location at [redacted]	Continuous

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
First mappable sand identified above the Upper Confining Interval (UCI)	DTS	CS004 Monitor Well 001	Distributed measurement from [redacted]	Continuous

4.2 *Analytical parameters*

Table 8 identifies the parameters to be monitored and the analytical methods Venture Global will use.

Table 8: Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods (1)
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry. An equivalent method may be employed with the prior approval of the UIC Program Director

Sampling will be performed as described in Section B.2 of the QASP; this section of the QASP describes the groundwater sampling methods to be employed, including sampling Standard operating Procedures (SOPs) (Section B.2.a/b), and sample preservation (Section B.2.g).

Sample handling and custody will be performed as described in Section B.3 of the QASP. Quality control will be ensured using the methods described in Section B.5 of the QASP.

4.3 *Sampling methods*

Fluid samples will be acquired from CS004 Monitor Well 001 at monitored formation temperatures and maintained at formation pressures within a pressurized container. This step is taken to ensure that dissolved gas losses do not occur. Venture Global will perform static fluid level and temperature measurements prior to sampling. A sampling flask will be lowered into the monitored zone using wireline or slickline.

Sampling will be performed as described in Section B.2 of the QASP; this section of the QASP will describe the groundwater sampling methods to be employed, including sampling SOPs (Section B.2.a/b), and sample preservation (Section B.2.g).

Sample handling and custody will be performed as described in Section B.3 of the QASP. Quality control will be ensured using the methods described in Section B.5 of the QASP.

4.4 Analytical methods

Venture Global will test water samples and maintain results for the parameters listed in Table 8. If results indicate the existence of impurities in the injectate, groundwater samples will also be tested to flag any concentrations exceeding the baseline. Testing results will be stored in an electronic database.

Potential signs that fluid may be leaking from the injection interval(s) may be detected upon observation of the following trends:

- Change in Total Dissolved solids
- Changing signature of major cations and anions
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increase concentration of leached constituents
- Increased reservoir pressure and/or static water levels

4.5 Laboratory to be used/chain of custody procedures

Water samples will be submitted to a Director-approved laboratory. Venture Global will observe standard chain-of-custody procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including problems encountered.

4.5.1 Quality Assurance and Surveillance Measures

Venture Global will collect duplicate samples and field blanks, i.e., samples that “travel” with the test samples to and from the sampling lab to ensure there is no contamination during travel. These will be used to validate test results and ensure samples have not been contaminated.

4.5.2 Plan for Guaranteeing Access to All Monitoring Locations

Placement of the well location entirely under shallow water results in extremely restricted access to the well. Unauthorized access will be prevented.

4.5.3 Reporting

Groundwater quality monitoring results will be reported semi-annually in compliance with 40 CFR 146.91(a).

5 External Mechanical Integrity Testing

In adherence to the requirements of 40 CFR 146.89(c) [LAC 43:XVII.3627.A.3], Venture Global will perform an annual external mechanical integrity test (MIT) up to forty-five (45) days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the Director.

Venture Global will monitor mechanical integrity using Temperature Logging according to the description below.

5.1 Testing location and frequency

Venture Global will conduct a temperature log, through tubing. Temperature logs will be run before initiating injection operations to establish a baseline against which future logs can be compared. Subsequent temperature log MITs will follow the same procedures outlined below as designed for the baseline MIT temperature log test.

All temperature logs recorded during the MIT will be submitted to the Director within thirty (30) days of log run completion.

5.2 Testing details

5.2.1 Temperature Logging Using Wireline

The well will be shut in for a duration of approximately thirty-six (36) hours prior to running the temperature logs to allow temperatures to stabilize. Satisfactory mechanical integrity is demonstrated by proper correlation between the baseline and subsequent logs.

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. The following procedures, will be employed for temperature logging:

The well should be in a state of injection for at least six (6) hours prior to commencing operations to cool injection zones. The procedure is as follows:

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a temperature survey from the base of the surface casing to the deepest point reachable in the well while injecting at a rate that allows for safe operations.
3. Stop injection, pull tool back to shallow depth, wait 1 hour.
4. Run a temperature survey over the same interval as step 2.
5. Pull tool back to shallow depth, wait 2 hours.
6. Run a temperature survey over the same interval as step 2.
7. Pull tool back to shallow depth, wait 2 hours.
8. Run a temperature survey over the same interval as step 2.

9. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the topmost section of the log, additional logging runs over a higher interval will be required to find the top of migration.
10. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 2.
11. Rig down the logging equipment.

Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity (i.e., tubing leak or movement of fluid behind the casing). As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

5.2.2 Temperature Logging Using DTS Fiber Optic Line

CS004 Well 001 will be equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the long string casing. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone.
2. During injection operation, record the temperature profile for 6 hours prior to shutting in the well.
3. Stop injection and record temperature profile for 6 hours.
4. Evaluate data to determine if additional cooling time is needed for interpretation.
5. Start injection and record the temperature profile for 6 hours.

Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity (i.e., tubing leak or movement of fluid behind the casing). The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down the temperature profile along the length of the casing is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. These data can be continuously monitored to provide real time MIT surveillance making this technology superior to wireline temperature logging.

6 Pressure Fall-Off Testing

Venture Global will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f) [LAC 43:XVII.3625.A.6]. The tests will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

6.1 Testing location and frequency

Venture Global will perform a required pressure falloff test after each recompletion or at least once every five (5) years during the injection phase. All pressure falloff test results will be submitted to the Director within thirty (30) days of test completion.

6.2 Testing Method

The injection rate and pressure will be held as constant as possible prior to the beginning of the test, and continuous data will be recorded during testing. Once the well has been shut in, continuous pressure measurements will be taken via a bottomhole pressure gauges. The falloff period will end once the pressure decay data plotted on a semi-log plot is a straight line, indicating radial flow conditions have been reached.

A pressure falloff test has a period of Injection followed by a period of no-injection or shut-in. Normal injection using the stream of CO_2 captured from the CP2 LNG and Calcasieu Pass facilities will be used during the injection period preceding the shut-in portion of the falloff tests.

The normal CO_2 injection rate is estimated to be 2,740 metric tonne/day. Prior to the falloff test, this rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased.

At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis. These data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition, or a pressure gauge will be conveyed via electric line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at five second intervals or less for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time.

Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure falloff test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (0.5% accuracy across full range). Wellhead pressure gauge range will be 0-4,000 psi. Downhole gauge range will be 0-10,000 psi.

6.2.1 <u>Analytical Methods</u>

Near-wellbore conditions, such as the prevailing flow-regimes, well skin, and hydraulic property and boundary conditions, will be determined through standard diagnostic plotting. This determination is accomplished via analysis of observed pressure changes and/or pressure derivates on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by the comparison of pressure falloff tests prior to initial injection with later tests. The effects of two-phase flow effects will also be considered. Such well parameters resulting from falloff testing will be compared against those used in AoR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AoR reevaluation is necessary.

A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the Director within thirty (30) days of test completion.

6.2.2 Quality Assurance/Control

All field equipment will undergo inspection and testing prior to operation. Manufacturer calibration recommendations will be adhered to during the use of pressure gauges in the falloff test. Documentation certifying proper calibration will also be enclosed with the test results.

7 Carbon Dioxide Plume and Pressure Front Tracking

Venture Global will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g) [LAC 43:XVII.3625.A.7].

Venture Global proposes a two-tiered system for both plume and pressure front tracking, per the operational monitoring requirements of 40 CFR 146.90(g) [LAC 43:XVII.3625.A.7]. A vertical Deep Monitoring Well, CS004 Monitor Well 002 will be drilled from the West Cameron Block 5 CS004 Well 001 platform and used to directly monitor the plume pressure front (Figure 2). Pre-completion, open hole logging of Well CS004 Monitor Well 002 will be performed over the interval [redacted] ft to enable precise location of successive perforations into the injection zone at each completion stage. Post-completion, cased hole logging will be performed over the intervals [redacted] ft to provide baseline measurements for subsequent additional logging, as necessary.

Direct plume monitoring will be achieved through continuous pressure and temperature monitoring in the vertical deep monitoring well, using downhole pressure gauges and DTS fiber optic cable to allow for continuous monitoring of the reservoir conditions and calculations.

To track the pressure front within the horizon of each recompletion stage of the injection well, the deep monitoring well will be recompleted in tandem with the injection well. The downhole pressure gauge will be installed at an equivalent depth location. This configuration will allow monitoring of the injection plume at each separate injection stage depth.

Indirect monitoring of plume migration will be achieved through periodic four-dimensional (4D) VSP surveys. The VSP will be run prior to injection initiation, at recompletion, or at a minimum of every five (5) years as needed (not to exceed five years).

[redacted]

7.1 Plume and pressure front monitoring location and frequency

Table 9 presents the methods that Venture Global will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies Venture Global will employ. Figure 3 shows the planned locations of the deep monitoring well, CS004 Monitor Well 002. Note that locations of all planned monitoring wells are shown in a surveyor's plat in Appendix 1 of Module 7 Construction Details.

Table 9: Plume and Pressure Front Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME AND PRESSURE FRONT MONITORING				
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge / DAS	CS004 Monitor Well 002	[redacted]	Continuous
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge / DAS	CS004 Monitor Well 002	[redacted]	Continuous
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge / DAS	CS004 Monitor Well 002	[redacted]	Continuous
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge / DAS	CS004 Monitor Well 002	[redacted]	Continuous
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge /DAS	CS004 Monitor Well 002	[redacted]	Continuous
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge / DAS	CS004 Monitor Well 002	[redacted]	Continuous
Middle & Lower Miocene Sandstones	DTS pressure / temperature gauge / DAS	CS004 Monitor Well 002	[redacted]	Continuous
INDIRECT PLUME AND PRESSURE FRONT MONITORING				
Middle & Lower Miocene Sandstones	Vertical Seismic Profiling	AoR through time	Injection well laterally through AoR	Baseline and at recompletion or minimum of every 5 years

[redacted]

Quality assurance procedures for these methods are presented in Section B.2 of the QASP.

7.2 Reporting

Plume and pressure front tracking results will be reported semi-annually in compliance with 40 CFR 146.91(a) [LAC 43:XVII.3629.A.1].

7.3 Direct Monitoring: Pressure Monitoring at Each Injection Stage

Continuous measurements of reservoir pressure will be recorded at the depth of each completion stage of the injection as detailed in Table 9. Pressure will be tracked using permanent downhole pressure gauges at these discrete locations. Continuous pressure and temperature measurements will augment the discrete pressure measurement via DTS fiber optic cable. Pressure at the depth location of the pressure gauge and the distributed temperature measurements made over the full injection zone will be routinely monitored to detect and track the pressure front of the CO_2 plume. Pressure front data will be compared with simulation modeling of the pressure front to verify the predicted plume migration.

7.4 Indirect Monitoring: 4D VSP Surveys

Venture Global will use time-lapse VSP as the first method to monitor the CO_2 plume extent to meet the operation monitoring requirements specified in 40 CFR 146.90(g)(2) [LAC 43:XVII.3625.A.7.b]. The VSP surveys will identify density changes within the various injection intervals between survey efforts. This information provides confidence that deploying the method in a time-lapse format will generate a 4D image of the plume's extent and development with time. Further, employing VSP in the injection well with a permanently installed fiber optic sensor will create an image that is centered on the injection location with higher resolution compared to a traditional wireline-deployed geophone array. This proposed method eliminates the need for additional penetrations within the injection formations for geophone monitoring purposes. This process has been used to quantify CO_2 plume movement with positive results from several similar operations worldwide (Shell Canada Limited, 2017[1]; Bacci et al., 2017[2]).

A fiber optic cable with DAS will be incorporated in the cemented annulus behind the long string casing of the CO_2 injection well. A long sensor array will effectively be produced from the surface to the injection zone depth and will enable real-time or periodic monitoring using pressure and temperature gauges and the periodic VSP. The DAS fiber optic cable, designed with sensors spaced one meter apart, will be used to generate a VSP profile at the highest possible resolution. Three-dimensional (3D) models of the CO_2 plume can be created using a walk-away seismic source, in this offshore case, a seismic recording vessel. The data are captured by monitoring the injection well and repositioning the surface acoustic source. For shallow water environments, an air-gun or buried explosive charges will be used. Venture Global will evaluate these proposed activities to ensure compliance with both the Marine Mammal Protection Act (MMPA) and the Endangered Species Act (ESA).

Figure 4 illustrates the acquisition pattern strategy employed for plume development surveys from an injection well.

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[1] Shell Canada Limited, 2017, "Shell Quest Carbon Capture and Storage Project, Measurement, Monitoring and Verification Plan," February 2017 Version, Calgary, Alberta, Revised: May 5, 2017.

[2] V.O. Bacci, S. O'Brien, J. Frank, M. Anderson, "Using a Walk-away DAS Time-lapse VSP for CO2 Plume Monitoring at the Quest CCS Project," Recorder, Canadian Society of Exploration Geophysics, April 2017, Vol. 42 No. 03.

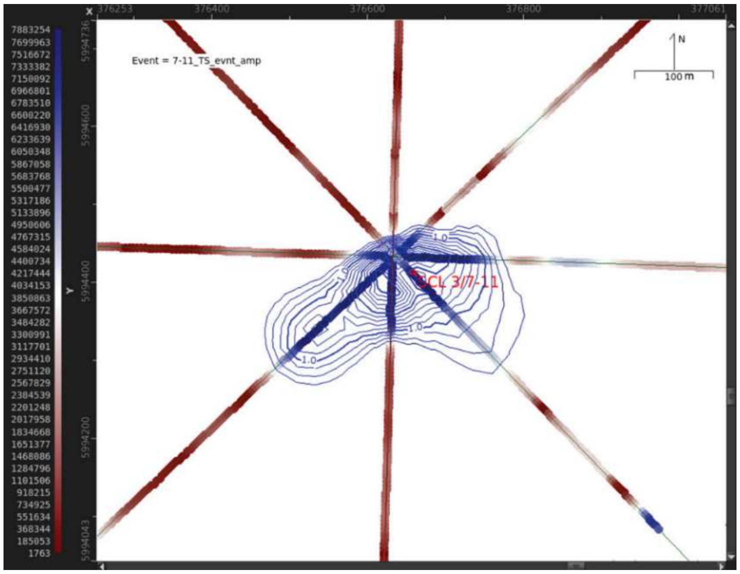

Figure 4: Minimum curvature interpolation of the amplitude difference between 2015 baseline and 2016 monitor in each VSP line, representing a map view of the seismic response to the presence of CO_2 after 6 months of injection (from Bacci et al., 2017.)

Geologic formation monitoring using time-lapse seismic has been used extensively in tertiary oil and gas recovery. The methodology has undergone thorough testing in saline aquifers with the presence of CO_2. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from compressional changes in velocity between high CO_2 concentrations and formation gases/fluids. As formation fluids are displaced by CO_2, the change in acoustic impedance during plume growth can be analyzed. With proper seismic processing, both the pressure front and the plume saturation are detectable with VSP.

The work steps involved in a time-lapse VSP survey primarily include:

- Rock physics model
- Petro-elastic model
- Fluid Substitution Feasibility Study
- Baseline survey (data acquisition)
- Repeat/time-lapse survey (data acquisition)
- Interpretation

7.4.1 Rock Physics Model

A rock physics model establishes a relationship between fluid substitution and the change in acoustic impedance and can be produced with a high degree of confidence, provided accuracy of the reservoir characterization data. Changes in seismic response can be projected with a synthetic survey design and reservoir model, relying on the rock physics model to calculate formation fluid impact on acoustic impedance. This model determines whether the monitoring program can facilitate the detection of expected formation fluid substitutions.

Deterministic petrophysical analysis estimations can be used to forecast the dry mineral rock components prior to any saturation modeling. The model accounts for the rock properties below:

- Total porosity
- Effective porosity
- Water saturation
- Clay (type)
- Quartz
- Mineral content

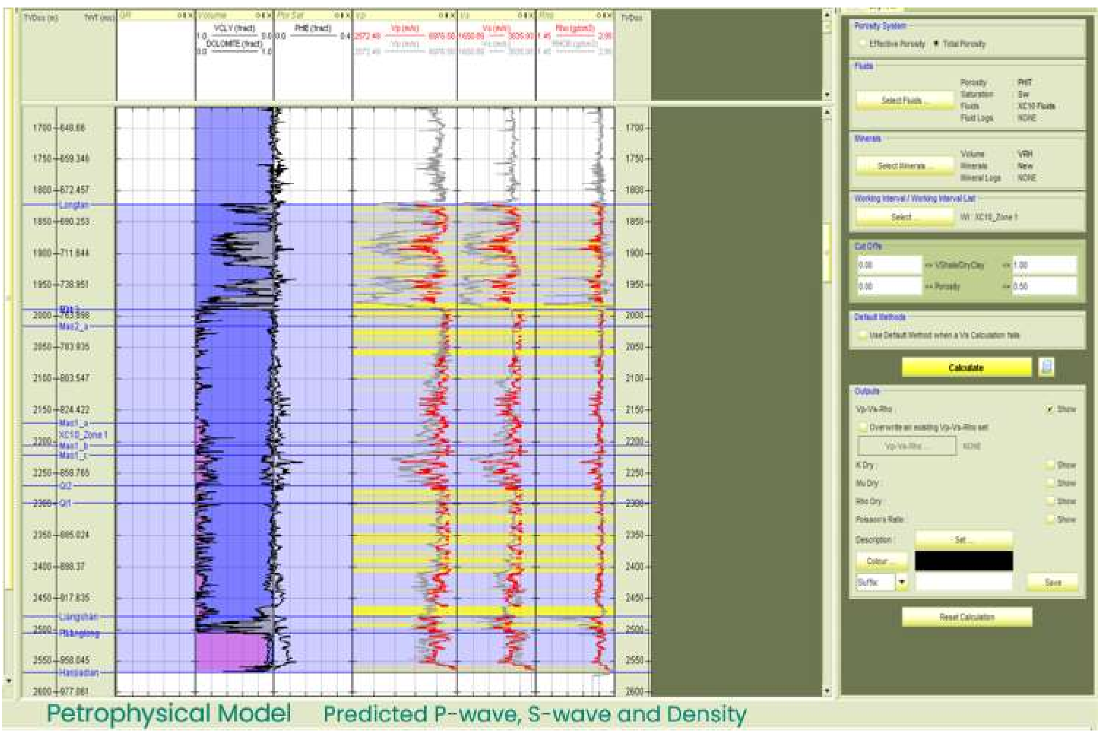

Figure 5: Typical Petrophysical Analysis View (Source: Baker Hughes)

Analytical software tools enable quality control of the deterministic inversion of the reconstructed mineral content compared to the observed petrophysical response (see Figure 5). The inversion allows for the stabilization of inverted results, evaluation of uncertainty in predicted attributes, and calculation of in-situ reservoir properties.

7.4.2 Petro-Elastic Model

The rock physics model will be used to generate a zero-order dry rock model, which is then used to establish a petro-elastic model by perturbing the elastic parameters for varying degrees of saturation.

The combination of the rock physics model (red) and the petro-elastic model at 52% water saturation (blue) is illustrated in Figure 6 below. Changes in saturation result primarily in changes to the compressional wave velocity for this type of rock. The effect of gas replacement of the reservoir fluid can be estimated using the fluid saturation and fluid replacement from the rock physics model.

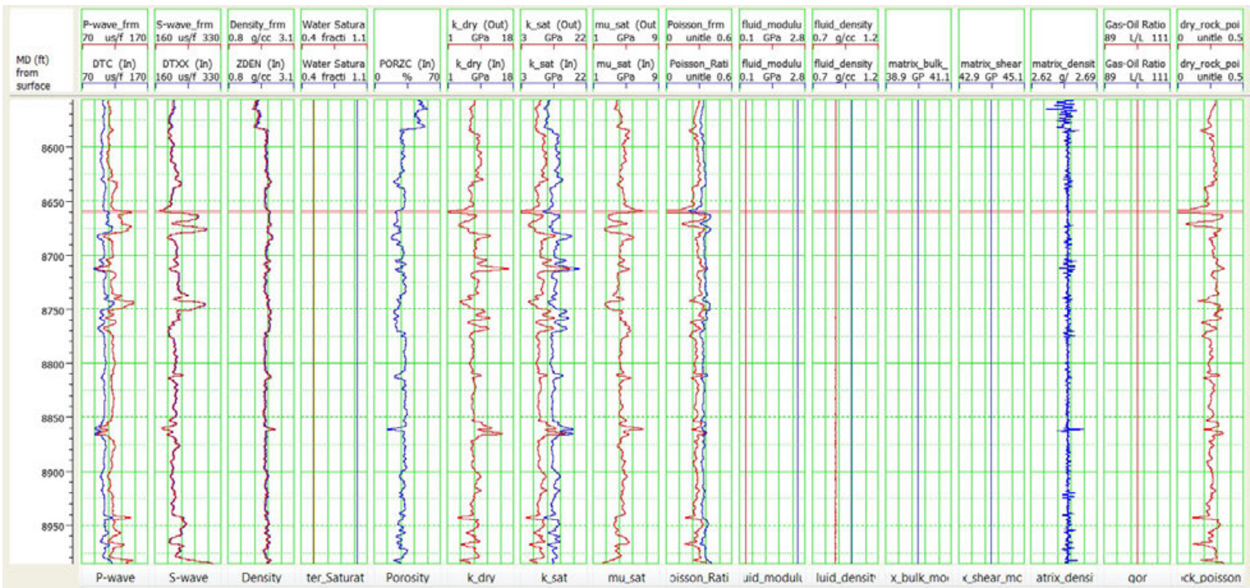

Figure 6: Application of Petro-Elastic Model to Rock Physics Model (Source: Baker Hughes)

Predictions of velocity and density as functions of injectate saturation are the final result of petro-elastic modeling (Figure 7). The seismic response measured during VSP surveys can be determined using the acoustic impedance calculated from elastic properties.

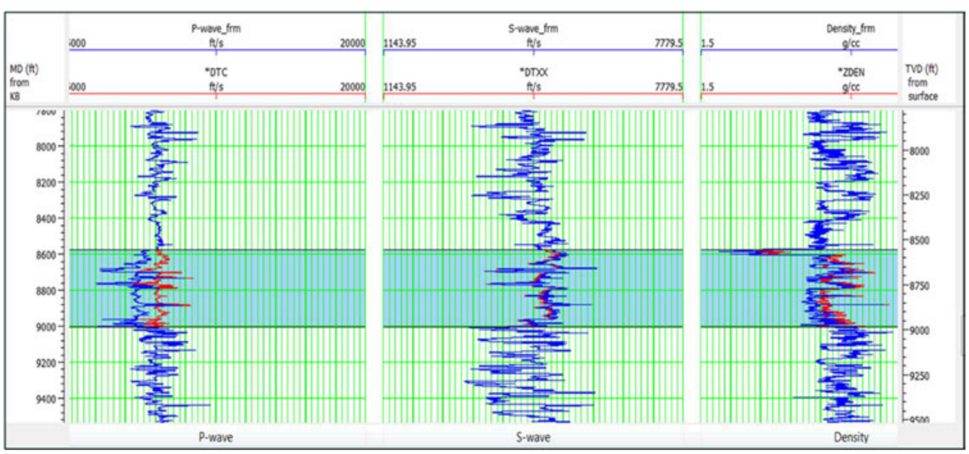

Figure 7: Fluid Replacement Model (Source: Baker Hughes)

7.4.3 *Feasibility Study*

A feasibility study will be designed to determine if connate fluids replaced with CO_2 could be detected by the petro-elastic model. This study will be conducted after recovering core material from the injection well. The CO_2 properties will be input in the model as replacement variables for open hole log readings that will be collected while drilling the CO_2 injection well for the project.

7.4.4 Baseline Survey

The baseline survey is the opportunity to capture an image of the reservoir prior to impact from injection operations or offset activity, natural or man-made. The extent of plume measurement ability is constrained by the size of the baseline survey. It is essential to acquire a baseline survey with sufficient coverage in the event the initial reservoir models are not accurately forecasting plume migration.

The initial baseline survey design will circumscribe the injection well through a series of quadrant VSP surveys (Figure 8). As the plume migrates with time, and the plume migration path is established, it is likely that fewer quadrant surveys will be required to accurately track plume movement.

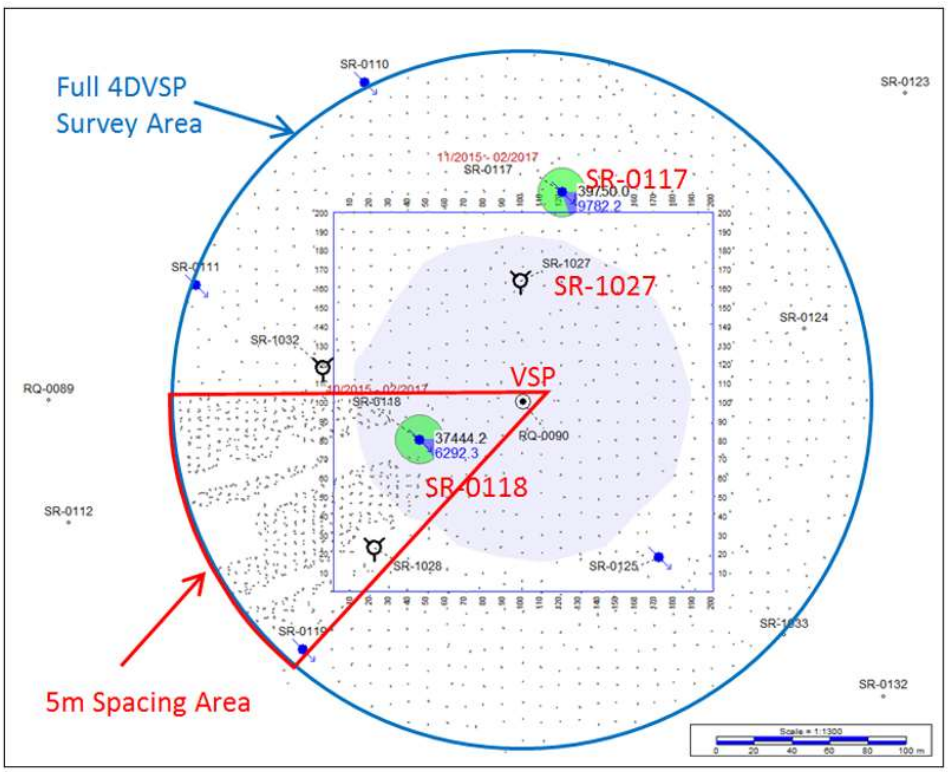

Figure 8: Example initial configuration and area of VSP surveys (Source: Baker Hughes)

7.4.5 1D and 2D Models

Changes in magnitude of the CO_2 plume are measured for different scenarios using one-dimensional (1D) and two-dimensional (2D) models. These models provide the base information on rock and fluid properties required for the 4D VSP site-specific feasibility study. This section will detail the methodology used to generate these models.

Seismic waves that travel through the earth are created with seismic surveys, where geophones or fiber optic DAS cable record the seismic waves that are subsequently reflected from subsurface horizons. The seismic waves can be created with a “shot,” referring to explosives or other mechanical sources. For these offshore and shallow water environments, water-based equipment will be used. A boat equipped with an air-gun for creating underwater percussions, will be used to produce a source detectable down the wellbore. The geophone/DAS receivers enable calculation of the two-way travel time it takes for seismic waves to reflect off transition zones between formations. Geologists can use the variation in seismic velocities to map the subsurface lithology. Figure 9 depicts a standard vertical seismic profile offshore survey with a DAS configuration.

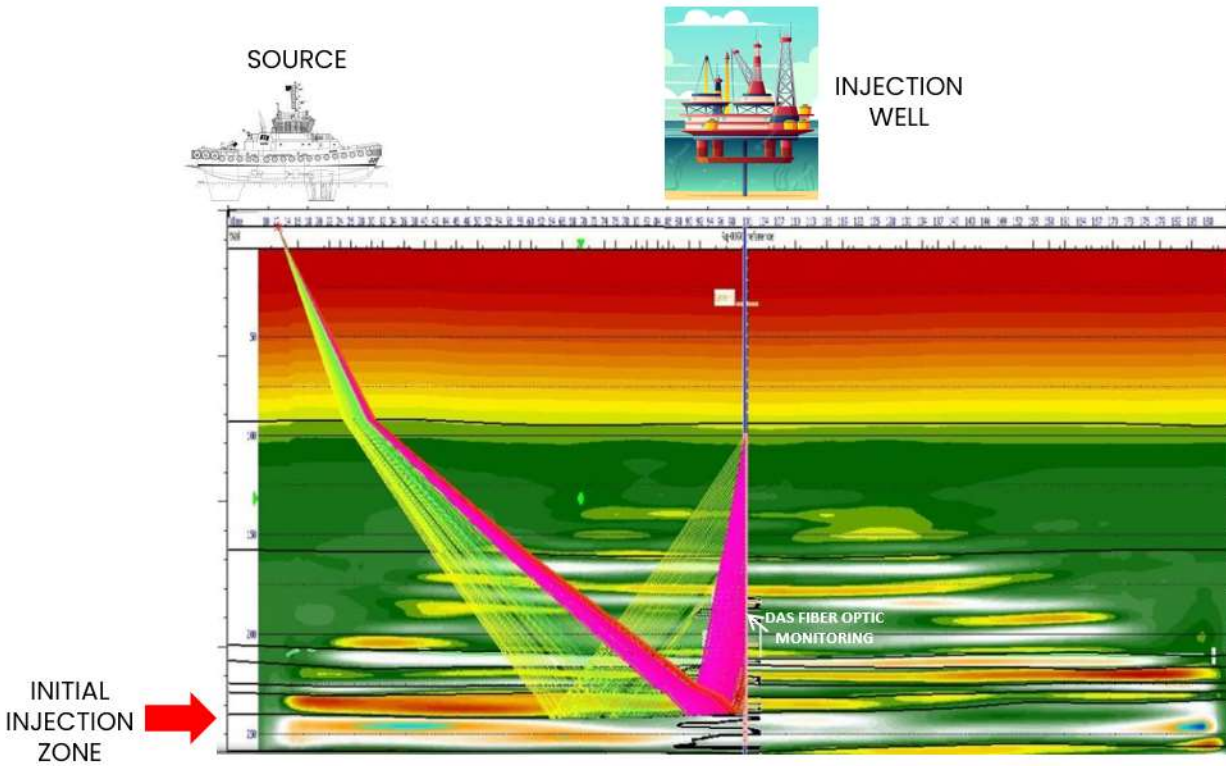

Figure 9: Illustration of a Vertical Seismic Profile Survey (Source: Baker Hughes)

To generate accurate 3D and 4D VSP surveys require the initial development of a 1D seismic model. The principles discussed previously also apply to 1D seismic surveys. A common method of obtaining 1D seismic data is with a checkshot survey, as illustrated in Figure 10. Geophones are situated vertically along the wellbore while shots are fired from an air-gun. This survey records seismic waves at different depths and provides measurements of sonic velocities of the geologic layers affected by wellbore construction at the highest levels of accuracy. This 1D survey methodology assumes each formation is homogeneous in the horizontal direction, so the surveys provide average seismic velocities.

The 1D survey data can also be used for correction of the acoustic logs and creation of synthetic seismograms, which are used to forecast seismic responses of the subsurface. One special variation of 1D seismic surveys is an acoustic log. Acoustic logs generate acoustic data along the wellbore using wireline sonic tools. Though these logs differ from those of seismic surveys, they can provide a 1D understanding of variation in velocities.

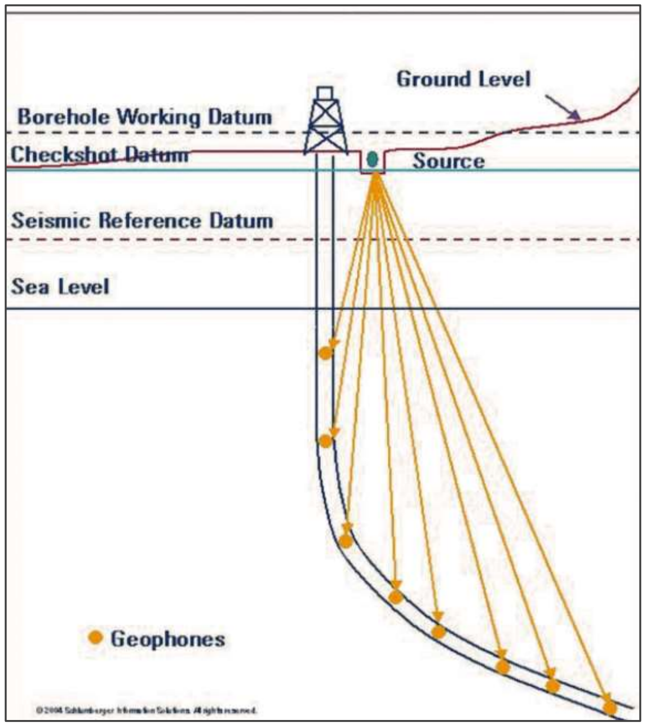

Figure 10: Illustration of a Checkshot Survey (Source: Baker Hughes)

A geologic model can be built once the results of a 1D model are interpretated. The model reflects two saturation scenarios: one with connate formation fluid and one with CO_2-replaced fluid.

7.4.6 <u>Processing Workflow and 4D Seismic Volume Determinations</u>

Gas volume build-ups from consecutive surveys will be observed over time to produce the final interpretation. A 4D model is created when 1D, 2D, and 3D seismic surveys are combined with a time element (i.e., surveys recorded at various time intervals such as year 1, year 5, year 10, etc.). Changing volumes of gas build-up, represented by either log shifts on 1D and 2D responses or heat blooms on the 3D model, are identified in the 4D interpretation of a seismic survey.

Figure 11 illustrates a basic workflow example.

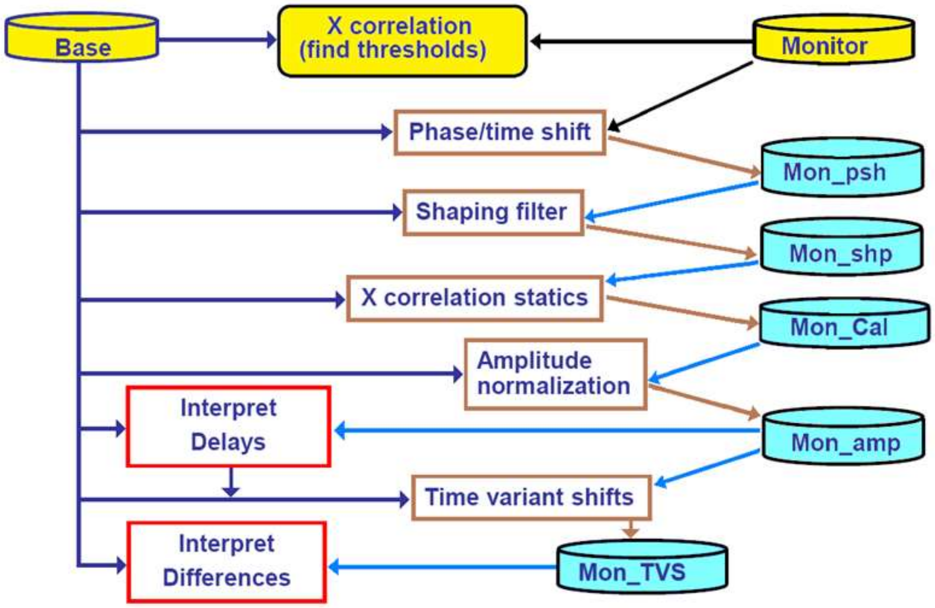

Figure 11: 4D VSP Processing Workflow Diagram (Source: Baker Hughes)

The 3D horizon model is established from the base survey, and each successive survey performed creates a reflection differential that is mapped on the 3D model. The map is used to determine plume geometry, and the process is repeated in time increments to illustrate time-lapsed development of the injectate plume.

7.4.7 Inversion Workflow

Well log data, post-stack seismic volumes, and a structural model will be used to invert baseline surveys. Later monitor surveys will employ the same low component and residual corrections for consistency and the detection of changes over time. Such changes over time will be assumed to be the result of the injection operations. Figures 12 and 13 demonstrate the results of the 4D seismic analysis for a CCS well located in Canada. Figure 14 provides a summary of the 4D workflow.

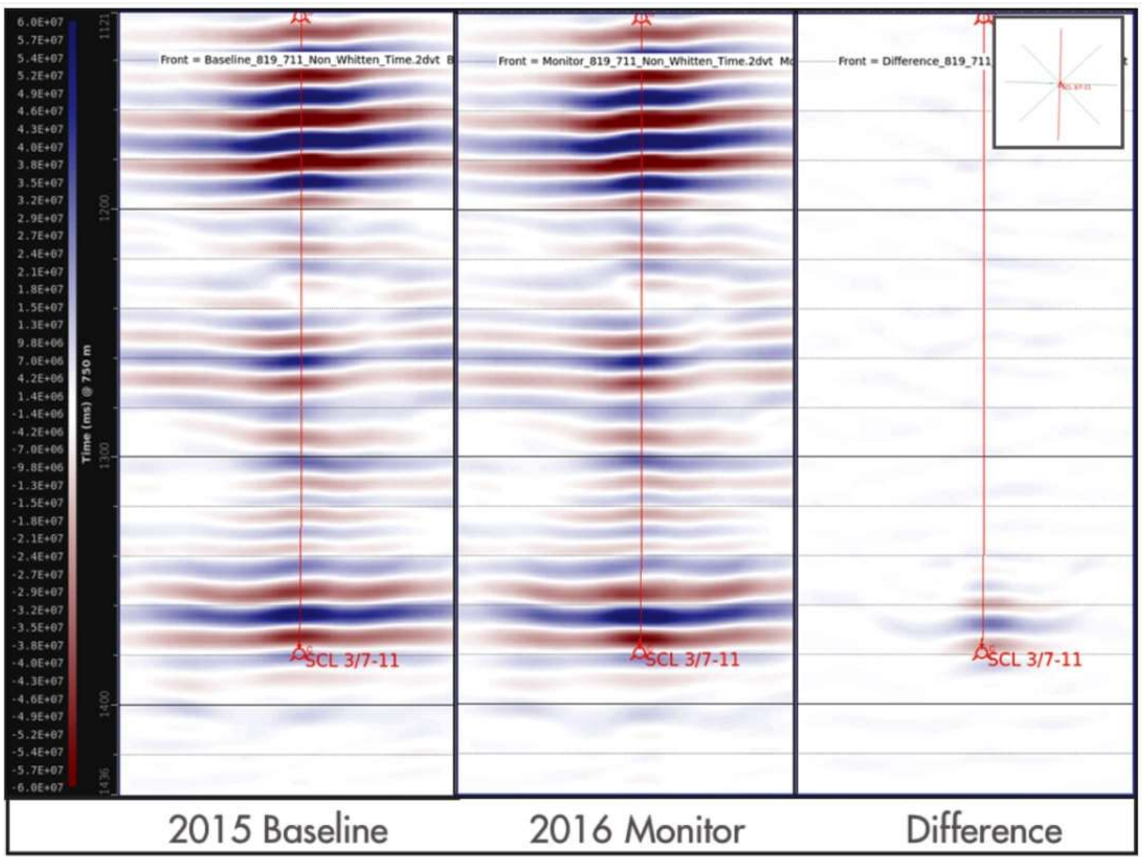

Figure 12: Time-lapse assessment after 6 months of injection of a DAS walk-away VSP line. The difference between the 2015 baseline and 2016 monitor clearly shows the time lapse anomaly representing the CO_2 plume (from Bacci et al., 2017).

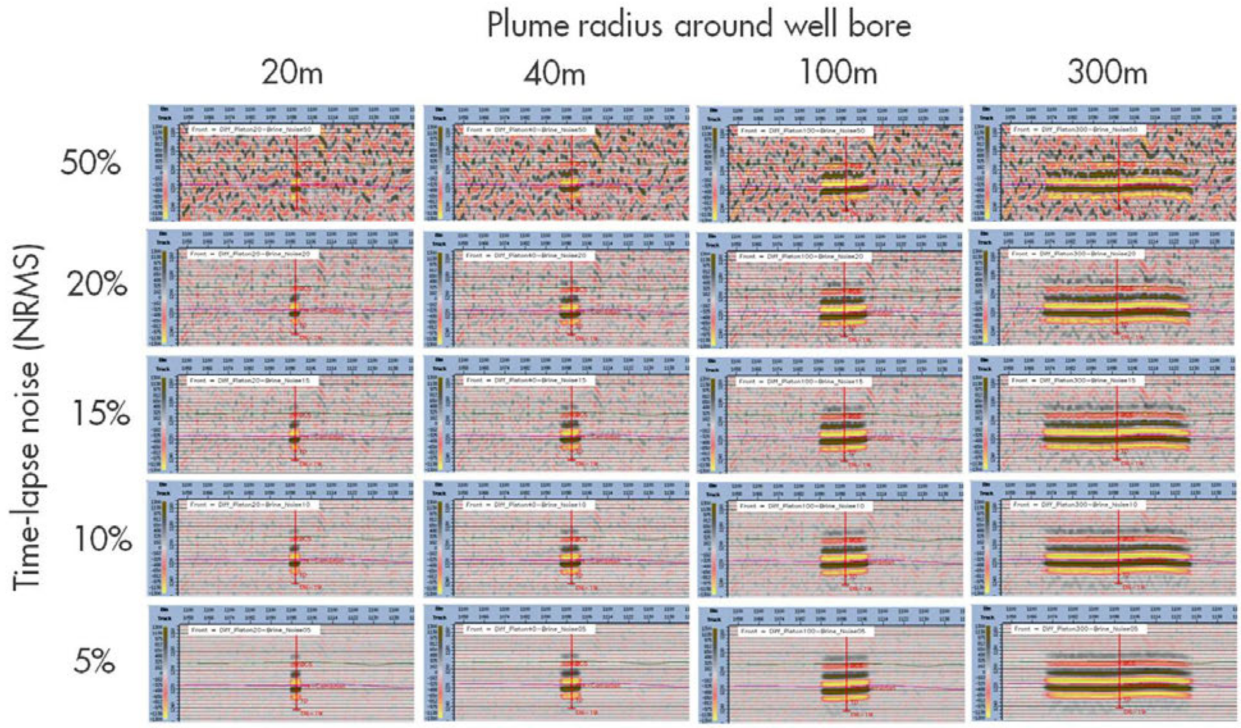

Figure 13: Model time-lapse difference signatures (monitor survey – baseline survey) for a range of CO_2 plume sizes and noise levels (from Bacci et al., 2017).

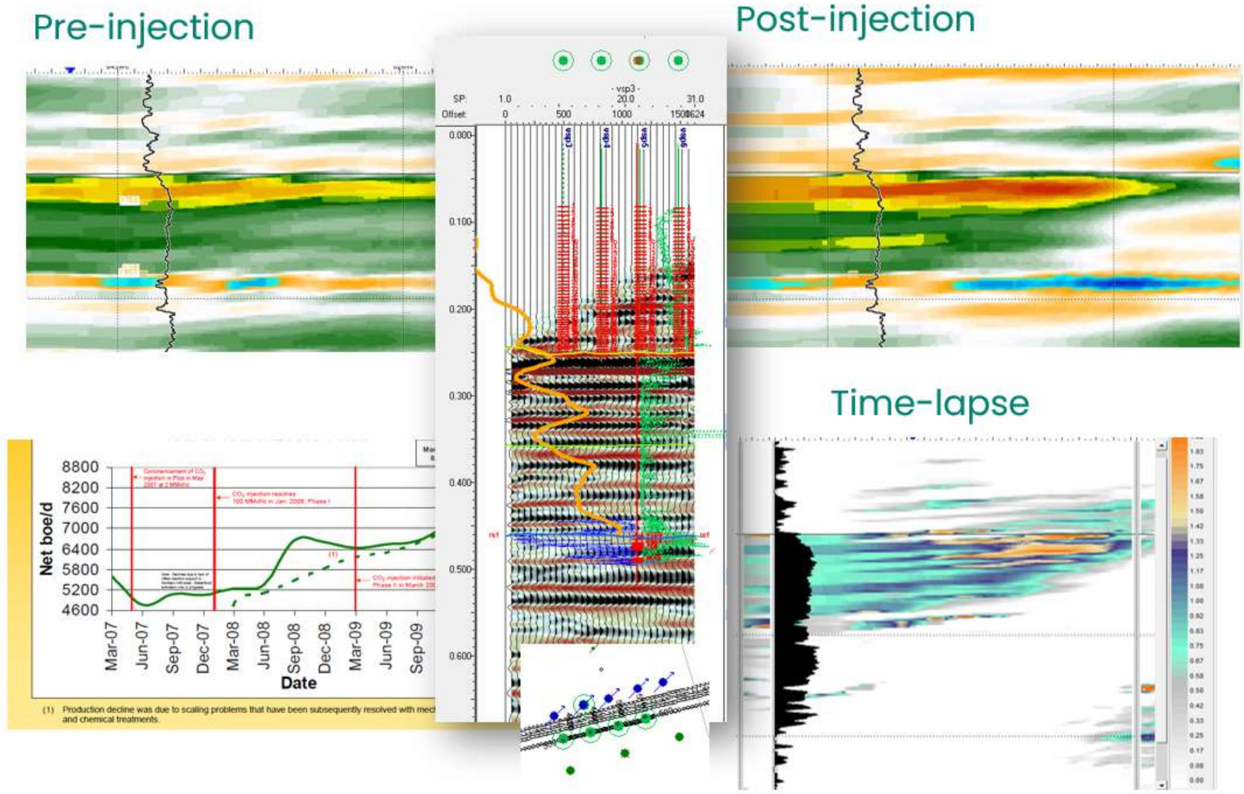

Figure 14: Example of 4D VSP results for CO_2 plume migration (Source: Baker Hughes)

7.5 Contingency CO_2 Plume and Pressure Front Tracking

If additional plume surveys are deemed necessary during permit review periods, a secondary monitoring system was devised to address this scenario. This secondary plan is only included as a reference to alternate methods considered capable of evaluating modeled versus actual plume migration results. This contingency plan was designed in accordance with 40 CFR 146.90(g)(2) [[LAC 43:XVII.3625.A.7.b] requirements, for indirect monitoring of the CO_2 plume and is through 2D seismic profiling surveys.

2D seismic surveys can provide a snapshot of a thin layer of the Earth's crust, applying the same principles as discussed in the previous section, though the geophones for this survey are deployed in a line streaming from the seismic vessel and reflected seismic waves from each formation are recorded. For best results, 2D surveys require setting multiple lines that are ideally located parallel to the structure dip and orthogonal to the geologic strike. The surveys provide subsurface information of various formations, faults, and other characteristics. Contour lines can be interpreted, and geologic maps produced using intersection of numerous 2D surveys.

7.6 Monitoring Conclusion

The VSP method for quantifying CO_2 plume development over time has been previously demonstrated in several cases (Shell Canada Limited, 2017[3]; Bacci et al., 2017[4]). For Venture Global, using offset petrophysical data modeling results has generated a modeled differential in compressional velocity and density likely to produce detectable changes in the reservoir where the connate fluid is replaced by CO_2. This information provides confidence that deploying the method in a time-lapse format will generate a 4D image of the plume extent and development into the future. Further, employing VSP in the injection well with a permanently installed fiber optic sensor will create an image that is centered on the injection location with higher resolution, compared to a traditional wireline-deployed geophone array. This method eliminates the need for additional penetrations within the injection formations for geophone placement monitoring purposes.

The installed fiber optic configuration in the well will facilitate ease of pressure and temperature monitoring in all well sections, which will be used in indirect pressure plume calculations.

8 References

PDF files for the following references are provided in Appendix 1.

Shell Canada Limited, 2017, “Shell Quest Carbon Capture and Storage Project, Measurement, Monitoring and Verification Plan,” February 2017 Version, Calgary, Alberta, Revised: May 5, 2017.

V.O. Bacci, S. O’Brien, J. Frank, M. Anderson, “Using a Walk-away DAS Time-lapse VSP for CO2 Plume Monitoring at the Quest CCS Project,” Recorder, Canadian Society of Exploration Geophysics, April 2017, Vol. 42 No. 03.

[3] Shell Canada Limited, 2017, “Shell Quest Carbon Capture and Storage Project, Measurement, Monitoring and Verification Plan,” February 2017 Version, Calgary, Alberta, Revised: May 5, 2017.

[4] V.O. Bacci, S. O’Brien, J. Frank, M. Anderson, “Using a Walk-away DAS Time-lapse VSP for CO2 Plume Monitoring at the Quest CCS Project,” Recorder, Canadian Society of Exploration Geophysics, April 2017, Vol. 42 No. 03.