TESTING AND MONITORING PLAN
40 CFR 146.90

Facility Information

Facility Name: Pelican Renewables, LLC
Well Names: Rindge Tract CCS Well #1
Rindge Tract CCS Well #2

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Well Locations: Rindge Tract Island, San Joaquin County, California
38.021507, -121.428926 (Well #1)
38.014567, -121.415405 (Well #2)

This Testing and Monitoring Plan describes how Pelican Renewables, LLC and its affiliates (Pelican) will monitor the CO_2 storage site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, that the carbon dioxide plume and pressure front are moving as predicted, and that there are no endangerments to USDWs; the monitoring data will be used to validate and adjust the geological and numerical models that predict the distribution of the CO_2 within the storage zone to support AOR reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan. Should any anomalous results be identified, Pelican will consult with EPA to implement the response actions identified in the Emergency and Remedial Response Plan.

Strategy & Approach for Testing and Monitoring

This Testing and Monitoring Plan summarizes an integrated strategy for monitoring various aspects of the Rindge Tract CO_2 storage project, including well integrity, various operational parameters, and changes imposed on the geologic system by injection practices (i.e., plume, pressure front, and potentially groundwater quality).

Two Class VI injection wells will be permitted for this storage project. Both will be located on the interior of Rindge Tract and will be connected with transfer piping. The two-well system is designed to efficiently use the pore space of the injection zone, provide for operational flexibility, and to allow for maximum deployment of devices to monitor the pressure front and the extent of the plume as injection proceeds. This Testing and Monitoring Plan was prepared to monitor the complete two-well injection system.

This plan is focused on the operational or injection phase of the CO_2 storage project and has close ties to the pre-operational testing plan and the post–injection site care and site-closure plan since there is overlap in certain types of testing and monitoring activities that occur in these separate project phases. For details on the pre-operational testing and post-operational testing and monitoring activities, please refer to those plans in **Sections 6** and **10**, respectively.

Although the UIC testing and monitoring guidance does not include specific recommendations for selecting geochemical monitoring parameters, it does require that they be selected on a site-specific basis. Therefore, Pelican's strategy is to optimize geochemical monitoring parameter lists per USEPA's Unified Guidance (2009). With this, the goal will be to maximize statistical power within the monitoring network and therefore minimize the site-wide false positive rate during any given sampling event.

It is important to note that this Testing and Monitoring Plan will be revised and refined as new site characterization data, computational modeling data, and pre-operational and operational data become available. Selection of methods and strategies may need to be altered to remain representative of the site-specific risk profile or identified potential concerns.

As discussed within the Site Characterization Narrative in **Section 2**, Pelican Renewables, LLC utilized data from nearby legacy hydrocarbon production wells, particularly the Citizen Green #1 well (outside of the AOR), geophysical well logs, and existing 2D and 3D seismic data to construct the model and complete the initial Area of Review (AOR) delineation. There are key uncertainties in understanding the character of the injection and confining zones resulting from the lack of site-specific primary data at Rindge Tract Island. These uncertainties will be reduced by initially treating Rindge Tract CCS #1 and #2 as stratigraphic test wells with complete core sampling, sidewall core sampling, and geophysical logging of the sequestration complex. The geological and numerical models will then be calibrated with these site-specific data, and the AOR and Testing and Monitoring Plan will subsequently be refined as needed.

An overview of the monitoring network within the delineated AOR is included in this plan as **Figure 8-1**. Information on planned monitoring well construction is included in **Section 5**.

Quality Assurance Procedures

All data quality assurance and surveillance procedures for this sequestration project were designed to maintain compliance with the requirements under 40 CFR 146.90(k). Quality assurance (QA) requirements for the measurements to be conducted as part of this Plan are described in the Quality Assurance and Surveillance Plan (QASP). The direct measurements outlined in this Plan are essential to the success of the CO_2 storage project; therefore, it is imperative that the measurements be performed based on best industry practices and by recommended QA protocols of geophysical services contractors and equipment manufacturers. The QASP is attached to this plan as **Appendix 8-A**.

Reporting Procedures

Pelican will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR 146.91.

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

Pelican will analyze the CO_2 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).

Sampling Location & Frequency

CO_2 stream sampling will take place on a quarterly basis, by the following dates each year: 3 months after the start of injection, 6 months after the start of injection, 9 months after the date of start of injection, and 12 months after the date of start of injection.

CO_2 will be sourced from Pelican Renewables' corn ethanol plant in Stockton and will be food-grade standard. We would not expect significant variability in the chemical composition of the CO_2 stream given the quality control standards in place at food-grade facilities; therefore, the quarterly basis will be sufficient frequency to yield data representative of the CO_2 stream characteristics in the context of this project. A comprehensive analyte list was developed based on the currently known chemical characteristics of these CO_2 streams (**Table 8-1**).

CO_2 stream samples will be collected from the feedstock via a sampling manifold connected to the CO_2 pipeline in the control building. It is important to sample the CO_2 feedstock from the pipeline upstream from the injection point to accurately represent the different impurities that may be present in the CO_2 stream. The presence of even small amounts of certain impurities has the potential to affect the economics of geologic storage downhole or affect compressor or pipeline operations (Last and Schmick, 2011).

Analytical Parameters

Pelican will analyze the CO_2 for the constituents identified in **Table 8-1** using the methods listed. All parameters will be collected and analyzed quarterly according to the above schedule. These parameters were carefully selected based on the currently known composition of Pelican's source streams, as well as any impurities that, if present, may have a negative impact on the storage capacity of the reservoirs and/or injection well construction materials (Last and Schmick, 2011).

Table 8-1. Summary of Analytical Parameters for CO_2 Stream

Parameter	Analytical Methods
Carbon Dioxide (CO_2) (% vol)	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
Methane (CH_4) (% vol)	ISBT 10.1 (FID)
Nitrogen (N_2) (% vol)	ISBT 4.0 (GC/DID)
Hydrogen (H_2) (% vol)	ISBT 4.0 (GC/DID)
Argon (Ar) (% vol)	ISBT 4.0 (GC/DID)
Water (H_2O) (ppmv)	ISBT 11.0 (GC/FID)
Oxygen (O_2) (ppmv)	ISBT 4.0 (GC/DID)
Hydrogen Sulfide (H_2S) (ppmv)	ISBT 14.0 (GC/SCD)
Sulfur Dioxide (SO_2) (ppmv)	ISBT 14.0 (GC/SCD)
Nitrogen Oxide (NOx) (ppmv)	ISBT 7.0 Colorimetric
Carbon Monoxide (CO) (ppmv)	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Total Hydrocarbons (ppmv)*	ISBT 10.0 THA (FID)

Notes:

1. *% vol = percentage of the total volume; ppmv = parts per million by volume; SOx = oxides of sulfur; NOx = oxides of nitrogen.*
2. ** = If total hydrocarbons are detected during a given event, a subsequent sample for Volatile Organic Compounds (VOCs) will be collected.*
3. *Any anti-corrosion chemicals – if used – will also be monitored.*
4. *The listed analytical methods are promulgated by the International Society of Beverage Technologists (ISBT) and are considered standard for analyzing gases related to the production of food-grade CO_2.*

Sampling Methods

A sampling station will be installed in the control building near the CO_2 transfer line and connected to the transfer line via a sampling manifold, which will allow the collection of representative CO_2 grab samples into containers that can be sealed and shipped to the laboratory. The collection procedure will be designed to maintain pressure, supercritical phase, and integrity while allowing ease of collection and sample shipment.

Additional information can be found in Sections A.4.a and B.1.a of the QASP (**Appendix 8-A**).

Laboratory to be Used/Chain of Custody & Analysis Procedures

Sample analyses will be conducted by a third-party laboratory. Pelican will follow the methods specified by the EPA's Air Emission Measurement Center (EMC) Promulgated Test Methods, which are codified in the Code of Federal Regulations. See Section B.3 of the QASP for further information on chain of custody and analysis procedures (**Appendix 8-A**).

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

Pelican will install and use continuous recording devices to monitor injection pressure, rate, 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 CO_2 stream in both wells, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Location & Frequency

Pelican will perform the activities identified in **Table 8-2** to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

Distributed Fiber Optic Sensing (DFOS), which will include Distributed Temperature Sensing (DTS), Distributed Acoustic Sensing (DAS), and Distributed Strain Sensing (DSS), will be deployed in Rindge Tract CCS Well #1 along the outside of the long string casing. Sensors are equipped with variable density clips to enable detection prior to casing perforation. Additional DFOS may be deployed in one or more monitoring wells. The DAS will provide information about microseismicity and will be utilized to conduct vertical seismic profiles. The DTS and DSS provide continuous temperature and pressure monitoring. All DFOS measurements will be reported in real-time. Refer to **Appendix 8-C** of this Plan for details on the DFOS technology.

Table 8-2. Sampling Devices, Locations, & Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Minimum Sampling/Recording Frequency
Injection pressure	Electronic Pressure Transducer	Injection Wellheads	$Minute^{-1}$
	DSS	Outside of the long string casings, along wellbores to packer	5 $seconds^{-1}$
Injection rate	Coriolis Mass-Flow Transmitter or equivalent flow meter	Injection Wellheads	$Minute^{-1}$
Injection Volume	System Totalizer	Downhole in the injection wells above packer	$Minute^{-1}$
Annular pressure	Electronic P/T Gauge or equivalent pressure transducer	Injection Wellheads	$Minute^{-1}$
CO_2 stream temperature	Electronic P/T Gauge	Downhole in the injection wells above packer	$Minute^{-1}$
	DTS	Outside of the long string casings, along wellbores to packer	5 $seconds^{-1}$

Notes:

- *Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter.*
- *Recording frequency refers to how often the sampled information gets recorded to digital format.*

Monitoring Details

The mass flow rate of CO_2 injected into both wells will be measured by flow meter skids with Coriolis mass flow transmitters, or equivalent flow meter devices. The flow meters will have analog outputs (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). A total of three flow meters will be supplied, providing a spare flow meter to allow for flow meter servicing and calibration. The flow meters will be connected to the main CO_2 storage site SCADA system for continuous monitoring and control of the CO_2 injection rate into the well.

The pressure of the injected CO_2 will be continuously measured at a regular frequency by an electronic pressure transducer with analog output mounted on the CO_2 line associated with each injection well at a location near the wellhead. The transducer will be connected to the annulus pressurization system (APS) programmable logic controller (PLC) located adjacent to the injection well pad.

The temperature of the injected CO_2 will be continuously measured for each well at a regular frequency by an electronic temperature transmitter. The temperature transmitter will be mounted in a temperature well in the CO_2 line at a location close to the pressure transmitter near the wellhead. The transmitter will be connected to the APS PLC located adjacent to the injection well pad.

Instruments for measuring surface injection pressure and temperature will be calibrated initially before commencing injection and recalibrated periodically per the manufacturer's specifications.

An electronic P/T gauge will be installed in the annular space approximately 30 ft above the packer, reading through the tubing to continuously measure CO_2 injection P/T inside the tubing at this depth. In addition, injection P/T will be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead.

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow, as part of the instrumentation and control system. The P/T will also be monitored at a position located immediately above the injection zones at the end of the injection tubing. The downhole sensor will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure.

DSS/DTS will be utilized outside of the long string casing to continuously monitor P/T within the injection zone.

Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), Pelican will monitor injection 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. Pelican will monitor corrosion using the corrosion coupon method according to the description below.

Monitoring Location & Frequency

The corrosion of well casing and tubing materials will be monitored on a quarterly basis during injection operations using the corrosion coupon method, beginning three months after the date of start of injection. The coupons will be deployed and located within the CO_2 injection tubing using wireline equipment and will be comprised of the same material as the well's casing and tubing. See **Section 5** of this application for injection well construction and material details.

Sample Description

Samples of materials used in the construction of the injection well that will come into contact with the injected CO_2 will be included as part of the corrosion coupon method (i.e., long string casing materials and injection tubing materials). Prior to initial deployment, the coupons will be weighed, measured, and photographed according to applicable ATSM methods as a baseline assessment. The coupons will be comprised of materials listed in **Table 8-3** below. Additional details on these materials are provided in **Section 5 (Injection Well Construction Plan, Tables 5-4 and 5-6)**.

Table 8-3. List of Equipment with Material of Construction

Equipment Coupon	Material of Construction
Conductor Casing	API Grade A252
Surface Casing	API Grade J-55
Intermediate Casing	API Grade HCL-80
Long String Casing	HCL-80 and 25 Cr-110
Injection Tubing	25 Cr-110
Packers	Stainless Steel, 7K, AS-1X
*Note: Well construction details are provided in **Section 5 (Injection Well Construction Plan)** of this application.*	

Monitoring Details

The coupons will be handled and assessed for corrosion in accordance with ASTM International (ASTM) Method G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM International, 2017).

Any coupons not in use and those that will be deployed for use will be stored in a non-corrosive environment to maintain integrity. The coupons must be subjected to the well's environment for a significant period of time (i.e., several months to years). At the prescribed frequency, the coupons will be removed and visually inspected for signs of corrosion. The coupons will be analyzed in accordance with the NACE RP0775-2018 (NACE, 2018) standard to assess and document corrosion wear rates based on mass loss. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration of exposure (i.e., weight loss method; Jaske et al. (1995)). The U.S. EPA UIC Class VI Testing and Monitoring Guidance (2013) suggests that target corrosion rates of one mil per year (approximately 25 micrometers or one-thousandth of an inch per year) or less are common in wells in the oil industry. NACE SP0775-2023 categorizes average general corrosion rates for carbon steel of less than 2 mils/year as low and maximum pitting rates of less than 5 mils/year as low (NACE, 2023). As such, a detected general corrosion rate of greater than 2 mil/year or pitting rate of greater than 5 mils/per year will initiate consultation with the EPA and more frequent monitoring may be invoked if appropriate. A casing inspection log will be run to assess thickness and quality of the casing if rates exceed these thresholds.

Corrosion monitoring is implemented in this project as a loss of containment prevention measure, coupled with the use of corrosion-resistant well construction materials.

As corrosion rates measured on a coupon cannot be entirely representative of actual corrosion rates experienced by well materials, periodic wireline casing inspection logs (CILs) may also be used to evaluate the condition of the injection well casing and tubing. The frequency of running these logs will be determined on a site-specific basis (e.g., physical and chemical characteristics of the injectate), keeping injection well performance in consideration. Pelican will follow EPA Region 9's CIL Guidance, which is included as **Appendix 8-B** of this Plan. The wireline tools will be lowered into the well to directly measure defects in the well casing and tubing. The tools that may be used include:

- Mechanical tools, such as caliper logs, which measure the internal diameter of the casing in several directions and allow the detection of loss of thickness of the well casing;
- Electromagnetic tools, which can accurately measure corrosion effects, such as pitting depths and metal loss is tubing or casing; and
- Ultrasonic imaging tools, which use a high transducer frequency to measure anomalies in the tubing or casing in terms of wall thickness (Schlumberger, 2009).

Corrosion Prevention

Preventative measures may be employed to prevent and/or inhibit corrosion of the injection well materials. The enactment of these preventative measures depends on corrosion monitoring results and results from CO_2 stream analysis throughout the operational period. Preventative measures may include the introduction of anticorrosion chemicals to the CO_2 stream and the use of consumable cathodic protection plates on the surface injection system. Any corrosion inhibitors used must be chemically compatible with the CO_2 stream and periodic fluid sampling will need to be conducted within the system to verify the inhibitor is present at proper concentrations for corrosion prevention.

Above Confining Zone Monitoring

Pelican will monitor groundwater quality and geochemical changes above the confining zone during the operational period to meet the requirements of 40 CFR 146.90(d). These monitoring procedures are designed to be protective of all Underground Sources of Drinking Water (USDWs) in the vicinity of the CO_2 storage project.

Monitoring Locations & Intervals

Table 8-4 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone. **Figure 8-1** shows the planned groundwater monitoring locations within the AOR and **Figures 8-2** through **8-9** show the monitoring locations relative to the predicted CO_2 plume and pressure front extent in five-year time intervals during the operational (injection) period. Proposed monitoring well construction schematic diagrams are included in **Section 5** (Injection Well Construction Plan).

Wells designated as GMW-Z will monitor the Mokelumne River Formation (in-zone) for pressure changes and geochemical changes induced by injection for the purposes of pressure front and plume tracking. The details of these proposed wells are discussed further under a later subsection, Carbon Dioxide Plume and Pressure Front Tracking.

Groundwater monitoring wells designated as GMW-D will monitor the lower Domengine Formation, which is the first sand unit located stratigraphically above the primary upper confining zone (Capay Shale). The Domengine Formation has pore water salinities higher than 10,000 ppm based on calculated estimates from petrophysical logs; therefore, the Domengine is not an USDW, and therefore would not be utilized as a water supply source.

Groundwater monitoring wells designated as GMW-M will monitor the sands within the Markley Formation, which is the lowermost USDW in this region. The salinity of pore water in the Markley Formation is variable, ranging from 2,000 to 16,000 ppm and averaging about 3,000 ppm based on calculated estimates from petrophysical logs. Because of its depth, the Markley Formation is not currently, and is not expected to be a source of drinking or irrigation water.

Groundwater monitoring wells designated as GMW-S will monitor the Eastern San Joaquin Valley Sub-basin’s principal freshwater aquifer system, which is utilized as the local USDW by the City of Stockton, CA and surrounding communities. This system includes the following water production zones:

- Shallow Zone: undifferentiated alluvial deposits (unconfined); Modesto/Riverbank formations (unconfined), upper Turlock Lake/Laguna formations (unconfined to locally semi-confined or confined);
- Intermediate Zone: Lower Turlock Lake/Laguna formations (unconfined to locally semi-confined or confined); and
- Deep Zone: Mehrten Formation (unconfined to locally semi-confined or confined).

The base of freshwater in the Eastern San Joaquin Valley Sub-basin near Rindge Tract is approximately 900 feet below ground surface, and most water wells in the vicinity of Rindge Tract are less than 400 feet deep (Eastern San Joaquin Groundwater Authority, 2019). Groundwater monitoring wells designated GMW-S will be screened at similar intervals to nearby public water supply and irrigation wells, which appear to be primarily within the Shallow Zone of the aquifer system. **Figure 8-10** shows the location of nearby water wells. There is only one water well within one mile of Rindge Tract according to California’s Water Well Database; most water wells on record in the vicinity of Rindge Tract are to the east in the north portion of Stockton.

When the borings for the monitoring wells are drilled, Pelican will collect cores and sidewall cores from all three monitoring zones to obtain direct measurements for porosity and permeability. These measurements will be used to inform the calibration of the numerical model.

The monitoring wells for this CO_2 storage project will be installed in clusters such that each water production zone is monitored in the same approximate ground location. Groundwater monitoring well cluster GMW-1 will be located approximately 2,500 feet southwest of CCS Well #1. This cluster was placed in this location because a) it will be close to CCS Well #1 and will capture ambient conditions near this injection well during the pre-operational period; b) be located within the predicted CO_2 plume and pressure front extent within the first five years of injection (**Figures 8-2** and **8-3**); and c) it will be near artificial penetrations that penetrate into the primary upper confining zone (Capay Shale) or deeper. Groundwater monitoring well cluster GMW-2 will be located approximately 2,300 feet southeast of CCS Well #2. This cluster was placed in this location because a) it will be close to CCS Well #2 and will capture ambient conditions near this injection well during the pre-operational period; b) be located within the predicted CO_2 plume and pressure front extent within the first five years of injection (**Figures 8-2** and **8-3**); and c) it will be near artificial penetrations that penetrate into the primary upper confining zone (Capay Shale) or deeper. Both monitoring well clusters GMW-1 and GMW-2 will be installed during the pre-operational period, with two years (eight quarters) of baseline data collected from each of the three wells in both clusters prior to commencement of injection.

Groundwater monitoring well cluster GMW-3 will be located approximately 4,500 feet northeast of CCS Well #1, on the north side of Rindge Tract Island. This well cluster will be installed at a later time (i.e., phased into the monitoring program) such that monitoring will begin during year 5 of the operational period. Two years (eight quarters) of baseline data will also be collected from this cluster (i.e., the cluster would be installed during year 2 such that baseline collection can start during year 3). This cluster was placed in this location because it will be located within the predicted pressure front extent after approximately 5 years of injection (**Figure 8-5**), within the CO2 plume extent by Year 10 (**Figure 8-4**), and will be near artificial penetrations that penetrate into the primary upper confining zone (Capay Shale).

Background Data

Data from the USGS produced waters database were presented in **Section 2, Table 2-7** and **Figure 2-39**. There were no data available for the Mokelumne River Formation or the Domengine Formation. There were limited data available for the Markley-Nortonville Formation (undifferentiated); however, these produced waters data were collected from legacy wells over 10 miles northwest of Rindge Tract. Public water supply wells for the City of Stockton and surrounding communities are tested on an annual basis at a minimum. No site-specific background data have been collected for any of the proposed monitoring units to date. Once the monitoring wells are installed, Pelican will collect baseline data at these wells according to the frequency and schedule described in a following section.

In addition, Pelican may coordinate with the City of Stockton, Eastern San Joaquin Groundwater Authority, and the appropriate landowners (if necessary) to obtain recent analytical and water level data from public water supply and irrigation wells near Rindge Tract. Pelican may additionally measure baseline water levels and pressure profiles at select shallow water wells prior to the commencement of CO_2 injection. Water wells of interest for obtaining and utilizing baseline data would be located on Rindge Tract Island (as irrigation or supply wells) and in the general direction of modeled CO_2 plume and pressure front migration.

Operational Monitoring Strategy

In-zone monitoring wells in the Mokelumne River Formation (GMW-Z) will be monitored according to the frequency outlined under Carbon Dioxide Plume and Pressure Front Tracking and **Table 8-7**. Monitoring of both analytical and field parameters (**Table 8-5**) will take place throughout the operational (injection) period. The primary purpose of these wells is for tracking the CO_2 plume and pressure front within the injection zone. DFOS will be utilized at all GMW-Z wells for continuous temperature and pressure monitoring via DTS/DSS as well as DAS imaging capabilities, which is discussed further in the later subsection Carbon Dioxide Plume and Pressure Front Tracking.

Deep monitoring wells in the Domengine Formation (GMW-D) will be monitored according to the frequency outlined in the next section and **Table 8-4**. Monitoring of both analytical and field parameters in these wells (**Table 8-5**) will take place throughout the operational (injection) period. Closely monitoring the Domengine will, in turn, allow monitoring of both the integrity of the primary upper confining zone, and integrity of existing artificial penetrations within the AOR that penetrate the primary upper confining zone or deeper. Since the Domengine is immediately above the injection and primary upper confining zones, DFOS (specifically DTS/DSS for continuous temperature and pressure monitoring) will be utilized at all GMW-D wells.

Monitoring the lowermost USDW (Markley Formation) and the freshwater aquifer system will also allow monitoring of existing artificial penetration integrity above the confining zones. Deep groundwater units that are not utilized as water sources are therefore not connected to man-made sources that could introduce variability to aqueous geochemistry. Shallow groundwater units, however, can display natural variability in their aqueous geochemistry due to both the geochemistry of the aquifer materials, as well as variability due to connection to man-made sources and other hydrologic influences. In addition, saltwater intrusion from the west is a concern in the freshwater aquifer system (Eastern San Joaquin Groundwater Authority, 2019). Monitoring the freshwater aquifer system in the same manner as the deep, saline units would be inappropriate in the context of this project and could ultimately lead to problematic interpretations when deviation from baseline occurs. As such, shallow monitoring wells in the Freshwater Aquifer System (GMW-S) will be monitored for water levels, pressure, and temperature as outlined in **Tables 8-4** and **8-5**. However, a measured increase in water levels of 10 feet or more, or pressure increase of 30,000 Pa in a shallow monitoring well during any given monitoring event will trigger analytical monitoring for salinity in that well, as specified in **Table 8-4**. Although the Markley Formation is not utilized for water supply and is not expected to be because of its depth, it is considered a USDW based on its salinity. Therefore, the Markley Formation will be monitored in the same manner as the freshwater aquifer system, as specified in **Tables 8-4** and **8-5**. As discussed in **Section 3, Attachment 1** of this application, Pelican conducted numerical modeling to examine overpressure-induced leakage through an improperly plugged well as a result of pressure front migration. The results suggest that monitoring for water level increases and pressure profiles in the freshwater aquifer system and the lowermost USDW is the most efficient and protective method to provide early warning of USDW endangerment.

Monitoring Frequency

All baseline sampling will occur on a quarterly schedule prior to authorization of injection. In order to account for seasonal and temporal variability, the quarterly baseline sampling will take place every 3 months for 8 consecutive quarters (2 years). During the operational period, quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection. All other frequencies proposed herein are specified in **Tables 8-4** and **8-5**.

Pelican will follow the methods outlined in the EPA's Unified Guidance (2009) for evaluating groundwater data. This will include the establishment of site background values during the pre-operational period and how to appropriately determine if data collected during the operational period deviate from site background values using statistics. Additionally, Pelican will continue to optimize the geochemical monitoring parameter list to maximize statistical power within the monitoring network and therefore minimize the site-wide false positive rate during any given sampling event.

The computational model will be calibrated with additional site-specific characterization and monitoring data during the pre-operational period. If future monitoring results suggest differences in the delineated AOR, additional monitoring wells for the operational period (injection phase) may be proposed in a later revision(s) to this Plan.

Table 8-4. Monitoring of Groundwater Quality & Geochemical Changes Above the Confining Zone

Target Formation	Monitoring Location(s)	Estimated Total Depth (ft)	Baseline Data	Operational Plan
Domengine Formation	GMW-1D	4,400	At least four quarterly consecutive events within one year prior to initiating injection	Quarterly monitoring of analytical parameters and continuous monitoring of field parameters (**Table 8-5**), starting when injection commences.
	GMW-2D			
	GMW-3D		At least four quarterly consecutive events within one year prior to Year 5.	Quarterly monitoring of analytical parameters and continuous monitoring of field parameters (**Table 8-5**), starting at Year 5.

Target Formation	Monitoring Location(s)	Estimated Total Depth (ft)	Baseline Data	Operational Plan
Markley Formation (Lowermost USDW)	GMW-1M GMW-2M	<4,000	At least four quarterly consecutive events within one year prior to initiating injection	Quarterly monitoring of water levels and continuous monitoring of field parameters (**Table 8-5**); geochemical monitoring of analytical parameters in **Table 8-5** will be triggered if a water level change or pressure changes are statistically significant compared to the current calibrated flow model results.
	GMW-3M		At least four quarterly consecutive events within one year prior to Year 5.	Quarterly monitoring of water levels and continuous monitoring of field parameters starting at Year 5 (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level change or pressure changes are statistically significant compared to the current calibrated flow model results.
Local Principal Freshwater Aquifer System (Shallow Zone)	GMW-1S GMW-2S	150-350	At least four quarterly consecutive events within one year prior to initiating injection	Quarterly monitoring of water levels and continuous monitoring of field parameters (**Table 8-5**); geochemical monitoring of analytical parameters in **Table 8-5** will be triggered if a water level
	GMW-3S		Eight consecutive quarterly events prior to Year 5.	Quarterly monitoring of water levels and continuous monitoring of field parameters starting at Year 5 (**Table 8-5**); geochemical modeling of analytical parameters in **Table 8-5** will be triggered if a water level change or pressure changes are statistically significant compared to the current calibrated flow model results.

Notes:

1. *See **Figure 8-1** for monitoring locations.*
2. *Post-Operational Period will include all Operational Period well clusters, plus any additional TBD during AOR updates. Refer to the Post-Injection Site Care Plan for additional detail.*
3. *Total depths of monitoring wells will be refined after the stratigraphic test well is drilled and the site-specific depths of the proposed monitoring intervals are confirmed.*

Analytical Parameters

Table 8-5 identifies the parameters to be monitored and the analytical methods Pelican will use. The main suite of analytical parameters includes major cations and anions that will allow geochemical fingerprinting of each monitored unit, as well as minor and trace cations and anions and other geochemical parameters that are likely to be the strongest indicators of CO_2 and formation fluid leakage.

Table 8-5. Summary of Analytical & Field Parameters for Groundwater Samples

Parameters	Analytical Methods
Domengine Formation (Above-Zone) and Mokelumne River Formation (In-Zone)[1]	
Cations: Mn, As	ICP-MS, EPA Method 6020B (U.S. EPA, 2014) or EPA Method 200.8 (U.S. EPA, 1994)
Cations: Ca, Fe, K, Mg, Na	ICP-OES, EPA Method 6010D (U.S. EPA, 2014) (U.S. EPA, 2014) or EPA Method 200.7 (U.S. EPA, 1994)
Anions: Cl and SO_4	Ion Chromatography, EPA Method 300.0 (U.S. EPA, 1993)
Dissolved CO_2	Coulometric titration, ASTM D513-16 (ASTM, 2016)
Total Dissolved Solids	Gravimetry, APHA 2540C (APHA)
Alkalinity	APHA 2320B (APHA, 1997)
pH (field)	EPA 150.1 (U.S. EPA, 1982); downhole gauges – continuously monitored
Specific Conductance (field)	APHA 2510 (APHA, 1992); downhole gauges – continuously monitored
Temperature	Downhole – continuously monitored via DTS
Pressure	Downhole – continuously monitored via DSS
Markley Formation (Lowermost USDW) and Local Principal Freshwater Aquifer System[2]	
Total Dissolved Solids[3]	Gravimetry, APHA 2540C (APHA)
Temperature, Pressure, pH, Specific Conductance	Downhole gauges – continuously monitored

Notes:

1. *In-zone geochemical monitoring is discussed in detail under the section "Carbon Dioxide Plume and Pressure Front Tracking".*
2. *Baseline data to be collected for same suite of parameters as the above-zone and in-zone listed above.*
3. *Parameter only to be monitored if triggered per Table 8-4 during operational period.*

Groundwater sampling will be performed based on the methods and practices described in Section B.1.a of the QASP. (**Appendix 8-A**).

Laboratory to be used/chain of custody procedures

Sample analyses will be conducted by a third-party laboratory certified to conduct the noted analysis in the State of California. See Section B.3 of the Pelican QASP for further information on chain of custody and analysis procedures (**Appendix 8-A**).

External Mechanical Integrity Testing

Pelican will conduct one of the tests presented in **Table 8-6** during the injection phase to verify external MI as required by 40 CFR 146.89(c) and 146.90.

Testing Location & Frequency

As required by the Class VI rule (40 CFR 146.87(a)(4)), an external MIT will be conducted on each well prior to injection to establish baseline. During the injection phase, an external MIT will be conducted annually on each well as required by 40 CFR 146.89(c) and 146.90(e), up to 30 days before the anniversary date of authorization of injection each year. After cessation of injection and prior to plugging of the injection wells, final external MITs will be conducted as required by 40 CFR 146.92(a). The DFOS sensors deployed at Rindge Tract CCS Well #1 and #2 will additionally allow supplemental continuous monitoring of external mechanical integrity.

In addition to continuous monitoring via DTS/DAS, one of the following MITs will be performed during each testing period:

Table 8-6. MITs

Test Description	Location	Frequency
Standard Temperature Logging	• Injection well casing • Monitoring well casing	• Annually for the injection well during injection phase • Every 5 years on in-zone monitoring wells (GMW-Z)
Standard Noise Logging	• Injection well casing • Monitoring well casing	• Annually for the injection well during injection phase • Every 5 years on in-zone monitoring wells (GMW-Z)
Temperature and Noise Logging via DTS/DAS	• Rindge Tract CCS Well #1 and #2, outside of the long string casing from storage interval to surface	• Continuous

Testing Details

Temperature logging is used to identify temperature anomalies near the well bore, which can therefore allow the identification of casing leaks. In order to conduct temperature logging, the injection well must be shut-in (i.e., temporary cessation of injection) to allow any temperature effects related to injection to dissipate and for temperature to equilibrate towards a static level. 36 hours is generally thought to be a sufficient shut-in period (USEPA, 2013; USEPA Region 5, 2008); therefore, this will be the minimum shut-in period for conducting temperature logging. The temperature logging tool is a wireline tool that is slowly lowered into the well casing, while measurements are collected in real time. A baseline temperature survey is conducted prior to injection. Intermediate and final temperature survey(s) will follow injection. Any leakage of fluids out of the injection well will be an anomaly in the otherwise linear temperature log, as the temperature within the surrounding formation will be altered from the leaking fluid. All logs will be compared to the baseline log taken prior to injection.

Standard temperature logging tools are capable of detecting very small changes in temperature. However, the accuracy and precision of the logging tool is dependent on the movement of the tool within the well casing during the logging process. The tool must be moved slowly in order to obtain accurate measurements and in order for the results to be reproducible, the movement speed must be consistent as well.

Standard noise logging is used to detect turbulent flow resulting from irregular channels formed within well cement, therefore allowing the detection of leaks within the well cement. Unlike temperature logging, noise logging can be completed while injection is still occurring. As recommended by USEPA (2013), measurements will be made at intervals of 100 feet to first create a log on a coarse grid. If any anomalies are found on the coarse log, a finer grid will be constructed on the coarse intervals with high noise levels at intervals of 20 feet. In addition, measurements will be made at 10-foot intervals through the first 50 feet above the injection interval and at intervals of 20 feet within 100 feet above that zone and the base of the lowermost USDW. Additional measurements may be taken as needed to distinguish at what depths the noise is produced. As with temperature logging, all logs will be compared to the baseline log taken prior to injection, and any departures will be considered an anomaly. The USEPA UIC Program Class VI Well Testing and Monitoring Guidance (2013) suggests that: “Ambient noise while injecting that produces a signal greater than 10 millivolts (mV) may indicate leakage and potential loss of external mechanical integrity.” Therefore, this will constitute a failure of the noise log MIT.

Radioactive tracer surveys (RTSs) may be used if anomalies are identified in temperature or noise logs. These surveys can identify the presence or absence of vertical fluid movement behind the casing near perforations in the injection wells. As outlined in USEPA’s Class VI Testing and Monitoring Guidance (2013), RTSs use a wireline tool that consists of an injector stage, one or more gamma radiation detector devices, and a collar locator (to pinpoint the location of leaks in reference to permanent markers) or correlation to a gamma ray log that is scaled to show lithologic effects. Using a collar locator will reveal whether an identified leak is at a collar, while using a gamma ray correlation log clarifies the stratigraphic location of the leak. The radioactive tracer should be an anionic material and is usually iodine-131 because of its short (eight-day) half-life.

A RTS may include more than one type of test (i.e., slug test or velocity shot; McKinley (1994)) and it involves releasing the radioactive tracer into the tubing above the interval to be tested and subsequently measuring gamma radiation as it moves through the well. In the slug test, a slug of tracer is released, and the tool is lowered up and down the well repeatedly while the position of the slug(s) is tracked. In the velocity shot method, the detectors are stationary and monitor the time at which the slug passes. The relative positions of the injector and stationary detectors are variable. Three detectors are sometimes used, with two below the injector. This allows for very accurate measurement of the speed of the injectate and simplifies location of the upward limit of leakage by eliminating some repositioning of the tool. RTSs can be effective for locating leaks in both the tubing and the casing. Testing is commonly conducted during injection where it is best to maintain an injection rate as close to the maximum injection rate as practical. After a slug of radioactive material is injected, it will migrate into the injection zone. If a measurable leak is present, the gamma ray detector will identify an area of increased radioactivity after the slug has passed. Importantly, to distinguish the impact of lithologic features, the gamma ray log needs to be compared to a baseline log that was run before injection commenced. If no additional radiation is observed after the slug has passed compared to the baseline log, the well has demonstrated internal mechanical integrity at the depth tested (USEPA, 2013).

Temperature and noise logging via DTS/DAS will allow continuous monitoring for leak detection along the entire length of the long string casing. The use of permanent fiber optics for mechanical integrity testing avoids the need to shut-in the injection well and temporarily cease injection operations. The sensors have robust sensitivity and report monitoring data in real-time. This will be a supplemental monitoring method in addition to standard testing methods highlighted above.

Internal MITs are also required by the Class VI rule in order to demonstrate that there are no significant leaks in the injection well construction materials. This is covered in the preceding section of this plan entitled "Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]." In addition to these continuously monitored parameters, the above-described external MITs, and as discussed in **Section 6 – Pre-Operational Testing Program**, a Standard Annulus Pressure Test (SAPT) will be conducted prior to commencing operations and annually during operations. As described in EPA's guidance for standard annulus pressure tests, the annular space will be pressurized and pressure readings will be recorded for a minimum of one hour. Internal mechanical integrity will be confirmed if the pressure gain or loss does not exceed 3% of the initial test pressure.

All monitoring wells under this permit will be designed and constructed to maintain mechanical integrity. Once constructed, in-zone monitoring wells (designated GMW-Z) will undergo a baseline external MIT and additional external MIT at least every 5 years thereafter until the monitoring wells are plugged.

Pressure Fall-Off Testing

Pelican will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

Testing Location & Frequency

Pressure fall-off testing will be performed:

- During injection, at least every 5 years; and
- At the end of the injection period.

Pelican will conduct fall-off testing according to the testing details below. The permitting agency will be notified 30 days before testing commences.

Testing Details

Pelican envisions performing pressure fall-off tests on its injection wells one at a time while injection continues at the other well(s), provided pressure communication between the wells during testing does not occur. To conduct pressure fall-off testing at an injection well, injection of CO_2 will be ceased temporarily (i.e., shut-in the injection well). Details on temporary CO_2 stream routing for both scheduled and unscheduled shut-ins can be found in the Contingency Plan. A wireline tool for continuous pressure and temperature monitoring will be deployed downhole with a casing collar locator. The wireline tool with a downhole pressure sensor will be set in the injection interval and prepared for injection. Following a one-hour equalization period, the wireline will record the baseline pressure. Using the existing pumps, the well operator will commence injection at a constant rate at or above the normal injection rate and continue for a minimum of one week. Pelican will periodically measure and record the injection rate and collect samples for analytes specified in **Table 8-1** of this plan (CO_2 stream analysis). Following injection, the well will be shut-in for at least four days or until adequate pressure transient data are collected to calculate the average pressure. Temperature measurements will be collected in conjunction with the pressure measurements to assist in data interpretation. The tools will be removed from the well and operation of the well will be returned to the well operator. A report containing the pressure fall-off data and interpretation of the reservoir ambient pressure will be submitted to the permitting within 30 days of the test.

Carbon Dioxide Plume & Pressure Front Tracking

Pelican 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).

Table 8-7 presents the methods that Pelican will use to monitor the position of the CO_2 plume and pressure front, including the activities, locations, and frequencies Pelican will employ. Quality assurance procedures for these methods are presented in section A.4.a of the QASP (**Appendix 8-A**).

Figures 8-2, **8-4**, **8-6**, and **8-8** show the monitoring locations relative to the predicted CO_2 plume extent in five-year time intervals during the operational (injection) period.

Direct Plume Monitoring Details

Pelican will directly monitor CO_2 plume migration and geochemical changes within the injection zone via geochemical sampling at in-zone monitoring wells (i.e., GMW-1Z, GMW-2Z, and GMW-3Z). The parameters to be analyzed as part of direct fluid sampling in the injection zone and associated analytical methods were presented in **Table 8-5**. The monitoring frequency is detailed below in **Table 8-7**.

Direct Pressure-Front Monitoring Details

Pelican will utilize Distributed Fiber Optic Sensing (DFOS) at Rindge Tract CCS Wells #1 and #2 and the in-zone (i.e., GMW-1Z, GMW-2Z, and GMW-3Z) monitoring wells along the outside of the long string casing. Pelican will use Distributed Temperature Sensing (DTS)/ Distributed Strain Sensing (DSS) for direct, continuous, real-time monitoring of temperature and the pressure front within the injection zone. Sensors are equipped with variable density clips to enable detection prior to casing perforation. DFOS will also be utilized in the above-zone (i.e., GMW-1D, GMW-2D, and GMW-3D) monitoring wells for continuous temperature and pressure monitoring.

Indirect Plume & Pressure-Front Monitoring Details

Indirect geophysical monitoring of the plume and pressure front is required to supplement the direct pressure front monitoring.

Pelican will conduct a baseline 3D seismic survey prior to the authorization of injection. This will supplement the site characterization efforts and assist in the refinement of the geologic model by providing additional details on the initial state of the reservoir (Mokelumne River Formation) prior to injection.

The DFOS network at Rindge Tract CCS Wells #1 and #2 will also be utilized for the indirect monitoring activities. Time-lapse 3D vertical seismic profiles (VSPs) will indirectly monitor the CO_2 plume movement and development. VSPs use DAS and offer higher resolution images of the subsurface than surface seismic, as well as better repeatability (El-kaseeh et al., 2018). These surveys will be conducted on an annual basis during the operational period, up to 45 days before the anniversary date of authorization of injection each year. Additionally, DAS will be used to monitor microseismicity. DAS continuously detects and reports seismic events as small as magnitude -1.4 in real-time.

Refer to **Appendix 8-C** of this Plan for additional details on the DFOS technology and applications for CO_2 plume and pressure front monitoring.

Table 8-7. Plume & Pressure-Front Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
Mokelumne River Formation (Injection Zone)	Direct fluid sampling and geochemical analysis	GMW-1Z, GMW-2Z, GMW-3Z	Perforated interval to be determined following construction of stratigraphic test well	Pre-Operational: At least four consecutive quarterly events Operational: Quarterly Post-Operational: Quarterly
DIRECT PRESSURE-FRONT MONITORING				
Mokelumne River Formation (Injection Zone)	DTS/DSS	Rindge Tract CCS Well #1 and #2;	Distributed measurements from surface to base of storage interval	Pre-Operational: Continuous Operational: Continuous Post-Operational: Continuous (throughout PISC at in-zone wells; ending prior to final MIT and plugging at injection wells)
INDIRECT PLUME AND PRESSURE-FRONT MONITORING				
Mokelumne River Formation (Injection Zone)	3D Seismic Survey	Full AOR coverage, focused on plume extent area	Approximately X acres	Pre-Operational: One baseline survey
	Time-Lapse VSP Survey	Rindge Tract CCS Well #1 and #2; GMW-1Z, GMW-2Z, GMW-3Z	Full coverage of approximately 1154 acres	Pre-Operational: One baseline survey Operational and Post-Operational: Annual

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Mokelumne River Formation (Injection Zone)	DAS Passive Seismicity	Rindge Tract CCS Well #1 and #2; GMW-1Z, GMW-2Z, GMW-3Z	Vertical: distributed measurements from surface to base of storage interval Lateral: 1154 acres	<u>Pre-Operational:</u> Continuous <u>Operational:</u> Continuous Post-Operational: Continuous (throughout PISC at in-zone wells; ending prior to final MIT and plugging at injection wells)

Notes:

1. *Pre-operational monitoring/baseline will be conducted before injection is authorized.*
2. *Operational monitoring will be conducted during the injection phase.*

Throughout the operational period, Pelican will review and evaluate plume and pressure front migration data on a quarterly basis at a minimum. As stated in the Area of Review and Corrective Action Plan, data will be considered a deviation when pressure front and/or plume tracking data differ from model predictions by 25% or more. Should this deviation occur, an AOR re-evaluation will be triggered. Refer to the Area of Review and Corrective Action Plan for additional detail on the AOR re-evaluation process.

Summary

This Testing and Monitoring Plan for Pelican Renewables, LLC summarizes an integrated strategy for monitoring various aspects of the Rindge Tract CO_2 storage project, including well integrity, various operational parameters, and changes imposed on the geologic system by injection practices (i.e., plume, pressure front, and potentially groundwater quality). This comprehensive Plan is based on the delineated AOR for the operation of both Class VI injection wells (Rindge Tract CCS#1 and #2). Pelican considered all aspects of the storage project that could potentially endanger USDWs in the vicinity of the project and presented herein an integrated, robust, and efficient strategy to protect all USDWs during the operational phase. In order to ensure optimal USDW protection past the operational phase, this strategy was additionally used to develop the Post-Injection Site Care Plan (**Section 10**).

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USEPA (2013). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance. EPA 816-R-13-001. Prepared by the Office of Water (4606M), March 2013. www.epa.gov/safewater.

Figures

Legend

- Monitoring well
- Injection Well

Artificial Penetrations

- Penetrates Capay Shale into MRF
- Penetrates top of Capay Shale
- Delineated Area of Review
- Maximum Extent of Pressure Front
- Maximum Predicted Extent of Super Critical CO_2
- Rindge Tract Island

Note:
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

FIGURE 8-1
OVERVIEW OF THE PROPOSED MONITORING NETWORK WITHIN THE AOR
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | February 2024

0 3,500 7,000 Feet

N

Legend

- ☆ Monitoring well
- ★ Injection Well
- Maximum Predicted Extent of Super Critical CO_2 for the Given Year

Artificial Penetrations

- Penetrates Capay Shale into MRF
- Penetrates top of Capay Shale
- Rindge Tract Island

FIGURE 8-2

PREDICTED CO_2 PLUME EXTENT - YEAR 5

PELICAN RENEWABLES INC.

SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | February 2024

0 3,500 7,000 Feet

N

Legend

☆ Monitoring well

★ Injection Well

Maximum Pressure Front Extent for the Given Year

Artificial Penetrations

● Penetrates Capay Shale into MRF

● Penetrates top of Capay Shale

Rindge Tract Island

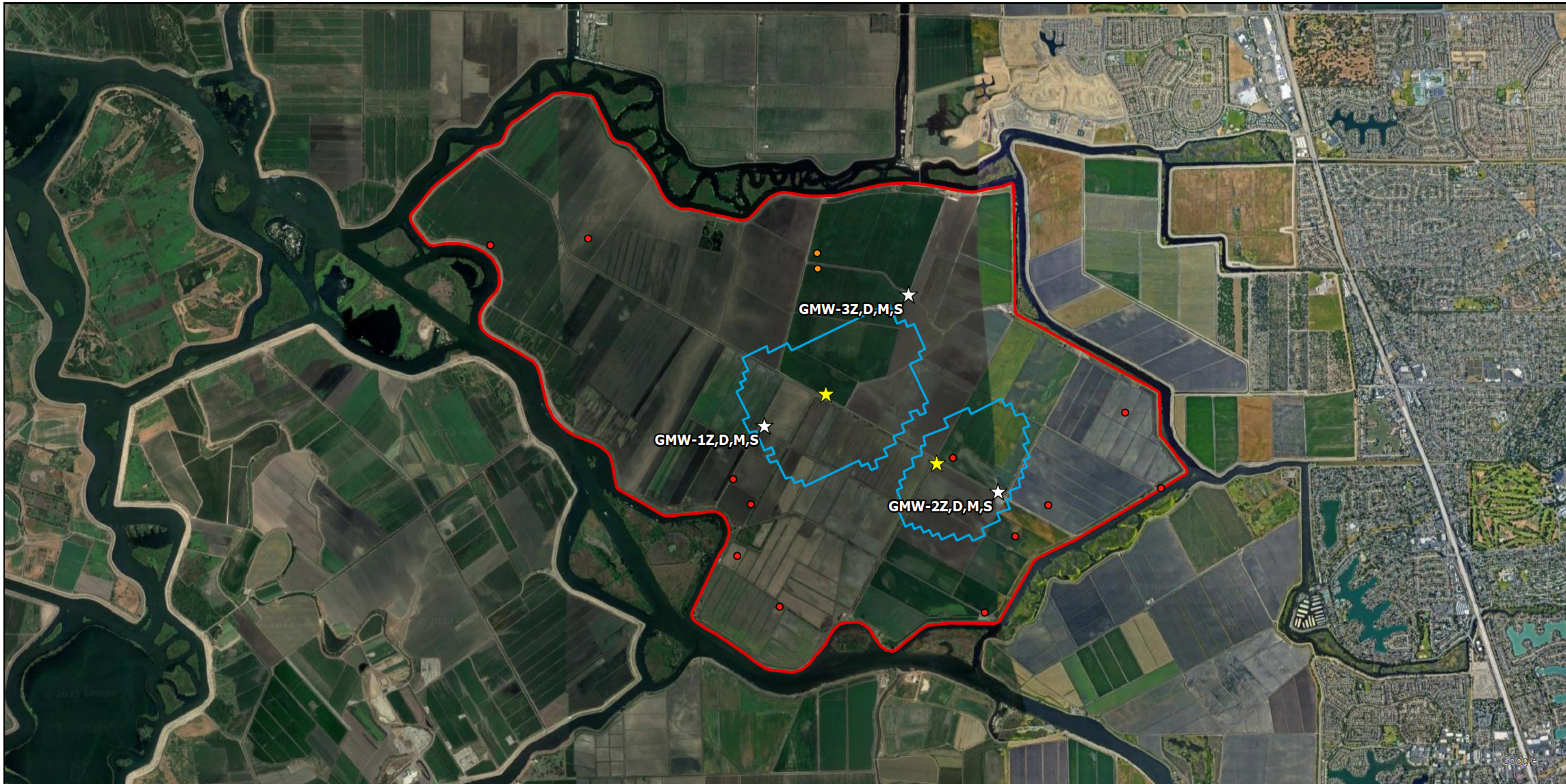
Note:
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

FIGURE 8-3
PREDICTED PRESSURE FRONT EXTENT - YEAR 5
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | February 2024

0 3,500 7,000 Feet

N



Legend

- ☆ Monitoring well
- ★ Injection Well
- Maximum Predicted Extent of Super Critical CO2 for the Given Year

Artificial Penetrations

- Penetrates Capay Shale into MRF
- Penetrates top of Capay Shale
- Rindge Tract Island

FIGURE 8-4

PREDICTED CO_2 PLUME EXTENT - YEAR 10

PELICAN RENEWABLES INC.

SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | February 2024

0 3,500 7,000 Feet

N

Legend

☆ Monitoring well

★ Injection Well

Maximum Pressure Front Extent for the Given Year

Artificial Penetrations

● Penetrates Capay Shale into MRF

● Penetrates top of Capay Shale

Rindge Tract Island

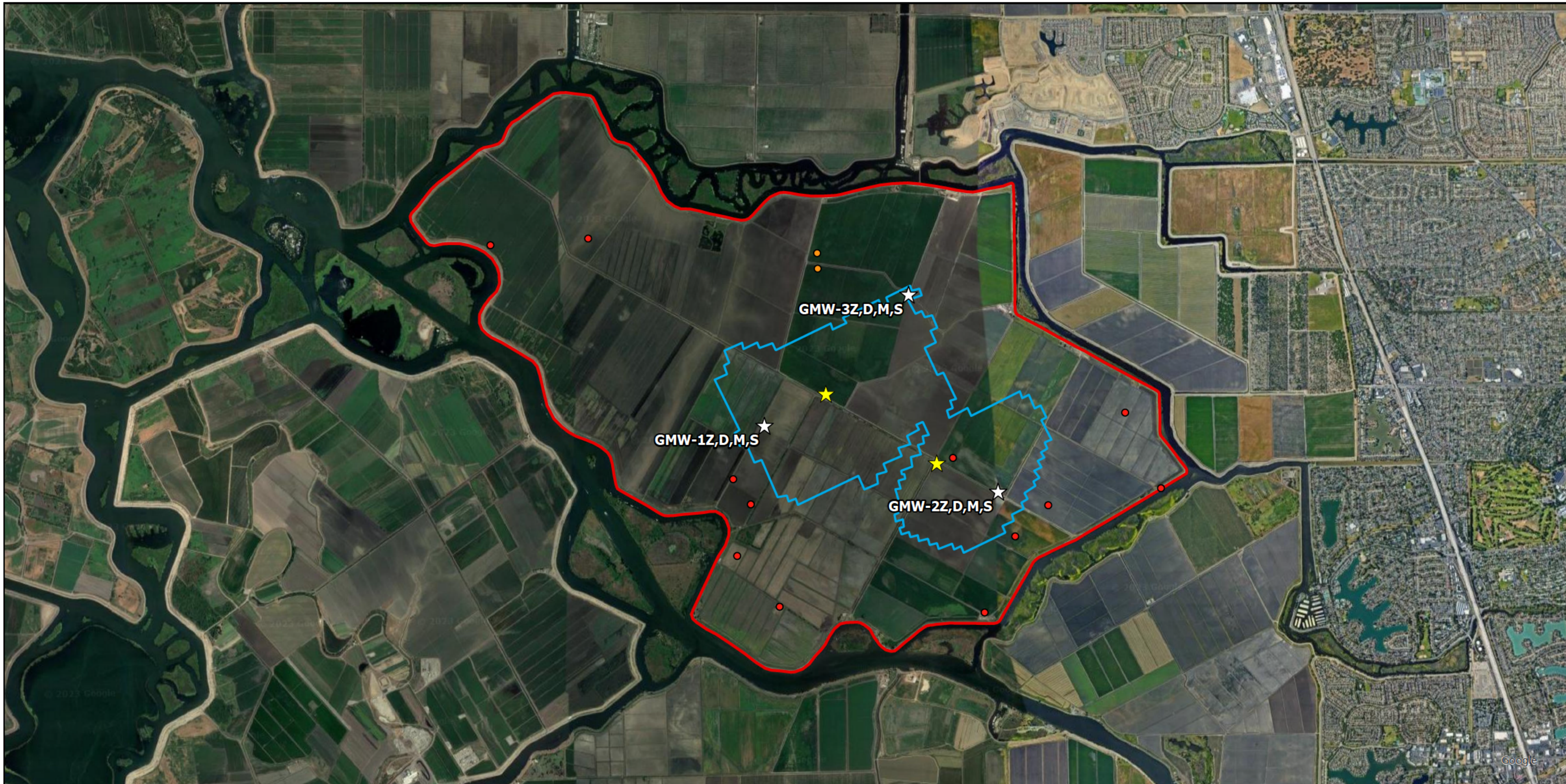
Note:
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

FIGURE 8-5
PREDICTED PRESSURE FRONT EXTENT - YEAR 10
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | February 2024

0 3,500 7,000 Feet

N



Legend

- Monitoring well
- Injection Well
- Maximum Predicted Extent of Super Critical CO_2 for the Given Year

Artificial Penetrations

- Penetrates Capay Shale into MRF
- Penetrates top of Capay Shale
- Rindge Tract Island

FIGURE 8-6

PREDICTED CO_2 PLUME EXTENT - YEAR 15

PELICAN RENEWABLES INC.

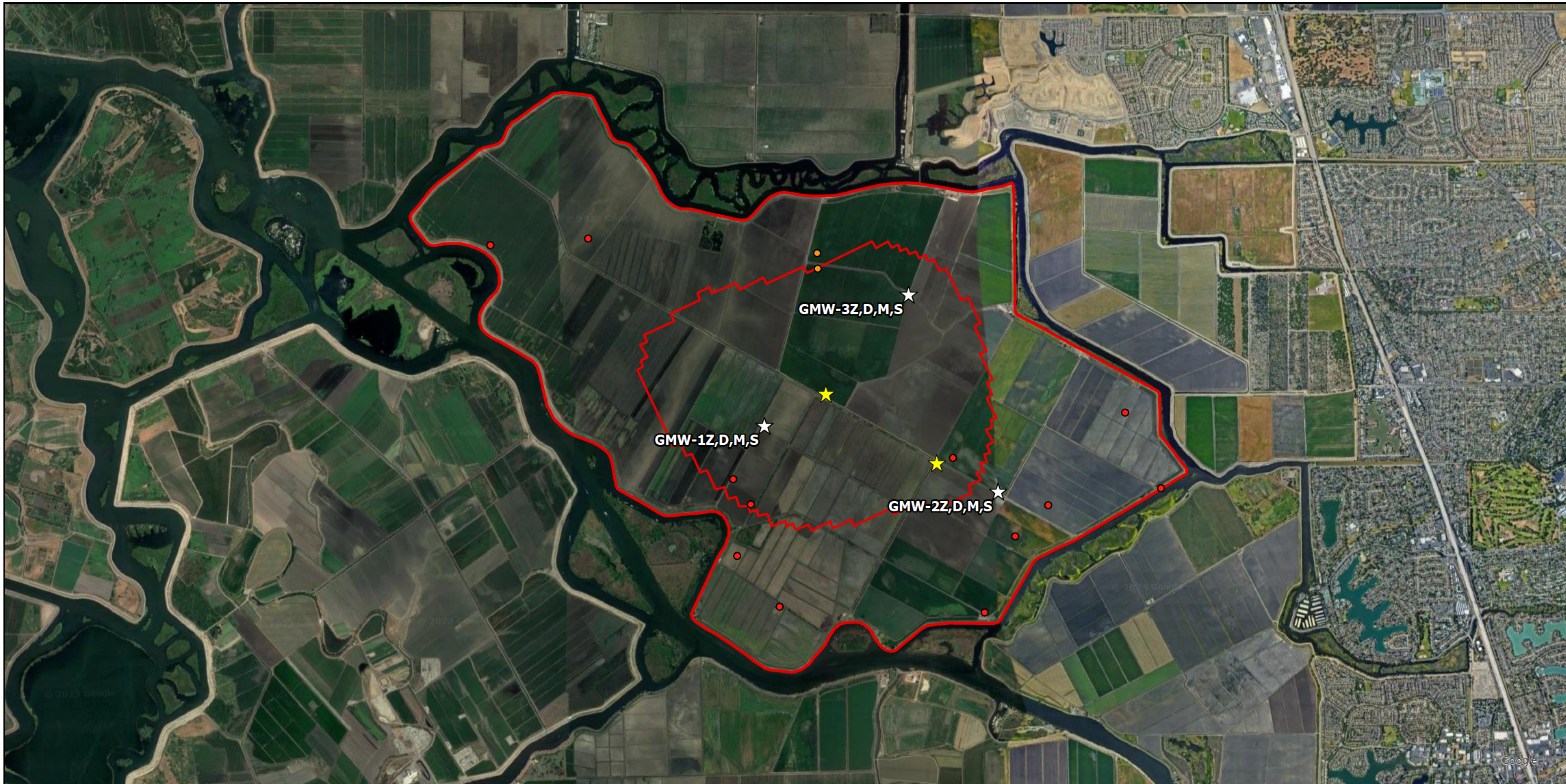
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | February 2024

0 3,500 7,000 Feet

N



Legend

☆ Monitoring well

★ Injection Well

Maximum Pressure Front Extent for the Given Year

Artificial Penetrations

● Penetrates Capay Shale into MRF

● Penetrates top of Capay Shale

Rindge Tract Island

Note:
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

FIGURE 8-7
PREDICTED PRESSURE FRONT EXTENT - YEAR 15
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | February 2024

0 3,500 7,000 Feet

N

Legend

- ☆ Monitoring well
- ★ Injection Well
- Maximum Predicted Extent of Super Critical CO_2 for the Given Year

Artificial Penetrations

- Penetrates Capay Shale into MRF
- Penetrates top of Capay Shale
- Rindge Tract Island

FIGURE 8-8

PREDICTED CO_2 PLUME EXTENT - YEAR 20
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | February 2024

0 3,500 7,000 Feet

N

Legend

- Monitoring well
- Injection Well
- Maximum Pressure Front Extent for the Given Year

Artificial Penetrations

- Penetrates Capay Shale into MRF
- Penetrates top of Capay Shale
- Rindge Tract Island

Note:
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

FIGURE 8-9
PREDICTED PRESSURE FRONT EXTENT - YEAR 20
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | February 2024

0 3,500 7,000 Feet
N

Legend

- ☆ Monitoring well
- ★ Injection Well
- Delineated Area of Review

Groundwater Wells

- <900' in Depth
- Depth Unknown
- Rindge Tract Island

FIGURE 8-10
SHALLOW WATER WELLS IN THE VICINITY
OF RINDGE TRACT ISLAND
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS
Wichita, KS | February 2024

0 5,000 10,000 Feet

N

Appendix 8-A

Appendix 8-A: Quality Assurance and Surveillance Plan

March 4, 2025

Pelican Renewables, LLC

Rindge Tract CCS Wells #1 and #2

Table of Contents

List of Tables

Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Pelican Renewables, LLC Rindge Tract Carbon Sequestration Injection Site. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

Signature	Date

TBD

Testing and Monitoring Plan Lead

Signature	Date

TBD

Rindge Tract CCUS Project Lead

Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Table A.1 lists the individuals that should receive a copy of the approved Quality Assurance and Surveillance Plan (QASP) and any subsequent revisions.

Table A.1. Distribution List

Name	Organization	Project Role	Contact (telephone, email)
John Zuckerman	Pelican Renewables, LLC	Managing Member	917-868-4346 john.zuckerman@pelicanrenewables.com
TBD	Pelican Renewables, LLC	Testing and Monitoring Plan Lead	TBD
TBD	Pelican Renewables, LLC	Rindge Tract CCUS Project Lead	TBD

A. Project Management

A.1. Project/Task Organization

A.1.a/b Key Individuals & Responsibilities

The project will be owned and operated by Pelican Renewables, LLC (Pelican), who will serve as the lead on project tasks while supervising the performance of contractors when required for individual tasks. The Project Manager will be responsible for the implementation of this QASP during pre-operational testing. The Operations Manager will be responsible for implementation of this QASP during injection and post-injection site care. Tasks which are related to testing and monitoring for the proposed project that will require supervision for the purposes of quality control and assurance are broadly divided into:

1. Groundwater Sampling and Analysis
2. Well Logging
3. Mechanical Integrity Testing and other Operational Testing
4. Injection Monitoring
5. CO_2 Stream Sampling and Analysis
6. Geophysical Monitoring

A.1.c. Independence from Project QA Manager & Data Gathering

Most of the data gathered as part of the testing and monitoring program will be analyzed, processed, or witnessed by third parties independent from and outside of the project management structure. Pelican will provide the UIC Program Director with the name and credentials of any vendors, subcontractors, or testing laboratories used for testing and monitoring protocols during each reporting period.

A.1.d. QA Project Plan Responsibility

Pelican (under the oversight of individuals listed in the distribution list) has the final responsibility for development, maintenance, and distribution of this QASP, and its conformance with all applicable quality requirements. Pelican will periodically review this QASP and consult the UIC Program Director if/when changes to the plan are warranted based on changes made to the Testing and Monitoring Plan or other applicable project plans.

A.1.e. Organizational Chart for Key Project Personnel

Pelican Renewables, LLC will add an organizational chart for key project personnel once determined.

A.2. Problem Definition/Background

A.2.a. Reasons for Initiating the Project

Pelican Renewables, LLC and its affiliates (Pelican) aim to design, permit and implement a Carbon Capture and Storage (CCS) project in the San Joaquin Delta, California (the Delta) to help achieve the promise of the Delta as a major carbon sequestration site. Pelican sees this project as a locally conceived and funded Delta-centric pilot project that will pave the way for broad efforts to prove up the Delta as a major storage site to help transition fossil fuel dependence phase out consistent with stated California objectives.

Pelican acquired the Pacific Ethanol facility at the Port of Stockton in November 2021. It is currently operating as a terminal facility. Pelican hopes to be able to recommence ethanol production within 6-12 months, depending on ethanol markets and demand and progress in the CCS permitting arena.

Once ethanol production is restarted, the Stockton plant will produce 60 million gallons of corn ethanol per year and capture 140,000 metric tonnes of CO_2 in the process. The CO_2 is purified to food grade standards by our subtenant Airgas. Airgas is entitled to distribute 25% of the product into the food market (mostly beverages) and return 75% to Pelican. That CO_2 will be piped to docks at the Port of Stockton under high pressure, loaded onto specifically designed barges and transported by low-emission tug boats to docks constructed at Rindge Tract where the CO_2 will be injected into competent permanent storage a mile or more beneath the land surface. Various permits will be required (or have been obtained in the case of the ethanol production and processing) for each step of the process.

When completed, the Pelican project will jump start a "new economy" for the Delta as a greenhouse gas repository and provide resilience against local impacts of global warming and sea level rise, while helping to reduce the threats of both.

A.2.b. Regulatory Information

The U.S. Environmental Protection Agency (EPA) established requirements for CO_2 geologic sequestration under the Underground Injection Control (UIC) Program for Geologic Sequestration (GS) Class VI Wells. These federal requirements (codified in the U.S. Code of Federal Regulations [40 CFR 146.81 et seq.], known as the Class VI Rule) set minimum technical criteria for CO_2 injection wells for the purposes of protecting underground sources of drinking water (USDWs). Testing and Monitoring Requirements (40 CFR 146.90) under the Class VI Rule require owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan that includes injectate monitoring; corrosion monitoring of the well's tubular, mechanical, and cement components; pressure fall-off testing; groundwater quality monitoring; and CO_2 plume and pressure-front tracking. These requirements (40 CFR 146.90[k]) also require owners and operators to submit a QASP for all testing and monitoring requirements.

This QASP details all aspects of the testing and monitoring activities that will be conducted, and ensures that they are verifiable, including the technologies, methodologies, frequencies, and procedures involved. As the project evolves, this QASP will be updated in concert with the Testing and Monitoring Plan.

A.3. Project/Task Description

Pelican will implement the Testing and Monitoring Plan as part of its program to verify that the storage site is operating as permitted and is not endangering any Underground Sources of Drinking Water (USDWs). The Testing and Monitoring Plan includes operational CO_2 injection stream monitoring, well corrosion monitoring, mechanical integrity and other operational testing, geochemical and indicator parameter monitoring of the reservoir, above-zone, and USDWs, and indirect geophysical monitoring, for characterizing the complex fate and transport processes associated with CO_2 injection.

A.3.a/b. Summary of Work to be Performed/Instrumentation

As summarized in **Table A.3.1,** Pelican plans to drill two (2) injection wells and twelve (12) monitoring wells strategically placed in specific formations with a specified function. **Table A.3.2** describes the general testing and monitoring activities, location, and purpose. Please refer to the **Testing and Monitoring Plan** and associated tables and figures for detailed descriptions of planned activities and methods, monitoring frequencies, and sample locations.

Table A.3.1 Pelican Project Well Summary

Well Type	Well Names	Geologic Unit	Estimated Depth (ft below ground surface)
Shallow USDW Monitoring	GMW-1S, GMW-2S, GMW-3S	Local Principal Freshwater Aquifer System	150-350
Lowermost USDW Monitoring	GMW-1M, GMW-2M, GMW-3M	Markley Formation	<4,000
Above-Zone Monitoring	GMW-1D, GMW-2D, GMW-3D	Domengine Formation	4,400
In-Zone Monitoring	GMW-1Z, GMW-2Z, GMW-3Z	Mokelumne River Formation	5,200-6,400
Injection Wells	Ringde Tract CCS #1 and CCS #2	Mokelumne River Formation	6,946 (CCS #1) 6,880 (CCS #2)

Table A.3.2. Summary of Testing & Monitoring

Activity	Location(s)	Method	Analytical Technique	Purpose
CO_2 Stream Analysis	Sampling Manifold	Laboratory analysis of CO_2 stream	Chemical Analysis	Analysis of injectate 40 CFR 146.90(a)
Injection rate and volume	Well #1 and #2 Wellheads Downhole in the injection well above packer	Coriolis Mass-Flow Transmitter or equivalent flow meter System Totalizer	Direct, continuous measurement	Continuous monitoring of injection rate and volume 40 CFR 146.90(b)
Injection pressure	Well #1 and #2 Wellheads Outside of the long string casing, along wellbore to packer	Electronic Pressure Transducer DSS	Direct, continuous measurement	Continuous monitoring of injection pressure 40 CFR 146.90(b)
Annular pressure	Well #1 and #2 Wellheads	Electronic P/T Gauge or equivalent pressure transducer	Direct, continuous measurement	Continuous monitoring of annular pressure 40 CFR 146.90(b)
Annular Volume	Well #1 and #2 wellheads	Annular volume gauge and record	Continuous direct measurement	Continuous monitoring of annulus fluid volume 40 CFR 146.90(b)
Downhole pressure/ temperature	CCS #1 and #2; GMW-1Z, GMW-2Z, GMW-3Z	Electronic Gauge or equivalent transducer, DTS	Direct measurement via downhole sensors and continuous fiber optics	Continuous monitoring of injection zone pressure and temperature 40 CFR 146.90(g)(1)
Corrosion monitoring	Well #1 and #2 Wellheads	Corrosion Coupon	Chemical analysis	Corrosion monitoring 40 CFR 146.90(c)

Activity	Location(s)	Method	Analytical Technique	Purpose
Mechanical integrity	CCS Wells #1 and #2, outside of the long string casing from storage interval to surface In-Zone wells, external only (GMW-1Z, GMW-2Z, GMW, 3Z)	External – Temperature or Noise Logging; Distributed Temperature Sensing (DTS) Internal – Annular pressure gauge monitoring (injection wells only)	Direct measurement Distributed indirect measurement (DTS)	Demonstration of internal and external mechanical integrity of the wellbore 40 CFR 146.90(e)
Groundwater Quality and Geochemical Monitoring[1]	Mokelumne River Formation (GMW-1Z through -3Z) Domengine Formation (GMW-1D through -3D) Markley Formation (Lowermost USDW, GMW-1M through -3M) Local Principal Freshwater Aquifer System (GMW-1S through -3S)	Fluid Sampling & Analysis and Bottom Hole Gauges	Chemical analysis and continuous direct measurement	Groundwater quality and geochemical monitoring 40 CFR 146.90(d)
CO_2 Plume and Pressure Front Monitoring	Injection Zone	DAS/DTS/DSS Downhole pressure gauges, Pulsed Neutron Capture (PNC) logs, and 3D Distributed Acoustic Sensing (DAS) VSPs	Real-time, continuous fiber optics Direct and indirect measurements	CO_2 plume imaging and pressure front tracking 40 CFR 146.90(g)
Pressure Fall Off Testing (FOT)	Injection tubing, CCS #1 and CCS #2	Pressure gauge or wireline tool	Direct Measurement	CO2 plume imaging and pressure front tracking 40 CFR 146.90(g)

Table A.3.3 shows the instrumentation summary that will be used to conduct the Testing and Monitoring Plan. Please refer to the Testing and Monitoring Plan for a detailed description of the testing and monitoring frequencies.

Table A.3.1. Instrumentation Summary

Monitoring Location	Instrument Type	Explanation	Monitoring Target (Formation or Other)	Data Collection Location(s)
CO_2 Facility	CO_2 Sampling and Analysis (S&A)	Used to analyze the chemical characteristic of the injectate stream to ensure compliance with the operators expected injectate stream composition.	N/A	Sampling manifold
CCS #1, CCS #2	Mass Flow Meter	Used to record total mass of CO_2 injected.	N/A	Wellhead
	Pressure/Temperature Gauges	Used to monitor injection zone for direct pressure front evolution, and for containment loss detection.	Mokelumne River Formation	Injection Zone
	DTS/DSS/DAS	Injection well external mechanical integrity, identify the vertical intervals taking injectate within the reservoir for use in computational model updates, and containment loss detection.		
	3D DAS VSP	Indirect CO_2 plume imaging		
GMW-1Z, GMW-2Z, GMW-3Z	Pressure/Temperature Gauges	Used to monitor injection zone direct pressure front evolution, and for containment loss detection.	Mokelumne River Formation	Injection Zone
	Groundwater S&A	ID pre-injection groundwater quality and geochemistry and monitor for changes during injection to track CO_2 plume		
	DTS/DSS/DAS	Identify the vertical intervals taking injectate within the reservoir for use in computational model updates, and containment loss detection.		
	3D DAS VSP	Indirect CO_2 plume imaging		
GMW-1D, GMW-2D, GMW-3D	Pressure Gauges	Used to monitor pressure front evolution, and for containment loss detection.	Domengine Formation	Above-Confining Zone
	Groundwater S&A	ID pre-injection groundwater quality and geochemistry and monitor for changes during injection; Early CO_2 and reservoir brine containment loss detection/verification		

Monitoring Location	Instrument Type	Explanation	Monitoring Target (Formation or Other)	Data Collection Location(s)
GMW-1M, GMW-2M, GMW-3M	Pressure/Temperature Gauges	Used to monitor pressure front evolution, and for containment loss detection.	Markley Formation	Lowermost USDW
	Groundwater S&A	ID pre-injection groundwater quality and geochemistry; CO_2 and reservoir brine containment loss detection/verification		
GMW-1S, GMW-2S, GMW-3S	Pressure/Temperature Gauges	Used to monitor pressure front evolution, and for containment loss detection.	Local Principal Aquifer System	Shallow USDW
	Groundwater S&A	ID pre-injection groundwater quality and geochemistry; CO_2 and reservoir brine containment loss detection/verification		

The objective of the storage site monitoring program is to select and implement a suite of monitoring technologies that are both technically robust and cost-effective and provide an effective means of 1) evaluating CO_2 mass balance (i.e., verify that the site is operating as permitted) and 2) detecting any unforeseen containment loss (i.e., verify that the site is not endangering any USDWs). Both direct and indirect measurements will be used collaboratively with numerical models of the injection process to verify that the storage site is operating as predicted and that CO_2 is effectively sequestered within the Mokelumne River Formation and is fully accounted for. The approach is based in part on reservoir-monitoring wells, pressure fall-off testing, and indirect (e.g., geophysical) methods. Early-detection monitoring wells will target regions of increased leakage potential (e.g., proximal to wells that penetrate the caprock). During baseline monitoring, a comprehensive suite of geochemical analyses will be performed on fluid samples collected from the reservoir and overlying monitoring intervals.

These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Selection of this initial analyte list was based on relevance for detecting the presence of reservoir formation fluids and CO_2. The results for this comprehensive set of analytes will be evaluated and a determination made regarding which analytes to carry forward through the operational phases of the project. Indicator parameters will be used to inform the monitoring program. Once baseline conditions and early CO_2 arrival responses have been established, observed relationships between analytical measurements and indicator parameters will be used to guide less-frequent aqueous sample collection and reduced analytical parameters in later years.

A.3.c. Geographic & Stratigraphic Locations

Surface locations within the AoR of all injection and monitoring wells, identified containment loss risks, and the CO_2 plume extents throughout the project are shown in Testing and Monitoring Plan. Injection wells and in-zone monitoring wells will be completed in the Mokelumne River Formation. Above-zone monitoring wells will be completed in the first porous and permeable interval above the primary confining layer, the Domengine Formation. USDW monitoring wells will be completed in the lowermost USDW within the AoR (Markley Formation) and shallow USDWs that are part of the local principal aquifer system in San Joaquin County.

A.3.d. Resource & Time Constraints

Pelican will coordinate deployment and uses of the monitoring and testing equipment described in the Testing and Monitoring Plan and in this QASP appropriate for field operations, service company availability (where necessary), and other field-level logistics and operations.

A.4. Quality Objectives & Criteria

A.4.a. Performance/Measurement Criteria

The qualitative and quantitative design objective of the Pelican CO_2 Storage Project's testing and monitoring activities is to develop and implement procedures for subsurface monitoring, field sampling, laboratory analysis, and reporting which will provide results to meet the characterization and non-endangerment goals of the Pelican Storage Project. The design of these activities is intended to provide reasonable assurance that decision errors regarding compliance with the permit and/or protection of the USDW are unlikely. In accordance with EPA 2013 EPA 816-R-13-001 – Testing and Monitoring Guidance, the well testing and monitoring program includes operational CO_2 injection stream monitoring, well MIT, geochemical and indicator parameter monitoring of groundwater above the confining zone, and indirect geophysical monitoring.

The monitoring well network will address transport uncertainties by using an "adaptive" or "observational" approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring results). The below **Tables A.4.1** through **Table A.4.13** summarize the specifications and action limits of technologies used for testing and monitoring.

Table A.4.1. Summary of Analytical Parameters for CO_2 Stream

Parameters	Analytical Methods(1)	Detection Limit/Range	Typical Precisions	QC Requirements
Carbon Dioxide (CO_2) (% vol)	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD	90.00% to 99.9%	± 15% of reading	User calibration per manufacturer
Methane	ISBT 10.1 (FID)	10 ppmv	± 15% of reading	daily standard within 10% of calibration, secondary standard after calibration
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD	1 uL/L to 5,000 uL/L (ppm by volume)	± 15% of reading	daily standard within 10% of calibration, secondary standard after calibration
Oxygen, Hydrogen, Argon	ISBT 4.0 (GC/DID) GC/TCD	1 uL/L to 5,000 uL/L (ppm by volume)	± 10% of reading	daily standard within 10% of calibration, secondary standard after calibration
Water Content	ISBT 11.0 (GC/FID)	To be updated with manufacturer specifications	To be updated with manufacturer specifications	To be updated with manufacturer specifications
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 15% of reading relative across the range	daily blank, daily standard within 10% of calibration, secondary standard after calibration

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Sulfur dioxide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)- dilution dependent	5 - 15% of reading relative across the range	daily blank, daily standard within 10% of calibration, secondary standard after calibration
Oxides of nitrogen	ISBT 7.0 Colorimetric	5 uL/L to 100 uL/L (ppm by volume)	± 20% of reading	duplicate analysis
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)	5 uL/L to 100 uL/L (ppm by volume)	± 20% of reading	duplicate analysis
Total Hydrocarbons	ISBT 10.0 THA (FID)	1 uL/L to 10,000 uL/L (ppm by volume)	5 - 10% of reading relative across the range	daily blank, daily standard within 10% of calibration, secondary standard after calibration

1. *An equivalent method may be employed with the prior approval of the UIC Program Director.*
2. *Abbreviations: GC=Gas Chromatography; FID=Flame Ionization Detector; DID=Discharge Ionization Detector; TCD=Thermal Conductivity Detector; SCD=Sulfur Chemiluminescence Detector*

Table A.4.2. Summary of Analytical & Field Parameters for Fluid Sampling

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Mn, As	ICP-MS EPA Method 6020B (U.S. EPA, 2014a) or EPA Method 200.8 (U.S. EPA, 1994a)	0.001 to 5 mg/L (Analyte, dilution, and matrix dependent)	±15%	Daily Calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na	ICP-AES / ICP-OES EPA Method 6010D (U.S. EPA, 2014b) or EPA Method 200.7 (U.S., EPA, 1994b)	0.005 to 2 mg/L (Analyte, dilution, and matrix dependent)	±15%	Daily Calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions: Cl, SO4	Ion Chromatography EPA Method 300.0 (U.S. EPA, 1993)	0.02 to 0.13 mg/L (Analyte, dilution, and matrix dependent)	±15%	Daily Calibration: blanks and duplicates at 10% or greater frequency
	Coulometric Titration ASTM 513-16 (ASTM, 2016)	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Dissolved CO_2				
Total Dissolved Solids	Gravimetry APHA 2540C (APHA)	12 mg/L	±15%	Balance calibration, duplicate analysis
pH (field)	EPA 150.1 (U.S. EPA, 1982)	2 to 12.5 pH units	±0.2 pH unit	User Calibration per manufacturer recommendation
Specific Conductance (field)	APHA 2510 (APHA, 1992)	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50 ºC	±0.2 ºC	Factory Calibration

1. *An equivalent method may be employed with the prior approval of the UIC Program Director.*
2. *Abbreviations: ICP=inductively coupled plasma; MS= mass spectrometry; OES= Optical emission spectrometry; GC-P=Gas chromatography-Pyrolysis*

Table A.4.3. Summary of Analytical Parameters for Corrosion Coupons

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2018 (NACE, 2018)	0.005 mg	±2%	Annual Calibration of Scale (3rd Party)
Thickness	NACE RP0775-2018 (NACE, 2018)	0.001 mm	±0.005 mm	Factory calibration

Table A.4.4. Specifications for MIT Testing & Geophysical Monitoring Technology

Logging Tool	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements	Calibration Frequency
Ultrasonic Cement Bong Log (SLB USI Tool)	Vendor best practice	0-10 MRayl (acoustic impedence)	±0.5 MRayl (acoustic impedence)	Vendor Calibration (3rd party)	Per Vendor Discretion
DTS	Vendor best practice	-40 ºF to 149 ºF	0.01 ºC	Vendor Calibration (3rd party)	Per Vendor Discretion

Table A.4.5. Summary of Measurement Parameters for Field Gauges/CO_2 Injection Process Monitoring

Parameters	Methods	Detection Limit/Range	Vendor Specified Accuracy	QC Requirements	Calibration Frequency
Operational Annular Pressure Monitoring	ISO/IEC 17025 (2017)	0-3,000 psi	± 0.5% FS	Annual Calibration (3rd party)	As suggested by control system/gauge manufacturer
Wellhead Injection pressure (e.g., PPS PPS31 Wellhead Pressure Logger or similar product)	ISO/IEC 17025 (2017)	0-5,000 psi	±0.03% FS	Annual Calibration (3rd party)	As suggested by gauge manufacturer
Injection mass flow rate (e.g., Emerson Coriolis mass flow meter or similar product)	AGA Report 3 API Chapter 14 Part 3 (API, 2016)	547.95-3,561.64 mt/day	±0.1% of rate for liquid ±0.35% of rate for gas	Annual Calibration (3rd party)	As suggested by gauge manufacturer
Downhole Pressure (e.g., Baker Hughes SureSENS QPT ELITE pressure/temperature gauge of similar product)	NA	200 psi to 10,000 psi	± 0.015% FS	Initial Manufacturer Calibration	Not required on downhole gauges

Table A.4.6. Actionable Testing & Monitoring Outputs

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External mechanical integrity	Loss of external mechanical integrity	Based on experienced log analyst's interpretation	Based on experienced log analyst's interpretation
Internal mechanical integrity	Loss of internal mechanical integrity	Failure of annular pressure test	Pressure drop outside prescribed limits
Surface/Downhole pressure	Injection stops if maximum surface injection pressure (MASP) is reached or 90% fracture pressure downhole is reached	Refer to **Table A.4.7** and **A.4.9**	<2,405 psi (CCS#1) or < 2,360 psi (CCS#2) at surface <4,489 psi (CCS#1) or < 4,440 psi (CCS#2) downhole
Above-zone water quality (fluid sampling) and pressure	Action to be taken when chemical profile anomaly is observed	Refer to **Table A.4.2**	Profiles TBD during baseline
DTS/DAS/DSS	Action to be taken when a temperature, pressure, or strain anomaly is observed	Refer to **Table A.4.4** and **Appendix**	Difference between profiles observed during baseline & injection (TBD during baseline)
CO_2 plume monitoring	Action to be taken if CO_2 plume is observed outside of expected/modeled spatial limits/geologic intervals	Dependent on geologic conditions	Profiles TBD during baseline

A.4.b. Precision

For groundwater samples, data accuracy will be assessed through field blanks and trip blanks. Field and trip blanks will be taken no less than one per sampling event to check for sample bottle contamination. Assessment of analytical precision will be the responsibility of the individual laboratories. Third party laboratories used will be EPA-approved and certified laboratories. Industry standard sampling and analysis procedures will be followed to obtain sample results with the highest possible level of precision.

A.4.c. Bias

Assessment of analytical bias is to be the responsibility of the individual laboratories per their standard operating procedures and analytical methodologies.

A.4.d. Representativeness

Data representativeness is the degree to which data accurately and precisely represent a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The monitoring network has been designed to provide data representative of site-specific conditions. Representativeness of groundwater analytical results will be estimated by ion and mass balances. Ion balances within ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help identify the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample will be considered non-representative.

A.4.e. Completeness

It is anticipated that data completeness of 90% for groundwater sampling will be acceptable to meet monitoring goals for the Pelican Storage Project. In cases of direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

A.4.f. Comparability

Datasets for the Pelican Storage Project will be generated in accordance with a consistent methodology so that each dataset is directly comparable to another. This allows for appropriate data comparison and identification of anomalies if present. To ensure appropriate QA/QC standards, direct pressure, temperature, and logging measurements obtained through the proposed operations will be directly comparable to data previously obtained.

A.4.g. Method Sensitivity

Table A.4.7 through **Table A.4.13** summarize additional details on gauge and logging tool specifications and sensitivities.

Table A.4.7. Downhole Pressure Gauge Vendor Specifications

Parameter	Value
Calibrated working pressure range	200 psi to 10,000 psi
Initial pressure accuracy	+-0.015% (1.5 psi at full scale)
Pressure resolution	0.0001 psi
Pressure drift stability	2.0 psi per year at full scale
Note: Specifications from the Baker Hughes SureSENS QPT ELITE Pressure Gauge are provided as an example of typical specifications from a vendor. A similar product may be used.	

Table A.4.8. Representative Logging Tool Specifications

Parameter	Ultrasonic Imager Log	DAS Fiber	DTS Fiber
Logging speed	1,800 ft/hr.	NA	NA
Vertical resolution	6 inches	25cm	25-50 cm
Investigation	Casing-to-cement interface	0-24.8 miles	At fiber location
Temperature rating	350°F (175°C)	500°F (250°C)	500°F (250°C)
Pressure rating	20,000 psi	20,000 psi	20,000 psi
Note: Specifications from Baker Hughes are provided as an example of typical specifications from a vendor. A similar product may be used			

Table A.4.9. Wellhead Pressure/Temperature Gauge

Parameter	Value
Calibrated working pressure range	0-5,000 psi
Initial pressure accuracy	±0.03% full scale
Pressure resolution	0.0003% full scale
Pressure drift stability	< 3.0 psi
Calibrated working temperature range	-4 ºF to 158 ºF
Initial temperature accuracy	±0.09 ºF
Temperature resolution	0.02 ºF
Max temperature	158 ºF
Note: Specifications from a PPS PPS31 Wellhead Pressure Logger are provided as an example of typical specifications from a vendor. A similar product may be used.	

Table A.4.10. Pressure Field Gauge-Injection Tubing

Parameter	Value
Calibrated working pressure range	0 – 5,000 psi and 4-20 mA
Initial pressure accuracy	<0.05%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	To be determined after first year

Table A.4.11. Pressure Field Gauge-Annulus Pressure

Parameter	Value
Calibrated working pressure range	0 to 5,000 psi
Initial pressure accuracy	< 0.05 %
Pressure resolution	0.001 psi
Pressure drift stability	To be determined after first year

Table A.4.12. Temperature Field Gauge-Injection Tubing, Annulus Temperature

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	To be determined after first year

Table A.4.13. Mass Flow Rate Field Gauge-CO_2 Mass Flow Rate

Parameter	Value
Calibrated working flow rate range	547.95-3,561.64 mt/d; Range spanning maximum anticipated injection rate per well with typical precision and accuracy of 0.5%
Initial mass flow rate accuracy	±0.10% of rate (liquid), ±0.35% of rate (gas)
Mass flow rate resolution	±0.10% of rate (liquid), ±0.20% of rate (gas)
Mass flow rate drift stability	To be determined
Note: Specifications from an Emerson Coriolis Mass Flow Meter are provided as an example of typical specifications from a vendor. A similar product may be used.	

A.5. Special Training/Certifications

A.5.a. Specialized Training & Certifications

All equipment and tools used for testing and monitoring will be operated by trained, qualified, and, where required, certified personnel according to the service company which provides the equipment. Subsequent data will be processed and analyzed by appropriately skilled personnel according to industry standards.

Groundwater sampling and laboratory chemical analysis will be evaluated by EPA-certified laboratories. Some special training will be required for project personal, particularly in the areas of certain geophysical methods, certain data-acquisition/transmission systems, and certain sampling technologies.

Pelican will provide relevant certifications and qualification for all vendor/subcontractor staff upon request by the UIC Program Director.

A.5.b/c. Training Provider & Responsibility

A Pelican-designated subcontractor will provide necessary training for personnel for the testing and monitoring activities. Training documentation will be maintained as project QA records.

A.6. Documentation & Records

The monitoring program is broken down into several focus areas:

- *Operational Monitoring:* CO_2 stream analysis, CO_2 injection rate and pressure, annular pressure/volume, corrosion monitoring.
- *Hydrogeologic Testing:* Pressure fall-off tests.
- *Mechanical Integrity Testing:* DTS and temperature or noise logging.
- *Direct Plume/Pressure Monitoring:* Fluid sampling, downhole pressure gauges
- *Indirect Plume Subsurface Monitoring:* DAS, VSPs, DTS.
- *Above-Zone Monitoring:* Downhole pressure gauges, fluid sampling.
- *USDW Monitoring:* Downhole pressure gauges, fluid sampling.

Each of the various monitoring areas will produce variable data types and will have unique data management needs. To organize and utilize data as required, databases will be developed for each of the data types based on their data management needs. Raw data will be screened, validated, and pre-processed as needed by qualified professionals to produce data ready for interpretation and reporting.

A.6.a. Report Format & Package Information

Pelican will provide the UIC Program Director with semi-annual reports containing all relevant project data and testing and monitoring information for the reporting period in compliance with 40

CFR 146.91(a). These reports will follow the format and content requirement specified in the final permit, including required electronic data formats. A.6.b. Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well and testing logs, installation and plugging reports, or other data will be stored and maintained for 10 years following site closure and provided at the request of the UIC Program Director.A.6.c/d. Data Storage and Duration Pursuant to 40 CFR 146.91(f)(3), any monitoring data collected through implementation of the Testing and Monitoring Plan will be retained for at least 10 years after it is collected and routinely backed up. All site characterization data will be retained throughout the life of the project and for at least 10 years following site closure.

A.6.b. QASP Distribution Responsibility

The Pelican Project Manager during pre-operational testing or the Pelican Storage Project Operations Manager during injection and post-injection will be designated as the responsible party for ensuring that all those on the distribution list will receive the most current copy of the approved QASP.

B. Data Generation & Acquisition

The primary goal of testing and monitoring activities is to verify that the Pelican Storage Project carbon dioxide (CO_2) storage site is operating as permitted and is not endangering any underground sources of drinking water (USDWs). To this end, the primary objectives of the testing and monitoring program are to track the lateral extent of supercritical carbon dioxide ($scCO_2$) within the target reservoir; characterize any geochemical or geomechanical changes that occur within the reservoir, caprock, and overlying aquifers; monitor any change in land-surface elevation associated with CO_2 injection; determine whether the injected CO_2 is effectively contained within the reservoir; and detect any adverse impact on USDWs.

This element of the Quality Assurance and Surveillance Plan (QASP) addresses data-generation and data-management activities, including experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to each testing and monitoring method. It should be noted that not all of these QASP aspects are applicable to all testing and monitoring methods.

B.1. Sampling Process Design

This section describes the design of the proposed monitoring network, which was developed to ensure safe, long-term containment of CO_2 within the injection intervals and non-endangerment of USDWs, human health, and the local environment.

B.1.a. Design Strategy

CO_2 Stream Monitoring Strategy

The objective of routinely analyzing the CO_2 stream is to evaluate the potential interactions of CO_2 and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports regulatory determinations under the Resource Conservation and Recovery Act (RCRA, 1976) and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, 1980). Additionally, monitoring the chemical and physical characteristics of the CO_2 may help distinguish the injectate from the native fluids and gases if unintended leakage from the injection zone occurs.

Corrosion Monitoring Strategy

Pelican will conduct corrosion monitoring of well materials to meet the requirements of 40 CFR 146.90(c). Corrosion-monitoring activities are designed to monitor the integrity of the injection wells throughout the operational period. This includes using corrosion coupons as well as periodic cement-evaluation and casing inspection logs when tubing is removed from the well (i.e., during well workovers). Monitoring will be conducted in accordance with the NACE RP0775-2018 (NACE, 2018) standard to identify and document corrosion rates based on mass loss and thickness changes. Corrosion coupons will be made of the same materials as the long string of casing and the injection tubing, and will be placed in the CO_2 pipeline for ease of access.

Groundwater Monitoring Strategy

Pelican will follow the methods outlined in the EPA's Unified Guidance (2009) for evaluating groundwater data. This will include the establishment of site background values during the pre-operational period and how to appropriately determine if data collected during the operational period deviate from site background values using statistics. Additionally, Pelican will continue to optimize the geochemical monitoring parameter list to maximize statistical power within the monitoring network and therefore minimize the site-wide false positive rate during any given sampling event.

The planned groundwater quality monitoring well network layout, number of wells, well design, and sampling regimen are based upon site-specific characterization data, and consider structural dip, the locations of existing wells, expected ambient flow conditions, and the potential for heterogeneities or horizontal/vertical anisotropy within the overburden materials. Pelican plans to conduct periodic fluid sampling as well as continuous monitoring of field parameters throughout the injection phase in monitoring wells as detailed in the Testing and Monitoring Plan. Pelican will also conduct thorough baseline sampling of all monitored zones as detailed in **Section A.4.a** and the Pelican **Testing and Monitoring Plan**

Shallow Zones

Shallow groundwater monitoring wells designated as GMW-M will be installed and screened in the Markley Formation (lowermost USDW). Wells designated GMW-S in the Eastern San Joaquin

Valley Sub-basin's principle freshwater aquifer system (uppermost USDW) will monitor the geochemistry of groundwater commonly accessed by water wells in the area. The analyte list in **Table 8-5** of the **Testing and Monitoring Plan** covers both baseline and operational monitoring. After baseline is collected and sufficiently characterized, Pelican may request a reduced set of analytes in consultation with the UIC Program Director. During any period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO_2 or brine migration, the analytical list would be expanded to the original set of monitoring parameters.

Above Zone

Pelican will conduct groundwater geochemical monitoring above the confining zone to meet the requirements of 40 CFR 146.90(d). The proposed monitoring wells will be constructed to monitor the sands within the Domengine Formation, which is the first reasonably permeable sand unit above the primary confining zone, at the GMW-D well pads. The purpose of the above-zone wells is to detect early leakage above the confining zone. MIT and downhole pressure monitoring at the injection wells will also provide data to ensure maintained well mechanical integrity. Prior to injection, baseline conditions will be documented and natural variability in conditions will be characterized. During injection or post-injection, this monitoring setup aims to detect unintended brine or CO_2 leakage. Pelican will collect sufficient data to demonstrate long-term containment within the storage reservoir.

Parameters include selected constituents that: (1) have primary and secondary EPA drinking water maximum contaminant levels, (2) will geochemically interact with CO_2 or brine, (3) are needed for quality control, and (4) may be needed for geochemical modeling. After the baseline is established, Pelican may request a reduced set of analytes that are (1) the most responsive to interaction with CO_2 or brine and (2) are needed for quality control to accurately test for and monitor the presence (or lack thereof) of CO_2 migration. Implementation of a reduced set of parameters would be done after the approval of the UIC Program Director. During any period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO_2 or brine migration, the analytical list would be expanded to the original set of monitoring parameters. The full list of analytical parameters and methods is provided in **Table 8-5** of the **Testing and Monitoring Plan** and **Table A.4.2** of this **QASP**.

Direct CO_2 Plume & Pressure Front Monitoring Strategy

Geochemical samples will be conducted and analyzed at the in-zone monitoring wells (GMW-1Z, GMW-2Z, GMW-3Z) to monitor for geochemical changes induced by CO_2 injection and to directly track the position of the CO_2 plume. Distributed Fiber Optic Sensing (DFOS) technology (DTS/DAS) will be deployed at the injection well and in-zone monitoring wells to continuously monitor temperature and pressure within the injection zone. Downhole pressure/temperature gauges will also be installed to monitor for changes in the formation pressure and temperature in response to injection.

Indirect CO_2 Plume & Pressure Front Monitoring Strategy

Several technologies will be deployed within the injection and in-zone monitoring wells to indirectly monitor the presence/absence of the CO_2 plume and elevated pressure front. A fiberoptic line with DTS/DAS capabilities will be cemented along the outside of the long-string casing through the confining zone and into the injection zone to continuously record temperature and acoustic variations. External mechanical integrity at all deep wells (injection and in-zone) will be monitored continuously using DTS. Noise and temperature logging will be utilized to verify external MIT for the injection well and in-zone wells throughout the injection phase.

B.1.b. Type & Number of Samples/Test Runs

Please refer to **Table A.3.2** for descriptions of sampling and test runs type. The number of samples and test runs are described in detail in the **Testing and Monitoring Plan.**

B.1.c. Site/Sampling Locations

Please refer to **Tables A.3.1** and **Table A.3.2** and the **Testing and Monitoring Plan** for descriptions of sampling and test locations.

B.1.d. Sampling Site Contingency

All testing and monitoring techniques will take place on private property. The binding unitization agreement that is in place among all Rindge Tract property owners ensures that Pelican will have access to the monitoring well locations throughout the life of the project. If inclement weather makes site access difficult, sampling schedules will be revised, and alternative dates may be selected that would still meet permit-related conditions.

B.1.e. Activity Schedule

Please refer to the **Testing and Monitoring Plan** for sampling and test schedules.

B.1.f. Critical/Informational Data

During sampling and analysis activities, detailed field and laboratory documentation will be collected in standard forms or notebooks. Critical information will include the time, date, and location of the activity; personnel involved; analytical equipment used; and a record of the analytical parameters, calibrations, and standards. For laboratory analyses, many critical data are generated during the analysis process and provided to end users in digital and printed formats. Noncritical data may include appearance and odor of the sample, issues with well or sampling equipment, and weather conditions.

B.1.g. Sources of Variability

Potential sources of variability relating to testing and monitoring activities include:

- Natural variation in formation pressure/temperature, fluid quality, and seismic activity.
- Induced variation in formation pressure/temperature, fluid quality, and seismic activity associated with project operations.
- Seasonal variability in groundwater.
- Changes in instrument calibration during sampling or analytical activity.
- Different personnel collecting or analyzing samples.
- Environmental conditions during field sampling.
- Changes in analytical data QA/QC procedures during the life of the project.
- Data entry errors.

Variability related to testing and monitoring activities may be eliminated or mitigated by:

- Gathering sufficient baseline data to observe natural variation in monitoring parameters.
- Analyzing chemical data within the appropriate holding times after collection to observe anomalies that can be addressed by resampling or reanalyzing.
- Conducting statistical analysis of data to determine whether variability is natural or unexpected.
- Maintaining weather-related data from onsite sources or from nearby locations (such as a local airport).
- Verifying instrument calibration before, during, and after sampling and analysis (as applicable/based on manufacturer's standards.
- Ensuring that staff are fully trained to complete the applicable work.
- Performing laboratory quality assurance checks using third party reference materials, and/or blind/duplicate samples.
- Utilizing a systematic review process of data that may include sample-specific data quality checks.

B.2. Sampling Methods

B.2.a/b. Sampling Standard Operating Procedures

The primary groundwater sampling method will be a low-flow sampling method consistent with ASTM D6452-99 (ASTM, 2005) or Puls and Barcelona (Puls et al., 1996). Prior to sampling, wells will be purged to ensure samples are representative of formation fluids. Before any purging or sampling activities begin, static water levels will be measured using an electronic water level indicator. Each groundwater monitoring well will contain a dedicated pump (e.g., bladder pumps). Given sufficient flow rates and volumes, field parameters such as groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell (where applicable) consistent with standard methods (APHA 2005). Probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three (3) minutes apart meet the criteria listed in **Table B.2.1.**

Table B.2.1. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging

Field Parameter	Stabilization Criteria
pH, temperature, specific conductance, dissolved oxygen, turbidity	*Parameter measurement until ±10% value stabilization
**Exact parameter stabilization threshold will depend on which purge method is selected from ASTM DX.*	

Groundwater samples will be collected after field parameters have stabilized. Flow-through filter cartridges (0.45 micrometers [µm]) will be utilized as required and consistent with ASTM D6564-00 (ASTM, 2017) for samples requiring field-filtering prior to analysis. Prior to sample collection, filters will be purged with a minimum of 1000 milliliters (mL) of well water (or as advised by the filter manufacturer). Samples will have minimal exposure to the atmosphere during filtration, collection in sample containers, and analysis.

B.2.c/d. In-Situ & Continuous Monitoring

In-situ monitoring of groundwater chemistry is not planned. Continuous monitoring is discussed below.

Injection Monitoring

Data related to the operational process (injection rate and volume, annular pressure and volume, and injection pressure) will be continuously monitored with pressure gauges, flow meters, and the annulus monitoring system, all of which will be linked to the surface control system controlled by Pelican. This operational data will ensure that injection is operating safely, efficiently, and not posing a risk to any USDWs. Additionally, continuously monitored operational parameters will be utilized in the reservoir and computational models to validate that the CO_2 plume and pressure front are migrating as expected.

Distributed Temperature Sensing (DTS)

DTS technology will continuously collect temperature data along a fiberoptic line installed along the outside of the long-string casing. The DTS line will collect temperature data along the long-string casing at set intervals of time which will be used when running external mechanical integrity tests to verify mechanical integrity and monitor the presence or absence of the CO_2 plume.

Distributed Acoustic Sensing (DAS)

DAS technology will continuously collect acoustic data along the long-string casing. Additionally, DAS will be utilized during VSPs to measure the arrival times of seismic waves in the subsurface to monitor the footprint of the CO_2 plume through imaging and to passively monitor and report micro-seismic events.

Pressure Gauges

Downhole pressure gauges will be deployed within all deep wells to continuously measure pressure variations within the injection zone and the above-zone monitoring zones. These gauges will directly monitor the presence or absence of the injection-related pressure front.

B.2.e. Sample Homogenization, Composition, Filtration

See **Section B.2.a/b** for further information.

B.2.f. Sample Containers & Volumes

All samples will be collected in new or sanitized containers using industry-accepted standards and practices provided by the analytical laboratory. Container type and size for each sample type are listed in **Table B.2.2** and **Table B.2.3.**

B.2.g. Sample Preservation

Sample preservation methods are outlined in **Table B.2.2** and **Table B.2.3.**

Table B.2.2. Summary of Sample Containers, Preservation Treatments, & Holding Times for CO_2 Gas Stream Analysis

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample Storage Cabinets	72 Hours

Table B.2.3. Summary of Anticipated Sample Containers, Preservation Treatments, & Holding Times for Groundwater Samples

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: **Ca, Fe, K, Mg, Na, Mn, As**	250 mL/HDPE	Trace metal-grade nitric acid, cool 4°C	60 days
Dissolved CO_2	2 × 60 mL/HDPE	Filtered, cool 4°C	14 days
Alkalinity, anions (Cl, SO4)	500 mL/HDPE	Cool 4°C	45 days

Field Confirmation: Temperature, dissolved oxygen, specific conductance, pH	200 mL/glass jar	None	< 1 hour
Total Dissolved Solids	150-1000 mL/HDPE	None	14 days

B.2.h. Cleaning/Decontamination of Sampling Equipment

Dedicated pumps (e.g., bladder pumps) will be installed in each groundwater monitoring well. Each installed pump will remain in the well for the duration of the project except for maintenance or replacement. The pumps will be cleaned on the outside before installation with a non-phosphate detergent. The pump will then be rinsed appropriately with deionized water. At least 1.0 liter (L) of deionized water will be cycled through the pump and tubing. Individual prepared pumps and tubing will be placed in clean containers for transport to the field for installation. All sampling glassware (such as pipettes, beakers, filter holders, etc.) will be cleaned using tap water and then washed in a dilute nitric acid solution before being thoroughly rinsed with deionized water prior to use.

B.2.i. Support Facilities

The following tools may be needed to sample groundwater: generator, vacuum pump, compressor, multi-electrode water quality sonde, and various meters to take analytical measurements such as pH and electrical conductance. Analytical field activities may take place in field vehicles and/or portable onsite trailers. Well gauges used for verification will be handled using industry standard best practices and procedures recommended from the vendor. Proper PPE, including nitrile gloves, safety goggles, hard hat, high-visibility clothing, and steel-toed boots will be worn by field and support personnel during field activities.

Coupons consisting of material that will directly contact the CO_2 stream will be placed within a flowline. Each sample will be attached to an individual holder and inserted in a flow through pipe arrangement, exposing the samples to the CO_2 stream, and allowing access for removal and testing. The flow through pipe arrangement will be located at the well location downstream of all process compression, dehydration, and pumping equipment. A parallel stream of high-pressure CO_2 will be routed from the flowline through the corrosion monitoring system. This loop will operate while injection is occurring, providing representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. Injection will be able to continue while samples are removed for testing.

B.2.j. Corrective Action, Personnel, & Documentation

Properly testing equipment and implementing corrective actions on broken or malfunctioning field equipment will be the responsibility of field personnel. If corrective action is not possible in the field, then equipment will be sent back to the manufacturer or qualified technician to be repaired, serviced, or replaced. Substantial corrective actions that may impact analytical results will be documented in field notes. If defective equipment causes disruptions to the approved sampling schedule, Pelican will contact the UIC Program Director.

B.3. Sample Handling & Custody

Sample handling and hold times will comply with US EPA (US EPA, 1974), APHA (APHA, 2005), Wood (Wood, 1976), and ASTM Method D6517-00 (ASTM, 2005) standards. Samples will be kept at their preservation temperature and sent to the selected laboratory within 24 hours of collection, or sooner if warranted by hold times. Analysis of the samples will be completed within the holding time specified in **Table B.2.3.** If alternative sampling methods become necessary, these methods will be discussed with the UIC Program Director prior to sampling and the Testing and Monitoring Plan will be modified as necessary.

B.3.a. Maximum Hold Time/Time Before Retrieval

Please refer to **Table B.2.2** and **Table B.2.3** for details.

B.3.b. Sample Transportation

Samples will be transported in coolers with ice and sent to the selected laboratory to meet specified hold times.

B.3.c. Sampling Documentation

Sampling personnel will assess field documentation for completeness before departing the field and will compile field documentation for all samples collected. Field notes will be archived for future reference.

B.3.d. Sample Identification

Each groundwater sample container will have a label with the following information: project name/number, sample date and location, sample ID number, fresh or brine water, volume taken, analyte, filtration used (if applicable), and preservative used (if any). Refer to **Table B.2.2** and **Table B.2.3.**

B.3.e. Sample Chain-of-Custody

A standardized form provided by the selected laboratory will be used to document groundwater sample chain-of-custody. Copies of this form will be provided to laboratory personnel upon delivery of groundwater samples for analysis. These forms will be archived for future reference.

B.4. Analytical Methods

B.4.a. Analytical Standard Operating Procedures

Analytical standard operating procedures are referenced in **Tables A.4.1** through **Table A.4.13.** Other laboratory-specific standard operating procedures utilized by the contracted laboratory will be determined after the laboratory is selected. Upon request, Pelican will provide the UIC Program Director with all laboratories' standard operating procedures developed for the specific parameter using the appropriate standard method.

B.4.b. Equipment/Instrumentation Needed

Details on the equipment and instrumentation needed are provided in **Tables A.4.1** through **Table A.4.13.**

B.4.c. Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.d. Analytical Failure

Each laboratory conducting the analyses in **Tables A.4.1** through **Table A.4.13**will be responsible for appropriately addressing analytical failure according to their individual standard operating procedures and the applicable analytical method.

B.4.e. Sample Disposal

Each laboratory conducting the analyses in **Tables A.4.1** through **Table A.4.13**will be responsible for appropriate sample disposal according to their individual standard operating procedures.

B.4.f. Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but turnaround of verified analytical results within two months will be suitable for project needs.

B.4.g. Method Validation for Nonstandard Methods

Non-standard methods are not anticipated for this project. Pelican would consult with the UIC Program Director should non-standard methods be needed during the project.

B.5. Quality Control

B.5.a. QC activities

Blanks

Field blanks will be utilized during groundwater sampling to identify potential contamination resulting from the sample collection and transportation processes. Field blanks will be collected for the analytes listed in **Table 8-5** of the **Testing and Monitoring Plan** at a frequency of one set of blanks per event. Field and trip blanks allow for QC of the groundwater samples because they are collected in the field and transported together; as such, they were subjected to the same field and transportation conditions.

Duplicates

During each round of groundwater sampling, a second groundwater sample will be collected from one well, selected based on a rotating schedule. These duplicate samples are collected from the same source and at the same time as the original sample in a separate, identical sample container. Duplicate samples are processed with the other groundwater samples and are used to assess sample heterogeneity and analytical precision.

B.5.b. Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will include evaluation of the ratio of the measured total dissolved solids (TDS) to the calculated TDS (i.e., mass balance) per the APHA method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and inter-laboratory results, if available. Suspect ion analyses would be brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance is recalculated, and if the error is still not resolved, suspect data are identified and may be given less importance in data interpretations.

B.5.c. Calculating Applicable QC Statistics

Charge Balance

The groundwater sample analytical results are evaluated based on anion-cation charge balance calculation. All potable waters are electrically neutral; in theory, the chemical analyses should produce equally negative and positive ionic activity. The cation-anion charge balance will be calculated using the formula:

$$\% \text{ difference} = 100 * (\sum \text{cations} - \sum \text{anions} / \sum \text{cations} + \sum \text{anions}),$$

where the sums of the ions are represented in milliequivalents (meq) per liter, and the criteria for acceptable charge balance is ±10%.

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the formula:

$$1.0 < * \text{(measured TDS / Calculated TDS)} < 1.2,$$

with anticipated values between 1.0 and 1.2.

Outliers

The identification of one or more statistical outliers is essential prior to the statistical evaluation of groundwater. This project will use the EPA's Unified Guidance (U.S. EPA, 2009) as a basis for selection of recommended statistical methods to identify outliers in groundwater chemistry data sets as appropriate. These techniques include Probability Plots and Box and Whisker Plots. The EPA-1989 (U.S. EPA, 2009) outlier test may also be used as another screening tool to identify potential outliers.

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

All equipment and instrumentation will be inspected regularly and maintained, serviced, and calibrated per industry best practices and manufacturer standards. Spare parts that may be needed should be on-hand during field sampling events. Laboratory equipment testing, inspection, and maintenance will be the responsibility of the analytical laboratory per standard practice or method-specific protocol.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration & Frequency of Calibration

Pressure gauge calibration information is in **Table A.4.7** and **A.4.10** through **11.** All field and downhole gauges will be calibrated prior to use by the equipment supplier. Gauges will be recalibrated as needed based on results of inspection, after any repairs or maintenance, or as required by the manufacturer. Logging tool calibration will be at the discretion of the service company providing the equipment, following manufacturer recommendations and/or standard industry practices. CO_2 flow meters will be calibrated using industry standards and at a frequency recommended by the manufacturer.

Portable field meters or multiprobe sondes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) will be calibrated according to manufacturer recommendations standards and equipment manuals before sample collection begins for each event. Recalibration is performed if any components yield values outside the appropriate ranges or fail to stabilize during sampling. Meters will be rinsed with deionized water between sampling locations to prevent potential cross contamination.

B.7.b. Calibration Methodology

As discussed in **Section B.7.A**, logging tool and all field and downhole gauge calibration methodology will follow standard industry practices recommended by the respective manufacturers.

Calibration of handheld field meters will be performed per manufacturer's specifications. For coulometry, sodium carbonate standards (typically with a concentration of 4,000 mg CO_2/L) are routinely analyzed to evaluate instruments.

B.7.c. Calibration Resolution & Documentation

Calibration resolution and documentation will follow standard industry practices. Groundwater sampling equipment calibration occurs regularly, and values are recorded in sampling records, with any errors in calibration noted. When possible, an additional set of field equipment should be on-hand if calibration issues cannot be resolved.

B.8. Inspection/Acceptance for Supplies & Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

Individual vendors and subcontractors selected and approved by Pelican will be responsible for obtaining supplies and consumables for field operations and ensuring they are acceptable for data collection activities. Analysis related supplies and consumables will be the responsibility of the laboratory conducting water analyses in accordance with the established standard methodologies and operating procedures.

B.9. Non-direct Measurements

B.9.a. Data Sources

The CO_2 plume will be indirectly monitored via DTS, DSS, and 3D DAS VSPs. DTS monitors variations in temperature along the wellbore at a high resolution, continuously measured in real-time. DAS and DSS measure strain caused by acoustic waves passing through/near the fiberoptic cable.

B.9.b. Relevance to Project

Time-lapse VSPs and in-zone geochemical monitoring will be used to track CO_2 plume evolution and migration. After initial baseline testing is conducted prior to injection, processing and comparison of subsequent surveys will allow Pelican to monitor the extent of the plume throughout the project. Numerical modeling will be updated with new seismic, pressure, and saturation data throughout the project to monitor CO_2 plume growth and movement over time.

B.9.c. Acceptance Criteria

The collection of seismic data will follow standard industry practices to ensure accuracy in the resulting data. Similar ground conditions, seismic shot points located within acceptable limits, carefully inspected and operational geophones, and uniform seismic input signal will be used for each survey to ensure repeatability.

Gauges and other logging equipment used to collect non-direct measurements will be checked periodically and maintained according to manufacturer recommendations.

B.9.d. Resources/Facilities Needed

Pelican will subcontract all necessary resources and facilities to complete the required testing and monitoring activities.

B.9.e. Validity Limits & Operating Conditions

Seismic surveys and numerical modeling will be validated against industry standards by trained and experienced personnel designated by Pelican.

B.10. Data Management

B.10.a. Data Management Scheme

Pelican will conduct all project data, recordkeeping, and reporting per the requirements of 40 CFR 146.91(f). Pelican or their designated contractor will maintain the required project data as described in **Section A.6** of this plan. Data will be backed up on secure servers.

B.10.b. Recordkeeping & Tracking Practices

Project records will be managed according to project record management requirements and Pelican Renewables representatives' internal records management procedures.

B.10.c. Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper industry standards. Pelican will ensure that all necessary supervisory control and data acquisition (SCADA) systems and vendor data acquisition systems will interface with one another, and that all subsequent data will be held on a secure server.

B.10.d. Responsibility

The Pelican Storage Project Manager will be responsible for ensuring proper data management is maintained during pre-operational testing and the Operations Manager for the injection and post-injection periods.

B.10.e. Data Archival & Retrieval

All data will be held and maintained by Pelican. Data will be backed up on secure servers to be accessed by project personnel as required.

B.10.f. Hardware & Software Configurations

Pelican will verify that vendor hardware and software configurations will interface appropriately and can integrate multiple data sources and maintain large quantities of data prior to implementation.

B.10.g. Checklists & Forms

Checklists and forms will be generated and completed, as necessary to ensure proper management, security, and quality of data collected.

C. Assessment & Oversight

C.1. Assessments & Response Actions

The Testing and Monitoring Plan includes numerous categories, methods, and frequencies of monitoring the performance of the CO_2 storage site. Staff responsible for the associated technical element or discipline will analyze the monitoring data and initiate any needed responses or corrective actions. Management will have ready access to performance data and will receive monitoring and performance reports on a regular basis.

C.1.a. Activities to be Conducted

Refer to the **Testing and Monitoring Plan** for a summary of work to be performed and proposed work schedule. After completion of sample analysis, the results will be reviewed for quality control criteria as noted in **Section B.5** of this plan. Evaluation for data consistency will be performed according to procedures described in the EPA 2009 Unified Guidance.

C.1.b. Responsibility for Conducting Assessments

Each organization gathering data will be responsible for conducting their own internal assessments. All stop-work orders will be handled internally within each individual organization.

C.1.c. Assessment Reporting

All assessment information will be reported to Pelican Project Manager during pre-operational testing or Operations Manager during injection and post-injection.

C.1.d. Corrective Action

All corrective actions which may affect a single organization's data collection responsibility shall be addressed, verified, and documented by the individual project managers, and communicated to others, as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the QASP distribution list. Integration of information from multiple monitoring sources may be required to determine whether data and/or measurement method corrections are required, as well as the most effective and cost-efficient action to implement. Pelican will coordinate multiorganization assessments and correction efforts as needed.

C.2. Reports to Management

C.2.a/b. QA Status Reports

QA status reports are not required unless there are significant adjustments to the methods and procedures listed above. If adjustments are needed, this QASP will be reviewed and updated appropriately after consultation with the UIC Program Director.

D. Data Validation & Usability

D.1. Data Review, Verification, & Validation

D.1.a.Criteria for Accepting, Rejecting, or Qualifying Data

Validation of data will include a review of concentration units, sample holding times, and the review of duplicate, blank, and other appropriate QA/QC results. In the semi-annual reports, groundwater data will be presented in a format appropriate to characterize general groundwater quality and identify interwell and intrawell variability with time. After sufficient data have been collected, additional methods, such as those described in the EPA 2009 Unified Guidance will be used to evaluate interwell and intrawell variations for groundwater constituents, to evaluate if significant changes have occurred.

D.2. Verification & Validation Methods

D.2.a. Data Verification & Validation Processes

See **Sections D.1. and B.5** of this plan. Appropriate statistical software will be utilized to determine data consistency.

D.2.b. Data Verification & Validation Responsibility

Pelican or its designated subcontractor will be responsible for verifying and validating all analytical data.

D.2.c. Issue Resolution Process & Responsibility

The Pelican Storage Project Manager during pre-operations testing or Operations Manager during injection and post-injection will oversee the data handling, management, and assessment process.

Staff involved in these processes will consult with the Project Manager or Operations Manager to determine actions required to resolve any issues.

D.2.d. Checklist, Forms, & Calculations

Checklists and forms will be developed specifically to meet permit requirements. These checklists will depend on the parameters that are being tested as well as standard operating procedures of the subcontractors and laboratories that will be gathering the data and conducting the analyses. Pelican will provide these forms and checklists to the UIC Program Director upon request.

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

Statistical software will be used to evaluate data consistency using methods consistent with standard data analysis procedures from the EPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Each vendor or subcontractor will be responsible for ensuring that data presented by their respective organizations is developed with the appropriate data-use limitations. Pelican will ensure that the data-use limitations are known and presented properly.

References

USEPA. 2009. Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities Unified Guidance. EPA 530-/R-09-007. Prepared by the Office of Resource Conservation and Recovery Program Implementation and Information Division, March 2009. Available on the Internet at: https://archive.epa.gov/epawaste/hazard/web/pdf/unified-guid.pdf

Attachments

Specifications for Distributed Fiber Optic Sensing (DFOS) Technology to be Utilized at Rindge Tract CCS Wells #1 and #2 (next page).

SILIXA

iDAS™ intelligent Distributed Acoustic Sensor

The world's finest distributed acoustic sensor, the iDAS, has a novel optoelectronics architecture that allows for digital recording of acoustic fields at every location along a standard optical fibre. Amplitude, frequency and phase fidelity allows for numerous advanced applications.

Specifications

Measurement Technology	Phase coherent distributed acoustic sensor with linear amplitude and phase response
Optical architecture	Balanced interferometric phase detection to achieve the ultimate shot-noise performance down to pico-metre resolution
Finest Sampling Resolution	0.25m
Sampling Frequency (1)	1kHz – 100kHz
Finest Spatial Resolution (2)	1m
Frequency Range	0.001Hz to 50kHz
Self-noise (Noise floor) @ 1 kHz (pε per sqrt Hz)	2 pε per sqrt Hz @ 1kHz
Dynamic Range @ 10 Hz (dB power)	>100 dB @ 10Hz
Interrogation range	up to 50 km
Gauge length	10m gauge length optimised for seismic applications. Other gauge length available 3m
Fibre Compatibility (3)	Works with both singlemode and multimode fibres
Physical dimensions	Rack mounted, 178mm x 444mm x 518mm (H x W x D)

Weight	24 kg
In-built Triggering	PXI Trigger Input, SMB Jack
In-built synchronization	GPS Antenna Input SMB Synchronisation Clock Output SMB
External connectors	Ethernet: 2 x Gigabit Ethernet Port, RJ45; 2 x 10Gb SFP+ Port USB: 4 x Type-A USB 2.0 Port; 2 x USB 3.0 Port Display 2 x DisplayPort Data: 2 x PCIe x4 Cable Port GPIB Port, Micro D-Sub 25P COM Port, D-sub9 serial LAN PTP (RJ45) Power Inlet IEC 60320-1 C20, use with IEC 60320-1 C19 power outlet Fibre: E2000/APC
Max data capacity	350MB/s over 10GbE (short range)
Laser Product Category	Class 1
Compliance	CE/UKCA/FCC

Electrical Specifications

Input Voltage Range	100 - 240 VAC *
Input Frequency	50 - 60 Hz
Input Current	13 A Max
Over Current Protection	16 A circuit breaker
Power Consumption	215 W typical & 300 W max

*Ensure the main supply voltage fluctuations do not exceed +/-10% of the operating voltage range

(1) The upper limit for the sampling frequency is dictated by the length of the optical fibre, as a laser pulse cannot be launched until the reflected light from the end of the fibre from the previous pulse fibre is received. A simple rule of thumb is that the maximum sampling frequency on a 10km fibre is 10kHz; and on a 5km fibre is approximately 20kHz.

(2) Spatial resolution is the degree of localization of an event source. With a particular gauge length (GL) system, a point-source event will be measured as a signal spanning approximately 1 GL width, but the centre of the signal will track the source to within 1 m depending on the system settings.

(3) Performance figures quoted for singlemode fibre.

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XT-DTS™

Silixa's ruggedised distributed temperature sensor, XT-DTS™, is the highest performing DTS for remote and hostile environments currently on the market.

The XT-DTS has superior accuracy and reliability with a class-leading operating temperature range and low power consumption enabling operation with solar or wind power. It can be configured and controlled off-site via a wireless or satellite link enabling remote data collection and allowing for effective asset optimisation and environmental risk management, even in previously unreachable locations.

Sensing Capabilities

Unit	Range	Channels	Resolution		Measurement Time	Fibre Type	External Reference
			Sampling	Temperature			
XT-DTS M	Up to 10 km	4 or 8	25/50cm	0.01°C	≥5 sec	50/125μm multimode	2 x Pt-100 probes
XT-DTS L	Up to 35 km		1/2m	0.03°C			

System

Operating system	Windows 10 IoT LTSC		
Network	2 x 1 Gb/s Ethernet		
Storage	Internal SSD (240 GB)		
Control and Data Monitoring	XT Viewer	XT Client	XT SDK

Operating Environment

Unit	XT-DTS M	XT-DTS L
Temperature	-40° to +65°C	-20° to +60°C
Humidity	10-85% Non-condensing	

Power Supply Requirements

Steady power rating measuring	XT-DTS M ≤ 43W	XT-DTS L ≤ 39W
Steady power rating idle	11 W	
Steady power rating hibernating	2 mW	
Nominal voltage range	12 to 24 VDC	
Absolute min and max voltages	11 to 36 VDC	

Physical Dimensions

Height (feet to lid)	171 mm
Height (feet to handle)	212 mm
Width (brackets closed)	364 mm
Depth	472 mm
Weight	12 kg

Certification & Compliance

Safety	EMC	FCC	CE Mark
Class 1 Laser Product IEC 60825-1: 2014 EN 61010-1: 2010	EN 61326-1:2013	CFR 47:2008 Part 15 Sub Part B	2014/35/EC (safety) 2014/30/EC (EMC)

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Silixa, Carbon Capture and Storage Monitoring with distributed fiber optic sensing, (March, 2022)

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Appendix 8-B

1. Initial Submission:
- Corrosion modeling results and well construction details submitted for CR25.

2. Parallel Evaluation:
- Corrosion modeling conducted for CR13 using same methodology.
- Results technically comparable.
- CR13 offers cost advantage.

3. Next Steps:
- Offer to share CR13 modeling results.
- Note additional time may be needed.

4. Industry-Wide Consideration:
- Material lead times for both options are 13–15 months.
- Materials are made to order.

5. Invitation:
- Pelican Renewables invites EPA to visit facility.
- Host testing or discussions.

6. Request for Feedback:
- EPA to advise on interest in CR13 review and next steps.

Appendix 8-C


SILIXA
actionable insight
CO2
Carbon Capture and Storage Monitoring
with Distributed Fiber Optic Sensing
MARCH 2022

Contents

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Figures

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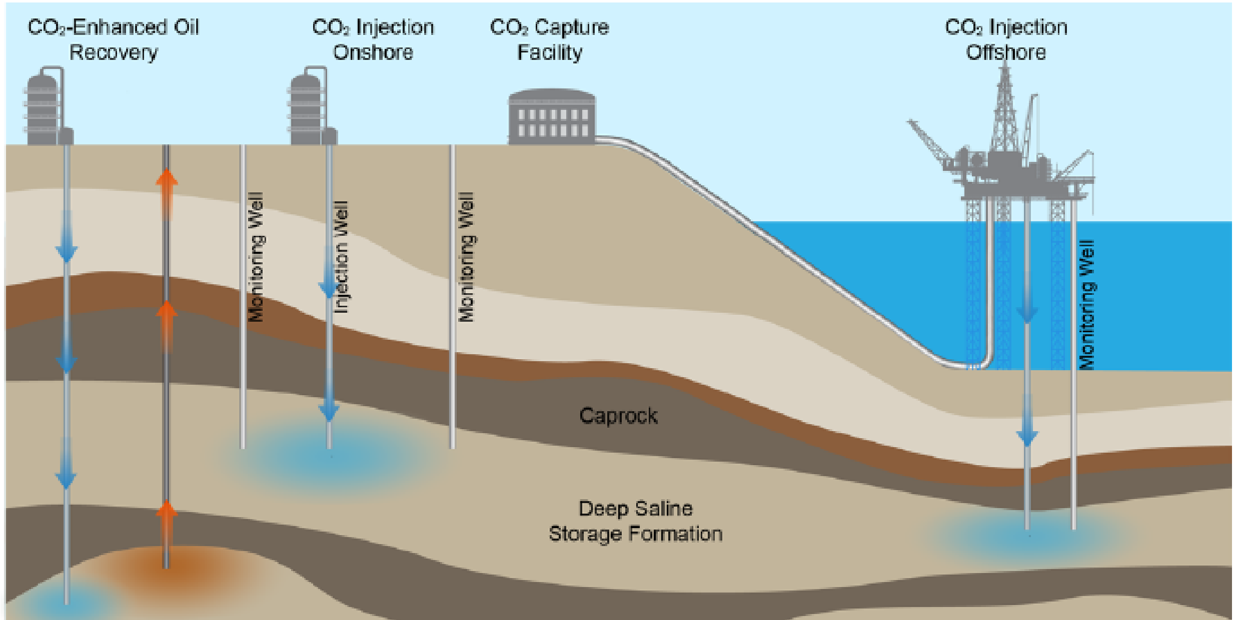
1

Carbon Capture and Storage: Introduction and Risks

SILIXA actionable insight



▲ **FIGURE 1:** Permanent storage of CO_2 underground into oil and gas fields or deep saline geologic formations.

According to the U.S. Environmental Protection Agency, carbon dioxide (CO_2) is the primary greenhouse gas emitted through anthropogenic sources.

In 2018, CO_2 accounted for about 81.3 percent of all U.S. greenhouse gas emissions from human activities. The main source of anthropogenically generated CO_2 emissions is the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation, although certain industrial processes (cement, steel, and chemical production) and land-use changes also emit CO_2.

Carbon capture and storage (CCS) technology offers an opportunity to reduce CO_2 emissions to the atmosphere. The process consists of capturing CO_2, for example, from coal-fired power plants, before it enters the atmosphere; transporting the CO_2 via pipeline; and injecting it underground into depleted oil and gas fields or deep saline geologic formations, where it can be securely stored (**FIGURE 1**).

Carbon dioxide is injected using dedicated wells in deep geologic formations for long-term storage. In the United States, these wells are known as Class VI wells (USEPA, 2010), which require extensive subsurface characterization, including observations from previously drilled boreholes and indirect data from geophysical methods.

1

Carbon Capture and Storage: Introduction and Risks

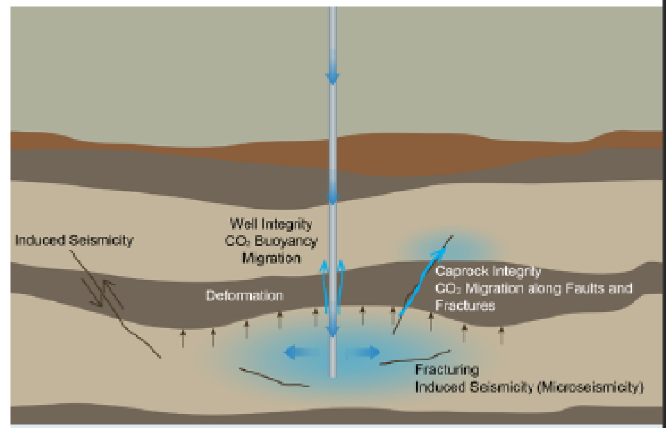
SILIXA actionable insight

A series of monitoring requirements exists during operation of a Class VI well for CO_2 injection. These requirements focus on mitigating risks arising from the injection of large volumes of CO_2 under high pressure in deep reservoirs (FIGURE 2). The evaluation of storage performance and containment is captured under the testing and monitoring (TM) framework.

The main risks identified are:

- **Well Integrity**: Problems with well cementation can cause leakage of CO_2 upward to shallow aquifers or the surface.
- **Migration of CO_2 along faults and fractures**: This could eventually lead to CO_2 leakage to shallow aquifers and the atmosphere.
- **Migration of CO_2 plume outside of the storage reservoir**: It is important to track the free-phase CO_2 plume distribution during CO_2 injection to ensure it is confined to the permitted storage interval and, after injection operations have ceased, to provide assurance that the plume has stabilized.
- **Induced seismicity**: Although extensive characterization and planning for Class VI wells are undertaken, injecting large volumes of CO_2 can create fractures and/or activate preexisting geological faults generating microseismic and seismic events. Continuous monitoring is important because these events can be informative and a precursor to potential leakage pathways and/or damage to infrastructure.
- **Deformation**: CO_2 injection could lead to a significant surface heave due to the pressure buildup in the reservoir and the buildup of injected CO_2.

The mitigation of risks involved with CO_2 storage underground is possible with detailed site characterization and advanced monitoring before, during, and after the injection period. Fiber optic distributed sensing methods can greatly advance the spatial and temporal resolution of the data acquired during the characterization and monitoring phases, while reducing overall monitoring costs when compared to standard methods using point transducers such as geophones, temperature, and



▲ FIGURE 2: Processes during active CO_2 injection into deep sedimentary formations and risks arising from the injection (Rutqvist, 2012).

pressure gauges. This report aims to present an overview of fiber optic distributed sensing technology, an introduction to the relevant instrumentation, and the sensing fiber optic cables and applications. The report describes the fiber optic downhole and surface deployment possibilities for temperature, strain, and acoustic data acquisitions. The data are used for reservoir characterization using reflection and refraction seismic, plume detection with time lapse seismic, detection and location of microseismic events, subsidence, well integrity, and leak detection. Applications can be extended to flow assurance, injectivity profile and monitoring transportlines for leaks.

Deployment of fiber optic sensing has a minimal environmental impact and provides large spatial coverage with no power requirements along the sensing cable.

Reservoir characterization capabilities and the short- and long-term monitoring applications for CCS projects are described. Finally, an overview of case studies is presented, highlighting the results and insights gained by applying distributed sensing methods in CCS projects.

2

Enabling Technology

2.1

Introduction

Distributed sensing enables continuous, real-time measurements along the entire length of an optical fiber with a maximum range of tens of kilometers.

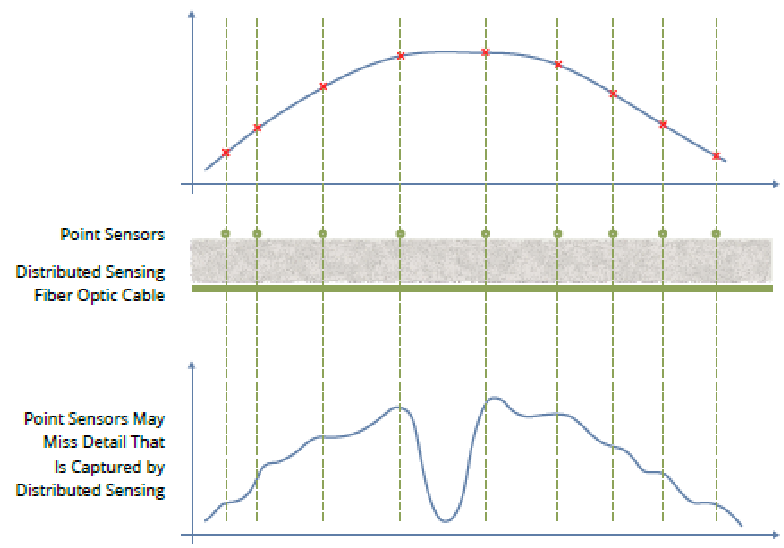
Unlike traditional sensing that relies on discrete sensors measuring at predetermined points such as geophones, distributed sensing utilizes the optical fiber as the sensing element without any additional transducers in the optical path (FIGURE 3). Fiber optic cables can be deployed on the surface or in boreholes either as permanent installations or temporary retrievable solutions.

A significant advantage of a cable permanently installed and grouted along the outside of a borehole casing is that it allows the collection of data while the well is operating, and simultaneously, the application of other methods and surveys in the well. This enables the installation in both injection and monitoring wells. In offshore wells, the cable can be strapped on the injection tubing.

A fiber optic distributed sensor emits pulses of laser light into an optical fiber. A portion of the emitted laser light is scattered within the fiber because of a variety of material-related attenuation mechanisms. The sensing principles rely on the backscattered light detected by the interrogators.

Characteristics of the light returning to the sensor are used to derive measurements of different physical properties along the optical fiber. The positional information along the fiber is determined from the time of flight between the emission of a laser pulse and the detection of backscattered light through application of the principles of optical time-domain reflectometry (OTDR).

▶ FIGURE 3: Spatial distribution plots illustrating the data gaps inherent in point sensor applications (above) compared to distributed sensor technology (below).



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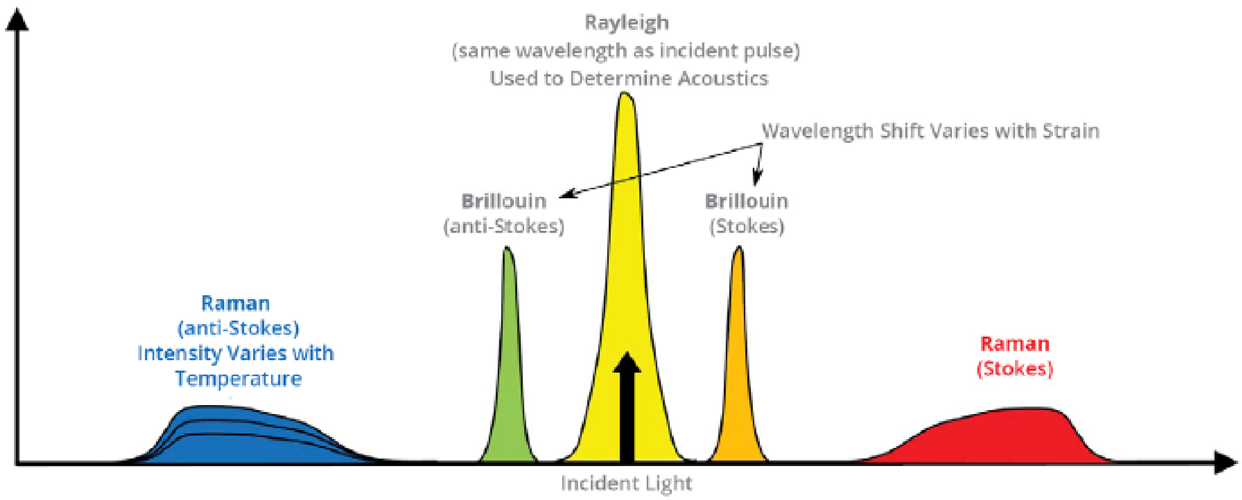
2.1 Introduction

Several scattering processes take place when the pulse of laser light interacts with the molecules of the optical fiber, and different measurements can be derived from analyses of the detected spectrum of light (FIGURE 4).

Most of the emitted light is backscattered without experiencing a change in wavelength through elastic Rayleigh scattering. True distributed acoustic sensors (DAS) use the Rayleigh scattering signal to derive the coherent full acoustic field (i.e., amplitude, wavelength, and phase) over a wide dynamic range allowing for characterization of localized acoustic environments.

Distributed temperature sensors (DTS) make use of wavelength-shifted backscattered light caused by inelastic interactions between the source light and temperature-dependent molecular vibrations within the fiber, known as Raman scattering.

Distributed strain sensors (DSS) use the interaction of emitted light with lower-frequency molecular vibrations (also referred to as material waves) within a fiber, known as Brillouin scattering, to derive the distribution of coupled strain across the entire length of the fiber.



▲ FIGURE 4: The spectrum of backscattered light inside an optical fiber includes (A) Rayleigh, utilized by DAS; (B) Raman, applied with DTS; and (C) Brillouin scattering, associated with DSS.

SILIXA actionable insight

2.1

Distributed Temperature Sensing (DTS)

2.2.1. Sampling and spatial resolutions

DTS instruments use Raman scattered light and the principles of OTDR to determine the temperature at each sampling point along an optical fiber.

A DTS unit launches a short pulse of light into an optical fiber. The forward propagating light generates Raman backscattered light at two new wavelengths from all points along the fiber.

The wavelengths of the Raman backscattered light differ from the forward propagating light and are named Stokes and anti-Stokes, according to the energy level measured for the absorbed photons (Stokes, if the energy is higher than the emitted photons; anti-Stokes if it is lower) (FIGURE 4). The amplitudes of the Stokes and anti-Stokes light are monitored by the DTS unit, and the spatial localization of the backscattered light is determined through knowledge of the propagation speed inside the fiber.

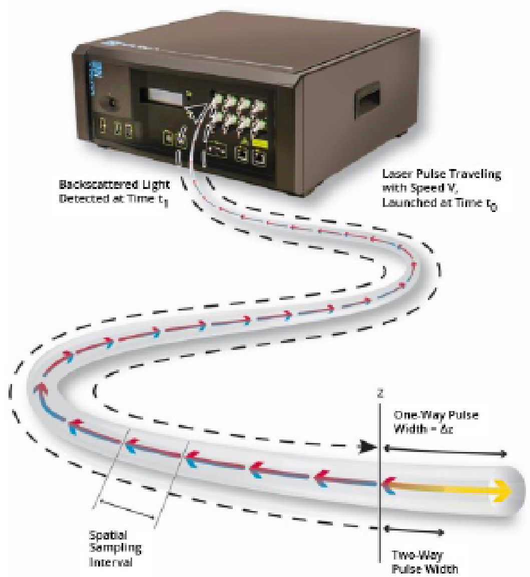
The determination of the source of light signal by measuring the time between the injection of a light source and the detection of a backscattered signal is the fundamental principle of OTDR. The amplitude of the Stokes light is very weakly dependent on temperature, while the amplitude of the anti-Stokes light is strongly dependent on temperature (FIGURE 4). The temperature at each sampling location is calculated by taking the ratio of the amplitudes of the measured anti-Stokes and Stokes light.

For more details about the DTS fundamentals, we recommend the reader to access "Introduction to Distributed Temperature Sensing" (Silixa, 2020).

2.2.1

Sampling and Spatial Resolutions

The sampling resolution of a DTS system is the smallest length increment a DTS system can sense (or sample) over the entire length of an optical fiber (FIGURE 5). The sampling resolution describes the DTS system's ability to convert the true continuous spatial distribution of temperature along a fiber into discrete measurements. The DTS system provides one averaged temperature measurement per spatial sample. The sampling resolution of a DTS system is determined by the sampling frequency of the data acquisition card, which is typically implemented with a field-programmable gate array and specialized high-speed analog to digital converters chip technology.



▶ FIGURE 5: The sampling resolution of a DTS system is the smallest length increment a DTS can sense.

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2.2.1

Sampling and Spatial Resolutions

Each temperature measurement provided by a DTS system is averaged over a specified length increment, known as the spatial sampling interval, so the sensor output response to a change in temperature along the fiber is somewhat blurred at the edges of the change.

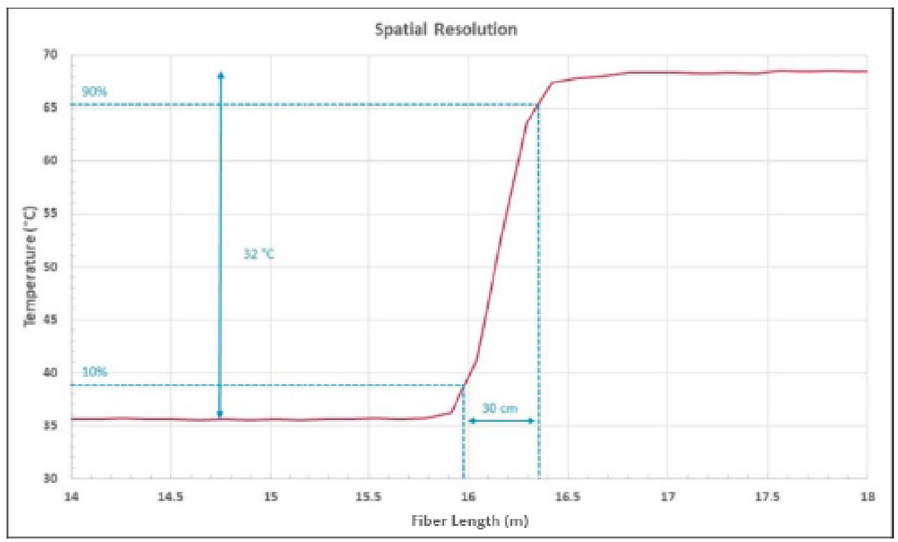
The spatial resolution of a DTS system is determined by applying a step change in temperature between two adjacent lengths of fiber (10 m or more) and determining the distance needed to capture between 10% and 90% of the variation (FIGURE 6).

Typically, a temperature step of about 30°C is applied. The 10% 90% definition of spatial resolution is appropriate for determining the degree to which a transition can be reproduced in the sensor output.

It is important to note that different DTS manufacturers may apply different definitions. For example, defining the sampling resolution as the spatial resolution, varying the amplitude of the step change in temperature, and/or accounting for another percentage of detection (e.g., between 20% and 80%). Care should be taken when comparing DTS systems, with specific attention as to how spatial resolution is defined.

Although the spatial resolution and sampling resolution are related, they must not be confused with each other. The sampling resolution cannot be equal to the spatial resolution. The sampling rate must be more than twice the highest frequency component of a signal to properly capture the signal. Similarly, the spatial resolution cannot be smaller than the interval distance of two consecutive samples.

In general, the spatial resolution is slightly larger than two times the sampling resolution. Oversampling at much greater than one half the spatial resolution results in increased data volumes without significant additional information contained within the dataset.



▶ **FIGURE 6:** Spatial resolution test for the Silixa Ultima-S with sampling resolution of 0.125 m. The applied temperature step change is 30°C, to yield a spatial resolution value of 0.30 m.

2.3

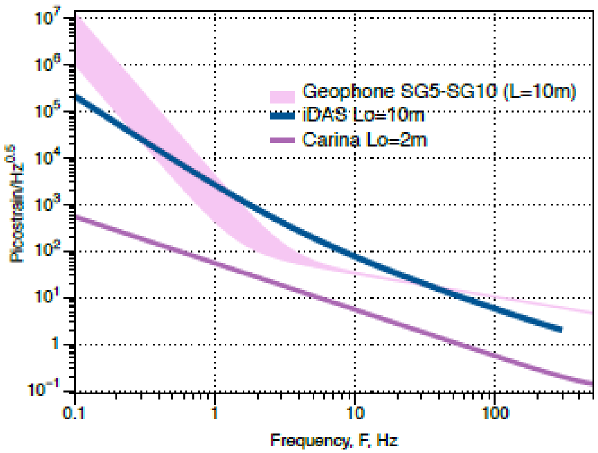
Distributed Acoustic Sensing (DAS)

DAS is an optoelectronic system that uses the Rayleigh backscattered light and principles of OTDR to demodulate dynamic strain events along the fiber cable.

By recording the returning signal against time, a measurement of the acoustic field all along the fiber can be determined. There are a wide range of DAS architectures, with the most advanced systems capable of measuring quantitative true acoustic signals (coherent in amplitude and phase) with low system noise over long ranges of tens of kilometers. The native data output is quantitative strain rate (dynamic strain). These systems can have a detection bandwidth from millihertz (mHz) to hundreds of kilohertz (kHz), depending on the temporal sampling rate, and can perform equally well with standard single mode and multimode fiber, without the introduction of external or additional apparatus. This feature makes it possible to access legacy fiber optic installations for new acoustic surveys, although new installations offer the ability to utilize specialty precision engineered sensing fiber for significantly improved measurement performance. As an example, see the case study on the Otway Project at the end of this document.

The importance of collecting the true acoustic signal–amplitude, frequency, and phase cannot be underestimated, as this opens the door to a wide range of array processing techniques that can be used to extract the maximum value from the data. For example, this capability uniquely allows DAS to be used to determine the speed of sound or seismic waves in the material surrounding the fiber optic sensing cable. This enables using the speed of sound for accurate time -lapse seismic surveys (White et al., 2019), or to monitor microseismic events with hypocenter localization capability (Richter et al., 2019). DAS has been used in many seismic acquisitions, encompassing vertical seismic profiling (VSP), in both flowing and non-flowing wells, passive seismic monitoring and surface seismic applications. The technology has been deployed in many industries, including unconventional hydrocarbon exploration (Richter et al., 2019) at CO_2 storage sites (Harris et al., 2016; White et al., 2019) in enhanced geothermal system wells (Mondanos and Coleman, 2019), and for infrastructure monitoring (Johansson et al., 2020).

The standard Silixa iDAS™ has a dynamic range of 120 dB (decibel) and a sampling frequency range from <1 mHz to >100 kHz, making it a highly versatile instrument. The iDAS responds to tiny strain events within the optical fiber which are induced by local wavefields. The system response to this strain is linear, making it possible to treat the iDAS data similarly to conventional sensor technologies such as geophones and accelerometers. This makes the iDAS a successful alternative system for seismic acquisition. The recent introduction of the Carina® system using specialty precision-engineered Constellation™ sensing fiber improves upon iDAS by offering a 20dB (100x) reduction in instrument noise floor and the ability to further extend measurement range (FIGURE 7).



▲ FIGURE 7: Noise floor comparison between geophones, iDAS, and Carina.

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2.4

Distributed Strain Sensing (DSS)

SILIXA actionable insight

DSS instruments use Brillouin scattered light to determine the strain at each sampling point along an optical fiber.

The wavelengths of the Brillouin backscattered light differ from the forward propagating light and are named Stokes and anti-Stokes (FIGURE 4). The wavelength shift of the Stokes and anti-Stokes light are monitored by the DSS unit, and the spatial localization of the source of backscatter signal is determined using the principles of OTDR.

One challenge with DSS is that the wavelength shift is dependent on both the strain and temperature of the optical fiber; thus, crosstalk exists between these two physical measurands. If temperature fluctuations are expected, the thermal component of DSS response must be removed to isolate (nonthermal) strain. This is traditionally accomplished through dual-element cable designs that have (1) a fiber component sensitive to both temperature and strain, and (2) a fiber component engineered to be primarily sensitive to temperature with minimized physical strain transfer (to the fiber).

In practice, completely isolating strain from temperature signals is impractical, with temperature correction being more reliably carried out using temperature measured independently from a Raman DTS system, as described above. In summary, temperature compensation as well as strain coupling to the formation are important considerations for a DSS deployment.

Alternative measurement approaches for DSS that do not utilize Brillouin backscatter and, instead, rely on differential travel times between scatter centers using specialty precision-engineered sensing fiber are also available. DSS can be used for wellbore integrity monitoring, geomechanical deformation as the result of CCS operations, and cross-well plume front arrival detection.

3 Deployments of Fiber Optic Cable

3.1 Near-Surface

3.1.1 Cable Options

Fiber optic cables for near-surface installations (upper ~20 m) can be either fiber in metal tube (FIMT)-based or all-dielectric polymer constructions, with the latter being the most common.

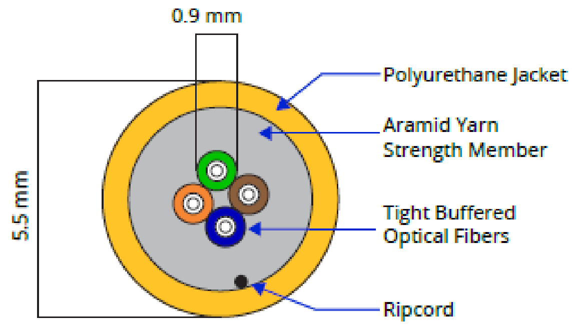
For DAS and DSS applications, signal coupling with the subsurface through the cable jacket and strength members to the optical fiber is an important consideration, with some cables offering efficient strain transfer to the optical fiber.

Near-surface deployments offer flexibility with the engineering design of the cable, as the cable is not subject to the harsh environments present downhole, including high temperatures, pressure corrosion risks, and constraints on deployment options. The types of materials, diameter, and fiber geometry within the cable are flexible to a greater degree which leads to numerous cable options that could be considered for deployment.

Although the surface environment is typically not as harsh as downhole, there are greater risks because of exposure to site activities. Tight buffered tactical (also referred to as military)-type cable has been widely installed for near-surface investigations due to its high level of durability and flexibility, leading to ease in deployments and relatively low risk of failure, good DAS/DSS signal sensitivity, and relatively low cost (FIGURE 8).

This cable type is also ideally suited to act as a link cable to facilitate connection from a mobile office to a cable installed downhole. Tactical cable is also well suited to DTS measurements, though extra attention needs to be paid to minimizing signal attenuation that can affect the accuracy of DTS measurements when compared with FIMT-based or loose tube designs.

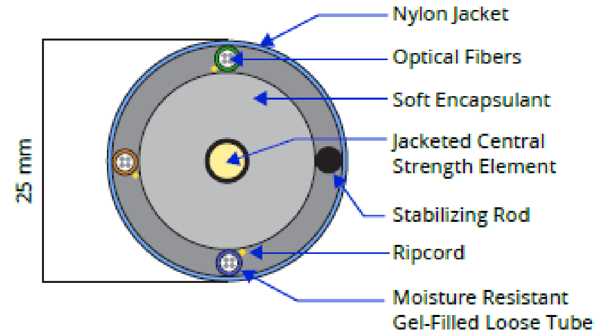
Bend-insensitive fibers are recommended to be incorporated into tactical cable to help minimize the chances of both microbend- and macrobend-induced attenuation. The directional sensitivity of fiber (acting as a single-component measurement) for DAS measurements is another critical consideration when the cable will be used for surface seismic surveys. These helically wound



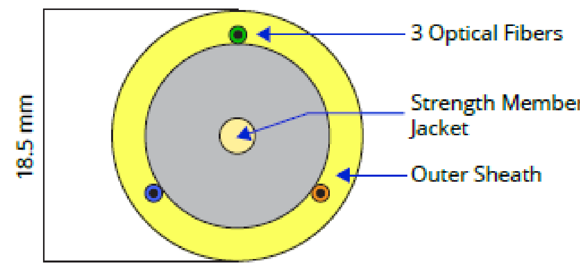
▲ FIGURE 8: Example four-fiber tactical cable construction.

3.1.1 Cable Options

specialty cables (HWC) are available to optimize the measurement response in these situations (FIGURES 9 AND 10). In general, it is important to remember that the fiber optic cable is the deployed sensing element, and so both the cable type and deployment method control the quality of data recorded in a survey to a significant degree.



▲ FIGURE 9: Example HWC with fibers 30° off axis to provide increased sensitivity to broadside seismic waves.



▲ FIGURE 10: Example HWC with fibers off axes.

3.1.2 Installation Methods

Direct burial is the preferred installation method for near-surface installations to ensure good formation-to-fiber signal coupling for DAS and DSS data acquisition.

However, retrofits onto existing cabling installed for telecom purposes in conduits have been carried out with success (e.g., Ajo-Franklin et al 2019), but evaluation on a case-by-case basis is required.

For new installations, cable can be installed using trench-and-cover methods with a backhoe, trencher, or plow. The bottom of the trench should be prepared (compacted) and backfilled with a layer of fine material prior to cable placement. The cables should then be backfilled and compacted. The cable has length markings, and x- y- and z-coordinates should be surveyed with regular spacing and at locations of array inflection/bends. Induced taps, temperature, and strain can be used for cable-mapping purposes. Measurements of optical signal should be performed during placement of the cable as well as during backfilling of the trench to ensure integrity is maintained and excess optical attenuation is not induced because of physical damage or overcompaction.

As an alternative to trench-and-cover methods, cable can be installed with directional drilling techniques in access-restricted areas. Steel-armored cable is an option, depending on the installation method.

SILIXA actionable insight

3.2

Downhole

3.2.1

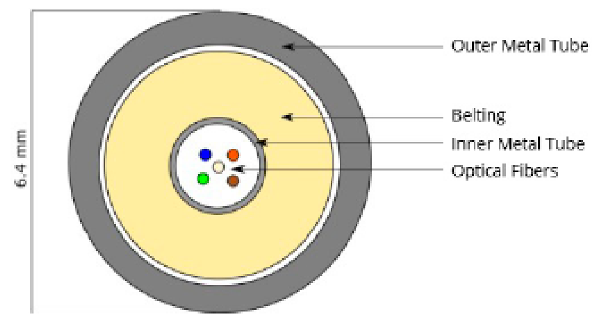
Cable Options

Downhole deployments require FIMT-based cable constructions to survive temperatures and pressures common with multikilometer-deep installations.

For permanent installations behind casing or attached to tubing, 1/4" (6.35mm OD) tube-in-tube designs (outer tube surrounding a small-diameter FIMT) are most common and generally manufactured with either SS316 or Incoloy A825 outer tube, with A825 preferred where corrosion is a concern. Outer tube wall thicknesses range from 0.028" to 0.049" depending on installation requirements, with 0.035" being the most common.

Belting is a layer of polymer between the FIMT and outer tube, which is recommended as it improves cable longevity, installation performance, and downhole termination reliability. (Figure 11) Polymer encapsulation can be extruded over the outer tube to provide an additional layer of protection if required. The downhole termination, commonly referred to as the bottomhole assembly, both seals the cable for fluid ingress and provides an environmentally sealed chamber for u-bend fiber splicing, which facilitates double-ended DTS measurements for improved accuracy and daisy-chaining multiple wells together for measurement with a single interrogator. Double-ended DTS configurations can improve accuracy and the ability to daily-chain wells together facilitates improved economics, as fewer distributed sensing interrogators are needed for acquisition. Smaller diameter (1/8" or 3.175mm OD) cables can be installed for temporary slickline deployments or FIMT-based wireline cables utilized for intervention wireline surveys.

For all downhole cables, there is wide variability in the number and type of optical fibers that can be integrated into cable construction. The precision-engineered Constellation™ sensing fiber enables DAS measurements with a 100x lower noise floor in comparison with standard single-mode fiber, which can be critical for microseismic and time-lapse VSP surveys. Although the mix of fiber types governs what type of measurements (DAS, DTS, DSS) can be made on a cable, cable design is a factor in measurement response. Cables optimized for DSS have been developed that



▲ **FIGURE 11:** 1/4" OD downhole fiber optic cable with belting.

prioritize efficient strain transfer through the cable construction to the optical fiber. The temperature rating of the cable is governed (along with other factors) by the coating type of the optical fibers. Common temperature ratings include 85°C, 150°C, and 300°C, with temperature rating being a significant factor controlling cable cost. Specialty high-temperature cables can be manufactured to survive at temperatures as high as 500°C. Hydrogen darkening (increasing optical attenuation with exposure to free hydrogen) can be a concern for long term installations, particularly at high temperatures. For peak temperatures less than 150°C, a hermetic carbon coating on the optical fibers provides an effective barrier to hydrogen ingression into the silica fiber; however, at temperatures above 150°C the efficacy of a carbon hermetic barrier is decreased. In this case, pure silica core fibers provide near immunity to hydrogen darkening by eliminating or substantially reducing the dopant concentration in the fiber core. Dopants such as germanium are generally used to control the refractive index profile of the fiber, but in harsh environments, a pure silica core may be preferred.

SILIXA actionable insight

3.2.2

Installation Methods

Casing – Permanent

Fiber optic cable is readily installed for permanent reservoir monitoring in both the injection and monitoring wells by clamping to casing and cementing in the borehole annulus during casing installation (Figure 12). Installing cable behind casing facilitates surveys and continuous monitoring without the need for well intervention to provide tool access. Thus monitoring can be carried out in the injection well without ceasing CO_2 injection, especially measurements of temperature and strain which are not affected by the injection process. Acoustic measurements could also be performed for flow allocation or active seismic surveys. Cable clamps/protectors are both used across couplings and midjoint to attach the cable to casing and prevent the concentration of stress on the cable at step changes in diameter at each coupling. Centralizers provide additional protection to the cable during installation while limiting variability in annular space for cementation. Protectors and centralizers are recommended to be used at every coupling location, with midjoint clamps used on each casing section.

▲ **FIGURE 12:** A) Permanent cable installation on casing at CO2CRC site, Otway, Australia, and B) an example of a fiber optic cable installed along a steel casing with a cross-coupling cable protection.

Tubing Deployed – Temporary/Semipermanent

Tubing deployments offer a means for semi-permanent installation in existing injection wells or for subsea installations where deployment behind casing may not be permissible. Cable is clamped to the tubing string during deployment and can be retrieved along with the tubing string at a later date. Cable coupling to the formation for DAS measurements has been demonstrated to be sufficient for most installations, although installation geometry should be considered. As an example, Pevzner et al. (2020) compare the data quality from different cable installation methods at the Otway CO_2 injection site in Australia.

Wireline and Slickline – Temporary

Although cable permanently deployed in casing or tubing provides the capability for intervention-free longterm monitoring, temporary deployments of optical fiber are common for monitoring in existing wells where fiber optic cable was not installed. In highly deviated or horizontal wells, the cable may be tractored or towed in place with a capillary injector unit. For both slickline and wireline interventions, cable coupling to the formation is an important consideration, as signal coupling to the cable can be relatively poor in vertical or near-vertical wellbores but has been demonstrated to be excellent for deviated (> 5 degrees) and horizontal wells.

SILIXA actionable insight

4 Applications

Fiber optic cables can be used at all stages of a CCS project to build a temperature, strain, microseismic/seismic baseline through site characterization, baseline monitoring to monitor injection activities. Because of the long-life expectancy of the cables, the same fibers can be used to continue monitoring postinjection. Here we focus on monitoring for onshore CCS sites.

4.1 Baseline-Site Characterization

4.1.1 Surface Seismic Reflection Surveys

Surface seismic reflection surveys are the most comprehensive method to image CO_2 storage sites and characterize the geologic setting before injection commences. The surveys are used to produce a 2D or 3D image of geologic formations and image faults, which could be potential leakage pathways breaching the storage integrity of the site.

It is important for CCS sites that the caprock or sealing rock for the reservoir is continuous over the expected extent of the future CO_2 plume. Seismic surveys are the best available method to verify caprock continuity. Ideally, the site should have a thick caprock and secondary sealing units above the reservoir. Multiple applications for seismic reflection data are possible and are in varying stages of development.

Fiber optic cables can be trenched at the surface to provide a permanent, dense, seismic monitoring array covering up to tens of square kilometers. Because of the broadside insensitivity of linear cable to P-waves, it is beneficial to record P-waves on helically wound cable, which can be constructed to have good sensitivity to P-waves arriving from all angles. Recent studies have shown that HWC can be used to image a CO_2 reservoir at a depth of 2km (Correa et al., 2020).

DAS may be used with the complete range of seismic sources (vibroseis, dynamite, surface orbital vibrators [SOVs] and ambient noise). In addition to stacking shots, the dense spatial sampling of the technology provides the opportunity to stack data from neighboring channels to improve signal strength.

Note there are limitations to surface seismic surveys. They will not, for example, identify small, or near-vertical, or small offset faults.

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4.1.2 VSP Surveys

VSPs use an active seismic source method using an array that is oriented vertically in a borehole.

VSPs measure downward and reflected energy. With vertical fiber orientation, the P-wave particle motion is close to in-line with the fiber, facilitating data collection with good signal-to-noise characteristics.

VSP surveys with fiber optics are among the best way to generate detailed structural information for CCS sites. They provide highly dense spatial sampling to produce well-resolved models in a relatively short timescale because data can be collected covering the full-length of the well with a single fiber. Surveys with geophones usually require intervention to move the geophone string up and down the well to achieve the desired resolution. This is typically achieved with the use of a rig, which increases the survey costs and inhibits any well activity for the duration of the survey. With the high-resolution structural information derived from DAS data, it is possible to generate a baseline image, produce 3D VSP results and assess the migration of a CO_2 plume through time within the geometry limits of VSP surveys.

With permanently installed fiber it is possible to efficiently take repeated measurements after baseline surveys to monitor changes long-term, including time-lapse plume imaging as discussed in the CO_2 Plume Mapping section.

4.1.3 Baseline Seismicity

To fully understand the effects of injection activities, it is essential to monitor a site for background seismicity. The location of background seismicity highlights active faults and, hence, enables a seismic risk assessment. Seismic monitoring can help identify active faults that are not observed in 3D seismic data. A baseline seismicity assessment is an important tool to enable an assessment of unexpected seismicity during CO_2 injection.

The risks posed by seismicity and monitoring solutions are discussed below in the Induced Seismicity Monitoring section.

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4.1.4

Periodic Hydraulic Testing

Periodic hydraulic testing uses an applied periodic pressure signal in a source well, with the pressure response monitored in surrounding boreholes, to characterize the hydraulic properties of an aquifer or reservoir.

The amplitude decay and phase lag of the pressure signal measured in the monitoring well provide an indication of the hydraulic diffusivity of the reservoir between the source-receiver well pair. The applied periodic signal can be altered in frequency to give diffusivity estimates at a range of spatial scales, with low frequencies (millihertz) providing adequate radii of penetration suitable for field studies at the reservoir scale.

Traditionally, individual pressure sensors are deployed in each monitoring well, which provide a bulk estimate of diffusivity. Strings of pressure gauges can provide depth discrete data to resolve diffusivity to a finer degree. More recently, DAS has been proven to be a highly effective tool for conducting periodic hydraulic tests, because of its high sensitivity to dynamic strain, which allows monitoring of hydraulic signals of even lower amplitude than is possible with pressure gauges (Becker et al., 2017, and 2020). Modulated pressure in the reservoir is translated to strain because of hydromechanical fracture dilation and contraction and the poroelastic response. The periodic strain measured by DAS can then be related to pressure using a coupled hydromechanical model or known relationship between pressure and strain.

The complete borehole sensory coverage provided by DAS (thousands vs. traditionally one or a few sensors) provides the opportunity for advanced reservoir tomography. In addition, periodic hydraulic testing can be used to monitor the integrity of the caprock and boreholes, as detection of the applied periodic signal at shallower depths may indicate hydraulic connection. Applying this technique at multiple instances throughout the life of the reservoir provides a means of time-lapse hydraulic monitoring.

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4.1.5

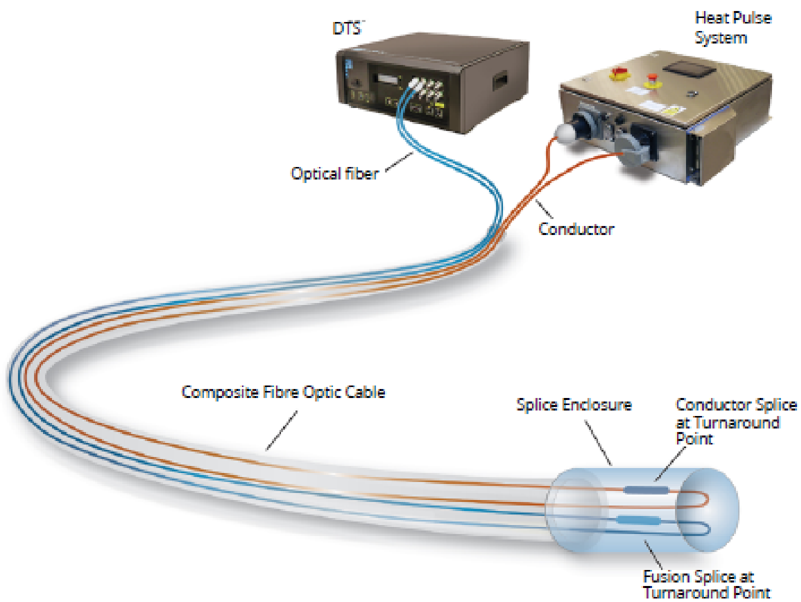
Apparent Thermal Conductivity

Thermal conductivity can be used to distinguish lithology units because of different mineralogy composition, providing to each rock type a characteristic bulk thermal conductivity and intervals with fluid flow.

When active fluid flow is occurring during an in situ thermal conductivity test, the bulk rock thermal conductivity values would be apparently enhanced because of increased heat dissipation caused by the fluid flow.

Hybrid fiber optic cables containing copper conductors and optical fibers provide the opportunity to heat the entire fiber optic cable length while maintaining the capability to monitor temperature variation over time.

A power controller, such as Silixa's heat pulse system (FIGURE 13), can be combined with a DTS unit to perform heat pulse tests to estimate in situ apparent thermal conductivity profiles that can be used to characterize lithology distribution and active fluid flow. Examples of this method applied in CCS projects include Freifeld et al. (2009) and Prevedel et al. (2014). Examples in shallow boreholes can be found in Coleman et al. (2015), Maldaner et al. (2019) and Munn et al. (2020).



▲ **FIGURE 13:** Example of an active DTS system setup using a DTS unit and heat pulse control unit with a composite cable containing both optical fibers and conductive wire.

SILIXA actionable insight

4.2

Injection Optimization

4.2.1

Flow Profiling

Using DAS, measurements of acoustic activity can be employed to assess the flow of fluids in wells as a function of depth.

The flow of fluids from well casing to formation, or from formation to well casing, has a characteristic acoustic signature that is localized to the region of fluid flux. A qualitative estimate of flux can be used to assign fluxes at known depths as a proportion of total flow out of (in the case of fluid production) or into (in the case of fluid injection) the well. Where the necessary input data allow, these flux values can be calibrated in a quantitative profile of fluid flow along the depth of installed fiber.

Acoustic activity is calculated for the purpose of flow profiling by using spectral analysis of downhole DAS data, typically installed in vertical or deviated wellbores. For best results, fiber optic cable assemblies should have good coupling with the well casing or surrounding formation by being secured or grouted in the well: within the casing, between casing and pipe, or between casing and surrounding formation. High-frequency (> 8 kHz) acoustic data are transformed to the frequency domain with an FFT (fast Fourier transform) calculation at each sampling location along the optical fiber path within the depth region of interest. Examination of FFT amplitudes for a given application or deployment inform the appropriate frequency range attributable to acoustic activity resulting from fluid flux. RMS (root mean square), summation, or other means of aggregating FFT amplitudes are applied at each depth, resulting in a proxy for fluid flux. These accumulated amplitudes may then be qualitatively compared or calibrated to provide estimates of downhole fluid flux.

In the context of CCS, flow-profiling techniques can be used to document the apportionment of CO_2 fluid injection into the surrounding formation in cases where there are multiple injection depths. Such information can inform decision making regarding the efficiency of individual perforation clusters after the beginning of CO_2 injection and over time.

4.2.2

Flow Assurance

Where CO_2 capture is a temporally variant, commingled stream from emitters of diverse industries, the differing impurities, although small, will have a significant and dynamic impact on the CO_2 phase behavior. To fully understand and manage the CO_2 phase behavior in the wellbore, accurate and high-resolution temperature measurements will be important.

4.2.3

Injection Well Monitoring

DTS is a powerful tool for understanding CO_2 injectivity. There are some clear indicators of the lowest point of injection, which changes over time as a function of injection rate. The major CO_2 sink can be identified by a slow warmback response during shut-in. It should be noted that these changes are relatively small in temperature, supporting the case for a high-resolution instrument.

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4.3 Wellbore Integrity

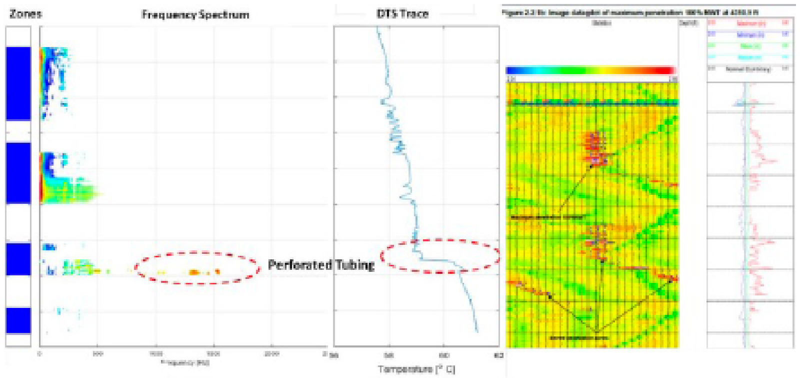
4.3.1 Temperature Monitoring

Continuous temperature data acquisition along CO_2 injector wells can provide important information about the wellbore integrity.

The temperature difference between the injected CO_2 and the reservoir temperature serves as a tracer to indicate locations of CO_2 leakage along the well.

The fiber optic distributed sensing system to detect CO_2 leakage consists of a fiber optic cable with multimode fibers cemented along the outside wall of a well casing. At the surface, the optical fibers are connected to a DTS unit, such as the Silixa ULTIMA™ DTS or XT-DTS™, that can be deployed in different operational environments to provide high-resolution temperature data.

Temperature data are continuously collected and an integrated system monitors variation of the actual temperature signals against the expected range. If readings occur outside of the expected range, an alarm is triggered, and a signal is sent to the operators to assess the data and take any required actions (FIGURE 14).



◄ **FIGURE 14**: Tubular failure identified by acoustic (left) and temperature (right) anomalies.

4.3.2 Acoustic Monitoring

A plan to continuously monitor fiber optic cable installed in a CO_2 injection well using DAS can be leveraged to notify operators of any damage to the wellbore along the entire depth of installed cable. This could include damage to plugs or valves, casing, grout, or surrounding formation (FIGURE 14).

Since the location of any such damage can be localized within a few meters, decision making is well informed of the potential severity of continued injection operation.

More intermittent acoustic monitoring can be carried out using periodic drive-by surveys to identify the locations and severity of potential CO_2 leaks. The flow of high-pressure fluids through well perforations (either intended or accidental) has a well-defined acoustic signature.

Acoustic data can be monitored for the onset and evolution of such leakage signals. The location of leakage is easily identifiable in the acoustic data, and the severity of leakage can be parameterized by the power distribution of the frequency spectrum.

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4.4

CO_2 Plume Mapping

4.4.1

Seismic Imaging

Time-lapse seismic is a way of using a series of seismic images of a reservoir through time to monitor changes in a survey area.

It is possible to create seismic images through either multiple 3D surface or VSP surveys. By viewing time-lapse data, both the storage reservoir and the overburden can be monitored. Changes in the seismic response to a CO_2 plume can be monitored and assessed. This geophysical exploration method is especially critical for safety monitoring at CO_2 sequestration sites because it makes it possible to view the migration of CO_2 over time. Consistent and accurate monitoring is critical for risk management of CO_2 injection.

Fiber optic cables provide a permanent monitoring capability to allow imaging of a CO_2 plume. This permanent installation provides the means for repeated measurements in the same area over tens of years with lowered costs, without compromising on data sampling.

Monitoring surveys are repeated with sufficient temporal resolution to capture the plume evolution. Typically, surface sources such as vibroseis trucks are used in a VSP setting to image plume boundaries and saturation around injection and monitoring wells. However, high survey costs and an increased need for higher temporal resolution are driving the development of continuous reservoir monitoring techniques by means of installation of permanent surface sources. Recent examples of SOVs coupled with DAS in a VSP setting have provided comparable results to conventional time-lapse seismic with vibroseis and geophones (Correa et al., 2017, 2018; Freifeld et al., 2016). Such a combination allows for cost-effective surveys, on-demand source interrogation, a minimally invasive approach, and a massively improved temporal resolution compared to traditional methods, and it represents the next step toward an affordable and truly continuous reservoir monitoring.

Crosswell survey settings are less common because of the higher costs derived from well occupation and the limitations of borehole sources in terms of energy and reliability. However, such an approach can guarantee a higher spatial resolution resulting in the ability of accurately mapping even subtle changes in the injection plume boundaries for early detection and quantification of leakage pathways and secondary accumulation. To successfully implement a crosswell approach, development is required to produce more dependable, highly repeatable, and low-impact sources (e.g., borehole orbital vibrators).

4.4.2

CO_2 Plume Breakthrough

A faster CO_2 plume dispersion can happen through highly permeable layers or preferential flow paths such as rock formation contacts, geologic faults, and dissolution features, especially in reservoirs formed by carbonate rocks. These preferential flow paths are difficult to predict during the characterization phase because of its small dimensions and heterogeneous distribution, requiring high spatial resolution and continuous monitoring to detect them.

Fiber optic distributed sensing methods offers an advantage over traditional point sensors because of their high temporal and spatial (≤1 m) resolutions and spatial coverage of tens of kilometers. Continuous monitoring of acoustic, strain, and temperature provides an opportunity to detect potential early arrival of the CO_2 plume at a monitoring well equipped with a fiber optic cable.

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4.5 Induced Seismicity Monitoring

Injection of CO_2 can induce seismicity via different mechanisms, and these events may pose a risk to CCS projects in different ways. Below is a summary of induced seismicity risks and the monitoring required to mitigate this risk.

4.5.1 Induced Seismicity

Induced seismicity in the form of felt earthquakes can occur due to an increase in stress on preexisting faults or because of lubrication of faults due to increases in pore pressure. These can be large magnitude seismic events and potentially damaging wellbores or surface infrastructure. Additionally, the reactivation of faults could result in leakage pathways for CO_2 and lead to potential migration of CO_2 and native fluids to the shallow subsurface.

The size and potential for this type of event depend on the specific geologic and structural history of the site. A thorough structural characterization of the site before injection can help identify potential seismicity risks. Surface or downhole DAS for seismic monitoring during CO_2 injection can also help mitigate this risk.

Often monitoring is required over a large area (km^2) at CCS sites because, over time, the CO_2 plume will occupy a significant volume and cause deformation over long distances. Large area coverage is possible with fiber optic cables. However, surface arrays are often further from the seismic source than borehole deployments; hence the signal is more attenuated.

Additionally, near-surface material is highly attenuating, and so surface deployments suffer from low signal-to-noise data. In this case smaller seismic events will not be detected. Surface cable deployments require helically wound fiber if P-waves are to be well detected.

Borehole monitoring for seismicity is discussed below in the context of microseismic monitoring because this is the most common application.

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4.5.2 Microseismic Event Detection and Monitoring

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Microseismic events are analogous to small earthquakes and generally have magnitudes (M)<0.

This type of seismic event occurs naturally but can also be induced by anthropogenic activities, particularly in scenarios where fluid/gas are injected into the subsurface. Microseismicity can occur on preexisting faults and fractures, but fractures may also be created by hydraulic fracturing in the injection process. CO_2 storage reservoirs are often chosen because they are thought to have high injectivity. Therefore, large volumes of fluid may be injected without exceeding the pressure required for hydraulic fracturing at the injection point or in the surrounding formation.

If this is the case, CO_2 storage projects are not expected to result in significant microseismicity. If microseismicity is detected, it could indicate the reactivation of a preexisting fracture network as described in Stork et al. (2015), which could trigger enhanced monitoring to ensure storage integrity.

The energy released by microseismicity is small, and it is necessary for monitoring equipment to be in close proximity (within hundreds of meters) to the events because the waves are quickly attenuated. Borehole monitoring is a good option because the array can be placed at or close to the injection depth. With multiple monitoring wells, precise event locations can be determined over the required area. Well-known seismic event locations aid the geomechanical interpretation of the effects of injection: an important aspect of verifying geological and geomechanical modeling of injection scenarios.

A microseismic array for CCS projects should cover a wide aperture (i.e., provide event detection over a range of directions and angles) because events may result from stress effects and pore pressure changes at significant distances from the injection point. DAS downhole monitoring provides coverage over the whole length of a borehole, while geophone arrays are often limited to a small number of instruments covering a specific depth interval.

Fiber optic cables can be deployed behind casing and cemented in place during well construction, providing a permanent monitoring array in a monitoring well, or even an injection well that can be interrogated continuously or periodically over tens of years.

Alternatively, a semipermanent installation can be made in a previously existing borehole by clamping the cable to the borehole tubing. A further possibility is deployment of a cable via wireline. However, to provide the best quality data, the cable should be well coupled to the borehole wall; therefore, unclamped wireline deployments in vertical wells are not recommended.

Highly sensitive instrumentation is required to detect microseismic events with expected ground motions on the order of nanometers. Therefore, it is important that sensors are well coupled to the ground or geologic formation and that the instrumentation noise is minimized to allow such small signals to be detected. Recent advances in DAS technology have produced fiber optic sensing systems with sensitivities equivalent to geophones.

In particular, the Carina® Sensing System provides data with a 20dB improvement over the highest performance single-mode fiber DAS systems, allowing the minimum detectable magnitude to be reduced by approximately one magnitude unit. The minimum detectable magnitude for a particular project is dependent on the source-cable distance, geologicl setting, and array geometry.

5 Deformation

CO_2 injection could lead to a significant surface heave because of pressure buildup in the reservoir and buildup of injected CO_2.

A successful field development program needs to take reservoir deformation into account to minimize risk to well integrity, casing failure, fault reactivation, surface infrastructure, and optimize storage.

The acoustic waveforms recorded by DAS are a measure of the strain rate applied to the fiber optic cable at any one point in time. By integrating continuously recorded strain rate data in the time domain, uniaxial cable relative strain can be measured.

Since linear fiber optic cable, interrogated by a DAS system, measures only normal strain rate in the direction of the axial dimension of the cable, the full strain tensor of the surrounding material or formation cannot be determined without additional information. Informed assumptions about the properties of the material to which the cable is coupled can leverage the uniaxial strain measurement toward an understanding of the rate and magnitude of formation deformation.

DAS-derived strain measurements, applied to CCS installations, can be used to model deformation in the reservoir formation. For example, monitoring strain along a cable installed in an observation well can show when, where, and to what degree the reservoir formation is deforming to accommodate CO_2 injection.

Strain and, therefore, deformation along the wellbore outside of the reservoir formation depth can indicate misallocation of injected CO_2 via damage to the injection well or poor cap formation integrity. Models of deformation near the surface can help with verification of compliance with local regulations applicable to CCS operations.

The relative strain method would be the most sensitive and potentially fastest to detect strain events; however, system interruptions (due to downtime or other measurements) will reset measurement of absolute change, which is why an absolute strain method is also important. A combination of these methods will be used to detect the strain and provide correlation for high degree of confidence.

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6

A Permanent Real-Time Monitoring System

6.1

Onshore CCUS Monitoring

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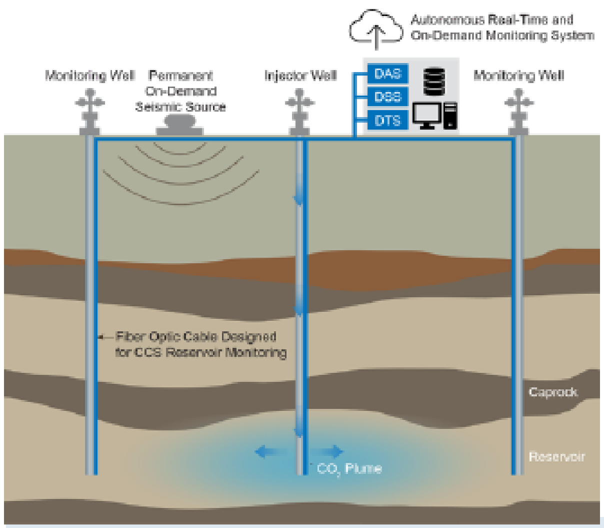
A permanent real-time monitoring system for CCS consists of an integrated system to facilitate continuous and cost-efficient CO_2 reservoir monitoring for risk mitigation and injection optimization.

In the injector well and monitoring wells, an online microseismic and wellbore integrity monitoring system is based on autonomous and continuous DTS, DAS, and DSS data acquisition with edge processing on a local server, with event data submission to a cloud storage system for further remote processing, interpretation, and verification (FIGURE 15). CO_2 plume evolution mapping is done based on on-demand, time-lapse VSP surveys. These surveys can be done remotely without expensive crew or equipment mobilization using permanently installed fiber optic cables, DAS units, and seismic sources such as the small footprint SOVs. (FIGURE 15).

The permanent monitoring system delivers enhanced quality data since the sensors and seismic sources are in the same location for all surveys, minimizing survey variability. Environmental impact is reduced, and cost-savings can be achieved by avoiding well intervention and mobilization of traditional seismic sources using vibe trucks. Critical for all operations is the repeatability and sensitivity of the measurements. Engineered fibers improve the signal-to-noise of DAS measurements while also enabling finer spatial resolution and extended measurement range. Extended range allows the optical fiber in multiple wells to be daisy-chained together to decrease overall system costs, and the improved noise performance enhances the ability to image CO_2 while improving survey efficiency through a reduction in the number of sweeps or shots at a given source point for seismic imaging. The same optical fiber cable is used for both temperature and strain profiling.

The first autonomous monitoring system was implemented in the CO2CRC Otway Project in Australia, and the preliminary results have been published by Isaenkov et al. (2021). The authors highlighted that the "monitoring system allows acquisition of seismic vintages every two days in an automated manner. The permanent installation requires no human effort on-site and thus drastically reduces the monitoring cost. Such a system can coexist within industrial or farm area as it produces a tolerable level of noise and operates only within the allowed time schedule (in the daytime).



▲ FIGURE 15: Silixa's integrated fiber optic distributed sensing monitoring system for carbon capture and storage projects.

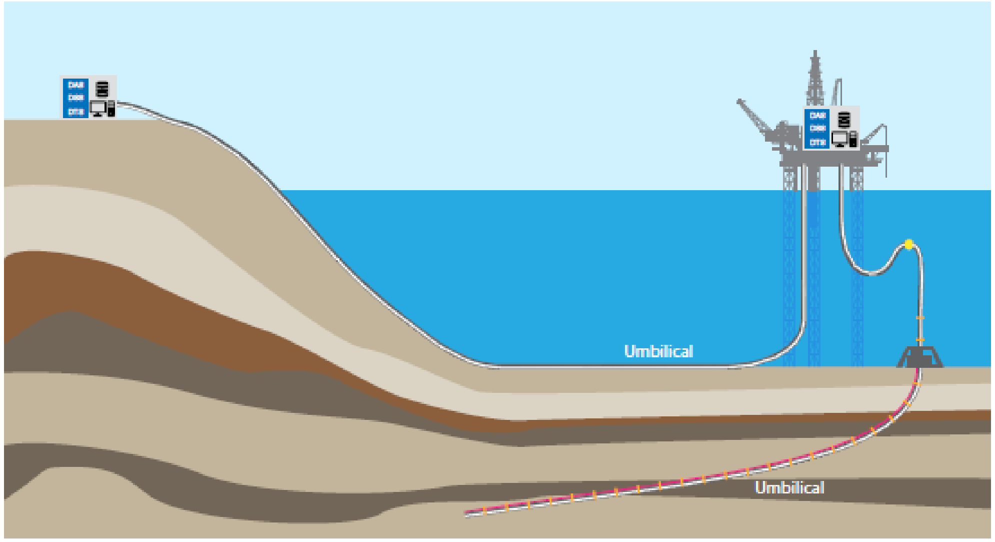
6.2 Offshore CCUS

In the context of subsea well monitoring, the huge increase in optical scattering from the Constellation fiber allows the interrogator to be placed much farther from the measurement location.

Deployments of the engineered fiber in offshore environments is unique in that it does not require any complex electronics to be placed on the seafloor. Acquisitions are performed from the topside facility utilizing existing fibers in the subsea umbilicals to carry the signal to the measurement region. Integration complexity and costs are, therefore, substantially reduced, and data management is simplified. The interrogator can address either the umbilical fiber or the fiber in the well often tens of kilometers away.

The long offset distance between the surface interrogator and subsea well does not compromise data quality. The engineered fiber optic cable and novel optical architectures allow the same high-quality data to be achieved as on existing land and platform systems. A typical subsea layout is shown in FIGURE 16.

The Carina® Subsea 4D interrogator can be located onshore, or on a remote platform, with the optical signal traveling through the umbilical to the well being monitored.



◄ **FIGURE 16:** Key components in a subsea well-monitoring system.

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7

Case Studies

7.1

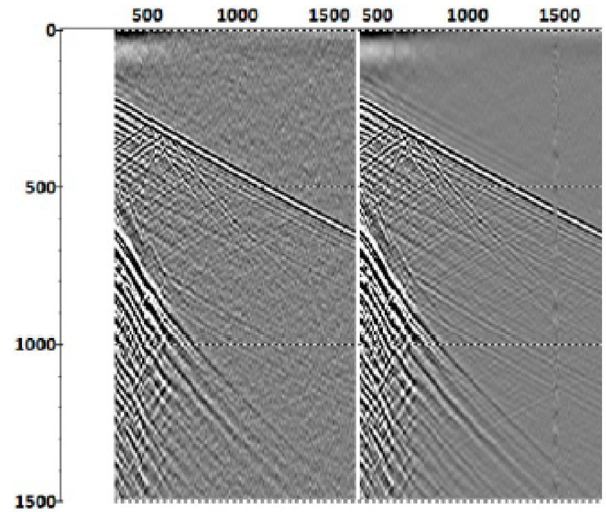
Otway, Victoria, Australia

An extensive, world-class monitoring program is ongoing at the CO2CRC Otway CO_2 storage test site in Victoria, Australia, where new capture and monitoring technologies are being benchmarked against conventional methods, such as traditional seismic surveys to monitor CCS sites.

Stage 3 of the project is now underway with the aim of developing continuous low-cost and low-environmental footprint solutions. This builds on the results from Stage 2 of the project which demonstrated safe injection of CO_2 into a saline formation and successful monitoring of the CO_2 plume evolution.

The inclusion of fiber optic monitoring at Otway began in Stage 1 with a cable deployed on borehole tubing. DTS measurements were used to monitor the geothermal profile and identify potential leaks. During Stage 2, CO2CRC injected 15,000 tons of CO_2 approximately 1,500 meters underground, and a further fiber optic cable was installed in one of the wells to benchmark DAS technology against seismic survey data recorded on geophones. (FIGURE 17). At the time of installation fiber optic DAS was a relatively new technology to be applied to seismic monitoring. However, it is now accepted that, with careful survey design, the latest DAS technology rivals geophones in data quality, and it provides many advantages, such as the potential for long-term repeatable measurements and dense spatial sampling without the need for well intervention. This was tested during Stage 2 at Otway with a cable cemented behind casing in a borehole.

Using 3D DAS VSP data recorded ata tubing installation at Otway, researchers from Curtin University and Lawrence Berkeley National Laboratory found the data were of good quality, and they were able to image geologic interfaces beyond the CO_2 injection depth. The use of Silixa's new Carina Sensing System technology highlighted a step change in the ability of DAS technology, with an improvement in noise levels of 20dB over previous systems. The advancement in technology enables far-offset surveys, facilitating monitoring over a wider area. These types of surveys are possible, even if cables are not cemented in place.



▲ **FIGURE 17:** VSP data recorded on iDAS (on the left) and Carina Sensing System (on the right). Data recorded using SOV source. Courtesy of CO2CRC.

7.1

Otway, Victoria, Australia

Recently for Stage 3 of the Otway project, further fiber optic cables have been installed in five wells at the site. The technology will be tested not only for active seismic surveys but will also be applied to microseismic monitoring and passive seismic imaging using recordings of background noise.

In addition, the cables include optical fibers to monitor temperature profiles during injection and for early detection of potential leaks. Also, as part of Stage 3, surface cables with different specifications were installed at the site, and similar surveys will be recorded on these cables.

The environmental impact of monitoring is an important consideration for CO2CRC. Vibroseis trucks or dynamite are the most used sources for land seismic surveys. Both these techniques have a significant environmental impact requiring the transport of heavy equipment and personnel. Once on-site the sources can also be disruptive to local residents and/or farming activities because they are noisy and require access to extensive areas of land, up to a few square kilometers. The deployment of large numbers (1000s) of geophones also requires considerable effort in terms of personnel.

To reduce the environmental impact of seismic surveys CO2CRC, Curtin University and Lawrence Berkeley National Laboratory have been trialing the use of SOVs in combination with fiber optic sensors. SOVs are small seismic sources that are permanently deployed on the surface and can be operated remotely without disrupting local stakeholders. They have a small physical footprint and although they are much less energetic than a vibroseis source, the remote operation of the SOVs over a period of time can impart total energy, and, hence, signal quality, equivalent to the data obtained from a vibroseis survey. SOVs offer an alternative or complementary approach to traditional dynamite and vibroseis sources.

The success and environmental, safety, and cost benefits of the combined SOV operation with DAS recordings have resulted in the carrying forward of both these technologies to Stage 3.

It is envisioned that fiber optic monitoring will be available for multipurpose monitoring, and for use in continuous passive and time-lapse active seismic surveys, in-well temperature measurements, and deformation measurements. Detailed techno-economic studies will be performed as part of the Otway project, but it is estimated that overall a cost saving of up to 75 percent of monitoring costs over traditional monitoring technologies can be realized.

Correa et al. (2019) 3D vertical seismic profile acquired with distributed acoustic sensing on tubing installation: A case study from the CO2CRC Otway Project, Interpretation, doi: 10.1190/INT-2018-0086.1

SILIXA actionable insight

7.2

Aquistore, Saskatchewan, Canada

Aquistore, the world's first combined commercial power plant and CCS project, is located in Estevan, Saskatchewan, Canada.

It is managed by the Petroleum Technology Research Centre (PTRC). CO_2 is captured at the nearby SaskPower Boundary Dam coal-fired power plant. Following capture, a portion of the CO_2 is sold for enhanced oil recovery operations, and the remainder is transported by pipeline to the Aquistore site approximately 5km away. The CO_2 is injected into a deep reservoir via a 3000m injection well, where more than 275,000 tons of CO_2 has been permanently stored since April 2015.

Any CCS project requires a comprehensive testing and monitoring plan to ensure safe storage of the CO_2. Conventional active seismic methods provide snapshots of the site over time but are expensive. One safety concern and monitoring challenge is verifying that the CO_2 does not leak into the geologic layers above the storage reservoir with the use of seismic imaging methods. Any leakage negates the positive impact of mitigating climate change effects by preventing emission of the CO_2 to the atmosphere.

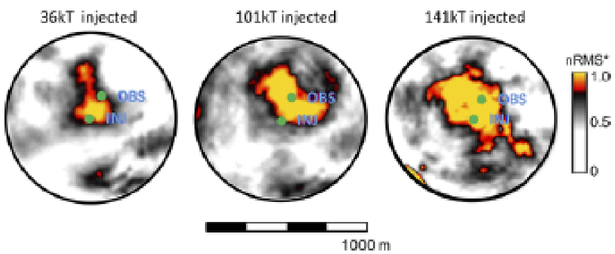
Another challenge is passive monitoring for any seismic events induced by the volume of CO_2 injected. These seismic events may indicate CO_2 leakage pathways or, if large enough, may damage infrastructure. An important part of measurement, monitoring and verification implementation is active seismic surveys to monitor and verify the behavior of the CO_2 underground and track the extent of the CO_2 plume.

Distributed sensing offers a viable alternative to geophone arrays for the acquisition of seismic data. It reduces monitoring costs and provides spatially and temporally continuous data. A fiber optic cable is permanently deployed in a monitoring well at the Aquistore site. This supplies a long-term and on-demand monitoring solution.

The benefits and quality of fiber optic DAS are proven for seismic acquisition, particularly for VSP surveys. DAS provides the capability to conduct repeat time-lapse surveys without intervention in the monitoring well, providing a cost-effective solution.

The data obtained from DAS are well suited to facilitating the detection of changes in seismic response due to the presence of CO_2 and the fiber can also be used to detect any seismic events at the site. With minimal environmental impact, Silixa's iDAS provides a long-term, on-demand, and cost-effective seismic monitoring solution for safe CO_2 storage at Aquistore and for CCS in general.

iDAS units have been used at Aquistore since 2013 to provide baseline and monitoring data via VSP surveys, with the most recent being in January 2020. These data have been used to image the CO_2 storage reservoir and track the extent of the CO_2 plume and verify caprock integrity. Significant leakage of CO_2 from the storage reservoir would be observable in the seismic response recorded by an iDAS interrogator.



3D DAS VSP INJ = Injection Well OBS = Observation Well

▲ **FIGURE 18:** Extent of CO_2 plume (bright colors) monitored over time with 3D VSP surveys recorded on a fiber optic cable and Silixa's iDAS unit. Monitoring surveys were conducted after 36kT, 102kT and 141kT of CO_2 were injected (courtesy of Don White, Geological Survey, Canada).

SILIXA actionable insight

7.3

Chester 16, Illinois, USA

The study was conducted under the U.S. Department of Energy National Energy Technology Laboratory's Regional Carbon Sequestration Program.

The Midwest Regional Carbon Sequestration Partnership is a multiyear research program to identify, test, and develop the best approach for carbon dioxide utilization and storage under the leadership of Battelle with partnership from Core Energy, LLC.

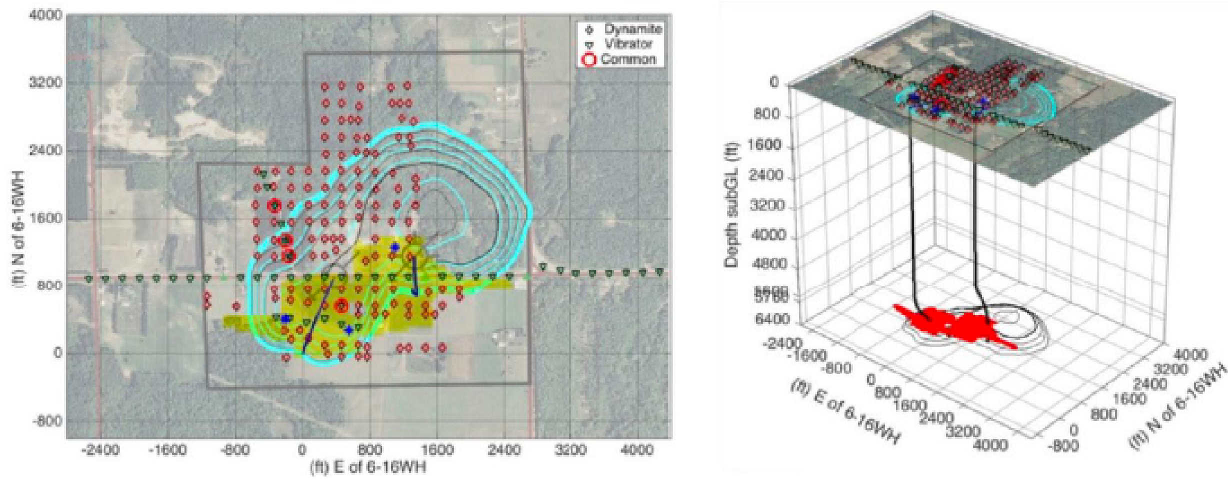
Part of the program is to map the injected CO_2 plume into carbonate reservoirs, and DAS time-lapse vertical seismic profiling was evaluated at Chester-16 pinnacle reef (FIGURE 19A).

Two new wells were drilled in late 2016/early 2017 with fiber optic cable installed outside casing to facilitate distributed sensing measurements (FIGURE 19B). Injection tubing was deployed in 6-16 and used to inject CO_2 into the reservoir, while a second well, 8-16, a future production well, was used to monitor the reservoir. A 3D DAS VSP survey was designed to illuminate the south part of the reef in an area between the two new wells. Because of access restriction, a combination of vibroseis and dynamite sources was used.

The operator carried out the first (baseline) 3D survey in 2017 prior to commencing injection of CO_2 into the reservoir, when reservoir pressure was low (approximately 700 psi). The second (repeat) 3D survey was acquired 16 months later in 2018 after 86,000 tons of CO_2 had been injected, raising the reservoir pressure to approximately 1500 psi.

4D VSP processing of the baseline and repeat surveys was aimed to determine the time-lapse effect of injected CO_2 on the seismic response. Two surveys were processed in parallel using the same workflow and parameters. The dynamite source data were processed separately from vibroseis source data.

▼ FIGURE 19: Seismic sources geometry design in (A) plan view, and (B) cross-sectional view.



SILIXA actionable insight

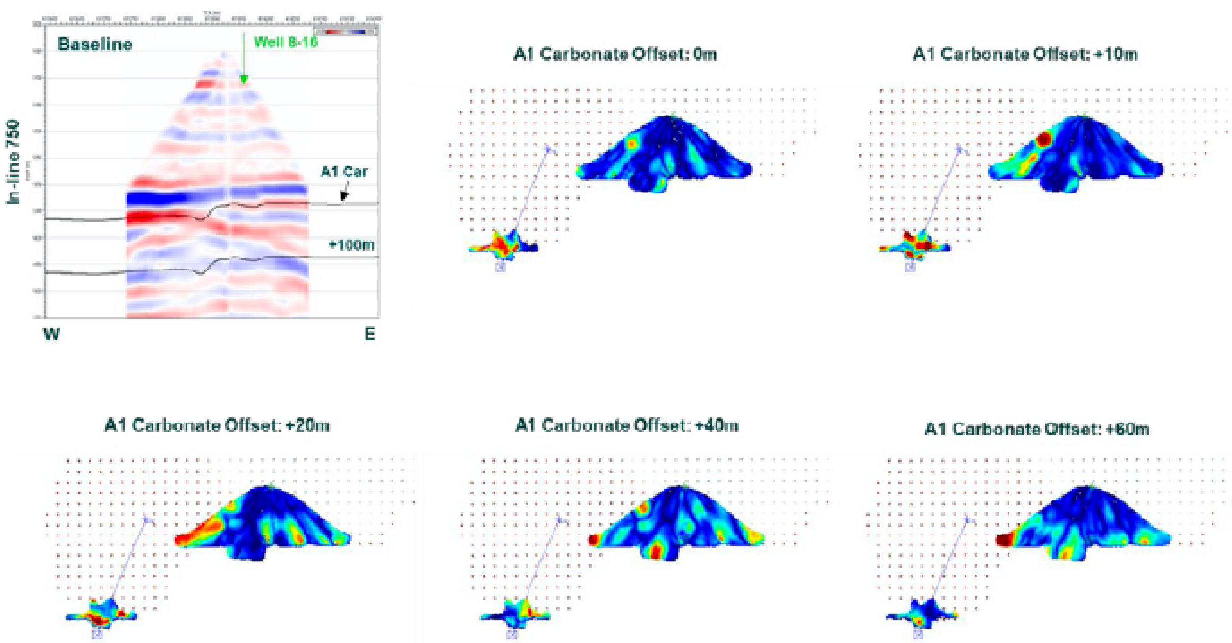
7.3

Chester 16, Illinois, USA

The quality of the data recorded using the vibroseis source was significantly better than that from the dynamite source, the refore the imaging was focused on the vibroseis data, as was the time-lapse analysis. The 3D velocity model used for VSP processing was constructed using the well acoustic logs and the well 8-16 ZVSP data. The recorded DAS time-lapse response was compared with several synthetic models. These models were built based on results from lab tests conducted on reservoir cores.

The 4D time-lapse analysis shows differences between the monitor and baseline surveys. Although part of the difference was attributed to noisier baseline-survey data, greater differences were present in the volume close to the injection well perforations which is considered to be caused by CO_2 injection. The importance of cementing the annulus across the entire depth range was highlighted, as data from part of the DAS array in 6-16 (the injector) were unusable because of excess injection noise from uncemented cable which limited the imaged volume around the well.

▼ FIGURE 20: (A) Difference amplitude RMS with the center of the analysis window at (B) the A1 Carbonate 3D surface and at (C) 10 m, (D) 20 m, (E) 40 m, and (F) 60 m below the A1 Carbonate 3D surface.



SILIXA actionable insight

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