# 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

Facility Contact: John Zuckerman, Pelican Renewables – Managing Member
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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.

## Strategy and 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 as **Appendix 8-B** to this Plan.

### *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 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 and frequency*

$CO_2$ stream sampling will take place on a quarterly basis, 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.

The $CO_2$ stream 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 |
|---|
| Carbon Dioxide ($CO_2$) (% vol) |
| Methane ($CH_4$) (% vol) |

| Parameter |
|---|
| Nitrogen ($N_2$) (% vol) |
| Hydrogen ($H_2$) (% vol) |
| Argon (Ar) (% vol) |
| Water ($H_2O$) (ppmv) |
| Oxygen ($O_2$) (ppmv) |
| Hydrogen Sulfide ($H_2S$) (ppmv) |
| Sulfur Dioxide ($SO_2$) (ppmv) |
| Nitrogen Oxide (NOx) (ppmv) |
| Carbon Monoxide (CO) (ppmv) |
| Total Hydrocarbons (ppmv)* |

*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.*

### *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 and 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 D.1 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) and 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 and 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-D** of this Plan for details on the DFOS technology.

**Table 8-2. Sampling devices, locations, and 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 and frequency*

The corrosion of well casing and tubing materials will be monitored on a quarterly basis using the corrosion coupon method, beginning three months after the date of authorization of injection. This frequency will be changed to once every 6 months after the first year of operation. 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.

### *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 also be weighed and measured and observations will be recorded. The corrosion rate will be calculated using the weight loss method, which is the weight loss of the coupon during the exposure period divided by the length of the exposure period (Jaske et al., 1995).

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 the injection well's performance in consideration. Pelican will follow EPA Region 9's CIL Guidance, which is included as **Appendix 8-C** 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 and Intervals*

**Table 8-3** 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 as **Appendix 8-B**.

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 all three water production zones are 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 need to be installed by 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 2-5** and **Figure 2-36**. There were no data available for 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*

Deep monitoring wells in the Domengine Formation (GMW-D) will be monitored according to the frequency outlined in the next section and **Table 8-3**. Monitoring of both analytical and field parameters in these wells 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 8-3** and **8-4**. 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 8-3** and **8-4**. 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 8-3** and **8-4**.

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 8-3. Monitoring of groundwater quality and geochemical changes above the confining zone.**

| Target Formation | Monitoring Location(s) | Estimated Total Depth (ft) | Baseline Data | Operational Plan |
|---|---|---|---|---|
| Domengine Formation | GMW-1D | 5000 | Eight consecutive quarterly events during pre-operational period. | Quarterly monitoring of analytical parameters and continuous monitoring of field parameters (**Table 8-4**), starting when injection commences. |
| | GMW-2D | 5000 | Eight consecutive quarterly events during pre-operational period. | Quarterly monitoring of analytical parameters and continuous monitoring of field parameters (**Table 8-4**), starting when injection commences. |
| | GMW-3D | 5000 | Eight consecutive quarterly events prior to Year 5. | Quarterly monitoring of analytical parameters and continuous monitoring of field parameters (**Table 8-4**), starting at Year 5. |

| Target Formation | Monitoring Location(s) | Estimated Total Depth (ft) | Baseline Data | Operational Plan |
|---|---|---|---|---|
| Markley Formation (Lowermost USDW) | GMW-1M | 4000 | Eight consecutive quarterly events during pre-operational period. | Quarterly monitoring of water levels and continuous monitoring of field parameters (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level increase of 10 feet or more or a pressure increase of 30,000 Pa is observed during a given quarterly event. |
| | GMW-2M | 4000 | Eight consecutive quarterly events during pre-operational period. | Quarterly monitoring of water levels and continuous monitoring of field parameters (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level increase of 10 feet or more or a pressure increase of 30,000 Pa is observed during a given quarterly event. |
| | GMW-3M | 4000 | Eight consecutive quarterly events prior to Year 5. | Quarterly monitoring of water levels and continuous monitoring of field parameters starting at Year 5 (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level increase of 10 feet or more or a pressure increase of 30,000 Pa is observed during a given quarterly event. |
| Local Principal Freshwater Aquifer System (Shallow Zone) | GMW-1S | 150-350 | Eight consecutive quarterly events during pre-operational period. | Quarterly monitoring of water levels and continuous monitoring of field parameters (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level increase of 10 feet or more or a pressure increase of 30,000 Pa is observed during a given quarterly event. |

| | | | | |
|---|---|---|---|---|
| | GMW-2S | 150-350 | Eight consecutive quarterly events during pre-operational period. | Quarterly monitoring of water levels and continuous monitoring of field parameters (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level increase of 10 feet or more or a pressure increase of 30,000 Pa is observed during a given quarterly event. |
| | GMW-3S | 150-350 | Eight consecutive quarterly events prior to Year 5. | Quarterly monitoring of water levels and continuous monitoring of field parameters starting at Year 5 (**Table 8-4**); geochemical modeling of analytical parameters in **Table 8-4** will be triggered if a water level increase of 10 feet or more or a pressure increase of 30,000 Pa is observed during a given quarterly event. |

*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 8-4** 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 8-4. Summary of analytical and field parameters for groundwater samples.**

| Parameters | Analytical Methods |
|---|---|
| **Domengine Formation** | |
| Analytical: Calcium, Magnesium, Sodium, Potassium, Chloride, Sulfate, Total Dissolved Solids, Dissolved $CO_2$, Alkalinity (as bicarbonate), Arsenic, Iron, Magnesium | Analytical: Per EPA SW-846 guidance |
| Field: pH, Specific Conductance, Pressure, Temperature | Field: Continuous pH/SC monitoring via downhole sensors; Continuous P/T monitoring via DSS/DTS |
| **Markley Formation (Lowermost USDW)** | |
| Analytical: Total Dissolved Solids (only if triggered per **Table 8-3**) during operational period; baseline collected for same parameters as Domengine listed above | Analytical: Per EPA SW-846 guidance |
| Field: Pressure, Temperature during operational period; baseline collected for same parameters as Domengine listed above | Field: Continuous P/T monitoring via downhole sensors |
| **Local Principal Freshwater Aquifer System** | |
| Analytical: Total Dissolved Solids (only if triggered per **Table 8-3**) during operational period; baseline collected for same parameters as Domengine listed above | Analytical: Per EPA SW-846 guidance |
| Field: Pressure, Temperature during operational period; baseline collected for same parameters as Domengine listed above | Field: Continuous P/T monitoring via downhole sensors |

### *Sampling methods*

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 A 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 8-5** during the injection phase to verify external MI as required by 40 CFR 146.89(c) and 146.90.

### *Testing location and 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 8-5. MITs.**

| Test Description | Location | Frequency |
|---|---|---|
| Standard Temperature Logging | • Injection well casing<br>• Monitoring well casing | • Annually for the injection well during injection phase<br>• Every 5 years on any monitoring wells that penetrate the confining zone (Capay Shale) |
| Standard Noise Logging | • Injection well casing<br>• Monitoring well casing | • Annually for the injection well during injection phase<br>• Every 5 years on any monitoring wells that penetrate the confining zone (Capay Shale) |
| 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.

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)]."

All monitoring wells under this permit will be designed and constructed to maintain mechanical integrity. Once constructed, any monitoring wells that reach the confining zone (Capay Shale) 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 and frequency*

Pressure fall-off testing will be performed:

- During injection, approximately 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*

To conduct pressure fall-off testing, 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 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). The well operator will cease injection after 24 hours. Following injection, the wireline will record the pressure until radial flow equilibrium is achieved. 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 and 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 8-6** 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 pressure-front monitoring details***

Pelican will utilize Distributed Fiber Optic Sensing at Rindge Tract CCS Well #1 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 deep groundwater monitoring wells (i.e., GMW-1D, GMW-2D, and GMW-3D) for continuous temperature and pressure monitoring.

***Indirect plume and 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 Well #1 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-D** of this Plan for additional details on the DFOS technology and applications for $CO_2$ plume and pressure front monitoring.

**Table 8-6. Plume and pressure-front monitoring activities.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **DIRECT PRESSURE-FRONT MONITORING** | | | | |
| Mokelumne River Formation (Injection Zone) | DTS/DSS | Rindge Tract CCS Well #1 | Distributed measurements from surface to base of storage interval | Pre-Operational: Continuous<br><br>Operational: Continuous |

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **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 | Full coverage of approximately 1154 acres | Pre-Operational: One baseline survey<br><br>Operational: Annual |
| Mokelumne River Formation (Injection Zone) | DAS Passive Seismicity | Rindge Tract CCS Well #1 | Vertical: distributed measurements from surface to base of storage interval<br><br>Lateral: 1154 acres | Pre-Operational: Continuous<br><br>Operational: Continuous |

*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**).

## References

ASTM International (2017). (ASTM) Method G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens.

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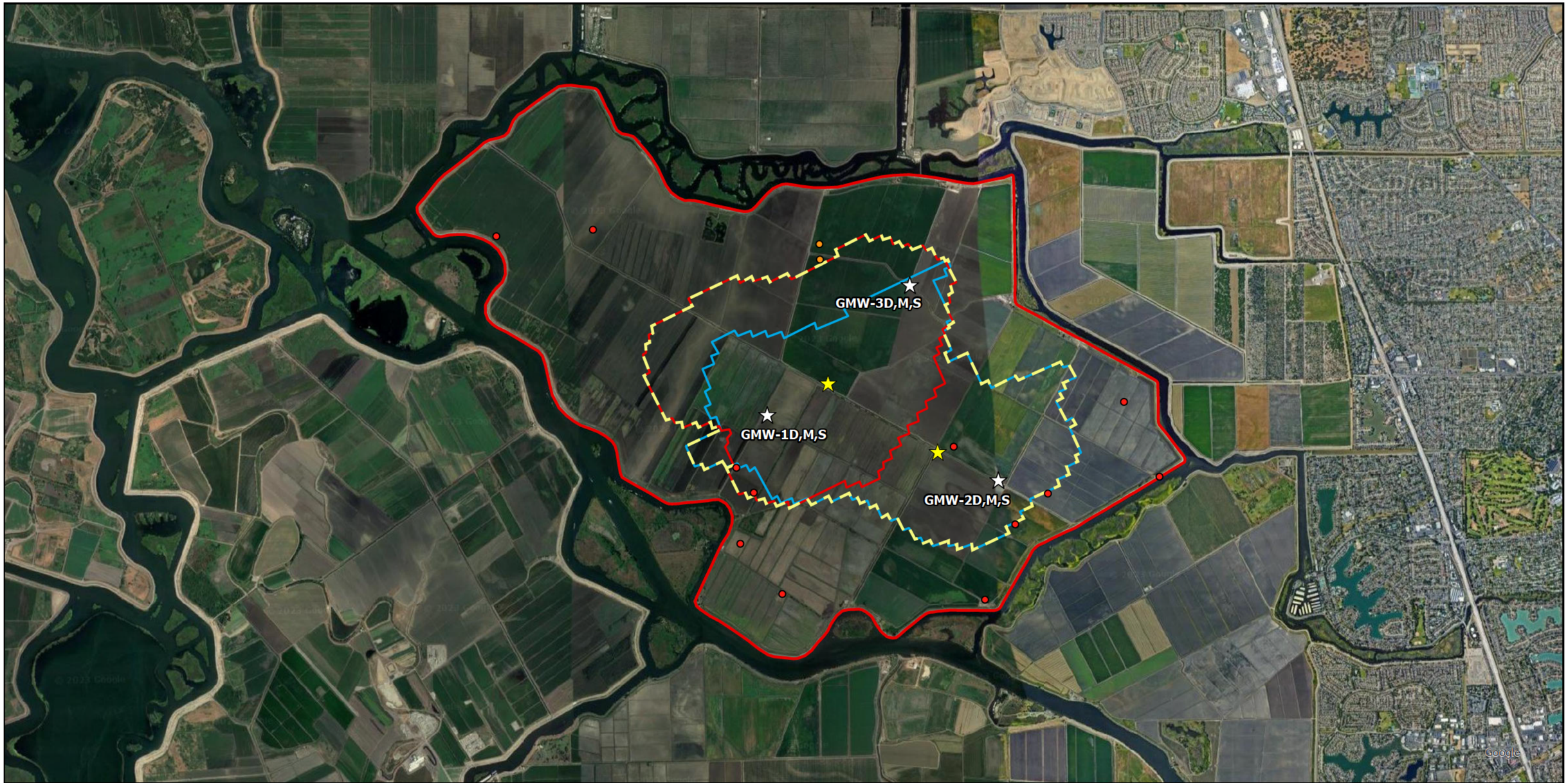
USEPA (2013). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance. EPA 816-R-13-001. Prepared by the Office of Water (4606M), March 2013. www.epa.gov/safewater.

# 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).

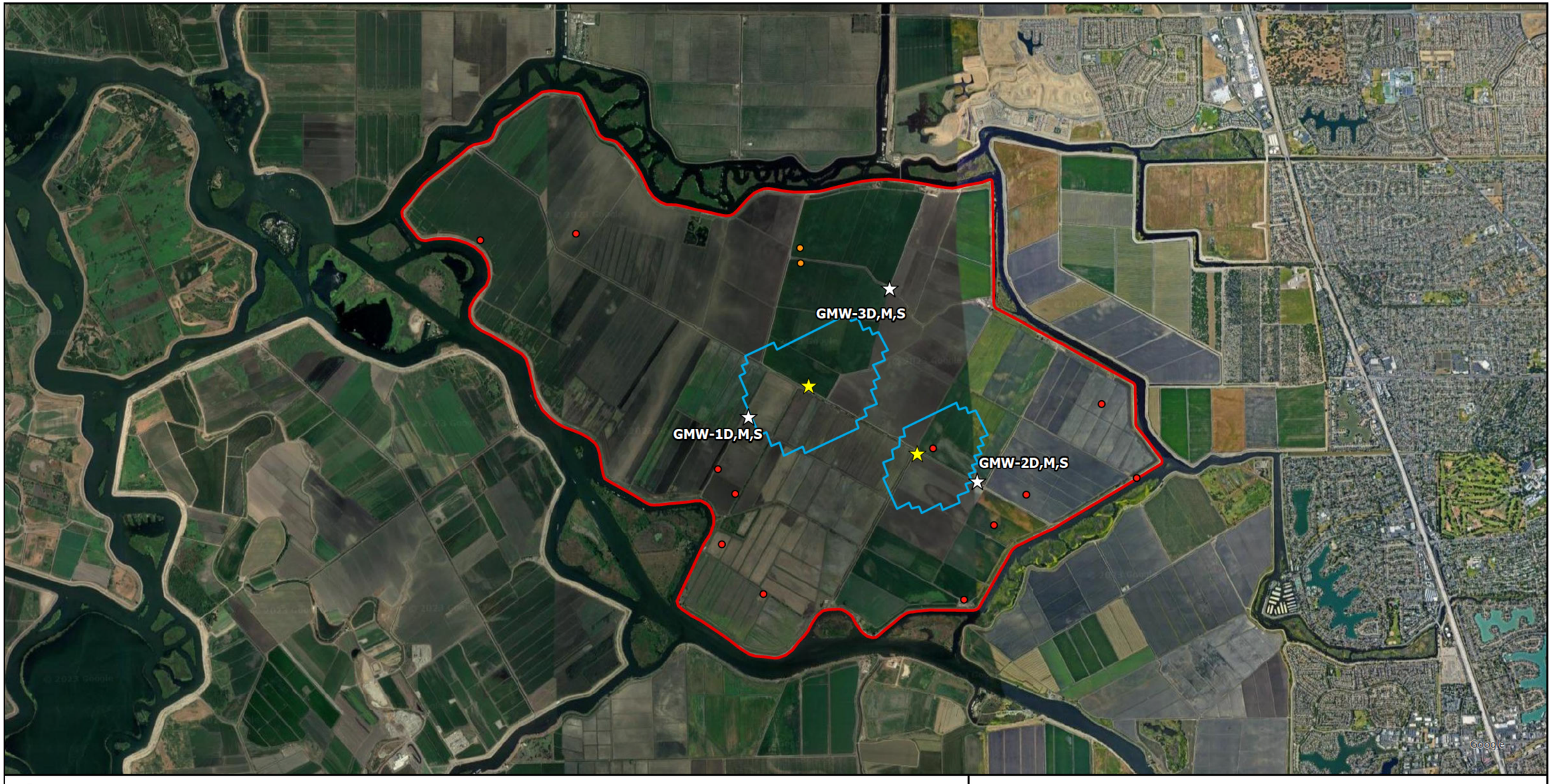
# FIGURE 8-1

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

SCS ENGINEERS
Wichita, KS | February 2023

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**

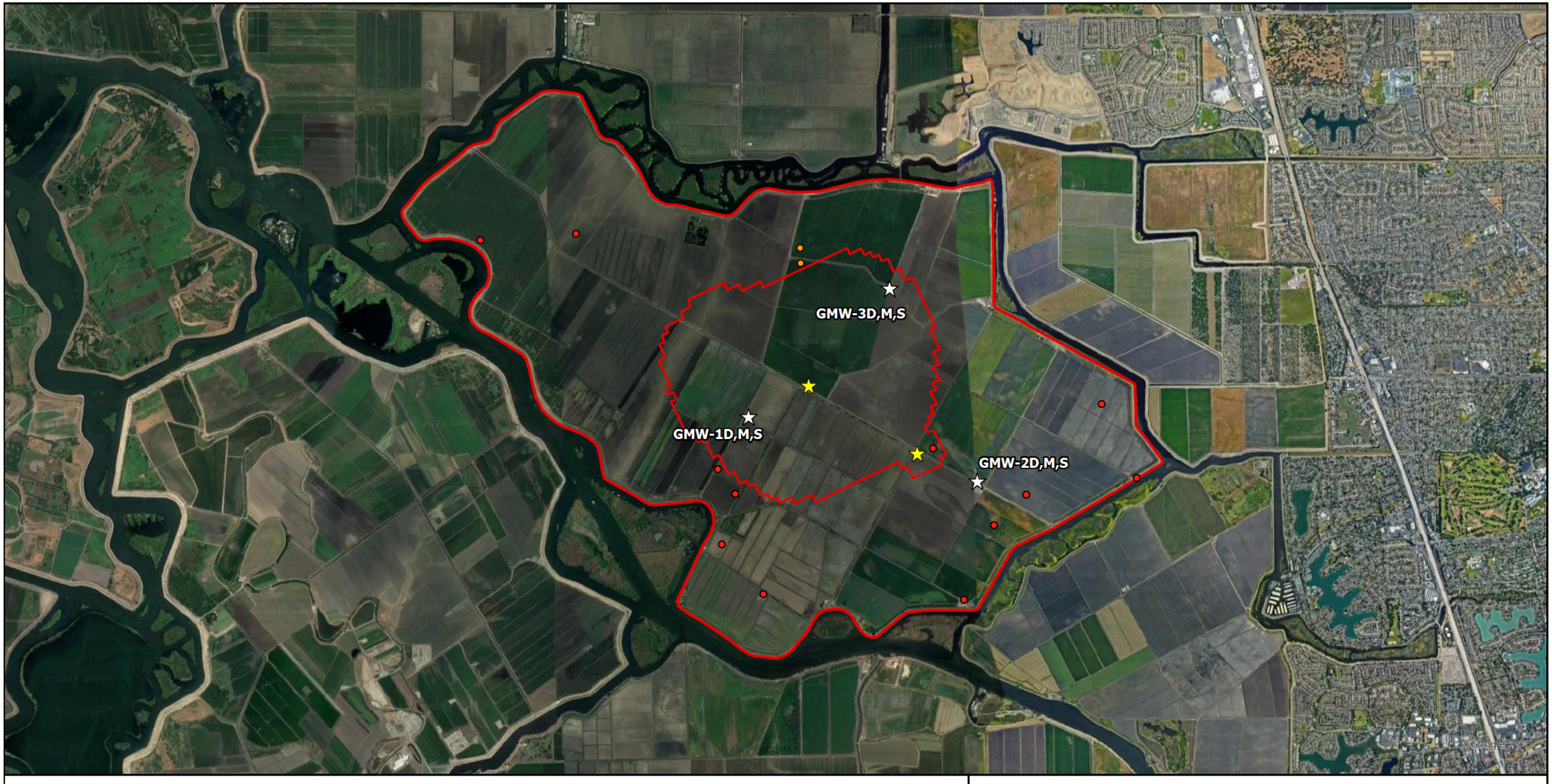
PREDICTED $CO_2$ PLUME EXTENT - YEAR 5
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS

Wichita, KS | February 2023

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 2023

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 2023

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).

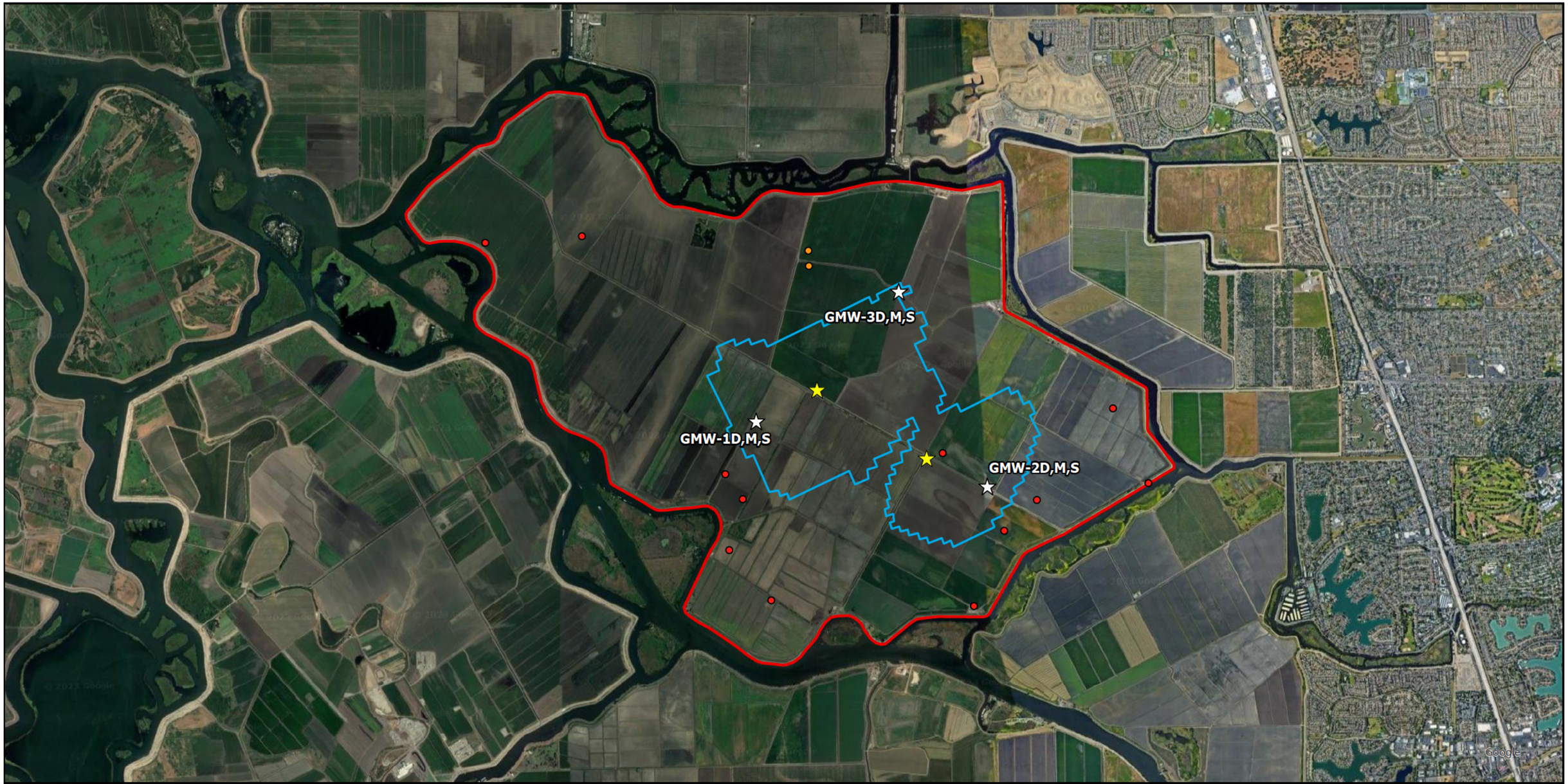
# FIGURE 8-5

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

SCS ENGINEERS
Wichita, KS | February 2023

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

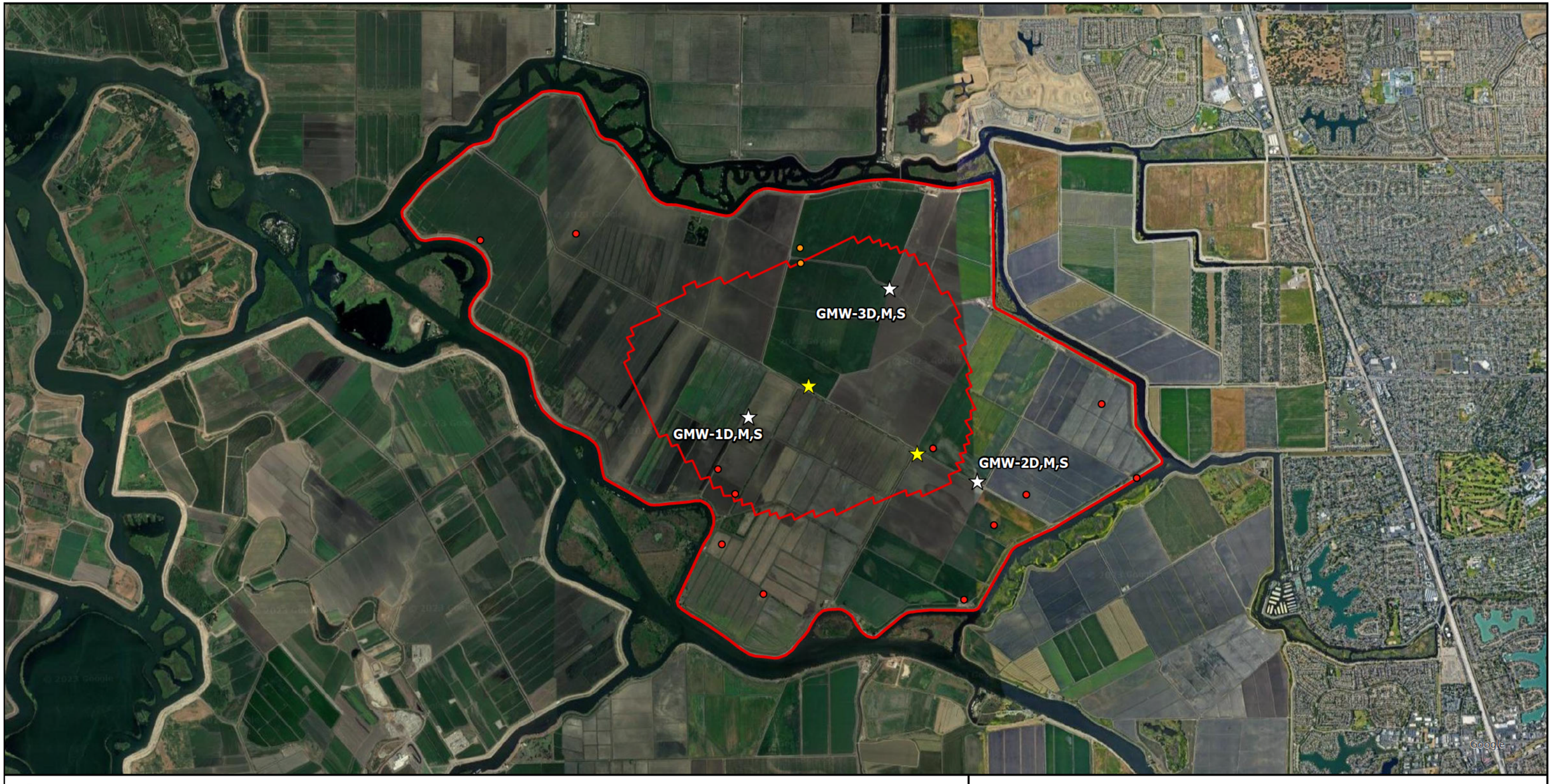
**FIGURE 8-6**

PREDICTED $CO_2$ PLUME EXTENT - YEAR 15
PELICAN RENEWABLES INC.
SAN JOAQUIN COUNTY, CALIFORNIA

SCS ENGINEERS | Wichita, KS | February 2023

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

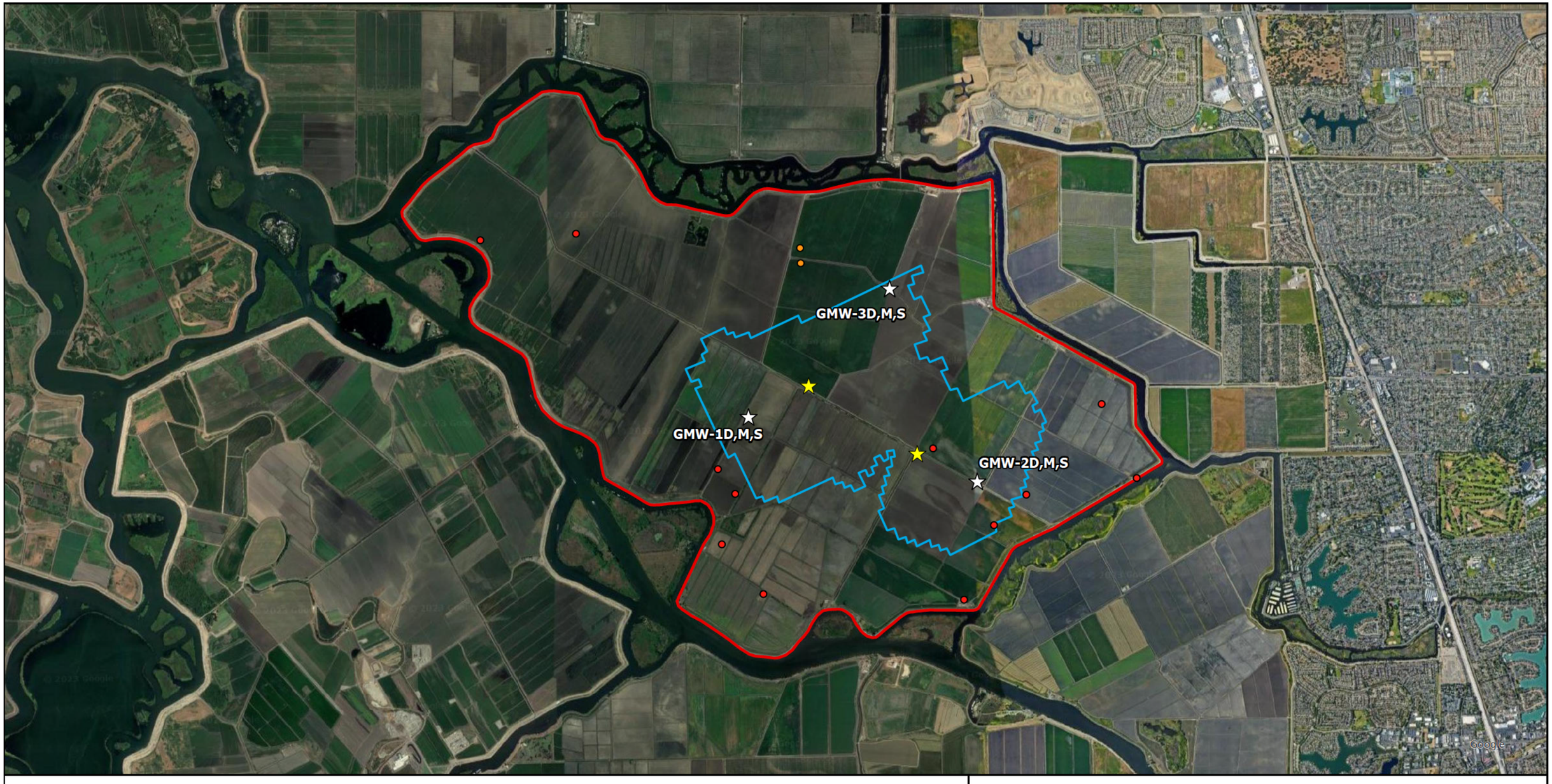
**Note:**
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

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

SCS ENGINEERS
Wichita, KS | February 2023

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

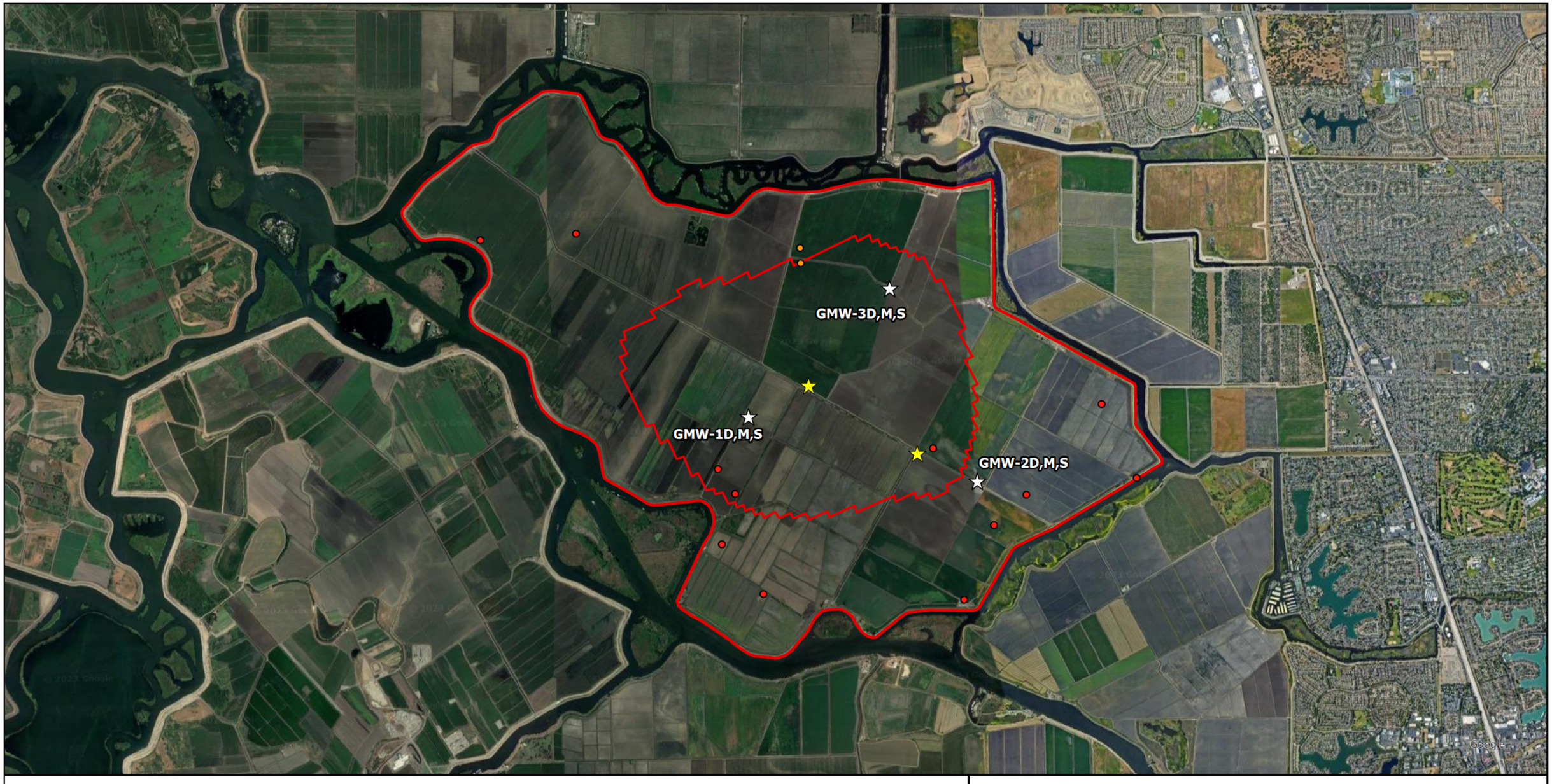
**FIGURE 8-8**

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

SCS ENGINEERS
Wichita, KS | February 2023

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

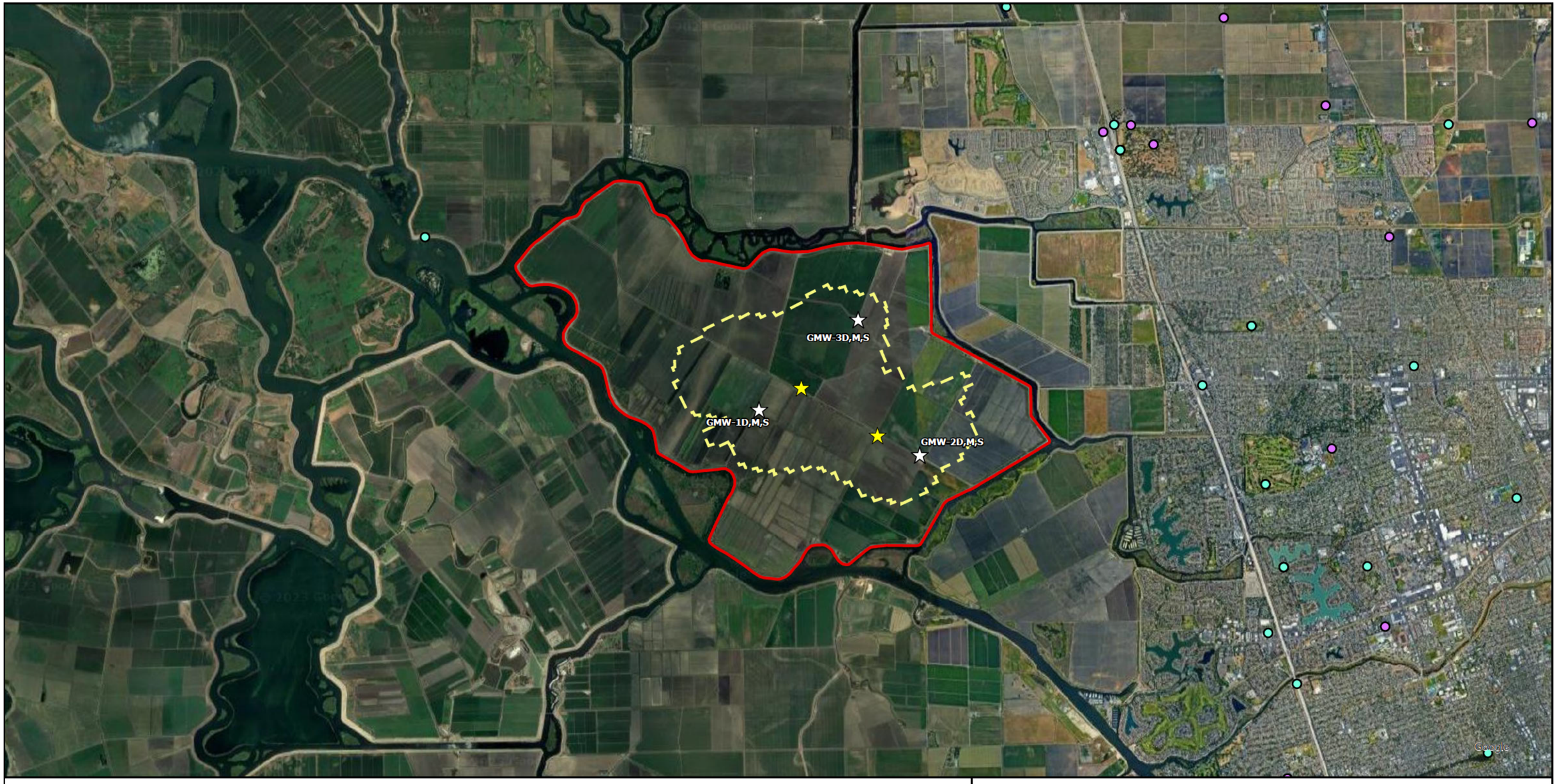
**Note:**
Pressure front extent is based on a 1 MPa delta P per Section 3 (AOR and Corrective Action Plan).

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

SCS ENGINEERS
Wichita, KS | February 2023

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 2023

0 5,000 10,000 Feet

N

# Appendix 8-A

# Appendix 8-A: Quality Assurance and Surveillance Plan

February 2, 2023

**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 |
|---|---|
| Kacey L. Garber, M.S.<br>Testing and Monitoring Plan Task Lead | |

| Signature | Date |
|---|---|
| Gary Vancil<br>Project Manager | |

| Signature | Date |
|---|---|
| Floyd E. Cotter, P.E.<br>National Partner for Quality Management | |

## 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<br>john.zuckerman@pelicanrenewables.com |
| Kacey L. Garber | SCS Engineers | Testing and Monitoring Task Lead | 309-202-6333<br>kgarber@scsengineers.com |
| Gary Vancil, Jr. | SCS Engineers | Project Manager | 618-841-2824<br>gvancil@scsengineers.com |
| Floyd E. Cotter, P.E. | SCS Engineers | Quality Engineer | 973-302-1428<br>fcotter@scsengineers.com |
| Charles J. Hostetler | SCS Engineers | Senior Project Advisor | 309-276-7005<br>chostetler@scsengineers.com |

# A. Project Management

## A.1. Project/Task Organization

### *A.1.a Key Individuals and Responsibilities*

The key individuals for the Testing and Monitoring Task are:

- The SCS Engineers' Project Manager (PM), who provides overall coordination and responsibility for all organizational and administrative aspects of the project. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans and ensure that project participants adhere to the plan.
- The SCS Engineers' Quality Engineer (QE), who identifies quality-affecting processes and monitors compliance with project requirements. The QE is responsible for ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements, monitoring project staff compliance with them, and documentation of those activities in the project records.
- The Testing and Monitoring Plan Task Lead (T&MP TL), who is responsible for the day-to-day implementation of the Testing and Monitoring Plan activities. The T&MP TL is responsible for developing, maintaining, and updating all well testing and monitoring plans, including this QASP; and for project conformance to the requirements of this QASP.
- Subject Matter Experts (SMEs), who have specialized knowledge in areas covered by the Testing and Monitoring Plan, including geologists, hydrologists, chemists, atmospheric scientists, ecologists, etc. The role of these SMEs is to develop testing and monitoring plans, to collect environmental data specified in those plans using best practices, and to maintain and update those plans as needed. The SMEs, assisted by the T&MP TL, are responsible for planning, collecting, and ensuring the quality of testing and monitoring data and managing all necessary metadata and provenance for these data. The SMEs are also responsible for data analysis and data products (e.g., publications), and acquisition of independent data quality/peer reviews.

### *A.1.b. Independence from Project QA Manager and Data Gathering*

The QE reports directly to the PM and is responsible for compliance of all Testing and Monitoring Plan activities with this QASP. Those responsible for data gathering activities (I.e., field technicians and SMEs will report to the PM through the T&MP TL. The QE will not conduct data gathering activities, but rather will provide an independent review of the data gathering and documentation activities with respect to conformance with this QASP.

### *A.1.c. QA Project Plan Responsibility*

The QE has the final responsibility for development and maintenance of this QASP, and its conformance with all applicable quality requirements. The T&MP TL has the final responsibility for implementation of this QASP to meet Testing and Monitoring Plan Task objectives.

### *A.1.d. Organizational Chart for Key Project Personnel*

The organizational structure specific to the Testing and Monitoring Plan is shown in **Table A.1**.

## A.2. Problem Definition/Background

### *A.2.a. Reasons for Initiating the Project*

Pelican Renewables, LLC and its affiliates (Pelican) want 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 and mechanical integrity testing, geochemical and indicator parameter monitoring of both the reservoir and shallow USDWs, and indirect geophysical monitoring, for characterizing the complex fate and transport processes associated with $CO_2$ injection. **Table A.3** summarizes the general Testing and Monitoring tasks, methods, and frequencies.

**Table A.3. Summary of Testing and Monitoring.**

| Activity | Location(s) | Method | Analytical Technique | Lab/ Custody | Purpose |
|---|---|---|---|---|---|
| Carbon dioxide stream analysis | Sampling Manifold | Laboratory analysis of $CO_2$ stream | EPA's Air Emission Measurement Center (EMC) Promulgated Test Methods | TBD | Yield data representative of its chemical and physical characteristics |
| Injection rate and volume | Injection Wellhead<br><br>Downhole in the injection well above packer | Coriolis Mass-Flow Transmitter or equivalent flow meter<br><br>System Totalizer | Direct measurement | N/A | Monitor operational parameters and verify internal mechanical integrity of the injection well |
| Injection pressure | Injection Wellhead<br><br>Outside of the long string casing, along wellbore to packer | Electronic Pressure Transducer<br><br>DSS | Direct measurement | N/A | Monitor operational parameters and verify internal mechanical integrity of the injection well |
| Annular pressure | Injection Wellhead | Electronic P/T Gauge or equivalent pressure transducer | Direct measurement | N/A | Monitor operational parameters and verify internal mechanical integrity of the injection well |
| Downhole pressure/ temperature | Downhole within sampling interval of monitoring wells | Electronic Gauge or equivalent transducer | Direct measurement via downhole sensors | N/A | Monitor aquifers for changes in P/T indicative of leak from reservoir |
| Corrosion monitoring | Within the $CO_2$ injection tubing | Corrosion Coupon | Mechanical tools<br><br>Electromagnetic tools<br><br>Ultrasonic imaging tools | N/A | Monitor 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 |

| Activity | Location(s) | Method | Analytical Technique | Lab/ Custody | Purpose |
|---|---|---|---|---|---|
| Mechanical integrity | CCS Wells #1 and #2, outside of the long string casing from storage interval to surface<br><br>Outer casing of any monitoring wells that penetrate the confining zone (Capay Shale) | Temperature Logging<br><br>Noise Logging | N/A | N/A | Monitor wellbore integrity to determine if leaks are present |
| Groundwater monitoring | Domengine Formation<br><br>Markley Formation (Lowermost USDW)<br><br>Local Principal Freshwater Aquifer System | Groundwater Sampling<br><br>Pressure/ Temperature Monitoring | EPA SW-846 | TBD | Monitor for changes in groundwater chemistry |
| Plume/Pressure Front Tracking | Injection Zone | DAS/DTS/DSS | Real-time, continuous fiber optics | N/A | Track movement and position of pressure front and $CO_2$ and monitor for induced seismicity |
| Pressure Fall Off Testing (FOT) | Injection tubing | Wireline Tool | Direct Measurement | TBD | Monitor for changes in the near wellbore environment that may impact injectivity and pressure increase |

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 targeted deep geologic 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 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 fugitive brine 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. This selection process will consider the uniqueness and signature strength of each potential analyte and whether its characteristics provide for a high-value leak-detection capability. 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.4.Quality Objectives and 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 monitor the performance of the storage reservoir relative to permit and USDW protection requirements. 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).

$CO_2$ Stream Analysis

The $CO_2$ injection stream will be continuously monitored at the surface for pressure, temperature, and flow, as part of the instrumentation and control systems for the Pelican Storage Project. Periodic grab samples will also be collected and analyzed to track $CO_2$ composition and purity. The pressure and temperature will be monitored within the injection well at a position located immediately above the injection zone at the end of the injection tubing. The downhole sensor will be the point of compliance for maintaining injection pressure below 90 percent of formation fracture pressure.

The composition and purity of the $CO_2$ injection stream will be monitored through the periodic collection and analysis of grab samples.

Pressure monitoring of the $CO_2$ stream at elevated pressure will be done using analog gauges, digital pressure transmitters, or pressure transmitters with local digital readouts. Flow monitoring will be conducted using Coriolis mass type meters. Normal temperature measurements will be made using thermocouples (TCs) or resistance temperature detectors (RTDs). A Supervisory Control and Data Acquisition (SCADA) system will be used to transmit operational power plant, pipeline, and injection well data long distances (~30 mi) for the pipeline and storage project.

Groundwater Monitoring

Groundwater will be monitored at multiple locations. Several clusters will be used to monitor the location of the $CO_2$ plume. As specified in the Testing and Monitoring Plan, Pelican will monitor three target groundwater zones:

1. Domengine Formation
2. Markley Formation (Lowermost USDW)
3. Local Principal Freshwater Aquifer System

Periodic fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at monitoring wells installed in the Domengine Formation. Periodic water level measurements and continuous monitoring of pressure and temperature will be conducted at monitoring wells installed in the Markley Formation and Freshwater Aquifer System. Fluid sampling (and subsequent geochemical analyses) will be conducted at a given well if triggered by exceedances of water level or pressure thresholds at that well.

Indicator Parameter Monitoring – Fluid pressure, temperature, pH, and specific conductance (P/T/pH/SpC) will be monitored continuously. These are primary parameters that will indicate the presence of $CO_2$ or $CO_2$-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building. In addition, monitoring wells in the Domengine Formation will be outfitted with Distributed Fiber Optic Sensing (DFOS) technology (DTS/DSS).

Geochemical Monitoring – Aqueous samples will be collected from monitoring wells as specified in the Testing and Monitoring Plan. Baseline sampling will be conducted on a quarterly basis for eight consecutive sampling events in order to capture seasonal and temporal variability in the respective aquifers. Refer to Table 8-3 in the Testing and Monitoring Plan for the proposed sampling schedule during the Operational Period. Pelican will monitor the analytical and field parameters specified in Table 8-4 of the Testing and Monitoring Plan, and will follow analytical methods specified in the EPA SW-846 guidance.

Corrosion Monitoring

Samples of injection well materials (coupons) will be periodically monitored 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.

**Table A.4.1. Summary of Parameters for Corrosion Coupons.**

| Parameters | Methods | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Mass | Electromagnetic tools | TBD | TBD | TBD |
| Thickness | Mechanical tools | TBD | TBD | TBD |
| Visual wear and tear | Visual only | TBD | TBD | TBD |

**Table A.4.2. Summary of Measurement Parameters for Field Gauges.**

| Parameters | Methods | Detection Limit/ Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Booster pump discharge pressure | Electronic P/T Gauge | TBD | TBD | TBD |
| Injection tubing temperature | Electronic P/T Gauge | TBD | TBD | TBD |
| Annulus pressure | Electronic P/T Gauge or equivalent pressure transducer | TBD | TBD | TBD |
| Injection tubing pressure | Electronic P/T Gauge | TBD | TBD | TBD |
| Wellhead pressure | Electronic pressure transducer with analog output mounted on the $CO_2$ line | TBD | TBD | TBD |
| Downhole temperature | Casing Collar | TBD | TBD | TBD |
| Injection mass flow rate | flow meter skid<br><br>Coriolis mass flow | TBD | TBD | TBD |

Temperature, noise logging and casing inspection logging will be conducted to verify the absence of significant fluid movement through potential channels adjacent to the injection well bore and/or to determine the need for well repairs.

Direct Pressure-Front Monitoring

Pelican will utilize Distributed Fiber Optic Sensing at CCS Wells #1 and #2 along the outside of the long string casing. See **Appendix A** to this Plan for specifications on the DTS technology. 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.

Indirect $CO_2$ Plume and Pressure-Front Tracking

The primary objectives of indirect (e.g., geophysical) monitoring are 1) tracking $CO_2$ plume evolution and $CO_2$ saturation levels; 2) tracking development of the pressure front; and 3) identifying or mapping areas of induced microseismicity, including evaluating the potential for slip along any faults or fractures identified by microseismic monitoring.

The DFOS network at 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 via Distributed Acoustic Sensing (DAS). These surveys will be conducted on an annual basis. See Appendix A to this Plan for specifications on the DAS technology.

Passive Microseismic Monitoring – The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of 1) addressing public and stakeholder concerns related to induced seismicity; 2) estimating the spatial extent of the pressure front from the distribution of seismic events; and 3) identifying features that may indicate areas of caprock failure and possible containment loss. DAS will be used to monitor microseismicity. DAS continuously detects and reports seismic events as small as magnitude -1.4 in real-time. See Appendix A to this Plan for specifications on the DAS technology.

**Table A.4.3. Actionable Testing and 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 |

| Activity or Parameter | Project Action Limit | Detection Limit | Anticipated Reading |
|---|---|---|---|
| Surface pressure | TBD –based on injection testing of Class VI well | TBD –based on injection testing of Class VI well | TBD –based on injection testing of Class VI well |
| Downhole pressure | TBD –based on injection testing of Class VI well | TBD –based on injection testing of Class VI well | TBD –based on injection testing of Class VI well |
| Water quality | TBD – based on background analytical data | TBD – based on background analytical data | TBD – based on background analytical data |
| Above-confining-zone pressure | TBD – based on baseline pre-injection pressures | TBD – based on baseline pre-injection pressures | TBD – based on baseline pre-injection pressures |

## A.5. Special Training/Certifications

Wireline logging, indirect geophysical methods, and some non-routine sampling will be performed by trained, qualified, and certified personnel, according to the service company's requirements. The subsequent data will be processed and analyzed according to industry standards.

Routine injectate and groundwater sampling will be performed by trained personnel; no specialized certifications are required. 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.

Training of project staff will be conducted by existing project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

## A.6. Documentation and Records

### *A.6.a. Report Format and Package Information*

The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)). 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*

All data are managed according to the project records management requirements.

### *A.6.c/d. Data Storage and Duration*

All data and project records will be stored electronically on secure servers and routinely backed-up.

### *A.6.e. QASP Distribution Responsibility*

The PM (assisted by the QE) will be responsible for ensuring that all affected project staff (as identified in the distribution list) have access to the current version of the approved QASP.

## B. Data Generation and Acquisition

The primary goal of testing and monitoring activities is to verify that the Pelican 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

### *B.1.a. Design Strategy*

*$CO_2$ Stream Monitoring Strategy*

Based on the anticipated composition of the $CO_2$ stream and impurities that may negatively impact reservoir storage capacity and/or injection well construction materials, a list of parameters has been identified for analysis. Samples of the $CO_2$ stream will be collected regularly (e.g., quarterly) for chemical analysis.

*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). 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 conduct ground-water-quality/geochemical monitoring above the confining zone to meet the requirements of 40 CFR 146.90(d).

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.

## B.9. Indirect Measurements

Existing data, including literature files and historic data from surrounding areas and previous onsite characterization, testing, and monitoring activities, have been used to guide the design of the testing and monitoring program. However, these data are only ancillary to the well testing and monitoring plan described here. These existing data will be used primarily for qualitative comparison to newly collected data.

All data will continue to be evaluated for their acceptability to meet project needs, that is, that the results, interpretation, and reports provide reasonable assurance that the project is operating as permitted and is not endangering any USDWs.

## B.10. Data Management

### *B.10.a. Data Management Scheme*

All project data, record keeping, and reporting will be conducted to meet the requirements of 40 CFR 146.91(f).

### *B.10.b. Recordkeeping and 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 data will be managed in a centralized electronic data management system. The underlying electronic servers will be routinely maintained, updated, and backed-up to ensure the long-term preservation of the data and records.

## C. Assessment and Oversight

### C.1. Assessments and 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.

In addition to the activities covered by the Testing and Monitoring Program data quality assessments will be performed to evaluate the state of configuration-controlled technical information in the Pelican technical data repository to ensure that the appropriate data, analyses, and supporting information are collected, maintained, and protected from damage, deterioration, harm, or loss. These data quality assessments will be performed by a team consisting of the PM, QE, SMEs, and additional knowledgeable and trained staff as appropriate for the scope and nature of the assessment. Assessments will be scheduled to occur at logical points in the project lifecycle, such as after completion and submission of a major deliverable that incorporates controlled technical information. Assessment results will be reported to management; deficiencies, weaknesses, opportunities for improvement, and noteworthy practices will be identified in the assessment reports. Assessment results will also be communicated to affected parties. Management will assign responsible staff to correct deficiencies and other nonconforming conditions and will ensure that corrective actions are implemented and verified in a timely manner. The QE and the PM will conduct follow-up surveillances to verify and document completion of corrective actions and to evaluate effectiveness.

### C.2. Reports to Management

Management will be informed of the project status via the regular monitoring and performance reports generated by the Testing and Monitoring Program as well as reports of assessments conducted to verify data quality and surveillances performed to verify completed corrective actions. These reports are described in Section C.1; additional periodic reporting is not anticipated at this time.

## D. Data Validation and Usability

## D.1. Data Review, Verification, and Validation

### *D.1.a. Data Verification and Validation Processes*

Project staff who generate, review, verify, validate, or manage data are trained to the requirements of one or more Data Management Plans. Raw data (resulting from the use of a procedure or technology), defined as Level 1, are put under configuration control in the data management system at the time of upload to the system. Data defined at other Data Levels are put under configuration control when the data become reportable or decision-affecting. The procedures used to verify, validate, process, transform, interpret, and report data at each Data Level are documented and captured as part of the data management process.

Peer reviews both validate the data—confirm that the appropriate types of data were collected using appropriate instruments and methods—and verify that the collected data are reasonable, were processed and analyzed correctly, and are free of errors. Data that have not undergone the peer-review process and are not yet under configuration control can be provided as preliminary information when accompanied by a disclaimer that clearly states that data are 1) preliminary and have not been reviewed in accordance with Pelican's quality assurance practices, 2) considered "For Information Only", and 3) not to be used for reporting purposes nor as the basis for project management decisions. Once data are placed under configuration control, any changes must be approved using robust configuration-management processes described in the Data Management Plans. The peer-review and configuration-management processes include methods for tracking chain-of-custody for data, ensuring that custody is managed and control is maintained throughout the life of the project.

If issues are identified during a peer review, they are addressed and corrected by the data owner and peer reviewer (involving others, as necessary) as part of the peer-review process. These unreviewed data will not have been used in any formal work product nor as the basis for project management decisions, so the impacts of data errors will be minimal. If an error is identified in data under configuration control, in addition to correcting the error, affected work products and management decisions will be identified, affected users will be notified, and corrective actions will be coordinated to ensure that the extent of the error's impact is fully addressed.

### *D.1.b. Data Verification and Validation Responsibility*

The QE will have the final responsibility for ensuring that all data validation and verification requirements have been met.

### *D.1.c. Issue Resolution Process and Responsibility*

All issues will be resolved by the QE with the concurrence of the PM.

## D.2. Reconciliation with User Requirements

During the course of a long-duration project, personnel changes over time can result in loss of institutional memory about the organization's data, thereby reducing the value of the data. New

project staff may have little understanding of the content, intended uses, and pedigree of existing data sets. Metadata can help protect the organization's investment in data by providing context and pedigree, as well as describing interrelationships between various data sets. Subject Matter Experts (SMEs) will establish and document metadata requirements for the data sets created by the Pelican project. Complete metadata will support data interpretation, provide confidence in the data, and encourage appropriate use of the data. To establish meaningful metadata requirements, SMEs must understand how data users and decision-makers will use the data. By adhering to metadata requirements when loading data into the project data repository, project staff ensure that user requirements addressed by the metadata are satisfied.

**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<br>Synchronisation Clock Output SMB |
| External connectors | Ethernet: 2 x Gigabit Ethernet Port, RJ45; 2 x 10Gb SFP+ Port<br>USB: 4 x Type-A USB 2.0 Port; 2 x USB 3.0 Port<br>Display 2 x DisplayPort<br>Data: 2 x PCIe x4 Cable Port<br>GPIB Port, Micro D-Sub 25P<br>COM Port, D-sub9 serial<br>LAN PTP (RJ45)<br>Power Inlet IEC 60320-1 C20, use with IEC 60320-1 C19 power outlet<br>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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SILIXA

DATASHEET: XT-DTS™

# 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<br>IEC 60825-1: 2014<br>EN 61010-1: 2010 | EN 61326-1:2013 | CFR 47:2008 Part 15 Sub Part B | 2014/35/EC (safety)<br>2014/30/EC (EMC) |


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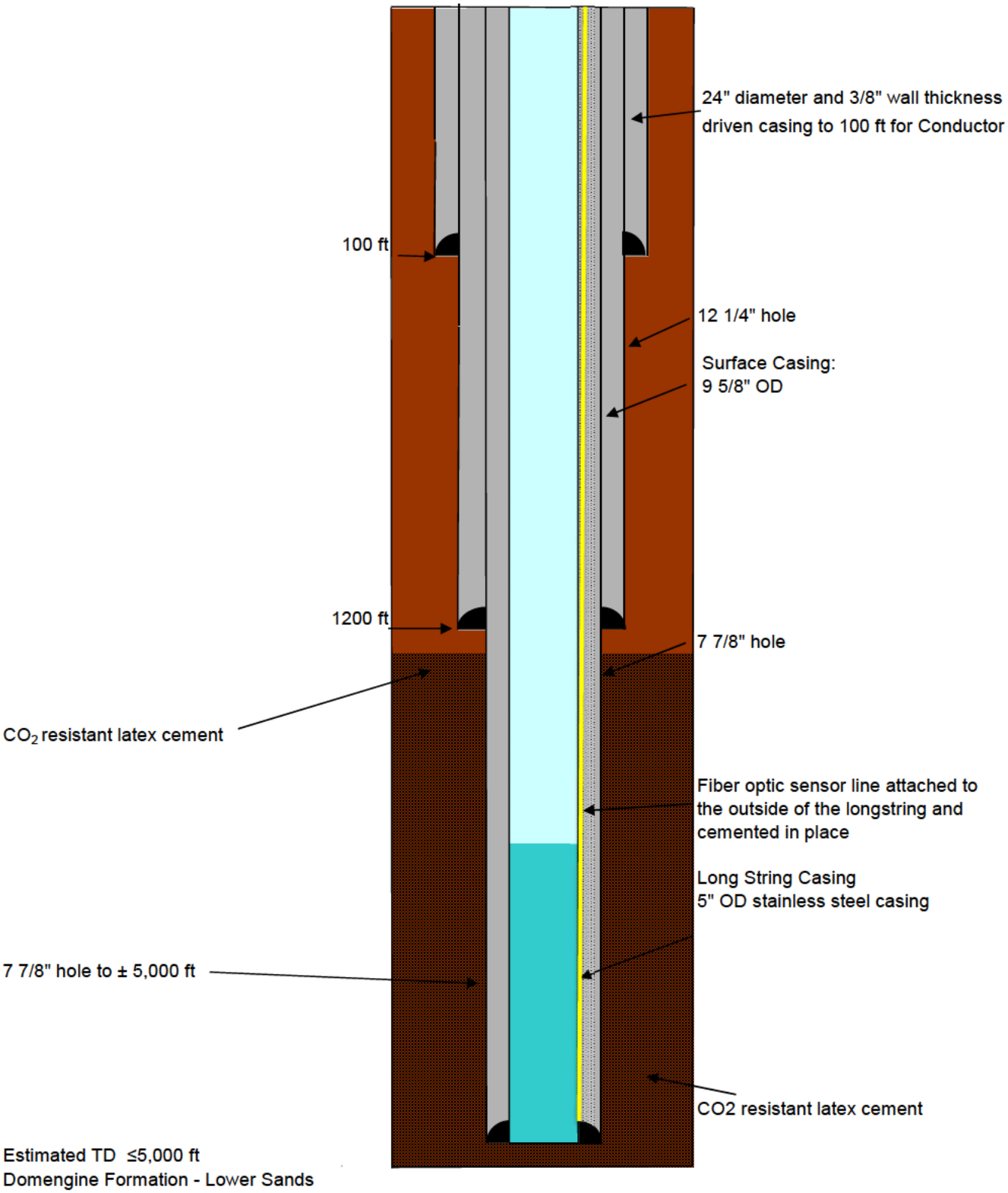
**Appendix 8-B**

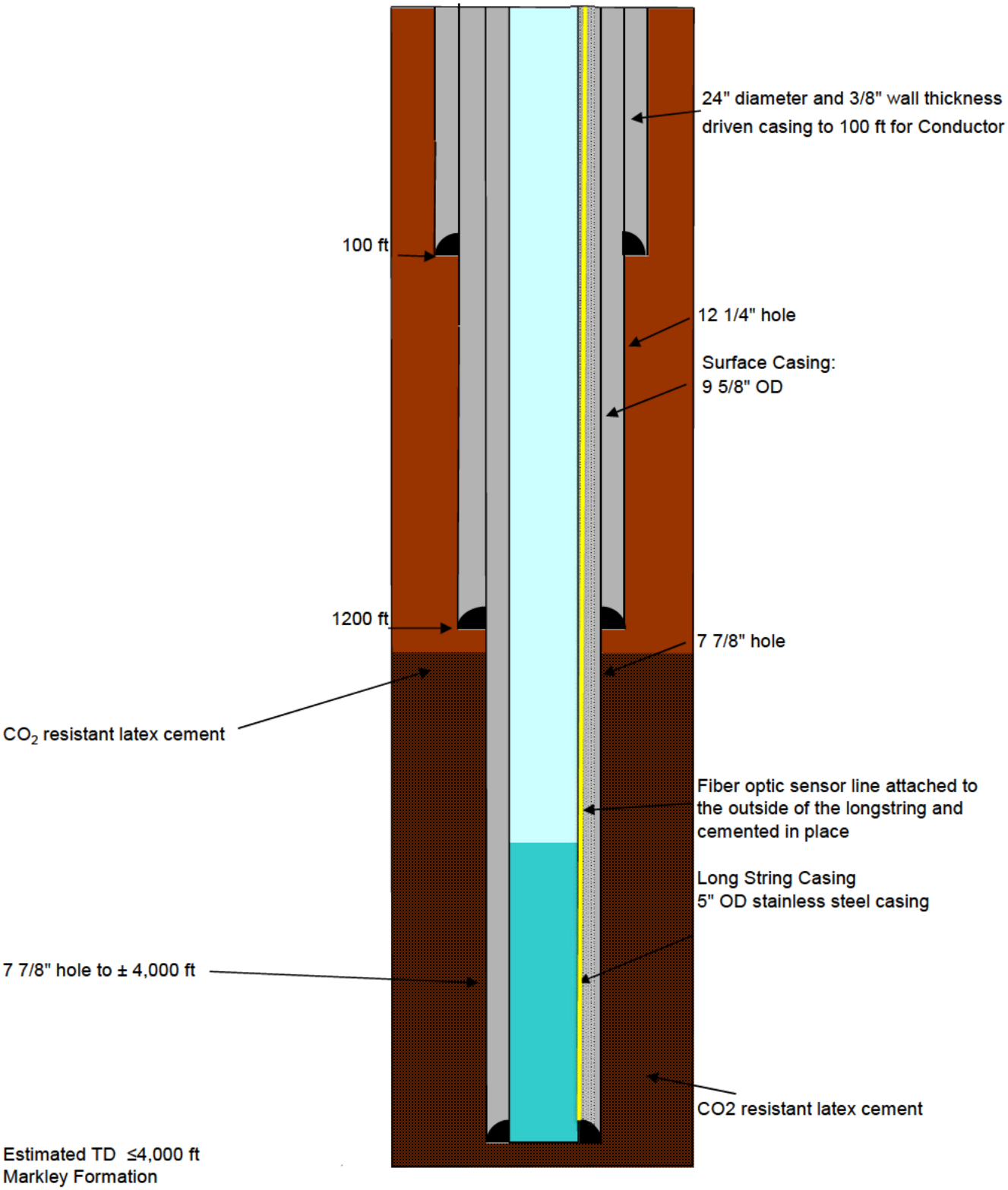
**APPENDIX 8-B**

# Pelican Renewables, LLC
# Proposed Groundwater Monitoring Well Schematic
# GMW-1D, GMW-2D, GMW-3D
# Rindge Tract Island, San Joaquin County, CA



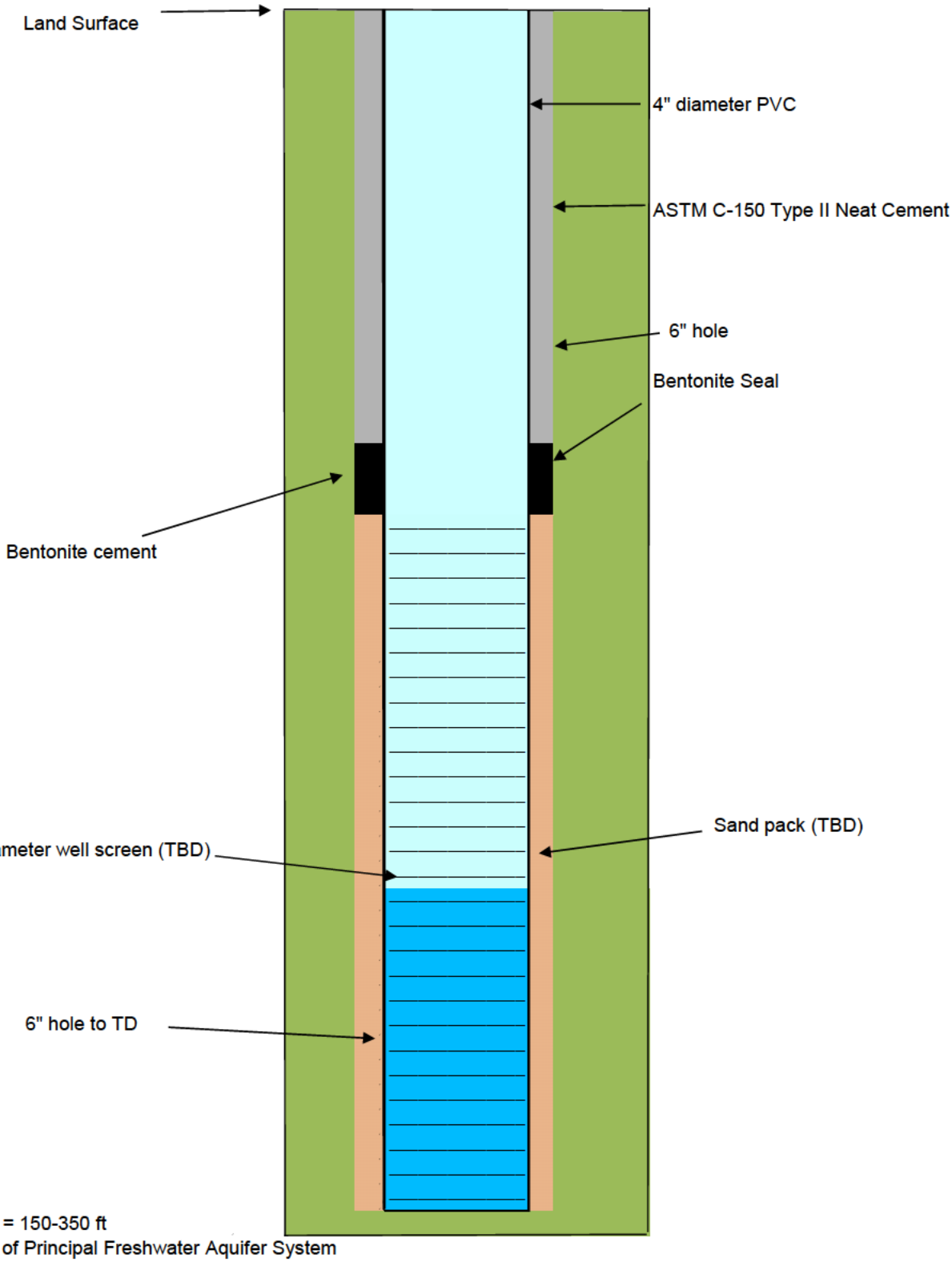
**APPENDIX 8-B**

# Pelican Renewables, LLC
# Proposed Groundwater Monitoring Well Schematic
# GMW-1M, GMW-2M, GMW-3M
# Rindge Tract Island, San Joaquin County, CA



**APPENDIX 8-B**

# Pelican Renewables, LLC
# Proposed Groundwater Monitoring Well Schematic
# GMW-1S, GMW-2S, GMW-3S
# Rindge Tract Island, San Joaquin County, CA

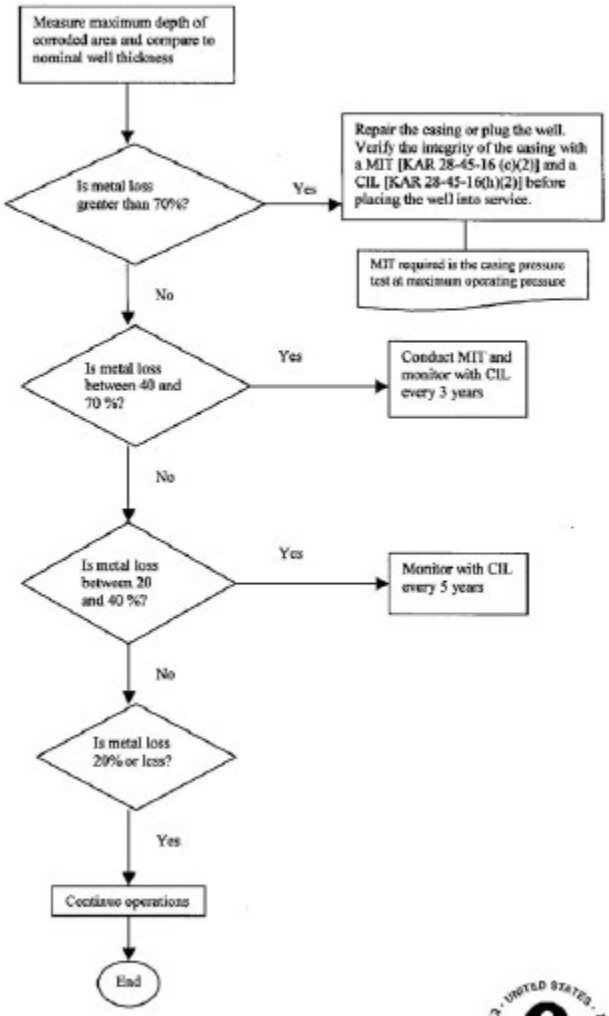



Estimated TD = 150-350 ft
Shallow Zone of Principal Freshwater Aquifer System

**Appendix 8-C**

## APPENDIX G - CASING INSPECTION LOG GUIDANCE

**EPA Region 9**
**Guidance for Casing Inspection Log Results**
**UIC Underground Injection Wells**




U.S. Environmental Protection Agency, Region 9
Underground Injection Control Program
October 2008

Adapted from Kansas Dept. of Health and Environment
Bureau of Water/Geology Section, July 2003

UIC Permit CA10910002

**Appendix 8-D**


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

# Contents

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Prepared for EERC and the PCOR Partnership

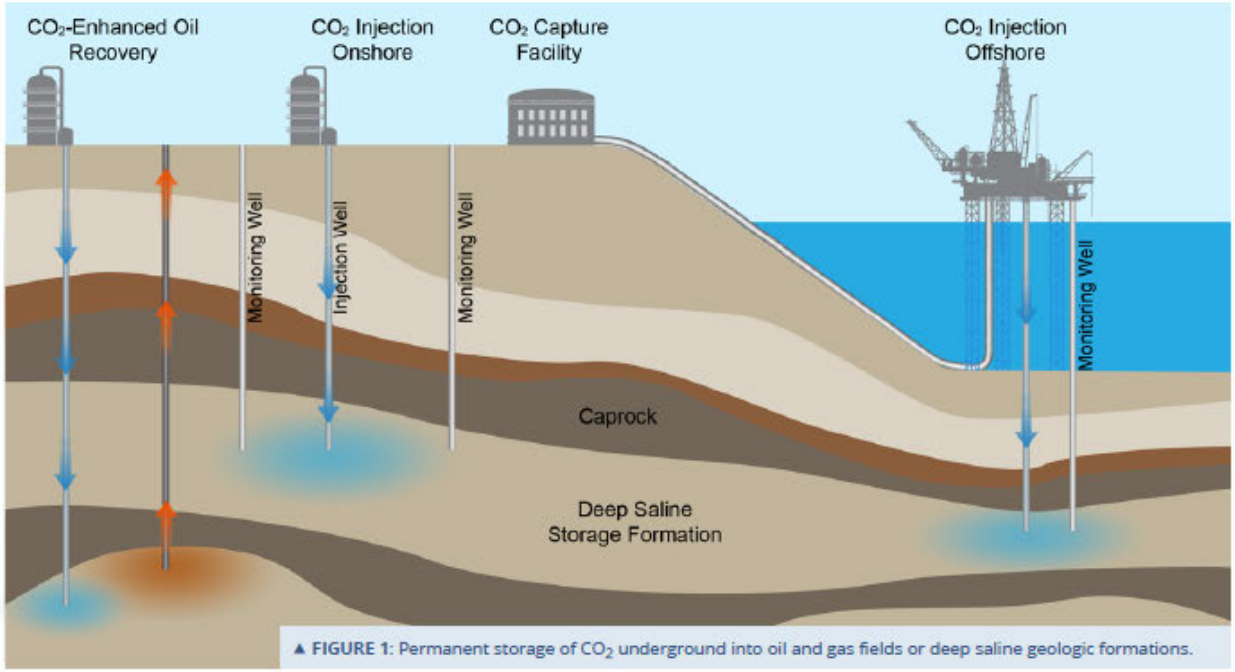
# Figures



SILIXA actionable insight

# 1

# Carbon Capture and Storage: Introduction and Risks




▲ **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.



SILIXA actionable insight

# 1

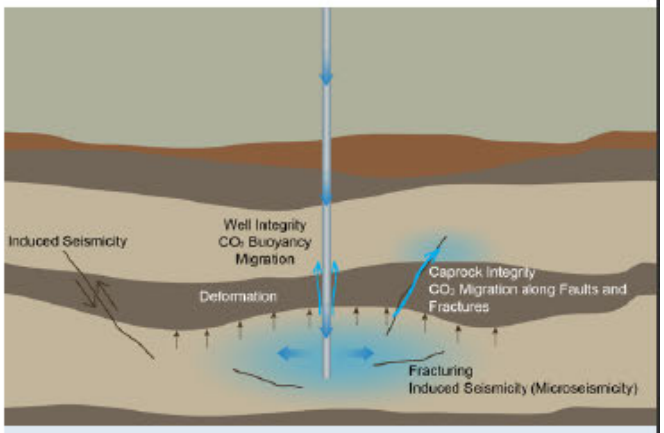
# Carbon Capture and Storage: Introduction and Risks

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 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.




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

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

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

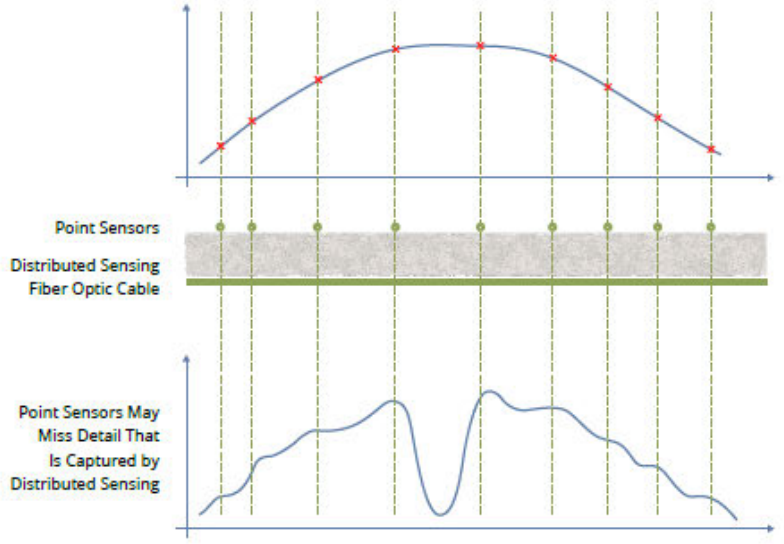
Unlike traditional sensing that relies on discrete sensors measuring at predetermined points such as geophones, distributed sensing utilizes the optical fiber as the sensing element without any additional transducers in the optical path (FIGURE 3). Fiber optic cables can be deployed on the surface or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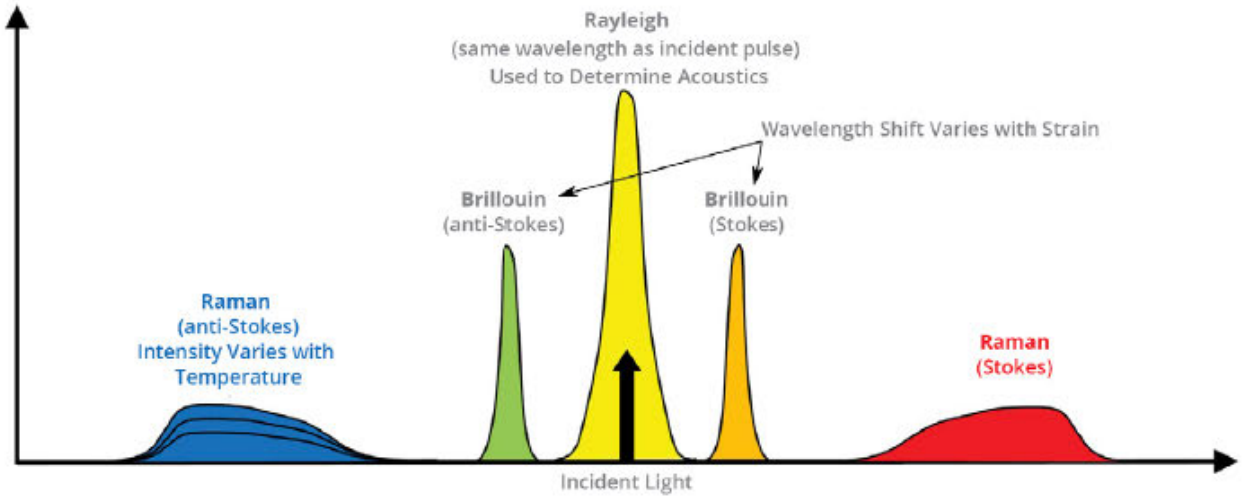
# 2.1 Introduction

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.

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# 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.

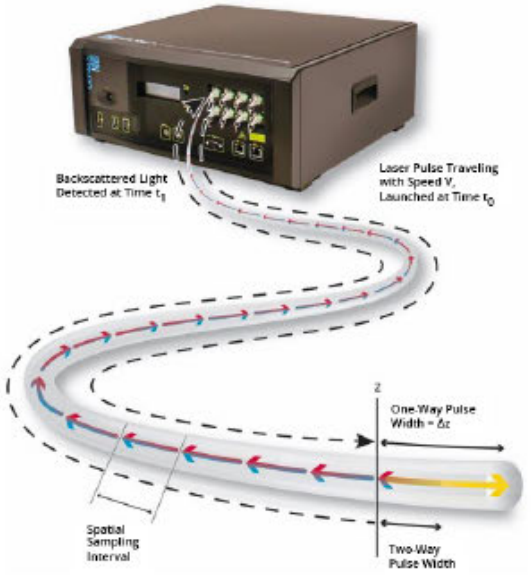
The wavelengths of the Raman backscattered light differ from the forward propagating light and are named Stokes and anti-Stokes, according to the energy level measured for the absorbed photons (Stokes, if the energy is higher than the emitted photons; anti-Stokes if it is lower) (FIGURE 4). The amplitudes 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.

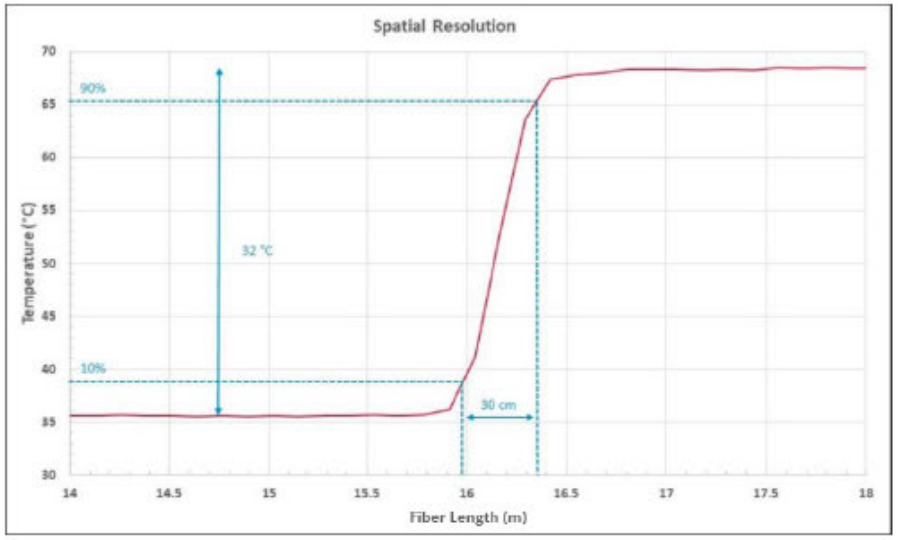
The spatial resolution of a DTS system is determined by applying a step change in temperature between two adjacent lengths of fiber (10 m or more) and determining the distance needed to capture between 10% and 90% of the variation (FIGURE 6).

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.

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# 2.3

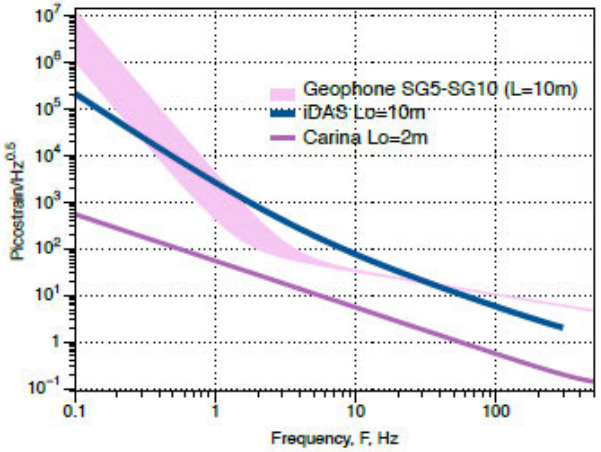
## Distributed Acoustic Sensing (DAS)

**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.

# 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.**

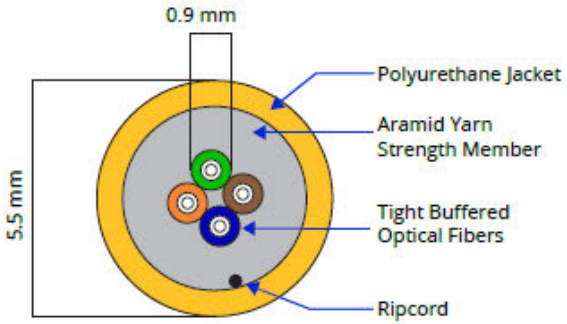
For DAS and DSS applications, signal coupling with the subsurface through the cable jacket and strength members to the optical fiber is an important consideration, with some cables offering efficient strain transfer to the optical fiber.

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

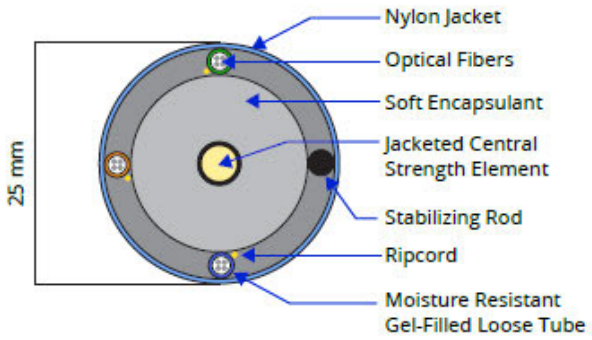



▲ FIGURE 8: Example four-fiber tactical cable construction.

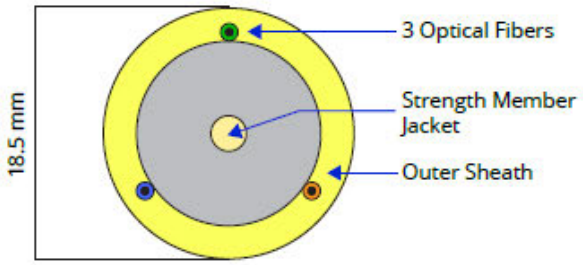
SILIXA actionable insight

## 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.

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# 3.2 Downhole

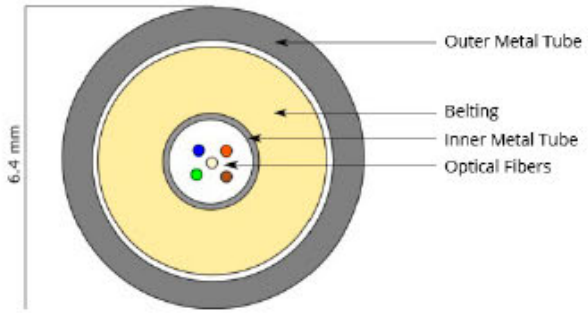
## 3.2.1 Cable Options

**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.

# 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.

# 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

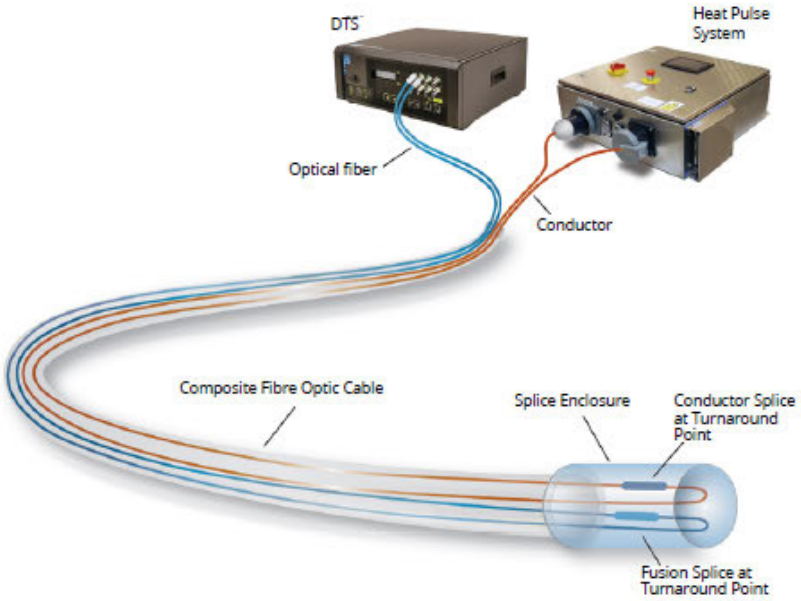
## Apparent Thermal Conductivity

**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.

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# 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

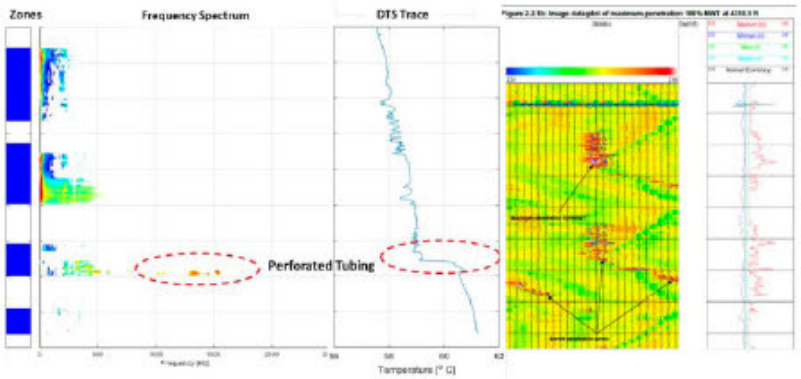
## 4.3.1 Temperature Monitoring

### 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.

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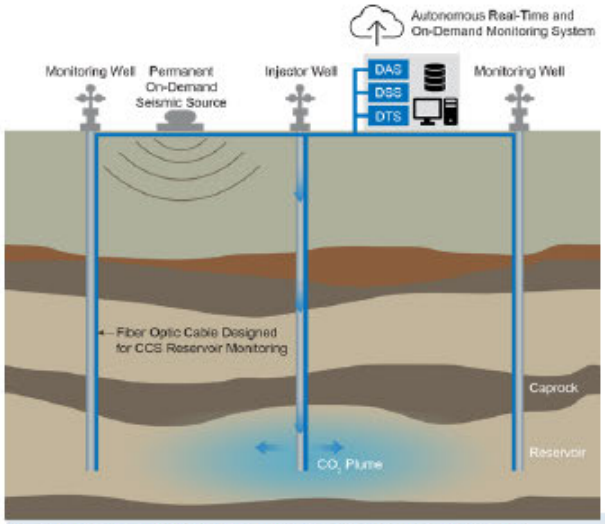
### A permanent real-time monitoring system for CCS consists of an integrated system to facilitate continuous and cost-efficient $CO_2$ reservoir monitoring for risk mitigation and injection optimization.

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

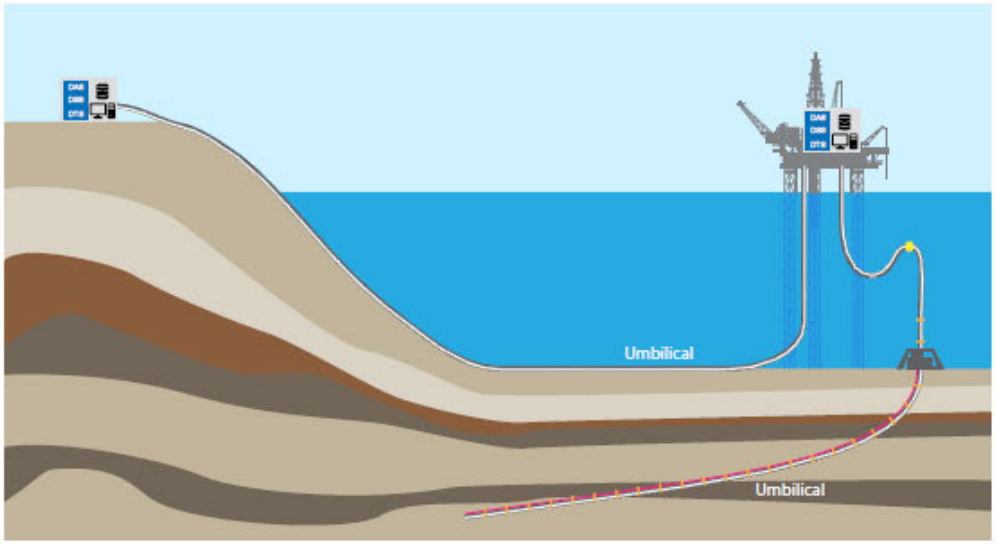
## Offshore CCUS

### 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

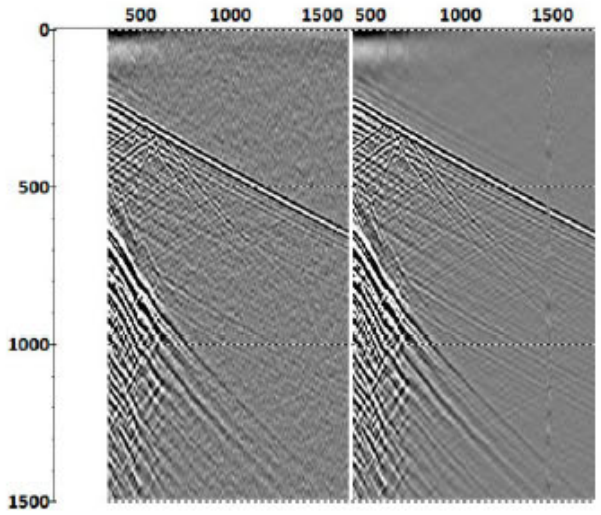
## Otway, Victoria, Australia

**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*

# 7.2

## Aquistore, Saskatchewan, Canada

SILIXA actionable insight

### 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.

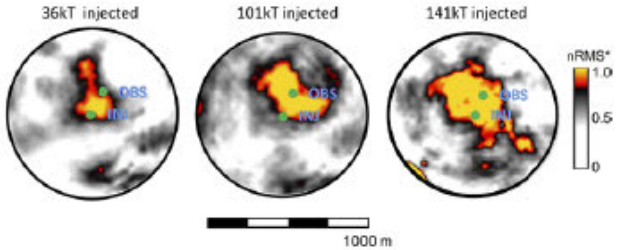
Another challenge is passive monitoring for any seismic events induced by the volume of $CO_2$ injected. These seismic events may indicate $CO_2$ leakage pathways or, if large enough, may damage infrastructure. An important part of measurement, monitoring and verification implementation is active seismic 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).

# 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.

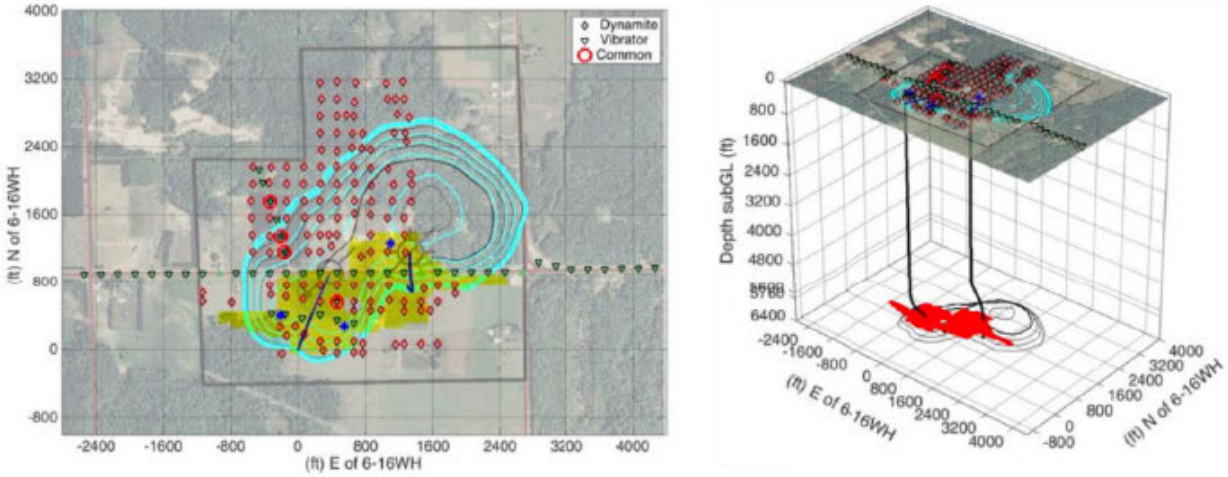
Part of the program is to map the injected $CO_2$ plume into carbonate reservoirs, and DAS time-lapse vertical seismic profiling was evaluated at Chester-16 pinnacle reef (FIGURE 19A).

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.

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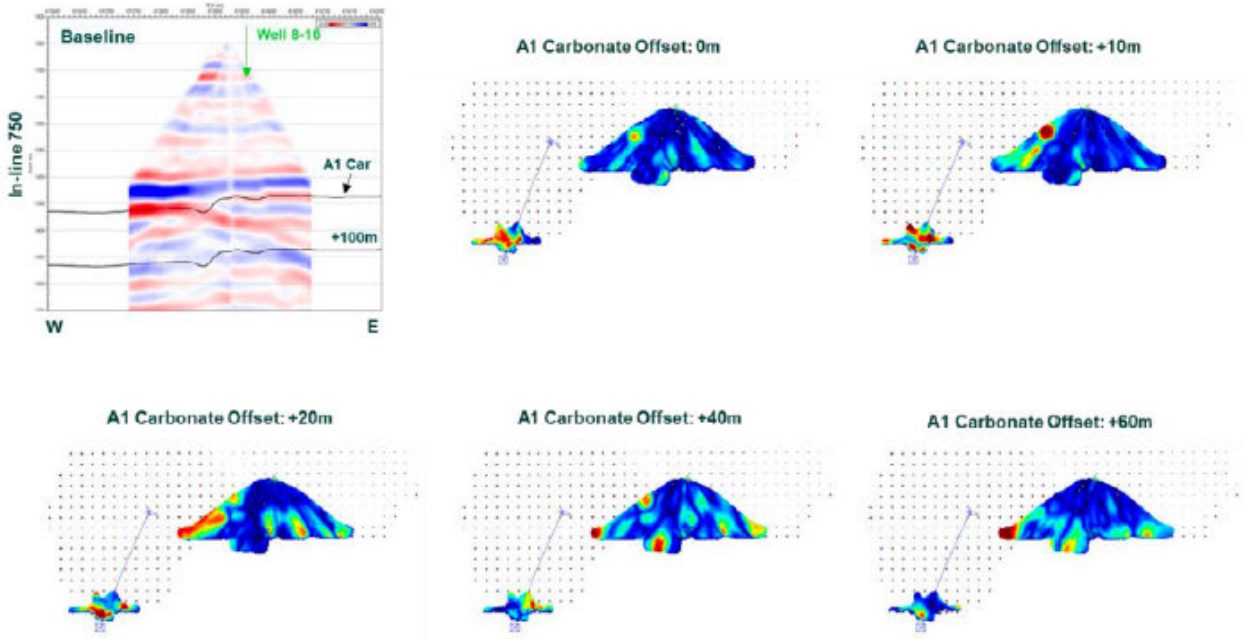
# 7.3

## 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.



# 8

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## How to cite this document

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