ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90

Elk Hills A1-A2 Storage Project

Facility Information

Facility Name:	Elk Hills A1-A2 Storage 357-7R & 355-7R
Facility Contact:	Travis Hurst / CCS Project Manager 28590 Highway 119 Tupman, CA 93276 (661) 342-2409 / Travis.Hurst@crc.com
Well Location:	Elk Hills Oil Field, Kern County, CA 35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment C- TM Final V3	3	11/4/22	Updated to include responses to EPA comments dated 07/20/22
Attachment C- TM V4	4	05/14/23	Updated to include responses to EPA comments dated 03/08/2023.

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills A1-A2 Storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations 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.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

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

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

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the start of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)

Parameter	Analytical Method(s)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane, Ethane, Ethylene	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry

Sampling Methods

CO_2 stream sampling will occur at the discharge of the last compressor upstream of the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a state certified full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

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

CTV 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 injected CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 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. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the "Injection & Monitoring Well Schematics_v2" document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 355-7R: 8,387' (MD) 357-7R: 8,420' (MD)	10 seconds	30 seconds
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 355-7R: 8,387' (MD) 357-7R: 8,420' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure of 90% of the injection zone's fracture pressure. Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

Calculation of Injection Volumes

The volume of CO_2 injected into the Monterey Formation A1-A2 will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation A1-A2 will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus for injection wells 355-7R and 357-7R will be maintained on average with 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring [40 CFR 146.90(c)]

CTV will monitor well materials during the operation period for loss of mass, change in thickness, cracking, pitting, or other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For wells 357-7R and 355-7R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 Carbon Steel (355-7R)
	N-80 Carbon Steel (357-7R)
	P-110 Carbon Steel (353A-7R, 335X-7R)
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. 327-7R-RD1 (Figure 1) is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 3,782' - 3,934' MD in 327-7R-RD1. In addition, the A1-A2 in zone monitoring wells (353A-7R and 335X-7R) will provide additional coverage for the Etchegoin Formation with continuous DTS temperature monitoring. In the event that temperature anomalies are observed at these locations, CTV will review with the EPA and potentially add additional Etchegoin monitoring to the project area.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure, decrease in temperature and change in composition of the Etchegoin. Compositional changes will be detectable with fluid sampling and geochemical monitoring within the 327-7R-RD1. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The location of the USDW monitoring well is structurally down-dip of the AoR to ensure that there is adequate water for sampling. The Upper Tulare is mostly unsaturated in the AoR and the water column height increases to the north, off the structure. The Upper Tulare Formation USDW will be monitored between 940' – 960' MD in the USDW monitoring well.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation A1-A2 CO_2 injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation A1-A2 CO_2 injection.

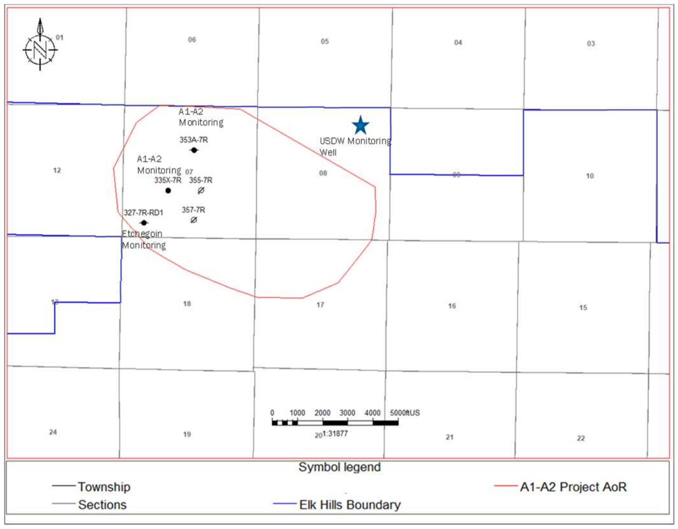
Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD	Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD 961' MD 854' MD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD	Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' MD 3850' - 3990' MD	Continuous

Figure 1: Above confining zone monitoring wells, USDW monitoring well and 327-7R-RD1.



Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si, Sb)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Dissolved Methane	SM 6211 B or 6211 C
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage Project site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, ie. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director.

Table 6. Internal MIT requirements

<table>
<tr><th>Monitoring Activity</th><th>Data Collection Location(s)</th><th>Spatial Coverage or Depth</th><th>Frequency (Baseline)</th><th>Frequency (Injection Phase)</th><th>Frequency (Post-Injection Phase)</th><th>Maximum Injection Pressure (psi)</th><th>Test Pressure (psi)</th></tr>
<tr><td rowspan="5">Standard Annular Pressure Test (SAPT)</td><td>355-7R[1]</td><td rowspan="5">Casing/tubing annulus from surface to packer</td><td rowspan="5">Once, upon initial installation</td><td rowspan="5">Any time packer is replaced or reset</td><td rowspan="2">Not Applicable</td><td>2990</td><td>3090</td></tr>
<tr><td>357-7R[1]</td><td>2993</td><td>3093</td></tr>
<tr><td>327-7R-RD1[2]</td><td rowspan="3">Any time packer is replaced or reset</td><td>--</td><td>1000</td></tr>
<tr><td>335X-7R[3]</td><td>--</td><td>1000</td></tr>
<tr><td>353A-7R</td><td>--</td><td>1000</td></tr>
<tr><td>Annular Pressure</td><td>355-7R[1]
357-7R[1]
327-7R-RD1[2]
335X-7R[3]
353A-7R[3]</td><td>Wellhead</td><td>Continuous</td><td>Continuous</td><td>Not Applicable</td><td>--</td><td>--</td></tr>
<tr><td>Fluid Sampling</td><td>345-7R[4]
388X-7R[4]
341-17R[4]</td><td>Wellhead</td><td>Baseline</td><td>Quarterly</td><td>Annual</td><td>--</td><td>--</td></tr>
</table>

[1] CO2 injection well
[2] Above Zone monitoring well
[3] Injection Zone monitoring well
[4] Monterey Formation A3-A11 monitoring well

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in realtime based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

Internal MIT for Monterey Formation A3-A11 Monitoring Wells

The active wells that will be used for monitoring the underlying A3-A11 reservoir will be monitored for internal mechanical integrity through fluid sampling. The wells are not configured with tubing and packer such than an annulus is not available to monitor or test using SAPT procedures. The current application of these wells precludes configuring these wells with this equipment. Fluid sampling, as described in the Carbon Dioxide Plume and Pressure Front Monitoring section below, will evaluate the presence or absence of CO_2 as a proxy for internal mechanical integrity. The presence of CO2 in the fluid sample will require EPA notification and diagnosis of the source of CO2 in the wellbore, either through the A3-A11 underlying reservoir or through wellbore mechanical integrity failure. In this event, CTV will provide a diagnostic plan and request approval from the EPA Director.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. To ensure mechanical integrity of the monitoring wells CTV will complete a SAPT, CBL and install DTS for continues temperature. DTS will enable CTV to develop a temperature log for any specified time to demonstrate mechanical integrity.

Table 7. External Mechanical Integrity Testing Methods

Test Description	**Location**
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will likely be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warmback can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in realtime. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

DTS will not be installed on the Monterey Formation A3-A11 wells.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

a. The base of the lowermost bleed-off zone above the injection interval and

b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50 foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.
7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV 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).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted A1-A2 zone. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Figure 2: Monterey Formation A1-A2 sequestration reservoir monitoring wells, 335X-7R and 353A-7R.

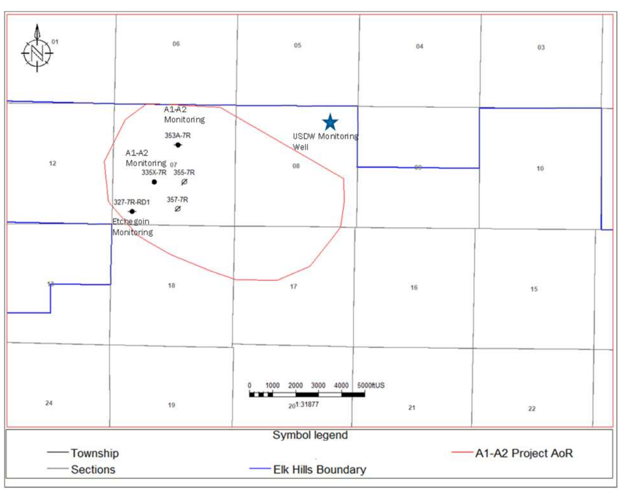


Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Table 8. Plume monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm A1-A2	Fluid Sampling	335X-7R	8737' - 9030' MD	Once	Quarterly
		Pressure		8667' MD	Baseline	Continuous
		Temperature		8667' MD	Baseline	Continuous
	Monterey Fm A1-A2	Fluid Sampling	353A-7R	8773' - 9130' MD	Once	Quarterly
		Pressure		8703' MD	Baseline	Continuous
		Temperature		8703' MD	Baseline	Continuous
	Monterey Fm A3-A11 (below injection zone)	Fluid Sampling	345-7R	8904' - 9402' MD	Once	Quarterly
		Fluid Sampling	388X-7R	8800' - 9290' MD	Once	Quarterly
		Fluid Sampling	341-17R	8844' - 9307' MD	Once	Quarterly
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	335X-7R	8737' - 9030' MD	Baseline	Every 2 years from start of injection
			353A-7R	8773' - 9130' MD		

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone and the Monterey Formation A3-A11.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B

Parameters	Analytical Methods
pH (field)	EPA 150.1
Specific Conductance	APHA 2510
Temperature (field)	Thermocouple
Dissolved Methane	SM 6211 B or 6211 C
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

The DTS from the two monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 96% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

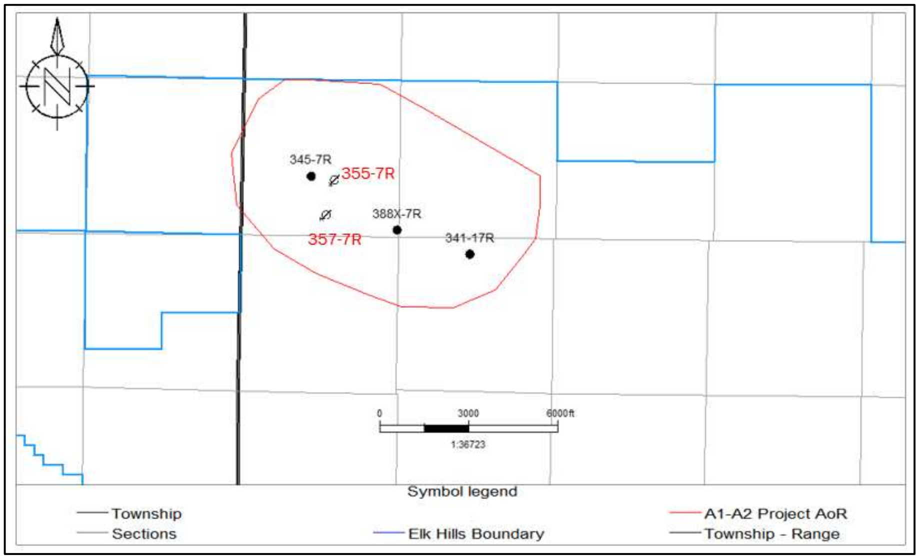
CTV does not plan to conduct VSP monitoring for the depleted A1-A2 oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Monitoring the Underlying Monterey A3-A11 Reservoir

The Monterey Formation A3-A11 reservoir will be monitored for the presence of CO_2 above baseline in the production stream as an indication of CO_2 migration below the A1-A2 injection zone. Waterflood producers shown in Figure 3 will be monitored during injection operations by sampling the produced fluid at surface once per quarter for changes in composition as per Table 9. Prior to the conclusion of A1-A2 injection and initiation of the post injection site care period, these producers and the A3+ waterflood operations will be abandoned as part of standard asset retirement as per CalGEM regulations.

Due to its waterflood infrastructure and high reservoir pressure, the A3-A11 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery.

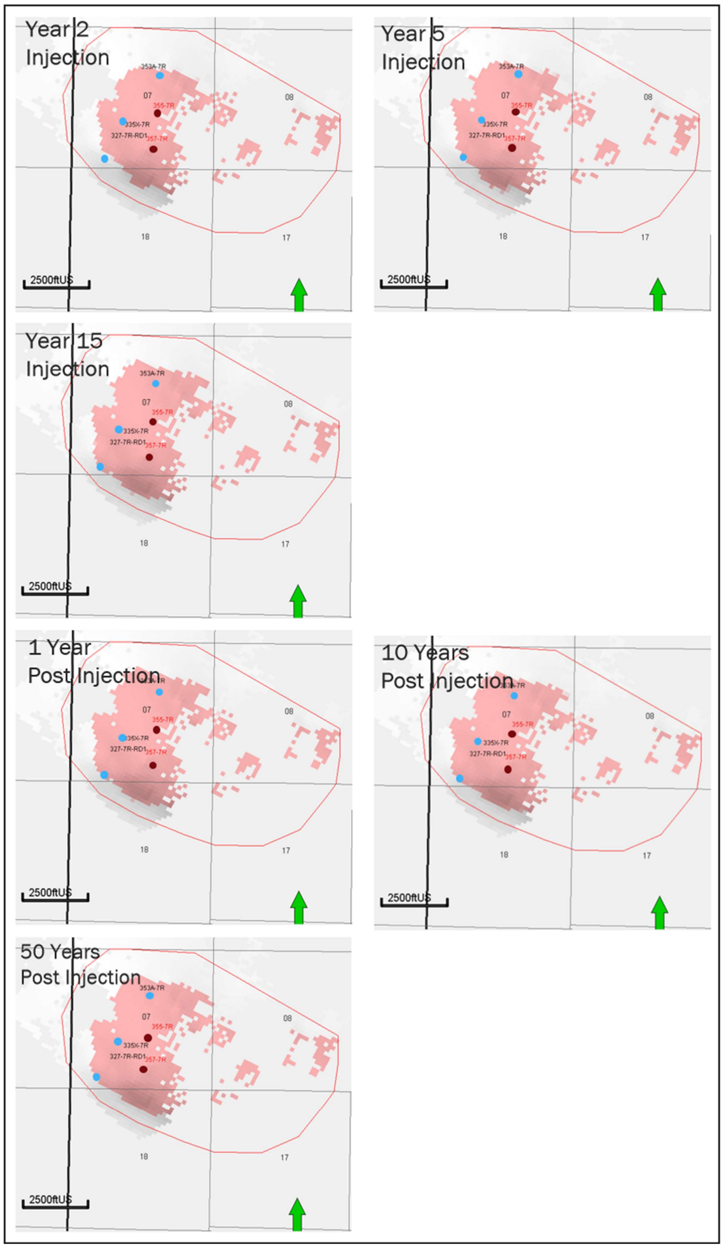
Figure 3: A3-A11 wells for fluid sampling to assess basal confinement of the CO_2 injectate.



Pressure Front Monitoring Location and Frequency

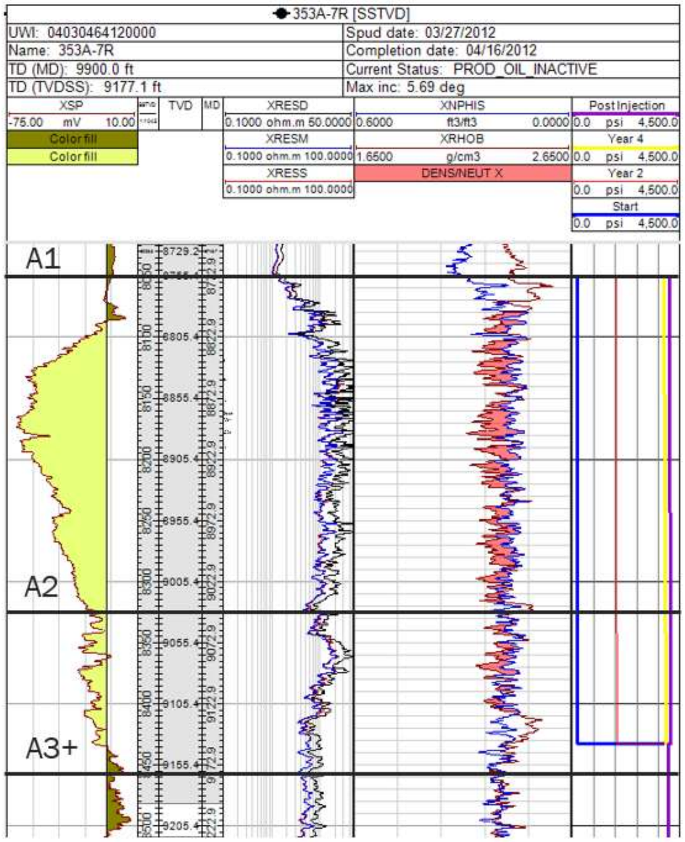
The aerial extent of plume development in the Monterey Formation A1-A2 reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 4.

Figure 4. Monitoring well location with maps showing plume development through time from computational modeling.



Monitoring well 353A-7R pressure development based on the computational model is shown in Figure 5 in the right-hand track. The reservoir pressure stabilizes after five years. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Figure 5: Monitoring well 353A-7R showing the pressure increase through time from the computational modeling results.



Pressure Front Monitoring Details

Direct pressure and temperature monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 353A-7R and 335X-7R. The depleted Monterey Formation A1-A2 oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 6 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

Figure 6: Monterey Formation A1-A2 pressure 100 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

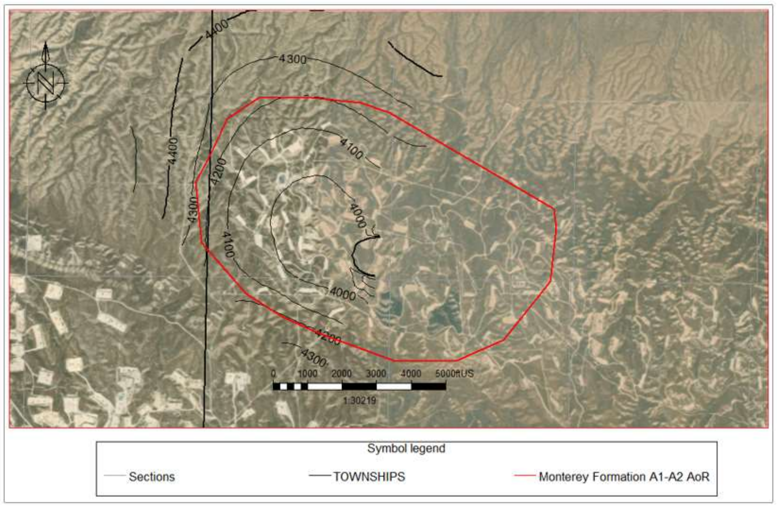


Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND ACQUISITION of the QASP.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm A1-A2	Pressure	335X-7R	8737' - 9030' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
	Monterey Fm A1-A2	Pressure	353A-7R	8773' - 9130' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)]	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 7)
- Borehole sensors will be deployed deeper than 1,500' to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events >M_w 0.0

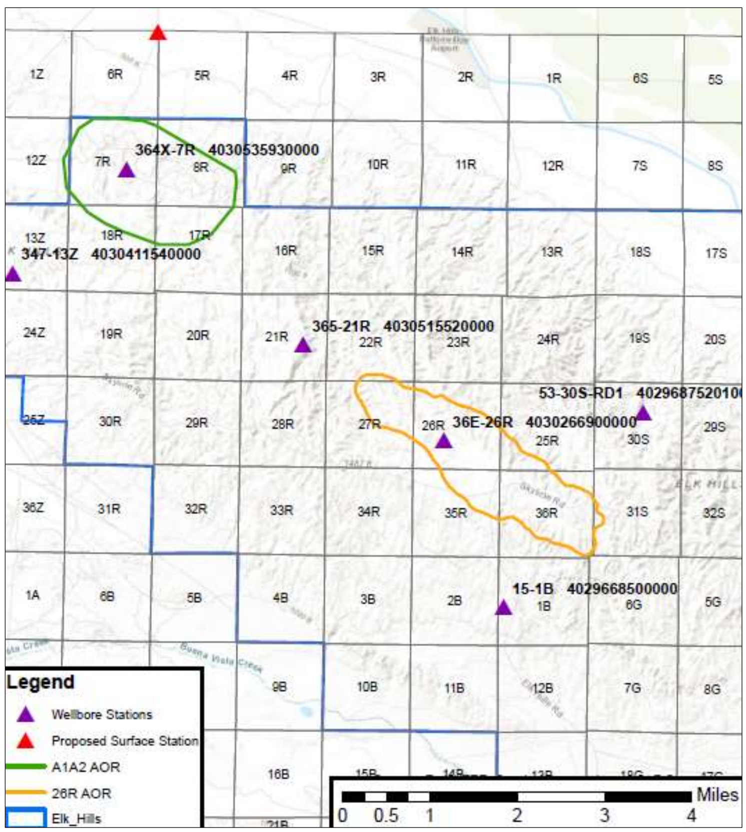


Figure 7: Elk Hills seismic monitoring network.

Baseline Analysis:

The monitoring network will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data transmitted near real-time via cellular modem or other wireless means and archived in a database
- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan