WELL CONSTRUCTION, OPERATION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Well 355-7R

Version History

File Name	Version	Date	Description of Change
COP_355-7R_v1	1	05/16/22	Combines documents, incorporates corrections and EPA feedback dated 04/25/22. COP document supersedes well construction portion of Narrative A2 and Attachment G2
COP_355-7R_v2	2	11/30/22	Revisions based on EPA feedback dated 8/17/22

Introduction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. The wells are in Section 7R within the unit boundary of the Elk Hills Oil Field. 357-7R and 355-7R surface elevations are 792' and 714' above mean sea level, respectively. These injectors are currently approved by CalGEM for Class II injection of up to 50 million cubic feet per day gas (up to 44% CO_2) for the purpose of reservoir pressure maintenance. The wells have been engineered for the injection of CO_2 with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

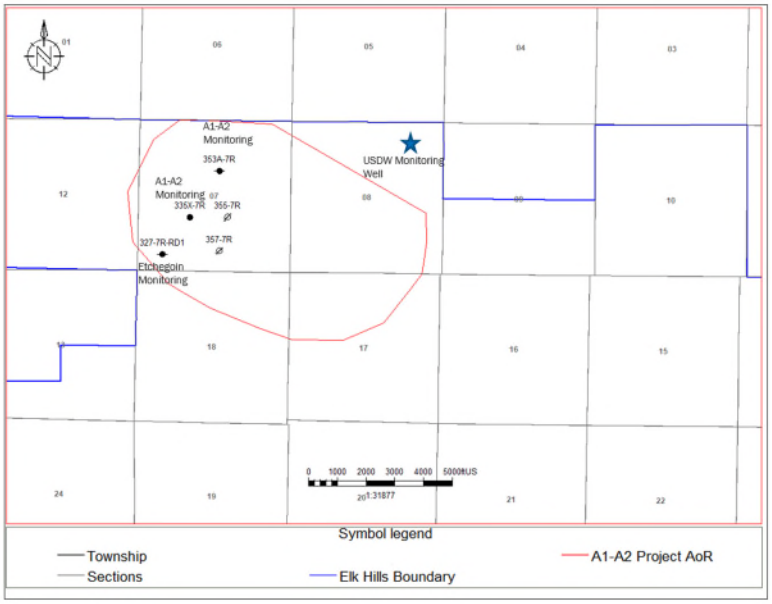


Figure 1: Map showing the location of injection wells and monitoring wells.

As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity. The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection wells with construction specifications and anticipated completion details in graphical and tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of the USDW

355-7R was drilled in 1973, at which time there were no drilling and completion issues. The base of USDW is located at 840' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors
2. Multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production tubing
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing was cemented with cement returns to surface. The 7" casing string was cemented with a theoretical volume to surface, but cement returns were not observed.

4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval, from base of 7" casing to ~5200 feet.
5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained and Mechanical Integrity Testing (MIT) to be conducted.
6. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
7. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
8. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

The 355-7R injection well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent loss of mechanical integrity in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.

4. Casing – the standard N-80 and K-55 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement - Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

Table 1: Casing Specifications for the 355-7R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 - 46	20.000	19.124	94	--	--	2.62	--	--
Surface	14 - 500	13.375	12.715	48	H-40	Short	2.62	1,730	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	2.62	5,750 3,950	3,090 2,570
Long-string	14 – 43 43 – 4,089 4,089 – 5,796 5,796 – 8,363 8,363 – 9,500	7.000	6.184 6.366 6.276 6.276 6.184	29 23 26 26 29	N-80 K-55 K-55 N-80 N-80	Long	2.62	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

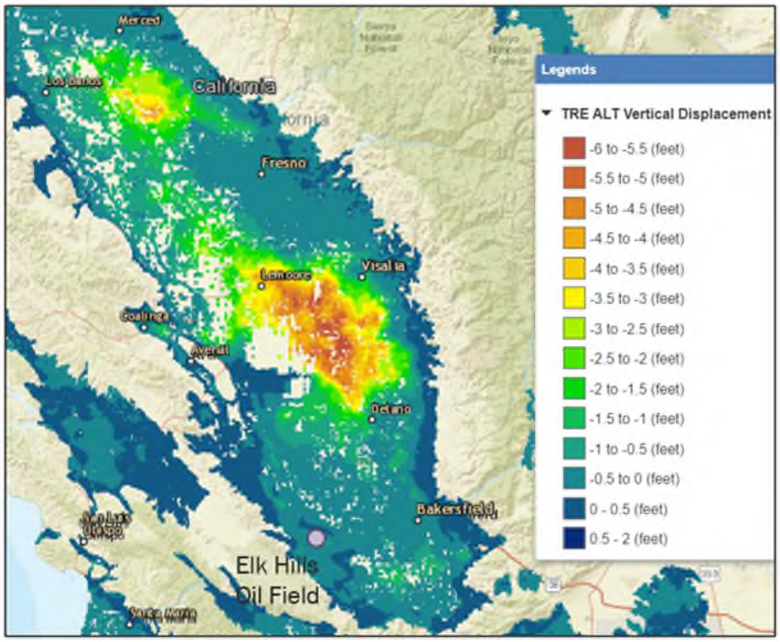


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing was cemented with returns to surface. The 9-5/8" casing string was cemented in place with circulation and top job to achieve cement to surface. The 7" casing string was cemented in place with Class G portland cement. Subsequently, a CBL was run from 5200' – 9400' and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

The information in Table 2 and Table 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications may be modified prior to conversion during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,423	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8,397	30.3	26-32	5.875	4.000

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with realtime injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating

Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded. The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 355-7R with a surface shut-off valve at the wellhead and not a down-hole device.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, corrosivity, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Table 4: Summary of Anticipated Risk Factors

Risk Factor	Justification for A1-A2 Reservoir
Temperature	Less than 300 degrees Fahrenheit reservoir temperature
Pressure	Less than 10,000 psi operating pressure
Corrosivity	Less than 25 lb/mmscf water content in the CO2 stream
Presence of Hydrogen Sulfide	H2S not present in A1-A2 production gas analysis
Proximity to populated area	Project located in Elk Hills oil field, unpopulated area

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 5 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 5: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
355-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Temperature Log Oxygen Activation Log Noise Log	Along the 7" casing to surface
	Pressure Fall-off Testing	Injection Zone

Deviation Checks During Drilling

Deviation checks for 355-7R were acquired during drilling every 100 feet from 3,500 feet measured depth (MD) to bottom hole at 10,500 feet MD (Table 6).

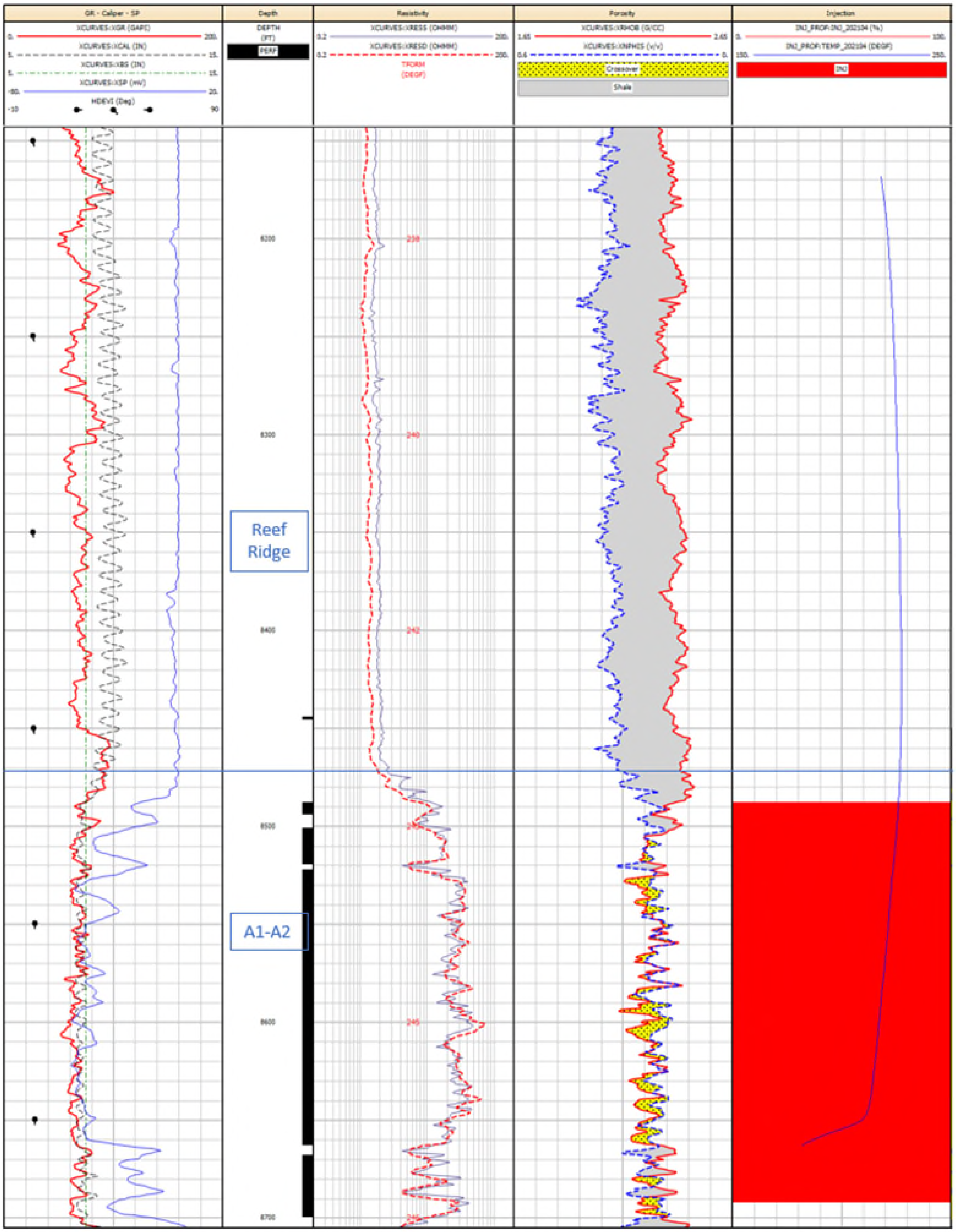
Table 6: Deviation checks during drilling for the 355-7R well.

MD	INC	AZI	TVD	MD	INC	AZI	TVD
0	0	0	0	7400	3	156.89	7396.6
3500	2	180.89	3499.3	7500	3	162.89	7496.4
3600	2	180.89	3599.2	7600	3	171.89	7596.3
3700	2	174.89	3699.2	7700	3	166.89	7696.2
3800	2	174.89	3799.1	7800	3	172.89	7796
3900	2	176.89	3899	7900	3	162.89	7895.9
4000	2	180.89	3999	8000	3	161.89	7995.8
4100	2	189.89	4098.9	8100	3	163.89	8095.6
4200	2	187.89	4198.9	8200	3	165.89	8195.5
4300	2	182.89	4298.8	8300	3	169.89	8295.4
4400	2	182.89	4398.7	8400	3	172.89	8395.2
4500	2	182.89	4498.7	8500	4	174.89	8495
4600	2	184.89	4598.6	8600	4	181.89	8594.8
4700	2	176.89	4698.6	8700	4	181.89	8694.5
4800	2	171.89	4798.5	8800	4	171.89	8794.3
4900	2	175.89	4898.4	8900	4	173.89	8894.1
5000	2	186.89	4998.4	9000	4	164.89	8993.8
5100	2	181.89	5098.3	9100	4	159.89	9093.6
5200	2	181.89	5198.3	9200	4	158.89	9193.3
5300	1	177.89	5298.2	9300	4	149.89	9293.1
5400	1	169.89	5398.2	9400	3	137.89	9392.9
5500	2	164.89	5498.2	9500	4	137.89	9492.7
5600	2	166.89	5598.1	9600	3	136.89	9592.5
5700	2	164.89	5698	9700	4	127.89	9692.3
5800	2	157.89	5798	9800	4	133.89	9792.1
5900	2	157.89	5897.9	9900	4	126.89	9891.8
6000	2	151.89	5997.9	10000	4	123.89	9991.6
6100	2	131.89	6097.8	10100	4	122.89	10091.4
6200	2	133.89	6197.7	10200	5	124.89	10191.1
6300	2	137.89	6297.7	10300	5	116.89	10290.7
6400	3	142.89	6397.6	10400	4	122.89	10390.4
6500	2	145.89	6497.5	10500	4	122.89	10490.1
7300	3	148.89	7296.7				

Open Hole Log Analysis

Open-hole wireline log data was acquired in 355-7R prior to installation of 7" casing long string. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3 (third from left).

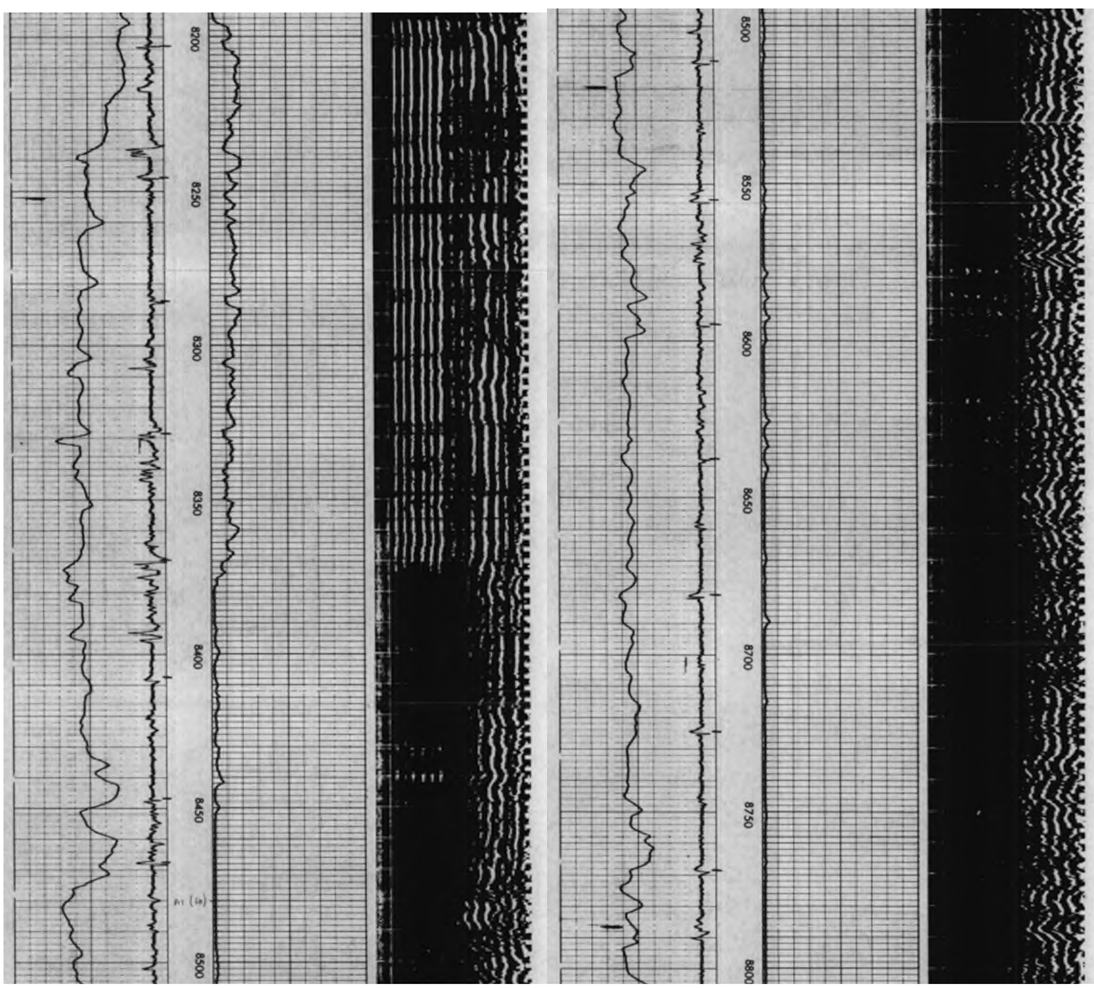
Figure 3: Open-hole well logs for 355-7R before installation of long string.



Cement Evaluation

The cement bond log seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 4). Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7” casing interval. The top of cement was not observed deeper than 5200’ - the top of the cement bond logging interval - and it is therefore shallower than 5200’. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7” casing string during pre-operational testing.

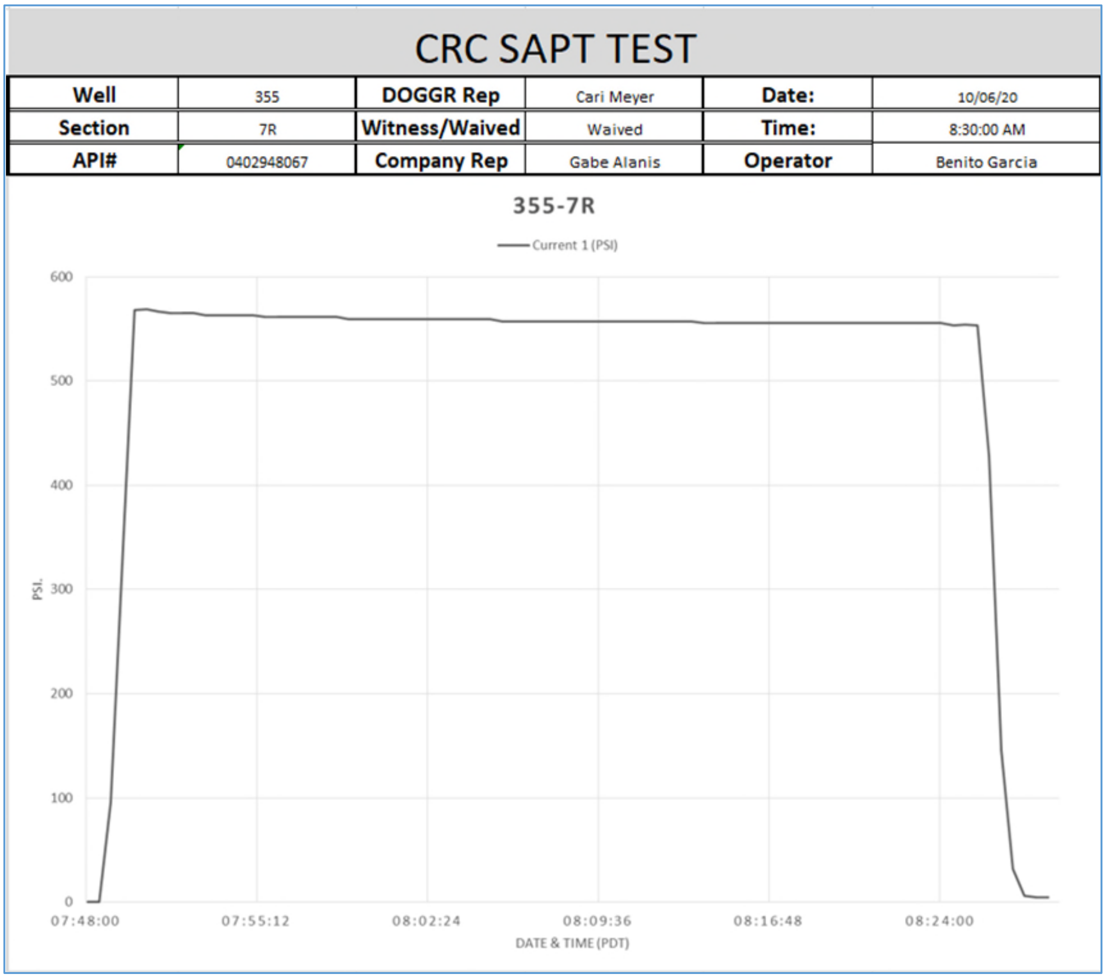
Figure 4: Cement bond log example for 355-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,470 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated October 6^{th}, 2020, shows that the annulus can hold pressure more than 500 psi without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer with the tubing and packer equipment currently in the well. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this will be addressed in the Pre-Operational Testing plan document.

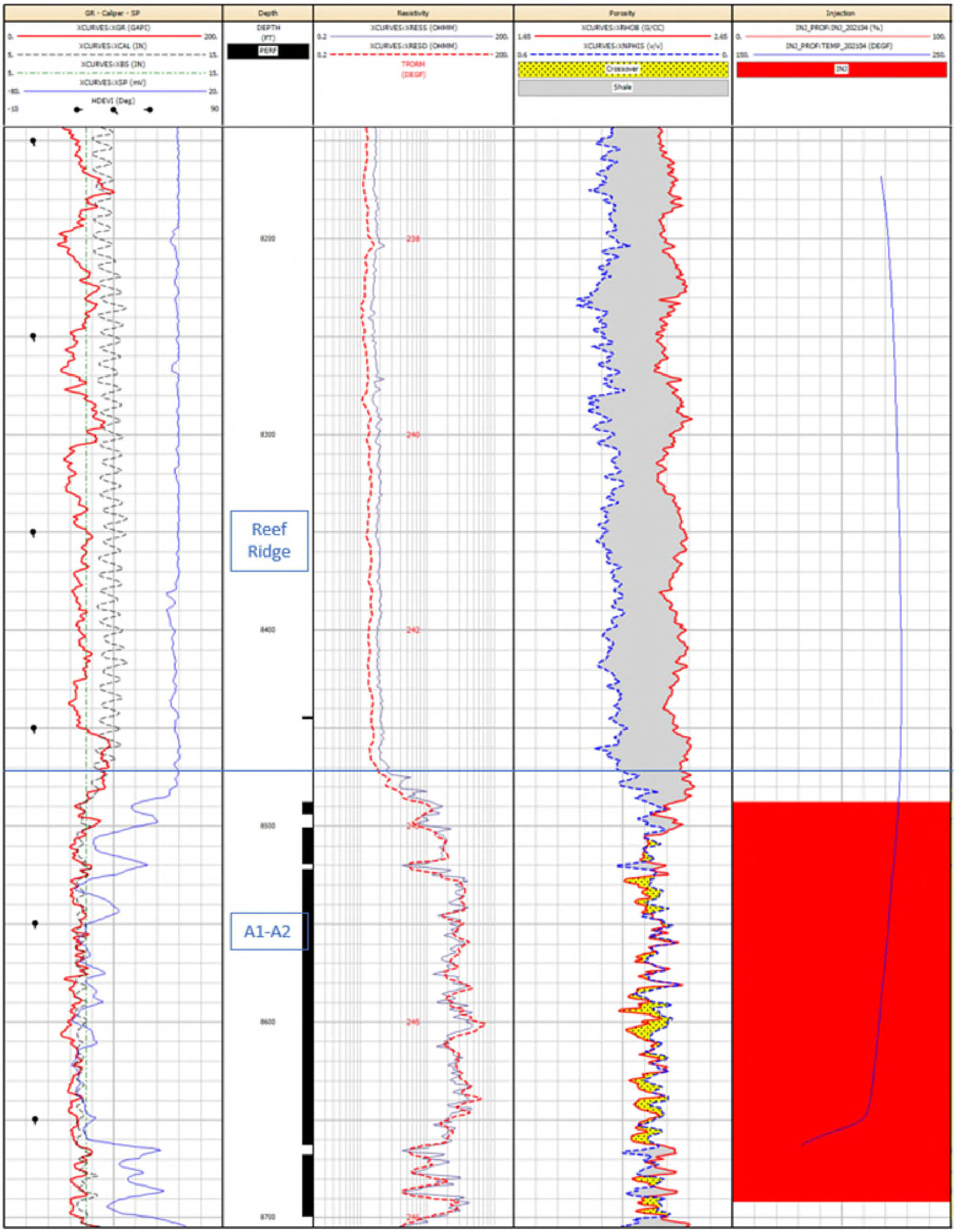
Figure 5: SAPT for 355-7R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 6 was acquired on April 13^{th}, 2021. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation at 8488' or at the packer at 8403'. The track on the right represents injection in percent of total rate with red shading showing 100% injection into A1-A2 perforations. The temperature curve shows that injection is confined below the packer as temperature trends toward geothermal gradient above the packer.

Figure 6: Radioactive tracer and temperature survey for well 355-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Temperature logs, noise logs and oxygen activation logs are approved forms of external mechanical integrity by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

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. The testing procedure is described in the Testing and Monitoring document.

Well Operation

Injection operation conditions of 355-7R are detailed in the document titled Operating Procedures – 355-7R V2.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be consistent with the properties of Class G portland cement used in well construction, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The wells will have this cement placed as detailed in Table 7, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 14' MD due to the depth reference to the kelly bushing 14' above ground level during drilling.

Table 7: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.276	6.366	6.184
Depth to bottom of tubing or drill pipe (ft)	8,692	3,061	1,509	39
Sacks of cement to be used (each plug)	59	24	148	5
Slurry volume to be pumped (ft^3)	67	27	170	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,371	2,936	740	14
Bottom of plug (ft)	8,692	3,061	1,509	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).
4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):
  - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
  - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.