WELL CONSTRUCTION, OPERATING, 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

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.

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

Injectate Migration Prevention

355-7R was drilled in 1973, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as 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 casing
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement.

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 enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted
6. Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
7. 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

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
3. Packer – corrosion resistant alloy material or coating and hardened rubber
4. Casing and Cement - N-80 and K-55 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing into the Reef Ridge Shale

Standards

Well materials follow the following standards:

1. API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Subsidence has not been observed historically in the areas around the injection wells because of hydrocarbon production, and shallow compression is not anticipated as a concern for casing or cement integrity.

Casing specifications are presented in Table 1. These specifications show that the well was engineered to standards that allow for the safe operation at the conditions outlined in Table 4 in operating parameters. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

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	19.5	52	--	--	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

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 cement returns were to surface for the 13-3/8” casing. 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 annular isolation throughout and above the Monterey and Reef Ridge formations.

Protection of USDW

The USDW and all strata overlying the injection zone will be protected by the following:

1. Surface casing is set and cemented to surface within the USDW interval, providing multiple protective barriers to ensure protection of the USDW above the casing point.

2. The intermediate casing string is set across the base of the USDW, and annular cement isolates the USDW from the injection string by providing multiple protective barriers to ensure protection of USDW.
3. The cement bond log on the 7” casing string indicates several thousand feet of annular cement within and above the injection and confining zones, providing adequate isolation of the USDW from CO_2 injectate.
4. SAPT tests that pressure the well annulus to 500 PSI for 30 minutes have been acquired through time. All SAPT’s demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
5. If mechanical integrity issues are indicated through monitoring during injection, CTV will perform diagnostics and remediate as necessary.

Tubing and Packer

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. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

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

Logging and Testing

The following data have been acquired during the initial well construction or during subsequent operations. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be addressed in the Pre-Operational Testing plan document.

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 (Figure 1).

Figure 1: Deviation checks during drilling for the 357-7R well.

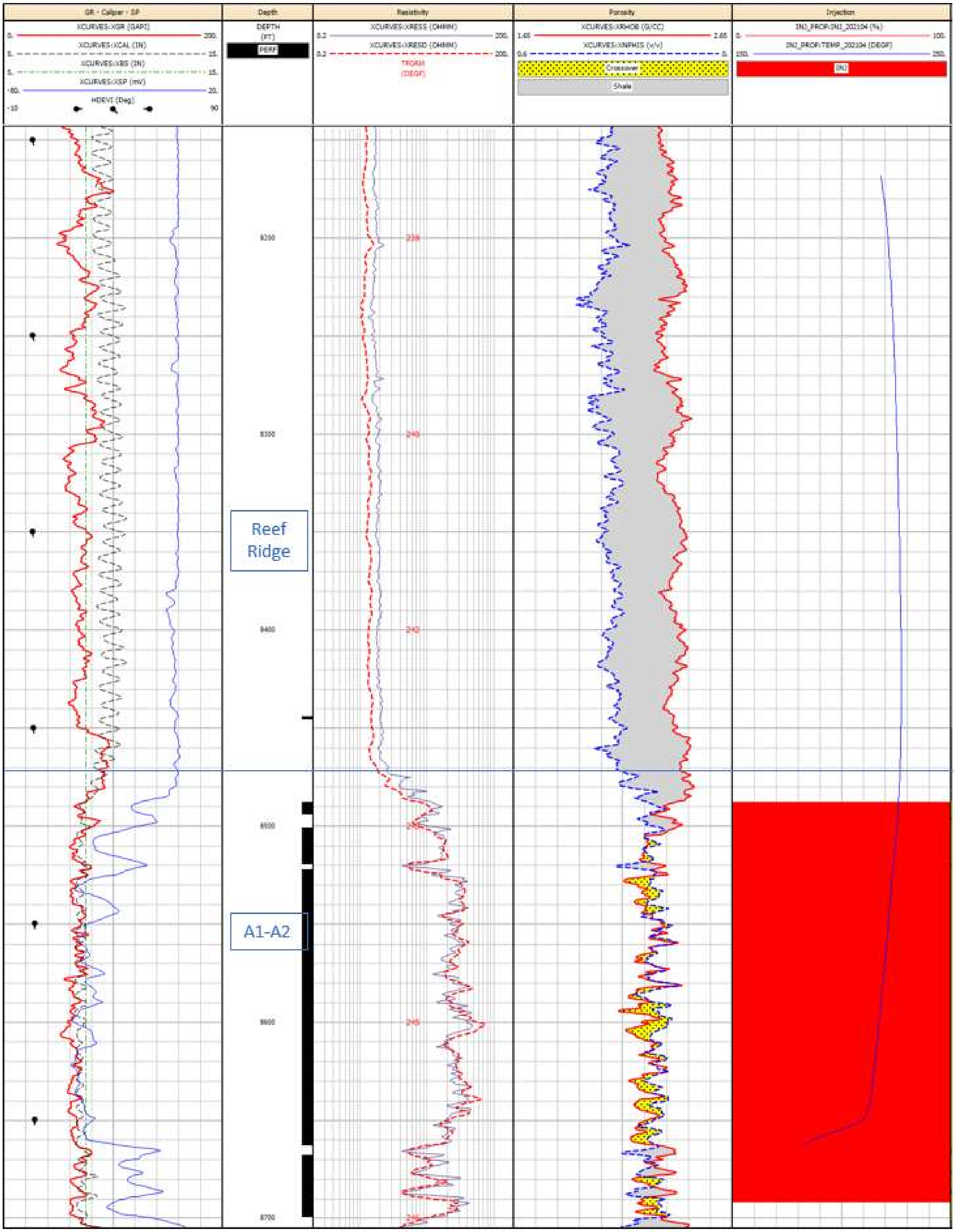
X ftUS	Y ftUS	Z ft	MD ft	Inclination deg	Azimuth GN deg	Azimuth TN deg	DX ftUS	DY ftUS	DX TN ftUS	DY TN ftUS	TVD (Well datum) ft	TWT ms	DLS deg/100ft
6101103.00	2310474.00	728.00	0.00	0.00	180.00	179.12	0.00	0.00	0.00	0.00	0.00		0.00
6101103.00	2310412.92	-2771.29	3500.00	2.00	180.00	179.12	0.00	-61.08	0.94	-61.07	3499.29		0.06
6101103.00	2310409.43	-2871.23	3600.00	2.00	180.00	179.12	0.00	-64.57	0.99	-64.56	3599.23		0.00
6101103.18	2310405.95	-2971.17	3700.00	2.00	174.00	173.12	0.18	-68.05	1.23	-68.04	3699.17		0.21
6101103.55	2310402.48	-3071.11	3800.00	2.00	174.00	173.12	0.55	-71.52	1.65	-71.50	3799.11		0.00
6101103.85	2310399.00	-3171.05	3900.00	2.00	176.00	175.12	0.85	-75.00	2.00	-74.98	3899.05		0.07
6101103.97	2310395.52	-3270.98	4000.00	2.00	180.00	179.12	0.97	-78.48	2.18	-78.46	3998.98		0.14
6101103.70	2310392.05	-3370.92	4100.00	2.00	189.00	188.12	0.70	-81.95	1.96	-81.93	4098.92		0.31
6101103.21	2310388.60	-3470.86	4200.00	2.00	187.00	186.12	0.21	-85.40	1.53	-85.39	4198.86		0.07
6101102.94	2310385.12	-3570.80	4300.00	2.00	182.00	181.12	-0.06	-88.88	1.31	-88.87	4298.80		0.17

X ftUS	Y ftUS	Z ft	MD ft	Inclination deg	Azimuth GN deg	Azimuth TN deg	DX ftUS	DY ftUS	DX TN ftUS	DY TN ftUS	TVD (Well datum) ft	TWT ms	DLS deg/100ft
6101181.90	2310156.91	-8897.80	9633.33	3.32	132.40	131.52	78.90	-317.09	83.76	-315.85	9625.80		1.14
6101183.43	2310155.58	-8931.07	9666.67	3.66	129.45	128.57	80.43	-318.42	85.32	-317.16	9659.07		1.14
6101185.18	2310154.20	-8964.33	9700.00	4.00	127.00	126.12	82.18	-319.80	87.09	-318.51	9692.33		1.14
6101187.91	2310152.03	-9014.21	9750.00	3.99	130.00	129.12	84.91	-321.97	89.85	-320.63	9742.21		0.42
6101190.52	2310149.73	-9064.09	9800.00	4.00	133.00	132.12	87.52	-324.27	92.49	-322.90	9792.09		0.42
6101193.14	2310147.43	-9113.97	9850.00	3.99	129.50	128.62	90.14	-326.57	95.15	-325.16	9841.97		0.49
6101195.89	2310145.30	-9163.85	9900.00	4.00	126.00	125.12	92.89	-328.70	97.93	-327.25	9891.85		0.49
6101198.74	2310143.28	-9213.72	9950.00	4.00	124.50	123.62	95.74	-330.72	100.81	-329.21	9941.72		0.21
6101201.64	2310141.35	-9263.60	10000.00	4.00	123.00	122.12	98.64	-332.65	103.74	-331.11	9991.60		0.21
6101204.57	2310139.46	-9313.48	10050.00	4.00	122.50	121.62	101.57	-334.54	106.70	-332.95	10041.48		0.07
6101207.52	2310137.60	-9363.36	10100.00	4.00	122.00	121.12	104.52	-336.40	109.68	-334.76	10091.36		0.07
6101209.57	2310136.30	-9396.60	10133.33	4.33	122.77	121.89	106.57	-337.70	111.74	-336.03	10124.60		1.01
6101211.76	2310134.87	-9429.84	10166.67	4.67	123.43	122.55	108.76	-339.13	113.96	-337.43	10157.84		1.01
6101214.09	2310133.31	-9463.05	10200.00	5.00	124.00	123.12	111.09	-340.69	116.31	-338.95	10191.05		1.01
6101217.78	2310131.01	-9512.86	10250.00	4.99	120.00	119.12	114.78	-342.99	120.04	-341.20	10240.86		0.70
6101221.62	2310128.97	-9562.67	10300.00	5.00	116.00	115.12	118.62	-345.03	123.91	-343.18	10290.67		0.70
6101224.13	2310127.70	-9595.89	10333.33	4.66	117.71	116.83	121.13	-346.30	126.43	-344.41	10323.89		1.10
6101226.42	2310126.45	-9629.12	10366.67	4.33	119.69	118.81	123.42	-347.55	128.74	-345.62	10357.12		1.10
6101228.50	2310125.21	-9662.36	10400.00	4.00	122.00	121.12	125.50	-348.79	130.84	-346.83	10390.36		1.10
6101234.41	2310121.51	-9762.12	10500.00	4.00	122.00	121.12	131.41	-352.49	136.81	-350.44	10490.12		0.00

Open Hole Log Analysis

Open-hole wireline log data was acquired in 355-7R prior to installation of 7" casing long string. Figure 2 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).

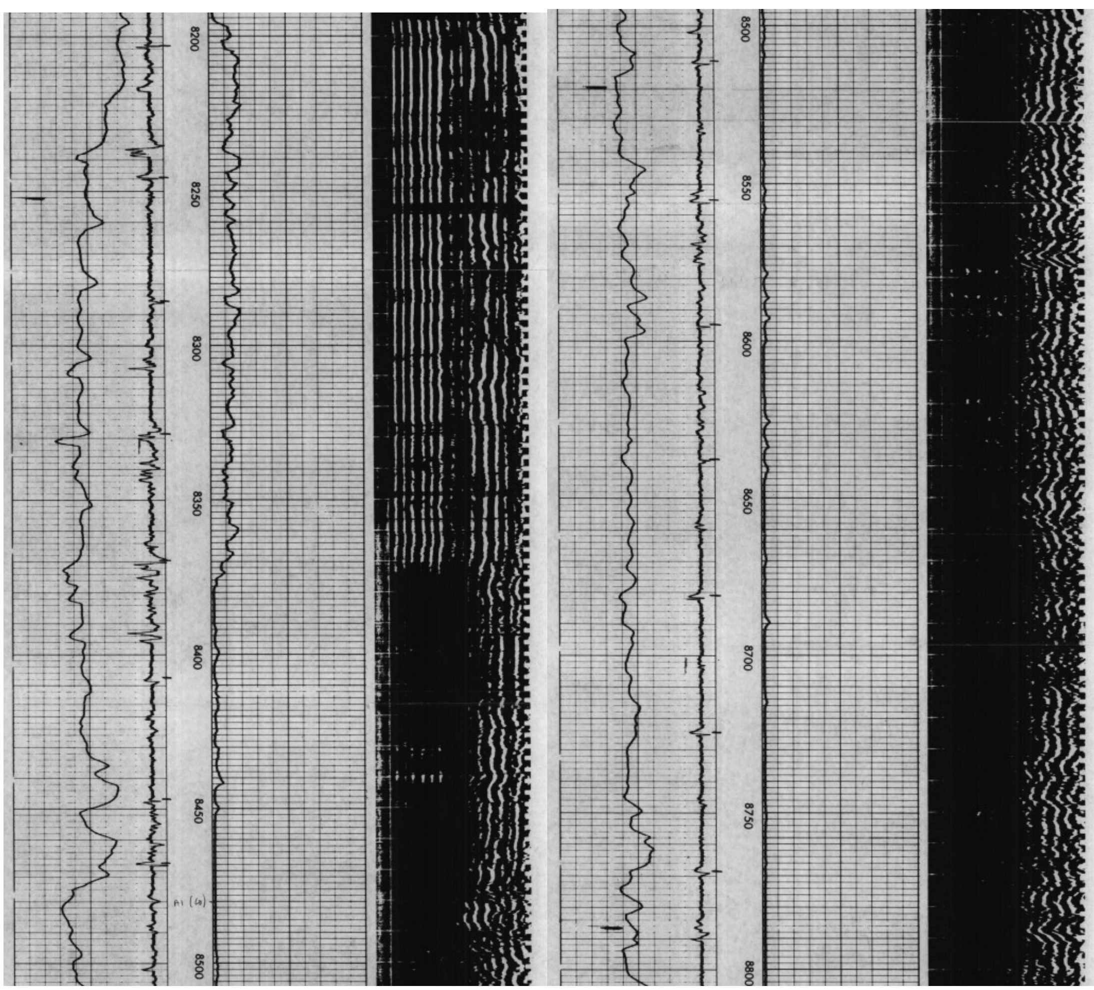
Figure 2: Open-hole well logs for 355-7R before installation of long string.



Cement Evaluation

The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing. The cement bond log seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 3). 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 identified below 5200', the top of the cement bond logging interval, and it is therefore shallower than 5200'.

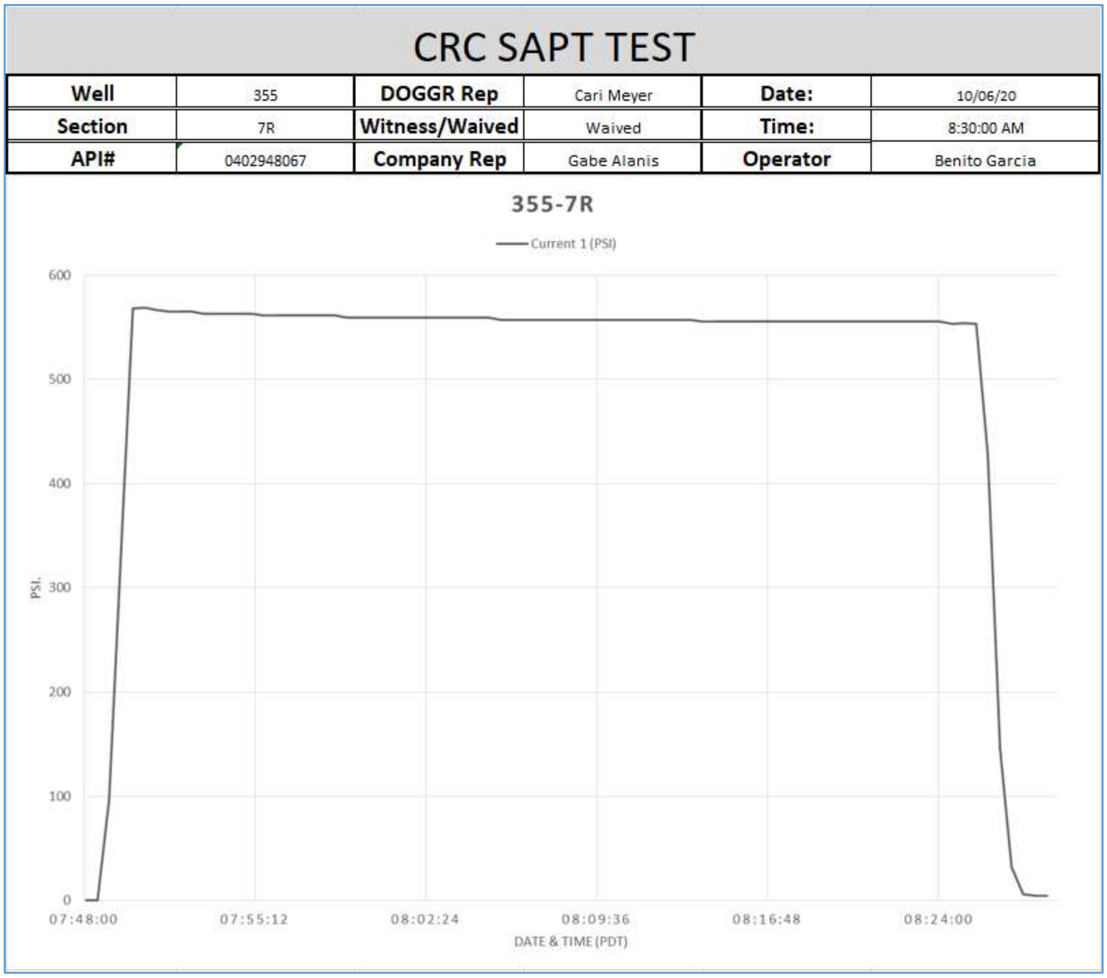
Figure 3: Cement bond log example for 355-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,470 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated October 6th, 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.

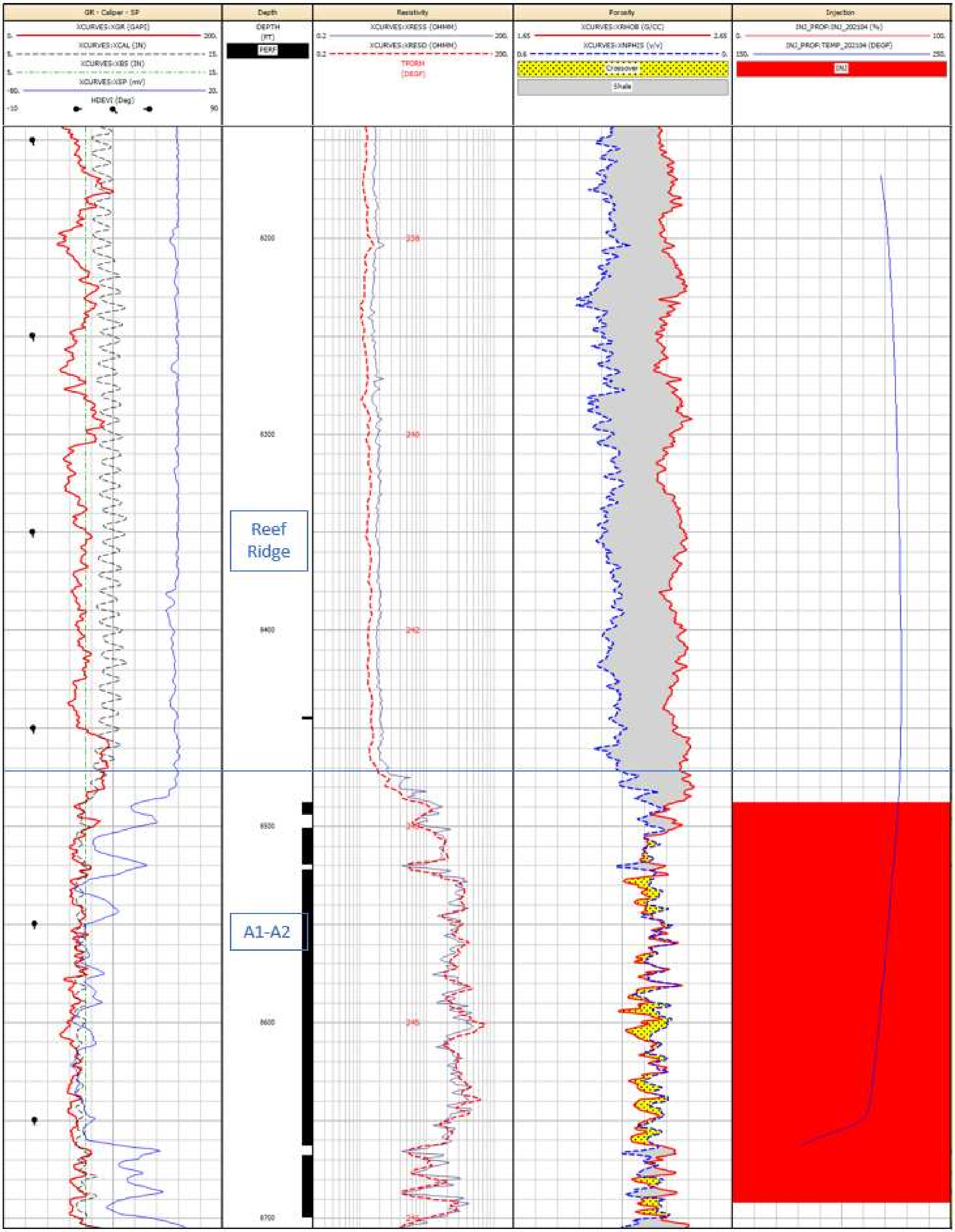
Figure 4: SAPT for 355-7R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 5 was acquired on April 13th, 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 5: Radioactive tracer and temperature survey for well 355-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Well Operation

Refer to 355-7R Operating Procedures appendix submitted to EPA on 3/31/2022. The final version of this document will include 355-7R Operational Procedures in this section.

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 5 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 5, 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 5: 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.