WELL CONSTRUCTION PLAN
ELK HILLS A1-A2 STORAGE PROJECT
INJECTION WELL 357-7R

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
357-7R

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.3280 / -119.5450

Version History

File Name	Version	Date	Description of Change
COP_357-7R_v1	1	5/16/2022	Combines documents, incorporates corrections and EPA feedback dated 04/25/22
COP_357-7R_v2	2	11/1/2022	Revisions based on EPA feedback dated 8/17/22
Attachment G2_Construction Plan_357-7R_v3	3	4/24/2024	Splitting COP_357-7R_v2 into Att. G2 and Att. D2

1. Introduction

CTV plans to use 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 (Figure 1). 357-7R and 355-7R surface elevations are 792 feet and 714 feet 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% carbon dioxide [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.

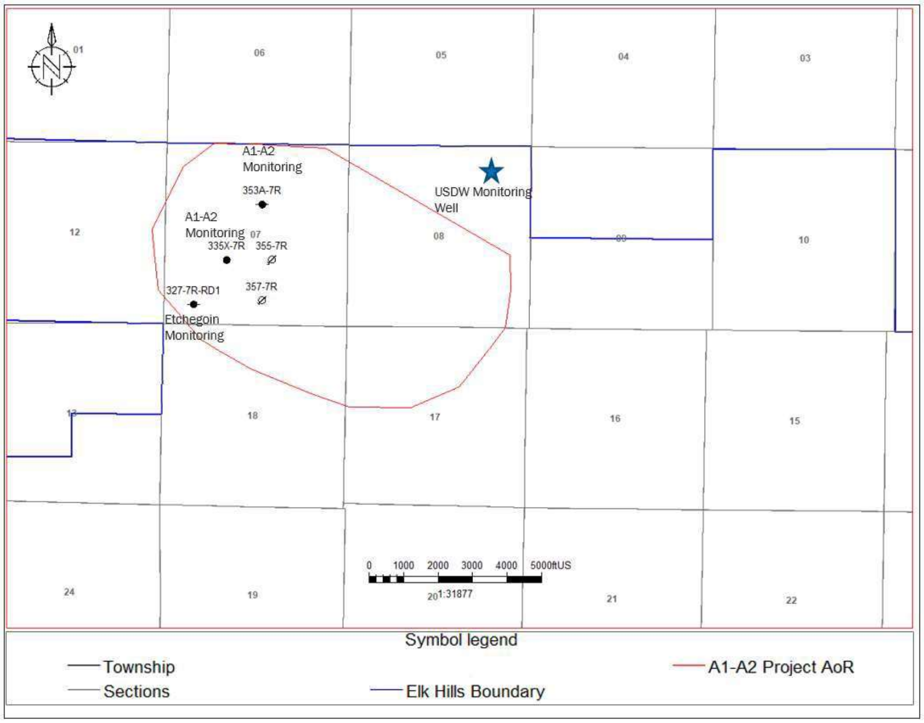


Figure 1. Map showing the location of injection wells and monitoring wells at A1-A2.

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

Injectate Migration Prevention

357-7R was drilled in 1980, during 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:

- Well design exceeds criteria of all anticipated load cases including safety factors.
- Multiple cemented casing strings protect potential shallow underground source of drinking water (USDW) zones from contacting fluids within the production casing.
- All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement.
- 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.
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and mechanical integrity testing (MIT) to be conducted.
- Real-time surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions.
- 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 used will be compatible with the CO_2 injectate and will limit corrosion:

- Tubing: corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification.
- Wellhead: stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification.
- Packer: CRA material or coating and hardened rubber.
- Casing and Cement: N-80 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:

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

Casing

Monterey Formation A1-A2 temperature is approximately 240°F. 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 1 in the Operating Parameters document. 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 357-7R 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	20–60	20.000	19.124	94	—	—	2.62	—	—
Surface	20–501	13.375	12.715	48	H-40	Short	2.62	1,730	770
Intermediate	20–3,517	9.625	8.835	40	N-80	Long	2.62	5,750	3,090
Long-string	20–76 76–2,953 2,953–6,158 6,158–8,990	7.000	6.184 6.366 6.276 6.184	29 23 26 29	N-80	Long	2.62	8,160 6,340 7,240 8,160	7,020 3,830 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.

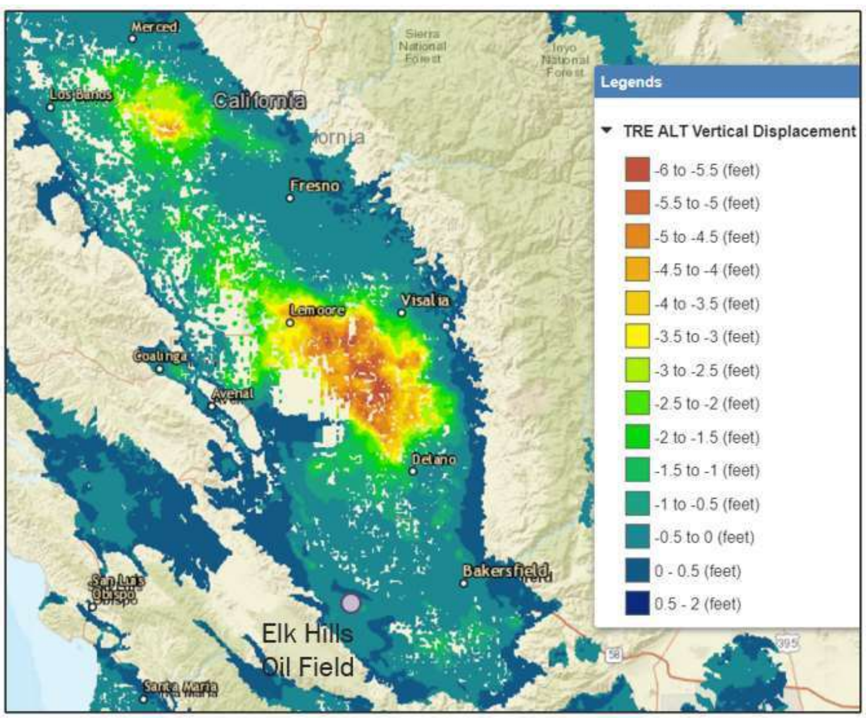


Figure 2. Subsistence in the Elk Hills Oil Field. Subsidence is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

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 13⅜-inch, 9⅝-inch, and 7-inch casing strings were cemented with returns to surface. Subsequently, a CBL was run from 6,250 to 8,970 feet, and indicates annular isolation within the Monterey and Reef Ridge Formations.

Protection of USDW

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

- 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.
- 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.
- The cement bond log on the 7-inch casing string indicates annular cement within and above the injection and confining zones, providing adequate isolation of the USDW from CO_2 injectate.
- Standard annular pressure tests (SAPTs) that pressure the well annulus to 500 pounds per square inch (psi) for 30 minutes have been acquired through time. All SAPTs demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPTs will be acquired before the start of injection and every five years thereafter.
- 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 and inspected prior to injection. A suitable CRA 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	8,470	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-inch casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lb/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8,430	30.3	26 – 32	5.875	4.00

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% potassium chloride (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-inch 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 real-time 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 used 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.

3. 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 are not presented and have not been acquired will be addressed in the Pre-Operational Testing plan document.

Deviation Checks During Drilling

Deviation checks for 357-7R were acquired during drilling every 10 feet from 3,541 feet measured depth (MD) to bottom hole at 9,005 feet MD (Figure 3).

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
6100830.00	2309245.00	812.00	0.00	0.00	165.70	164.82	0.00	0.00	0.00	0.00	0.00		0.00
6100843.74	2309191.11	-2728.52	3541.10	1.80	165.70	164.82	13.74	-53.89	14.56	-53.68	3540.52		0.05
6100843.83	2309190.81	-2738.51	3551.10	1.80	158.50	157.62	13.83	-54.19	14.67	-53.97	3550.51		2.26
6100843.91	2309190.53	-2748.51	3561.10	1.50	170.00	169.12	13.91	-54.47	14.75	-54.25	3560.51		4.45
6100843.95	2309190.28	-2758.51	3571.10	1.40	174.30	173.42	13.95	-54.72	14.79	-54.50	3570.51		1.48
6100843.98	2309190.03	-2768.40	3581.00	1.60	170.00	169.12	13.98	-54.97	14.83	-54.75	3580.40		2.32
6100947.59	2308941.03	-8136.56	8957.60	2.30	76.40	75.52	117.59	-303.97	122.25	-302.14	8948.56		0.00
6100947.98	2308941.13	-8146.45	8967.50	2.30	75.00	74.12	117.98	-303.87	122.63	-302.03	8958.45		0.57
6100948.36	2308941.23	-8156.45	8977.50	2.30	76.40	75.52	118.36	-303.77	123.02	-301.93	8968.45		0.56
6100948.75	2308941.30	-8166.44	8987.50	2.20	80.70	79.82	118.75	-303.70	123.41	-301.84	8978.44		1.96
6100949.12	2308941.36	-8176.43	8997.50	2.10	82.10	81.22	119.12	-303.64	123.78	-301.78	8988.43		1.13
6100949.39	2308941.40	-8183.93	9005.00	2.10	82.10	81.22	119.39	-303.60	124.05	-301.74	8995.93		0.00

Figure 3. Deviation checks during drilling for the 357-7R well.

Open Hole Log Analysis

Open-hole wireline log data were acquired in 357-7R prior to installation of 7-inch casing long string. Figure 4 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), and neutron porosity and bulk density in track 3 (third from left).

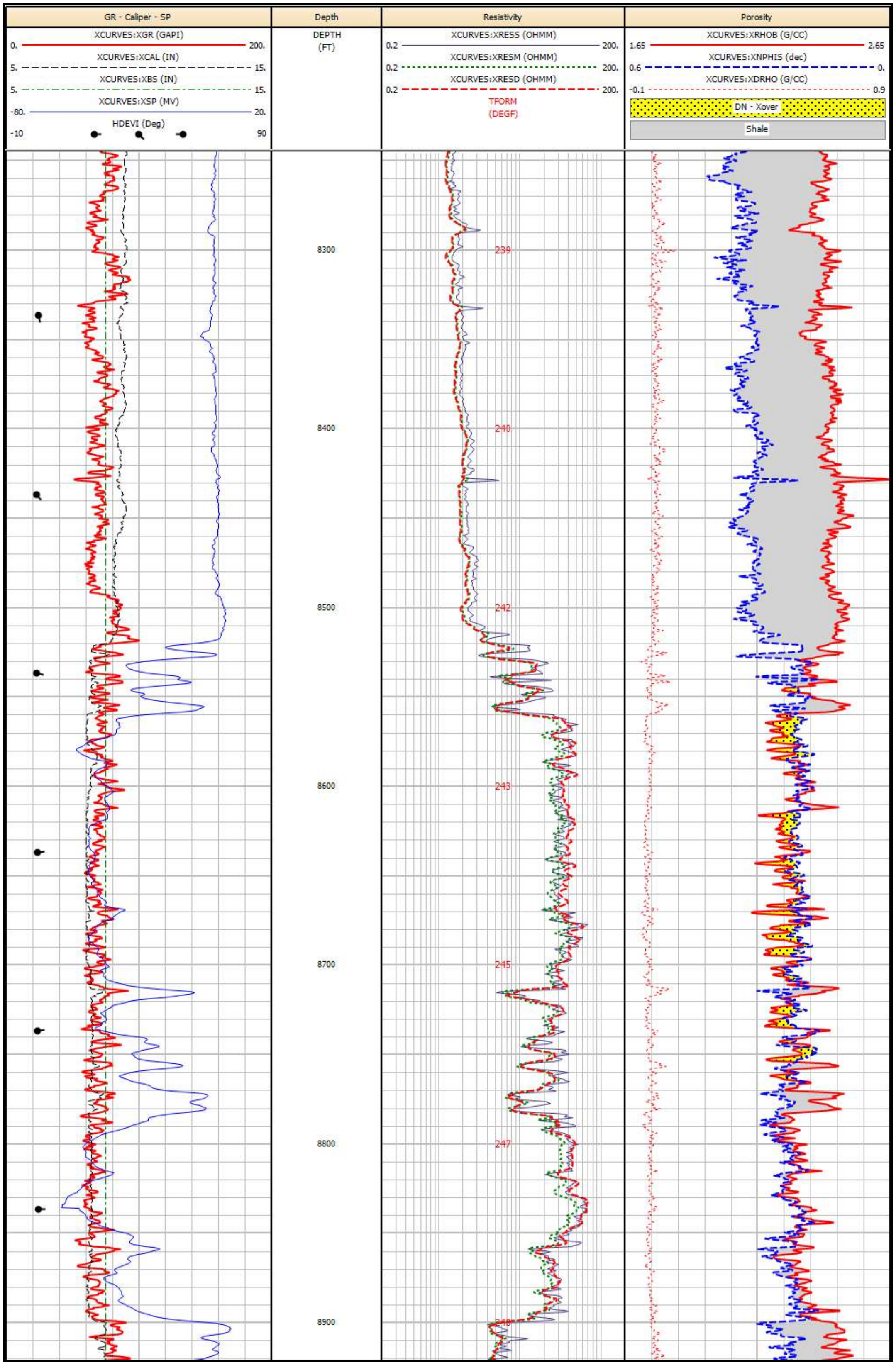


Figure 4. Open-hole well logs for 357-7R before installation of long string.

Cement Evaluation

The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7-inch casing string during pre-operational testing. The CBL seismogram and percent bond show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 5). 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-inch casing interval.

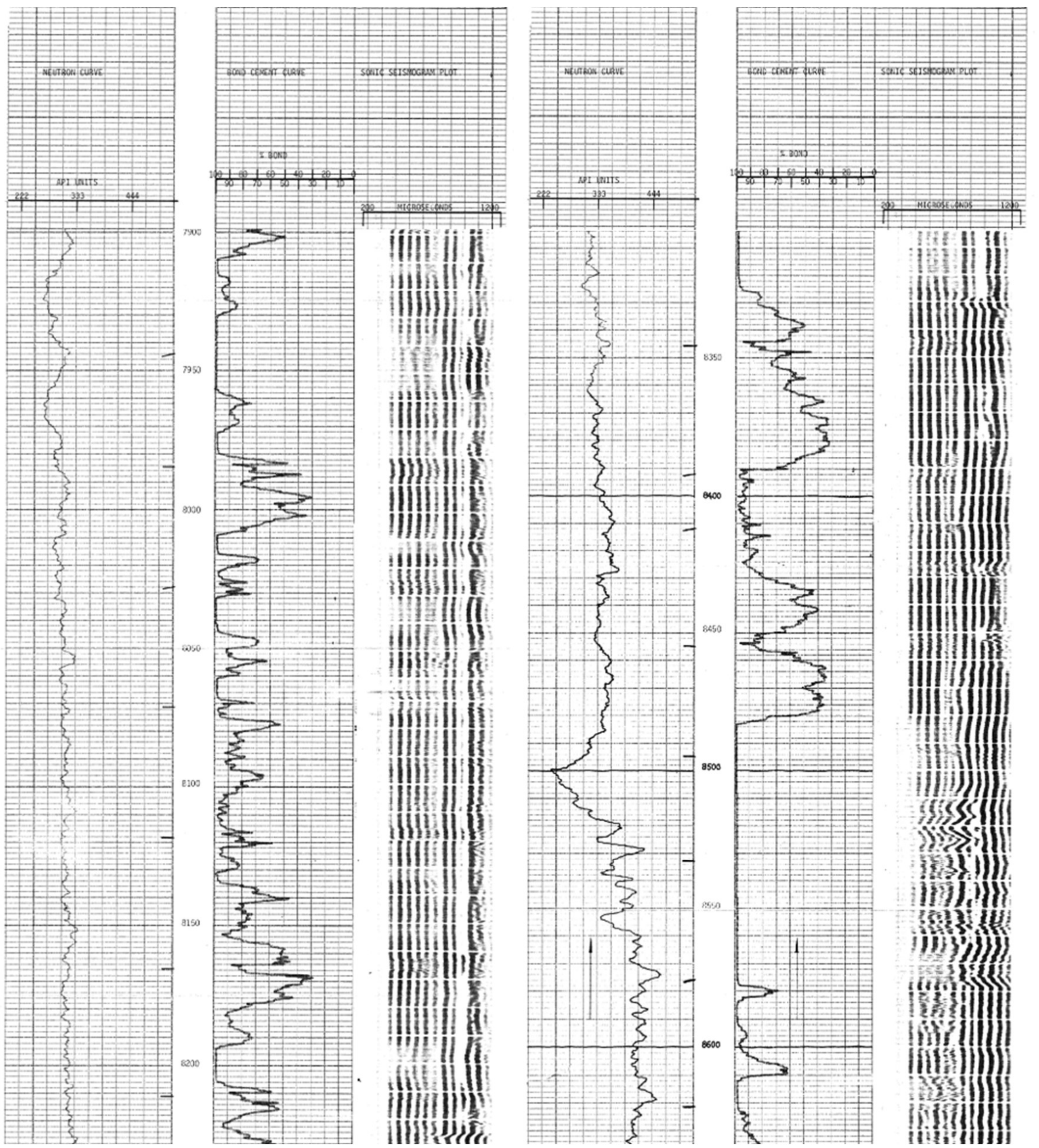


Figure 5. Cement bond log example for 357-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,518 feet.

MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated February 7, 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 (Figure 6). 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.

CRC SAPT TEST

Well	357	**DOGGR Rep**	Rene Tellez	**Date:**	02/07/20
Section	7R	**Witness/Waived**	Waived	**Time:**	12:55:00 PM
API#	0402962150	**Company Rep**	Tony Shadden	**Operator**	Benito Garcia

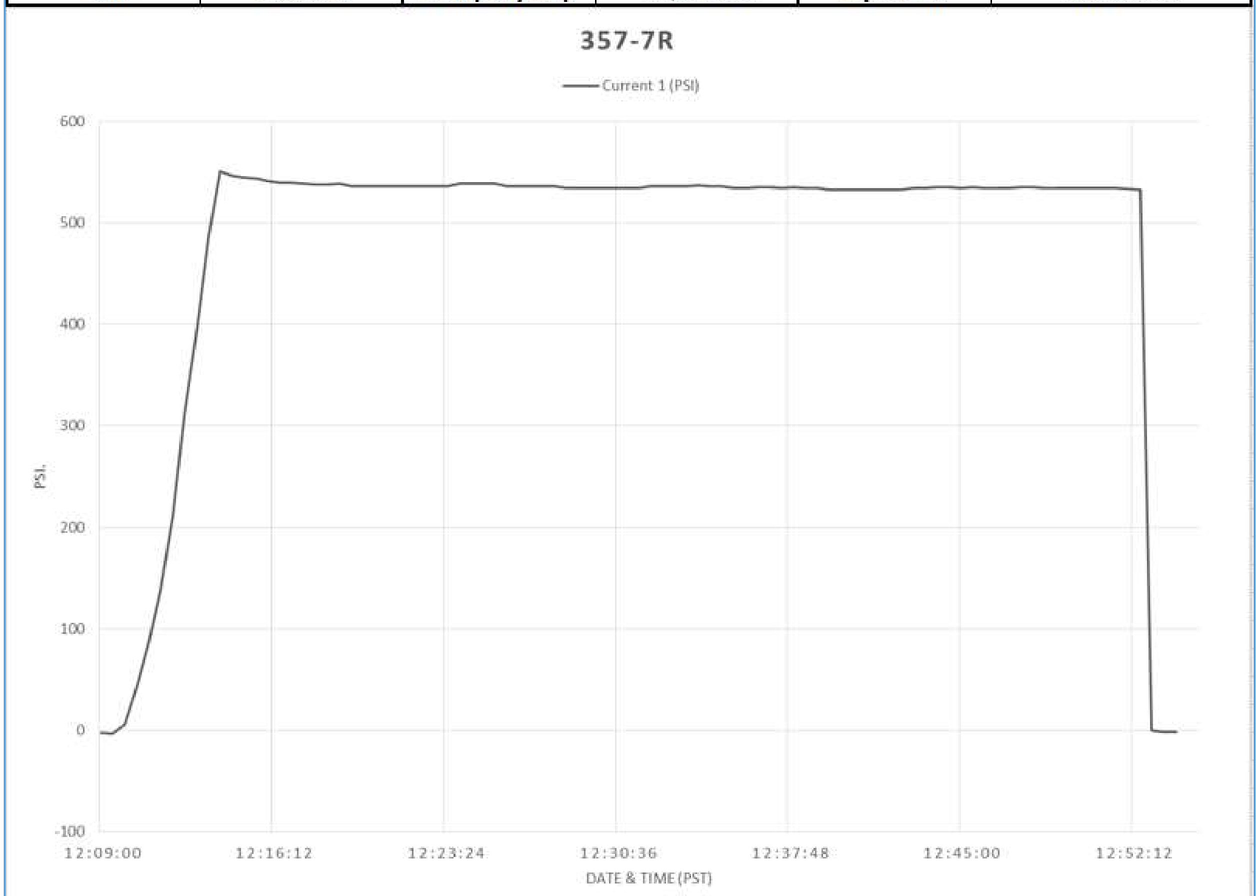


Figure 6. SAPT for 357-7R showing mechanical integrity of the tubing, casing, and packer.

MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 7 below was acquired in 2019. The survey uses radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation or at the packer. 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.

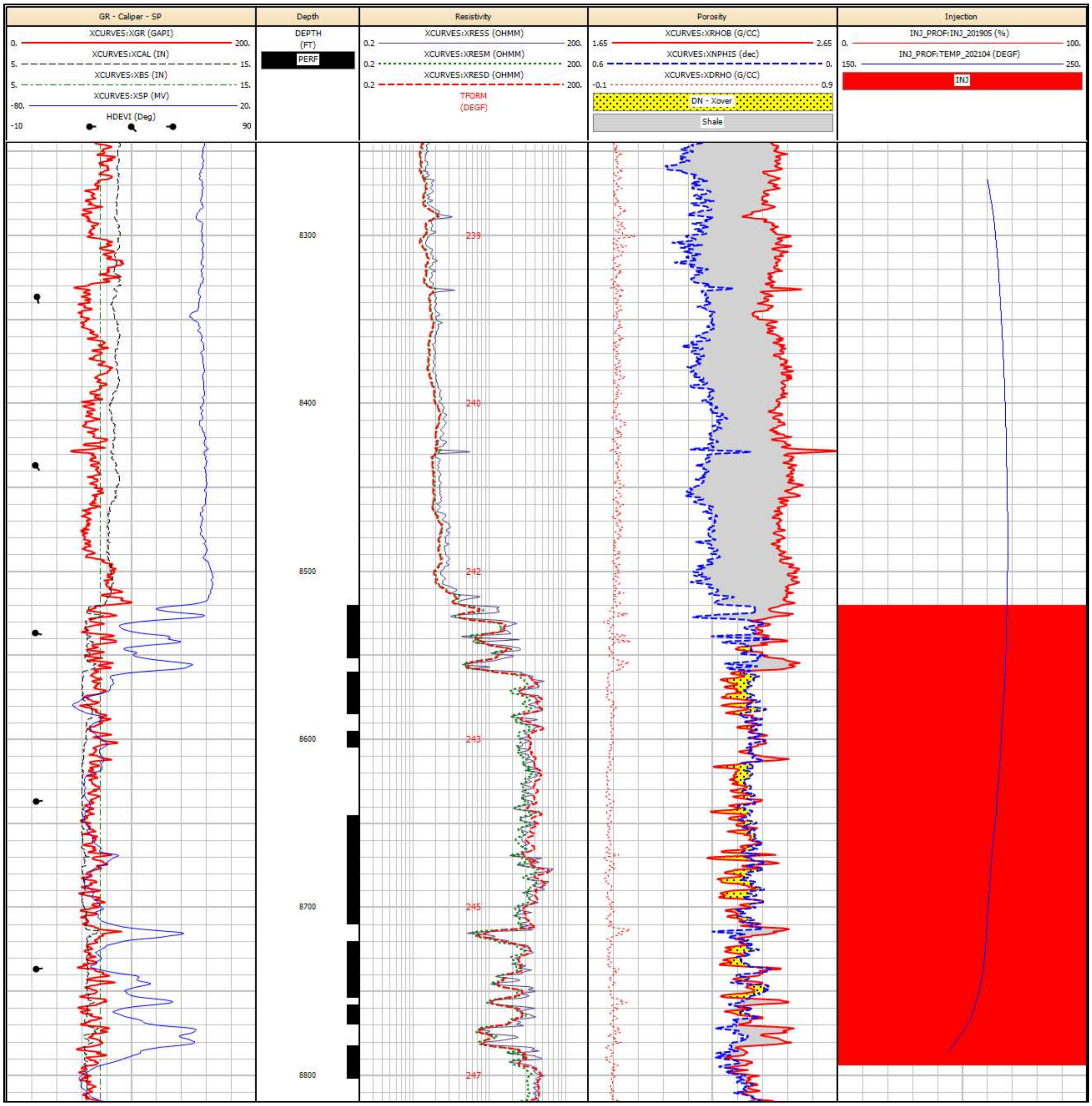


Figure 7. **Radioactive tracer and temperature survey for well 357-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.**

4. Planned Well Retrofitting

Prior to first injection, the existing wellbore will be reconfigured for injection through the following procedure:

1. Install and test blowout prevention equipment (BOPE).
2. Pull existing injection tubing and packer.
3. Clean out well to plugback measure depth (PBMD).
4. Acquire remaining pre-operational phase data per Attachment G and the Testing and Monitoring Plan (T&M).
5. Install carbon capture and storage (CCS) injection tubing, packer, injection tree, and all monitoring equipment per T&M, well schematics (Figure 8).
6. Perform SAPT per T&M procedure.
7. Perform injectivity test and pressure fall-off test.
8. Suspend well temporarily for CCS project startup.

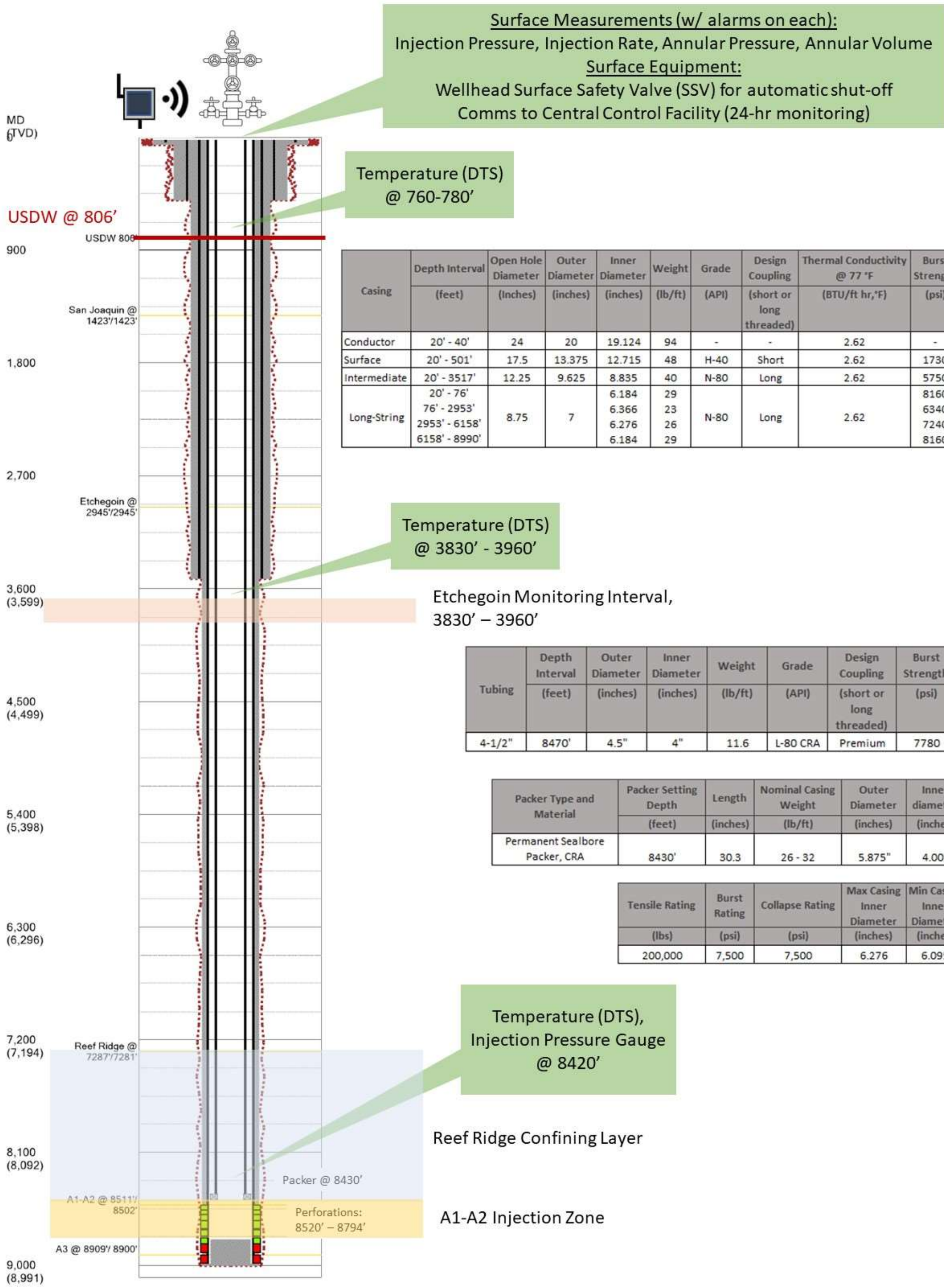
5. Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, the U.S. Environmental Protection Agency (EPA) has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

- Regional Geology and Geologic Structure
  - ◇ Perform pressure build-up testing (anticipated testing method: pressure build-up test).
  - ◇ Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).
- Geochemistry/Geochemical Data
  - ◇ Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the T&M (anticipated testing methods: various geochemical analyses).
- Seismic History and Seismic Risk
  - ◇ Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).
- Facies Changes in the Injection or Confining Zones

  - ◇ Determine if there are any heterogeneities within the Monterey A1-A2 injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

- CO_2 Stream Compatibility with Subsurface Fluids and Minerals
  - ◇ Confirm the composition and water content of the CO_2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).
  - ◇ Confirm that the properties of the CO_2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
  - ◇ Confirm that the analytes for injectate and groundwater quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).
- Confining Zone Integrity
  - ◇ Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).
  - ◇ Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the A1-A2 project wells (anticipated testing methods: core and log data during well drilling).
  - ◇ Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).
- Injection Well Construction
  - ◇ Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval	Open Hole Diameter	Outer Diameter	Inner Diameter	Weight	Grade	Design Coupling	Thermal Conductivity @ 77 °F	Burst Strength
	(feet)	(Inches)	(inches)	(inches)	(lb/ft)	(API)	(short or long threaded)	(BTU/ft hr,°F)	(psi)
Conductor	20' - 40'	24	20	19.124	94	-	-	2.62	-
Surface	20' - 501'	17.5	13.375	12.715	48	H-40	Short	2.62	1730
Intermediate	20' - 3517'	12.25	9.625	8.835	40	N-80	Long	2.62	5750
Long-String	20' - 76' 76' - 2953' 2953' - 6158' 6158' - 8990'	8.75	7	6.184 6.366 6.276 6.184	29 23 26 29	N-80	Long	2.62	8160 6340 7240 8160

Tubing	Depth Interval	Outer Diameter	Inner Diameter	Weight	Grade	Design Coupling	Burst Strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(short or long threaded)	(psi)
4-1/2"	8470'	4.5"	4"	11.6	L-80 CRA	Premium	7780

Packer Type and Material	Packer Setting Depth	Length	Nominal Casing Weight	Outer Diameter	Inner diameter
	(feet)	(inches)	(lb/ft)	(inches)	(inches)
Permanent Sealbore Packer, CRA	8430'	30.3	26 - 32	5.875"	4.00"

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

Figure 8. Injection Well 357-7R, CO_2 Injection Schematic