Evaluation of Construction and Plugging Procedures for Injection Well 355-7R at the CTV-Elk Hills Monterey Formation A1-A2 Class VI Project

This well construction and plugging evaluation report for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration (GS) project summarizes EPA's evaluation of several related activities associated with the construction and plugging of the 355-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands. These activities are described in an update to CTV's Class VI permit application that was submitted on December 2, 2021, including updated sections of the permit application narrative (Narrative A2), Attachments D2 and G2, and logging and testing information about the 355-7R injection well. This review also identifies preliminary questions for the applicant. (Note that the permit application contains common information that applies to both injection wells planned for the project. Therefore, there is some repetition between this evaluation and EPA's evaluation of attachments relevant to Well 357-7R. This is necessary to provide a complete evaluation for each Class VI permit record.)

Injection Well Construction

Narrative A2 and Attachment G2 describe the construction design for Well 355-7R. Well 355–7R is an existing Class II pressure maintenance well, approved by CalGEM (California Geologic Energy Management Division) to inject up to 50 mmscf (million standard cubic feet) of CO_2 per day. The applicant states that Well 355–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2. Well 355-7R was drilled in 1973; Narrative A2 contains the following brief construction details regarding Well 355-7R:

1. The well design exceeds criteria for all anticipated load cases, accounting for 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. 13-3/8" and 9-5/8" casing string were cemented with 30 cubic feet and 35 cubic feet returns to surface, respectively.
4. A 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 the base of the 7" casing to approximately 5,200 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 provide 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.

Table 5: Temperature profile and casing construction data 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 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14 - 520 520 - 3,393	9.625	8.835	40	N-80 K-55	Long	31	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	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

Table 5 of the Narrative A2, reproduced above, matches the casing specifications listed in Attachment G2 for Well 355-7R (see below). Attachment G2 also includes tubing and packer specifications for Well 355-7R, which are excerpted below. The tubing and packer specifications in Attachment G2 mostly correspond to Table 7 of the Narrative A2, however there appear to be typos regarding: tubing outside diameter and weight (in the Narrative A2) and regarding packer tensile rating (in Attachment G2).

Injection Well 355-7R Construction Details (from Attachment G2)

Casing Specifications

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 - 60	20.000	19.5	52	H-40	Short	31	875	90
Surface	14 - 500	13.375	12.715	48	H-40	Short	31	1,727	740
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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	31	8,160 4,360 4,980 7,240 8,160	7,020 3,270 4,320 5,410 7,020

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	8,398	4.500	3.920	13.5	L-80	Long	9,020	8,540

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)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
10,0000	8,000	8,000	6.466	6.184

CTV states that all the well materials and the stainless-steel wellhead are designed to be compatible with the CO_2 injectate and expected subsurface temperature and pressure regimes. The surface and downhole pressure gauge and logging tool specifications detailed in Tables 8-14 of the quality assurance surveillance plan (QASP) are consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. The Applicant notes that the Class G Portland cement used to complete well 355-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor and long string (injection string), had cement returns to surface according to Narrative A2. A CBL indicated that the top of cement in the injection string annulus is above 5,200 ft, which is above the Reef Ridge Shale upper confining layer, reported as 6,929 ft-7,962 ft true vertical depth (TVD), per Table 1 of the Narrative A2.

The cement integrity is supported by information from existing wells and a CBL in Well 355-7R. California Resources Corporation (CRC) has conducted standard annulus pressure tests (SAPTs) historically to ensure continued internal mechanical integrity of the well. No SAPT results were provided in the permit application materials, however. These tests will also be conducted prior to injection and every five years thereafter and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1 of Attachment G2 is illegible, so information such as geologic formation tops (for the injection and confining zones and the Base of the USDW), perforation depths, and casing depths, cannot be evaluated. The applicant will need to resubmit an updated, resolvable casing diagram for Well 355-7R that demonstrates proper construction, including either that the base of the lowermost USDW is covered by the surface casing in accordance with 40 CFR 146.86(b)(2), or how the construction otherwise ensures protection of USDWs, per 40 CFR 146.86(a)(1). According to the tables on Page G2, the surface casing is set to a depth of 500 feet; however, the average depth of the Tulare Formation (Upper and Lower) within the AoR is 600-2,500 ft (as reported on pg. 31 of the Narrative). EPA is requesting clarification of the depth of the Upper Tulare Formation (the lowermost USDW) in its questions on the geologic narrative, and CTV's response to this question will help confirm whether the surface casing is sufficiently deep to protect the lowermost USDW. . Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.

Multiple sources of anthropogenic CO_2 are being considered for the Elk Hills A1-A2 Injection Project. These include the Elk Hills NGCC Power Plant as well as third party existing and proposed industrial sources in the Southern San Joaquin Valley area. The CO_2 stream will be approximately 95% CO_2 by volume, also containing residual water (25#/mmscf) and oxygen (<50 parts per million) which will be controlled for corrosion mitigation. The applicant notes that the CO_2 stream corrosivity is low if the entrained water is kept in solution with the CO_2. The applicant states that the 25#/mmscf water volume specification is conservative and should allow for water solubility across super-critical CO_2 operating ranges. The water content of 25#/mmscf equates to approximately 0.4 ppm and is unlikely to present corrosion concerns. However, water solubility will vary with depth and time as temperatures and pressures change. Gas phase CO_2 is likely to exist in the lowered depths of the tubing string early in the injection phase, resulting in the possibility of existing free phase water. According to Well 355-7R Construction Details (Attachment G2), excerpted above, L-80 tubing is currently installed in the well. CTV states that they plan to configure the well with corrosion-resistant tubing; however, the type of tubing planned for installation is not specified. No details were provided as to the amount of time free phase water can persist without severely damaging the tubing. According to Table 1 in *Attachment C – Testing and Monitoring Plan,* CTV will analyze the following CO_2 stream constituents based on established ASTM methods: O_2, N_2, CO, CH_4, H_2S, total hydrocarbons, total Sulfur, and CO_2 purity. It appears that H_2O was excluded from the CO_2 stream constituent analysis and will need to be included (a request was provided with the testing and monitoring evaluation). Additionally, the applicant does not state if the compatibility of the CO_2 stream and well construction components will be determined prior to well operation. Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.

The well construction and cementing criteria described in the Narrative A2 and Attachment G2 appear to be acceptable, however an updated casing diagram, in addition to addressing the deficiencies noted below, is needed. Additionally, the applicant did not provide a pre-operational testing plan to test the compatibility of the injectate with well construction materials. This will be needed prior to operation of Well 355-7R.

The Emergency and Remedial Response Plan, described in Attachment F, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. However, the applicant did not provide discussion regarding safety valves and automated shut-off devices in Attachment G2.

The permit application Narrative (on pg. 2) notes that the "…continuously subsiding [San Joaquin] basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide." The effects of subsidence on the mechanical integrity of injection wells has been cited as a concern in other California oil fields, and some operators have developed mitigation measures to relieve stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings).

Questions/Requests for the applicant:

- *There appear to be typos regarding tubing outside diameter and weight and the packer tensile rating for Well 355-7R in Attachment G2. Please reconcile these inconsistencies:*
    - *The outside diameter of the injection tubing (on Table 6 of Narrative A2) is 00.*
    - *The tensile rating (of "10,0000" lbs) for the packer on pg G2 of Attachment G2.*
- *Please explain how the current well architecture—with the 7" (injection/long) string cemented to 5,200 ft, which is above the confining layer was engineered and constructed to ensure protection of USDWs, per 40 CFR 146.86(a)(1).*

- *Please describe the fluid in the annulus between the tubing and the long string casing, including how it is a non-corrosive fluid, as required by 40 CFR 146.88(c).*
- *Please describe the specific materials that will be removed from well 355-7R, and provide details regarding the corrosion-resistant tubing, packer, and wellhead materials that will replace these.*
- *Is Well 355-7R equipped with automatic shutoff systems connected to the real-time surface monitoring equipment and alarms, as required at 146.88(e)(2)? If so, please describe these systems in Attachment G2 and how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G2 to include these required components.*
- *Please discuss the duration that free phase water is expected to be present at the beginning of the injection phase and the corresponding impact on tubing integrity. For example, please provide additional discussion regarding the study of this phenomenon, e.g., in existing, nearby* CO_2 *injection wells.*
- *Figure 1 of Attachment G2 is illegible. Please submit an updated, resolvable diagram for Well 355-7R that includes the following information:*
    - *All relevant formations (e.g., the injection and confining zones and the base of the USDW);*
    - *Either surface casing that extends through the base of the USDW, per 40 CFR 146.86(b)(2), or an explanation of how the well's construction otherwise ensures protection of USDWs, per 40 CFR 186(a)(1);*
    - *The depths of the perforations; and*
    - *Please label the well diagram to indicate that the well is a Class VI (i.e., not Class II) well.*
- *What is the surface elevation (i.e., relative to mean sea level) at the location of the well?*
- *Please include relevant information from Narrative A2 about the construction of the well into Attachment G2 for completeness.*
- *Please provide versions of Attachments A2 and G2 in full page mode to improve their legibility.*
- *For completeness, please include the description of testing of the deep monitoring wells (i.e., as described in Attachment G) in Attachment G2.*
- *Please explain how the injection well's design will mitigate potential shallow compression related to land subsidence while still complying with the requirement to cement to the surface.*
- *Please provide the most recent SAPT reports for the well.*

Injection Well Pre-Operational Testing

The proposed pre-operational formation and well testing program for Well 355-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in Narrative A2 and in Attachment G2. Attachment G2 identifies several tests that CTV indicates have been performed and were provided. These include deviation checks, a cement bond log, and open-hole well logs. CTV notes that mechanical integrity tests, including a temperature log and SAPT, were also acquired after the drilling of 355-7R; however, these were not provided. Attachment G2 also indicates that a SAPT, Temperature Log, and Radioactive Tracer Survey will be conducted prior to injection operations.

In the Testing and Monitoring Plan, CTV says that it "does not currently plan to complete pressure fall off testing" (pg. 10), given the extent of available information about the Monterey Formation A1-A2

Sands. However, a pressure fall off test must be performed prior to injection. See the testing and monitoring evaluation for additional discussion.

Cement bond logs and SAPTs of the injection wells are listed in Table 1 of the QASP (Summary of testing and monitoring). It appears that a SAPT was previously run and will be run prior to injection, but Attachment G does not indicate that a CBL will be run. Clarification on the well testing to be performed is needed. Despite the deficiencies listed here, the proposed testing and logging program is considered comprehensive and generally acceptable.

Questions/Requests for the applicant:

- *Please provide the results of the temperature log and SAPT that were performed on Well 355-7R.*
- *Figure 2 of the 355-7R Logging and Testing document is illegible. Please provide a legible log plot demonstrating open-hole well logs for Well 355-7R.*
- *The CBL provided with the Logging and Testing plan does not cover the entire injection and confining zones. Please provide a CBL that covers the entire injection and confining zones and explain the varying amplitude and seismogram signal throughout both zones.*

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the review. This information is summarized below (along with the planned tests that will address each data need) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c).

Regional Geology and Geologic Structure

- Confirm hydraulic separation of the Monterey A1-A2 reservoir and the Monterey Formation A3-A11 reservoir (anticipated testing method: downhole pressure measurement via gauges).
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (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 Testing and Monitoring Plan (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 that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; also, core, log, seismic analysis have been performed).

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).
- 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 ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

- 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).

Well Stimulation

The application materials do not include a stimulation plan. 40 CFR §146.88(a) requires that all stimulation programs be approved by the EPA Director as part of the permit application and incorporated into the permit. If the initial permit does not include a stimulation program and the operator identifies a need for well stimulation later in the life of the project, a major permit modification would be necessary. EPA suggests that CTV consider preparing and including a proposed well stimulation program in the permit application. A generic stimulation program may be used for the pre-construction phase of the project.

Questions/Requests for the applicant:

- *To avoid the need for a permit modification if stimulation were to become necessary in the future, EPA requests that CTV prepare a draft stimulation plan. EPA can provide some additional guidance about the content of the plan, but anticipates that the plan should describe:*
    - *The stimulation fluids to be used, including any additives (e.g., corrosion inhibitors, clay inhibitors, biocides, complexing agents, or surfactants) or diverting agents; and*
    - *Step-by-step procedures that would be employed during stimulation.*

Monitoring Well Pre-Operational Testing

The pre-operational formation well testing program for monitoring wells 342-7R-RD1 and 327-7R-RD1 is described in Attachment G. These wells have been drilled and completed, and data from deviation checks and open-hole well logs were acquired. Demonstration of mechanical integrity will be conducted via mechanical integrity logs and tests prior to injection operations. A SAPT will also be conducted for each monitoring well. However, the type of MIT methods planned for mechanical integrity demonstration prior to injection was not discussed.

Questions/Requests for the applicant:

- *What specific MITs are planned for monitoring wells 342-7R-RD1 and 327-7R-RD1?*
- *Please include information about MITs on the deep monitoring wells in Attachment G2 for completeness.*

Injection Well Plugging Plan

CTV states that, before plugging the injection well, it will determine the bottom-hole pressure needed to successfully squeeze cement for plugging operations. At least one external MIT will be conducted prior to plugging, including but not limited to a temperature log. The temperature log will be run over the entire depth of the well and the results will be compared to temperature logs performed before and during CO_2 injection. Generic procedures for plugging wells are described in the attachment. Specific plugging procedures will be needed.

During plugging operations, CTV states that the cement slurry and displacement fluids will be over-balanced to prevent reservoir fluids from entering the wellbore during cementing operations. Table 1 of Attachment D2—Injection Well Plugging Plan, describes the various types of plug information and is excerpted below. The plugging details listed in Table 1 are consistent with injection well construction details; however, the applicant did not provide a plugging diagram. Also, because the well diagram (Figure 1 of Attachment G2) and the perforation depths are illegible, it is not possible to confirm that the placement of plugs, as described below, are appropriate.

Plug #1 (bottom-hole cement plug) will cover all perforations and will extend at least 100 ft. above the uppermost perforations. However, the uppermost perforation depth is illegible on the well diagram, thus preventing confirmation of cement coverage by Plug #1 to 100 ft above the uppermost perforation.

Table 1: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.184	6.184, 6.276, 6.366	6.184, 6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,692	8,371	1,384	25
Sacks of cement to be used (each plug)	58	1322	258	4
Slurry volume to be pumped (ft^3)	67	1520	297	5
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8,371	1,384	25	0
Bottom of plug (ft)	8,692	8,371	1,384	25
Type of cement or other material	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)	Running Plug (Coiled Tubing)

The Base of the USDW will be covered by Plugs #2 and #3. If cement exists behind the casing and across the Base of the USDW, a 100 ft. cement plug will be placed inside the casing across this interface. If the top of cement behind the casing is found to be below the Base of the USDW, a cement squeeze will be performed through perforations. Additionally, a 100 ft cement plug will be placed inside the casing across the freshwater-saltwater interface. Plug #4 (the surface plug) will plug the casing at the surface with at least 25 ft of cement. The diameter of the boring for Plug #4 listed in Table 1 above (6.366 in.) does not correspond to the Well 355-7R construction details listed in Attachment G2 (6.184 in). All cement plugs will be composed of a Class G cement blend that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The applicant does not explicitly state if this is the same cement used to cement the casing strings in well construction.

The plugging procedures that will be used to place these plugs appear to be acceptable, provided responses to the questions below are adequate. The plugging plan does not include a schematic.

Questions/Requests for the applicant:

- *Please include "flushing" among the steps to be completed prior to injection well plugging, in accordance with 40 CFR 146.92(a).*
- *Please provide a plugging schematic that includes:*
  - *Labels of the USDW and other relevant formations (i.e., the injection and confining zones) and all perforations; and*
  - *Plug coverage (for Plugs #1-4) that corresponds to the depth of the Base of the USDW and the perforations in Figure 1 of Attachment G2.*
- *Please provide a full-page printout of Attachment D2.*

- *Please confirm that the Class G cement blend is the same as the Class G Portland cement that was used in the well's construction, and that this cement is CO_2-resistant.*
- *Please revise the diameter of boring for Plug #4 listed in Table 1 of Attachment D2 (6.366 in.) to correspond to the Well 355-7R construction details listed in Attachment G2 (6.184 in).*