Evaluation of Construction and Plugging Procedures for Injection Well 357-7R 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 construction and plugging of the 357-7R injection well to inject CO_2 into the Monterey Formation A1-A2 Sands. These activities are described in the permit application narrative, and Attachment D to the permit application dated August 30, 2021, and an updated version of Attachment G (a file entitled Attachment G—Final), submitted on December 2, 2021. 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 the attachments relevant to Well 355-7R. This is necessary to provide a complete evaluation for each Class VI permit record.)

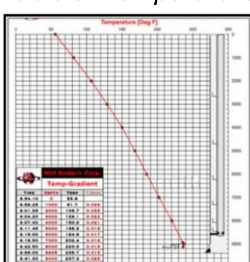
Injection Well Construction

Attachment A--Narrative (referred to as The Narrative herein) and Attachment G describe the well construction design for Well 357-7R. Well 357-7R is an existing Class II pressure maintenance well that is currently permitted 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 357–7R was constructed using CO_2-resistant materials and can meet operating conditions for the injection of CO_2.

Well 357-7R was drilled in 1980; the Narrative contains the following brief construction details regarding Well 357-7R:

1. Descriptions of the conductor, surface, and intermediate casing.
2. Cement across each casing string with cement returns to surface during completion. A cement bond log was acquired to confirm cement along the well.
3. Casing specifications that exceed the operating conditions of the well (per Table 5 of the Narrative, reproduced below).
4. Long string casing diameter of seven inches with stainless steel tubing of 4.5 inches. This casing and tubing size will enable monitoring devices to be installed, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted.

Table 5: Temperature profile and casing construction data 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	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

Table 5 of the Narrative, pictured above, corresponds to the casing specifications listed in Attachment G for Well 357-7R, pictured below. Attachment G also includes tubing and packer specifications for Well

357-7R, which are excerpted below. The tubing and packer specifications in Attachment G mostly correspond to Table 7 of the Narrative, however the packer burst strength (psi) and collapse rating (psi) differ between the documents.

Injection Well 357-7R Construction Detials (Attachment G)

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	20-60	20.000	19.5	52	H-40	Short	31	875	90
Surface	20-501	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	20-3,517	9.625	8.835	40	N-80	Long	31	5,750	3,090
Long-string	20-8,990	7.000	6.184 6.276 6.366	29 26 23	N-80	Long	31	8,160 7,240 6,340	7,020 5,410 3,830

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	8,454	4.500	3.826	15.2	13CR-95	Long (premium)	12,450	12,760

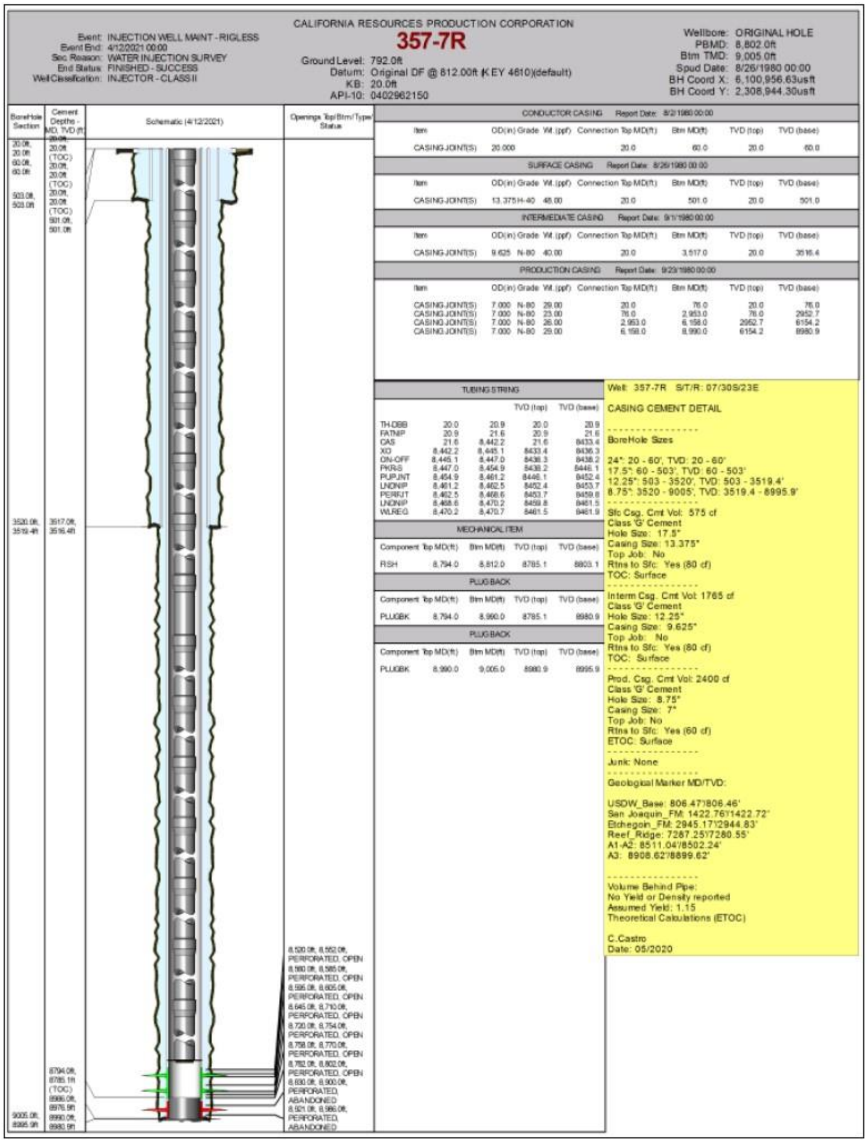
Packer Specifications

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	8,447	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

All well materials noted in the tables above, in addition to 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 mostly consistent with the well construction equipment and surface and subsurface temperature and pressure conditions. However, the surface pressure field gauges listed in Tables 10, 11, 12, and 14 of the QASP show a maximum calibrated working pressure of 3,000 psi, which is lower than the maximum surface injection pressure of 3,800 psi. The Applicant notes that the Class G Portland cement used to complete Well 357-7R, with cement to surface for each stage, has been used extensively in enhanced oil recovery injectors. Each casing string, except for the surface conductor, had cement returns to surface according to Figure 1 of Attachment G (reproduced below). The cement integrity is supported by data from existing wells and a cement bond log (CBL) in Well 357-7R. California Resources Corporation (CRC) has conducted MITs and standard annulus pressure test (SAPTs) every five years (no SAPT results were provided with the application materials, however). These tests will also be conducted prior to injection and are discussed further in the *Pre-Operational Testing* section of this evaluation.

Figure 1: Injection Well 357-7R casing diagram (Attachment G)



Relevant geologic formation tops were noted in Figure 1 of Attachment G. The figure shows that the Base of the USDW is approximately 806 ft. TVD (true vertical depth), which is behind both the long string and intermediate casing. The surface casing is set to a depth of 501 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 in accordance with 40 CFR 146.86(a)(1). Based on the aquifer exemption record of decision for the Elk Hills Oil Field, the Upper Tulare is shallower than 400 feet.

The San Joaquin and Etchegoin Formation tops are located at depths of 1,422 ft TVD and 2,945 ft TVD, respectively, and are also protected by the long string and intermediate casing. The Reef Ridge Shale (confining zone), Monterey Formation A1-A2 (reservoir), and Monterey Formation A3 are located at depths of 7,281 ft TVD, 8,502 ft TVD, and 8,900 ft TVD, respectively; these three formations will be behind the long string casing. The depth of the Etchegoin Formation on the well diagram is consistent with information in the permit application narrative, and the depth of the Monterey Formation A1-A2 Sands differs from the depth reported on Figure 13 of the permit application narrative of 8,403 ft – 9,598 ft TVD.

The perforations for Well 357-7R are shown at depths of 8,782 to 8,830 feet. The perforations are also described in the AoR and Corrective Action Plan; however, they are presented in depth relative to mean sea level, so confirmation that the depths are consistent is not possible.

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. Stainless steel (13 CR-95) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. However, no details were provided as to the amount of time that 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.

Figure 1 of Attachment G, excerpted above, demonstrates the casing design for Well 357-7R. The well construction and cementing criteria described in the Narrative and Attachment G appear to be acceptable, except as noted in the questions below. However, 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 357-7R.

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 describe safety valves and automated shut-off devices in Attachment G.

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:

- *Please reconcile the following differences between Attachment G and Table 7 of the Narrative:*
  - *The burst rating of the packer is 8,160 psi on Table 7 of Attachment A and 8,000 psi on page G3, and*
  - *The tensile strength of the packer on page G3 has a typo, with an extra 0 in "10,0000."*
- *There are several discrepancies in the descriptions of Well 357-7R between tables 5, 6, and 7 of Attachment A and the tables on pages G2 and G3 of Attachment G. Please make the tables and the well bore diagram in Attachment G (if needed) consistent.*
  - *Attachment A, Table 5, and the Table on page G2 indicate that the intermediate casing in Well 357-7R is to a depth of 3,517 ft; on Table 6, this depth is 3,516 ft.*
  - *The conductor casing material is H-40 in Attachment A, Table 5 and Attachment G, and it is J-55 in Table 6.*
  - *The surface casing material is H-40 in Table 5 and in Attachment G, pg. 2, and it is H-80 in Table 6.*
- *Please verify that the annulus between the tubing and the long string casing is filled with a non-corrosive fluid, as required by 40 CFR 146.88(c), and describe the fluid.*
- *Please confirm that the surface casing extends through the base of the lowermost USDW, in accordance with 40 CFR 146.86(b)(2). If it does not, please explain how the well will otherwise meet the requirements of 40 CFR 146.86(a)(1).*
- *Is Well 357-7R equipped with real-time surface monitoring equipment and alarms and, if so, are these connected to automatic shutoff systems, as required at 146.88(e)(2)? If so, please describe these in Attachment G and describe how the safety valves and shut-off devices will be linked to the continuous injection and annulus monitoring system. If not, please update Attachment G to include these required components.*
- *Please provide additional detail about the construction procedures for Well 357-7R, for example, to be consistent with the level of detail in the construction procedures for Well 355-7R on page 2 of Attachment A2.*
- *Please include relevant information from the narrative (Attachment A) about the construction of the well into Attachment G for completeness.*
- *In Figure 1 of Attachment G (Well 357-7R casing diagram), the top of cement for the existing bottom-hole plug is listed at 8,794 ft MD / 8,785 ft TVD while the base of the open perforated interval is 8,802 ft. Please revise Figure 1 to correct this inconsistency.*
- *Please label the well diagram to indicate that the well is a Class VI (i.e., not Class II) well.*
- *Please explain how the injection well's design will mitigate potential shallow compression resulting from land subsidence and comply with the requirement to cement to the surface.*
- *What is the surface elevation (i.e., relative to mean sea level) at the location of the well?*

- *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.*
- *Please include alternative pressure monitoring devices to those listed in Tables 10, 11, 12, and 14 of the QASP with pressure field gauges with higher pressure ratings to function at the maximum surface injection pressure of 3,800 psi safely and reliably.*
- *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 357-7R required at 40 CFR 146.82(a)(8) and 146.87 is described in the Narrative and in Attachment G. Table 1 of the Pre-Operational Testing Plan for Well 357-7R identifies several tests that CTV indicates have been performed, and that these were provided. These include deviation checks, cement bond log, open-hole well logs, mechanical integrity test, SAPT, injection zone and confining layer core, reservoir conditions and fluid, injection zone and confining layer fracture gradients, and pressure testing. Attachment G 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:

- *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?*

Injection Well Plugging Plan

Plugging details for Well 357-7R are provided in Table 1, which is reproduced below. Before plugging the injection well, CTV 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.

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	6.366	6.366	6.366
Depth to bottom of tubing or drill pipe (ft)	8,785	2,970	1,448	25
Sacks of cement to be used (each plug)	65	25	25	5
Slurry volume to be pumped (ft^3)	75	28	28	6
Slurry weight (lb./gal)	15.6	15.6	15.6	15.6
Calculated top of plug (ft)	8,427	2,845	1,323	0
Bottom of plug (ft)	8,785	2,970	1,448	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)

CTV states that, during plugging operations, 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 D—Injection Well Plugging Plan describes the various types of plug information, which 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.

Plug #1 (bottom-hole cement plug) will cover all perforations and will extend at least 100 ft. above the uppermost perforations. However, based on Figure 1 of Attachment G, the uppermost perforations occur at 8,520 ft, resulting in the top of the plug occurring 93 ft above the uppermost perforation. The cement volume will need to be revised for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.

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. However, Figure 1 of Attachment G lists the Base of the USDW at 806 ft TVD. The inconsistency in depth between Plugs #2, #3, and the Base of the USDW will need to be resolved, and the corresponding well construction and plugging information updated accordingly.

Plug #4 (the surface plug) will plug the casing at the surface with at least 25 ft of cement. 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 revise the cement volume for Plug #1 to ensure at least 100 ft of cement coverage above the uppermost perforation.*
- *Please reconcile the inconsistency in depth between Plugs #2, #3, and the Base of the USDW as shown in Table 1 of Attachment D and Figure 1 of Attachment G.*
- *Please correct the typo in the second bullet at the bottom of Attachment D, pg. 3, referring to the ">10,000 mg/L DTS."*
- *Please provide a plugging schematic and label the USDW and other relevant formations (i.e., the injection and confining zones) and perforations on the plugging diagram.*
- *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.*