ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills 26R Storage Project

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate four CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) 26R reservoir located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the 26R Monterey Formation reservoir up to 1.46 million tonnes annually for 26 years with injection starting in 2025. The anthropogenic CO_2 will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of four injectors, surface facilities, and monitoring wells. This supporting documentation applies to the four injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

GSDT Submission - Project Background and Contact Information

GSDT Module: Project Information Tracking
Tab(s): General Information tab; Facility Information and Owner/Operator Information tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

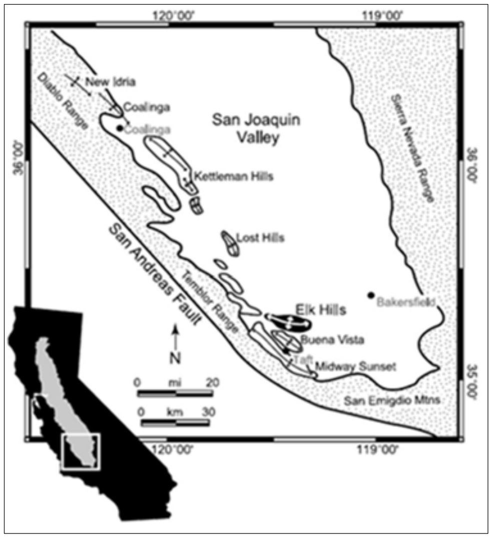
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation 26R sequestration reservoir was discovered in the 1940's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding 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 basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

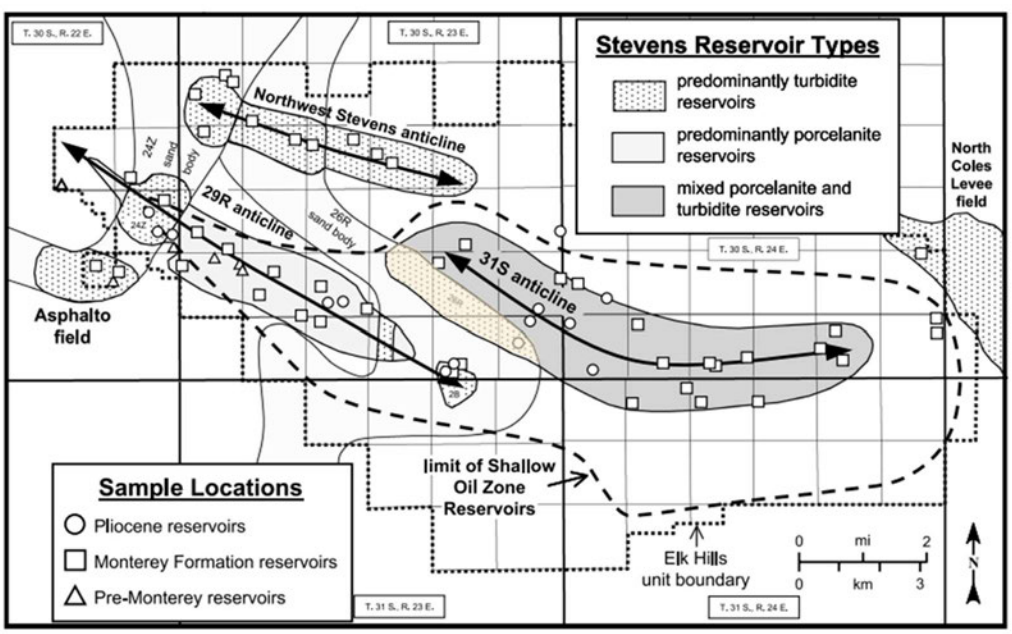
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure sub-divides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

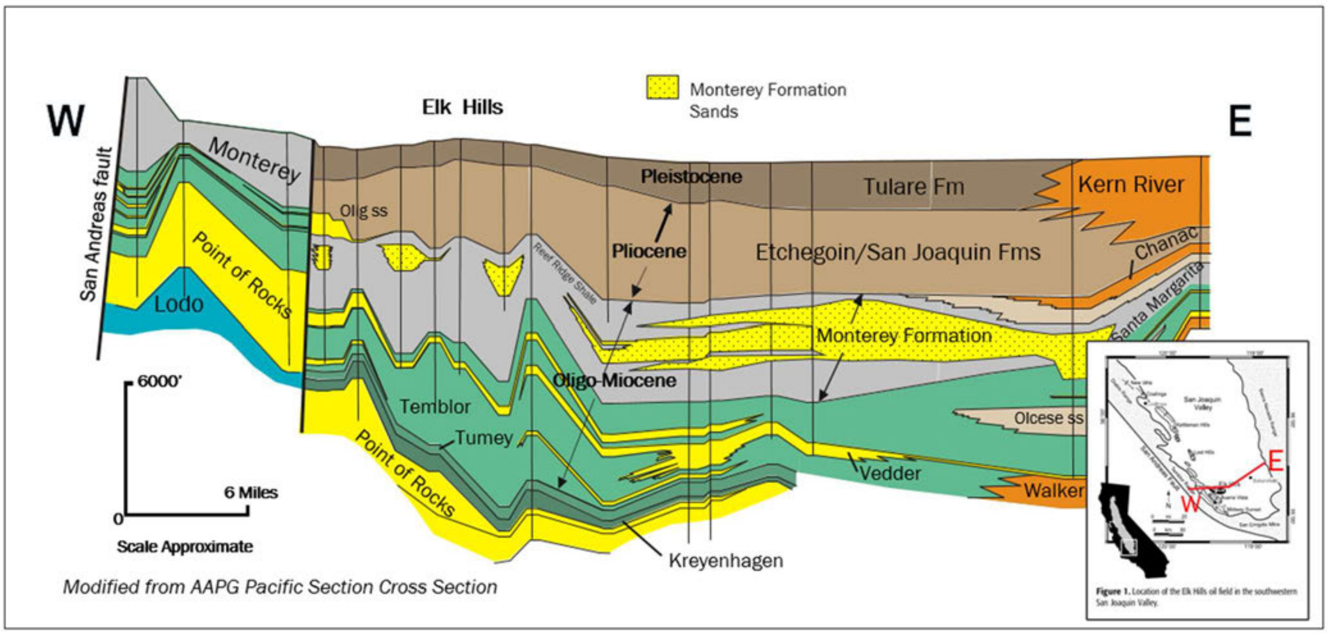
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation 26R CO_2 sequestration reservoir is located in the 31S anticline (Zumberge, 2005).



Geological Sequence

Figure 3 shows the stratigraphy of the EHOF. The Miocene aged Monterey Formation 26R reservoir at the 31S anticline is approximately 6,000 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by over 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



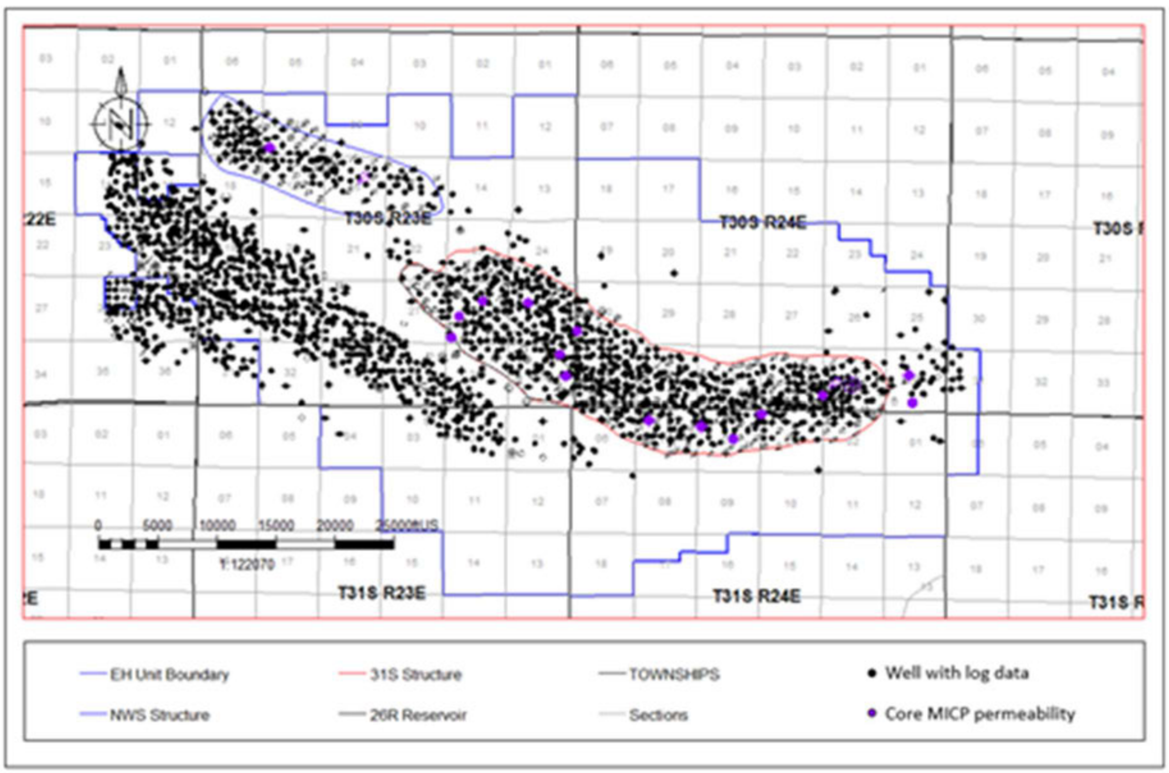
Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin and serves as the primary confining layer for the Monterey Formation 26R reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 4), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

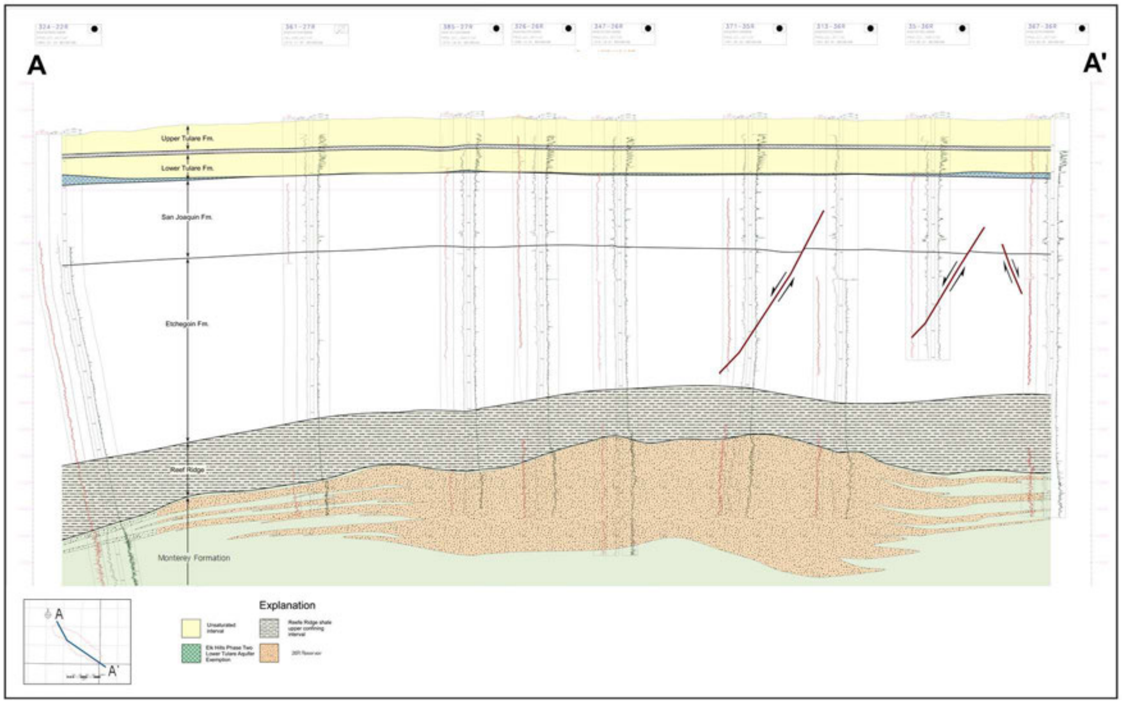
Figure 4: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core from the Monterey Formation are shown in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 5 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 5: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the 31S anticline.



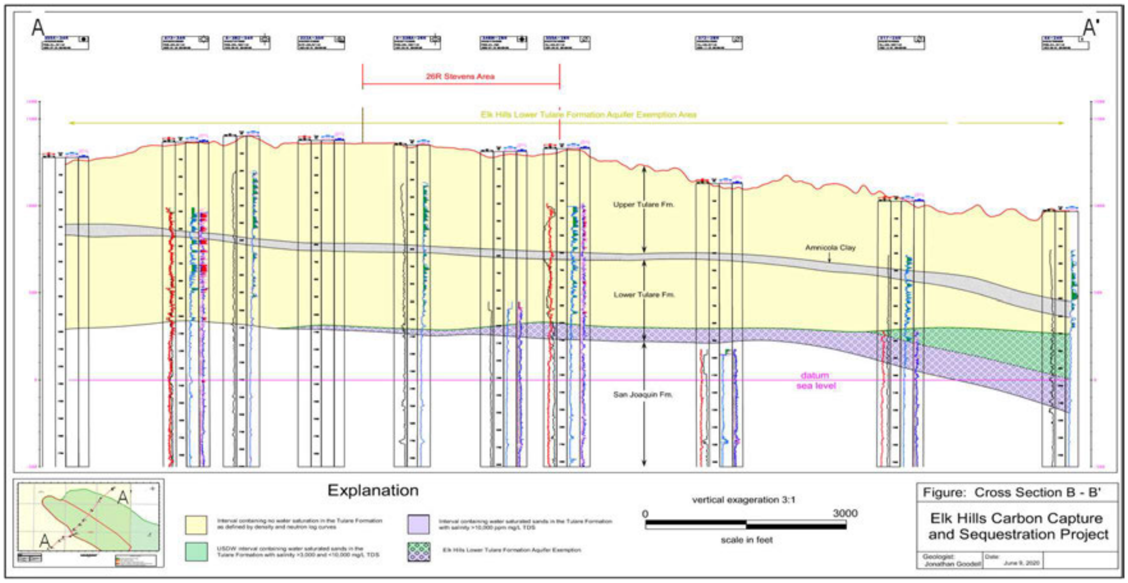
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 6), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare is an unsaturated air sand above the Monterey Formation 26R reservoir. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 6: The Tulare Formation consists of the Upper Tulare and Lower Tulare separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer and the Upper Tulare is an unsaturated air sand.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and conglomerate of the Tulare Formation interfinger with the San Joaquin beds (Maher et al., 1975). The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000’ in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

The Etchegoin Formation will dissipate CO_2 and CTV will drill and equip a monitoring well to assess formation pressure and water quality changes during the project.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 5,000 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

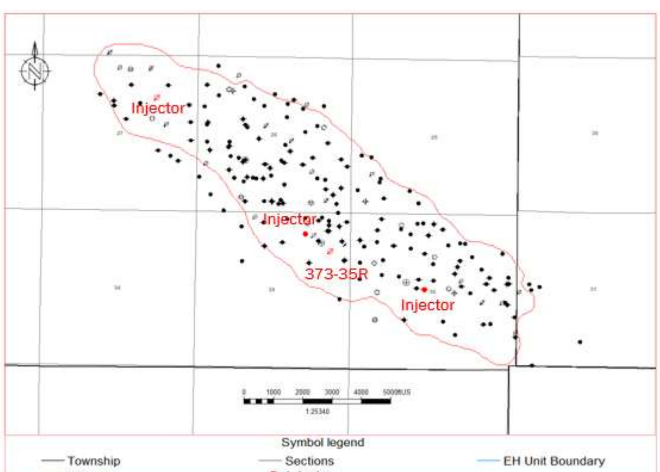
The Reef Ridge directly overlies the 26R Monterey Formation sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

The 26R Monterey Formation sequestration reservoir is approximately 6,000 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 25% and 45 mD, respectively.

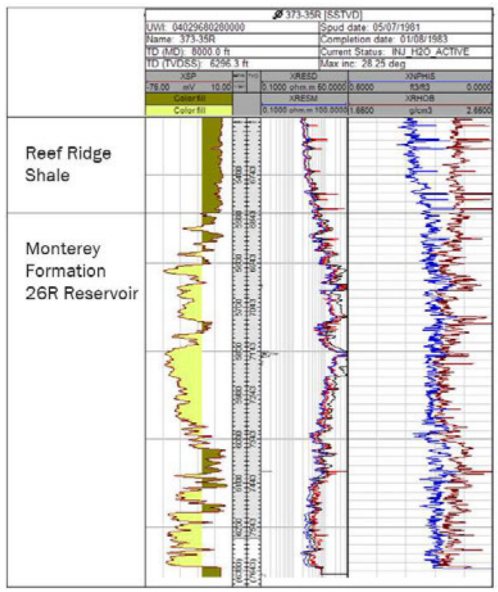
The 26R Monterey Formation sands were deposited as a turbidite channel influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. The turbidite sands were largely aggregational with minimal erosive deposition.

Figure 7: AoR and injection well location map for the Elk Hills 26R project. Well location shown is defined by the well path intersection with the Monterey Formation.



The reservoir is continuous across the AoR and the sands pinch-out up-dip and on the channel edges (Figure 5). As such, the 26R Monterey Formation sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

Figure 8: 373-35R injector showing the Monterey Formation 26R reservoir.



Summary:

The Monterey Formation 26R project will be developed with four injectors (Figure 7), three wells to be drilled prior to the initiation of injection and the existing 373-35R well (Figure 8).

The storage reservoir depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as vertical confinement by the Reef Ridge Shale and lateral reservoir confinement.

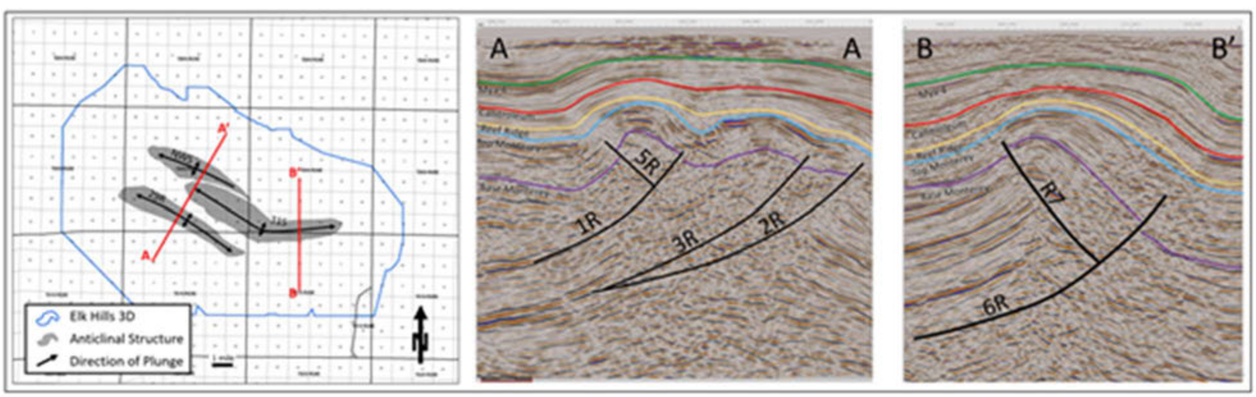
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 9 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the 26R anticline are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

Figure 9: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the 26R Monterey Formation sands:

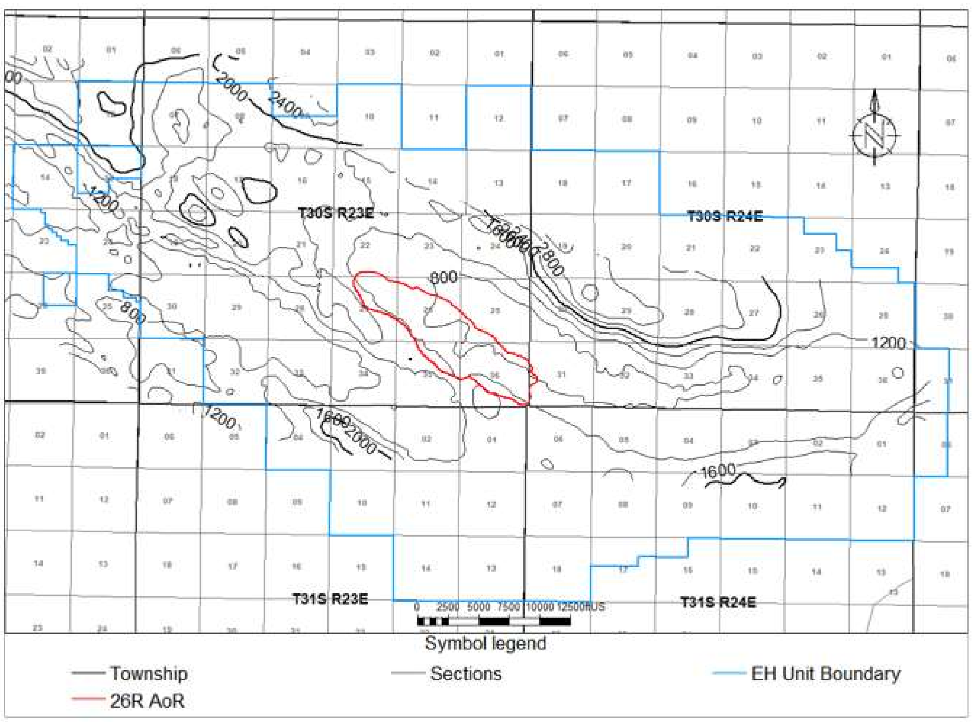
1. There are no faults that extend into the confining Reef Ridge Shale (refer to Figure 9).

2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,000 feet (Figure 10) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 10: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



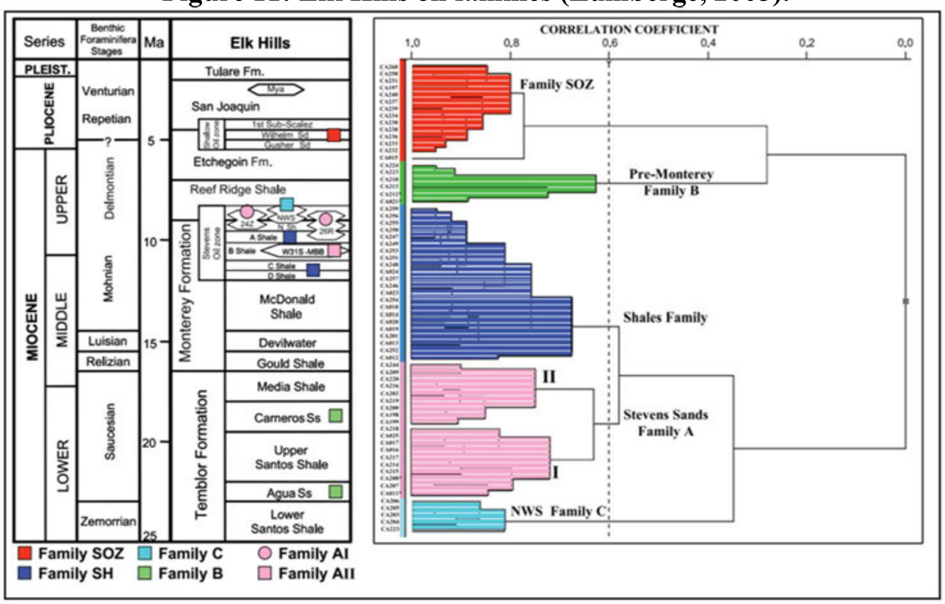
2. Waterflooding and Gas Injection

Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than 114 million barrels of water and 841 billion cubic feet of gas have been injected into the 26R Monterey Formation sands. There has been no evidence of water or gas migrating through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically confined.

3. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 11) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

Figure 11: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

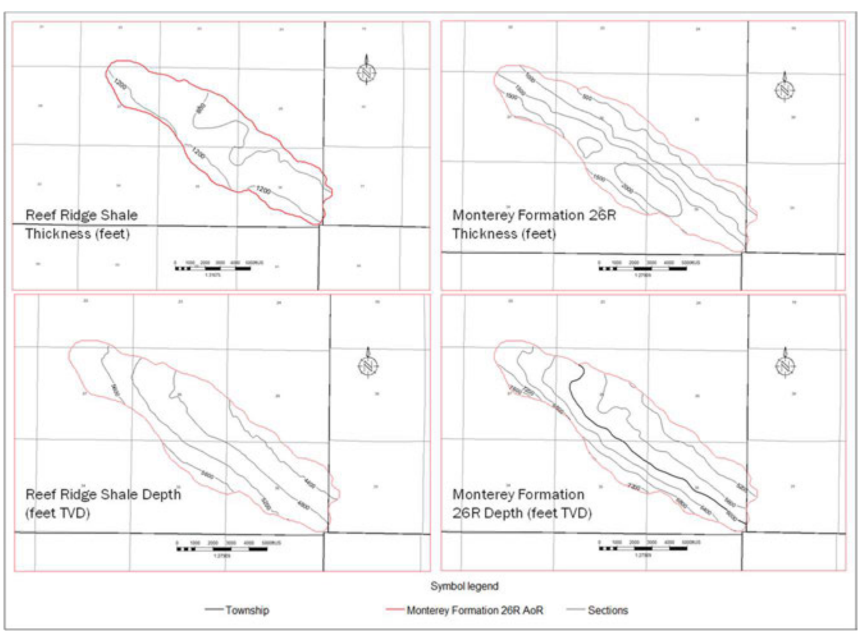
Depths and thickness of the 26R Monterey Formation reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 12) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability is due to deposition of the Monterey Formation sands.
3. Monterey Formation thickness variability is from pinch-out of the reservoir on the 31S structure.

Table 1: Reef Ridge Shale and Monterey Formation 26R thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone	Thickness (feet)	640	1,598	985.1
Reef Ridge Shale	Depth (feet TVD)	4,084	5,949	4,992
Reservoir	Thickness (feet)	255	2,497	1,283
Monterey Formation 26R Reservoir	Depth (feet TVD)	4,828	7,827	6,014

Figure 12: Reef Ridge Shale and Monterey Formation 26R thickness and depth maps.



Variability in the thickness and depth of the either the Reef Ridge Shale or the 26R Monterey Formation sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

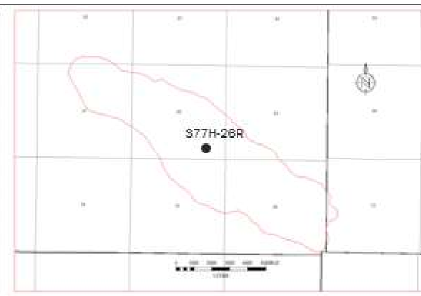
Mineralogy

Monterey Formation 26R:

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Well 377H-26R (Figure 13) provides an example of the mineralogy for the reservoir interval in 373-35R. Clean reservoir sand intervals have an average of 39% quartz, 49% potassium feldspar, albite and oligoclase as well as 12% total clay.

Figure 13: Monterey Formation 26R sand mineralogy from well 377H-26R.

	Whole Rock Mineralogy (Weight %)							Relative Clay Abundance (Normalized to 100%)			
Depth	Quartz	K-Feldspar	Plagioclase	Siderite	Pyrite	Gypsum	Total Clay	Illite / Smectite *	Fe-Illite & Mica	Kaolinite	Chlorite
5912.5	38	15	32	0	1	1	13	28	65	4	3
5981.5	40	16	32	0	1	1	10	29	56	11	4
6046.0	40	14	29	0	2	0	15	32	45	20	3
6046.9	37	17	37	0	1	Tr	8	36	45	15	4
6066.4	41	18	32	0	1	0	8	30	41	26	3
6097.1	41	16	34	0	0	0	9	19	53	25	3
6113.3	35	19	34	0	1	0	11	16	46	33	5
6141.0	44	6	17	3	3	1	26	75	22	3	0



Reef Ridge Shale:

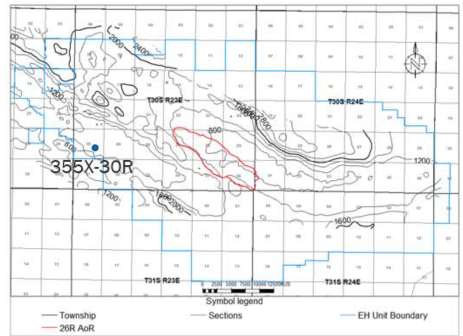
Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 14). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AoR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 14: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.

FTIR Mineralogy
(Weight Percent)

Depth (ft)	Density (g/cc)	Quartz	Albite	Oligoclase	Andesine	K-Feldspar	Calcite	Dolomite	Pyrite	Opal-A	Opal-CT	Chert	Cristobalite	Total Clay	Kaolinite	Chlorite	Illite+Smectite
5285.5	2.51	12	9	0	10	10	0	0	0	0	26	0	0	33	5	3	25
5290.0	2.38	0	5	0	0	6	2	0	2	0	57	0	19	9	5	0	4
5291.8	2.51	0	7	0	3	9	3	0	3	0	39	11	0	25	9	0	16
5295.5	2.49	0	7	0	0	8	3	0	2	0	42	12	0	26	8	0	18
5299.2	2.52	0	0	0	0	5	0	35	1	0	35	0	19	5	4	0	1
5299.8	2.49	0	7	0	3	7	0	0	2	0	37	13	0	31	9	0	22
5302.2	2.44	0	8	0	0	7	0	0	2	0	39	7	13	24	9	0	15
5304.2	2.50	0	6	0	3	8	1	2	2	0	25	9	10	34	9	0	25
5308.1	2.51	0	7	0	6	5	0	3	0	0	23	17	0	39	11	0	28
5318.0	2.50	0	7	0	3	7	2	0	2	0	34	14	0	31	8	0	23
5325.0	2.52	12	0	0	9	7	0	3	0	0	23	0	0	46	14	0	32
5333.0	2.51	10	7	0	3	6	0	2	1	0	30	0	0	41	12	0	29
5336.9	2.37	0	5	0	0	4	0	0	2	0	63	0	20	6	4	0	2
5338.8	2.48	0	8	0	0	9	2	0	3	0	45	10	0	23	8	0	15
5341.2	2.81	0	0	0	0	3	3	75	1	0	0	12	0	6	0	0	6
5341.7	2.50	9	6	0	4	8	0	0	2	0	34	0	0	37	12	0	25
5346.1	2.78	0	0	0	0	0	4	70	0	0	0	18	0	8	0	0	8
5350.1	2.49	13	5	11	0	3	0	2	0	0	31	0	0	35	12	0	23
5356.0	2.51	16	7	0	5	8	0	2	0	0	25	0	0	37	11	0	26
5361.1	2.82	0	0	0	0	0	2	81	1	0	0	10	0	6	0	0	6
5364.6	2.37	0	0	0	0	9	0	0	1	0	58	0	22	10	5	0	5
5371.0	2.55	0	7	0	2	10	2	0	3	0	25	16	0	35	9	0	26
5380.6	2.37	0	7	0	0	4	1	0	0	0	58	0	16	14	5	0	9
5381.0	2.49	10	5	12	8	8	0	0	0	0	29	0	0	28	4	0	24
5383.3	2.41	0	6	0	0	8	1	1	1	0	47	0	17	19	7	0	12
5386.4	2.39	0	7	0	0	7	1	0	1	0	52	0	17	15	6	0	9
5387.4	2.45	0	7	0	2	7	2	2	0	0	32	7	15	26	8	0	18
5391.4	2.40	0	8	0	0	6	0	0	1	0	51	5	16	13	6	0	7
5398.6	2.51	11	6	0	5	6	2	2	0	0	28	0	0	40	14	0	26
5406.5	2.49	0	6	0	2	7	5	0	0	0	31	13	0	36	11	0	25
5410.9	2.41	0	7	0	0	8	2	0	1	0	46	0	16	20	7	0	13
5416.2	2.45	0	8	0	0	7	0	0	0	0	44	10	0	31	9	0	22
5418.5	2.46	5	6	0	2	8	2	0	0	0	30	0	11	36	11	0	25
5423.6	2.51	0	7	0	0	8	3	0	2	0	33	15	0	32	7	0	25
5433.5	2.51	12	6	0	7	8	0	0	0	0	26	0	0	41	12	0	29
5447.5	2.46	0	8	0	0	6	0	0	1	0	45	13	0	27	8	0	19



335X-30R Reef Ridge Shale confining layer core analysis.

Porosity and Permeability

26R Monterey Formation:

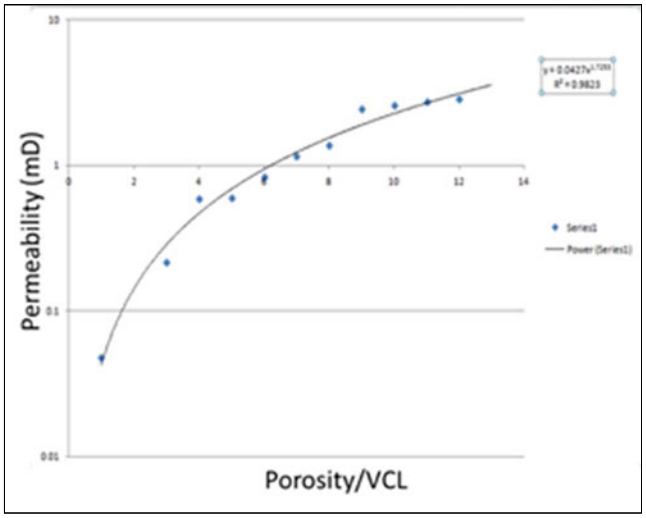
Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.

Volume of clay is determined by neutron-density separation and is calibrated to core data.

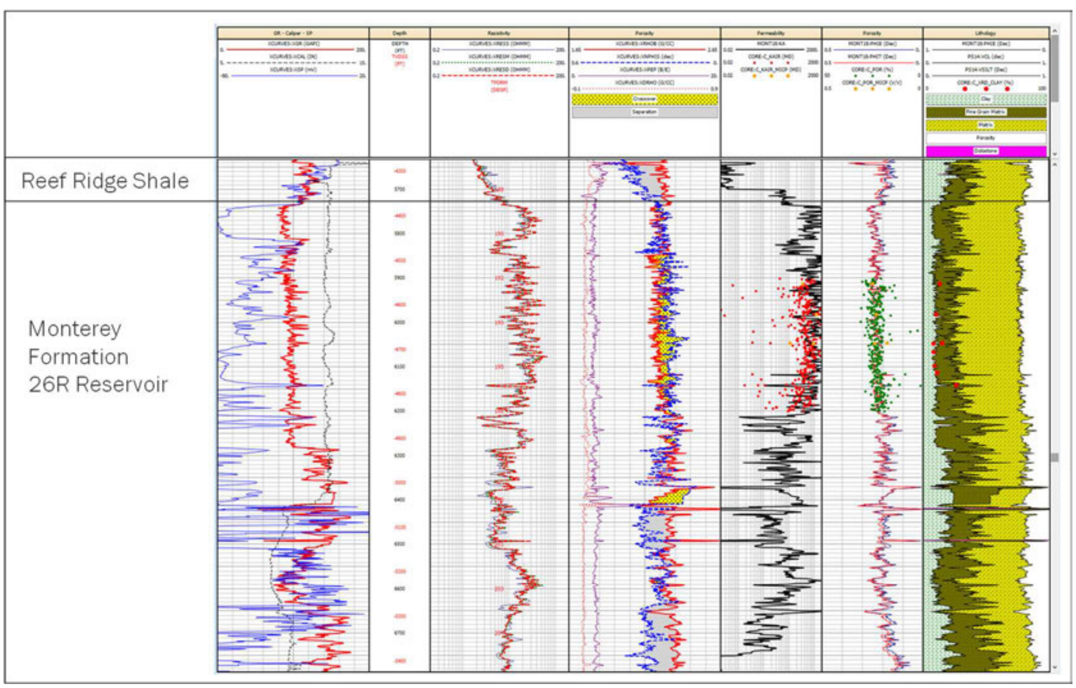
Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated in Figure 15 below.

Figure 15: Permeability function developed based on mercury injection capitally pressure data and calculated from log derived porosity and clay volume.



In the example below for the 26R Monterey Formation sands, the porosity ranges from 20% - 30% with a mean of 24%. The permeability ranges from 3 mD – 1,500 mD with a log mean of 45 mD (Figure 16).

Figure 16: Porosity and permeability for well 377H-26R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2).

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

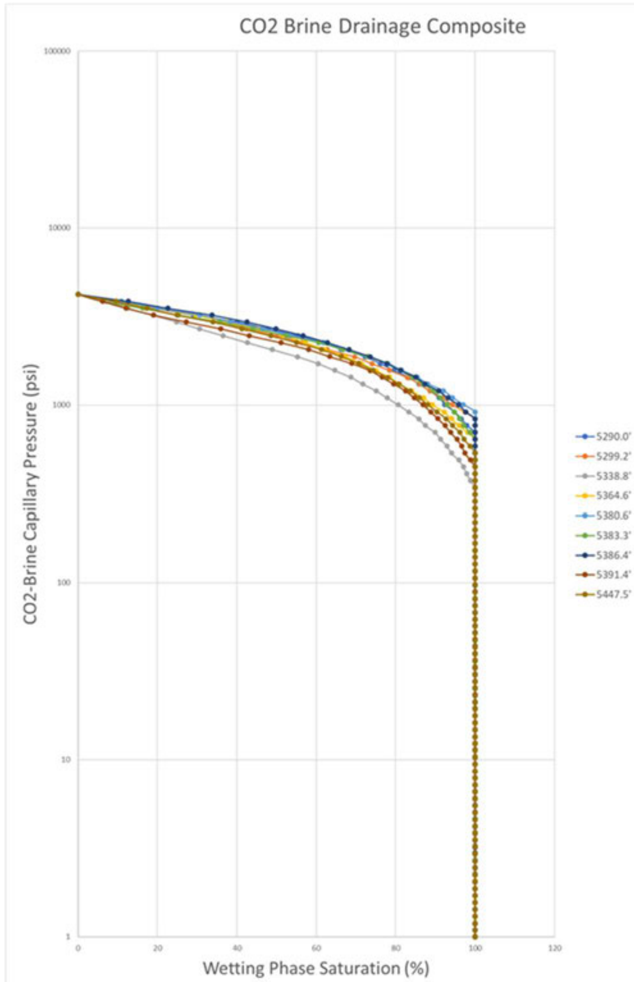
Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 17). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-

brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 17: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 11 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 22,592 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

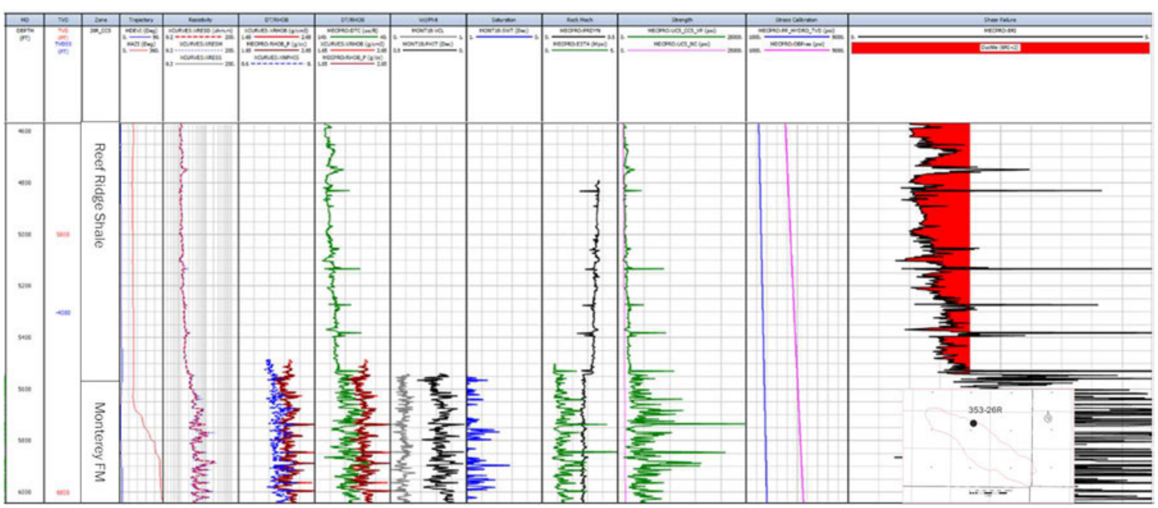
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 353-26R is shown below (Figure 18). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method.

Figure 18: Unconfined compressive strength and ductility calculations for well 353-26R. The Reef Ridge Shale ductility is shaded where less than two.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than two, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to anneal discontinuities. The BRI less than two confirms that the Reef Ridge is a ductile confining layer.

The average ductility of the confining zone based on data from 11 wells is 1.59.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,385 PSI.

As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the 26R Monterey Formation reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 20 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

Figure 19: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).

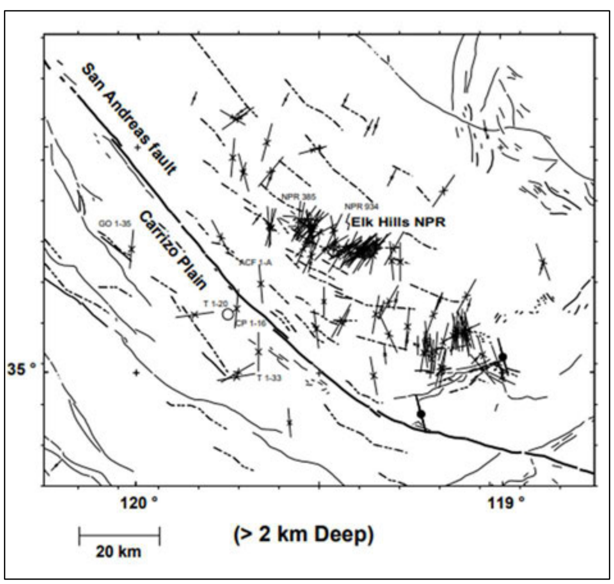


Table 3 shows the horizontal fracture gradients for the Reef Ridge Shale and the Monterey Formation 26R reservoir.

Table 3: Pressure gradients for the Monterey Formation 26R reservoir and Reef Ridge Shale.

Stress	Reef Ridge Confining Layer	Monterey Formation
Pore Pressure Gradient (psi/ft)	0.433	0.5
Overburden Gradient (psi/ft)	0.91	0.92
Breakdown Gradient (psi/ft)	1.12	1.03

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOME0.CH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Description:

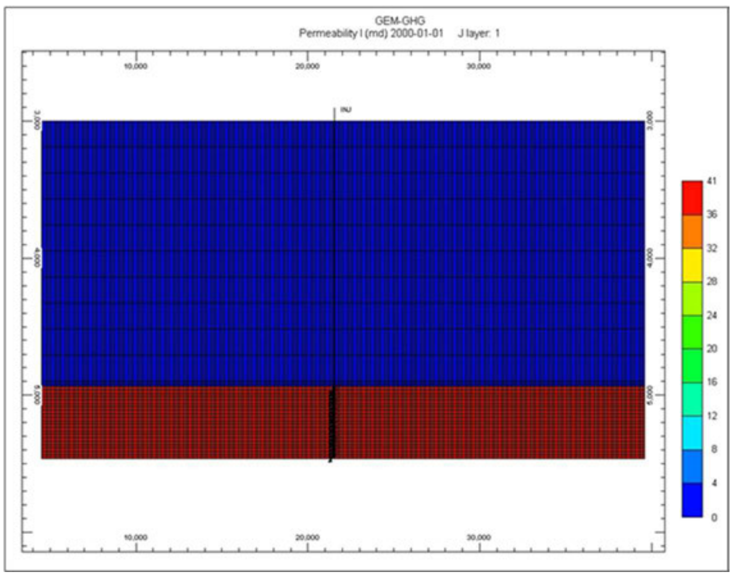
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 21.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 20: Geomechanics Model.



Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 22 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 21: Normal Fracture Stress and Pressure for Geomechanics Cases.

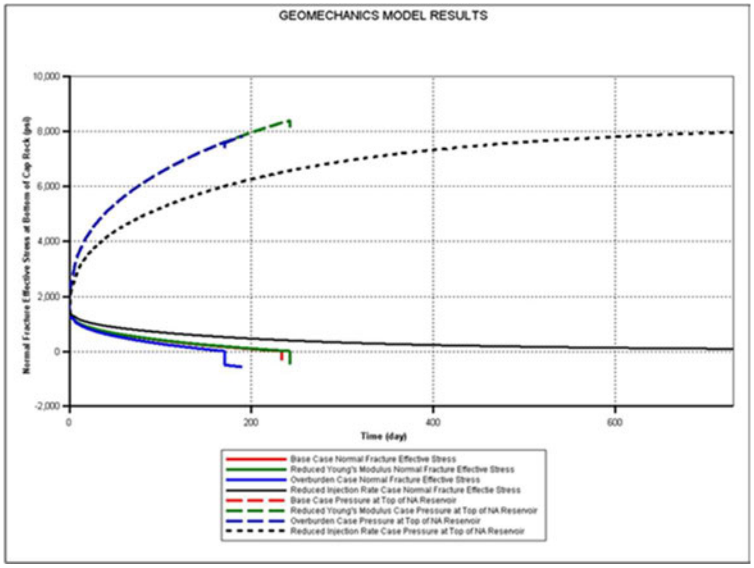


Table 4: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, psia**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Results:

Failure pressures for the four scenarios are given in Table 4. These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,600 PSI or more without tensile failure.

Seismic History [40 CFR 146.82(a)(3)(v)]

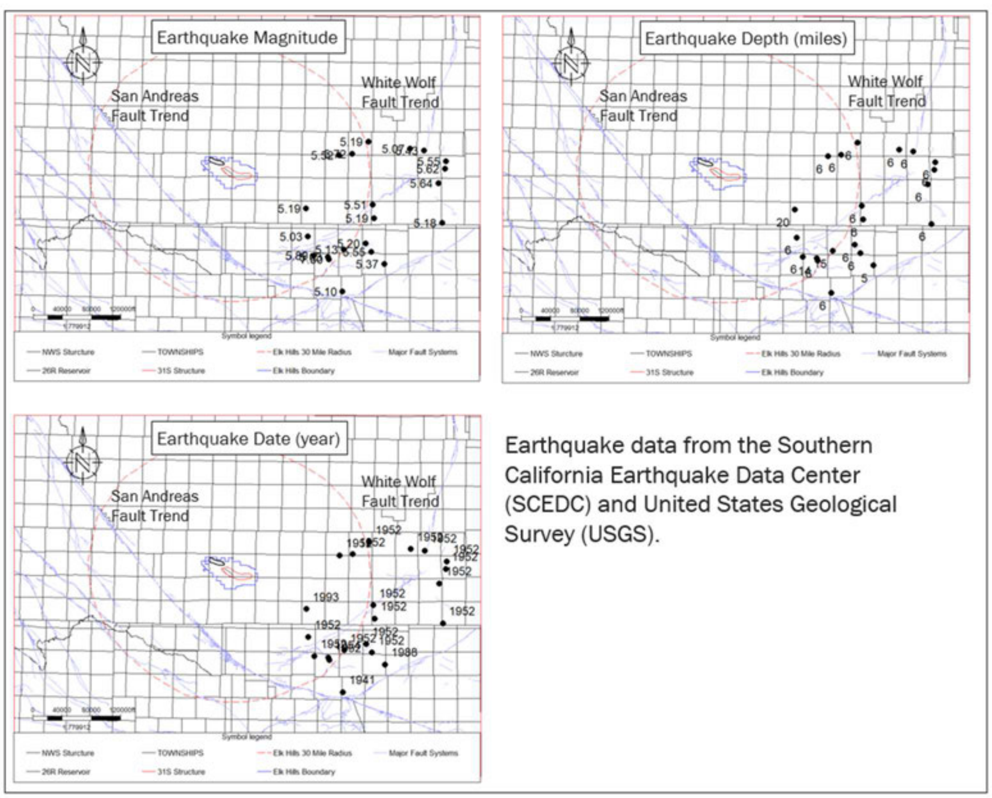
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

Within the EHOF there have been no earthquakes recorded greater than 3.0. In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF (Figure 23). The average depth of these earthquakes is 6.3 miles.

Figure 22: Earthquakes in the San Joaquin Basin with a magnitude greater than 5 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.



Seismic Risk:

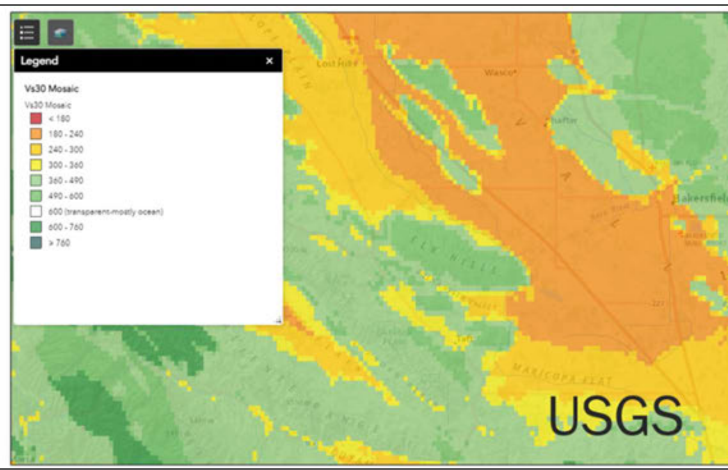
The EHOF has been closely monitored for the effects of seismicity by CTV and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

1. No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
2. VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high VS30 means (Figure 24) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
3. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Effects of the earthquake were catastrophic with loss of life, and significant property damage (SCEDC). Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure (Jenkins, 1955).

Figure 23: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.

Table: NEHRP seismic site classification based on shear-wave velocity (Vs) ranges.

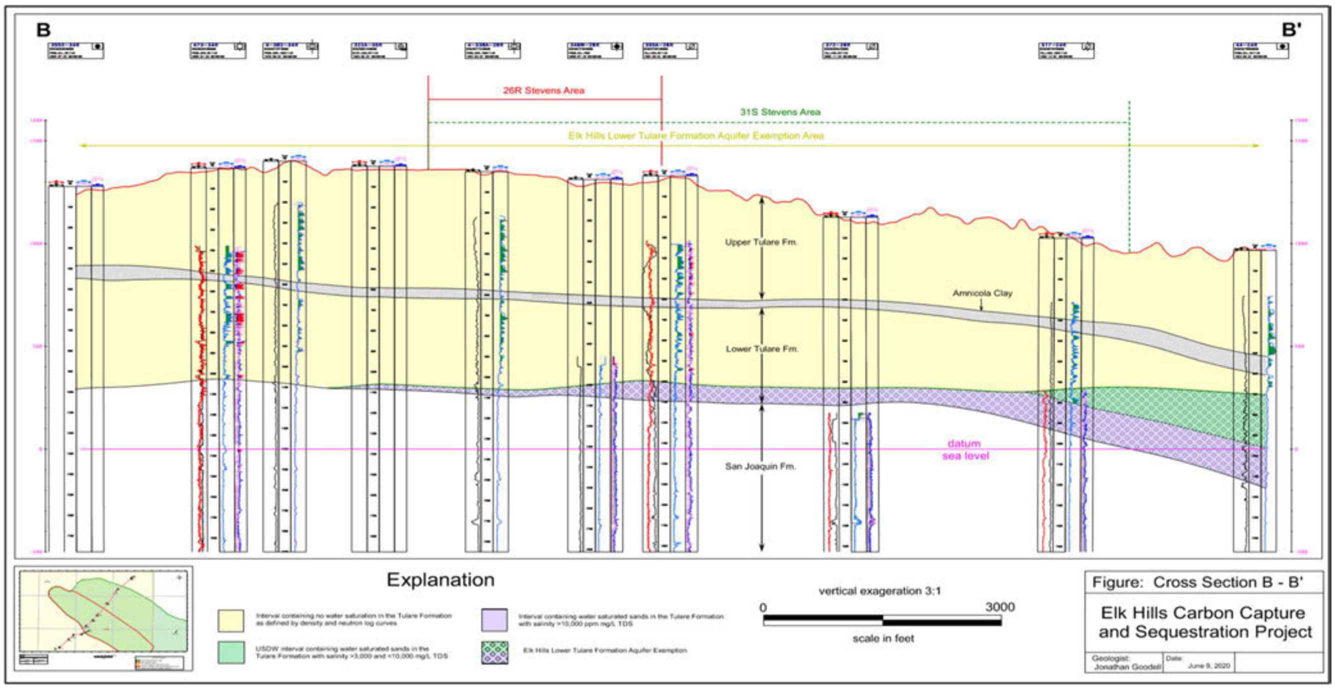
Site Class	S-Velocity (Vs) (ft/sec)	S-Velocity (Vs) (m/sec)
A (Hard Rock)	> 5,000	> 1500
B (Rock)	2,500 – 5000	760 – 1500
C (Very Dense Soil and Soft Rock)	1,200 – 2,500	360 – 760
D (Stiff Soil)	600 – 1,200	180 – 360
E (Soft Clay Soil)	< 600	< 180
F (Soils requiring additional response)	< 600, and meeting some additional conditions.	< 180, and meeting some additional conditions.



Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

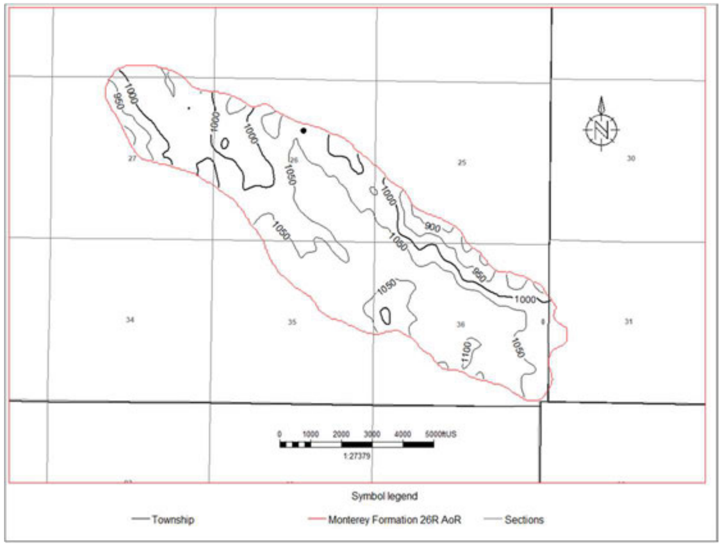
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 25). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 24: The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands are unsaturated in the 26R area.



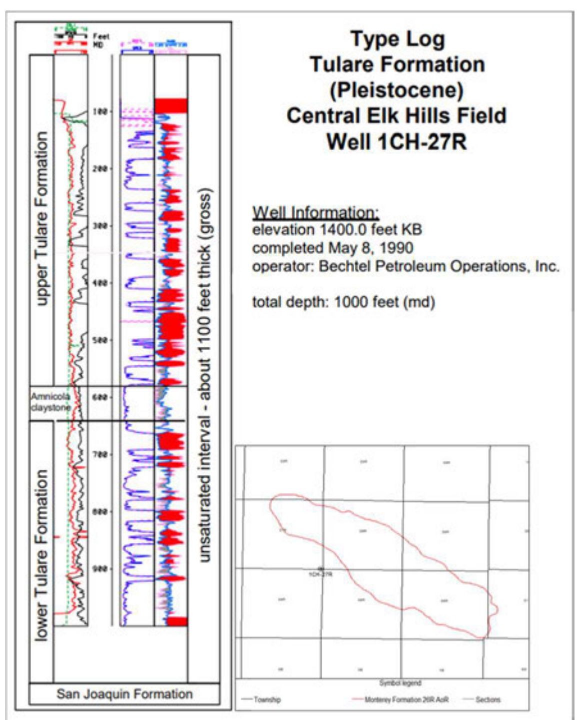
The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 25). The depth is 900 - 1,000 feet and the thickness ranges from 900 – 1,000 feet (Figure 26).

Figure 25: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 27). The characteristic density-neutron crossover (red-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 26: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, and Lower Tulare exempt aquifer.



Tulare Formation (Figure 28) water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum contaminant levels (MCL).

In 2018 the Lower Tulare aquifer was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

Figure 27: Upper Tulare and Lower Tulare Formation water analysis.

Upper Tulare

Table 4a. WATER SOURCE WELL #43WS-133
WATER ANALYSIS DATA (mg/kg)

DATE	6-95	7-95	8-95	9-95
SAMPLE #	95094	95150	95182	95189
CONSTITUENTS:				
Calcium, Ca	230	230	220	220
Magnesium, Mg	85	85	92	93
Sodium, Na	1380	1300	1200	1300
Potassium, K	9.2	9.8	8.8	8.6
Iron, Fe	0.4	0.51	0.38	0.54
Hydroxide, OH	0	0	0	0
Carbonate, CO3	0	0	0	0
Bicarb, HCO3	180	190	190	180
Chloride, Cl	1360	1400	1300	1400
Sulfate, SO4	1600	1600	1500	1600
Sulfide, S	<5.0	<5.0	<5.0	<5.0
Totals	4660	4700	4480	4700
Boron, B	4.7	4.6	4.7	4.7
TDS (Grav)	4890	4800	4900	4900
Hardness, CaCO3	920	920	930	930
Alkalinity, CaCO3	150	160	160	150
Sodium Chloride	3690	3700	3500	3800
pH	7.8	8.1	8.0	7.9
Electrical Conductivity	6.99 mmhos/cm	7.02 mmhos/cm	6.99 mmhos/cm	6.99 mmhos/cm
Specific Gravity	1.003	1.003	1.004	1.003
Resistivity	1.43 ohm	1.43 ohm	1.43 ohm	1.43 ohm
NOTE: Sample analysis is from Zalco Laboratory.				

(Source: NPR-1 Ground Water Monitoring Plan, 1995)

Lower Tulare

Water Analysis (General Chemistry)

BCL Sample ID: 1411064-01 | Client Sample Name: Elk Hills Well 82-28, 5/17/2014 4:05:00PM, Rick Ogletree

Constituent	Result	Units	PQL	MDL	Method	MB Bias	Lab Quals
Electrical Conductivity @ 25 C (Field Test)	27000	umhos/cm	1.0	1.0	EPA-120.1		
pH (Field Test)	7.23	pH Units	0.05	0.05	EPA-150.1		
Temperature (Field Test)	87.6	F	32.0	32.0	SM-2550B		
Total Calcium	650	mg/L	2.0	0.30	EPA-6010B	ND	A10
Total Magnesium	230	mg/L	1.0	0.38	EPA-6010B	0.75	A10
Total Sodium	4700	mg/L	10	1.0	EPA-6010B	ND	A01
Total Potassium	31	mg/L	20	2.6	EPA-6010B	ND	A10
Bicarbonate Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Carbonate Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Hydroxide Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Total Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Bromide	50	mg/L	5.0	2.2	EPA-300.0	ND	A01
Chloride	10000	mg/L	50	6.7	EPA-300.0	20	A01
Fluoride	ND	mg/L	2.5	0.70	EPA-300.0	ND	A10
Nitrate as NO3	ND	mg/L	22	5.5	EPA-300.0	ND	A10
Sulfate	320	mg/L	50	9.0	EPA-300.0	19	A01
pH	7.47	pH Units	0.05	0.05	EPA-150.1		S05
Electrical Conductivity @ 25 C	26100	umhos/cm	1.00	1.00	EPA-120.1		
Total Dissolved Solids @ 180 C	20000	mg/L	1000	1000	EPA-160.1	ND	

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the

Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry 26R Reservoir:

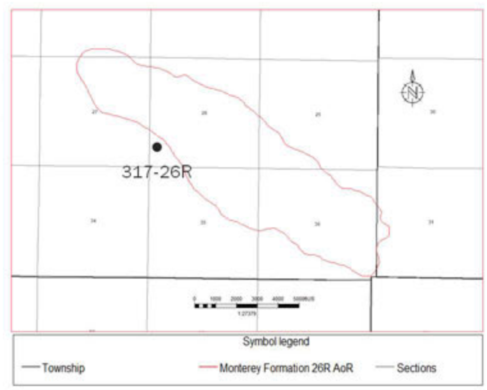
The 26R Monterey Formation reservoir has a gas cap that overlies a thin oil band and a basal water zone. CTV and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Geochemical water analysis for the 26R Monterey Formation reservoir has been completed across the AoR and collected since reservoir discovery as part of routine surveillance. This data is consistent through time and over the AoR, Figure 29 shows the geochemical water analysis for well 317-26R.

Figure 28: Monterey Formation 26R reservoir water geochemistry from well 317-26R.

RADICALS		PARTS PER MILLION MILLIGRAMS PER LITER	REACTING VALUE EQUIVALENTS PER MILLION	REACTING VALUE PERCENT
SODIUM +Potassium	Na+K	8775	381.71	49.10
CALCIUM	Ca	92	4.59	0.59
MAGNESIUM	Mg	19	1.56	0.20
BARIUM	Ba	57	0.83	0.11
STRONTIUM	Sr			
SULPHATE	SO_4	1198	24.92	3.22
CHLORIDE	Cl	11424	322.16	41.61
CARBONATE	CO_3			
BICARBONATE	HCO_3	2441.8	40.05	5.17
HYDROXIDE	OH			
IODIDE	I			
SILICA	SiO_2	50		
IRON, ALUMINA	R_2O_3			
TOTAL		24056.8	775.82	100.00

GROUP	CHEMICAL CHARACTER	MISCELLANEOUS		
ALKALIS	PRIMARY SALINITY	BORON	42.46	PPM
EARTHS	SECONDARY SALINITY	HYDROGEN SULFIDE	3.6	
STRONG ACIDS	PRIMARY ALKALINITY	EQUIVALENT SALT	23944	PPM
WEAK ACIDS	SECONDARY ALKALINITY	RESISTIVITY @ 77°F	0.24	O.M.
Ca/EARTHS		CHLORINITY	18846	PPM
CHLORIDE SALINITY		SPECIFIC GRAVITY	1.017	
SULPHATE SALINITY	CARBONATE/CHLORIDE	pH	8.2	



The hydrocarbon composition for the Monterey Formation 26R reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 30 shows the results of the hydrocarbon composition for well 356-26R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

Figure 29: Monterey Formation reservoir hydrocarbon analysis from well 356-26R.

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PERCENT	WEIGHT PERCENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	1.29	0.65			
Nitrogen	0.07	0.02			
Methane	38.83	7.16			
Ethane	8.38	2.89			
Propane	7.05	3.57			
iso-Butane	1.38	0.92			
n-Butane	3.92	2.61			
iso-Pentane	1.50	1.24			
n-Pentane	1.72	1.42			
Hexanes	2.15	2.12			
Heptanes plus	33.71	77.40	0.8516	34.5	200
	100.00	100.00			

26R Monterey Formation Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The 26R Monterey Formation reservoir will store 7% of the injectate CO_2 in aqueous phase with water saturations of 34% saturation in the gas cap, 25% in the oil band and 100% in the basal water.
2. Residual oil saturation (15- 37%) in the 26R Monterey Formation reservoir will dissolve 20% of the CO_2 injectate.
3. The Monterey Formation has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will stay on grain surfaces.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and is discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Site Suitability [40 CFR 146.83]

The 26R Monterey Formation reservoir in the 26R anticline was discovered in the 1940's and developed in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the 26R Monterey Formation reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

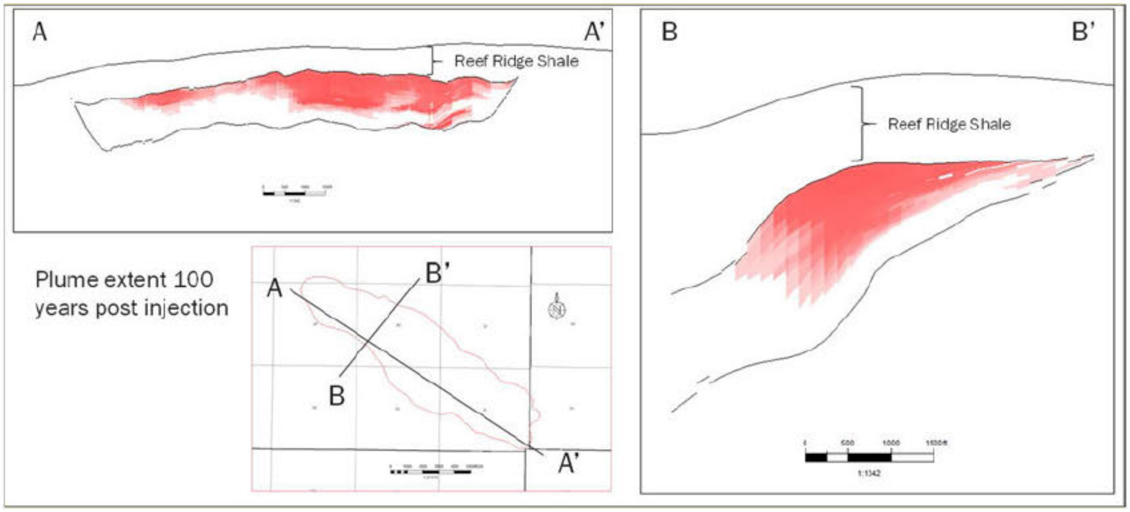
A key component of the 26R Monterey Formation reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale).

CO2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Monterey Formation 26R reservoir hydrocarbons were confined for several million years.
2. The Reef Ridge Shale primary confining layer is 800-1,000 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 841 billion cubic feet of gas and 114 million barrels of water with no leakage.
3. Cross section A-A' (Figure 31) shows confinement of the injected CO_2 plume by up-dip pinch-out of the reservoir on the anticline structure and lateral confinement by reservoir edges. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does not migrate beyond the edges of the anticline structure or into the Reef Ridge Shale.

Figure 31: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the Monterey Formation 26R sand facies and the edges of the reservoir.



Storage capacity for the Monterey Formation 26R storage reservoir based on computational modeling results is up to 38 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate volume.

AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software, and results to establish the AoR, and the wells that require corrective action.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

Injection Well Construction

CTV plans to repurpose existing injector 373-35R and drill three new injectors for the Elk Hills 26R storage project. Well 373-35R is currently approved by CalGEM for Class II injection of water for the purpose of reservoir pressure maintenance.

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

Injectate Migration Prevention:

373-35R was drilled in 1981, 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 with cement to surface using industry-proven recommended practices for slurry design and placement
4. Cement bond log indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results
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 –13 CR-95 or other corrosion resistant alloy
2. Wellhead – stainless steel or other corrosion resistant alloy
3. Packer – corrosion resistant alloy 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

The well will be tested for mechanical integrity prior to injection.

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 and Cementing

Casing:

26R Monterey Formation temperature is approximately 210 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.

Casing specifications are presented in Table 5. These specifications show that the well was engineered to standards that allow for the safe operation at a bottomhole injection pressure that will not be greater than 4,900 PSI (0.71 PSI per foot). Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues attributed to the casing design.

Table 5: Casing construction data for the 373-35R 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	14-53	20.000	19.5	52	H-40	Short	31	875	90
Surface	14-331	13.375	12.715	48	H-40	Short	31	1,727	740
Intermediate	14-3,006	9.625	8.835	40	K-55	Long	31	3,950	2,570
Long-string	14-7,988	7.000	6.276 6.276 6.366	26 26 23	N-80 K-55 K-55	Long	31	7,240 4,980 4,360	5,410 4,320 3,270

Casing below injection packer and exposed to CO2 injectate.

Table 6. Casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	53	24	0.25	20	H40	52
Surface	331	17.5	0.33	13.375	H40	48
Intermediate	3,006	12.25	0.395	9.625	K-55	40
Long String	7,988	8.75	6.276 6.276 6.366	7.0	N-80 K-55 K-55	26 26 23

Tubing and Packer

The information in this table meets the minimum requirements at 40 CFR 146.86(c).

CTV plans to use the following and will update the EPA as part of pre-operational testing.

Table 7. Tubing and packer details.

Component	Setting Depth (ft)	Min Yield Strength (psi)	Burst Pressure (psi)	Collapse Pressure (psi)	Material
Tubing	7,043	80,000	10,480	11,080	13CR L-80
Packer	7,049	80,000	7,500	7,500	13CR L-80 or other CRA

Pre-Operational Logging and Testing

CTV has provided operational and testing data to support the Elk Hills 26R project. Data and information provided meets the requirements pursuant to 40 CFR 146.82(a)(8) and 40 CFR 146.87.

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing
Tab(s): Welcome tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

373-35R Well Operation

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of super-critical (SC) phase CO_2. For attaining SC flow, surface injection pressure will be a minimum of 1,200 PSI. As the depleted oil reservoir fills up, a higher surface injection pressure will likely be required. Final reservoir pressure target is 3,250 PSI. It is assumed that at shut-in, the downhole injection pressure will be 4,010 PSI (0.59 PSI/FT) for well 373-35R.

Table 8 values shown below for average injection pressure are an average of initial conditions and final conditions. As the reservoir fills up with CO_2 it will pressure up, thus creating a continually changing reservoir and injector condition over injection life. A downhole injection pressure of 4,010 PSI is assumed to occur at shut-in timing when reservoir pressure has reached its final level at 3,250 PSI. This translates to a surface injection pressure of ~1,600 PSI, which will be achieved via a surface booster pump.

The final/maximum values for surface and downhole injection pressures are far below those associated with the Class II permitted fracture gradients of 0.8 psi/foot. Over 40 years of gas and water injection experience into the Monterey Formation supports that these operating limits are appropriate and effective. Additionally, the final reservoir pressure target of 3,250 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical tensile failure pressure of ~7,500 PSI.

As mentioned above, as the reservoir fills up with CO_2, the reservoir pore pressure will increase. A surface booster pump will be needed to supplement surface injection pressure from the initial value of ~1,200 PSI to the final requirement of ~1,600 PSI.

Table 8. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	2,300	psig
Downhole	4,900	psig
Average Injection Pressure	Average over time	
Surface	1,375	psig
Downhole	3,699	psig
Maximum Injection Rate	30 per well	mmscfpd
Average Injection Rate	15-25 per well	mmscfpd
Maximum Injection Volume and/or Mass	38 million	tonnes
Average Injection Volume and/or Mass	38 million	tonnes
Annulus Pressure	2,984 @ packer	psig
Annulus Pressure/Tubing Differential	715 @ packer @ average injection condition	psig

Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

There are currently multiple sources of anthropogenic CO_2 being considered for 26R Monterey Formation sequestration. These include capture off of the Elk Hills NGCC Power Plant as well as 3rd party existing and proposed industrial sources in the Southern San Joaquin Valley area. The carbon dioxide stream will consist of a minimum of 95% CO_2 by volume. Other key constituents that will be controlled for corrosion mitigation include water content (<50ppmv) and oxygen level (<50 ppm)

Corrosiveness of the CO_2 stream is very low as long as the entrained water is kept in solution with the CO_2. This is ensured by the < 50ppmv injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. In early injection time, it is likely that gas phase CO_2 will exist towards the lower depths of the tubing string. Stainless steel (13 CR L-80) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. CTV may optimize the maximum water content specification prior to injection based on technical analysis.

Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

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.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***

PISC and Site Closure GSDT Submissions

GSDT Module: Alternative PISC Timeframe Demonstration
Tab(s): All tabs (only if an alternative PISC timeframe is requested)

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

Emergency and Remedial Response GSDT Submissions

GSDT Module: Project Plan Submissions
Tab(s): Emergency and Remedial Response tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

References:

1. Callaway, D.C., and Rennie, E.W., Jr., 1991, San Joaquin Basin, California, in Gluskoter, H.J., Rice, D.D., and Taylor, R. B., eds., Economic geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 417-430.
2. Zumberge, John, Russell, Just and Reid, Stephen, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10 (October 2005), pp. 1347–1371.
3. Hosford, Allegra and Magoon, Les, 2007 Age, U.S. Geological Survey Professional Paper 1713, California Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Chapter 5.
4. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.