Evaluation of Geologic Information in the CTV III CO_2 Sequestration Project Class VI Permit Application

This site characterization evaluation report for the proposed CTV III Class VI Sequestration Project summarizes the geologic evaluation and data submitted by Carbon TerraVault Holdings LLC (CTV) in an undated permit application narrative (identified as version 4 in the file name), submitted per 40 CFR 146.82(a). This report describes and evaluates the available data on which the UIC Class VI permit application is based and identifies uncertainties that EPA recommends be addressed via the pre-operational testing that will be performed before the applicant will receive authorization to inject CO_2. Clarifying questions for CTV are provided in blue in the text below. Additional objectives for pre-operational testing to address identified data gaps are identified at the end of the evaluation text. While some of the needed testing is described in the narrative or the pre-operational testing plan, CTV did not submit procedures for all needed testing. Evaluating these testing procedures is outside of the scope of this site characterization review; however, approval of testing procedures will be needed prior to well construction and testing.

Project Background

CTV plans to develop the CTV III CO_2 storage site in San Joaquin County near Stockton, California. CTV proposes to construct and operate six CO_2 injection wells to be completed in the Mokelumne River Formation (the injection zone) at a depth of approximately 7,700 feet true vertical depth (ft TVD). The Capay Shale will serve as the upper confining zone, and the H&T Shale will provide lower confinement. CTV plans to inject 2.5 million tonnes of CO_2 annually for a period of 28 years, for a total injection volume of 70 million tonnes. At the proposed injection site, the base of the lowermost underground source of drinking water (USDW) is contained within the Markley Formation at a depth of approximately 2,500 ft TVD. CTV is not requesting an injection depth waiver or aquifer exemption expansion for this project.

Site Characterization

CTV utilized literature review and available 2D and 3D seismic data, core data, well logs, and reservoir performance data to characterize the proposed injection site. Core and porosity data was available from 46 wells drilled within and near the Area of Review (AoR) as shown in Figures 2.2-1 and 2.4-1[1]. Wireline log data included measurements such as spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity, neutron porosity, bulk density, and nuclear magnetic resonance. X-ray diffraction (XRD) and Fourier transform infrared spectroscopy (FTIR) data is available for cores from one well located approximately 6 miles northeast of the AoR and three wells located approximately 12 miles northwest of the AoR (Figure 2.4-1).

Figure 2.2-2 contains a type log from well Salyer_A_1 located in the center of the modeled CO_2 plume showing average rock properties used in CTV's site model for the injection and confining zones. Traces of the available seismic data and well ties are shown in Figure 2.2-3 (including 3D seismic throughout and

[1] All figures and tables referenced in this evaluation, with limited exception, are contained in the CTV III Narrative Report (Attachment A, Version 4) and are not reproduced in this document.

beyond the AoR and several 2D seismic lines, including lines that transect the AoR), where CTV tied merged 3D data to 2D data to create the structural model for the project site.

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

Regional Geology

The CTV III project area lies in Victoria Island southeast of the Rio Vista major gas field, south of McDonald Island Gas Field (about 1 mile to the north/northeast of the AoR boundary), and west of Union Island Gas Field (adjacent to the east/southeast AoR boundary) within the Sacramento Basin, the northern, asymmetric sub-basin of the larger Great Valley Forearc. The sedimentary formations of the Great Valley range in age from Jurassic to Holocene age. The basin is constrained on the west by the Coast Range Thrust, on the north by the Klamath Mountains, on the east by the Cascade Range and Sierra Nevadas, and on the south by the Stockton Arch Fault (which forms the eastern boundary of the AoR). Sedimentation thickens southward towards the Stockton Arch Fault due to the southern tilt of the basin. Figure 2.1-2 displays the Sacramento Basin regional study area, and Figure 2.1-1 shows the location of the proposed AoR in the context of the southern half of the Sacramento Basin.

Formation Summary

Figure 2.1-6 is a schematic NW-SE cross section representing the stratigraphy of the project area. The major stratigraphic intervals comprising the injection zone and the upper and lower confining zones are lower Cretaceous to lower Eocene in age. Separating the Mokelumne River injection zone and Capay Shale upper confining zone is a basin-wide unconformity, which CTV asserts will create a secondary seal between the injection zone and base of the lowermost USDW.

Available data about geologic formations within the AoR are summarized in Table 1 below. Average depths and thicknesses for the injection and confining zones were provided in Table 2.4-2, and the values for other units were estimated from Figures 2.2-2 and 2.2-4.

Table 1. Formation Summary.

Unit	Depth within the AoR (ft TVD)	Thickness Across the AoR (ft)	Total Dissolved Solids (mg/L)	Average Porosity (%)	Average Permeability (millidarcies, mD)
Markley Formation (lowermost USDW)	~2,500	--	3,000 – 10,000 (calculated based on an unspecified number of salinity logs)		
Nortonville Shale	4,750	300	--		
Domengine Sandstone	5,050	700	--		
Capay Shale (upper confining zone)	5,582 (mean); ranges from 4,954 to 6,164 ft	207 (mean); ranges from 100 to 360 ft	--	29.3 (17 wells with porosity logs)	0.34 (Citizen_Green_1 nuclear magnetic

Unit	Depth within the AoR (ft TVD)	Thickness Across the AoR (ft)	Total Dissolved Solids (mg/L)	Average Porosity (%)	Average Permeability (millidarcies, mD)
					resonance logging)
Mokelumne River Formation (injection zone)	7,395 (mean); ranges from 5,044 to 10,281	1,024 (mean); ranges from 316 to 1,336 ft	14,000 – 16,000 (unspecified number of logs from within the AoR)	27.0 (18 wells with porosity logs)	75.4 (18 wells with porosity logs)
H&T Shale (lower confining zone)	7,800	200	--	21.4 (16 wells with porosity logs)	0.49 (16 wells with porosity logs)

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

CTV's proposed injection wells are depicted in Figure 2.2-6. The confining Midland, West Tracy, and Stockton Arch faults are depicted on the figure as the western, southern, and eastern boundaries of the delineated AoR, respectively (see Faults and Fractures below).

Figure 2.2-7 shows surface bodies of water, surface features, and infrastructure and political boundaries in San Joaquin, Contra Costa, and Alameda Counties. Major surface water bodies in the area are Discovery Bay, Clifton Court Forebay, Victoria Canals, Grant Line Canal, and the Indian Slough. State and EPA subsurface cleanup sites are depicted in Figure 2.2-8.

Questions for CTV:

- ***Please indicate the delineated AoR on Figure 2.2-3.***
- ***Please provide a single map that contains all of the elements required at 40 CFR 146.82(a)(2).***

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

The AoR for the CTV III project is structurally bounded on three sides by faults: the Stockton Arch reverse fault to the east, the West Tracy reverse fault to the south, and the Midland normal fault to the west. These faults are predicted to contain the pressure front but are beyond the predicted extent of the CO_2 plume. Figure 2.3-1 displays these local faults as interpreted from 2D and 3D seismic data, well control from gas fields in the area, and published data. The fault traces are consistent with mapping (Figure 2.6-1) developed by the California Geologic Survey (CGS), although limited CGS information is available for the West Tracy Fault.

- The Midland Fault is a west dipping normal fault which bounds the AoR to the west. The fault was active during the late Cretaceous-Eocene creation of the Rio Vista sub-basin, later reactivating to the south as a reverse fault in the late Cenozoic. At the Rio Vista Gas Field, there is gas production on either side of the Midland Fault, where structural closures from the fault are sealing for gas. Due to this behavior, CTV assumes the Midland Fault to be sealing at the edge of the CTV III AoR. The trace of the Midland Fault was confirmed by CTV with licensed 2D seismic data. The fault is depicted in cross section in Figure 2.2-4, where it does not appear to completely offset the injection and confining zones.

- The Stockton Arch Fault is a southeast dipping reverse fault trending NE-SW which bounds the AoR to the southeast. The Stockton Arch Fault is associated with Eocene-Miocene uplift of the Stockton Arch which separated the Sacramento Basin from the San Joaquin Basin. The fault trace is defined by the 3D seismic data and well control from the Union Island Gas Field. CTV asserts that the Stockton Arch Fault will provide a seal to stratigraphically trap injected CO_2 and contain formation pressure increases because of gas trapping and pressure containment demonstrated within the Winters Formation at the Union Island gas field. The fault there was reported to contain formation pressure draw down due to gas production from its field discovery pressure of 5,040 psi down to its current pressure of 1,200 psi.
- The West Tracy Thrust Fault is a steep southwest dipping reverse fault which bounds the AoR to the south. CTV interpreted the trace of the fault using 2D and 3D seismic data and review of published work. The fault was probably active between the Eocene and Miocene with later reactivation during late Cenozoic transpression. CTV asserts that the striking of the faults in the region and available literature indicate that the West Tracy Fault connects to the Midland Fault in the west and the Stockton Fault in the east. CTV notes that there are no established hydrocarbon fields along the West Tracy Fault that demonstrate fault seal; however, they assert that the fault is sealing based on evidence of gas trapping from other faults in the region and the steep offset of strata across the West Tracy Fault ranging from 700 to 1,000 ft at the top of the Mokelumne River Formation injection zone.

The lines of evidence presented by CTV to demonstrate that these faults are sealing are insufficient. The Midland Fault appears to not fully juxtapose formations on the 2D seismic data presented, and no other evidence of sealing within the AoR is presented for the Midland Fault. There is no site-specific evidence (e.g., pressure data, shale gouge calculations, or core analyses) to indicate whether the Stockton Arch Fault is sealing within the AoR. CTV interprets an offset of 700 to 1,000 ft across the West Tracy Fault, but no cross sections are provided to demonstrate this interpretation.

One normal fault transects the injection zone within the boundary of the modeled CO_2 plume as shown in Figure 2.3-1. CTV notes that this fault is within the area studied by 3D seismic surveying, and it has 100 ft of offset in the uppermost Mokelumne River Formation injection zone. Figure 2.3-2 is a schematic NW-SE structural cross section which shows this normal fault cutting across the local stratigraphy, where it appears to extend from below the lower confining zone up through the injection zone, and above the Capay Shale upper confining zone (Figure 2.3-2). There is no evidence of a complete off-set of the upper and lower confining zones against another formation based on available information in wells in the area. Based on data from CTV's type well and the Victoria Islands Farms 1 well (depicted on the inset map in Figure 2.3-2 as being inside the AoR), CTV asserts that the Capay Shale confining zone is sufficiently thick such that the offset from the fault is not large enough to completely offset the confining zone against another formation, and this appears to also be the case for the H&T Shale lower confining zone. However, the fault does transect the entire thickness of the upper confining zone. CTV asserts that based on the known properties of the H&T Shale lower confining zone, the Capay Shale upper confining zone is expected to be clay rich and able to provide a vertical seal to the injection zone across the transecting normal fault.

Questions for CTV:

- ***Was 3D seismic data available to confirm the locations of the bounding faults and confirm whether they are connected in the corners of the AoR?***

- ***It appears, based on Figure 2.3-2, that the normal fault within the plume boundary completely transects the upper confining zone. What formation-specific evidence is there that this fault would not interfere with containment in the Capay Shale upper confining zone, per 146.82(a)(3)(i) and the confining zone is "free of transmissive faults or fractures" to contain the CO_2 per 146.83?***
- ***Is any site-specific evidence available (other than the offset and thickness of the upper and lower confining zones) to demonstrate that the normal fault in the boundary of the CO_2 plume is sealing? See Section 3.5.2 of EPA's Class VI Site Characterization Guidance for acceptable lines of evidence and associated data, (e.g., Allan charts for unit juxtaposition; capillary pressure and permeability measurements for fault leakage, catalysis, or diagenetic sealing; shale gouge ratio; and pore pressure measurements for pressure compartmentalization).***
- ***When and where was the "current" 1,200 psi pressure measurement taken? If it was not within the past 2-3 years, please discuss how field operations since the pressure measurement may have affected current pressures in the reservoir.***
- ***Does CTV have core data from drilling any wells in the McDonald Island Gas Field or Union Island Gas Field or from any other research on GS in the state of California that can provide porosity, permeability, capillary pressure, pore pressure, mineralogy, etc., data about the injection or confining zones to increase the number of data points on which the site characterization is based?***
- ***If no site-specific data exist to address the above questions, what pre-operational testing does CTV plan to address these data gaps?***
- ***On page 40, the application states that "the small normal fault within the plume does not breach confining zones;" however, Figure 2.3-2 shows that the fault does appear to transect these confining zones. Please clarify the discrepancy.***

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

Figure 2.4-1 shows the location of wells with mineralogy data relative to the AoR, along with wells with porosity data and wells used for CTV's ductility calculation (see Geomechanical and Petrophysical Properties below). There appear to be 18 wells with porosity data (mostly within the AoR), 5 wells with core data (all of which are 6 miles or more to the northwest and northeast of the AoR), and 7 wells with data for the ductility calculations (all of which are within or immediately southwest of the AoR).

CTV states that quantitative mineralogical data is unavailable from within the AoR, so the mineralogical data presented in the application is from four wells located outside the AoR, ranging in distance from the AoR of approximately 5 to 12 miles. These core data are presented in Table 2.4-1. Formations, sample depths, and the quantities of minerals are provided in the table as derived from XRD and FTIR. However, they do not provide the site-specific data points for the injection and confining zones that are needed to reduce uncertainty in the site characterization and modeling inputs that will be needed for final approval/authorization to inject. **Cores collected during construction will need to confirm site-specific properties, including porosity, permeability, capillary pressure, pore pressure, mineralogy, etc.**

CTV determined formation porosities from bulk density using a matrix density of 2.65 g/cc as calibrated from core grain density and core porosity data, and from compressional sonic logs and the Raymer-Hunt equation. Formation clay volumes were determined by spontaneous potential and were calibrated to core data. CTV then estimated permeability by applying a core-based permeability transform that utilizes capillary pressure, porosity, and permeability with clay values from XRD and/or FTIR. The permeability transform is based on 13 core data points from two wells, and an example transform for Sacramento Basin zones is provided in Figure 2.4-2.

CTV verified the transform by comparing nuclear magnetic resonance (NMR) log-generated permeability values (calculated from the Timur-Coates method) from the well Citizen_Green_1 to values calculated from the transform (Figure 2.4-3). These values appear to correlate well. CTV cites Track 10 of a log in the Citizen_Green_1 well (located about 8 miles north of the AoR), shown in Figure 2.4-3, as evidence that the permeability calculated from the transform correlates well with log-generated permeability and rotary sidewall core permeability. Figures 2.4-4, 2.4-5, and 2.4-6 are example data from well Ohlendorf_Unit_1_1 located on the southeastern end of the AoR. **Pre-operational testing data will need to confirm these estimations and reduce uncertainty.**

Figure 2.4-7 is a map of wells within the AoR from which available porosity and permeability data was collected; 18 wells are located throughout the AoR, primarily in its eastern half. CTV notes that no capillary pressure data are available for the injection or confining zones, and all calculations and modeling based on injection zone capillary pressure used estimations from the Winters Formation in the Union Island Gas Field. According to Figure 2.1-7, capillary pressure data for the Winters Formation was taken from wells about 12,000 feet to the east of the AoR. The capillary pressure curve for the Winters Formation is presented in Figure 2.4-8. The approach of using data from the Winters Formation is not appropriate; **the lack of site-specific data introduces uncertainty that will need to be addressed in updated modeling before injection may be authorized.**

CTV determined formation depths and thicknesses from structural and isopach maps based on wireline logs. Gross thickness and structure maps within the AoR for the injection and upper confining zones are provided in Figure 2.4-9. CTV notes that there is structural variability in the thickness of the injection and confining zones due to the Late Paleocene/Early Eocene Meganos submarine canyon erosional event, a NE-SW sequence of fine-grained submarine fan deposits and transgressive deep-water shales west of the AoR. CTV asserts that variability in the thickness and depth of the injection or confining zones will not affect containment, although it is noted that the upper confining zone is at minimum 100 ft thick.

Injection Zone Properties

The Mokelumne River Formation injection zone is a fluvial-deltaic sandstone sourced by the Sierra Nevada terrain to the east and prograded west-southwest into the forearch basin, truncating and pinching out to the north. Within the AoR, its thickness ranges from 316 to 1,336 ft and its depth ranges from 5,044 to 7,395 ft TVD.

The average porosity of the injection zone is 27.0% (based on data from 18 wells with porosity logs and 30,487 individual logging data points), and its average permeability is 75.4 mD (based on data from 18 wells with porosity logs and 30,073 individual logging data points). In the Ohlendorf_Unit_1_1 well (within the AoR), the porosity ranges from 1.5 to 34% with a mean of 26.5%, and the permeability ranges from 0.003 to 697 mD with a log mean of 68 mD.

Table 2.4-1 presents XRD data available for the Mokelumne River injection zone from the Speckman_Decarli_1 well located approximately 6 miles outside the AoR. Four sand samples from this well averaged 33% quartz, 42% plagioclase and potassium feldspar, and 24% total clay (primarily kaolinite and mixed layer illite/smectite). CTV notes that calcite and dolomite were not detected in any of the samples.

Confining Zone Properties

Capay Shale (Upper Confining Zone)

The Capay Shale upper confining zone is an Eocene-aged transgressive surface that unconformably overlies the Mokelumne River injection zone. Figure 2.2-4 is a cross section interpreted from well logs spanning the AoR which demonstrates the local stratigraphy as laterally continuous across the AoR. CTV states that this cross section is representative of formations and sand continuity for all six injection well locations, and this appears accurate based on the trend of the cross section and trend line between each of the three clusters of injection wells as shown in Figure 2.2-6. The upper confining zone thickness ranges from 100 to 360 ft, and its depth ranges from 4,954 to 6,164 ft TVD.

The average porosity of the upper confining zone is 29.3% (based on data from 17 wells with porosity logs and 10,044 individual logging data points), and its average permeability is 0.34 mD (based on data from the Citizen_Green_1 well, about 8 miles north of the AoR, NMR permeability from the Timur-Coates method).

XRD and FTIR data presented in Table 2.4-1 is available from three wells located in the Rio Vista Gas Field located approximately 12 miles north of the AoR. Nine samples contain an average of 32% quartz, 39% plagioclase and potassium feldspar, 29% total clay (primarily a mixed layer illite/smectite with kaolinite and chlorite present), minimal pyrite, and less than 1% calcite and dolomite.

H&T Shale (Lower Confining Zone)

The H&T Shale directly underlies the injection zone in the AoR and will serve as the lower confining zone for the CTV III project. Mineralogical data was available from well Speckman_Decarli_1 well located 6 miles outside the AoR (Table 2.4-1), where nine shale samples averaged 46% total clay, with mixed layer illite/smectite being the dominant species and kaolinite and chlorite still prevalent. They also contain 23% quartz, 29% plagioclase and potassium feldspar, 2% pyrite, and 1% calcite and dolomite. The average porosity of the lower confining zone is 21.4% (based on data from 16 wells with porosity logs and 31,279 individual logging data points), and its average permeability is 0.49 mD (based on data from 16 wells with porosity logs and 30,853 individual logging data points).

Questions for CTV:

- ***Where are the two wells (described on pg. 24) that are the source of the core data used for the permeability transform?***
- ***What site-specific evidence is available to support the statement on pg. 31 that variability in the thickness and depth of the injection or confining zones will not affect containment?***
- ***Where is the Meganos Submarine Canyon relative to the AoR? For clarity, please denote this feature on Figure 2.2-4 and other relevant figures.***
- ***Please explain why the Winters Formation is considered to be a representative analog for the proposed injection zone within the Mokelumne River Formation.***
- ***Why does CTV consider capillary pressure data for the Winters Formation to be an appropriate value for the Mokelumne River Formation within the AoR?***

- ***Which of the "wells with relative perm or capillary pressure data" on Figure 2.1-7 provided the capillary pressure data used?***

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

CTV acquired data from 6 wells comprising 3,769 individual logging data points within the AoR that, it asserted, had suitable compressional sonic and bulk density data to determine confining zone ductility. Unconfined compressive strength (UCS) of the confining zone was based on data from 15 wells comprising 9,413 individual logging data points within the AoR that had suitable data over the Capay Shale upper confining zone. The average rock strength of the upper confining zone was determined to be 2,091 psi as calculated using a log derived UCS methodology (Ingram et. Al., 1997). Based on calculations performed for well Ohlendorf_Unit_1_1 located in the southeastern portion of the AoR, the brittleness index (RBI) of the Capay Shale upper confining zone, and the Nortonville Shale above, decreases to a factor of <2.0, which CTV considers to be ductile and less prone to fracturing. Figure 2.5-1 presents log-based unconfined compressive strength and ductility calculations from well Ohlendorf_Unit_1_1. The figure appears to be missing the brittleness factor described in the narrative. **EPA recommends that CTV perform a triaxial load test as part of pre-operational testing, consistent with the Class VI Site Characterization Guidance.**

CTV states that the AoR has a strike-slip/reverse fault regime based on studies conducted within the Sacramento basin. The maximum principal horizontal stress orientation is estimated to be N40^{o}E±10^{o} which is consistent with regional data (Heidback et al., 2016) and is shown on Figure 2.5-3.

No site-specific fracture pressure and fracture gradient is available for the Mokelumne River Formation injection zone, or pore pressure data for the confining zones, but CTV intends to collect this information via pre-operational step rate testing. Fracture gradients are available for the H&T Shale lower confining zone and for the Mokelumne River Formation injection zone outside of the AoR. These gradients are based on formation integrity testing from wells within the AoR (see Figure 2.5-4). The fracture gradient was observed to range from 0.75 to 0.76 psi/ft from these wells, and CTV applied a fracture gradient of 0.76 psi/ft for their computational modeling. CTV states that the overburden stress gradient in the reservoir and confining zone is 0.91 psi/ft.

Questions for CTV:

- ***The narrative states that the brittleness factor for the Ohlendorf_Unit_1_1 well is shown on Figure 2.5-1; however, this is not included on the figure. Please revise the figure.***
- ***Please clarify where the 0.91 psi/ft overburden stress gradient was referenced, or state how it was determined.***

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

CTV researched historical seismic events within the vicinity of the project site via the U.S. Geologic Survey (USGS) earthquake catalog of events of a magnitude greater than 3 from 1850 to the present. Figure 2.6-2 shows the locations of the events, and Table 2.6-1 summarizes the events, including their date, depth, and magnitude. Based on the historical earthquake data, fifteen events have occurred from 1866 through 2018; their depths ranged from 2.9 to 18 km and magnitudes ranged from 3.1 to 6.0. The most recent event (magnitude 3.2) occurred in 2018 approximately 7 miles northwest of the AoR boundary at a depth of 10.4 km. The closest events occurred in 1979 and 2002, within the western and southern portions of the AoR. The shallowest event occurred in 1976 over 11 miles from the southern edge of the AoR at a depth of 2.9 km at a magnitude of 3.3. The highest magnitude earthquakes occurred in 1866 and 1889, but these events occurred over 10 miles to the northwest and south of the AoR boundary. The depth of these events is unknown.

As described above, major fault systems near the project include the Midland Fault, the West Tracy Fault, and the Stockton Fault which surround and bound the AoR to the east, south, and west, respectively. In characterizing the risk of induced seismicity associated with CO_2 injection, CTV describes potential links between select natural events and the surrounding major fault systems. The event that poses the most concern would be Event 3 from Table 2.6-1, a magnitude 3.4 event within the western portion of the AoR in 2002. However, this event occurred at the depth of the basement rock, at around 16,000 ft. CTV asserts that fault stability within the project is demonstrated based on the surrounding formations around the faults trapping hydrocarbons at pressures above hydrostatic. CTV states that injection operations will result in formation pressures that are lower than pre-gas-production historical reservoir pressures that were exerted on the faults. However, they provide no data within the narrative on which this assertion is based, e.g., pre-gas-production reservoir pressure vs. model-predicted pressure increases. Figure 2.6-3 of the Narrative shows the proposed injection site in an area of low relative stress magnitude and minimal clusters of stress inversions.

There is no discussion regarding the natural or potential induced seismicity along the normal fault that is located within the projected CO_2 plume area. In subsection 2.6.2, CTV asserts that the normal fault does not breach the confining zones, which contradicts the interpreted seismic data presented in Figure 2.3-2. Confirmation during pre-operational testing that the normal fault will not interfere with containment of CO_2 is required, per 40 CFR 146.82(a)(3)(ii).

CTV intends to monitor for pressure changes and associated seismicity as part of the Testing and Monitoring during operation. CTV's seismic hazard mitigation is detailed in Section 2.6.2.

Questions for CTV:

- ***Please provide an evaluation, based on site-specific data and in consideration of proposed operating data (e.g., injection pressure), of the potential for induced seismicity along the normal fault within the AoR.***
- ***Please discuss further how the anticipated pressure increases due to CO_2 injection compare to existing/historical reservoir pressures and why CTV asserts that there are no concerns for fault reactivation.***
- ***What pre-operational testing will be conducted to confirm CTV's assumptions regarding seismic hazards and induced seismicity?***

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

The CTV III project site AoR is located mostly within the western portion of the Tracy Subbasin in the San Joaquin Valley Groundwater Basin (Figure 2.7-1). A portion of the western section of the AoR extends over to the East Contra Costa Subbasin. Surface water sources in the area include the San Joaquin River, the Old River, and the Middle River. Man-made hydrological features include the California Aqueduct, Delta-Mendota Canal, and other irrigation canals.

CTV identifies both the base of fresh water (BFW) and the base of the lowermost USDW (Figures 2.7-2 and 2.2-4, respectively). Groundwater usage is somewhat limited to the eastern Contra Costa County and the Tracy City area to the south, and the occurrence of groundwater is linked to the layers of sand

and gravel from river channels and flood deposits that are bound by lower permeable clays and silts. The base of the lowermost USDW is estimated to be within the Markley Formation at a depth of 2,541 ft based on geophysical logs and salinity calculations. The four-step process CTV used to conduct salinity calculations is described in Subsection 2.7.2.2; however, this is based on data from outside of the AoR. The Markley Formation has a calculated total dissolved solids (TDS) content of 3,000 to 10,000 mg/L; pre-operational water quality testing will be needed to provide a more precise TDS content. Other formations identified as containing USDWs in the Tracy Subbasin include Alluvium, Flood Basin and Intertidal deposits, Alluvial Fan Deposits, Older Alluvium, Modesto Formation, Los Banos Alluvium, Tulare Formation, and Fanglomerates. These formations are depicted in Figure 2.7-1.

Hydrogeologic cross sections of the Tracy Subbasin are provided in Section 2.7.4. Cross Section B-B' in Figure 2.7-4 runs northwest-southeast through the non-Delta and Delta portions of the Tracy Subbasin. Cross Section C-C’ in Figure 2.7-5 runs northeast-southwest across the Delta area. These cross sections demonstrate the principal aquifers of the Tracy Subbasin – the Upper and Lower Aquifer zones – and their separation from the injection zone by the Corcoran Clay, a lakebed deposit within the Tulare Formation. The Upper Aquifer is an unconfined to semi-confined aquifer existing in the Alluvial Fan Deposits, Intertidal Deposits, Modesto Formation, Flood Basin Deposits, and the upper portions of the Tulare Formation. CTV reports that the Upper Aquifer is used by community water systems and for agriculture. The Lower Aquifer is mainly comprised of the lower portions of the Tulare Formation below the Corcoran Clay and extends to the base of fresh water, and it is typically used by community water systems and agriculture. The estimated thickness and lateral extent of the separating Corcoran Clay is shown in Figure 2.7-3. Where the Corcoran Clay pinches out in the southern end of the AoR, the Upper and Lower Aquifer zones merge. A schematic profile is provided in Figure 2.7-6.

Potentiometric maps for the Upper and Lower Aquifer zones are provided in Figures 2.7-7 and 2.7-8, respectively. Data on groundwater levels were obtained from the Tracy Subbasin GSP (GEI 2021), which included groundwater level measurements from over 226 wells across the Tracy Subbasin. From these data, a groundwater gradient was established, the details of which are provided in Section 2.7.6. The gradient is typically downward in the aquifer zones. In the non-delta areas, the gradient ranges from a few feet bgs to 70 feet bgs, and groundwater levels are 10 to 30 feet higher in the Upper Aquifer than the Lower Aquifer. In the delta areas, groundwater levels are at sea level.

CTV identified 155 water supply wells within one mile of the AoR using California State Water Resources Control Board Groundwater Ambient Monitoring Assessment Program (GAMA) and Department of Water Resources (DWR) public databases. Water wells are depicted in Figure 2.7-9 and listed in Table 2.7-1. CTV states that Table 2.7-1 includes known water well depths and other available information, but Table 2.7-1 does not appear to be included in the application Narrative document. CTV notes that water wells were identified solely through well logs contained within public records; thus, wells that were not recorded or wells whose records may not have survived are not included in CTV’s tabulation of wells. However, CTV asserts that all local water supply wells are completed in intervals much shallower than the injection zone.

CTV’s permit application narrative includes substantial information on USDWs. **Additional characterization of the lowermost USDW within the Markley Formation to satisfy the requirements of 146.82(a)(5) is required.**

Questions for CTV:

- ***Is any site-specific information available about the TDS content of the Markley Formation that contains the USDW?***
- ***Where are the wells on which the geophysical logs used for the Markley Formation salinity calculations are based?***
- ***On page 46, the reference to Figure 2.2-3 in the statement about TDS range of 3,000 to 10,000 mg/L is incorrect (this figure is a summary map of the seismic data used to build the structural model). Please correct the figure reference.***
- ***Please provide Table 2.7-1 in the text of the narrative or as an attachment.***

Confining Zone and Injection Zone Geochemistry [40 CFR 146.82(a)(6)]

The permit application narrative indicates that no quantitative minerology information exists for the injection or confining zones within the AoR, and that this data will be acquired during pre-operational testing across all zones of interest. Figure 2.4-1 shows the locations of wells with mineralogy data relative to the AoR. Core descriptions from 3 wells located about 35 miles northwest of the AoR and 1 well about 13 miles northeast of the AoR characterize the Mokelumne River Formation injection zone as consisting of quartz, feldspar, and clay. Table 2.4-1 summarizes XRD data from the Speckman_Decarli_1 well (located 6 miles outside the AoR) including 6 reservoir sand samples. CTV evaluated the mineralogy of the H&T Shale lower confining zone from the Speckman_Decarli_1 well (6 miles outside the AoR) and the Capay Shale upper confining zone from the Wilcox_20, RVGU_209, and RVGU_248 wells in the Rio Vista Field. Data from within the AoR for the Mokelumne River injection zone, and the Capay and H&T confining zones should be collected and analyzed during pre-operational testing for comparison to the available XRD data. Mineralogy data for the Capay and H&T shales are summarized in Table 2.4-1. CTV asserts that it does not anticipate any CO_2 compatibility issues with the injection zone due to the larger quartz and feldspar content, limited dissolution, and minimal calcium and magnesium cations. **However, these statements are based on data from wells located 6 miles or more outside of the AoR, and because they form the basis of the geochemical modeling (as described further in CO_2 Stream Compatibility below), collection of site-specific data prior to any authorization to inject is needed to eliminate uncertainties about CO_2-rock-fluid compatibility.**

Fluid samples from 1980 of the Mokelumne River Formation were evaluated from the Midland_Fee_Water_Injection_1 well (located over 13 miles north of the AoR). The formation consists of saline water. Laboratory water chemistry analytical results are provided in the CTV III Geochemical Modeling_V2 pdf document, and summarized on Figure 2.8-1 and Table 2.8-1. The results indicated a TDS concentration of 13,889.4 mg/L, elevated concentrations of chloride and sodium, and a strong calcium and bicarbonate signature. However, given the age of the fluid sample and the distance of the sample source from the AoR, pre-operational water quality testing will be important to confirm these data. Log-based salinity calculations that CTV used to describe the base of the lowermost USDW also showed TDS values ranging from 14,000 – 16,000 ppm in the injection zone, and CTV asserts 15,500 ppm as a conservative estimate. Absent site-specific fluid data from the injection zone, this assertion is reasonable in the pre-construction phase of the project as it appears to be well above the 10,000 ppm threshold for a USDW.

No fluid geochemistry data was available for the Capay Shale and H&T Shale upper and lower confining zones. CTV states that fluid for analysis will only be extracted from the shale if stimulation is performed, and CTV does not anticipate any CO_2 compatibility issues with the formation fluids within the confining zones due to their low permeability and carbonate content. **Additional collection of site-specific data during the pre-operating phase will be necessary to confirm assumptions of site parameters and reduce uncertainty in modeling inputs. Injection formation fluid compatibility is discussed further in CO_2 Stream Compatibility below.**

Question for CTV:

- ***How did CTV determine that the Capay Shale and H&T Shale will only provide formation fluid samples if stimulated?***
- ***Which wells are the sources of the TDS values cited for the Mokelumne River Formation?***

Site Suitability [40 CFR 146.83]

Facies Changes

CTV asserts that available data from wells and seismic data collection demonstrate the integrity and lateral continuity of the injection zone across the AoR, and regional mapping completed by West Coast Regional Carbon Sequestration Partnership, CGS, and the National Energy and Technology Laboratory support the local stratigraphy. The provided maps, cross sections, and seismic data appear to support these assertions. No concerns about potential facies changes that could affect the project were noted as part of this evaluation. **However, as noted elsewhere, these assertions are based on data collected outside the AoR; data collected during pre-operational testing should be evaluated to confirm these assertions and reduce uncertainties in the characterization of facies changes and allow final approval of the AoR.**

Structural Information

The project site is situated in a minor structural trap with a slight dip of about 2.8° to the west, leaving the area mostly flat. The AoR is surrounded on three sides by the Midway, Tracy, and Stockton Arch major faults, which are predicted to contain the pressure front to the west, south, and east. CTV asserts that these structural features, and the confining nature of the shale formations above and below the injection zone, will allow lateral dispersion of the CO_2 across the AoR and contribute to the local immobilization and containment of the CO_2 injectate. A normal fault appears to transect injection zone from the upper confining zone to the lower confining zone. CTV asserts based on formation thicknesses (as shown in maps in the application) that the confining zones are adequately sealing across the 100 ft offset over the upper confining zone and the 170 ft offset across the lower confining zone. These assertions about reginal structural features appear to be supported by available regional data. **However, additional characterization of the faults that form the AoR boundaries and the normal fault is needed to confirm these assertions.** CTV should provide additional evidence of fault sealing, i.e., data to clarify the juxtaposition of units, potential for leakage along faults, catalysis, diagenetic sealing, shale gouge ratio, and/or pressure compartmentalization per EPA's Class VI Site Characterization Guidance.

CO_2 Stream Compatibility

CTV asserts that it does not anticipate any CO_2 compatibility issues with the injection zone due to its dominant quartz and feldspar content, limited dissolution, and minimal calcium and magnesium cations associated with the injection zone formation water. These conclusions are based on the geochemical modeling presented in Appendix 3. CTV conducted geochemical modeling using PHREEQC (pH-REdox-Equilibrium) software, assumed parameters based on analogous data, and measured thermodynamic parameters from the LLNL.dat database from Lawrence Livermore National Laboratory to estimate the compatibility of the injectate with the injection and confining zones (the modeling is presented in Appendix 3).

The modeling input for the formation fluid used to define the baseline geochemistry of the injection zone was derived from the Midland_Fee_Water_Injection_1 fluid sample from the Rio Vista Gas Field, as a sample was not available from within the AoR. This fluid sample was collected from the well in 1980 and had a measured TDS of 13,889.4 mg/L (Figure 2.8-1; Appendix Table 1). Mineralogy inputs for the injection zone were derived from XRD data from the Speckman_Decarli_1 well located outside the AoR, and inputs for the confining zone mineralogy were derived from available data from the wells RVGU_209, RVGU_248, and Wilcox_20 in the Rio Vista Gas Field (Appendix Tables 2 and 4). Estimated compositions for the injectate are provided in Appendix Table 3. An initial reservoir pressure of 207.5 atm and temperature of 66°C were used. The modeling used the injection zone groundwater sample and equilibrated it with injection zone mineralogy data set for the injection zone and CO_2 at given reservoir pressures. Then, the model results for the injection zone were equilibrated with the upper confining zone mineralogy data set and CO_2 at final reservoir pressure.

Predicted reactions from the modeling include mineral dissolutions and precipitations, including carbonate formation and CO_2 dissolution into the formation brine. Mineralogical changes are presented in Table 6, and the final equilibrium aqueous concentrations are presented in Table 7. Molar mass increases due to mineral precipitations were calculated at less than 2% for the injection zone and less than 1.5% for the upper confining zone. The results of the geochemical modeling support CTV's assertion and appear to indicate that there are no concerns for injectivity and that CO_2 injection will not cause significant reactions that will affect the containment of CO_2.

Given the limited amount of geochemical and mineralogic data on the injection and confining zones from within the AoR, geochemical modeling inputs will need to be updated with site-specific data collected within the AoR during pre-operational testing to reduce uncertainty about the geologic characterization of the site and ultimately approve the AoR delineation before CTV is authorized to inject CO_2.

Storage Capacity

CTV estimated the storage capacity for the project area as up to 70.7 million tonnes of CO_2, which CTV states was arrived at through computational modeling. However, the details of this determination were not provided in the narrative application.

Confining Zone Integrity

The Capay Shale and H&T Shale provide upper and lower confinement of the injection zone, respectively. The Capay Shale upper confining zone has a mean thickness of 207 ft within the AoR and the H&T Shale lower confining zone is approximately 200 ft thick, and both are laterally extensive across the AoR. CTV cites local well data (Figure 2.2-1), seismic data (Figure 2.2-3), and regional mapping from West Coast Regional Carbon Sequestration Partnership (WESTCARB), California Geological Surgery (CGS), and the National Energy and Technology Lab (NETL) to support the local stratigraphy and the lateral continuity and regional thickness of the confining zones.

While the upper confining zone is relatively thin (i.e., 100 feet in some areas), pre-operational testing, particularly formation characterization as the injection and monitoring wells are drilled, should confirm uniformity in the thickness and a lack of any transecting faults or fractures to clear potential concerns for confinement. Notably, the transecting normal fault within the extent of the CO_2 plume must be demonstrated to not interfere with containment of the injectate. **Additionally, step-rate testing to determine fracture pressure will be needed to ensure that operating pressures are appropriate to confining zone geomechanical properties.**

Secondary Confinement

CTV asserts that characterizing secondary confinement is not necessary for the CTV III project due to the regional continuity and low permeability of the Capay Shale upper confining zone. However, CTV notes that the Nortonville Shale overlying the Domengine Sandstone acts as a regional seal providing additional upper confinement to the Mokelumne River Formation injection zone. Additional collection of site-specific data on the primary upper confining zone is needed to reduce uncertainty in the geologic characterization and the modeling inputs. Additionally, it is recommended that CTV fully characterize the Nortonville Shale and Domengine Sandstone as secondary confining zones using any available data from the pre-construction phase of the project, pursuant to 40 CFR 146.83(b).

Questions for CTV:

- ***Please provide information and calculations regarding how CTV determined the storage capacity of the injection zone, and how site-specific properties of the injection zone and operational conditions were factored into this evaluation.***
- ***Please characterize the Nortonville Shale and Domengine Sandstone as secondary confining zones to satisfy the requirements of 40 CFR 146.83(b).***

Site Geomodel

CTV developed a static 3D representation of site geology in Schlumberger's Petrel software using well data and 3D seismic data rendered into a geo-cellular grid. The Area of Review and Corrective Action Plan (AoR/CA) document describes the static geomodel created for the AoR delineation. CTV's geomodel appears to be consistent with the site characterization data as described in the narrative document, and there are no initial concerns with the methodologies used to construct the geomodel. All concerns regarding the geomodel reflect the concerns about the deficiencies in site-specific characterization data as described in this evaluation. Details of the geomodel are discussed below.

- The model domain is described in Table 3.1. Figure 3.3 displays the geomodel boundary and geo-cellular grid (shown as hatch marks on the plan view map) used to define the CO_2 plume extent and delineated AoR. CTV rotated the model 40° to align it with local structural and depositional trends. CTV notes that grid sizes are as small as 50 by 50 feet near the injectors, and grid size increases with distance from the injectors. The static geomodel grid layering is displayed in Figure 3.4. Cells were modeled with heights of 20 ft to provide vertical resolution for identification of sand vs. shale layers; this height appears to represent vertical facies distribution when compared to open hole log data from well Allied Properties Et Al 1 (Figure 3.5). **As data are collected from within the AoR during pre-operational testing, the inputs at the finer grids should be revised as necessary to reflect any heterogeneities identified.**
- CTV used Sequential Gaussian simulation with porosity and permeability measurements and calculations (as described in Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)] above) to calculate porosity/permeability distributions for the static geomodel. Histograms of the porosity/permeability distributions are provided in Figure 3.8, and the distribution of these

properties is displayed in cross section view in Figure 3.9. Core data used for these distribution calculations are consistent with data collected from wells outside of the AoR as described in the narrative (Figure 3.6). No site-specific capillary pressure data is available, so CTV used data from the Winters Formation in the neighboring Union Island Gas Field.

- CTV references the results of geochemical modeling provided in Appendix 3: CTV III Geochemical Modeling (described in CO_2 Stream Compatibility above) for potential geochemical reactions in the injection zone. CTV excluded reactive transport from the site geomodel due to the low salinity of the proposed injection zone, the stable mineralogy of the injection zone, and the minor effect of mineralization trapping on the AoR as shown in the IPCC Special Report on Carbon Dioxide Capture and Storage (2005).
- CTV set the Capay Shale upper confining zone as a vertical no-flow boundary in the geomodel. This is consistent with the site characterization, as the Capay is characterized as an upper confining layer in the site characterization. No lower boundary is defined in the geomodel, given the buoyant nature of the CO_2 plume. CTV also considers the Midland, West Tracy and Stockton Arch faults as no-flow boundaries for the western, southern, and part of the eastern edges of the geomodel domain. This assumption is consistent with the site characterization narrative, but substantial pre-operational testing information is needed to confirm that these faults will be pressure sealing within the AoR (see Faults and Fractures [40 CFR 146.82(a)(3)(ii)] above). CTV modeled the northern and the remainder of the eastern edges of the geomodel as open boundaries; this is consistent with the narrative, given the lack of bounding structural features in these directions as described in the narrative.
- Initial reservoir conditions are described in Table 3.2. At an elevation of 6,900 ft MSL, formation temperature is 151°F based on bottom hole temperature data from logs in the area; pressure is 2,860 psi based on downhole RFT data.
- Salinity is 15,500 ppm and is consistent with salinity calculations (based on data from outside the AoR) described in the narrative. As noted above, the results of geochemical modeling based on site-specific formation water quality testing may necessitate revision to these inputs.
- Theinjection zone fracture pressure gradient was assumed to be 0.76 psi/ft based on formation integrity tests conducted on wells Yamada L.W 1 and Galli 1 in the Union Island Gas Field. These wells appear to be located on the western side of the Stockton Arch Fault within one mile of the AoR based on Figure 2.5-4. CTV's assumed fracture pressure gradient is thus consistent with the narrative, but CTV will need to confirm this fracture pressure gradient by conducting a step rate test in the injection zone as part of pre-operational testing. CTV notes that fracture gradient information is unavailable for the Capay Shale upper confining zone, so CTV will also conduct a step rate test for the Capay Shale as part of the pre-operational testing.
- Table 3.4 contains injection pressure details, including the estimated maximum allowable injection pressures at 90% of the assumed fracture pressure and elevations in each well corresponding to the maximum injection pressure. **The fracture pressure used in the model is assumed, and CTV will be required to perform a step rate test to confirm these values as part of the pre-operational testing.**

Overall, the data inputs to the site geomodel are consistent with data collected and described in the narrative document. However, as noted above, many data points require confirmation via pre-operational testing to affirm their appropriateness as modeling inputs to generate a final approvable

AoR. CTV states that the simulation and AoR will be updated once site specific core data is obtained during pre-operational testing.

Questions for CTV:

- ***Figure 3.4 in the AoR/CA Plan appears to be mislabeled as Figure 3.2. Please correct this discrepancy.***
- ***The reference to Figure 3.9 in the AoR/CA Plan on pg. 11 appears to refer to Figure 3.8 a second time. Please correct this typographical error.***
- ***Please provide the data source used to estimate the fracture pressure value used in the geomodel.***
- ***Please further elaborate on the data sources listed in Table 3.2, and please provide the data that were used to determine formation initial conditions.***

Summarized Objectives for Pre-Operational Testing

In their pre-operational testing plan (POTP), CTV describes the formation testing to be performed during drilling of the new injection wells to meet the requirements of 146.87. Pre-operational testing will consist of a logging suite, coring, geohydrologic testing, and reservoir testing on the injection and monitoring wells. The reservoir testing will consist of pressure, temperature, and fluid sampling of the injection zone, monitoring zones, and USDW.

CTV plans to perform wireline logging on the surface, intermediate, and long-string casing sections of the wells. The logging will be a combination of conventional and open-hole logs including deviation checks, dual induction laterolog, gamma ray, caliper, compensation neutron, formation density, and mud log. CTV will also perform geophysical logging in the monitoring wells.

The POTP describes the coring program that will be implemented during the drilling of the injection wells. CTV states that it plans to collect a whole core and sidewall core from one of the wells to determine the properties of the confining layer and injection zone (however, they do not specify in which wells the cores will be taken and at what depths). However, consistent with the requirements of 146.87(b) which would apply to each Class VI permit (i.e., for each of the injection wells) and to provide for a more complete site characterization of the entire AoR, CTV will be required to sample cores in each of the proposed injection wells. The proposed core analysis includes porosity, permeability, saturation, grain density, and general core descriptions. Specialized core analysis will also be conducted and include capillary pressure, XRD, CO_2 to water permeability, confining and injection zone geomechanical measurements, pore compressibility, and scanning electron microscopy (SEM).

While CTV did not include the specific procedures for performing the testing described above, this testing should address the data uncertainties identified.

CTV will perform a step rate test on the injection and formation monitoring wells as part of the reservoir testing to define fracture gradients of the confining and injection zone formations. CTV will also perform injectivity and pressure fall-off tests in the injection wells prior to CO_2 injection. **Approval of all pre-operational testing procedures will be needed prior to well construction and testing.**

Based on the data gaps identified in the evaluation as described above, additional pre-operational testing objectives (listed below) can help address the uncertainties identified.

Pre-Operational Testing Objectives:

- Identify site-specific mineral composition and petrophysical characteristics of the injection and confining zones at the location of each injection well.
- Clarify formation ductility, principal stresses, pore pressure, fracture gradient, and other petrophysical parameters to confirm assumptions used in geomechanical modeling.
- Determine static fluid levels (per 40 CFR 146.87(c)).
- Characterize the hydrogeologic characteristics of the injection zones using a pump test or injectivity test (per 146.87(e)).
- Characterize formation fluid geochemistry and identify potential geochemical reactions and interactions between the injection and confining zone mineralogies and formation brines with the CO_2 injectate to confirm the assumptions and results of the initial geochemical modeling to predict changes in formation water chemistry, mineral precipitation, and dissolution reactions.
- Identify potential fractures within the carbonates of the Capay and H&T Shale confining zones and evaluate their effect on confinement.
- Determine precise injection zone storage capacity based on site-specific injection zone characteristics and operational data.
- Confirm pressure isolation within the Mokelumne River Formation injection zone and other stratigraphic intervals across the major faults surrounding the AoR.
- Confirm that the unnamed normal fault transecting the upper and lower confining zones within the boundary of the CO_2 plume will not interfere with containment (per 40 CFR 146.82(a)(3)(ii); see Section 3.5.2 of EPA's Class VI Site Characterization Guidance).

Questions for CTV:

- ***Please update Attachment G to include the following:***
  - ***Detailed procedures for all planned testing.***
  - ***Core sampling in each of the injection wells to provide a distribution of site-specific data, which will aid in accuracy.***
  - ***Triaxial load testing to determine compressive strength and ductility in the upper confining zone.***

Comments on CTV III Computational Modeling
Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY22-5.1-5.6

This Computational and Static Modeling Evaluation report for the proposed Carbon TerraVault III (CTV) Class VI geologic sequestration project summarizes EPA's review of the computational modeling performed by CTV as described in the Narrative Report (Attachment A, Version 4) and the Area of Review and Corrective Action Plan (AoR CAP) (Attachment B, Version 3.1). Clarifying questions or requests that require further work are provided below in ***bold, italic*** text. Text that is not ***bold, italic*** is provided to give background information or is recommended for further work.

Summary of Significant Comments

1. CTV models the Midland Fault to the west, the Stockton Arch Fault to the east, and the West Tracy Fault as no-flow boundaries. The impact of the three no-flow boundaries is to limit the extent of the AoR boundary to the south while allowing greater extent of the AoR to the north. ***Please provide strong evidence about the impermeability of these faults that would justify their consideration as no-flow boundaries. Alternatively, expansion of the western, eastern and southern boundaries of the modeled domain beyond these faults, and implementation of appropriate properties for these fault zones, could be used to show that these faults are appropriate no-flow boundaries.***
2. The model horizontal extent should be larger than the current version. The pressure plume is expected to preferentially extend toward the north, north-east boundary given that combination of no-flow boundaries at the top and bottom and south and west sides. The current boundary location will artificially impose a pressure gradient that will not be reflective of an open flow boundary condition in spite of the use of a large volume multiplier for the boundary blocks. ***To accurately represent the open flow boundary condition, please use GEM's "aquifer" option and test the sensitivity of the predicted pressure plume (and subsequent AoR) to the parameters used to set up the open flow boundary condition.***
3. In the absence of site-specific data, the applicant used relative permeability curves measured on cores from a different formation from the neighboring gas field. The residual liquid saturation on this data is rather high. Given that the residual saturation and subsequently the gas relative permeability affect the CO_2 plume extent and post-injection migration, it will be important to understand the sensitivity of these to the assumed relative permeability curve parameters. ***Please conduct a thorough uncertainty analysis of relative permeability-capillary pressure-saturation function parameters (ideally also including hysteresis).***
4. The applicant has postulated that the target zone is under-pressured due to gas production from the same formation. This implies that there is potential for pressure communication between the proposed injection operations and any active gas production operations within the boundary of the pressure plume. ***Please take into consideration this potential interference and its effect on CO_2 and pressure plumes in the model.***
5. The approach used to determine the sensitivity of the predicted AoR to porosity and permeability values may not be adequate. ***Please develop P10, P50, P90 realizations of porosity and permeability to assess the sensitivity of predicted pressure and saturation fronts (and related AoR) to those parameter uncertainties.***

Model Suitability

6. The CMG-GEM compositional simulator has capabilities to accommodate site-specific geologic conditions, including faults, and operational conditions such as wells with multiple perforations

and varying injection schedules. The applicant simulated known faults that are shown to be barriers to flow, including the Midland, West Tracy, and Stockton Arch faults to define the western and southern boundaries.

7. ***It is not specified how injection occurs into the well: is there a wellbore model, a source at the top of the well and a large vertical permeability in grid blocks representing the well, or mass sources distributed along the well with strength proportional to permeability-thickness product of the layer?***
8. Salt precipitation is not mentioned. Salt precipitation can decrease near-well porosity and permeability, thereby decreasing injectivity. Site-specific relative permeability and capillary pressure curves, and a fine grid around the injection well are required to assess this issue, which should be done when site-specific data becomes available.
9. No temperature changes are shown. Minor effects are expected if CO_2 injection temperature is the same as initial reservoir temperature, but injection temperature is not provided.

Model Design

10. The lateral extent of the computational model appears adequate to cover the extent of the CO_2 plume, but not the pressure pulse. The lateral boundaries representing sealing faults are appropriate. The extent of the model where there are no fault boundaries (to the North and Northeast) is only about 8-10 miles from the injection wells. A good rule of thumb for estimating how far a grid needs to extend to not impose an artificial boundary condition on a problem is to use the pressure diffusion length: $L = [4kt/(\mu\phi C)]^{1/2}$, where L (m) is the distance the pressure pulse extends to in time t (sec), k is permeability (m^2), μ is viscosity (Pa-sec), ϕ is porosity, and C is pore compressibility (Pa^{-1}). Taking k = 75.4 mD and ϕ = 0.26 from the problem specifications, estimating μ = 4.46e-4 Pa-sec for T=66 °C and salinity of 15,500 ppm, and assuming a moderate C = 3e-9 Pa^{-1} (not specified in application), yields L = 17.3 mi at the end of the 40-year injection period and L = 37 mi at the end of the 140-year post-injection period. This calculation indicates that the lateral extent of the current grid may be too small. ***Please provide results of the predicted pressure at the end of the injection and the end of the simulation time.*** Given that three side boundaries and the top and bottom of the injection zone are no flow boundaries, the pressure front will extend unsymmetrically towards the north, north-east side of the model domain and most probably beyond the current model boundary.
11. Lateral spacing ranges from 50' x 50' around the injectors, increasing to 500' x 500' and to 100' x 100' in the far-field. The grid spacing is probably fine for the bulk of the model, but it is much too coarse to properly resolve near-injection-well effects such as the actual pressure increase during injection, formation of a dryout zone, and salt precipitation. ***Please revise the model to include smaller grid spacing near the injectors.***
12. The injection rate is constant, and the resulting pressure response stays below maximum operating pressure. However, the grid resolution at the injection well is too coarse to properly calculate the near-injection well pressure. Unless the model includes a special well feature that eliminates the need for fine grid resolution near the well (which CMG-GEM has but is not mentioned in the application), then modeled pressure will be too small, possibly enabling injection rate to be too large.
13. The Western, Southern, and part of the Eastern edge of the model domain, defined by the Midland, West Tracy and Stockton Arch faults are set as no-flow boundaries. The remaining Northern and part of the Eastern Edges of the model domain are stated to be "modeled as open boundaries using large volume modifiers at the edge cells to model an infinite aquifer." However, large volume modifiers make the boundary a constant-property boundary, in

particular a constant-pressure boundary. As mentioned earlier, the pressure plume will likely extend beyond the current grid boundary. The predicted pressure response will be sensitive to the value of the volume modifier especially given that the grid used for simulations may not be adequately large. The combination of the grid dimension and assumed volume modifier value will artificially influence predicted pressure. This could dampen the modeled pressure response to injection and make the predicted AoR too small. CMG-GEM has an "aquifer" option available for lateral boundary conditions, which enables the boundary to model an infinite aquifer. ***Please use the "aquifer" option instead of using large volume modifiers. It is recommended to study the sensitivity of the predicted pressure response to both grid dimension and the parameters used to set up the infinite aquifer.***

14. In the absence of site-specific data on the caprock, the applicant has assumed that the caprock (shale) has the same geomechanical response as the target zone (sandstone) and assumed that the fracture pressure of the caprock is the same as that of the target zone. ***Please provide justification for these assumptions.***
15. ***Please create plots of CO_2 saturation/pressure vs. lateral distance from the injection wells at various times, CO_2 saturation/pressure vs. time at the distance corresponding to the leading edge of the plume after CO_2 injection is terminated, and distance traversed by the plume for the injection and post-injection periods vs. time, in order to provide further evidence that plume movement has ended and that pressure has stabilized.***

Input Parameters vs. Site-Specific Conditions

16. ***Please clarify how temperature, pressure, and salinity were populated throughout the model domain.*** It appears that the model was run as isothermal at average reservoir temperatures despite its large thickness. The application does not discuss the local geothermal gradient and how much the temperature would vary based on the target injection zone. Given that CO_2 properties including density and viscosity are strongly dependent on the temperature and these properties affect the CO_2 movement and plume extent, it will be important to assess the variability of the temperature over injection interval and subsequent variability in the CO_2 plume extent and migration. ***Please clarify whether the initial pressure condition in the reservoir was set based on a hydrostatic equilibrium or constant pressure.***
17. Hysteretic gas-phase relative permeability is claimed to be used, but the plots provided of relative permeability and capillary pressure (Figures 3.10 and 3.11) are non-hysteretic. ***Please provide hysteretic gas-phase relative permeability plots.***
18. ***Please provide the values used for the vertical permeability and the pore compressibility.***
19. The applicant determined the fracture gradient of the injection zone from the results of formation integrity tests in the Mokelumne River formation in nearby wells, and thereby determined the maximum pressure allowable in the storage formation. Plots of average pressure resulting from CO_2 injection suggest that reservoir pressure neared but did not come anywhere close to that value. However, pressure at the wells will be much larger than average reservoir pressure. ***Please verify that the pressure at the wells will be less than the fracture gradient of the injection zone.***

Description of Computational Modeling Results

20. The critical pressure calculation was not documented adequately. Figure 3.17 shows that the storage formation is underpressured relative to the deepest USDW. However, the applicant does not use EPA's suggested formula for the underpressured case (EPA 2013, Method 1, Eq-1, Eq-2). Instead, they use EPA's suggested formula (Nicot et al., 2009, Eq. 9) designed for the

hydrostatic case, with an ad hoc correction to account for underpressure (Eqs. (1) and (2)), with no explanation or justification. Even if Eqs. (1) and (2) do represent a reasonable approach, the applicant did not show the values for any of the variables that go into these equations except one (the amount of underpressure). They do not show any resulting critical pressure values, only the corresponding AoR footprint. A better approach would be to consider the geometry for which critical pressure will be a minimum (the smallest distance between the top of the storage formation and the bottom of the USDW), and calculate that one value of critical pressure, for which there is one set of input parameters to Eqs. (1) and (2). Then all the parameters should be displayed in a table. Also, as stated earlier the sensitivity of predicted pressure with respect to the imposed boundary condition and grid will affect the predicted AoR. ***Please revise the critical pressure calculation.***

21. ***In Figure 3.12, which shows CO_2 saturation at 100 years as a color map, please include values on the color scale.*** This will make it possible to see whether a dryout zone developed.
22. ***In Figure 3.12 and Figure 3.13, please identify the horizon or depth of the cross sections in plan view.***

Model Calibration and Sensitivity Analyses

23. A regression relationship between porosity and horizontal permeability was derived from well log and core analysis using 13 data points from two wells located near the AoR. Then porosities from well-logs from about 70 wells within the model footprint were used to create a 3D porosity distribution and then a 3D horizontal permeability distribution. Permeability and porosity values were only varied by 10% from the mean. This is a very low variability and is not really a rigorous uncertainty quantification. ***Please develop P10, P50, P90 realizations of porosity and permeability to assess the sensitivity of predicted pressure and saturation fronts (and related AoR) to those parameter uncertainties.*** This should not be too time-consuming or computationally expensive given that the applicant has already utilized a sequential gaussian based kriging approach.
24. Based on the range of porosity and permeability values, the sensitivity analysis does not represent a conservative approach since the range of variability used by the applicant is too small.
25. ***Please perform a mesh refinement sensitivity study.*** The applicant claimed to use 50' wide cells in the injection zone, but these are not shown in the grid figure. Even 50' is too large to properly model a potential water vaporization/dry out region and salt precipitation, and accurately reproduce pressure changes at the well.

General Comments

26. ***Geomechanical modeling is needed because of the presence of the faults. A leakage risk assessment for faults and penetrating wells is also needed.***
27. Many figures and tables are too low resolution - details cannot be read.
28. References for critical pressure calculation are missing: Nicot et al., 2009 and McCutcheon et al., 1993.
29. The residual liquid saturation (Slr=0.53) is very large, making both liquid and gaseous relative permeabilities rather small. It would be worthwhile trying smaller values of Slr in the sensitivity studies (possibly in conjunction with higher intrinsic permeability), to see if the CO_2 plume moves more post-injection. As it is currently, it scarcely moves at all.

30. The brine density (1010 kg/m3) and viscosity (1.26E-3 Pa-sec) at reservoir conditions (T = 151 °F = 66 °C and P = 19.7 MPa = 2860 psi, salinity 15,500 ppm) both seem too big. Justification for these values is needed.
31. The lowermost USDW is referred to as "*undifferentiated non-marine sediments*" in one place and as "*the Markley Formation*" elsewhere. Please clarify the inconsistency.
32. The file "Att A – CTV III Storage Project_V4.pdf" (Project Narrative), Figure 2.7-4 shows a cross section B-B'. Along the cross-section, intersections with other cross-sections are indicated: C-C' seems to be in the wrong place, D-D' and E-E' are never mentioned, and B-B' does not make sense for a cross-section to intersect itself.
33. Some Figures were numbered incorrectly, e.g., Figure 3.2 was used twice on pages 5 and 8 of the "Att B - AoR_CA CTV III V3.1.pdf" file.
34. On page 20 of the "Att B - AoR_CA CTV III V3.1.pdf" file, the applicant notes that "*The results of CTV's simulation compare favorably against the previous work by LBNL regarding storage capacity and CO_2 plume size.*". The applicant neither shows any comparison plot nor cited the LBNL's study that was referenced.
35. On page 20 of the "Att B - AoR_CA CTV III V3.1.pdf" file, Figure 1 should be named Figure 3.15.
36. On page 20 of the "Att B - AoR_CA CTV III V3.1.pdf" file, the applicant notes that "*The CO_2 plume for Injectate 1 and Injectate 2 is consistent with the plume outline for 100% CO_2 injectate (Figure 1), which was defined by a 0.05 global CO_2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 1.*". There is no Figure 1 in the report.
37. On page 27 of the "Att B - AoR_CA CTV III V3.1.pdf" file, the applicant states that "*Attachment B-3 shows diagrams for the current well configuration and proposed corrective action*." Attachment B-3 is missing.

ENCLOSURE
Request for Additional Information
Project Interference with the Pelican Renewables and CTV V Projects
Carbon TerraVault Holdings LLC (CTV) III Project
Underground Injection Control (UIC) Permit Application
Class VI Pre-Construction Permit Application Nos. R9UIC-CA6-FY22-5.1-5.6

This Enclosure for the proposed CTV III Class VI geologic sequestration project summarizes an issue that came to light during the technical review of this project and during the technical review of other Class VI permit applications located near CTV III's Area of Review (AoR). The Pelican Renewables (Pelican) project is proposed to be located on Rindge Tract Island and has a calculated AoR approximately five (5) miles away from the CTV III AoR, and the CTV V project located in Sacramento Valley, nine (9) miles east of the Rio Vista Gas Field and four miles northwest of Stockton, California is also close to the proposed CTV III project. A preliminary investigation determined that the pressure changes from the three projects are overlapping.

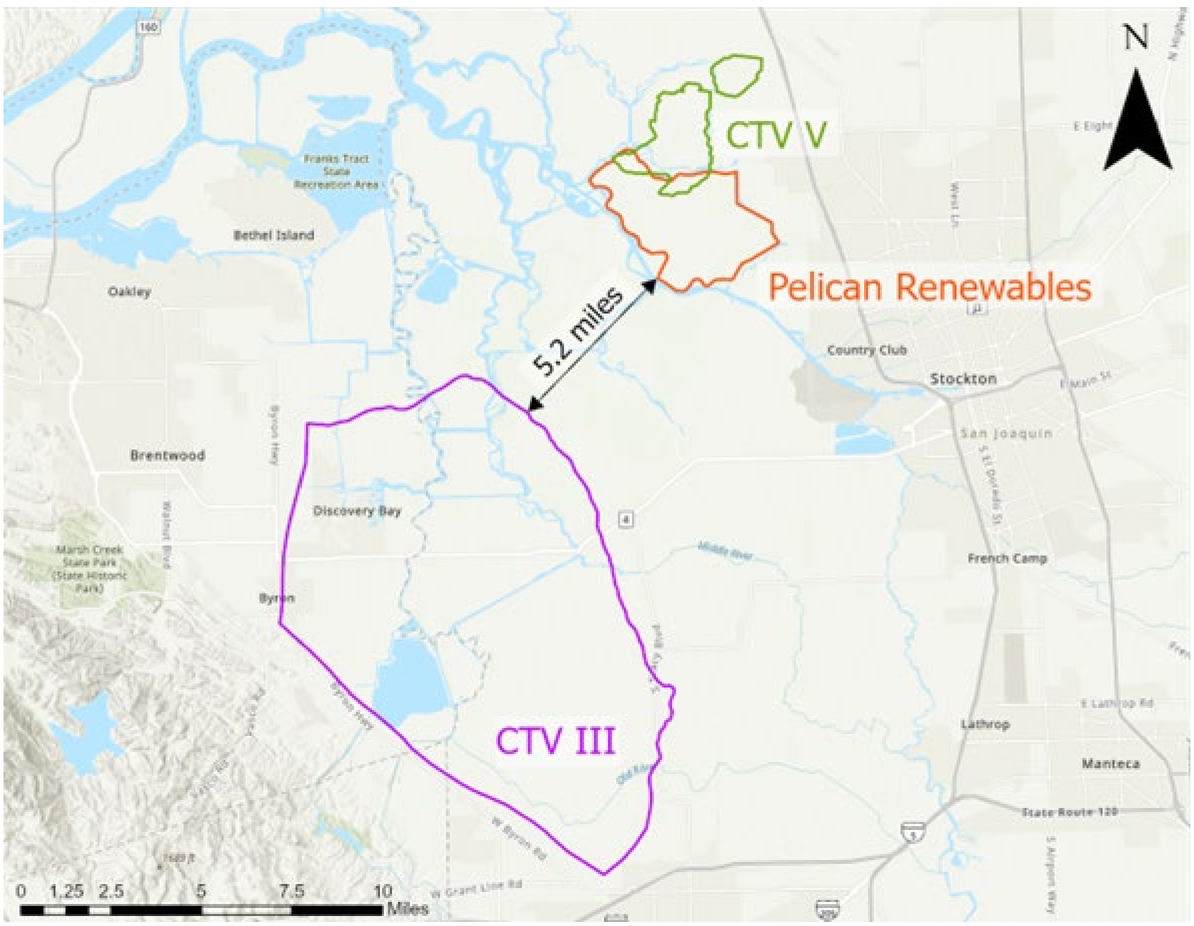

Figure 1: Proposed Area of Reviews of the CTV III, CTV V, and Pelican projects.

The three projects present similar geological models and subsurface stratigraphy that need to be investigated due to their potential to overlap. For example, pressure propagation results for CTV III and

Pelican are shown in **Figure 5** where the red line on the left side of the figure is the extent of the AoR for CTV III, and the right side of the figure shows the pressure change (delta Pressure) for Pelican.

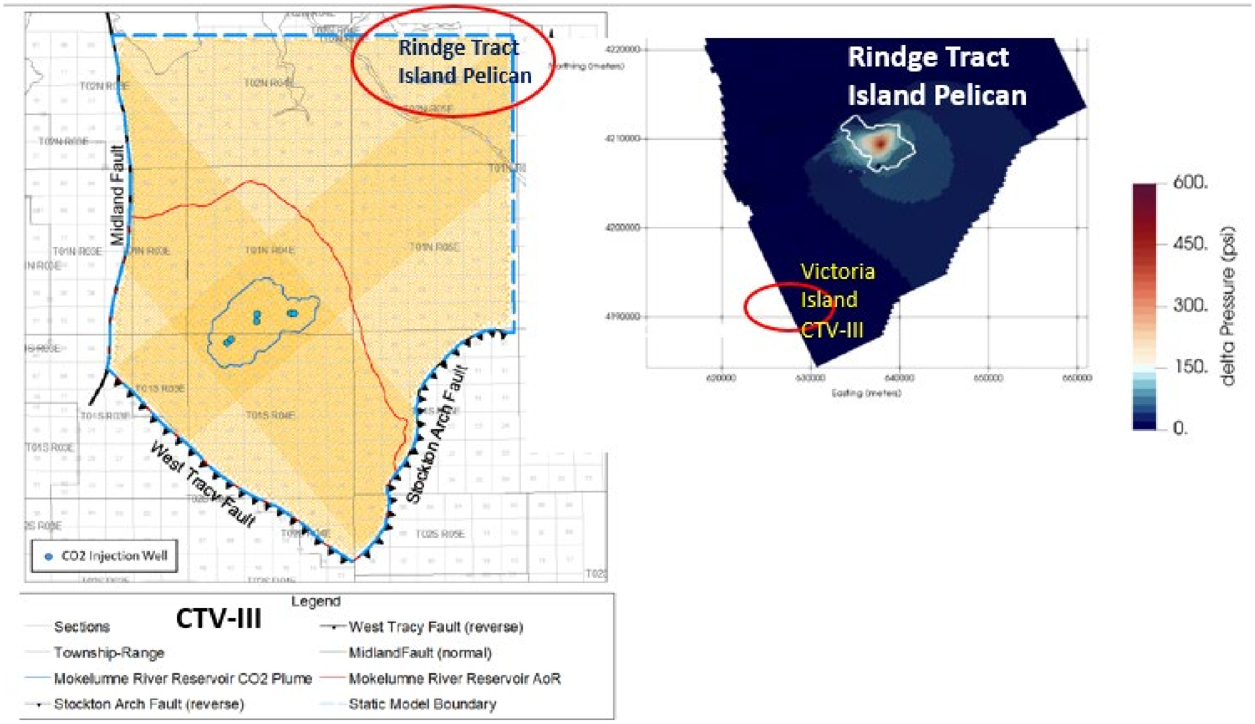

Figure 2: Comparison of pressure impacts from the CTV III project (left) and the Pelican project (right).

EPA guidance[1] states that "In all cases, EPA recommends that AoR delineation models account for all wells injecting into (including any injection wells associated with other UIC well classes or other Class VI operations) or pumping from the injection zone or any other zones that are hydraulically connected to the injection zone." Pressure plumes follow the principle of superposition, where pressure is additive. Thus, to correctly calculate the AoR for these three close sites, CTV and Pelican should include the pressure buildup of the other sites in their calculations; for example, add an extra injection well to reflect the total injection volume from the other projects in the simulations.

Please propose how CTV would like to proceed. Pelican has been provided this information as well, and their application materials can be found on the EPA's website[2]. If it would be helpful, EPA can facilitate a meeting between CTV and Pelican to discuss this issue.

[1] https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13005.pdf
[2] https://www.epa.gov/uic/uic-permits-epas-pacific-southwest-region-9#class-vi