ATTACHMENT G1: INJECTOR KI-I-S1 CONSTRUCTION AND PLUGGING PLAN
40 CFR 146.86, 146.92

CTV V– Storage Project

Injection Well KI-I-S1

1.0 Document Version History

Version	Revision Date	File Name	Description of Change
1	5/31/2023	Att G1 – CP – Inj – KI-I-S1_v1	Original Submission

2.0 Facility Information

Facility Name: CTV V Storage Project

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Well Location: CTV V, San Joaquin County, CA
38.08 / -121.42

3.0 Introduction

Carbon Terra Vault Holdings, LLC (CTV) intends to drill six new CO_2 injection wells (three Upper Injection Zone injectors and three Lower Injection Zone injectors) for CO_2 injection for the CTV V storage project. **Figure 1** identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as logging while drilling (LWD) and mud logs to ensure protection of shallow formations. Due to the depth of the base of lowermost underground source of drinking water (USDW), surface casing will be utilized to isolate and protect the USDW. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

Appendix 5: Injection and Monitoring Well Schematics provides casing diagram figures for all injection and monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

4.0 Construction Details

4.1 Injectate Migration Prevention and Protection of the USDW

New well construction will occur during the pre-operational testing phase, and no abnormal drilling and completion challenges are anticipated. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates, to prevent migration of fluids out of the injection zones, to protect USDWs and the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors.
- Multiple cemented casing strings will protect shallow USDW-bearing zones from contacting injection fluid within the production tubing.
- All casing strings will be cemented in place using industry-proven recommended practices for slurry design and placement. The surface casing will be cemented with cement returns to surface. The intermediate and long-string casing will be cemented with a theoretical volume to surface.
- Cement-bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer.
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus.
- Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained and MIT to be conducted.
- Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions.
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

The injection well will be constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications:

- API Spec 5CT / ISO 11960 – Specifications for Casing and Tubing
- API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
- API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
- API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
- API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

4.2 Materials

Well materials utilized will be compatible with the CO_2 injectate to prevent the loss of mechanical integrity in the well:

- Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification.
- Packer – corrosion-resistant alloy or coating and hardened rubber elastomer element material.
- Casing – standard N-80 casing will be installed to be compatible with the CO_2 injectate and verified through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
- Cement – Portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 where good cement bond between formation and casing exists.

4.3 Casing

The Upper and Lower Injection zones are neither significantly depleted nor over pressured, and formation temperatures are approximately 136 and 152 degrees Fahrenheit (° F), respectively. 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. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

The casing specifications in **Table 1** are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottom-hole monitoring conditions.

As shown in **Figure 2,** recent subsidence data demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

4.4 Cement

Class G Portland cement will be used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The cement returns will be to surface for the surface casing. The long-string casing string will be cemented in place with Class G Portland cement to surface. Subsequently, a CBL will be run to confirm annular isolation throughout and above the injection and confining formations (Section 6).

4.5 Tubing and Packer

The information in **Appendix 5**: Injection and Monitoring Well Schematics is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications may be modified during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element.

4.6 Annular Fluid

At the time of tubing installation, 4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottom-hole temperatures to prevent internal corrosion of the long-string casing and external corrosion of the tubing.

4.7 Injectate and Formation Fluid Properties

Details about the proposed injectate composition and properties can be found in Section 7.2 of the Narrative Application Report (**Attachment A**). Similarly, the formation fluid composition and properties can be found in Section 2.8.2 of the Narrative document.

The anticipated injection temperature at the wellhead is 90 – 130° F.

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This is ensured by a <25 pounds per million standard cubic feet (lb/MMscf) injectate specification limit, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry-phase CO_2 with no free-phase water present.

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. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate and formation water analysis will be performed during pre-operational testing and reviewed to ensure compatibility with well construction materials.

4.8 Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan (**Attachment C**), injection wells will be configured with real-time injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures (**Appendix 4**) detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The U.S. Environmental Protection Agency (EPA) Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design the injection well with a surface shut-off valve at the wellhead and not a down-hole device.

5.0 Pre-Operational Logging and Testing

The tests and logs listed in **Table 3** will be conducted in accordance with the testing required under 40 CFR 146.87. The methods are described in **Attachment C**: Testing and Monitoring Plan. **Table 3** summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

CTV will notify EPA at least 30 days prior to conducting mechanical integrity and formation tests and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

6.0 Well Operations

Injection operation conditions are detailed in the document titled **Appendix 4**: Operational Procedures.

7.0 Injection Well Plugging Plan

CTV will conduct injection well plugging and abandonment according to the procedures below.

7.1 Planned Tests or Measures to Determine Bottom-hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the weighted cement slurry displacement fluids will be over-balanced to the reservoir pressure ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

7.2 Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well (**Table 4**). Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

7.3 Information on Plugs

CTV will use the materials and methods noted in **Table 5** to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard Portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 pounds per square inch (psi) compressive strength and a maximum liquid permeability of 0.1 millidarcies (mD). The properties of this cement blend will be at least equivalent to the properties of Class G Portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in **Table 5**, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

7.4 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

7.5 Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom-hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore, and (2) there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface

due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to total depth (TD) during rig operations. Subsequent operations are carried out utilizing a CTU.
4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100 feet inside of the cement plug and is pulled up-hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up-hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up-hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CTV follows the following standards for plugging operations:

- Bottom-hole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug [USDW is defined as a non-exempt aquifer that has <10,000 milligrams per liter (mg/L) total dissolved solids (TDS)]:
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

Table 1: Casing details

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (pounds/foot)	Grade (API)	Design Coupling (Short or Long-Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)	Tensile Strength (psi)
Conductor	14 - 54	20	19.124	94	-	-	2.62	-	-	-
Surface	14 – 2,150	9.625	8.755	43.5	N-80	Long	2.62	6,330	3,810	1,065,350
Long string	14 – 4,705 4,705 - 7,709	7	6.276	26	L-80 L-80 CRA	Long	2.62	7,240	5,410	603,930

Note: Burst pressure is the same as internal pressure, collapse pressure is the same as external pressure, and tensile strength is the same as axial loading.

Table 2: Tubing and packer details

Components	Setting Depth Interval (feet)	Tensile Strength/Rating (pounds)	Burst Strength/Rating (psi)	Collapse Strength/Rating (psi)	Material (e.g., weight/grade/connection)
Injection tubing - 3.5 inch	6,420	207,220	10,160	10,530	9.3 lb/ft, L-80 CRA, Premium
Packer	6,390	200,000	7,500	7,500	23-32 lb/ft, Permanent Sealbore Packer, CRA

Table 3: Summary of pre-operational logging and testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
CTV KI-I-S1	Deviation Checks	Every 120 feet during drilling operations
	Dual Induction Laterolog	During drilling operations
	Spontaneous Potential	During drilling operations
	Gamma Ray	During drilling operations
	Caliper	During drilling operations
	Compensated Neutron	During drilling operations
	Formation Density	During drilling operations
	Mud Log	During drilling operations
	Cement Bond Log	Along all casing strings to surface
	Casing Inspection Log	Along the long-string casing to surface
	Internal MIT: SAPT	Casing/tubing annulus above packer
	External MIT (at least one of): Oxygen Activation Log Noise Log	Along the long-string casing to surface
	Injectivity Test	Injection zone
	Pressure Fall-off Testing	Injection zone

Table 4: Planned MITs

Test Description	Location
Temperature	Entire length of the sequestration well

Table 5: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5
Diameter of boring in which plug will be placed (inches)	6.276	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (feet)	7,632	5,131	3,933	2,138	39
Sacks of cement to be used (each plug)	245	23	23	23	10
Slurry volume to be pumped (bbl)	50.18	4.71	4.71	4.71	2.05
Slurry weight (pounds/gallon)	15.8	15.8	15.8	15.8	15.8
Calculated top of plug (feet)	6,321	5,006	3,808	2,013	14
Bottom of plug (feet)	7,632	5,131	3,933	2,138	39
Type of cement or other material	Class G	Class G	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug				

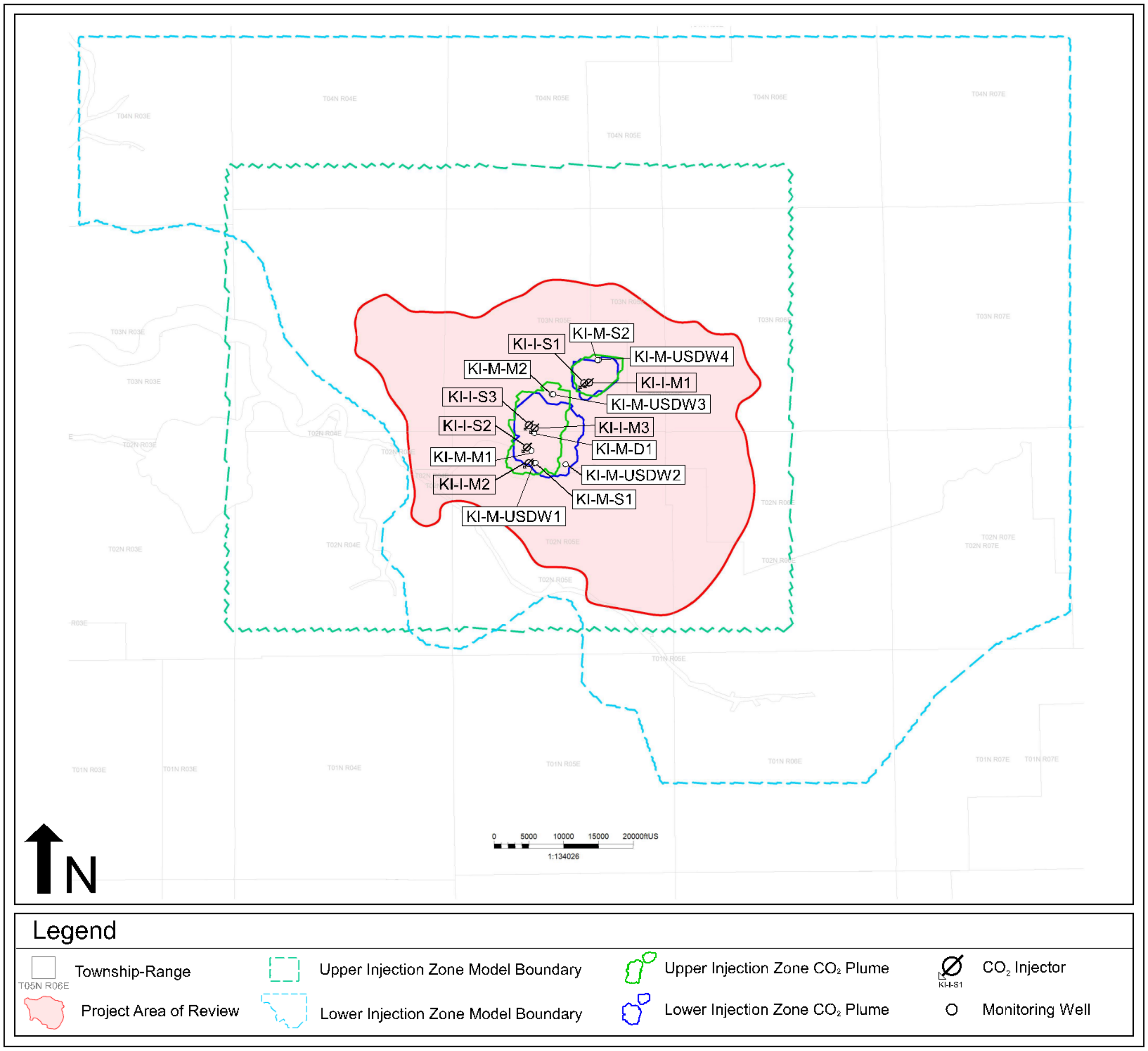

Figure 1. Map showing the location of injection wells and monitoring wells.

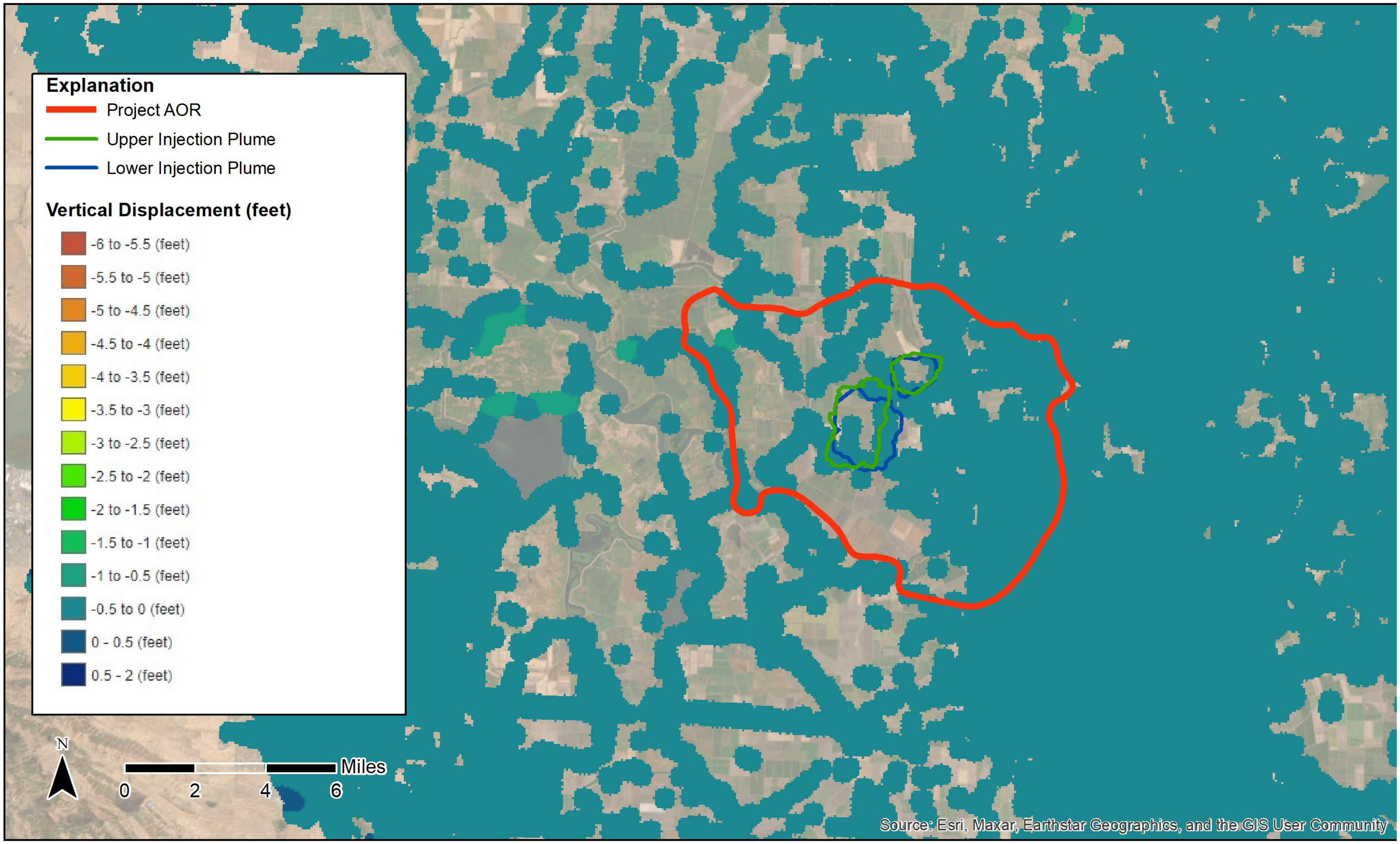

Figure 2. Subsidence in the project Area of Review is -0.5 to 0 feet for June 2015 to July 2022. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).