4 INJECTION WELL CONSTRUCTION PLAN

40 CFR 146.82(a) (9), (11), (12)

TULARE COUNTY CARBON STORAGE PROJECT (TCCSP)

Facility Information

Facility (site) Name: Tulare County Carbon Storage Project (TCCSP)
Facility Operator: TCCSP, LLC.

Facility Contact: [redacted]

Project Location: [redacted] Tulare County, California

Injection Well Name and Coordinates:

Well Name	Latitude	Longitude
TCCSP_INJ-1	[redacted]	[redacted]
TCCSP_INJ-2	[redacted]	[redacted]

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2D	2-Dimensional
3D	3-Dimensional
AoR	Area of Review
bbl/d	Barrels per day
BHP	Bottom Hole Pressure
CCS	Carbon capture, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
D_H	Hydraulic Diameter
DRM	Dynamic Reservoir Model
EoS	Equation of State
EPA	Environmental Protection Agency
f_D	Darcy's Friction Factor
ft	feet
g	Acceleration due to Gravity
GEM	General Equation of State
KB	Kelly Bushing
$k_{r,CO2}$	CO_2 Relative Permeability
kh	Permeability-Thickness Product
k_h	Absolute Horizontal Permeability
k_v	Absolute Vertical Permeability
$k_{r,w}$	Water Relative Permeability
mg/L	milligrams per liter
MIP	Mercury Intrusion Porosimetry
MMt	Millions of Metric tons
MMtpa	Millions of Metric tons per annum
MSL	Mean Sea Level
ΔP	Pressure Drop
ΔP_{TH}	Threshold Pressure
PISC	Post-Injection Site Care
P_{grid}	Grid Block Pressure
pH	Potential Hydrogen
ppm	Parts per Million
psi	Pounds per square inch
psia	Pounds per square inch, absolute
ρ	Fluid Density
ρ_i	Injection Zone Fluid Density
ρ_u	Underground Source for Drinking Water Fluid Density
RCA	Routine Core Analysis
R_e	Reynolds Number
SCA	Specialized Core Analysis
SEM	Static Earth Model
S_{grmax}	Maximum Residual Gas Saturation

SS	Subsea
S_{wconn}	Connate Water Saturation
S_{wirr}	Irreducible Water Saturation
TCCSP	Tulare County Carbon Storage Project
T_{grid}	Grid Block Temperature
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
v	Fluid Velocity
z_i	Injection Zone Top Depth
zu	Underground Source for Drinking Water Bottom Depth

4.1 Introduction

The construction details for TCCSP_INJ-1 and TCCSP_INJ-2 of the Tulare County Carbon Storage Project (TCCSP) are described in this attachment. The injection wells have been designed to accommodate the maximum instantaneous mass rate of [redacted] per well of CO_2 that could be delivered to site in the case that one injection well is shut-in for workover operations. Target average injection rates for each well are listed in **Table 4-1**. Key characteristics of the [redacted], which are the storage reservoirs, were considered in the design of these wells. This attachment illustrates the comprehensive analysis performed to meet U.S. EPA UIC Class VI well design requirements for casing, cement, and wellhead under 40 CFR 146.86(a).

TCCSP_INJ-1 is proposed to be drilled to a total drilled depth (TD) of [redacted] from surface and will be completed in the [redacted] [redacted] with injection taking place for the [redacted]. TCCSP_INJ-2 is proposed to be drilled to [redacted] TD. TCCSP_INJ-2 will be first completed in the [redacted] for [redacted] of injection and subsequently plugged and recompleted into the [redacted] for the remaining [redacted] of injection. This well construction plan has been designed around this completion strategy to utilize the [redacted] while managing the lateral extent of the free phase CO_2 and elevated pressure plume.

4.2 Wellhead Injection Pressure

[redacted] software was used to conduct a nodal analysis to determine the feasibility of injection of the target rate for TCCSP_INJ-1 and TCCSP_INJ-2 through [redacted]. The analysis assumed an estimated wellhead pressure of approximately [redacted]. The nodal analysis was designed with a long-string of [redacted] premium thread long-string set through the injection zone. See **Table 4-4** for long-string casing depths. The injection tubing strings in both injection wells used are planned to be [redacted]. The composition of the CO_2 stream used in the modeling is available in **section 6.3 Specifications of CO_2 Stream** of the **Injection Well Operations Plan.** Modeling results are shown for the two injection wells TCCSP_INJ-1 and TCCSP_INJ-2. Design parameters from the geologic model and target injection rates are shown in **Table 4-1.** The schematics for the tubular design used in nodal analysis are shown in **Figure 4-1**.

Table 4-1. [redacted] Reservoir Data Inputs.

Well	Formation	Average Flow Rate (MMtpa)	Top (ft)	Bottom (ft)	Mid-Point (ft)	Net Thickness (ft)	Pressure at Mid-Point (psi)	Average Permeability (md)	Reservoir Temperature at Mid-Point (F)
TCCSP_INJ-1	[redacted]								
TCCSP_INJ-2	[redacted]								
TCCSP_INJ-2	[redacted]								

[1] [redacted] references the [redacted] including the [redacted].

[redacted]

Figure 4-1. Nodal Analysis Schematics.

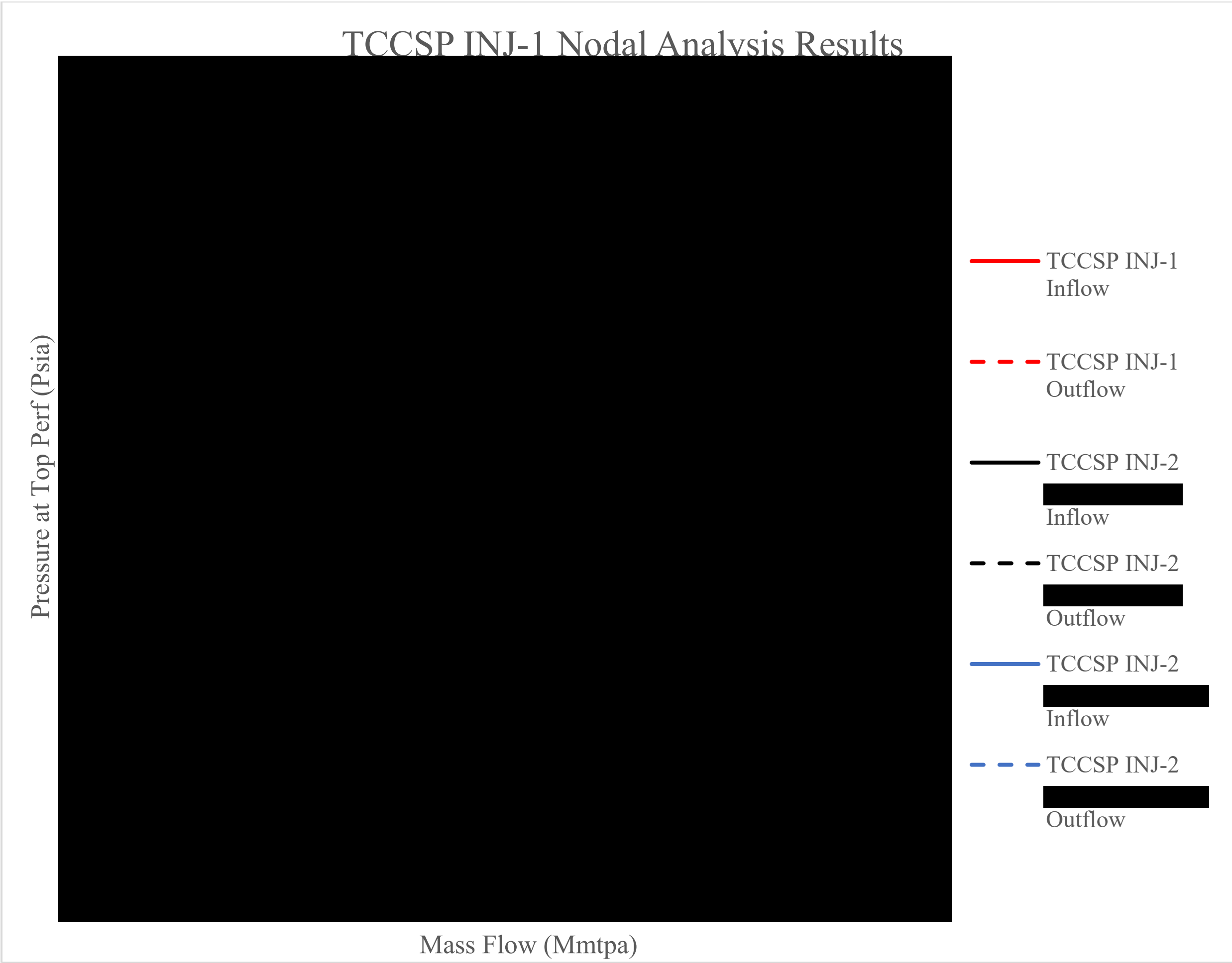

Figure 4-2. [redacted] Tubing Nodal Analysis Results.

The nodal analysis results in **Figure 4-2.** indicate that at the estimated wellhead pressure of [redacted] tubing will be able to deliver the average flowrates listed in **Table 4-1** to the reservoir. All injection wells were modeled to achieve injection rates above the maximum expected instantaneous rate of [redacted] without violating the [redacted] fracture pressure constraint. A [redacted] tubing pipe in each injection well was determined to be adequate to support injection at TCCSP.

[redacted] was also used to determine normal operating ranges for the wellhead pressures for injection wells at modeled injection rates.

Table 4-2 summarizes the expected operating wellhead pressures at the average respective rates and maximum expected instantaneous rates. The maximum instantaneous injection rate was determined based on the possibility of one of the injection wells going offline for maintenance or workovers, therefore routing all the CO_2 to a single injection well. For all modeled cases, the wellhead pressures were found to remain below the maximum allowable wellhead pressure as noted in **section 4.3** of this plan.

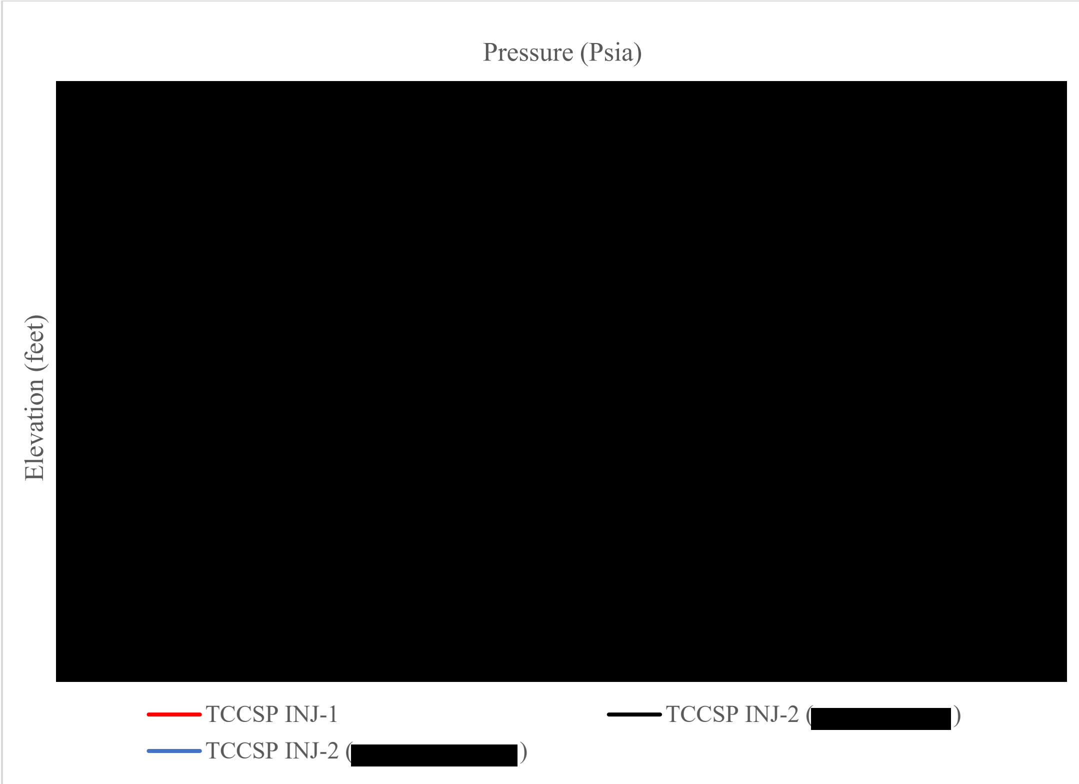

Figure 4-3. Pressure Profile at Average Injection Rates.

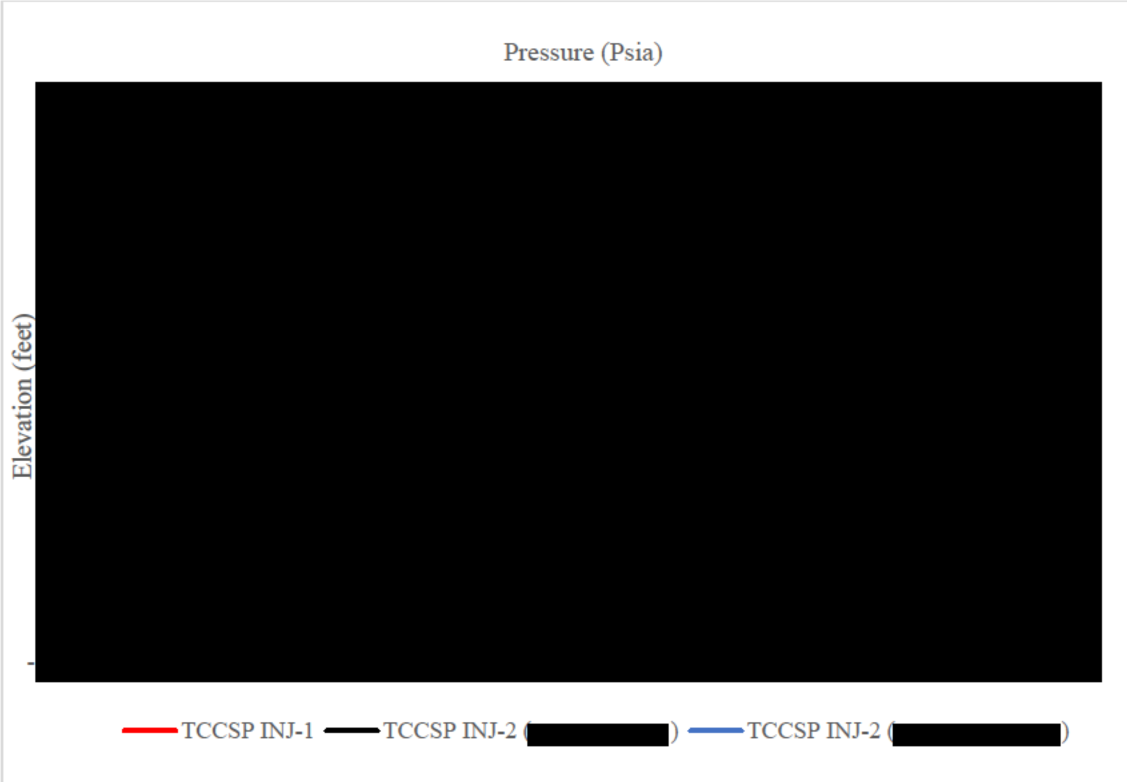

Figure 4-4. Pressure Profile at Maximum Rate Injection Rate [redacted]

Table 4-2. Expected Wellhead Operating Pressures.

Well	Average Operating Injection Rate (MMtpa)	Expected Operating Wellhead Pressure (psia)	Expected Operating Wellhead Pressure at [redacted] (psia)
TCCSP_INJ-1	[redacted]	[redacted]	[redacted]
TCCSP_INJ-2 [redacted]	[redacted]	[redacted]	[redacted]
TCCSP_INJ-2 [redacted]	[redacted]	[redacted]	[redacted]

4.3 Maximum Allowable Wellhead Injection Pressure

[redacted] modeling was completed to determine the maximum allowable wellhead pressure. This was done by determining the required wellhead pressure at the maximum instantaneous rate that corresponded to [redacted] of the fracture pressure of the topmost perforation in each well. **Figure 4-5.** shows the pressure profile for each well at the [redacted] fracture pressure. **Table 4-3** shows each wells individual, top perforation depth, [redacted] fracture pressure, corresponding wellhead pressure, and the maximum proposed wellhead pressure.

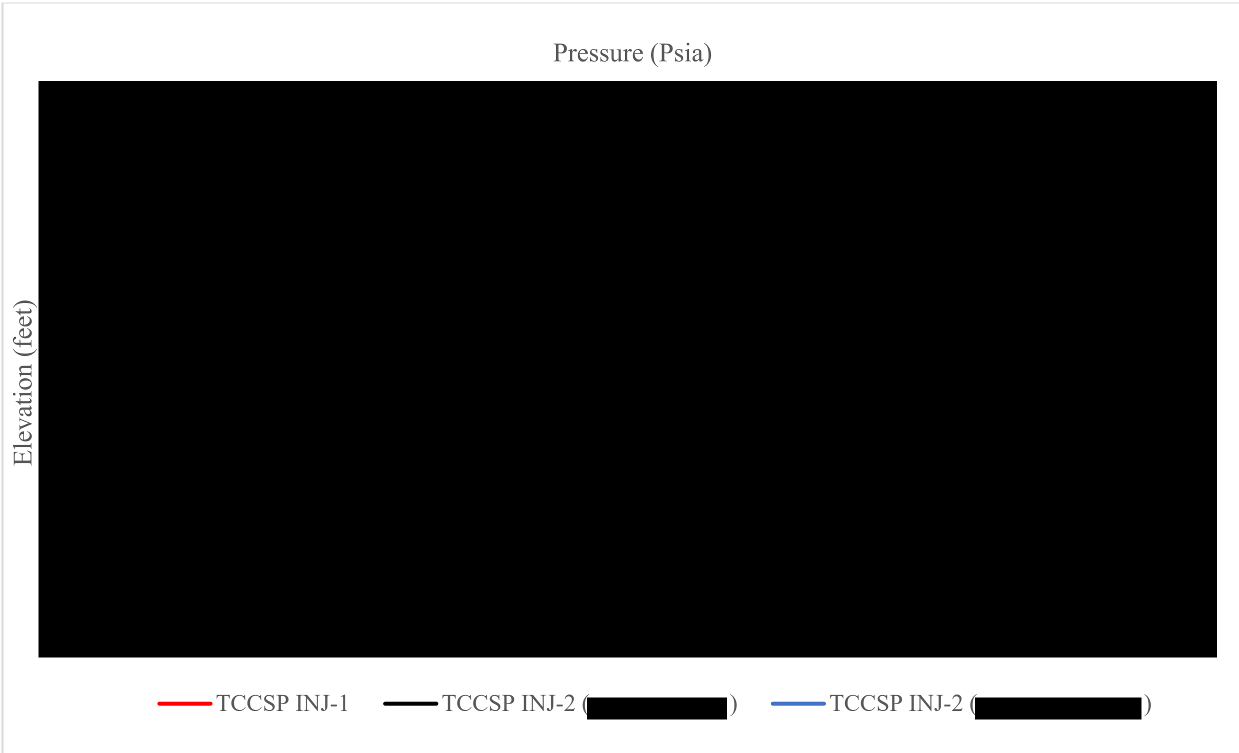

Figure 4-5. Pressure Profile for Maximum Allowable Wellhead Pressure.

Table 4-3. Top Perforation Depth, [redacted] Fracture Pressure, and Associated Maximum Allowable Wellhead Pressures.

Well	Top Perforation Depth (ft)	[redacted] Fracture Pressure (Psia)	Pressure at Top Perforation Depth (Psia)	Associated Wellhead Pressure (Psia)	Maximum Proposed Wellhead Pressure (psia)
TCCSP_INJ-1	[redacted]				
TCCSP_INJ-2 ([redacted])					
TCCSP_INJ-2 ([redacted])					

4.4 Casing Program

The injection wells have been sized and designed based on results of the nodal analysis to accommodate [redacted] injection tubing. The wells were designed with concentric casing sizes to isolate the injection zone and protect the USDWs. Carbon dioxide in the presence of water creates carbonic acid, which is mildly acidic and can cause increased corrosion to metal components with which it comes into contact. The water content in the injectate stream will be reduced as much as possible, as shown in **Table 7-3** of **section 7.3.3** of the **Testing and Monitoring Plan.** As the CO_2 stream enters the reservoir, it encounters brine and forms carbonic acid which can create a corrosive environment that mild steel may not withstand. Though formation fluid is not expected to enter the wellbore, the metallurgy for each casing string was selected to be compatible with the fluids and stresses encountered in bottomhole conditions as modeled and to meet API TR 5C3. Casing strings that will come into contact with CO_2 or CO_2-saturated brine will include a minimum of [redacted] or similar metallurgy to be resistant to corrosion from carbonic acid or wet CO_2. Results from corrosion testing and modeling under comparable downhole conditions indicate that in a high-temperature CO_2 and steam environment, the corrosion rate of [redacted] steel was less than [redacted] mm/year [1]. The steel also passed the localized corrosion requirements, with no pitting observed and a potential difference between the passivation potential and the corrosion potential greater than [redacted]. Together, these results demonstrate that [redacted] steel provides sufficient resistance to metallurgical corrosion should moisture or formation fluid come into contact with the CO_2. The selection of [redacted] is therefore a conservative measure that exceeds the corrosion resistance offered by [redacted]. The entire injection tubing string will be comprised of [redacted] or higher grade material. The [redacted] long-string casing will be constructed of [redacted] or similar material through the injection zone to approximately [redacted] above the confining zone. In areas where the risk of CO_2 corrosion is not of concern, such as above the caprock where injected CO_2 is not expected, mild steel or similar material will be used. The lithology of the storage reservoir's injection and confining zones are discussed in **section 1.2.5** of the **Project Narrative** and reservoir fluid characteristics are discussed in **section 1.2.9** of the **Project Narrative**. CO_2 stream characteristics are discussed in **section 1.8.2** of the **Project Narrative**. Constructing the wells with [redacted] or a higher grade steel components meets U.S. EPA's requirements and exceeds the corrosion resistance standards established by Guoqing [1].

4.5 Casing Summary

Injection well tubulars were designed and analyzed for the TCCSP_INJ-1 location given the geologic formations and target depths at this location were [redacted] compared to TCCSP_INJ-2 albeit the differences being minor since the two wells are [redacted] However, TCCSP_INJ-1 is estimated to experience [redacted] bottomhole stresses compared to TCCSP_INJ-2. The hydro-static pressure determined from the regional data indicated a pressure gradient of [redacted] as outlined in **section 1.2.6** of the **Project Narrative**. This yielded a maximum down hole pressure of [redacted]. Similar design principles from TCCSP_INJ-1 will be adopted in TCCSP_INJ-2. The wells will consist of: [redacted] All casing strings will be cemented to the surface using staged cement jobs as needed. The borehole diameters are considered conventional sizes for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall. This will ensure that a continuous cement seal can be emplaced along the entire length of the casing string. **Table 4-4** summarizes the casing program for the injection well. **Table 4-5** summarizes the properties of each casing material. Each section of the well is discussed in a separate section below. Strength calculations for the selected casing strings are provided in **section 4.6**.

[2] The [redacted] references the [redacted] including the Domengine, [redacted]

Table 4-4. Expected Open Hole and Casing Setting Depths.

Well	Conductor Open Hole / Casing Setting Depth (ft)	Surface Open Hole / Casing Setting Depth Setting Depth (ft)	Intermediate Open Hole / Casing Setting Depth Setting Depth (ft)	Long-String Open Hole / Casing Setting Depth Setting Depth (ft)
TCCSP_INJ-1	[redacted]			
TCCSP_INJ-2				

Table 4-5. Borehole and Casing Program for All Injection Wells.

Casing String	Borehole Diameter (in)	Casing Outside Diameter (in)	Casing Material (weight/grade/ connection)	Coupling Outside Diameter (in)
Conductor	[redacted]			
Surface				
Intermediate				
Long-String				

*Premium connection type to be determined based on availability. [redacted] was used for strength calculations.

Table 4-6. Tubular Materials and Strength Properties.

Casing String	Material (weight / grade / connection)	Outside Diameter (in.)	Inside Diameter (in.)	Wall Thickness (in.)	Drift Diameter (in.)	Burst (psia) Plain End	Collapse (psia)	Joint Tensile Strength ([redacted] psia)
Conductor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Surface	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long-String	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tubing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.5.1 Conductor Casing

The conductor casing consists of [redacted] and provides the stable base required for drilling activities in unconsolidated sediment. The conductor will be drilled and cemented into place. A final determination of depth will be made after site preparation. This section of casing is also cemented in place.

4.5.2 Surface Casing

The surface casing is a [redacted] with buttress thread couplings (BTCs). The metallurgy of this casing string is carbon steel. Surface casing is to be cemented to surface, isolating the shallow drinking water and the lowermost USDWs. Following the cement setting, a [redacted] will be run to verify cement bond.

4.5.3 Intermediate Casing

The intermediate casing is [redacted] with buttress thread couplings (BTCs). The metallurgy of this casing string is carbon steel. The intermediate will be cemented to surface in one or more stages to isolate [redacted] and other drilling hazards. It will be set into the first competent zone identified within the [redacted]. Following the cement setting, a [redacted] will be run to ensure cement bond.

4.5.4 Long-String Casing

The long-string casing will be a [redacted]. The long-string casing is designed to extend from the surface to the injection zone per 40 CFR 146.86(b)(3). The uppermost section will be [redacted] or similar with buttress thread couplings (BTCs); the lower section will be a corrosion-resistant alloy ([redacted] or a higher grade) having strength properties equivalent to or better than [redacted] with premium connections. The transition will be targeted for approximately [redacted] above the confining zone targeted caprock. A [redacted] will be run outside the casing from surface into the confining unit and cemented in place with the casing.

4.5.5 Tubing

The tubing connects the injection zone to the wellhead and provides a pathway for injecting CO_2. This design utilizes [redacted]. A packer will be set to the depths listed in **Table 4-13** to isolate injection zones from the tubing-casing annulus and will be set at approximately [redacted] above the first perforation interval. At the end of the tubing string, a landing nipple, or "no-go" tool will be run. This will allow a plug to be set inside the tubing at this depth and the packer to be released in order to remove the tubing string if needed. [redacted] or equivalent will be hung in the tubing string immediately above the top packer and ported to the tubing. More information on the selected wellbore monitoring technologies is available in **section 7.2** of the **Testing and Monitoring Plan**. Considering the anticipated formation pressure, temperature, and stress, the grade of tubing was selected with the API specifications outlined in **Table 4-6**, which includes the calculated safety factors. These safety factors represent sufficient quality standards to preserve the integrity of the injected fluid, the injection zone, and USDWs. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in **section 4.9** in accordance with 40 CFR 146.88(c).

4.6 Casing Strength Calculations

Casing stresses and loadings were modeled using [redacted] To ensure sufficient structural strength and mechanical integrity throughout the life of the project, stresses were analyzed and calculated according to worst-case scenarios and tubular specifications were selected accordingly. Minimum design factors are presented in **Table 4-7** and are based on API TR 5C3 [2]. **Table 4-8** through **Table 4-11** summarize the results of this stress analysis. The burst, collapse, and tensile strength of each tubular was calculated according to the scenarios defined below and was dependent on fracture gradients, mud weight, depths, and minimum safety factors. Modeling was completed at a static temperature gradient of [redacted] This resulted in a total depth temperature [redacted] Due to the nearly identical designs, and the fact that TCCSP_INJ-1 is to be drilled [redacted] only the results for TCCSP_INJ-1 are shown.

The casing and tubing materials were designed to be compatible with the CO_2 stream and formation fluids and the stresses induced throughout the sequestration project. [redacted] design standards were incorporated to develop the casing design load scenarios, and [redacted] group standards were incorporated to develop the tubing design load scenarios. These design standards used to develop the [redacted] software are based on work by Klementich et al. [3] and Prentice [4] and use the API TR 5C3 [2] standard equations for burst, collapse, axial, and triaxial strength calculations.

Table 4-7. Minimum Design Factors.

Load	Casing Design Criteria	Tubing Design Criteria
Burst	[redacted]	[redacted]
Collapse	[redacted]	[redacted]
Tension	[redacted]	[redacted]
Compression	[redacted]	[redacted]
VME	[redacted]	[redacted]

The casing installed in any well should be designed to withstand collapse loading based on the following assumptions:

1. The hydrostatic head of the drilling fluid or cement in which the casing is run acts on the exterior of the casing at any given depth.
2. Subject to the casing being at a minimum two-thirds evacuated.
3. The production casing is two-thirds evacuated.
4. The effect of axial stresses on collapse resistance shall be considered; and
5. The effect of temperature derating, and casing wear shall be considered.

Any casing or liner that creates an annular space with the production tubing was treated as a production casing or liner. The casing installed in any well was designed to withstand tensile loading based on the following assumptions:

1. The weight of casing is its weight in air; and
2. The tensile strength of the casing is the yield strength of the casing wall or of the joint, whichever is lesser.

The following additional assumptions were made during the design process for the injection well:

1. A [redacted] casing wear due to bottomhole assembly (BHA) rotation is assumed on all casing design segments with consecutive hole sections.
2. Wall tolerance of [redacted] is assumed as per API standard TR 5C3 [2].
3. Temperature deration is considered on the design of the [redacted] casing string; and
4. The [redacted] casing is being proposed and engineered to comply with a casing designed to pass a two-thirds evacuation loading on collapse.

If the casing as designed is not available, final casing selection would be based on available technical options that are in stock at the time of construction provided they satisfy or exceed the design criteria discussed here.

Table 4-8. Surface Casing Load Scenarios Evaluated the Calculated Design Factors (DF).

Load Case	Pressure Profile; Pressure at Minimum DF		Axial Loading	Temperature Profile	Wear Percentage	Minimum Design Factor				
	Internal	External				Pressure		Axial		Triaxial
						Load	Factor	Load	Factor	Factor

[redacted]

Table 4-9. Intermediate Casing Load Scenarios Evaluated and the Calculated Design Factors (DF).

Load Case	Pressure Profile; Pressure at Minimum DF		Axial Loading	Temperature Profile	Wear Percentage	Minimum Design Factor				
	Internal	External				Pressure		Axial		Triaxial
						Load	Factor	Load	Factor	Factor

[redacted]

Table 4-10. Long-String Casing Load Scenarios Evaluated and the Calculated Design Factors (DF).

Load Case	Pressure Profile: Pressure at Minimum DF		Axial Loading	Temperature Profile	Wear Percentage	Minimum Design Factor				
						Pressure		Axial		Triaxial
	Internal	External				Load	Factor	Load	Factor	Factor
[redacted]										

Table 4-11. Tubing Load Scenarios Evaluated and the Calculated Design Factors (DF).

Load Case	Pressure Profile: Pressure at Minimum DF		Axial Loading	Temperature Profile	Wear Percentage	Minimum Design Factor				
						Pressure		Axial		Triaxial
	Internal	External				Load	Factor	Load	Factor	Factor
[redacted]										

4.7 Packer Details

The packer system will be equivalent to [redacted] or better, depending on availability, and [redacted]. The packer will be connected to a [redacted] for easy workover operations. Both the packer and locator seal assembly will feature premium couplings matched to the tubing and will be comprised of [redacted] alloy to be compatible with expected reservoir fluids. Please refer to **Table 4-11** for modeled load scenarios for tubing and **Table 4-12** specifications for the packer. The packers will be set per the depths listed in **Table 4-13**. TCCSP_INJ-2 will feature a re-completion after the first [redacted] years of injection, therefore, both set depths are listed. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in further detail within the annular fluid program in **section 4.9** below.

Table 4-12. Packer Details.

Item	Tensile Strength (1000 lbs.)	Burst Strength (psi)	Collapse Strength (psi)	Material (weight/grade/ connection)
Packer ([redacted] [redacted] or equivalent)	[redacted]	[redacted]	[redacted]	[redacted]

Table 4-13. Packer Setting Depths.

Well	Packer Setting Depth (ft)
TCCSP_INJ-1	[redacted]
TCCSP_INJ-2 ([redacted])	[redacted]
TCCSP_INJ-2 ([redacted])	[redacted]

4.8 Cementing Program

This section discusses the types and quantities of cement that will be used for each string of casing. Cement selection (composition and volume) and cementing procedure discussed here is anticipated to be applied to both injection wells. The conductor, surface casing, intermediate, and long-string casing will be cemented to surface in accordance with requirements at 40 CFR 146.86(b)(3). The proposed cement types and quantities for each casing string are summarized in **Table 4-14** and **Table 4-15**. The final blends and quantities will be determined through discussions with cement vendors. The final volumes will be determined through caliper logs. These will be provided to the UIC Program Director promptly upon finalizing and well prior to injection well construction.

Casing centralizers will be used on all casing strings to centralize the casing in the hole and ensure that cement completely surrounds the casing along the entire length of pipe. The casing string will be centralized to attempt a minimum of [redacted] standoff. The actual hole trajectory as drilled will be input into the cementing service company's mud removal software to optimize centralizer placement. Centralizers will be placed either over the connections or at mid-joint using stop-rings as appropriate. It is estimated that approximately [redacted] centralizers will be used depending upon the hole trajectory. Additionally, collar guards will be run on every-other collar and blast protectors near target perforation intervals on the long-string to protect the [redacted] during installation and perforation. Except for the conductor casing, a guide shoe or float shoe is to be run on the bottom joint of casing, and a float collar will be run on the top of the bottom joint of casing.

The [redacted] long-string casing will be cemented to the surface using a lead and a tail. The tail used will be CO_2 resistant cement such as [redacted] or any other comparable and proven cement blend. Bartlet-Gouédard et al. [5] showed through lab testing that [redacted] provided significant resistance to degradation in the presence of CO_2 at reservoir conditions [redacted], as compared to common [redacted] cement. These testing conditions provide a comparable environment in comparison to the TCCSP injection well's bottom hole condition ([redacted] and indicate that the application of [redacted] should provide adequate CO_2 protection. Final selection of the type of CO_2 resistant cement will be dependent on market availability and technical properties of the selected cement. The selected cement will at a minimum meet or exceed the resistance of [redacted]. The second stage consists of [redacted]. The transition will be targeted at an approximate depth of [redacted] above the caprock. [redacted] will be run and analyzed for each casing string.

During the recompletion of TCCSP_INJ-2 the perforations will be squeezed with cement via a cement retainer. The plugging procedure is described in the **Injection Well Plugging Plan**.

Table 4-14. Proposed Cement Program.

Casing String	Casing Depth (ft)	Borehole Diameter (in)	Casing O.D. (in)	Cement Interval (ft)	Cement
Conductor Casing	[redacted]				
Surface Casing					
Intermediate Casing					
Long-String Casing					
*See acronym list for definition of abbreviations used in this table.					

Table 4-15. Proposed Cement Design Expected Volumes

Well	Conductor Volume (Sacks / bbls)	Surface Volume (Sacks / bbls)	Intermediate Lead Volume (Sacks / bbls)	Intermediate Tail Volume (Sacks / bbls)	Long-String Lead Volume (Sacks / bbls)	Long-String Tail Volume (Sacks / bbls)
TCCSP_INJ-1	[redacted]					
TCCSP_INJ-2						

4.9 Annular Fluid

The annular space above the packer between the [redacted] long-string casing and the [redacted] injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be controlled to remain between [redacted] during injection operations (see **section 7.4.2** of the **Testing**

and Monitoring Plan for a full description of the injection well annulus monitoring system). This surface pressure, added to the hydrostatic pressure of the fluid column, will ensure that the annular pressure downhole will be greater than injection pressure.

The annular fluid will be fresh water treated with additives and inhibitors including a corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. The fluid will either be mixed onsite using freshwater and liquid and dry additives, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The final choice of the type of fluid will depend on availability.

Example additives and inhibitors are listed below along with approximate mix rates:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

These products were recommended and provided by [redacted]
The actual products will be similar but may vary from those described above.

4.10 <u>Wellhead</u>

The wellhead will consist of the following or similar components, from bottom to top:

- [redacted] casing head
- [redacted] casing head
- [redacted] port/access
- [redacted] tubing head
- [redacted] port/access
- [redacted] full-open master control gate valve
- [redacted] automated tubing flow control valve
- [redacted] cross with one (1) [redacted] blind flange
- [redacted] automated tubing flow control valve
- [redacted] automated safety shut down valve.
- [redacted] top flange and pressure gauge.

The wellhead and Christmas tree materials are designed to be compatible with the CO_2 stream. Critical components that come into contact with the CO_2 stream will be made of a corrosion-resistant alloy such as stainless steel. Materials that are not expected to contact the injection fluid will be carbon steel. A preliminary materials specification for the wellhead and Christmas tree assembly is presented in **Table 4-16**. This is based on the material classes as defined in API Specification 6A [6]. A summary of material class definitions is provided in **Table 4-17**. The final wellhead and Christmas tree materials specification may vary from the information given below based on availability and final product selection. An illustration of the preliminary wellhead and Christmas tree design is provided in **Figure 4-6.**. The flowline leading to the wellhead and Christmas tree will be equipped with an [redacted] as required in 40 CFR 146.88. Additionally, the wellhead will be equipped with a [redacted] on each tubing and annulus. Each annulus will be equipped with a [redacted]. Please refer to **Table 7A-11** of **section 7A.1.4.7** of the **Quality Assurance and Surveillance Plan (QASP)** attached to the **Testing and Monitoring Plan** for additional details on the wellhead gauges to be installed.

Table 4-16. Materials Specification of Wellhead and Christmas Tree.

Component	Material Class[(a)]
[redacted]	

Table 4-17. Material Classes from API 6A.

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
[redacted]		

[redacted]

Figure 4-6. Working Wellhead Design Diagram for Injection Wells.

4.11 Perforations

The long-string casing will be perforated across the [redacted] with deep-penetrating shaped charges. Due to the installation of [redacted], oriented perforations will be used to avoid damaging the [redacted]. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The planned perforation intervals will be [redacted] shots per foot. Proposed perforation interval depths are found below in **Table 4-18**. TCCSP_INJ-1 is designed to inject into the perforations in the [redacted] for the entirety of the injection period. TCCSP_INJ-2 is designed to inject into the first set of perforations ([redacted]) for the first [redacted] years of injection and subsequently recompleted into the second set of perforations ([redacted]) for [redacted] years of injection. During the recompletion of TCCSP_INJ-2 the perforations will be squeezed with cement via a cement retainer. The plugging procedure is described in the **Injection Well Plugging Plan**.

Table 4-18. Proposed Perforated Intervals.

Well	Zone	Top (ft)	Mid-Point (ft)	Bottom (ft)
TCCSP_INJ-1	[redacted]			
TCCSP_INJ-2				
TCCSP_INJ-2				

4.12 Proposed Stimulation Program

After perforation of all injection wells an acid wash will take place. This will be done with [redacted]. This will be done at low pressures and will not endanger the confining zone or create a leakage pathway while improving the injectivity of the near wellbore and allow for injection of CO_2 to take place at lower startup pressures. No other stimulation is proposed.

4.13 Summary of Monitoring Technology

[redacted] will be the primary wellbore technology used to monitor various operational parameters, wellbore mechanical integrity, formation properties, and the movement of CO_2 and the associated pressure front across the project.

Operational parameters such as injection pressure and temperature and annulus pressure will be [redacted] ported to the injection tubing and annulus along with [redacted] ported to the tubing at depth. Internal mechanical integrity will be continuously monitored using [redacted] ported to the injection tubing and annulus whereas external mechanical integrity will be demonstrated [redacted] during injection operations using [redacted]. Formation properties, such as transmissivity (obtained by [redacted]), along with the pressure front associated with the CO_2 plume, will be monitored with [redacted]. [redacted] will be the primary method utilized to track the CO_2 plume across the project; however, [redacted] installed in each injection well may act as an additional method for indirectly tracking the plume. For detailed information on all testing and monitoring activities and technologies including automatic shutoff devices, please refer to **section 7.2** of the **Testing and Monitoring Plan.**

4.14 Schematic of the Subsurface Construction Details of the Wells

A schematic of the design for the injection wells is shown in **Figure 4-7**, **Figure 4-8,** and **Figure 4-9.** The injection wells will include the following casing strings: a [redacted] diameter conductor string; a [redacted] diameter surface string; [redacted] diameter intermediate string and a [redacted] diameter long-string. All depths are preliminary and will be adjusted based on additional characterization data obtained while drilling the CO_2 injection wells. All casing strings will be cemented to surface.

[redacted]

Figure 4-7. Schematic of TCCSP_INJ-1.

[redacted]

Figure 4-8. Schematic of TCCSP_INJ-2 ([redacted]).

[redacted]

Figure 4-9. Schematic of TCCSP_INJ-2 (Recompleted to the [redacted]).

4.15 Schematic of the Subsurface Construction Details of the Monitoring Wells

TCCSP has developed well designs for the [redacted] and [redacted] monitoring wells following the same design standards and basis described for the injection wells. The technology included in the designs is to fulfill the proposed **Testing and Monitoring Plan**. These well designs will be permitted under the jurisdiction of California Geologic Energy Management Division (CalGEM) and are subject to changes required during the state agency's permitting process. Additionally, TCCSP may use new or different technology if it meets or exceeds the requirements proposed in the **Testing and Monitoring Plan**. The location chosen for these wells is discussed in the **Testing and Monitoring Plan** and the coordinates are provided in **Table 4-19**.

TCCSP_OBS-1 is an already drilled well completed as part of TCCSP's site characterization efforts and was equipped with monitoring equipment to satisfy the requirements of the [redacted] proposed in the **Testing and Monitoring Plan**. The as-drilled well schematic is given in **Figure 4-10**. The planned schematics for the remaining deep monitoring wells are provided in **Figure 4-11** through **Figure 4-13.**

Table 4-19. Deep Monitoring Well Locations.

Well	API Number:	Latitude	Longitude
[redacted]			

[redacted]

Figure 4-10. TCCSP_OBS-1 As Drilled Well Schematic.

[redacted]

Figure 4-11. [redacted] Well Design.

[redacted]

Figure 4-12. [redacted] Well Design.

[redacted]

Figure 4-13. [redacted] Well Design.

4.16 References

[1] Guoqing Xiao et al., "CO2 Corrosion Behaviors of 13Cr Steel in the High-Temperature Steam Environment," *Petroleum* 6, no. 1 (March 2020): 106–13, https://doi.org/10.1016/j.petlm.2019.12.001.

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[3] Klementich, E.F. and Jellison, M.J. 1983. "A Service Life Model for Casing String", SPE 12361

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[5] V. Barlet-Gouédard and G. Rimmelé, Schlumberger; B. Goffé, CNRS/ENS*; and O. Porcherie, Schlumberger. (2006). Mitigation Strategies for the Risk of CO_2 Migration Through Wellbores. IADC/SPE

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