INJECTOR WELL CONSTRUCTION DETAILS PLAN
40 CFR 146.82(a)(11) and (12), 146.86, 146.87, and 146.88 (a), (b), (c), and (e)

Bluebonnet Sequestration Hub

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 wells.

Facility contacts: Claimed as PBI [redacted]

Well location: Claimed as PBI [redacted]

	Surface Coordinates		Bottom Hole Coordinates	
Well Name	Latitude (NAD27)	Longitude (NAD27)	Latitude (NAD27)	Longitude (NAD27)
Claimed as PBI [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Bluebonnet Sequestration Hub, LLC will be building the Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project) where it will construct CO2 injector wells, Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3, according to the procedures below. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, and pressure control systems, amongst others.

2.0 Overview

This Construction Plan sets forth the operational parameters and material selection requirements to provide mechanical integrity, minimize potential endangerment of the Underground Sources of Drinking Water (USDW), and optimize operation during the life of the project. While this Construction Details Plan describes the intended procedures for drilling and construction of the project, changes to the plan may be required based on technical, operational, or safety conditions encountered during the development and execution. The project team will notify the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director if substantial deviations from this plan are required.

As mentioned, the Bluebonnet Sequestration Hub, LLC will drill three new CO_2 injector wells, Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3. The wells will target the Oligocene formation, specifically the Frio and Hackberry sands.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled one stratigraphic well, Encanto 01 in the Bluebonnet Hub in 2022-2023. This well has been used to obtain site-based information and additional characterization to complement the geological and numerical simulation models. The stratigraphic well Encanto 01 was designed with the goal of being converted into an in-zone monitoring well to track the CO_2 plume extension and pressure front in the Frio and Miocene formations, as described in the Testing and Monitoring Plan.

Additionally, the project plans to drill two new in-zone monitoring wells in Frio/Miocene injection zone to directly monitor the injection targets, one in-zone monitoring well in the Lower Miocene injection zone, six USDW monitoring wells (targeting the shallowest zone above the confining zone that was defined by the project as the deepest USWD), two water production wells in the Frio injection zone to manage increases in the reservoir pressure, and two water disposal wells .

Since the shallowest above-confining zone has been defined as the base of the USDW, the six USDW monitoring wells will track the quality of the water and variations in geochemistry in the USDW. These shallow water wells will be produced and sampled based on the requirements described in the Testing and Monitoring Plan presented in this application.

Location, well schematics, and construction details for the in-zone monitoring wells, above confining zone/USDW monitoring wells, water production wells, and water disposal wells are included in the Testing and Monitoring Plan of this application.

3.0 Design Considerations for CO_2 Injector Wells

Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 are designed to maximize the rate of injection and reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the frac gradient. A nodal analysis using PROSPER software performed sensitivities on the tubing size, rate of erosion, stresses, operating pressures, and potential movement of the tubulars. The injection rate may continue to be refined as the project acquires, processes, evaluates, and interprets additional data.

Well materials and equipment were selected based on the maximum operating conditions expected during the life of the well and the compatibility with the expected CO_2 stream, to ensure mechanical integrity and reliability of the system during the life of the project.

The selected design provides enough clearance to deploy pressure and temperature gauges on the tubing and continuous surveillance of external mechanical integrity through an external fiber optic cable.

During the design process, the project team integrated years of experience and data collected by Oxy (the parent company of Bluebonnet Sequestration Hub, LLC) as a CO_2 operator in enhanced oil recovery (EOR) fields, with the expertise of worldwide-recognized providers of tubulars, cementing services companies, and downhole and surface equipment manufacturers, amongst others to complete the final design of the CO_2 injectors.

The operating conditions expected during the life of the CO_2 injector wells are shown in Tables CON-1, CON-2, and CON-3. Table CON-4 shows the CO_2 specifications of Bluebonnet Hub.

Table CON-1: Operating design parameters for Bluebonnet CCS 1.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Claimed as PBI [redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

(1) MD: Measured Depth
(2) TVD: True Vertical Depth

Table CON-2: Operating design parameters for Bluebonnet CCS 2.

Parameter/Completion	Completion 1	Completion 2
Claimed as PBI [redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table CON-3: Operating design parameters for Bluebonnet CCS 3.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Claimed as PBI [redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table CON-4: CO_2 Specification for Bluebonnet Hub.

Component	Specification
Claimed as PBI [redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

4.0 Well Design Bluebonnet CCS 1 - CO_2 Injector Well

The Bluebonnet CCS 1 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figures CON-1, CON-2 and CON-3 show the proposed well schematics for Bluebonnet CCS 1 for the original completion, first recompletion, and second recompletion, respectively.

Claimed as PBI

[redacted]

Figure CON-1: Bluebonnet CCS 1 well schematic – original completion.

Claimed as PBI

[redacted]

Figure CON-2: Bluebonnet CCS 1 well schematic – first recompletion.

Claimed as PBI

[redacted]

Figure CON-3: Bluebonnet CCS 1 well schematic – second recompletion.

4.1 Design Overview Bluebonnet CCS 1

4.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately of [redacted]. The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

4.1.2 Surface Section

The [redacted] vertical wellbore will be drilled to [redacted] to cover the base of the USDW, estimated at [redacted] TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

4.1.3 Long String Section

Bluebonnet CCS 1 will be drilled directionally in a "J" type profile, with the kickoff point planned at [redacted] TVD, a maximum angle of [redacted] and [redacted] displacement. The detailed trajectory is provided in the Table CON-5.

A [redacted] directional wellbore will be drilled from [redacted] to total depth (MD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of [redacted] casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustical sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

After the cementing is complete, Section B of the wellhead will be installed and the DTS/DAS cable will be threaded through the slips and pack off. The team will then install the rest of the wellhead to prepare for completion operations.

4.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run to approximately [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

4.2 Directional Plan Bluebonnet CCS 1

Table CON-5 summarizes the proposed trajectory for Bluebonnet CCS 1.

Table CON-5: Bluebonnet CCS 1 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
[redacted]							

Claimed as PBI

4.3 Casing, Tubing and Completion Design Bluebonnet CCS 1

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-6 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-6: Minimum safety factors for tubular design.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
[redacted]							

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document. The second recompletion case was selected as worst-case scenario since provides the more conservatives values.

Figure CON-4 shows the design limits envelope for the [redacted] injection tubing used to validate the selection of the material. The analysis was developed with WELLCAT^{TM} software from Landmark.

[redacted]

Figure CON-4: Bluebonnet CCS 1 injection tubing design limits.

A summary of the loads used in the simulation of the tubing with WELLCAT™ is provided in Attachment E of this Injection Well Construction Plan.

The tables listed below provide further details regarding the Bluebonnet CCS 1 well. Table CON-7 contains the open hole diameters and intervals, Table CON-8 lists the casing specifications, Table CON-9 details the conductor material, and Table CON-10 details the casing material properties for Bluebonnet CCS 1.

Table CON-7: Open hole diameters and intervals - Bluebonnet CCS 1.

Claimed as PBI [redacted]

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at Claimed as PBI [redacted] ft TVD.

Table CON-8: Casing specifications - Bluebonnet CCS 1.

Claimed as PBI [redacted]

Table CON-9: Conductor material properties - Bluebonnet CCS 1.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
Claimed as PBI [redacted]				

Table CON-10: Casing material properties - Bluebonnet CCS 1.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]						

Notes:

- A stage tool will be located at [redacted] in the 9 5/8-in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum [redacted] standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Tables CON-11 and CON-12 contain the upper completion specifications for the original completion and first and second recompletions. Table CON-13 shows the specification of the [redacted] tubing.

Table CON-11: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
[redacted]							

Table CON-12: Tubing material properties – second recompletion - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Claimed as PBI [redacted]							

Table CON-13: Tubing material properties - Bluebonnet CCS 1.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Claimed as PBI [redacted]					

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the Claimed as PBI [redacted] will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-14 shows the specifications of the injection packer.

Table CON-14: Packer specifications - Bluebonnet CCS 1.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Claimed as PBI [redacted]					

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and the completion elements are included in Appendix A.

4.4 Cementing Program Bluebonnet CCS 1

Table CON-15 shows the cementing program details.

Table CON-15: Cementing program - Bluebonnet CCS 1.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
[redacted]						

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at [redacted], but the depth will be adjusted based on final drilling conditions.

Details on cementing operation design, materials, and additives selection are included in the Appendix B, with examples of the proposed cementing slurries.

4.5 Mud Program Bluebonnet CCS 1

Table CON-16 shows the mud program details for Bluebonnet CCS 1.

Table CON-16: Mud program - Bluebonnet CCS 1.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
Claimed as PBI								

4.6 Wellhead Schematic Bluebonnet CCS 1

Figure CON-5 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 1 well. Details on the blowout preventors (BOP) and wellhead design are included in the Appendix C.

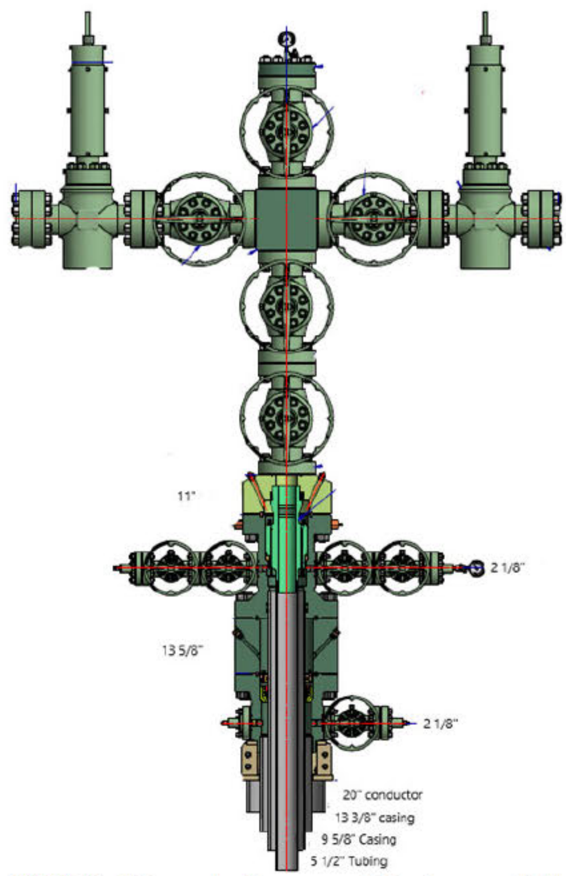

Figure CON-5: Schematic diagram of Bluebonnet CCS 1 well.

4.7 Bluebonnet CCS 1 Procedure

4.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth of [redacted]t.
- Set a [redacted] conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

4.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform pre-Section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.

- Make up shoe track and run Claimed as PBI surface casing to TD. Break circulation every 10 joints.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Rig up cementing equipment and test lines at 250 psi and at 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- Perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the Claimed as PBI BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi, BOPE to 3,000 psi.

4.7.3 Long String Section

- Perform pre-section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up Claimed as PBI directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out Claimed as PBI surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill Claimed as PBI hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations.

If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.

- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations per the program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and the casing slips and test the correct function of the tools.
- Rig up the spooler and the equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note 1: The casing must be ordered, inspected, and drifted on the rack a minimum of two days before the run. Make sure a marker joint is located at the top of injection zone.

  Note 2: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum [redacted] standoff.

  Note 3: Stage cementing tools and casing float equipment should be ordered at least two days before the operation for inspection on location.

- Make up float equipment with two joints of shoe track. Use liquid welding on the float equipment.
- Run long string casing per program, coordinating running speed with the fiber optic installation.

- Once on the bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and at 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. Ten bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and at 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. Reduce the rate 20 bbl before the plug reaches the float collar. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, it is recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips, threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

4.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

5.0 Well Design Bluebonnet CCS 2 - CO_2 Injector Well

The Bluebonnet CCS 2 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figures-CON 6 and CON-7 show the proposed well schematic for Bluebonnet CCS 2 for the original completion and the recompletion, respectively.

Claimed as PBI

[redacted]

Figure CON-6: Bluebonnet CCS 2 well schematic – original completion.

Claimed as PBI

[redacted]

Figure CON-7: Bluebonnet CCS 2 well schematic – recompletion.

5.1 Design Overview Bluebonnet CCS 2

5.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately of [redacted] ft. The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.1.2 Surface Section

The [redacted] vertical wellbore will be drilled to [redacted] to cover base of the USDW, estimated at [redacted] TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

5.1.3 Long String Section

Bluebonnet CCS 2 will be drilled directionally in a "J" type profile, with the kickoff point planned at [redacted] TVD, a maximum angle of [redacted], and [redacted] displacement. The detailed trajectory is provided in the Table CON-17.

A [redacted] directional wellbore will be drilled from [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed and the DTS/DAS cable will be threaded through the slips and pack off. The team will install the rest of the wellhead to prepare for completions operations.

5.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted]ubing and packer completion will be run to approximately [redacted], in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

5.2 Directional Plan Bluebonnet CCS 2

Table CON-17 summarizes the proposed trajectory for Bluebonnet CCS 2.

Table CON-17: Bluebonnet CCS 2 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
[redacted]							

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

5.3 Casing, Tubing and Completion Design Bluebonnet CCS 2

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.
- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-18 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-18: Minimum safety factors for tubular design - Bluebonnet CCS 2.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
[redacted]							

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2 and Bluebonnet CCS 3 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 2 well. Table CON-19 contains the open hole diameters and intervals, Table CON-20 lists the casing specifications, Table CON-21 details the conductor material, and Table CON-22 details the casing material properties.

Table CON-19: Open hole diameters and intervals - Bluebonnet CCS 2.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
[redacted]			

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at [redacted] ft TVD.

Table CON-20: Casing specifications - Bluebonnet CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
[redacted]							

Table CON-21: Conductor material properties - Bluebonnet CCS 2.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
[redacted]				

Table CON-22: Casing material properties - Bluebonnet CCS 2.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted]						

Notes:

- A stage tool will be located at [redacted]n the [redacted] casing to perform the two-stage cementing job.
- The centralization program will aim at minimum [redacted] standoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-23 contains the upper completion specifications for the original completion. Table CON-24 shows the specification of the [redacted] tubing.

Table CON-23: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Claimed as PBI [redacted]							

Table CON-24: Tubing material properties - Bluebonnet CCS 2.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Claimed as PBI [redacted]					

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the Claimed as PBI [redacted] will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-25 shows the specifications of the injection packer.

Table CON-25: Packer specifications - Bluebonnet CCS 2.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Claimed as PBI [redacted]					

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.

- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

5.4 Cementing Program Bluebonnet CCS 2

Table CON-26 shows the cementing program details.

Table CON-26: Cementing program - Bluebonnet CCS 2.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Claimed as PBI [redacted]						

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at Claimed as PBI [redacted] but the depth will be adjusted based on final drilling conditions.

Details on cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

5.5 Mud Program Bluebonnet CCS 2

Table CON-27 shows the mud program details for Bluebonnet CCS 2.

Table CON-27: Mud program - Bluebonnet CCS 2.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
Claimed as PBI								

5.6 Wellhead Schematic Bluebonnet CCS 2

Figure CON-8 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 2 well. Details on blowout preventors (BOP) and wellhead design are included in Appendix C.

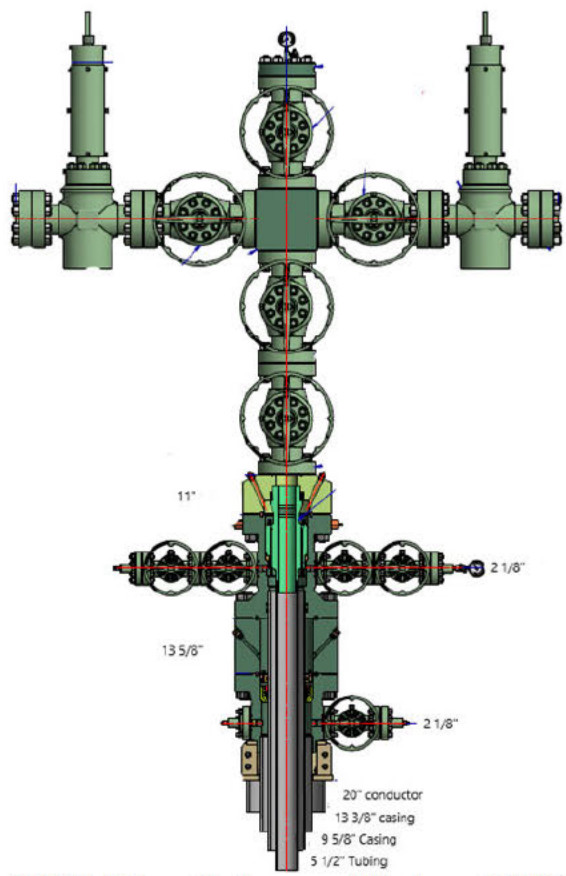

Figure CON-8: Schematic diagram of Bluebonnet CCS 2 well.

5.7 Bluebonnet CCS 2 Procedure

5.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth of [redacted] ft.
- Set a [redacted] conductor on bottom and pump cement.
- Move equipment off location and secure the site.

5.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform pre-Section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional bottom hole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Make up shoe track and run [redacted] surface casing to TD. Break circulation every 10 joints.

- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Rig up cementing equipment and test lines at 250 psi and at 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- Perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] BOP stack.
- Perform pressure testing safety meeting and discuss the operational plan and risks.
- Test casing to 1500 psi and BOPE to 3000 psi.

5.7.3 Long String Section

- Perform pre-section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from WBM to SBM. Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on directional plan. Survey must be taken minimum every 100 ft. Pump sweep pills to improve hole-cleaning base on the hydraulics simulations. If signs

of drag or hole-cleaning issues are observed, increase the frequency of pumping of the sweep pills.

- Pump viscous pills and circulate minimum of two bottoms up or until the returns of cuttings in the shaker are minimum, and prepare to trip out of hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] clean out BHA.
- Run in hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips, test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendation to install the external centralizers, clamps, bands, and markers joints.

  Note 1: The casing must be ordered, inspected, and drifted on the rack minimum two days before the run. Make sure a marker joint is located at the top of the injection zone.

  Note 2: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target minimum [redacted] standoff.

  Note 3: Stage cementing tools and casing float equipment should be ordered at least two days before the operation to be able to be inspected on location.

- Make up float equipment with two joints of shoe track. Use liquid welding on the float equipment.
- Run long string casing per program, coordinate running speed with the fiber optic installation.
- Once on bottom, start circulation with low flow rate and increase it gradually to reach the target flow rate for the cementing job. Circulate at least 2 bottoms up or until the well is clean.

- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and at 5,000 psi, each for 5 minutes . Secure the area while executing high-pressure operations. Start the first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop the top plug and displace the cement. Reduce the rate 10 bbl before the plug reaches the float collar. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to the manufacturer (follow specific procedure by provider and model of the tool). Circulate the annulus.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and at 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. Reduce the rate 20 bbl before the plug reaches the float collar. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, its recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift BOPs.
- Install casing slips threading the fiber optic cable through the port.
- Cut casing and install pack off and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

5.6.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize rig to the location.
- Rig up equipment.
- Nipple up BOP
- Test BOP
- Pick up work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. In the failure persists, the operator may require assessing the root cause and correct it.
- Pull BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate well with inhibited packer fluid.
- Set packer as per program and test annulus to 1000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test, step rate test, and fall off test.

6.0 Well Design Bluebonnet CCS 3 - CO_2 Injector Well

The Bluebonnet CCS 3 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figures CON-9, CON-10 and CON-11 show the proposed well schematics for Bluebonnet CCS 3 for the original completion and recompletions.

Claimed as PBI

[redacted]

Figure CON-9: Bluebonnet CCS 3 well schematic – original completion.

Claimed as PBI

[redacted]

Figure CON-10: Bluebonnet CCS 3 well schematic – first recompletion.

Claimed as PBI

[redacted]

Figure CON-11: Bluebonnet CCS 3 well schematic – second recompletion.

6.1 Design Overview Bluebonnet CCS 3

6.1.1 Conductor

The [redacted] wellbore for the conductor casing will be drilled via auger to a depth approximately of [redacted] ft. The wellbore will be cased with a [redacted] line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

6.1.2 Surface Section

The [redacted] vertical wellbore will be drilled to [redacted] to cover base of the USDW, estimated at [redacted] TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, [redacted] casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

6.1.3 Long String Section

Bluebonnet CCS 3 will be drilled directionally in a “J” type profile, with the kickoff point planned at [redacted] TVD, a maximum angle of [redacted] and [redacted] displacement. The detailed trajectory is provided in Table CON-28.

A [redacted] directional wellbore will be drilled from [redacted] to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of [redacted] casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations.

6.1.4 Completion

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted] tubing and packer completion will be run to approximately [redacted] in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

6.2 Directional Plan Bluebonnet CCS 3

Table CON-28 summarizes the proposed trajectory for Bluebonnet CCS 3.

Table CON-28: Bluebonnet CCS 3 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
[redacted]							

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)

Claimed as PBI

[redacted]

6.3 Casing, Tubing and Completion Design Bluebonnet CCS 3

The different casing sections and completion tubing were designed to withstand expected operating loads such as:

- Gas kick
- Pore pressure and overburden
- Pressure test
- Lost circulation
- Tubing leaks during injection
- Injection operations
- Thermal changes during injection
- Shut-in operations.

- Full evacuation of the tubing
- Uncontrolled release of CO_2
- Overpull
- Corrosion environments

Table CON-29 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-29: Minimum safety factors for tubular design - Bluebonnet CCS 3.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
[redacted]							

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document.

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2 and Bluebonnet CCS 3 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 3 well. Table CON-30 contains the open hole diameters and intervals, Table CON-31 lists the casing specifications, Table CON-32 details the conductor material, and Table CON-33 details the casing material properties.

Table CON-30: Open hole diameters and intervals - Bluebonnet CCS 3.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
[redacted]			

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at [redacted] ft TVD.

Table CON-31: Casing specifications - Bluebonnet CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
[redacted] Claimed as PBI							

Table CON-32: Conductor material properties - Bluebonnet CCS 3.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
[redacted] Claimed as PBI				

Table CON-33: Casing material properties - Bluebonnet CCS 3.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
[redacted] Claimed as PBI						

Notes:

- A stage tool will be located at [redacted] Claimed as PBI in the 9 5/8-in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum [redacted] Claimed as PBI tandoff and be adjusted using the field data for deviation, caliper, and hole conditions.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-34 contains the upper completion specifications for the original completion and recompletions. Table CON-35 shows the specification of the 5 ½ in. tubing.

Table CON-34: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Claimed as PBI [redacted]							

Table CON-35: Tubing material properties - Bluebonnet CCS 3.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Claimed as PBI [redacted]					

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Claimed as PBI [redacted]
- The annular space between the Claimed as PBI [redacted] will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-36 shows the specifications of the injection packer.

Table CON-36: Packer specifications - Bluebonnet CCS 3.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Claimed as PBI [redacted]					

Notes:

- Specification of the packers might vary based on the selected vendor; however, they will comply with the minimum requirements proposed in the table.
- Packers will be selected ensuring all anticipated tubing-to-packer forces fall within the operational envelope provided by the supplier.

Details on material selection for the well tubulars and completion elements are included in Appendix A.

6.4 Cementing Program Bluebonnet CCS 3

Table CON-37 shows the cementing program details.

Table CON-37: Cementing program - Bluebonnet CCS 3.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
[redacted]						

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at [redacted] but the depth will be adjusted based on final drilling conditions.

Details on the cementing operation design, materials, and additives selection are included in Appendix B, with examples of the proposed cementing slurries.

6.5 Mud Program Bluebonnet CCS 3

Table CON-38 shows the mud program details for Bluebonnet CCS 3.

Table CON-38: Mud program - Bluebonnet CCS 3.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
[redacted] Claimed as PBI								

6.6 Wellhead Schematic Bluebonnet CCS 3

Figure CON-12 Below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 1 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

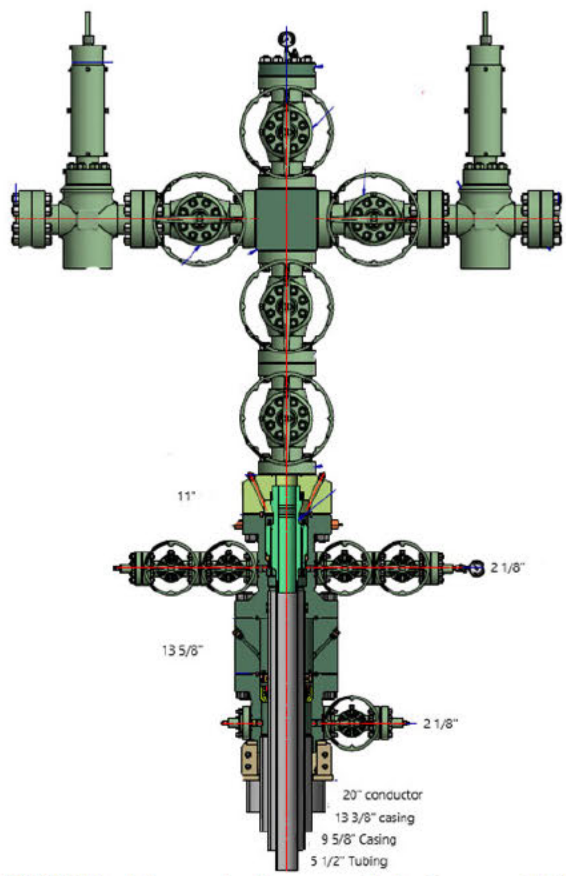

Figure CON-12: Schematic diagram of Bluebonnet CCS 3 well.

6.7 Bluebonnet CCS 3 Procedure

6.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform Pre-Spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger [redacted] hole to a depth of [redacted]
- Set a [redacted] conductor on bottom and pump cement.
- Move equipment off location and secure the site.

6.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform pre-Section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional bottom hole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill [redacted] surface hole to surface casing TD.
- Pump viscous pills and circulate until well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Make up shoe track and run [redacted] surface casing to TD. Break circulation every 10 joints.
- Circulate and prepare to cement surface casing.

- Hold a pre-cement meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Rig up cementing equipment and test lines at 250 psi and at 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbl of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate 10 bbl before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- Perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the [redacted] BOP stack.
- Perform pressure testing safety meeting and discuss the operational plan and risks.
- Test casing to 1500 psi, BOPE to 3000 psi.

6.7.3 Long String Section

- Perform pre-section meeting and discuss drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from WBM to SBM. Ensure that all solid control equipment is installed and operating properly.
- Pick up [redacted] directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate well.
- Conduct choke drill prior to drilling out.
- Drill out [redacted] surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill [redacted] hole to TD based on the directional plan. Survey must be taken a minimum of every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping of the sweep pills.

- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimum, and prepare to trip out of hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up [redacted] clean out BHA.
- Run in hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips, test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note 1: The casing must be ordered, inspected, and drifted on the rack minimum two days before the run. Make sure a marker joint is located at the top of the injection zone.

  Note 2: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target minimum [redacted] standoff.

  Note 3: Stage cementing tools and casing float equipment should be ordered at least two days before the operation to be able to be inspected on the location.

- Make up float equipment with two joints of shoe track. Use liquid welding on the float equipment.
- Run long string casing per program, coordinate running speed with the fiber optic installation.
- Once on bottom, start circulation with low flow rate and increase it gradually to reach the target flow rate for the cementing job. Circulate at least 2 bottoms up or until the well is clean.

- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and at 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop top plug and displace the cement. Reduce the rate 10 bbl before the plug reaches the float collar. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to the manufacturer (follow specific procedure by provider and model of the tool). Circulate the annulus.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and at 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. Reduce the rate 20 bbl before the plug reaches the float collar. Bump the plug and increase required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

  Note: This is a standard process for stage tool application; however, its recommended to evaluate the different methods in the market to include annular packers in combination with circulating ports that could improve the seal, reduce the wait on cement time, and optimize time and cost.

- Rig down cementing equipment.
- Perform nipple down safety meeting and discuss the operational plan and risks.
- Lift the BOPs.
- Install casing slips threading the fiber optic cable through the port.
- Cut casing and install packoff and fiber optic connectors.
- Wait on cement to reach 500 psi.
- Continue installation of section B and wellhead.
- Rig down drilling equipment.

6.7.4 Original Completion

- Perform a field inspection of onthe location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize rig to the location.
- Rig up equipment.
- Nipple up BOP
- Test BOP
- Pick up work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. In the failure persists, the operator may require assessing the root cause and correct it.
- Pull BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate well with inhibited packer fluid.
- Set packer as per program and test annulus to 1000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test, step rate test, and fall off test.

Appendix A: Material Selection for Casing, Tubing and Accessories in CO2 Injector Wells.

Proper materials and metallurgy selections in the well construction provide structural integrity to the wellbore, protection from corrosion, and assurance of external and internal mechanical integrity. The casing string materials for the injection wells were selected based on the risk of corrosion within the different sections of the wellbore. Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted]

Table CON-39: Formation water composition.

Element	Unit	Value
Claimed as PBI [redacted]		

A.1 Testing Program

The test environment selected was much harsher than the expected conditions for this project and assumed that the maximum impurities level possible would exist at the same time. Claimed as PBI [redacted] Table CON-40 summarizes the test parameters and conditions. The crevice test utilized a Teflon washer assembly as shown in Figure CON-13.

Claimed as PBI [redacted]

Table CON-40: Test environment, materials, parameters and conditions.

Claimed as PBI [redacted]

Figure CON-13: Crevice corrosion coupon assembly.

A.2 Results of the Material Testing

The stress cracking corrosion (SCC) test results and results of the localized corrosion evaluation in accordance with ASTM G48 for the C-ring and crevice corrosion specimens are given in Table CON-41 and Table CON-42. Claimed as PBI [redacted] Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted]

Figure CON-14: Crevice corrosion features of 25Cr-125 material.

Table CON-41: Results of stress corrosion cracking tests.

Claimed as PBI

[redacted]

Table CON-42: Crevice corrosion test results and penetration corrosion rates.

Material	Density A	Size B	Depth C	Max. Depth (mils)	Pen. Rate (mpy)	Observations
[redacted]						

Claimed as PBI

A.3 Discussion

Claimed as PBI [redacted]

Table CON-43: Comparison of expected CO_2 stream vs. test conditions.

Component	Project Limits	Testing Conditions (ppmv)
Claimed as PBI [redacted]		

Claimed as PBI [redacted] An example of properties and composition of 2507 alloy is provided in Figure CON-15.

Super 25 Chrome

Super Duplex 25 Chrome grades, 25CRW & 25CRS, are cold hardened duplex stainless steels intended for corrosion resistance in sweet (CO_2) and moderately sour (H_2S) environments with high chloride content, requiring high strength up to 450°F. The "Super" designation indicates that it has a Pitting Resistance Equivalence (PREN) ≥40. This provides increased resistance to H_2S and localized corrosion from high chlorides and/or oxygen relative to standard 25 Chrome.

It is therefore a common choice for use as tubing and liner in seawater and water injection wells. However, all environmental factors, including H_2S, CO_2, temperature, pH, and chloride concentration, should be considered before final material selection.

These alloys are classified in MR0175/ISO15156 as duplex stainless steels having a Pitting Resistance Equivalent Number ≥40, suitable for H_2S partial pressure ≤3.0 psi.

NOMINAL COMPOSITION

25CRS	Chromium 25%	Nickel 7%	Molybdenum 4%		Iron Balance
25CRW	Chromium 25%	Nickel 7%	Molybdenum 3%	Tungsten 2%	Iron Balance

API 5CRA / ISO 13680 Group 2 Category 25-7-4

Grade	Yield Strength min. (ksi)	Tensile Strength min. (ksi)	Elongation min. (%)	NACE MR0175/ISO 15156 Environmental Limits
110	110	115	11	Table A.25
125	125	130	10	Table A.25
140	140	145	9	N/A

TYPICAL PHYSICAL PROPERTIES

		70°F	200°F	400°F
Density	lbs/in^3	0.28		
Thermal Expansion	X10^{-6}/ °F	7.5	7.5	7.5
Elastic Modulus	psi x 10^6	29.0	28.2	27.0
Poisson Ratio		0.24	0.24	0.24
Thermal Conductivity	Btu/ft h °F	8	9	10
Specific Heat	Btu/lb °F	0.12	0.12	0.12

Corrosion Resistant Alloys
www.cralloys.com

Legal Disclaimer: Although the data found here has been produced and processed from third party sources believed to be reliable, no warranty expressed or implied is made regarding accuracy, adequacy, completeness, legality, reliability or usefulness of any information.

Figure CON-15: Example of technical specification for Super 25 Chrome material.

The tubing was sized using PROSPER software for the IPM suit to develop the nodal analysis evaluation. Several iterations were performed changing well configurations as well as surface and reservoir conditions such as inlet temperature, injection pressure, skin, and reservoir pressure, amongst others. Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted].

TK-805 is a medium thickness, powder applied, phenolic novolac coating formulated for environments to 350°F (177°C). The resin system utilized in TK-805 results in a coating with a high degree of chemical and temperature resistance, while producing an extremely smooth surface. Modifications in the resin system, in conjunction with the filler package, result in a coating with the highest degree of abrasion resistance found in the TK® product line. This combination of properties produces a coating with superior hydraulic efficiency, a decrease in deposition of organic and inorganic materials, and an excellent resistance toward wireline wear.

TK®-805

Specifications

Type	Phenolic Novolac
Color	Black
Temperature	To 350°F (177°C)
Pressure	To yield strength of pipe
Applied Thickness	6-13 mils (152-330 μm)
Primary Applications	Production tubing, water and CO_2 injection, and disposal wells
Primary Services	Oil and gas, sweet corrosion (CO_2), mild H_2S and alkaline service to pH 12

STIMULATION FLUIDS:

When stimulation fluids are charged through coated tubing, there is generally little effect if the fluids are flushed completely through the tubular. However, some organic acids, caustic and solvents may have a detrimental effect on certain organic coating systems and should be evaluated prior to use. If stimulation fluids are left in the tubing, they can reach formation temperature and cause accelerated attack on the coating. A NOV Tuboscope representative should be consulted when stimulation is contemplated.

SAMPLE OF TESTING CAPABILITIES:

Thermal Analysis
- Differential Scanning Calorimeter
- Thermogravimetric Analyzer

Spectroscopy
- Fourier Transform Infrared Spectrophotometer
- UV-VIS Spectrophotometer

Chromatography
- Gel Permeation Chromatograph (SEC)
- High Performance Liquid Chromatograph
- Gas Chromatograph

Additional Physical/Chemical Testing
- Microscope Analysis
- Autoclave
- Immersion Testing
- Flow Loop Analysis

Product Development
- Lab Compounding Capabilities

Figure CON-16: Example of internal coating for CO_2 injector well tubing.

Appendix B : Cementing Design and Materials Selection for CO_2 Injector Wells

B.1 Surface Section

Claimed as PBI [redacted] Figures CON-17 and CON-18 show examples of the proposed slurries for the surface section.

Claimed as PBI [redacted]

Claimed as PBI [redacted]

Figure CON-17: Surface section lead slurry example for CO_2 injector well.

Claimed as PBI

[redacted]

Figure CON-18: Surface section tail slurry example for CO_2 injector well.

B.2 Long String Section

The long string section will be cemented through direct circulation using a combination of lead and tail slurries. The work will be performed in two stages to reduce the equivalent circulating density (ECD) in the weak parts of the wellbore and decrease the risk of lost circulation while cementing due to the long column of cement. A detailed report of the cementing simulation is presented in Appendix F to illustrate the limitation of cementing the long string section in a single stage.

Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted]

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

Published support and additional information regarding the techniques and testing validation for above can be found at:

- Claimed as PBI [redacted]
- [redacted]
- [redacted]
- [redacted]

Figures CON-19 and CON-20 show examples of cementing slurries for cementing the long string section.

Claimed as PBI

[redacted]

Figure CON-19: Long string section lead slurry example for CO_2 injector well.

Claimed as PBI

[redacted]

Figure CON-20: Long string section tail slurry example for CO_2-resistant cement.

Appendix C: Blow Out Preventors and Wellhead Design for CO_2 Injector Wells

C.1 Blowout Preventer Equipment (BOPE)

- The BOPE must be API-monogrammed and adhere to API Standard 53 and Specifications 16A and 16C, as a minimum, and meet or exceed all applicable regulatory specifications.
- The BOPE other than annular preventers must have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
- All BOPE stacks must incorporate a set of blind rams.
- All rigs must have a calibrated trip tank. The trip tank and sheet are used to measure the fluid required to fill or displace from the hole during all tripping operations, including the running casing or completion strings.
- A full opening safety valve (FOSV) and an inside BOP safety valve (IBOPSV) must be always available on the rig floor for each drill pipe, drill collar size, and connection type in use.
- If a wireline lubricator is used for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline must be available if a lubricator is not in use.

C.2 Choke Manifolds and Kill Line

- The choke manifold must be API-monogrammed, meet API SPEC 16C as a minimum, and meet or exceed all applicable regulatory specifications.
- All BOPE must include a choke manifold with at least one remotely operated choke and one manual choke installed.
- Flare/vent lines must be as long as practical (a minimum of 100 ft from the well center), be as straight as possible (without sumps, collection areas, or uphill flow areas to prevent fluid buildup and resulting backpressure), and be securely anchored.

C.3 Closing Units

- The BOPE closing units must adhere to API Specification 16D and API Standard 53, as a minimum, and meet or exceed all applicable regulatory specifications.
- The BOPE control systems must include full controls on the closing unit and at least one remote control station. One control station must be located within 10 ft of the driller's console.
- The BOPE closing units must have two separate charging pumps with two independent power sources, as specified in API Specification 16D, or have N_2 bottle backup.

C.4 Pressure Testing

- The BOPE components (including the BOP stack, choke manifold, and choke lines) must be pressure-tested at the following frequency:
    - When installed. If the BOPE is stump tested, only the new connections are required to be tested at installation.
    - Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due soon, consider testing the BOPE prior to drilling any H_2S, abnormal pressure, or lost return zones to avoid having to test while drilling these intervals.
    - Anytime a BOPE connection seal is broken, the break must be pressure tested.

C.5 Wellhead Design for CO_2 Injector Wells

The wellhead design was based on the expected maximum pressure expected on the surface during construction, maintenance, and injection operations. The materials were selected according to the risk of corrosion due to the exposure wet CO_2 and potential extreme operating conditions during emergency scenarios.

The wellhead is composed of the following parts:

[redacted]

[redacted]

[redacted]

[redacted]

<u>Appendix D : Stress Check Reports Bluebonnet CCS 1, Bluebonnet CCS 2 and Bluebonnet CCS 3.</u>

Claimed as PBI

[redacted]

Appendix E: WELLCAT™ Tubing Design Report

During the life of the CO_2 injector well, the casing and tubing are subjected to compression, collapse, burst, and axial forces related to the different loads applied during installation, operation, and decommissioning. These loads and the stresses generated by them are evaluated using Stress Check™ software. The results are shown in Appendix D for Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3. For conventional oil and gas wells, this evaluation yields adequate confidence in the material selection, as it is a standard methodology for casing design.

However, for wells that operate with extreme changes of temperature such as CO_2 injector, steam injector, high-pressure and high-temperature, and exploration wells, among others, using WELLCAT is recommended to enhance the casing design through the study of thermal loads and their effect on the selected materials.

The Bluebonnet team used WELLCAT to evaluate the stress generated during startup, injection operations, and emergency and response events such as blowout, among others. Some of the loads used in WELLCAT were generated using PROSPER simulator and are included in the stress analysis as a custom load.

Figure CON-21 shows the PROSPER pressure profile at injection operating parameters used in the WELLCAT analysis. Figure CON-22 shows the PROSPER temperature profile at injection operating parameters.

Claimed as PBI

[redacted]

Figure CON-21: Pressure profile at injection operating parameters for Bluebonnet CC 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 using PROSPER modeling.

Claimed as PBI

[redacted]

Figure CON-22: Temperature profile at injection operating parameters for Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 using PROSPER modeling.

Figures CON-23 and CON-24 show the pressure and temperature profiles, respectively, assuming a blowout scenario.

Claimed as PBI

[redacted]

Figure CON-23: Pressure profile of CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2 and Bluebonnet CCS 3, assuming the event of a blowout with loss of containment.

Claimed as PBI

[redacted]

Figure CON-24: Temperature profile of CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3, assuming the event of a blowout with loss of containment.

Figure CON-25 shows the internal load profiles for the selected load scenarios.

Claimed as PBI

[redacted]

Figure CON-25: Internal pressure profiles applied for 5 ½-in. tubing design.

Figure CON-26 shows the external load profiles for the selected load scenarios.

Claimed as PBI

[redacted]

Figure CON-26: External pressure profiles applied for 5 ½-in. tubing design.

Figure CON-27 shows the temperature profiles for the selected load scenarios.

Claimed as PBI

[redacted]

Figure CON-27: Temperature profile applied for 5 ½-in. tubing design.

Figure CON-28 shows the design limits and stress envelope for the selected load scenarios and Figure CON-29 shows the triaxial safety factor results.

Table CON-44 shows the values of minimum absolute API safety factors for the simulation.

Claimed as PBI

[redacted]

Figure CON-28: Design limits plot for 5 ½-in. tubing design.

Claimed as PBI

[redacted]

Figure CON-29: Triaxial safety factor for 5 ½-in. tubing design.

Table CON-44: Minimum absolute API safety factor for 5 ½-in. tubing design.

MD (ft)	Minimum Absolute API Safety Factor			
	Triaxial	API Burst	API Collapse (V)	Axial

Claimed as PBI

[redacted]

MD (ft)	Minimum Absolute API Safety Factor			
	Triaxial	API Burst	API Collapse (V)	Axial

Claimed as PBI

[redacted]

MD (ft)	Minimum Absolute API Safety Factor			
	Triaxial	API Burst	API Collapse (V)	Axial

Claimed as PBI [redacted]

Figure CON-30 shows the envelope analysis for the proposed packer.

Claimed as PBI [redacted]

Figure CON-30: Packer operating envelope analysis for 5 ½-in. tubing design.

Appendix F: Long String Cementing Job Simulation

Claimed as PBI

[redacted]

References

Claimed as PBI

[redacted]