INJECTION WELL CONSTRUCTION PLAN
LAC 43:XVII.3607(C)(2)(j) and (k), LAC 43:XVII.3617(A) and (B), LAC 43:XVII.3621(A)(1) through (6)

Magnolia Sequestration Hub

1.0 Facility Information

Facility name:	Magnolia Sequestration Project (Magnolia Hub) Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 Wells
Facility contacts:	Kelly Watson, Project Manager 5 Greenway Plaza Houston, TX 77046 713-552-8613 kelly_watson@oxy.com
Well location:	Allen Parish, Louisiana Magnolia CCS 1 30° 40' 56.2474" N, 092° 50' 1.2244" W (NAD 27) 30° 40' 56.9387" N, 092° 50' 1.7707" W (NAD 83) Magnolia CCS 2 30° 41' 40.1623"N, 092° 50' 23.1767"W (NAD 27) 30° 41' 40.8527" N, 092° 50' 23.7241" W (NAD 83) Magnolia CCS 3 30° 41' 6.1794" N, 092° 50' 24.1145" W (NAD 27) 30° 41' 6.8705" N, 092° 50' 24.6617" W (NAD 83) Magnolia CCS 4 30° 41' 38.4597" N, 092° 50' 23.1814" W (NAD 27) 30° 40' 39.1501" N, 092° 50' 23.7288" W (NAD 83)

Magnolia Sequestration Hub, LLC, will construct CO_2 injection wells Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3 and Magnolia CCS 4 according to the procedures below. This Well Construction document includes special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, pressure control systems, and other well construction details that meet the standards under per LAC 43:XVII.3617(A).

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 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 Louisiana Department of Conservation and Energy (C&E) if substantial deviations from this plan are required. All phases of well construction will be supervised by a person knowledgeable and experienced in practical drilling and engineering who is familiar with the special conditions and requirements of well construction according to LAC 43:XVII.3617(A)(1).

Oxy Low Carbon Ventures, LLC, the parent company of Magnolia Sequestration Hub, LLC, drilled one stratigraphic well, YAMS MLR 004, in the Magnolia Hub in 2022. This well has been used to obtain site-based information and additional characterization to complement the geological and numerical simulation models. The YAMS MLR 004 stratigraphic well 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 formation, as described in the Testing and Monitoring Plan.

The project plans to drill three new in-zone monitoring wells in the Frio injection zone to directly monitor the injection targets (MLR), two above confining zone (ACZ) and two USDW monitoring wells.

The two 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.

Well schematics and construction details for the in-zone, above confining zone, and USDW monitoring wells are included in Appendix G.

3.0 Design Considerations for CO_2 Injector Wells

Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3 and Magnolia CCS 4 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.

Well materials and equipment were selected based on the maximum operating conditions expected during the life of the well and 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 Magnolia 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 Table CON-1, Table CON-2, Table CON-3, and Table CON-4. Table CON-5 shows the CO_2 specifications of the Magnolia Hub.

Table CON-1—Operating design parameters for Magnolia CCS 1

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	6,662-7,008	6,507-6,635	6,222-6,466
Perforation Interval TVD[2], top-bottom (ft)	6,662-7,008	6,507-6,635	6,222-6,466
Bottomhole gauge depth MD[1]/TVD[2] (ft)	6,120	6,120	6,120
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	14	6	10
Operating Wellhead Surface Injection Pressure (psig)	1,100-2,100	1,100-2,100	1,100-2,100
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	4,497	4,392	4,200
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	4,291	4,245	4,162
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

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

Table CON-2—Operating design parameters for Magnolia CCS 2

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	6,504- 6,854	6,345- 6,471	6,064- 6,308
Perforation Interval TVD[2], top-bottom (ft)	6,504- 6,854	6,345- 6,471	6,064- 6,308
Bottomhole gauge depth MD[1]/TVD[2] (ft)	5,960	5,960	5,960
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	14	6	10
Operating Wellhead Surface Injection Pressure (psig)	1,100-2,100	1,100-2,100	1,100-2,100
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	4,390	4,283	4,093
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	4,183	4,138	4,053
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

Table CON-3—Operating design parameters for Magnolia CCS 3

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	5,788- 6,149	5,473- 5,749	4,985- 5,443
Perforation Interval TVD[2], top-bottom (ft)	5,788- 6,149	5,473- 5,749	4,985- 5,443
Bottomhole gauge depth MD[1]/TVD[2] (ft)	4,885	4,885	4,885
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	11	6	13
Operating Wellhead Surface Injection Pressure (psig)	950-1,800	950-1,950	900-1,800
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	3,907	3,694	3,365
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	3,564	3,471	3,327
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

Table CON-4—Operating design parameters for Magnolia CCS 4

Parameter/Condition	Completion 1	Completion 2	Completion 3
Perforation Interval MD[1], top-bottom (ft)	5,683- 6,035	5,376- 5,646	4,883- 5,344
Perforation Interval TVD[2], top-bottom (ft)	5,683- 6,035	5,376- 5,646	4,883- 5,344
Bottomhole gauge depth MD[1]/TVD[2] (ft)	4,780	4,780	4,780
Maximum Injection Rate (metric tonnes per day)	7,700	7,700	7,700
Average Injection Rate (metric tonnes per day)	5,480	5,480	5,480
Total Volume Injected (millions of metric tonnes)	11	6	13
Operating Wellhead Surface Injection Pressure (psig)	950-1,800	950-1,900	900-1,800
Maximum Surface Wellhead Injection Pressure	2,300	2,300	2,300
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ top of perforations (psig)	3,836	3,629	3,296
Maximum Bottomhole Pressure at 90% of frac gradient (0.75 psi/ft) @ bottomhole gauge (psig)	3,493	3,403	3,257
Minimum Annulus Pressure/Tubing Differential (psi)	100	100	100

Table CON-5—CO_2 Specification for Magnolia Hub

Component	Specification
CO_2 (% mol)	>95
Water (lbs/MMCF)	<10
Nitrogen (% mol)	<4
Oxygen (ppm by wgt)	<10
Hydrogen (% mol)	<1
SOx (ppm by wgt)	<1
NOx (ppm by wgt)	<1
Hydrogen Sulfide (ppm by vol)	<20
HCN (ppm by vol)	<40
Hydrocarbons (%mol)	<5
Carbon Monoxide (ppm by wgt)	<4250
Glycol (gal/MMSCF)	<0.3
Ammonia (ppm by wgt)	<50
Argon (%mol)	<1
Sulfur (ppm by wgt)	<35
Carbonyl Sulfide (ppmv)	<5
Alcohols (ppmv)	<3000

4.0 Well Design Magnolia CCS 1 - CO_2 Injector Well

The Magnolia CCS 1 well design includes three main sections: conductor casing, surface casing, and long string casing. The casing sections 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.

Figure CON-1 shows the proposed well schematic for the Magnolia CCS 1 initial completion. Recompletion well schematics are included in Section 8.0.

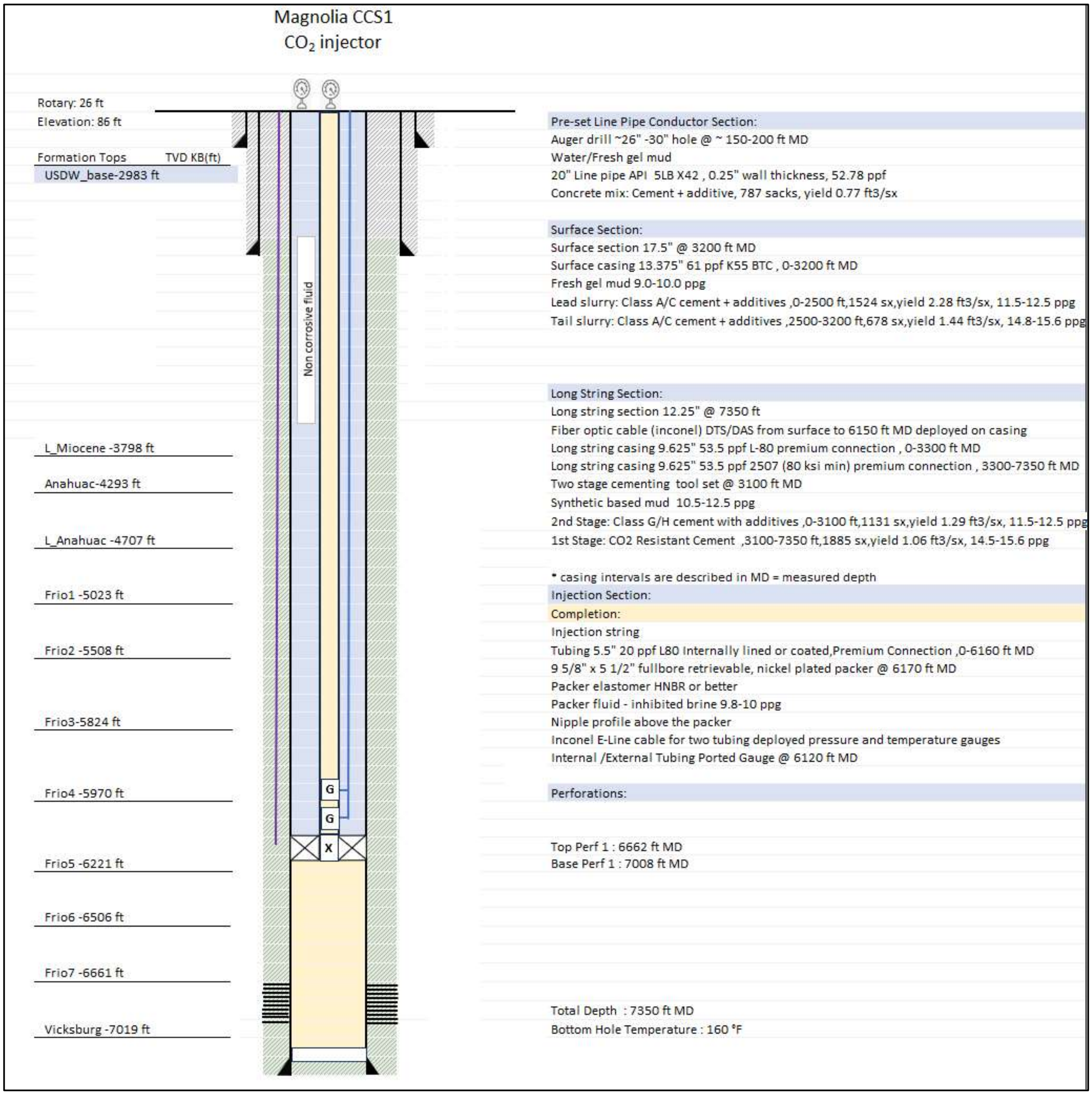

Figure CON-11—Magnolia CCS 1 well schematic for initial completion.

4.1 Design Overview Magnolia CCS 1

4.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. 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 17 ½ in. vertical wellbore will be drilled to 3,200 ft to cover base of the USDW, estimated at 2,983 ft 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 target 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, 13 3/8 in. 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 C&E and then 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 Commissioner. 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 according to LAC 43:XVII.3617(A)(3) requirements 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

A 12 ¼ in. vertical wellbore will be drilled from 3,200 ft to 7,350 ft 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. Returns will be observed at surface 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. Test casing per Louisiana Statutes and Regulations 3617.A.3 requirements

4.1.4 Completion

Before completion operations, the rig crew will test the casing to 1,000 psi over a 1 hour time period, 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 5 ½-in. tubing and packer completion will be run to approximately 6,170 ft, 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 Casing, Tubing and Completion Design Magnolia 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 for Magnolia CCS 1

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,200	1.18	1.31	2.51	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,300	2.05	1.77	2.95	2.03
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,300-7,350	1.92	1.36	3.41	1.77
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-6,160	2.44	1.39	2.06	1.57

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

The WELLCAT™ evaluation performed for Magnolia CCS 1 applies to the loads observed for Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 (Appendix E).

The tables listed below provide further details regarding the Magnolia 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.

Table CON-7—Open hole diameters and intervals for Magnolia CCS 1

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,200	17 ½	Cover USDW
Long String Section	3,200 to 7,350	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 2,983 ft TVD.

Table CON-8—Casing specifications for Magnolia CCS 1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,200	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,300	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,300 to 7,350	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-9—Conductor material properties for Magnolia CCS 1

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-10—Casing material properties for Magnolia 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)
13 ⅜-in. 61 ppf K55 BTC	0 to 3,200	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,300	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,300 to 7,350	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,100 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The centralization program will aim at minimum 70% 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-11 contains the upper completion specifications for the original completion and recompletions. Table CON-12 shows the specification of the 5 ½ in. tubing.

Table CON-11—Upper completion specifications – initial completion and first recompletion for Magnolia CCS 1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 6,160	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-12—Tubing material properties for Magnolia CCS 1

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

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 5 ½-in. tubing and 9 ⅝-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-13 shows the specifications of the injection packer.

Table CON-13—Packer specifications for Magnolia 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)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

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.

4.3 Cementing Program Magnolia CCS 1

Table CON-14 shows the cementing program details.

Table CON-14—Cementing program for Magnolia CCS 1

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,500	11.5-12.5	1,524	2.28	100%
	Class A/C cement with additives	2,500 to 3,200	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,100	11.5-12.5	1,131	1.29	50%
	CO_2-Resistant Cement	3,100 to 7,350	14.5-15.6	1,885	1.06	50%

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 3,100 ft, 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.

4.4 Mud Program Magnolia CCS 1

Table CON-15 shows the mud program details for Magnolia CCS 1.

Table CON-15—Mud program for Magnolia CCS 1

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,200	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,200–7,350	10.5-12.5	12–20	8–12	n/a	<5	<5

4.5 Wellhead Schematic Magnolia CCS 1

Figure CON-2 below is a basic mechanical drawing of the wellhead to be used for the Magnolia CCS 1 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

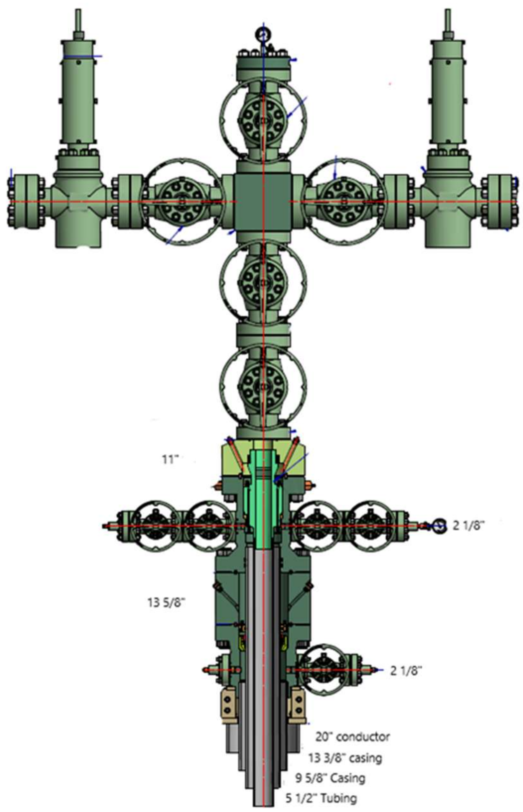

Figure CON-2—Schematic diagram of Magnolia CCS 1 well

4.6 Magnolia CCS 1 Procedure

4.6.1 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 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

4.6.2 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 a pre-spud 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 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. 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 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 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 at 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.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks. Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements

4.6.3 Long String Section

- Perform a pre-spud 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 12.25 in. 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 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken minimum every 100 ft.
- 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 as per program.

- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. 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 casing slips and 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: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on 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 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. At 10 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 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 two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. 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.

4.6.4 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 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 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 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 Magnolia CCS 2 - CO_2 Injector Well

The Magnolia 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.

Figure-CON 3 shows the proposed well schematic for the Magnolia CCS 2 original completion. Recompletion well schematics are included in Section 8.0.

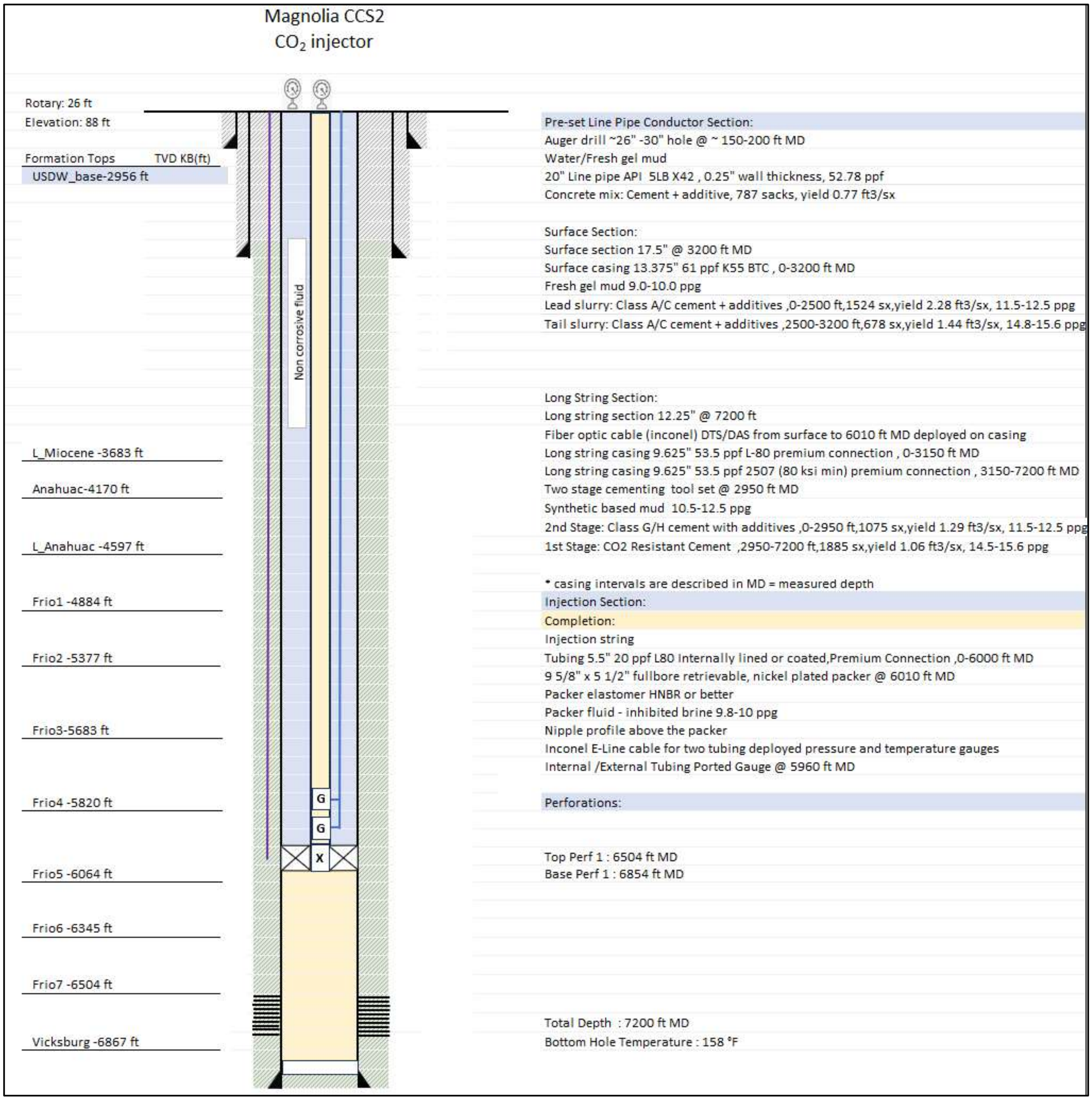

Figure CON-32—Magnolia CCS 2 well schematic for initial completion.

5.1 Design Overview Magnolia CCS 2

5.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. 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 17 ½ in. vertical wellbore will be drilled to 3,200 ft to cover base of the USDW, estimated at 2,956 ft 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 (POT) Plan. Then, 13 3/8 in. 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 C&E, 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 Commissioner. 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 according to LAC 43:XVII.3617(A)(3) requirements 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

A 12 ¼ in. vertical wellbore will be drilled from 3,200 ft 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 packoff. The team will install the rest of the wellhead to prepare for completions operations. Test casing per Louisiana Statutes and Regulations 3617.A.3 requirements

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 5 ½-in. tubing and packer completion will be run to approximately 6,010 ft, 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 Casing, Tubing and Completion Design Magnolia 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-16 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-16—Minimum safety factors for tubular design for Magnolia CCS 2

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,200	1.18	1.35	2.51	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,150	2.06	1.78	2.99	2.06
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,150-7,200	1.93	1.39	3.523	1.81
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-6,000	2.41	1.41	2.17	1.59

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

The WELLCAT™ evaluation performed for Magnolia CCS 1 applies to the loads observed for Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 (Appendix E).

The tables listed below provide further details regarding the Magnolia CCS 1 well. Table CON-17 contains the open hole diameters and intervals, Table CON-18 lists the casing specifications, Table CON-19 details the conductor material, and Table CON-20 details the casing material properties.

Table CON-17—Open hole diameters and intervals for Magnolia CCS 2

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,200	17 ½	Cover USDW
Long String Section	3,200 to 7,200	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 2,956 ft TVD.

Table CON-18—Casing specifications for Magnolia CCS 2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,200	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,150	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,150 to 7,200	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-19—Conductor material properties for Magnolia CCS 2

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-20—Casing material properties for Magnolia 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)
13 ⅜-in. 61 ppf K55 BTC	0 to 3,200	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,150	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,150 to 7,200	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~2,950 ft in the 9 5/8-in. casing to perform the two-stage cementing job.

- The centralization program will aim at minimum 70% 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-21 contains the upper completion specifications for the original completion and recompletions. Table CON-22 shows the specification of the 5 ½ in. tubing.

Table CON-21—Upper completion specifications – initial completion and first recompletion for Magnolia CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 6,000	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-22—Tubing material properties for Magnolia CCS 2

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

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 5 ½-in. tubing and 9 ⅝-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-23shows the specifications of the injection packer.

Table CON-23—Packer specifications for Magnolia 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)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

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.

5.3 Cementing Program Magnolia CCS 2

Table CON-24 shows the cementing program details.

Table CON-24—Cementing program for Magnolia CCS 2.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,500	11.5-12.5	1,524	2.28	100%
	Class A/C cement with additives	2,500 to 3,200	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 2,950	11.5-12.5	1,075	1.29	50%
	CO_2-Resistant Cement	2,950 to 7,200	14.5-15.6	1,885	1.06	50%

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 2,950 ft, 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.

5.4 Mud Program Magnolia CCS 2

Table CON-25 shows the mud program details for Magnolia CCS 2.

Table CON-25—Mud program for Magnolia CCS 2.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,200	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,200–7,200	10.5-12.5	12–20	8–12	n/a	<5	<5

5.5 Wellhead Schematic Magnolia CCS 2

Figure CON-4 below is a basic mechanical drawing of the wellhead to be used for the Magnolia CCS 2 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

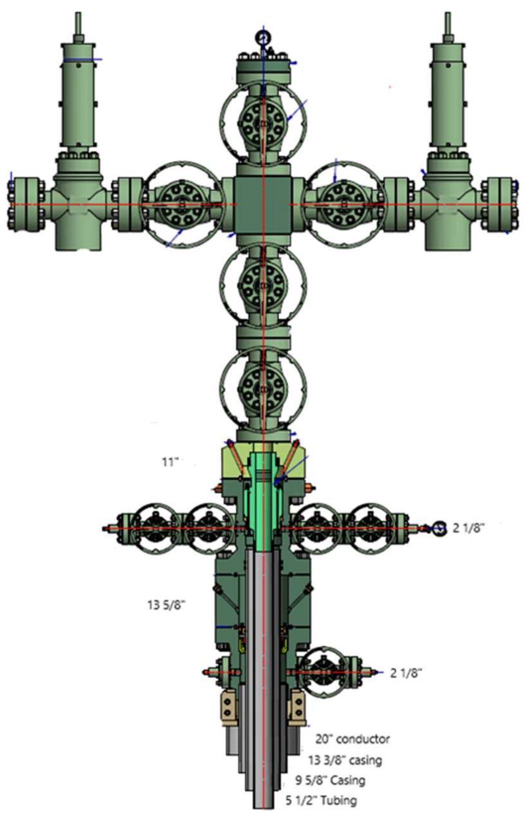

Figure CON-4—Schematic diagram of Magnolia CCS 2 well.

5.6 Magnolia CCS 2 Procedure

5.6.1 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 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

5.6.2 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 a pre-spud 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 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. 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 13-3/8 in. surface casing to TD.

- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 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 at 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.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements

5.6.3 Long String Section

- Perform a pre-spud 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 12.25 in. 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 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken minimum every 100 ft.
- 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 as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. 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 casing slips and 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: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on 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 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. At 10 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 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 two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. 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.

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 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 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 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.

6.0 Well Design Magnolia CCS 3 - CO_2 Injector Well

The Magnolia 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.

Figure CON-5 shows the proposed well schematic for the Magnolia CCS 3 original completion. Recompletion well schematics are included in Section 8.0.

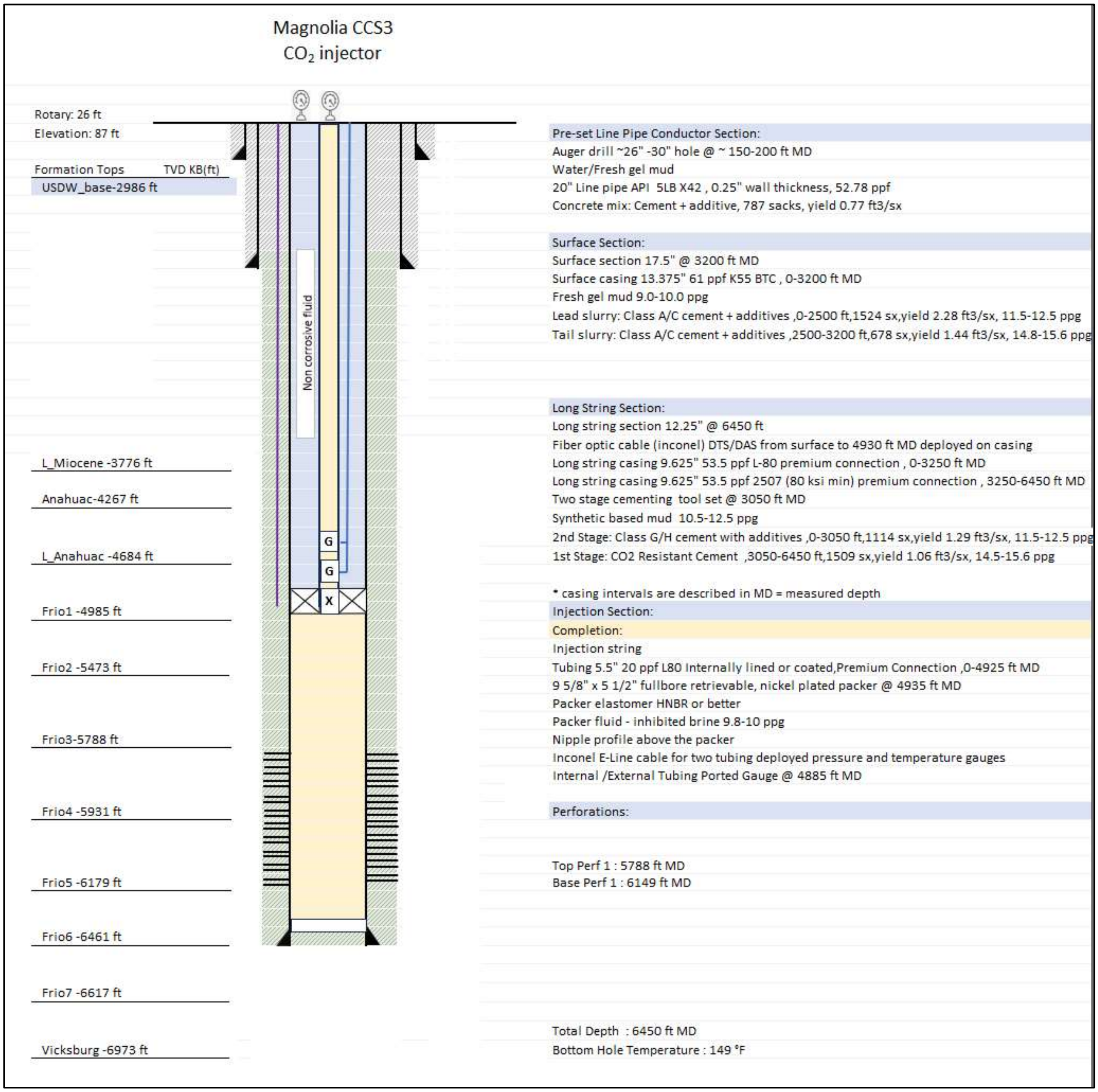

Figure CON-53—Magnolia CCS 3 well schematic for initial completion.

6.1 Design Overview Magnolia CCS 3

6.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. 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 17 ½ in. vertical wellbore will be drilled to 3,200 ft to cover base of the USDW, estimated at 2,986 ft 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, 13 3/8 in. 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 C&E, 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 Commissioner. 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 according to LAC 43:XVII.3617(A)(3) requirements 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

A 12 ¼ in. vertical wellbore will be drilled from 3,200 ft 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 packoff. The team will install the rest of the wellhead to prepare for completions operations. Test casing per Louisiana Statutes and Regulations 3617.A.3 requirements

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 5 ½-in. tubing and packer completion will be run to approximately 4,935 ft, 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 Casing, Tubing and Completion Design Magnolia 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-26 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-26—Minimum safety factors for tubular design for Magnolia CCS 3.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,200	1.19	1.49	2.51	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,250	2.06	1.77	3.25	2.09
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,250-6,450	1.95	1.56	3.56	1.97
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-4,925	2.36	1.53	2.27	1.72

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

The WELLCAT™ evaluation performed for Magnolia CCS 1 applies to the loads observed for Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 (Appendix E).

The tables listed below provide further details regarding the Magnolia CCS 3 well. Table CON-27 contains the open hole diameters and intervals, Table CON-28 lists the casing specifications, Table CON-29 details the conductor material, and Table CON-30 details the casing material properties.

Table CON-27—Open hole diameters and intervals for Magnolia CCS 3.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,200	17 ½	Cover USDW
Long String Section	3,200 to 6,450	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 2,986 ft TVD.

Table CON-28—Casing specifications for Magnolia CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,200	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,250	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,250 to 6,450	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-29—Conductor material properties for Magnolia CCS 3.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-30—Casing material properties for Magnolia 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)
13 ⅜-in. 61 ppf K55 BTC	0 to 3,200	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,250	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,250 to 6,450	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,050 ft in the 9 5/8-in. casing to perform the two-stage cementing job.

- The centralization program will aim at minimum 70% 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-31 contains the upper completion specifications for the original completion and recompletions. Table CON-32 shows the specification of the 5 ½ in. tubing.

Table CON-31—Upper completion specifications – initial completion and first recompletion for Magnolia CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 4,925	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-32—Tubing material properties for Magnolia CCS 3.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

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 5 ½-in. tubing and 9 ⅝-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-33shows the specifications of the injection packer.

Table CON-33—Packer specifications for Magnolia 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)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

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.

6.3 Cementing Program Magnolia CCS 3

Table CON-34shows the cementing program details.

Table CON-34—Cementing program for Magnolia CCS 3.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,500	11.5-12.5	1,524	2.28	100%
	Class A/C cement with additives	2,500 to 3,200	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,050	11.5-12.5	1,114	1.29	50%
	CO_2-Resistant Cement	3,050 to 6,450	14.5-15.6	1,509	1.06	50%

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 3,050 ft, 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.

6.4 Mud Program Magnolia CCS 3

Table CON-35 shows the mud program details for Magnolia CCS 3.

Table CON-35—Mud program for Magnolia CCS 3.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,200	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,200–6,450	10.5-12.5	12–20	8–12	n/a	<5	<5

6.5 Wellhead Schematic Magnolia CCS 3

Figure CON-6 below is a basic mechanical drawing of the wellhead to be used for the Magnolia CCS 3 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

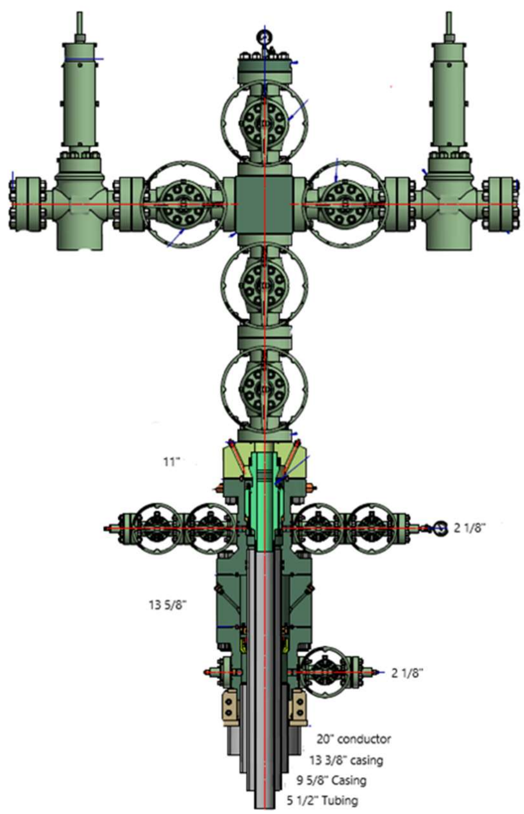

Figure CON-6—Schematic diagram of Magnolia CCS 3 well.

6.6 Magnolia CCS 3 Procedure

6.6.1 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 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

6.6.2 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 a pre-spud 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 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. 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 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.

- Rig up cementing equipment and test lines at 250 psi and 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 at 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.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements.

6.6.3 Long String Section

- Perform a pre-spud 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 12.25 in. 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 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken minimum every 100 ft.
- 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 as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. 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 casing slips and 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: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on 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 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. At 10 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 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 two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. 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.

6.6.4 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 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 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 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.

7.0 Well Design Magnolia CCS 4 - CO_2 Injector Well

The Magnolia CCS 4 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.

Figure CON-7 shows the proposed well schematic for the Magnolia CCS 4 original completion. Recompletion well schematics are included in Section 8.0.

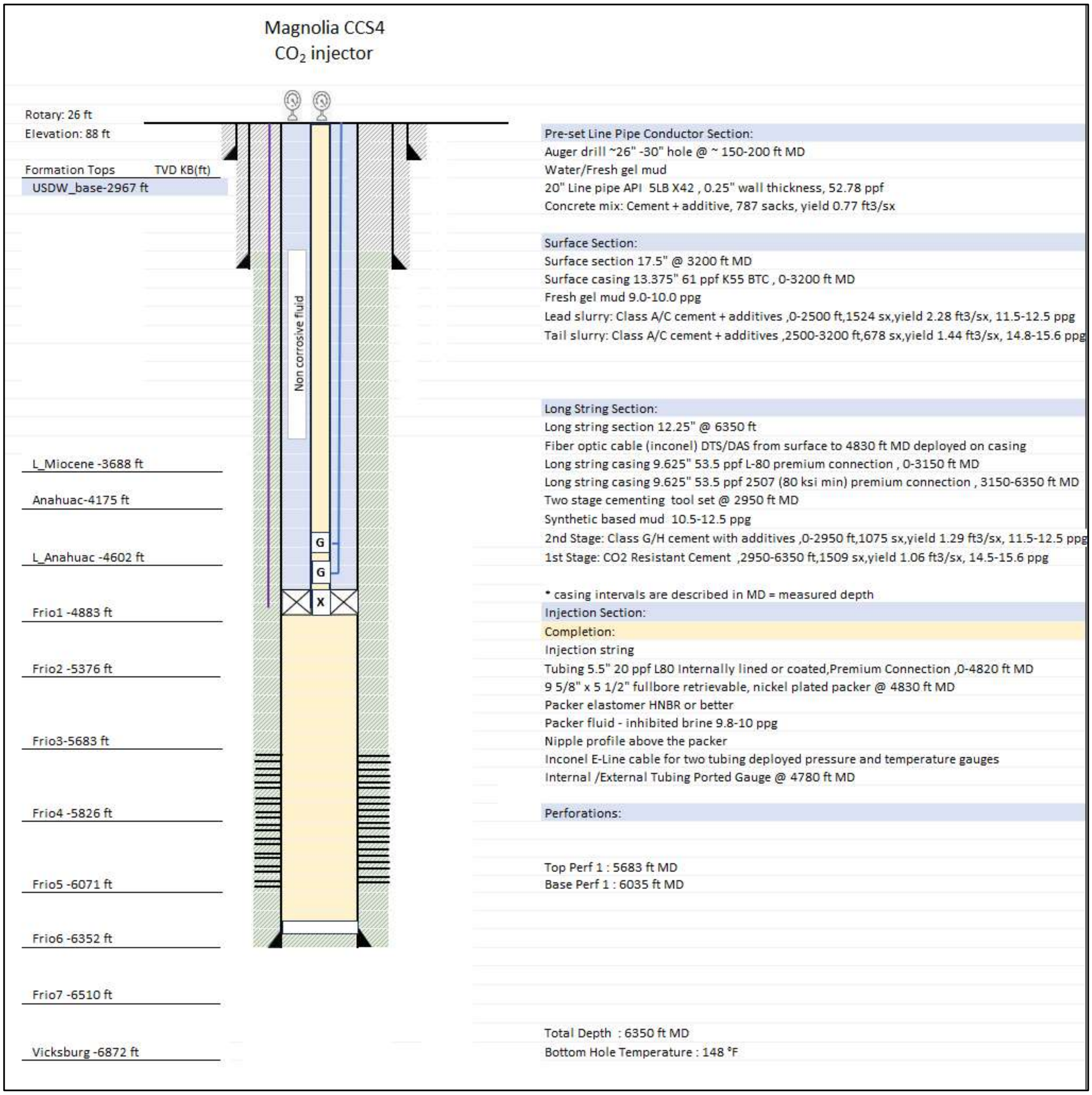

Figure CON-74—Magnolia CCS 4 well schematic for initial completion.

7.1 Design Overview Magnolia CCS 4

7.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. 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.

7.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,200 ft to cover base of the USDW, estimated at 2,967 ft 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, 13 3/8 in. 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 C&E, 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 Commissioner. 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 according to LAC 43:XVII.3617(A)(3) requirements 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).

7.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,200 ft 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 packoff. The team will install the rest of the wellhead to prepare for completions operations. Test casing per Louisiana Statutes and Regulations 3617.A.3 requirements

7.1.4 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 5 ½-in. tubing and packer completion will be run to approximately 4,830 ft, 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.

7.2 Casing, Tubing and Completion Design Magnolia CCS 4

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-36 shows the minimum safety factors calculated using Stress Check^{TM} 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-36—Minimum safety factors for tubular design for Magnolia CCS 4.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,200	1.18	1.52	2.51	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,150	2.07	1.78	3.29	2.10
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,150-6,350	1.96	1.58	3.75	1.99
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-4,820	2.35	1.55	2.29	1.74

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

The WELLCAT^{TM} evaluation performed for Magnolia CCS 1 applies to the loads observed for Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 (Appendix E).

The tables listed below provide further details regarding the Magnolia CCS 4 well. Table CON-37 contains the open hole diameters and intervals, Table CON-38 lists the casing specifications, Table CON-39 details the conductor material, and Table CON-40 details the casing material properties.

Table CON-37—Open hole diameters and intervals for Magnolia CCS 4.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,200	17 ½	Cover USDW
Long String Section	3,200 to 6,350	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 2,967 ft TVD.

Table CON-38—Casing specifications for Magnolia CCS 4.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,200	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,150	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,150 to 6,350	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-39—Conductor material properties for Magnolia CCS 4.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)	Elongation %
20-in. API 5LB X42 52.78 ppf	0 to 200	42	60	23

Table CON-40—Casing material properties for Magnolia CCS 4.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 61 ppf K55 BTC	0 to 3,200	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,150	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,150 to 6,350	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~2,950 ft in the 9 5/8-in. casing to perform the two-stage cementing job.

- The centralization program will aim at minimum 70% 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-41 contains the upper completion specifications for the original completion and recompletions. Table CON-42 shows the specification of the 5 ½ in. tubing.

Table CON-41—Upper completion specifications – initial completion and first recompletion for Magnolia CCS 4.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 4,820	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-42—Tubing material properties for Magnolia CCS 4.

Tubing	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowable Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Injection Tubing: 5 ½-in. 20# L80 Special – Coated TK-805	9,190	8,830	466	67°	26.2

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 5 ½-in. tubing and 9 ⅝-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-43shows the specifications of the injection packer.

Table CON-43: Packer specifications - Magnolia CCS 4.

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)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
8,050	7,790	530	• Feed through, HNBR (RGD) elastomers

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.

7.3 Cementing Program Magnolia CCS 4

Table CON-44 shows the cementing program details.

Table CON-44—Cementing program for Magnolia CCS 4.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,500	11.5-12.5	1,524	2.28	100%
	Class A/C cement with additives	2,500 to 3,200	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 2,950	11.5-12.5	1,075	1.29	50%
	CO_2-Resistant Cement	2,950 to 6,350	14.5-15.6	1,509	1.06	50%

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 2,950 ft, 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.

7.4 Mud Program Magnolia CCS 4

Table CON-45 shows the mud program details for Magnolia CCS 4.

Table CON-45—Mud program for Magnolia CCS 4

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,200	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,200–6,350	10.5-12.5	12–20	8–12	n/a	<5	<5

7.5 Wellhead Schematic Magnolia CCS 4

Figure CON-8 below is a basic mechanical drawing of the wellhead to be used for the Magnolia CCS 4 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

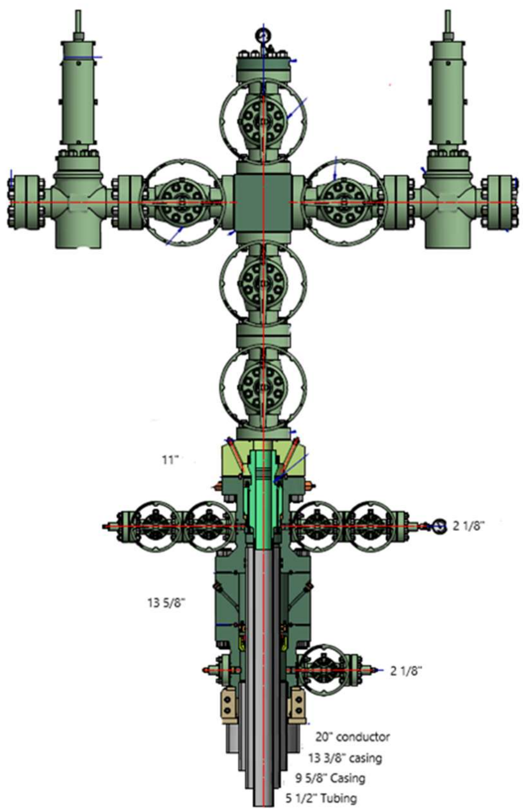

Figure CON-8—Schematic diagram of Magnolia CCS 4 well.

7.6 Magnolia CCS 4 Procedure

7.6.1 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 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

7.6.2 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 a pre-spud 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 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. 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 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 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 at 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.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi in accordance with Louisiana Statutes and Regulations 3617.A.3 requirements.

7.6.3 Long String Section

- Perform a pre-spud 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 12.25 in. 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 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the plan. Surveys must be taken minimum every 100 ft.
- 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 as per program.

- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. 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 casing slips and 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: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on 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 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. At 10 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 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 two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. 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.

7.6.4 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 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 60 minutes with 1,000 psi. If the pressure decreases more than 5% in 60 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.

8.0 Recompletion Wellbore Diagrams

Information about squeeze plugs pumped during recompletions are available in the Injector Well Plugging Plan.

8.1 Magnolia CCS 1

8.1.1 Magnolia CCS 1 First Recompletion

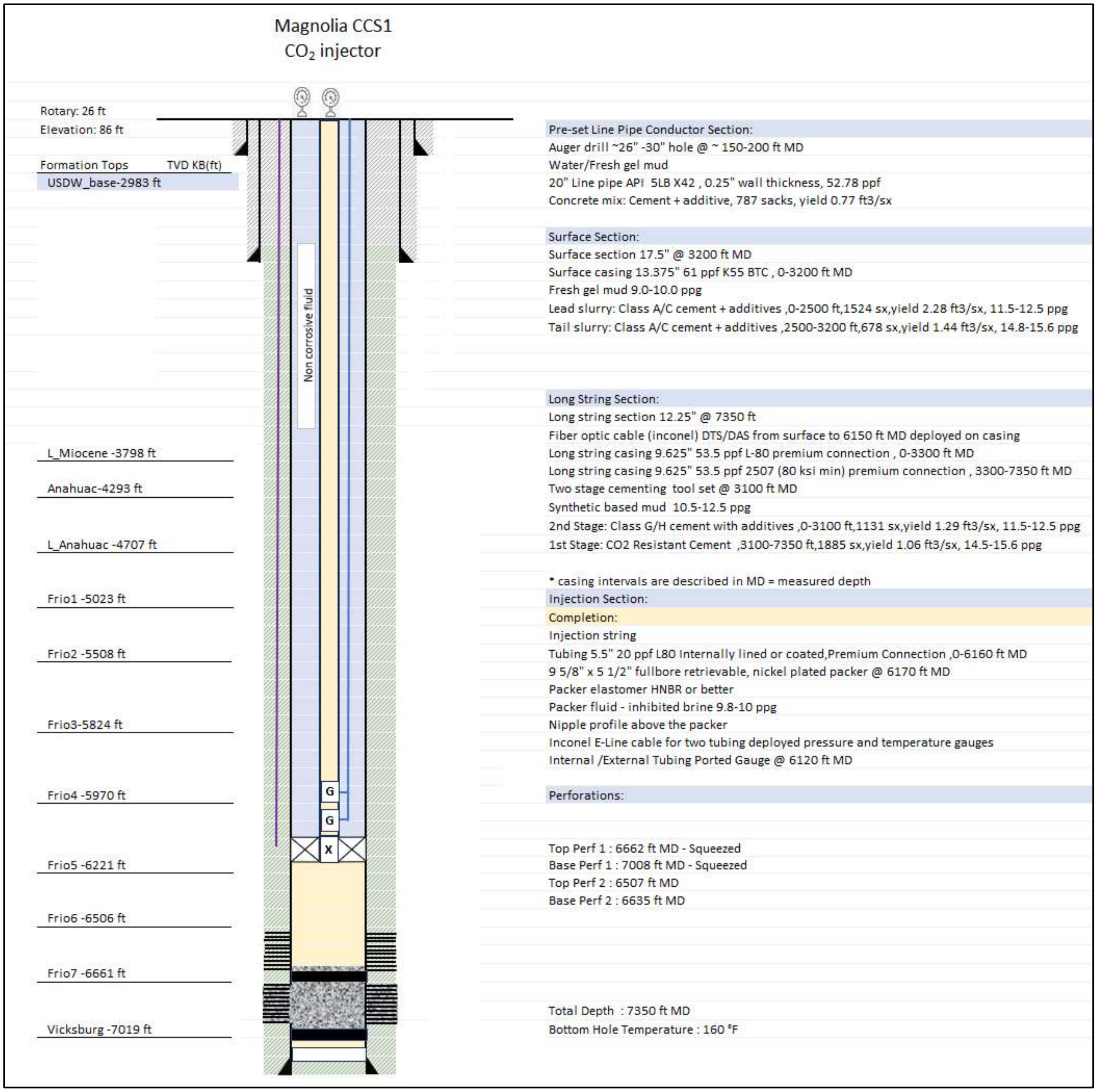

Figure CON-9—First Recompletion Schematic diagram of Magnolia CCS 1 well.

8.1.2 Magnolia CCS 1 Second Recompletion

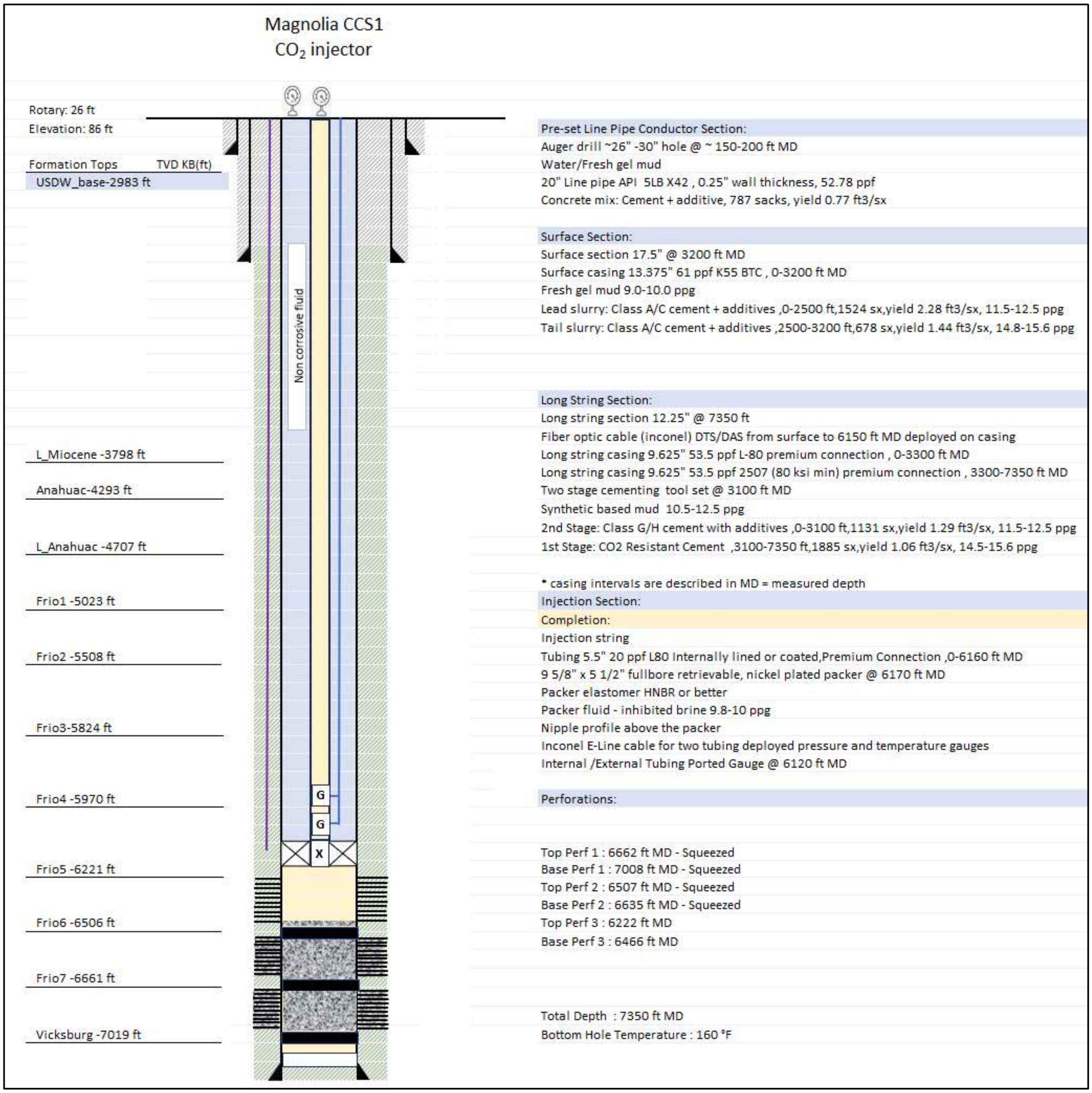

Figure CON-10—Second Recompletion Schematic diagram of Magnolia CCS 1 well.

8.2 Magnolia CCS 2

8.2.1 Magnolia CCS 2 First Recompletion

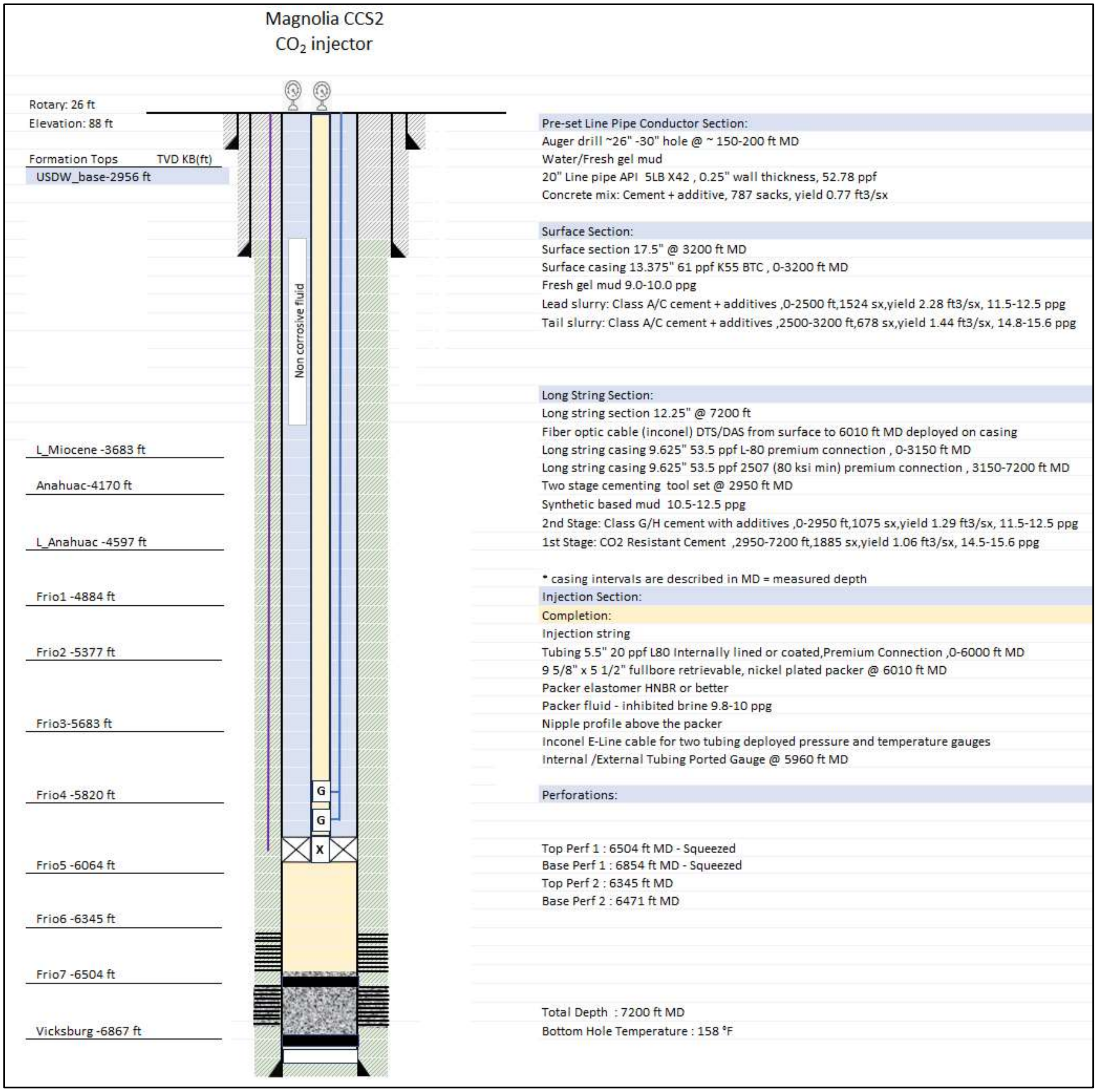

Figure CON-11—First Recompletion Schematic diagram of Magnolia CCS 2 well.

8.2.2 Magnolia CCS 2 Second Recompletion

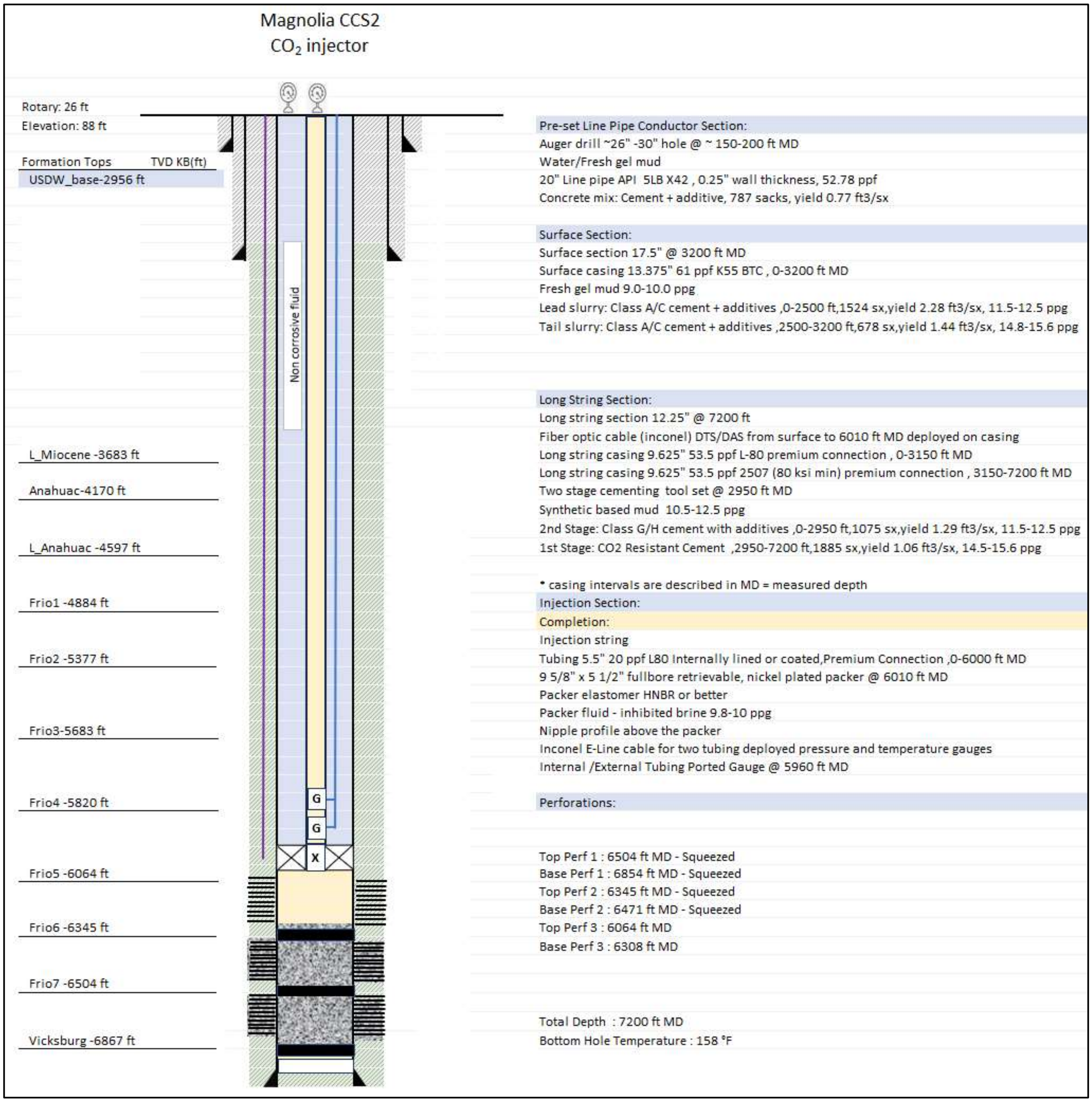

Figure CON-12—Second Recompletion Schematic diagram of Magnolia CCS 2 well.

8.3 Magnolia CCS 3

8.3.1 Magnolia CCS 3 First Recompletion

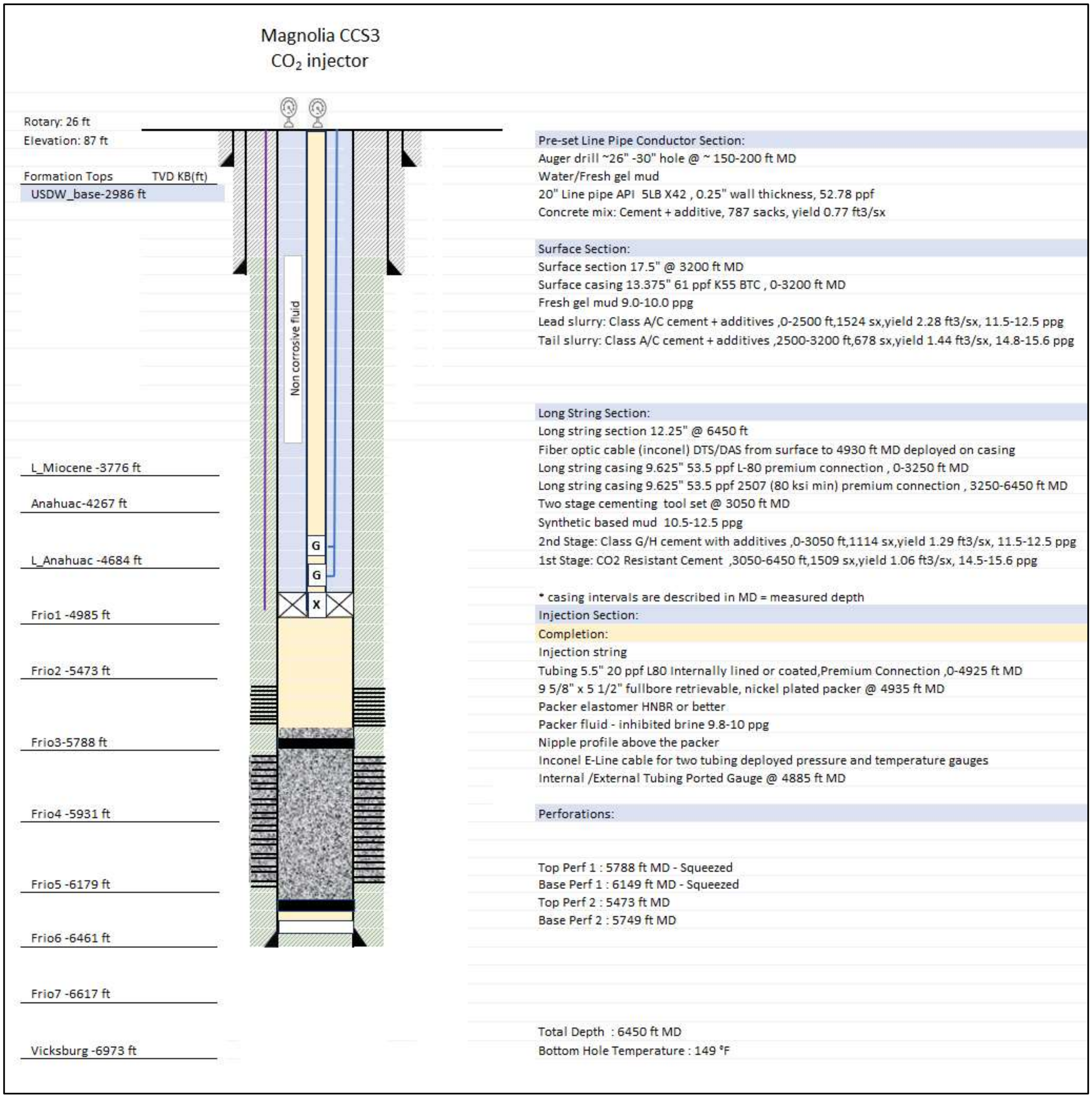

Figure CON-13—First Recompletion Schematic diagram of Magnolia CCS 3 well.

8.3.2 Magnolia CCS 3 Second Recompletion

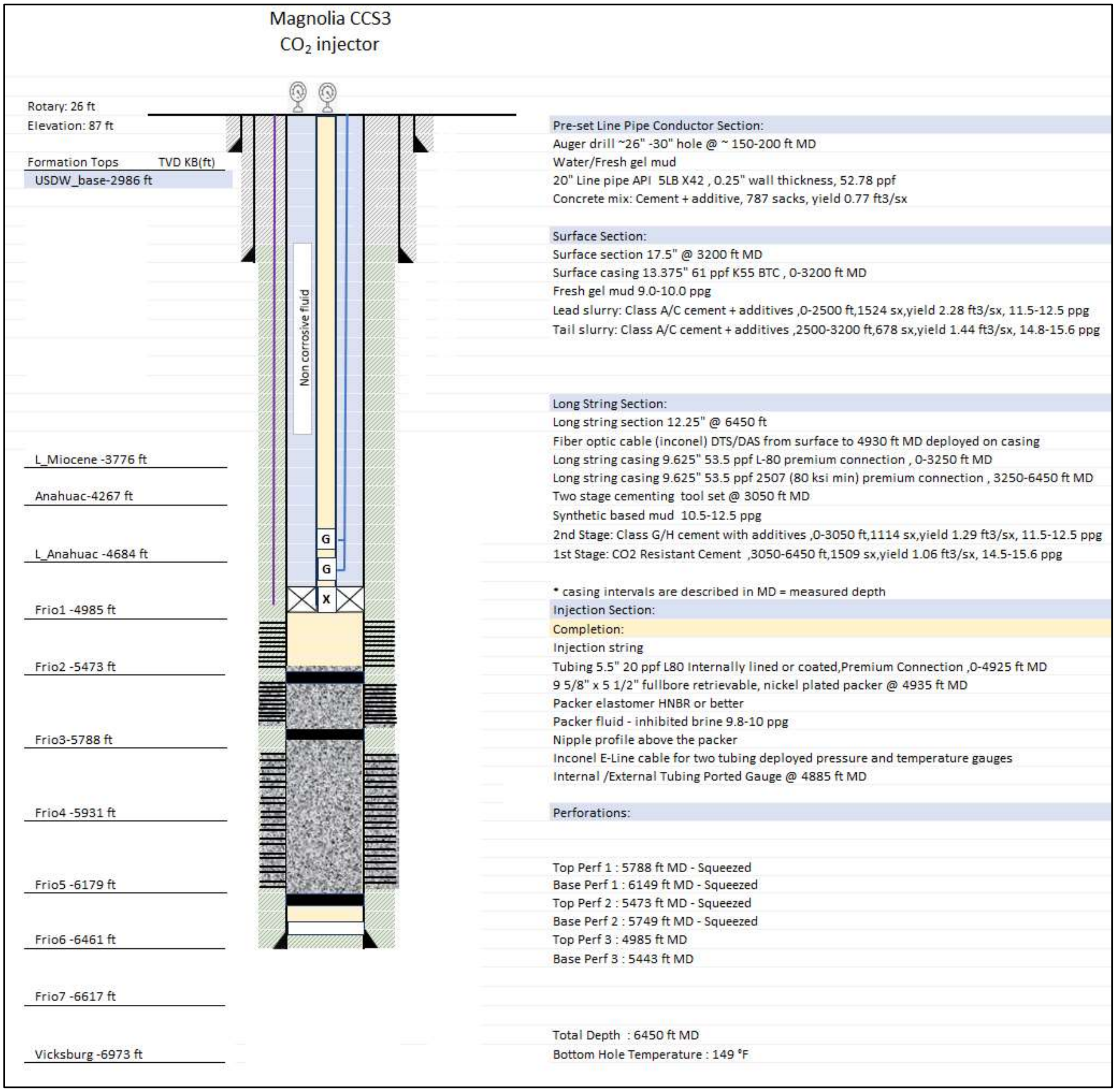

Figure CON-14—Second Recompletion Schematic diagram of Magnolia CCS 3 well.

8.4 Magnolia CCS 4

8.4.1 Magnolia CCS 4 First Recompletion

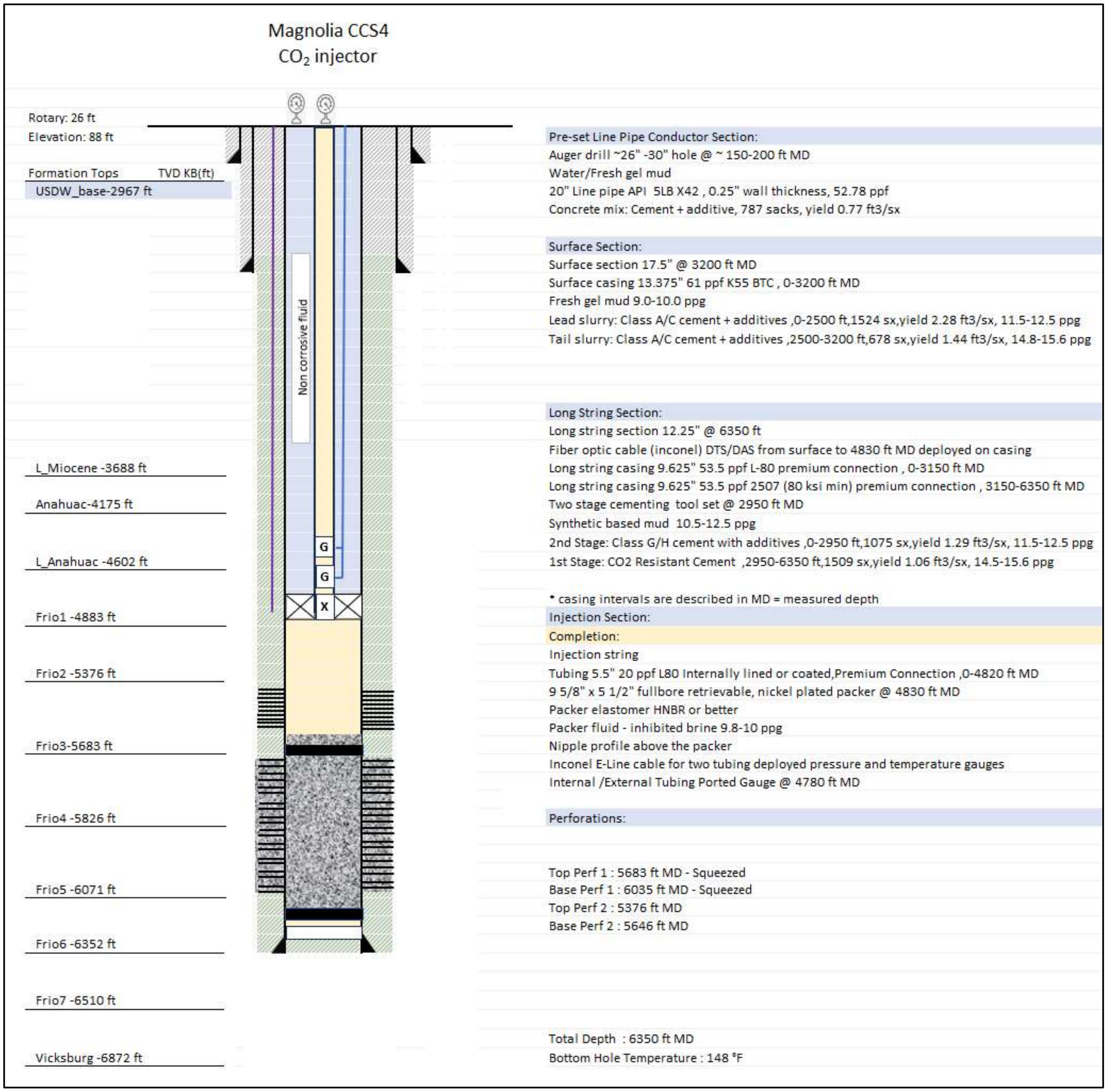

Figure CON-15—First Recompletion Schematic diagram of Magnolia CCS 4 well.

8.4.2 Magnolia CCS 4 Second Recompletion

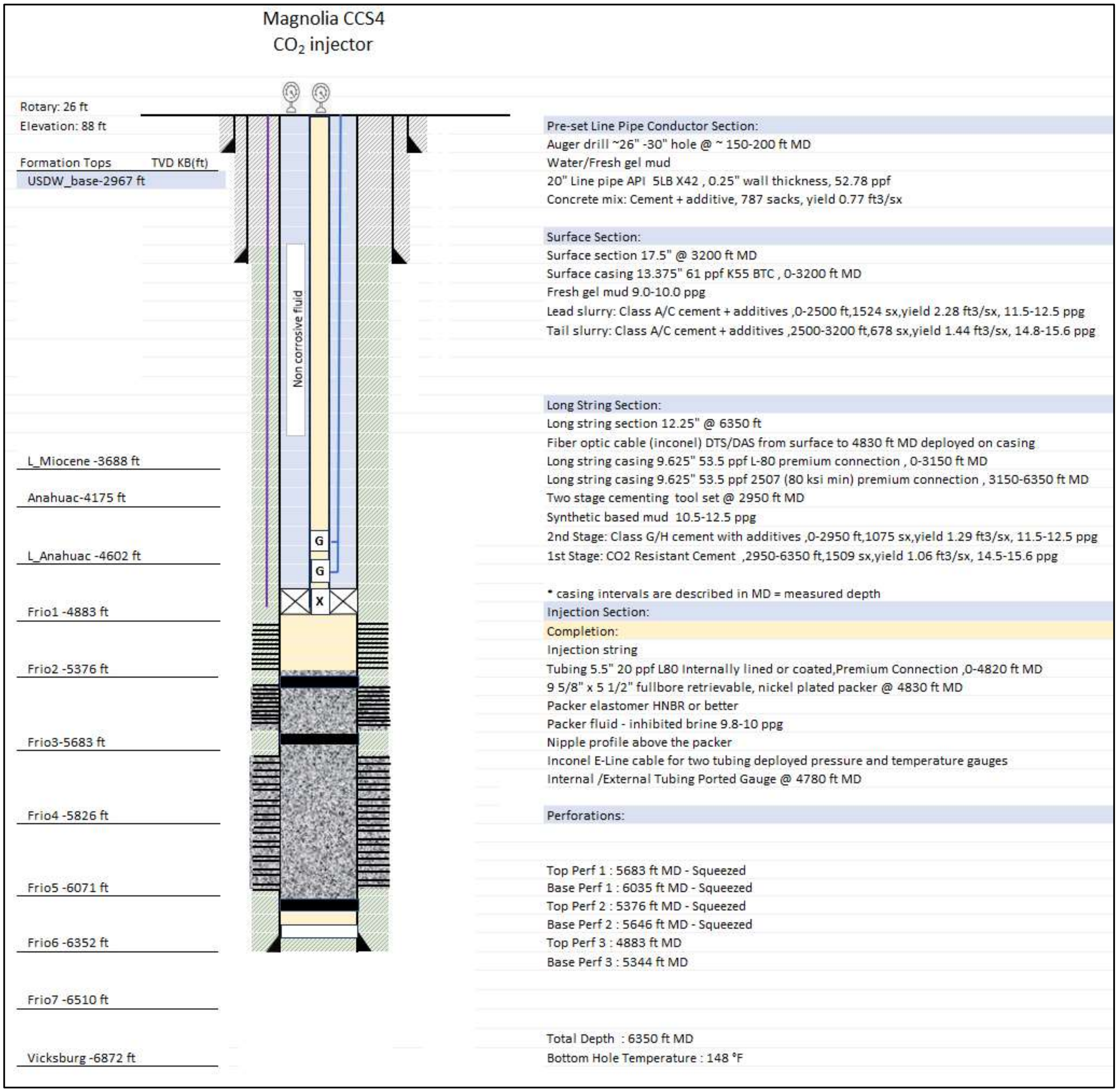

Figure CON-16—Second Recompletion Schematic diagram of Magnolia CCS 4 well.

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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. The sections of the casing string that are not in contact with the injected CO_2 were designed using alloy steel following the requirements described in API Specification 5CT, while the sections of the long string casing that could be exposed to CO_2 potentially dissolved in formation waters were designed with corrosion-resistant alloy (CRA) following API Specification 5CT, NACE MR0175/ISO15156 and AMPP guide 21535-2023, as well as the oil and gas industry best practices .

The casing string materials, within the injection zone, were selected based on corrosion modeling with OLI software to predict the in-situ pH and corrosion severity around the wellbore. During the well design, the Magnolia team simulated the chemical reaction of the proposed CO_2 stream and formation waters as shown in Table CON-46 at maximum downhole conditions of 5,500 psi reservoir pressure and 212 °F temperature. The OLI simulation predicts the in-situ pH in the range of 3.3 – 3.7.

The CO_2 stream injection operating conditions, pH, and chloride content were used to select the conditions to start testing on a selected numbers of materials that included 13CR, 15 Cr, 17Cr, 2205 DSS, and 2507 SDSS.

Table CON-46—Formation water composition.

Element	Unit	Value
Na^+	(mg/L)	35,103
K^+	(mg/L)	177
Mg^{2+}	(mg/L)	851
Ca^{2+}	(mg/L)	3,114
Sr^{2+}	(mg/L)	202
Ba^{2+}	(mg/L)	81.7
Fe^{2+}	(mg/L)	< 0.1
Cl^-	(mg/L)	62,271
SO_4^{2-}	(mg/L)	4.5
F^-	(mg/L)	0.18
Br^-	(mg/L)	84
Total Alkalinity	(mg/L as HCO3)	120
TDS (gravimetric)	(mg/l)	131,148

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. The conditions selected include 100,000 mg/L Cl- solution, 100 ppm H2S, 4,250 ppmv CO, 20 ppmv NO2, 40 ppmv SO2, and 150 ppmv O2 with the balance CO2 at a total pressure of 5,500 psi and at temperature of 212 ± 5 °F. The test duration was 90 days (2,160 hours). Table CON-47 summarizes the test parameters and conditions. The crevice test utilized a Teflon washer assembly as shown in Figure CON-17.

OLI's Stream Analyzer simulation software (Version 11.5.1.7 – MSE Databank) was used to calculate the quantity of each of the pure chemical components and partial pressures of each of the gases required at ambient conditions to achieve the specified environmental condition at test temperature and pressure. To ensure the samples are continuously exposed to the downhole reservoir environment and impurities are not consumed, the test solution and gas composition were replenished every week for the first four weeks and every two weeks for the remaining two months.

Table CON-47—Test environment, materials, parameters and conditions

Environment 2	Materials	Specimen Type	Applied Stress	Temperature (°F)	Duration (hours)
Gas Phase: 100 ppm H_2S 4250 ppm v CO 20 ppm v NO_2 40 ppm v SO_2 150 ppm O_2 Bal. CO_2 Liquid Phase: 100,000 mg/L Cl^-	UHP 15Cr-125 UHP 17Cr-110 22Cr-125 SM25Cr-125	C-rings	90% AYS	212 ± 5	2160
	HP2 13Cr-95 UHP 15Cr-125 UHP 17Cr-110 22Cr-125 SM25Cr-125	Crevice Coupons	N/A		

Figure CON-17—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-48 and Table CON-49. Only the 15Cr-125 material experienced SCC, which was observed on one specimen only. The other three materials (17Cr-110, 22Cr-125, and 25Cr-125) did not experience any cracking.

Evaluation of the localized corrosion showed that both 15Cr-125 and 17Cr-110 experienced both pitting and crevice corrosion. However, 22Cr-125 and 25Cr-125 duplex and super duplex only showed crevice corrosion and no pitting.

The average penetration depth for 22Cr-125 was 57.4 mpy and 31.3 mpy for 25Cr-125. The likely penetration rate for 25Cr-125 was much less as the average of two of the samples with similar penetration rates was 10.8 mpy. The sample with the highest penetration rate is likely an anomaly since the 71.9 mpy rate was higher than the rate experienced by 22Cr-125, which was expected to have less crevice corrosion resistance. The extent of crevice attack is very limited both in depth and area coverage, as shown in Figure CON-18 for the 25Cr-125 super duplex material.

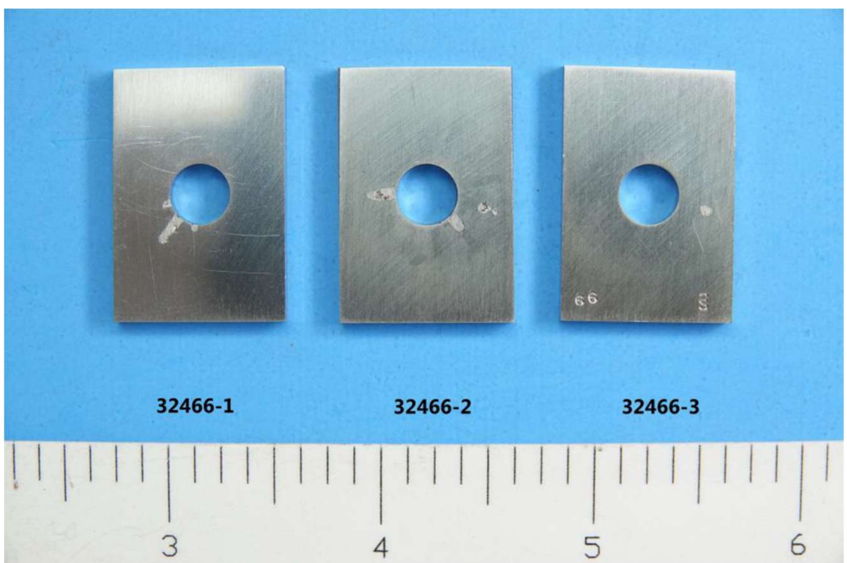

Figure CON-18— Crevice corrosion features of 25Cr-125 material

Table CON-48—Results of stress corrosion cracking tests.

Material Grade	AYS at 212 °F (psi)	Target Stress	Target Strain (με)	Applied Strain (με)	Observations
UHP 15Cr-125	134,000	90% AYS	4120	4121	Cracking / No Pitting
				4122	No Cracking / No Pitting (7 µm deep)
				4127	No Cracking / No Pitting (11 µm deep)
UHP 17Cr-110	111,000		3750	3755	No Cracking / No Pitting
				3755	No Cracking / No Pitting
				3754	No Cracking / No Pitting
22Cr-125	123,000		3780	3789	No Cracking / No Pitting
				3781	No Cracking / No Pitting
				3784	No Cracking / No Pitting
SM25Cr-125	128,000		4650	4659	No Cracking / No Pitting
				4658	No Cracking / No Pitting
				4656	No Cracking / No Pitting

Table CON-49—Crevice corrosion test results and penetration corrosion rates.

Material	Density A	Size B	Depth C	Max. Depth (mils)	Pen. Rate (mpy)	Observations
HP2 13Cr-95	--	--	--	0.8	--	No Crevice / No Pitting (<1.0 mils)
	--	--	--	0.8	--	No Crevice / No Pitting (<1.0 mils)
	--	--	--	0.8	--	No Crevice / No Pitting (<1.0 mils)
UHP 15Cr-125	A1	B1	C2	16.9	68.3	Crevice / Pitting
	A1	B2	C1	10.8	43.8	Crevice / Pitting
	A1	B2	C2	24.2	97.9	Crevice / Pitting
UHP 17Cr-110	A1	B2	C1	6.9	27.9	Crevice / Pitting
	A1	B2	C1	10.3	41.8	Crevice / Pitting
	A1	B2	C1	6.9	28.1	Crevice / Pitting
22Cr-125	--	--	--	13.7	55.7	Crevice / No Pitting
	--	--	--	17.2	69.8	Crevice / No Pitting
	--	--	--	11.5	46.8	Crevice / No Pitting
SM25Cr-125	--	--	--	3.4	14.0	Crevice / No Pitting
	--	--	--	17.7	71.9	Crevice / No Pitting
	--	--	--	1.9	7.5	Crevice / No Pitting

A.3 Discussion

The analysis of the literature, modeling and laboratory testing demonstrate that Super Duplex 2507 stainless steel is resistant to corrosion and stress corrosion cracking in the anticipated environmental conditions of this project. The test results show that 2507 SDSS can tolerate a much higher level of impurities in the CO_2 stream than the expected level of impurities in this project as shown in Table CON-50. The measured average corrosion rates under crevice corrosion conditions are very low (10.8 – 31.3 mpy) that the casing could experience during the well shut-in conditions assuming extreme conditions.

Table CON-50—Comparison of expected CO_2 stream vs. test conditions

Component	Project Limits	Testing Conditions (ppmv)
CO_2 Content	>95 mol%	Balance
Water	<30 lbs/MMSCF	saturated
H2S	<20 ppm by vol	100
Carbon Monoxide	<4,250 ppm by wt	4250
NOx	<1 ppm by wt	20
SOx	<1 ppm by wt	40
Oxygen	<10 ppm by wt	150

Based on the material analysis and testing, 2507 will be used in areas that will potentially be in contact with CO_2 dissolved in formation water due to the expected levels of oxygen and impurities in the CO_2 composition near by the CO_2 injector wellbore. An example of properties and composition of 2507 alloy is provided in Figure CON-19.

Corrosion Resistant Alloys

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

Figure CON-19—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. The tubing was selected as 5 ½ in. 20# L80 gas seal connection, coated internally with fusion bonded epoxy coating, since the expected CO_2 stream that is in contact with the internal ID of the tubing will be mainly dehydrated, reducing the risk of corrosion, in comparison with the bottom section of the wellbore that will be in contact with the formation waters. This coating has been previously qualified for CO_2 injection applications. An example of the proposed coating material is provided in Figure CON-20.

If needed, the tail pipes below the packers will be made of CRA materials matching the casing selection to prevent damage, should formation water enter the well during short periods of shutdown.

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-20—Example of internal coating for CO_2 injector well tubing

NOV Wellbore Technologies

100% CO_2 Coating Testing of TK™-70, TK-70XT, TK-15XT, TK-805, TK-236, and TK-TC

Autoclave Testing

July 11, 2022

Background

NOV Tuboscope performed autoclave testing on select Tuboscope coatings being considered for use in Carbon Capture Utilization and Storage (CCUS). The purpose of the testing was to establish the performance of these coating systems in an environment that contained 100% CO_2.

Analysis

Autoclave Testing

Using NACE TM0185-2006 Test method, autoclave testing was used to evaluate the materials under high temperature and pressure in 100% CO_2 environments. Evaluation consists of inspecting the tested samples for any coating imperfection (blistering, foaming, swelling, etc.) and evaluating the coatings adhesion using a modified ASTM standard D 6677-01 Knife Adhesion Test. Any imperfection results in a failing grade.

Temperature	Pressure	Duration	Primary Testing	Criteria
200°F	4000 psi	30 days	Tap water, 100% CO_2	No blisters, no disbondment, adhesion rating C or greater per modified ASTM D6677-01

Figure CON-21—Coating Testing TK-805 (page 1 of 2)

Results

Coating	Phase	Blisters	Adhesion
TK-70	Liquid	#2	C+
	Gas	#6	C+
TK-70XT	Liquid	None	B
	Gas	None	B+
TK-15XT	Liquid	None	B+
	Gas	None	B+
TK-805	Liquid	None	A
	Gas	None	A
TK-236	Liquid	None	A
	Gas	None	A
TK-TC*	Liquid	None	B
	Gas	None	B

*New thermally insulating coating technology

The TK-70 exhibited softening and blistering and would therefore be considered a failure. TK-70XT softened slightly and showed no signs of blistering. TK-15XT, TK-805, TK-236, and TK-TC exhibited no effects.

Figure CON-21—Coating Testing TK-805 (page 2 of 2)

A.4 Packers and Accessories:

The injection packer elements in contact with the fluid will be nickel-plated in all wet areas. Elastomers will be hydrogenated nitrile butadiene rubber (HNBR), which is resistant to rapid gas decompression (RGD).

Table CON-51—Packer Specifications -Example – Halliburton 12MFT985H001-F

Casing Size (inch)	9 5/8”
Weight Range (ppf)	47 to 53.5
Max OD (inch)	8.35
Min ID (inch)	4.575
Drift (inch)	4.545
Nominal Mandrel	7
Length (inch)	126.35
Material Yield Strength – Min ksi	80
Element Material	HNBR
Temperature Rating °F	40 to 325
Service	H_2S/CO_2
Pressure Rating (psi)	10730
Setting Method	Hydraulic
Flow Wetted Part	Nickel-Plated

HALLIBURTON
COMPLETION PRODUCTS

Long Term Guidelines: Packer Elements[1]

	ASTM D1418 Designation	NBR	HNBR	EPDM [9]	EPDM	FKM	FEPM
	Trade Name	Nitrile	HNBR	EPDM (Y-267)	EPDM	Viton® / Fluorel®	Aflas®
	Temperature Range °F, (°C) for permanent packers	40 to 325 (4.4 to 163)	40 to 350 (4.4 to 177)	40 to 575 (4.4 to 302)	40 to 500 (4.4 to 260)	40 to 400 (4.4 to 204)	100 to 300/450[12] (38 to 149/231)
	Temperature Range °F, (°C) for retrievable packers	40 to 275 (4.4 to 135)	40 to 325 (4.4 to 163)	40 to 575 (4.4 to 302)	40 to 500 (4.4 to 260)	40 to 350 (4.4 to 177)	100 to 350/400[11,12] (38 to 177/204)
	End Element Eng Spec	ES-R-1-4	ES-R-18-5	ES-R-17	ES-R-20-Z	ES-R-9-3	ES-R-14-3
	Center Element Eng Spec	ES-R-1-2	ES-R-18-4	ES-R-17	ES-R-20-Y	ES-R-9-1	ES-R-14-1
Gases	H_2S [2,3]	C 8	B 4	A	A	B	A
Gases	CO_2 [2,3]	A	A	A	A	A	A
Gases	CH_4 (Methane) [2,3]	A	A	C	C	A	A
Gases	N_2 [2,3]	A	A	A	A	A	A
Gases	Explosive Decompression[2,3]	D - ED Resistance is compound dependent. Consult Elastomer Best Practies & Specs					
Oil Base Fluids	Sweet Crude	A	A	C	C	A	A
Oil Base Fluids	Diesel	B	B	C	C	A	C
Oil Base Fluids	Aromatic Hydrocarbons[5]	C8	C8	C	C	A	C
Oil Base Fluids	Oil - Based Muds / Fluids	D - Testing required based on the variability of proprietary mud ingredients					
Oil Base Fluids	Amine / Oil inhibitors	B	B	C	C	C	A
Water Base Fluids	Water based inhibitors	A	A	E	E	E	A
Water Base Fluids	Steam	C	B	A	A	B	A
Water Base Fluids	Salt Water (Chlorides)	A	A	A	A	A	A
Water Base Fluids	Zn Bromide	C 8	B 6	A	A	A	A
Water Base Fluids	Ca Bromide (<14.2 ppg)	B 7	A	A	A	A	A
Water Base Fluids	Na Bromide (<12.4 ppg)	A	A	A	A	A	A
Water Base Fluids	Formates	A	A	A	A	C	A
Water Base Fluids	High pH fluids (>8)	A	A	A	A	C	A
Other Fluids	Alcohols	A	A	A	A	B	A
Other Fluids	Methanol	A	A	A	A	B	A
Other Fluids	HCl & HF Acid Mixture	C 8	B	C	C	A	A
Other Fluids	Weak Acid (HCL<15%)	B	B	C	C	A	A
Other Fluids	Strong Acid (HCL>15%)	C	B	C	C	A	A
Other Fluids	Acetic & Formic Acids	B	B	B	B	C	A

A	Recommended for long term service, chemical resistance is good, physical properties will change < 20%
B	Caution: results may vary due to time, temperature, and fluid concentration. consult Best Practices or Materials Engineer
C	Not recommended for long term service, consult Materials Engineer for limited short term applications
D	Testing is recommended and results may be compound dependent, consult Best Practices or Materials Engineer
E	Not Tested

Notes
1 These fluid compatibility recommendations apply to other seals with cross sections greater than 1/2 inches.
2 Damage from ED can be reduced by following proper bleed down procedures (Matrix object D00134737).
3 ED Resistance is compound dependent. Consult Elastomer Best Practices for ED resistant compounds. All packer elements will have ED damge when pulled from a well.
4 HNBR can be used in H2S concentrations below 5%.
5 Aromatic solvents include Xylene, Toluene, and Benzene.
6 Permanent packer elements can be used if set within 24 hours with <16 ppg fluid and within 8 hours for >16 ppg fluid.
7 Caution should be taken with retrievable and resettable thick cross section seals because they may harden with time.
8 Consult with Materials engineer for limited applications of permanent packers
9 Pertains to modified Y-267 EPDM for use in hydrocarbon free steam or geothermal environments.
10 The lower temperature is for element package with standard back-ups; the higher is for HPHT elements with mesh back-ups.
11 Use caution wiht Aflas retrievable packer elements. Straight substitution by Aflas for standard elements is not recommended.
12 Can be extended to 400 F depending on back-up shoe configuration.

Matrix # D00139696 Rev F

Figure CON-22—Guidelines for HNBR for CO_2 resistance

Nickel-alloy electric cables and quartz sensors are proposed for this project. The injection well annular space will be filled with treated packer fluid to prevent corrosion.

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

B.1 Surface Section

The surface section will be cemented via conventional circulation using a combination of lead and tail slurries. The lead slurry will be formulated with Portland cement type A or C and an extender such as bentonite to achieve a density between 11.5 and 12.5 ppg. The tail slurry will be formulated with Portland cement type A or C with an accelerator, such as calcium chloride or equivalent, to reduce the thickening time of the slurry and accelerate development of gels and compressive strength. The estimated density of the tail slurry is between 14.8 and 15.6 ppg. Figure CON-23 and Figure CON-24 show examples of the proposed slurries for the surface section.

The surface casing will be centralized with the target of achieving at least 70% of standoff. Depending on the condition of the hole, cement baskets might be placed to help with cement fall off after placement.

Well Information

Casing/Liner Size	9.625 in	**Depth MD**	3500 ft	**BHST**	57°C / 134°F
Hole Size	12.25 in	**Depth TVD**	3500 ft	**BHCT**	38°C / 100°F
Pressure	3530 psi				

Drilling Fluid Information

Mud Supplier Name	**Mud Trade Name**	**Density**	8.4 lbm/gal

Cement Information - Lead Design

Conc	UOM	Cement/Additive	MP	Sample Type	Sample Date	Lot No.
		ExtendaCem				
0.1	% BWOC	Fe-2 (citric acid)	PB			
0.4	% BWOC	HR-7	PB			

Cement Properties

Slurry Density	12	lbm/gal
Slurry Yield	2.28	ft3/sack
Water Requirement	13.12	gal/sack
Total Mix Fluid	13.12	gal/sack
Water Source	Field (Fresh) Water	
Water Chloride	N/A	

Figure CON-23—Surface section lead slurry example for CO_2 injector well.

Well Information

Casing/Liner Size	9.625 in	**Depth MD**	3500 ft	**BHST**	57°C / 135°F
Hole Size	12.25 in	**Depth TVD**	3500 ft	**BHCT**	38°C / 100°F
Pressure	3530 psi				

Drilling Fluid Information

Mud Supplier Name	**Mud Trade Name**	**Density**	8.4 lbm/gal

Cement Information - Tail Design

Conc	UOM	Cement/Additive	MP	Sample Type	Sample Date	Lot No.
		HalCem				
0.6	% BWOC	HR-5 (PB)	PB			

Cement Properties

Slurry Density	14.5	lbm/gal
Slurry Yield	1.44	ft3/sack
Water Requirement	7.02	gal/sack
Total Mix Fluid	7.02	gal/sack
Water Source	Field (Fresh) Water	
Water Chloride	N/A	

Figure CON-24—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.

The cement slurry above the Lower Miocene Confining Zone was selected as Portland cement, blended with dispersants, fluid loss control additives, defoamers, and light weight additives such as glass beads and special particle size packaging to reduce the density of the slurry while maintaining a high solid volume fraction to maximize compressive strength. The slurry density ranges between 11.5 ppg and 12.5 ppg.

The cement slurry across the CO_2 injection zones will be formulated to minimize degradation from carbonic acid while maintaining integrity of the cement sheath, providing hydraulic isolation, and providing mechanical integrity to the casing during construction and injection operations. For long-term barrier integrity under anticipated carbon capture and sequestration (CCS) conditions at and near the injection zone, the slurry design(s) based on Portland cement have been modified to improve chemical and mechanical resistance to the effects of carbonic acid exposure, resulting in CO_2-resistant slurries. The modifications, which may vary slightly due to well conditions, formation pressures and strengths, etc., all contain the following composition adjustments when compared to conventional Portland cement. These modifications are:

- Reduced Portland Content: Incorporation of non-Portland solid materials including, but not limited to, pozzolan(s), fly ash, and silica sand/flour in concentrations > 20% by weight of cement (BWOC).
- Reduced Structural Permeability:

- Incorporation of fluid loss and latex cement additive technology to block internal matrix communication of components vulnerable to carbonization. Design threshold: < 150 ml API Fluid Loss, per API RP 10B-2, Recommended Practice for Testing Well Cements.
- Incorporation of small and fine particle size distribution (when compared to P50 cement granular size) via materials including, but not limited to, pozzolan(s) and silica sand/flour in concentrations > 20% BWOC.

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

- Nelson E. and Guillot D. (2006) "Well Cementing" Cements for Corrosive Environments Chapter 7-7 'Cements for corrosive environments'*
- Sweatman, R. E., Santra, E. Kulakofsky, D. S. et al. 2009. Effective Zonal Isolation for CO_2 Sequestration Wells. Presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, San Diego, California, USA. SPE-126226-MS. 2-4 November. https://doi.org/10.2118/126226-MS
- Kutchko et. al. 2007 Environmental Science & Technology, "Degradation of Well Cement by CO_2 under Geologic Sequestration Conditions"
- Carey, J. W., Wigand, M., Chipera, S. J. et al. 2007. Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC unit, West Texas. *USA. International Journal of Greenhouse Gas Control*, **1**(1): 75-85.

Figure CON-25 and Figure CON-26 show examples of cementing slurries for cementing the long string section.

Well Information

Casing/Liner Size	5.5 in	**Depth MD**	5050 ft	**BHST**	68°C / 155°F
Hole Size	8.5 in	**Depth TVD**	5050 ft	**BHCT**	43°C / 110°F
Pressure	5120 psi				

Drilling Fluid Information

Mud Supplier Name		**Mud Trade Name**		**Density**	11.7 lbm/gal

Cement Information - Lead Design

Conc	UOM	Cement/Additive	MP	Sample Type	Sample Date	Lot No.
		NeoCem™ E+ Cement				
3	% BWOW	NaCl (Sodium Chloride) Salt	PB			
0.15	% BWOC	SA-1015 (PB)	PB			
0.25	lb/sk	WellLife 1094 (PB)	PB			
0.2	% BWOC	HR-5 (PB)	PB			

Cement Properties		
Slurry Density	12.5	lbm/gal
Slurry Yield	1.29	ft3/sack
Water Requirement	5.95	gal/sack
Total Mix Fluid	5.95	gal/sack
Water Source	Field (Fresh) Water	

Figure CON-25—Long string section lead slurry example for CO_2 injector well.

Well Information

Casing/Liner Size	5.5 in	**Depth MD**	8579 ft	**BHST**	93°C / 200°F
Hole Size	8.5 in	**Depth TVD**	8579 ft	**BHCT**	63°C / 145°F
Press.	4813 psi				

Drilling Fluid Information

Mud Supplier Name		**Mud Trade Name**		**Density**	9.5 lbm/gal

Cement Information - Tail Design

Conc	UOM	Cement/Additive	Description
		CorrosaCem	Blend Name
20 - 50	%	>Prairie State Poz	Fly Ash
40 - 70	%	> Texas LeHigh A	API Class A Portland Cement
100	% BWOC	Cement Blend	
2.11	gal/sack	Field (Fresh) Water	
0.1 – 0.5	% BWOC	D-Air 5000	Defoamer
0.1 – 0.8	% BWOC	HR-5 (PB)	Retarder
0.02 – 0.1	gps	Stabilizer 434D	
1.0 - 3.0	gps	Latex 3000	Liquid SBR Latex
0.1 – 0.5	lb/sk	WellLife 1094 (PB)	Polyolefin Fiber
1.0 – 5.0	%BWOC	Microbond M	Expansion Additive

Cement Properties

Slurry Density	14.0 - 15.5	lbm/gal
Slurry Yield	1.06	ft3/sack
Water Requirement	2.11	gal/sack
Total Mix Fluid	4.19	gal/sack

Figure CON-26—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:

- Section A: A 13 5/8 in. 5K casing head housing will be installed after the 13 3/8 in. casing is cemented and will be supported on the base plate installed at the bottom of the cellar. This section includes a lateral valve to monitor pressure between the surface and the long string casing. Material Class DD, API 6A, PSL2, and PR2.

- Section B: A slip hanger casing hanger 13 5/8 in. x 9 5/8 in., Material Class DD, API 6A, PSL-3, and PR 2 with 2 ports for ¼ inch control lines to be used with the packoff seal (DD).

- Section C: A 13 5/8 in. x 13 5/8 in. 10K double-studded flanged adapter, Material Class DD, API 6A, PSL-2. Includes two ports for control lines and fiber optic. Over the flange adapter, a casing spool 13 5/8 in. 10K x 11 in. 10K will be installed and includes two lateral outlets to monitor pressure between the long string and tubing string (EE, API 6A, PSL-2, and PR-2).

- Section D: Tubing hanger for 5 ½-in. tubing in the Section C, 10K, with two exits for control lines. It also includes the Christmas tree with two master valves, tee, swab valve, and two wing valves with automatic shutdown devices in each wing. Material Class HH, API 6A, PSL-2, and PR-2 for the tubing hanger and all the Christmas tree elements to account for surfaces potentially in contact with wet CO_2.

Appendix D : Stress Check Reports Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4

See CON Appendix D for details.

Appendix E: WELLCAT^{TM} 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^{TM} software. The results are shown in Appendix D for Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4. 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 and validate the casing and tubing design through the study of thermal loads and their effect on the selected materials.

The Magnolia 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.

One of the deepest tubing installation was used to perform the thermal analysis since results will be applicable to the other cases. The detail results and loads are included in the document CON Appendix E.

Appendix F: Long String Cementing Job Simulation

In the attached a single stage cementing job for Magnolia CCS 1 Long String section was simulated and the results indicated a high risk of lost circulation due to equivalent circulating densities (ECD) higher than the fracture gradient in the bottom of the section as well as in the shoe of the surface string. As described during the cementing program. The project will perform the cementing job in the long string section in two stages in order to reduce the risk of lost circulation and poor cement quality.

Appendix G: Monitoring Wells

Magnolia MLR 1

The Magnolia MLR 1 will be drilled before CO_2 injection starts. The well location was selected to track CO_2 movement and development of the pressure front to the west section of the AOR. It will serve to calibrate the simulation model and provide the capability to image the CO_2 plume with a 3D VSP, utilizing the fiber optic cable to be installed in the well.

The well will be completed in the Frio injection zones [~4,840-6,800 ft total vertical depth (TVD)] and will be equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow for tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

Since the well will be drilled from the surface to the Vicksburg, it will enable tracking any changes in CO_2 saturation around the wellbore, not only for the Frio injection zones, but also for the Lower Miocene confining zone and overburden.

The proposed schematic for this well is presented in Figure CON-27.

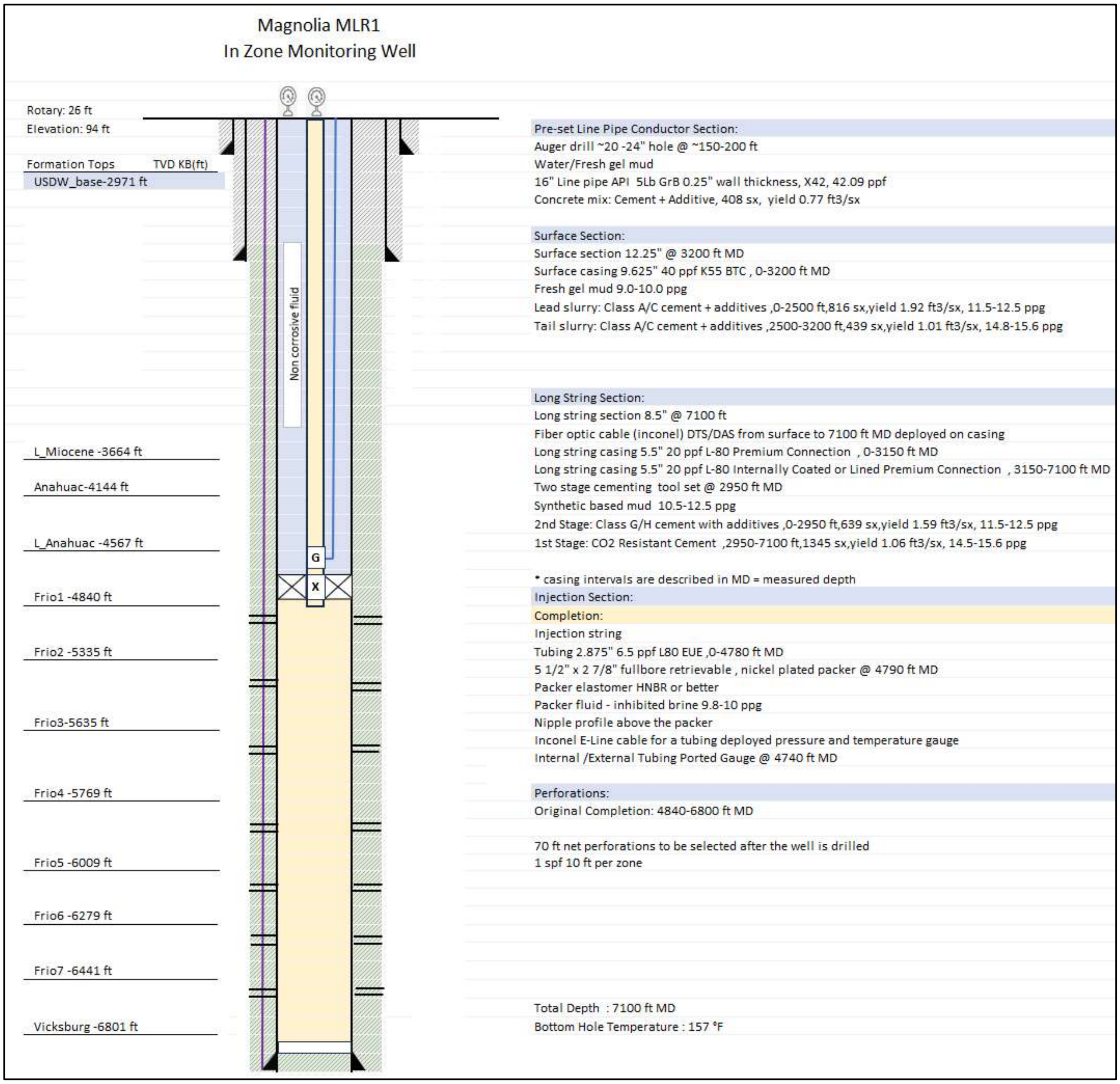

Figure CON-27—Proposed Magnolia MLR 1 wellbore diagram.

Magnolia MLR 2

The Magnolia MLR 2 will be drilled before CO_2 injection starts. The well location was selected to track CO_2 movement and development of the pressure front to the north section of the AOR. This well will be located strategically in the updip direction and preferential path of the plume development. It will serve to calibrate the simulation model and provide the capability to image the CO_2 plume with a 3D VSP, utilizing the fiber optic cable to be installed in the well.

The well will be completed in the Frio injection zones [~4,715-6,644 ft total vertical depth (TVD)] and will be equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow for tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

Since the well will be drilled from the surface to the Vicksburg, it will enable tracking any changes in CO_2 saturation around the wellbore, not only for the Frio injection zones, but also for the Lower Miocene confining zone and overburden.

The proposed schematic for this well is presented in Figure CON-28.

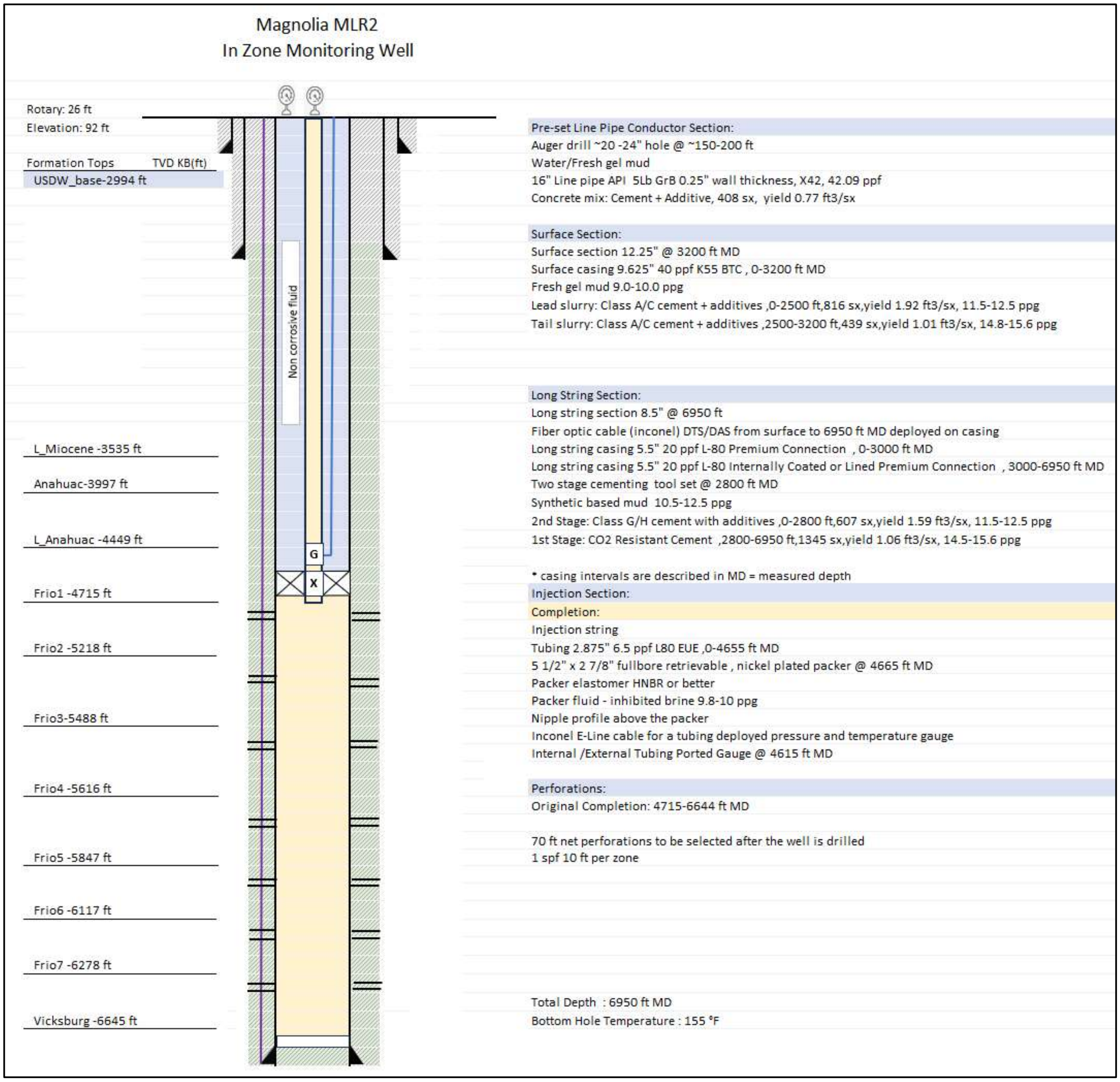

Figure CON-28—Proposed Magnolia MLR 2 wellbore diagram.

Magnolia MLR 3

The Magnolia MLR 3 will be drilled after CO_2 injection starts. The well location was selected to track CO_2 movement and development of the pressure front to the far north section of the AOR. This well will be located strategically in the updip direction and preferential path of the plume development. It will serve to calibrate the simulation model and provide the capability to image the CO_2 plume with a 3D VSP, utilizing the fiber optic cable to be installed in the well.

The well will be completed in the Frio injection zones [~4,529-6,402 ft total vertical depth (TVD)] and will be equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow for tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

Since the well will be drilled from the surface to the Vicksburg, it will enable tracking any changes in CO_2 saturation around the wellbore, not only for the Frio injection zones, but also for the Lower Miocene confining zone and overburden.

The proposed schematic for this well is presented in Figure CON-29.

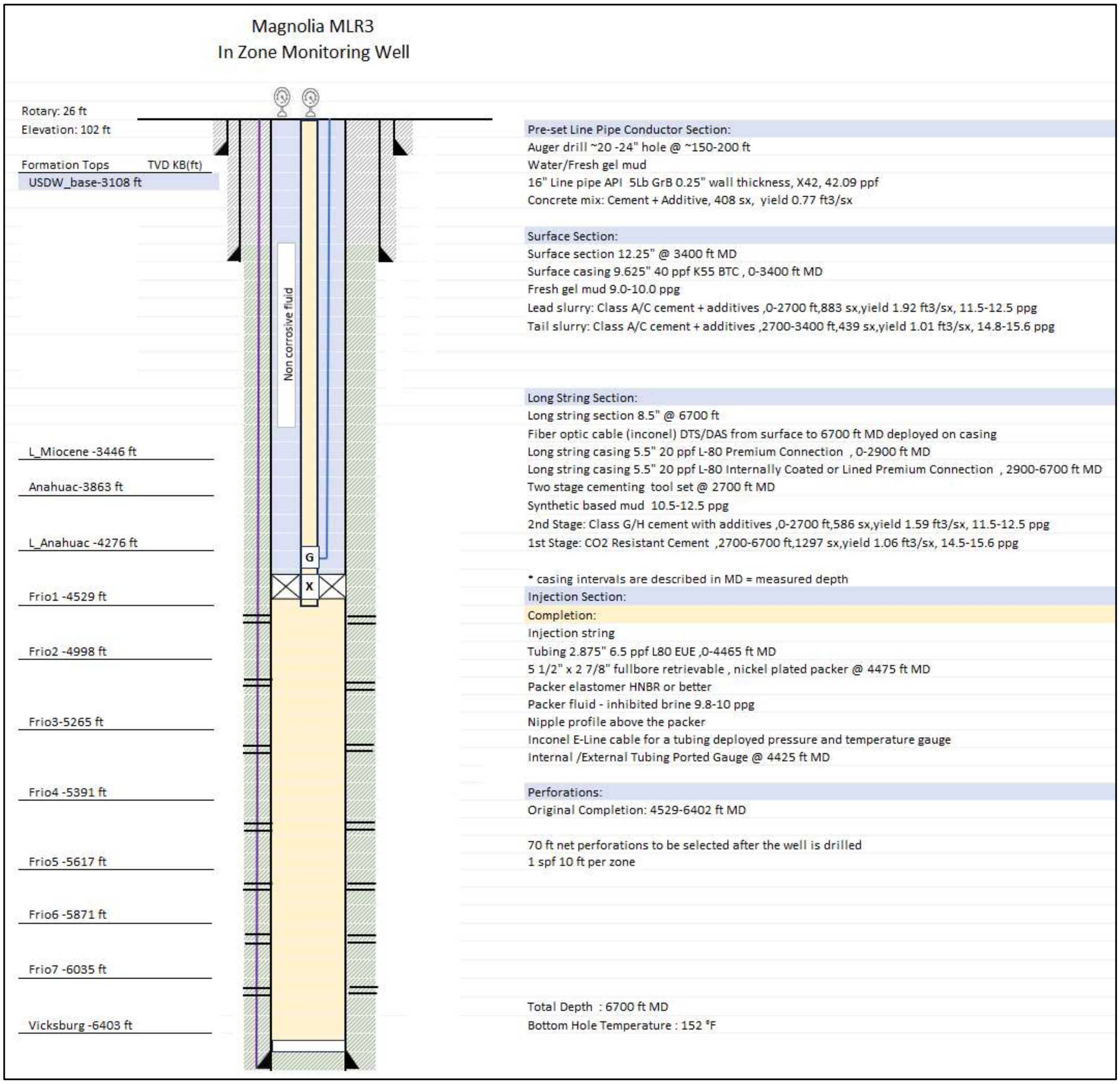

Figure CON-29—Proposed Magnolia MLR 3 wellbore diagram.

YAMS MLR 004

The YAMS MLR 004 is a stratigraphic well drilled in 2022 to support data collection for this project. The current wellbore diagram is shown in Figure CON-30.

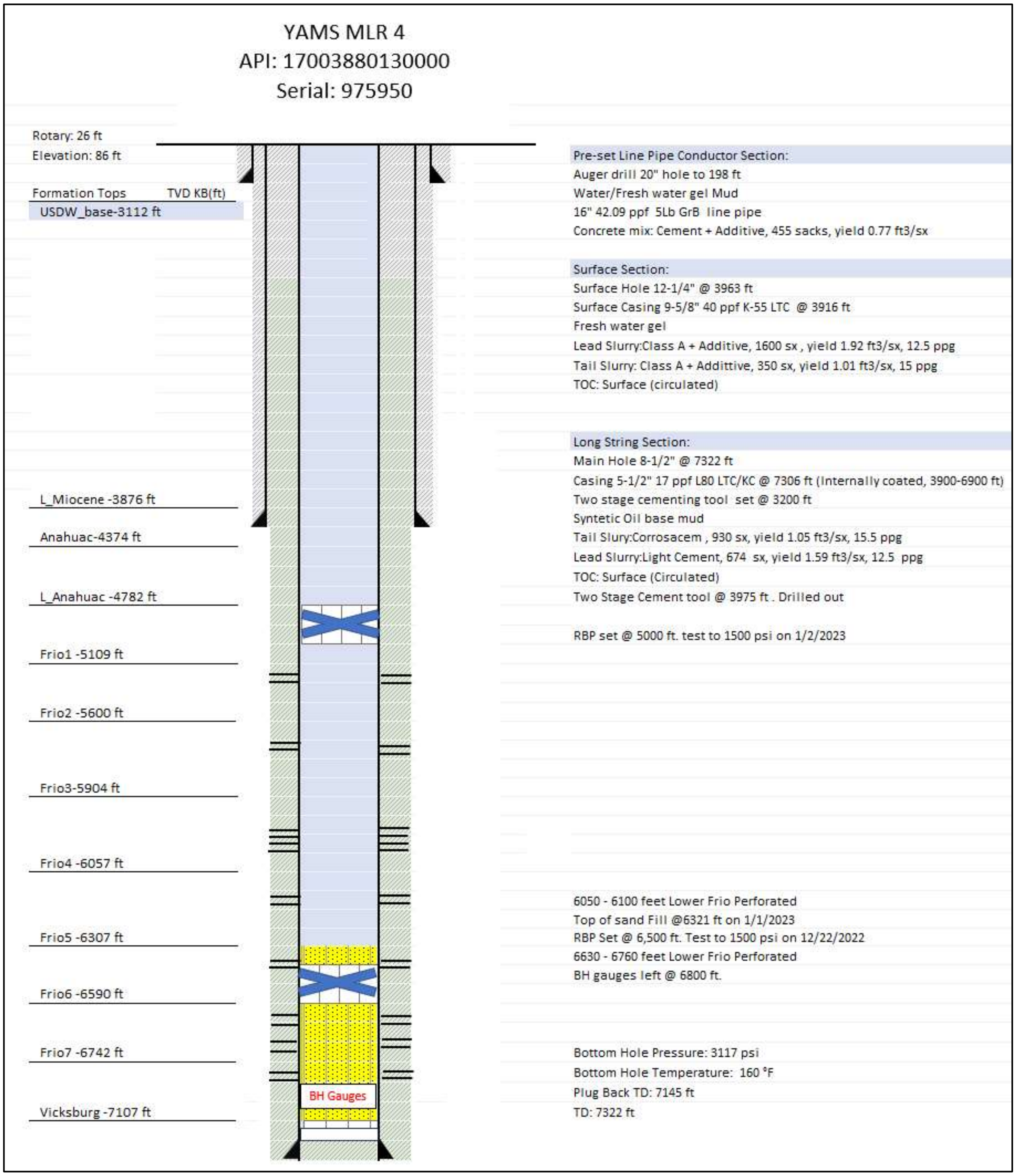

Figure CON-30—YAMS MLR 004 current wellbore diagram.

The well will be converted to an in zone monitoring well before CO_2 injection starts. It is located south and down dip of the injector wells. The well will be recompleted in the Frio injection zones [~5,109-7,106 ft total vertical depth (TVD)] and will be equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow for tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

The proposed schematic for this well is presented in Figure CON-31.

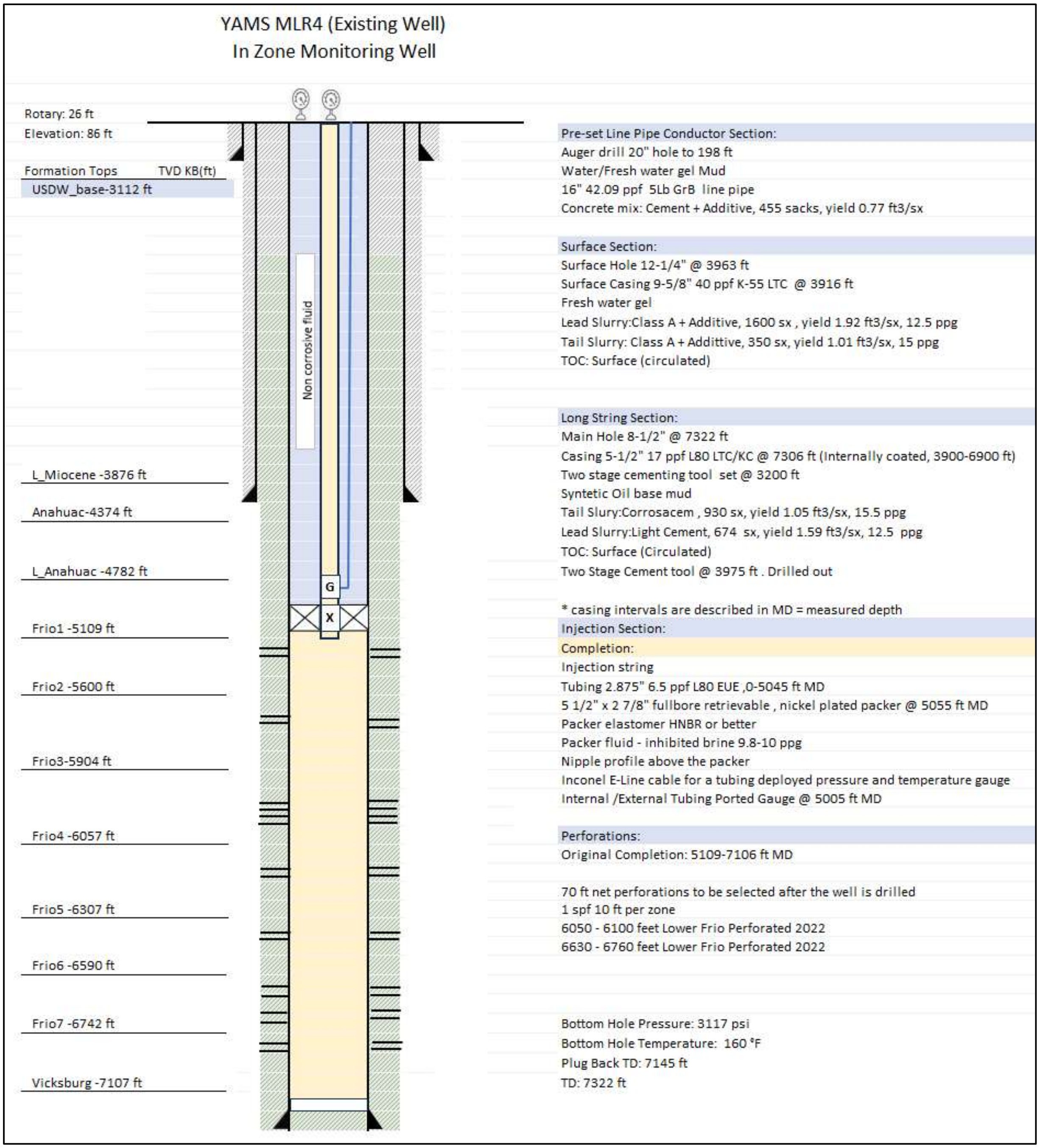

Figure CON-31—Proposed YAMS MLR 004 recompletion wellbore diagram

Magnolia ACZ 1

The Magnolia ACZ 1 will be drilled and completed before the start of injection. This well is designed to monitor changes in pressure and temperature in the above confining zone. The well will also allow the project to sample the first permeable sand above the confining zone to monitor any geochemical change in the aquifer that could indicate a leak from the storage complex. The proposed schematic is shown in Figure CON-32.

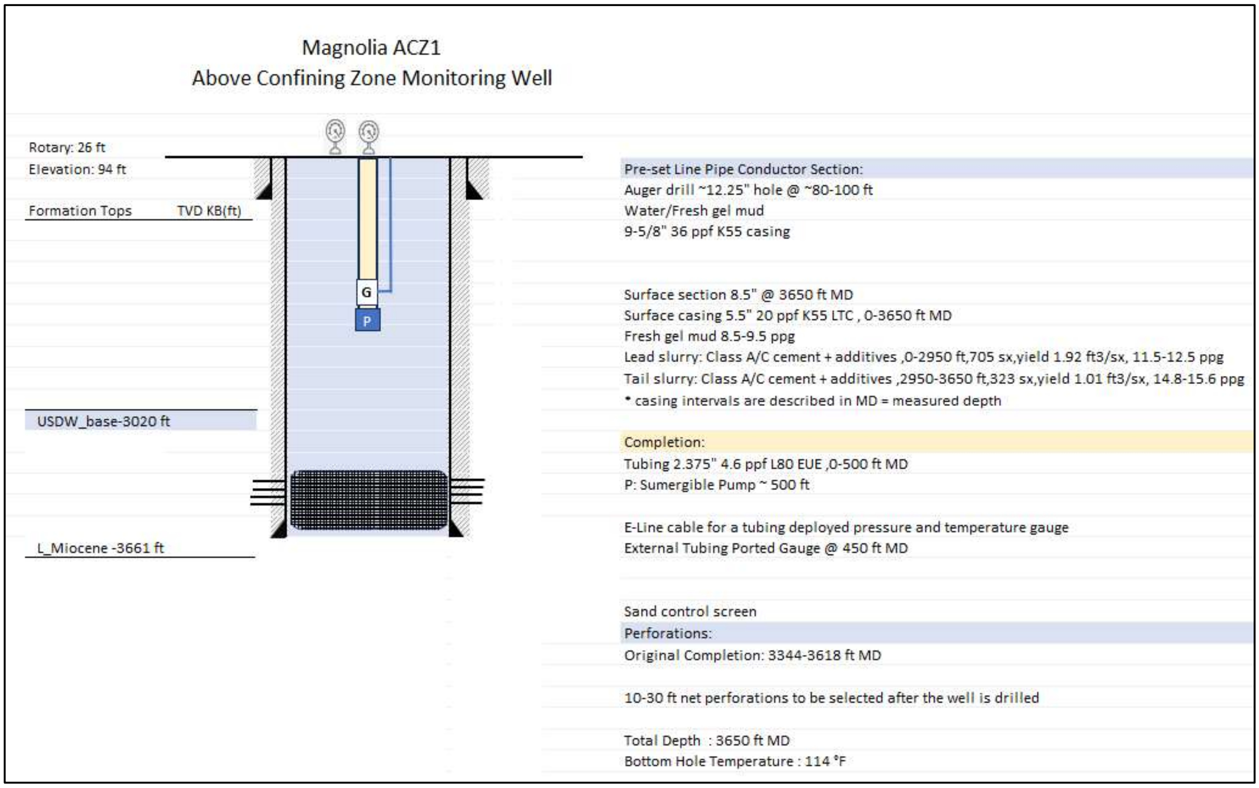

Figure CON-32—Proposed Magnolia ACZ 1 wellbore diagram

Magnolia ACZ 2

The Magnolia ACZ 2 will be drilled and completed before the start of injection. This well is designed to monitor changes in pressure and temperature in the above confining zone. The well will also allow the project to sample the first permeable sand above the confining zone to monitor any geochemical change in the aquifer that could indicate a leak from the storage complex. The proposed schematic is shown in Figure CON-33.

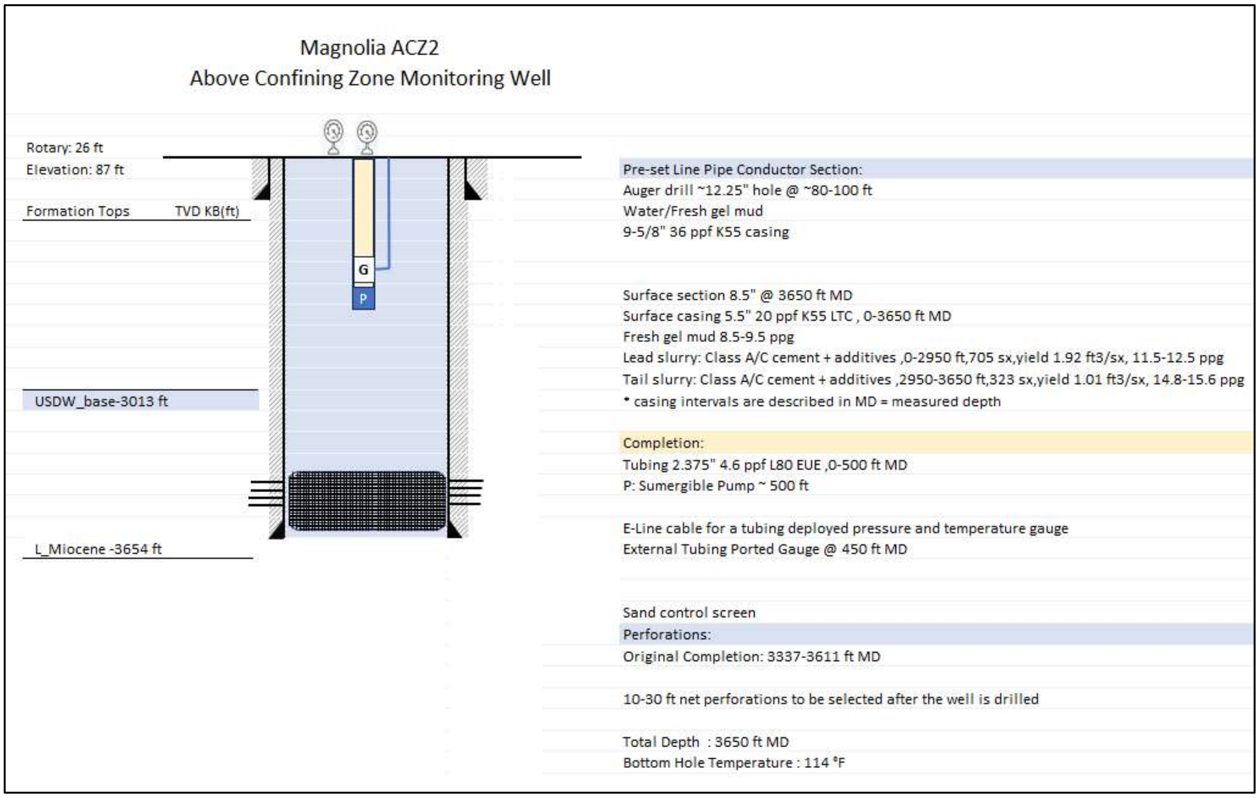

Figure CON-33—Proposed Magnolia ACZ 2 wellbore diagram

Magnolia USDW 1

Figure CON-34—Proposed Magnolia USDW 1 wellbore diagram

Magnolia USDW 2

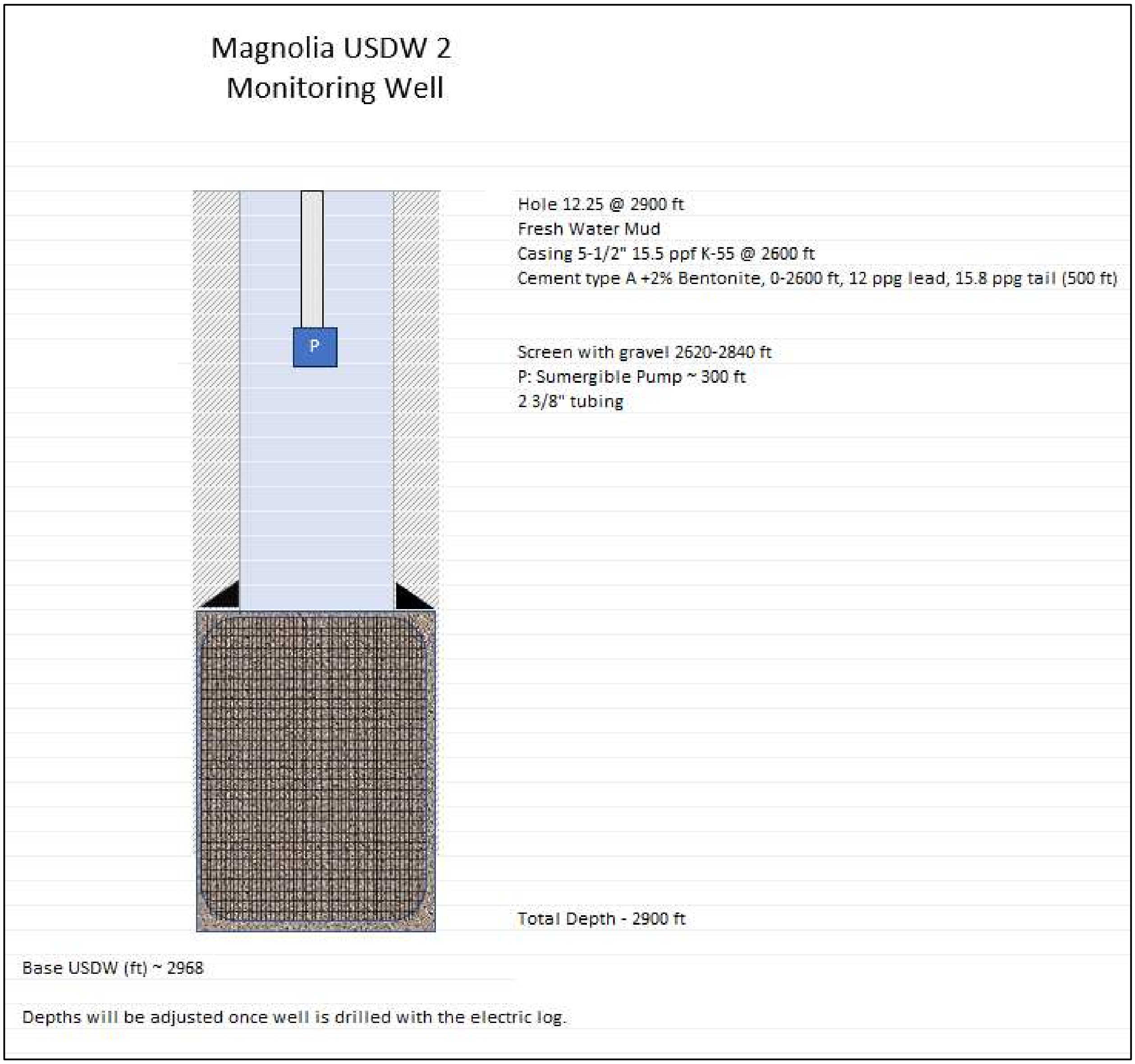

Figure CON-35—Proposed Magnolia USDW 2 wellbore diagram