CONSTRUCTION DETAILS FOR LO-04 F-M
LAC 43:XVII.3617

Project Name: Live Oak CCS Hub

Facility Information

Facility Contact: Live Oak CCS, LLC
14302 FNB Parkway
Omaha, Nebraska 68154
402-691-9500

OOC Code No.: L1135

Well locations:

Well Name	Latitude (WGS84)	Longitude (WGS84)	Parish	State
LO-04 F-M	Claimed as PBI [redacted]	[redacted]	Iberville	Louisiana

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List of Acronyms

°F	Degree Fahrenheit
22Cr-110	22% Chromium Duplex Stainless Steel with 110,000 Pounds per Square Inch Minimum Yield Strength
AMPP	Association for Materials Protection and Performance
API	American Petroleum Institute
Ar	Argon
Ba^{2+}	Barium
BGS	Below Ground Surface
BTC	Buttress Thread Coupling
BTU	British Thermal Unit
Ca^{2+}	Calcium
CCS	Carbon Capture and Storage
CFR	Code of Federal Regulations
Cl^-	Chloride
CO_2	Carbon Dioxide
DF	Design Factor

DTS	Distributed Temperature Sensing
EPDM	Ethylene Propylene Diene Monomer
ft	Feet
gal	Gallon
gpm	Gallons Per Minute
GRP	Group
HCO^{3-}	Bicarbonate
HNBR	Hydrogenated Nitrile Butadiene Rubber
ID	Internal Diameter
in	Inch
J55	J55 Carbon Steel
K^{+}	Potassium
KLBF	Kilo Pound-Force
L80	L80 Grade Steel
LAC	Louisiana Administrative Code
lb	Pound
LMIC	Lower Miocene Injection Complex
mg/L	Milligrams Per Liter
Mg^{2+}	Magnesium
mm	Millimeter
MMSCF	Million Metric Standard Cubic Feet
MMt	Million Metric Tonnes
MMt/y	Million Metric Tonnes per Year
MOL%	Molecular Percentage of Total Moles in a Mixture made up by One Constituent
N_2	Nitrogen
NA	Not Applicable
Na^{+}	Sodium
O_2	Oxygen
OC	Louisiana Department of Energy and Natural Resources' Office of Conservation
OD	Outer Diameter
OFIC	Oligocene Frio Injection Complex
PH	Potential of Hydrogen
PPG	Pounds Per Gallon
ppmv	Parts Per Million, Volume
psi	Pounds Per Square Inch
psig	Pounds Per Square Inch Absolute
RBW	Remaining Body Wall
sec	Second
SITP	Shut-In Tubing Pressure

SO_4^{2-}	Sulphate ion
STC	Short Thread Coupling
TDS	Total Dissolved Solids
TEC	Tubing Encapsulated Cables
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VME	Von Mises Equivalent Stress

1. Introduction

The construction details for the LO-04 F-M injection well at the Live Oak CCS Hub in Iberville parish, Louisiana (the "project") are described in this document. The injection well has been designed to accommodate the anticipated mass of carbon dioxide (CO_2) and the subsurface characteristics of the CO_2 injection intervals that affect the well design. The following reviews the analysis performed to comply with Class VI Underground Injection Control (UIC) well requirements at LAC 43:XVII.3617(A) regarding the design of the casing, cement, and wellhead.

All phases of well construction will be supervised by a person knowledgeable and experienced in practical drilling engineering and familiar with the special conditions and requirements of injection well construction (LAC 43:XVII.3617(A)(1)). Live Oak CCS, LLC will submit a notice of well construction completion to the Louisiana Department of Energy and Natural Resources' Office of Conservation (OC) as outlined in LAC 43:XVII.3609(L)(2) and receive written approval from the OC prior to commencing CO_2 injection.

2. LO-04 F-M Construction Details

2.1 Wellhead Injection Pressure

Petroleum Experts' PROSPER software was used to perform nodal analysis on multiple tubing diameters for injection of supercritical CO_2 into the subsurface. The nodal analysis was designed for a long string casing of 9.625-inch 47 lb/ft set to a total depth of 9,890 ft with L80 grade steel (L80) from surface to 5,630 ft, and 22Cr-110 grade duplex stainless steel (22Cr-110) from 5,630 ft to 9,890 ft. A 7.625-inch 39 lb/ft 22Cr-110 liner extends from 9,590 ft to 11,900 ft with tubing set to 10,842 ft. Feasibility of CO_2 injection was determined with a 7-inch outer diameter (OD) 26 lb/ft 22Cr-110 tubing tapered down to 5.5-inch OD 17 lb/ft 22Cr-110 which is further tapered down to 3.5-inch OD 9.2 lb/ft 22Cr-110 to accommodate completion assembly into the injection intervals.

Maximum allowable surface pressure (MASP) of 2,220 psig was identified based on CO_2 transport pipeline specifications and was verified to be below 90% of the fracture gradient at the depth of the shallowest perforated interval at anticipated maximum instantaneous rate of 3.5 MMt/y (see subsection 2.3 of the Summary of Requirements – Class VI Operating and Reporting Conditions). The reservoir model provided an estimate of the average injection rate of 2.9 MMt/y in the Lower Miocene Injection Complex (LMIC) and 0.5 MMt/y in the Oligocene Frio Injection Complex (OFIC). Similarly, the maximum injection rates are anticipated to be 3.5 MMt/y in the LMIC and 1.5 MMt/y in the OFIC. Potential CO_2 sources and specifications are discussed in subsection 2.2 of the Summary of Requirements – Class VI Operating and Reporting Conditions. The injection tubing string in the well will use corrosion resistant duplex alloy (i.e., 22Cr-110 or higher alloy for CO_2 + H_2O wetted sections) or an appropriately lined (i.e., glass reinforced epoxy) carbon steel string. Final alloy selection at procurement will be based on the most current applicable materials testing results from API, AMPP, or other standard bodies currently focused on carbon capture and sequestration (CCS; (LAC 43:XVII.3617(A)(4)(a)).

Several tubing sizes from 5.5-inch through 7.625-inch OD were compared for CO_2 injection at the maximum rate and MASP (2,220 psig) into both the LMIC and OFIC (Figure 1). Nodal analysis suggested that for the Lower Miocene Sands at maximum injection rate of 3.5 MMt/y, and with an injection (wellhead) pressure of 2,220 psig, barring the 4.892-inch inner diameter (ID) tubing, other tubing sizes allowed for safe CO_2 injection. Specifically, the 4.892-inch case suggested insufficient pressure at the injection intervals, as calculated values are below the estimated average reservoir pressures identified from the modeling results. In addition, the 4.892-inch tubing string has a continuous diameter with no reduction in ID and exhibits a linear gradient along the entire well depth as seen in Figure 1. For the selected 6.276-inch ID tubing proposed for well construction, modeling projected a bottomhole pressure of 4,128 psig at an injection depth of 6,135 ft. This pressure is higher than the estimated average reservoir pressure (3,064 psig) and lower than the maximum bottomhole pressure (4,528 psig) calculated using 90% of fracture gradient at the top perforation of Lower Miocene Sands.

Similarly, for the Frio Sand injection interval at the maximum injection rate of 1.5 MMt/y, nodal analysis suggested that all the tubing designs modelled allow for safe CO_2 injection (Figure 2). Specifically, the pressure at top perforation (6,135 ft) for all tubing sizes was lower than the maximum bottomhole pressure (4,528 psig) calculated using 90% of fracture gradient at the top perforation in the well. Additionally, the modelled pressure at the injection depth of 10,842 ft was higher than the estimated average reservoir pressure (5,152 psig) at the injection interval.

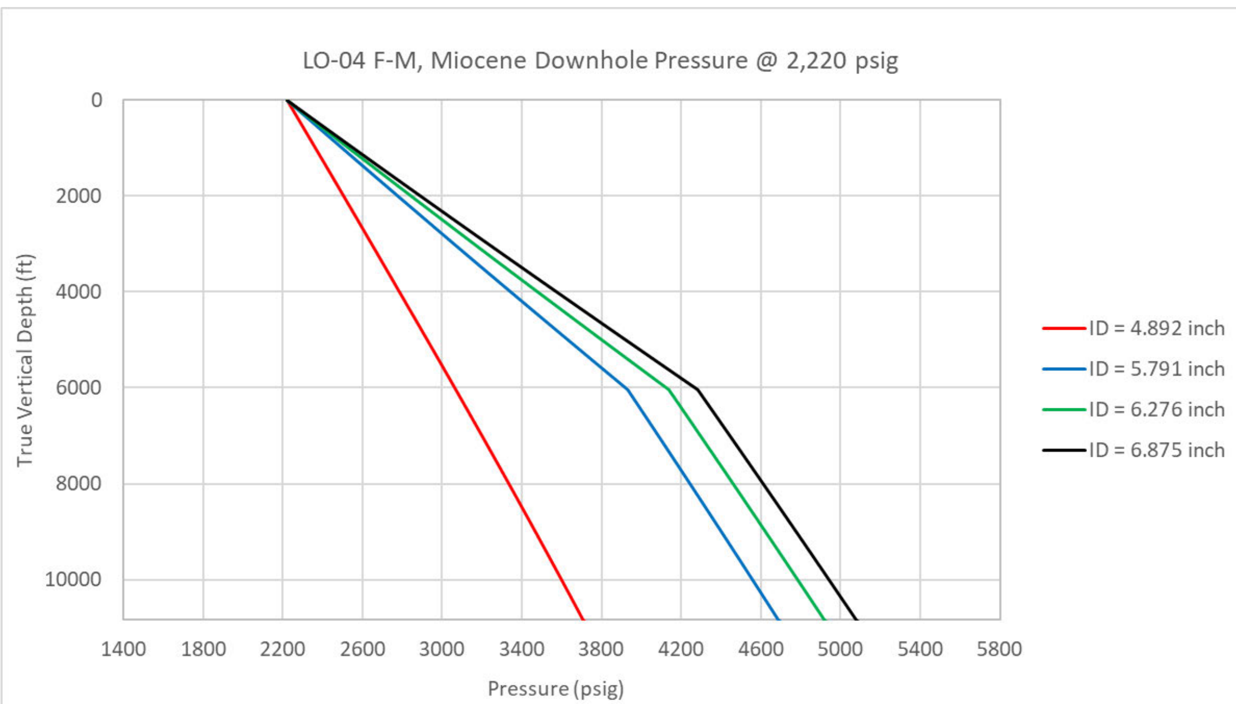

Figure 1: LO-04 F-M downhole pressure at maximum injection rate (3.5 MMt/y) and maximum injection pressure (2,220 psig) in different tubing sizes for CO_2 injection into the LMIC.

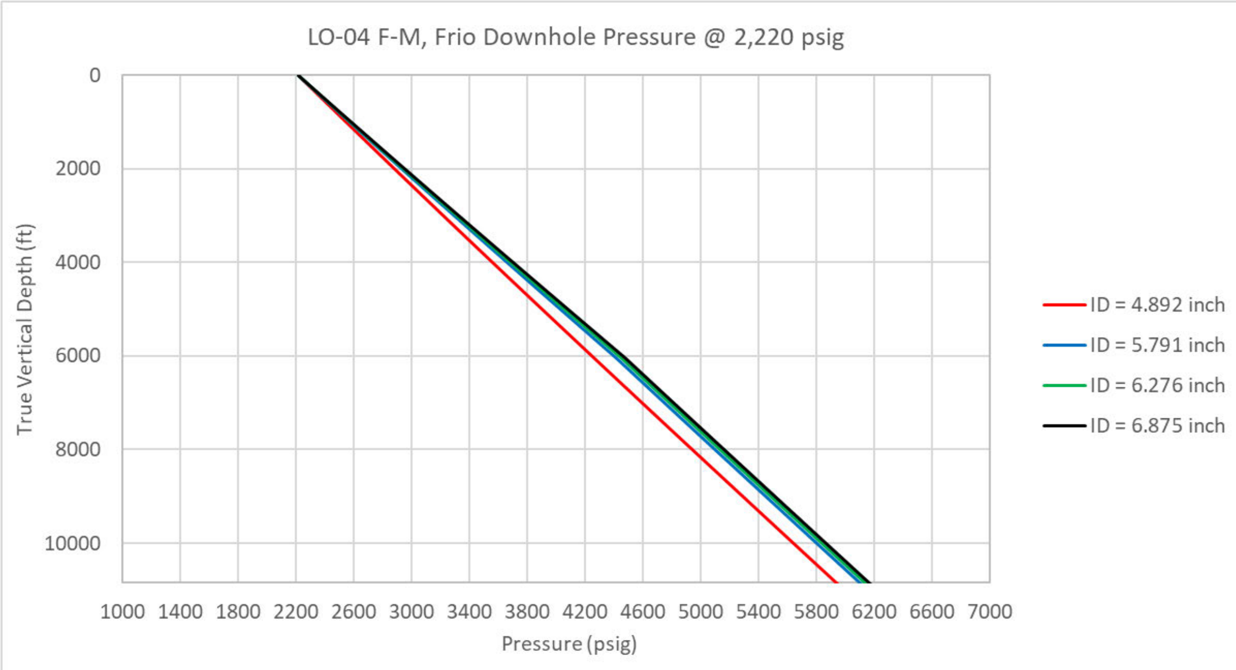

Figure 2: LO-04 F-M downhole pressure at maximum injection rate (1.5 MMt/y) and maximum injection pressure (2,220 psig) in different tubing sizes for CO_2 injection into the OFIC.

Nodal analysis suggested that for Lower Miocene Sands at an average injection rate of 2.9 MMt/y, the average surface pressure was 2,230 psig for the 4.892-inch ID tubing design (Figure 3). Since this is higher than the MASP (2,220 psig), this tubing size is likely not suitable for this well. For the selected 6.276-inch ID tubing case, the estimated surface pressure of 1,655 psig is lower than the MASP and can be used. Similarly, the nodal analysis for injection into the Frio Sand (Figure 4) at an average rate of 0.5 MMt/y showed that for the all the tubing sizes being tested, the surface pressure stayed at approximately 1,375 psig, which is lower than the MASP.

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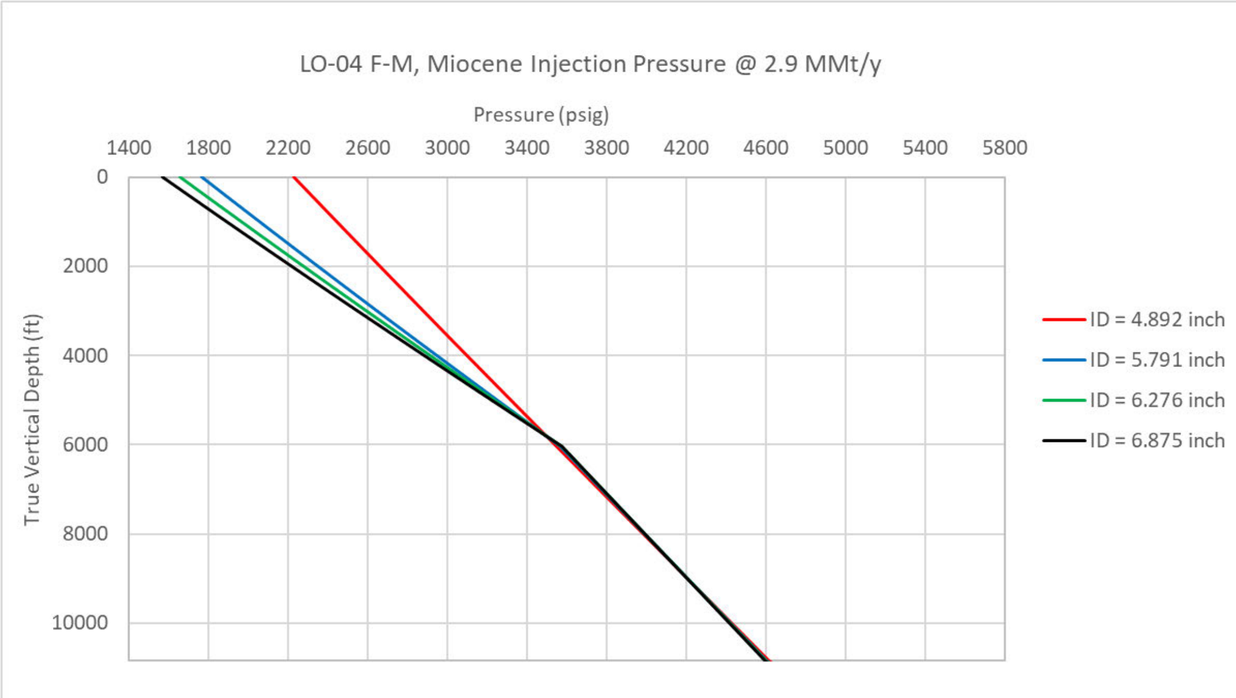

Figure 3: LO-04 F-M injection pressure at average injection rate of 2.9 MMt/y using different tubing sizes for CO_2 injection into the LMIC.

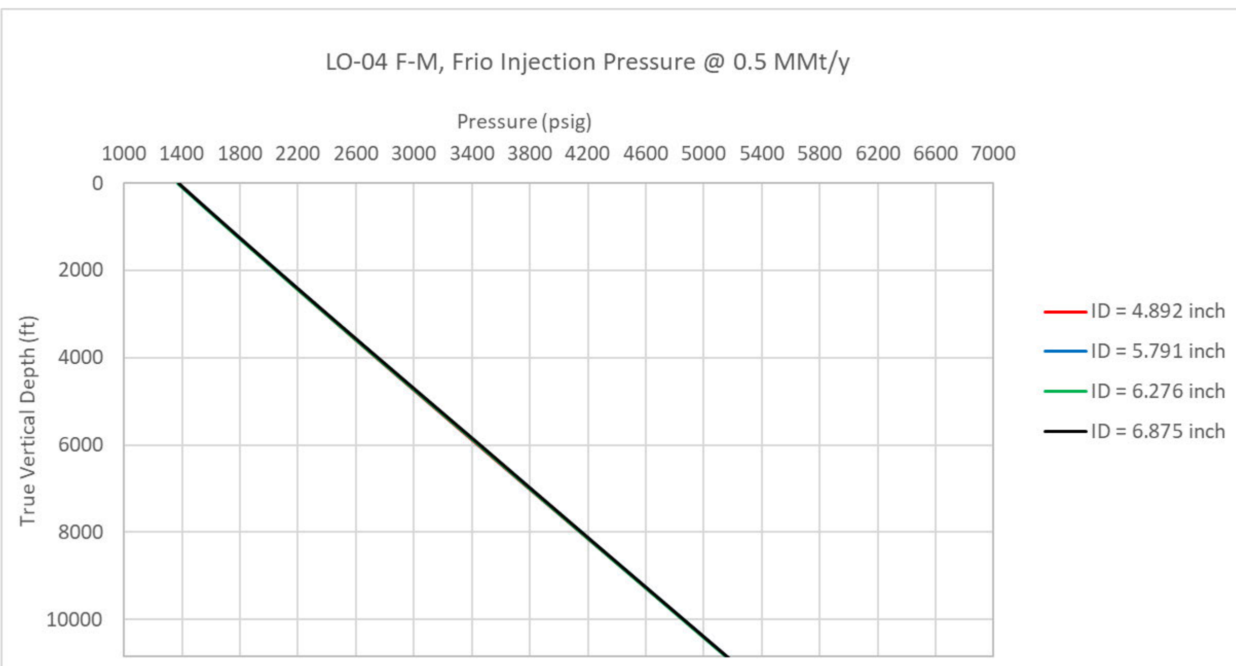

Figure 4: LO-04 F-M injection pressure at average injection rate of 0.5 MMt/y using different tubing sizes for CO_2 injection into the OFIC. The pressure profiles are almost identical for the four tubing designs.

2.2 Injection Well Operating Conditions

Table 1 provides the injection well operating conditions anticipated for LO-04 F-M that form the basis of design and material selection (LAC 43:XVII.3617(A)(2)(a)(i), (v), and (ix) and (A)(4)(c)(ii) – (v)).

Table 1: LO-04 F-M Operating Conditions.

Parameter	Value	Notes
Maximum Proposed Injection Rate	LMIC: 3.5 MMt/y OFIC: 1.5 MMt/y	Anticipated CO_2 volume from sources discussed in subsection 2.2 of the Summary of Requirements – Class VI Operating and Reporting Conditions
Average Injection Rate	LMIC: 2.9 MMt/y OFIC: 0.5 MMt/y	
Planned Injection Duration	30 years	Planned total 87 MMt CO_2 injection into LMIC and 15 MMt CO_2 injection into OFIC in LO-04 F-M in 30 years.
Injection type	Continuous	Operational target is for continuous injection. However, some intermittent injection will be likely due to operational downtime.
Volume Flow Rate	277 gpm	Maximum flow rate inside tubing.
Flow Velocity in Tubing	7-inch: 21 ft/sec 5.5-inch: 34 ft/sec 3.5 inch: 93 ft/sec	Maximum flow velocity assuming: 7-inch OD tubing w/ 6.276-inch ID from surface to 6,035 ft 5.5-inch OD tubing w/ 4.892-inch ID from 6,035 ft to 10,762 ft 3.5 -inch OD tubing w/ 2.992-inch ID from 10,762 ft to 10,842 ft
CO_2 Stream Characteristics	CO_2 Content - >95 mol% dry Water - <20 lb/MMSCF Total Hydrocarbon - <2 mol% dry Inert Gases (N_2, Ar, O_2) - <4 mol% dry Hydrogen - <1 mol% Alcohols, Aldehydes, Esters - <500 ppmv Hydrogen Sulfide - <50 ppmv Total Sulfur - <100 ppmy Oxygen - <20 ppmv Carbon Monoxide - <100 ppmv Glycol - <1 ppmv	Anticipated CO_2 stream characteristics.
CO_2 Stream Corrosiveness	Non-corrosive	

Parameter	Value	Notes
Formation Brine Corrosiveness	Mildly corrosive	
Mixture (CO_2 Stream with Formation Brine) Corrosiveness	Corrosive	
CO_2 Stream Density	7.8 lb/gal	At maximum pressure and 67 ºF on the wellhead.
Fracture Gradient	0.82 psi/ft	To be confirmed by step rate test at later date.
In-Situ Pressure at Top Perforation	2,853 psi (LMIC) 5,042 psi (OFIC)	Determined using the pore pressure gradient of 0.465 psi/ft.
Maximum pressure at top perforation	4,528 psi	Determined using 90% of the fracture gradient 0.82 psi/ft.
Maximum proposed annular pressure at wellhead	2,320 psi	
Maximum proposed injection (wellhead) pressure	2,220 psi	Limited by pipeline specifications as discussed in subsection 2.3 of the Summary of Requirements – Class VI Operating and Reporting Conditions.
Minimum annulus pressure at wellhead	100 psi	To maintain 100 psi differential pressure.
Minimum differential pressure (directly above and across packer)	100 psi	For continuous mechanical integrity assurance.
Injection Zones True Vertical Depth	LMIC: 5,834 ft – 9,489 ft OFIC: 10,842 ft – 11,709 ft	
Injection Intervals True Vertical Depth	LMIC: 6,135 ft – 7,025 ft 7,500 ft – 8,080 ft 8,630 ft – 9,280 ft OFIC: 10,842 ft –11,709 ft	

2.3 Formation Conditions

Table 2 presents the anticipated formation conditions for LO-04 F-M (LAC 43:XVII.3617(A)(2)(a)(vi)-(vii) and (ix)).Formation fluid characteristics will be updated following data collection programs described in the Pre-Operational Testing Program.

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Table 2: Formation conditions for LO-04 F-M.

Parameter	Value	Notes
Bottomhole Temperature	218 °F	0.0126 °F/ft geothermal gradient + 68 °F surface temperature
Injectate Temperature	67 °F	Anticipated CO_2 stream sources discussed in subsection 2.2 of the Summary of Requirements – Class VI Operating and Reporting Conditions.
Injection Lithology	Sandstone (LMIC) Sandstone (OFIC)	Perforating the sandstone formations of the LMIC and OFIC, respectively.
Confining Lithology	Shale	The shale layers of Middle Miocene and Anahuac Shale are the confining units of the LMIC and OFIC, respectively.
Formation Fluid Chemistry - Middle Miocene Confining Zone	TDS – 190,000 mg/L pH – 6.8 Ba^{2+} – 177 HCO_3^- – 589 Ca^{2+} – 2,047.6 Cl^- – 54,321.4 K^+ – 264 Mg^{2+} – 450.7 Na^+ – 32,494 SO_4^{2-} – 9.7	Based on USGS (National Produced Waters Geochemical Database, 2023)
Formation Fluid Chemistry – Lower Miocene Sands Injection Zone	TDS – 190,000 mg/L pH – 6.6 Ba^{2+} – 92.4 HCO_3^- – 269.3 Ca^{2+} – 2,269.5 Cl^- – 57,141.7 K^+ – 223.8 Mg^{2+} – 571.3 Na^+ – 33,160.4 SO_4^{2-} – 44.4	Based on USGS (National Produced Waters Geochemical Database, 2023)
Formation Fluid Chemistry – Anahuac Formation Confining Zone	TDS – 150,000 mg/L pH – 5.7 Ba^{2+} – 32.1 HCO_3^- – 462.9 Ca^{2+} – 2,738.5 Cl^- – 50,997 K^+ – 228 Mg^{2+} – 474.2 Na^+ – 29,290.4 SO_4^{2-} – 176.9	Based on USGS (National Produced Waters Geochemical Database, 2023)

Parameter	Value	Notes
Formation Fluid Chemistry – Frio Sands Injection Zone	TDS – 150,000 mg/L pH – 6.7 Ba^{2+} – 33.6 HCO_3^- – 508.4 Ca^{2+} – 2,837.4 Cl^- – 44,625 K^+ – 365 Mg^{2+} – 489.4 Na^+ – 25,467.6 SO_4^{2-} – 101.6	Based of USGS (National Produced Waters Geochemical Database, 2023)
Lowermost USDW True Vertical Depth	~2,300 ft to 2,500 ft	As discussed in subsection 2.7.5 of the Application Narrative.

2.4 Casing Program

Access to the injection intervals will utilize 9.625-inch casing and 7.625-inch liner to accommodate a 7-inch, 5.5-inch and 3.5-inch OD tubing. LO-04 F-M has been designed to accommodate concentric casing sizes required to isolate the injection reservoirs from the USDWs. Material for the casing was selected to be appropriate for the fluids and stresses expected to be encountered within the well including flow induced vibrations (LAC 43:XVII.3617(A) (1) and (2)(a)). For instance, the casing string and liner that will be exposed to injected CO_2 will be 22Cr-110 or higher alloy. The entire injection tubing string will comprise 7-inch, 5.5-inch and 3.5-inch 22Cr-110 or lined carbon steel tubing with gas tight premium connections. In case of lined tubing, corrosion rings will be utilized in all connections. Similarly, the 9.625-inch OD long-string casing going through the LMIC will be constructed of 22Cr-110 or higher alloy to 204 ft above the bottom of the Middle Miocene confining zone. In brine wetted, non-CO_2 exposed portions of the wellbore, L-80 will be utilized. Lithology of the storage reservoir's injection and confining zones is discussed in subsection 2.4 of the Application Narrative, and reservoir fluid characteristics are discussed in subsection 2.8 of the Application Narrative.

Casing stresses and loadings were modeled using Blade Energy Partners' StrinGnosis® software. To ensure sufficient structural strength and mechanical integrity throughout the life of the project (LAC 43:XVII.3617(A)(2)(a)), stresses were analyzed based on worst-case scenarios, and tubular specifications were selected accordingly. Minimum design factors and casing load scenarios are summarized below in Table 3, Table 4, Table 5, and Table 6 (LAC 43:XVII.3617(A)(2)(a)(ii)). The burst, collapse, and tensile strength of each tubular specification were calculated according to the scenarios defined below and were dependent on fracture gradients, depths, and minimum safety factors. The casing and tubing materials are designed to be compatible with the fluids encountered and the stresses induced throughout the sequestration project. If the recommended casing is not available for well construction, alternate tubulars will meet or exceed suitability criteria presented herein.

Table 3: Minimum Design Factors.

Load	Casing Design Criteria	Tubing Design Criteria	Connection Design Criteria
Triaxial	1.25	1.25	NA
Burst	1.1	1.1	1.1
Collapse	1.1	1.1	1.0
Tension	1.6	1.4	1.6
Compression	1.2	1.2	1.6

Table 4: Load scenarios evaluated for 13.375-inch Surface Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	8.7 ppg	8.7 ppg	Static
Overpull	8.7 ppg	8.7 ppg	Static
Bump Cement Plug	8.7 ppg + 500 psi	Cement	Static
As Cemented	8.7 ppg	Cement	Static
Pressure Test	8.7 ppg + 1,000 psi	Pore Pressure	Static
Full Evacuation	No Fluid	8.7 ppg	Static
Negative Pressure Test	8.33 ppg	8.7 ppg	Static
Drilling with Maximum Mud Weight	9.5 ppg	Pore Pressure	Static

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Table 5: Load scenarios evaluated for 9.625-inch Long-String Casing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	9.5 ppg	9.5 ppg	Static
Overpull	9.5 ppg	9.5 ppg	Static
Bump Cement Plug	9.5 ppg + 500 psi	Cement	Static
As Cemented	9.5 ppg	Cement	Static
Pressure Test	9.5 ppg + 3,500 psi	Pore Pressure	Static
Full Evacuation	No Fluid	9.5 ppg	Static
Negative Pressure Test	8.33 ppg	9.5 ppg	Static
Drilling with Maximum Mud Weight	10.0 ppg	Pore Pressure	Static

Table 6: Load scenarios evaluated for 7.625-inch Liner.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running In Hole	9.5 ppg	9.5 ppg	Static
Overpull	9.5 ppg	9.5 ppg	Static
Bump Cement Plug	9.5 ppg + 500 psi	Cement	Static
As Cemented	9.5 ppg	Cement	Static
Pressure Test	9.5 ppg + 4,000 psi	Pore Pressure	Static
Negative Pressure Test	8.33 ppg	9.5 ppg	Static

2.5 Casing Summary

The injection well design for LO-04 F-M will include the following casing strings: a 20-inch diameter conductor casing string set at a depth of approximately 200 ft below ground surface (BGS); a 13.375 inch diameter surface casing string set at a depth of approximately 2,800 ft BGS inside a 17.5-inch borehole; a 9.625-inch diameter long casing string set at approximately 9,890 ft BGS (401 ft below the top of the Anahuac Shale confining zone) inside a 12.25-inch borehole; a 7.625-inch diameter liner set at approximately 11,900 ft BGS inside a 9.125-inch borehole; and a 7-inch diameter injection tubing string tapered down to 5.5-inch diameter and then to 3.5-inch diameter set at approximately 10,842 ft BGS (top of the Frio injection interval). The liner will be overlapped 300 ft inside the bottom of the long string casing. Tubing will be equipped with retrievable packers, to isolate all four injection intervals (three in LMIC and one in OFIC) from the annulus, and sliding sleeves to allow selective injection of CO_2.

All casing strings will be cemented to the surface except the liner which will be cemented to the liner hanger. The borehole diameters are considered conventional for the sizes of casing string and liner that will be used. This should allow ample clearance between the outside of the pipe and the borehole wall to ensure that a continuous cement seal can be emplaced along the entire length of the casing string and liner. Proposed casing, liner and tubing sizes should also allow the use of appropriate testing devices and workover tools (LAC 43:XVII.3617(A)(1)(b)). While specific alloy compositions, weights, grades, and connections may change due to availability, construction of the well will utilize corrosion resistant alloys such as 22Cr-110 or higher alloy for $CO_2 + H_2O$ wetted sections and adhere to mechanical specifications consistent with design inputs presented herein. Final alloy selection at procurement will be based on the most current applicable materials testing results from API, AMPP, or other standard bodies currently focused on CCS.

Drilling and log data from nearby wells in the region indicate a possibility of formation sand entering the wellbore especially during interruptions in CO_2 injection into the Lower Miocene Sands. Live Oak CCS, LLC proposes using a resin control system where liquid resin is pushed into the perforations to consolidate sand particles and prevent sand production. Given the limited available data, specific treatment details are not defined. After data collection from the pre-operational testing program, laboratory tests will be conducted to evaluate the necessity for mitigation efforts as discussed in subsection 1 and 5.2 of the Stimulation Program.

Table 7 summarizes the proposed casing program for LO-04 F-M (LAC 43:XVII.3617(A)(2)(a)(iii-iv) and (A)(4)(c)(i) and (vi)-(vii)). Table 8 summarizes properties of each casing material. Each section of the well is discussed in a separate section below.

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Table 7: Summary of borehole and casing program for LO-04 F-M.

Casing String	Casing Depth (TVD; ft)	Borehole Diameter (in.)	Casing Outside Diameter (in.)	Casing Material (weight, grade, connection)	Coupling Outside Diameter (in.)
Conductor	0 – 200	NA	20.0	94 lb/ft, J55, STC	NA
Surface	0 – 2,800	17.5	13.375	61 lb/ft, J55, BTC	14.375
Long String	0 – 5,630	12.25	9.625	47 lb/ft, L80, Premium Connection	10.420
	5,630 – 9,890			47 lb/ft, 22Cr-110, Premium Connection	
Liner	9,590 – 11,900	9.125	7.625	39 lb/ft, 22Cr-110, Premium Connection	8.483
Tubing	0 – 6,035	NA	7.0	26 lb/ft, 22Cr-110, Premium Connection	7.593
	6,035 – 10,762		5.5	17 lb/ft, 22Cr-110, Premium Connection	6.018
	10,762 – 10,842		3.5	9.2 lb/ft, 22Cr-110, Premium Connection	3.930

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Table 8: Properties of well-casing materials for LO-04 F-M.

Casing String	Casing Diameter (inches) Outside / Inside / Drift / Thickness)	Burst Rating (psi)	Collapse Rating (psi)	Tension Rating (klbf)	Compression Rating (klbf)	Thermal Conductivity (BTU / hr-ft °F)
Conductor	20.0 / 19.124 / 18.936 / 0.438	2,110	520	1,480	1,480	26.2 @ 77°F
Surface	13.375 / 12.515 / 12.359 / 0.43	3,090	1,540	962	962	
Long String	9.625 / 8.681 / 8.525 / 0.472	6,870	4,750	1,086	1,086	8.4 @ 77°F
		9,710	5,300	1,493	1,194	
Liner	7.625 / 6.625 / 6.5 / 0.5	12,980	11,080	1,231	985	
Tubing	7.0 / 6.276 / 6.151 / 0.362	10,240	6,230	830	664	
	5.5 / 4.892 / 4.767 / 0.304	10,940	7,480	546	437	
	3.5 / 2.992 / 2.867 / 0.254	14,370	13,530	285	228	

2.5.1 Conductor Casing

The conductor casing is 20-inch diameter 94-lb/ft J55 carbon steel (J55) pipe with short thread couplings (STCs). Conductor casing provides a stable base required for drilling activities in unconsolidated sediment. Depending on wellsite conditions, this can be drilled and installed or driven directly. If drilled and installed, this section of the casing will be cemented in place and circulated.

2.5.2 Surface Casing

The surface casing is 13.375-inch diameter 61-lb/ft J55 pipe with buttress thread couplings (BTCs). Surface casing extends into a confining bed at 2,800 ft TVD below the base of the deepest formation containing USDW at 2,300 ft to 2,500 ft TVD. After installation, surface casing will be cemented in place and circulated from casing shoe to surface as described in subsection 2.7 (LAC 43:XVII.3617(A)(2)(b)). This will isolate all the USDWs through which the string extends. Following the cement setting, a bond log will be run to ensure a sufficient seal to prevent the migration of fluid into USDWs.

Before drilling out the casing shoe, surface casing will be hydrostatically tested to verify casing integrity at a minimum pressure of 500 psig. Casing test pressure will be maintained for one hour after stabilization with allowable pressure loss of less than five percent of test pressure over the stabilized test duration (LAC 43:XVII.3617(A)(3)(a)). Test pressure will never exceed the rated burst or collapse pressure as summarized in Table 8 (LAC 43:XVII.3617(A)(3)(a)(i)).

Live Oak CCS, LLC will monitor and record all pressure tests using surface readout pressure gauges and a chart or a digital recorder. All instruments will be calibrated and in good working order. If there is a failure of required tests as per LAC 43:XVII.3617(A)(3)(a)-(b), Live Oak CCS LLC will take necessary actions to obtain a passing test.

Figure 5 shows the casing stress analysis for anticipated operating scenarios.

2.5.3 Long-String Casing

The long-string casing is 9.625-inch diameter pipe composed of two sections. The uppermost section from surface to 5,630 ft TVD will be L-80, and the lower section from 5,630 ft to 9,890 ft TVD will be 22Cr-110 or higher alloy, both with gas tight premium connections. The transition will be targeted at approximately 5,630 ft TVD or 204 ft above the bottom of Middle Miocene Confining Zone (5,834 ft TVD).

Long string casing extends through the base of the Lower Miocene Sand injection zone and will be perforated for CO_2 injection (LAC 43:XVII.3617(A)(2)(c)). A DTS fiber optic cable will be run outside the casing from surface to casing shoe and cemented in place with the casing. Casing will be cemented by circulating cement from casing shoe to surface as described in subsection 2.7. Following the cement setting, a bond log will be run, and the casing will be hydrostatically tested at a minimum pressure of 1,000 psig before drilling out the casing shoe (LAC 43:XVII.3617(A)(3)(a)). After drilling at least 10 ft of formation below the casing shoe, the casing seat and cement will be hydrostatically tested at a minimum pressure of 1,000 psig (LAC 43:XVII.3617(A)(3)(b)). Test pressures in both the cases will be maintained for one hour after stabilization with allowable pressure loss of less than five percent of test pressure over the stabilized test duration. Test pressures will also never exceed the rated burst or collapse pressure as summarized in Table 8 (LAC 43:XVII.3617(A)(3)(a)(i) and (3)(b)(i)).

Live Oak CCS, LLC will monitor and record all pressure tests using surface readout pressure gauges and a chart or a digital recorder. All instruments will be calibrated and in good working order. If there is a failure of required tests as per LAC 43:XVII.3617(A)(3)(a)-(b), Live Oak CCS LLC will take necessary actions to obtain a passing test.

Figure 6 and Figure 7 show the casing stress analysis for anticipated operating scenarios.

2.5.4 Liner

The liner is 7.625-inch diameter 39 lb/ft 22Cr-110 or higher alloy pipe with gas tight premium connections which extends from 9,590 ft TVD through the base of the Frio injection zone to approximately 11,900 ft TVD and will be perforated for CO_2 injection (LAC 43:XVII.3617(A)(2)(c)). After installation, liner will be cemented in place and circulated from shoe to liner hanger. Following the cement setting, a bond log will be run, and the liner will be hydrostatically tested at a minimum pressure of 1,000 psig (LAC 43:XVII.3617(A)(3)(a)). After drilling at least 10 ft of formation below the shoe, the liner seat and cement will be hydrostatically tested at a minimum pressure of 1,000 psig (LAC 43:XVII.3617(A)(3)(b)). Test pressures in both the cases will be maintained for one hour after stabilization with allowable pressure loss of less than five percent of test pressure over the stabilized test duration. Test pressures will also never exceed the rated burst or collapse pressure as summarized in Table 8. Figure 8 shows the casing stress analysis for anticipated operating scenarios (LAC 43:XVII.3617(A)(3)(a)(i) and (b)(i)).

Live Oak CCS, LLC will monitor and record all pressure tests using surface readout pressure gauges and a chart or a digital recorder. All instruments will be calibrated and in good working order. If there is a failure of required tests as per LAC 43:XVII.3617(A)(3)(a)-(b), Live Oak CCS LLC will take necessary actions to obtain a passing test.

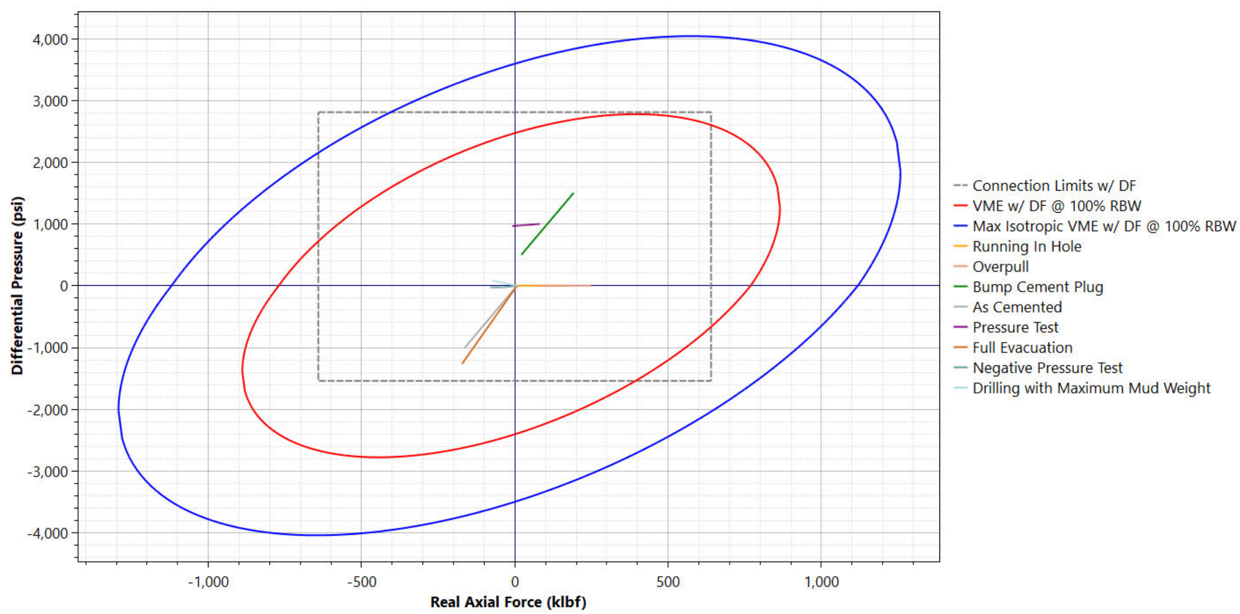

Figure 5: 13.375-inch surface casing (J55) axial force design envelope.

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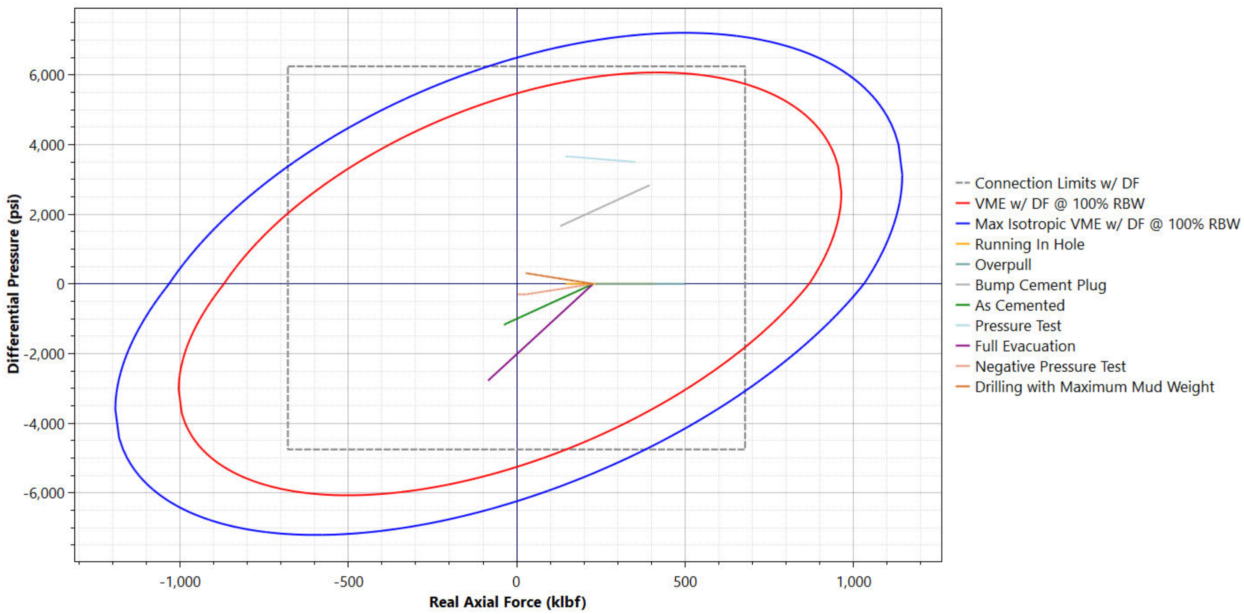

Figure 6: 9.625-inch long-string casing (L-80) axial force design envelope.

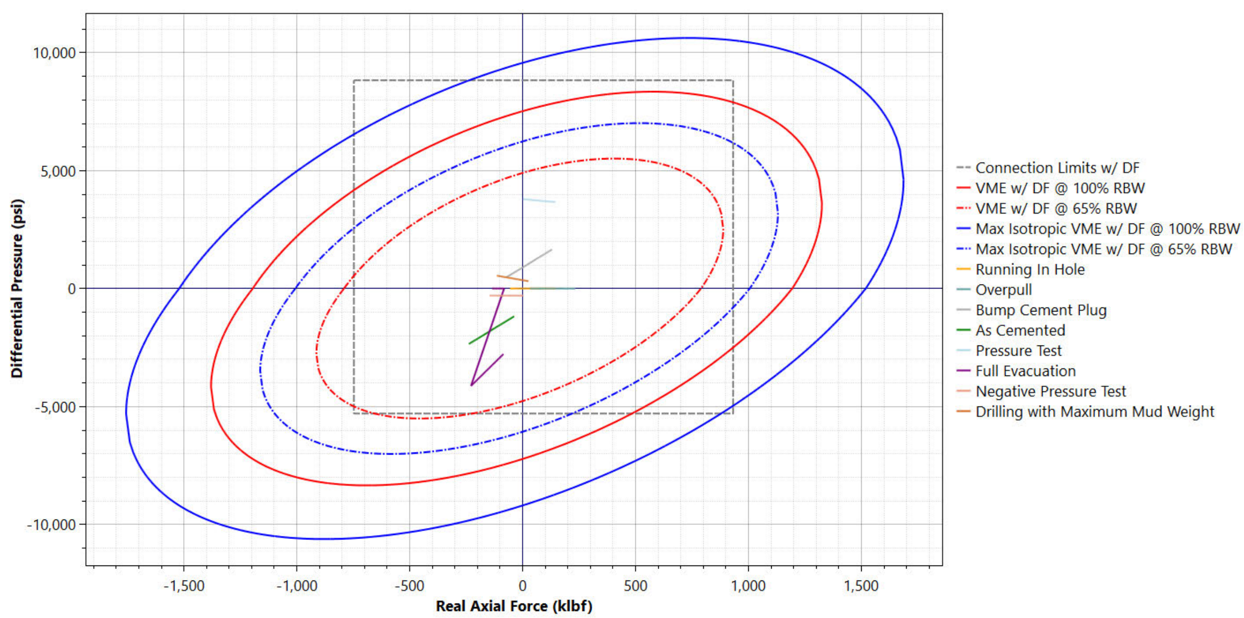

Figure 7: 9.625-inch long-string casing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall.

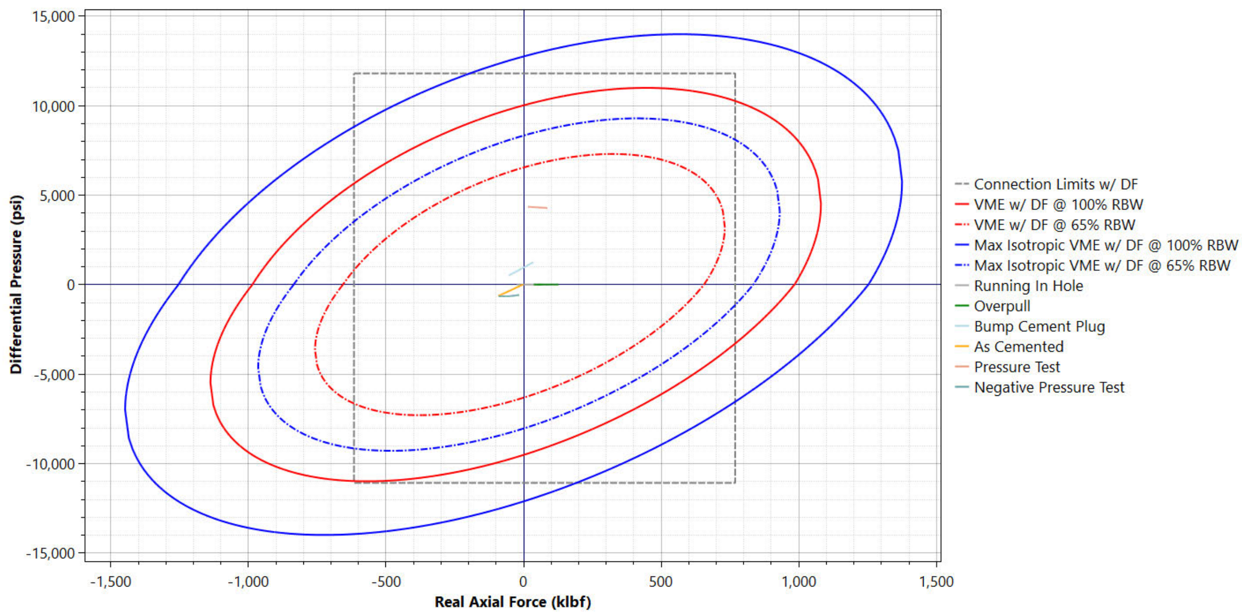

Figure 8: 7.625-inch liner (22Cr-110) axial force design envelope with 100% and 65% remaining body wall.

2.5.5 Tubing

The tubing connects the injection intervals to the wellhead and provides a pathway for storing CO_2. This design utilizes 7.0-inch 26 lb/ft 22Cr-110 tubing to approximately 6,035 ft TVD which is tapered down to 5.5-inch 17 lb/ft 22Cr-110 tubing to approximately 10,762 ft TVD and then further tapered down to 3.5-inch 9.2 lb/ft 22Cr-110 to approximately 10,842 ft TVD. At depths of approximately 6,085, 7,450, 8,580, and 10,802 ft, cased-hole packers will be set to isolate injection intervals from the tubing-casing annulus. At the end of the tubing string, a no-go profile nipple and wireline re-entry guide will be installed. This will allow flow control equipment to be installed for flow regulation or pressure isolation. Four sliding sleeves will be utilized to open or close the injection intervals to accommodate fluctuations in injection rates due to CO_2 availability. There will be a packer above and below the top three sliding sleeves to isolate each injection interval as well as the annulus.

Downhole gauges will include high resolution tubing and annulus pressure gauges. Considering the anticipated formation pressure, temperature, and stress, the grade of tubing was selected to preserve the integrity of the injected fluid, the injection intervals, and USDWs. Modeled load scenarios are summarized in Table 9. Figure 9, Figure 10 and Figure 11 show the casing stress analysis for anticipated operating scenarios. The tubing may be replaced as necessary during the planned injection period. The annulus between the tubing and long-string casing will be filled with non-corrosive fluid in accordance with LAC 43:XVII.3621(A)(3) (see subsection 2.7.1 below).

Table 9: Load scenarios evaluated for 7-inch, 5.5-inch and 3.5-inch tubing.

Load Case	Pressure Profile		Temperature Profile
	Internal	External	
Running in Hole	9.0 ppg	9.0 ppg	Static
As Run (Installed Load)	9.0 ppg	9.0 ppg	Static
Tubing Pressure Test	9.0 ppg + 2,220 psi	9.0 ppg	Static
Annular Pressure Test	9.0 ppg	9.0 ppg + 1,500 psi	Static
Full Evacuation	Tubing Evacuated	9.0 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Maximum CO_2 Injection	2,220 psi	9.0 ppg + 2,320 psi	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Tubing Shut In	SITP	9.0 ppg	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate
Shut In Tubing Leak	7.8 ppg	9.0 ppg + SITP	Wellbore Temperature at Maximum Wellhead Pressure and Injection Rate

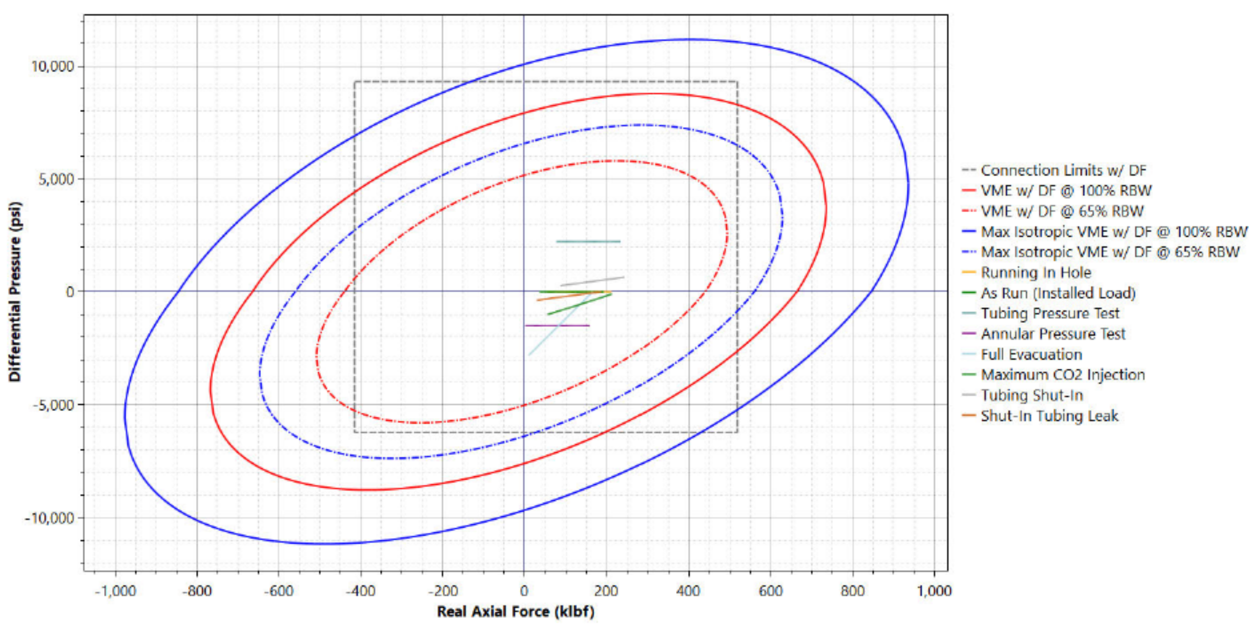

Figure 9: 7-inch tubing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall.

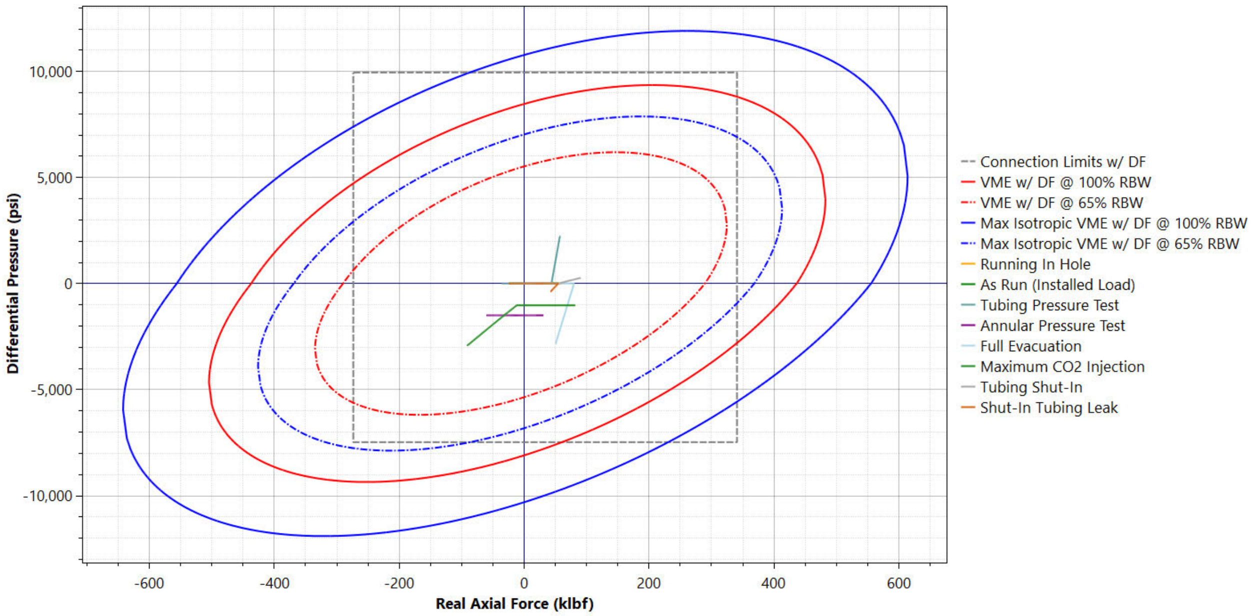

Figure 10: 5.5-inch tubing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall.

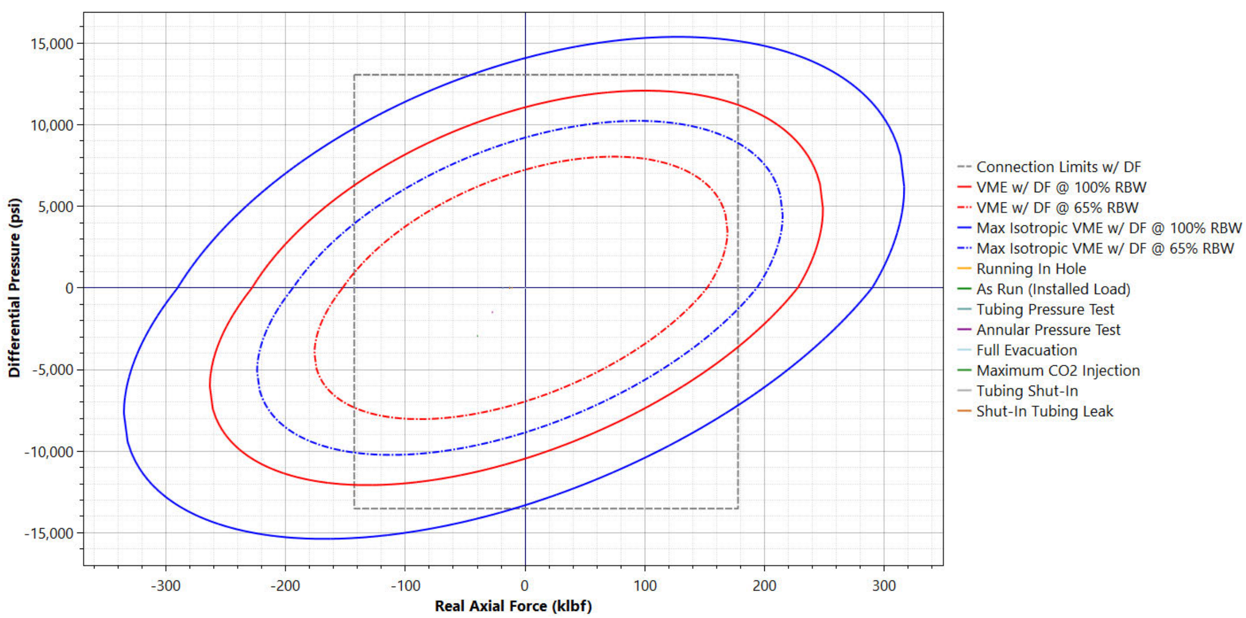

Figure 11: 3.5-inch tubing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall.

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2.6 Packer Details

LO-04 F-M in anticipated to utilize four retrievable cased hole packers to isolate the tubing-casing annulus and one liner hanger packer. The cased-hole packer will consist of Baker Hughes or equivalent Premier Packer with 22Cr-110 or higher alloy base pipe with hydrogenated nitrile butadiene rubber (HNBR) or similar CO_2 resistant packing element. Refer to Table 10 for proposed cased-hole packer specifications. The liner hanger packer will consist of Baker Hughes or equivalent Ultra Liner Packer. Refer to Table 11 for proposed liner hanger packer specifications. The final packer design and vendor selection will be made after gathering additional characterization data from the data collection well at the time of construction. (LAC 43:XVII.3617(A)(4)(c)).

Table 10: Cased-hole Packer specifications for LO-04 F-M.

Packer Type and Material	Setting Depth (TVD; ft)	Length (ft)	Nominal Pipe Weight (lb/ft)	Packer Main Body OD (in.)	Packer ID (in.)	Tensile Rasing (klbf)	Burst Rating (psi)
Baker Hughes Premier Packer 22Cr-110 or Higher Alloy	6,085 7,450 8,580 10,802	10.6	39	6.450	2.884	150,000	7,500

Collapse Rating (psi)	Maximum Casing ID (in.)	Minimum Casing ID (in.)
7,500	6.5	6.64

Table 11: Liner Hanger Packer specifications for LO-04 F-M.

Packer Type and Material	Setting Depth (TVD; ft)	Length (ft)	Nominal Pipe Weight (lb/ft)	Packer Main Body OD (in.)	Packer ID (in.)	Tensile Rasing (klbf)	Burst Rating (psi)
ZXP Ultra Liner Packer 22Cr-110 or Higher Alloy	9,590	22.45	47	8.350	6.525	500,000	10,000

Collapse Rating (psi)	Maximum Casing ID (in.)	Minimum Casing ID (in.)
10,000	8.835	8.405

2.7 Cementing Program

The surface and long-string casings will be cemented and circulated to the surface while liner will be cemented to the liner hanger. The proposed cement types and quantities for each casing string are summarized in Table 12 (LAC 43:XVII.3617(A)(2)(a)(viii)). Casing centralizers will be used on all casing strings to centralize the casing in the hole and to help ensure that cement completely surrounds the casing along the entire length of pipe (LAC 43:XVII.3617(A)(2)(c)). Logging and fluid data information will be incorporated into the cementing model to optimize centralizer placement. Except for the conductor casing, a guide or float shoe will be run on the bottom of the casing string, and a float collar will be run a minimum of one joint above the shoe. A stage tool will be utilized if needed for multistage cementing operations and will be either nickel plated or of compatible metallurgy with casing.

The 9.625-inch long-string casing will be cemented using CO_2 resistant tail cement, and 7.625-inch liner will be cemented using CO_2 resistant cement from bottom to liner hanger. Cement and cement additives will be compatible with CO_2 stream and formation fluids, and of sufficient quality and quantity to maintain integrity over the design life of the project. Following the cement setting, a bond log will be run and analyzed for all the casing strings to identify channels and ensure USDWs are not endangered (LAC 43:XVII.3617(A)(2)(e)). Remedial cementing will be performed if adequate cement isolation of the USDW or the injection intervals cannot be demonstrated (LAC 43:XVII.3617(A)(2)(d)(ii)). If cement cannot be circulated to surface due to excessive losses, Live Oak CCS LLC will submit an alternative method of cementing to the OC and will show using wireline logs that sufficient cement is present in the annulus to prevent movement of fluids (LAC 43:XVII.3617(A)(2)(d)(i)).

The actual job design including cement volume, displacement rates, and technique (i.e., single vs two-stage) will be refined using data from drilling operations (i.e., caliper logs, fracture logs, mud losses, etc.). A spacer will be pumped ahead of all cement jobs to assist in mud removal. Live Oak CCS, LLC will submit a copy of the cementing company's job summary or cementing tickets indicating returns to the surface to the OC with the notice of well construction completion, per LAC 43:XVII.3617(A)(2)(d).

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Table 12: Cementing program for LO-04 F-M.

Casing String	Casing Depth (TVD; ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (TVD; ft)	Cement
Surface	0 – 2,800	17.5	13.375	0 – 2,800 (cemented to surface)	Class A with additives; weight:15.2 lb/gal; yield: 1.25 ft^3/sack; quantity: 1,895 sacks.
Long String	0 – 9,890	12.25	9.625	0 – 4,575	Class G cement with additives; weight: 13.5 lb/gal; yield: 1.45 ft^3/sack; quantity: 1,235 sacks.
				4,575 – 9,890 (cemented to surface)	Lead: Class G cement with additives; weight: 13.5 lb/gal; yield: 1.45 ft^3/sack; quantity: 250 sacks. Tail: CO_2 resistant cement with additives; weight: 14.8 lb/gal; yield: 1.40 ft^3/sack; quantity: 1,239 sacks.
Liner	9,590 – 11,900	9.125	7.625	9,590 – 11,900 (cemented to liner hanger)	CO_2 resistant cement with additives; weight: 14.8 lb/gal; yield: 1.40 ft^3/sack; quantity: 289 sacks.

2.7.1 Annular Fluid

The annular space above the top tubing packer from surface to approximately 6,085 ft TVD between the long-string casing and injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be continuously monitored (LAC 43:XVII.3617(A)(1)(c)) and adjusted to maintain a 100-psi positive pressure differential in excess of tubing pressure (see subsection 3.3 of the Testing and Monitoring Plan for a full description of the injection well annulus monitoring system; LAC 43:XVII.3621(A)(4)).

The annular fluid will be non-corrosive fluid or a fluid with additives and inhibitors including corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular pressure management system. The final fluid composition will be based on anticipated injection pressures derived from data gathered during drilling and pressure transient testing of injection wells. Live Oak CCS, LLC will submit final fluid composition along with the Completion Report and Site Reassessment to the OC and receive written approval before commencing CO_2 injection (see subsection 2.9 of the Pre-Operational Testing Program; LAC 43:XVII.3621(A)(3)).

2.7.2 Wellhead

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

- 7.0625-inch, 5000 psi Tree Cap
- 7.0625-inch, 5000 psi Gate Valve (Crown Valve)
- 7.0625-inch, 5000 psi Flow Cross
- 7.0625-inch, 5000 psi Gate Valve x 2 (Wing Valves)
- 7.0625-inch, 5000 psi Actuated Gate Valve (Automatic Shutoff Valve)
- 7.0625-inch, 5000 psi Gate Valve (Master Valve)
- 11.0-inch x 7.0-inch, 5000 psi Tubing Hanger
- 2.0625-inch, 5000 psia Gate Valve x 2 (Wing Valves)
- 13.625-inch x 9.625-inch, 5000 psia Casing Hanger
- 2.0625-inch, 5000 psia Gate Valve (Wing Valve)

The wellhead and Christmas tree will be composed of materials that are designed to be compatible with the injection fluid. A preliminary material specification for wellhead and Christmas tree assembly is described in Table 13, using material classes as defined in API Specification 6A (Specification for Wellhead and Christmas Tree Equipment). The final wellhead and Christmas tree material specification may vary slightly from the information given and will meet or exceed what is outlined below.

The proposed wellhead schematic is presented in Figure 12. The flow line leading to the wellhead and Christmas tree will be equipped with an automatic shutoff valve as required in LAC 43:XVII.3621(A)(6)(a). Each annulus will have a pressure monitoring system installed on the wellhead. The final wellhead design will have the necessary number of ports for fiber optic and Tubing Encapsulated Cables (TEC) lines and is subject to change based on additional data collected from the data collection well.

Table 13: Material specification of wellhead and christmas tree for LO-04 F-M.

<table>
<tr><th colspan="2">Component</th><th>Material Class</th></tr>
<tr><td colspan="2">Casing Head Housing</td><td>DD</td></tr>
<tr><td colspan="2">Casing Spool Assembly</td><td>FF</td></tr>
<tr><td colspan="2">Tubing Hanger</td><td>FF</td></tr>
<tr><td colspan="2">Tubing Spool Assembly</td><td>FF</td></tr>
<tr><td rowspan="4">Christmas Tree</td><td>Tree Cap</td><td>FF</td></tr>
<tr><td>Manual Gate Valves</td><td>FF, DD</td></tr>
<tr><td>Flow Cross</td><td>FF</td></tr>
<tr><td>Actuated Gate Valve</td><td>FF</td></tr>
</table>

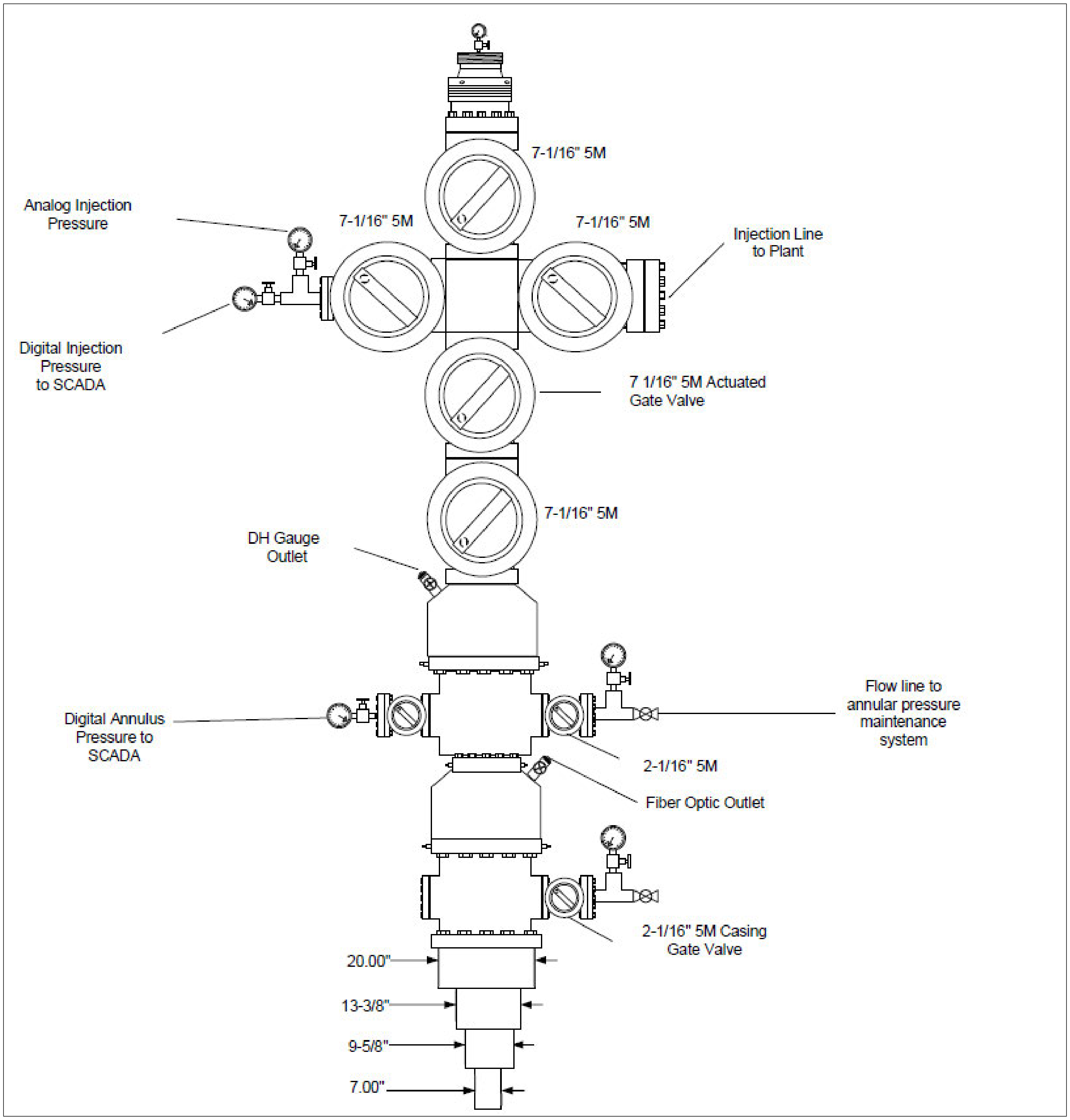

Figure 12: Proposed wellhead and christmas tree schematic for LO-04 F-M.

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2.7.3 Perforations

The long-string casing will be perforated using deep-penetrating shaped charges in both the LMIC and OFIC injection intervals. For the Lower Miocene Sands, three separate perforated intervals are planned. These are estimated to be from 6,135 to 7,025 ft; 7,500 to 8,080 ft; and 8,630 to 9,280 ft TVD. In Frio Sands, the perforated interval is estimated to be between 10,842 to 11,709 ft TVD. Due to the installation of fiber optics, oriented perforations will be used to avoid damaging the fiber optic cable. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. Proposed perforation interval depths for LO-04 F-M are found below in Table 14, subject to change based on data collected from the pre-operational testing program and injection well characterization data.

Table 14: Planned perforated intervals for LO-04 F-M.

Perforated Intervals	Perforated Interval No.	Top (TVD; ft)	Bottom (TVD; ft)	Mid-Point (TVD; ft)
LMIC	1	6,135	7,025	6,580
	2	7,500	8,080	7,790
	3	8,630	9,280	8,955
OFIC	4	10,842	11,709	11,275.5

2.8 Injection Well Construction Diagrams

The proposed well schematic is shown in Figure 13 and Figure 14 with details of perforation, sliding sleeve, gauges, and tubing string packers.

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Well Name	Prepared By	Prepared Date	Completion Fluid	Final MD (ft)
LO-04 F-M	R. Pandey	10/02/2024	Brine	11,900
Coordinates	**Wellhead**		**RKB (ft)**	
Claimed as PBI	TBD		TBD	
Parish	**State**		**GL (ft)**	
Iberville	Louisiana		TBD	

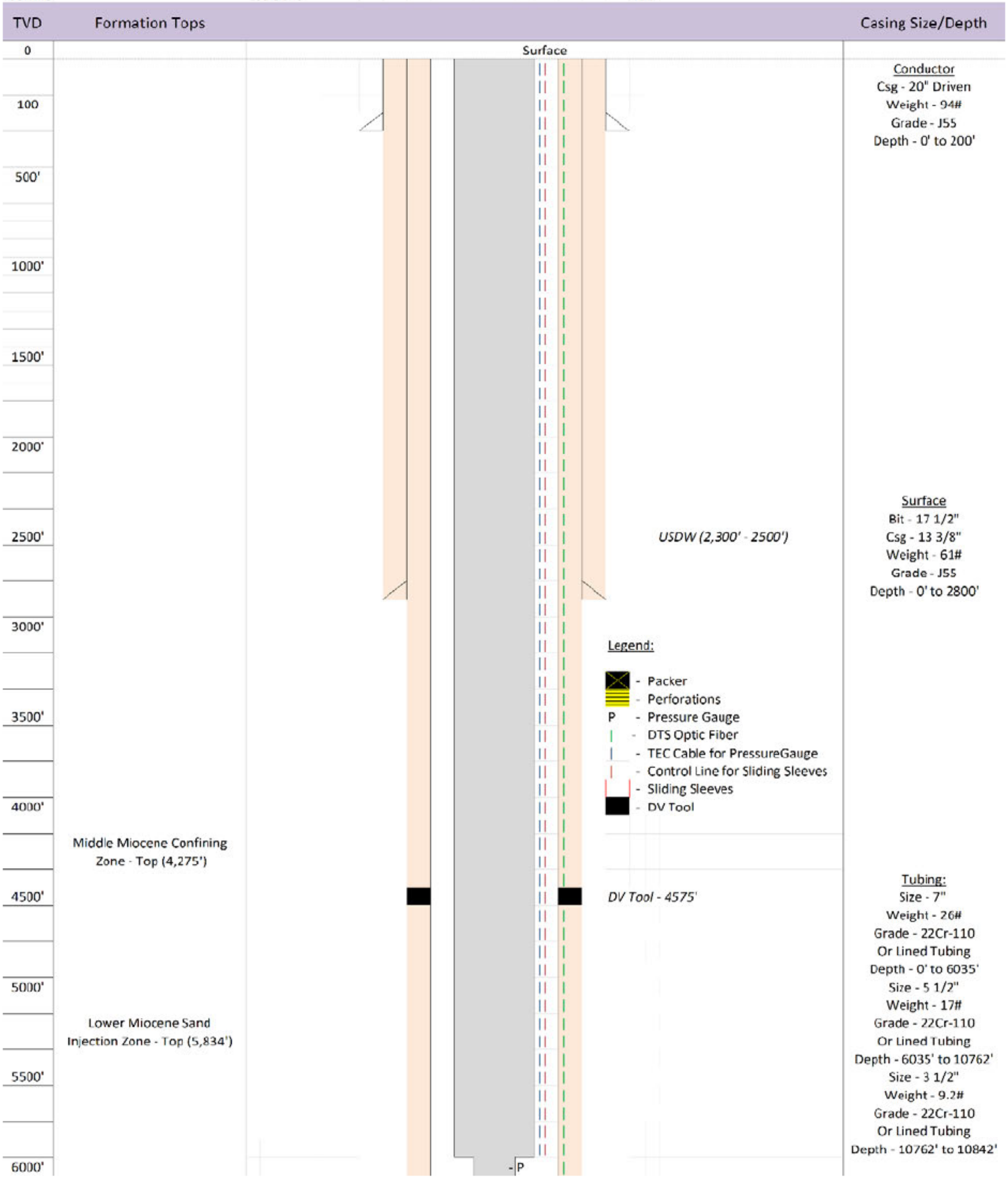

Figure 13: Proposed well schematic for LO-04 F-M (0 ft to 6,000 ft TVD).

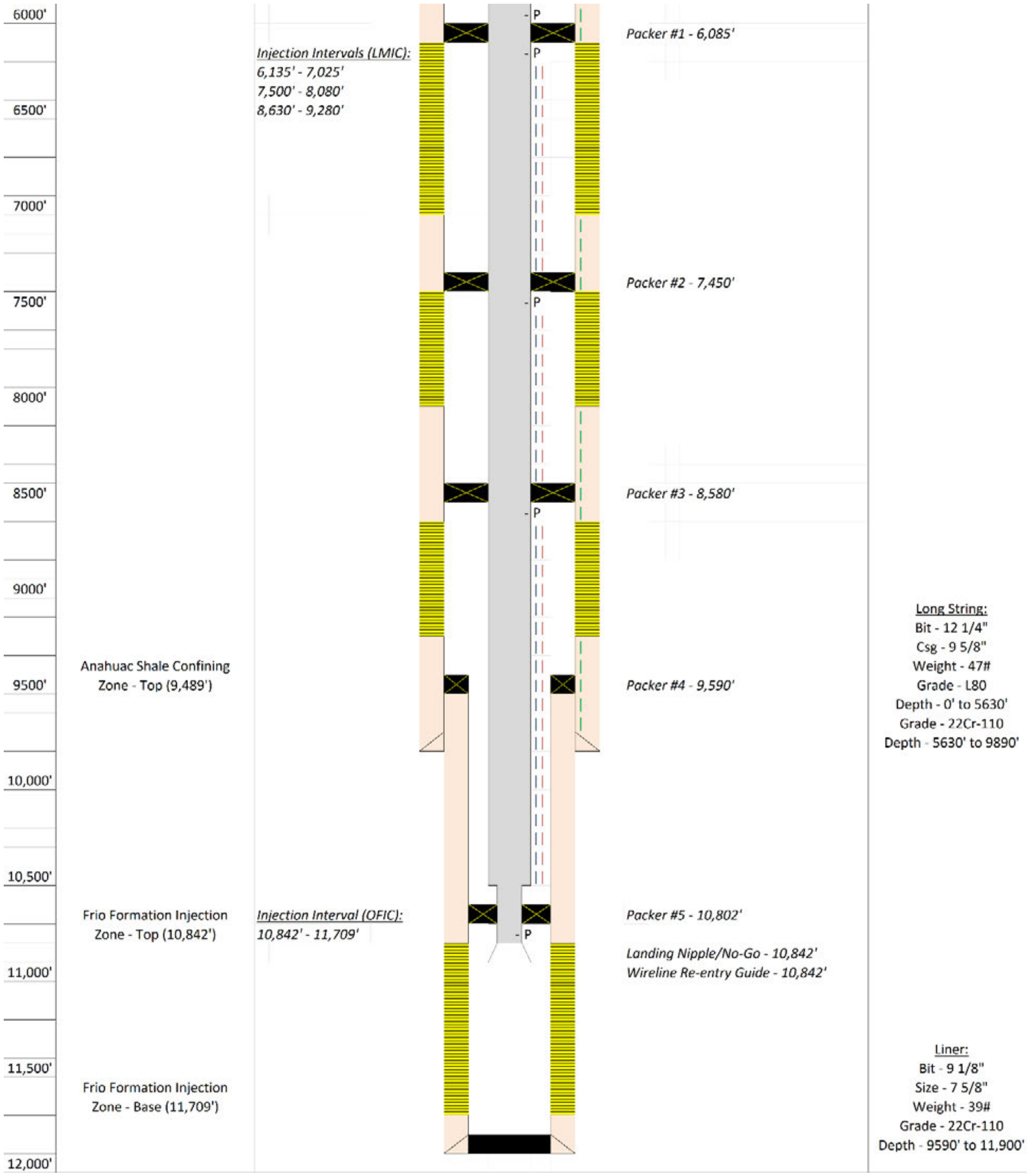

Figure 14: Proposed well schematic for LO-04 F-M (6,000 ft – 11,900 ft TVD).

Note: All depths are preliminary and will be adjusted based on additional characterization data obtained from the pre-operational testing program. At minimum, the surface casing and long string casing will be cemented from casing shoe to surface.

3. References

Blondes, Madalyn S., Knierim, Katherine J., Croke, Mary R., Freeman, Philip A, Doolan, Colin, Herzberg, Amanda S & Shelton, Jenna L (2024). U.S. Geological Survey National Produced Waters Geochemical Database (ver. 3.0, December 2023).