CONSTRUCTION DETAILS FOR LO-01 F
LAC 43:XVII.3617

Project Name: Live Oak CCS Hub

<u>Facility Information</u>

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

OOC Code No.: L1135

Well Location:

Well Name	Latitude (WGS84)	Longitude (WGS84)	Parish	State
LO-01 F	Claimed as PBI [redacted]	[redacted]	West Baton Rouge	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
Cl^-	Chloride
CO_2	Carbon Dioxide
DF	Design Factor
DTS	Distributed Temperature Sensing
DV	Differential Valve
ECP	External Casing Packer

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
LMIC	Lower Miocene Injection Complex
lb	Pound
mg/L	Milligrams Per Liter
Mg^{2+}	Magnesium
mm	Millimeter
MMSCF	Million Metric Standard Cubic Ft
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 Gauge
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-01 F injection well at the Live Oak CCS Hub in West Baton Rouge parish, Louisiana (the "project") are described in this document. The injection well has been designed to accommodate the anticipated mass flowrate of carbon dioxide (CO_2) and the subsurface characteristics of the CO_2 injection intervals that effect 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-01 F 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 9,320 ft with L80 grade steel (L80) from surface to 5,890 ft and 22Cr-110 grade duplex stainless steel (22Cr-110) from 5,890 ft to 9,320 ft. A 7.625-inch 39 lb/ft liner extends from 9,020 ft to 11,990 ft with tubing set to 10,731 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 into the injection interval.

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 injection interval at anticipated maximum instantaneous rate of 1.5 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 0.5 MMt/y in the Oligocene Frio Injection Complex (OFIC). Similarly, the maximum injection rate is anticipated to be 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 the OFIC (Figure 1). Nodal analysis suggested that for the Frio Formation at a maximum injection rate of 1.5 MMt/y, and with an injection (wellhead) pressure of 2,220 psig, all studied tubing sizes allowed for safe CO_2 injection. For the selected 6.276-inch ID tubing proposed for well construction, modeling projected a bottomhole pressure of 5,098 psig at an injection depth of 10,731 ft. This pressure is slightly higher than the estimated average reservoir pressure (5,091 psig) and lower than the maximum bottomhole pressure (7,919 psig) calculated using 90% of fracture gradient at the depth of the shallowest injection interval in the Frio Formation. Further analysis for the required minimum injection pressure at the maximum planned injection rate suggests that the 4.892-inch inner diameter (ID) tubing requires a much higher injection pressure of 1,650 psig to achieve 1.5 MMt/y (Figure 2).

Nodal analysis suggested that at average injection rate of 0.5 MMt/y, the average surface pressure stayed well below the MASP (2,220 psig) for all the tested tubing designs (Figure 3). Specifically, for the selected 6.276-inch ID tubing case, the estimated surface pressure stayed at approximately 1,360 psig, which is lower than the MASP and can be used effectively for this well.

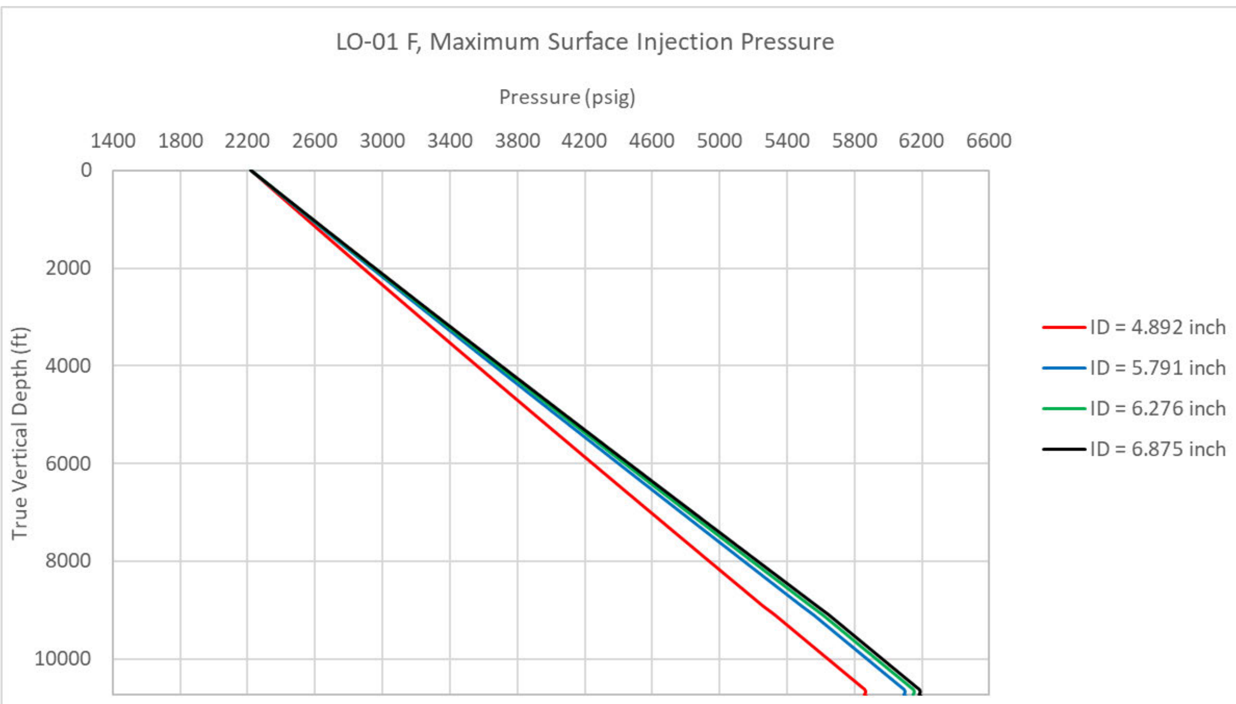

Figure 1: LO-01 F downhole pressure at maximum injection rate (1.5 MMt/y) and maximum injection pressure (2,220 psig) using different tubing sizes for CO_2 injection into the OFIC.

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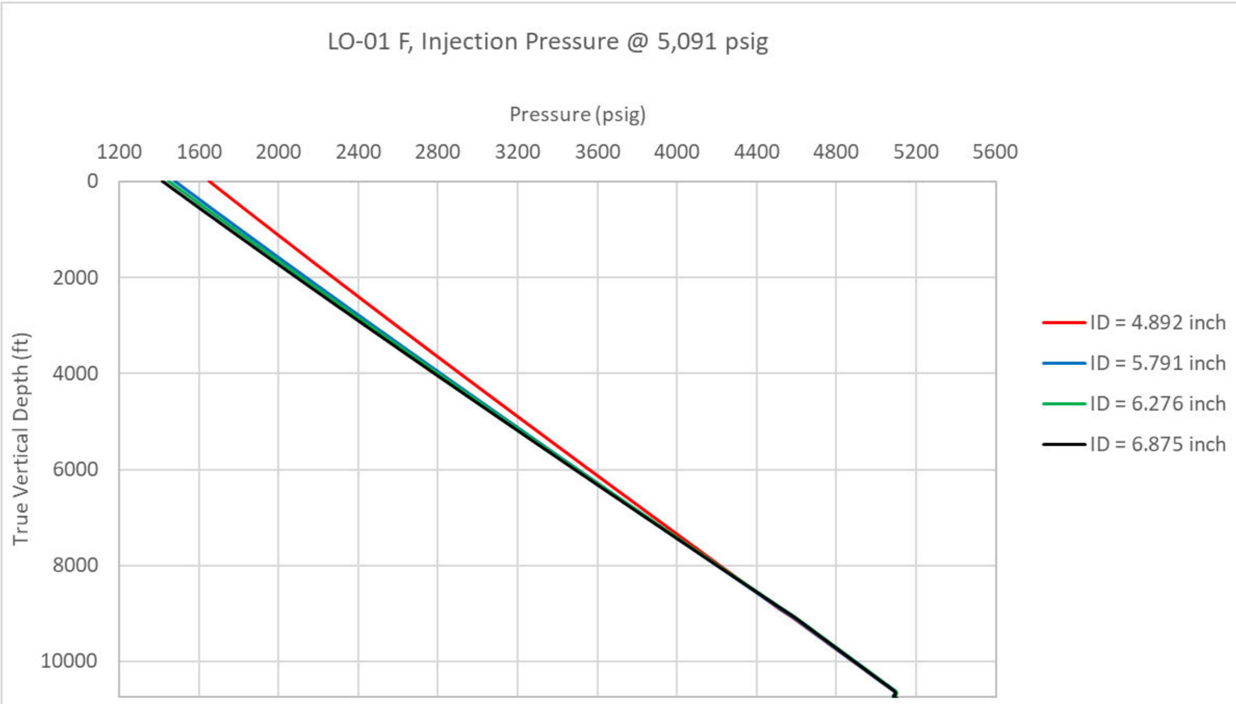

Figure 2: LO-01 F injection pressure at maximum injection rate (1.5 MMt/y) and average reservoir pressure (5,091 psig) using different tubing sizes for CO_2 injection into the OFIC.

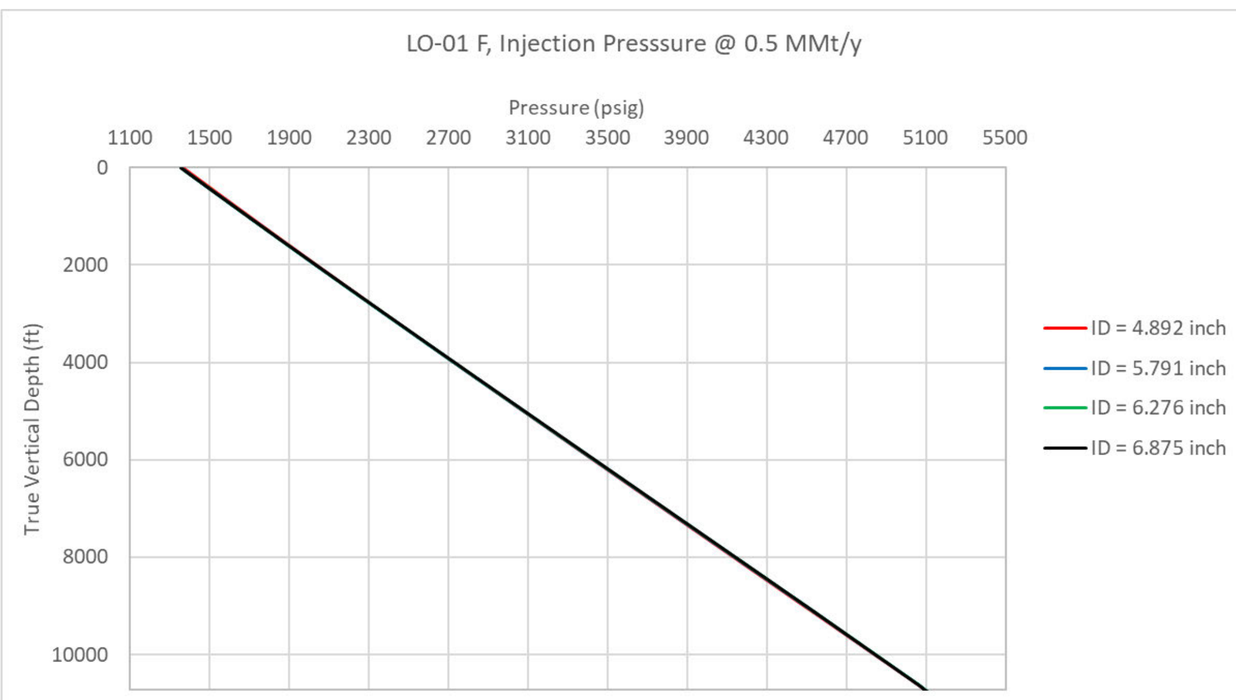

Figure 3: LO-01 F injection pressure at average injection rate of 0.5 MMt/y using different tubing sizes for CO_2 injection into the OFIC. The pressure profiles are almost identical for the tubing designs.

2.2 Injection Well Operating Conditions

Table 1 provides the injection well operating conditions anticipated for LO-01 F 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-01 F Operating Conditions.

Parameter	Value	Notes
Maximum Proposed Injection Rate	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	0.5 MMt/y	
Planned Injection Duration	30 years	Planned total 15 MMt CO_2 injection in LO-01 F 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	119 gpm	Maximum flow rate inside tubing.
Flow Velocity in Tubing	7-inch: 9 ft/sec 5.5-inch: 14.6 ft/sec 3.5 inch: 39 ft/sec	Maximum flow velocity assuming: 7-inch OD tubing w/ 6.276-inch ID from surface to 8,920 ft 5.5-inch OD tubing w/ 4.892-inch ID from 8,920 ft to 10,650 ft 3.5 -inch OD tubing w/ 2.992-inch ID from 10,650 ft to 10,731 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	
Formation Brine Corrosiveness	Mildly corrosive	

Parameter	Value	Notes
Mixture (CO_2 Stream with Formation Brine) Corrosiveness	Corrosive	
CO_2 Stream Density	7.2 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 shallowest injection interval in the Frio Formation Injection Zone	4,990 psi	Determined using the pore pressure gradient of 0.465 psi/ft.
Maximum pressure at shallowest injection interval in the Frio Formation Injection Zone	7,919 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.
OFIC Injection Zone True Vertical Depth	10,731 ft – 11,882 ft	
OFIC Injection Interval True Vertical Depth	10,731 ft – 11,882 ft	

2.3 Formation Conditions

Table 2 presents the anticipated formation conditions for LO-01 F (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-01 F.

Parameter	Value	Notes
Bottomhole Temperature	219 °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	Perforating the sandstone formation of the OFIC.
Confining Lithology	Shale	The Anahuac Shale formation is the confining unit of the OFIC.
Formation Fluid Chemistry – Anahuac Shale 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)
Formation Fluid Chemistry – Frio Formation 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 on 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 interval 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-01 F 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 liner that will be exposed to injected CO_2 will be 22Cr-110 or higher alloy. The entire injection tubing string will comprise 22Cr-110 or lined carbon steel tubing with gas tight premium connections. In the case of lined tubing, corrosion rings will be utilized in all connections. Similarly, the 9.625-inch OD long-string casing going through the Lower Miocene Sand formation will be constructed of 22Cr-110 or higher alloy to 205 ft above the bottom of the Middle Miocene Confining Zone as CO_2 injected into the Lower Miocene Injection Complex (LMIC) using LO-01 M may come into contact with this interval. In brine wetted, non-CO_2 exposed portions of the wellbore, L80 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. 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 were calculated according to the scenarios defined below and were dependent on fracture gradients and depths. 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

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-01 F 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 9,320 ft BGS (403 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 11,990 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 10,731 ft BGS (top of the Frio Formation injection interval). The liner will be overlapped 300 ft inside the bottom of the long string casing, and tubing will be equipped with a retrievable packer to isolate the injection interval from the annulus.

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 strings 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.

Table 7 summarizes the proposed casing program for LO-01 F (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.

Table 7: Summary of borehole and casing program for LO-01 F.

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 – 5,890	12.25	9.625	47 lb/ft, L80, Premium Connection	10.420
	5,890 – 9,320			47 lb/ft, 22Cr-110, Premium Connection	
Liner	9,020 – 11,990	9.125	7.625	39 lb/ft, 22Cr-110, Premium Connection	8.483
Tubing	0 – 8,920	NA	7.0	26 lb/ft, 22Cr-110, Premium Connection	7.593
	8,920 – 10,650		5.5	17 lb/ft, 22Cr-110, Premium Connection	6.018
	10,650 – 10,731		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-01 F.

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

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 4 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 5,890 ft TVD will be L80, and the lower section from 5,890 ft to 9,320 ft TVD will be 22Cr-110 or higher alloy, both with gas tight premium connections. The transition will be targeted at approximately 5,890 ft TVD or 205 ft above the bottom of the Middle Miocene Confining Zone (6,095 ft TVD). The casing string will extend through the base of the Lower Miocene Sand formation to 403 ft below the top of the Anahuac Shale confining zone (8,917 ft TVD).

Casing will be cemented by circulating cement from casing shoe to surface as described in subsection 2.7 (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. Following the cement setting, a bond log will be run, and 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, 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 (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 and Figure 6 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 9,020 ft TVD through the base of the Frio Formation injection interval to approximately 11,990 ft TVD and will be perforated for CO_2 injection (LAC 43:XVII.3617(A)(2)(c)). 300 ft of liner will be overlapped inside the bottom of the 9.625-inch diameter long string casing. After installation, the liner will be cemented in place and circulated from shoe to the 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 7 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.

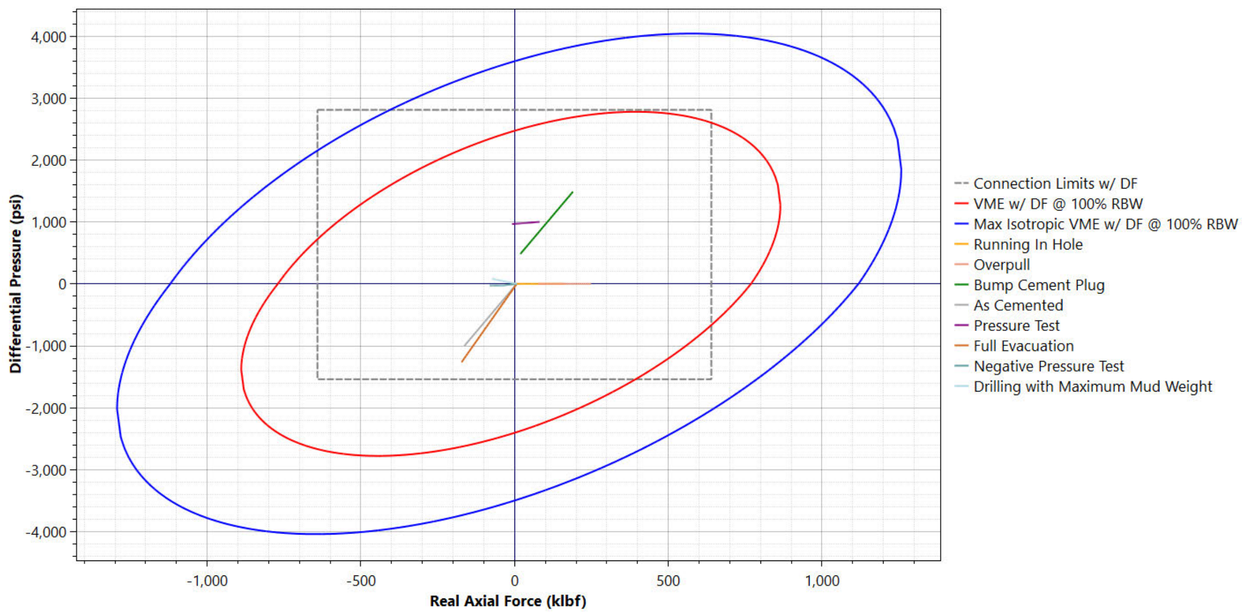

Figure 4: 13.375-inch surface casing (J55) axial force design envelope.

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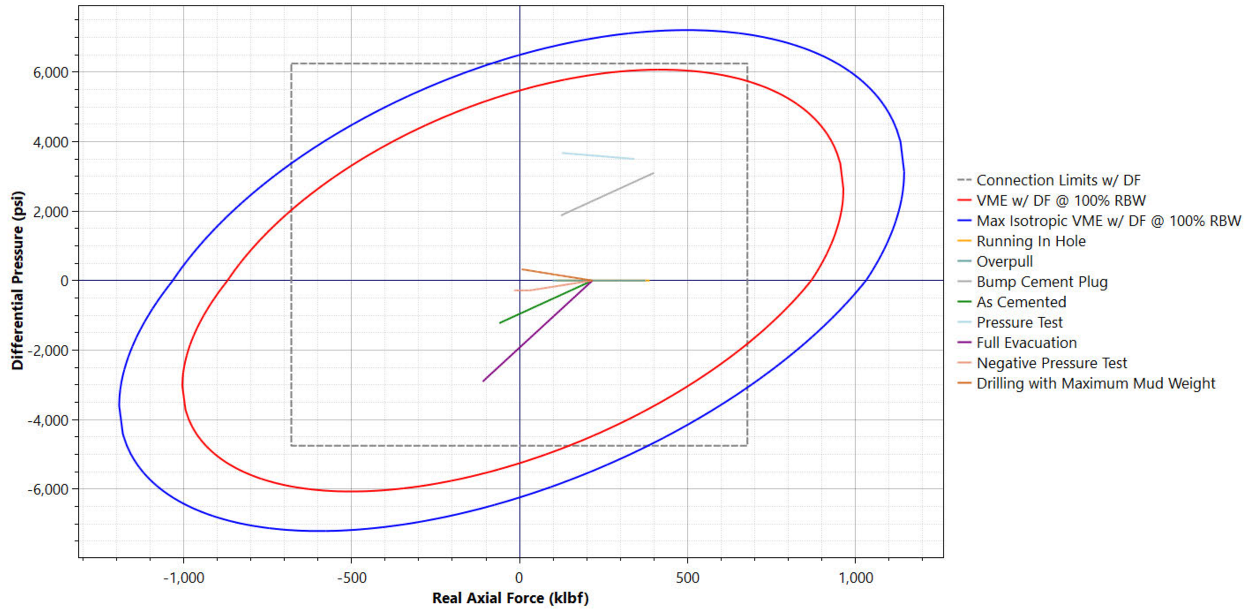

Figure 5: 9.625-inch long-string casing (L80) axial force design envelope.

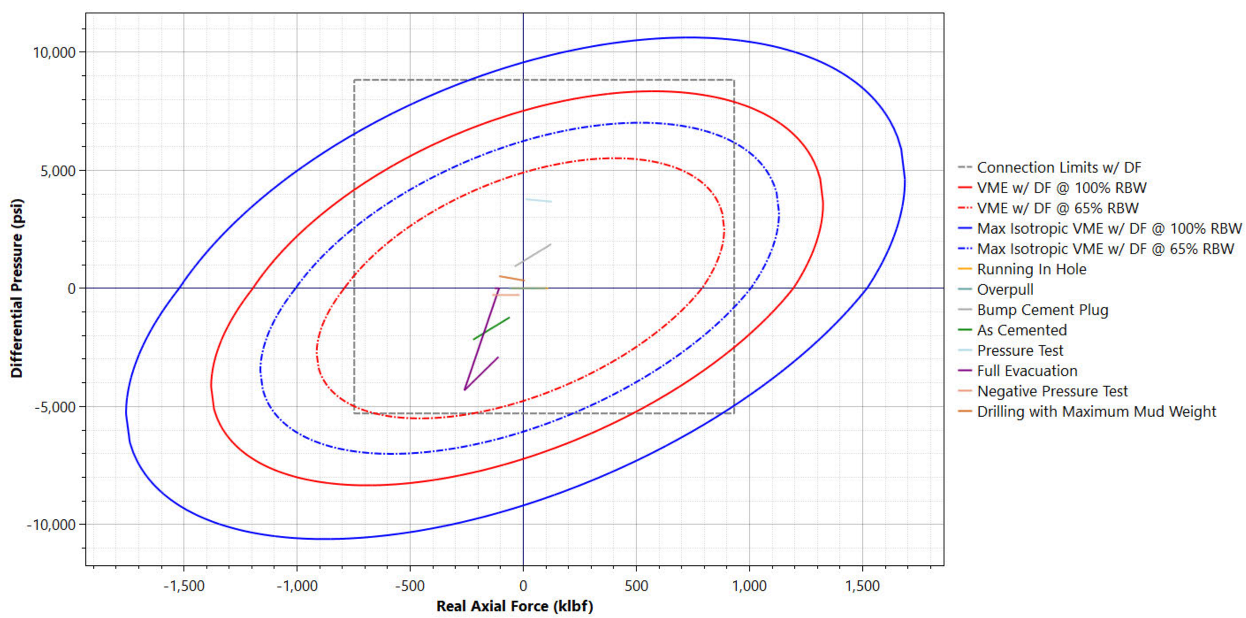

Figure 6: 9.625-inch long-string casing (22Cr-110) axial force design envelope with 100% and 65% remaining body wall (RBW).

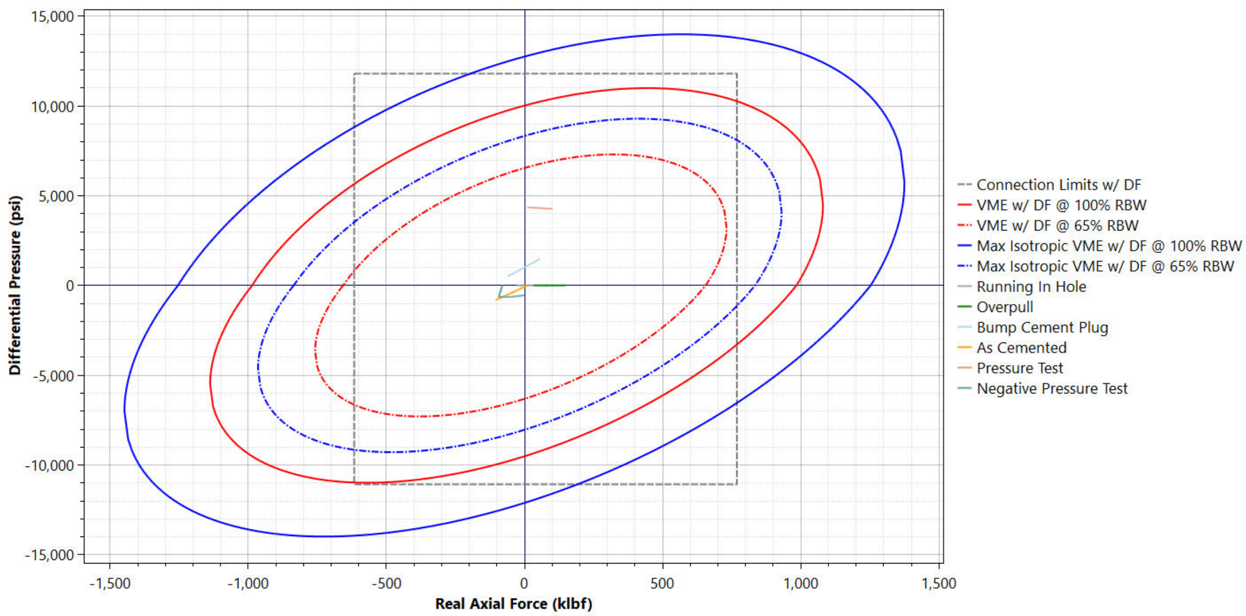

Figure 7: 7.625-inch liner (22Cr-110) axial force design envelope with 100% and 65% RBW.

2.5.5 Tubing

The tubing connects the injection interval 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 8,920 ft TVD which is tapered down to 5.5-inch 17 lb/ft 22Cr-110 to approximately 10,650 ft TVD and then further tapered down to 3.5-inch 9.2 lb/ft 22Cr-110 to approximately 10,731 ft TVD. A cased-hole packer will be set at the bottom of the tubing at approximately 10,690 ft TVD to isolate the injection interval 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.

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 interval, and USDWs. Modeled load scenarios are summarized in Table 9. Figure 8, Figure 9, and Figure 10 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).

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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 CO2 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

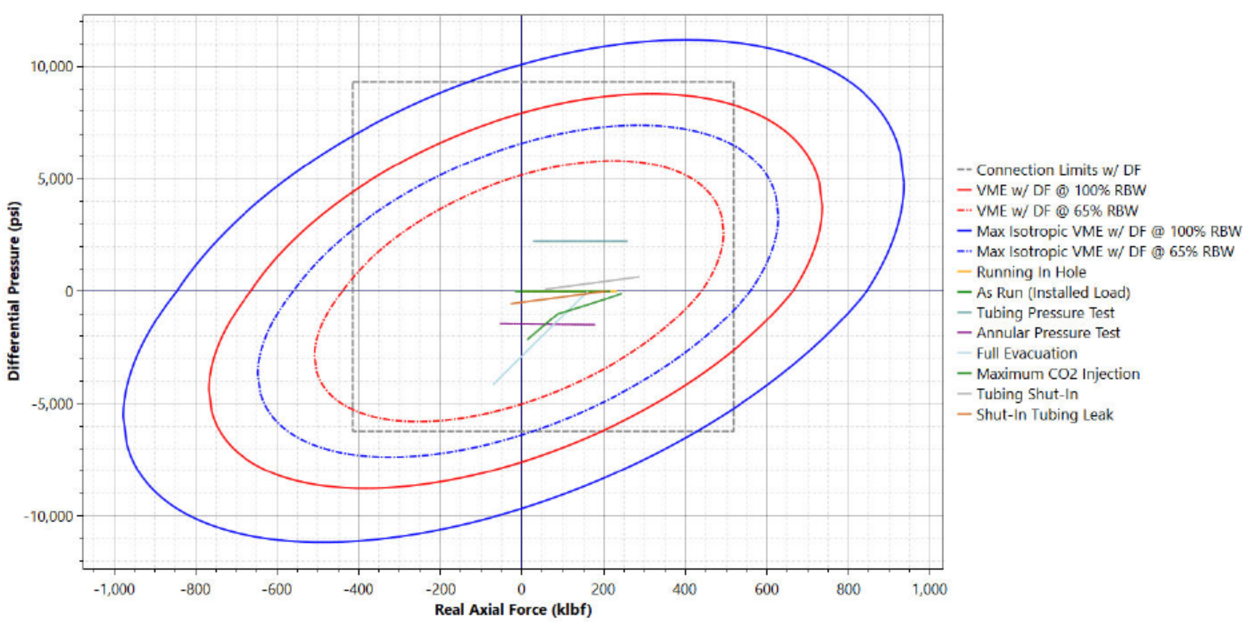

Figure 8: 7-inch tubing (22Cr-110) axial force design envelope with 100% and 65% RBW.

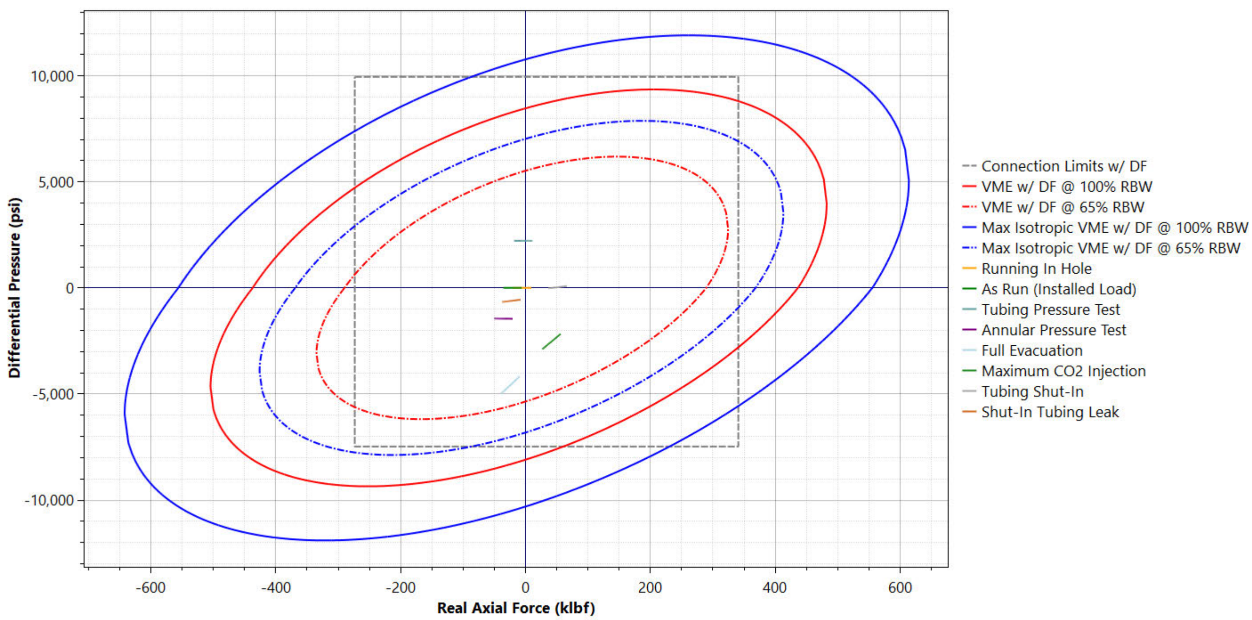

Figure 9: 5.5-inch tubing (22Cr-110) axial force design envelope with 100% and 65% RBW.

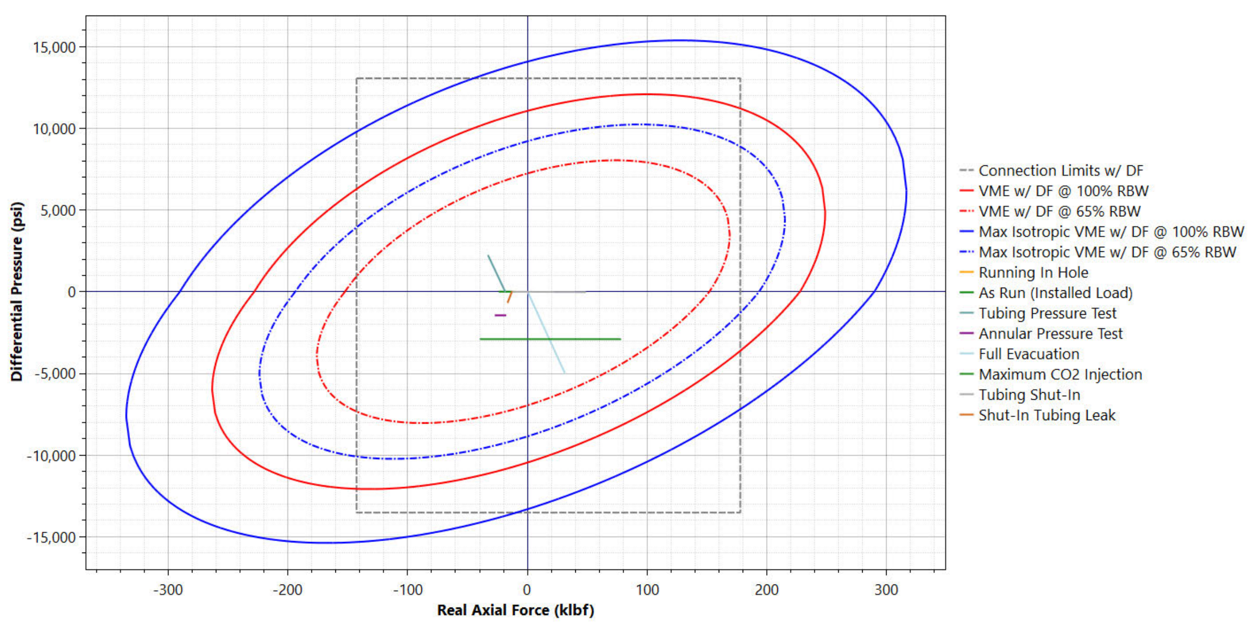

Figure 10: 3.5-inch tubing (22Cr-110) axial force design envelope with 100% and 65% RBW.

2.6 Packer Details

LO-01 F is anticipated to utilize one retrievable cased-hole packer to isolate the Goo-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.

Table 10: Cased-hole Packer specifications for LO-01 F.

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	10,690	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-01 F.

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	9,020	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 the 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 to centralize casing in the hole and to help ensure that cement completely surrounds the casing (LAC 43:XVII.3617(A)(2)(c)). Logging and fluid data information will be incorporated into the cementing model to optimize centralizer placement.

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 shoe 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 interval 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).

Table 12: Cementing program for LO-01 F.

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:15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 2,118 sacks.
Long String	0 – 9,170	12.25	9.625	0 – 5,540	Class G cement with additives; weight: 13.5 lb/gal; yield: 1.45 ft^3/sack; quantity: 1,582 sacks.
				5,540 – 9,320 (cemented to surface)	Lead: Class G cement with additives; weight: 13.5 lb/gal; yield: 1.45 ft^3/sack; quantity: 67 sacks. Tail: CO_2 resistant cement with additives; weight: 14.8 lb/gal; yield: 1.40 ft^3/sack; quantity: 1011 sacks.
Liner	9,020 – 11,990	9.125	7.625	9,020 – 11,990 (cemented to liner hanger)	CO_2 resistant cement with additives; weight: 14.8 lb/gal; yield: 1.40 ft^3/sack; quantity: 300 sacks.

2.7.1 Annular Fluid

The annular space above the top tubing packer from surface to approximately 10,690 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 11. 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 required 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-01 F.

Component		Material Class
Casing Head Housing		DD
Casing Spool Assembly		FF
Tubing Hanger		FF
Tubing Spool Assembly		FF
Christmas Tree	Tree Cap	FF
	Manual Gate Valves	FF, DD
	Flow Cross	FF
	Actuated Gate Valve	FF

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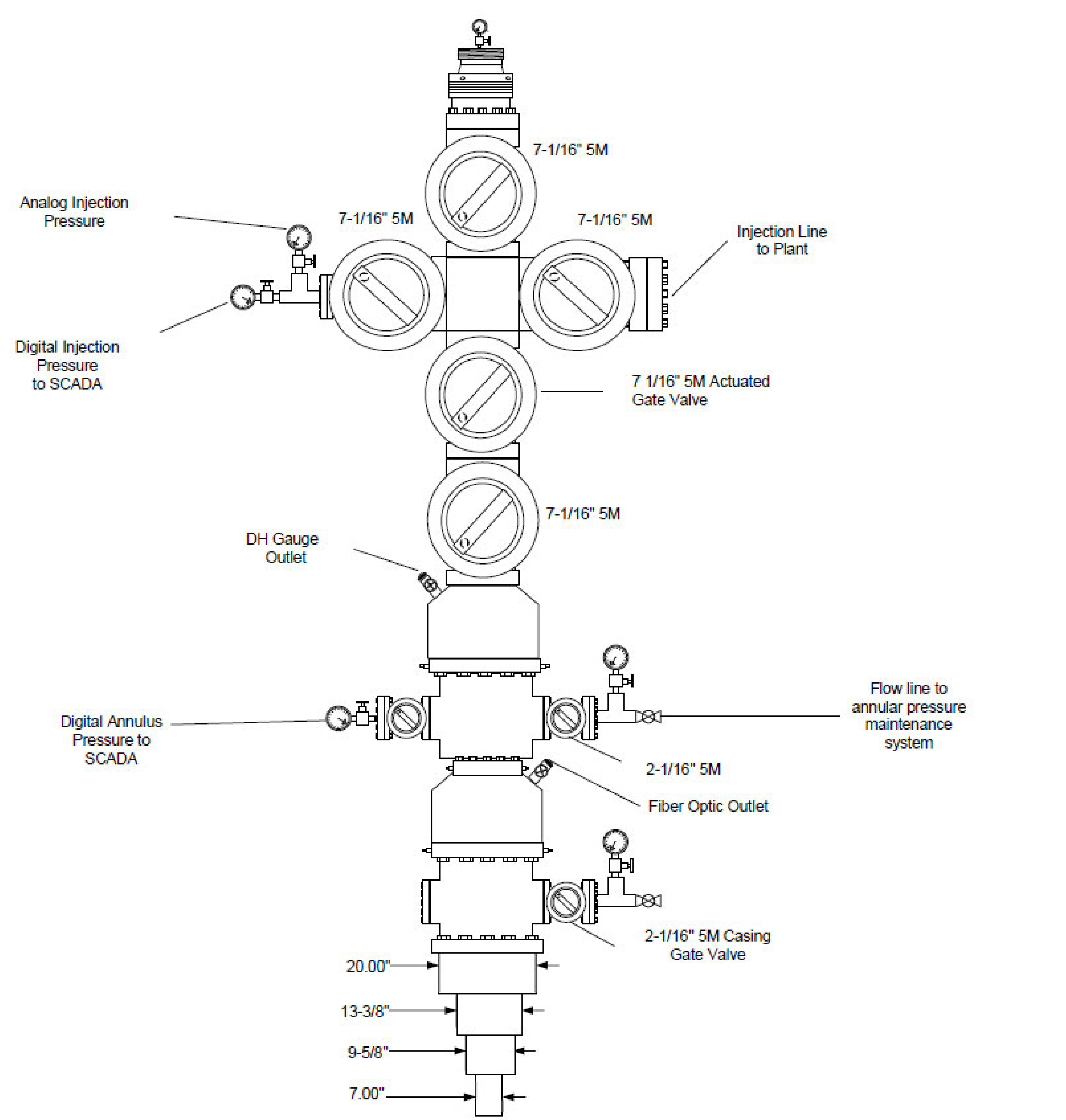

Figure 11: Proposed wellhead and christmas tree schematic for LO-01 F.

2.7.3 Perforations

The liner will be perforated across the Frio Formation with deep-penetrating shaped charges from 10,731 to 11,882 ft. The exact injection interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The proposed injection interval depth for LO-01 F is 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 interval for LO-01 F.

Perforated Interval No.	Top (TVD; ft)	Bottom (TVD; ft)	Mid-Point (TVD; ft)
1	10,731	11,882	11,307

2.8 Injection Well Construction Diagrams

The proposed well schematics are shown in Figure 12 and Figure 13.

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Revision: 0
October 2024

Well Name	Prepared By	Prepared Date	Completion Fluid	Final MD (ft)
LO-01 F	R.Pandey	10/01/2024	Brine	11,930
Coordinates	**Wellhead**		**RKB (ft)**	
Claimed as PBI	TBD		TBD	
Parish	**State**		**GL (ft)**	
West Baton Rouge	Louisiana		TBD	

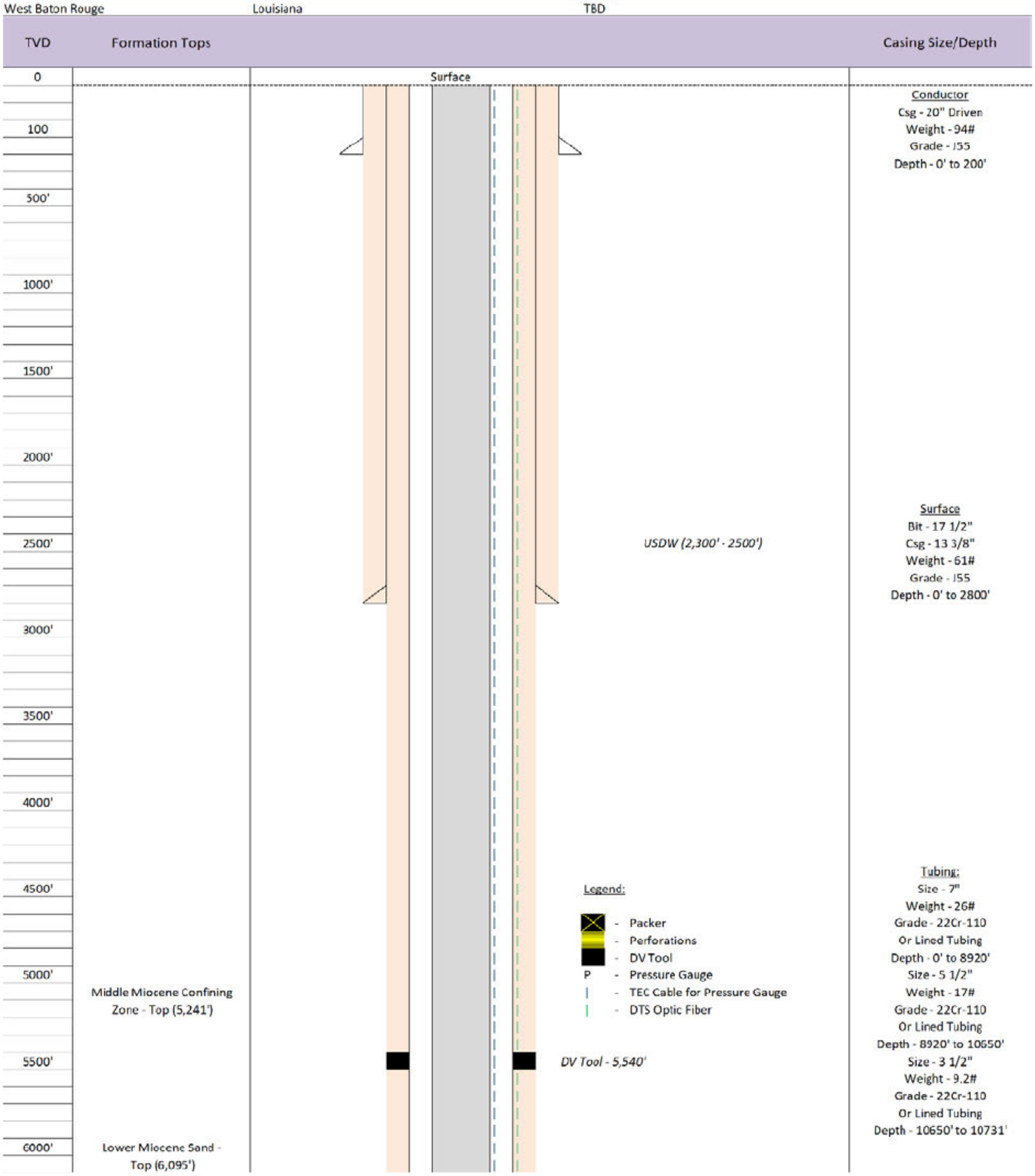

Figure 12: Proposed well schematic for LO-01 F (0 ft to 6,000 ft TVD).

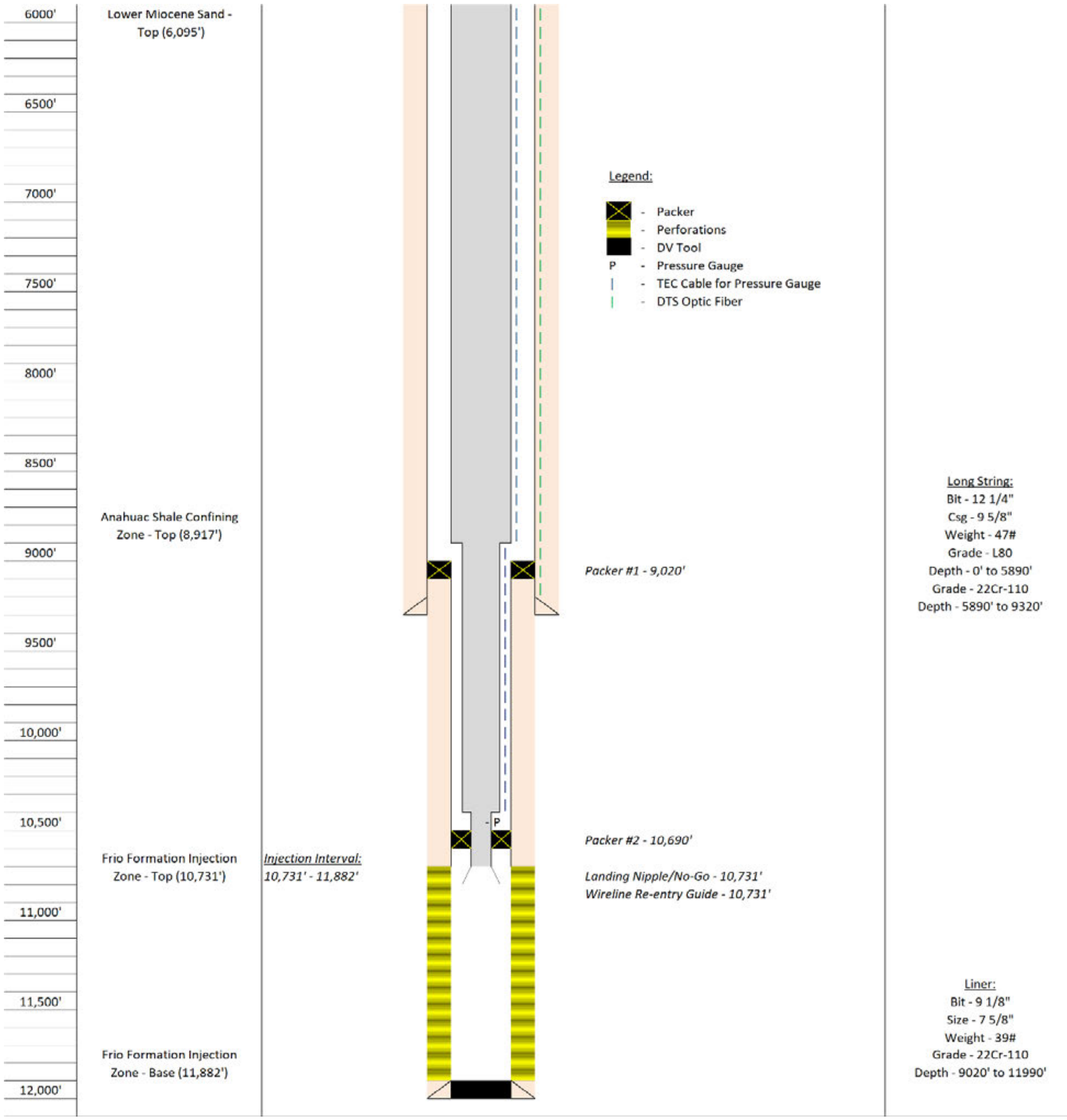

Figure 13: Proposed well schematic for LO-01 F (6,000 ft – 11,990 ft TVD).

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 show to surface.

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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).