Longleaf CCS Hub

Longleaf CCS, LLC

Injection Well Construction Designs

40 CFR 146.82(a)(11, 12), 40 CFR 146.86(b), 40 CFR 146.86(c) and 40 CFR 146.88(e)

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama
LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W
LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W
LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W
LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mg/l	Milligrams per liter
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
psi	Pounds per square inch
psi/ft	Pounds per square inch per foot
SS	Sub-Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Introduction

The injection wells have been designed to accommodate the mass of CO_2 that will be delivered to the storage site, considering key characteristics of the CO_2 storage reservoir that affect the well design. This section illustrates the comprehensive analysis performed to comply with and exceed the EPA Class VI UIC well standards regarding the design of the casing, cement, and wellhead [40 CFR 146.86(a)].

A.1 Wellhead Injection Pressure

SLB's *PIPESIM* software was used to conduct a nodal analysis to determine the feasibility of CO_2 injection through 6.625-inch tubing for the CO_2 injection wells. The analysis assumes an expected wellhead (injection) pressure of about 1,500 psia (**Section *A.3.1*** of the *Injection Well Operations Plan*). The nodal analysis for Injection Wells LL #2, LL #3, and LL #4 used was designed for a surface casing string with a 9.625-inch 53 lb/ft LTC thread casing set at approximately 11,400 feet, with a 6.625-inch 28lb/ft long injection tubing string set at 10,210 feet.

The nodal analysis for Injection Well LL #1 was designed with the same casing construction, however the 6.625-inch tubing will be run from surface to a depth of 10,950 feet. The tubing is then converted to 5.5-inch 20 lb/ft tubing with two sliding sleeves installed to isolate access to the Upper and Lower Paluxy, respectively. Additionally, when both sleeves are fully open, the flow profile is equivalent to the Nodal analysis case with no sliding sleeves (i.e., full access to all of the injection perforations). The injection tubing strings in all four injection wells use L-80 grade steel and 13% chrome type (13Cr-L80). Design parameters from the geologic model are shown in **Table 1** below. The schematics for the casing nodal analysis of both designs are shown in **Figure 1**.

Table 1. Zonal Inputs for Nodal Analysis

	Perforated Interval	Top (ft)	Bottom (ft)	Mid Point (ft)	Gross Thickness (ft)	Net Thickness (ft)	Pressure (psi)	Average Permeability (md)	Reservoir Temp (F)
Depth of Caprock	NA	10,125	10,220	10,173	95		4,710	7.0E-05	233
Unperforated Paluxy Shale Interval	NA	10,220	10,269	10,245	49		4,743	5.2E-03	234
Upper Paluxy	1	10,269	10,318	10,294	49	49	4,766	233	235
	2	10,351	10,400	10,376	49	49	4,804	172	236
	3	10,433	10,743	10,588	310	198	4,902	106	240
	4	10,809	10,956	10,883	147	99	5,039	87	245
Lower Paluxy	5	11,191	11,217	11,204	26	26	5,187	31	250
	6	11,295	11,347	11,321	52	52	5,242	75	252

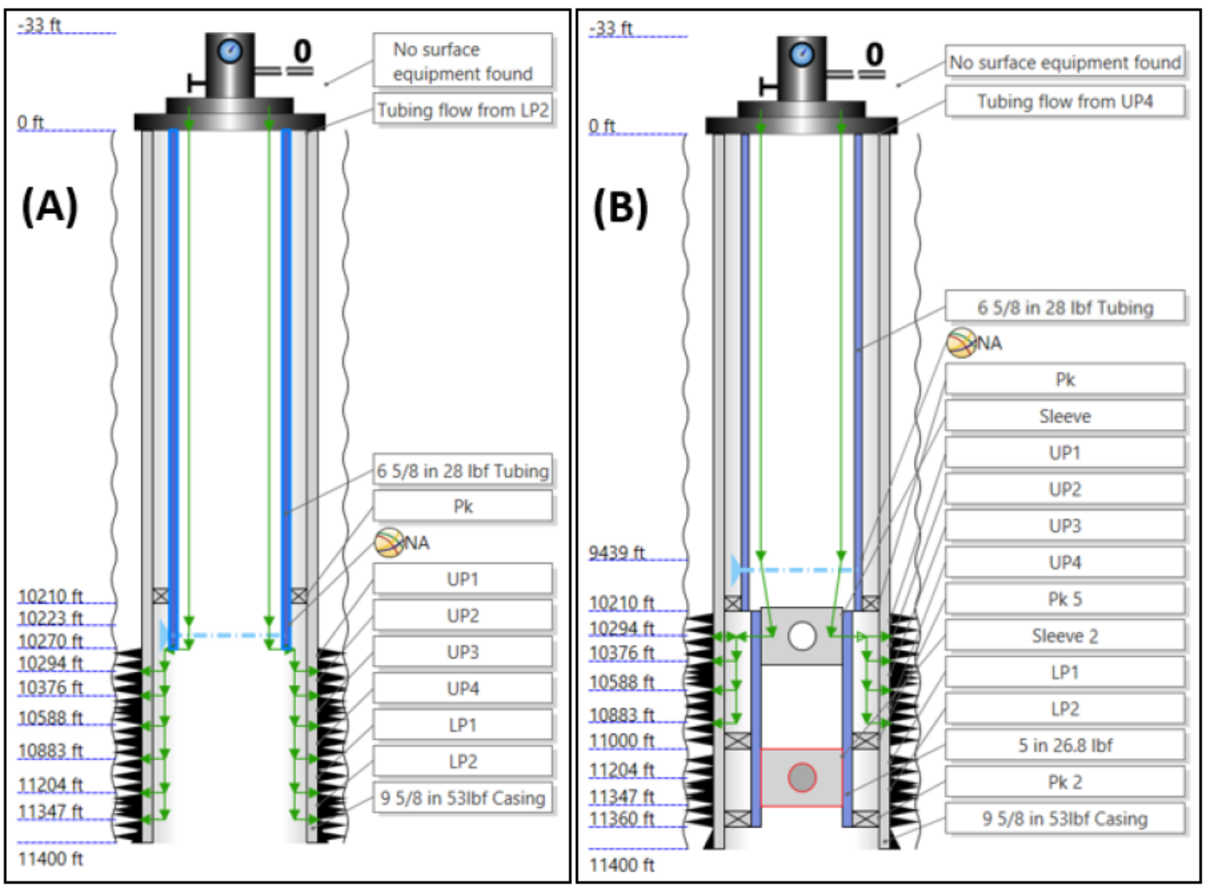

Figure 1. (A) Nodal Analysis Design, LL #2-4 Schematic[1], (B) Nodal Analysis Design, LL #1 Schematic

[1] Surface equipment was not included in the model since it has no effect on downhole flow profiles.

At an injection rate of 1.25 MT/y, the resulting wellhead pressure (no sliding sleeves) is expected to be 1,491 psia, which conforms to the expected delivery pressure (**Figure 2**). If the injection rate momentarily spikes, an injection rate of 1.50 MT/y results in a wellhead pressure of 1,534 psia (**Figure 3**).

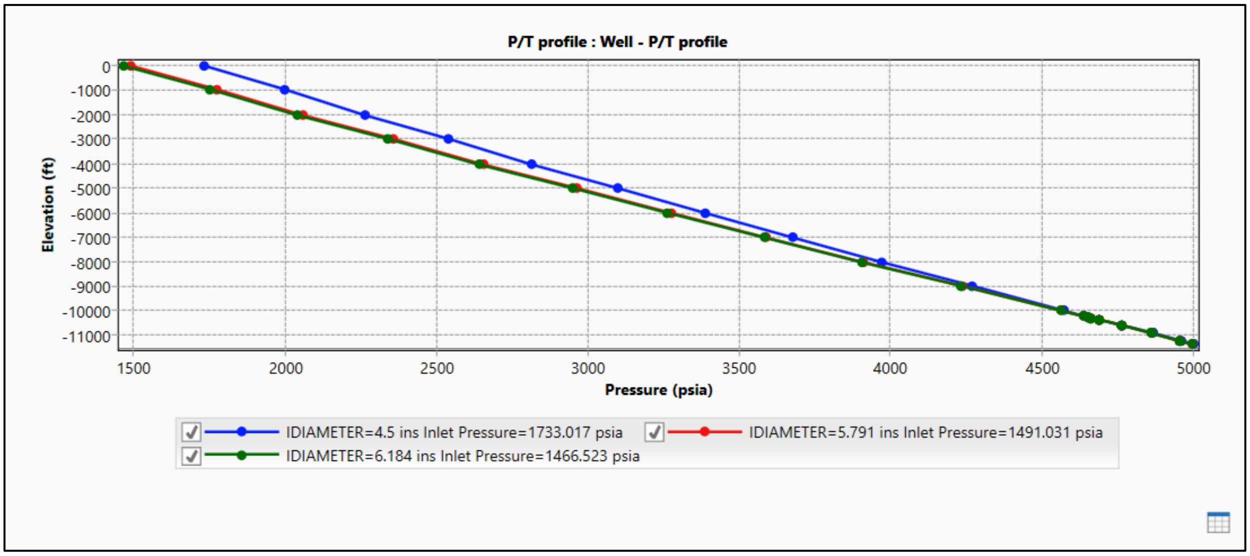

Figure 2. Wellhead Pressure at 1.25 MT/y (No sliding sleeves)

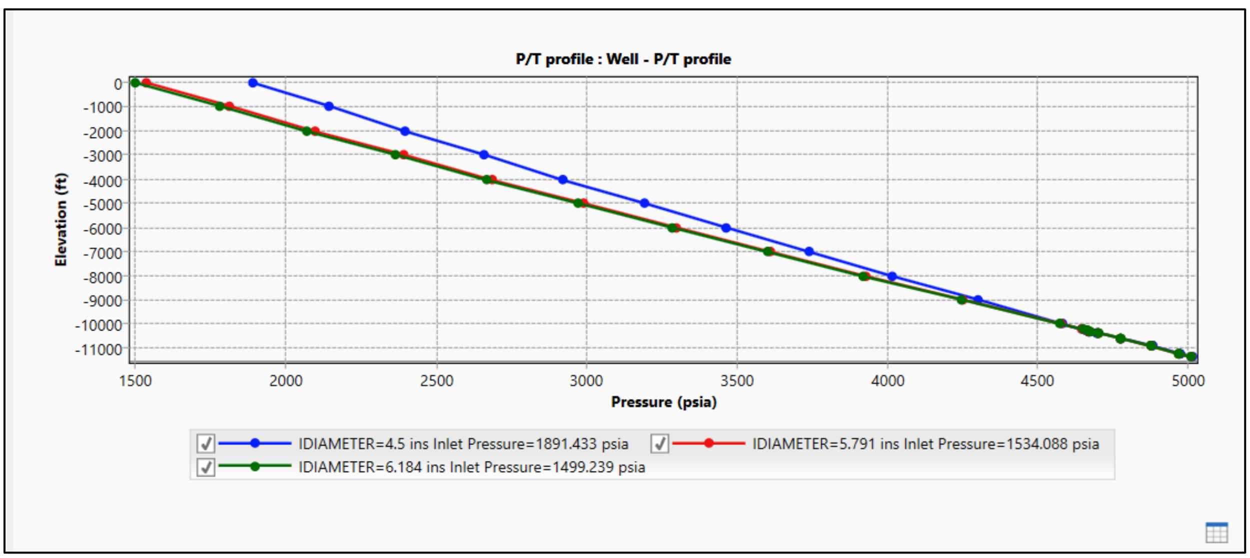

Figure 3. Wellhead Pressure at 1.50 MT/y (No sliding sleeves)

If the sleeve accessing the Lower Paluxy is closed, and only the Upper Paluxy is open to injection, the tubing is still able to support an injection rate of 1.25 MT/y, with a wellhead pressure of 1,500 psia (**Figure 4**). However, if the Upper Paluxy sleeve is closed, and only the Lower Paluxy sleeve is open to injection, an injection rate of 0.25 MT/y results in a wellhead pressure of 1,465 psia (**Figure 5**). Maximum injection wellhead pressure is set forth in **Section *A.5*** of the *Injection Well Operations Plan.*

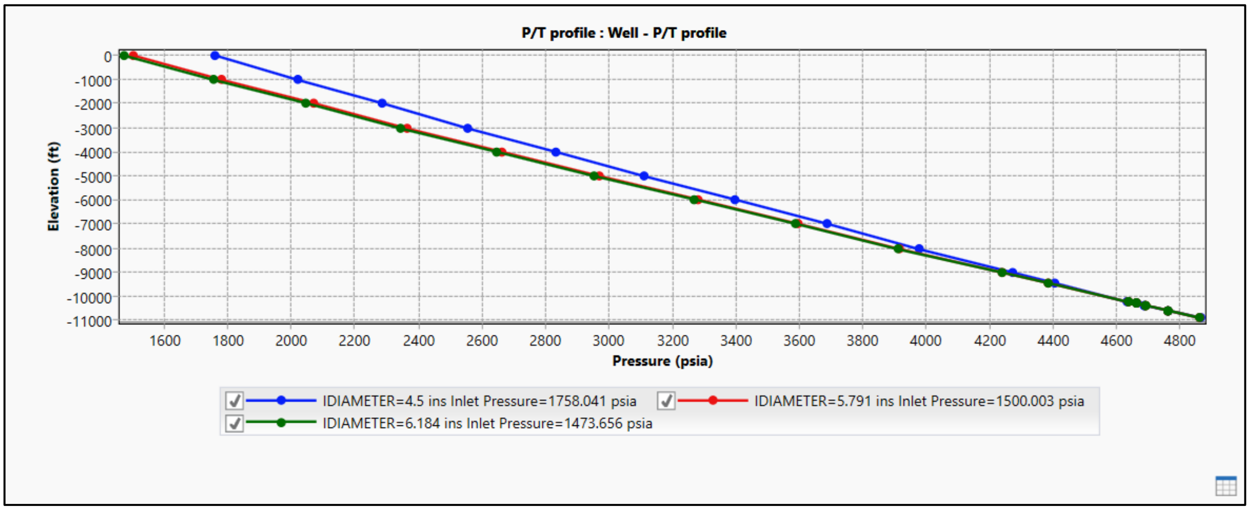

Figure 4. Upper Paluxy Only, Wellhead Pressure at 1.25MT/y

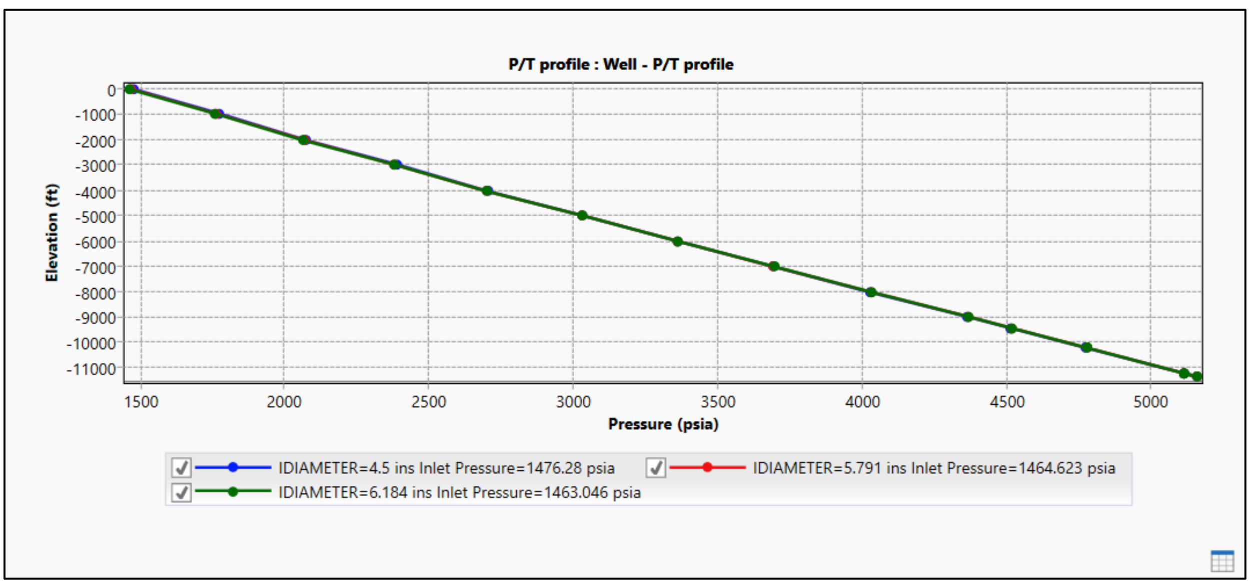

Figure 5. Lower Paluxy Only, Wellhead Pressure at 0.25 MT/y

A.2 Casing Program

Nodal analysis aided in the development of an injection well design to accommodate a 6.625-inch outer diameter (OD) tubing. Additionally, the injection wells have been designed to accommodate the concentric casing sizes required to isolate the injection reservoir from USDWs. Material for the casing was selected to be appropriate for the fluids and stresses encountered within the well [40 CFR 146.86(b)(1)]. For instance, casing strings that will be exposed to injected CO_2 will be 13Cr-L80 steel, which is resistant to corrosion from CO_2.

Lab results have shown the corrosion rate of 13Cr steel in the high-temperature steam environment was less than 0.04 mm/a (Guoqing Xiao, 2020), which is sufficient to retard metallurgical corrosion should moisture or formation fluid come into contact with the CO_2. The entire injection tubing string will be comprised of 13Cr-L80 steel. Similarly, the 9.625-inch-long string casing will be constructed of 13Cr-L80 steel through the injection zone to above the confining zone. In areas where the risk of CO_2 corrosion is not a concern, J-55 mild steel will be utilized. Lithology of the storage reservoir's injection and confining zones are discussed in **Section *B.4*** of the *Application Narrative* and reservoir fluid characteristics are discussed in **Section *B.9*** of the *Application Narrative*. The anticipated composition and temperature of the CO_2 stream, discussed in **Section *A.2*** and **Table 1** of the *Injection Well Operations Plan*, is consistent with that of the U.S. CO_2-EOR industry, where mild steel is used. Constructing the wells with 13Cr steel components should exceed the protection requirements and be consistent with Guoqing Xiao (2020). The planned injection quantity is 1.25 Mt/y of CO_2 per well.

Stresses were analyzed and calculated according to worst-case scenarios, and casing specifications were selected accordingly. **Table 2** below summarizes the results of this analysis. The burst, collapse, and tensile strength of the casing were calculated according to the scenarios defined below and were dependent on fracture gradients, mud weight, depths, and minimum safety factors.

As demonstrated, the safety factors are sufficient in the worst-case scenarios to prevent migration of fluids into or out of USDWs or unauthorized zones (**Table 3**). The casing and tubing materials are designed to be compatible with the fluids encountered and the stresses induced throughout the sequestration project.

Table 2. Load Scenarios Evaluated

Load Name	Description	Casing String
Burst	The largest pressure differential occurs at either casing shoe or surface locations. The shoe scenario assumes formation fracture prior to casing rupture while the surface scenario assumes a gas kick while the wellbore contains drilling mud.	S
Collapse	For collapse consideration, the interior of the pipe is to be considered void and the consideration points are the casing shoe and the top of tail cement.	S
Burst	Cementing operation induces the largest rupture stresses, if lost circulation occurs during cementing, with all the tail cement in the pipe. The drilling fluid is used as a back-up.	P
Collapse	The greatest collapse stress occurs while cementing the casing, with an interior column of mud to counteract the external cement slurries.	P
Burst	The injection process induces the maximum pressure onto the injection tubing and, as such, represents the scenario of investigation.	T
Collapse	The design case for maximum loading occurs during annular pressure testing of the well, which assumes fluid inside the tubing is at a minimum specific gravity.	T
Tension	Tensile strength of the casing is governed by the entire weight of the string being analyzed while accounting for buoyancy effects.	S, P, T

S = surface casing; P = production or long-string casing; T = tubing

Table 3. Calculated Safety Factors for the Proposed Tubular Program

Tubular	Safety Factors		
	Burst (psia)	Collapse (psia)	Tension (lbs)
Surface (S)	3.82	1.61	7.76
Production (P)	1.54	1.82	2.40

A.3 Casing Summary

The injection well design will include the following casing strings: a 20-inch-diameter conductor casing string set at a depth of approximately 60 feet below ground surface (BGS) inside a 26-inch borehole; a 13.375-inch diameter surface casing string set at a depth of approximately 1,800 feet below ground surface (BGS) inside a 16-inch borehole; a 9.625-inch diameter long casing string set at a depth of approximately 11,400 feet BGS inside a 12.25-inch borehole; and a 6.625-inch diameter deep (injection) tubing string set at an approximate depth of 10,950 feet BGS. The 6.625-inch tubing will then crossover to a 5.5-inch diameter tubing string set to a depth of 11,360 feet BGS and be equipped with two sliding sleeves run in series, corresponding with the two injection zones. All casing strings will be cemented to the surface. The borehole diameters are considered conventional sizes for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall to ensure that a continuous cement seal can be emplaced along the entire length of the casing string. **Table 4** summarizes the casing program for the injection well. **Table 5** summarizes properties of each tubular material. Each section of the well is discussed in a separate section below.

Table 4. Borehole and Casing Program for the CO_2 Injection Well

Casing String	Casing Depth (Feet BGS)	Borehole Diameter (in.)
Conductor	60	26
Surface	0-1,800	16
Long String	0-7,250	12.25
	7,250-11,400	

Table 5. Properties of Well-Tubular Materials

Tubular String	Tubular Material (weight/grade/ connection)	Tubular Outside/Inside/Drift Diameter (in.)	Burst (psia) Plain End	Collapse (psia)	Joint Tensile Strength (1,000 psia)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)
Conductor Casing	94 lb/ft, Welded	20 / 19.124 / 18.936 (0.438 in wall)	2,110	520	907	31
Surface Casing	54.5 lb/ft, J-55, STC	13.375 / 12.615 / 12.459 (0.38 in wall)	2,730	1,130	909	31
Long String Casing	53.5 lb/ft, L-80, LTC	9.625 / 8.535 / 8.379 (0.545 in wall)	7,930	6,620	1,047	31
	53.5 lb/ft, CR13-L80, LTC	9.625 / 8.535 / 8.379 (0.545 in wall)	7,930	6,620	1,047	16
Tubing (LL#1 before crossover connection, LL#2, LL#3, and LL#4)	28 lb/ft, CR13-L80, EUE	6.625 / 5.791 / 5.666 (0.417 in wall)	8,810	8,170	693	16
Tubing (LL#1 after crossover connector)	20 lb/ft, CR13-L80, EUE	5.5 / 4.778 / 4.653 (0.361 in wall)	9,190	8,830	503	16

STC – Short Thread Coupling
LTC – Long Thread Coupling
EUE – External Upset End

A.3.1 Conductor Casing

The conductor casing consists of 20-inch diameter mild steel and provides the stable base required for drilling activities in unconsolidated sediment. Depending on wellsite conditions, this can be drilled and installed or driven directly. This section of casing is also cemented in place.

A.3.2 Surface Casing

The surface casing is 13.325-inch diameter 54.5-lb/ft J-55 pipe with short thread couplings (STCs). The metallurgy of this casing string is carbon steel. Surface casing is to be cemented to surface, isolating the USDWs through which the string extends. Following the cement setting, a bond log is run to ensure a sufficient seal to prevent the migration of fluid into USDWs.

A.3.3 Long-String Casing

The long-string casing will be 9.625-inch diameter pipe composed of two sections. The long-string casing is required to extend from the surface to the injection zone [40 CFR 146.86(b)(3)]. The uppermost section (approximately 7,250 feet) will be L-80 53.5-lb/ft carbon steel pipe with long thread couplings (LTCs); the lower section (7,250 to 11,400 feet) will be a corrosion-resistant alloy (e.g., 13Cr-L80 steel) having strength properties equivalent to or better than L-80 53.5-lb/ft pipe with LTCs. A DTS/DAS fiber optic cable will be run outside the casing from surface through the Tuscaloosa Marine Shale and cemented in place with the casing. The DTS/DAS cable will continuously monitor pressure and temperature as part of the mechanical integrity testing (MIT) program outlined in the Testing and Monitoring Plan. Changes in these conditions may indicate unwanted migration of fluids between stratigraphic zones.

A.4 Tubing

The tubing connects the injection zone to the wellhead and provides a pathway for storing CO_2. This design utilizes 6.625-inch 28 lb/ft 13Cr-L80 steel for LL#2, LL#3, and LL#4, which resists corrosion from the injected fluid. The same tubing will be used for LL#1, down to approximately 10,950 feet, above the bottom packer, where a 6.625-inch 28 lb/ft by 5.5-inch 20 lb/ft Crossover Connector will be run in the string to taper down the wellbore diameter to 5.5-inch 20 lb/ft 13Cr-L80 tubing. Across the injection zones in LL#1, sliding sleeves will be utilized in the tubing string. These sleeves will enable two injection zones to be open or closed, independent of each other, to accommodate fluctuations in injection rates due to CO_2 availability. A packer will be placed between the sleeves at a depth of 11,075 feet to isolate injection into the Upper and Lower Paluxy.

At a depth of approximately 10,200 feet, a packer will be set to isolate injection zones from the tubing-casing annulus. At the end of the tubing string, a landing nipple, or "no-go" tool will be run. This will allow a plug to be set inside the tubing at this depth and the packer to be released in order to remove the tubing string if needed. **Table 6** summarizes the packer specifications for the injection well.

Table 6. Packer Specifications

Item	Setting Depth (ft)	Tensile Strength (psi)	Burst Strength (psi)	Collapse Strength (psi)	Material	Length (inches)	OD/ID (inches)	Casing Range (OD in/Drift ID*/lbs.)
Top Packer	10,200	300,000	7,500	7,500	13Cr80	90.78	8.31/4.68	9.625 /8.525-8.379 / 47-53.5#
Bottom Packer	11,075	300,000	7,500	7,500	13Cr80	90.78	8.31/4.68	9.625 /8.525-8.379 / 47-53.5#

* Drift Diameter is the inside diameter that the pipe manufacturer guarantees per specifications. There are minor, allowable fluctuations in ID through the length of the casing, and the Drift Diameter is the smallest ID allowable by API standards. Tools (drill bits, logging tools, packers, etc) can be no larger than the drift diameter to guarantee unrestricted passage through the casing.

Tandem Pressure/Temperature gauges will be hung in the tubing string immediately above the top packer. These gauges are to ensure the integrity of the tubing packer. Taking into account the anticipated formation pressure, temperature, and stress, the grade of tubing was selected with the API specifications outlined in **Table 7**, which includes the calculated safety factors. These safety factors represent sufficient quality standards to preserve the integrity of the injected fluid, the injection zone, and above USDWs. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in subsection C.5.1 below in accordance with 40 CFR 146.88(c).

Table 7. Calculated Safety Factors for the Proposed Injection Tubing

	Safety Factors		
Tubular	**Burst (psia)**	**Collapse (psia)**	**Tension (lbs)**
Tubing	2.75	1.22	2.28

A.5 Cementing Program

This section discusses the types and quantities of cement that will be used for each string of casing. The conductor, surface casing, and deep casing will be cemented to the surface in accordance with requirements at 40 CFR 146.86(b)(3). The proposed cement types and quantities for each casing string are summarized in **Table 8**.

Casing centralizers will be used on all casing strings to centralize the casing in the hole and help ensure that cement completely surrounds the casing along the entire length of pipe. The casing string will be centralized to attempt a minimum of 75% standoff. The actual hole trajectory will be input into the cementing service company's mud removal software to optimize centralizer placement. Centralizers will be placed either over the connections or at mid-joint using stop-rings as appropriate. It is estimated that approximately 150 or more centralizers will be used depending upon the hole trajectory. Except for the conductor casing, a guide shoe or float shoe will be run on the bottom of the bottom joint of casing, and a float collar will be run on the top of the bottom joint of casing.

The long-string casing is to be cemented to the surface and will need to be completed in two stages. To facilitate a two-stage cement job, a multiple-stage cementing tool will be installed at an approximate depth of 5,000 feet. After the completion of the first-stage cement job, the multiple-stage cementing tool will be opened and fluid will be circulated down the casing and up the annulus above the cementing tool for a minimum of 8 hours to allow the first-stage cement job to acquire sufficient gel strength. The lower 4,150 feet (7,250 to 11,400 feet) of the 9.625-inch long-string casing will be cemented with "EverCRETE" (or similar) CO_2 corrosion-resistant cement.

The below table shows the expected volume of cement to be pumped. However, after the drilling of each section, before the casing is run, a caliper log will be used to calculate actual volumes needed to ensure complete coverage of cement to surface, including excess cement. After each string of casing (surface, long string) is cemented in place, an ultrasonic cement imaging log will be run, analyzed and a letter report provided to the EPA Director. If the log shows poor cement coverage, or the top of cement significantly lower than expected, remedial cementing procedures will be used. Drilling out of cement will not proceed until adequate cement coverage is confirmed.

Table 8. Cementing Program

Casing String	Casing Depth (ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (ft)	Cement
Conductor Casing	60	26	20	0-60 (cemented to surface)	Class A with 2% $CaCl_2$ (calcium chloride) and 0.25 lb/sack cell flake; cement weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 77 sacks.
Surface Casing	1,800	16	13.375	0-600 (cemented to surface)	Class A with 2% $CaCl_2$ and 0.25 lb/sack cell flake; weight: 15.6 lb/gal; yield: 1.20 ft^3/sack; quantity: 693 sacks.
Long Casing String – Stage 1	11,400	12.25	9.625	5,000-11,400	Lead-in: 65/35 Pozmix with 2% gel; weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 826 sacks. Tail: EverCRETE CO_2- resistant cement (or similar); weight: 15.92 lb/gal; yield: 1.08 ft^3/sack; quantity: 1,120 sacks.
Long Casing String – Stage 2				0-5,000 (cemented to surface)	65/35 Pozmix with 2% gel; weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 1485 sacks.

See acronym list for definition of abbreviations used in this table.

A.5.1 Annular Fluid

The annular space above the packer between the 9.625-inch long-string casing and the 6.625-inch injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be controlled to remain between 250 psia and 500 psia during injection operations (See **Section *D.2.2.*** of the *Testing and Monitoring Plan* for a full description of the injection well annulus monitoring system. Added to the hydrostatic pressure of the fluid column, this will ensure that the annular pressure downhole will be greater than injection pressure.

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

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

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars [i.e., casings, tubing]) – 10 gal per 100 bbl of packer fluid
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbl of packer fluid
- Spec-cide 50 (biocide) – 1 gal per 100 bbl of packer fluid
- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbl of packer fluid.

These products were recommended and provided by Tetra Technologies, Inc., of Houston, Texas. Actual products may vary from those described above.

A.5.2 Wellhead

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

- 20.75-inch x 13.375-inch, 3,000-psia casing head
- 13.625-inch fiber optic line port/access
- 13.625-inch x 9.625-inch, 5,000-psia casing head
- 11-inch x 7.0625-inch, 5,000-psia tubing head
- 7.0625-inch 5,000-psia full-open master control gate valve
- 7.0625-inch 5,000-psia automated tubing flow control valve
- 7.0625-inch 5,000-psia cross with one (1) 7.0625-inch, 5,000-psia blind flange
- 7.0625-inch 5,000-psia automated tubing flow control valve
- 7.0625-inch x 2.875-inch, 5,000-psia top flange and pressure gauge.

The wellhead and Christmas tree will be composed of materials that are designed to be compatible with the injection fluid. Critical components that come into contact with the CO_2 injection fluid will be made of a corrosion-resistant alloy such as stainless steel. Materials that are not expected to contact the injection fluid, such as the surface casing and shallow portion of the long-string casing, will be manufactured of carbon steel. A preliminary materials specification for the wellhead and Christmas tree assembly is described in **Table 9**, using material classes as defined in American Petroleum Institute (API) Specification 6A (Specification for Wellhead and Christmas Tree Equipment). A summary of material class definitions is provided in **Table 10**. The final wellhead and Christmas tree materials specification may vary slightly from the information given below because neither has been selected yet. An illustration of the wellhead and Christmas tree is provided in **Figure 6.** The flow line leading to the wellhead and Christmas tree will be equipped with an automatic shutoff valve as required in section 146.88.

Table 9. Materials Specification of Wellhead and Christmas Tree

Component		Material Class[a]
Casing Head Housing (for 20-in. surface casing)		DD, EE
Casing Head Spool (for 13-3/8-in. intermediate casing	Casing spool (20-3/4 in. 3K X 13-5/8 5K)	AA, BB, DD, EE
	Casing hanger (20 in. X 13-3/8 in.)	AA, DD
Tubing Spool Assembly (for 9-5/8-in. long-string casing)	Spool	AA
	Casing hanger	AA, DD
Christmas Tree	Tubing head adapter	DD, EE
	Manual gate valve	BB
	Pneumatic actuated gate valves (2)	BB
	Tubing hangar (for 6-5/8-in. tubing)	CC

(a) When multiple classes are given, the highest class applies. Vault uses this convention because not all components are available in all class types.

Table 10. Material Classes from API 6A (Specification for Wellhead and Christmas Tree Equipment)

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
AA – General Service	Carbon or alloy steel	Carbon or low-alloy steel
BB – General Service	Carbon or low-alloy steel	Stainless steel
CC – General Service	Stainless steel	Stainless steel
DD – Sour Service[(a)]	Carbon or low-alloy steel[(b)]	Carbon or low-alloy steel[(b)]
EE – Sour Service[(a)]	Carbon or low-alloy steel[(b)]	Stainless steel[(b)]
FF – Sour Service[(a)]	Stainless steel[(b)]	Stainless steel[(b)]
HH – Sour Service[(a)]	Corrosion-resistant alloy[(b)]	Corrosion-resistant alloy[(b)]

Source: Cameron Surface Systems, Houston, Texas

(a) As defined by National Association of Corrosion Engineers (NACE) Standard MR075.

(b) In compliance with NACE Standard MR0175.

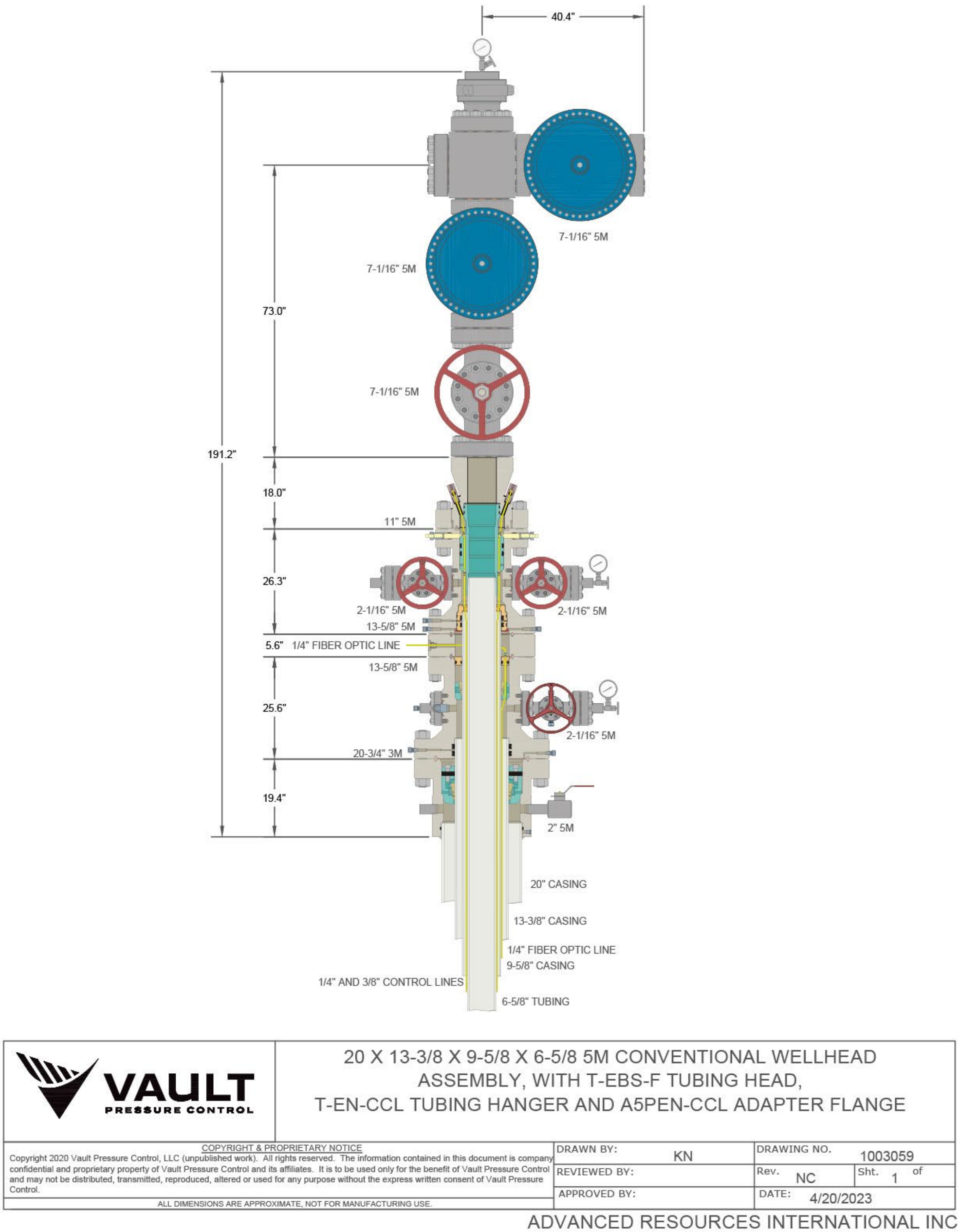

Figure 6. Illustration of the Wellhead and Christmas Tree

A.5.3 Perforations

The long-string casing will be perforated across the Paluxy Sandstone with deep-penetrating shaped charges. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The planned perforation intervals will be set between 10,269 feet and 11,347 feet with 6 shots-per-foot and 60-degree phasing. Proposed perforation interval depths are found below in **Table 11**.

Table 11. Proposed Perforated Intervals

Perforated Zones	Perforated Interval	Top (ft)	Bottom (ft)	Mid-Point (ft)
Upper Paluxy	1	10,269	10,318	10,294
	2	10,351	10,400	10,376
	3	10,433	10,743	10,588
	4	10,809	10,956	10,883
Lower Paluxy	5	11,191	11,217	11,204
	6	11,295	11,347	11,321

A.5.4 Schematic of the Subsurface Construction Details of the Well

A schematic of the Injection Well LL#1 is shown in **Figure 7**. **Figure 8** shows the detail of the perforations, sliding sleeves, gauges, and tubing string packers. A schematic of Injection Wells LL#2, LL#3, and LL#4 is shown in **Figure 9.**

As discussed in the previous sections, the injection well(s) will include the following casing strings: a 20-inch diameter conductor string set at a depth of approximately 60 feet BGS; a 13.325-inch diameter surface string set at a depth of approximately 1,800 feet BGS; and a 9.625-inch diameter deep string set at an approximate depth of 11,400 feet BGS. All depths are preliminary and will be adjusted based on additional characterization data obtained while drilling the CO_2 injection wells. At minimum, the conductor, surface, and long casing strings will be cemented to surface.

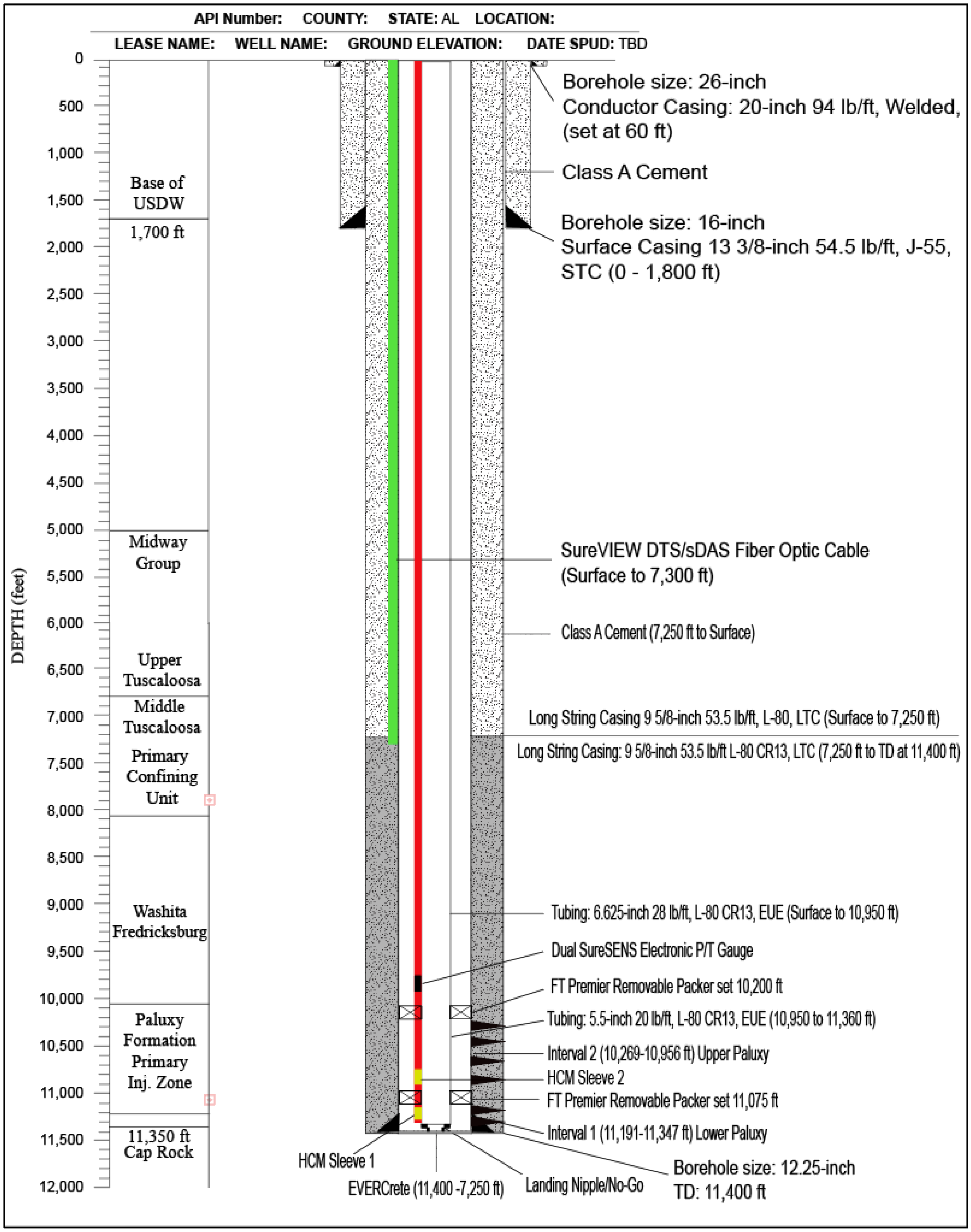

Figure 7. LL#1 Injection Well Schematic

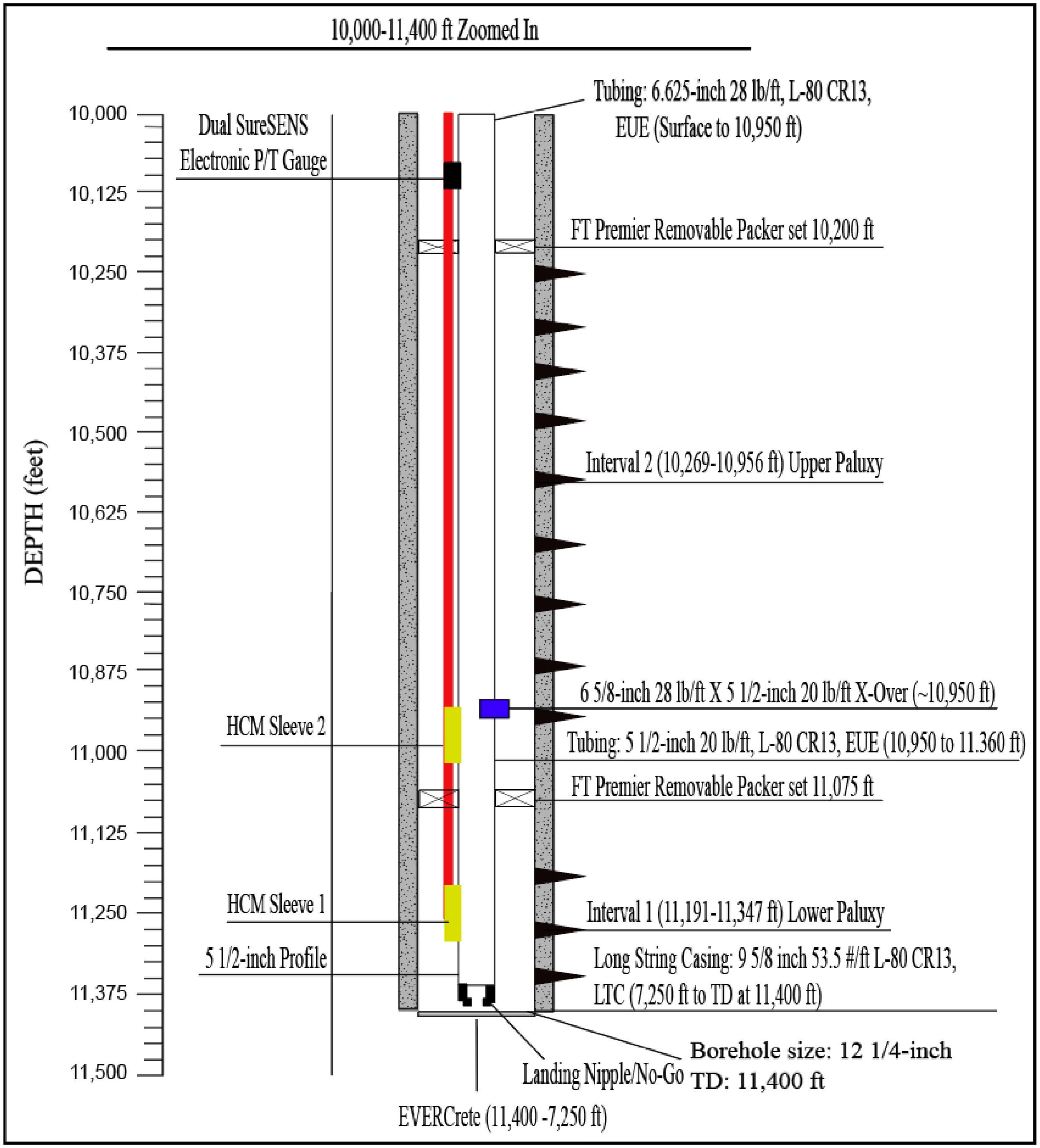

Figure 8. LL#1 Injection Well Schematic (Zoomed 10,000-11,400 ft.)

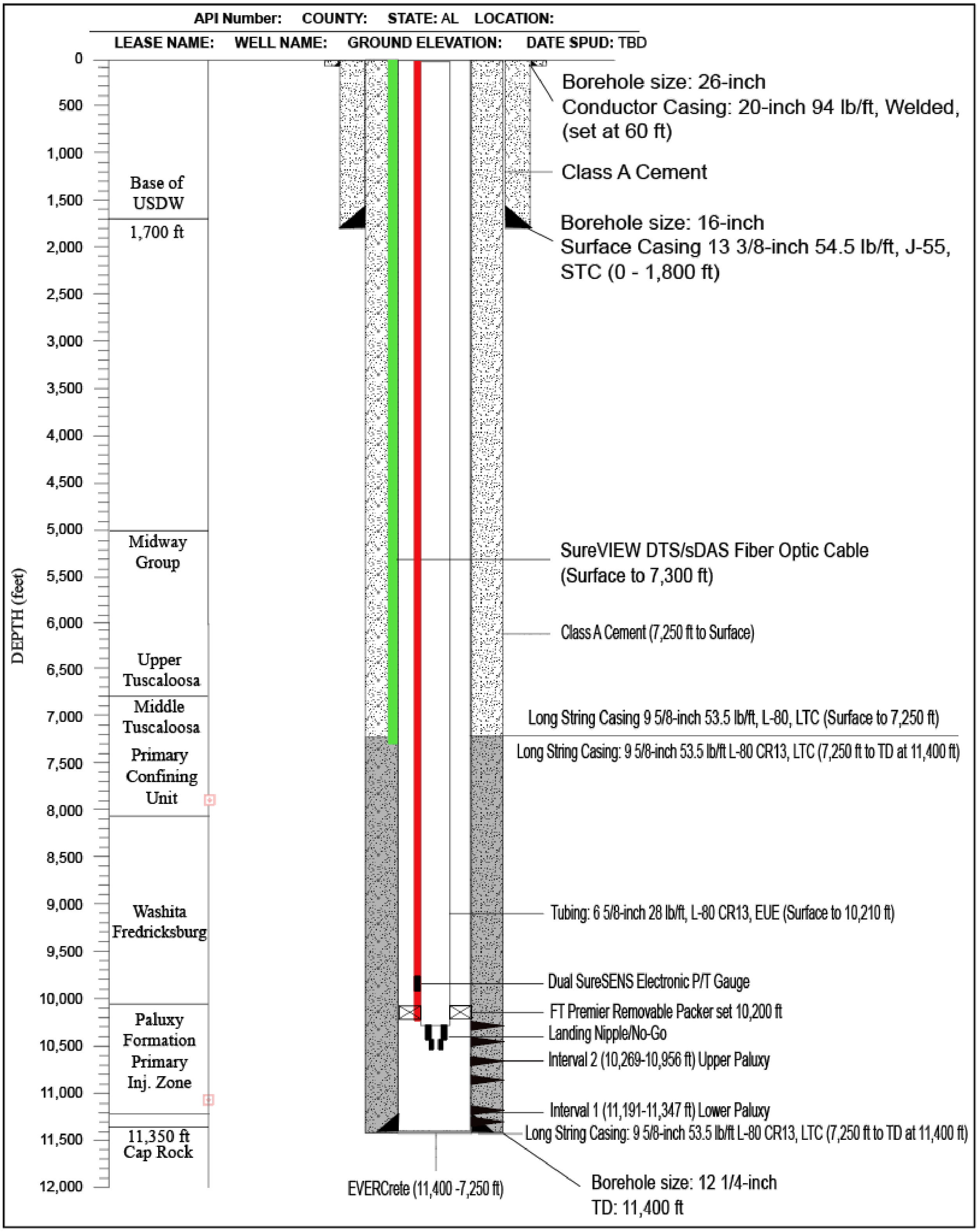

Figure 9. LL #2, #3, and #4 Injection Well Schematic (No Sleeves)

A.6 Drilling Operations and Safety

A blow out preventer (BOP) of a design and construction to easily handle pressures that can be present down to a depth of 10,000' or total depth (TD) will be placed on the well following the setting and completion of each casing string. The BOP will be in place during all drilling, testing, and logging operations, until the final wellhead is installed. Upon each installation, the BOP will be tested before drilling operations continue. Pressure testing will be conducted to 80% of the maximum pressure rating, and above expected drilling pressures.

To further control well pressure during drilling operations, a water-based mud system will be used. The basic mud mixture will consist of approximately 9.2-9.5 pounds per gallon drilling mud, comprised mainly of water combined with a gelling additive and barite. Mud weight will vary to balance formation pressures encountered. Total volume will be dependent on actual field depths. If field observations, such as formation water, formation locations, etc., show that a heavier mud density is needed to prevent fluid migration between formations, the necessary amendments and additions will be made to the mud mixture.

It is not expected that the drilling will encounter any H_2S gas; however, as a precaution, a H_2S detector ("gas sniffer") will be on location and continuously monitor for H_2S gas during the drilling procedure. A pre-project evacuation plan will be developed and enacted should any H_2S be detected. The onsite geologists (mud loggers) will operate the H_2S detector and immediately notify the driller if H_2S gas is detected. The driller has the ability to shut down the drilling rig, shut-in the wellbore with the BOP (blowout preventer), and evacuate the location, until the seriousness of the problem can be properly and comprehensively evaluated. The gas monitoring equipment is generally calibrated by the mud logger every day.

A true vertical wellbore is necessary to mitigate risk of sticking logging tools and to maximize efficient cement coverage between casing and the wellbore. Certain drilling and stratigraphic conditions can cause unexpected tortuosity in the wellbore during drilling operations. To monitor wellbore verticality, the driller will conduct wellbore surveys regularly. If the wellbore strays too far from vertical, adjustments will be made to the drilling bit, drilling rate, etc. as needed to return to true vertical. If verticality cannot be maintained with such adjustments, directional drilling tools will be used to ensure minimal tortuosity.