CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Bluebonnet Sequestration Hub

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1.0 Project Background and Contact Information

Facility name: Bluebonnet Sequestration Hub
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 Wells.

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

The advancement of carbon capture and sequestration (CCS) technology is critically important in addressing CO_2 emissions and global climate change concerns. The Bluebonnet Sequestration Hub is designed to demonstrate utility-scale integration of transport and permanent storage of captured CO_2 into a deep geologic formation.

The Bluebonnet Hub will display that the geologic sequestration process can be deployed safely, ensuring retainment of the injected CO_2 within the intended storage reservoir and protection of the underground sources of drinking water (USDW). By using safe and proven pipeline technology, the CO_2 will be transported to a storage site located in Chambers County, Texas, where it will be injected into the Lower Miocene, Frio, and Hackberry formations utilizing six newly built dedicated CO_2 injector wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7. A total of 157.2 million metric tons (MMT) is estimated to be stored during the 20-year injection period.

The Bluebonnet Hub is strategically located near a concentration of industrial power-generating plants, refineries, and chemical production, natural-gas processing, and natural-gas liquefaction facilities along the Gulf Coast, from the Beaumont/Port Arthur area to the east and to the Houston area in the west.

The project will get custody of the CO_2 captured by these emitters through offtake agreements and transport the captured CO_2 via a third-party pipeline to the site, where the CO_2 will be stored. Bluebonnet Sequestration Hub, LLC, (through its affiliates) has leased approximately 70,000 acres across Chambers, Liberty, and Jefferson Counties, as part of the project development. These

agreements include rights to sequester CO_2 in the pore space, surface use, and land access necessary to facilitate this proposed carbon sequestration project.

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒Required project and facility details ***[40 CFR 146.82(a)(1)]***

2.0 Site Characterization

The Bluebonnet Sequestration Hub is located approximately 60 miles east of Houston on the Lower Coastal Gulf Plain, where the topographic elevation ranges from 25 – 40 ft above mean sea level, with site access available via roads.

The surface geology of the proposed site is characterized by the clay, silt, and sand-rich deposits of the Beaumont Formation. The site contains several freshwater bodies such as lakes/ponds, canals, ditches, and a slow-moving bayou. The site is partially classified as farmed palustrine wetland among minor other wetland types.

No previously recorded National Register of Historic Places (NRHP) districts or properties, sites designated as State Antiquities Landmarks, Recorded Texas Historic Landmarks, or historical markers are within the project Area of Review (AoR). The Texas Archeological Sites Atlas (TASA) revealed no previously recorded archaeological sites within 0.5 mile of the proposed project area.

No schools, hospitals, or nursing homes are known within the AoR. There is a local small-craft airport, a major interstate (I-10), seventy-five residential houses or small farms, and one commercial site within the boundaries of the AoR.

No Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), aka Superfund, or Resource Conservation and Recovery Act (RCRA) sites were identified. No springs, no mines or mineral deposits, and no quarries were identified in the AoR.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled and completed Encanto 01 as a stratigraphic test well in 2022-2023, and acquired an extensive set of site-based data to complete the site characterization and AoR delineation. The project also drilled two shallow water well to refine the base of USDW with multiple fluid samples above and below the USDW and performed additional characterization in the Miocene Composite Confining zone.



The Bluebonnet Sequestration Hub accommodates a stacked storage complex, located in a structural province called the Houston Embayment, into which the Houston Delta deposited thick Tertiary siliciclastic sediments. In this embayment, the formation dip is relatively flat and steepens

with depth at varying rates ranging between 2.31 – 3.38°. The present-day structure is oriented towards the Southeast, i.e., in the direction of the Texas Gulf coastline. Tertiary sediments were deposited by fluvial-deltaic processes associated with the Houston Delta. This resulted in a series of gulfward-thickening formations, comprised of stacked porous sandstones overlain by confining low-permeability strata.

Within the Bluebonnet Sequestration Project site, areal sand trends of the Miocene, Frio, and Hackberry were mapped, providing largescale storage capacity, which are capped by five confining zones.

2.1 Regional Geology, Local Structural Geology, Injection & Confining Zone Summary [40 CFR 146.82(a)(3)(vi)], [40 CFR 146.82(a)(3)(iii)]

The Bluebonnet Sequestration Hub is located on the Texas Gulf Coast, approximately 20 miles inland, within a structural province called the Houston Embayment, into which the Oligocene-aged Houston Delta, and the Lower Miocene-aged Newton fluvial system and Calcasieu delta systems deposited Tertiary siliciclastic sediments. These sediments were transported to the coastal margin by rivers and subsequently deposited in deltas or reworked by marine processes.

Three examples of these fluvial-deltaic siliciclastic sedimentary systems are the Frio, Hackberry and Lower Miocene formations, which are the three proposed injection zones for permanent CO_2 storage. The deposition of these gulfward-prograding depocenters was interrupted repeatedly by marine transgressions during the Oligocene, where the continental platform was submerged over a widespread period. These flooding events reflect increases in sea level and associated shale deposition, one of which is the prominent regional marine shale, the Anahuac Formation, which represents one of the five proposed confining units, capping the proposed Frio and Hackberry Injection Zones. The Lower Miocene Confining zone and Miocene Composite Confining Zones capping the Lower Miocene Injection Zone, however, are mostly composed of nonmarine coastal plain mudrocks, because at that time the system had evolved into a terrestrial environment.

At the time of deposition, the Bluebonnet Sequestration Hub was located on the landward updip stable shelf of the Gulf Coast basin, where contemporaneous growth faults developed parallel to the shelf margin and syndepositional movement resulted in sediment thickening on the downthrown side of the faults. Various faulting styles within the Bluebonnet 3D seismic region were evaluated extensively to ensure that the AoR selected for the Bluebonnet Sequestration Hub has no faulting that would impact the integrity of the storage complex.

The proposed storage complex includes, from top to bottom (shown in Figure NAR-2):

- Miocene Composite Confining Zone (upper most confining system)
- Lower Miocene Confining Zone
- **Lower Miocene Injection Zone**
- Anahuac Confining Zone
- **Frio Injection Zone**
- Frio Confining Zone
- **Hackberry Injection Zone**

- Hackberry Confining Zone

Only modeling purposes in CMG the study was divided into two storage complex the Oligocene Storage Complex and the Miocene Storage Complex. The Oligocene Storage Complex includes the formations from the Hackberry Confining Zone to the Anahuac Confining Zone. The Miocene Storage Complex includes the formations from the Anahuac Confining Zone to the Lower Miocene Confining Zone.

The **Hackberry Injection Zone** is laterally continuous in a north-south dip direction and is better developed in the northern updip part of the proposed AoR and thins toward the south and downdip. The Hackberry Injection Zone is also continuous in an east-west strike direction within and beyond the AoR, where minor thickness changes occur as well. The sandstones within the Hackberry Injection Zone were likely deposited in a proximal delta front and are characterized by high porosity and permeability, both critical parameters for input in the storage capacity and injectivity estimations.

The **Frio Injection Zone** (sandstones) are composed of a series of fluvial/deltaic and marginal-marine to nonmarine sands. Based on whole core data, the internal architecture of the Frio Injection Zone reservoir sandstone covers a range from a terminal distributary channel to a proximal delta front. These sands exhibit high porosity and permeability as well. The structure of the injection zone is a gently southeast-dipping monocline inside the proposed AoR. The Frio Injection Zone is laterally continuous in a north-south dip direction, beyond the limits of the AoR. The Top, Mid, and Low Frio log signatures are correlative and very similar among the offset wells, which indicates preferred connectivity of reservoir properties in a dip direction. The Frio Injection Zone is also laterally continuous in an east-west strike direction, beyond the limits of the AoR; however, small scale well-to-well lateral facies changes are expected, affecting the injectivity within the multiple stacked flow units of the Frio formation due to sedimentary distribution patterns, which are oriented perpendicular to the coastline.

The **Lower Miocene Injection Zone (sandstones)** is characterized by a fluvial-deltaic system that received sediment from the north. Multiple stacking of sedimentary deposits is observed including meander belts, storm washover deposits and crevasse splays in a mixed load system. These Lower Miocene sandstones are fine- to medium grained, very unconsolidated and contain sediment structures ranging from massive to low- and high-angled cross stratification as well as soft-sediment deformation. The porethroats are large and well interconnected, resulting in high porosity and permeability measurements. Different depositional environments exist within the individual subzones, which are perforated and injected into separately at different times.

The **Hackberry, Frio, and Anahuac Confining Zones** are laterally continuous in north-south dip and east-west strike directions, with typical shale thickening towards the south and downdip. These marine transgressive shales reflect flooding events when the Gulf Coast was submerged under water due to rises of sea level and thus are excellent stratigraphic markers. Sequence stratigraphic analysis confirms the continuity of these confining zones. These compact shales are of marine origin and contain varying amounts of silt and bioturbation, depending on water depth. Overall, they are characterized by low permeabilities. Clay speciation is dominantly illite/smectite. Textural and mineralogical clay alignment varies among the multiple confining zones. Depending on the individual rock fabric, mineralogy, porosity, permeability, and capillary pressure measurements,

these shales offer good to excellent seal potential to contain the injected CO_2 within the injection zones.

The **Lower Miocene and Miocene Composite Confining Zones** are characterized by a paleosol, silty calcareous mudstones and non-silty lime mudstones. The depositional environment for the paleosol of the Lower Miocene Confining Zones is a coastal marsh. The paleosol can be hematitic where iron was oxidized, resulting in a red color. The common texture in the paleosol is mottled, potentially caused by rooting, and burrowed, and contains many small calcareous nodules. Fine-grained interbedded sandstones are present as well representing storm washover deposits or crevasse splays. The mineralogical composition consists of clays, which are dominantly illite/smectite, calcite, quartz, and minor plagioclase, K-feldspar, hematite, pyrite, and anatase. In the sequence stratigraphic framework, the paleosol is a weathering surface, which is a sequence boundary that caps the Lower Miocene sandstones. Based on the fabric and mercury injection capillary pressure (MICP) data, these non-silty lime mudstones have a competent sealing capacity.

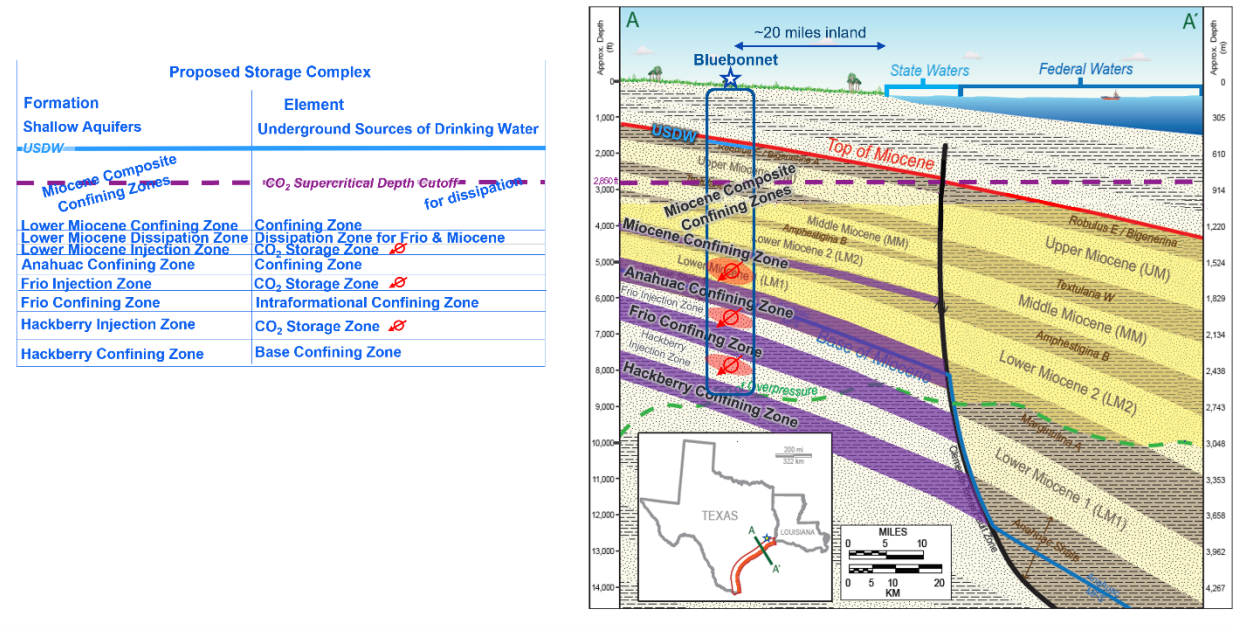


Figure NAR-2: Proposed storage complex at Bluebonnet Sequestration Hub, identifying formations and elements of the storage complex. This permit requests approval for CO_2 injection into the Hackberry, Frio, and Lower Miocene sandstones, utilizing the Anahuac, Lower Miocene Confining zone and the Lower Miocene Composite Confining zones as containment. After BEG 2017.

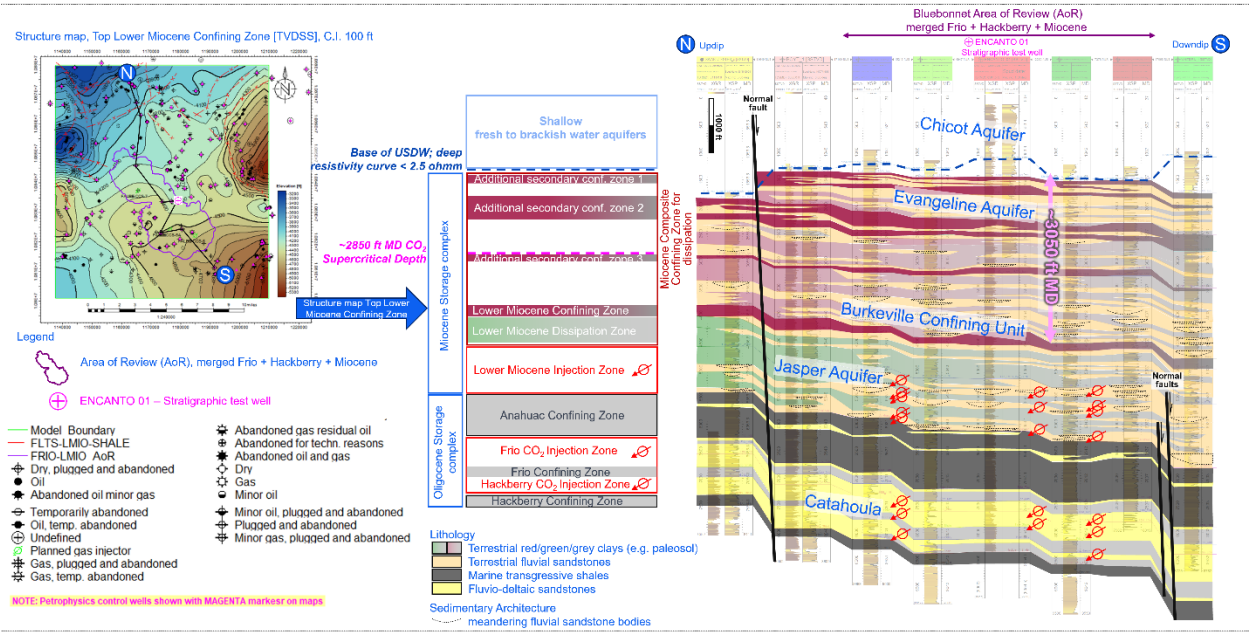


Figure NAR-3: Regional structural dip cross section through the Area of Interest (AOI), highlighting the proposed storage complex; scale 1:8,000. The proposed CO_2 injection zones are the Hackberry, Frio, and Lower Miocene sandstones. The proposed confining zones to contain the sequestered CO_2 within the subsurface are the transgressive marine Hackberry, Frio, and Anahuac shales, as well as the terrestrial Lower Miocene Confining Zone and the Miocene Composite Confining Zones. Major faults are highlighted in black. The base of Underground Sources of Drinking Water (USDW), below which TDS>10,000 mg/L is shown in dashed blue.

2.2 Faults and Fracture Analysis and Structural Styles [40 CFR 146.82(a)(3)(ii)]

The AoR was chosen due to the lack of seismic-scale faulting within the Frio Confining Zone, Anahuac Confining Zone, Lower Miocene Confining Zone and the Miocene Composite Confining Zone (Figure NAR-4). The structural styles interpreted from 3D seismic data include regional growth faulting, salt doming, transtensional faulting, and growth fault reactivation. All of these identified structural styles fit within the larger regional context and are common along the Texas Gulf Coast. Fault interpretation was manually performed with additional context provided by seismic attribute enhancements. Large-scale movement of the regional faults ceased prior to the end of Frio deposition and strain resulting from subsequent loading is concentrated more discreetly along select zones of weakness.

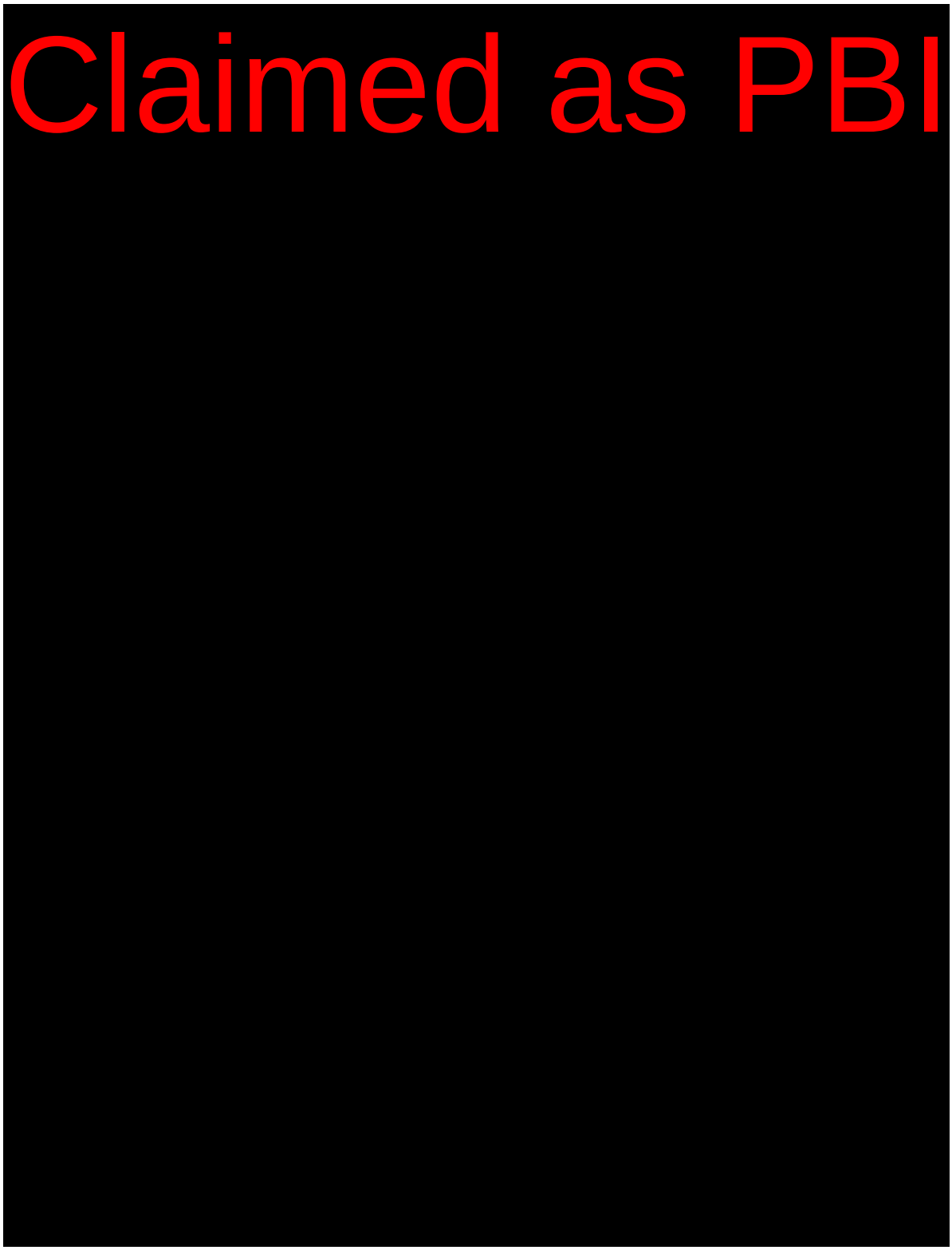


Figure NAR-4: Example map view of fault likelihood extraction on confining zone surfaces with 3D seismic cross section for reference. There is no evidence for faulting within the AoR at the Top Anahuac, the Top Frio Confining Zones, the Top of Lower Miocene Confining Zone. The Top Hackberry Confining Zone displays patterns from underlying Vicksburg faults, but no offset is visible.

Fault seal analysis was performed on all faults included in the geomodel. Two techniques were performed, shale gouge ratio and CO_2 column height modeling (Figure NAR-5). The results from the independent techniques are complementary and demonstrate that the fault offset is sufficiently large for the modeled faults to seal in all the examined confining and injection zones.



Figure NAR-5: Fault B06, a Frio growth fault that rises nearly to the surface within the model, is the most proximal updip fault to the AoR. Within the injection and confining intervals, fault offset is sufficient to create seals within porous lithologies.

2.3 Petrophysical Information [40 CFR 146.82(a)(3)(iii)]

In the geomodel for the Oligocene storage complex, the net effective porosity in the main injection zones, Frio and Hackberry Injection Zones range from 2 to 17%, with a net sand thickness from 18 to 202 ft and an average permeability that ranges from 49 to 425 md. The confining zones' net effective porosity ranges from 0 to 2%, the gross thickness from 192 to 683 ft, and an average permeability from 1 to 29 md. The average reservoir properties are calculated with the volume of shale cutoff $\leq$ 45%.

In the Miocene storage complex, the average of the effective porosity is 20%, with an average gross thickness of 1,003 ft and an average permeability of 3.8 darcies. In the Lower Miocene Confining Zone, the average effective porosity is 11%, with a gross thickness of 168 ft and an average permeability from 62 mD (Figure NAR-6).

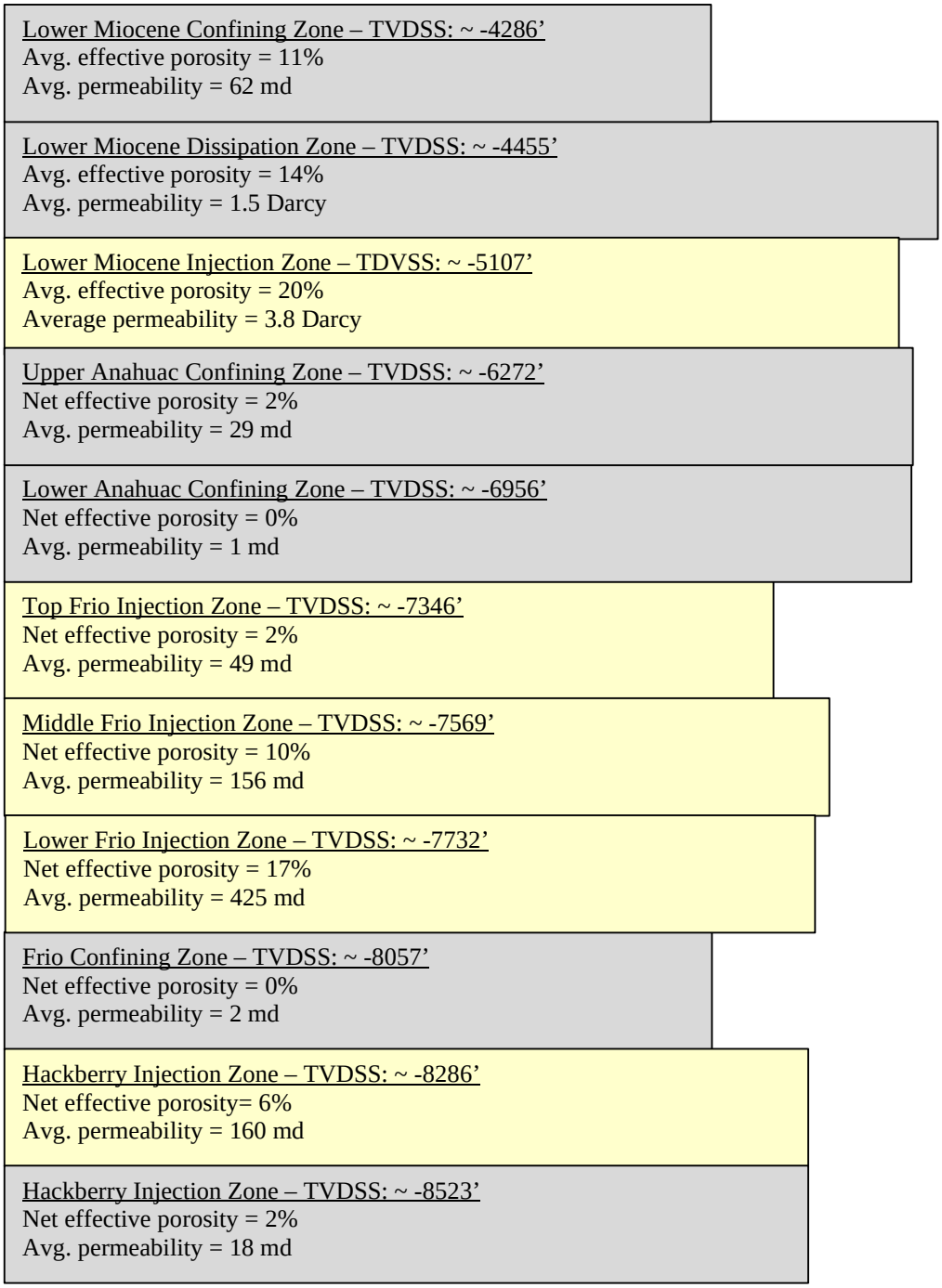


Figure NAR- 6 : Geomodel net effective porosity, permeability, net sand and thickness over the injection's zones (Average reservoir properties used <= 45% shale as a cutoff) for Frio and Hackberry Injection Zones. For Miocene injection and confining zone, we are using average effective porosity calculated in the petrophysical analysis, permeability and gross thickness.

2.4 Seal Capacity Analysis in Confining Zones Summary [40 CFR 146.82(a)(3)(iii)]

The Bluebonnet Hub project team performed the seal capacity analysis for the confining zones utilizing data from MICP (Mercury Injection Capillary Pressure). The project also performed additional tests to obtain the threshold entry pressure (TEP). The integration of MICP seal capacity analysis and TEP results obtained so far are explained in Appendix A.

The seal capacity of a particular formation or zone will vary based on the pore system. The Lower Miocene Confining Zone, Anahuac Confining Zone, and Hackberry Confining Zone are composed of layers that are highly effective as confining zones, intercalated with some slightly transmissive layers that, all together, provide the seal capacity of the zone. Table NAR-1 shows the results of the seal capacity analysis for each of the confining zones in terms of displacement pressure and reservoir height. Details of the seal capacity analysis for each confining zone are presented in the Appendix A of the AoR and Corrective Action Plan of this application.

Table NAR-1: Displacement pressure and reservoir height.

Confining zone	Surface	Sample	Depth	Bi-modal	Entry H @ Res	Displacement H @ Res	Avg. H Bi-modal	Comment	Avg. Displacement pressue on Bi-modal (psi)	Avg. H Uni-modal	Comment	Avg. Displacement pressue on Uni-modal (psi)
Adtl. Comp. Conf. Zone	Seal3 bellow USDW (base)	31m - RSWC	3399.97		563.264	2194.699384				563'	We need to inj. on over 563' to penetrate the system	2193
		13m - RSWC	4122.98		563.264	2192.162159						
Confining zone for the Miocene and FRIO injection	Miocene confining zone	5HCm	4372.70	X	55.18	103.08	68'	We need to inject on over 68' to penetrate the bi-modal samples	228	915'	We need to inject on over 915' to penetrate the system	3300
		1VCm	4373.00	X	58.81	231.35						
		4VbCm	4376.20		908.03	3105.55						
		11HCm	4376.70		908.44	3560.48						
		7VbCm	4396.00	X	90.69	349.77						
		48HCm	4397.70		908.24	3560.19						
		72HCm	4414.50		908.20	3560.02						
		10VbCm	4415.00		1041.34	3105.53						
		6M - RSWC	4415.00		816.99	3171.53						
Confining zone for FRIO injection	Anahuac confining zone (upper)	18VCm	6569.20	X	67.51	304.41	48'	We need to inject on over 48' to penetrate the bi-modal samples	168	1117'	We need to inject on over 1117' to penetrate the uni-modal samples	6148
		167HCm	6569.70	X	48.71	134.11						
		20VCm	6573.00	X	29.89	67.61						
		175HCm	6574.00		1193.19	6149.09						
		23VCm	6585.35		1041.58	6148.89						
	Anahuac confining zone (lower)	197HCm	6955.95		1041.45	4678.92				1122'	We need to inject on over 1122' to penetrate the uni-modal samples	4455
		217HCm	6967.70		1042.22	4679.89						
		28VaCm	6967.90		791.99	2061.23						
		227HCm	6973.10		1368.25	4678.74						
		29VCm	6973.40		1368.22	4678.59						
Basal confining zone for FRIO and Hackberry injection zone	Hackberry confining zone	38VaCm	8451.30	X	18.98	68.80	38'	We need to inject on over 38' to penetrate the bi-modal samples	106	1380'	We need to inject on over 1380' to penetrate the uni-modal samples	5413
		300HCm	8451.70	X	67.54	176.26						
		316HCm	8461.70		1568.29	6148.59						
		41VaCm	8463.00	X	23.00	77.44						
		327HCm	8468.70		1192.93	4677.89						
		42VCm	8469.00	X	42.97	103.08						

2.5 Geochemical Modeling [40 CFR 146.82(a)(6)]

The Bluebonnet Hub project team conducted a geochemical equilibrium modeling to identify primary chemical reactions (solid and aqueous phase) to be included into the reactive-transport simulations and provide an initial assessment of the CO_2 compatibility with rocks and fluids present in the confining and reservoir zones. Lower Miocene and Frio/Hackberry geochemical interactions were modeled separately as two independent systems and include: (1) Frio and Hackberry Injection Zones and Anahuac Confining Zone (AOR Section 4.11), and (2) Lower Miocene Injection Zone, Lower Miocene Dissipation and Lower Miocene Confining Zones (AOR Section 5.14). The modeling included brines speciation, geochemical baseline prior injection, and CO_2 interaction with reservoir brine and minerals.

Fluid-rock interactions were found to be largely similar for the Lower Miocene and Frio/Hackberry geochemical models. Quartz and smectite are the most stable phases initially present in the injection zones. Lower Miocene and Frio/Hackberry Injection Zones simulation results show plagioclase (anorthite) dissolution as CO_2 dissolved in water shifts the equilibria to more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite. Lower Miocene and Anahuac Confining Zones shows overall lower reactivity compared to their respective Injection Zones, associated with higher clay contents and corroborating literature findings that suggest CO_2 sequestration has negligible effects on confining zone integrity.

Reactive-transport simulations were conducted to evaluate geochemical impacts on reservoir storage capacity, possible injectivity modification, and long-term trapping mechanisms. Porosity slightly increased with a maximum of 0.3% and 0.5% for the Lower Miocene and Frio/Hackberry Injection Zones from the start of injection up to about 100 years after injection. Results at long timescales (100s of years) post-injection show injection zones decrease in porosity due to calcite and kaolinite precipitation. Maximum porosity reduction from mineral precipitation was about 3.5% in the region where the CO_2 plume contacted the reservoir.

Porosity remained unchanged for the Lower Miocene and Anahuac Confining Zones in reactive-transport models, however geochemical equilibrium modeling showed CO_2-rock interactions in confining zones would yield a decrease in porosity. Lower Miocene and Anahuac Confining Zones have low permeability and small fluid mobility, and no significant changes are observed in the current models that would comprise their integrity.

The main trapping mechanisms during injection periods are the super-critical phase as mobile and trapped CO_2. Post-injection, super-critical mobile CO_2 steadily decreases, reaching close to zero at long timescales. Mineral CO_2 storage is negative during injection periods due to calcite dissolution and release of HCO_3^-. Trapping of CO_2 predominantly occurs in a residual phase for several hundred years post-injection, during which time CO_2 is slowly trapped as carbonate precipitation. Mineralization (calcite) of injected CO_2 eventually becomes the dominant and permanent CO_2 trapping mechanism.

2.6 Geomechanics Study [40 CFR 146.82(a)(3)(iv)]

In the case of CO_2 injection into the reservoir, pore pressure and horizontal principal stress magnitudes increase while decreasing the magnitude of the effective principal stresses. The stress model was constrained by core measurements and calibrated to pressures and interpretations of minimal principal horizontal stress from wellbore pressure tests. Pore pressure increases required to cause failure on a hypothetical, optimally oriented fault and matrix are summarized in Table NAR-2. The Mohr Coulomb failure analysis was conducted at a particular depth and is representative of the entire formation.

Table NAR-2: Summary of pore pressure increase (psi) required to cause failure in a hypothetical, optimally oriented fault and matrix in formations identified as confining and injection zones.

Formation	Depth (ft TVD)	ΔP_{pore} Hypothetical Fault Activation Pressure (psi)	ΔP Matrix Failure (psi)
Lower Miocene Confining Zone	4,500	1,660	1,780
Lower Miocene Injection Zone	5,350	1,600	1,915
Anahuac Confining Zone	6,800	2,000	2,500
Frio Injection Zone	7,800	1,660	2,450
Hackberry Confining Zone	8,200	1,800	2,500

The maximum expected increase in well bottomhole pressures for Lower Miocene, Frio, and Hackberry Injection Zones are 174 psi, 256 psi and 795 psi respectively.

2.7 Hydrogeology and Underground Source of Drinking Water [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

Groundwater production for drinking and municipal use in Chambers, Liberty, and Jefferson Counties, Texas, is primarily sourced from the Chicot Aquifer, the shallowest of three primary aquifers that make up the overall Gulf Coast Aquifer. The primary recharge mechanism for fresh groundwater is precipitation and infiltration that has not been consumed as runoff or stream flow. Aquifers under the Chicot Aquifer in the project area are generally considered too saline for drinking water and few water supply wells in the area penetrate the deeper Evangeline and Jasper Aquifers. Figure NAR-7 shows the geologic and hydrogeologic units of the Gulf Coast Aquifer system.

The USDW is defined by the Environmental Protection Agency (EPA) as an aquifer or part of an aquifer that contains fewer than 10,000 ppm total dissolved solids (TDS). Publicly available studies suggest base USDW depth ranges from 1,000 to 2,000 ft MD (lower Chicot Aquifer) across Chambers and Jefferson Counties. Within the Bluebonnet Sequestration project site, USDW depth ranges between 1,100 and 1,700 ft MD. Multiple fluid samples were acquired in a shallow water well above and below the USDW to reduce the uncertainty in salinity variations with depth and to assess salinity-depth relationships. The salinity-depth relationships were found to be nonlinear and increased rapidly with depth. Fluid samples and well logs were used to support base USDW interpretation.

Figure NAR-8 shows a cross-section for the base of the USDW in Bluebonnet Hub AoR.

ERA	EPOCH		AGE (M.Y.)	GEOLOGIC UNIT	HYDRO-GEOLOGIC UNIT	
CENOZOIC	PLEISTOCENE		0.7	BEAUMONT	CHICOT AQUIFER	GULF COAST AQUIFER
			1.6	LISSIE		
	PLIOCENE		3.8	WILLIS		
	MIOCENE	LATE	11.2	UPPER GOLIAD	EVANGELINE AQUIFER	
			14.5	LOWER GOLIAD		
		MIDDLE	17.8	UPPER LAGARTO		
				MIDDLE LAGARTO	BURKEVILLE	
		EARLY		LOWER LAGARTO	JASPER AQUIFER	
			24.2	OAKVILLE		
	OLIGOCENE		32	FRIO	CATAHOULA	
			34	VICKSBURG		

Figure NAR-7: Geologic and hydrogeologic units of the Gulf Coast Aquifer system, modified from Young et al. (2016).

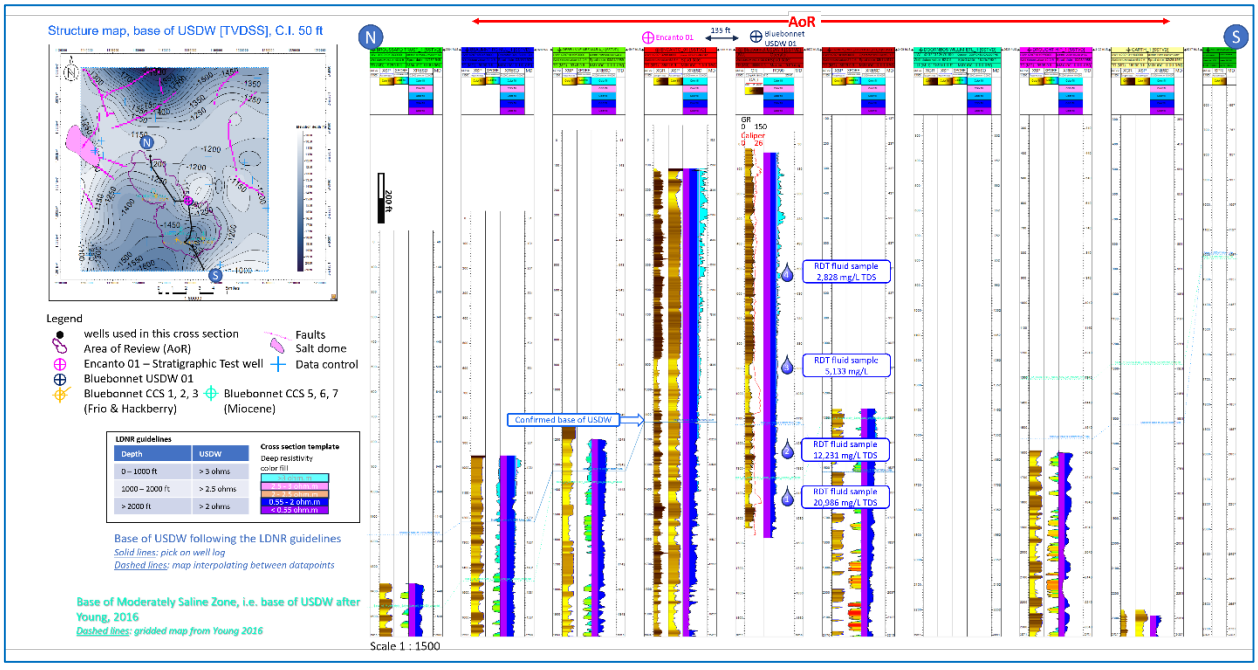


Figure NAR-8: Base of USDW shown in blue following the LDNR-IMD deep resistivity method. Site-specific RDT fluid samples acquired from Bluebonnet USDW 01 (offsetting Encanto 01) showed TDS values >10,000 mg/L in the sands below 1,182 ft and are compared to the interpreted base Moderately Saline Zone (10,000 mg/l TDS) after Young et al. (2016).

2.8 Seismic History [40 CFR 146.82(a)(3)(v)]

Regional earthquakes were identified using the USGS online database, cross-checked against the Bureau of Economic Geology's TEXNET database to determine the location of events (Figure NAR-9). No recorded events of any magnitude from 1900 to present were identified within 50 miles of the Bluebonnet site. A single earthquake was identified within a 75-mile radius of the Bluebonnet project: a magnitude 3.8 event occurring 1 km WNW of Sulphur, Louisiana, in 1983 at a depth of 5.9 km. The USGS Long-Term Seismic Hazard Map indicates that this area is at relatively low risk for natural earthquake activity. Plans for Bluebonnet include placement of a dense network of seismometers that will offer reliable location of seismic events with magnitude as small as 0.0 on the Richter scale (also shown in Figure NAR-9).

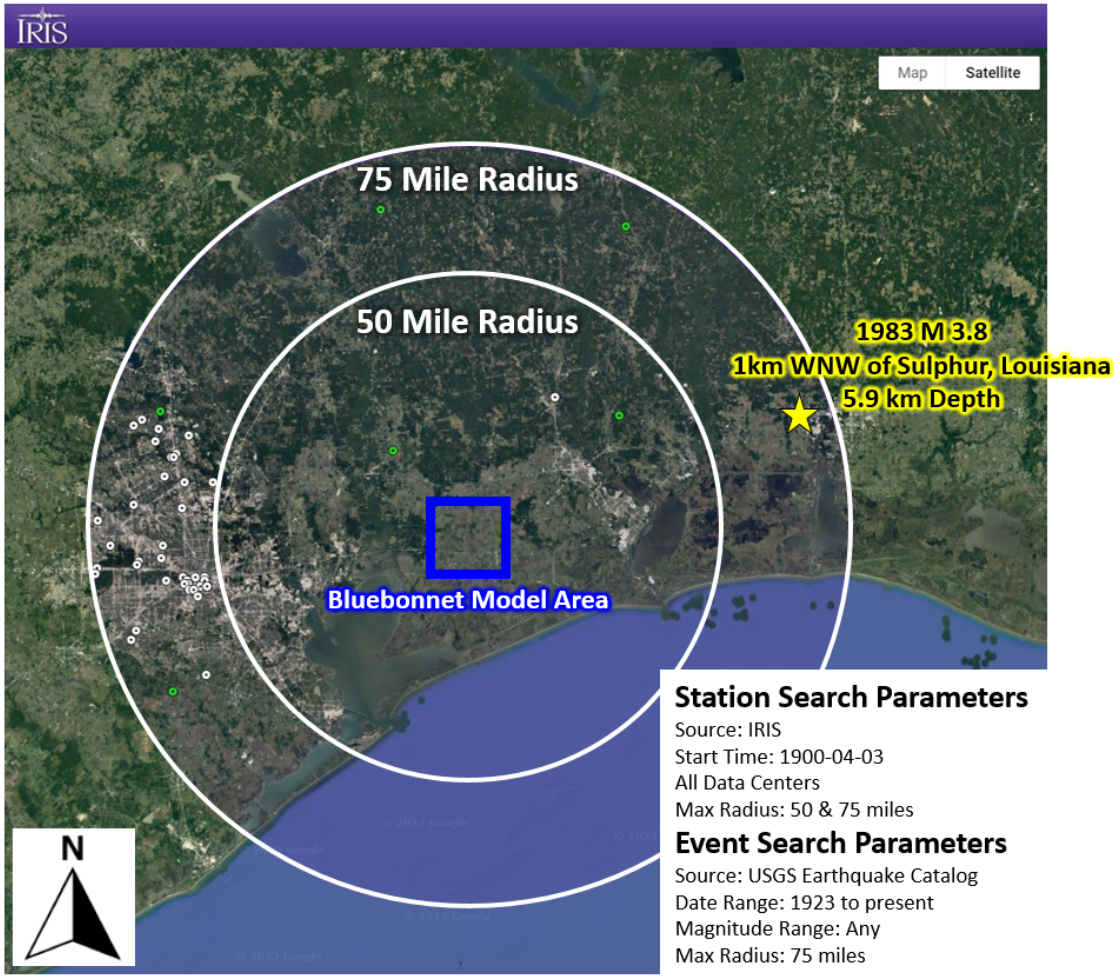


Figure NAR-9: Seismometer stations (green and white circles) and historic seismic activity (yellow star).

2.9 Geocellular and Dynamic Model Construction – Frio and Hackberry Injection Zones

The static geomodel was created using Schlumberger Petrel (v2021) and is based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout public data, literature, and in-house 3D seismic data.

The methodology applied to the static geomodel was to model the large-scale features, followed by modeling progressively smaller and more uncertain features. The first step applied to the Bluebonnet geomodel was to establish a conceptual structural and depositional model as well as its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, net sand, and other attributes within each layer. Next, petrophysical values were distributed for each zone using a cell-based methodology.

The project used 152 wells with quality logs and reservoir top data, in conjunction with 3D seismic data, to construct reservoir top surfaces. Eighty-nine of these wells also had the appropriate digital logs to be petrophysically analyzed and used in building the petrophysical property models. Sixty-three of these wells have basic logs and have been used to pick the formation tops.

The model includes several major geological zones, from top to bottom: the Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac Confining Zone, Frio Injection Zone, Frio Confining Zone, Hackberry Injection Zone, and the Hackberry Confining Zone. The model covers an area of about 13.58 miles by 13.69 miles. The bottom confining zone is the Hackberry Confining Zone. The grid cell area is consistent throughout the geomodel area at 500 ft x 500 ft. The grid thickness varies somewhat but averages about 10 ft. The final geomodel is represented by a 143 × 142 × 310 grid in a Cartesian system for a total of 6+ million active grid cells.

The total porosity of the injection zone is based on neutron and density porosity logs from 33 wells within and around the Geomodel Domain (see Figure NAR-10). An interconnected (effective) porosity for wells with porosity logs was calculated from total porosity corrected for the shale volume. The remaining wells did not have neutron and/or density porosity logs but were required for porosity calculations in the petrophysical interpretation. A linear correlation between volume of shale and effective porosity from wells with porosity logs developed by the GCCC (Frio Pilot in CO_2 Sequestration in Brine – Bearing Sandstones, Hovorka et al. 2003) was used and corroborated with local data. The results of this method compared largely with the 33 well subset, so the linear correlation was applied to the remaining wells.

The horizontal permeability for the injection zones is based on a porosity-permeability relationship established by the GCCC in the ‘Frio Pilot CO_2 Sequestration in Brine – Bearing Sandstones.’

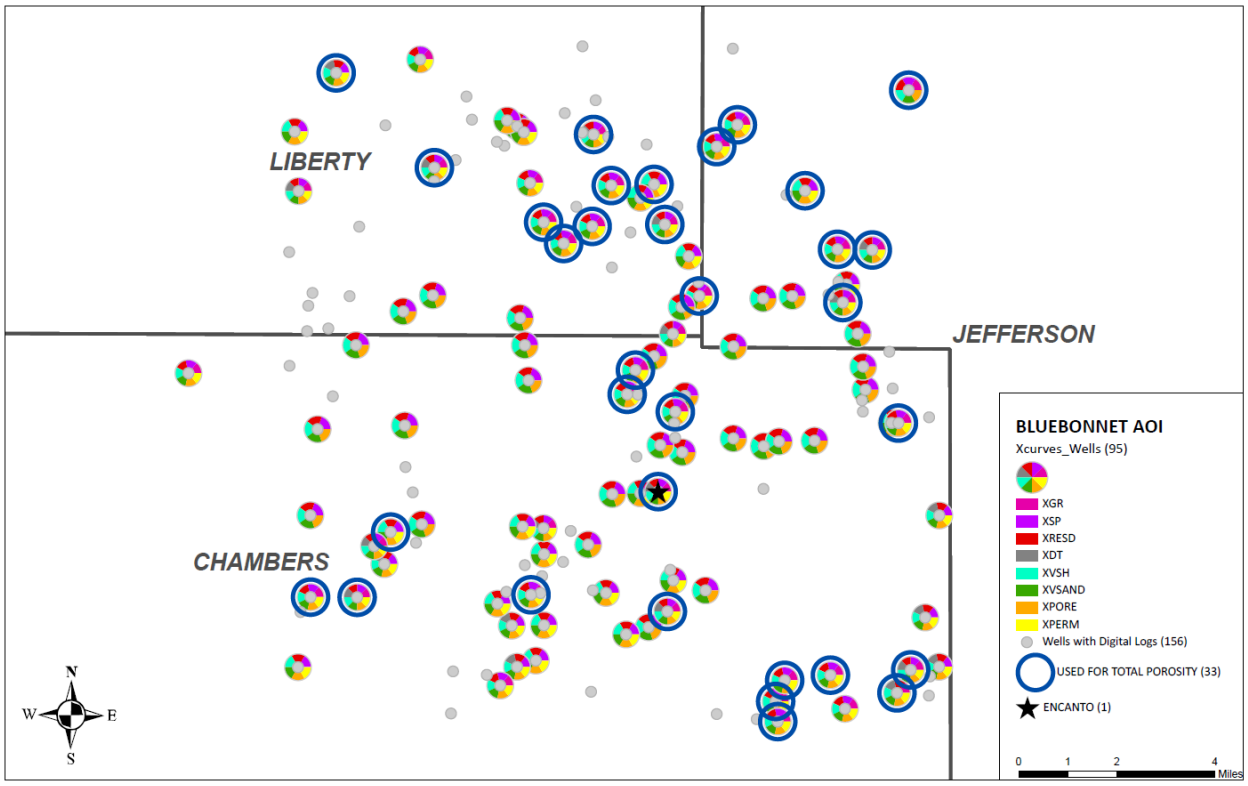


Figure NAR-10: Map representing 156 control wells within and surrounding the Bluebonnet Hub AoR used for petrophysical interpretation of porosity, permeability, and net reservoir thickness of the Frio Injection Zone, Hackberry Injection Zone, and Confining Zones. A total of 89 wells are within the geomodel. Pie charts outlined in blue represent 33 wells with neutron and density well-logs. The stratigraphic well Encanto 01 is identified with a black star.

2.10 Geocellular and Dynamic Model Construction – Lower Miocene Injection Zone

The Lower Miocene static geomodel was built with collaborative interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired from public databases, published literature, in-house studies, and in-house 3D seismic data. The geological subzones were created from horizons based on a combination of well log correlations in combination with the 3D seismic horizon interpretation. The internal layer subdivisions of the zones were based on the interpretation of digital well logs to determine the thickness of each subzone.

The model includes several major geological zones: Lower Miocene Confining Zone, Lower Miocene Dissipation Zone, Lower Miocene Injection Zone, and Anahuac Confining Zone. The Lower Miocene was subdivided into six injection zones (LMIO_INJ_1, LMIO_INJ_5, LMIO_INJ_4, LMIO_INJ_3, LMIO_INJ_6, and LMIO_INJ_2), each with additional vertical layers to capture reservoir heterogeneity. The model extent covers approximately 14 miles by 15 miles. The top and bottom confining zones are the Lower Miocene Shale (LMIO_Shale_CZ) and Anahuac Shale (Anahuac_CZ), respectively.

Model horizons were first interpreted from available well log datasets, including depth-registered image logs and digital log data. These horizons were then combined with interpreted 3D seismic

data to provide more accurate control of horizon construction where log data may be sparse. The methodology applied to the static geomodel was to model the large-scale features, followed by modeling progressively smaller and more uncertain features. The first step applied to the Bluebonnet geomodel was to establish a conceptual structural and depositional model as well as its characteristic stratigraphic layering.

Lithofacies logs were upscaled and propagated into the 3D grid using a Sequential Indicator Simulation (SIS) algorithm, conditioned by probability trend maps from depositional trends and seismic attributes. Porosity logs were upscaled and distributed using a Sequential Gaussian Simulation (SGS) algorithm, constrained by lithofacies and co-kriging with depositional trends. Permeability was modeled similarly, with co-kriging using the porosity model. Core data from the Encanto 01 well indicated that permeability curve data might overestimate permeability in shale intervals, hence, the permeability property was updated with reduced permeability values by a factor of ten in shale facies.

2.11 Site Storage Capacity and CO_2 Retention

The dynamic simulation model provides an advanced method for determining the storage capacity. Details of the construction and physics of the base case dynamic model are described in detail in the Area of Review and Corrective Action Plan. The base case model includes CO_2 dissolved in the aqueous phase or as free or trapped supercritical CO_2 but does not model trapping due to mineralization. Figure NAR-11, Figure NAR-12 and Figure NAR-13 show the change in storage capacity and CO_2 plume area with time from the dynamic simulation, forecasted for 100 years after injection.

For the Lower Miocene Injection Zone, the storage capacity will reach a peak at the end of the injection period at 7.09 million mt/mi^2, then decline to a value of 3.6 million mt/mi^2 at the stop of plume migration. In the case of Frio Injection Zone, the storage capacity will reach a peak at the end of the injection period at 9.36 million mt/mi^2, then decline to a value of 6.6 million mt/mi^2 at the stop of plume migration. And for the Hackberry Injection Zone the storage capacity will reach a peak at the end of the injection period at 5.16 million mt/mi^2, then decline to a value of 2.32 million mt/mi^2 at the stop of plume migration. The storage capacity on a per-area basis from dynamic modeling is ultimately higher near the injector than at the outer edges of the CO_2 plume due to the heterogeneity of the storage formation and the CO_2 migration updip.

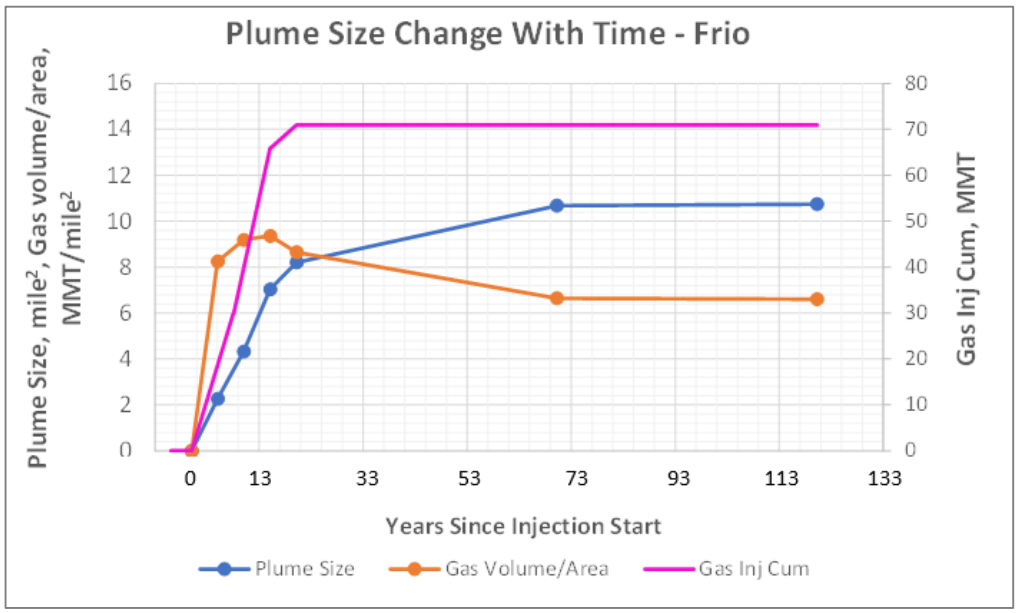


Figure NAR-11: CO_2 plume area and storage capacity from dynamic simulation, from start of injection to 100 years post injection in Frio Injection Zone.

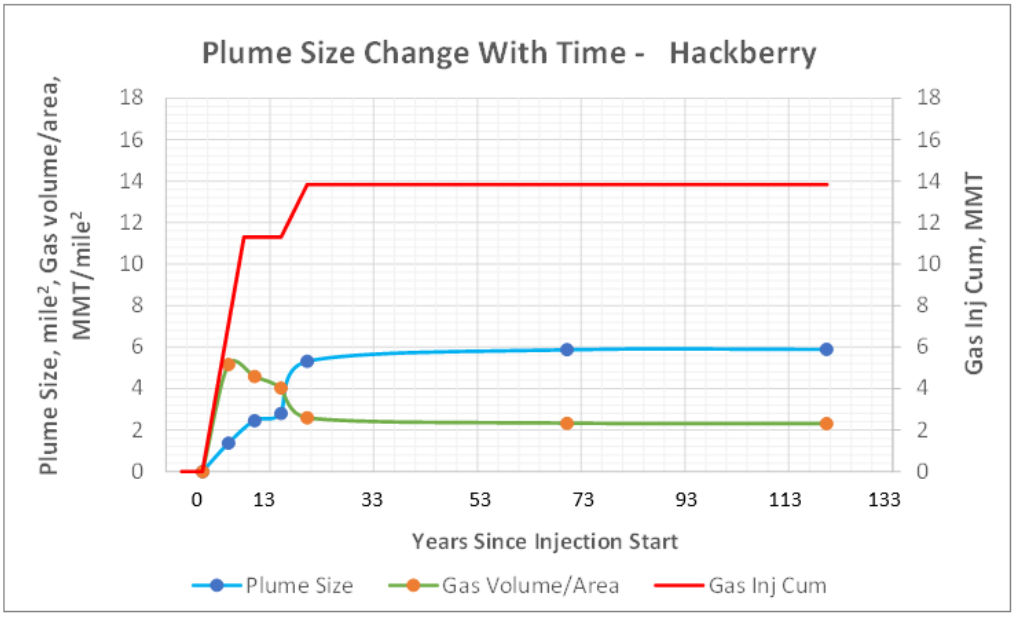


Figure NAR-12: CO_2 plume area and storage capacity from dynamic simulation, from start of injection to 100 years post injection in the Hackberry Injection Zone.

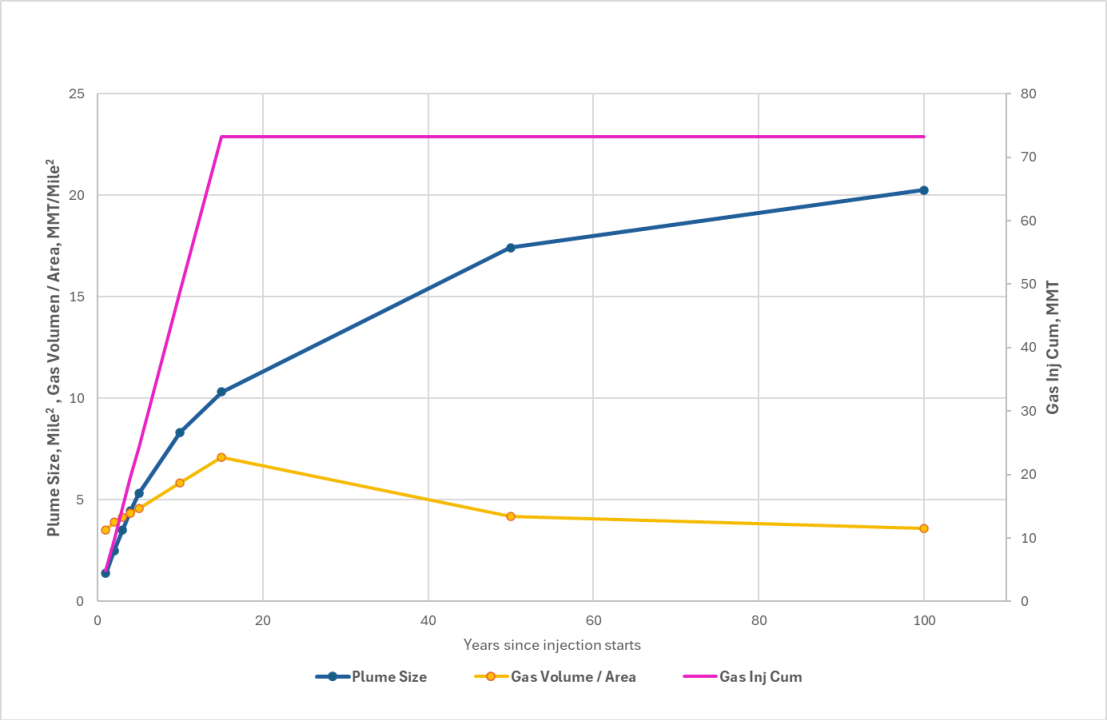


Figure NAR-13: CO_2 plume area and storage capacity from dynamic simulation, from start of injection to 100 years post injection in the Lower Miocene Injection Zone.

More detailed geological description and site characterization is included in the AoR and Corrective Action Plan attachment of this application.

3.0 AoR and Corrective Action [40 CFR §146.82(a)(13)]

3.1 Definition of CO_2 Plume and Pressure Front – Frio and Hackberry Injection Zones

As described in Section 2.9 above, the static geocellular models was constructed using Schlumberger's Petrel (v2021) 3D geostatistical modeling software, which is a comprehensive, integrated subsurface platform containing data interpretation tools for well correlation, mapping, and structural and property modeling.

The dynamic simulation model was created using the GEM (v2023.30) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd. (CMG). GEM is a commercially available, compositional, and finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. The GHG module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions.

The model was initialized with hydrostatic conditions and run without any active wells for four years to ensure equilibrium and no fluid movement. In the fifth year, the Bluebonnet CCS 1, CCS 2, and CCS 3 wells all begin injecting with a primary rate constraint of 105 MMscfd [2.0 million metric ton (MMTA)], 89.25 MMscfd (1.7 MMTA), and 73.5 MMscfd (1.4 MMTA), respectively. A secondary bottomhole pressure (BHP) constraint (76% of the minimum estimated fracture gradient of 0.76 psi/ft) is set at the well reference depth (Table NAR-3). The frac gradient, 0.76 psi/ft, has been established by step rate and leak-off tests on the stratigraphic well Encanto 01. The injection stream composition is 100% CO_2. CCS 1 and CCS 3 will continue injection until the end of Year 20, while CCS 2 only injects for 15 years. The base-case run continued for 100 years post-injection to simulate CO_2 migration after post-injection site closure.

Two water withdrawal wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2, are proposed to help relieve the pressure increase from CO_2 injection. Both wells will be completed in the Frio only and will produce for the first 15 years of injection.

Table NAR-3: Stage injection, injection, and production rate for all the wells.

Injection Years	CCS 1 Completion	CCS 1 injection rate , MMTA	CCS 2 Completion	CCS 2 injection rate , MMTA	CCS 3 Completion	CCS 3 injection rate , MMTA	PRDW F1, bwpd	PRDW F2, bwpd	DSW M2, bwpd
1	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
2	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
3	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
4	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
5	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
6	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
7	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
8	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
Shut-In									
9	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
10	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
11	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
12	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
13	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
14	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
15	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
Shut-In									
16	Hackberry	0.5			Frio_Mid	1			
17	Hackberry	0.5			Frio_Mid	1			
18	Hackberry	0.5			Frio_Mid	1			
19	Hackberry	0.5			Frio_Mid	1			
20	Hackberry	0.5			Frio_Mid	1			
Shut-In									

The CO_2 plume extent was simulated assuming 20 years of injection as described in the previous section. The project simulated 50 years post-injection as well as 100 years post-injection. The plume tends to stabilize before the end of the 50-year post-injection period; however, the project defined the 100-year plume outline to delineate the maximum extend of the CO_2 plume in the AoR as a conservative approach. The project used a cutoff of 3% CO_2 saturation as supported by the

fluid substitution analysis. Figure NAR-14 and Figure NAR-15 show the pore-volume-weighted CO_2 saturation map distribution for the Frio and Hackberry Injection Zones, respectively.

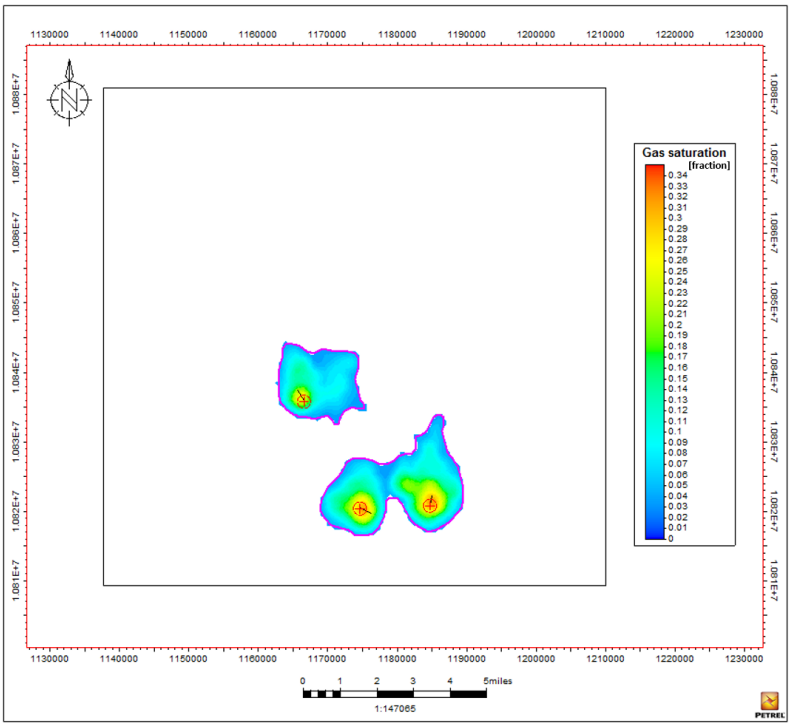


Figure NAR-14: Pore-volume-weighted CO_2 saturation map distribution after 70.3 million MT CO_2 injection in the Frio Injection Zone.

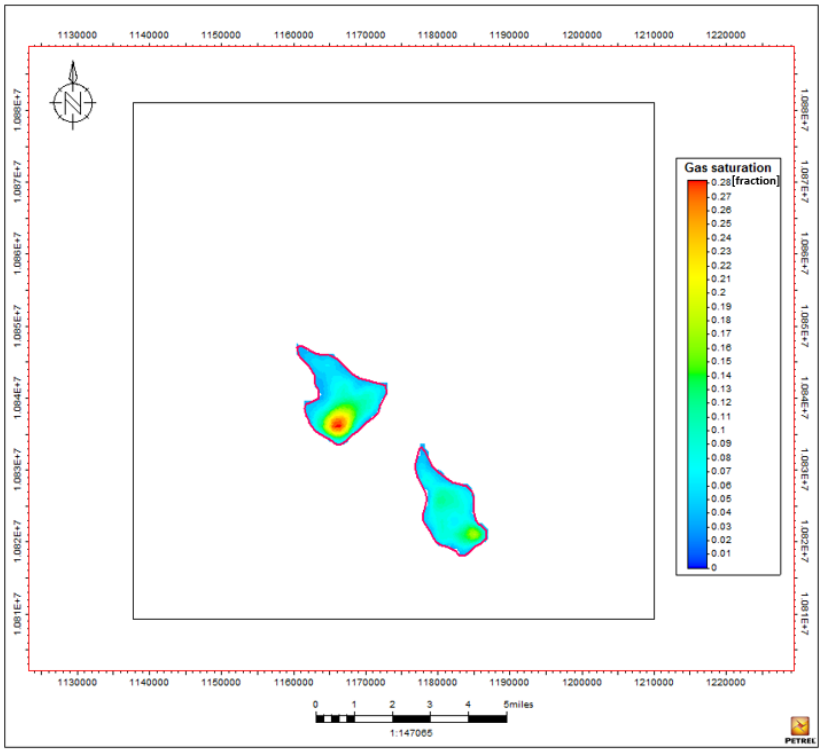


Figure NAR-15: Pore-volume-weighted CO_2 saturation map distribution after 13.7 million MT CO_2 injection in the Hackberry zone.

The Bluebonnet Hub project team evaluated different approaches to estimate the critical pressure threshold as describe in the AoR and Corrective Action Plan attachment. The calculated critical pressure differential for the Bluebonnet Hub is 172 psi for the Frio Injection Zone and 158 psi for the Hackberry Injection Zone.

Figure NAR-16 and Figure NAR-17 shows the critical pressure delineation for Frio and Hackberry Injection Zones.

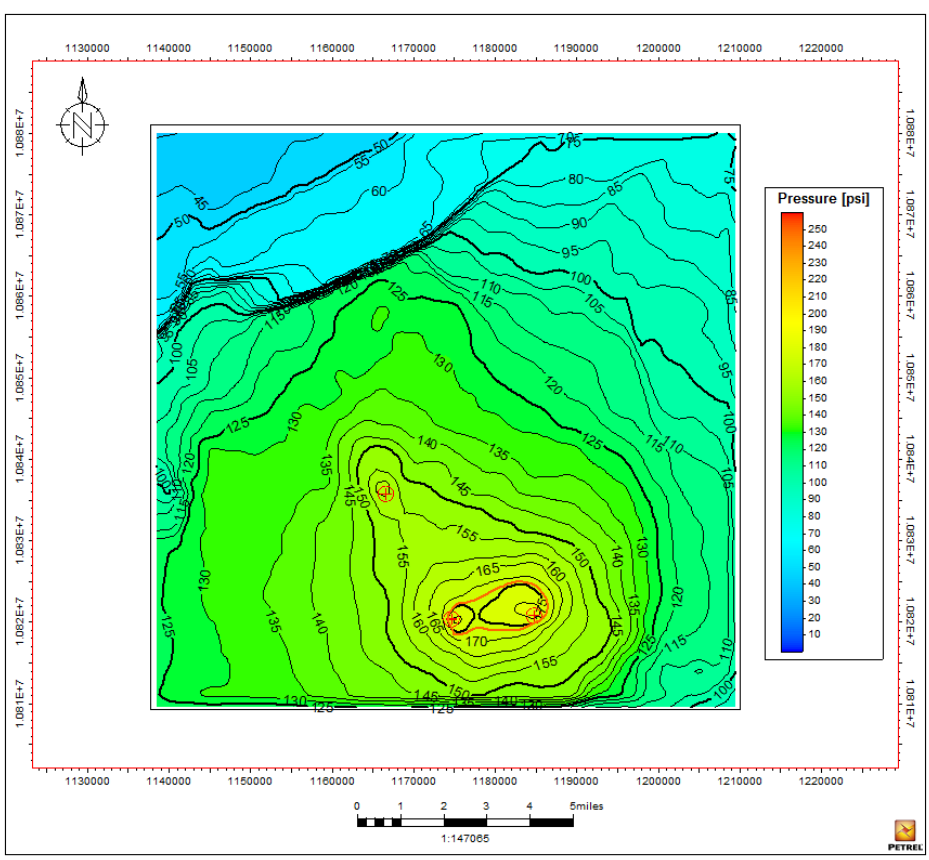


Figure NAR-16: View of highest pore-pressure increases after 65.3 million MT of total CO_2 injection in Frio for 15 years. Values displayed are pore-volume-weighted averages across the injection interval. The orange polygon is the pressure front for the Frio Injection Zone.

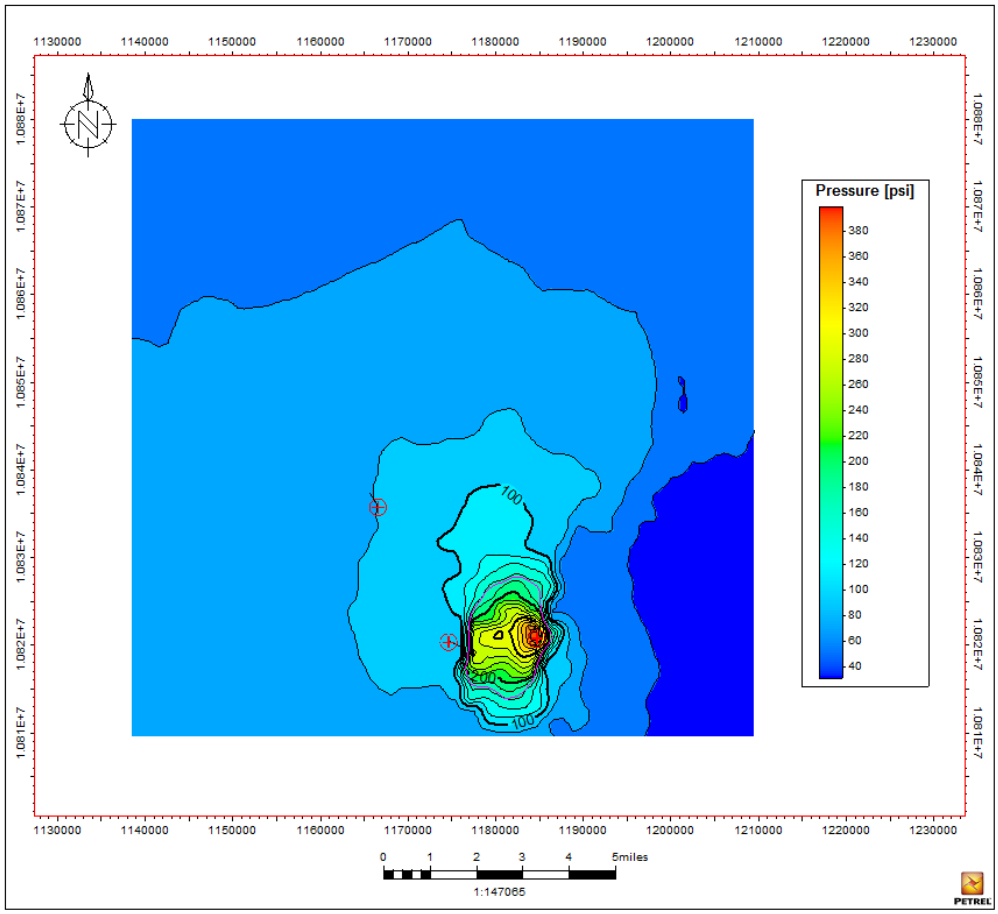


Figure NAR-17: View of highest pore-pressure increases after 13.7 million MT of total CO_2 injection in Hackberry for 20 years. Values displayed are pore-volume-weighted averages across the injection interval. The purple polygon is the pressure front for Hackberry Injection Zone.

3.2 Definition of the CO_2 Plume and Pressure Front – Lower Miocene Injection Zones

As described in Section 2.10 above, the static geocellular models were constructed using Schlumberger's Petrel (v2023.7.0) 3D geostatistical modeling software.

The dynamic simulation model was created using the GEM (2024.10) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd. (CMG). GEM is a commercially available, compositional, and finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. The GHG module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions.

Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells all begin injection with primary rate constraints of 97.6 MMscfd (1.86 million metric ton (MMTA)), 85.4 MMscfd (1.63 MMTA), and 73.2 MMscfd (1.39 MMTA), respectively. Secondary constraints using maximum bottomhole pressure (BHP) were set at 3,300 psi (80-82% of the minimum estimated fracture gradient of 0.76 psi/ft) for all injectors. Frac gradient was established from step-rate and leak-off tests on the Encanto 01 stratigraphic well. The injection stream composition is assumed to be 100% CO_2. Recompletion of injector wells were simulated with addition of successively shallower perforations. Proposed injection period for each injector wells is 15 years with 50 years of post-injection, and base-case simulation times were allowed to run for 100 years post-injection to simulate an extra buffer for CO_2 migration after post-injection site closure.

Table NAR-4: Stage injection, injection, and production rate for all the wells.

Injection Years	CCS 5 Completion	CCS 5	CCS 6 Completion	CCS 6	CCS 7 Completion	CCS 7
		Rate MMTA	Rate MMTA			Rate MMTA
1	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
2	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
3	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
4	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
5	Recompletion No 1	1.86	Original Completion	1.63	Recompletion No 1	1.39
6	Recompletion No 1	1.86	Original Completion	1.63	Recompletion No 1	1.39
7	Recompletion No 1	1.86	Original Completion	1.63	Recompletion No 1	1.39
8	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 1	1.39
9	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
10	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
11	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
12	Recompletion No 3	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
13	Recompletion No 3	1.86	Recompletion No 1	1.63	Recompletion No 3	1.39
14	Recompletion No 4	1.86	Recompletion No 1	1.63	Recompletion No 3	1.39
15	Recompletion No 4	1.86	Recompletion No 2	1.63	Recompletion No 3	1.39

The CO_2 plume extent was simulated assuming 15 years of injection as described in the previous section. The project simulated 50 years post-injection as well as 100 years post-injection. The plume tends to stabilize before the end of the 50-year post-injection period; however, the project defined the 100-year plume outline to delineate the maximum extend of the CO_2 plume in the AoR as a conservative approach. The project used a cutoff of 3% CO_2 saturation as supported by the fluid substitution analysis. Figure NAR-18 show the CO_2 saturation map distribution for the Lower Miocene Injection Zone at 100 years of Post-Injection.

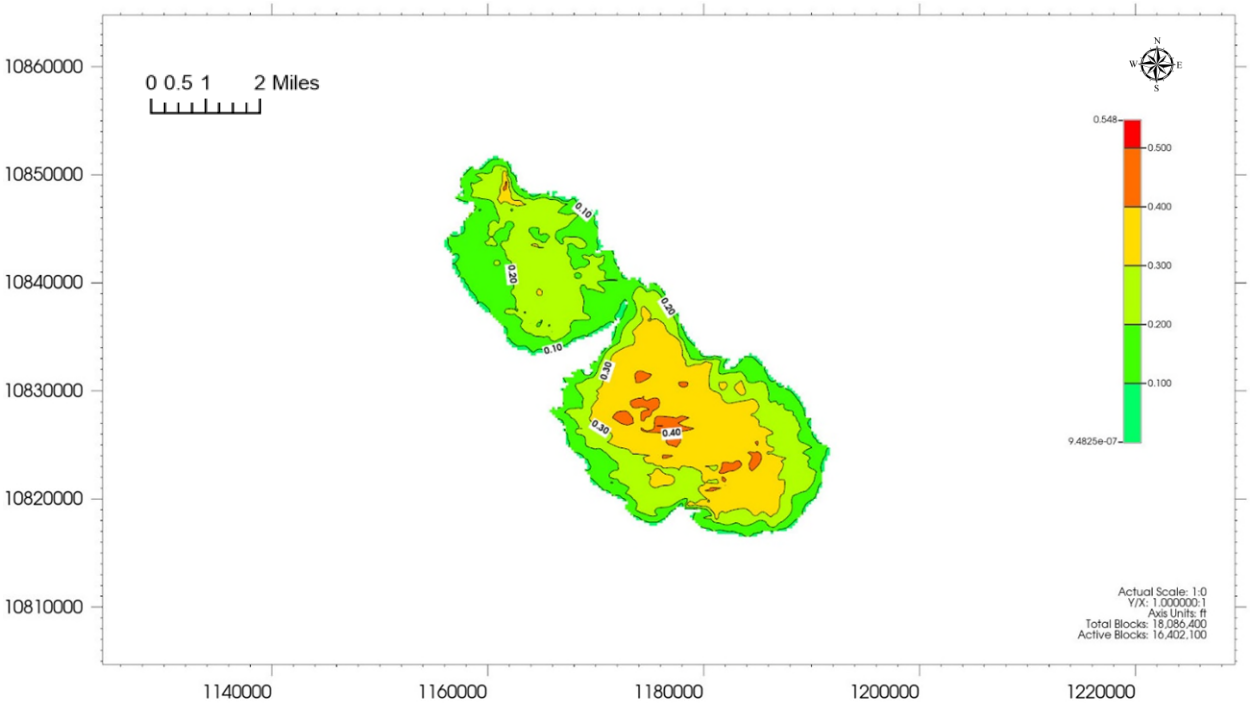


Figure NAR-18: CO_2 saturation map distribution after 73.2 million MT CO_2 injection in the Lower Miocene Injection Zone.

The calculated critical pressure differential for the Bluebonnet Hub is 110 psi for the Lower Miocene Injection Zone. Figure NAR-19 shows the critical pressure delineation for the Lower Miocene Injection Zone.

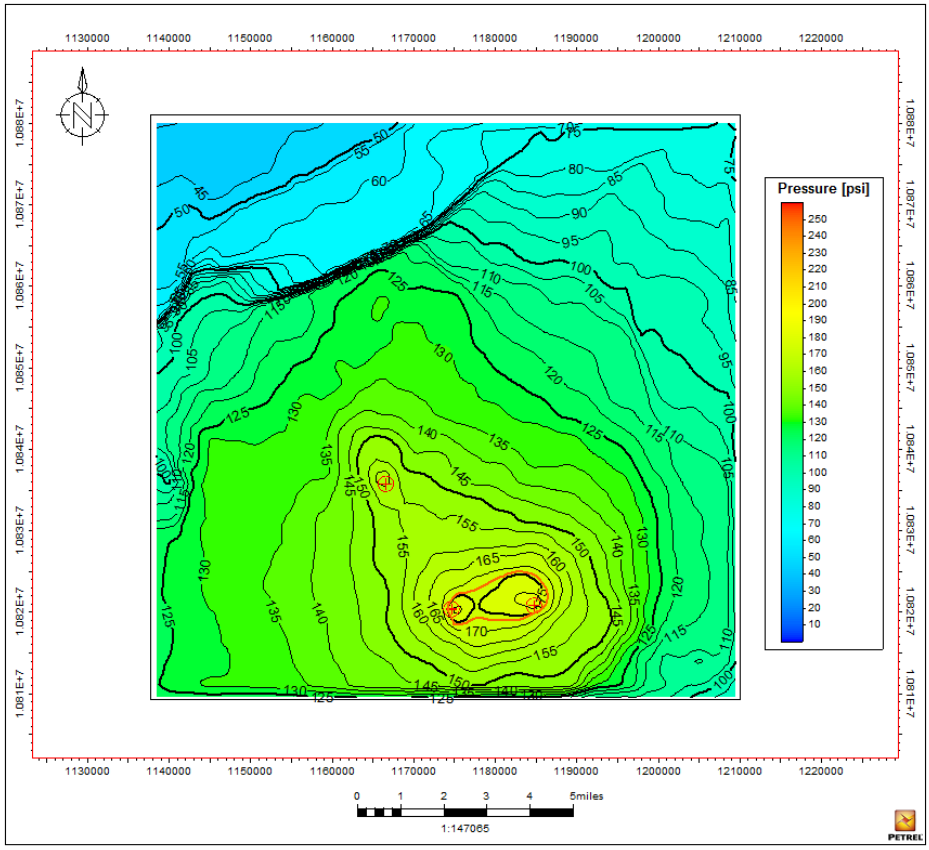


Figure NAR-19: View of highest pore-pressure increases in the Lower Miocene Injection zone at year 4 of the injection period. The red polygon is the critical pressure for the Lower Miocene Injection Zone.

3.3 Delineation of Bluebonnet Hub AoR

For the Lower Miocene Confining Zone, the Miocene Composite Confining Zone as well as the base of USDW, the Frio/Hackberry AoR was merged with the Miocene AoR, as the confining zones are utilized for both storage complexes and also to capture the largest footprint to assess and mitigate any potential USDW contamination.

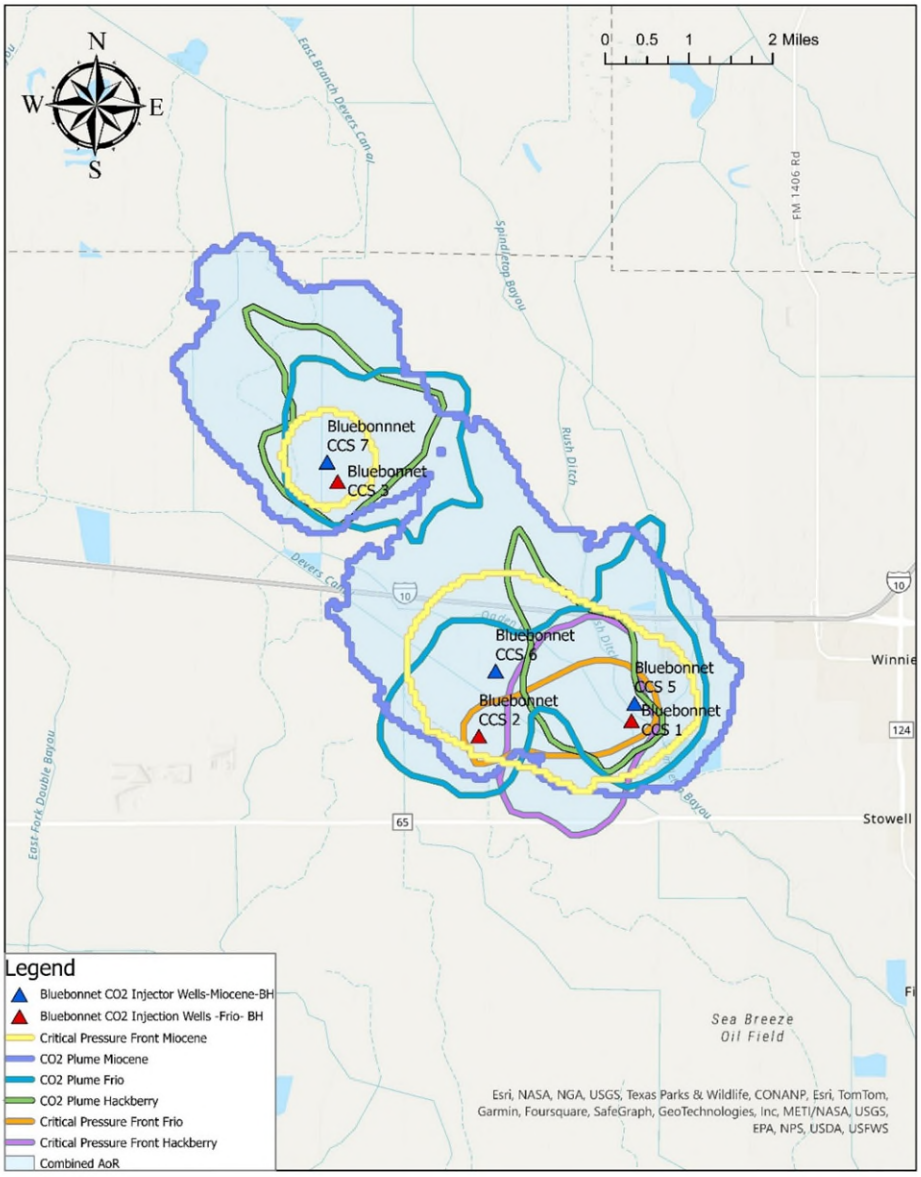


Figure NAR- 20: Combined AoR Lower Miocene, Frio and Hackberry Injection Zone

3.2 Corrective Action Plan

The proposed AoR represents approximately twenty-two square miles of extension (combination of pressure front at 20 years of injection and CO_2 plume at 100 years post injection) and includes twenty-nine legacy oil and gas wells and fourty-seven water wells, according to the records obtained and the additional research performed by the Project. The area is dedicated mostly to farming and recreational activities. Oil and gas development is present in areas outside of the AoR; however, exploration activities in the proposed AoR have not proved to be economical, as all the legacy wells were classified as dry holes.

The forty-seven water wells inside the AoR targeted the Chicot aquifer. These wells are dedicated to domestic use, stock, rig supply, and groundwater monitoring activities. None of these forty-seven wells penetrated the confining or injection zone; thus, none require any corrective action.

From the twenty-nine oil and gas wells within the AoR , twenty-six wells were drilled through the Miocene Lower Confining Zone into the Frio formation.

A detailed analysis was performed to evaluate the risk and timing of the plume and/or pressure front reaching each of the wells inside the AoR, relative to the project schedule, to propose corrective actions and a timeline for these procedures.

From the individual well analysis, twenty-five of the twenty-nine wells were identified as requiring remedial actions to isolate the injection zone properly from the USDW zones. These wells are listed in the AoR and Corrective Action attachment, along with the main mechanism of failure and proposed schedule. The project complemented this evaluation with a magnetic survey conducted in March 2025 .

At a fixed frequency specified in the Area of Review and Corrective Action Plan or more frequently when monitoring and operational conditions warrant, Bluebonnet Sequestration Hub, LLC, will reevaluate the AoR and perform any required corrective action in the manner specified in 40 CFR §146.84. As part of this reevaluation process, Bluebonnet Hub must also update the Area of Review and Corrective Action Plan or demonstrate to Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director that no update is needed.

Following each Area of Review and Corrective Action Plan reevaluation or demonstration showing that no new evaluation is needed, the Bluebonnet Hub shall submit the resultant information in an electronic format to the UIC program Director for review and approval of the results. Once approved by the UIC Program Director, the revised Area of Review and Corrective Action Plan will become an enforceable condition of this permit.

AoR and Corrective Action GSDT Submissions

GSDT Module: AoR and Corrective Action
Tab(s): All applicable tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]***
☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]***
☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility [40 CFR §146.82(a)(14)]

Bluebonnet Sequestration Hub, LLC, shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall

be maintained through all phases of the project. The approved financial assurance mechanisms are found in the Financial Assurance Plan document of this permit. The financial instrument(s) must be sufficient to cover the cost of:

- Corrective action (meeting the requirements of 40 CFR 146.84).
- Injection well plugging (meeting the requirements of 40 CFR 146.92).
- Post-injection site care and site closure (meeting the requirements of 40 CFR 146.93).
- Emergency and remedial response (meeting the requirements of 40 CFR 146.94).

During the active life of the geologic sequestration project, Bluebonnet Sequestration Hub, LLC, must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the UIC Program Director in an electronic format. Bluebonnet Sequestration Hub, LLC, must also provide to the Director written updates of adjustments to the cost estimate in an electronic format within 60 days of any amendments to the project plans that address the cost items covered in the financial assurance plan.

Bluebonnet Sequestration Hub, LLC, shall provide notification to meet the requirements of 40 CFR §146.85 and the conditions of this permit.

- Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, Bluebonnet Sequestration Hub, LLC, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such an increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after Bluebonnet Sequestration Hub, LLC, has received written approval from the Director.

- Bluebonnet Sequestration Hub, LLC, must notify the Director by certified mail and in an electronic format of adverse financial conditions, such as bankruptcy, that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under the Corrective Action and/or Emergency and Remedial Response.

    - If Bluebonnet Sequestration Hub, LLC, or a third-party provider of a financial responsibility instrument is going through a bankruptcy, Bluebonnet Sequestration Hub, LLC, must notify the Director by certified mail and in an electronic format of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code, which names Bluebonnet Sequestration Hub, LLC, as the debtor within 10 days after commencement of the proceeding.

    - A guarantor of a corporate guarantee must make such a notification, if he or she is named as debtor, as required under the terms of the guarantee.

- A permittee who fulfills the requirements of financial assurance by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee (or issuing institution) or suspension/revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

Bluebonnet Sequestration Hub, LLC, must establish other financial assurance or liability coverage, acceptable to the Director, within 60 days of a change to the Area of Review and Corrective Action Plan.

Financial Responsibility GSDT Submissions

GSDT Module: Financial Responsibility Demonstration
Tab(s): Cost Estimate tab and all applicable financial instrument tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 CO_2 Injector Well Design and Construction [40 CFR §146.82(a)(11) and (12)]

The Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injector wells were designed with the highest standards and best practices for drilling and well construction. The operational parameters and material selection are intended to ensure mechanical integrity in the system and to optimize operations during the life of the project.

5.1 Well Design and Construction: Bluebonnet CCS 1

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

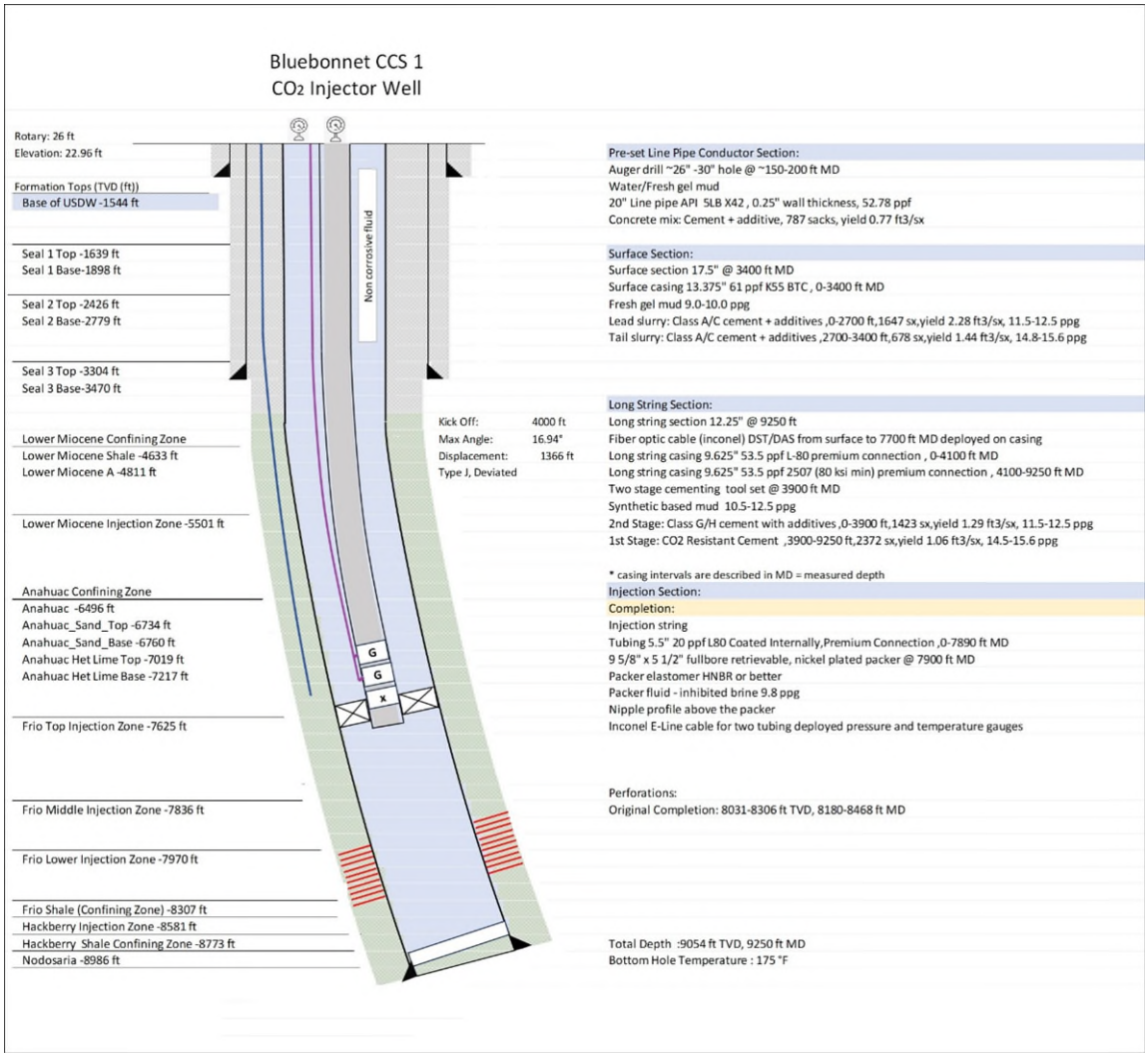


Figure NAR 21: Bluebonnet CCS 1 well schematic – original completion.

5.1.1 Conductor Bluebonnet CCS 1

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth of approximately 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mousehole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.1.2 Surface Section Bluebonnet CCS 1

The 17 ½ in. vertical wellbore will be drilled to 3,400 ft to cover the base of the USDW, estimated at 1,544 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken a minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run openhole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to the surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the UIC Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a formation integrity test (FIT).

5.1.3 Long String Section Bluebonnet CCS 1

Bluebonnet CCS 1 will be drilled directionally in a “J” type profile, with the kickoff point planned at 4,000 ft TVD, a maximum angle of 16.94°, and 1,366 ft displacement. The detailed trajectory is provided in Table CON-5.

A 12 ¼ in. directional wellbore will be drilled from 3,400 ft to TD while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8 in. casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustical sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

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

5.1.4 Completion Bluebonnet CCS 1

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

The 5 ½ in. tubing and packer completion will be run to approximately 7,900 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

5.2 Well Design and Construction: Bluebonnet CCS 2

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

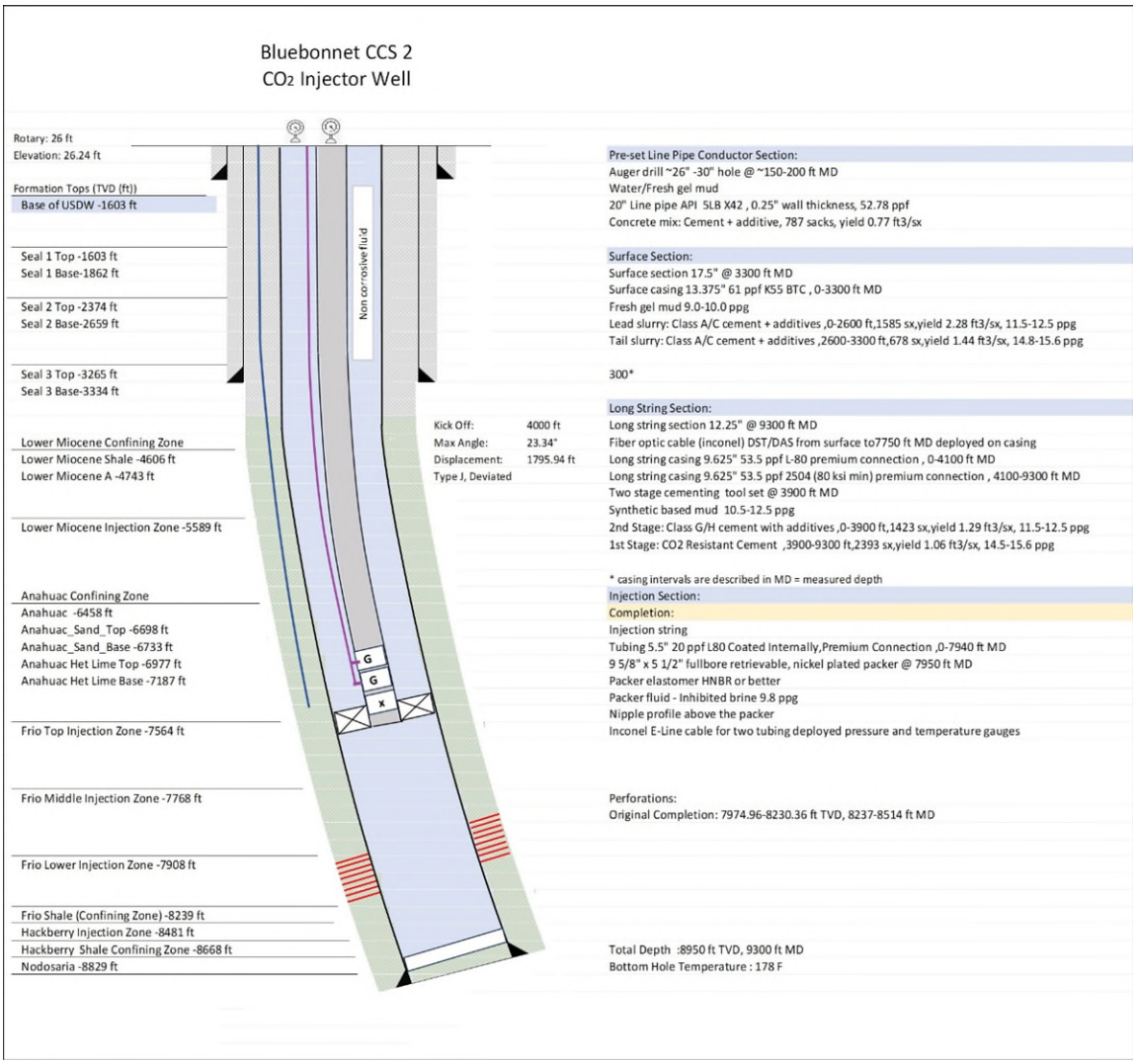


Figure NAR-22: Bluebonnet CCS 2 well schematic – original completion.

5.2.1 Conductor Bluebonnet CCS 2

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth of approximately 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mousehole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.2.2 Surface Section Bluebonnet CCS 2

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover the base of the USDW, estimated at 1,603 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken a minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be

circulated and conditioned to run openhole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to the surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the UIC Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and BOP equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute an FIT.

5.2.3 Long String Section Bluebonnet CCS 2

Bluebonnet CCS 2 will be drilled directionally in a "J" type profile, with the kickoff point planned at 4,000 ft TVD, a maximum angle of 23.34°, and 1,795 ft displacement. The detailed trajectory is provided in Table CON-17.

A 12 ¼ in. directional wellbore will be drilled from 3,300 ft to TD while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs and acquire SWC and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

5.2.4 Completion Bluebonnet CCS 2

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

The 5 ½ in. tubing and packer completion will be run to approximately 7,950 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

5.3 Well Design and Construction: Bluebonnet CCS 3

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

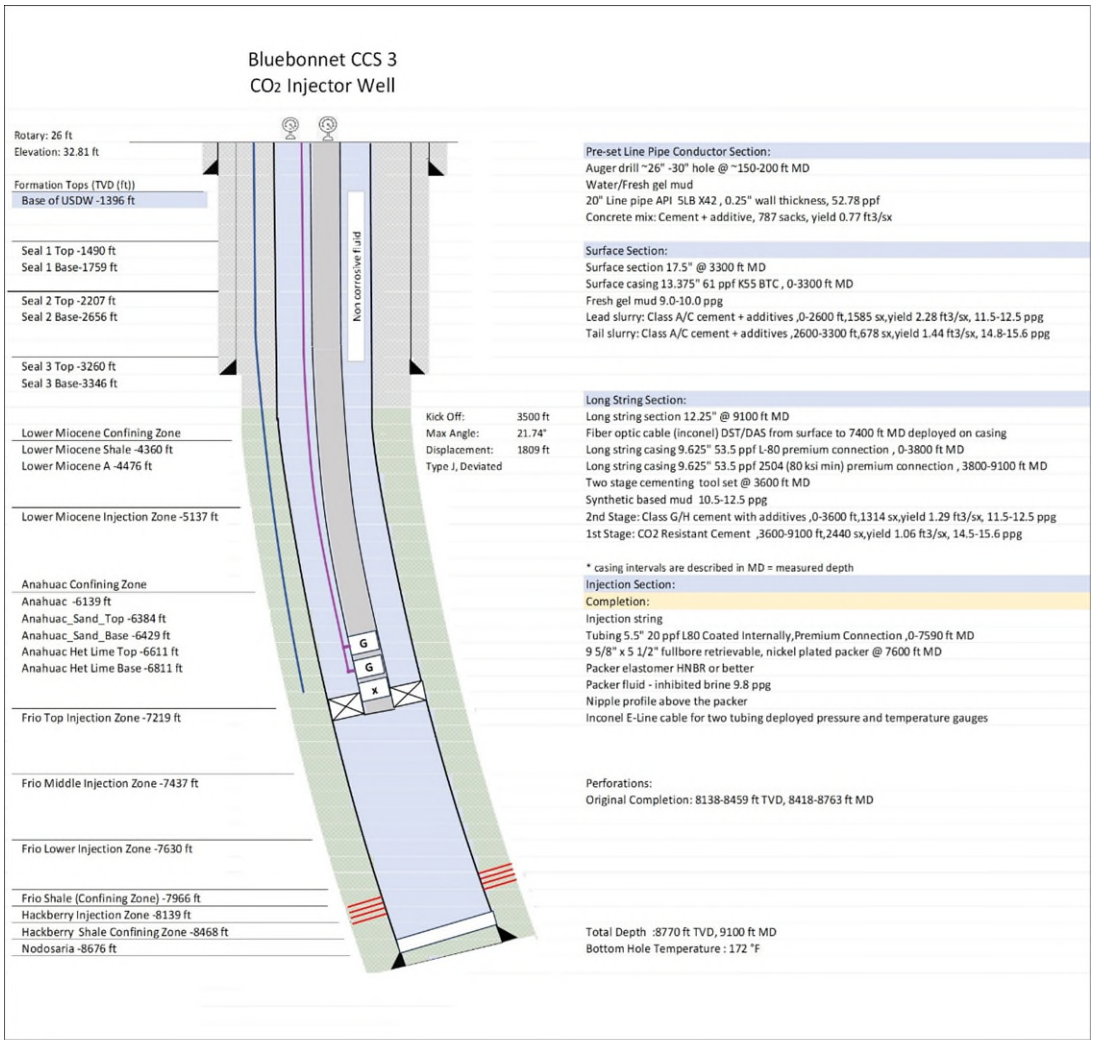


Figure NAR-23: Bluebonnet CCS 3 well schematic – original completion.

5.3.1 Conductor Bluebonnet CCS 3

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth of approximately 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mousehole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.3.2 Surface Section Bluebonnet CCS 3

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover the base of the USDW, estimated at 1,396 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken a minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run openhole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to the surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the UIC Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and BOP equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute an FIT.

5.3.3 Long String Section Bluebonnet CCS 3

Bluebonnet CCS 3 will be drilled directionally in a "J" type profile, with the kickoff point planned at 3,500 ft TVD, a maximum angle of 21.74°, and 1,809 ft displacement. The detailed trajectory is provided in Table CON-28.

A 12 ¼ in. directional wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs and SWC and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

5.3.4 Completion Bluebonnet CCS 3

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

The 5 ½ in. tubing and packer completion will be run to approximately 7,600 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced

with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

5.4 Well Design and Construction: Bluebonnet CCS 5

The Bluebonnet CCS 5 well design includes three main sections, conductor casing, surface casing, and long string casing, to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

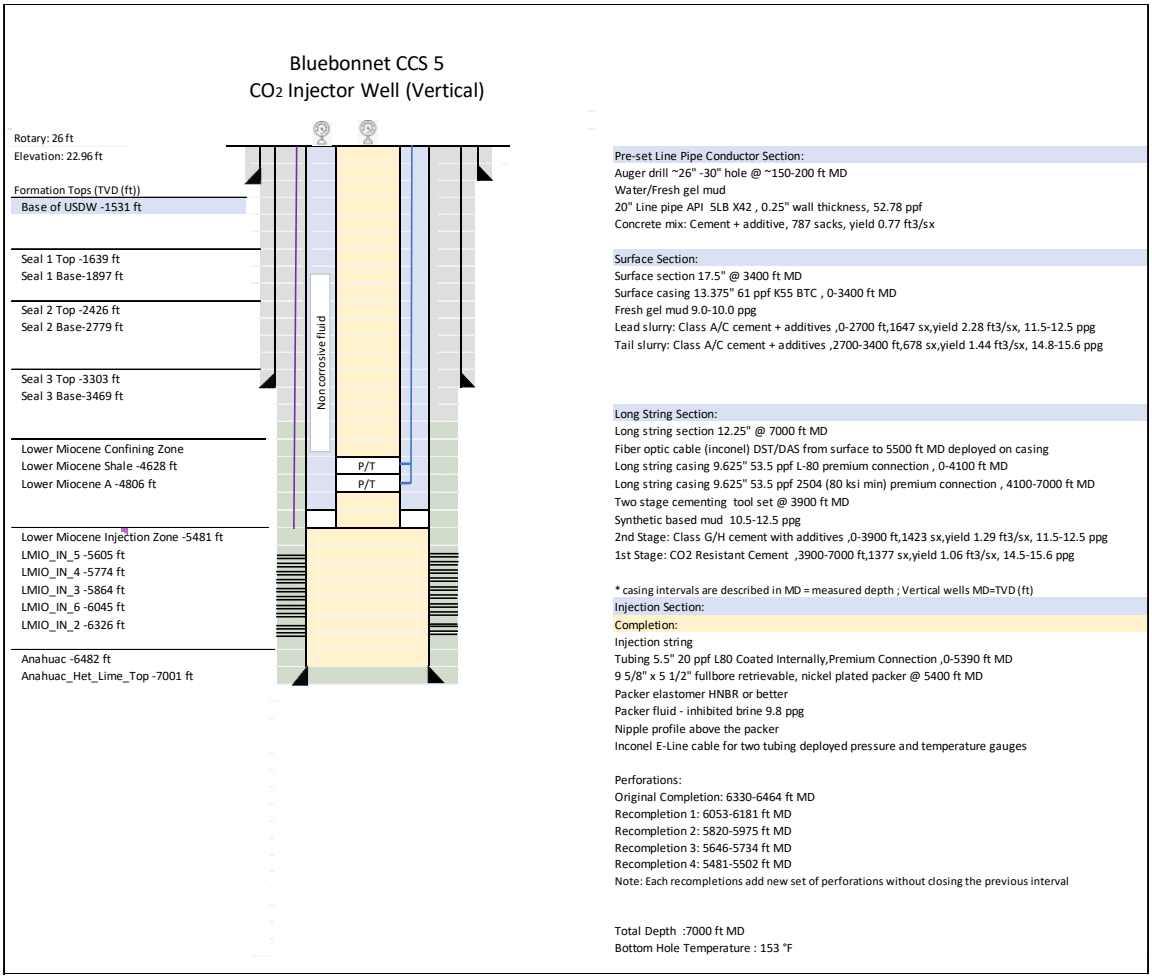


Figure NAR-24: Bluebonnet CCS 5 well schematic – original completion.

5.4.1 Conductor Bluebonnet CCS 5

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth of approximately 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mousehole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.4.2 Surface Section Bluebonnet CCS 5

The 17 ½ in. vertical wellbore will be drilled to 3,400 ft to cover the base of the USDW, estimated at 1,531 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken a minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run openhole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to the surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the UIC Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and BOP equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute an FIT.

5.4.3 Long String Section Bluebonnet CCS 5

A 12 ¼ in. vertical wellbore will be drilled from 3,400 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs and SWC and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

5.4.4 Completion Bluebonnet CCS 5

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

The 5 ½ in. tubing and packer completion will be run to approximately 5,400 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

5.5 Well Design and Construction: Bluebonnet CCS 6

The Bluebonnet CCS 6 well design includes three main sections, conductor casing, surface casing, and long string casing, to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

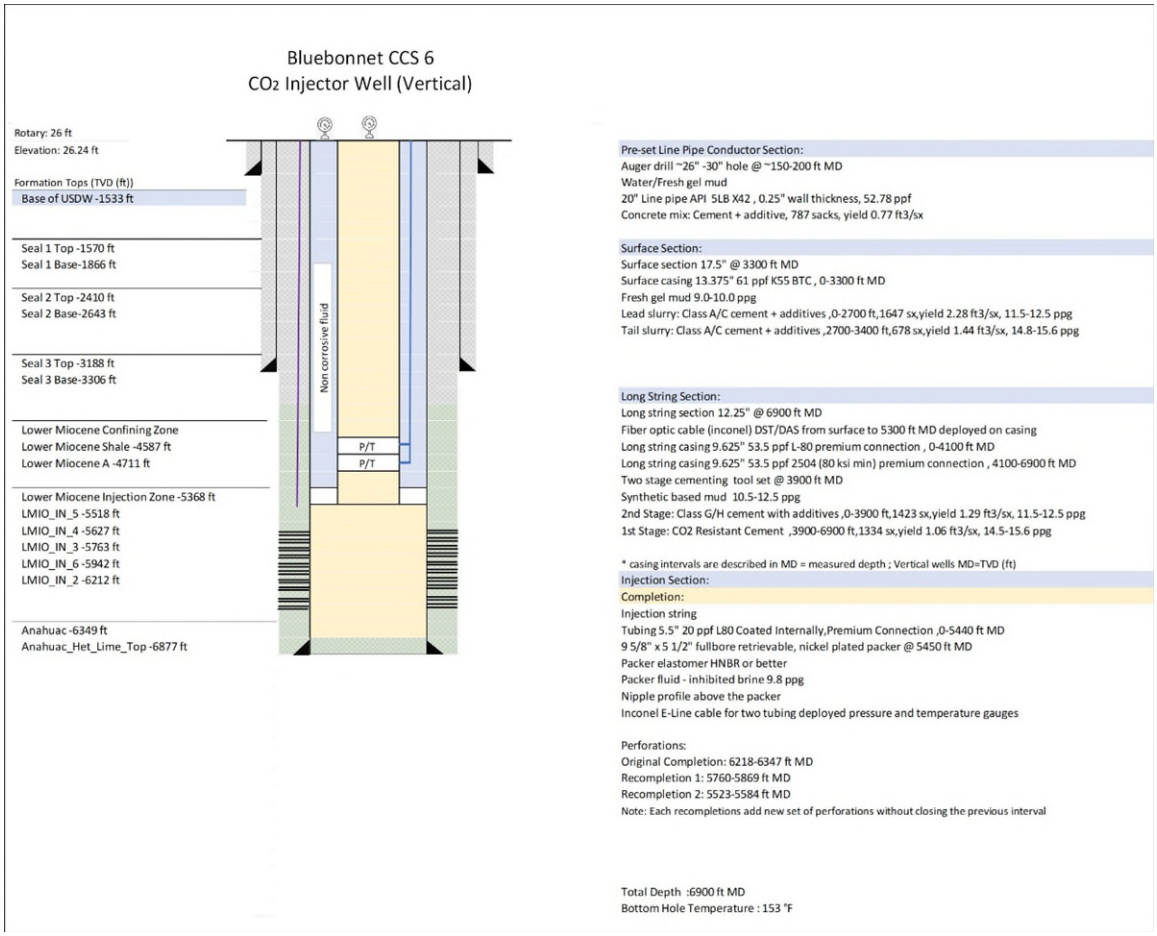


Figure NAR-25: Bluebonnet CCS 6 well schematic – original completion.

5.5.1 Conductor Bluebonnet CCS 6

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth of approximately 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mousehole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.5.2 Surface Section Bluebonnet CCS 6

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover the base of the USDW, estimated at 1,533 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken a minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run openhole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to the surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the UIC Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and BOP equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute an FIT.

5.5.3 Long String Section Bluebonnet CCS 6

A 12 ¼ in. vertical wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs and SWC and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

5.5.4 Completion Bluebonnet CCS 6

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

The 5 ½ in. tubing and packer completion will be run to approximately 5,450 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

5.6 Well Design and Construction: Bluebonnet CCS 7

The Bluebonnet CCS 7 well design includes three main sections, conductor casing, surface casing, and long string casing, to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

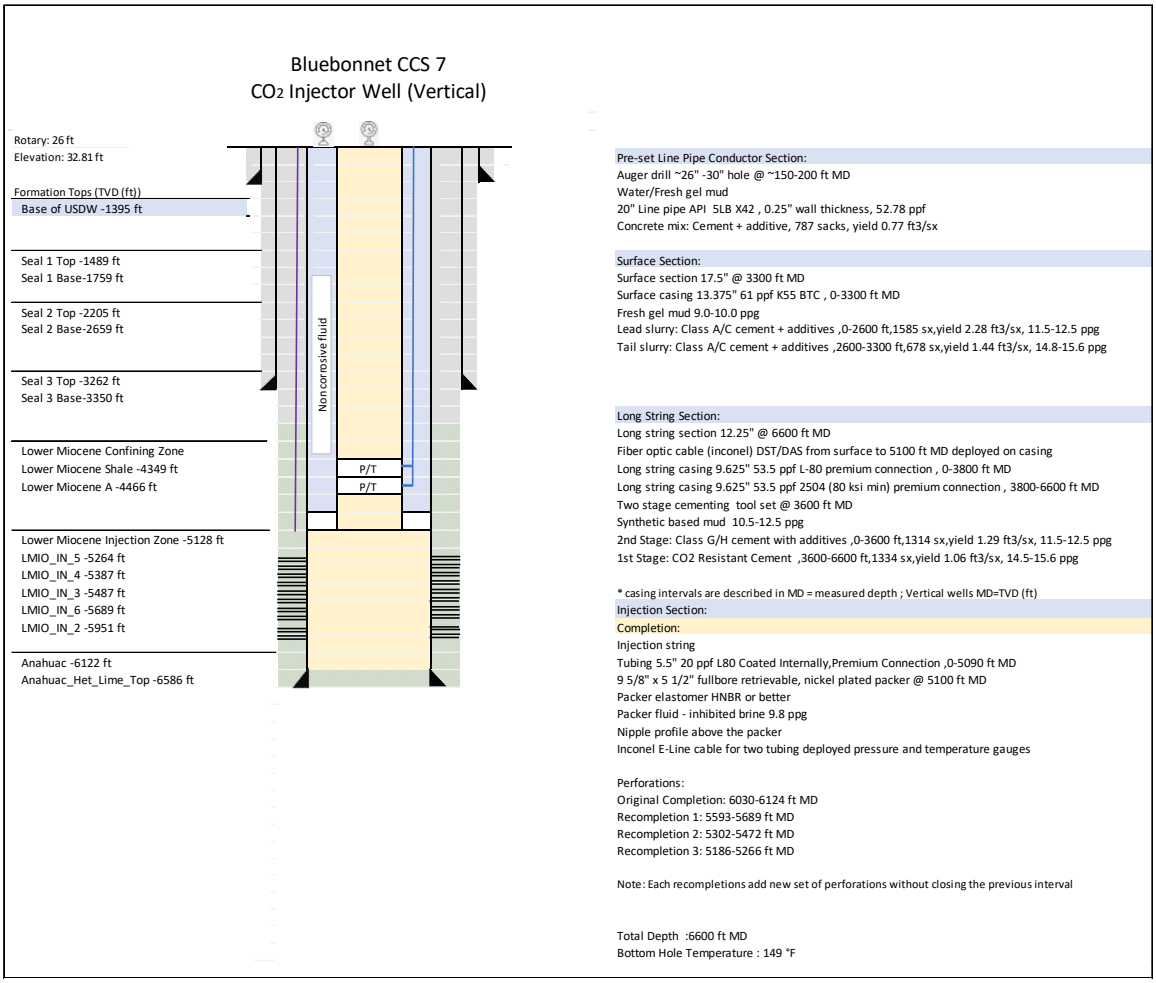


Figure NAR-26: Bluebonnet CCS 7 well schematic – original completion.

5.6.1 Conductor Bluebonnet CCS 7

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth of approximately 150 – 200 ft. The wellbore will be cased with a 20 in. line pipe and cemented with a mixture of concrete to the surface. This section will provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mousehole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.6.2 Surface Section Bluebonnet CCS 7

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover the base of the USDW, estimated at 1,395 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken a minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run openhole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to the surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the UIC Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and BOP equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute an FIT.

5.6.3 Long String Section Bluebonnet CCS 7

A 12 ¼ in. vertical wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs and SWC and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

5.6.4 Completion Bluebonnet CCS 7

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

The 5 ½ in. tubing and packer completion will be run to approximately 5,100 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

6.0 Pre-Operational Logging and Testing [40 CFR §146.82(a)(8)]

Bluebonnet Sequestration Hub, LLC, will construct six new CO_2 injection wells, (Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7), targeting injection in the Lower Miocene, Frio, and Hackberry sands.

In addition to the injector wells, the project will construct two new in-zone monitoring wells (Bluebonnet IZM FM1 and Bluebonnet IZM FM2) and will recomplete the stratigraphic well Encanto 01.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled the stratigraphic well Encanto 01 in 2022 and acquired advanced geophysical logs as well as 204 ft of full core and 22 sidewall cores (SWC). The project also performed step rate tests and falloff tests in the prospect reservoirs and leak-off tests on the proposed confining zones. The results and a summary of the data acquisition program for Encanto 01 are shown in Appendix A of the Area of Review and Corrective Action Plan. In May 2024, Encanto 01 was reentered to collect additional water samples from the Frio reservoir. Stratigraphic well Encanto 01 was temporarily abandoned and will be recompleted as an in-zone monitoring well for the project.

The project plans to construct two water producer wells (Bluebonnet PRDW F1 and Bluebonnet PRDW F2) to extract water from the Frio formation as a technique to control the pressure front during the injection phase.

The project defines the above-confining zone as the first permeable zone above the Miocene Composite Confining Zone. This first permeable formation is the base of the USDW as characterized by stratigraphic well Encanto 01 and mapped laterally though the storage complex.

In May 2024, the project drilled Bluebonnet USDW 1, targeting the shallow aquifers from the surface to 1,500 ft. The main objective of this well was to validate the base of the USDW and determine the water composition of the different flow units as part of the site characterization and

baseline for injection operations. The detailed data acquired during Bluebonnet USDW 1 construction is provided in Appendix B of the Area of Review and Corrective Action Plan. Bluebonnet USDW 1 will be used as a monitoring well for the shallow aquifer to monitor changes in water composition during the injection and post-injection phases of the project.

In 2025, the project team undertook the drilling of the Bluebonnet USDW 8 at the same location as the Encanto 01 well, with the primary objective of obtaining cores from the intershales situated within the Miocene Composite Confining Zone. The team successfully acquired 79 feet of whole cores and 35 sidewall cores. The well was drilled to a depth of 2,750 feet and subsequently plugg ed back to 1,050 feet. Completion of the well involved a lower completion with sand control scre ens and an upper completion featuring 1 ¼" tubing and an ESP pump installed at 300 feet. The detailed data acquired during Bluebonnet USDW 8 construction is provided in Appendix G of the Area of Review and Corrective Action Plan.

The project plans to construct one additional USDW monitoring well, Bluebonnet USDW 2 and three Miocene Composite Confining Zone monitoring wells (Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3). These wells will be used to track changes in pressure, in temperature and in water composition of the base of the USDW and within the Miocene Composite Confining Zone across the Hub.

The project also plans to drill one water disposal well (Bluebonnet DSW M2), targeting the sands of the Miocene formation above the Lower Miocene Confining Zone. This well will be used to dispose the water extracted from the Frio formation, as well as fluid generated during the construction and operation of the Bluebonnet site.

The Pre-Operational Formation Testing Plan for Bluebonnet Hub aims to obtain the chemical and physical characteristics of the injection and confining zone(s). This program includes a combination of logging, sidewall coring, formation hydrogeologic testing, and other activities performed during the drilling and construction of the CO_2 injection well, monitoring wells, water production wells, and water disposal wells.

The pre-operational testing program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the injection zone, overlying confining zone, and other relevant geologic formations. In addition, formation fluid characteristics are to be obtained from the injection zone to establish baseline data against which future measurements may be compared after the start of injection operations.

Specific details on the proposed pre-operational logging and testing program are found in Pre-Operational Testing Plan of this permit.

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing
Tab(s): Welcome tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

7.0 Proposed Stimulation Program [40 CFR §146.82(a)(9)]

Bluebonnet Sequestration Hub, LLC, may stimulate the injection zone in the CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 to enhance or regain injection capabilities.

Stimulation and cleanouts to enhance or regain the injection potential of the Lower Miocene, Frio and Hackberry sandstones in the CO_2 injector wells may include, but are not limited to, coil tubing cleanouts, stick pipe cleanouts, matrix acid stimulation, sand control procedures and water flushes.

The need for stimulation and cleanouts will be determined once the characterization data from the Bluebonnet Sequestration Hub is completed, and the wells are available and have been evaluated (i.e., results of geophysical logs, core analyses, and hydrogeologic testing, operating conditions).

8.0 Well Operation [40 CFR §146.88]

The CO_2 wells are designed to maximize the rate of injection and to reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the frac gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and to ensure continuous surveillance of external integrity and conformance through the external fiber optic cable. The design allows for other logs to be periodically run, (e.g., pulse neutron).

8.1 Operational Procedures [40 CFR 146.82(a)(10)]

The operational procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

During the startup period, Bluebonnet Sequestration Hub, LLC, will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, Bluebonnet Sequestration Hub, LLC, may be required to schedule a daily conference call to discuss this information. The injection rates will be successively higher, controlled with variable frequency drive pumps. The elapsed time and pressure values will be read and recorded for each rate and time step. The injection rate will be measured and recorded using a Coriolis meter.

Additional operational parameters are detailed in the Summary of Operating Conditions document of this permit. Table NAR-5 through Table NAR-10 show the operating parameters proposed for the CO_2 injector wells.

Table NAR-5: Bluebonnet CCS 1 Operating Conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top-bottom (ft)	8,180-8,468	7,967-8,468	8,766-8,950
Perforation interval TVD[2], top-bottom (ft)	8,031-8,306	7,828-8,306	8,591-8,768
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	1,370
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	1,300-1,900
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,495	5,355	5,880
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	5,405	5,335	5,795
Bottomhole gauge depth MD/TVD (ft)	7,900/7,763	7,900/7,763	8,500/8,337
Operating injection rate (metric tonnes per day)	5,480	5,480	1,370
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100	1,300-1,900
Minimum annulus-/tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	16	14	2.5

1. MD: measured depth.
2. TVD: true vertical depth.
3. Maximum rate is limited by tubing size, not by reservoir.

Table NAR-6: Bluebonnet CCS 2 Operating Conditions.

Parameter/Completion	Completion 1	Completion 2
Perforation interval MD[1], top-bottom (ft)	8,237-8,514	8,009-8,514
Perforation interval TVD[2], top-bottom (ft)	7,974-8,230	7,766-8,230
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,455	5,315
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	5,370	5,295
Bottomhole gauge depth MD/TVD (ft)	7,950/7,711	7,950/7,711
Operating injection rate (average) (metric tonnes per day)	4,660	4,660
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100
Average bottomhole pressure at operating rate (psi)	3870	3780
Minimum annulus /tubing differential pressure (psig)	100	100
Total volume injected (millions of tonnes)	13.6	11.9

1. MD: measured depth.
2. TVD: true vertical depth.
3. Maximum rate is limited by tubing size, not by reservoir.

Table NAR-7: Bluebonnet CCS 3 Operating Conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top-bottom (ft)	8,418-8,763	7,943-8,223	7,659-8,223
Perforation interval TVD[2], top-bottom (ft)	8,138-8,459	7,697-7,957	7,433-7,957
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,570	5,265	5,085
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	5,315	5,160	5,065
Bottomhole gauge depth MD/TVD (ft)	7,600/7,376	7,600/7,376	7,600/7,376
Operating injection rate (average) (metric tonnes per day)	3,840	3,840	2,740
Operating wellhead surface injection pressure (psig)	1,000-1,800	1,000-1,800	1,000-1,600
Minimum annulus /tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	11.2	11.2	5

1. MD: measured depth.
2. TVD: true vertical depth.
3. Maximum rate is limited by tubing size, not by reservoir.

Table NAR-8: Bluebonnet CCS 5 Operating Conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4	Completion 5
Perforation interval MD, top-bottom (ft)	6,330-6,464	6,053-6,181	5,820-5,975	5,646-5,734	5,481-5,502
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,330	4,140	3,980	3,860	3,750
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	4,025	3,925	3,845	3,780	3,725
Bottomhole gauge depth MD (ft)	5,400	5,400	5,400	5,400	5,400
Operating injection rate (average) (metric tonnes per day)	5,095	5,095	5,095	5,095	5,095
Operating wellhead surface injection pressure (psig)	1,000-1,500	1,000-1,500	1,000-1,500	1,000-1,500	1,000-1,500
Minimum annulus /tubing differential pressure (psig)	100	100	100	100	100
Total volume injected (millions of tonnes)	7.44	5.58	7.44	3.72	3.72

1. MD: measured depth.
2. Maximum rate is limited by tubing size, not by reservoir.

Table NAR-9: Bluebonnet CCS 6 Operating Conditions

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD, top-bottom (ft)	6,218-6,347	5,760-5,869	5,523-5,584
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,250	3,940	3,780
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	4,000	3,840	3,755
Bottomhole gauge depth MD (ft)	5,450	5,450	5,450
Operating injection rate (average) (metric tonnes per day)	4,465	4,465	4,465
Operating wellhead surface injection pressure (psig)	950-1,500	950-1,500	950-1,500
Minimum annulus /tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	11.41	11.41	1.63

1. MD: measured depth.
2. Maximum rate is limited by tubing size, not by reservoir.

Table NAR-10: Bluebonnet CCS 7 Operating Conditions

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4
Perforation interval MD, top-bottom (ft)	6,030-6,124	5,593-5,689	5,302-5,472	5,186-5,266
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,125	3,825	3,630	3,550
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	3,820	3,665	3,560	3,520
Bottomhole gauge depth MD (ft)	5,100	5,100	5,100	5,100
Operating injection rate (average) (metric tonnes per day)	3,808	3,808	3,808	3,808
Operating wellhead surface injection pressure (psig)	900-1,300	900-1,300	900-1,300	900-1,300
Minimum annulus /tubing differential pressure (psig)	100	100	100	100
Total volume injected (millions of tonnes)	5.56	5.56	5.56	4.17

1. MD: measured depth.
2. Maximum rate is limited by tubing size, not by reservoir.

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well that will prevent the return of the injection fluid to the surface. The wellbore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that can resist the pressure differential. A BOP must be installed and kept in proper operational condition whenever the wellhead is removed for work on the well.

Bluebonnet Sequestration Hub, LLC, shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

8.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The proposed carbon dioxide stream composition is shown below in Table NAR-11. No injectant other than that identified in this permit shall be injected into the well except fluids used for stimulation, rework, and well tests as approved by the UIC Program Director.

Table NAR-11: CO_2 stream composition.

Component	Specification
CO_2 (% mol)	>95
Water (lb/MMCF)	<10
Nitrogen (% mol)	<4
Oxygen (ppm by wt.)	<10
Hydrogen (% mol)	<1
SO_x (ppm by wt.)	<1
NO_x (ppm by wt.)	<1
Hydrogen Sulfide (ppm by vol)	<20
HCN (ppm by vol)	<40
Hydrocarbons (% mol)	<5
Carbon Monoxide (ppm by wt.)	<4,250
Glycol (gal/MMSCF)	<0.3
Ammonia (ppm by wt.)	<50
Argon (% mol)	<1
Sulfur (ppm by wt.)	<35
Carbonyl Sulfide (ppmv)	<5
Alcohols (ppmv)	<3,000

8.3 Reporting and Record Keeping

Electronic reports, submittals, notifications, and records made and maintained by Bluebonnet Sequestration Hub, LLC, under this permit must be in an electronic format approved by EPA. Bluebonnet Sequestration Hub, LLC, will electronically submit all required reports to the UIC Program Director.

Bluebonnet Sequestration Hub, LLC, shall submit semiannual reports containing:

- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data.
- Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure.
- A description of any event that exceeds operating parameters for the annulus or injection pressure specified in the permit.
- A description of any event that triggers the required shutoff systems and the responses taken.
- The monthly volume and/or mass of the CO_2 stream injected over the reporting period and volume and/or mass injected cumulatively over the life of the project.
- Monthly annulus fluid volume added or produced.
- Results of the continuous monitoring required including:
  - A tabulation of the:
    (1) daily maximum injection pressure
    (2) daily minimum annulus pressure
    (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure
    (4) daily volume
    (5) daily maximum flow rate
    (6) average annulus tank fluid level
  - Graph(s) of the continuous monitoring required or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director.
- Results of any additional monitoring identified in the Testing and Monitoring Plan.

Any permit noncompliance shall be reported to the Director within 24 hours as described below:

- Bluebonnet Sequestration Hub, LLC, shall report to the Director any permit noncompliance that may endanger human health or the environment, and/or any events that require implementation of actions in the Emergency and Remedial Response Plan document of this permit. Any information shall be provided orally within 24 hours from the time Bluebonnet Sequestration Hub, LLC, becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:
  - Any evidence that the injected CO_2 stream or associated pressure front may have caused an endangerment to a USDW or any monitoring or other information, which indicates that any contaminant may have caused endangerment to a USDW.
  - Any noncompliance with a permit condition or malfunction of the injection system, which may have caused fluid migration into or between USDWs.
  - Any triggering of the shutoff system.
  - Any failure to maintain mechanical integrity.
  - Pursuant to compliance with the requirement at 40 CFR 146.90 (h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of CO_2 to the atmosphere or biosphere.
  - Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan document of this permit.
- A written submission shall be provided to the Director in electronic format within five days of the time Bluebonnet Sequestration Hub, LLC, becomes aware of the circumstances. The submission shall contain a description of the noncompliance and its cause; the period of noncompliance (including the exact dates and times); and if the noncompliance has not been corrected, then the anticipated time it is expected to continue, as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan document of this permit. This submission should also include the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

Within 30 days, Bluebonnet Sequestration Hub, LLC, will report to the Director the results of periodic tests of mechanical integrity; any well workover, including stimulation; any other test of the injection well conducted by the Project, if required by the Director; and any test of any monitoring well required by this permit.

The following items require advance notification from Bluebonnet Sequestration Hub, LLC, to the Director:

- **Well Tests –** Bluebonnet Sequestration Hub, LLC, shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.
- **Planned Changes** – Bluebonnet Sequestration Hub, LLC, shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or

maintenance activities. An analysis of any new injection fluid shall be submitted to the Director for review and written approval at least 30 days prior to injection. This approval may result in a permit modification.

- **Anticipated Noncompliance –** Bluebonnet Sequestration Hub, LLC, shall give at least 14 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity that may result in noncompliance with the permit requirements.

The following paragraphs include other reporting requirements:

- **Compliance Schedules –** Reports of compliance or noncompliance with or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by Bluebonnet Sequestration Hub, LLC, no later than 30 days following each scheduled date.
- **Transfer of Permits –** This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to the transfer and requirements of 40 CFR 144.38 (a) have been met. Pursuant to the requirements at 40 CFR 144.38 (a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.
- **Other Noncompliance –** Bluebonnet Sequestration Hub, LLC, shall report in an electronic format all other instances of noncompliance not otherwise reported in the next monitoring report. The reports shall contain the information previously listed in Section N (3)(b) of this permit.
- **Other Information –** When Bluebonnet Sequestration Hub, LLC, becomes aware of a failure to submit any relevant facts in the permit application or incorrect information has been submitted in a permit application or in any report to the Director, the Bluebonnet Sequestration Hub, LLC, shall submit such facts or corrected information in an electronic format, within 10 days, in accordance with 40 CFR 144.51 (l)(8).
- **Report on Permit Review –** Within 30 days of receipt of this permit, Bluebonnet Sequestration Hub, LLC Project Manager, shall certify to the UIC Program Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

The following guidelines are provided for record keeping:

- Bluebonnet Sequestration Hub, LLC, shall retain records and all monitoring information, including all calibration and maintenance records and original chart recordings for continuous monitoring instrumentation and copies of all reports required

by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

- Bluebonnet Sequestration Hub, LLC, shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations and plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.
- Bluebonnet Sequestration Hub, LLC, shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.
- The retention periods may be extended at any time at a request of the Director. Bluebonnet Sequestration Hub, LLC, shall continue to retain records after the specified retention period of this permit or any requested extension thereof expires, unless Bluebonnet Sequestration Hub, LLC, delivers the records to the Director or obtains written approval from the Director to discard the records.
- Records of monitoring information shall include:
  - The date, exact place, and time of sampling or measurements.
  - The name(s) of the individual(s) who performed the sampling or measurements.
  - A precise description of both the sampling methodology and handling of samples.
  - The date(s) analyses were performed.
  - The name(s) of the individual(s) who performed the analyses.
  - The analytical techniques or methods used.
  - The results of such analyses.

9.0 Testing and Monitoring [40 CFR §146.82(a)(15)]

The Testing and Monitoring Plan document of this permit describes how Bluebonnet Sequestration Hub, LLC, will monitor the Bluebonnet Sequestration Hub pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geomodel used to predict the distribution of the CO_2 within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

Bluebonnet Hub Testing and Monitoring Plan was tailored based on a qualitative risk assessment of the site that was also used to inform the Emergency and Remedial Response Plan for the Bluebonnet Hub.

Several components are integrated into the master monitoring plan for the Bluebonnet Hub, which are classified in the following categories:

1. Operational testing and monitoring during injection.
2. Mechanical integrity testing.
3. Groundwater quality and geochemical monitoring.
4. CO_2 plume and pressure-front tracking.

5. Near-surface and surface monitoring.
6. Induced seismicity.

The methodology and frequency of testing and monitoring methods are expected to change throughout the project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure the containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment.

The proposed testing and monitoring plan will collect sufficient geospatial and monitoring data to validate the numerical simulation model, inform operational decisions on the quantity and rate of CO_2 injected, and trigger corrective or preventive maintenance actions, amongst others, to operate the site as designed, efficiently and safely. The monitoring results will allow the project to reevaluate the AoR and show that there is no endangerment to the USDW.

Bluebonnet Sequestration Hub, LLC, plans to drill six CO_2 injector wells: Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7, as part of the field development plan for the Bluebonnet Hub. The monitoring program proposed is designed based on the modeled CO_2 plume extension and propagation of the pressure front for the three wells injecting simultaneously according to the AoR delineation process.

Each CO_2 injector will be equipped with flow rate meters, pressure and temperature transducers at the surface, and downhole pressure and temperature gauges to monitor real time variations in operating conditions that could indicate changes in reservoir behaviors or potential loss of mechanical integrity. The well designs include the installation of fiber optic cable from surface to the top of the injection target, providing the capability for real-time monitoring a continuous distribution of temperature alongside the casing and enabling the project to execute frequent vertical seismic profile (VSP) surveys to image the CO_2 plume.

The proposed monitoring plan includes a layout of three in-zone (reservoir) monitoring wells, (Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01). These wells will be equipped with pressure and temperature transducers on the surface as well as pressure and temperature gauges downhole to monitor in real time the variation of pressure and temperature in the reservoir. These wells will allow the use of pulse neutron logs to identify early breakthroughs of CO_2 if required and will be equipped with fiber optic cable alongside the casing, except for Encanto 01, enabling the project to perform VSP surveys to calibrate the early response of the injection.

The Testing and Monitoring Plan includes three USWD monitoring wells (Bluebonnet USDW 1, Bluebonnet USDW 2 and Bluebonnet USDW 8) and three Miocene Composite Confining Zone monitoring wells (Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3) to track geochemical changes in the aquifers as well as pressure and temperature variations. Bluebonnet USWD 1 was drilled in 2024 and Bluebonnet USDW 8 was drilled in 2025 as part of the efforts to characterize the USDW and the Miocene Composite Confining Zone.

In addition to utilizing a well-based network to monitor pressure, temperature, CO_2 plume migration, and geochemistry changes in aquifers, the Bluebonnet Hub will also employ surface and near-surface methods to monitor CO_2 containment. Details for all the monitoring techniques proposed for Bluebonnet Hub are described in the Testing and Monitoring Plan of this permit.

9.1 Mechanical Integrity

Bluebonnet Sequestration Hub, LLC, will conduct tests to verify the internal and external mechanical integrity of the CO_2 injector wells before and during the injection period pursuant to 40 CFR §146.89(c), 40 CFR §146.90(e), 40 CFR §146.87(a)(2)(ii), and 40 CFR §146.87 (a)(3)(ii)]. Other than during periods of well workover or maintenance approved by the UIC Program Director, in which the sealed tubing-casing annulus will be disassembled for maintenance or corrective procedures, the injection wells must have and maintain mechanical integrity consistent with 40 CFR 146.89.

The purpose of internal mechanical integrity testing is to confirm the absence of significant leakage withing the injection tubing, casing, or packer [40 CFR§146.89 (a)(1)]. Continuous monitoring of injection pressure, injection rate, injected volume, and annulus pressure will be used to ensure internal mechanical integrity.

The purpose of external mechanical integrity testing is to confirm the absence of significant leakage outside of the casing [40 CFR §146.89(a)(2)]. The Bluebonnet Hub proposes conducting pulse neutron logs in the CO_2 injector wells on an annual basis to demonstrate external mechanical integrity. In addition, the Bluebonnet Hub plans to monitor continuous temperature profiles above the injection zone in real time using DTS technology.

Additional details regarding demonstration of mechanical integrity are described in the Testing and Monitoring Plan, the Well Construction Details Plan, the Pre-Operational Formation Testing Plan, and the Plugging Plan.

Bluebonnet Sequestration Hub, LLC, will observe the following reporting guidelines:

- Bluebonnet Sequestration Hub, LLC, shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. However, at the discretion of the Director, a shorter time may be allowed.

- Bluebonnet Sequestration Hub, LLC, shall report in an electronic format the results of a mechanical integrity demonstration. Reports of mechanical integrity demonstrations that contain logs must include an interpretation of the results by a knowledgeable log analyst.

- Bluebonnet Sequestration Hub, LLC, shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the UIC Program Director in an electronic format with the report of

the test. Pressure gauge resolution shall be no greater than 5 psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the UIC Program Director prior to the test.

Bluebonnet Sequestration Hub, LLC, must adhere to the following guidelines regarding failure to maintain mechanical integrity:

- If Bluebonnet Sequestration Hub, LLC, or Director finds that the well fails to demonstrate mechanical integrity during a test; is unable to maintain mechanical integrity during operation; or that a loss of mechanical integrity as defined by 40 CFR 146.89 (a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the project must:

    - Immediately cease injection.
    - Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, Bluebonnet Sequestration Hub, LLC, shall implement the Emergency and Remedial Response Plan document of this permit.
    - Follow the reporting requirements as directed in the Emergency and Remedial Response Plan.
    - Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Program Director prior to resuming injection.
    - Notify the Program Director in an electronic format when injection is expected to resume.

- If a shutdown (e.g., downhole or at the surface) is triggered, Bluebonnet Sequestration Hub, LLC, must immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity or if monitoring required indicates that the well may be lacking mechanical integrity, Bluebonnet Sequestration Hub, LLC, must take the actions as described in the Emergency and Remedial Response Plan.

- If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. Bluebonnet Sequestration Hub, LLC, shall not resume injection until the mechanical integrity is demonstrated and the Program Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

Bluebonnet Sequestration Hub, LLC, shall demonstrate mechanical integrity at any time upon written notice from the UIC Program Director.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions

Tab(s): Testing and Monitoring tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

10.0 Injection Well Plugging [40 CFR §146.82(a)(16)]

Upon the end of life, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 will be plugged and abandoned (P&A) consistent with the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of CO_2 with water mixtures, and protect any underground sources of drinking water (USDWs).

Detailed plugging procedures and diagrams are presented in the Plugging Plan that is submitted as part of this application.

Injection Well Plugging GSDT Submissions

GSDT Module: Project Plan Submissions
Tab(s): Injection Well Plugging tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

11.0 Post-Injection Site Care (PISC) and Site Closure [40 CFR §146.82(a)(17)]

The Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Bluebonnet Sequestration Hub, LLC, will perform to meet the requirements of 40 CFR 146.93. Bluebonnet Sequestration Hub, LLC, will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years. Bluebonnet Sequestration Hub, LLC, may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, Bluebonnet Sequestration Hub, LLC, will plug all remaining monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

PISC and Site Closure GSDT Submissions

GSDT Module: Project Plan Submissions
Tab(s): PISC and Site Closure tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***

PISC and Site Closure GSDT Submissions
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

12.0 Emergency and Remedial Response [40 CFR §146.82(a)(19)]

The Emergency and Remedial Response Plan (ERRP) document of this permit describes actions that Bluebonnet Sequestration Hub, LLC, shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If Bluebonnet Sequestration Hub, LLC, obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, Bluebonnet Sequestration Hub, LLC, will initiate shutdown plan for the injection well, take all steps reasonably necessary to identify and characterize any release, notify the permitting agency (UIC Program Director) of the emergency event within 24 hours, and implement applicable portions of the approved ERRP.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

13.0 Injection Depth Waiver and Aquifer Exemption Expansion

Injection depth waivers are not requested in this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

14.0 References

Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Frailey, S., Small, M., Allen, D., Romanov, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, B., and Guthrie, G., 2011. U.S. DOE Methodology for the Development of Geologic Storage Potential for Carbon Dioxide at the National and Regional Scale, J. Greenhouse Gas Control, Vol 5, pp 952-965.

Hovorka, S. D., Holtz, M. H., Sakurai, S., Knox, P. R., Collins, D., Papadeas, P., and Stehli, D. 2003. Frio pilot in CO_2 sequestration in brine-bearing sandstones: The University of Texas at Austin, Bureau of Economic Geology, report to the Texas Commission on Environmental Quality to accompany a class V application for an experimental technology pilot injection well. GCCC Digital Publication Series #03- 04.

Tinsley, W. E., Shurbet, M., Gilmore, R. B., Potts, M. T., McCoy, J. H., Illig, C., Burleigh, H. P., Arnow, S. 1971. Report 133: Ground-Water Resources of Chambers and Jefferson Counties, Texas. Prepared by United States Geological Survey in cooperation with the Texas Water Development Board.

Young, S. C., Jigmong, M., Deeds, N., Blainey, J. et al. 2016. Final Report: Identification of Potential Brackish Groundwater Production Areas – Gulf Coast Aquifer System, Texas Water Development Board Contract Number 1600011947, Intera Incorporated.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas
29.81179233, -94.4364423 (North American Datum 1927)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1.

Table OP-1: Injection well operating conditions.

Parameter/Completion (TVD ft)	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top-bottom (ft)	8,180-8,468	7,967-8,468	8,766-8,950
Perforation interval TVD[2], top-bottom (ft)	8,031-8,306	7,828-8,306	8,591-8,768
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	1,370
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	1,300-1,900
Maximum bottom hole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,495	5,355	5,880
Maximum bottom hole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	5,405	5,335	5,795
Bottomhole gauge depth MD/TVD (ft)	7,900/7,763	7,900/7,763	8,500/8,337
Operating injection rate (metric tonnes per day)	5,480	5,480	1,370
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100	1,300-1,900
Minimum annulus/tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	16	14	2.5

(1) MD: measured depth.
(2) TVD: true vertical depth.
(3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 1 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01, performed in 2023. Analysis of the well test in the stratigraphic well in the Lower Frio formation shows a fracture gradient of 0.76 psi/ft. The Hackberry Injection Zone was also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of 0.76 psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Completion 1 = 8,031 ft x 0.9 x 0.76 psi/ft = 5,493 psig
Completion 2 = 7,828 ft x 0.9 x 0.76 psi/ft = 5,354 psig
Completion 3 = 8,591 ft x 0.9 x 0.76 psi/ft = 5,876 psig

The downhole gauge for injection pressure monitoring will be located at approximately 7,763 ft TVD during Completion 1 and Completion 2. For Completion 3, the gauges will be at 8,337 ft TVD. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Completion 1: 5,493 psig - (8,031-7,763) ft x 0.33 psi/ft = 5,404 psig
Completion 2: 5,354 psig - (7,828-7,763) ft x 0.33 psi/ft = 5,332 psig
Completion 3: 5,876 psig - (8,591-8,337) ft x 0.33 psi/ft = 5,792 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The main pipeline design pressure is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 1 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 1 wellhead will be between 1,200 and 2,100 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,500 psig at the maximum injection rate proposed, with wellhead pressure setpoints of 2,650 and 2,850 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long-string casing and tubing was estimated as follows:

DP (psi) = max bottom hole pressure during injection – hydrostatic pressure in annulus +100 psi

Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2: Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the Bluebonnet Hub will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below, in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,500 psig, measured at the wellhead.
(4) The planned injection rates are shown in Table OP-3.

Table OP-3: Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	24	40
2,740	24	50
3,616	24	60
4,548	24	70
4,932	24	80
5,206	24	90
5,480	24	100

(5) The injection rates will be controlled with variable-frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.
(b) The permittee will notify the agency within 24 hours of the determination.
(c) The permittee will consult with the agency before initiating any further injection.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Well Name: Bluebonnet CCS 2

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas
29.804552, -94.463937 (North American Datum 1927)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion (TVD ft)	Completion 1	Completion 2
Perforation interval MD[1], top-bottom (ft)	8,237-8,514	8,009-8,514
Perforation interval TVD[2], top-bottom (ft)	7,974-8,230	7,766-8,230
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,455	5,315
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	5,370	5,295
Bottomhole gauge depth MD/TVD (ft)	7,950/7,711	7,650/7,711
Operating injection rate (average) (metric tonnes per day)	4,660	4,660
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100
Minimum annulus /tubing differential pressure (psig)	100	100
Total volume injected (millions of tonnes)	13.6	11.9

(1) MD: measured depth.
(2) TVD: true vertical depth.
(3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 2 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of 0.76 psi/ft.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Completion 1 = 7,974 ft x 0.9 x 0.76 psi/ft = 5,454 psig
Completion 2 = 7,766 ft x 0.9 x 0.76 psi/ft = 5,311 psig

The downhole gauge for injection pressure monitoring will be located at approximately 7,711 ft TVD during Completion 1 and Completion 2. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Completion 1: 5,454 psig - (7,974-7,711) ft x 0.33 psi/ft = 5,367 psig
Completion 2: 5,311 psig - (7,766-7,711) ft x 0.33 psi/ft = 5,292 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 2 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 2 wellhead will be between 1,200 and 2,100 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,500 psig at the maximum injection rate, with wellhead pressure setpoints of 2,650 and 2,850 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing was estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi

Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shutoff device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and

methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,500 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
2,191	24	40
2,740	24	50
3,616	24	70
4,548	24	80
4,660	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:
    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.

(c) The permittee will consult with the agency before initiating any further injection.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 3

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas
29.852812, -94.498078 (North American Datum 1927)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top-bottom (ft)	8,418-8,763	7,943-8,223	7,659-8,223
Perforation interval TVD[2], top-bottom (ft)	8,138-8,459	7,697-7,957	7,433-7,957
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,570	5,265	5,085
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	5,315	5,160	5,065
Bottomhole gauge depth MD/TVD (ft)	7,600/7,376	7,600/7,376	7,600/7,376
Operating injection rate (average) (metric tonnes per day)	3,840	3,840	2,740
Operating wellhead surface injection pressure (psig)	1,000-1,800	1,000-1,800	1,000-1,600
Minimum annulus /tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	11.2	11.2	5

(1) MD: measured depth.
(2) TVD: true vertical depth.
(3) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 3 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of 0.76 psi/ft. The Hackberry Injection zone was also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of 0.76 psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Completion 1 = 8,138 ft x 0.9 x 0.76 psi/ft = 5,566 psig
Completion 2 = 7,697 ft x 0.9 x 0.76 psi/ft = 5,264 psig
Completion 3 = 7,433 ft x 0.9 x 0.76 psi/ft = 5,084 psig

The downhole gauge for injection pressure monitoring will be located at approximately 7,376 ft TVD during Completion 1, Completion 2, and Completion 3. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Completion 1: 5,566 psig - (8,138-7,376) ft x 0.33 psi/ft = 5,314 psig
Completion 2: 5,264 psig - (7,697-7,376) ft x 0.33 psi/ft = 5,158 psig
Completion 2: 5,084 psig - (7,433-7,376) ft x 0.33 psi/ft = 5,065 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 3 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 3 wellhead will be between 1,000 and 1,800 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,500 psig at the maximum injection rate, with wellhead pressure setpoints of 2,600 and 2,750 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi
Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,500 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,500	24	40
1,900	24	50
2,690	24	70
3,070	24	80
3,840	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the

injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.
(b) The permittee will notify the agency within 24 hours of the determination.
(c) The permittee will consult with the agency before initiating any further injection.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 5

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas
29.812133, -94.436456 (North American Datum 1927)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4	Completion 5
Perforation interval MD, top-bottom (ft)	6,330-6,464	6,053-6,181	5,820-5,975	5,646-5,734	5,481-5,502
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,330	4,140	3,980	3,860	3,750
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	4,025	3,925	3,845	3,780	3,725
Bottomhole gauge depth MD (ft)	5,400	5,400	5,400	5,400	5,400
Operating injection rate (average) (metric tonnes per day)	5,095	5,095	5,095	5,095	5,095
Operating wellhead surface injection pressure (psig)	1,000-1,500	1,000-1,500	1,000-1,500	1,000-1,500	1,000-1,500
Minimum annulus /tubing differential pressure (psig)	100	100	100	100	100
Total volume injected (millions of tonnes)	7.44	5.58	7.44	3.72	3.72

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 5 well is 90% of the fracture propagation pressure of the Frio

injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of 0.76 psi/ft. The Lower Miocene and Hackberry injection zones were also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of 0.76 psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Completion 1 = 6,330 ft x 0.9 x 0.76 psi/ft = 4,330 psig
Completion 2 = 6,053 ft x 0.9 x 0.76 psi/ft = 4,140 psig
Completion 3 = 5,820 ft x 0.9 x 0.76 psi/ft = 3,980 psig
Completion 4 = 5,646 ft x 0.9 x 0.76 psi/ft = 3,860 psig
Completion 5 = 5,481 ft x 0.9 x 0.76 psi/ft = 3,750 psig

The downhole gauge for injection pressure monitoring will be located at approximately 5,400 ft MD during Completion 1, Completion 2, Completion 3, Completion 4 and Completion 5. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Completion 1: 4,330 psig - (6,330-5,400) ft x 0.33 psi/ft = 4,023 psig
Completion 2: 4,140 psig - (6,053-5,400) ft x 0.33 psi/ft = 3,924 psig
Completion 3: 3,980 psig - (5,820-5,400) ft x 0.33 psi/ft = 3,841 psig
Completion 4: 3,860 psig - (5,646-5,400) ft x 0.33 psi/ft = 3,778psig
Completion 5: 3,750 psig - (5,481-5,400) ft x 0.33 psi/ft = 3,723 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 5 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 5 wellhead will be between 1,000 and 1,500 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,200 psig at the maximum injection rate, with wellhead pressure setpoints of 2,250 and 2,300 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi
Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,600	24	30
2,200	24	40
2,750	24	50
3,300	24	60
3,850	24	70
4,400	24	80
4,950	24	90
5,494	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.
    (c) The permittee will consult with the agency before initiating any further injection.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 6

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas
29.817417, -94.464104 (North American Datum 1927)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD, top-bottom (ft)	6,218-6,347	5,760-5,869	5,523-5,584
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,250	3,940	3,780
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	4,000	3,840	3,755
Bottomhole gauge depth MD (ft)	5,450	5,450	5,450
Operating injection rate (average) (metric tonnes per day)	4,465	4,465	4,465
Operating wellhead surface injection pressure (psig)	950-1,500	950-1,500	950-1,500
Minimum annulus /tubing differential pressure (psig)	100	100	100
Total volume injected (millions of tonnes)	11.41	11.41	1.63

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 6 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of 0.76 psi/ft. The Lower Miocene and Hackberry Injection zone were also tested in 2023 in the stratigraphic well. The test reached the maximum injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of 0.76 psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Completion 1 = 6,218 ft x 0.9 x 0.76 psi/ft = 4,253psig
Completion 2 = 5,760 ft x 0.9 x 0.76 psi/ft = 3,939 psig
Completion 3 = 5,523 ft x 0.9 x 0.76 psi/ft = 3,777 psig

The downhole gauge for injection pressure monitoring will be located at approximately 5,450 ft TVD during Completion 1, Completion 2, and Completion 3. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Completion 1: 4,253 psig - (6,218-5,450) ft x 0.33 psi/ft = 4,000 psig
Completion 2: 3,939 psig - (5,760-5,450) ft x 0.33 psi/ft = 3,836 psig
Completion 2: 3,777 psig - (5,523-5,450) ft x 0.33 psi/ft = 3,752 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 6 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 6 wellhead will be between 950 and 1,500 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,200 psig at the maximum injection rate, with wellhead pressure setpoints of 2,250 and 2,300 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi
Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the Project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,300 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,500	24	30
1,900	24	40
2,400	24	50
2,900	24	60
3,350	24	70
3,900	24	80
4,300	24	90
4,794	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.
(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.
(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the

injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.
(b) The permittee will notify the agency within 24 hours of the determination.
(c) The permittee will consult with the agency before initiating any further injection.

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 7

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas
29.853222, -94.498078 (North American Datum 1927)

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements are specified in this attachment and are summarized below in Table OP-1

Table OP-1—Injection well operating conditions.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4
Perforation interval MD, top-bottom (ft)	6,030-6,124	5,593-5,689	5,302-5,472	5,186-5,266
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,125	3,825	3,630	3,550
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at bottomhole gauge (psig)	3,820	3,665	3,560	3,520
Bottomhole gauge depth MD (ft)	5,100	5,100	5,100	5,100
Operating injection rate (average) (metric tonnes per day)	3,808	3,808	3,808	3,808
Operating wellhead surface injection pressure (psig)	900-1,300	900-1,300	900-1,300	900-1,300
Minimum annulus /tubing differential pressure (psig)	100	100	100	100
Total volume injected (millions of tonnes)	5.56	5.56	5.56	4.17

(1) MD: measured depth.
(2) Maximum rate is limited by tubing size, not by reservoir.

Notes:

- 5 ½ in. tubing select as injection string.
- Assumed 90°F as injection temperature for the CO_2 on surface for maximum pressure calculations for estimations.

2.1 Maximum Bottomhole Injection Pressure

The maximum injection pressure limitation serves to prevent fracturing the confining formation. Operating requirements from 40 CFR 146.88(a) specify that injection pressure must not exceed 90% of the injection zone fracture pressure. To meet this requirement, the maximum pressure considered for the Bluebonnet CCS 7 well is 90% of the fracture propagation pressure of the Frio injection zone, measured with downhole pressure gauges during the testing of the stratigraphic well Encanto 01 performed in 2023. Analysis of the well test in the stratigraphic well in the Frio Lower formation shows a fracture gradient of 0.76 psi/ft. The Lower Miocene and Hackberry injection zones were also tested in 2023 in the stratigraphic well. The test reached the maximum

injection rate proposed of 34-36 bpm without creating a fracture in the formation. A conservative fracture gradient value of 0.76 psi/ft was used based on the Frio fracture gradient.

The maximum bottomhole pressures at the top of perforations are calculated as follows:

Completion 1 = 6,030 ft x 0.9 x 0.76 psi/ft = 4,124 psig
Completion 2 = 5,593 ft x 0.9 x 0.76 psi/ft = 3,825 psig
Completion 3 = 5,302 ft x 0.9 x 0.76 psi/ft = 3,626 psig
Completion 4 = 5,186 ft x 0.9 x 0.76 psi/ft = 3,547 psig

The downhole gauge for injection pressure monitoring will be located at approximately 5,100 ft MD during Completion 1, Completion 2, Completion 3, and Completion 4. Therefore, the maximum injection pressures using a downhole pressure gauge are calculated as:

Completion 1: 4,124 psig - (6,030-5,100) ft x 0.33 psi/ft = 3,817 psig
Completion 2: 3,825 psig - (5,593-5,100) ft x 0.33 psi/ft = 3,662 psig
Completion 3: 3,626 psig - (5,302-5,100) ft x 0.33 psi/ft = 3,559 psig
Completion 4: 3,547 psig - (5,186-5,100) ft x 0.33 psi/ft = 3,518 psig

The packer and gauge settings will be adjusted based on logs and well information after the well is constructed, and pressures will be calibrated during the well testing and startup of the operation.

2.2 Wellhead Surface Injection Pressure Ranges

The surface wellhead injection pressure is limited by the selected tubing size, CO_2 supply pipeline, and booster pumping system. The design pressure of the main pipeline is planned to be 2,200 psig, consistent with ASME 900# flange class piping specifications. The design pressure of the booster pumping system is planned to be 3,700 psig, consistent with ASME 1500# flange class piping specifications, though the operating conditions will be significantly lower than design.

Wellbore tubing curves representative of the Bluebonnet CCS 7 were created in PROSPER for 5.5 in. tubing. Normal operating pressure at the Bluebonnet CCS 7 wellhead will be between 900 and 1,300 psig for the proposed operating rate. The surface pressure will be between 2,100 and 2,200 psig at the maximum injection rate, with wellhead pressure setpoints of 2,200 and 2,300 psig, respectively, to protect against operational excursions.

If the downhole pressure gauge fails to function properly, the maximum injection pressure shall be limited by the maximum surface wellhead injection pressure until it can be repaired or replaced.

2.3 Wellhead Minimum Differential Annulus/Tubing Pressure

The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of 9.8 ppg. The project team will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as

proposed in Table OP-1. The calculated pressure required in the annulus space between the long string casing and tubing will be estimated as follows:

DP (psi) = max bottomhole pressure during injection – hydrostatic pressure in annulus +100 psi Calculated at packer depth.

3.0 Reporting Frequencies

Bluebonnet Sequestration Hub, LLC, will maintain the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI reporting frequencies.

Activity	Minimum Reporting Frequency
CO_2 stream characterization	Semiannually
Monthly injection pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature (min, max, and avg.)	Semiannually
Corrosion monitoring	Semiannually
Monthly and cumulative volume and mass of the CO_2 stream injected	Semiannually
Monthly annulus fluid volume added	Semiannually
Results and reports for the monitoring systems proposed: plume tracking, above-confining-zone monitoring, surface monitoring	Semiannually
Description of any event that triggers a shutoff device and the response taken	Semiannually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semiannually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document on this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR 146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

This section specifies the procedures related to the startup of operations and monitoring and reporting during startup. The injection rates will gradually increase to the planned rate over seven to ten days as the CO_2 volumes become available at the site, during the commissioning period.

The multi-stage (step rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the operative injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

The procedures detailed below describe how Bluebonnet Sequestration Hub, LLC will initiate injection and conduct startup-specific monitoring of the CO_2 injector well pursuant to 40 CFR 146.90.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 injector well.
(2) During the startup period, the project will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 2,100 psig, measured at the wellhead.
(4) The planned injection rates are as follows:

Table OP-3—Planned injection rates during startup.

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
1,250	24	30
1,650	24	40
2,100	24	50
2,500	24	60
2,900	24	70
3,300	24	80
3,712	24	90
4,125	24	100

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using Coriolis meters.
(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) The temperature profile will be continuously read from the fiber optic installed alongside the casing.

(9) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(10) If, during the startup period, any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to better characterize the anomaly. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

   (a) The instantaneous shut-in pressure (ISIP) will be measured.
   (b) The permittee will notify the agency within 24 hours of the determination.
   (c) The permittee will consult with the agency before initiating any further injection.

Plan revision number: 3
Plan revision date: 09/25/2025

Claimed as PBI

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

2.0 Overview

Pursuant to 40 CFR §146.82, 40 CFR §146.83, and 40 CFR §146.84, this plan describes the site characterization for the Bluebonnet Hub, delineates the Area of Review (AoR), and describes the action plans for the wells that require corrective action. Delineation of the AoR is one of the key elements in Class VI permit to ensure Underground Sources of Drinking Water (USDW) in the region surrounding the geologic sequestration project will not be endangered by the injection activity.

The AoR is defined as the larger of the maximum extent of the separate-phase plume and pressure front during the life of the project. Both the CO_2 plume and critical pressure front are determined using a multiphase CO_2-brine transport computational model, constructed from a geocellular model that accounts for the site-specific hydrogeology and physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids. The methods and approaches for developing this complex multiphase simulation model and delineating the AoR are defined below.

3.0 Site Characteristics

3.1 Site Overview

The Bluebonnet Hub is located west of the town of Winnie, between Houston and Beaumont, Texas. It comprises parts of Chambers, Liberty, and Jefferson Counties. The Bluebonnet

Sequestration Hub, LLC (Bluebonnet) (through its affiliates) has leased approximately 70,000 acres across Chambers, Liberty, and Jefferson counties as part of the project development. These agreements include rights to sequester CO_2 in the pore space, surface use, and land access necessary to facilitate this proposed carbon sequestration project.

The Bluebonnet Hub is strategically located near a concentration of industrial power-generating plants, refineries, and chemical production, natural-gas processing, and natural-gas liquefaction facilities along the Gulf Coast from the Beaumont/Port Arthur area to the east to the Houston area in the west. The project will get custody of the CO_2 captured by these emitters through offtake agreements and transport the captured CO_2 via a third-party pipeline to the site, where the CO_2 will be stored.

The Bluebonnet Hub project team conducted detailed assessments of the surface and subsurface features of the proposed site via multiple integrated scientific methods, including regional geology, structural geology, hydrogeology, geophysics, petrophysics, fluid substitution, petrology, mineralogy, geochemistry, geomechanics, seismic history, legacy well analysis, and reservoir engineering to characterize the proposed storage complex consisting of multiple stacked confining and injection zones.

No previously recorded National Register of Historic Places (NRHP) districts or properties, sites designated as State Antiquities Landmarks, Recorded Texas Historic Landmarks, or historical markers are within the project AoR. The Texas Archeological Sites Atlas (TASA) revealed no previously recorded archaeological sites within 0.5 mile of the AoR (THC 2022). Note: Cultural resources review conducted by third-party contractor with access to restricted databases: Texas Historical Commission (THC) 2022; Texas Archeological Sites Atlas (TSA) restricted database; and Texas Historical Commission and Texas Archeological Research Laboratory. Available at: http://pedernales.thc.state.tx.us. Accessed November 2022.

No schools, hospitals, or nursing homes are known within the AoR. There is a local small-craft airport and a major interstate, I-10, within the boundaries of the AoR. There are seventy-five residential houses or small farms and one commercial site.

No Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), aka Superfund, or Resource Conservation and Recovery Act (RCRA) sites were identified in a database search of the Bluebonnet AoR (EPA 2022e): U.S. Environmental Protection Agency (EPA) 2022e. Hazardous Waste Sites. Available at: https://www.map22.epa.gov.Accessed November 2024.

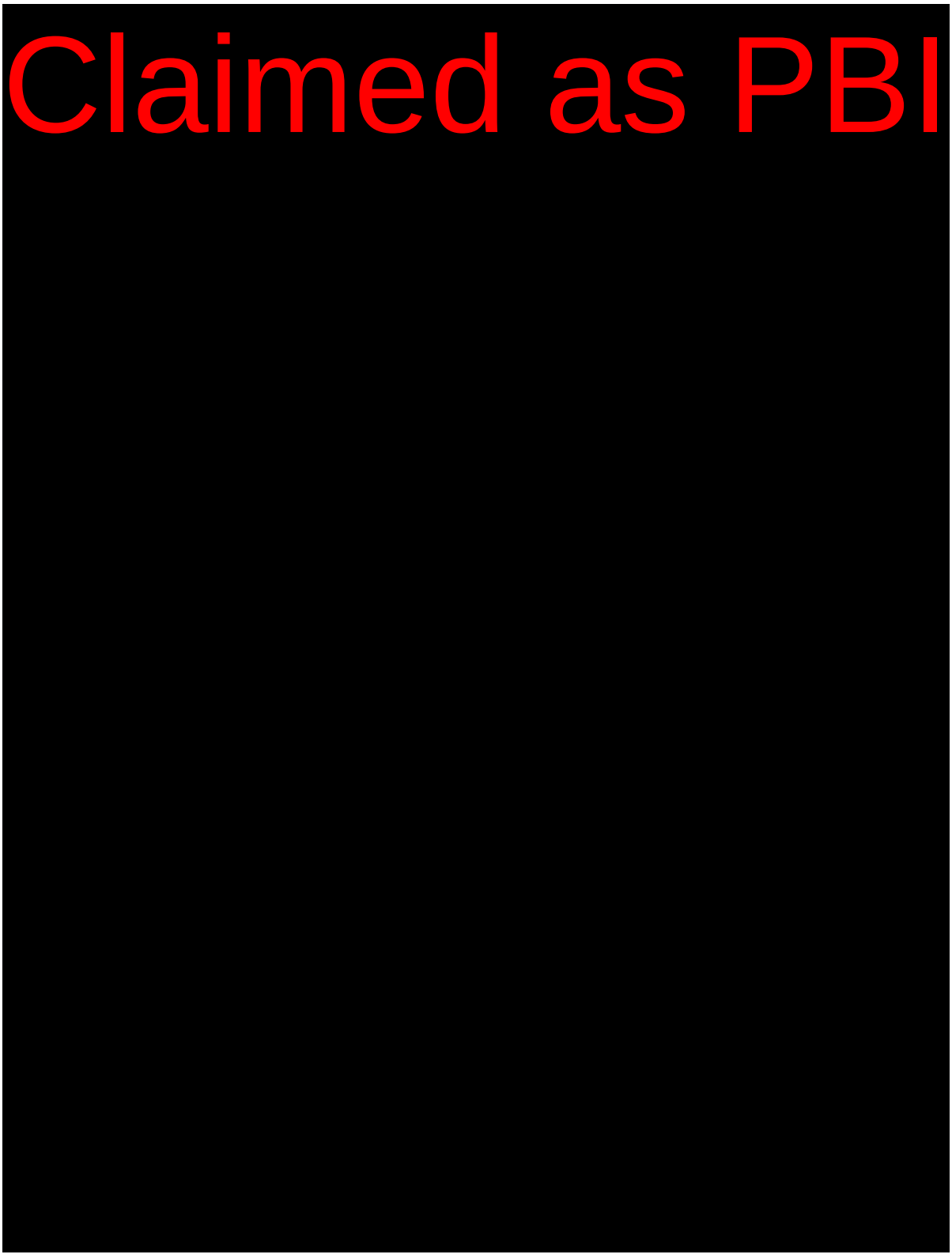
No springs were identified in the study area: USGS Database of Historically Documented Springs and Spring Flow Measurements in Texas: USGS Open-File Report 03-315. Maps | Data Basin. National Hydrography Dataset: USGS NHD Best Resolution for HU8 – Published 2024-01-04. The National Map Downloader Revisiting Major and Historical Springs of Texas by Gunnar Brune (1975) . Springs Database (February 2024). Groundwater Database Viewer (TWDB). Published May 2024. Accessed October 2024.

No mines or mineral deposits identified in the study area: USGS Mineral Resources Data System: Mineral Resources Data System: Records graded for completeness and consistency (usgs.gov) University of Texas at Austin: Texas Mineral Resources Map (utexas.edu) Accessed October 2024.

No quarries identified in the study area: Database of registrations for Aggregate Production Operations, maintained by the Texas Commission on Environmental Quality. Central Registry Search for Aggregate Production Operation. USGS Prospect- and mine- related features (Includes quarries, gravel and borrow pits, and other features): https://mrdata.usgs.gov/usmin/ Texas database Map: Map: Texas quarry sites (expressnews.com) Accessed October 2024.

Oxy Low Carbon Ventures, LLC (Oxy), the parent company of Bluebonnet, drilled and completed Encanto 01 as a stratigraphic test well in 2022-2023, and acquired an extensive set of site-based data to complete the site characterization and AoR delineation. The different datasets across multiple disciplines acquired in this well have been integrated and are presented in this permit. Oxy drilled Bluebonnet USDW 1 well in 2024 in the same location of the Encanto 01 well to 1,630 ft to characterize the water composition from the base of the USDW to surface. Bluebonnet drilled Bluebonnet USDW 8 in 2025 in the same location of Encanto 01 well to 2,750 ft to obtain whole core and Rotary Side Wall Cores (RSWC) to characterize the confining shales present in the Miocene Composite Confining Zone. Some remaining data integration is still in progress and awaiting laboratory results for the samples obtained while drilling Bluebonnet USDW 8.

A detailed regional and local geological evaluation of the area around the Bluebonnet Hub was conducted using geological, geophysical, and petrophysical data obtained from public literature and data, licensed data, and site-specific data collected for this project. These data are described in the following sections.



Figu
legac

3.2 Location and Data Control

The Bluebonnet Hub technical staff conducted a detailed subsurface evaluation over approximately 193 square miles in Chambers, Jefferson, and Liberty Counties. Multiple types of data were integrated, including publicly available literature, maps, and cross sections; publicly available GIS data including topography, surface geology, land use, and culture data; a licensed 3D seismic survey; and publicly available and licensed well data and logs. Also, core, mudlog, biostratigraphy, and wireline log data from the stratigraphic test well was included in the evaluation.

The Frio model includes 156 wells, 95 of those containing high quality logs with petrophysical analyses that were used to populate the 3D geocellular model and 61 of those containing basic logs (Figure AoR-2).

The Lower Miocene model includes 158 wells, 102 of which are inside the geo-mode Area of Interest (AOI) (Figure AoR-3). For facies classification, 158 wells were used, and 14 wells with triple combo and PEF that were used for facies classification as based wells to distribute petrophysical parameter to the rest of the 144 wells. For more detail on how the petrophysical properties were distributed in the field, refer to Appendix A.

The core database consists of three wells: the stratigraphic test well (Encanto 01) and two historical wells (Sterrett Eat Fred R_1 UWI: 42-071-019580000 and Debellvue Mrs Maria_1 UWI: 42-071-019620000). The Sterrett Eat Fred R_1 well had sidewall core (SWC) data confined to discrete intervals above and below the proposed Oligocene storage complex, and Debellvue Mrs Maria_1 well had percussion sidewall cores that were also confined to discrete intervals above and below the proposed Oligocene storage complex.

The most recent data point is the stratigraphic test well Encanto 01, in which whole cores, rotary sidewall cores (RSWCs), and mud cuttings data were acquired across the stratigraphic column, within, below, and above the proposed storage complex. Also, a series of petrophysical logs and well tests from TD to surface was received.

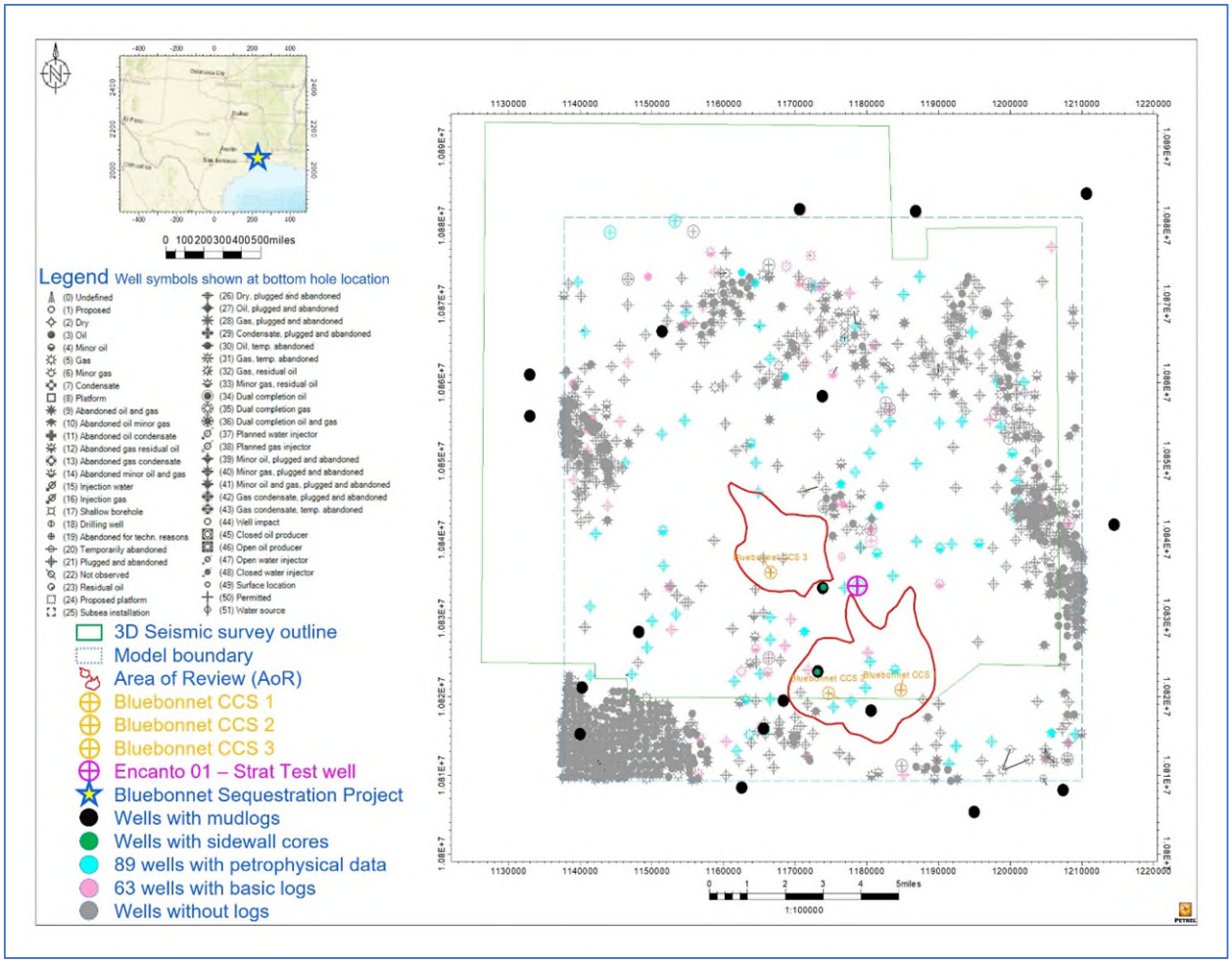


Figure AoR-2: Subsurface data control for the Frio model in the Bluebonnet Sequestration Hub.

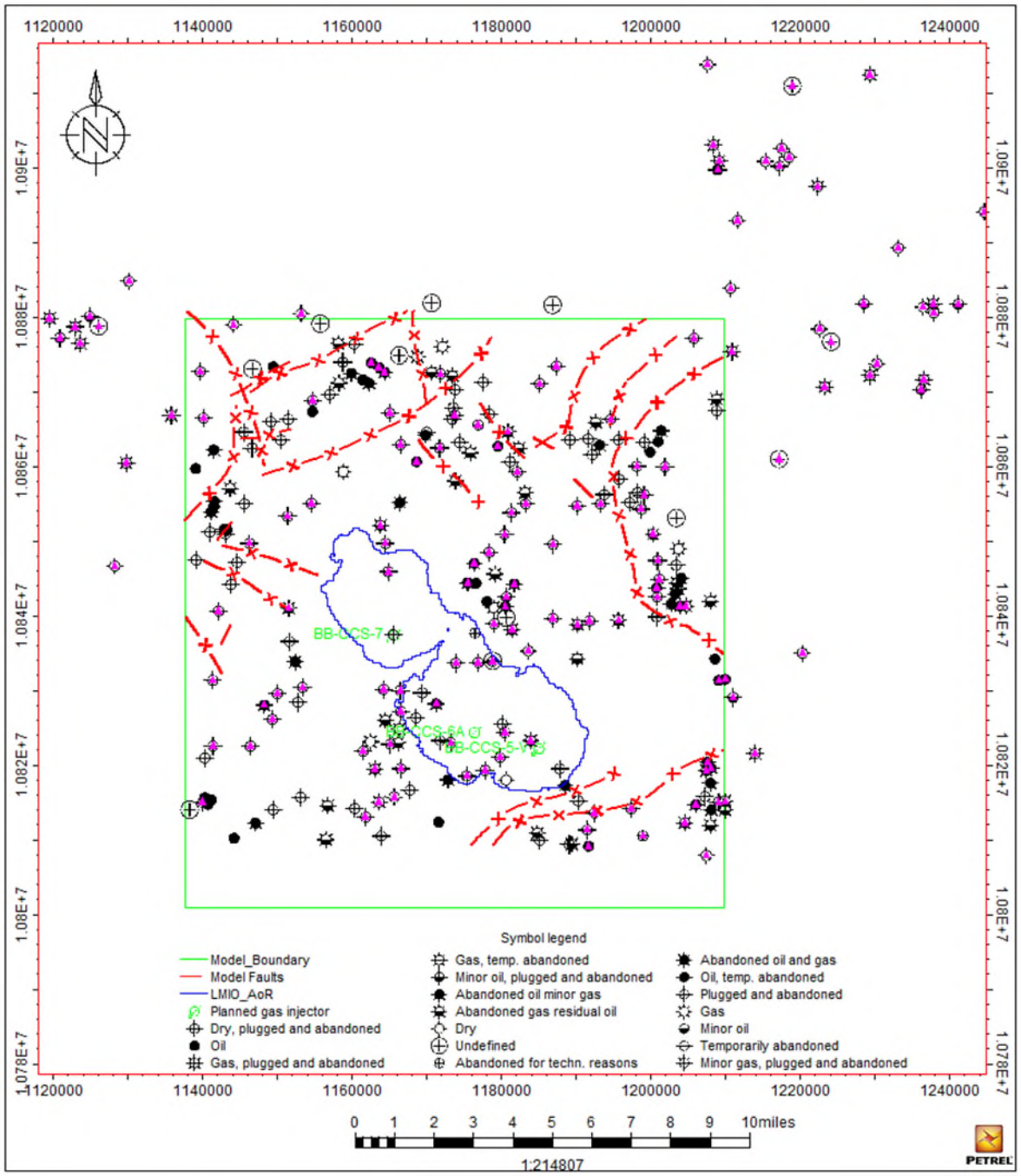


Figure AoR-3: Subsurface data control for the Miocene model in the Bluebonnet Sequestration Hub.

3.3 Physical Geography

The Bluebonnet Hub is located on the Lower Coastal Gulf Plain, which is a flat, low-relief surface (Galloway 2008,Figure AoR-4).

Common features such as marshes and swamps occur along a belt of deltaic and interdeltaic sediments that typify the emerged Gulf segment of the coastal plain (USGS, 1996). This area grades landward to a band of steplike deposits and terraces of relatively young geologic age (USGS, 1996). The Paleogene, Neogene, and Quarternary sediments deposited in the Gulf Coastal Plain fall into two major classes: sand and clay. The sand layers are more resistant to erosion because they absorb rainfall, thereby reducing surface runoff. The clay sediments are less resistant, resulting in topographic lows. Soils develop on each geologic unit, which supports unique flora, so that vegetation is an aid in identifying both physiographic features and underlying rock type (USGS, 1996).

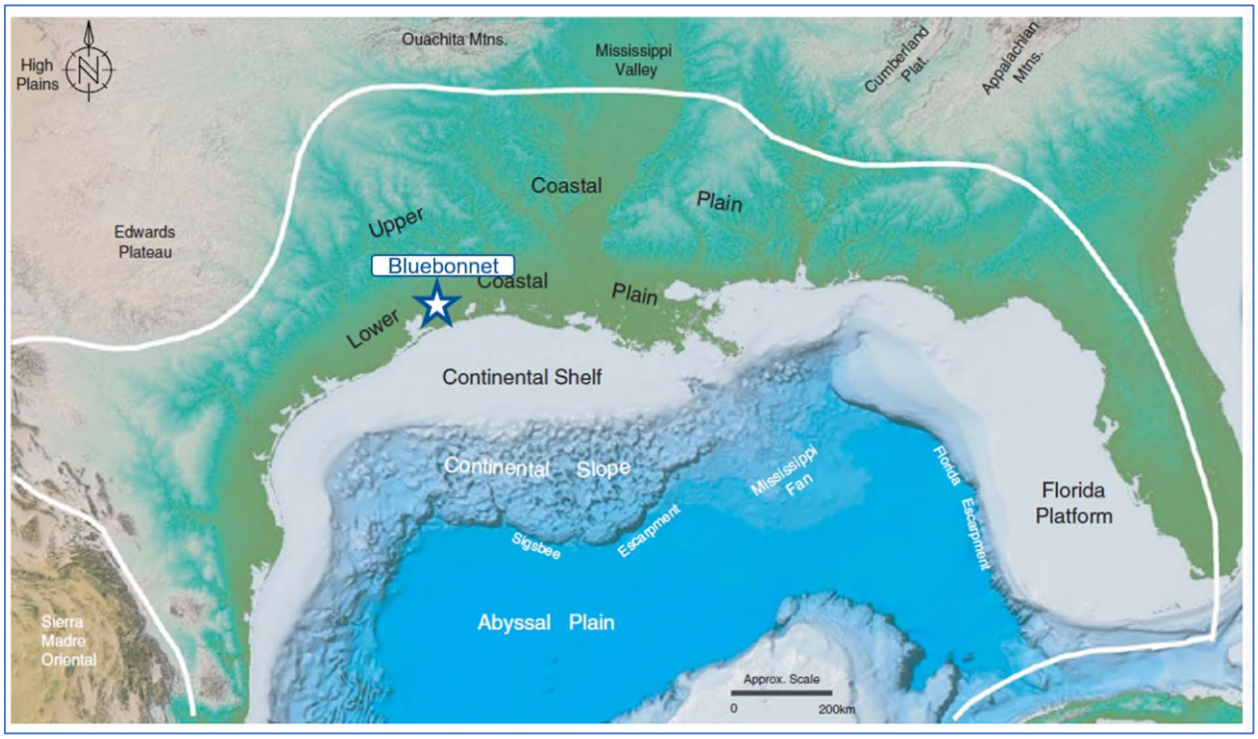


Figure AoR-4: Principal physiographic elements of the Gulf Coast. Source: Galloway, 2008.

The Bluebonnet Hub is located on the Houston Sheet (Figure AoR-5). The surface is covered by Quaternary strata, namely rocks of the Pleistocene-aged Beaumont Formation, which consist of barrier island and beach deposits. Lithologically, these rocks are constituted of clay, silt, and sand that were deposited in stream channels with meander patterns and ridges, point bars, natural levees, backswamp, and minor coastal marsh and mudflats. A majority of the project extent is underlain by “clay- and mud-rich deposits of low permeability, high water-holding capacity, high compressibility, high to very high shrink-swell potential, poor drainage, level to depressed relief, low shear strength, and high plasticity” (UT BEG, 1982). These geologic units represent interdistributary muds, abandoned channel-fill muds, and overbank fluvial muds.

The Trinity and Neches Rivers are the two closest major rivers, approximately ~12 miles to the west and ~21 miles to the east, respectively. These present-day Holocene-aged rivers cut into the Pleistocene rocks described above and deposit alluvium consisting of clay, silt, sand, and organic matter in similar depositional environments. The entire Bluebonnet Hub site is cut through by the Spindletop Bayou, flowing from north to south, eventually draining into the Gulf of Mexico.

The topographic elevation above mean sea level ranges from 25 – 40 ft across the project extent (Figure AoR-6).

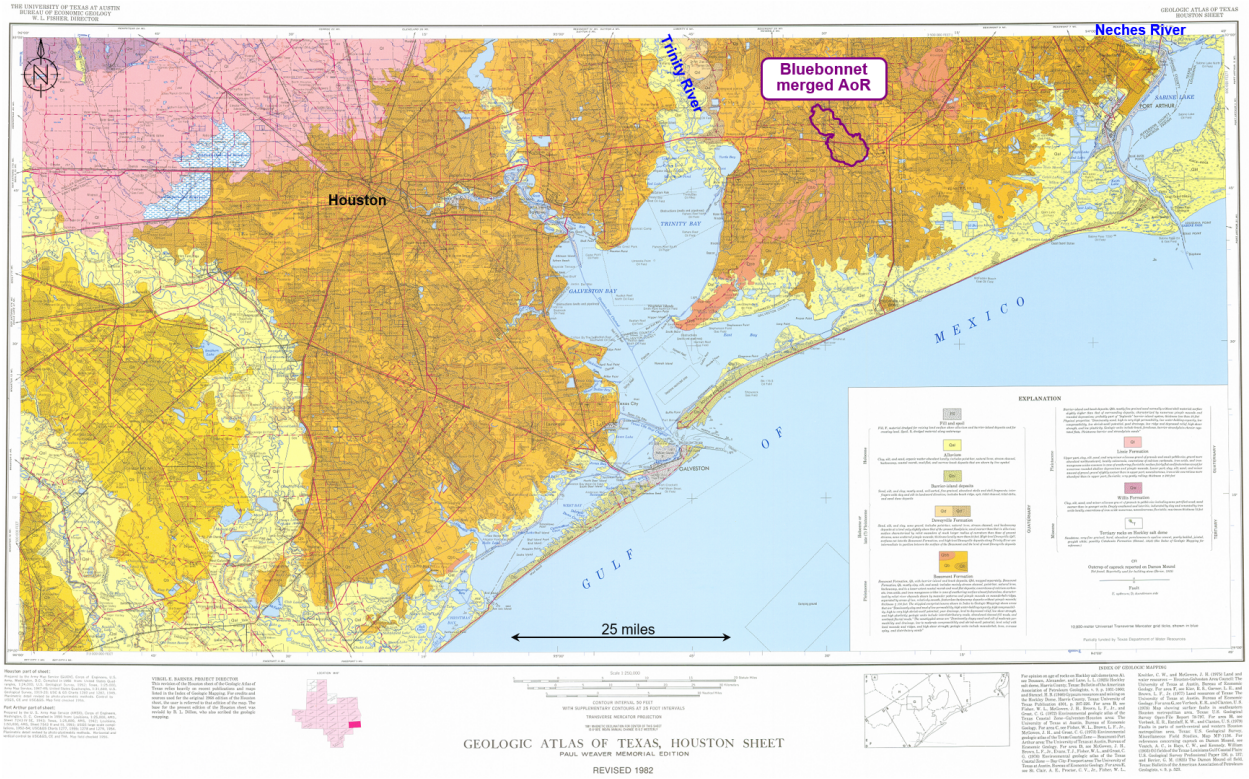


Figure AoR-5: Geologic Atlas of Texas, Houston Sheet, depicting the surface geology on a scale 1:250,000. Purple polygon: Bluebonnet Area of Review (AoR). Map source: University of Texas - Bureau of Economic Geology, 1982.

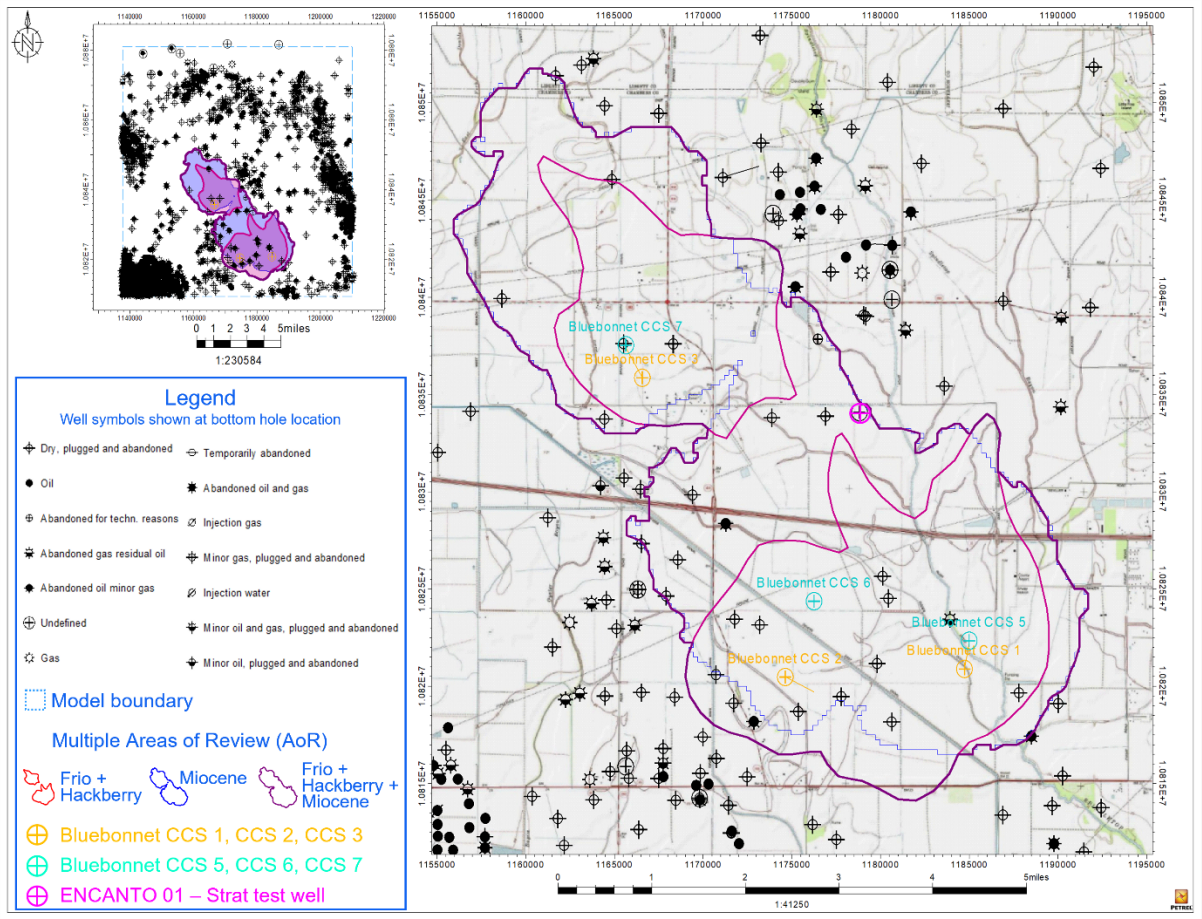


Figure AoR-6: The proposed AoR overlain on top of a topography map, scale 1:41,250. Source: 2013 National Geographic Society.

The surface land is classified as farmed palustrine wetland (Figure AoR-7). Palustrine systems include nontidal wetlands dominated by trees, shrubs, persistent emergent, emergent mosses, or lichens. Farmed wetlands occur where the soil surface has been mechanically or physically altered for production of crops, but where hydrophytes would become reestablished, if the farming were to be discontinued. Other physical surface characteristics of the Bluebonnet Sequestration Project site include minor freshwater forested/shrub wetland, minor freshwater emergent wetland, minor emergent persistent seasonally to temporarily flooded palustrine wetlands (seasonally flooded during the growing season but absent by the end of the season in most years; temporarily flooded for a few days to a few weeks during the growing season), perennial and intermittent lakes/ponds, a bayou, several ditches, roads, and canals (Figure AoR-8).

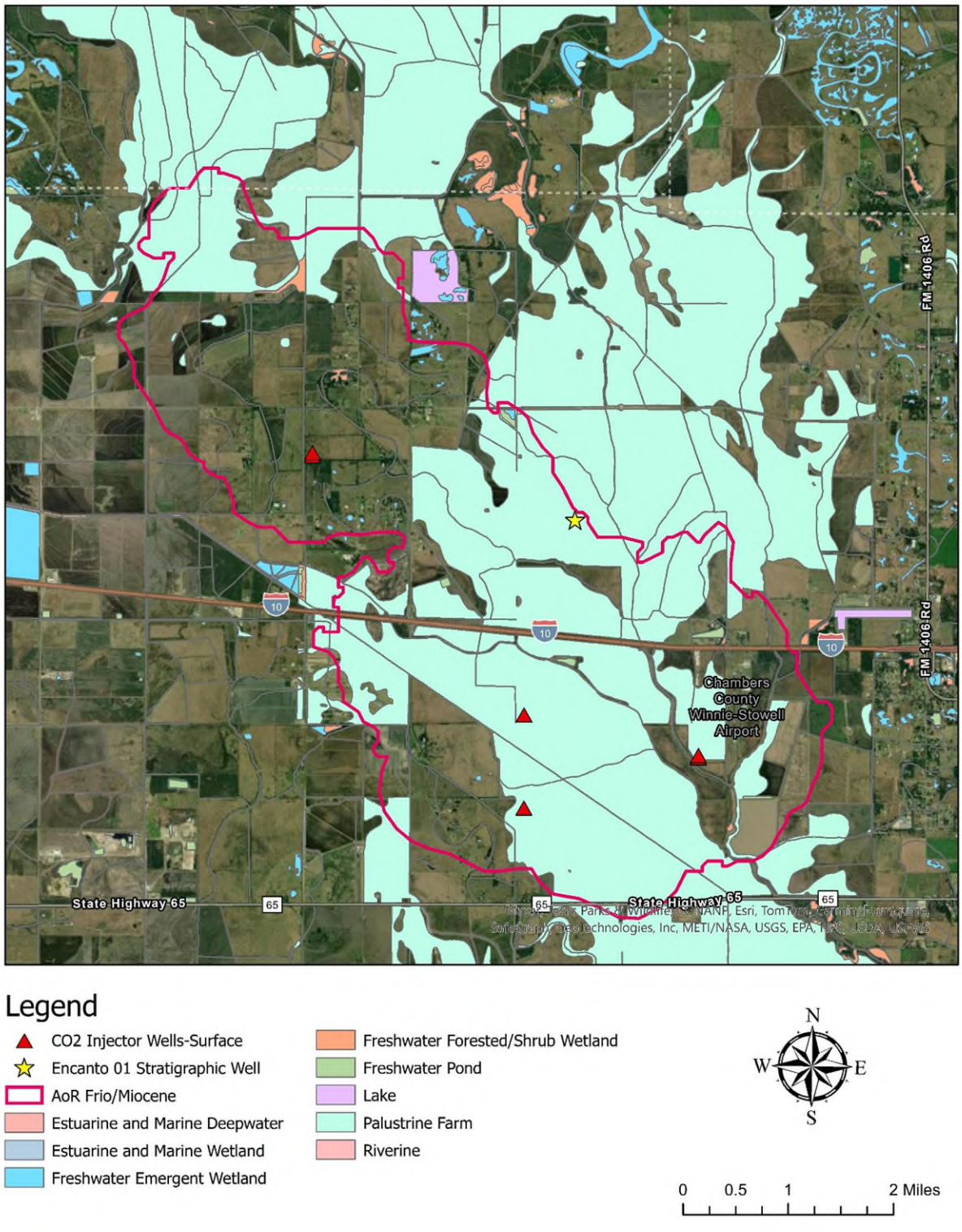


Figure AoR-7: National Wetland Inventory – this map shows that the Bluebonnet Sequestration Project site encompasses palustrine farmed wetland. The six CO_2 injection wells are shown with red triangles at their proposed surface location.

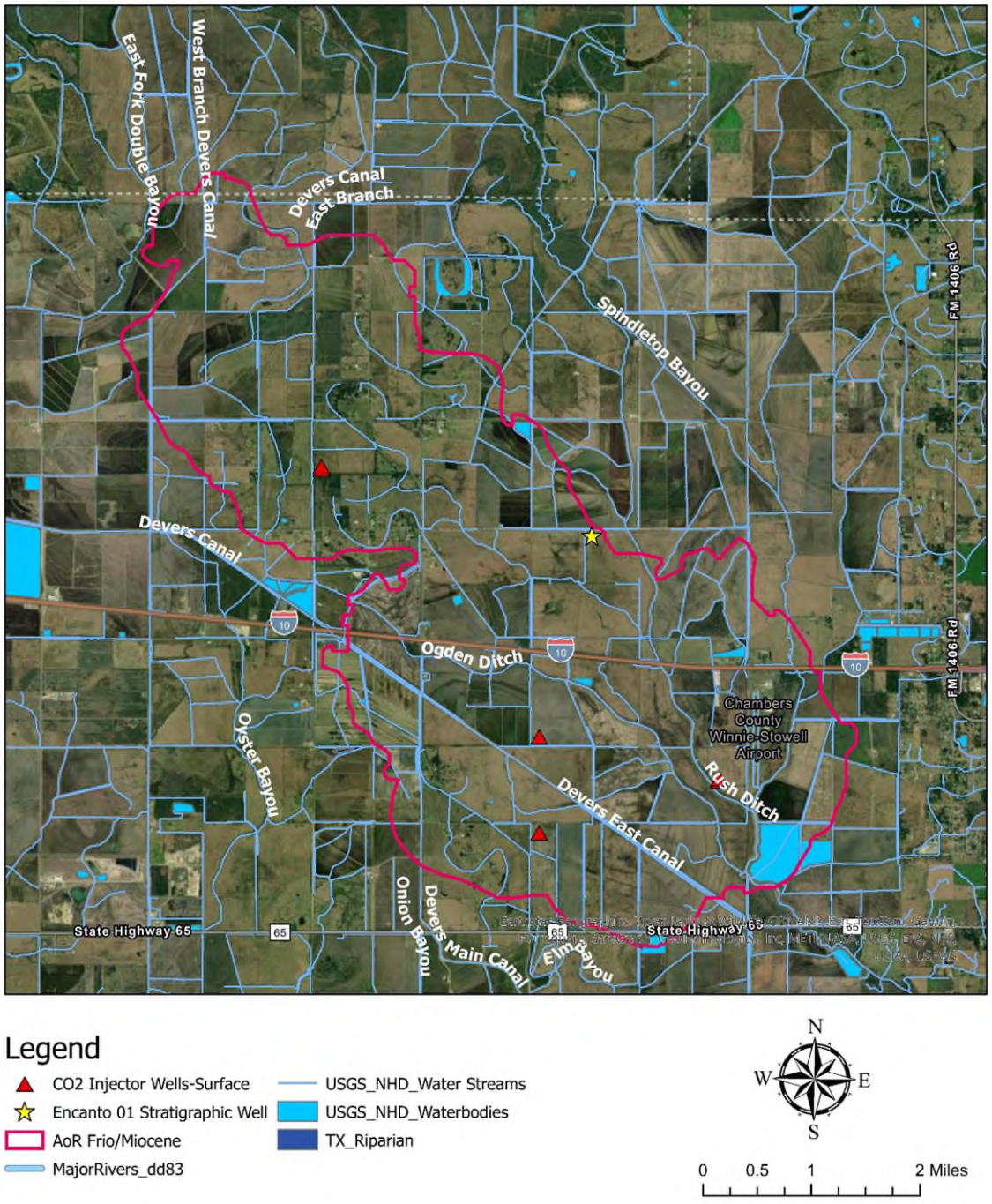


Figure AoR-8: Hydrologic map showing flowlines and waterbodies from the USGS National Hydrographic Database. The Bluebonnet Sequestration Project site encompasses several canals, ditches, and bayous as well as small lakes/ponds. The six CO_2 injection wells are shown with red triangles at their proposed surface location.

3.4 Regional Geology

During the Cenozoic, the Gulf of Mexico (GoM) developed as a passive margin basin displaying a continuous record of basin infilling by terrigenous clastic sediments (Galloway et al., 2000). Across the northern Gulf, sediment supply by large continental rivers initiated continental margin offlap that continued throughout the remaining Cenozoic. The depositional history of the northern Gulf Basin was an interplay of several sedimentary distribution systems that sourced large deltas, one of them being the Houston Delta (Galloway et al., 2000). These sedimentary distribution systems are clustered in three major broad structurally defined entry points. These entry points are a series of gentle synclines and anticlines, which are oriented perpendicular to the coastline (USGS, 1996). One of the three distinct structural provinces of the onshore Texas Gulf Coast is the Houston Embayment, which is tied to the Houston Delta where the Bluebonnet Hub is located.

Within this province, Tertiary sediments were deposited as a series of gulfward-thickening, terrigenous clastic wedges (BEG Dodge and Posey, 1981). These sediments were transported to the coastal margin by rivers, and subsequently deposited in deltas or reworked by marine processes into strandplains and barrier bars (BEG Dodge and Posey, 1981). Contemporaneous growth faults developed parallel to the shelf margin and syndepositional movement resulted in sediment thickening on the downthrown side of the faults (Figure AoR-9). Due to the throw offsetting these sediments, they became isolated from sediments on the upthrown side of the fault. In some of these isolated sediments, abnormally high pressure and temperature gradients develop as a result of fluid entrapment (BEG Dodge and Posey, 1981) because high sedimentation rates fed by large river systems in these deltaic deposits prevented the escape of pore water trapped in the shales.

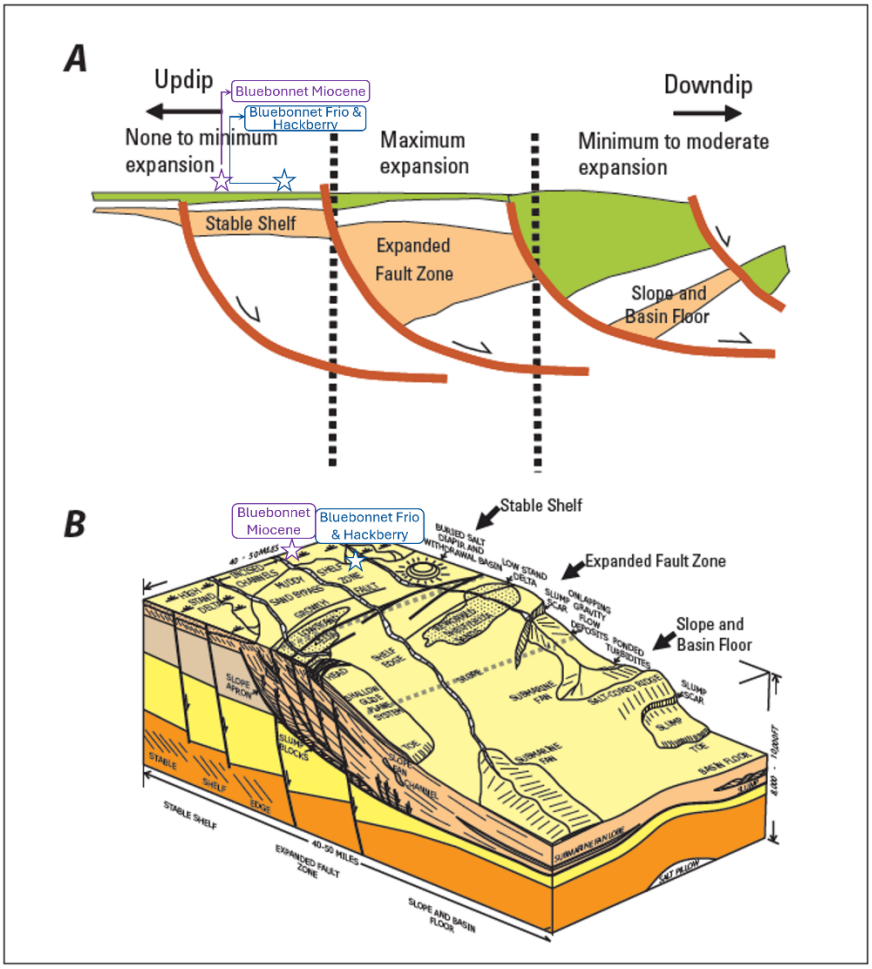


Figure AoR-9: Generalized block diagram showing structural compartments and depositional environments. The Bluebonnet Sequestration Hub is located on the stable shelf at the time of Frio and Miocene deposition. After USGS, 2013.

Beneath the Gulf Coastal Plain of Texas lies the Jurassic Louann salt. Salt displacement occurs from loading by laterally continuous depositional systems. Major rapid diapirism of the salt domes in the Gulf Coast Basin was initiated during the Tertiary period due to sediment loading of the Wilcox and subsequent fluvio-deltaic sediments (Annual report, 1986). By the end of the Oligocene, the salt diapirs had reached the surface and entered the post-diapir development stage. Salt domes are numerous in the Gulf Coastal Plain and may penetrate thousands of feet of sediments. Salt dome development impacts local faulting and sedimentation patterns (BEG Dodge and Posey, 1981). Although the degree of salt intrusion can be very great, disruption of adjacent strata is limited to the vicinity of the dome (USGS, 1996). Salt domes can provide structural and stratigraphic hydrocarbon traps and also affect the groundwater chemistry in their vicinity. No salt domes are present within the proposed Bluebonnet Hub AoR. The closest salt dome is the Hankamer Salt Dome, which is located approximately 2.3 miles to the west.

River systems to the west transported siliciclastic sand and mud to the Gulf Coast throughout the Paleogene and Neogene. Through time, the depositional centers of these rivers shifted in an east-west direction and prograded in a north-south direction. The deposition of these gulfward-prograding depocenters was interrupted repeatedly by transgressions. These flooding events reflect increases in sea level and can be recognized on logs as marine shales. Some of the prominent regional marine shales are the Anahuac Formation, Marginulina, and Amphistegina B shales (Figure AoR-10). During the deposition of these marine shales, the continental platform was submerged over a widespread period. After these cyclical flooding episodes, the sedimentary system prograded over these shales and resulted in the next sandstone-rich depositional event, which prograded steadily basinward (Bump et al., 2021).

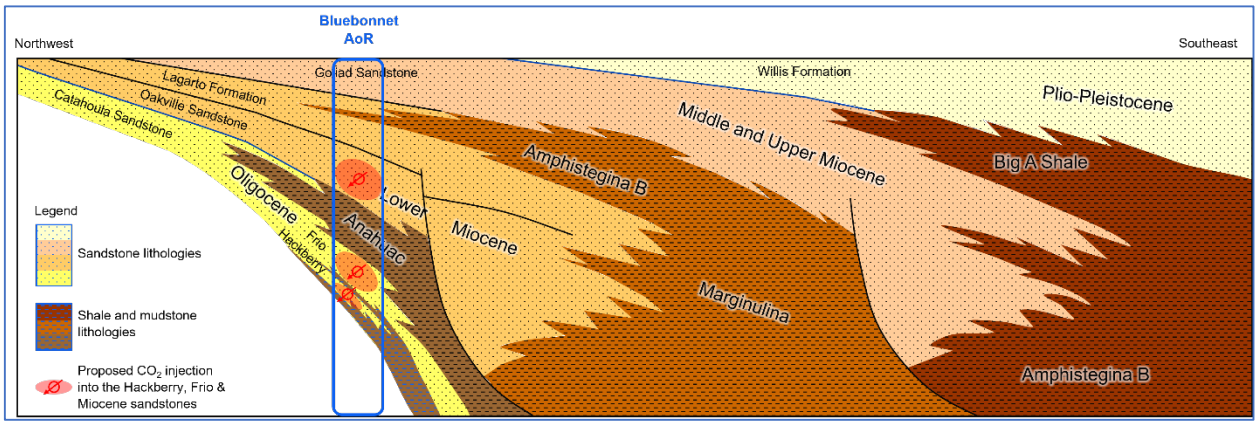


Figure AoR-10: Northwest-southeast schematic cross section of the Oligocene, Lower, Middle and Upper Miocene depositional complexes. Lithostratigraphic features and their correlations are highlighted. After Seni et al., 1997.

On the regional upper Texas Gulf Coast, dip cross sections were published by the BEG in 1981. In the dip section, the main sand depocenter in each unit shifts seaward, which explains the progradational nature of the sand wedges. Within the Bluebonnet Hub, areal Frio, Hackberry, and Miocene sand trends were mapped, providing largescale storage capacity (Figure AoR-11).

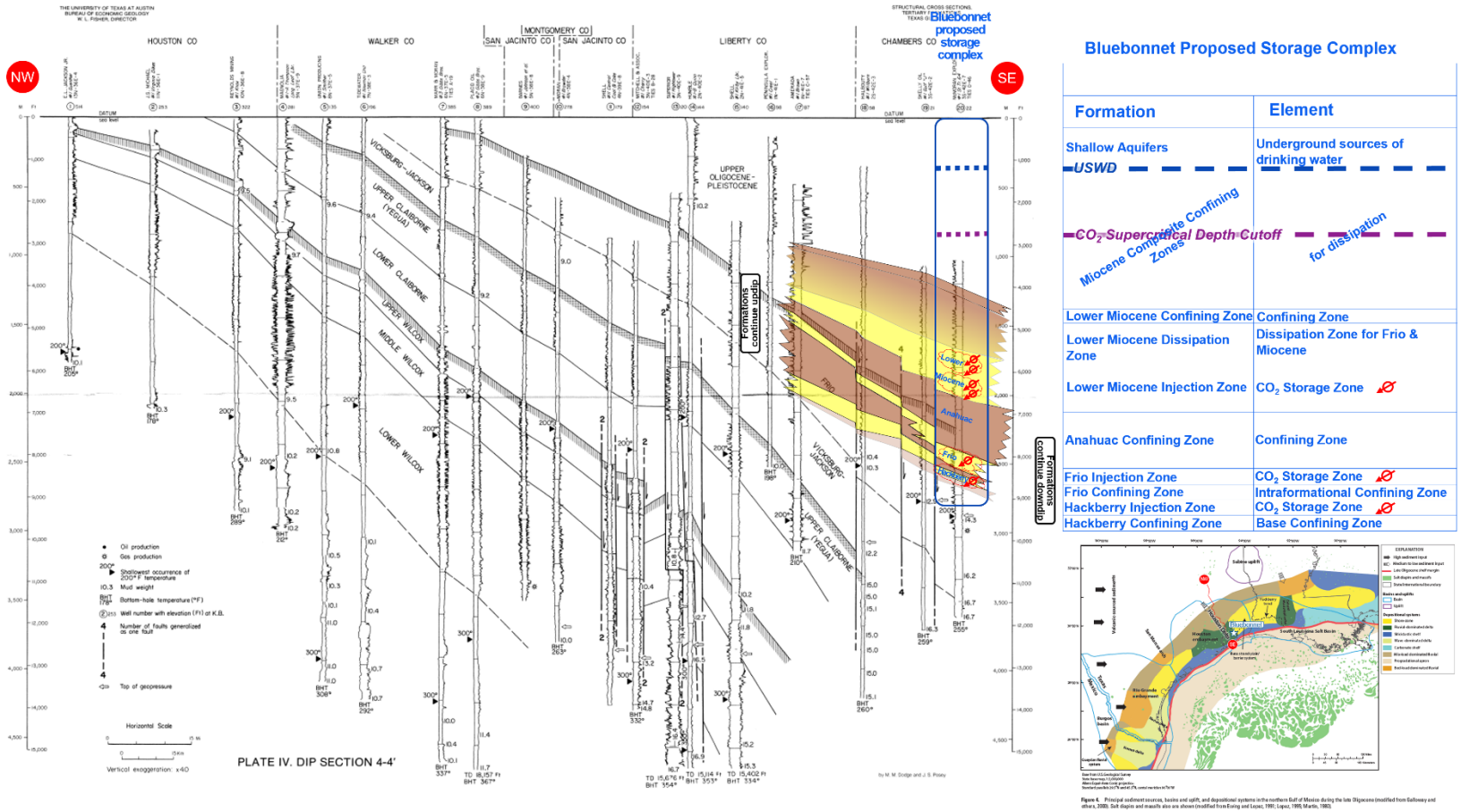


Figure AoR-11: Regional dip cross section, highlighting the proposed storage complex. The planned CO_2 injection zones are the Hackberry, Frio, and Lower Miocene sandstones. The planned confining zones to contain the sequestered CO_2 within the subsurface are the thick marine transgressive Anahuac Confining Zone, the Lower Miocene Confining Zone, and the Miocene Composite Confining Zone acting as a dissipation zone (modified after BEG, 1981).

The Early Miocene was a period of relative paleogeographic stability of the Gulf Basin. Galloway et al. (2000) identified two major supersequences (deposodes) during the Early/Lower Miocene (Figure AoR-12). Although the volumes of the Lower Miocene supersequences are substantially less than that of the Frio section, their shorter durations resulted in comparably high calculated supply rates (Galloway et al. 2011). The rate of continental margin accretion declined but remained high (Figure AoR-12). This is reflected at least in part in the declining volcanic activity and active uplift across western North America (Snedden and Galloway, 2019). The sedimentation pattern in the Miocene–Pliocene was dominated by fluvial systems entering the basin from the north.

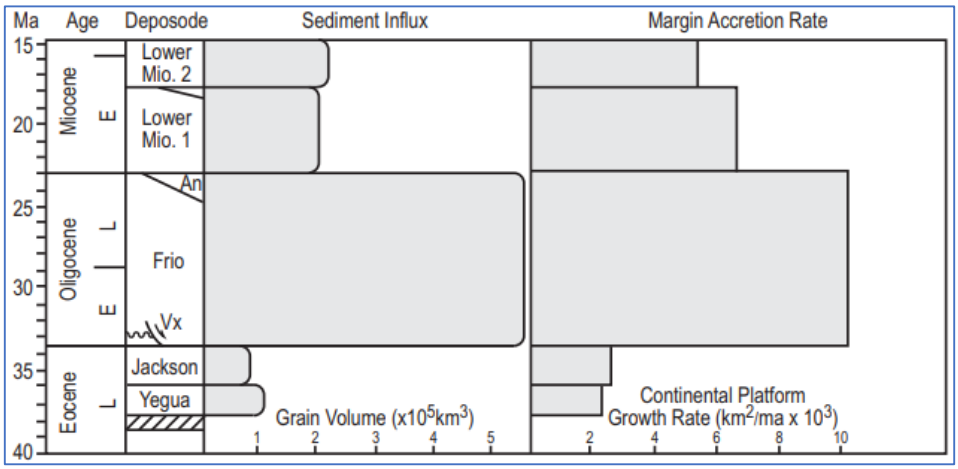


Figure AoR-12: Depositional episodes and chronology of the Middle Cenozoic Geothermal Phase; (A) Northern Gulf (US) margin deposodes, sediment influx, calculated as total grain volume, and continental margin accretion rates. Miocene sediment influx and margin accretion reduced compared to Oligocene, but was still high (GBDS, 2019).

Two major fluvial-dominated delta systems developed during the Lower Miocene (i.e., the paleo Mississippi and paleo Red River). These prograded rapidly across the Anahuac transgressive shelf and onto the central GoM continental margin (Snedden and Galloway, 2019). The main depositional system, Mississippi fluvial–deltaic axis, continued its long history as a major continental river and deltaic depocenter. To the west, the other fluvial axis (paleo Red River fluvial system) traversed the easternmost Texas Miocene coastal plain (Galloway et al. 1986). It supplied the Calcasieu delta system, which was somewhat smaller in area and depocenter volume than the Mississippi delta system (Figure AoR-13). Both delta systems persisted during the Lower Miocene deposodes (Snedden and Galloway, 2019).

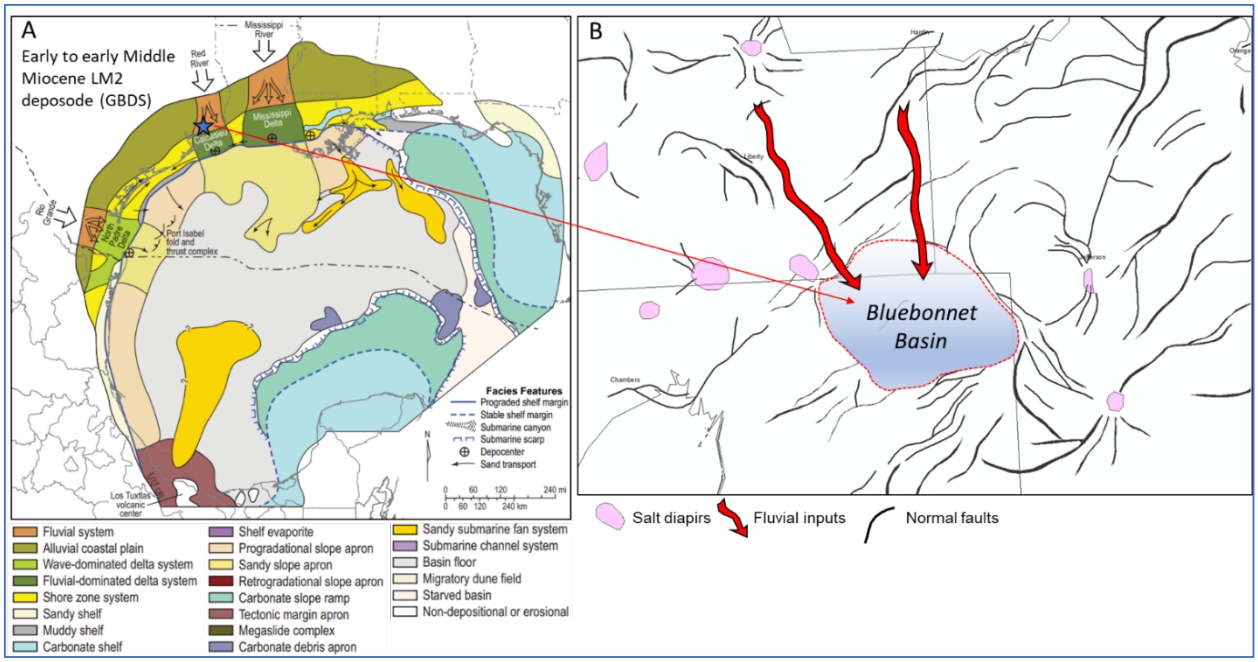


Figure AoR-13: A) Gulf of Mexico regional depositional setting during Lower Miocene and lower part of Middle Miocene (deposode LM2, Snedden and Galloway, 2019). B) Subregional understanding around the AOI (Bluebonnet basin). Also, showing main fluvial fairways into the Bluebonnet basin, normal faults, and salt diapirs.

The Bluebonnet Hub is located in the sediment fairway of the Red River and Calcasieu delta system, and specifically within the Houston embayment (Figure AoR-13). Extensional tectonic affected the larger area, with growth faulting developed parallel to the shelf margin resulting in sediment thickening on the downthrown side of the faults, though mostly seen south of the Bluebonnet site (Figure AoR-10).

A regional structural dip cross section showing the USDW, major aquifers, and proposed storage complex including the confining and injection zones, additional composite confining zones for dissipation and vertical distance between the proposed injection zone, and USDW is shown in Figure AoR-14. The present-day structure of the top of the confining and injection zones dips towards the Gulf Coast in the southeast at varying rates ranging between 2.31 – 3.38° degrees, as observed on 3D seismic data over the project area. This formation dip impacts the CO_2 plume migration, which is driven by buoyancy forces in an updip direction.

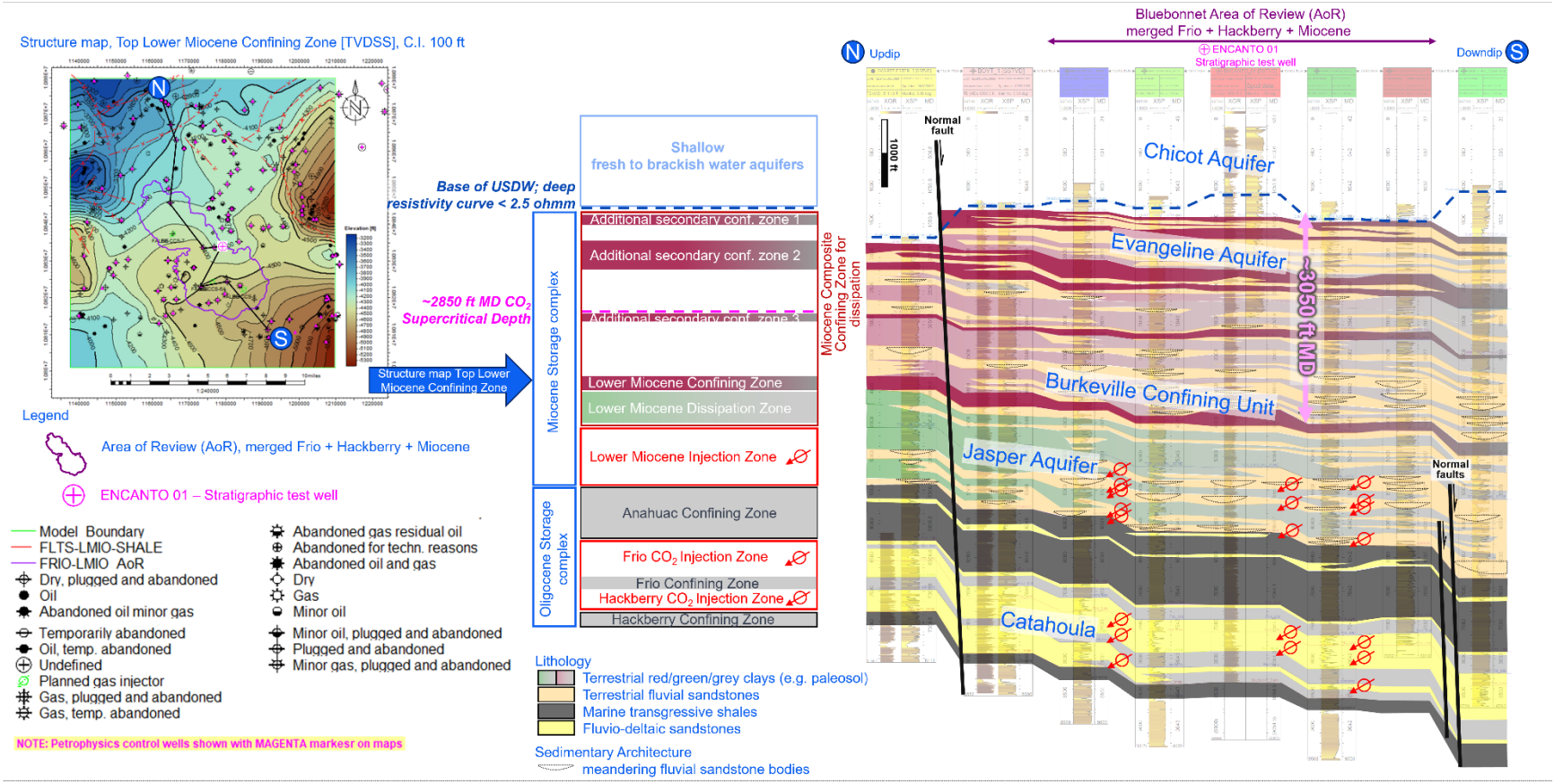


Figure AoR-14: Regional structural dip cross section through the Area of Interest (AOI), highlighting the proposed storage complex; scale 1:8,000. The proposed CO_2 injection zones are the Hackberry, Frio, and Lower Miocene sandstones. The proposed confining zones to contain the sequestered CO_2 within the subsurface are the transgressive marine Hackberry, Frio, and Anahuac shales, as well as the terrestrial Lower Miocene Confining Zone and the Miocene Composite Confining Zones. Major faults are highlighted in black. The base of Underground Sources of Drinking Water (USDW), below which TDS>10,000 mg/L is shown in dashed blue.

3.5 Basin History and Structure

Understanding of the regional structure in the Bluebonnet area was developed from published literature, regional well data, regional 2D seismic owned or licensed by Oxy USA Inc., and 3D seismic licensed by Oxy USA Inc. The result is a structural synthesis that aligns regional structural trends with observations of local structural elements. Numerous structural styles are interpretated within the Bluebonnet 3D seismic region (defined here as the ~200 square mile area covered by licensed 3D seismic used in this evaluation), including salt doming, growth faulting, transtensional faulting, and growth fault reactivation. These various faulting styles were evaluated extensively to select an AoR for the Bluebonnet Sequestration Hub in which any faulting that impacts the integrity of the storage complex is absent. The dominant structural features in the Bluebonnet region are Cenozoic growth faults resulting from sediment loading of progradational sequences on top of older unstable slopes. This progradational loading and resulting growth faulting is observed by mapped growth structures that decrease in age geographically towards the Gulf of Mexico Basin (Figure AoR-15 and Figure AoR-16). Deposition of the Bluebonnet Storage Complex occurred in the Middle Cenozoic Geothermal Phase during periods of Frio-Vicksburg detachment faulting and regional volcanism and uplift.

The Bluebonnet site is located on the paleo Frio Shelf between the Frio maximum transgression and Frio shelf edge, where shelf-parallel listric growth faults detached on the older Wilcox slope below as a result of sediment loading during Frio deposition (Figure AoR-16a). Growth faulting at this time was widespread throughout the Bluebonnet 3D seismic area (Figure AoR-16b). However, observations from 3D seismic demonstrate that significant and widespread movement along these faults ceased prior to the end of Frio deposition and strain resulting from subsequent loading is concentrated more discretely along select zone of weakness, resulting in the more organized and geographically discrete faults that are observed in the map in Figure AoR-17.

Faulting within the 3D survey was interpreted manually with the assistance of various fault enhancement attributes including Landmark's Structure Oriented Filter and Fault Likelihood attributes. All faults were interpreted using fault plane mapping techniques to assure reasonable and proper fault geometries. All interpreted faults were incorporated into the geomodel.

Detailed interpretation of local structures from 3D seismic are shown in the map and cross section views in Figure AoR-17. Fault intercepts are shown in the map view for the top of Vicksburg surface below the storage complex (blue), top of Hackberry Injection zone surface (orange), top of Frio Injection Zone surface (green), and top of Lower Miocene Confining Zone surface above the storage complex (red).

Five faulting styles are identified in the area shown in the map as:

1) Salt doming and associated radial faulting
2) Widespread Vicksburg growth faulting
3) Coast-parallel reactivated growth faulting
4) Coast-sub-parallel reactivated growth faulting, and
5) Minor transtensional faulting.

Cross sections AA', BB', and CC' in Figure AoR-17, and cross section DD' in Figure AoR-18 are interpreted from 3D seismic and show the various faulting styles across the area. The timing of fault movement for each fault style was interpreted from 3D seismic utilizing observations of fault plane terminations, identification of pre-, syn-, and post-depositional seismic reflector cross-fault relationships, and pseudo-structural reconstructions (i.e., flattening on relevant surfaces).

Additional context for a fault included in the model that intersects the top of the Hackberry outside of the AoR boundaries. A map view of the fault intersection with the top of the Hackberry Confining Zone outside of the AoR is visible in Figure AoR-19.

Particular attention was paid to faulting within the Bluebonnet AoR (widespread Vicksburg growth faulting). Manual fault interpretations were cross-checked against Fault Likelihood attribute overlays and surface extractions (see Figures AoR19 and AoR20). All mapping and attribute analyses indicate that movement on widespread Vicksburg growth faulting ceased before the end of Hackberry, Frio, and Lower Miocene deposition. No measurable offset is present within the Hackberry, Frio, and Lower Miocene injection zones or confining zones. The confining and injection zones are free of transecting or transmissive faults within the AoR (see Figure AoR-20). Fault likelihood maps seen in Figure AoR-20 are horizon extractions at the top of the confining zones.

Regional data indicated the presence of faulting south of the AoR outside of the primary interpretation 3D (see Figure AoR-21). Out of an abundance of caution, additional 3D licensed by Oxy USA Inc. was preliminarily evaluated to locate and characterize these faults. These faults, which are located a mile south and down dip of the southern limit of the AoR, are interpreted as Frio Growth Structures. These faults set up the updip trap for the Fig Ridge North and Fig Ridge Frio fields, and thus, are interpreted to be sealing.

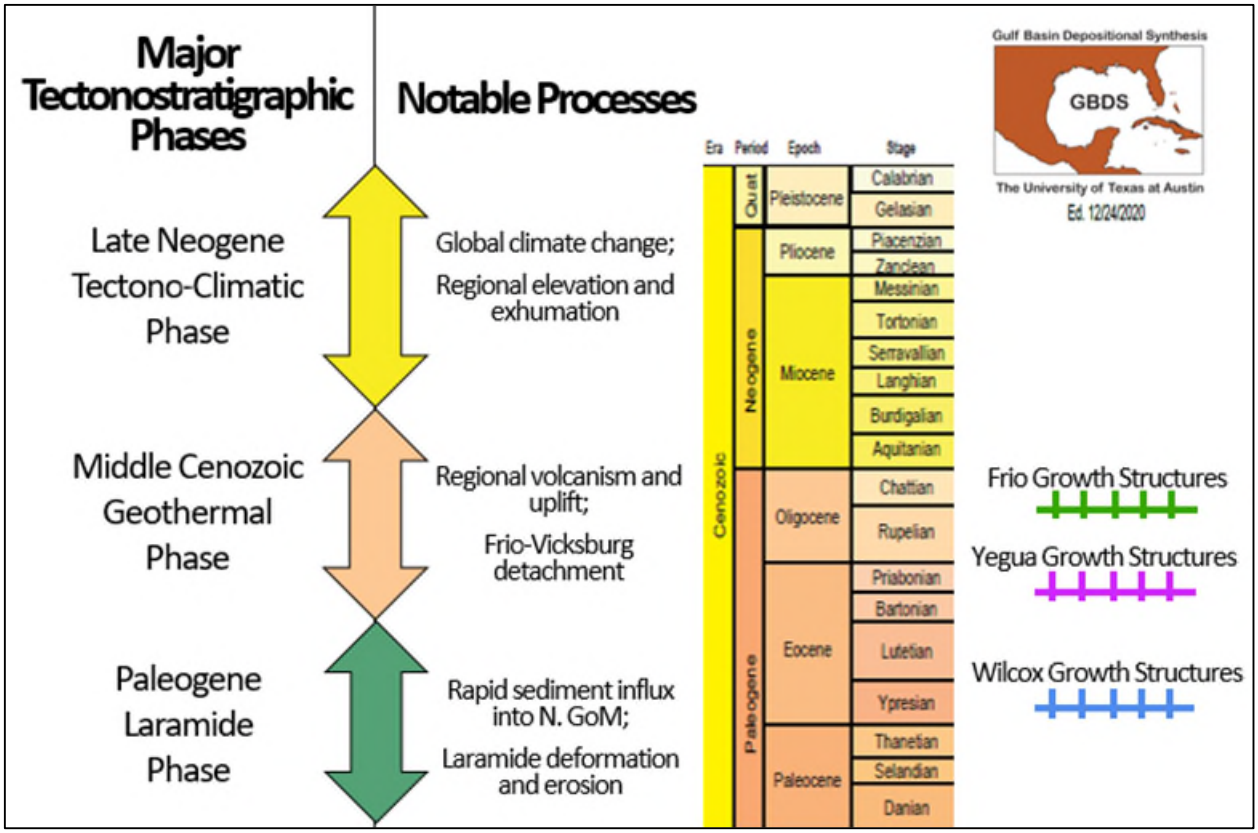


Figure AoR-15: Tectono-stratigraphic chart showing key processes related to structural history of the Gulf Coast Bluebonnet region (modified from the University of Texas at Austin's Gulf Basin Depositional Synthesis).

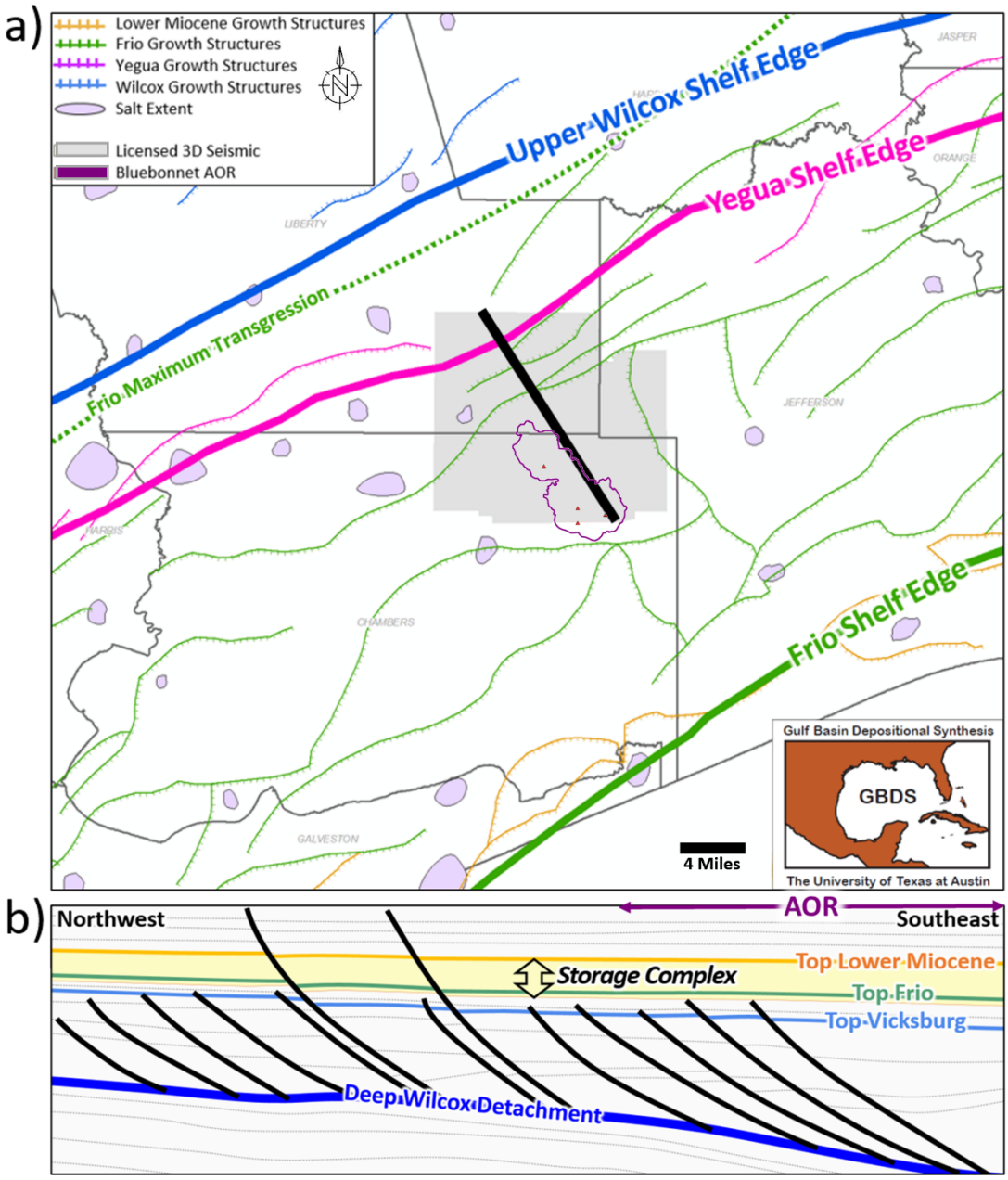


Figure AoR-16: a) Regional structural elements from the University of Texas at Austin's Gulf Basin Depositional Synthesis. b) Cross section interpretation from 3D seismic showing the growth faulting (dominant structural style) in the Bluebonnet area.

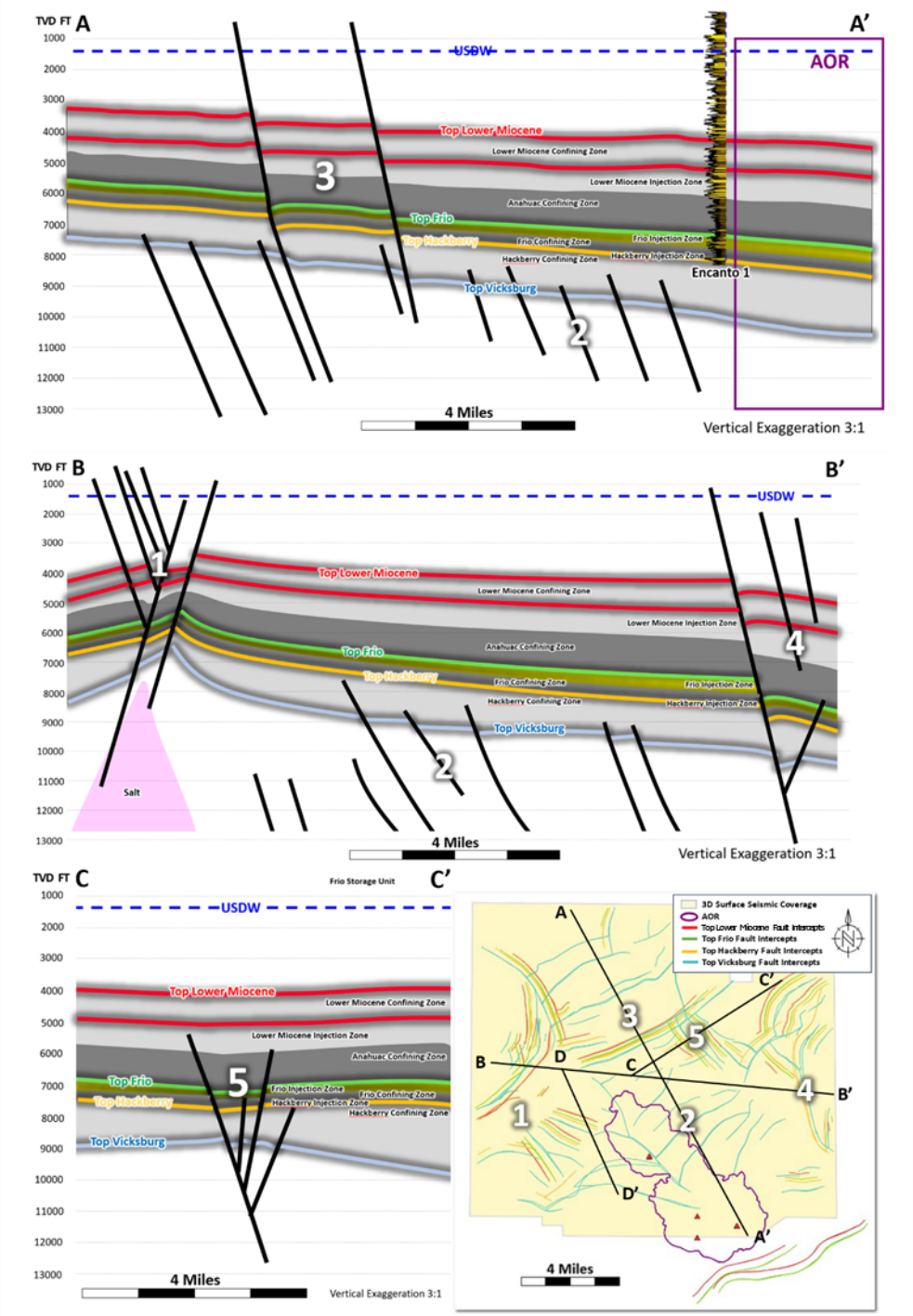


Figure AoR-17: Interpretations from 3D seismic showing various structural styles in the Bluebonnet region. Locations for cross sections A-C are shown map. The confining and injection zones are free of transecting or transmissive faults within the AoR .

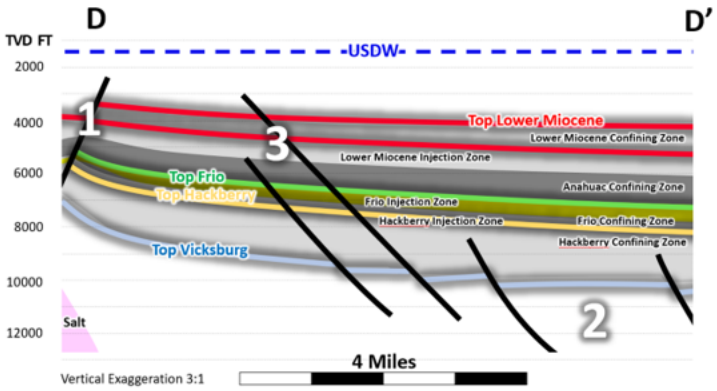


Figure AoR-18: Additional section demonstrating structural styles in Bluebonnet region, particularly style 2, which impacts the Hackberry storage interval outside of the AoR.

Claimed as PBI



Figure AoR-20: Example map view of fault likelihood extraction on confining zone surfaces with 3D seismic cross section for reference. There is no evidence for faulting within the AoR at the Top of Lower Miocene Confining Zone, The Top of Anahuac and the Top of Frio Confining Zones. The Top of Hackberry Confining Zone displays patterns from underlying Vicksburg faults, but no offset is visible.

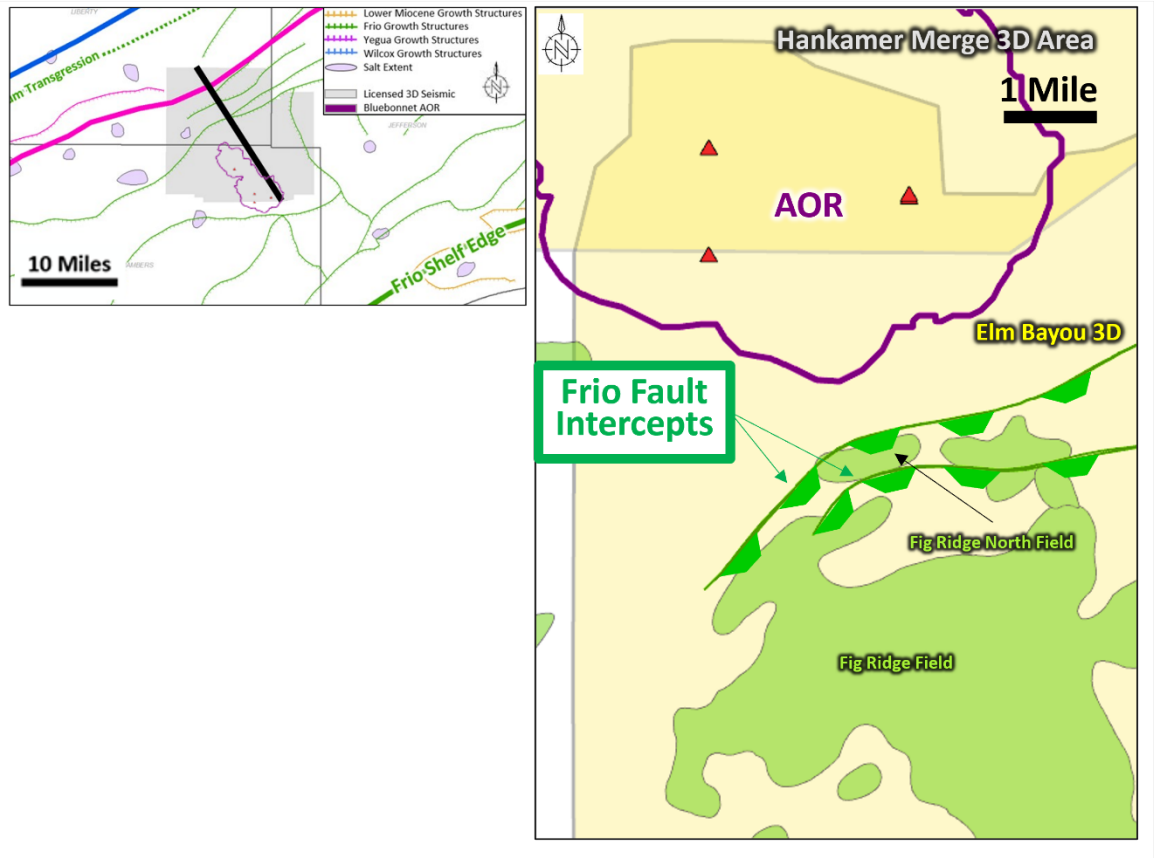


Figure AoR-21: Regional publications indicate presence of faulting south of the AoR and acreage position Faults have been preliminarily mapped on additional 3D seismic licensed by Oxy USA Inc.

3.6 Stratigraphy of the Storage Complex

Two stacked storage complexes have been identified in the Bluebonnet Sequestration Hub (Figure AoR-22). The deeper and older Oligocene storage complex will be developed first and comprises the Hackberry and Frio Injection Zones, as well as the Hackberry, Frio, and Anahuac Confining Zones. The shallower and younger Miocene storage complex comprises the Lower Miocene Injection Zone, Lower Miocene Confining Zone, and Miocene Composite Confining Zones. Both storage complexes are vertically stacked and described in the following from oldest to youngest.

Frio and Hackberry Injection Zone

This storage complex is composed of 284 ft Frio and 52 ft Hackberry net sand thickness, totaling 335 ft net sand thickness, as the storage reservoir for CO_2 and 1,074 ft of overlying Anahuac Confining Zone as the confining unit.

Lower Miocene Injection Zone

The Miocene section of this storage complex is composed of 1,004 ft sand thickness as the storage reservoir for CO_2 and 168 ft of overlying confining zone as the confining unit. The base confining zone for the Miocene storage section is represented by the Anahuac confining zone, which it is 1,074 ft in average at the site. Figure AoR-22 show the stratigraphic column of the hydrologic units within the storage complex.

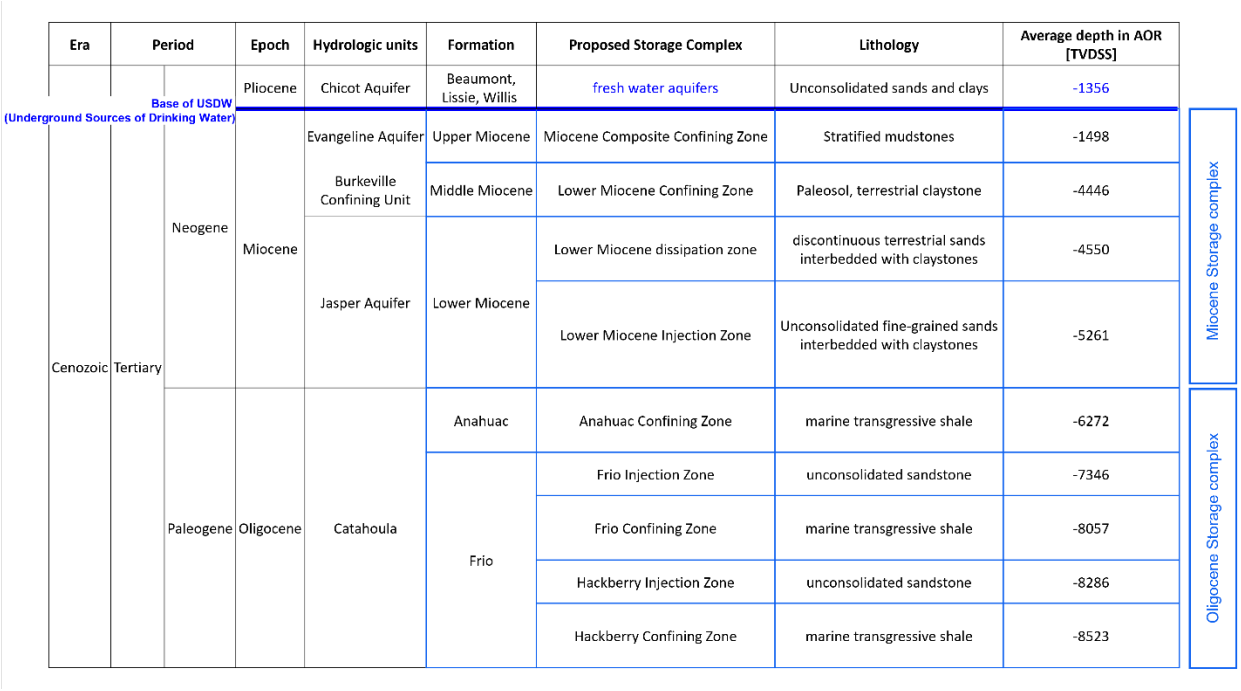


Figure AoR-22: Stratigraphic column of the hydrologic units and geologic formations and their lithologies. The average subsea depths over the proposed AoR are shown for the proposed Oligocene storage complex.

The stratigraphy of the storage complex is described from older and deeper to younger and shallower strata.

The **Hackberry Confining Zone** is the base confining zone for the proposed storage complex. The Hackberry Confining Zone is a low-permeability confining zone that is regionally contiguous in both the north-south dip direction and in the east-west strike direction. This third-order marine transgressive shale represents a time in the Oligocene when the Gulf Coast was submerged under water due to rising sea levels, which explains the lateral continuity. Transgressive shales offer good to excellent seal potential depending on their fabric and petrophysical properties.

Above this base confining zone, is the lower CO_2 injection zone within the **Hackberry Injection Zone**. These sandstones were likely deposited in a proximal delta front and are better developed

in the northern updip part of the acreage and thin toward the south and downdip, which drives the completion strategy of the proposed CO_2 injection wells. The Hackberry sandstones exhibit high porosity and permeability, both of which are critical parameters for input in the storage capacity and injectivity estimations.

The **Frio Confining Zone**, which caps the proposed Hackberry Injection Zone, is a laterally continuous and intraformational marine shale reflecting another flooding event in the Oligocene. This also serves as the base confining zone for the Frio Injection Zone above and represents a lower third-order, shale-prone transgressive system tract (TST).

The upper CO_2 injection zone within the Oligocene storage complex is the **Frio formation**. The **Frio Injection Zone** is composed of a series of deltaic and marginal-marine to nonmarine sandstones and shales (USGS, 2013). On regional and local cross sections, the Frio was subdivided and mapped in three units: the Top, Mid, and Low Frio. These Frio subunits expand basinward and are characterized by thick, undifferentiated sandstone bodies, which were deposited within the lobes of a slowly prograding delta system called the Houston Delta (refer to Section 3.5 Basin History and Structure). The internal architecture of the Frio Injection Zone reservoir sandstone is interpreted as an assemblage of a stacked, high-constructive, and lobate delta (Bebout 1976). The collected Frio core from the stratigraphic test well Encanto 01 and log data from surrounding wells within the AoR confirmed this interpretation and documented both fluvial and subaqueous environments within a deltaic setting, as well as nonmarine to marginal-marine deposited sequences based on biostratigraphic analyses. The Frio sandstones exhibit high porosity and permeability, both are critical parameters for input in the storage capacity and injectivity estimations.

In a sequence stratigraphic interpretation performed on a cross section through the Encanto 01 stratigraphic test well logs and surrounding wells, the Frio Formation is characterized by a fluvial/deltaic signature with numerous trough cross beddings and minor carbonaceous plant debris. The third-order sequence stratigraphic framework comprises a lower third-order, shale-prone TST, which is the Frio Confining Zone and an overlying sand-prone third-order highstand system tract (HST). The third-order highstand can be split into fourth-order sequences, each of those made up of thin TST and a thicker sand-prone HST, which are the Top, Mid, and Low Frio sandstones (i.e., the Frio Injection Zone).

The **Frio Injection Zone** is regionally overlain by an onlapping transgressive marine shale wedge, the **Anahuac Formation** (Galloway, 1982). This is an excellent stratigraphic marker and the upper confining zone for the proposed Frio Injection Zone.

The Anahuac Confining Zone is mostly composed of dense marine shale, but also contains deltaic and carbonaceous sediments. During the Late Oligocene transgressive flooding was a time of carbonate deposition and associated decrease in clastic supply on the shelf platform. The resulting Heterostegina carbonates (Het Lime) occur as far west as Houston (Galloway 2000). The Anahuac does not crop out within the state of Texas and caps the stacked Hackberry and Frio Injection Zones. The Anahuac shale is a major seal that separates two regional pressure

compartments (i.e., the Frio and Miocene sands). It represents the lower confining zone for the Miocene storage complex and is a good base seal for the proposed CO_2 injection into the Lower Miocene sands.

The Anahuac transgression was terminated by a renewed progradation of siliciclastic sediments of the **Lower Miocene Injection Zone**, which was a period of relative paleogeographic stability in the Gulf Basin. These Lower Miocene sandstones were deposited in a transitional to terrestrial setting. It is common to observe nonmarine, stacked meandering fluvial channel complexes of variable thickness, especially in the upper part of the reservoir section. The lower part of the reservoir section contains predominantly delta-front sands interbedded with distributary channels of variable thickness and continuity.

In the sequence stratigraphic context, deltaic progradation resumed in the Lower Miocene, with delta front sands prevailing in the Bluebonnet area at the initial progradation. This deltaic progradation occurred as part of a highstand system tract (HST), which developed uninterrupted during the Lower Miocene. The Bluebonnet basin in the Lower Miocene was initially infilled with marginal marine sediments, and later fluvio-deltaic sediments (see Section 3.7 Depositional Environment). Then, the Miocene storage section and corresponding confining zone (mostly composed of coastal plain and related deposits) would correspond to a third-order highstand system tract (HST). The transgressive episode above this HST should correspond to the Amphistegina B shale, though it is not well observed at the Bluebonnet site.

The **Lower Miocene Confining Zone** acts as the confining zone for the Lower Miocene Injection target and as a secondary confining zone for the Frio and Hackberry Injection Zones below. The Lower Miocene Confining Zone is mostly composed of terrestrial sediments, including paleosols and reddish mudrocks, which were deposited in a coastal marsh along the northern Gulf Coast.

This paleosol is overlain by additional mudrock intervals interbedded with sandstones in the shallower Miocene section, collectively called the **Miocene Composite Confining Zones.** The Miocene Composite Confining Zone represents the upper most confining system for the Lower Miocene Injection Zone, Frio Injection Zone, and Hackberry Injection Zone. The Miocene Composite Confining zone includes as minimum three lateral continuous seals mapped across the AoR, intercalated with intervals of sands. The low permeability of the seals combined with the permeability contrast within this stratified sequence of interbedded sandstones and mudrock will act as a composite confining system (Bump et al, 2023) by imposing a highly tortuous path for any CO_2 migrating upward, and would therefore, attenuate any CO_2 and/or pressure in case of a leak through the Lower Miocene Confining Zone.

On top of the **Miocene Composite Confining Zone** is the base of the Underground Source of Drinking Water (USDW). The described base Hackberry, intraformational Frio, Anahuac, and Lower Miocene Confining Zones as well as the upper most Miocene Composite Confining Zones (five confining zones altogether) are in place to prevent any fluid migration from the permitted Hackberry, Frio, and Miocene Injection Zones into the USDW.

All described zones are laterally continuous in a north-south dip and west-east strike direction within and beyond the AoR. Figure AoR-23 shows a generalized stratigraphic column and Figure AoR-24 shows a cross-sectional view of the proposed storage complex.

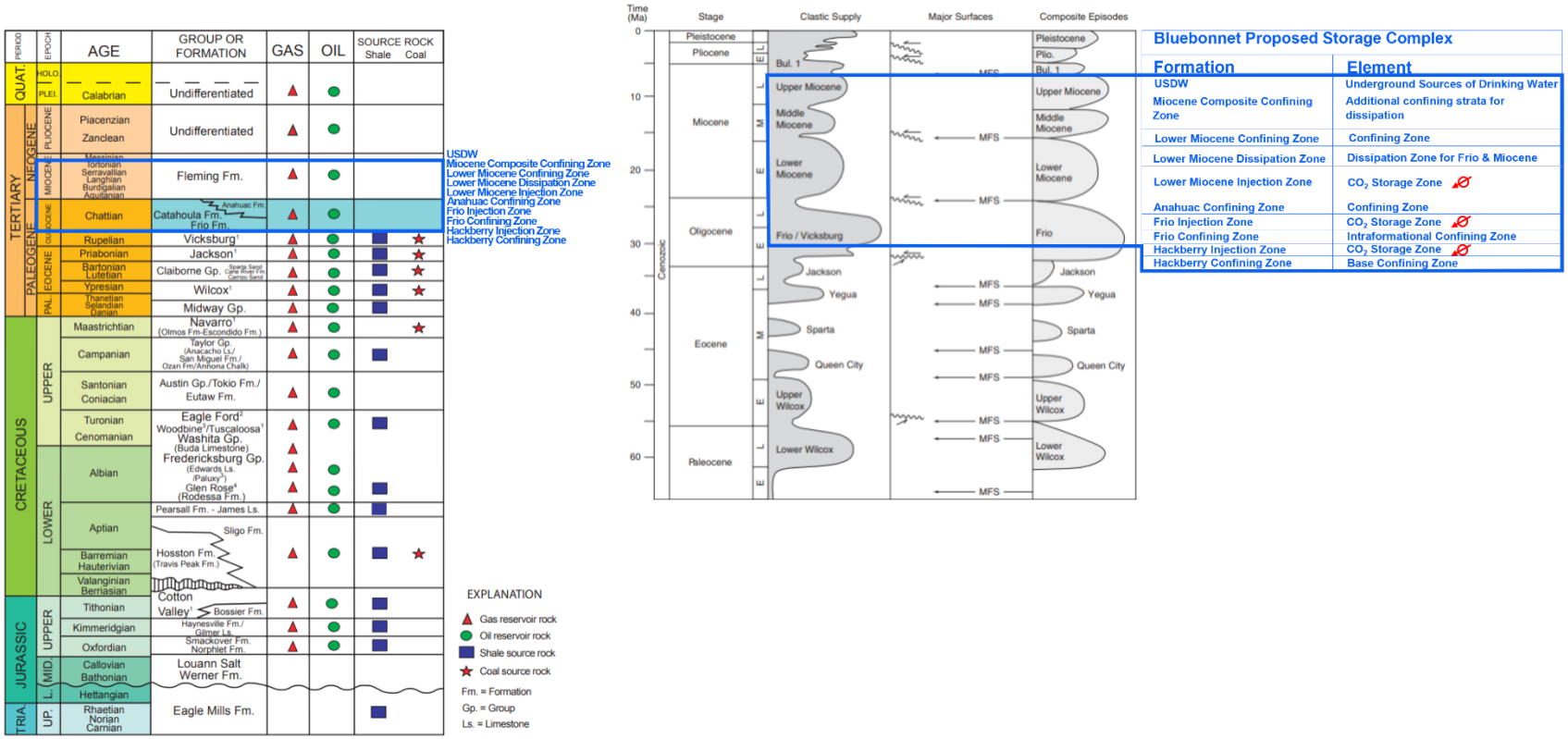


Figure AoR-23: Generalized stratigraphic column of the northern Gulf of Mexico coastal plain, highlighting the proposed storage complex in blue (modified after Swanson et al., 2013 and Galloway, 2008).

Proposed Storage Complex	
Formation	**Element**
Shallow Aquifers	Underground Sources of Drinking Water
USDW	
Miocene Composite Confining Zones	CO_2 Supercritical Depth Cutoff for dissipation
Lower Miocene Confining Zone	Confining Zone
Lower Miocene Dissipation Zone	Dissipation Zone for Frio & Miocene
Lower Miocene Injection Zone	CO_2 Storage Zone
Anahuac Confining Zone	Confining Zone
Frio Injection Zone	CO_2 Storage Zone
Frio Confining Zone	Intraformational Confining Zone
Hackberry Injection Zone	CO_2 Storage Zone
Hackberry Confining Zone	Base Confining Zone

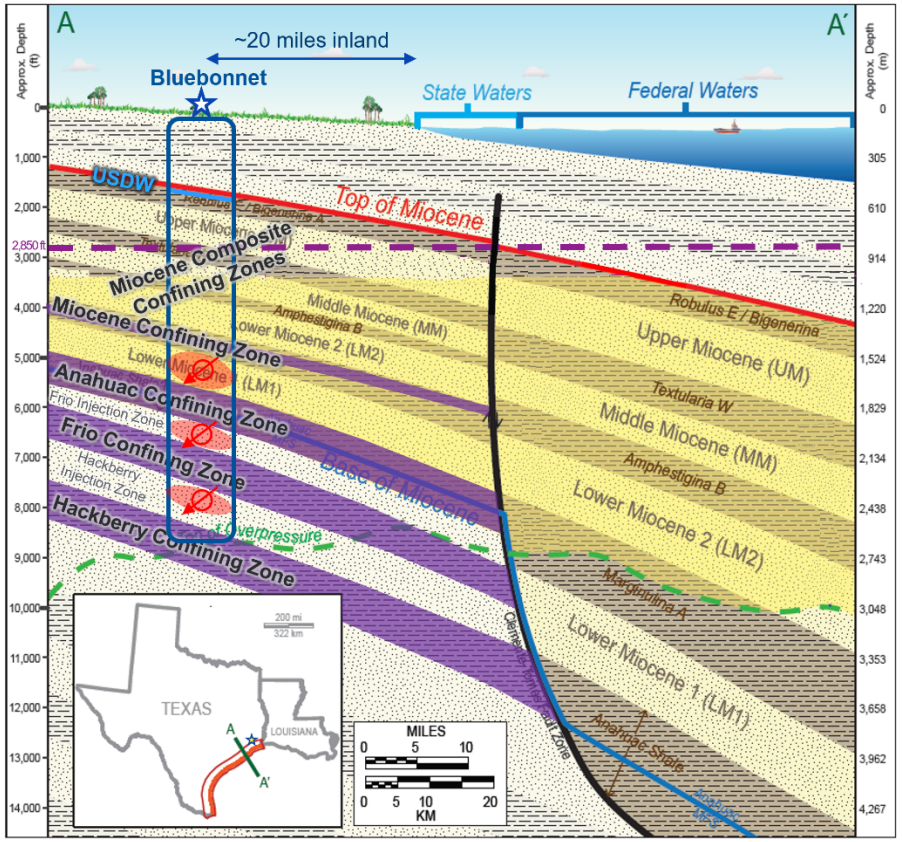


Figure AoR-24: Proposed storage complex at Bluebonnet, identifying formations and elements of the storage complex. This permit requests approval for CO_2 injection into the Hackberry, Frio, and Lower Miocene sandstones, utilizing the Anahuac shale, the Lower Miocene Confining Zone and the Miocene Composite Confining Zone as confining systems. After BEG, 2017.

3.7 Depositional Environment

The Oligocene was a time of massive sediment influx, primarily from the southwest United States (Galloway et al., 2000). The response in the Gulf was the sediment-supply dominated Frio depositional episode, which built out the coast in the form of a regionally extensive wedge of sand and shale deposited along the northern margin of the Gulf of Mexico (BEG, 1997).

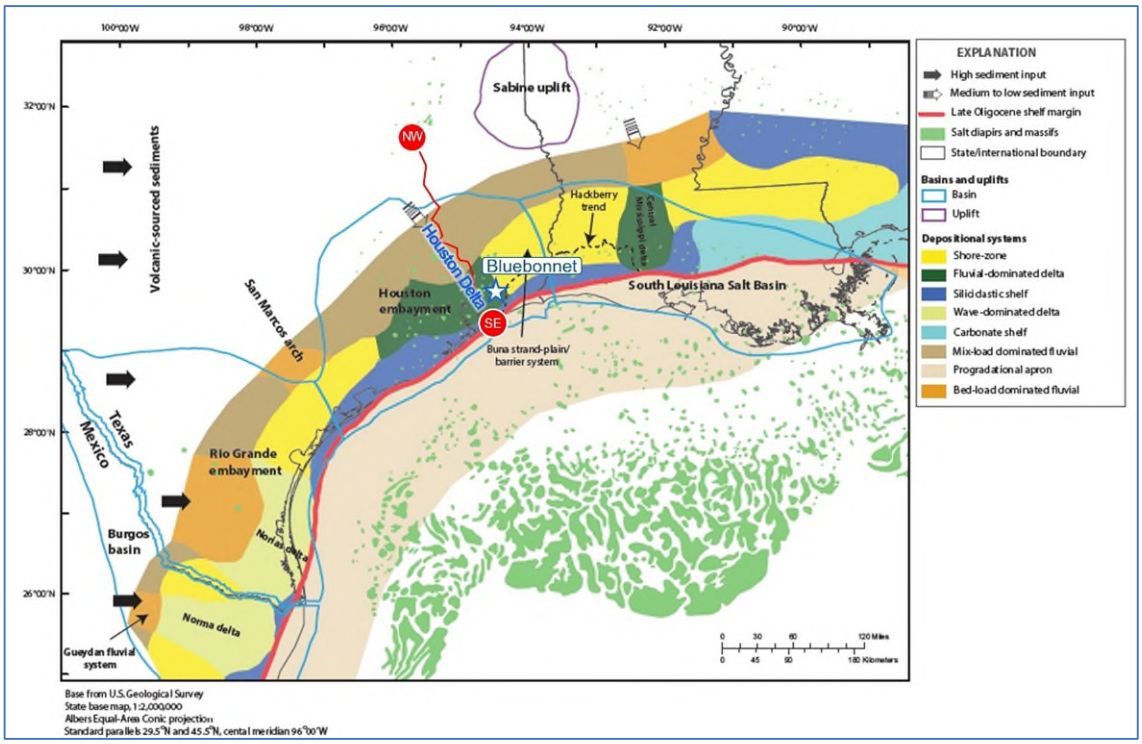


Figure AoR-25: Late Oligocene sediment sources in the northern Gulf of Mexico. Highlighted are the fluvial-dominated Houston Delta, cross section from Figure AoR-10 in red and proposed Bluebonnet Sequestration Hub with the blue star. After Swanson, USGS 2013.

The geometry of these sands impacts injectivity and plume migration. The Frio Formation is composed of a series of fluvial/deltaic and marginal-marine sandstones and shales that are the downdip equivalent of the continental Catahoula Formation (Swanson, 2013). Frio sediments were deposited along the northern margin of the Gulf of Mexico in a major fluvio-deltaic depocenter, which accumulated in the Houston Embayment (Figures AoR-25). The Houston Delta formed multiple lobes, which were fed by numerous smaller fluvial tributaries. These multiple deltaic lobes coalesced to produce a broad expanse of sediment across the continental shelf and onto the continental margin (Seni, 1997). The Oligocene and all younger sequences thin rapidly as they approach their outcrop towards the north (Galloway, 2008).

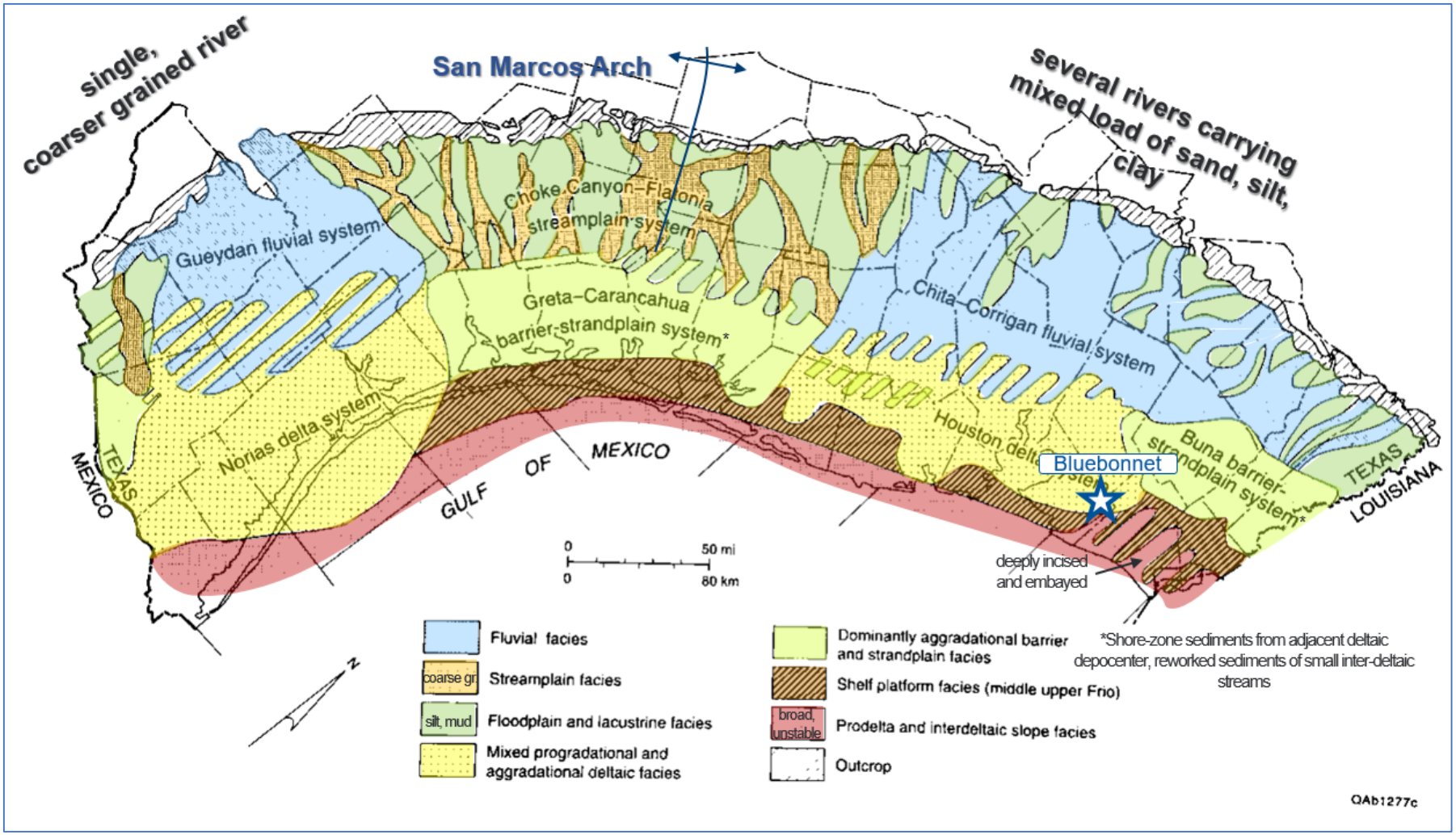


Figure AoR-26: Oligocene-aged Frio depositional system along the northern Gulf Coast. The Bluebonnet Sequestration Hub is in mixed progradational and aggradational deltaic facies (modified after Seni, 1997).

Depositional styles of the Oligocene are classified in retrogradational (shelf facies), progradational (distal deltaic facies), and aggradational (proximal deltaic and fluvial facies) based on well log responses Figure AoR-26 (Seni,1997). At the Bluebonnet Sequestration Hub, the Frio Formation consists of a terminal distributary channel, an interdistributary bay, and a proximal delta front. A schematic representation of the depositional setting for the Frio Formation is shown in Figure AoR-27.

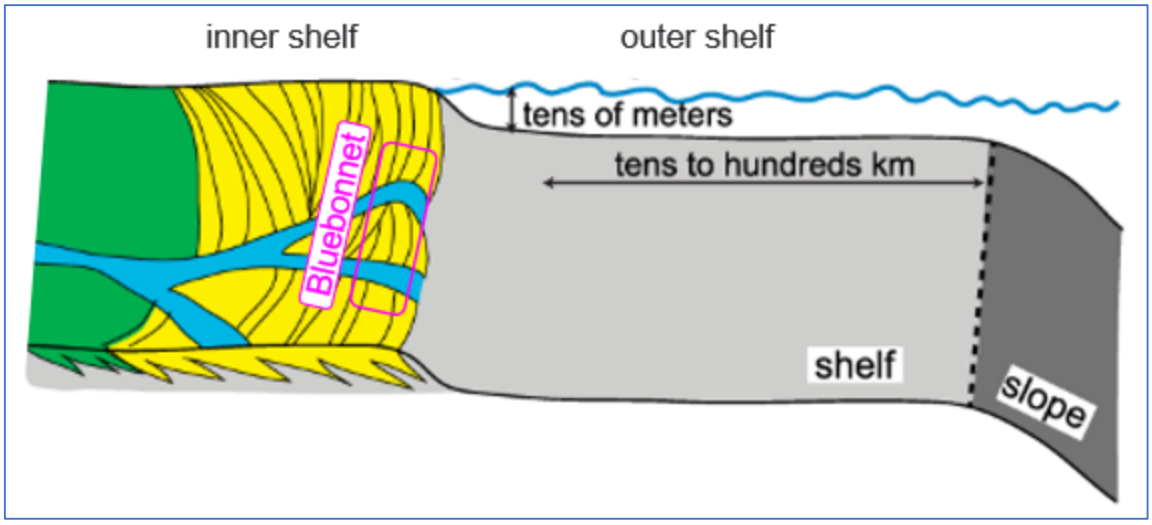


Figure AoR-27: Oligocene-aged Frio delta along the northern Gulf Coast showing a deltaic progradation across a stable shelf. The delta on the inner shelf is dominated by fluvial rivers (blue) discharging sediments (yellow) towards a coast where wave processes dominate the deltaic progradation into deeper water of the outer shelf (modified after Olariu, 2015).

Both facies are overlain by successions of transgressive or back-stepping coastal and marine shelf-facies (Galloway, 2008). Galloway defined multiple maximum flooding surfaces based on these patterns of transgressions related to glacioeustatic sea-level rise events. The overlying Anahuac Shale – a regionally extensive marine transgressive shale – was deposited because of such a eustatic rise in sea level.

In this proposed storage complex, the Anahuac Formation constitutes the primary confining layer for the injected CO_2. This is an excellent stratigraphic marker and many cuttings and whole core were acquired in the stratigraphic test well Encanto 01. This late Oligocene Anahuac shale represents a major marine transgression over the Gulf of Mexico shelf. The transgression occurred during a period of climate warming, which also explains the presence of carbonate building organisms in the Het Lime (see 3.6 Stratigraphy of the Storage Complex).

Upon the Anahuac transgression, an extended phase of high sedimentation rates and building the continental margin followed (Galloway, 2008). The Lower Miocene of the northwestern Gulf of Mexico Basin evolved from a Paleogene (Paleocene–Oligocene) pattern of sediment supply dominated by northwestern fluvial systems to a Neogene (Miocene–Pliocene) pattern dominated by fluvial systems entering the basin from the north. (BEG, 2017). In eastern Texas, where the

Bluebonnet site is located, there was an important sediment input represented by the Newton fluvial system (paleo Red River) and Calcasieu delta system (Figure AoR-28). Within the Lower Miocene, there are multiple stacking patterns of depositional styles, a result of many temporary transgressions in an overall regressive environment (USGS, 1996). Sands of the Newton fluvial system are fine to medium grained and present themselves with blocky and/or fining-upward log signatures. Outcrop features and detailed sand-body geometry indicate meandering channel patterns, which can also be mapped on seismic in various azimuths. Meanderbelt, storm washover, and crevasse splay deposits constitute the sandstone facies of this mixed load fluvial system. Basinward, the system may become increasingly suspended-load dominated (Galloway et al. 1986). The Newton/Red River fluvial system supplied the Calcasieu delta, which extended beneath the Texas coastal plain and adjacent offshore area (Figure AoR-29).

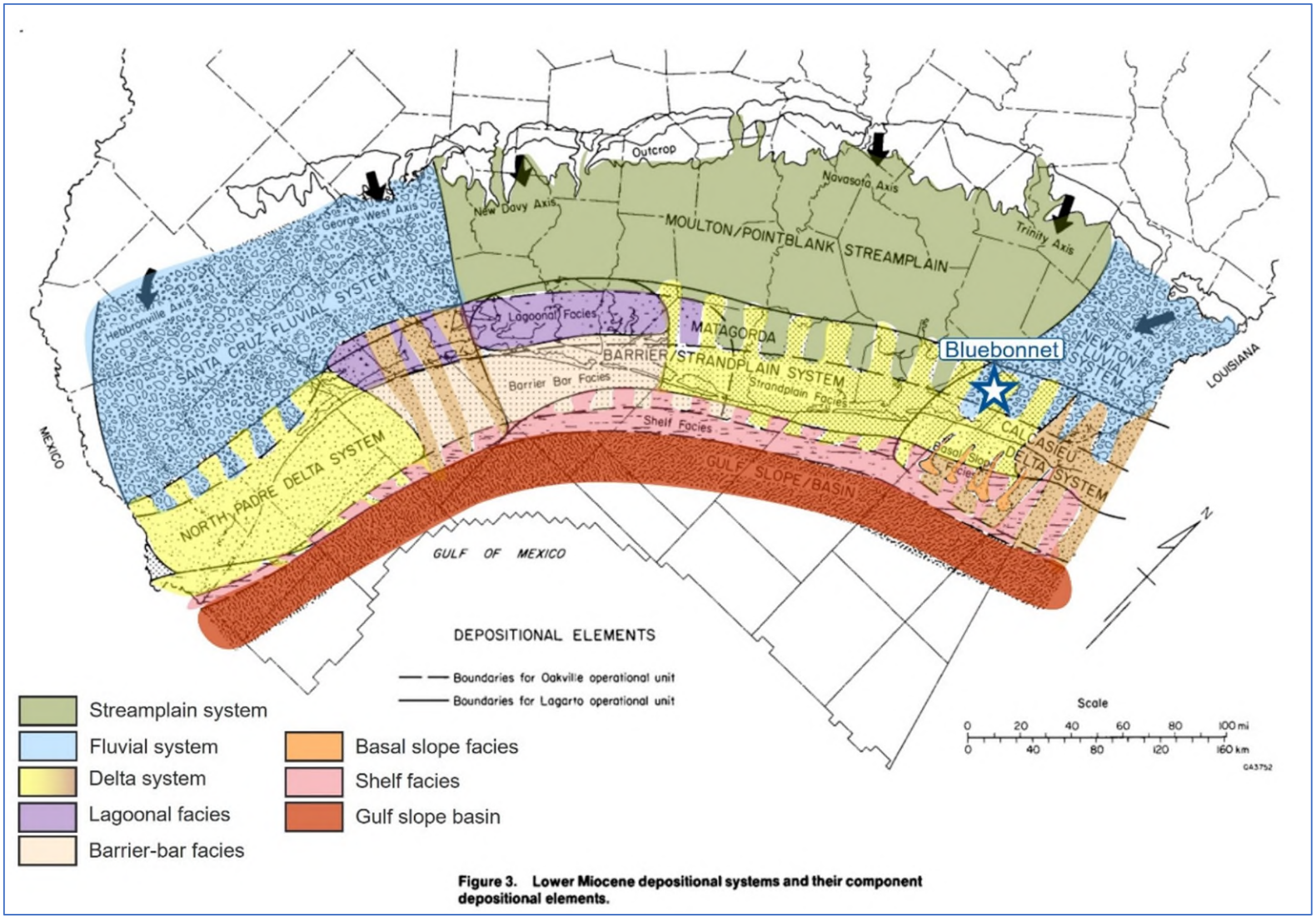


Figure AoR-28: Lower Miocene depositional system along the northern Gulf Coast (modified after Galloway, 1985).

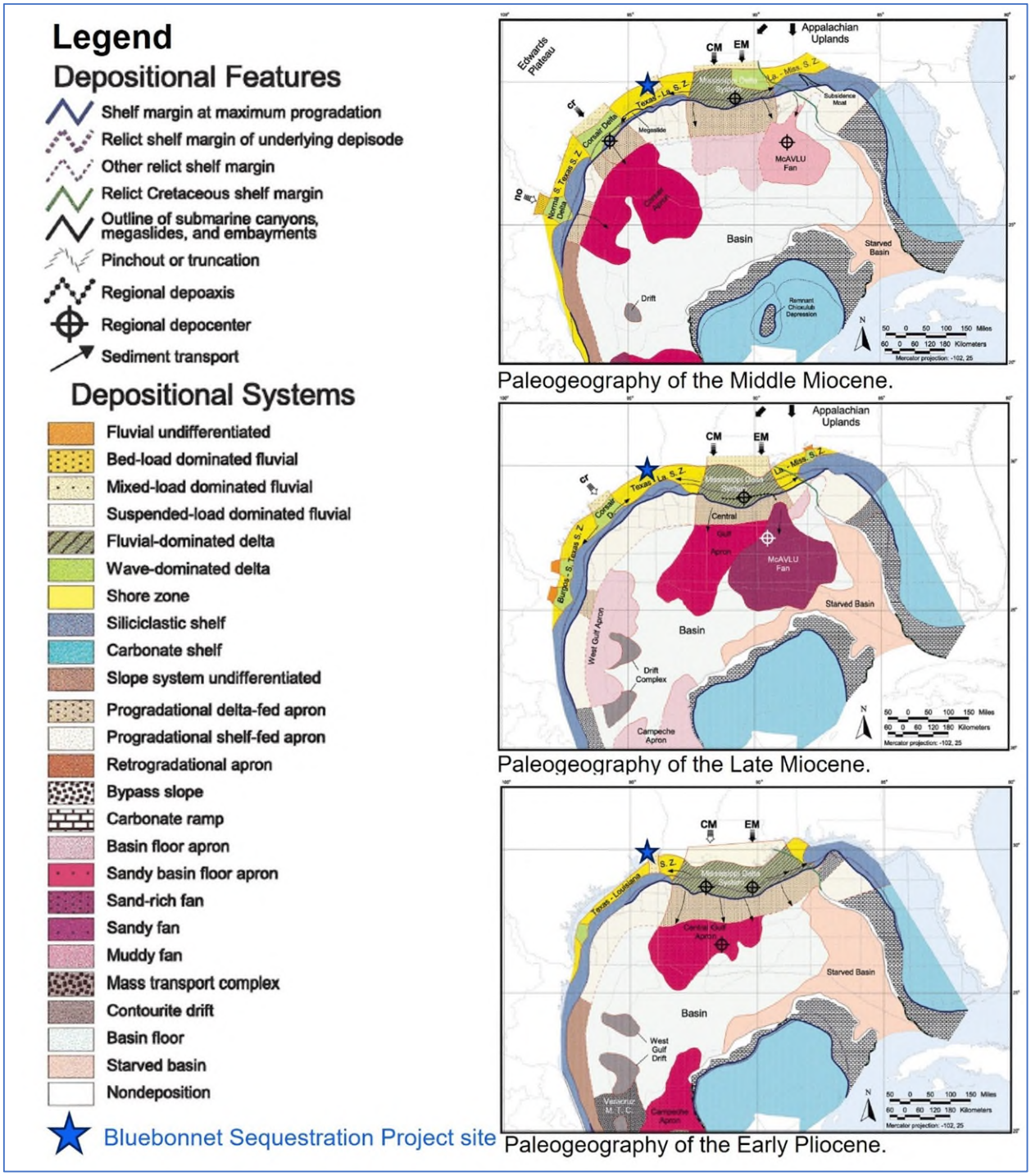


Figure AoR-29: Paleogeographic reconstruction of the Gulf of Mexico Basin from Middle through Late Miocene and Pliocene, after Galloway et al., 2000. The blue star identifies the location of the Bluebonnet Sequestration Project site on a shore zone with mixed-load dominated fluvial input across a coastal plain.

The depositional environment interpretation is based on whole cores from the stratigraphic test well Encanto 01, taken at 5415'-5445' and 4370'-4430'. The lower cored section is part of the LMIO_INJ_5 injection zone, and it is interpreted as a stacking of fluvial channels mostly composed of cross-bedded fine-grained sandstones with some mud clasts and soft-sediment deformation (Figure AoR-30). The upper cored section is part of the Lower Miocene Confining Zone. It comprises a section of reddish calcareous mudstones, mostly mottled, with some rooting and bioturbation (Figure AoR-31). Some layers of silty sandstones with some bioturbation, climbing ripples, soft-sediment deformation, and occasional mud clasts are interbedded with the mudrocks. This upper section was deposited within a coastal plain/floodplain setting, with some paleosols involved. The sandy levels probably correspond to channel margin, storm washover, or crevasse splay deposits where the soft-sediment deformed sandstones might imply sediment instability at the channel margin The climbing ripples indicate rapid deposition from suspension and can be associated with in crevasse splays and channel levees.

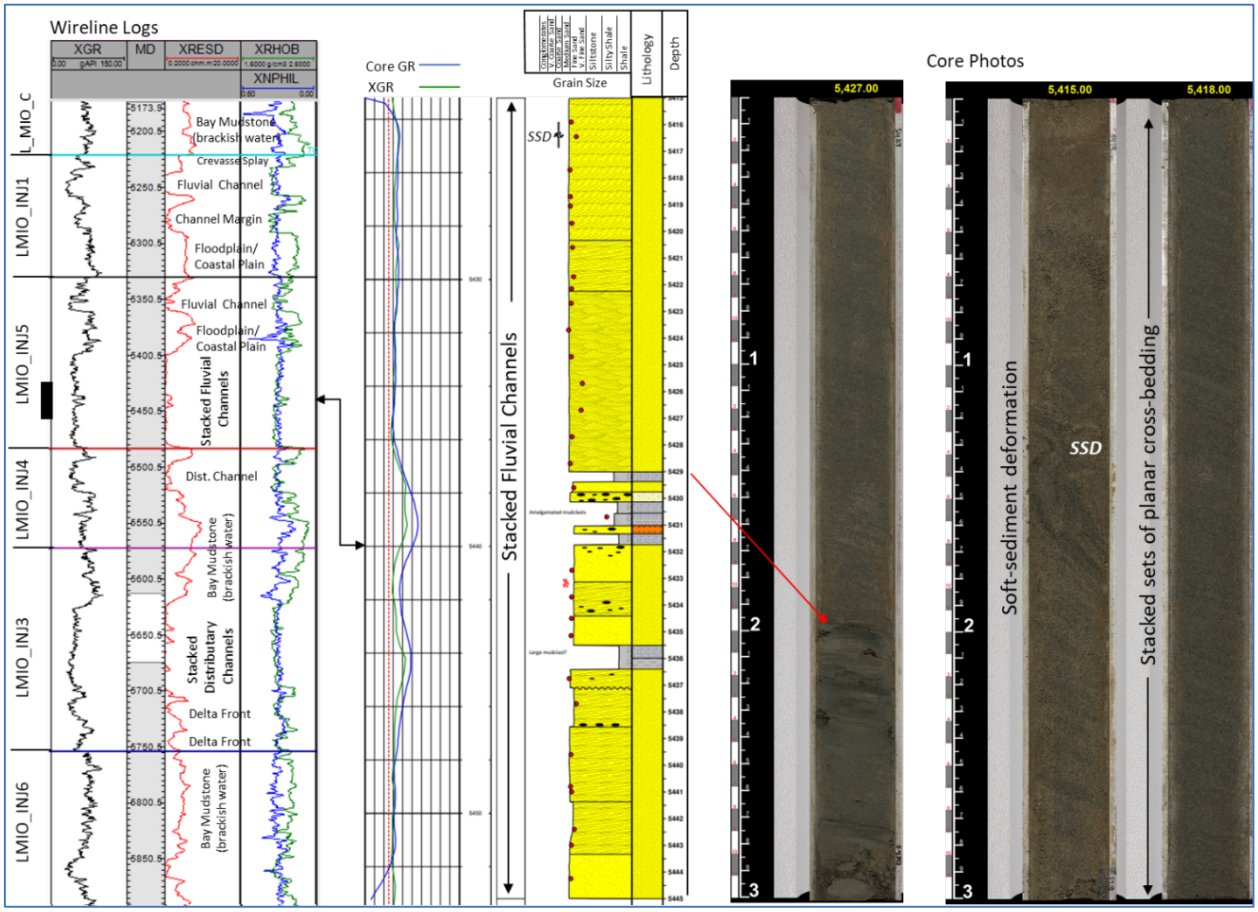


Figure AoR-30: Depositional facies from Encanto 01 core (5,415-5,445 ft) showing part of a stacking of fluvial channels, with cross-bedded sandstones and soft-sediment deformation. Black rectangle in wireline log to the left represents the cored section.

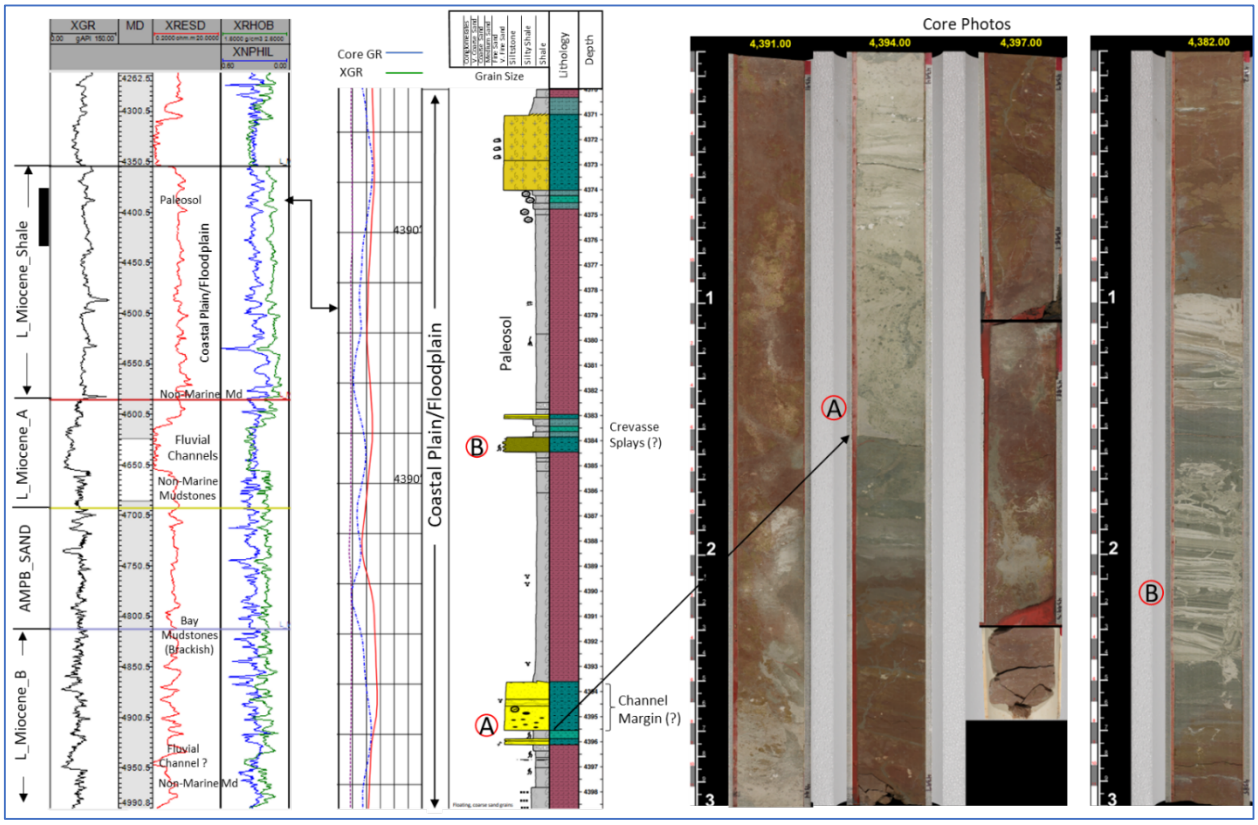


Figure AoR-31: Depositional facies from Encanto 01 core (4,370-4,430 ft) showing a section of reddish calcareous mudstones, mottled, with some rooting and bioturbation. Also, sandy intervals that might be associated with crevasse splays, storm washover, or channel margin.

To reconstruct the depositional history of the basin, many types of data sets from the stratigraphic well Encanto 01 well were integrated (cores, biostratigraphy, image logs, etc.). The observations from this well were combined with log data from approximately 149 wells and a 3D reprocessed seismic survey. Extensive well-log correlation, RMS amplitude, and spectral decomposition seismic attributes, as well as paleoenvironments from biostratigraphy, were integrated to understand the spatial evolution of the depositional environments within the Bluebonnet basin. From bottom to top, the depositional history can be summarized in Figure AoR-32 to Figure AoR-37, and described as follow.

Above the transgressive Anahuac interval, delta progradation resumed in the Bluebonnet area with delta front facies mostly towards the south of the Bluebonnet basin (i.e., LMIO_INJ2 zone, Figure AoR-32). Moving up in the section (i.e., LMIO_INJ6 zone), the southern portion of the basin was still dominated by delta-front facies, but channel facies prevailed in the north (Figure AoR-33). A mud-filled channel is identified within the LMIO_INJ6 zone, which might represent a flow barrier between sandstones in the north and south (see Figure AoR-33). This mud-filled channel is better observed within unit LMIO_INJ3 (Figure AoR-34). Up in the Miocene section, and within the LMIO_INJ5 zone, two clear meandering channel systems entered the Bluebonnet basin from the

NW and NE (see Figure AoR-35). The core in Encanto 01 well confirms that these meandering channels are fluvial in origin.



Figure AoR-32: Interpretation of depositional environments for LMIO_INJ2 zone (base of the Miocene section). Bright amplitudes to the south of the Bluebonnet basin are interpreted as delta-front deposits, which are fed by narrow distributaries-oriented N-S. Green dashed line on the RMS amplitude map represents the cross-section with depositional facies (green: shales, yellow: delta-front, red: distributary channels).



Figure AoR-33: Interpretation of depositional environments at top of LMIO_INJ6 zone, with delta front interpreted to the south and narrow distributaries feeding this delta front. A mud-filled channel (opaque RMS amplitude) is interpreted in the center of the area.



Figure AoR-34: Interpretation of depositional environments within LMIO_INJ3 zone, highlighting the mud-filled channel (opaque amplitude) seen in lower injection zone LMIO_INJ6.



Figure AoR-35: Interpretation of depositional environments within LMIO_INJ5 zone, showing two meandering systems entering the basin from NW and NE.

The confining (for dissipation) zones for the Miocene storage section (L_MIO_A, L_MIO_B, and L_MIO_C) are not completely muddy, but contain thick mudstone intervals that are continuous across the Bluebonnet area (i.e., Figure AoR-36). According to the biostratigraphy from Encanto 01 well, these muddy intervals are not fully marine, but correspond to transitional and nonmarine mudstones and should have enough sealing capacity to prevent or retard the vertical movement of CO_2. Interbedded with these thick mudstone intervals, there are sandy intervals of variable thickness and continuity that are interpreted as likely channels and crevasse splays or storm washover deposits. Figure AoR-37 shows a cross-section with a proposed reconstruction of the depositional environments in a transect through the Encanto 01 well.


Claimed as PBI

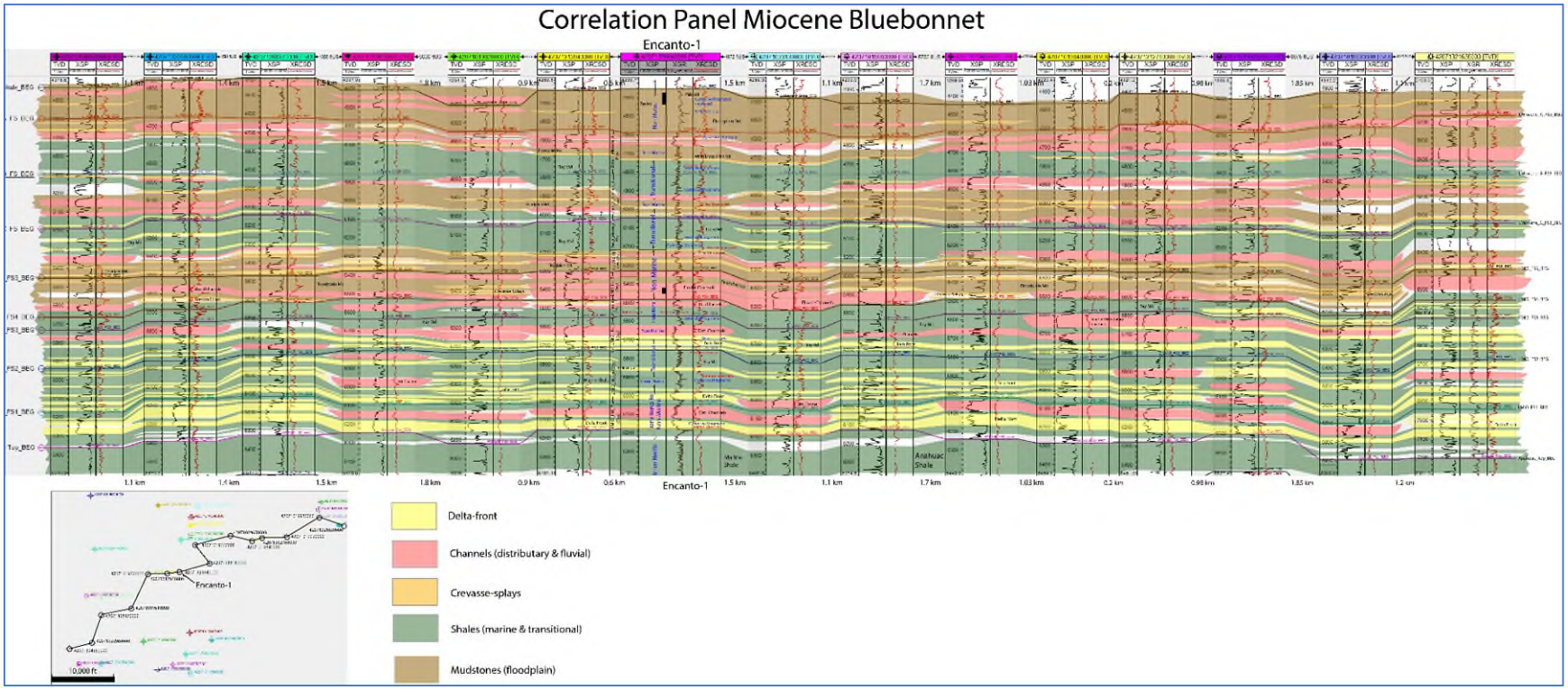


Figure AoR-37: Correlation panel Miocene section in Bluebonnet area. Interpretation of depositional environments based on cores and biostratigraphy from Encanto 01 well, and well data from neighboring wells. Depositional environments from well data also confirm interpretation from seismic facies.

During the Middle and Late Miocene through **Pliocene** (Figure AoR-29), the depositional axes of the rivers shifted towards the east, resulting in a change of depositional system from fluvial-deltaic to coastal plain to shore-zone (BEG, 2017). In these shore-zone systems, the sediment was transported along strike between the adjacent deltas to the east and west. Within the Bluebonnet Sequestration Project site, mixed-load dominated fluvial sediment supply across a coastal plain persisted.

3.8 Characterization of Injection and Confining Zones

The proposed AoR was selected in a location where the average reservoir and confining zone properties meet the criteria needed for permanent CO_2 storage and protection of the USDW(s). All zones were characterized by interpreting well log data and reservoir property maps derived from the geomodel, which also includes the structural interpretation based on seismic.

3.8.1 AoR Injection Zone Characteristics

This section describes in detail the information related to the proposed injection targets, Lower Miocene, Frio, and Hackberry sandstones. It describes depths, areal extents, thicknesses, mineralogy, porosity, permeability, and capillary pressure of the injection zones, including geology changes and facies based on geological cores, well logs, names, and lithology description according to 40 CFR § 1476.82 (3)(iii).

The following set of four cross sections consists of a structural dip cross section (Figure AoR-38), stratigraphic dip cross section (Figure AoR-39), structural strike cross section (Figure AoR-40), and stratigraphic strike cross section (Figure AoR-41). Those are presented over the proposed storage complex and include the strata from the Hackberry Confining Zone at the base through the Lower Miocene Confining Zone at the top. These structural cross sections indicate where the strata are downdip and where the strata are updip, indicating potential flow direction based on buoyancy forces of the injected supercritical CO_2 towards an updip direction. The accompanying stratigraphic cross sections indicate reservoir continuity, lateral facies changes based on log signatures, and thickness trends. Specific trends that can be observed on these cross sections are described in the following paragraphs by zone.

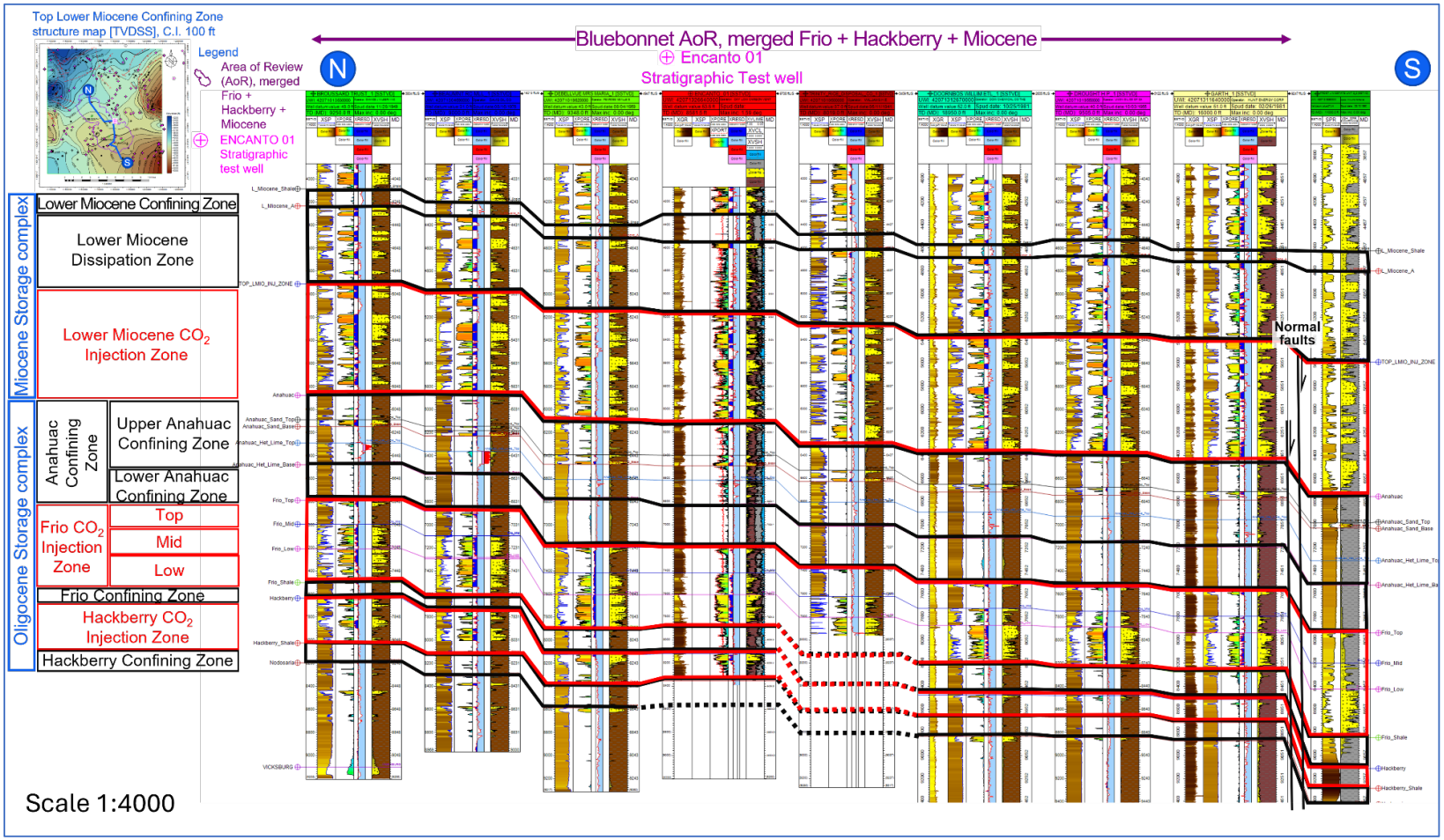


Figure AoR-38: Structural dip cross section, north-south through the AoR, scale 1:4000. Tracks shown are GR, SP, Porosity, Resistivity and VShale. The Hackberry, Frio, and Lower Miocene Injection Zones, as well as the Hackberry, Frio, Anahuac and Lower Miocene Confining Zones are laterally continuous along the structural dip within the AoR. The Hackberry Injection Zone shales out towards the south and downdip and is better developed towards the northern part of the AoR. The porosity over the Mid Frio and the Hackberry Injection Zones increases toward the northern part, which is also reflected in the net sand thickness increase towards the north. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

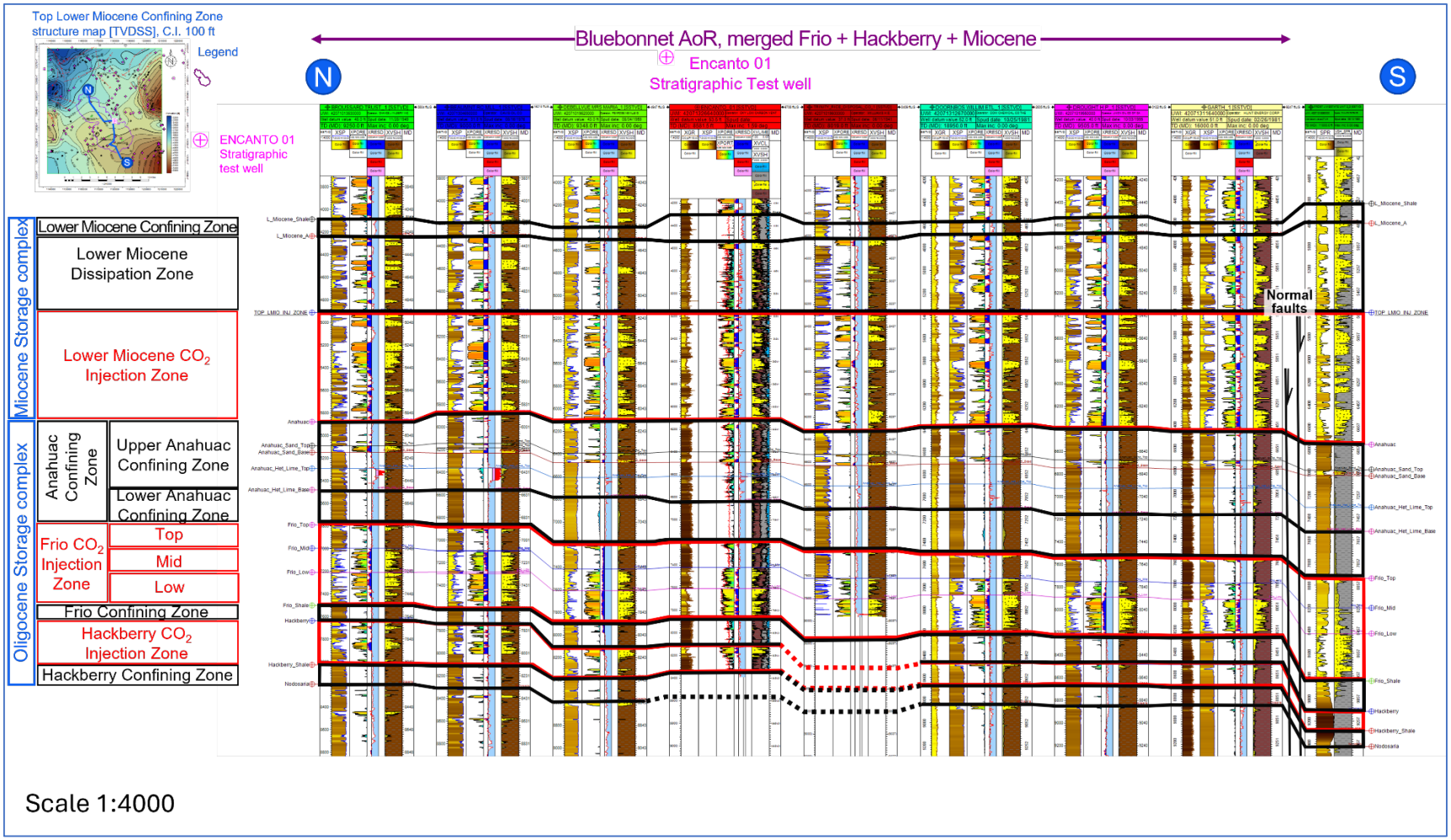


Figure AoR-39: Stratigraphic dip cross section, north-south through the AoR, scale 1:4000. The datum on which this cross section is hung on on the Top Lower Miocene Injection Zone. Tracks shown are GR, SP, Porosity, Resistivity and VShale. The Hackberry, Frio, Anahuac, and Lower Miocene Confining Zones are laterally continuous within the AoR. The Hackberry and Frio log signatures are correlative among the offset wells, which indicates preferred connectivity of reservoir properties in a dip direction and might influence plume migration pathways together with structural formation dip. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

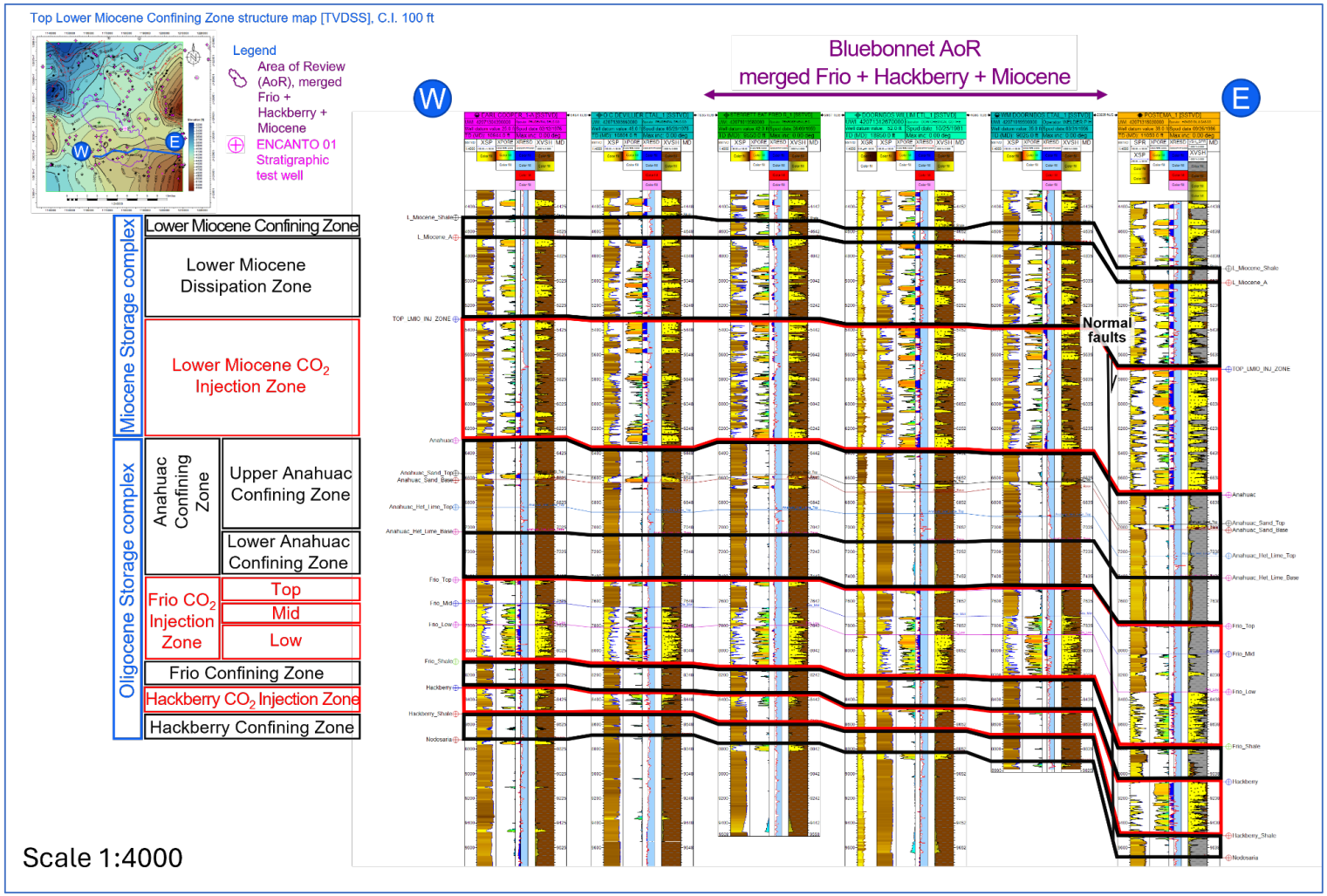


Figure AoR-40: Structural strike cross section, west-east through the southern AoR, scale 1:4000. Tracks shown are GR, SP, Porosity, Resistivity and VShale. The Hackberry, Frio, Anahuac and Lower Miocene Confining Zones are laterally continuous along strike within the AoR. The west side of the AoR is slightly more updip than the east side. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

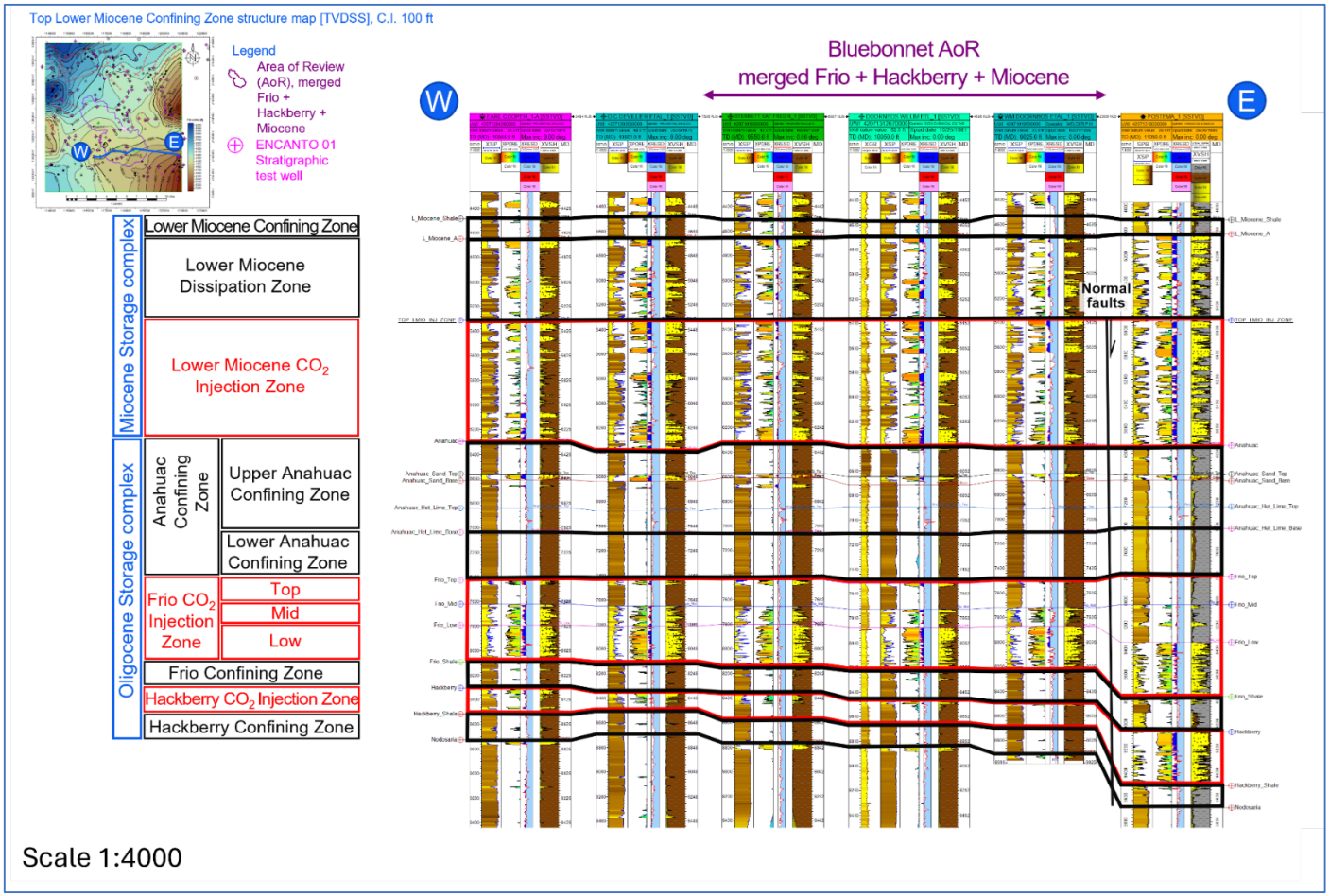


Figure AoR-41: Stratigraphic strike cross section, west-east through the southern AoR, scale 1:4000. The datum on which this cross section is hung on the Top Lower Miocene Injection Zone. Tracks shown are GR, SP, Porosity, Resistivity, and VShale. The Hackberry, Frio, Anahuac and Lower Miocene Confining Zones are laterally continuous within the AoR. The Hackberry Injection Zone sand thickness increases towards the west and decreases towards the east (in addition to the thickening towards the north and shaling out towards the south), which is also displayed in the net sand thickness map. The Top, Mid, and Low Frio are correlative in a strike direction as well. In the Low Frio lateral facies changes on a local well-to-well scale can be observed. The Lower Miocene Dissipation Zones tend to have thinner sands, interbedded with siltstone, and are laterally less continuous in the AoR. The Lower Miocene Injection Zones are generally thicker and laterally more continuous, generally thickening to the east and southeast.

3.8.1.1 Hackberry Injection Zone

The Hackberry sandstones at the Bluebonnet Sequestration Project site were likely deposited in a proximal delta front and are better developed in the northern updip part of the acreage and thin toward the south and downdip. The net sand thickness of the Hackberry Injection Zone is 52 ft and only drill cuttings from the stratigraphic test well Encanto 01 exist in this zone along with the log data. The Hackberry Injection Zone shales out towards the south and downdip (i.e., is thinner), and is better developed towards the north and updip (i.e., is thicker), which is why the average net sand thickness is somewhat misleading.

The Hackberry Injection Zone is laterally continuous in a north-south dip and east-west strike direction within and beyond the AoR (Figure AoR-38 through Figure AoR-41). However, along the stratigraphic west-east strike cross section (Figure AoR-41), the Hackberry Injection Zone sand thickness increases towards the west and decreases towards the east (in addition to the thickening towards the north and shaling out towards the south), which is also displayed in the net sand thickness map (Figure AoR-46). Further to the east, approximately 3 miles beyond the AoR, the Hackberry was likely deposited in a different environment or affected by faulting.

3.8.1.1.1 Petrologic description

Petrological characterization of the Hackberry thin sections made from cuttings indicate that the sands are typically unconsolidated quartz-rich sands dominated by quartz, minor K-feldspar, and plagioclase grains, along with a few volcanic rock fragments, chert, and minor coarse siltstone. Additionally, minor argillaceous rock fragments are noted. Typically, a few quartz grains also have Böhm lamellae indicating tectonized quartz. Additionally, a quartz with inherited quartz overgrowths can be observed. The pores are well connected.

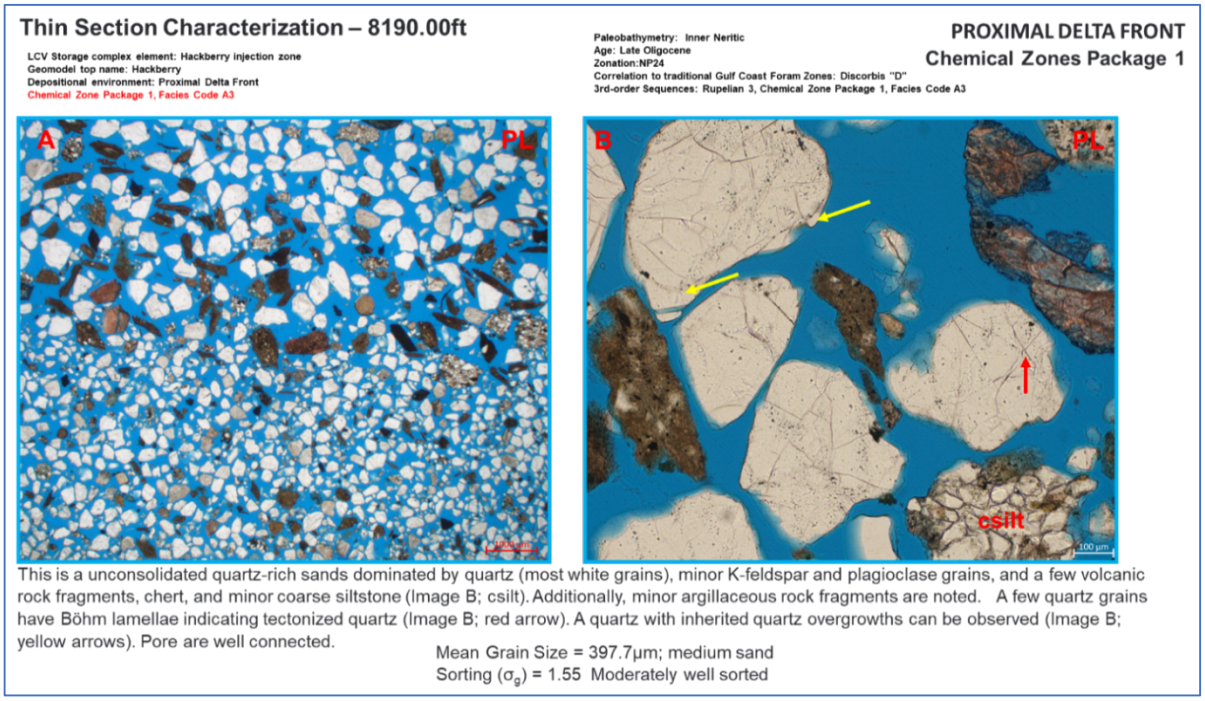


Figure AoR-42: Thin section analysis and petrologic description of the Hackberry Injection Zone at 8,190 ft MD.

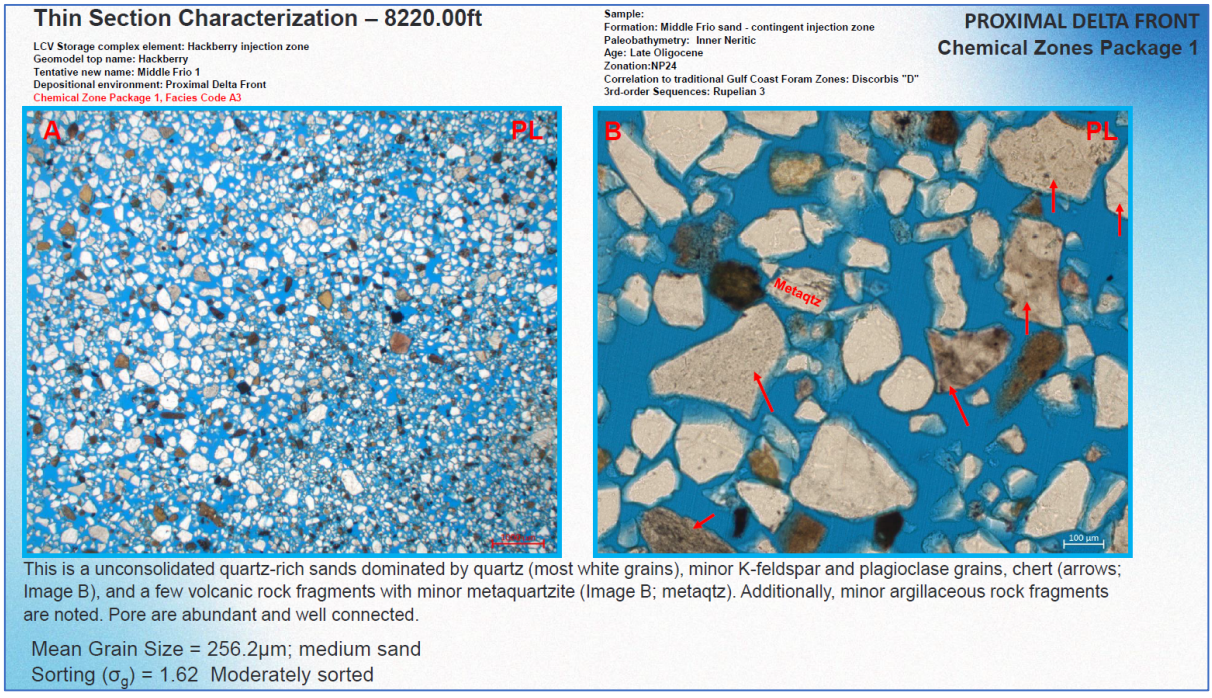


Figure AoR-43: Thin section analysis and petrologic description of the Hackberry Injection Zone at 8,220 ft MD.

3.8.1.1.2 Hackberry Injection Zone maps

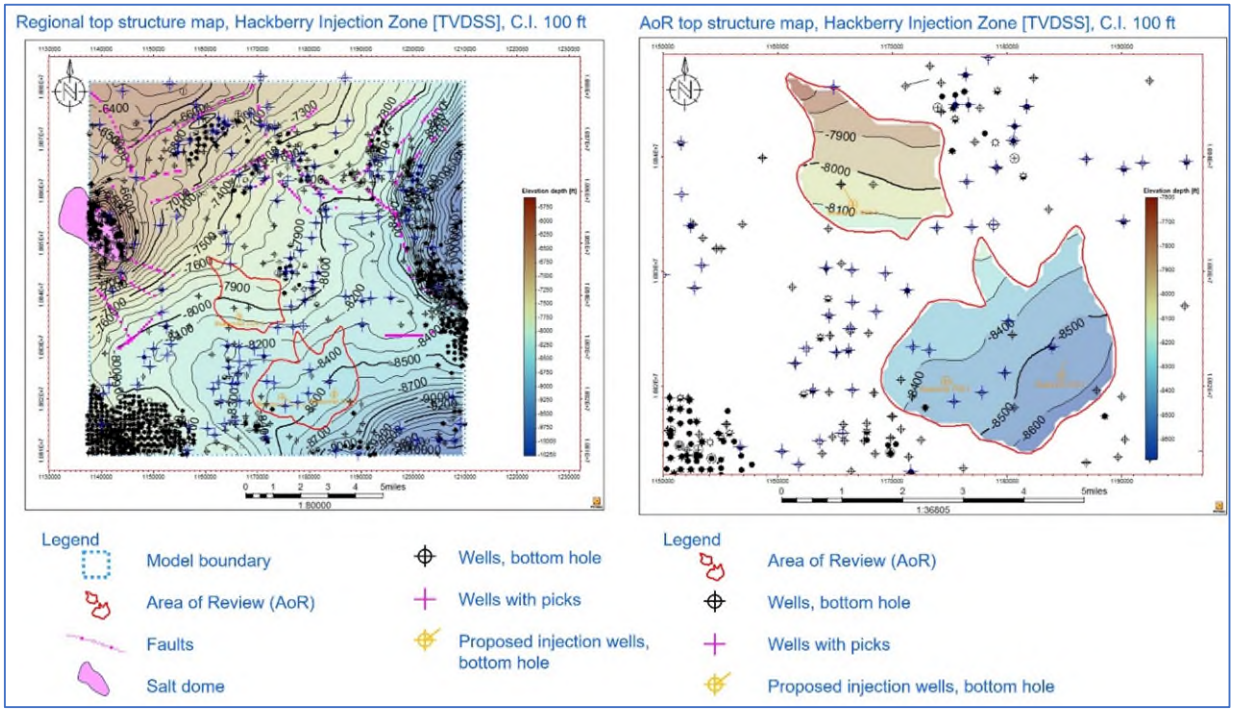


Figure AoR-44: Regional and AoR top structure map of the Hackberry Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

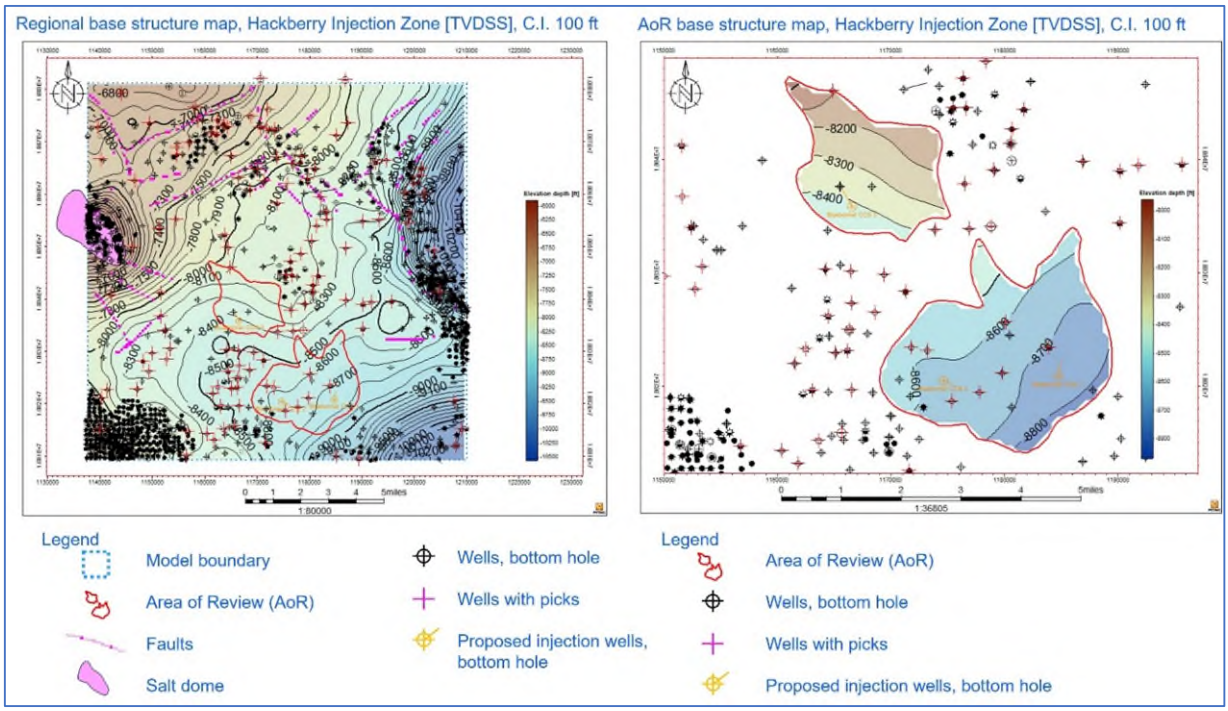


Figure AoR-45: Regional and AoR base structure map of the Hackberry Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

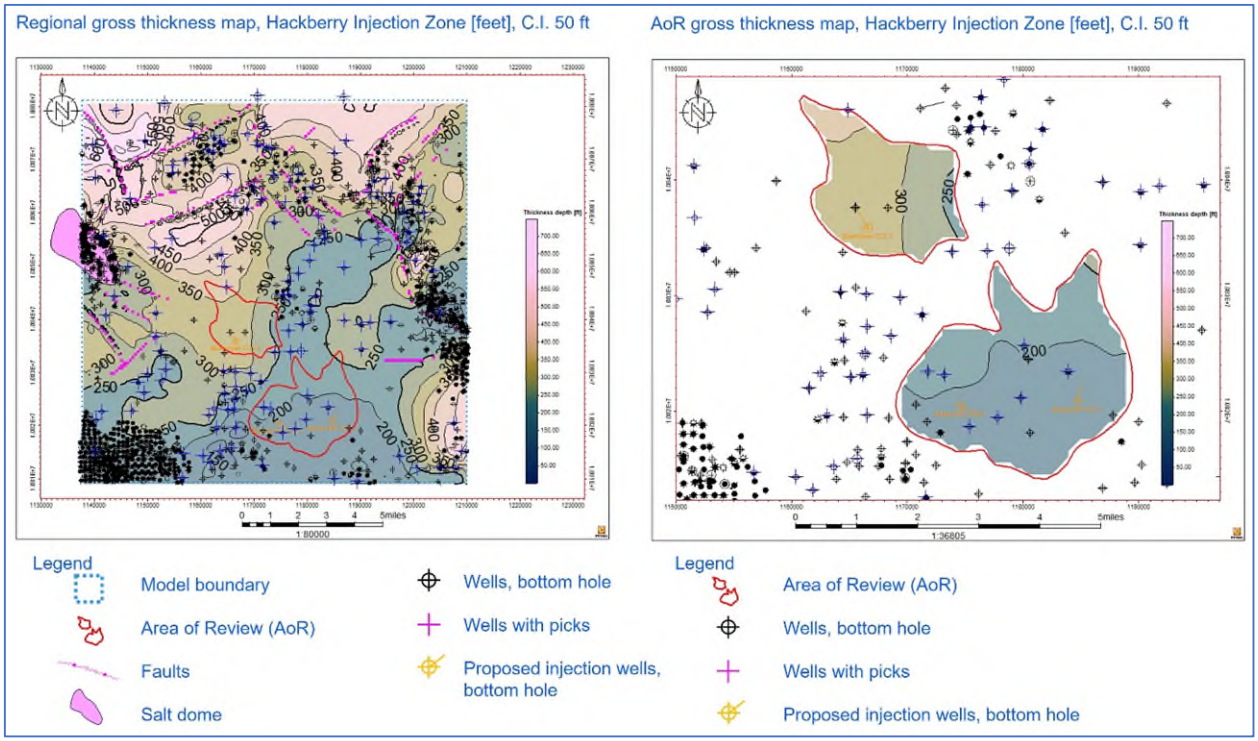


Figure AoR-46: Regional and AoR gross thickness map of the Hackberry Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

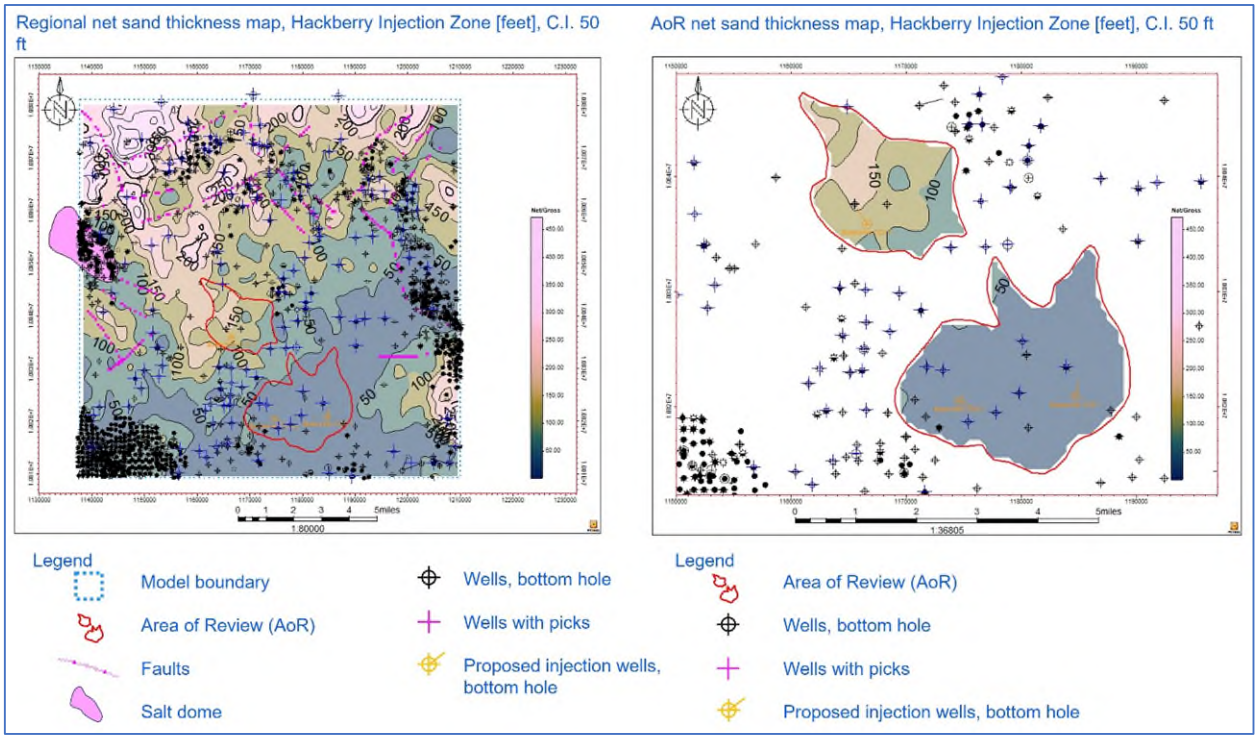


Figure AoR-47: Regional and AoR net sand thickness map of the Hackberry Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

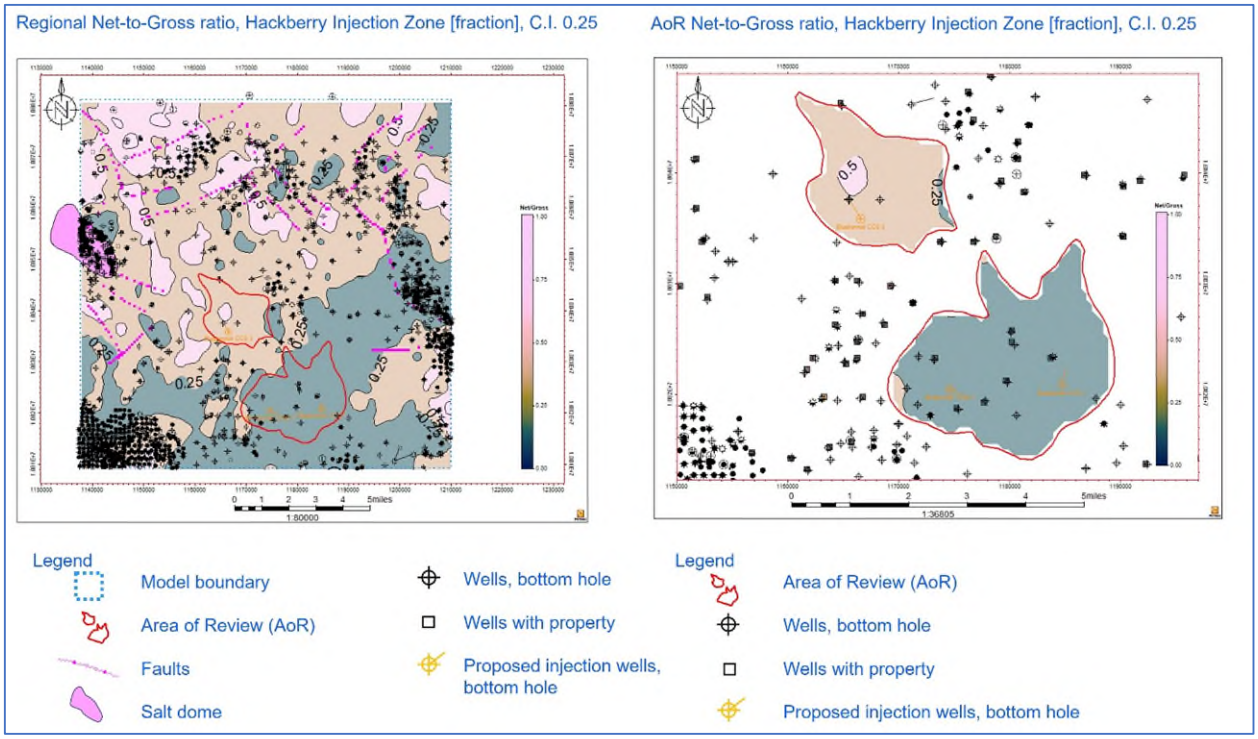


Figure AoR-48: Regional and AoR Net-to-Gross (NTG) ratio map of the Hackberry Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

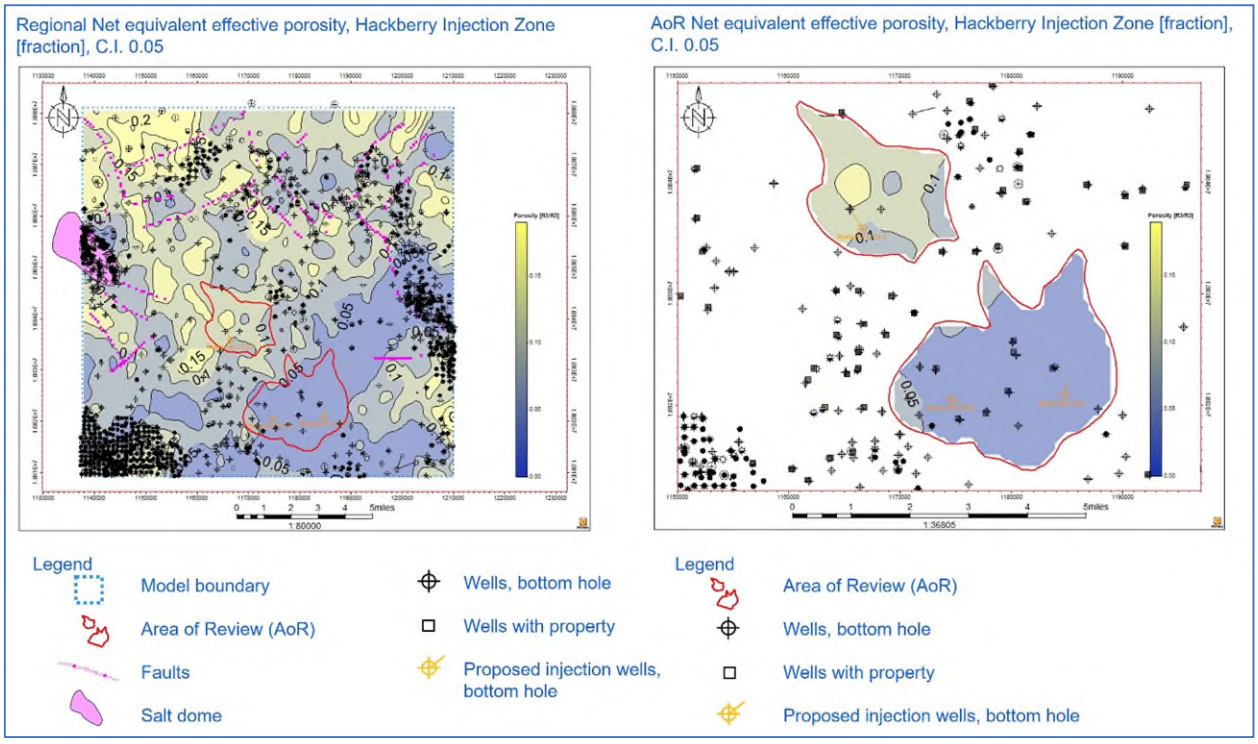


Figure AoR-49: Regional and AoR net equivalent effective porosity map of the Hackberry Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

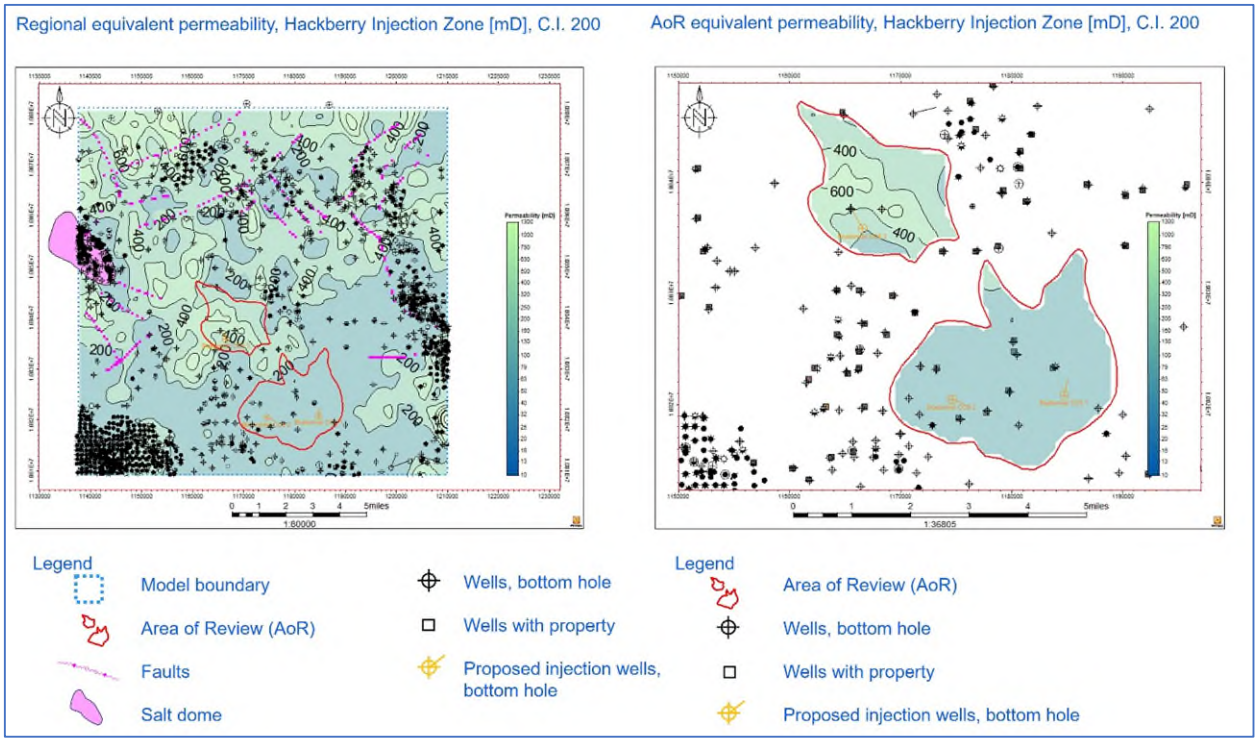


Figure AoR-50: Regional and AoR equivalent permeability map of the Hackberry Injection Zone in millidarcy (md), contour interval 200 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-1 represent map-based average numbers extracted from the geomodel over the AoR.

Table AoR-1: Reservoir properties for the Hackberry Injection Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Injection Zone
Top depth [TVDSS]	Minimum	-8,683
	Maximum	-7,598
	Average	**-8,286**
Base depth [TVDSS]	Minimum	-8,869
	Maximum	-7,961
	Average	**-8,523**
Gross Thickness [ft]	Minimum	158
	Maximum	379
	Average	**235**

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Injection Zone
Net Sand Thickness [ft]	Minimum	0
	Maximum	184
	Average	**53**
NtG Ratio [fraction]	Minimum	0
	Maximum	0.55
	Average	**0.19**
Porosity [fraction] EQI, net eff. porosity * NTG	Minimum	0
	Maximum	0.17
	Average	**0.06**
Permeability [md]	Minimum	0
	Maximum	649
	Average	**160**

Figures AoR-44 through Figure AoR-50 show the associated maps for each of the discussed formations.

3.8.1.2 Frio Injection Zone

The upper CO_2 injection zone within the Oligocene storage complex is the Frio formation as described in previous sections. The Frio formation is characterized by numerous trough cross beddings and minor carbonaceous plant debris.

The net sand thickness of the Frio Injection Zone is 284 ft. A 30-ft core in the Mid Frio was collected in the stratigraphic test well Encanto 01, which is reported under Appendix A, Coring and RSWC section.

As described under 3.7 Depositional Environment, the Frio sediments were deposited in the fluvial-dominated Houston Delta. Based on the log signatures, different depositional environments within that system can be interpreted. The Low Frio, with its coarsening upward trend (i.e., sandy at the top), has a deltaic character often found at terminal distributary channels. The Mid and Top Frio can be interpreted as variable, mixed-load fluvial deposits. Along the north-south stratigraphic dip cross section the Top, Mid, and Low Frio log signatures are correlative among the offset wells, which indicates preferred connectivity of reservoir properties in a dip direction and might influence plume migration pathways together with structural formation dip.

On an east-west strike cross section some wells are sandy at base of the Low Frio interval compared to other wells, which are sandier at the top of the Low Frio. This could be explained by deltaic lobe shifting, resulting in lateral facies changes on a local well-to-well scale. Altogether,

the Top, Mid, and Low Frio are correlative in a strike direction as well; however, small scale well-to-well lateral facies changes are expected, affecting the injectivity within the multiple stacked flow units of the Frio Injection Zone due to sedimentary distribution patterns, which are oriented perpendicular to the coastline.

The lithologic composition of the Frio Injection Zone is described below based on mud cuttings acquired during drilling operations of the stratigraphic test well Encanto 01 and mudlogs from two legacy wells nearby.

The Frio Injection Zone lithology shows 70 – 100 % milky white to clear transparent to light grey sand, frosted grains in places, very fine-to medium to coarse-grained sand, predominantly friable, loose and unconsolidated to moderately cemented quartz grains, poorly to moderately sorted sandstone, rounded to angular and subrounded elongated grains, silty argillaceous to slightly calcareous matrix in places, arkosic in places, light red chert in places, glauconitic slightly silty, and interbedded with 10 – 30%: soft to firm green-grey shaly interbeds. These clays are pyritic and contain feldspar shreds and earthy textures. Traces of white amorphous blocky soft limestone were also observed. No visible hydrocarbon cut, hydrocarbon, or mineral fluorescence were observed during mudlogging the Frio injection interval.

3.8.1.2.1 Petrologic Description

The Frio Injection Zone is characterized by quartz-rich sandstones. For the three subdivisions of Low, Mid, and Top, thin sections were made, characterized, and point counted to decipher the modal composition of the sandstone, diagenetic minerals, and any effects of diagenesis on reservoir quality. In addition, key framework grains were examined for provenance.

Generally, in the Low Frio, quartz grains are the most abundant mineral, followed by feldspar grains and plagioclase. Rock fragments are more abundant and are mostly volcanics containing mixtures of K-feldspar, plagioclase, and lesser quartz. Other grains are minor argillaceous rock fragments. Intergranular pores are commonly abundant and well interconnected. Some grains have authigenic titanium oxide and pyrite framboids attached.

The Mid Frio sands are commonly massive (structureless) with quartz grains, which are abundant, some of which are polycrystalline. Common K-feldspar and plagioclase grains are observed. Additionally, moderate volcanic rock fragments (vrf) are mostly rich in K-feldspar, but also contain variable amounts of plagioclase and sometimes quartz. Other rock fragments include chert, argillaceous, and plutonic varieties. Intergranular pores are abundant and well interconnected. Grain-coating authigenic minerals such as pyrite framboids, incipient K-feldspar and quartz overgrowths, and titanium oxide are rare. One of the selected sandstones had nodules of zeolite still with ample intergranular pores. SEM analysis indicated that the zeolite is sodium-rich analcime, which consists of hydrated sodium aluminum silicate in crystalline form $NaAlSi_2O_6 \cdot H_2O$ (Figure AoR-56 and Figure AoR-57). The sandstones are virtually unconsolidated.

The plot of sandstone compositional diagram for all the Frio and Miocene sandstones is shown below in Figure AoR-51, based on thin section 300-point count conventional analysis:

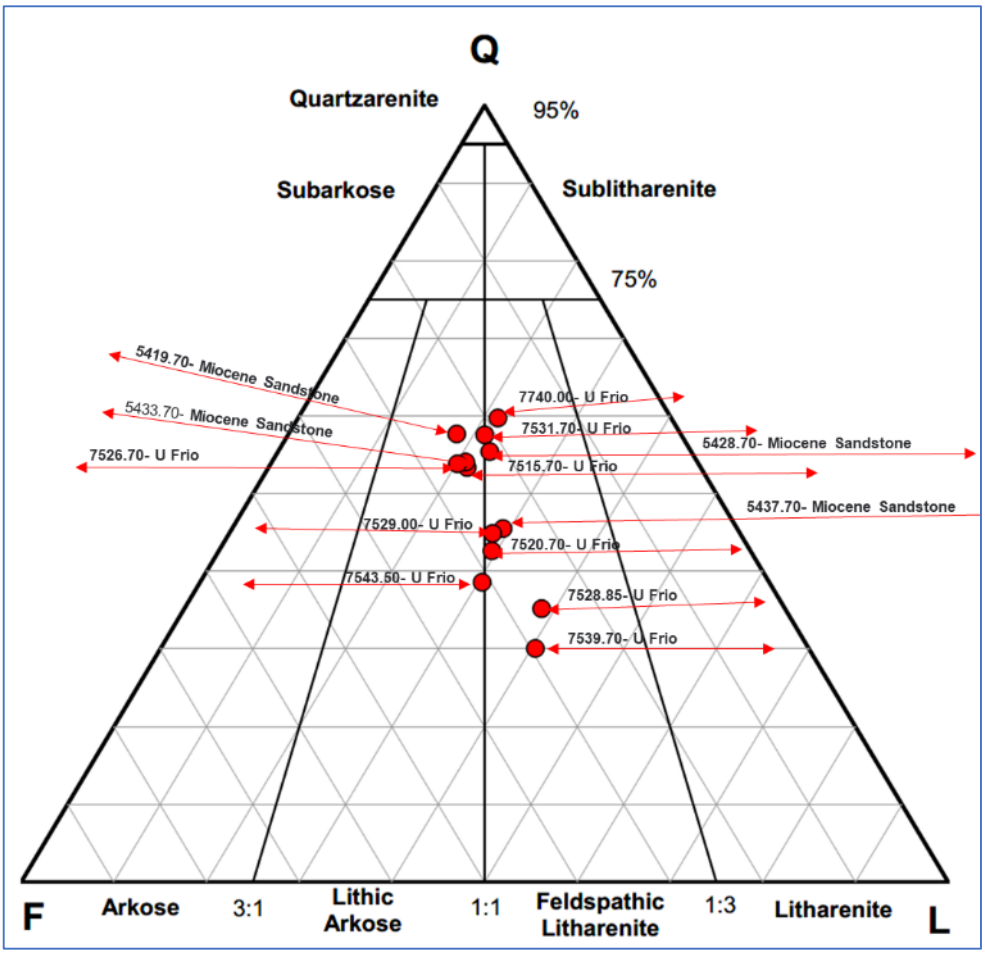


Figure AoR-51: Ternary compositional diagram for the Frio Injection Zone.

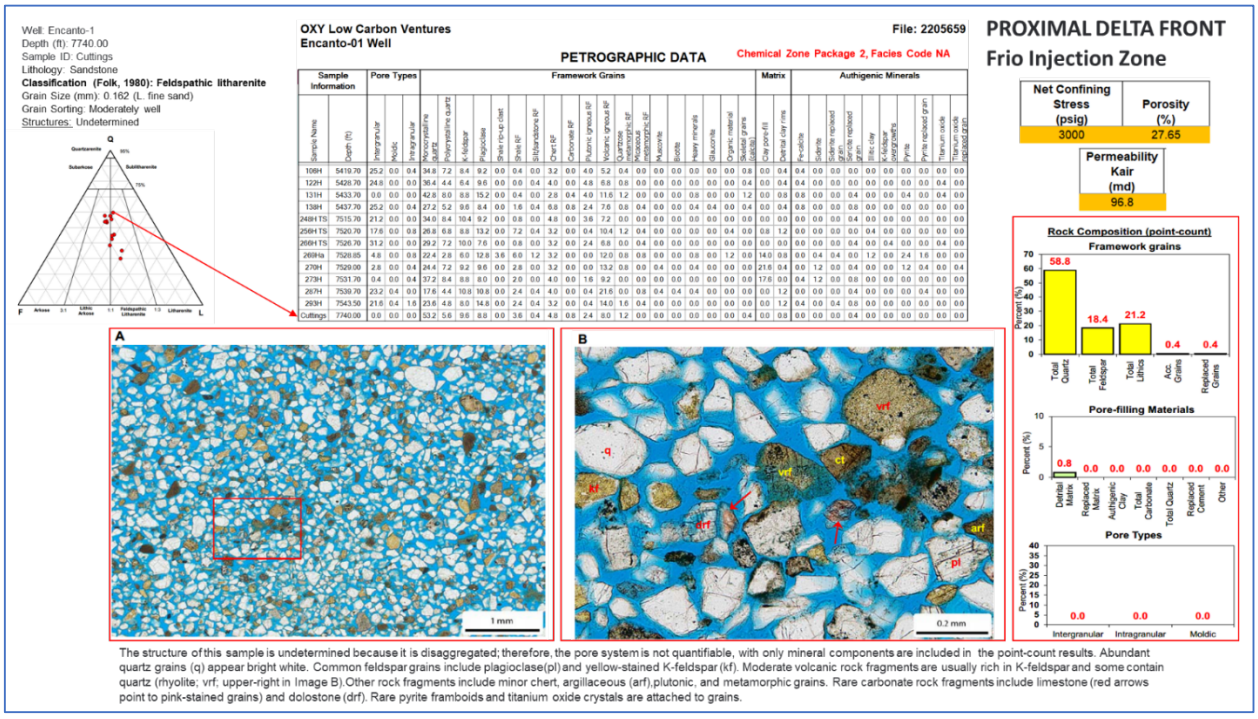


Figure AoR-52: Thin section analysis and petrologic description of the Low Frio Injection Zone. This thin section is made from cuttings and therefore the pore system is not quantifiable.

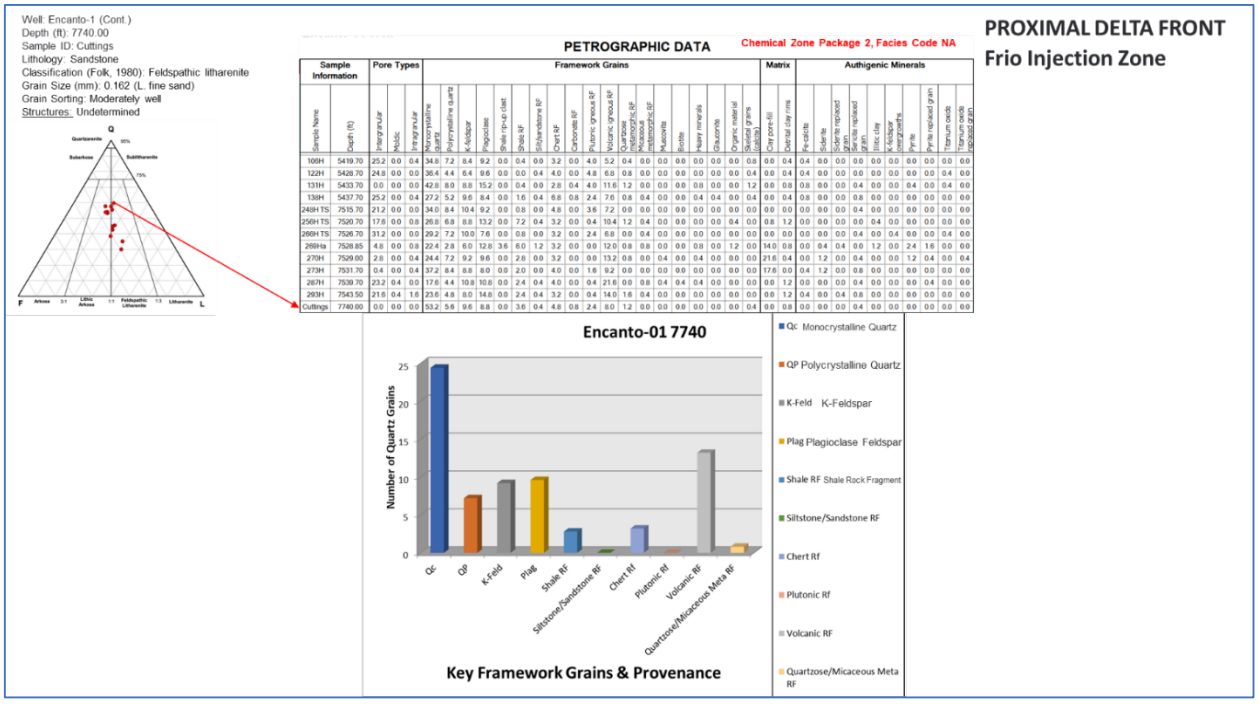


Figure AoR-53: Petrographic analysis of the Low Frio Injection Zone, from cuttings. Key framework grains and provenance are highlighted in the bottom graph.

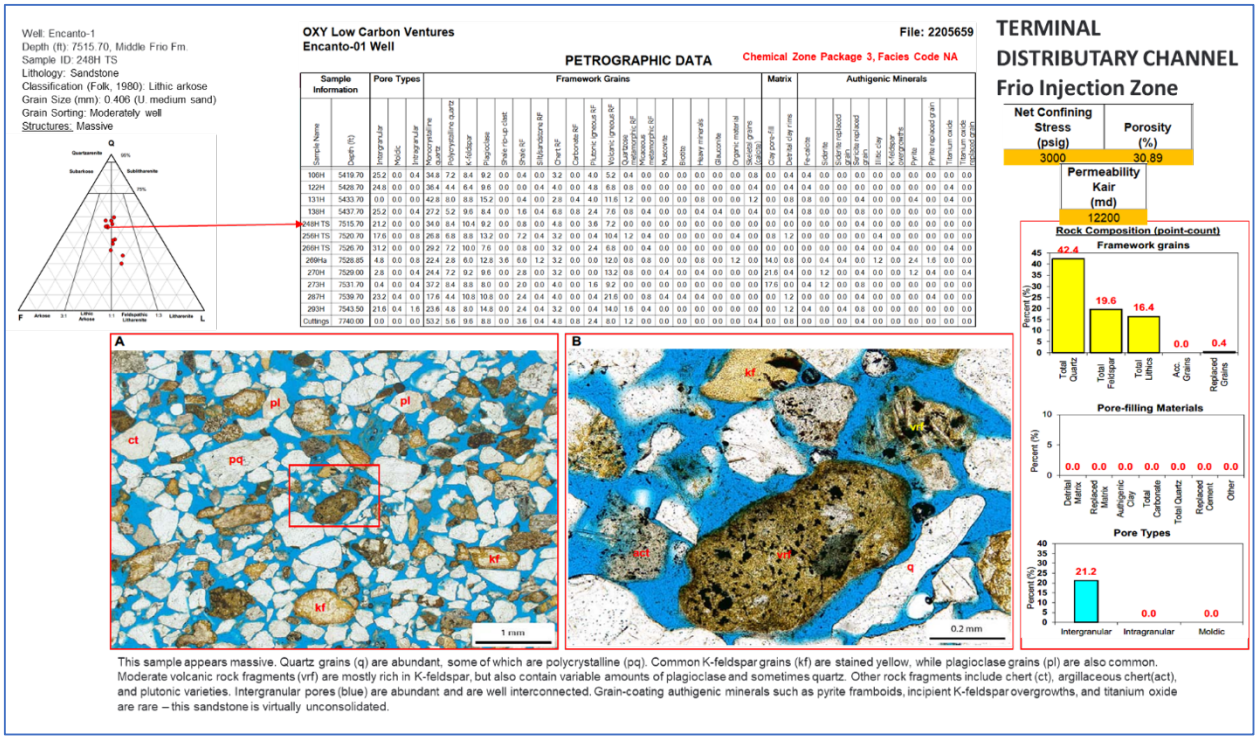


Figure AoR-54: Thin section analysis and petrologic description of the Mid Frio Injection Zone. This thin section is made from a plug from whole core.

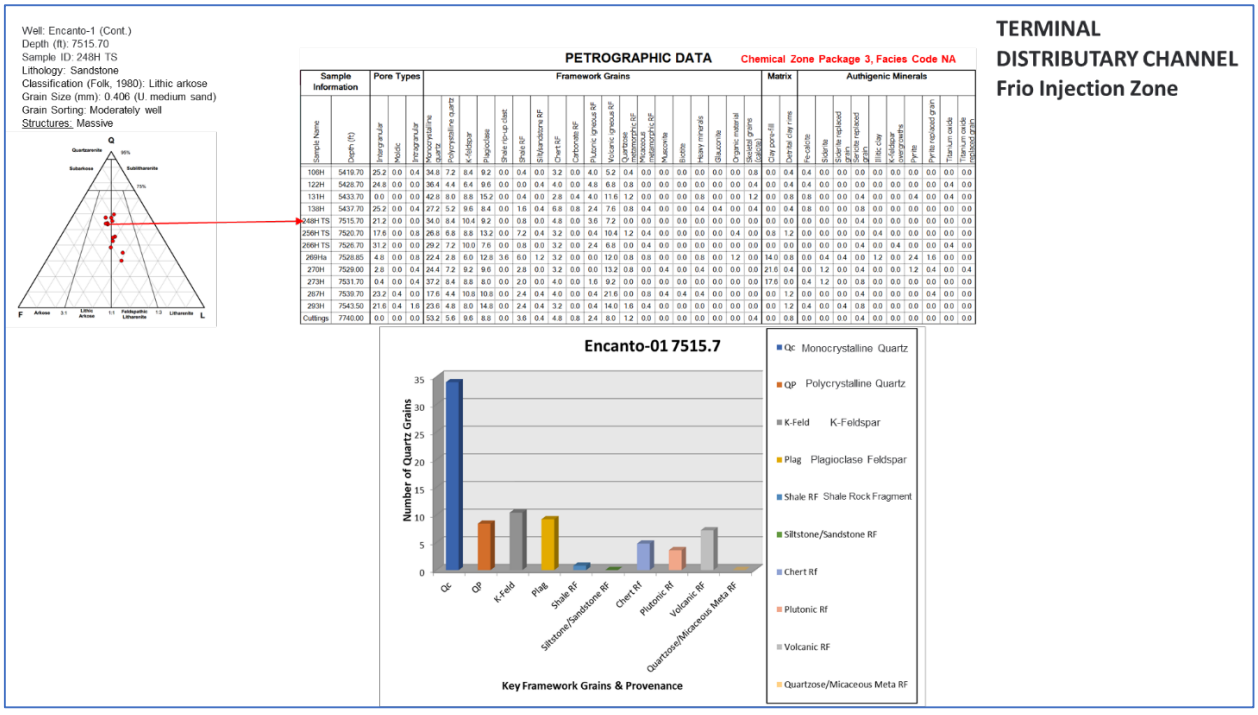


Figure AoR-55: Petrographic analysis of the Mid Frio Injection Zone, from plugs acquired from whole core. Key framework grains and provenance are highlighted in the bottom graph.

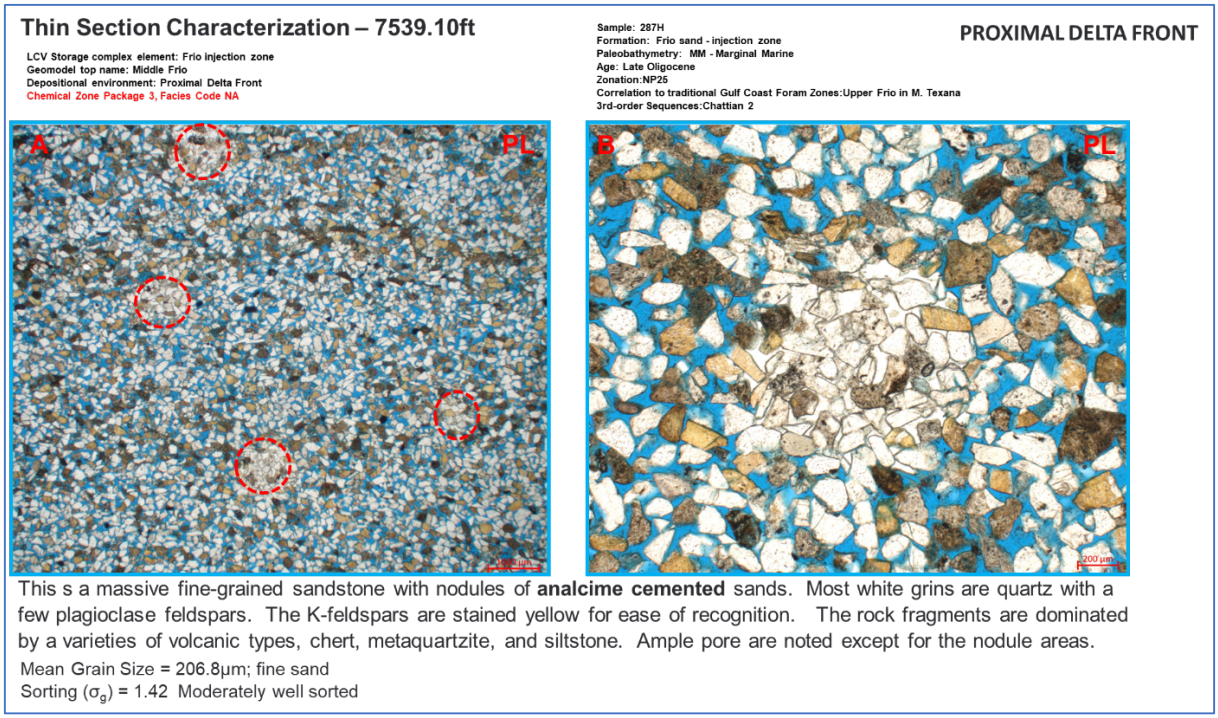


Figure AoR-56: The Mid Frio Injection Zone showing a massive fine-grained sandstone with nodules of analcime cemented sands.

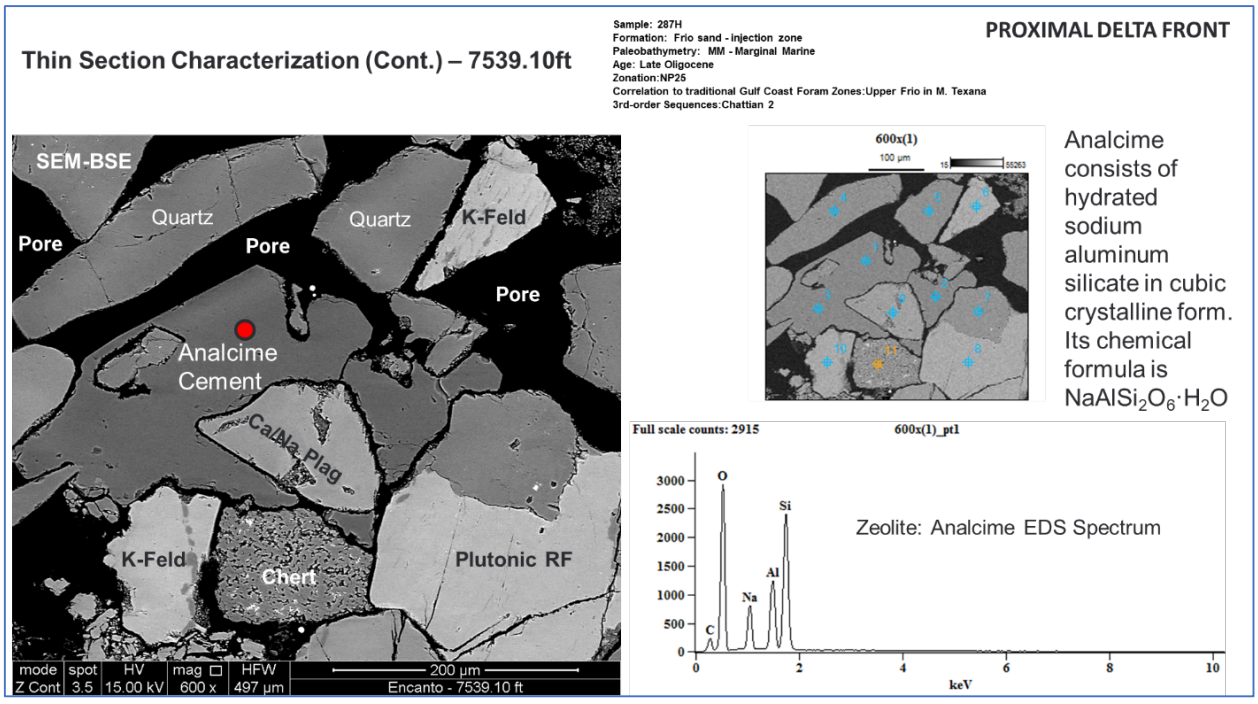


Figure AoR-57: SEM of cemented analcime nodule present in the Mid Frio Injection Zone. Analcime consists of hydrated sodium aluminum silicate in crystalline form.

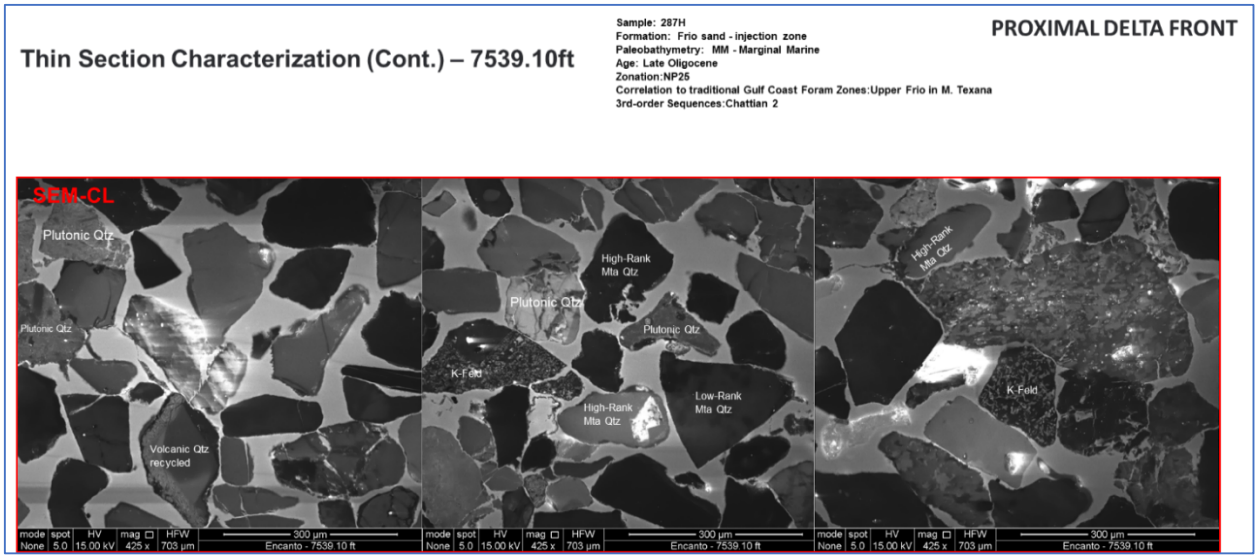


Figure AoR-58: SEM-CL images from the Mid Frio Injection Zone. A variety of quartz types such as High-Rank Metamorphic, Low-Rank Metamorphic, volcanic and plutonic type is observed.

3.8.1.2.2 Frio Injection Zone maps

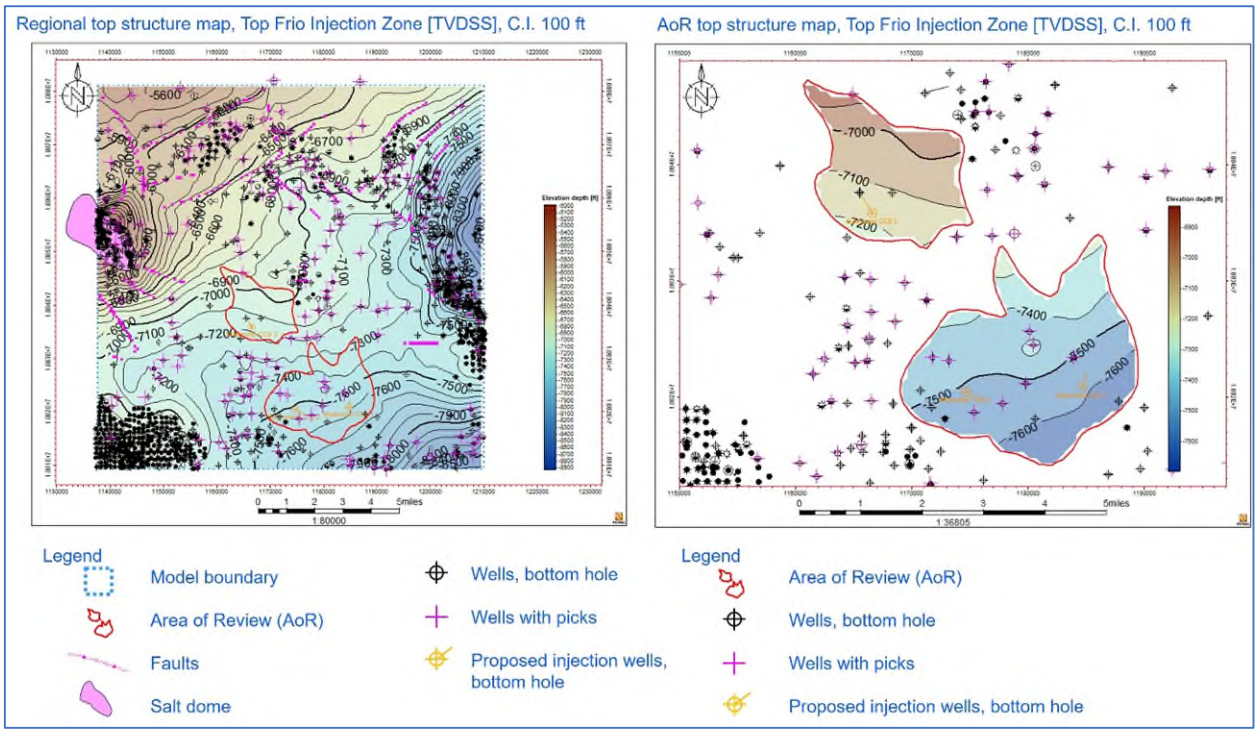


Figure AoR-59: Regional and AoR top structure map of the Top Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

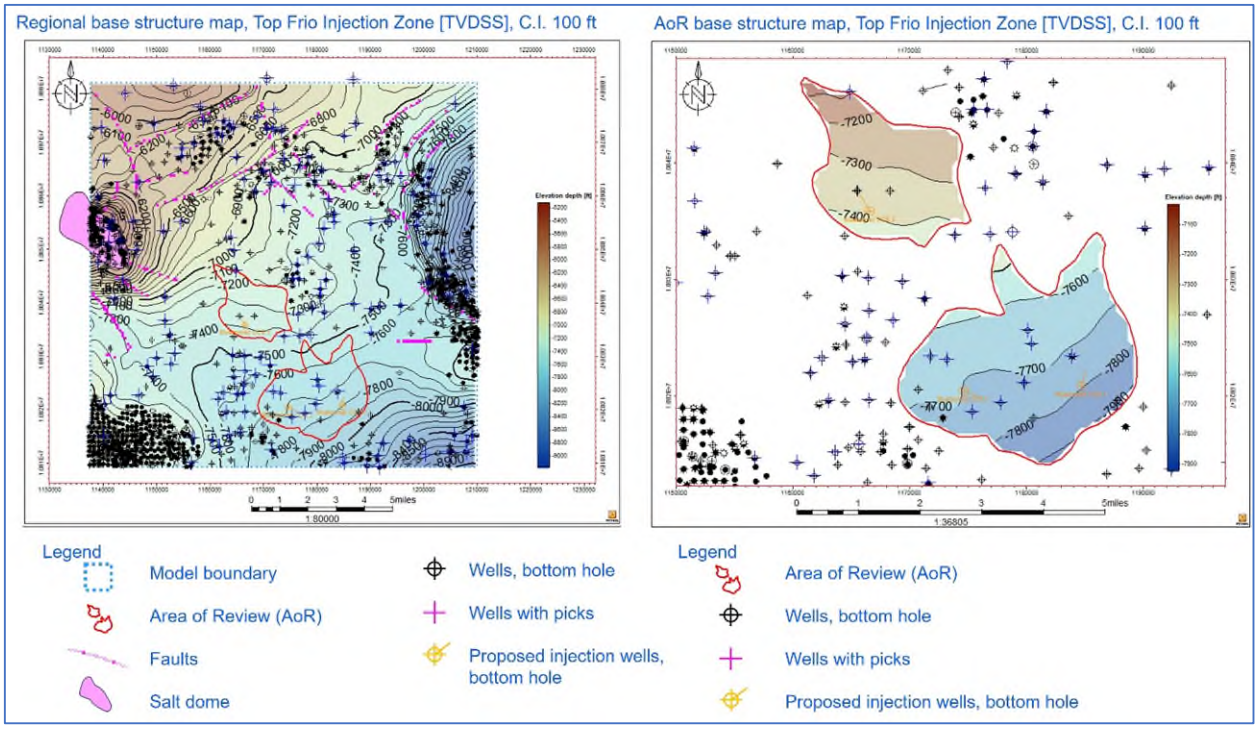


Figure AoR-60: Regional and AoR top base map of the Top Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

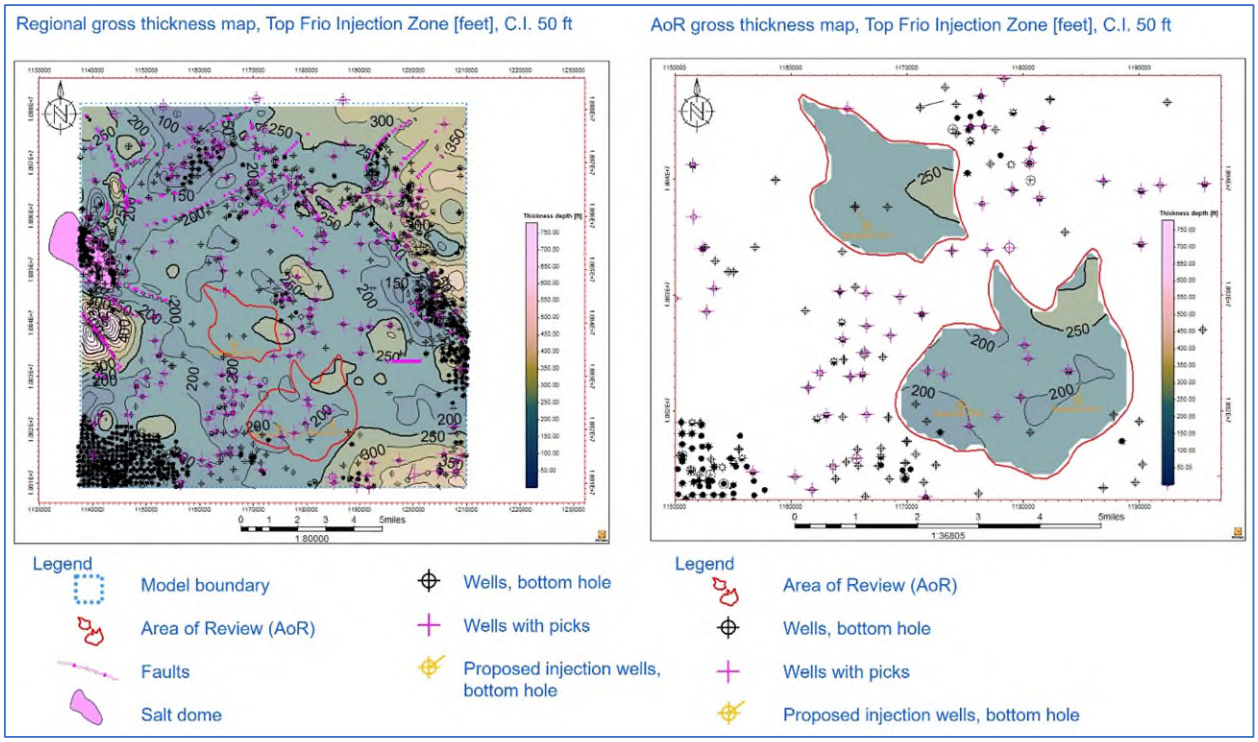


Figure AoR-61: Regional and AoR gross thickness map of the Top Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

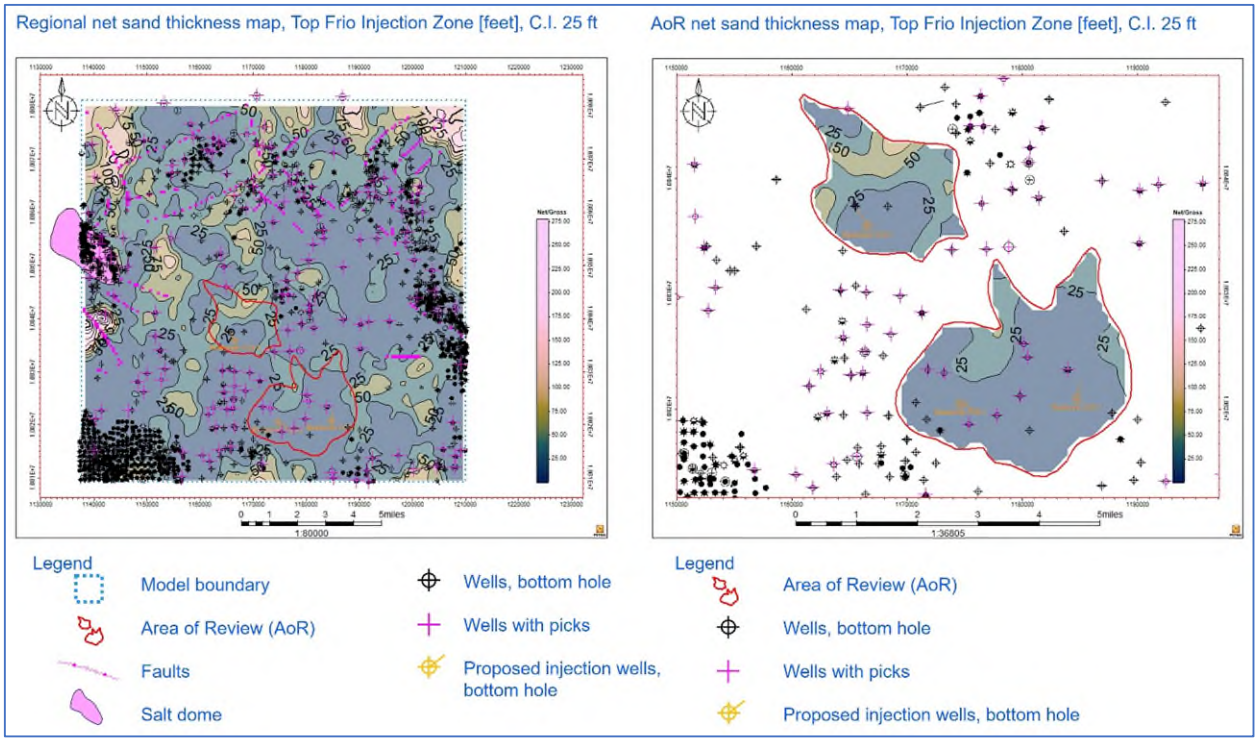


Figure AoR-62: Regional and AoR net thickness map of the Top Frio Injection Zone in feet, contour interval 25 ft. This map was generated from the Oligocene Model described under 4.0.

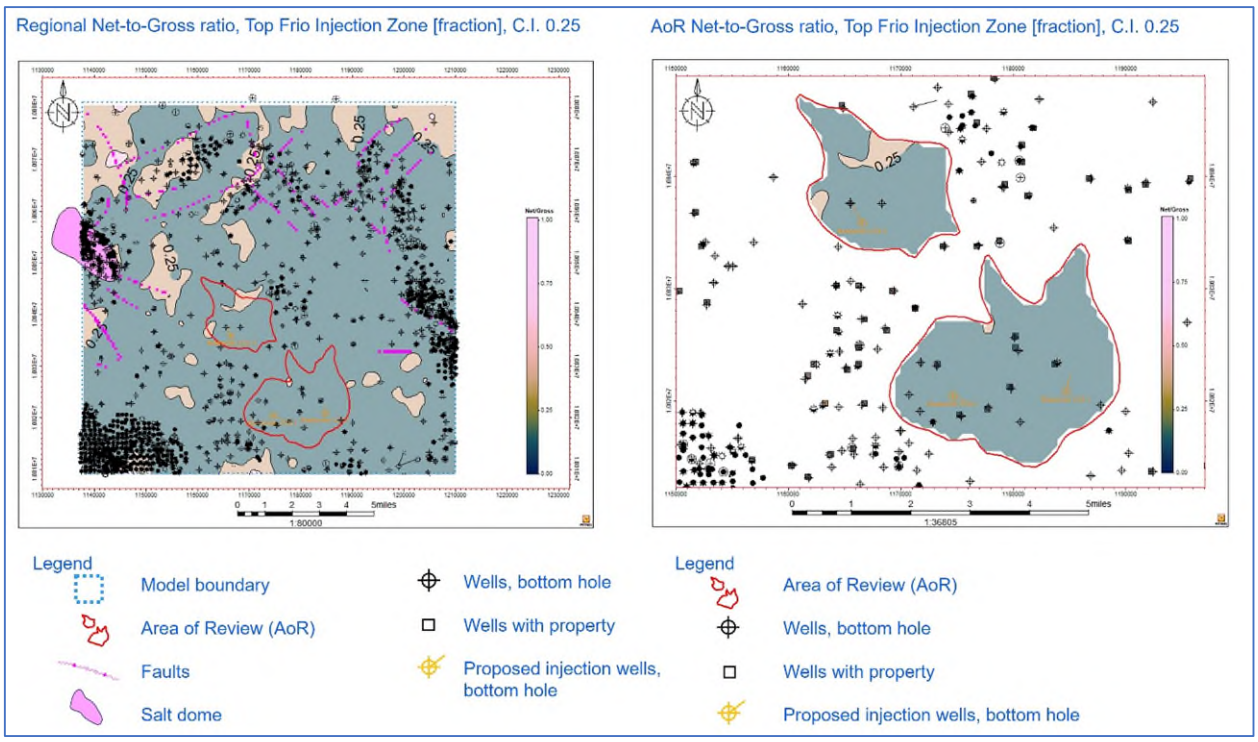


Figure AoR-63: Regional and AoR Net-to-Gross (NTG) ratio map of the Top Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

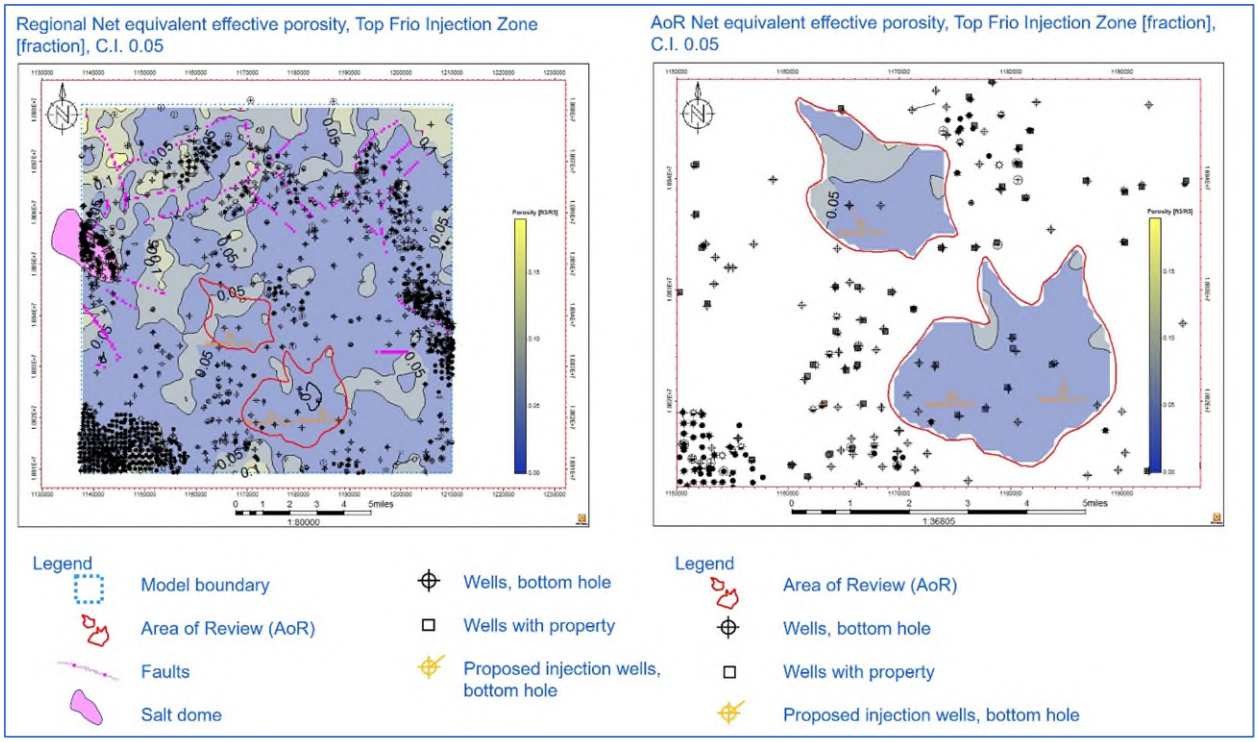


Figure AoR-64: Regional and AoR net equivalent effective porosity map of the Top Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

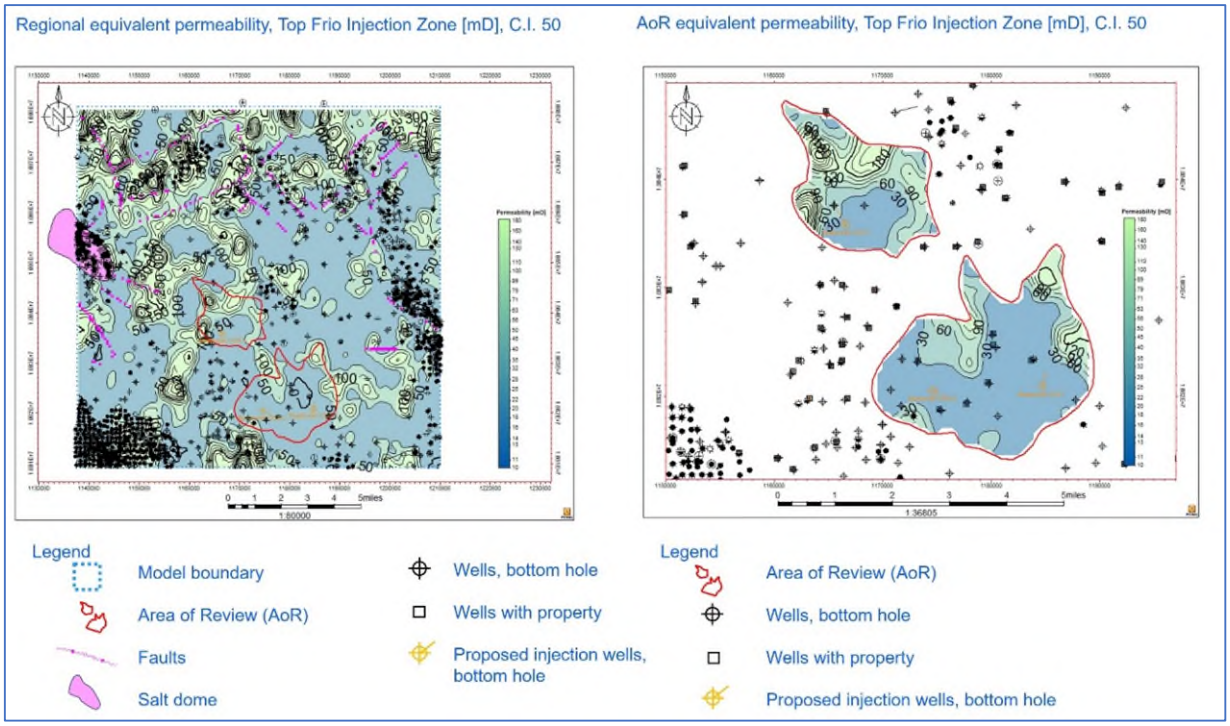


Figure AoR-65: Regional and AoR equivalent permeability map of the Top Frio Injection Zone in millidarcy (md), contour interval 50 md. This map was generated from the Oligocene Model described under 4.0.

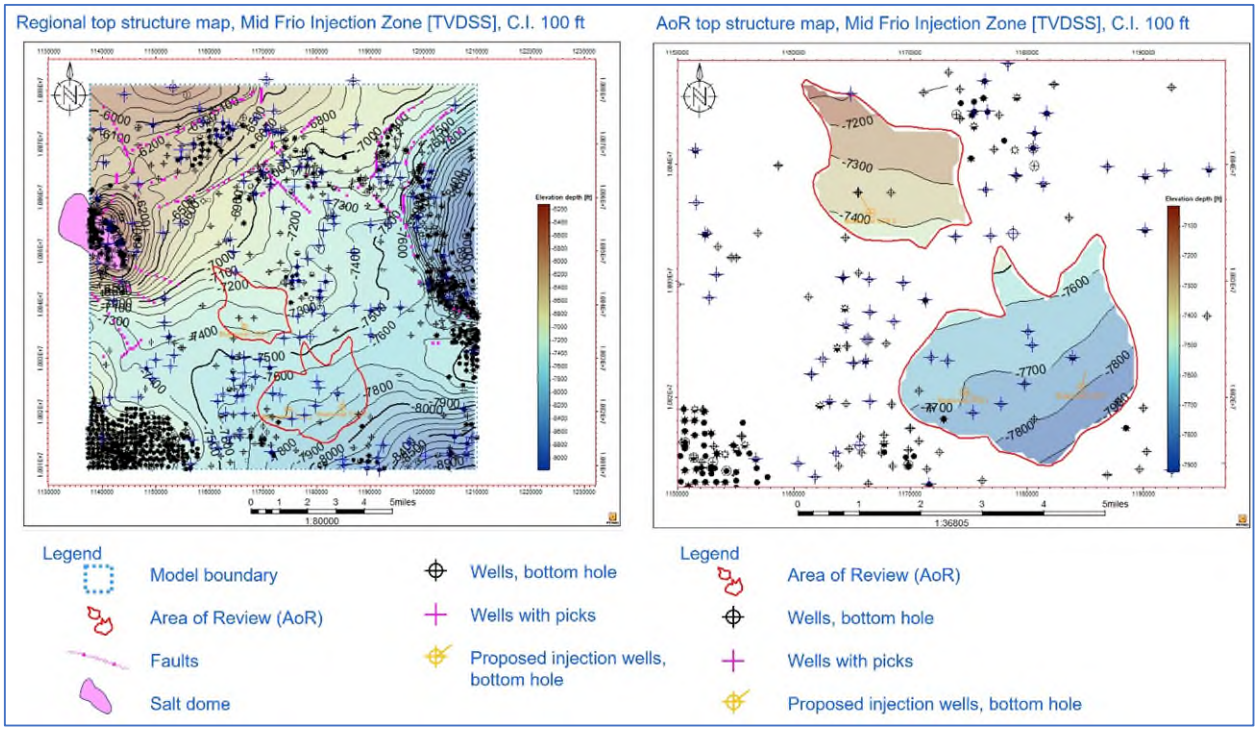


Figure AoR-66: Regional and AoR top structure map of the Mid Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

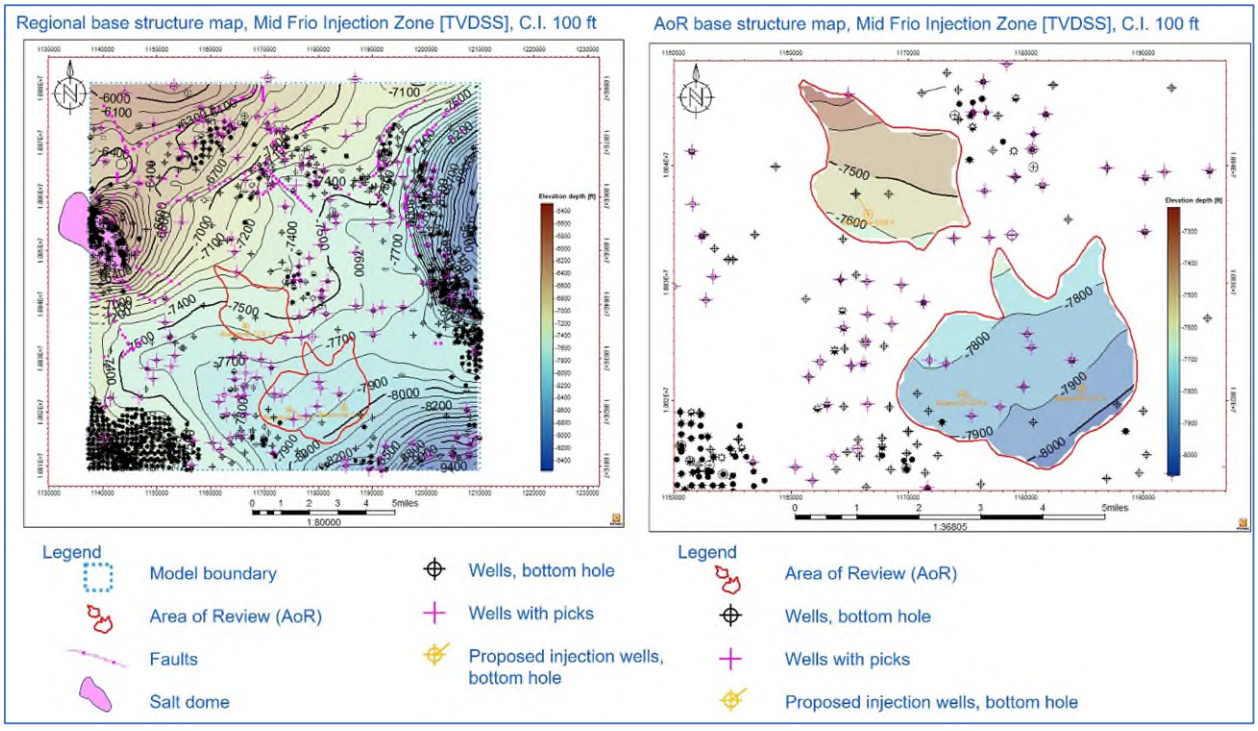


Figure AoR-67: Regional and AoR base structure map of the Mid Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

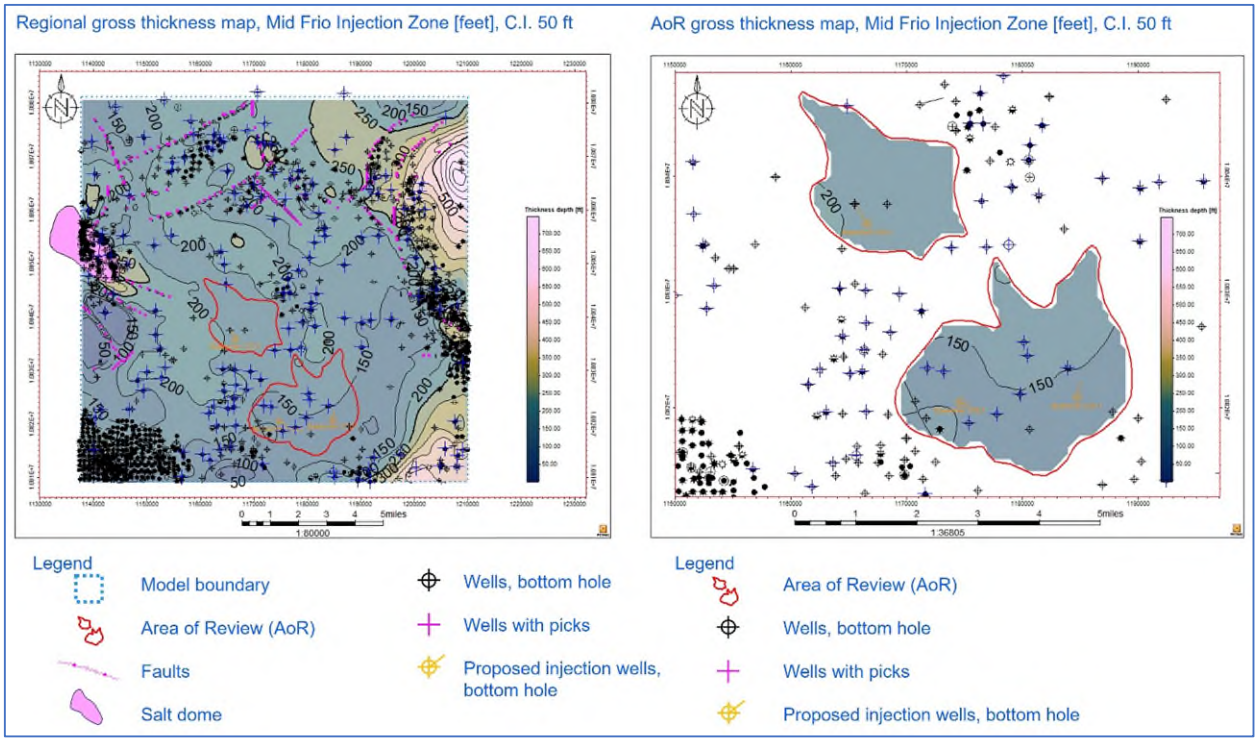


Figure AoR-68: Regional and AoR gross thickness map of the Mid Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

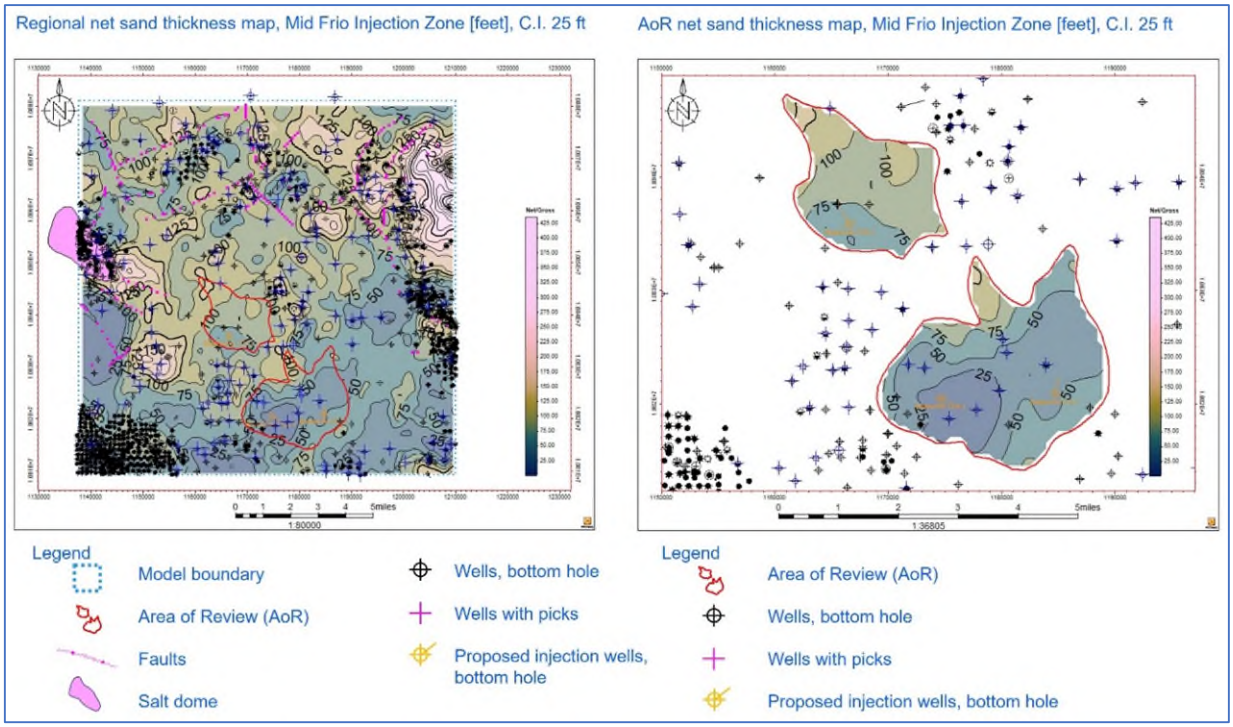


Figure AoR-69: Regional and AoR net thickness map of the Mid Frio Injection Zone in feet, contour interval 25 ft. This map was generated from the Oligocene Model described under 4.0.

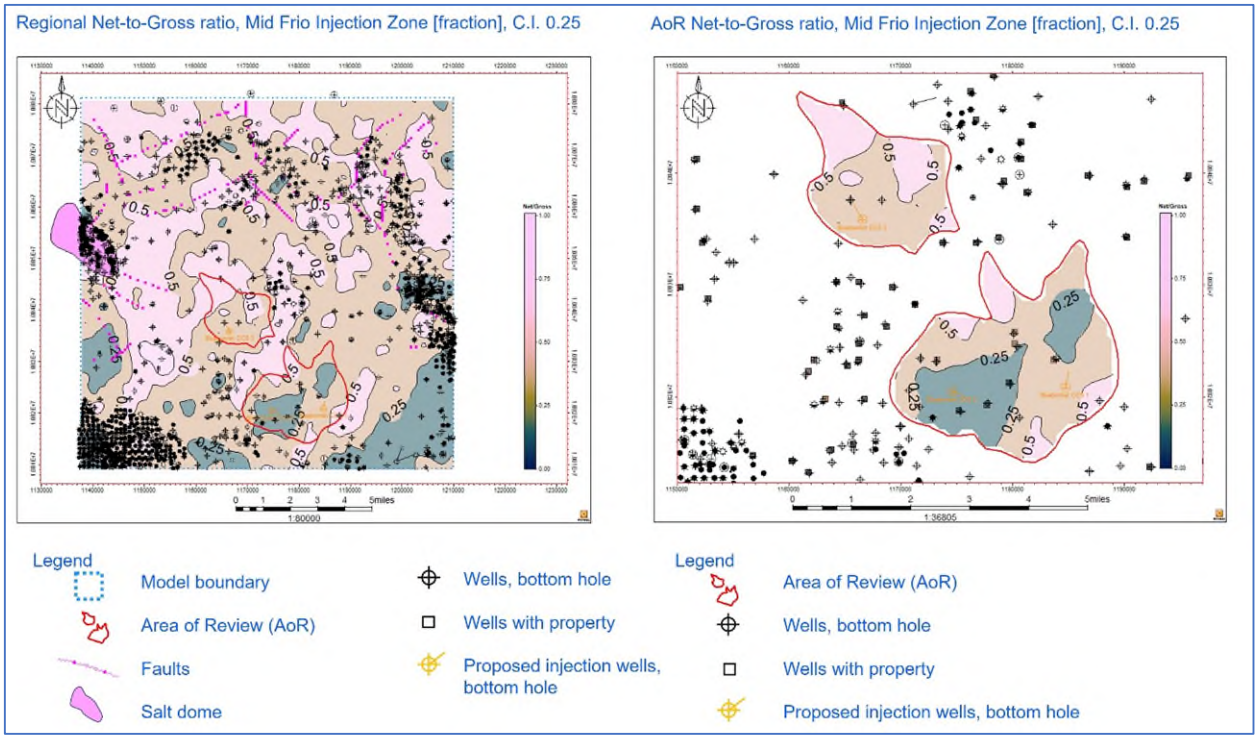


Figure AoR-70: Regional and AoR Net-to-Gross (NTG) ratio map of the Mid Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

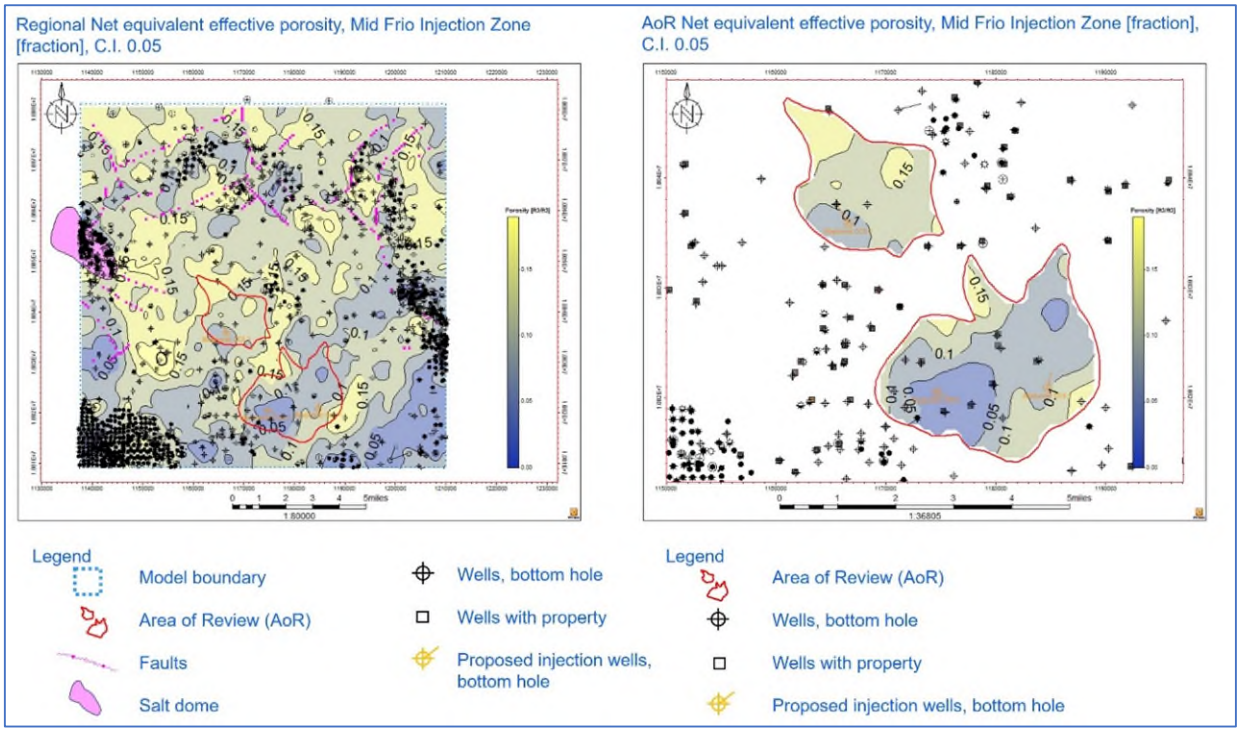


Figure AoR-71: Regional and AoR net equivalent effective porosity map of the Mid Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

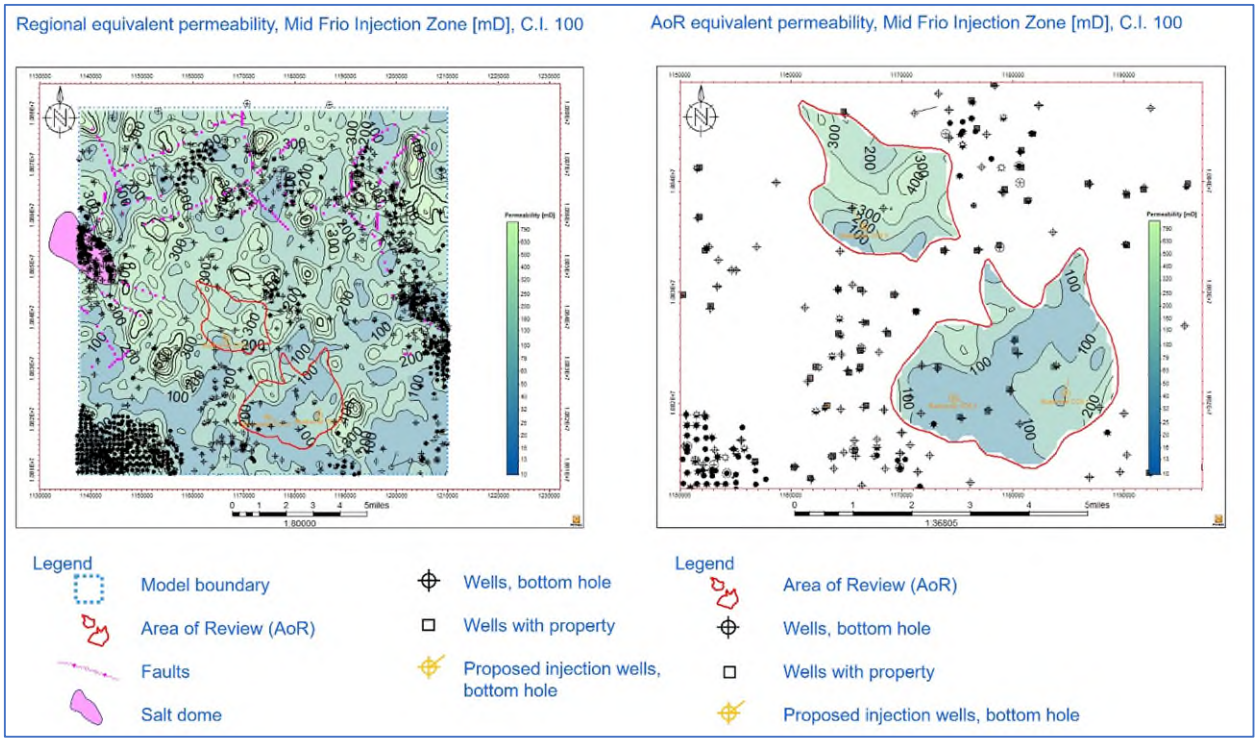


Figure AoR-72: Regional and AoR equivalent permeability map of the Mid Frio Injection Zone in millidarcy (md), contour interval 100 md. This map was generated from the Oligocene Model described under 4.0.

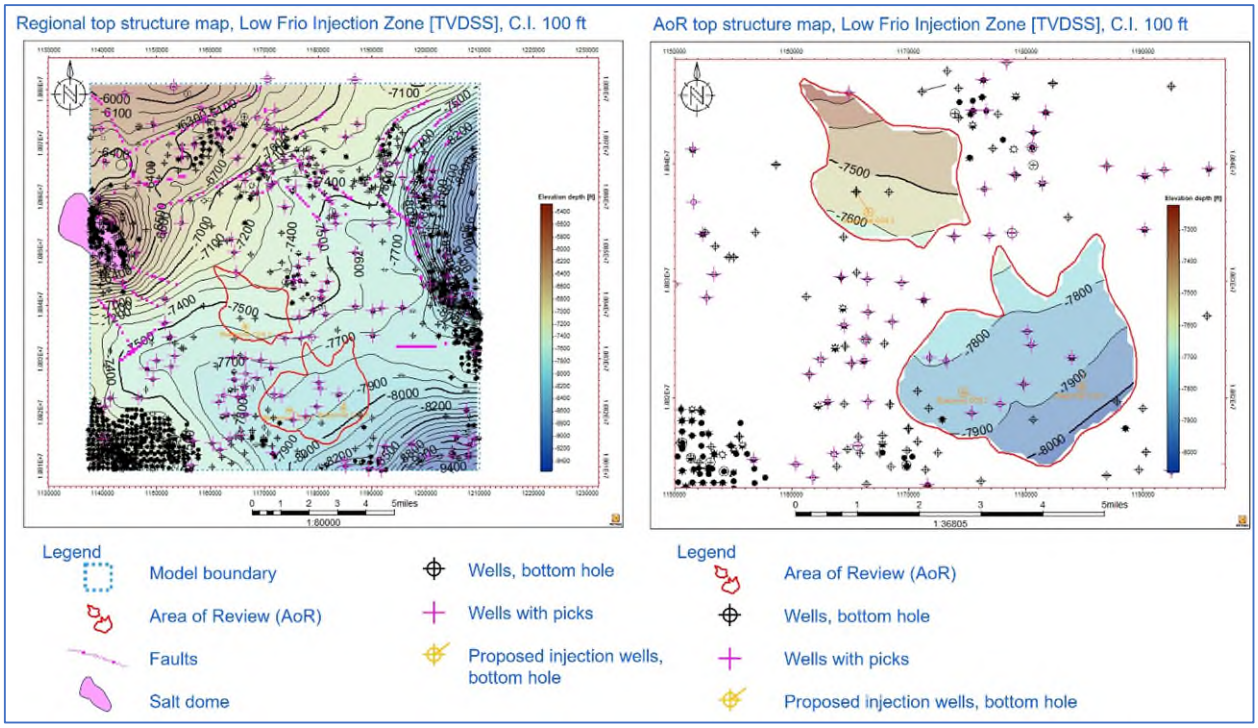


Figure AoR-73: Regional and AoR top map of the Low Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

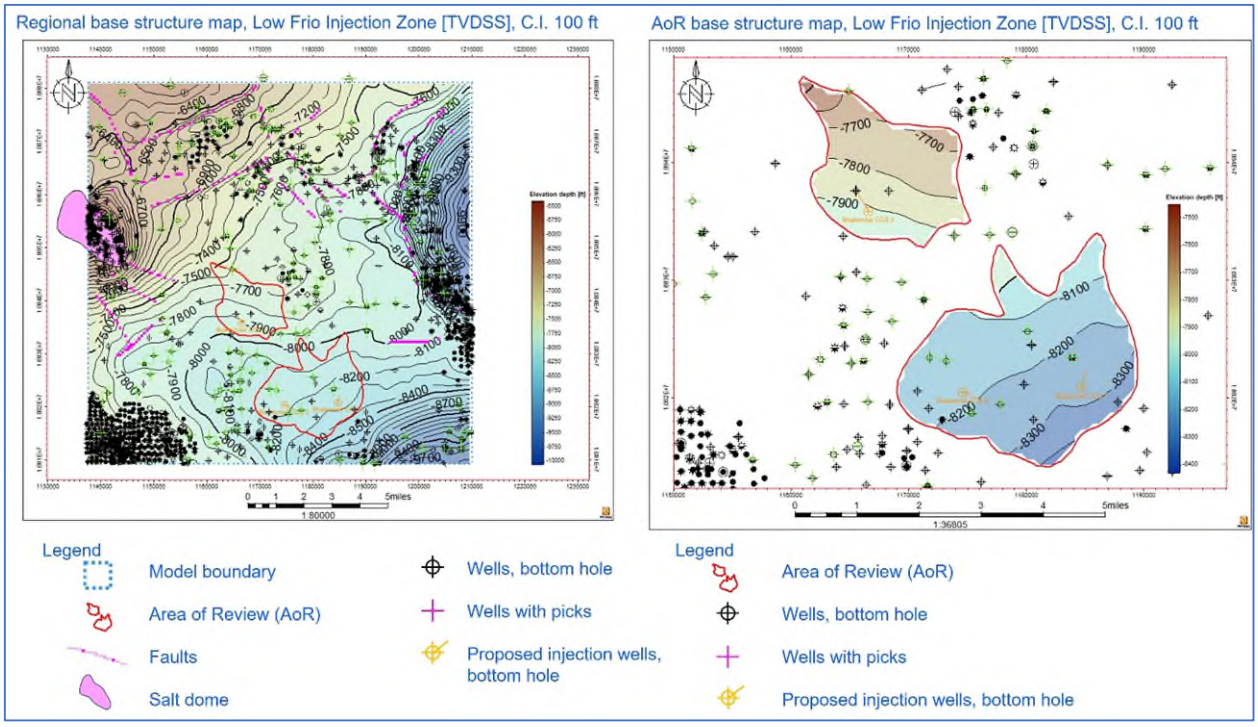


Figure AoR-74: Regional and AoR base structure map of the Low Frio Injection Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

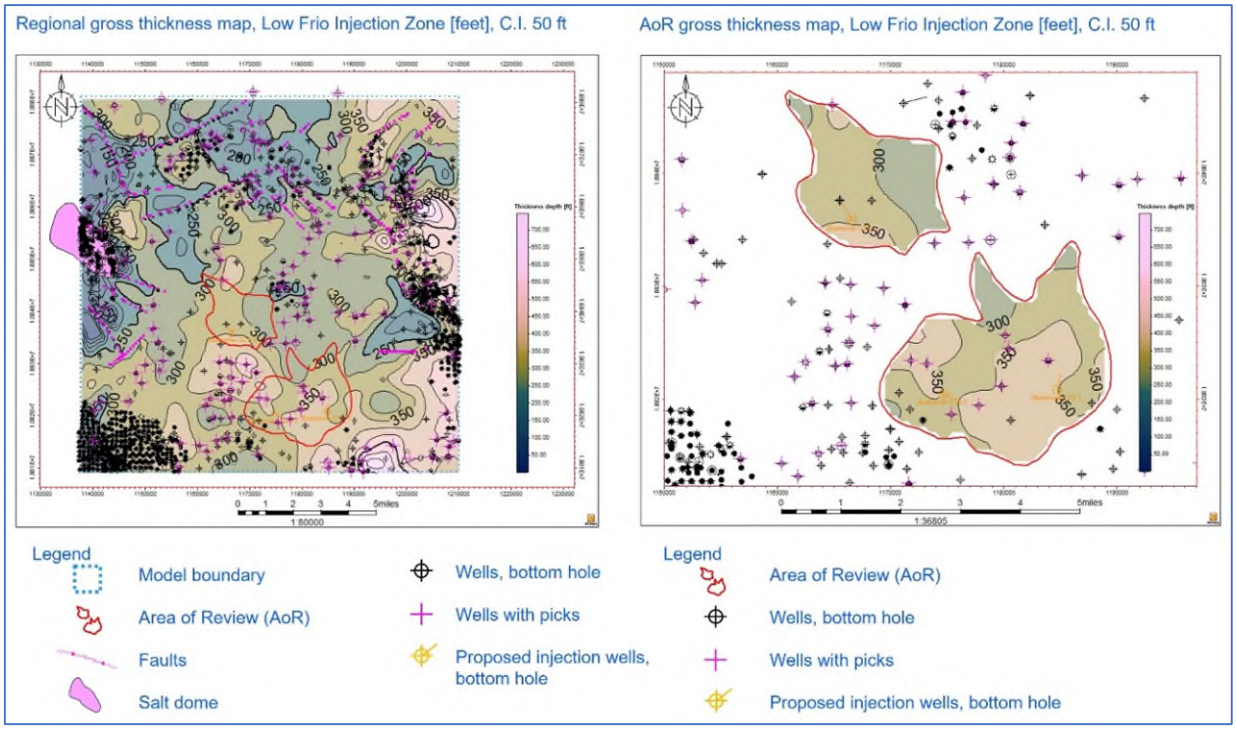


Figure AoR-75: Regional and AoR gross thickness map of the Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

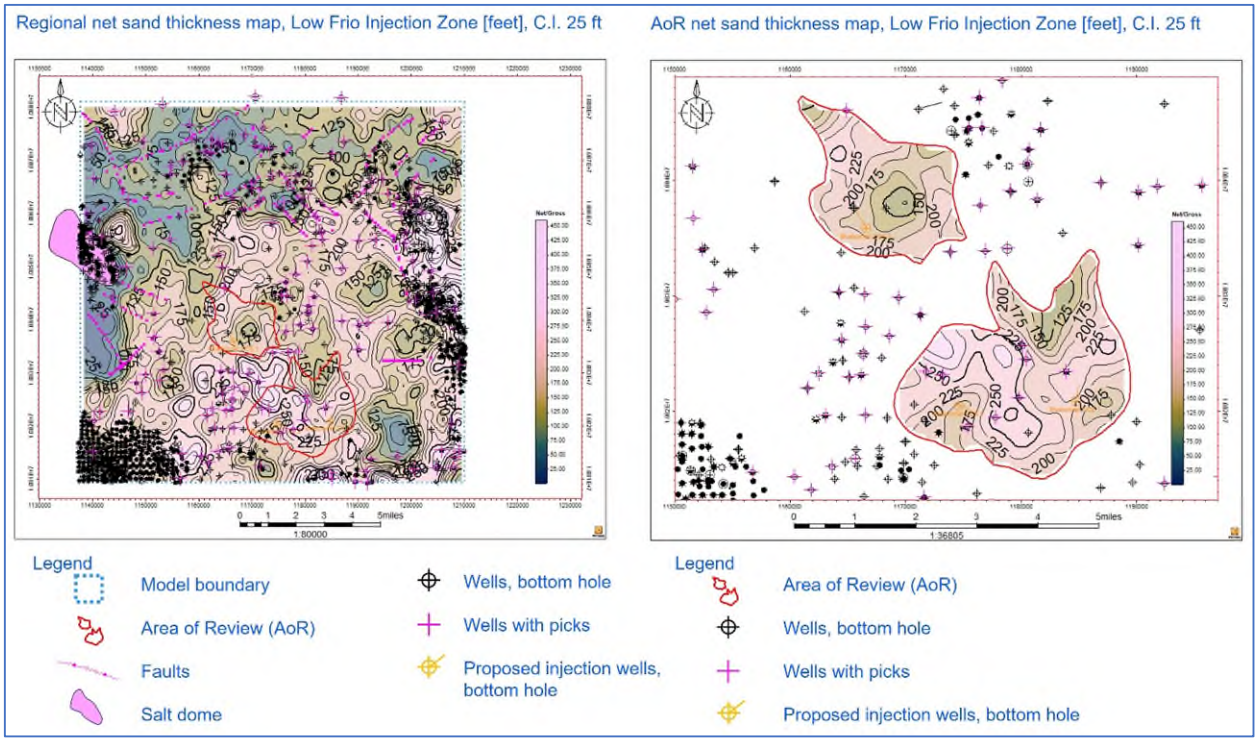


Figure AoR-76: Regional and AoR net sand thickness map of the Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

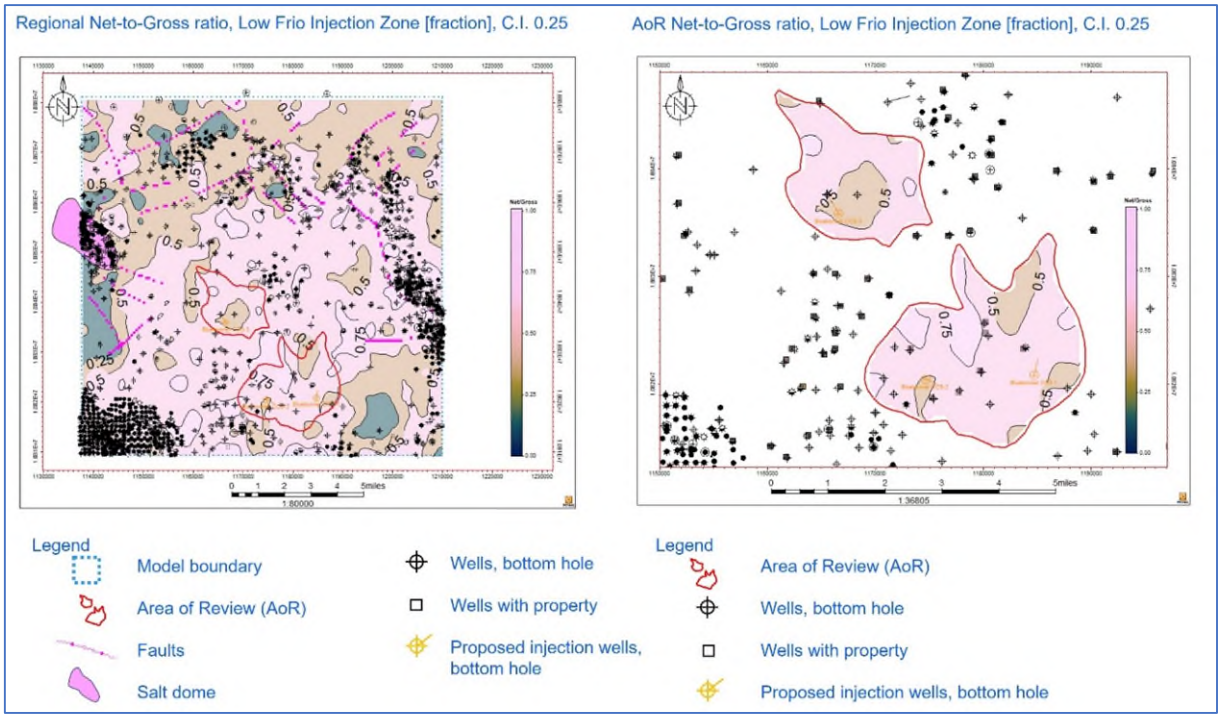


Figure AoR-77: Regional and AoR Net-to-Gross (NTG) ratio map of the Low Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

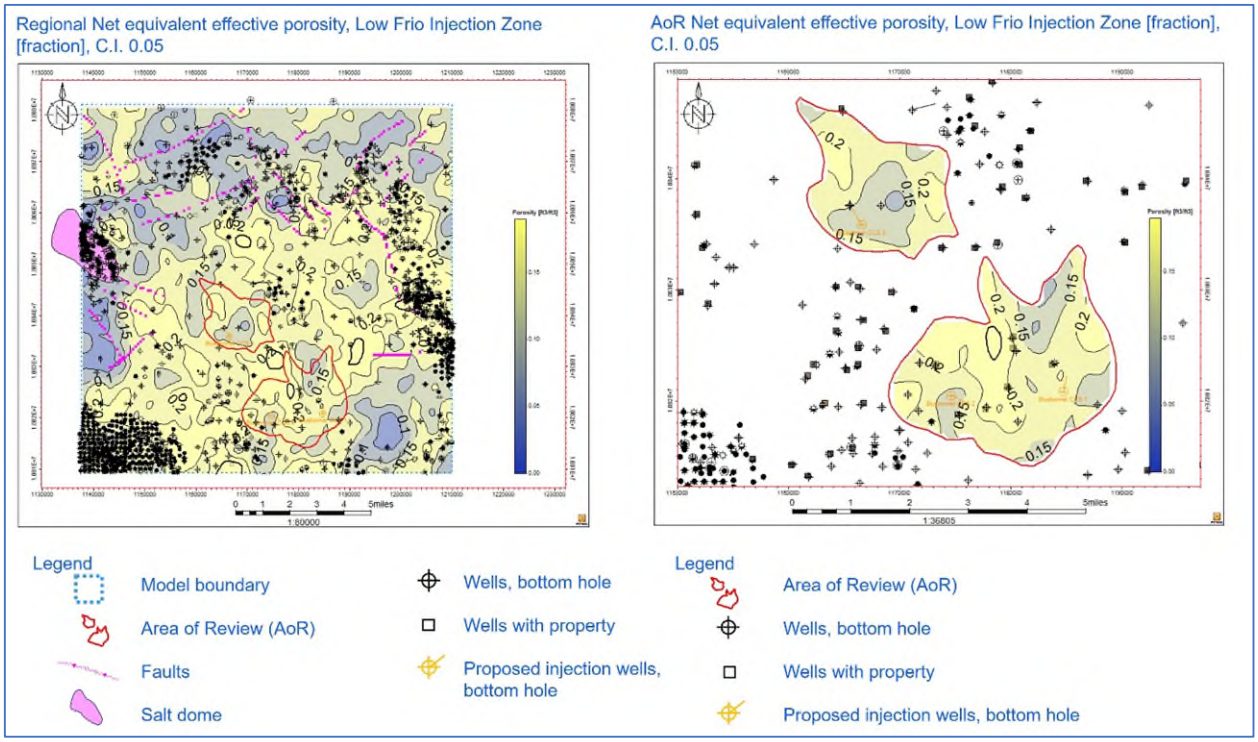


Figure AoR-78: Regional and AoR net equivalent effective porosity map of the Low Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

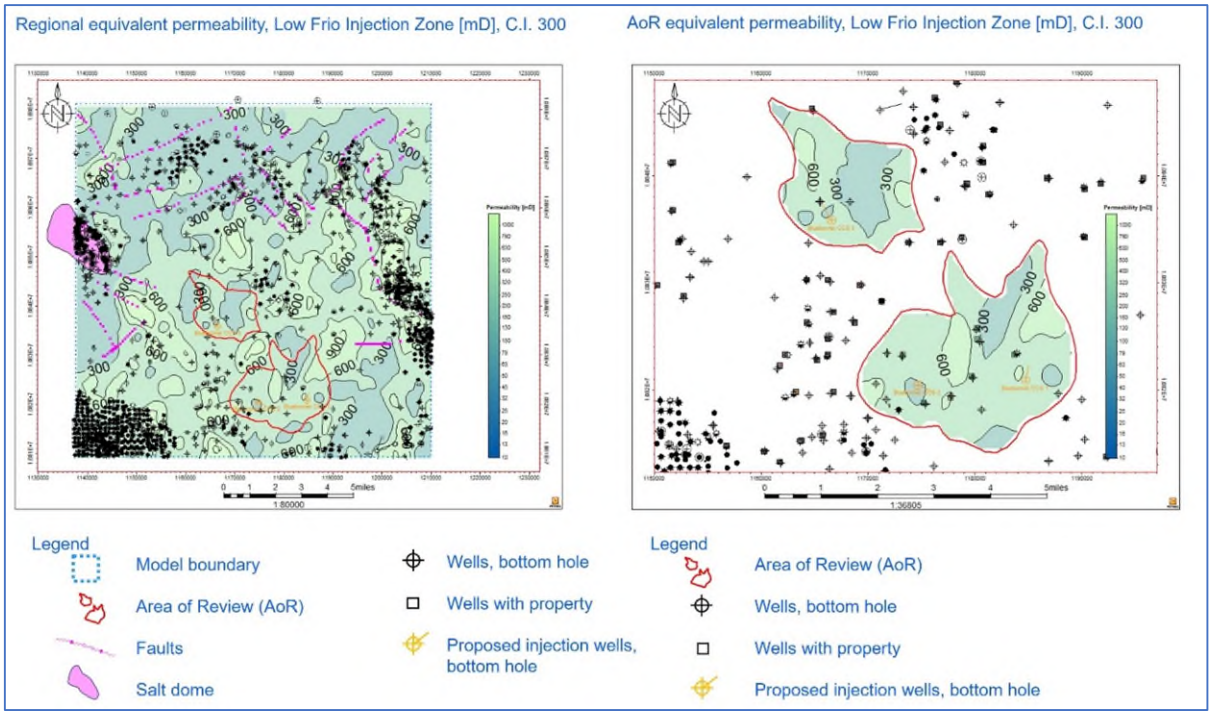


Figure AoR-79: Regional and AoR equivalent permeability map of the Low Frio Injection Zone in millidarcy (md), contour interval 300 md. This map was generated from the Oligocene Model described under 4.0.

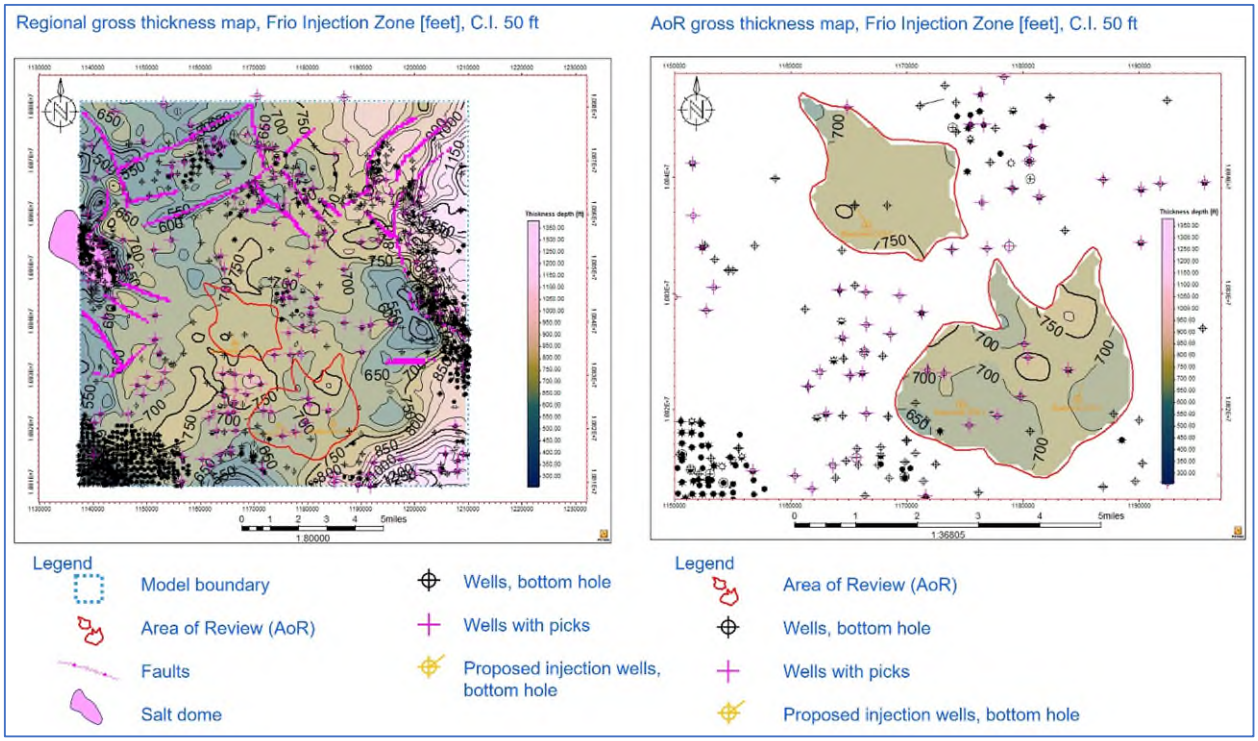


Figure AoR-80: Regional and AoR gross thickness map of the combined Top, Mid, and Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

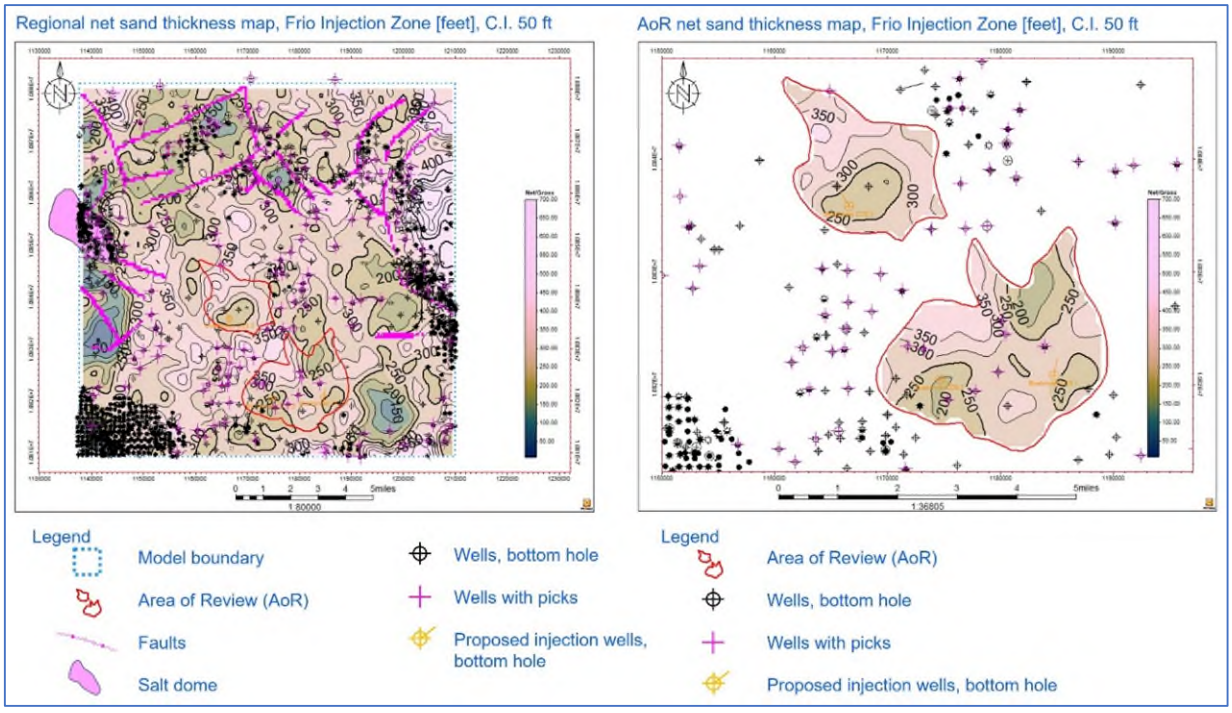


Figure AoR-81: Regional and AoR net thickness map of the combined Top, Mid, and Low Frio Injection Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

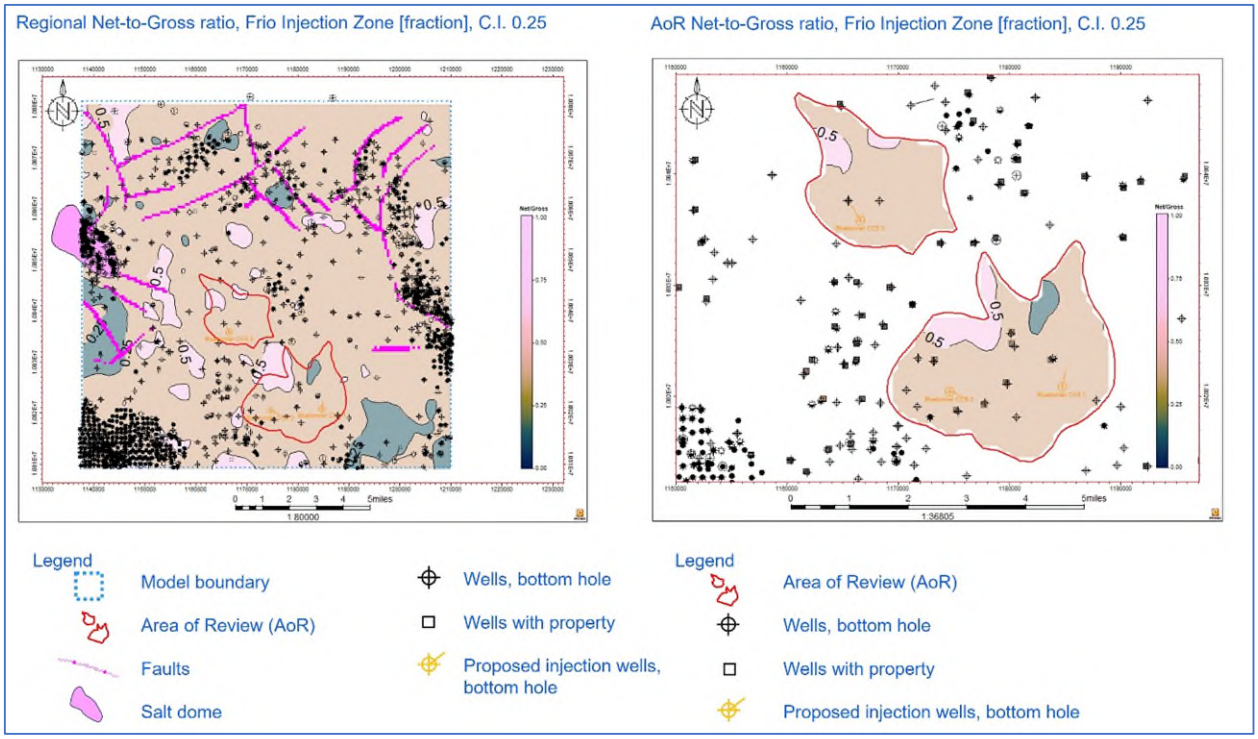


Figure AoR-82: Regional and AoR Net-to-Gross (NTG) ratio map of the combined Top, Mid, and Low Frio Injection Zone in fraction, contour interval 0.25. This map was generated from the Oligocene Model described under 4.0.

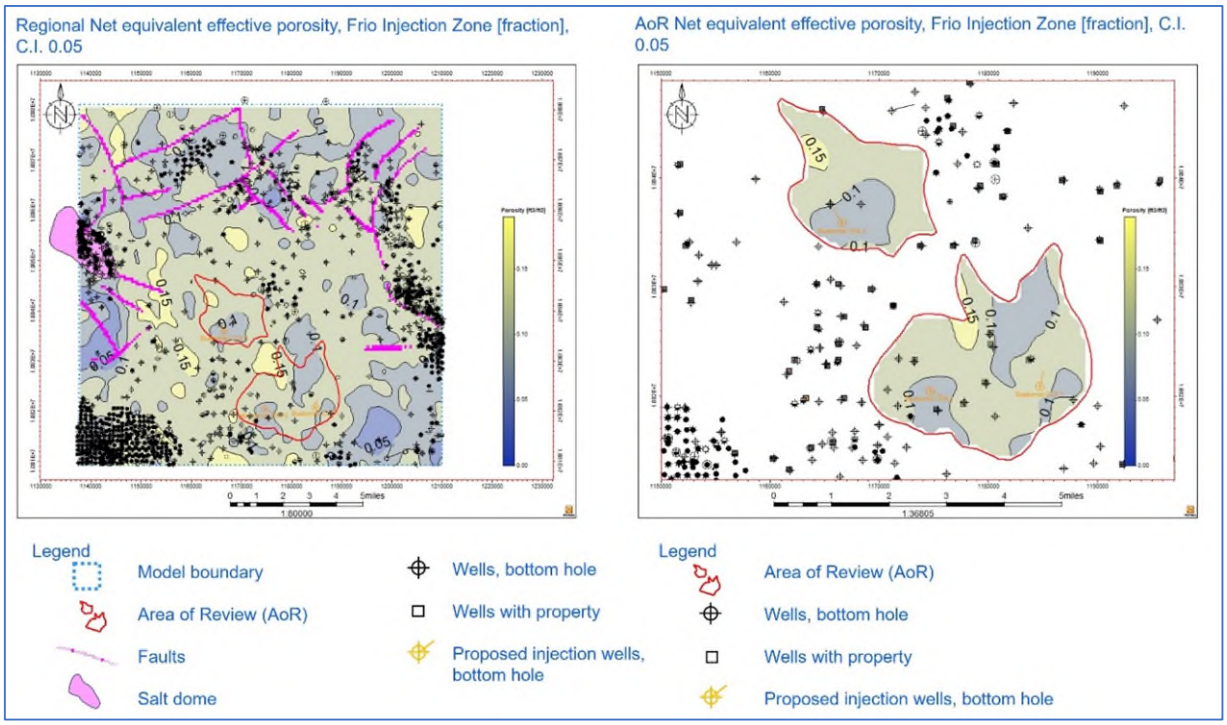


Figure AoR-83: Regional and AoR net equivalent effective porosity map of the combined Top, Mid, and Low Frio Injection Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

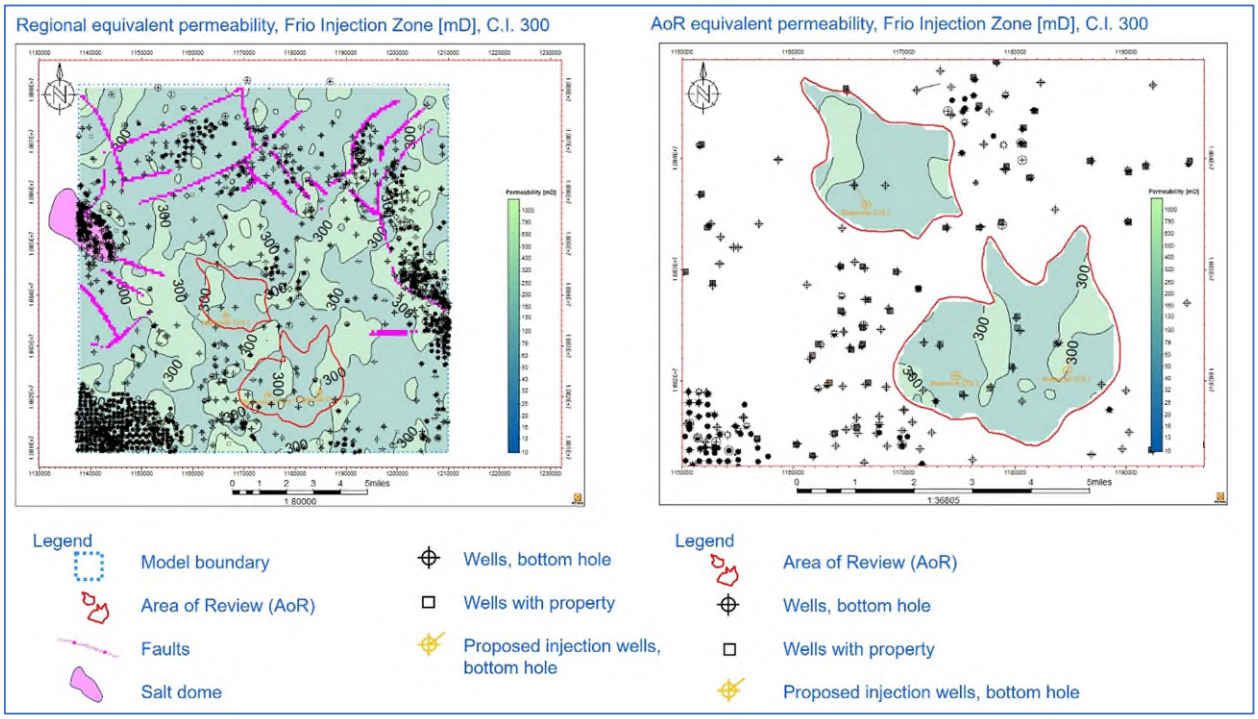


Figure AoR-84: Regional and AoR equivalent permeability map of the combined Top, Mid, and Low Frio Injection Zone in millidarcy (md), contour interval 300 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-2 represent map based average numbers extracted from the geomodel over the AoR.

Table AoR-2: Reservoir properties for the Frio Injection Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Frio injection zone			
		Top Frio	Mid Frio	Low Frio	Combined
Top depth [TVDSS]	Minimum	-7,697	-7,922	-8,062	-7,697
	Maximum	-6,829	-7,032	-7,222	-6,829
	Average	**-7,346**	**-7,569**	**-7,732**	**-7,346**
Base depth [TVDSS]	Minimum	-7,922	-8,062	-8,431	-8,431
	Maximum	-7,032	-7,222	-7,451	-7,451
	Average	**-7,569**	**-7,732**	**-8,057**	**-8,057**
Gross Thickness [ft]	Minimum	170	105	248	622
	Maximum	288	208	406	804
	Average	**220**	**162**	**334**	**710**
Net Sand Thickness [ft]	Minimum	0	10	98	169
	Maximum	84	130	313	417

Reservoir properties in AoR	Extracted map values from geomodel	Frio injection zone			
		Top Frio	Mid Frio	Low Frio	Combined
	Average	**19**	**62**	**203**	**284**
NtG Ratio [fraction]	Minimum	0	0.07	0.32	0.22
	Maximum	0.36	0.7	0.87	0.58
	Average	**0.08**	**0.38**	**0.61**	**0.4**
Porosity [fraction] EQI, net eff. porosity * NTG	Minimum	0.00	0.02	0.09	0.06
	Maximum	0.1	0.20	0.26	0.17
	Average	**0.02**	**0.10**	**0.17**	**0.11**
Permeability [md]	Minimum	0	5	106	72
	Maximum	353	469	864	484
	Average	**49**	**156**	**425**	**251**

Figures AoR-59 to AoR-84 show the associated maps for each of the discussed formations.

3.8.1.3 Miocene Injection Zone

The Miocene Injection Zone is characterized by moderately to well sorted, fine- to medium-grained sandstones, which are virtually unconsolidated. These sandstones are fluvial in origin. Sedimentary structures contain massive sands, trough cross-bedding, low- to high-angle cross stratifications, and contorted bedding. These sands also contain angular and amalgamated mudclasts. The mineral composition is rich in quartz with moderate amounts of K-feldspar and plagioclase, containing various kinds of (un)altered volcanic and metamorphic rock fragments and limestone fragments. Cementing and grain-coating authigenic minerals such as pyrite framboids and incipient K-feldspar overgrowths are very rare. Intergranular pores are abundant and are well interconnected, resulting in large pore throats and high porosity and permeability measurements.

3.8.1.3.1 Petrologic Description

The selected sandstones have abundant quartz grains with common feldspar grains including plagioclase and K-feldspar. Moderate volcanic rock fragments are often rich in K-feldspar (stained yellow for ease of recognition), although a few are plagioclase-rich and altered. Additionally, some have pink-stained limestone rock fragments. Intergranular pores are commonly abundant and are well interconnected. A few sandstones have microfossils including foraminifera with the chambers that are commonly filled with Fe-calcite.

The Miocene sandstone compositional diagrams are shown in the following figures in the top left and are based on thin section 300-point count conventional analysis.

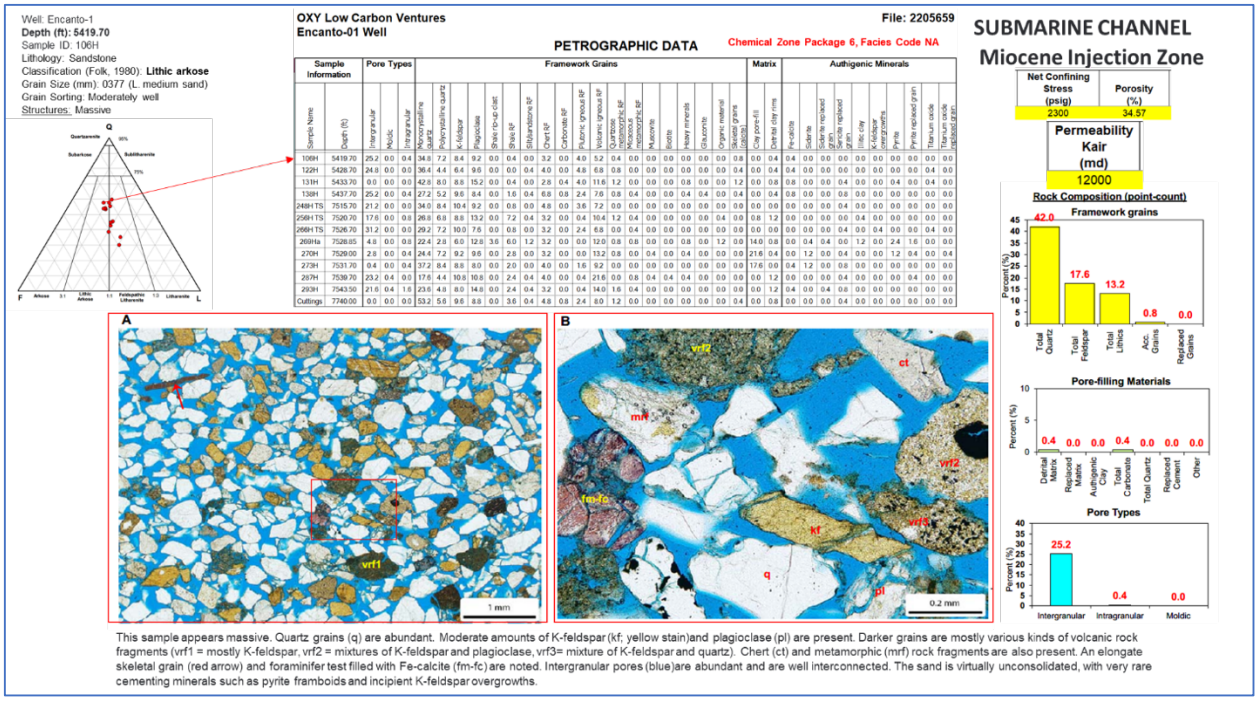


Figure AoR-85: Thin section analysis and petrographic description at 5,419.7 ft MD.

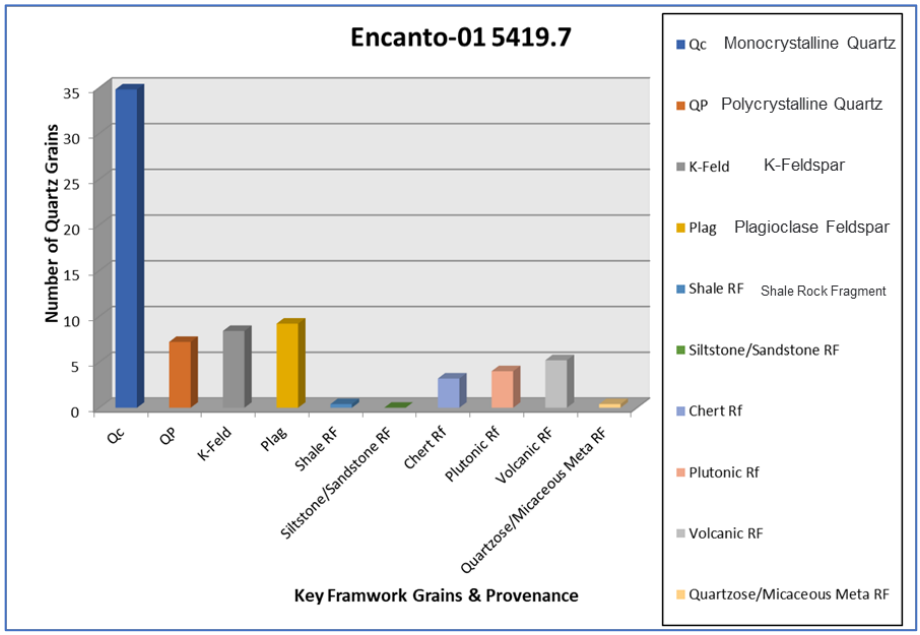


Figure AoR-86: Key framework grains and provenance analysis at 5,419.7 ft MD.

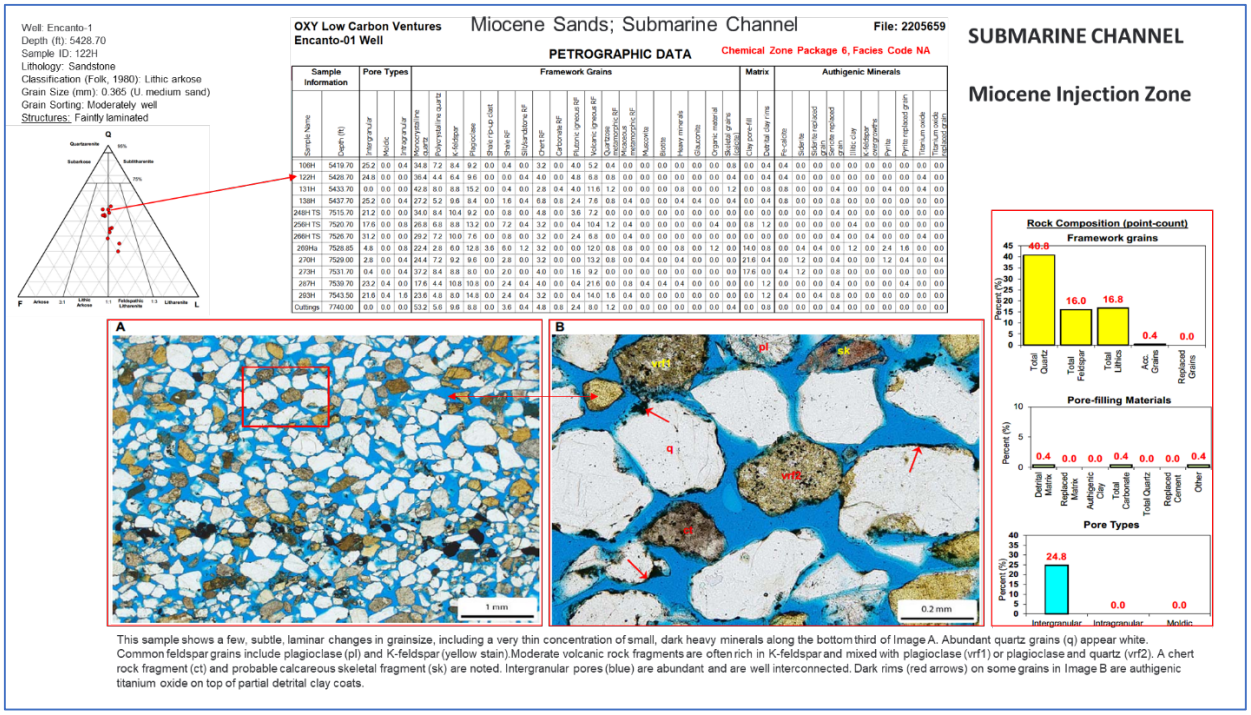


Figure AoR-87: Thin section analysis and petrographic description at 5,428.7 ft MD.

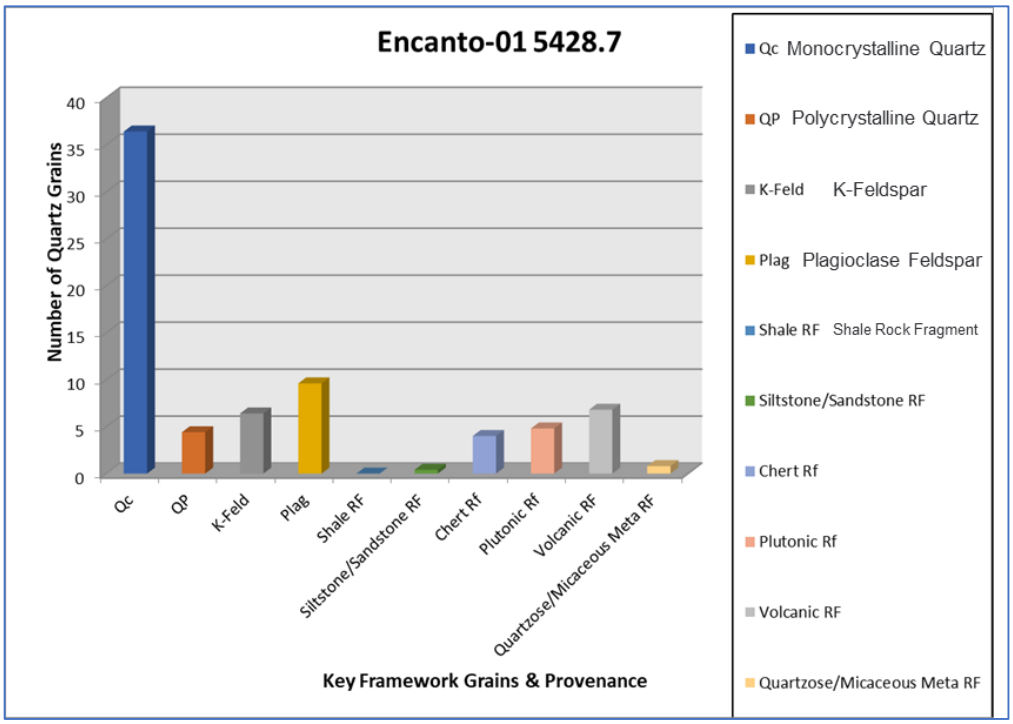


Figure AoR-88: Key framework grains and Provenance analysis at 5,428.7 ft MD.

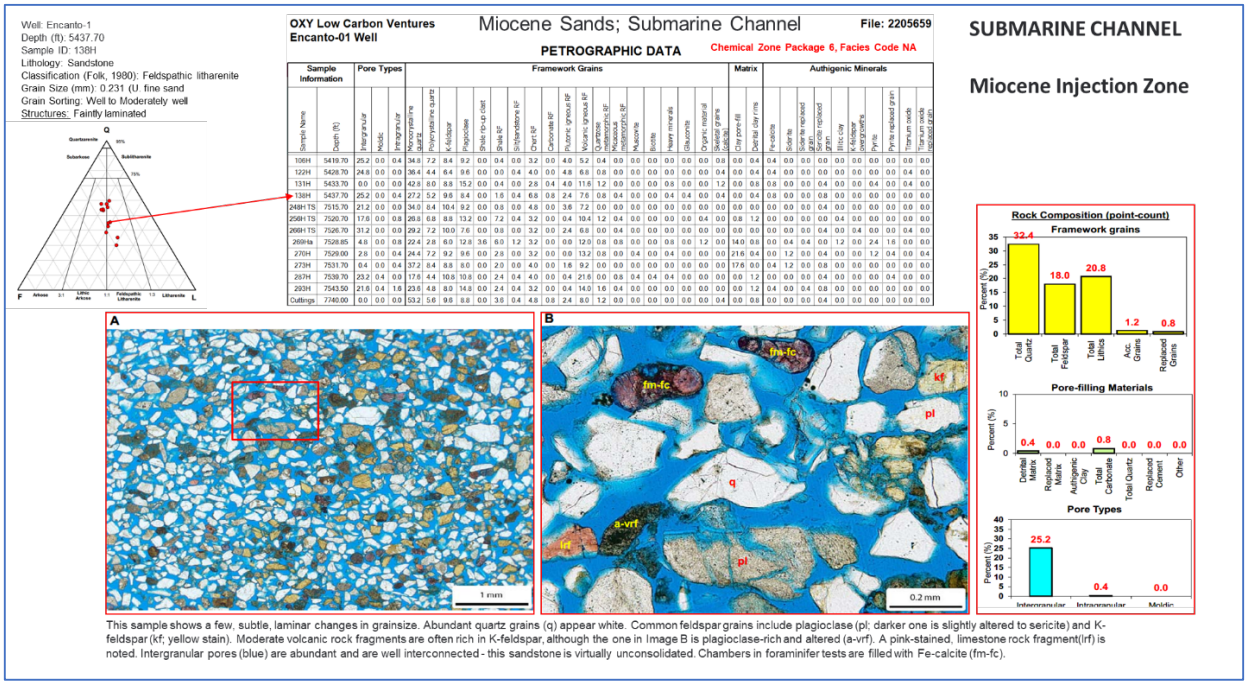


Figure AoR-89: Thin section analysis and petrographic description at 5,437.7 ft MD.

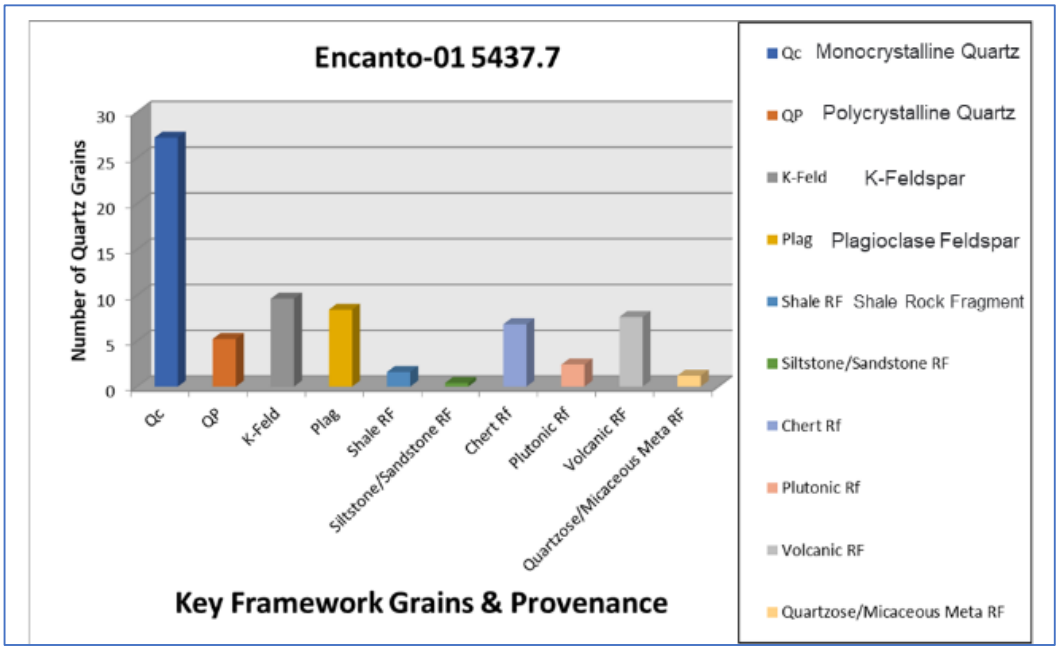


Figure AoR-90: Key framework grains and Provenance analysis at 5,437.7 ft MD.

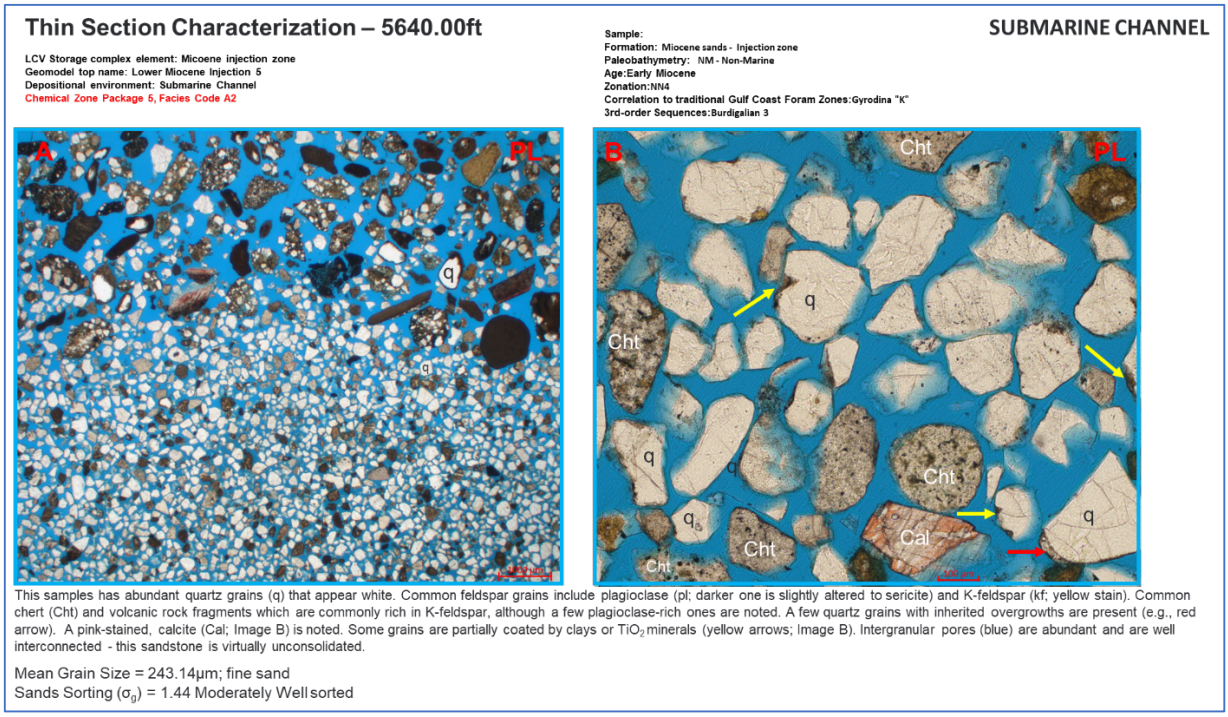


Figure AoR-91: Thin section analysis and petrographic description at 5,640.0 ft MD.

3.8.1.3.2 Miocene Injection Zone Maps

Petrophysically calculated porosity and permeability was calibrated to core. Average gross porosity from the petrophysical analysis performed in Encanto 01 in the Miocene Injection Zone is 22 %, sand porosity is 32%, average gross permeability is 78 md, and sand permeability is 3.2 darcy. For more detail about the petrophysical workflow, please refer to the petrophysical Appendix A.

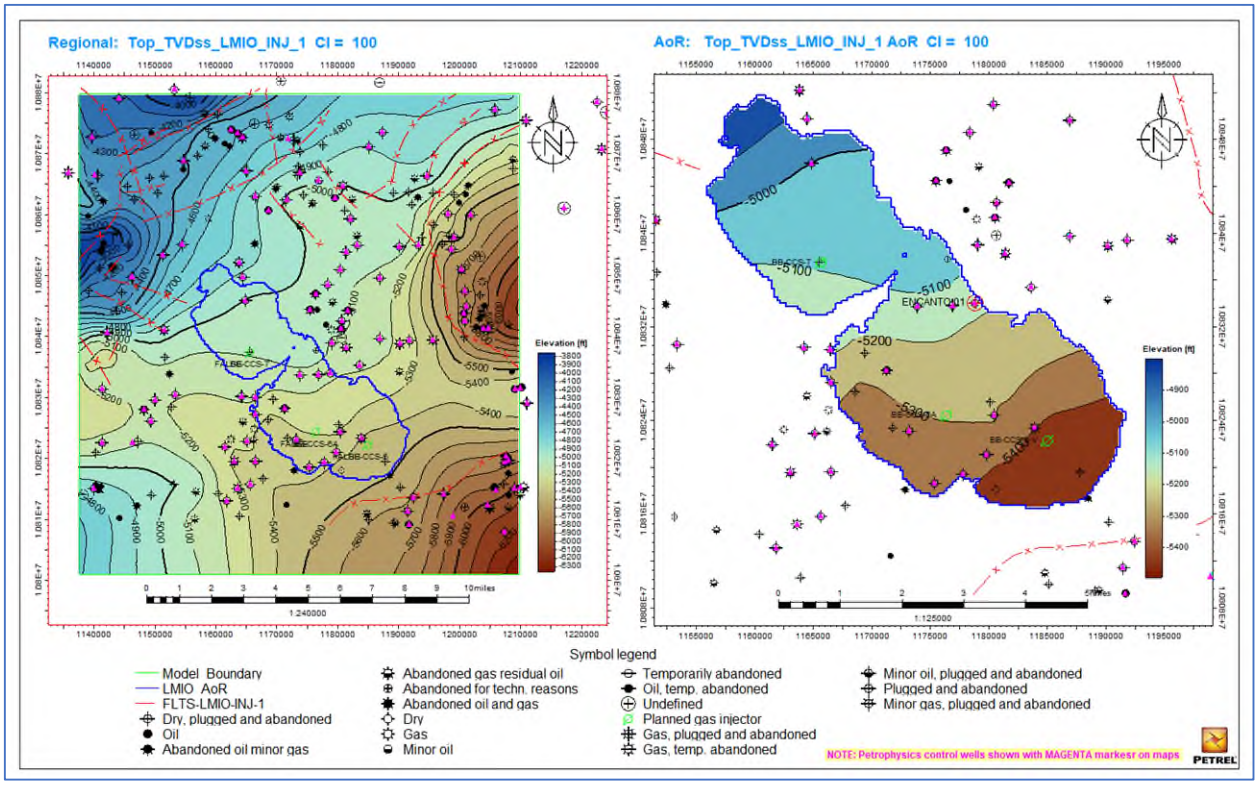


Figure AoR-92: Regional and AoR top structure maps of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

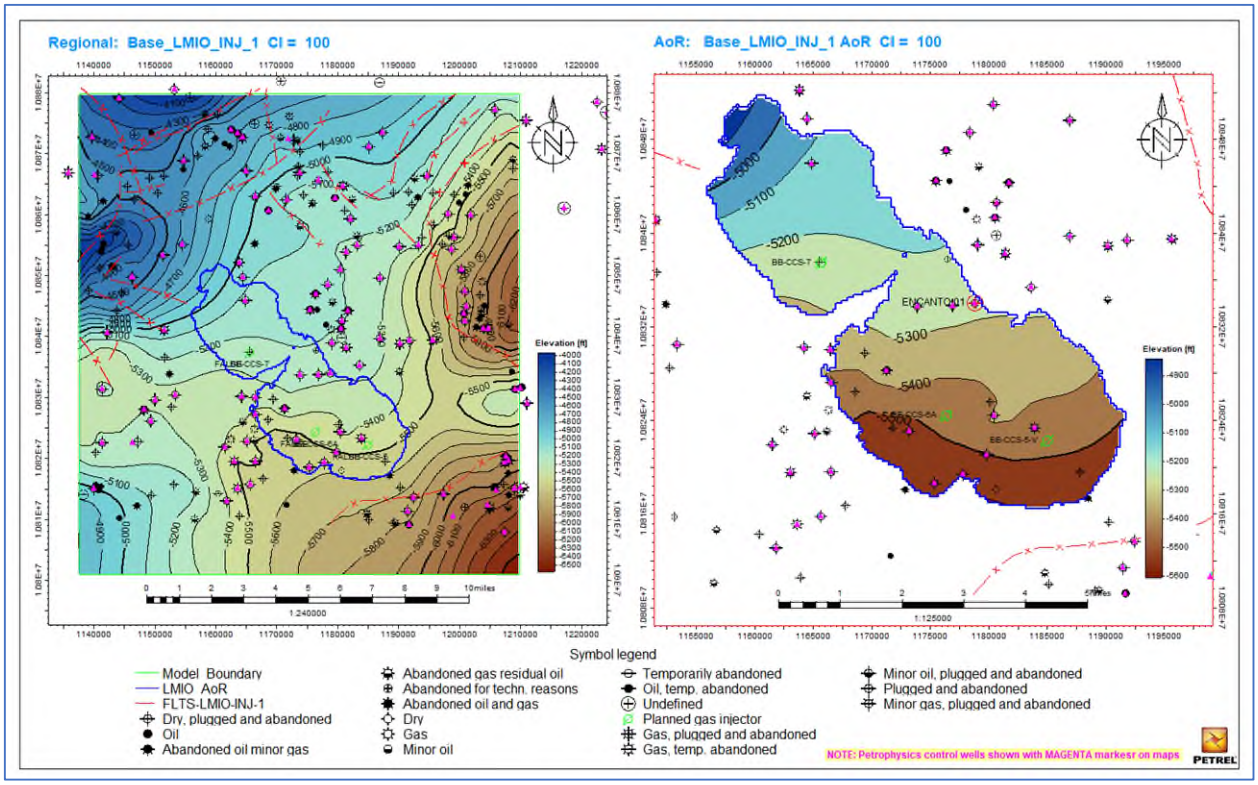


Figure AoR-93: Regional and AoR base structure maps of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

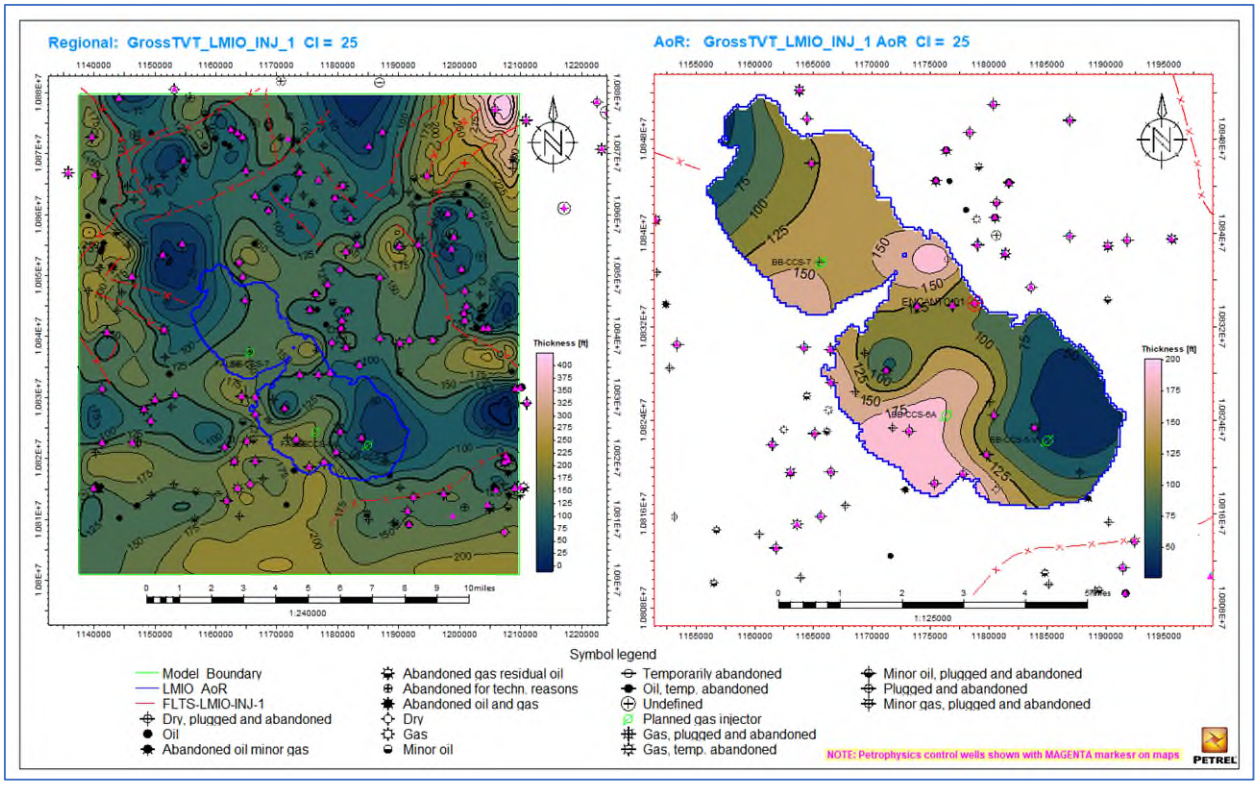


Figure AoR-94: Regional and AoR gross thickness maps of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0

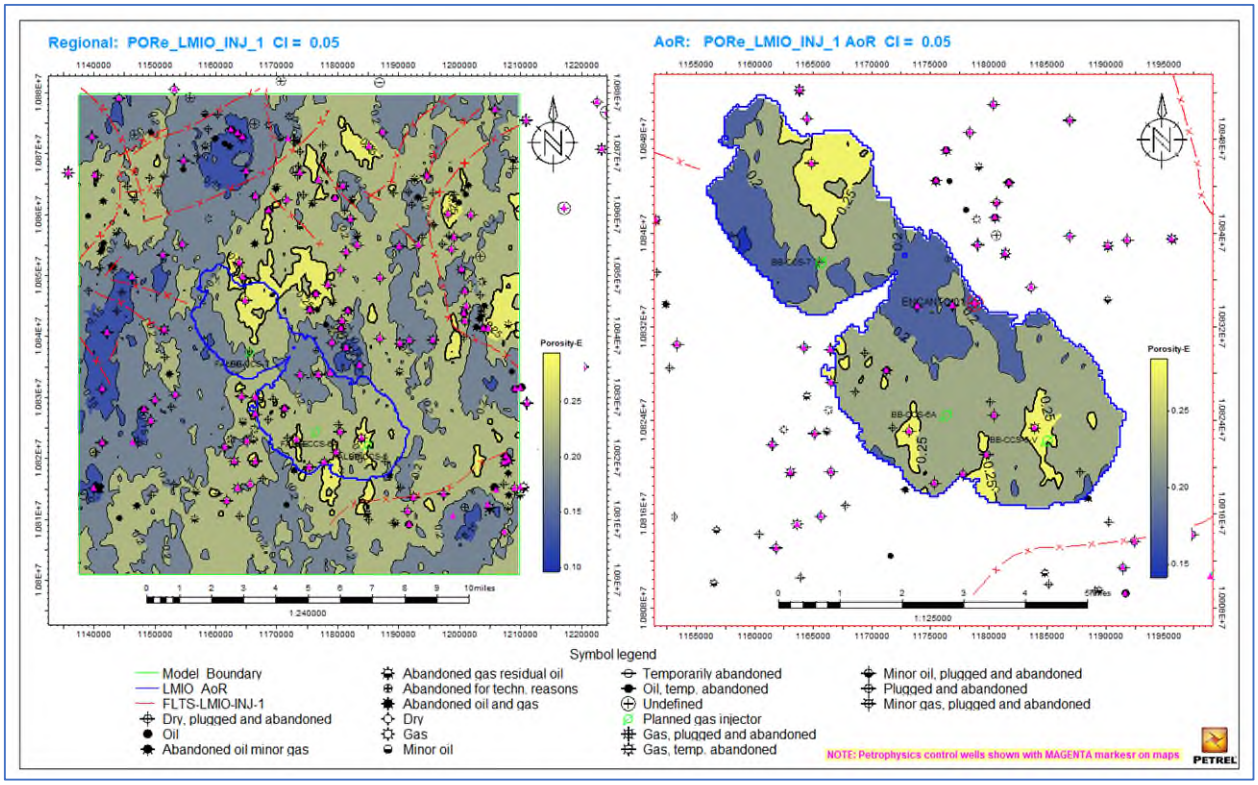


Figure AoR-95: Regional and AoR average effective porosity of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

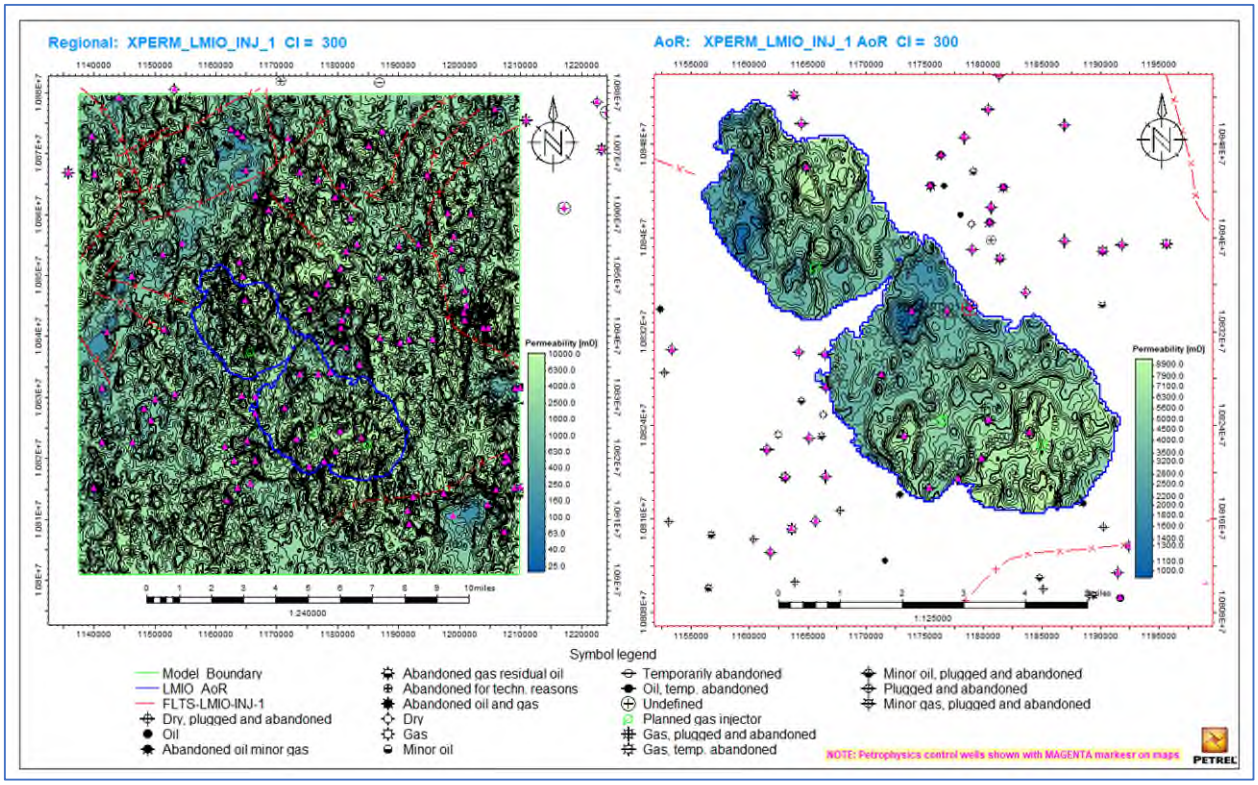


Figure AoR-96: Regional and AoR average permeability of the LMIO_INJ_1 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers in Table AoR-3 represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-3: Reservoir properties for the LMIO_INJ_1 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_1 Injection Zone
Top Depth (TVDss)	Average	-5,199.90
	Minimum	-5,494.62
	Maximum	-4,801.57
Base Depth (TVDss)	Average	-5,317.69
	Minimum	-5,604.56
	Maximum	-4,843.44
Gross Thickness (ft.)	Average	117.56
	Minimum	26.11
	Maximum	200.67
	Average	0.22

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_1 Injection Zone
Effective Porosity (fraction)	Minimum	0.14
	Maximum	0.28
Permeability (md)	Average	4861.00
	Minimum	932.00
	Maximum	9492.00

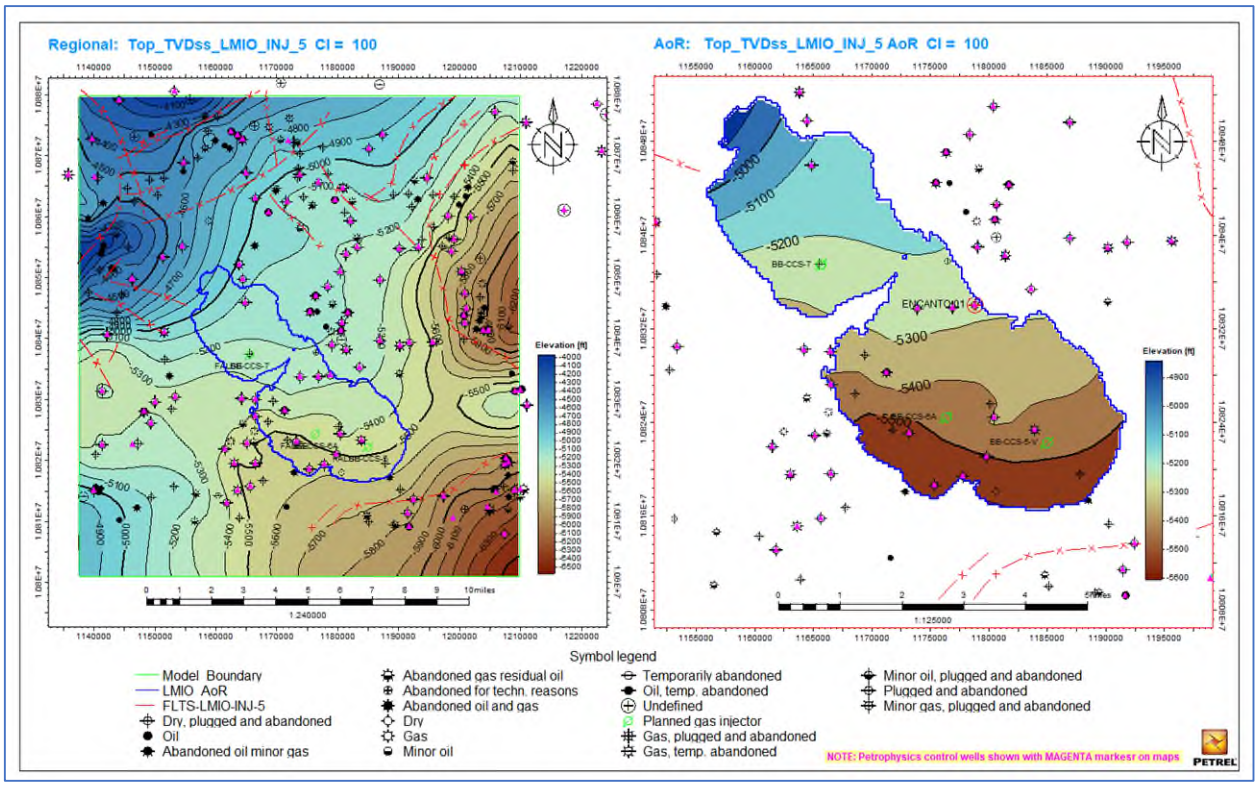


Figure AoR-97: Regional and AoR top structure maps of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

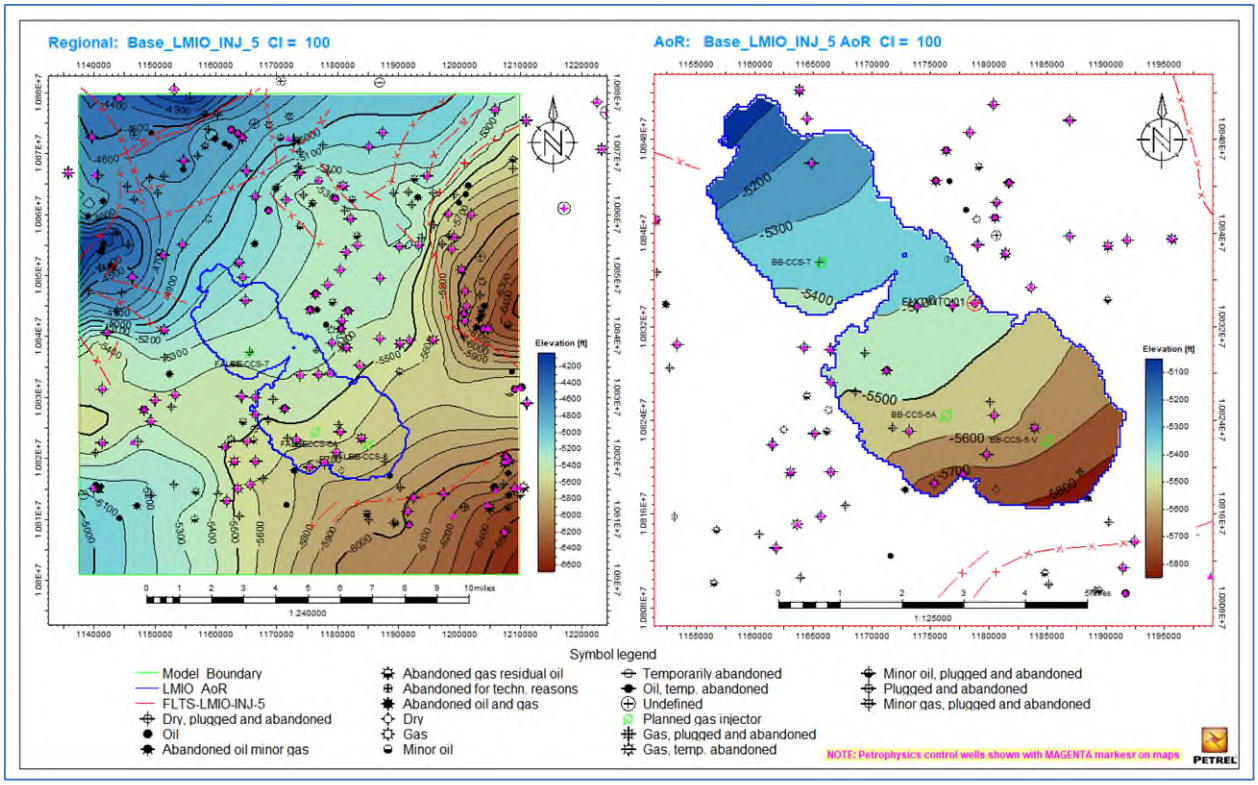


Figure AoR-98: Regional and AoR base structure maps of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

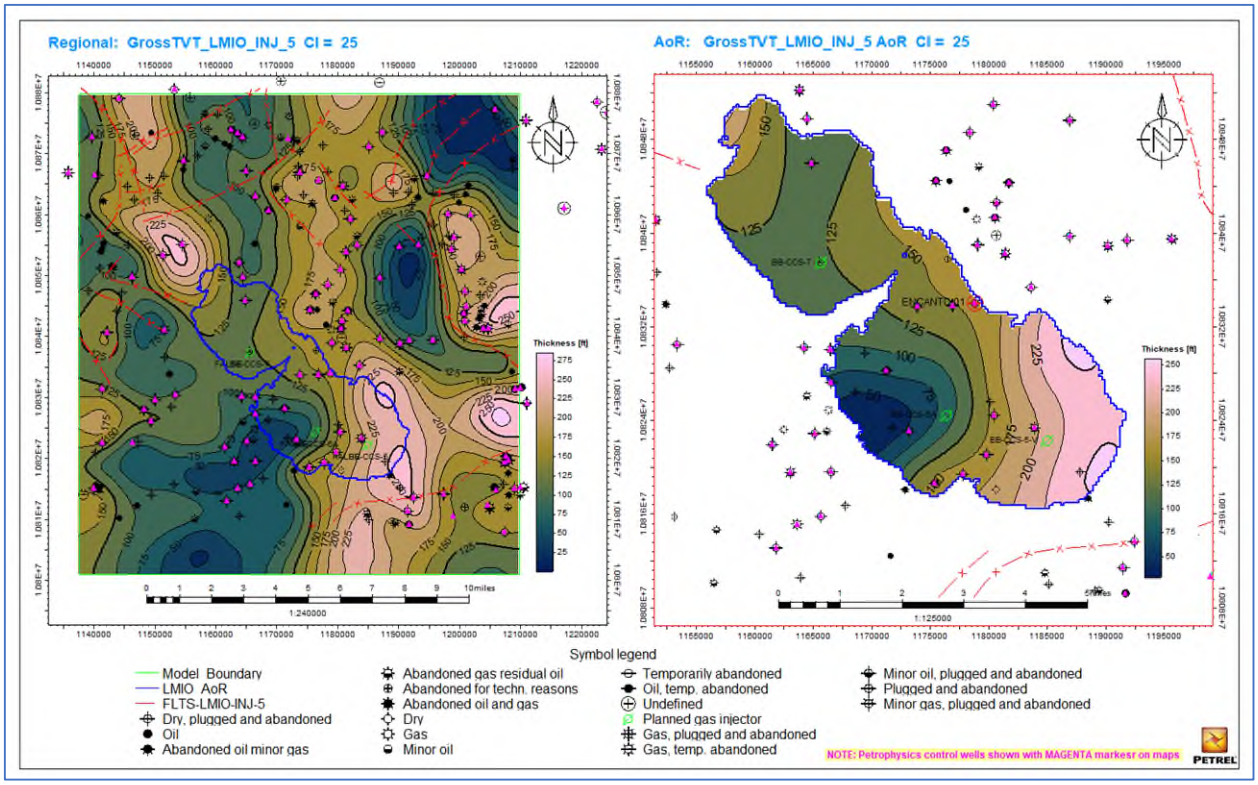


Figure AoR-99: Regional and AoR gross thickness maps of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

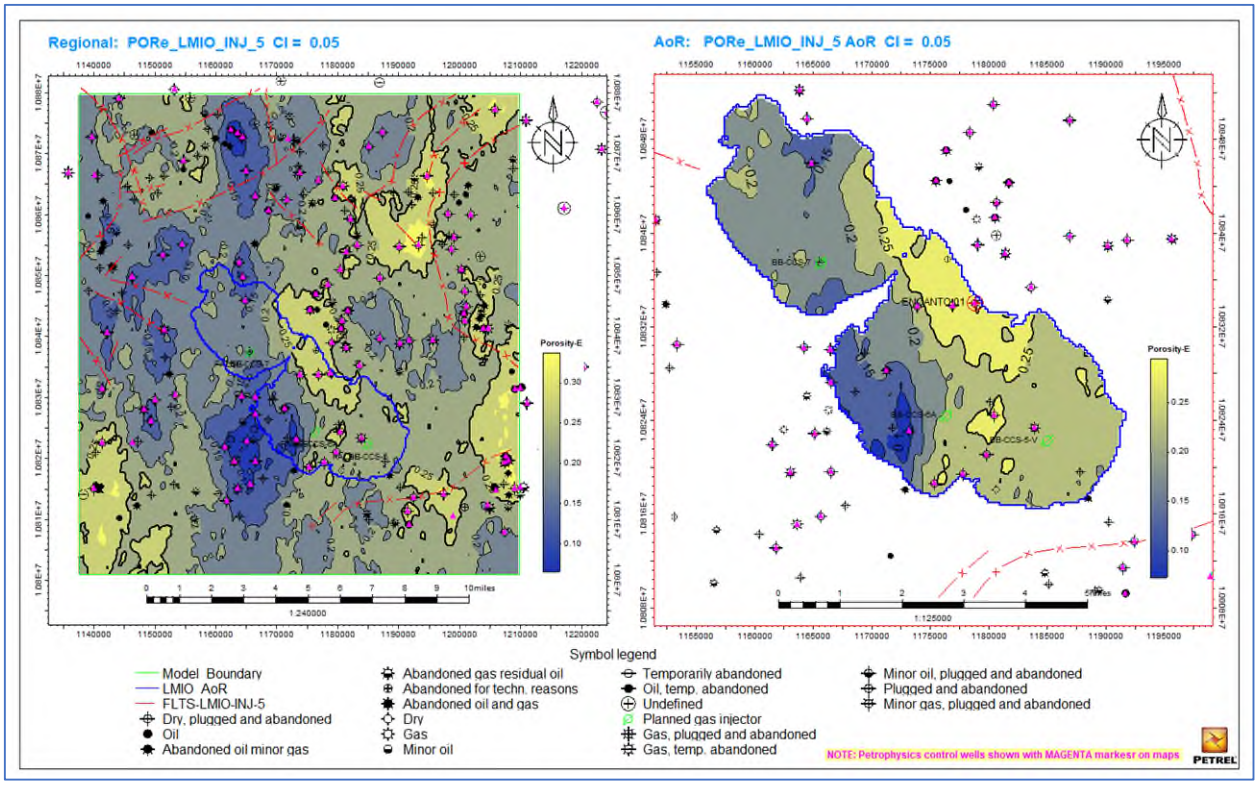


Figure AoR-100: Regional and AoR average effective porosity of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

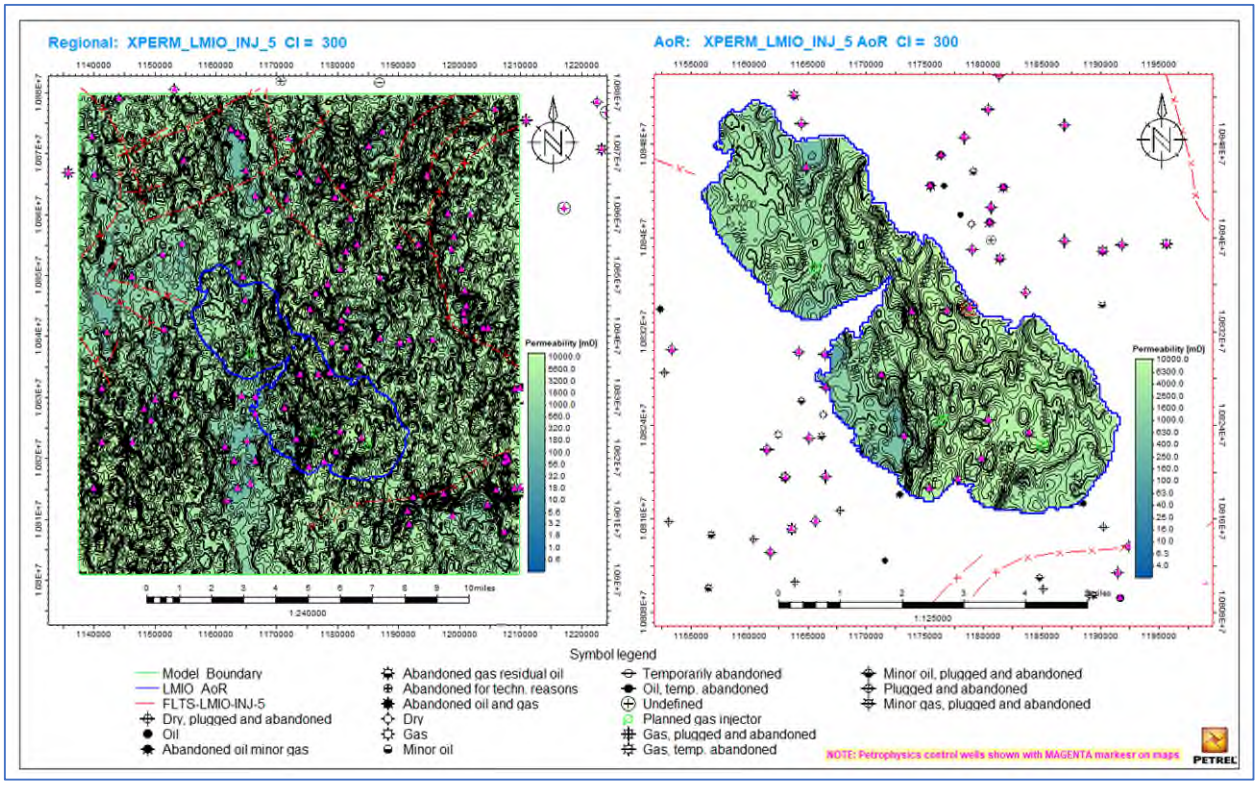


Figure AoR-101: Regional and AoR average permeability of the LMIO_INJ_5 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-4: Reservoir properties for the LMIO_INJ_5 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_5 Injection Zone
Top Depth (TVDss)	Average	-5,317.69
	Minimum	-5,604.56
	Maximum	-4,843.44
Base Depth (TVDss)	Average	-5,462.75
	Minimum	-5,848.14
	Maximum	-5,051.33
Gross Thickness (ft.)	Average	145.25
	Minimum	28.35
	Maximum	255.97
Effective Porosity (fraction)	Average	0.20
	Minimum	0.07
	Maximum	0.29
Permeability (md)	Average	4,285.00
	Minimum	0.00
	Maximum	12,357.00

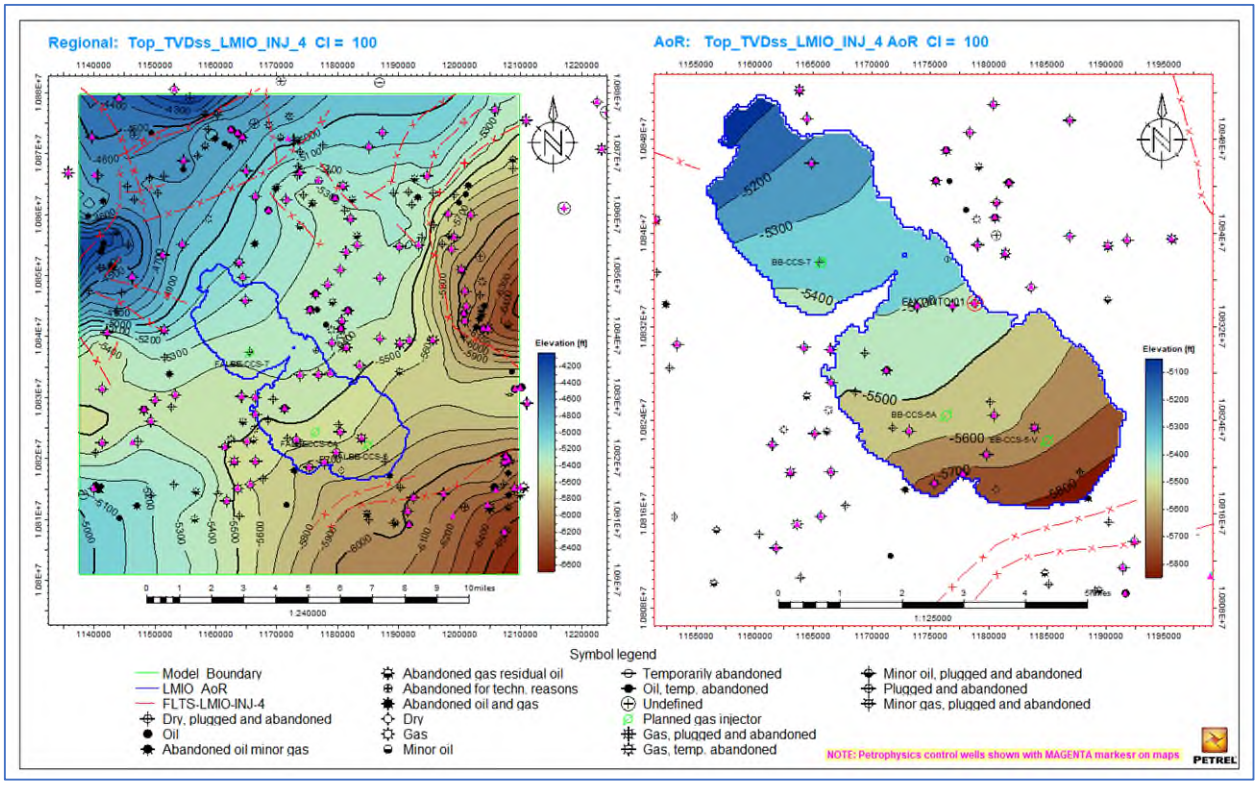


Figure AoR-102: Regional and AoR top structure maps of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

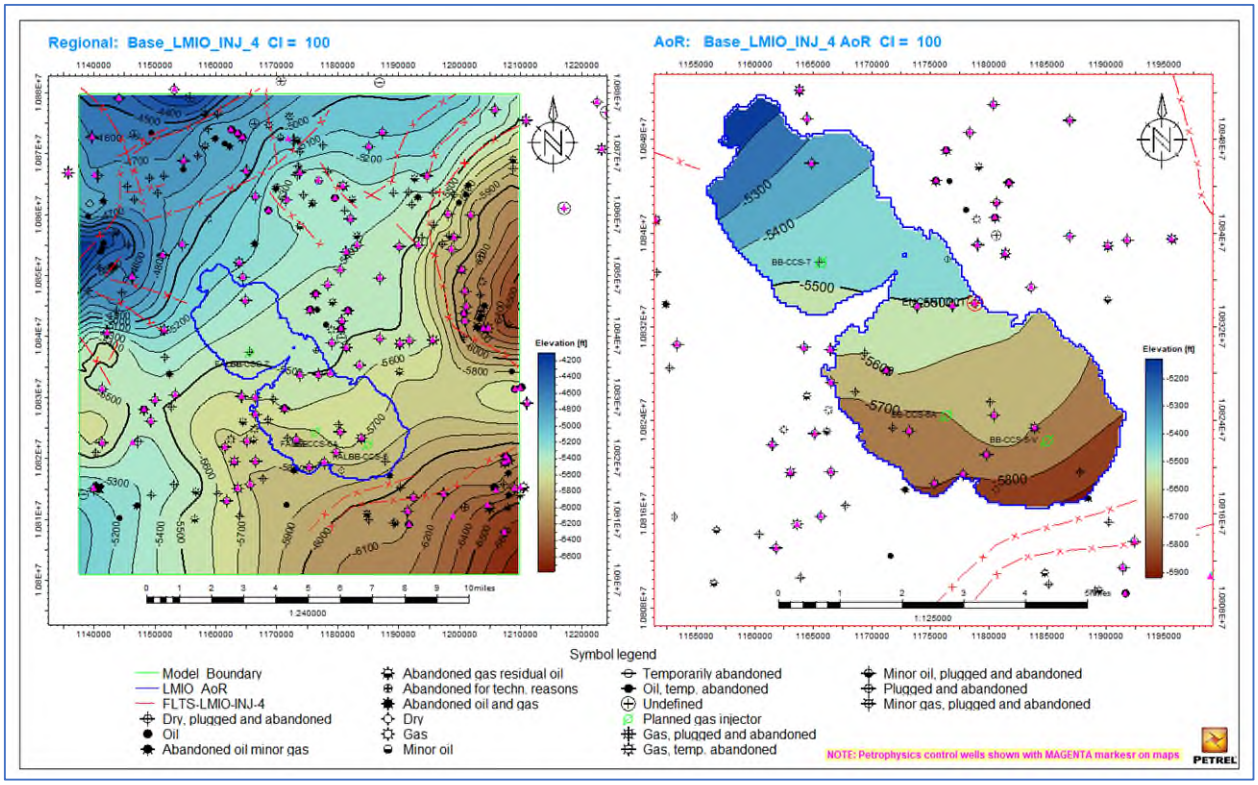


Figure AoR-103: Regional and AoR base structure maps of the LMIO_INJ_4 Injection Zone, in feet. Contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

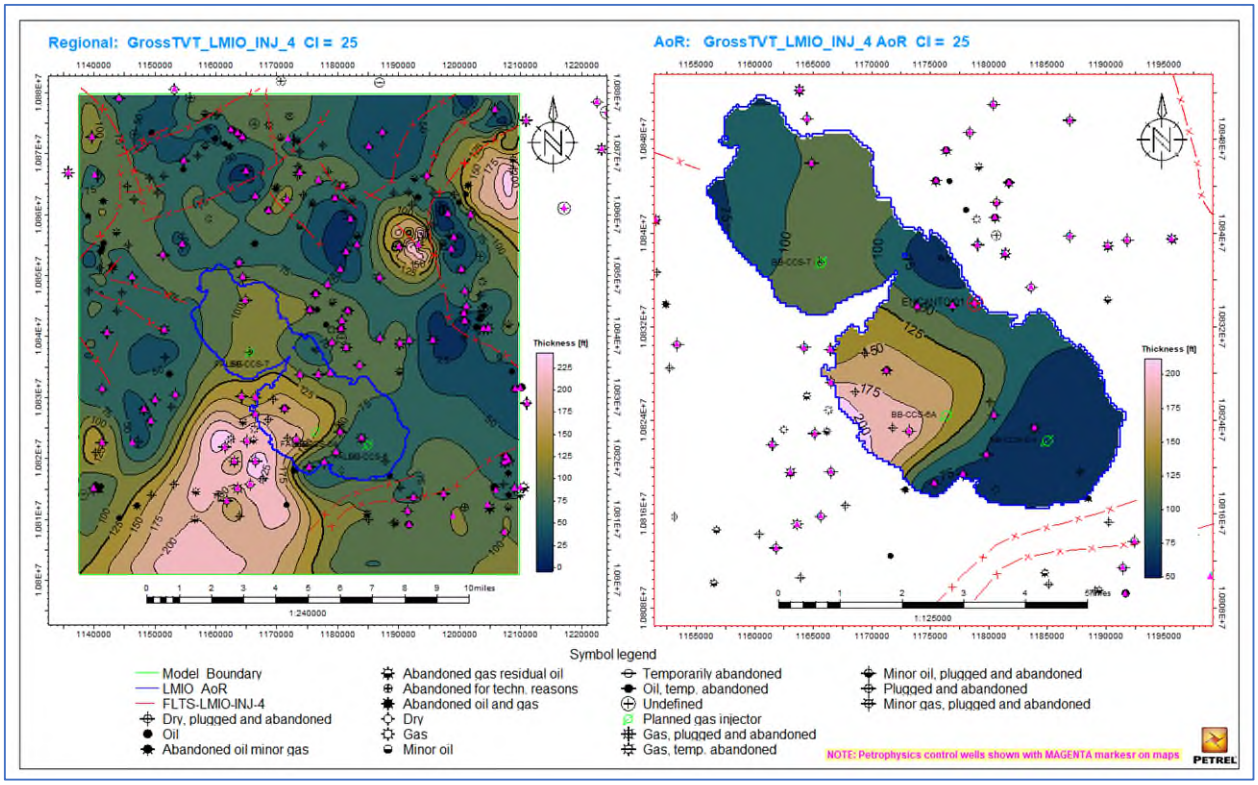


Figure AoR-104: Regional and AoR gross thickness maps of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

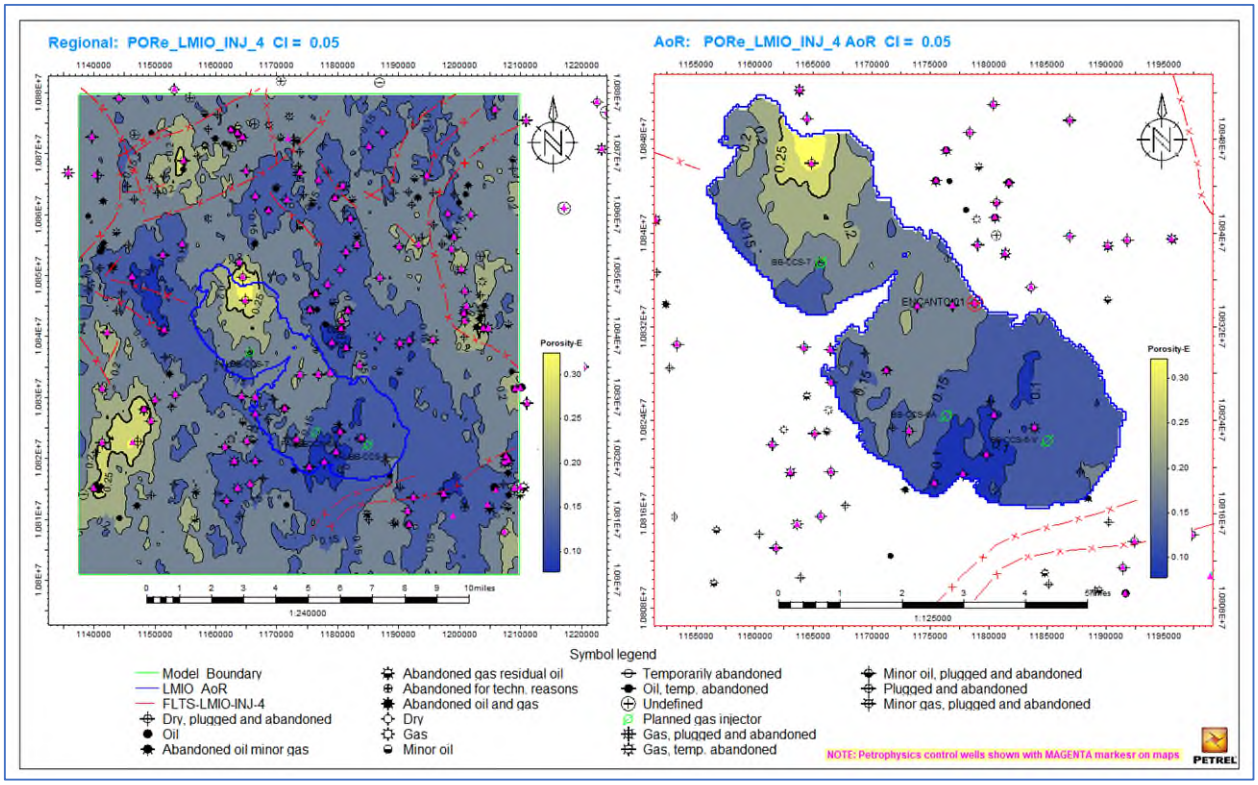


Figure AoR-105: Regional and AoR average effective porosity of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

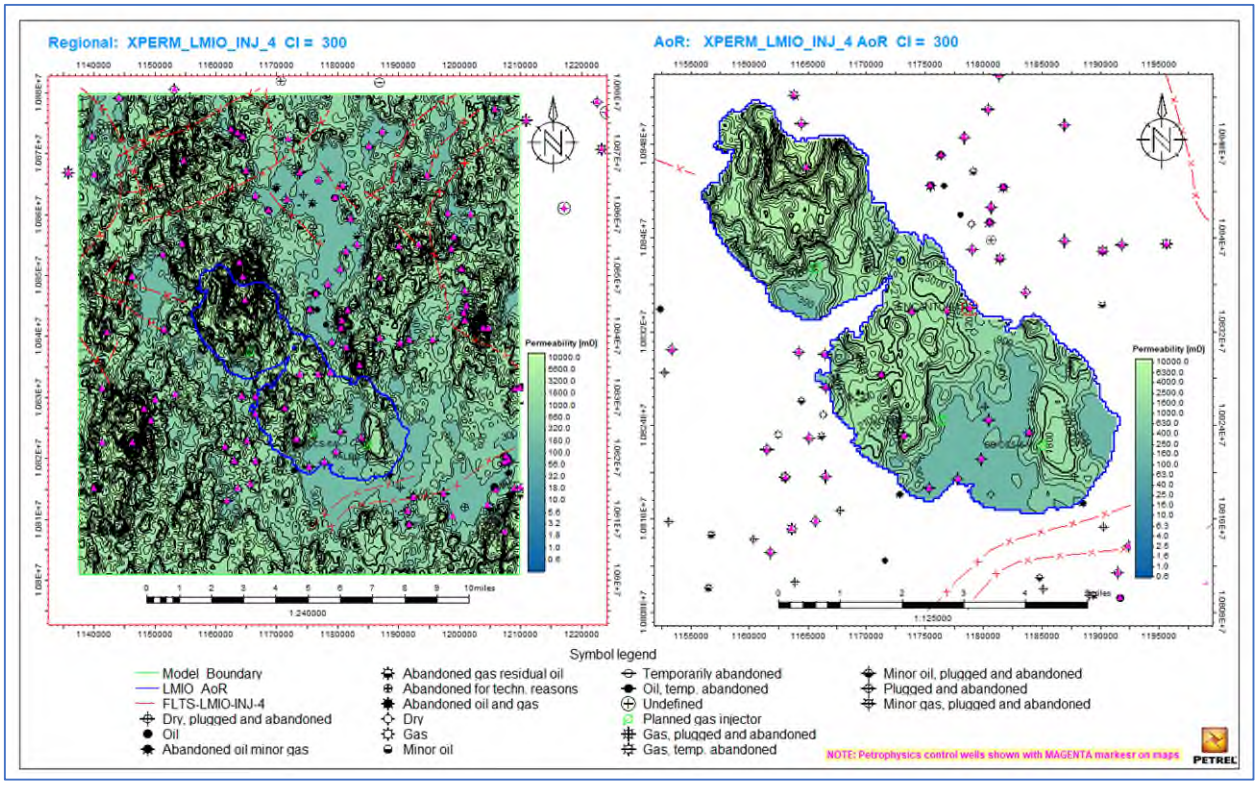


Figure AoR-106: Regional and AoR average permeability of the LMIO_INJ_4 Injection Zone, in feet, contour interval = 300250 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-5: Reservoir properties for the LMIO_INJ_4 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_4 Injection Zone
Top Depth (TVDss)	Average	-5,462.75
	Minimum	-5,848.14
	Maximum	-5,051.33
Base Depth (TVDss)	Average	-5,565.16
	Minimum	-5,918.09
	Maximum	-5,129.14
Gross Thickness (ft.)	Average	102.37
	Minimum	49.80
	Maximum	211.29
Effective Porosity (fraction)	Average	0.16
	Minimum	0.08
	Maximum	0.32
Permeability (md)	Average	2,244.00
	Minimum	1.00
	Maximum	11,650.00

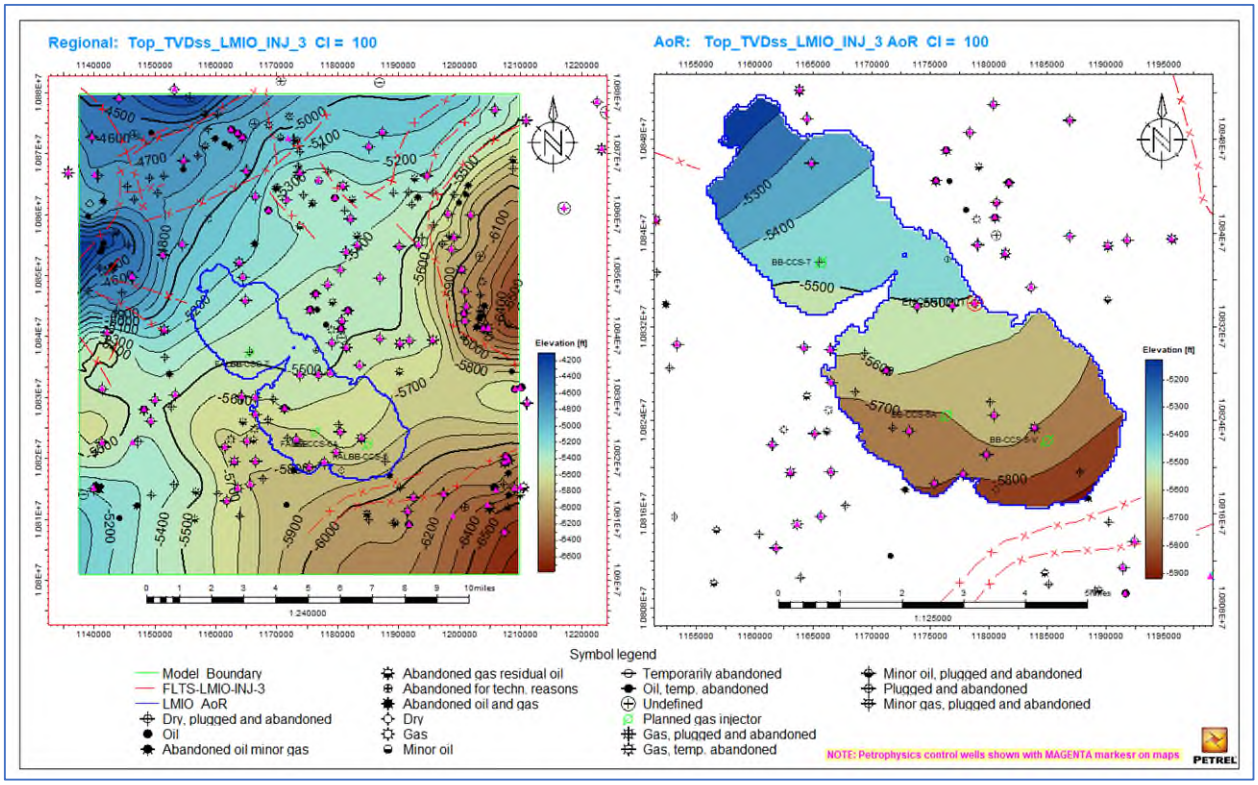


Figure AoR-107: Regional and AoR top structure maps of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

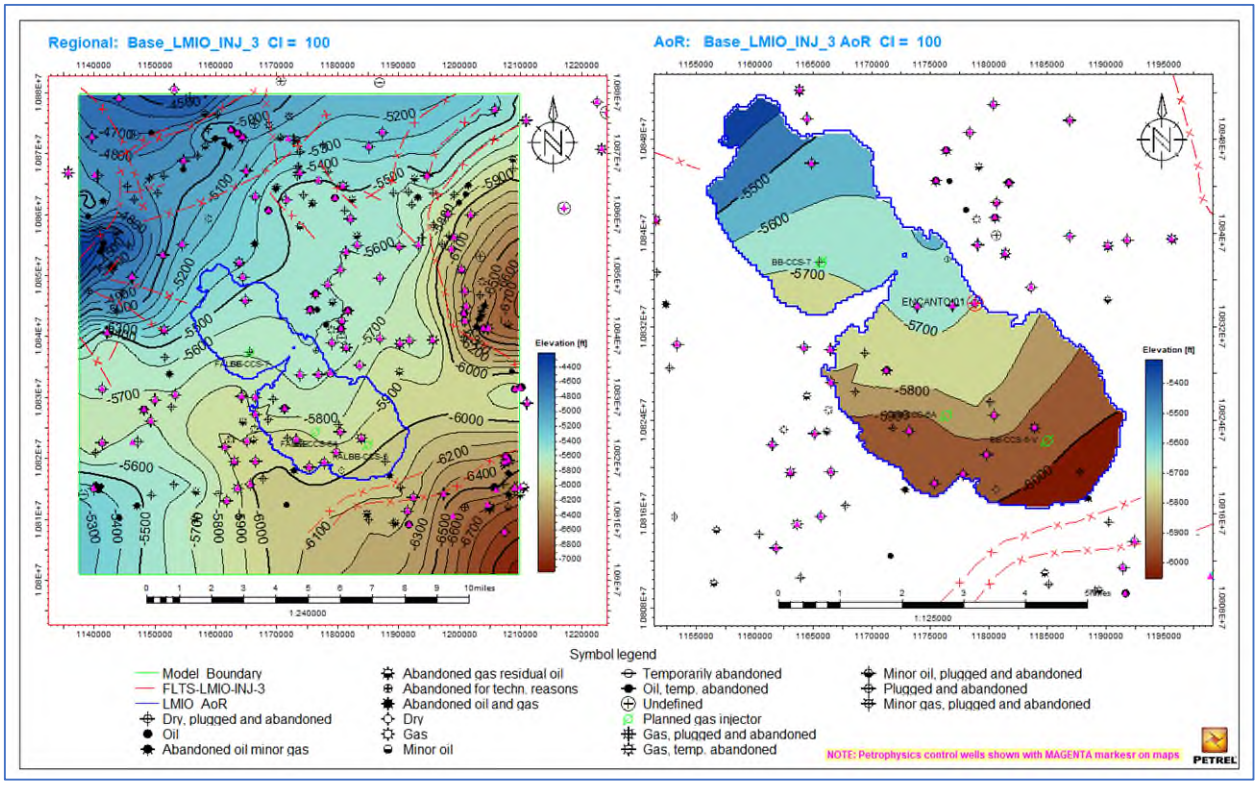


Figure AoR-108: Regional and AoR base structure maps of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

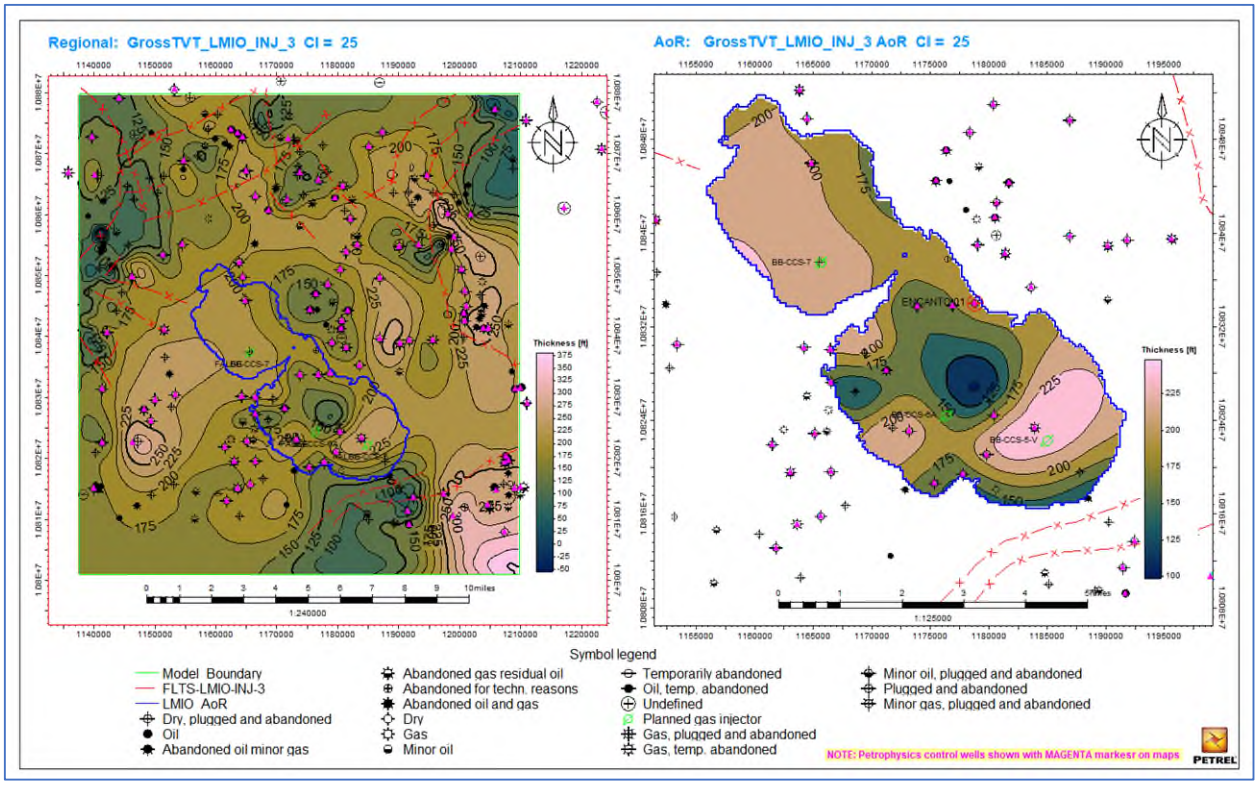


Figure AoR-109: Regional and AoR gross thickness maps of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

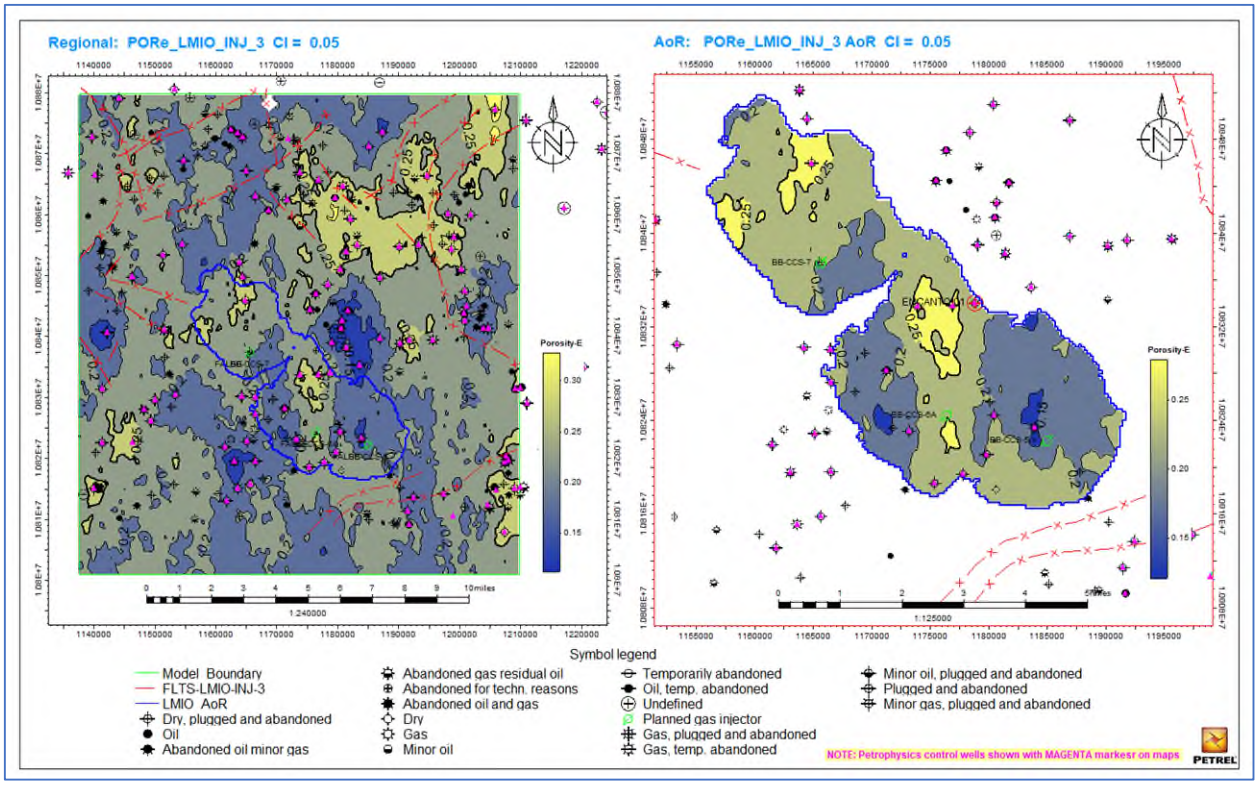


Figure AoR-110: Regional and AoR average effective porosity of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

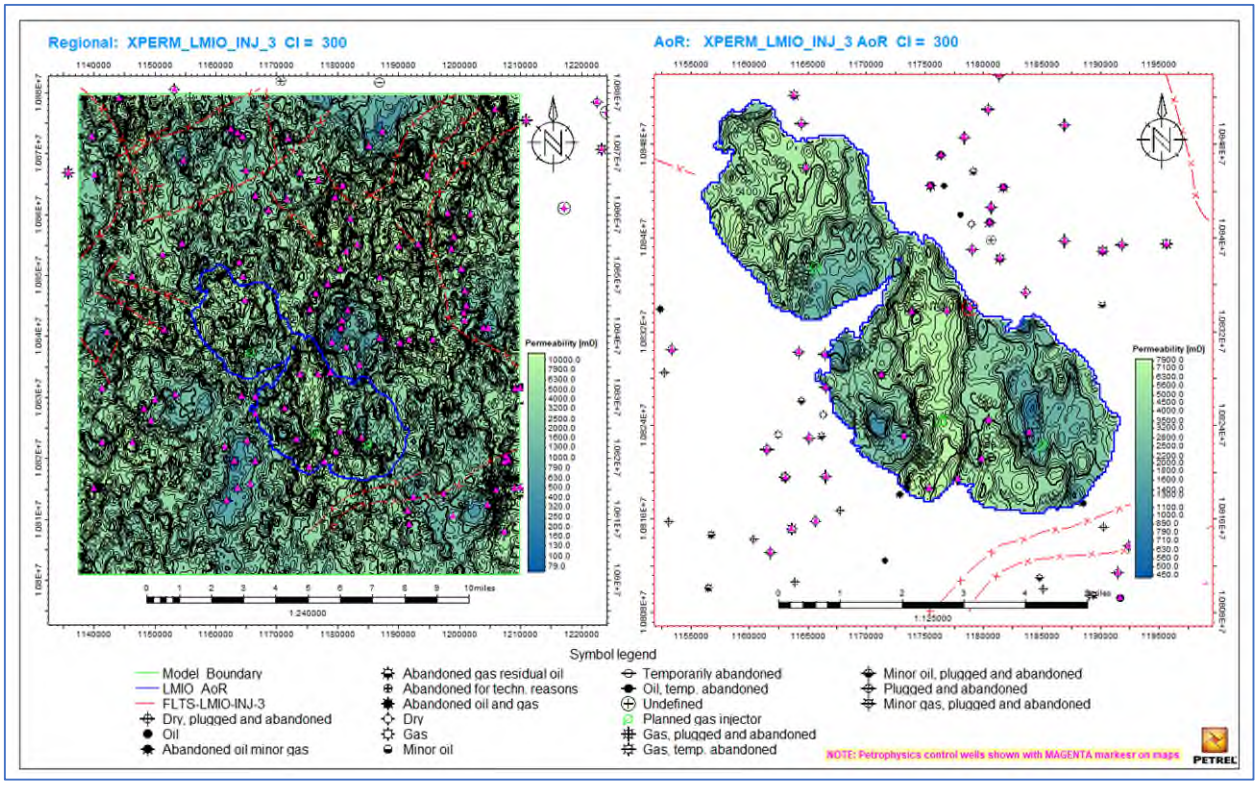


Figure AoR-111: Regional and AoR average permeability of the LMIO_INJ_3 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-6: Reservoir properties for the LMIO_INJ_3 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_3 Injection Zone
Top Depth (TVDss)	Average	-5,565.16
	Minimum	-5,918.09
	Maximum	-5,129.14
Base Depth (TVDss)	Average	-5,755.42
	Minimum	-,6051.02
	Maximum	-5,322.31
Gross Thickness (ft.)	Average	190.50
	Minimum	98.75
	Maximum	247.93
Effective Porosity (fraction)	Average	0.21
	Minimum	0.12
	Maximum	0.28
Permeability (md)	Average	4,364.00
	Minimum	435.00
	Maximum	8,044.00

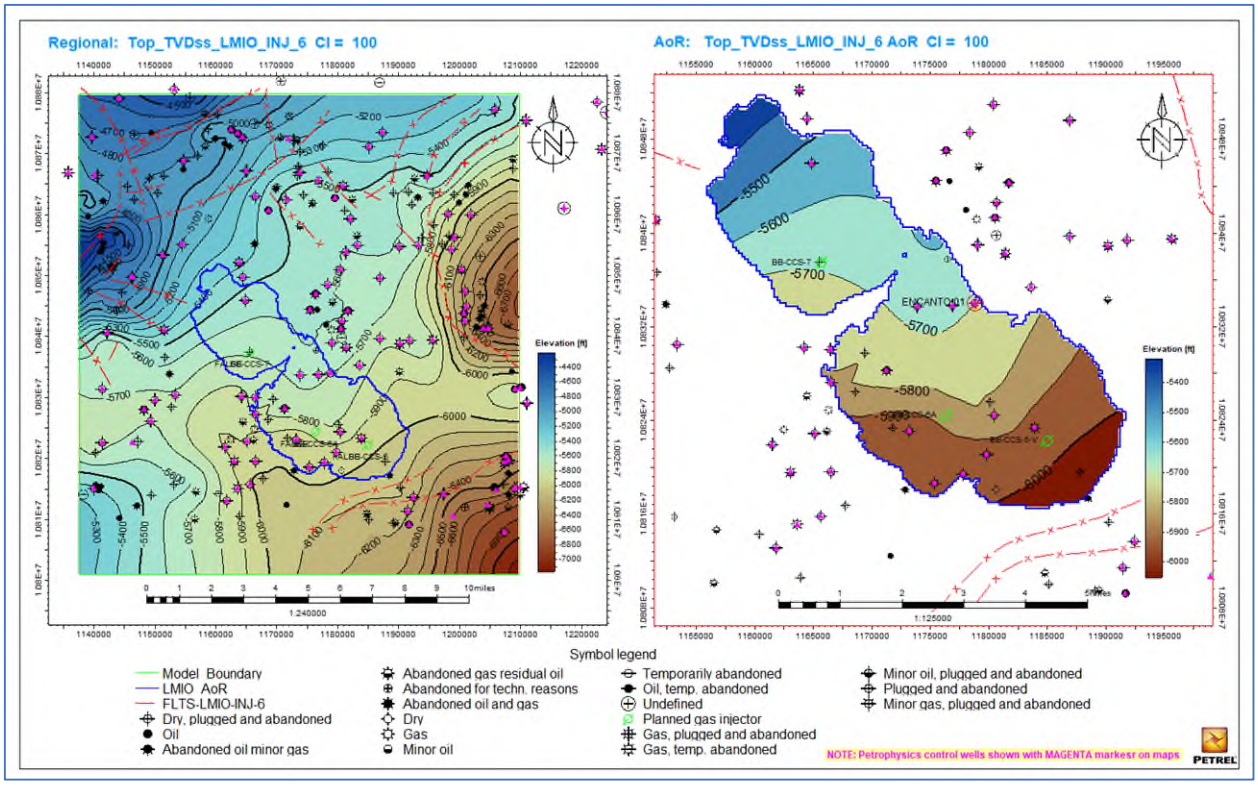


Figure AoR-112: Regional and AoR top structure maps of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

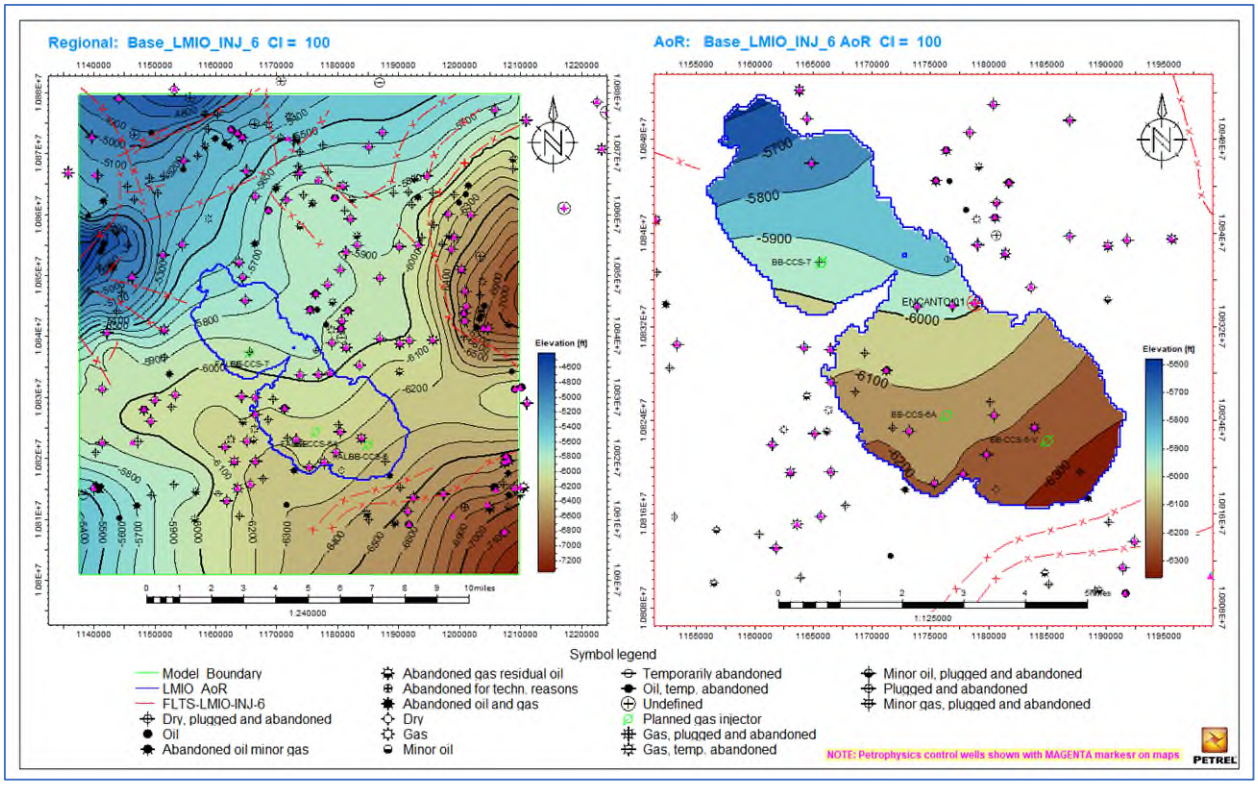


Figure AoR-113: Regional and AoR base structure maps of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

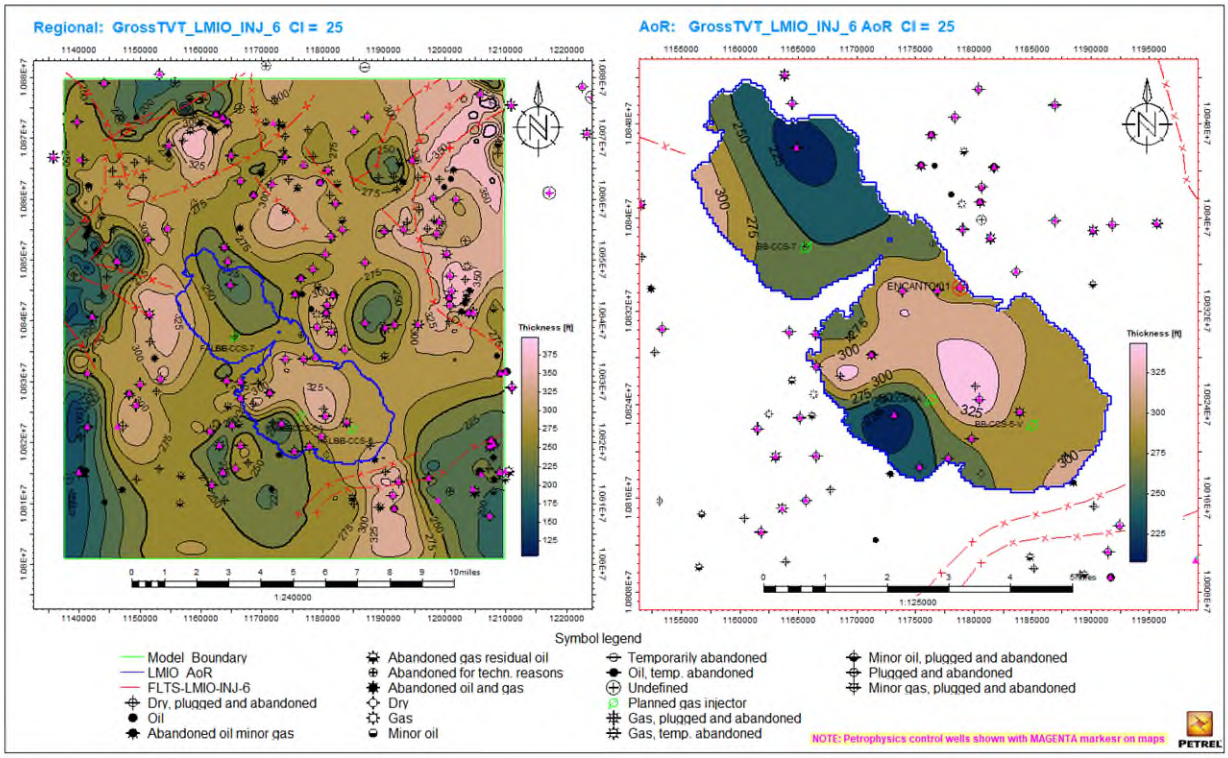


Figure AoR-114: Regional and AoR gross thickness maps of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

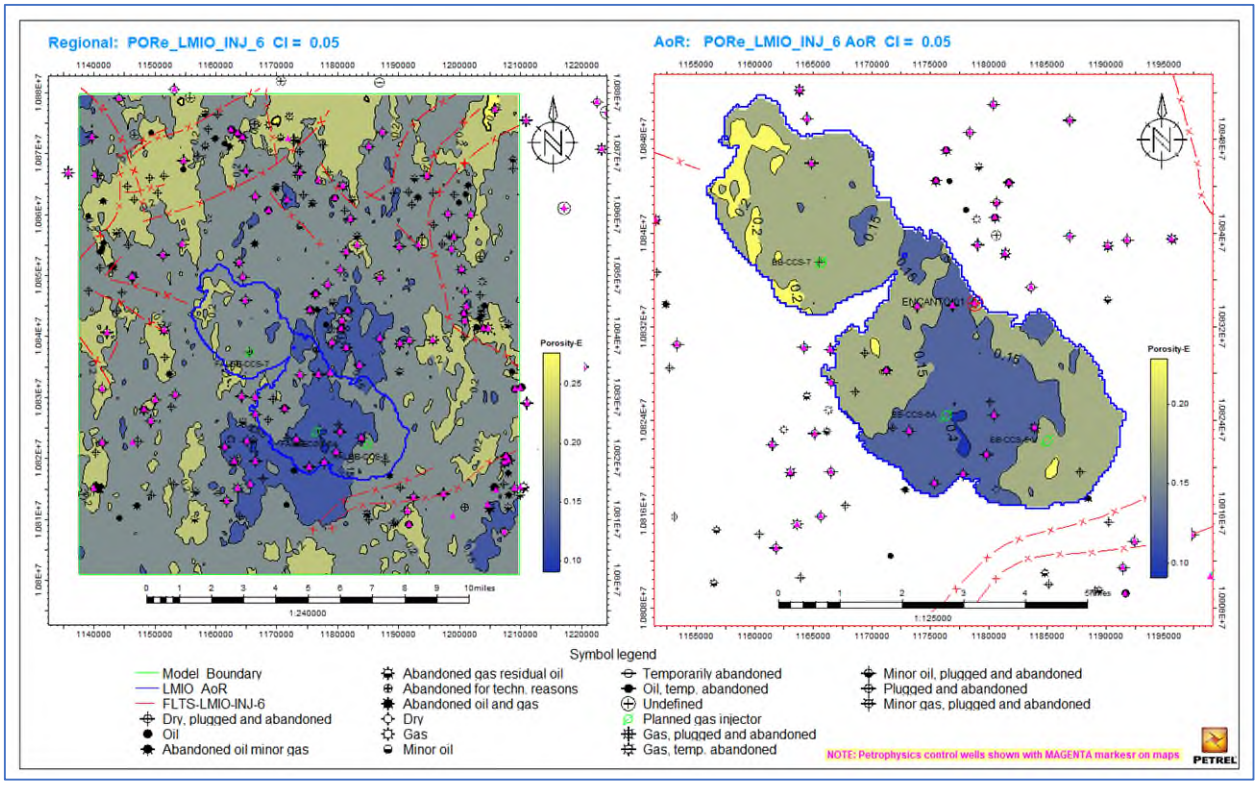


Figure AoR-115: Regional and AoR average effective porosity of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

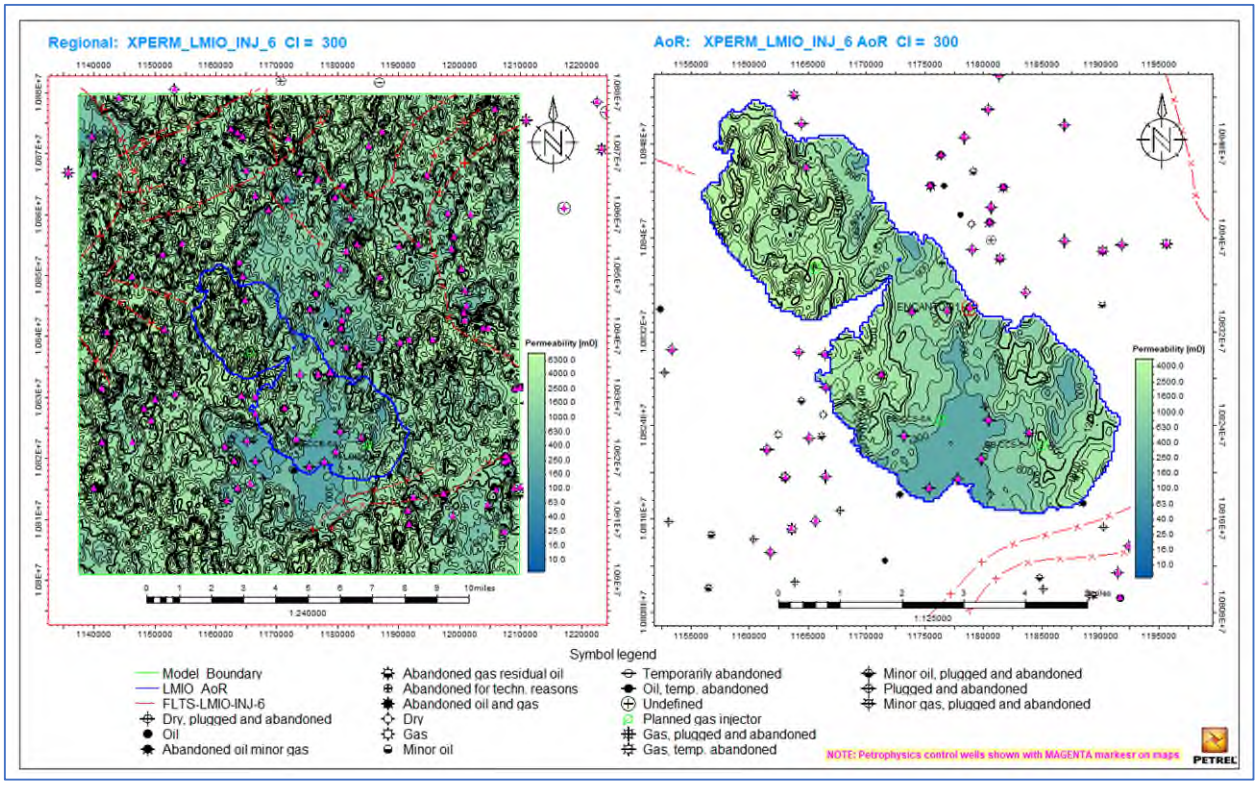


Figure AoR-116: Regional and AoR average permeability of the LMIO_INJ_6 Injection Zone, in feet, contour interval = 250 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-7: Reservoir properties for the LMIO_INJ_6 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_6 Injection Zone
Top Depth (TVDss)	Average	-5,755.42
	Minimum	-6,051.02
	Maximum	-5,322.31
Base Depth (TVDss)	Average	-6,031.88
	Minimum	-6,358.13
	Maximum	-5,581.05
Gross Thickness (ft.)	Average	276.44
	Minimum	208.08
	Maximum	343.02
Effective Porosity (fraction)	Average	0.16
	Minimum	0.09
	Maximum	0.23
Permeability (md)	Average	1,606.00
	Minimum	7.00
	Maximum	5,022.00

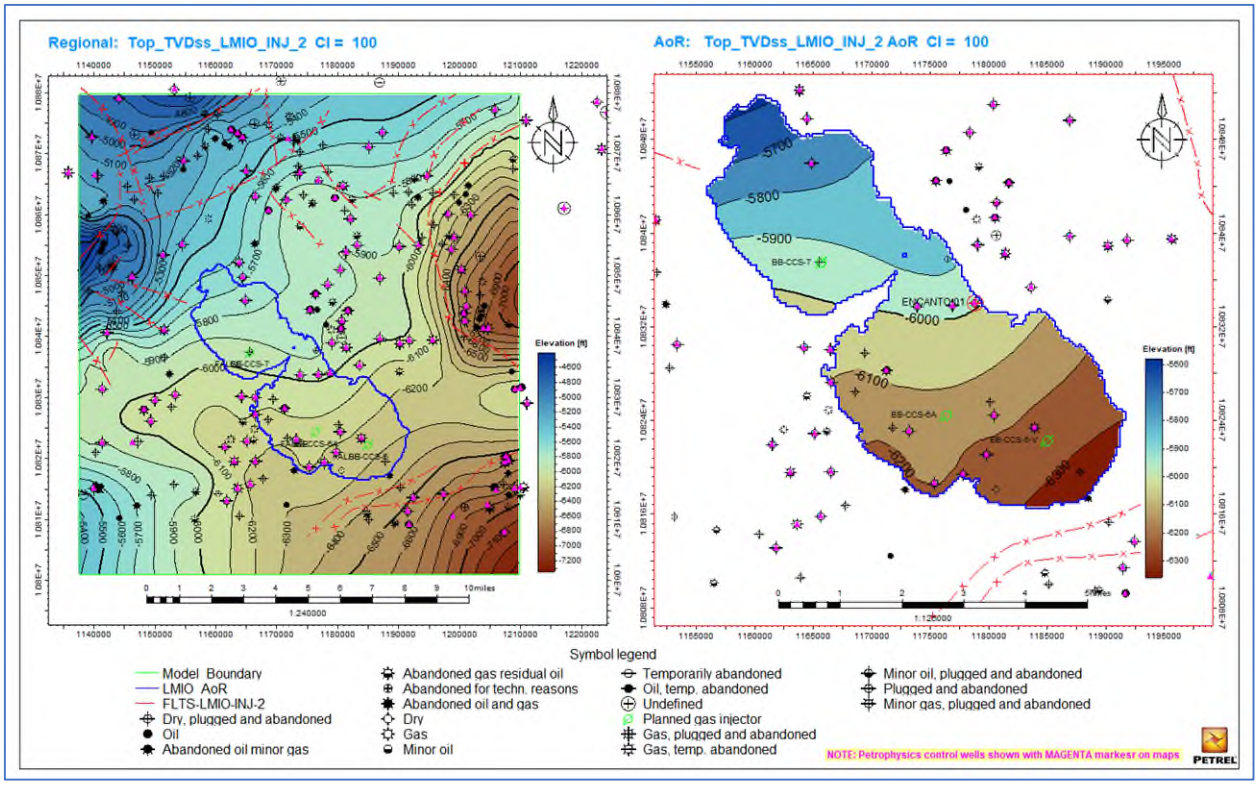


Figure AoR-117: Regional and AoR top structure maps of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

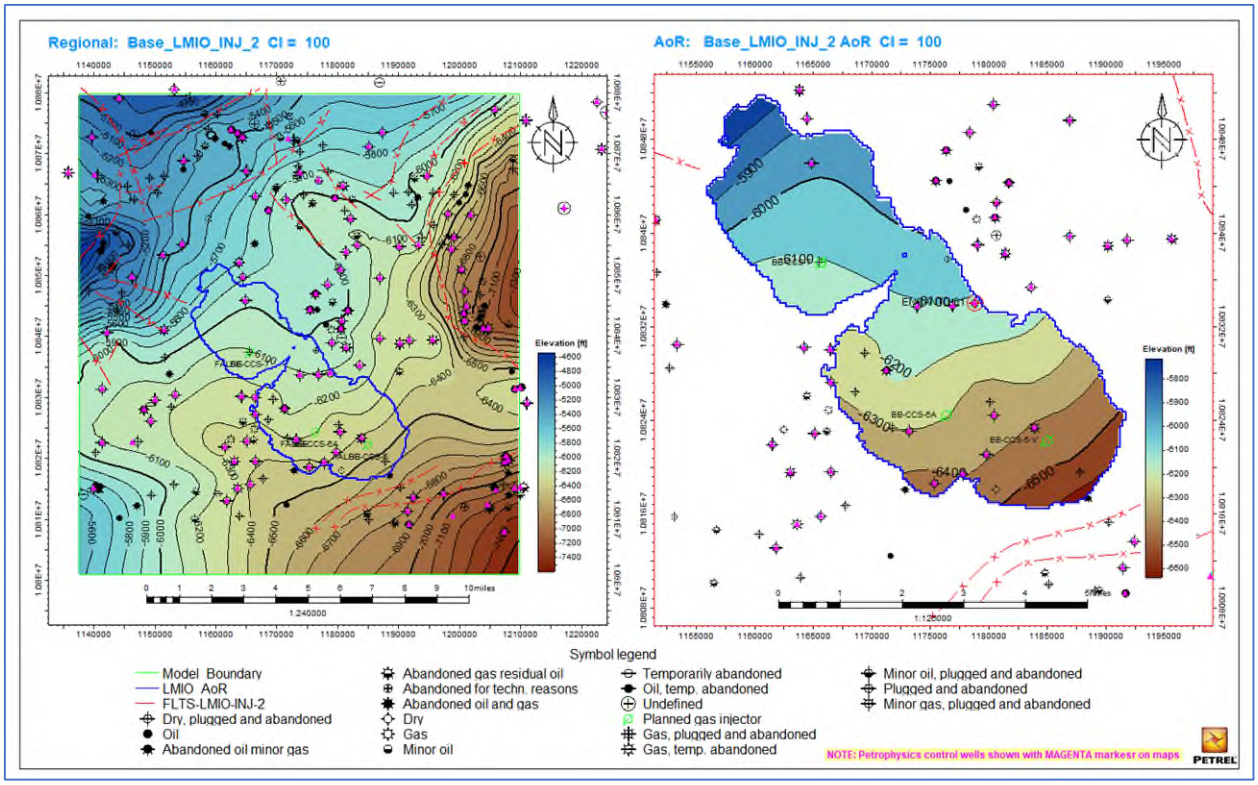


Figure AoR-118: Regional and AoR base structure maps of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

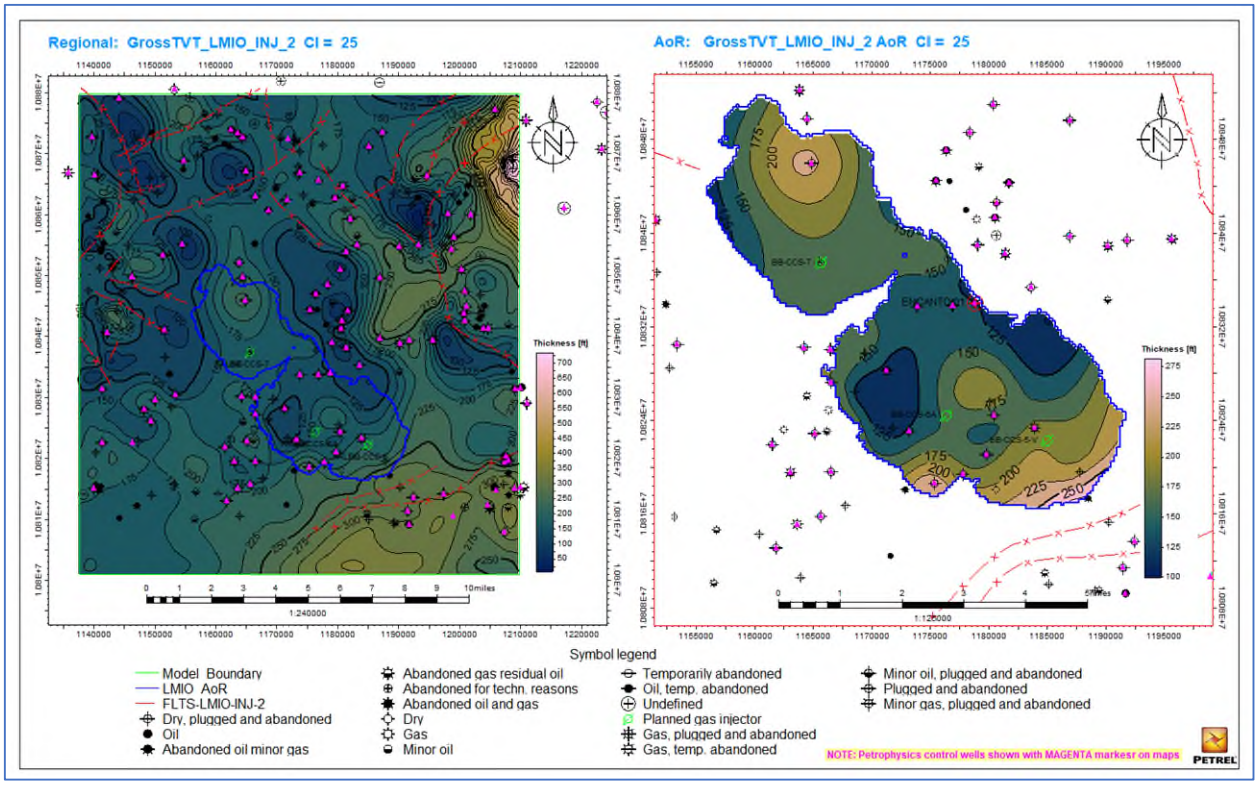


Figure AoR-119: Regional and AoR gross thickness maps of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

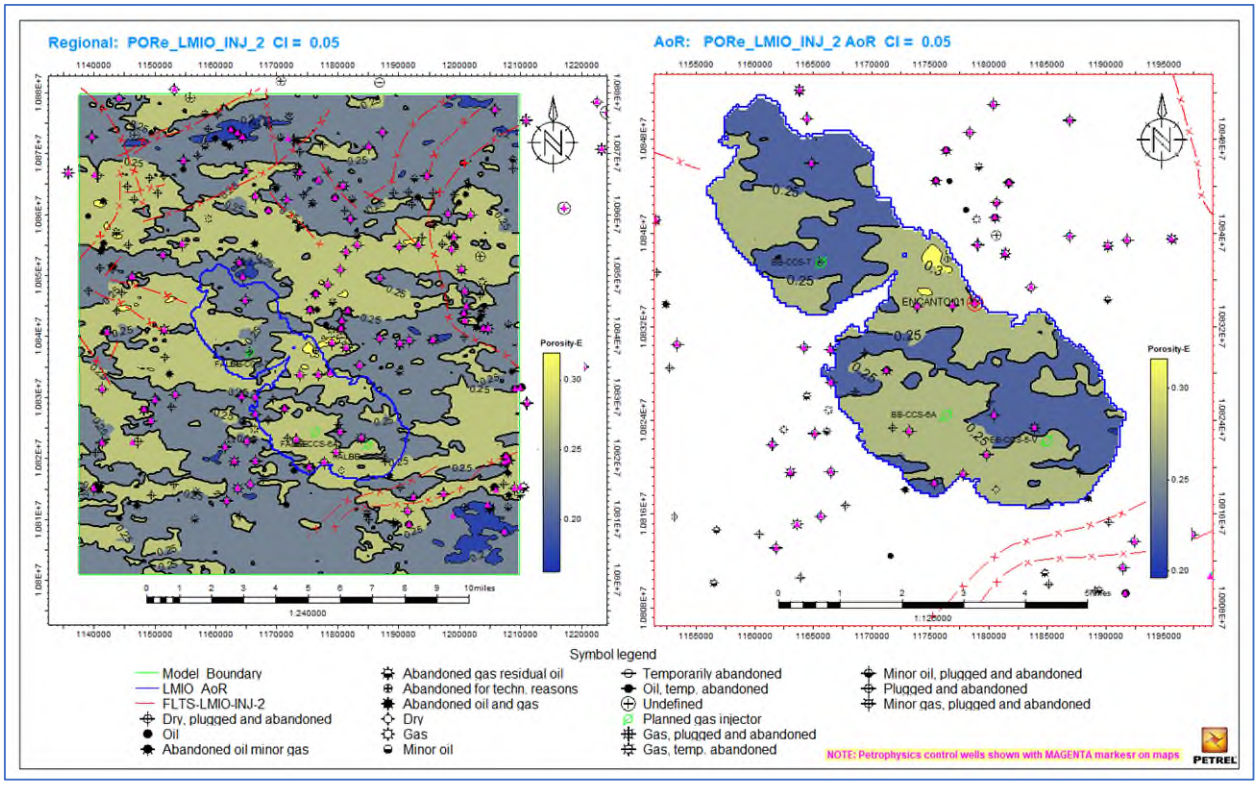


Figure AoR-120: Regional and AoR average effective porosity of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

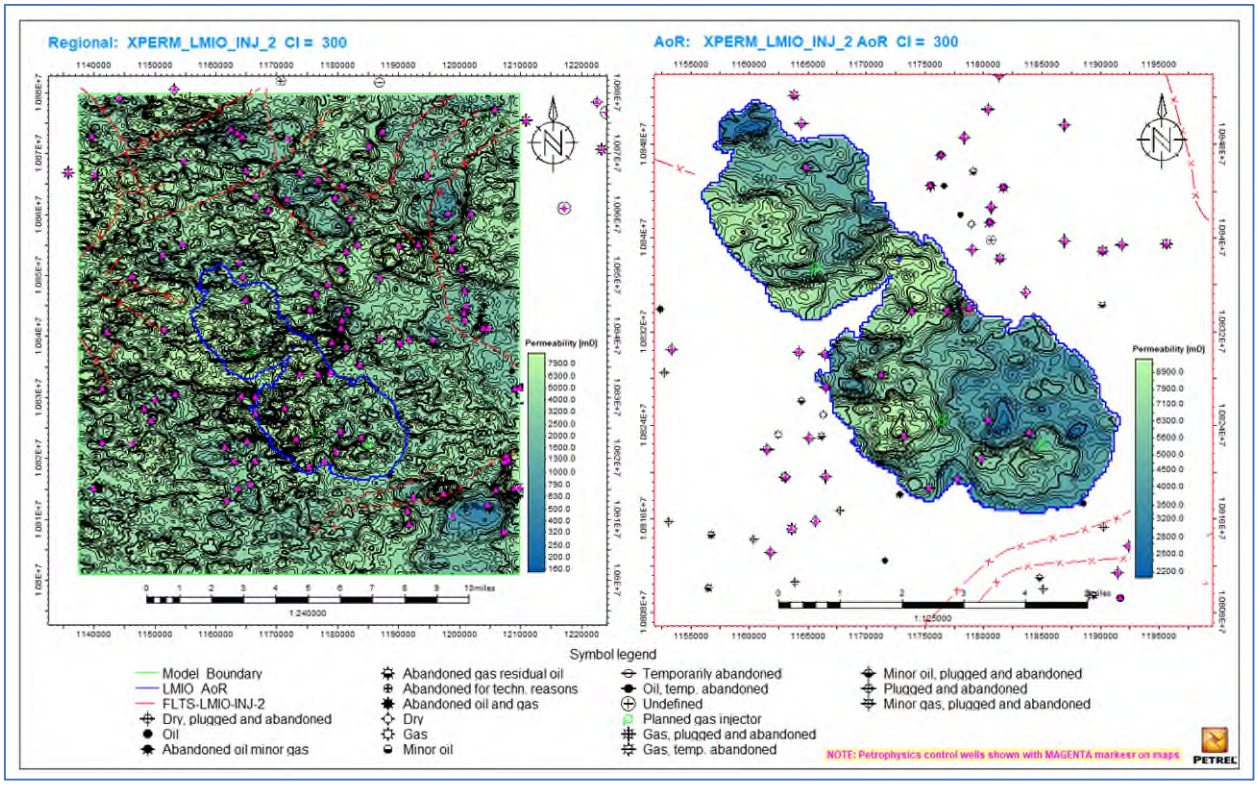


Figure AoR-121: Regional and AoR average permeability of the LMIO_INJ_2 Injection Zone, in feet, contour interval = 300 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-8: Reservoir properties for the LMIO_INJ_2 Injection Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	LMIO_INJ_2 Injection Zone
Top Depth (TVDss)	Average	-6,031.88
	Minimum	-6,358.13
	Maximum	-5,581.05
Base Depth (TVDss)	Average	-6,196.05
	Minimum	-6,636.04
	Maximum	-5,716.16
Gross Thickness (ft.)	Average	164.13
	Minimum	99.81
	Maximum	281.31
Effective Porosity (fraction)	Average	0.25
	Minimum	0.20
	Maximum	0.32
Permeability (md)	Average	5,627.00
	Minimum	2,120.00
	Maximum	9,741.00

3.8.2 AoR Confining Zone Characteristics

This section describes in detail the information related to the proposed confining zones. It describes the depths, areal extents, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection zones, including geology changes and facies based on geological cores, well logs, names, and lithology description according to 40 CFR § 1476.82 (3)(iii).

3.8.2.1 Hackberry Confining Zone

The Hackberry Confining Zone is the base confining zone for the proposed storage complex. Based on the slabbed whole core description (Appendix A core panel 7), this is dominantly a bioturbated argillaceous siltstone to silty mudstone, which was deposited in an offshore transition inner neritic depositional environment. Within the cored interval, several feet are argillaceous, very fine-grained sandstones with varying textures ranging from bioturbated or massive to horizontally laminated to low-angle cross stratified. The burrows represent a time hiatus when organisms had time to burrow into the sediment; those burrows were subsequently filled with the fine-grained

sands. Trace fossils were observed, specifically trace fossils from a lower energy setting. The clay rich shales are good baffles that compartmentalize this confining zone.

The Hackberry Confining Zone is a low-permeability (confirm with MICP and whole core, average air permeability from core is 2.4 md) confining zone that is regionally contiguous in both the north-south dip direction, as well as in the east-west strike direction. This third-order marine transgressive shale represents a time in the Oligocene when the Gulf Coast was submerged under water due to rising sea levels, which explains the lateral continuity.

3.8.2.1.*1 Petrologic description*

The associated Hackberry silty mudstones and shales were analyzed for composition, nature of the clay species, and presence of structural alignment for anisotropy evaluation. Examples are shown in Figures AoR-122 and AoR-126, which describe a silica-rich argillaceous mudstone with quartz, feldspars, rock fragments, and mica and sandy mudstone with quartz, feldspars, and volcanic rock fragments, respectively. The quartz richness in this confining unit may impact the sealing capacity because of larger pore throats 0.055 to ~ 0.4 microns in the fine sands and laminations, but the mudstone intervals with small pore throat radii between 0.001 to ~0.025 microns can act as a seal, and the combination of pore throats, will act as a confining system.

There is in general a weak alignment (anisotropy). Most clays are smectite and smectite-illite based on XRD and SEM analyses. The nature of pores including assessment of kerogen pores, if any, clay species, and structural alignment were the key objectives of SEM analysis. The intrinsic anisotropy due to clay orientation is high. The extrinsic anisotropy due to textural and mineralogical alignment is low to insignificant. Two mudstone samples were ion-milled; based on the SEM examination, sample 8455.3 ft shows no structural alignment, and 8463.70 ft displays slight textural anisotropy at thin section scale.

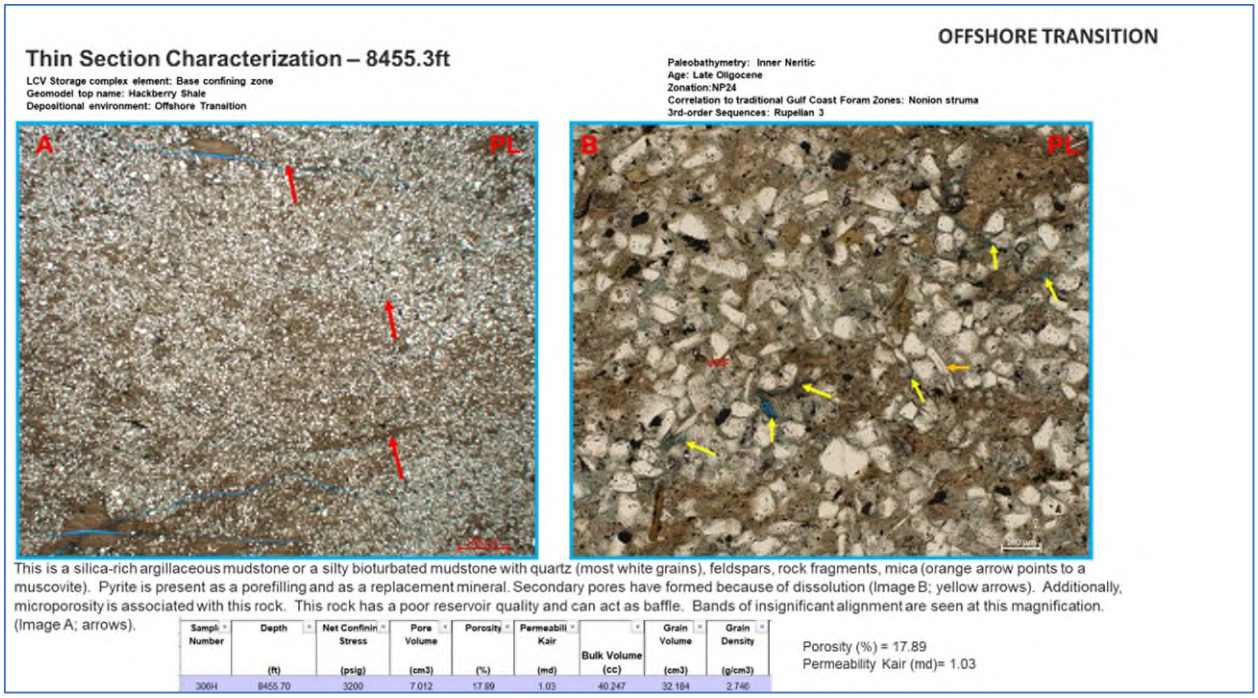


Figure AoR-122: Thin section analysis and petrologic description of the Hackberry Confining Zone.

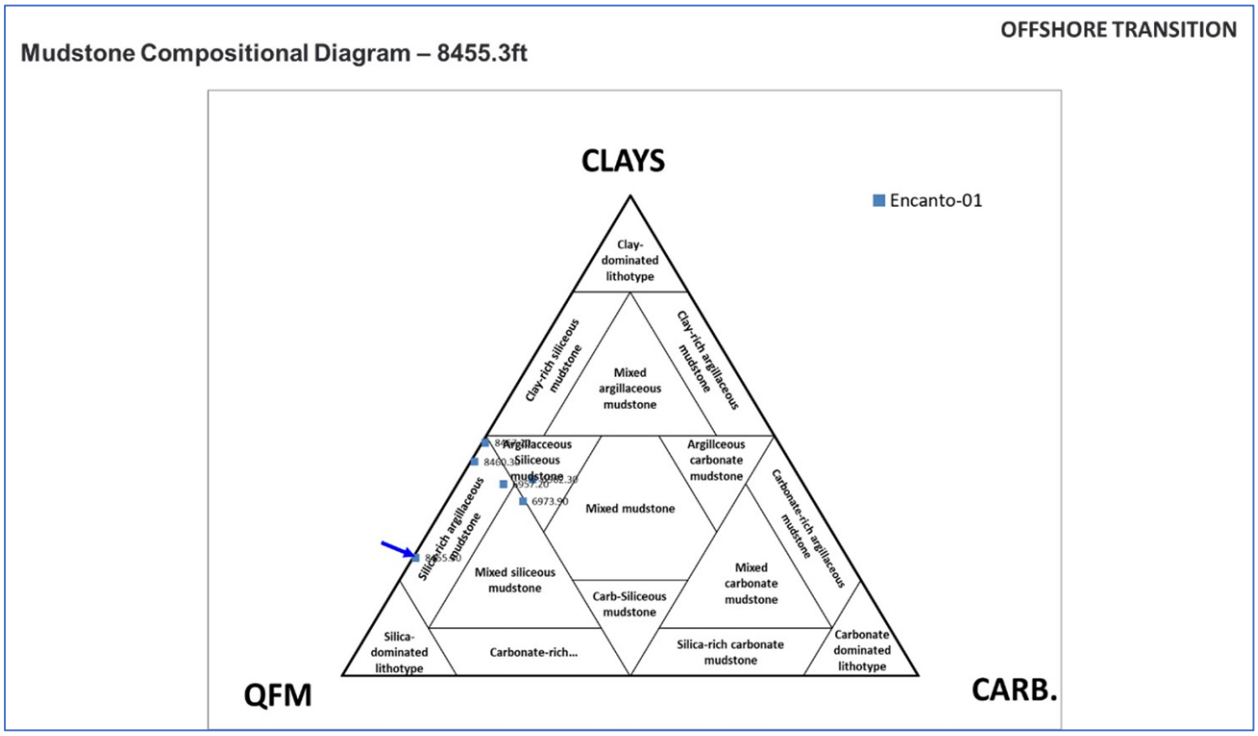


Figure AoR-123: Mudstone compositional diagram of the Hackberry Confining Zone.

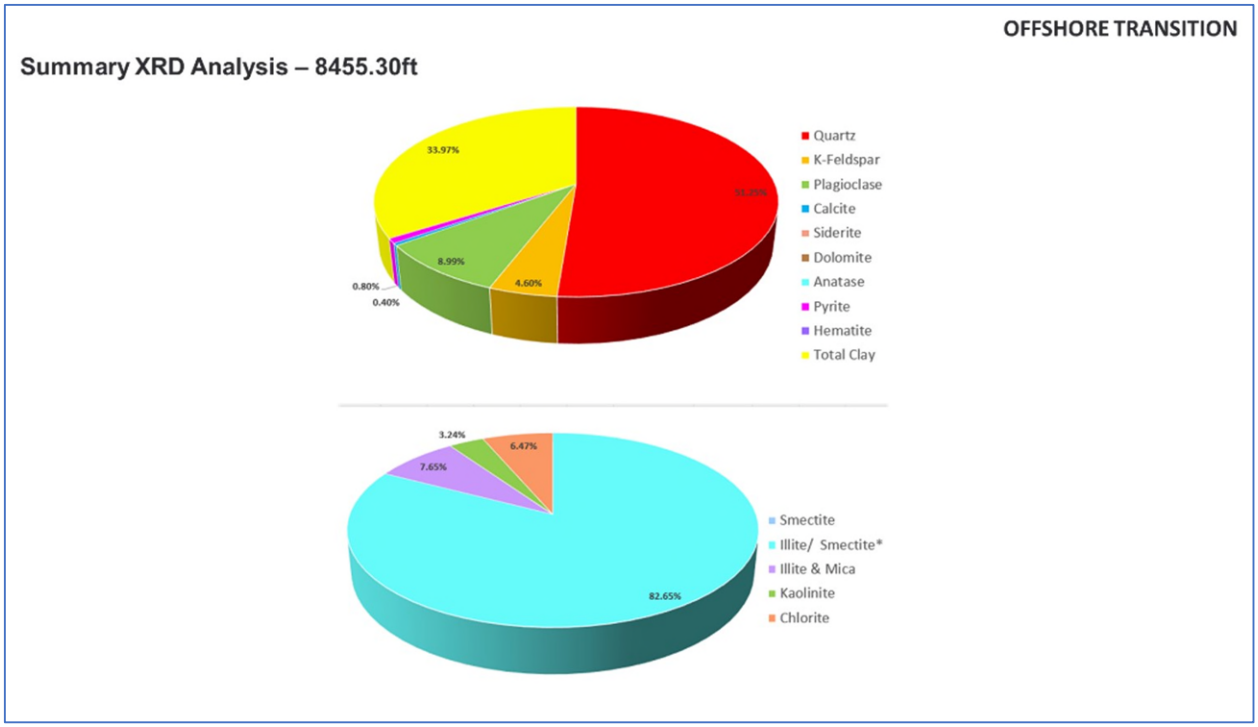


Figure AoR-124: Summary of XRD analysis of the Hackberry Confining Zone.

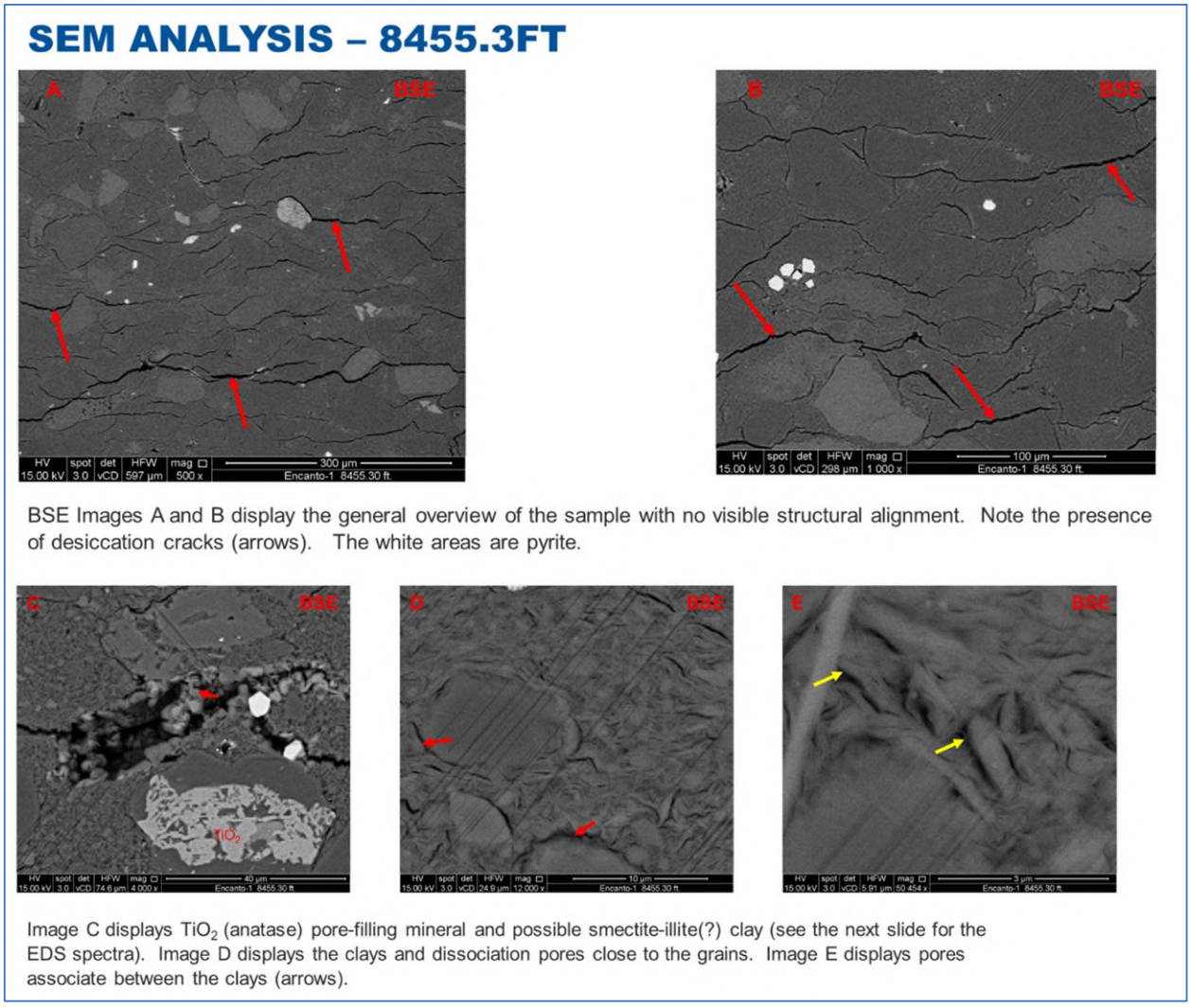


Figure AoR-125: Summary of SEM analysis of the Hackberry Confining Zone.

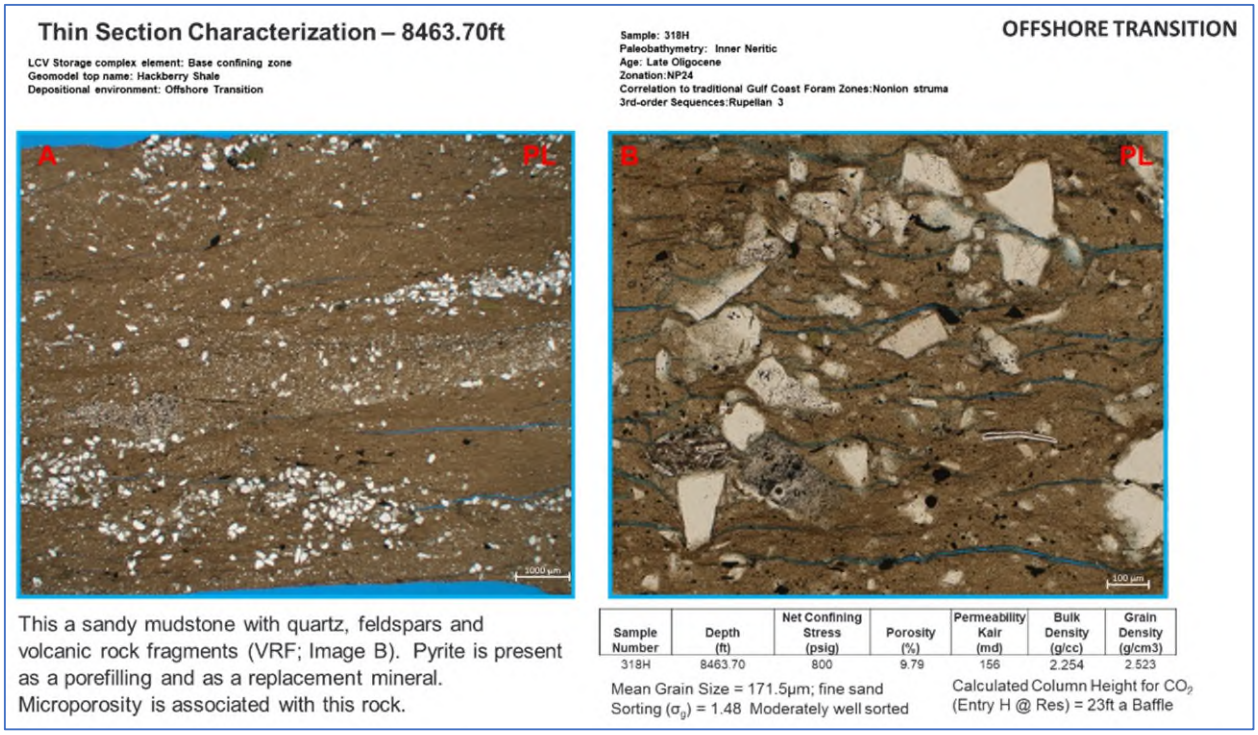


Figure AoR-126: Thin section analysis and petrologic description of the Hackberry Confining Zone.

If the mudstone was silty, thin section grain sizes were measured in addition to laser particle size distribution analysis (LPSA). As is common, 200 grains were analyzed. The MICP data were supplemented as well. An example is shown in Figure AoR-127.

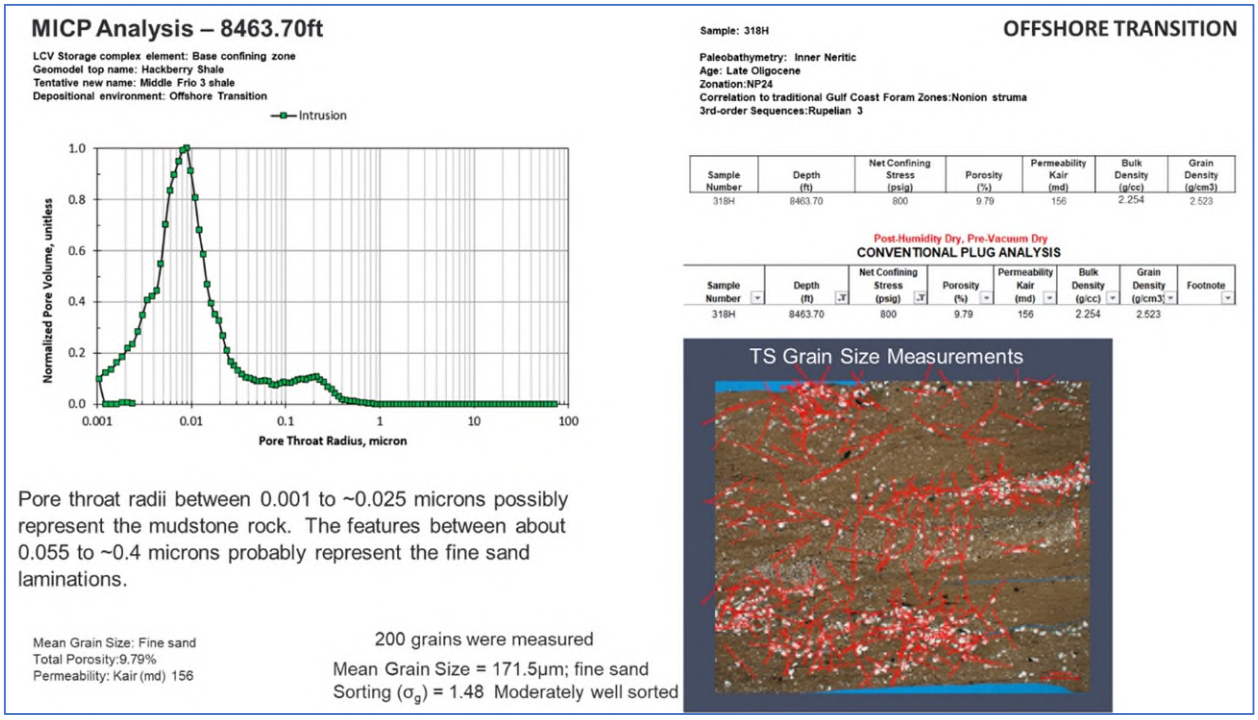


Figure AoR-127: MICP analysis of the Hackberry Confining Zone.

3.8.2.1.2 Organic petrography, maturity evaluation, and extraction for presence of oil

Based on the organic petrography and thermal alteration index (Chevron) study that Stratochem Services conducted, the Encanto 01 Hackberry shale samples selected below the injection zone are immature to marginally mature. The average %VRo =0.39%, Min=0.31%, Max=0.49%. Vitrinite Reflectance Equivalent Vre from Bitumen Reflectance: Average=0.43%, Min=0.40%, Max=0.44%. In the samples examined, both bitumen and kerogen are present. Additionally, the sample's position in the oil generation zone arrived at from Chevron TAI indicates that the kerogen is currently immature to marginally mature.

SUMMARY ORGANIC PETROGRAPHY DATA

Client: Stratochem Job#: 23EG0078

Well: Encanto-1

Table 1: Whole rock vitrinite reflectance results from cuttings

Depth (ft.)	Vitrinite reflectance equivalent VRE [1]	Standard deviation	Count	Confidence (95%)	Client ID	Sample Type	Generation zone	Thermal maturation zone	Formation	R Values (RGB)	KMI
8250.00	0.54	0.00	2	0.02	1	OXEG002034	Minor oil	Marginally mature (0.50-0.60%)	N/A	219.15	0.556
8280.00	0.51	0.01	6	0.01	2	OXEG002035	Minor oil	Marginally mature (0.50-0.60%)	N/A	205.43	0.587
8400.00	0.53	0.02	4	0.04	3	OXEG002036	Minor oil	Marginally mature (0.50-0.60%)	N/A	220.23	0.554

Depth (ft.)	% Vitrinite reflectance equivalent VRE [2]	Standard deviation	Count	Confidence (95%)	Client ID	Sample Type	Generation zone	Thermal maturation zone	Formation
8250.00	0.45	0.00	2	0.03	1	OXEG002034	No generation	Immature (< 0.50%)	N/A
8280.00	0.41	0.01	6	0.01	2	OXEG002035	No generation	Immature (< 0.50%)	N/A
8400.00	0.43	0.03	4	0.05	3	OXEG002036	No generation	Immature (< 0.50%)	N/A

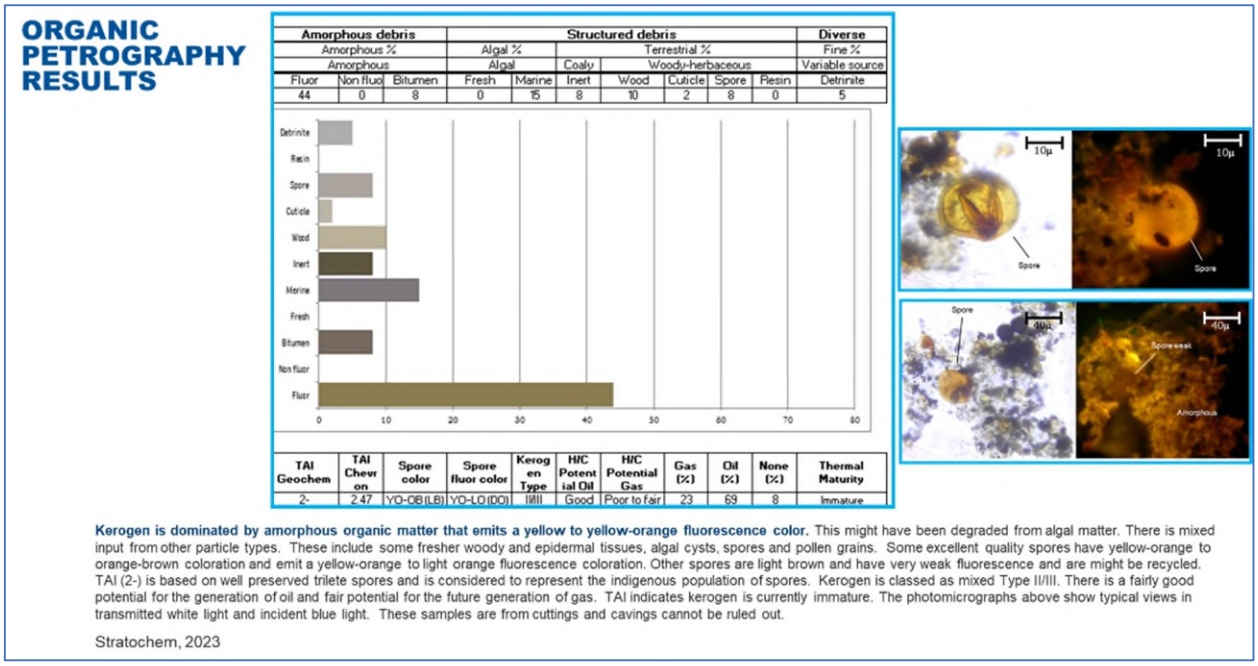
Depth (ft.)	Vitrinite reflectance (%Ro)	Standard deviation	Count	Confidence (95%)	Client ID	Sample Type	Generation zone	Thermal maturation zone	Formation
8250.00	0.49	0.01	2	0.10	1	OXEG002034	No generation	Immature (< 0.50%)	N/A
8280.00	0.31	0.06	13	0.04	2	OXEG002035	No generation	Immature (< 0.50%)	N/A
8400.00	0.37	0.06	10	0.04	3	OXEG002036	No generation	Immature (< 0.50%)	N/A

VRE [1] calculated from solid bitumen reflectance using the formula of Jacob, 1989

VRE [2] calculated from solid bitumen reflectance using the formula of Schoenherr et al., 2007

Data from Stratochem, 2023

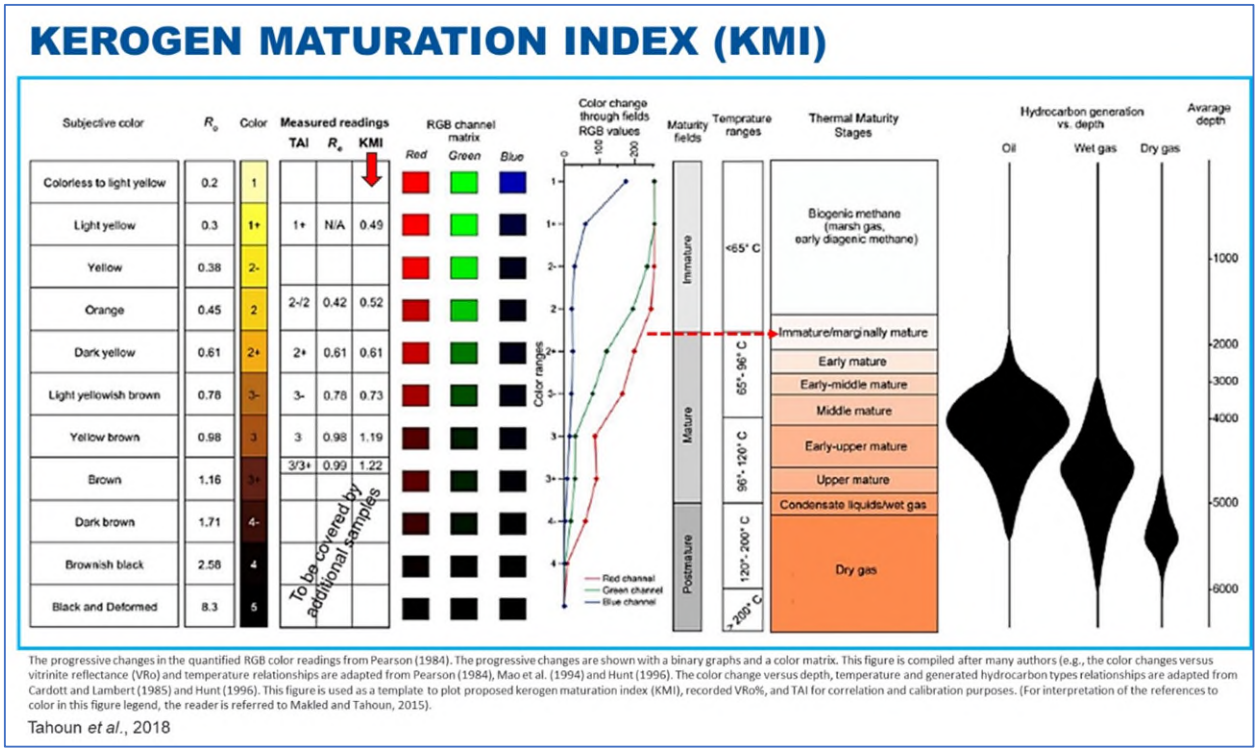
Figure AoR-128: Summary of organic petrographic analysis of selected Hackberry shale samples listing vitrinite reflectance, thermal maturation zone and Kerogen Maturation Index.



Kerogen is dominated by amorphous organic matter that emits a yellow to yellow-orange fluorescence color. This might have been degraded from algal matter. There is mixed input from other particle types. These include some fresher woody and epidermal tissues, algal cysts, spores and pollen grains. Some excellent quality spores have yellow-orange to orange-brown coloration and emit a yellow-orange to light orange fluorescence coloration. Other spores are light brown and have very weak fluorescence and are might be recycled. TAI (2-) is based on well preserved trilete spores and is considered to represent the indigenous population of spores. Kerogen is classed as mixed Type II/III. There is a fairly good potential for the generation of oil and fair potential for the future generation of gas. TAI indicates kerogen is currently immature. The photomicrographs above show typical views in transmitted white light and incident blue light. These samples are from cuttings and cavings cannot be ruled out.

Stratochem, 2023

Figure AoR-129: Summary of organic petrographic analysis describing the analyzed kerogen in selected Hackberry shale samples.



The progressive changes in the quantified RGB color readings from Pearson (1984). The progressive changes are shown with a binary graphs and a color matrix. This figure is compiled after many authors (e.g., the color changes versus vitrinite reflectance (VRo) and temperature relationships are adapted from Pearson (1984), Mao et al. (1994) and Hunt (1996). The color change versus depth, temperature and generated hydrocarbon types relationships are adapted from Cardott and Lambert (1985) and Hunt (1996). This figure is used as a template to plot proposed kerogen maturation index (KMI), recorded VRo%, and TAI for correlation and calibration purposes. (For interpretation of the references to color in this figure legend, the reader is referred to Makled and Tahoun, 2015).

Tahoun *et al.*, 2018

Figure AoR-130: Kerogen Maturation Index (KMI) analysis of selected Hackberry shale samples.

The hydrocarbon potential of the samples for oil is fair to good. Furthermore, the kerogen type is dominantly II/III, but the zones examined are too immature to have generated any oil or gas. It should be noted that the section was drilled with synthetic oil-based mud (OBM), precluding pyrolytic analysis on any free *in-situ* hydrocarbons. Mud extract gas chromatograms are shown depicting the OBM contamination, which is also shown to be present in the cuttings and core samples.

3.8.2.1.3 Contamination of the rock by synthetic oil-based mud

However, if there was oil in the zone, it would be noticed even with the OBM. In order to confirm that any "oil" in the cuttings was due to the synthetic oil-based mud, four cutting samples were quantitatively extracted with dichloromethane to remove all soluble organic matter, and the extracted material was analyzed by gas chromatography (GC). The four extract GCs are shown below and are identical to the synthetic oil added to the drilling mud (refer to Appendix E); the OBM contaminants tower above any indigenous hydrocarbons. This proves that there was no indigenous oil-like material in the cuttings. Therefore, indigenous "oil" in this zone is not present in measurable quantities. Given the low thermal maturity, this is not surprising.

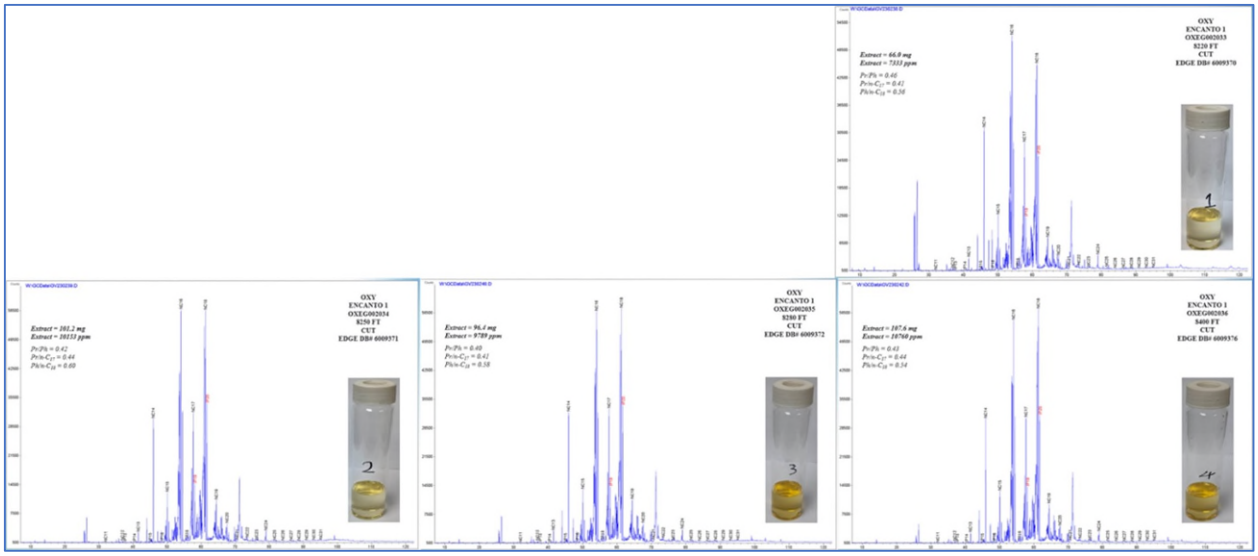


Figure AoR-131: Gas chromatography analysis of selected Hackberry shale samples showing contamination by synthetic oil-based drilling mud.

3.8.2.1.4 Seal Analysis

There are six samples with MICP (Mercury Injection Capillary Pressure) in the Hackberry Confining Zone; three from vertical and three horizontals whole core plugs. Following a conservative approach (please see Appendix A for a more detailed analysis), the displacement pressure criteria will need an injection height of ~1380 feet before breaking in the confining zone. These results will be corroborated/calibrated to TEP (Threshold Entry Pressure) test results.

3.8.2.1.5 Hackberry Confining Zone Maps

The Hackberry confining zone maps are shown below.

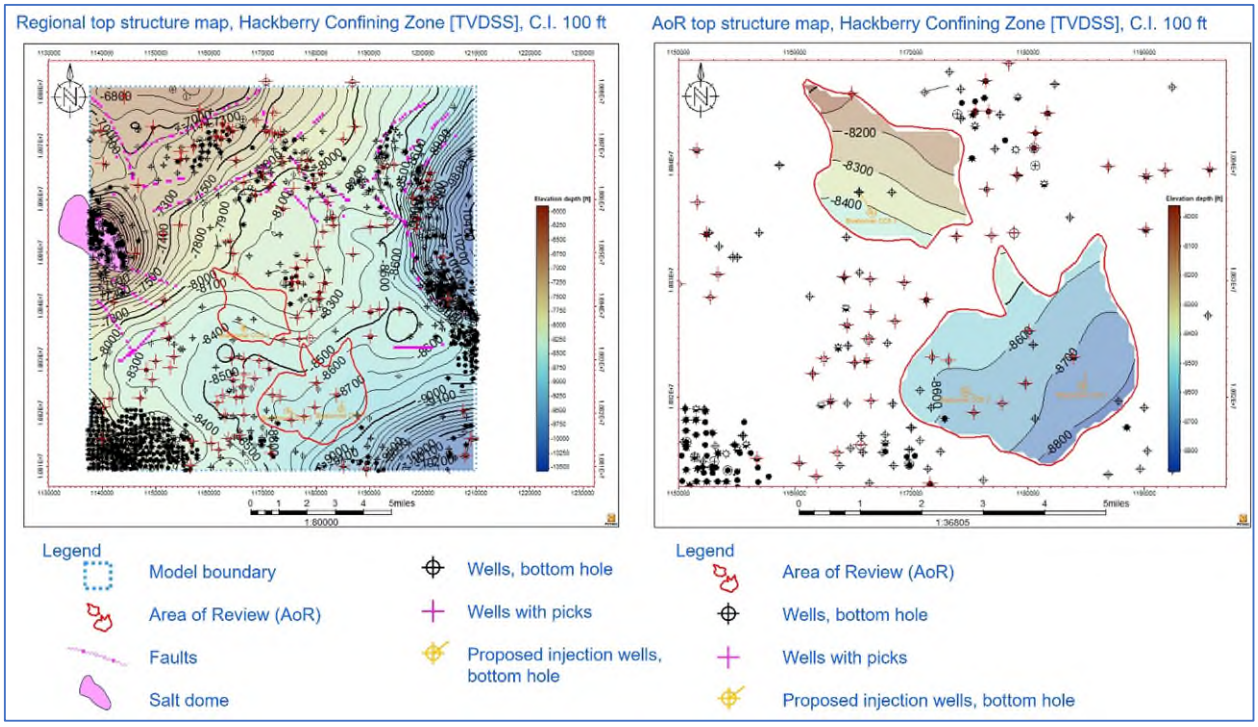


Figure AoR-132: Regional and AoR top structure map of the Hackberry Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

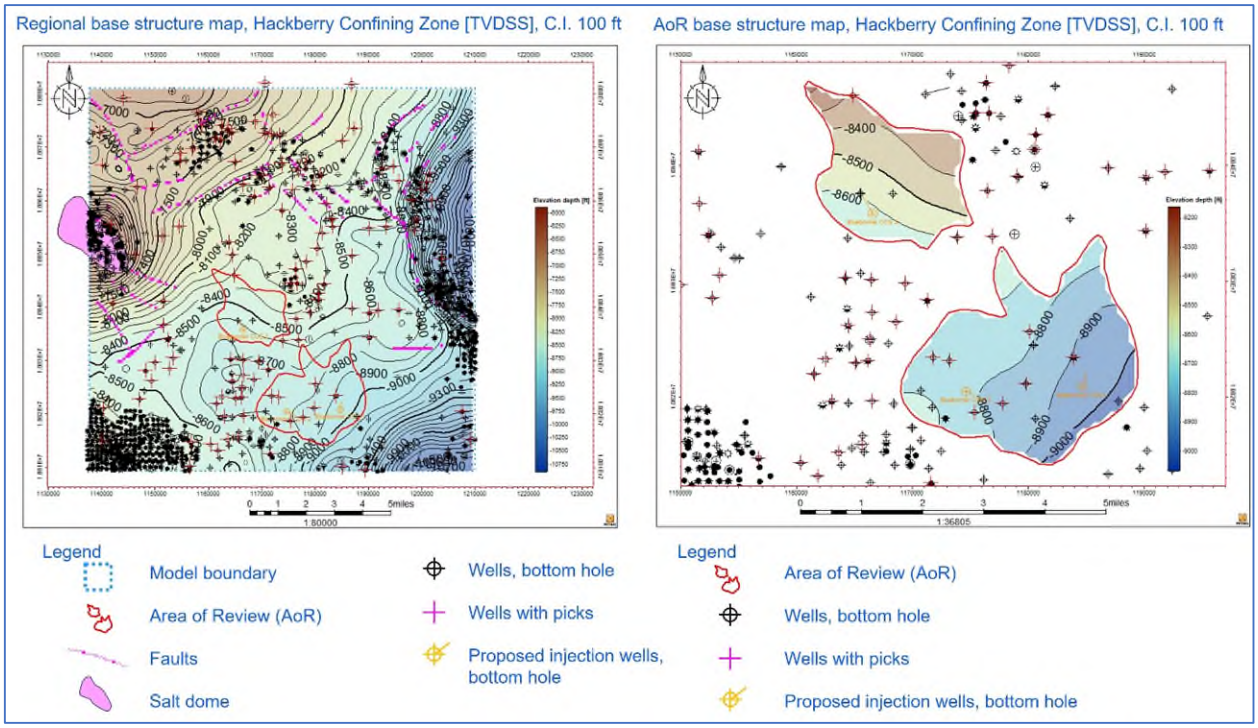


Figure AoR-133: Regional and AoR base structure map of the Hackberry Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

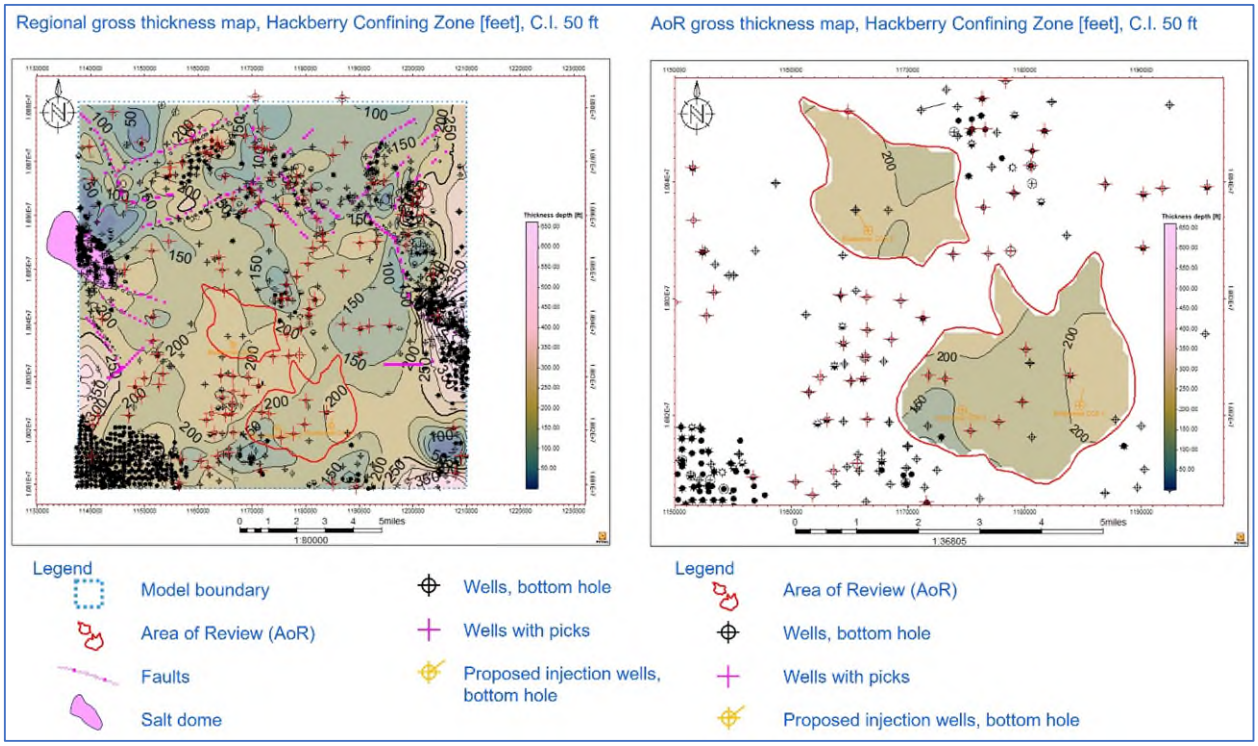


Figure AoR-134: Regional and AoR gross thickness map of the Hackberry Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

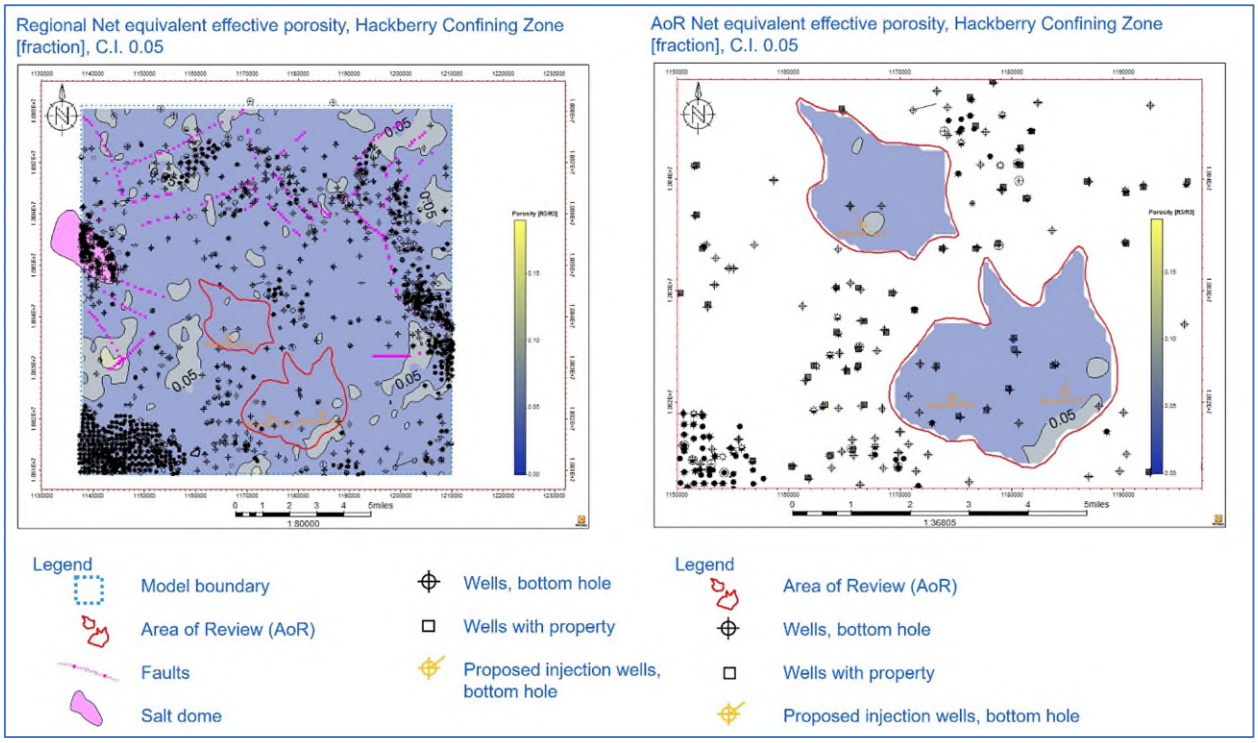


Figure AoR-135: Regional and AoR net equivalent effective porosity map of the Hackberry Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

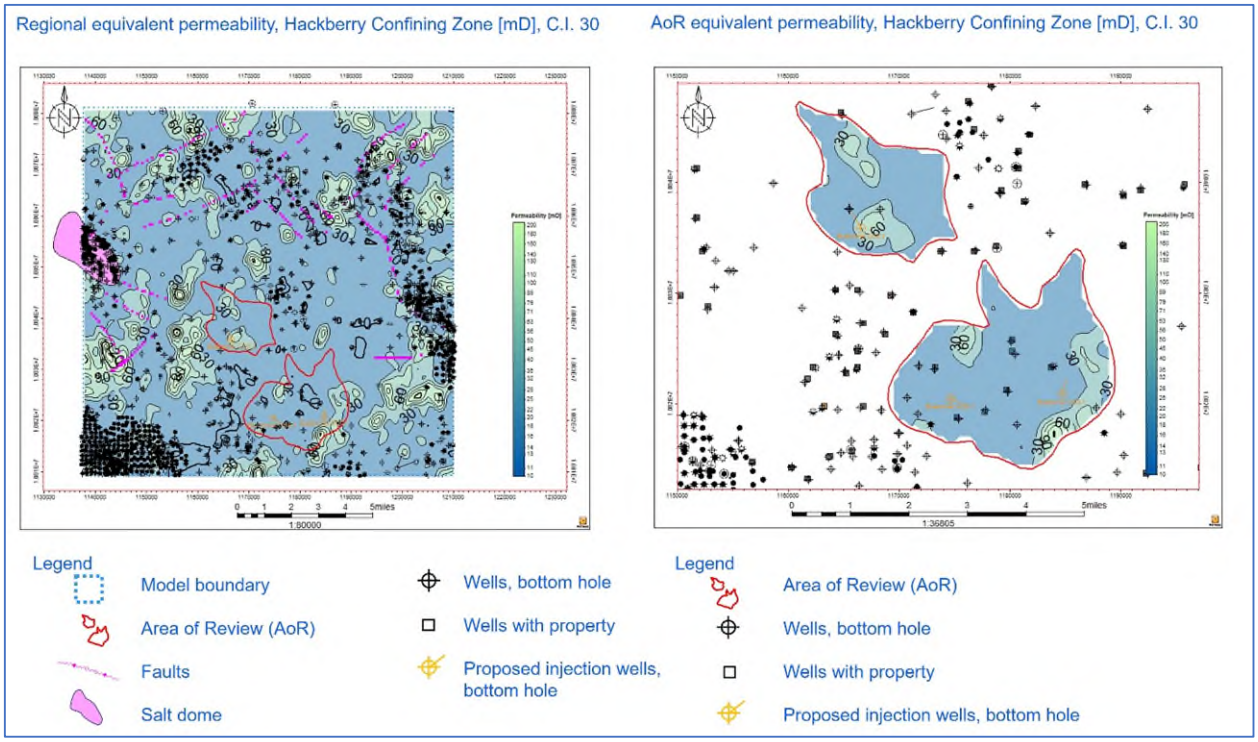


Figure AoR-136: Regional and AoR equivalent permeability map of the Hackberry Confining Zone in millidarcy (md), contour interval 30 md. The average permeability in the Hackberry Confining Zone across the AoR is driven by a lack of data points and can be misleading. This map was generated from the Oligocene Model described under 4.0.

The following numbers represent map-based average numbers extracted from the geomodel over the AoR. The localized permeability bullseyes in the Hackberry Confining Zone across the AoR are driven by a lack of data points, where the model predicts porosity and estimates permeability but has no actual control points. Therefore, the resulting permeability maps look patchy in this zone, which is not substantiated with well control and not accurate. The permeability map, however, does show low permeability values where data points do exist, which correlates with permeability measurements from core.

Table AoR-9: Reservoir properties for the Hackberry Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Confining Zone
Top depth [TVDSS]	Minimum	-8,869
	Maximum	-7,961
	Average	**-8,523**
Base depth [TVDSS]	Minimum	-9,068
	Maximum	-8,161
	Average	**-8,717**

Reservoir properties in AoR	Extracted map values from geomodel	Hackberry Confining Zone
Gross Thickness [ft]	Minimum	93.87
	Maximum	229.01
	Average	**193**
Porosity [fraction] EQI, net eff. Porosity * NTG	Minimum	0
	Maximum	0.09
	Average	**0.02**
Permeability [md]	Minimum	0
	Maximum	152
	Average	**18**

3.8.2.2 Frio Confining Zone

After the sandstones of the Hackberry Injection Zone were deposited, another sea level rise followed that flooded the northern Gulf Coast of Texas and resulted in another laterally contiguous shale called the Frio Confining Zone. This shale provides the top confining zone for the Hackberry Injection Zone below as well as the base confining zone for the Frio Injection Zone above. As such, it is an intraformational confining zone in between two vertically stacked injection zones of the Hackberry and Frio.

The Frio Confining Zone can be mapped laterally in both the north-south dip and east-west strike direction. The SP log character stands out as a blocky shale in between the Hackberry sandstones below and Frio sandstones above. The gross thickness map shows shale thickening towards the south and downdip along with a decrease in thickness towards the north and updip which is a function of water depth during a marine transgression of the gently dipping Gulf Coast. Based on a sequence stratigraphic approach, the Frio Confining Zone represents a third-order shale-prone transgressive system tract (TST), which is overlain by the sand-prone third order highstand system tract (HST) fluvio-deltaic Frio Injection Zone.

The lithologic composition of the Frio Confining Zone is described below based on mud cuttings acquired during drilling operations of the stratigraphic test well Encanto 01 and mudlogs from two legacy wells nearby:

The Frio Confining Zone lithology shows 80-100% light to dark grey and blue to green shale, soft to poorly-moderately firm and brittle, subblocky to subplaty and splintery, massive, dull, predominantly very clay-rich with traces of brown red to purple minerals, traces of calcite containing 0-20% minor soft and ashy intervals, light to dark grey and translucent clear silty sand, very fine-grained, poorly consolidated to moderately cemented with silty argillaceous matrix, very poorly sorted, traces of calcite, limestone, and glauconite. No visible hydrocarbon cut, hydrocarbon, or mineral fluorescence were observed during mudlogging this interval.

3.8.2.2.1 Petrologic Description

Based on cuttings and XRD (see Appendix A), these are clay-rich mudstones with components of quartz, plagioclase, calcite, and K-feldspar with traces of pyrite, siderite, and anatase. XRD on the clay fraction determined that the clays are dominantly illite-smectite and minor kaolinite, illite+mica, and chlorite. The quartz weight percent varies and is reflective of isolated thin, approximately 2 ft thick, siltier stringers within the Frio Confining Zone, which can also be recognized on SP logs. Those intervals contain porosity but are surrounded by hundreds of feet of clay-rich transgressive muds.

3.8.2.2.3 Frio Confining Zone Maps

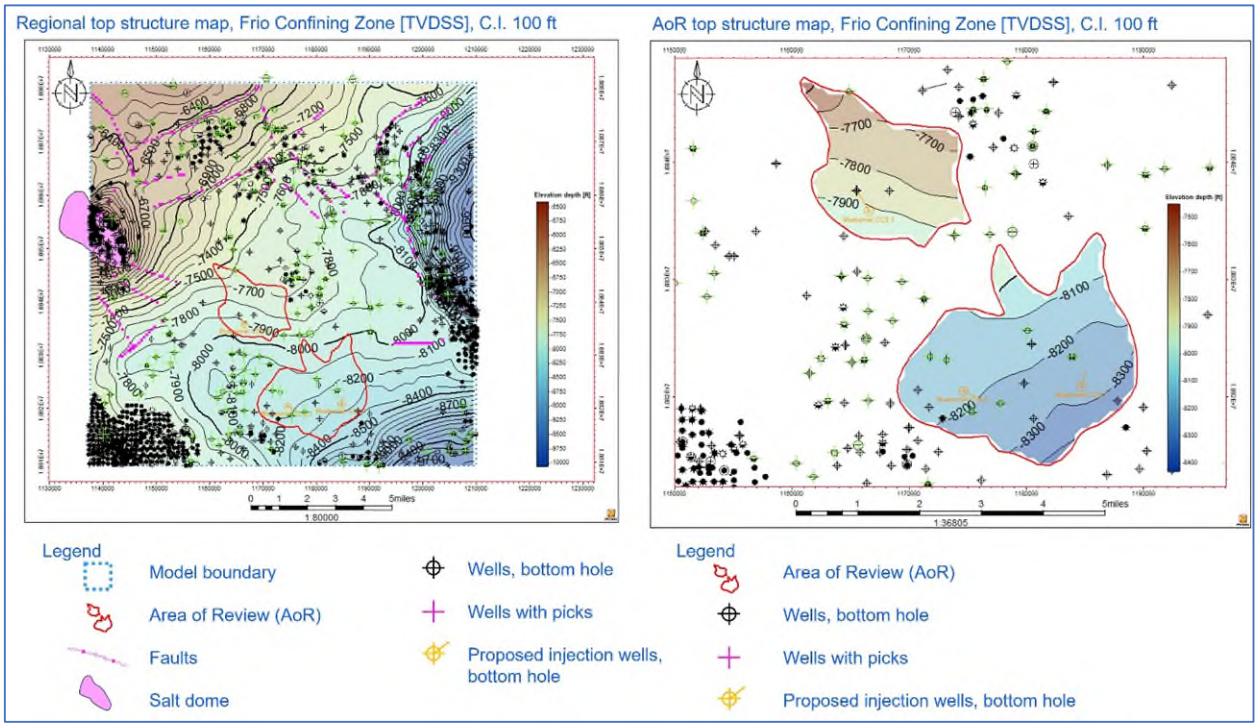


Figure AoR-137: Regional and AoR top structure map of the Frio Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

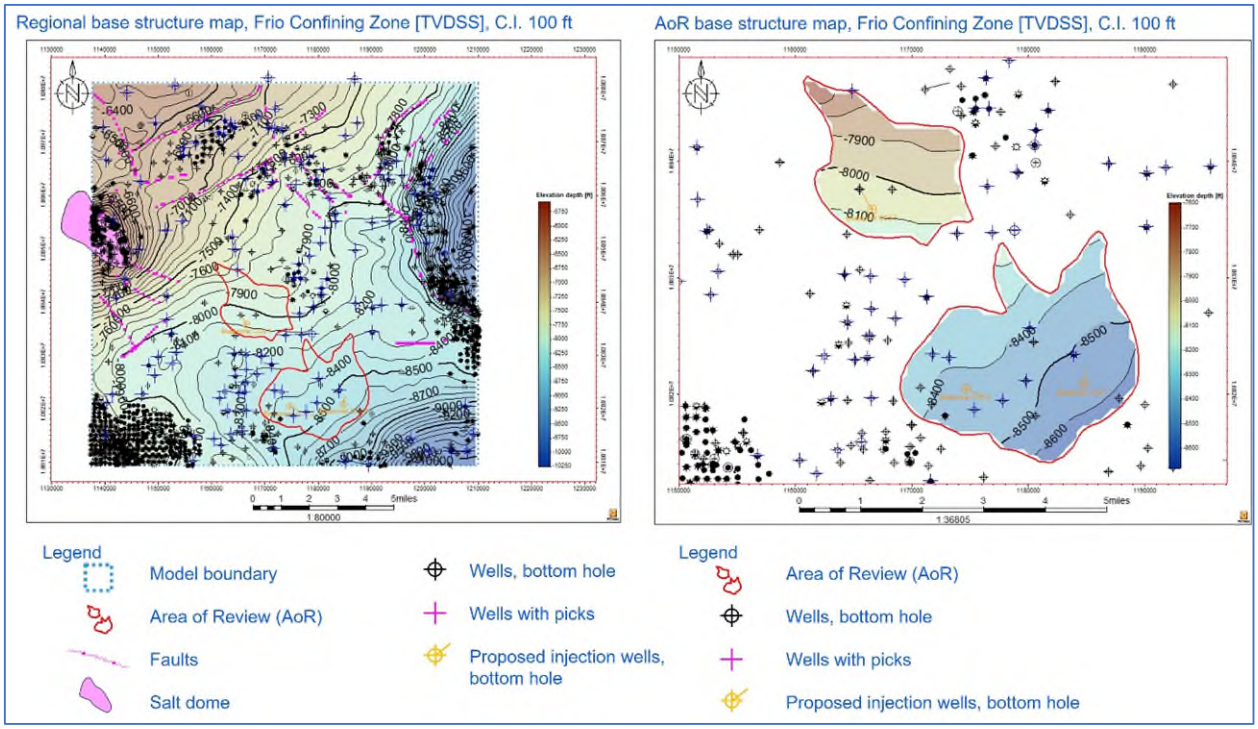


Figure AoR-138: Regional and AoR base structure map of the Frio Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

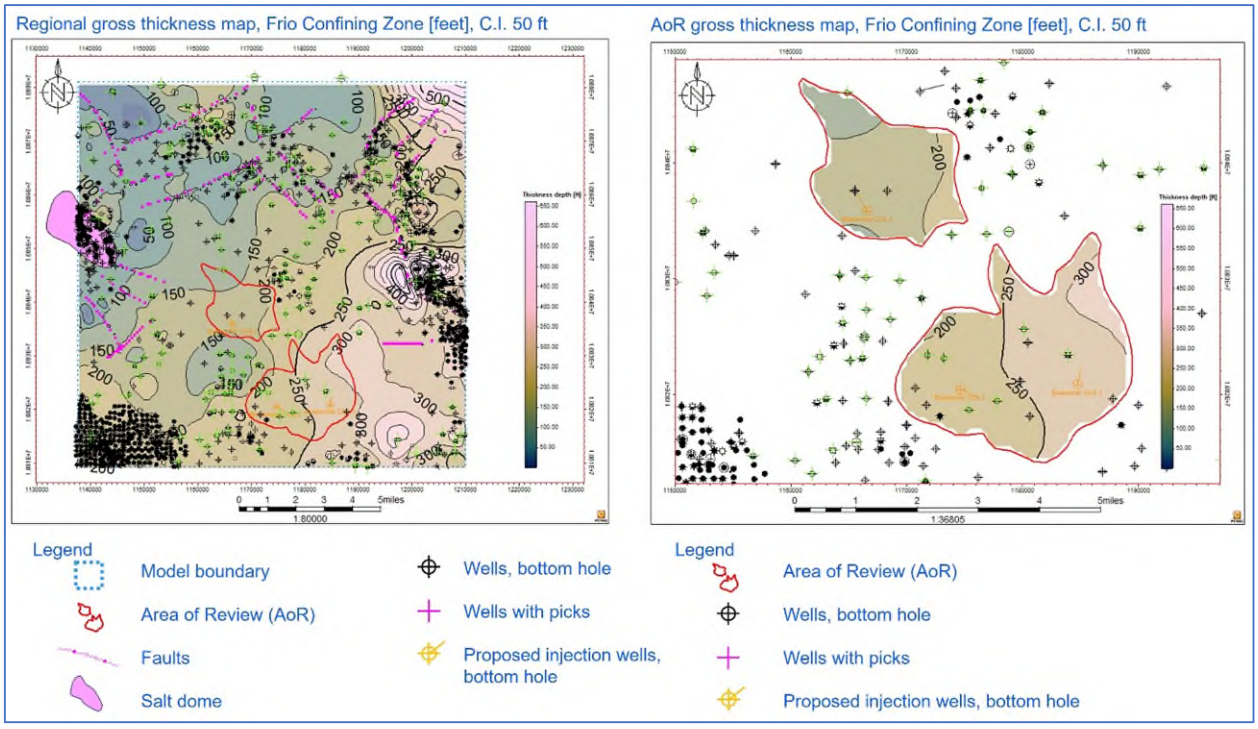


Figure AoR-139: Regional and AoR gross thickness map of the Frio Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

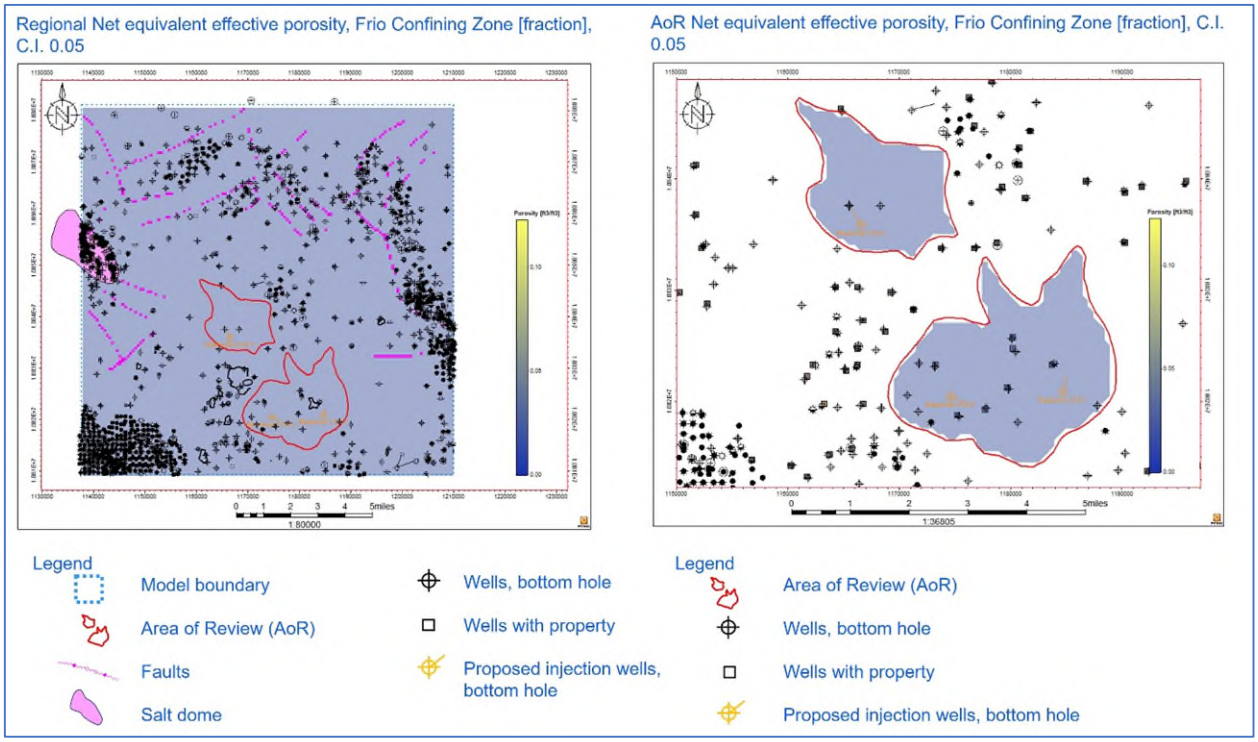


Figure AoR-140: Regional and AoR net equivalent effective porosity map of the Frio Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

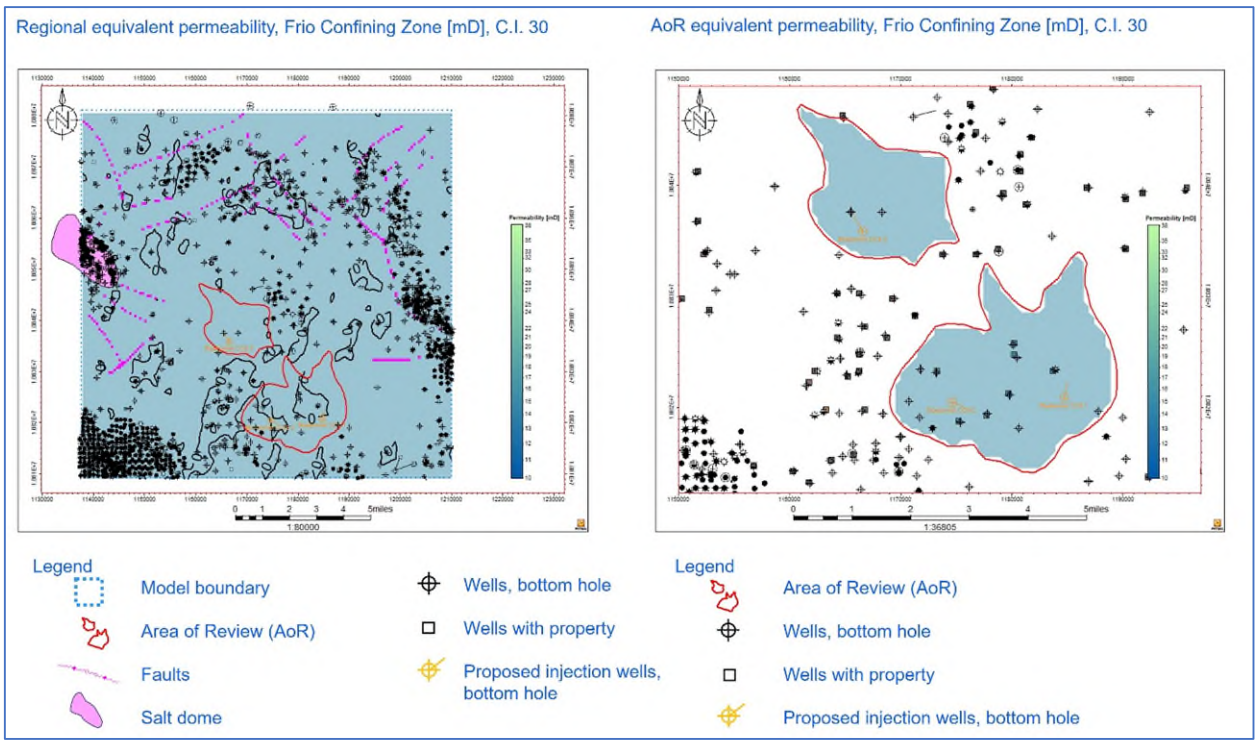


Figure AoR-141: Regional and AoR equivalent permeability map of the Frio Confining Zone in millidarcy (md), contour interval 30 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-10 represent map based average numbers extracted from the geomodel over the AoR.

Table AoR-10: Reservoir properties for the Frio Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Frio Confining Zone
Top Depth [TVDSS]	Minimum	-8,431
	Maximum	-7,451
	Average	**-8,057**
Base Depth [TVDSS]	Minimum	-8,683
	Maximum	-7,598
	Average	**-8,286**
Gross Thickness [ft]	Minimum	118.29
	Maximum	312.25
	Average	**229**
Porosity [fraction] EQI, net eff. Porosity * NTG	Minimum	0
	Maximum	0.01
	Average	**0**
Permeability [md]	Minimum	0
	Maximum	12
	Average	**2**

3.8.2.3 Anahuac Confining Zone

The Anahuac Confining Zone is a low-permeability primary confining zone that is regionally contiguous in both the north-south dip direction as well as in the east-west strike direction beyond the limits of the AoR. This is due to the nature of a major marine transgression on a passive continental margin, where sea level changes affect large areas. As mentioned under Section 3.6, the Anahuac Confining Zone is a well-known stratigraphic seal along the northern Texas Gulf Coast that is interbedded with calcareous and siliciclastic strata.

The Anahuac Confining Zone is 1074 ft thick inside the proposed AoR and two 30-ft cores were collected in the stratigraphic test well Encanto 01 well (Appendix A).

The Anahuac Confining Zone is composed of a Lower Anahuac Confining Zone with a better sealing capacity (390 ft thick) and an Upper Anahuac Confining Zone (684 ft thick). The properties measured in the lab seem to be correlated to the depositional environment.

The Lower Anahuac Confining Zone consists mostly of shales deposited offshore in a middle neritic environment. The whole core acquired in this interval is a bioturbated, calcareous, and silty mudstone interbedded with bioturbated, calcareous, and argillaceous siltstone. Trace fossils were identified as Asterosoma, which are temporary stationary burrows where marine animals probe deeply into substrate to search for deposited food, Arenicolites, and vertical feeding tube traces from Teichichnius. Minor thin-walled mollusk shells, e.g., pelecypod fragments, occur throughout the interval, indicating a starved and stressed environment where oxygen and nutrient levels were probably low, which is expected in a middle neritic environment. Some calcareous siltstone laminae have been preserved, while other laminae have been destroyed due to bioturbation. The preserved laminae are typically ripple-laminated, have sharp bases, and some are normally graded. One interpretation could be that those laminae represent tempestites. One conjugate set of induced fractures was identified.

The Upper Anahuac Confining Zone consists mostly of shales deposited offshore in an inner neritic environment. Because the water depth when this zone was deposited was shallower, sunlight was more pervasive and nutrient supply and oxygen levels were higher, there is overall a higher percentage of silt and bioturbation within the Upper Anahuac Confining Zone. The base of the whole core is a non- to slightly calcareous, silty mudstone with textures varying from faintly laminated to massive to bioturbated. Vertical feeding traces produced by a Teichichnus trace fossil were identified. Sedimentary structures are laminations to thin beds of ripple-laminated, argillaceous siltstone. An isolated zone with soft sediment deformation was identified. Three normal shear fractures (microfaults) and several coring induced fractures occur in the lower part of the whole core. The upper part of the whole core is described as a bioturbated, slightly calcareous to calcareous, and silty mudstone interbedded with bioturbated, slightly calcareous, and argillaceous siltstone. At the boundary is a basal bed of a bioturbated, non-calcareous, argillaceous, and very fine-grained sandstone. Those thin sands can be seen as bright features on the CT scan. Trace fossils are identified as Asterosoma. The primary sedimentary structures are still apparent on a few siltstone beds and include ripple and parallel lamination. Only one coring-induced fracture was identified in this top part of the core.

Overall, the Anahuac Confining Zone transitions from middle neritic offshore silty mudstone in the Lower Anahuac Confining Zone to an inner neritic more argillaceous siltstone in the overlying Upper Anahuac Confining Zone.

The lithologic composition of the Anahuac Confining Zone is described below based on mud cuttings acquired during drilling operations of the stratigraphic test well Encanto 01 and mudlogs from two legacy wells nearby.

The Anahuac Confining Zone lithology shows 80 – 100 % light to dark green to grey and blue shale, light to medium to dark and bright red, soft to moderately firm, poorly to moderately consolidated, subfissile to subplaty and splintery, predominantly clay, massive and dull, predominantly clay with laminations, traces of cream clear fossils, traces of lignite and pyrite, and trace white cream crystalline limestone with earthy texture in the Het Lime interval. It is interbedded with 10 – 20%: very finely laminated silts and light to dark-grey, off-white to translucent very fine-grained sandy layers, which are predominantly loose and unconsolidated and

have a silty/argillaceous/calcareous matrix, poorly sorted. Trace mineral fluorescence has been observed, but no hydrocarbon fluorescence or hydrocarbon cut has been observed during mudlogging the Anahuac Confining Zone.

3.8.2.3.1 Petrologic Description

The Lower Anahuac Confining Zone is an argillaceous siliceous mudstone/mixed siliceous mudstone, as shown in the mudstone compositional diagram (Figure AoR-144). Coarse silt and very fine sands are present in burrows, along with fine clays, pyrite and calcite, and intergranular pores when bioturbated (Figure AoR-142). Quartz, plagioclase, and K-feldspars are present. The fine silt made up of laminations and bioturbation is present as well. Pyrite and minor amounts of titanium oxide TiO_2 and calcite are present as a pore-filling cement. Mineral and textural alignment was identified. Microporosity is present.

SEM analysis shows that clays appear to be compacted and structurally aligned, also clay wrapping around grains was observed. Microfossil fragments, e.g., foraminifers and fine-grained material associated with this rock, was also observed. Backscattered Electron (BSE) images on ion-milled samples show presence of organic particles, but those lack pores associated with organics, which possibly indicates the immature nature of these organics. A few desiccation pores (Figure AoR-146) and possibly some small natural pores can also be seen. Based on the general lack of both intergranular and kerogen pores, and structural alignment, the rock could be a competent baffle. The clay speciation is dominantly illite/smectite. Further thin section description, petrologic analysis, and seal capacity analysis confirm the confining potential of the Lower Anahuac Confining Zone depending on rock fabric, mineralogy, porosity, permeability, and capillary pressure measurements. The sequence stratigraphic analysis confirms the continuity of this confining zone.

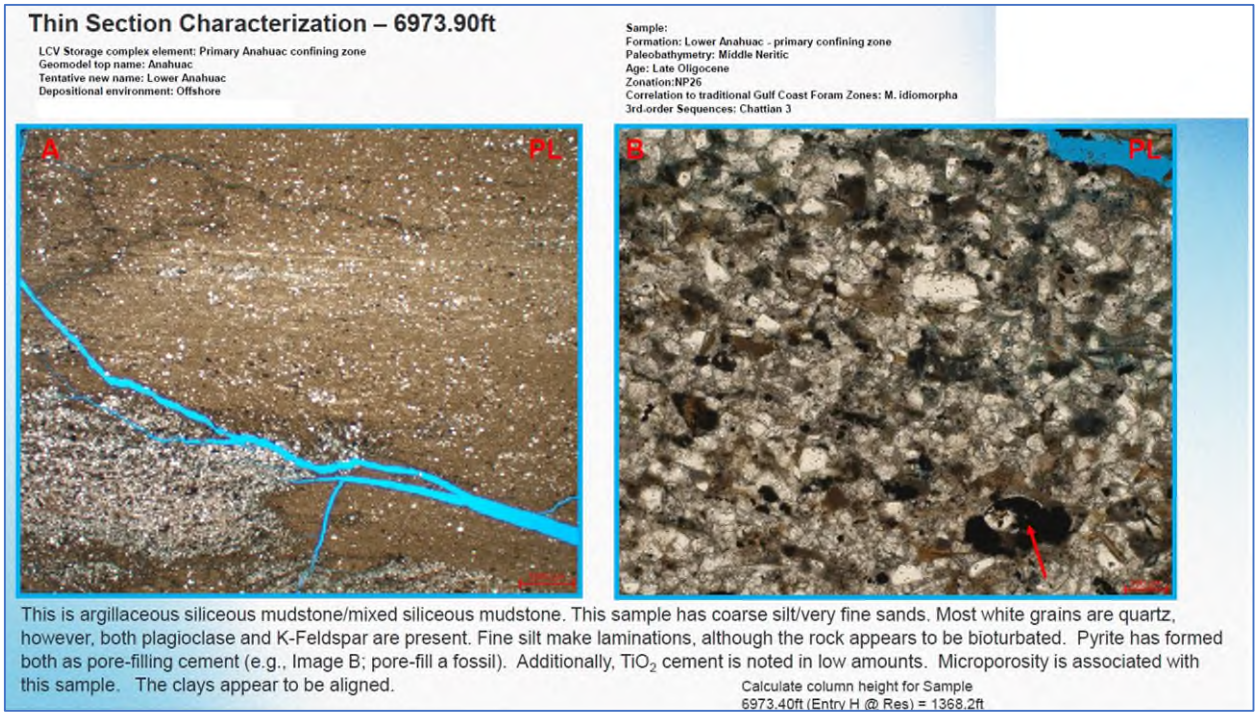
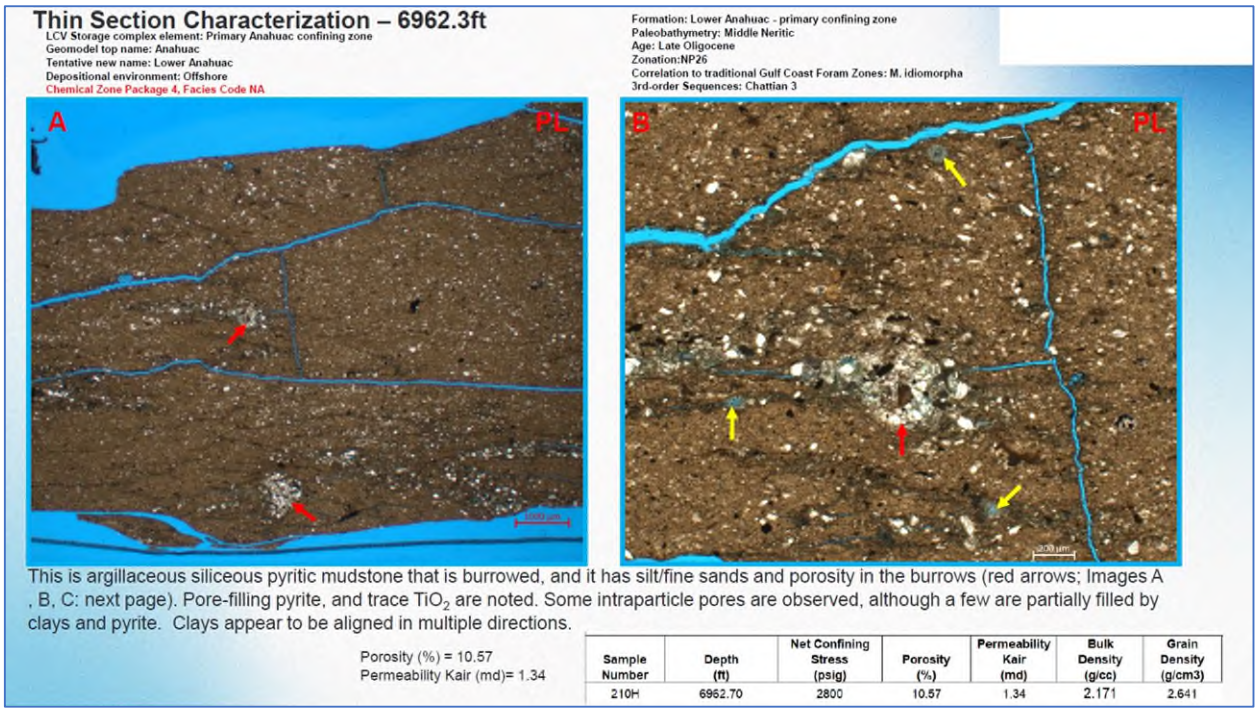


Figure AoR-142: Thin section analysis and petrologic description of the Lower Anahuac Confining Zone at 6,973.9 ft MD. Cracks are present owing to thin section preparation.



Sample Number	Depth (ft)	Net Confining Stress (psig)	Porosity (%)	Permeability Kair (md)	Bulk Density (g/cc)	Grain Density (g/cm3)
210H	6962.70	2800	10.57	1.34	2.171	2.641

Figure AoR-143: Thin section analysis and petrologic description of the Lower Anahuac Confining Zone at 6,962.3 ft MD.

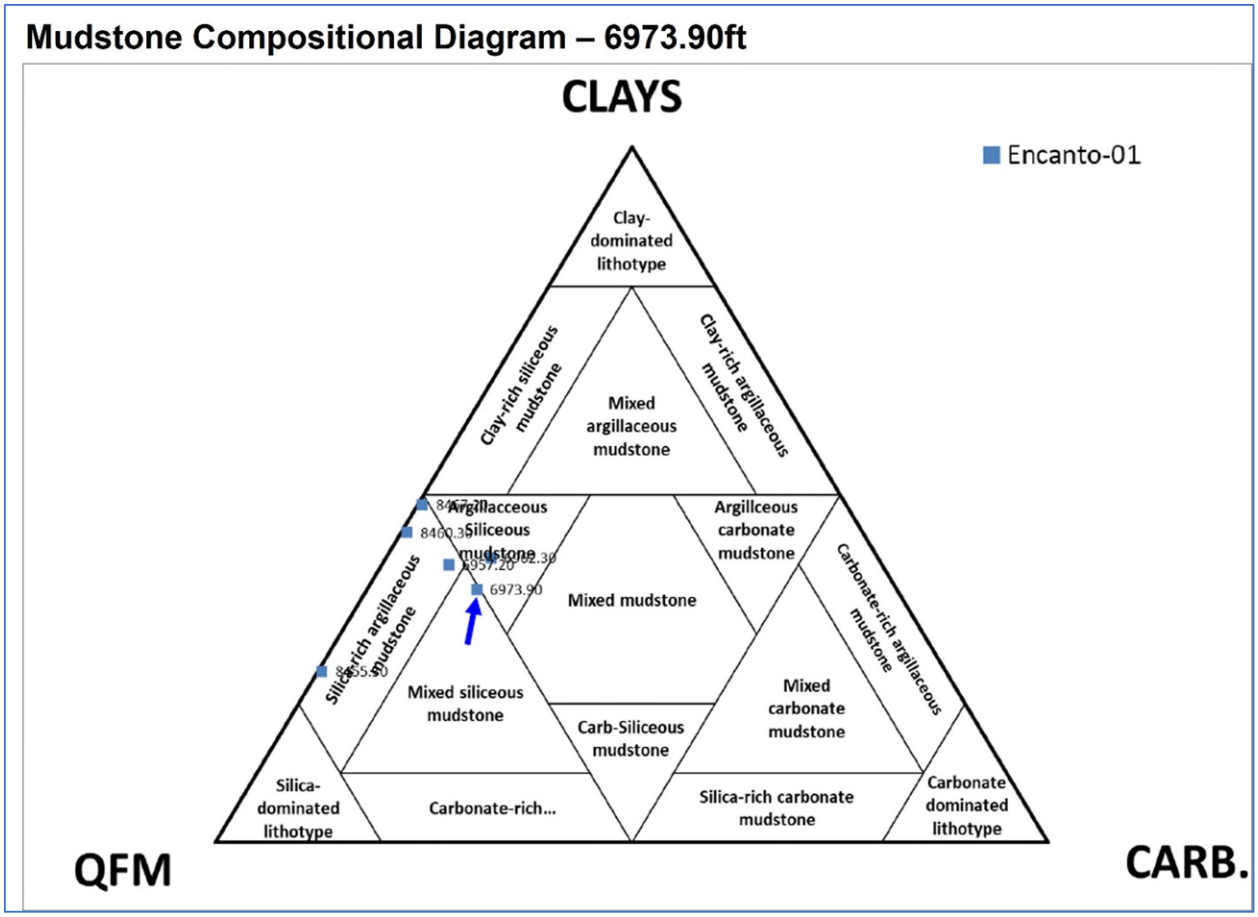


Figure AoR-144: Mudstone Composition of the Lower Anahuac Confining Zone.

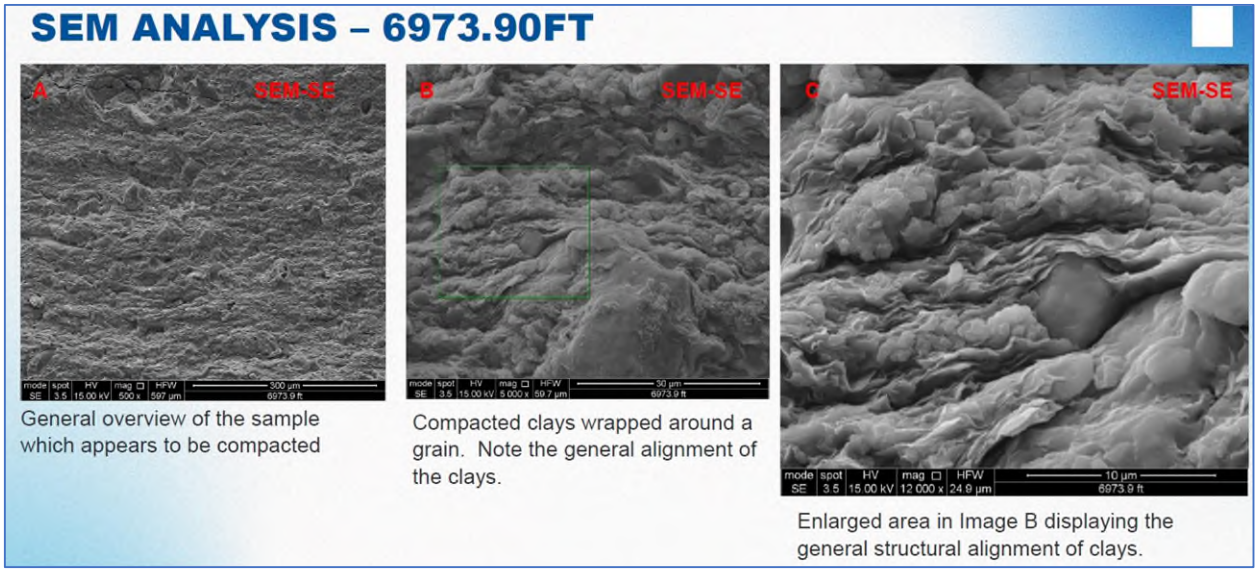


Figure AoR-145: SEM analysis of the Lower Anahuac Confining Zone, displaying the structural alignment of clays.

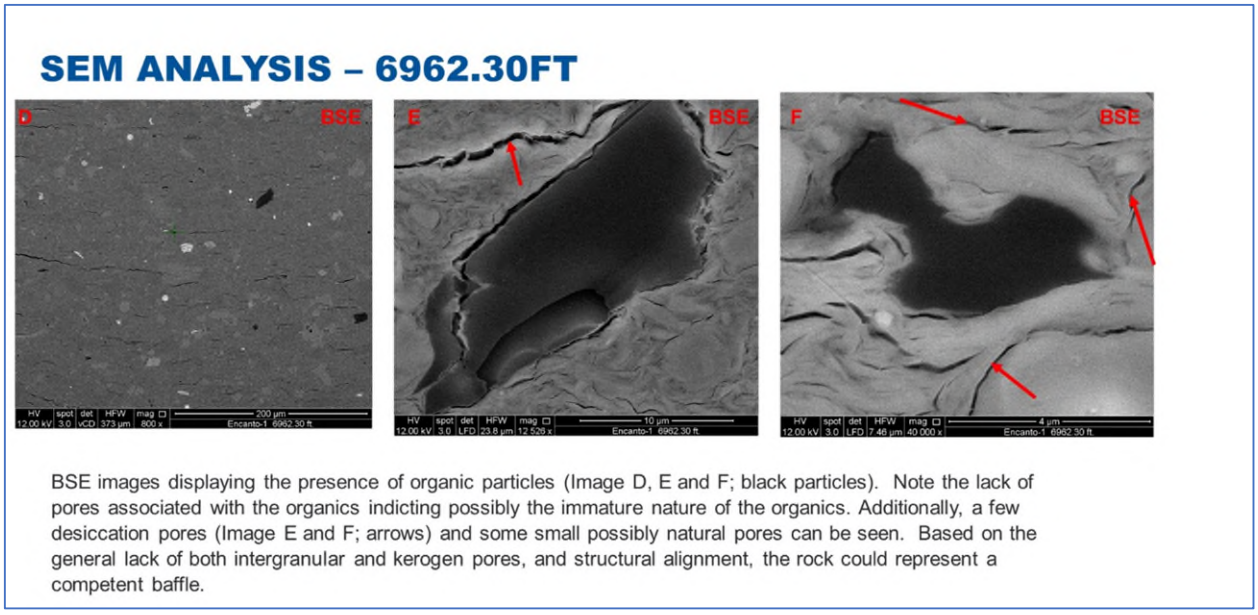


Figure AoR-146: SEM analysis of the Lower Anahuac Confining Zone, displaying immature organic particles with no visible kerogen pores.

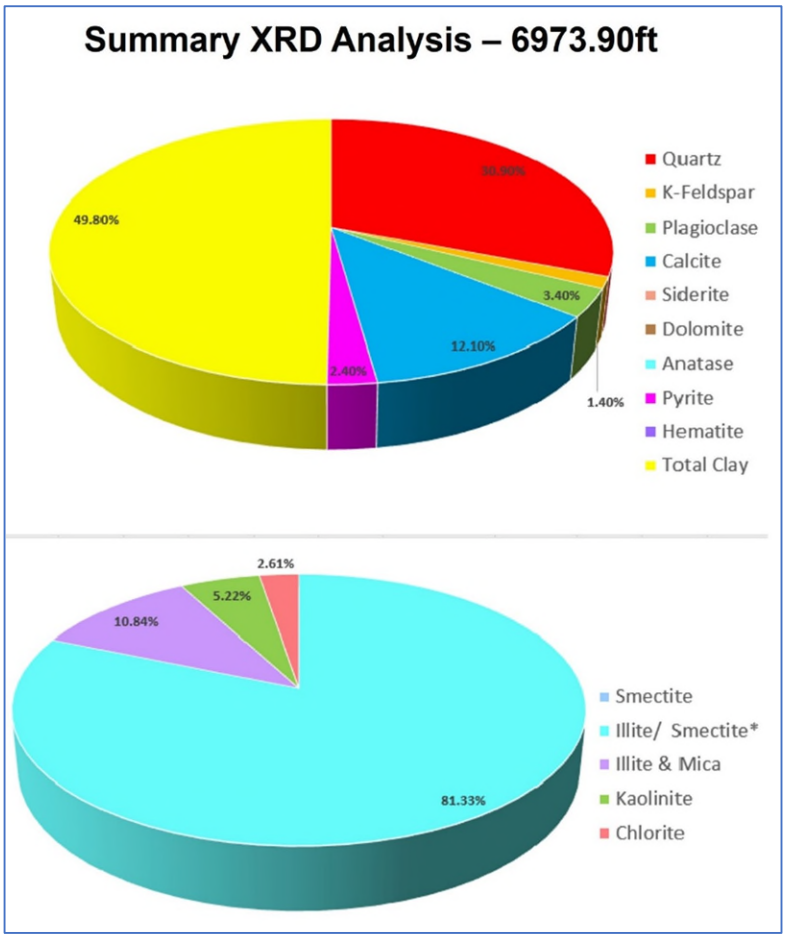


Figure AoR-147: XRD Analysis of the Lower Anahuac Confining Zone.

The Upper Anahuac Confining Zone cored interval is composed of an argillaceous siliceous pyritic and burrowed mudstone. The silt and fine sand fraction, along with porosity, is concentrated in the burrows. The mudstone rock is represented by pore throat radii between 0.001 to ~0.024 microns, this rock will act as a confining system. The sandy burrows are represented by larger pore throat radii 0.03 to ~0.9 microns, which likely reduce the seal capacity due to the bi-modal pore throat system.

Another rock type is silty/sandy faintly laminated mudstone. Small pore throat radii between 0.001 to ~0.03 microns possibly represent the mudrock, which may act as a baffle. Slightly larger pore throat radii, 0.03 to ~ 0.3 microns, possibly represent sandy burrows or faint laminations. Framboidal pyrite was observed. The clay speciation derived from XRD displays that the clay is dominantly illite-smectite.

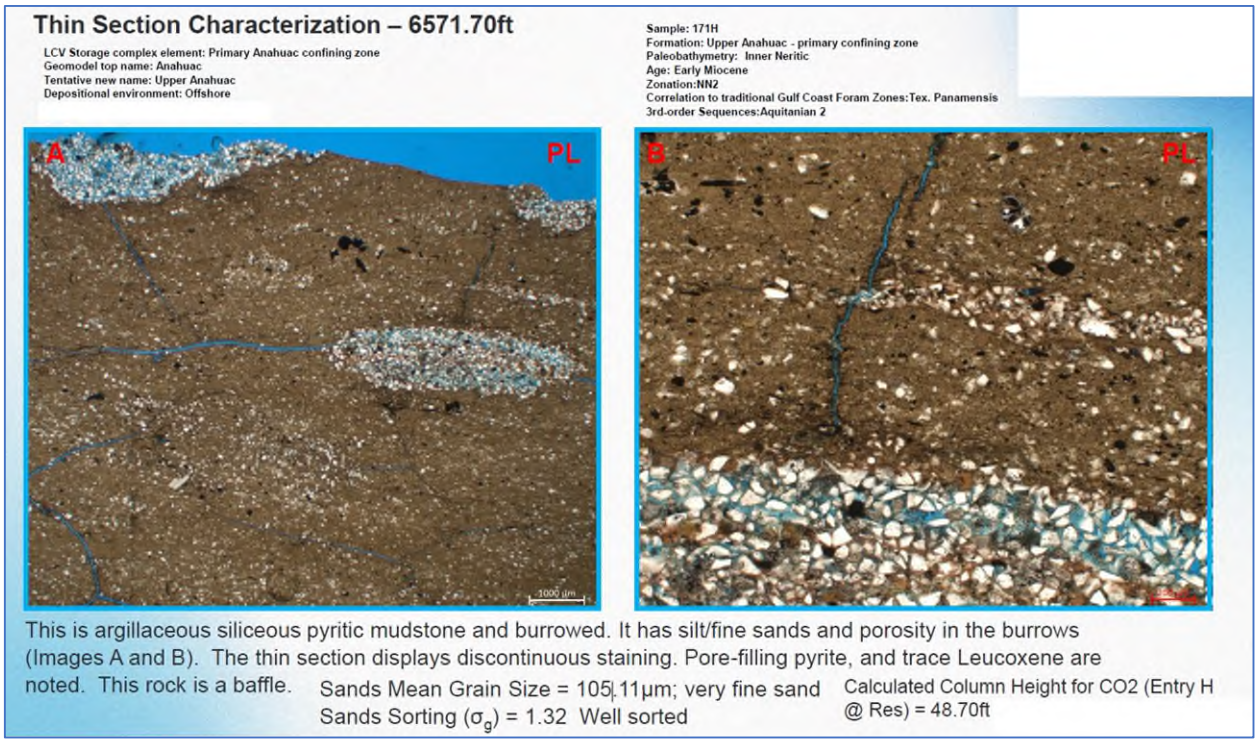


Figure AoR-148: Thin section analysis and petrologic description of the Upper Anahuac Confining Zone at 6,571.7 ft MD.

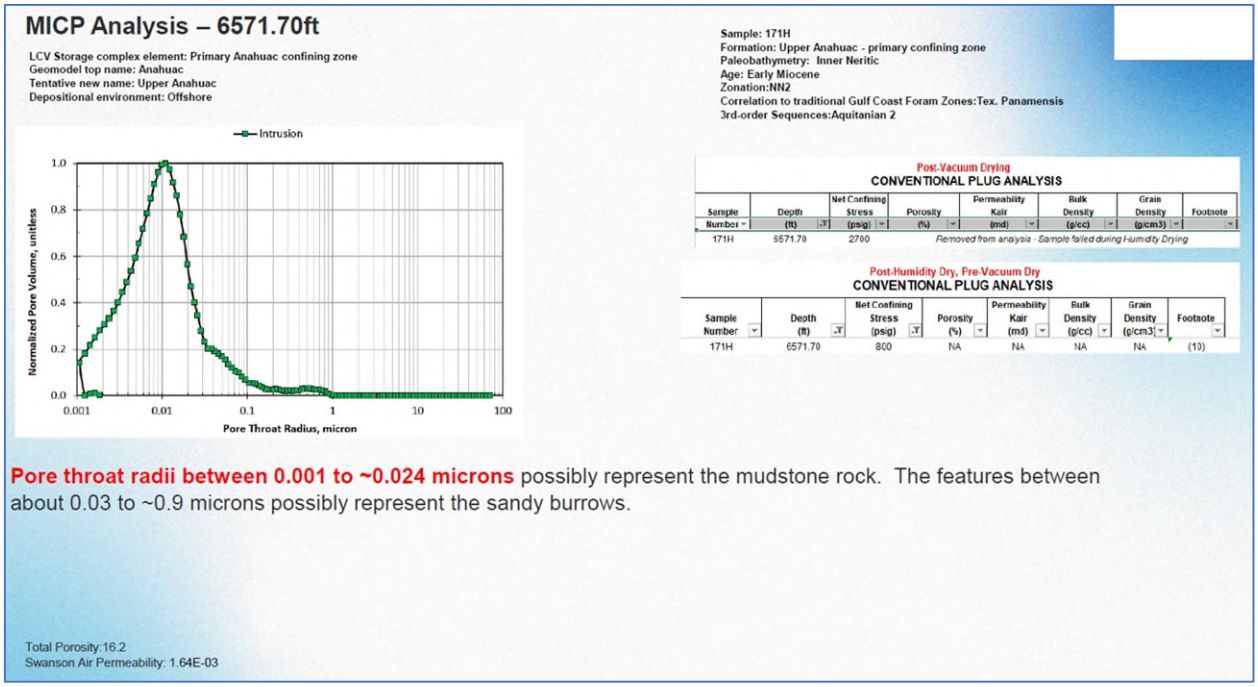


Figure AoR-149: MICP pore throat radius of the Upper Anahuac Confining Zone in argillaceous siliceous pyritic burrowed mudstone.

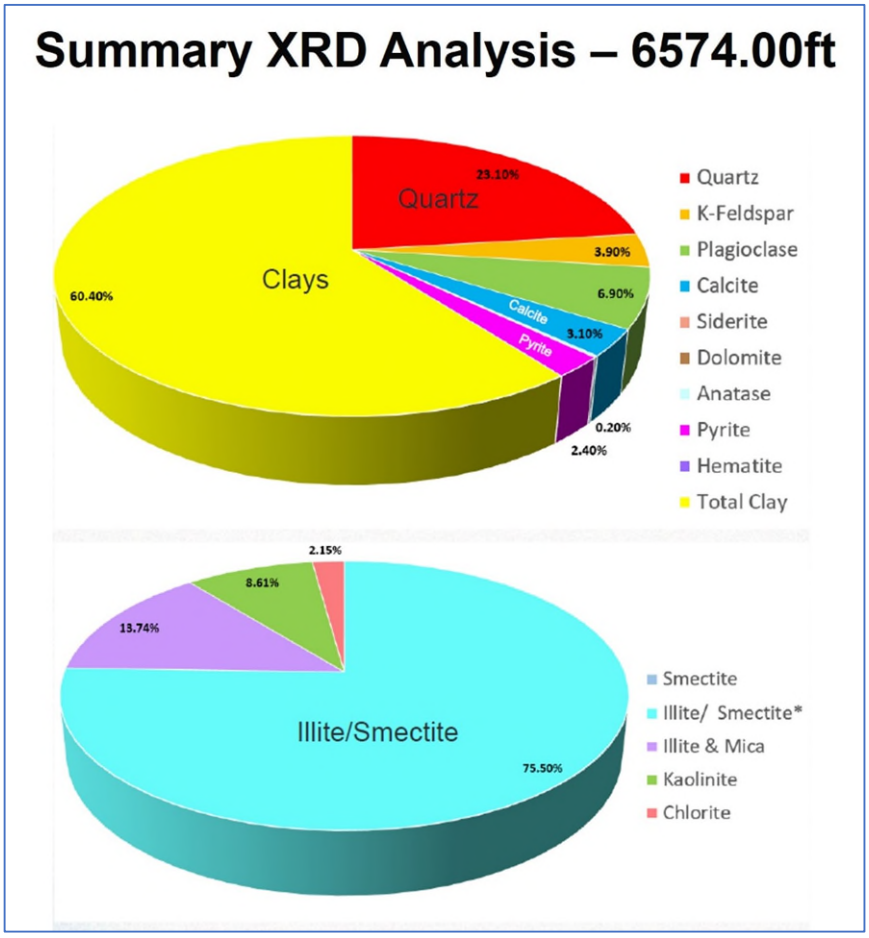


Figure AoR-150: XRD analysis of the Upper Anahuac Confining Zone in argillaceous siliceous pyritic burrowed mudstone.

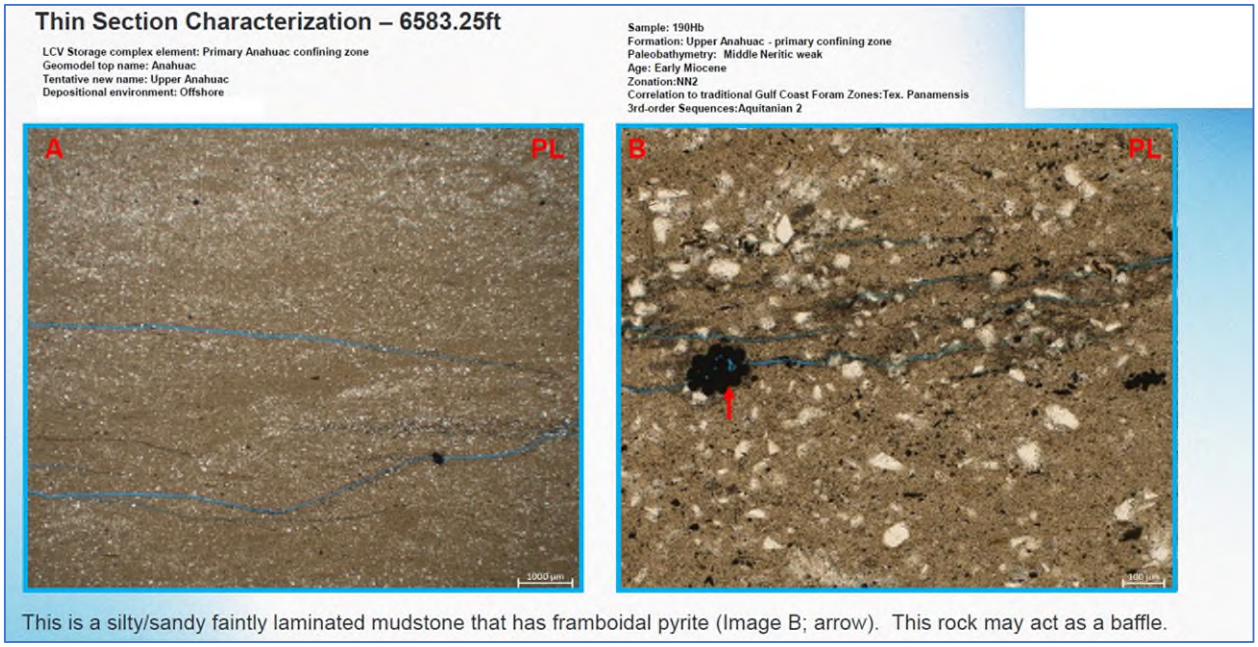


Figure AoR-151: Thin section analysis and petrologic description of the Upper Anahuac Confining Zone at 6,583.25 ft MD.

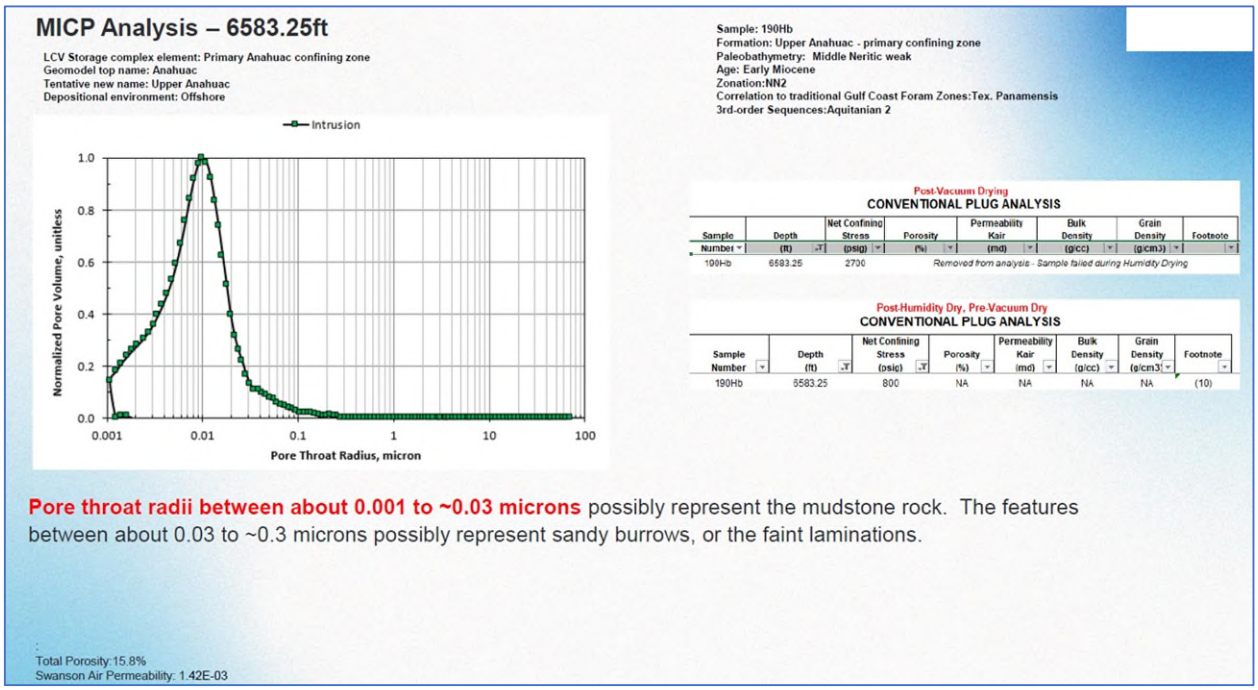


Figure AoR-152: MICP pore throat radius of the Upper Anahuac Confining Zone in silty/sandy faintly laminated mudstone.

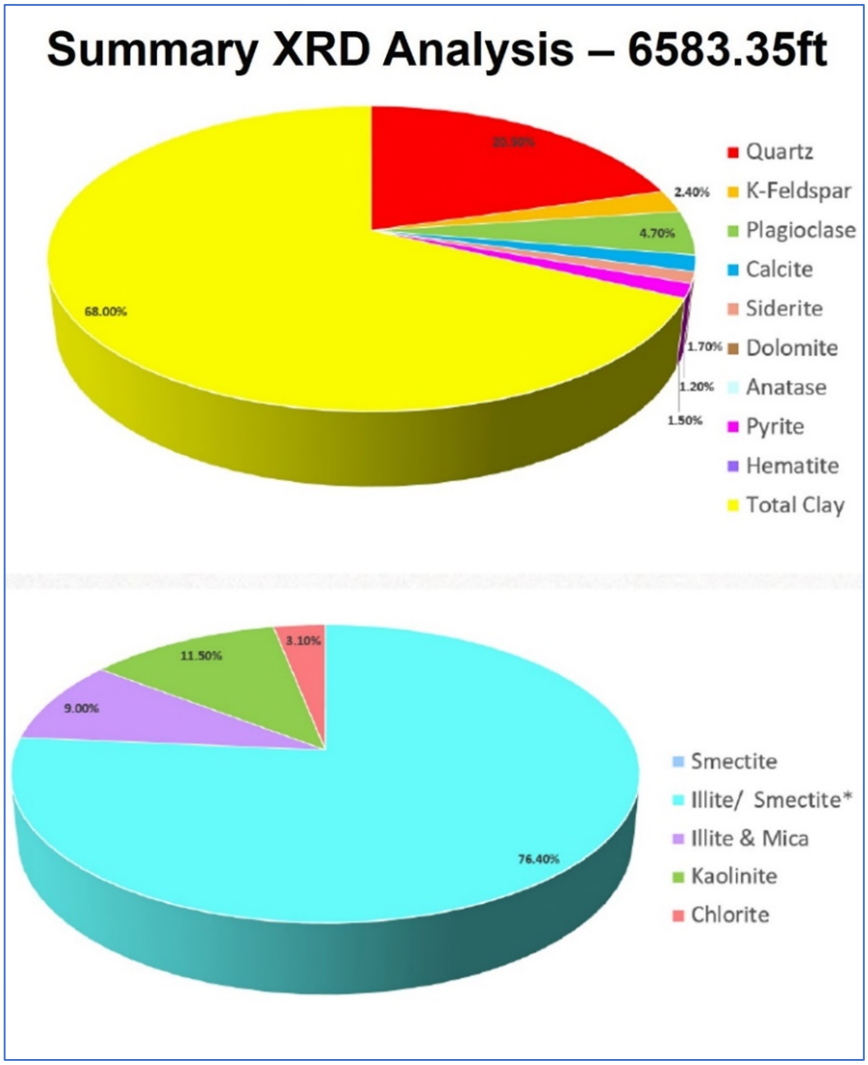


Figure AoR-153: XRD analysis of the Upper Anahuac Confining Zone in silty/sandy faintly laminated mudstone.

3.8.2.3.2 Seal Analysis

There are five samples with MICP data in the Lower Anahuac Confining Zone, two verticals and three horizontal plugs from whole core. Following a conservative approach (please see Appendix A for more detail analysis), the displacement pressure criteria will need an injection height of ~1122 feet before breaking into the confining zone. These results will be corroborated / calibrated to TEP (Threshold Entry Pressure) test results.

In the Upper Anahuac Confining Zone, there are five plugs, three vertical and two horizontals plugs, from whole core. Three plugs present a bi-modal pore system and will not be considered for seal analysis. Following a conservative approach (please see Appendix A for more detail analysis), the displacement pressure criteria will need an injection height of ~1117 feet before breaking into the confining zone. These results will be corroborated / calibrated to TEP (Threshold Entry Pressure) test results.

3.9.2.3.3 Anahuac Confining Zone Maps

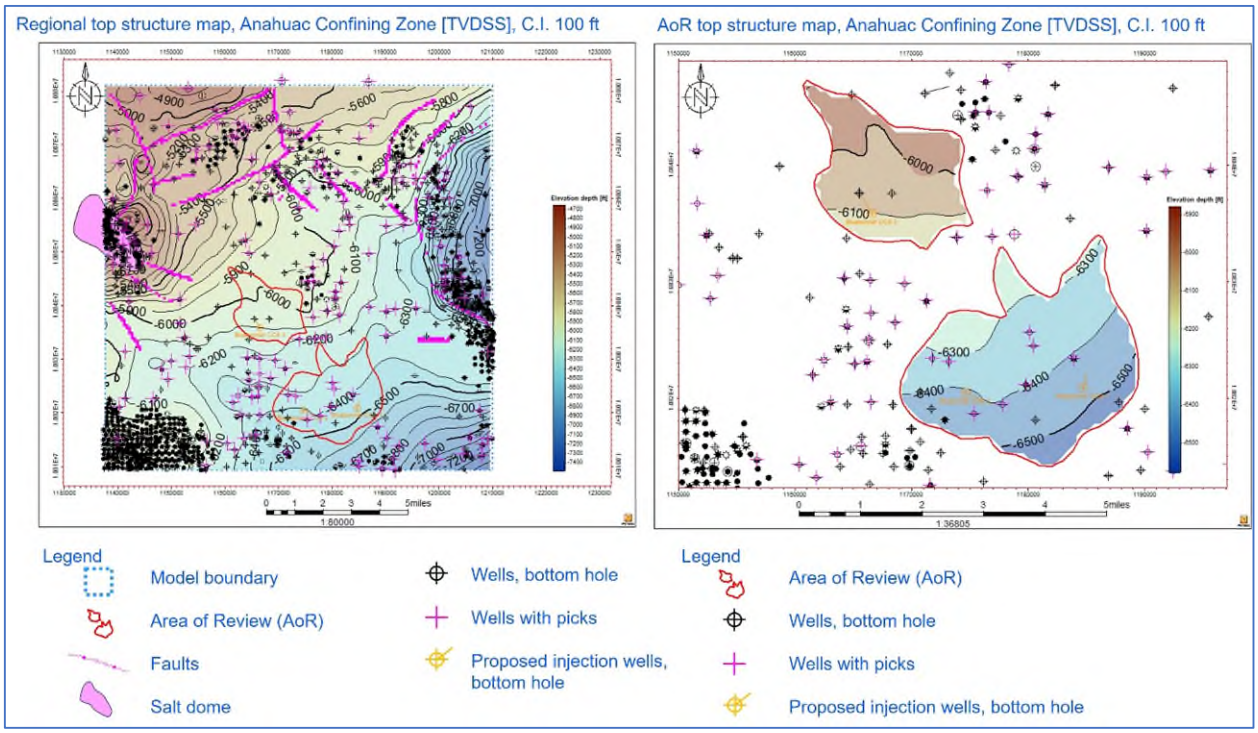


Figure AoR-154: Regional and AoR top structure map of the Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

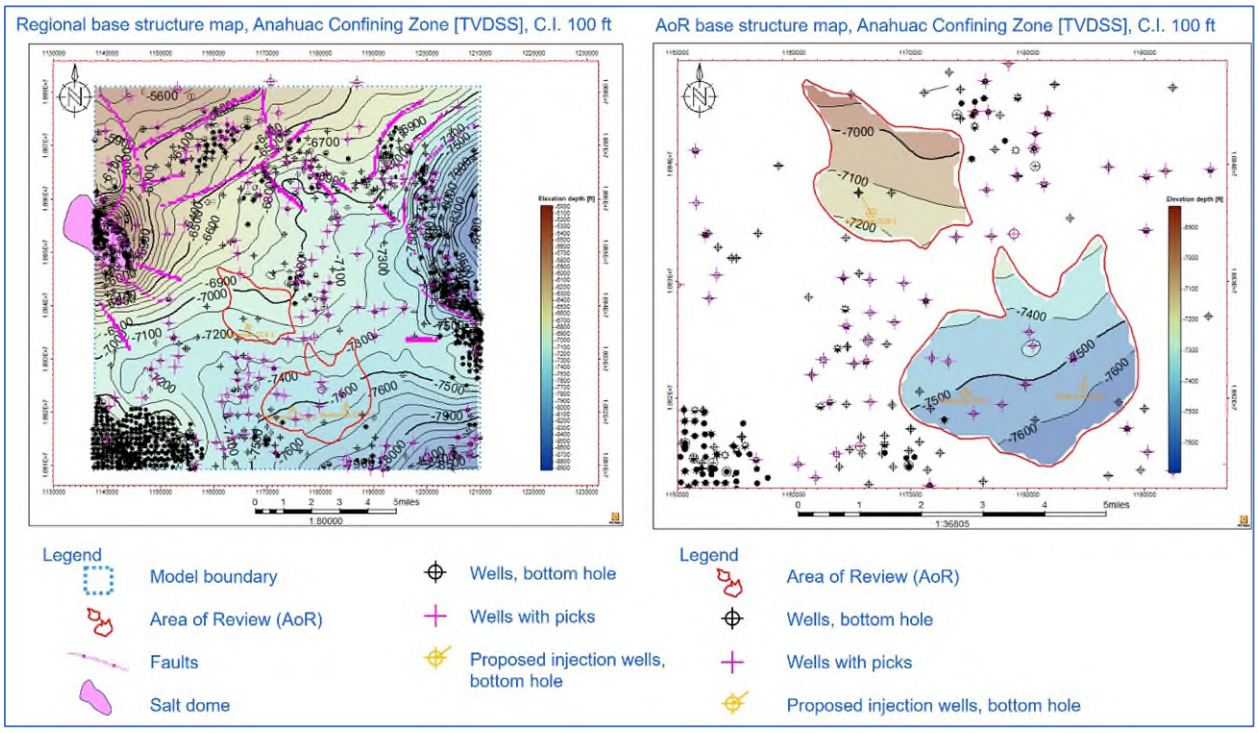


Figure AoR-155: Regional and AoR base structure map of the Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

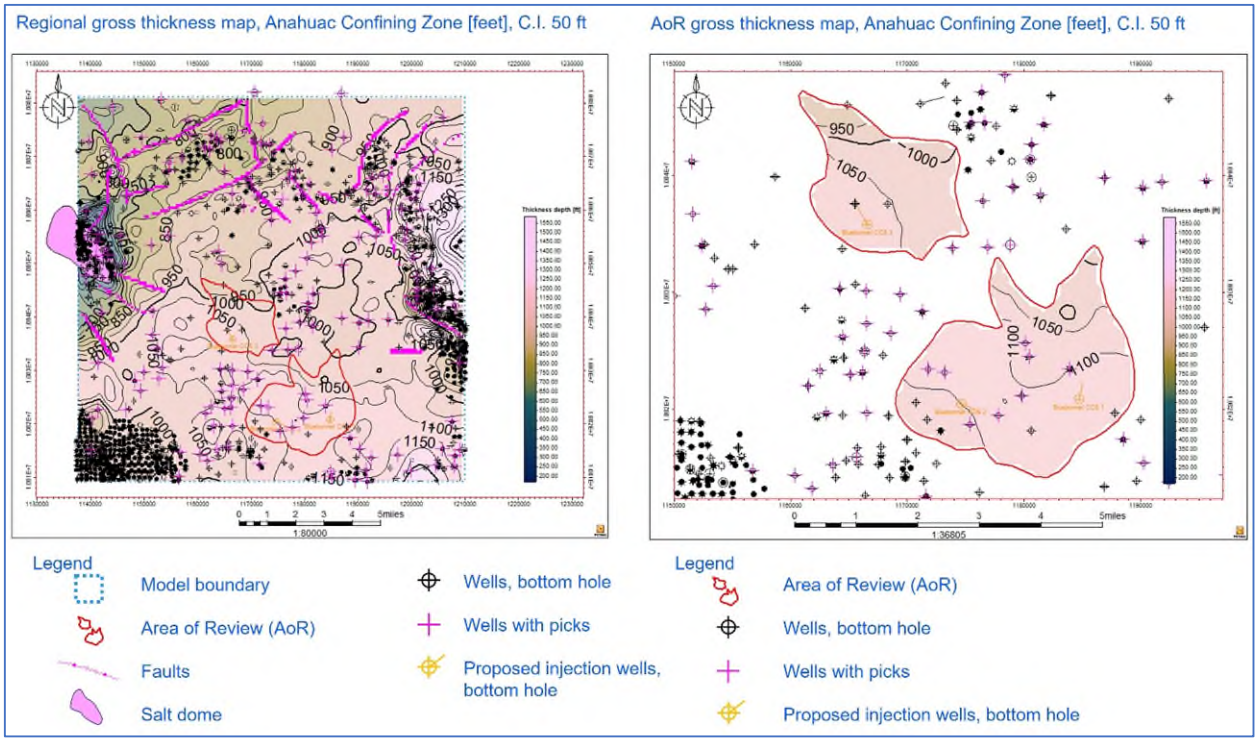


Figure AoR-156: Regional and AoR gross thickness map of the Anahuac Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

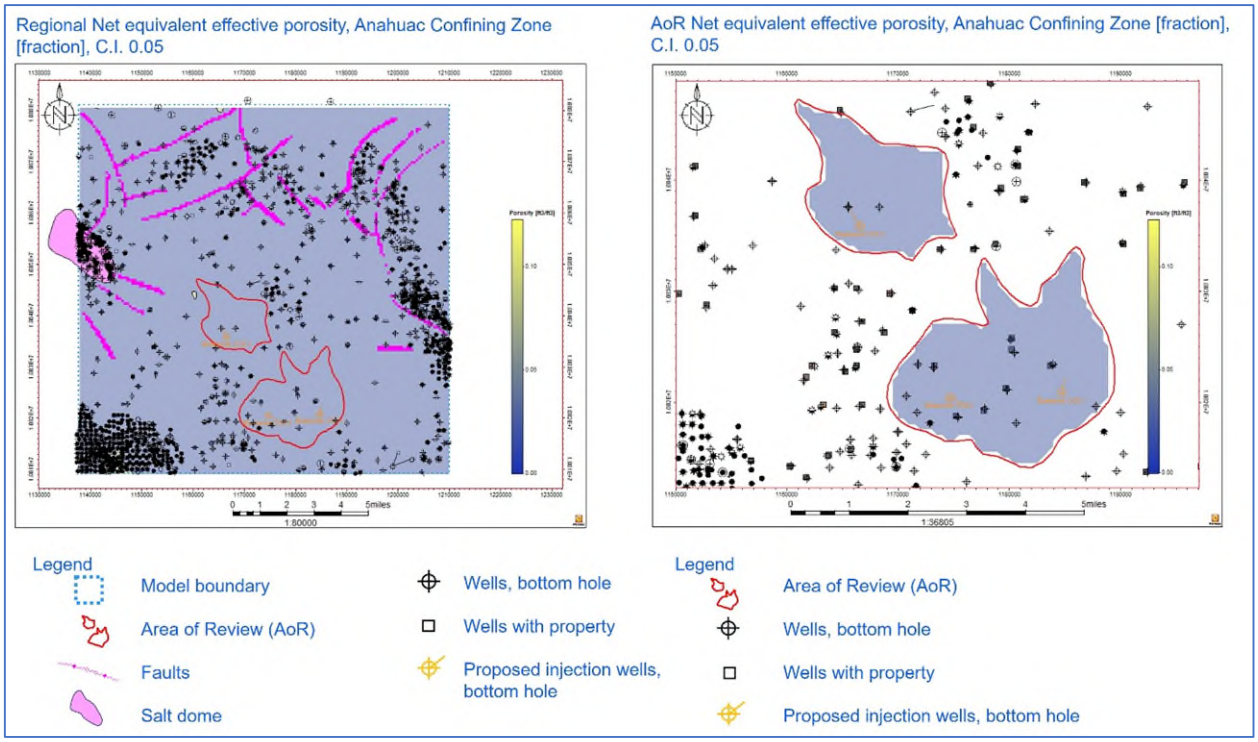


Figure AoR-157: Regional and AoR net equivalent effective porosity map of the Anahuac Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

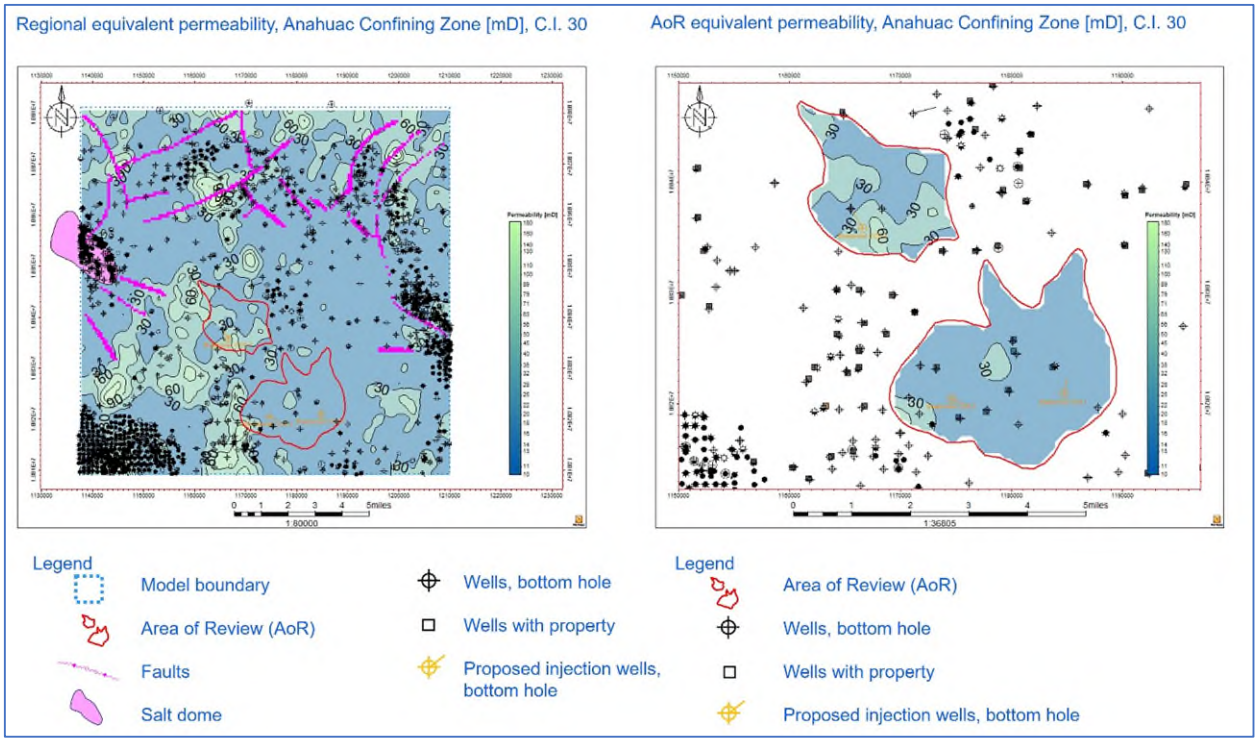


Figure AoR-158: Regional and AoR equivalent permeability map of the Anahuac Confining Zone in millidarcy (md), contour interval 30 md. This map was generated from the Oligocene Model described under 4.0.

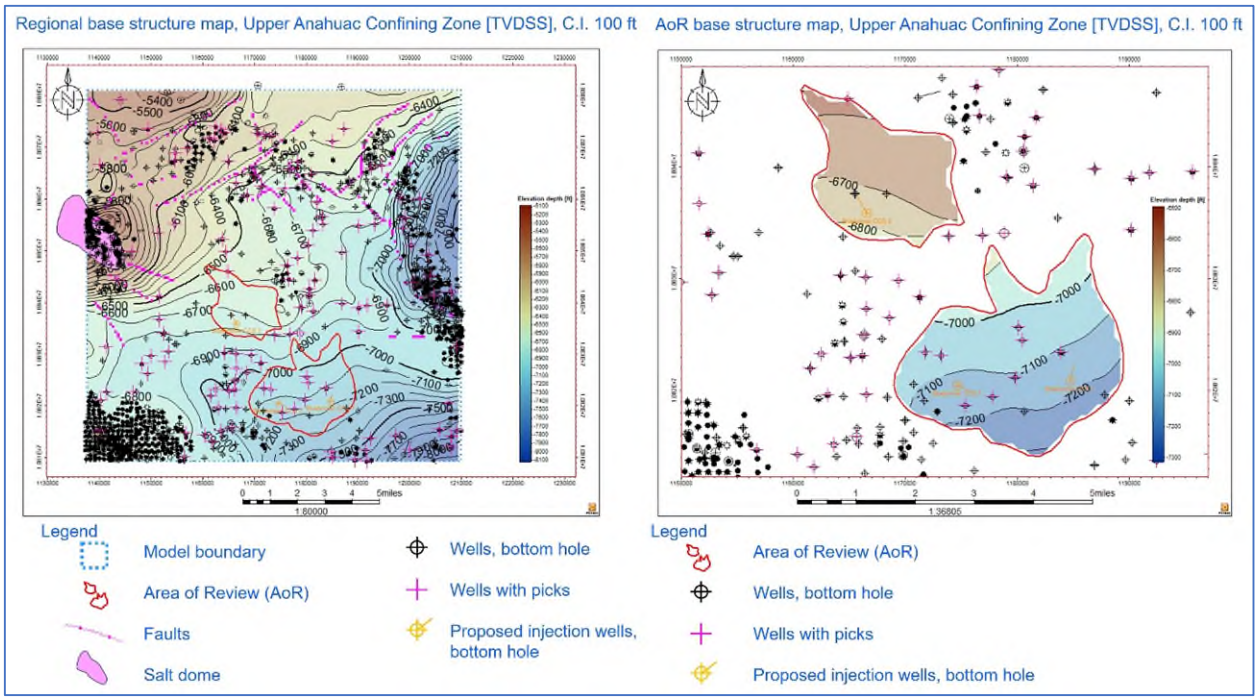


Figure AoR-159: Regional and AoR base structure map of the Upper Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

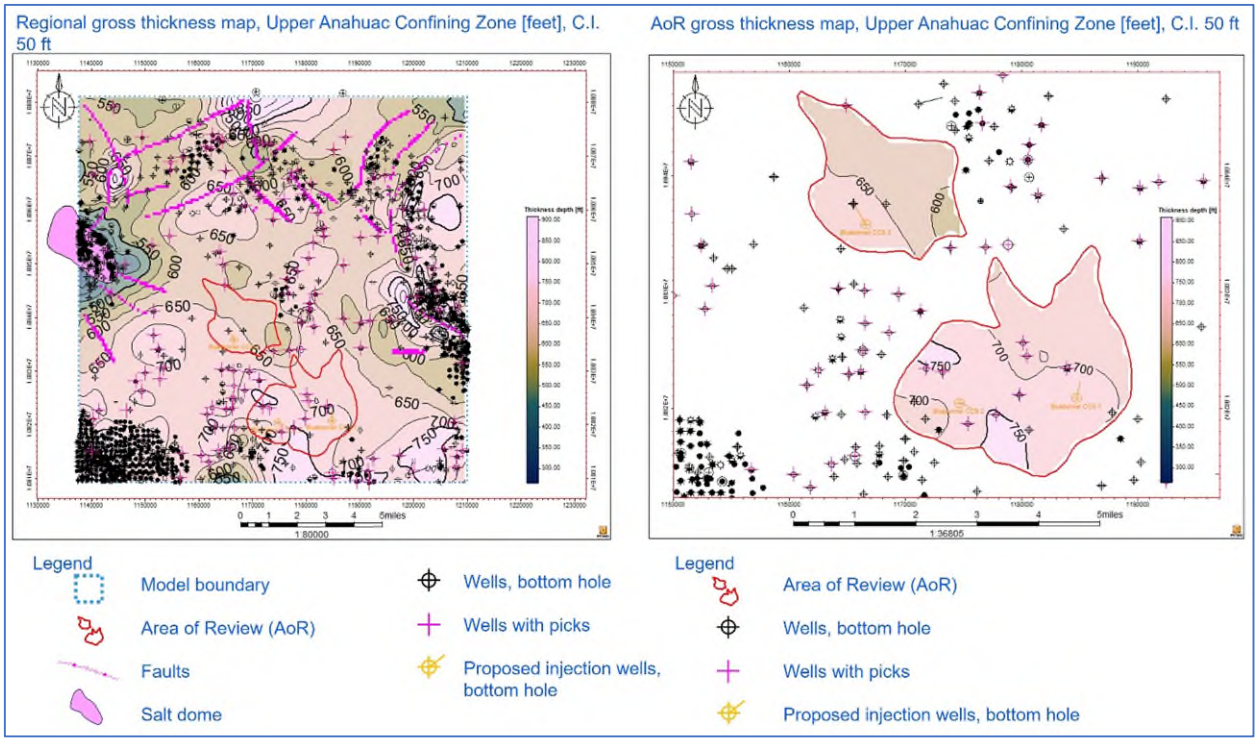


Figure AoR-160: Regional and AoR gross thickness map of the Upper Anahuac Confining Zone in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

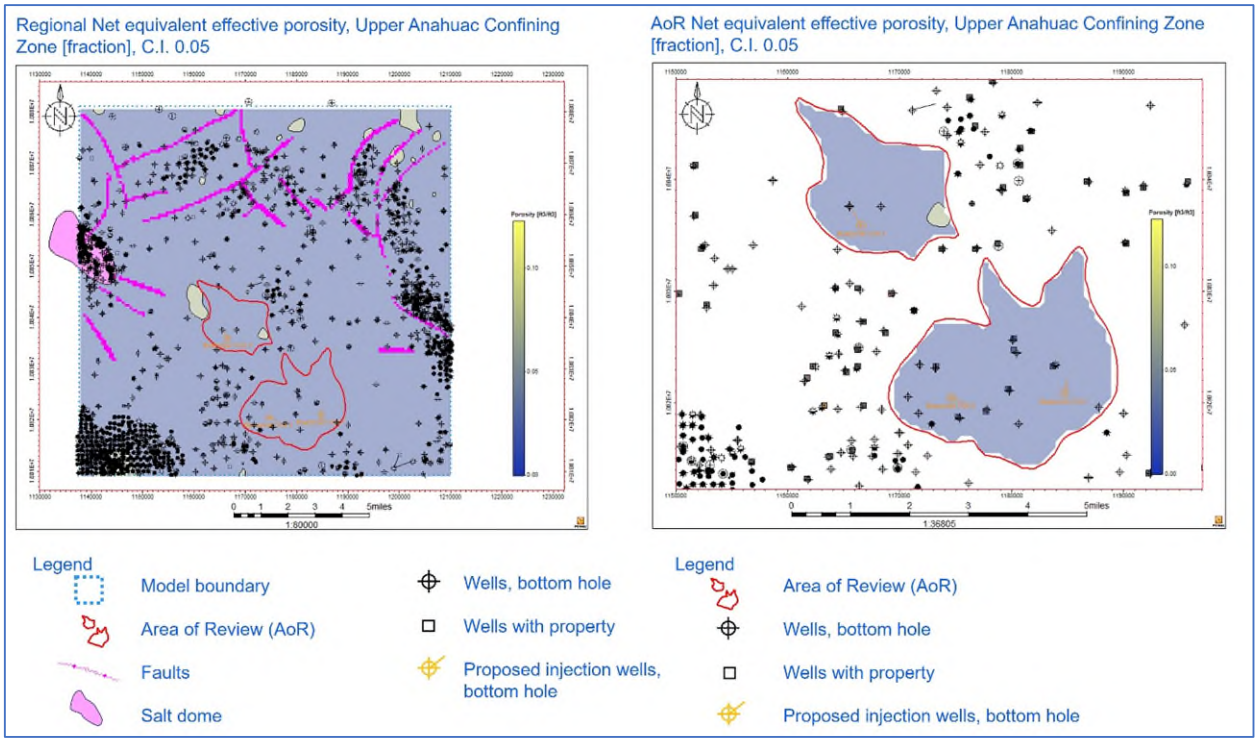


Figure AoR-161: Regional and AoR net equivalent effective porosity map of the Upper Anahuac Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

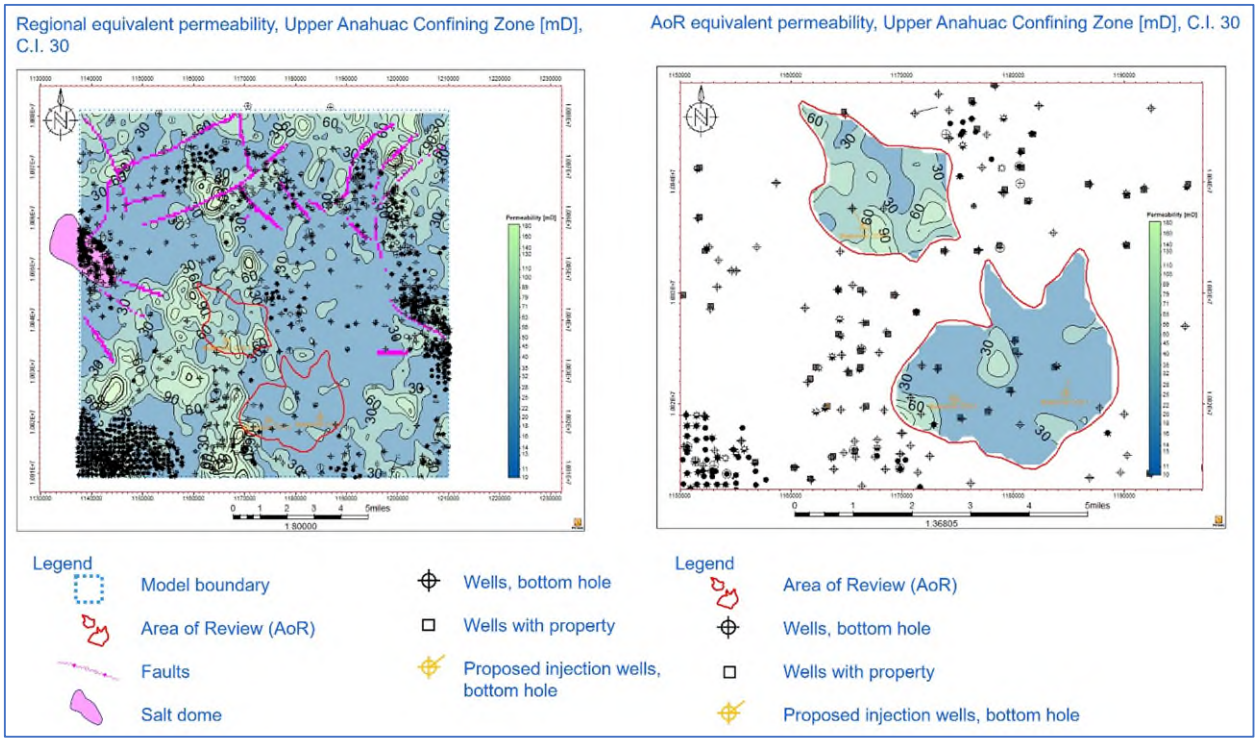


Figure AoR-162: Regional and AoR equivalent permeability map of the Upper Anahuac Confining Zone in millidarcy (md), contour interval 30 md. This map was generated from the Oligocene Model described under 4.0.

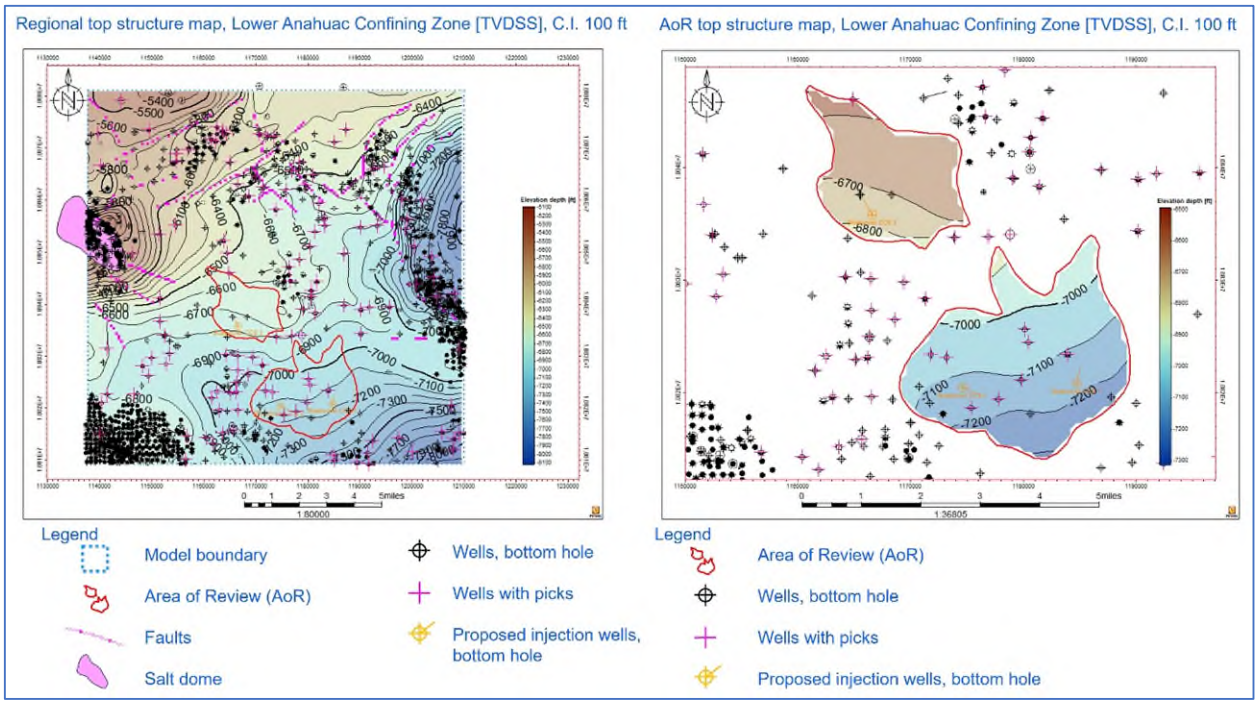


Figure AoR-163: Regional and AoR top structure map of the Lower Anahuac Confining Zone in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

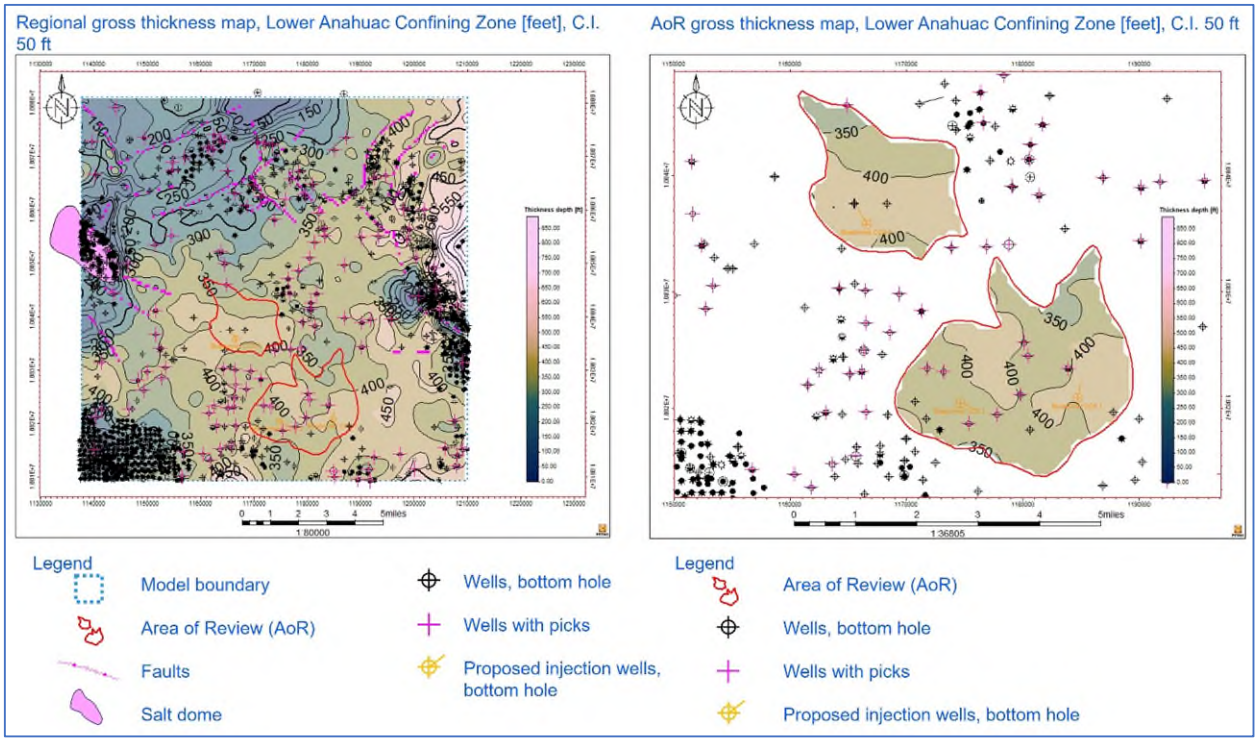


Figure AoR-164: Regional and AoR gross thickness map of the Lower Anahuac Confining Zone in feet, contour interval 50 ft. The gross thickness is drawn to the base structure map of the Anahuac Confining Zone, Figure AoR-213. This map was generated from the Oligocene Model described under 4.0.

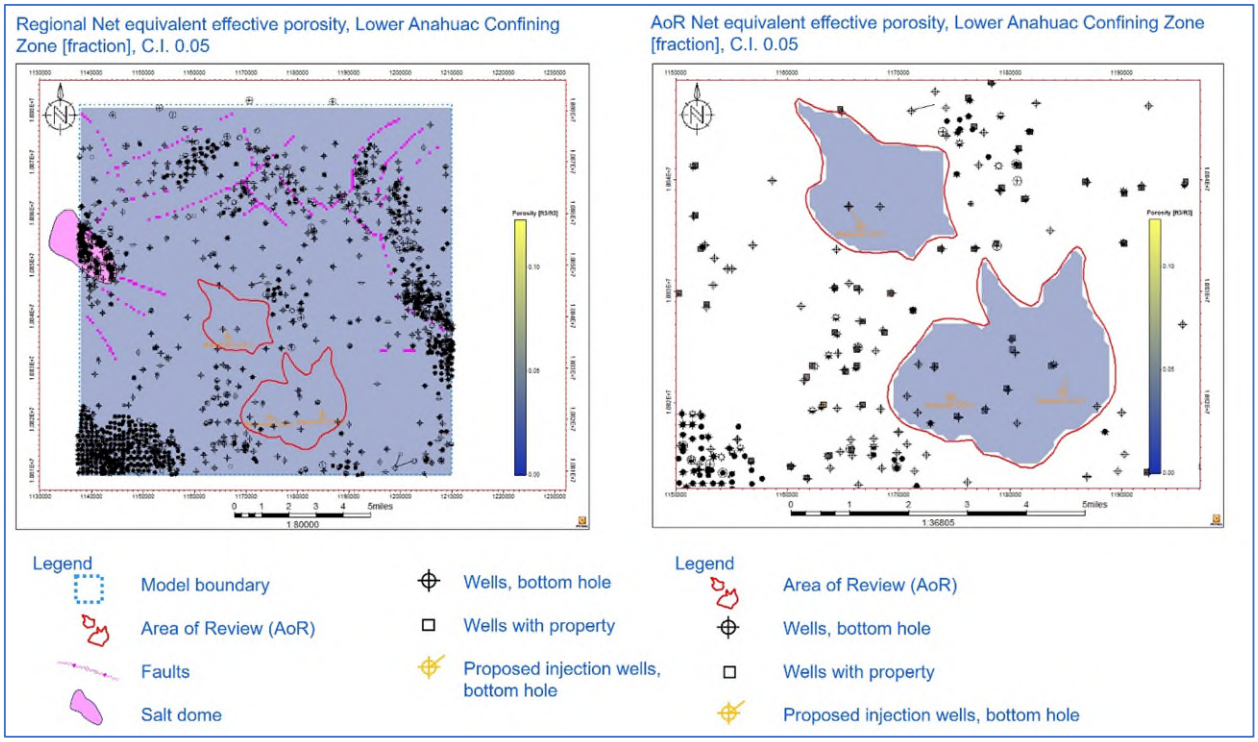


Figure AoR-165: Regional and AoR net equivalent effective porosity map of the Lower Anahuac Confining Zone in fraction, contour interval 0.05. This map was generated from the Oligocene Model described under 4.0.

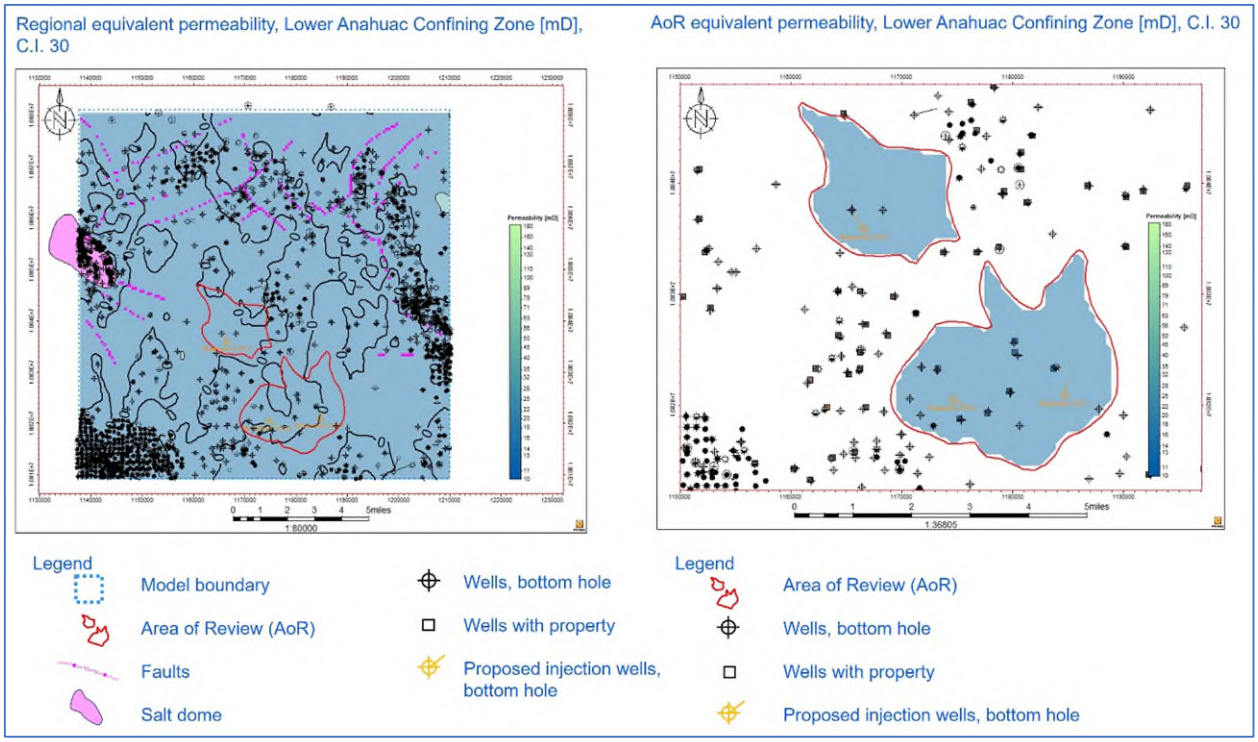


Figure AoR-166: Regional and AoR equivalent permeability map of the Lower Anahuac Confining Zone in millidarcy (md), contour interval 300 md. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-11 represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-11: Reservoir properties for the Anahuac Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Anahuac Confining Zone		
		Upper Anahuac	Lower Anahuac	Combined
Top Depth [TVDSS]	Minimum	-6,577	-7,314	-6,577
	Maximum	-5,879	-6,494	-5,879
	Average	**-6,272**	**-6,956**	**-6,272**
Base Depth [TVDSS]	Minimum	-7,314	-7,697	-7,697
	Maximum	-6,494	-6,829	-6,829
	Average	**-6,956**	**-7,346**	**-7,346**
Gross Thickness [ft]	Minimum	566.78	303.41	915.08
	Maximum	759.9	447.7	1,150.3
	Average	**684**	**391**	**1074**

Reservoir properties in AoR	Extracted map values from geomodel	Anahuac Confining Zone		
		Upper Anahuac	Lower Anahuac	Combined
Porosity [fraction] EQI, net eff. porosity * NTG	Minimum	0.00	0.00	0
	Maximum	0.06	0.02	0.03
	Average	**0.02**	**0.00**	**0.01**
Permeability [md]	Minimum	0	0	0
	Maximum	151	16	92
	Average	**29**	**1**	**19**

3.8.2.4 Lower Miocene Confining Zone = Secondary Confining Zone for Frio Injection

The Lower Miocene Confining Zone is characterized as a paleosol, silty calcareous mudstone, and non-silty lime-mudstone. The paleosol was deposited in a coastal marsh/floodplain. On the mudlog as well as the slabbed whole core, two main colors were observed: green mudstone intervals are the result of reduced iron and red mudstone intervals are the result of oxidized iron, those red soils are hematitic. In the third-order sequence stratigraphic framework, the paleosol is a weathering surface, which is a sequence boundary (S.B.) that caps the Miocene sand-prone third-order highstand.

The formation of a paleosol on a coastal marsh was influenced by changing salinity and fluid migration over long time periods. The changing salinity is the reason why there are syneresis cracks: the clays expand in fresh water and shrink in saline water. Slickensides are local to common, have striation, and contain high clay content, and thus, are natural structures and planes of weakness. Some of the paleosol exhibits root traces with a fine organic core with the apparent porphyroskelic fabric (see Figure AoR-172). Below the reddish paleosol, most samples are limey mudstone. There are also non-silty lime-mudstones.

Mottled textures in the calcareous red mudstone are common and may be caused by rooting. Very fine-grained interbedded sandstones may represent storm washover deposits or crevasse splays, ranging from massive to mottled to ripple-laminated. In between the sand laminations, occur mudstone intervals with silt-filled desiccation cracks. Two sand injectites occur at the base of the first core. Burrows are present in both the mudstones and interbedded sandstones. Many small calcareous nodules occur and are recognized as bright white features on the CT scan. Local brecciation was observed.

3.8.2.4.1 Petrologic Description

An argillaceous sandy marly mudstone with calcite (stained red) and quartz grains (white) is shown in Figure AoR-167.



Figure AoR-167: Thin section analysis and petrologic description of the Lower Miocene Confining Zone in an argillaceous sandy marly mudstone.

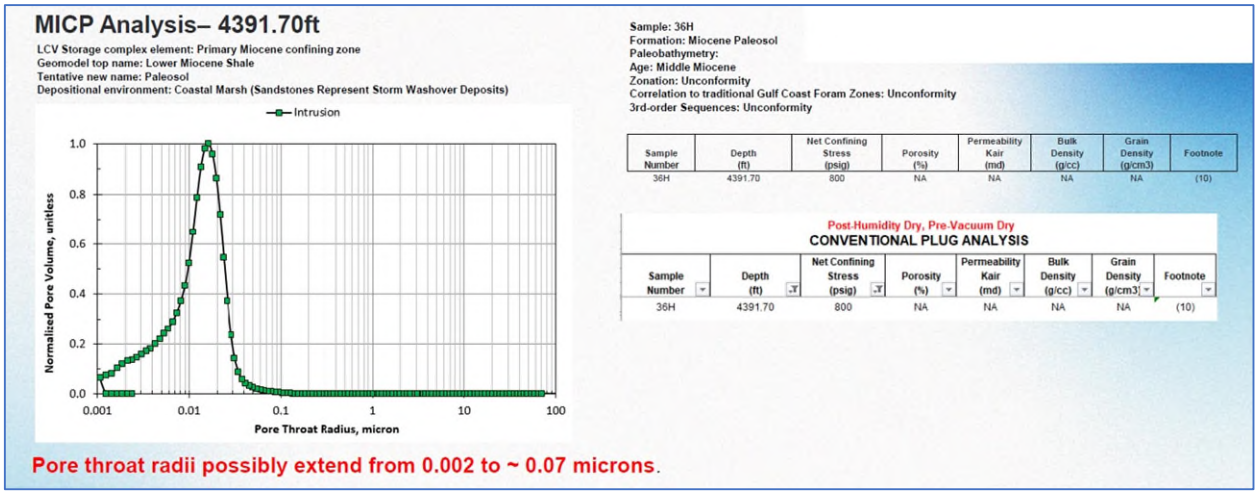


Figure AoR-168: MICP pore throat radius of the Lower Miocene Confining Zone in an argillaceous sandy marly mudstone.

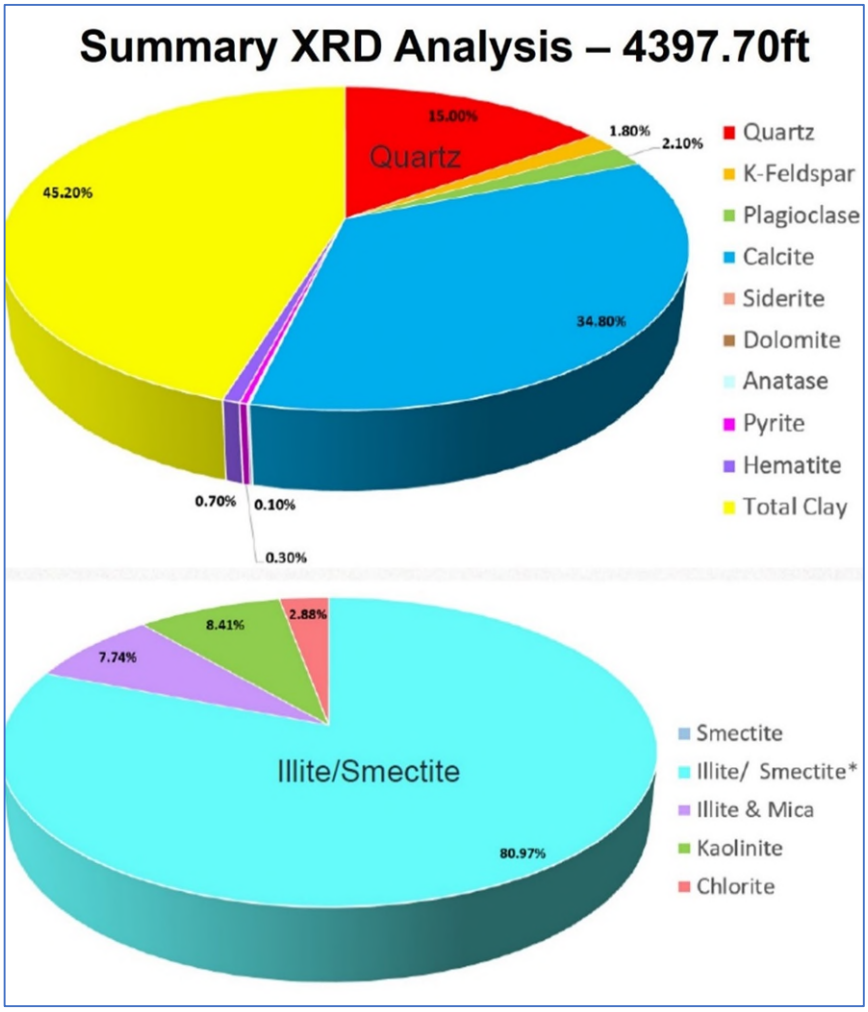


Figure AoR-169: XRD analysis of the Lower Miocene Confining Zone in a mottled calcareous hematitic mudstone.

Figure AoR-170 shows a uniform non-silty limey mudstone. Based on the fabric and MICP data, these non-silty lime-mudstones have a competent sealing capacity.

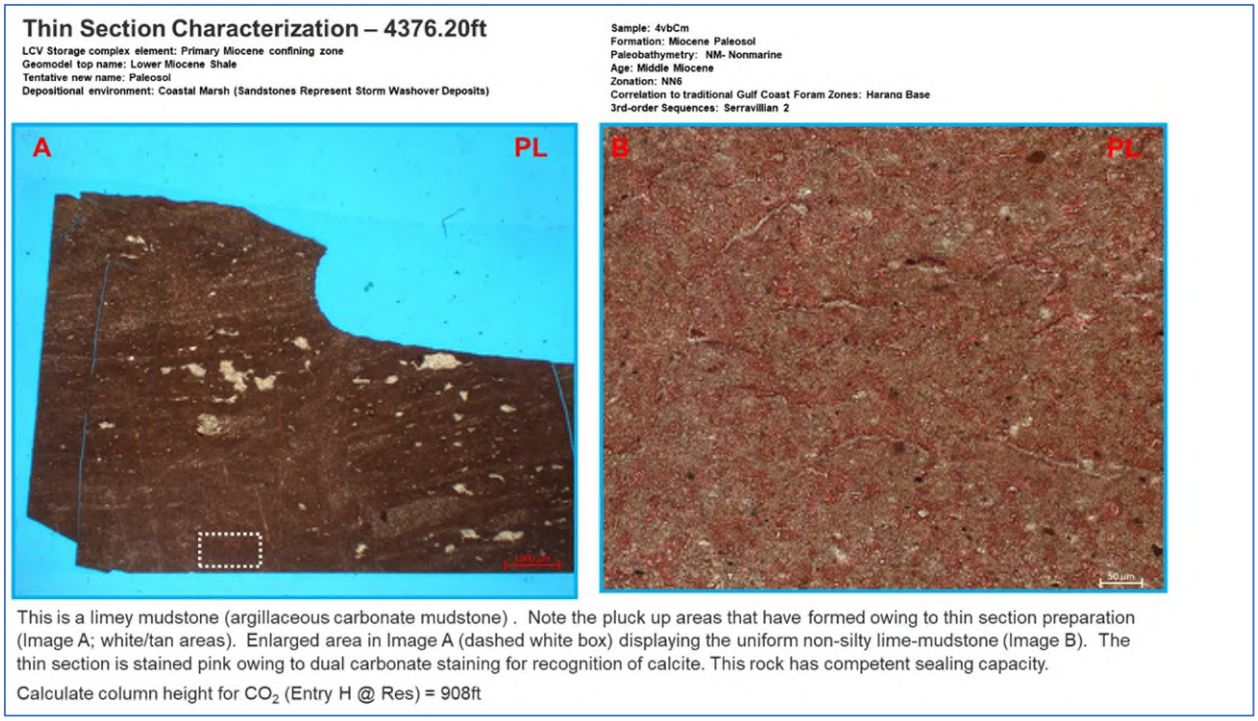


Figure AoR-170: Thin section analysis and petrologic description of the Lower Miocene Confining Zone in a limey mudstone.

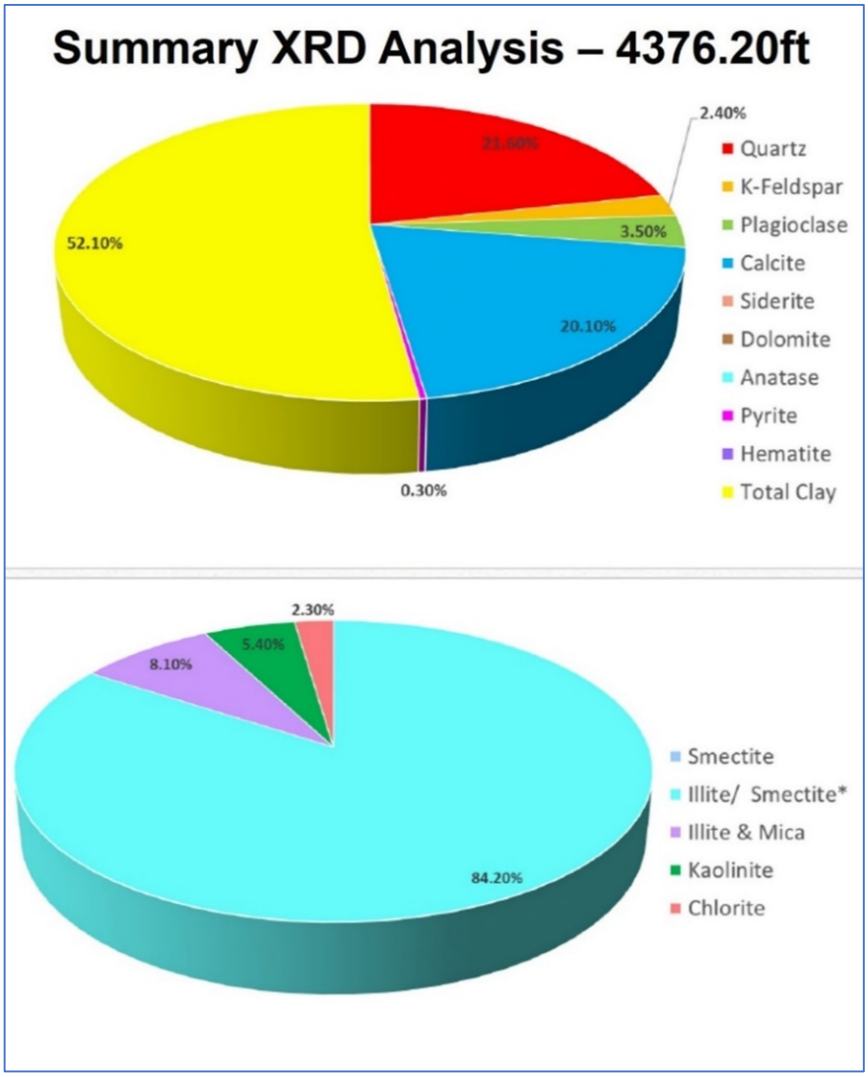


Figure AoR-171: XRD analysis of the Lower Miocene Confining Zone in a limey mudstone.

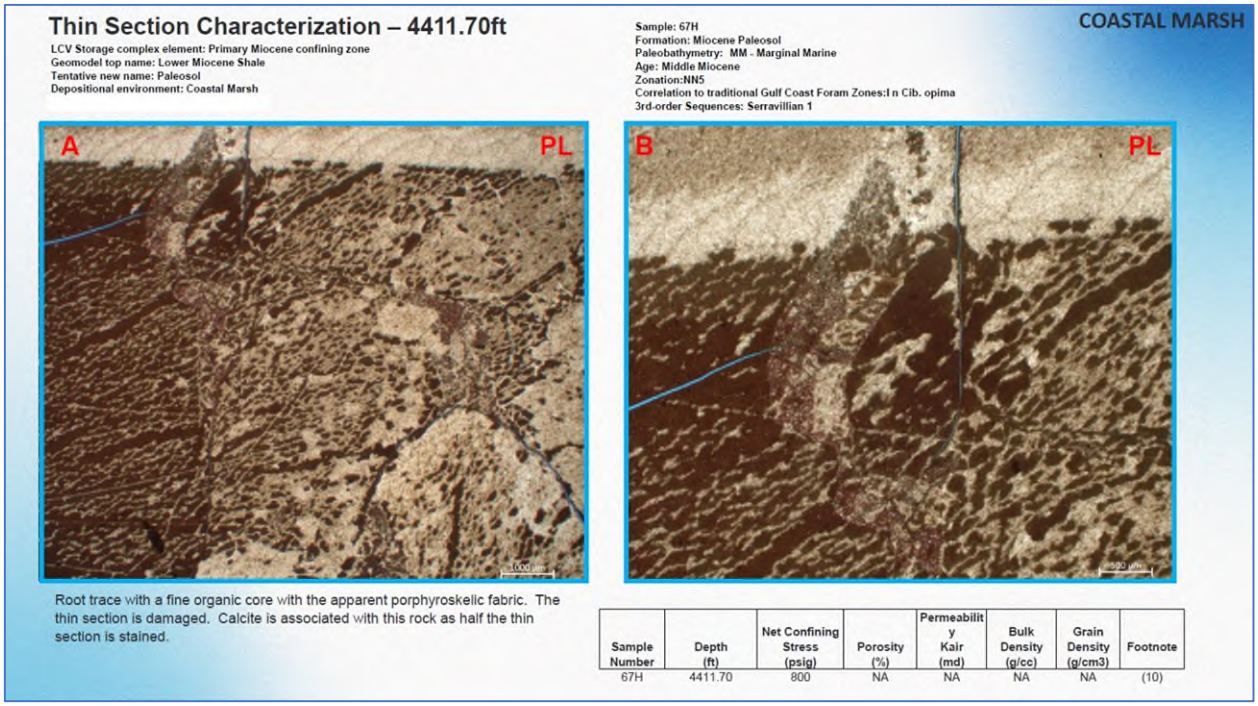


Figure AoR-172: Thin section analysis and petrologic description of the Lower Miocene Confining Zone showing a root trace with a fine organic core with the apparent porphyroskelic fabric.

3.8.2.4.2 Seal Analysis

There are eight samples with MICP data in the Lower Miocene Confining Zone, three from vertical plugs and five from horizontals whole core plugs. With results from the Threshold Entry Pressure (TEP), the conservative approach was changed to a more aggressive approach to tie in with TEP results. Following this update, the displacement pressure criteria will need an average injection height of 4,224.64 (see Table AoR-11, in appendix A) feet before breaking into the confining zone. The comparison and calibration of the MICP with TEP results is explained in the Appendix A.

3.8.2.4.3 Lower Miocene Confining Zone maps

The Lower Miocene Confining Zone maps are shown below.

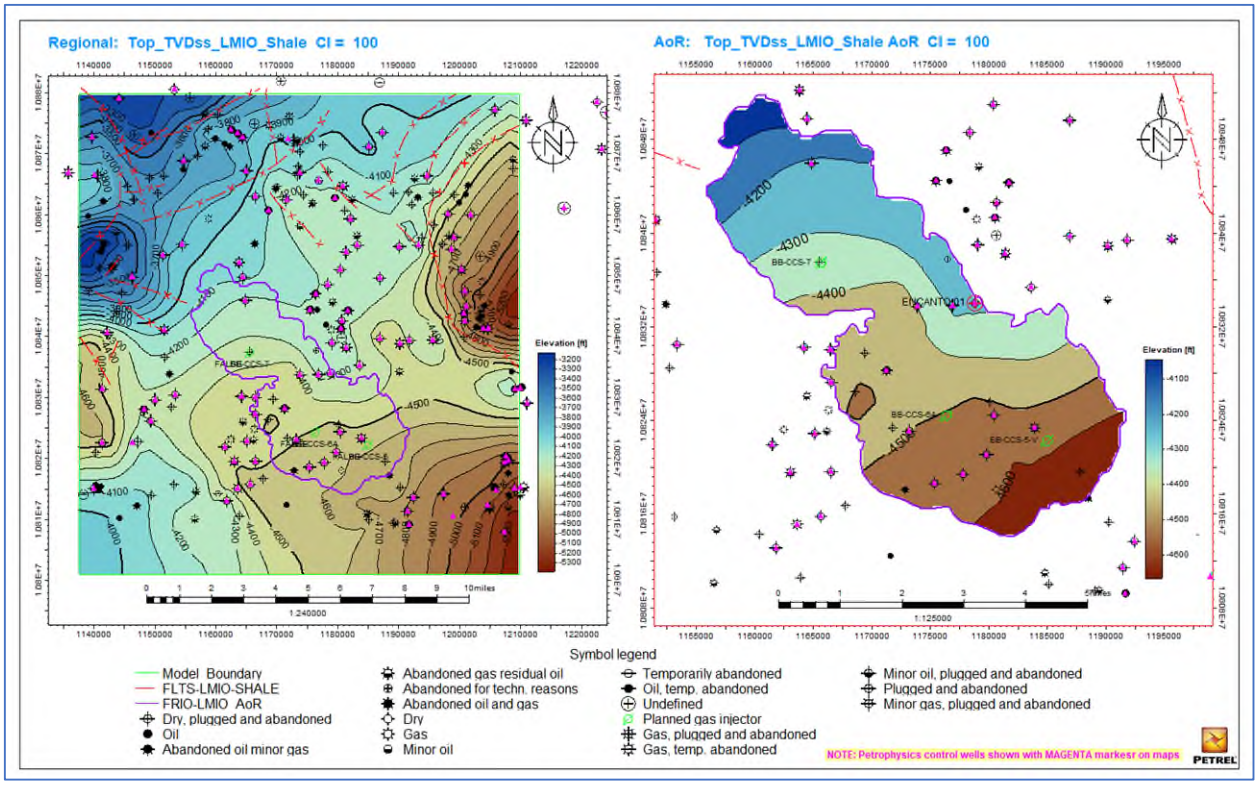


Figure AoR-173: Regional and AoR top structure maps of the Lower Miocene Shale Confining Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

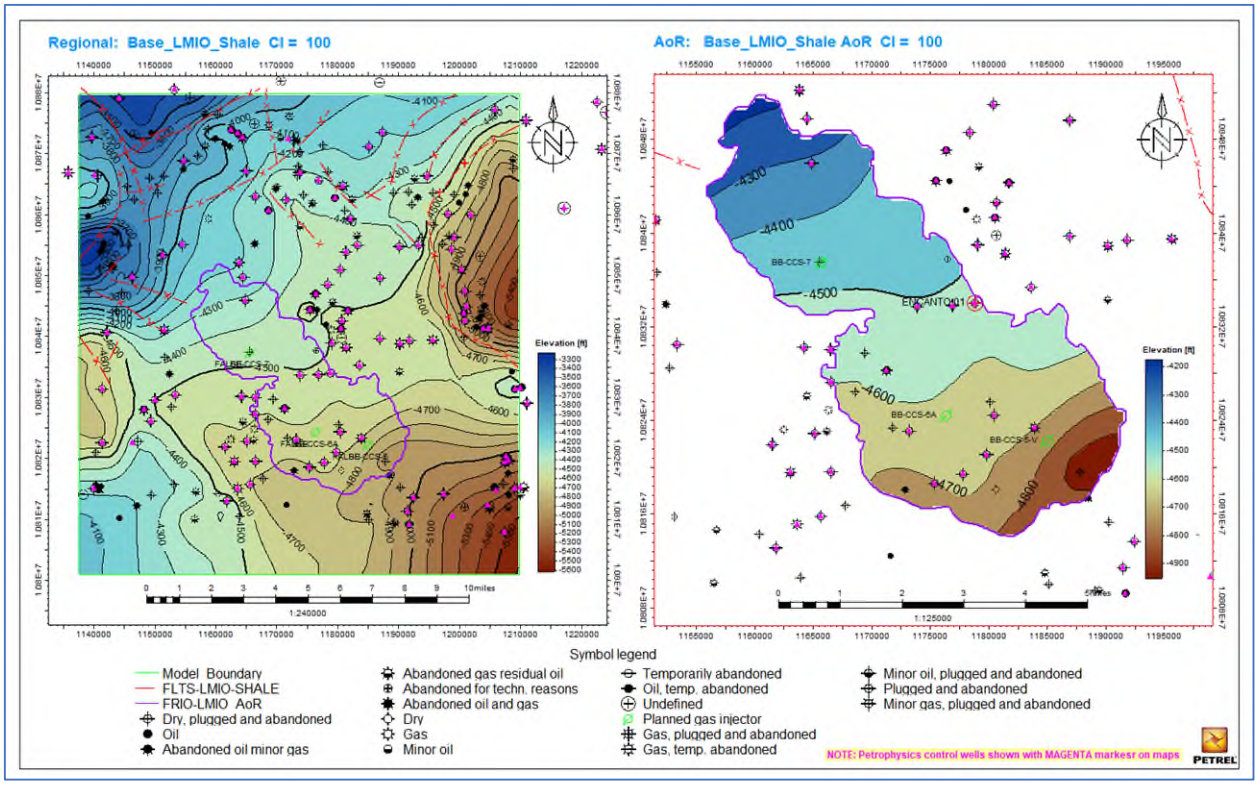


Figure AoR-174: Regional and AoR base structure maps of the Lower Miocene Shale Confining Zone, in feet, contour interval = 100 ft. This map was generated from the Miocene Model described under 5.0.

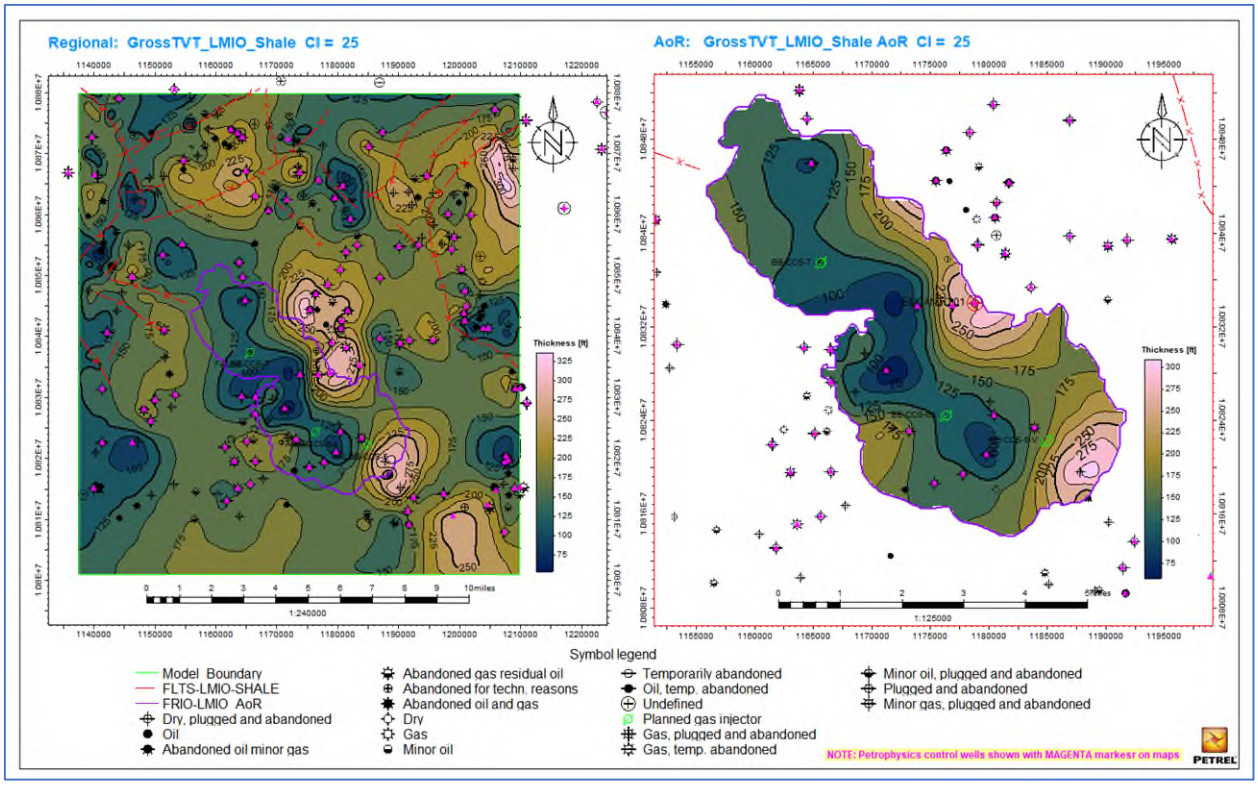


Figure AoR-175: Regional and AoR gross thickness maps of the Lower Miocene Shale Confining Zone, in feet, contour interval = 25 ft. This map was generated from the Miocene Model described under 5.0.

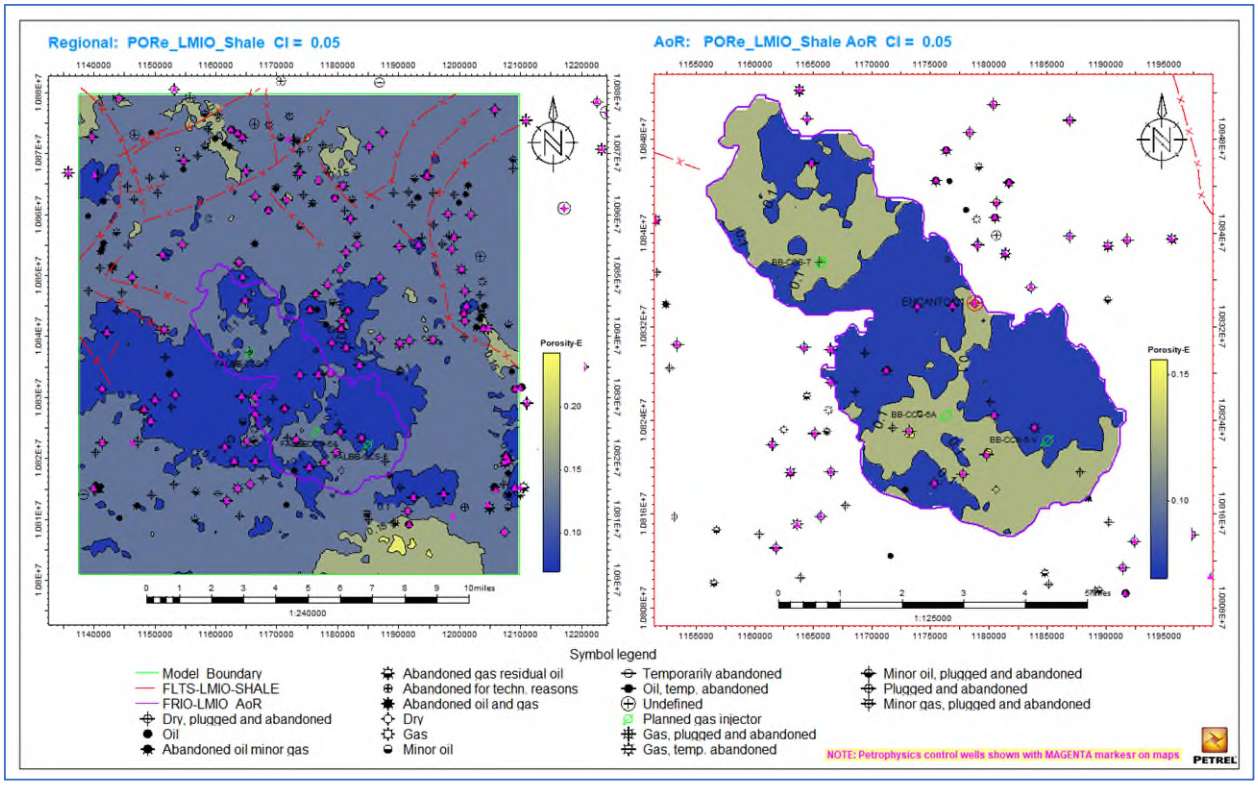


Figure AoR-176: Regional and AoR average effective porosity of the Lower Miocene Shale Confining Zone, in feet, contour interval = 0.05 p.u. This map was generated from the Miocene Model described under 5.0.

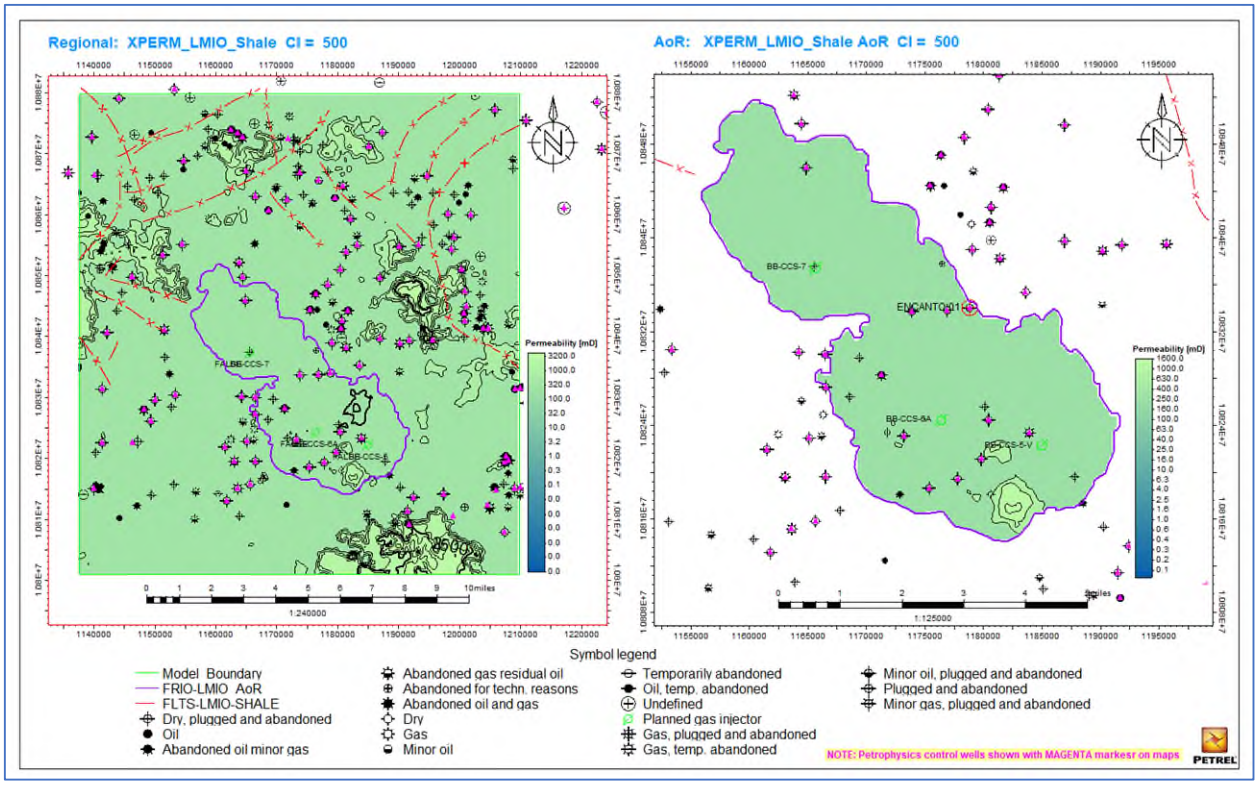


Figure AoR-177: Regional and AoR average permeability of the Lower Miocene Shale Confining Zone, in feet, contour interval = 500 md. This map was generated from the Miocene Model described under 5.0.

The following numbers represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-12: Reservoir properties for the Lower Miocene Shale Confining Zone, summary of values extracted from geomodel maps within the AoR boundary. This table was generated from the Miocene Model described under 5.0.

Reservoir Properties in AoR	Values Extracted From Geomodel	Lower Miocene Confining Zone
Top Depth (TVDss)	Average	-4,404.42
	Minimum	-4,667.21
	Maximum	-4,046.22
Base Depth (TVDss)	Average	-4,558.92
	Minimum	-4,953.14
	Maximum	-4,175.98
Gross Thickness (ft.)	Average	154.23
	Minimum	57.55
	Maximum	308.39
Effective Porosity (fraction)	Average	0.12
	Minimum	0.07
	Maximum	0.24
Permeability (md)	Average	62.00
	Minimum	0.00
	Maximum	1,592.00

3.8.2.5 Miocene Composite Confining Zone = Dissipation Zone

Miocene Composite Confining Zones were mapped based on integrating petrophysical well logs with completion and injection depths of seven permitted saltwater disposal wells in and around the greater Area of Interest (AOI) (see Table AoR-13).

Table AoR-13: Seven saltwater disposal wells that were integrated in the mapping of the Miocene Composite Confining Zone for dissipation.

Relative location	UWI	Well Name	Injection interval [MD]	
			top	base
inside area of interest (AoR)	42-071-31590	Dugat 1	3,050	4,400
	42-071-32453	Dugat SWD_3	2,500	4,500
	42-071-31663	Epler John L_2	1,960	2,020
	42-071-30370	O C Devillier_3	2,550	4,050
in neighboring producing fields	42-291-04582	Dan Harrison Fee 19-A	2,288	2,312
	42-071-01554	Wilcox SWD 17	1,400	2,100
	42-071-31968	Syphrettdw 13	1,790	2,029

Three individual confining zones were chosen because they were located immediately above discrete permitted and approved injection zones in those seven SWDs and correlative on Spontaneous Potential and deep resistivity logs in the dip and strike directions within the Bluebonnet model boundary. The fact that shallow saltwater disposal wells were permitted and allowed to inject at shallow depths ranging from 1400 ft to 4,500 ft measured depth, implies that regional fluid-migration barriers exist on top of the approved disposal zones.

To characterize these three confining zones within the Miocene Composite Confining Zone, wireline logs (spontaneous potential and deep resistivity curves) from 45 to 120 wells were used to make structure and gross thickness maps within the Bluebonnet model boundary. The well count is dependent on depth, as not every well has logs that cover all additional composite confining zones up to surface; instead, most logs only have partial coverage. The number of wells with logs – and accordingly the amount of tops correlated – decreases with shallower depths of the zones of interest. For example, the deeper Miocene Composite Confining Zone 3 has a greater number of wells with log coverage and tops correlated than the shallower Miocene Composite Confining Zone 1 as shown in Figure AoR-179. This is proportional with the level of confidence in well tops over the regional extent in strike and dip direction.

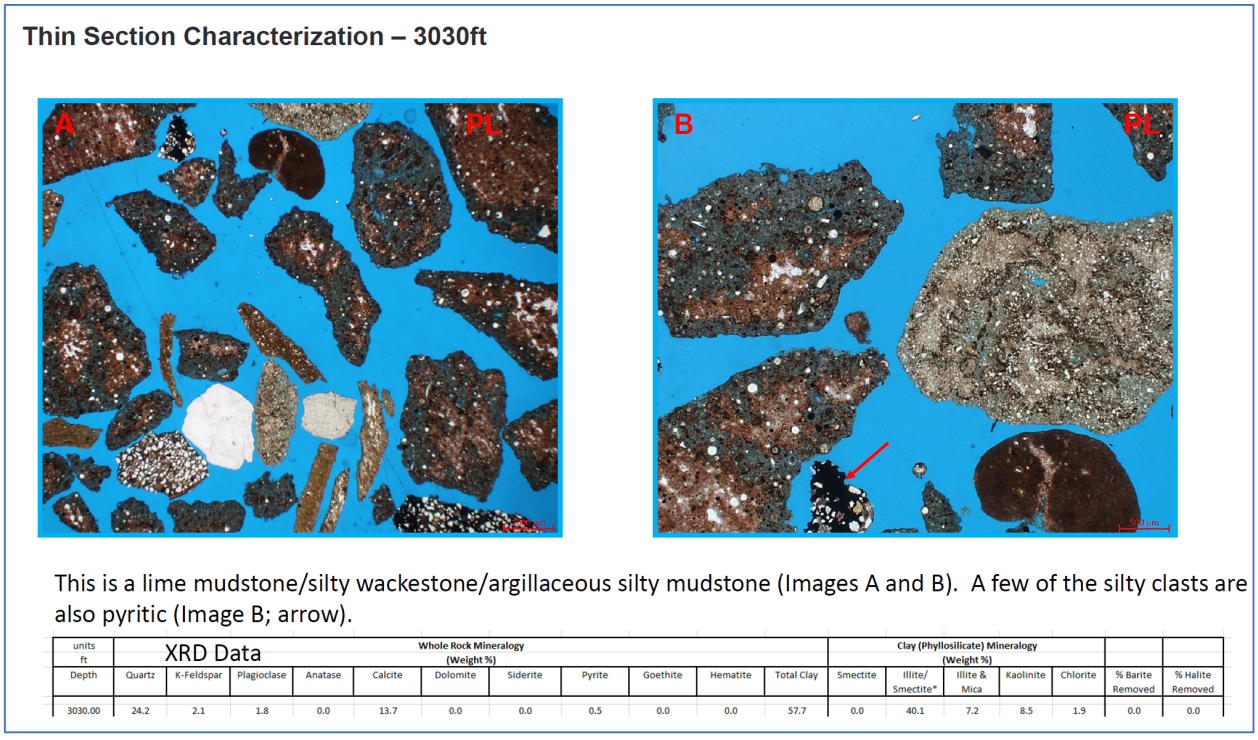
This Miocene Composite Confining Zone, located above the primary Lower Miocene Confining Zone, will attenuate any vertical fluid displacement and pressure buildup outside the proposed injection zones, and is requested to be permitted as the upper-most confining system. The individual Confining Zones 1 through 3 that make up the Miocene Composite Confining Zone are most likely terrestrial paleosols, analog to the Lower Miocene Confining Zone, which was cored in the stratigraphic test well Encanto 01. Bluebonnet drilled a dedicated well Bluebonnet USDW 8 and acquired 79 ft of whole core and 29 RSWC with a targeted data acquisition in the confining shales of the Miocene Composite Confining Zone. Out of the 29 RSWC only 5 RSWC passed the laboratory inspection to continue with further analysis and most of the 79 ft of whole core are utilized in the ongoing core analysis. Bluebonnet is currently working with the laboratory performing routine and special core analyses to characterize the shallow mudrocks and their ability to trap, attenuate, or seal any escaped CO_2

Special core analyses include geomechanical measurements such as compressibility of these matrix materials in the sands and the confining shales, since those values and associated upper and lower ranges have a significant impact in the dynamic simulations. The results from these routine and special core analyses will be provided to supplement this analysis, once the laboratories complete the experiments and release the data.

The data acquisition on Bluebonnet USDW 8 also included collecting two sets of wet drill cuttings every 60 ft from surface to TD. The cuttings are crucial to inform the project about the lithology in between the cored intervals, including the shallow freshwater aquifers which are mainly unconsolidated sands containing fresh water, the confining shales in between and additional shales below the base of USDW, which make up the Miocene Composite Confining Zone.

3.8.2.5.1 Petrologic Description

This is an example of a limey mudstone/silty wackestone/argillaceous silty mudstone comprising the Miocene Composite Confining Zone. Based on XRD data, the majority of the whole rock mineralogy are clays, dominantly illite/smectite, followed by quartz, calcite, and minor K-feldspar and plagioclase. A few of the silty clasts are also pyritic (arrow).



XRD Data

units ft	Whole Rock Mineralogy (Weight %)											Clay (Phyllosilicate) Mineralogy (Weight %)						
Depth	Quartz	K-Feldspar	Plagioclase	Anatase	Calcite	Dolomite	Siderite	Pyrite	Goethite	Hematite	Total Clay	Smectite	Illite/ Smectite*	Illite & Mica	Kaolinite	Chlorite	% Barite Removed	% Halite Removed
3030.00	24.2	2.1	1.8	0.0	13.7	0.0	0.0	0.5	0.0	0.0	57.7	0.0	40.1	7.2	8.5	1.9	0.0	0.0

Figure AoR-178: Thin section analysis, petrologic description and XRD of the Miocene Composite Confining Zone from cuttings.

3.8.2.5.2 MICP from Miocene Composite Confining Zone

As described under 3.8.2.5, dedicated whole core (79 ft) and RSCW (5 valid out of 29) as well as cuttings every 60 ft were acquired in this Miocene Composite Confining Zone to evaluate seal integrity and seal capacity. This data acquisition specifically targeted the confining shales of the Miocene Composite Confining Zones 1 and 2. Currently routine and special core analyses with multiple labs are underway and data delivery is expected soon.

Based on two RSWC samples situated below the Miocene Composite Confining Zone 3 and USDW, the displacement pressure criteria will need an injection height of ~563 feet before breaking into the confining zone.

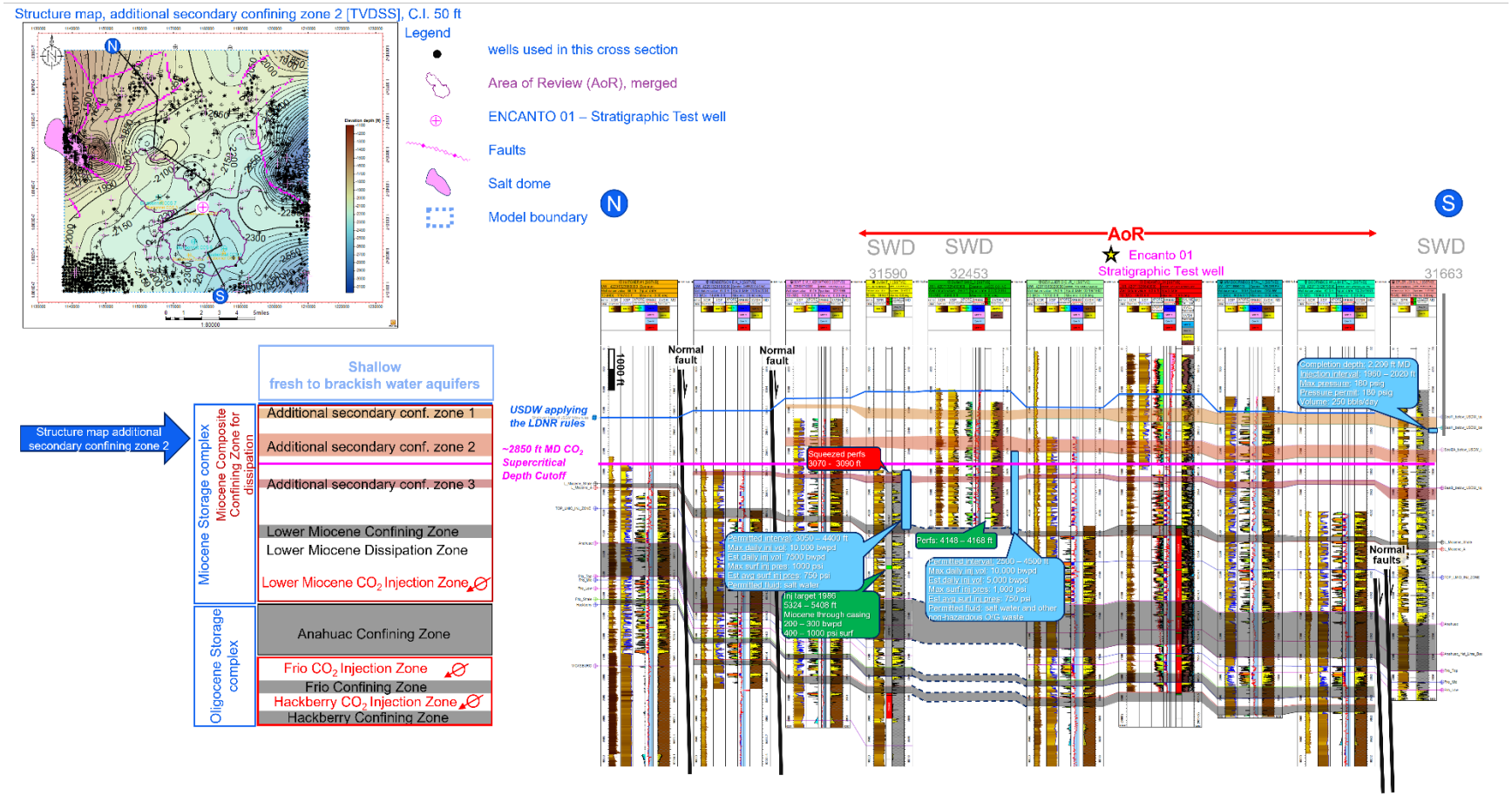


Figure AoR-179: Regional structural cross section through the Area of Interest (AOI), scale 1:8000. This cross section highlights the additional Miocene Composite Confining Zones above the Lower Miocene Confining Zone. Existing saltwater disposal wells (SWD) have been integrated to map three confining zones above the permitted SWD injection intervals; those are shown in shades of brown. They are most likely terrestrial paleosols, analog to the Lower Miocene Confining Zone, which was cored in the stratigraphic test well Encanto 01. Bluebonnet Sequestration HUB, LLC, will pursue additional core data, e.g. whole cores and rotary sidewall cores, in these Miocene Composite Confining Zone.

3.8.2.5.3 Miocene Composite Confining Zone Maps

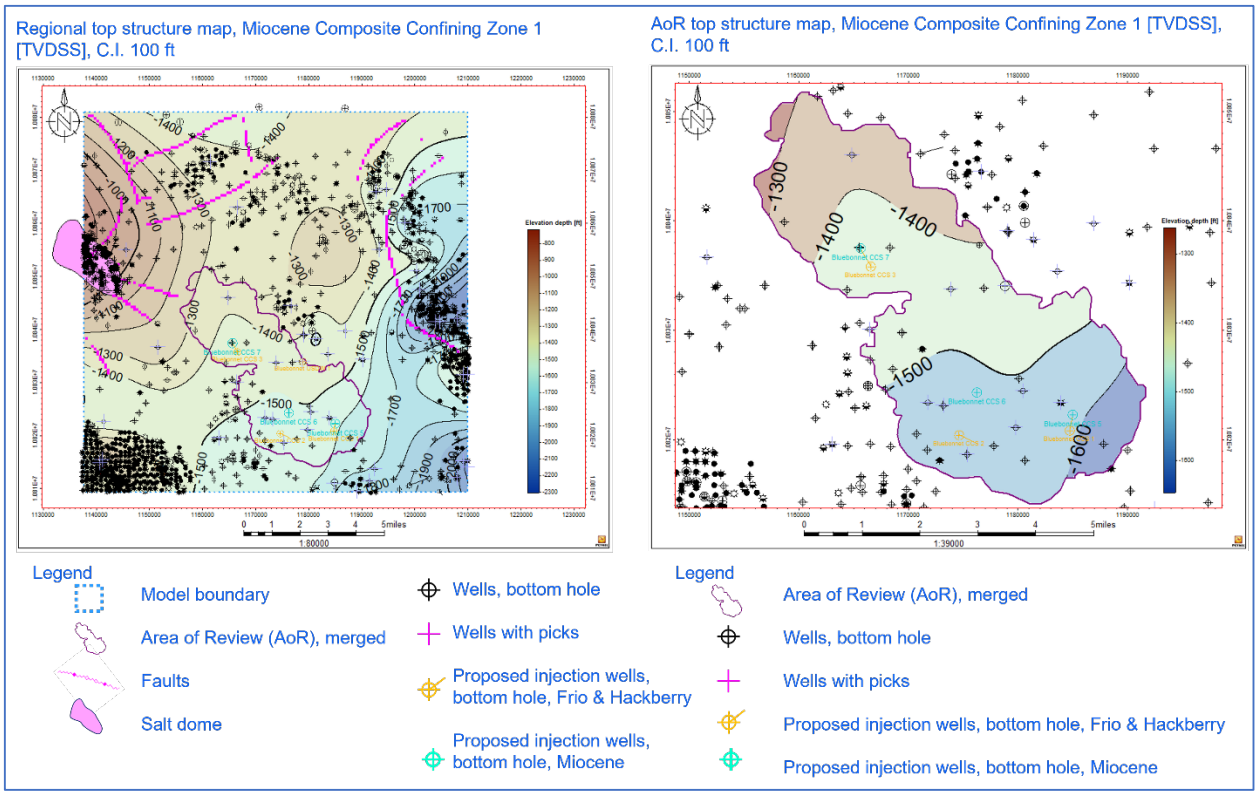


Figure AoR-180: Regional and AoR top structure map of the Miocene Composite Confining Zone 1 in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

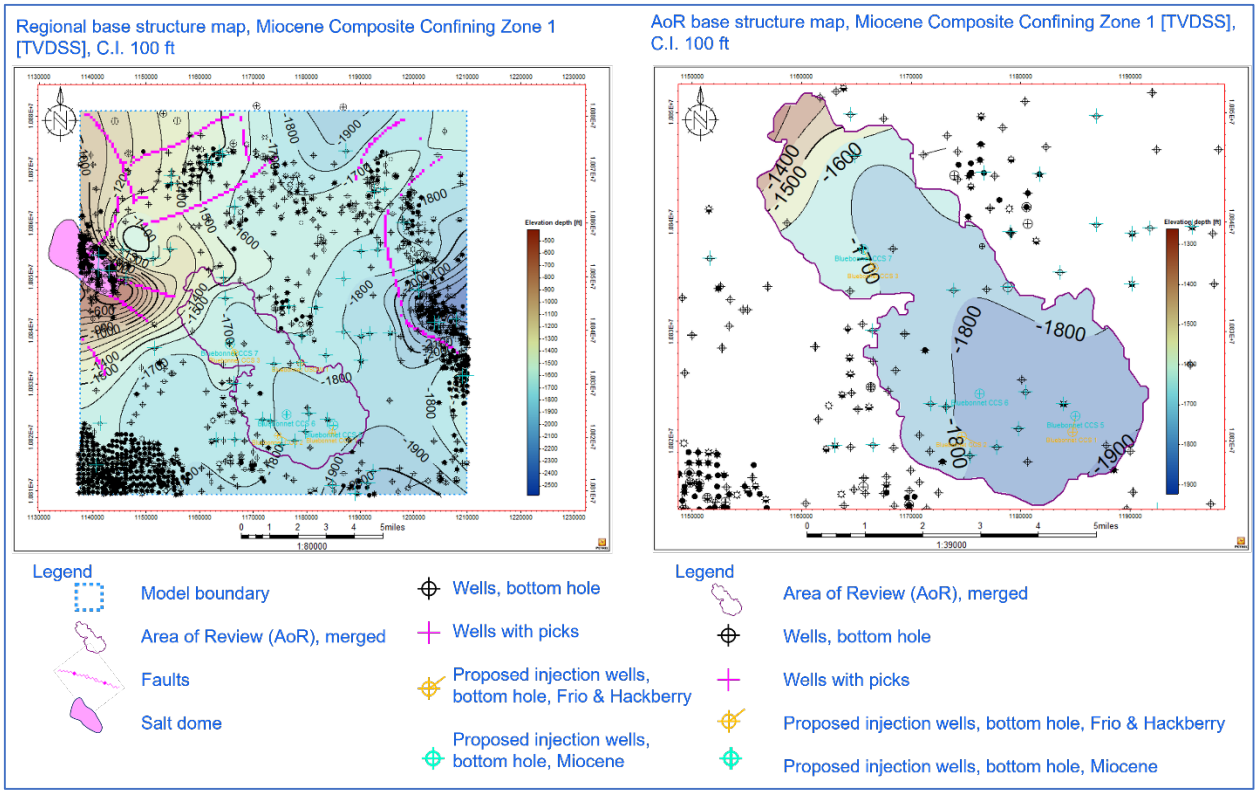


Figure AoR-181: Regional and AoR base structure map of the Miocene Composite Confining Zone 1 in TVDSS, contour interval 100 ft. This map was generated from the Oligocene Model described under 4.0.

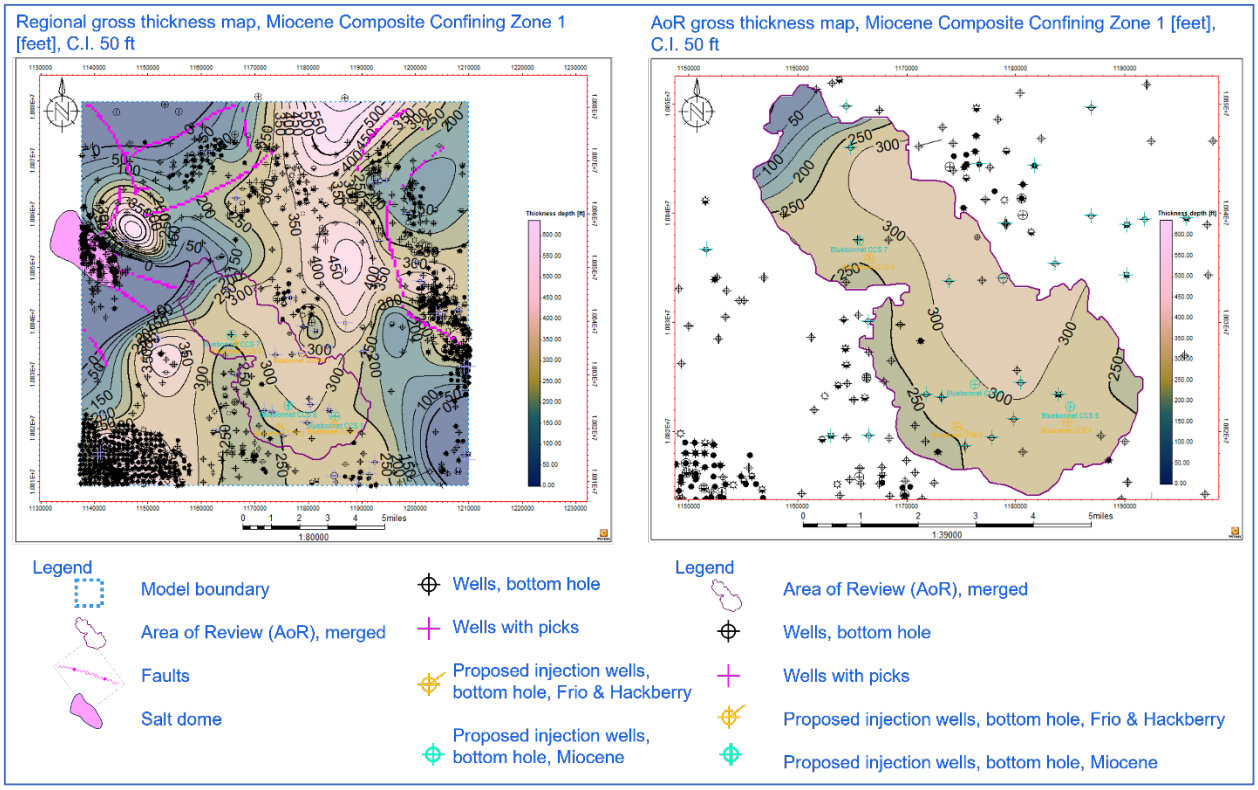


Figure AoR-182: Regional and AoR gross thickness map of the Miocene Composite Confining Zone 1 in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

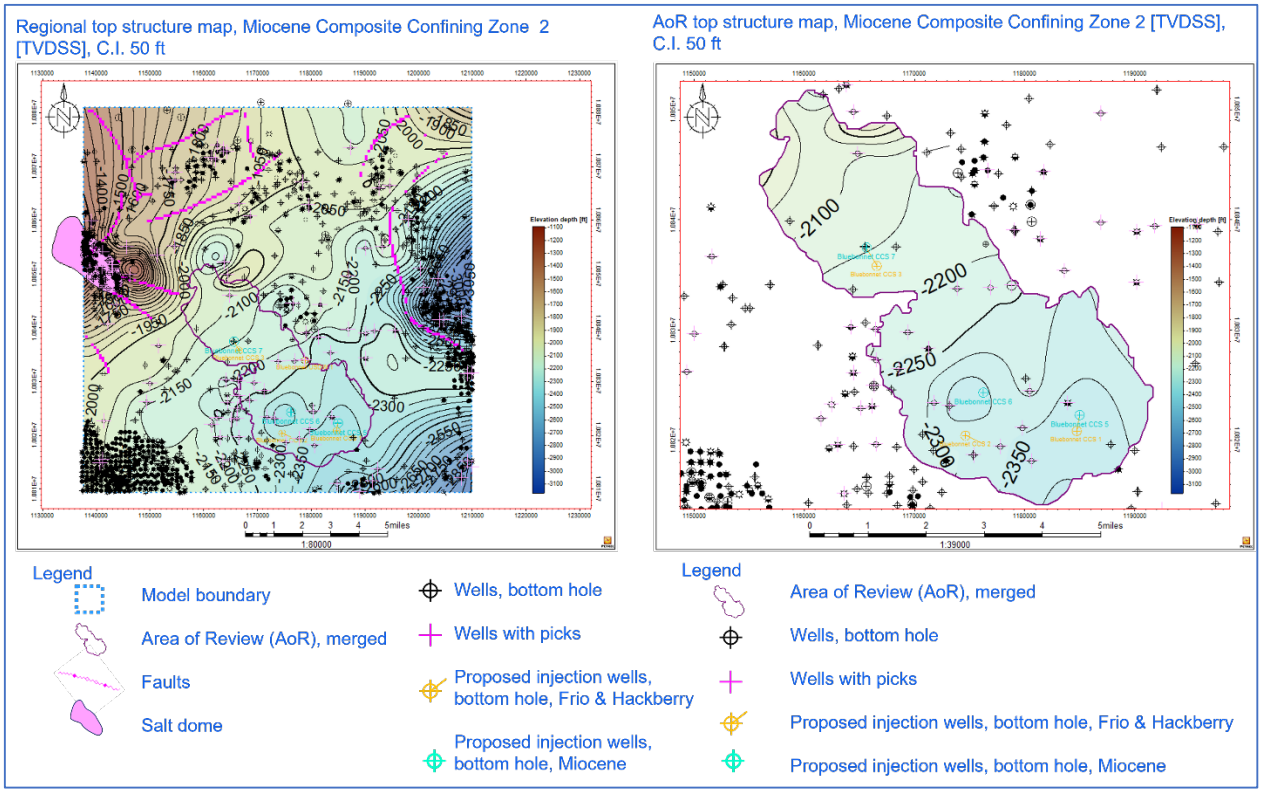


Figure AoR-183: Regional and AoR top structure map of the Miocene Composite Confining Zone 2 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

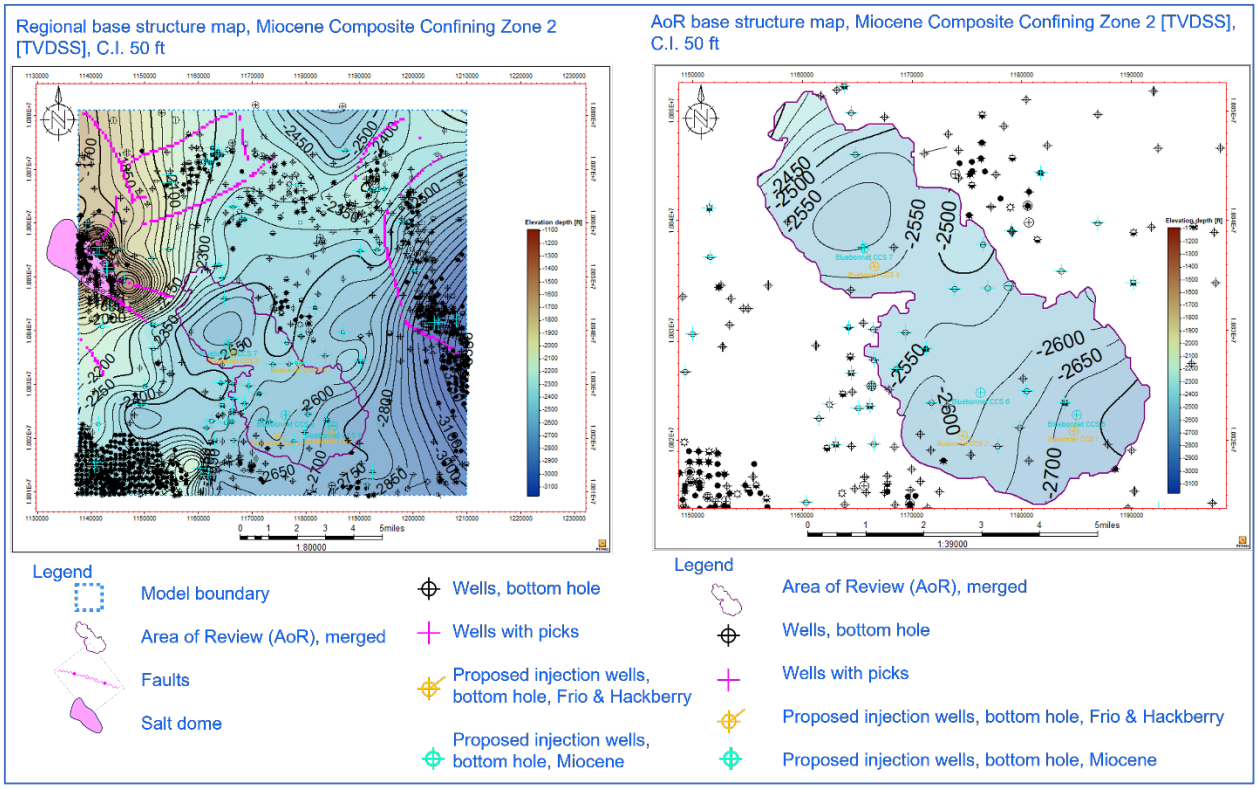


Figure AoR-184: Regional and AoR base structure map of the Miocene Composite Confining Zone 2 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

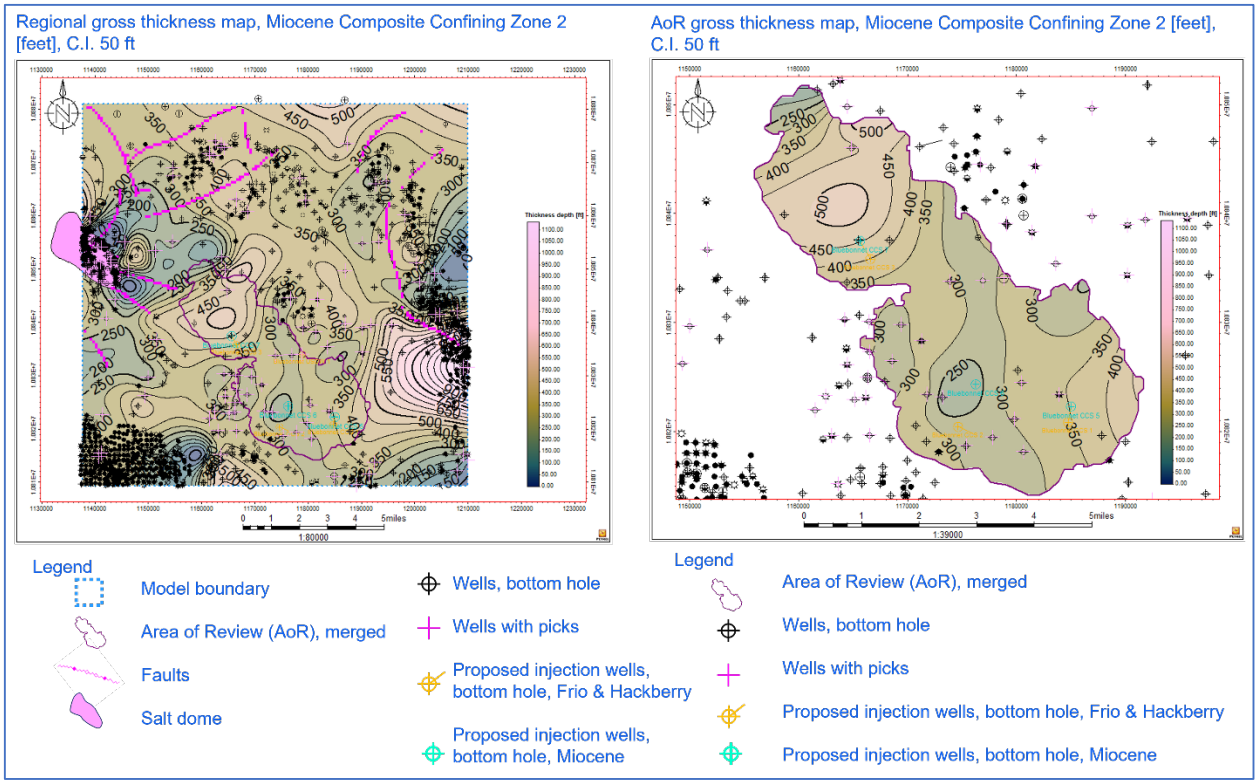


Figure AoR-185: Regional and AoR gross thickness map of the Miocene Composite Confining Zone 2 in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

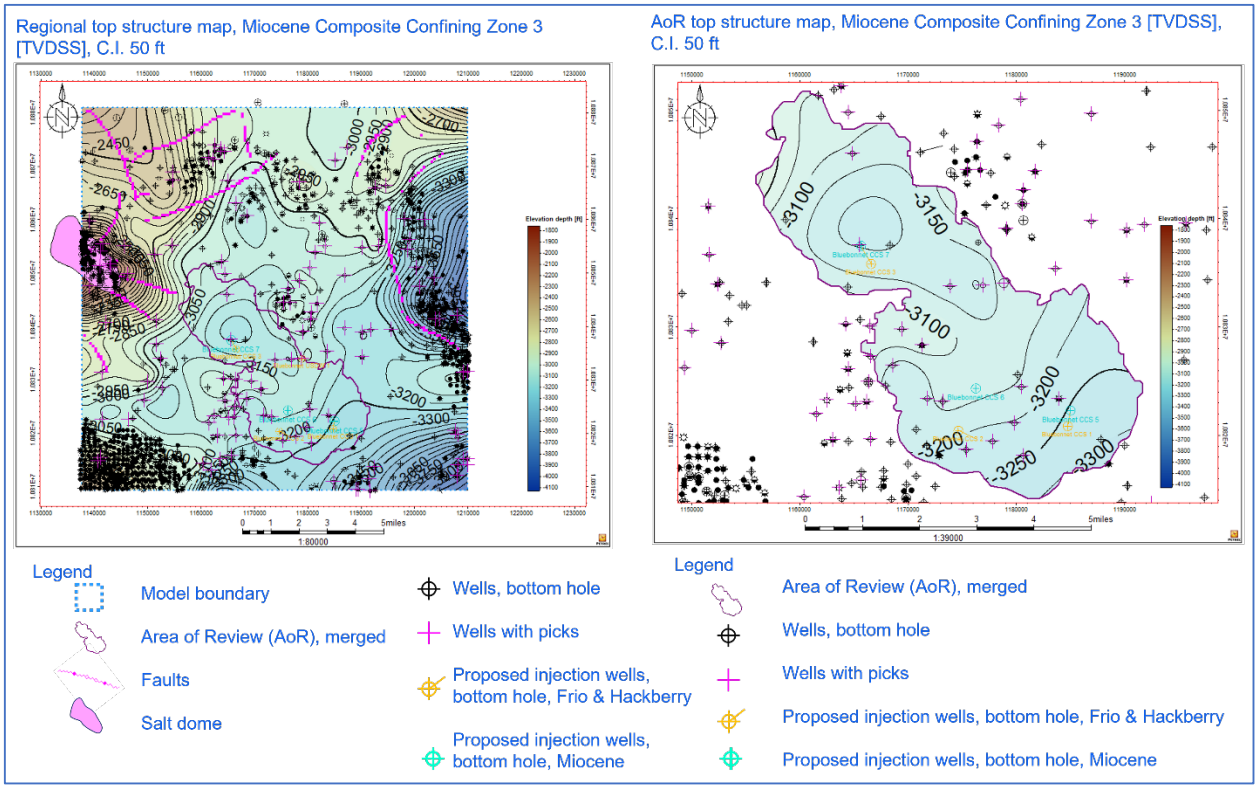


Figure AoR-186: Regional and AoR top structure map of the Miocene Composite Confining Zone 3 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

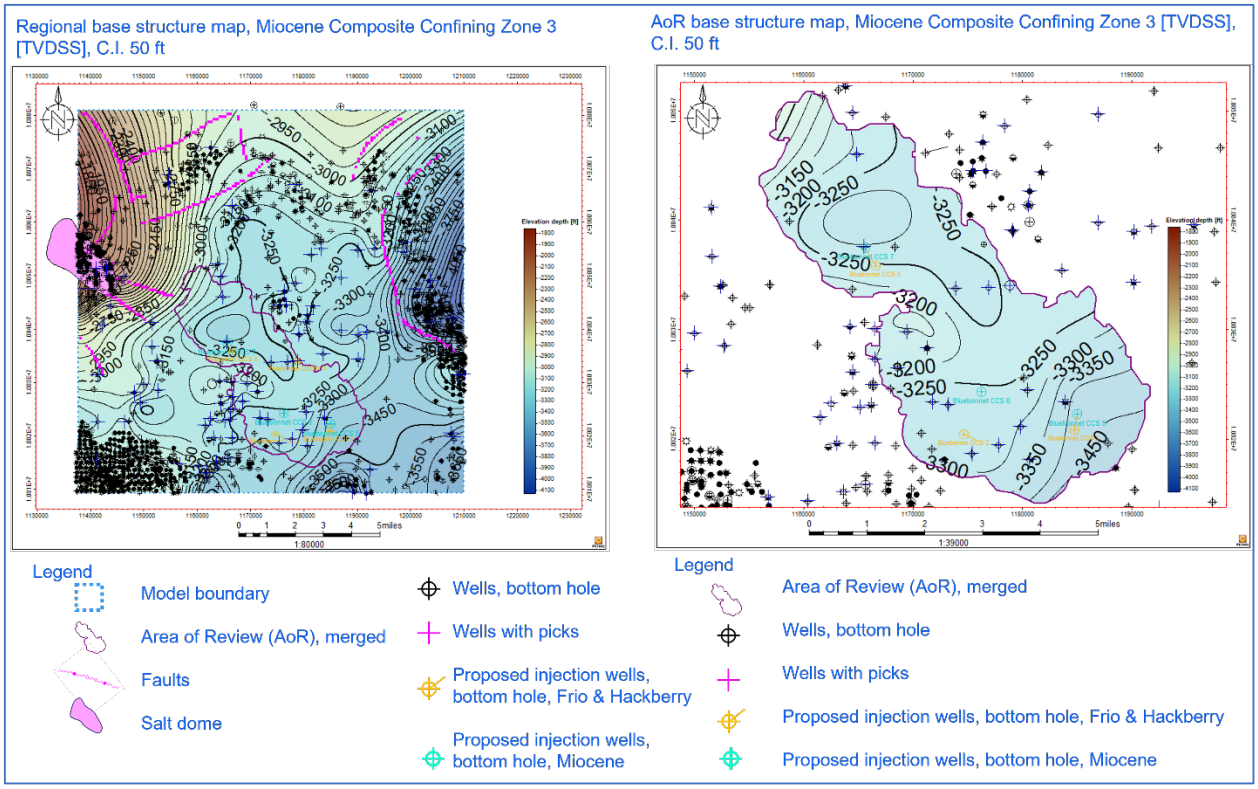


Figure AoR-187: Regional and AoR base structure map of the Miocene Composite Confining Zone 3 in TVDSS, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

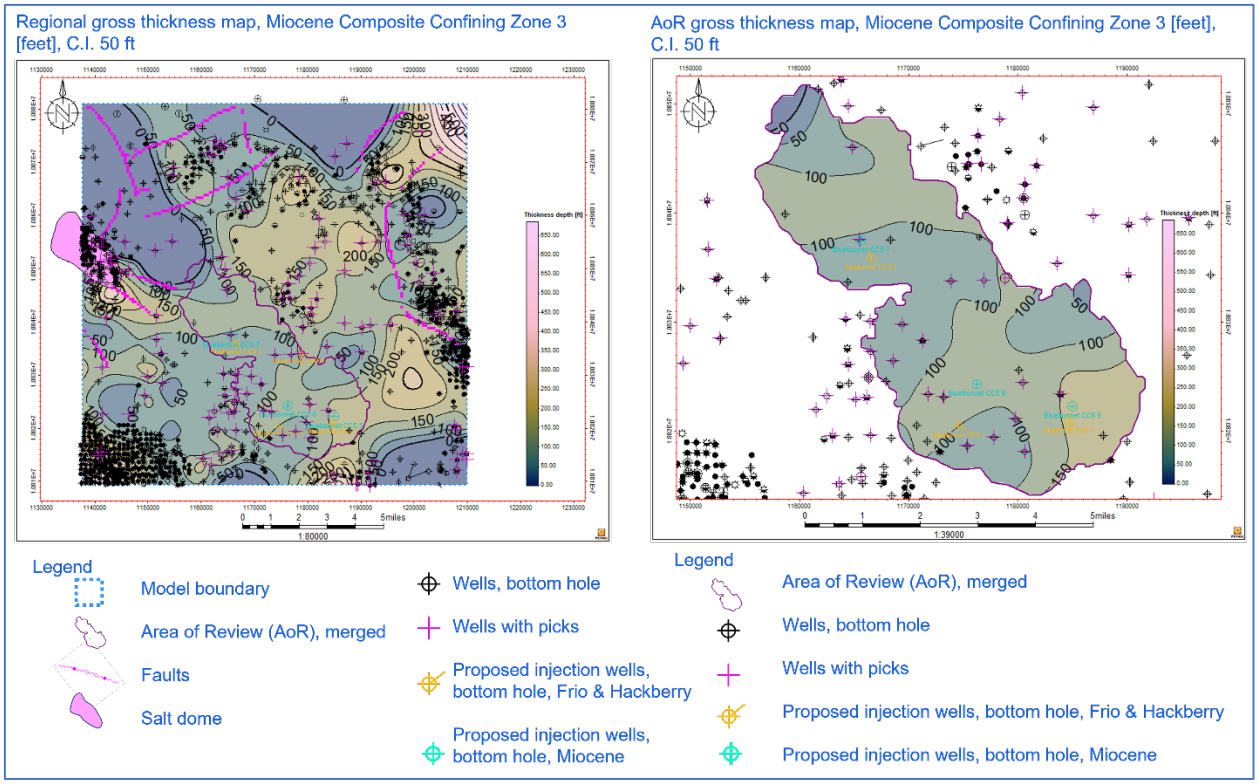


Figure AoR-188: Regional and AoR gross thickness map of the Miocene Composite Confining Zone 3 in feet, contour interval 50 ft. This map was generated from the Oligocene Model described under 4.0.

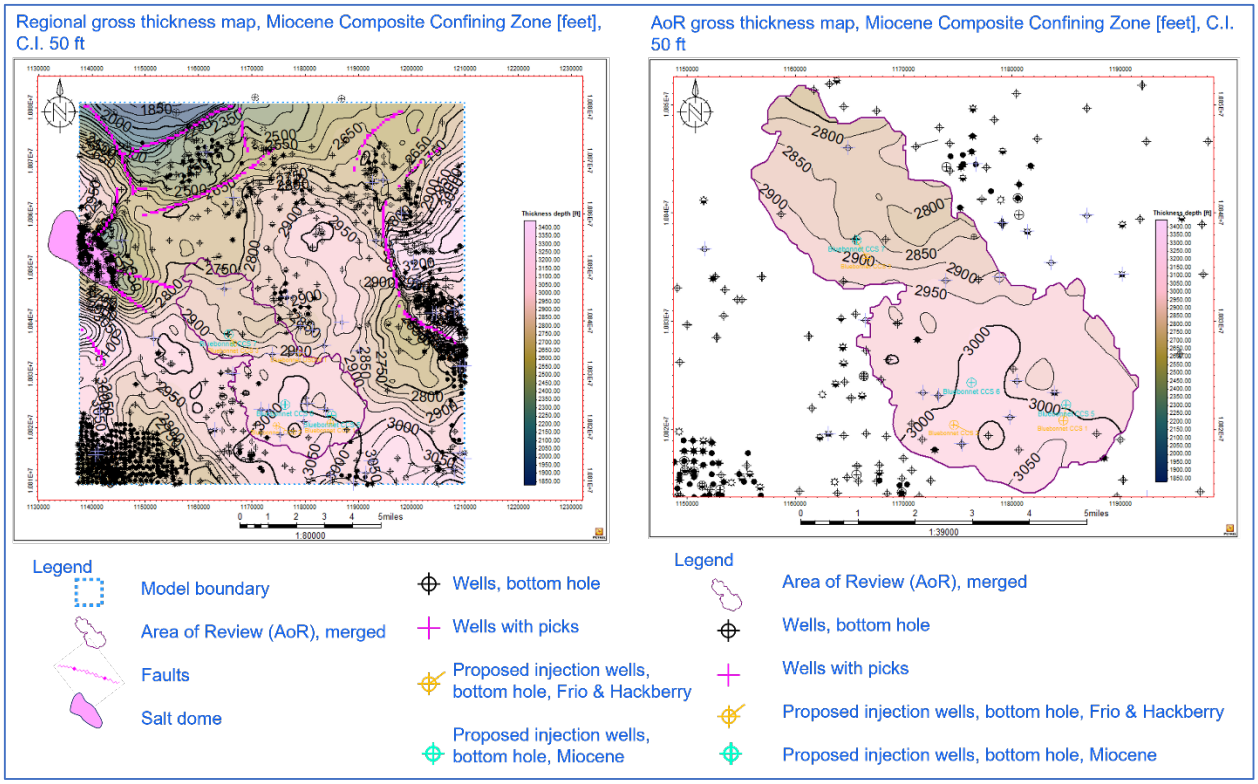


Figure AoR-189: Regional and AoR gross thickness map of the combined Miocene Composite Confining Zone in feet, contour interval 50 ft. The base of this gross thickness map is the top of the Lower Miocene Confining Zone. This map was generated from the Oligocene Model described under 4.0.

The following numbers in Table AoR-14 represent map based average numbers extracted from the geomodel over the AoR:

Table AoR-14: Reservoir properties for the Miocene Composite Confining Zone, summary of mean values extracted from geomodel maps over the AoR. This table was generated from the Oligocene Model described under 4.0.

Reservoir properties in AoR	Extracted map values from geomodel	Miocene Composite Confining Zone			
		Zone 1	Zone 2	Zone 3	Combined
Top depth [TVDSS]	Minimum	-1,647	-2,407	-3,327	-1,647
	Maximum	-1,262	-1,916	-2,928	-1,262
	Average	**-1,473**	**-2,236**	**-3,167**	**-1,473**
Base depth [TVDSS]	Minimum	-1,923	-2,777	-3,492	-4,663
	Maximum	-1,262	-2,224	-2,937	-4,034
	Average	**-1,745**	**-2,583**	**-3,270**	**-4,406**
Gross Thickness [ft]	Minimum	-2	143	-80	2,722
	Maximum	341	542	178	3,075
	Average	**272**	**347**	**103**	**2932**

These three individually mapped confining zones are characterized by blocky SP log signatures that were identified above the permitted injection zones in existing saltwater disposal wells. The Miocene Composite Confining Zones 1, 2, and 3 were mappable across several miles in a north-south dip and east-west strike direction. In addition to mapping Miocene Composite Confining Zones 1, 2, and 3, the Bluebonnet Project team completed a shallow water well (Bluebonnet USDW 01) to validate the base of the USDW. Four open-hole fluid samples were acquired in Bluebonnet USDW 01 to confirm the base of the USDW. One explanation for water quality results from Bluebonnet USDW 01, used to revise the base USDW, is the presence of a low permeability shale underlying the revised base USDW, which is observed on open-hole logs in Encanto 01 and Bluebonnet USDW 01. Although this additional shale was not mapped across the AoR, yet due to sparse well log control in offset wells, it may act as an additional confining zone to protect the USDW. Further, results from Bluebonnet USDW 01, showed a strong nonlinear water quality trend with an inflection point in water quality occurring across this shale (Figure AoR-190). This boundary occurs approximately 300 ft above (i.e., 1,200 ft MD) what is currently defined as Miocene Composite Confining Zone 1.

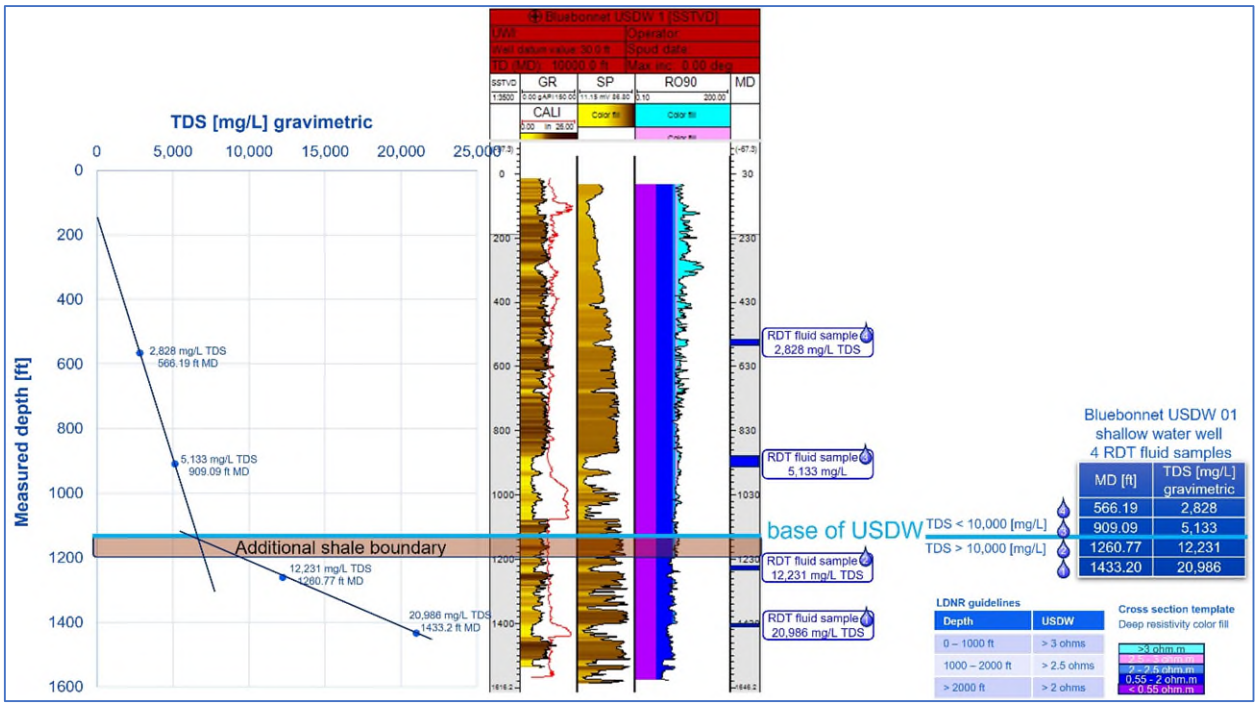


Figure AoR-190: Formation water TDS (mg/L) versus MD at Bluebonnet USDW 01. Strong inflection point in water quality across a shale boundary is shown below the revised base USDW at approximately 1,200 ft MD. Water quality and available openhole log data suggest that this additional shale may act as a confining zone.

3.8.2.5.4 Miocene Composite Confining Zone – Oil based image logs

During the characterization, the Project acquired oil-based image logs over the interval from Total Depth (TD) to the surface casing shoe. Figure AoR-191 shows the image over the interval corresponding to the Seal 3.

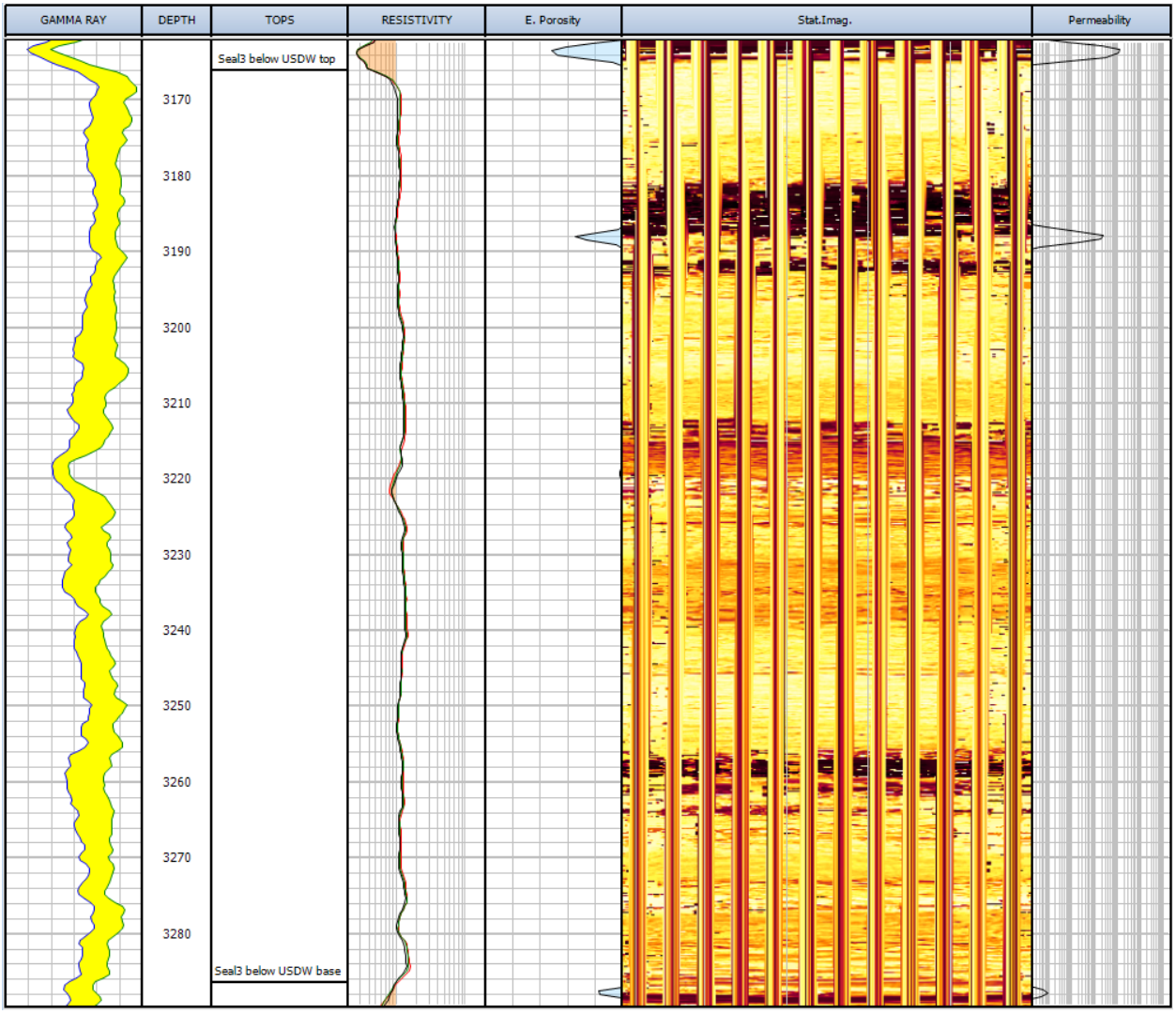


Figure AoR-191 Oil-based imager over the Seal 3. First track has the total gamma ray and uranium free gamma ray, the difference is shaded in yellow; second track has the measure depth; third track has the formation names; fourth track has the resistivity followed by the effective porosity track; the sixth track shows the static image, and the last track has the permeability.

Zooming in to see more detail, Figure AoR-192 shows the complexity of this seal. It is laminated and it has different rock characteristics, notice how the colors change.

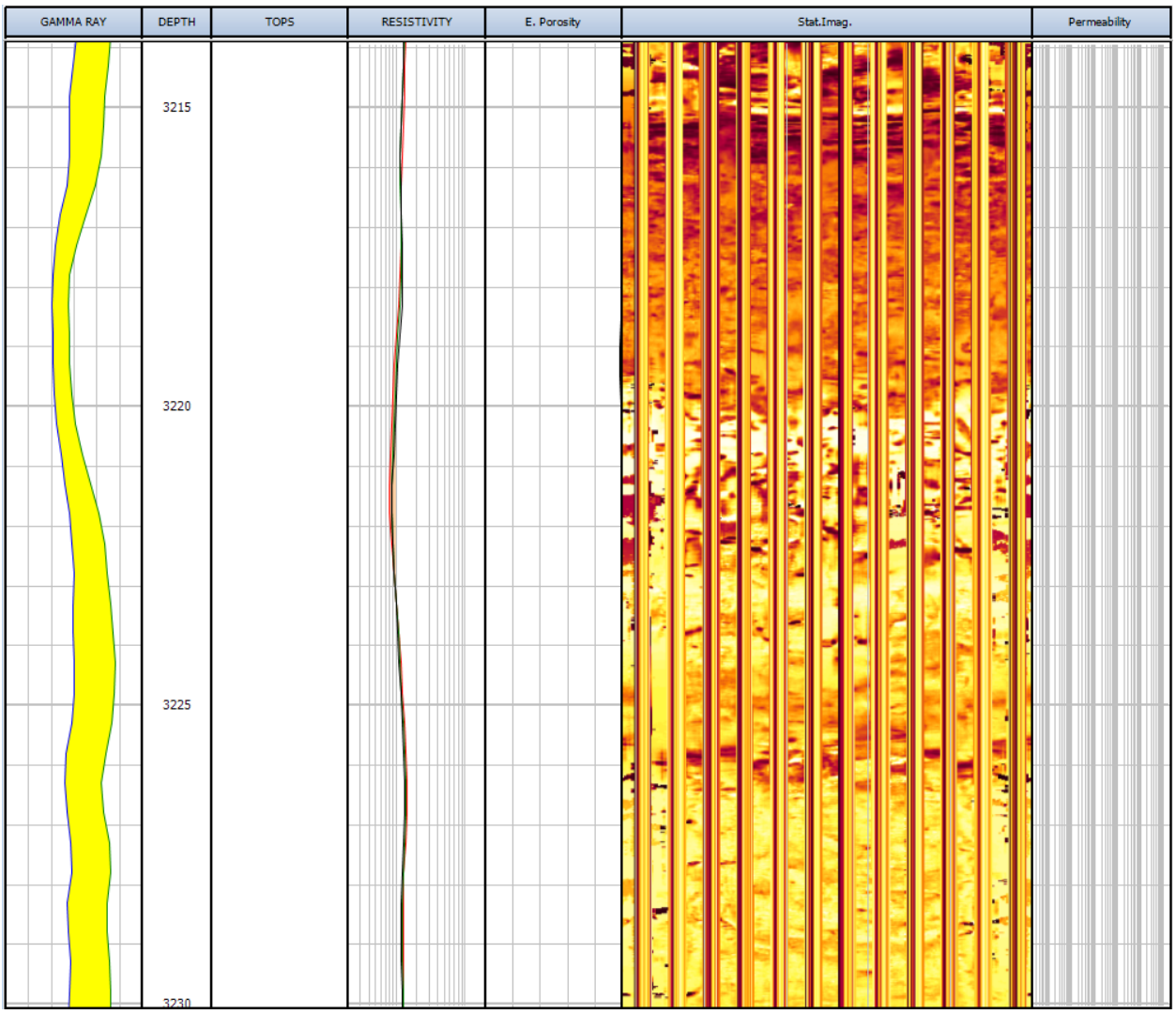


Figure AoR-192: Oil-based imager over the Seal 3. Zooming to see only 15 feet, we can appreciate the laminations and different rock composition in how the colors are changing. First track has the total gamma ray and uranium free gamma ray, the difference is shaded in yellow; second track has the measure depth; third track has the formation names; fourth track has the resistivity followed by the effective porosity track; the sixth track shows the static image, and the last track has the permeability.

3.9 Freshwater Aquifers

Groundwater production for drinking and municipal use in Chambers, Liberty, and Jefferson Counties, Texas is primarily sourced from the Chicot Aquifer, the shallowest of three primary aquifers that make up the overall Gulf Coast Aquifer. The Gulf Coast Aquifer can be subdivided into major and minor flow units. The full stratigraphic column (Figure AoR-193) includes the hydrogeologic units and geologic subunits of the Gulf Coast Aquifer. The cross section (Figure AoR-200 from 3.10) illustrates the gently sloping nature, south southeast, of these units towards the Gulf of Mexico. The oldest aquifer making up the lower-most Gulf Coast aquifer is the Jasper

Aquifer, which comprises the Oakville Formation and Lower Lagarto Formation (Young 2016). The Jasper Aquifer is composed of fine to coarse sand, sandstone, and clay intervals (Shaw 2016), and ranges from approximately 900 ft to 3,100 ft thick across Chambers and Jefferson counties. The Burkeville confining unit (Middle Lagarto), sometimes referred to as the Burkeville Aquiclude, is a clay-rich formation with a low specific yield and ranges from 130 ft to 300 ft thick (Tinsley 1971). This confining unit separates the Jasper Aquifer from the Evangeline Aquifer and may act as an effective hydraulic barrier between overlying and underlying aquifer systems (Young et al. 2016). The Evangeline Aquifer, which includes the Upper Lagarto, Lower Goliad, and Upper Goliad Formations, is made up of sand and sandstone with interbedded gravel and clay (Shaw 2016) and ranges in thickness across both counties from approximately 1,250 ft to 4,900 ft (Young 2016). The youngest major flow unit is the Chicot Aquifer, made up of the Willis, Lissie, and Beaumont Formations (Osbourne 2013, Young 2016). The Chicot Aquifer is comprised of sand, gravel, sandy clay, and clay, with grain size generally increasing with depth (Shaw 2016) and ranges from approximately 900 ft to 2,500 ft thick (Young 2016) across Chambers and Jefferson counties. Here, the base of the Gulf Coast Aquifer System is defined as the base of Jasper Aquifer or the lower Oakville Formation; however, the selected base can vary study to study as well as regionally (Young 2016; Young et al. 2010, 2012). In certain areas of the aquifer, the Anahuac Shale separates the base of the Jasper from the underlying Catahoula/Frio Formation. This shale section appears to be present in both Jefferson and Chambers counties.

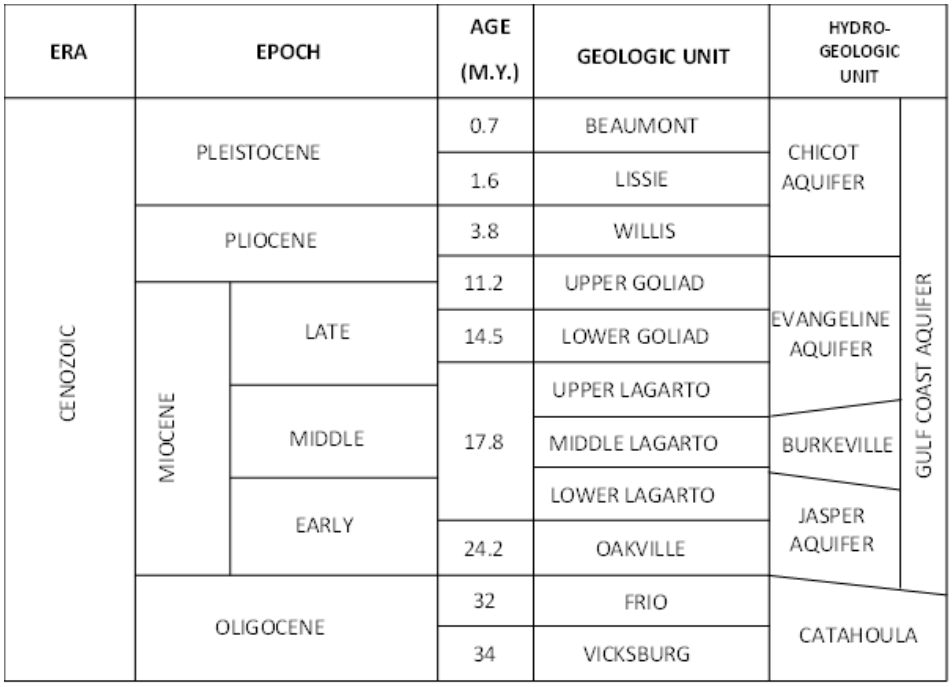


Figure AoR-193: Geologic and hydrogeologic units of the Gulf Coast Aquifer system (modified from Young et al. 2016).

Regionally, the Gulf Coast Aquifer System extends from the southern tip of Texas into western Florida with dip directions generally perpendicular to the coastline (Osbourne 2013). Aside from

the Beaumont Shale, which outcrops within both Chambers and Jefferson counties, most of the formations making up the Gulf Coast Aquifer crop out farther inland with the Jasper Aquifer cropping out up to 100 miles inland from the coast. An overpressured zone crosscuts the deepest extents of the aquifer system (Young 2016), of which the upper-most boundary can be observed at depths around 7,750 ft in Jefferson County; however, upper limits of this overpressured zone does not follow one consistent depth trend. Additionally, several fault systems running generally parallel to the coastline crosscut deeper hydrostratigraphic units, with the shallowest extents tipping out in the lower half of the Lagarto Formation (Young et al. 2016; 2012). The Frio fault zone likely extends from south to north into Chambers County and Yegua fault zone is present north of Chambers in the northwest portion of Jefferson County.

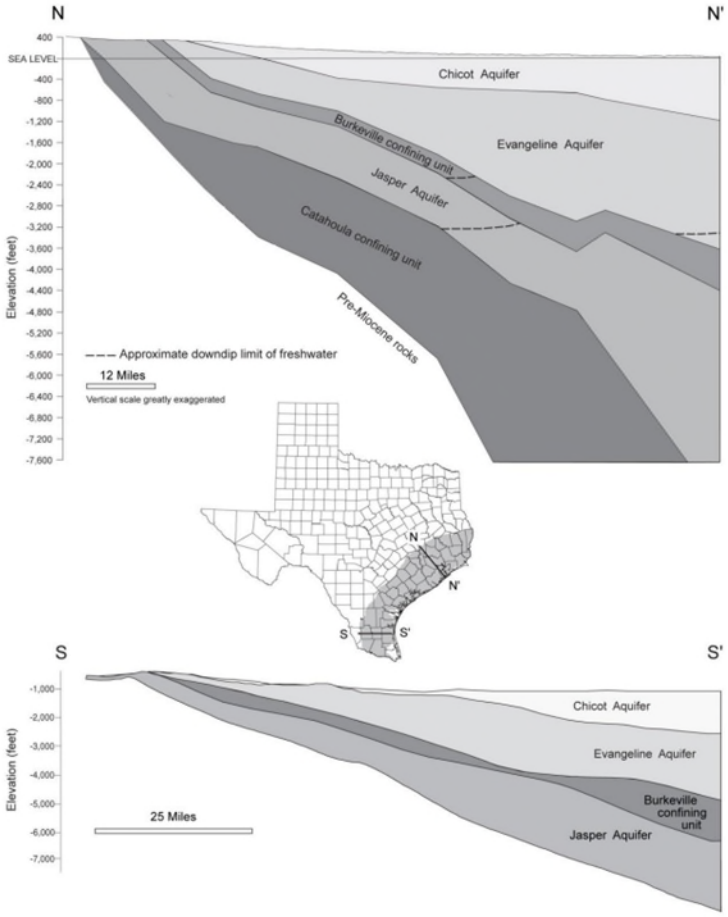


Figure AoR-194: Cross sections across the Gulf Coast Aquifer (TWDB 2016).

The Gulf Coast Aquifer System recharges mainly by precipitation on unconfined outcrop areas. Units comprising the Gulf Coast Aquifer outcrop in bands that parallel the Gulf Coast (Figure AoR-195). This is due to geologic units dipping towards the Gulf of Mexico and erosion exposing underlying layers of rock. The primary recharge mechanism of fresh groundwater is through precipitation that has not been consumed as runoff or stream flow (Tinsley 1971). Precipitation falls onto outcropped areas where a small percentage infiltrates the water table, creating recharge. In some cases, portions of water that reach saturated zones return to the surface as spring flow.

Salinity values of groundwater within the Gulf Coast Aquifer, including the Evangeline and Jasper aquifers, typically increase with depth and vary laterally.

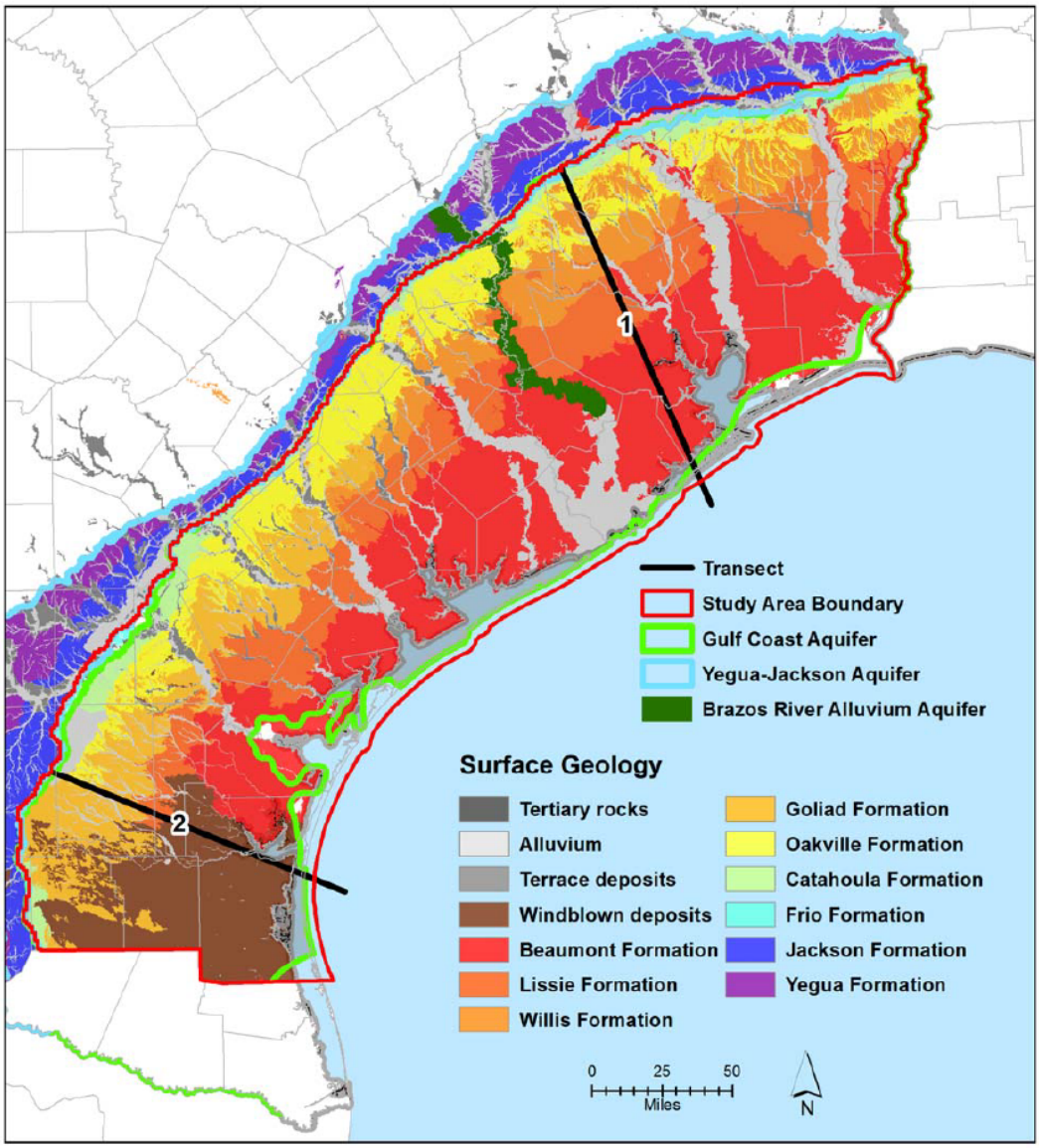


Figure AoR-195: Map of the Texas Gulf Coast showing the surface geology (outcrops) of the Gulf Coast Aquifer System (Young 2016).

The predevelopment potentiometric surface of the Chicot Aquifer flows south-southeast toward the Gulf of Mexico (Figure AoR-196). The southwardly dipping structure and northern updip limit of the Chicot Aquifer cause high head observed in the north and gradually less head moving south, resulting in the south-southeast hydraulic gradient. Groundwater development has resulted in changes to both local and regional hydraulic gradients for the Chicot Aquifer (Figure AoR-197). For example, groundwater drawdown observed in Harris County (City of Houston) has resulted in a regional pressure sink and now influences regional groundwater flow directions. Simulated

potentiometric surfaces for the Chicot Aquifer suggest current groundwater flows west-southwest (towards Harris County) in Chambers, Jefferson, and Liberty Counties (Figure AoR-197).

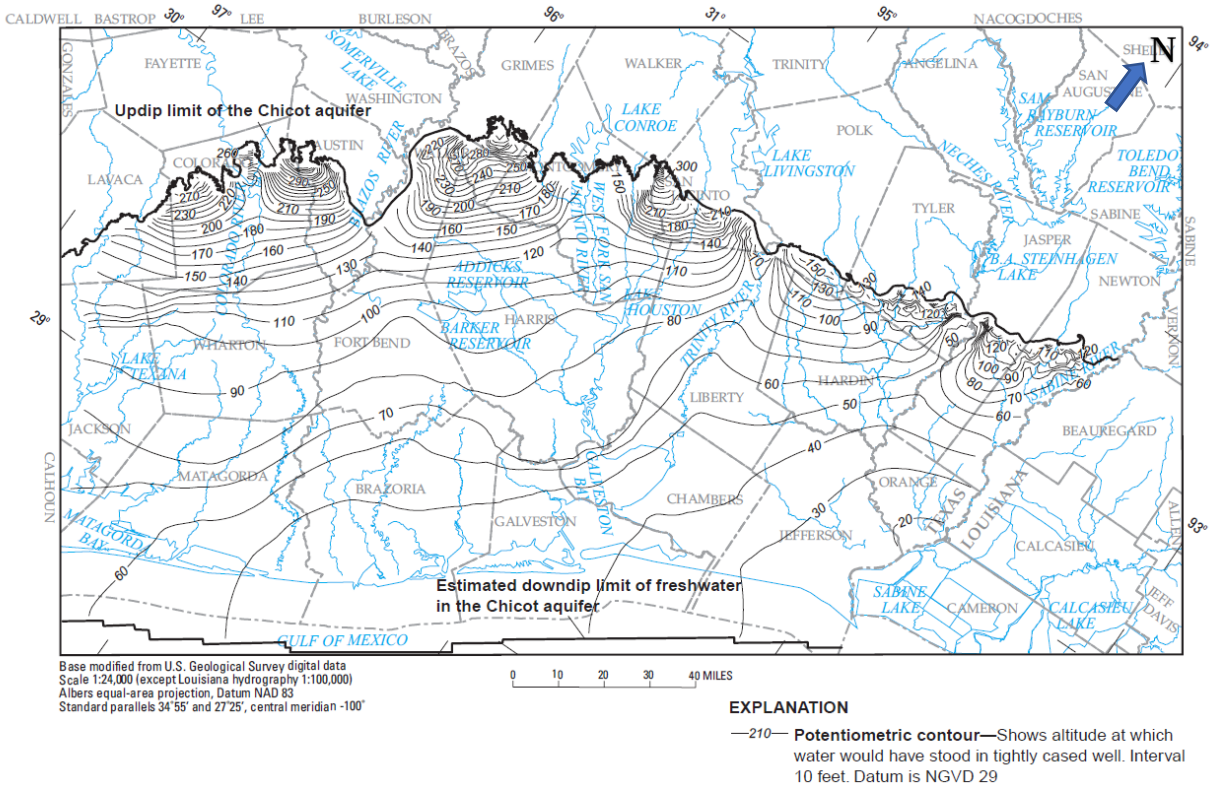


Figure AoR-196: Predevelopment potentiometric surface of the Chicot aquifer, simulated in the Groundwater Availability Model (modified from USGS).

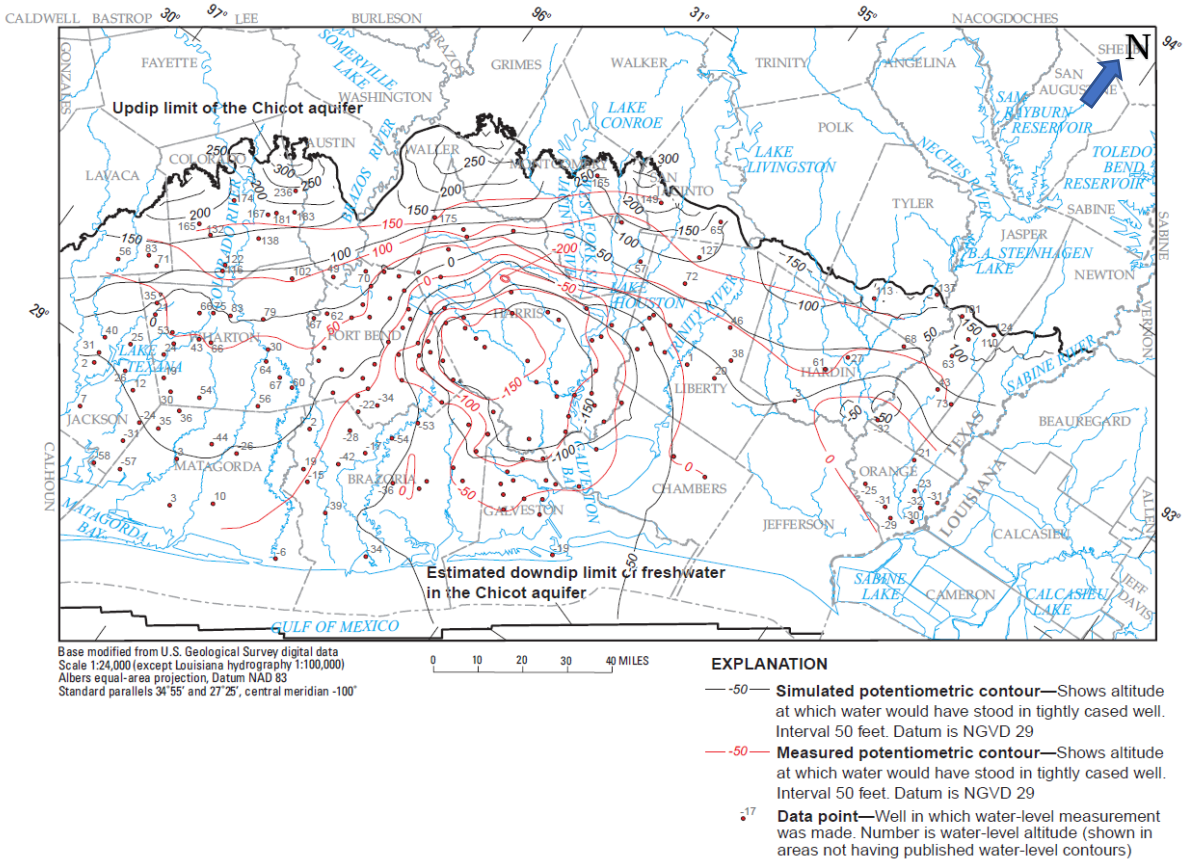


Figure AoR-197: 2000 potentiometric surface (black) and measured water levels (red) of the Chicot Aquifer, simulated in the Groundwater Availability Model (modified from Coplin and Santos 2000).

The number of water wells within the AoR is best characterized by the Texas Water Development Board (TWDB) groundwater database and Submitted Drillers Report Database (SDRDB) (Table AoR-15). Other sources of well data, although numerous, often focus on oil and gas wells. Additional research was done to located not registered legacy wells including interviews with landowners and the acquisition of a magnetic survey in 2025. The results of the magnetic survey and additional research are presented in the corrective action section. For this section, the TWDB and SDRDB data will be used. All water wells in the AoR are coded to the Chicot Aquifer. Aquifers underlying the Chicot Aquifer in the project area are generally considered too saline for drinking water and few water supply wells in the area penetrate the deeper Evangeline and Jasper Aquifers. Well use for the TWDB and SDRDB data were slightly different. TWBD well use data is broken into domestic, industrial, plugged/destroyed, stock, unused, and oil/gas (Table AoR-16). SDRDB groups wells by domestic, irrigation, rig supply, and stock (Table AoR-17). Forty water wells exist within the AoR.

Table AoR-15: The number of wells within the AoR by database. TWDB GWDB, SDRDB

Data Source	Total Wells in AoR
TWDB GWDB	14
SDRDB	25
SDRDB Plug	1

Table AoR-16: Number of wells within the AoR by use (TWDB Groundwater database).

TWDB Well Use	Number of wells
Domestic	2
Industrial	1
Plugged or Destroyed	3
Stock	1
Unused	7
Total	**14**

Table AoR-17: Number of wells within the AoR by use (SDRDB).

SDRDB Well Use	Number of wells
Domestic	19
Rig Supply	1
Stock	3
Plugged	1
Monitoring	1
Total	**25**

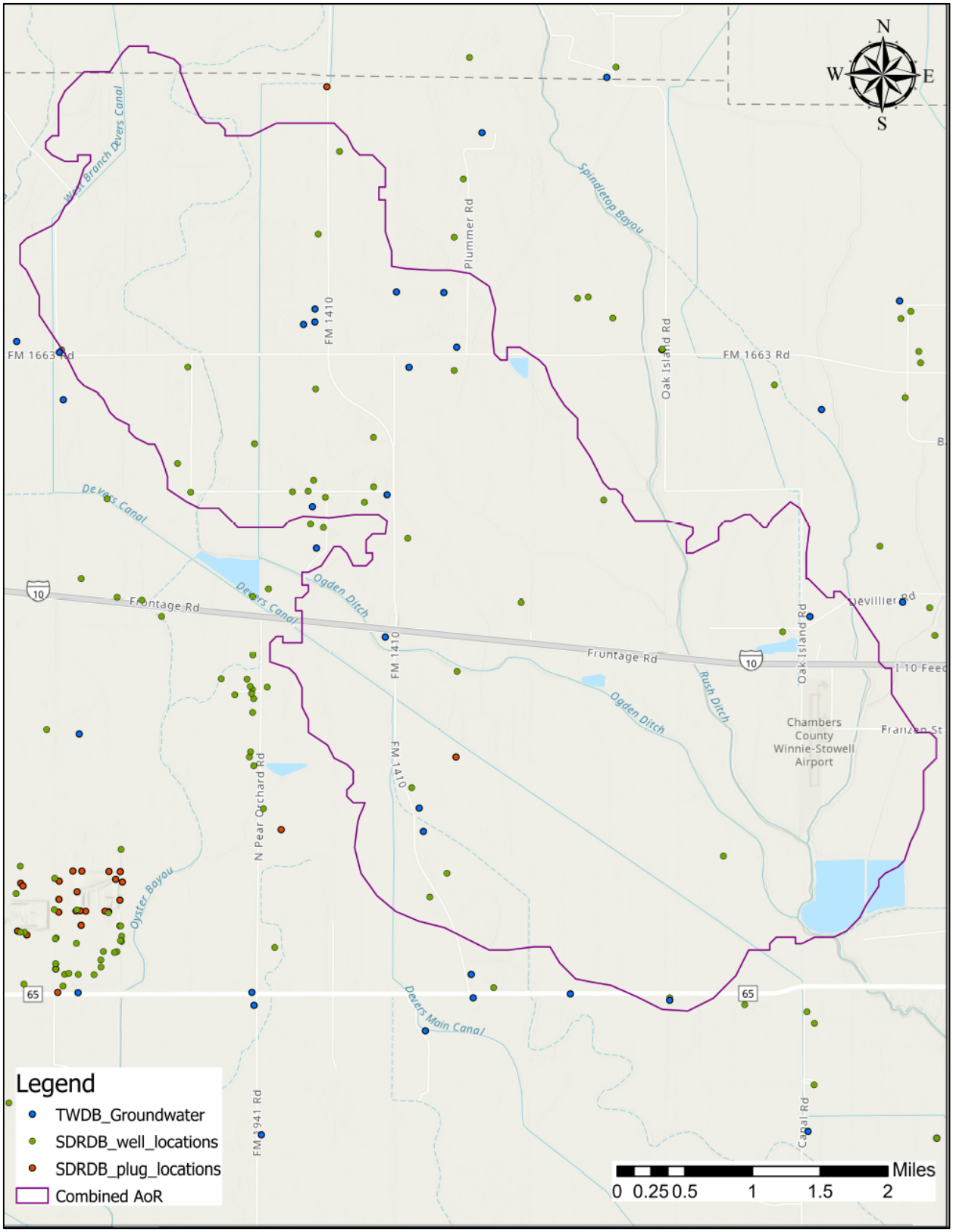


Figure AoR-198: Wells within the AoR from TWDB GWDB and SDRDB databases.

3.10 Base of the Underground Source of Drinking Water (USDW)

The Chicot Aquifer is the primary groundwater production zone for drinking and municipal use in Chambers and Jefferson Counties (Tinsley 1971). However, only small quantities of fresh groundwater (<1,000 mg/l TDS) are available in Chambers and Jefferson Counties, and these supplies are fairly well developed (Tinsley 1971). Overall, water use in Chambers and Jefferson Counties is largely sourced from surface water compared to groundwater from the Chicot Aquifer (Freese and Nichols, Inc., 2020). Historically, fresh water from neighboring Hardin and Orange Counties has been used to supplement water demand in Chambers and Jefferson Counties (Tinsley 1971).

The underground source of drinking water (USDW) is defined by USEPA as an aquifer or part of an aquifer that contains <10,000 ppm TDS. Publicly available studies suggest base USDW depth ranges from 1,000 to 2,000 ft MD (lower Chicot Aquifer) from across Chambers and Jefferson Counties (Young et al. 2016; Figure AoR-199). Within the AOI, USDW depth ranges between 1,100 ft and 1,700 ft MD (Young et al. 2016; Table AoR-18). Site-specific base USDW determinations are discussed in detail further below. Water quality in the Evangeline and Jasper Aquifers underlying the Chicot Aquifer is generally considered very saline (>10,000 mg/l) or brine (>35,000 mg/l) within the AOI, and no water supply wells within the AOI were found to penetrate these deeper aquifers. Fresh water is produced from wells in the Evangeline Aquifer towards the western extent of Chambers County (e.g., Mont Belvieu) and along the far northern and eastern extent of Jefferson County.

Table AoR-18: Base depth ranges of total dissolved solid (TDS) concentrations based on area.

Water Quality	TDS (mg/L)	Chambers Co. Base Depth (ft.)	Proposed Project Site Base Depth (ft.)
Fresh	0 - 1,000	250 - 1000	400 - 500
Slight Saline	1,000 - 3,000	300 - 1,500	500 - 750
Moderately Saline	3,000 - 10,000	800 - 3,500	1,100 - 1,700
Very Saline	10,000 - 35,000	1,600 - 5,000	2,500
Brine	>35,000	>5,000	>2,500

Groundwater classification based on the criteria established by Winslow and Kister (1956)
Base of USDW (< 10,000 mg/l TDS) depths are from TWDB Report 1600011947 (Young 2016)

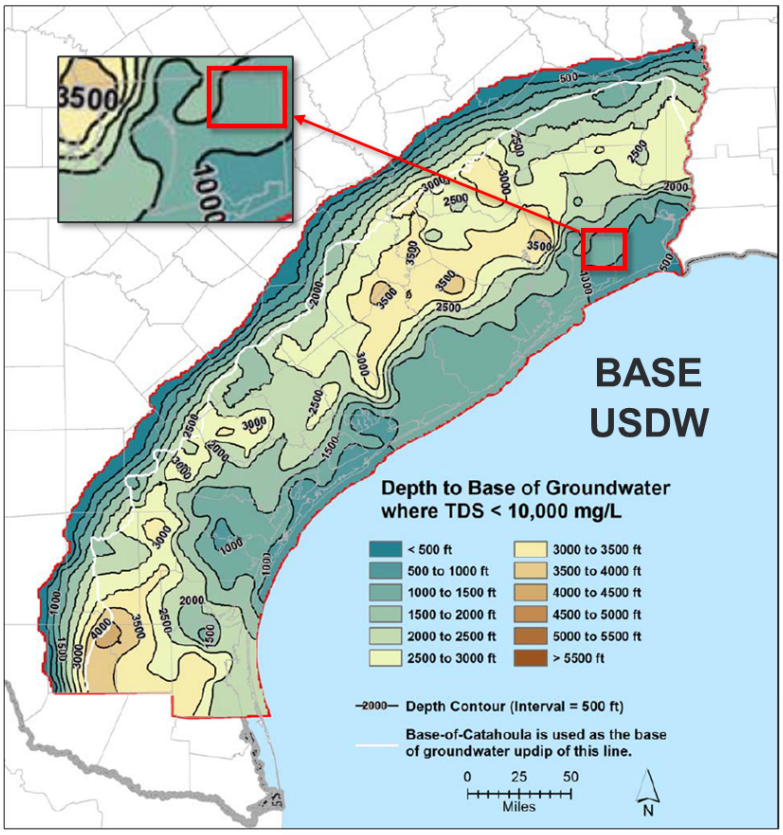


Figure AoR-199: Base of USDW (TDS < 10,000 mg/l TDS) (modified from Young et al. 2016).

Site-specific interpretation base USDW was completed using two methods: (1) deep resistivity readings from open-hole logs and (2) spontaneous potential readings from open-hole logs. Deep resistivity methodology followed the Louisiana Department of Natural Resources (LDNR) Office of Conservation, Injection, and Mining Division (IMD) guidelines. LDNR-IMD methodology was applied to wells within and outside of the AoR. Results from both methods were compared to publicly available water quality studies of the region that utilized similar methods followed by open-hole fluid samples collected *in-situ* onsite to characterize and confirm base USDW. The LDNR-IMD methodology utilizes deep resistivity readings from open-hole logs under the following guidance:

> "The IMD typically uses the deep induction curve on an e-log to define the base of the USDW. The following guidelines are used: (1) ground surface to 1,000 feet: 3 ohms or greater is considered USDW; 2) from 1,000 feet to 2,000 feet: 2 ½ ohms or greater is considered USDW; and 3) 2,000 feet and deeper: 2 ohms or greater is considered USDW. The base of the USDW is established at the base of the sand unit that contains the lowermost USDW with an isolating shale beneath it (LDNR-IMD, 2022)."

One concern with deep resistivity readings is that, in addition to resistivity responses from formation fluid salinity, resistivity responds to pore fluids such as hydrocarbons, gases, and drilling

fluids, as well as cementation effects in tight sandstones. Here, care was taken by technical staff to consistently select clean basal sandstones with high water saturations for formation water salinity estimation. Figure AoR-202 shows results of the LDNR-IMD deep resistivity method, which shows a base USDW of approximately 1,182 ft MD in Encanto 01 is reasonable. The average base of USDW using this method is -1,356 ft TVDSS within the AoR. Previous base USDW interpretations for this site did not utilize LDNR-IMD methods, but instead applied higher resistivity value cutoffs that resulted in an overly conservative interpretation of base USDW (1,845 ft MD in Encanto 01). Interpretation for revised base USDW (1,182 ft MD) using LDNR-IMD methodology is supported by water quality results from downhole fluid sampling conducted onsite in a water well drilled by Bluebonnet.

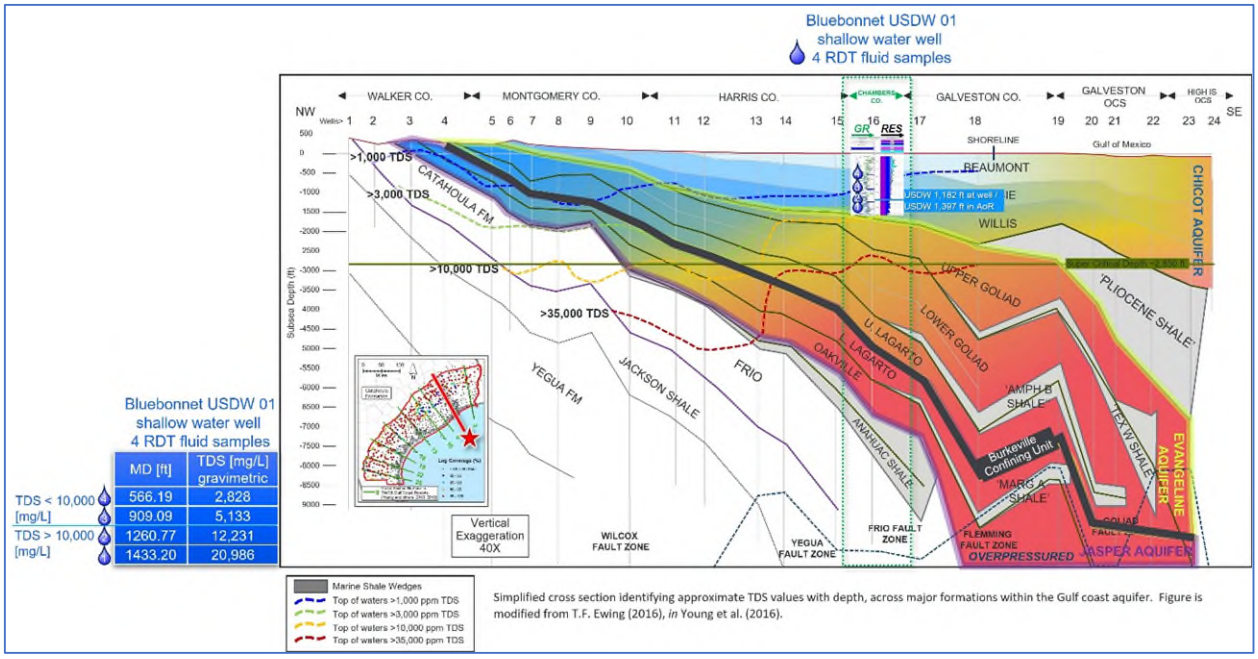


Figure AoR-200: Cross section showing TDS values with depth based on log interpretation across major formations within the Gulf Coast aquifer (modified after T. F. Ewing 2016 and Young et al. 2016). Superimposed are TDS values obtained from downhole fluid samples acquired using Halliburton's Reservoir Description Tool (RDT) in Bluebonnet USDW 01. Bluebonnet Sequestration Project site-specific fluid samples show actual base USDW is shallower than regional interpretation studies suggest.

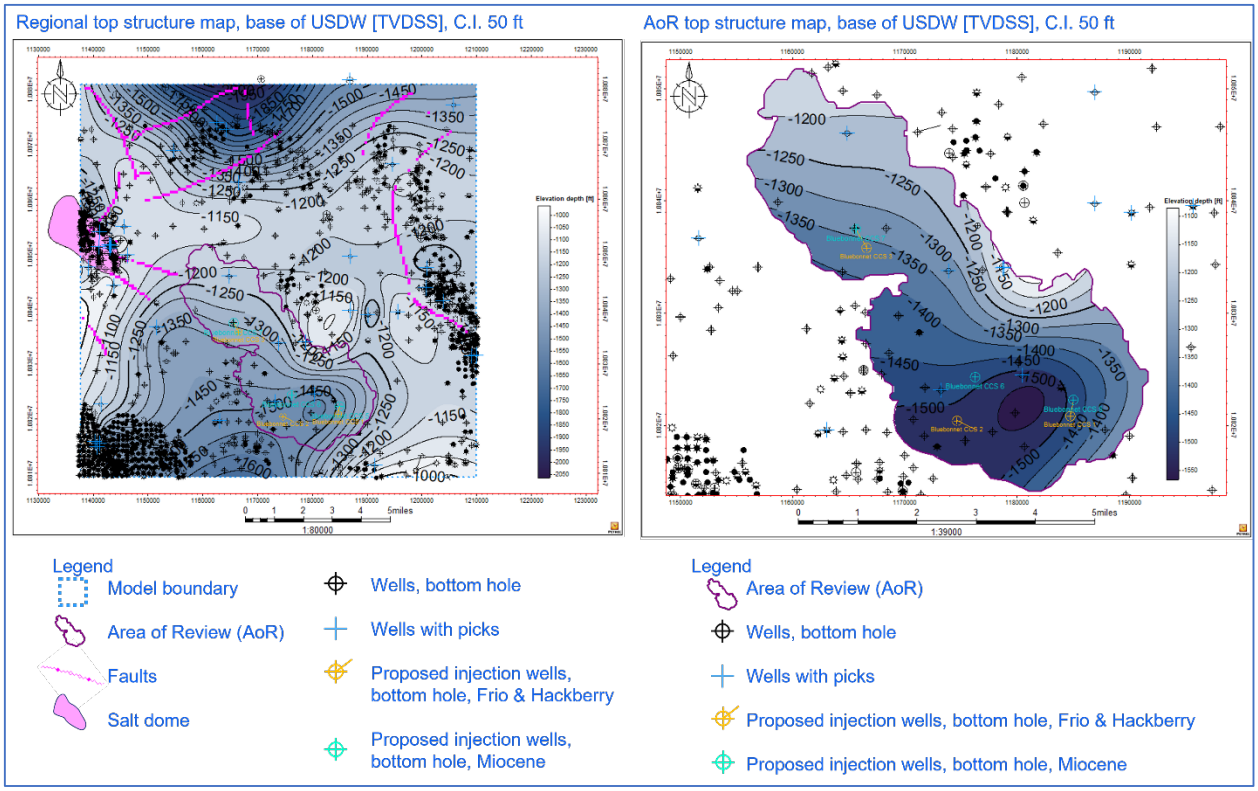


Figure AoR-201: Structure map (ft TVDSS) of the base USDW. Contour interval is 50 ft. The average base of USDW within the AoR is -1,356 ft TVDSS.

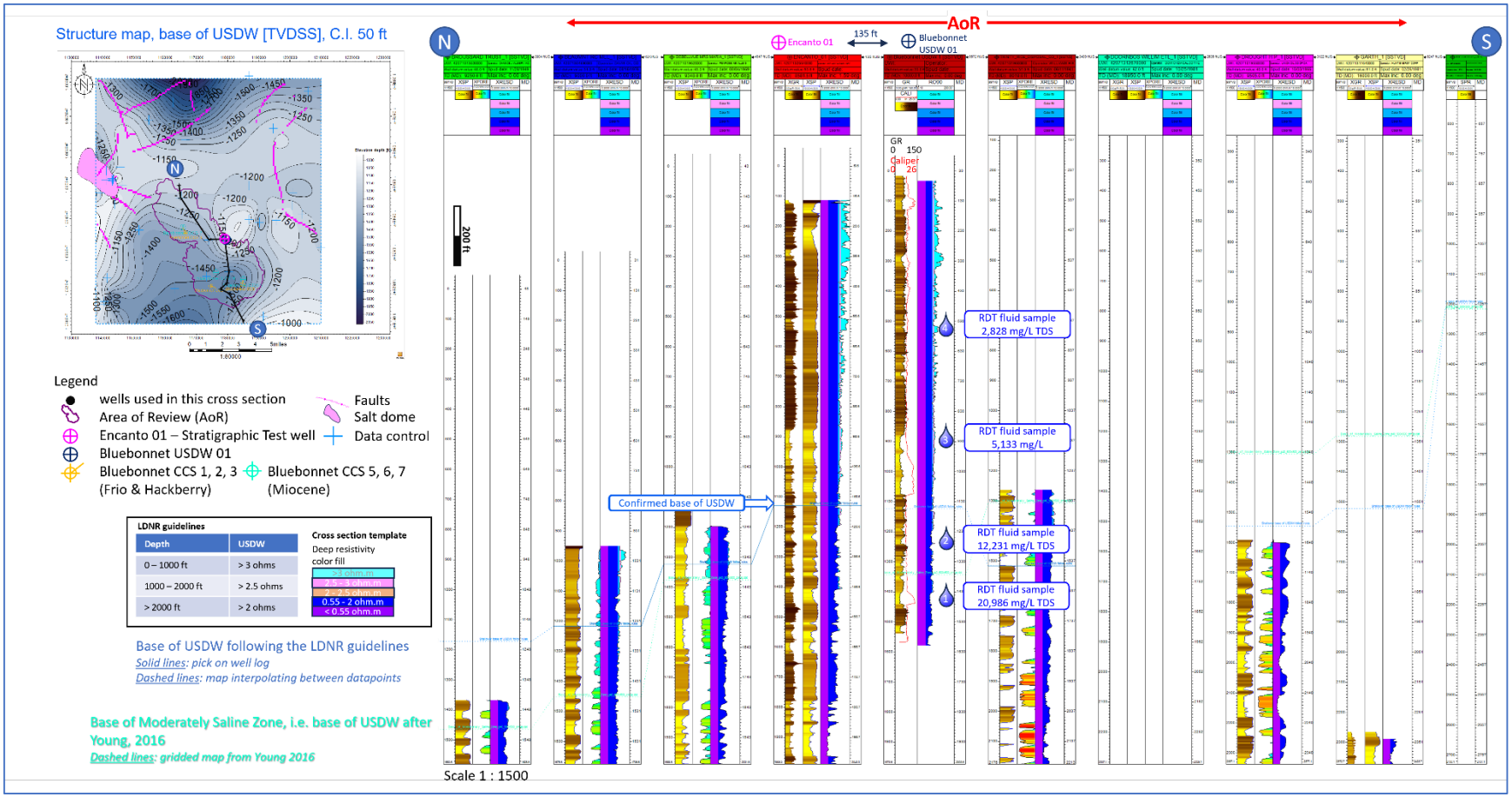


Figure AoR-202: Confirmed updated base of USDW shown in blue following the LDNR-IMD deep resistivity method. Site-specific RDT fluid samples acquired from Bluebonnet USDW 01 showed TDS values >10,000 mg/L in the sands below 1,182 ft and are compared to the interpreted base Moderately Saline Zone (10,000 mg/l TDS) after Young et al. (2016).

The second method used for base USDW was interpretation of formation water salinity using open-hole spontaneous potential (SP) logs. The SP log is a record of direct current voltage that develops naturally between a moveable electrode in the wellbore and fixed electrode at the surface (Asquith and Krygowski 2004). Electrical voltages arising from electrochemical factors (e.g., mud filtrate and formation water) within the borehole and adjacent rock create the SP log response. These electrochemical differences are used to interpret the resistivity (salinity) of formation waters in clean permeable sands. The SP method, with temperature correction, was applied to the petrophysical log obtained in the stratigraphic test well Encanto 01. Resistivity values from the SP method were compared to the LDNR-IMD deep resistivity method and indicated >10,000 mg/l TDS at 1,280 ft MD, the first clean sand below proposed base USDW at 1,182 ft MD (Figure AoR-203).

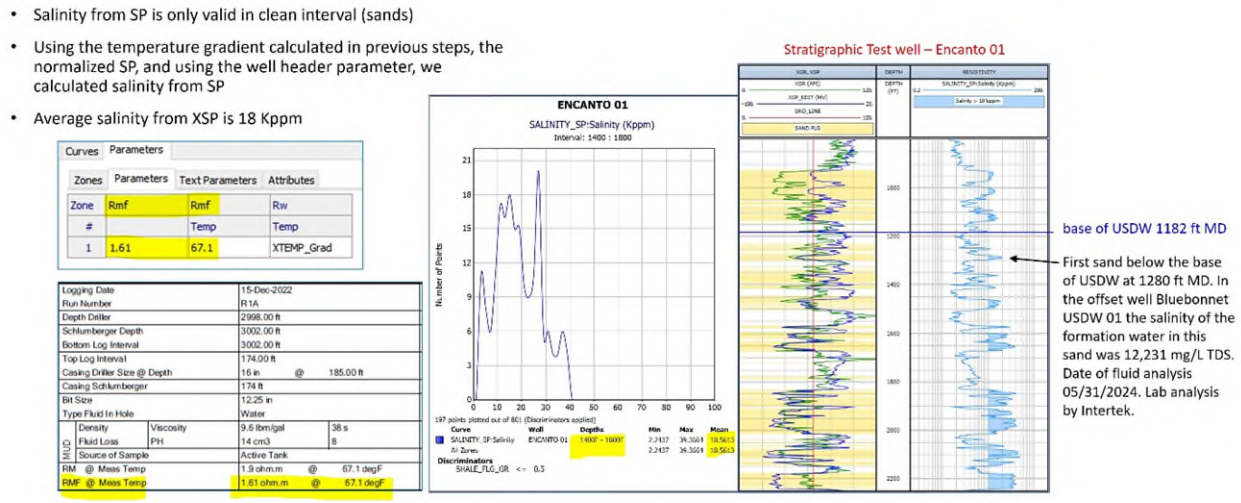


Figure AoR-203: Salinity estimation based on the Spontaneous Potential (SP) log.

LDNR-IMD and SP log-interpretation results for formation water quality were used to inform sample selection depths for open-hole fluid sampling in the Bluebonnet USDW 01 well, located 135 ft due east of the stratigraphic test well Encanto 01. Four depths were selected for open-hole fluid sampling (Table AoR-19). Open-hole fluid sampling (RDT) protocol is described further in the QASP section.

Table AoR-19: Sampling depths and lab analytical results for gravimetric TDS.

MD [ft]	Gravimetric TDS [mg/L]
566.19	2,828
909.09	5,133
1260.77	12,231
1433.20	20,986

Lab analytical results matched well with interpreted formation water salinity values. Gravimetric TDS measurements provide a high level of confidence because the actual mass of the dissolved solids is measured and compared to estimations from fluid conductivity or summation of measured dissolved constituent concentrations. Multiple fluid samples were acquired in Bluebonnet USDW 01 above and below the USDW to reduce uncertainty in salinity variations with depth and assess salinity-depth relationships. The salinity-depth relationships were found to be nonlinear and increased rapidly with depth. The fluid sample acquired from the 1,260 ft MD sand (12,231 mg/L TDS) in Bluebonnet USDW 01 correlates to the 1,280 ft sand in Encanto 01 and supports the mapped base USDW using the LDNR-IMD deep resistivity method described above.

Application of the two independent log-interpretation techniques and newly acquired field data provide support for a revised (shallower) base USDW than previously proposed in the Class VI permit application submitted to USEPA on September 28, 2023. This amendment uses the revised base USDW which ranges from 1,100 to 1,700 ft MD within the AoR.

3.11 Faults and Fractures in the Area of Review

3.11.1 Fault Analysis in the Area of Review.

The AoR was chosen due to the lack of seismic-scale faulting within the Frio, Anahuac, and Lower Miocene Confining Zones. A detailed description of the structural styles and fault interpretation are included in Section 3.5. Fault-seal analysis was performed on the faults included in the geologic model.

Shale Gouge Ratio (SGR) was evaluated as a sealing proxy to assess transmissibility of modeled faults. SGR was modeled two ways using a triangle juxtaposition plot and in a 2D sense, along each fault plane, as were other attributes, including Vshale and CO_2 column height. SGR is an attribute that is used to assess the possibility of an impermeable fault zone developing between juxtaposed reservoirs. The main assumption for SGR is that sand and shale are incorporated into the fault gouge in the same proportions (ratio) as they occur in the wall rocks of the slipped interval (Foxford et al 1998). Calculated SGR is used to model fault zone composition with a higher SGR assumed to correspond to more clay smear in the fault zone and subsequently higher capillary pressure and lower permeability. Higher SGR indicates potential for greater fault seal between juxtaposed reservoirs along the fault surface. Values of SGR <20% (<0.2 ratio) are typically associated with cataclastic fault gouge, whereas values >20% (>0.2) indicate more clay-rich or shaly gouge (Yielding et al. 1997 and Manzocchi et al. 1999). In the Bluebonnet Hub area, minimum vertical fault offset of 75 ft is required to result in SGR >0.2; this minimum is achieved in confining and injection intervals in bounding faults.

The actual VShale profile from the Vshale logs generated from petrophysical analysis are used to calculate SGR attribute values, which is defined as the net clay/shale content in the interval that has slipped past that point along the fault plane (Yielding et al., 1997). The SGR values were evaluated utilizing the 1D triangle diagram plots for various wells in the geologic model to assess the window of throw allowing for possible transmissibility. The triangle plot (Figure AoR-204) is shaded with hot colors indicating zones of greater sealing potential. Greens and bright yellows

reflect SGR values <0.2 (<20%) and indicate potential transmissible zones within juxtaposed reservoirs. SGR values were modeled in a 2D sense along the fault planes utilizing the same color scheme (see Figure AoR-205) to assess the frequency and geometry of any potentially transmissible zones through the stratigraphic intervals intersected by the fault planes.

Expected fluids within the AOI warranted the methodology of modeling CO_2 column height for comparison with the results of the SGR analysis. The Karolyte et al. (2020) equation was used to calculate CO_2 column height, which is equivalent to hydrocarbon column height modeling, but uses the CO_2 capillary pressure and substitutes expected CO_2 fluid density for hydrocarbon fluid density. CO_2 column height was also assessed utilizing both the triangle diagram juxtaposition plots, and in a 2D sense, projected along each fault plane in question. The CO_2 column height is computed at each sample node in the triangle juxtaposition plot and reflects the maximum height of the selected column that can be supported by the SGR at that point. When compared to the results of the SGR analysis, the zones of lower gamma rays indicated by the bright green and yellow colors correspond in proximity and frequency to zones of lower CO_2 column height indicated by the warmer colors on the CO_2 column height color bar. Assumptions for the CO_2 column height assessment include the same assumptions associated with the SGR analysis as well as the accuracy of the expected CO_2 fluid density in the model. For this analysis, an average of the range of expected CO_2 fluid density for the model was used.

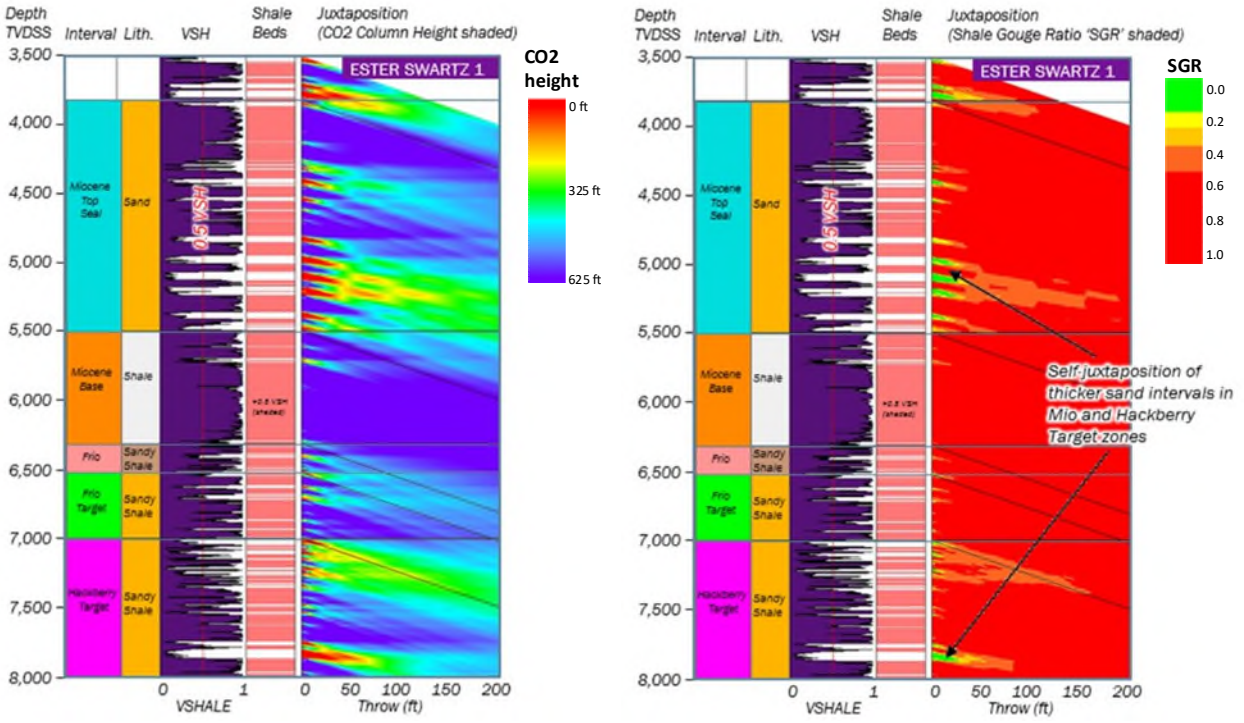


Figure AoR-204: Fault modeling of CO_2 column height (left) and Shale Gouge Ratio (right). Intervals in which lesser CO_2 column height (hot colors on left image) and intervals in which higher vertical throw values (cool colors on right image) directly correspond to each other.

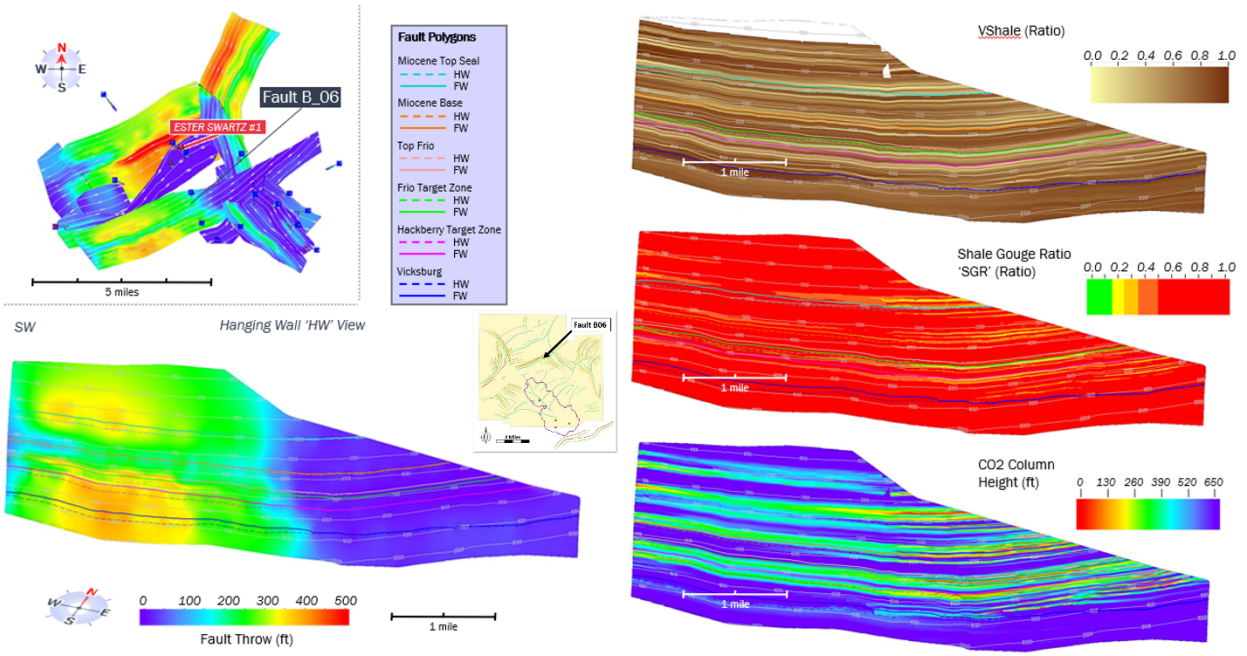


Figure AoR-205: Fault B06, a Frio growth fault that rises nearly to surface within the model, is the most proximal updip fault to the AoR. Within the injection and confining intervals, fault offset is sufficient to create seals within porous lithologies.

3.11.2 Fracture Characterization Using Oil-Based Imager.

Oxy Low Carbon Ventures, LLC ran an oil-based imager log in Encanto 01 for structural information and fracture characterization, as described in section 3.8.2.5. The tool used was the Quanta Geo, a Schlumberger tool. The logging occurred on January 6 of 2023.

Overall, the quality of SLB's Quanta Geo was medium to poor. Interestingly, the calipers were engaged nicely for most of the well, minus a few sections in the Lower Miocene Injection Zone. Typically, image log data quality is worse in sections of wellbore rugosity. This Quanta Geo seemed to suffer quality issues from other influences.

Schlumberger's "Bed Boundary" dip-type was used for interval bedding orientations, as it discriminated between actual bed boundaries and stratigraphy nuanced from deformed bedding. This gave a more representative estimation of the background true dip of the intervals and eliminated using data from crossbedding, debris flows, slumps, etc. The true dip values ranged between 5° - 7°, with dip azimuths ranging between 135° - 190° (SE-S), consistent with Gulf Coast trends (see Table AoR-20, below).

Table AoR-20: Average dip and azimuth by formation.

Formation name	Avg. Dip	Avg. azimuth
Miocene Lower Confining Zone	7°	151°
Miocene Lower Injection Zone	7°	165°
Anahuac Conf. Zone	6°	175°
Frio Injection Zone	6°	179°
Frio Confining Zone	5°	144°
Hackberry Injection Zone	6°	159°
Hackberry Confining Zone	5°	135°

Most of the in-house interpretation was focused on structural characterization and fracture analysis, which, in the end, was a minor part of the results. Only one minor fault was observed in the Frio Injection Zone. This one minor fault (dip: 42°, dip azimuth: 142°) had no associated fractures, suggesting it was not part of a significant fault zone (see Figure AoR-209). This strike ° is consistent with Gulf Coast trends. Image logs often provide insightful data on SHMax (Maximum Horizontal Stress Direction) orientation, if borehole breakout or induced tensile fractures are observed. None were seen in this image. This fault is under the seismic resolution; therefore, it cannot be identified in seismic.

The analysis of the Quanta Geo log in the confining zones, Lower Miocene, Anahuac, and Hackberry Confining Zones, shows no fractures or faults as observed in Figure AoR-206, Figure AoR-207, Figure AoR-208, and Figure AoR-210.

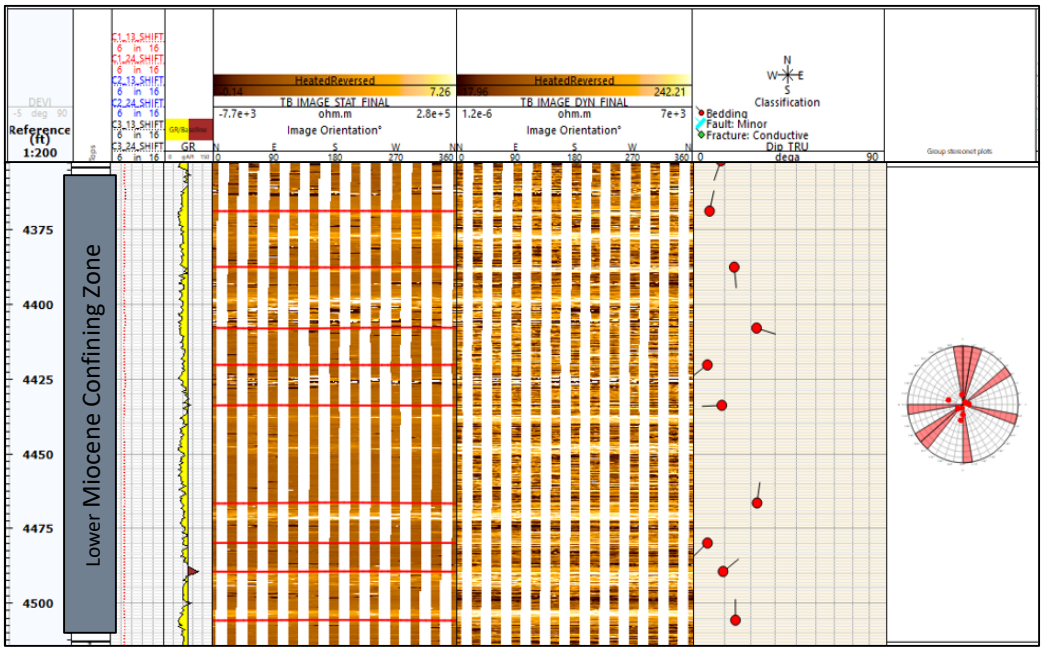


Figure AoR-206: Lower Miocene Confining Zone, no visible fractures.

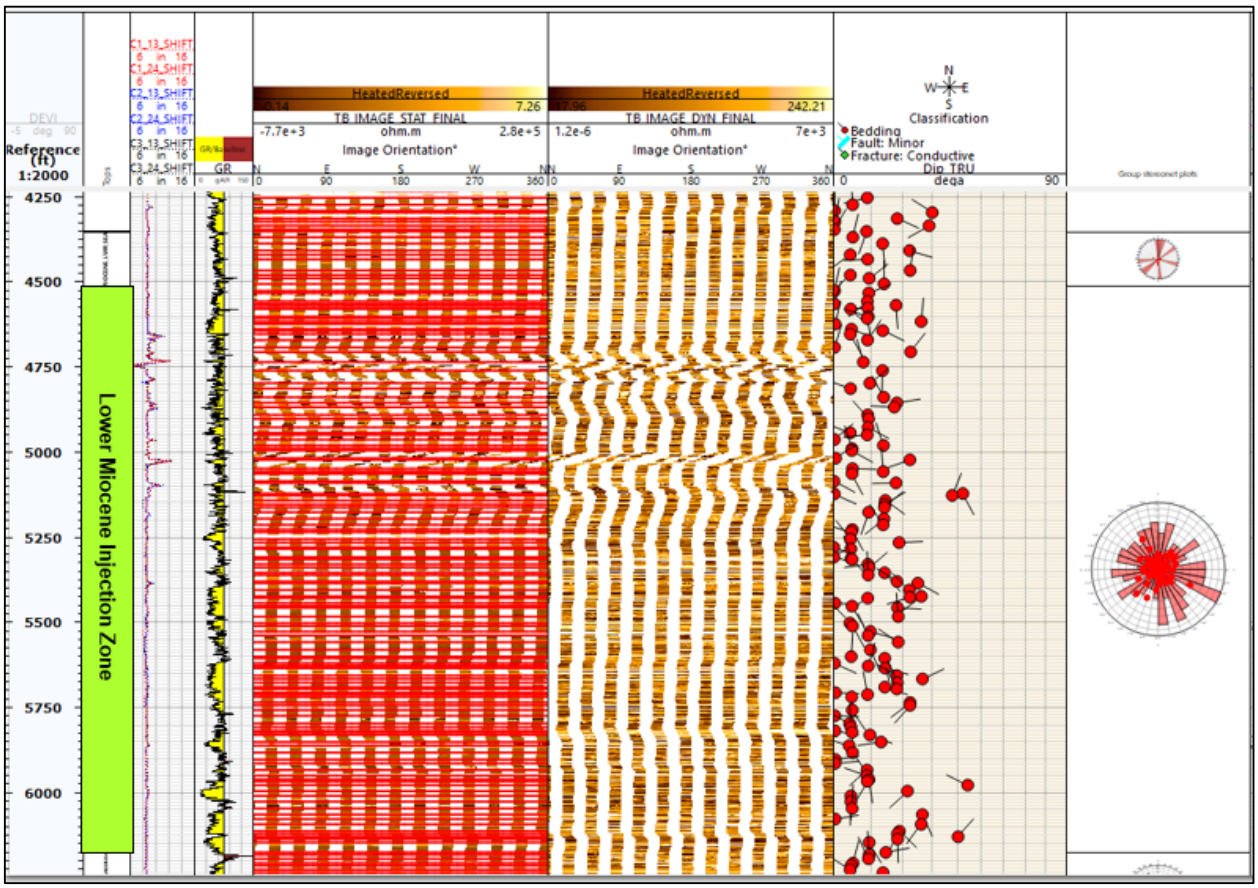


Figure AoR-207: Lower Miocene Injection Zone, no visible fractures present.

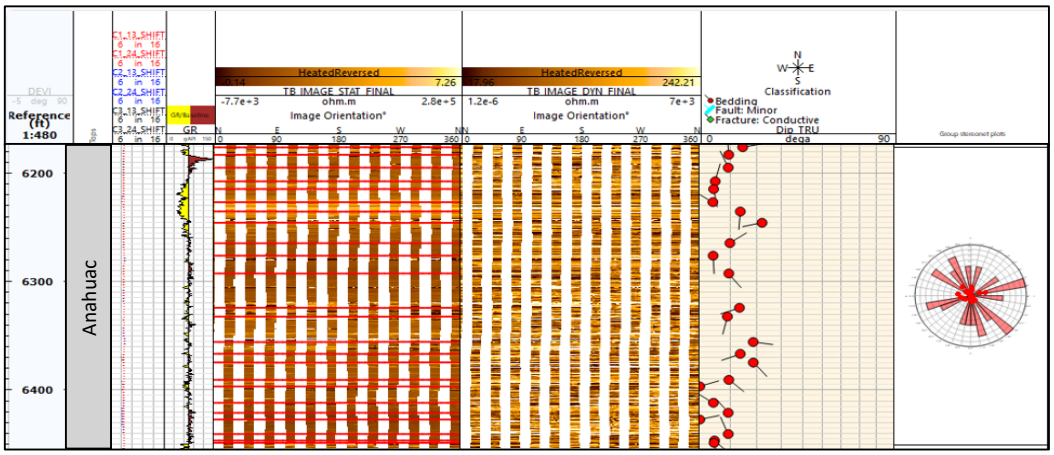


Figure AoR-208: Anahuac Confining Zone, no visible fractures.

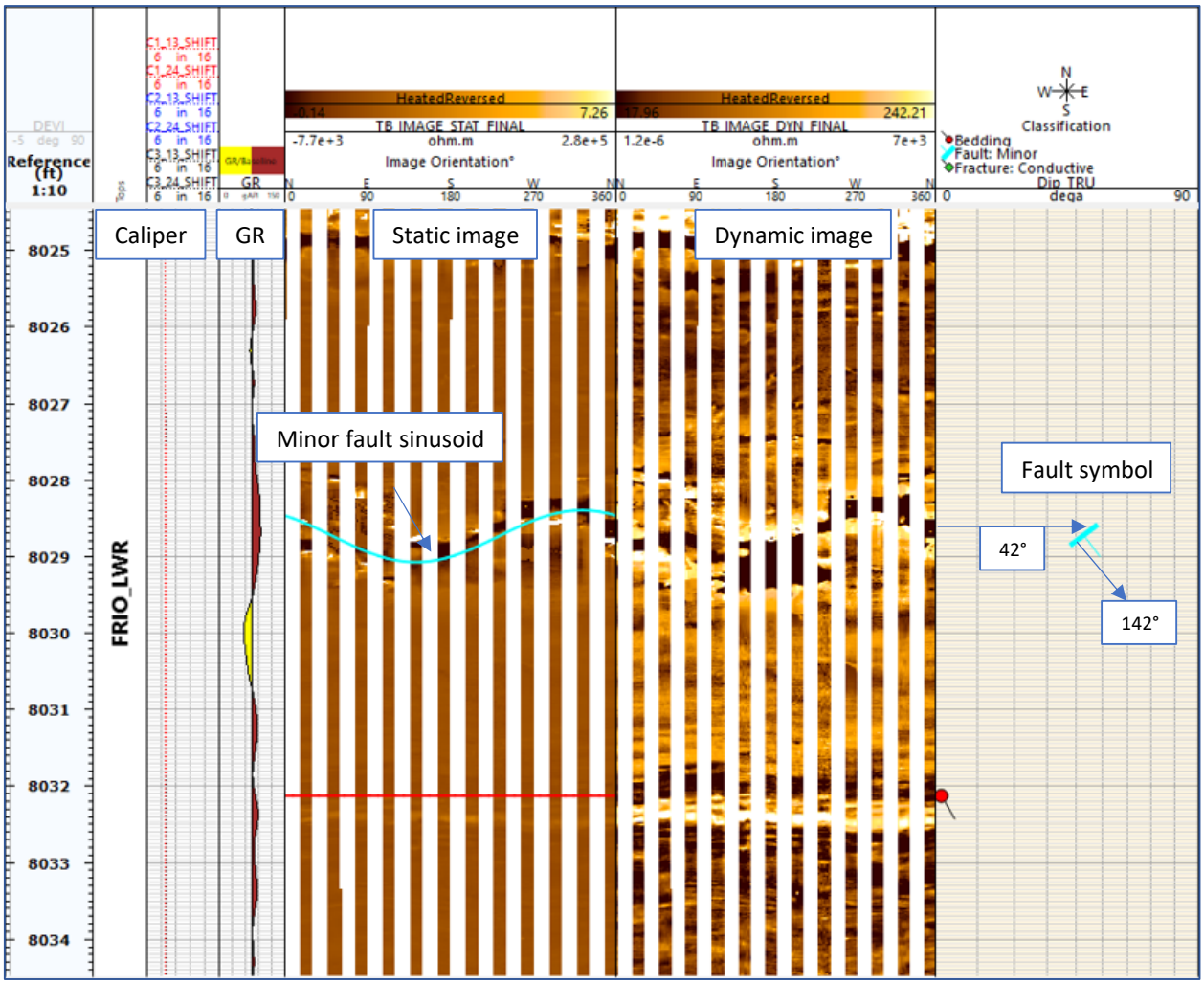
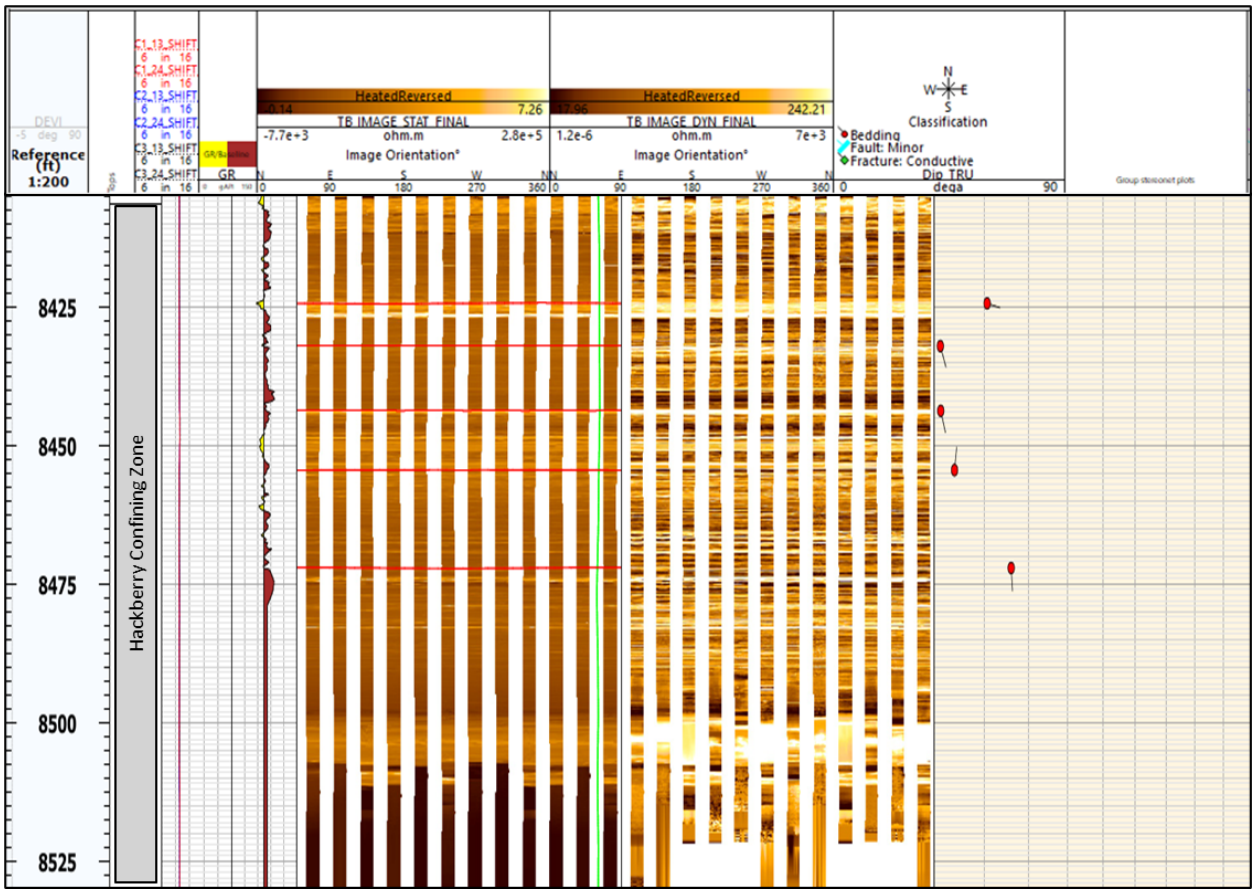


Figure AoR-209: Minor fault in Frio Injection Zone is represented by light blue sinusoid.



3.12 Geomechanics Analysis

The risk associated with formation breakdown and fracture generation during or after CO_2 injection is understood in the context of long-term pressure changes in the subsurface and potential to induce fractures in the formation. The resolved normal and shear stresses acting on an existing fault surface are calculated, and then, the Mohr-Coulomb analysis uses those stresses to estimate the risk of failure during CO_2 injection. Uncertainties of inputs to the in-situ stress model increase the risk due to the decreased accuracy and precision of stress magnitudes and injection pressures required to induce tensile or shear failure, collectively described as failure tendency. The increase in fluid pressure from CO_2 injection has the potential to cause failure from the generation of fractures in the matrix of the formation, dilation or shear slip along pre-existing faults, and/or reactivation of the basement fault systems, producing induced seismicity. This analysis only includes the risk of failure initiation of the matrix.

Mohr-Coulomb analysis considers the ratio of shear stress (τ) and effective normal stress (σ'_n) acting on a plane in a given orientation compared with the amount of friction of that plane. The plane can be an existing fault surface or a potential failure plane in the matrix of the subsurface. The coefficient of friction (μ) is defined as the ratio of shear stress to effective normal stress:

Figure AoR-210: Hackberry Injection Zone, no visible fractures.

$$\mu = \frac{\tau}{\sigma n}$$ ..... (Equation 3)

Failure using the Mohr-Coulomb failure criterion is defined as conditions where the ratio of shear stress to effective normal stress acts on an optimally orientated plane and exceeds the failure limit defined by the relationship:

$$\tau = \mu\sigma + So$$ ..... (Equation 4)

where So is cohesion and is a function of friction and unconfined compressive strength (UCS):

$$UCS = 2So(\sqrt{\mu^2 + 1} + \mu)$$ ..... (Equation 5)

Figure AoR-211 shows the graphical representation of the linear Mohr-Coulomb failure criterion. The state of stress is represented by the Mohr circle defined by the maximum (σ'_1) and minimum (σ'_3) effective principal stresses. Any plane orientation is defined along the boundary of the circle by an angle of 2β from σ_1 to σ_3, where β is the angle between the σ_1 and normal plane. In Figure AoR-211, the red circle represents the original state of effective stress. In the case of CO_2 injection into the reservoir, pore pressure is estimated to increase while decreasing the magnitude of the effective principal stresses and moving the circle to the left on the x-axis. The failure limit shown is the sloped solid black line defined by Equation 6. The dashed line would represent the failure limit of a preexisting fault with comparatively little friction. While the friction of faults is not zero, it is small compared to the friction required to initiate a fracture in the matrix.

As pore pressure increases during injection, the Mohr circle moves to the left along the x-axis and the circle boundary eventually intersects the failure envelope. Under those conditions, any plane oriented along the Mohr circle that crosses or intersects the failure envelope will be subject to failure risk. The linear model presented below represents a simplified version of the Mohr-Coulomb failure criterion, as the failure envelope is not often linear and as pore pressure increases, the effective stress decreases but the horizontal principal stress magnitude increases, making the circle smaller. The result of the linear model is a conservative interpretation, which is appropriate in a scenario where large uncertainties exist in the stress model.

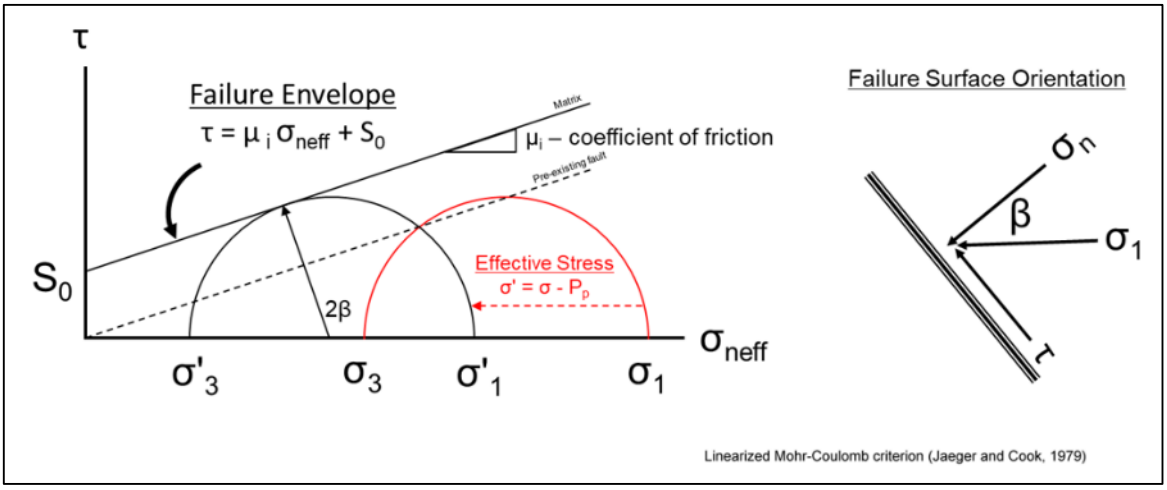


Figure AoR-211: Mohr-Coulomb Failure Criterion.

The Oxy Best Practices workflow for calculating pore pressure and the three principal stresses was implemented. Pore pressure was modeled using the effective stress, normal compaction trend Eaton method, using compressional velocity well data. The method utilized the Terzaghi effective stress principle to estimate pore pressure from the calculation of overburden and estimate of effective stress such that:

$$Pp = TVDft*0.465\ psi/ft \quad \text{..... (Equation 6)}$$

The state of stress was modeled using the isotropic poroelastic uniaxial strain model shown in Equation 6.

$$\sigma 3 = \frac{\nu}{1-\nu}(\sigma v - \alpha Pp) + \frac{\varepsilon hE}{1-\nu^2} + \frac{\varepsilon H\nu E}{1-\nu^2} + \alpha Pp \quad \text{..... (Equation 7)}$$

$$\sigma 3 = \frac{\nu}{1-\nu}(\sigma v - \alpha Pp) + \alpha Pp \quad \text{..... (Equation 8)}$$

where:

σ_3 = least horizontal principal stress
ν = Poisson's ratio
σ_v = maximum principal stress
α = Biot's coefficient
Pp = pore pressure
ε_h = minimum tectonic strain
ε_H = maximum tectonic strain
E = Young's modulus

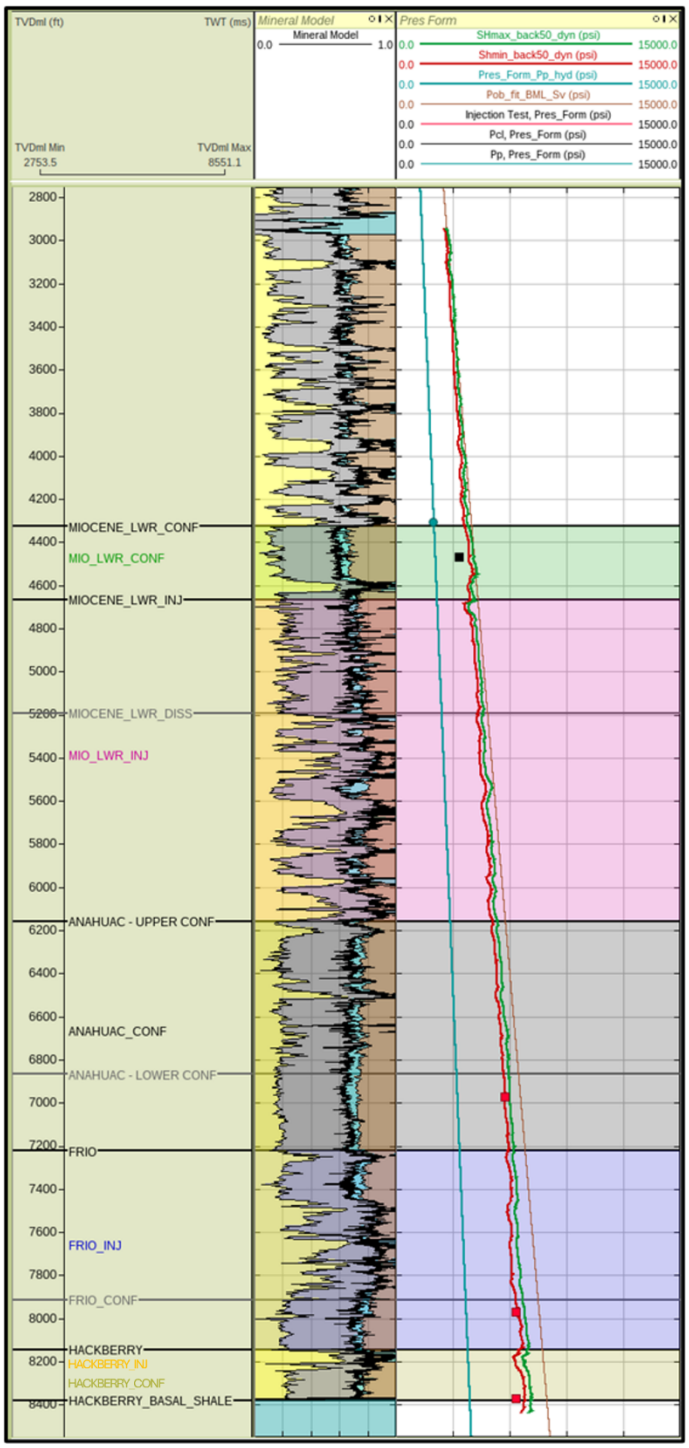


Figure AoR-212: Stress model for Encanto 01 well. Lower Miocene Confining Zone (Green), Lower Miocene Injection Zone (pink), Anahuac Confining Zone (gray), Frio Injection Zone (Blue), and Hackberry Injection Zone (Yellow) highlighted.

Results

The stress model was constrained by core measurements and calibrated to pressures and interpretations of minimal principal horizontal stress from wellbore pressure tests. The elastic properties of core from geomechanical core tests are summarized in Table AoR-21. The stresses used to calibrate the stress model are summarized in Table AoR-22.

Table AoR-21: Summary of elastic properties interpreted from geomechanical core tests results for Anahuac Confining Zone and Hackberry Confining Zone. Lower Miocene Confining Zone core sample testing is in progress at the time of publication.

Formation	Sample No.	Depth	Young's Modulus (GPa)	Poisson's Ratio (unitless)
Lower Miocene Confining Zone	ENC-RM4	4395.2	1.2	0.38
	ENC-RM4B	4395.2	1.14	0.37
	ENC-RM5	4400.3	1.08	0.24
Anahuac Confining Zone	ENC-RM12	6,971.3	5.62	0.17
	ENC-RM13	6,982.9	5.49	0.39
Hackberry Confining Zone	ENC-RM17	8,461.3	12.45	0.37
	ENC-RM18	8,466.3	19.42	0.18
	ENC-RM19	8,473.2	9.98	0.34

Table AoR-22: Summary of pore pressure increase (psi) required to cause failure in a hypothetical, optimally oriented fault and matrix in formations identified as confining and injection zones.

Formation	Depth (ft TVD)	Pore Pressure (psi)	Pp Gradient (psi/ft)	Overburden Stress (psi)	Overburden Gradient (psi/ft)	Sh_{max} (psi)	Sh_{max} Gradient (psi/ft)	Sh_{min} (psi)	Sh_{min} Gradient (psi/ft)
Lower Miocene Confining Zone	4,450	2,084	0.47	4,100	0.92	4,050	0.91	3,845	0.86
Lower Miocene Injection Zone	5,350	2,500	0.47	4,965	0.93	4,435	0.83	4,435	0.83
Anahuac Confining Zone	6,800	3,178	0.47	6,388	0.94	5,628	0.83	5,628	0.83
Frio Injection Zone	7,800	3,638	0.47	7,363	0.94	6,140	0.79	6,140	0.79
Hackberry Confining Zone	8,260	3,853	0.47	7,820	0.95	6,625	0.80	6,625	0.80

The stress model was plotted in Mohr circle space to assess the required increase in pore pressure required to initiate shear and /or tensile failure on the optimally oriented faults and rock matrix for the Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac Confining Zone, Frio Injection Zone, and Hackberry Confining Zone. Mohr Coulomb failure analysis is conducted at a particular depth as shown in Figure AoR-213 to Figure AoR-217 but are representative of the entire formations.

Figure AoR-213 shows the state of stress in the Mohr circle space for the Lower Miocene Confining Zone at around 4,460 ft TVD in the Encanto 01 well. The failure envelope defines the failure threshold for faults. A matrix failure envelope (not shown) would be at the same slope but have a larger y-axis intercept as a function of cohesion (rock strength). Even a small amount of cohesion would likely result in tensile effective minimum stress causing initial failure, so that threshold (zero effective normal stress) is used as the failure limit here. It is a conservative estimate as a function of cohesion and tensile strength, both of which are poorly constrained. Pore pressure increases required to cause failure on a hypothetical, optimally oriented fault and matrix are summarized in Table AoR-23.

The results of failure analysis in the Lower Miocene Confining Zone indicate ~1660 psi increase in pore pressure would be required to reactivate a hypothetical fault optimally oriented to be the most susceptible fault in the area as the highest risk and most conservative estimate. The black arrow in Figure AoR-213 intersects the Mohr circle at the location of the most susceptible orientation of any fault. The risk of matrix failure is ~1780 psi and is interpreted here when effective minimum horizontal stress reaches the origin of the plot and changes from compressive to tensile. That interpretation is likely conservative as it does not consider rock matrix cohesion or tensile strength.

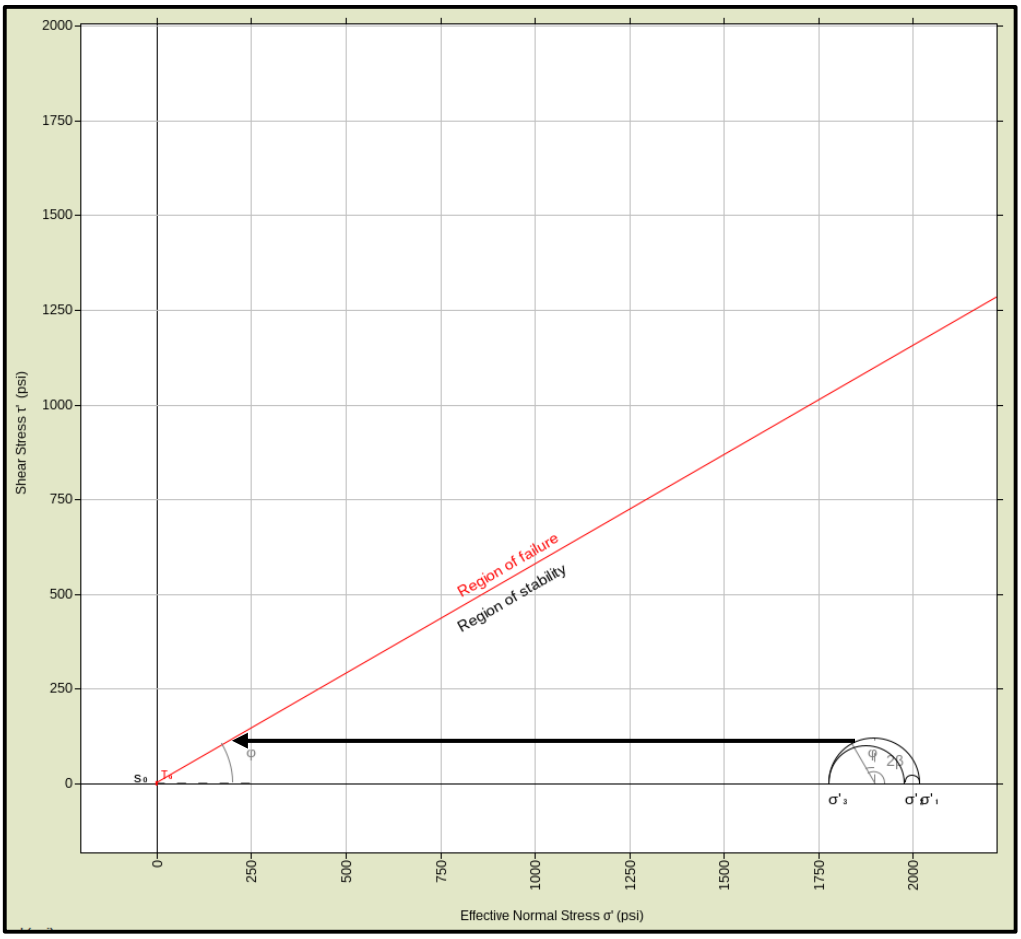


Figure AoR-213: Mohr Coulomb plot showing the state of stress in the middle of the Lower Miocene Confining Zone requires ~1660 psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Lower Miocene Confining Zone would require ~1,780 psi.

The results of failure analysis in the Lower Miocene Injection Zone indicate ~1,600 psi increase in pore pressure (black arrow in Figure AoR-214) and risk of matrix failure is ~1,915 psi.

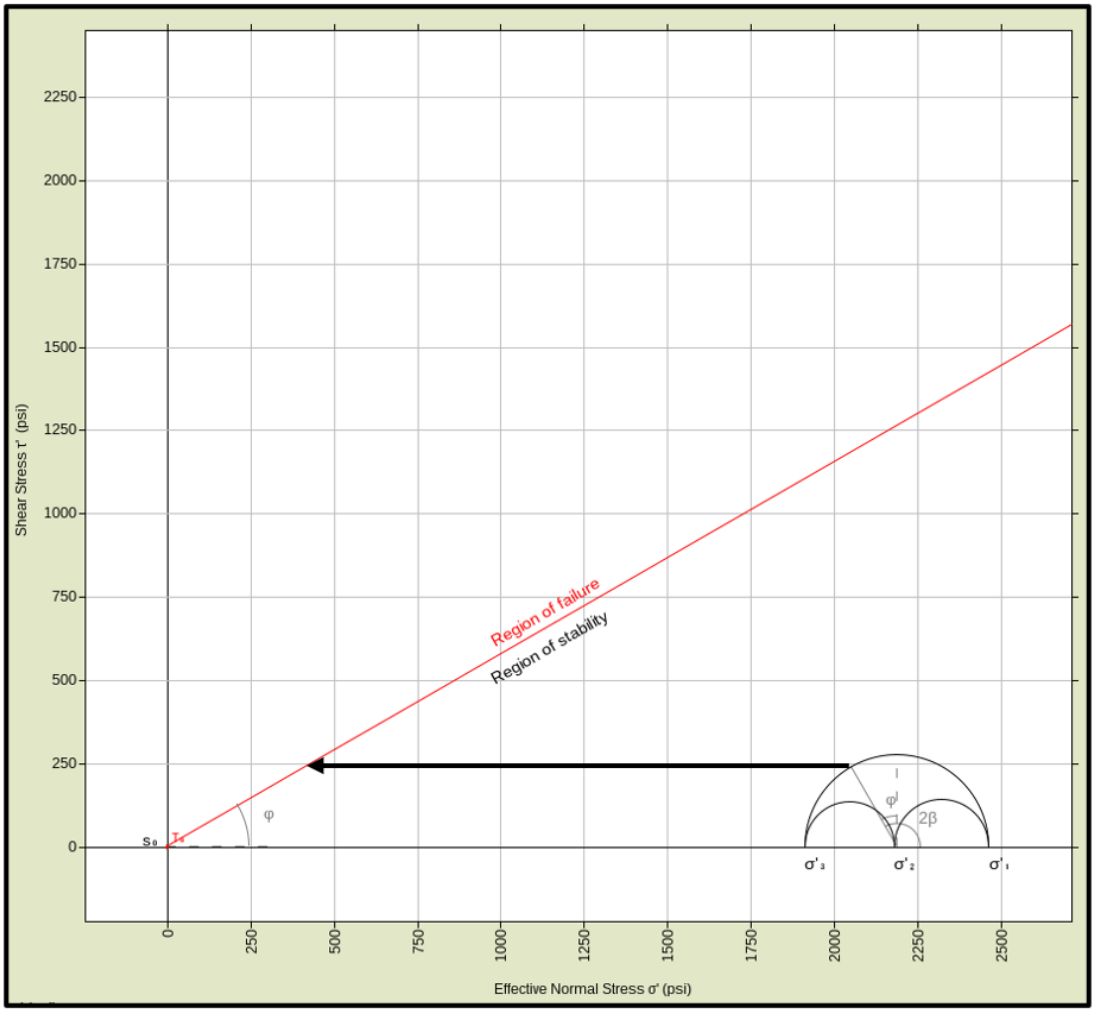


Figure AoR-214: Mohr Coulomb plot showing the state of stress in the middle of the Lower Miocene Injection Zone requires ~1600 psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Lower Miocene Injection Zone would require ~1915 psi.

The results of failure analysis in the Anahuac Confining Zone indicate ~2000 psi increase in pore pressure (black arrow in Figure AoR-215) and risk of matrix failure is ~2500 psi.

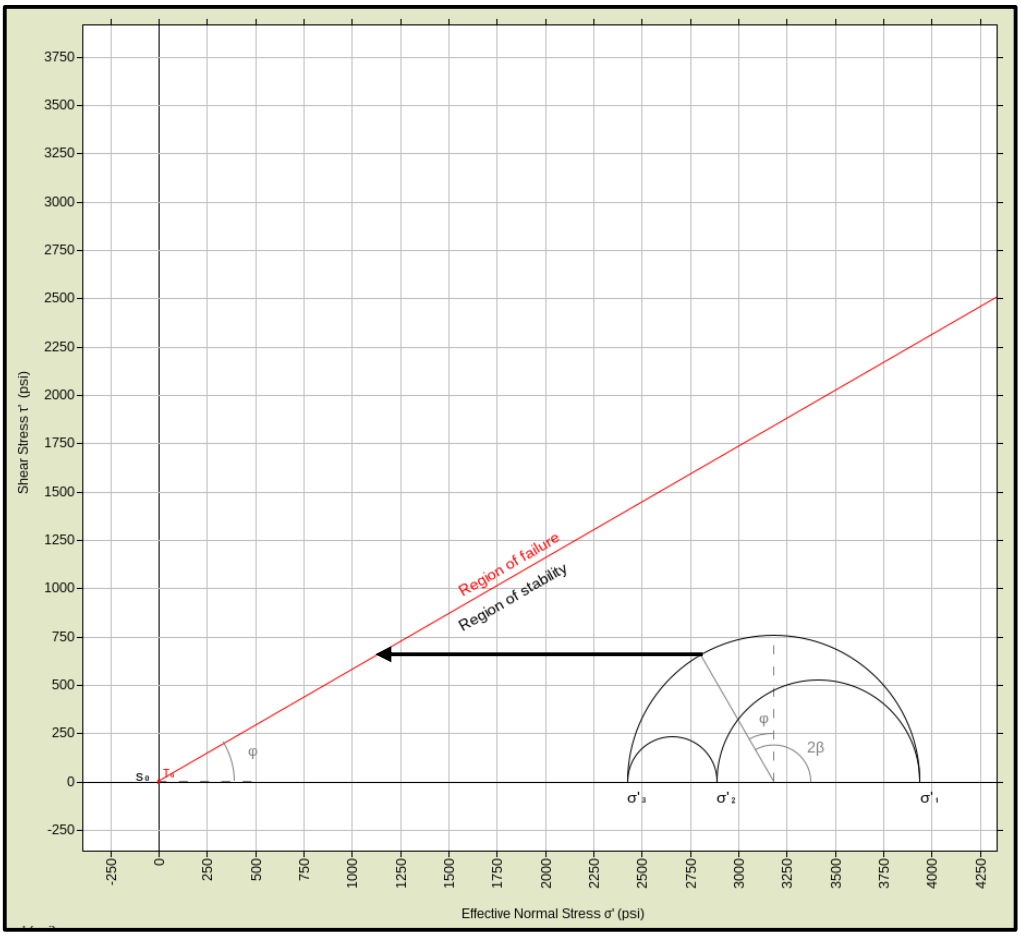


Figure AoR-215: Mohr Coulomb plot showing the state of stress in the middle of the Anahuac Confining Zone requires ~2000 psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Anahuac Confining Zone would require ~2500 psi.

The results of failure analysis in the Frio Injection Zone indicate ~1660 psi increase in pore pressure (black arrow in Figure AoR-216) and risk of matrix failure is ~2450 psi.

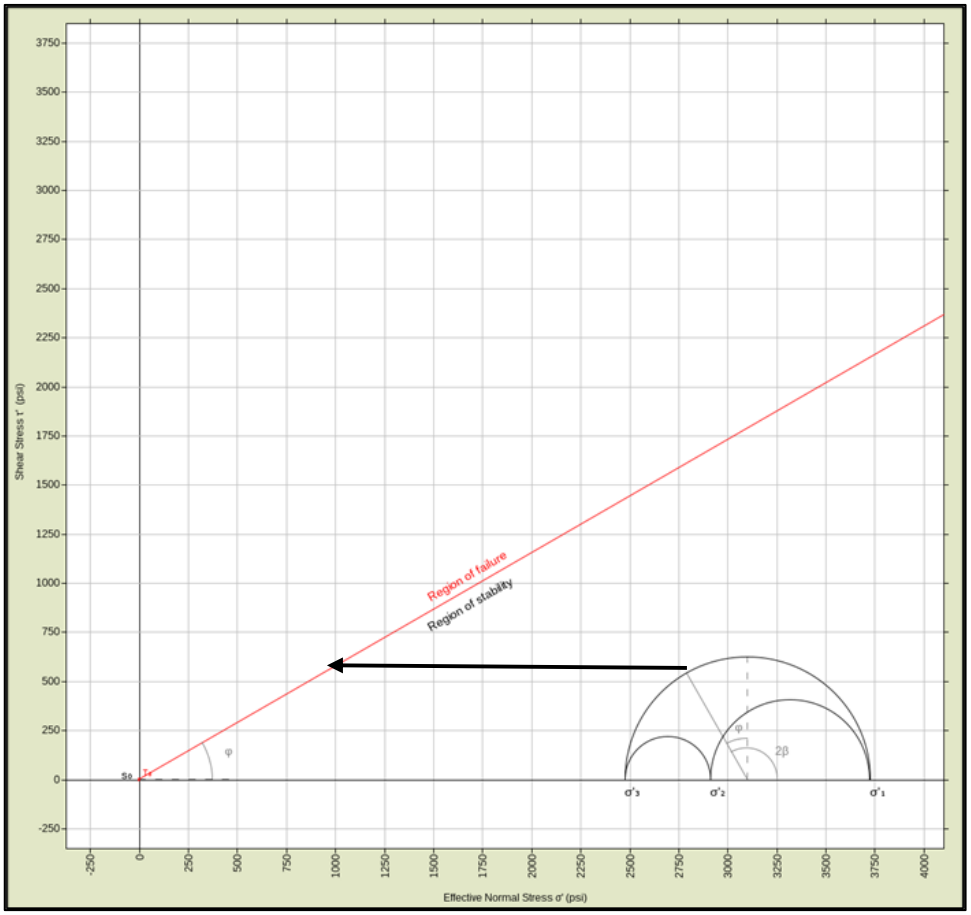


Figure AoR-216: Mohr Coulomb plot showing the state of stress in the middle of the Frio Injection Zone requires ~1660 psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Frio Injection Zone would require ~2450 psi.

The results of failure analysis in the Hackberry Confining Zone indicate ~1800 psi increase in pore pressure (black arrow in Figure AoR-217) and risk of matrix failure is ~2500 psi.

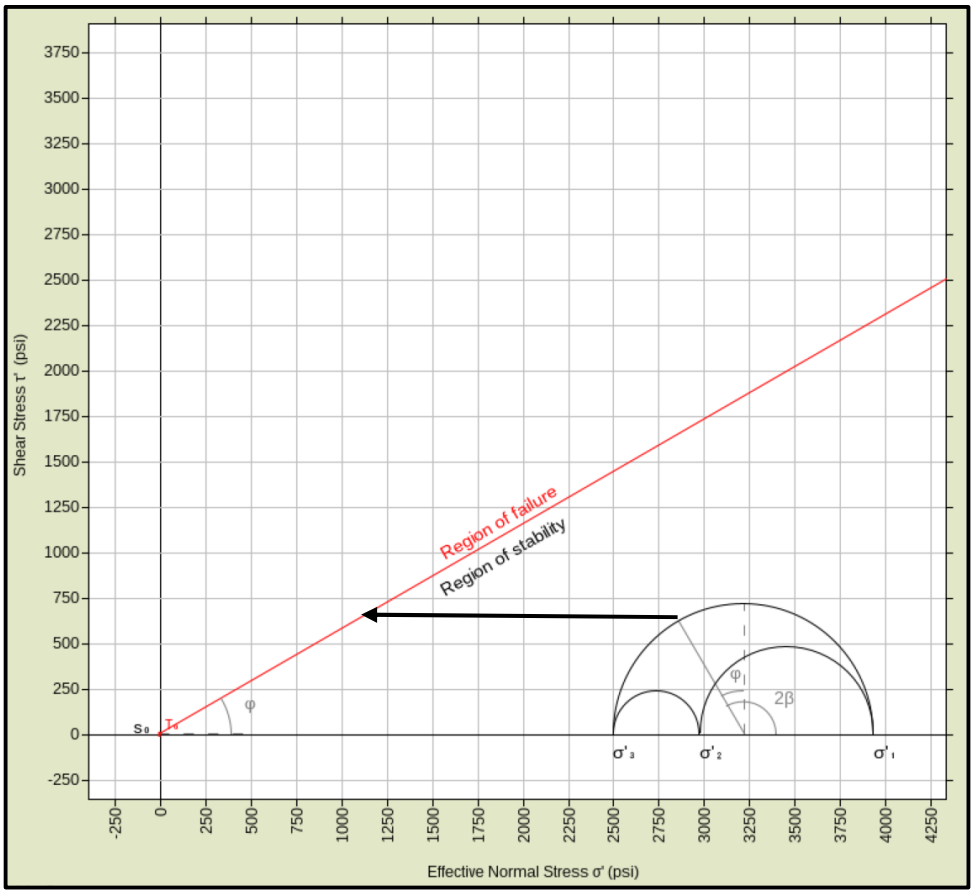


Figure AoR-217: Mohr Coulomb plot showing the state of stress in the middle of the Hackberry Confining Zone requires ~1800 psi of pressure increase to activate a fault in the optimal orientation in the location of the black arrow on the Mohr circle. Initiation of tensile fracture in the matrix of the Hackberry Confining Zone.

Table AoR-23: Summary of pore pressure increase (psi) required to cause failure in a hypothetical, optimally oriented fault and matrix in formations identified as confining and injection zones.

Formation	Depth (ft TVD)	Hypothetical Fault	Matrix
Lower Miocene Confining Zone	4,500	1,660	1,780
Lower Miocene Injection Zone	5,350	1,600	1,915
Anahuac Confining Zone	6,800	2,000	2,500
Frio Injection Zone	7,800	1,660	2,450
Hackberry Confining Zone	8,200	1,800	2,500

Summary

Preliminary critical stress analysis indicates that the risk of tensile or shear failure is similar in both all the confining and target injection zones. Using a hypothetical, optimally oriented fault for the purpose of analysis, it can be demonstrated that around 1,600 – 2,000 psi of pore pressure increase would be required to reactivate that fault in shear failure. Assuming a minimal amount of cohesion and tensile strength would indicate that initiation of matrix failure would occur in tension at about 1,800 – 2,500 psi pore pressure increase. The stress model is well calibrated and constrained, while the critical strength and frictional properties are constrained through interpretation. Reasonable estimates indicate that the rock properties are less a control on the failure analysis than are the stress magnitudes at the Encanto 01 well.

Table AoR-24: Fracture and injection pressure details.

Injection Pressure Details	CCS 1	CCS 2	CCS 3	CCS 5	CCS 6	CCS 7
Fracture gradient (psi/ft)	0.76	0.76	0.76	0.76	0.76	0.76
Maximum injection pressure (90% of the isotropic fracture pressure) (psia)	5,493 5,354 5,876	5,454 5,311	5,566 5,264 5,084	4,329 4,140 3,980 3,861 3,749	4,253 3,939 3,777	4,124 3,825 3,626 3,547
Depth corresponding to maximum injection pressure (ft TVD)	8,031 7,828 8,591	7,974 7,766	8,138 7,697 7,433	6,330 6,053 5,820 5,646 5,481	6,218 5,760 5,523	6,030 5,593 5,302 5,186

Table AoR-25 summarizes the key results gathered from the step-rate-tests (SRT) and leak-off tests (LOT) on the Encanto 01 stratigraphic well. In this project, the simulation model used the transmissibility, fracture gradient, and injectivity test results at the Frio formation. For all practical purposes, the use of 0.76 psi/ft as fracture gradient was reasonable.

Table AoR-25: Key results of step-rate and leak-off tests on Encanto 01 well.

Formation	Test	FBP (psia)	FPP (psia)	LOP (psia)	Frac Gradient (psi/ft)	Transmissibility mD*ft
Hackberry Confining Zone	LOT	8,046	7,530	7,430	0.91	n/a
Hackberry Injection Zone	SRT	n/a	>6,024	>6,024	>0.73	25,585
Frio Confining Zone	LOT	7,828	7,363	7,263	0.915	n/a
Frio Injection Zone	SRT	5,744	5,692	5,686	0.761	73,923
Anahuac Confining Zone	LOT	7,962	6,734	6,634	0.962	n/a
Lower Miocene Injection Zone	SRT	n/a	>3,690	>3,690	>0.68	426,024

Notes:

- LOT: Leakoff Test
- SRT: Step Rate Test
- FBP: Fracture Breakdown Pressure
- LOP: Leakoff Point
- FPP: Fracture Propagation Pressure

3.13 Geopressure Analysis

Identification of overpressured and underpressured regions is a critical parameter for assessing the viability of geological sequestration and long-term containment of supercritical fluids (GCAGS Journal, v. 1, 2012), such as CO_2.

Within the Houston Delta, sediments were transported to the coastal margin by rivers, and subsequently deposited in deltas or reworked by marine processes into strandplains and barrier bars (BEG Dodge and Posey, 1981). Contemporaneous growth faults developed parallel to the shelf margin and syndepositional movement resulted in sediment thickening on the downthrown

side of the faults. Due to the throw offsetting these sediments, they became isolated from sediments on the upthrown side of the fault. In some of these isolated sediments, abnormally high pressure and temperature gradients developed as a result of fluid entrapment (BEG Dodge and Posey, 1981) because high sedimentation rates, i.e., rapid burial, fed by large river systems in these deltaic deposits prevented the escape of pore water trapped in the shales, and thus, built-up fluid pressures and under compacted sediments. Under overpressure conditions, the shale layers can act as detachment planes for faults and can accumulate significant hydrocarbon accumulations (Texas Water Development Board Report 365, 2006).

The U.S. Geological Survey created a comprehensive geopressured-gradient model of the regional pressure system spanning the onshore and offshore portions of the U.S. Gulf of Mexico basin (GCAGS Journal, v. 1, 2012). From that model, several regional subsurface geopressured-gradient maps are available, based on mud weight data obtained from vertical wells, which are plotted on regional cross sections and well logs. These contour maps characterize surfaces of equal pressure, also called isopressure-gradient maps.

They characterize the depth and distribution of isopressure-gradient surfaces from 0.60 psi/ft to 1.00 psi/ft, in 0.10 psi/ft intervals. The depth at which the 0.70 psi/ft pressure gradient occurs is critical as it represents the “top of overpressure” or the “top of the overpressure transition zone” (Figure AoR-218).

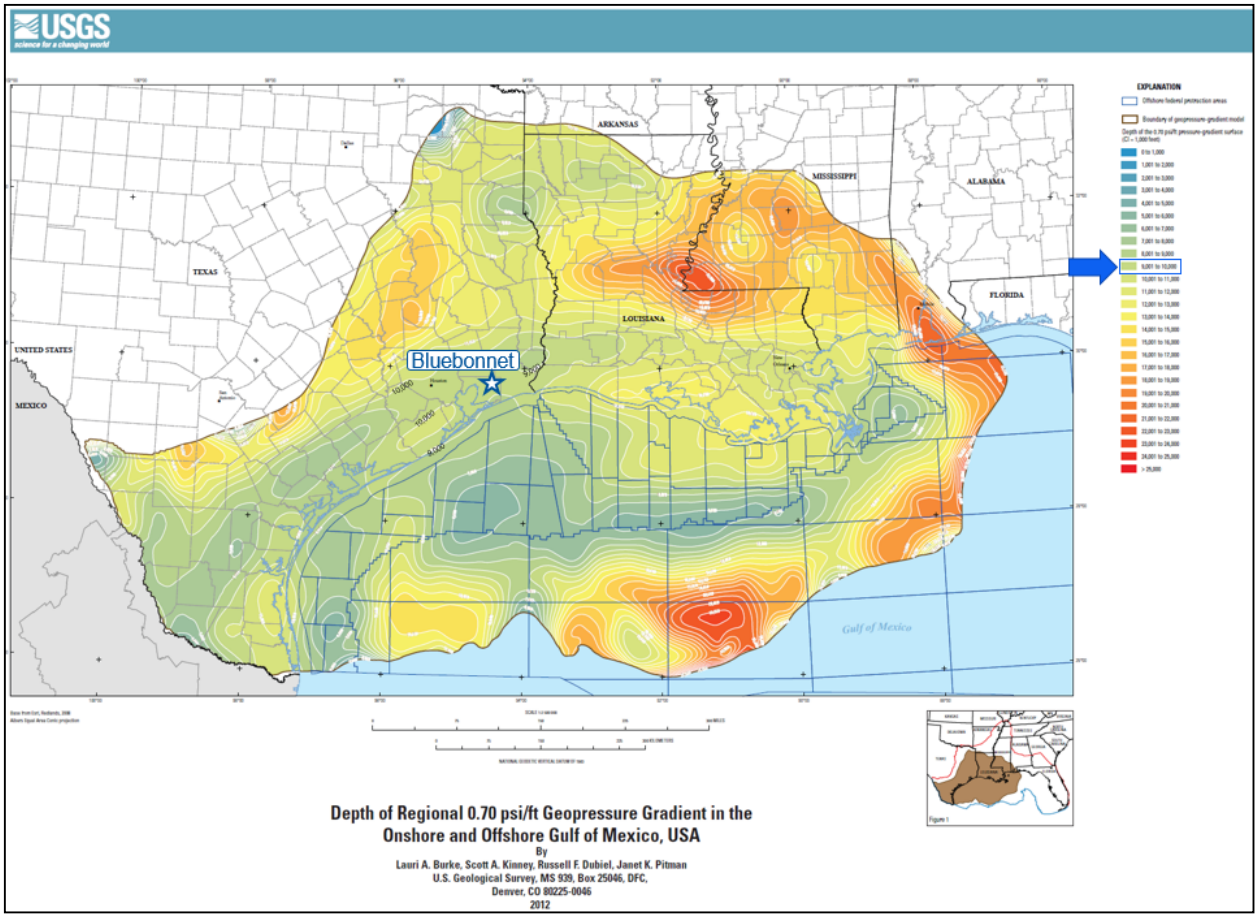


Figure AoR-218: Regional 0.7 psi/ft Geopressure Gradient map by Burke et al., U.S. Geological Survey, 2012. The depth at which the 0.7 psi/ft gradient occurs is interpreted as the onset of overpressure. Based on this regional map, the overpressure at the Bluebonnet Sequestration site is expected to occur between 9,000 ft and 10,000 ft measured depth.

In the shallow subsurface of the Gulf Coast, pressure gradients generally follow a hydrostatic pressure-gradient trend, which represents the theoretical pressure gradient exerted by a column of fresh water. In the Gulf of Mexico Basin, using an average formation water salinity of 100,000 ppm TDS, yields a hydrostatic pressure-gradient of 0.465 psi/ft (GCAGS Journal, v. 1, 2012). The pressure gradient deviates from the hydrostatic gradient line with increasing depth. Pressure gradients in the region below the hydrostatic gradient represent underpressured regimes; whereas, overpressured regimes refer to regions with pressure gradients above the hydrostatic gradient.

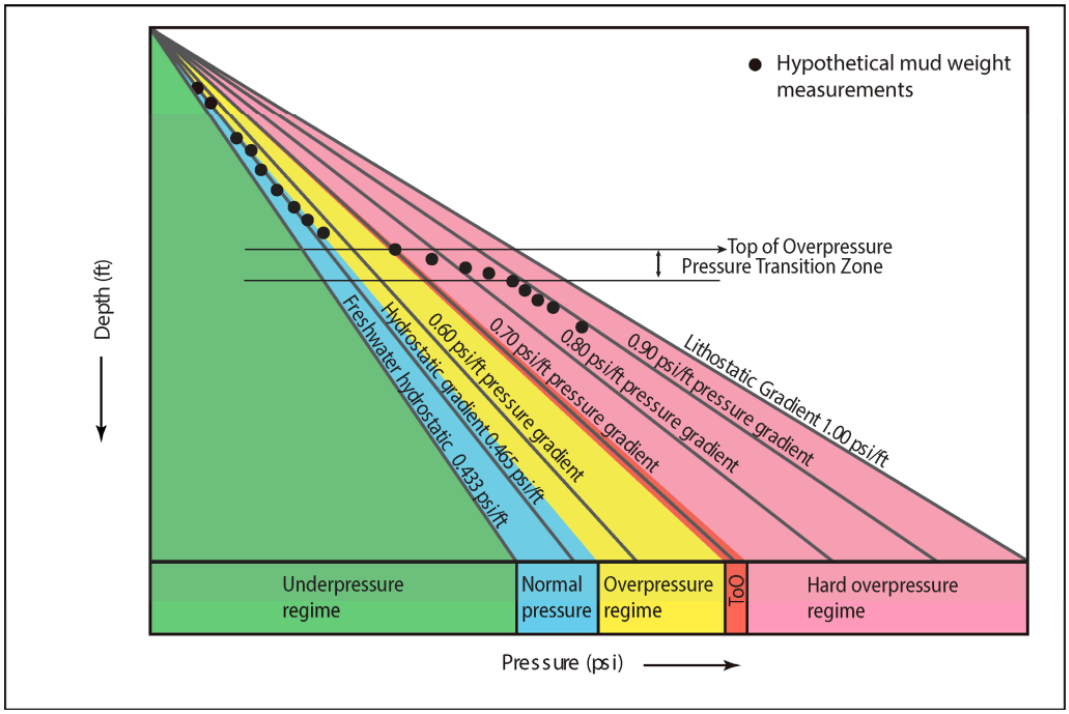


Figure AoR-219: Schematic diagram of generalized pressure gradients and associated pressure regimes. The top of overpressure is denoted by ToO; by Burke et al., U.S. Geological Survey, 2012.

Because this regional geopressure-gradient model characterizes subsurface isopressure gradients spanning the entire Gulf of Mexico basin, the results from this regional investigation are not applicable for small-scale, detailed pressure examinations of specific locations. Therefore, this regional map was supplemented at the local Bluebonnet Hub site scale by analyzing sonic logs and mud weights by depth.

Within the proposed Bluebonnet Hub, sonic logs were used to determine the onset of overpressure at the transition to slow velocities at depth, in addition to the expected values from the regional map (Figure AoR-218). The top of overpressure based on sonic logs occurs between 8470 ft, two miles north of the AoR (shallowest), and 10,365 ft, three and three-quarters miles south southeast of the AoR (deepest). The onset of overpressure is located 229 – 1040 ft below the targeted Frio and Hackberry injection zones (Figures AoR-220 and AoR-221) within the proposed AoR.

These estimated depths based on increasing sonic velocities are in agreement with the actual measured mud weights from wells drilled within and nearby the AoR (Figure AoR-222).

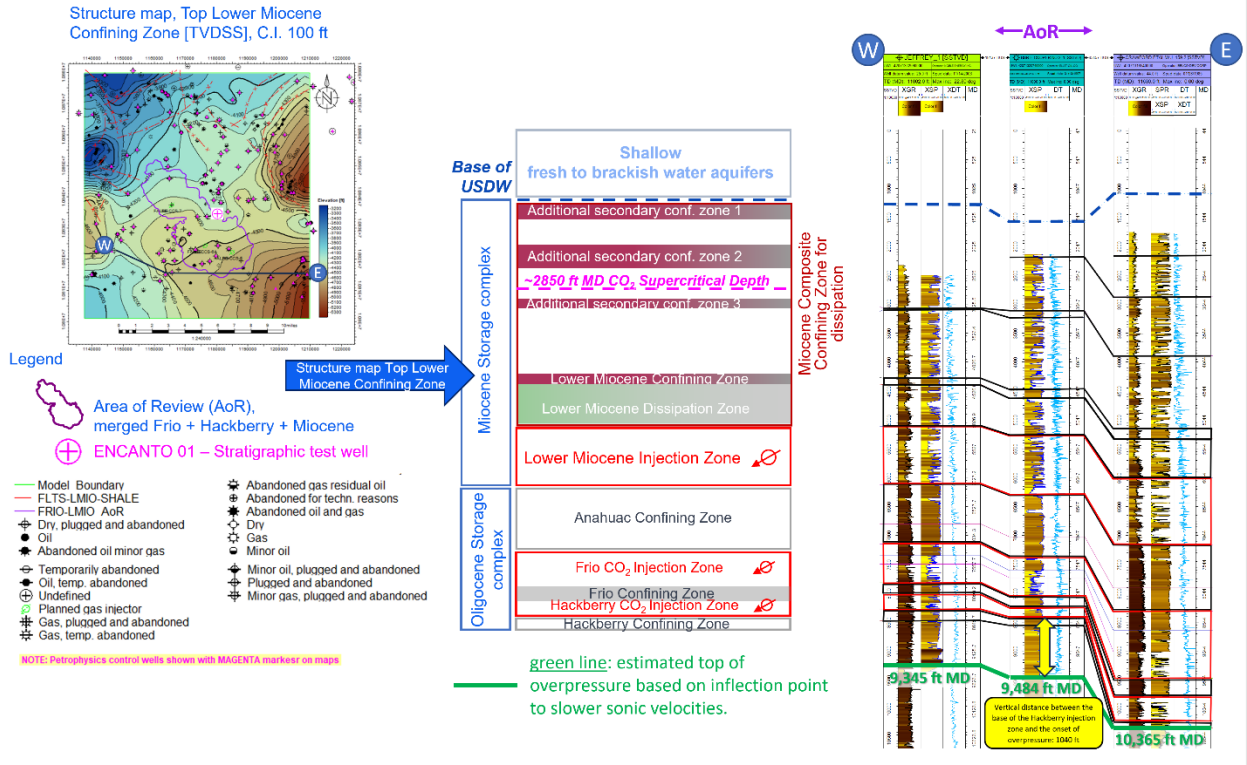


Figure AoR-220: West-east strike cross section through the proposed Bluebonnet Sequestration Hub site. The top of overpressure is shown by the green line and estimated based on the inflection to slower velocities on the sonic log shown in blue. The onset of overpressure in this strike cross section occurs approximately 1,040 ft below the base of the injection zone.

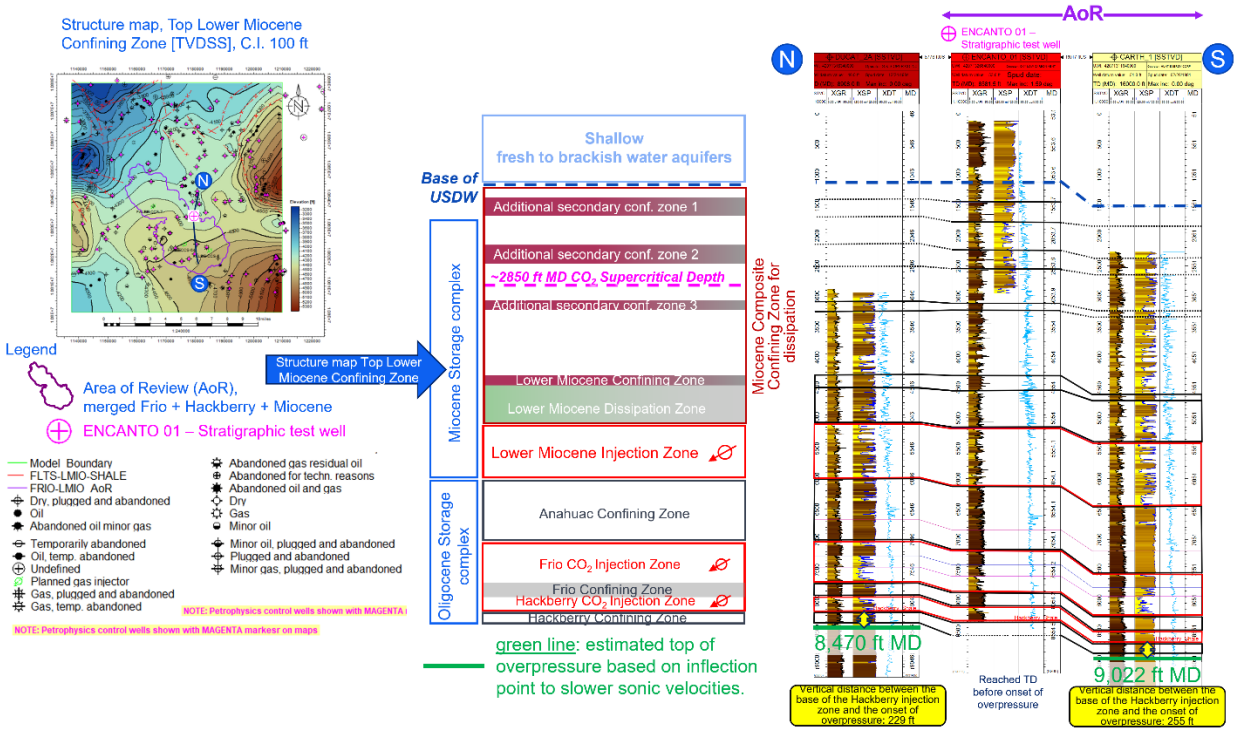


Figure AoR-221: North-south dip cross section through the proposed Bluebonnet Sequestration hub site. The top of overpressure is shown by the green line and is estimated based on the inflection to slower velocities on the sonic log shown in blue. The onset of overpressure in this dip cross section occurs approximately 229 to 255 ft below the base of the injection zone.

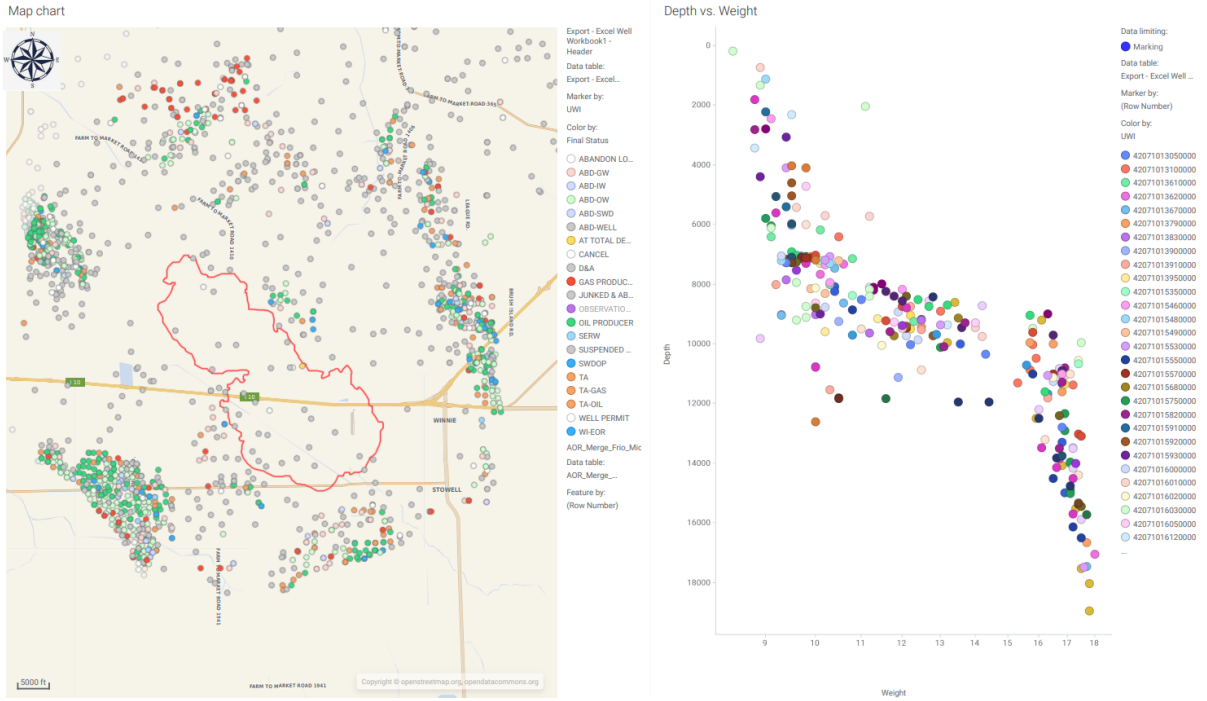


Figure AoR-222: Mud weights over depth from wells drilled within and nearby the proposed Bluebonnet Sequestration Hub. The Top of Overpressure is shown by the increase in mud weight.

3.14 Existing hydrocarbon fields

In the Tertiary section of the Upper Texas Gulf Coast, the majority of known fields produce from structural traps: salt domes (Spindletop Field); faulted anticlines (Anahuac Field); elongated anticlines located downthrown to the growth faults; and smaller fields produce from subtle stratigraphic traps (Devillier Field) (Gordon, 1982). The accumulation of the Walla-Boyt Field was likely controlled by the contemporaneous effects of deltaic sedimentation and of growth-fault tectonics. The Walla-Boyt and Spindletop Bayou Fields are oil and gas fields producing from sands below the proposed storage complex. In the Texas Railroad Commission well files, those sands are called Frio Basal, Struma 1st Sand, and Texas Mississippian Sand, and they occur stratigraphically below the lowest proposed Hackberry Injection Zone. These two fields are located on the downthrown side of Vicksburg aged faults and they are localized structures outside the proposed AoR.

The Bluebonnet Project team performed a detailed analysis of the isotube mud gases and samples collected in the stratigraphic well Encanto 01. The encountered methane gas in the Hackberry formation is likely not thermogenic. Synthetic oil-based mud was used to drill Encanto 01. The drilling fluid was also analyzed and solvent extracted. The purpose of this was to obtain the fingerprint of the added synthetic oil so that if oil was noted in rock samples, a differentiation could be made of any possible thermogenic natural crude oil from the drilling mud additive. However, no naturally derived crude oil was found in any of the rock samples analyzed in Encanto 01 via rock pyrolysis and gas chromatography (see Appendix D).

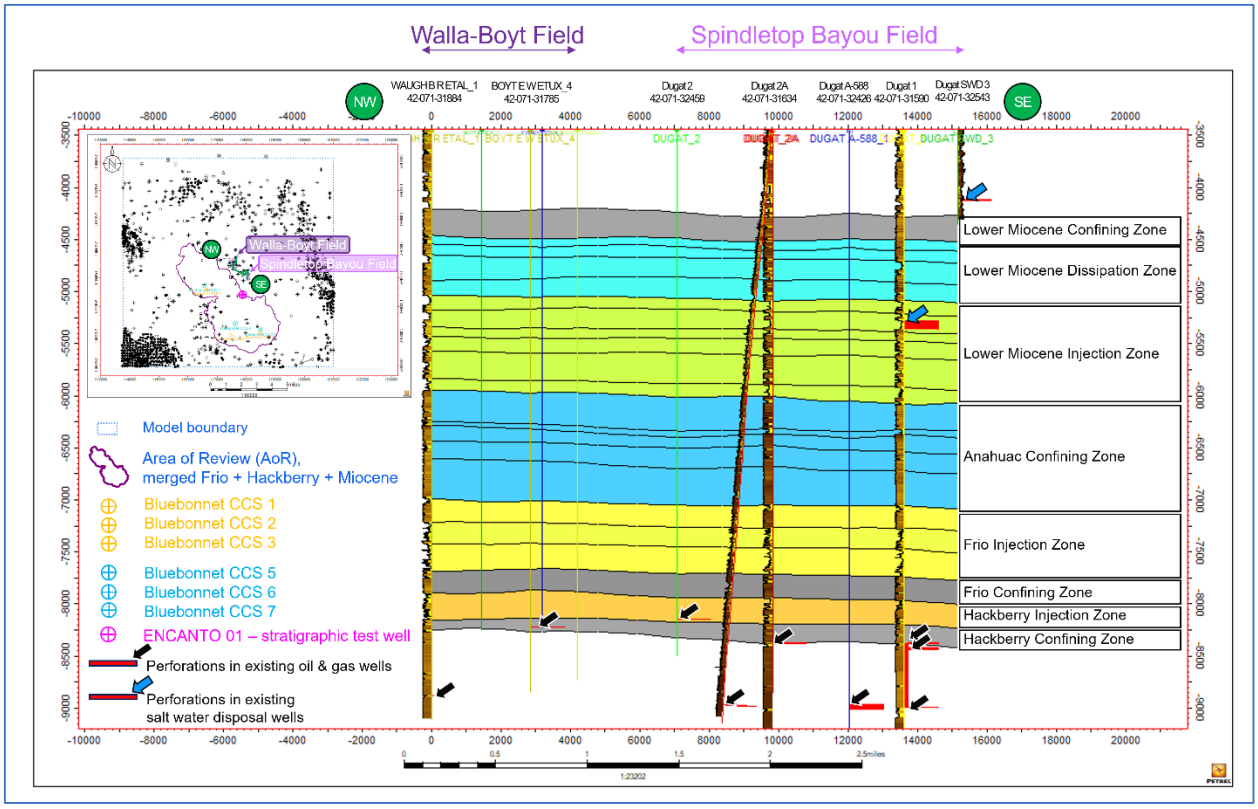


Figure AoR-223: Northwest-southeast cross section through Walla-Boyt and Spindletop Bayou producing oil and gas fields. The logs shown are Gamma Ray (GR) and Spontaneous Potential (SP) logs; perforations are shown in red. Walla-Boyt and Spindletop Bayou Fields are localized structures on the downthrown side of Vicksburg aged faults (not shown here) below the proposed storage complex. These producing fields and salt water disposal operations are located outside of the proposed AoR (purple polygons in inset map).

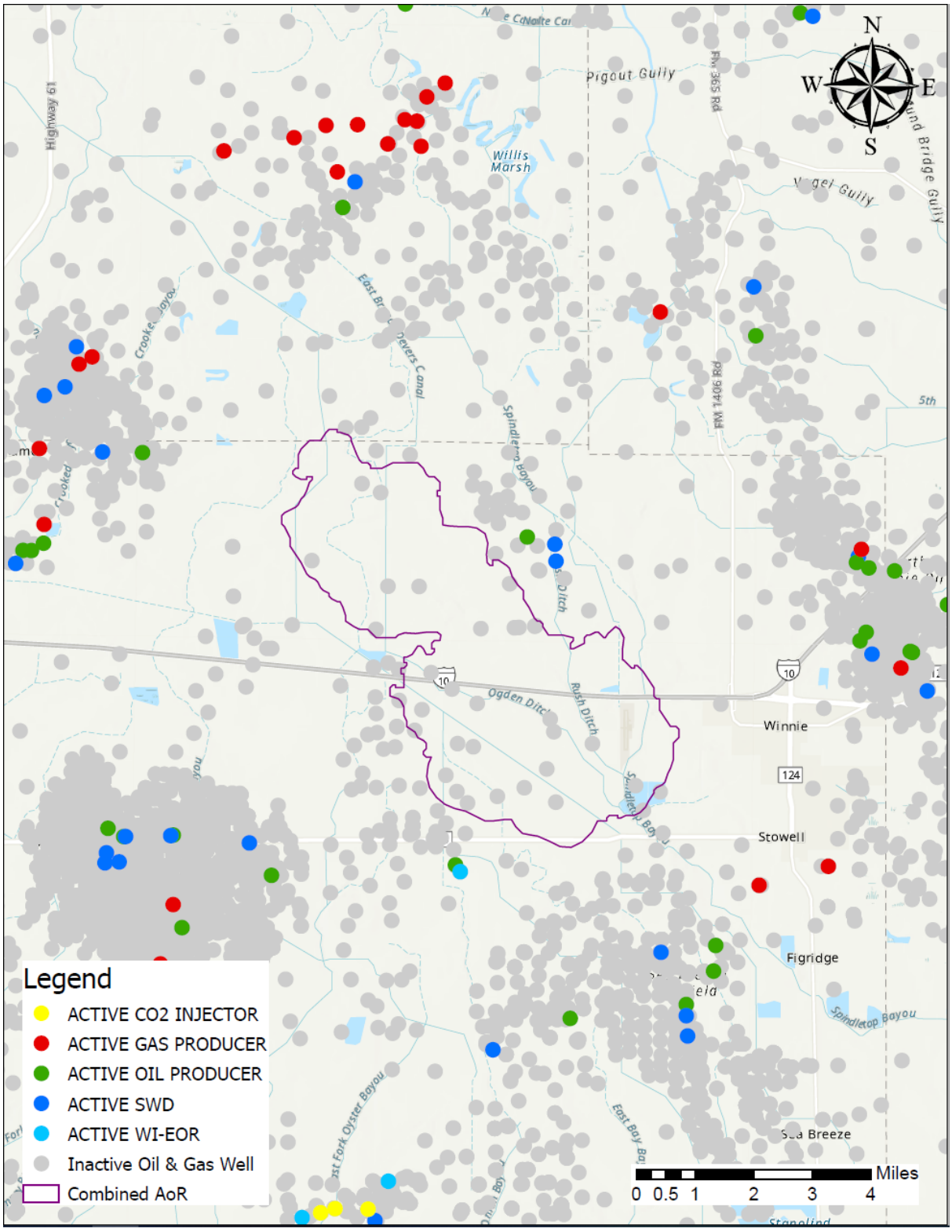


Figure AoR-224: Active oil and gas wells near the CCS project area from the IHS Database.

3.15 Seismic History

Regional earthquakes were identified using the USGS online database cross checked against the Bureau of Economic Geology's TEXNET database to determine the location of events (Figure AoR-225). No recorded events of any magnitude from 1900 to present were identified within 50 miles of the Bluebonnet site. A single earthquake was identified within a 75-mile radius of the Bluebonnet project: this magnitude 3.8 event occurred in 1983, 1 km WNW of Sulphur Louisiana at a depth of 5.9 km. The USGS Long-Term Seismic Hazard Map (Figure AoR-227) indicates that this area is at relatively low risk for natural earthquake activity.

Seismometer stations were identified via the Incorporated Research Institute for Seismology's database (Figure AoR-225 and Table AoR-26). There are three stations identified within a 50-mile radius of the Bluebonnet project, none of which are active today. A total of 68 stations are identified within a 75-mile radius of the Bluebonnet project, seven of which are currently recording. A local seismometer array consisting of 14 sensors was installed for the Bluebonnet project area with a designed Magnitude of Completeness of <0.0 on the Richter scale. The array is designed to provide reliable seismic coverage of the AoR and surrounding project area, focusing on monitoring around the planned injection well(s) and local faults. The installed seismometer locations in relation to injection well(s) and faults are seen in Figure AoR-226 .

A risk assessment of induced seismicity due to injection activities is presented in Figures AoR-228, AoR-229, and AoR-230.

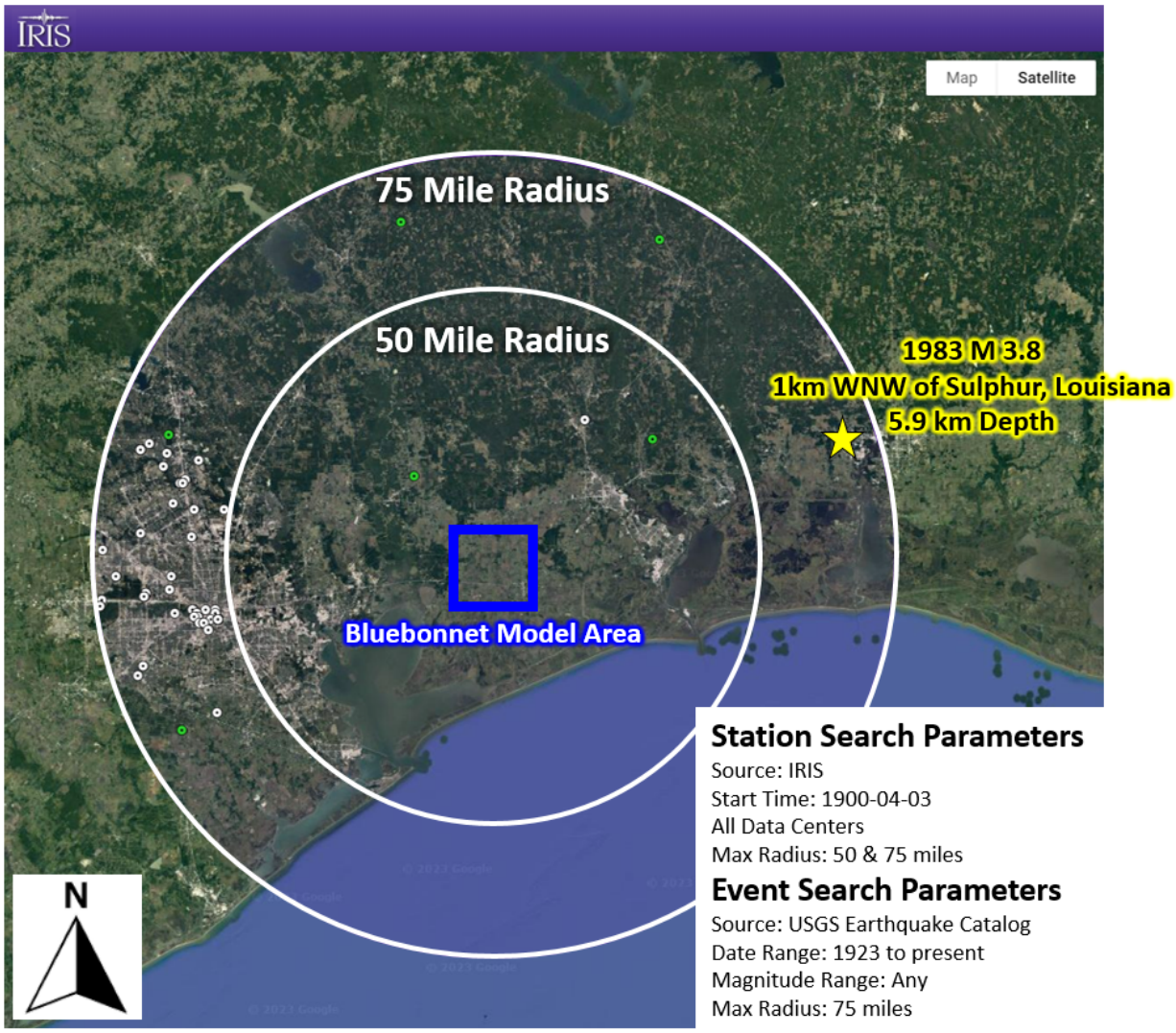


Figure AoR-225: Seismometer stations (green and white circles) and historic seismic activity (yellow star).

Table AoR-26: Seismometer stations within a 50- and 75-mile search parameter of Bluebonnet.

Network	Station	Latitude	Longitude	Start Date	End Date
Stations within 50 Mile Radius of Bluebonnet					
AM	RFDFC	30.26126126	-94.19050493	7/22/2020	8/9/2020
TA	539A	30.1084	-94.723602	4/13/2010	11/10/2011
TA	540A	30.209299	-93.979599	5/23/2010	12/7/2011
Stations within 75 Miles Radius of Bluebonnet					
AM	R0172	30.18018018	-95.57948534	3/18/2017	4/22/2019
AM	R0F1A	29.59459459	-95.56960457	12/2/2016	1/16/2023
AM	R0F1A	29.59459459	-95.56941507	1/16/2023	12/31/2599
AM	R1294	29.74774775	-95.41182473	7/2/2020	10/15/2020
AM	R151C	30.01801802	-95.41090816	7/22/2020	8/8/2020
AM	R151C	29.72072072	-95.33627264	5/16/2021	6/12/2021
AM	R1E10	29.72972973	-95.40954644	1/2/2020	2/17/2020
AM	R21BC	29.74774775	-95.41334752	6/29/2021	8/4/2021
AM	R22C0	29.72072072	-95.35825576	12/6/2016	4/22/2019
AM	R347E	29.75675676	-95.70602629	7/28/2018	12/31/2599
AM	R3C08	29.79279279	-95.56185406	5/18/2021	6/8/2021
AM	R4457	29.72072072	-95.33589264	6/3/2020	5/16/2021
AM	R4457	29.72072072	-95.33627264	5/16/2021	11/25/2021
AM	R475C	30.17117117	-95.49596743	6/1/2020	5/4/2021
AM	R475C	29.72072072	-95.33627264	5/4/2021	12/31/2599
AM	R475C	29.73873874	-95.40316622	5/5/2021	5/15/2021
AM	R5378	29.83783784	-95.65642907	7/21/2020	7/21/2020
AM	R5378	29.83783784	-95.65623752	7/21/2020	8/7/2020
AM	R5378	29.69369369	-95.36695782	8/7/2020	5/16/2021
AM	R5378	29.72072072	-95.33627264	5/16/2021	6/9/2021
AM	R5771	29.72072072	-95.33627264	5/16/2021	6/18/2021
AM	R5DDF	30.09009009	-95.445128	12/4/2019	12/31/2599
AM	R5E2B	30.0990991	-95.43712881	12/31/2020	12/31/2599
AM	R60B9	29.71171171	-95.39442894	7/21/2021	12/31/2599
AM	R7489	30.18018018	-95.57948534	11/11/2017	4/22/2019
AM	R7A14	29.79279279	-95.56185406	5/18/2021	6/8/2021
AM	R7AF6	30.03603604	-95.47670271	10/8/2019	10/11/2019
AM	R87F8	30.18018018	-95.57948534	2/11/2019	4/25/2021
AM	R89CA	29.8018018	-95.4886332	6/29/2021	12/6/2021
AM	R8A94	29.75675676	-95.70593077	2/17/2018	4/22/2019
AM	R9393	29.72972973	-95.40021753	12/31/2019	1/13/2020
AM	R9393	29.72972973	-95.4000273	2/5/2020	6/11/2021
AM	R95FA	29.95495495	-95.57962713	7/18/2020	5/16/2021
AM	R95FA	29.72072072	-95.33627264	5/16/2021	7/1/2021
AM	R98DD	29.75675676	-95.70593077	1/22/2019	12/31/2599
AM	R98E5	29.72972973	-95.41182938	7/22/2020	5/16/2021
AM	R98E5	29.72072072	-95.33627264	5/16/2021	6/7/2021
AM	R98E5	30.01801802	-95.31851566	5/28/2021	6/7/2021
AM	R9B84	29.90990991	-95.69529211	4/4/2018	2/13/2021
AM	RA140	30.1981982	-95.55056527	2/23/2023	12/31/2599
AM	RA302	29.75675676	-95.70583525	3/11/2018	4/22/2019
AM	RAD87	30.09009009	-95.45380285	1/14/2018	10/18/2019
AM	RAD87	30.09009009	-95.445128	10/18/2019	12/6/2019
AM	RC1A6	29.71171171	-95.38063469	5/30/2020	6/12/2020
AM	RC1A6	29.71171171	-95.38053968	6/12/2020	8/28/2020
AM	RC9DD	29.78378378	-95.56679185	3/4/2021	5/19/2021
AM	RC9DD	29.78378378	-95.56707832	5/20/2021	6/19/2021
AM	RC9DD	29.46846847	-95.33968893	5/28/2021	6/3/2021
AM	RC9DD	29.78378378	-95.56688734	9/3/2021	1/6/2022
AM	RCD56	29.72072072	-95.33627264	5/5/2021	6/9/2021
AM	RE0EF	29.83783784	-95.48091615	7/16/2020	7/16/2020
AM	RE0EF	29.83783784	-95.48082055	7/16/2020	1/20/2023
AM	RE117	29.73873874	-95.47246479	1/17/2018	4/22/2019
AM	RE998	30.18018018	-95.57938832	2/11/2019	5/26/2021
AM	REA98	29.56756757	-95.58660898	1/1/2017	8/15/2019
AM	REC5C	29.77477477	-95.70007855	3/2/2021	8/16/2022
AM	REF4D	30.13513514	-95.50665562	5/8/2017	5/9/2021
AM	RF3D8	30.15315315	-95.39586037	8/28/2021	6/6/2022
AM	RFF98	29.72072072	-95.33627264	5/17/2021	8/26/2021
AM	RFF98	29.74774775	-95.34413504	6/1/2021	6/1/2021
AM	RFF98	29.73873874	-95.34557167	6/1/2021	6/1/2021
AM	RFF98	29.74774775	-95.41572712	6/1/2021	6/1/2021
AM	RFF98	29.74774775	-95.37393402	6/1/2021	6/1/2021
AM	RFF98	29.94594595	-95.41914435	6/1/2021	6/10/2021
TA	439A	30.793699	-94.765999	4/12/2010	12/13/2011
TA	440A	30.7456	-93.958702	5/22/2010	12/7/2011
TA	538A	30.221901	-95.489998	1/28/2010	11/10/2011
TA	638A	29.4193	-95.448097	2/17/2011	11/6/2011

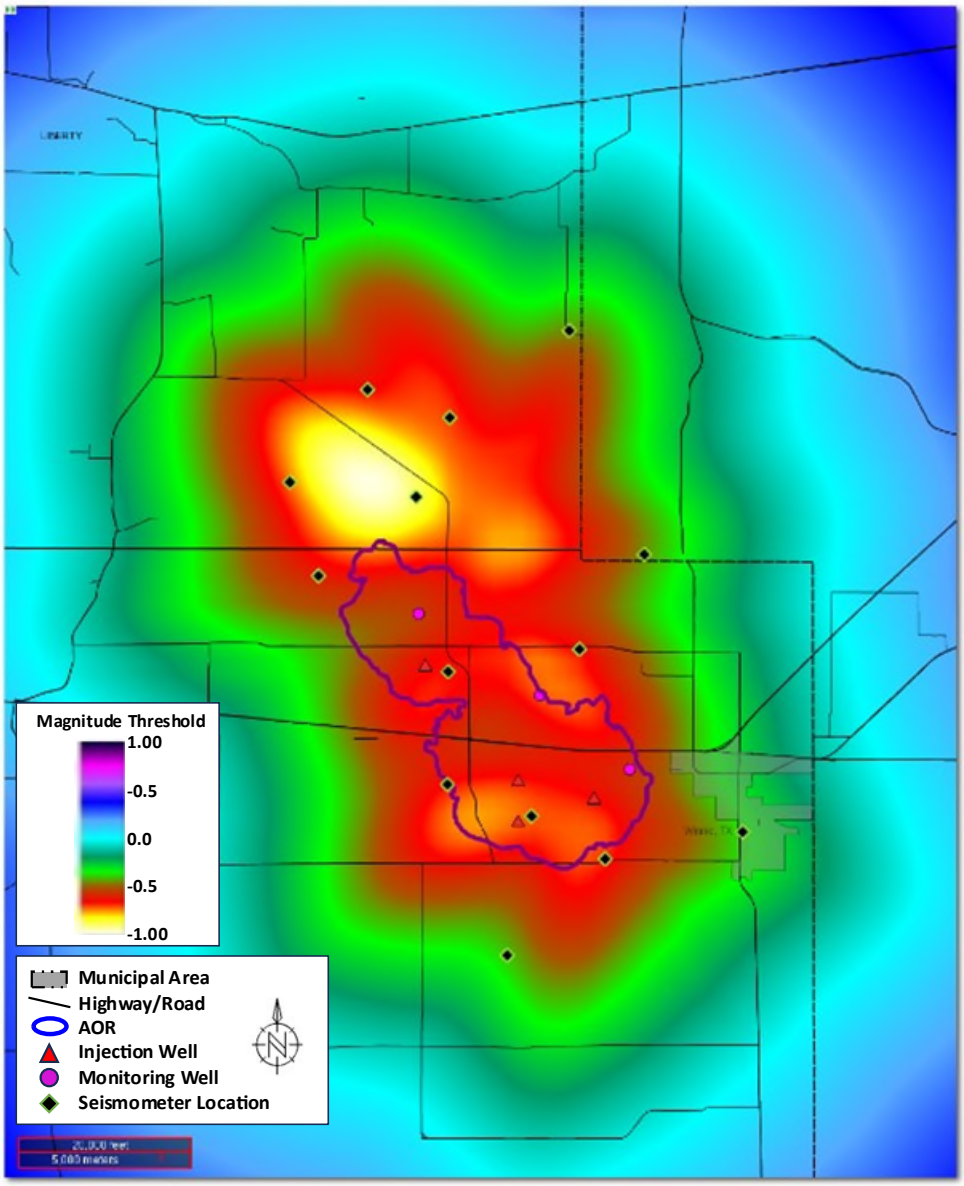


Figure AoR-226: Proposed seismometer array to monitor for induced seismicity at or related to injection wells and regional faults. Faults are colored according to relative hazard, determined by comparing the strike of the fault to principle horizontal stress direction.

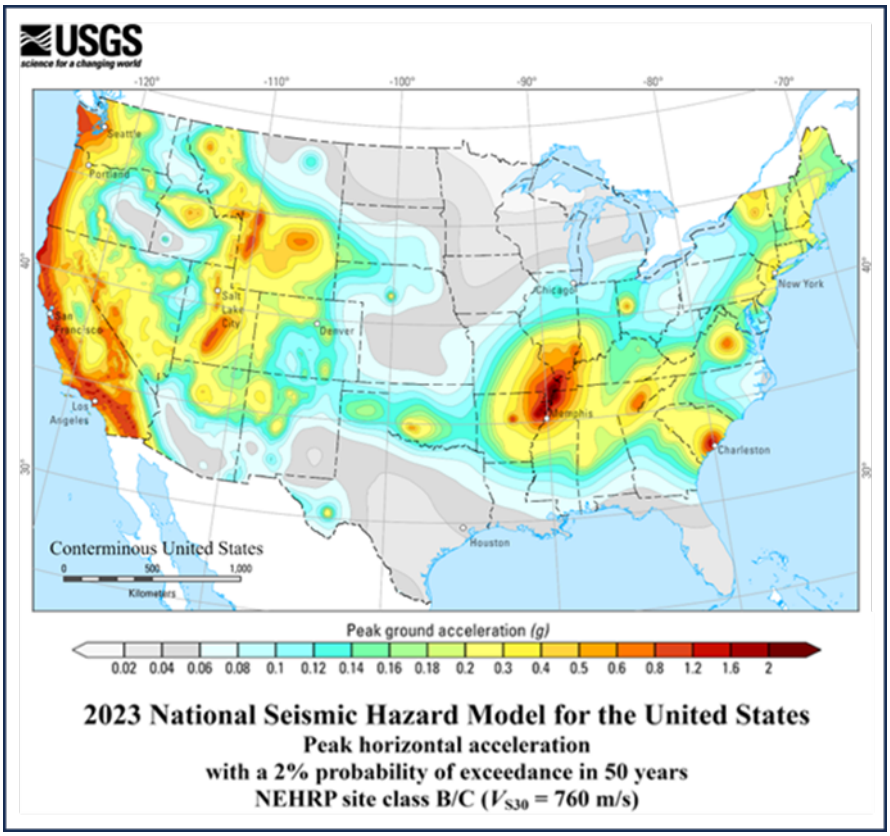


Figure AoR-227: Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2018 Long-Term National Seismic Hazard Map (USGS, 2018). Seismic hazard potential in the study area is one of the lowest in the U.S.

Probability

Probability of a Seismic Event	Historic Seismicity	Seis-mometer Coverage	Seismic Coverage	Basement Faulting (proximity to a fault of concern)	Injection Zone's Proximity to Basement	Injection Rate	Count
High (3)							6/18
Medium (2)							
Low (1)	✓	✓	✓	✓	✓	✓	

Figure AoR-228: Assessed probability of a seismic event. Historic Seismicity: There are no recorded historic seismic events within a 50-mile radius of the Bluebonnet Hub.

Details on the basis for the probability presented in Figure AoR-172 are given below.

- **Seismometer Coverage**: 14 new seismometers were installed within the project area, providing reliable detection of seismic events measuring 0.0 on the Richter scale in the AoR and along mapped faults.

- **Seismic Coverage**: High quality 3D seismic is available over the project area.
- **Basement Faulting**: All faults proximal to the Bluebonnet Hub are observed to detach within the Wilcox (more than 10,000 ft above the estimated basement depth).
- **Basement Proximity**: The proposed injection zone is more than 20,000 ft above the estimated basement depth.
- **Injection Rate**: Fault reactivation pressures were modeled for the greater Bluebonnet Hub area and all faults required a delta-P of >1000 PSI to reactivate. Modeled injection pressures for the Bluebonnet Hub do not exceed 232 psi in the Frio and 541 psi in the Hackberry.

Consequence

Consequence of a Seismic Event	Public Impact / Tolerance	Proximity to Critical Infrastructure (e.g. Dams)	Seismicity Regulatory Regime	Impact on Development	Final
High (3)	✓		✓	✓	10/12
Medium (2)					
Low (1)		✓			

Figure AoR-229: Assessed consequence of a seismic event.

Details on the basis for the probability presented in Figure AoR-173 are given below.

- **Public Impact/Tolerance:** Public tolerance for induced seismicity is fragile in Texas and media exposure of induced seismic events related to CCS activity is predicted to be high.
- **Proximity to Critical Infrastructure:** The Bluebonnet Hub is not proximal to critical infrastructure.
- **Seismic Regulatory Regime:** Local seismicity monitoring is recommended for CCS operations.
- **Impact on Development:** Significant seismic events have the potential to stop project advancement.

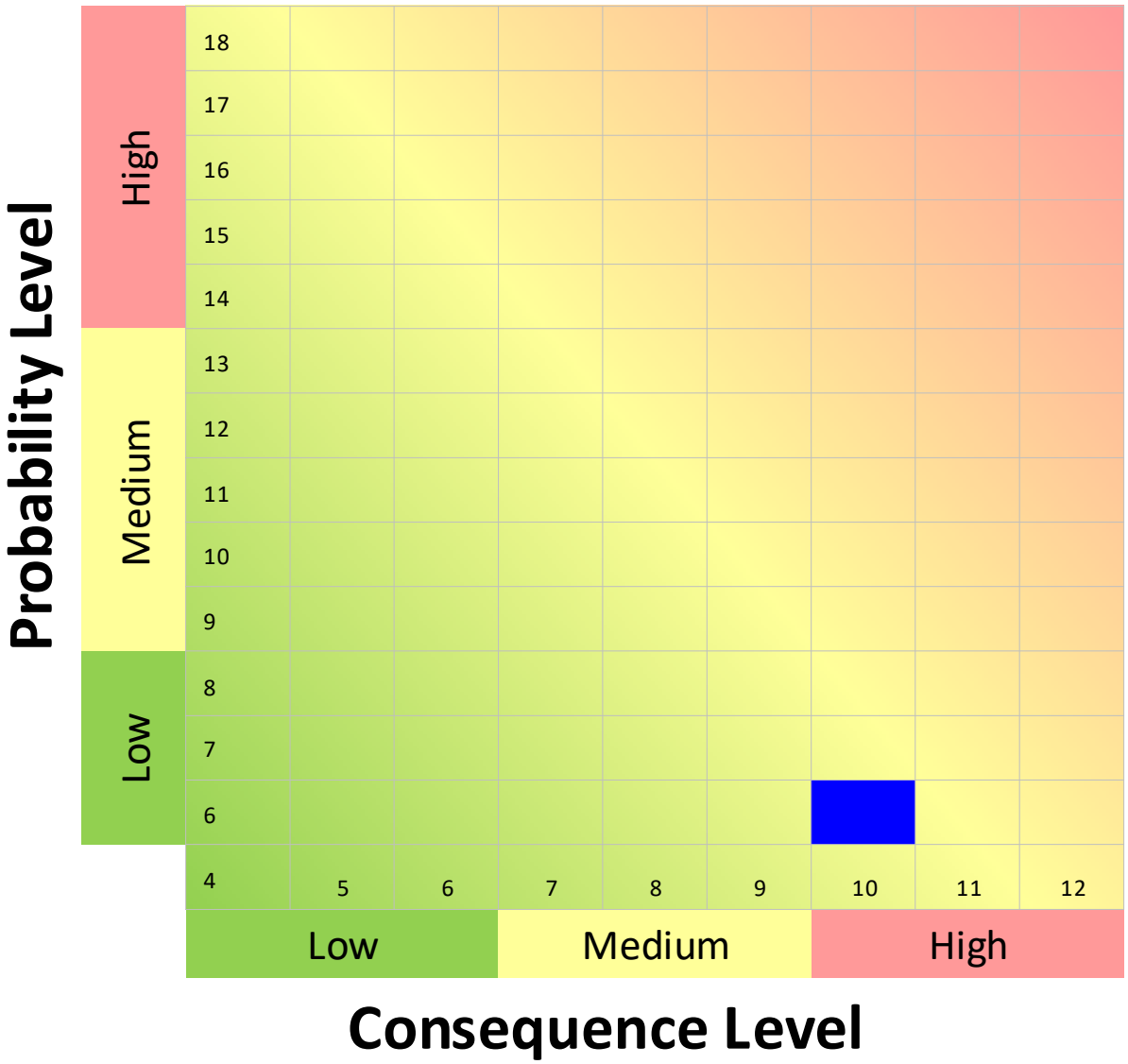


Figure AoR-230: Assessed risk matrix for induced seismicity at the Bluebonnet site. The probability of induced seismicity related to injection activity is low, while the assessed consequence of an event is classified as high.

4.0 Oligocene Storage Complex Model

4.1 Simulation Model Background – Oligocene Storage Complex

4.1.1 Geocellular Model Introduction

The static geocellular model was constructed using Schlumberger's Petrel (v2021) 3D geostatistical modeling software, which is a comprehensive, integrated subsurface platform containing data interpretation tools for well correlation, mapping, and structural and property modeling. Application of this software has been demonstrated in reliable subsurface models containing faults, horizons, and properties, which are then used to estimate volumetrics and are further passed on to dynamic reservoir simulation.

4.1.2 Dynamic Simulation Model Introduction

The dynamic simulation models were created using the GEM (v2023.3YES0) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd. (CMG). GEM is a commercially available, compositional, and finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. GEM has also been used to model several carbon capture and storage projects. The Greenhouse Gas (GHG) module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, and enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions, including temperature ranges between 53.6°F (12°C) and 302°F (150°C) and pressures up to 16,000 psi (110 MPa). Details of this method can be found in Collins et al. (1992, CMG GEM Manual), Thomas and Thurnau (1983, CMG GEM Manual), and Nghiem and Li (1989, CMG GEM Manual).

Additional assumptions governing the phase interactions throughout the simulations are as follows:

- CO_2-rich phase (gas) density is obtained by using the Peng-Robinson equation of state. The model was accurately tuned and modified as described below (Peng and Robinson, 1976, CMG GEM Manual).
- CO_2 dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey, 1996, CMG GEM Manual).
- Brine density is specified at a reference pressure of 1,952 psi and corrected for local pressure variations using a specified water compressibility. Brine density is then corrected for the dissolved CO_2 and ionic components using their partial molar volumes. Brine viscosity is calculated using the Kestin (1981) correlation.
- Chemical equilibria among H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2, H_4SiO_4, HCO^-, OH^-, CO_3^{2-}, $CaOH^+$, $MgHCO_3^+$, and $AlOH^{+2}$ ions in the aqueous phase are modeled with 13 equilibrium constants. Aqueous complexes were selected based on simulation results from geochemical equilibrium runs (Geochemist's Workbench) with minerals and CO_2. Solid phases included calcite, kaolinite, anorthite, dolomite, illite, K-feldspar, and quartz

minerals. Reactions among these minerals and ions are modeled with chemical reactions and reaction coefficients from the Lawrence Livermore National Laboratory database (Thibeau, 2007) which were also used in a simulation study by Nghiem et al. (2004).

- The CO_2 gas viscosity is calculated per the methods described by Pedersen et al. (1984).
- The gas density is obtained by using a cubic equation of state developed by Peng and Robinson (1976) described by Equation 1:

$$P = \frac{RT}{(v - b_{mix})} - \frac{a_{mix}}{(v^2 + 2vb_{mix} - b_{mix}^2)} \quad \text{..... (Equation 1)}$$

Where:
v is the molar volume;
P is the pressure;
T is the temperature in Kelvin;
R is the universal gas constant;
a_{mix} and b_{mix} are mixture-specific functions of temperature and composition, calculated from the critical properties and acentric factors of the components.

The CMG WinProp software has a built-in library for the properties CO_2 and CH_4 based on Reid et al. (1977). No changes were made to the library components.

The transition between liquid and gaseous CO_2 can lead to rapid density changes in the gas phase. The simulator uses a narrow transition interval between the liquid and gaseous density to represent the two-phase CO_2 region.

Because the compression/pumping facility controls the CO_2 delivery temperature to the injection well to keep it between 60°F and 120°F, the temperature of the injectant will be comparable to the reservoir formation temperature at the injection interval. Therefore, the simulations were based on isothermal operating conditions with a linear initial reservoir temperature gradient of 0.01757°F/ft.

With respect to the timestep selection, the software algorithm optimizes the timestep duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the timestep size ranged from 0.001 to 10 days. In all cases, the maximum solution change over a timestep was monitored and compared with the specified target. Convergence was achieved once the model reaches the maximum tolerance where small changes of the temperature and pressure calculation results occur on successive iterations. New timesteps were chosen so that the predicted solution change is less than a specified target.

Chemical equilibria of ionic species in brine and reactions of minerals with ions were simulated in only limited cases due to their long computing times. The results suggested negligible net carbon capture by minerals during the CO_2 injection period. After CO_2 injection has ceased, however, continued precipitation of calcite, dolomite, and other minerals over an extended period (100+ years) may indeed play a key role in retaining a large fraction of carbon atoms permanently in the reservoir.

4.2 Model Domain - Oligocene Storage Complex

This Class VI permit contains information about both stacked Oligocene and Miocene storage complexes which collectively comprise the Bluebonnet Sequestration Project. Site-specific subsurface characterization does not suggest vertical fluid communication between each storage complex; therefore, each storage complex is described and modeled independently. Examples of subsurface characterization supporting separate storage complexes include differences in local geology, depositional environment, seismic amplitudes, fairway mapping, sand distribution, facies, formation fluids, and well tests. The first model described under 4.0 is the original Frio model submitted in the July 2024 Class VI permit, which was calibrated to well logs and adjusted to well test data. The second model described under 5.0 is the latest Miocene model, which is calibrated to the core data and adjusted to well test data, and includes two additional faults in the south, with which the existing Class VI permit is now updated, merged, and completed. The Bluebonnet Sequestration HUB LLC is seeking approval for CO_2 storage in both storage complexes as a whole unit.

Figure AoR-231 displays the Bluebonnet Hub location in Chambers, Jefferson, and Liberty Counties with 3D seismic coverage and legacy wells in the area where the Bluebonnet geomodel has been built to quantify CCS potential and plan for its development.

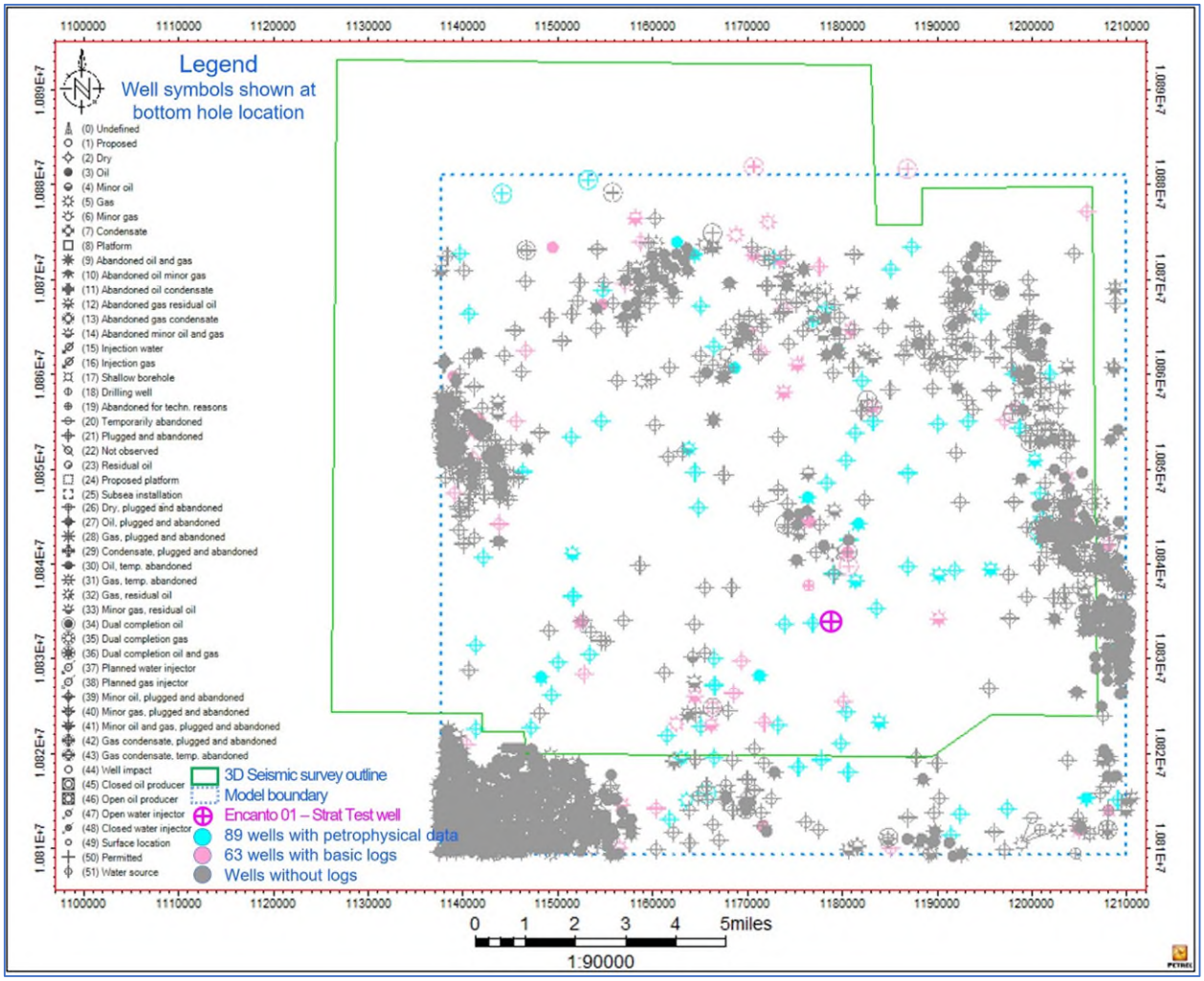


Figure AoR-231: Map of the Bluebonnet Sequestration Hub geomodel area for Frio in dashed blue outline and legacy wells in the region. The green outline is the 3D seismic coverage.

The static geological model was created using Schlumberger Petrel (v2021) and is based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout public data, literature, and in-house 3D seismic data.

Figure AoR-232 displays 152 wells with quality logs and reservoir top data that were used, in conjunction with 3D seismic data, to construct reservoir top surfaces. Eighty-nine of these wells also had the appropriate digital logs to be petrophysically analyzed and used in the building of the petrophysical property models. Sixty-three of these wells have basic logs and have been used to pick the formation tops. Detailed information of these wells is tabulated in Appendix D.

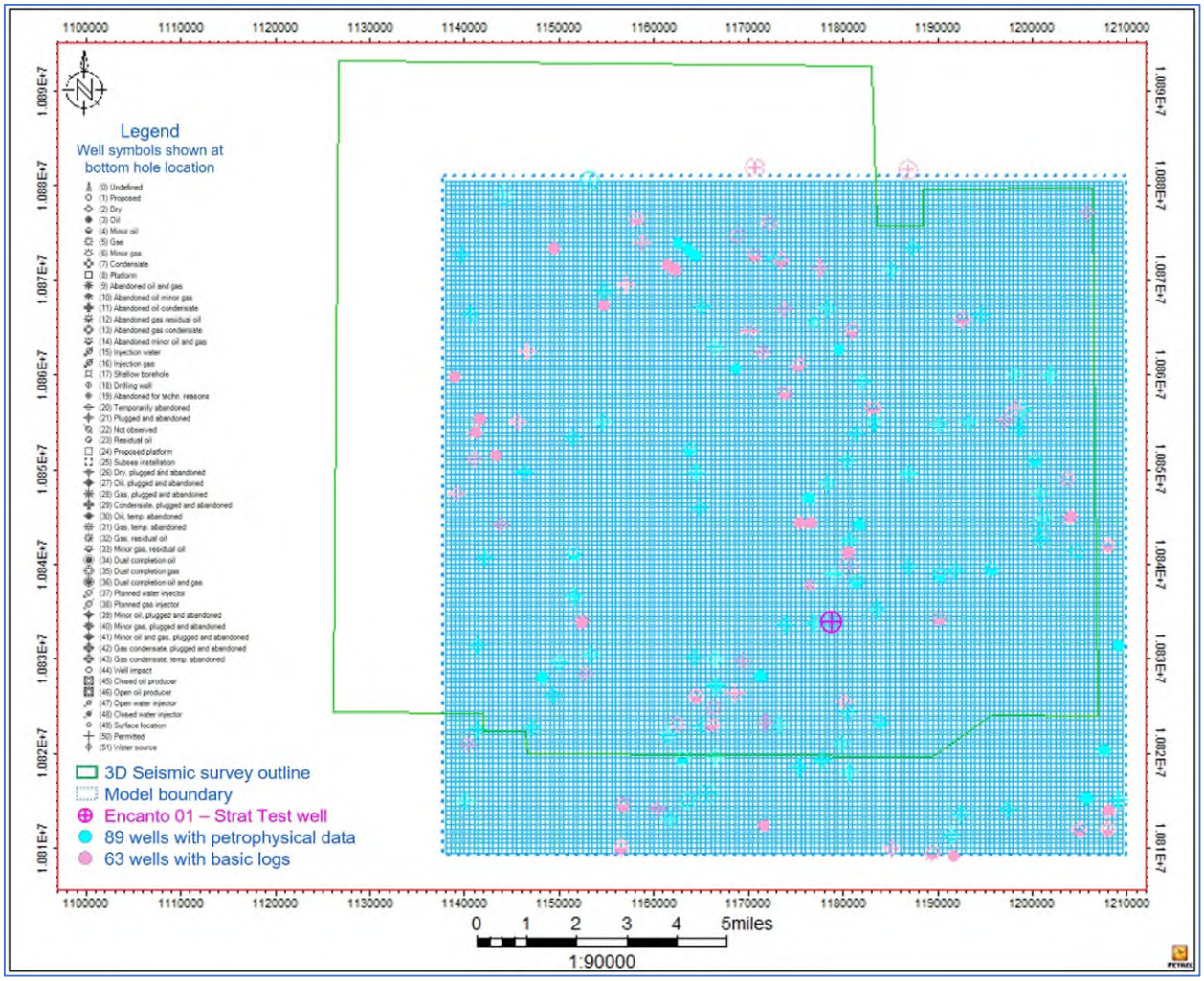


Figure AoR-232: Map of the Bluebonnet Hub geomodel area in blue dash outline. Blue dots are 89 wells with Vshale and porosity logs used to develop reservoir property distributions in the model. Black dots are 63 wells with basic logs that were used to pick the well tops. Pink outline is the 3D seismic coverage. Frio

The model includes several major geological zones from top to bottom: the Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac Confining Zone, Frio Injection Zone, Frio Confining Zone, Hackberry Injection Zone, and Hackberry Confining Zone. The model covers an area of about 13.58 miles by 13.69 miles. The bottom confining zone is the Hackberry Confining Zone. Grid cell area is consistent throughout the geomodel area at 500 ft x 500 ft. The grid thickness varies somewhat but averages at about 10 ft. The final geologic model is represented by a 143 × 142 × 310 grid in a Cartesian system for a total of 6+ million active grid cells.

Horizons were first interpreted from multitude of well log data sets including both depth registered image logs and digital log data on 152 wells shown in Figure AoR-232. Those horizons were then combined with 3D seismic data to give a more accurate view of the horizons where log data may have been scarce.

The methodology applied to the static geomodel was to model the large-scale features, followed by modeling progressively smaller and more uncertain features. The first step applied to the Bluebonnet geomodel was to establish a conceptual structural and depositional model as well as

its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, net sand, and other attributes within each layer. Next, petrophysical values were distributed for each zone using a cell-based methodology.

Figure AoR-233 displays locations of Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 wells. Also, shown is the location of the stratigraphic well Encanto 01, which was drilled to gather key reservoir/performance data in support for this supplication.

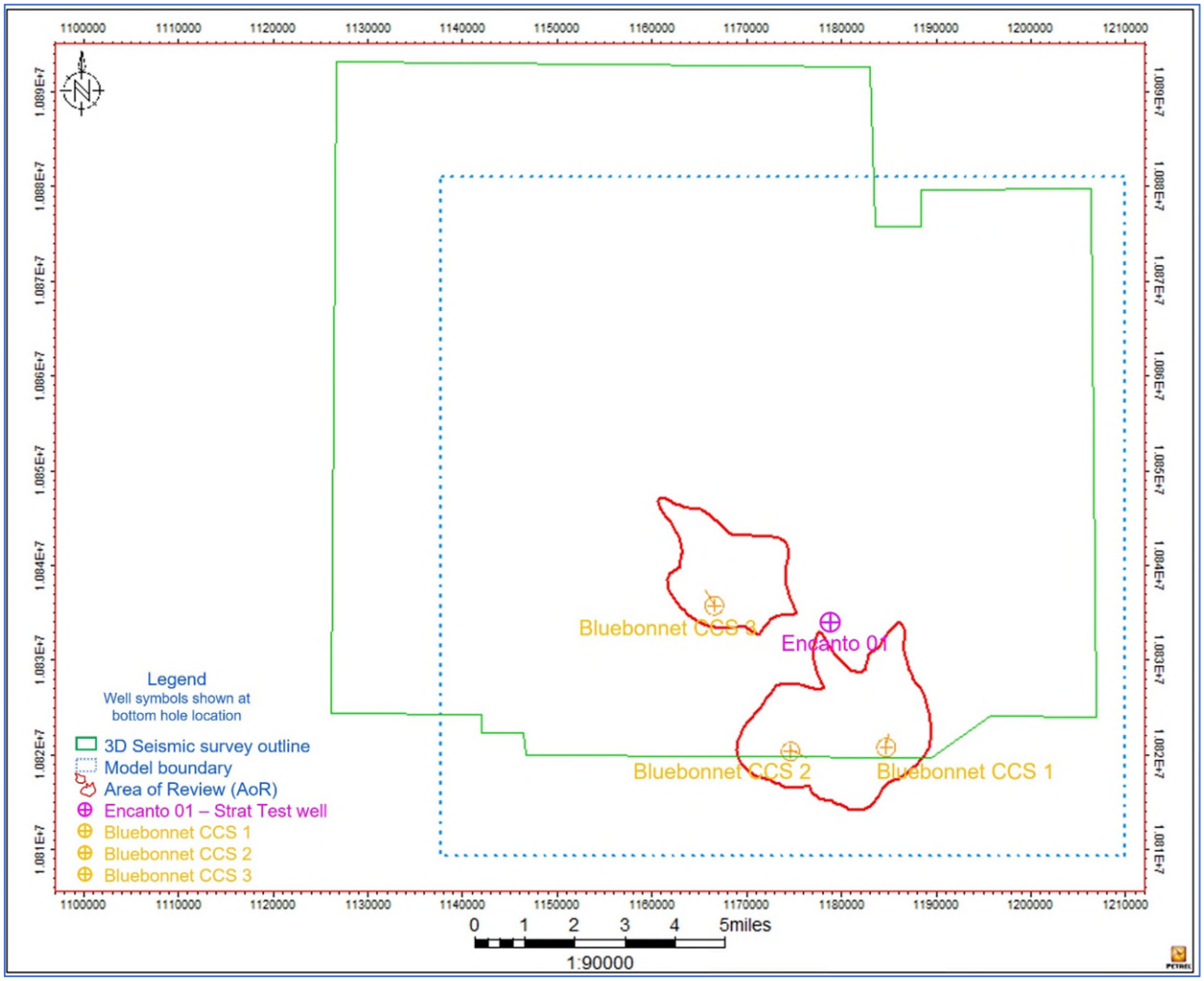


Figure AoR-233: Areal extent of the 3D seismic survey in green, the static geologic model extent in dashed blue, the Area of Review (AoR) in red, the proposed locations of the CO_2 injection wells Bluebonnet CCS 1, Bluebonnet CCS 2 and Bluebonnet CCS 3 in orange and the stratigraphic test well Encanto 01 in pink.

The model domain coordinate reference system is summarized in Table AoR-27.

Table AoR-27: Geologic model domain information.

Coordinate System	NAD 27/BLM zone 15 N (ftUS)		
Horizontal Datum	NAD1927		
Coordinate System Units	Ft US		
Zone	BLM 15 N		
FIPSZONE	N/A	**ADSZONE**	N/A
Coordinate of X min	1138000	**Coordinate of X max**	1209500
Coordinate of Y min	10809500	**Coordinate of Y max**	10880500
Elevation of top of domain	-3,144	**Elevation of bottom of domain**	-10,879

4.3 3D Seismic Input to Model Geologic Structure – Oligocene Storage Complex

4.3.1 3D Seismic Data

Approximately 193 square miles of Seitel Inc's Hankamer Merge survey was licensed by Oxy Inc. covering the 78% of the Bluebonnet Model Area (Figure AoR-234). The Hankamer Merge 3D Survey is a pre-stack merge processed by Matrix Geophysical in 2008. The two source surveys that cover the Bluebonnet model area are the Raywood South (acquired 2001) and Hankamer (acquired 2007) 3D surveys. Both surveys were acquired by Quantum Geophysical for Seitel, Inc. using dynamite with 220' source spacing and a 220' line interval. Volumes licensed from Seitel, Inc. are shown in Table AoR-28 below. Table AoR-29 lists the acquisition parameters for the constituent volumes and Figure AoR-235 presents the processing flow.

Additional 3D seismic licensed by Oxy Inc. from SEI Seismic Exchange is currently under evaluation. The SEI survey overlaps the Hankamer Merge survey and provides full coverage over the southern portion of the AoR that is not covered by the Hankamer Merge. Preliminary results from the SEI survey interpretation support the conclusion that the AoR is absent of any transmissive or transecting faults impacting the storage complex, but a comprehensive interpretation will be integrated into the existing geo model in conjunction with pre-operational testing.

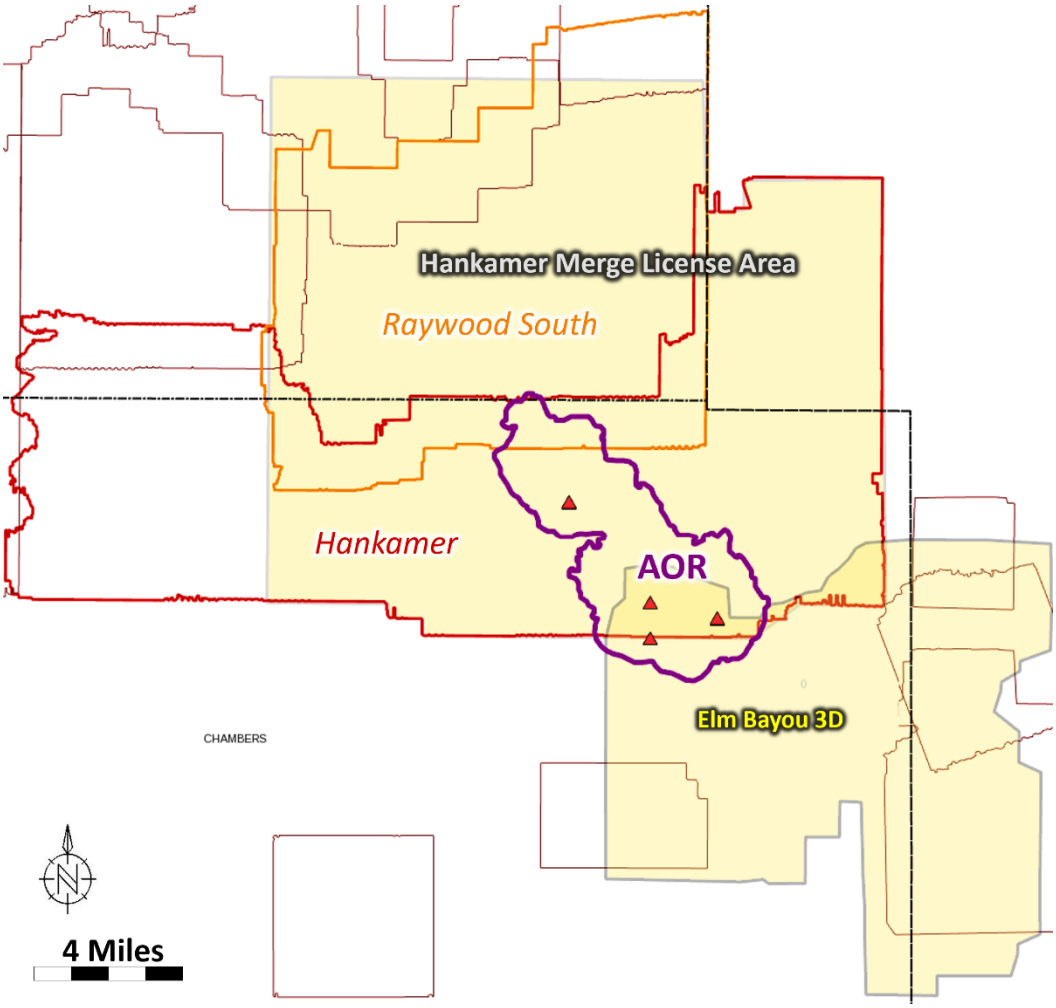


Figure AoR-234: Basemap showing licensed 3D seismic merge and constituent 3D surveys.

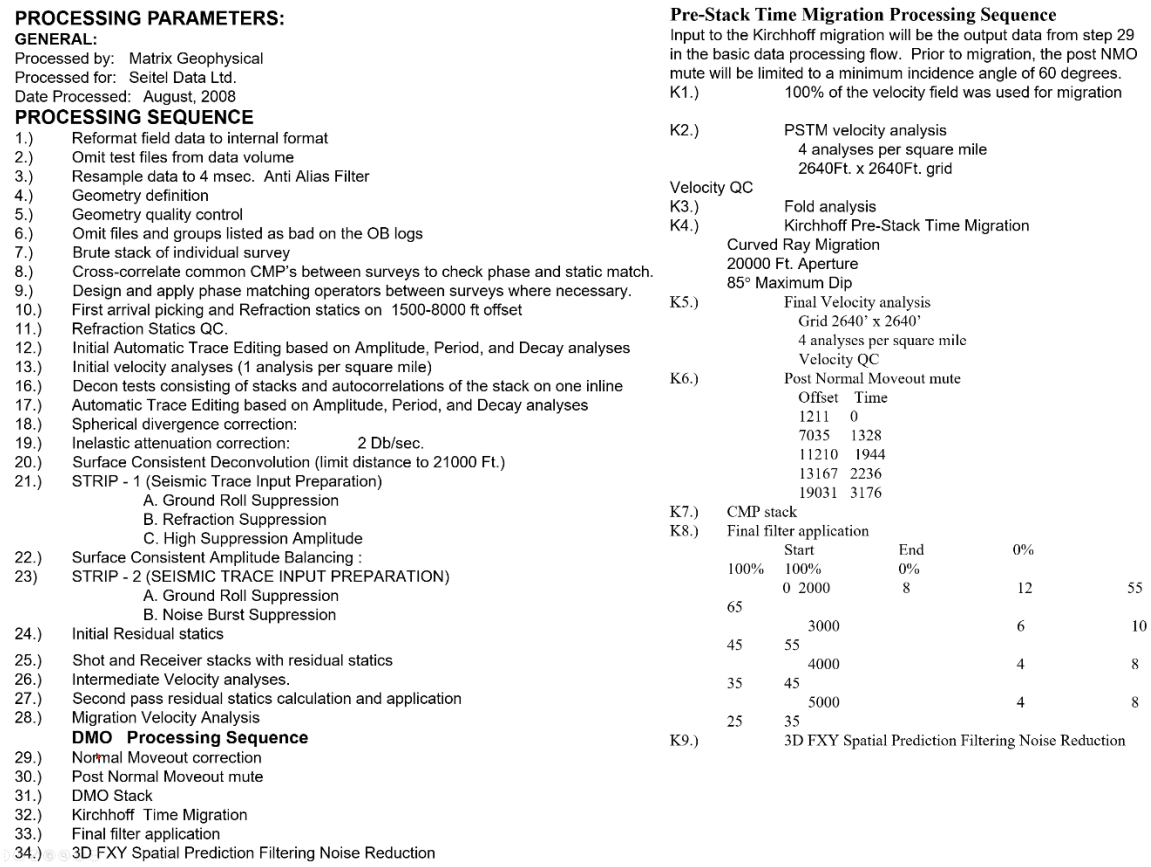
Table AoR-28: Deliverables licensed from Seitel Inc. for Hankamer merge.

Unfiltered DMO Stack
Unfiltered Migration Of DMO Stack
Migration of DMO Stack – TV Filter
Migration of DMO Stack – TVF & Noise Reduction
Pre-stack Migration – Raw
Pre-stack Migration – TV Filter
Pre-stack Migration – TV Filter & Noise Reduction
Pre-Stack Kirchhoff Migrated Gathers NMO Corrected
PSTM Angle Stack: 0-10°
PSTM Angle Stack: 10-20°
PSTM Angle Stack: 20-30
PSTM Angle Stack: 30-40

Table AoR-29: Raywood South and Hankamer 3D Surveys.

RAYWOOD SOUTH 3D SURVEY	
FIELD PARAMETERS:	
GENERAL:	
Recorded By:	Quantum Geophysical
Party Number:	NA
Recorded For:	Seitel, Inc
Recording Date:	2001
Location:	Liberty and Chambers Counties, Texas
Native Bin Grid:	110 ft. x 110 ft.
Recorded record Length:	7 Sec
Recorded Sample Rate:	2 msec
Nominal Fold:	46
Square Miles:	96.190
INSTRUMENTATION:	
Recording Instrument Manufacturer:	I/O System II RSR-3
Field Filters:	3 - out
Maximum Number of Channels:	1480 Average
ENERGY SOURCE:	
Vibroseis	NA
Air Gun	NA
Dynamite	Dynoseis
Hole Depth.:	60'
Charge per Hole:	3 lbs
Source Spacing:	220 Ft
Source Line Interval:	1760 Ft
Source Line Orientation:	E - W
GEOPHONES:	
Manufacturer:	OYO Geospace
Model:	30 CT 1x6
Array:	10 Lines x 148 Channels
Receiver Interval:	220 Ft
Receiver Line Interval:	1760 Ft
Receiver Line Orientation:	N - S
Maximum Number of Live Channels:	1480
TAPE FORMAT:	
Format:	SEGY
Record Length:	7 Sec
Sample Interval:	2 msec
Number of Aux Channels:	2
Nominal Number of Live Channels:	1480
Tape Media:	3490 Cartridge

HANKAMER 3D SURVEY	
FIELD PARAMETERS:	
GENERAL:	
Recorded By:	Quantum Geophysical
Party Number:	307
Recorded For:	Seitel, Inc
Recording Date:	2007
Location:	Liberty and Chambers Counties, Texas
Native Bin Grid:	110 ft. x 110 ft.
Recorded record Length:	8 Sec
Recorded Sample Rate:	2 msec
Nominal Fold:	46
Square Miles:	N/A
INSTRUMENTATION:	
Recording Instrument Manufacturer:	I/O System II RSR-3
Field Filters:	N/A
Maximum Number of Channels:	1480 Average
ENERGY SOURCE:	
Vibroseis	NA
Air Gun	NA
Dynamite	Dynoseis
Hole Depth.:	60'
Charge per Hole:	2.2 lbs
Source Spacing:	220 Ft
Source Line Interval:	1760 Ft
Source Line Orientation:	NE - SW
GEOPHONES:	
Manufacturer:	OYO Geospace
Model:	30 CT 1x6
Array:	10 Lines x 148 Channels
Receiver Interval:	220 Ft
Receiver Line Interval:	1760 Ft
Receiver Line Orientation:	N - S
Maximum Number of Live Channels:	1480
TAPE FORMAT:	
Format:	SEGY
Record Length:	8 Sec
Sample Interval:	2 msec
Number of Aux Channels:	2
Nominal Number of Live Channels:	1480
Tape Media:	3490 Cartridge



PROCESSING PARAMETERS:
GENERAL:
Processed by: Matrix Geophysical
Processed for: Seitel Data Ltd.
Date Processed: August, 2008
PROCESSING SEQUENCE
1.) Reformat field data to internal format
2.) Omit test files from data volume
3.) Resample data to 4 msec. Anti Alias Filter
4.) Geometry definition
5.) Geometry quality control
6.) Omit files and groups listed as bad on the OB logs
7.) Brute stack of individual survey
8.) Cross-correlate common CMP's between surveys to check phase and static match.
9.) Design and apply phase matching operators between surveys where necessary.
10.) First arrival picking and Refraction statics on 1500-8000 ft offset
11.) Refraction Statics QC.
12.) Initial Automatic Trace Editing based on Amplitude, Period, and Decay analyses
13.) Initial velocity analyses (1 analysis per square mile)
16.) Decon tests consisting of stacks and autocorrelations of the stack on one inline
17.) Automatic Trace Editing based on Amplitude, Period, and Decay analyses
18.) Spherical divergence correction:
19.) Inelastic attenuation correction: 2 Db/sec.
20.) Surface Consistent Deconvolution (limit distance to 21000 Ft.)
21.) STRIP - 1 (Seismic Trace Input Preparation)
A. Ground Roll Suppression
B. Refraction Suppression
C. High Suppression Amplitude
22.) Surface Consistent Amplitude Balancing :
23) STRIP - 2 (SEISMIC TRACE INPUT PREPARATION)
A. Ground Roll Suppression
B. Noise Burst Suppression
24.) Initial Residual statics
25.) Shot and Receiver stacks with residual statics
26.) Intermediate Velocity analyses.
27.) Second pass residual statics calculation and application
28.) Migration Velocity Analysis
DMO Processing Sequence
29.) Normal Moveout correction
30.) Post Normal Moveout mute
31.) DMO Stack
32.) Kirchhoff Time Migration
33.) Final filter application
34.) 3D FXY Spatial Prediction Filtering Noise Reduction

Pre-Stack Time Migration Processing Sequence
Input to the Kirchhoff migration will be the output data from step 29 in the basic data processing flow. Prior to migration, the post NMO mute will be limited to a minimum incidence angle of 60 degrees.
K1.) 100% of the velocity field was used for migration
K2.) PSTM velocity analysis
4 analyses per square mile
2640Ft. x 2640Ft. grid
Velocity QC
K3.) Fold analysis
K4.) Kirchhoff Pre-Stack Time Migration
Curved Ray Migration
20000 Ft. Aperture
85° Maximum Dip
K5.) Final Velocity analysis
Grid 2640' x 2640'
4 analyses per square mile
Velocity QC
K6.) Post Normal Moveout mute
Offset Time
1211 0
7035 1328
11210 1944
13167 2236
19031 3176
K7.) CMP stack
K8.) Final filter application
Start End 0%
100% 100% 0%
0 2000 8 12 55
65
3000 6 10
45 55
4000 4 8
35 45
5000 4 8
25 35
K9.) 3D FXY Spatial Prediction Filtering Noise Reduction

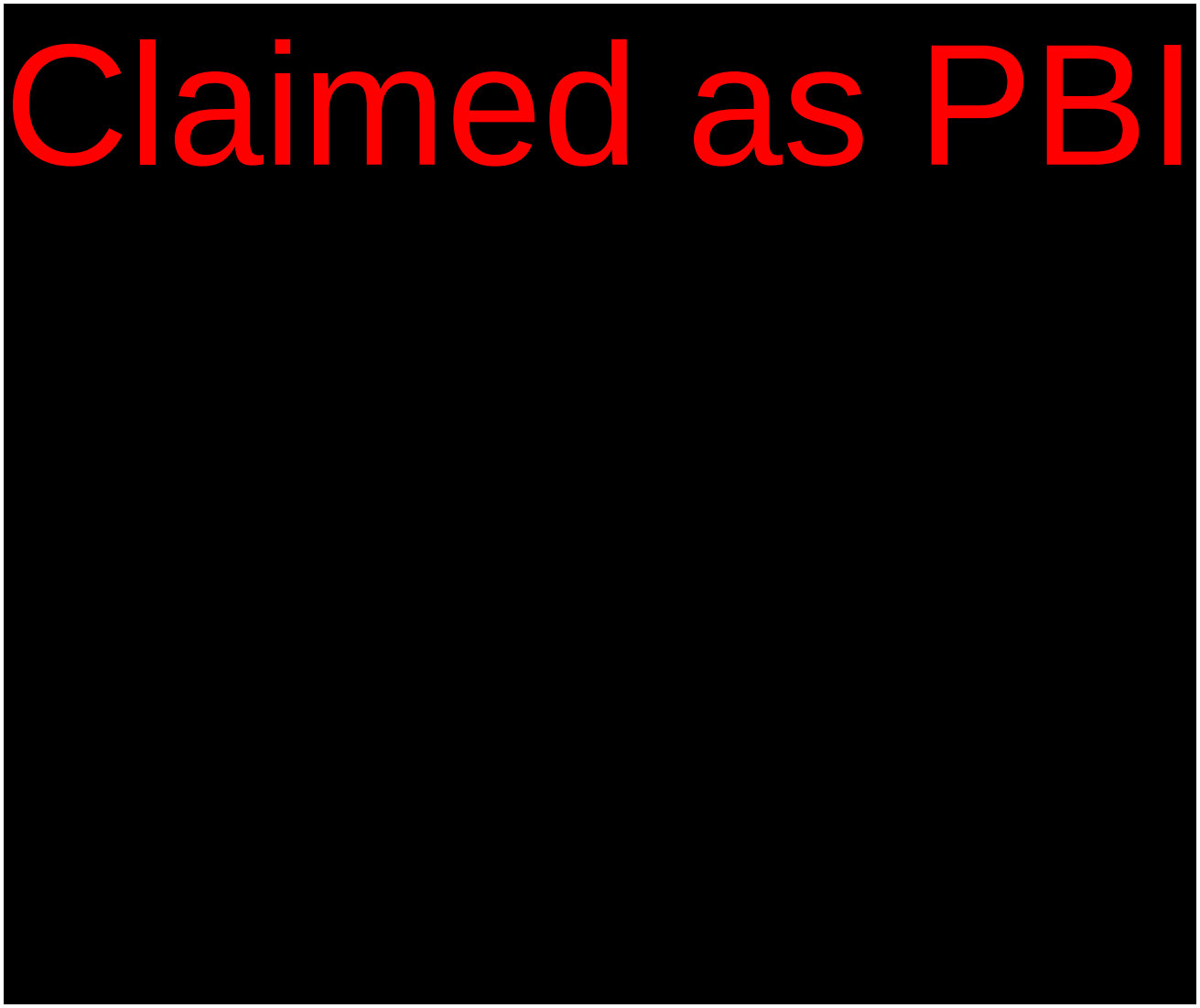
Figure AoR-235: Acquisition and processing parameters for relevant constituent surveys composing Hankamer merge over AoR.

4.3.2 Interpretation Workflow

The 3D seismic interpretation workflow is summarized in Figure AoR-236. Synthetic well ties were initially generated for five wells in the 3D area including the stratigraphic test well Encanto 01 (see Figure AoR-237, Figure AoR-238, and Figure AoR-239). Relevant horizons were identified from well surface picks and mapped across the survey.

The 3D structure framework was smoothed to generate a structure model used to guide the 3D velocity model in conjunction with time depth curves from synthetic well ties and well surface picks tied to horizons in all available wells (Figure AoR-240). The resulting 3D velocity model was used to convert all interpretations and seismic volumes to depth.

The depth converted structure grid was then quality-controlled against the depth converted seismic volumes and refined slightly where needed. The final depth structure model contained eight surfaces ranging in depth from the Top Vicksburg to the Top of Lower Miocene Confining Zone along with roughly 60 individual fault planes.


Claimed as PBI

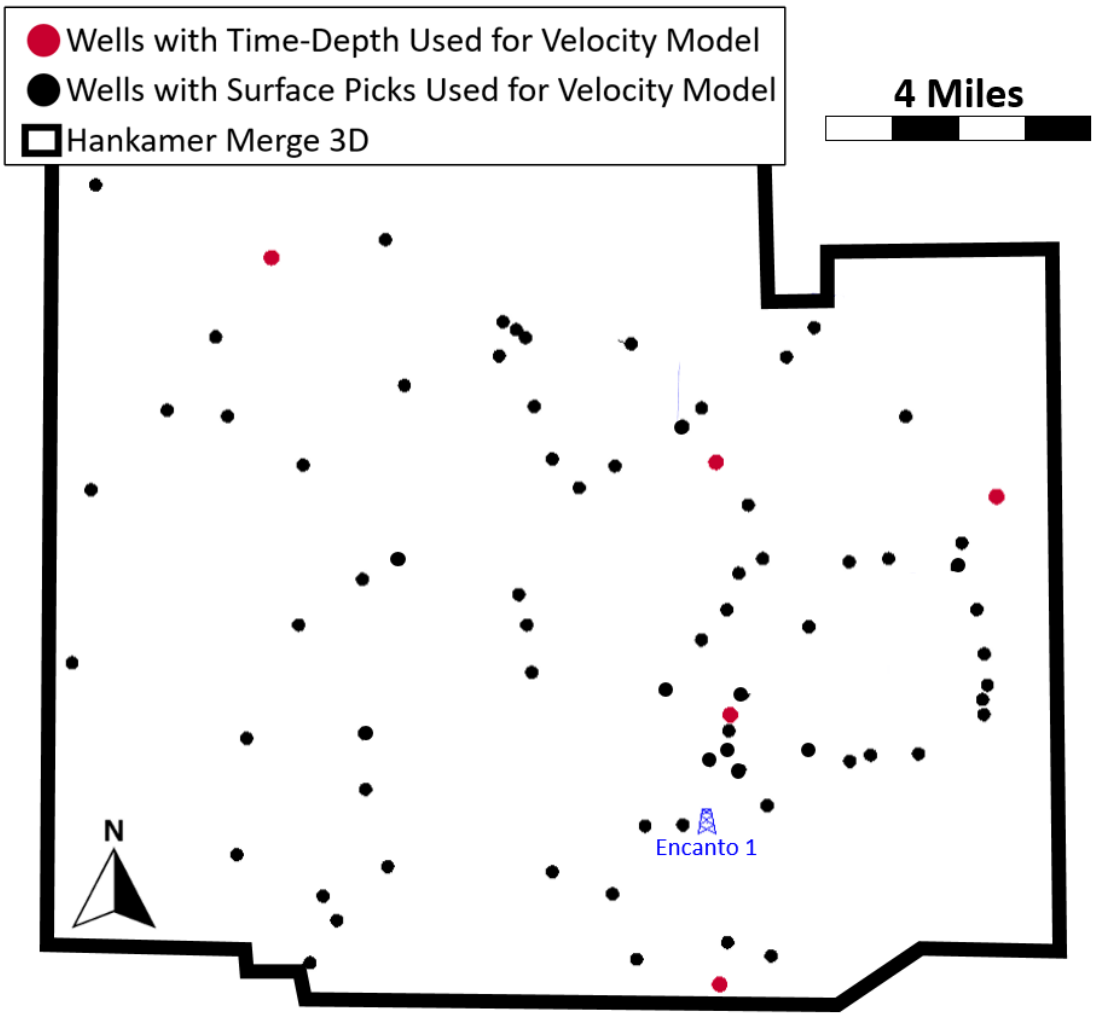
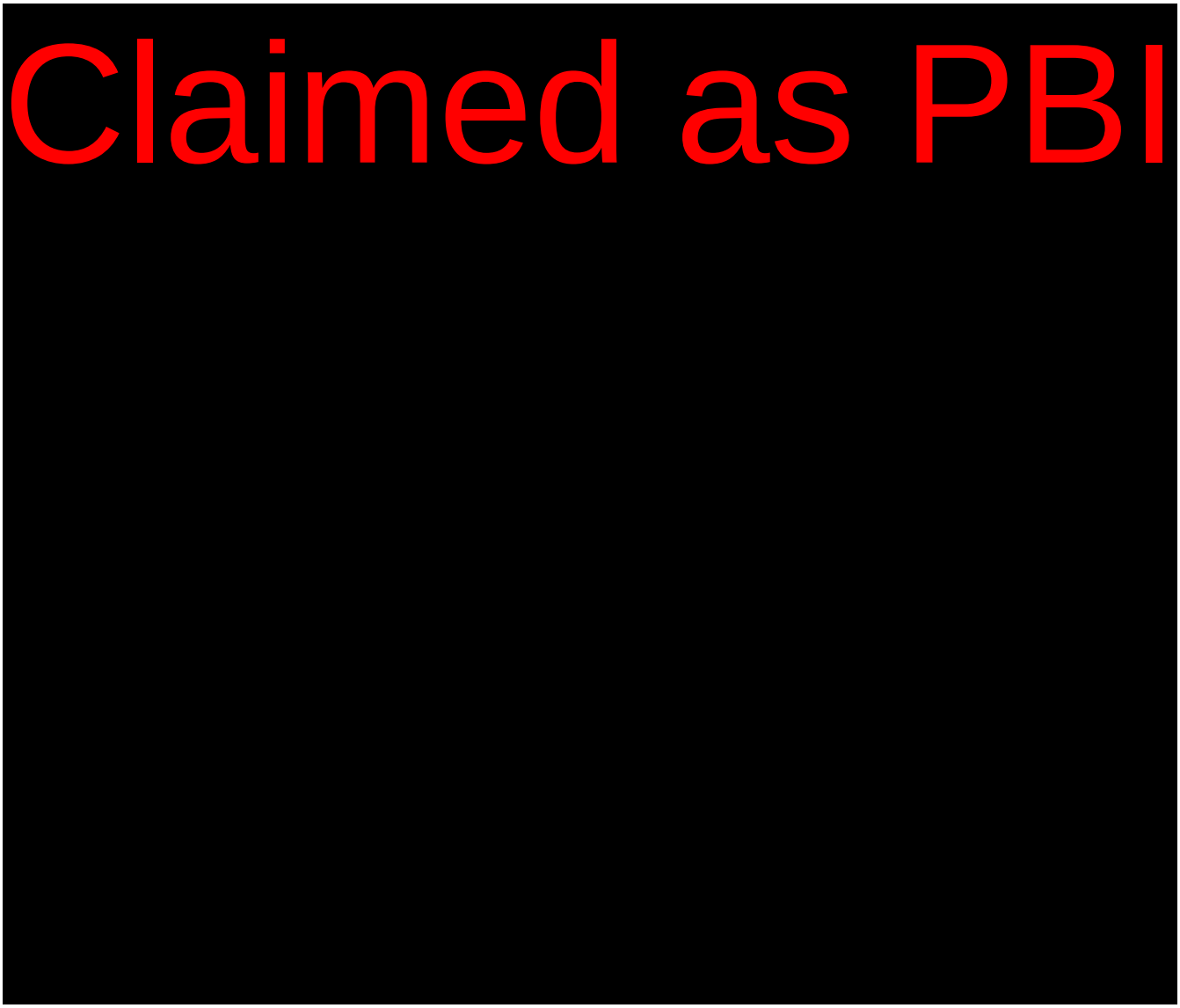


Figure AoR-237: Basemap showing well data used for synthetic well ties, velocity modeling, and structure control.


Claimed as PBI



Faulting within the 3D survey was interpreted manually with the assistance of various fault enhancement attributes including Lankmark's Structure Oriented Filter and Fault Likelihood attributes. All faults were interpreted using fault plane mapping techniques to assure reasonable and proper fault geometries. All interpreted faults were incorporated into the Geomodel. There is no evidence from the 3D seismic data interpretation for faults that transect the storage unit within the AoR.

The unconsolidated amalgamated sands in the Frio formation do not generate seismic signal conducive to attribute analysis needed to provide stratigraphic constraints on the model. Additional seismic interpretation methods such as spectral decomposition similarly did not result in any usable output.

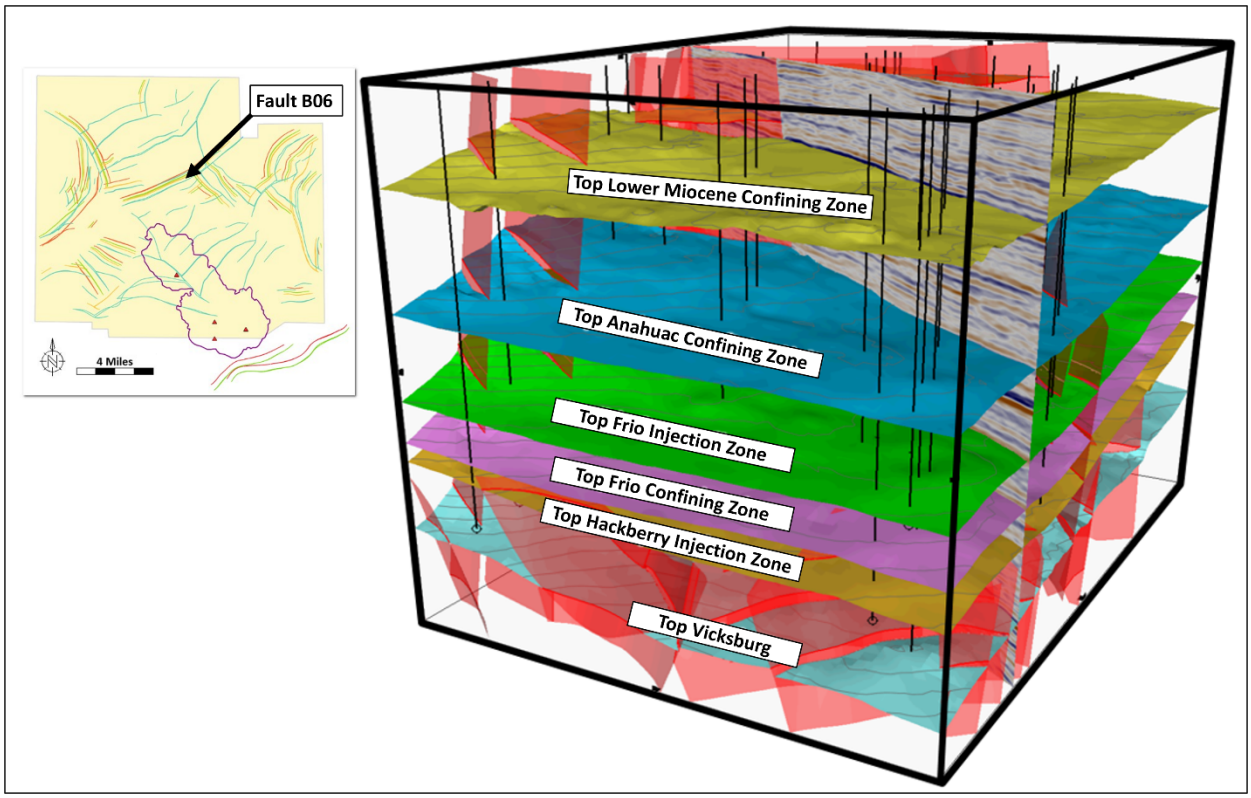


Figure AoR-240: Excerpt from 3D structure model generated from 3D seismic interpretation.

4.4 Geologic Model Zones and Layering

The geological model has four major zones: the Lower Miocene, Anahuac, Frio, and Hackberry. These major zones were further subdivided to contrast lithology variations and were subsequently modeled separately.

1. The Lower Miocene was further subdivided into the following: Lower Miocene Confining Zone, Lower Miocene Dissipation Zone, and Lower Miocene Injection Zone

2. The Anahuac has four subzones to isolate a thin sand and the Het lime within the Upper Anahuac Confining Zones and below that the Lower Anahuac Confining Zone

3. The Frio was further divided into the three distinct Top, Mid, and Low Frio Injection Zones, and the underlying Frio Confining Zone

4. The Hackberry was split into two separate zones, namely the Hackberry Injection Zone and underlying Hackberry Confining Zone.

Out of the three Frio Injection Zones, the Mid Frio and Low Frio are the main CO_2 storage reservoirs within the proposed AoR. They are composed of unconsolidated sandstones and interbedded clay layers, which were deposited in a fluvial-deltaic environment. The Mid and Low Frio Injection Zones yield excellent storage quality. Figure AoR-241 depicts the NW-SE cross section of these geological subzones.

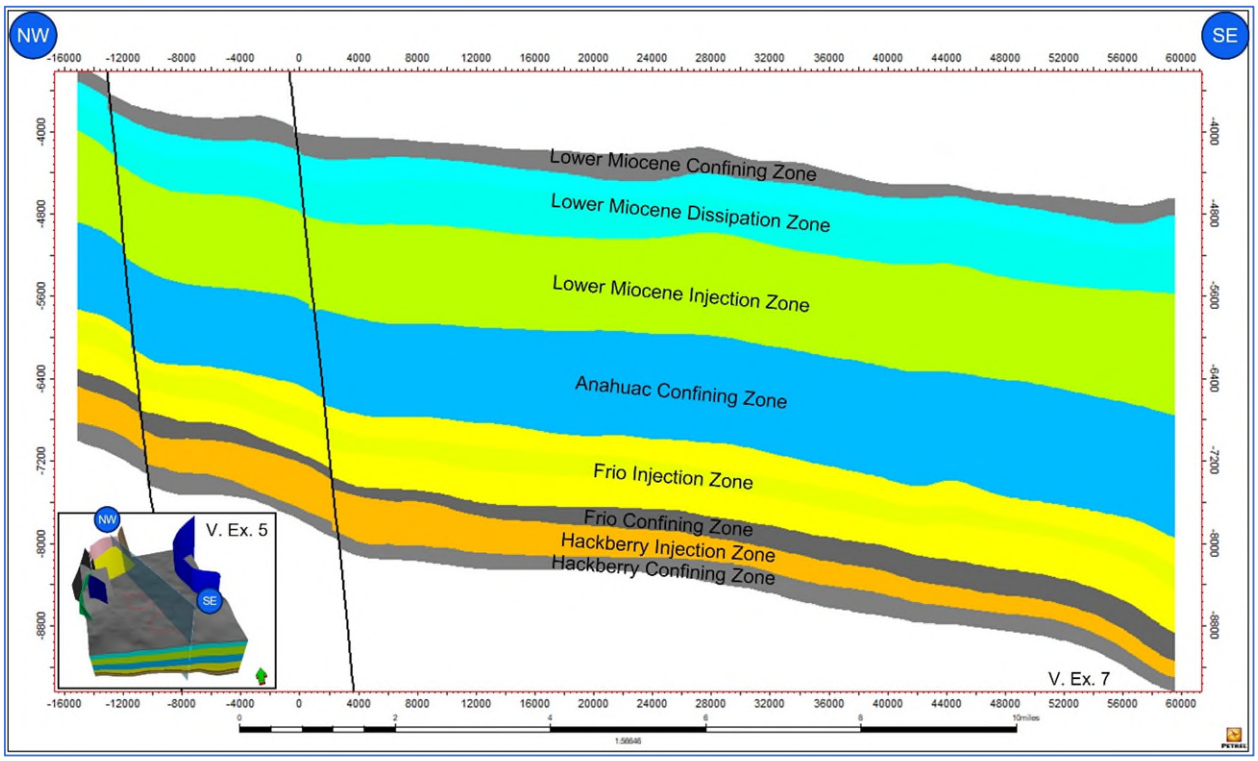


Figure AoR-241: Northwest-southeast cross section of the main geological zones, Lower Miocene, Anahuac, and Frio, and Hackberry subzones in the Petrel geological model. Note that Lower Miocene Confining Zone and Anahuac Confining Zone represent a competent confining system above the Frio and Hackberry Injection Zones. V. Ex. = Vertical exaggeration.

The geologic subzones were created from horizons based on well log correlations with 3D seismic data. In addition, for the internal characterization of the stacked injection and confining zones, 152 digital logs were interpreted to create the horizons that were used to interpret thicknesses, which determined each subzone. Proportional layering was applied to each subzone and the number of layers within each zone division was based on the upscaled thickness of each interpreted zone, targeting ~10 ft for each grid layer as a guideline, with the actual average incremental cell thickness being 13.5 ft. A 3D index view of the eleven subzones is shown in Figure AoR-242.

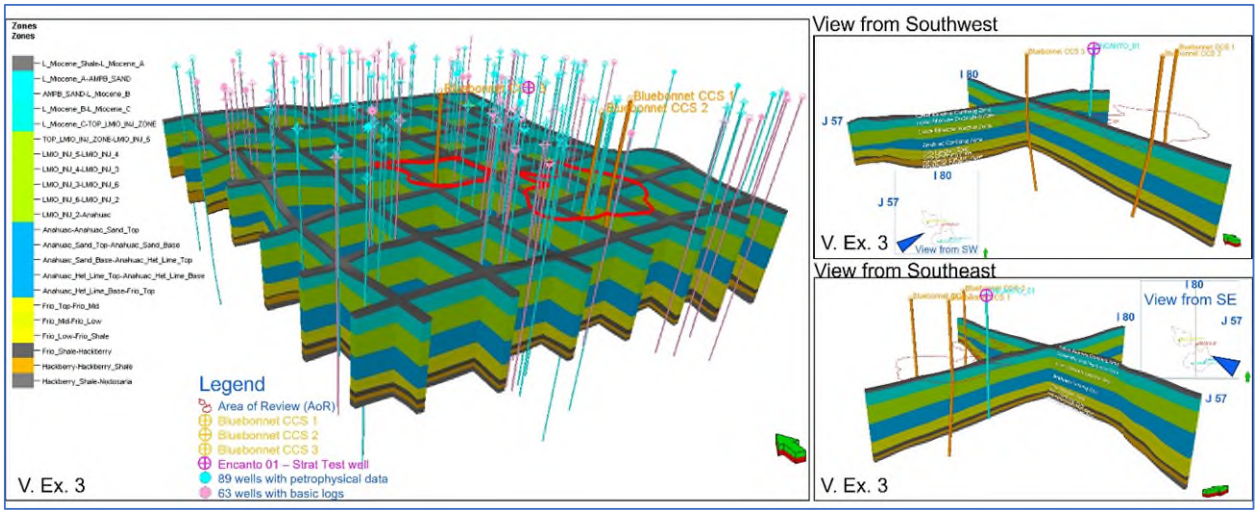


Figure AoR-242: A fence diagram displaying the 3D index view of the geologic model subzones from the Lower Miocene Confining Zone to the basal Hackberry Confining Zone.

The 21 individual zones within the geological model include the strata from the base of the Hackberry Confining Zone as the lowermost confining zone to the top of the Lower Miocene Confining Zone as the uppermost confining zone.

A total of 89 wells were selected for petrophysical calculation of porosity, permeability, and net reservoir thickness that provided the best data quality and coverage. Within the geomodel, 89 petrophysically analyzed wells were selected for 3D distribution of petrophysical properties as shown in Figure AoR-244 and listed in Table AoR-30. A summary of the average properties by zone is shown in Figure AoR-245.

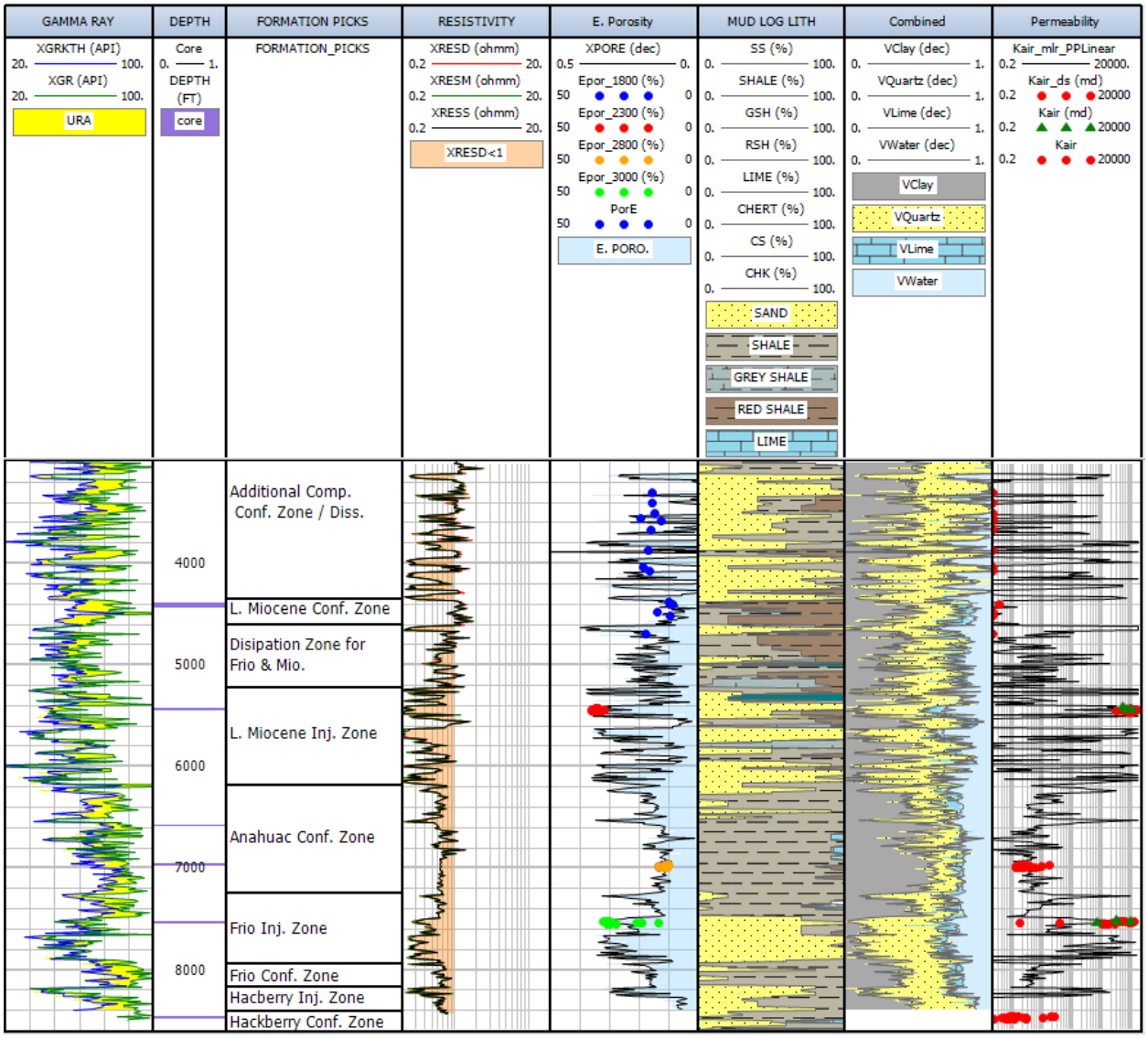


Figure AoR-243: Composite type well-log interpretation from Encanto 01 of the injection zones and confining zones.

A composite type well log from Encanto 01 is shown in Figure AoR-243. The Gamma ray track contains the total and uranium free GR and the difference is shaded in yellow. The Depth track is showing in purple the cored intervals. The formation picks track has labeled the different confining and injections zones. The E. Porosity (Effective porosity) Color coded by NCS (net confining stress): Blue points have a NCS of 1800 psi and represent the Lower Miocene Confining Zone, red points have a NCS of 2300 psi and represent the Lower Miocene Injection Zone, orange points have a NCS of 2800 psi and represent the Anahuac Confining Zone, and green points have a NCS of 3000 psi and represent the Frio Injection Zone. This is followed by the mud log lithology track, the interpreted lithology, and finally the permeability track with our calculated permeability and core data in red points and the green triangles is the data from MICP.

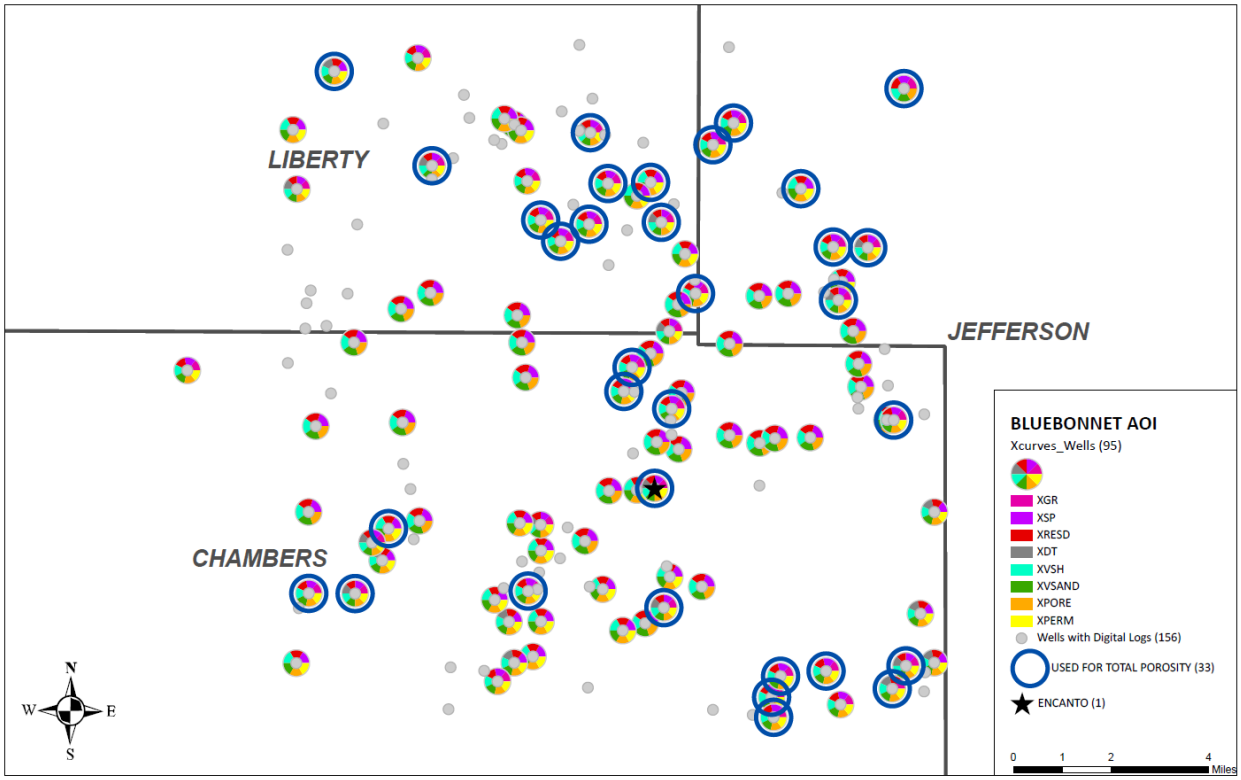


Figure AoR-244: Map representing 156 control wells within and surrounding the Bluebonnet Focus Area (dotted line) used for petrophysical interpretation of porosity, permeability, and net reservoir thickness of the Primary Storage Unit (FRIO), and Confining Zones. Pie charts outlined in blue represent 33 wells with Neutron and Density well-logs. The stratigraphic well, Encanto 01 is identified with a black star. Detailed information of these wells is summarized in Appendix D.

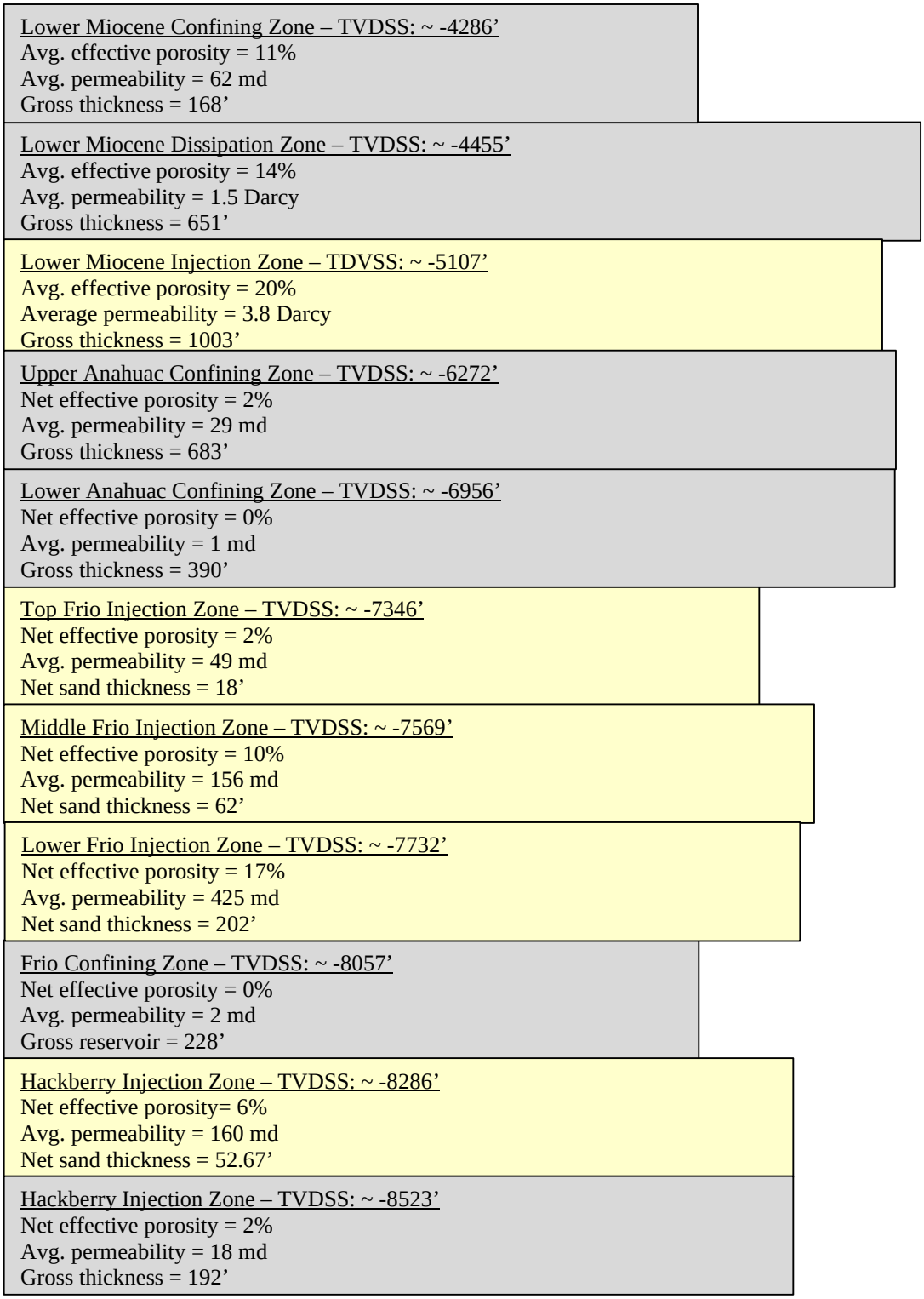


Figure AoR-245: Geologic model with averages porosity, permeability, gross thickness for confining zones and net sand thickness over the injection zones. (Average reservoir properties used ≤ 45% shale as a cutoff.) from Anahuac to Hackberry Injection Zone. For the Miocene section we have the average effective porosity and permeability for the complete interval.

Net reservoir thickness was calculated using a petrophysical cutoff of ≤ 0.45 volume of shale and was used to create a net-to-gross (NTG) sand distribution per zone. Porosity was then modeled for each zone separately based on data analysis and a collocated, co-kriging method for net to gross distribution. Permeability was calculated using the porosity model.

The porosity and NTG logs were sampled into the geomodel's 3D grid for each zone and used to determine the lateral ranges in the long and short axes and vertical direction. Furthermore, a trend map of the net to gross distribution within the geomodel area was constructed based on petrophysically analyzed well log data for each subzone, and this 2D trend map was used as soft information to guide the net to gross distribution in between data points. The net porosity log was generated using the NTG logs to only populate net porosity in the net sand. The Petrel grid was populated using the following procedure:

1. Net porosity and NTG curves were upscaled into the geomodel grid at the well locations.

2. NTG in the geomodel grid was populated using Sequence Gaussian Simulation (SGS) honoring the values at well locations, ranges in long/short axes and vertical direction, and guided by the 2D trend map of the net to gross sand distribution.

3. Porosity in the geomodel grid was populated using SGS honoring values at the well location, ranges in long/short axes and vertical direction, and co-kriged with the NTG property.

4. Permeability was calculated using the porosity – permeability regression developed by the GCCC (Frio Pilot in CO_2 Sequestration in Brine – Bearing Sandstones, Hovorka et al. 2003)

5. Steps 2 through 4 were done on a zone-by-zone basis.

4.4.1 Porosity

The total porosity of the injection zone is based on Neutron and Density porosity logs from 33 wells within and around the Geologic Model Domain (Figure AoR-244 and listed in Table AoR-30). An interconnected (effective) porosity for wells with porosity logs was calculated from total porosity corrected for the shale volume. The remaining wells did not have neutron and/or density porosity logs but were required for porosity calculation in the petrophysical interpretation. A linear correlation between volume of shale and effective porosity from wells with porosity logs developed by the GCCC (Frio Pilot in CO_2 Sequestration in Brine – Bearing Sandstones, Hovorka et al. 2003) was used and corroborated with local data. The results of this method compared largely with the 33 well subset, so the linear correlation was applied to the remaining wells.

Table AoR-30: The 33 wells in the petrophysical interpretation used to calculate total porosity from neutron and density porosity logs.

Well Name	UWI
WAUGH B. R. ET AL #1	42071318840000
DOORNBOS ETAL #1	42071321630000
OGDEN ET AL #1	42071322280000
JEFFREY #1	42071322590000
CLEMENT UNIT #1	42071322680000
KAHLA #1	42071323230000
WHITE-OLSEN HEIRS UNIT #1	42071323850000
BAUER #1	42245322660000
E. COOPER #1	42071322960000
LOHMANN #1	42245322750000
MCADAMS JOHN P. #1	42071318690000
E.W. BOYT ET UX #4	42071317850000
JENKINS #1	42071309340000
DOORNBOS WILLIAM ET AL #1	42071312670000
R L WHITE #1	42071313750000
DUGAT #2A - PILOT	42071316340000
BEAVERS W H #1	42245314850000
SARAH HUNT B #1	42291328690000
HENDERSON WILLIS #1	42291325550000
ALDRICH R C ET AL #1	42291325280000
BAUER JACK WAYNE #1	42245323540000
WILDI #1	42291327970000
BOYT #1	42291321820000
BONNER #1	42291318930000
DUNAGAN #1-A	42291318010000
SECURITY STATE BANK #1	42291315790000
MCDERMAND #1	42245322940000
MCDERMAND F D #1	42245314110000
ELM BAYOU #1	42071326020000
CARROLL W M ESTATE #1	42245321180000
HUDSON #1	42291328880000
FROST/KEENAN #1	42291321760000
ENCANTO 01	42071326640000

Based on the properties in the geomodel, the Frio injection zones start from a TDVSS of ~7346' The average net effective porosity for the Low Frio is 17% with an average net reservoir thickness of 203 ft (Figure AoR-245). The average net effective porosity for the Mid Frio is 10% with an average net reservoir thickness of 62 ft. The average net effective porosity for the Top Frio is 2% with an average net reservoir thickness of 19 ft. The net effective porosity of the Anahuac Confining Zone, Frio Confining Zone, and Hackberry Confining Zone is also based on Neutron and Density porosity logs from 33 wells within the geomodel domain. An interconnected (effective) porosity for those wells was calculated from total porosity corrected for shale volume. The average net effective porosity of the Anahuac Confining Zone is 1%; the average net effective porosity of the Frio Confining Zone is 0%; and the average effective porosity of the Hackberry Confining Zone is 2% based on the above-mentioned methodology.

Before distributing net-sand porosity into the geological model, the net-to-gross volume was developed first. To guide the Sequential Gaussian Simulation process, 2D net-to-gross trend maps were developed by a geological subject matter expert, guided by well control and likely sand distributions in the perceived depositional environment. These 2D maps were then used as soft

trends to guide the subsequent Sequential Gaussian Simulations, which honored the actual well controls, to generate the net-to-gross volumes for all subzones. An outcome of the simulation process is the 3D net-to-gross distribution as shown in Figure AoR-246.

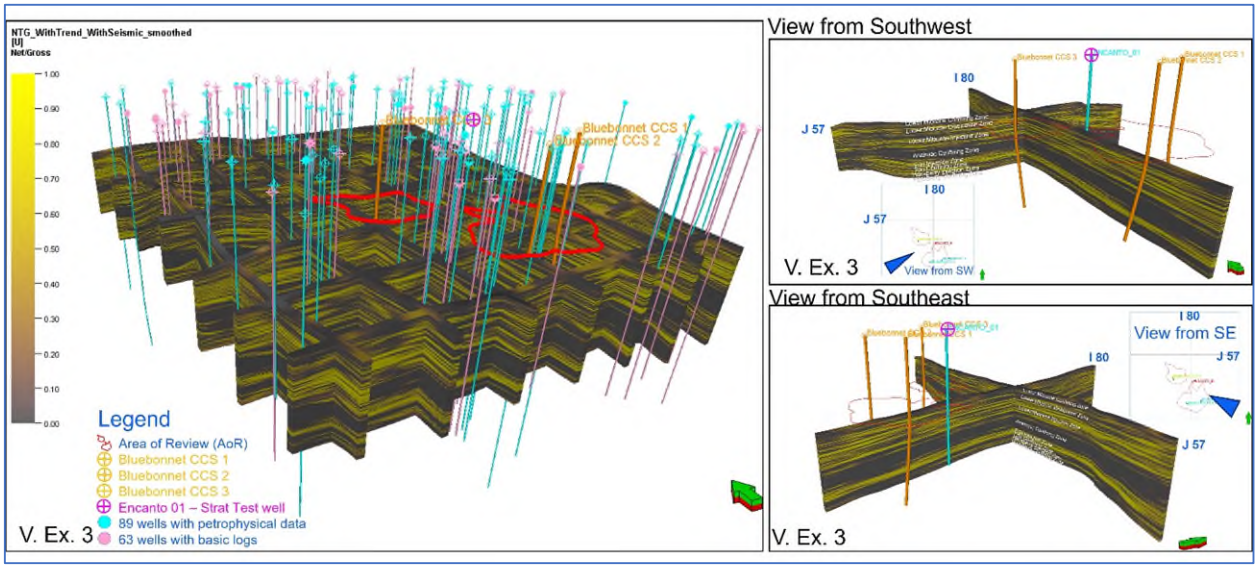


Figure AoR-246: The Net-to-Gross distribution generated from subzone 2-D trend maps and hard data at the wells. Yellow regions represent sands whilst dark gray regions are shales.

The porosity model was constructed using Sequential Gaussian Simulation (SGS) Local Varying Mean (LVM) with Net-to-Gross (NTG) model with varying coefficients applied. The porosity logs were upscaled using arithmetic averaging. The raw upscaled porosity histogram was used during SGS and final porosity model was then smoothed. The following parameters were used as inputs:

I. Variogram
    a. Type: Spherical
    b. Nugget: 0.0001
    c. Anisotropy range and orientation:
        i. Lateral range: 8000 x 5000 in the base case
        ii. Vertical range: 20-50

II. Distribution
    a. Actual histogram range (0.0–0.40) from upscaled logs
    b. Distribution method: General

III. Co-kriging for the three cases built from the static porosity model
    a. Secondary variable volume: NTG[U]
    b. Method: Collocated co-kriging
        i. LVM (no co-kriging coefficient applied)
        ii. Coef. Constant: 0.75
        iii. Coef. Constant: 0.5
        iv. Untrended (NTG secondary variable was not applied)

This methodology resulted in three porosity cases based on the value of the co-kriging coefficient with NTG. The base-case porosity model distribution uses the co-kriging coefficient of 0.5. High

and low cases of porosity distribution were chosen as the co-kriging coefficient of 0.75 and the untrended case, respectively. Figure AoR-247 depicts distributions of equivalent porosity (net-porosity * net-to-gross) at various net-to-gross values in the entire geological model. Figure AoR-248 shows the base-case porosity distribution in the Petrel geological model.

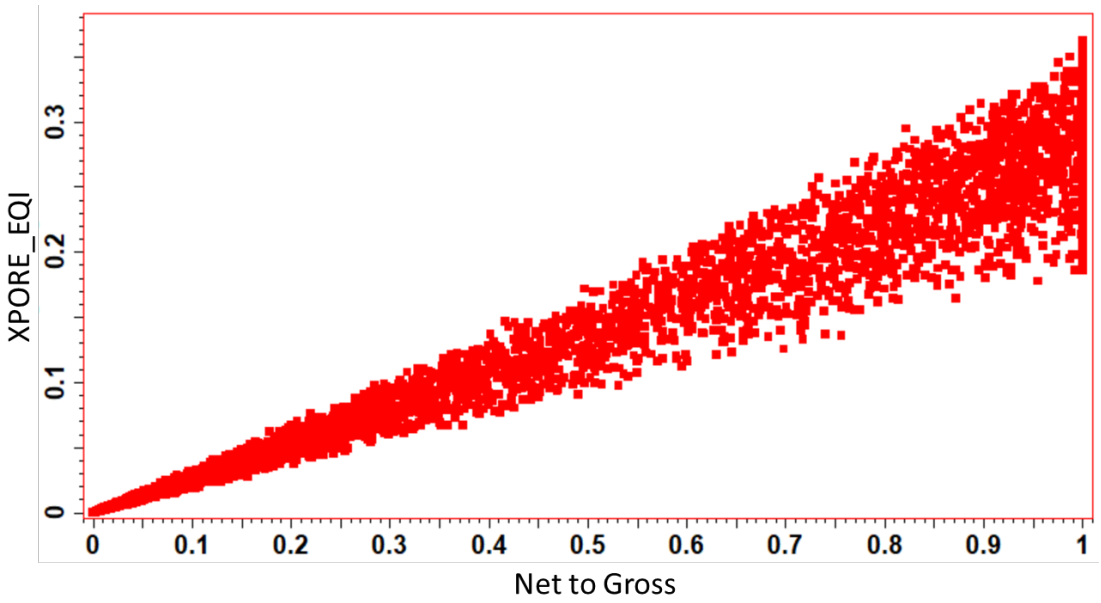


Figure AoR-247: Equivalent Porosity relationship to Net-to-Gross ratio (NTG) for the base case (Phi_Eq_50_vs_NTG) porosity distribution used in the reservoir simulation.

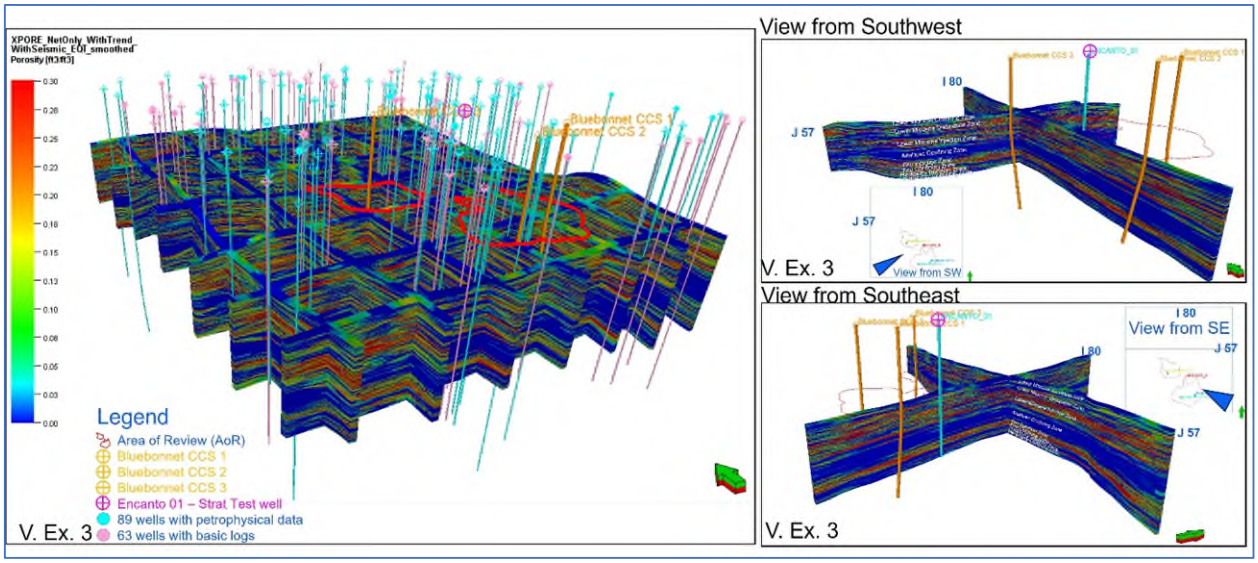


Figure AoR-248: The 3D net equivalent porosity index view from the Lower Miocene Confining Zone to the Hackberry Confining Zone.

4.4.2 Permeability

For the pre-construction static modeling effort, the horizontal permeability for the injection zones is based on a porosity permeability relationship established by the GCCC in the 'Frio Pilot CO_2 Sequestration in Brine – Bearing Sandstones' by Susan Hovorka and others 2003. Using this relationship, an average horizontal permeability of 251 md is calculated for the Frio Injection Zone within the geomodel using the modeled net effective porosity. This average is composed of 49 md in the Top Frio and higher average permeabilities of 156 md in the Mid Frio and 425 md in the Low Frio. Please note that these are average numbers, and the minimum and maximum ranges are wider. These permeabilities are based on well logs only and that method is described below. The static geomodel does not include a calibration to permeabilities derived from well test data; the dynamic simulation model, however, does.

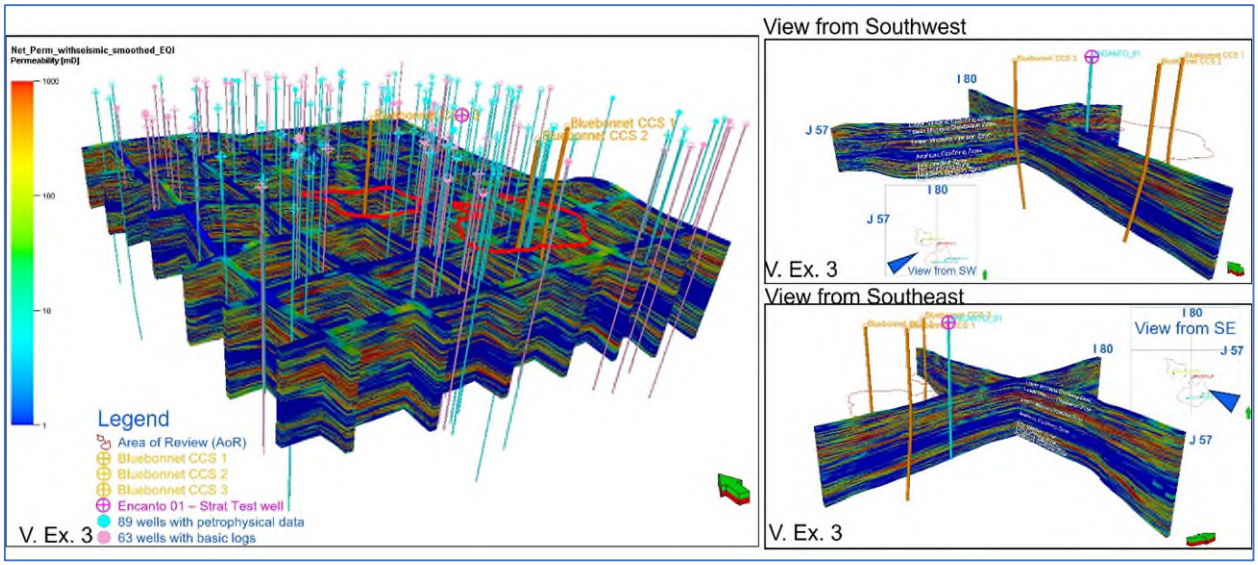


Figure AoR-249: Reservoir permeability distribution in the base-case simulation model. Blue represents lower permeability and red represents the highest permeability within the model.

The porosity and permeability relationships used were extracted from 'Frio Pilot CO2 Sequestration in Brine-Bearing Sandstones', GCCC digital publication series #03-04 by Susan D. Hovorka and others, 2003. The area of this pilot study is 27 miles to the northwest of Encanto 01.

Calculated volume of shale is based on a normalized SP (spontaneous potential) log and GR (Gamma Ray) log when available and used the correlation presented in Figure V-27 in the cited paper to calculate porosity from volume of shale. To calculate permeability, the barrier values (empty diamonds in Figure AoR) were used from routine core analysis in the Frio formation from the Felix Jackson No.1 well in Chambers County (Hovorka and others, 2003).

In Encanto 01, a full core was collected in the Lower Miocene Confining Zone, Lower Miocene Injection zone, Anahuac Confining Zone, Frio Injection Zone, and Hackberry Confining Zone. Plugs were extracted from the core, and Routine Core Analysis (RCA) was performed to extract porosity and permeability (P&P) in the plugs. The P&P cross-plots are presented in the Figure

AoR-250. P&P vary per zone, with the highest P&P values in the Lower Miocene Injection Zone and lowest values in the Hackberry Confining Zone.

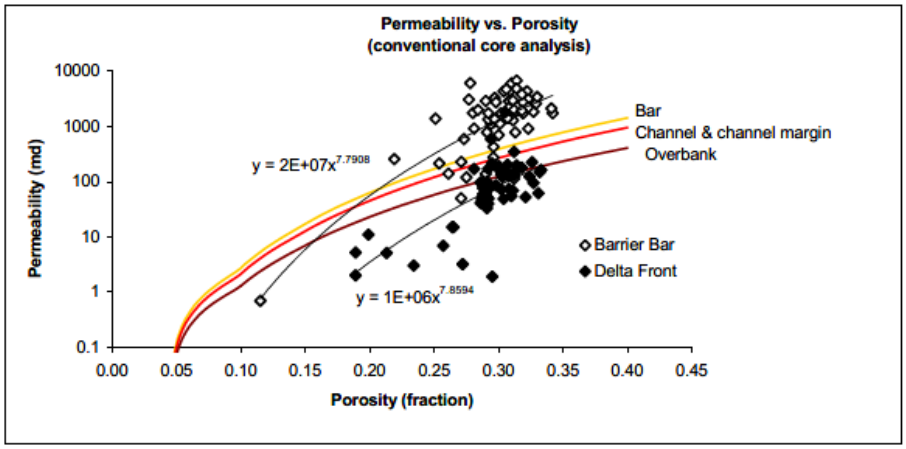


Figure V-28. Cross plot of porosity vs. permeability from conventional core analysis for the Frio, Felix Jackson No. 1 well, Chambers County. The barrier-bar values were used to estimate permeability from calculated porosity for the Frio injection zone. Bar, channel, and overbank lines presented for comparison are from a detailed study of the Frio Formation, Rincon field, South Texas (Holtz and others, 1996).

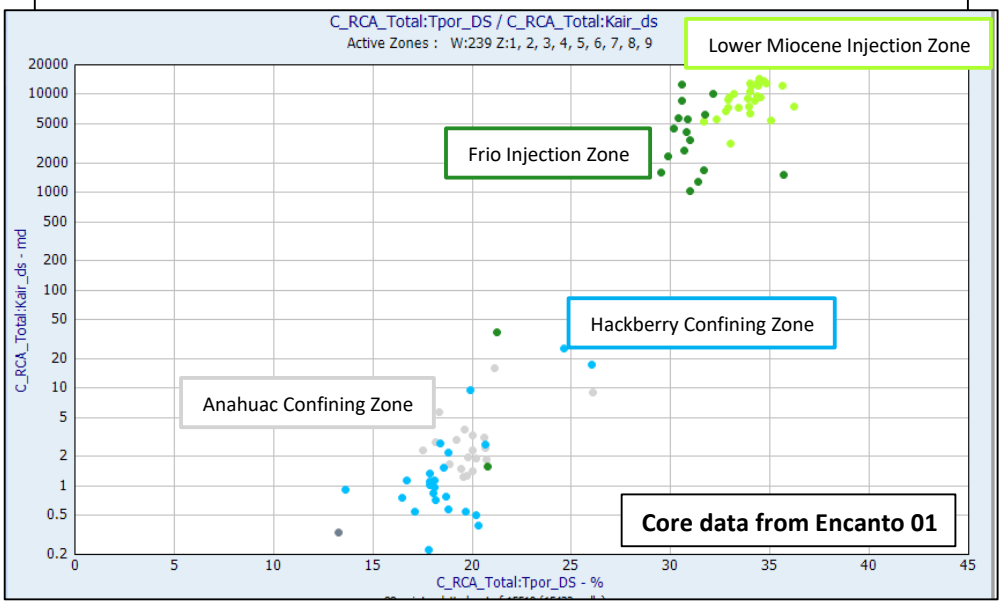


Figure AoR-250: The top cross-plot has the core porosity and permeability (P&P) from the Frio Pilot study (Susan D. Hovorka and others, 2003), and the lower figure is the RCA porosity and permeability from Encanto 01. Both cross-plots show Frio sands with ~30% porosity and ~1 Darcy of permeability.

4.5 Constitutive Relationships and Other Rock Properties

The Bluebonnet Sequestration Hub dynamic reservoir simulation followed a method developed by Ghomian et al. (2008), who had successfully matched the results of a 2004 Frio pilot injection test, described in detail by Sakurai et al. (2004). The project team adopted these established processes in petrophysical evaluation, geological model construction, Equation-of-State (EOS) modeling for CO_2 properties and solubility, and the gas-water relative permeability model with higher trapped gas saturations during the imbibition process.

Further, all simulations runs were executed using the GEM simulator, as used by Ghomian et al. (2008). The grid properties of porosity, horizontal net sand permeability (k_{sand}), and Net-to-Gross ratio (NTG) were directly imported from the static geomodel. The base vertical permeability (k_v) for each grid cell was calculated using a geometric average of sand and shale permeability based on the NTG, as shown in Equation 2.

$$kv = [(A * k_{sand})^{(NTG)}] * [(k_{shale})^{(1 - NTG)}] \quad \text{..... (Equation 2)}$$

Where:

kv is the base vertical permeability;
A is a multiplier for sand permeability;
k_{sand} is the horizontal net sand permeability;
NTG is the net-to-gross ratio;
k_{shale} is the horizontal shale permeability;

The base case used a value of A = 0.25 and k_{shale} = 0.001.

The water-gas relative permeability curves were constructed using a Corey model with exponents previously reported by Ghomian (2008). These curves were also used in the simulation of the Frio CO_2 Pilot test. The following endpoint values and Corey exponents were used:

- S_{wr} = 0.133
- S_{gc} = 0.13
- K_{rw} (at 100% S_w) = 1.0
- K_{rg} (at S_{wr}) = 0.71
- N_w = 2.7
- N_g = 1.78

During the imbibition cycle (water displacing gas), the gas is trapped at S_{gt} or trapped gas saturation. S_{gt} values depend on the maximum gas saturation, S_{gh}, that a grid block has experienced. The base case maximum trapped gas saturation is specified as S_{gt} = 0.35. All dynamic simulation runs include relative permeability hysteresis.

To calculate the capillary pressure, the maximum capillary pressure during drainage is estimated as 15.47 psi and the threshold capillary entry pressure as 1.4 psi.

4.6 Boundary Conditions

Pore volume multipliers of 52 to 211 were applied to the outermost ring of the cells adjacent to the horizontal boundaries of the GEM model to simulate an extensive reservoir. The horizontal boundaries were initialized as hydrostatic conditions, and no changes were made to the boundary conditions following pre-operational testing. One of the faults, B06, is identified as sealing fault based on the Fault Analysis described in Section 3.11 and its transmissibility is set as zero in the model.

Figure AoR-251 shows a high probability of thick Frio sands over the entire Gulf Coast region, though there is some uncertainty about good hydraulic connectivity over such a large distance. To quantify its impact on AoR predictions, the horizontal boundary conditions were included as a sensitivity parameter. In Figure AoR-251, the red dash line rectangle represents the low case boundary, red solid rectangle represents the mid (base) case boundary, and blue rectangle represents the high case boundary, within which reservoir pore volumes were included to predict the pore pressure increases from CO_2 injection.

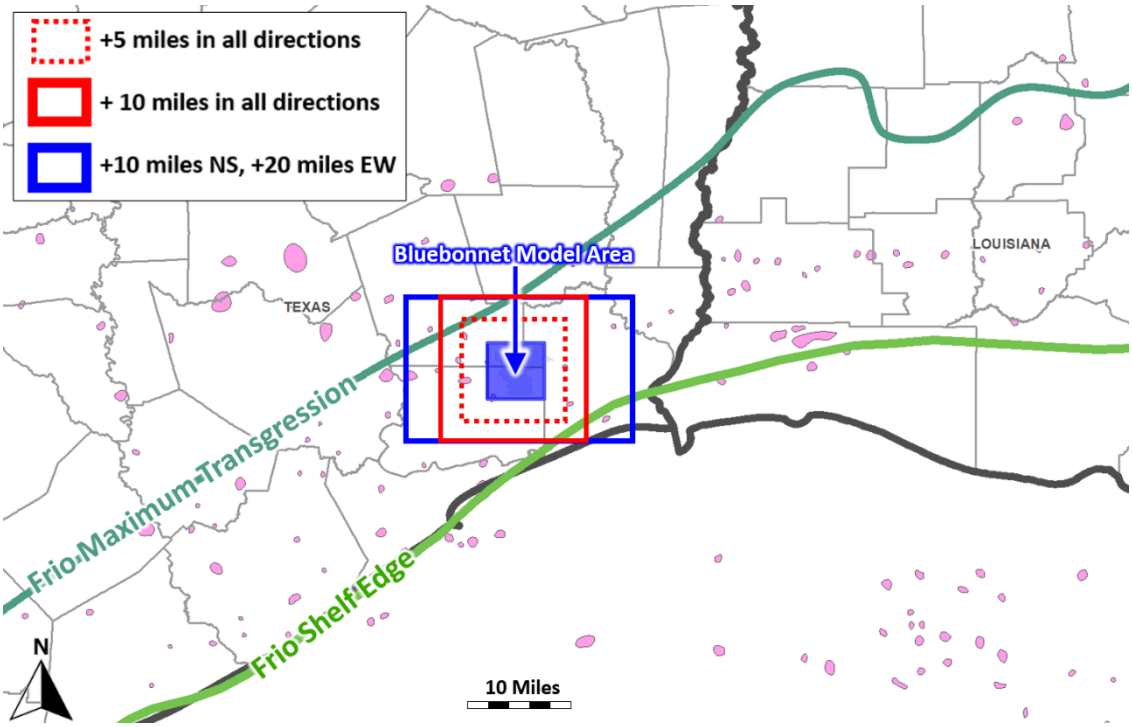


Figure AoR-251: A map showing Frio sand thickness in the Gulf Coast area and edge volumes added to the dynamic simulation model (Swanson, 2013).

4.7 Initial Conditions

Initial conditions for the model are given in Table AoR-31.

Table AoR-31: Initial Condition.

Parameter	Value or Range	Units	Corresponding Elevation (ft, MD)	Data Source
Temperature	134, 170	^{o}F	5,682 ft, 7,731 ft	Measured Data
Formation pressure	2,105	psi	4,644 ft	Measured Data from MDT
Formation water density	67.86	lb/ft^3	4,337 ft	Measured Data from Miocene water sample
Formation water salinity	114,735	ppm	4,337 ft	Measured Data from Miocene water sample
Rock compressibility	1×10^{-5}	1/psi	n/a	Newman 1973; Hall 1953

In this study, a pressure gradient based on 2105 psia at 4644 ft was adopted in the model. For the modeled pressure gradient within the injection zone, a water density of 67.86 lb/ft^3 (for 114,735 ppm TDS brine) was specified. This formation salinity of 114,735 ppm TDS was determined from the water analysis report in the Encanto 01 well Miocene formation since there was not any Frio salinity data available at that time. The actual Frio salinity received in May 2024 is ~127,000 TDS, which will not bring any noticeable difference in our predicted AoR. The reservoir temperature was initialized using a linear temperature gradient representative of with reference temperatures of 56.7°C/134°F at 5682 ft and 76.7°C/170°F at 7731 ft from the actual temperature measurement in Encanto 01 well. Brine viscosity is calculated using Kestin, Khalifa, and Correia correlation in CMG. There is no measured rock compressibility. It is assumed as 1e-05 1/psi based on Newman (1973).

In all the simulations, a maximum BHP was assigned based on a very conservative 0.576 psi/ft fracture gradient (76% of 0.76 psi/ft), but even under this BHP constraint, the model had no problems in taking in the desired CO_2 rate for all three injectors.

The geomodel permeability was adjusted based on the GCCC correlation, transmissibility, and injectivity test results from Encanto 01 stratigraphic well. The estimated transmissibility from the Frio sand test is 73,923 md.ft. A comparison of the transmissibility values for the same intervals from the Encanto 01 well log was made, which is used in the geologic model. The results show that, on the average, the transmissibility is about 1.56 higher than that from the Encanto 01 well log. Consequently, a regional multiplier of 1.56 was applied in the Frio and Hackberry injection zones.

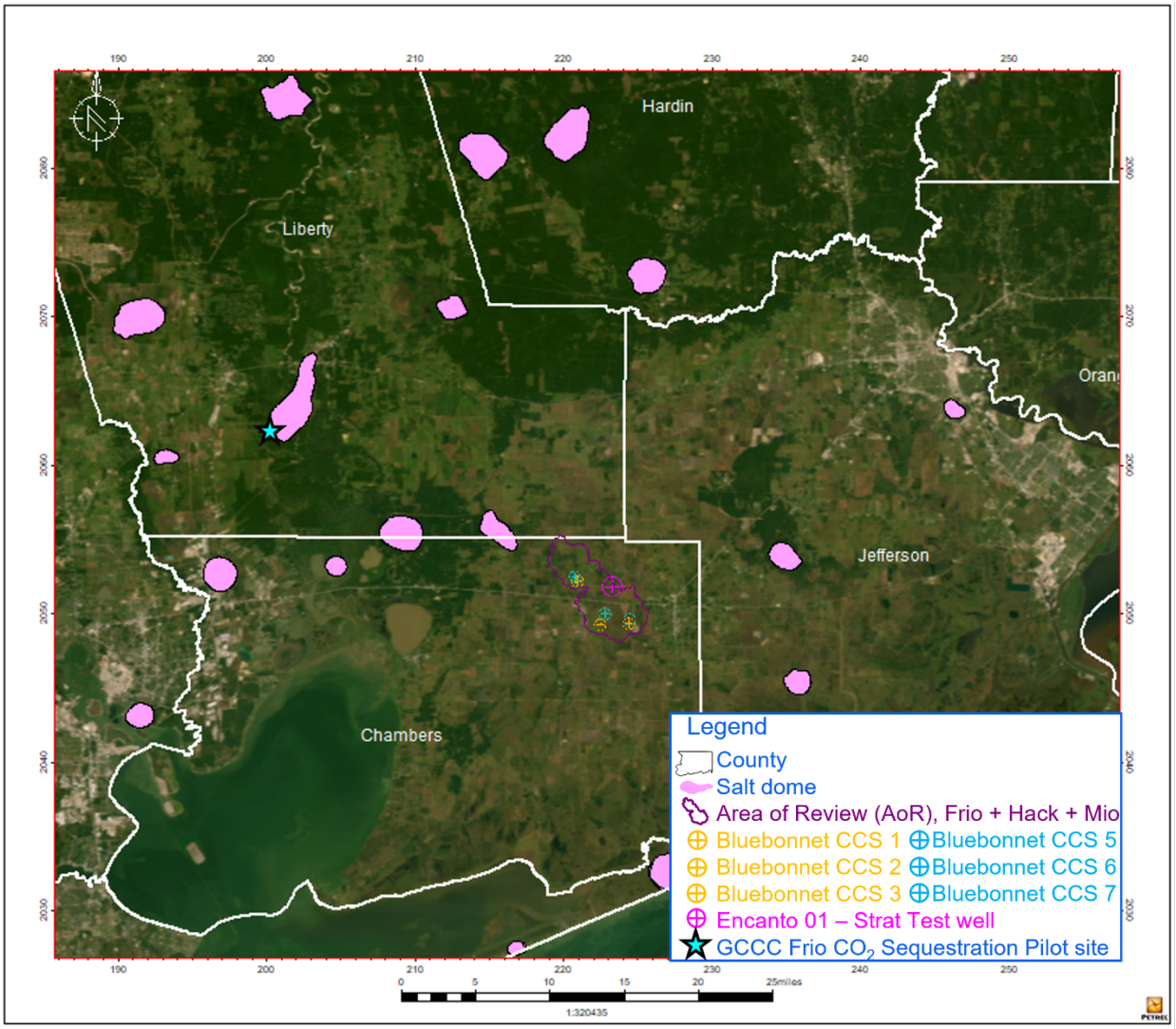


Figure AoR-252: Location of the GCCC-led CO_2 Sequestration pilot into the Frio brine-bearing sandstones, Liberty County, Texas. The distance to the proposed Bluebonnet Sequestration Project is approximately 27 miles.

4.8 Operational Information

The model was initialized with hydrostatic conditions and run without any active wells for four years to ensure equilibrium and no fluid movement. In the fifth year, the Bluebonnet CCS 1, CCS 2, and CCS 3 wells begin injecting with a primary rate constraint of 105 MMscfd (2.0 million metric ton (MMTA)), 89.25 MMscfd (1.7 MMTA), and 73.5 MMscfd (1.4 MMTA), respectively. A secondary bottomhole pressure (BHP) constraint (76% of the minimum estimated fracture gradient of 0.76 psi/ft) is set at the well reference depth. The frac gradient, 0.76 psi/ft, has been established by step-rate and leak-off tests on the Encanto 01 stratigraphic well. The injection stream composition is assumed as 100% CO_2. CCS 1 and CCS 3 continue injection until the end

of Year 20, but CCS 2 only injects for 15 years. The base-case run continued for 100 years post-injection to simulate CO_2 migration after post-injection site closure.

Two water withdrawal wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2, are proposed to help relieve the pressure increase from CO_2 injection. Both wells are completed in the Frio only and produce for the first 15-years of injection. Produced water from the water withdrawal wells is reinjected to Upper Miocene formation that includes the sands between the Lower Miocene Confining Zone and base of the USDW.

Table AoR-32 shows the completion design for all three injectors. During the first 8 years of injection, Bluebonnet CCS 1 is completed at Frio Low only (Layer 231 - Layer 262). Starting from Year 9, this well is recompleted in Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230). Meanwhile, the Frio Low intervals are opened for the first 9-year injection period and are left open. Starting from Year 16, this well is recompleted into the Hackberry (Layer 271 – Layer 304) and all the Frio completions will be plugged. Bluebonnet CCS2 is only completed in the Frio formation. This well first completes in Frio Low (Layer 231 - Layer 262), and then, recompletes in Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230) at Year 9, while leaving the Frio Low open. CCS 3 completes in the Hackberry (Layer 271 – Layer 304) for the first eight years and all perforations in the Hackberry are plugged at the end of Year 8. At year 9, this well is recompleted into the Frio Low (Layer 231 - Layer 262), and then in Year 16, is recompleted into the Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230).

The recompletion design provides higher CO_2 storage capacity by filling each zone of the reservoir separately. The CO_2 plume areal extent is also reduced by injecting to the high permeable zone for shorter time. Both Bluebonnet PRDW F1 and Bluebonnet PRDW F2 are completed at Frio Low only (Layer 231 – Layer 262) during the first eight years of injection and are recompleted in Mid Frio (Layer 193 – Layer 222) and top high permeable Frio Low layers (Layer 223 – Layer 230) from Year 9 to Year 15. Bluebonnet PRDW F1 and Bluebonnet PRDW F2 are shut in permanently after Year 15.

Details on the injection operation are presented in Table AoR-32 and Table AoR-33.

Table AoR-32: Operating details of Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3.

Operating Information	Bluebonnet CCS 1	Bluebonnet CCS 2	Bluebonnet CCS 3
Bottomhole Location (NAD27) Latitude Longitude	 29.80813285 -94.43723568	 29.80664177 -94.46905961	 29.84865529 -94.49510821
Model coordinates (ft) X Y	 1184728.1 10820884.0	 1174630.0 10820469.2	 1166568.3 10835850.8
No. of perforated intervals	3	2	3
Perforated interval (ft TVDSS) Z top Z bottom	 7982.66 8257.46	 7922.72 8178.12	 8079.94 8400.57
Recompletion interval (ft TVDSS) Z top Z bottom	 7779.96 8257.46	 7714.06 8178.12	 7638.44 7898.79
Recompletion interval (ft TVDSS) Z top Z bottom	 8542.85 8719.46	 n/a	 7374.83 7898.79
Wellbore diameter (in.)*	6.0	6.0	6.0
Planned injection period Start End	 time = 0 time = 20	 time = 0 time = 15	 time = 0 time = 20
Injection duration (years)	20	15	20
Average Injection rate (t/day)	5,479 (1^{ST} and 2^{nd} completion) 1370 (3^{rd} completion)	4,658 (1^{ST} and 2^{nd} completion)	3,836 (1^{ST} and 2^{nd} completion) 2,740 (3^{rd} completion)

TVDSS: True Vertical Depth Sub Sea

Table AoR-33: Operating details for water withdrawal wells.

Operating Information	Bluebonnet PRDW F1	Bluebonnet PRDW F2
Bottomhole Location (NAD27) Latitude Longitude	 29.852257630 -94.51667365	 29.810133590 -94.49717700
Model coordinates (ft) X Y	 1,159,749.99 10,837,250.00	 1,165,730.49 10,821,853.47
No. of perforated intervals	2	2
Perforated interval (ft MSL)* Z top Z bottom	 7627.63 7885.58	 7864.68 8105.80
Recompletion interval (ft MSL) Z top Z bottom	 7344.93 7885.58	 7624.00 8105.80
Wellbore diameter (in.)*	6.0	6.0
Planned injection period Start End	 time = 0 time = 15	 time = 0 time = 15
Injection duration (years)	15	15
Injection rate (bbl/day)	8500 (1^{ST} and 2^{nd} completion)	8500 (1^{ST} and 2^{nd} completion)

4.9 Computational Modeling Results

The dynamic simulations were carried out in 3D using full physics, an Equation of State for fluid PVT, and on the full geologic model encompassing a 13.58 × 13.69 square mile area. The dynamic reservoir simulation was performed with the same 500 ft × 500 ft × ~13.5 ft grid cells as those in the geologic model. The areal extent of the simulation model is shown in Figure AoR-71.

Twenty-two zones were imported into CMG BUILDER (Table AoR-34).

Table AoR-34: Zones imported into CMG Builder.

Zone	Layers
L_Miocene_SH	1-4
L_Miocene_A	5-14
AMPB_SAND	15-22
L_Miocene_B	23-42
L_Miocene_C	43-54
LMIO_INJ	55-64
LMIO_INJ_5	65-72
LMIO_INJ_4	73-80
LMIO_INJ_3	81-98
LMIO_INJ_6	99-124
LMIO_INJ_2	125-142
Anahuac	143-148
Anahuac_Sand_Top	149-152
Anahuac_Base	153-158
Anahuac_Het_Lime_Top	159-168
Anahuac_Het_Lime_Base	169-172
Frio_Top	173-192
Frio Mid	193-222
Frio Low	223-262
Frio_Shale	263-270
Hackberry	271-304
Hackberry_Shale	305-310

The dynamic model contains 143 × 142 × 310 cartesian grids and more than 6.2 million active cells.

4.9.1 Predictions of System Behavior

The simulated well rates and pressures are shown in Figures AoR-253, AoR-254, and AoR-255. Wellhead pressures were calculated using a PROSPER-generated tubing table with 5.5-inch tubing. Table AoR-35 shows the maximum bottomhole and well head pressure for each stage at operative conditions.

Table AoR-35: Well Bottomhole pressure and wellhead pressure for each stage at proposed average rates.

Injector	Completion	Reference Depth, TVDSS, ft	Maximum Well Bottom-hole pressure, psi	Maximum Well Head Pressure, psi	Average Well Bottom-hole Pressure, psi	Average Well Head Pressure, psi
Bluebonnet CCS 1	Stage 1	7983	4017	1986	3855	1874
	Stage 2	7780	3817	1896	3798	1884
	Stage 3	8543	4914	1885	4605	1662
Bluebonnet CCS 2	Stage 1	7912	4266	2006	3867	1727
	Stage 2	7707	3793	1726	3774	1713
Bluebonnet CCS 3	Stage 1	8080	4032	1639	3913	1563
	Stage 2	7638	3886	1646	3739	1550
	Stage 3	7375	3702	1402	3596	1383

Simulation results supported bottom-up, staged completions as an attractive completion strategy (Table AoR-36). The proposed completion design for each well is based on the overall forecasted sequestration volume, injectivity of each well, and availability of the pore space. At the beginning of injection, Bluebonnet CCS 1 is completed in the Frio Low subzones only. After injecting CO_2 for more than eight years in the Frio Low, the Frio Mid subzones are added to the injection interval in Year 9 and Hackberry is added in Year 16.

Bluebonnet CCS 2 only injects in the Frio formation. Similar to CCS1, it injects in the Frio Low for the first eight years, then recompletes Frio Mid in Year 9.

CCS 3 starts injecting in Hackberry first, then moving up to the Frio Low and Frio Mid. Simulation results suggested that there is not much difference in pressure increase and plume size between plugging back or leaving the Frio Low open after adding Frio Mid.

Different from Bluebonnet CCS3, Bluebonnet CCS1 recompletes into the Hackberry after Frio development because of the overall volume balance needs and pressure front extent at that time.

Table AoR-36: Stage injection, injection, and production rate for all the wells.

Injection Years	CCS 1 Completion	CCS 1 injection rate , MMTA	CCS 2 Completion	CCS 2 injection rate , MMTA	CCS 3 Completion	CCS 3 injection rate , MMTA	PRDW F1, bwpd	PRDW F2, bwpd	DSW M2, bwpd
1	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
2	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
3	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
4	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
5	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
6	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
7	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
8	Frio_Low	2	Frio_Low	1.7	Hackberry	1.4	8,500	8,500	17,000
Shut-In									
9	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
10	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
11	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
12	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
13	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
14	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
15	Frio_Mid	2	Frio_Mid	1.7	Frio_Low	1.4	8,500	8,500	17,000
Shut-In									
16	Hackberry	0.5			Frio_Mid	1			
17	Hackberry	0.5			Frio_Mid	1			
18	Hackberry	0.5			Frio_Mid	1			
19	Hackberry	0.5			Frio_Mid	1			
20	Hackberry	0.5			Frio_Mid	1			
Shut-In									

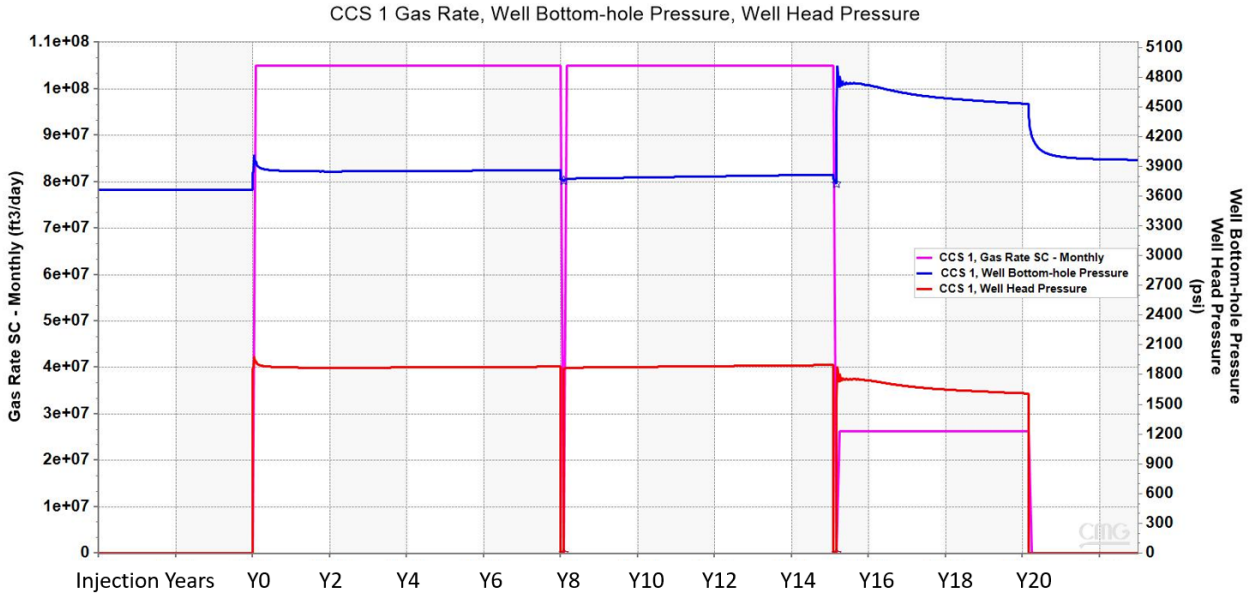


Figure AoR-253: Simulated well Bluebonnet CCS 1 gas injection rates and corresponding wellhead and bottomhole pressures.

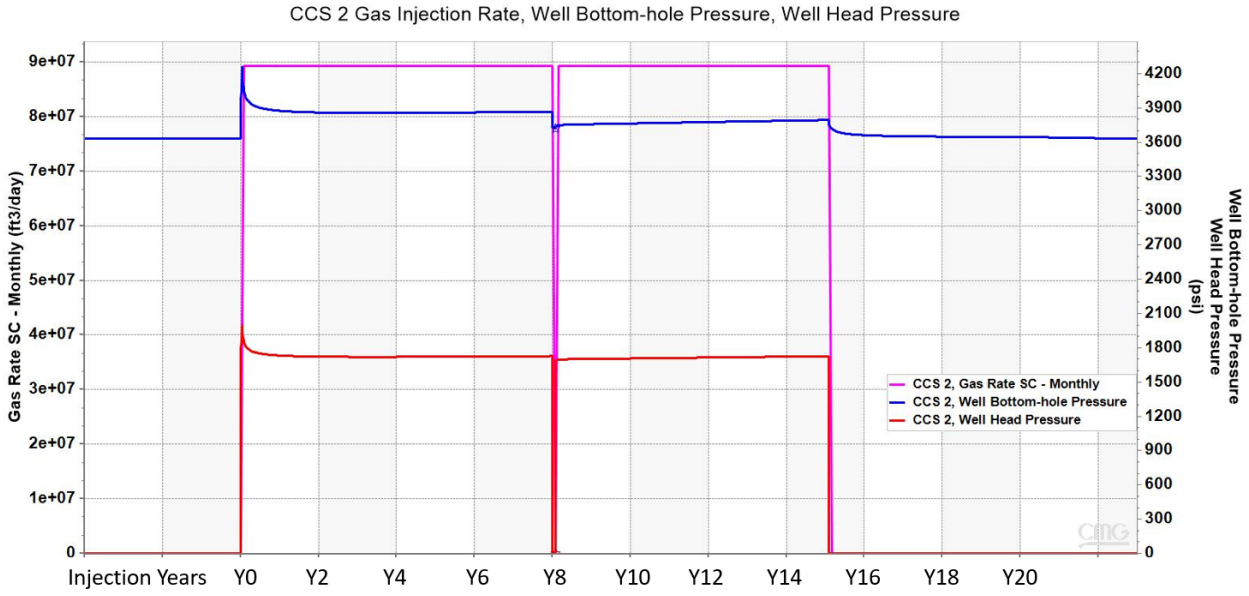


Figure AoR-254: Simulated well Bluebonnet CCS 2 gas injection rates and corresponding wellhead and bottomhole pressures.

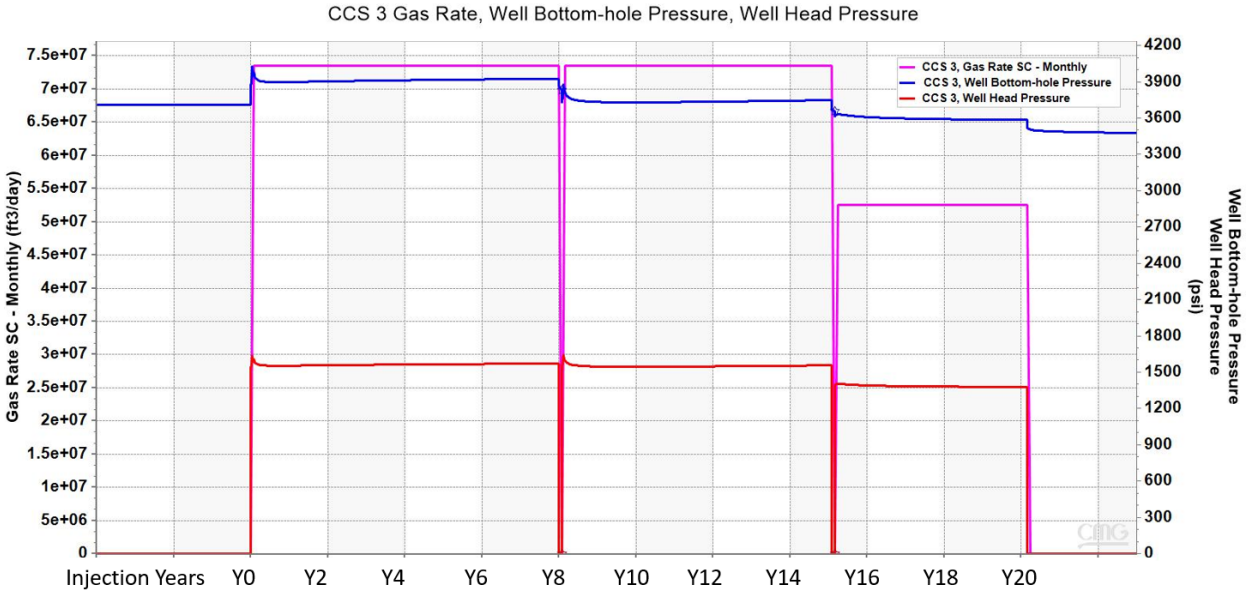


Figure AoR-255: Simulated well Bluebonnet CCS 3 gas injection rates and corresponding wellhead and bottomhole pressures.

4.9.2 Model Calibration and Validation

4.9.3 Sensitivity to Input Parameters

Due to the uncertainties in some of site-specific pilot data used to calibrate the dynamic model, sensitivity of the results to subsurface input was explored. These subsurface uncertainties include vertical-to-horizontal permeability ratio (K_v/K_h), trapped gas saturations (S_{gt}), faults transmissibility, rock compressibility, plugging back the first stage during completion of the second stage, and size of the boundary aquifers.

Table AoR-37 summarizes the possible ranges of these subsurface inputs. The base case inputs are indicated in the left column. Many simulation runs were made by varying these parameters one at a time and plotting the results to see their impacts. The parameters used to compare the different sensitivity cases are reservoir pressure increase and CO_2 retention.

Table AoR-37: Simulation sensitivity cases.

Parameter	Best Value	Sensitivity Values	
Kv/Kh	(0.25Kh)^N2G*0.001^(1-N2G)	(0.5Kh)^N2G*0.001^(1-N2G)	
Sgt (fraction)	0.35	0.3	0.4
Edge Volume Enhancement	10-mile-wide edge volume	5-mile-wide edge volume	20-mile-wide edge volume(East-West)
Faults Transmissibility Multiplier	*0.1	*0.01	*0.5
Stage 2 Completion	Leave Stage 1 open	Plug Back Stage 1	
Rock Compressibility, 1/psi	1.00E-05	5.00E-06	

Figure AoR-256 shows the sensitivity of forecasted reservoir pressure to various reservoir parameters. The highest change in the reservoir pressure occurs in the low rock compressibility or low edge pore volume cases. This change is at the local level near the injection wellbores with the highest increase less than 600 psia. Figure AoR-256 also shows the reservoir pressure is most sensitive to the size of the boundary aquifer. The pressure increase is moderately sensitive to K_v/K_h and faults transmissibility multiplier. The pressure increase is not sensitive to the trapped gas saturation, S_{gt}, and plugging back or leaving the first stage open. Figure AoR-257 shows the CO_2 100-year post injection plume in the Frio and Hackberry formations, respectively, for two most sensitive cases (High edge volume and high Kv/Kh case) to CO_2 migration. They are almost identical to the base case.

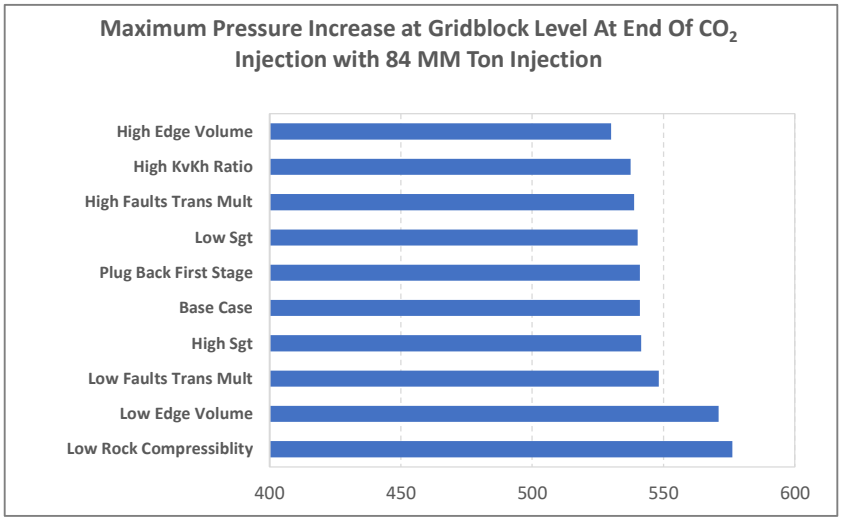


Figure AoR-256: Maximum pressure increase at gridblock level at end of CO_2 injection with 84 MM Ton injection.

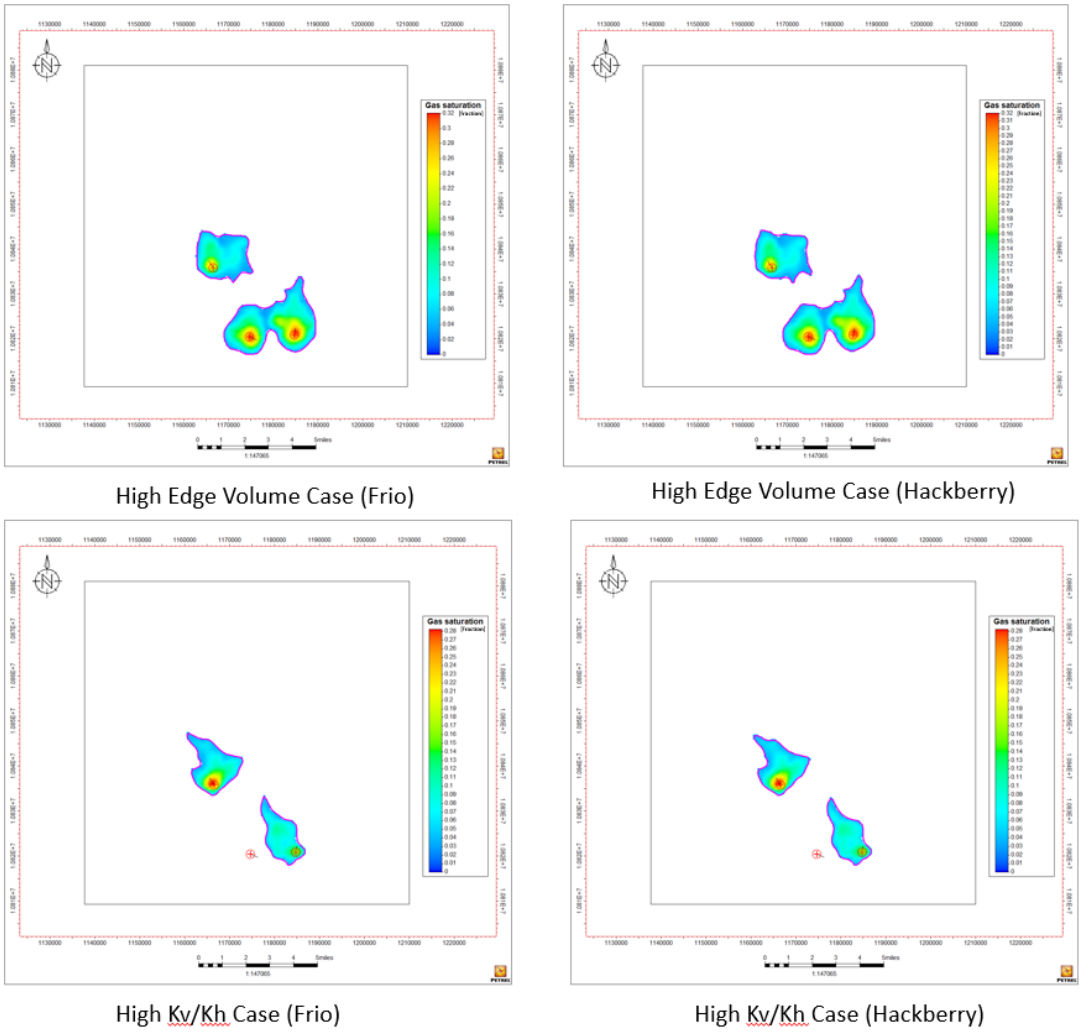


Figure AoR-257: Forecasted CO_2 saturation for high edge volume case and high Kv/Kh case.

4.10 Area of Review (AoR)

4.10.1 Critical pressure calculations

To delineate the critical pressure front, it is necessary to calculate the minimum pressure differential that can reverse flow direction between the lowermost USDW and injection zone, thereby, causing fluid flow from the injection zone into the USDW formation matrix. In other words, the pore pressure increase is high enough to overcome the hydraulic head of the fluid in a hypothetical wellbore and enter the USDW.

In the previous application, the Project team calculated the critical pressure threshold, ΔP_c, using Method 2 provided in the EPA May 2013 Program Class VI Well Area of Review and Corrective Action Evaluation Guidance (EPA, 2013). Method 2 was developed and published by Nicot et al. (2008), that assumes the critical pressure threshold (ΔPc) in the injection zone is given by Equation 8:

$$\Delta P_c = ½ * g * \xi * (z_u - z_i)^2 \quad \text{..... (Equation 8)}$$

where:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \quad \text{..... (Equation 9)}$$

This method, also called uniform density approach, estimates a pressure differential that would displace fluid initially present in a hypothetical borehole into the lowermost USDW and is based on the following assumptions: (1) hydrostatic conditions; (2) initially linearly varying densities in the borehole and constant density once the injection zone fluid is lifted to the top of the borehole; (3) brine from the injection formation will not equilibrate with the borehole surroundings; and (4) a constant density of the brine in the injection formation. In Nicot's paper, another approach is introduced assuming that fluid can reach thermal equilibrium with the surrounding rock (Equation 10). Whether using uniform density approach or the equilibrium approach, it is assumed that the wellbore is open and filled with brine.

$$\frac{\Delta P}{g} = (z_v - z_I)\left(\frac{\lambda - \xi}{2}(z_v - z_I) + \rho_{I,\lambda} - \rho_I\right) \quad \text{..... (Equation 10)}$$

However, after collecting and reviewing the site base data, in reality, the assumptions made in developing the uniform density approach are not valid for this site, rendering the derived formulas unacceptable. The existing formation fluids do not have a lineal behavior with depth, having considerable variation of salinity with depth as demonstrated during the water sampling in Encanto 01 stratigraphic well (see AoR and Corrective Action Attachment). The existing formations have hydrostatic pressure gradients slightly more than 0.433 psi/ft and the bottom sections of the injection targets are close to the transition zone for the overpressure section, as described in the AoR and Corrective Action Attachment. Lastly, the assumption that the wells are filled just with formation brine is not realistic since, at the very minimum, the wells are filled with native drilling mud.

As an alternative, the project evaluated different approaches used in permitting Class I wells and studies done by subject matter experts in hazardous and nonhazardous waste disposal, plugging

and abandonment of wells, and drilling fluid properties, amongst others. Studies such as Bump (2023), Johnston and Knape (1986), J.E Clark (2005), and others support the following methodology.

The project assumed that the wellbore of a well that drilled to the injection zone is filled with a minimum of 9 pound-per-gallon (ppg) mud and that the mud develops a gel strength that increases with time. The recommended value for minimum mud gel in the literature ranges between 20 and 25 lbs/ft^2 as a very conservative value; however. the project assumed a minimum of 10 lbs/ft^2 to add additional safety factor in the calculation.

The calculated critical pressure is defined as the pressure due to the mud column inside the wellbore and pressure needed to overcome the gel strength, subtracting the initial reservoir pressure (pre-injection). The project also added a 50 ft falloff of the mud level inside the wellbore as additional safety factor.

Assuming a mud weight of 9.0 ppg, a falloff of 50 ft, reservoir pressure gradient of 0.445 psi/ft in the Frio Injection Zone and 0.449 psi/ft in the Hackberry Injection Zone (measured from pressure gauges in Encanto 01), and gel strength of 10 lbs/ft^2, the calculated critical pressure differential for the Bluebonnet Hub is 172 psi for the Frio Injection Zone and 158 psi for the Hackberry Injection Zone.

$$\text{Critical Pressure} = MW \times 0.052 \times (TD_{perf} - 50) + GS - \nabla P_{Reservoir} \times TD_{perf} \quad \text{(Equation 11)}$$

$$\text{Gel Strength Pressure (GS)} = A \times \text{Gel Strength} \times L_{Hole} / D_{Hole} \quad \text{(Equation 12)}$$

MW: Mud weight (ppg)
TD_{perf}: Top of perforation depth (ft)
GS: Gel Strength Pressure (psi)
$\nabla P_{Reservoir}$: Reservoir Pressure Gradient (psi/ft)
A: Conversion factor (1/300)
Gel Strength (lbs/ft^2)
L_{Hole}: Length of the wellbore (ft)
D_{hole}: Diameter of the wellbore (inch)

Additional details and justification for the critical pressure calculation methodology are included in Appendix F of this application.

4.10.2 AoR delineation

4.10.2.1 Critical pressure front

The maximum differential pressure occurs at the maximum cumulative volume of CO_2 injection since the wells are operating at a constant injection rate. In the model, this occurs 15 years after injection commences for the Frio formation and 20 years after injection commences for the Hackberry formation. The movement of the pressure front was evaluated at 5, 10, 15, and 20 years after injection starts to find optimal locations for the in-zone monitoring wells. The forecasted

pressure increases in year 15 (Frio) and 20 (Hackberry) after injection are shown in Figures AoR-258 and AoR-259, respectively. A critical pressure front of 172.3 psi for the Frio and 157.9 psi for the Hackberry is projected onto the 2D areal map.

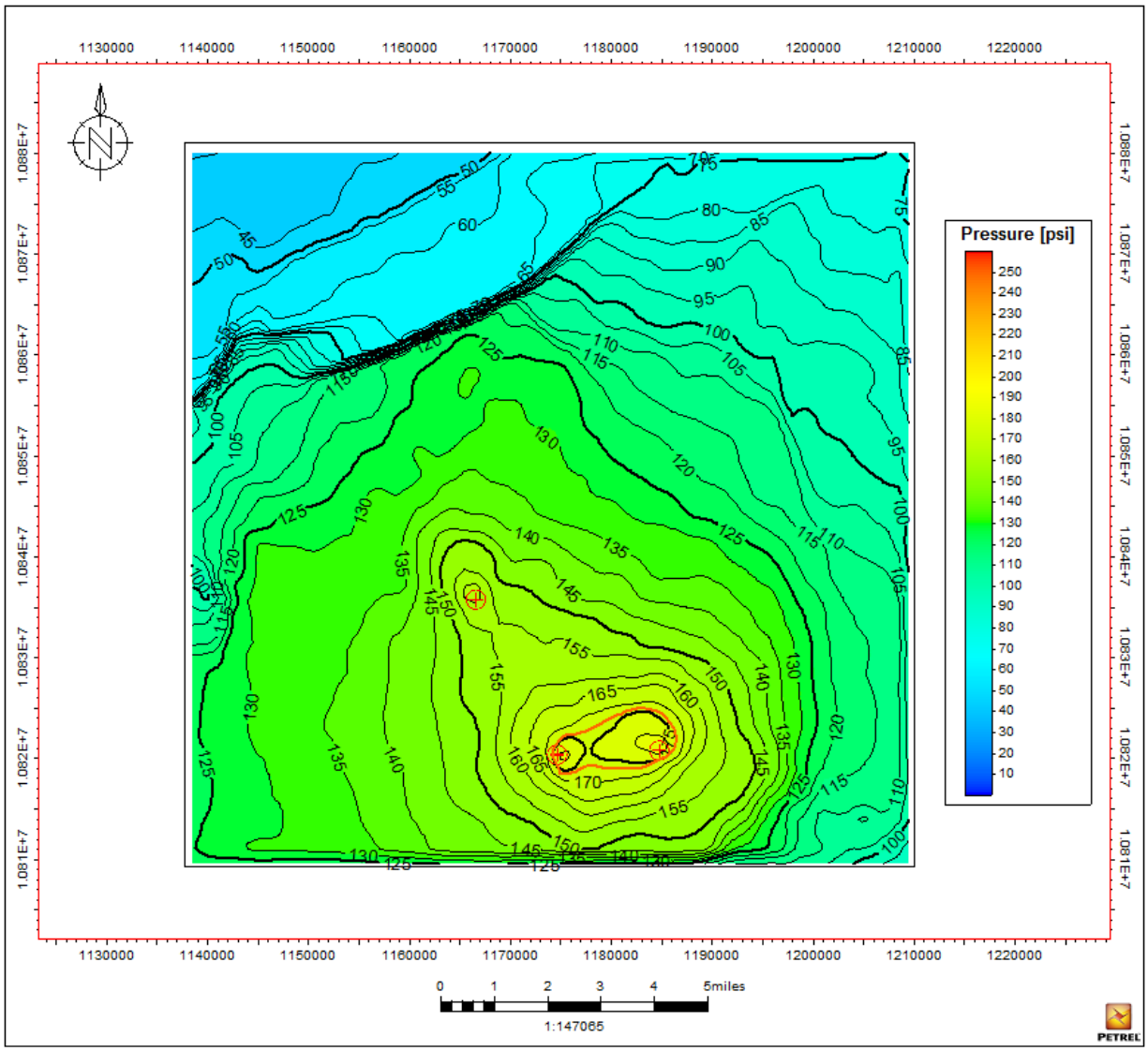


Figure AoR-258: View of highest pore-pressure increases after 65.3 million MT of total CO_2 injection in Frio for 15 years. Values displayed are pore-volume-weighted averages across the injection interval. The orange polygon is the pressure front for Frio Formation.

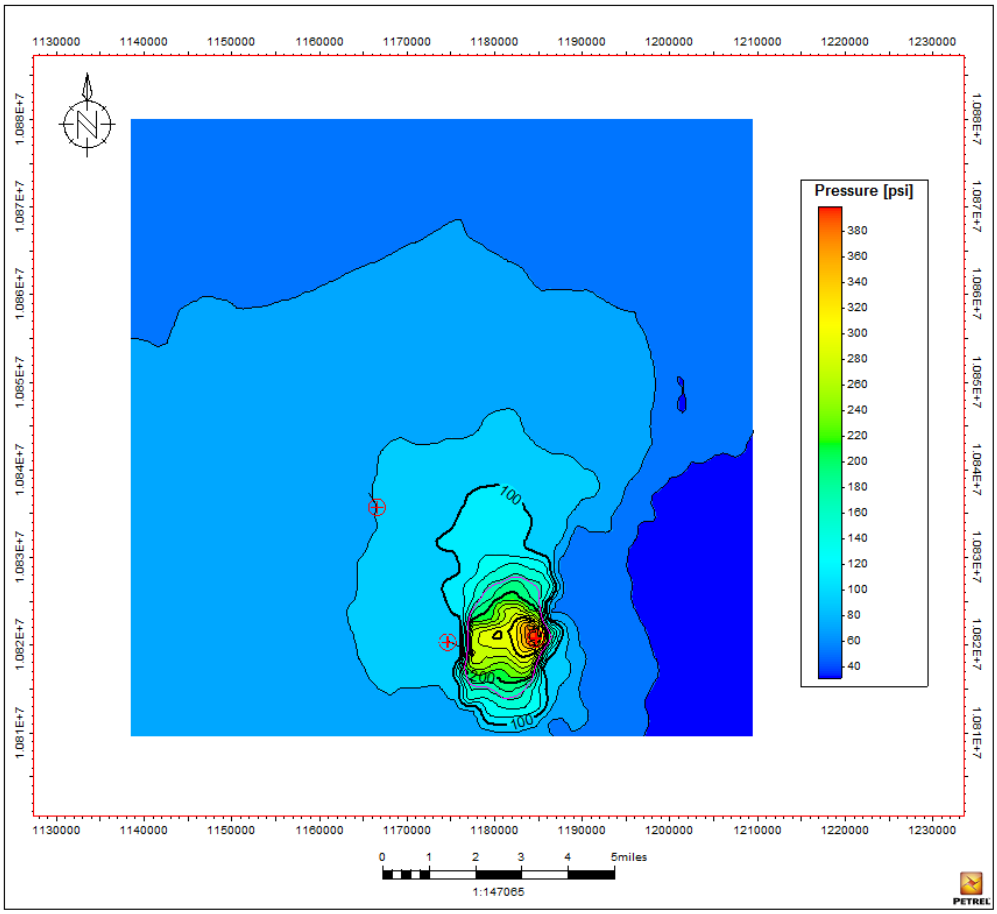


Figure AoR-259: View of highest pore-pressure increases after 13.7 million MT of total CO_2 injection in Hackberry for 20 years. Values displayed are pore-volume-weighted averages across the injection interval. The purple polygon is the pressure front for Hackberry Formation.

4.10.2.2 CO_2 plume extent

The CO_2 plume extend was simulated assuming 20 years of injection as described in the previous section. The Project simulated 50 years post-injection as well as 100 years post-injection. Plume tends to stabilize before the 50 years of post-injection period; however, the Project defined the 100-year plume outline to delineate the maximum extend of the CO_2 plume in the AoR as a conservative approach. The Project used a cut off of 3% CO_2 saturation as supported by the fluid substitution analysis provided in Section 7.

Figures AoR-260 and AoR-261 show CO_2 distribution at 100 years after injector shut-in in Frio and Hackberry, respectively. The highest CO_2 saturation is around the wellbore and has moved up dip with time. Figures AoR-262 and AoR-263 display the top view of CO_2 plume extents at 5, 10, 15, and 20 years (during injection) and 50 and 100 years after injection is shut-in. Results suggested that CO_2 plume extents can be retained within the AoR and migration of CO_2 plume from 50 to 100 years is predicted to be minimal.

Figure AoR-264, Figure AoR-265, and Figure AoR-266 show the simulated CO_2 saturations along a north-south cross section through Bluebonnet CCS 1, CCS 2, and CCS 3 wells in year 20 after injection. The figure displays a desirable uniform CO_2 profile within the injection zone, effectively utilizing all intervals in the project's pore spaces. In the modeling exercises, such a profile has been achieved by employing the staged completions bottom up.

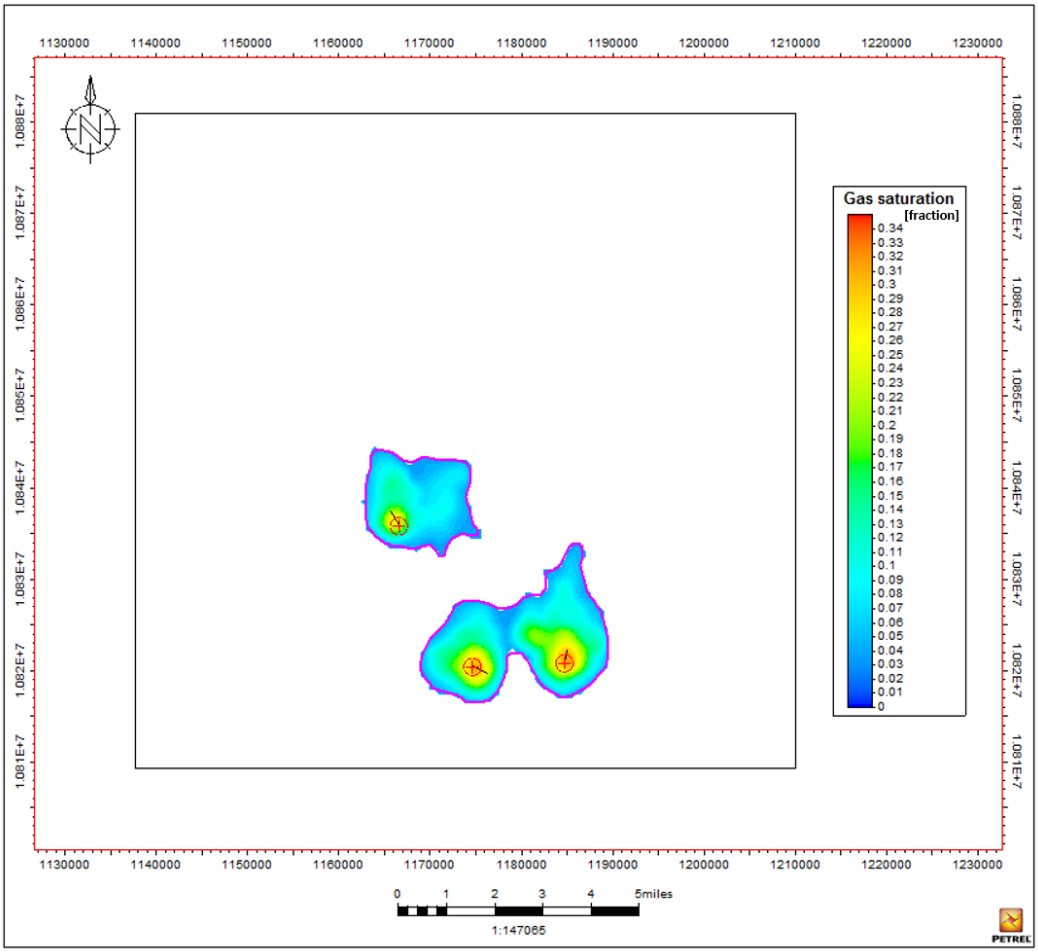


Figure AoR-260: Pore volume weighted CO_2 saturation map distribution after 70.3 million MT CO_2 injection in Frio.

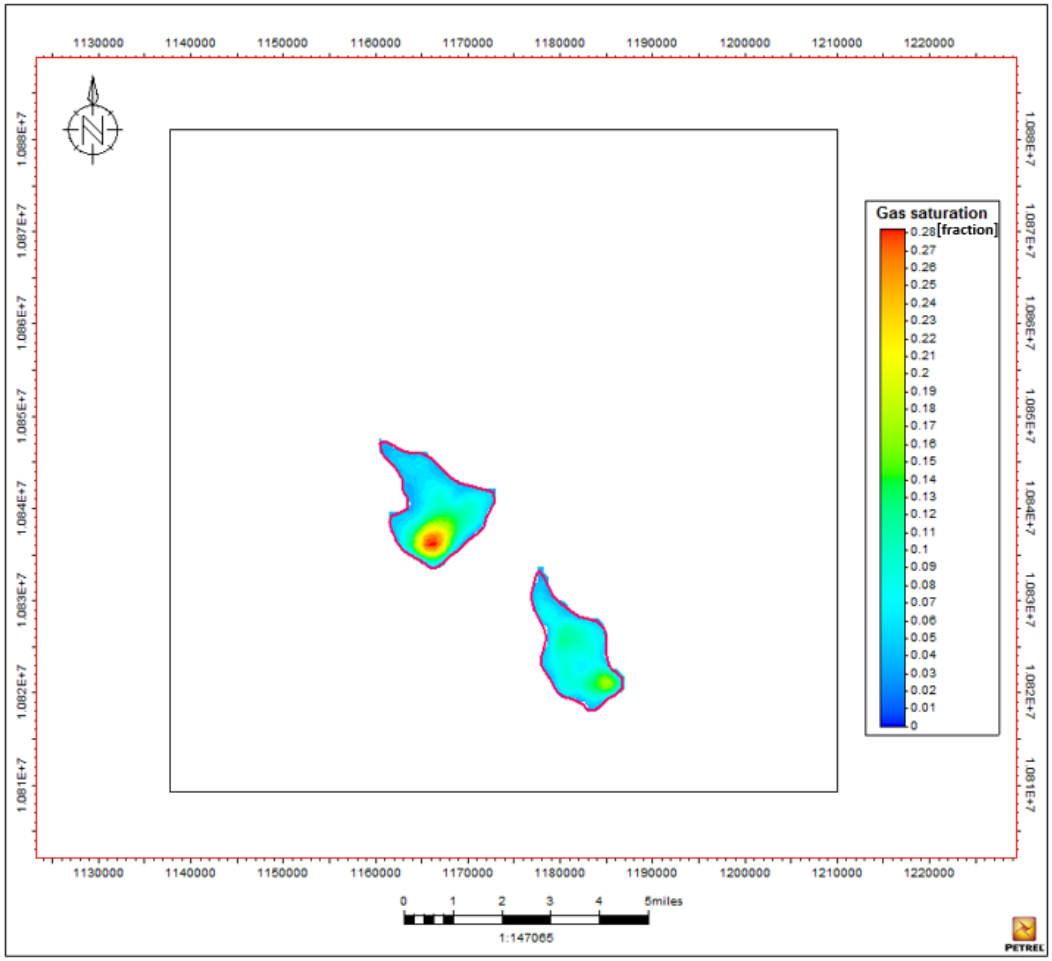


Figure AoR-261: Pore volume weighted CO_2 saturation map distribution after 13.7 million MT CO_2 injection in Hackberry.



Figure AoR-262: Frio CO_2 plume extents predicted by the simulation model - 5 years (green), 10 years (orange), 15 years (purple), 20 years (blue), 50 year after shut-in (pink), 120 year after shut-in (red).

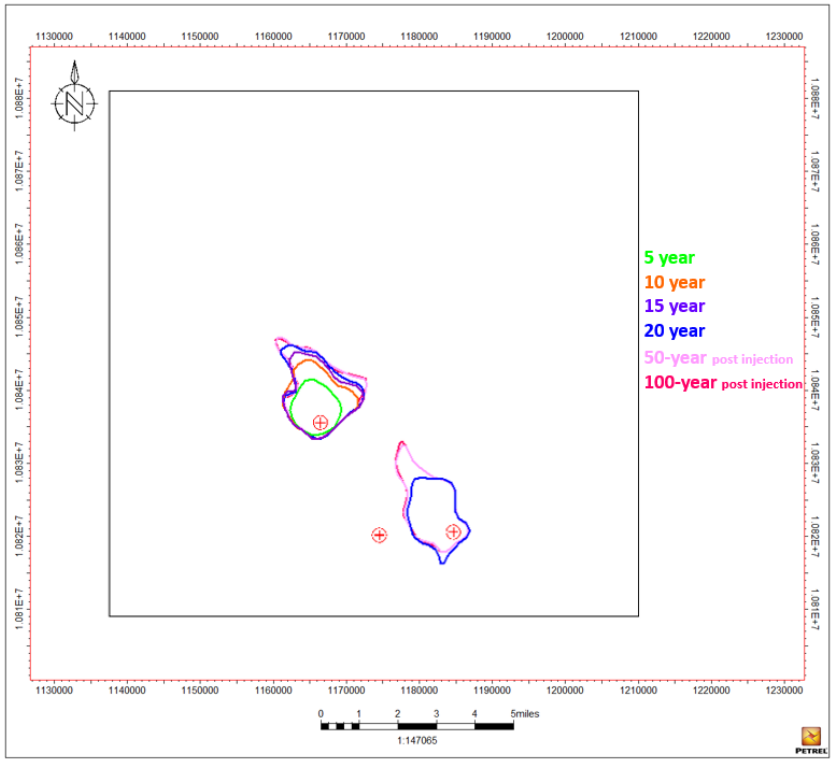


Figure AoR-263: Hackberry CO_2 plume extents predicted by the simulation model - 5 year (green), 10 year (orange), 15 year (purple), 20 year (blue), 50 year after shut-in (pink), 100 year after shut-in (red).

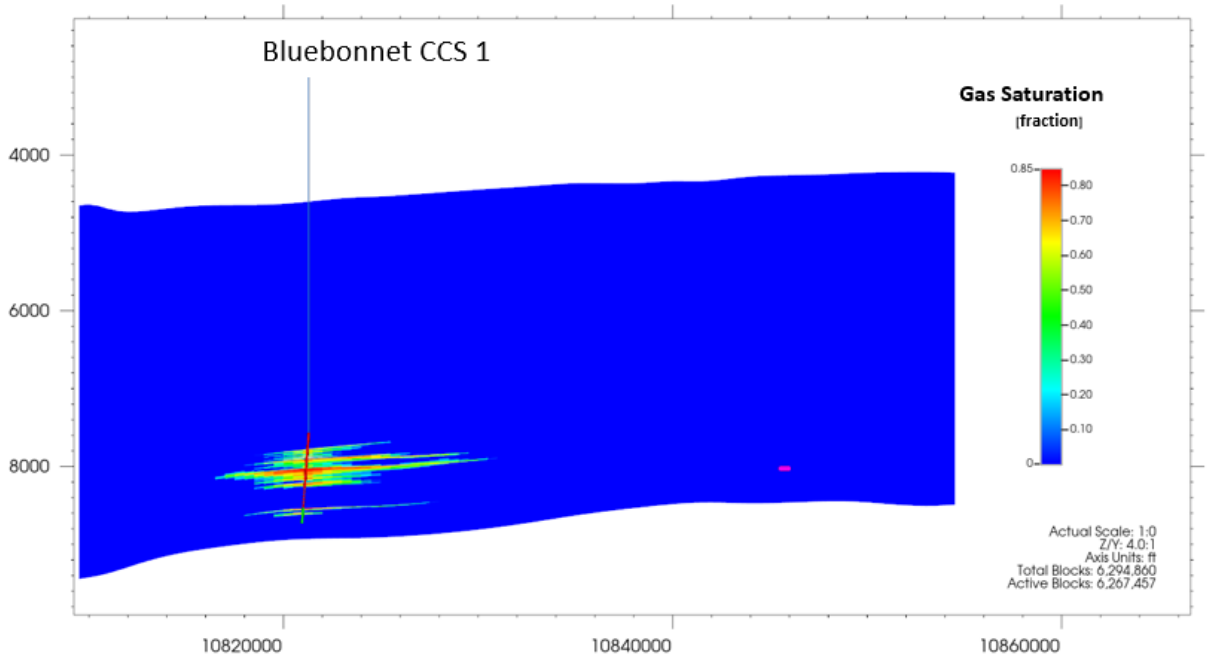


Figure AoR-264: North-south cross section through well CCS 1 showing simulated CO_2 saturation at year 20 after injection starts.

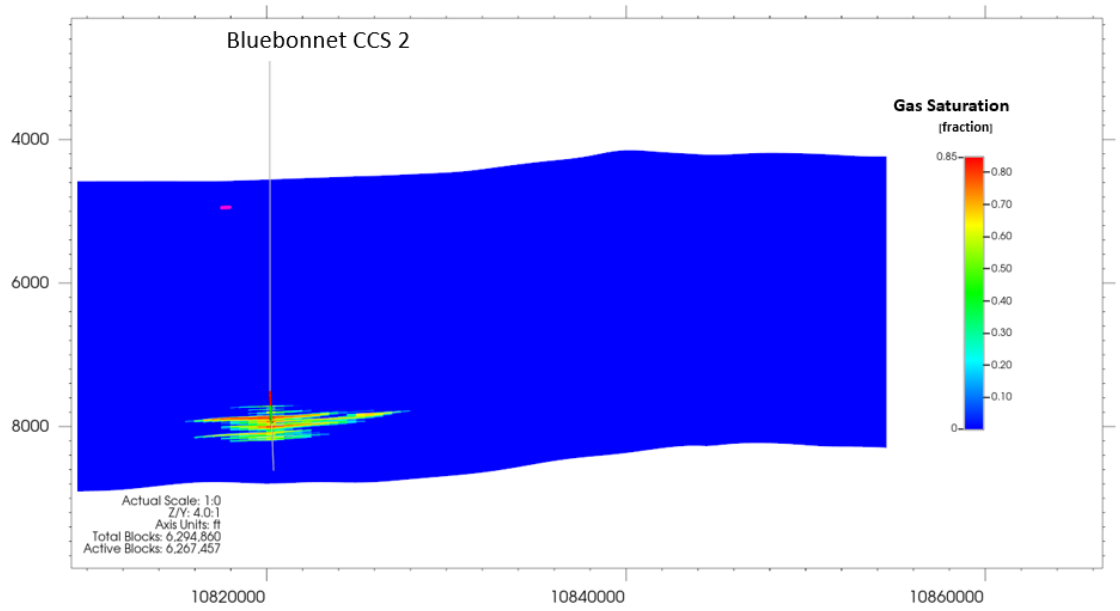


Figure AoR-265: North-south cross section through well CCS 2 showing simulated CO_2 saturation at year 20 after injection starts.

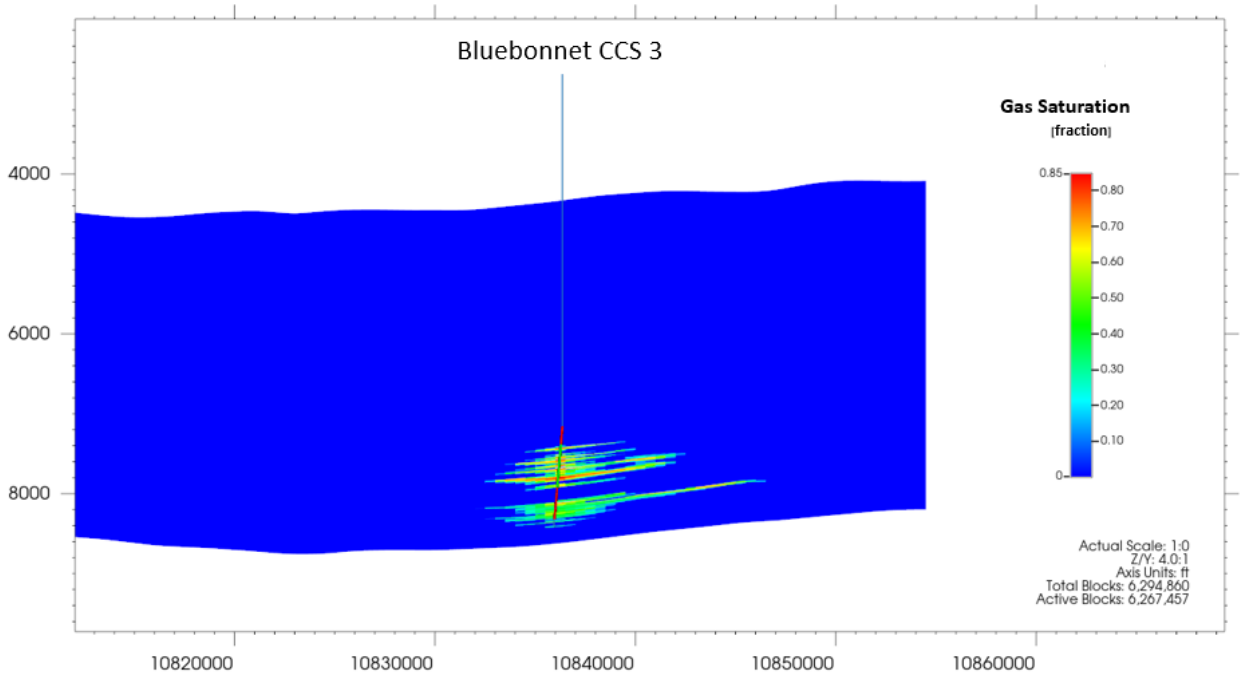


Figure AoR-266: North-south cross section through well CCS 3 showing simulated CO_2 saturation at year 20 after injection starts.

4.11 Geochemical Modeling

4.11.1 Background and Literature Review

The main reactive-transport pathways in clastic reservoirs for CCS projects are (1) carbonic gas dissolution in in-situ brine, (2) carbonic acid increase, (3) mineral dissolution and precipitation that could result, and (4) overall net CO_2 mineralization for long-term storage. The dissolution or precipitation of the mineral can alter the porosity and permeability of the reservoir rock, affecting sequestration storage capacity, well injectivity, and integrity of confining zones. For the Bluebonnet Sequestration Project, quartz is the dominant mineral in the Frio and Hackberry Injection Zones and a mixture of quartz and clays are the dominate minerals in the Anahuac Confining Zone. Oxy's operational experience in CO_2 injection in subsurface reservoirs has shown that the effect of reactive transport on reservoir performance is usually insignificant. However, a geochemical and reactive-transport literature review was performed to evaluate the lessons learned from previous projects and current on-site available data.

In October 2004, a CO_2 pilot was conducted by GCCC in the Frio sand formation, same as one of the target injection zones for this project. This pilot was later named Frio-I. A small quantity was injected, about 1,600 tons of CO_2, for about 10 days. Various post-injection measurements were acquired to evaluate the short-term geochemical impact such as injection and monitoring wells for fluid sampling, saturation logs, and pressure data collection. Publications showed attempts to interpret the observed results in relation to reactive-transport modeling and the main findings are described in the following paragraphs.

Hovorka et al. (2006) provided a comprehensive overview of the Frio-I pilot program executed with details on the experimental design, reservoir characterization, well construction, injection and hydrogeological testing, seismic profiling, well logging, tracer tests, fluid sampling, modeling, and monitoring. Regarding geochemical analysis, fluid sampling, modeling, and monitoring are the most important. With fluid sampling, the authors reported issues in degassing effect and temperature changes that might have affected the data significantly. In-situ brine showed high TDS content, close to 93,000 mg/L, and low CO_2 concentration. After a few hours of injection, the collected fluid samples from monitoring showed a sharp drop in pH, from about 6.7 to 5.8, and a large increase in CO_2, bicarbonate, iron, calcium, and magnesium concentrations. After the injection period, the pH showed a tendency to increase steadily. Modeling showed acceptable agreement between observed data and simulations.

Kharaka et al. (2006) corroborated with the findings provided by Hovorka et al. (2006), showing the same results for the fluid sampling and monitoring in Frio-I. However, the authors provided a more detailed interpretation of the results. The publication showed that pH is the most sensitive parameter to track CO_2 content in the subsurface. In addition, the authors mentioned that the pH modeled previously to the injection was about 3.0, much lower than observed. This larger pH was

attributed to the presence of carbonate minerals that would result in a buffer effect as expected from the CO_2-carbonate system equilibria, already pointed out by Hovorka et al. (2003) in a preliminary study.

Hovorka et al. (2009) reported the results of continued monitoring of the Frio-I pilot conducted in in 2004, and a second injection test, called Frio-II, conducted in 2006. The later test had the same experimental design as the Frio-I trial conducted in 2004. Similar geochemical results were obtained with the Frio-II pilot showing a sharp pH drop at CO_2 breakthrough and increase in alkalinity, iron, calcium, and magnesium. The authors discuss the limitations of modeling the increase on iron content since it was not predicted initially. It was attributed to three different causes: (1) combinations of various reactions, (2) dissolution of Fe-oxyhydroxides, and (3) corrosion of the tubing in contact with acidic environment. Kharaka et al. (2009) developed a more detailed chemical modeling on the possible dissolution of iron-bearing minerals using complex redox reactions. The authors concluded that no leakage was observed from the Frio sand to the Anahuac shale formation. Both publications could not determine the origin of increased iron content at that time, keeping the corrosion from pipes a reasonable possibility.

Xu et al. (2010) conducted a reactive-transport modeling study of the Frio-I pilot. The authors included detailed information on the kinetic parameters used such as reaction rates, reactive surface area, and activation energy for each selected reaction. The authors discussed the importance initial assessment with batch equilibrium reactions and combination of multiphase flow with geochemical reactions for improved results accuracy. Besides primary minerals that were present initially in the formation (e.g., quartz, kaolinite, calcite, illite, and oligoclase), the authors modeled secondary minerals that could precipitate from complex chemical reactions, such as magnesite, dolomite, smectite, and others. The publication had a special focus on modeling the unusual iron concentration increase in the monitoring wells, assuming that pipe corrosion is not a determinant factor. The long-term simulation results indicate rapid carbonate mineral dissolution followed by its reprecipitation, including kaolinite and illite precipitation. Other secondary minerals were considered stable.

The data results and interpretations provided by the authors in the previous publications is not meant to be an exact behavior expected for the current project, but a reference on which type of chemical reactions could occur when CO_2 contacts the Frio formation. It is important to highlight that the brine and mineral composition provided in the publications differ from the ones collected at the Encanto 01 stratigraphic well for this project. One of the most probable reasons is that the pilot tests were conducted closer to a salt dome, while the current study is performed for a different region and depth of the reservoir. In addition to literature and Oxy's experience in CO_2 injection at various formations, the Bluebonnet technical team conducted geochemical equilibrium and reactive-transport simulation modeling to evaluate site specific data acquired from the Encanto 01 stratigraphic well. The study is separated in two steps: first batch reactions with detailed

geochemical equilibrium simulations performed followed by reactive-transport, and the multiphase flow simulations are then conducted using the full-field model.

4.11.2 Geochemical Equilibrium Simulations

Geochemical equilibrium modeling was conducted using PHREEQC Simulator Version 3 (Parkhurst and Appelo, 2013), a program developed by the USGS, that includes a robust thermodynamic database for aqueous, mineral, and gaseous interactions (Krupka et al. 2010). PHREEQC includes the Peng-Robinson equation of state to improve the solubility calculation of gas at high pressures, which is important to consider when studying CO_2 sequestration in saline aquifers.

The objective of this work is to identify primary chemical reactions (solid and aqueous phase) to be included into the reactive-transport simulations and provide initial assessment of the CO_2 compatibility with rocks and fluids in the Frio and Hackberry Injection Zones and Anahuac Confining Zone. The modeling includes brines speciation, geochemical baseline prior injection, and CO_2 interaction with reservoir brine and minerals.

Table AoR-38 shows the brine composition used in geochemical simulations (See Appendix A: Stratigraphic Well Summary for full geochemical results). At the time of geochemical and reactive-transport modeling, the Miocene formation brine was used as reference because the Frio Injection Zone water analysis was only available closer to the application submission date. A comparison between each water composition is performed at the end of the Geochemical Modeling section. Other ions were not considered in modeling because their concentration is negligible or below detection limits. Trace metals (i.e., arsenic, mercury, and lead) have insignificant concentration values and were not tracked during modeling.

Table AoR-39 summarizes the rock mineralogy used during geochemical equilibrium runs for the Frio Injection Zone, Hackberry Injection Zone, and Anahuac Confining Zone. The normalized values were obtained from the average of the five closest depth samples reported in the XRD data (See Appendix A: Stratigraphic Well Summary for XRD results).

Table AoR-38: Water composition and brine properties for geochemical and reactive-transport simulations.

Ion (mg/L)		Brine sample
Calcium	Ca^{2+}	5,783
Magnesium	Mg^{2+}	1,809
Potassium	K^{+}	122.5
Sodium	Na^{+}	35,675
Barium	Ba^{2+}	164.6
Iron	Fe^{2+}	4.4
Silicon	Si^{4+}	11.2

Ion (mg/L)		Brine sample
Strontium	Sr^{2+}	242.8
Bicarbonate (alkalinity)	HCO_3^-	83.6
Chloride	Cl^-	72,040
Sulfate	SO_4^{2-}	<2.0
Borate	$B(OH)_4^-$	4.5
Bromide	Br^-	85.1
pH (lab)		7.4
Total dissolved solids		114,470

Table AoR-39: Rock mineralogy retrieved from average XRD data for the five closest core samples.

Mineral (mol %)	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
Quartz	77.7	82.1	70.1
K-Feldspar	2.9	1.6	1.3
Plagioclase	4.7	2.7	2.1
Anatase	0.1	0.1	0.4
Calcite	2.1	2.7	4.2
Siderite	0.0	0.1	0.5
Pyrite	0.8	0.9	1.6
Smectite	8.7	6.9	12.0
Illite	2.4	1.9	4.5
Kaolinite	0.4	0.9	3.0
Chlorite	0.1	0.2	0.3

Although some chemical reactions are known to be time-dependent, the equilibrium assumption was selected at this stage because it is the most conservative approach. In this method, minerals can dissolve or precipitate instantaneously and achieve the final stage of interaction with other solid phase and aqueous species. Thus, this process can simulate the long-term exposure and mimic permanent CO_2 storage. For reactive-transport simulations, kinetics approach is assumed and further details are presented in Section 12.3.

Geochemical simulations were performed to equilibrate each sample with its respective reservoir mineralogy and in-situ CO_2 concentration to simulate conditions prior to the injection period and establish the baseline condition. Table AoR-40 shows the results for the Hackberry Injection Zone, Frio Injection Zone, and Anahuac Confining Zone, respectively. For equilibrium simulations, a rock with porosity equal to 10% is assumed. The initial CO_2 concentration in the reservoir was

retrieved using flashed gas composition and fugacity was calculated using PHREEQC based on Peng-Robinson model at reservoir pressure and temperature. The fugacity calculated is -0.07 atm.

The PHREEQC database file was selected as the thermodynamic data and activity coefficient model for equilibrium and reactive-transport simulations. Although Pitzer virial model is known to be more suitable for brines with high ionic strength (above 1.0 M) at certain conditions, the extended Debye-Hückel equation is determined to be suitable for the brines analyzed for this site. Besides the ion-size parameters, the extended terms based on ionic strength have been fit for the main ions in chloride-dominated waters such as calcium, magnesium, sulfate, potassium, and carbonate species (Truesdell and Jones 1974). In addition, the Pitzer approach has limited parametrization for iron and aluminum species as pointed out by Krupka et al. (2010). These aqueous components are very important for brines in equilibrium with clay-type minerals because they modify the ions' activity, having a critical impact on mineral solubility product (Appelo and Postma 2005).

Secondary mineral phases were included in the simulation even though they are not present in measured XRD data (i.e., dolomite, hematite, goethite, anhydrite, gypsum, k-mica, barite, strontianite, celestite, and magnesite) to evaluate their precipitation tendency. In addition, plagioclase is assumed to be anorthite phase. Since the reservoir is assumed to be initially in equilibrium, saturation indexes were slightly adjusted (from database equilibrium constant value, Ksp) to avoid large mineral dissolution or precipitation and honor measured brine composition and XRD data. Positive and negative saturation index numbers (ΔSI) indicate changes to more supersaturated or undersaturated conditions in relation to a mineral, respectively.

Table AoR-40: Adjusted saturation indexes and pH for the Hackberry and Frio Injection Zones and the Anahuac Confining Zones prior to CO_2 injection (baseline reservoir condition).

Mineral ΔSI (adjusted)	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
Quartz	0	0	0
K-Feldspar	-1.5	-1.6	-1.5
Plagioclase	-2.0	-2.0	-0.65
Anatase	0	0	0
Calcite	1.0	0.085	2.0
Siderite	0	0	0
Pyrite	0	0	0
Smectite	0	0	-1.0
Illite	1.0	1.0	-0.06
Kaolinite	5.0	4.97	5.0
Chlorite	0	0	0
pH	7.0	6.9	7.1

Quartz, siderite, smectite, dolomite, hematite, goethite, anhydrite, gypsum, k-mica, barite, strontianite, celestite, and magnesite were considered stable phases without precipitation tendencies. As expected, all brine samples are in close equilibrium conditions with their respective minerals and initial CO_2 in the reservoir. Kaolinite is the phase that requires the largest changes in saturation index caused by negligible concentrations of aluminum in the formation brine. Quartz and smectite are the most stable phases initially present in the reservoir.

The calculated pH from simulations is noticeable smaller in comparison to the laboratory-measured values, due to the degassing effect from depressurization when the samples are open to atmospheric conditions for analysis. Even with the quickest analysis in the laboratory after the chamber has been open, CO_2 is quickly released to atmosphere, decreasing its amount dissolved in water and shifting the equilibria to more a basic condition (Appelo and Postma, 2005, page 14). In addition, the calculated pH has similar values as reported by other publications (Kharaka et al. 2009 and Xu et al. 2010)

The same shift in saturation index found in previous simulations was used to equilibrate the brines and minerals with fully saturated CO_2 gas to represent the injection period. CO_2 fugacity was assumed to be 1.78 for 100% CO_2 gas at reservoir temperature and pressure. Table AoR-41 shows the mineral stability tendency after equilibration for each sample in the Hackberry Injection Zone, Frio Injection Zone, and Anahuac Confining Zone. Delta minerals (Δ Mineral) represent the qualitative analysis of the solid to dissolve, precipitate, or be stable based on the mineral mass reduction, increase, or maintenance after equilibration with CO_2, respectively.

Precipitation or dissolution was negligible or not observed for quartz, siderite, smectite, hematite, goethite, dolomite, anhydrite, gypsum, k-mica, barite, strontianite, celestite, and magnesite. Quartz and smectite are the most stable phases initially present in the reservoir. For the Hackberry and Frio Injection Zones, simulation results show plagioclase (anorthite) dissolution as larger amounts of CO_2 dissolved in water shifts the equilibria to a more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite. However, the dynamics in the reservoir during injection are more complicated as reactions are time-dependent and calcite might dissolve first at a lower pH, then reprecipitate at later times (equilibrium conditions). The Anahuac Confining Zone shows smaller reactivity as clay content increases.

The Anahuac Confining Zone shows lowest reactivity in comparison to the other formations, corroborating the assumption that CO_2 will not affect the Anahuac Confining Zone integrity as pointed out by Kharaka et al. (2009). It is important to highlight that further precipitation might provide a healing effect to microfracture that might have been formed due pressure increase (i.e., mechanical deformation), as proposed by Hangx et al. (2009), improving the Anahuac Confining Zone long-term integrity.

Table AoR-41: Mineral stability tendency, pH, and overall molar change for Hackberry and Frio Injection and Anahuac Confining Zones in equilibrium with fully saturated CO_2.

Δ Mineral	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
K-Feldspar	stable	stable	minor dissolution
Plagioclase	dissolve	dissolve	dissolve
Calcite	precipitate	precipitate	precipitate
Illite	stable	minor dissolution	stable
Kaolinite	precipitate	precipitate	precipitate
pH	5.4	5.2	5.4
Overall change (mol)	4.3%	2.4%	1.4%

Thus, the most important mineral reactions with CO_2 identified for the injection are the solubility equilibria for calcite, plagioclase, and kaolinite. Minor changes are observed for quartz, k-feldspar, and illite, and are included in the reactive-transport simulations since previous publications pointed out their possible reactivity when using the kinetics approach.

4.11.3 Reactive-Transport Simulations

The reactive-transport simulations were conducted using CMG-GEM. The objective of this section is to evaluate geochemical impact on reservoir storage capacity, possible injectivity modification, and long-term trapping mechanisms. The same activity model is used (extended Debye-Hückel equation) to be consistent with geochemical equilibrium simulations. Quartz, calcite, plagioclase (anorthite), kaolinite, k-feldspar, and illite are the minerals considered during the dynamic simulations. The minerals present in the XRD results as nonreactive are not included in the simulations (e.g. anatase, pyrite, and chlorite) and are lumped with the quartz phase. Figure AoR-267 illustrates a vertical cross section for different mineralogy regions based on each formation depth. Table AoR-42 shows the mineral volume fraction based on the normalized average XRD data for each region.

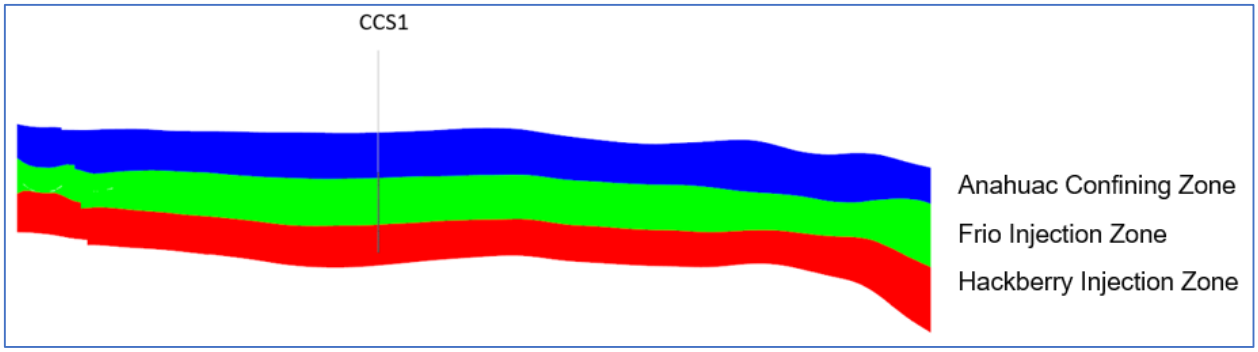


Figure AoR-267: Cross section schematic of the simulation model showing the different lithology zones based on lithology logs.

Table AoR-42: Mineral volume fraction used to initialize the reactive-transport simulation model per lithology region.

Mineral (volume %)	Frio Injection Zone	Hackberry Injection Zone	Anahuac Confining Zone
Quartz	0.75	0.8	0.75
Calcite	0.02	0.02	0.03
Kaolinite	0.01	0.02	0.05
Plagioclase	0.09	0.06	0.04
K-feldspar	0.06	0.04	0.02
Illite	0.07	0.06	0.11

Quartz, calcite, kaolinite, plagioclase, and illite mineral solubility reactions were simulated using the kinetics approach based on the transition state theory (TST). K-feldspar solubility reaction is simulated using the equilibrium approach because its reaction is assumed to be much faster than the fluid residence time in the reservoir compared to other minerals (Appelo and Postma, 2005, page 119). Activation energies, TST reaction rate constants, and equilibrium constants are retrieved from the literature (Palandri and Kharaka, 2004, Krupka et al. 2010, Jia et al. 2021, and Zhang et al. 2019). The mineral reactive surface area is considered one of the largest uncertainties for modeling kinetic reactions. Actual reactivity area values are assumed to be significantly lower in comparison to the conventional methods of surface area measurements (e.g., BET adsorption method) because certain pores are not expected to contact the injected fluid due to preferential flow paths in the porous media. For the current simulations, reactive surface area values were retrieved from Jia et al. (2021) and Zhang et al. (2019) and were multiplied by 0.01 as recommended by Xu et al. (2010). For practical purposes, the final state of mineral stability is insensitive to the reactive surface area (hundreds of years after injection). However, as reactive surface area value increases, the simulation will reach equilibrium faster. Thus, it allows the interpretation of how long-term CO_2 storage affects reservoir properties within a reasonable computational time.

The effect of mineral dissolution and precipitation on porosity is also included to evaluate its impact on reservoir storage capacity. The model is a direct correlation of the amount of mineral change (dissolution or precipitation) with the solid volume using its respective mineral mass, molar weight, and density to calculate the new void volume (porosity) over time. The effect of porosity changes in rock permeability is included to evaluate the effect of possible modification in well injectivity. Simulations use the modified Kozeny-Carman model (Equation 7), where the porosity exponent r is assumed to be equal to 3.0 and where k, Ø, and r represent permeability, porosity, and porosity exponent, respectively.

$$\frac{k_n}{k_k} = \left(\frac{\text{Ø}_\text{n}}{\text{Ø}_\text{k}}\right)^r \left(\frac{1-\text{Ø}_\text{k}}{1-\text{Ø}_\text{n}}\right)^2 \qquad \text{Equation 7}$$

The subscripts n and k represent the properties changes in previous and current timesteps, respectively.

The reservoir is initialized with the brine composition as shown in Table AoR-38. In total, 12 aqueous species were initialized in reservoir connate water and allowed to flow with aqueous phase in the reactive-transport simulations. The aqueous species modeled are $H_4SiO_4^0$, H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2^0, HCO_3^-, OH^-, CO_3^{2-}, and $CaOH^+$. The selection of the aqueous complexes was based on the simulation results from geochemical equilibrium runs (PHREEQC) with minerals and CO_2. Aqueous species that were not originally in the complete water analysis were assumed to have trace concentrations. The reservoir is allowed to equilibrate prior to the simulation start.

Figures AoR-268 and AoR-269 illustrate the aggregate of all layers in a top map view of the maximum pH and HCO_3- concentration values at end of the injection period (Year 20). Note that the pH values (initially equal to 7.5 and at saturated CO_2 equal to 5.8) are in similar ranges with the values simulated using PHREEQC (Tables 13 and 14). Bicarbonate concentration increases significantly, almost 21 times more than initial conditions, which aligns with results reported in previous publications and simulations using PHREEQC.

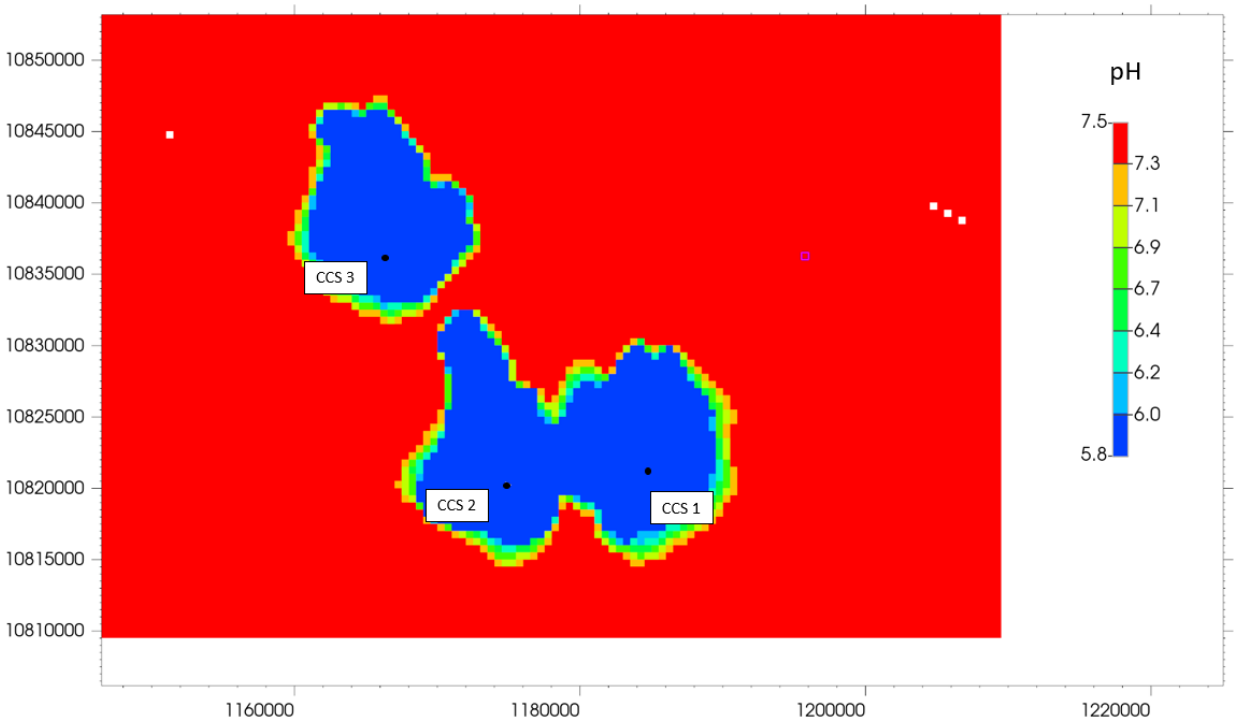


Figure AoR-268: pH map view of the layer with the largest CO_2 extension at the end of injection period (20 years).

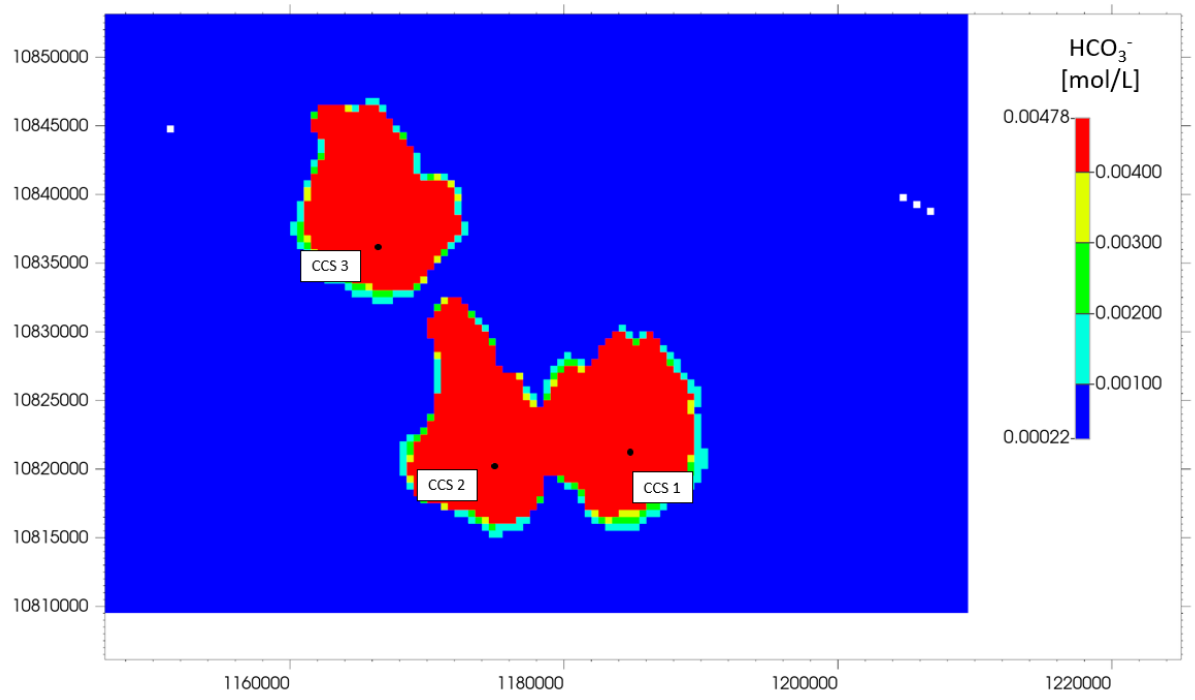


Figure AoR-269: HCO_3^- concentration (mol/L) map view of the layer with the largest CO_2 extension at the end of injection period (20 years).

Figures AoR-270 and AoR-271 show the reservoir mineral volume change for calcite, anorthite, kaolinite, illite, k-feldspar, and quartz at 100 and 1,000 years after injection time finished, respectively. For the injection period, a quick dissolution of calcite and anorthite with precipitation of kaolinite is observed. The initial dissolution of calcite is expected and has been reported in several previous publications (Xu et al. 2010, Hovorka et al. 2009). For longer periods of time, anorthite continues to dissolve while calcite starts to reprecipitate. Most of the total decrease in mineral volume is due to a solid change that occurs after the injection period. Kaolinite precipitates due to the release of aluminum from the anorthite mineral. Calcite starts to precipitate due to excess of calcium and bicarbonate as a result from the CO_2 injection (mineralization). Figure AoR-214 shows the increase of bicarbonate ion in relation to their initial value.

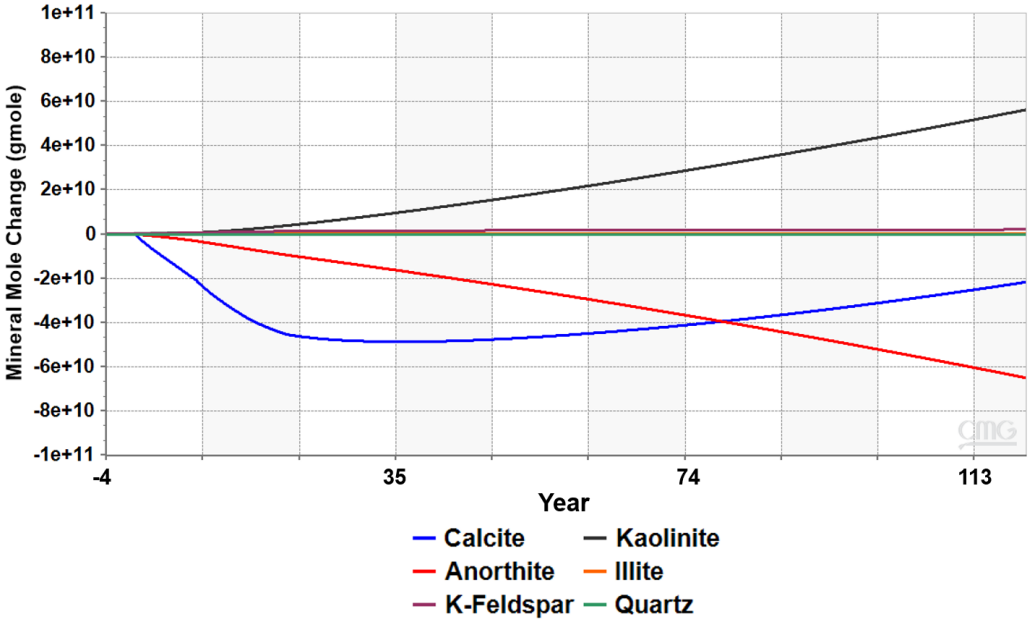


Figure AoR-270: Molar change over time in the reservoir for calcite, kaolinite, anorthite, illite, k-feldspar, and quartz for 100 years after the injection period.

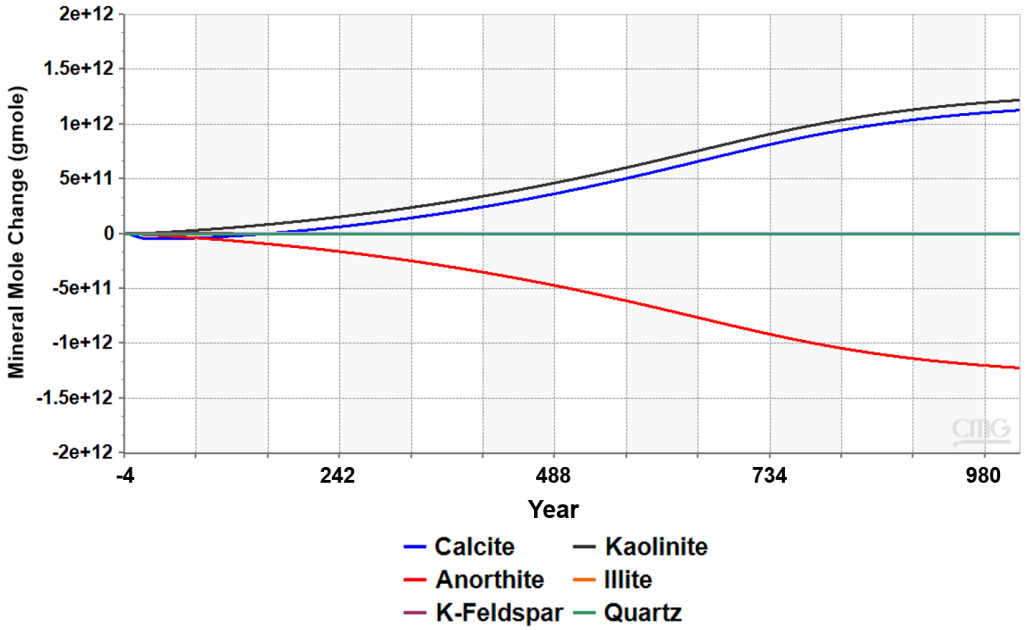


Figure AoR-271: Molar change over time in the reservoir for calcite, kaolinite, anorthite, illite, k-feldspar, and quartz up to 1,000 years after end of injection period.

Figures AoR-272, AoR-273, and AoR-274 show the aggregate of all layers in a top map view of the maximum porosity change due to dissolution/precipitation at end of the injection period as well as 100 and 1,000 years after the end of the injection period. Figures AoR-275, AoR-276, and AoR-277 show the north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation at end of the injection period as well as 100 and 1,000 years after the end of the injection period. Negative and positive values represent the amount of increase and decrease from the initial porosity, respectively. Porosity slightly increased with a maximum of 0.5% for the Frio and Hackberry Injection Zones from the start of injection up to about 100 years after injection. Porosity remained unchanged for the Anahuac Confining Zone. Since the Anahuac Confining Zone has a very low permeability and small fluid mobility, no significant changes are observed in the current model, confirming its integrity. The long-term decrease in porosity is due to calcite and kaolinite precipitation. A maximum decrease in porosity was about 3.5% in the region where the CO_2 plume contacted the reservoir. This represents less than 1% change in pore volume within the simulation domain.

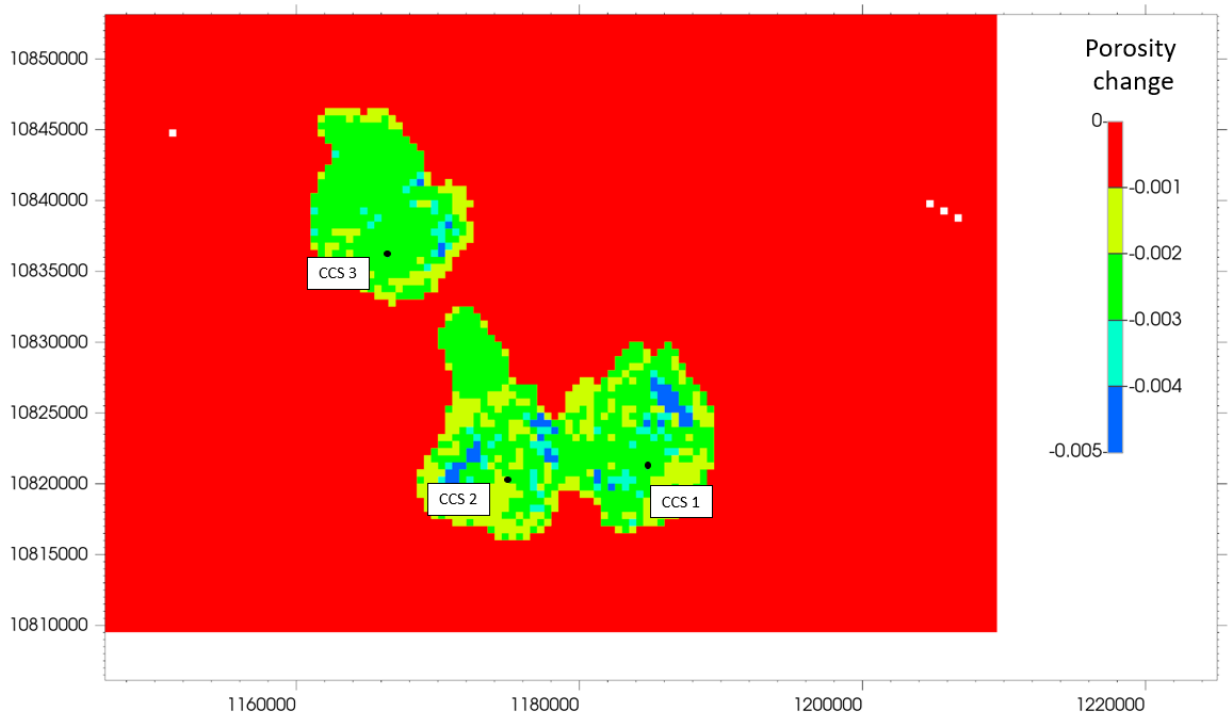


Figure AoR-272: Porosity change aggregate of all layers in a top map view at the end of injection period (20 years).

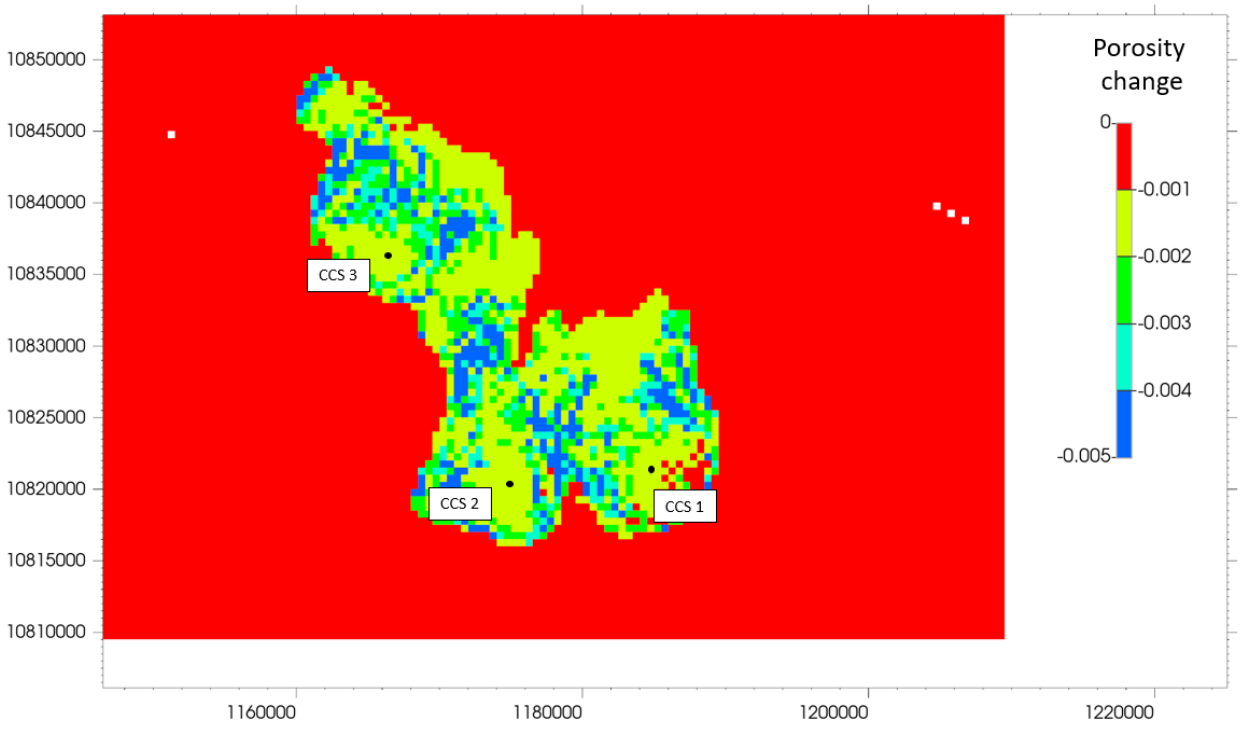


Figure AoR-273: Porosity change aggregate of all layers in a top map view after 100 years post injection.

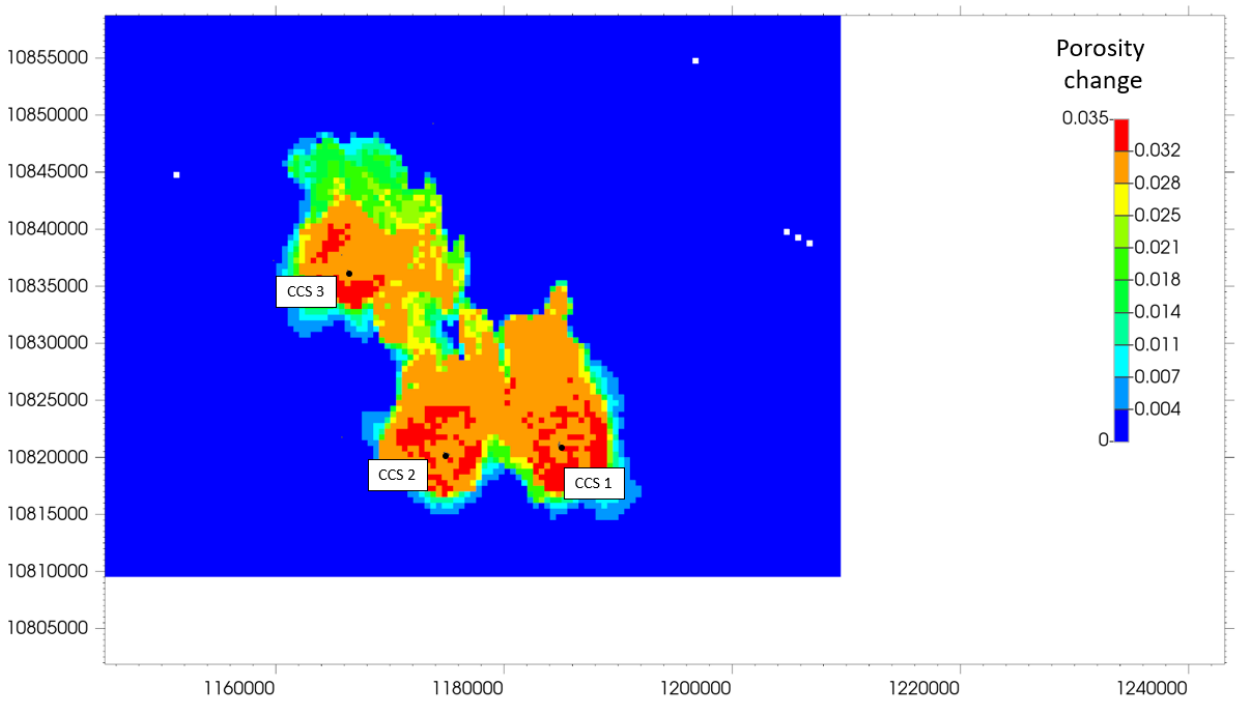


Figure AoR-274: Porosity change aggregate of all layers in a top map view after 1000 years post injection.

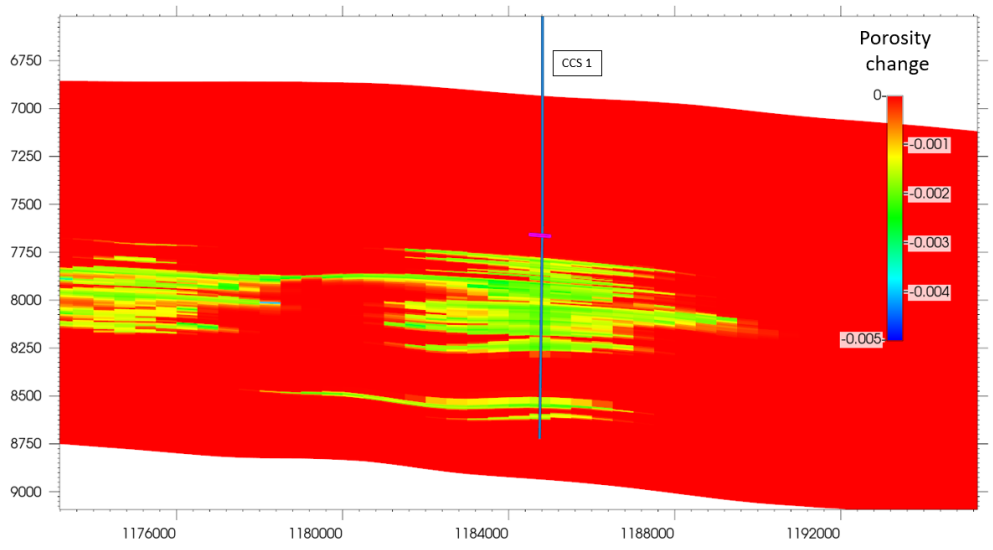


Figure AoR-275: The north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation at the end of the injection period (20 years). The highlighted grid block in pink the interface between the Frio Injection Zone and the Anahuac Confining Zone.

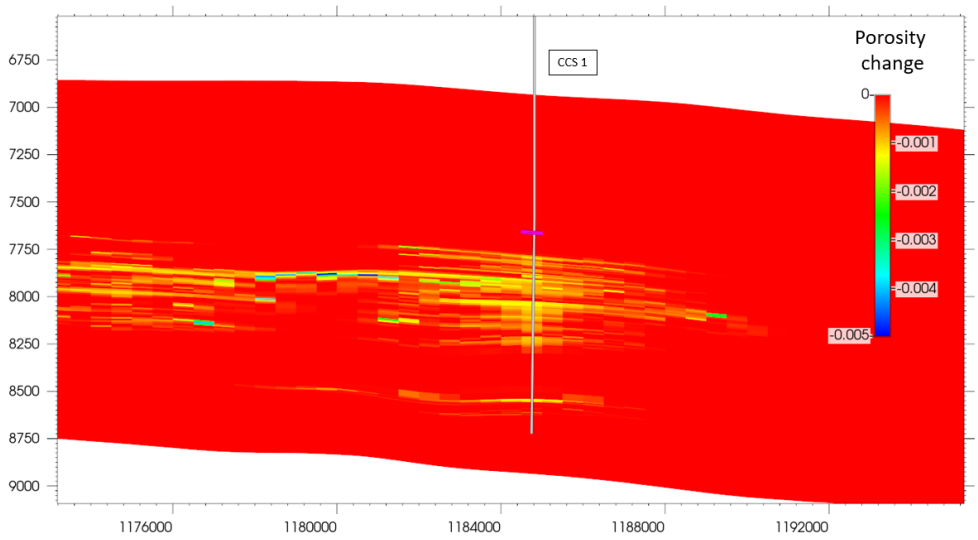


Figure AoR-276: The north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation after 100 years post injection. The highlighted grid block in pink shows the interface between the Frio Injection Zone and the Anahuac Confining Zone.

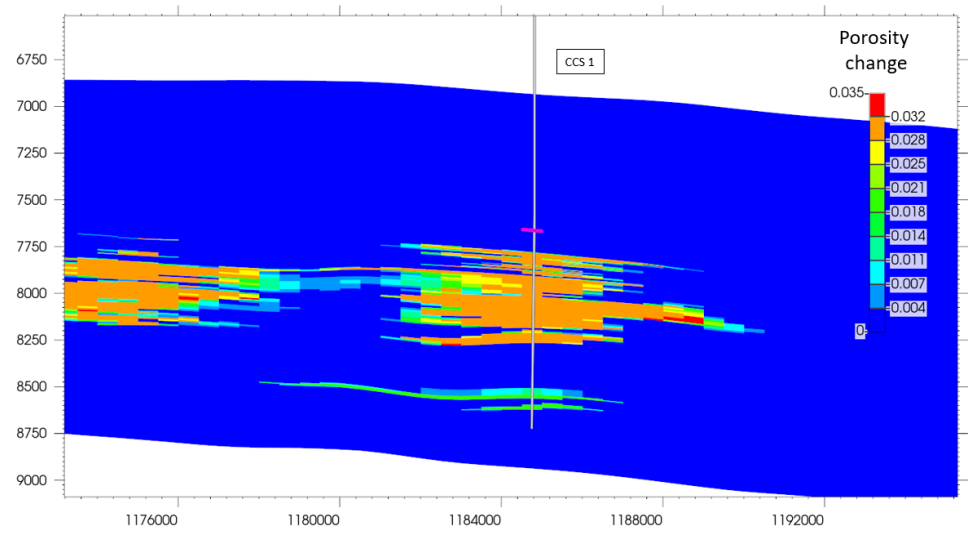


Figure AoR-277: The north-south cross section view at the Bluebonnet CCS 1 well location of the porosity change due dissolution/precipitation after 1000 years post injection. The highlighted grid block in pink shows the interface between the Frio Injection Zone and the Anahuac Confining Zone.

Figures AoR-278 and AoR-279 show the aggregate of all layers in a top map view of the maximum CO_2 saturation to compare compositional simulation (without geochemistry) and reactive-transport simulation (with geochemistry) at the end of the injection period and 100 years after the injection period. The compositional simulation shows a larger plume in relation to the reactive-

transport runs. The reason the reactive-transport simulations have smaller CO_2 plumes, even with smaller pore volume, is due to part of the CO_2 being transferred from the super-critical state to two additional conditions that are not modeled using conventional runs: conversion in aqueous ions (e.g., HCO_3^-) and precipitation as solid phase (e.g., kaolinite, calcite). Thus, the compositional simulations (without geochemistry) provide the most conservative approach to estimate the CO_2 plume (largest extent).

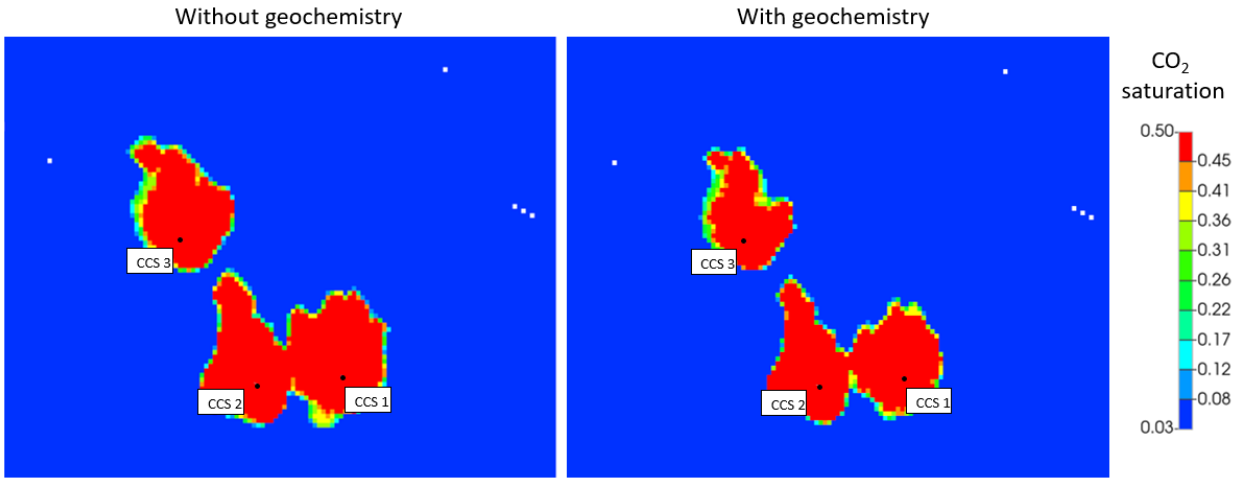


Figure AoR-278: The aggregate of all layers in a top map view of the maximum CO_2 saturation to compare simulations without and with geochemistry capability turned on at the end of injection period (20 years).

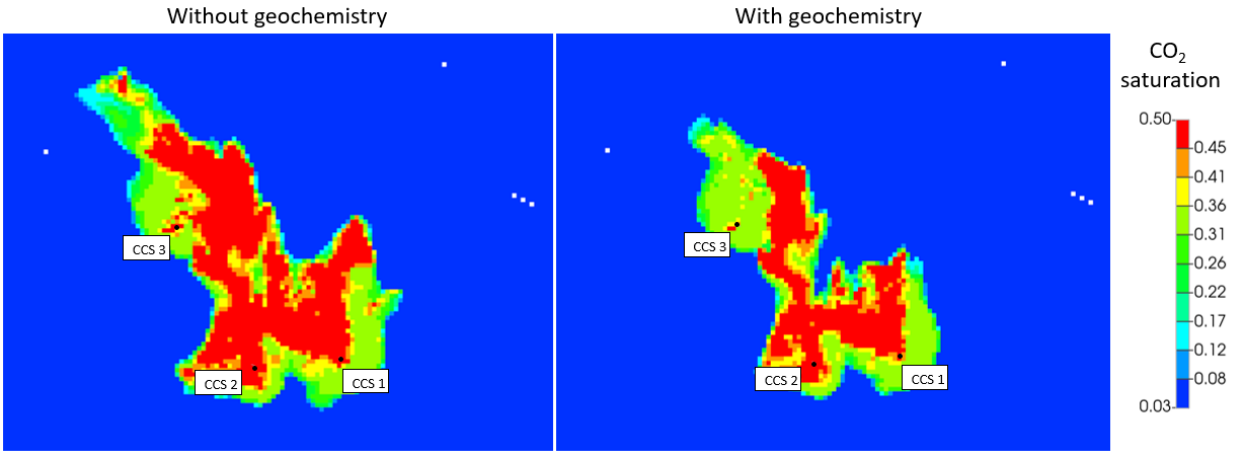


Figure AoR-279: The aggregate of all layers in a top map view of the maximum CO_2 saturation to compare simulations without and with geochemistry capability turned on at 100 years after the end of injection period (2147).

Figures AoR-280 and AoR-281 show the injection comparison for the simulations with and without geochemistry capability turned on, including the gas injection rate and injectivity index

over time. The injectivity index is calculated by the gas injection rate divided by the difference between the bottomhole pressure and reservoir pressure (Inj. Index = $q_{gas}/\Delta P$). The differences in injection rate and injectivity index are negligible as both curves collapse in top of each other. Thus, the increase in porosity has insignificant impact on wells injectivity.

An additional risk to the injectivity is the possible halite ($NaCl_{(s)}$) precipitation because of high-saline water vaporization formed by continuous dry CO_2 injection that could induce pore blockage. Muller et al. (2008) conducted laboratory experiments and simulation modeling to quantity halite precipitation in 22 wt.% reservoir brine in similar reservoir conditions of this project. The authors showed that in just a few hours, freshwater pre-flush would be sufficient to mitigate the salt precipitation. Since the Injection Zone contains brine that is identified to have high TDS of about 110,000 ppm, a pre-flush of fresh water for a brief period will be performed to avoid this potential risk.

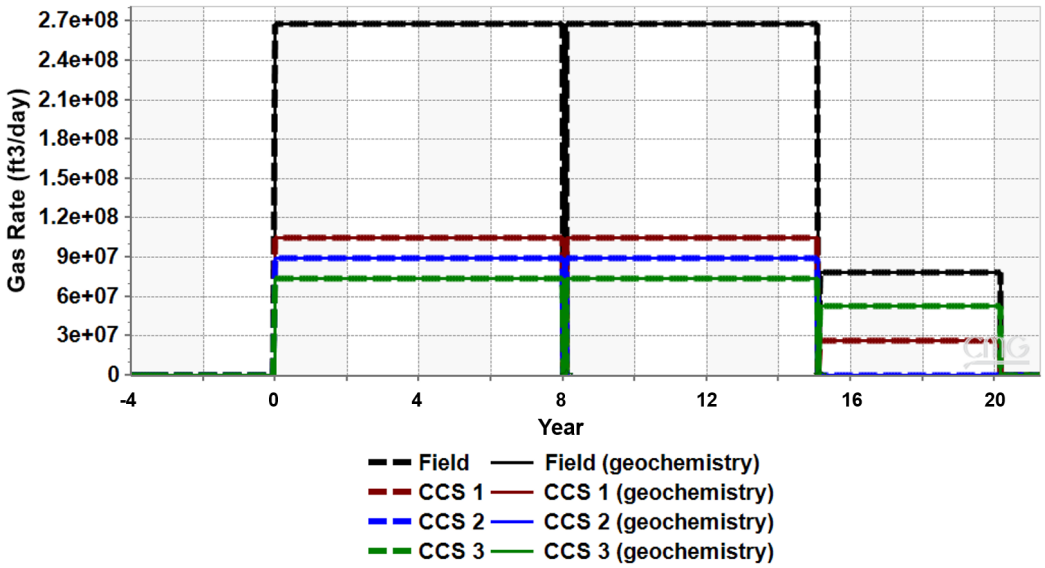


Figure AoR-280: Injection gas rate over time comparison for the simulations with and without geochemistry capability turned on, including total field rate (black line), Bluebonnet CCS1 (red line), Bluebonnet CCS 2 (blue line) and Bluebonnet CCS 3 (green line).

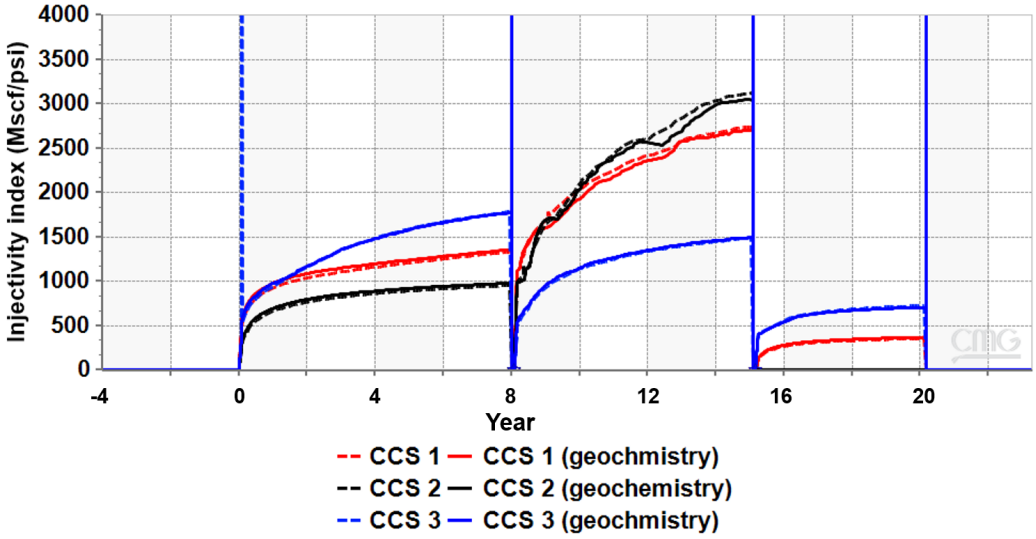


Figure AoR-281: Injectivity index over time comparison for the simulations with and without geochemistry capability turned on, including Bluebonnet CCS1 (red line), Bluebonnet CCS 2 (black line) and Bluebonnet CCS 3 (blue line).

Figures AoR-282 and AoR-283 show the CO_2 trapping mechanisms (total stored, aqueous ions, dissolved in water, mineralization, super-critical, and trapped in residual phase) comparison with geochemistry capability turned on up to 100 and 1,000 years after the injection period. Results indicate that the main trapping mechanisms during the injection period are the super-critical phase as mobile and trapped CO_2. Note that the mineral CO_2 storage is negative during initial period due to calcite dissolution and release of HCO_3^-. Then, CO_2 is mainly trapped in residual phase up to about 600 years after injection, when the mineralization starts to be the main storage mechanism due to carbonate precipitation. Super-critical mobile CO_2 show a steady decrease over time, reaching close to zero at longer periods.

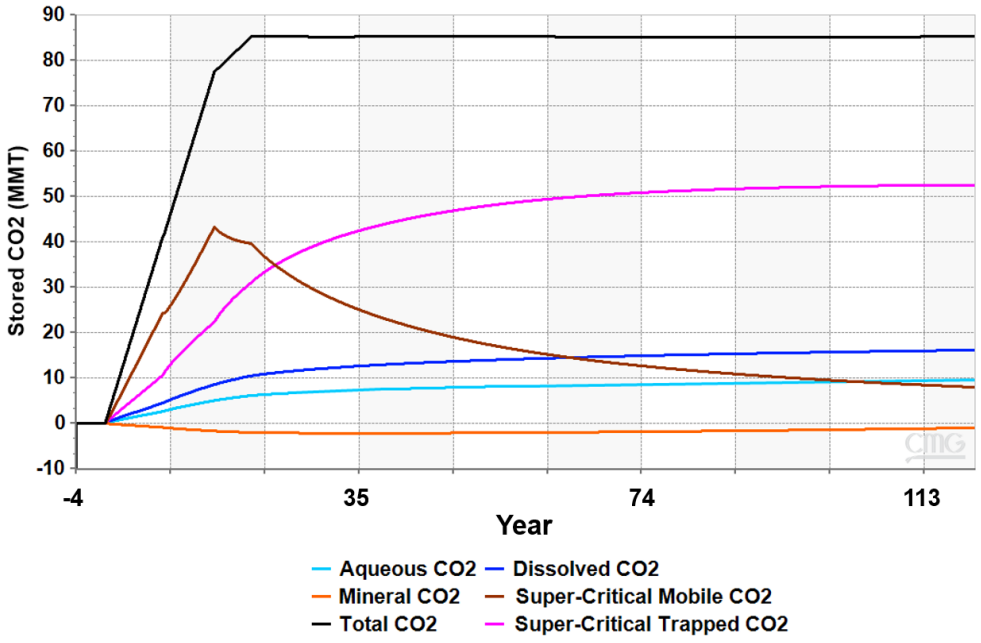


Figure AoR-282: Total, aqueous ions, dissolved, mineral, super-critical and trapped stored CO_2 for simulations with geochemistry turned on up to 100 years after injection period.

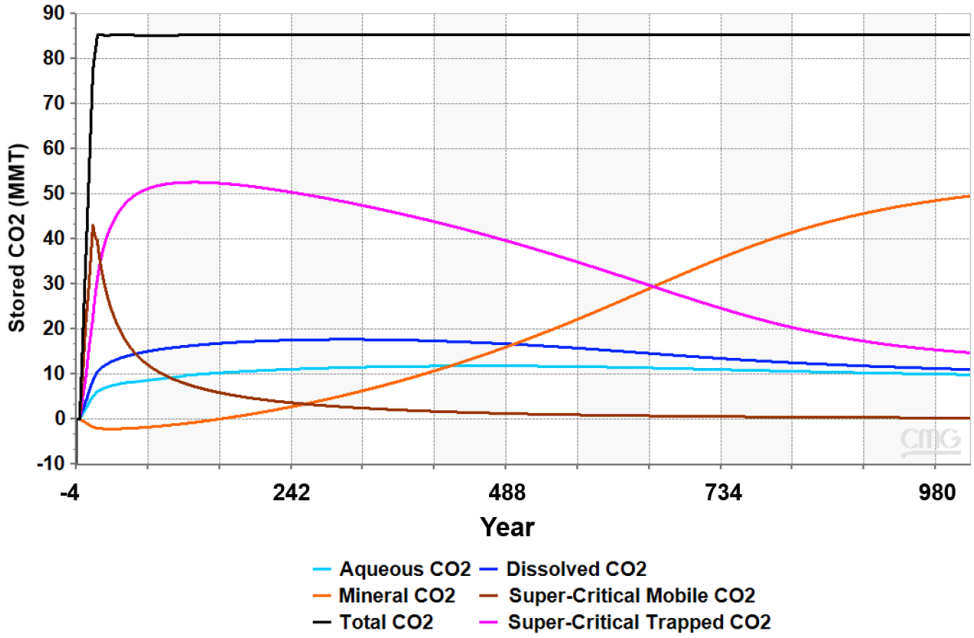


Figure AoR-283: Total, aqueous ions, dissolved, mineral, super-critical and trapped stored CO_2 for simulations with geochemistry turned on up to 1,000 years after injection period.

4.11.4 Miocene and Frio formation water composition comparison

As mentioned previously, the Miocene formation brine was used as reference because the Frio Injection Zone water analysis was available only closer to the application submission date. The brine composition comparison is shown in Table AoR-43. In general, the concentration values have similar proportion for both brines since the Miocene and Frio formations have analogous mineral composition (as shown in XRD data). Since the baseline brines are equilibrated for long periods of time with its respective reservoir rock, it is reasonable that both brines have similar composition. The salinity values (TDS) are within the same range corroborated by the large values for Na^+ and Cl^- ions. The largest difference observed is for Mg^{2+} and Ca^{2+} ion concentrations within the Frio Injection Zone brine being much lower values than the Miocene formation. However, the Mg^{2+}/Ca^{2+} ratios are similar (approximately 0.3 and 0.2 for each formation, respectively). This means that the expected precipitation of calcite mineral, as shown in the modeling as the main long-term trapping mechanism, is still expected to occur in the Frio Injection Zone since the solubility product for magnesium-type mineral is proportionally lower than calcium-type mineral. In addition, calcium concentration is still at least one order of magnitude larger than the other cations.

Table AoR-43: Water composition and brine properties for geochemical and reactive-transport simulations.

Ion (mg/L)		Miocene formation brine sample	Frio Injection Zone brine sample
Calcium	Ca^{2+}	5,783	2,418.4
Magnesium	Mg^{2+}	1,809	544.4

Ion (mg/L)		Miocene formation brine sample	Frio Injection Zone brine sample
Potassium	K^+	122.5	220.1
Sodium	Na^+	35,675	39,449.1
Barium	Ba^{2+}	164.6	63.2
Iron	Fe^{2+}	4.4	37.3
Silicon	Si^{4+}	11.2	7.1
Strontium	Sr^{2+}	242.8	205.4
Bicarbonate (alkalinity)	HCO_3^-	83.6	33.5
Chloride	Cl^-	72,040	64,421.1
Sulfate	SO_4^{2-}	<2.0	10.4
Borate	$B(OH)_4^-$	4.5	34.0
Bromide	Br^-	85.1	150.7
pH (lab)		7.4	6.31
Total dissolved solids		114,470	127,080

5.0 Miocene Storage Complex Model

5.1 Simulation Model Background – Miocene Storage Complex

5.1.1 Geocellular Model Introduction

The static geocellular model was constructed using Schlumberger's Petrel (v.2023.7.0) 3D geostatistical modeling software, which is a comprehensive, integrated subsurface platform containing data interpretation tools for well correlation, mapping, and structural and property modeling. Application of this software has been demonstrated in reliable subsurface models containing faults, horizons, and properties, which are then used to estimate volumetrics and are further passed on to dynamic reservoir simulation.

5.1.2 Model Grid Creation and Revisions

Figure AoR-284 summarizes various grids involved in static to dynamic model. The original Frio model under Oligocene storage complex section 4 encompasses the Lower Miocene section with a grid of 500 × 500 × 14 ft; however, a more refined grid was adopted for the detailed modeling of the Miocene storage complex using a grid size of 250 × 250 × 14 ft to capture lateral complexities of fluvial facies in the Miocene section. All static model properties were populated into this refined stair-step Miocene Static model grid.

Some artifacts were observed in cells near faults when static stair-step grid was exported from Petrel to CMG. To eliminate those grid anomalies in the Petrel stair-step grid, a new un-faulted "Simple" Petrel grid was built in order to transfer to the Dynamic model. All static properties were upscaled from the static stair-step grid into it. This new un-faulted grid does not attain the exact same I, J, K index as the static stair-step grid used in the property modeling.

Furthermore, to optimize the computational time for the dynamic model in CMG software, zones below Anahuac_CZ were excluded along with cropping northern boundary area cells of Miocene static stair-step grid. Later, faults were added as "Petrel simulation faults" into the dynamic grid to simplify fault handling in the CMG model.

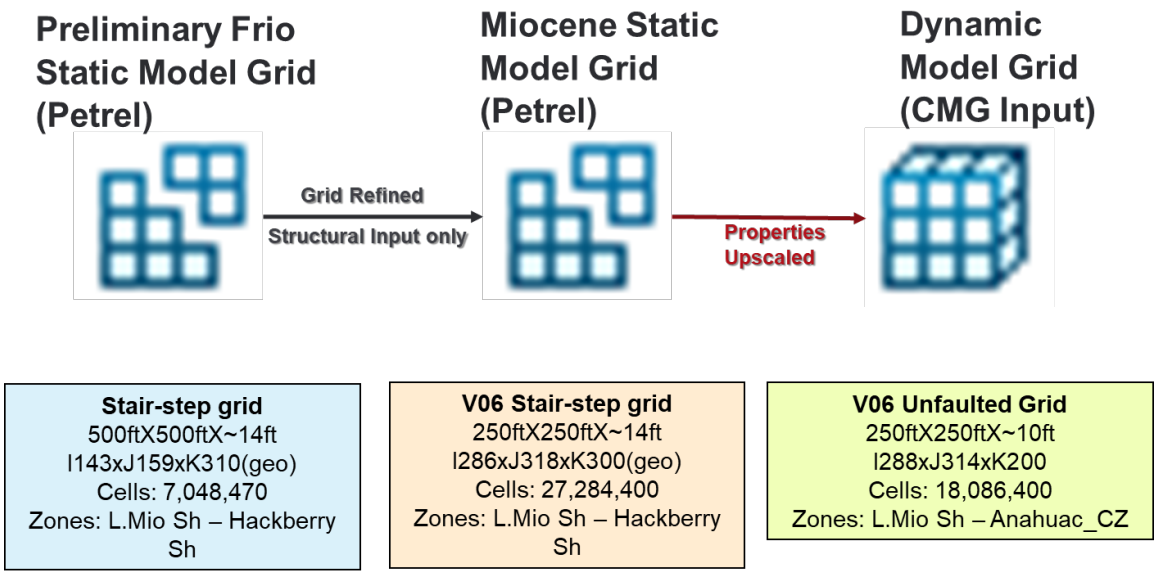


Figure AoR-284: Static and Dynamic Model Grids.

5.1.3 Dynamic Simulation Model Introduction

The dynamic simulation models were created using the GEM (2024.10) reservoir simulator with the Greenhouse Gas (GHG) module from Computer Modeling Group Ltd. (CMG). GEM is a commercially available, compositional, and finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. GEM has also been used to model several carbon capture and storage projects. The Greenhouse Gas (GHG) module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, and enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions, including temperature ranges between 53.6°F (12°C) and 302°F (150°C) and pressures up to 16,000 psi (110 MPa). Details of this method can be found in Collins et al. (1992, CMG GEM Manual), Thomas and Thurnau (1983, CMG GEM Manual), and Nghiem and Li (1989, CMG GEM Manual).

Additional assumptions governing the phase interactions throughout the simulations are as follows:

- CO_2-rich phase (gas) density is obtained by using the Peng-Robinson equation of state. The model was accurately tuned and modified as described below (Peng and Robinson, 1976, CMG GEM Manual).
- CO_2 dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey, 1996, CMG GEM Manual). Here, CO_2 dissolution in brine was only modeled in reactive-transport simulations.

- Brine density is specified at a reference pressure of 14.7psi. Brine viscosity is calculated using the Kestin (1981) correlation.
- Chemical equilibria among H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2, H_4SiO_4, HCO^-, OH^-, CO_3^{2-}, $CaOH^+$, $MgHCO_3^+$, and $AlOH^{+2}$ ions in the aqueous phase are modeled with 13 equilibrium constants. Aqueous complexes were selected based on simulation results from geochemical equilibrium runs (Geochemist's Workbench) with minerals and CO_2. Solid phases included calcite, kaolinite, anorthite, dolomite, illite, K-feldspar, and quartz minerals. Reactions among these minerals and ions are modeled with chemical reactions and reaction coefficients from the Lawrence Livermore National Laboratory database (Thibeau, 2007), which were also used in a simulation study by Nghiem et al. (2004).
- The CO_2 gas viscosity is calculated per the methods described by Pedersen et al. (1984).
- The gas density is obtained by using a cubic equation of state developed by Peng and Robinson (1976) described by Equation 1:

$$P = \frac{RT}{(v - b_{mix})} - \frac{a_{mix}}{(v^2 + 2vb_{mix} - b_{mix}^2)} \quad \text{..... (Equation 1)}$$

Where:
v is the molar volume;
P is the pressure;
T is the temperature in Kelvin;
R is the universal gas constant;
a_{mix} and b_{mix} are mixture-specific functions of temperature and composition, calculated from the critical properties and acentric factors of the components.

The CMG WinProp software has a built-in library for the properties CO_2 and CH_4 based on Reid et al. (1977, CMG GEM Manual). No changes were made to the library components.

The transition between liquid and gaseous CO_2 can lead to rapid density changes in the gas phase. The simulator uses a narrow transition interval between the liquid and gaseous density to represent the two-phase CO_2 region.

Because the compression/pumping facility controls the CO_2 delivery temperature to the injection well to keep it between 60°F and 120°F, the temperature of the injectant will be comparable to the reservoir formation temperature at the injection interval. Therefore, the simulations were based on isothermal reservoir conditions at 127.4°F.

With respect to the timestep selection, the software algorithm optimizes the timestep duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the timestep size ranged from 0.001 to 30 days. In all cases, the maximum solution change over a timestep was monitored and compared with the specified target. Convergence was achieved once the model reaches the maximum tolerance where small changes of the temperature and pressure calculation results occur on successive iterations. New timesteps were chosen so that the predicted solution change is less than a specified target.

Considerations for computational efficiency of numerical simulations of geochemical reactive transport models resulted in modeling only aqueous constituents and minerals that are highly reactive or comprise significant proportions of their respective liquid- and solid-phases. Model

results suggested negligible mineralization (sequestering) of injected CO_2 during injection periods. However, upon cessation of CO_2 injection, mineral precipitation (e.g., calcite) occurs over long timescales (100s of years). Preliminary model results suggest geochemical reactions play a key role in permanent (mineralized) sequestration of injected CO_2 as well as reduction in potential stray CO_2 migration due to porosity loss from mineralization in the reservoir.

5.2 Model Domain Miocene Storage Complex

The Lower Miocene static geological model was created using Schlumberger Petrel (v.2023.7.0, Build Date: April 2, 2024, Build Number I11012) and is based on the collaborative interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired from public databases, published literature, in-house studies, and in-house 3D seismic data.

Figure AoR-285 displays 166 wells total used for the construction of the stratigraphic framework. The geological subzones were created from horizons based on a combination of well log correlations in combination with the 3D seismic horizon interpretation. The internal layer subdivisions of the zones were based on the interpretation of 153 digital well logs, which were used to determine the thickness of each subzone. Detailed information for the wells used in model construction as well as the wells used in the petrophysical analysis is tabulated in Appendix A.

The static geological model includes several major geological zones from top to bottom: Lower Miocene Confining Zone, Lower Miocene Dissipation Zone, Lower Miocene Injection Zone, and Anahuac Confining Zone. The model extent covers approximately 14 miles by 15 miles. The top and bottom confining zones are the Lower Miocene Shale (LMIO_Shale_CZ) and Anahuac Shale (Anahuac_CZ), respectively.

The 3D geomodel was constructed with an orthogonal, north-south oriented grid, with grid cell dimensions of 250 ft. x 250 ft. Vertical grid layer thickness varies slightly by zone, but the average layer thickness is 10 ft. The final 3D geological model is represented by a 288 x 314 x 200 grid in a Cartesian system for a total of 18.1 million cells (includes from LMIO_Shale_CZ to Anahuac_CZ).

Model horizons were first interpreted from available well log datasets, including depth-registered image logs and digital log data on 153 wells shown on Figure AoR-285. These horizons were then combined with interpreted 3D seismic data to provide more accurate control of horizon construction where log data may be sparse.

The methodology applied to the static geomodel was to model the large-scale features, followed by modeling progressively smaller and more uncertain features. The first step applied to the Bluebonnet geomodel was to establish a conceptual structural and depositional model as well as its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, net sand, and other attributes within each layer. Next, petrophysical values were distributed for each zone using a cell-based methodology. Detailed discussion of model property development is presented below.

Figure AoR-285 displays locations of the proposed Bluebonnet injection wells, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, targeting the Lower Miocene Injection Zone. Also, shown is the location of the stratigraphic test well Encanto 01, which was drilled to gather key reservoir and performance data in support for this application.

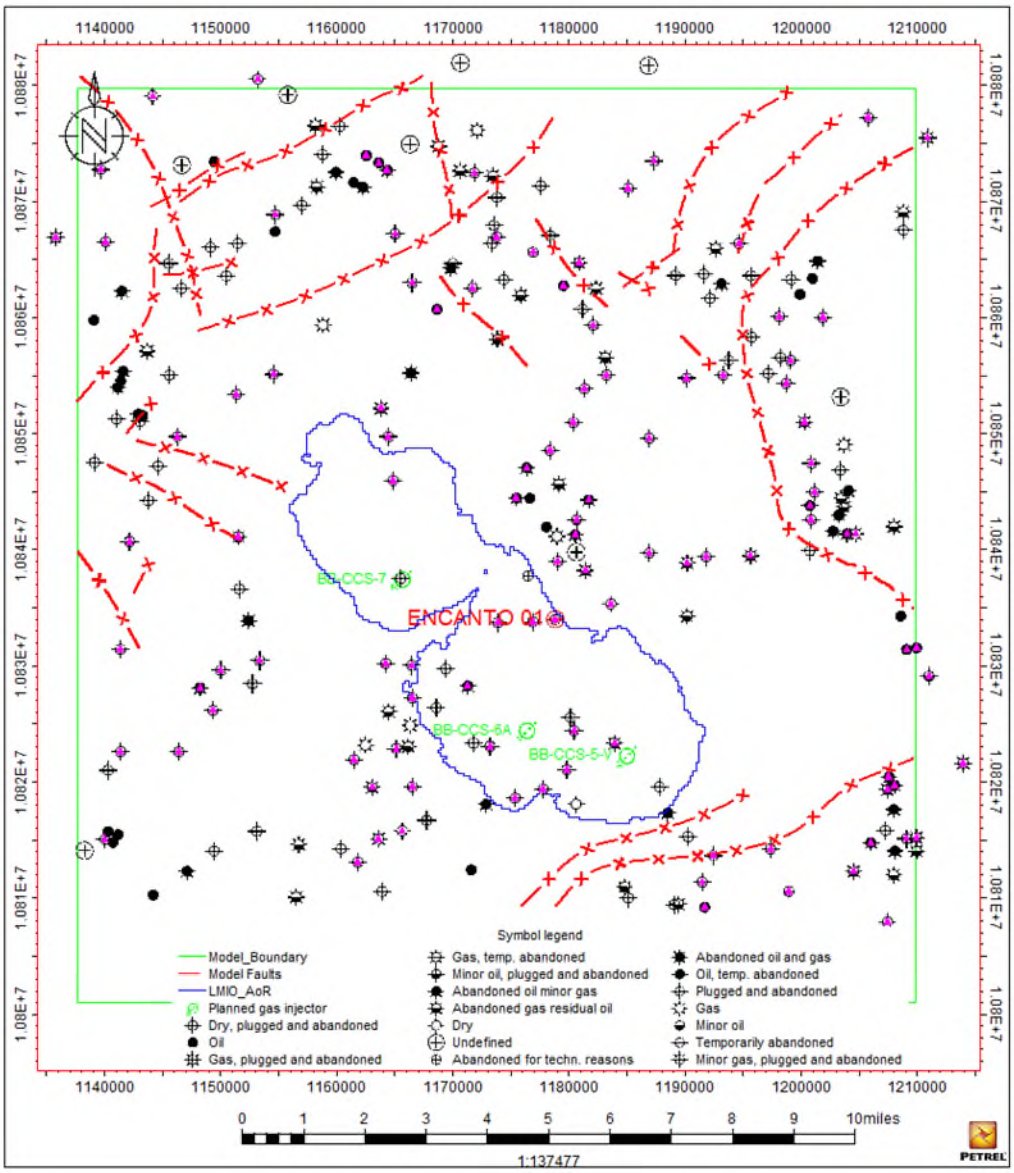


Figure AoR-285: Map of Bluebonnet AOI showing available well control, with purple over post points indicating the 166 wells with stratigraphic tops used in construction of the stratigraphic framework horizons. Encanto 01 is labeled in red and the proposed injection wells are labeled in green

The geomodel domain coordinate reference system is summarized in Table AoR-44.

Table AoR-44: Summary of geomodel domain coordinate system

Coordinate System	NAD 27/BLM zone 15 N (ftUS)		
Horizontal Datum	NAD1927		
Coordinate System Units	ftUS		
Zone	BLM 15 N		
FIPSZONE	N/A	**ADSZONE**	N/A
Coordinate of X min	1,137,700	**Coordinate of X max**	1,209,700
Coordinate of Y min	10,801,000	**Coordinate of Y max**	10,879,500
Elevation of top of domain	-3,100	**Elevation of bottom of domain**	-7,800

5.2.1 Well Data Description

A total of 158 wells with digital curves and petrophysical analysis were used for Facies interpretation (for more detail on facies interpretation see Appendix A). Several of these wells were outside the geomodel AOI, thick blue squared in Figure AoR-286. Fourteen wells with PEF were the base wells for facies analysis and were used to distribute the facies to the rest 144 wells. From the 158 wells with porosity, permeability, and facies, 102 were used in the geo-model, these wells fall inside the AOI.

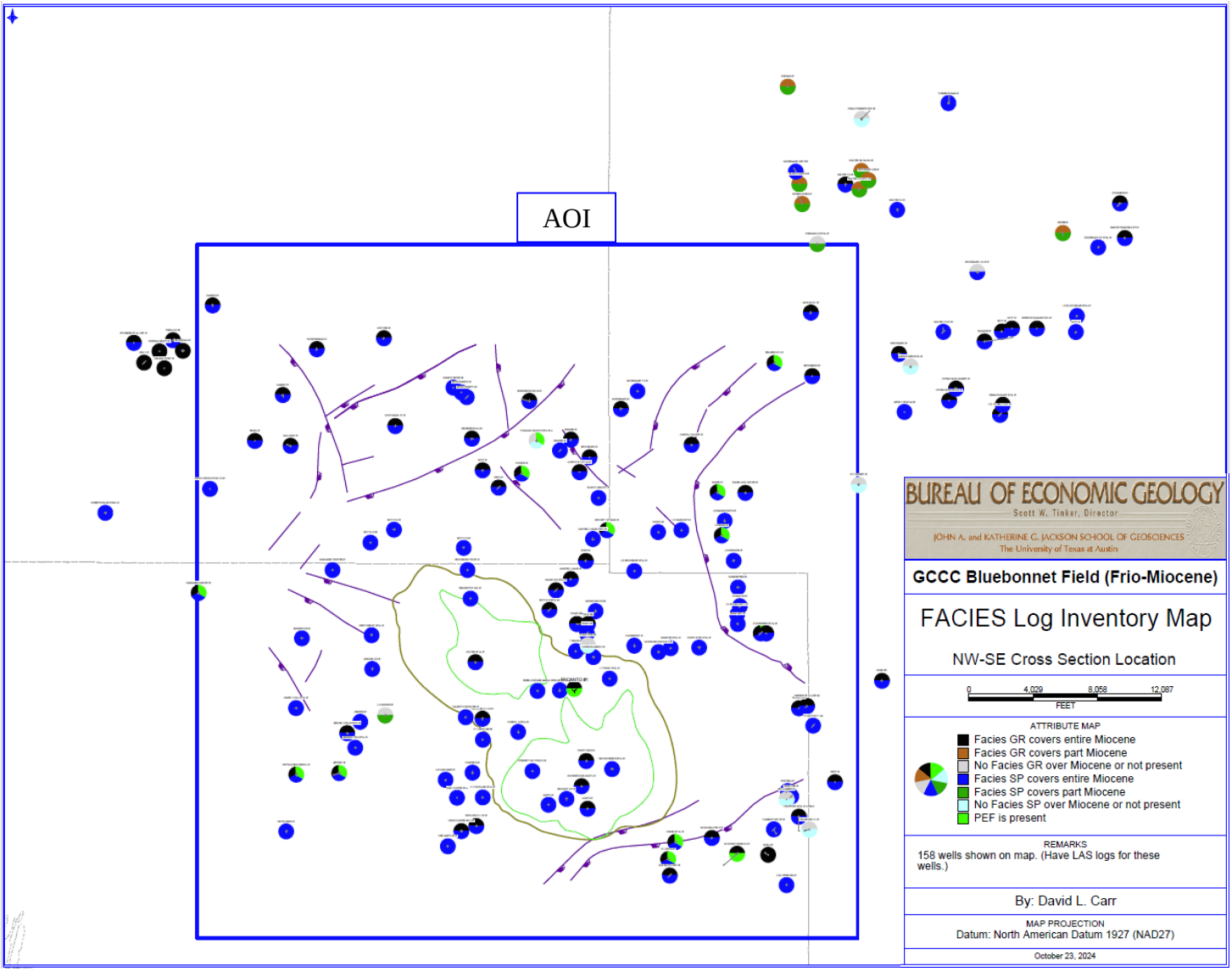


Figure AoR-286: Map showing the 158 wells with calculated porosity and permeability inside and around the AOI. Wells are color coded by facies curve available. There 14 wells with lime green color representing the 14 base wells with PEF used for facies determination and distribute it to the rest 144 wells.

Table AoR-45 provides a summary of the computed log data inside AoI used for the static model properties.

Table AoR-45: Computed log data for static model inside the AOI.

Log Data Set	Inside Model AOI
Phi and K logs	102
GR Facies	52
Additional SP Facies (no GR Facies)	54
GR + SP Facies Logs (used in Facies Model)	106

5.2.2 Log-Derived Lithofacies Data

The facies definitions were adjusted using the Encanto 01 core data for calibration. In addition to the core calibration, refinement of the facies categories was expanded to include the following log-based lithotypes (with the legend key and color code show to the right):

A complete description of this methodology is included in Appendix A. The log-based lithofacies data were imported as discrete lithology logs based on the SP and GR curves, designated with the FACIES_CORE_ prefix in the global curve name. Also, the normalized SP and RESD curves were added as well as the Vshale from GR calculated curve:

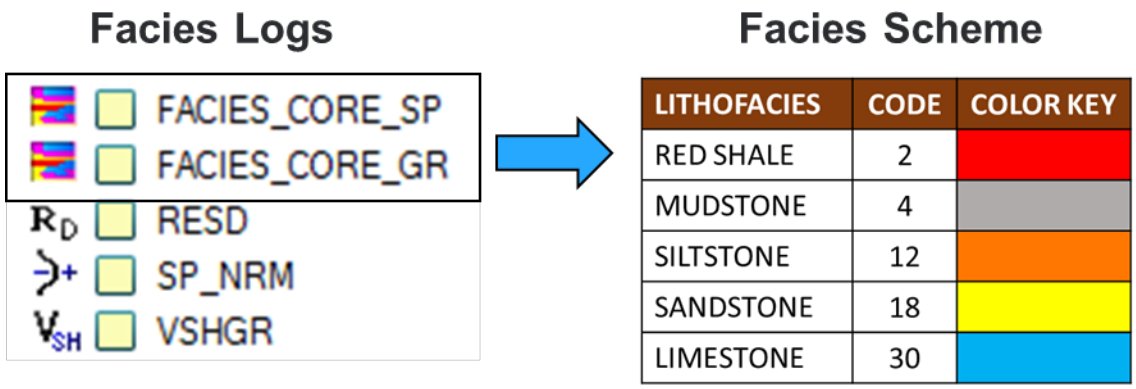


Figure AoR-287: Lithofacies Scheme and Facies Curves.

Because the GR-derived lithofacies data are considered more reliable than the SP-based interpretation, the FACIES_CORE_SP logs were upscaled into the 3D grid using a “most of” upscaling algorithm, and then, replaced by (or added to) with the FACIES_CORE_GR logs into the same model property (FACIES_CORE) for a combined 106 upscaled lithology curves inside the static model boundary used in Facies modeling process.

5.3 3D Seismic Input to Model Geologic Structure – Miocene Storage Complex

The incorporation of the seismic data was described in section 4.3 including the Miocene Storage complex. Seismic interpretation provides top and base horizons for the Miocene Storage Complex. Between the confining Miocene horizons, seismic attribute extractions informed facies distributions within the Miocene geologic model. Similar attribute extractions were performed on the Frio Storage Complex, but they did not produce any geologically reasonable output and were not utilized in the geological model for the Frio.

5.4 Geologic Model Zones and Layering –Miocene Storage Complex Model

The geological model was constructed from a volume-based framework (VBF) model derived from 3D seismic interpretation. There are a total of 12 major zones in the model: Lower Miocene Shale Confining Zone, Lower Miocene Dissipation Zones (4), Lower Miocene Injection Zones (6) and Anahuac Shale Confining Zone. These major zones were further subdivided by layering and modeled separately to better characterize the depositional trends and reservoir parameters for each zone in more detail.

The Lower Miocene Dissipation Zone was subdivided into the Lower Miocene A, AMPB Sand, Lower Miocene B, and Lower Miocene C. Together these zones represent the expected Lower Miocene dissipation zone.

The Anahuac Confinement Zone was not subdivided into additional zones as was done for the Frio, but only the upper Anahuac was included in the geomodel, with appropriate vertical layering created to facilitate the distribution of reservoir properties and better characterize the vertical heterogeneity of this zone.

The remainder of the Lower Miocene was subdivided into injection disposal zones as follows: LMIO_INJ_1, LMIO_INJ_5, LMIO_INJ_4, LMIO_INJ_3, LMIO_INJ_6, and LMIO_INJ_2. Each of these zones was in turn subdivided into additional vertical layers to facilitate distribution of reservoir properties to capture the vertical heterogeneity of the target injection reservoirs.

The Lower Miocene Injection Zones are the main CO_2 storage reservoirs proposed for the Miocene Storage Complex within the proposed AoR. These reservoirs are characterized by relatively unconsolidated sandstones with high porosity and permeability, with interbedded siltstones, minor mudstones and shales, and some calcareous layers. These units were deposited in a dominantly fluvial to fluvio-deltaic environment.

The geological subzones were created from horizons based on a combination of well log correlations in combination with the 3D seismic horizon interpretation. The internal layer subdivisions of the zones were based on the interpretation of 153 digital well logs, which were used to determine the thickness of each subzone. Proportional layering was applied to each subzone, with the number of layers in a zone determined from the subzone thickness targeting a layer thickness of approximately 10 ft. for each layer. The average incremental vertical cell thickness for the total model is 14 ft. and approximately 10 ft. in the injection zones.

The 12 individual zones within the geological model include the stratigraphic units from the base of the Anahuac Confining Zone as the lowermost confining zone to the top of the Lower Miocene Shale Confining Zone as the uppermost confining zone.

Table AoR-46: Summary of key statistics for the Lower Miocene Confinement, Dissipation, and Injection zones.

ZONE TYPE	Model Zone Name	TVDss (ft.)	PORe (frac.)	PERM (md)	Gross TVT (ft.)
TOP CONFINING ZONE	LMIO Shale CZ	-4,286	0.116	62	168.26
LOWER MIOCENE DISSIPATION ZONES	LMIO A	-4,455	0.200	4,039	128.98
	AMPB Sand	-4,584	0.091	83	115.34
	LMIO B	-4,699	0.174	2,064	236.01
	LMIO C	-4,935	0.105	178	171.49
LOWER MIOCENE INJECTION ZONES	LMIO_INJ_1	-5,107	0.219	4,861	134.61
	LMIO_INJ_5	-5,241	0.202	4,285	134.16
	LMIO_INJ_4	-5,375	0.159	2,244	92.04
	LMIO_INJ_3	-5,467	0.211	4,364	180.69
	LMIO_INJ_6	-5,648	0.160	1,606	271.71
	LMIO_INJ_2	-5,921	0.254	5,627	190.34
BASE CONFINING ZONE	Anahuac Shale	-6,109	0.104	415	218.24

An oblique 3D index view of the 12 subzones of the Lower Miocene section is shown below in Figure AoR-288.

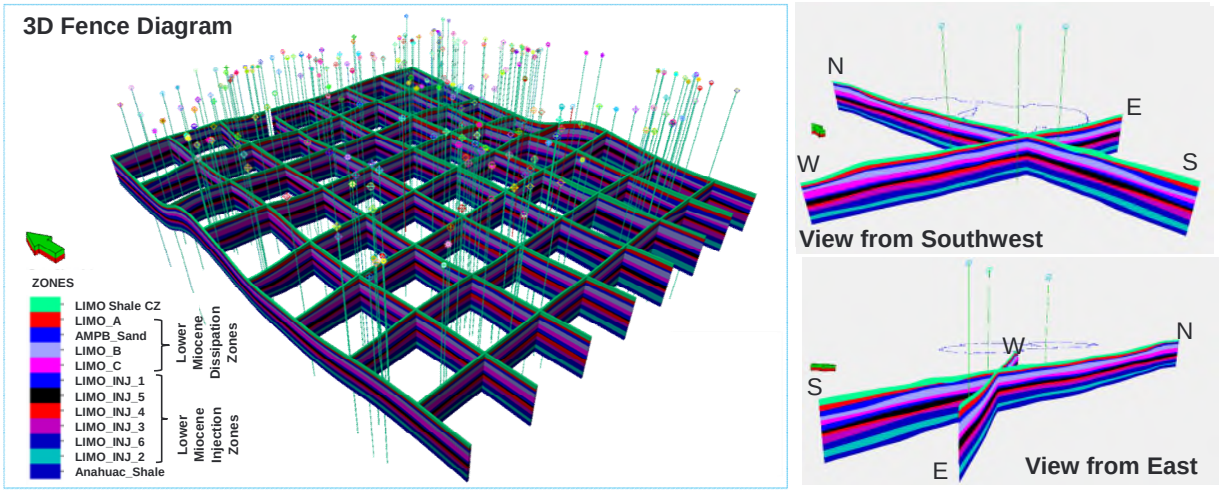


Figure AoR-288: 3D Fence diagram, NS section and EW section showing the geologic model subzones from the Lower Miocene Confinement, Dissipation, and Injection zones to the basal Anahuac Confining Zone.

A total of 158 wells were selected that provided the best data quality and coverage, and used to make petrophysical calculations of porosity, permeability, and net reservoir thickness. Within the geomodel, 153 petrophysically analyzed wells were available for use in 3D distribution of petrophysical properties, as shown in Figure AoR-289. A summary of average petrophysical properties is shown in Table AoR-47.

5.5 Property Modeling Workflows and Procedures

Property modeling for the Bluebonnet Lower Miocene static geomodel followed standard procedures in most cases. Generally, the well log data were upscaled into the model, data analyses were performed, and log data was checked for accuracy and consistency. In some cases, extreme outlier data points were filtered from the data analyses (generally petrophysical properties with spurious or incorrect data). For example, out-of-range porosity and permeability values <0.00 were considered analytical artifacts and were set to “Undefined” in the data analysis distributions.

Basic geometric properties (Layers, Zones, and Regions) were created for use in checking grid consistencies and for input to other intermediate property calculations.

5.5.1 Well Log Upscaling

Upscaling of the fundamental petrophysical logs (porosity, permeability, and shale volume) used the computed X-Curves: XPORE, XPORT, XK, and XVsh created for the original project dataset. The logs were upscaled using a Mid-Point Pick (MPP) algorithm rather than the traditional and standard Arithmetic, Harmonic, or Geometric algorithms. Although these methods were tested, the use of the MPP algorithm is much better at characterizing vertically heterogeneous reservoirs.

Lithofacies data (Appendix A) were upscaled into the model using a standard “most of” upscaling algorithm, the preferred methodology for discrete properties. As noted above, the SP-based lithofacies data were upscaled first, then GR-based lithofacies logs (52 wells) were re-upscaled

while keeping SP-based lithofacies where there is no GR-base lithofacies exists (54 wells). This provided a total of 106 wells with facies control points inside the model boundary.

5.5.2 Data Analysis

All continuous petrophysical properties were evaluated using the Petrel Data Analysis tools. A vertical proportion curve and probability curve was created for each facies by zone. For continuous properties, data transform distributions were created by facies in each zone. The example below shows the data distribution curve definitions for the LMIO_INJ_3 zone. While there is limited overlap between the sand and siltstone facies, there is more overlap between siltstone and shale/mudstone facies, indicating that the shale/mudstone facies are gradational in nature.

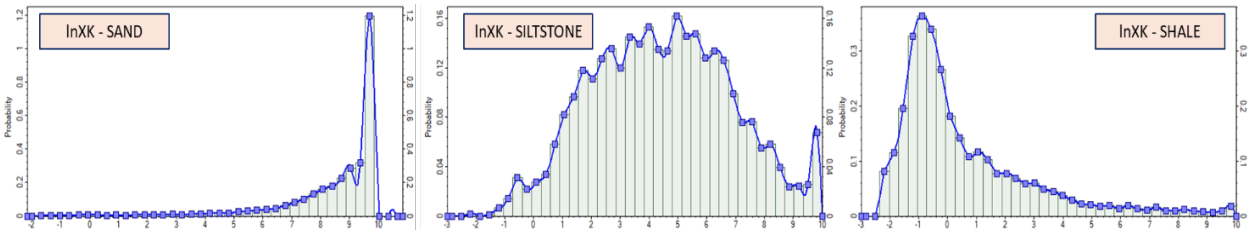


Figure AoR-289: Permeability distribution by facies for the LMIO_INJ_3 zone (logarithmic horizontal scale) showing the gradational nature of the siltstone facies with shale/mudstone and sandstone.

During the data analysis work, it became apparent that the mean permeability values for shale/mudstone facies appeared to be higher than expected. A comparison to limited core plug permeability data from the Encanto 01 well through a shale interval suggested that the log-based permeability calculation for shales was almost an order of magnitude higher than the corresponding plug permeability, which averaged about 0.16 md.

Table AoR-47: Example Average petrophysical values for the LMIO_INJ_3 zone.

AVERAGE PETROPHYSICS: LMIO_INJ_3				
LITHOFACIES	PORE	PORT	log-k	k
SHALE	0.130	0.160	0.6558	1.927
SILTSTONE	0.200	0.209	4.0160	55.479
SANDSTONE	0.293	0.285	8.2330	3763.106

To compensate for this difference, the grid property values for shale/mudstone facies (only) was reduced by a factor of 10 to bring the overall values into closer alignment with the core analysis data.

5.5.3 Lithofacies Modeling

The new, core-calibrated lithofacies were upscaled into the grid using the methodology described above. The upscaled cells were distributed into the 3D space using sequential indicator simulation (SIS), with conditioning to geometric trends that are intended to act as proxies for depositional trends indicated by seismic data (as described in previous documents). Although a regional NS

variogram trend was used for most lithologies, an isotropic variogram with a wider range was used to condition the non-reservoir lithofacies (red shale and mudstone).

Upscaled lithofacies logs (Appendix A) were distributed into the 3D grid using a Sequential Indicator Simulation (SIS) algorithm, with the distribution conditioned with a probability trend map generated from depositional trend lines interpreted from the above workflow. The trend line polygons and derived probability maps used as horizontal trend surfaces were generated for each zone in the Lower Miocene section as geometric distance-to-object properties.

5.5.4 Model Property Distribution Workflow

Lithofacies were distributed in the geomodel using methodology described in Appendix A. The basic workflow, however, incorporates a combination of interpreted environments of deposition from well log cross-sections, amplitude extractions from 3D seismic, and interpretations of sand distribution and geometries. Initial stratigraphic correlations were developed in a network of well log cross sections, primarily intended to help visualize the distribution of depofacies in the AOI.



Figure AoR-291 shows SW-NE stratigraphic cross-section where Encanto 01 is highlighted in red dashed box. Seven (7) distinct depofacies have been interpreted for the Lower Miocene section between the Lower Miocene Shale and Anahuac Shale.

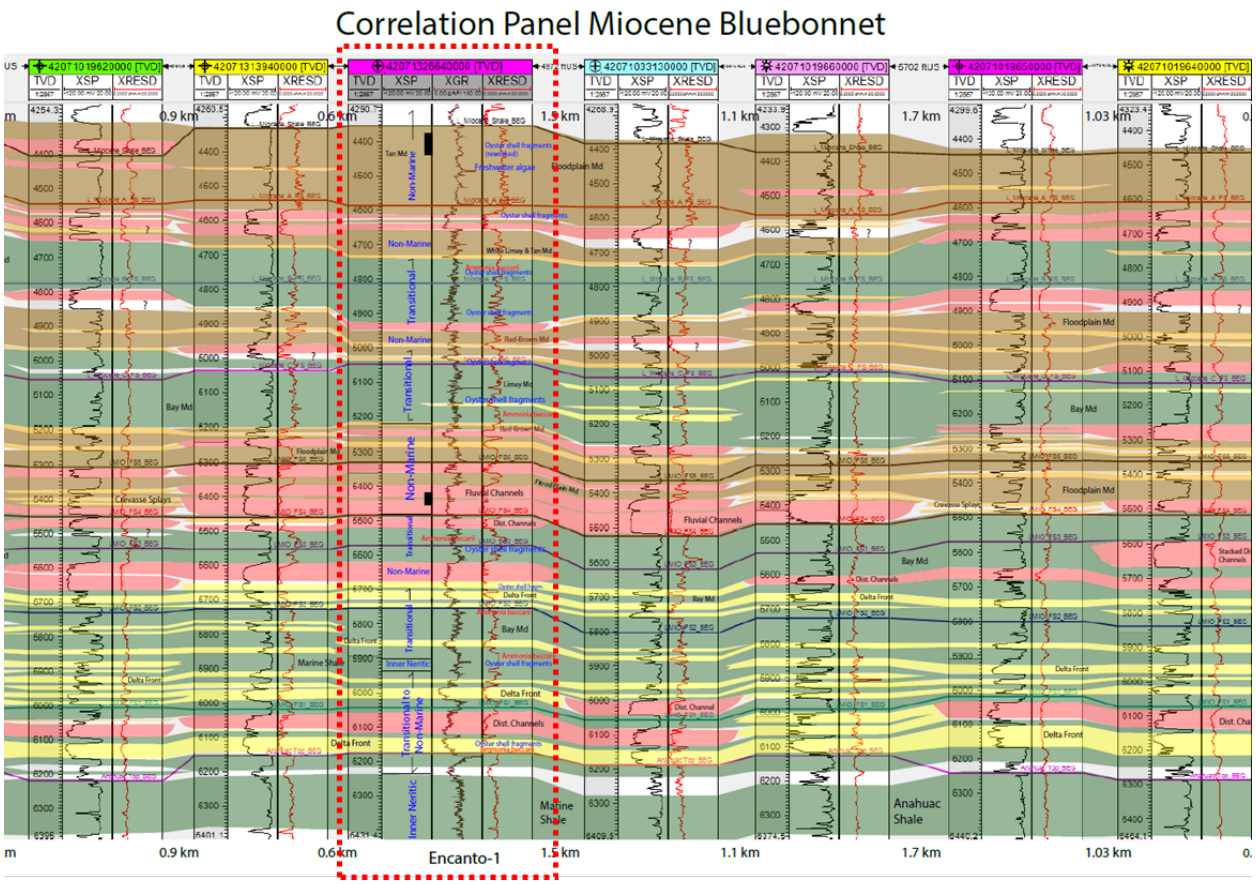


Figure AoR-291: SW-NE Stratigraphic cross-section showing depofacies in the Lower Miocene section.

Note that while the detailed correlations of depofacies interpreted from log signature is somewhat difficult to relate to the log-derived lithofacies. Specifically, the interpreted depofacies (on the left) often contain various percentages of the lithofacies (on the right), Figure AoR-292.

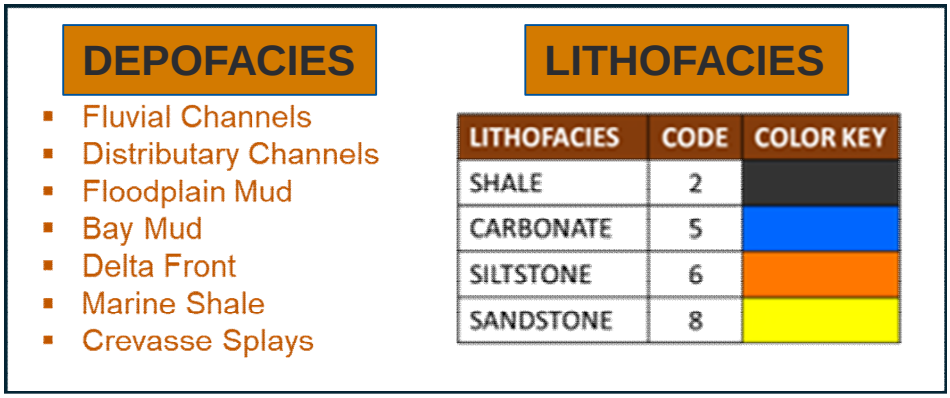


Figure AoR-292: Comparison of depofacies interpreted from log signature and seismic attribute data (left) with the log-derived lithofacies codes.

The general steps in the property modeling workflow incorporated the interpretation of depofacies distribution in combination with RMS amplitude extractions at specific 3D seismic levels. As shown in Figure AoR-293 below, data trends in the RMS amplitude extraction are highlighted (far left view, in yellow) and combined with the depofacies at that level interpreted from well log cross-sections (left center view). These trends are then used to condition the distribution of model properties and compared with the original depofacies distributions (right center and far right views):



The key steps in the Petrel property modeling workflow are shown below on Figure AoR-294. The first step is to distribute the log-derived lithofacies using a general N-S variogram with a 2:1 major to minor axis ratio as a preliminary estimate to distribute the lithofacies properties with a Sequential Gaussian Simulation (SIS) algorithm. Next, the interpreted environment of deposition (EOD) trends were digitized as polylines and a distance-to-object (DTO) property was created in the 3D grid. The DTO property was then inverted and normalized to create a sand deposition probability property (*Ps*) in the grid, which represents the likelihood of sand deposition (*Ps* = 1.0) or non-sand (*Ps* = 0.0). This property (*Ps*) was then used to condition the property distribution and compared with the original EOD trends as shown on the far right:



Figure AoR-294: Property modeling workflow steps to condition property distribution to the depositional trends interpreted from seismic and EOD interpretation.

Using the workflows for interpretation of EOD and depositional trends from seismic and well log interpretation and incorporation of these trends into the property modeling process in Petrel, the distribution of the key model properties (lithofacies, porosity, and permeability uses the following general steps:

- Distribute the lithofacies in the 3D grid using a Sequential Indicator Simulation (SIS) with a general N-S variogram with a 2:1 major:minor axis ratio, with conditioning to the depositional probability (*Ps*). To compare the lithofacies distribution for the 3D property on a zone-by-zone basis, net sand maps (for the zone) were generated and compared with the digitized depositional trends.

- Using the Petrel Data Analysis tools, normal-score distributions for each lithofacies were generated for each of the model zones.

- Porosity modeling was done with a Sequential Gaussian Simulation (SGS) algorithm by conditioning the well data to each facies using the normal-score distributions created in the data analysis process. After conditioning to lithofacies, an isotropic variogram was combined with the facies-specific data distributions, with co-kriging to the horizontal depositional probability trend (*Ps*) with collocated co-kriging using a coefficient from the upscaled data.

- Permeability modeling was also done with an SGS algorithm conditioned by facies using the data distribution curves from the data analysis process. After the facies conditioning, the property was distributed using an isotropic variogram and co-kriging with the porosity property as a secondary variable volume. Again, collocated co-kriging was applied with the coefficient from the upscaled data.

These workflow steps are shown below on Figure AoR-295 showing an example of each of the products of the modeling process:



Figure AoR-295: Property modeling workflow incorporating seismic and depofacies trends, data analysis, and petrophysical modeling to create the key petrophysical properties for the 3D grid.

A comparison of the results of the overall modeling workflow is best visualized by comparing the net sand maps for each of the twelve major zones in the 3D model (Figure AoR-296). In these maps, the warmer color represents higher sand percentages, while cooler colors represent non-sand intervals (i.e. mostly fine-grained siltstones and mudstone). The displays compare the upper confinement zone (LMIO_Shale) on the upper left, the dissipation zones (LMIO_A, AMPB, LMIO_B, and LMIO_C), the injection zones (LMIO_INJ_1, LMIO_INJ_5, LMIO_INJ_4, LMIO_INJ_3, LMIO_INJ_6, and LMIO_INJ_2), and finally the lower confinement zone (Anahuac Shale) on the lower right.

Claimed as PBI

5.5.5 Porosity

The XPORE (Effective Porosity) log defines 3D porosity property for the static and dynamic model, although both XPORE and XPORT (Total Porosity) properties were populated as part of the overall Frio–Lower Miocene study. The log curves were upscaled in the fine grid and distributed using a Sequential Gaussian Simulation (SGS) algorithm, with the porosity property conditioned both by depositional trends as described in previous section sand by lithofacies.

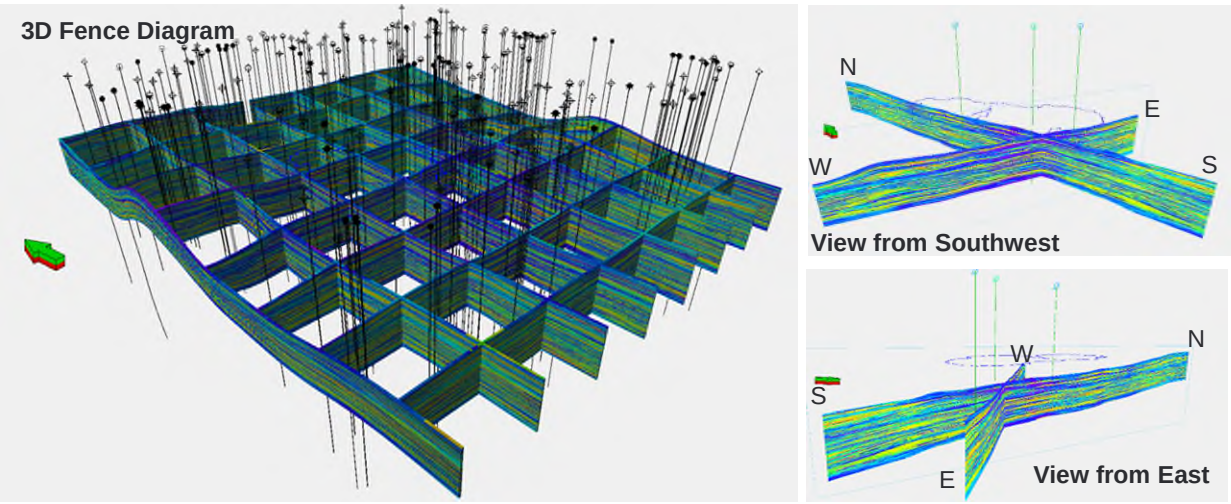


Figure AoR-297: 3D Fence diagram, NS Section and EW Section showing effective porosity property from the Lower Miocene Confinement, Dissipation, and Injection zones to the basal Anahuac Confining Zone.

5.5.6 Permeability

The XK curve was upscaled into the fine grid and distributed in the model using a SGS algorithm, with conditioning to lithofacies and collocated co-kriging to XPORE as a secondary variable. Although a porosity-permeability transform was used for the Frio section, the availability of a calculated XK curve permitted the generation of a facies-conditioned horizontal permeability directly from log data.

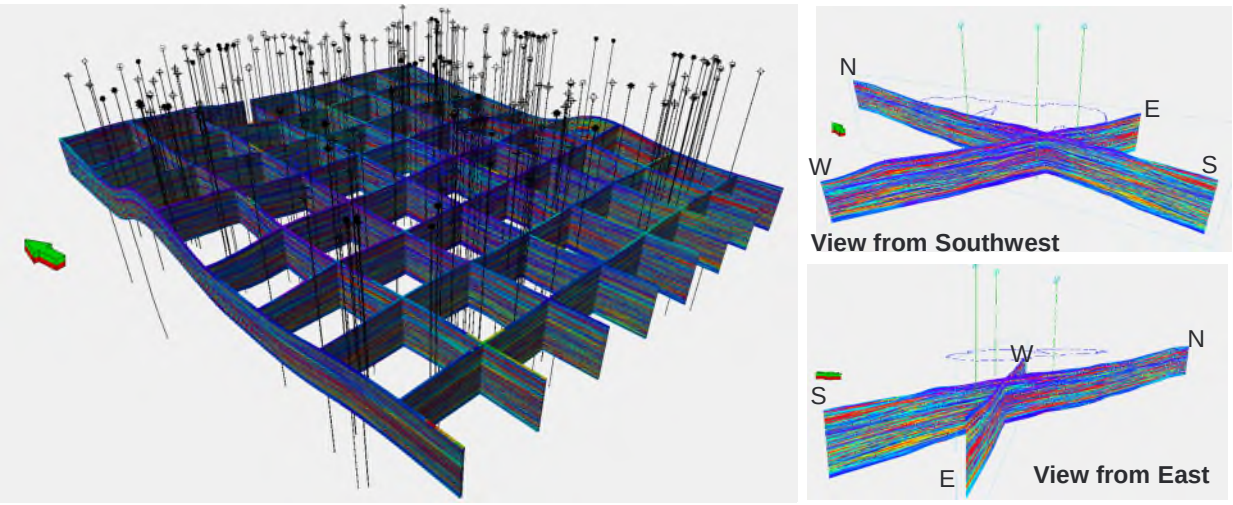


Figure AoR-298: 3D Fence diagram, NS and EW Sections showing the permeability property from the Lower Miocene Confinement, Dissipation, and Injection zones to the basal Anahuac Confining Zone.

A key observation in the core data from the Encanto 01 well suggests that the XK curve data may be overestimating the permeability in the "true" shale intervals by almost an order of magnitude. To allow for testing of this possibility, a pseudo permeability property was created that reduces the XK value (XK/10) in the cells containing the fine-grained facies (red shale and relative mudstone).

During the data analysis work, the XK property distribution did not provide a good match between log, upscaled cells, and total property in 3D. Truncating the XK curve to 15,000 md (from the log data maximum of 16,000 md) provided a much better match. Further investigation of the XK data range might be done or a core-derived porosity-permeability transform should be created by facies to derive a more accurate model permeability.

5.6 Constitutive Relationships and Other Rock Properties – Miocene Model

All simulations runs were executed using the GEM simulator. The grid properties of porosity and horizontal permeability (k_h) were directly imported from the static geomodel. Horizontal permeability for each grid cell was considered isotropic ($k_x = k_y$). Vertical permeability for each grid cell was considered anisotropic and calculated using $k_v = k_h \times 0.1$.

The water-gas relative permeability curves were constructed using a Corey model with exponents previously reported by Ghomian (2008). These curves were also used in the simulation of the Frio CO_2 Pilot test. Three set of curves were generated and assigned to each of the facies included in the dynamic simulation. For the injection zone (coarse sand facies) the curves were calibrated using the core lab data obtained from the plugs collected in Lower Miocene Sand in the Encanto 01 well. Refer to Appendix A for more details.

During the imbibition cycle (water displacing gas), the gas is trapped at S_{gt} or trapped gas saturation. S_{gt} values depend on the maximum gas saturation, S_{gh}, that a grid block has experienced. The base case maximum trapped gas saturation is specified as $S_{gt} = 0.2$. All dynamic simulation runs include relative permeability hysteresis.

5.7 Boundary Conditions

Pore volume multipliers were used to represent additional reservoir volume beyond the model domain and transmissibility multipliers were specified along each respective model boundary to properly account for additional pore volume. Pore volume multipliers of 211.2 along north and south boundaries and 422.4 along east and west boundaries were applied. The numerical model was initialized assuming hydrostatic conditions. Fault B06 was identified as sealing fault based on the fault analysis described in Section 3.11 and transmissibility multiplier for Fault B06 was specified as 0.00001 in the model. The additional faults in the model were set at 0.1 transmissibility multiplier.

Figure AoR-299 shows continuous Jasper net sands in an East-West strike direction parallel to the Gulf Coast. The Jasper flow direction map shows variability across multiple counties; however, the Bluebonnet site seems to be located within one larger flow compartment that may be linked to the Lower Miocene depositional environment map. To quantify its impact on AoR predictions, the horizontal boundary conditions were included as a sensitivity parameter. In Figure AoR-299, the red solid rectangle represents the low value boundary and blue solid rectangle represents the mid value boundary that was used in the base case, within which reservoir pore volumes were included to predict the pore pressure increases from CO_2 injection.

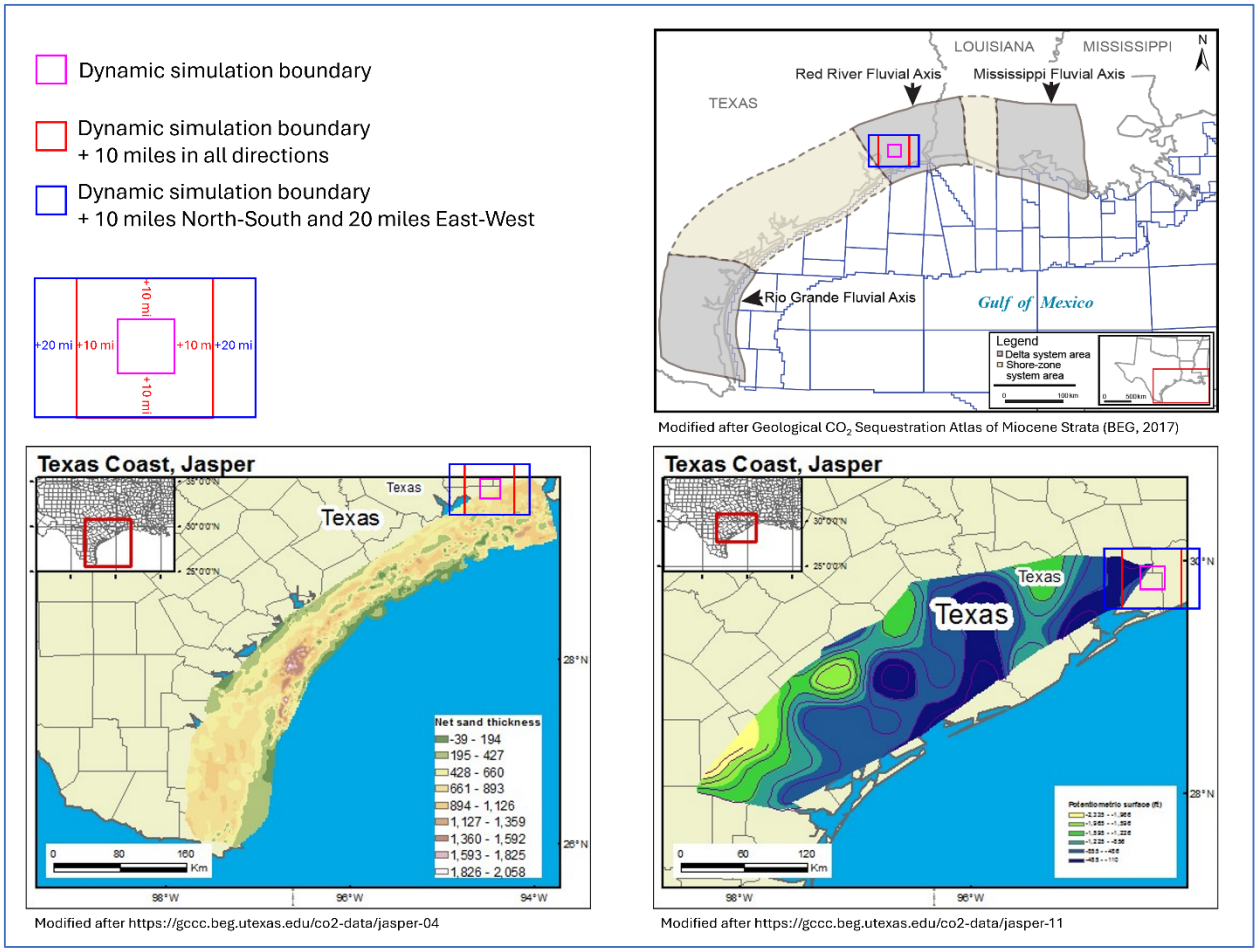


Figure AoR-299: Gulf Coast wide maps showing the depositional system for the Lower Miocene in the upper right, the Jasper net sand thickness in the lower left and the Jasper flow direction map in the lower right.

5.8 Initial Conditions

Initial conditions for the model are given in Table AoR-48.

Table AoR-48: Initial Condition.

Parameter	Value or Range	Units	Corresponding Elevation (ft, MD)	Data Source
Temperature	127.4 °	°F	n/a	
Formation pressure	2,511	psi	5,400 ft	Hydrostatic
Brine viscosity	Kestin correlation		n/a	Kestin et al. 1981
Fluid density	62	lb/ft^3	n/a	reference at 14.7 psi
Rock compressibility	4.25×10^{-6}	1/psi	n/a	Hall, 1953; Newman, 1973

In this study, a pressure gradient based on 2,511 psia at 5400 ft (0.465 psi/ft) was adopted in the model. For the modeled pressure gradient within the injection zone, a water density of 62 lbs/ft^3 was specified. The reservoir temperature was initialized using a constant temperature of 127 °F. Brine viscosity is calculated using Kestin correlation in CMG. Site-specific values for rock compressibility were not determined and a value of 4.25×10^{-6} was specified based on values reported in the literature (Hall, 1953; Newman, 1973).

The estimated transmissibility from the Lower Miocene reservoir is 426,024 md.ft based on the data acquired during the step rate test performed in Encanto 01 stratigraphic well. The static model is predicting higher permeabilities in the sands up to 15,000 mD due to the XK curves being adjusted with the core analysis results for the Lower Miocene plugs. In order to calibrate the permeability predicted by the model with the field data acquired during the step rate test, a permeability multiplier of 0.2 was applied to the Lower Miocene Injection Zone.

5.9 Operational Information

Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells all begin injection with primary rate constraints of 97.6 MMscfd (1.86 million metric ton (MMTA)), 85.4 MMscfd (1.63 MMTA), and 73.2 MMscfd (1.39 MMTA), respectively. Secondary constraints using maximum bottomhole pressure (BHP) were set at 3,300 psi (80-82% of the minimum estimated fracture gradient of 0.76 psi/ft) for all injectors. Frac gradient was established from step-rate and leak-off tests on the Encanto 01 stratigraphic well. The injection stream composition is assumed to be 100% CO_2. Recompletion of injector wells were simulated with addition of successively shallower perforations using the completion schedule proposed in Section 5.11. Proposed injection period for each injector wells is 15 years with 50 years of post-injection, and base-case simulation times were allowed to run for 100 years post-injection to simulate an extra buffer for CO_2 migration after post-injection site closure.

Table AoR-49 shows the completion design for all three injectors. The recompletion design provides higher CO_2 storage capacity by filling each zone of the reservoir separately.

Table AoR-49: Completion design for Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7

Injection Years	CCS 5 Completion Formation	CCS 5 Layer No	CCS 6 Completion Formation	CCS 6 Layer No	CCS 7 Completion Formation	CCS 7 Layer No
1	LMIO_IN_2	172-185	LMIO_IN_2	173-189	LMIO_IN_2	174-184
2						
3						
4						
5	LMIO_IN_6 LMIO_IN_2	172-185 152-160			LMIO_IN_3 LMIO_IN_2	174-184 136-144
6						
7						
8	LMIO_IN_3 LMIO_IN_6 LMIO_IN_2	172-185 152-160 133-145	LMIO_IN_3 LMIO_IN_2	173-189 131-144		
9					LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_2	174-184 136-144 115-119 91-97
10						
11						
12	LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_6 LMIO_IN_2	172-185 152-160 133-145 102-111				
13					LMIO_INJ LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_2	174-184 136-144 115-119 91-97 75-85
14	LMIO_INJ LMIO_IN_5 LMIO_IN_4 LMIO_IN_3 LMIO_IN_6 LMIO_IN_2	172-185 152-160 133-145 102-111 72-81				
15			LMIO_IN_5 LMIO_IN_3 LMIO_IN_2	173-189 131-144 92-106		
Shut-In						

Details on the injection operation are presented in Table AoR-50.

Table AoR-50: Operating details Bluebonnet CCS 5, Bluebonnet CCS 6, Bluebonnet CCS 7.

Operating Information	Bluebonnet CCS 5	Bluebonnet CCS 6	Bluebonnet CCS 7
Bottomhole Location (NAD27) Latitude Longitude	 29.812133 -94.436456	 29.817417 -94.464104	 29.853222 -94.498078
Model coordinates (ft) X Y	 1,184,993.56 10,822,335.15	 1,176,251.281 10,824,366.75	 1,165,648.56 10,837,523.25
No. of perforated intervals	5	3	4
Perforated interval (ft TVDSS) Z top Z bottom	 6,281 6,415	 6,166 6,295	 5,971 6,065
Recompletion interval (ft TVDSS) Z top Z bottom	 6,004 6,132	 5,708 5,817	 5,534 5,630
Recompletion interval (ft TVDSS) Z top Z bottom	 5,771 5,926	 5,470 5,532	 5,243 5,413
Recompletion interval (ft TVDSS) Z top Z bottom	 5,597 5,685	 n/a	 5,127 5,207
Recompletion interval (ft TVDSS) Z top Z bottom	 5,432 5,453	 n/a	 n/a
Wellbore diameter (in.) *	6.0	6.0	6.0
Planned injection period Start End	 time = 0 time = 15	 time = 0 time = 15	 time = 0 time = 15
Injection duration (years)	15	15	15
Average Injection rate (t/day)	5,095	4,465	3,808

TVDSS: True Vertical Depth Sub Sea

5.10 Computational Modeling Results

Dynamic simulations were carried out in 3D using full physics, an Equation of State for fluid PVT. The dynamic reservoir simulation was performed with the same 250 × 250 × ~10 ft grid cells as those in the geologic model.

Twelve zones were imported from Petrel into CMG BUILDER (Table AoR-51).

Table AoR-51: Zones imported into CMG Builder from Petrel – Miocene Storage Complex.

Zone	Layers
L_Miocene_SH	1-10
L_Miocene_A	11-30
AMPB_SAND	31-40
L_Miocene_B	41-60
L_Miocene_C	61-70
LMIO_INJ	71-90
LMIO_INJ_5	91-110
LMIO_INJ_4	111-130
LMIO_INJ_3	131-150
LMIO_INJ_6	151-170
LMIO_INJ_2	171-190
Anahuac	191-200

As described in previous section, the static model imported to CMG contained 288 x 314 x 200 cartesian grids (18.1 million of cells). In order to reduce computational time, a section of the model to the north was deactivated. The final simulation contains 288 × 285 × 200 cartesian grids and more than 16 million active cells.

5.11 Predictions of System Behavior

The simulated well rates and pressures are shown in Figure AoR-300, Figure AoR-301 and Figure AoR-302 . Wellhead pressures were calculated using a PROSPER-generated tubing table with 5.5-inch tubing. Table AoR-52 shows the average bottomhole for each stage at operative conditions.

Table AoR-52: Well bottomhole pressure for each stage at proposed average rates.

Injector	Completion	Reference Depth TVDSS (ft)	Average Well Bottomhole pressure psi
Bluebonnet CCS 5	Stage 1	6,405	3,147
	Stage 2	6,405	3,121
	Stage 3	6,405	3,090
	Stage 4	6,405	3,039
	Stage 5	6,405	3,030
Bluebonnet CCS 6	Stage 1	6,289	3,087
	Stage 2	6,289	3,010
	Stage 3	6,289	2,991
Bluebonnet CCS 7	Stage 1	6,054	2,948
	Stage 2	6,054	2,906
	Stage 3	6,054	2,879
	Stage 4	6,054	2,865

Simulation results supported bottom-up, staged completions as an attractive completion strategy (Table AoR-53). The proposed completion design for each well is based on the overall forecasted sequestration volume, the injectivity of each well, and the availability of the pore space.

Table AoR-53: Stage injection, injection, and production rate for all the wells.

Injection Years	CCS 5 Completion	CCS 5 Rate MMTA	CCS 6 Completion	CCS 6 Rate MMTA	CCS 7 Completion	CCS 7 Rate MMTA
1	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
2	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
3	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
4	Original Completion	1.86	Original Completion	1.63	Original Completion	1.39
5	Recompletion No 1	1.86	Original Completion	1.63	Recompletion No 1	1.39
6	Recompletion No 1	1.86	Original Completion	1.63	Recompletion No 1	1.39
7	Recompletion No 1	1.86	Original Completion	1.63	Recompletion No 1	1.39
8	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 1	1.39
9	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
10	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
11	Recompletion No 2	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
12	Recompletion No 3	1.86	Recompletion No 1	1.63	Recompletion No 2	1.39
13	Recompletion No 3	1.86	Recompletion No 1	1.63	Recompletion No 3	1.39
14	Recompletion No 4	1.86	Recompletion No 1	1.63	Recompletion No 3	1.39
15	Recompletion No 4	1.86	Recompletion No 2	1.63	Recompletion No 3	1.39
Total MMT		27.9		24.45		20.85

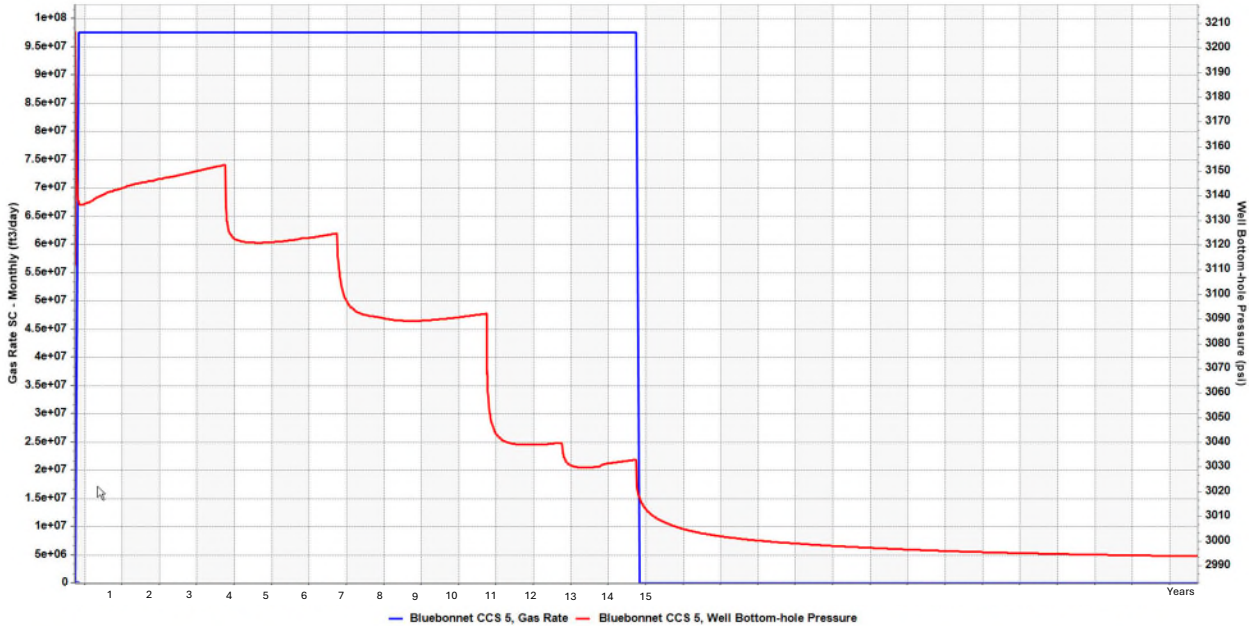


Figure AoR-300: Simulated well Bluebonnet CCS 5 gas injection rates and corresponding bottomhole pressures.

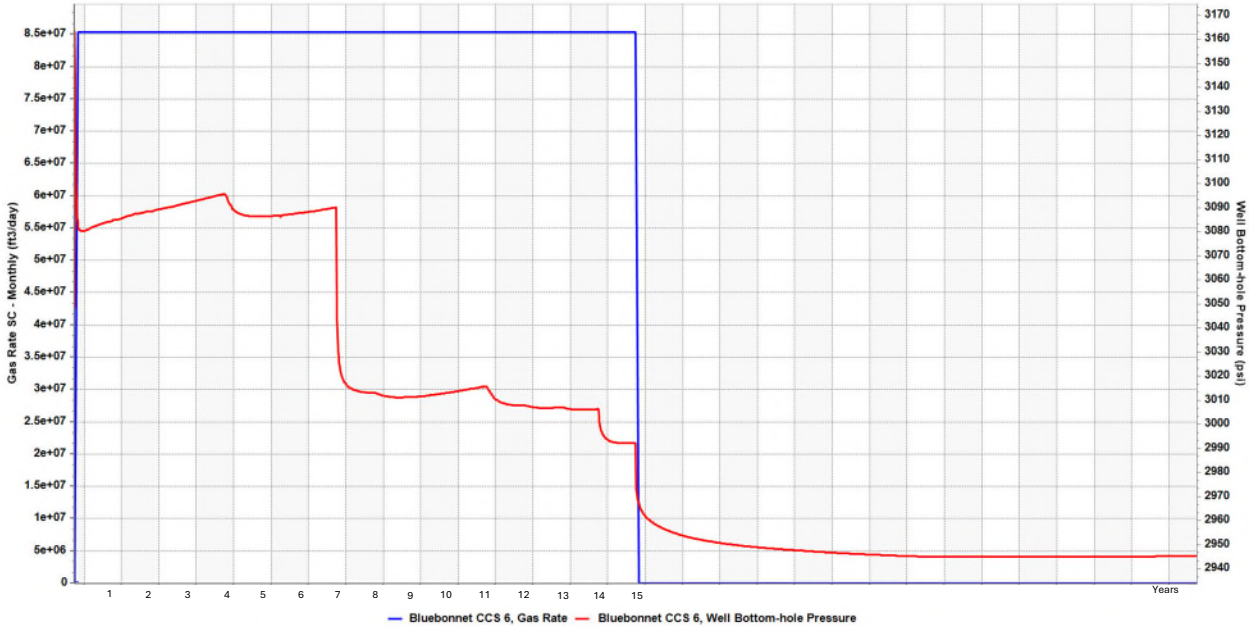


Figure AoR-301: Simulated well Bluebonnet CCS 6 gas injection rates and corresponding bottomhole pressures.

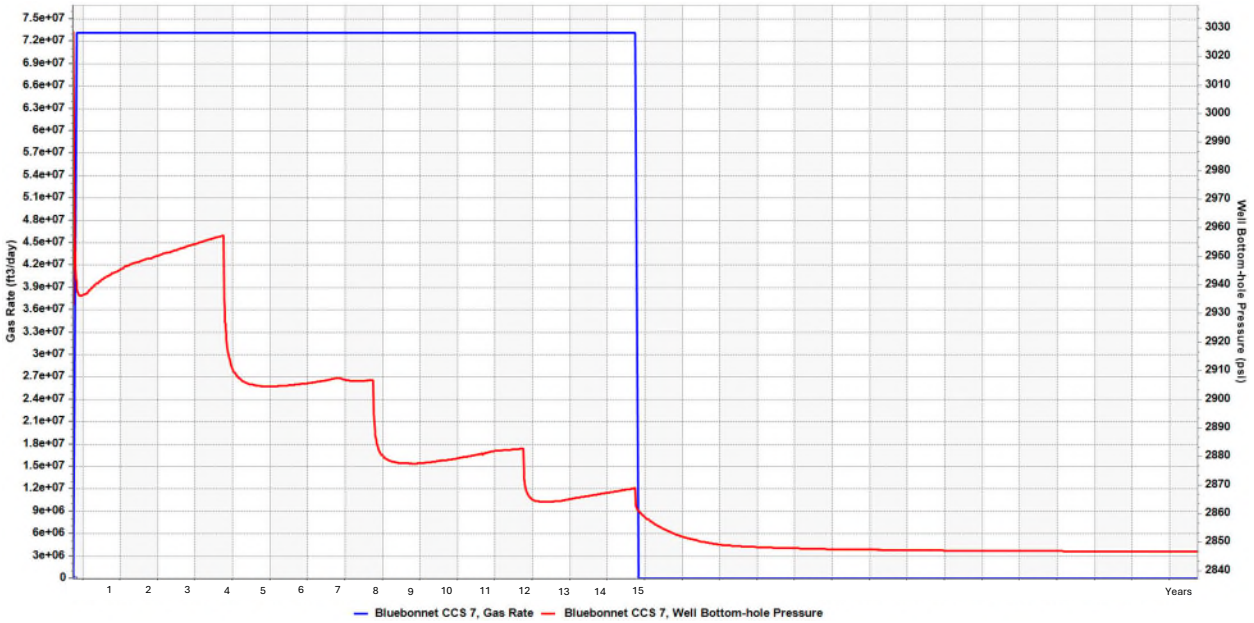


Figure AoR-302: Simulated well Bluebonnet CCS 7 gas injection rates and corresponding bottomhole pressures.

5.12 Model Calibration and Validation

5.12.1 Sensitivity to Input Parameters

Due to the uncertainties in some of site-specific pilot data used to calibrate the dynamic model, sensitivity of the results to subsurface input was explored. These subsurface uncertainties include vertical-to-horizontal permeability ratio (K_v/K_h), residual gas saturation (S_{gr}), permeability multiplier, faults transmissibility, rock compressibility, and size of the boundary aquifers.

Table AoR-54 summarizes the possible ranges of these subsurface inputs. The base case inputs are indicated in the left column. Many simulation runs were made by varying these parameters one at a time and plotting the results to see their impacts. The parameters used to compare the different sensitivity cases are reservoir pressure increase and CO_2 retention.

Table AoR-54: Simulation sensitivity cases.

Case	Parameter	Base Case	Sensitivity Values	
			High	Low
1	Boundary Extension	10 miles x 20 miles	n/a	10 miles x 10 miles
2	Kv/Kh	0.1	0.5	0.05
3	Fault Transmissibility Multiplier	0.1, 0 B_06	1.0, 0.1 B_06	0.01, 0 B_06
4	Residual Gas Saturation (Sgr)	0.2	0.4	0.12
5	Rock Compressibility	4.25E-06	8.00E-06	1.00E-06
6	Permeability Multiplier	0.2	1.0	0.1 (Rate Forced, BHP > max)

Figure AoR-303 to Figure AoR -308 shows the impact on the AoR delineation by each of the sensitivity's cases.

The highest changes in AoR occurs in the scenarios of low rock compressibility and permeability multiplier. Both scenarios are very unlikely for the Miocene storage complex based on the site-based data presented in previous sections and extensive literature of the Gulf Coast reservoirs.

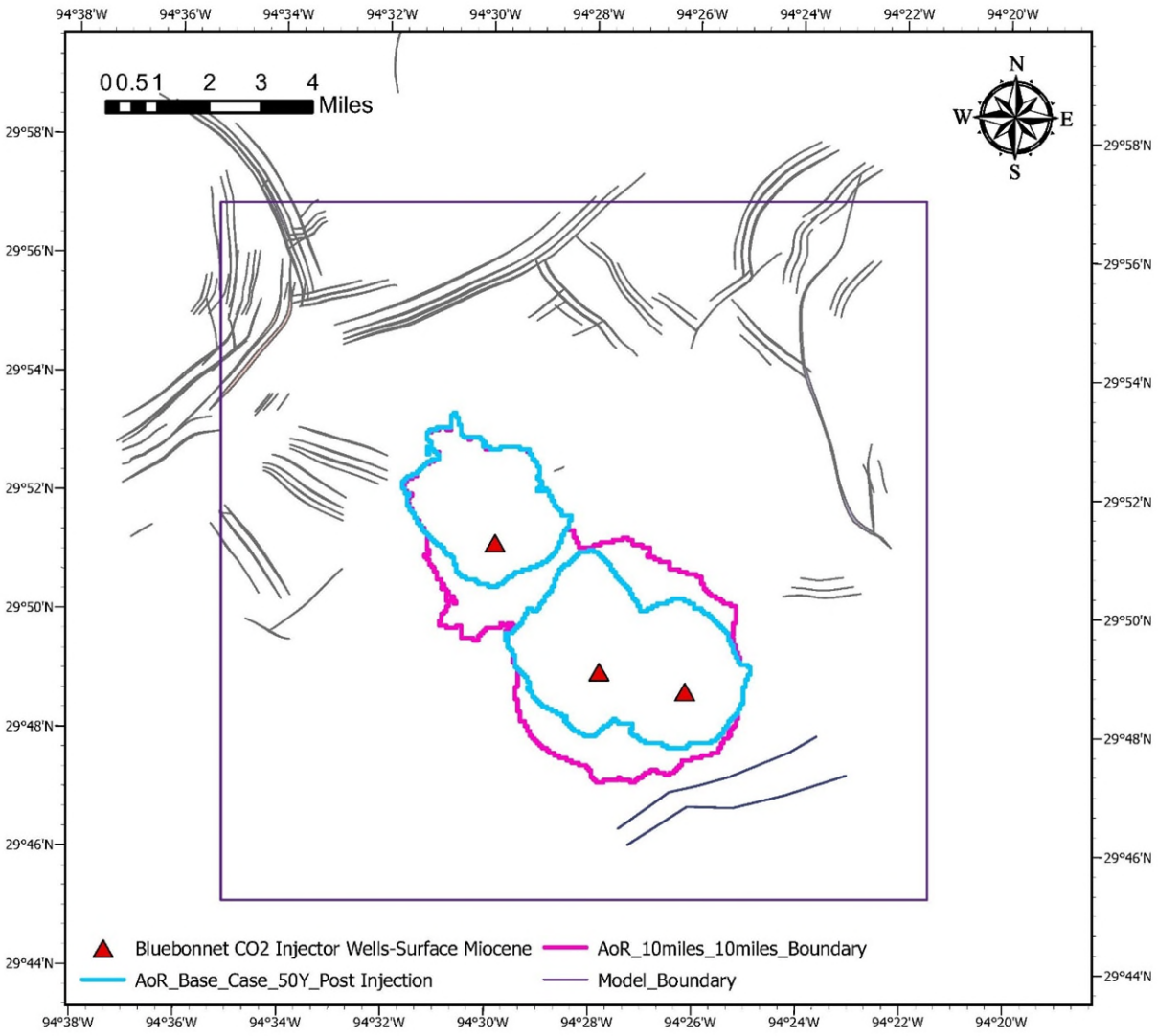


Figure AoR-303: Effect of the boundary extension in the AoR size. Base case is represented in blue. Low case is represented in magenta. The increment in the AoR size is related to the increase of the pressure front. The CO2 plume has minimum variation.

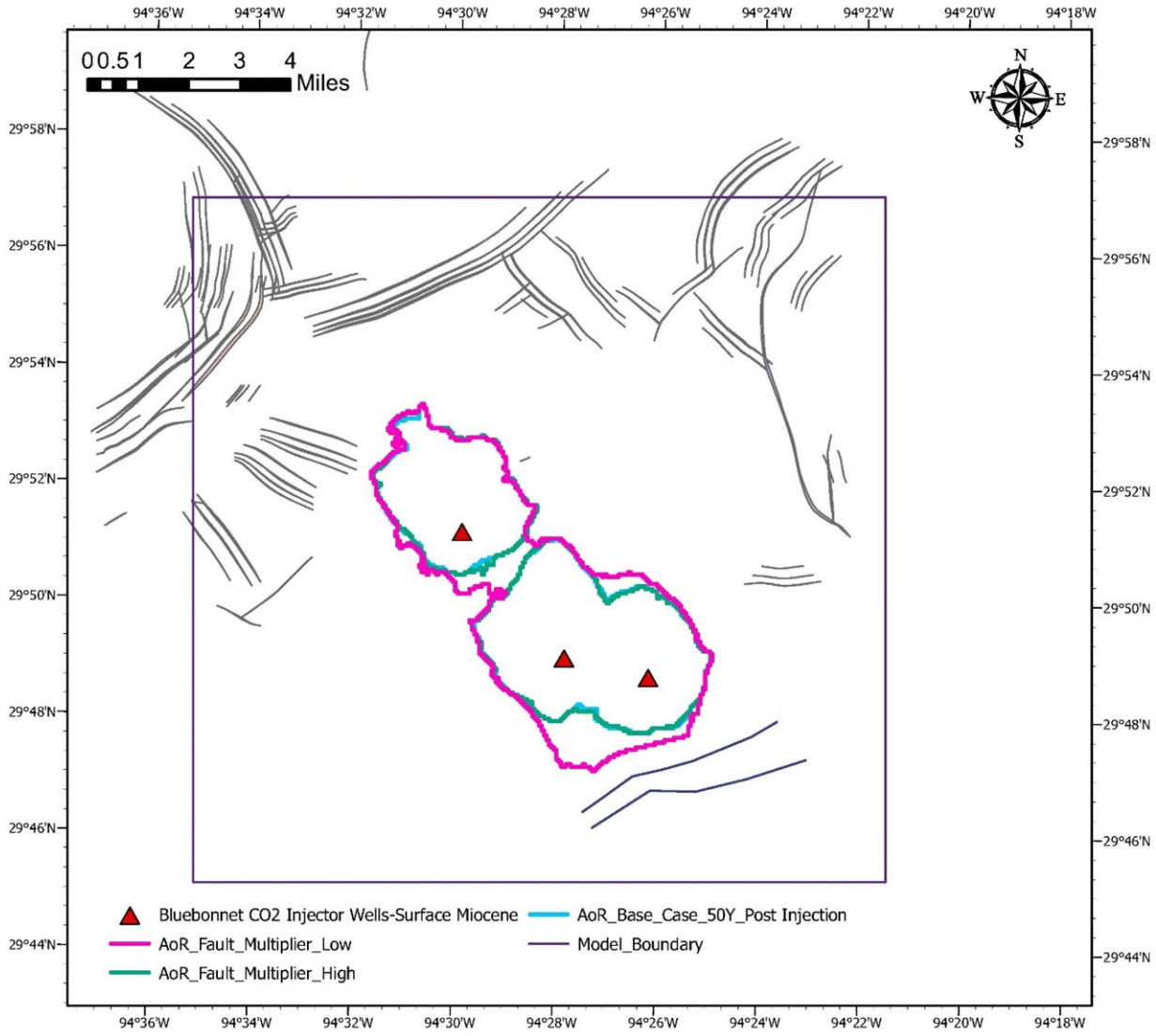


Figure AoR-304: Effect of the fault multiplier in the AoR size. Base case is represented in blue. Low case is represented in magenta. High case is represented in green. The CO2 plume has minimum variation. The main increase of AoR is related to the increase of the pressure front towards the south fault in the low case.

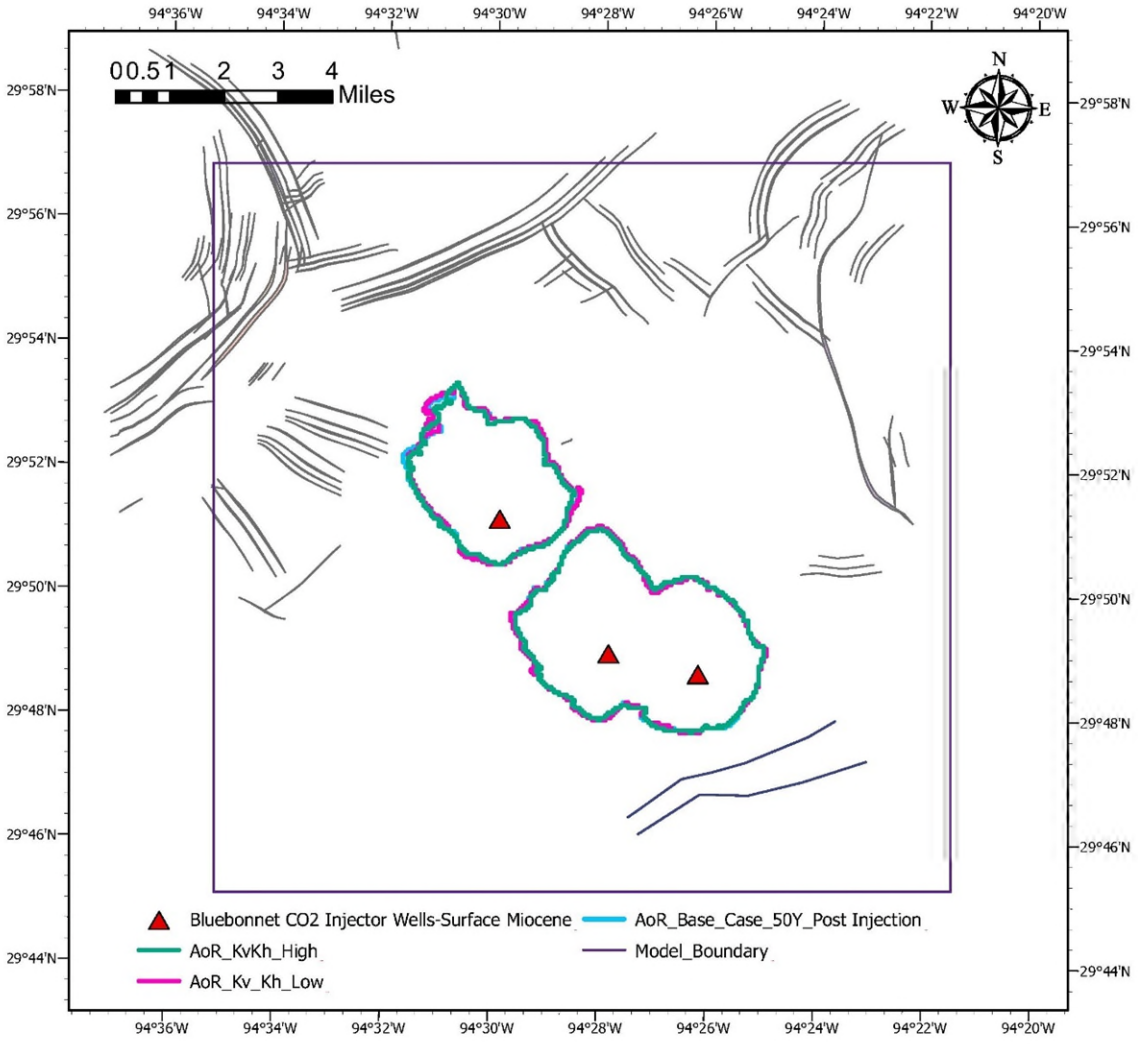


Figure AoR-305: Effect of the Kv/Kh relationship in the AoR size. Base case is represented in blue. Low case is represented in magenta. High case is represented in green.



Figure AoR-306: Effect of the residual gas saturation in the AoR size. Base case is represented in blue. Low case is represented in magenta. High case is represented in green.

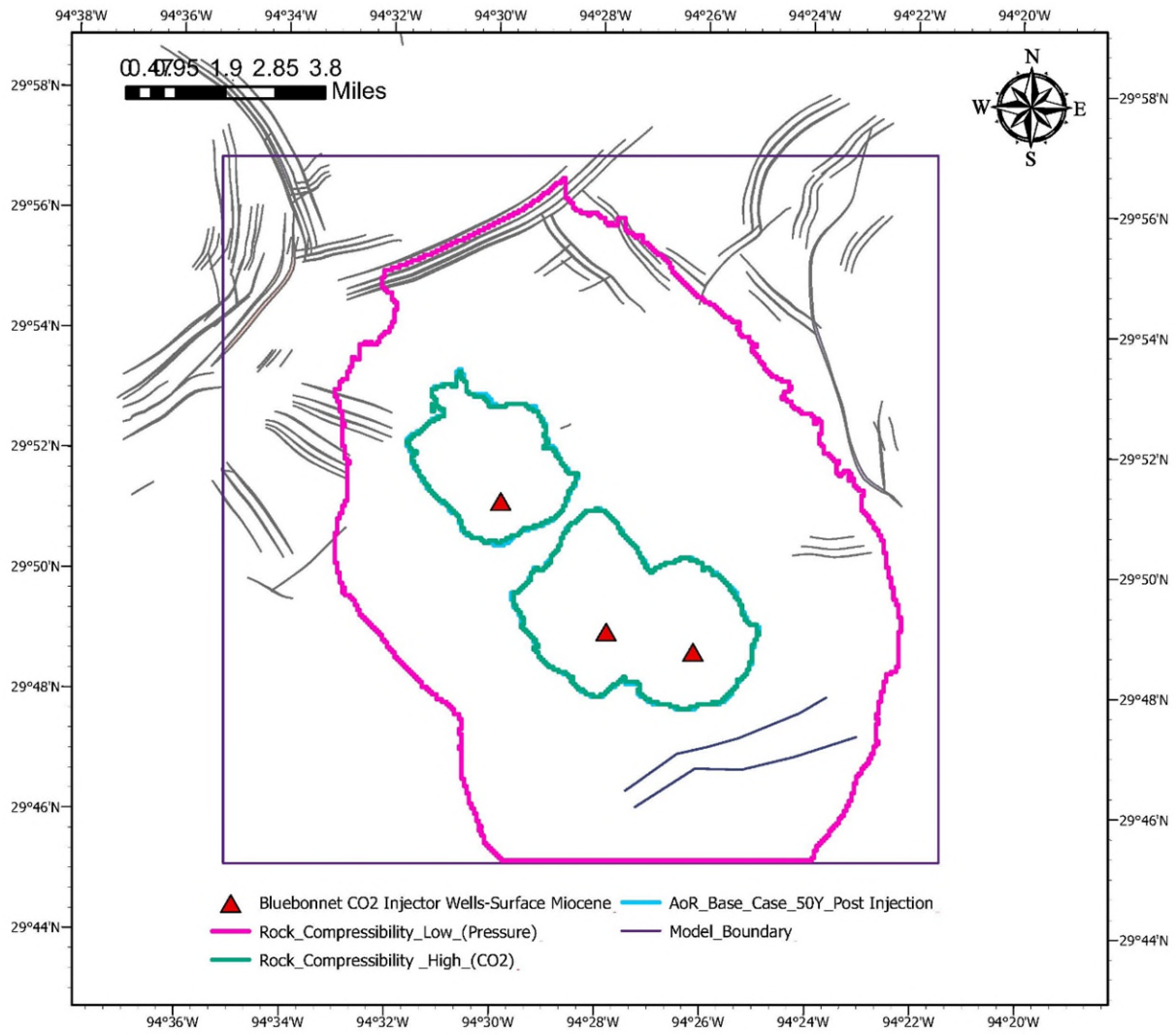


Figure AoR-307: Effect of the rock compressibility in the AoR size. Base case is represented in blue. Low case is represented in magenta. High case is represented in green. The increment in the AoR size is related to the increase of the pressure front. The CO_2 plume has minimum variation.

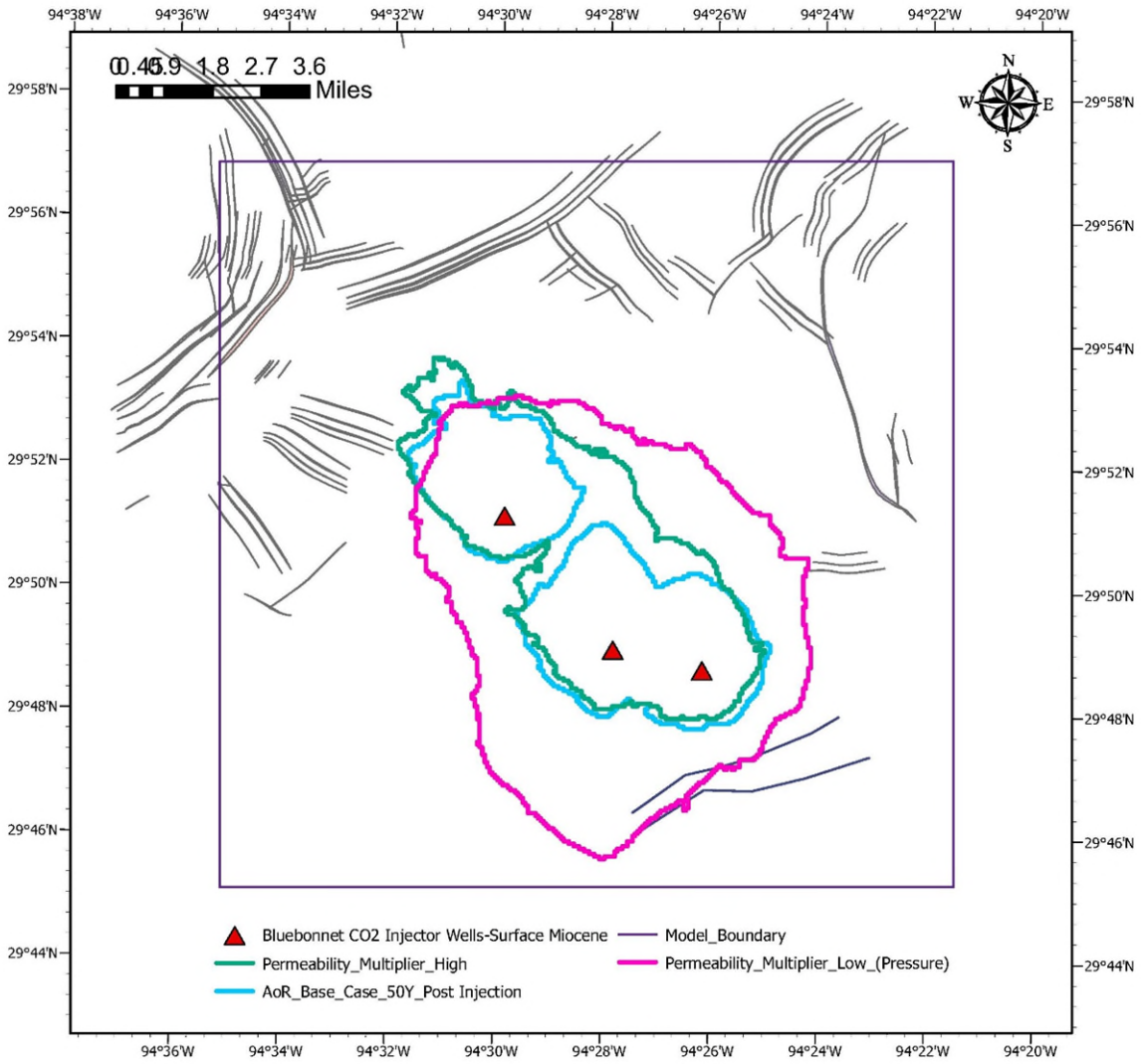


Figure AoR-308: Effect of the permeability multiplier in the AoR size. Base case is represented in blue. Low case is represented in magenta. High case is represented in green. The increment in the AoR size is related to the increase of the pressure front. The CO_2 plume has minimum variation.

5.13 Area of Review (AoR)

5.13.1 Critical pressure calculations

Assuming a mud weight of 9.0 ppg, a falloff of 50 ft, reservoir pressure gradient of 0.45 psi/ft in the Miocene Injection Zone, and gel strength of 10 lbs/ft^2, the calculated critical pressure differential for the Miocene Injection Zone is 110 psi.

$$\text{Critical Pressure} = MW \times 0.052 \times (TD_{perf} - 50) + GS - \nabla P_{Reservoir} \times TD_{perf} \quad \text{(Equation 11)}$$

$$\text{Gel Strength Pressure (GS)} = A \times \text{Gel Strength} \times L_{Hole} / D_{Hole} \quad \text{(Equation 12)}$$

MW: Mud weight (ppg)
TD_{perf}: Top of perforation depth (ft)
GS: Gel Strength Pressure (psi)
$\nabla P_{Reservoir}$: Reservoir Pressure Gradient (psi/ft)
A: Conversion factor (1/300)
Gel Strength (lbs/ft^2)
L_{Hole}: Length of the wellbore (ft)
D_{hole}: Diameter of the wellbore (inch)

5.13.2 AoR delineation

5.13.2.1 Critical pressure front

The maximum differential pressure occurs at year 4 of injection since the three wells, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7, are operating at a constant injection rate, in the same reservoir zone, simultaneously. The movement of the pressure front was evaluated at 5, 10, and 15 years after injection starts. The forecasted pressure increases in year 4 of the injection period is shown in Figure AoR-309. A critical pressure front of 110 psi for the Lower Miocene is projected onto the 2D areal map.

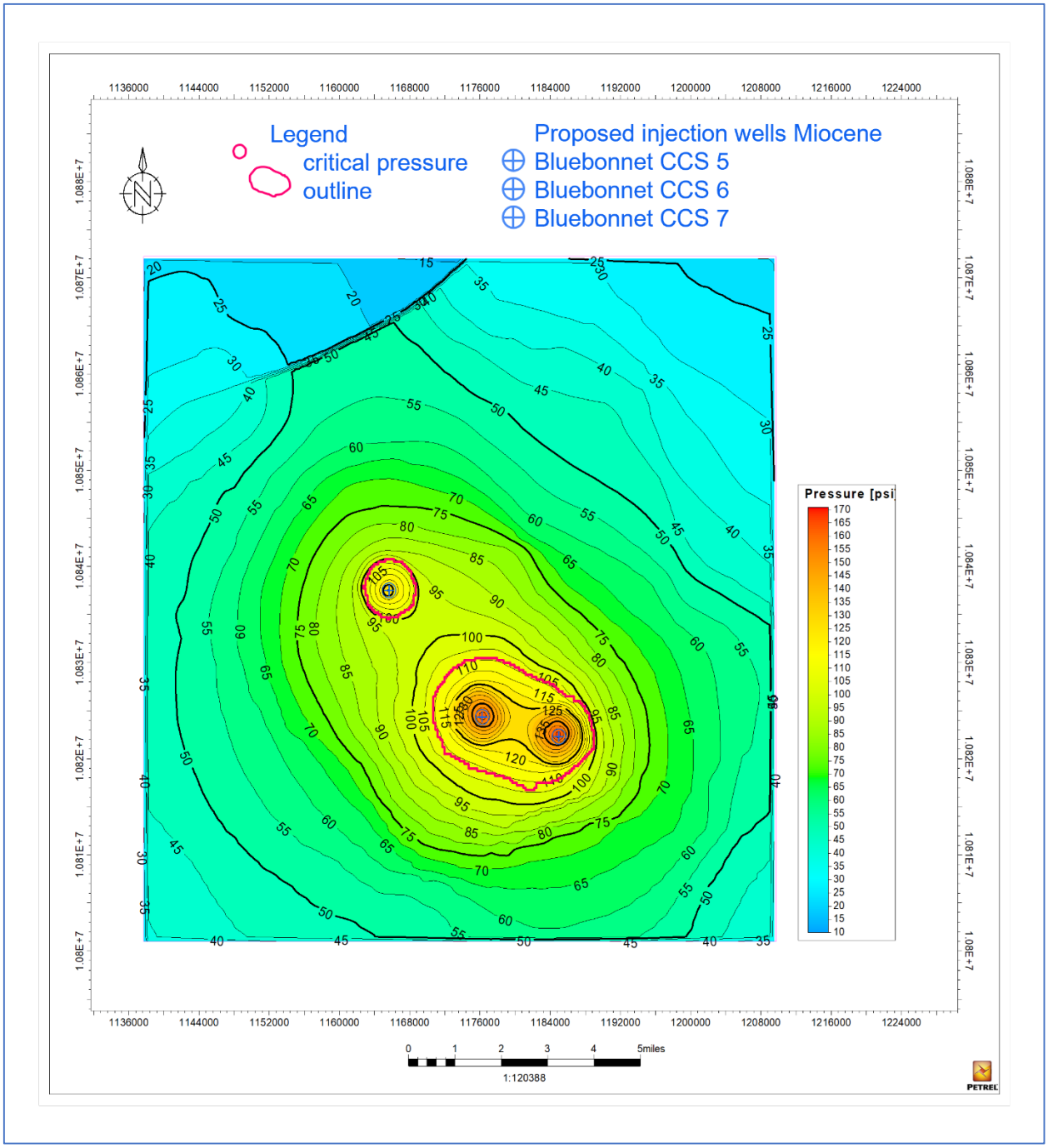


Figure AoR-309: View of highest pore-pressure increases when CCS 5, CCS 6, and CCS 7 are injecting in the same stage at the same time within the first 4 years of injection. Values displayed are pore-volume-weighted averages across the lowermost injection interval, which is opened first. The red polygon is the pressure front for the Miocene Formation after 4 years of injection when the highest pressure occurs because of the staged bottom-up completion strategy.

5.13.2.2 CO_2 plume extent

The CO_2 plume extend was simulated assuming 15 years of injection as described in the previous section. The Project simulated 50 years post-injection as well as 100 years post-injection. Plume tends to stabilize before the 50 years of post-injection period; however, the Project defined the 100-year plume outline to delineate the maximum extend of the CO_2 plume in the AoR as a conservative approach. The Project used a cut off of 3% CO_2 saturation as supported by the fluid substitution analysis provided in Section 8.0.

Figure AoR-310, Figure AoR-311, and Figure AoR-312 show CO_2 distribution at End of Injection, 50 years of post-injection, and 100 years post injection. The highest CO_2 saturation is around the wellbore and has moved up dip with time. Results suggested that CO_2 plume extents can be retained within the AoR and migration of CO_2 plume from 50 to 100 years is predicted to be minimal.

Figure AoR-313, Figure AoR-314, and Figure AoR-315 show the simulated CO_2 saturations along a north-south cross section through Bluebonnet CCS 5, CCS 6, and CCS 7 wells in year 15 after injection. The figure displays a desirable uniform CO_2 profile within the injection zone, effectively utilizing all intervals in the project's pore spaces. In the modeling exercises, such a profile has been achieved by employing the staged completions bottom up.

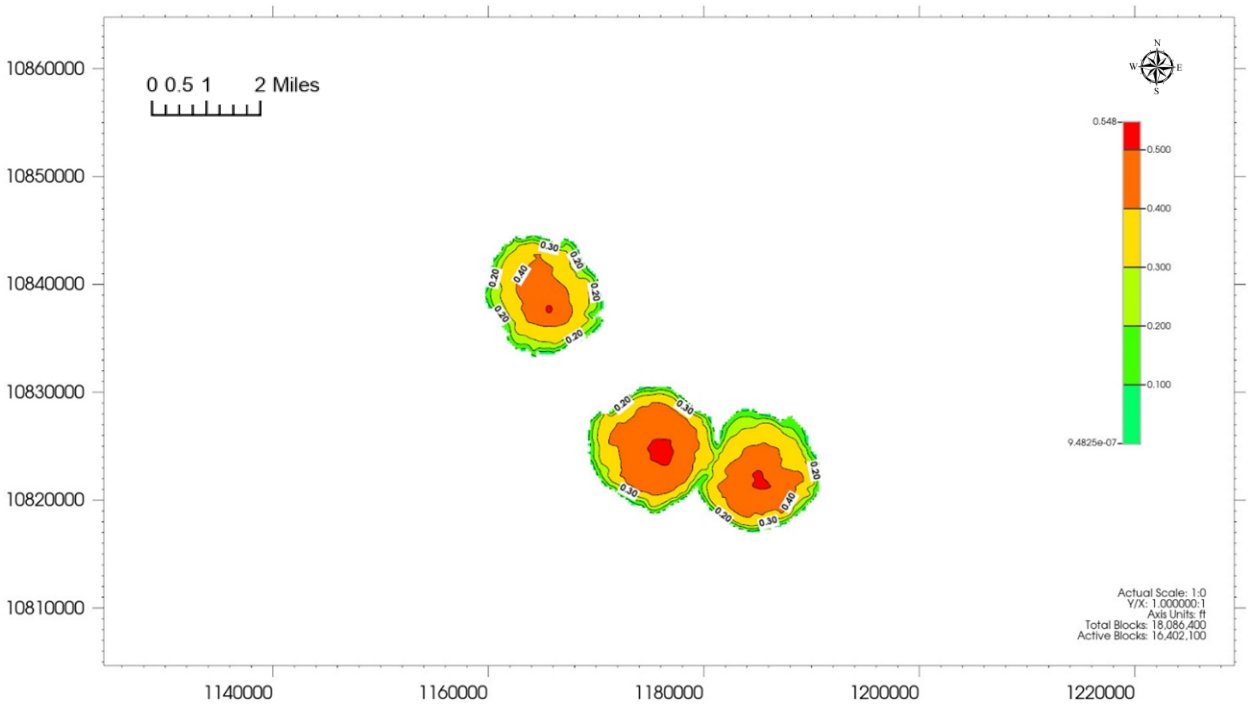


Figure AoR-310: CO_2 saturation map distribution after 73.2 million MT CO_2 injection in Lower Miocene at the End of Injection.

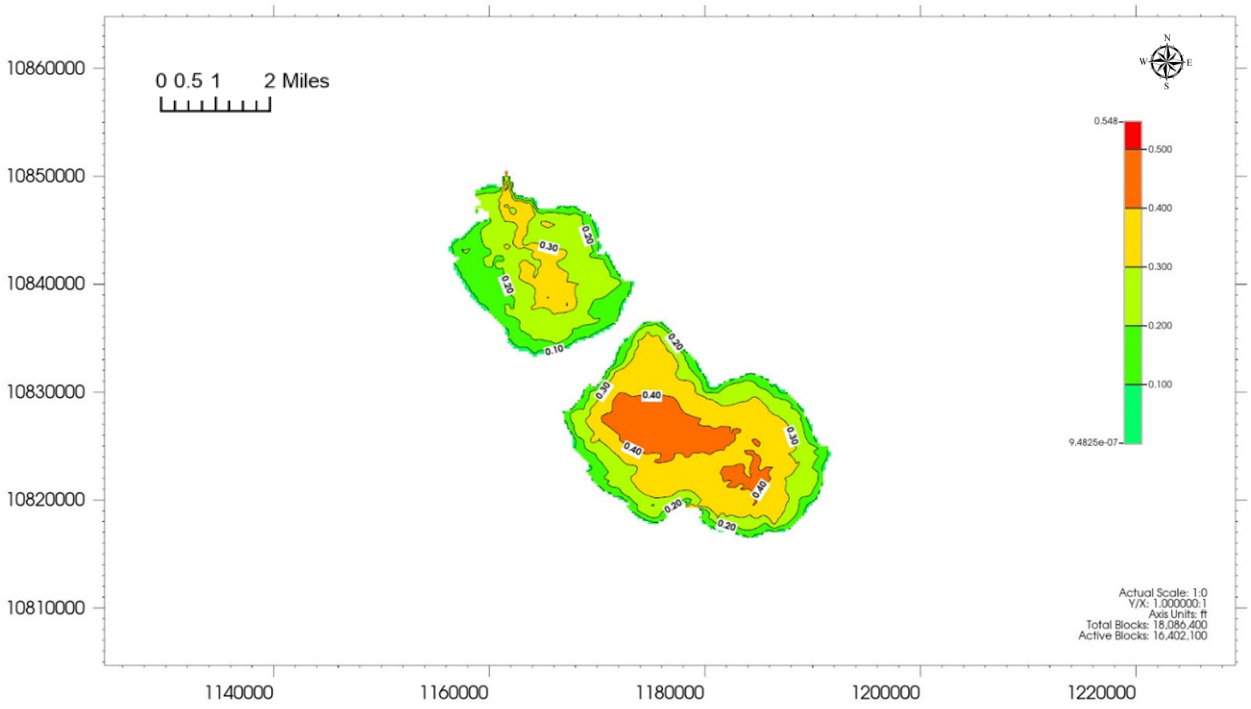


Figure AoR-311: CO_2 saturation map distribution after 73.2 million MT CO2 injection in Lower Miocene, after 50 years of post-injection.

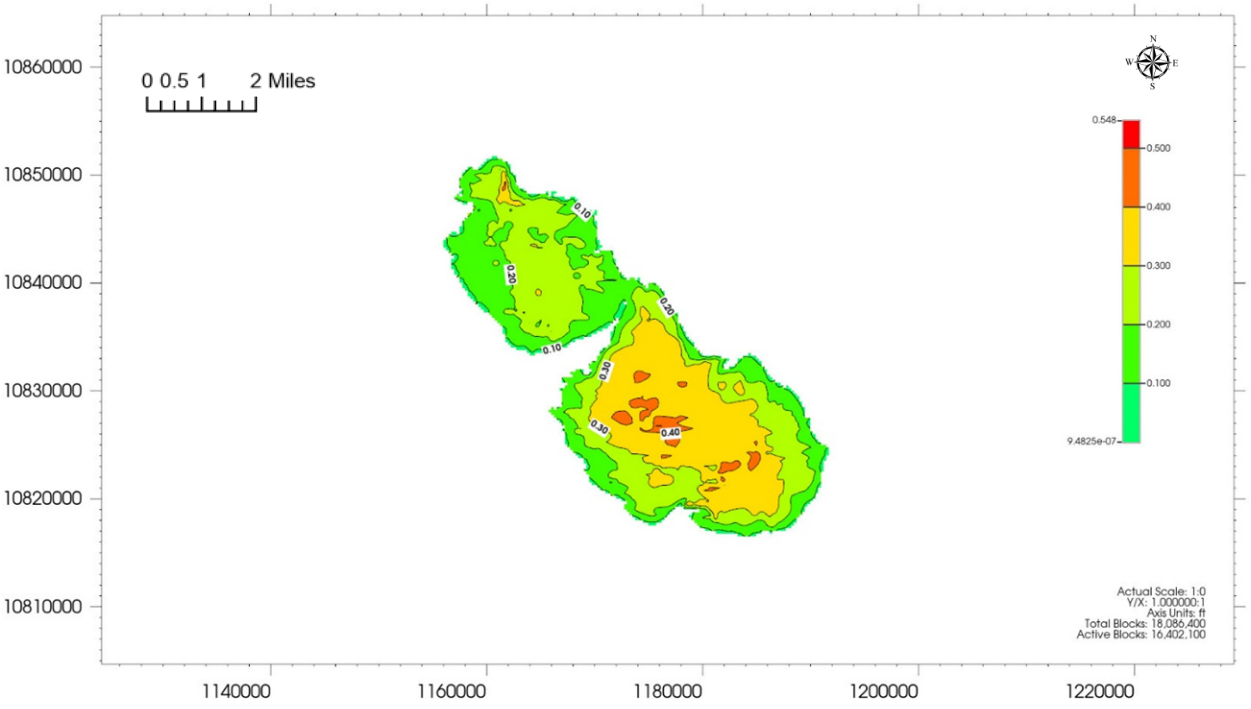


Figure AoR-312: CO_2 saturation map distribution after 73.2 million MT CO_2 injection in Lower Miocene, after 100 years of post-injection.

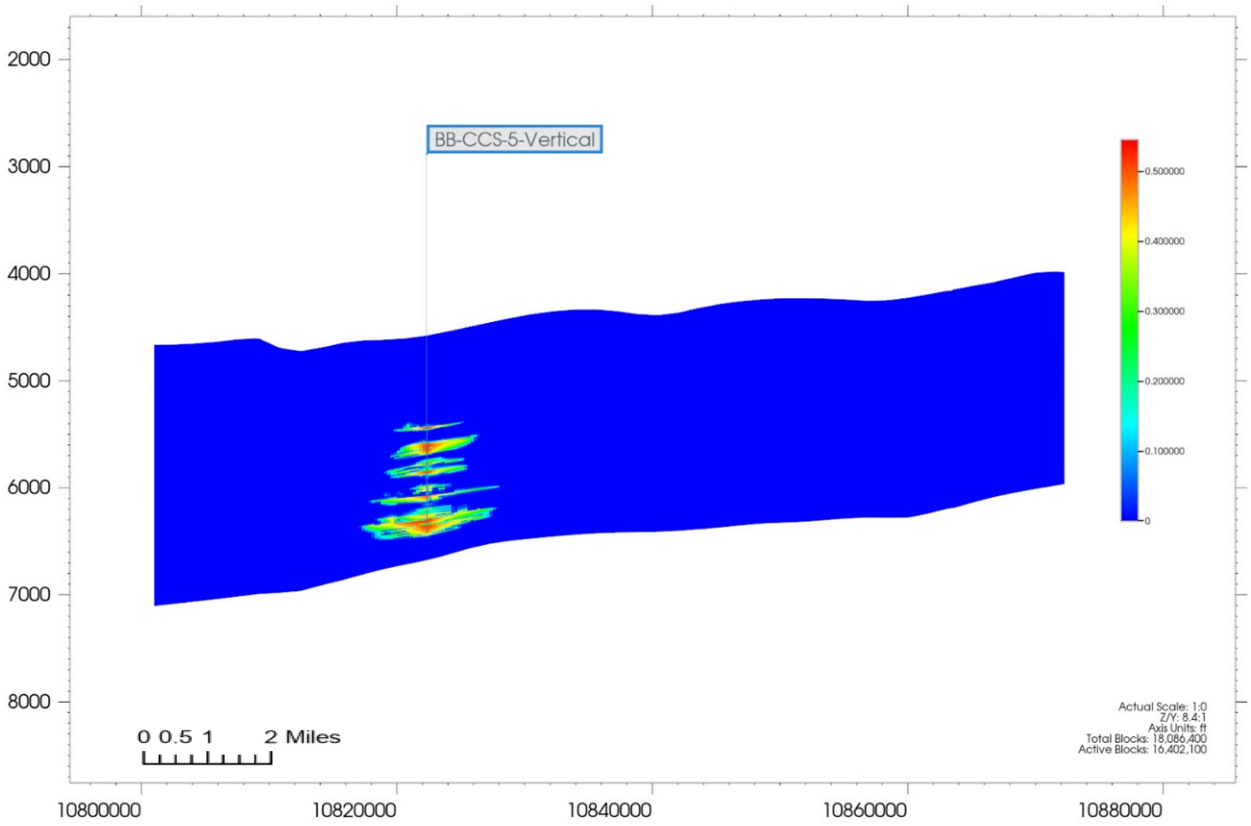


Figure AoR-313: North-south cross section through well CCS 5 showing simulated CO_2 saturation at year 15 after injection starts.

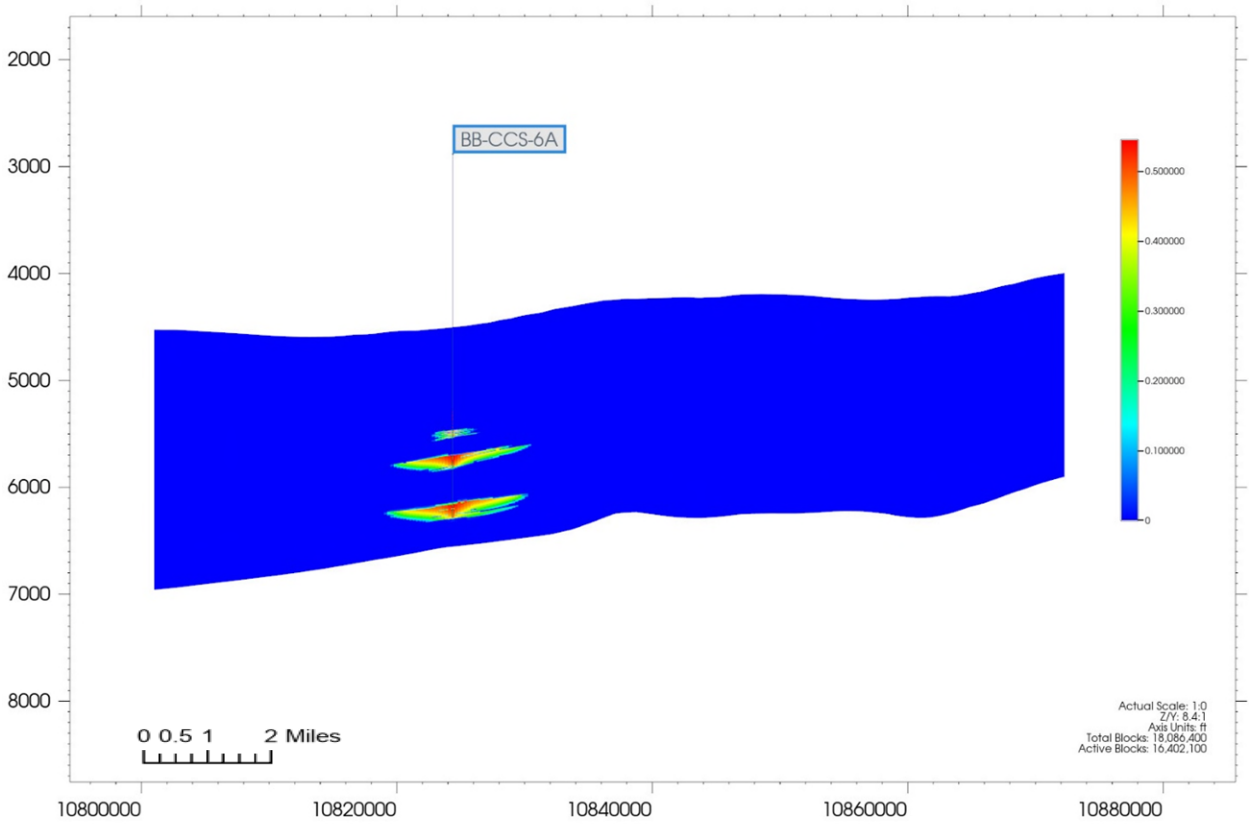


Figure AoR-314: North-south cross section through well CCS 6 showing simulated CO_2 saturation at year 15 after injection starts.

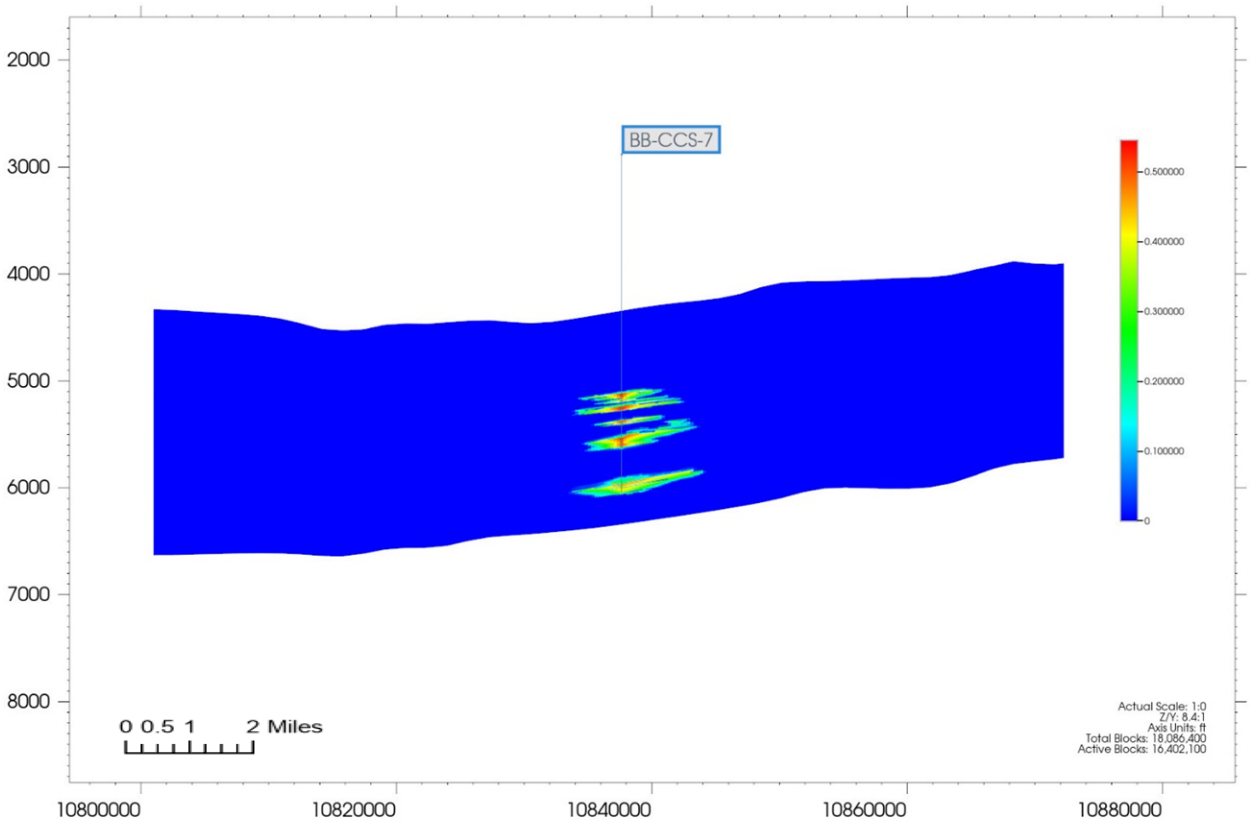


Figure AoR-315: North-south cross section through well CCS 7 showing simulated CO_2 saturation at year 15 after injection starts.

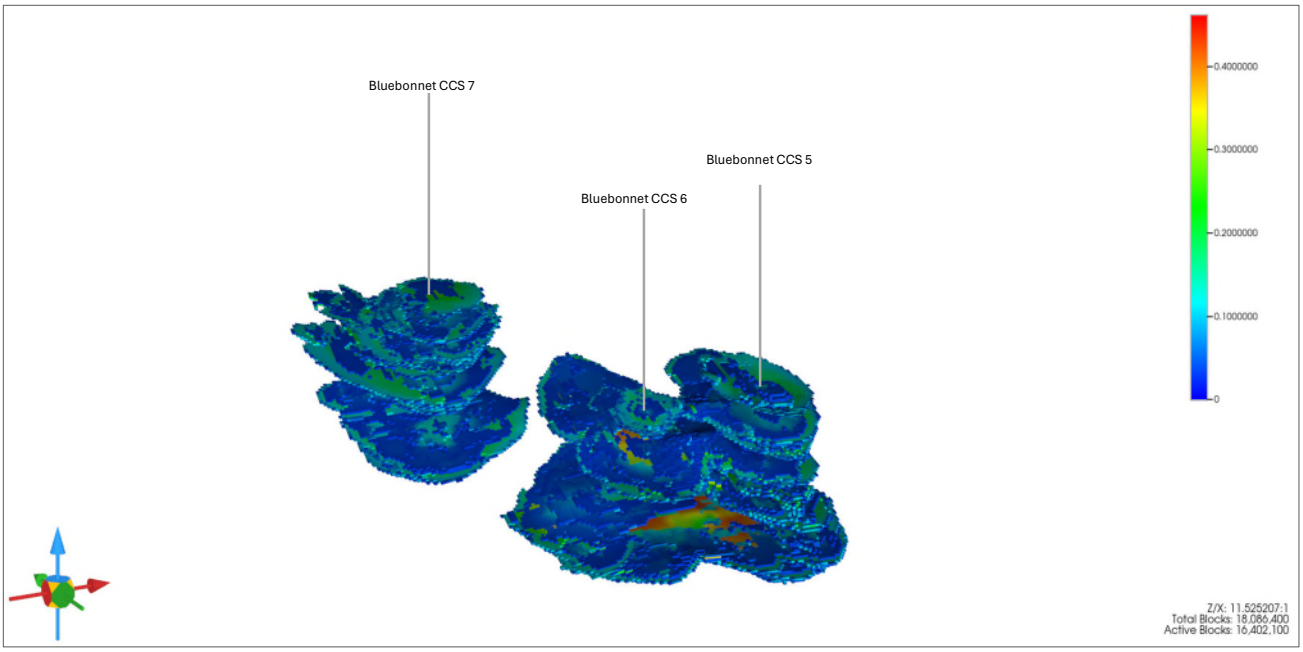


Figure AoR-316: 3D View of the CO_2 plumes for Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7.

5.14 Geochemical Modeling

Geochemical equilibrium and reactive-transport simulation modeling was conducted for the Lower Miocene confining and injection zones at Bluebonnet Sequestration Hub to evaluate site specific data acquired from the stratigraphic well. Two geochemical modeling studies were performed: (1) batch reactions with detailed geochemical equilibrium simulations and (2) reactive-transport and the multiphase flow simulations using the full-field model. Literature review for geochemical and reactive-transport modeling at carbon sequestration sites was described in detail in Section 4.11.1 of this document.

5.14.1 Geochemical Equilibrium Simulations

Geochemical equilibrium modeling was conducted using Geochemist's Workbench and the Lawrence Livermore National Laboratory thermodynamic database for aqueous, mineral, and gaseous interactions (Wolery 1992a; Wolery 1992b). The Tsonopoulos equation of state was used to improve the solubility calculation of gas at high pressures (Tsonopoulos, 1974, Tsonopoulos and Heidman, 1990).

The objective of this work is to identify primary chemical reactions (solid and aqueous phase) to be included into the reactive-transport simulations and provide initial assessment of CO_2 compatibility with rocks and fluids in the reservoir and confining zones. This modeling includes brines speciation, geochemical baseline prior injection, and CO_2 interaction with reservoir brine and minerals.

Table AoR-55 shows brine compositions for the reservoir and composite confining zone used in geochemical simulations. Dissolved constituents not shown in the table were not considered in geochemical models because their concentration was negligible or below detection limits. Trace metals (*e.g.*, arsenic, mercury, and lead) have negligible concentrations and were not tracked during modeling.

Table AoR-56 describes mineralogy used in geochemical equilibrium runs for the reservoir and confining zones. Values were obtained from XRD analysis of representative samples within each reservoir or confining system interval.

Table AoR-55: Brine chemical compositions used in geochemical and reactive-transport simulations – Lower Miocene

Name	Description	Units	Miocene Composite Confining Zone	Lower Miocene Injection Zone
Sample Depth	-	ft	3,144.7	4,337.0
Reservoir Pressure	-	psi	1,352	1,865
Reservoir Temp	-	°F	89	110
TDS	Sum of Ions	mg/L	102,754	115,470
pH	Lab	SU	7.19	7.4
Sodium	Na^+	mg/L	30,651	35,675
Calcium	Ca^{2+}	mg/L	5,471	5,783
Magnesium	Mg^{2+}	mg/L	2,060	1,809
Potassium	K^+	mg/L	102	123
Strontium	Sr^{2+}	mg/L	190	243
Barium	Ba^{2+}	mg/L	103	165
Silica	SiO_2 (aq)	mg/L	1.0×10^{-3}	1.0×10^{-3}
Aluminum	Al^{3+}	mg/L	1.0×10^{-3}	1.0×10^{-3}
Iron (total)	Fe^{2+}	mg/L	4.46	4.36
Chloride	Cl^-	mg/L	64,003	71,493
Total Alkalinity	Alkalinity	mg HCO_3^-/L	90.3	83.6
Borate	$B(OH)_3^-$	mg/L	18.4	25.5
Bromide	Br^-	mg/L	73.44	85.11
Sulfate	SO_4^{2-}	mg/L	2.0	2.0

Table AoR-56: Solid-phase mineralogy from RSWC XRD data used in geochemical equilibrium and reactive-transport simulations – Lower Miocene.

Mineral (wt%)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
Quartz	30.6	64.1
K-Feldspar	3.6	17.1
Plagioclase	3.5	14.4
Calcite	19.4	1.2
Dolomite	0.5	0
Pyrite	0.0	0.2
Illite/Smectite	32.2	1.8
Kaolinite	1.8	0.2
Analcime	0.0	0.0
Chlorite	0.7	0.0

Although some chemical reactions are known to be time dependent, equilibrium assumption was first modeled to represent the most conservative approach. The equilibrium approach allows minerals to dissolve or precipitate instantaneously and achieve final stage of interaction with other solid phase and aqueous species. This approach can simulate expected late time fluid-rock interactions anticipated in permanent CO_2 storage.

The Wolery database was selected as the thermodynamic data and activity coefficient model for equilibrium and reactive-transport simulations. Although Pitzer virial model is known to be more suitable for brines with high ionic strength (above 1.0 M) at certain conditions, the extended Debye-Hückel equation ("Bdot" equation) is determined to be more suitable for the brines analyzed for this site. Besides the ion-size parameters, the extended terms based on ionic strength have been fit for main ions in chloride-dominated waters (Truesdell and Jones, 1974) such as calcium, magnesium, sulfate, potassium, and carbonate species. In addition, the Pitzer approach has limited parametrization for iron and aluminum species as pointed out by Krupka et al. (2010). These aqueous components are very important for brines in equilibrium with clay-type minerals because they modify the ions activity, having critical impact on minerals solubility product (Appelo and Postma, 2005).

For equilibrium simulations, a rock with porosity equal to 17% is assumed. Initial CO_2 concentration in the reservoir was retrieved using flashed gas composition and the fugacity was calculated at reservoir pressure and temperature. Calculated pre-injection fugacity is 0.009 and 0.006 atm for the Lower Miocene Confining Zone and Lower Miocene Injection Zone, respectively. Secondary mineral phases were included in the simulation even though they are not present in measured XRD data (e.g., dolomite, anhydrite, gypsum, barite, strontianite, and celestite) to evaluate their precipitation tendency. In addition, plagioclase is assumed to be anorthite phase.

Three geochemical scenarios were modeled: (1) fluid equilibrium without minerals present, (2) baseline (pre-injection) equilibrium modeling between existing formation fluids and mineralogy, and (3) equilibrium modeling of formations fully saturated with CO_2 to represent the most aggressive injection case. Table AoR-57 shows reservoir fluid equilibrium state for the confining and reservoir zones. Positive and negative saturation index numbers (SI) indicate supersaturated or undersaturated condition in relation to a mineral, respectively. Fluid equilibrium modeling can provide assurance of quality fluid analysis and insight to flow paths or potential commingling as minerals in equilibrium are assumed to be primary sources of dissolved ions in formation fluids. Lower Miocene Confining Zone results suggest formation fluids are in equilibrium with the formation mineralogy including barite and calcite. Lower Miocene Injection Zone fluids are in equilibrium with barite and calcite.

Modeled pH values are lower in comparison to laboratory measured values. This result can be explained by CO_2 exsolving from fluids exposed to atmospheric conditions during analysis. Even rapid laboratory analytical result in CO_2 loss prior to measurements, resulting in a shift to more basic conditions (Appelo and Postma, 2005, page 14). Here, the Lower Miocene Confining and Injection Zones show calculated pH values similar to those reported in the literature (Kharaka et al. 2009 and Xu et al., 2010).

Table AoR-57: Mineral saturation indexes and reservoir pH of formation waters in Lower Miocene Confining and Injections Zones prior to CO_2 injection (baseline reservoir condition).

Model Results (SI)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
pH (SU)	6.9	7.1
Anhydrite	-3.6	-3.4
Barite	0.0	0.0
Calcite	0.0	0.4
Celestite	-3.0	-2.9
Dolomite	1.1	1.9
Gypsum	-3.5	-3.5
Halite	-1.6	-1.5
Illite	-14.3	-15.8
Kaolinite	-8.2	-9.8
K-Feldspar	-11.7	-12.4
Plagioclase	-15.4	-15.5
Quartz	-3.7	-3.9
Strontianite	1.2	1.6
Dawsonite	-0.9	-1.6
Analcime	-8.4	-8.8

Baseline (pre-injection) equilibrium modeling included the addition of formation mineralogy previously described in Table AoR-56. Overall, similar mineral stability tendency is observed for the Lower Miocene Confining and Injection Zones (Table AoR-58). Pre-injection, formation waters are saturated with respect to calcite, dawsonite, kaolinite, and K-feldspar and are predicted to precipitate at equilibrium. Calcite precipitation at equilibrium and associated removal of bicarbonate ions is likely the cause low pH values observed with fluid-rock equilibrium models. Clay minerals, including kaolinite, are highly sensitive to dissolved aluminum concentrations and values were reported below detection limit. Despite predicted kaolinite supersaturation, it is likely that both kaolinite and illite are stable at existing reservoir conditions considering kinetics of clay mineral precipitation. Quartz, pyrite, illite, and dolomite are considered stable phases initially present in the reservoir. Plagioclase is considered unstable at pre-injection reservoir conditions and predicted to be dissolve at existing reservoir conditions.

Table AoR-58: Mineral stability tendency and fluid pH of Lower Miocene Confining and Injections Zones in equilibrium with reservoir mineralogy.

Model Results (SI)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
pH (SU)	7.1	6.8
Fluid TDS	Minor increase	Minor decrease
Reservoir Porosity	Minor decrease	Minor decrease
Anhydrite	Dissolution	Dissolution
Barite	Stable	Stable
Calcite	Precipitation	Precipitation
Celestite	Dissolution	Dissolution
Dawsonite	Precipitation	Dissolution
Dolomite	Precipitation	Precipitation
Gypsum	Dissolution	Dissolution
Halite	Dissolution	Dissolution
Illite	Stable	Stable
Kaolinite	Precipitation	Precipitation
K-Feldspar	Precipitation	Precipitation
Plagioclase	Dissolution	Dissolution
Pyrite	Stable	Stable
Quartz	Stable	Stable
Strontianite	Minor precipitation	Minor precipitation
Analcime	Stable	Stable

Geochemical equilibrium modeling of formations fully saturated with CO_2 to simulate injection suggests CO_2 addition cause minor effects on mineral saturation states. CO_2 fugacity was assumed to be 1.26 and 1.67 for 100% CO_2 gas at Lower Miocene Confining and Injection Zone

temperatures and pressures, respectively. Table AoR-59 shows the mineral stability tendency after equilibration for each sample in the Lower Miocene Confining and Injection Zones.

Negligible changes for mineral saturation states were observed for most minerals when comparing results for existing (Table AoR-58) versus fully saturated (Table AoR-59). Values for pH are predicted to decrease approximately 1.5 SU. Minor precipitation of Dawsonite is predicted in Lower Miocene Confining and Injection Zones. Saturation with respect to illite is predicted to decrease at equilibrium; however, the mineral is relatively stable and minimal dissolution is predicted. Dolomite is considered stable and precipitation is suppressed due to slow reaction kinetics associated with dolomite. Therefore, quartz, pyrite, and dolomite likely remain the most stable phases initially present. Plagioclase dissolution will increase as larger amount of CO_2 dissolves in water shifting the equilibria to a more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite; enhanced further under CO_2-saturated reservoir conditions. However, dynamics in the reservoir during injection are more complicated as reactions are time dependent and calcite likely dissolve first at lower pH, reprecipitating at later times (equilibrium conditions).

Lower Miocene Confining Zone results show minimal effects from saturation with 100% CO_2 and equilibrium conditions have a small (~1.5%) porosity loss due to high proportions of clay minerals and mineral reprecipitation in the pore space. This finding corroborates the assumption that CO_2 will not affect the confining system integrity as pointed out by Kharaka et al. (2009). It is important to highlight that further precipitation might provide a healing effect to microfracture that might have been formed due to pressure increase (*i.e.*, mechanical deformation), as proposed by Hangx et al. (2009), enhancing long-term integrity of the confining system.

Table AoR-59: Directional shift in mineral stability tendency and fluid pH of Lower Miocene Confining Zone and Injections Zones in equilibrium with reservoir mineralogy and saturated CO2.

Model Results (SI)	Lower Miocene Confining Zone	Lower Miocene Injection Zone
pH (SU)	5.5	5.3
Fluid TDS	Minor increase	Minor decrease
Reservoir Porosity	Minor decrease	Minor decrease
Anhydrite	-	-
Barite	-	-
Calcite	Inc. precipitation	Inc. precipitation
Celestite	-	-
Dawsonite	Inc. precipitation	Inc. precipitation
Dolomite	-	-
Gypsum	-	-
Halite	-	-
Illite	Minor dissolution	Minor dissolution
Kaolinite	-	-
K-Feldspar	-	-
Plagioclase	Inc. dissolution	Inc. dissolution
Pyrite	-	-
Quartz	-	-
Strontianite	-	-
Analcime	Inc. dissolution	Inc. dissolution

5.14.2 Reactive-Transport Simulations

Reactive-transport simulations were conducted using CMG-GEM. This section provides an evaluation of geochemical influences on reservoir storage capacity and long-term trapping mechanisms. The extended Debye-Hückel equation ("Bdot") is used for consistency with geochemical equilibrium simulations. Quartz, calcite, plagioclase (anorthite), kaolinite, k-feldspar, illite, and dolomite are minerals considered in dynamic simulations. Minerals present in the XRD that resulted as non-reactive (e.g. pyrite) are not included in simulations and lumped with the quartz phase.

All mineral solubility reactions were simulated using the kinetics approach based on the transition state theory (TST). Activation energies, TST reaction rate constants, and equilibrium constants are retrieved from the literature (Palandri and Kharaka, 2004, Krupka et al. 2010, Jia et al. 2021, and Zhang et al. 2019). Mineral reactive surface area is considered one of the largest uncertainties for modeling kinetic reactions. Actual reactivity area values are assumed to be significantly lower in comparison to the conventional methods of surface area measurements (***e.g.***, BET adsorption

method). This is because certain pores are not expected to contact injected fluid due to preferential flow paths in porous media. For the current simulations, reactive surface area values were retrieved from Jia et al. (2021) and Zhang et al. (2019) and their values multiplied by 0.01 as recommended by Xu et al. (2010). For practical purposes, the final state of mineral stability is insensitive to the reactive surface area (hundreds of years after injection). However, as reactive surface area value increases, the simulation will reach the equilibrium condition faster. Thus, it allows the interpretation of how the long-term CO_2 storage affects reservoir properties within a reasonable computational time.

The effect of mineral dissolution and precipitation on porosity is also included to evaluate its impact on reservoir storage capacity. The model is based on the simple correlation that the amount of mineral change will directly impact the solid volume using the respective mineral mass, mineral molar weight, and mineral density to calculate the new void volume (porosity) over time. The modified Kozeny-Carman equation was included to model the effect of porosity changes in rock permeability.

The model is initialized into two regions, confining and reservoir, with each region having a distinct mineralogy and water chemical composition (Table AoR-55 and Table AoR-56). In total, twelve aqueous species were initialized in reservoir connate water and allowed to flow with aqueous phase in the reactive-transport simulations. The aqueous species modeled are $H_4SiO_4^0$, H^+, Ca^{2+}, Mg^{2+}, K^+, Na^+, Al^{3+}, SiO_2^0, HCO_3^-, OH^-, CO_3^{2-}, and $CaOH^+$. The selection of aqueous complexes was based on the simulation results from geochemical equilibrium runs with minerals and CO_2. Aqueous species that were not originally in the complete water analysis were assumed to have trace concentration. The reservoir is allowed to equilibrate prior to simulation start. Preliminary reactive-transport simulation results are described below and multiple parameter sets are still being considered to understand current model observations and improve simulation runtimes.

Figure AoR-317, shows minimum value results for fluid pH values at end of the injection period, aggregated across all model layers. Reservoir fluid pH values pre- and post-injection are similar to values obtained from equilibrium modeling (Table AoR-58 and Table AoR-59).

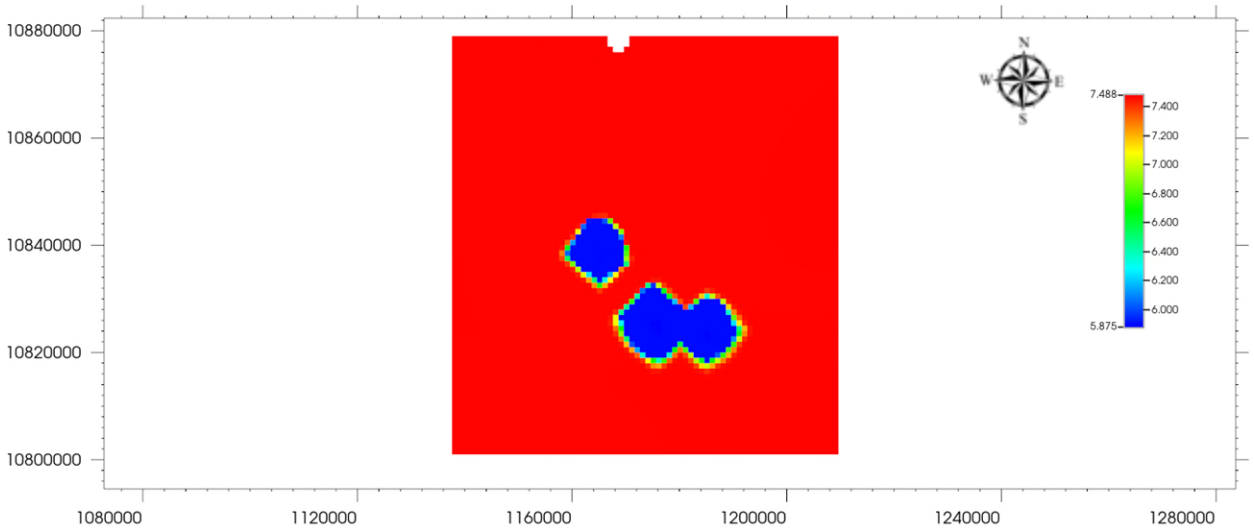


Figure AoR-317: Aggregate view for all model layers of minimum values for modeled fluid pH after cessation of CO_2 injection.

Figure AoR-318,shows reservoir mineral volume change for calcite, plagioclase, kaolinite, illite, k-feldspar, and dolomite upon cessation of injection. Dissolution of anorthite and calcite is observed during injection; however, molar changes are small due to minor proportions of calcite (1.2 mol %) in the Lower Miocene Injection Zone. Post-injection, it is expected that plagioclase continues to dissolve while calcite, kaolinite, and illite will precipitate (Xu et al., 2010, Hovorka et al. 2009). Kaolinite and minor illite precipitation are related to dissolution of plagioclase, which releases additional dissolved aluminum into formation waters.

Modeled porosity changes due to mineral dissolution and precipitation at end of the injection period are shown in Figure AoR-319 and Figure AoR-320. Negative and positive values represent the amount of increase and decrease from the initial porosity, respectively. Porosity increased a maximum of 0.3% in Lower Miocene Injection Zone through the end of injection. Porosity remained unchanged for the Lower Miocene Confining Zone due to the presence of low-permeability shales that prevent vertical upward migration of CO_2-saturated fluids. Reservoir porosity is expected to decrease over long post-injection timescales as calcite and kaolinite precipitate.

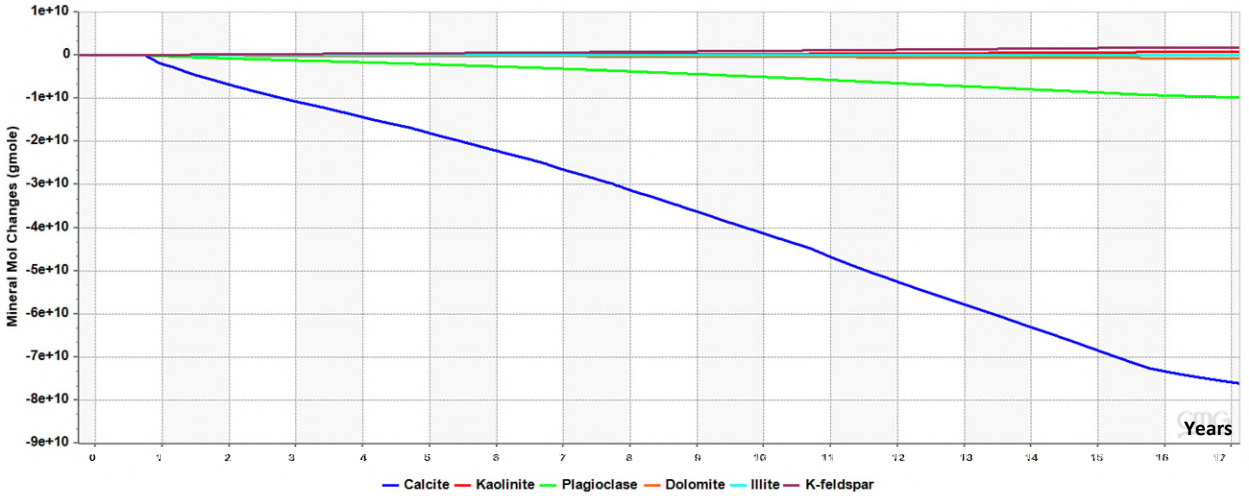


Figure AoR-318: Modeled molar change in minerals change through end of injection.

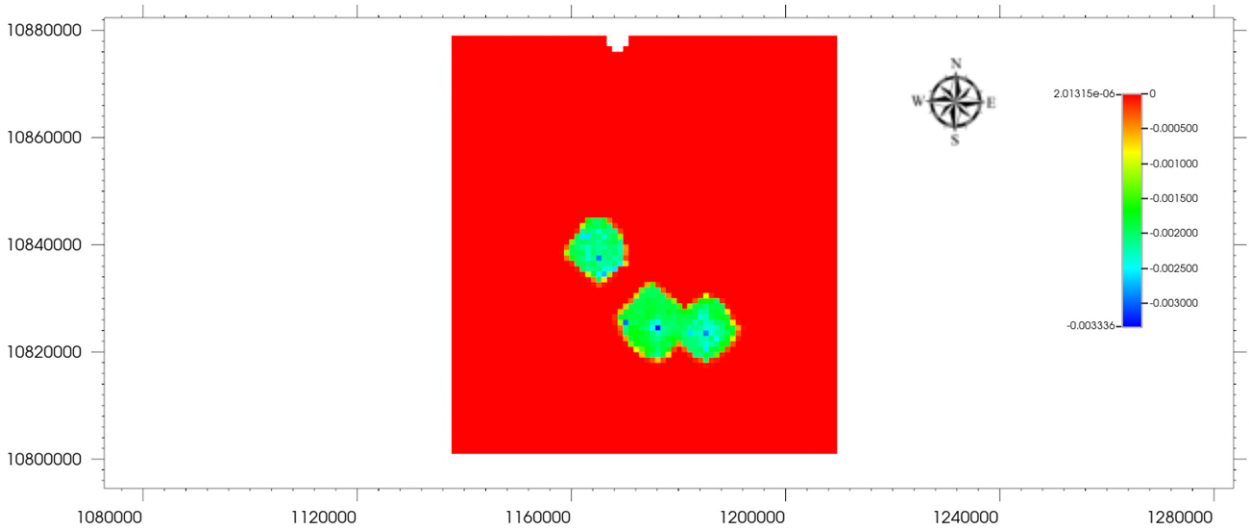


Figure AoR-319: Aggregate view for all model layers of modeled maximum porosity increase from mineral dissolution and precipitation upon cessation of injection.

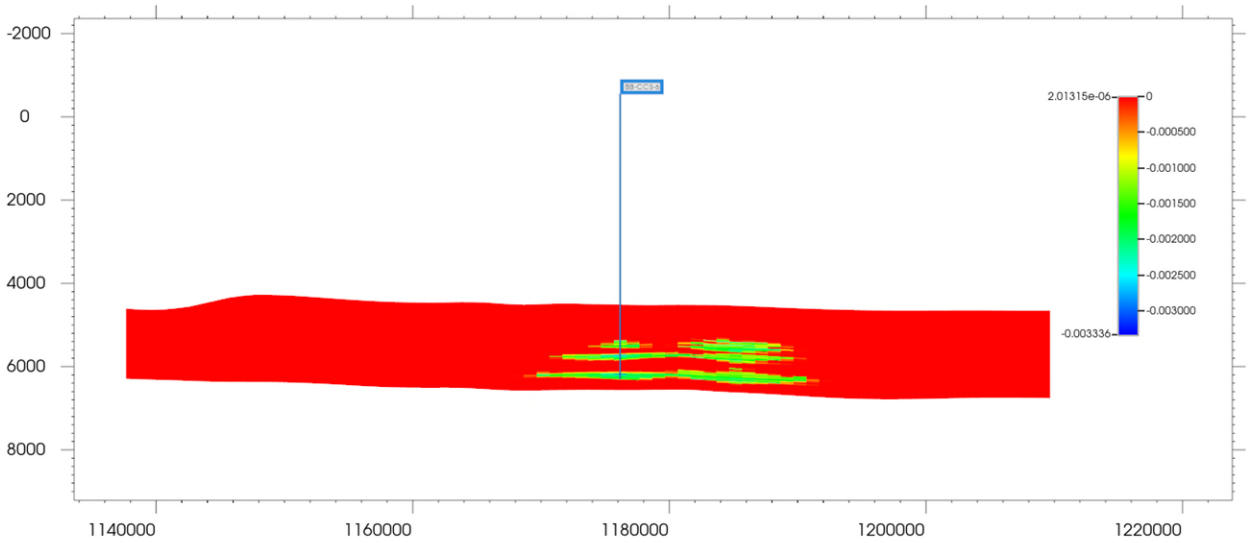


Figure AoR-320: Select E-W cross-section modeled porosity decrease from mineral dissolution and precipitation upon cessation of injection.

Modeled CO_2 trapping mechanisms (aqueous, dissolved in water, mineralization, super-critical mobile, and trapped in residual phase) are shown in Figure AoR-321. Results show primary trapping mechanisms of injected CO_2 at injection timescales is the super-critical phase as mobile and trapped CO_2. Mineral CO_2 storage is negative during injection due to calcite dissolution. Permanent sequestration of injected CO_2 as calcite is expected to occur over long post-injection timescales, eventually becoming a dominant trapping mechanism.

Compositional simulation commonly shows a larger CO_2 plume compared to reactive transport simulation. The reason for the reactive-transport simulations showing a smaller CO_2 plume, even with smaller pore volume, is due to part of the CO_2 being transferred from the super-critical state to two additional conditions that are not modeled using conventional runs: conversion in aqueous ions (*e.g.*, HCO_3^-) and precipitation as solid phase (*e.g.*, kaolinite, calcite). Thus, the compositional simulations (without geochemistry) typically provide the most conservative assessment of CO_2 plume extent.

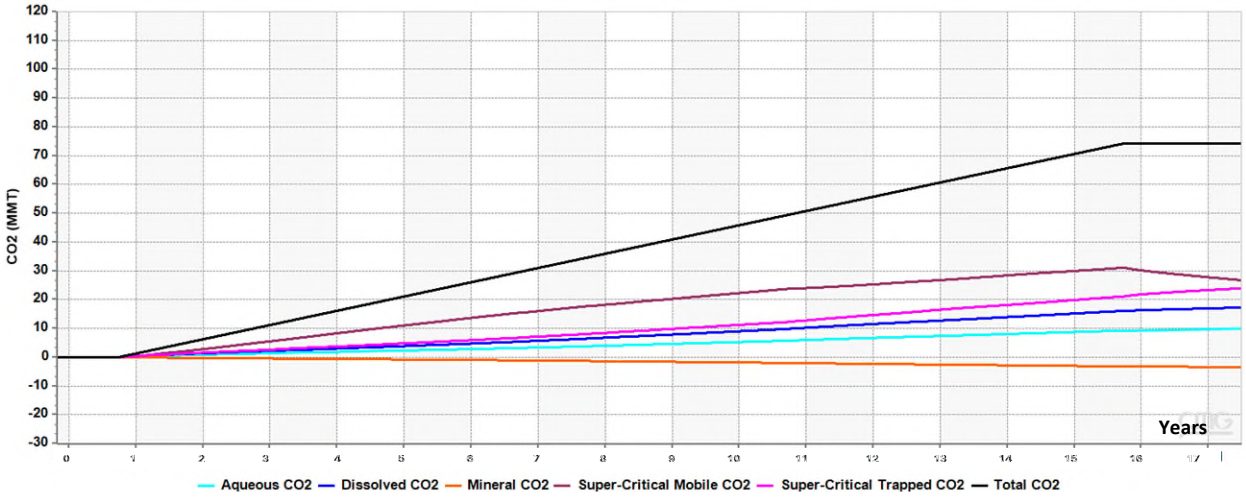


Figure AoR-321: CO_2 partitioning in reactive-transport model until cessation of injection.

6.0 Combined AoR – Oligocene & Miocene Storage Complex

For the Lower Miocene Confining Zone, the Miocene Composite Confining Zone as well as the base of USDW, the Frio/Hackberry AoR was merged with the Miocene AoR, as the confining zones are utilized for both storage complexes and also to capture the largest footprint to assess and mitigate any potential USDW contamination.

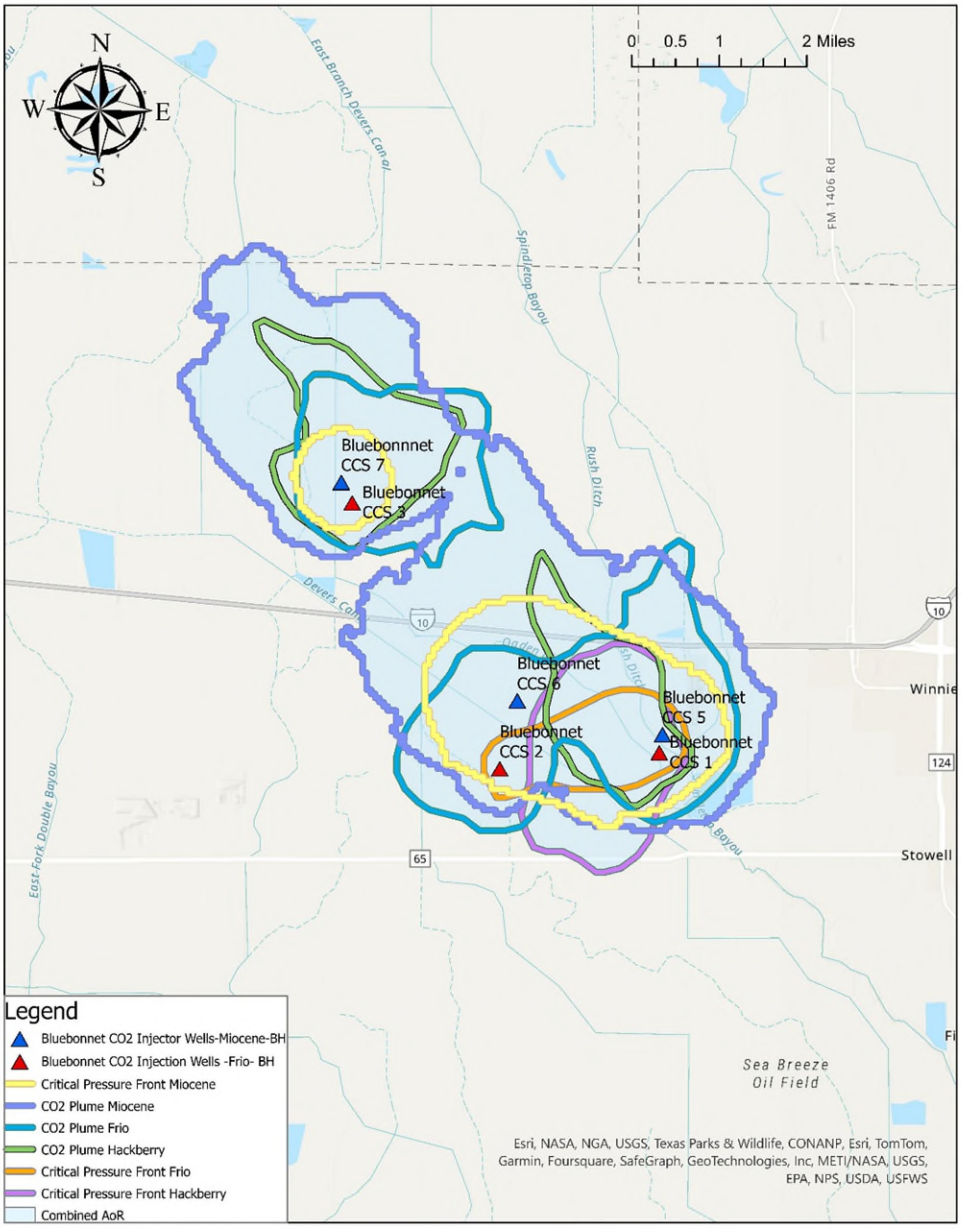


Figure AoR-322: Combined AoR Lower Miocene, Frio and Hackberry Injection Zone

7.0 Fluid Substitution Study – Frio Injection Zone

An important aspect of all CCS projects is the demonstration of viable methods for monitoring of CO_2 plume development during injection, to ensure reservoir containment, and provide data necessary for dynamic model update(s). In high porosity saline aquifers, in-situ reservoir and elastic properties are amenable to robust detection of CO_2 using time-lapse geophysical methods sensitive to elastic property (bulk density and P-wave velocity) changes with increasing CO_2 saturation. The best-known example of this – from an offshore setting - is the Sleipner project in the North Sea (Dupuy et al. 2017); credible results from an active onshore sequestration site are known from the QUEST project in Alberta, Canada (Harvey et al. 2022). While Sleipner is a shallow reservoir and monitoring clearly benefits from high-quality repeat marine seismic data, similar opportunities are expected for geophysical monitoring in high porosity, acoustically 'soft' onshore reservoirs. Our feasibility modeling workflow makes no assumption about the monitoring method (3D and/or 2D surface seismic, in-well (DAS), cross-well, VSP, etc.) eventually selected, as the modeled response of expected changes due to increasing CO_2 saturation can be detected by all methods that respond to in-situ changes in acoustic impedance (density*P-wave velocity). The presence of a 'soft' fluid (CO_2) in a brine-saturated aquifer creates a significant change in acoustic impedance, which is readily detected with traditional geophysical methods sensitive to amplitude (density and Vp) and/or AVO (Vp and Vs) response due to fluid type and saturation changes.

Key elements of our feasibility modeling workflow are summarized in Figure 1. Additional comments about specific workflow elements are highlighted here for reference.

- Fluid properties. Brine acoustic properties are determined using extant (Batzle and Wang, 1992) geophysical properties model, with inputs Pressure (P), Temperature (T), and brine salinity (NaCl equivalent). Properties for CO_2 are also a function of P and T and are obtained using the Span and Wagner (1996) equation of state (EOS) model for pure CO_2. These estimates are made readily available using the convenient worksheet calculator provided by NIST(https://webbook.nist.gov/chemistry/fluid/).

- End-member elastic properties. Geophysical response in this Gulf Coast setting is controlled by the contrast between non-reservoir mudrock and reservoir (aquifer) wet sand. In a compaction setting, with normal pressure, elastic properties of both endmember lithologies is largely a function of effective stress, manifest as present-day burial depth. Acoustic impedance of both end-member rock types generally increases with depth in a monotonic and predictable manner. The contrast between end-member rock types is generally small, given the brine-saturated nature of the reservoir material.

- Reservoir rock physics model. An advocated approach to reservoir rock physics model development is applying model(s) tied to matrix composition, total porosity (petrophysical model and core-log calibration), and with an understanding of present-day (vertical) effective stress. The workflow ensures that core-log calibration done for petrophysical properties and geophysical measurements are compatible and enable full multi-physics integration. In the absence of core, the workflow is still able to deliver model-based geophysical calibration and well-base Close-the-Loop in uncored well control and further enabled by geological analog(s) with available core-based measurements.

- Fluid replacement modeling. Expected change in reservoir rock elastic properties (primarily Vp and bulk density) with an increasing volume of CO_2 is modeled using traditional (Gassmann) fluid replacement modeling (e.g., Wang, 2001) workflows. Following on extensive legacy lab-based studies and consistent with data included therein, the fluid mixing model is varied as a function of increasing CO_2 saturation. This has an important impact on modeled expectations for geophysical response in the reservoir, particularly at early (low) volumes of in-situ CO_2 saturation.

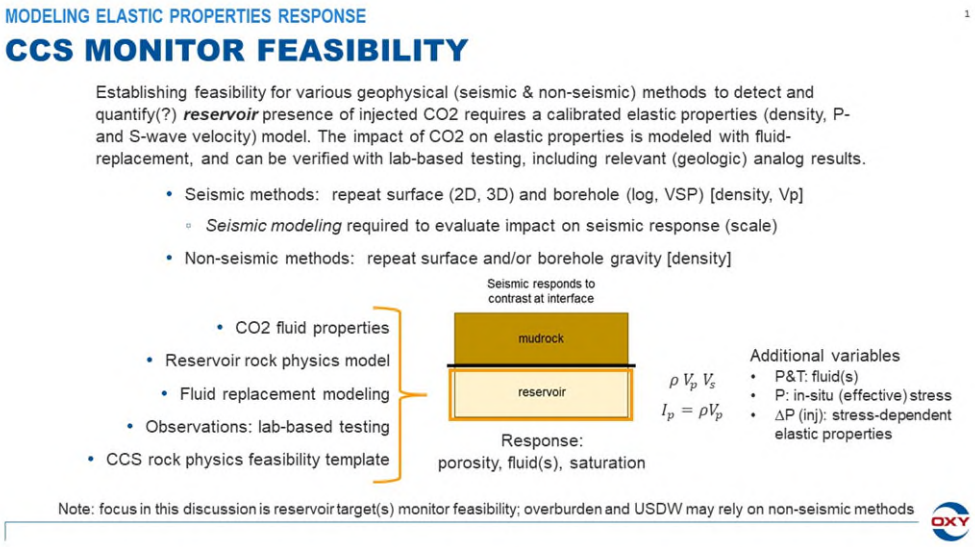


Figure AoR-323: Geophysical Modeling for CCS Monitor Feasibility – Workflow.

7.1 Challenges with Well-Based Forward Model(s).

The workflow depicted above follows established practice as commonly applied in traditional exploration and production studies where quantitative interpretation (QI) methods are used to exploit amplitude and/or Amplitude Versus Offset (AVO) signatures associated with potential oil and gas accumulations. Adaptations for modeling the behavior of CO_2 are minor and will be further detailed below.

Frequent challenges for site-specific well-based forward modeling in support of CCS site characterization may include one or more of the following.

- Legacy well control – data availability and quality. Well control associated with saline aquifer sequestration targets are frequently very limited in data and often further challenged with the quality of measured data. Borehole data quality may suffer in intervals drilled with limited hydrocarbon potential where drilling efficiency commonly takes priority. Similarly, actual petrophysical data acquisition is also limited so data common for extensive reservoir characterization (nuclear logs, cores, and fluid samples) or geophysical integration (acoustic log data, particularly shear velocity) are often unavailable. Rigorous

geophysical data quality control (QC) and synthetic log creation are often required to include geologically significant legacy well control.

- Pilot well control – Site-specific characterization. In nearly all potential CCS sites, one or more new pilot ('strat') wells are drilled with the intention of gathering detailed data necessary for quality 3D reservoir site characterization. New well control is often better borehole quality, but careful geophysical data QC will still be required. Acquisition of modern multimode acoustic log data affords the opportunity to gain high-quality P- and S-wave velocity data required for geophysical forward modeling but will also require careful post-processing (from waveform data) to ensure robust results. Recovered core and fluid samples will require additional time for analyses prior to core-log integration studies.

- Geophysical response modeling – With a local pilot well and detailed petrophysical reservoir characterization results, porosity and reservoir composition (e.g., core-log) are established and fluid sample(s) provide essential data for in-situ brine properties. The model's expected response can be forwarded to varied CO_2 presence (saturation, vertical extent in reservoir) using fluid replacement modeling. An important limitation in this workflow, not a function of data quality or availability, is the non-unique geophysical response to varied combinations of CO_2 saturation and thickness. In addition, the detailed vertical resolution afforded by wellbore measurements will be optimistic when compared to expectations from 2D/3D geophysical monitoring, where vertical resolution will be less and controlled by actual frequency content of the monitor data. Careful handling of well data with a view to eventual geophysical resolution (wavelet frequency) is essential to the feasibility modeling workflow. Including a range of expected geophysical 'noise' for monitor data is important for ensuring that reliable estimates of dynamic plume detection and resolution are made during feasibility modeling.

7.2 Well-based Geophysical Response Modeling

In this section, the geophysical modeling workflow described above will be applied to data gathered in the Encanto 01 pilot well. The project team worked closely with Petrophysics during the data evaluation and integration phase. The geophysical response modeling described here is fully aligned with petrophysical characterization results and relies on application of key core data to constrain various input parameters in modeling the expected reservoir geophysical response.

The focus of the discussion and all associated modeling described here is taken from the Frio 'Mid' interval in Encanto 01, for which conventional core (Core-6) was recovered, and from associated analyses for calibration and validation of key reservoir properties. Well-based results will also be included from the top of the immediately underlying Frio 'Lower' reservoir as additional evidence of the effectiveness of the well-based forward modeling workflow. In a subsequent section, comments will be provided on the expected geophysical response for other (deeper) Frio age reservoir intervals in the Encanto 01 well.

7.3 Petrophysical Reservoir Characterization

Well data from Encanto 01 are all acquired from a wellbore drilled with oil-based mud (OBM). Hole conditions were variable but generally good; minimal geophysical log QC was made to the recorded bulk density log and only in non-reservoir (mudrock) intervals. All multimode acoustic log data have been post-processed from the original raw waveform data to ensure that high-quality P- and S-wave velocities are available. Geophysical QC workflows using a variety of relevant models for shale (mudrock) and sand (wet) support the viability of the assembled density and velocity (Vp and Vs) data set.

Conventional core recovered from the Frio target reservoir provided essential routine core analysis (RCA) data to enable reservoir petrophysics model calibration (core-log). Core-log alignment was made using GR recorded on the recovered core. Key measured data included porosity (at simulated net confining stress) and grain density. Additional measurements of reservoir composition (X-ray diffraction) provide vital data on mineralogy (including non-quartz minerals) present in the Frio target reservoir; compositional data yield estimated grain density values in very good agreement with core-measured values.

7.4 Geophysical Fluid Properties

Fluid properties required for fluid replacement modeling include density and (adiabatic) bulk modulus. These properties for brine and CO_2 are a function of Pressure (P) and Temperature (T), and, in the case of brine, also the salinity. Local Frio reservoir P and T were estimated from regional well control including in-situ formation pressure obtained from wireline formation test (WFT) tool measurements. Fluid properties used in subsequent modeling are given in Table AoR-60.

Table AoR-60: Geophysical fluid properties – Encanto 01.

Encanto 01: Frio Mid-Lower (P = 3,500 psi; T = 175 F)			
Fluid	Density (g/c3)	Bulk modulus (GPa)	Comment(s)
Brine	1.039	2.917	Salinity 84,000 ppm; Batzle & Wang (1992) model
CO_2	0.6762	0.112	Supercritical; data from NIST, (Span and Wagner [1996] EOS)

7.5 Reservoir Rock Physics Model

To model the expected change in elastic properties within the reservoir due to increased presence of CO_2, an approach was adopted that relies on a model-based relationship between the (total) porosity and dry-rock moduli (bulk and shear) of the reservoir frame. This robust workflow is suitable for use in a variety of theoretical and/or heuristic rock physics model(s) and is directly tied to core-calibrated reservoir properties (porosity and grain mineralogy), benefits from integration of well-specific and/or geologically sensible analog measurements of geophysical properties (Vp and Vs) and creates an interpretive framework where dry-rock modulus diagnostics

can be applied (Kittridge, 2006). Further support in model validation results from the iterative application of a well-based petrophysical Close-the-Loop (CtL) workflow, which provides in-situ model validation when compared to measured density and velocity log data (see Figure AoR-324).

The Frio reservoir section in Encanto 01 is a high porosity (27-32 pu) sand. Measured velocity data suggest the reservoir framework is very poorly consolidated. An appropriate public-domain model was applied for this loosely consolidated reservoir tied to framework grain composition (see below), in-situ effective stress, and total porosity. Well-measured Vp and Vs data, along with local core-measured (stress-dependent) velocities, further supported with geologically analogous core measured velocities, yield a core-calibrated model for the local Frio reservoir section. A petrophysical CtL workflow was then applied to further validate consistency between petrophysical properties (porosity and grain composition) and measured Vp and Vs. A simple empirical model for high-porosity wet sands provides additional validation of shear velocity integrity (Vernik & Kachanov, 2010).

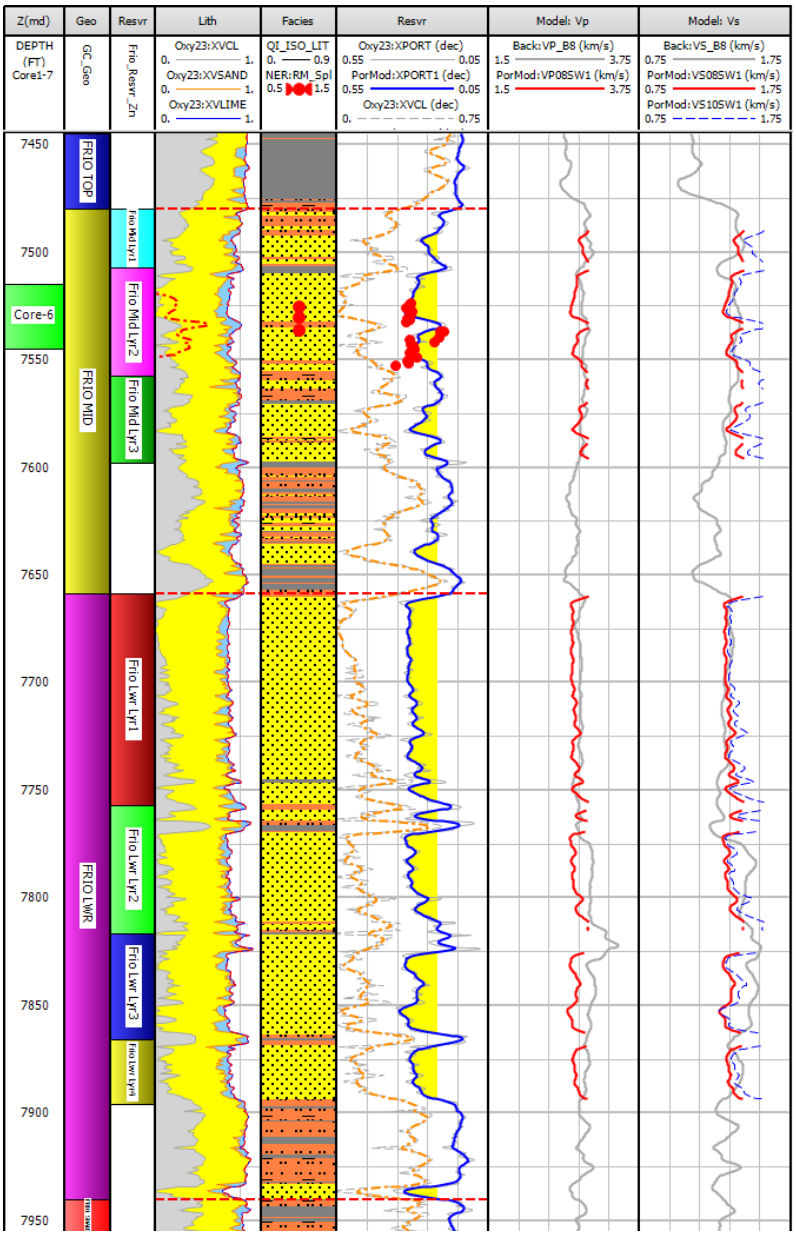


Figure AoR-324: Petrophysical Close-the-Loop (CtL), Encanto 01 Frio (Mid, Lower) reservoir interval. Depth (2) Formation Tops (3) Frio reservoir subzones (also used for fluid replacement modeling intervals) (4) Petrophysical volumes and total porosity (5) formation properties porosity and Vclay, with core calibration (6) P-wave velocity, including model-based prediction and (7) S-wave velocity, including model-based prediction and empirical model.

7.6 Fluid replacement modeling

Establishing a basis for understanding the expected geophysical response to injected CO_2 in a brine-saturated reservoir relies on fluid replacement modeling to estimate expected changes in compressional velocity, using the Gassmann model (see Wang [2001] for a complete description

of the model). The geophysical fluid properties of CO_2 (Table AoR-60) cause a reduction in reservoir P-wave velocity as the saturation increases, making traditional geophysical methods sensitive to amplitude (P-wave velocity and bulk density) suitable for time-lapse detection and characterization of the evolving CO_2 plume. The change in saturated bulk density is a simple volumetric mixing model that accounts for changes in fluid density with increasing CO_2 saturation. While S-wave velocity is also sensitive to the change in saturated bulk density, the focus here was on the change in P-wave velocity, expected to be significant and amenable to geophysical detection.

Experience in the field, supported by legacy laboratory data (Gist 1994) and recent modeling work (Papageorgiou et al. 2016), demonstrates that applying the fluid mixing model, particularly at low (< 10%) CO_2 saturation, is important in estimating expected response. At higher CO_2 saturation, 'traditional' Wood's model (isostress) is applied to estimate the bulk modulus of the mixed fluid. A traditional volumetric mixing equation calculates the density of the fluid mixture. Specific CO_2 saturation cases were modeled to establish feasibility, using the well-defined reservoir fluid properties (Table AoR-60). Results for the fluid mixture replacement modeling are shown in Figure AoR-325.

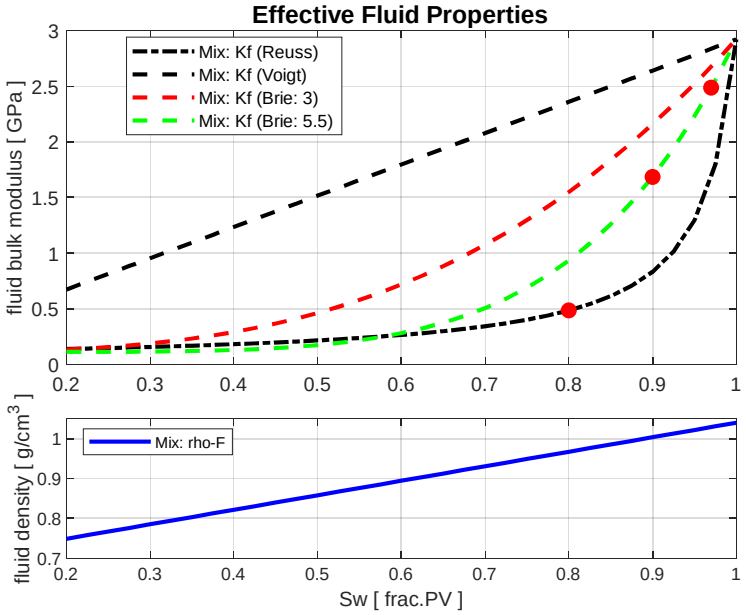


Figure AoR-325: Geophysical fluid properties for fluid replacement modeling.

Remaining input properties and parameters required for Gassmann fluid replacement modeling are noted here. Porosity is the total porosity from well log (core-calibrated). The matrix grain properties (grain density and grain bulk modulus) are based on reservoir composition as determined by XRD, using constant values based on Mid Frio conventional core data. Results for modeling in specific layers from Mid Frio and upper portion of Lower Frio are shown in Figure AoR-326.

7.7 Feasibility for geophysical monitoring – Frio Reservoir

The well-based fluid replacement model scenarios provide a log-scale vertical resolution image of expected changes in P-velocity and P-impedance (density*Vp). Geophysical monitor methods will all operate at a resolution (vertical) that is less than that seen at well log scale. An estimate of geophysical resolution is made using an appropriate up-scaling (filter) Backus average that ensures both bulk density and P-velocity bed boundaries are consistent. Expected changes in P-impedance are estimated by comparing fluid-replacement scenarios to the original in-situ (Sw 100%) starting point (Figure AoR-326).

Observations from the modeled replacement scenarios (Figures AoR-326 and AoR-327) suggest that clear geophysical identification of CO_2 would be expected for saturation greater than 10%; however, it is unlikely that geophysical methods would credibly resolve the presence of very low (3%) CO_2. The target Frio reservoir sands are high porosity and very loosely consolidated (grain-to-grain contacts and no cement), and are, therefore, very responsive to increasing CO_2 saturation. The impedance changes when compared to the low contrast in-situ wet reservoir sands will make geophysical monitoring very effective in this reservoir.

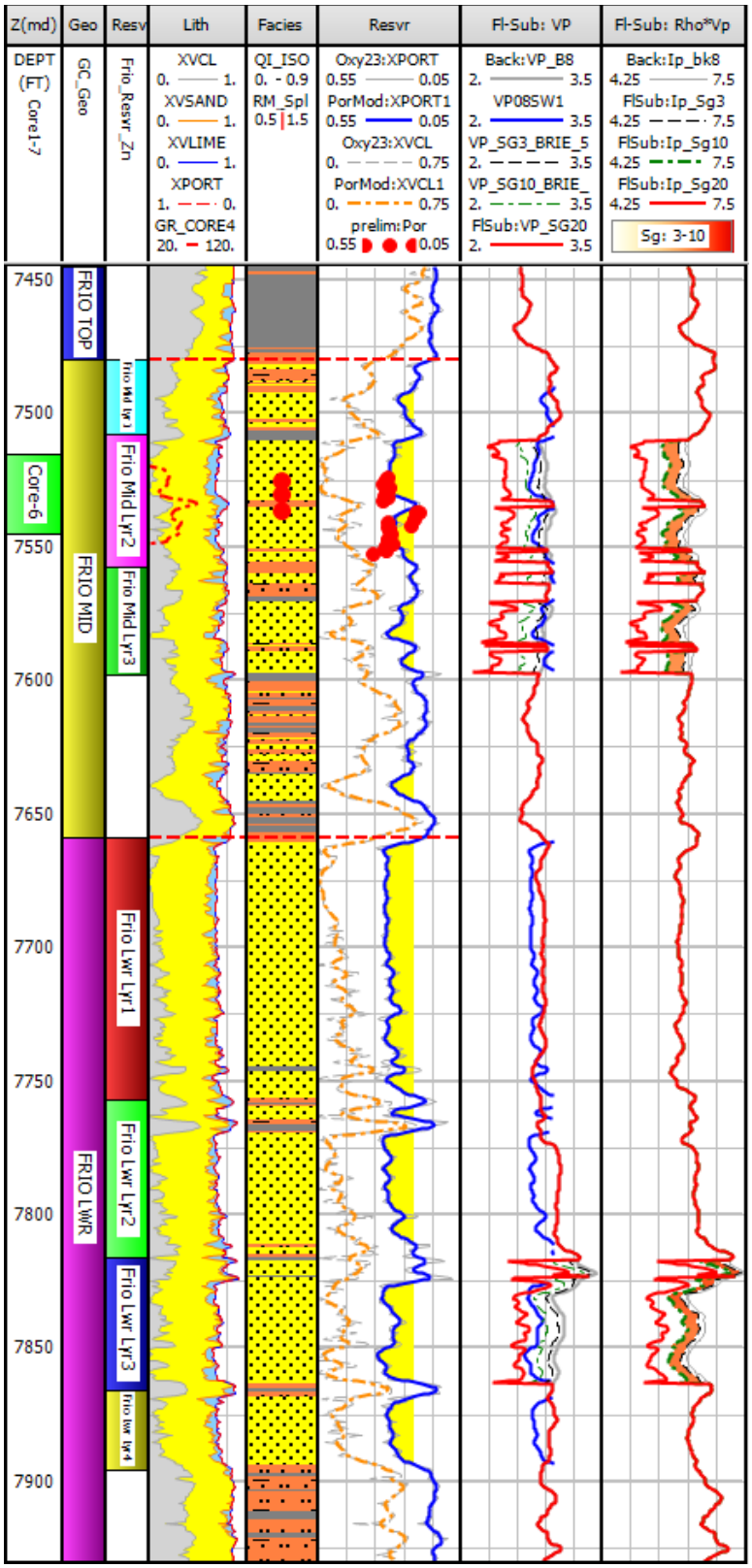


Figure AoR-326: Fluid replacement modeling, Mid and Lower Frio, Encanto 01 well.

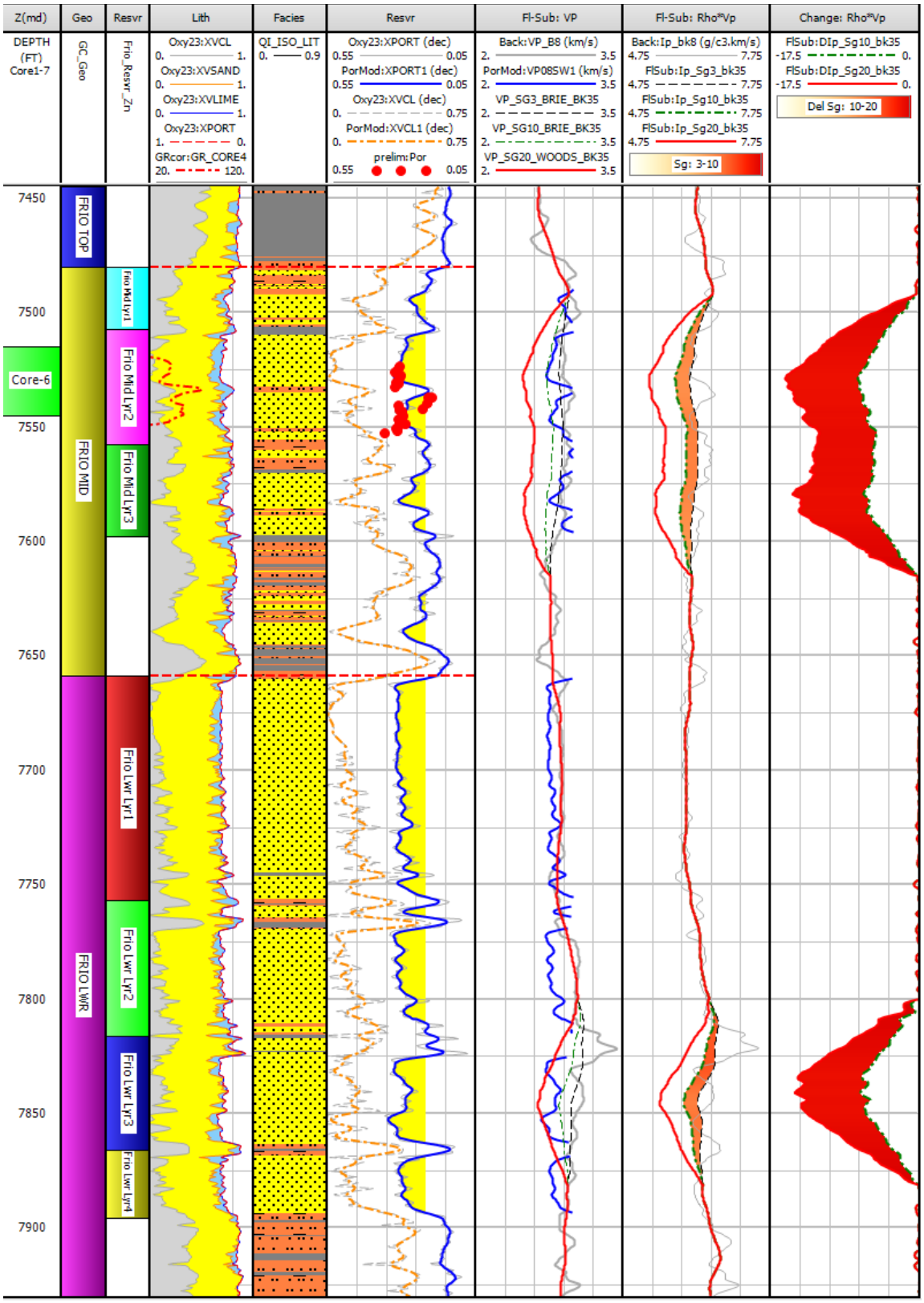


Figure AoR-327: Geophysical up-scaling fluid replacement scenarios, Mid and Lower Frio, Encanto 01 well.

The feasibility modeling of the Frio (Mid and Lower) interval provides clear evidence that robust geophysical monitoring is expected that will enable time-lapse characterization of plume development. Some cautionary notes should be noted on the feasibility workflow applied in this reservoir example.

- Fluid mixing model. As noted in the previous section, different fluid mixing models are applied at low (3% and 10%) and high (20%) CO_2 saturation, based on published laboratory and modeling studies. The choice of mixing model change at 10% CO_2 is supported by available public-domain laboratory experiments in similar (high-porosity) loosely-consolidated reservoir sands.

- Saturation change. The current modeling addresses saturation change only. It is expected that any changes in reservoir pressure (increase) due to injection, which would decrease in-situ (vertical) effective stress in the reservoir, would further increase the current modeled change in P-velocity.

- Geophysical resolution – saturation vs. thickness. The fluid replacement model scenarios included here put a constant saturation of CO_2 in all reservoir layers defined in each Frio (Mid and Lower) zone. During injection and migration, it is likely that the reservoir layers would develop variable thickness and saturation layers over time. The geophysical resolution is not expected to be able to distinguish a thin interval of high CO_2 saturation versus a thick(er) interval of low(er) saturation.

8.0 Fluid Substitution Study – Miocene Injection Zone

8.1 Well-based Geophysical Response Modeling.

In this section, the geophysical modeling workflow is applied to data gathered in the Encanto 01 pilot well. Working closely with Petrophysics during the data evaluation and integration phase, the geophysical response modeling described here is fully aligned with petrophysical characterization results and relies on application of key core data to constrain various input parameters in the modeling of expected reservoir geophysical response.

The focus of the discussion and all associated modeling described here is taken from the Lower Miocene injection interval in Encanto 01, where conventional core (Core-3) and associated analyses for calibration and validation of key reservoir properties have been recovered. As the Encanto 01 well is outside the dynamic model plume, scCO2 saturation taken from the dynamic model (year-5 injection) was used in a similar reservoir quality (porosity) reservoir. The average scCO2 saturation is the pore volume weighted (petrophysical) average.

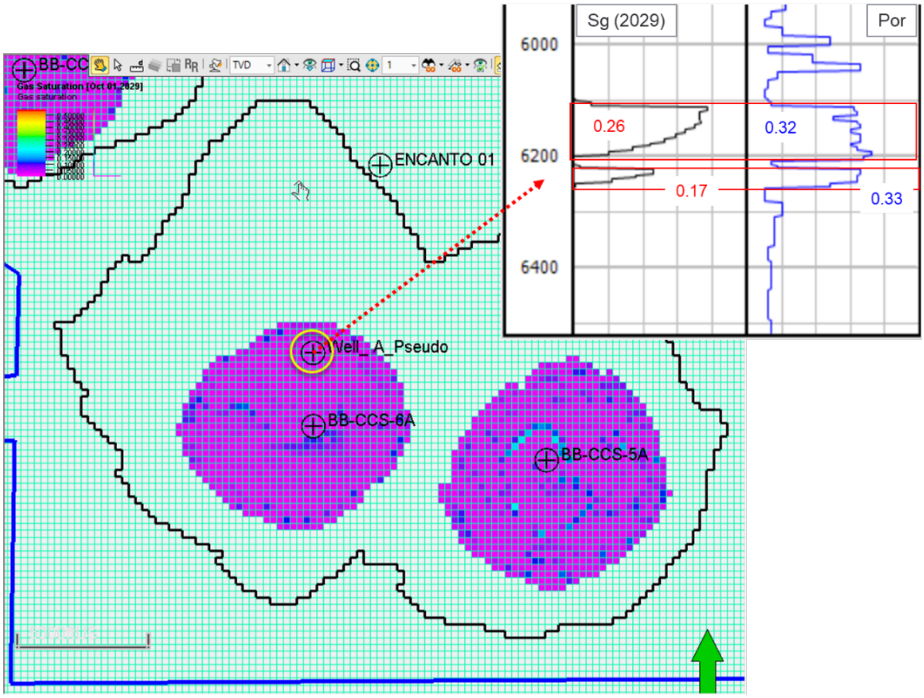


Figure AoR-328: Portion of dynamic model and layer-based evidence for average scCO2 saturation.

8.2 Geophysical Fluid Properties

Fluid properties required for fluid replacement modeling include density and (adiabatic) bulk modulus. These properties for brine and scCO2 are a function of Pressure (P) and Temperature (T), and in the case of brine, also the salinity. Local Lower Miocene reservoir P and T were estimated from regional well control including in-situ formation pressure obtained from Wireline Formation Test (WFT) tool measurements. Fluid properties used in subsequent modeling are given in Table AoR-61.

Table AoR-61: Geophysical fluid properties – Encanto 01.

Encanto 01: Lower Miocene (P = 2,500 psi; T = 150 F)			
Fluid	Density (g/c3)	Bulk modulus (GPa)	Comment(s)
Brine	1.063	3.031	Salinity 110,000 ppm; Batzle & Wang (1992) model
CO2	0.626	0.071	Supercritical; data from NIST, (Span and Wagner [1996] EOS)

8.3 Fluid replacement modeling

Establishing a basis for understanding the expected geophysical response to injected scCO2 in a brine saturated reservoir relies on fluid replacement modeling to estimate expected changes in compressional velocity, using the Gassmann model (see Wang [2001] for a complete description of the model). The geophysical fluid properties of scCO2 cause a reduction in reservoir P-wave

velocity as the saturation increases, making traditional geophysical methods sensitive to amplitude (P-wave velocity and bulk density) suitable for time-lapse detection and characterization of the evolving scCO2 plume. The change in saturated bulk density is a simple volumetric mixing model that accounts for changes in fluid density with increasing scCO2 saturation. While S-wave velocity is also sensitive to the change in saturated bulk density, focus here is on the change in P-wave velocity, expected to be significant and amenable to geophysical detection.

Remaining input properties and parameters required for Gassmann fluid replacement modeling are noted here. Porosity is the total porosity from well log (core-calibrated). The matrix grain properties (grain density and grain bulk modulus) are based on reservoir composition as determined by XRD; using constant values based on Lower Miocene conventional core data.

8.4 Feasibility for geophysical monitoring – Lower Miocene Reservoir

The well-based fluid replacement model scenarios provide a log-scale vertical resolution image of expected changes in P-velocity and P-impedance (density*Vp). Geophysical monitor methods will all operate at a (vertical) resolution that is less than that seen at well log scale. An estimate of geophysical resolution is made using an appropriate up-scaling (filter) Backus average that ensures both bulk density and P-velocity bed boundaries are consistent. Expected changes in P-impedance are estimated by comparing fluid-replacement scenarios to the original in-situ (Sw 100%) starting point (Figure AoR-329).

Observations from the modeled replacement scenarios suggest that a clear geophysical identification of scCO2 would be expected at year 5 (saturation 0.17 – 0.26 v/v). The target Lower Miocene reservoir sands are high porosity and very loosely consolidated (grain-to-grain contacts and no cement), and are therefore, very responsive to increasing scCO2 saturation. The impedance changes (generally > 8% across reservoir injection interval) when compared to the low contrast in-situ wet reservoir sands will make geophysical monitoring very effective in this reservoir.

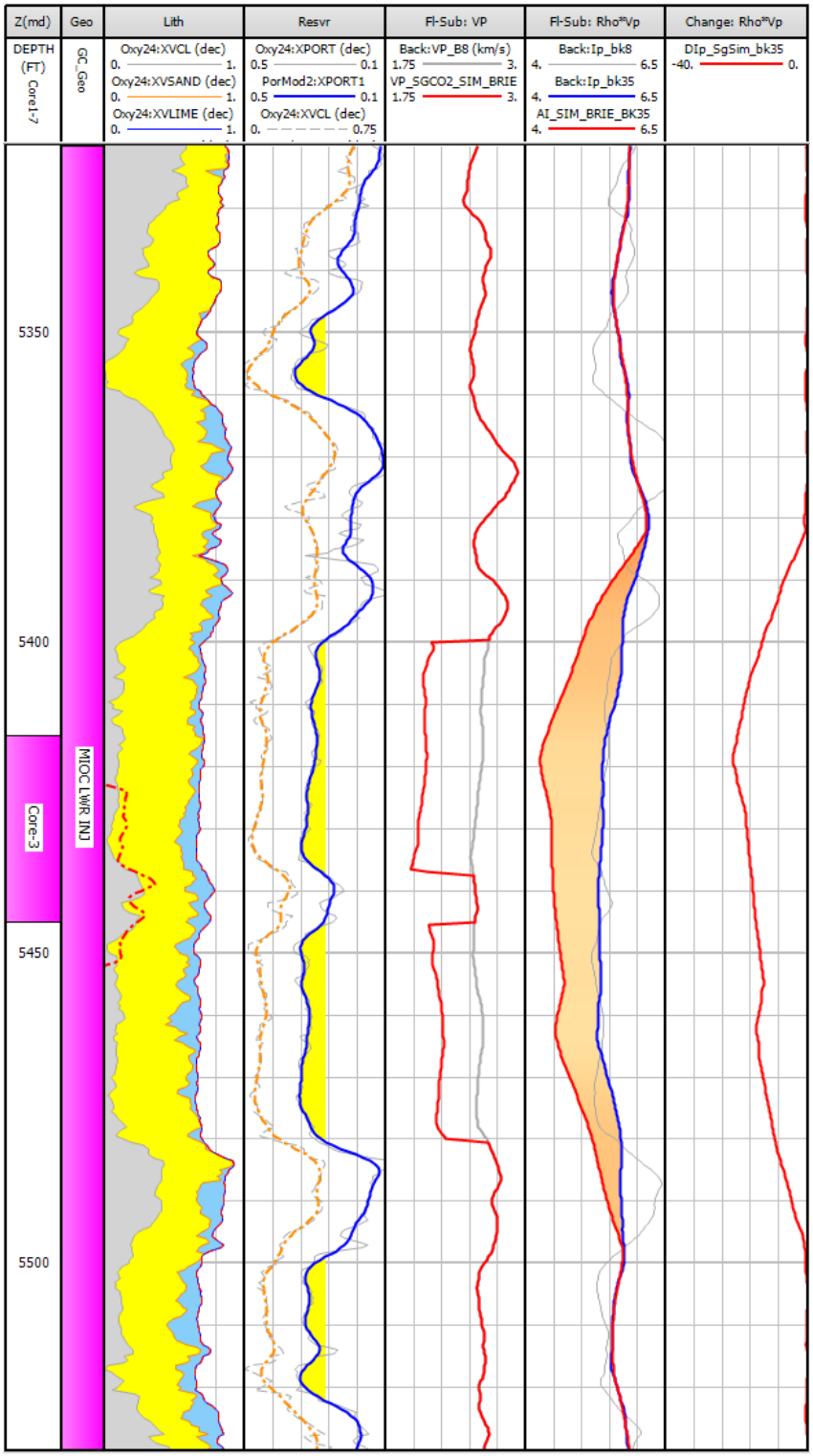


Figure AoR-329: Geophysical up-scaling fluid replacement scenarios, Lower Miocene, Encanto 01 well.

9.0 Corrective Action

9.1 Tabulation of wells within the AoR

Pursuant to 40 CFR §146.82(a)(4). 40 CFR §146.82(a), 40 CFR §146.84(c)(2), and 40 CFR §146.84(d), an exhaustive search using multiple methods is required to identify artificial penetrations (APs) in the Area or Review (AoR). The Bluebonnet Sequestration Hub, LLC, used the following methods when evaluating the area:

- Public records searches
    - Texas Railroad Commission (TRRC) online records search and interactive Geographic Information System (GIS) viewer. (https://rrc.texas.gov/resource-center/research/gis-viewer)
    - Texas Railroad Commission (TRRC) microfilm/Hardcopy records search.
    - Texas Bureau of Economic Geology (BEG) database. (https://coastal.beg.utexas.edu/continuum/#!/)
    - Texas Commission on Environmental Quality (TECQ) online records.
    - Texas Water Development Board (TWDB) online records.
    - Texas Department of Licensing and regulation (TDLR) online records.
    - Texas General Land Office (GLO) database. (https:?/gisweb.glo.texas.gov/glomapjs/index.html)
    -
- Third-party well databases licensed by Oxy Low Carbon Ventures, LLC.

- Review of historical aerial photos licensed by Bluebonnet.
- Aerial Magnetic Survey acquired by Bluebonnet in 2025 (Appendix F).

The proposed AoR represents approximately 22 square miles of extension (combination of pressure front at 15 and 20 years of injection and CO_2 plume at 100 years post injection) and includes 29 legacy oil and gas wells and 39 water wells (excluding Bluebonnet USDW 01), according to the records obtained from the public records and private databases. Bluebonnet USDW 01 well was reported originally as a water well through TWDB with the permit number 668850 but was later converted to an aquifer monitoring well and reported in TRRC database with the API 42071326720000. The locations of these wells are shown in Figure AoR-330 (oil and gas wells) and Figure AoR-331 (water wells). The area is dedicated mostly to farming and recreational activities. Oil and gas development is present in areas outside of the AoR; however, exploration activities in the proposed AoR have not proved to be economical, as all the legacy wells were classified as dry holes.

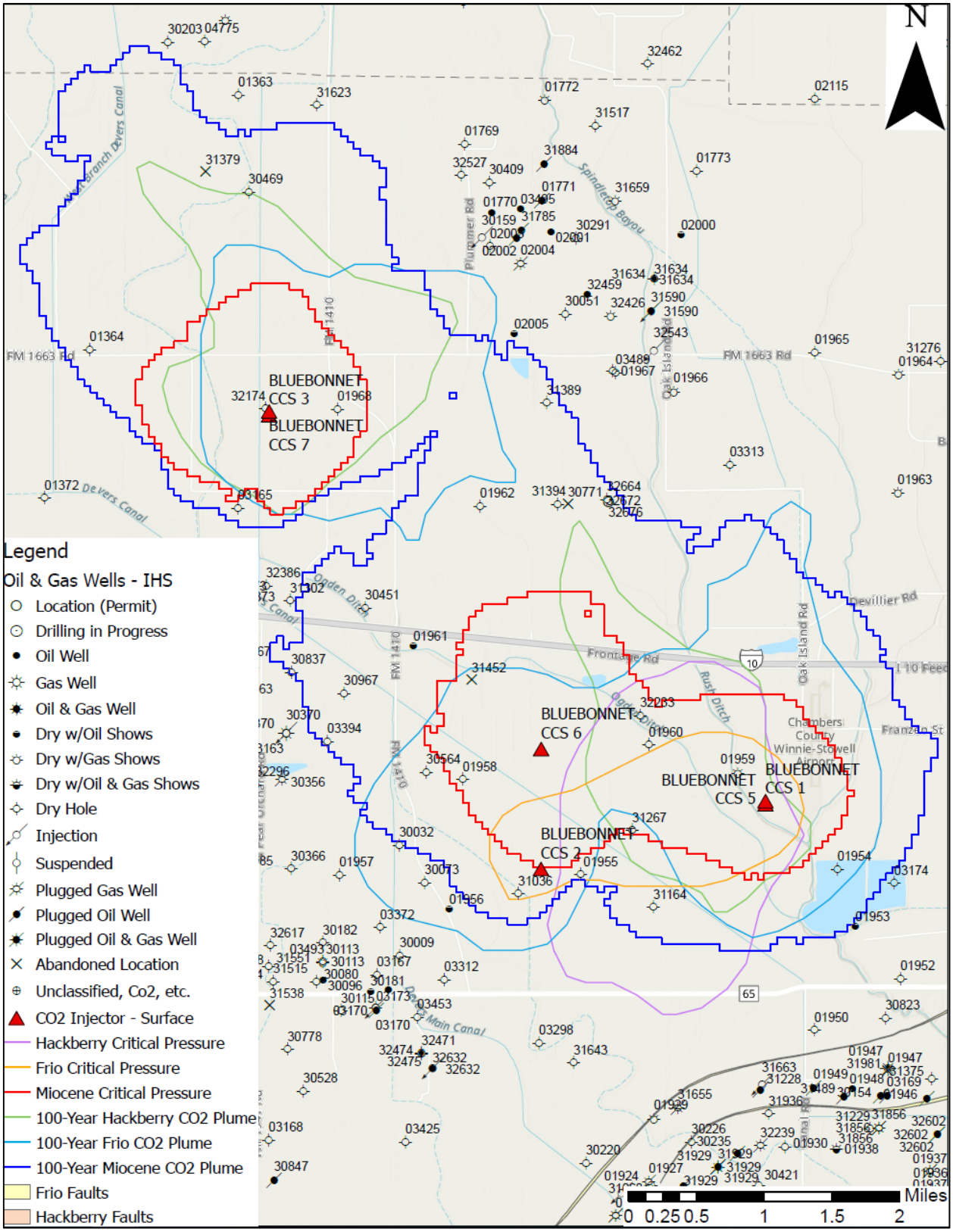


Figure AoR-330: Oil and gas wells and deep penetrations in the Area of Review.



Figure AoR-331: Water well distribution in the Area of Review.

9.1.1 Oil and Gas Wells Within the AoR

As outlined in the previous section, there are 29 oil and gas wells within the AoR, identified through both public and private databases (Table AoR 62). During the research and evaluation of these wells/deep penetrations, some discrepancies were noted between the TRRC, BEG, GLO, and IHS databases. To verify the locations, the files for each well were obtained from TRRC offices, and the plats were compared with the positions presented in the maps and viewers. In addition to reviewing databases and microfilms, Bluebonnet conducted a Magnetic Survey over the AoR in 2025 to validate the locations and eliminate the possibility of unreported wells that could pose a leakage risk. Furthermore, Bluebonnet licensed historical imagery to aid in the identification of well locations.

The reconciliation of the different well databases, imagery, films, plats and data from the Magnetic Survey is summarized as follows (for additional information please refer to appendix F of the AoR):

- API (42071019540000) - Well is not shown in TRRC viewer or BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using information from IHS and GLO as well. The magnetic survey validated the well location with a minimum displacement to the south-west.
- API (42071019550000) - Well is not shown in TRRC viewer. Location was confirmed with paper files obtained from TRRC files. Reported using data from IHS, BEG and GLO as well. The magnetic survey validated the location of the well.
- API (42071019560000) - Well is not shown in BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using data from IHS, TRRC, and GLO. The magnetic survey validated the location of the well. Aerial imagery from 1970 confirmed the location of the well.
- API (42071019580000) - Location was confirmed with paper files obtained from TRRC files. Reported using information from BEG, IHS, TRRC and GLO. The magnetic survey validated the location of the well.
- API (42071019590000) - Well is not shown in BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using data from IHS, TRRC, and GLO. The magnetic survey validated the location of the well.
- API (42071019600000) - The well location in BEG and IHS align, but do not correspond with the TRRC or the plat. Additionally, the TRRC and the plat information themselves are not in agreement. The GLO database has reported the well based on the plat information. A magnetic survey did not identify an existing well at the reported locations, and aerial imagery from 1941 did not reveal a clearly defined path. The project will proceed with an additional ground survey to definitively rule out the presence of the legacy well.
- API (42071019610000) – Well is not shown in BEG Viewer. Reported using data from IHS, TRRC, and GLO. The magnetic survey validated the location of the well.

- API (42071019620000) – Location was reported using data from TRRC, GLO, BEG and IHS. Aerial imagery from 1960 validated the well location. The magnetic survey validated the well location.
- API (42071019680000) – Location was reported using data from TRRC, and while IHS and BEG are aligned, there is a discrepancy regarding the location and plat information on GLO. The Magnetic survey has confirmed that the well's location matches the GLO coordinates.
- API (42071031650000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location. The project will conduct additional on the ground survey due to the proximity of the well to surface structures.
- API (42071033940000) – Well is not shown in TRRC viewer or BEG Viewer. The well coordinates are consistent with both the GLO and IHS records. The magnetic survey indicates that the well location is slightly displaced to the southeast from the GLO coordinates.
- API (42071300320000) - Well is not shown in TRRC viewer or BEG Viewer. The well coordinates align with both the GLO and IHS records. The magnetic survey and aerial images from 1969 confirm the well coordinates as GLO.
- API (42071300730000) – Well is not shown in BEG Viewer. Location was confirmed with paper files obtained from TRRC files. Reported using information from TRRC, GLO and IHS. The magnetic survey and the aerial imagery from 1970 validated the reported well location.
- API (42071304510000) – Location was reported using data from TRRC, GLO, BEG and IHS. Aerial imagery from 1978 validated the well location. The magnetic survey validated the well location.
- API (42071305640000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.
- API (42071304690000) – Well is not shown in BEG Viewer. The well is reported using data from TRRC, GLO and IHS. The magnetic survey shows interference with the pipeline and the Project will conduct an on-ground survey to validate well location.
- API (42071308370000) – The well is not displayed in BEG. The well's data, sourced from TRRC and GLO, reveals discrepancies in the coordinates when compared to IHS records. Both the magnetic survey and aerial imagery have confirmed the well's location as per the data from GLO and TRRC.
- API (42071309670000) – The well is not displayed in BEG. Reported using information from TRRC, GLO and IHS. The magnetic survey and the aerial imagery from 1979 validated the reported well location.
- API (42071310360000) – The well is not displayed in BEG. Reported using information from TRRC, GLO and IHS. The magnetic survey and the aerial imagery from 1980 validated the reported well location.

- API (42071311640000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey and the aerial imagery from 1982 validated the well location.
- API (42071312670000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey and the aerial imagery from 1982 validated the well location.
- API (42071313890000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.
- API (42071313940000) – The well is not displayed in BEG. Reported using information from TRRC, GLO and IHS. The magnetic survey validated the reported location.
- API (42071321740000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.
- API (42071322330000) – Location was reported using data from TRRC, GLO, BEG and IHS. The magnetic survey validated the well location.

Table AoR-62: Oil and Gas wells within the AoR (Source IHS Database for coordinates).

	Lease Name	Well No	Field Name	Status	Depth(ft)	Spud Date	Completion date	Surface Latitude	Surface Longitude
42071013640000	Drought	1	Wildcat	D&A	1,200	1/1/1926	4/14/1926	29.859561	-94.520235
42071019540000	J W Garth Jr Etal	1	Wildcat	D&A	9,012	9/11/1947	10/12/1947	29.804871	-94.427522
42071019550000	Drought H P	1	Wildcat	D&A	9,505	10/3/1955	11/1/1955	29.803999	-94.459076
42071019560000	Garth Brothers	1	Wildcat	D&A	9,250	1/22/1955	2/7/1955	29.800048	-94.475151
42071019580000	Sterrett Eat Fred R	1	Wildcat	D&A	9,550	8/9/1959	8/25/1959	29.813985	-94.47371
42071019590000	Wm Doornbos Etal	1	Wildcat	D&A	9,025	3/31/1956	4/25/1956	29.815109	-94.439906
42071019600000	Trinity Rice	1	Wildcat	D&A	8,019	6/11/1941	7/2/1941	29.817958	-94.450897
42071019610000	Ogden L G Etal	1	Wildcat	D&A	9,617	3/23/1958	4/22/1958	29.828219	-94.479973
42071019620000	Debellvue Mrs Maria	1	Wildcat	D&A	9,348	8/4/1959	8/23/1959	29.843271	-94.471986
42071019680000	Simon Walter	1	Wildcat	D&A	7,788	8/20/1935	9/16/1935	29.853512	-94.489681
42071031650000	C H Lanz	1	Wildcat	D&A	7,629	6/25/1939	7/8/1939	29.842743	-94.501766
42071033940000	O C Devillier Jr	1	Wildcat	D&A	9,317	4/4/1967	4/16/1967	29.81786	-94.490392
42071300320000	Earl Cooper Etal	1	Wildcat	D&A	9,500	9/10/1969	9/28/1969	29.806837	-94.481391
42071300730000	Garth Co	3	Wildcat	D&A	9,265	2/16/1970	2/26/1970	29.802837	-94.478207
42071304510000	O C Devillier	4	Wildcat	D&A	12,215	5/13/1976	7/20/1976	29.832207	-94.485955
42071304690000	Beaumnt Rc Mll	1	Wildcat	D&A	9,008	8/16/1976	8/25/1976	29.876635	-94.500944
42071305640000	M E Hunter	1	Devillier	D&A	12,665	6/19/1977	7/25/1977	29.814713	-94.478177
42071308370000	O C Devillier	6	Devillier	D&A	10,993	6/21/1978	8/9/1978	29.825214	-94.494929
42071309670000	Devillier O C	7	Devillier	D&A	11,270	10/12/1979	11/23/1979	29.823003	-94.488418
42071310360000	Garth	1	Wildcat	D&A	11,000	4/3/1980	5/24/1980	29.80178	-94.466697
42071311640000	Garth	1	Wildcat	D&A	16,000	2/26/1981	6/4/1981	29.800518	-94.450078
42071312670000	Doornbos Willim Etl	1	Wildcat	D&A	18,950	10/25/1981	8/5/1982	29.808728	-94.452779
42071313890000	Simon S E	1	Wildcat	J& A	9,119	12/30/1982	1/19/1983	29.854472	-94.463966
42071313940000	Devillier L C	1	Wildcat	D&A	9,300	12/10/1982	12/28/1982	29.843595	-94.462472
42071321740000	Holter Et Al	1	Devillier	D&A	11,000	4/12/2000	5/5/2000	29.853463	-94.498527
42071322330000	Doornbos	1	Wildcat	D&A	10,800	10/11/2002	12/10/2002	29.821072	-94.451988
42071326640000	Encanto	1	Unnamed	TA	8,581	12/2/2022	2/10/2023	29.844177	-94.456423
42071326720000	Bluebonnet USDW	1	Monitoring Well	Active	1,630	5/5/2024	6/5/2024	29.844028	-94.456689
42071326760000	Bluebonnet USDW	8	Monitoring Well	Active	2,950	5/10/2025	5/29/2025	29.844026	-94.456309

9.1.2 Water Wells Within the AoR

The thirty-nine water wells identified from databases and reports within the AoR are listed in Table AoR-63 (excluding Bluebonnet USDW 01). All the wells targeted the Chicot aquifer. These wells are dedicated to domestic use, stock, rig supply, and groundwater monitoring activities. The measured depths range from 122 ft to 500 ft. None of these forty wells penetrated the injection zone or the confining zone. None of the wells require corrective action.

In addition to reviewing databases and microfilm, Bluebonnet conducted interviews with several landowners in the area. Through these interviews, eight additional water wells were identified that lacked reporting numbers or documentation, yet are being utilized as water supply for domestic purposes or irrigation (Table AoR 64). These wells are shallow, targeting freshwater zones between 50-500 feet, and none of them penetrated the injection or confining zones.

Table AoR-63: Water wells within the AoR.

Well Report/Plugging Report/State Well Number	Well Type	Owner Name	Use	Latitude	Longitude	Borehole Depth (ft)	Date Completion	Aquifer
6413102	Withdrawal of Water	Sun Oil Co	Plugged or Destroyed	29.86639	-94.48278	175	0/0/1945	Chicot
6413111	Withdrawal of Water	W.M. McBride	Domestic	29.86278	-94.49417	171	0/0/1960	Chicot
6413105	Withdrawal of Water	U.S. Dept of Agriculture	Unused	29.86056	-94.47528	122	0/0/1937	Chicot
6413106	Withdrawal of Water	Lawrence Rowland	Unused	29.84472	-94.48361	180	0/0/1940	Chicot
6413101	Withdrawal of Water	Oscar Devillier	Unused	29.85833	-94.48111	500	0/0/1917	Chicot
6413103	Withdrawal of Water	L.L. Fontenot	Plugged or Destroyed	29.86445	-94.49278	331	0/0/1943	Chicot
6413112	Withdrawal of Water	C.B. Jeffery	Stock	29.86639	-94.47694	176	0/0/1962	Chicot
6413110	Withdrawal of Water	O.C. DeVillier	Domestic	29.84333	-94.49278	160	0/0/1950	Chicot
6413401	Withdrawal of Water	Mary Hunter O.C. Devillier,Jr	Unused	29.81111	-94.47917	257	0/0/1937	Chicot
6413402	Withdrawal of Water	Starrett	Unused	29.80861	-94.47861	240	0/0/1931	Chicot

Well Report/Plugging Report/State Well Number	Well Type	Owner Name	Use	Latitude	Longitude	Borehole Depth (ft)	Date Completion	Aquifer
6413501	Withdrawal of Water	U.S. Dept.of Agriculture	Unused	29.83222	-94.43139	164	0/0/1937	Chicot
6413104	Withdrawal of Water	S.E. McBride	Plugged or Destroyed	29.86306	-94.49278	176	0/0/1936	Chicot
6413801	Withdrawal of Water	Unknown	Unused	29.79083	-94.44806	340	0/0/1935	Chicot
10030	Withdrawal of Water	Goldston Oil Corp.	Unknown	29.81667	-94.47472	275	9/20/2002	Chicot
68156	New Well	Mr. & Mrs. Larry De Villier, Jr.	Rig Supply	29.85806	-94.47556	180	1/14/2004	Chicot
114973	New Well	Lisa Martin/Brad Cron	Domestic	29.84389	-94.48639	170	10/27/2004	Chicot
142520	New Well	Mark Huddleston	Stock	29.85	-94.5	165	9/25/2007	Chicot
214038	New Well	Cenpeck LLC	Domestic	29.79111	-94.44806	172	3/7/2010	Chicot
254611	New Well	M. Bramble	Domestic	29.85806	-94.50833	165	9/14/2005	Chicot
259784	New Well	Juan Rodriguez	Domestic	29.845	-94.49333	172	1/17/2011	Chicot
326165	New Well	Richard Ferguson	Domestic	29.84556	-94.48528	170	7/27/2012	Chicot
326856	New Well	Steve Devillier	Domestic	29.83056	-94.43472	160	6/26/2010	Chicot

Well Report/Plugging Report/State Well Number	Well Type	Owner Name	Use	Latitude	Longitude	Borehole Depth (ft)	Date Completion	Aquifer
438155	New Well	Jesse Robertson	Domestic	29.85588	-94.49257	172	4/10/2016	Chicot
442143	New Well	Neal Prejean	Domestic	29.85085	-94.48538	174	10/18/2016	Chicot
449017	New Well	Veronica L Vargas	Domestic	29.84492	-94.49525	178	7/3/2016	Chicot
480424	New Well	Larry Harper	Domestic	29.81329	-94.48012	256	5/22/2018	Chicot
512073	New Well	James Smiley	Domestic	29.84436	-94.49121	180	5/15/2019	Chicot
547012	New Well	Robert Lee	Domestic	29.80639	-94.44167	146	4/14/2020	Chicot
626776	New Well	Kolton Page	Domestic	29.80417	-94.47564	175	10/21/2022	Chicot
6413406	Withdrawal of Water	O.C. Devillier	Industrial	29.82944	-94.48361	160	0/0/1960	Chicot
58643	New Well	Kervin Sonnier	Domestic	29.84472	-94.50778	170	4/25/2003	Chicot
124609	New Well	John Savoie	Stock	29.83333	-94.46694	180	9/19/2007	Chicot
134506	New Well	John C. Saooie	Domestic	29.82583	-94.47472	180	10/29/2004	Chicot
193725	New Well	Stacy Devillier	Domestic	29.8725	-94.4925	170	11/21/2006	Chicot
256323	New Well	Dustin Huff	Domestic	29.84778	-94.50945	170	5/31/2011	Chicot
326863	New Well	Steve Devillier	Stock	29.88139	-94.49	170	6/25/2010	Chicot
479003	New Well	Mike Reed	Domestic	29.84007	-94.481	176	6/12/2017	Chicot
669003	New Well	Joshua Warthen	Domestic	29.84617	-94.49268	177	6/13/2024	Chicot

Well Report/Plugging Report/State Well Number	Well Type	Owner Name	Use	Latitude	Longitude	Borehole Depth (ft)	Date Completion	Aquifer
675775	New Well	Brain and Brooklin Ellis	Domestic	29.8016	-94.47772	180	4/17/2024	Chicot

Table AoR-64: Additional Water Wells within the AoR.

FID	Name	Surface Latitude	Surface Longitude	Use	Aquifer	Permit	Depth (ft)
0	Irrigation Well #1	29.806256	-94.424117	Irrigation	Chicot	n/a	unknown
1	WSW Buddy #2	29.860364	-94.481723	Domestic	Chicot	n/a	unknown
2	WSW George #1	29.860032	-94.483133	Domestic	Chicot	n/a	unknown
3	WSW Gerry #1	29.853107	-94.487661	Domestic	Chicot	n/a	unknown
4	WSW Monteau #3	29.860134	-94.480589	Domestic	Chicot	n/a	unknown
5	WSW Ritchie #1	29.828734	-94.430079	Domestic	Chicot	n/a	unknown
6	WSW Ritchie #2	29.833544	-94.427970	Domestic	Chicot	n/a	unknown
7	WSW Stevie #2	29.876300	-94.492544	Domestic	Chicot	n/a	unknown

9.1.3 Wells Penetrating the Confining Zone Within the AoR

The 29 oil and gas wells within the Area of Review (AoR) are listed in Table AoR-62. Twenty-six of these wells were drilled through the Confining Zone into the Miocene and Frio formations.

The Drought 1 well (API 42071013640000) was drilled to a depth of 1,200 ft and did not penetrate the Confining Zone, therefore no corrective action is required.

The Bluebonnet USDW 01 well (API 42071326720000), originally drilled as a water well and later converted to an above confining zone/USDW monitoring well, targeted the base of the USDW water, reaching a total depth (TD) of 1,630 ft. The well was plugged back to 1,410 ft and completed with a gravel packed screen from 1,370 ft to 1,420 ft. No corrective action is required.

The Bluebonnet USDW 8 well (API 42071326760000) was drilled to 2,950 ft to core the shale intervals described in the composite confining zone. The well was plugged back to 1,050 ft and completed above the base of the USDW. No corrective action is needed.

Sixteen of the 29 oil and gas wells identified in the AoR were abandoned open hole, while nine ran intermediate casing through the proposed storage complex to reach the deepest formation.

The Encanto 01 well (API 42071326640000) was drilled as a stratigraphic well in support of this project and will be converted to a monitoring well before the start of injection. The well is currently temporarily abandoned.

9.2 Plan for Site Access

The project wells and wells in the remediation plan are located inside the area proposed for the Bluebonnet Hub. Bluebonnet has acquired the rights to access the Bluebonnet Hub project area and the various well locations via agreements with the surface owners.

9.3 Corrective Action Schedule

A detailed analysis was performed to evaluate the risk and timing of the plume and/or pressure front reaching each of the wells inside the AoR, relative to the project schedule, to propose corrective actions and a timeline for these procedures. Schematics and proposed repairs for each well that penetrates the seal or injection formations are included in Appendix C of this document.

The analysis was divided into two main categories to assess the risk and mitigations, based on the possible mechanism of failure:

1) **CO_2 plume corrosive effect and contamination of USDW aquifer.** The analysis focused on potential leakage paths from the injection zone that could endanger the USDW for those wells that are projected to be exposed to the CO_2 plume. The lack of proper isolation, cement degradation by carbonic acid, mechanical barrier failures, and micro-annulus or casing corrosion are some of the situations that increase the risk of brine/CO_2 leaks.

2) **Pressure front effect with brine contamination from deeper saline reservoirs to USDW aquifers.** This category includes wells that were not projected to be in contact with the CO_2 plume but are inside the simulated pressure front. In this scenario, the wells were evaluated for proper hydraulic isolation between the injection zone and USDW. The degradation or corrosion of cement, tubulars, and tools is not considered a high-risk scenario in this category.

The study was also divided into time periods from initial injection to 100 years post-injection in order to propose the schedule and approach for the corrective actions.

From the individual well analysis, 25 of the 29 wells were identified as requiring remedial actions to isolate the injection zone properly from the confining zone and USDW zones. These wells are listed in Table AoR-65, along with the main mechanism of failure and proposed schedule. Although the Magnetic Survey has not identified Trinity Rice 1 well within the project area, it has nonetheless been included in the financial assurance and risk evaluation for the ERRP. The project plans to conduct additional on-the-ground surveys to definitively rule out this well as a potential leak path.

Table AoR-65: Wells to be remediated in the proposed AoR.

API Number	Lease Name	Well No	Status	Failure Mechanism	Total Depth (ft)	Schedule
42071019540000	J W Garth Jr Etal	1	Dry & Abandoned	CO2 Plume	9,012	Year 0
42071019550000	Drought H P	1	Dry & Abandoned	CO2 Plume	9,505	Year 0
42071019560000	Garth Brothers	1	D&A-O	CO2 Plume	9,250	Year 0
42071019580000	Sterrett Eat Fred R	1	Dry & Abandoned	CO2 Plume	9,550	Year 0
42071019590000	Wm Doornbos Etal	1	Dry & Abandoned	CO2 Plume	9,025	Year 0
42071019600000	Trinity Rice	1	Dry & Abandoned	CO2 Plume	8,019	Year 0
42071019680000	Simon Walter	1	Dry & Abandoned	CO2 Plume	7,788	Year 0
42071031650000	C H Lanz	1	Dry & Abandoned	CO2 Plume	7,629	Year 0
42071305640000	M E Hunter	1	Dry & Abandoned	CO2 Plume	12,665	Year 0
42071310360000	Garth	1	Dry & Abandoned	CO2 Plume	11,000	Year 0
42071321740000	Holter Et Al	1	Dry & Abandoned	CO2 Plume	11,000	Year 0
42071322330000	Doornbos	1	Dry & Abandoned	CO2 Plume	10,800	Year 0
42071300320000	Earl Cooper Etal	1	Dry & Abandoned	CO2 Plume	9,500	Year 5

API Number	Lease Name	Well No	Status	Failure Mechanism	Total Depth (ft)	Schedule
42071300730000	Garth Co	3	Dry & Abandoned	CO2 Plume	9,265	Year 5
42071312670000	Doornbos Willim Etl	1	Dry & Abandoned	CO2 Plume	18,950	Year 5
42071019610000	Ogden L G Etal	1	D&A-O	CO2 Plume	9,617	Year 10
42071019620000	Debellvue Mrs Maria	1	Dry & Abandoned	CO2 Plume	9,348	Year 15
42071033940000	O C Devillier Jr	1	Dry & Abandoned	CO2 Plume	9,317	Year 15
42071304510000	O C Devillier	4	Dry & Abandoned	CO2 Plume	12,215	Year 15
42071304690000	Beaumnt Rc Mll	1	Dry & Abandoned	CO2 Plume	9,008	Year 15
42071308370000	O C Devillier	6	Dry & Abandoned	CO2 Plume	10,993	Year 15
42071309670000	Devillier O C	7	Dry & Abandoned	CO2 Plume	11,270	Year 15
42071311640000	Garth	1	Dry & Abandoned	CO2 Plume	16,000	Year 15
42071313890000	Simon S E	1	Junked & Abandoned	CO2 Plume	9,119	Year 15
42071313940000	Devillier L C	1	Dry & Abandoned	CO2 Plume	9,300	Year 15

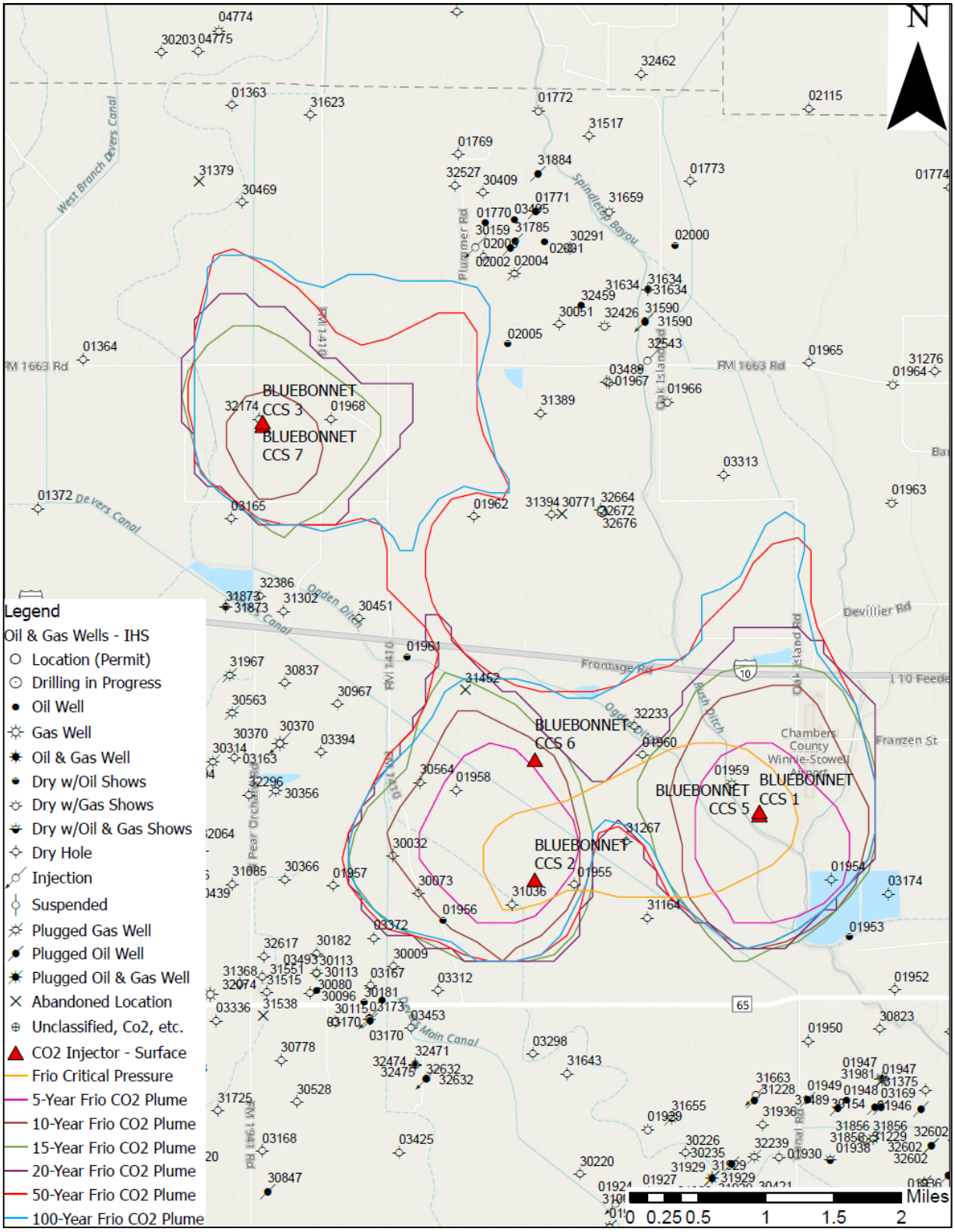


Figure AoR-332: Oil and gas wells and deep penetrations compared with Frio plume movement at 5 years, 10 years, 15 years and 20 years of injection and 50 years and 100 years after injection. The figure also shows the critical pressure front.

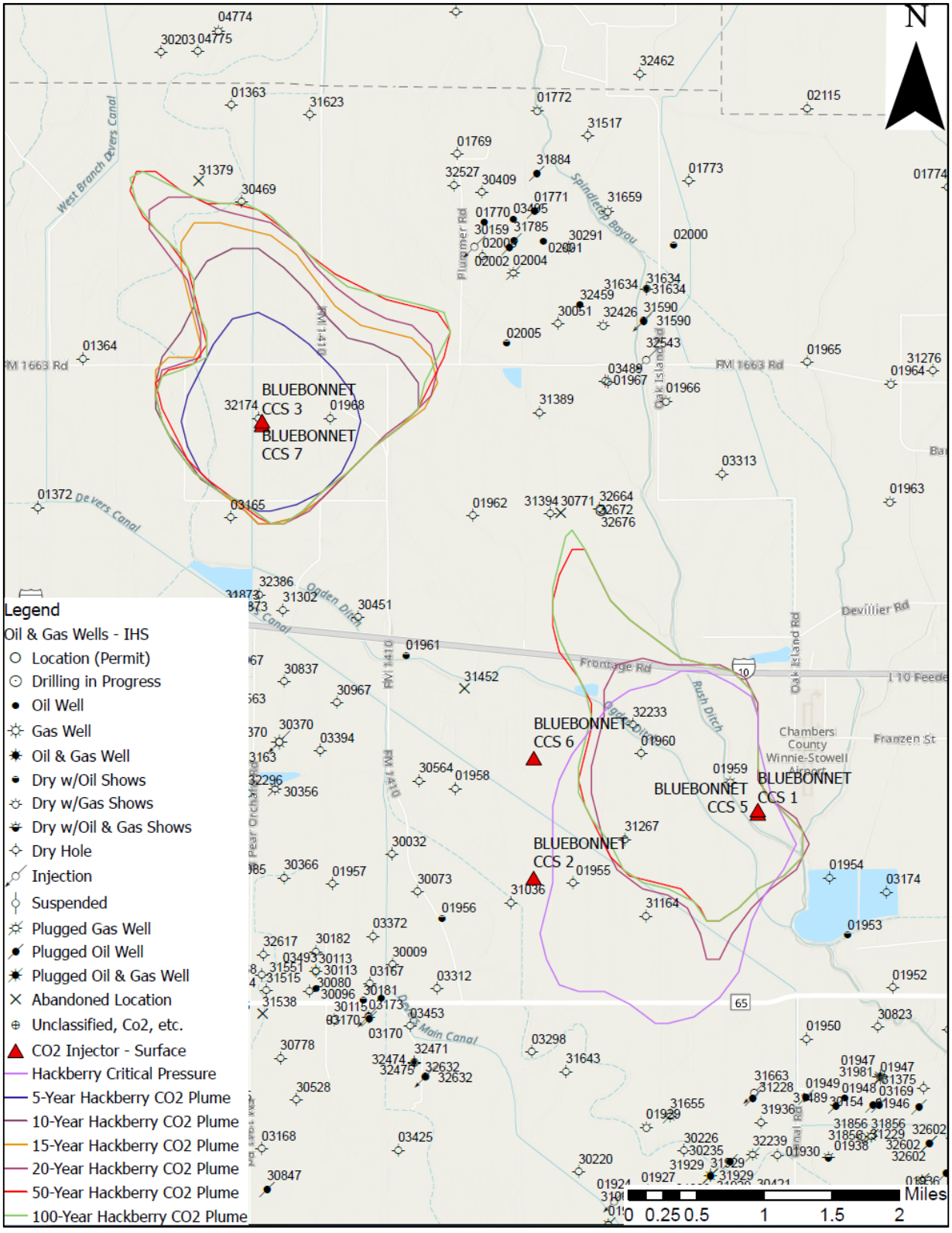


Figure AoR-333: Oil and gas wells and deep penetrations compared with Hackberry plume movement at 5 years, 10 years, 15 years and 20 years of injection and 50 years and 100 years after injection. The figure also shows the critical pressure front.

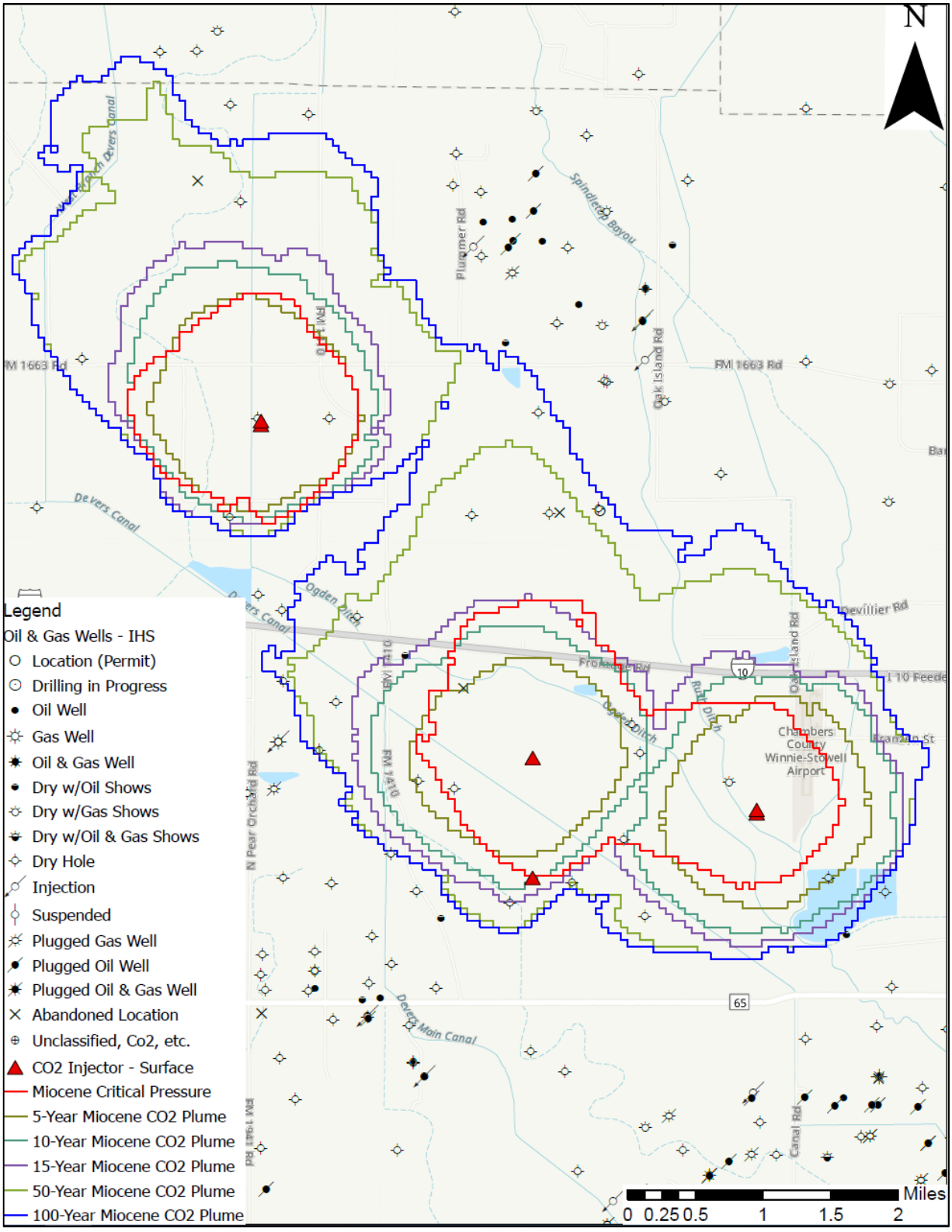


Figure AoR-3344: Oil and gas wells and deep penetrations compared with Miocene plume movement at 5 years, 10 years and 15 years of injection and 50 years and 100 years after injection. The figure also shows the critical pressure front.

10.0 Reevaluation Schedule and Criteria

10.1 AoR Reevaluation Cycle

The Bluebonnet Sequestration Hub, LLC will reevaluate the AoR every five years at a minimum during the injection and post-injection phases. In addition, monitoring and operational data will be reviewed periodically by the Bluebonnet technical team during the injection and post-injection phases.

Activities to be performed during reevaluation include reviewing and analyzing available monitoring and operational data and comparing it to the dynamic simulation forecast to assess whether the predicted CO_2 plume migration is consistent with the actual data. This includes data from the CO_2 injector wells, monitoring wells, geophysical surveys, and other sources. The monitoring activities to be conducted are described in the Testing and Monitoring Plan of this permit and PISC and Closure Plan.

Specific steps of this review and analysis include:

- Reviewing collected data on the position of the CO_2 plume and pressure front. This data will be collected from the CO_2 injector wells, monitoring wells, and near-surface monitoring systems as well as geophysical surveys as described in the testing and monitoring plan.

- Reviewing water chemistry monitoring data taken in the Bluebonnet USDW monitoring wells and verify that there is no evidence of CO_2 or brines that represent an endangerment to any USDWs.

- Reviewing operating data (e.g., injection rates and pressures) and verify consistency with the inputs used in the most recent modeling effort. History-match the numerical simulation model with operational data for well performance.

- Reviewing any geologic data acquired since the last modeling effort (e.g., additional site characterization performed and updates of petrophysical properties from core analysis). Identify whether any new data is materially different from the modeling inputs and assumptions.

- Comparing the results of computational modeling used for AoR delineation to the monitoring data collected. Monitoring data will be used to history-match the computational model and validate that the model provides an accurate representation of the storage site and can be used as a proxy to determine the plume's properties and size. The degree of accuracy is demonstrated by comparing monitoring data with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to represent the storage site accurately.

If the collected data is consistent with model inputs and/or if the model forecast has not materially changed after the incorporation of such data, no update to the AoR will be needed. In this case, a report will be prepared to demonstrate that, based on the monitoring and operating data, no reevaluation of the AoR is needed. This report will include the data and results demonstrating that no changes are necessary.

If material changes in site conditions or operating parameters have occurred or if data indicates that the actual plume or pressure front may extend beyond the modeled plume and pressure front, the AoR will be re-delineated. Steps to re-delineate the AoR include:

- Revising the site conceptual model based on the new site characterization, operational, or monitoring data.
- Calibrating and history-matching the model in order to minimize the differences between monitoring data and model simulations.
- Performing the AoR delineation method as described in the AoR Delineation section of this AoR and Corrective Action Plan.
- Reviewing wells in any newly identified areas of the AoR and applying corrective action to deficient wells, if needed. Specific steps include:
    - Identifying any new wells within the AoR. Evaluate the status and records for wells that were not evaluated previously and provide description of each well including well type, construction, date drilled, location, depth, and record of plugging and/or completion.
    - Determining which wells in the newly delineated AoR are constructed or plugged/abandoned in a manner that could be a risk for endangering USDWs.
    - Performing or scheduling corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs using materials compatible with CO_2.
- Preparing a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to the EPA within one year of the reevaluation and will include maps that highlight similarities and differences with previous AoR delineations.
- Updating the AoR and Corrective Action Plan to reflect the revised AoR along with other related project plans, as needed.

10.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled AoR reevaluations will be based on quantitative and material changes of the monitoring and operative parameters in CO_2 injectors, monitoring wells, seismometer networks, and geophysical surveys that could indicate that the actual plume and pressure front may extend

beyond the area modeled or outside the proposed storage complex. These changes might include, but not be limited to the following:

- **Pressure:** Changes in injection pressure that are excessive and unexpected in timing or magnitude from those predicted by the model.
- **RST Saturation:** Increases in CO_2 saturation in monitoring wells that indicate an earlier breakthrough of CO_2.
- **Deep Groundwater Constituent Concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brine into or above the confining zone.
- **Exceeding Fracture Pressure Conditions:** Pressure in injection wells exceeding 90% of the geologic formation fracture pressure.
- **Compromise in Injection Well Mechanical Integrity:** A significant change in annular pressure for the injection well or abnormal reading of temperature in the fiber optic cable that indicates a loss of mechanical integrity or a failed mechanical integrity test (MIT) in an injector or monitoring wells.
- **Induced Seismicity Monitoring:** Seismic monitoring data that indicates reactivation of a fault or structures due to pressurization of the reservoir because of the CO_2 injection. The project will review the monitoring data to discard naturally occurring events not related to the injection.

The Bluebonnet Sequestration Hub, LLC will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, the Project will perform the steps described in the 10.1 AoR Reevaluation Cycle.

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AREA OF REVIEW AND CORRECTIVE ACTION PLAN 40 CFR 146.84 (Bluebonnet Sequestration Hub)

1.0 Project Background and Contact Information 2

1.0 Project Background and Contact Information

Facility name: Bluebonnet Sequestration Hub
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 Wells.

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Appendices A, B, E, F, G are fully redacted an claimed as PBI.

AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Appendix C: Schematics of Legacy Wells in the AoR and Recommended Corrective Action

This appendix summarizes the evaluation of the deep legacy wells in the proposed AoR and recommendations for corrective actions. All existing wellbore configurations and abandonment procedures are as reported in the Texas Railroad Commission files (TRRC).

1. J W Garth JR Etal 1 (API 42071019540000): D&A 1947

The J W Garth JR Etal 1 well is projected to be inside the CO_2 plume before year 5 of CO_2 injection. The well status is drilled and abandoned (D&A) and was drilled through the Miocene, Anahuac, Frio, and Hackberry formations reaching a TD of 9,012 ft. The 10 ¾ in. surface casing set at 1,000 ft does not cover the USDW, located at approximately 1,419 ft. The abandonment procedure consisted of a 20-sack (sx) cement plug set below the surface shoe and five sx of cement spotted on surface, according to the TRRC records. The well was left filled with 10.5 ppg mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-1: General information for W Garth JR Etal 1 (API 42071019540000).

API	42071019540000
Operator	Blanke Frost & Frazier
Lease Name	J W Garth JR Etal
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.80487053
Surface Longitude	-94.42752166
Total Depth	9,012
Formation	Frio
Spud Date	9/11/1947
Drilling End	10/12/1947
Abandonment Date	10/16/1947
Survey	T&NO 278 RR 57

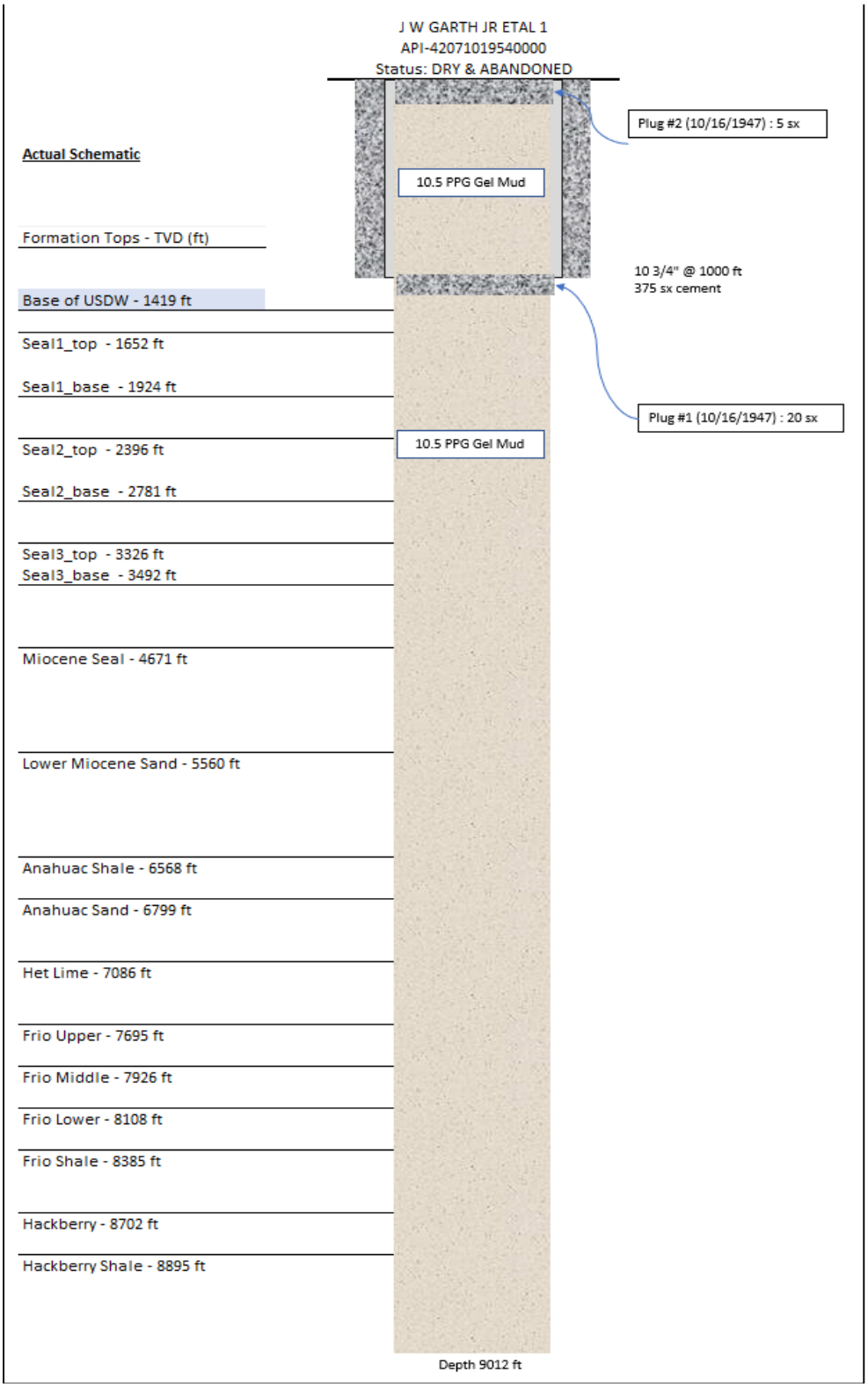


Figure C-AoR-1: Actual wellbore schematic of W Garth JR Etal 1 (API 42071019540000).

Table C-AoR-2: Formation tops from W Garth JR Etal 1 (API 42071019540000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,419
Seal1_top	1,652
Seal1_base	1,924
Seal2_top	2,396
Seal2_base	2,781
Seal3_top	3,326
Seal3_base	3,492
L_Miocene_Shale	4,671
L_Miocene_A	4,910
AMPB_SAND	4,979
L_Miocene_B	5,102
L_Miocene_C	5,400
TOP_LMIO_INJ_ZONE	5,560
LMIO_INJ_5	5,676
LMIO_INJ_4	5,906
LMIO_INJ_3	5,956
LMIO_INJ_6	6,115
LMIO_INJ_2	6,375
Anahuac	6,568
Anahuac_Sand_Top	6,799
Anahuac_Sand_Base	6,819
Anahuac_Het_Lime_Top	7,086
Anahuac_Het_Lime_Base	7,276
Frio_Top	7,695
Frio_Mid	7,926
Frio_Low	8,108
Frio_Shale	8,385
Hackberry	8,702
Hackberry_Shale	8,895

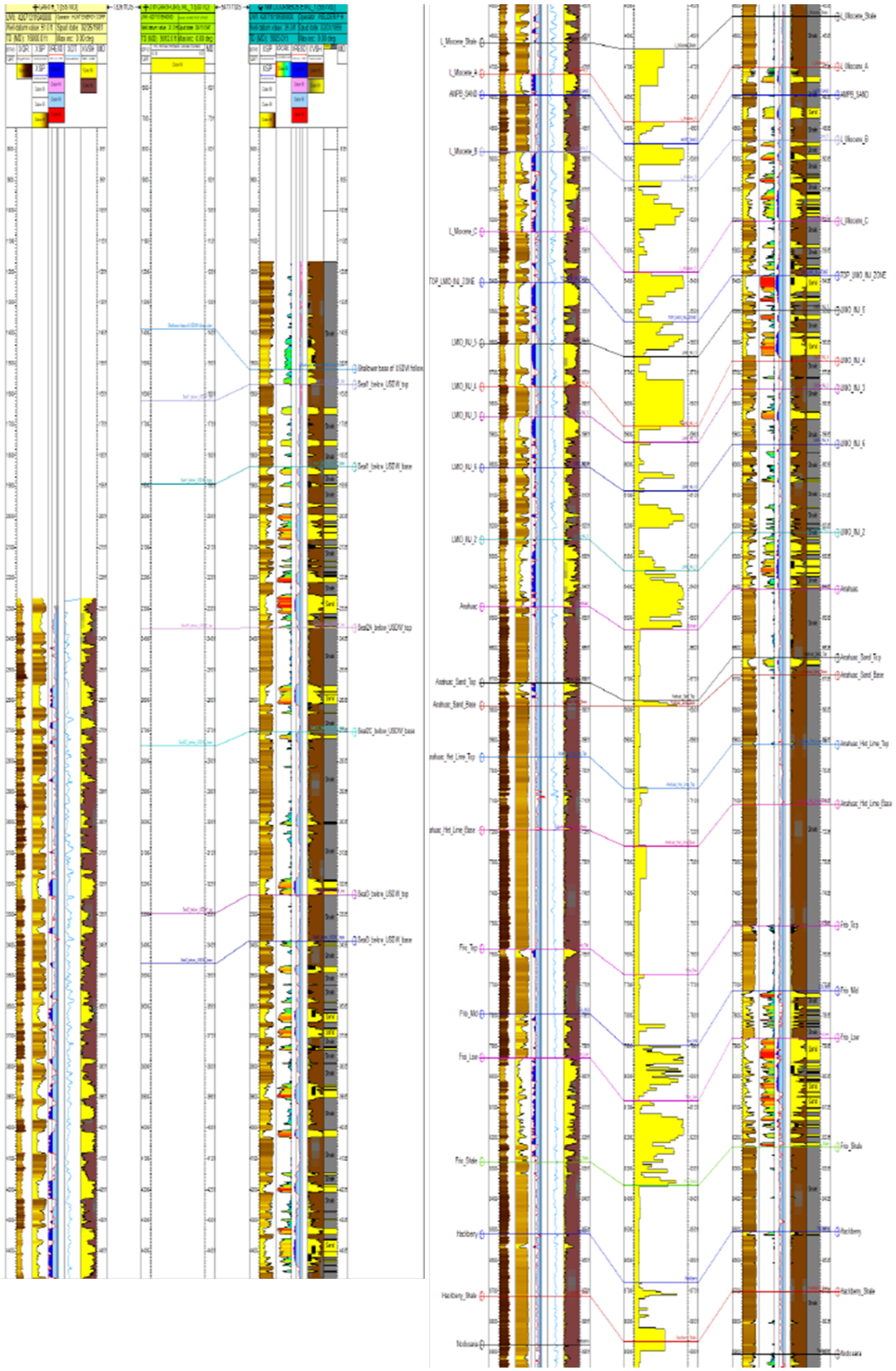


Figure C-AoR-2: Pseudo-log and formation tops from W Garth JR Etal 1 (API 42071019540000).

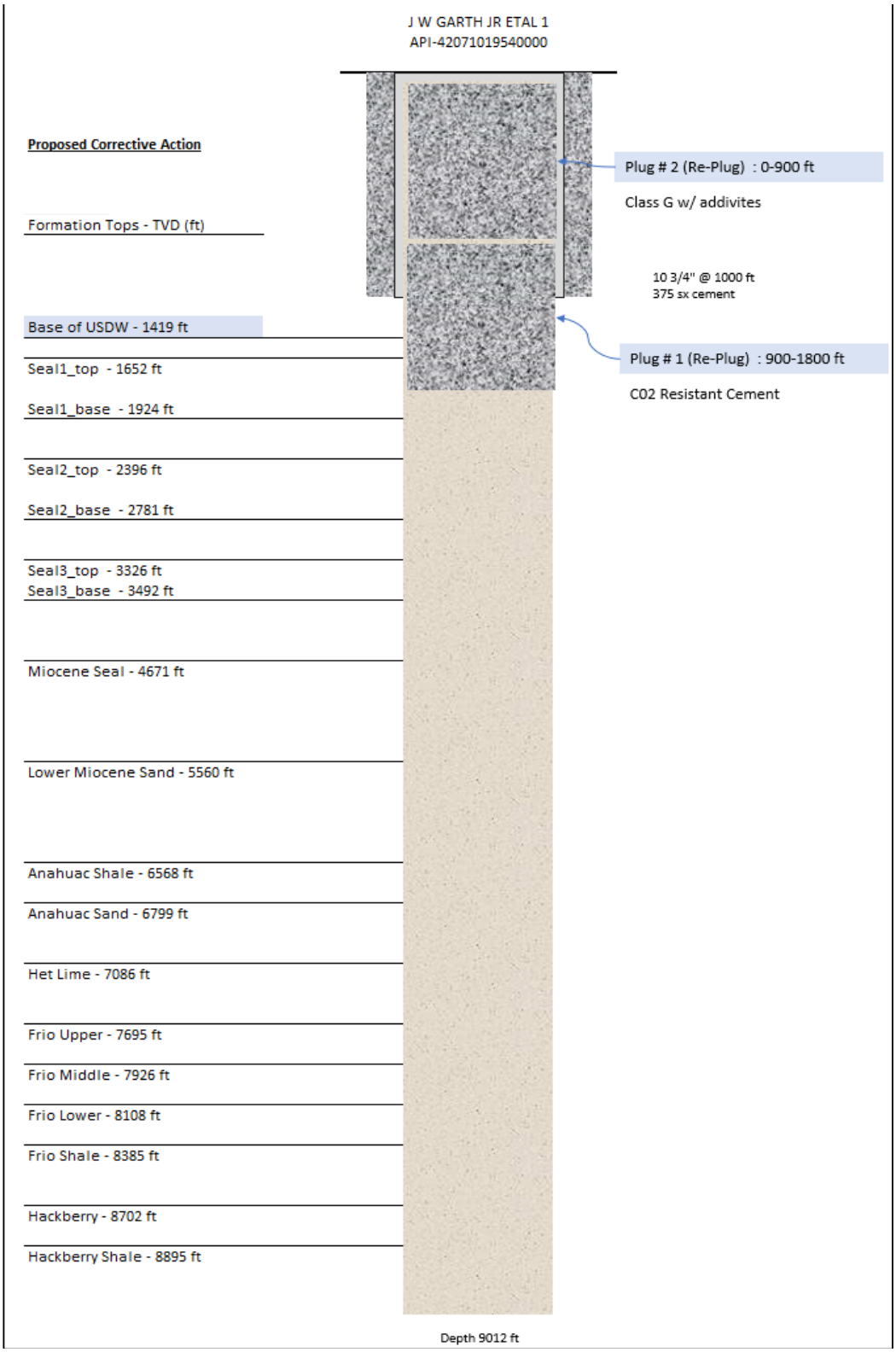


Figure C-AoR-3: Proposed remediation for W Garth JR Etal 1 (API 42071019540000).

Table C-AoR-3: Plug information for proposed abandonment procedure for W Garth JR Etal 1 (API 42071019540000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	900	1800	CO2 Resistant	14.8-15.5	91	1.06	481
Plug # 2	Balanced Plug	0	900	Class G w/ additives	15-15.5	91	1.01	504

Plugging Procedure

1. Move in rig onto J W Garth JR Etal 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a 9-7/8 in. bit and run in hole, cleaning down to 1,800 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in hole with the work string to 1,800 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 900 – 1,800 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0 – 900 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

2. Drought H P 1 (API 42071019550000): D&A 1955

The Drought H P 1 well is projected to be inside the CO_2 plume between years 5 and 10 of injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 9,505 ft. The 10 ¾ in. surface casing set at 1,641 ft does cover the USDW, located at approximately 1,594 ft. The abandonment procedure consisted of a 50 sx cement plug set below the surface shoe, according to the TRRC records. The well was left filled with mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-4: General information Drought H P 1 (API 42071019550000).

API	42071019550000
Operator	Union Oil Co of California
Lease Name	Drought H P
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.80399857
Surface Longitude	-94.45907552
Total Depth	9,500
Formation	Frio
Spud Date	10/2/1955
Drilling End	10/25/1955
Abandonment Date	10/25/1955
Survey	T&NO A-280 Sect 61

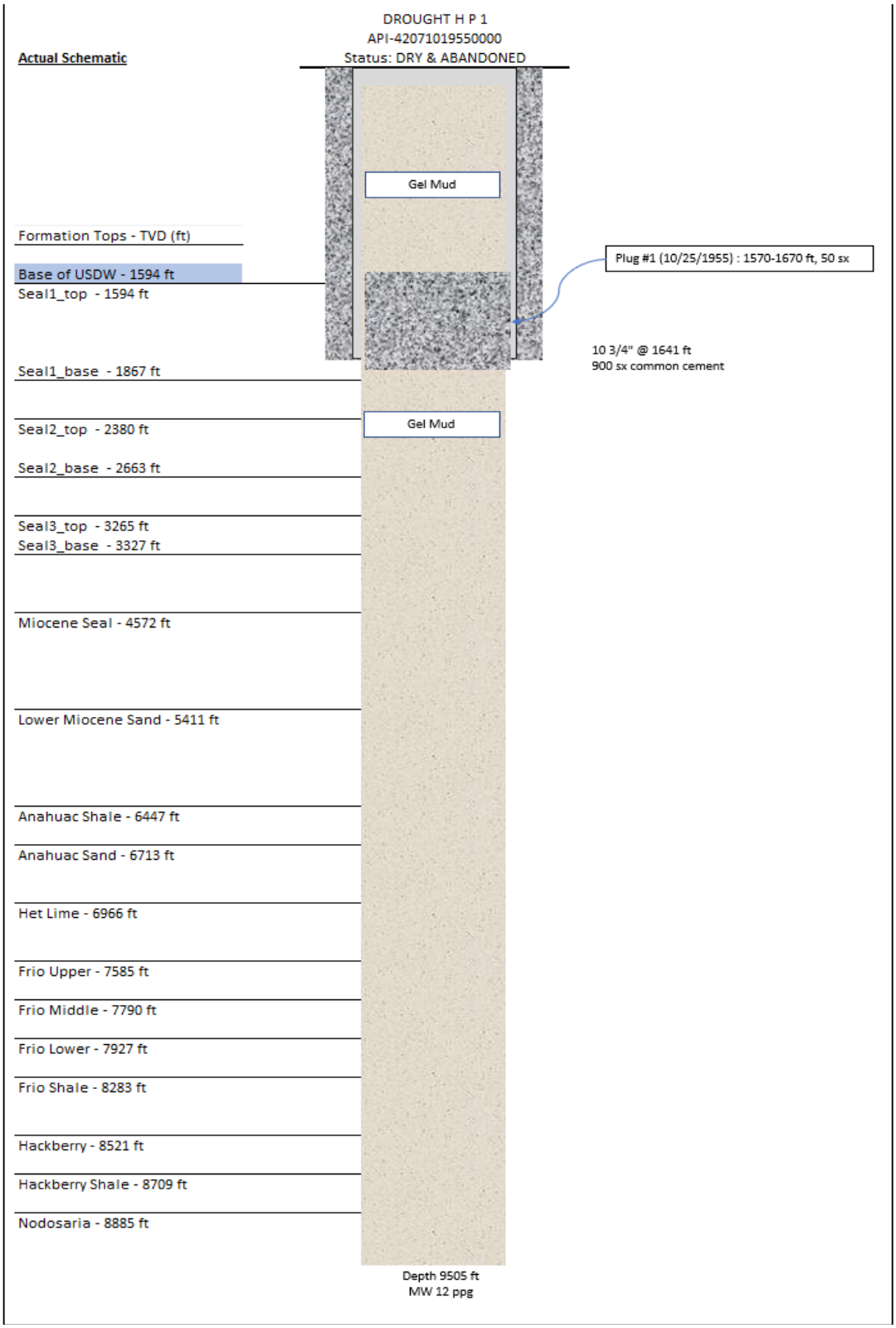


Figure C-AoR-4: Actual wellbore schematic for Drought H P 1 (API 42071019550000).

Table C-AoR-5: Formation tops from Drought H P 1 (API 42071019550000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,594
Seal1_top	1,594
Seal1_base	1,867
Seal2_top	2,380
Seal2_base	2,663
Seal3_top	3,265
Seal3_base	3,327
L_Miocene_Shale	4,572
L_Miocene_A	4,717
AMPB_SAND	4,832
L_Miocene_B	4,977
L_Miocene_C	5,269
TOP_LMIO_INJ_ZONE	5,411
LMIO_INJ_5	5,591
LMIO_INJ_4	5,751
LMIO_INJ_3	5,831
LMIO_INJ_6	5,994
LMIO_INJ_2	6,258
Anahuac	6,447
Anahuac_Sand_Top	6,713
Anahuac_Sand_Base	6,785
Anahuac_Het_Lime_Top	6,966
Anahuac_Het_Lime_Base	7,198
Frio_Top	7,585
Frio_Mid	7,790
Frio_Low	7,927
Frio_Shale	8,283
Hackberry	8,521
Hackberry_Shale	8,709
Nodosaria	8,885

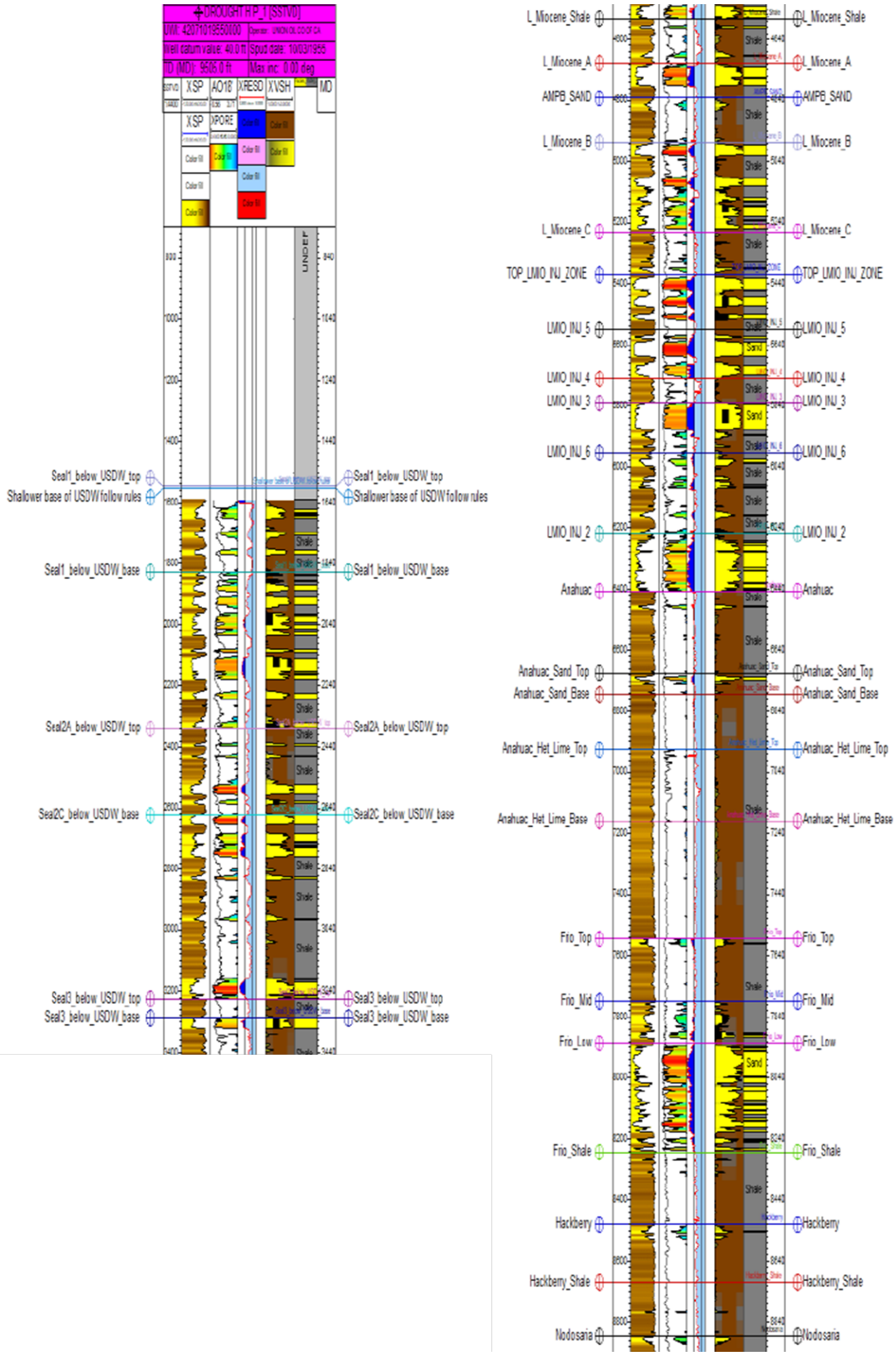


Figure C-AoR-5: Electric log and formation tops from Drought H P 1 (API 42071019550000).

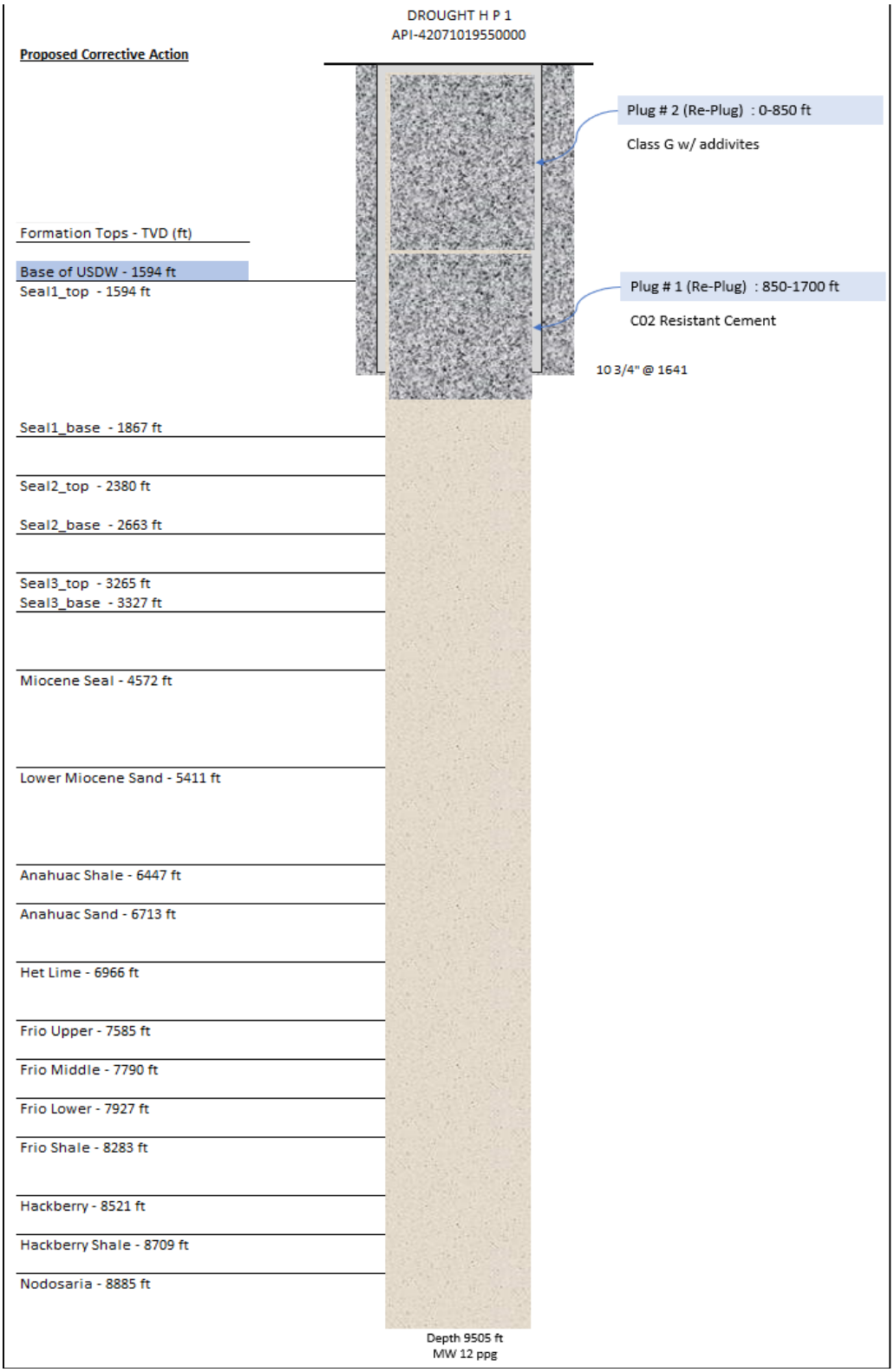


Figure C-AoR-6: Proposed remediation for Drought H P 1 (API 42071019550000).

Table C-AoR-6: Plug information for proposed re-abandonment procedure for Drought H P 1 (API 42071019550000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	850	1700	CO2 Resistant	14.8-15.5	86	1.06	454
Plug # 2	Balanced Plug	0	850	Class G w/ additives	15-15.5	86	1.01	476

Plugging Procedure

1. Move in rig onto Drought H P 1 site and rig up.
1. Conduct and document safety meeting.
2. Check the shut-in casing pressure.
3. Test the pump and lines to 5,000 psi. Kill the well if necessary.
4. Function test blowout preventers (BOPs) and nipple up.
5. Pick up the work string with a 9-7/8 in. bit and run in hole, cleaning down to 1,700 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
6. Run in the hole the with the work string to 1,700 ft. Circulate the well clean.
7. Plug #1: Set a balanced plug 850 – 1,700 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
8. Plug #2: Set a balanced plug 0 – 850 ft with 15-15.5 ppg Class G cement.
9. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

3. WM Doornbos Etal 1 (API 42071019590000): D&A 1956

The WM Doornbos Etal 1 well is projected to be inside the CO_2 plume during the first 5 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations, reaching a TD of 9,025 ft. The 10 ¾” surface casing was set at 1,192 ft and does not cover the USDW, which is located at approximately 1,553 ft. The abandonment procedure consisted of a cement plug set below the surface shoe from 1,142 to 1,242 ft and 25 sx of cement spotted on surface according to the TRRC records. The well was left filled with 10.8ppg mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-7: General information for WM Doornbos Etal 1 (API 42071019590000).

API	42071019590000
Operator	Welder P H
Lease Name	WM Doornbos Etal
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.815109
Surface Longitude	-94.43990623
Total Depth	9,025
Formation	Frio
Spud Date	3/31/1956
Drilling End	4/24/1956
Abandonment Date	4/24/1956
Survey	T&NO Sec 59

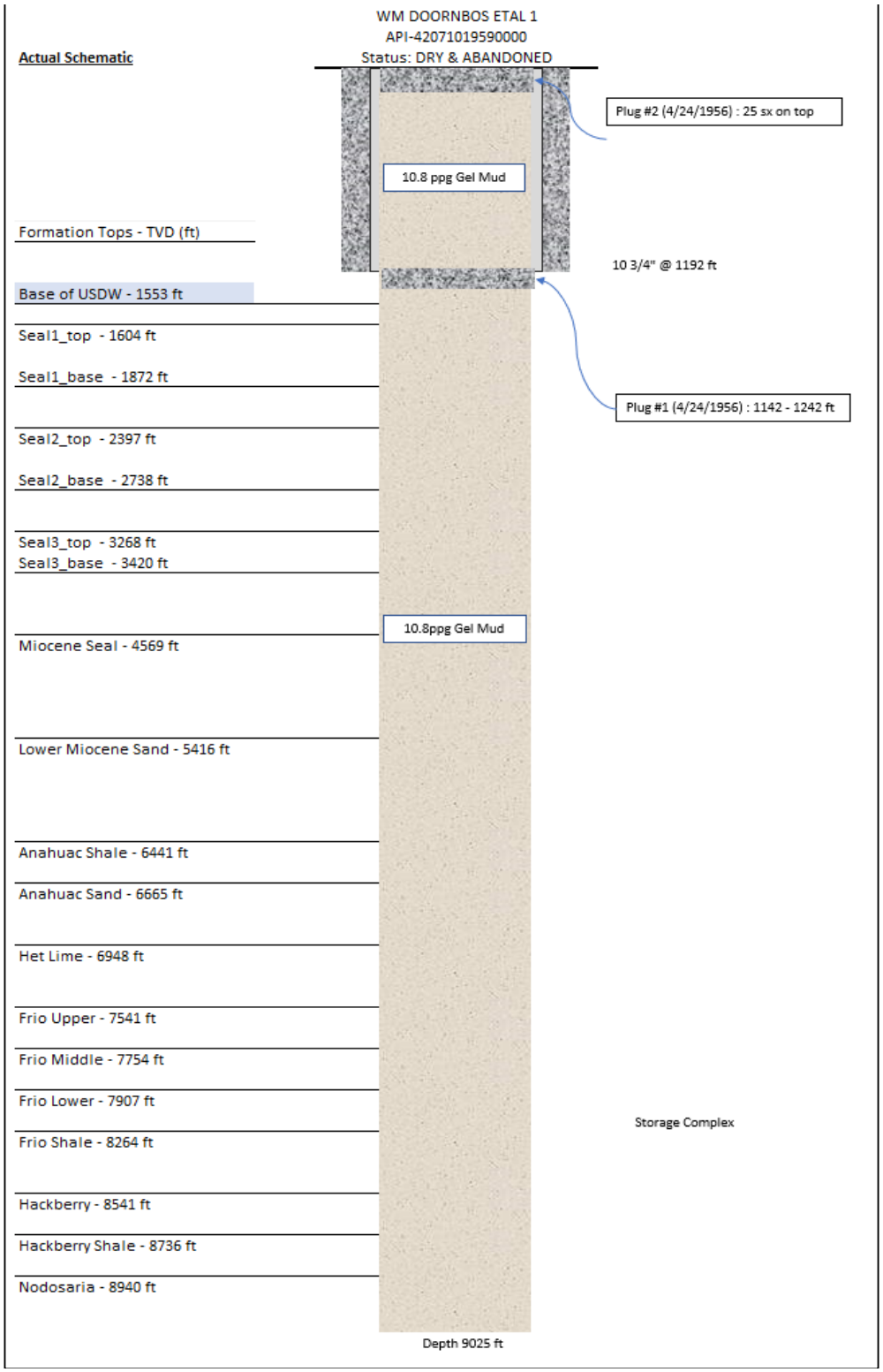


Figure C-AoR-7: Actual wellbore schematic of WM Doornbos Etal 1 (API 42071019590000).

Table C-AoR-8: Formation tops from WM Doornbos Etal 1 (API 42071019590000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,553
Seal1_top	1,604
Seal1_base	1,872
Seal2_top	2,397
Seal2_base	2,738
Seal3_top	3,268
Seal3_base	3,420
L_Miocene_Shale	4,569
L_Miocene_A	4,733
AMPB_SAND	4,825
L_Miocene_B	4,972
L_Miocene_C	5,237
TOP_LMIO_INJ_ZONE	5,416
LMIO_INJ_5	5,530
LMIO_INJ_4	5,695
LMIO_INJ_3	5,786
LMIO_INJ_6	5,967
LMIO_INJ_2	6,256
Anahuac	6,441
Anahuac_Sand_Top	6,665
Anahuac_Sand_Base	6,722
Anahuac_Het_Lime_Top	6,948
Anahuac_Het_Lime_Base	7,144
Frio_Top	7,541
Frio_Mid	7,754
Frio_Low	7,907
Frio_Shale	8,264
Hackberry	8,541
Hackberry_Shale	8,736
Nodosaria	8,940

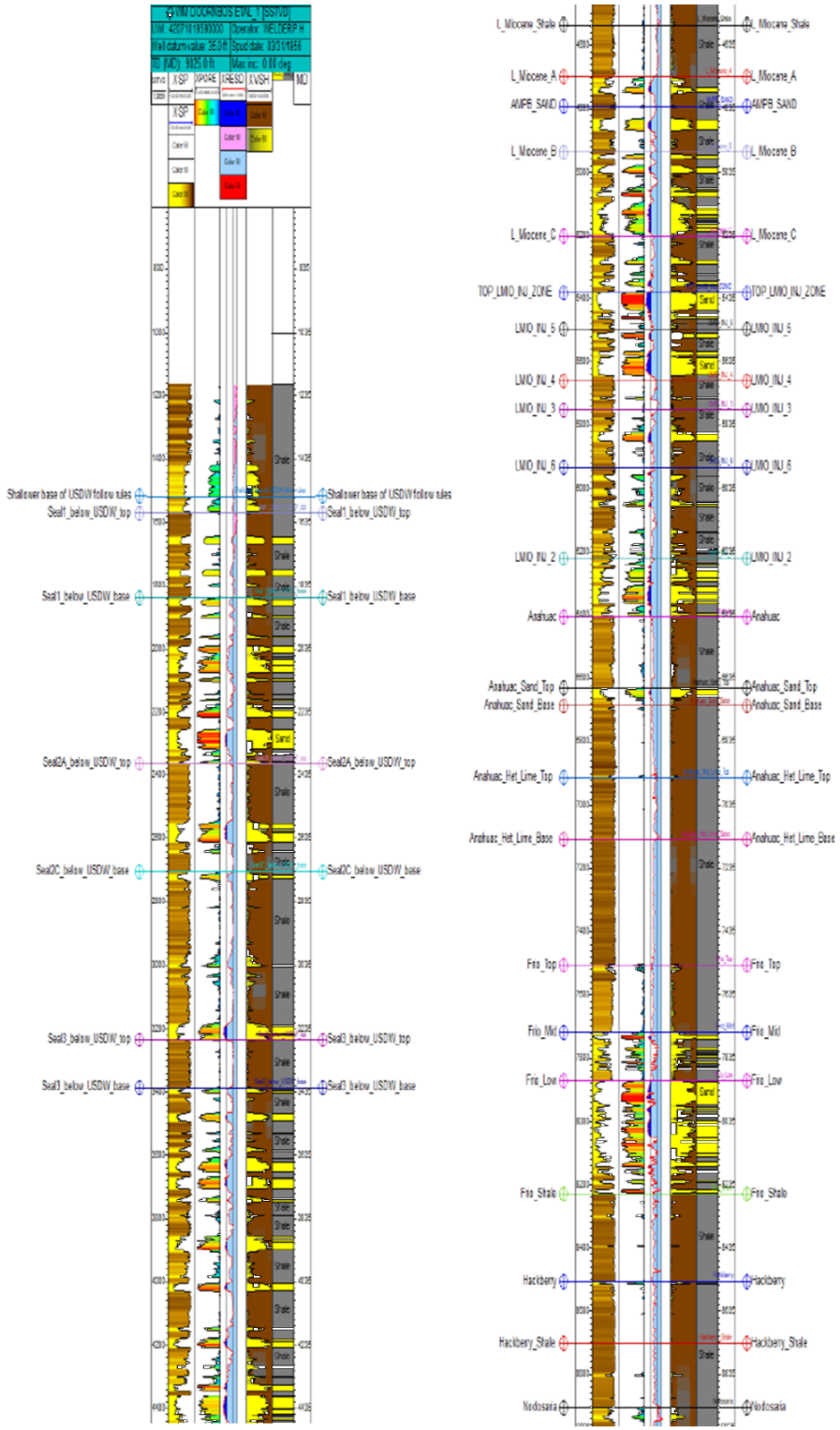


Figure C-AoR-8: Electric log and formation tops from WM Doornbos Etal 1 (API 42071019590000).

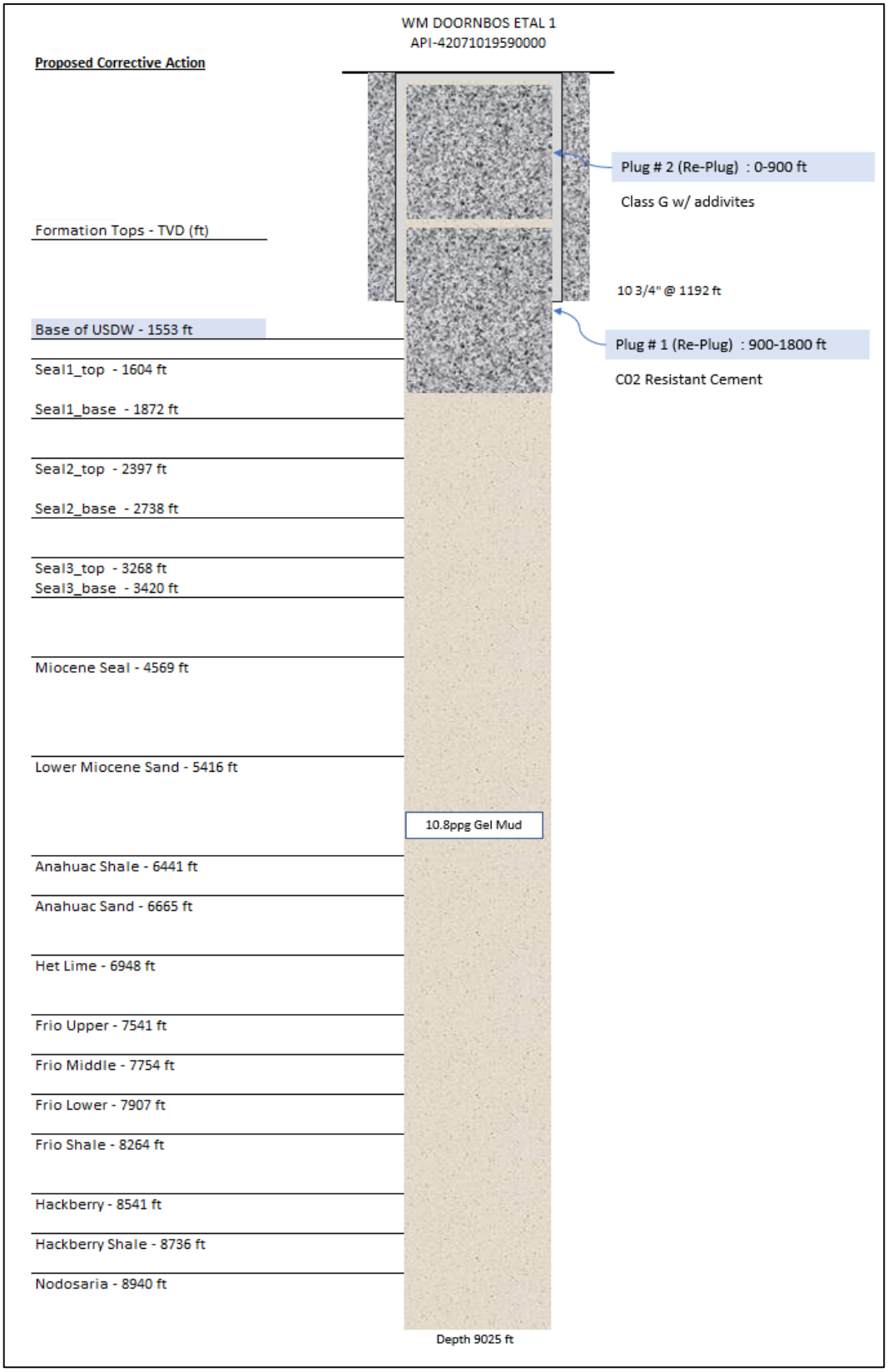


Figure C-AoR-9: Proposed remediation for WM Doornbos Etal 1 (API 42071019590000).

Table C-AoR-9: Plug information for proposed re-abandonment procedure for WM Doornbos Etal 1 (API 42071019590000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	900	1800	CO2 Resistant	14.8-15.5	91	1.06	481
Plug # 2	Balanced Plug	0	900	Class G w/ additives	15-15.5	91	1.01	504
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto WM Doornbos Etal 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with 9-7/8 in. bit and run in hole.
    a. If primary cement records have been located and there is cement behind the surface casing: Clean down to 1,800 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If primary cement records have not been located: Clean down to 1,200 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed with step 7.
7. Set the bridge plug at 1,170 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on the 10-3/4 in. casing from 1,170 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,800 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to the surface: Perforate the 10-3/4 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify the new top of the cement. Proceed to step with step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 1,170 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure.
10. Drill out the bridge plug at 1,170 ft and continue running in hole with the work string, cleaning down 1,800 ft. Circulate the well clean and pull out of the hole. Lay down the bit.
11. Run in the hole with the work string to 1,800 ft. Circulate the well clean.
12. Plug #1: Set a balanced plug 900 – 1,800 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0 – 900 ft with 15-15.5 ppg Class G cement.

14. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

4. Trinity Rice Disposal 1 (API 42071019600000): D&A 1941

The Trinity Rice 1 well was not identified during the magnetic survey acquisition. The project plans to conduct additional on-ground surveys to either discard the existence of the well or implement a monitoring approach. According to the abandonment files, the well status is D&A and it was drilled through the Miocene, Anahuac, and Frio formations, reaching a total depth of 8,019 feet. The 10 3/4 inch surface casing was set at 1,264 feet and does not cover the USDW, which is located at approximately 1,553 feet. The abandonment procedure consisted of filling the well with mud, according to TRRC records. No cement plugs were reported. In the event that the well location is validated between the 5-year and 10-year plume, the well will be scheduled for remedial action in Year 0.

Table C-AoR-10: General information for Trinity Rice Disposal 1 (API 42071019600000).

API	42071019600000
Operator	Williams H E
Lease Name	Trinity Rice
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.8179581
Surface Longitude	-94.45089738
Total Depth	8,019
Formation	Frio
Spud Date	6/11/1941
Drilling End	7/2/1941
Abandonment Date	7/2/1941
Survey	T&NO S561 NO 45

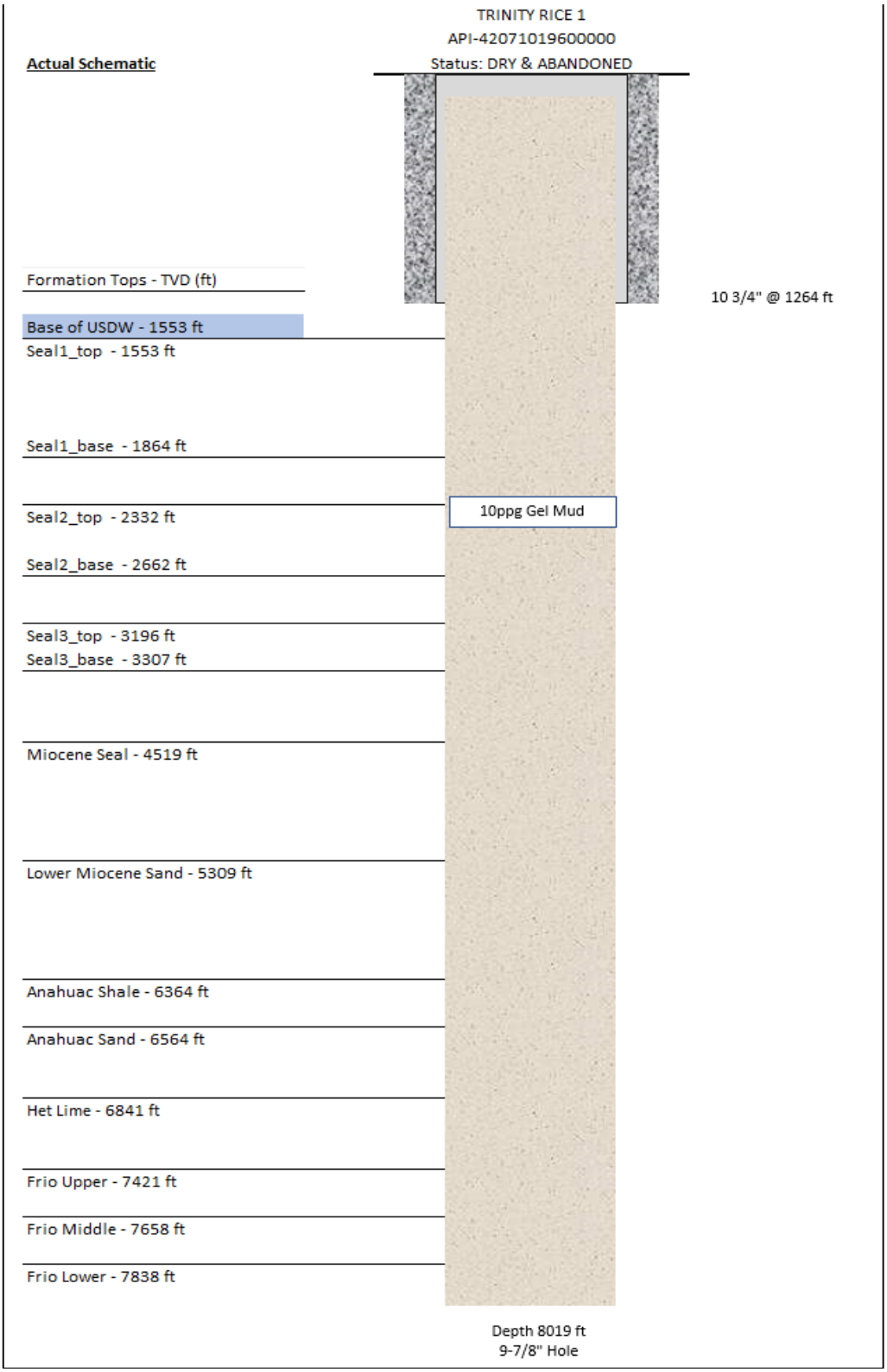


Figure C-AoR-10: Actual wellbore schematic of Trinity Rice Disposal 1 (API 42071019600000)

Table C-AoR-11: Formation tops from Trinity Rice Disposal 1 (API 42071019600000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,553
Seal1_top	1,553
Seal1_base	1,864
Seal2_top	2,332
Seal2_base	2,662
Seal3_top	3,196
Seal3_base	3,307
L_Miocene_Shale	4,519
L_Miocene_A	4,655
AMPB_SAND	4,745
L_Miocene_B	4,892
L_Miocene_C	5,175
TOP_LMIO_INJ_ZONE	5,309
LMIO_INJ_5	5,425
LMIO_INJ_4	5,589
LMIO_INJ_3	5,679
LMIO_INJ_6	5,860
LMIO_INJ_2	6,166
Anahuac	6,364
Anahuac_Sand_Top	6,564
Anahuac_Sand_Base	6,662
Anahuac_Het_Lime_Top	6,841
Anahuac_Het_Lime_Base	7,051
Frio_Top	7,421
Frio_Mid	7,658
Frio_Low	7,838

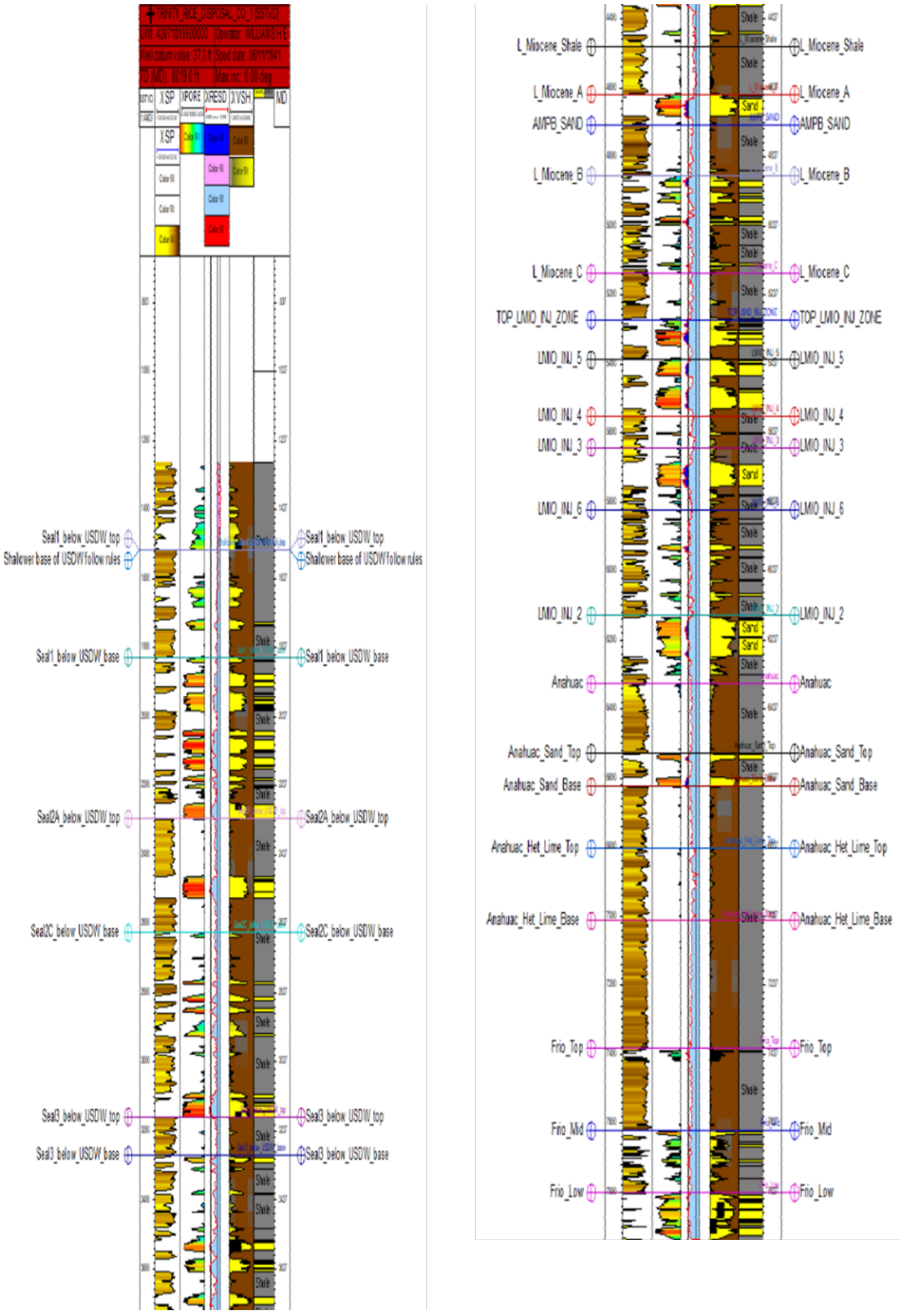


Figure C-AoR-11: Electric log and formation tops from Trinity Rice Disposal 1 (API 42071019600000).

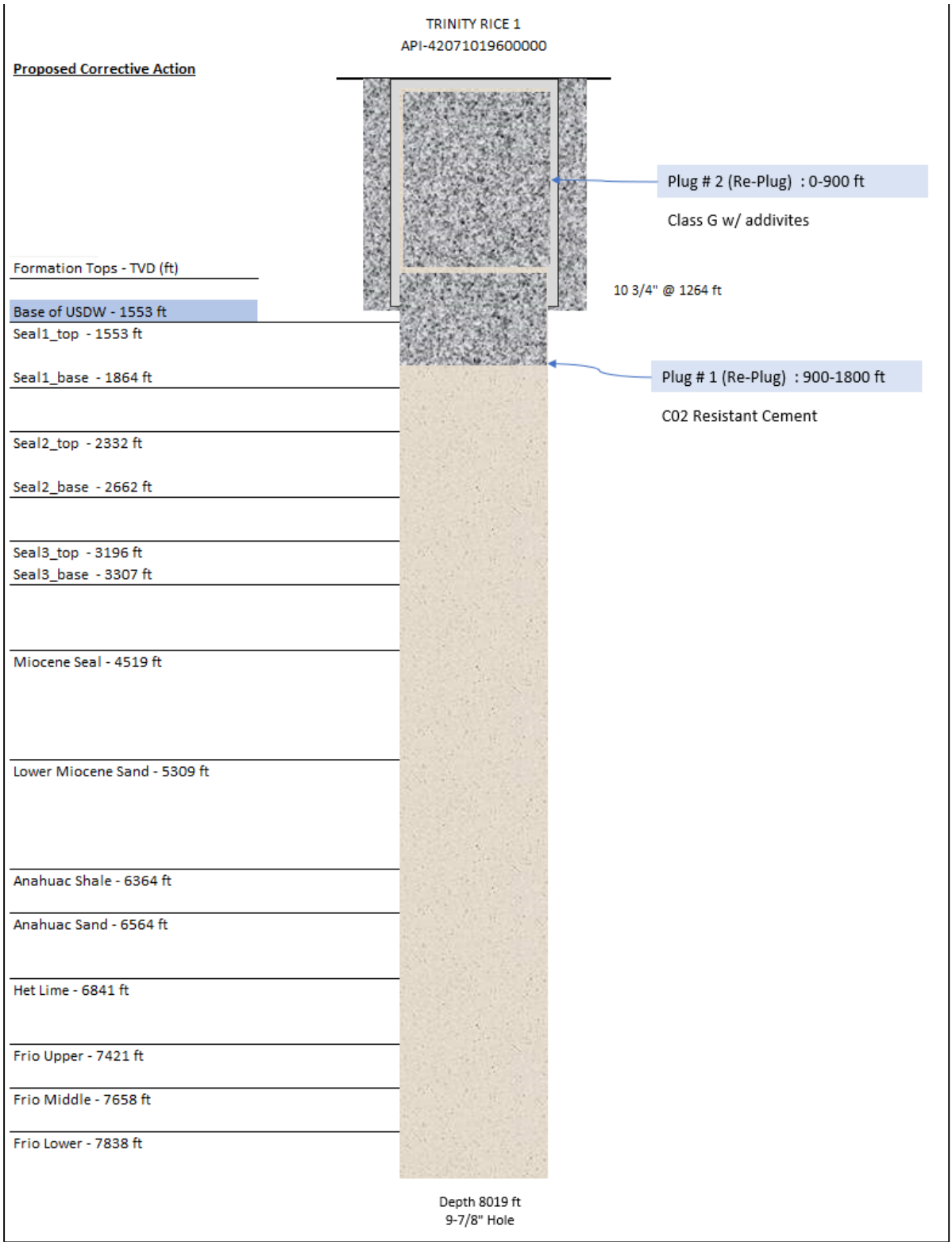


Figure C-AoR-12: Proposed remediation for Trinity Rice Disposal 1 (API 42071019600000)

Table C-AoR-12: Plug information for proposed re-abandonment procedure for Trinity Rice Disposal 1 (API 42071019600000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	900	1800	CO2 Resistant	14.8-15.5	91	1.06	481
Plug # 2	Balanced Plug	0	900	Class G w/ additives	15-15.5	91	1.01	504
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto Trinity Rice 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a 9-7/8 in. bit and run in the hole.
   a. If primary cement records have been located and there is cement behind the surface casing: Clean down to 1,800 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed to step 11.
   b. If primary cement records have not been located: Clean down to 1,300 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed with step 7.
7. Set the bridge plug at 1,240 ft. Test plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on the 10-3/4 in. casing from 1,240 ft to surface with 500 psi on the casing.
   a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,800 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
   b. If the CBL does not show cement to the surface, then perforate the 10-3/4 in. casing 25 ft above the top of the cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to the surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify the new top of cement. Proceed to step 9.
9. Run in the hole with the bit. Drill out the CICR and cement down to the bridge plug at 1,240 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.
10. Drill out the bridge plug at 1,240 ft and continue running in the hole with the work string, cleaning down 1,800 ft. Circulate the well clean and pull out of the hole. Lay down the bit.
11. Run in the hole with the work string to 1,800 ft. Circulate the well clean.
12. Plug #1: Set balanced plug 900 – 1,800 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull string to the next plug stage.
13. Plug #2: Set a balanced plug 0-900 ft with 15-15.5 ppg Class G cement.

14. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5. Garth 1 (API 42071311640000): D&A 1981

The Garth 1 is projected to be inside the Miocene CO_2 plume after 15 years of injection. The well targeted the deeper formations for oil and gas exploration. The construction was done in four phases. A 17 ½ in. surface section was drilled to 2,341 ft, cased with 13 3/8 in. 54.5/61 ppf casing, and cemented to surface. The USDW base depth is 1,583 ft and was covered by this first section of the well. The 12 ¼ in. hole intermediate section # 1 was drilled to 9,808 ft and penetrated the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations. The intermediate section #1 was cased with 9 5/8 in. 47/53.3 ppf casing and partially cemented to provide integrity to drill through the overpressure zones. The top of cement of the intermediate casing is not reported in the records obtained from TRRC files. The 8 ½ in. hole for intermediate section #2 was drilled to 13,300 ft and was cased and cemented with a 7 in. liner 32/35 ppf, from 9,562 to 13,300 ft. The production section, a 5 7/8 in. hole, was drilled to 16,000 ft. The well was abandoned with cement plugs from 13,200-14,273 ft, 350-450 ft, and 100-200 ft after the well was found dry. The current abandonment of the well isolates the USDW from the critical pressure. The well is scheduled for remedial action year 15.

Table C-AoR-13: General information for Garth 1 (API 42071311640000).

API	42071311640000
Operator	Hunt Energy Corp
Lease Name	Garth
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.8005178
Surface Longitude	-94.4500779
Total Depth	16,000
Formation	Frio
Spud Date	2/26/1981
Drilling End	6/2/1981
Abandonment Date	6/2/1981
Survey	T&NORR Survey A-280 sec 61

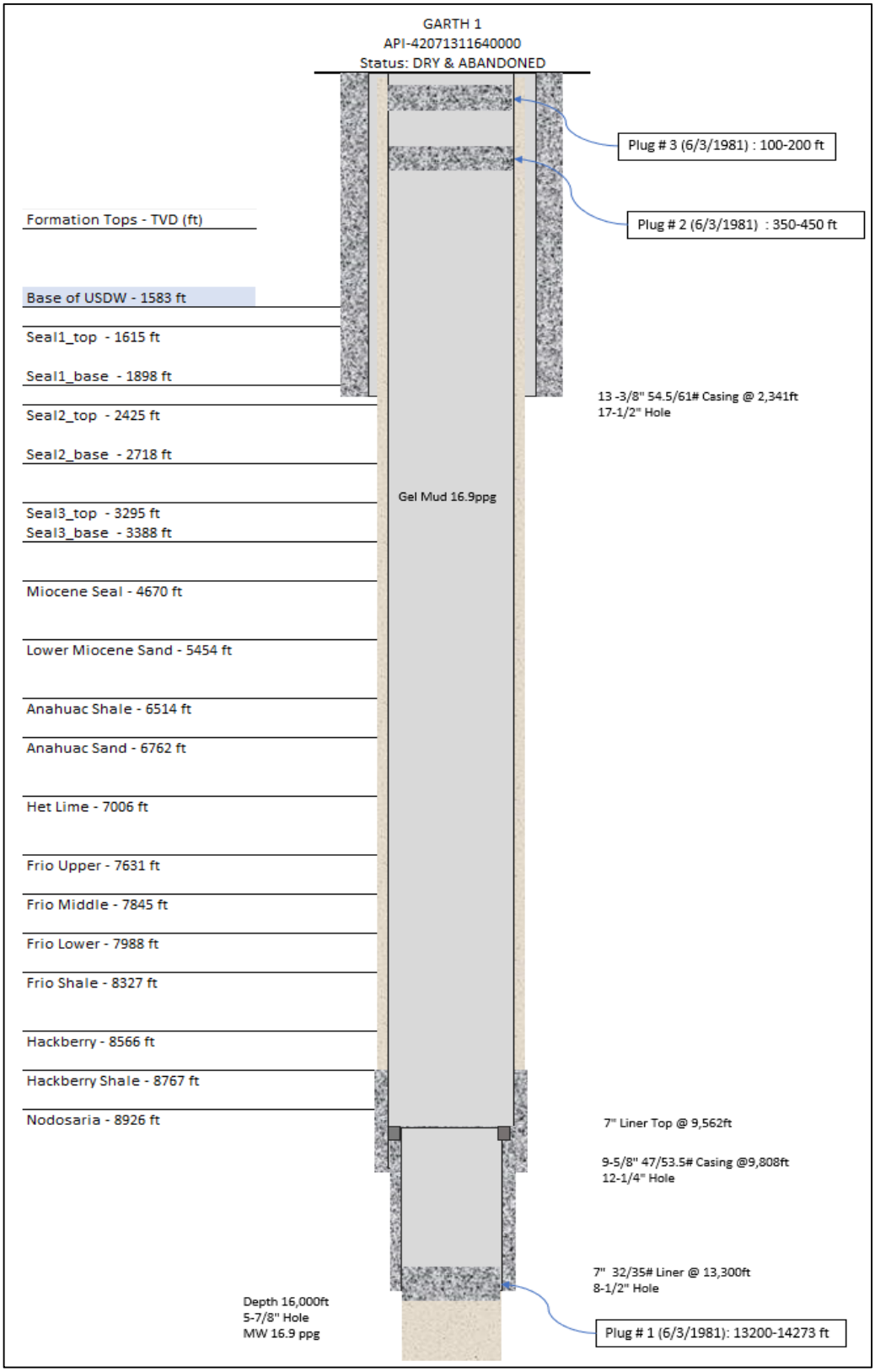


Figure C-AoR-13: Actual wellbore schematic of Garth 1 (API 42071311640000).

Table C-AoR-14: Actual plugging information from TRRC files for Garth 1 (API 42071311640000).

Plug Description	Date	Hole/ Pipe Size (inch)	Method	Top (ft)	Bottom (ft)	Sx	Cement Type	Density (ppg)	Yield (ft3/sx)
Plug # 1 : P&A – 5 7/8" hole	6/3/1981	5.875	Spotted	13,200	14,273	150	H	18	1.45
Plug # 2 : P&A 9 5/8" Casing	6/3/1981	9.625	Spotted	350	450	35	H	15.6	1.18
Plug # 3 : P&A 9 5/8" Casing	6/3/1981	9.625	Spotted	100	200	35	H	15.6	1.18

Table C-AoR-15: Formation tops from Garth 1 (API 42071311640000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,583
Seal1_top	1,615
Seal1_base	1,898
Seal2_top	2,425
Seal2_base	2,718
Seal3_top	3,295
Seal3_base	3,388
L_Miocene_Shale	4,670
L_Miocene_A	4,771
AMPB_SAND	4,841
L_Miocene_B	5,026
L_Miocene_C	5,289
TOP_LMIO_INJ_ZONE	5,454
LMIO_INJ_5	5,652
LMIO_INJ_4	5,795
LMIO_INJ_3	5,891
LMIO_INJ_6	6,059
LMIO_INJ_2	6,296
Anahuac	6,514
Anahuac_Sand_Top	6,762
Anahuac_Sand_Base	6,836
Anahuac_Het_Lime_Top	7,006
Anahuac_Het_Lime_Base	7,245
Frio_Top	7,631
Frio_Mid	7,845
Frio_Low	7,988
Frio_Shale	8,327
Hackberry	8,566
Hackberry_Shale	8,767
Nodosaria	8,926

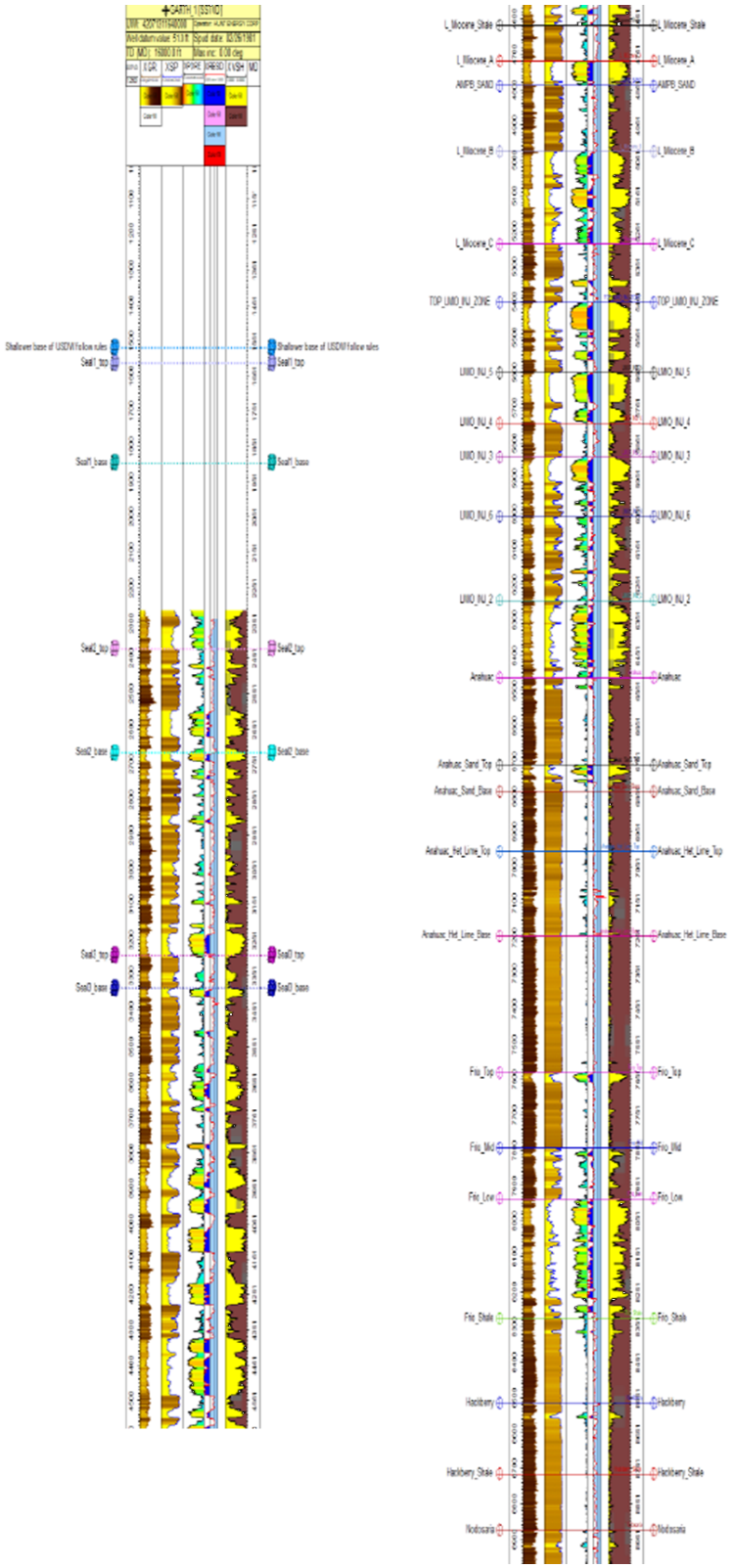


Figure C-AoR-14: Electric log and formation tops from Garth 1 (API 42071311640000).

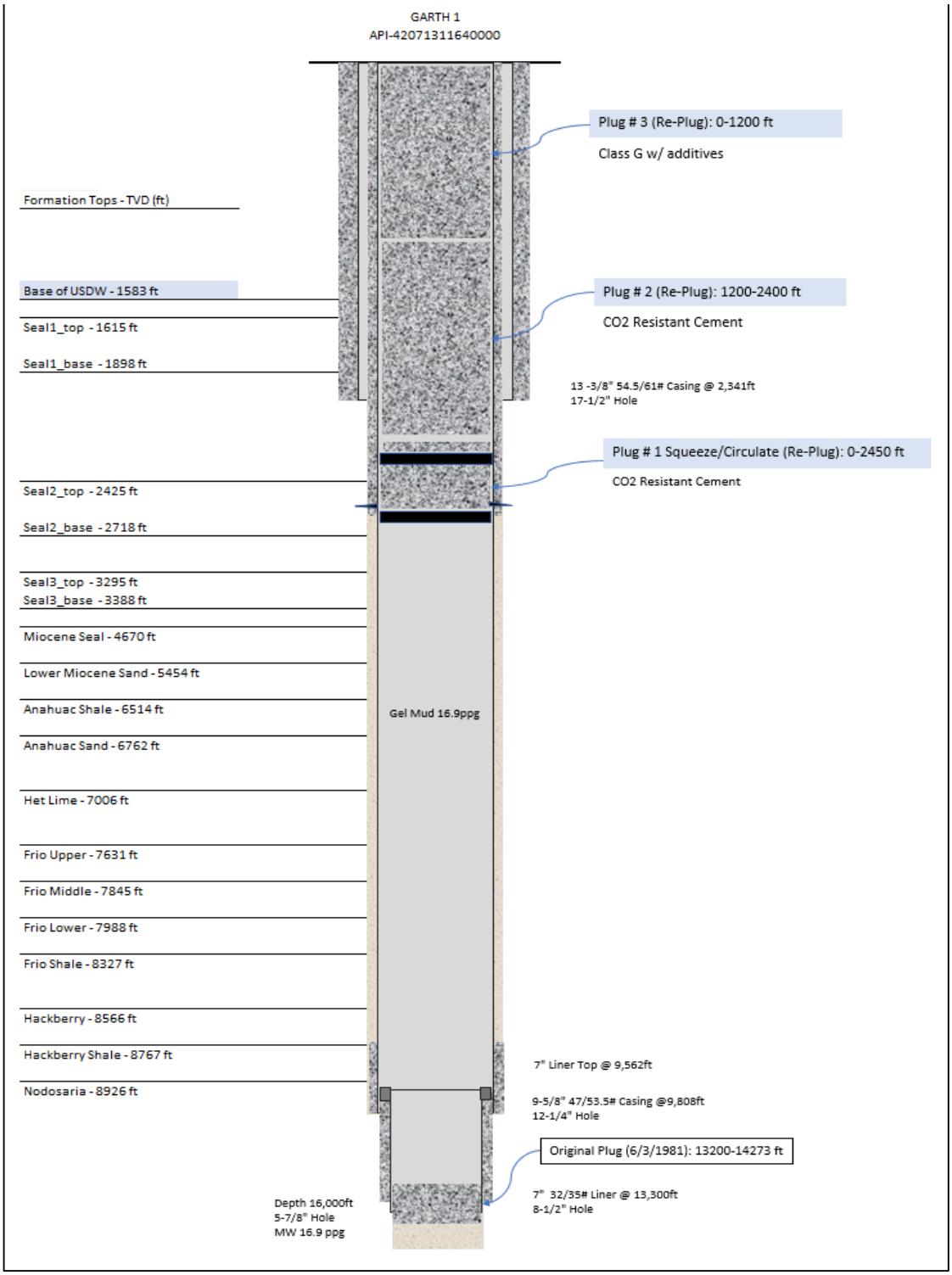


Figure C-AoR-15: Proposed remediation for Garth 1 (API 42071311640000)

Table C-AoR-16: Plug information for proposed re-abandonment procedure for Garth 1 (API 42071311640000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Squeeze/Circ	0	2450	CO2 Resistant	14.8-15.5	175	1.06	926
Plug # 2	Balanced Plug	1200	2400	CO2 Resistant	14.8-15.5	88	1.06	465
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	88	1.01	488

Plugging Procedure

1. Move in rig onto Garth 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in 53.5ppf casing and run in the hole, cleaning down to 2,450 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Set a cast iron bridge plug (CIBP) at 2,450 ft. Test plug and casing to 500 psi for 15 minutes.
8. Perforate the 9-5/8 in casing at 2,425 ft.
9. Trip in hole with the work string and cement retainer to the top of plug #1 at 2,400 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations
10. Plug #1: Squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 9-5/8 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement.
11. Run in the hole with the work string to 2,400 ft. Circulate well clean
12. Plug #2: Set balanced plug 1,200 – 2,400 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull string to the next plug stage.
13. Plug #3: Set a balanced plug 0-1,200 ft with 15-15.5 ppg Class G cement.
14. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

6. Doornbos Willim ETL 1 (API 42071312670000): D&A 1982

The Doornbos Willim ETL 1 well is projected to be inside the CO_2 plume aftert year 10 of CO_2 injection. The well targeted the deeper formations for oil and gas exploration. The construction was done in four phases. A 17 ½ in. surface section was drilled to 4,009 ft, cased with 13 3/8 in. 54.5/61ppf casing, and cemented to surface. The USDW base depth is approximately 1,607 ft and was covered by this first section of the well. The 12 ¼ in. hole intermediate section was drilled to 9,934 ft and penetrated the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations. The intermediate section #1 was cased with 9 5/8 in. 53.3 ppf casing and partially cemented to provide integrity to drill through the overpressure zones. The top of cement of the intermediate casing #1 is not reported in the records obtained from TRRC files. The 8 ½ in. hole for intermediate section #2 was drilled to 13,000 ft and cased and cemented with a 7 5/8 in. liner 39 ppf from 7,080 to 13,000 ft. The production section, 6 ½ in. hole, was drilled to 18,950 ft. A 5 ½ in. casing was run to 18,950 ft and partially cemented. The top of cement of the 5 ½ in. casing is not reported in TRRC files. This section was perforated and tested, declared dry, and abandoned along with the well. The 5 ½ in. casing was cut and partially recovered during the abandonment as well as part of the 9 5/8 in. casing. The well is scheduled for remedial actions in Year 5.

Table C-AoR-17: General information for Doornbos Willim ETL 1 (API 42071312670000).

API	42071312670000
Operator	Dow Chemical Co
Lease Name	Doornbos Willim ETL
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.808728
Surface Longitude	-94.4527792
Total Depth	18,950
Formation	Yegua
Spud Date	10/25/1981
Drilling End	2/11/1982
Abandonment Date	8/5/1982
Survey	T&NORR A-279

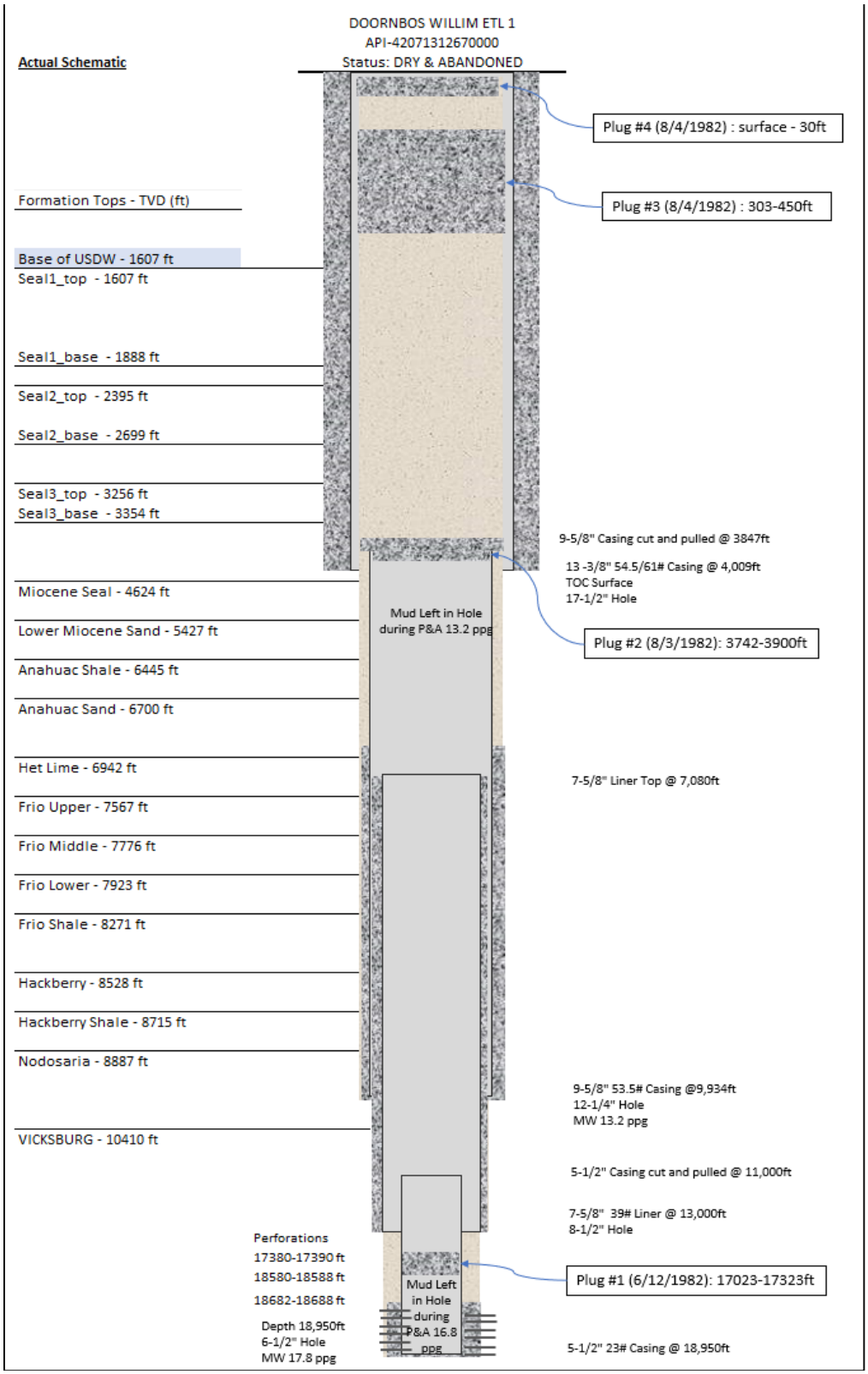


Figure C-AoR-16: Actual wellbore schematic of Doornbos Willim ETL 1 (API 42071312670000).

Table C-AoR-18: Plug information for proposed re-abandonment procedure for Doornbos Willim ETL 1 (API 42071312670000).

Description	Date	OD (inch)	Sx	Yield (ft3/sx)	Bls	FT	Estimated TOC (ft)	Additives
Lead Surface String	9/1/1982	17.500	2850	1.54	782	3,613	0	DWL + 0.2% D-46
Tail Surface String	9/1/1982	17.500	400	1.18	84	389	3620	0.2% D-46

Plug Description	Date	Method	Cement Type	Density (ppg)	Tagged	cu. ft	Yield (ft3/sx)
Plug # 1: P&A – 5 ½" hole	6/12/1982	Spotted	H	18	No	36.11	1.64
Plug # 2: P&A 9 5/8" Casing	8/3/1982	Spotted	H	15	No	94.4	1.18
Plug # 3: P&A 13 3/8" Casing	8/4/1982	Spotted	H	15	No	129	1.18
Plug # 4: P&A 13 3/8" Casing	8/4/1982	Spotted	H	15	No	23	1.18

Table C-AoR-19: Formation tops from Doornbos Willim ETL 1 (API 42071312670000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,607
Seal1_top	1,607
Seal1_base	1,888
Seal2_top	2,395
Seal2_base	2,699
Seal3_top	3,256
Seal3_base	3,354
L_Miocene_Shale	4,624
L_Miocene_A	4,738
AMPB_SAND	4,844
L_Miocene_B	4,972
L_Miocene_C	5,264
TOP_LMIO_INJ_ZONE	5,427
LMIO_INJ_5	5,554
LMIO_INJ_4	5,716
LMIO_INJ_3	5,812
LMIO_INJ_6	5,989
LMIO_INJ_2	6,268
Anahuac	6,445
Anahuac_Sand_Top	6,700
Anahuac_Sand_Base	6,767
Anahuac_Het_Lime_Top	6,942
Anahuac_Het_Lime_Base	7,169
Frio_Top	7,567
Frio_Mid	7,776
Frio_Low	7,923
Frio_Shale	8,271
Hackberry	8,528
Hackberry_Shale	8,715
Nodosaria	8,887
VICKSBURG	10,410

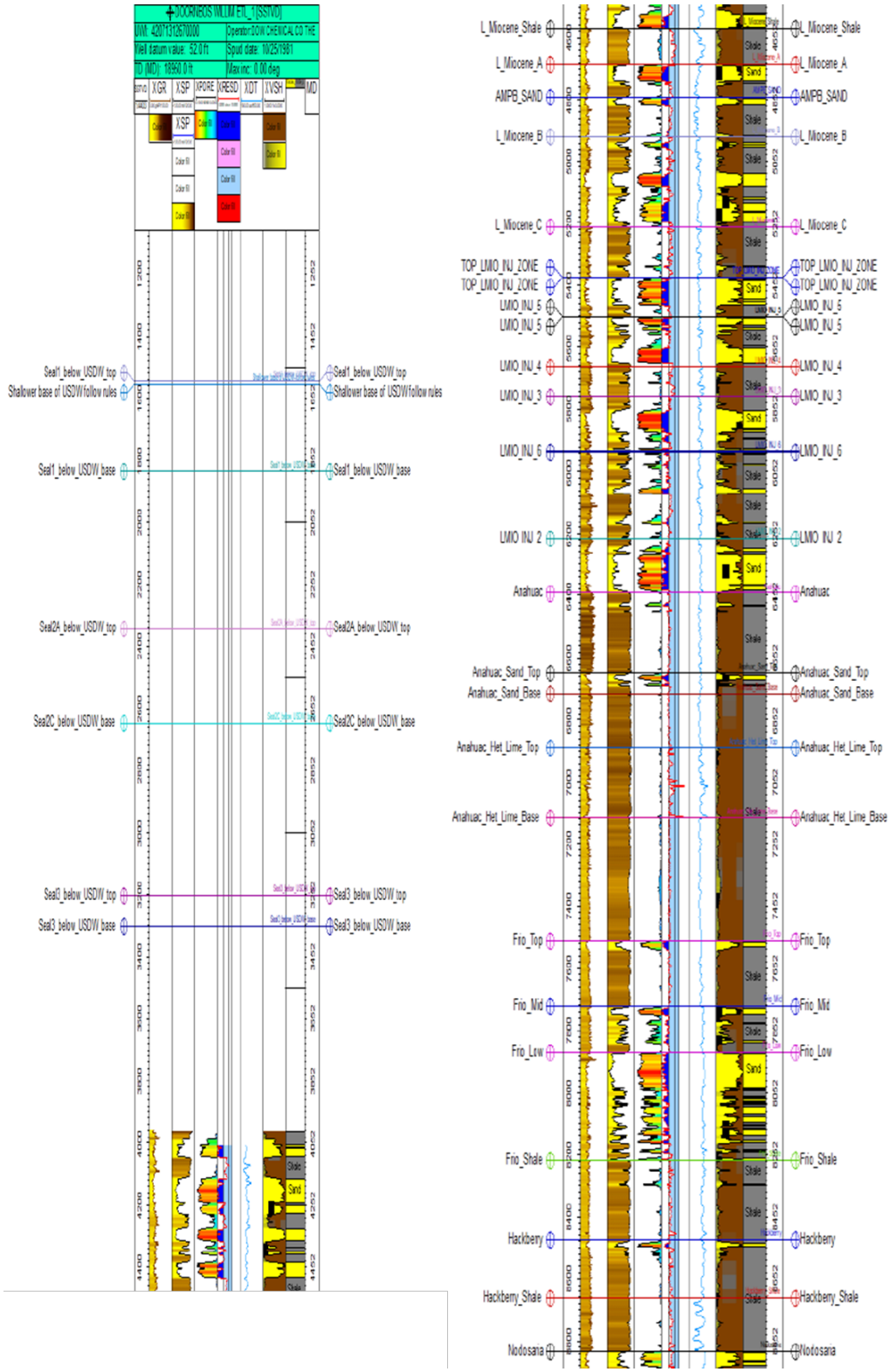


Figure C-AoR-17: Electric log and formation tops from Doornbos Willim ETL 1 (API 42071312670000).

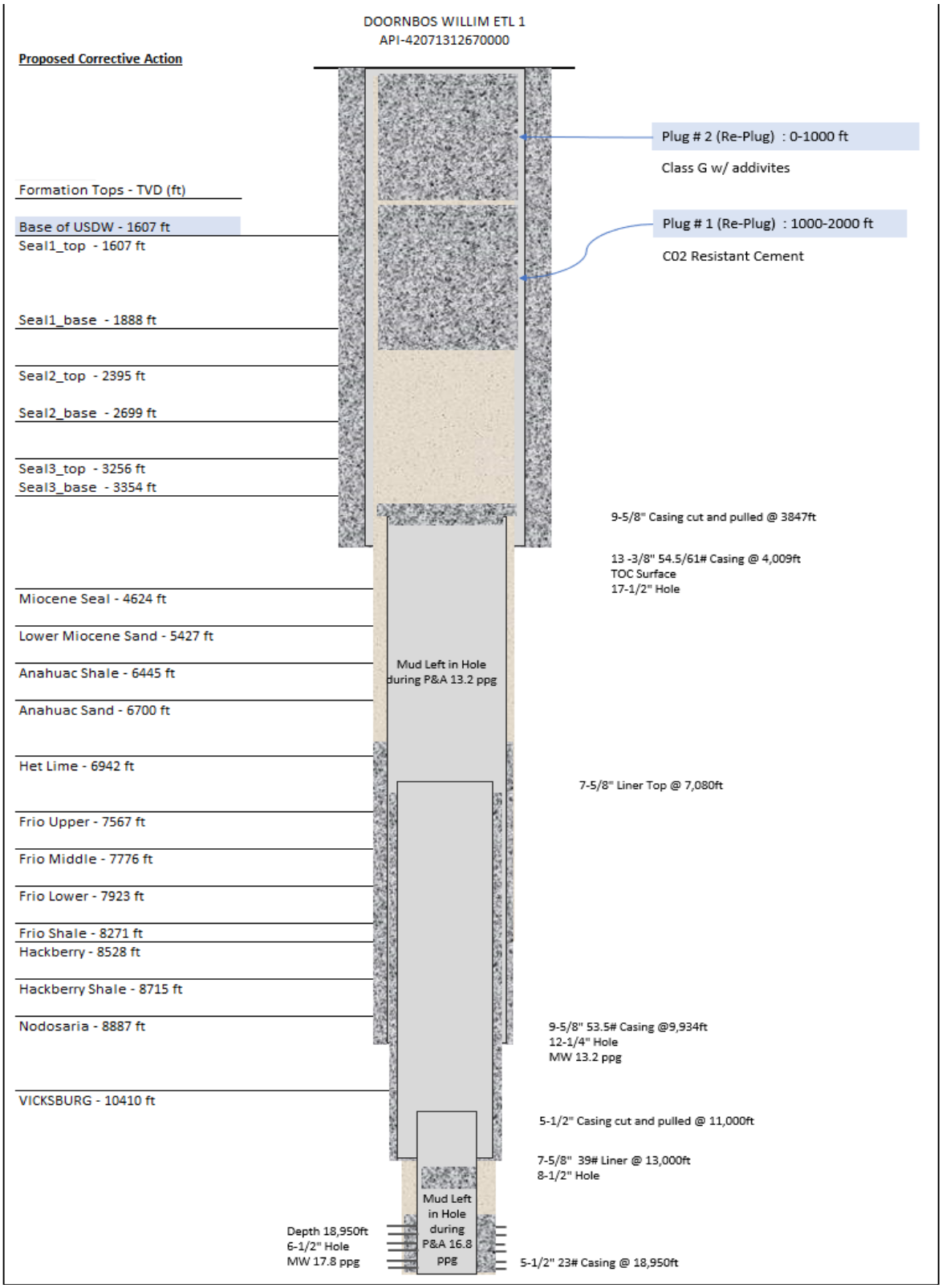


Figure C-AoR-18: Proposed remediation for Doornbos Willim ETL 1 (API 42071312670000).

Table C-AoR-20: Plug information for proposed abandonment procedure for Doornbos Willim ETL 1 (API 42071312670000).

Plug	Method	Top (ft)	Bottom (ft)	Cement Type	Density	Volume	Yield	Sx
Plug # 1	Balanced Plug	1000	2000	CO2 Resistant	14.8-15.5	155	1.06	818
Plug # 2	Balanced Plug	0	1000	Class G w/ additives	15-15.5	155	1.01	859

Plugging Procedure

1. Move in rig onto Doornbos Willim ETL 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a bit for 13-3/8 in. casing and run in the hole, drilling out cement plugs and cleaning down to 2,000 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with the work string to 2,000 ft. Circulate well clean.
8. Plug #1: Set a balanced plug 1,000-2,000 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull string to the next plug stage.
9. Plug #2: Set a balanced plug 0-1,000 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

7. Doornbos 1 (API 42071322330000): D&A 2002

The Doornbos 1 well is projected to be inside the CO_2 plume between years 5 and 10 of CO_2 injection. The well targeted the deeper formations for oil and gas exploration. The construction was done in three phases. A 14 ¾ in. surface section was drilled to 2,100 ft, cased with 10 3/4 in. 40.5 ppf casing, and cemented to surface. The USDW base depth is approximately 1,535 ft and was covered by this first section of the well. The 9 7/8 in. hole intermediate section was drilled to 9,719 ft and penetrated the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations. The intermediate section was cased with 7 5/8 in. 33.7 ppf casing and partially cemented to provide integrity to drill through the overpressure zones. The top of cement of the intermediate casing is calculated based on the cementing reports obtained from TRRC files. The top of cement is estimated to be 4,460 ft. The 6 1/2 in. hole for the production section was drilled to 10,800 ft and abandoned open hole after the well was found dry. The well will scheduled for corrective action in year 0.

Table C-AoR-2116: General information for Doornbos 1 (API 42071322330000).

API	42071322330000
Operator	Goldston Oil Corp
Lease Name	Doornbos
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.82107163
Surface Longitude	-94.45198822
Total Depth	10,800
Formation	Frio
Spud Date	10/11/2002
Drilling End	11/12/2002
Abandonment Date	12/10/2022
Survey	T&NORR Sec 45 A-272

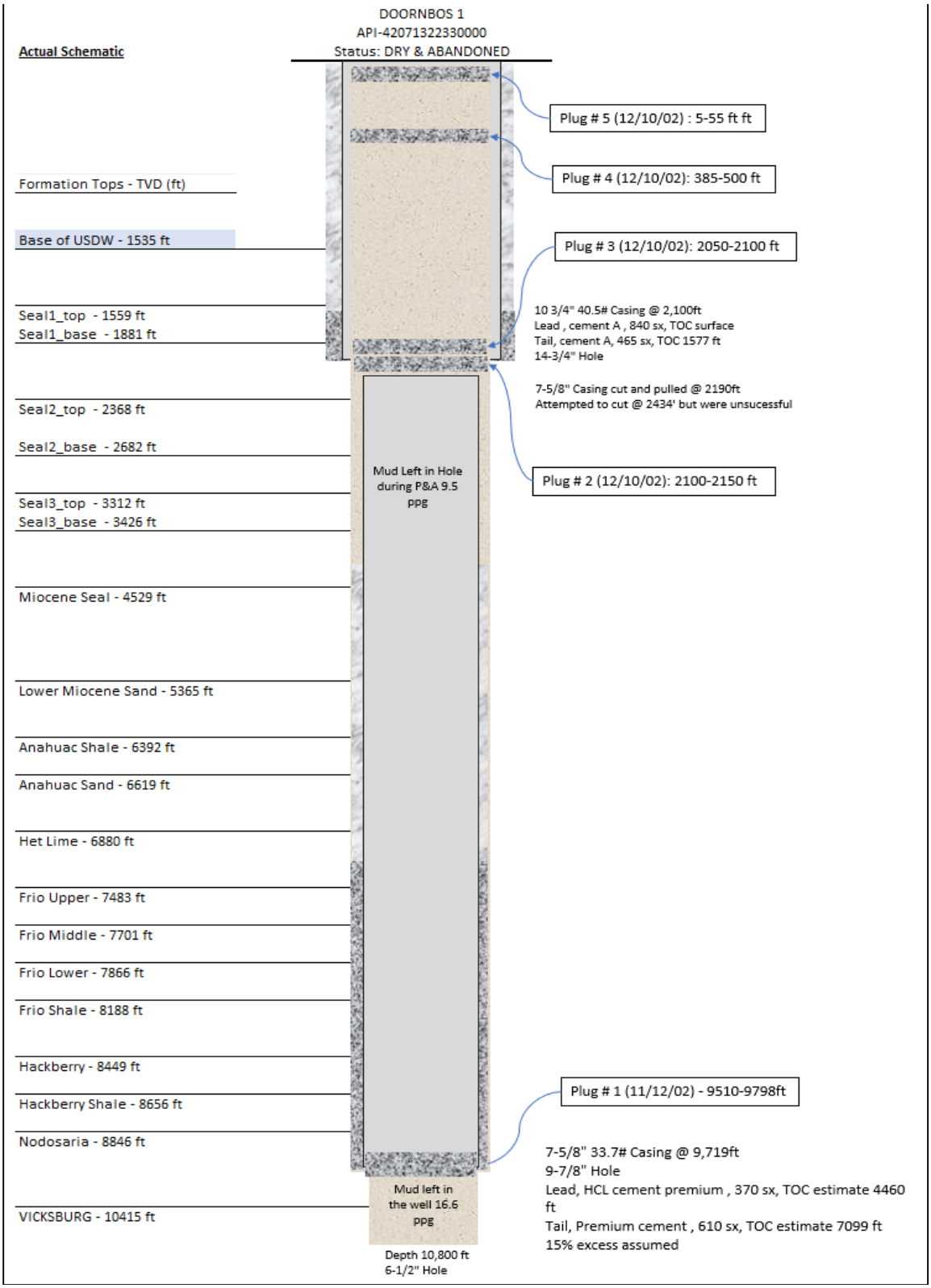


Figure C-AoR-19: Actual wellbore schematic of Doornbos 1 (API 42071322330000).

Table C-AoR-22: Plug information for proposed re-abandonment procedure for Doornbos 1 (API 42071322330000).

Description	Date	OD (inch)	Excess	Sx	Yield (ft3/sx)	Estimated TOC (ft)
Surface string cementing	10/13/2002	14.750	100%	840	2.14	0
Surface string cementing	10/13/2002	14.750	100%	465	1.25	1577
Intermediate string cementing	11/1/2002	9.875	15%	370	1.76	4460
Intermediate string cementing	11/1/2002	9.875	15%	610	1.06	7099

Plug Description	Date	Hole/ Pipe Size (inch)	Method	Top (ft)	Bottom (ft)	Sx	Cement Type	Density (ppg)	Tag	Yield ft3/sx
Plug # 1: P&A - 6 ½" hole and 7 5/8" casing shoe	11/12/2002	6.5	Spotted	9,510	9,798	75	H	15.6*	No	1.18*
Plug # 2: P&A 9 7/8" Casing	12/10/2002	9.875	Spotted	2,100	2,150	25	H	15.6	No	1.18
Plug # 3: P&A 10 ¾" Casing	12/10/2002	10.750	Spotted	2,050	2,050	75	H	15.6	No	1.18
Plug # 4: P&A 10 ¾" Casing	12/10/2002	10.750	Spotted	385	500	50	H	15.6	Yes	1.18
Plug # 5: P&A 10 ¾" Casing	12/10/2002	10.750	Spotted	5	55	25	H	15.6	No	1.18

* Assumed a 15.6 ppg slurry, cement H, Yield = 1.18 ft3/sx

** Calculated based on reported ft^3 pumped and number of sacks.

Table C-AoR-23: Formation tops from Doornbos 1 (API 42071322330000).

Formation Tops (MD ft)	
Shallower base of USDW follow rule	1,535
Seal1_top	1,559
Seal1_base	1,881
Seal2_top	2,368
Seal2_base	2,682
Seal3_top	3,312
Seal3_base	3,426
L_Miocene_Shale	4,529
L_Miocene_A	4,726
AMPB_SAND	4,801
L_Miocene_B	4,916
L_Miocene_C	5,202
TOP_LMIO_INJ_ZONE	5,365
LMIO_INJ_5	5,470
LMIO_INJ_4	5,629
LMIO_INJ_3	5,734
LMIO_INJ_6	5,881
LMIO_INJ_2	6,202
Anahuac	6,392
Anahuac_Sand_Top	6,619
Anahuac_Sand_Base	6,692
Anahuac_Het_Lime_Top	6,880
Anahuac_Het_Lime_Base	7,086
Frio_Top	7,483
Frio_Mid	7,701
Frio_Low	7,866
Frio_Shale	8,188
Hackberry	8,449
Hackberry_Shale	8,656
Nodosaria	8,846
VICKSBURG	10,415

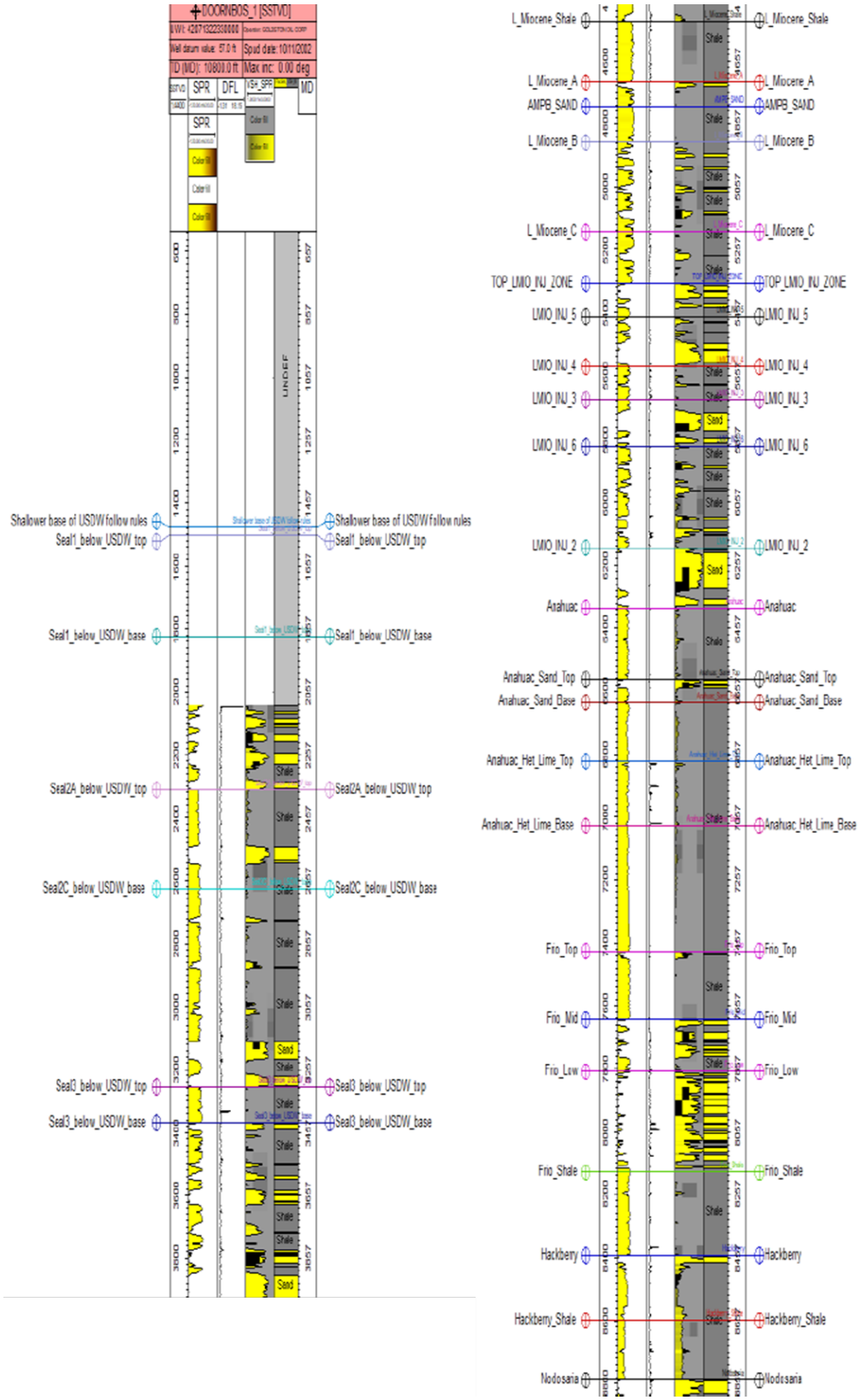


Figure C-AoR-20: Electric log and formation tops from Doornbos 1 (API 42071322330000).

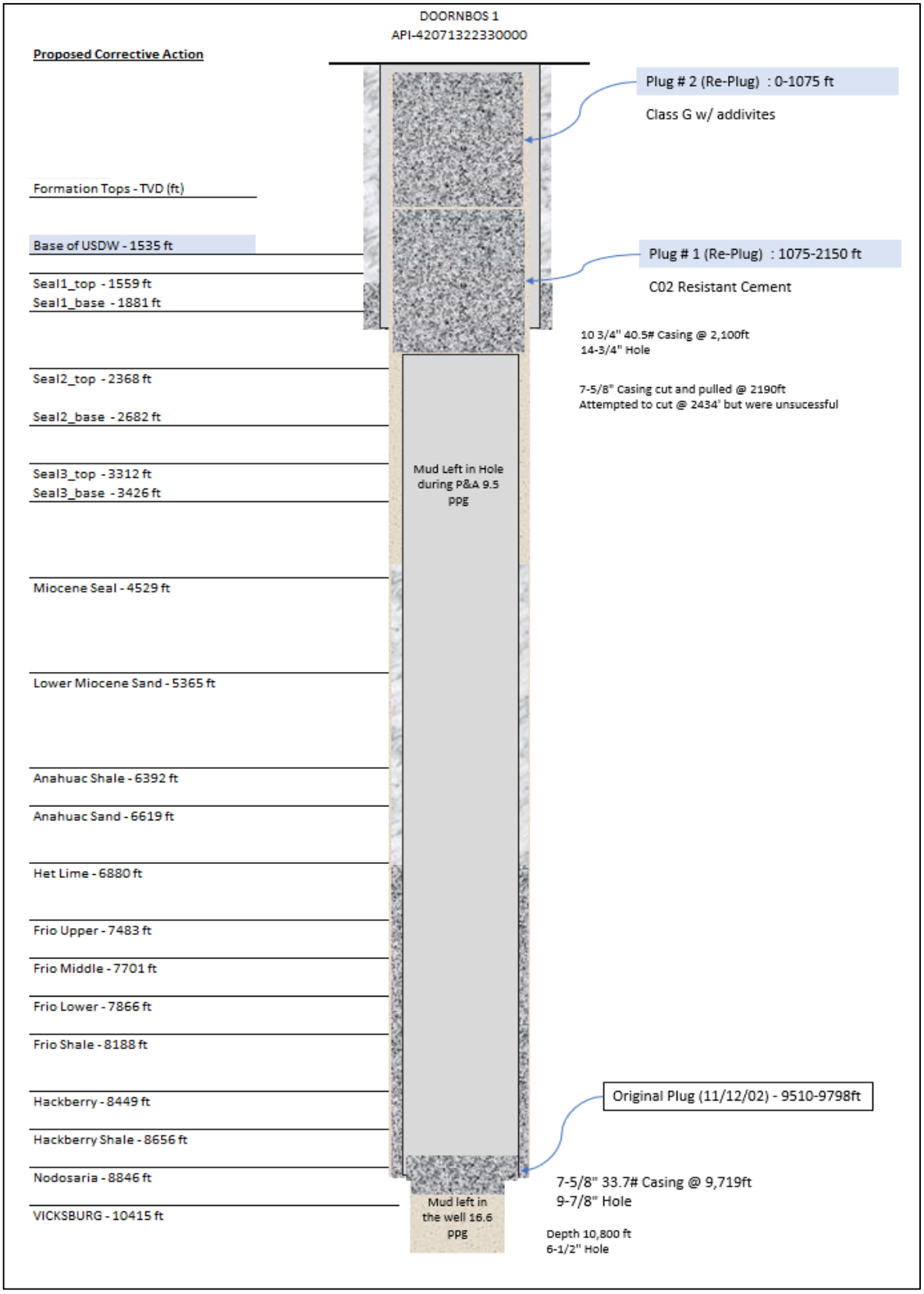


Figure C-AoR-21: Proposed remediation for Doornbos 1 (API 42071322330000).

Table C-AoR-24: Plug information for proposed re-abandonment procedure for Doornbos 1 (API 42071322330000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	1075	2150	CO2 Resistant	14.8-15.5	105	1.06	558
Plug # 2	Balanced Plug	0	1075	Class G w/ additives	15-15.5	105	1.01	586

Plugging Procedure

1. Move in rig onto Doornbos 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a bit for 10-3/4 in. 40.5 ppf casing and run in the hole, drilling out cement plugs down to 2,150 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with work the string to 2,150 ft. Circulate well clean.
8. Plug #1: Set a balanced plug 1,075 – 2,150 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull string to the next plug stage.
9. Plug #2: Set a balanced plug 0-1,075 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

8. Earl Cooper Etal 1 (API 42071300320000): D&A 1969

The Earl Cooper Etal 1 well is projected to be at the border of the CO_2 plume after10 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry and Nodosaria formations reaching a TD of 9,475 ft. The 10 3/4 in. surface casing set at 1,167 ft does not cover the USDW, located at approximately 1,537 ft. The abandonment procedure consisted of a 50 sx cement plug set below the surface shoe and 10 sx of cement spotted on the surface, according to the TRRC records. The well was left filled with 10.5 ppg mud in open hole. The well will be scheduled for remedial action in Year 5.

Table C-AoR-25: General information for Earl Cooper Etal 1 (API 42071300320000).

API	42071300320000
Operator	Texas Consolidated Pet Corp
Lease Name	Earl Cooper Etal
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.80683743
Surface Longitude	-94.48139089
Total Depth	9,475
Formation	Unknown
Spud Date	9/10/1969
Drilling End	9/28/1969
Abandonment Date	9/28/1969

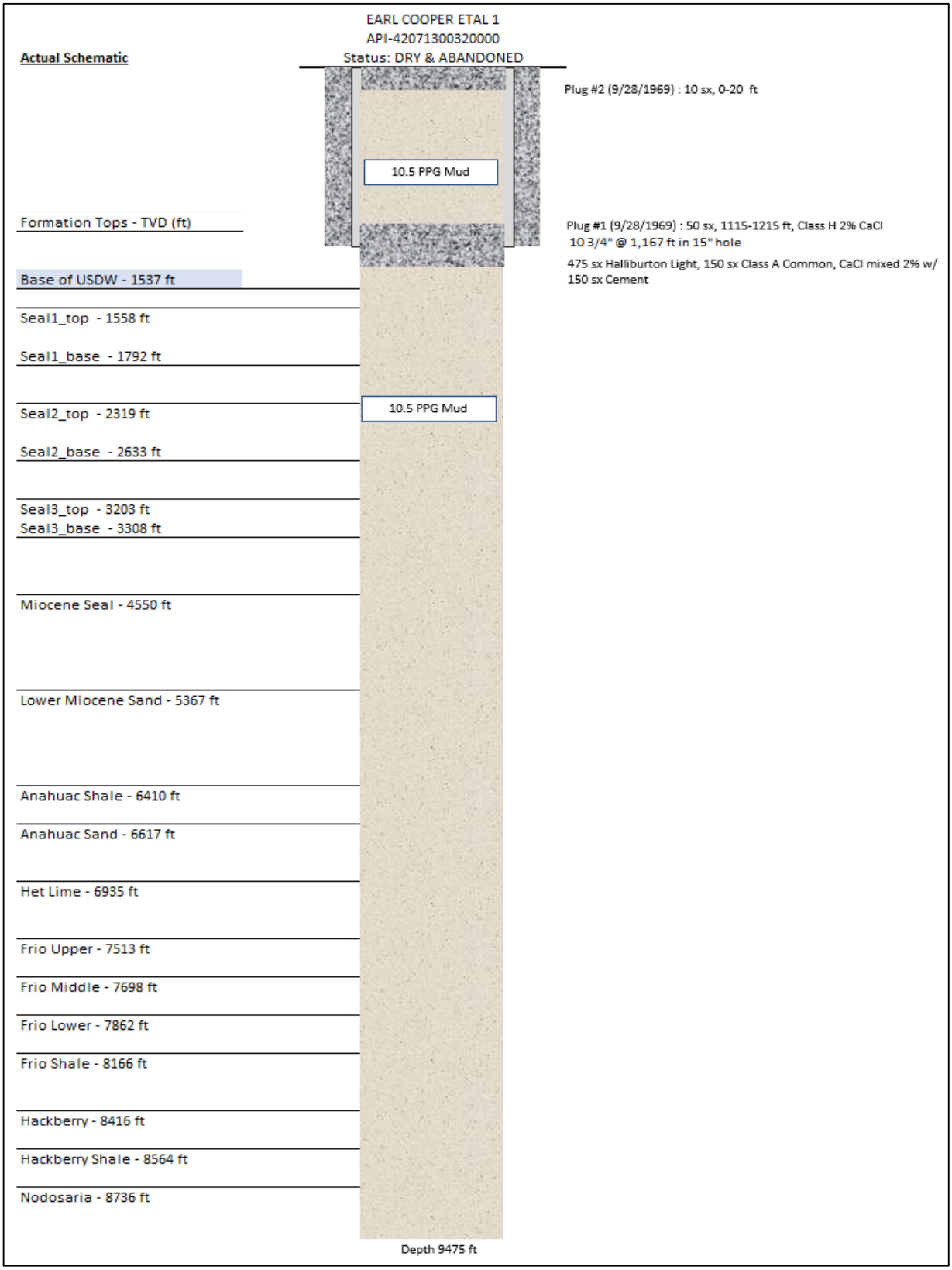


Figure C-AoR-22: Actual wellbore schematic of Earl Cooper Etal 1 (API 42071300320000).

Table C-AoR-26: Formation tops from Earl Cooper Etal 1 (API 42071300320000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,537
Seal1_top	1,558
Seal1_base	1,792
Seal2_top	2,319
Seal2_base	2,633
Seal3_top	3,203
Seal3_base	3,308
L_Miocene_Shale	4,550
L_Miocene_A	4,682
AMPB_SAND	4,832
L_Miocene_B	4,975
L_Miocene_C	5,244
TOP_LMIO_INJ_ZONE	5,367
LMIO_INJ_5	5,564
LMIO_INJ_4	5,609
LMIO_INJ_3	5,792
LMIO_INJ_6	5,986
LMIO_INJ_2	6,236
Anahuac	6,410
Anahuac_Sand_Top	6,617
Anahuac_Sand_Base	6,679
Anahuac_Het_Lime_Top	6,935
Anahuac_Het_Lime_Base	7,123
Frio_Top	7,513
Frio_Mid	7,698
Frio_Low	7,862
Frio_Shale	8,166
Hackberry	8,416
Hackberry_Shale	8,564
Nodosaria	8,736

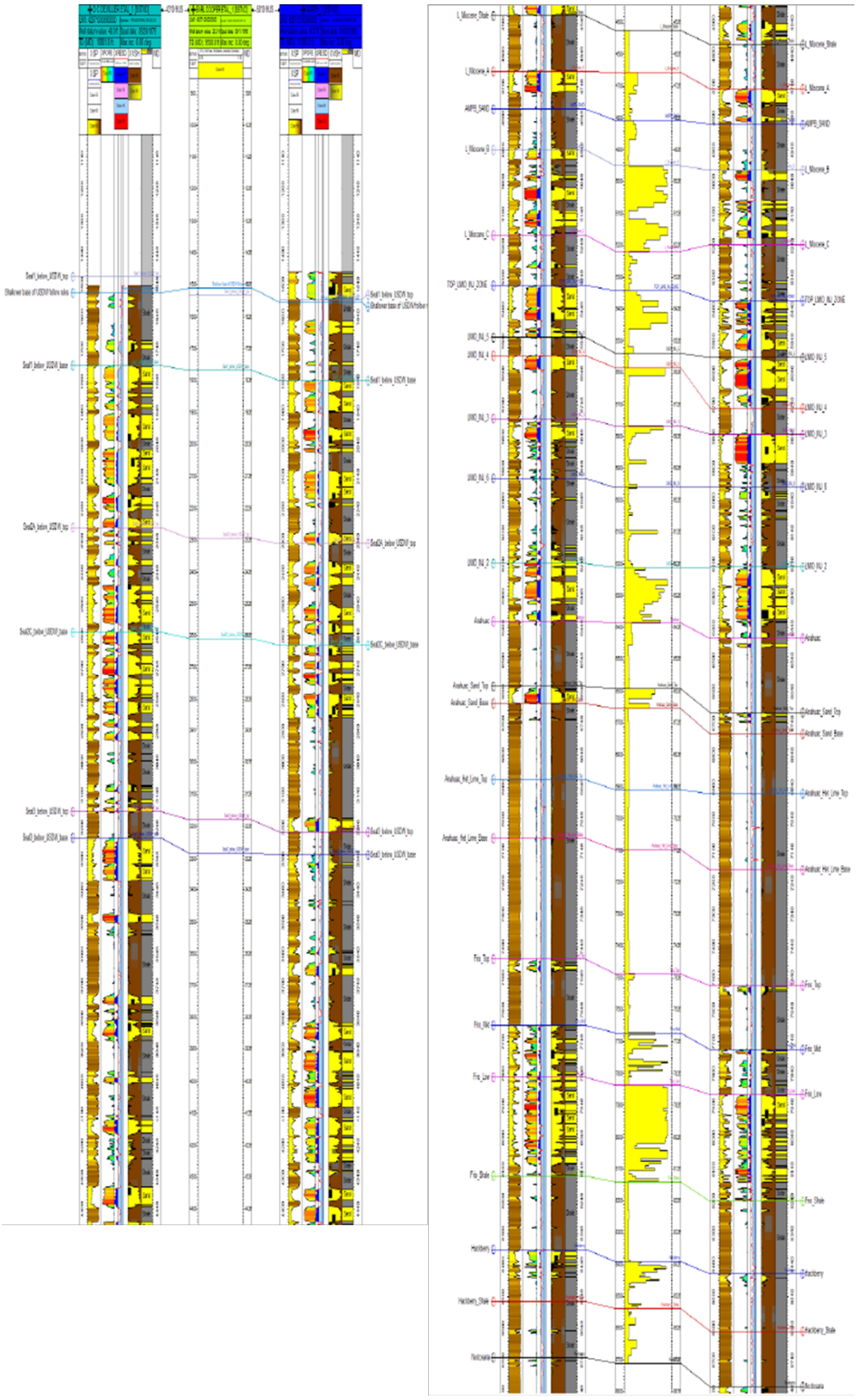


Figure C-AoR-23: Pseudo-log and formation tops from Earl Cooper Etal 1 (API 42071300320000).

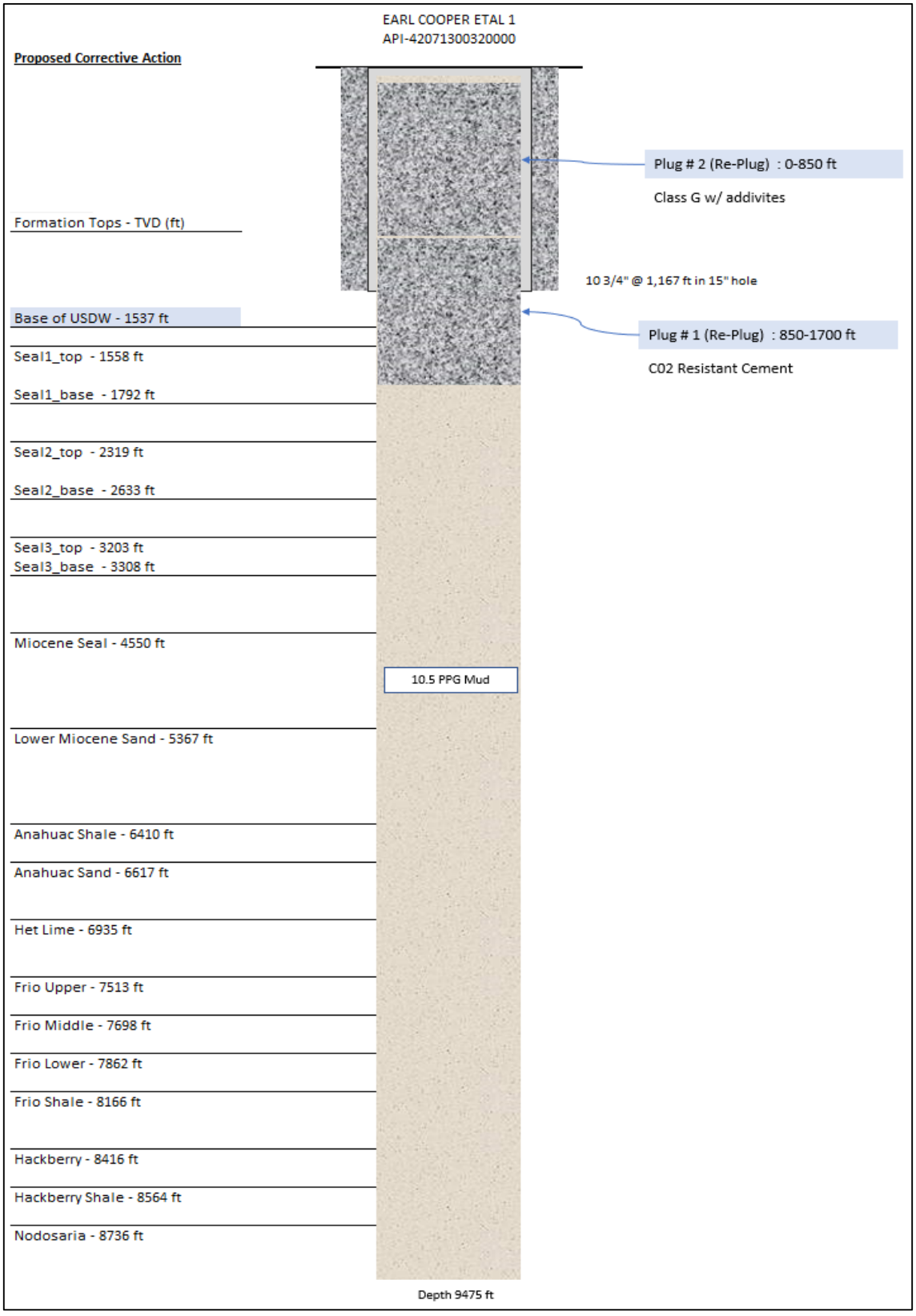


Figure C-AoR-24: Proposed remediation for Earl Cooper Etal 1 (API 42071300320000).

Table C-AoR-27: Plug information for proposed re-abandonment procedure for Earl Cooper Etal 1 (API 42071300320000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	850	1700	CO2 Resistant	14.8-15.5	86	1.06	454
Plug # 2	Balanced Plug	0	850	Class G w/ additives	15-15.5	86	1.01	476

Plugging Procedure

1. Move in rig onto Earl Cooper Etal 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a 9-7/8 in. bit and run in the hole, cleaning down to 1,700 ft. Circulate the hole clean and pull out of the hole. Lay down bit.
7. Run in the hole with work string to 1,700 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 850 – 1,700 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-850 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

9. Garth CO 3 (API 42071300730000): D&A 1970

The Garth CO 3 well is projected to be at the border of the CO_2 plume after 10 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 9,265 ft. The 10 3/4 in. surface casing set at 1,208 ft does not cover the USDW, located at approximately 1,580 ft. The abandonment procedure consisted of a 100 sx cement plug set below the surface shoe and 10 sx of cement spotted on surface, according to the TRRC records. The well was left filled with 10.5 ppg mud in open hole. The well will be scheduled for remedial action in Year 5.

Table C-AoR-28: General information for Garth CO 3 (API 42071300730000).

API	42071300730000
Operator	Texas Consolidated Pet Corp
Lease Name	Garth CO
Well Number	3
Status	Dry & Abandoned
Surface Latitude	29.80283695
Surface Longitude	-94.47820661
Total Depth	9,265
Formation	Unknown
Spud Date	2/16/1970
Drilling End	2/26/1970
Abandonment Date	2/26/1970

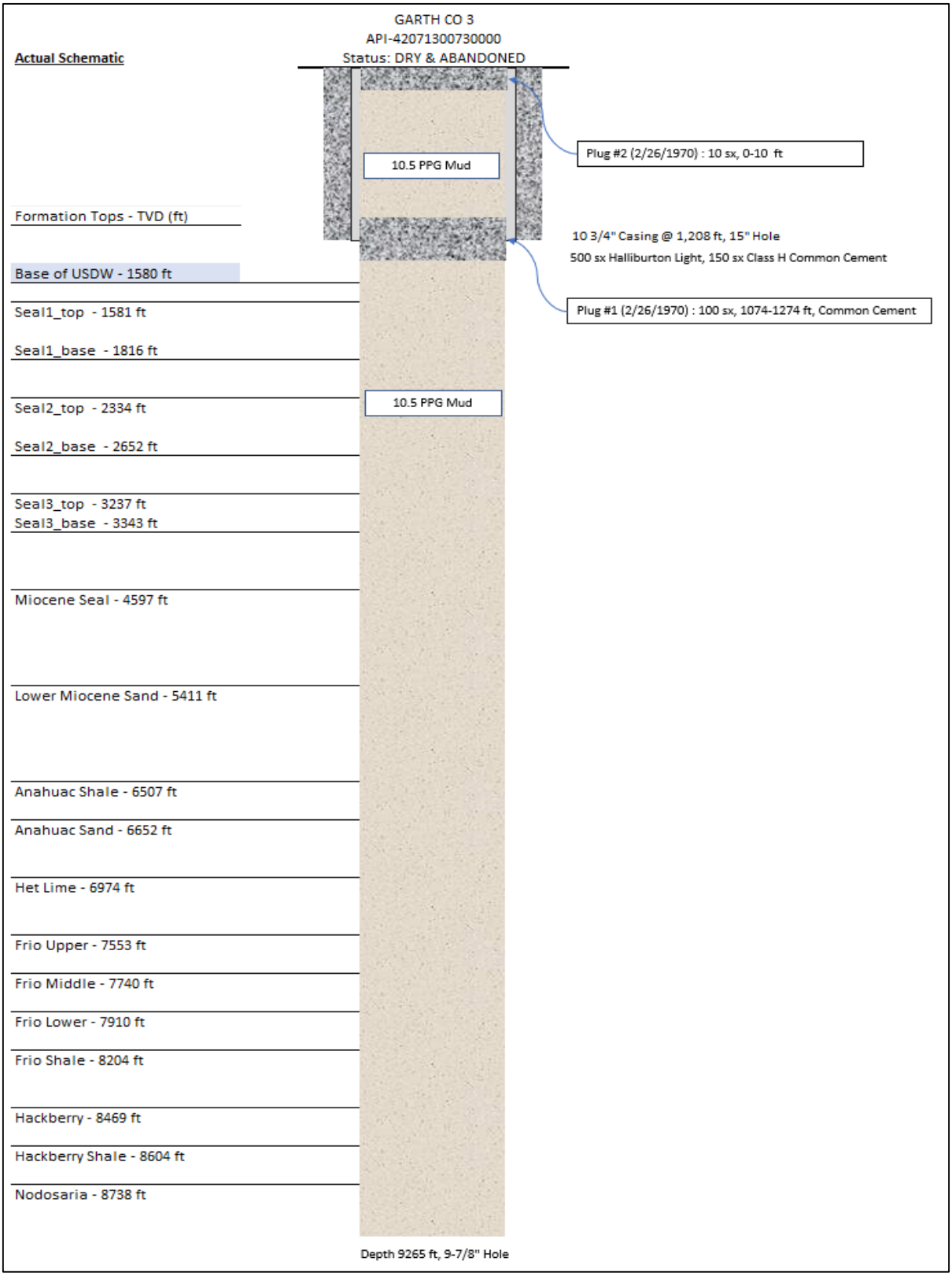


Figure C-AoR-25: Actual wellbore schematic of Garth CO 3 (API 42071300730000).

Table C-AoR-29: Formation tops from Garth CO 3 (API 42071300730000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,580
Seal1_top	1,581
Seal1_base	1,816
Seal2_top	2,334
Seal2_base	2,652
Seal3_top	3,237
Seal3_base	3,343
L_Miocene_Shale	4,597
L_Miocene_A	4,755
AMPB_SAND	4,873
L_Miocene_B	5,008
L_Miocene_C	5,247
TOP_LMIO_INJ_ZONE	5,411
LMIO_INJ_5	5,595
LMIO_INJ_4	5,677
LMIO_INJ_3	5,831
LMIO_INJ_6	6,011
LMIO_INJ_2	6,257
Anahuac	6,507
Anahuac_Sand_Top	6,652
Anahuac_Sand_Base	6,723
Anahuac_Het_Lime_Top	6,974
Anahuac_Het_Lime_Base	7,167
Frio_Top	7,553
Frio_Mid	7,740
Frio_Low	7,910
Frio_Shale	8,204
Hackberry	8,469
Hackberry_Shale	8,604
Nodosaria	8,738

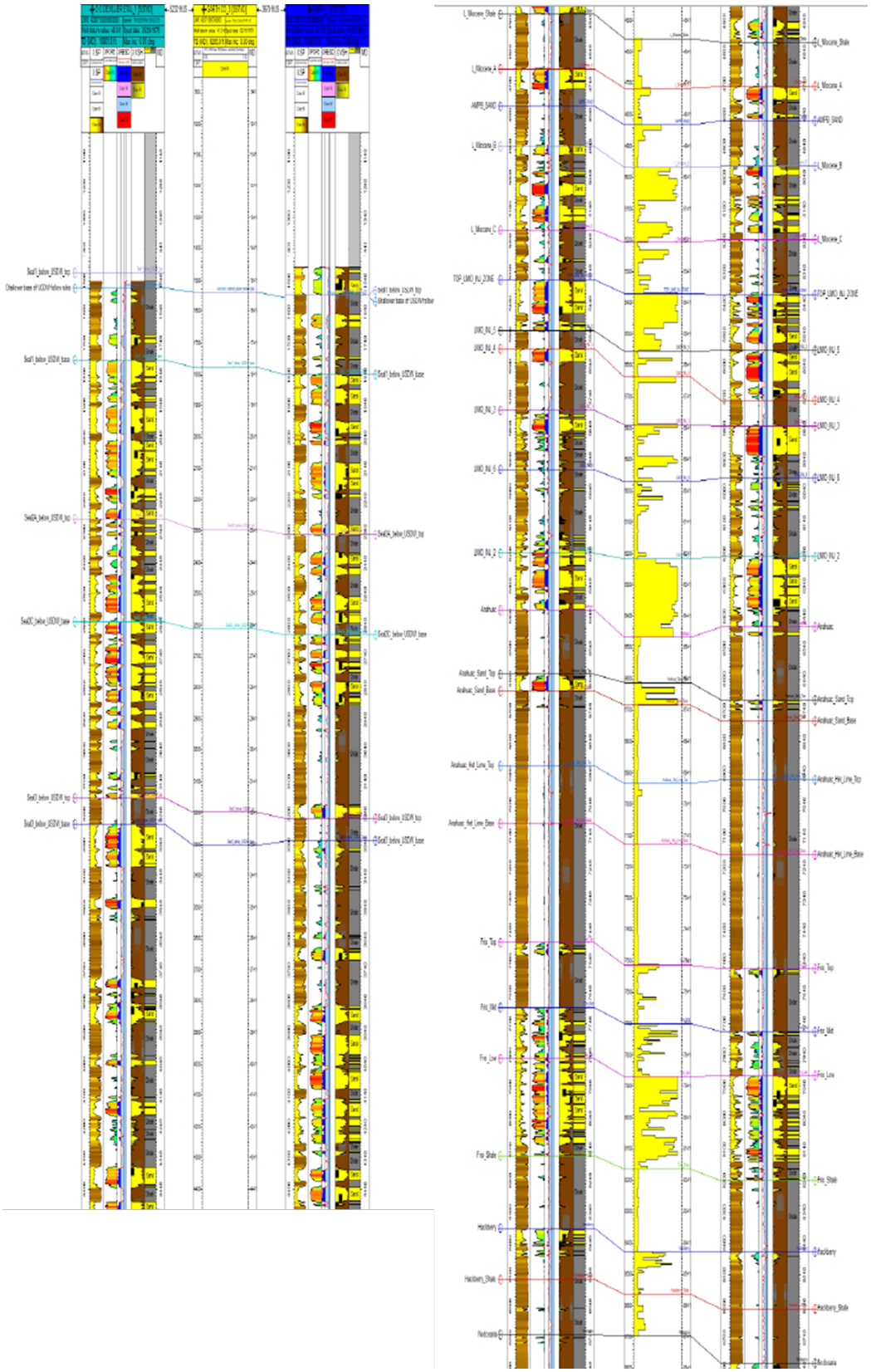


Figure C-AoR-26: Pseudo-log and formation tops from Garth CO 3 (API 42071300730000).

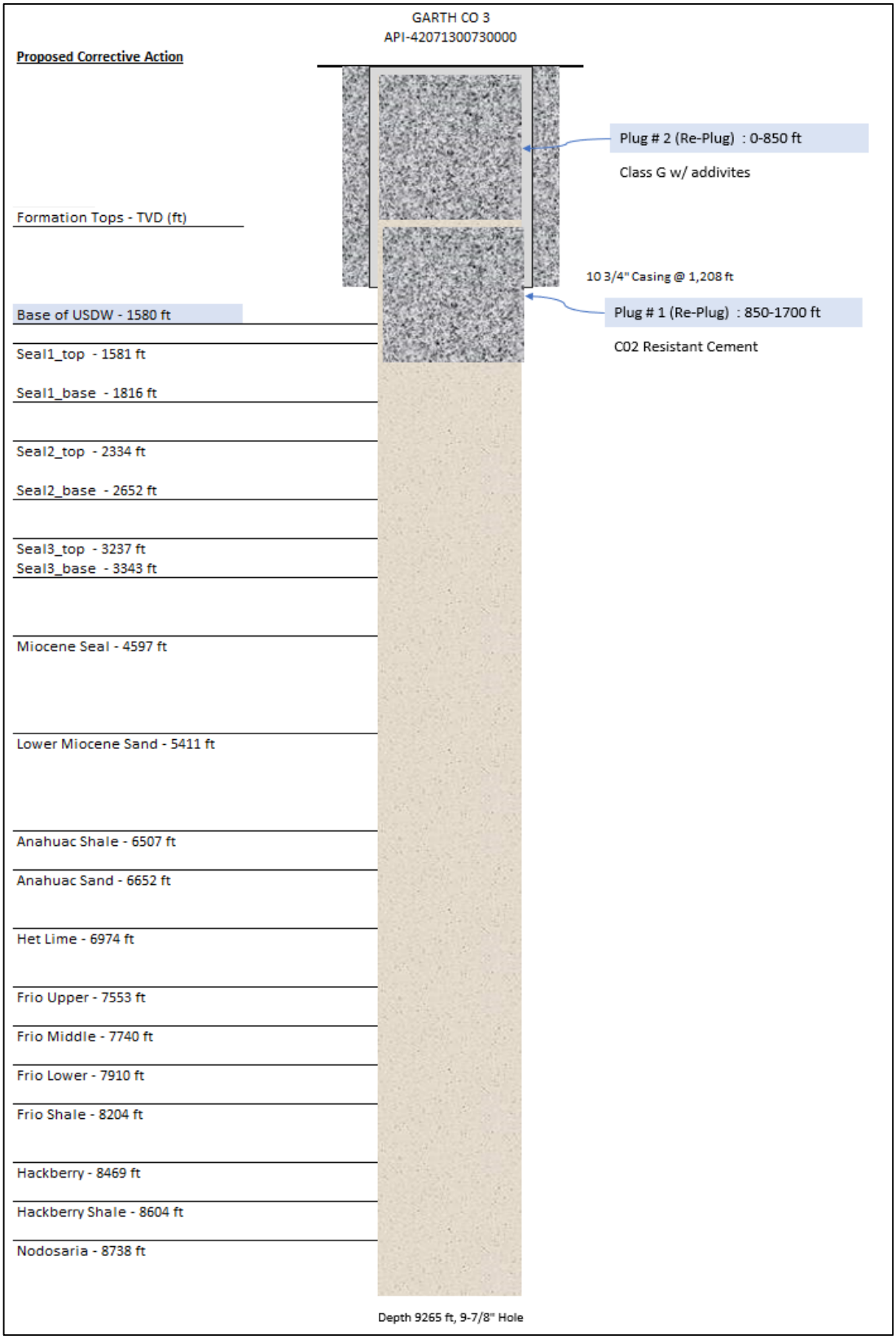


Figure C-AoR-27: Proposed remediation for Garth CO 3 (API 42071300730000).

Table C-AoR-30: Plug information for proposed re-abandonment procedure for Garth CO 3 (API 42071300730000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	850	1700	CO2 Resistant	14.8-15.5	81	1.06	426
Plug # 2	Balanced Plug	0	850	Class G w/ additives	15-15.5	81	1.01	447

Plugging Procedure

1. Move in rig onto Garth CO 3 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill well the if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a 9-7/8 in. bit and run in the hole, cleaning down to 1,700 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with the work string to 1,700 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 850 – 1,700 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-850 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

10. Sterrett Eat Fred R 1 (API 42071019580000): D&A 1959

The Sterrett Eat Fred R 1 well projected to be inside the CO_2 plume after 2 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 9,545 ft. The 9 5/8 in. surface casing set at 1,261 ft does not cover the USDW, located at approximately 1,522 ft. The abandonment procedure consisted of a 50 sx cement plug 7,536 ft – 7,636 ft, 100 sx cement plug set below the surface shoe, and 10 ft of cement spotted on surface, according to the TRRC records. The well was left filled with 13 ppg mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-31: General information for Sterrett Eat Fred R 1 (API 42071019580000).

API	42071019580000
Operator	Penrose Neville G
Lease Name	Sterrett Eat Fred R
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.81398544
Surface Longitude	-94.47370955
Total Depth	9,545
Formation	Unknown
Spud Date	8/9/1959
Drilling End	8/25/1959
Abandonment Date	8/25/1959
Survey	

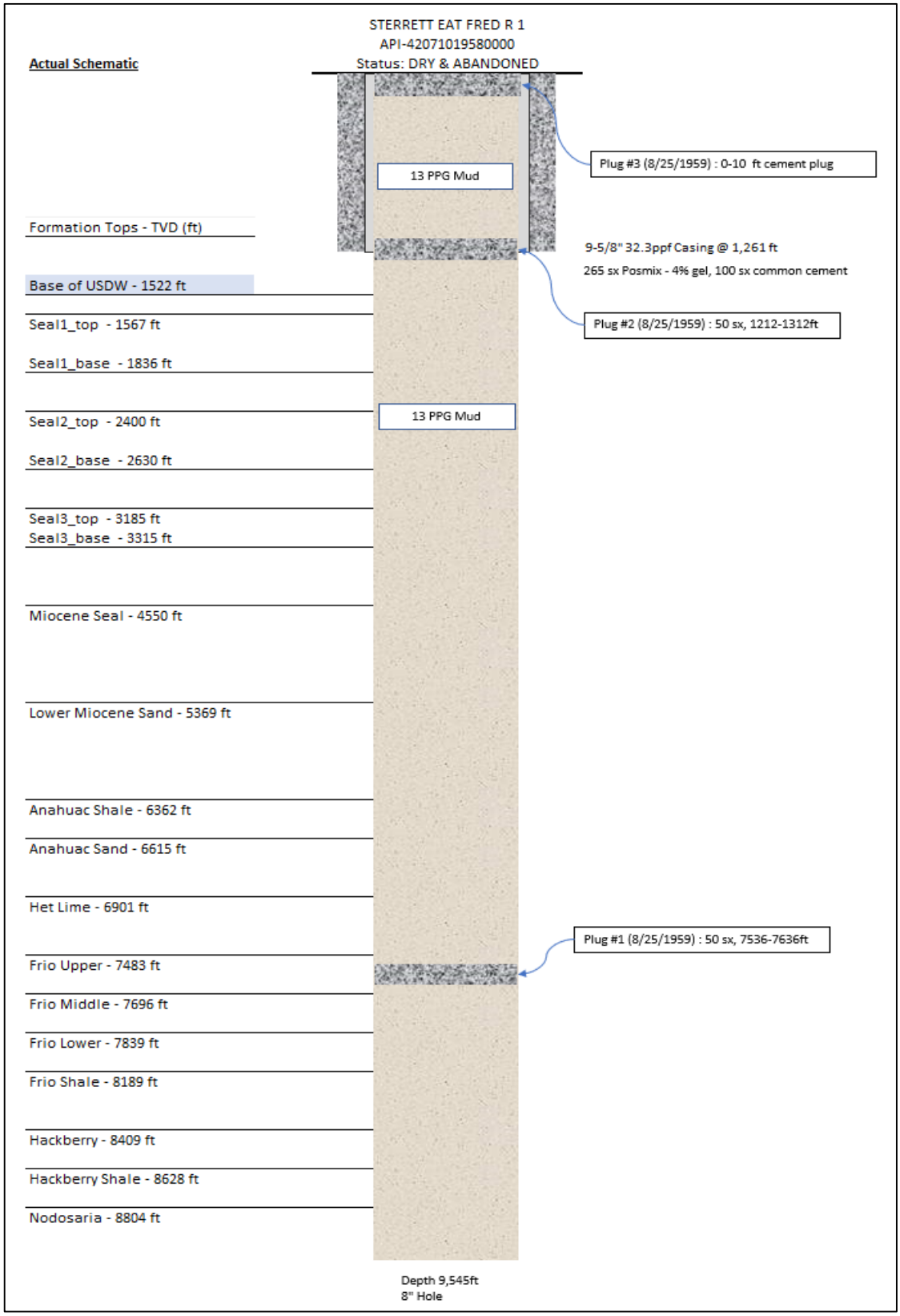


Figure C-AoR-28: Actual wellbore schematic of Sterrett Eat Fred R 1 (API 42071019580000).

Table C-AoR-32: Formation tops from Sterrett Eat Fred R 1 (API 42071019580000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,522
Seal1_top	1,567
Seal1_base	1,836
Seal2_top	2,400
Seal2_base	2,630
Seal3_top	3,185
Seal3_base	3,315
L_Miocene_Shale	4,550
L_Miocene_A	4,696
AMPB_SAND	4,794
L_Miocene_B	4,950
L_Miocene_C	5,224
TOP_LMIO_INJ_ZONE	5,369
LMIO_INJ_5	5,538
LMIO_INJ_4	5,617
LMIO_INJ_3	5,780
LMIO_INJ_6	5,975
LMIO_INJ_2	6,212
Anahuac	6,362
Anahuac_Sand_Top	6,615
Anahuac_Sand_Base	6,653
Anahuac_Het_Lime_Top	6,901
Anahuac_Het_Lime_Base	7,104
Frio_Top	7,483
Frio_Mid	7,696
Frio_Low	7,839
Frio_Shale	8,189
Hackberry	8,409
Hackberry_Shale	8,628
Nodosaria	8,804

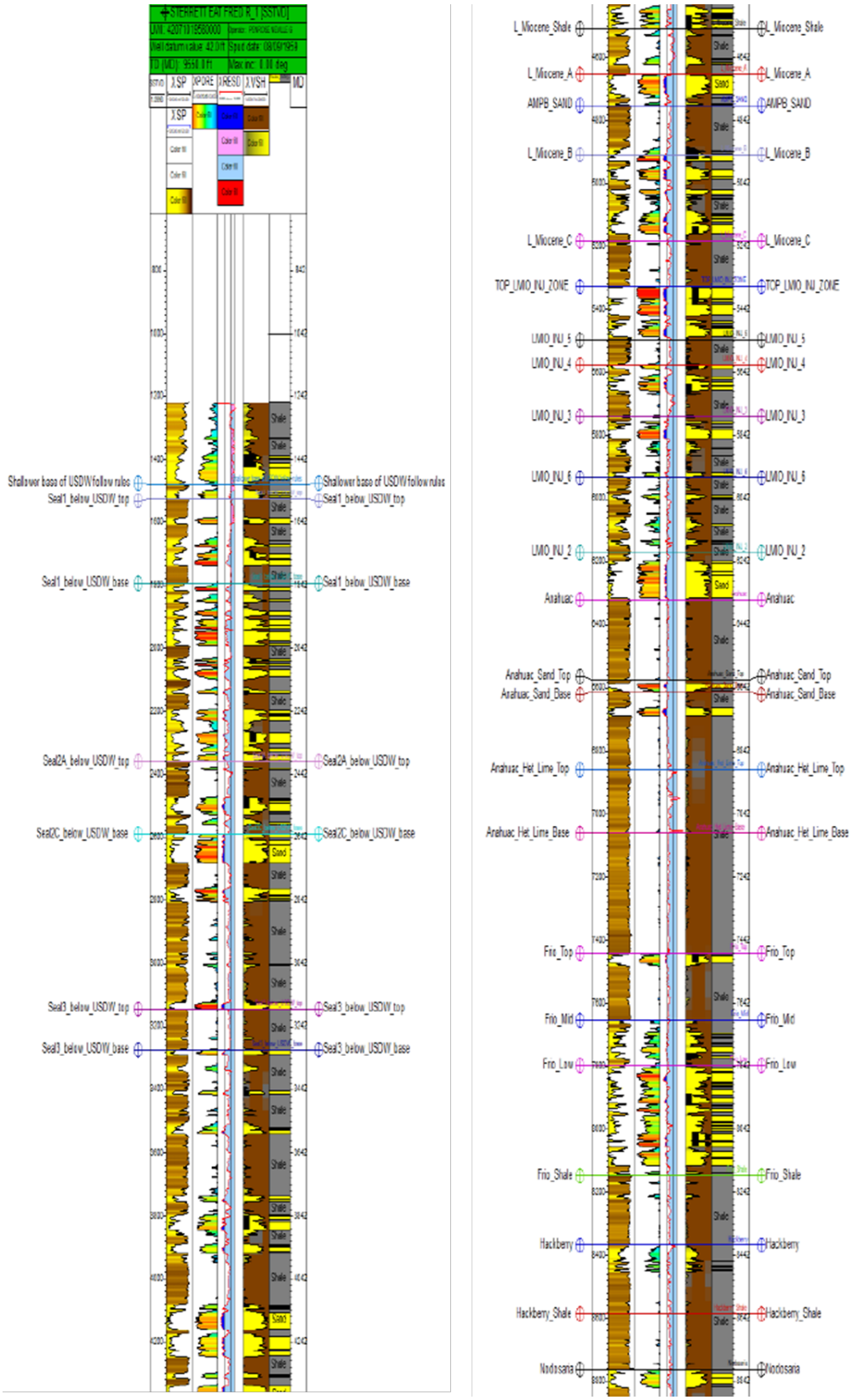


Figure C-AoR-29: Electric log and formation tops from Sterrett Eat Fred R 1 (API 42071019580000).

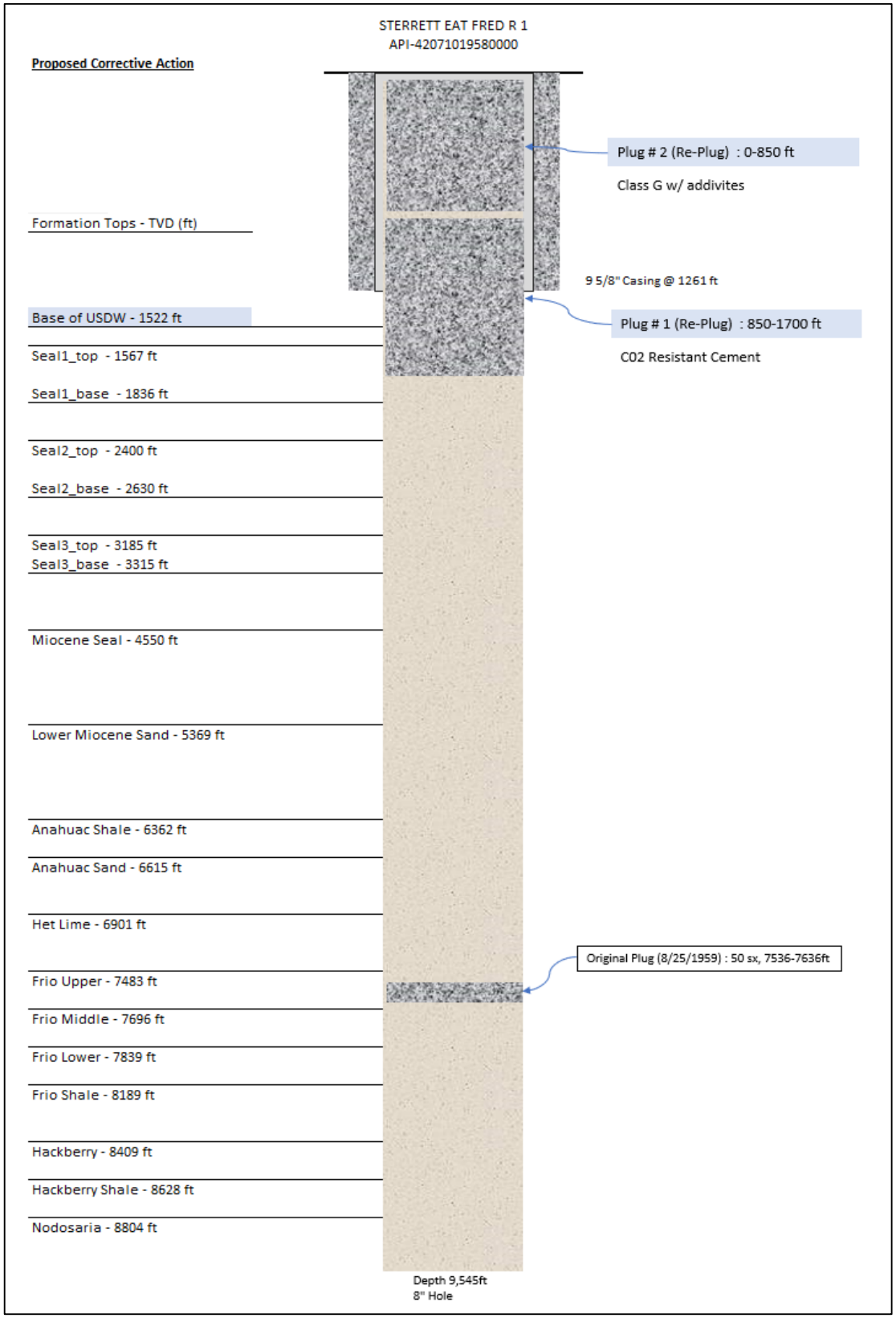


Figure C-AoR-30: Proposed remediation for Sterrett Eat Fred R 1 (API 42071019580000).

Table C-AoR-33: Plug information for proposed re-abandonment procedure for Sterrett Eat Fred R 1 (API 42071019580000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	850	1700	CO2 Resistant	14.8-15.5	53	1.06	280
Plug # 2	Balanced Plug	0	850	Class G w/ additives	15-15.5	53	1.01	294

Plugging Procedure

1. Move in rig onto Sterrett Eat Fred R 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with a bit sized for 9-5/8” 32.3# casing and run in the hole, cleaning down to 1,700 ft. Circulate the hole clean and pull out of hole. Lay down the bit.
7. Run in the hole with the work string to 1,700 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 850 – 1,700 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-850 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

11. Simon Walter 1 (API 42071019680000): D&A 1935

The Simon Walter 1 well is projected to be within the border of the CO_2 plume after 1 year of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, and Frio Lower, reaching a TD of 7,788 ft. The 13 3/8 in. surface casing set at 1,532 ft does cover the USDW, located at approximately 1,365 ft. A CBL will be run on the surface casing to verify the top of cement if primary cement records are unable to be located. No cement plugs were placed during abandonment, according to the TRRC records. The well was left filled with 9.6 ppg mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-34: General information Simon Walter 1 (API 42071019680000).

API	42071019680000
Operator	Bunte Oil & Gas Co
Lease Name	Simon Walter
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.85351237
Surface Longitude	-94.48968121
Total Depth	7,788
Formation	Unknown
Spud Date	1935-08-20
Drilling End	1935-09-16
Abandonment Date	9/16/1935

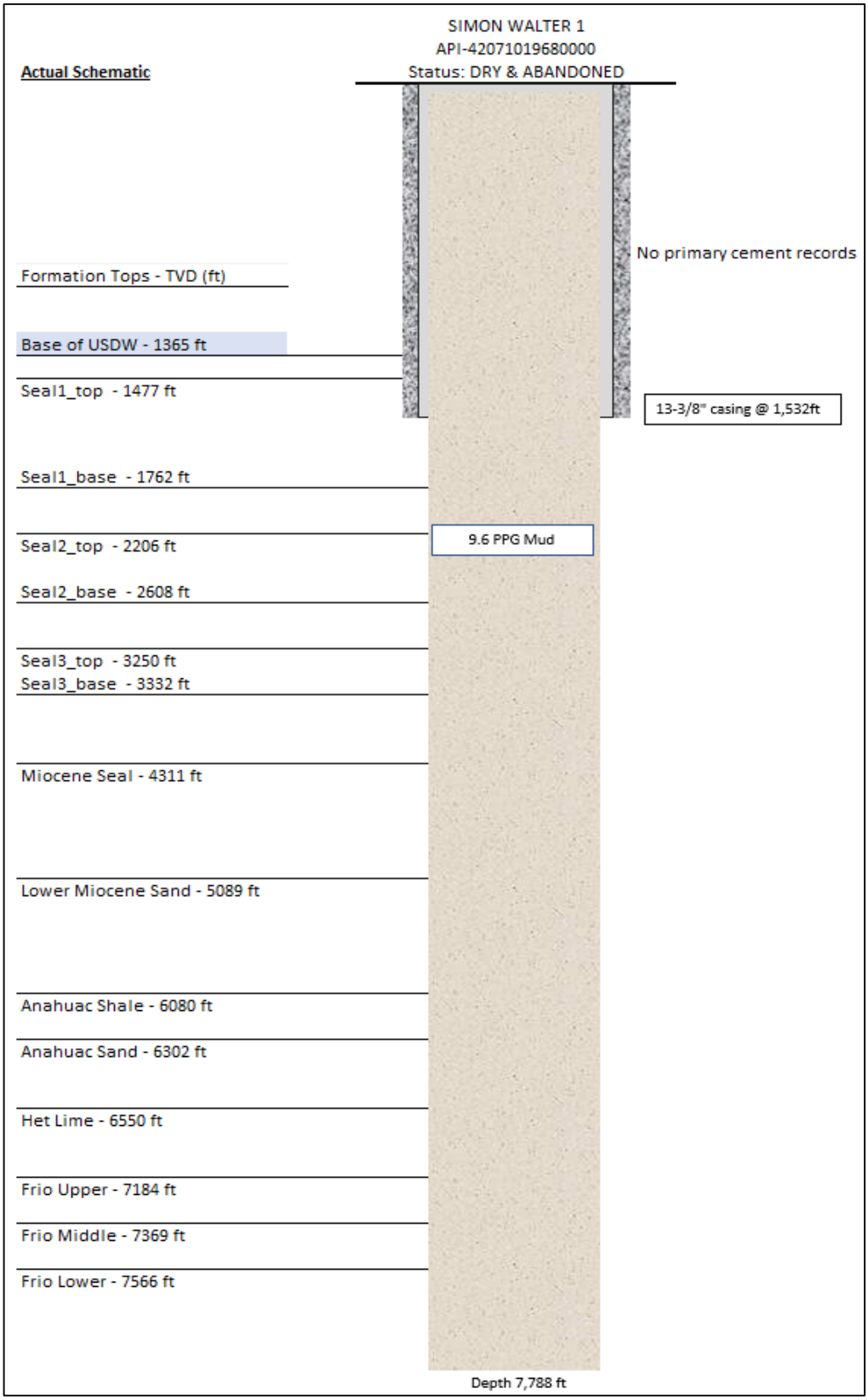


Figure C-AoR-31: Actual wellbore schematic of Simon Walter 1 (API 42071019680000).

Table C-AoR-35: Formation tops from Simon Walter 1 (API 42071019680000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,365
Seal1_top	1,477
Seal1_base	1,762
Seal2_top	2,206
Seal2_base	2,608
Seal3_top	3,250
Seal3_base	3,332
L_Miocene_Shale	4,311
L_Miocene_A	4,446
AMPB_SAND	4,573
L_Miocene_B	4,654
L_Miocene_C	4,939
TOP_LMIO_INJ_ZONE	5,089
LMIO_INJ_5	5,237
LMIO_INJ_4	5,404
LMIO_INJ_3	5,559
LMIO_INJ_6	5,705
LMIO_INJ_2	5,973
Anahuac	6,080
Anahuac_Sand_Top	6,302
Anahuac_Sand_Base	6,402
Anahuac_Het_Lime_Top	6,550
Anahuac_Het_Lime_Base	6,749
Frio_Top	7,184
Frio_Mid	7,369
Frio_Low	7,566

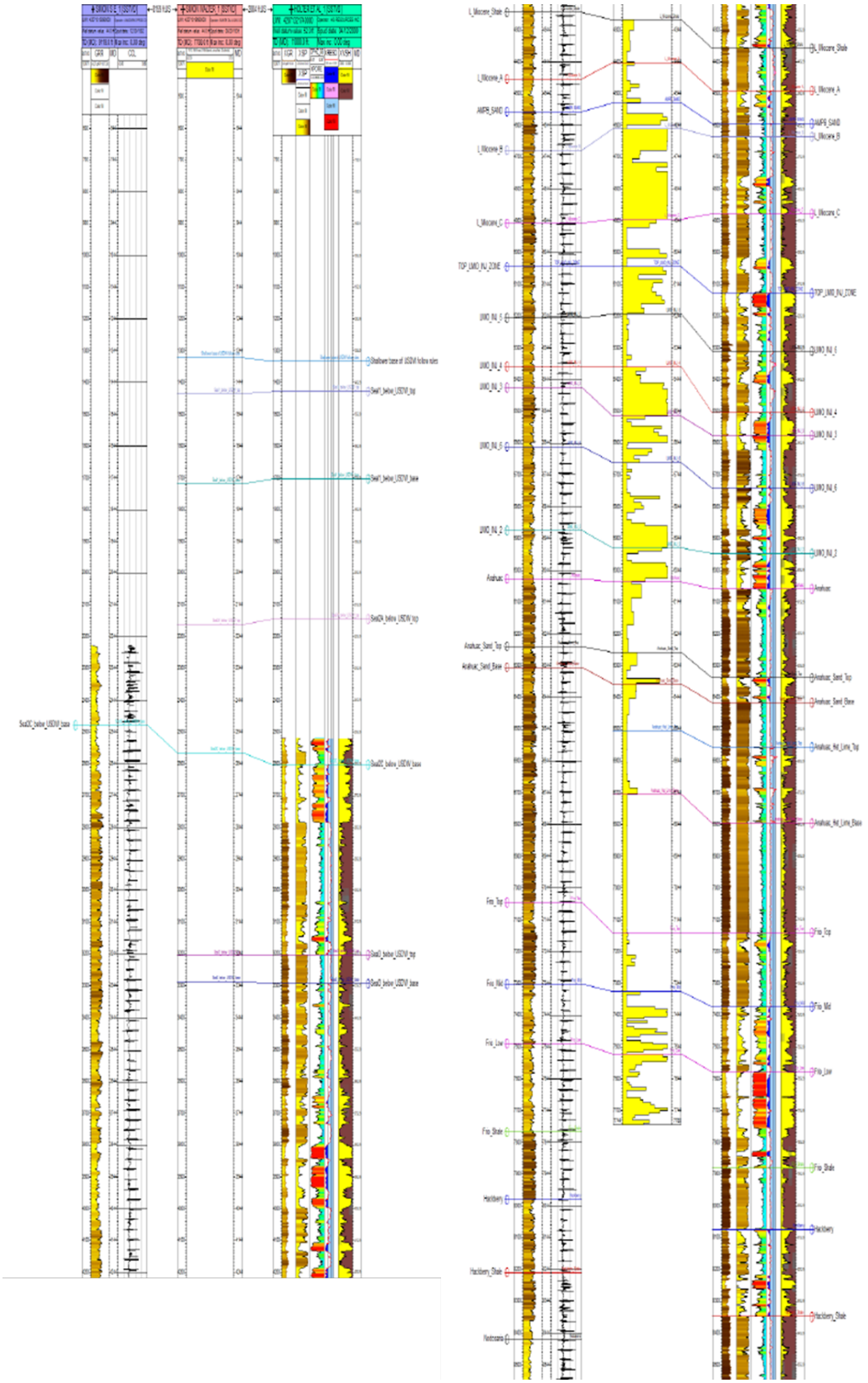


Figure C-AoR-32: Pseudo-log and formation tops from Simon Walter 1 (API 42071019680000).

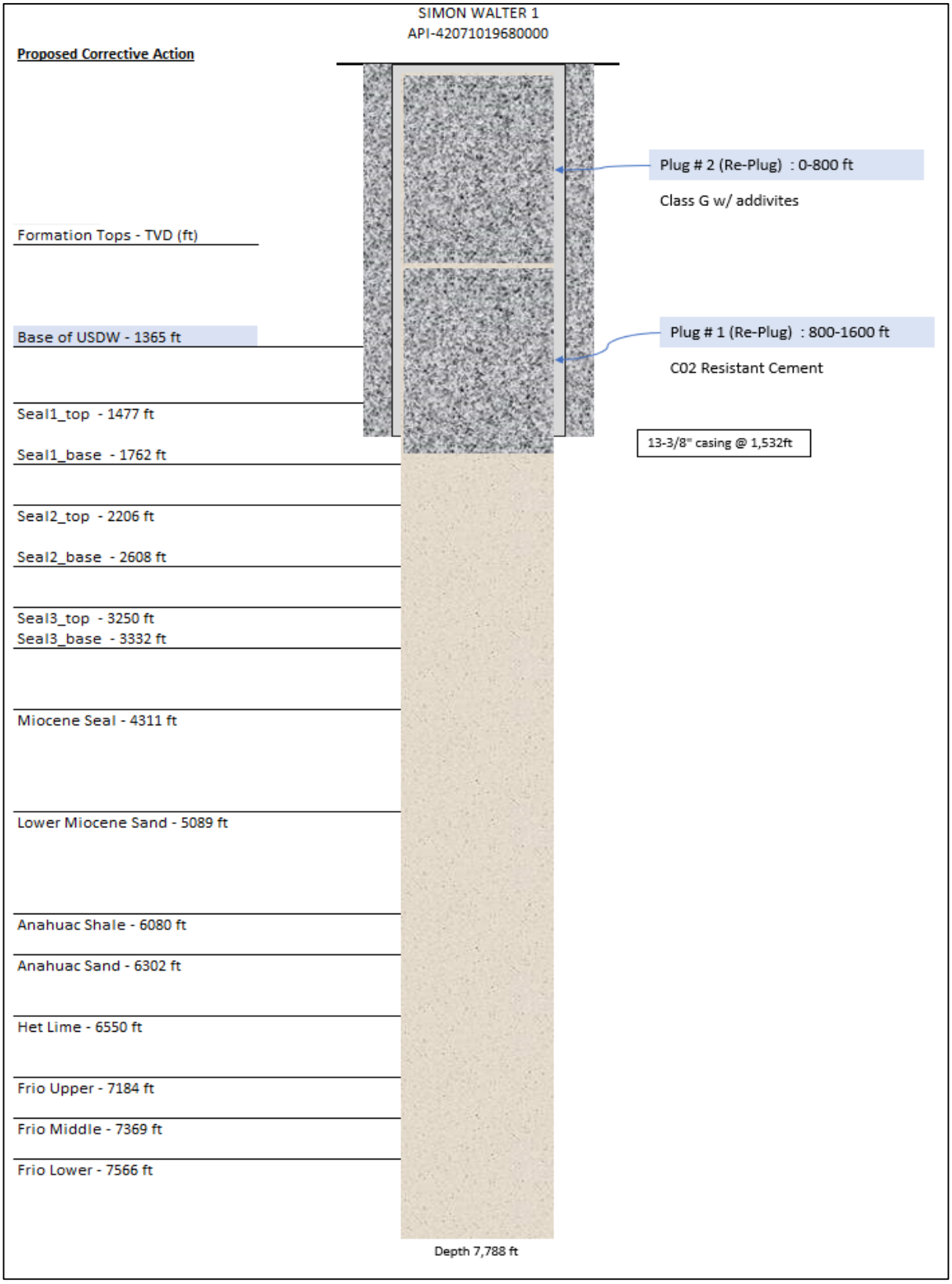


Figure C-AoR-33: Proposed remediation for Simon Walter 1 (API 42071019680000).

Table C-AoR-36: Plug information for proposed re-abandonment procedure for Simon Walter 1 (API 42071019680000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	800	1600	CO2 Resistant	14.8-15.5	126	1.06	665
Plug # 2	Balanced Plug	0	800	Class G w/ additives	15-15.5	126	1.01	698
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto Simon Walter 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with bit sized for 13-3/8 in. casing and run in the hole. Clean down to 1,600 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
    a. If primary cement records have been located and there is cement behind the surface casing: Proceed to step 11.
    b. If primary cement records have not been located: Proceed with step 7
7. Set the bridge plug at 1,500 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 13-3/8 in. casing from 1,500 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to the surface, then perforate the 13-3/8 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 13-3/8 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out CICR and cement down to bridge plug at 1,500 ft. Test casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure.
10. Drill out bridge plug at 1,500 ft and continue running in the hole with work string cleaning down to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down the bit.
11. Run in the hole with work string to 1,600 ft. Circulate the well clean.
12. Plug #1: Set a balanced plug 800 – 1,600 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-800 ft with 15-15.5 ppg Class G cement. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar to such that plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

12. M E Hunter 1 (API 42071305640000): D&A 1977

The M E Hunter 1 well is projected to be the within the border of the CO_2 plume after 4 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Nodosaria, and Vicksburg formations reaching a TD of 12,665 ft. The 10 3/4 in. surface casing set at 2068 ft does cover the USDW, located at approximately 1493 ft. If primary cement records are unable to be located a CBL will be run on the surface casing to verify the top of cement. Cement plugs were placed 9,616 – 9,916 ft (80 sx), 1,800-2,250 ft (325 sx), and 6 – 30 ft (20 sx) during abandonment, according to the TRRC records. The 7-5/8 in. production casing was also cut and pulled during abandonment at 2,200 ft. The well was left filled with 12.8 ppg mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-37: General information for M E Hunter 1 (API 42071305640000).

API	42071305640000
Operator	Gulf Oil Corp
Lease Name	M E Hunter
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.8147126
Surface Longitude	-94.478177
Total Depth	12,665
Formation	Vicksburg
Spud Date	1977-06-19
Drilling End	1977-07-25
Abandonment Date	7/25/1977

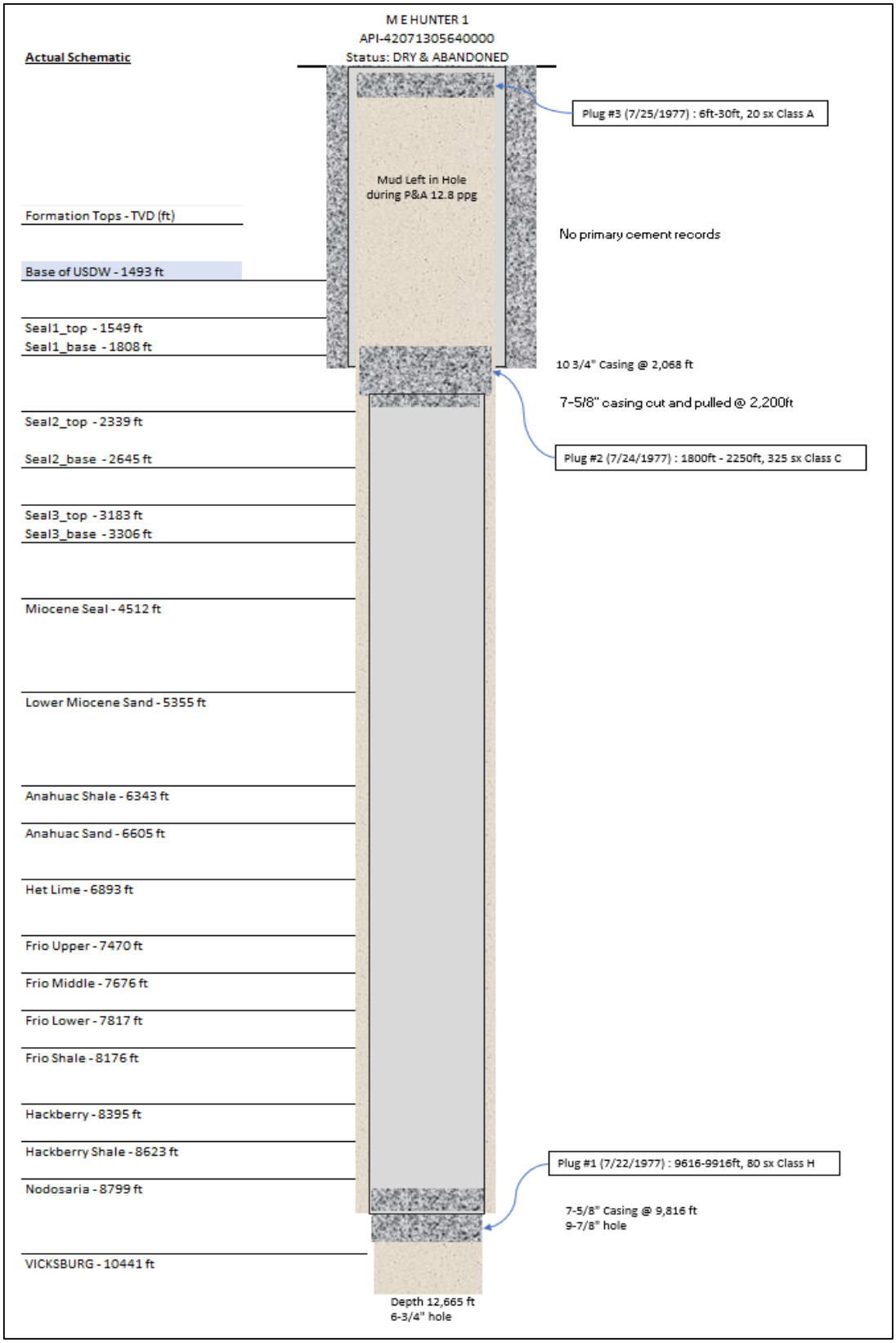


Figure C-AoR-34: Actual wellbore schematic of M E Hunter 1 (API 42071305640000).

Table C-AoR-38: Formation tops from M E Hunter 1 (API 42071305640000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,493
Seal1_top	1,549
Seal1_base	1,808
Seal2_top	2,339
Seal2_base	2,645
Seal3_top	3,183
Seal3_base	3,306
L_Miocene_Shale	4,512
L_Miocene_A	4,687
AMPB_SAND	4,805
L_Miocene_B	4,937
L_Miocene_C	5,211
TOP_LMIO_INJ_ZONE	5,355
LMIO_INJ_5	5,531
LMIO_INJ_4	5,596
LMIO_INJ_3	5,762
LMIO_INJ_6	5,962
LMIO_INJ_2	6,206
Anahuac	6,343
Anahuac_Sand_Top	6,605
Anahuac_Sand_Base	6,650
Anahuac_Het_Lime_Top	6,893
Anahuac_Het_Lime_Base	7,090
Frio_Top	7,470
Frio_Mid	7,676
Frio_Low	7,817
Frio_Shale	8,176
Hackberry	8,395
Hackberry_Shale	8,623
Nodosaria	8,799
VICKSBURG	10,441

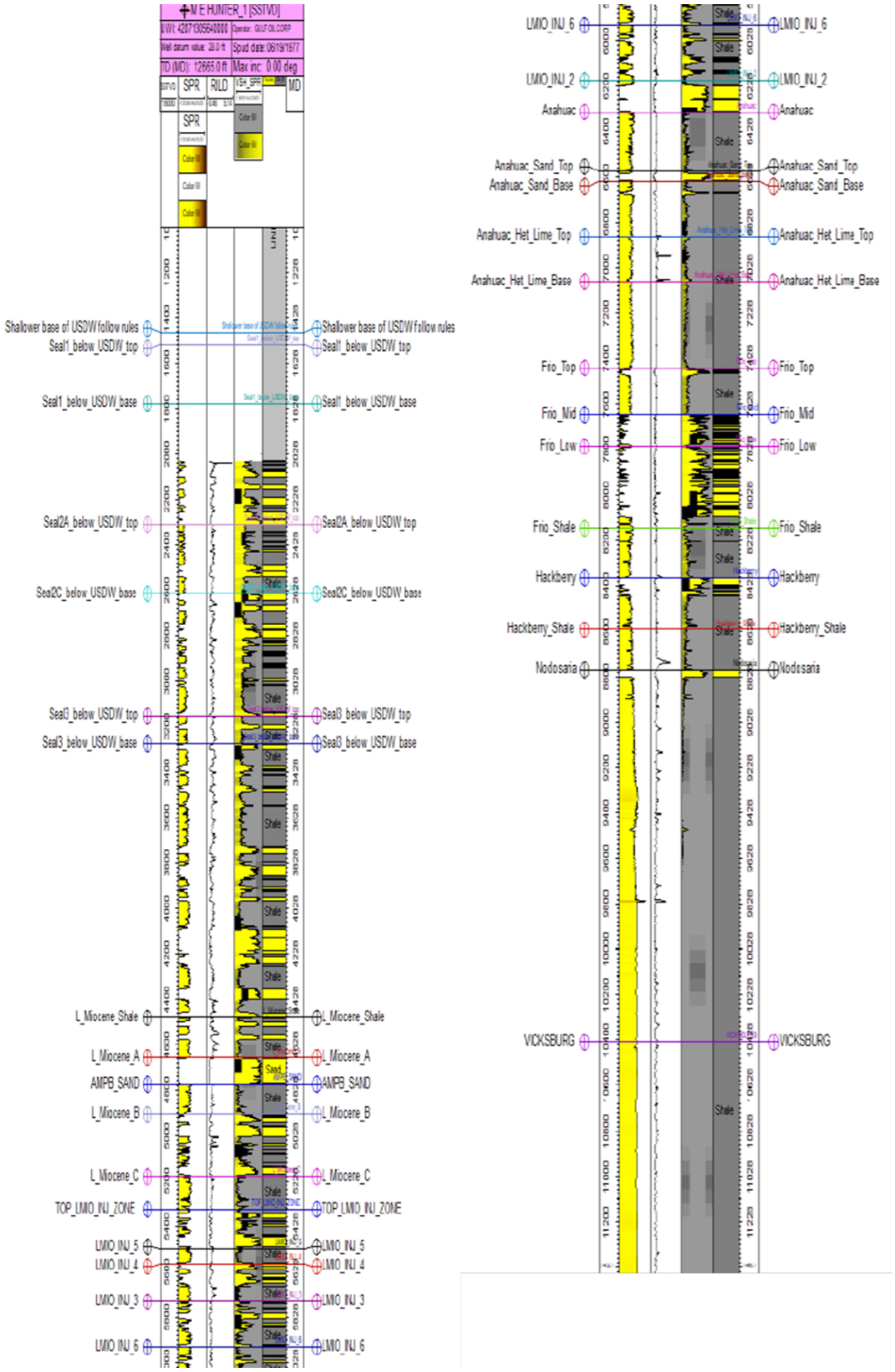


Figure C-AoR-35: Electric log and formation tops from M E Hunter 1 (API 42071305640000).

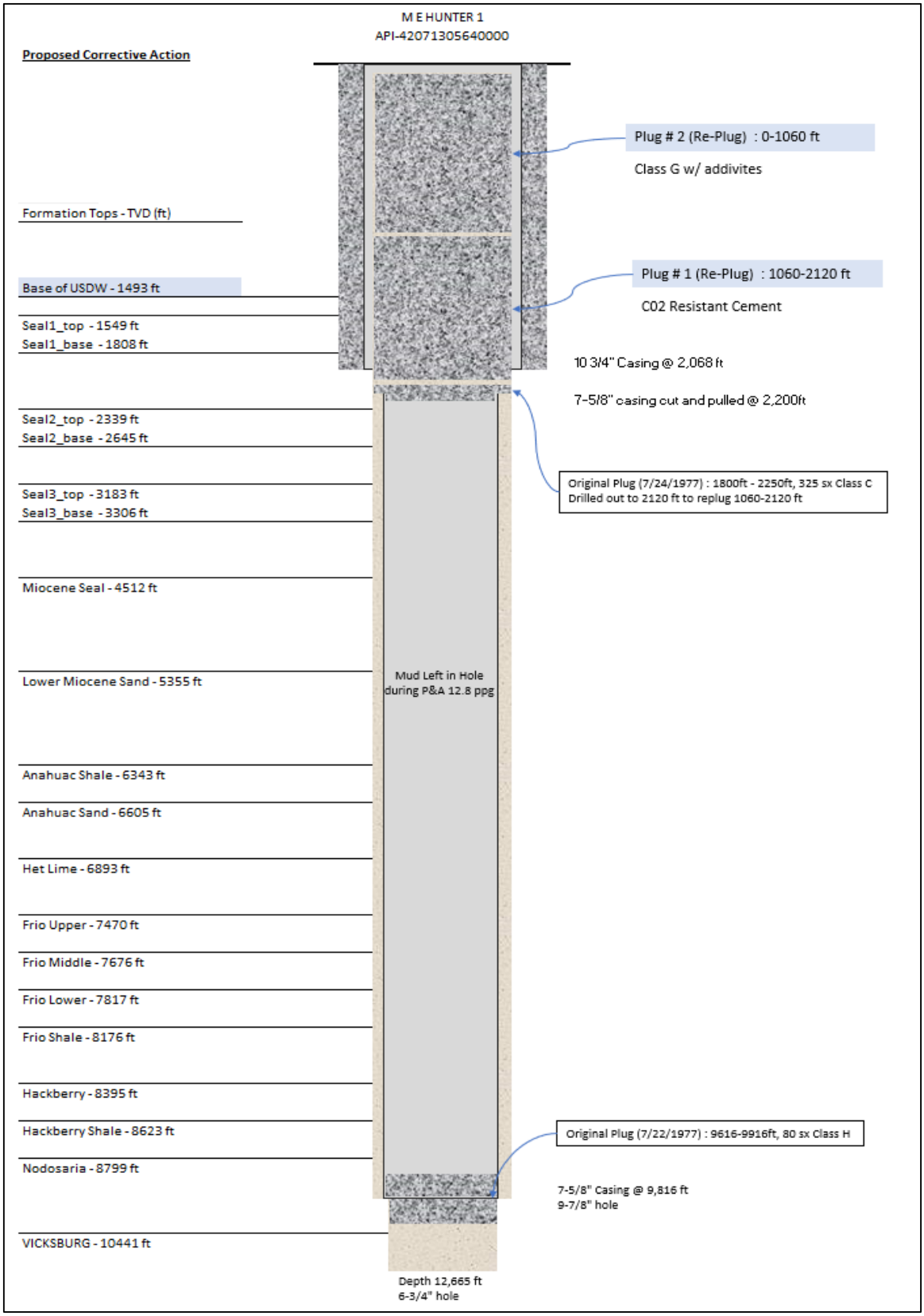


Figure C-AoR-36: Proposed remediation for M E Hunter 1 (API 42071305640000).

Table C-AoR-39: Plug information for proposed re-abandonment procedure for M E Hunter 1 (API 42071305640000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	1060	2120	CO2 Resistant	14.8-15.5	107	1.06	566
Plug # 2	Balanced Plug	0	1060	Class G w/ additives	15-15.5	107	1.01	594
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto M E Hunter 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with 9-7/8 in. bit and run in the hole, cleaning down to 2,120 ft. Circulate the hole clean and pull out the of hole. Lay down the bit.
    a. If primary cement records have been located and there is cement behind the surface casing: Proceed to step 11.
    b. If primary cement records have not been located: Proceed with step 7
7. Set a bridge plug at 2,000 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 10-3/4 in. casing from 2,000 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 2,120 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 10-3/4 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 2,000 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 2,120 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 2,120 ft.
12. Plug #1: Set a balanced plug 1,060 – 2,120 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-1,060 ft with 15-15.5 ppg Class G cement.

14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

13. Garth 1 (API 42071310360000): D&A 1980

The Garth 1 well is projected to be inside the border of the CO_2 plume within 5 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, and Nodosaria reaching a TD of 11,000 ft. The 10 3/4 in. surface casing set at 1,497 ft does not cover the USDW, located at approximately 1,596 ft. Primary cement records for the surface casing could not be located. Cement plugs were placed 8,755 – 8,900 ft (25 sx), 1,550 – 1,650 ft (50 sx), and 6 – 36 ft (15 sx) during abandonment, according to the TRRC records. The 7 in. production casing was cut and pulled during abandonment at 1,600 ft. The well was left filled with 10 ppg mud. The well will be scheduled for remedial action in Year 0.

Table C-AoR-40: General information Garth 1 (API 42071310360000).

API	42071310360000
Operator	Cannan Morris
Lease Name	Garth
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.8017803
Surface Longitude	-94.4666967
Total Depth	11,000
Formation	Frio
Spud Date	4/3/1980
Drilling End	5/24/1980
Abandonment Date	5/24/1980

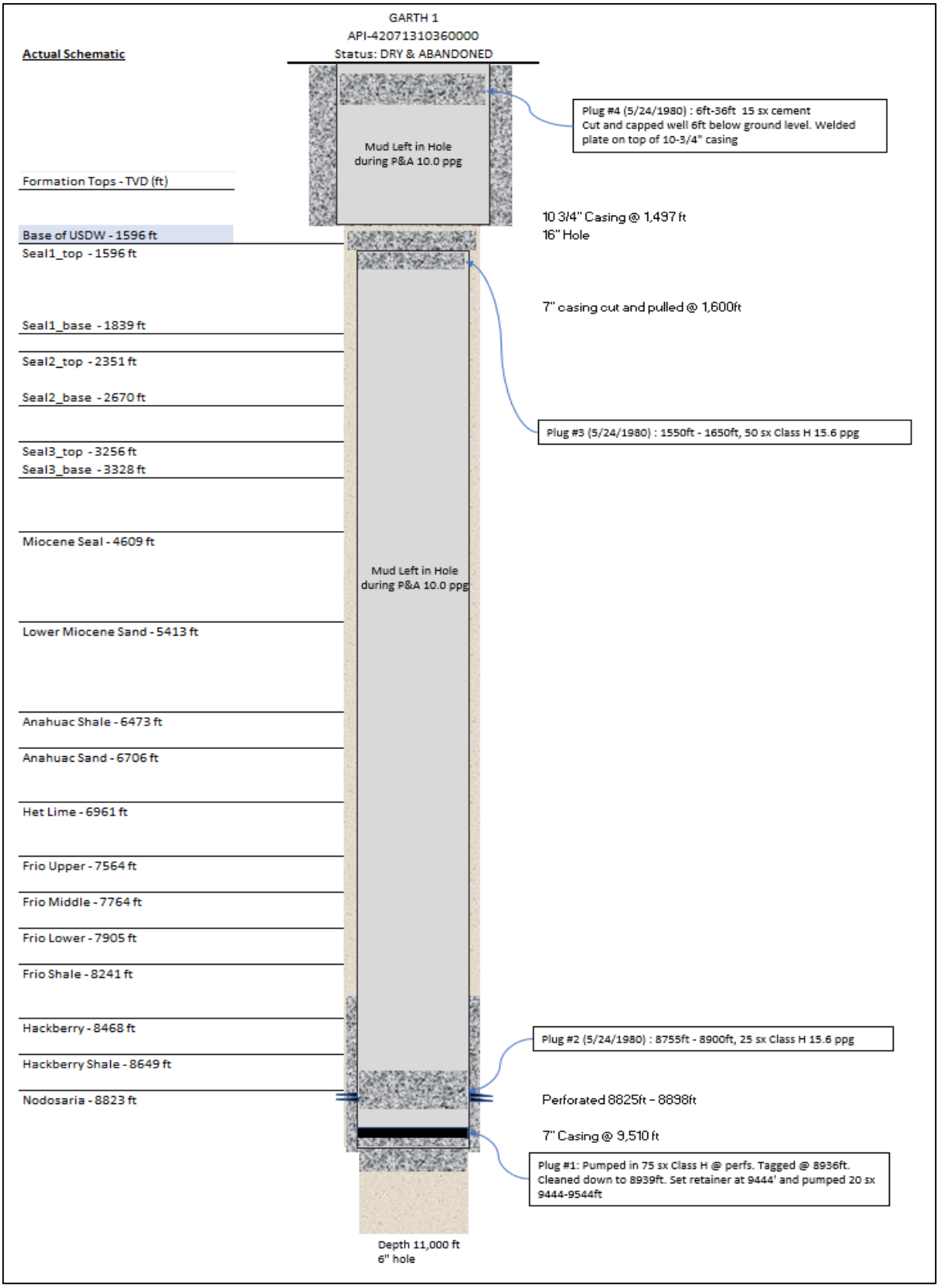


Figure C-AoR-37: Actual wellbore schematic of Garth 1 (API 42071310360000).

Table C-AoR-41: Formation tops from Garth 1 (API 42071310360000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,596
Seal1_top	1,596
Seal1_base	1,839
Seal2_top	2,351
Seal2_base	2,670
Seal3_top	3,256
Seal3_base	3,328
L_Miocene_Shale	4,609
L_Miocene_A	4,748
AMPB_SAND	4,859
L_Miocene_B	5,003
L_Miocene_C	5,237
TOP_LMIO_INJ_ZONE	5,413
LMIO_INJ_5	5,592
LMIO_INJ_4	5,750
LMIO_INJ_3	5,833
LMIO_INJ_6	5,999
LMIO_INJ_2	6,249
Anahuac	6,473
Anahuac_Sand_Top	6,706
Anahuac_Sand_Base	6,773
Anahuac_Het_Lime_Top	6,961
Anahuac_Het_Lime_Base	7,200
Frio_Top	7,564
Frio_Mid	7,764
Frio_Low	7,905
Frio_Shale	8,241
Hackberry	8,468
Hackberry_Shale	8,649
Nodosaria	8,823

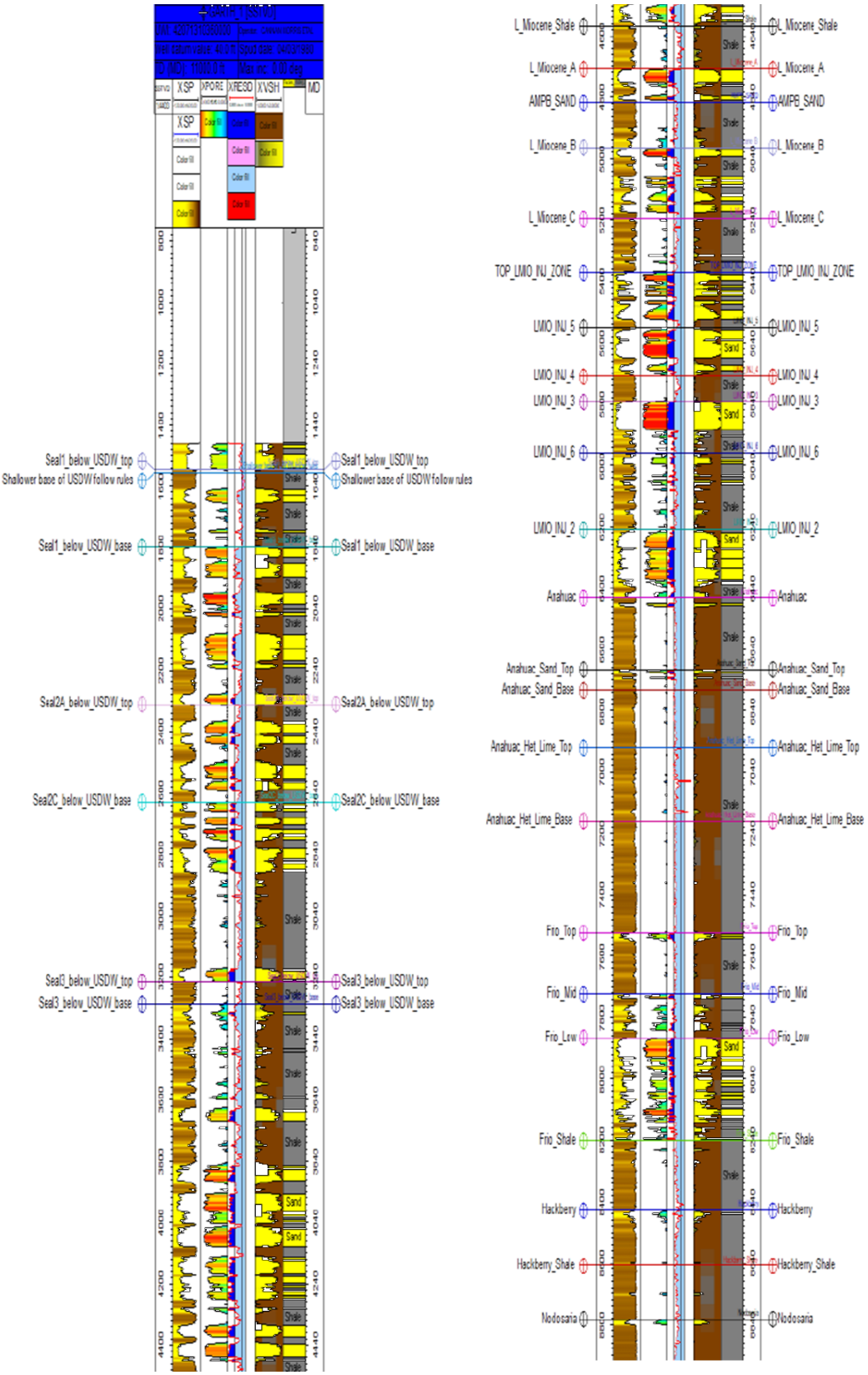


Figure C-AoR-38: Electric log and formation tops from Garth 1 (API 42071310360000).

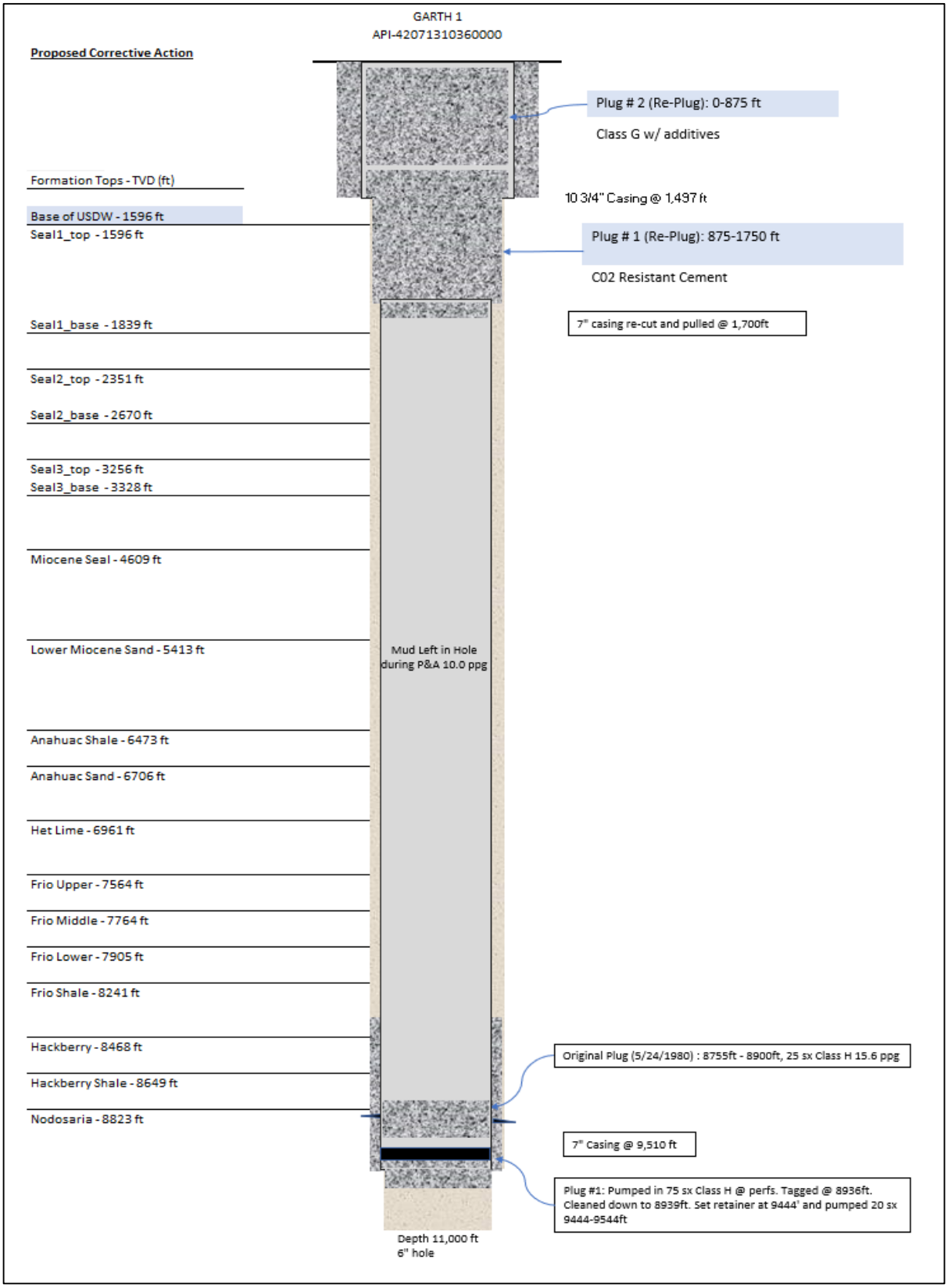


Figure C-AoR-39: Proposed remediation for Garth 1 (API 42071310360000).

Table C-AoR-42: Plug information for proposed re-abandonment procedure for Garth 1 (API 42071310360000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Perf & Squeeze	875	1750	CO2 Resistant	14.8-15.5	132	1.06	701
Plug # 2	Balanced Plug	0	875	Class G w/ additives	15-15.5	88	1.01	490
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto Garth 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with 9-7/8 in. bit and run in the hole.
    a. If primary cement records have been located and there is cement behind the surface casing: Clean down to 1,600 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If primary cement records have not been located: Clean down to 1,500 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed with step 7
7. Set the bridge plug at 1,450 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 10-3/4 in. casing from 1,450 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 10-3/4 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 1,450 ft. Test casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then release the pressure.
10. Drill out the bridge plug at 1,450 ft and continue running in the hole with work string cleaning down to top of 7 in. casing at 1,600 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with mill and redress top of 7 in. casing. Pull out of the hole and lay down mill.
12. Run in the hole with bit sized for 7 in. casing and cleanout down to 1,800 ft. Circulate the well clean and pull out of the hole. Lay down the bit.
13. Cut and pull 7” casing at 1,700.
14. Run in the hole with work string to 1,750 ft. Circulate the well clean.

15. Plug #1: Set a balanced plug 875 – 1,750 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull string to the next plug stage.
16. Plug #2: Set a balanced plug 0-875 ft with 15-15.5 ppg Class G cement.
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground.
18. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

14. Garth Brothers 1 (API 42071019560000): D&A 1955

The Garth Brothers 1 well is projected to be inside the CO_2 plume within 10 years of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 9,250 ft. The 10 3/4 in. surface casing set at 1,626 ft, does cover the USDW, located at approximately 1,597 ft. The abandonment procedure consisted of a 100 sx cement plug set below the surface shoe and a 10 sx cement plug set at surface, according to the TRRC records. The well was left filled with mud in open hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-43: General information for Garth Brothers 1 (API 42071019560000).

API	42071019560000
Operator	Austral Oil Co Inc
Lease Name	Garth Brothers
Well Number	1
Status	D&A-O
Surface Latitude	29.800048
Surface Longitude	-94.475151
Total Depth	9250
Formation	Unknown
Spud Date	1/22/1955
Drilling End	2/7/1955
Abandonment Date	2/10/1955

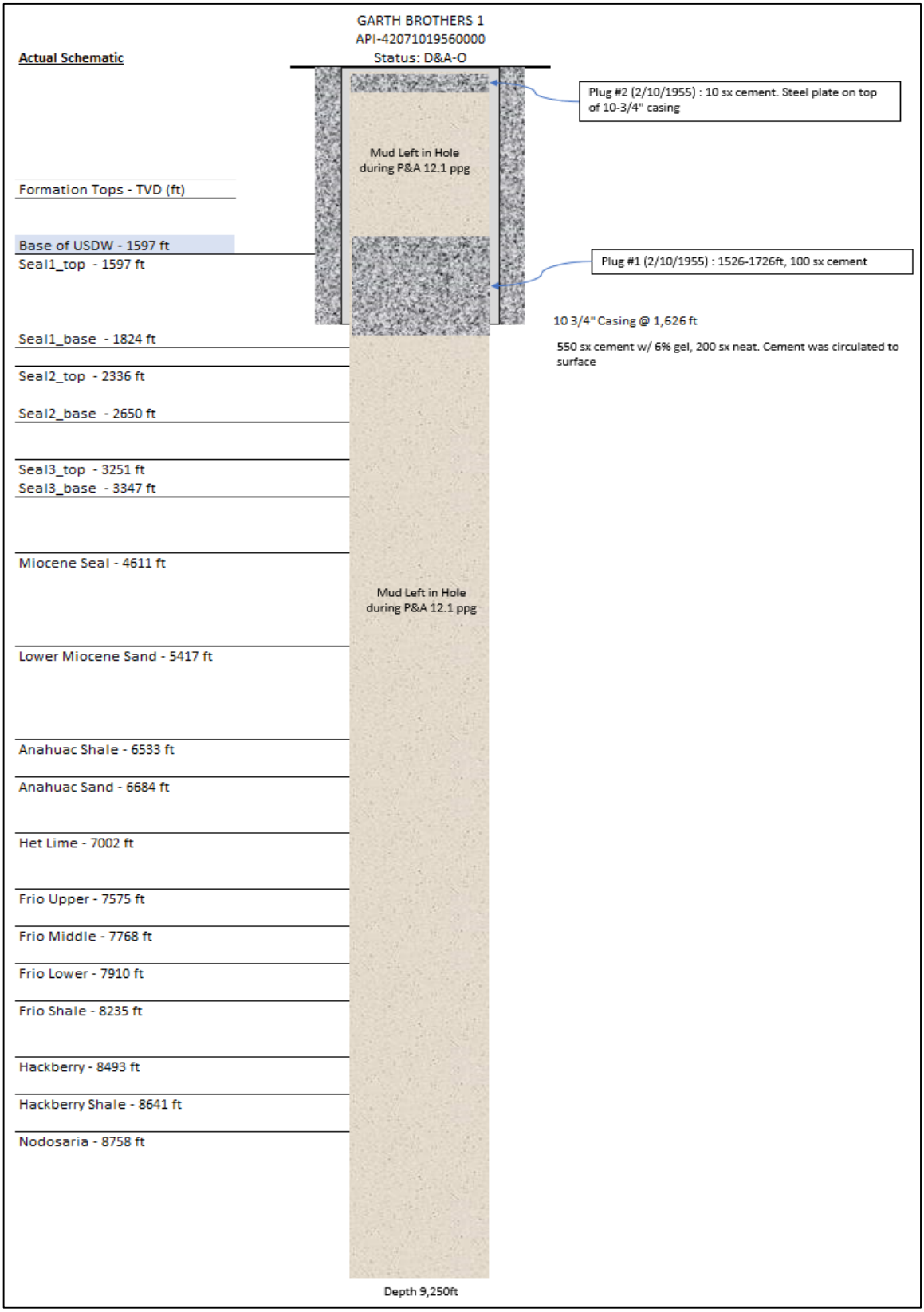


Figure C-AoR-40: Actual wellbore schematic for Garth Brothers 1 (API 42071019560000).

Table C-AoR-44: Formation tops from Garth Brothers 1 (API 42071019560000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,597
Seal1_top	1,597
Seal1_base	1,824
Seal2_top	2,336
Seal2_base	2,650
Seal3_top	3,251
Seal3_base	3,347
L_Miocene_Shale	4,611
L_Miocene_A	4,761
AMPB_SAND	4,876
L_Miocene_B	5,017
L_Miocene_C	5,237
TOP_LMIO_INJ_ZONE	5,417
LMIO_INJ_5	5,605
LMIO_INJ_4	5,724
LMIO_INJ_3	5,839
LMIO_INJ_6	6,014
LMIO_INJ_2	6,258
Anahuac	6,533
Anahuac_Sand_Top	6,684
Anahuac_Sand_Base	6,755
Anahuac_Het_Lime_Top	7,002
Anahuac_Het_Lime_Base	7,203
Frio_Top	7,575
Frio_Mid	7,768
Frio_Low	7,910
Frio_Shale	8,235
Hackberry	8,493
Hackberry_Shale	8,641
Nodosaria	8,758

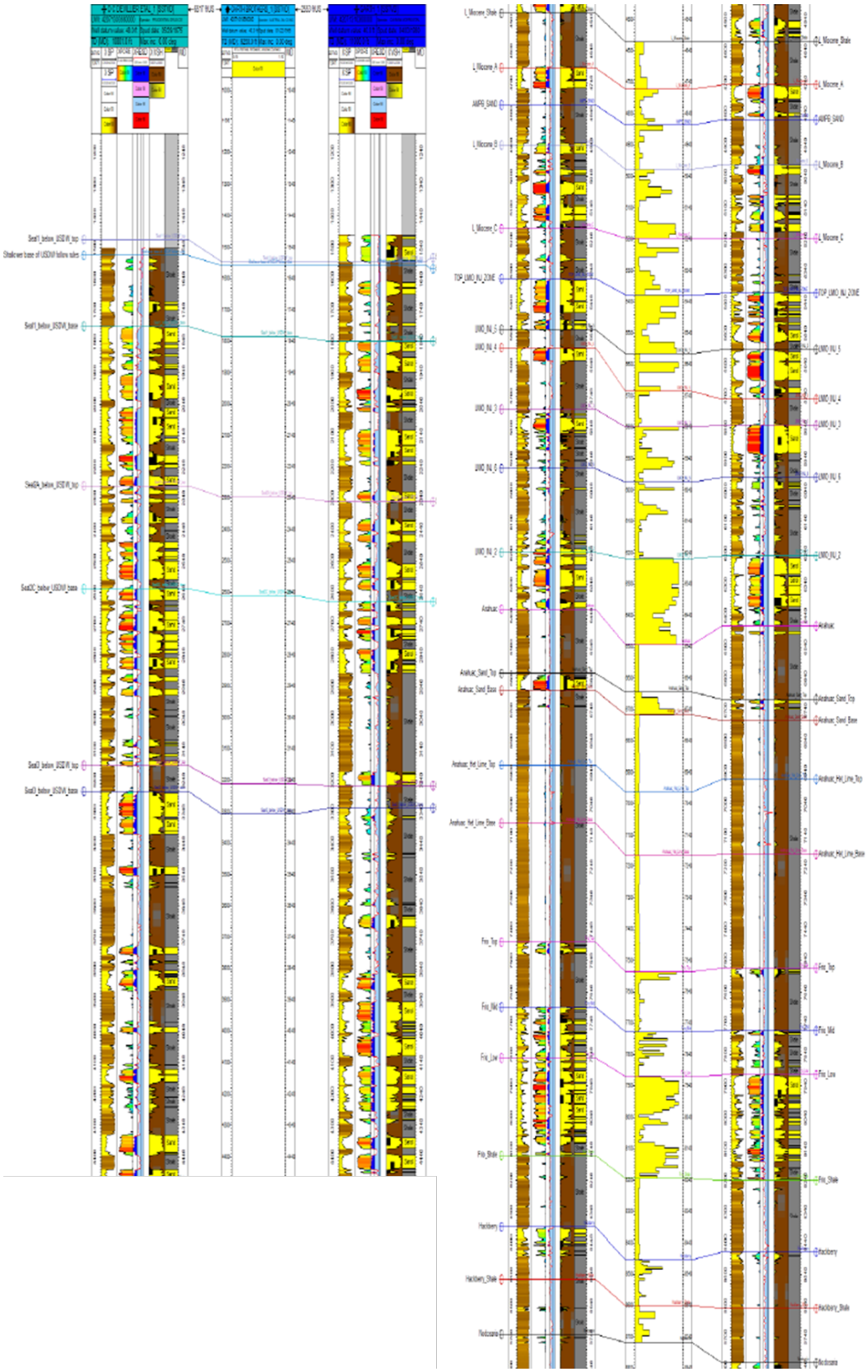


Figure C-AoR-41: Pseudo-log and formation tops from Garth Brothers 1 (API 42071019560000).

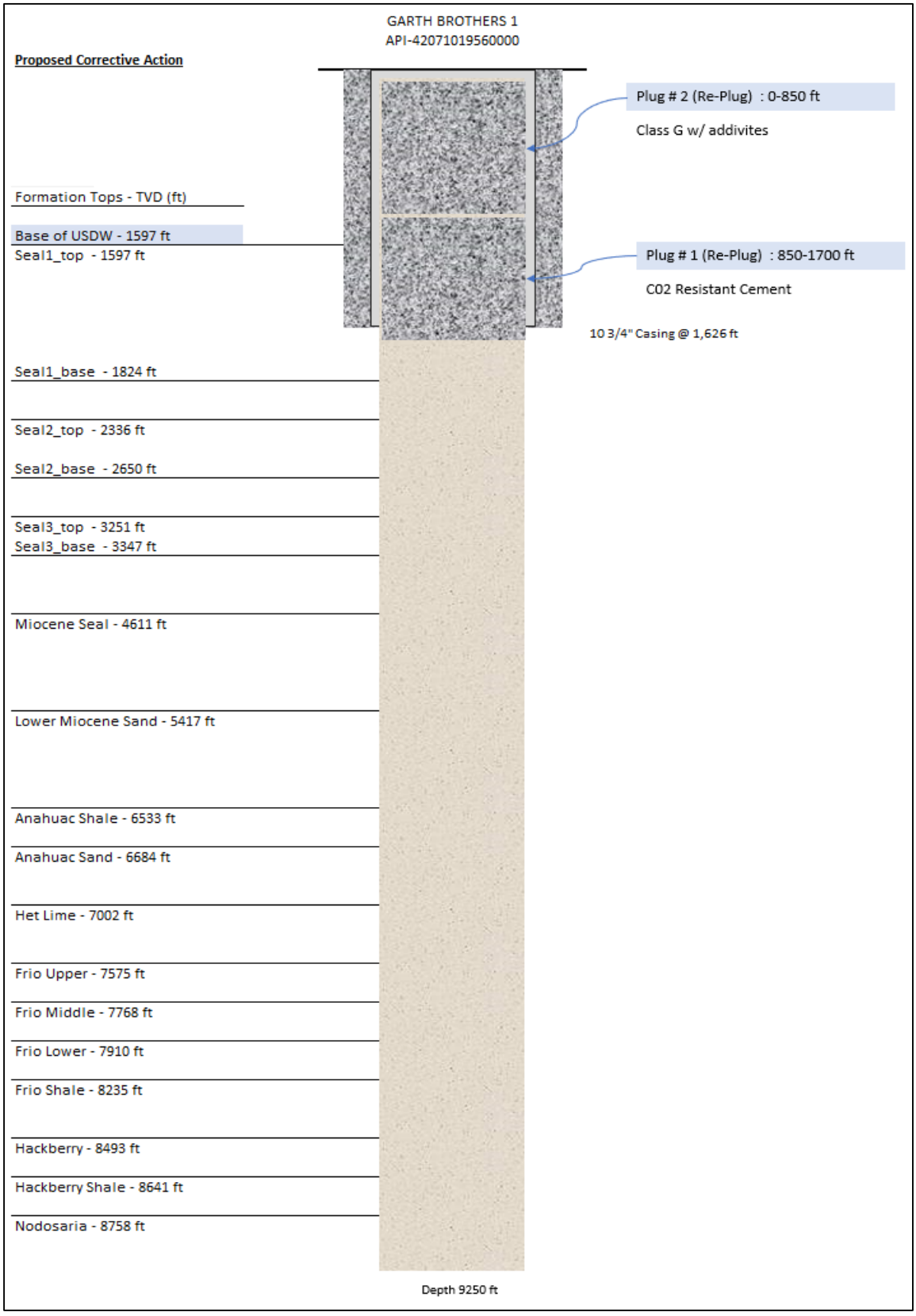


Figure C-AoR-42: Proposed remediation for Garth Brothers 1 (API 42071019560000).

Table C-AoR-45: Plug information for proposed re-abandonment procedure for Garth Brothers 1 (API 42071019560000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	850	1700	CO2 Resistant	14.8-15.5	86	1.06	454
Plug # 2	Balanced Plug	0	850	Class G w/ additives	15-15.5	86	1.01	476

Plugging Procedure

1. Move in rig onto Garth Brothers 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with 9-7/8 in. bit and run in the hole, cleaning down to 1,700 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with the work string to 1,700 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 850 – 1,700 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-850 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

15. Holter Et Al 1 (API 42071321740000): D&A 2000

The Holter Et Al 1 well is projected to be inside the CO_2 plume within 1 year of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 11,000 ft. The 10 3/4 in. surface casing set at 2,240 ft (cement circulated to surface) covers the USDW, located at approximately 1,387 ft. Production casing (7-5/8 in.) was run to 9,550 ft and cemented with 595 sx. The abandonment procedure consisted of cement plugs from 10,655 – 11,000 ft (75 sx), 9,255 – 9,595 ft (75 sx), 2,180 – 2,307 ft (60 sx), 600-700 ft (60 sx) and 4-14 ft (10 sx), according to the TRRC records. The well was left filled with 10 ppg mud in the hole. The well will be scheduled for remedial action in Year 0.

Table C-AoR-46: General information Holter Et Al 1 (API 42071321740000).

API	42071321740000
Operator	HS Resources Inc
Lease Name	Holter Et Al
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.85346284
Surface Longitude	-94.49852689
Total Depth	11000
Formation	Vicksburg
Spud Date	4/12/2000
Drilling End	5/5/2000
Abandonment Date	5/30/2000

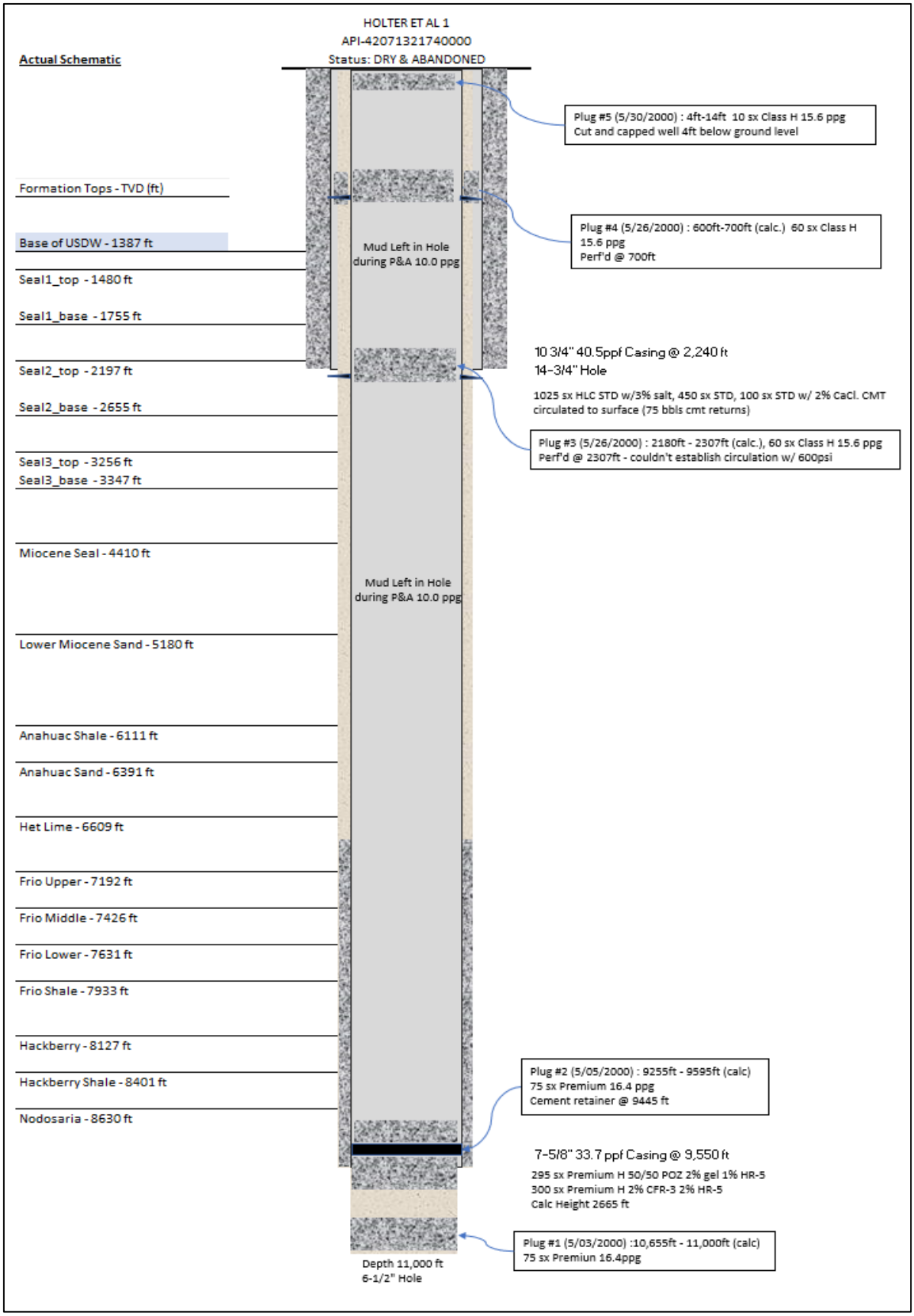


Figure C-AoR-43: Actual wellbore schematic for Holter Et Al 1 (API 42071321740000).

Table C-AoR-47: Formation tops from Holter Et Al 1 (API 42071321740000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,387
Seal1_top	1,480
Seal1_base	1,755
Seal2_top	2,197
Seal2_base	2,655
Seal3_top	3,256
Seal3_base	3,347
L_Miocene_Shale	4,410
L_Miocene_A	4,542
AMPB_SAND	4,647
L_Miocene_B	4,688
L_Miocene_C	4,930
TOP_LMIO_INJ_ZONE	5,180
LMIO_INJ_5	5,362
LMIO_INJ_4	5,557
LMIO_INJ_3	5,628
LMIO_INJ_6	5,794
LMIO_INJ_2	6,000
Anahuac	6,111
Anahuac_Sand_Top	6,391
Anahuac_Sand_Base	6,469
Anahuac_Het_Lime_Top	6,609
Anahuac_Het_Lime_Base	6,848
Frio_Top	7,192
Frio_Mid	7,426
Frio_Low	7,631
Frio_Shale	7,933
Hackberry	8,127
Hackberry_Shale	8,401
Nodosaria	8,630

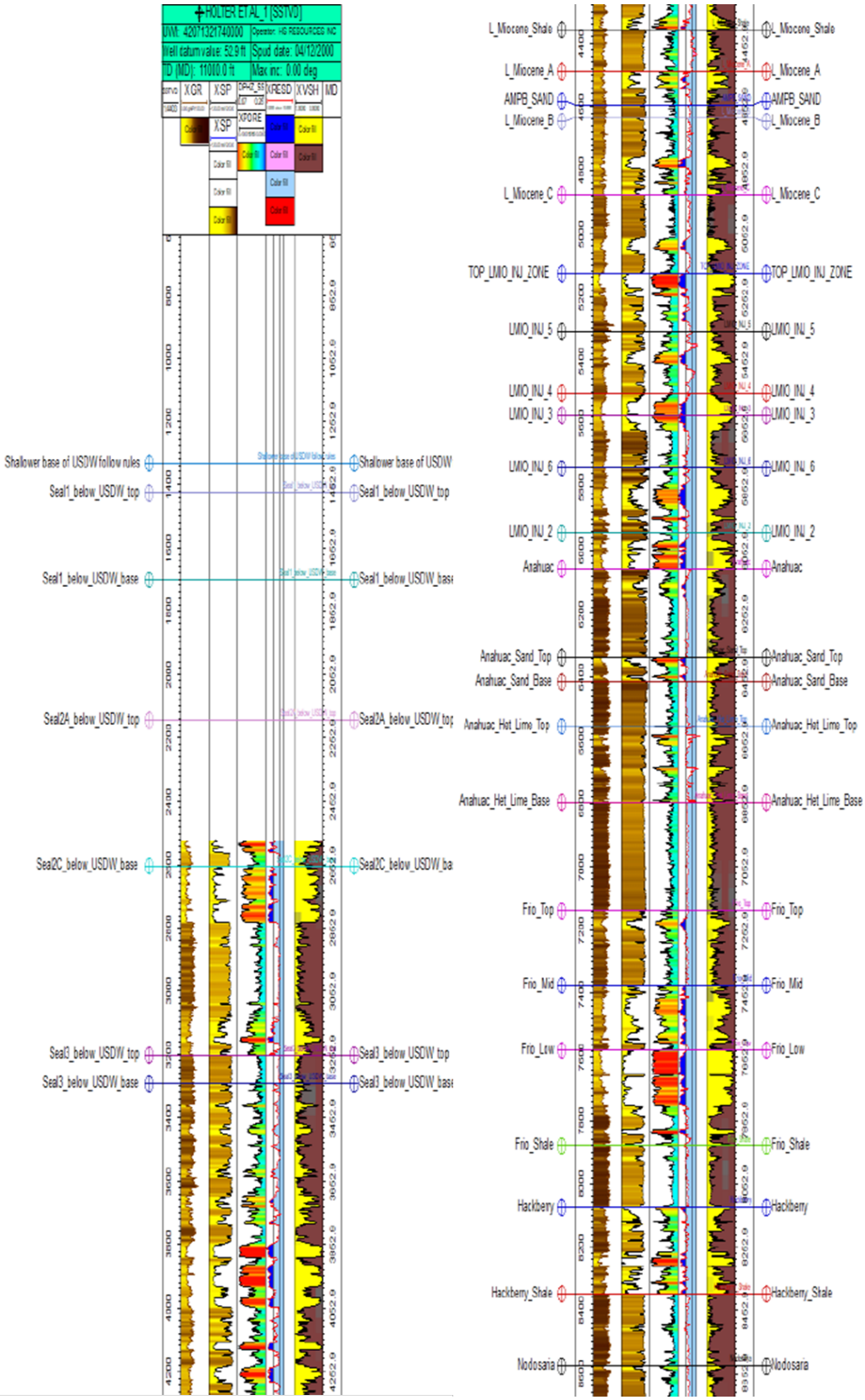


Figure C-AoR-44: Electric log and formation tops from Holter Et Al 1 (API 42071321740000).

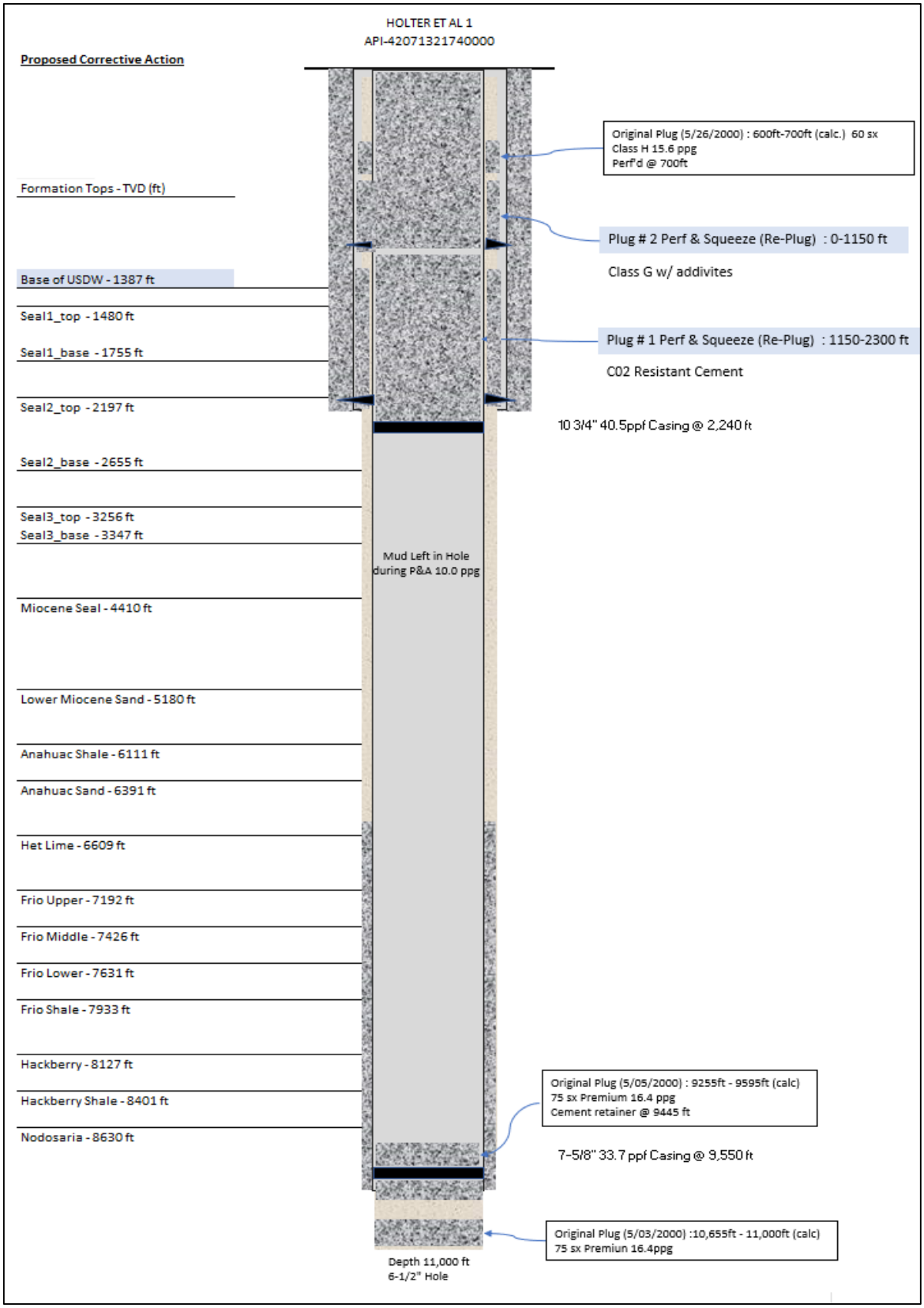


Figure C-AoR-45: Proposed remediation for Holter Et Al 1 (API 42071321740000).

Table C-AoR-48: Plug information for proposed re-abandonment procedure for Holter Et Al 1 (API 42071321740000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Perf & Squeeze	1150	2300	CO2 Resistant	14.8-15.5	100	1.06	529
Plug # 2	Perf & Squeeze	0	1150	Class G w/ additives	15-15.5	100	1.01	555

Plugging Procedure

1. Move in rig onto Holter Et Al 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and a bit sized for 7-5/8 in. 33.7 ppf casing and run in the hole, cleaning down to 2,300 ft. Circulate the hole clean and pull out of hole. Lay down bit.
7. Set a cast iron bridge plug (CIBP) at 2,300 ft.
8. Run in the hole with the work string and packer.
9. Set packer and test the plug and casing to 500 psi for 15 minutes.
10. Plug #1: Perf (2,200 ft) & squeeze plug 1,150-2,300 ft with 14.8-15.5 ppg CO_2-resistant slurry. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull string to the next plug stage.
11. Plug #2: Perf (1,000 ft) & squeeze plug 0-1,150 ft with 15-15.5 ppg Class G cement.
12. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground.
13. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the Plugging Plan.

16. O C Devillier 6 (API 42071308370000): D&A 1978

The O C Devillier 6 is projected to be the within the border of the CO_2 plume after the end of CO_2 injection between years 50 and 100. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Nodosaria, and Vicksburg formations reaching a TD of 10,993 ft. The 10 3/4 in. surface casing set at 2,053 ft does cover the USDW, located at approximately 1,496 ft. If primary cement records are unable to be located a CBL will be run on the surface casing to verify the top of cement. Cement plugs were placed 9,370 – 9,818 ft (100 sx), 1,850-2,189 ft (225 sx), 321-497 ft (75 sx) and 6 – 26 ft (15 sx) during abandonment, according to the TRRC records. The 7-5/8 in. production casing was also cut and pulled during abandonment at 2,130 ft. The well was left filled with 12.5 ppg mud in open hole. The well will be scheduled for remedial action in Year 15.

Table C-AoR-49: General information for O C Devillier 6 (API 42071308370000).

API	42071308370000
Operator	Gulf Oil Corp
Lease Name	O C Devillier
Well Number	6
Status	Dry & Abandoned
Surface Latitude	29.8252144
Surface Longitude	-94.4949291
Total Depth	10993
Formation	Vicksburg
Spud Date	1978-06-21
Drilling End	1978-08-09
Abandonment Date	8/8/1978

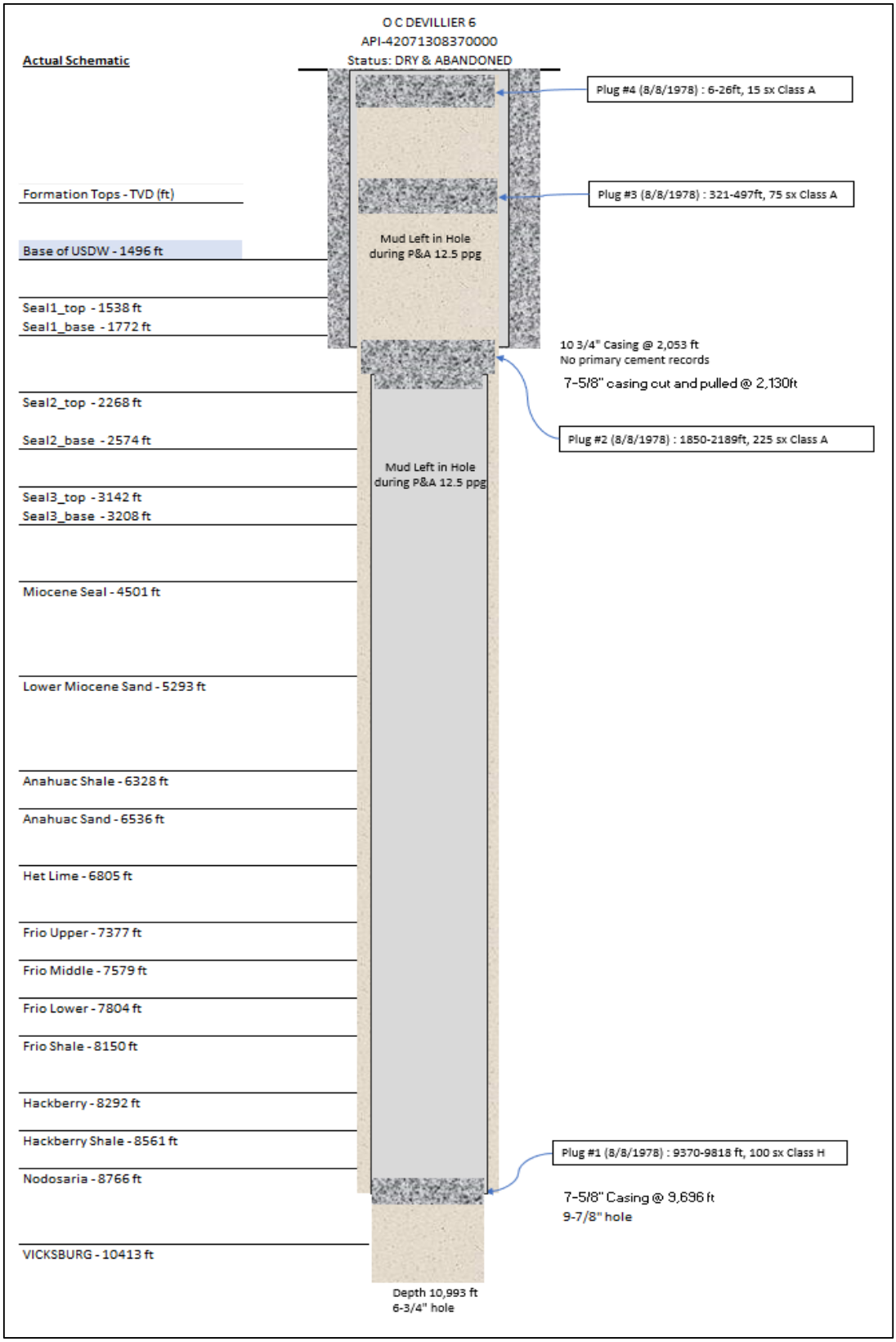


Figure C-AoR-46: Actual wellbore schematic of O C Devillier 6 (API 42071308370000).

Table C-AoR-50: Formation tops from O C Devillier 6 (API 42071308370000).

Formation Tops (MD ft)	
Shallower base of USDW follow rule:	1,496
Seal1_top	1,538
Seal1_base	1,772
Seal2_top	2,268
Seal2_base	2,574
Seal3_top	3,142
Seal3_base	3,208
L_Miocene_Shale	4,501
L_Miocene_A	4,643
AMPB_SAND	4,759
L_Miocene_B	4,868
L_Miocene_C	5,125
TOP_LMIO_INJ_ZONE	5,293
LMIO_INJ_5	5,457
LMIO_INJ_4	5,543
LMIO_INJ_3	5,707
LMIO_INJ_6	5,873
LMIO_INJ_2	6,157
Anahuac	6,328
Anahuac_Sand_Top	6,536
Anahuac_Sand_Base	6,570
Anahuac_Het_Lime_Top	6,805
Anahuac_Het_Lime_Base	6,990
Frio_Top	7,377
Frio_Mid	7,579
Frio_Low	7,804
Frio_Shale	8,150
Hackberry	8,292
Hackberry_Shale	8,561
Nodosaria	8,766
VICKSBURG	10,413

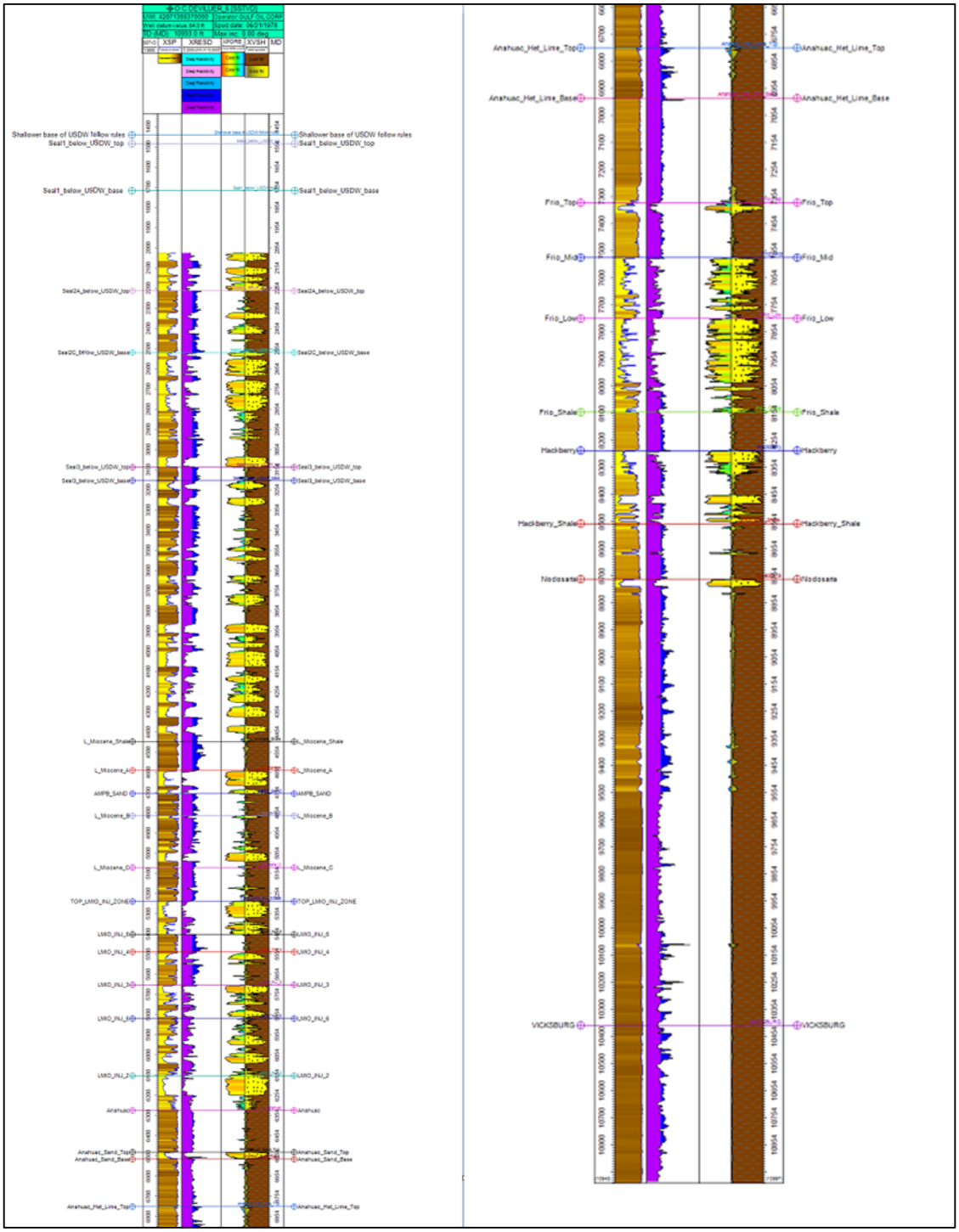


Figure C-AoR-47: Electric log and formation tops O C Devillier 6 (API 42071308370000).

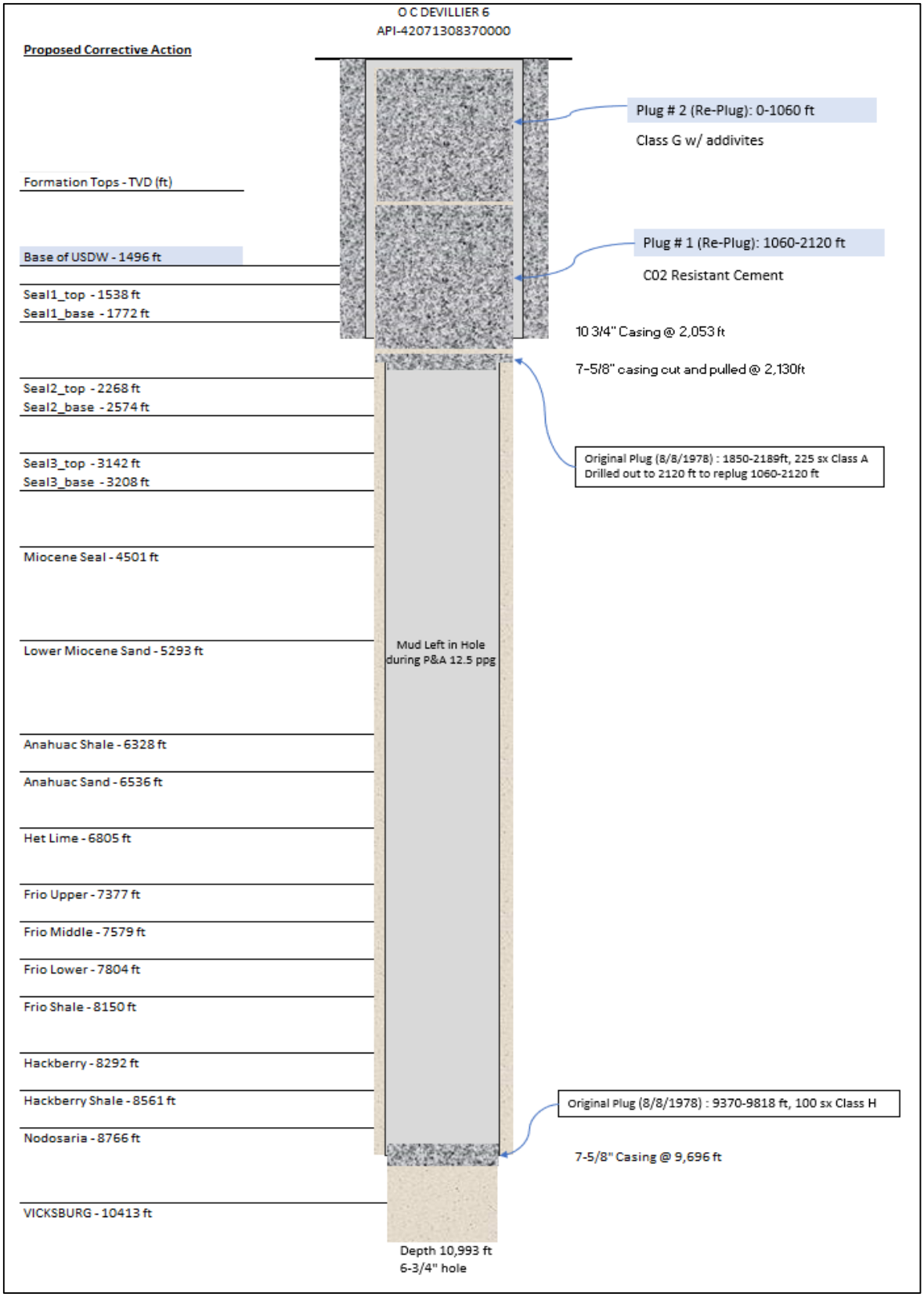


Figure C-AoR-48: Proposed remediation for O C Devillier 6 (API 42071308370000).

Table C-AoR-51: Plug information for proposed re-abandonment procedure for O C Devillier 6 (API 42071308370000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density	Volume	Yield	Sx
Plug # 1	Balanced Plug	1060	2120	CO2 Resistant	14.8-15.5	107	1.06	566
Plug # 2	Balanced Plug	0	1060	Class G w/ additives	15-15.5	107	1.01	594
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto O C Devillier 6 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with 9-7/8 in. bit and run in the hole, cleaning down to 2,120 ft. Circulate the hole clean and pull out the of hole. Lay down the bit.
    a. If primary cement records have been located and there is cement behind the surface casing: Proceed to step 11.
    b. If primary cement records have not been located: Proceed with step 7
7. Set a bridge plug at 2,000 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 10-3/4 in. casing from 2,000 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 2,120 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 10-3/4 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 2,000 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 2,120 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 2,120 ft.
12. Plug #1: Set a balanced plug 1,060 – 2,120 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-1,060 ft with 15-15.5 ppg Class G cement.
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

17. Devillier L C 1 (API 42071313940000): D&A 1982

The Devillier L C 1 is projected to be inside the CO_2 plume between years 15 and 50 after the start of injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 9,284 ft. The 9-5/8 in. surface casing set at 1,783 ft does cover the USDW, located at approximately 1,263 ft. The abandonment procedure consisted of cement plugs set at 1,660-1,860 ft (75 sx), 610-710 ft (40 sx) and 4-14 ft (10 sx) according to the TRRC records. The well was left filled with mud in open hole. The well will be scheduled for remedial action in Year 15.

Table C-AoR-52: General information for Devillier L C 1 (API 42071313940000).

API	42071313940000
Operator	Pyramid Exploration
Lease Name	Devillier L C
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.8435954
Surface Longitude	-94.4624718
Total Depth	9284
Formation	Frio
Spud Date	1982-12-10
Drilling End	1982-12-28
Abandonment Date	12/27/1982

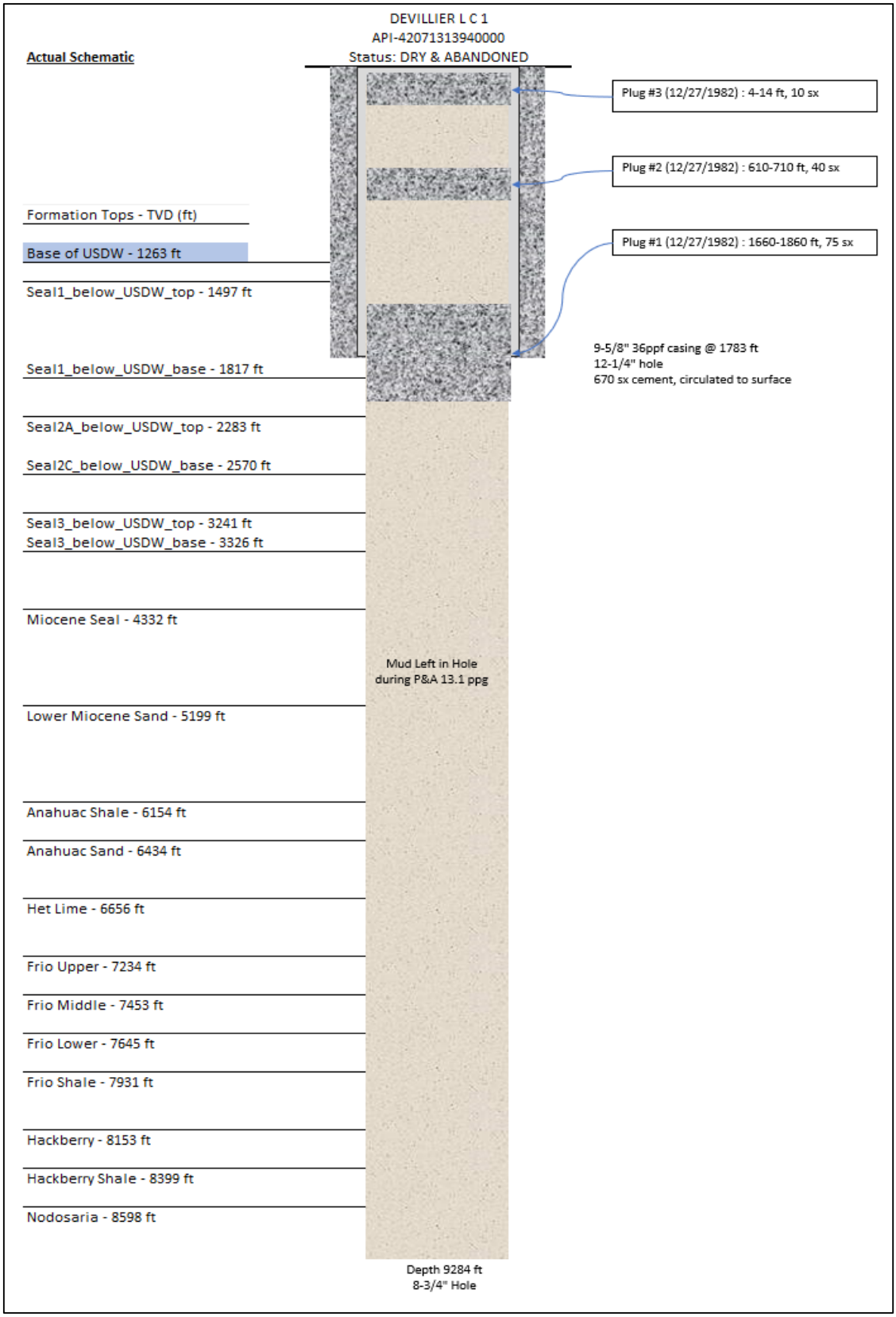


Figure C-AoR-49: Actual wellbore schematic of Devillier L C 1 (API 42071313940000).

Table C-AoR-53: Formation tops from Devillier L C 1 (API 42071313940000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,263
Seal1_below_USDW_top	1,497
Seal1_below_USDW_base	1,817
Seal2A_below_USDW_top	2,283
Seal2C_below_USDW_base	2,570
Seal3_below_USDW_top	3,241
Seal3_below_USDW_base	3,326
L_Miocene_Shale	4,332
L_Miocene_A	4,567
AMPB_SAND	4,668
L_Miocene_B	4,782
L_Miocene_C	5,035
TOP_LMIO_INJ_ZONE	5,199
LMIO_INJ_5	5,304
LMIO_INJ_4	5,459
LMIO_INJ_3	5,552
LMIO_INJ_6	5,726
LMIO_INJ_2	6,018
Anahuac	6,154
Anahuac_Sand_Top	6,434
Anahuac_Sand_Base	6,526
Anahuac_Het_Lime_Top	6,656
Anahuac_Het_Lime_Base	6,840
Frio_Top	7,234
Frio_Mid	7,453
Frio_Low	7,645
Frio_Shale	7,931
Hackberry	8,153
Hackberry_Shale	8,399
Nodosaria	8,598

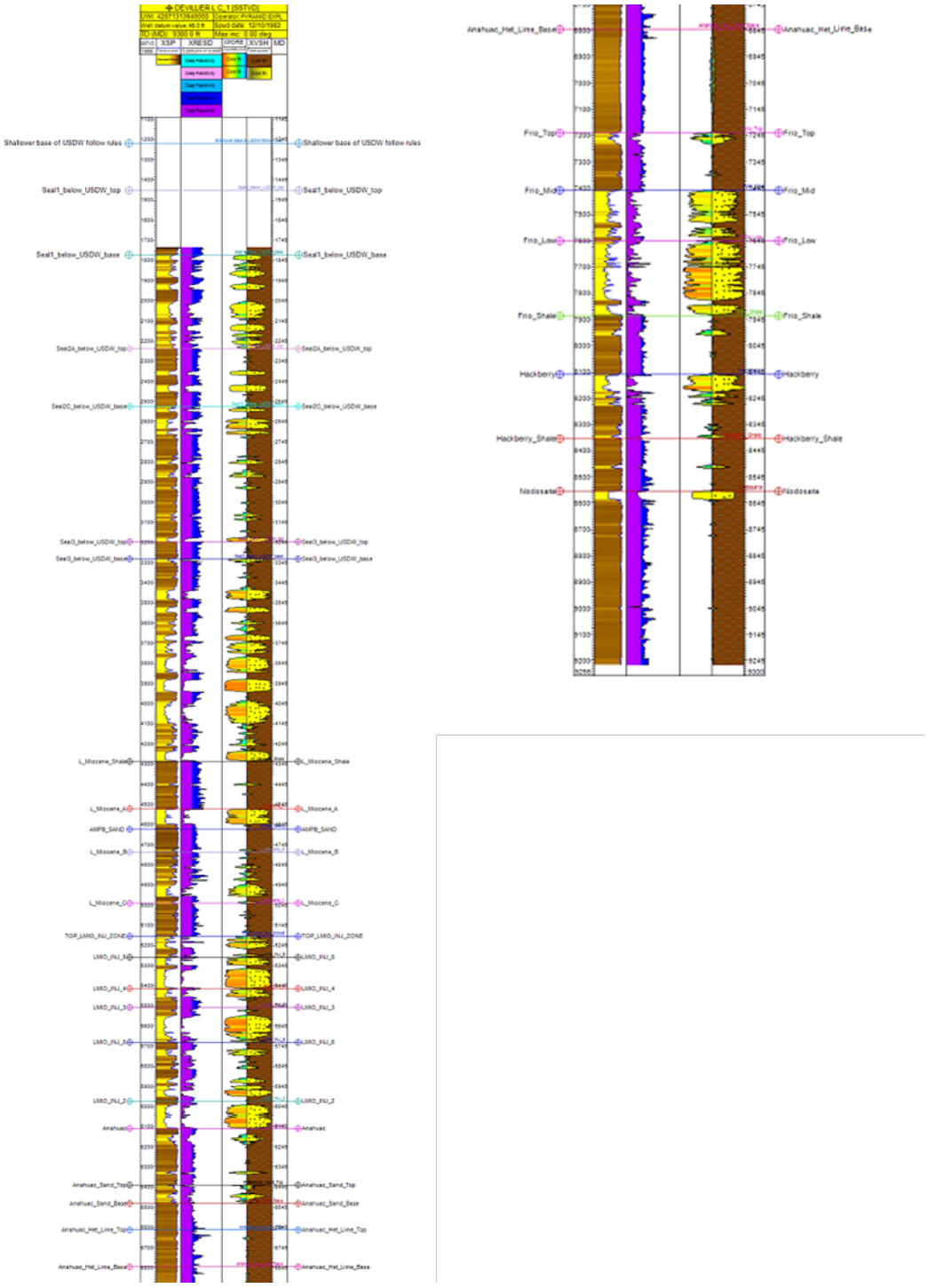


Figure C-AoR-50: Electric log and formation tops from Devillier L C 1 (API 42071313940000).

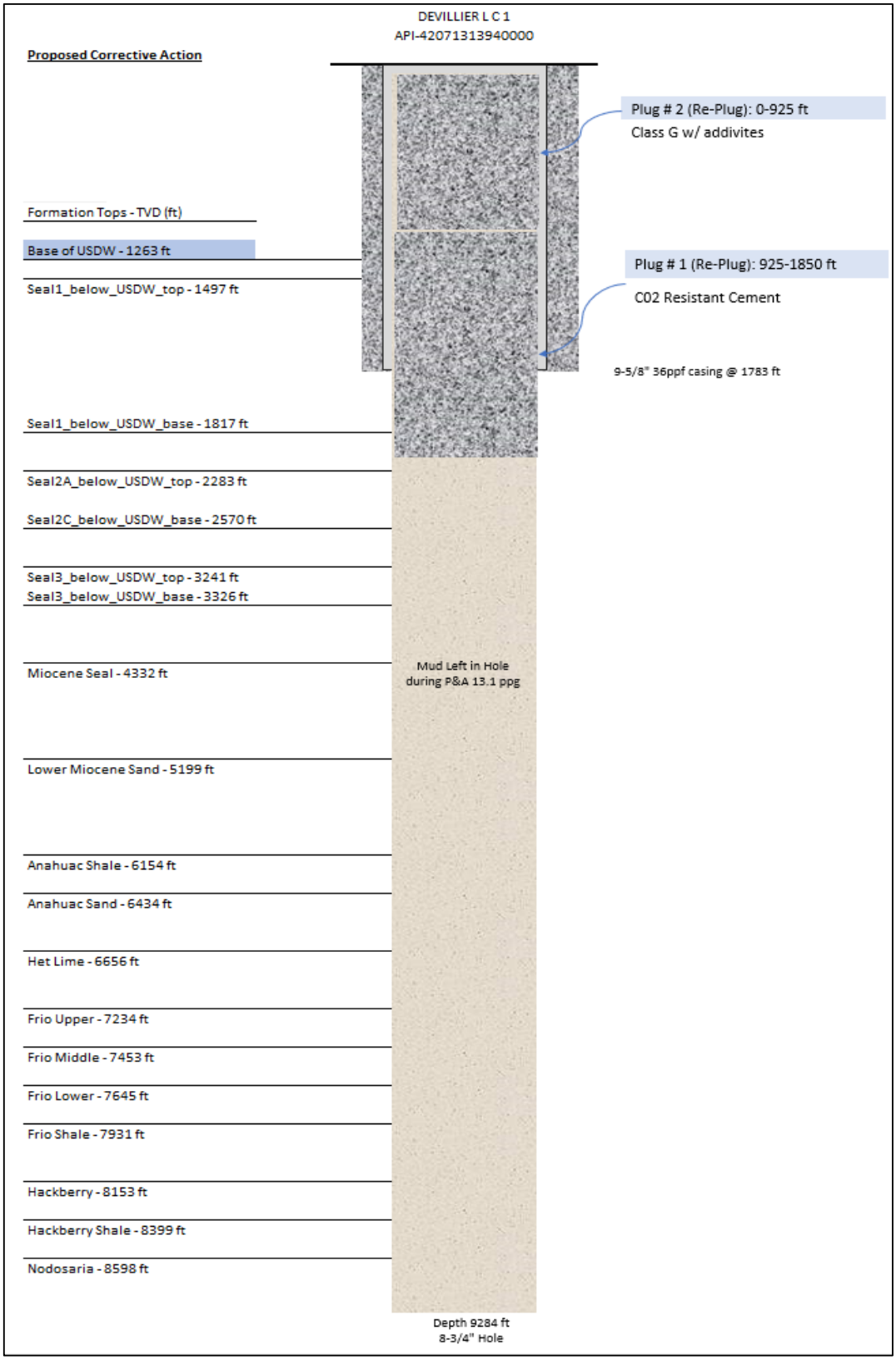


Figure C-AoR-50: Proposed remediation for Devillier L C 1 (API 42071313940000).

Table C-AoR-54: Plug information for proposed re-abandonment procedure for Devillier L C 1 (API 42071313940000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	925	1850	CO2 Resistant	14.8-15.5	72	1.06	378
Plug # 2	Balanced Plug	0	925	Class G w/ additives	15-15.5	72	1.01	397

Plugging Procedure

1. Move in rig onto Devillier L C 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in 36 ppg casing and run in the hole, cleaning down to 1,700 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with the work string to 1,850 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 925 – 1,850 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-925 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report

18. OGDEN L G ETAL 1 (API 42071019610000): D&A 1958

The OGDEN L G ETAL 1 is projected to be inside the CO_2 plume between years 15 and 50 after the start of injection. The well status is D&A-O and was drilled through the Miocene, Anahuac, Frio, Hackberry, and Nodosaria formations reaching a TD of 9,617 ft. The 9-5/8 in. surface casing set at 2,264 ft does cover the USDW, located at approximately 1,466 ft. The abandonment procedure consisted of cement plugs set at 2,222-2,327 ft (40 sx) and 17-43 ft (10 sx) according to the TRRC records. The well was left filled with mud in open hole. The well will be scheduled for remedial action in Year 10.

Table C-AoR-55: General information for Ogden L G Etal 1 (API 42071019610000).

API	42071019610000
Operator	Continental Oil Co
Lease Name	Ogden L G Etal
Well Number	1
Status	D&A-O
Surface Latitude	29.82821903
Surface Longitude	-94.47997279
Total Depth	9616
Formation	Unknown
Spud Date	1958-03-23
Drilling End	1958-04-22
Abandonment Date	4/22/1958

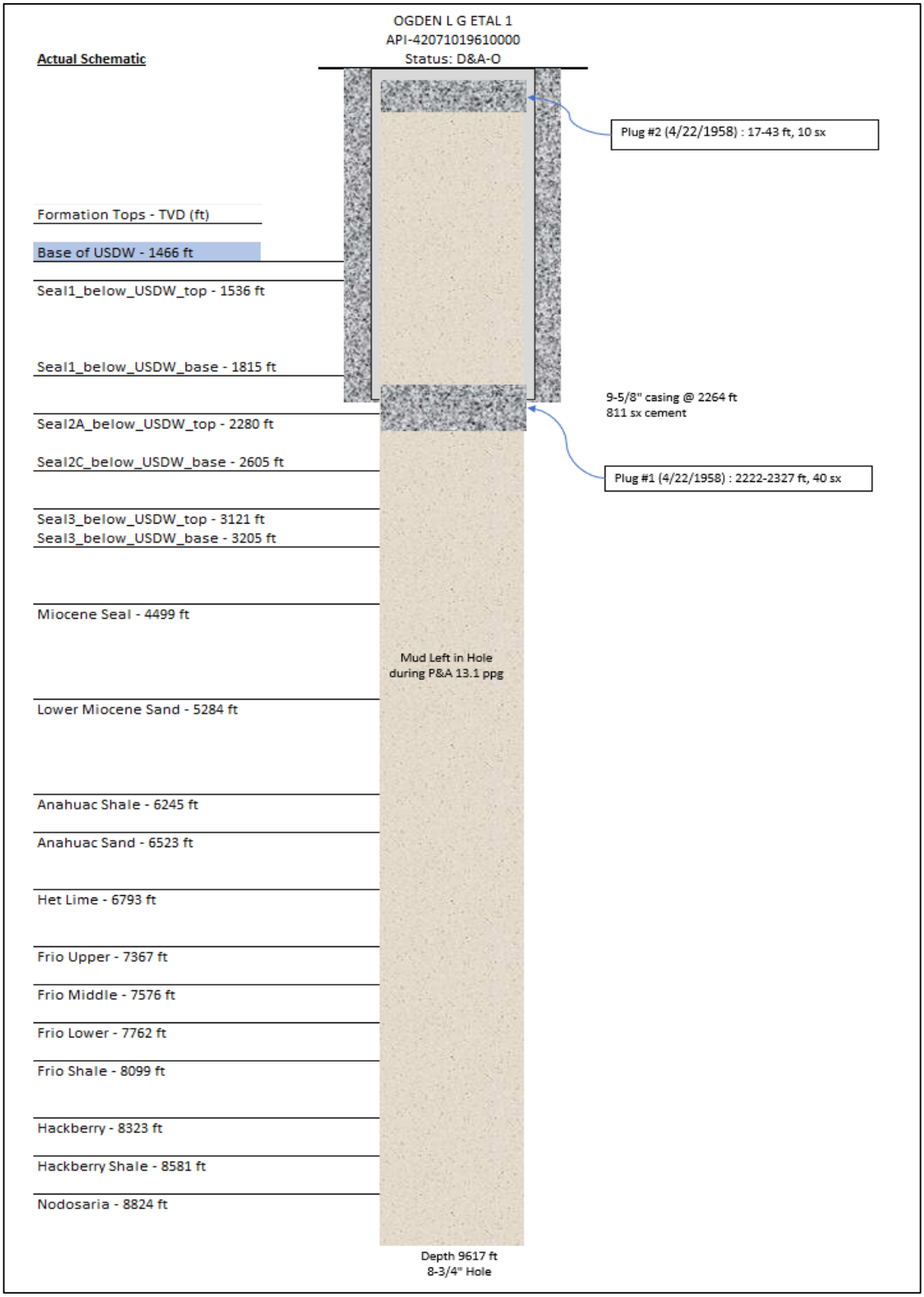


Figure C-AoR-51: Actual wellbore schematic of Ogden L G Etal 1 (API 42071019610000).

Table C-AoR-56: Formation tops from Ogden L G Etal 1 (API 42071019610000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,466
Seal1_below_USDW_top	1,536
Seal1_below_USDW_base	1,815
Seal2A_below_USDW_top	2,280
Seal2C_below_USDW_base	2,605
Seal3_below_USDW_top	3,121
Seal3_below_USDW_base	3,205
L_Miocene_Shale	4,499
L_Miocene_A	4,590
AMPB_SAND	4,705
L_Miocene_B	4,852
L_Miocene_C	5,120
TOP_LMIO_INJ_ZONE	5,284
LMIO_INJ_5	5,384
LMIO_INJ_4	5,490
LMIO_INJ_3	5,636
LMIO_INJ_6	5,807
LMIO_INJ_2	6,112
Anahuac	6,245
Anahuac_Sand_Top	6,523
Anahuac_Sand_Base	6,562
Anahuac_Het_Lime_Top	6,793
Anahuac_Het_Lime_Base	6,989
Frio_Top	7,367
Frio_Mid	7,576
Frio_Low	7,762
Frio_Shale	8,099
Hackberry	8,323
Hackberry_Shale	8,581
Nodosaria	8,824

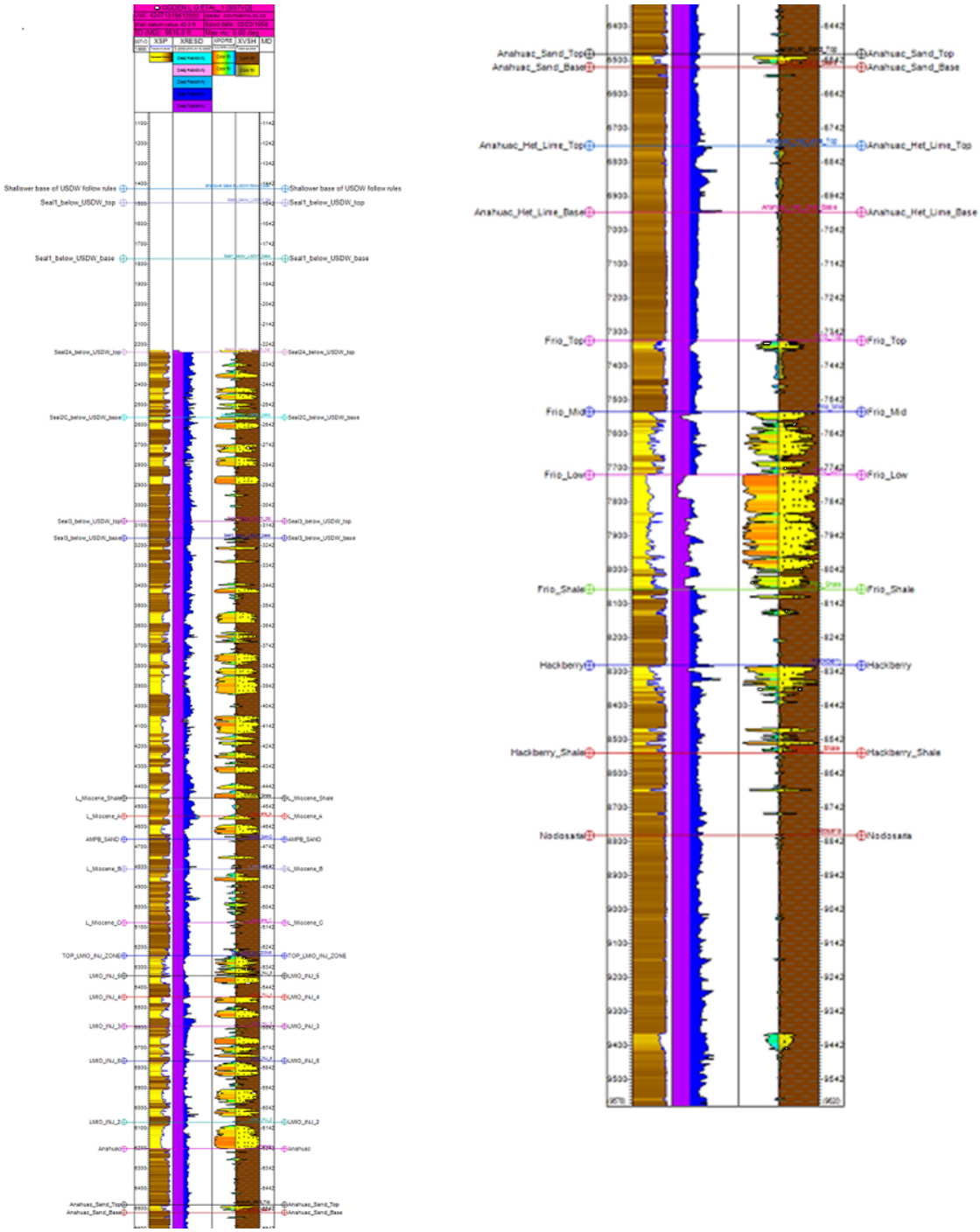


Figure C-AoR-52: Electric log and formation tops from Ogden L G Etal 1 (API 42071019610000).

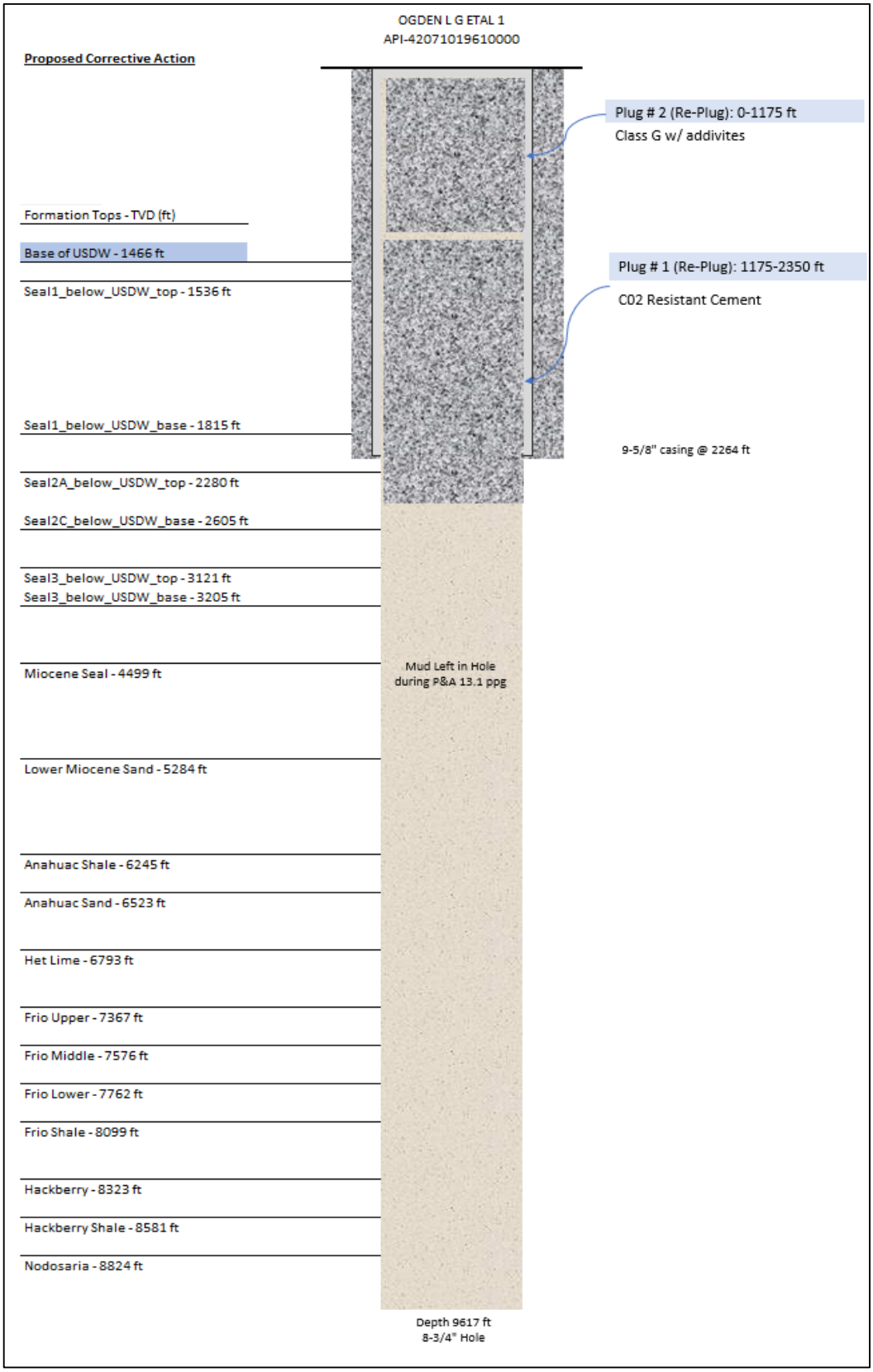


Figure C-AoR-53: Proposed remediation for Ogden L G Etal 1 (API 42071019610000).

Table C-AoR-57: Plug information for proposed re-abandonment procedure for Ogden L G Etal 1 (API 42071019610000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	1175	2350	CO2 Resistant	14.8-15.5	92	1.06	489
Plug # 2	Balanced Plug	0	1175	Class G w/ additives	15-15.5	92	1.01	514

Plugging Procedure

1. Move in rig onto Ogden L G Etal 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in casing and run in the hole, cleaning down to 2,350 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with the work string to 2,350 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 1,175 – 2,350 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-1,175 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report

19. Beaumnt RC MLL 1 (API 42071304690000): D&A 1976

The Beaumnt RC MLL 1 is projected to be inside the CO_2 plume between years 15 and 50 after the start of injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, and Nodosaria formations reaching a TD of 9,000 ft. The 9-5/8 in. surface casing set at 987 ft does not cover the base of the USDW, located at approximately 1,247 ft. If primary cement records are unable to be located a CBL will be run on the surface casing to verify the top of cement. Cement plugs were placed 897 – 1,050 ft (50 sx), and 10-33 ft (10 sx) during abandonment, according to the TRRC records. The well was left filled with 10.1 ppg mud in open hole. The well will be scheduled for remedial action in Year 15.

Table C-AoR-58: General information for Beaumnt RC MLL 1 (API 42071304690000).

API	42071304690000
Operator	Davis Oil Co
Lease Name	Beaumnt RC MLL
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.87663474
Surface Longitude	-94.50094383
Total Depth	9,000
Formation	Frio
Spud Date	1976-08-16
Drilling End	1976-08-25
Abandonment Date	1976-08-25

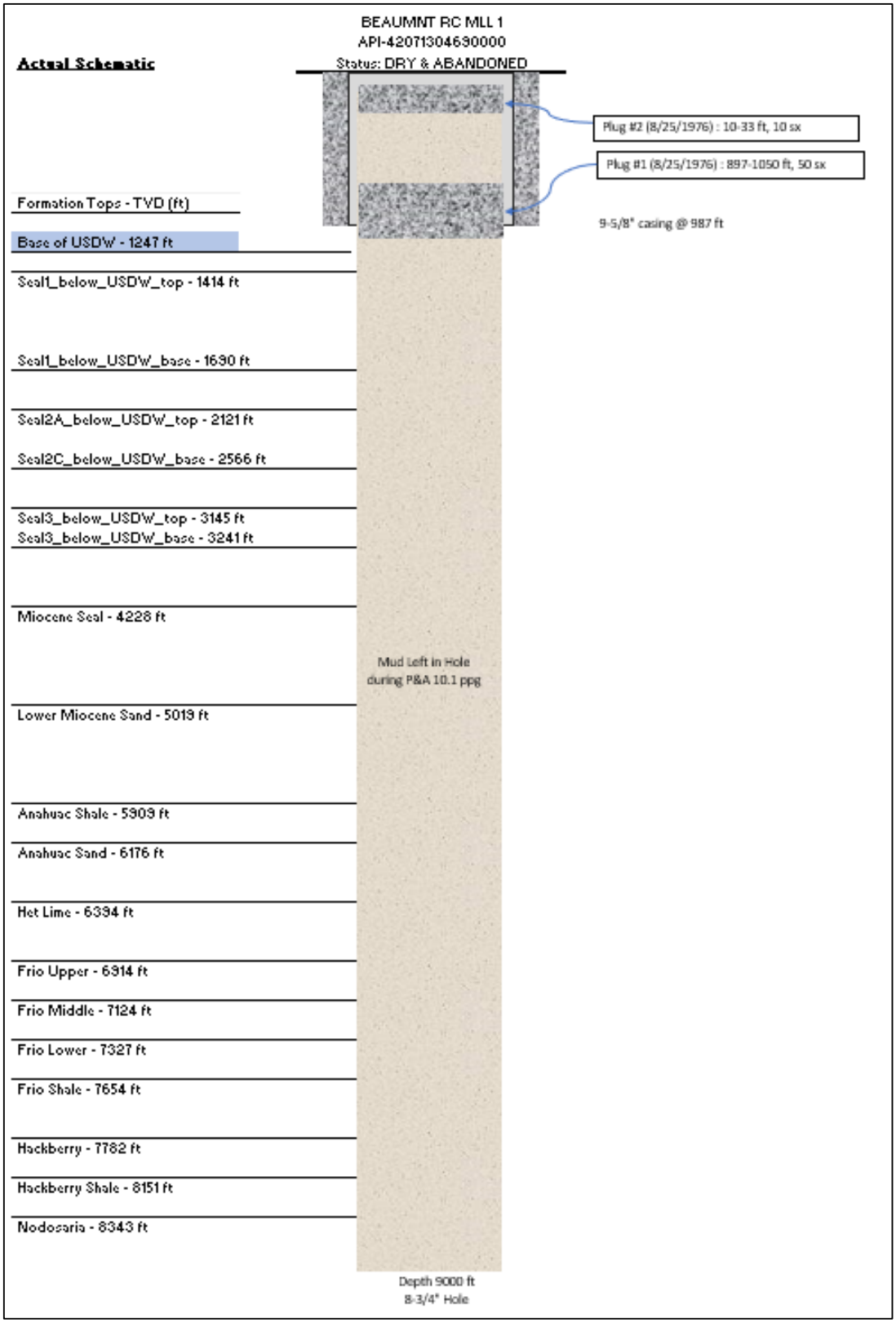


Figure C-AoR-54: Actual wellbore schematic of Beaumnt RC MLL 1 (API 42071304690000).

Table C-AoR-59: Formation tops from Beaumnt RC MLL 1 (API 42071304690000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,247
Seal1_below_USDW_top	1,414
Seal1_below_USDW_base	1,690
Seal2A_below_USDW_top	2,121
Seal2C_below_USDW_base	2,566
Seal3_below_USDW_top	3,145
Seal3_below_USDW_base	3,241
L_Miocene_Shale	4,228
L_Miocene_A	4,351
AMPB_SAND	4,482
L_Miocene_B	4,543
L_Miocene_C	4,841
TOP_LMIO_INJ_ZONE	5,019
LMIO_INJ_5	5,151
LMIO_INJ_4	5,271
LMIO_INJ_3	5,362
LMIO_INJ_6	5,560
LMIO_INJ_2	5,789
Anahuac	5,909
Anahuac_Sand_Top	6,176
Anahuac_Sand_Base	6,261
Anahuac_Het_Lime_Top	6,394
Anahuac_Het_Lime_Base	6,596
Frio_Top	6,914
Frio_Mid	7,124
Frio_Low	7,327
Frio_Shale	7,654
Hackberry	7,782
Hackberry_Shale	8,151
Nodosaria	8,343

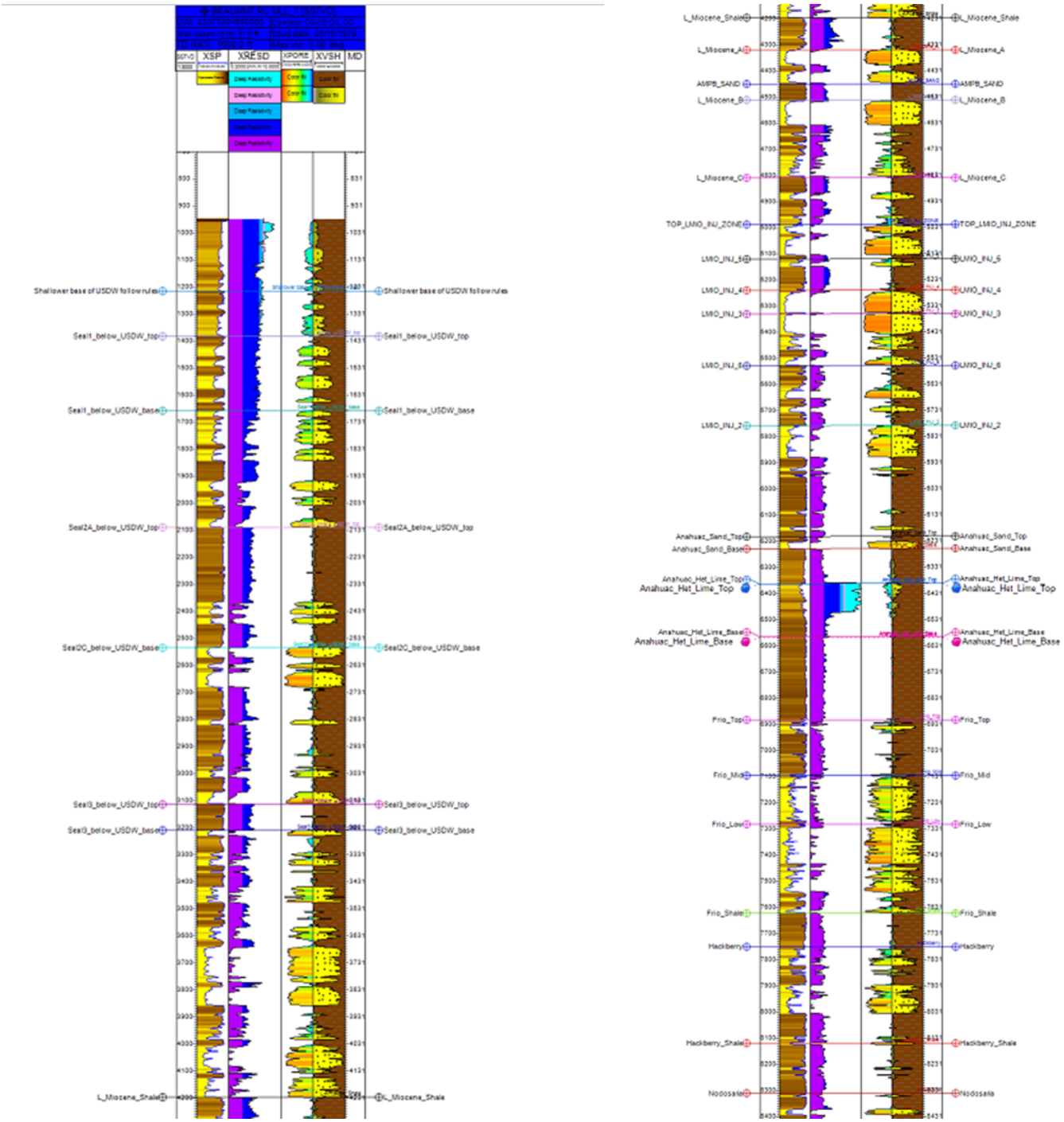


Figure C-AoR-55: Electric log and formation tops from BEAUMNT RC MLL 1 (API 42071304690000).

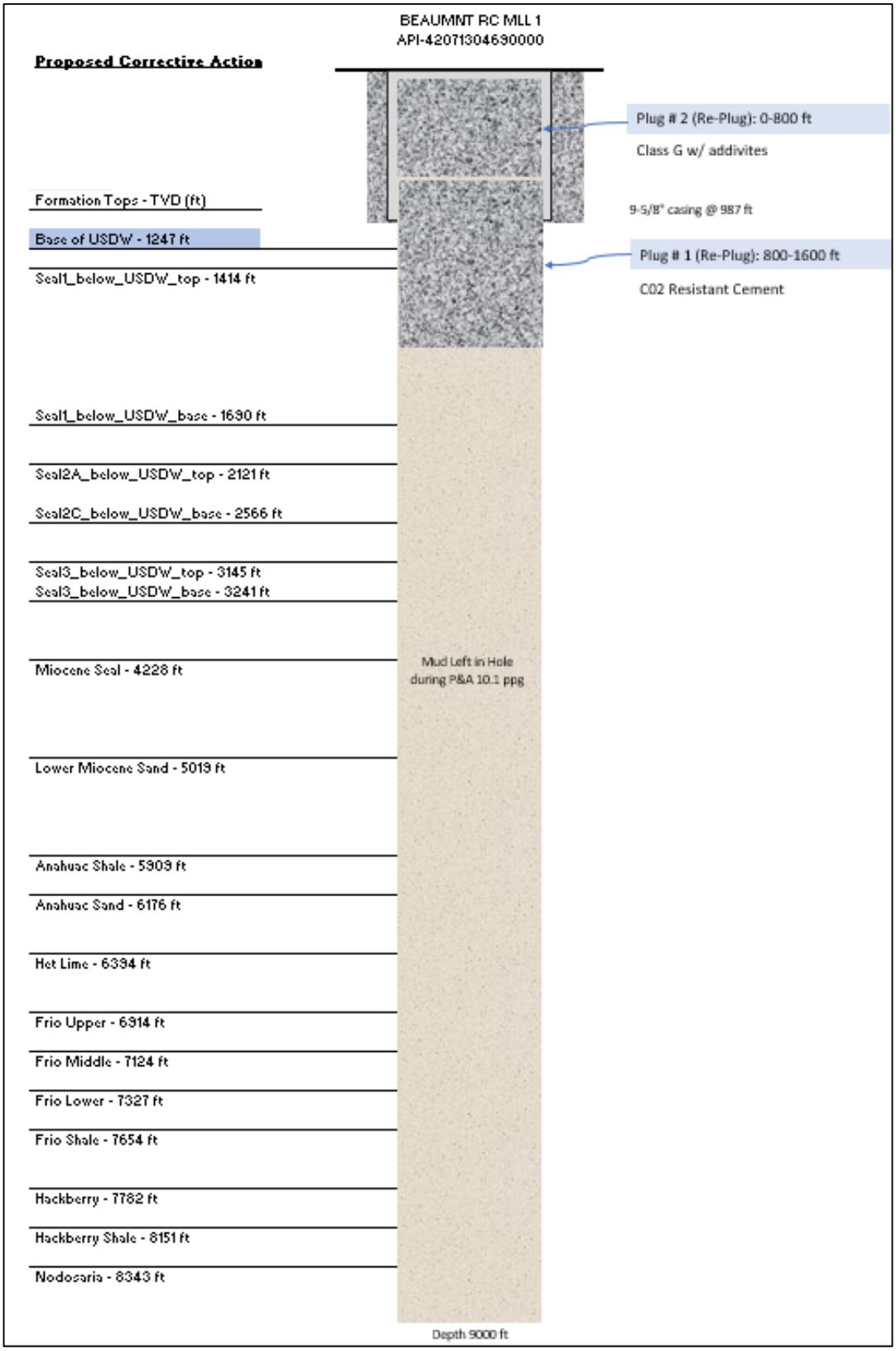


Figure C-AoR-56: Proposed remediation for BEAUMNT RC MLL 1 (API 42071304690000).

Table C-AoR-60: Plug information for proposed re-abandonment procedure for Beaumnt RC MLL 1 (API 42071304690000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	800	1600	CO2 Resistant	14.8-15.5	63	1.06	333
Plug # 2	Balanced Plug	0	800	Class G w/ additives	15-15.5	63	1.01	350
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto Beaumnt RC MLL 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in. casing and run in the hole.
    a. If primary cement records have been located and there is cement behind the surface casing: Clean down to 1,600 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If primary cement records have not been located: Clean down to 1,000 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed with step 7.
7. Set a bridge plug at 950 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 9-5/8 in. casing from 950 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 9-5/8 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 9-5/8 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 950 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 1,600 ft and circulate the hole clean.
12. Plug #1: Set a balanced plug 800-1,600 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-800 ft with 15-15.5 ppg Class G cement.

14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

20. Debellvue Mrs Maria 1 (API 42071019620000): D&A 1959

The Debellvue Mrs Maria 1 is projected to be inside the CO_2 plume between years 15 and 50 after the start of injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, and Nodosaria formations reaching a TD of 9,347 ft. The 9-5/8 in. surface casing set at 1,238 ft does not cover the base of the USDW, located at approximately 1,366 ft. Cement plugs were placed 7,459-7,559 ft (50 sx), 1,186-1,286 ft (50 sx) and 0-10 ft during abandonment, according to the TRRC records. The well was left filled with 13.2 ppg mud in open hole. The well will be scheduled for remedial action in Year 15.

Table C-AoR-61: General information for Debellvue Mrs Maria 1 (API 42071019620000).

API	42071019620000
Operator	Penrose Neville G
Lease Name	Debellvue Mrs Maria
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.84327052
Surface Longitude	-94.47198606
Total Depth	9348
Formation	UNKNOWN
Spud Date	1959-08-04
Drilling End	1959-08-23
Abandonment Date	1959-08-23

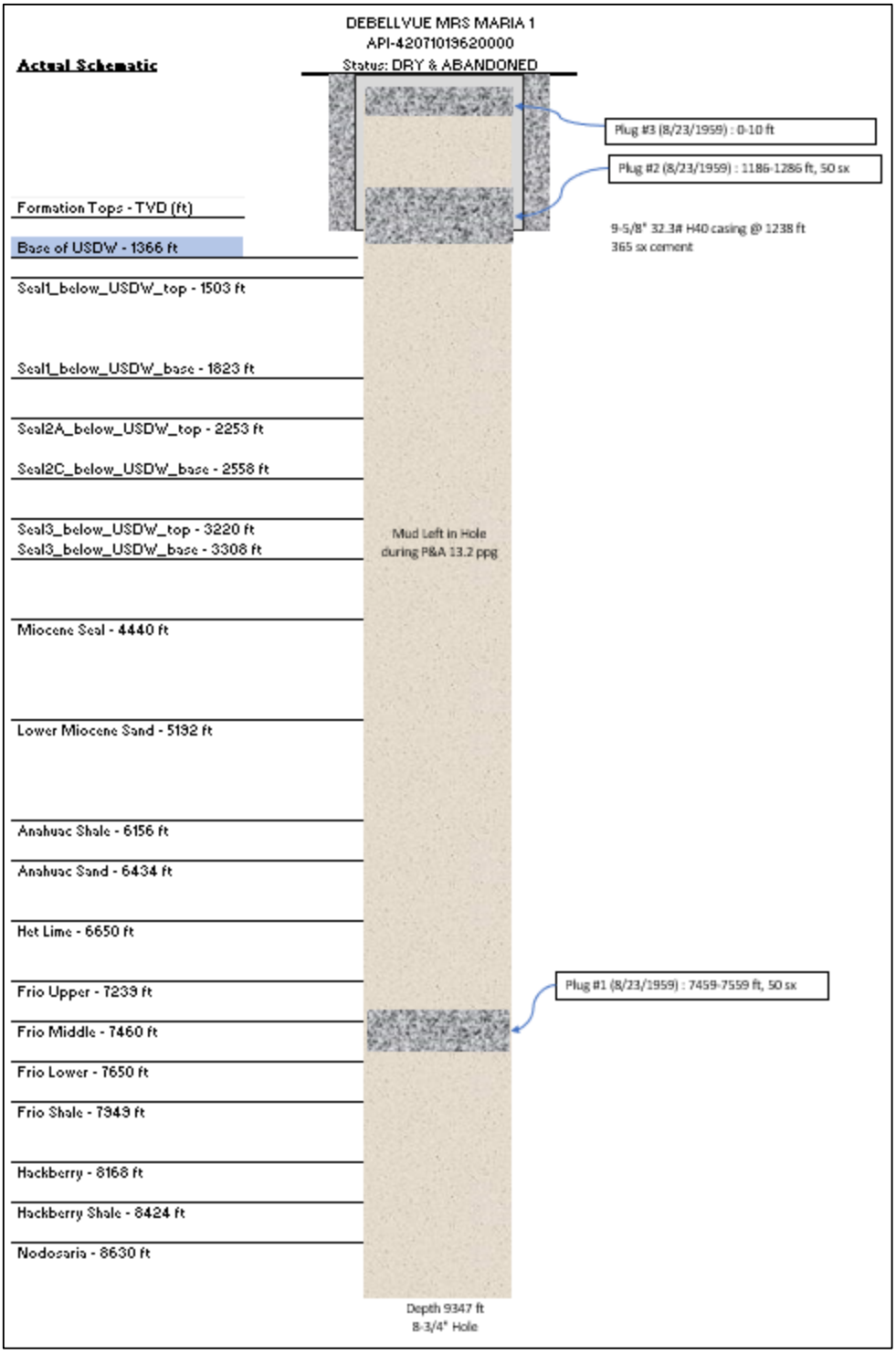


Figure C-AoR-57: Actual wellbore schematic of Debellvue Mrs Maria 1 (API 42071019620000).

Table C-AoR-62: Formation tops from Debellvue Mrs Maria 1 (API 42071019620000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,366
Seal1_below_USDW_top	1,503
Seal1_below_USDW_base	1,823
Seal2A_below_USDW_top	2,253
Seal2C_below_USDW_base	2,558
Seal3_below_USDW_top	3,220
Seal3_below_USDW_base	3,308
L_Miocene_Shale	4,440
L_Miocene_A	4,554
AMPB_SAND	4,657
L_Miocene_B	4,776
L_Miocene_C	5,051
TOP_LMIO_INJ_ZONE	5,192
LMIO_INJ_5	5,314
LMIO_INJ_4	5,455
LMIO_INJ_3	5,552
LMIO_INJ_6	5,715
LMIO_INJ_2	6,019
Anahuac	6,156
Anahuac_Sand_Top	6,434
Anahuac_Sand_Base	6,519
Anahuac_Het_Lime_Top	6,650
Anahuac_Het_Lime_Base	6,829
Frio_Top	7,239
Frio_Mid	7,460
Frio_Low	7,650
Frio_Shale	7,949
Hackberry	8,168
Hackberry_Shale	8,424
Nodosaria	8,630

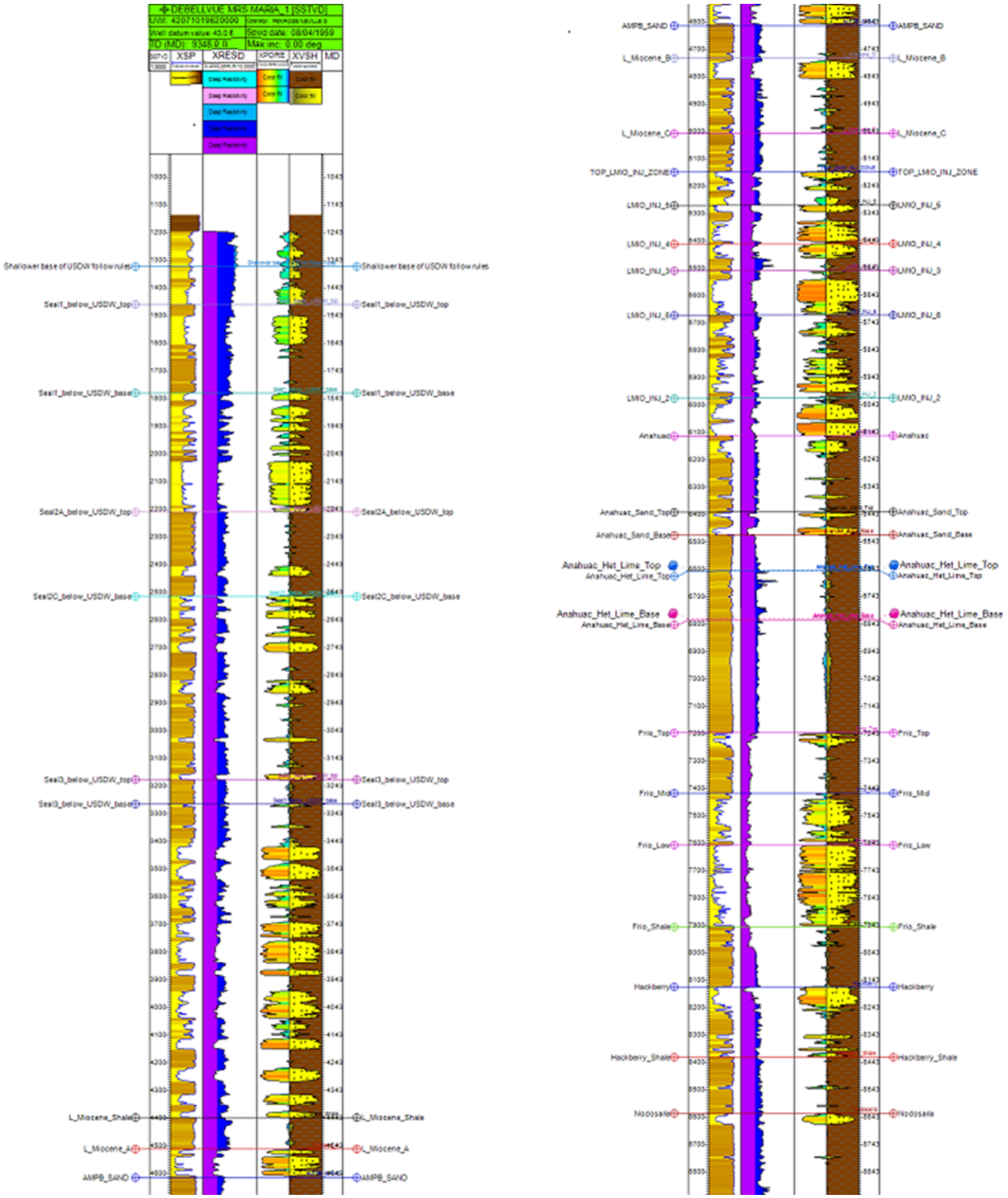


Figure C-AoR-58: Electric log and formation tops from Debellvue Mrs Maria 1 (API 42071019620000).

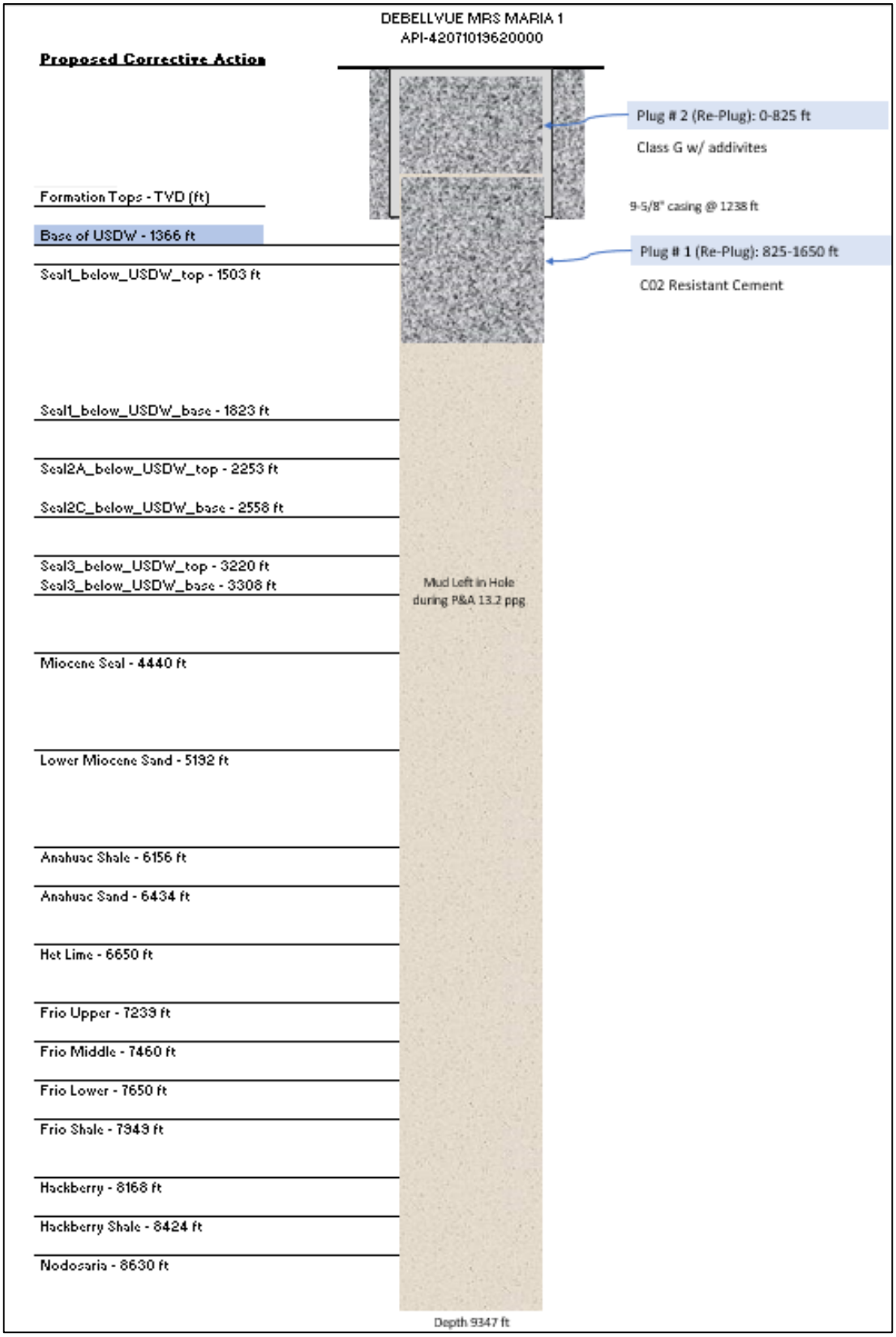


Figure C-AoR-59: Proposed remediation for Debellvue Mrs Maria 1 (API 42071019620000).

Table C-AoR-63: Plug information for proposed re-abandonment procedure for Debellvue Mrs Maria 1 (API 42071019620000).

Plug	Method	Top (ft)	Bottom (ft)	Cement Type	Density	Volume	Yield	Sx
Plug # 1	Balanced Plug	825	1650	CO2 Resistant	14.8-15.5	65	1.06	344
Plug # 2	Balanced Plug	0	825	Class G w/ additives	15-15.5	65	1.01	361

Plugging Procedure

1. Move in rig onto Debellvue Mrs Maria 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in casing and run in the hole, cleaning down to 1,650 ft. Circulate the hole clean and pull out of the hole. Lay down the bit.
7. Run in the hole with the work string to 1,650 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 825 – 1,650 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
9. Plug #2: Set a balanced plug 0-825 ft with 15-15.5 ppg Class G cement.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report

21. O C Devillier Jr 1 (API 42071033940000): D&A 1967

The O C Devillier Jr 1 is projected to be inside the CO_2 plume at year 50 after the start of injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, and Nodosaria formations reaching a TD of 9,317 ft. The 9-5/8 in. surface casing set at 1,081 ft does not cover the base of the USDW, located at approximately 1,490 ft. If primary cement records are unable to be located a CBL will be run on the surface casing to verify the top of cement. Cement plugs were placed 930 – 1,130 ft (70 sx), and 0-50 ft (20 sx) during abandonment, according to the TRRC records. The well was left filled with 12 ppg mud in open hole. The well will be scheduled for remedial action in Year 15.

Table C-AoR-64: General information for O C Devillier Jr 1 (API 42071033940000).

API	42071033940000
Operator	Southern Natural Gas Co
Lease Name	O C Devillier Jr
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.81786014
Surface Longitude	-94.49039232
Total Depth	9317
Formation	Unknown
Spud Date	1967-04-04
Drilling End	1967-04-16
Abandonment Date	1967-04-16

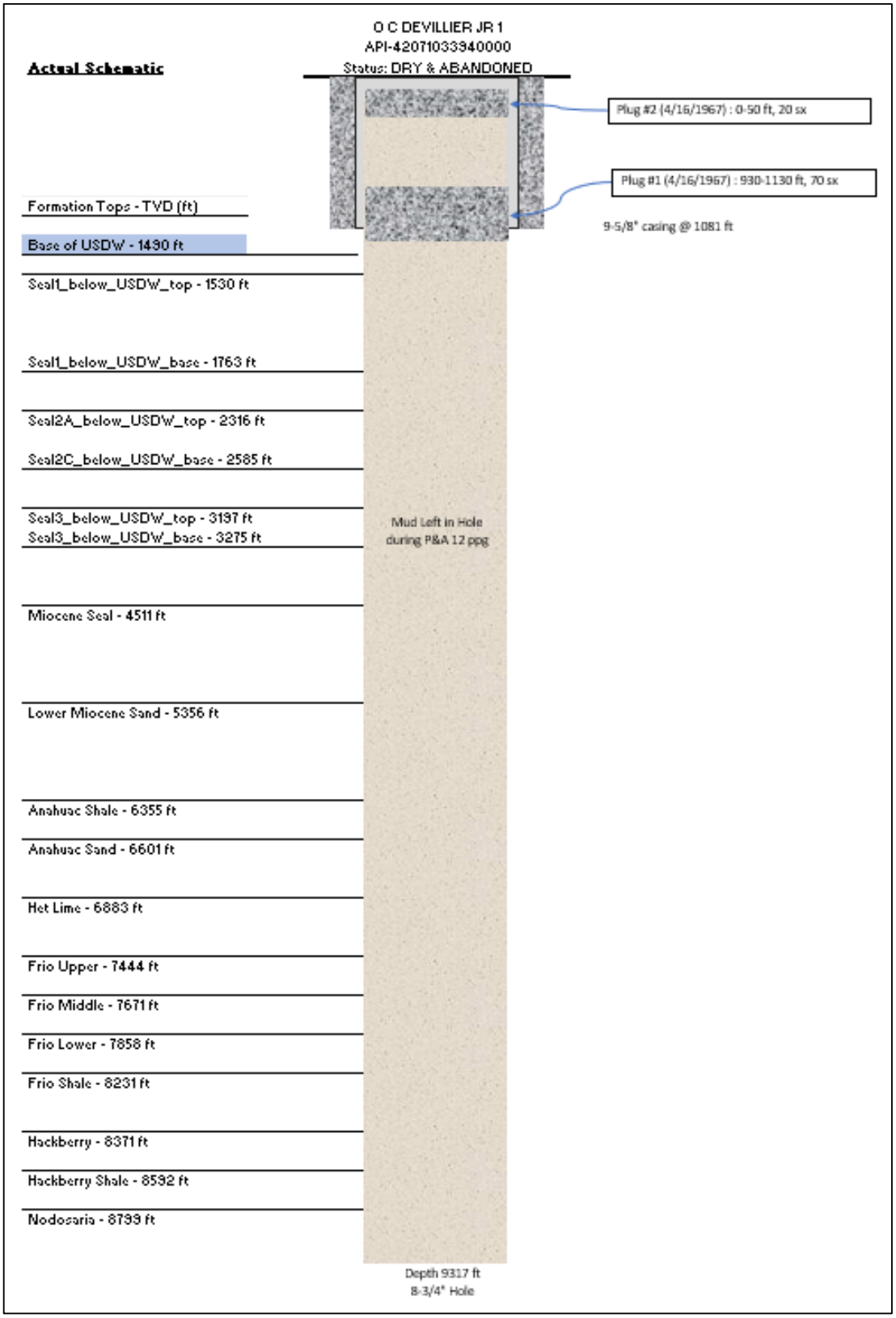


Figure C-AoR-60: Actual wellbore schematic of O C Devillier Jr 1 (API 42071033940000).

Table C-AoR-65: Formation tops from O C Devillier Jr 1 (API 42071033940000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,490
Seal1_below_USDW_top	1,530
Seal1_below_USDW_base	1,763
Seal2A_below_USDW_top	2,316
Seal2C_below_USDW_base	2,585
Seal3_below_USDW_top	3,197
Seal3_below_USDW_base	3,275
L_Miocene_Shale	4,511
L_Miocene_A	4,681
AMPB_SAND	4,794
L_Miocene_B	4,933
L_Miocene_C	5,175
TOP_LMIO_INJ_ZONE	5,356
LMIO_INJ_5	5,514
LMIO_INJ_4	5,551
LMIO_INJ_3	5,761
LMIO_INJ_6	5,931
LMIO_INJ_2	6,182
Anahuac	6,355
Anahuac_Sand_Top	6,601
Anahuac_Sand_Base	6,656
Anahuac_Het_Lime_Top	6,883
Anahuac_Het_Lime_Base	7,072
Frio_Top	7,444
Frio_Mid	7,671
Frio_Low	7,858
Frio_Shale	8,231
Hackberry	8,371
Hackberry_Shale	8,592
Nodosaria	8,799

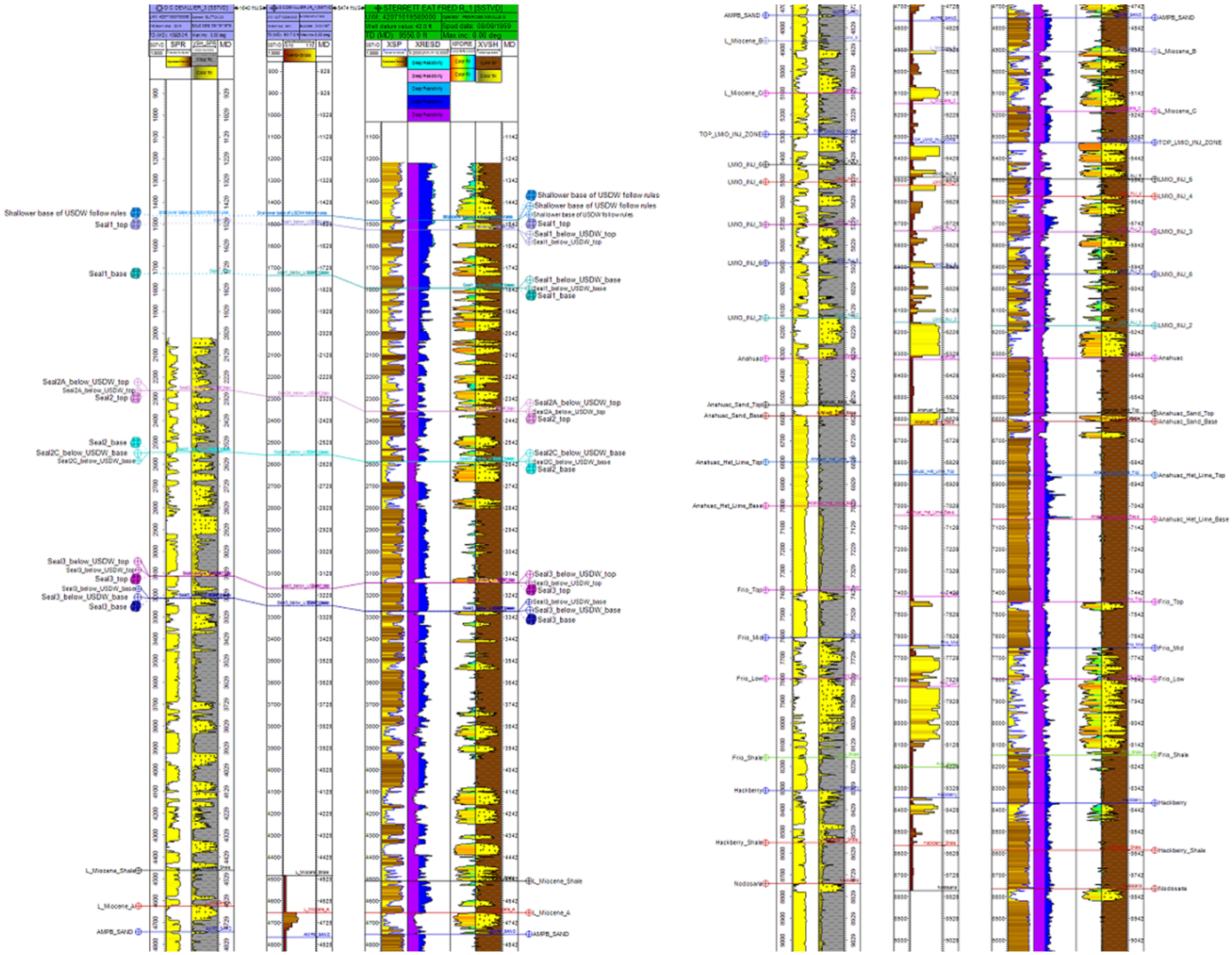


Figure C-AoR-61: Pseudo-log and formation tops from O C Devillier Jr 1 (API 42071033940000).

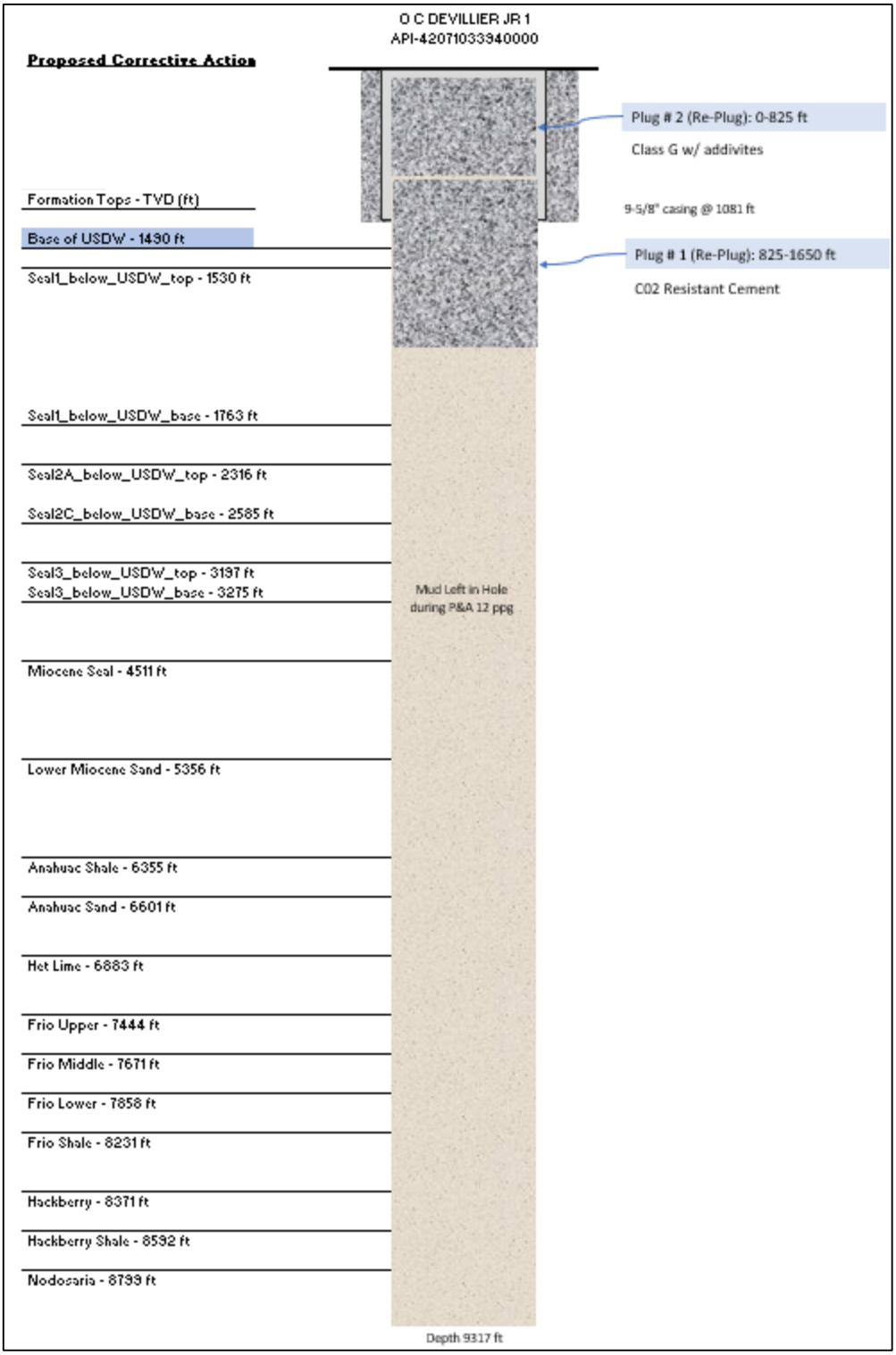


Figure C-AoR-62: Proposed remediation for O C Devillier Jr 1 (API 42071033940000).

Table C-AoR-66: Plug information for proposed re-abandonment procedure for O C Devillier Jr 1 (API 42071033940000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	825	1650	CO2 Resistant	14.8-15.5	65	1.06	344
Plug # 2	Balanced Plug	0	825	Class G w/ additives	15-15.5	65	1.01	361
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto O C DEVILLIER JR 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in. casing and run in the hole.
    a. If primary cement records have been located and there is cement behind the surface casing: Clean down to 1,650 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If primary cement records have not been located: Clean down to 1,100 ft. Circulate the hole clean and pull out of the hole. Lay down the bit. Proceed with step 7.
7. Set a bridge plug at 1,050 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 9-5/8 in. casing from 1,050 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,650 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 9-5/8 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 9-5/8 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 1,050 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 1,650 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 1,650 ft. Circulate the well clean.
12. Plug #1: Set a balanced plug 825-1,650 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-825 ft with 15-15.5 ppg Class G cement.

14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

22. O C Devillier 4 (API 42071304510000): D&A 1976

The O C Devillier 4 is projected to be inside the border of the CO_2 plume between years 15 and 50 after the start of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Nodosaria and Vicksburg reaching a TD of 12,215 ft. The 13 3/8 in. surface casing set at 2,026 ft does cover the USDW, located at approximately 1,468 ft. The 9 5/8 in production casing was run to 9,616 ft and was later cut and pulled at 2,132 ft during abandonment. If primary cement records for the surface casing are unable to be located a CBL will be run on the surface casing to verify cement. Cement plugs were placed 9,400 – 9,733 ft (100 sx), 1,833 – 2,132 ft (270 sx), and 4-24 ft (15 sx) during abandonment, according to the TRRC records. The well was left filled with 16.8 ppg mud. The well will be scheduled for remedial action in Year 15.

Table C-AoR-67: General information for O C Devillier 4 (API 42071304510000).

API	42071304510000
Operator	Gulf Oil Corp
Lease Name	O C Devillier
Well Number	4
Status	Dry & Abandoned
Surface Latitude	29.83220725
Surface Longitude	-94.48595484
Total Depth	12215
Formation	Vicksburg
Spud Date	1976-05-13
Drilling End	1976-07-20
Abandonment Date	1976-07-20

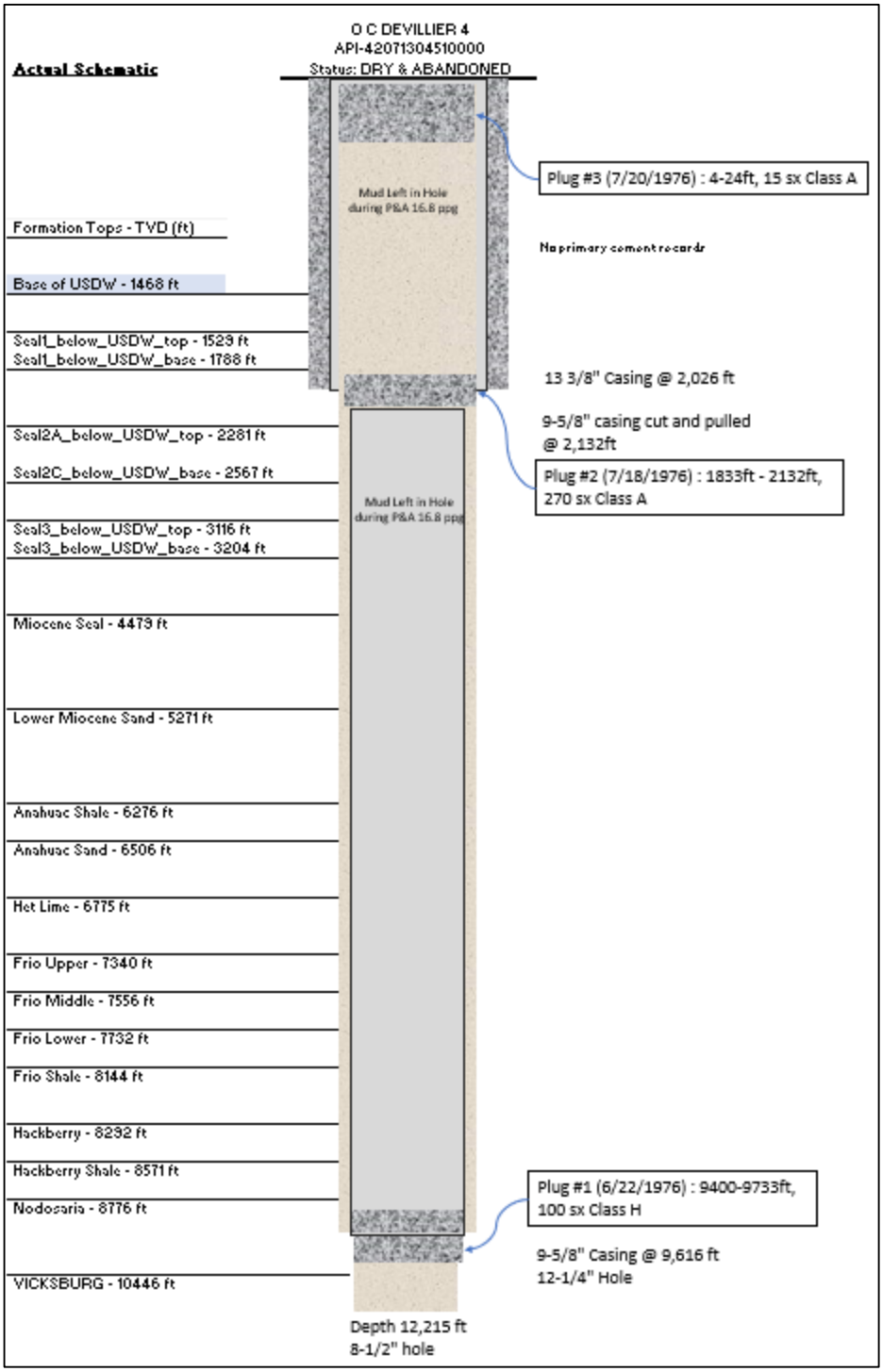


Figure C-AoR-63: Actual wellbore schematic of O C Devillier 4 (API 42071304510000).

Table C-AoR-68: Formation tops from O C Devillier 4 (API 42071304510000).

Formation Tops (MD ft)	
Shallower base of USDW follow ru	1,468
Seal1_below_USDW_top	1,529
Seal1_below_USDW_base	1,788
Seal2A_below_USDW_top	2,281
Seal2C_below_USDW_base	2,567
Seal3_below_USDW_top	3,116
Seal3_below_USDW_base	3,204
L_Miocene_Shale	4,479
L_Miocene_A	4,616
AMPB_SAND	4,711
L_Miocene_B	4,868
L_Miocene_C	5,107
TOP_LMIO_INJ_ZONE	5,271
LMIO_INJ_5	5,399
LMIO_INJ_4	5,500
LMIO_INJ_3	5,645
LMIO_INJ_6	5,850
LMIO_INJ_2	6,114
Anahuac	6,276
Anahuac_Sand_Top	6,506
Anahuac_Sand_Base	6,546
Anahuac_Het_Lime_Top	6,775
Anahuac_Het_Lime_Base	6,980
Frio_Top	7,340
Frio_Mid	7,556
Frio_Low	7,732
Frio_Shale	8,144
Hackberry	8,292
Hackberry_Shale	8,571
Nodosaria	8,776
VICKSBURG	10,446

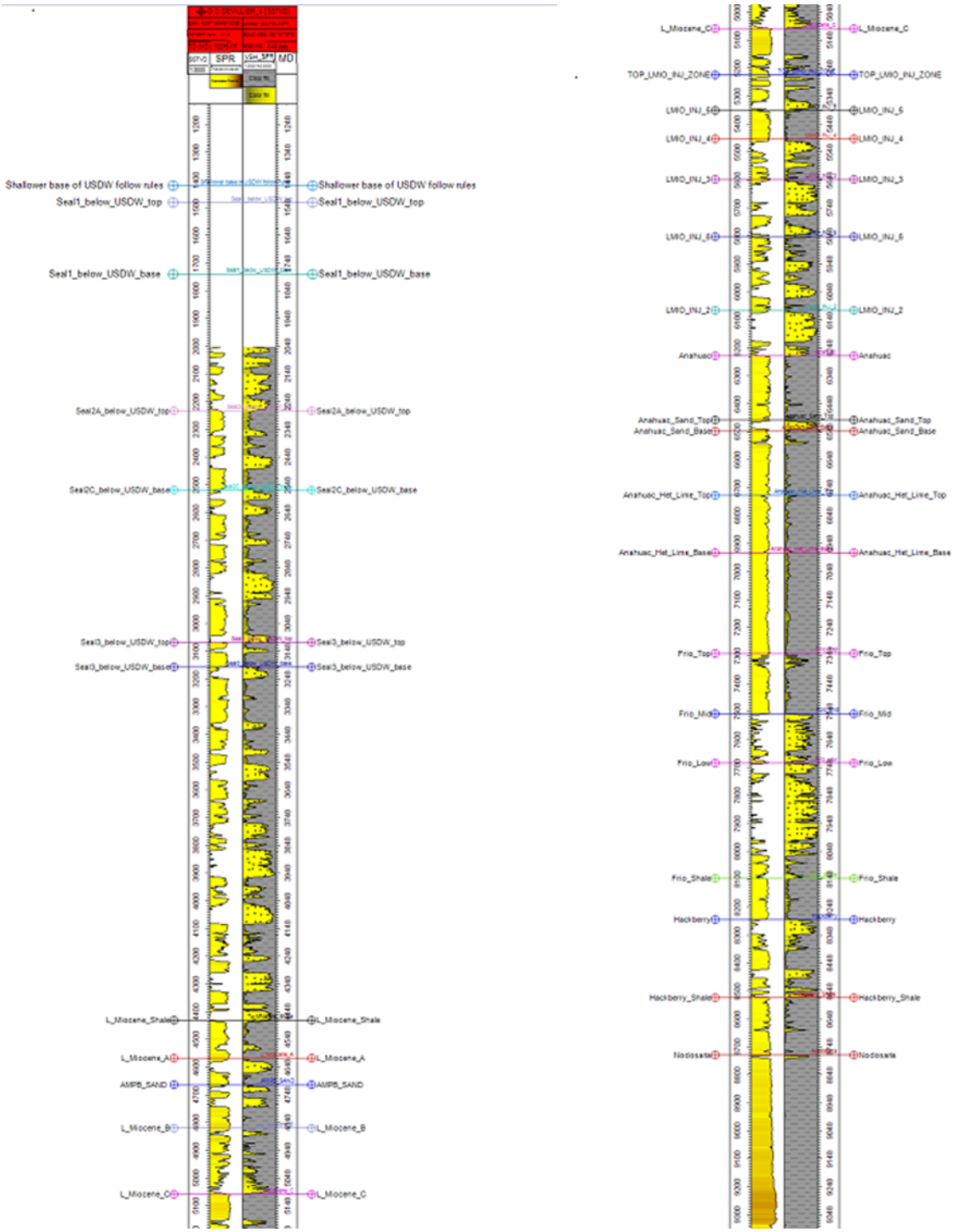


Figure C-AoR-64: Electric log and formation tops from O C Devillier 4 (API 42071304510000).

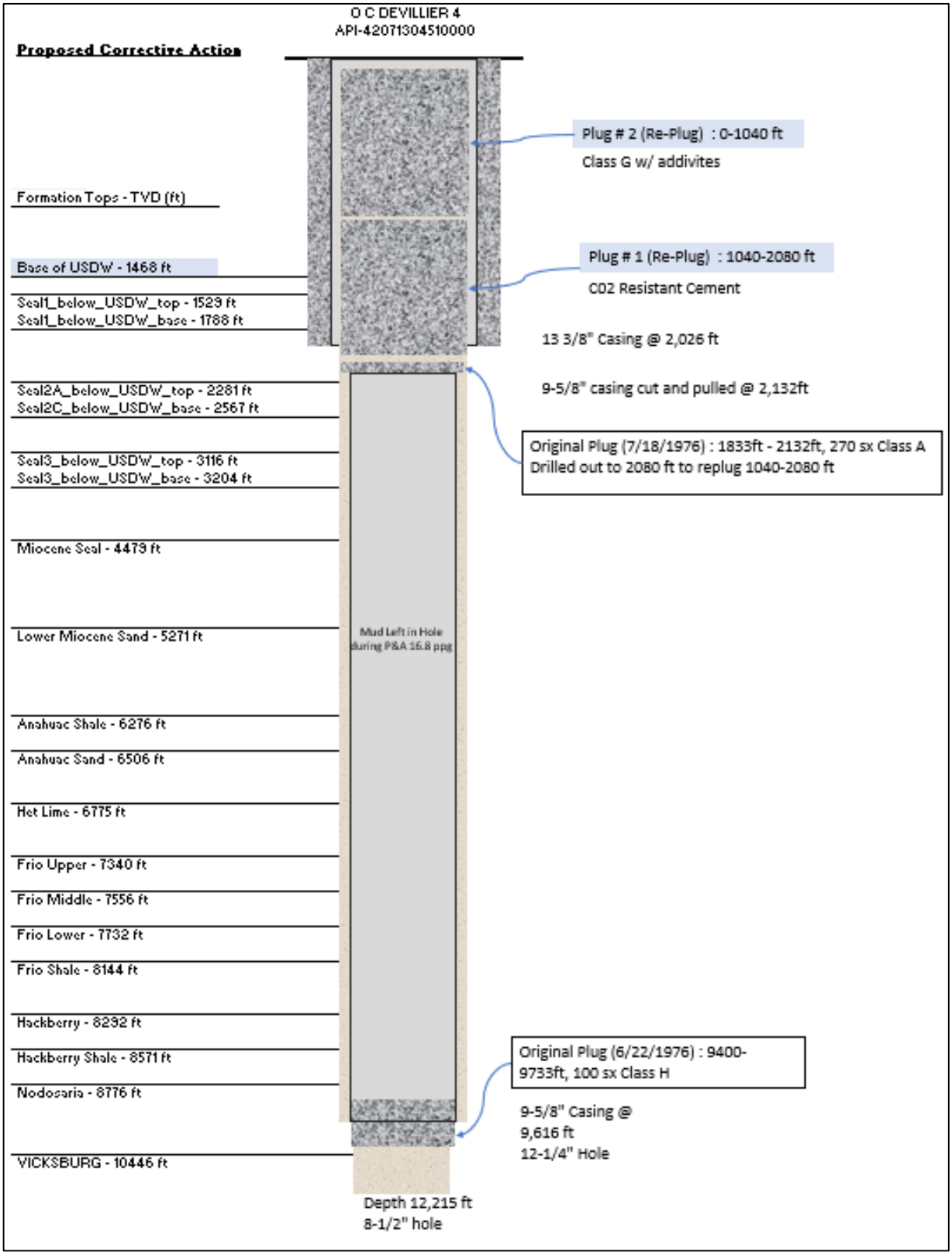


Figure C-AoR-65: Proposed remediation for O C Devillier 4 (API 42071304510000).

Table C-AoR-69: Plug information for proposed re-abandonment procedure for O C Devillier 4 (API 42071304510000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	1040	2080	CO2 Resistant	14.8-15.5	163	1.06	864
Plug # 2	Balanced Plug	0	1040	Class G w/ additives	15-15.5	163	1.01	907
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto O C Devillier 4 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 13-3/8 in. casing and run in the hole, cleaning down to 2,080 ft. Circulate the hole clean and pull out the of hole. Lay down the bit.
    a. If primary cement records have been located and there is cement behind the surface casing: Proceed to step 11.
    b. If primary cement records have not been located: Proceed with step 7
7. Set a bridge plug at 2,000 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 13-3/8 in. casing from 2,000 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 2,080 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 13-3/8 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 13-3/8 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 2,000 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 2,080 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 2,080 ft.
12. Plug #1: Set a balanced plug 1,040-2,080 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-1,040 ft with 15-15.5 ppg Class G cement.

14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

23. C H Lanz 1 (API 42071031650000): D&A 1939

The C H Lanz 1 is projected to be inside the CO_2 plume at year 10 of injection. The well status is D&A and was drilled through the Miocene, Anahuac, and Frio formations, reaching a TD of 7,629 ft. The 10 ¾ in. surface casing was set at 1,030 ft and does not cover the USDW, which is located at approximately 1,422 ft. There are no primary cement records; a CBL will be run to verify cement behind the surface casing. The is no record of the abandonment procedure, no cement plugs were reported. The well will be scheduled for remedial action in Year 0.

Table C-AoR-70: General information for C H Lanz 1 (API 42071031650000).

API	42071031650000
Operator	Franklin Louis & Son
Lease Name	C H Lanz
Well Number	1
Status	Dry & Abandoned
Surface Latitude	29.84274313
Surface Longitude	-94.50176562
Total Depth	7629
Formation	Unknown
Spud Date	1939-06-25
Drilling End	1939-07-08

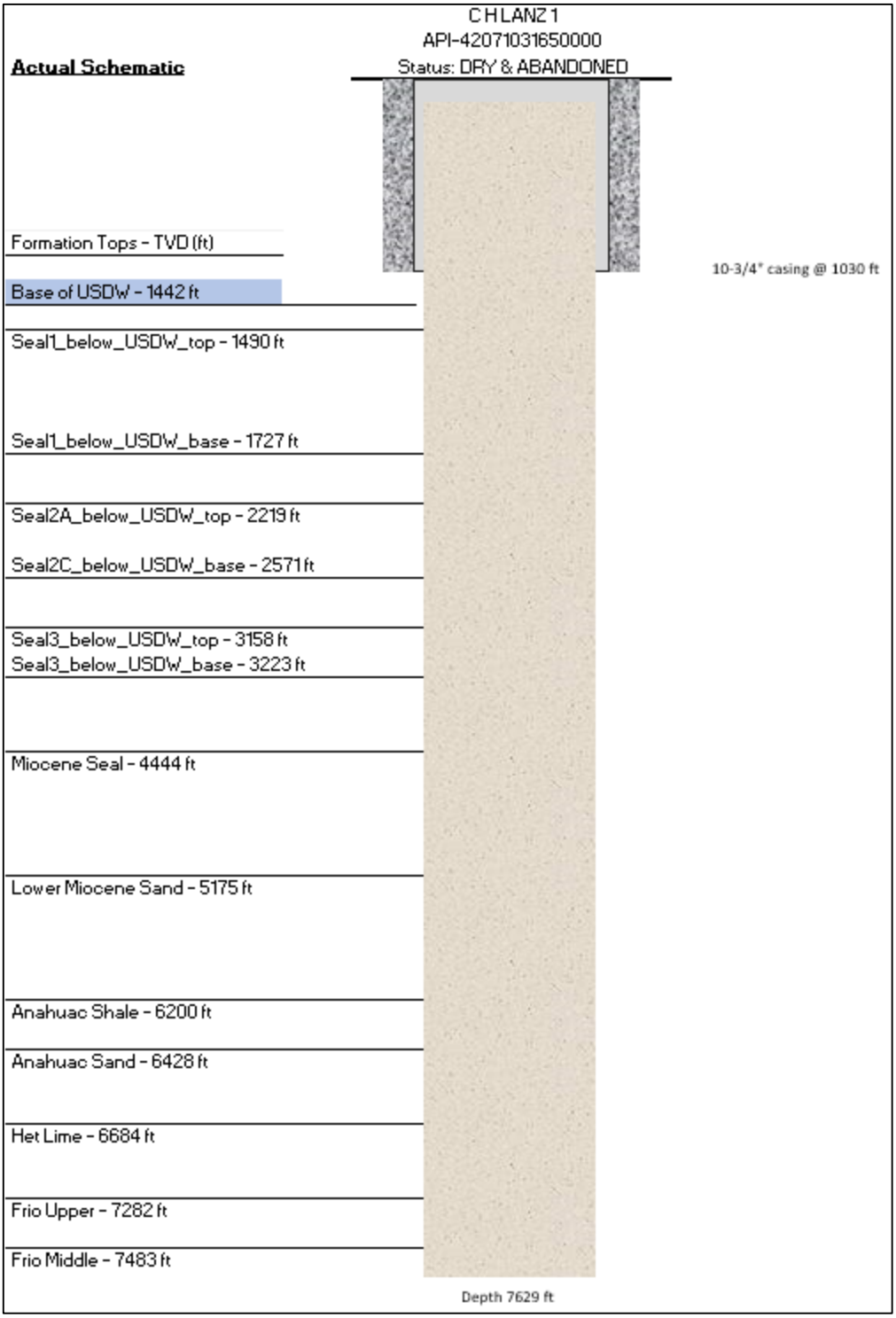


Figure C-AoR-66: Actual wellbore schematic of C H Lanz 1 (API 42071031650000).

Table C-AoR-71: Formation tops from C H Lanz 1 (API 42071031650000).

Formation Tops (MD ft)	
Shallower base of USDW follow ru	1,442
Seal1_below_USDW_top	1,490
Seal1_below_USDW_base	1,727
Seal2A_below_USDW_top	2,219
Seal2C_below_USDW_base	2,571
Seal3_below_USDW_top	3,158
Seal3_below_USDW_base	3,223
L_Miocene_Shale	4,444
L_Miocene_A	4,539
AMPB_SAND	4,686
L_Miocene_B	4,766
L_Miocene_C	5,039
TOP_LMIO_INJ_ZONE	5,175
LMIO_INJ_5	5,338
LMIO_INJ_4	5,450
LMIO_INJ_3	5,569
LMIO_INJ_6	5,777
LMIO_INJ_2	6,043
Anahuac	6,200
Anahuac_Sand_Top	6,428
Anahuac_Sand_Base	6,465
Anahuac_Het_Lime_Top	6,684
Anahuac_Het_Lime_Base	6,882
Frio_Top	7,282
Frio_Mid	7,483

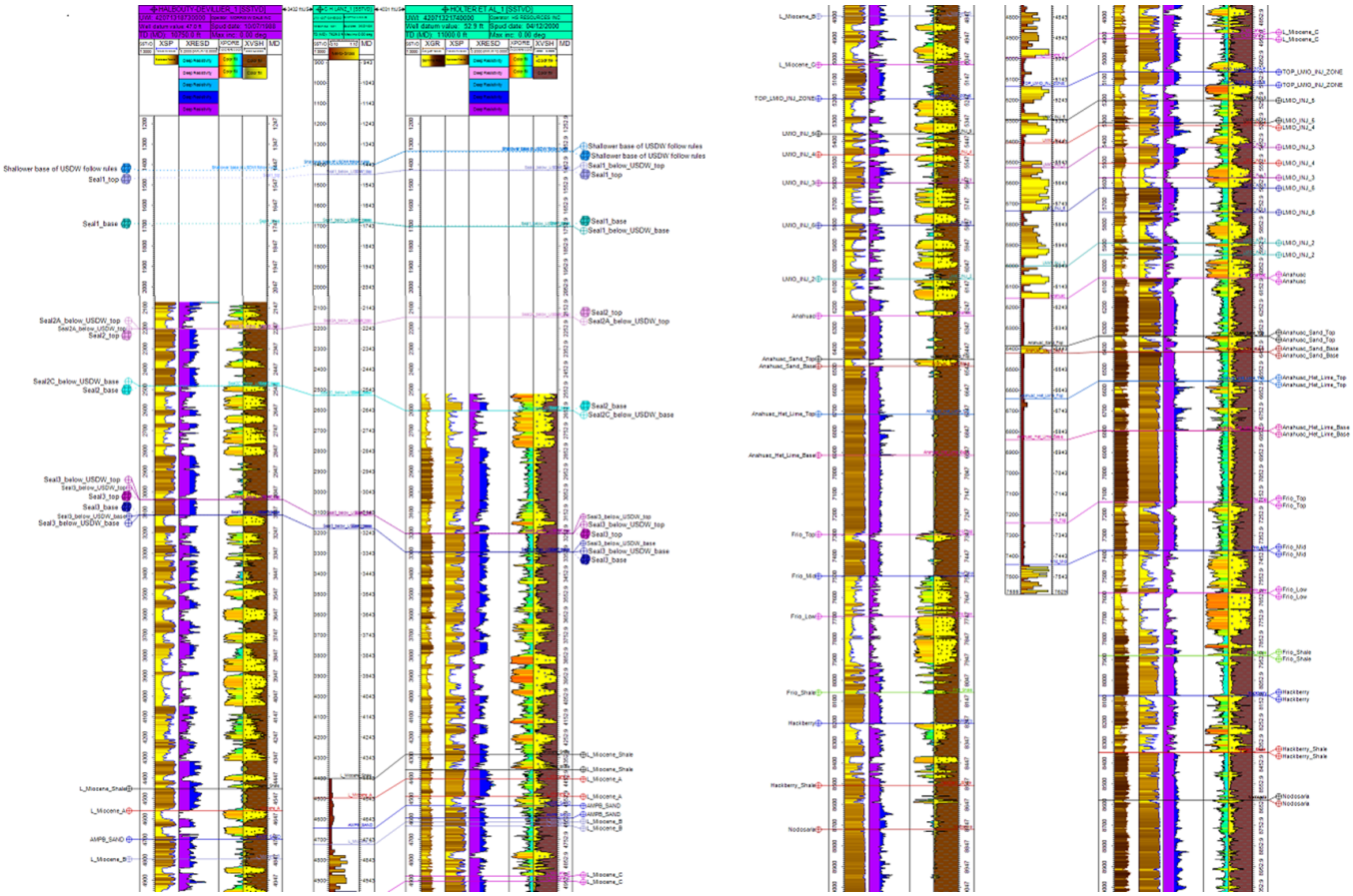


Figure C-AoR-67: Pseudo-log and formation tops from C H Lanz 1 (API 42071031650000).

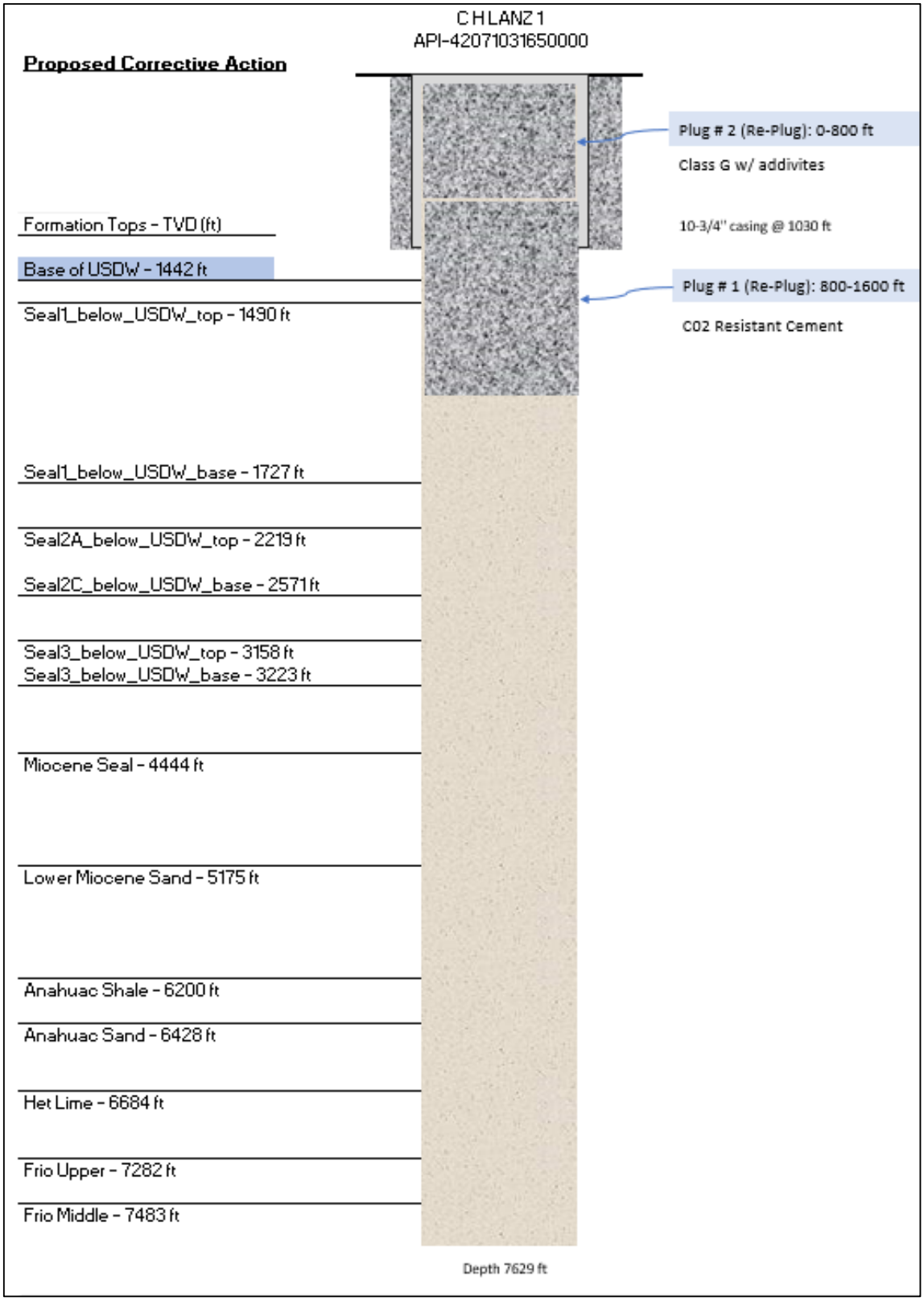


Figure C-AoR-68: Proposed remediation for C H Lanz 1 (API 42071031650000).

Table C-AoR-72: Plug information for proposed re-abandonment procedure for C H Lanz 1 (API 42071031650000).

ug	Method	Top (ft)	Bottom (ft)	Cement Type	Density	Volume	Yield	Sx
Plug # 1	Balanced Plug	800	1600	CO2 Resistant	14.8-15.5	81	1.06	427
Plug # 2	Balanced Plug	0	800	Class G w/ additives	15-15.5	81	1.01	448
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto C H Lanz 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string with 9-7/8 in. bit and run in the hole, cleaning down to 1,050 ft. Circulate the hole clean and pull out the of hole. Lay down the bit.
7. Set a bridge plug at 1,000 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 10-3/4 in. casing from 1,000 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 10-3/4 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 1,000 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 1,600 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 1,600 ft.
12. Plug #1: Set a balanced plug 800-1,600 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-800 ft with 15-15.5 ppg Class G cement.
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

24. Devillier O C 7 (API 42071309670000): D&A 1979

The Devillier O C 7 is projected to be inside the border of the CO_2 plume between years 15 and 50 after the start of CO_2 injection. The well status is D&A and was drilled through the Miocene, Anahuac, Frio, Nodosaria and Vicksburg reaching a TD of 11,270 ft. The 10 ¾ in. surface casing set at 2,045 ft does cover the USDW, located at approximately 1,474 ft. The 7 5/8 in production casing was run to 9,696 ft and was later cut and pulled at 2,493 ft during abandonment. If primary cement records for the surface casing are unable to be located a CBL will be run on the surface casing to verify cement. Cement plugs were placed 9,475-9,798 ft (75 sx), 2,350-2,550 ft (110 sx), 391-500 ft (50 sx) and 4-20 ft (10 sx) during abandonment, according to the TRRC records. The well was left filled with 16.8 ppg mud. The well will be scheduled for remedial action in Year 15.

Table C-AoR-73: General information for Devillier O C 7 (API 42071309670000).

API	42071309670000
Operator	Gulf Oil Corp
Lease Name	Devillier O C
Well Number	7
Status	Dry & Abandoned
Surface Latitude	29.8230033
Surface Longitude	-94.4884179
Total Depth	11270
Formation	Vicksburg
Spud Date	1979-10-12
Drilling End	1979-11-23
Abandonment Date	11/28/1979

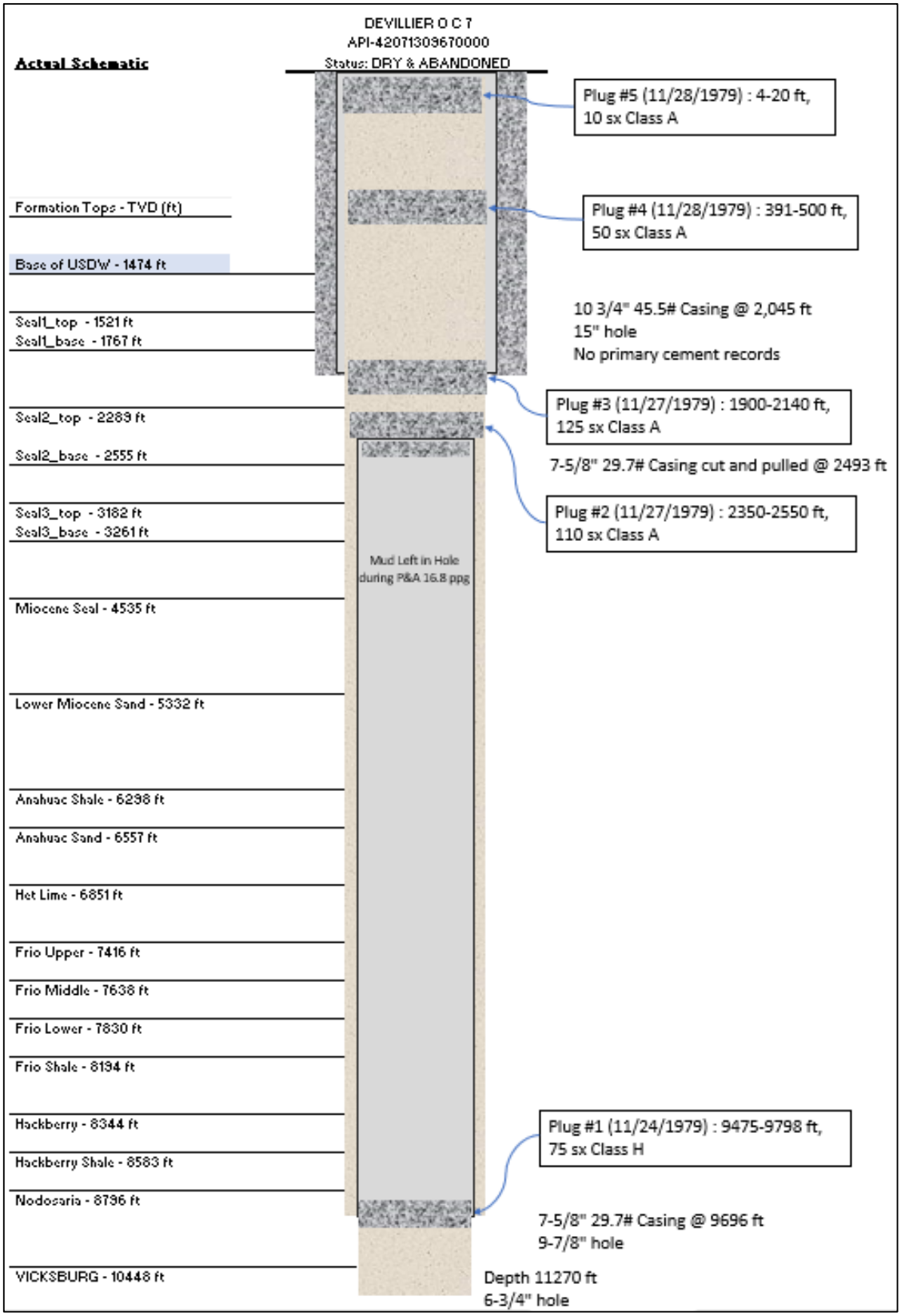


Figure C-AoR-69: Actual wellbore schematic of Devillier O C 7 (API 42071309670000).

Table C-AoR-74: Formation tops from Devillier O C 7 (API 42071309670000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,474
Seal1_top	1,521
Seal1_base	1,767
Seal2_top	2,289
Seal2_base	2,555
Seal3_top	3,182
Seal3_base	3,261
L_Miocene_Shale	4,535
L_Miocene_A	4,647
AMPB_SAND	4,759
L_Miocene_B	4,904
L_Miocene_C	5,156
TOP_LMIO_INJ_ZONE	5,332
LMIO_INJ_5	5,476
LMIO_INJ_4	5,538
LMIO_INJ_3	5,706
LMIO_INJ_6	5,850
LMIO_INJ_2	6,163
Anahuac	6,298
Anahuac_Sand_Top	6,557
Anahuac_Sand_Base	6,608
Anahuac_Het_Lime_Top	6,851
Anahuac_Het_Lime_Base	7,036
Frio_Top	7,416
Frio_Mid	7,638
Frio_Low	7,830
Frio_Shale	8,194
Hackberry	8,344
Hackberry_Shale	8,583
Nodosaria	8,796
VICKSBURG	10,448

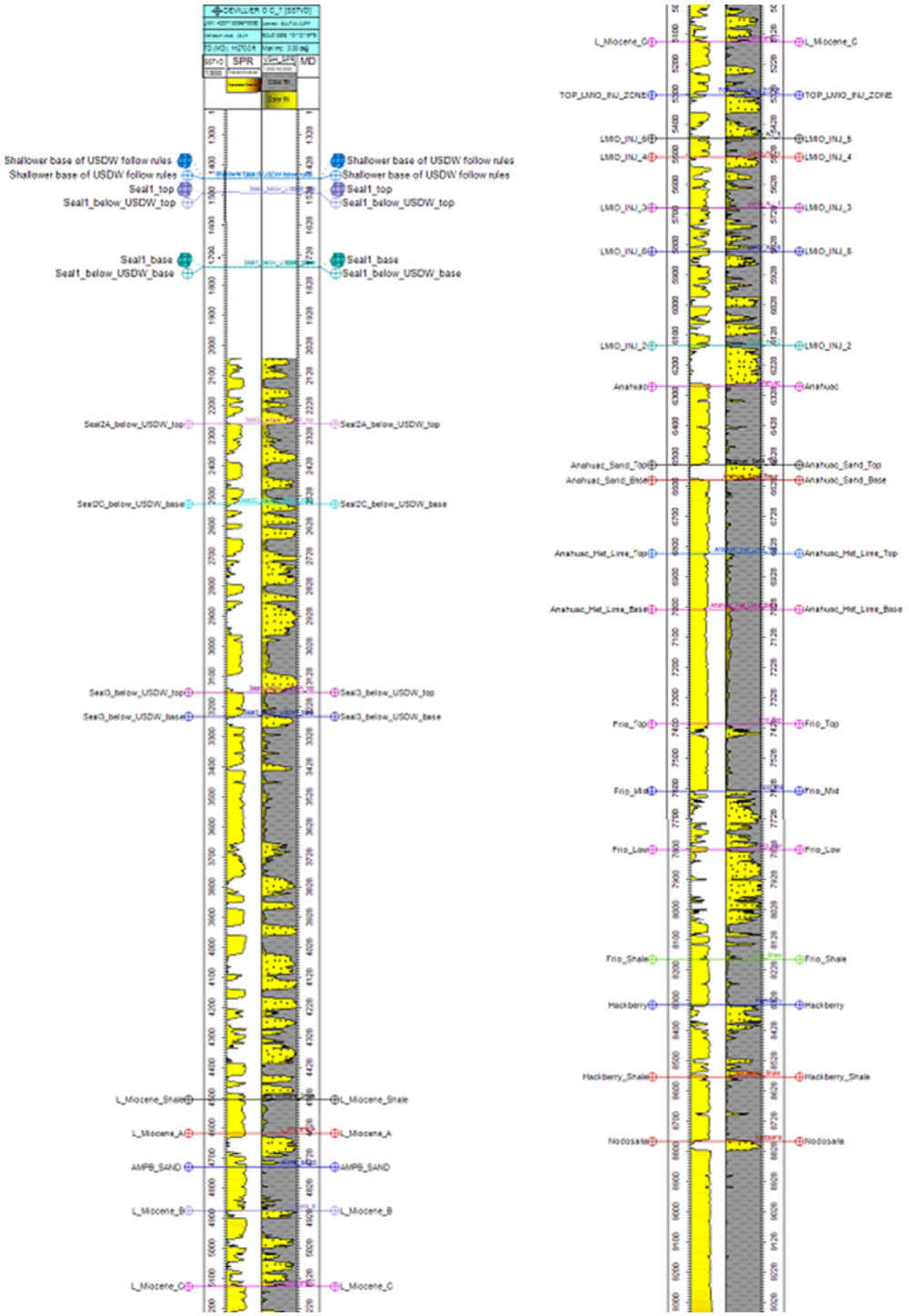


Figure C-AoR-70: Electric log and formation tops from Devillier O C 7 (API 42071309670000).

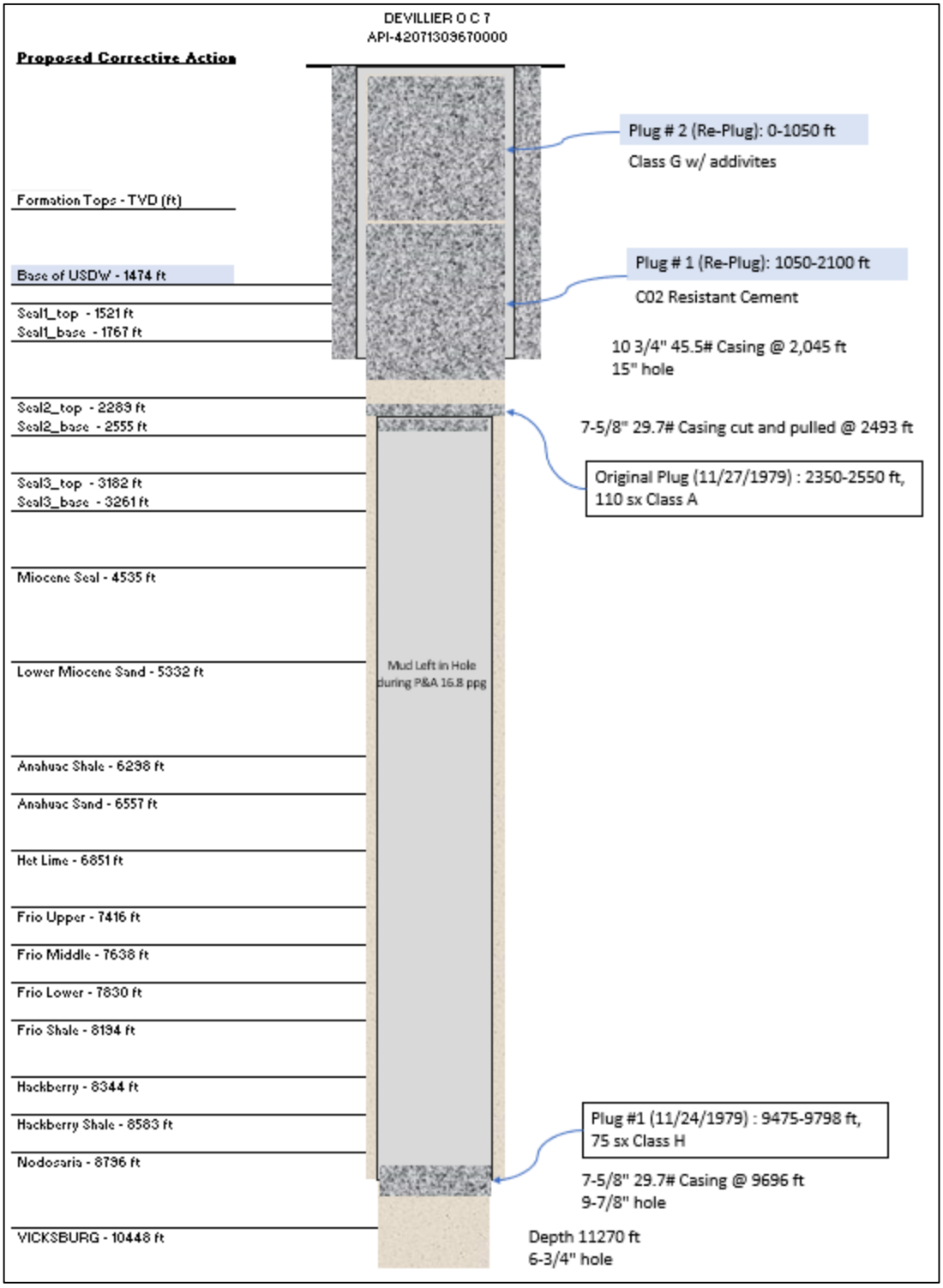


Figure C-AoR-71: Proposed remediation for Devillier O C 7 (API 42071309670000).

Table C-AoR-75: Plug information for proposed re-abandonment procedure Devillier O C 7 (API 42071309670000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	1050	2100	CO2 Resistant	14.8-15.5	101	1.06	534
Plug # 2	Balanced Plug	0	1050	Class G w/ additives	15-15.5	101	1.01	561
Plug # 3 TBD	Squeeze	TBD (CBL)	TBD (CBL)	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

Plugging Procedure

1. Move in rig onto Devillier O C 7 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 10-3/4 in. 45.5 ppf casing and run in the hole, cleaning down to 2,100 ft. Circulate the hole clean and pull out the of hole. Lay down the bit.
    a. If primary cement records have been located and there is cement behind the surface casing: Proceed to step 11.
    b. If primary cement records have not been located: Proceed with step 7
7. Set a bridge plug at 2,000 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 10-3/4 in. casing from 2,000 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 2,100 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 10-3/4 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 10-3/4 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 2,000 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 2,100 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 2,100 ft.
12. Plug #1: Set a balanced plug 1,050-2,100 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-1,050 ft with 15-15.5 ppg Class G cement.
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

25. Simon S E 1 (API 42071313890000): D&A 1983

The SIMON S E 1 is projected to be inside the CO_2 plume between years 50 and 100 after the start of injection. The well status is junked and abandoned having stuck drill pipe from 2901-9119 ft. The well was drilled through the Miocene, Anahuac, Frio, and Nodosaria formations reaching a TD of 9,119 ft. The 9-5/8 in. surface casing set at 2,340 ft covers the base of the USDW, located at approximately 1,231 ft. A CBL will be run on the surface casing to verify the top of cement if primary cement records are unable to be located. Cement plugs were placed 8,942-9,119 ft (200 sx), 2,671-2,900 ft (75 sx), 2,227-2,390 ft (60 sx), 596-719 ft (45 sx) and 3-15 ft (20 sx) during abandonment, according to the TRRC records. The well was left filled with 9.5 ppg mud in open hole. The well will be scheduled for remedial action in Year 15.

Table C-AoR-76: General information for Simon S E 1 (42071313890000).

API	42071313890000
Operator	Anadarko Production Co
Lease Name	Simon S E
Well Number	1
Status	Junked & Abandoned
Surface Latitude	29.8544722
Surface Longitude	-94.4639662
Total Depth	9119
Formation	Frio
Spud Date	1982-12-30
Drilling End	1/19/1983
Abandonment Date	1/19/1983

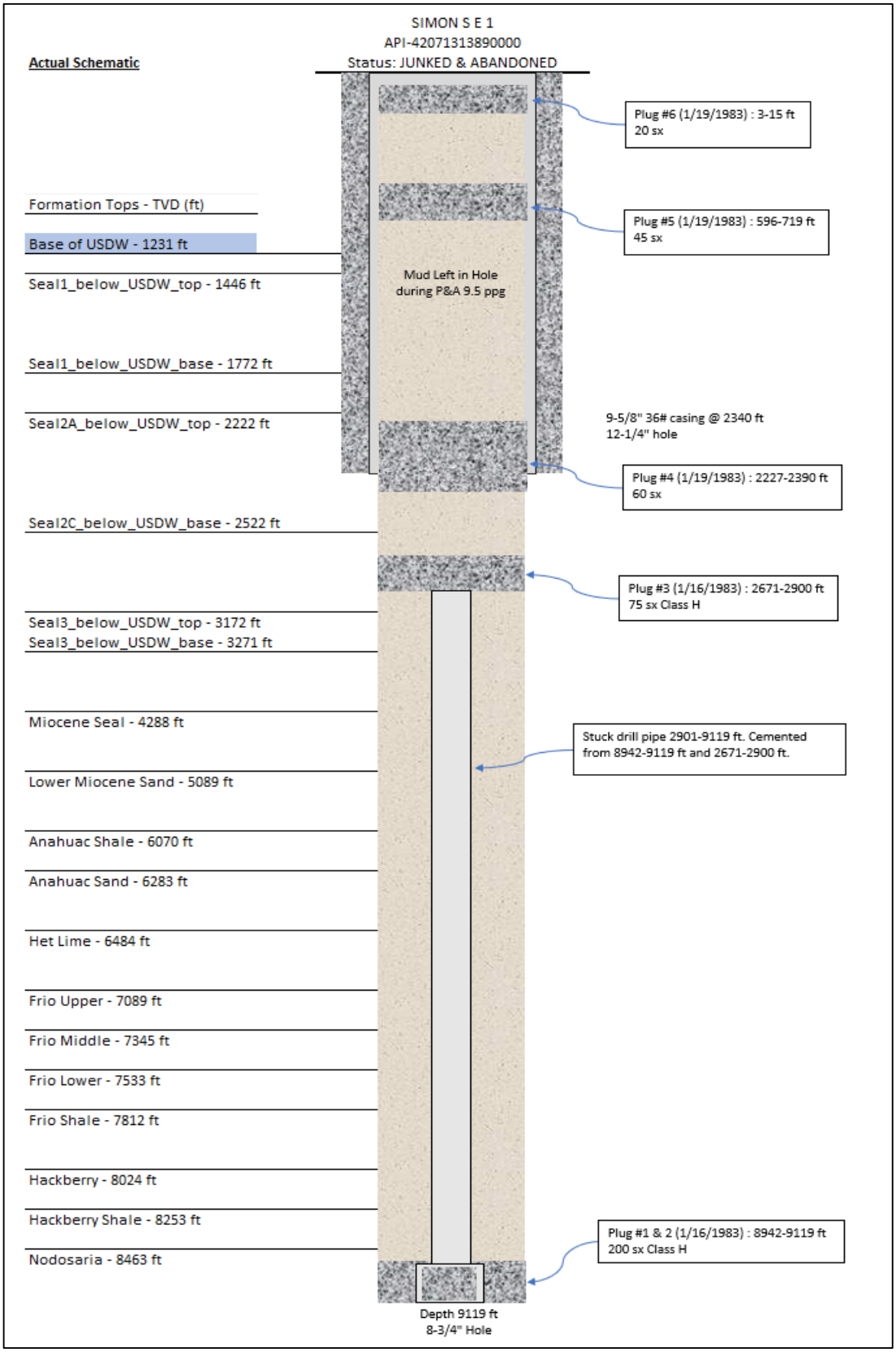


Figure C-AoR-72: Actual wellbore schematic of Simon S E 1 (42071313890000).

Table C-AoR-77: Formation tops from Simon S E 1 (42071313890000).

Formation Tops (MD ft)	
Shallower base of USDW follow rules	1,231
Seal1_below_USDW_top	1,446
Seal1_below_USDW_base	1,772
Seal2A_below_USDW_top	2,222
Seal2C_below_USDW_base	2,522
Seal3_below_USDW_top	3,172
Seal3_below_USDW_base	3,271
L_Miocene_Shale	4,288
L_Miocene_A	4,496
AMPB_SAND	4,600
L_Miocene_B	4,721
L_Miocene_C	4,951
TOP_LMIO_INJ_ZONE	5,089
LMIO_INJ_5	5,249
LMIO_INJ_4	5,402
LMIO_INJ_3	5,468
LMIO_INJ_6	5,654
LMIO_INJ_2	5,918
Anahuac	6,070
Anahuac_Sand_Top	6,283
Anahuac_Sand_Base	6,348
Anahuac_Het_Lime_Top	6,484
Anahuac_Het_Lime_Base	6,662
Frio_Top	7,089
Frio_Mid	7,345
Frio_Low	7,533
Frio_Shale	7,812
Hackberry	8,024
Hackberry_Shale	8,253
Nodosaria	8,463

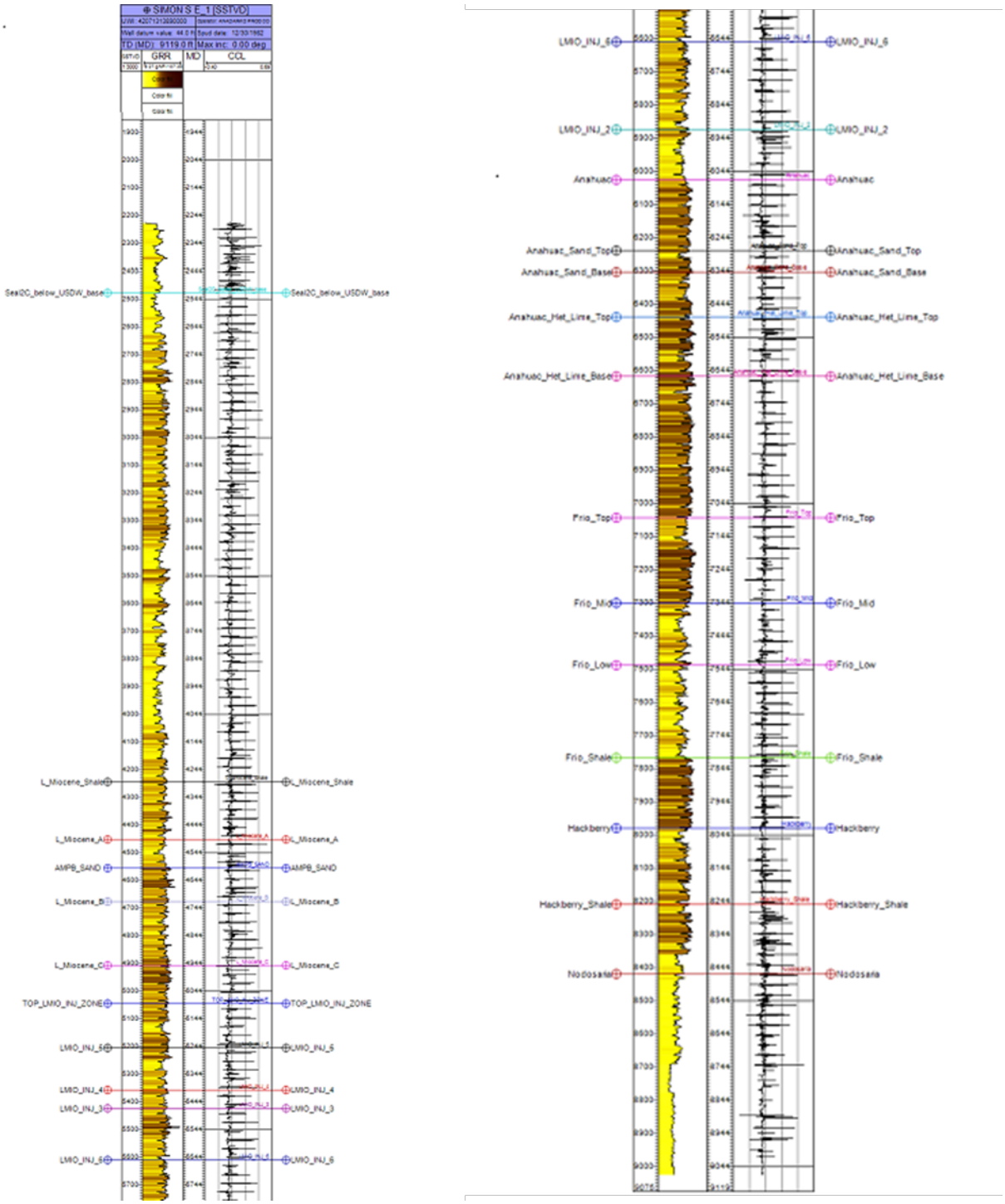


Figure C-AoR-73: Electric log and formation tops from Simon S E 1 (42071313890000).

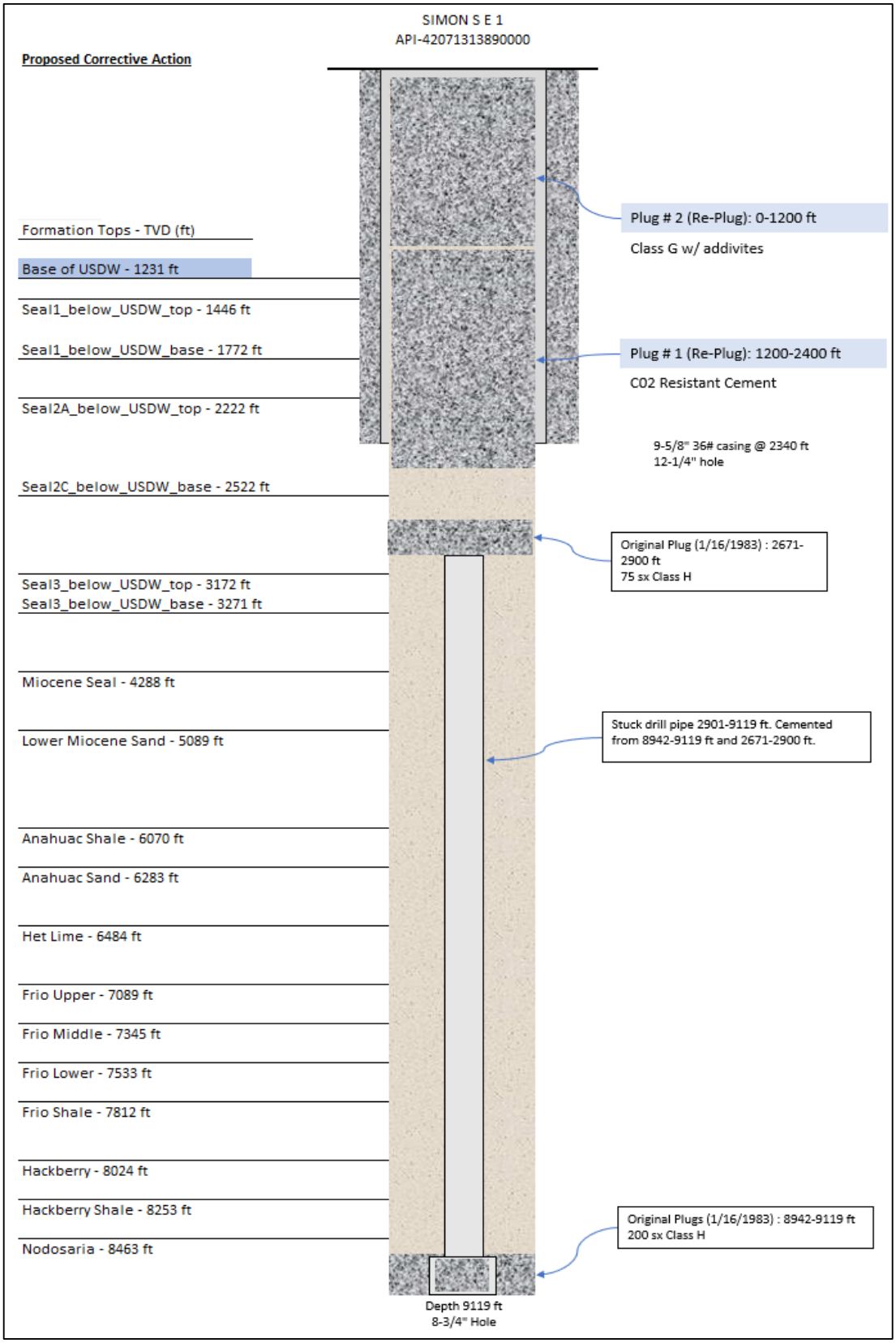


Figure C-AoR-74: Proposed remediation for SIMON S E 1 (42071313890000).

Table C-AoR-78: Plug information for proposed re-abandonment procedure for Simon S E 1 (42071313890000).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft2/sx)	Sx
Plug # 1	Balanced Plug	1200	2400	CO2 Resistant	14.8-15.5	93	1.06	491
Plug # 2	Balanced Plug	0	1200	Class G w/ additives	15-15.5	93	1.01	515

Plugging Procedure

1. Move in rig onto SIMON S E 1 site and rig up.
2. Conduct and document safety meeting.
3. Check the shut-in casing pressure.
4. Test the pump and lines to 5,000 psi. Kill the well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up the work string and bit sized for 9-5/8 in. 36 ppf casing and run in the hole, cleaning down to 2,400 ft. Circulate the hole clean and pull out the of hole. Lay down the bit.
    a. If primary cement records have been located and there is cement behind the surface casing: Proceed to step 11.
    b. If primary cement records have not been located: Proceed with step 7
7. Set a bridge plug at 2,300 ft. Test the plug and casing to 500 psi for 15 minutes.
8. Run cement bond log (CBL) on 9-5/8 in. casing from 2,300 ft to surface with 500 psi on the casing.
    a. If the CBL shows cement to surface drill out the CIBP and cleanout well to 2,400 ft. Circulate the well clean and pull out of the hole. Lay down the bit. Proceed to step 11.
    b. If the CBL does not show cement to surface, then perforate the 9-5/8 in. casing 25 ft above the top of cement, set a cast iron cement retainer (CICR) 25 ft above the perforations, and squeeze/circulate 14.8-15.5 ppg CO_2-resistant cement slurry up the 9-5/8 in. casing annulus to surface. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and run CBL to verify new top of cement. Proceed to step 9.
9. Run in the hole with bit. Drill out the CICR and cement down to the bridge plug at 2,300 ft. Test the casing to 500 psi for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check surface lines and connections, and repeat the test. Then, release the pressure.
10. Drill out the bridge plug and clean down to 2,400 ft. Circulate the well clean and pull out of the hole. Lay down bit.
11. Run in the hole with the work string to 2,400 ft. Circulate the well clean.
12. Plug #1: Set a balanced plug 1,200-2,400 ft with 14.8-15.5 ppg CO_2-resistant slurry. Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
13. Plug #2: Set a balanced plug 0-1,200 ft with 15-15.5 ppg Class G cement.
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar such that a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Appendix D: Tables of Wells

The following tables in this appendix summarize the wells and their associated well log data located within the geomodel AOI and used for analysis of structure, thickness, and/or reservoir characteristics used in the property model.

Table D-AoR-1: All wells with image logs within the geomodel.

UWI	Common Well Name	Top (ft)	Base (ft)	Log Scale	Log Section Name	Latitude	Longitude
42071013590000	BROWN HEIRS KING_1	699.75	6878.71	2 Inch, 5 Inch	Electrical log	29.87113508	-94.56736658
42071013620000	HANKAMER TRUSTEE_1	507.30	7671.20	1 Inch	Induction electric log	29.88636669	-94.55973426
42071013630000	BROUSSARD TRUST_1	1415.00	9256.00	5 Inch	Shallow resistivity	29.88702312	-94.50236130
42071013650000	WEST WESLEY ETAL_1	2046.80	8971.60	1 Inch	Induction electric log/Spontaneous potential	29.86277171	-94.54277556
42071013670000	JENKINS W E_1	1147.10	8628.60	2 Inch, 5 Inch	Electrical log/Spontaneous potential/Formation tops	29.86133108	-94.57237764
42071013700000	JENKINS W E_1	1242.00	9076.00	1 Inch	Induction electric log	29.85048174	-94.54234856
42071013710000	JENKINS W E_1	1978.87	11021.66	1 Inch	Induction electric log/Spontaneous potential	29.84301261	-94.53975879
42071019550000	DROUGHT H P_1	1617.90	9529.50	1 Inch	Electrical log/Spontaneous potential	29.80399858	-94.45907552
42071019580000	STERRETT EAT FRED R_1	1249.90	9573.20	1 Inch	Induction electric log/Spontaneous potential	29.81398544	-94.47370954
42071019580000	STERRETT EAT FRED R_1	4491.70	9547.30	5 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current/Mud log	29.81398544	-94.47370954
42071019590000	WM DOORNBOS ETAL_1	1177.70	9047.30	1 Inch	Electrical log/Spontaneous potential	29.81510900	-94.43990623
42071019600000	TRINITY RICE_1	1261.50	8030.20	1 Inch, 2.5 Inch	Electrical log/Spontaneous potential	29.81795809	-94.45089736
42071019610000	OGDEN L G ETAL_1	2259.50	9629.00	1 Inch	Electrical log/Spontaneous potential	29.82821903	-94.47997278
42071019620000	DEBELLVUE MRS MARIA_1	1175.64	9360.06	1 Inch	Induction electric log/Spontaneous potential	29.84327051	-94.47198606
42071019620000	DEBELLVUE MRS MARIA_1	4465.60	9360.40	5 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current/Mud log show	29.84327051	-94.47198606
42071019630000	DE VELLIER_1	916.90	9033.70	1 Inch	Electrical log/Spontaneous potential	29.84538041	-94.42066585
42071019640000	MOORE ESTATE ELIZ H_1	1238.50	9013.30	1 Inch	Electrical log/Spontaneous potential/Formation tops	29.85801713	-94.42074314
42071019650000	I DAVENPORT_1	991.70	8595.20	1 Inch	Electrical log/Spontaneous potential	29.86021835	-94.43109097
42071019660000	JOHNSON ANNIE H_1	1269.00	7668.50	1 Inch	Electrical log/Spontaneous potential/Formation tops	29.85590937	-94.44838906
42071019670000	T SIMON_1	1310.40	9185.50	1 Inch	Induction electric log/Spontaneous potential	29.85795639	-94.45589662
42071019920000	HOWTZ SYBIL ETAL_1	981.00	9198.60	1 Inch	Electrical log/Spontaneous potential	29.85984737	-94.40353223
42071019920000	HOWTZ SYBIL ETAL_1	984.46	9206.32	2 Inch	Electrical log	29.85984737	-94.40353223
42071019930000	SHAW UNIT_1	779.79	7227.36	1 Inch	Electrical log	29.86861236	-94.38721311
42071019960000	H J SOLEM UNIT 1_1	1008.50	8951.10	1 Inch	Electrical log/Spontaneous potential	29.87194324	-94.38755376
42071020000000	MOORE ESTATE_2	1713.20	9163.80	1 Inch	Electrical log/Spontaneous potential/Formation tops	29.87264987	-94.44769861
42071020010000	STANOLIND OIL & GAS_1	70.30	10512.90	1 Inch	Induction electric log/Spontaneous potential	29.87282259	-94.46371055
42071303560000	E COOPER ETAL_1	2013.25	11016.89	1 Inch	Caliper/ISF Induction log/Sonic log/Spontaneous potential	29.81367539	-94.49590039
42071303560000	E COOPER ETAL_1	2035.29	11088.60	1 Inch	ISF Induction log	29.81367539	-94.49590039
42071303560000	E COOPER ETAL_1	2041.80	9746.08	5 Inch	Caliper/ISF Induction log/Sonic log/Spontaneous potential	29.81367539	-94.49590039
42071303560000	E COOPER ETAL_1	2100.00	11000.00	1 Inch	Electrical log	29.81367539	-94.49590039
42071303560000	E COOPER ETAL_1	9701.80	11024.00	5 Inch	Caliper/ISF Induction log/Sonic log/Spontaneous potential	29.81367539	-94.49590039
42071303660000	O C DEVILLIER ETAL_1	1511.40	10728.90	1 Inch	ISF Induction log/Spontaneous potential	29.80416493	-94.49463244
42071303700000	O C DEVILLIER_3	2040.60	10933.80	1 Inch	Induction electric log/Spontaneous potential	29.81872100	-94.49546900
42071303720000	L G JENKINS_1	5463.64	11134.82	1 Inch	Induction electric log	29.83359596	-94.53655397
42071303720000	L G JENKINS_1	9437.50	11137.80	1 Inch, 5 Inch	Induction electric log	29.83359596	-94.53655397
42071303720000	L G JENKINS_1	9449.20	11119.90	5 Inch	Medium resistivity/Induction electric log/Spontaneous potential	29.83359596	-94.53655397
42071303930000	JANET MACCARTHY_1	2971.67	11048.52	1 Inch	Induction electric log	29.82808558	-94.53844166
42071303930000	JANET MACCARTHY_1	6952.50	11037.60	2 Inch	Induction electric log/Spontaneous potential	29.82808558	-94.53844166
42071303940000	EARL COOPER_2	1984.61	11270.11	1 Inch	ISF Induction log	29.81393580	-94.50750679
42071303940000	EARL COOPER_2	2000.00	11200.00	1 Inch	Electrical log	29.81393580	-94.50750679
42071304390000	EARL COOPER_1-A	1469.70	9635.60	1 Inch	ISF Induction log/Spontaneous potential	29.80393449	-94.50555299
42071304390000	EARL COOPER_1-A	1500.74	10970.88	2 Inch, 5 Inch	ISF Induction log/Sonic logging tool	29.80393449	-94.50555299
42071304390000	EARL COOPER_1-A	9671.90	10967.90	1 Inch	ISF Induction log/Spontaneous potential	29.80393449	-94.50555299
42071304390000	EARL COOPER_1-A	9684.35	10958.96	5 Inch	ISF Induction log/Sonic logging tool	29.80393449	-94.50555299
42071304510000	O C DEVILLIER_4	2002.70	12249.20	1 Inch	Caliper/Induction electric log/Spontaneous potential	29.83220726	-94.48595485
42071304690000	BEAUMNT RC MLL_1	969.00	9036.70	1 Inch	ISF Induction log/Spontaneous potential	29.87663474	-94.50094384

Table D-AoR-1: All wells with image logs within the geomodel (continued).

UWI	Common Well Name	Top (ft)	Base (ft)	Log Scale	Log Section Name	Latitude	Longitude
42071304690000	BEAUMNT RC MLL_1	7924.90	9018.90	1 Inch, 5 Inch	Four Arm High Res Continuous Dipmeter/Laterolog	29.87663474	-94.50094384
42071304850000	A S HANKAMER_1	10794.35	10906.35	5 Inch	ISF Induction lod/Sonic logging tool	29.81039702	-94.51052018
42071305630000	O C DEVILLIER ETAL_5	2040.95	11043.40	1 Inch	Dual inductin guard	29.82190719	-94.50138600
42071305630000	O C DEVILLIER ETAL_5	2100.00	11000.00	1 Inch	Electrical log	29.82190719	-94.50138600
42071305640000	M E HUNTER_1	2014.25	12679.19	1 Inch	Caliper/ISF Induction lod/Spontaneous potential/Formation tops	29.81471260	-94.47817701
42071308370000	O C DEVILLIER_6	2064.27	10986.20	1 Inch	ISF Induction lod	29.82521440	-94.49492911
42071308370000	O C DEVILLIER_6	9698.00	11028.42	1 Inch	Compensated Neutron log/Temperature	29.82521440	-94.49492911
42071308370000	O C DEVILLIER_6	9700.10	11020.58	0.5 Inch, 2.5 Inch	Dual induction tool/Spherically focused log	29.82521440	-94.49492911
42071308370000	O C DEVILLIER_6	9701.60	11021.86	5 Inch	Compensated Neutron log/Temperature	29.82521440	-94.49492911
42071309670000	DEVILLIER O C_7	2370.30	11324.90	1 Inch	Caliper/Gamma ray/Induction log/Spontaneous potential	29.82300331	-94.48841791
42071309670000	DEVILLIER O C_7	9694.53	10791.78	1 Inch	Induction electric log	29.82300331	-94.48841791
42071310360000	GARTH_1	1499.80	11033.00	1 Inch	Dual induction tool/Spontaneous potential/Formation tops	29.80178029	-94.46669670
42071312670000	DOORNBOS WILLIM ETL_1	4007.84	18976.80	5 Inch	Dual induction tool/Gamma ray/Spherically focused log/Sonic logging tool	29.80872799	-94.45277918
42071312670000	DOORNBOS WILLIM ETL_1	4011.80	18982.10	1 Inch	Dual induction tool/Gamma ray/Spontaneous potential	29.80872799	-94.45277918
42071312760000	DOMEYER ETAL_1	1559.30	9231.10	1 Inch	Gamma ray/Induction log/Spontaneous potential	29.85947040	-94.41560119
42071313020000	DEVILLIER O C JR_1	2070.19	9716.74	1 Inch	Deep laterolog	29.83290779	-94.49520200
42071313020000	DEVILLIER O C JR_1	9250.00	11700.82	1 Inch	Deep laterolog	29.83290779	-94.49520200
42071313500000	JENKINS LYDIA ETAL_1	2040.00	9484.50	1 Inch	Dual induction tool	29.82165219	-94.54909398
42071313500000	JENKINS LYDIA ETAL_1	2041.10	10978.80	1 Inch	Dual induction tool/Spontaneous potential /Formation tops	29.82165219	-94.54909398
42071313500000	JENKINS LYDIA ETAL_1	2042.99	10990.43	1 Inch	ISF Induction log	29.82165219	-94.54909398
42071313750000	WHITE R L_1	998.03	8764.57	2 Inch	Dual induction tool	29.78249421	-94.41563741
42071313890000	SIMON S E_1	2254.97	9077.17	1 Inch, 5 Inch	Thermal decay time tool	29.85447220	-94.46396621
42071313890000	SIMON S E_1	2300.00	9060.00	1 Inch	Electrical log	29.85447220	-94.46396621
42071313940000	DEVILLIER L C_1	1769.61	9269.67	1 Inch	Dual induction tool	29.84359539	-94.46247180
42071313940000	DEVILLIER L C_1	1800.00	9200.00	1 Inch	Electrical log	29.84359539	-94.46247180
42071314410000	JENKNS LYDIA GUIDRY_1	2934.29	17355.13	1 Inch	Dual induction tool/Spherically focused log	29.82693140	-94.55264600
42071315170000	MAXWELL LAMAR_1	3010.00	9170.00	5 Inch	Gamma ray/Shallow resistivity/	29.88423939	-94.45842909
42071315510000	DEVILLIER O C JR_1	2905.50	10920.70	1 Inch	Digital focused laterolog/Spontaneous potential	29.79369351	-94.49723220
42071315510000	DEVILLIER O C JR_1	7400.90	10951.90	1 Inch	Mud log gas/Mud log lithology/Density shaleRate of penetration/Mud log	29.79369351	-94.49723220
42071315510000	DEVILLIER O C JR_1	7509.80	10949.10	5 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.79369351	-94.49723220
42071315510000	DEVILLIER O C JR_1	7547.90	10934.90	1 Inch	Monitored Mudstream Analysis	29.79369351	-94.49723220
42071315510000	DEVILLIER O C JR_1	8000.00	10969.80	0.2 Inch	Mud log /Density shale	29.79369351	-94.49723220
42071315900000	DUGAT_1	2987.40	10529.10	1 Inch	Dual induction tool/Spontaneous potential	29.86440399	-94.45127750
42071316340000	DUGAT_2A	2928.61	8922.77	1 Inch	Dual induction tool	29.86788632	-94.45094413
42071316340000	DUGAT_2A	2947.77	8902.20	1 Inch, 5 Inch	Dual induction tool/Gamma ray/Litho density tool/Neutron log	29.86788632	-94.45094413
42071316340000	DUGAT_2A	3000.00	9380.00	1 Inch	Electrical log	29.86788632	-94.45094413
42071316440000	WHITE HEIRS_1	1972.82	10514.37	1 Inch	Dual induction tool/Spherically focused log	29.79079161	-94.57794030
42071316440000	WHITE HEIRS_1	7384.90	10535.70	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Mud log show	29.79079161	-94.57794030
42071316440000	WHITE HEIRS_1	7440.30	10507.90	5 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current/Mud log show	29.79079161	-94.57794030
42071316440000	WHITE HEIRS_1	7463.90	10569.60	0.2 Inch	Mud log /Density shale	29.79079161	-94.57794030
42071316540000	CRAWFORD ETAL W J_159-2	1800.99	10397.07	1 Inch	Dual induction tool	29.79333509	-94.36027240
42071316700000	BATEN_1	9992.00	12228.53	0.5 Inch, 2.5 Inch	Deep Induction Conductivity/Compensated Neutron log/Dual induction tool/Gamma ray	29.79044151	-94.36336689
42071316740000	SORELLE_2	500.00	7800.00	1 Inch	Electrical log	29.83813801	-94.36084209
42071317470000	EDWARDS W S ETAL_1	2043.69	10500.39	1 Inch	Dual inductin guard	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	2044.25	9169.07	5 Inch	Dual induction/Sonic	29.80712941	-94.57733590

Table D-AoR-1: All wells with image logs within the geomodel (continued).

UWI	Common Well Name	Top (ft)	Base (ft)	Log Scale	Log Section Name	Latitude	Longitude
42071317470000	EDWARDS W S ETAL_1	2048.57	9170.80	1 Inch	Induction electric log	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	6330.19	9157.60	5 Inch	Dual spaced Neutron log/Salim hole density tool	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	6376.00	10487.90	0.2 Inch	Mud log /Density shale	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	6400.00	10500.00	1 Inch	Monitored Mudstream Analysis	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	6400.80	10481.90	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	8726.56	9170.31	5 Inch	Dual induction/Sonic	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	8930.83	10483.61	5 Inch	Dual spaced Neutron log/Slim hole density tool	29.80712941	-94.57733590
42071317470000	EDWARDS W S ETAL_1	9090.00	10506.95	1 Inch, 5 Inch	Medium resistivity	29.80712941	-94.57733590
42071317650000	THORNTON_1	514.00	7128.26	1 Inch	Dual induction tool	29.87510449	-94.38642622
42071317850000	BOYT E W ETUX_4	2470.41	8943.14	1 Inch, 5 Inch	Compensated Neutron log/Dual induction tool/Litho density tool/Spherically focused log	29.87287501	-94.46736400
42071317850000	BOYT E W ETUX_4	2473.47	8939.97	1 Inch	Dual induction tool/Spherically focused log	29.87287501	-94.46736400
42071318030000	POSTEMA_1	3396.65	10051.11	5 Inch	Dual induction tool/Spherically focused log/Sonic logging tool	29.80787810	-94.36519981
42071318100000	JACOBSON UNIT_4	903.90	9350.50	1 Inch, 5 Inch	Caliper/Compensated Neutron log/Dual induction tool/Gamma ray/Litho density tool/Spontaneous potential	29.87558599	-94.37719399
42071318100000	JACOBSON UNIT_4	904.54	9348.84	1 Inch	Dual induction tool	29.87558599	-94.37719399
42071318100000	JACOBSON UNIT_4	5449.30	9069.80	5 Inch	Cement bond log/Casing colar locator/Gamma ray	29.87558599	-94.37719399
42071318100000	JACOBSON UNIT_4	5489.80	9069.60	5 Inch	Cement bond log/Casing colar locator/Gamma ray	29.87558599	-94.37719399
42071318100000	JACOBSON UNIT_4	7368.80	9260.70	2 Inch, 5 Inch	Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Laterolog/Spontaneous potential	29.87558599	-94.37719399
42071318100000	JACOBSON UNIT_4	8549.90	9338.00	5 Inch	Caliper/Compensated Neutron log/Dual induction tool/Gamma ray/Litho density tool/Spontaneous potential	29.87558599	-94.37719399
42071318560000	FEDERAL LAND BANK OF TEXAS_1	2810.10	10530.40	5 Inch, 10 Inch	Caliper/Compensated Neutron log/Dual induction tool/Gamma ray/Litho density tool/Spontaneous potential	29.77716071	-94.42200679
42071318560000	FEDERAL LAND BANK OF TEXAS_1	2810.40	11629.10	1 Inch	Dual induction tool/Spontaneous potential/Formation tops	29.77716071	-94.42200679
42071318590000	WAGENSTEEN_1	1001.00	7233.81	1 Inch	Dual induction tool/Spherically focused log	29.88194861	-94.38731770
42071318610000	WEAVER_1	700.00	6023.66	1 Inch	Deep laterolog	29.87998369	-94.58222309
42071318690000	MCADAMS JOHN P_1	3825.00	11024.20	1 Inch	Dual induction tool/Spontaneous potential	29.79047221	-94.39716071
42071318730000	HALBOUTY-DEVILLIER_1	2068.20	10772.20	1 Inch	Dual induction tool/Gamma ray/Spontaneous potential/Formation tops	29.83331620	-94.50231730
42071318840000	WAUGH B R ETAL_1	2487.32	9178.61	1 Inch	Dual induction tool	29.88006279	-94.46466870
42071319360000	FROST J M ESTATE UNIT 2_2	3505.75	11018.23	5 Inch	Borehole Compensated Sonic/Digital focused laterolog/Gamma ray	29.77844981	-94.43558869
42071319360000	FROST J M ESTATE UNIT 2_2	9493.65	11015.85	5 Inch	Gamma ray/Microlog	29.77844981	-94.43558869
42071320690000	SUN FEE_1	1956.94	10719.13	1 Inch	Electrical log	29.86717329	-94.36468991
42071320690000	SUN FEE_1	2000.00	10700.00	1 Inch	Electrical log	29.86717329	-94.36468991
42071320740000	HSR E COOPER NO 2_1	2165.44	11012.20	1 Inch, 5 Inch	Dual spaced Neutron log/Hydrocarbon Resistivity Index/Laterolog shallow/Salim hole density tool	29.79176969	-94.50358339
42071320870000	SYPHRETT D W HEIRS_1	2949.90	9164.00	1 Inch, 5 Inch	Caliper/Compensated Neutron log/Digital focused laterolog/Gamma ray/Spontaneous potential/Bulk density	29.79016210	-94.52527399
42071320910000	HSR GARTH #1_1	9285.92	10814.08	1 Inch, 5 Inch	Array induction imager tool/Caliper/Digitaizing sonic tool/Gamma ray	29.78616692	-94.50919420
42071320910000	HSR GARTH #1_1	9286.14	10800.00	1 Inch	Array induction imager tool/Gamma ray	29.78616692	-94.50919420
42071320910000	HSR GARTH #1_1	9300.00	10800.00	1 Inch	Electrical log	29.78616692	-94.50919420
42071321480000	GARTH `B`_1	249.30	10819.46	1 Inch, 5 Inch	Deep Induction Conductivity/Compensated Neutron log/Gamma ray/High definition induction log/3 Arm caliper	29.78927460	-94.51380988
42071321630000	DOORNBOS ET AL_1	1839.70	9628.80	1 Inch, 5 Inch	Array induction imager tool/Compensated Neutron log/Gamma ray/Litho density tool	29.86534399	-94.37510059
42071322280000	OGDEN ET AL_1	1361.00	8501.20	1 Inch	Gamma ray/High definition induction log	29.78876640	-94.41266337
42071322330000	DOORNBOS_1	2088.97	10822.54	1 Inch, 2 Inch	Digital focused laterolog/Gamma ray/Hydrocarbon Resistivity Index	29.82107162	-94.45198821

Table D-AoR-1: All wells with image logs within the geomodel (continued).

UWI	Common Well Name	Top (ft)	Base (ft)	Log Scale	Log Section Name	Latitude	Longitude
42071322590000	JEFFREY_1	2333.98	11011.76	1 Inch, 5 Inch, 10 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Spontaneous potential/ /Bulk density	29.81172140	-94.55818010
42071322680000	CLEMENT UNIT ST_1	3259.00	11156.40	1 Inch, 5 Inch	Compensated Neutron log/Digital acoustic log/Gamma ray/High definition induction log/Bulk density	29.79230554	-94.36991667
42071322960000	COOPER E_1	1868.10	10810.00	5 Inch	Compensated Neutron log/Gamma ray/High definition induction log/ /Bulk density	29.81314159	-94.49916593
42071322990000	TROY_1	3358.30	8960.80	1 Inch, 5 Inch	3 Arm caliper/Compensated Neutron log/Digital acoustic log/Gamma ray/High definition induction log/Bulk density	29.77769628	-94.52578807
42071323230000	KAHLA_1	3359.90	12032.40	1 Inch, 5 Inch, 10 Inch	Caliper/Compensated Neutron log/Digital acoustic log/Gamma ray/High definition induction log/Bulk density	29.78545556	-94.37449723
42071323850000	WHITE-OLSEN HEIRS UNIT_1	1080.40	8152.40	1 Inch, 2 Inch, 5 Inch	Array induction imager tool/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.81158899	-94.57399481
42071324750000	GALLO_1A	3629.80	9350.00	5 Inch	Caliper/Deep Induction Conductivity/Compensated Neutron log/Gamma ray/Shallow resistivity/Sonic logging tool	29.78467100	-94.47833799
42071326020000	ELM BAYOU UNIT_1	2801.70	9695.30	1 Inch, 5 Inch, 10 Inch	Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.77652526	-94.41485228
42071326640000	ENCANTO_01	200.00	6560.00	1 Inch	Mudlog	29.84417700	-94.45642300
42245021150000	J E BROUSSARD ETAL_1	1109.18	8585.74	1 Inch	Electrical log	29.88743353	-94.43147014
42245021170000	J S EDWARDS_1	1479.85	9868.38	1 Inch	Electrical log	29.89166751	-94.38928661
42245302800000	HOWTH_2	1492.80	8758.70	1 Inch	ISF Induction log/Spontaneous potential	29.90176982	-94.42156579
42245311580000	L W RANKIN ET_1	1290.51	10804.73	1 Inch	ISF Induction log	29.90257250	-94.41166001
42245311830000	W M CARROLL EST #1_1	1380.70	9179.60	1 Inch	ISF Induction lod/Spontaneous potential/Formation tops	29.93250569	-94.41408631
42245313430000	LOHMANN-HOWTH_1	1440.72	9621.83	1 Inch, 5 Inch	Dual induction tool/Spherically focused log	29.90620571	-94.39329988
42245313430000	LOHMANN-HOWTH_1	1441.30	9619.40	1 Inch	Dual induction tool/Spontaneous potential	29.90620571	-94.39329988
42245314110000	MCDERMAND F D_1	1011.92	8726.22	1 Inch	Dual induction tool/Spherically focused log	29.95308189	-94.43106080
42245314290000	PEVETO MARY A UN_1	1447.70	8488.90	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.97563059	-94.43293701
42245314850000	BEAVERS W H_1	641.39	8108.06	1 Inch	Dual induction tool/Spherically focused log	29.96395440	-94.37295411
42245317750000	LOHMANN-HOWTH_2	649.50	5881.54	1 Inch	Deep Induction Conductivity/Digital focused laterolog/Gamma ray	29.90694599	-94.39608269
42245318010000	LOHMANN HOWTH /A/_1	670.94	5926.19	1 Inch	Dual induction tool	29.90312221	-94.39938828
42245321180000	CARROLL W M EST_1	662.08	8862.62	1 Inch, 5 Inch	Array induction imager tool/Compensated Neutron log/Gamma ray/Litho density tool	29.93381430	-94.40778261
42245321180000	CARROLL W M EST_1	750.00	8800.00	1 Inch	Electrical log	29.93381430	-94.40778261
42245321180000	CARROLL W M EST_1	8528.63	8862.03	5 Inch	Array induction imager tool/Compensated Neutron log/Gamma ray/Litho density tool	29.93381430	-94.40778261
42245322660000	BAUER_1	1479.56	9485.06	1 Inch, 2 Inch, 5 Inch	Caliper/Compensated Neutron log/Gamma ray/Sonic digital/Stuck Tool	29.91658693	-94.39650394
42245322750000	LOHMANN_1	2942.05	9534.83	1 Inch, 5 Inch	Array induction imager tool/Compensated Neutron log/Litho density tool/Sonic logging tool/Spontaneous potential	29.90083020	-94.39447139
42245322750000	LOHMANN_1	9407.38	10504.39	1 Inch, 5 Inch	Array induction imager tool/Compensated Neutron log/Gamma ray/Litho density tool/Sonic logging tool/Spontaneous potential	29.90083020	-94.39447139
42245322940000	MCDERMAND_1	2355.51	8922.64	1 Inch, 5 Inch	Litho density tool/Array induction imager tool/Compensated Neutron log	29.94654850	-94.43799771
42245323540000	BAUER JACK WAYNE_1	3321.26	10187.43	1 Inch, 5 Inch	Compensated Neutron log/Digital acoustic log/Gamma ray/High definition induction log/ /Bulk density	29.91651016	-94.38467343
42245323540000	BAUER JACK WAYNE_1	9960.19	11331.75	1 Inch, 5 Inch	Compensated Neutron log/Digital acoustic log/Gamma ray/High definition induction log/ /Bulk density	29.91651016	-94.38467343
42245323540000	BAUER JACK WAYNE_1	11141.15	13030.46	1 Inch, 5 Inch	Compensated Neutron log/Digital acoustic log/Gamma ray/High definition induction log/ /Bulk density	29.91651016	-94.38467343
42291047710000	BOYT E W_2	1295.30	8209.90	1 Inch	Electrical log/Spontaneous potential	29.89655706	-94.54380880

Table D-AoR-1: All wells with image logs within the geomodel (continued).

UWI	Common Well Name	Top (ft)	Base (ft)	Log Scale	Log Section Name	Latitude	Longitude
42291047720000	BOYT E W_1	1250.30	8399.60	1 Inch	Electrical log/Spontaneous potential	29.90141808	-94.53383552
42291047740000	BOYT E W_1	1738.64	9290.61	1 Inch	Induction electric log	29.89367648	-94.50446827
42291052760000	HIRSCH ISAAC ETAL_1	1367.35	8160.96	1 Inch, 5 Inch	Induction electric log	29.94599829	-94.51019389
42291052760000	HIRSCH ISAAC ETAL_1	1376.40	8164.00	1 Inch	Induction electric log/Spontaneous potential	29.94599829	-94.51019389
42291053750000	ESTER SWARTZ_1	1323.20	8154.70	1 Inch	Induction electric log/Spontaneous potential	29.95181890	-94.50594890
42291300010000	ESTER SWARTZ_4	1326.92	8136.10	1 Inch, 5 Inch	Induction electric log	29.95008921	-94.50363219
42291300010000	ESTER SWARTZ_4	1341.00	8149.50	1 Inch	Induction electric log/Spontaneous potential	29.95008921	-94.50363219
42291300560000	SWARTZ ESTER_5	1365.40	8167.50	1 Inch	Induction electric log/Spontaneous potential	29.95350399	-94.50937999
42291313830000	BOYT HEIRS GAS UNIT_1	3480.18	9384.03	2.5 Inch	Dual induction tool/Spherically focused log	29.91037819	-94.47311461
42291313830000	BOYT HEIRS GAS UNIT_1	3480.58	17531.04	1 Inch	Dual induction tool/Spherically focused log	29.91037819	-94.47311461
42291313830000	BOYT HEIRS GAS UNIT_1	6851.30	17554.90	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current/Mud log show	29.91037819	-94.47311461
42291313830000	BOYT HEIRS GAS UNIT_1	6995.80	17597.80	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current/Mud log show	29.91037819	-94.47311461
42291315130000	BLANCH GRACE_1	3986.60	16564.90		Dual induction tool/Gamma ray/Spontaneous potential	29.90634299	-94.44364021
42291315260000	BROUSSARD_1	3820.49	16538.74	1 Inch	Dual induction tool/Spherically focused log/Sonic logging tool	29.92874460	-94.45110449
42291315640000	KRAHL_1	1144.12	6477.45	1 Inch	Induction electric log	29.90165680	-94.57475949
42291315790000	SECURITY ST BANK_1	2446.23	8932.23	1 Inch	Dual induction tool	29.90225030	-94.44330610
42291315790000	SECURITY ST BANK_1	6805.13	9002.49	1 Inch, 5 Inch	Continuous Dipmeter	29.90225030	-94.44330610
42291315950000	MAXWELL LAMAR B ETL_1	2468.57	9015.38	1 Inch	Dual induction tool	29.89895399	-94.44924110
42291316180000	WILLIS ESTATE_1-A	-0.40	700.00	5 Inch	Formation multitester log	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	1903.92	8657.71	1 Inch	Digital focused laterolog	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	6991.00	8700.00	1 Inch	Microresistivity	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	6997.20	8644.80	0.4 Inch	Derived Density Tool/Mud log gas/Mud log lithology	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	6999.20	8640.80	5 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	6999.40	8640.50	5 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	6999.60	8638.60	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	7000.00	8749.10	0.4 Inch	Mud log gas/Mud log lithology/Photoelectric Factor/Rate of penetration/Electric Current	29.97574449	-94.48406981
42291316180000	WILLIS ESTATE_1-A	7000.50	8639.20	1 Inch	Mud log gas/Mud log lithology/Rate of penetration/Electric Current	29.97574449	-94.48406981
42291317690000	FINGER M A TR ETAL_1	3491.63	8391.87	5 Inch	Compensated Neutron log/Dual induction tool/Temperature/Spherically focused log	29.95359760	-94.52134070
42291317690000	FINGER M A TR ETAL_1	3492.42	8391.56	1 Inch, 5 Inch	Dual induction tool/Gamma ray/Spherically focused log/Sonic logging tool	29.95359760	-94.52134070
42291317690000	FINGER M A TR ETAL_1	3496.44	12540.07	1 Inch, 5 Inch	Compensated Neutron log/Dual induction tool/Temperature/Spherically focused log	29.95359760	-94.52134070
42291317690000	FINGER M A TR ETAL_1	8370.26	12539.84	1 Inch, 5 Inch	Compensated Neutron log/Dual induction tool/Gamma ray/Litho density	29.95359760	-94.52134070
42291318930000	BONNER_1	1518.27	8748.72	1 Inch, 2 Inch, 5 Inch	Compensated Neutron log/Dual induction tool/Temperature/Gamma ray	29.93513291	-94.45914200
42291320430000	BLANCH GRACE F_1	2000.98	8932.78	1 Inch	Dual induction tool	29.91398470	-94.44706280
42291320560000	GARWOOD-TAUB_1	686.00	5776.11	1 Inch	Dual induction tool	29.89784530	-94.57611701
42291321050000	HARRIS MATTIE B_8	600.00	5740.00	1 Inch	Electrical log	29.89120140	-94.56920890
42291321700000	HENDERSON_1	3429.00	8527.36	1 Inch	Dual induction tool/Spherically focused log	29.95018771	-94.48382890
42291321700000	HENDERSON_1	3440.00	8530.00	1 Inch	Electrical log	29.95018771	-94.48382890
42291321760000	FROST/KEENAN_1	2200.00	8140.00	1 Inch	Electrical log	29.96690120	-94.56772879
42291321820000	BOYT_1	1257.03	8617.92	1 Inch, 5 Inch	Dual induction tool/Dual spaced Neutron log/Slim hole density tool	29.92350239	-94.49651220
42291321820000	BOYT_1	1260.00	8600.00	1 Inch	Electrical log	29.92350239	-94.49651220
42291321840000	GOODWIN MARTHA_1	570.23	6040.99	1 Inch	Digital focused laterolog	29.90085341	-94.56212551
42291321840000	GOODWIN MARTHA_1	600.00	6040.00	1 Inch	Electrical log	29.90085341	-94.56212551

Table D-AoR-1: All wells with image logs within the geomodel (continued).

UWI	Common Well Name	Top (ft)	Base (ft)	Log Scale	Log Section Name	Latitude	Longitude
42291323750000	RAMSEY_1	2377.30	11211.31	1:3 Inch	Array induction imager tool/Caliper/Deep Induction Conductivity/Compensated Neutron log/Gamma ray/Microlog/Spontaneous	29.94935231	-94.58156100
42291323750000	RAMSEY_1	2377.30	8567.94	0.3 Inch, 1.3 Inch	Array induction imager tool/Borehole Compensated Sonic/Caliper/Compensated Neutron log/Gamma ray/Litho density	29.94935231	-94.58156100
42291323750000	RAMSEY_1	2381.40	11210.87	0.3 Inch	Array induction imager tool/Gamma ray/Spontaneous potential	29.94935231	-94.58156100
42291323860000	HATCHER_1	2676.65	9998.45	1 Inch, 5 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Bulk	29.97121470	-94.53922570
42291323860000	HATCHER_1	9787.50	11587.94	1 Inch, 5 Inch, 10 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Bulk	29.97121470	-94.53922570
42291324590000	BONNER_1	3379.21	8750.61	1 Inch, 5 Inch	Array induction imager tool/Gamma ray	29.93108821	-94.46374431
42291324620000	BOND_1	3000.00	9050.16	1 Inch, 5 Inch	Array induction imager tool/Gamma ray/Sonic logging tool	29.89092635	-94.45210267
42291324640000	HOFSTETTER BROS_1	2921.30	8889.80	5 Inch	Array induction imager tool/Bulk density/Gamma ray/Microlog	29.95156933	-94.55073796
42291324750000	SCHWARZ_1	3079.70	13973.68	5 Inch	Array induction imager tool/Gamma ray/Laterolog shallow/Spontaneous	29.94157501	-94.52671110
42291324850000	DUNAGAN JIMBO_1	2959.42	13952.50	5 Inch	Array induction imager tool/Caliper/Bulk density/Gamma ray/Microlog/Spontaneous potential	29.94690566	-94.46184152
42291324860000	GALLOWAY_1	3046.35	13650.38	5 Inch, 6 Inch	Array induction imager tool/Gamma ray/Laterolog shallow/Spontaneous	29.93225889	-94.57993249
42291325100000	HENDERSON E A_1	2839.41	8378.71	1 Inch, 5 Inch	Caliper/Gamma ray/High definition induction log/Spontaneous potential	29.93506203	-94.50130170
42291325100000	HENDERSON E A_1	8150.00	11053.81	1 Inch, 5 Inch	Caliper/Digital acoustic log/Gamma ray/High definition induction log/Spontaneous potential	29.93506203	-94.50130170
42291325280000	ALDRICH R C ET AL_1	40.50	8795.81	1 Inch, 5 Inch, 10 Inch	Caliper/Compensated Neutron log/Gamma ray/High definition induction log/Acoustic log/Bulk density	29.92329308	-94.45530571
42291325280000	ALDRICH R C ET AL_1	8462.00	11731.10	1 Inch, 5 Inch, 10 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Acoustic log/Bulk density	29.92329308	-94.45530571
42291325280000	ALDRICH R C ET AL_1	11500.00	13963.96	1 Inch, 5 Inch, 10 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Bulk	29.92329308	-94.45530571
42291325290000	LIBERTY FARMS_1	3070.36	13973.40	5 Inch	Array induction imager tool/Bulk density/Gamma ray	29.95588440	-94.48982061
42291325300000	FROST-KEENAN_1	2626.37	8489.84	5 Inch	Array induction imager tool/Bulk density/Well test	29.92147416	-94.55917864
42291325510000	HIRSCH ESTATE_4-B	1307.83	8147.80	1 Inch, 5 Inch	Litho density tool/Array induction imager tool/Compensated Neutron log/Gamma ray	29.94712306	-94.51276259
42291325550000	HENDERSON WILLIS_1	3030.40	14901.40	1 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Acoustic log/Bulk density	29.94968260	-94.47993721
42291325830000	JEFFREY J ET AL_1	3278.58	8643.42	1 Inch, 5 Inch	Array induction imager tool/Gamma ray/Sonic logging tool	29.92821389	-94.48546447
42291325830000	JEFFREY J ET AL_1	8581.14	12352.22	1 Inch, 5 Inch, 10 Inch	Array induction imager tool/Compensated Neutron log	29.92821389	-94.48546447
42291325830000	JEFFREY J ET AL_1	11330.50	13542.35	1 Inch, 5 Inch, 10 Inch	Array induction imager tool/Compensated Neutron log	29.92821389	-94.48546447
42291325900000	DOC_1	3166.20	13956.70	1 Inch, 5 Inch	Dual spaced Neutron log/Gamma ray/Hydrocarbon Resistivity Index/Salim hole density tool/Spontaneous potential	29.95981807	-94.47937110
42291326160000	KENT-SPRADLEY UNIT_1	3491.80	12551.90	1 Inch	Caliper/Gamma ray/High definition induction log	29.96042769	-94.52331389
42291326160000	KENT-SPRADLEY UNIT_1	3494.12	8234.83	1 Inch, 5 Inch	Litho density tool/Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Spontaneous potential	29.96042769	-94.52331389
42291326160000	KENT-SPRADLEY UNIT_1	12600.00	15379.10	1 Inch	Gamma ray/High definition induction log	29.96042769	-94.52331389
42291327500000	GORDY SUSAN_1	3486.40	12599.30	1 Inch	Digital acoustic log/Gamma ray/High definition induction log/Spontaneous potential	29.92082109	-94.46694545
42291327500000	GORDY SUSAN_1	11380.10	14189.60	1 Inch, 5 Inch	Array induction imager tool/Caliper/Dual spaced Neutron log/Gamma ray/Salim hole density tool/Spontaneous potential	29.92082109	-94.46694545
42291327970000	WILDI_1	1779.40	8708.10	1 Inch, 5 Inch	Caliper/Compensated Neutron log/Gamma ray/High definition induction log/Spontaneous potential/ /Bulk density	29.91728888	-94.48962501
42291328680000	HUNT SARAH `A`_1	1230.00	8508.90	1 Inch, 5 Inch	Caliper/Compensated Neutron log/Gamma ray/High definition induction log/Spontaneous potential/ /Bulk density	29.93519948	-94.53390151
42291328690000	HUNT SARAH `B`_1	1118.60	8508.00	1 Inch, 5 Inch	Compensated Neutron log/Gamma ray/High definition induction log/Acoustic log/Spontaneous potential/Bulk density	29.93923333	-94.53390281
42291328710000	WEAVER_1	174.00	5518.50	1 Inch, 5 Inch	Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.89031389	-94.57641945
42291328730000	MCH_1	3446.50	8571.30	1 Inch, 5 Inch	Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.94902660	-94.47490204
42291328730000	MCH_1	6982.10	12443.80	1 Inch, 5 Inch	Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.94902660	-94.47490204
42291328730000	MCH_1	11079.80	16044.60	1 Inch, 5 Inch	Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.94902660	-94.47490204
42291328880000	HUDSON_1	3489.50	13760.10	5 Inch	Array induction imager tool/Caliper/Compensated Neutron log/Gamma ray/Litho density tool/Spontaneous potential	29.92246014	-94.47999726
42291328880000	HUDSON_1	3490.70	13757.40	1 Inch	Array induction imager tool/Gamma ray/Spontaneous potential	29.92246014	-94.47999726
42291329030000	EVANS ABBIE M `C`_15	750.30	6410.30	1 Inch, 2 Inch, 5 Inch	Caliper/Compensated Neutron log/Gamma ray/High definition induction log/Microlog/Spontaneous potential/Bulk density	29.91365831	-94.58286669

Table D-AoR-2: All wells with digital logs within the geomodel.

API	Common Well Name	Total Depth (feet)	Field	Completion Date	Latitude (deg)	Longitude (deg)
42071013590000	BROWN HEIRS KING_1	6859	WILDCAT	1/31/1955	29.87113508	-94.56736658
42071013620000	HANKAMER TRUSTEE_1	7661	WILDCAT	7/21/1959	29.88636669	-94.55973426
42071013630000	BROUSSARD TRUST_1	9250	WILDCAT	12/9/1949	29.88702312	-94.50236130
42071013650000	WEST WESLEY ETAL_1	8950	WILDCAT	8/26/1959	29.86277171	-94.54277556
42071013670000	JENKINS W E_1	8622	WILDCAT	10/10/1951	29.86133108	-94.57237764
42071013700000	JENKINS W E_1	9000	WILDCAT	12/21/1961	29.85048174	-94.54234856
42071013710000	JENKINS W E_1	11004	WILDCAT	3/21/1958	29.84301261	-94.53975879
42071017790000	TYRRELL TR_3	10368	WINNIE NORTH	8/25/1948	29.88643190	-94.37848972
42071019550000	DROUGHT H P_1	9505	WILDCAT	11/1/1955	29.80399858	-94.45907552
42071019580000	STERRETT EAT FRED R_1	9550	WILDCAT	8/25/1959	29.81398544	-94.47370954
42071019590000	WM DOORNBOS ETAL_1	9025	WILDCAT	4/25/1956	29.81510900	-94.43990623
42071019600000	TRINITY RICE_1	8019	WILDCAT	7/2/1941	29.81795809	-94.45089736
42071019610000	OGDEN L G ETAL_1	9616	WILDCAT	4/22/1958	29.82821903	-94.47997278
42071019620000	DEBELLVUE MRS MARIA_1	9348	WILDCAT	8/23/1959	29.84327051	-94.47198606
42071019630000	DE VELLIER_1	9015	WILDCAT	2/21/1948	29.84538041	-94.42066585
42071019640000	MOORE ESTATE ELIZ H_1	9002	WILDCAT	1/28/1945	29.85801713	-94.42074314
42071019650000	I DAVENPORT_1	8565	WILDCAT	8/7/1954	29.86021835	-94.43109097
42071019660000	JOHNSON ANNIE H_1	7664	WILDCAT	1/4/1937	29.85590937	-94.44838906
42071019670000	T SIMON_1	9155	WILDCAT	2/28/1962	29.85795639	-94.45589662
42071019920000	HOWTZ SYBIL ETAL_1	9186	WILDCAT	4/10/1960	29.85984737	-94.40353223
42071019930000	SHAW UNIT_1	7190	WINNIE NORTH	11/23/1958	29.86861236	-94.38721311
42071019960000	H J SOLEM UNIT 1_1	8928	WINNIE NORTH	3/19/1958	29.87194324	-94.38755376
42071020000000	MOORE ESTATE_2	9132	WILDCAT	9/12/1945	29.87264987	-94.44769861
42071020010000	STANOLIND OIL & GAS_1	10502	WALLA-BOYT	9/15/1956	29.87282259	-94.46371055
42071033710000	JAMES C HALL ETAL_1	9800	WILDCAT	8/19/1966	29.83580203	-94.57444579
42071034170000	OWEN H ACOM ETAL_2	15017	ANGELINA	5/15/1967	29.78475419	-94.36364221
42071303560000	E COOPER ETAL_1	11000	DEVILLIER	5/23/1975	29.81367539	-94.49590039
42071303660000	O C DEVILLIER ETAL_1	10801	WILDCAT	8/7/1975	29.80416493	-94.49463244
42071303700000	O C DEVILLIER_3	10925	DEVILLIER	8/5/1975	29.81872100	-94.49546900
42071303720000	L G JENKINS_1	11100	WILDCAT	8/2/1975	29.83359596	-94.53655397
42071303930000	JANET MACCARTHY_1	11031	WILDCAT	10/4/1975	29.82808558	-94.53844166
42071303940000	EARL COOPER_2	11200	DEVILLIER	11/27/1975	29.81393580	-94.50750679
42071304390000	EARL COOPER_1-A	10944	DEVILLIER	3/14/1976	29.80393449	-94.50555299
42071304510000	O C DEVILLIER_4	12215	WILDCAT	7/20/1976	29.83220726	-94.48595485
42071304690000	BEAUMNT RC MLL_1	9000	WILDCAT	8/25/1976	29.87663474	-94.50094384
42071304850000	A S HANKAMER_1	11020	DEVILLIER	10/18/1976	29.81039702	-94.51052018
42071305630000	O C DEVILLIER ETAL_5	10998	DEVILLIER	9/23/1977	29.82190719	-94.50138600
42071305640000	M E HUNTER_1	12665	DEVILLIER	7/25/1977	29.81471260	-94.47817701
42071308370000	O C DEVILLIER_6	10993	DEVILLIER	8/9/1978	29.82521440	-94.49492911
42071309340000	JENKINS_1	9370	WILDCAT	4/10/1979	29.83116481	-94.54709470
42071309670000	DEVILLIER O C_7	11270	DEVILLIER	11/23/1979	29.82300331	-94.48841791
42071310360000	GARTH_1	11000	WILDCAT	5/24/1980	29.80178029	-94.46669670
42071312670000	DOORNBOS WILLIM ETL_1	18950	WILDCAT	8/5/1982	29.80872799	-94.45277918
42071312760000	DOMEYER ETAL_1	9200	WILDCAT	11/26/1981	29.85947040	-94.41560119
42071313020000	DEVILLIER O C JR_1	11702	DEVILLIER	4/14/1982	29.83290779	-94.49520200
42071313500000	JENKINS LYDIA ETAL_1	10961	WILDCAT	7/23/1982	29.82165219	-94.54909398
42071313750000	WHITE R L_1	8762	FIG RIDGE	10/29/1982	29.78249421	-94.41563741

Table D-AoR-2: All wells with digital logs within the geomodel (continued)

API	Common Well Name	Total Depth (feet)	Field	Completion Date	Latitude (deg)	Longitude (deg)
42071313890000	SIMON S E_1	9119	WILDCAT	1/21/1983	29.85447220	-94.46396621
42071313940000	DEVILLIER L C_1	9300	WILDCAT	12/28/1982	29.84359539	-94.46247180
42071314410000	JENKNS LYDIA GUIDRY_1	17340	WILDCAT	12/15/1983	29.82693140	-94.55264600
42071315170000	MAXWELL LAMAR_1	9120	WILDCAT	4/30/1984	29.88423939	-94.45842909
42071315510000	DEVILLIER O C JR_1	10900	ANAHUAC EAST	6/29/1984	29.79369351	-94.49723220
42071315900000	DUGAT_1	10516	SPINDLETOP BAYOU	9/19/1984	29.86440399	-94.45127750
42071316340000	DUGAT_2A	8908	SPINDLETOP BAYOU	12/23/1984	29.86788632	-94.45094413
42071316440000	WHITE HEIRS_1	10500	ANAHUAC	12/13/1984	29.79079161	-94.57794030
42071316540000	CRAWFORD ETAL W J_159-2	11630	ANGELINA NORTH	3/14/1985	29.79333509	-94.36027240
42071316700000	BATEN_1	12231	ANGELINA NORTH	9/15/1985	29.79044151	-94.36336689
42071316740000	SORELLE_2	7806	STOWELL	3/15/1985	29.83813801	-94.36084209
42071317470000	EDWARDS W S ETAL_1	10488	ANAHUAC	12/8/1985	29.80712941	-94.57733590
42071317650000	THORNTON_1	7116	WINNIE NORTH	12/12/1985	29.87510449	-94.38642622
42071317850000	BOYT E W ETUX_4	8900	WALLA-BOYT	7/30/1986	29.87287501	-94.46736400
42071318030000	POSTEMA_1	11050	ANGELINA NORTH	11/1/1986	29.80787810	-94.36519981
42071318100000	JACOBSON UNIT_4	9334	WINNIE NORTH	4/8/1987	29.87558599	-94.37719399
42071318560000	FEDERAL LAND BANK OF TEXAS_1	11603	FIG RIDGE NORTH	6/2/1988	29.77716071	-94.42200679
42071318590000	WAGENSTEEN_1	7200	WILDCAT	3/6/1988	29.88194861	-94.38731770
42071318610000	WEAVER_1	6016	HANKAMER SOUTHEAST	5/11/1988	29.87998369	-94.58222309
42071318690000	MCADAMS JOHN P_1	11119	WILDCAT	8/22/1988	29.79047221	-94.39716071
42071318730000	HALBOUTY-DEVILLIER_1	10750	DEVILLIER	10/7/1988	29.83331620	-94.50231730
42071318840000	WAUGH B R ETAL_1	9162	WALLA-BOYT	1/26/1989	29.88006279	-94.46466870
42071319360000	FROST J M ESTATE UNIT 2_2	11000	FIG RIDGE NORTH	10/31/1990	29.77844981	-94.43558869
42071320690000	SUN FEE_1	10705	WINNIE NORTH	1/9/1998	29.86717329	-94.36468991
42071320740000	HSR E COOPER NO 2_1	11000	DEVILLIER	4/1/1997	29.79176969	-94.50358339
42071320870000	SYPHRETT D W HEIRS_1	9135	ANAHUAC EAST	7/11/1997	29.79016210	-94.52527399
42071320910000	HSR GARTH #1_1	10800	DEVILLIER	8/23/1997	29.78616692	-94.50919420
42071321480000	GARTH `B`_1	10400	WILDCAT	3/15/1999	29.78927460	-94.51380988
42071321630000	DOORNBOS ET AL_1	9616	WINNIE NORTH	10/25/1999	29.86534399	-94.37510059
42071322280000	OGDEN ET AL_1	8500	FIG RIDGE NORTH	10/24/2002	29.78876640	-94.41266337
42071322330000	DOORNBOS_1	10800	WILDCAT	12/10/2002	29.82107162	-94.45198821
42071322590000	JEFFREY_1	11002	ANAHUAC TOWNSITE	1/7/2004	29.81172140	-94.55818010
42071322680000	CLEMENT UNIT ST_1	11125	SPRUCE	5/11/2005	29.79230554	-94.36991667
42071322960000	COOPER E_1	10800	DEVILLIER	5/17/2005	29.81314159	-94.49916593
42071322990000	TROY_1	8952	ANAHUAC EAST	8/30/2005	29.77769628	-94.52578807
42071323230000	KAHLA_1	12012	ANGELINA	4/2/2006	29.78545556	-94.37449723
42071323850000	WHITE-OLSEN HEIRS UNIT_1	8129	ANAHUAC	10/8/2009	29.81158899	-94.57399481
42071324750000	GALLO_1A	9350	GALLO	1/7/2013	29.78467100	-94.47833799
42071326020000	ELM BAYOU UNIT_1	10700	FIG RIDGE NORTH	6/8/2015	29.77652526	-94.41485228
42071326640000	ENCANTO_01	8581	UNNAMED		29.84417700	-94.45642300
42245021150000	J E BROUSSARD ETAL_1	8560	WILDCAT	8/10/1952	29.88743353	-94.43147014
42245021170000	J S EDWARDS_1	9859	WILDCAT	4/28/1948	29.89166751	-94.38928661
42245302800000	HOWTH_2	8712	WILDCAT	7/16/1974	29.90176982	-94.42156579
42245311580000	L W RANKIN ET_1	10774	WILDCAT	8/14/1977	29.90257250	-94.41166001
42245311830000	W M CARROLL EST #1_1	9114	NOME SOUTH	1/8/1978	29.93250569	-94.41408631
42245313430000	LOHMANN-HOWTH_1	9600	BAUER RANCH	12/21/1979	29.90620571	-94.39329988
42245314110000	MCDERMAND F D_1	8718	NOME SOUTH	9/30/1980	29.95308189	-94.43106080

Table D-AoR-2: All wells with digital logs within the geomodel (continued)

API	Common Well Name	Total Depth (feet)	Field	Completion Date	Latitude (deg)	Longitude (deg)
42245314290000	PEVETO MARY A UN_1	8437	WILDCAT	12/20/1980	29.97563059	-94.43293701
42245314850000	BEAVERS W H_1	8042	WILDCAT	6/27/1981	29.96395440	-94.37295411
42245317750000	LOHMANN-HOWTH_2	5866	BAUER RANCH	7/10/1984	29.90694599	-94.39608269
42245318010000	LOHMANN HOWTH /A/_1	5916	BAUER RANCH	6/12/1985	29.90312221	-94.39938828
42245321180000	CARROLL W M EST_1	8850	WILDCAT	10/7/1995	29.93381430	-94.40778261
42245322660000	BAUER_1	9461	BAUER RANCH	12/4/2000	29.91658693	-94.39650394
42245322750000	LOHMANN_1	10380	BAUER RANCH	4/23/2001	29.90083020	-94.39447139
42245322940000	MCDERMAND_1	8900	WILDCAT	6/8/2001	29.94654850	-94.43799771
42245323540000	BAUER JACK WAYNE_1	13000	BAUER RANCH	4/27/2004	29.91651016	-94.38467343
42291047710000	BOYT E W_2	8184	WILDCAT	5/21/1958	29.89655706	-94.54380880
42291047720000	BOYT E W_1	8373	WILDCAT	3/26/1958	29.90141808	-94.53383552
42291047740000	BOYT E W_1	9280	WILDCAT	8/11/1959	29.89367648	-94.50446827
42291052760000	HIRSCH ISAAC ETAL_1	8116	COTTONWOOD	3/16/1967	29.94599829	-94.51019389
42291053750000	ESTER SWARTZ_1	8114	COTTONWOOD	11/10/1967	29.95181890	-94.50594890
42291300010000	ESTER SWARTZ_4	8108	COTTONWOOD	2/4/1969	29.95008921	-94.50363219
42291300560000	SWARTZ ESTER_5	8111	COTTONWOOD	8/20/1969	29.95350399	-94.50937999
42291313830000	BOYT HEIRS GAS UNIT_1	17500	COTTONWOOD SOUTHEAST	6/7/1981	29.91037819	-94.47311461
42291315130000	BLANCH GRACE_1	16550	NOLTE MARSH	6/27/1982	29.90634299	-94.44364021
42291315260000	BROUSSARD_1	16500	NOME SOUTH	11/8/1982	29.92874460	-94.45110449
42291315640000	KRAHL_1	6460	HANKAMER	10/4/1982	29.90165680	-94.57475949
42291315790000	SECURITY ST BANK_1	8918	WILDCAT	12/6/1982	29.90225030	-94.44330610
42291315950000	MAXWELL LAMAR B ETL_1	9000	WILDCAT	2/23/1983	29.89895399	-94.44924110
42291316180000	WILLIS ESTATE_1-A	8640	WILDCAT	5/18/1983	29.97574449	-94.48406981
42291317690000	FINGER M A TR ETAL_1	12525	COTTONWOOD	8/2/1984	29.95359760	-94.52134070
42291318010000	DUNAGAN GRACE W ETAL_1-A	8580	WILDCAT	11/30/1984	29.93463309	-94.47368989
42291318930000	BONNER_1	8740	NOLTE MARSH	7/10/1985	29.93513291	-94.45914200
42291320430000	BLANCH GRACE F_1	8921	NOLTE MARSH	9/15/1988	29.91398470	-94.44706280
42291320560000	GARWOOD-TAUB_1	5718	HANKAMER	2/10/1989	29.89784530	-94.57611701
42291321050000	HARRIS MATTIE B_8	5716	HANKAMER SOUTHEAST	12/20/1990	29.89120140	-94.56920890
42291321700000	HENDERSON_1	16600	CROOKED BAYOU	11/13/1993	29.95018771	-94.48382890
42291321760000	FROST/KEENAN_1	8115	WILDCAT	6/24/1993	29.96690120	-94.56772879
42291321820000	BOYT_1	8600	COTTONWOOD	10/16/1993	29.92350239	-94.49651220
42291321840000	GOODWIN MARTHA_1	6016	HANKAMER SOUTHEAST	11/24/1993	29.90085341	-94.56212551
42291323750000	RAMSEY_1	11188	COTTONWOOD WEST	4/12/2001	29.94935231	-94.58156100
42291323860000	HATCHER_1	11600	COTTONWOOD NORTH	6/22/2001	29.97121470	-94.53922570
42291324590000	BONNER_1	13091	WILDCAT	1/22/2003	29.93108821	-94.46374431
42291324620000	BOND_1	9008	WILDCAT	1/16/2003	29.89092635	-94.45210267
42291324640000	HOFSTETTER BROS_1	8864	RICE BELT	8/20/2003	29.95156933	-94.55073796
42291324750000	SCHWARZ_1	14350	COTTONWOOD	9/18/2003	29.94157501	-94.52671110
42291324850000	DUNAGAN JIMBO_1	13910	WILDCAT	9/25/2003	29.94690566	-94.46184152
42291324860000	GALLOWAY_1	14110	WILDCAT	3/9/2004	29.93225889	-94.57993249
42291325100000	HENDERSON E A_1	14495	NOME	2/2/2004	29.93506203	-94.50130170
42291325280000	ALDRICH R C ET AL_1	13885	NOLTE MARSH	6/3/2004	29.92329308	-94.45530571
42291325290000	LIBERTY FARMS_1	13950	WILLIS MARSH	6/15/2004	29.95588440	-94.48982061
42291325300000	FROST-KEENAN_1	8218	WILDCAT	5/25/2004	29.92147416	-94.55917864
42291325510000	HIRSCH ESTATE_4-B	8144	COTTONWOOD	1/27/2006	29.94712306	-94.51276259
42291325550000	HENDERSON WILLIS_1	14879	WILLIS MARSH	4/2/2005	29.94968260	-94.47993721
42291325830000	JEFFREY J ET AL_1	13500	COTTONWOOD SOUTH	5/7/2005	29.92821389	-94.48546447
42291325900000	DOC_1	13909	WILLIS MARSH	7/8/2005	29.95981807	-94.47937110
42291326160000	KENT-SPRADLEY UNIT_1	12515	COTTONWOOD	4/18/2007	29.96042769	-94.52331389
42291327500000	GORDY SUSAN_1	14193	NOLTE MARSH	3/15/2009	29.92082109	-94.46694545
42291327970000	WILDI_1	8700	COTTONWOOD	11/25/2009	29.91728888	-94.48962501
42291328680000	HUNT SARAH `A`_1	8500	COTTONWOOD	5/19/2012	29.93519948	-94.53390151
42291328690000	HUNT SARAH `B`_1	8500	COTTONWOOD	5/9/2012	29.93923333	-94.53390281
42291328710000	WEAVER_1	5500	HANKAMER SOUTHEAST	7/18/2012	29.89031389	-94.57641945
42291328730000	MCH_1	16000	CROOKED BAYOU	2/11/2013	29.94902660	-94.47490204
42291328880000	HUDSON_1	13729	CROOKED BAYOU	6/1/2013	29.92246014	-94.47999726
42291329030000	EVANS ABBIE M `C`_15	6410	HANKAMER	8/18/2014	29.91365831	-94.58286669

Table D-AoR-3: All wells with digital logs that were used to create petrophysically analyzed logs within the geomodel. Petrophysically analyzed logs were used to create the various property models.

API	Well	XGR	XSP	XRESD	XDT	XVSH	XVSAND	XPORE	XPERM	Longitude	Latitude	START	STOP
42071033710000	JAMES C. HALL #1		X	X		X	X	X		-094° 34' 28.0049	029° 50' 8.8872	2548.00	9824.00
42071318840000	WAUGH B. R. ET AL #1	X	X	X		X	X	X	X	-094° 27' 52.8073	029° 52' 48.2261	2494.00	9150.00
42071320740000	HSR E COOPER #2		X	X	X	X	X	X	X	-094° 30' 12.9002	029° 47' 30.3709	2167.00	10997.00
42071321630000	DOORNBOS ETAL #1	X	X	X		X	X	X	X	-094° 22' 30.3622	029° 51' 55.2384	1910.00	9615.00
42071322280000	OGDEN ET AL #1	X	X	X		X	X	X	X	-094° 24' 45.5882	029° 47' 19.559	1480.00	8479.00
42071322590000	JEFFREY #1	X	X	X	X	X	X	X	X	-094° 33' 29.4484	029° 48' 42.1971	2351.00	10986.00
42071318730000	HALBOUTY-DEVILLIER #1		X	X		X	X	X	X	-094° 30' 8.3423	029° 49' 59.9383	2118.00	10734.00
42071322680000	CLEMENT UNIT #1	X	X	X	X	X	X	X	X	-094° 22' 11.7001	029° 47' 32.3002	3274.00	11128.00
42071323850000	WHITE-OLSEN HEIRS UNIT #1	X	X	X		X	X	X	X	-094° 34' 26.3813	029° 48' 41.7204	1080.00	8135.00
42245322660000	BAUER #1	X	X	X		X	X	X	X	-094° 23' 47.4144	029° 54' 59.7128	1487.00	9468.00
42071322960000	E. COOPER #1	X	X	X		X	X	X	X	-094° 29' 56.9972	029° 48' 47.3098	1882.00	10784.00
42245322750000	LOHMANN #1	X	X	X	X	X	X	X	X	-094° 23' 40.097	029° 54' 2.9887	2966.50	10483.00
42071318690000	MCADAMS JOHN P. #1	X	X	X		X	X	X	X	-094° 23' 49.7785	029° 47' 25.6999	3822.00	11010.00
42071304390000	EARL COOPER #1A		X	X	X	X	X	X	X	-094° 30' 19.9908	029° 48' 14.1642	1500.00	10943.50
42071304850000	A. S. HANKAMER #1		X	X		X	X	X	X	-094° 30' 37.8727	029° 48' 37.4292	2065.00	11021.00
42071308370000	O. C. DEVILLIER #6		X	X		X	X	X	X	-094° 29' 41.7448	029° 49' 30.7718	2080.00	10997.00
42071309340000	JENKINS #1		X	X		X	X	X	X	-094° 32' 49.5409	029° 49' 52.1933	2022.00	9369.00
42245302800000	2_HOWETH		X	X		X	X	X		-094° 25' 17.6368	029° 54' 6.3714	1500.00	8740.00
42071318030000	POSTEMA #1		X	X	X	X	X	X	X	-094° 21' 54.7193	029° 48' 28.3612	3475.00	11047.00
42071312670000	DOORNBOS WILLIAM ET AL #1	X	X	X	X	X	X	X	X	-094° 27' 10.0051	029° 48' 31.4208	4009.00	18950.00
42071313750000	R L WHITE #1	X	X	X		X	X	X	X	-094° 24' 56.2946	029° 46' 56.9791	998.00	8748.00
42071316340000	DUGAT #2A - PILOT	X	X	X		X	X	X	X	-094° 27' 3.3989	029° 52' 4.3908	2929.00	9040.00
42071316540000	W J CRAWFORD 159 #2		X	X	X	X	X	X	X	-094° 21' 36.9806	029° 47' 36.0064	1797.00	11529.00
42071316740000	SORELLE #2		X	X	X	X	X	X	X	-094° 21' 39.0316	029° 50' 17.2968	532.00	7790.00
42071313500000	JENKINS LYDIA ETAL #1		X	X	X	X	X	X	X	-094° 32' 56.7384	029° 49' 17.9479	2088.00	10958.00
42291328690000	SARAH HUNT B #1	X	X	X	X	X	X	X	X	-094° 32' 2.0501	029° 56' 21.24	1137.00	8488.00
42291325550000	HENDERSON WILLIS #1	X	X	X	X	X	X	X	X	-094° 28' 47.7739	029° 56' 58.8574	3046.00	14847.00
42291325280000	ALDRICH R C ET AL #1	X	X	X	X	X	X	X	X	-094° 27' 19.1005	029° 55' 23.8552	62.00	13852.00
42291323860000	HATCHER #1	X	X	X		X	X	X	X	-094° 32' 21.2125	029° 58' 16.3729	2691.00	11574.00
42245323540000	BAUER JACK WAYNE #1	X	X	X	X	X	X	X	X	-094° 23' 4.8243	029° 54' 59.4365	3344.00	13013.00
42291327970000	WILDI #1	X	X	X		X	X	X	X	-094° 29' 22.65	029° 55' 2.24	1780.00	8689.00
42291321820000	BOYT #1	X	X	X		X	X	X	X	-094° 29' 47.4439	029° 55' 24.6086	1258.00	8591.00
42291320430000	GRACE BLANCHE #1		X	X		X	X	X	X	-094° 26' 49.4261	029° 54' 50.3449	2007.00	8900.00
42291318930000	BONNER #1		X	X		X	X	X	X	-094° 27' 32.9112	029° 56' 6.4784	1519.00	8724.00
42291315790000	SECURITY STATE BANK #1	X	X	X		X	X	X	X	-094° 26' 35.902	029° 54' 8.1011	2470.00	8914.00
42245322940000	MCDERMAND #1	X	X	X		X	X	X	X	-094° 26' 16.7917	029° 56' 47.5746	2381.00	8909.00
42245314110000	MCDERMAND F D #1	X	X	X		X	X	X	X	-094° 25' 51.8189	029° 57' 11.0948	1022.00	8714.00
42245313430000	LOHMANN-HOWTH #1		X	X		X	X	X	X	-094° 23' 35.8796	029° 54' 22.3405	1499.00	9589.00
42245321180000	CARROLL W M ESTATE #1		X	X		X	X	X	X	-094° 24' 28.0174	029° 56' 1.7315	662.00	8841.00
42291053750000	ESTER SWARTZ #1		X	X		X	X	X	X	-094° 30' 21.416	029° 57' 6.548	1340.00	8113.00
42291300010000	ESTER SWARTZ #4		X	X		X	X	X	X	-094° 30' 13.0759	029° 57' 0.3211	1363.00	8107.00
42291300560000	ESTER SWARTZ #5		X	X		X	X	X	X	-094° 30' 33.768	029° 57' 12.6144	1380.00	8110.00
42291324590000	BONNER #1		X	X		X	X	X	X	-094° 27' 49.4795	029° 55' 51.9175	3380.00	8710.00
42291324860000	GALLOWAY #1	X	X	X	X	X	X	X	X	-094° 34' 47.757	029° 55' 56.132	3077.00	13631.00
42291325100000	HENDERSON E A #1	X	X	X		X	X	X	X	-094° 30' 4.6861	029° 56' 6.2232	2860.00	11032.00
42291324620000	BOND #1	X	X	X	X	X	X	X	X	-094° 27' 7.5697	029° 53' 27.335	3011.00	9050.00
42071303660000	O. C. DEVILLIER ET AL #1		X	X		X	X	X	X	-094° 29' 40.677	029° 48' 14.9936	1550.00	10795.00

Table D-AoR-3: All wells with digital logs that were used to create petrophysically analyzed logs within the geomodel. Petrophysically analyzed logs were used to create the various property models (continued).

API	Well	XGR	XSP	XRESD	XDT	XVSH	XVSAND	XPORE	XPERM	Longitude	Latitude	START	STOP
42071320910000	HSR GARTH #1	X	X	X		X	X	X	X	-094° 30' 33.0991	029° 47' 10.2008	2120.00	10800.00
42071310360000	GARTH #1		X	X		X	X	X	X	-094° 28' 0.1081	029° 48' 6.4091	1498.00	11000.00
42071313020000	O. C. DEVILLIER JR. #1	X	X	X	X	X	X	X	X	-094° 29' 42.7272	029° 49' 58.4681	109.00	11679.00
42071314410000	JENKNS LYDIA GUIDRY #1	X	X	X	X	X	X	X	X	-094° 33' 9.5256	029° 49' 36.953	2939.00	17352.00
42071315510000	DEVILLIER O. C. JR ET AL #1		X	X		X	X	X	X	-094° 29' 50.0359	029° 47' 37.2966	2984.00	10890.00
42071316440000	WHITE HEIRS #1		X	X		X	X	X	X	-094° 34' 40.5851	029° 47' 26.8498	2019.00	10494.00
42071019550000	N_P_DROUGHT_STN_1		X	X		X	X	X		-094° 27' 32.6719	029° 48' 14.3949	1630.00	9520.00
42071019580000	1_FRED STERRETT EST		X	X		X	X	X	X	-094° 28' 25.3544	029° 48' 50.3476	1260.00	9550.00
42071019590000	WILLIAM_DORNBOS_1		X	X		X	X	X		-094° 26' 23.6624	029° 48' 54.3924	1200.00	9000.00
42071019600000	TRINITY_RICE_DISPOSAL_CO_1		X	X		X	X	X	X	-094° 27' 3.2306	029° 49' 4.6492	1300.00	9317.00
42071019610000	OGDEN_1		X	X		X	X	X		-094° 28' 47.902	029° 49' 41.5885	2270.00	9620.00
42071019620000	MRS_MARIE_DE_BELLEVUE_1		X	X		X	X	X		-094° 28' 19.1498	029° 50' 35.7739	1180.00	9360.00
42071019640000	MOORS_1		X	X		X	X	X		-094° 25' 14.6753	029° 51' 28.8617	1240.00	9000.00
42071019650000	IRENE DAVENPORT_1		X	X		X	X	X		-094° 25' 51.9275	029° 51' 36.786	1000.00	8570.00
42071019660000	ANNIE_H_JOHNSON_1		X	X		X	X	X		-094° 26' 54.2006	029° 51' 21.2737	1300.00	7600.00
42071019670000	T_SIMON_1		X	X		X	X	X		-094° 27' 21.2278	029° 51' 28.643	1320.00	9180.00
42071019920000	SYBIL_HOWTH_1		X	X		X	X	X		-094° 24' 12.7161	029° 51' 35.4505	1000.00	9200.00
42071020000000	COMPOSITS (1-3)		X	X		X	X	X		-094° 26' 51.715	029° 52' 21.5396	1730.00	9140.00
42071304690000	BEAUMONT_RIGE_MILLS_1		X	X		X	X	X		-094° 30' 3.3978	029° 52' 35.8851	980.00	9000.00
42071312760000	DOMEYER_1		X	X		X	X	X		-094° 24' 56.1643	029° 51' 34.0934	1570.00	9230.00
42071313940000	L_C_DEVILLER_1		X	X		X	X	X	X	-094° 27' 44.8985	029° 50' 36.9434	1780.00	9260.00
42071315170000	LAMAR_MAXWELL_1		X	X		X	X	X		-094° 27' 30.3448	029° 53' 3.2618	3010.00	9170.00
42071317650000	THORNTON_1		X	X		X	X	X		-094° 23' 11.1343	029° 52' 30.3762	520.00	7120.00
42245021150000	J_E_BROUSSARD_ET_AL_1		X	X		X	X	X		-094° 25' 53.2926	029° 53' 14.7607	1120.00	8570.00
42245311580000	LEONORA_W. RANKIN_ESTATE_EL_AL_1		X	X		X	X	X		-094° 24' 41.976	029° 54' 9.261	1300.00	10790.00
42291047710000	E_W_BOYT_2		X	X		X	X	X		-094° 32' 37.7117	029° 53' 47.6055	1300.00	8200.00
42291047720000	BOYT_1		X	X		X	X	X		-094° 32' 1.8078	029° 54' 5.1051	1260.00	8380.00
42291047740000	E_W_BOYT_1		X	X		X	X	X		-094° 30' 16.0858	029° 53' 37.2354	1750.00	9280.00
42071013650000	WESLET_WEST_1		X	X		X	X	X		-094° 32' 33.992	029° 51' 45.9782	2060.00	8960.00
42071013630000	BROUSSARD_TRUST_1		X	X		X	X	X		-094° 30' 8.5007	029° 53' 13.2832	1415.00	9256.00
42291315950000	MAXWELL_1		X	X		X	X	X		-094° 26' 57.268	029° 53' 56.2344	2500.00	9000.00
42071013620000	E_C_HANKAMER_ET_AL_1		X	X		X	X	X		-094° 33' 35.0433	029° 53' 10.9201	510.00	7670.00
42071013670000	JENKINS_1		X	X		X	X	X		-094° 34' 20.5595	029° 51' 40.7919	1170.00	8628.00
42245021170000	J_S_EDWARDS_1		X	X		X	X	X		-094° 23' 21.4318	029° 53' 30.003	1490.00	9850.00
42071318590000	WANGANSTEEN_1		X	X		X	X	X		-094° 23' 14.3437	029° 52' 55.015	1000.00	7230.00
42071303720000	LYDIA_G_JENKIN _1		X	X		X	X	X		-094° 32' 11.5943	029° 50' 0.9455	5510.00	11100.00
42291321760000	FROST/KEENAN #1		X	X	X	X	X	X	X	-094° 34' 3.792	029° 58' 0.84	2204.00	8110.00
42291323750000	RAMSEY #1		X	X		X	X	X	X	-094° 34' 53.616	029° 56' 57.66	2377.00	11189.00
42071326640000	ENCANTO 01	X	X	X	X	X	X	X	X	-094° 27' 23.124	029° 50' 39.036	0.00	9260.00

Table D-AoR-4: Wells used to account for the number of shallow water wells with in the AOI (TWDB).

OID	State Well N	Owner Name	Primary Wat	Elevation	Well Depth	Water Level	Water Quality	Aquifer Code	Coord DD Lat	Coord DD Lon	County Name	Well Type
0	6405902	C. W. Howth	Plugged or Destroyed	35	150	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.899445	-94.398611	Jefferson	Withdrawal of Water
1	6406401	Texas Pipeline Co.	Plugged or Destroyed	25	255	Historical	Y	112CHCTU - Chicot Aquifer, Upper	29.955556	-94.363612	Jefferson	Withdrawal of Water
2	6406403	John N. Gilbert	Plugged or Destroyed	20	150	None	Y	112CHCTU - Chicot Aquifer, Upper	29.918611	-94.348334	Jefferson	Withdrawal of Water
3	6405901	Lohman Brothers	Domestic	28	135	None	Y	112CHCTU - Chicot Aquifer, Upper	29.909167	-94.382222	Jefferson	Withdrawal of Water
4	6405903	Martin Koelemay	Domestic	35	260	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.900278	-94.413334	Jefferson	Withdrawal of Water
5	6405502	Freemont McDermand	Industrial	45	160	TWDB Current Site Visit	Y	112CHCTU - Chicot Aquifer, Upper	29.937222	-94.43	Jefferson	Withdrawal of Water
6	6406404	Lawrence Leger	Unused	23	20	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.958612	-94.374167	Jefferson	Withdrawal of Water
7	6412301	U.S. Dept. of Agriculture	Unused	34	146	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.860556	-94.529444	Chambers	Withdrawal of Water
8	6405801	G.C. Bond	Unused	33	46	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.889722	-94.457223	Chambers	Withdrawal of Water
9	6413203	E.C. Devillier	Domestic	26	12	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.833889	-94.42	Chambers	Withdrawal of Water
10	6405301	Texas Public Service Co.	Unused	33	176	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.963334	-94.402501	Jefferson	Withdrawal of Water
11	6413107	O.C. Devillier, Jr	Unused	30	135	None	Y	112CHCTU - Chicot Aquifer, Upper	29.838889	-94.492222	Chambers	Withdrawal of Water
12	6413110	O.C. DeVillier	Domestic	32	160	None	Y	112CHCTU - Chicot Aquifer, Upper	29.843334	-94.492778	Chambers	Withdrawal of Water
13	6413401	Mary Hunter O.C. Devillier,Jr	Unused	28	257	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.811111	-94.479167	Chambers	Withdrawal of Water
14	6413402	Starrett	Unused	27	240	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.808612	-94.478611	Chambers	Withdrawal of Water
15	6413501	U.S. Dept.of Agriculture	Unused	27	164	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.832222	-94.431389	Chambers	Withdrawal of Water
16	6405602	Texas Public Service Co.	Plugged or Destroyed	29	150	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.957223	-94.375833	Jefferson	Withdrawal of Water
17	6413103	L.L. Fontenot	Plugged or Destroyed	35	331	Miscellaneous Measurements	Y	112CHCT - Chicot Aquifer	29.864445	-94.492778	Chambers	Withdrawal of Water
18	6413112	C.B. Jeffery	Stock	33	176	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.866389	-94.476944	Chambers	Withdrawal of Water
19	6413202	U.S. Dept. of Agriculture	Unused	30	142	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.854445	-94.430278	Chambers	Withdrawal of Water
20	6413102	Sun Oil Co	Plugged or Destroyed	35	175	Miscellaneous Measurements	N	112CHCTU - Chicot Aquifer, Upper	29.866389	-94.482778	Chambers	Withdrawal of Water
21	6405701	Boytwell #B-1		38	9183	None	N	NOT-APPL - Aquifer Code Is Not Applicable to this Well	29.898334	-94.476111	Liberty	Oil or Gas
22	6413111	W.M. McBride	Domestic	33	171	None	Y	112CHCTU - Chicot Aquifer, Upper	29.862778	-94.494167	Chambers	Withdrawal of Water
23	6413101	Oscar Devillier	Unused	34	500	Miscellaneous Measurements	N	112CHCTL - Chicot Aquifer, Lower	29.858334	-94.481111	Chambers	Withdrawal of Water
24	6405501	Willis McDermand	Domestic	44	413	None	Y	112CHCTL - Chicot Aquifer, Lower	29.936945	-94.431111	Jefferson	Withdrawal of Water
25	6405702	F.W. Plummer	Unused	37	527	Miscellaneous Measurements	Y	112CHCTL - Chicot Aquifer, Lower	29.883611	-94.4725	Chambers	Withdrawal of Water

OID	State Well N	Owner Name	Primary Wat	Elevation	Well Depth	Water Level	Water Quality	Aquifer Code	Coord DD Lat	Coord DD Lon	County Name	Well Type
26	6412302	Pat Boyt	Domestic	33	324	None	Y	112CHCTL - Chicot Aquifer, Lower	29.859445	-94.524167	Chambers	Withdrawal of Water
OID	State Well N	Owner Name	Primary Wat	Elevation	Well Depth	Water Level	Water Quality	Aquifer Code	Coord DD Lat	Coord DD Lon	County Name	Well Type
27	6412303	W.E. Jenkins	Domestic	33	403	Miscellaneous Measurements	Y	112CHCTL - Chicot Aquifer, Lower	29.854445	-94.523611	Chambers	Withdrawal of Water
28	6413105	U.S. Dept of Agriculture	Unused	30	122	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.860556	-94.475278	Chambers	Withdrawal of Water
29	6413106	Lawrence Rowland	Unused	31	180	Miscellaneous Measurements	N	112CHCTU - Chicot Aquifer, Upper	29.844722	-94.483611	Chambers	Withdrawal of Water
30	6413403	Garth Bros.	Unused	25	30	None	Y	112CHCTU - Chicot Aquifer, Upper	29.793334	-94.4725	Chambers	Withdrawal of Water
31	6413406	O.C. Devillier	Industrial	30	160	None	Y	112CHCTU - Chicot Aquifer, Upper	29.829444	-94.483611	Chambers	Withdrawal of Water
32	6413104	S.E. McBride	Plugged or Destroyed	35	176	Miscellaneous Measurements	Y	112CHCTU - Chicot Aquifer, Upper	29.863056	-94.492778	Chambers	Withdrawal of Water

Table D-AoR- 5: Wells used to account for the number of shallow water wells with in the AOI (SDRDB).

FID	Shape *	WellReport	WellType	ProposedUs	County	WellOwner	WellStreet	WellCity	WellZipCod	LatitudeDD	LongitudeD	BoreholeDe	InjuriousW	PluggingRe	LocationEr
0	Point	49955	New Well	Rig Supply	Liberty	Camden Resources, Inc	4 mi. WSW from			29.934445	-94.476944	155	no		0
1	Point	56754	New Well	Domestic	Jefferson	Dishman and Sons Farn	1 mi E of Inter. F			29.949445	-94.366389	130	no		0
2	Point	57418	New Well	Domestic	Caldwell	Roger Dillon	CR 159	Taylorsville	78662	29.891667	-94.474167	440	no		0
3	Point	58643	New Well	Domestic	Chambers	Kervin Sonnier	1120 McBride D	Winnie	77665	29.844722	-94.507778	170	no		0
4	Point	68116	New Well	Rig Supply	Liberty	Westport Oil & Gas Co.	2 mi S Intersect	Nome		29.931944	-94.470555	180	no		0
5	Point	68156	New Well	Rig Supply	Chambers	Mr. & Mrs. Larry De Vill	8601 FM 1663	Winnie	77665	29.858056	-94.475555	180	no		0
6	Point	74003	New Well	Rig Supply	Liberty	CAMDEN RESOURCES IN	4 Mi W Intersec	Cottonwood		29.929167	-94.487222	197			0
7	Point	114973	New Well	Domestic	Chambers	Lisa Martin/Brad Cron	McBride-Devill	Winnie		29.843889	-94.486389	170	no		0
8	Point	120887	New Well	Rig Supply	Liberty	Rising Star Energy LLC/I	South End of He			29.930278	-94.476944	215	no		0
9	Point	124609	New Well	Stock	Chambers	John Savoie	730 N. fm.1410	winnie	77665	29.833334	-94.466944	180	no		0
10	Point	132996	New Well	Stock	Chambers	Richard Devillier	1819c devillier	winnie	77665	29.833334	-94.416667	160	no		0
11	Point	134506	New Well	Domestic	Chambers	John C. Saooie				29.825833	-94.474722	180	no		0
12	Point	135822	New Well	Stock	Jefferson	Freemont McDermand	1932 hwy	Nome	77629	29.917778	-94.418055	150	no		0
13	Point	138183	New Well	Rig Supply	Chambers	Kerr McGee O&G Onsh	1 mi. S. int.IH10	6 mi. W Winnie		29.810834	-94.498334	201	no		0
14	Point	142520	New Well	Stock	Chambers	Mark Huddleston	7275 Fm1663	winnie	77665	29.850001	-94.500001	165	no		0
15	Point	142522	New Well	Stock	Chambers	Mark Huddleston	940 McBrideDev	winnie	77665	29.833611	-94.500001	170	no		0
16	Point	149140	New Well	Domestic	Chambers	Larry Tinkle, Jr.	End of Oak Islar	Winnie		29.890834	-94.456112	155	no		0
17	Point	165053	New Well	Domestic	Chambers	monica Gomez	39053 IH-10 nor	winnie	77665	29.816944	-94.500001	170	no		0
18	Point	167349	New Well	Rig Supply	Jefferson	Edge Oil by Grey Wolf D	1 mi ESE FM 140			29.925555	-94.391389	180	no	19653	0
19	Point	174115	New Well	Rig Supply	Jefferson	Black Creek Drilling, Inc	Willis Road	Nome	77629	29.924167	-94.426944	160	no		0
20	Point	180716	New Well	Domestic	Chambers	Luttrell	11037 Hwy 65	Winnie		29.791945	-94.469722	160	no		0
21	Point	193725	New Well	Domestic	Chambers	Stacy Devillier	3113 FM 1410 N	Winnie	77665	29.8725	-94.4925	170			0
22	Point	201255	New Well	Rig Supply	Chambers	Black Creek Drilling, Inc	F.M. 1410	Winnie	77665	29.834445	-94.498056	200	no		0
23	Point	203813	New Well	Rig Supply	Liberty	First Strike	CR 1010	Nome	77629	29.921111	-94.466667	210	no		0
24	Point	205127	New Well	Domestic	Chambers	Cecil Oldham	North Pear Orch	Winnie		29.823889	-94.498056	170	no		0
25	Point	217642	New Well	Rig Supply	Liberty	Black Creek	CR 1010	Nome	77629	29.916389	-94.465001	160			0
26	Point	247125	New Well	Rig Supply	Jefferson	Choice Exploration,Inc.	2.7 mi. W Intsc.	7.8 mi. S Nome		29.923889	-94.426389	225	no		0
27	Point	250624	New Well	Rig Supply	Jefferson	Choice Exploration,Inc.	Approx 12 mi. N	7.1 mi. SE Felici		29.923889	-94.426389	175	no		0
28	Point	251104	New Well	Domestic	Chambers	Steve Stelly	FM 1663	Winnie		29.856945	-94.436111	155	no		0
29	Point	254611	New Well	Domestic	Chambers	M. Bramble	149 McBride-De	Winnie	77665	29.858056	-94.508334	165	no		0
30	Point	256323	New Well	Domestic	Chambers	Dustin Huff	916 McBride De	Winnie Tx.	77665	29.847778	-94.509445	170	no		0
31	Point	259784	New Well	Domestic	Chambers	Juan Rodriguez	1715 McBrideDe	Winnie	77665	29.845	-94.493334	172	no		0
32	Point	265312	New Well	Rig Supply	Jefferson	Shore Petroleum by Bla	3.5 NW Intsc. Hv	7.9 mi. S Nome		29.922222	-94.422222	225	no		0
33	Point	285975	New Well	Rig Supply	Liberty	Square Mile Energy LC	5.2 mi. SE from	Felicia		29.945278	-94.472222	200	no		0
34	Point	286415	New Well	Rig Supply	Liberty	Choice Exploration Inc.	on lease road o	Felicia		29.917222	-94.489722	175	no		0
35	Point	299823	New Well	Domestic	Jefferson	Patty Rayburn	2225 N. Major D	Beaumont	77713	29.899445	-94.438889	140	no		0
36	Point	307021	New Well	Rig Supply	Liberty	GCER Onshore by Preci	Henderson Ran	9.7 mi. SE Devee		29.941389	-94.472778	92	no	88845	0
37	Point	317703	New Well	Rig Supply	Liberty	GCER,LLC(Gulf Coast En	on SE corner of	10.2 mi. SE Deve		29.923055	-94.48	182	no		0
38	Point	320432	New Well	Rig Supply	Liberty	GCER Onshore LLC	off FM 1410; 5 m	10.2 mi. NW Wi		29.916944	-94.511112	172	no		0
39	Point	323411	New Well	Irrigation	Jefferson	Gerald Bauer	18615 George B	Winnie	Tx	29.895556	-94.406945	180	no		0
40	Point	323412	New Well	Irrigation	Jefferson	Gerald Bauer	18615 George B	Winnie	77665	29.895834	-94.408056	165	no		0
41	Point	326165	New Well	Domestic	Chambers	Richard Ferguson	2425 McBride D	Winnie TX		29.845556	-94.485278	170			0
42	Point	326493	New Well	Stock	Liberty	L & S Farm & Ranch	Willis & Ebner R	Nome		29.905556	-94.445556	135			0
43	Point	326856	New Well	Domestic	Chambers	Steve Devillier	2611 Devillier R	Winnie		29.830555	-94.434722	160			0
44	Point	326863	New Well	Stock	Chambers	Steve Devillier	North 1410	Winnie		29.881389	-94.49	170			0
45	Point	335762	New Well	Rig Supply	Liberty	Chesapeake Operating	8 mi south from			29.923333	-94.455278	175	no		0
46	Point	340038	New Well	Rig Supply	Liberty	Choice Exploration,Inc.	off FM 1410; 5 m	10.2 mi. NW Wi		29.916389	-94.492778	192	no		0
47	Point	348148	New Well	Rig Supply	Chambers	Samson Exploration, LL	Plummer Road	6 mi. NW Winni		29.878611	-94.474722	192	no		0
48	Point	366766	New Well	Domestic	Chambers	William Deering	Hamilton Latera	Hankamar		29.859723	-94.523889	330			0
49	Point	395329	New Well	Stock	Jefferson	jack bauer	3 miles on right	wennie	77665	29.900001	-94.383611	170	no		0
50	Point	395330	New Well	Stock	Jefferson	Jack bauer	I10 W TO 1406 G	WENNIE	77665	29.916667	-94.400001	160	no		0
51	Point	403407	New Well	Stock	Jefferson	Cody Teel	11495 Heisig Rd	Hampshire	77662	29.927222	-94.354445	165	no		0
52	Point	406669	New Well	Rig Supply	Jefferson	SV Energy Company,LL	6.3 mi. NW Ham	Hamshire		29.916694	-94.394667	187	no		0
53	Point	438155	New Well	Domestic	Chambers	Jesse Robertson	2275 N FM 1410	Winnie		29.855882	-94.492567	172	no		0
54	Point	442143	New Well	Domestic	Chambers	Neal Prejean	1545 N. FM 141(	Winnie	77665	29.85085	-94.485383	174	no		0
55	Point	442845	New Well	Rig Supply	Chambers	Fairways Exploration &	off N Pair Orcha	7 mi. SW Winnie		29.79595	-94.496717	263	no		0
56	Point	443286	New Well	Domestic	Chambers	robert garcia	8015 nfm565	baytown	77523	29.83985	-94.422883	310	no		0
57	Point	449017	New Well	Domestic	Chambers	VERONICA L VARGAS	1790 MCBRIDG D	WINNIE	77665	29.844917	-94.49525	178	no		0
58	Point	479003	New Well	Domestic	Chambers	Mike Reed	724 Fm. 1410	Winnie	77665	29.840067	-94.481	176	no		0
59	Point	480424	New Well	Domestic	Chambers	Larry Harper	1401 FM 1410 S	Winnie	77665	29.813291	-94.480117	256	no		0
60	Point	481234	New Well	Domestic	Chambers	Guadalupe Montalvo	364 Olede Devil	Winnie	77665	29.841467	-94.492983	190	no		0
61	Point	512073	New Well	Domestic	Chambers	James Smiley	2090 Mcbride D	Winnie	77665	29.844361	-94.491206	180	no		0
62	Point	518702	New Well	Domestic	Chambers	Brent A. Potier	43515 IH -10	Winnie	77665	29.830362	-94.415985	195	no		0
63	Point	521613	New Well	Domestic	Chambers	Roberto Elorza	372 Olide Devill	Winnie	77665	29.841111	-94.491389	178	no		0
64	Point	523713	New Well	Irrigation	Liberty	L & S Farm & Ranch	13270 Ebner Rd	Nome	77665	29.910633	-94.461467	142	no		0
65	Point	524205	New Well	Domestic	Chambers	Halley Ray Moor Jr.	5555 FM 1663	Winnie	77665	29.866017	-94.5348	290	no		0
66	Point	547012	New Well	Domestic	Chambers	ROBERT LEE	1519 EAST BUCC	WINNIE	77665	29.806389	-94.441667	146	no		0
67	Point	583234	New Well	Domestic	Chambers	Gary Monteau	975 Plummer rd	winnie tx.	77665	29.872362	-94.475762	170	no		0
68	Point	586057	New Well	Domestic	Chambers	Lee Sanders	550 N Pear orch	winnie	77665	29.821151	-94.499812	178	no		0
69	Point	601978	New Well	Domestic	Chambers	Brady Hood	43680 IH-10	Winnie	77665	29.824012	-94.41119	168	no		0
70	Point	624185	New Well	Stock	Liberty	Angela and Albert Myre	7820 Fm 1410	Devers	77538	29.9	-94.491944	180	no		0
71	Point	626776	New Well	Domestic	Chambers	Kolton Page	1805 FM 1410 S	Winnie	77665	29.804171	-94.475639	175	no		0

Table D-AoR-6: Wells used to account for the number of shallow water wells with in the AOI (TRRC).

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
0	Point	1199351	7	29132797	40	-94.4898	29.91728	-94.4898	29.91728	32797
1	Point	159104	3	291	15	-94.5045	29.89368	-94.5047	29.8939	
2	Point	163049	3	245	15	-94.4458	29.95913	-94.446	29.95934	
3	Point	163069	3	291	15	-94.4695	29.95405	-94.4696	29.95427	
4	Point	163071	3	291	15	-94.4502	29.9507	-94.4504	29.95092	
5	Point	163068	3	291	15	-94.473	29.9502	-94.4732	29.95041	
6	Point	1095144	3	29132485	40	-94.4618	29.94691	-94.462	29.94712	32485
7	Point	163070	3	291	15	-94.4665	29.94606	-94.4666	29.94628	
8	Point	1179544	8	29132764	40	-94.4722	29.94523	-94.4724	29.94544	32764
9	Point	163075	3	29131279	15	-94.4737	29.94397	-94.4739	29.94419	31279
10	Point	159105	3	291	15	-94.5112	29.89119	-94.5114	29.89141	
11	Point	163125	8	29132226	55	-94.4725	29.94167	-94.4727	29.94188	32226
12	Point	1256764	7	29132876	40	-94.4728	29.94138	-94.4729	29.9416	32876
13	Point	163074	3	29131368	15	-94.4792	29.94125	-94.4794	29.94147	31368
14	Point	163082	3	291	15	-94.4509	29.93938	-94.4511	29.9396	
15	Point	1109486	8	29132549	55	-94.4664	29.94001	-94.4666	29.94022	32549
16	Point	163080	3	291	15	-94.4623	29.9393	-94.4625	29.93952	
17	Point	163078	3	29132018	15	-94.4745	29.93733	-94.4747	29.93755	32018
18	Point	1095965	87	29132484	40	-94.4575	29.93597	-94.4577	29.93618	32484
19	Point	163079	3	291	15	-94.4696	29.93597	-94.4698	29.93619	
20	Point	163113	8	291	15	-94.4638	29.93567	-94.464	29.93589	
21	Point	163081	3	29131893	15	-94.4591	29.93513	-94.4593	29.93535	31893
22	Point	163077	3	29131801	15	-94.4737	29.93463	-94.4739	29.93485	31801
23	Point	163109	2	29131669	15	-94.4737	29.93372	-94.4739	29.93393	31669
24	Point	163084	3	291	15	-94.4549	29.93231	-94.4551	29.93252	
25	Point	1089718	87	29132468	40	-94.4638	29.93266	-94.464	29.93288	32468
26	Point	163076	3	29132047	15	-94.4749	29.93313	-94.4751	29.93334	32047
27	Point	159174	3	291	15	-94.5082	29.88998	-94.5084	29.8902	
28	Point	163083	3	291	15	-94.4595	29.93211	-94.4597	29.93233	
29	Point	1087508	3	29132459	55	-94.4637	29.93109	-94.4639	29.93131	32459
30	Point	163073	3	291	15	-94.4811	29.93161	-94.4813	29.93182	
31	Point	163085	3	29131466	15	-94.4501	29.92886	-94.4503	29.92908	31466
32	Point	163115	7	29131526	15	-94.4511	29.92875	-94.4513	29.92896	31526
33	Point	163114	7	291	15	-94.4559	29.92821	-94.4561	29.92843	
34	Point	163100	3	291	15	-94.4804	29.92912	-94.4806	29.92934	
35	Point	1087754	3	29132460	40	-94.4671	29.9282	-94.4673	29.92841	32460
36	Point	1116402	20	29132583	40	-94.4855	29.92821	-94.4857	29.92843	32583
37	Point	163087	3	291	15	-94.4602	29.92707	-94.4604	29.92729	

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
38	Point	163102	3	291	15	-94.4925	29.92847	-94.4927	29.92869	
39	Point	163110	7	29131366	50	-94.4861	29.92739	-94.4863	29.92761	31366
40	Point	163086	3	29131349	15	-94.4546	29.926	-94.4548	29.92622	31349
41	Point	163129	87	29130590	40	-94.486	29.92712	-94.4862	29.92734	30590
42	Point	163105	3	291	15	-94.4839	29.92546	-94.4841	29.92568	
43	Point	163101	3	291	15	-94.4716	29.92454	-94.4718	29.92476	
44	Point	163117	8	291	15	-94.4886	29.92477	-94.4888	29.92499	
45	Point	1169804	87	29132528	40	-94.4553	29.92329	-94.4555	29.92351	32528
46	Point	163103	3	291	15	-94.4921	29.92486	-94.4923	29.92508	
47	Point	1205916	87	29132807	40	-94.4466	29.92156	-94.4467	29.92178	32807
48	Point	163088	3	291	15	-94.4548	29.92186	-94.455	29.92208	
49	Point	163123	3	29132182	40	-94.4965	29.9235	-94.4967	29.92372	32182
50	Point	1266785	3	29132888	55	-94.48	29.92246	-94.4802	29.92268	32888
51	Point	163120	3	291	15	-94.4589	29.92142	-94.4591	29.92163	
52	Point	163089	3	291	15	-94.4584	29.92137	-94.4586	29.92158	
53	Point	163099	3	291	15	-94.4806	29.9216	-94.4808	29.92182	
54	Point	1175743	86	29132750	40	-94.4669	29.92082	-94.4671	29.92104	32750
55	Point	163116	8	291	15	-94.4927	29.9212	-94.4929	29.92141	
56	Point	163090	3	291	15	-94.45	29.91777	-94.4502	29.91798	
57	Point	163104	3	29131624	15	-94.4968	29.91802	-94.497	29.91823	31624
58	Point	1207820	3	29132810	55	-94.457	29.91618	-94.4572	29.91639	32810
59	Point	163111	2	291	15	-94.4836	29.91628	-94.4838	29.9165	
60	Point	1252733	3	29132872	55	-94.4927	29.91628	-94.4928	29.9165	32872
61	Point	163091	3	29132043	15	-94.4471	29.91399	-94.4473	29.9142	32043
62	Point	163098	3	291	15	-94.4934	29.91451	-94.4936	29.91473	
63	Point	163112	5	29131383	15	-94.4731	29.91038	-94.4733	29.9106	31383
64	Point	163121	10	29131630	15	-94.4453	29.9085	-94.4455	29.90871	31630
65	Point	163122	10	29131513	15	-94.4436	29.90634	-94.4438	29.90656	31513
66	Point	163092	3	29131567	15	-94.4472	29.90536	-94.4474	29.90558	31567
67	Point	163093	3	29131579	15	-94.4433	29.90225	-94.4435	29.90247	31579
68	Point	163097	3	291	15	-94.4965	29.90215	-94.4967	29.90237	
69	Point	163096	3	29131496	15	-94.4674	29.90048	-94.4676	29.9007	31496
70	Point	163094	3	29131595	15	-94.4492	29.89895	-94.4494	29.89917	31595
71	Point	163095	3	291	15	-94.4749	29.8973	-94.475	29.89752	
72	Point	1088101	3	29132462	40	-94.4521	29.89096	-94.4523	29.89117	32462
73	Point	159111	3	29131323	15	-94.544	29.93226	-94.5442	29.93248	31323
74	Point	159110	3	291	15	-94.5514	29.93125	-94.5516	29.93146	
75	Point	159176	3	291	15	-94.5503	29.93093	-94.5505	29.93115	
76	Point	159108	3	291	15	-94.5357	29.92823	-94.5359	29.92845	
77	Point	159109	3	291	15	-94.5471	29.92453	-94.5473	29.92474	

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
78	Point	159101	3	291	15	-94.501	29.92056	-94.5012	29.92078	
79	Point	1269108	3	29132890	55	-94.5113	29.91711	-94.5115	29.91733	32890
80	Point	159102	3	291	15	-94.5012	29.91457	-94.5014	29.91479	
81	Point	159103	3	291	15	-94.5172	29.91379	-94.5174	29.91401	
82	Point	159131	8	29130642	15	-94.5206	29.91322	-94.5208	29.91344	30642
83	Point	159173	3	291	15	-94.5286	29.91322	-94.5288	29.91344	
84	Point	159106	3	291	15	-94.5159	29.9004	-94.5161	29.90061	

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
0	Point	159078	3	71	15	-94.5024	29.88702	-94.5026	29.88724	
1	Point	159076	9	7131379	15	-94.5063	29.87879	-94.5065	29.87901	31379
2	Point	159077	3	71	15	-94.5017	29.87802	-94.5019	29.87824	
3	Point	162875	3	71	15	-94.4551	29.88803	-94.4553	29.88825	
4	Point	162877	3	71	15	-94.4639	29.88796	-94.4641	29.88818	
5	Point	162912	3	71	15	-94.467	29.88791	-94.4672	29.88813	
6	Point	162878	3	71	15	-94.4647	29.88696	-94.4649	29.88718	
7	Point	162879	3	71	15	-94.4677	29.88677	-94.4679	29.88699	
8	Point	162881	3	7131623	15	-94.4927	29.88608	-94.4929	29.8863	31623
9	Point	162911	3	7131517	15	-94.4584	29.88424	-94.4586	29.88446	31517
10	Point	162880	3	71	15	-94.4723	29.88189	-94.4725	29.88211	
11	Point	162876	3	71	15	-94.4459	29.87951	-94.4461	29.87973	
12	Point	162883	7	7131884	15	-94.4647	29.88006	-94.4649	29.88028	31884
13	Point	1278800	87	7132527	55	-94.4748	29.87875	-94.475	29.87897	32527
14	Point	162882	2	7131659	15	-94.4559	29.87627	-94.4561	29.87649	31659
15	Point	162886	7	7101771	15	-94.4649	29.8761	-94.4651	29.87632	1771
16	Point	162885	7	71	15	-94.4681	29.87589	-94.4683	29.87611	
17	Point	162884	4	71	15	-94.4713	29.87525	-94.4715	29.87546	
18	Point	157840	3	71	15	-94.5204	29.85365	-94.5206	29.85387	
19	Point	158167	3	71	15	-94.5018	29.84274	-94.502	29.84296	
20	Point	157842	8	7130563	15	-94.5014	29.82191	-94.5016	29.82213	30563
21	Point	157858	3	71	15	-94.501	29.81718	-94.5012	29.8174	
22	Point	157860	5	7130314	15	-94.5037	29.81667	-94.5039	29.81689	30314
23	Point	162627	4	71	15	-94.4713	29.87483	-94.4715	29.87504	
24	Point	162629	7	7131785	15	-94.4674	29.87288	-94.4676	29.87309	31785
25	Point	162630	7	7102002	15	-94.4679	29.87209	-94.4681	29.87231	2002
26	Point	162859	3	7130159	15	-94.4722	29.8721	-94.4724	29.87232	30159
27	Point	162620	3	71	15	-94.4712	29.87116	-94.4714	29.87137	
28	Point	162633	10	7102004	15	-94.4674	29.86936	-94.4676	29.86958	2004
29	Point	162621	3	71	15	-94.4681	29.86184	-94.4683	29.86206	
30	Point	162634	3	71	15	-94.4311	29.86022	-94.4313	29.86044	

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
31	Point	162624	3	71	15	-94.4559	29.85796	-94.4561	29.85818	
32	Point	162625	3	71	15	-94.4484	29.85591	-94.4486	29.85613	
33	Point	162623	3	7131389	15	-94.464	29.85447	-94.4642	29.85469	31389
34	Point	162619	3	71	15	-94.4897	29.85351	-94.4899	29.85373	
35	Point	1053943	3	7132174	55	-94.4985	29.85346	-94.4987	29.85368	32174
36	Point	162855	3	71	15	-94.4414	29.84808	-94.4416	29.8483	
37	Point	162636	3	71	15	-94.4207	29.84538	-94.4209	29.8456	
38	Point	162853	9	7130771	15	-94.4612	29.84368	-94.4614	29.8439	30771
39	Point	162638	3	7131394	15	-94.4625	29.8436	-94.4627	29.84382	31394
40	Point	162637	3	71	15	-94.472	29.84327	-94.4722	29.84349	
41	Point	1200520	3	7132386	55	-94.4982	29.83448	-94.4984	29.8347	32386
42	Point	162861	2	7131302	15	-94.4952	29.83291	-94.4954	29.83313	31302
43	Point	162849	3	71	15	-94.486	29.83221	-94.4861	29.83243	
44	Point	162795	3	71	15	-94.4114	29.82555	-94.4116	29.82577	
45	Point	162640	3	71	15	-94.48	29.82822	-94.4802	29.82844	
46	Point	162854	9	7131452	15	-94.4728	29.82473	-94.4729	29.82495	31452
47	Point	162848	87	7130837	15	-94.4949	29.82521	-94.4951	29.82544	30837
48	Point	162639	3	7130967	15	-94.4884	29.823	-94.4886	29.82322	30967
49	Point	162644	3	71	15	-94.4569	29.82137	-94.4571	29.82159	
50	Point	1085697	3	7132233	40	-94.452	29.82108	-94.4522	29.8213	32233
51	Point	162658	22	7130370	15	-94.4955	29.81872	-94.4957	29.81894	30370
52	Point	162646	3	71	15	-94.4399	29.81511	-94.4401	29.81533	
53	Point	162641	3	7130564	15	-94.4782	29.81471	-94.4784	29.81493	30564
54	Point	162642	3	71	15	-94.4737	29.81399	-94.4739	29.81421	
55	Point	162657	8	7130356	15	-94.4959	29.81368	-94.4961	29.8139	30356
56	Point	162645	3	7131267	15	-94.4528	29.80873	-94.453	29.80895	31267
57	Point	162643	2	71	15	-94.4787	29.80649	-94.4789	29.80671	
58	Point	162659	3	71	15	-94.4205	29.80342	-94.4207	29.80364	
59	Point	162656	3	71	15	-94.4946	29.80417	-94.4948	29.80439	
60	Point	162733	3	71	15	-94.4887	29.80357	-94.4889	29.80379	
61	Point	162738	2	71	15	-94.4782	29.80284	-94.4784	29.80306	
62	Point	162737	3	7131036	15	-94.4667	29.80178	-94.4669	29.802	31036
63	Point	162749	3	7131164	15	-94.4501	29.80052	-94.4503	29.80074	31164
64	Point	162660	3	71	15	-94.421	29.79898	-94.4212	29.7992	
65	Point	162736	3	71	15	-94.4746	29.8003	-94.4748	29.80052	
66	Point	162732	3	71	15	-94.4836	29.798	-94.4838	29.79822	
67	Point	162661	3	71	15	-94.4196	29.79321	-94.4198	29.79343	
68	Point	1322630	87	7132617	55	-94.4971	29.7959	-94.4973	29.79612	32617
69	Point	162734	3	71	15	-94.4812	29.79498	-94.4813	29.79521	
70	Point	162653	3	7131551	15	-94.4972	29.79369	-94.4974	29.79392	31551

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
71	Point	162731	3	71	15	-94.4839	29.79288	-94.4841	29.7931	
72	Point	162735	3	71	15	-94.4757	29.79246	-94.4758	29.79268	
73	Point	162739	87	7130096	15	-94.4905	29.79232	-94.4907	29.79254	30096
74	Point	162652	3	7131515	15	-94.4967	29.79202	-94.4968	29.79225	31515
75	Point	162741	7	7103484	15	-94.4825	29.79137	-94.4827	29.79159	3484
76	Point	162740	7	7181503	15	-94.4848	29.79134	-94.485	29.79157	81503
77	Point	162730	87	7120340	15	-94.4907	29.79403	-94.4909	29.79426	20340
78	Point	1425623	2	7132664	55	-94.4564	29.84418	-94.4566	29.84441	32664

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
0	Point	162972	3	24531429	15	-94.4329	29.97563	-94.4331	29.97585	31429
1	Point	162995	3	24531260	15	-94.3757	29.97087	-94.3759	29.97108	31260
2	Point	162994	3	245	15	-94.3797	29.96892	-94.3799	29.96914	
3	Point	162971	3	24531519	15	-94.4342	29.96832	-94.4344	29.96854	31519
4	Point	162990	3	245	15	-94.3911	29.96001	-94.3912	29.96023	
5	Point	162970	3	245	15	-94.4258	29.9588	-94.426	29.95901	
6	Point	162989	3	245	15	-94.3995	29.95726	-94.3997	29.95748	
7	Point	162981	3	24531345	15	-94.3813	29.95374	-94.3815	29.95395	31345
8	Point	162980	3	245	15	-94.3769	29.9518	-94.3771	29.95202	
9	Point	162996	3	24531411	15	-94.4311	29.95308	-94.4313	29.9533	31411
10	Point	162979	3	245	15	-94.3965	29.94984	-94.3967	29.95005	
11	Point	162977	3	245	15	-94.4077	29.94624	-94.4079	29.94645	
12	Point	1070057	3	24532294	55	-94.438	29.94655	-94.4382	29.94677	32294
13	Point	162968	3	245	15	-94.3924	29.94392	-94.3926	29.94414	
14	Point	163001	10	245	15	-94.4123	29.94351	-94.4125	29.94372	
15	Point	162974	3	245	15	-94.4161	29.94285	-94.4163	29.94306	
16	Point	162978	3	245	15	-94.4072	29.94245	-94.4074	29.94266	
17	Point	162961	3	24502157	15	-94.4017	29.94066	-94.4019	29.94088	2157
18	Point	163019	7	24530372	15	-94.4009	29.94046	-94.4011	29.94067	30372
19	Point	162967	3	245	15	-94.3919	29.93957	-94.3921	29.93978	
20	Point	162976	3	245	15	-94.4124	29.94024	-94.4126	29.94045	
21	Point	162975	3	245	15	-94.4149	29.94001	-94.4151	29.94023	
22	Point	163030	7	24530048	15	-94.4156	29.93972	-94.4158	29.93994	30048
23	Point	162957	3	245	15	-94.4186	29.93885	-94.4188	29.93907	
24	Point	163000	10	24530171	15	-94.4122	29.93834	-94.4124	29.93856	30171
25	Point	163051	3	24531809	15	-94.4145	29.9378	-94.4147	29.93801	31809
26	Point	163010	7	24502155	40	-94.4132	29.93736	-94.4134	29.93758	2155
27	Point	162958	3	24530053	15	-94.417	29.93714	-94.4172	29.93736	30053
28	Point	162955	3	245	15	-94.4376	29.93662	-94.4378	29.93683	

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
29	Point	162959	3	245	15	-94.4157	29.93456	-94.4159	29.93478	
30	Point	162966	3	24531547	15	-94.3924	29.93348	-94.3926	29.9337	31547
31	Point	163128	3	24532118	40	-94.4078	29.93381	-94.408	29.93403	32118
32	Point	163008	8	24503137	15	-94.4118	29.93338	-94.412	29.93359	3137
33	Point	162965	3	245	15	-94.3904	29.93238	-94.3906	29.9326	
34	Point	162964	3	24531861	15	-94.3922	29.93218	-94.3924	29.9324	31861
35	Point	163029	7	24531191	15	-94.3936	29.93216	-94.3938	29.93237	31191
36	Point	163018	7	245	15	-94.4145	29.93287	-94.4147	29.93309	
37	Point	163009	10	24531183	40	-94.4141	29.93251	-94.4143	29.93272	31183
38	Point	163028	4	24531844	40	-94.3939	29.93074	-94.3941	29.93096	31844
39	Point	162963	3	245	15	-94.3924	29.92941	-94.3926	29.92963	
40	Point	162960	3	24503113	15	-94.4172	29.93037	-94.4174	29.93059	3113
41	Point	162962	3	245	15	-94.3974	29.9294	-94.3975	29.92962	
42	Point	163011	5	24530443	15	-94.3945	29.92882	-94.3947	29.92904	30443
43	Point	162916	11	24531249	15	-94.3957	29.92875	-94.3959	29.92896	31249
44	Point	162956	3	245	15	-94.4298	29.93005	-94.43	29.93027	
45	Point	162954	3	245	15	-94.4403	29.92929	-94.4405	29.92951	
46	Point	162999	7	24530276	15	-94.3946	29.92681	-94.3948	29.92703	30276
47	Point	163027	7	245	15	-94.3876	29.92571	-94.3878	29.92593	
48	Point	162940	3	245	15	-94.4044	29.92622	-94.4046	29.92643	
49	Point	162942	3	245	15	-94.4117	29.92648	-94.4119	29.9267	
50	Point	162938	3	245	15	-94.3931	29.92552	-94.3933	29.92574	
51	Point	162945	3	245	15	-94.4172	29.92642	-94.4174	29.92664	
52	Point	162950	3	24531629	15	-94.4279	29.92641	-94.4281	29.92662	31629
53	Point	162949	3	245	15	-94.4249	29.92602	-94.4251	29.92624	
54	Point	163025	87	24502137	15	-94.3924	29.92454	-94.3926	29.92476	2137
55	Point	162915	2	24531180	15	-94.3976	29.92427	-94.3978	29.92449	31180
56	Point	162951	3	245	15	-94.4287	29.92534	-94.4289	29.92556	
57	Point	162944	3	245	15	-94.416	29.9247	-94.4162	29.92491	
58	Point	163024	7	245	15	-94.4124	29.92427	-94.4126	29.92448	
59	Point	162952	3	245	15	-94.4325	29.92434	-94.4327	29.92455	
60	Point	163026	4	245	15	-94.3881	29.92231	-94.3883	29.92253	
61	Point	163017	7	245	15	-94.391	29.9219	-94.3912	29.92212	
62	Point	162941	3	24531793	15	-94.4097	29.9227	-94.4099	29.92292	31793
63	Point	1221508	87	24532685	40	-94.4265	29.92325	-94.4266	29.92347	32685
64	Point	1224402	87	24532689	55	-94.4221	29.92225	-94.4223	29.92247	32689
65	Point	162939	3	245	15	-94.4031	29.92122	-94.4033	29.92143	
66	Point	162937	3	245	15	-94.3875	29.9205	-94.3877	29.92072	
67	Point	162947	3	245	15	-94.4204	29.92141	-94.4206	29.92163	
68	Point	162953	3	245	15	-94.4334	29.92162	-94.4336	29.92183	

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
69	Point	162943	3	245	15	-94.4155	29.92068	-94.4156	29.92089	
70	Point	1148356	3	24532477	40	-94.4227	29.92066	-94.4229	29.92088	32477
71	Point	163013	8	245	15	-94.3789	29.91873	-94.3791	29.91895	
72	Point	163012	8	245	15	-94.3954	29.9194	-94.3956	29.91961	
73	Point	162914	3	24532018	15	-94.3973	29.91851	-94.3975	29.91872	32018
74	Point	163016	7	245	15	-94.3915	29.91774	-94.3917	29.91795	
75	Point	162948	3	24531849	15	-94.4247	29.91878	-94.4249	29.91899	31849
76	Point	163007	8	24580092	15	-94.393	29.91722	-94.3932	29.91744	80092
77	Point	1103233	3	24532354	40	-94.3847	29.91651	-94.3849	29.91673	32354
78	Point	1063087	3	24532266	55	-94.3965	29.91659	-94.3967	29.91681	32266
79	Point	162946	3	245	15	-94.4181	29.91702	-94.4183	29.91723	
80	Point	162936	3	245	15	-94.388	29.91559	-94.3882	29.9158	
81	Point	163015	7	245	15	-94.391	29.9152	-94.3912	29.91541	
82	Point	162998	10	24531544	15	-94.3936	29.91465	-94.3938	29.91487	31544
83	Point	162934	3	24531354	15	-94.3842	29.91287	-94.3844	29.91309	31354
84	Point	162933	3	245	15	-94.3798	29.91205	-94.3799	29.91227	
85	Point	162935	3	245	15	-94.3877	29.91233	-94.3879	29.91255	
86	Point	163003	8	245	15	-94.3949	29.91199	-94.3951	29.9122	
87	Point	162923	3	245	15	-94.404	29.91166	-94.4042	29.91188	
88	Point	163004	8	24580096	15	-94.3916	29.91109	-94.3918	29.91131	80096
89	Point	162921	3	245	15	-94.4154	29.91209	-94.4156	29.9123	
90	Point	162919	3	245	15	-94.4237	29.91194	-94.4239	29.91215	
91	Point	162918	3	245	15	-94.4378	29.91146	-94.4379	29.91167	
92	Point	163005	5	245	15	-94.3864	29.90767	-94.3866	29.90789	
93	Point	163023	4	245	15	-94.4121	29.90878	-94.4123	29.909	
94	Point	162932	3	245	15	-94.3882	29.90746	-94.3884	29.90767	
95	Point	162925	3	245	15	-94.396	29.90744	-94.3962	29.90766	
96	Point	162931	3	24531264	15	-94.3818	29.90674	-94.382	29.90696	31264
97	Point	162924	3	24531775	15	-94.3961	29.90695	-94.3963	29.90716	31775
98	Point	163050	3	245	15	-94.4097	29.90713	-94.4099	29.90735	
99	Point	163022	7	24531343	15	-94.3933	29.90621	-94.3935	29.90642	31343
100	Point	163033	3	24531911	15	-94.3968	29.90502	-94.397	29.90524	31911
101	Point	163002	8	245	15	-94.391	29.90315	-94.3912	29.90337	
102	Point	162913	9	24531801	15	-94.3994	29.90312	-94.3996	29.90334	31801
103	Point	162930	3	245	15	-94.386	29.90237	-94.3862	29.90259	
104	Point	162922	3	24531158	15	-94.4117	29.90257	-94.4119	29.90279	31158
105	Point	162997	6	24531201	15	-94.382	29.90055	-94.3822	29.90076	31201
106	Point	1118437	11	24532396	40	-94.3842	29.90051	-94.3844	29.90073	32396
107	Point	1065859	3	24532275	55	-94.3945	29.90083	-94.3947	29.90105	32275
108	Point	162929	3	24531577	15	-94.3886	29.90042	-94.3888	29.90064	31577

FID	Shape *	SURFACE_ID	SYMNUM	API	RELIAB	LONG27	LAT27	LONG83	LAT83	WELLID
109	Point	162920	3	245	15	-94.4216	29.90177	-94.4218	29.90199	
110	Point	162917	3	245	15	-94.4313	29.88827	-94.4315	29.88849	
111	Point	163192	3	24531485	15	-94.373	29.96395	-94.3731	29.96417	31485
112	Point	163147	3	24531234	15	-94.337	29.92057	-94.3372	29.92079	31234
113	Point	163146	3	245	15	-94.3362	29.92042	-94.3364	29.92064	
114	Point	163150	3	245	15	-94.3664	29.9204	-94.3666	29.92062	
115	Point	163149	87	24531733	15	-94.3632	29.91869	-94.3634	29.9189	31733
116	Point	1296103	4	24532823	55	-94.3949	29.91664	-94.3949	29.91664	32823

Table D-AoR-7: Additional wells with digital logs used to create petrophysically analyzed logs within the Lower Miocene geomodel. Petrophysically analyzed logs were used to create the various property models

PETROPHYSICA ANALYSIS - RESULTS CURVES IN WELLS USED FOR FACIES						
UWI (APINum)	Well Label	XVCL	XVSH	XPORE	XPORT	XK
42245315320000	WALTER CO NCT-1 #1	X	X	X	X	X
42245315530000	DISHMAN #1	X	X	X	X	X
42245317500000	WALTER UN O/A GU #1	X	X	X	X	X
42245317780000	BLANCH GRACE #1	X	X	X	X	X
42245318390000	BROUSSARD JOE #1	X	X	X	X	X
42245321280000	BOWER JONES #1	X	X	X	X	X
42245321880000	CLUBB PROSPECT #1	X	X	X	X	X
42245326930000	GEHEB #1	X	X	X	X	X
42071310770000	EVANS W L #3	X	X	X	X	X
42071313750000	R L WHITE #1	X	X	X	X	X
42071316790000	HANKAMER ADOLPH #1	X	X	X	X	X
42071322280000	OGDEN ET AL #1	X	X	X	X	X
42071322590000	JEFFREY #1	X	X	X	X	X
42071323850000	WHITE-OLSEN HEIRS U #1	X	X	X	X	X
42245314850000	BEAVERS W H #1	X	X	X	X	X
42245322660000	BAUER #1	X	X	X	X	X
42245322750000	LOHMANN #1	X	X	X	X	X
42291315790000	SECURITY ST BANK #1	X	X	X	X	X
42291328880000	HUDSON #1	X	X	X	X	X
42071325240000	MCGOWN FARMS GU #1	X	X	X	X	X
42071326640000	ENCANTO #1	X	X	X	X	X
42071019600000	TRINITY RICE #1	X	X	X	X	X
42071311640000	GARTH #1	X	X	X	X	X
42071312670000	DOORNBOS WILLIM ETL #1	X	X	X	X	X
42071313020000	DEVILLIER O C JR #1	X	X	X	X	X
42071314410000	JENKNS LYDIA GUIDRY #1	X	X	X	X	X
42071315170000	MAXWELL LAMAR #1	X	X	X	X	X
42071315510000	DEVILLIER O C JR #1	X	X	X	X	X
42071316340000	DUGAT #2A	X	X	X	X	X
42071316340100	DUGAT #2A	X	X	X	X	X
42071316540000	CRAWFORD ETAL W J #159-2	X	X	X	X	X
42071316740000	SORELLE #2	X	X	X	X	X
42071317850000	BOYT E W ETUX #4	X	X	X	X	X
42071318690000	MCADAMS JOHN P #1	X	X	X	X	X
42071318840000	WAUGH B R ETAL #1	X	X	X	X	X
42071320740000	HSR E COOPER NO 2 #1	X	X	X	X	X
42071321630000	DOORNBOS ET AL #1	X	X	X	X	X
42071321740000	HOLTER ET AL #1	X	X	X	X	X
42071324470000	WASSON ET AL UNIT #4	X	X	X	X	X
42071326020000	ELM BAYOU UNIT #1	X	X	X	X	X
42245314050000	BROUSSARD #1	X	X	X	X	X
42245314200000	WALTER CO #1	X	X	X	X	X
42245317300000	BOYT #1	X	X	X	X	X
42245318260000	MACKAN R L #1	X	X	X	X	X
42245319470000	CRTI/MCLEOD INC GIL #1	X	X	X	X	X

Table D-AoR-7: Additional wells with digital logs used to create petrophysically analyzed logs within the Lower Miocene geomodel. Petrophysically analyzed logs were used to create the various property models (continued)

PETROPHYSICA ANALYSIS - RESULTS CURVES IN WELLS USED FOR FACIES						
UWI (APINum)	Well Label	XVCL	XVSH	XPORE	XPORT	XK
42245319590000	CRTI/MCLEOD-GILBERT #1	X	X	X	X	X
42245321180000	CARROLL W M EST #1	X	X	X	X	X
42245321270000	KIKER #01	X	X	X	X	X
42245321920000	BOYT #1	X	X	X	X	X
42245321930000	CLUBB J T #1	X	X	X	X	X
42245322030000	WINGATE PANSY ETAL #1	X	X	X	X	X
42245322040000	SHERRON ELEANOR ETA #1	X	X	X	X	X
42245322300000	BROUSSARD #1	X	X	X	X	X
42245322590000	DOORNBOS #1	X	X	X	X	X
42245322630000	BAIKOW FRANCES G ET #1	X	X	X	X	X
42245322940000	MCDERMAND #1	X	X	X	X	X
42245323510000	RIEFF #1	X	X	X	X	X
42245323540000	BAUER JACK WAYNE #1	X	X	X	X	X
42245325780000	ELEANOR #1	X	X	X	X	X
42291315260000	BROUSSARD #1	X	X	X	X	X
42291316700000	STOESSER ET AL UNIT #1	X	X	X	X	X
42291318930000	BONNER #1	X	X	X	X	X
42291321760000	FROST/KEENAN #1	X	X	X	X	X
42291321820000	BOYT #1	X	X	X	X	X
42291323750000	RAMSEY #1	X	X	X	X	X
42291323860000	HATCHER #1	X	X	X	X	X
42291324620000	BOND #1	X	X	X	X	X
42291324650000	DANIELS #1	X	X	X	X	X
42291324860000	GALLOWAY #1	X	X	X	X	X
42291325100000	HENDERSON E A #1	X	X	X	X	X
42291325270000	BRAZIL #1	X	X	X	X	X
42291325280000	ALDRICH R C ET AL #1	X	X	X	X	X
42291325550000	HENDERSON WILLIS #1	X	X	X	X	X
42291325610000	PENN-CAT #2	X	X	X	X	X
42291327970000	WILDI #1	X	X	X	X	X
42291328690000	HUNT SARAH `B` #1	X	X	X	X	X
42071323230000	KAHLA #1	X	X	X	X	X
42291321400000	NELSON TRUST #1	X	X	X	X	X
42291322600000	KELLY #1	X	X	X	X	X
42291323630000	TRISTEN-TRUETT #1	X	X	X	X	X
42291326020000	BLOXSOM A #1	X	X	X	X	X
42291318010000	DUNAGAN GRACE W ETA #1-A	X	X	X	X	X
42071303720000	L G JENKINS #1	X	X	X	X	X
42245319970000	DISHMAN H E ETAL #1	X	X	X	X	X
42245021930000	BROUSSARD J E JR #1	X	X	X	X	X
42071320880000	CRAWFORD `A` #1	X	X	X	X	X
42071325430000	DUGAT SWD #3	X	X	X	X	X
42071325690000	BUCCANEER #1	X	X	X	X	X
42245022070000	MARIE B WIER ETAL #1	X	X	X	X	X
42245022420000	W C GILBERT #1	X	X	X	X	X

Table D-AoR-7: Wells with digital logs used to create petrophysically analyzed logs within the Lower Miocene geomodel. Petrophysically analyzed logs were used to create the various property models (continued)

PETROPHYSICA ANALYSIS - RESULTS CURVES IN WELLS USED FOR FACIES						
UWI (APINum)	Well Label	XVCL	XVSH	XPORE	XPORT	XK
42245321360000	CHINA TOWNSITE UNIT #1	X	X	X	X	X
42071013620000	HANKAMER TRUSTEE #1	X	X	X	X	X
42071013630000	BROUSSARD TRUST #1	X	X	X	X	X
42071013650000	WEST WESLEY ETAL #1	X	X	X	X	X
42071013670000	JENKINS W E #1	X	X	X	X	X
42071013700000	JENKINS W E #1	X	X	X	X	X
42071019550000	DROUGHT H P #1	X	X	X	X	X
42071019580000	STERRETT EAT FRED R #1	X	X	X	X	X
42071019590000	WM DOORNBOS ETAL #1	X	X	X	X	X
42071019610000	OGDEN L G ETAL #1	X	X	X	X	X
42071019620000	DEBELLVUE MRS MARIA #1	X	X	X	X	X
42071019640000	MOORE ESTATE ELIZ H #1	X	X	X	X	X
42071019650000	I DAVENPORT #1	X	X	X	X	X
42071019660000	JOHNSON ANNIE H #1	X	X	X	X	X
42071019670000	T SIMON #1	X	X	X	X	X
42071019920000	HOWTZ SYBIL ETAL #1	X	X	X	X	X
42071019930000	SHAW UNIT #1	X	X	X	X	X
42071019960000	H J SOLEM UNIT 1 #1	X	X	X	X	X
42071020000000	MOORE ESTATE #2	X	X	X	X	X
42071033130000	J T TERRY ETAL #1	X	X	X	X	X
42071033710000	JAMES C HALL ETAL #1	X	X	X	X	X
42071303660000	O C DEVILLIER ETAL #1	X	X	X	X	X
42071304390000	EARL COOPER #1-A	X	X	X	X	X
42071304690000	BEAUMNT RC MLL #1	X	X	X	X	X
42071304850000	A S HANKAMER #1	X	X	X	X	X
42071308370000	O C DEVILLIER #6	X	X	X	X	X
42071309340000	JENKINS #1	X	X	X	X	X
42071310360000	GARTH #1	X	X	X	X	X
42071312760000	DOMEYER ETAL #1	X	X	X	X	X
42071313500000	JENKINS LYDIA ETAL #1	X	X	X	X	X
42071313940000	DEVILLIER L C #1	X	X	X	X	X
42071315900000	DUGAT #1	X	X	X	X	X
42071315940000	LULU STERLING #1	X	X	X	X	X
42071316440000	WHITE HEIRS #1	X	X	X	X	X
42071316710000	MOBIL FEE #1	X	X	X	X	X
42071317650000	THORNTON #1	X	X	X	X	X
42071318030000	POSTEMA #1	X	X	X	X	X
42071318590000	WAGENSTEEN #1	X	X	X	X	X
42071318730000	HALBOUTY-DEVILLIER #1	X	X	X	X	X
42071320910000	HSR GARTH #1 #1	X	X	X	X	X
42071322680000	CLEMENT UNIT ST #1	X	X	X	X	X
42071322960000	COOPER E #1	X	X	X	X	X
42245021150000	J E BROUSSARD ETAL #1	X	X	X	X	X
42245021170000	J S EDWARDS #1	X	X	X	X	X
42245302100000	TF KOCH NCT 1 #4	X	X	X	X	X

Table D-AoR-7: Wells with digital logs used to create petrophysically analyzed logs within the Lower Miocene geomodel. Petrophysically analyzed logs were used to create the various property models (continued)

PETROPHYSICA ANALYSIS - RESULTS CURVES IN WELLS USED FOR FACIES						
UWI (APINum)	Well Label	XVCL	XVSH	XPORE	XPORT	XK
42245302800000	HOWTH #2	X	X	X	X	X
42245311580000	L W RANKIN ET #1	X	X	X	X	X
42245312100000	LUCILLE DURAND ETAL #1	X	X	X	X	X
42245312290000	APPELT PROP /A/ #2	X	X	X	X	X
42245313430000	LOHMANN-HOWTH #1	X	X	X	X	X
42245314110000	MCDERMAND F D #1	X	X	X	X	X
42245315450000	BOUDREAUX N F ETAL #1	X	X	X	X	X
42245317200000	WALTER CO /C/ #1	X	X	X	X	X
42245317250000	WALTER CO #1	X	X	X	X	X
42245317590000	BOYT #1	X	X	X	X	X
42245322270000	MCDERMAND UNIT #1R	X	X	X	X	X
42245324980000	TURNER-BOGAN #1	X	X	X	X	X
42291045370000	ROBERTSON-MCDONAL #1	X	X	X	X	X
42291047710000	BOYT E W #2	X	X	X	X	X
42291047720000	BOYT E W #1	X	X	X	X	X
42291047740000	BOYT E W #1	X	X	X	X	X
42291053750000	ESTER SWARTZ #1	X	X	X	X	X
42291300010000	ESTER SWARTZ #4	X	X	X	X	X
42291300560000	SWARTZ ESTER #5	X	X	X	X	X
42291312300000	AMOCO PRODUCTION CO #1	X	X	X	X	X
42291315950000	MAXWELL LAMAR B ETL #1	X	X	X	X	X
42291320430000	BLANCH GRACE F #1	X	X	X	X	X
42291324590000	BONNER #1	X	X	X	X	X

Table D-AoR-8: Wells with digital logs used to define facies distribution within the Lower Miocene geomodel.

See Appendix D.1

Bluebonnet Facies Log Curve Inventory

David L. Carr, Geologist, BEG-UT Austin

158 wells for which LAS curves (any) were available

NUMBER CODES
1 = Curve covers entire Miocene interval*
3 = Curve covers part Miocene interval
0 = No curve coverage over Miocene interval
NULL = No curve available

*Miocene interval = top L. Miocene Shale to top Anahuac

Note: If a facies curve was created, then a deep resisitivty curve was available.

FACIES_GR curve inventory SUMMARY (preferred facies estimate)		
# wells	%	
73	46%	wells for which FACIES_GR curves were available over entire Miocene interval
8	5%	wells for which FACIES_GR curves were available over part of Miocene interval
10	6%	wells for which FACIES_GR curves were present, but did not cover Miocene interval
67	42%	wells for which no FACIES_GR curves was present (i.e., no GR curve available)

FACIES_SP curve inventory SUMMARY (secondary facies estimate)		
# wells	%	
134	85%	wells for which FACIES_SP curves were available over entire Miocene interval
10	6%	wells for which FACIES_SP curves were available over part of Miocene interval
7	4%	wells for which FACIES_SP curves were present, but did not cover Miocene interval
7	4%	wells for which no FACIES_SP curves was present (i.e., no SP curve available)

PEF curve inventory SUMMARY		
# wells	%	
14	9%	wells for which PEF curves were available
144	91%	wells for which no PEF curves were present

UWI (APINum)	Well Label	FACIES_GR	FACIES_SP	PEF
42245315320000	WALTER CO NCT-1 #1	3	3	
42245315530000	DISHMAN #1	3	3	
42245317500000	WALTER UN O/A GU #1	3	3	
42245317780000	BLANCH GRACE #1	3	3	
42245318390000	BROUSSARD JOE #1	3	3	
42245321280000	BOWER JONES #1	3	3	
42245321880000	CLUBB PROSPECT #1	3	3	
42245326930000	GEHEB #1	3	3	
42071310770000	EVANS W L #3	1	1	1
42071313750000	R L WHITE #1	1	1	1
42071316790000	HANKAMER ADOLPH #1	1	1	1
42071322280000	OGDEN ET AL #1	1	1	1
42071322590000	JEFFREY #1	1	1	1
42071323850000	WHITE-OLSEN HEIRS U #1	1	1	1
42245314850000	BEAVERS W H #1	1	1	1
42245322660000	BAUER #1	1	1	1
42245322750000	LOHMANN #1	1	1	1
42291315790000	SECURITY ST BANK #1	1	1	1
42291328880000	HUDSON #1	1	1	1
42071325240000	MCGOWN FARMS GU #1	1		1
42071326640000	ENCANTO #1	1		1
42071019600000	TRINITY RICE #1	1	1	
42071311640000	GARTH #1	1	1	
42071312670000	DOORNBOS WILLIM ETL #1	1	1	
42071313020000	DEVILLIER O C JR #1	1	1	
42071314410000	JENKNS LYDIA GUIDRY #1	1	1	
42071315170000	MAXWELL LAMAR #1	1	1	
42071315510000	DEVILLIER O C JR #1	1	1	
42071316340000	DUGAT #2A	1	1	
42071316340100	DUGAT #2A	1	1	
42071316540000	CRAWFORD ETAL W J #159-2	1	1	
42071316740000	SORELLE #2	1	1	
42071317850000	BOYT E W ETUX #4	1	1	
42071318690000	MCADAMS JOHN P #1	1	1	
42071318840000	WAUGH B R ETAL #1	1	1	
42071320740000	HSR E COOPER NO 2 #1	1	1	
42071321630000	DOORNBOS ET AL #1	1	1	
42071321740000	HOLTER ET AL #1	1	1	
42071324470000	WASSON ET AL UNIT #4	1	1	
42071326020000	ELM BAYOU UNIT #1	1	1	
42245314050000	BROUSSARD #1	1	1	
42245314200000	WALTER CO #1	1	1	
42245317300000	BOYT #1	1	1	
42245318260000	MACKAN R L #1	1	1	
42245319470000	CRTI/MCLEOD INC GIL #1	1	1	
42245319590000	CRTI/MCLEOD-GILBERT #1	1	1	
42245321180000	CARROLL W M EST #1	1	1	
42245321270000	KIKER #01	1	1	
42245321920000	BOYT #1	1	1	
42245321930000	CLUBB J T #1	1	1	
42245322030000	WINGATE PANSY ETAL #1	1	1	
42245322040000	SHERRON ELEANOR ETA #1	1	1	
42245322300000	BROUSSARD #1	1	1	
42245322590000	DOORNBOS #1	1	1	
42245322630000	BAIKOW FRANCES G ET #1	1	1	
42245322940000	MCDERMAND #1	1	1	
42245323510000	RIEFF #1	1	1	
42245323540000	BAUER JACK WAYNE #1	1	1	
42245325780000	ELEANOR #1	1	1	
42291315260000	BROUSSARD #1	1	1	
42291316700000	STOESSER ET AL UNIT #1	1	1	
42291318930000	BONNER #1	1	1	
42291321760000	FROST/KEENAN #1	1	1	
42291321820000	BOYT #1	1	1	
42291323750000	RAMSEY #1	1	1	
42291323860000	HATCHER #1	1	1	
42291324620000	BOND #1	1	1	
42291324650000	DANIELS #1	1	1	

UWI (APINum)	Well Label	FACIES_GR	FACIES_SP	PEF
42291324860000	GALLOWAY #1	1	1	
42291325100000	HENDERSON E A #1	1	1	
42291325270000	BRAZIL #1	1	1	
42291325280000	ALDRICH R C ET AL #1	1	1	
42291325550000	HENDERSON WILLIS #1	1	1	
42291325610000	PENN-CAT #2	1	1	
42291327970000	WILDI #1	1	1	
42291328690000	HUNT SARAH `B` #1	1	1	
42071323230000	KAHLA #1	1		
42291321400000	NELSON TRUST #1	1		
42291322600000	KELLY #1	1		
42291323630000	TRISTEN-TRUETT #1	1		
42291326020000	BLOXSOM A #1	1		
42291318010000	DUNAGAN GRACE W ETA #1-A	0	0	1
42071303720000	L G JENKINS #1	0	3	
42245319970000	DISHMAN H E ETAL #1	0	3	
42245021930000	BROUSSARD J E JR #1	0	1	
42071320880000	CRAWFORD `A` #1	0	0	
42071325430000	DUGAT SWD #3	0	0	
42071325690000	BUCCANEER #1	0	0	
42245022070000	MARIE B WIER ETAL #1	0	0	
42245022420000	W C GILBERT #1	0	0	
42245321360000	CHINA TOWNSITE UNIT #1	0	0	
42071013620000	HANKAMER TRUSTEE #1		1	
42071013630000	BROUSSARD TRUST #1		1	
42071013650000	WEST WESLEY ETAL #1		1	
42071013670000	JENKINS W E #1		1	
42071013700000	JENKINS W E #1		1	
42071019550000	DROUGHT H P #1		1	
42071019580000	STERRETT EAT FRED R #1		1	
42071019590000	WM DOORNBOS ETAL #1		1	
42071019610000	OGDEN L G ETAL #1		1	
42071019620000	DEBELLVUE MRS MARIA #1		1	
42071019640000	MOORE ESTATE ELIZ H #1		1	
42071019650000	I DAVENPORT #1		1	
42071019660000	JOHNSON ANNIE H #1		1	
42071019670000	T SIMON #1		1	
42071019920000	HOWTZ SYBIL ETAL #1		1	
42071019930000	SHAW UNIT #1		1	
42071019960000	H J SOLEM UNIT 1 #1		1	
42071020000000	MOORE ESTATE #2		1	
42071033130000	J T TERRY ETAL #1		1	
42071033710000	JAMES C HALL ETAL #1		1	
42071303660000	O C DEVILLIER ETAL #1		1	
42071304390000	EARL COOPER #1-A		1	
42071304690000	BEAUMNT RC MLL #1		1	
42071304850000	A S HANKAMER #1		1	
42071308370000	O C DEVILLIER #6		1	
42071309340000	JENKINS #1		1	
42071310360000	GARTH #1		1	
42071312760000	DOMEYER ETAL #1		1	
42071313500000	JENKINS LYDIA ETAL #1		1	
42071313940000	DEVILLIER L C #1		1	
42071315900000	DUGAT #1		1	
42071315940000	LULU STERLING #1		1	
42071316440000	WHITE HEIRS #1		1	
42071316710000	MOBIL FEE #1		1	
42071317650000	THORNTON #1		1	
42071318030000	POSTEMA #1		1	
42071318590000	WAGENSTEEN #1		1	
42071318730000	HALBOUTY-DEVILLIER #1		1	
42071320910000	HSR GARTH #1 #1		1	
42071322680000	CLEMENT UNIT ST #1		1	
42071322960000	COOPER E #1		1	
42245021150000	J E BROUSSARD ETAL #1		1	
42245021170000	J S EDWARDS #1		1	
42245302100000	TF KOCH NCT 1 #4		1	
42245302800000	HOWTH #2		1	
42245311580000	L W RANKIN ET #1		1	
42245312100000	LUCILLE DURAND ETAL #1		1	
42245312290000	APPELT PROP /A/ #2		1	
42245313430000	LOHMANN-HOWTH #1		1	
42245314110000	MCDERMAND F D #1		1	
42245315450000	BOUDREAUX N F ETAL #1		1	
42245317200000	WALTER CO /C/ #1		1	
42245317250000	WALTER CO #1		1	
42245317590000	BOYT #1		1	
42245322270000	MCDERMAND UNIT #1R		1	
42245324980000	TURNER-BOGAN #1		1	
42291045370000	ROBERTSON-MCDONAL #1		1	
42291047710000	BOYT E W #2		1	
42291047720000	BOYT E W #1		1	
42291047740000	BOYT E W #1		1	
42291053750000	ESTER SWARTZ #1		1	
42291300010000	ESTER SWARTZ #4		1	
42291300560000	SWARTZ ESTER #5		1	
42291312300000	AMOCO PRODUCTION CO #1		1	
42291315950000	MAXWELL LAMAR B ETL #1		1	
42291320430000	BLANCH GRACE F #1		1	
42291324590000	BONNER #1		1	

TESTING AND MONITORING PLAN
40 CFR 146.90

Bluebonnet Sequestration Hub

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the project)
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

This Testing and Monitoring Plan describes how the Bluebonnet Sequestration Hub, LLC, will monitor the Bluebonnet Hub pursuant to 40 CFR §146.90. In addition to demonstrating that the wells are operating as planned, the CO_2 plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan attached to this application.

2.0 Overall Strategy and Approach of the Testing and Monitoring Plan

The testing and monitoring plan is designed to detect unforeseen CO_2 and/or brine leakage out of the injection zone that could endanger the USDW, migrate to a different stratus, or create a risk to human health or the environment.

This monitoring plan was tailored based on a qualitative risk assessment of the site that also was used to inform the Emergency and Remedial Response Plan for the Bluebonnet Hub. Table TM-1 summarizes the residual risk ranking, assuming the proposed controls and mitigations of the project design and monitoring plan are in place.

Table TM-1: Risk ranking for Bluebonnet Hub evaluation.

No	Risk	Probability	Impact	Ranking
1	Loss of internal mechanical integrity in CO2 Injection Wells - tubing / packer leak (assumed casing barrier) NO LOC	Medium	Low	Low
2	Loss of internal mechanical integrity in In zone monitoring wells, water production wells - tubing / packer leak (assume casing barrier) NO LOC	Medium	Low	Low
3	Loss of internal mechanical integrity in Above confining zone / USDW monitoring wells - tubing leak (assume casing barrier) NO LOC	Low	Low	Low
4	Loss of internal mechanical integrity in Water Disposal Wells - tubing / packer leak (assumed casing barrier) NO LOC	Medium	Low	Low
5	Loss of internal mechanical integrity in Water Disposal Wells - Casing Leak - NO LOC	Low	Medium	Low
6	Loss of internal mechanical integrity in CO2 injection wells - Casing Leak - NO LOC	Low	Medium	Low
7	Loss of internal mechanical integrity in In zone monitoring wells or water production wells - Casing leak - NO LOC	Low	Low	Low
8	Loss of internal mechanical integrity in Above confining zone / USDW monitoring wells - Casing leak - NO LOC	Low	Low	Low
9	Vertical migration of CO2 or brines via injection wells that could endanger USDW or other reservoirs - Loss of external mechanical integrity - Cement	Low	Medium	Low
10	Vertical migration of CO2 or brines via In zone monitoring wells, USDW monitoring wells and water production wells - Loss of external mechanical	Low	Low	Low
11	Vertical migration of CO2 or brines via Water Disposal Wells - Loss of external mechanical integrity - Cement degradation or damage NO LOC	Low	Medium	Low
12	Vertical migration of brine or CO2 via legacy wells . NO LOC	Low	Medium	Low
13	Vertical migration due to failure of confining rock , faults or fractures. NO LOC	Low	Medium	Low
14	Plume migration do not match the predicted model, and extend beyond proposed AOR (Inside the lease acres)	Medium	Medium	Medium
15	Higher pressure increase in the reservoir than the one projected by the model.	Medium	Medium	Medium
16	Loss of injectivity due to precipitation of halite or other minerals in the formation , or chemical reactions between the rock, CO2 and formation waters	Medium	Low	Low
17	Loss of injectivity due to scale, sand, damage or obstruction in the Injector Wells.	Low	Low	Low
18	External Impact - CO2 Injector well - Loss of containment	Low	High	High
19	External Impact - In zone monitoring well and water production wells -Loss of containment	Low	Low	Low
20	External Impact - Water Disposal Wells -Loss of containment	Low	Low	Low
21	External Impact - In above confining / USDW monitoring wells - Loss of containment	Low	Low	Low
22	External Impact - Pipeline distribution inside the AOR	Low	Medium	Medium
23	Monitoring equipment failure or malfunction	Medium	Low	Low
24	Induced seismicity	Low	Medium	Low
25	Major seismic event	Low	High	High

Several components are integrated into the master monitoring plan for the Bluebonnet Hub, which are classified in the following categories:

1. Operational testing and monitoring during injection.
2. Mechanical integrity testing.
3. Groundwater quality and geochemical monitoring.
4. CO_2 plume and pressure-front tracking.
5. Near-surface and surface monitoring.
6. Induced seismicity.

Table TM-2 summarizes the different methods proposed to monitor the AoR, including the CO_2 plume and pressure front from the CO_2 injection wells proposed at the Bluebonnet Hub: Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7.

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan.

Ct	Description	Method	Location	Pre-Injection		Injection Period
1	Operational testing and monitoring during injection.	Carbon Dioxide Stream Analysis.	Sampling point upstream CO_2 Injector wells	n/a		Quarterly
		Measurement of injection pressure and temperature on surface - surface transducers	Flow line of CO_2 Injector wells	n/a		Continuously
		Measurement of casing-tubing annular pressure in surface- surface transducers	Wellhead of CO_2 Injector wells	n/a		Continuously
		Measurement of rate and injection volume in surface - coriolis flow meter	Flow Line CO_2 Injector wells	n/a		Continuously
		Measurement of casing-tubing annular pressure above packer- donwhole gauges	Downhole CO_2 Injector wells	n/a		Continuously
		Measurement of pressure and temperature at top of the perforations - downhole gauges	Downhole CO_2 Injector wells	n/a		Continuously
		Automatic surface shut off devices.	Flow Line CO_2 Injector wells	n/a		Continuously
		Corrosion coupons analysis.	Upstream CO_2 Injector wells	n/a		Quarterly
		Pressure Fall Off test	CO_2 Injector Well		x	Every 5 years
		Measurements of tubing pressure and temperature on surface- Surface transducers	Wellhead of IZM and USDW wells	n/a		Continuously
		Measurement of downhole conditions - Downhole sensors and Gauges	Completion of IZM and USDW wells	n/a		Continuously
		Visual inspections and handheld monitors (LEL, H2S, CO_2)	General facilities		x	Weekly
		Leak detection and repair (LDAR) program using Optical Gas Imaging cameras , handheld during inspections	General facilities	n/a		Quarterly

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan (continued).

Ct	Description	Method	Location	Pre-Injection		Injection Period
2	Mechanical Integrity testing.	Ultrasonic cement evaluation , CBL, VDL	CO_2 injector wells		x	
		Ultrasonic cement evaluation , CBL, VDL	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1		x	
		Ultrasonic casing inspection log	CO_2 injector wells		x	During workover or well maintenance
		Pulse neutron log	CO_2 injector wells		x	Annually
		DTS fiber alongside the casing to the top of the perforations	CO_2 injector wells		x	Continuously
		DTS fiber alongside the casing to total depth.	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1		x	Continuously
		Pulse neutron, temperature log,or electromagnetic log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01		x	Every 5 years or during planned maintenance or workover activities if fibers fails or its not installed. Event triggered by other monitoring results.
		Annular pressure test	CO_2 injector wells		x	After every WO
		Annular pressure test	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01 Bluebonnet IZM M1			Annually

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan (continued).

Ct	Description	Method	Location	Pre-Injection		Injection Period
3	Ground water quality and geochemical monitoring	Water sampling and testing in USDW monitoring wells.	USDW wells	Bluebonnet USDW 1 Baseline. Quarterly min 1 year before injection.		Quarterly sample first 2 years of injection. Semi-annually from year 3 to end of injection.
		Water sampling and testing in the Miocene Composite Confining Zone	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3		x	Quarterly sample the first 2 years of injection. Semi-annually from year 3 to end of injection.
		Water sampling and testing in legacy shallow fresh aquifer water wells.	Legacy water wells	Quarterly samples from selected wells for minimum 1 year before injection.		Quarterly sample first 2 years of injection. As needed based on other monitoring tools.
		Measurement of pressure and temperature downhole in USDW - Downhole Gauges	USDW wells		x	Continuously
		Measurement of pressure and temperature downhole in the Miocene Composite Confining Zone- Downhole Gauges	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3		x	Continuously
		Isotopic fingerprinting of water in shallow aquifers, overburden, and injection targets	USDW, IZM M and CO_2 injector wells	Initial samples before injection during well construction .		

Table TM-2: Summary of Bluebonnet Hub Testing and Monitoring Plan (continued).

Description	Method	Location	Pre-Injection		Injection Period
Carbon Dioxide Plume and Pressure Front Tracking	Timed lapsed Pulse Neutron Log for CO_2 plume tracking	CO_2 injector		x	Annually for the CO_2 injectors. Event triggered in the IZM wells based on other monitoring techniques.
	Measurement of pressure and temperature in the reservoir - Downhole gauges	CO_2 injectors Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01			Continuously
	Measurement of PH, Conductivity and Fluid Level in the injection zone	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01		x	Annually
	3D surface seismic survey - baseline	AoR		x	
	2D time lapsed surface seismic survey	AoR		x	Every 5 years
	3D time-lapsed VSP	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 6 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1		x	Annually until plume extend beyond detection.
Near Surface & Surface	Airborne electromagnetic survey	AoR		x	
	Airborne magnetic survey	AoR		x	
	Process-based soil gas approach	AoR	Minimum(1) year characterization		Quarterly
	Isotopic fingerprinting of the soil gas	AoR	Minimum(1) year characterization		If required to compliment other methods
	Atmospheric CO_2 sensors in wellhead.	CO_2 injector wells			Continuously
	Atmospheric CO_2 sensors in wellhead.	IZM FM wells			Continuously
Induced Seismicity	Surface seismometers network	AoR	Minimum (1) year baseline		Continuously

The methodology and frequency of testing and monitoring methods are expected to change throughout the project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure the containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment.

The proposed testing and monitoring plan will collect sufficient geospatial and monitoring data to validate the numerical simulation model, inform operational decisions on the quantity and rate of CO_2 injected, and trigger corrective or preventive maintenance actions, amongst others, to operate the site as designed, efficiently and safely. The monitoring results will allow the project to reevaluate the AoR and show that there is no endangerment to the USDW.

These methods and their applications in the proposed monitoring plan are discussed in the following sections. Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

The testing and monitoring plan will be reviewed at least once every five years and will be amended, if necessary, to ensure monitoring and storage performance is achieved and new technologies are appropriately incorporated. 40 CFR §146.90 (j).

2.1 Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for testing and monitoring activities, required pursuant to 146.90(k), is provided as a separate document in this permit.

2.2 Reporting Procedures

The Bluebonnet Sequestration Hub, LLC, will report the results of all testing and monitoring activities to Texas rail Road Commission in compliance with the requirements under 40 CFR 146.91.

3.0 Well Monitoring Network Design

Bluebonnet Sequestration Hub, LLC, plans to drill six CO_2 injection wells: Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, as part of the field development plan for the Bluebonnet Hub. The monitoring program proposed is designed based on the modeled CO_2 plume extension and propagation of the pressure front for the six wells injecting simultaneously according to the AoR delineation process to account for the maximum AoR extension and pressure impact. The injection schedule and field development plan might be adjusted based on the availability of CO_2.

The proposed monitoring plan includes a layout of three in zone (reservoir) monitoring wells, (Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Encanto 01), three monitoring wells within the Miocene Composite Confining Zone (Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet

IZM M3), and three USWD monitoring wells (Bluebonnet USDW 1, Bluebonnet USDW 2, and Bluebonnet USDW 8).

The project team plans to drill two water production wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2, to extract formation water from the Frio Injection Zone as a technique to control reservoir pressure. The project team plans to permit one water disposal well, Bluebonnet DSW M2, to reinject the water produced from the Frio formation to the shallow sands of the Miocene, above the Lower Miocene Confining Zone. Figure TM-1 and Figure TM-2 show the location of the monitoring wells relative to the CO_2 injection wells and predicted AoR and the legacy wells.

Table TM-3: Monitoring Wells Bluebonnet Hub.

Well Name & No	API No./Well ID	Purpose	Total Depth TVD (ft)	Date Drilled
Bluebonnet IZM FM1	TBD	Monitoring Frio and Hackberry Injection Zones	8,400	TBD
Bluebonnet IZM FM2	TBD	Monitoring Frio and Hackberry Injection Zones	9,000	TBD
Encanto 01	071-32664	Monitoring Lower Miocene Injection Zone	PBTD: 8,560 TD: 8,581	02/10/2023
Bluebonnet IZM M1	TBD	Monitoring Miocene Composite Confining Zone – Permeable formation between Seal 2 and Seal 3	2,900	TBD
Bluebonnet IZM M2	TBD	Monitoring Miocene Composite Confining Zone – Permeable formation between Seal 1 and Seal 2	2,000	TBD
Bluebonnet IZM M3	TBD	Monitoring Miocene Composite Confining Zone – Permeable formation between Seal 1 and Seal 2	1,900	TBD
Bluebonnet USDW 1	071-32672	Monitoring USDW zone	1,420	06/25/2024
Bluebonnet USDW 2	TBD	Monitoring USDW zone	1,500	TBD
Bluebonnet USDW 8	071-32676	Monitoring USDW zone	PBTD: 1,050 TD: 2,750	05/09/2025

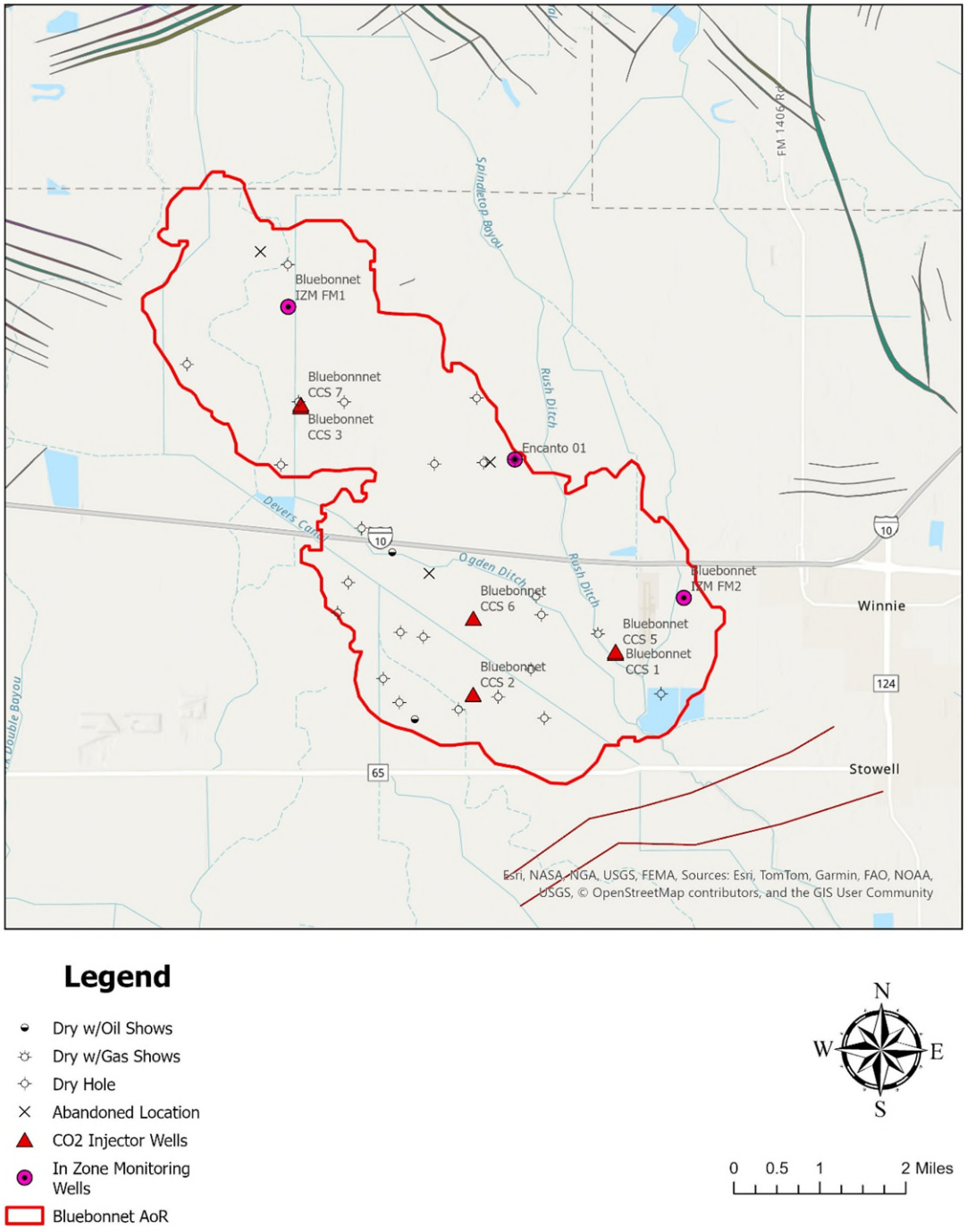


Figure TM-1: Location and layout of in-zone monitoring wells relative to the CO_2 injector wells, legacy wells and the predicted AoR.

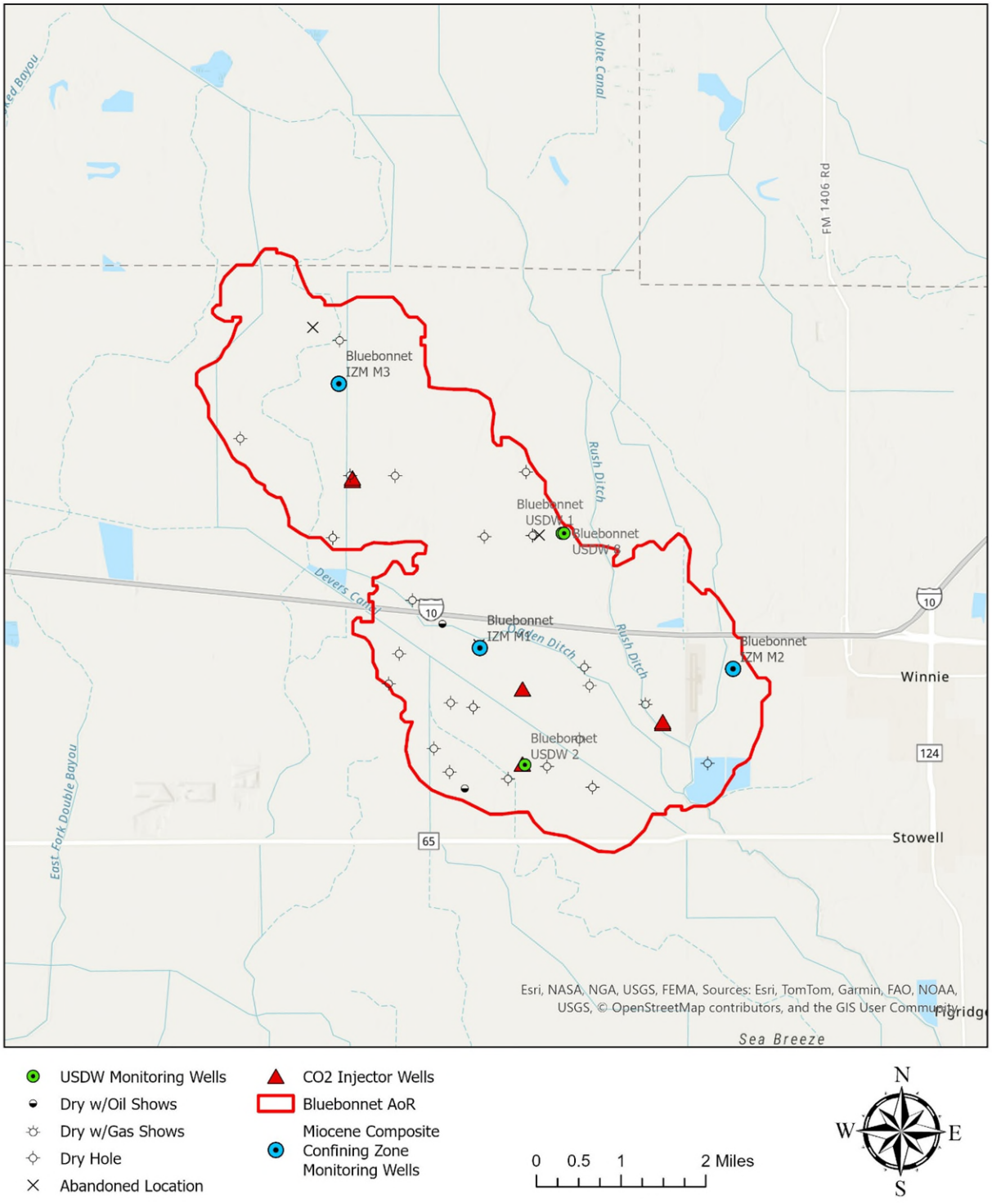


Figure TM-2: Location and layout of the legacy wells, USDW monitoring wells and Miocene Composite Confining Zone monitoring wells relative to the CO_2 injector wells and the predicted AoR.

The well locations show the approximate position of the CO_2 injector and monitoring wells. The exact locations might have a slight variation depending on the final design of the surface pads as well as the negotiations with the landowners when the locations are surveyed.

3.1 CO_2 Injector Wells (CCS)

The CO_2 injection wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 are designed to maximize CO_2 injection rates and operate the site efficiently. The wells will be equipped with surface and downhole sensors to track reservoir behavior in real time, allowing the project team to validate the predictions of the numerical simulation model and optimize injection parameters.

The implementation of a pulse neutron/saturation log will evaluate the mechanical integrity of the CO_2 injection wells and provide information about the vertical conformance of the injected CO_2 in the injection zone and validate containment.

The project plans to install fiber optic alongside each CO_2 injection well from surface to top of the perforations to track in real time the vertical conformance of the CO_2 near the wellbore to identify any potential migration paths. The fiber will be used from the beginning of the injection period to image the development of the CO_2 plume in 3D and validate the containment of CO_2 in the injection zones.

Details of the well construction and proposed schematics of the CO_2 injectors are included in the Injector Wells Construction Details Plan of this application.

3.2 In-Zone Monitoring Wells (IZM)

The location and completion design of the in-zone monitoring wells was defined with the objective of tracking the early development of the pressure front as it precedes the movement of the plume, to allow for history-matching of the model. The wells were located strategically to mitigate the main risks identified during the evaluation of the site and comply with 40 CFR §146.90 requirements. These areas included highly populated areas, faults, and high density of legacy wells, amongst others.

The in-zone monitors well locations and completions (Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Encanto 01) allow for the tracking of movement of the CO_2 plume through pressure and temperature matching, from early stages to the end of the injection period. Bluebonnet IZM FM1 and Bluebonnet IZM FM2 will be equipped with DTS/DAS fiber optics alongside the casing to support the acquisition of 3D vertical seismic profile (VSP) surveys, as further described in this document. If the surface seismometer network (described in the next sections) detects any activity related to induced seismicity due to the injection, these wells can acquire real time acoustic data to track downhole micro seismicity.

Annually the Project team will take water samples from the IZM wells through tubing, and will measure PH, conductivity and fluid level. (16 TAC § 5.203(j)(2)(D)(i))

3.2.1 Bluebonnet IZM FM1

The Bluebonnet IZM FM1 will be drilled before the CO_2 injection on the Bluebonnet CCS 3 or the Bluebonnet CCS 7 wells starts or shortly thereafter. The well location was selected to track CO_2 movement and development of the pressure front to the northwest section of the AoR. This well will be located strategically in the updip direction and preferential path of the plume development. The well will serve to calibrate the simulation model and provide the capability to image the CO_2 plume with a 3D VSP, utilizing the fiber optic cable to be installed in the well, covering a radius 0.5 mile around the monitoring well to predict CO_2 plume migration rates.

The well will be completed in the Hackberry and Frio Injection Zones [~7,243-8,250 ft total vertical depth (TVD)] and will be equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow for tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

Since the well will be drilled from the surface to the Hackberry Confining Zone, it will enable tracking any changes in CO_2 saturation around the wellbore, not only for the Frio and Hackberry Injection Zones, but also for the Lower Miocene Injection Zone and overburden.

If the surface seismometer network (described in the next sections) detects any activity that could be related to induced seismicity from CO_2 injection, the Bluebonnet IZM FM1 has the capability to acquire real-time acoustic data to track downhole micro seismicity.

The proposed schematic for this well is presented in Figure TM-3.

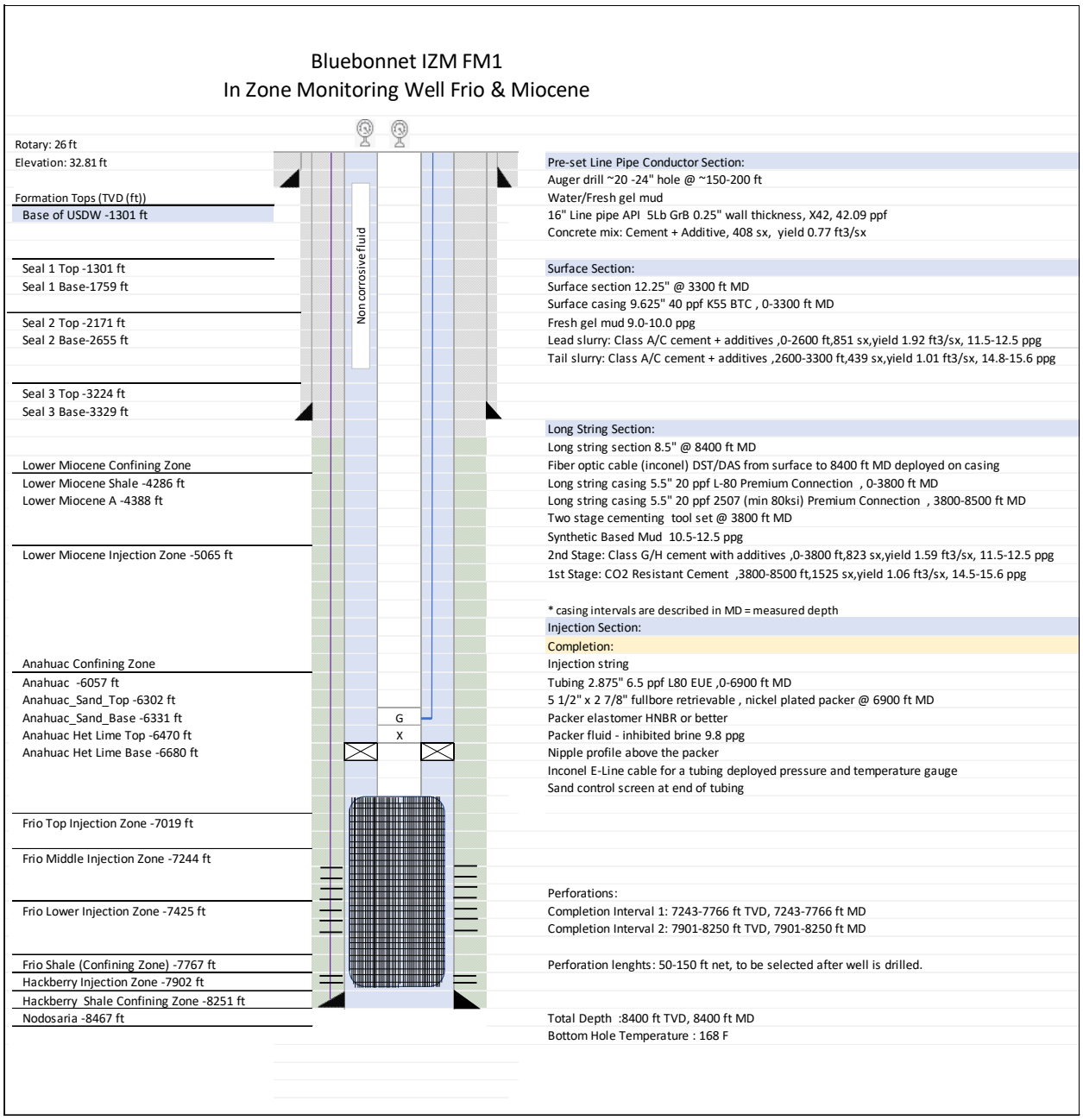


Figure TM-3: Well design and schematic for Bluebonnet IZM FM1.

3.2.2 Bluebonnet IZM FM2

The Bluebonnet IZM FM2 will be drilled before CO_2 injection starts on Bluebonnet CCS 1 or Bluebonnet CCS 5, or shortly thereafter. The well location was selected to track the development of the CO_2 plume and pressure front towards the east of the AoR. The east section of the plume will be near the town of Winnie, Texas, including the Winnie airport. The well will be on the border of the CO_2 plume and placed strategically to track any abnormal development of the plume eastward.

The well will be completed in the Hackberry and Frio Injection Zones (~7,824-8,790 ft TVD) and equipped with pressure and temperatures gauges downhole, ported to the tubing that will allow to tracking changes in the reservoir conditions. Pressure monitoring is extremely valuable to history-match the simulation model and improve accuracy in the prediction of the CO_2 plume movement.

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

The well will be equipped with a fiber optic cable alongside the casing, providing the capability to image the CO_2 plume with a 3D VSP and covering a radius 0.5 mile around the monitoring well, to predict CO_2 plume migration rates.

If the surface seismometer network (described in the next sections) detects any activity that could be related to induced seismicity from injection, then Bluebonnet IZM FM2 can acquire real-time acoustic data to track downhole micro seismicity with the fiber optic cable installed in the well.

The proposed schematic for this well is presented in Figure TM-4.

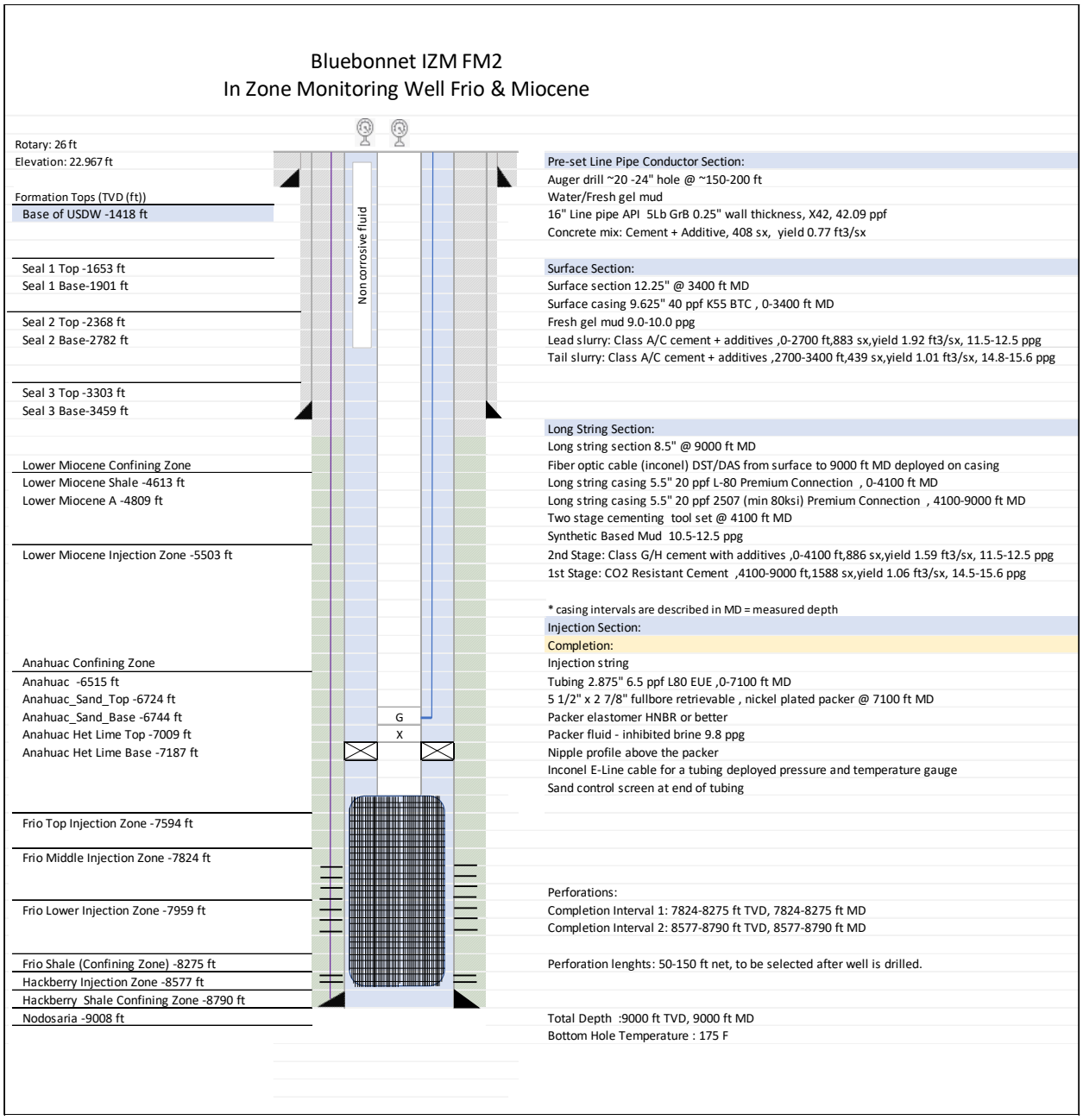


Figure TM-4: Well design and schematic for Bluebonnet IZM FM2.

3.2.3 Encanto 01

The Encanto 01 well was drilled in 2022 as part of the stratigraphic well campaign to acquire site-based data for the project and is temporarily abandoned, pending recompletion as part of the project's monitoring network. The well is strategically placed to track any potential migration in the field to the north of the Bluebonnet CCS 2 and Bluebonnet CCS 6 injection wells and will provide monitoring capabilities to track the pressure and temperature changes in the shallowest permitted reservoir interval in the AoR. The well will be completed in the Lower Miocene Injection Zone.

The proposed schematic for this well is presented in Figure TM-5.

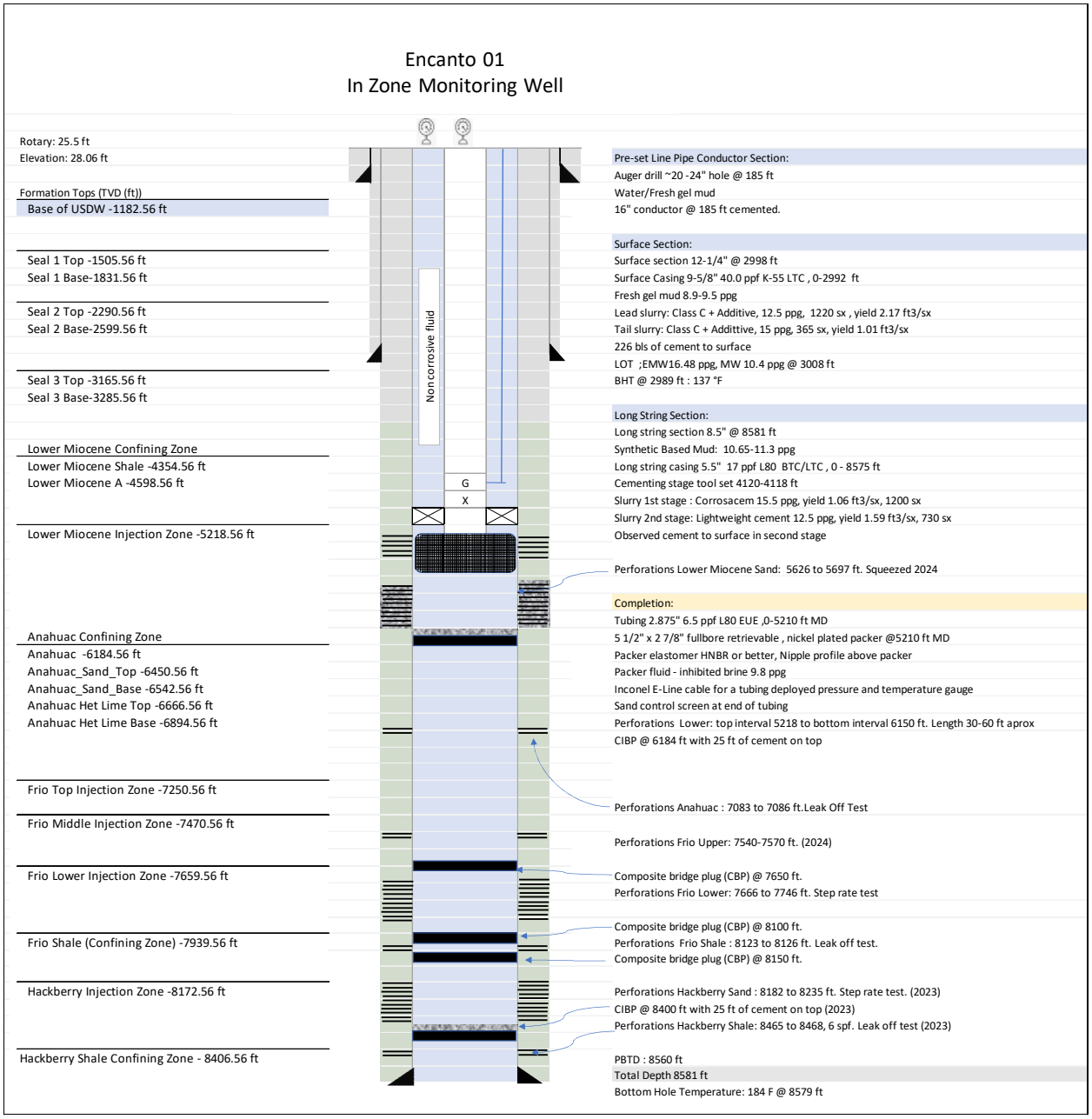


Figure TM-5: Well design and schematic for Encanto 01.

3.3 Miocene Composite Confining Zone Monitoring Wells

Bluebonnet plans to drill three monitoring wells withing the Miocene Composite Confining Zone—Bluebonnet IZM M1, Bluebonnet IZM M2, and Bluebonnet IZM M3. These wells will provide continuous pressure and temperature monitoring, as well as periodic geochemical sampling, within the permeable intervals located between the shallowest injection zone (Lower Miocene Injection Zone) and the base of the underground source of drinking water (USDW). The monitoring program is designed to detect potential changes in formation pressure, temperature or fluid chemistry and to provide early indication of any unexpected vertical fluid migration.

3.3.1 Bluebonnet IZM M1

The location of Bluebonnet IZM M1 was selected to monitor pressure, temperature, and geochemical changes within the permeable interval located between Seal 2 and Seal 3 of the Miocene Composite Confining Zone. The well will be equipped with a fiber-optic cable installed along the casing, providing the capability to conduct three-dimensional vertical seismic profiling (3D VSP) and image the CO_2 plume within an approximately 0.5-mile radius of the well. The completion will also include permanent downhole pressure and temperature gauges to provide continuous, real-time monitoring of changes within the monitored aquifer.

If the surface seismometer network (described in the next sections) detects any activity that could be related to induced seismicity from CO_2 injection, then the Bluebonnet IZM M1 can acquire real-time acoustic data to track downhole micro seismicity with the fiber optic cable installed in the well.

The proposed schematic for this well is presented in Figure TM-6.

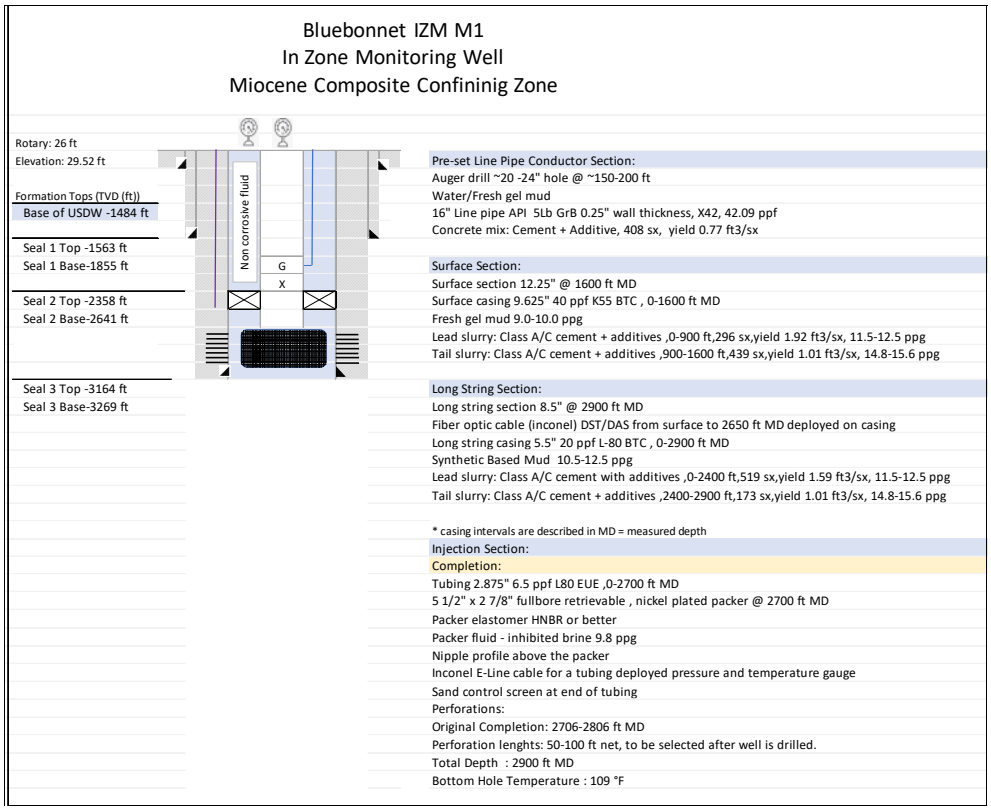


Figure TM-6: Well design and schematic for Bluebonnet IZM M1.

3.3.2 Bluebonnet IZM M2 and Bluebonnet IZM M3

Bluebonnet IZM M2 and Bluebonnet IZM M3 are designed to monitor the permeable interval immediately below Seal 1 within the Miocene Composite Confining Zone. Each well will be equipped with permanent downhole pressure and temperature gauges to provide continuous monitoring of formation conditions. The wells will also include water-sampling capabilities to support periodic geochemical analyses and identify potential changes in groundwater composition. The proposed schematic for these well are presented in Figure TM-7 and Figure TM-8.

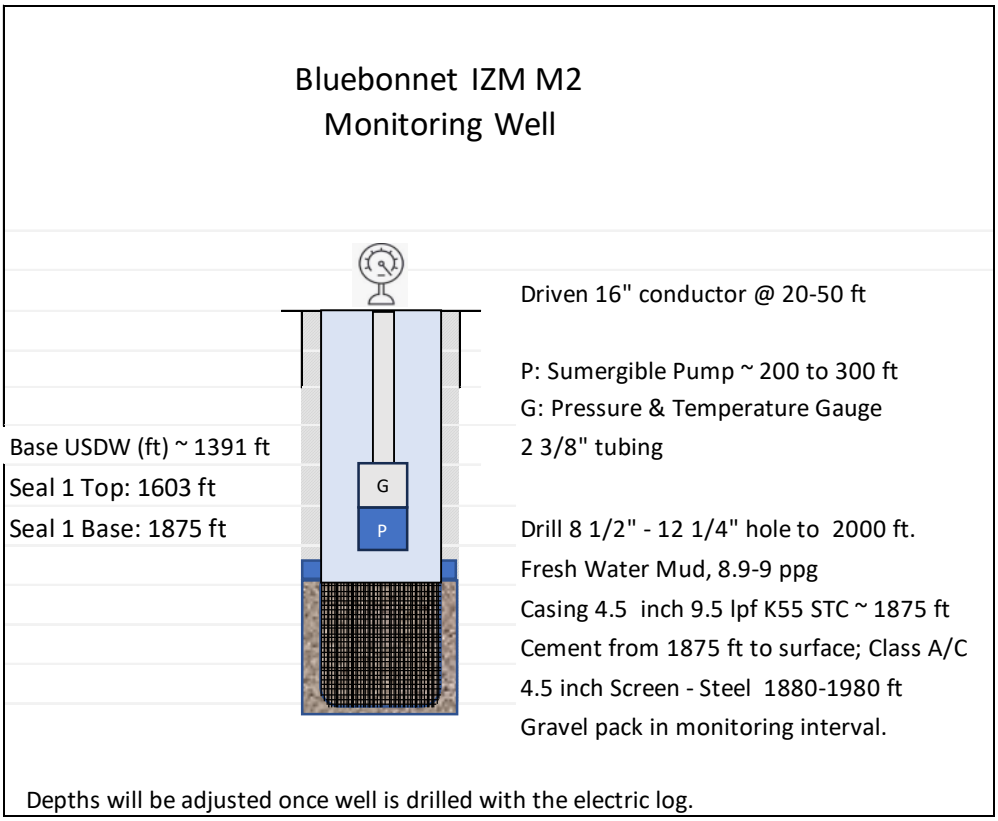


Figure TM-7: Well design and schematic for Bluebonnet IZM M2.

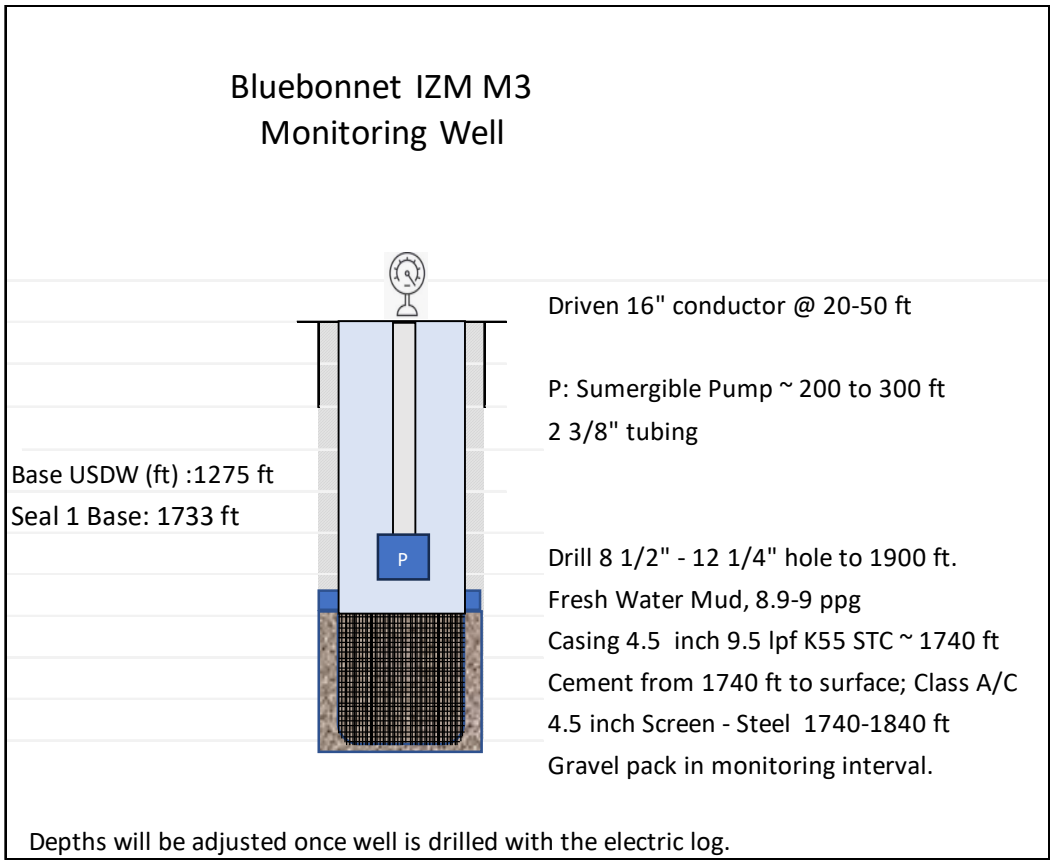


Figure TM-8: Well design and schematic for Bluebonnet IZM M3.

3.4 ACZ/USDW Monitoring Wells

The project team drilled the Bluebonnet USDW 1 well in 2024 with the objective of characterizing the shallow aquifers and validating the base of the USDW. The well was drilled to 1,630 ft. Electric logs were run and water samples were collected to be used in the delineation of the AoR. The lower section of the well was abandoned from 1,420 ft to 1,630 ft with a cement plug and the well was completed in the sand below the base of USDW.

In 2025, the project team undertook the drilling of the Bluebonnet USDW 8 at the same location as the Encanto 01 well, with the primary objective of obtaining cores from the intershales situated within the Miocene Composite Confining Zone. The team successfully acquired 79 feet of whole cores and 35 sidewall cores. The well was drilled to a depth of 2,750 feet and subsequently plugged back to 1,050 feet.

In addition to Bluebonnet USDW 1 and Bluebonnet USDW 8, the project team plans to construct one additional USDW monitoring well, Bluebonnet USDW 2, to closely monitor the USDW by acquiring water samples and monitoring real time pressure and temperature. Bluebonnet USDW 2 will be drilled to the base of the USDW and completed in the lowest-most sand. The wells USDW monitoring wells will be equipped with pressure and temperature sensors at the surface and downhole.

Figure TM-9 to Figure TM-11 show the as build and proposed construction for the USDW monitoring wells.

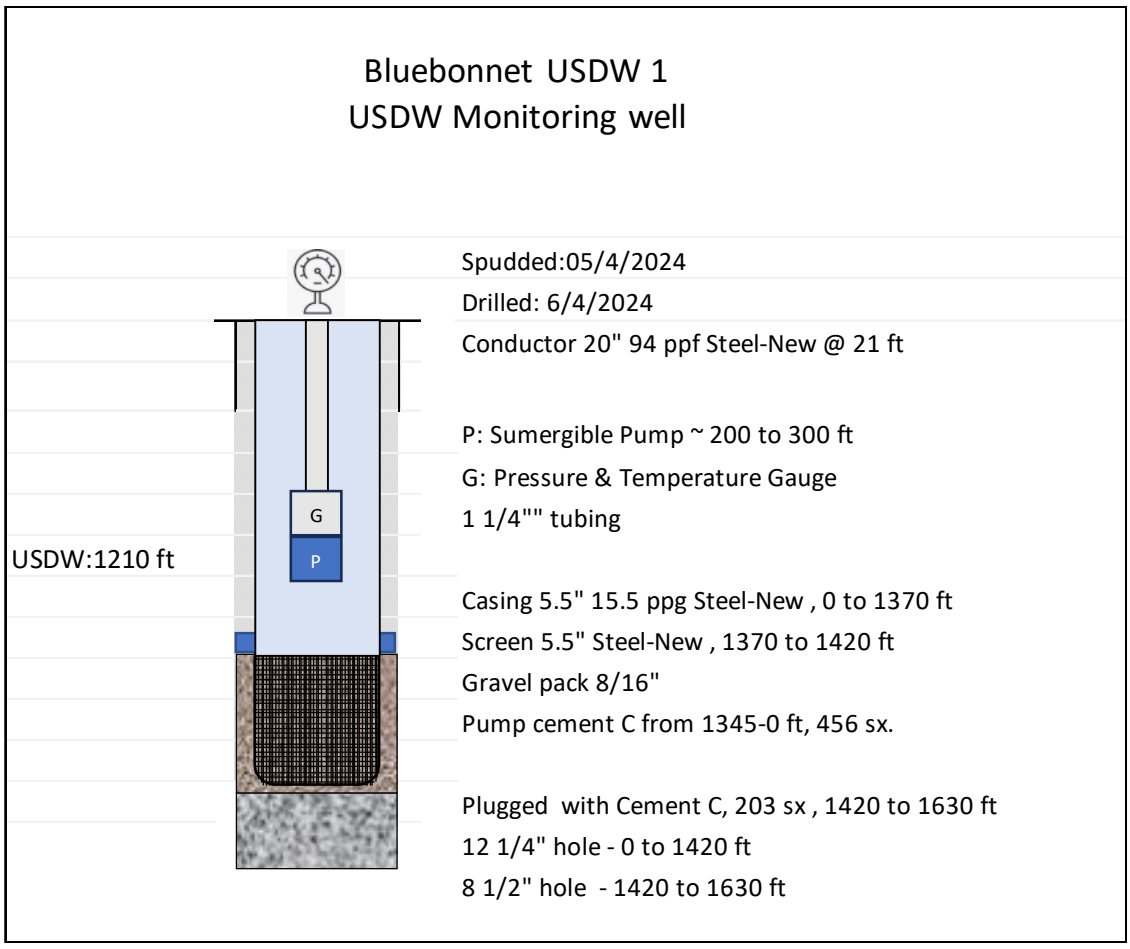


Figure TM-9: Well design and schematic for Bluebonnet USDW 1.

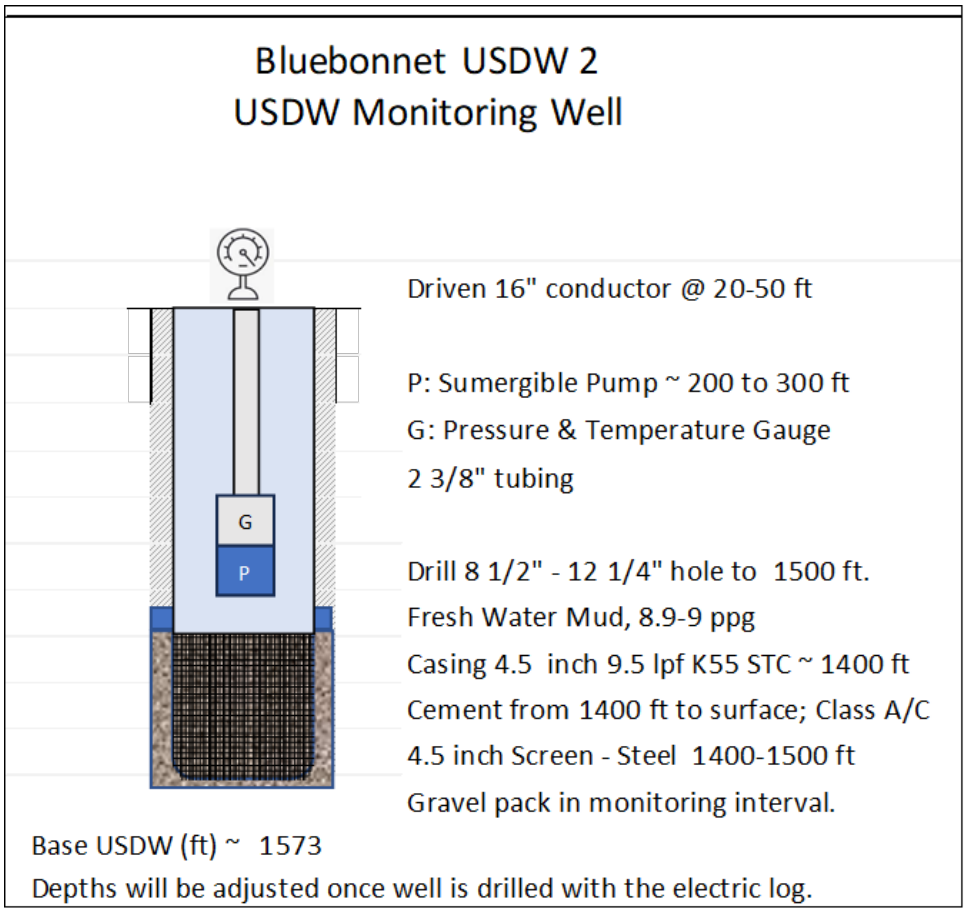


Figure TM-10: Well design and schematic for Bluebonnet USDW 2.

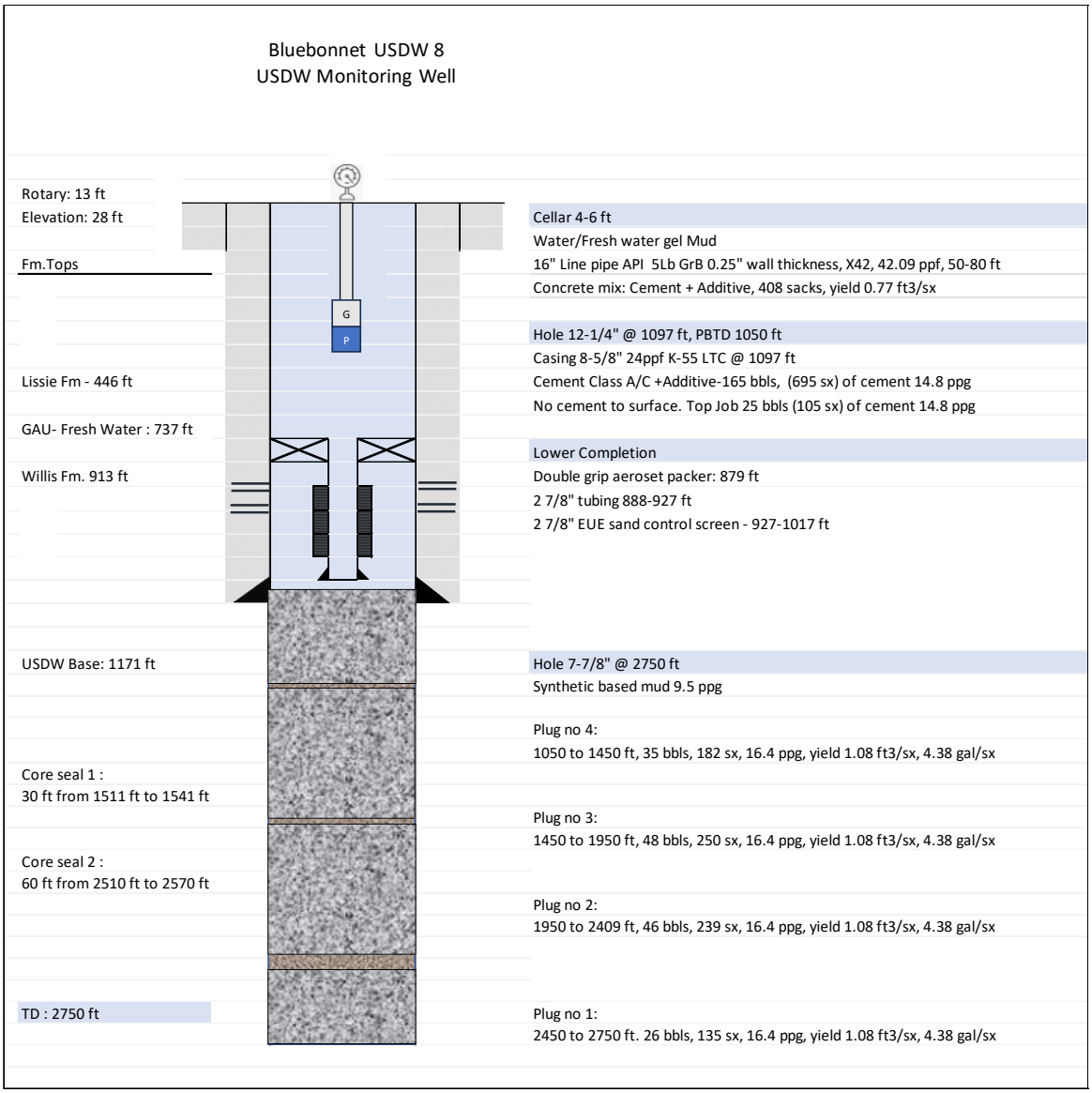


Figure TM-11: Well design and schematic for Bluebonnet USDW 8.

4.0 Operational Testing and Monitoring During Injection

4.1 CO_2 Stream Analysis

Pursuant to 40 CFR 146.90(a), during the operation period, Bluebonnet Sequestration Hub, LLC, will analyze the CO_2 stream for its chemical and physical characteristics.

4.1.1 Sampling Location and Frequency

The CO_2 stream sampling will occur quarterly during operation either upstream or downstream of the custody transfer flowmeter that measures the flow rate of the injectant at the site. Multiple samples will be acquired during the startup period of the project (first injection) to validate that the CO_2 stream complies with the required minimum specifications. After the startup period, a sample will be taken 3 months after the start of injection, at 6 months, at 9 months, and at 12 months, as a minimum frequency, continuing every quarter. The sampling period could be increased and slightly shifted in timing, depending on the operations.

The project has developed a minimum standard CO_2 specification, as shown in Table TM-4, to be enforced with the emitters and distribution channels that control the quality of the CO_2 injected at the site. The project will install a gas analyzer at the custody transfer meter located in the sequestration site to monitor CO_2 quality continuously before it is distributed to each well in the site, to detect any major deviation from the contractual specifications. The project could require additional components to be limited and analyzed based on final contractual terms with the emitters.

Table TM-4: CO_2 Stream specifications.

Component	Specification
CO_2 (% mol)	>95
Water (lbs/MMCF)	<10
Nitrogen (% mol)	<4
Oxygen (ppm by wt)	<10
Hydrogen (% mol)	<1
SO_x (ppm by wt)	<1
NO_x (ppm by wt)	<1
Hydrogen Sulfide (ppm by vol)	<20
HCN (ppm by vol)	<40
Hydrocarbons (%mol)	<5
Carbon Monoxide (ppm by wt)	<4,250
Glycol (gal/MMSCF)	<0.3
Ammonia (ppm by wt)	<50
Argon (%mol)	<1
Sulfur (ppm by wt)	<35
Carbonyl Sulfide (ppmv)	<5
Alcohols (ppmv)	<3,000

The CO_2 composition will be monitored continuously at each receipt point into the pipeline network along with at the delivery point to the sequestration site. In addition, samples will be collected and analyzed periodically at each receipt point and delivery point.

If the inline analyzers or sample results indicate a deviation from the CO_2 specification, the sampling frequency for the relevant receipt point(s) will be increased until the sampling results return to normal for a specified period.

If the CO_2 delivered to a receipt point does not meet the CO_2 specification, the project team will notify the CO_2 source facility and either shut in the source facility or increase the sample frequency, depending on the risk associated with the out-of-specification component.

If a CO_2 source facility is shut in, offtake will only resume from that facility once it has demonstrated the resumption of in-specification product for an agreed period between 12 and 48 hours.

4.1.2 Analytical parameters

The Bluebonnet Sequestration Hub, LLC, will analyze the CO_2 for the constituents identified in Table TM-5 as a minimum (but not limited to) requirement.

Table TM-5: CO_2 stream analysis.

Component	Frequency	Analytical Method
CO_2 (% mol)	Quarterly	Gas chromatography
Water (lbs/MMCF)	Quarterly	Gas chromatography.
Nitrogen (%)	Quarterly	Gas chromatography
Oxygen (ppm)	Quarterly	Gas chromatography
Hydrogen (% mol)	Quarterly	Gas chromatography
SO_x (ppm)	Quarterly	Gas chromatography
NO_x (ppm)	Quarterly	Gas chromatography
Hydrogen Sulfide (ppm)	Quarterly	Gas chromatography
HCN (ppm)	Quarterly	Gas chromatography
Hydrocarbons (%)	Quarterly	Gas chromatography
Carbon Monoxide (ppm)	Quarterly	Gas chromatography
Glycol (gal/MMSCF)	Quarterly	Gas chromatography
Ammonia (ppm by wt)	Quarterly	Gas chromatography
Argon (%mol)	Quarterly	Gas chromatography
Sulfur (ppm by wt)	Quarterly	Gas chromatography
Carbonyl Sulfide (ppmv)	Quarterly	Gas chromatography
Alcohols	Quarterly	Gas chromatography
δ13C of CO_2	During Characterization	Chromatographic separation with combustion and dual-inlet isotope ratio mass spectrometry (IRMS) or compound-specific analysis (GC-C-IRMS)
14C of CO_2	During Characterization	Accelerator mass spectrometry (AMS)

The project team may deem it necessary to test additional elements to ensure the CO_2 delivered to the Bluebonnet Hub complies with contractual specifications.

Isotopes will be analyzed during the first year of operation and after any major change of CO_2 source composition to fingerprint the stream.

4.1.3 Sampling Methods

A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed. All sample containers will be labeled with durable labels and indelible markings. A unique identification number and sampling date will be recorded on the sample containers. The sample containers will be sent to the third-party authorized laboratory contracted for testing.

Sampling procedures will follow the third-party authorized laboratory protocols to ensure the sample is representative of the injectant and samples will be processed, packaged, and shipped to the contracted laboratory, following standard sample handling and chain-of-custody guidance. Sampling methods are described in the QASP.

4.1.4 Laboratory to be Used/Chain-of-Custody and Analysis Procedures

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Analytic methods and chain-of-custody procedures are described in the QASP.

4.2 Monitoring and Recording of Operating Parameters in CO_2 Injector Wells

The Bluebonnet Sequestration Hub, LLC, will install and use continuous recording devices to monitor injection pressure, rate, and volume, including the pressure on the annulus between the tubing and long string casing and the temperature of the injected stream in the CO_2 injector wells (Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7) as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

The project will record any changes in annular fluid volumes during daily or weekly inspections, as needed. Additionally, the project plans to install a downhole gauge above the packer, ported to the annulus, to track in real time changes of pressure above the packer in the annulus.

Injection operations will be continuously monitored and controlled by the operations staff, using the process control system. The system will continuously monitor, control, record, and set alarms for critical system parameters of pressure, temperature, and flow rate.

The process control system will limit maximum flow according to the operation parameters for each well.

The system will initiate a shutdown if specified control parameters deviate from the intended operating range and will allow for remote shutdown under emergency conditions. Trend analysis will help evaluate the performance (e.g., drift) of the instruments, suggesting the need for maintenance or calibration.

4.2.1 Monitoring Location and Frequency

Real-time monitoring activities will begin during the startup of the wells for first injection. The injection pressure and temperature will be continuously measured at the surface via real-time pressure and temperature (P/T) instruments installed in the CO_2 injection line near the interface with the wellhead. The pressure will be measured by an electronic pressure transducer with analog output mounted on the CO_2 line associated with the injection well. The temperature will be measured by an electronic temperature transducer mounted in the CO_2 line near the pressure transducer, with both transducers mounted near the wellhead.

The flow rate of CO_2 injected into the well will be measured by flowmeter skids with a Coriolis type flowmeter in the CO_2 injection line near the interface with the wellhead. Piping and valving will be configured to permit flowmeter calibration/verification. The flow transmitter will be connected to a remote terminal unit (RTU) on the flowmeter skid.

A P/T gauge will be installed downhole as part of the upper completion and will be ported into the tubing to continuously measure CO_2 injection pressure and temperature at the reservoir. The downhole gauges will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure and for evaluating the reservoir performance and history-matching the operation with the projection of the model.

If the downhole gauge stops working between scheduled maintenance events, then the surface pressure limit approved for this permit will be used as a backup until the downhole gauge is repaired or replaced. For calibration purposes, in lieu of removing the injection tubing, the accuracy of the downhole gauges will be demonstrated by using a second pressure gauge with current certified calibration lowered into the well at the same depth as the permanent downhole gauge.

Electronic pressure and temperature transducers will be used to continuously monitor the pressure and temperature of the annulus between the tubing and long-string casing at the surface. Gauges and sensors will be connected to the automation system to provide continuous data analysis and alarms for malfunctioning events when the values deviate from the intended operating range.

A minimum of 100 psi differential will be maintained across the packer with the addition of packer fluid volume. Changes in pressure will be noted by the operator in the field and recorded in the project well databases daily. A pressure gauge and temperature sensor will be installed downhole as part of the upper completion and will be ported into the annulus above the packer to continuously measure the pressure in the annular space and identify any potential loss of mechanical integrity. If a major variation of pressure is observed in the annular gauges (surface/downhole), then the field operator will proceed to troubleshoot the well.

A fiber optic cable will be attached along the side of the casing and a distributed temperature sensing (DTS) interrogator will be installed on the surface, which will provide a distributed temperature profile while injecting. This system will continuously record the temperature to assist in monitoring the CO_2 behavior and identifying any unforeseen mechanical integrity issue in the well.

Automated shutoff devices will be installed at each exit of the flowlines in the wellhead and will be connected to the control system. If the operational parameters deviate from the program operational limits, the system will send an alarm to the operators to evaluate and correct the situation, which might include starting the shutdown protocol if the parameter exceeds the maximum operating limits [40 CFR 146.88 (e)(2)]. The Bluebonnet Sequestration Hub, LLC, will perform the activities identified in Table TM-6 to monitor operational parameters. All monitoring will take place at the locations and frequencies shown in the table.

Table TM-6: Monitoring devices, locations, and frequencies for continuous monitoring during injection operations in the CO_2 injector wells.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection Pressure	Pressure Transducer	Flowline close to the wellhead	1 sec	15 sec
Injection Rate	Coriolis Meter	Flowline into the wellhead	1 min	1 hr
Injection Volume	Coriolis Meter	Flowline into the wellhead	15 sec	15 sec
Injection Temperature	Temperature Transducer	Flowline close to the wellhead	1 sec	15 sec
Surface Annular Pressure	Pressure Transducer	Wellhead Injector	1 sec	15 sec
Annulus Volume	Calibrates Surface Tank	Wellhead	Daily	Daily
Downhole Annular Pressure and Temperature	Pressure Gauges, Temperature Sensor	Deployed in tubing ported to annular above packer	15 sec	30 sec
Distributed Temperature Profile	Fiber Optic + DTS Interrogator	Alongside long string	10 min	30 min
Downhole Injection Pressure and Temperature	Pressure Gauges, Temperature Sensor	Deployed in tubing ported to tubing above packer	15 sec	30 sec
Automatic Surface Shutoff Devices	Electric Actuated Valve	Each exit of the flowline in the wellhead	n/a	n/a

4.2.2 Monitoring Devices Description and Technical Specifications

Technical specifications for the tools to use for real-time data acquisition, monitoring, and shut down are described in the QASP.

4.3 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), the Bluebonnet Sequestration Hub, LLC, will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting,

and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

The Bluebonnet Sequestration Hub, LLC, will monitor corrosion using coupons and collect samples according to the description below. The project team will complement the corrosion coupons with casing inspection logs, visual inspection of the facilities, a robust leak detection and repair program, the use of optical gas imaging cameras (OGI), and the data collected in real time from the fiber optic cable installed in the injector wells.

During well material selection, the Bluebonnet Sequestration Hub, LLC, simulated the chemical reactions of the selected material, formation waters, and proposed CO_2 stream at downhole conditions. The project team proceeded to test the selected metallurgy to the maximum limits of the specification and operating parameters to validate the correct selection for downhole materials that will be exposed to the injection stream and formation waters.

4.3.1 Monitoring Location and Frequency

Table TM-7: Monitoring location and frequency of corrosion coupon testing.

Tool	Location	Pre-Injection	Injection
Corrosion coupons	Flowline CO_2 stream	n/a	Quarterly

4.3.2 Corrosion Coupon Analysis Description

Samples of selected materials in the wells and facilities (coupons) will be exposed to the injected CO_2 stream and monitored for signs of corrosion to verify that the selected materials meet the minimum standards for material strength and performance and to identify well maintenance needs.

Coupons shall be collected and sent quarterly to a third-party company for analysis, conducted in accordance with NACE Standard SP-0775-2018-SC, to determine and document corrosion wear rates based on mass loss. The project will begin corrosion coupon monitoring after the start of injection and will continue quarterly until the end of injection period.

Table TM-8: Summary of methods to evaluate corrosion coupons.

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

Table TM-9: List of equipment with materials of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Long String Casing – CO_2 Injector Well (above injection zone)	Carbon Steel L80
Long String Casing – CO_2 Injector Well (injection zone)	CRA 2507 min 80 ksi
Tubing (Internally Coated) – CO_2 Injector Well	Carbon Steel L80
Wellhead – CO_2 Injector Well (no CO_2 wetted areas)	Carbon Steel DD specification
Injection Tree and Tubing Hanger – CO_2 Injector Well	Sour Service - HH specifications
Packers – CO_2 Injector Well & In-Zone Monitoring Wells	Nickel-Plated
Long String Casing –-Confining Zone/USDW Monitoring Wells	Carbon Steel L80
Long String Casing –In Zone Monitoring Wells (above injection zones)	Carbon Steel L80
Long String Casing –In Zone Monitoring Wells (Injection zones) . With the exception of Encanto 01	CRA 2507 min 80 ksi
Tubing – In-Zone Monitoring Wells	Carbon Steel L80
Wellhead and Tree – In-Zone Monitoring Wells	Carbon Steel DD specification

4.4 Visual Inspection and Leak Detection and Repair (LDAR) Program using Optical Gas Imaging Camera (OGI)

The project will perform visual inspection of the facilities and wells as part of the maintenance and mechanical integrity program, as summarized in Table TM-10. Inspection will start from the commissioning date and will continue weekly after the site is injecting steadily. Leak detection and repair (LDAR) field inspections will be performed quarterly after the start of injection and continue until injection ceases, using optical gas imaging (OGI) cameras.

During visual inspections, the field operator will be provided with handheld devices to measure explosive gases, H_2S, and CO_2 as part of the safety requirements of the site.

Table TM-10: Monitoring locations and frequency of visual inspections and LDAR program.

Tool	Location	Pre-Injection	Injection
Leak detection and repair (LDAR) program using optical gas imaging cameras, handheld during inspections	Surface facilities and wellheads	n/a	Quarterly
Visual inspections and handheld monitors (LEL, $H2_S$, CO_2)	Surface facilities and wellheads	Before start of injection	Weekly

Notes:

1. Multiple inspections using OGI cameras will be performed during the startup of the well (first injection) after authorization to inject is received and will continue quarterly as minimum frequency during the injection period.

4.5 Pressure Falloff Testing in CO_2 Injector Wells

The Bluebonnet Sequestration Hub, LLC, will perform pressure falloff tests in the CO_2 injection wells during the injection phase as described below to meet the requirements of 40 §CFR 146.90(f).

4.5.1 Testing Location and Frequency

Pressure falloff testing will be conducted upon completion of the injection well to characterize reservoir hydrogeologic properties, aquifer response model characteristics, and changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Pressure falloff testing will be conducted in the CO_2 injection wells at least once every five years during injection for the AoR until the wells are plugged. The objective of the periodic pressure falloff testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect the well or reservoir performance.

4.5.2 Testing Details

Detailed procedure and analytics proposed for the falloff test are described in the QASP.

4.6 Tracking and Recording Pressure and Temperature in In-Zone Monitoring Wells

The Bluebonnet Sequestration Hub, LLC, will continuously measure pressure and temperature in the in-zone monitoring wells at the surface via real-time P/T instruments installed in the wellhead. Table TM-11 summarizes the monitoring locations of P/T gauges and frequency of testing.

A pressure and temperature (P/T) gauge will be installed downhole as part of the upper completion and will be ported into the tubing to continuously measure pressure and temperature in the reservoir. These measurements will allow the project team to calibrate and verify the model, improve predictive capability for confirming CO_2 containment, and evaluate the development of the pressure front.

Since the changes in reservoir pressure precede the movement of the CO_2 plume, in-zone monitoring wells will provide data to history-match the model and calibrate the response expected from the reservoir regarding the development of pressure front and CO_2 plume migration.

Table TM-11: Monitoring locations and frequency of pressure and temperature measurement in in-zone monitoring wells.

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface P/T transducers	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	n/a	Continuously	1 sec	15 sec
Downhole P/T gauges	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	n/a	Continuously	15 sec	30 min

In the event the downhole sensor fails before a planned well maintenance operation, the project will continue monitoring the pressure with the surface transducers and might implement measurement of fluid levels in the well to calculate the bottomhole pressure while the equipment is replaced and repaired. The project team might install temporary pressure gauges in the well and limit the collection of data to one sample per day.

4.7 Tracking and Recording Pressure and Temperature in Miocene Composite Confining Zone monitoring wells.

The project team plans to install P/T sensors in the Miocene Composite Confining Zone monitoring wells, Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3. These sensors and gauges will be included as part of the upper completion.

In the event the downhole sensor fails before a planned well maintenance operation, the project team will continue monitoring the pressure with the surface transducers and might implement measurement of fluid levels in the well to calculate the bottomhole pressure while the equipment is replaced and repaired.

Table TM-12 summarizes the monitoring locations and frequency of pressure and temperature tracking on the Miocene Composite Confining Zone monitoring wells.

Table TM-12: Monitoring locations and frequency of pressure and temperature measurements in Miocene Composite Confining Zone monitoring wells.

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface Pressure and Temperature Transducers	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	n/a	Continuously	1 sec	15 sec
Downhole P/T Gauges	Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	n/a	Continuously	15 sec	30 min

4.8 Tracking and Recording Pressure in ACZ/USDW Monitoring Wells

The Bluebonnet Sequestration Hub, LLC, will continuously measure pressure and temperature in the USDW monitoring wells at the surface via real-time P/T instruments installed in the wellhead.

The project team plans to install P/T gauges in the upper completion of the USDW monitoring wells to track changes in the downhole conditions.

4.8.1 Monitoring Location and Frequency

Table TM-13: Monitoring locations and frequency of pressure and temperature measurement for USDW monitoring wells.

Tool	Location	Pre-Injection	Injection	Min. Sampling Frequency	Min. Recording Frequency
Surface P/T transducers	Bluebonnet USDW 1 Bluebonnet USDW 2 Bluebonnet USDW 8	n/a	Continuously	1 sec	15 sec
Downhole P/T gauges	Bluebonnet USDW 1 Bluebonnet USDW 2 Bluebonnet USDW 8	n/a	Continuously	15 sec	30 min

5.0 Mechanical Integrity Testing

5.1 External Mechanical Integrity Testing

The Bluebonnet Sequestration Hub, LLC, will perform a cement logging evaluation with one or more of the following tools to validate zonal isolation between the injection zones, confining and dissipation zones, and overburden formations after installation of the long string casing during construction of the CO_2 injector and in-zone monitoring wells [40 CFR 146.87 (a)(2)(ii) 40 CFR 146.87 (a)(3)(ii)]:

a) Cement bond logging
a) Ultrasonic cement evaluation tool
a) Variable density log (VDL)

The project team will run a pulse neutron log (PNL) in the CO_2 injection wells after initial installation of the completion equipment, and at least once a year to evaluate external mechanical integrity (40 CFR 146.89(c) and 40 CFR 146.90(e)).

The project team will install a fiber optic cable alongside the long-string casing in the CO_2 injection wells with the capability of continuously monitoring temperature changes from the top of the perforations to the surface, exceeding the requirements in 40 CFR 146.89(e) and 40 CFR 146.90(e).

Additionally, during well maintenance operations or workovers for the CO_2 injection well, an ultrasonic casing inspection tool will be run to evaluate casing thickness and conditions.

The project team will run a PNL in the in-zone monitoring wells after initial installation of the completion equipment to set the baseline for mechanical integrity evaluation as well as for CO_2 plume tracking in the reservoir if required.

The project team will also install a fiber optic cable alongside the casing in the in-zone monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2, and the Miocene Composite Confining Zone monitoring well Bluebonnet IZM M1, that will allow tracking of mechanical integrity in real time as well as changes in reservoir and overburden conditions.

If a fiber optic cable fails in any of the in-zone monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2, or Bluebonnet IZM M1 the project team will run one of the following tools at least every five years or during well maintenance operations or workovers to evaluate external mechanical integrity:

a) Pulse neutron through tubing
b) Electromagnetic casing inspection log
c) Temperature log

For Encanto 01 stratigraphic well which does not have fiber optic cable installed on the long string, the project team will run one of the following tools at least every five years or during planned well maintenance or workover activities to demonstrate external mechanical integrity:

a) Pulse neutron through tubing
b) Electromagnetic casing inspection log
c) Temperature log

5.1.1 Testing Location and Frequency

Table TM-14 below provides a summary of the external mechanical integrity tools.

Table TM-14: Corrosion monitoring and surface leak detection tools.

Tool	Location	Pre-Injection	Injection
USIT, CBL, VDL	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1	After long-string installation before completion	If required by future operations.
Pulse Neutron	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	After completion installation or before injection to set baseline.	Once a year.
Pulse neutron, temperature log, or electromagnetic log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01 Bluebonnet IZM M1	After completion installation or before injection to set baseline.	Every 5 years or during planned maintenance or workover activities. Event triggered by other monitoring results.
DTS survey	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	Before injection as baseline	Continuously
DTS survey	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1	Before injection as baseline	Continuously

5.1.2 Testing Details

The logging industry has made impressive advancements in tools that provide images of and data identifying the quality of the cement bond behind the casing after cementing jobs are complete. The casing inspection tool and multi-finger calipers can provide information about ovality, collapse, and/or damage in the casing, as well as estimations of wall thickness to evaluate wearing and corrosion effects.

The most advanced tools can evaluate up to five concentric tubulars to measure changes in thickness that could be related to corrosion or wearing effects.

The tools described below are readily available technologies on the market and the basis of the project's master monitoring program for mechanical integrity. No specific provider has been selected. In the future, new technologies or tools may be proposed for further discussion with regulators.

5.1.2.1 Cement Bond Log and Variable Density Log

Cement bond log (CBL) is a basic method to evaluate cement quality in the annulus. It is an acoustic wave measurement. The tool usually includes a transmitter and receiver, separated by 3 ft. The acoustic wave is emitted by the transmitter, propagated down and across the annulus, and recorded by the receiver. The attenuation of the wave is analyzed to interpret the bonding behind the pipe. Signal coming from a properly cemented casing will be more attenuated than the signal coming from a poorly cemented one.

The arriving signal recorded by the receiver is a mixed signal coming from casing, cement, mud, and formations. Each signal has its own pathway because they travel at different velocities through each medium. The signal through the casing is the fastest, as sound travels the quickest through steel. As a result, it is the first signal detected on the receiver. The second signal most likely to arrive is the signal through the formation and last one is the drilling fluid signal because sound travels slower in a liquid.

Variable density log (VDL) is commonly used as an adjunct to the cement bond log and offers better insights with its interpretation. In most cases, micro annulus and fast-formation-arrival effects can be identified using this additional display.

Figure TM-12 and Figure TM-13 show examples of CBL and VDL output.

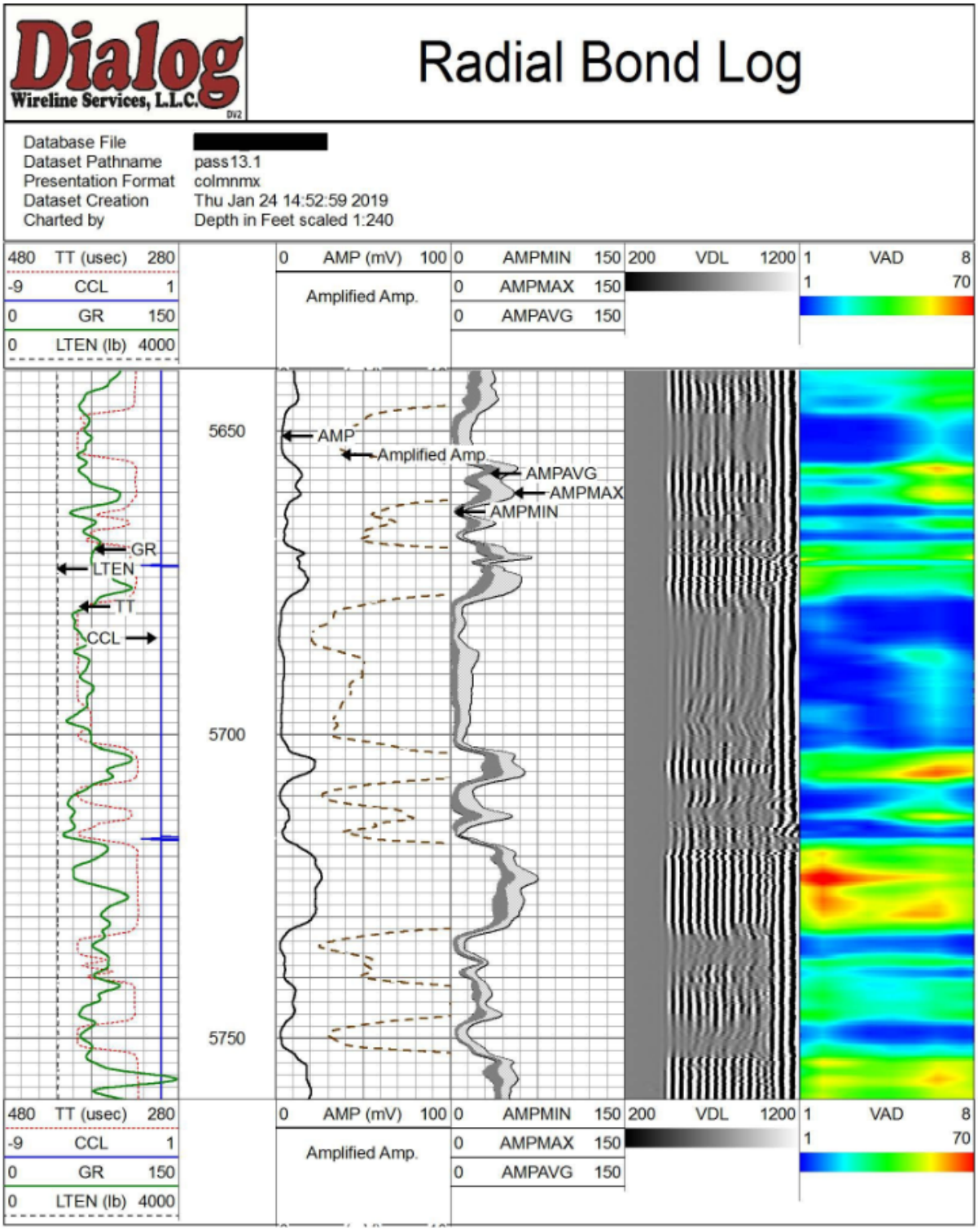


Figure TM-12: CBL and VDL example from dialog wireline services web page.

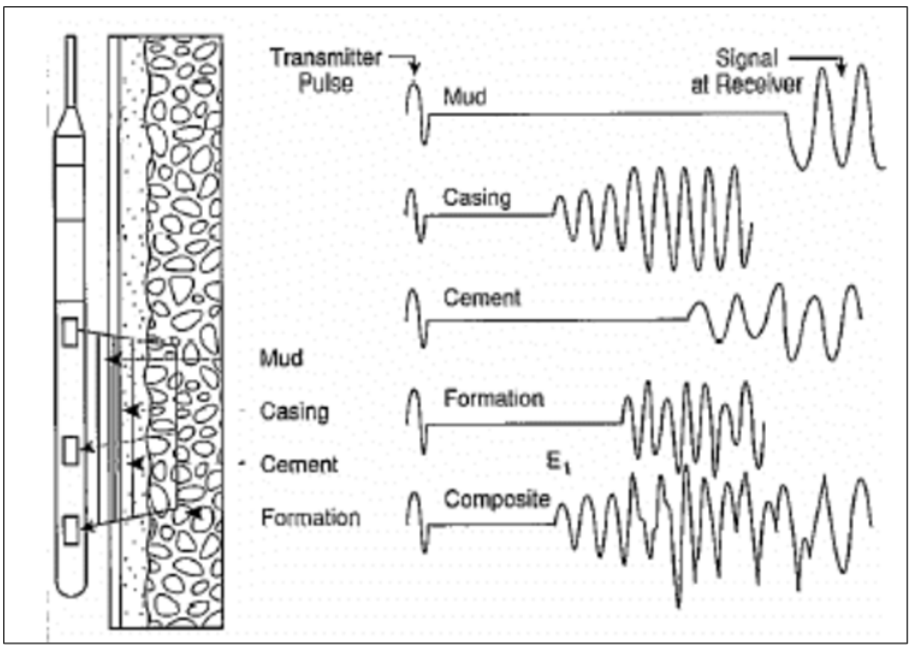


Figure TM-13: Signal received by CBL-VDL.

5.1.2.2 Ultrasonic Cement and Casing Evaluation Tools

USIT (SLB technology) is an example of an ultrasonic imager that delivers an accurate, comprehensive, and high-resolution confirmation of the pipe-to-cement bond quality and downhole pipe condition in real time. Casing inspection and monitoring applications include corrosion detection, identification of internal and external damage or deformation, and casing thickness analysis for collapse and burst pressure calculations.

The rate of decay of the waveforms received indicates the quality of the cement bond at the cement-casing interface and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. The resulting 360° data coverage enables evaluation of the quality of the cement bond and determination of both the internal and external condition of the casing.

Isolation Scanner™ (SLB Technology) is a combination of independent measurements that fully characterizes the annular environment, differentiating low-density solids from liquids to distinguish lightweight and contaminated cements from liquids. Its azimuthal coverage provides results around the entire circumference of the casing, pinpointing any channels in the cement and confirming the effectiveness of the annular barrier for zonal isolation.

The Isolation Scanner™ tool also identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing. The flexural wave measurement produces entirely new information from the third-interface echoes (TIEs) between the annulus and borehole or outer casing. The TIEs image the borehole shape, define the position of the casing within the borehole or outer casing, and image the outer string to reveal corrosion and damage.

5.1.2.3 Distributed Temperature Sensing

Distributed temperature sensing (DTS) technology uses fiber optic sensor cables, typically several kilometers in length, that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the sensor cable. DTS uses the Raman effect to measure temperature. An optical laser pulse sent through the fiber results in some scattered light reflecting to the transmitting end, where the information is analyzed. The intensity of the Raman scattering is a measure of the temperature along the fiber. The Raman anti-Stokes signal changes its amplitude significantly with changing temperature, while the Raman Stokes signal is relatively stable. The position of the temperature reading is determined by measuring the arrival timing of the returning light pulse like a radar echo.

The fiber optic cable is run alongside the casing as an umbilical and is protected with clamps and centralizers to avoid any damage while deploying it into the well. The fiber is connected on the surface to an interrogator that converts the signal to temperature values and transmits the data to the monitoring platform in real time for surveillance purposes.

The equipment maintenance and calibration will be performed according to the manufacturer's manuals and will be the technology provider's responsibility. Technical specifications are available in the QASP.

5.1.2.4 Electromagnetic Casing Inspection Tool

Electromagnetic Pipe Xaminer® V (EPX™ V) (Halliburton technology) is an example of a proprietary electromagnetic tool. The operating principle of the tool is to induce a high-definition frequency (HDF) electromagnetic energy into the surrounding pipe, which propagates through the concentric well strings with no wellbore fluid influences. The interaction with the metal of the pipe returns a signal to the tool, yielding information on the metal loss present in the tubulars. The magnitude and location of corrosion-induced defects are identified using HDF variance algorithms of the returning electromagnetic waves. This information leads to a quick total thickness calculation determining the overall condition of the pipe structure. This technology enables examination of the whole well in one trip, for up to five concentric strings of pipe.

5.1.2.5 Temperature Log

Temperature logs are used to locate gas entries, detect casing leaks, and evaluate fluid movement behind casing. They are also used to detect lost-circulation zones and cement placement. Temperature logs are used as a basic diagnostic tool and are usually paired with other tools like acoustics or multi-arms calipers, if more in-depth analysis is required.

Temperature instruments used today are based on elements with resistances that vary with temperature. The variable resistance element is connected to bridge circuitry or a constant current circuit, so that a voltage response is proportional to temperature. The voltage signal from the temperature device is then usually converted to a frequency signal that is transmitted to the surface, where it is converted back to a voltage signal and recorded. The absolute accuracy of temperature logging instruments is not high (in the order of +- 5°F), but the resolution is good (0.05°F or better) although this accuracy can be compromised by present day digitalization of the signal on the

surface. The temperature instrument can usually be included in the string with other tools, such as radioactive tracer tools or spinners flowmeters. Temperature logs are run continuously, typically at cable speeds of 20 to 30 ft/min. (A. Daniel Hill 2021).

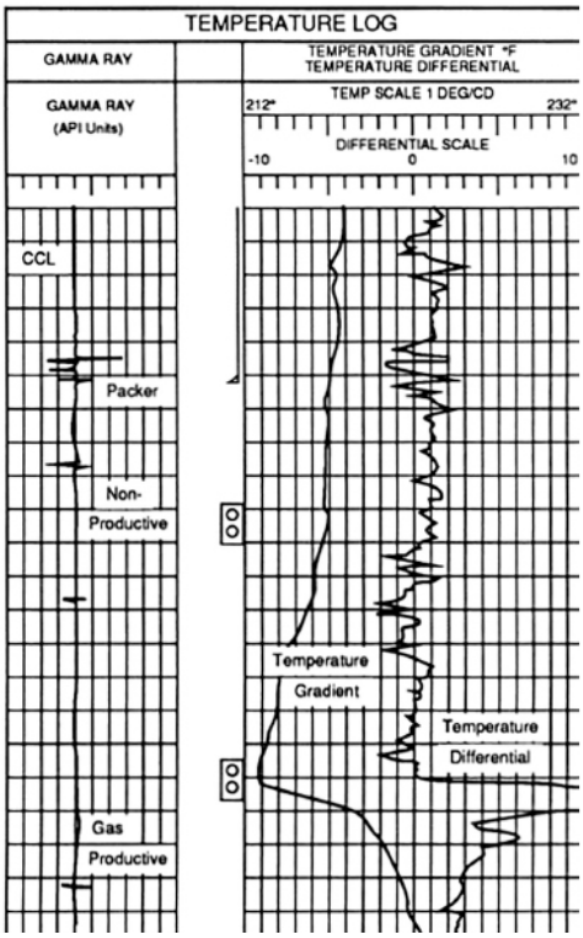


Figure TM-14: Example of temperature log output.

5.1.2.6 Pulse Neutron Log

Pulse neutron log (PNL) provides formation evaluation and reservoir monitoring in cased holes. The PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays. High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements. Each logging company has its own proprietary designs and improvements on the tool.

SLB's Pulsar multifunction spectroscopy service (PNX) pairs multiple detectors with a high-output pulsed neutron generator in a slim tool with an outer diameter (OD) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The tool's integration of the high neutron output and fast

detection of gamma rays, with proprietary pulse processing electronics, allows differentiation and quantification of gas-filled porosity from liquid-filled and tight zones. The tool can accurately determine saturation in any salinity of formation water, across a wide range of well conditions, mineralogy, lithology, and fluid contents profile at any inclination. Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity. Detailed measurement and mechanical specifications for the PNX tool are provided in the QASP document. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Halliburton's Reservoir Monitor Tool 3-Detector™ (RMT-3D) is a pulsed-neutron tool that solves for water, oil, and gas saturations within reservoirs using three independent measurements (Sigma, C/O, and SATG). This provides the ability to uniquely solve simple or complex saturation profiles in reservoirs, while eliminating phase-saturation interdependency. The RMT-3D provides gas phase analysis to identify natural gases, nitrogen, CO_2, steam, and air. The tool has 2.125 in. OD that allows it to be run through tubing.

5.1.3 Description and Technical Specifications of the Tools for External Mechanical Integrity Evaluation

Detailed information and technical references of these tools are provided in the QASP.

5.2 Internal Mechanical Integrity Testing

The Bluebonnet Sequestration Hub, LLC, will perform an annular pressure test in the CO_2 injection wells and in the in-zone monitoring wells to demonstrate internal mechanical integrity, according to 40 CFR 146.89(b).

Annular pressure testing is used to validate mechanical integrity. Tests will be performed according to the frequency presented in Table TM-15.

Table TM-15: Annular pressure testing frequency.

Tool	Location	Pre-Injection	Injection
Annular Pressure Test	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	After long-string installation before completion	After every well maintenance operation
Annular Pressure Test	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01 Bluebonnet IZM M1	After long-string installation before completion	Annually

If the additional monitoring systems indicate a potential mechanical integrity issue, the Bluebonnet Sequestration Hub, LLC, will perform troubleshooting and perform an annular pressure test as part of the protocol, if needed.

An example overview of the procedure is as follows (actual procedures may vary based upon operating conditions at the well and other safety or technical considerations):

1. First, shut in the well to stabilize the pressures in the injectors and validate static conditions in the monitoring wells.

2. Connect the testing equipment to the annular valves and test surface lines to 1,500 psi above the testing pressure.

3. Verify that there are no surface leaks from the pumping unit to the wellhead valve. Bleed off any air in the system. If needed, fill the annular space with packer fluid and corrosion inhibitor (if needed, it should require only a minimal amount). Record the initial tubing and casing pressure.

4. Test the well to 1,000 psi in the annular space for the CO_2 injection wells and 500 psi in the annular for in-zone monitoring wells. The pressure should not decrease more than 10% in 30 minutes.

5. Continuously monitor the tubing and casing pressures. Record the final tubing and casing pressure. If the pressure decreases more than 10%, bleed the pressure completely, test the surface connection, and repeat the test.

6. If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the Director.

7. Document and store the test results in the centralized database of the project for reporting and documentation.

Note: Surface gauges should be calibrated according to manufacturer recommendations. There should be a pressure range that will allow the test pressure to be near the gauge's mid-range. Additionally, the gauge must be of sufficient accuracy and scale to allow an accurate reading of 5% change to be read.

6.0 Groundwater Quality and Geochemical Monitoring

The Bluebonnet Sequestration Hub, LLC, will monitor water quality and geochemical changes within the Miocene Composite Confining Zone and in the base of the USDW during the operation period to meet the requirements of 40 CFR 146.90(d).

The monitoring locations were selected based on the original screening of the AoR for existing legacy wells, results of the numerical simulation for CO_2 plume and pressure front, and risk assessment performed by the project. The location, techniques, and frequency were optimized, taking into consideration the complementary techniques proposed in this monitoring plan for direct and indirect measurements, such as 2D seismic surveys, 3D time lapse VSP, pulse-activated neutron logs, soil gas analysis, and others that are explained in additional sections of this document.

The Bluebonnet Sequestration Hub, LLC, selected 23 potential legacy shallow water wells distributed around the AoR to sample and test the freshwater aquifer in the area. These wells targeted the Chicot Aquifer to provide water for domestic, public, stock, and irrigation uses. Some of these wells could be replaced or eliminated after the project performs a mechanical integrity assessment on the wells.

Additionally, the project team drilled Bluebonnet USDW 1 in May 2024 and Bluebonnet USDW 8 in May 2025 to characterize the different zones between surface and base of the USDW. The Bluebonnet USDW 1 well was completed in the first permeable zone below the base of the USDW and will serve to monitor geochemical and pressure changes in the sands underlying the base of USDW while Bluebonnet USDW 8 was complete on the sand above the base of USDW.

The project team plans to drill one additional USDW monitoring well, Bluebonnet USDW 2, that will be completed in the base of the USDW to track pressure and temperature changes as well as geochemical changes in the aquifers across the AoR. Figure TM-2 shows the proposed well network for USDW and confining zone monitoring wells.

6.1 Freshwater Shallow Aquifer Water Sampling and Testing

Groundwater production for drinking and municipal use in Chambers, Liberty, and Jefferson Counties, Texas, is primarily sourced from shallow wells completed in the Chicot Aquifer. Therefore, proposed locations for sampling and testing the shallow freshwater (< 1,000 mg/l TDS) aquifer utilize existing wells completed in the Chicot Aquifer (Table TM-16).

Candidate wells for sampling and testing were meticulously selected to encompass a broad area within and surrounding the defined Area of Review (AoR). These candidate wells were evaluated using publicly available data, considering factors such as installation age, usage, depth, and their relative location to the AoR and other monitoring wells. In August 2025, field evaluations were conducted for each proposed candidate well to assess their mechanical integrity and accessibility. It was noted that some of the wells proposed in the previous submission were either inactive, defective, or misreported. Consequently, the list of legacy wells has been updated and is now presented in Table TM-16.

Shallow freshwater aquifer sampling and characterization is planned to commence a minimum of one year prior to the start of injection (Table TM-17). Detailed analytical suite for water samples is shown in Table TM-20, which includes characterization of physical and chemical compositions as well as analysis of dissolved gases and major isotope systems.

6.1.1 Monitoring Location and Frequency

Table TM-16 shows the proposed locations for sampling the freshwater shallow aquifer and Table TM-17 shows the frequencies proposed (40 CFR §146.90(d)(1) and 40 CFR §146.90 (d)(2)).

Table TM-16: Location of the freshwater shallow water wells selected for sampling in the AoR.



Table TM-17: Sampling frequency for existing shallow freshwater wells (40 CFR §146.90(d)(1) and 40 CFR §146.90(d)(2)).

Monitoring Location(s)	Monitoring Activity	Target Formation	Pre-Injection	Injection Period
10-23 shallow water wells distributed in the AoR.	Fresh water sampling and analysis.	Upper Chicot Aquifer	1 year before injection, 4 samples a year, 1 sample every quarter.	The first samples are 3 months after start of injection and quarterly after that for years 1 and 2.

6.2 Miocene Composite Confining Zone and ACZ/USDW Wells Water Sampling and Testing

Recent field investigations conducted onsite supported publicly available data that showed base USDW (<10,000 mg/l TDS) is in the lower Chicot Aquifer, at depths ranging from 1,100 to

1,700 ft MD within the AoR. Bluebonnet USDW 01 and Bluebonnet USDW 8 were recently drilled and completed, and one additional USDW monitoring well is planned. Bluebonnet plans to drilled three well to collect sample within the Miocene Composite Confining Zone, Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3.The detailed analytical suite is shown in Table TM-20 and is identical to the analytical suite used for the existing shallow freshwater wells.

Table TM-18: Planned and drilled Miocene Composite Confining Zone and USDW wells for water sampling and testing.

Well Name	Latitude	Longitude	Elevation (ft)	Status	Target monitoring Depth TVD (ft)	Target Formation
Bluebonnet USDW 1	29.844028	-94.456689	28.06	Drilled 2024	1,370-1,420	Lower Chicot
Bluebonnet USDW 2	29.80423	-94.463443	26.24	To be Drilled	1,400-1,500	Lower Chicot
Bluebonnet USDW 8	29.844026	-94.456309	41	Drilled 2025	927-1,017	Lower Chicot
Bluebonnet IZM M1	29.824174	-94.472579	29.52	To be Drilled	2,700-2,800	Upper Miocene
Bluebonnet IZM M2	29.821141	-94.422738	22.97	To be Drilled	1,880-1,980	Upper Miocene
Bluebonnet IZM M3	29.869180	-94.500983	36.09	To be Drilled	1,740-1,840	Upper Miocene

Table TM-19: Location and frequency of the water sampling and testing in the USDW wells.

Monitoring Location(s)	Monitoring Activity	Target Formation	Pre-Injection	Injection Period
Bluebonnet USDW 1 Bluebonnet USDW 8	Water Sampling	Lower Chicot	Baseline. Quarterly min 1 year before injection.	Quarterly first 2 years of injection. Semi-annually from year 3 to end of injection.
Bluebonnet USDW 2	Water Sampling	Lower Chicot	Baseline. Data acquired during installation of the wells.	Quarterly first 2 years of injection. Semi-annually from year 3 to end of injection.
Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	Water Sampling	Upper Miocene	Baseline. Data acquired during installation of the wells.	Quarterly first 2 years of injection. Semi-annually from year 3 to end of injection.

6.3 Analytical Parameters for Water Testing in Miocene Composite Confining Zone and ACZ/USDW monitoring wells.

The Bluebonnet Sequestration Hub, LLC, has proposed an extensive water quality characterization program using natural tracers and unique fluid chemical characteristics to define reservoirs within the storage complex The sampling and analysis protocol will be used to establish baseline geochemical characteristics and differentiate changes in water quality between natural and anthropogenic influences.

The pre-injection baseline analytical suite will include detailed characterization of the chemical composition and major isotope systems. Following baseline characterization, a reduced analytical suite will be developed from baseline characterization results to focus on primary indicators of potential leakage. Isotopic compositions will likely not be routinely conducted during injection unless required for source attribution. Proposed changes to the analytical suite will be discussed with the UIC Director after the baseline data is collected and the routine testing protocol is finalized. Table TM-20 outlines the analytical suite for water analysis.

Field sampling methods and chain of custody procedures for water quality sampling are described in the QASP. All field and laboratory analytical tests will be performed by third-party certified laboratories and will follow applicable EPA or industry standard methods.

Table TM-20: Measured parameters and analytical methods summary for existing shallow freshwater wells and Confining Zone / USDW monitoring wells.

Parameter	Analytical Method
Cations: Al, Ba, B, Cd, Ca, Cu, Cr, Fe, Pb, Li, Mg, Mn, Ni, P, K, Si, Na Sr, Zn	ICP-OES, EPA Method 6010d, ICP-MS Method 200.8 or equivalent
Other Metals: As, U, Co, Se, Pb, Mo, V	ICP-MS Method 200.8 or equivalent
Mercury	EPA 245.7 CVAA, or equivalent
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-, $NO2^-$	Ion Chromatography, EPA Method 300.1 or similar
Carbonate, bicarbonate and hydroxide	Titration, ASTM D3875.
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C, ASTM D5907 or equivalent
Water Density	ASTM D5057, ASTM D4052 or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas Bench and CF-IRMS for $^{13/12}C$
Radiocarbon 14C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, ASTM 1945D, RSK 175 or equivalent
pH	ASTM D1293, EPA 150.23 or equivalent
Temperature	ASTM 2550
Conductivity	ASTMD1125

Parameter	Analytical Method
Conductivity (field)	EPA 120.1
ICP-OES = inductively coupled plasma optic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; GC/MS = gas chromatography–mass spectrometry; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: Cold Vapor Atomic Absorption;	

6.4 Sampling Methods for Water Characterization

Water sampling will be performed by personnel of a certified laboratory, following the specific methods approved by the EPA or other standards. Operators might audit the procedures and results of the selected laboratory with a third party to improve quality control.

Sampling procedures and technical specification of the tools are provided in the QASP.

6.5 Laboratory to be Used/Chain of Custody Procedures

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Sampling methods and chain of custody procedures are described in the QASP.

7.0 CO_2 Plume and Pressure-Front Tracking

7.1 Summary of Direct and Indirect Methods to Monitor CO_2 Plume and Pressure Front Development

Table TM-21 presents methods that Bluebonnet Sequestration Hub, LLC, will use to monitor the position of the CO_2 plume and development of the pressure front, including the activities, locations, and frequencies for the Bluebonnet Hub to comply with 40 CFR 146.90(g).

Table TM-21: Summary of methods for monitoring of CO_2 plume extension and pressure front.

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
AoR	2D Time-lapsed surface seismic survey	Reservoir, seal, and overburden	Baseline acquisition before injection	Every 5 years
AoR	3D Surface seismic survey	Reservoir, seal, and overburden	Baseline acquisition before injection	n/a

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 6 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1	3D VSP time lapsed survey	Reservoir, seal, and overburden	Baseline once the wells are drilled	Annually in CO2 injectors until plume extend beyond detection. Event triggered based on other monitoring techniques.
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	Pulse Neutron Log	Reservoir, seal, and overburden	Baseline will be acquired once the wells are drilled	Annually
Bluebonnet IZM FM 1 Bluebonnet IZM FM2 Encanto 01	Pulse Neutron Log	Reservoir, seal, and overburden	Baseline will be acquired once the wells are drilled	Event triggered in monitoring well based on other monitoring techniques.
Bluebonnet IZM FM 1 Bluebonnet IZM FM2 Encanto 01	PH, Conductivity and Fluid Level	Reservoir	Initial completion	Annually
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7 Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	Downhole gauges; pressure and temperature.	Reservoir	Baseline line will be acquired during completion of the wells	Continuously

7.2 Pressure and Temperature Measurement in the Reservoir

The use of pressure and temperature gauges and transducers for monitoring the CO_2 injectors and monitoring wells was explained in Sections 3 and 4 of this document.

Table TM-22: Summary of the sampling frequency for downhole pressure measurements in CO_2 injectors and in-zone monitoring well.

Location	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	Pressure and temperature gauges	Downhole deployment on tubing	1 sec	15 sec
Bluebonnet IZM FM 1 Bluebonnet IZM FM2 Encanto 01	Pressure and temperature gauges	Downhole deployment on tubing	15 sec	30 min

7.3 Pulse Neutron/Saturation Log for CO_2 Plume Tracking

The implementation of PNL was described in Section 3 as well as in Section 5 of this document.

Table TM-23: Location and frequency of pulse neutron or saturation log implementation for CO_2 plume monitoring in CO_2 injector wells and in-zone monitoring wells.

Tool	Location	Pre-Injection	Injection
Pulse Neutron	Bluebonnet CCS 1 Bluebonnet CCS 2 Bluebonnet CCS 3 Bluebonnet CCS 5 Bluebonnet CCS 6 Bluebonnet CCS 7	After completion installation or before injection to set baseline.	Once a year
Pulse Neutron	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Encanto 01	After completion installation or before injection to set baseline.	Event triggered in monitoring well based on other monitoring techniques.

7.4 Geophysical Methods for CO_2 Plume Extension Monitoring Details

A multi-scale approach will be employed for plume migration, CO_2 saturation monitoring, and potential leak detection with multiple seismic methods.

A baseline acquisition program consisting of surface 2D seismic, surface 3D seismic, and 3D VSP will be acquired prior to injection and is designed to calibrate the in-situ seismic response across multiple scales of investigation and model the predicted seismic response resulting from injection.

During the injection period, 3D VSP timelapse surveys will be acquired and analyzed annually, to provide high quality imaging and temporal resolution of plume movement proximal to injection wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, and Bluebonnet CCS 6, and monitoring wells Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Bluebonnet IZM M1. Injection wells Bluebonnet CCS 5 and Bluebonnet CCS 7 are not planned for 3D VSP since they

share well pads with Bluebonnet CCS 1 and Bluebonnet CCS 3, respectively. Monitoring well Encanto 01 will not encounter a modeled plume during injection period and is not included in the VSP program. Modeling indicates that the plume extents will be detectable from the injection well VSPs from the start of injection but will move beyond the radius of investigation by as early as year 5 of injection in the respective injection zone. Modeled plumes and VSP radius of investigation may be seen in Figure TM-15 for the Frio injection, Figure TM-16 for the Hackberry injection, and Figure TM-17 for the Miocene injection.

A 2D timelapse surface seismic will be acquired and analyzed every five years during injection to monitor plume movement and saturation on an AoR-wide scale. The 2D timelapse monitoring will be repeated at the end of injection period and before site closure to demonstrate non-endangerment to USDW. If any aspect of the monitoring system indicates unfavorable plume movement at any point during the injection and post-injection periods, the project team will evaluate the need for additional geophysical surveys. The proposed 2D program is conceptual and will be refined as needed to suit monitoring needs.

The combined 3D VSP and 2D seismic program is designed to leverage the high-resolution of 3D VSP (particularly at the injection well) to understand the early plume development in detail, with the broader scope of the timelapse 2D to monitor for long-term movement.

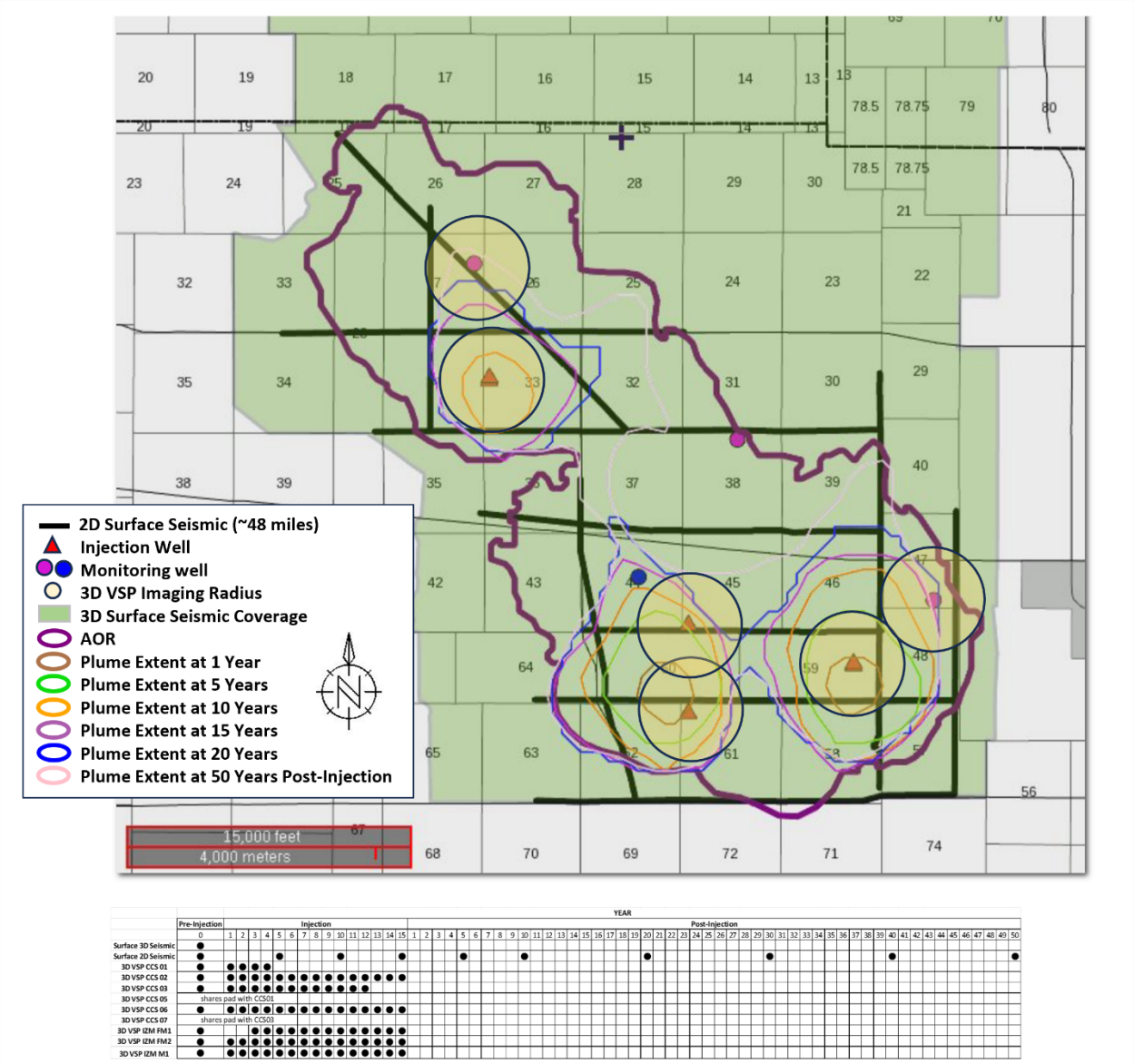


Figure TM-15: Proposed geophysical monitoring program for the Frio injection.

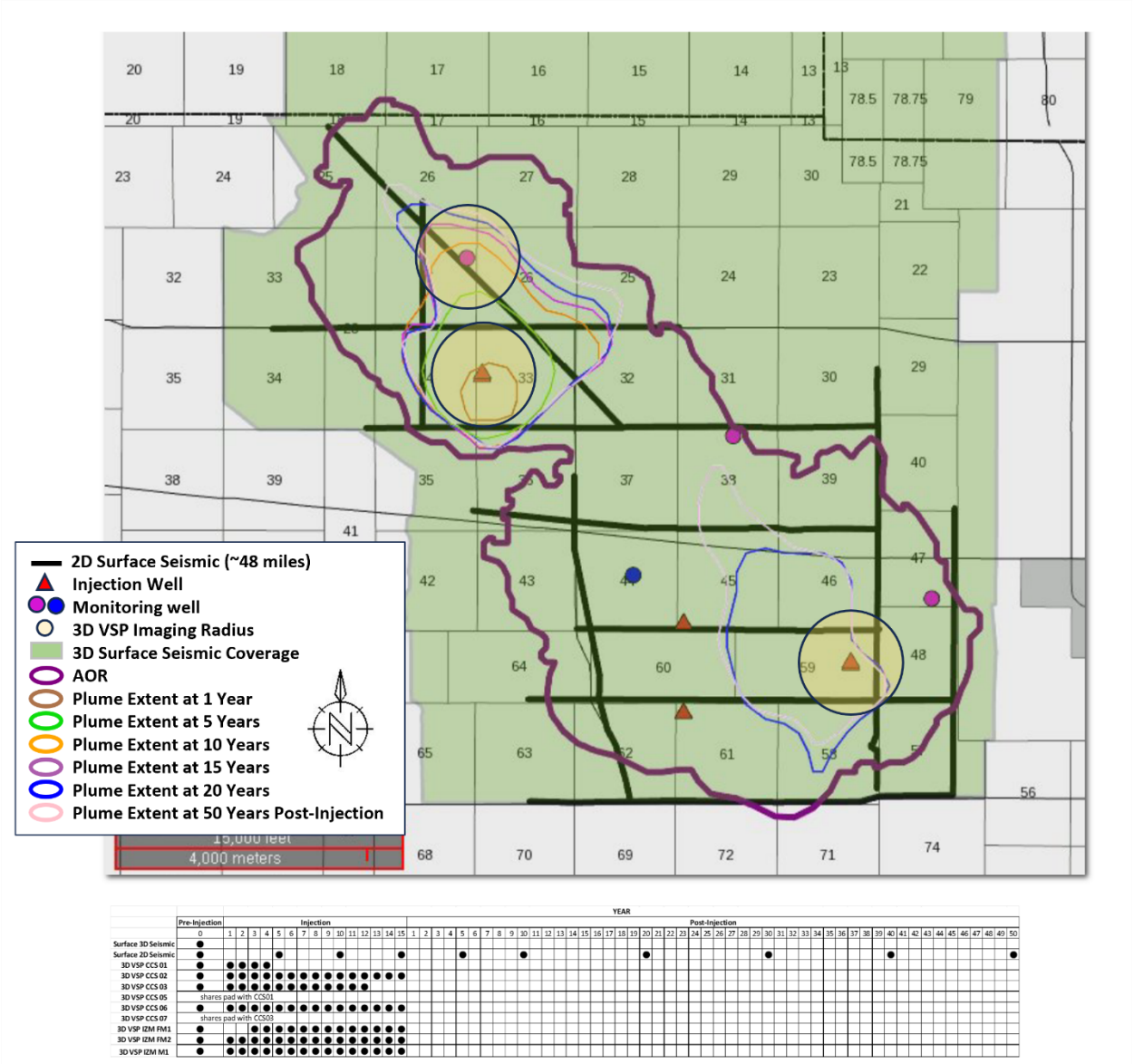


Figure TM-16: Proposed geophysical monitoring program for the Hackberry Injection.

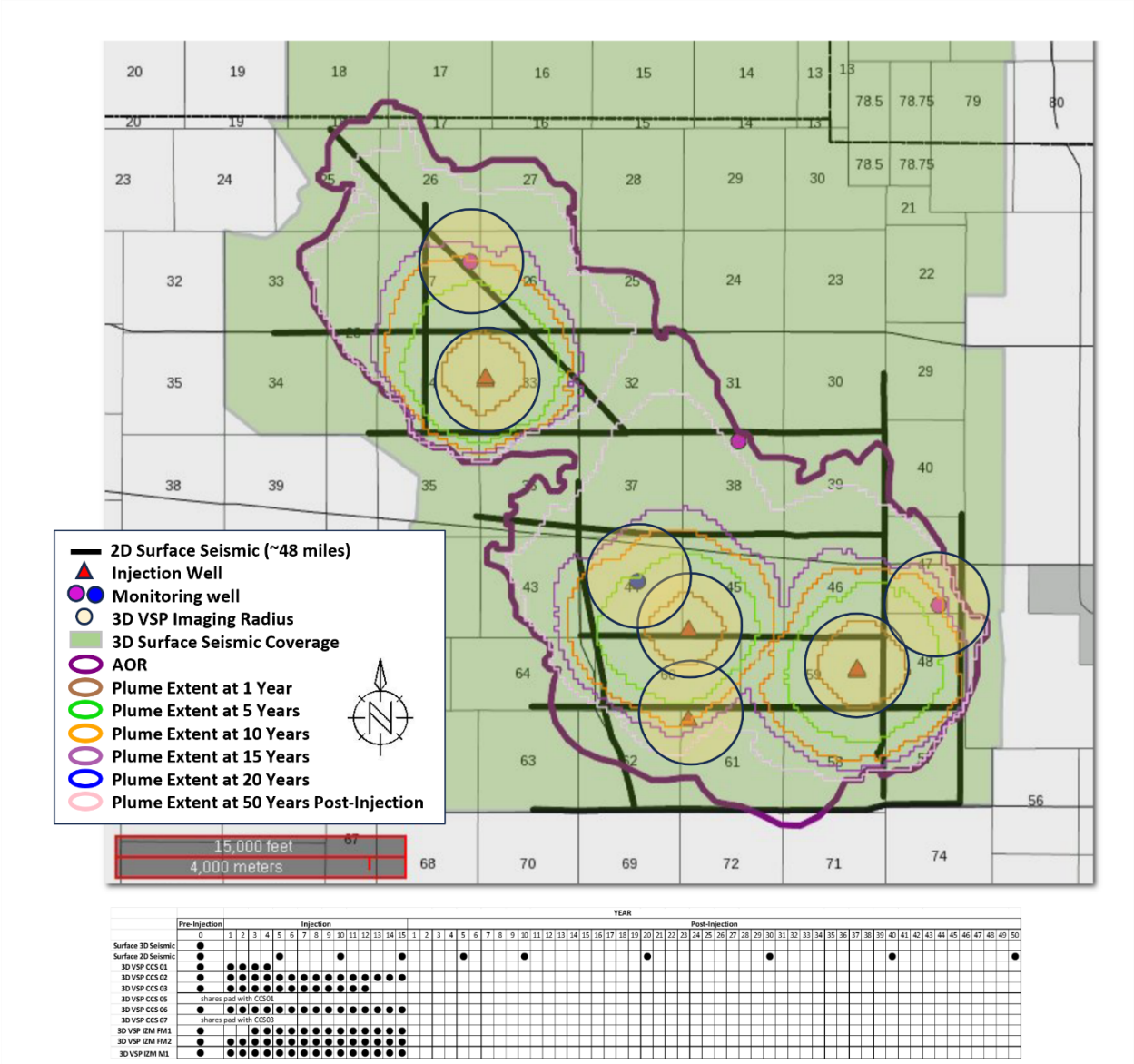


Figure TM-17 Proposed geophysical monitoring program for the Miocene injection.

7.3.1 3D Surface Seismic Baseline Survey

A 3D surface seismic baseline was acquired in 2025 covering the AoR prior to injection. Acquisition parameters for the survey were specifically designed to provide full-fold coverage of the storage complex and strata above. The 3D baseline was acquired with Vibroseis. The survey utilized a high density of sources and receivers designed to increase the definition of shallow horizons above the confining zone. The 3D baseline has a large surface footprint encompassing the AoR and is designed to image from surface to basement on a broad frequency band. The outline of planned 3D is seen in Figure TM-18. The processing sequence includes state-of-the-art onshore preprocessing and depth imaging (pre-stack depth migration and velocity model building),

followed by complete post-migration processing. Survey results will be used to update the structure, faulting (if any), and stratigraphy for input into an updated static model prior to injection.

Survey results will also be integrated with rock-physics studies to determine the expected timelapse 2D surface seismic response given predicted CO_2 saturation values.

Figure TM-19 and Figure TM-20 show examples of a modeled seismic response to CO_2 saturation performed using the Encanto 01 well. The model included the AoR document tested CO_2 saturations of 3%, 10%, and 20% within the Frio injection zone. No discernable seismic response was seen with 3% saturation, but 10% and 20% saturations resulted in detectable acoustic impedance signal deflection. Similarly, the Miocene injection zone was modeled and a similar detectable alteration to seismic response is expected within the CO_2 plumes. This modeling indicates that acoustic monitoring techniques, such as the planned 2D seismic and 3D VSPs, are valid for the Bluebonnet Project.

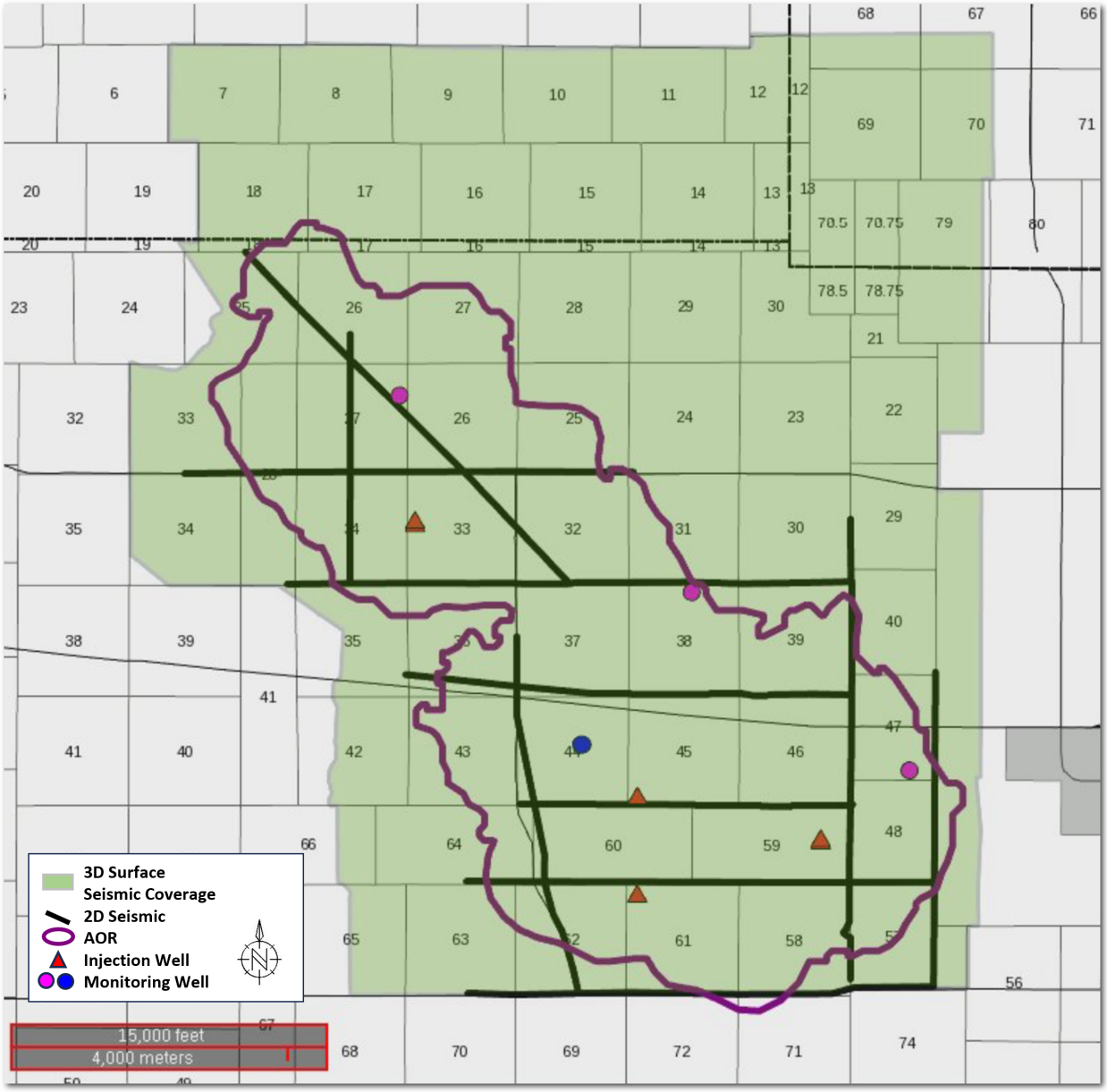


Figure TM-18: Baseline 3D seismic acquisition covering ~57.2 sq. miles of the Bluebonnet Project area.

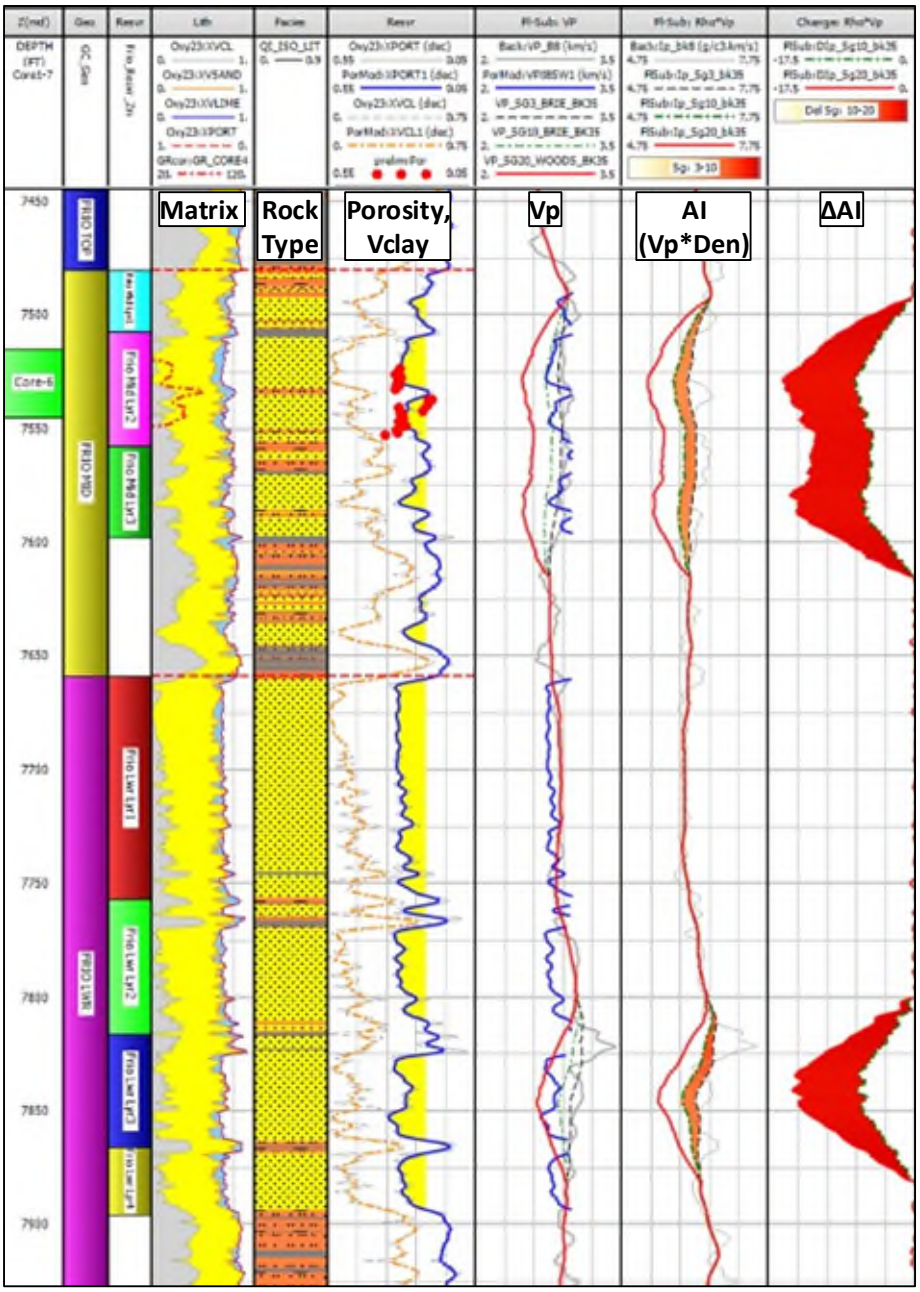


Figure TM-19: Example modeled seismic response from CO_2 saturation at Encanto 01. The right-most track, ΔAI, demonstrates the acoustic impedance signal change from baseline due to 10% and 20% CO_2 saturation; the red shading between curves is the difference between the two test cases.

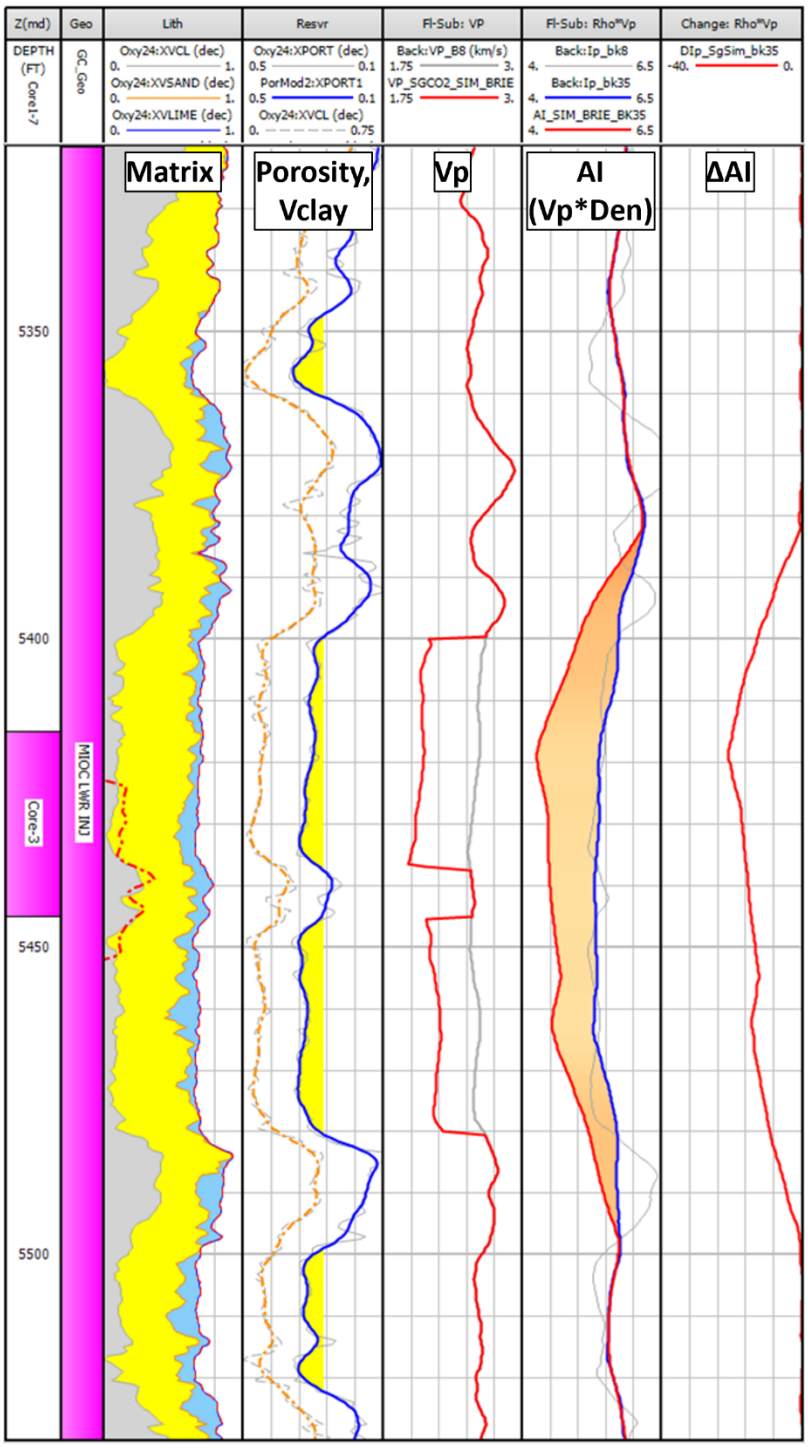


Figure TM-20: Example modeled seismic response from CO_2 saturation for a pseudo well within the CCS 6 Miocene plume utilizing well data from Encanto 01. As in the previous figure, the right-most track demonstrates acoustic impedance signal change due to CO_2 saturation. substitution

7.3.2 2D Surface Seismic Base Line and Timelapse Surveys

Approximately 48 statute miles of 2D surface seismic was acquired in 2025 to establish a baseline The 2D layout covered the extent of the AoR and beyond, with 2D lines positioned along low-traffic roads as much as possible to minimize disruption and allow for frequent and cost-effective repeat surveys. The 2D baseline design was based upon the modeled plume and AoR, and may change according to subsequent model refinements and future re-evaluations.

The 2D baseline was acquired primarily with Vibroseis. The survey used a high density of sources and receivers designed to increase the definition of shallow horizons above the confining zone. The baseline 2D data will be processed with state-of-the-art 2D preprocessing and pre-stack migration, followed by complete post-migration processing. Survey results will be integrated with rock-physics studies to determine the expected timelapse 2D surface seismic response, given predicted CO_2 saturation values.

Repeat 2D timelapse surveys will be acquired (using the same acquisition parameters as the 2D baseline) every five years during injection. The 2D timelapse monitoring will be repeated at the end of the injection period, and before site closure to demonstrate non-endangerment to the USDW. The 2D timelapse data will be processed with state-of-the-art joint parallel 2D timelapse preprocessing of the baseline, current, and previous monitor surveys, followed by pre-stack time migration and complete post-migration processing. Seismic amplitude changes observed between the current and previous surveys will be evaluated against the rock-physics model to determine changes in CO_2 saturations. These results will be checked against and integrated into the predictive models.

7.3.3 3D VSP baseline and timelapse surveys

The 3D baseline vertical seismic profile (VSP) surveys will be acquired at the injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, and Bluebonnet CCS 6, and monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2, and Bluebonnet IZM M1, using permanent DAS fiber optic cables installed in the wellbores with Vibroseis surface sources. The VSP survey will use state-of-the-art VSP preprocessing and depth imaging (pre-stack depth migration), followed by post-migration processing. The imaging radius for the 3D VSP survey is assumed to be 0.5 mile (see Figures TM-15, Figure TM-16, and Figure TM-17). Within this radius, high-resolution seismic imaging (exceeding that of surface seismic) is expected, along with accurate time-depth control. Structure and stratigraphy from the 3D baseline VSP surveys will be evaluated and integrated into the geomodel. Survey results will be integrated with rock-physics studies to determine the expected timelapse VSP seismic response given predicted CO_2 saturation values.

Repeat timelapse VSP surveys will be acquired on an annual basis (using the same acquisition parameters as the VSP baseline surveys) until a time when the plume is determined to have moved beyond the imaging radius for a particular location. The timing of plume movement into or out of the 3D VSP radius of influence varies according to the injection or monitoring well location and timing of injection into respective storage zones and may be seen in Figure TM-15, Figure TM-16, and Figure-17. The timelapse surveys will be processed using state-of-the-art joint parallel VSP timelapse preprocessing of baseline, current, and previous monitor surveys, followed by pre-

stack depth migration and complete post migration processing. Seismic amplitude changes observed between the current and previous surveys will be evaluated against the rock-physics model to infer changes in CO_2 saturations. The high-resolution imaging and frequent (annual) acquisition of repeat VSP surveys are intended to provide detailed information on the early evolution of the CO_2 plume, including (but not limited to) the response to heterogeneity within the injection reservoir, the integrity of the confining zones, the rate of CO_2 movement, and the fidelity of the subsurface geomodel and resulting simulation.

8.0 Surface and Near Surface Monitoring

8.1 Soil Gas Monitoring and Isotopic Fingerprinting

The Bluebonnet Sequestration Hub, LLC, installed 20 soil gas sample stations with the objective of collecting soil gas samples. The project plans to characterize the soil gas samples using a methodology developed by Dr. Katherine Romanak from the Gulf Coast Carbon Center (GCCC) 40 CFR §146.90 (h).

The samples will be analyzed by a certified commercial laboratory to determine gas composition and isotopic signatures of carbon and hydrogen elements. This data will be used to inform process-based soil gas monitoring (Romanak 2012) to monitor for ecological stress and distinguish a leakage signal from natural vadose-zone CO_2, providing for attribution at the site. Modeling and additional geochemical data from the subsurface overburden will be used to define diagnostic parameters for attribution in soil gas.

Soil gas assessment will consist of characterization of soil gas CO_2, CH_4, O_2, and N_2 ratios within a process-based framework and, if thresholds are ever exceeded, collection of additional isotopic parameters for further assessment.

For a minimum of one year prior to injection, soil gas will be analyzed quarterly for CO_2, O_2, N_2, CH_4, C1-C5 hydrocarbons, δ13C and 14C of CO_2, and CH_4 and δD of CH_4 (Table TM-25). At the end of characterization period, protocols for detection of leakage signal will be tailored to site base data.

As part of the process for designing the soil gas stations and selecting locations, an airborne electromagnetic survey was conducted over the AoR. The aerial electromagnetic (EM) data will be used to identify and map the extent of near-surface and surface salinization. This environmental determination will inform additional parameters for groundwater monitoring to complement soil gas as part of the near-surface monitoring strategy.

8.1.1 Sampling Location and Frequency for Soil Gas

Field activities at the Bluebonnet Site began on May 27, 2025. A total of twenty permanent soil gas monitoring wells were installed. Nineteen wells were installed using a Geoprobe® dual-tube sampling system; one well (SG-05) was installed using a hand auger due to limited rig access at that location. Boreholes were generally advanced to depths of 4 to 10 feet below ground surface (ft bgs), with specific wells installed deeper based on site conditions: SG-6 was installed to 13 ft,

SG-2 was installed to 12 ft and SG-15 was installed to 8 ft with a flush-mount surface completion due to potential for agricultural traffic nearby.

Each boring was continuously logged for soil lithology in accordance with the Unified Soil Classification System (USCS). Soil cuttings were collected for subsequent laboratory analysis. Soil cores were screened for volatile organic compounds (VOCs) using a photoionization detector (PID), and results were recorded on soil boring logs.

Wells were constructed using 6-inch stainless steel wire mesh screens and 0.25-inch flexible Teflon tubing risers extending to the surface. Clean #10 silica sand was used as the sand pack surrounding the screen. Above the sand pack, granular bentonite was placed in one- to two-foot lifts and hydrated to form a seal. The remaining annular space was filled with neat-cement grout to the surface. Each well was completed at the surface with a concrete pad and either a protective steel cover with a locking cap or a flush-mount completion. Teflon tubing risers were sealed from ambient air using stainless-steel caps. Figure TM-21 shows the schematic of the installation for SG-1 as an example.

Figure TM-22 shows the location for the soil gas probes installation relative to the AoR and CO_2 injectors.

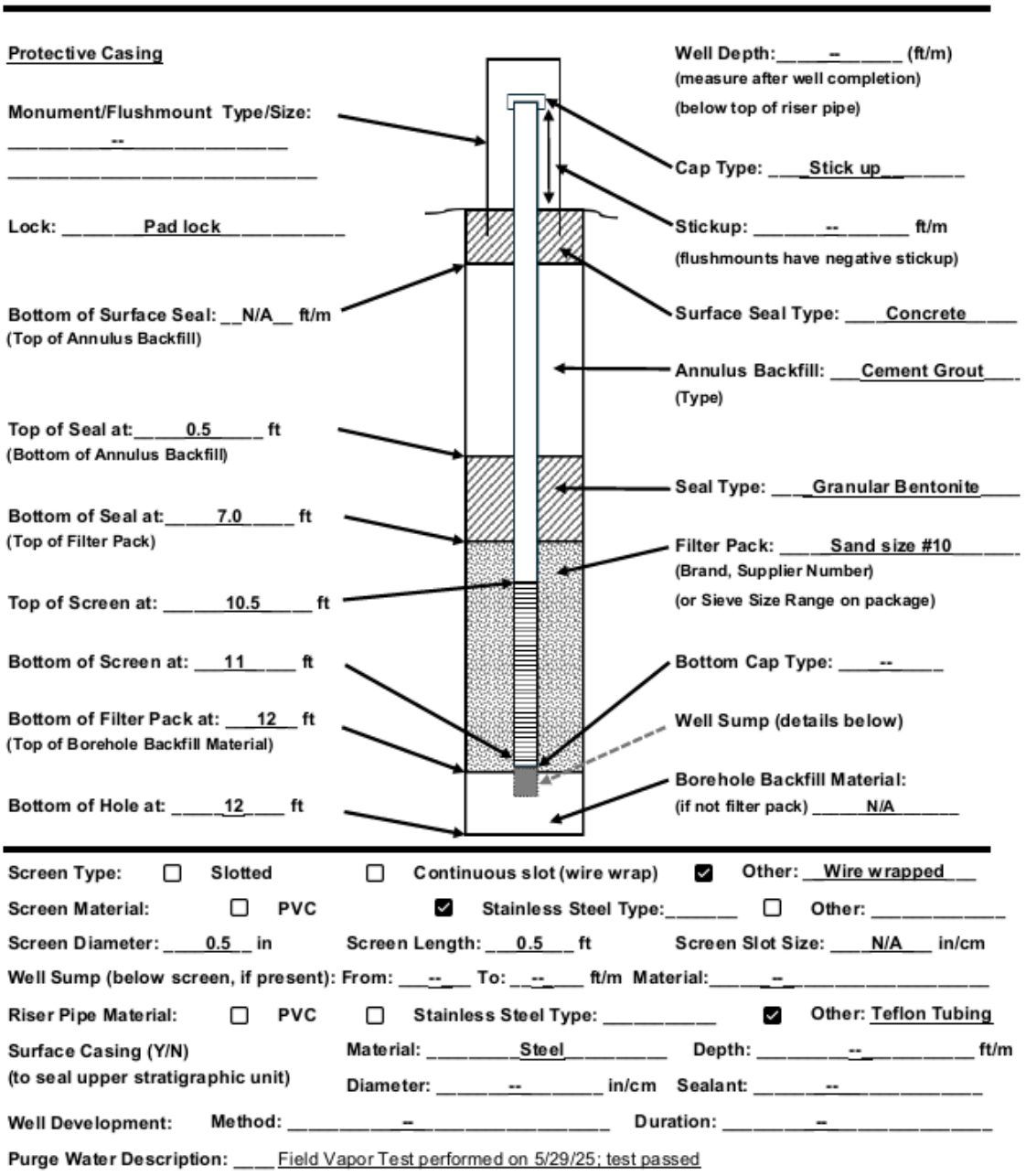


Figure TM-21: Schematic of soil gas sampling station installed (SG-1).

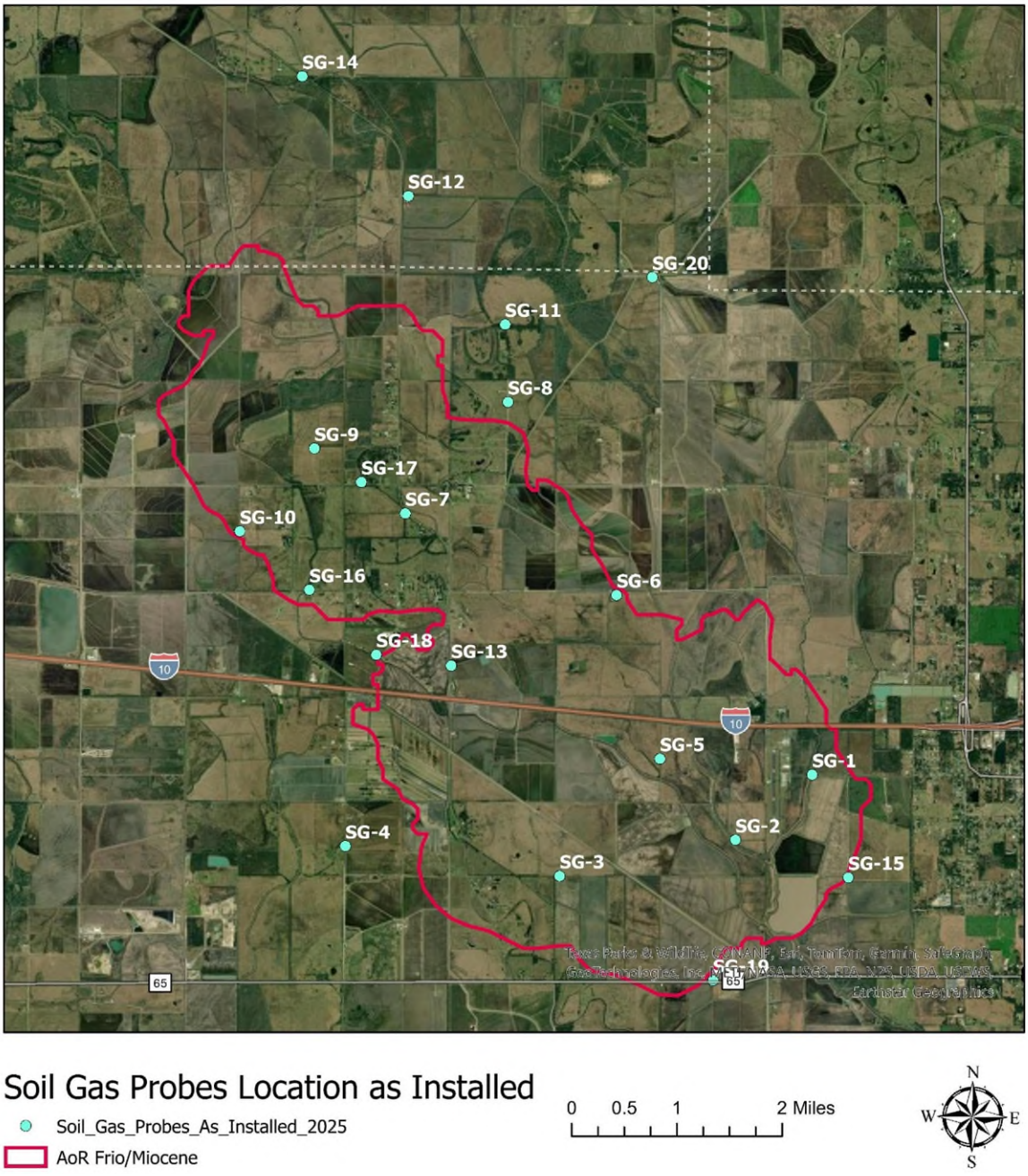


Figure TM-22: Location of the Soil Gas Probes as Installed in 2025.

Table TM-24 shows the frequency proposed for soil gas sampling and testing.

Table TM-24: Soil gas sampling locations and frequencies.

Monitoring Locations	Monitoring Activity	Target Formation	Pre-injection	Injection Period
Soil gas stations	Soil gas sampling and basic gas analysis	Vadose zone	1-2 years of characterization, 1-2 sample per station per quarter	Quarterly starting 3 months after injection is approved, 1-2 sample per station
Soil gas stations	Isotopes analysis of CH_4 and CO_2	Vadose zone	1-2 years of characterization, 1-2 sample per station per quarter	As required
AoR	Electromagnetic airborne survey	Surface	1-2 years before injection	As required based on other monitoring techniques responses

8.1.2 Parameters for Soil Gas Analysis

Table TM-25: Soil Gas Analysis Parameters.

Soil Gas Parameter	Analysis method
CO_2, N_2, O_2,	Gas Chromatography (GC)
CH_4, C_2-C_4	Gas Chromatography (GC)
C_5-C_6	Gas Chromatography (GC)
$\delta^{13}C$ of CO_2	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)
$\delta^{13}C$ of CH_4	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)
δD of CH_4	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
^{14}C of CO_2	Accelerated mass spectrometry (AMS).
^{14}C CH_4	Accelerated mass spectrometry (AMS).

8.1.3 Sampling Soil Gas Analysis

Trained or specialized personnel will perform the sampling and the field operator will be trained in the process for taking samples and monitoring gas compositions with handheld devices as a routine operation. The samples are taken in specialized bags to collect the gas and will be sent to a third-party laboratory. Calibration of the field equipment will be performed per manufacturer protocol.

8.1.4 Laboratory to be Used/Chain of Custody and Analysis Procedures.

The samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Analytic methods and chain of custody procedures will follow the laboratory protocol.

8.2 CO_2 Sensors in Surface - Wellheads

The Bluebonnet Sequestration Hub, LLC, will install infrared gas detectors close to the wellheads of the injector, monitoring, and water production wells. These sensors will interface with the surveillance system to set alarms and identify potential leaks at the surface. The final selection of the technology will consider the integration of all the sensors and transducers in a unique surveillance system. Calibration and maintenance protocols will be based on the manufacturer specifications and performed by specialized professionals. Technical specifications for the CO_2 leak detector are provided in the QASP Plan.

Table TM-26: Atmospheric CO_2 sensor in wellhead.

Tool	Pre-Injection	Injection
Atmospheric CO_2 sensor in wellhead – CO_2 injector well	n/a	Continuously
Atmospheric CO_2 sensor in wellhead – In-zone monitoring wells	n/a	Continuously

8.3 Airborne Electromagnetic Survey

As part of the Class VI application's testing and monitoring plan, a baseline time-lapse airborne time-domain electromagnetic (AEM) survey was conducted from July 7th to July 23rd 2025 to characterize and map the near-surface electrical resistivity distribution. This effort aims to detect fluctuations in the water table and groundwater salinity, providing a robust reference for ongoing environmental monitoring. The electromagnetic data will be integrated with soil gas and water sample analyses to enhance the reliability of site characterization and long-term monitoring.

The survey utilized a helicopter-mounted Versatile Time-Domain Electromagnetic (VTEM™ ET) system from Geotech Ltd., employing full-waveform processing. Measurements included the vertical (Z) component of the electromagnetic field and total magnetic field. A total of 1,493 line-kilometers of geophysical data were acquired.

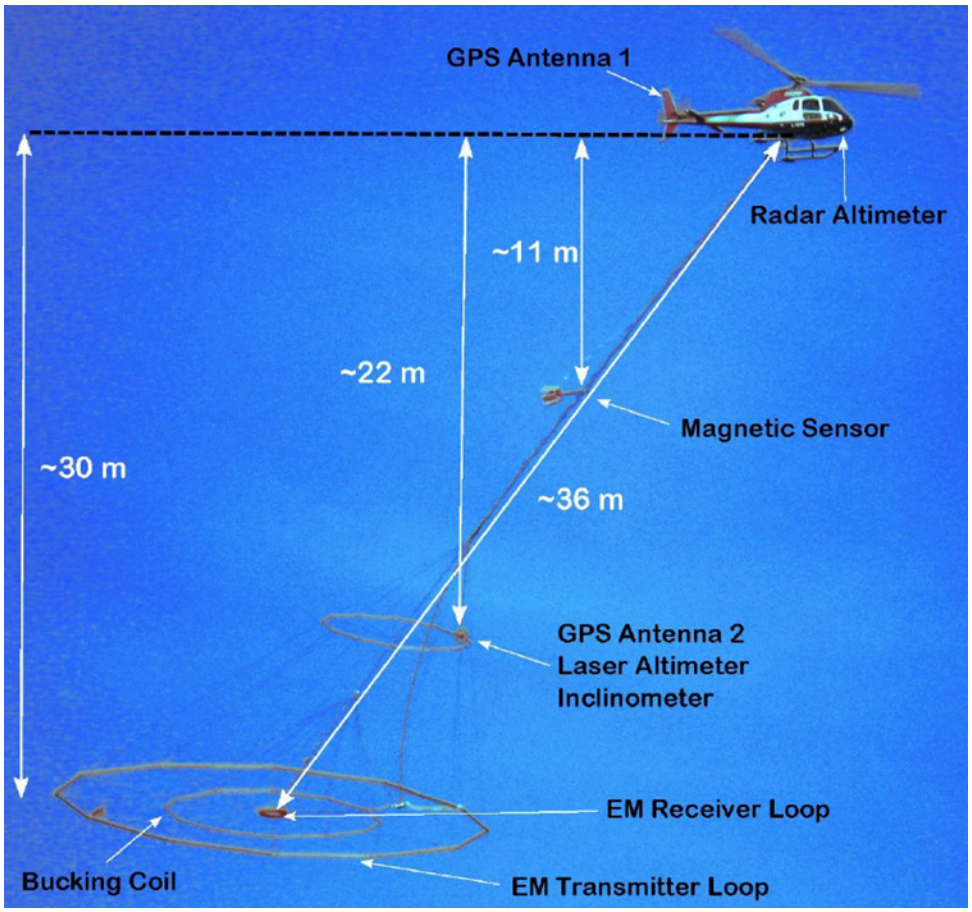


Figure TM-23: VTEM™ System Configuration, courtesy of Geotech Ltd.

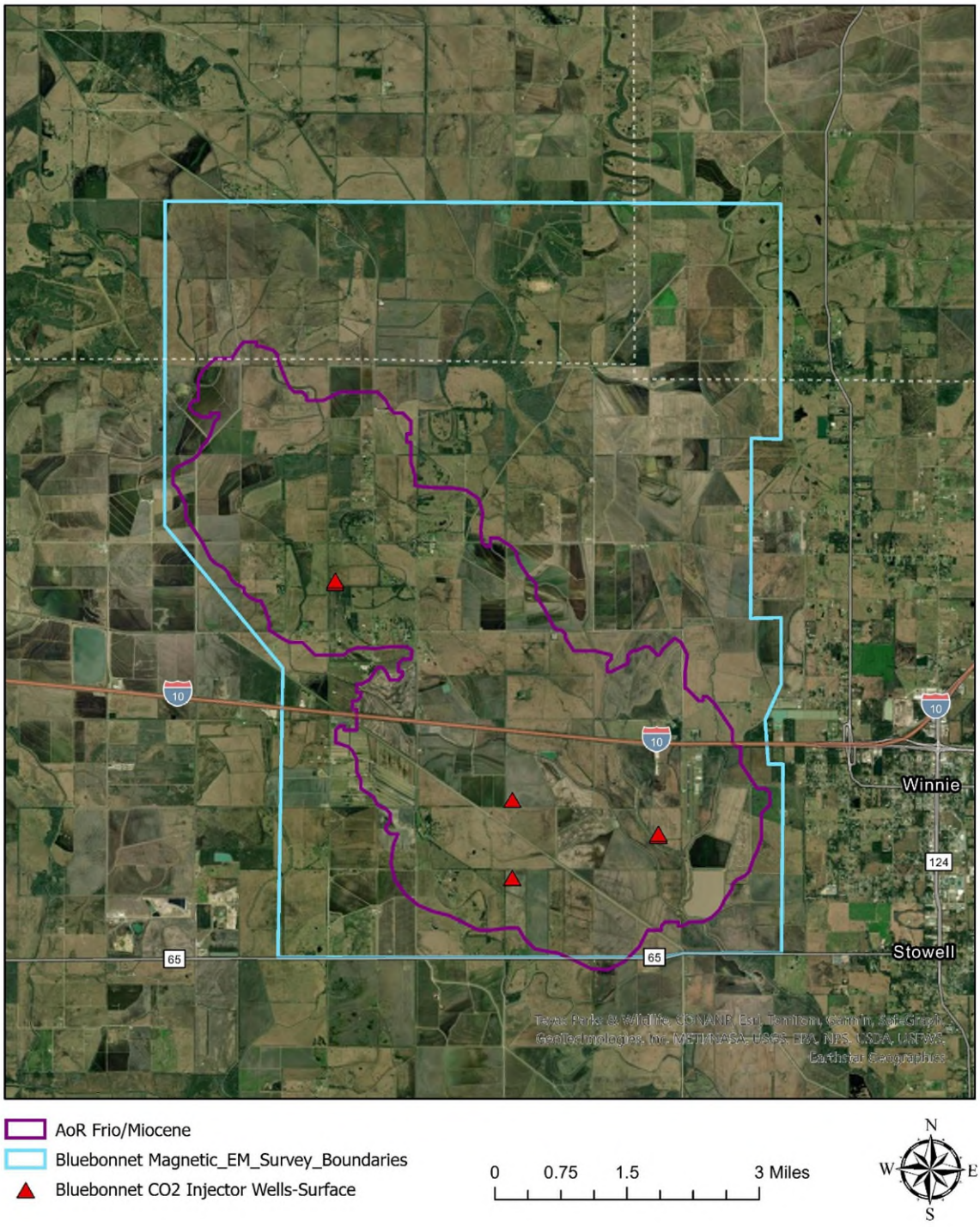


Figure TM-25: Location and the outline of the time-domain electromagnetic survey.

Note: Imagery courtesy of ESA contains modified Copernicus Sentinel data processed by Sentinel Hub.

To interpret the near-surface resistivity, a 1D inversion of the VTEM data was performed using the Geoscience Australia airborne electromagnetic 1D layered Earth inversion code (Brodie, 2016). Both raw data and inversion results were delivered in digital format for further analysis and for comparison with future measurements.

Table TM-27: Airborne electromagnetic survey.

Tool	Pre-Injection	Injection
Airborne Electromagnetic Survey	1 or 2 years prior the injection	As needed based on other monitoring techniques

8.4 Airborne Magnetic Survey

The Bluebonnet heliborne magnetic survey (Figure 1) was conducted in March 2025 by Xcalibur Inc. for Bluebonnet Sequestration Hub LLC. The survey aimed to enhance the understanding of the location of legacy wells and the other magnetic infrastructure in the Bluebonnet area. The data acquisition was followed up by in-house integrated interpretation.

8.4.1 Methodology to Acquire and Process Airborne Magnetic Survey.

Based on experience with in-house airborne magnetic surveys, the Bluebonnet Sequestration Hub, LLC, determined that magnetic anomalies resulting from steel-cased wells and wellheads would be detectable and resolvable by an airborne acquisition system, if the magnetometer height is 20 – 40 m above ground level and with line spacing not larger than 20 m. The Bluebonnet Sequestration Hub, LLC, engaged a third party to conduct the survey using a heliborne magnetic data acquisition system. In such a system, a magnetometer or an ensemble of magnetometers is attached or towed beneath a helicopter (Figure TM-26).

Data acquisition systems can have various configurations depending on the provider. However, regardless of the magnetic system configuration and provider, all types of heliborne magnetic data acquisition systems are equipped with GPS navigation system and laser and radar altimeters to ensure accurate positioning of the data. The data acquisition systems are also equipped with video recording capabilities, which was used in data interpretation for a real-time visual aid in detecting magnetic anomaly sources.

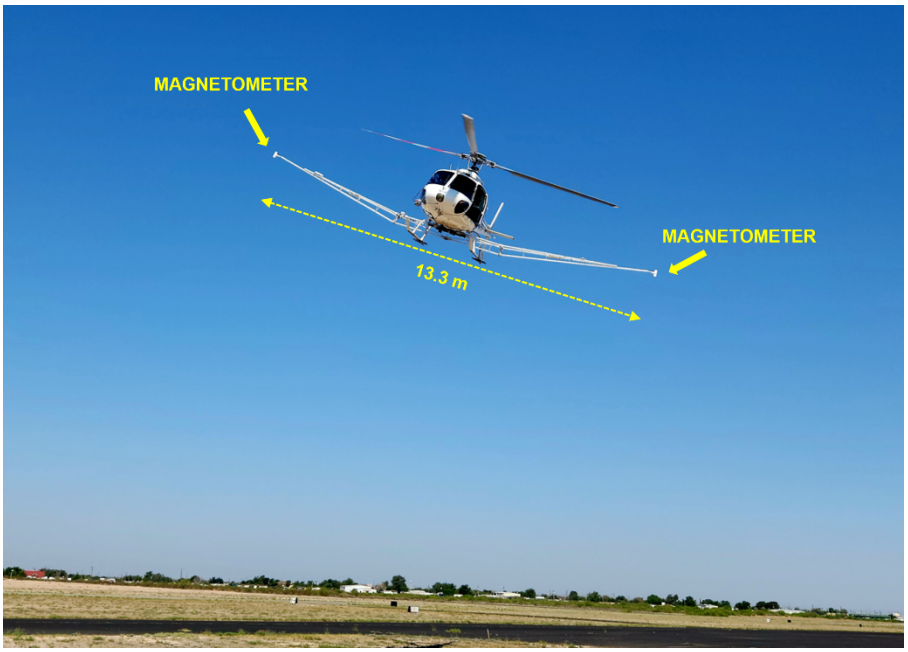


Figure TM-26: An example of heliborne magnetic data acquisition system (MIDAS by Xcalibur Inc.) used in a previous Oxy magnetic survey.

The Bluebonnet Sequestration Hub, LLC, magnetic survey was located at the intersection of Chambers, Liberty, and Jefferson counties in Texas. The data acquisition parameters were as follows: N-S 25 m flight line spacing resulting in 12-13 m data line spacing, E-W 250 m tie-line spacing, with an average flight altitude of 25 m above ground. The parameters were chosen to reduce the long wavelength aliasing (Reid, 1980), sample the anomalous field in direction of the Earth's filed declination for a proper recovery of induced anomalies (Reevs, 2025) and to detect signals due to legacy wells with weaker magnetic amplitudes.

Data processing was performed for eight weeks following the data acquisition by a vendor, while the data post-processing and interpretation was conducted in-house.

8.4.2 Methodology to Interpret Airborne Magnetic Survey.

The Bluebonnet Sequestration Hub, LLC, performed advanced data processing in house that includes transformations of the anomalous magnetic field to reduce the effects of inclination, declination, and remanent magnetization. Examples of such transformations are reduction to pole, magnetic magnitude (or magnetic amplitude), and their derivatives such as total gradient of the magnetic anomaly and normalized source signal. All transformations are intended to focus the magnetic signal close to the location of a source, independent of magnetization orientation.

The processed magnetic data was used to interpret locations of magnetic anomalies associated with surface and near-surface expression of steel-cased wells. This data was combined with helicopter-acquired video and high-resolution imagery to interpret sources of magnetic anomalies.

In addition to the surface locations of steel-cased wellbores, the Bluebonnet Sequestration Hub, LLC, was able to identify magnetic responses resulting from pipelines, electric power lines, and industrial activity. These features are located at the surface or near-surface and do not present a leakage hazard.

Table TM-28: Airborne magnetic survey.

Tool	Pre-Injection	Injection
Airborne Magnetic Survey	1 or 2 years prior to injection	n/a

9.0 Induced Seismicity Monitoring

The Bluebonnet Sequestration Hub, LLC, deployed a seismometer monitoring network to determine the locations, magnitudes, and focal mechanisms of the injection-induced seismic events when observed. This information will be used to address public concerns and identify features that may help to evaluate the plume and pressure front behavior.

9.1 Monitoring Location and Frequency for Induced Seismicity Measurement

The seismometer monitoring network contains 14 sensors strategically placed throughout the Bluebonnet Project area. The network is designed to provide a magnitude threshold equivalent to 0.0 on the Richter scale around the injection wells as well as along faults outside the AoR that are more likely to respond to reservoir pressure increases. Geomechanical modeling indicates that injection pressures will remain significantly below the threshold needed to initiate seismic movement along area faults, but those faults are still included in the seismometer monitoring network. The modeled seismometer network and modeled magnitude threshold in relation to the AoR is shown in Figure TM-27, and the coordinates of the seismometers are available in Table TM-30. Bluebonnet will connect at least one of its seismic monitoring stations to the State of Texas public seismic monitoring network, currently operated by TexNet.

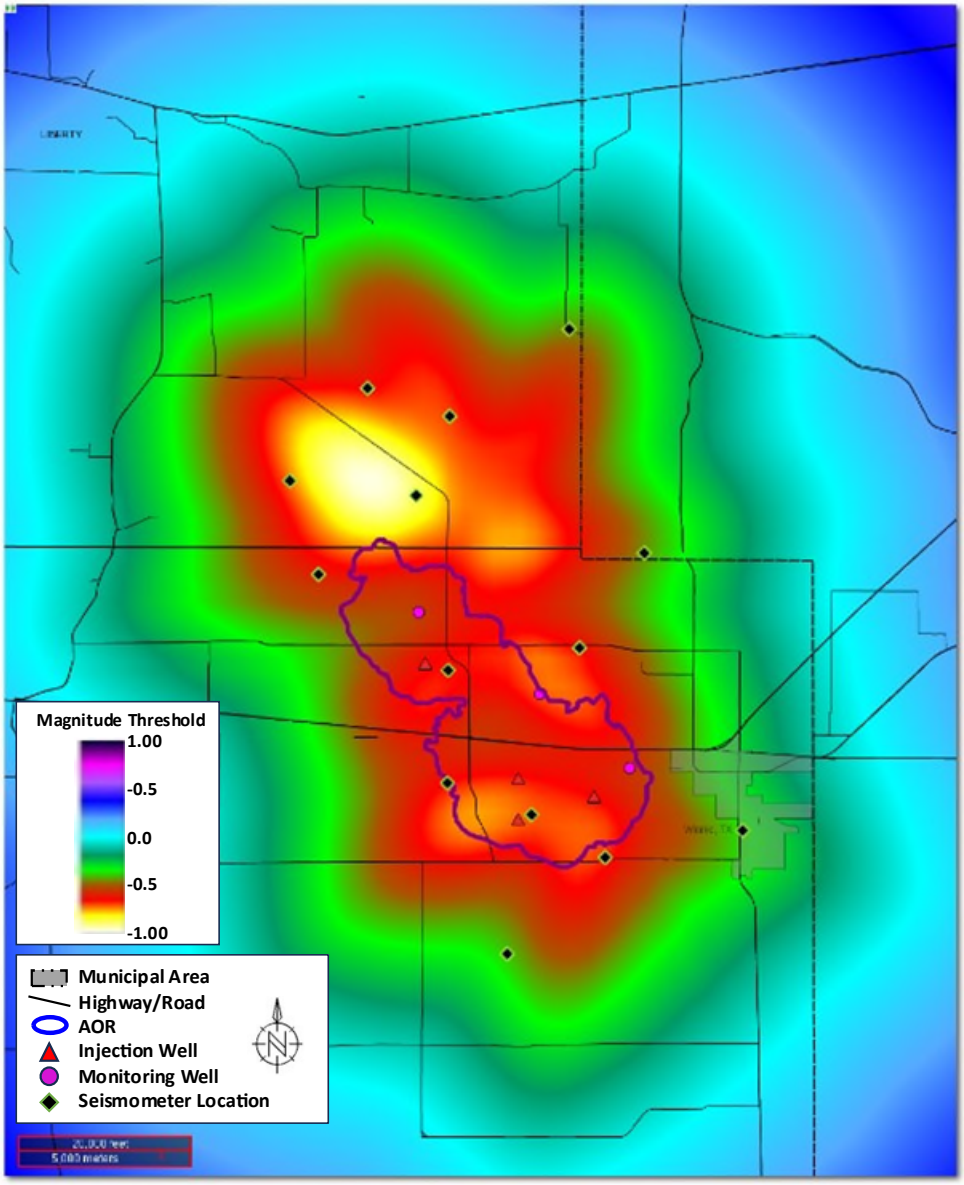


Figure TM-27: Seismometer monitoring network with 14 sensors placed in relation to the CO_2 injector wells and the AoR.

Table TM-29: Seismicity monitoring tools and frequency.

Tool	Pre-Injection	Injection
Seismometer network in surface to measure potential induced seismicity events.	Baseline 1-2 years before injection	Continuously

Table TM-30: Location of the seismometer**s. (WGS-84)**

Station ID	Latitude	Longitude
4P.BB01	29.762008	-94.467255
4P.BB02	29.851393	-94.489995
4P.BB03	29.801950	-94.382229
4P.BB04	29.806102	-94.459035
4P.BB05	29.815731	-94.489757
4P.BB06	29.859028	-94.442407
4P.BB07	29.881170	-94.537578
4P.BB08	29.889259	-94.419299
4P.BB10	29.910657	-94.548475
4P.BB09	29.931684	-94.490668
4P.BB11	29.906505	-94.502465
4P.BB12	29.792859	-94.432114
4P.BB13	29.959722	-94.447500
4P.BB14	29.940218	-94.520638

9.2 Traffic Light System Protocol

The Richter Magnitude (or Local Magnitude) defines the local magnitude (ML) of an earthquake observed at a station to be ML = log A - log Ao (Δ), where A is the maximum amplitude in millimeters recorded on the Wood Anderson seismograph for an earthquake at epicentral distance of Δ km and Ao (Δ) is the maximum amplitude at Δ km for a standard earthquake; seismometers are calibrated so that consistent magnitudes are recorded from different seismographs. The local magnitude is thus a number characteristic of the earthquake, and is independent of the location of the recording station.

While the historical seismicity of the project area indicates no measured earthquakes in the area, the project intends to maintain a surface array for the duration of the project to ensure the safe operation of both the storage facility and adjacent infrastructure in the area. This seismic monitoring will be conducted with a surface array deployed to ensure detection of events above ML 2.0 with epicentral locations within 5.6 miles of any injection well covering an area of 100 square miles.

This areal coverage was determined by referencing the Texas Railroad Commission’s historic designation of Seismic Response Areas (SRA). SRAs are areas determined by RRC seismologists for which consistent identification and seismic response approach will be implemented after the occurrence of seismic events with a magnitude of 3.5 or greater (TRRC, January 2022). For example, after a magnitude 5.4 earthquake occurred on December 19, 2022, the RRC designated the SRA with a radial area of 100 square miles (TRRC December 2022). Out of an abundance of caution, the seismic monitoring area for this project is designed to preemptively cover an area equivalent to the RRC’s post-event SRA coverage.

If an event is recorded by either the local private array or public national array to have occurred within 5.6 miles of the injection well, the operator will implement its response plan, subject to detected earthquake magnitude limits defined below to eliminate or reduce the magnitude and/or frequency of seismic events.

- For events above ML 2.0 within 5.6 miles of the injection well, the project team will closely monitor seismic activity and may pause operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity.

- For events above ML 3.5 within 5.6 miles of the injection well, the project team will reduce the injection rate by at least 50%. A detailed analysis will be conducted to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan will be developed to reduce or eliminate operationally related seismicity. Such plans will be dependent on the pressures and seismicity observed and may include, but not be limited to:

    1. Pausing operations until reservoir pressures fall below a critical limit,
    2. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

- For events above ML 4.5 within 5.6 miles of the injection well, the Bluebonnet Hub operations team will stop injection as soon as safely practical. The project team will inspect surface infrastructure for damage that may have resulted from the earthquake. The project team will then immediately inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis.

    A detailed analysis will be conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan will be developed to reduce or eliminate operationally related seismicity before resuming injection operations and will be discussed with the UIC Director. Such plans will be dependent on the pressures and seismicity observed, and may include, but not be limited to:

    1. Pausing operations until reservoir pressures fall below a critical limit,
    2. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

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Appendix A Testing and Monitoring Plan

IN ZONE MONITORING WELL CONSTRUCTION DETAILS

Bluebonnet Sequestration Hub

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1.0 Overview

The Project plans to drill two new In-Zone Monitoring (IZM) wells in the Frio/Miocene injection zone (IZM FM). Additionally, the Encanto 01 well will be re-entered and converted into an In-Zone monitoring well in Lower Miocene Injection Zone.

The following procedures detail the engineering designs for the In Zone Monitoring wells as well and the material selection and best practices proposed to ensure mechanical integrity during the life of the wells.

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

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

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

2.0 Well Design Bluebonnet IZM FM1 - In Zone Monitoring Well

The Bluebonnet IZM FM1 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

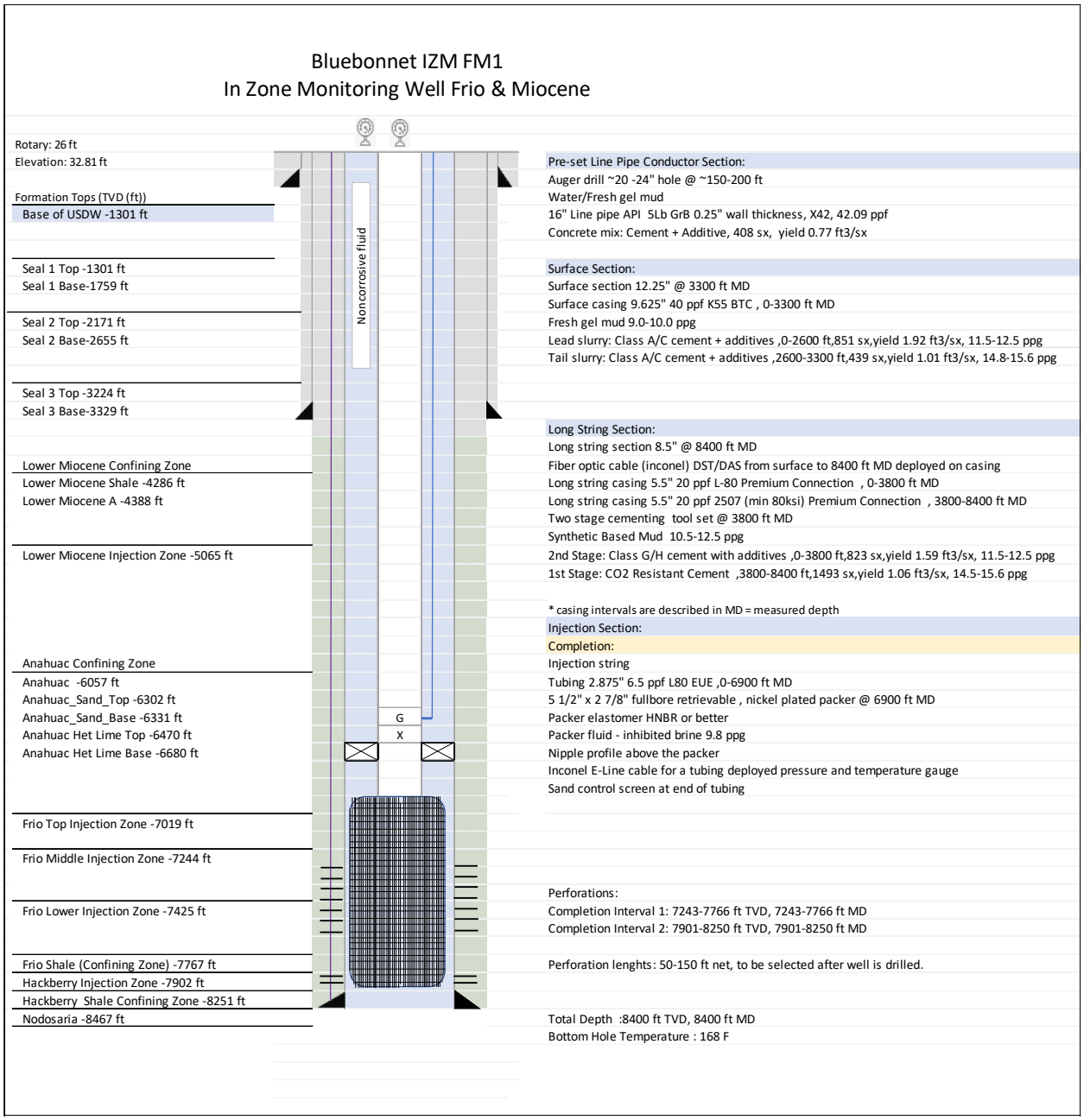


Figure TM-A- 1: Bluebonnet IZM FM1 well schematic

2.1 Design Overview Bluebonnet IZM FM1

2.1.1 Conductor

The 24 – 20 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 16-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

2.1.2 Surface Section

The 12 ¼-in. vertical wellbore will be drilled to 3,300 ft to cover the base of the USDW, estimated at 1,301 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 9 5/8-in. casing will be run and cemented to surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

2.1.3 Long String Section

The 8 ½-in. vertical wellbore will be drilled from 3,300 ft to total depth (MD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operational Formation Testing Plan. Then, the long string of 5 1/2-in. casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustic sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

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

2.1.4 Completion

During completion operations, the rig crew will condition the long string with a bit and scraper, displace the fluid in the wellbore with brine, run the magnetic orientation tool to map the location of the fiber optic and the metal markers, run cement bond and casing inspection logs to evaluate cement bonding and casing conditions and pressure test the casing integrity.

The crew will proceed to run oriented guns to perforate the monitoring interval and run the upper completion. After perforating, the rig crew will perform a wiper trip to TD and will circulate the bottoms up, replacing the brine inside the wellbore with inhibited packer fluid.

The 2 7/8-in. tubing, packer and screens will be run in the hole, in conjunction with the electric cable and pressure and temperature gauges. Once the packer is set, an annular pressure test will be performed to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

2.2 Casing, Tubing and Completion Design Bluebonnet IZM FM1

The tables listed below provide further details regarding the Bluebonnet IZM FM1 well. Table TM-A- 1 contains the open hole diameters and intervals, Table TM-A- 2 lists the casing specifications, Table TM-A- 3 details the conductor material, and Table TM-A- 4 details the casing material properties for Bluebonnet IZM FM1.

Table TM-A- 1: Open hole diameters and intervals - Bluebonnet IZM FM1.

Name	Depth Interval (ft)	Open hole Diameter (in.)	Comment
Conductor	0-200	20-24	Auger Drilled
Surface Section	0 to 3,300	12 1/4	Cover USDW
Long String Section	3,300 to 8,400	8 1/2	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,301 ft TVD.

Table TM-A- 2 : Casing specifications - Bluebonnet IZM FM1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	16	0.25-in. wall thickness, 15.5-in. ID		42.09	API 5LB GrB	Welded
Surface String	0 to 3,300	9 5/8	8.835	8.750	40	K55	BTC
Long String	0 to 3,800	5 1/2	4.778	4.653	20	L80	Premium
Long String	3,800 to 8,400	5 1/2	4.778	4.653	20	2507 Min 80 ksi	Premium

Table TM-A- 3: Conductor material properties - Bluebonnet IZM FM1.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)
16-in. API 5LB GrB X42 42.09 ppf	0 to 200	42	60

Table TM-A- 4: Casing material properties - Bluebonnet IZM FM1.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
9 5/8-in. 40 ppf K55 BTC	0 to 3,300	3,950	2,570	630	26	26.2
5 ½-in. 20 ppf L80 Premium connection	0 to 3,800	9,190	8,830	466	67	26.2
5 ½ -in. 20 ppf 2507 80 ksi Premium Connection	3,800 to 8,400	9,190	8,830	466	67	8

Notes:

- A stage tool will be located at ~3,800 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table TM-A- 5 contain the upper completion specifications

Table TM-A- 5: Upper completion specifications - Bluebonnet IZM FM1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Tubing (Coated TK-805)	0 to 6,900	2 7/8	2.441	2.347	6.5	L80	EUE
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						
Screens	Sand Control Screens						

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table TM-A- 6 shows the specifications of the injection packer.

Table TM-A- 6: Packer specifications - Bluebonnet IZM FM1.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	20-23	4.5	2.35	325	5,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
Min casing	Min casing	Min casing	• HNBR (RGD) elastomers

Notes:

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

Details on material selection for the well tubulars and completion elements are included in Appendix A of the Injector Well Construction Attachment.

2.3 Cementing Program Bluebonnet IZM FM1

Table TM-A- 7 shows the cementing program details.

Table TM-A- 7: Cementing program - Bluebonnet IZM FM1.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	851	1.92	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	439	1.01	100%
Long String Section	Portland cement with additives	0 to 3,800	11.5-12.5	823	1.59	50%
	CO_2-Resistant Cement	3,800 to 8,400	14.5-15.6	1493	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,800 ft, but the depth will be adjusted based on final drilling conditions.

2.4 Centralization Program Bluebonnet IZM FM1

2.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 9 5/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

2.4.2 Long String Casing

Approximately 120-125 centralizers will be installed on the 5 1/2-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the

field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,800 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

2.5 Fluids Program Bluebonnet IZM FM1

Table TM-A- 8 shows the mud program details for Bluebonnet IZM FM1.

Table TM-A- 8: Mud program - Bluebonnet IZM FM1.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
12 ¼-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
8 ½-in.	Synthetic-Based Mud	3,300–8,400	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the tubing and the 5 1/2-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

2.6 Wellhead Schematic Bluebonnet IZM FM1

Figure TM-A- 2 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet IZM FM1 well.

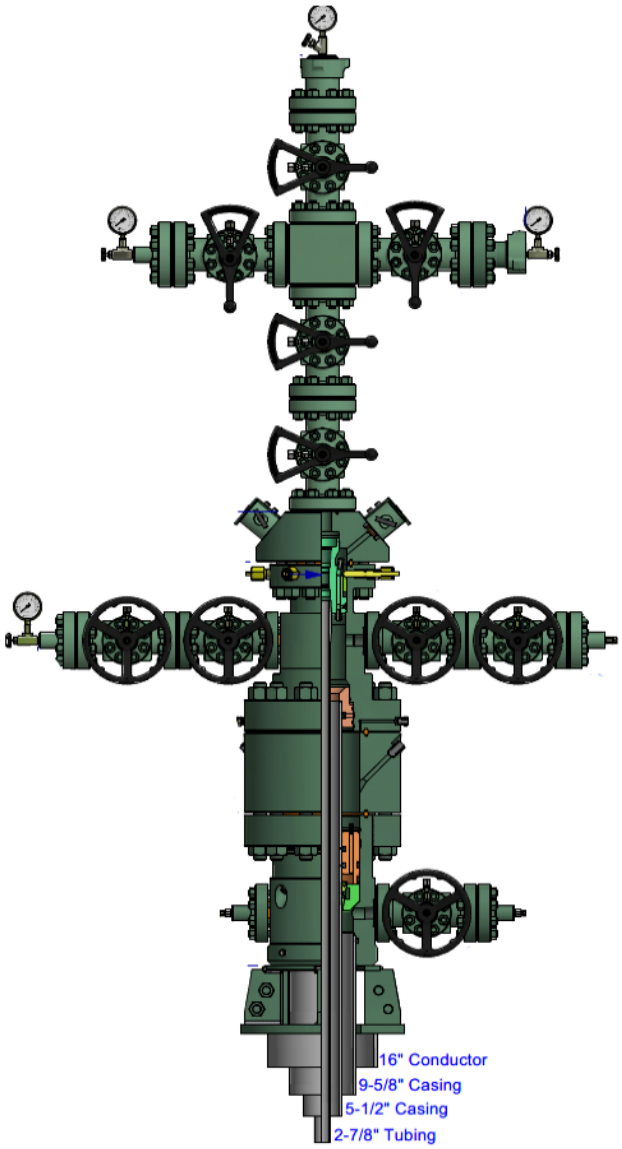


Figure TM-A- 2: Bluebonnet IZM FM1 Wellhead

3.0 Well Design Bluebonnet IZM FM2 - In Zone Monitoring Well

The Bluebonnet IZM FM2 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

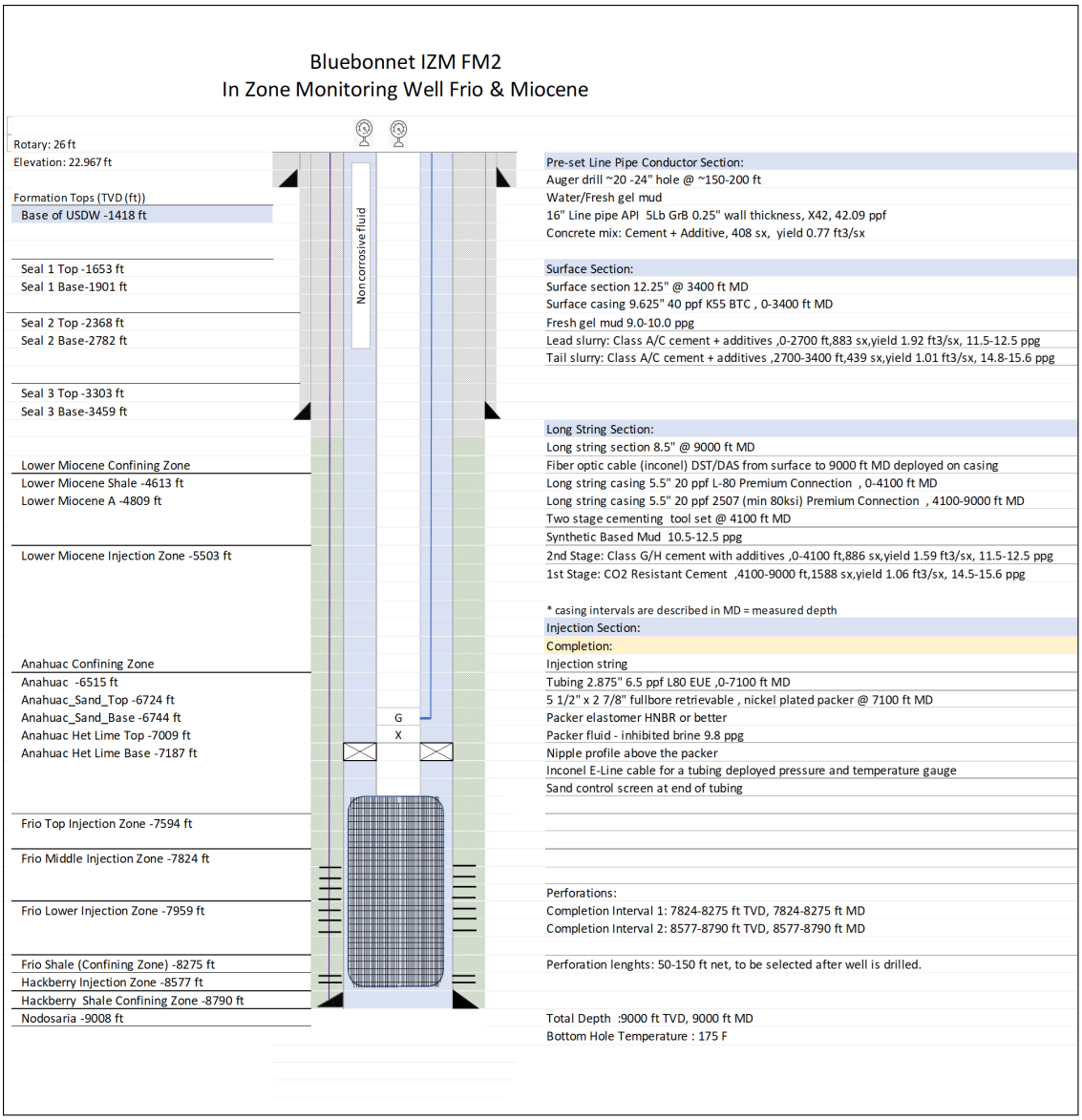


Figure TM-A- 3: Bluebonnet IZM FM2 well schematic

3.1 Design Overview Bluebonnet IZM FM2

3.1.1 Conductor

The 24 – 20 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 16-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

3.1.2 Surface Section

The 12 ¼-in. vertical wellbore will be drilled to 3,400 ft to cover the base of the USDW, estimated at 1,418 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 9 5/8 in. casing will be run and cemented to surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

3.1.3 Long String Section

The 8 ½-in. vertical wellbore will be drilled from 3,400 ft to total depth (MD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operational Formation Testing Plan. Then, the long string of 5 1/2-in. casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustic sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

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

3.1.4 Completion

During completion operations, the rig crew will condition the long string with a bit and scraper, displace the fluid in the wellbore with brine, run the magnetic orientation tool to map the location of the fiber optic and the metal markers, run cement bond and casing inspection logs to evaluate cement bonding and casing conditions and pressure test casing integrity.

The crew will proceed to run oriented guns to perforate the monitoring interval and run the upper completion. After perforating, the rig crew will perform a wiper trip to TD and will circulate the bottoms up, replacing the brine inside the wellbore with inhibited packer fluid.

The 2 7/8-in. tubing, packer and screens will be run in the hole, in conjunction with the electric cable and pressure and temperature gauges. Once the packer is set, an annular pressure test will be performed to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

3.2 Casing, Tubing and Completion Design Bluebonnet IZM FM2

The tables listed below provide further details regarding the Bluebonnet IZM FM2 well. Table TM-A- 9 contains the open hole diameters and intervals, Table TM-A- 10 lists the casing specifications, Table TM-A- 11 details the conductor material, and Table TM-A- 12 details the casing material properties for Bluebonnet IZM FM2.

Table TM-A- 9: Open hole diameters and intervals - Bluebonnet IZM FM2.

Name	Depth Interval (ft)	Open hole Diameter (in.)	Comment
Conductor	0-200	20-24	Auger Drilled
Surface Section	0 to 3,400	12 1/4	Cover USDW
Long String Section	3,400 to 9,000	8 1/2	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,418 ft TVD.

Table TM-A- 10 : Casing specifications - Bluebonnet IZM FM2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	16	0.25-in. wall thickness, 15.5-in. ID		42.09	API 5LB GrB	Welded
Surface String	0 to 3,400	9 5/8	8.835	8.750	40	K55	BTC
Long String	0 to 4,100	5 1/2	4.778	4.653	20	L80	Premium
Long String	4,100 to 9,000	5 1/2	4.778	4.653	20	2507 Min 80 ksi	Premium

Table TM-A- 11: Conductor material properties - Bluebonnet IZM FM2.

Casing	Depth Interval (ft)	Yield (ksi)	Tensile Strength (ksi)
16-in. API 5LB GrB X42 42.09 ppf	0 to 200	42	60

Table TM-A- 12: Casing material properties - Bluebonnet IZM FM2.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
9 5/8-in. 40 ppf K55 BTC	0 to 3,400	3,950	2,570	630	26	26.2
5 ½-in. 20 ppf L80 Premium connection	0 to 4,100	9,190	8,830	466	67	26.2
5 ½ -in. 20 ppf 2507 80 ksi Premium Connection	4,100 to 9,000	9,190	8,830	466	67	8

Notes:

- A stage tool will be located at ~4,100 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table TM-A- 13 contain the upper completion specifications

Table TM-A- 13: Upper completion specifications - Bluebonnet IZM FM2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Tubing (Coated TK-805)	0 to 7,100	2 7/8	2.441	2.347	6.5	L80	EUE
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						
Screens	Sand Control Screens						

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table TM-A- 14 shows the specifications of the injection packer.

Table TM-A- 14: Packer specifications - Bluebonnet IZM FM2.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	20-23	4.5	2.35	325	5,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
Min casing	Min casing	Min casing	• HNBR (RGD) elastomers

Notes:

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

Details on material selection for the well tubulars and completion elements are included in Appendix A of the Injector Well Construction Attachment.

3.3 Cementing Program Bluebonnet IZM FM2

Table TM-A- 15 shows the cementing program details.

Table TM-A- 15: Cementing program - Bluebonnet IZM FM2.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	883	1.92	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	439	1.01	100%
Long String Section	Portland cement with additives	0 to 4,100	11.5-12.5	886	1.59	50%
	CO_2-Resistant Cement	4,100 to 9,000	14.5-15.6	1588	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 4,100 ft, but the depth will be adjusted based on final drilling conditions.

3.4 Centralization Program Bluebonnet IZM FM2

3.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 9 5/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

3.4.2 Long String Casing

Approximately 125-130 centralizers will be installed on the 5 1/2-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the

field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 4,100 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

3.5 Fluids Program Bluebonnet IZM FM2

Table TM-A- 16 shows the mud program details for Bluebonnet IZM FM2.

Table TM-A- 16: Mud program - Bluebonnet IZM FM2.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
12 ¼-in.	Freshwater Gel	0–3,400	9.0-10.0	12–14	14–18	40–50	n/a	5–7
8 ½-in.	Synthetic-Based Mud	3,400–9,000	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the tubing and the 5 1/2-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

3.6 Wellhead Schematic Bluebonnet IZM FM2

Wellhead schematic is shown in figure TM-A-2

4.0 Well Design Encanto 01 – In Zone Monitoring Well

Encanto 01 well was built by the Project in 2022 as part of the stratigraphic campaign to collect site-based data that will complement the modeling and validation of the site. The well was retested in 2024 to collect additional reservoir water samples and temporarily abandoned to be converted in an In-Zone Monitoring Well for the site. Figure TM-A- 5 shows the As-Build schematic and Figure TM-A- 6 shows the proposed completion of Encanto 01 as In-Zone Monitoring Well.

Encanto 01 will be active during the injection phase of Bluebonnet Project, however it would not get in contact with the CO_2 plume during that period. The well will be abandoned as proposed in the plugging and abandonment plan presented in this application.

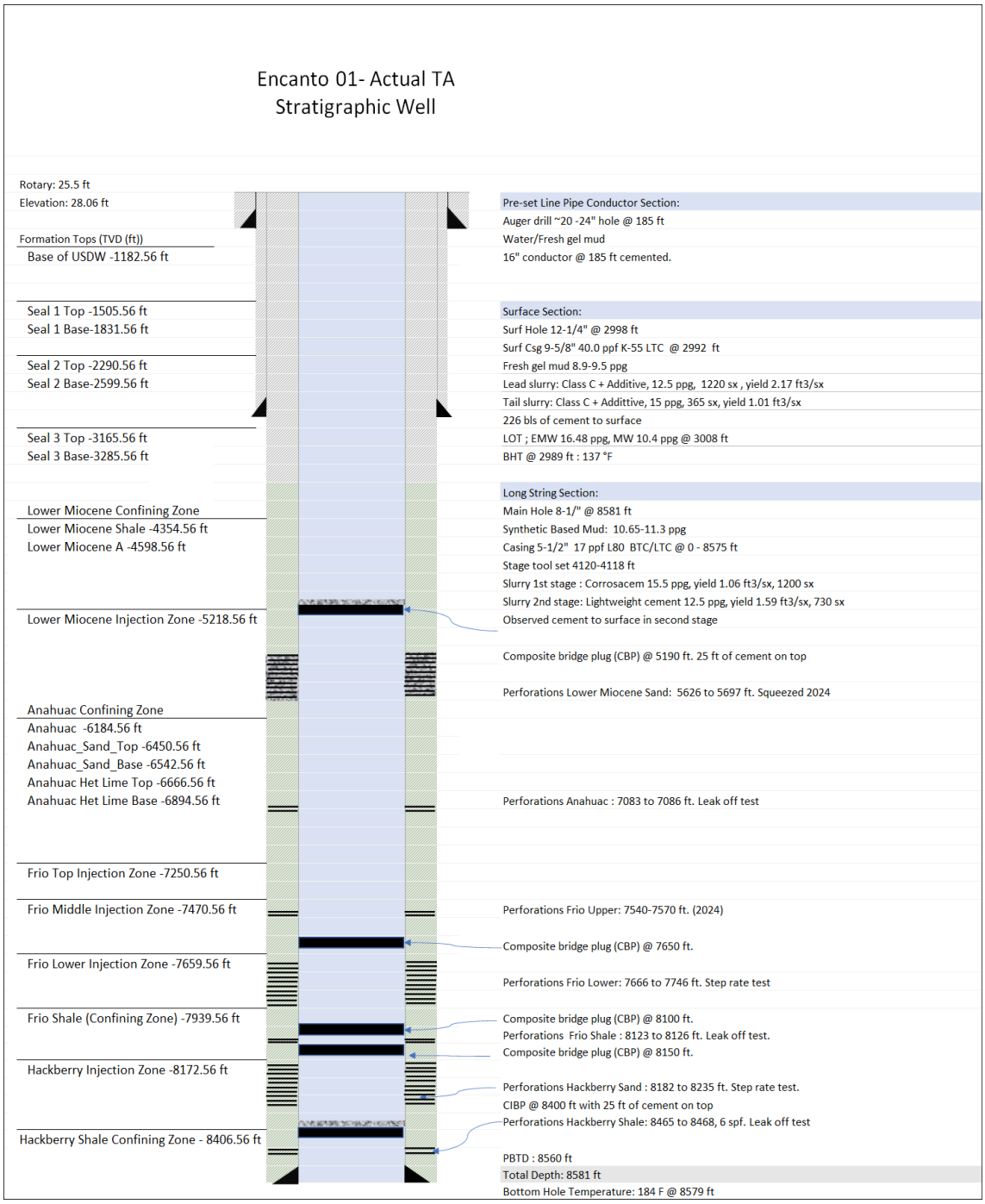


Figure TM-A- 4: As-Built Schematic of Encanto 01

4.1 Encanto 01 – Construction Summary (2022-2023)

Encanto 01 well was spudded on December 12. 2022 at 21:30. The Encanto 01 well was constructed in three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

The 24- in. wellbore for the conductor casing was drilled via auger to a depth of 185 ft. The wellbore was cased with a 16-in. line pipe and cemented with a mixture of concrete to surface. Due to the shallow depth of this section, no logging or testing was executed.

The 12 ¼-in. vertical wellbore was drilled to 2,998 ft to cover the base of the USDW, identified at 1,182 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey was taken at a minimum of every 100 ft while drilling. This section was drilled with freshwater mud. Once the final depth was reached, the well was circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 9 5/8-in. casing was run and cemented to surface via circulation with a conventional Portland cement plus additives slurry and displaced with fresh water. There were 226 bls of cement to surface. The rig installed sections and BOP and tested casing to 1000 psi. Made up directional BHA, circulated synthetic mud and drilled a shoe track an additional 10 ft of new formation. The team performed a leak off test at the shoe with an equivalent mud weight of 16.48 ppg.

The 8 ½-in. vertical wellbore was drilled from 3,008 ft to 8,581 ft while taking deviation surveys minimum every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. The project acquired full core at the intervals: 4,370-4,431; 5,415-5,446; 6,560-6,591; 6,955-6,986; 7,515-7,546; and 8,450-8,480. Once TD was reached, the well was circulated and conditioned to run open-hole electric logs according to the logging plan (the data acquired during the Encanto 01 construction is reported in the AoR document of this application). Then, the long string of 5 1/2-in. casing was deployed to 8,575 ft. The casing was cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries in a two-stage cementing procedure.

After the cementing was completed, Section B of the wellhead was installed and the temporary surface equipment.

Table TM-A- 17: Open hole diameters and intervals – Encanto 01.

Name	Depth Interval (ft)	Open hole Diameter (in.)	Comment
Conductor	0-185	24	Auger Drilled
Surface Section	0 to 2,998	12 1/4	Cover USDW
Long String Section	2,998 to 8,581	8 1/2	To Total Depth

Table TM-A- 18 : Casing Data – Encanto 01.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-185	16	0.25-in. wall thickness, 15.5-in. ID		42.09	API 5LB GrB	Welded
Surface String	0 to 2.998	9 5/8	8.835	8.750	40	K55	LTC
Long String	0 to 4,120	5 1/2	4.892	4.767	17	L80	BTC modified
Stage Tool	4,118 to 4,120	5 1/2	4.892	4.767	17	L80	BTC modified
Long String	4,120 to 8,575	5 1/2	4.892	4.767	17	L-80 coated TK-805	BTC modified

Table TM-A- 19: Cementing Data – Encanto 01.

Section	Type	Density (ppg)	Sacks (sx)	Volume (bls)	Comments
Surface Section	Lead Cement: Portland cement with additives (2.17 ft3/sx)	12.5	1,220	472	Returned 226 bls to surface
	Tail Cement: Portland cement with additives (1.01 ft3/sx)	15	364	65.7	
Long String Section	Stage 2: Portland cement with additives (1.59 ft3/sx)	12.5	730	207	Displaced with fresh water. 38 bls cement to surface
	Stage 1: Corrosacem cement (1.06 ft3/sx)	15.5	1,200	227	Displaced with fresh water.

4.2 Encanto 01 Testing Summary (2023)

In January 29,2023 the Project mobilized a workover rig to initiate the testing of Encanto 01 well. Installed Cameron tubing head, master valve, BOP's and surface lines. Condition the well with 4 ¾-inch bit and scrapper to the stage tool 4,118 ft. Tested casing successfully. Drilled out the stage tool and cleaned up until 8,482 ft. Tested casing 5,000 psi. Drilled cement to 8,560 ft. Ran CBL, VDL, GR, CCL and USIT. Ran cased hole sonic scanner and gyro. The Project proceeded to perform well testing as follow.

- Leak Off Test (LOT) Hackberry Shales: The Project perforated from 8,465 ft to 8,468 ft (Hackberry Shale). Performed an step rate. Installed a cast iron bridge plug (CIBP) at 8,400 ft. Tested CIBP at 2,000 psi. Dumped 12.5 ft of cement on top of the CIBP.

- Step Rate Test and Fall Off Test Hackberry Sands: The Project perforated from 8,225 ft to 8,235 ft. Run PVT fluid sampler to retrieve water samples from the formation. Peforated from 8,182 ft to 8,225 ft. Performed an step rate test and a fall-off test. Installed a CIBP at 8,150 ft. Tested the composite bridge plug (CBP) with 2,000 psi.

- Leak Off Test Frio Shales: The Project perforated from 8,126 ft to 8,123 ft. Performed a LOT. Installed CBP 8,100 ft.

- Step Rate Test and Fall Off Test Frio Sands: The Project perforated from 7,736 ft to 7,746 ft. Ran a PVT fluid sampler to retrieve water samples from the formation. Perforated 7,701 ft to 7,736 ft, and 7,666 ft to 7,701 ft. Performed SRT and Fall Off test. Installed a CBP at 7,600 ft.

- Leak Off Test Anahuac Shales: The Project perforated from 7,083 ft to 7,7086 ft. Performed a LOT. Installed CBP 6,000 ft.

- Step Rate Test and Fall Off Test Lower Miocene Sands: The Project perforated from 5,687 ft to 5,697 ft. Ran a PVT fluid sampler to retrieve water samples from the formation. Perforated 5,656 ft to 5,687 ft, and 5,626 ft to 5,656 ft. Performed SRT and Fall Off test. Installed a CBP at 5,200 ft. Tested plug 2,000 psi. Set 25’ of cement on top of the CBP.

Encanto 01 was temporarily abandoned on February 9,2023.

4.3 Encanto 01 Re-enter Summary (2024)

The Project Re-entered Encanto 01 well on April 30,2024 with the objective of recovering additional samples of Frio formation water due to a contamination observed in the original samples acquired during the testing in 2023. The Project mobilized a workover rig to the Encanto 01 location. Installed BOP and tested. Run in the hole with cleaning assembly to 5,200 ft. Drilled out cement and CBP. Cleaned to 6,020 ft. Observed issues when calibrating with gauge ring. Run cleaning assembly to remove sand bridge. The BHA got stuck in sand. Retrieved after fishing operations. Ran cleaning assembly to 5,796 ft. Performed a squeeze in the perforation of Lower Miocene with corrosacem 14.5 ppg, 30 barrels. Run cleaning BHA and tagged cement at 4,450 ft. Cleaned wellbore to 5,626 ft. Tested perforation squeeze successfully. Cleaned wellbore to 7,598 ft, drilled the CBP and cleaned to 7,670 ft. Perforated from 7,540 to 7,570 ft. Ran tubing with sand control screen on the bottom and a packer set to 7,493 ft. Swabbed the well and recovered Frio formation water samples with PVT sampler. Pulled out screens, packer and tubing. Run CBP at 5,190 ft. Well has been temporary abandoned in May 25,2024.

4.4 Future Completion of Encanto 01 as In-Zone Monitoring Well

Figure TM-A-6 shows the proposed completion of Encanto 01 as In Zone monitoring well.

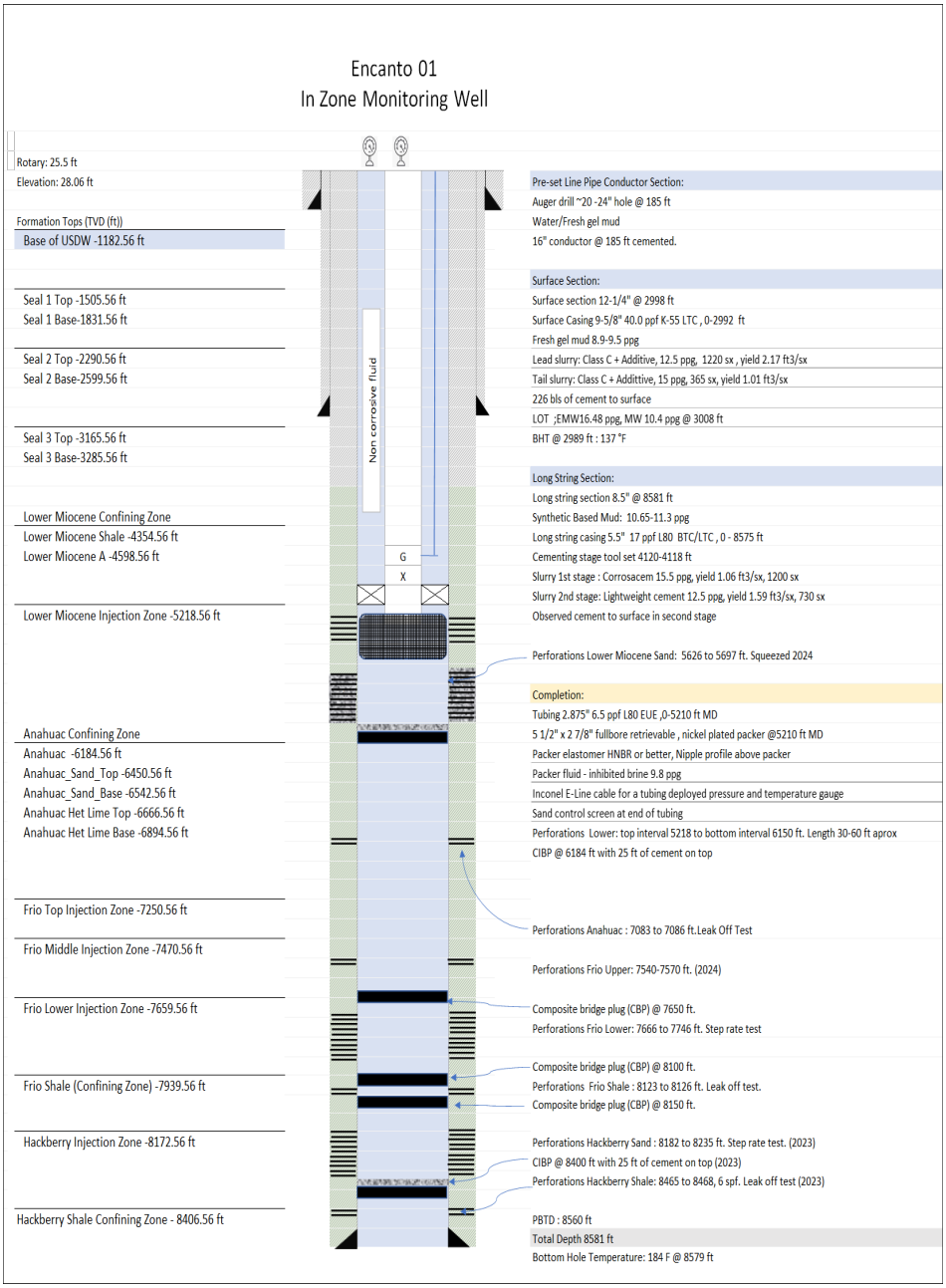


Figure TM-A- 5: Proposed Completion of Encanto 01 as In-Zone Monitoring Well

During completion operations, the rig crew will set a CIBP ~ 6,184 ft and spot 25 ft of cement on top of it. The crew will perforate the Miocene Sands. After perforating, the rig crew will perform a wiper trip to TD and will circulate the bottoms up, replacing the brine inside the wellbore with inhibited packer fluid.

The 2 7/8-in. tubing, packer and screens will be run in the hole, in conjunction with the electric cable and pressure and temperature gauges. Once the packer is set, an annular pressure test will be

performed to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

Table TM-A- 20: Upper completion specifications – Encanto 01.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Tubing (Coated TK-805)	0 to 5,210	2 7/8	2.441	2.347	6.5	L80	EUE
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						
Screens	Sand Control Screens						

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with treated packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table TM-A- 29 shows the specifications of the packer.

Table TM-A- 21: Packer specifications - Bluebonnet IZM FM1.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	20-23	4.5	2.35	325	5,000

Burst Pressure (psi)	Collapse Pressure (psi)	Tensile Strength (ksi)	Comments
Min casing	Min casing	Min casing	• HNBR (RGD) elastomers

Notes:

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

The original CBL for Encanto 01 well is presented in appendix A.1.

Details on material selection for the well tubulars and completion elements are included in Appendix A of the Injector Well Construction Attachment.

INJECTION WELL PLUGGING PLAN
40 CFR §146.92

Bluebonnet Sequestration Hub

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas

	Surface Coordinates	
Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant 40 CFR §146.92, this Injection Well Plugging Plan describes the actions the Bluebonnet Sequestration Hub, LLC, will take to plug and abandon the CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7. This plan also describes the proposed abandonment of the monitoring wells, water production wells, and water disposal wells in Appendix A.

After 15 years of injection, the project will plug and abandon Bluebonnet CCS 2, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7. The injection will continue for five additional years in Bluebonnet CCS 1 and Bluebonnet CCS 3 as described in the Area of Review (AoR) delineation and Corrective Action document of this application. When the injection period is completed in Bluebonnet CCS 1 and Bluebonnet CCS 3, the project will proceed to plug and abandon both of those wells.

The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

Bluebonnet Sequestration Hub, LLC, will notify the Underground Injection Control (UIC) Program Director in writing at least 60 days before plugging operations start. If there are changes required to the plugging plan, the project team will provide a revised program to the UIC Director for review and approval, per 40 CFR §146.92(c).

The project will submit a plugging report to the UIC Director within 60 days after plugging each well and will comply with the requirements in 40 CFR §146.92(d).

2.0 General Tests and Measures Before Plugging and Abandoning CO_2 Injector Wells

Pursuant to 40 CFR §146.92(a), the project will perform the following activities prior to plugging each well.

1. Bottomhole pressure (BHP) measurements will be taken using the installed downhole gauges. In case the gauges are not functioning properly, the Bluebonnet Hub will run downhole pressure gauges during the plug and abandon (P&A) process of the well.
2. After injection has ceased, the well will be flushed with a kill/buffer fluid. A minimum of three tubing volumes will be injected without exceeding the fracture pressure.
3. An annular pressure test will be performed to assess internal mechanical integrity before the tubing and packer are removed from the well.
4. The project will evaluate the external mechanical integrity and condition of the casing using one of the methods described in Section 3.
5. If a loss of mechanical integrity is discovered, the well will be repaired before proceeding further with the plugging operations.
6. All casing in this well will have been cemented to the surface at the time of construction and will not be retrievable at abandonment.
7. A cement retainer will be used to squeeze and isolate the perforated section to prevent flowback of formation fluids that could contaminate the plug. The balanced-plug placement method will be used for the additional cement plugs planned.
8. Heavy gel mud (9.5-10.5 ppg) will be left between cement plugs.
9. All casing strings will be cut off at least 5 ft below the surface and plow line.
10. A blanking plate with the required permit information will be welded on top of the cutoff casing.

3.0 Planned External Mechanical Integrity Test(s)

The Bluebonnet Sequestration Hub, LLC, will conduct at least one of the tests listed below to verify external mechanical integrity prior to plugging each injection well as required by 40 CFR §146.92(a):

a. Pulse neutron log
b. Noise log
c. DTS (Distributed Temperature Sensing)/DAS (Distributed Acoustic Sensing) survey
d. Temperature log.

4.0 Information on Plugs

The Bluebonnet Sequestration Hub, LLC, will use the materials and methods noted in Table PLG-1, Table PLG-2, and Table PLG-3 to plug the CO_2 injector wells. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the CO_2

stream. The cement formulation and required certification documents will be submitted to the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director as well as Texas regulators with the well plugging plan. Bluebonnet Sequestration Hub, LLC, will report the wet density and retain duplicate samples of the cement used for each plug.

An example of CO_2-resistant cement formulation is provided in Appendix B.

4.1 Bluebonnet CCS 1 Plug and Abandonment Details

Table PLG-1: Bluebonnet CCS 1 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze & Spot On Top CICR	7867	8980	CO2 Resistant	14.8-15.5	1.06	150%	8.535	617
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2450	3500	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 4	Balanced Plug	1400	2450	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

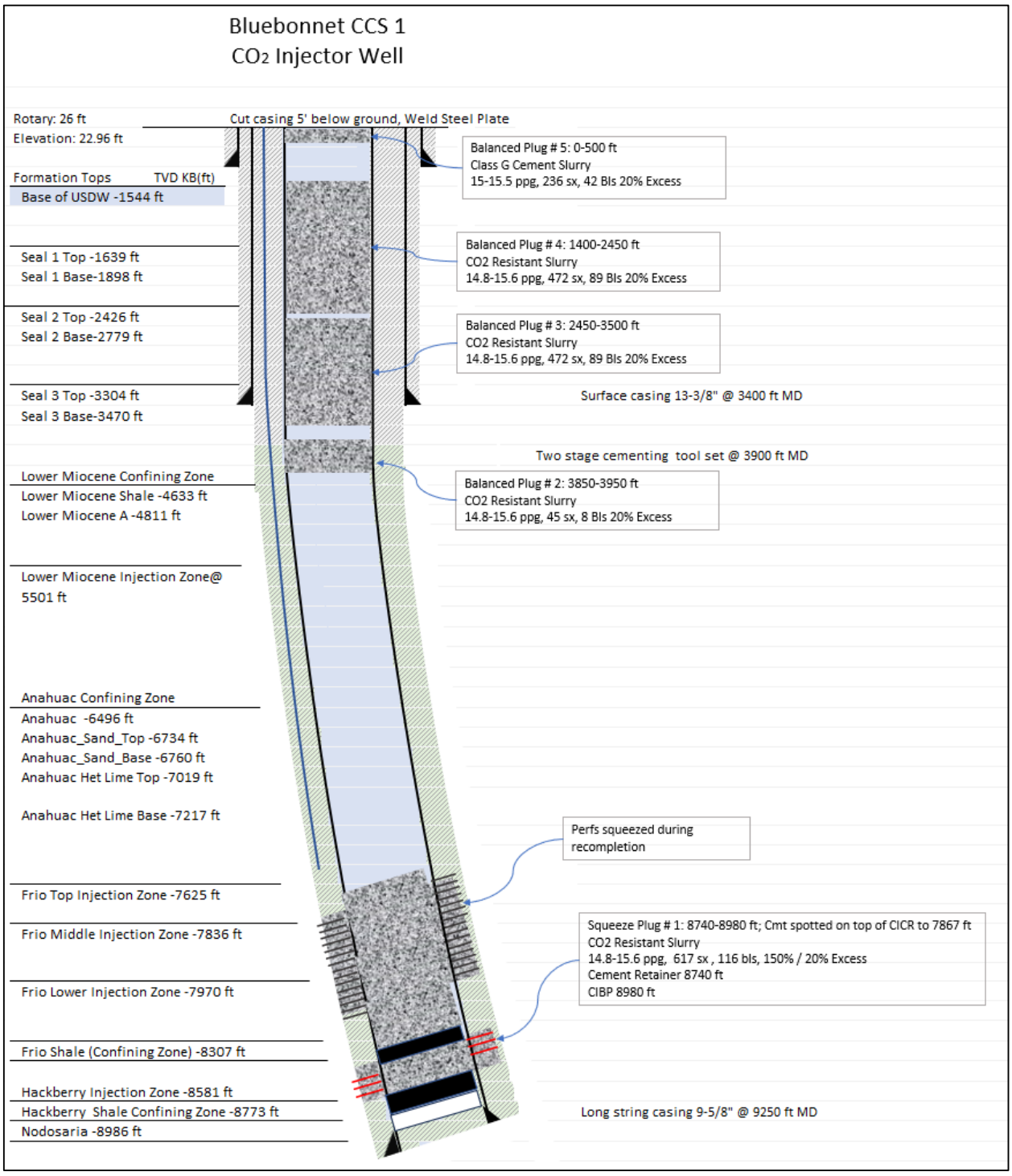


Figure PLG-1: Bluebonnet CCS 1 injection well plug schematic.

4.2 Bluebonnet CCS 2 Plug and Abandonment Details

Table PLG-2: Bluebonnet CCS 2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7980	8545	CO2 Resistant	14.8-15.5	1.06	150%	8.535	529
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2450	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	427
Plug # 4	Balanced Plug	1500	2450	CO2 Resistant	14.8-15.5	1.06	20%	8.535	427
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

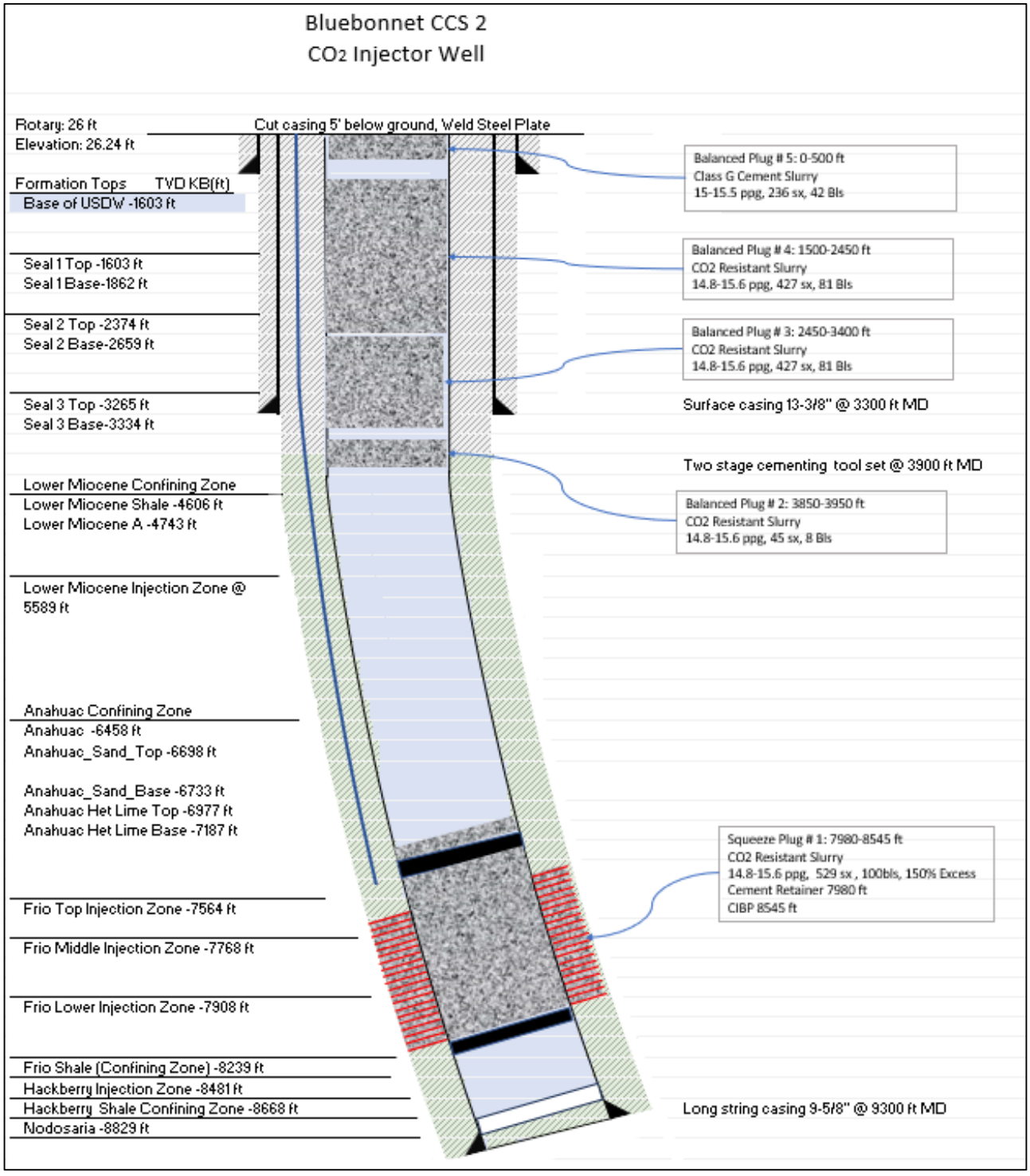


Figure PLG-2: Bluebonnet CCS 2 injection well plug schematic.

4.3 Bluebonnet CCS 3 Plug and Abandonment Details

Table PLG-3: Bluebonnet CCS 3 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7630	8250	CO2 Resistant	14.8-15.5	1.06	150%	8.535	581
Plug # 2	Squeeze & Spot On Top CICR	7550	8785	CO2 Resistant	14.8-15.5	1.06	20%	8.535	929
Plug # 3	Balanced Plug	3550	3650	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 4	Balanced Plug	2345	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	474
Plug # 5	Balanced Plug	1290	2345	CO2 Resistant	14.8-15.5	1.06	20%	8.535	474
Plug # 6	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

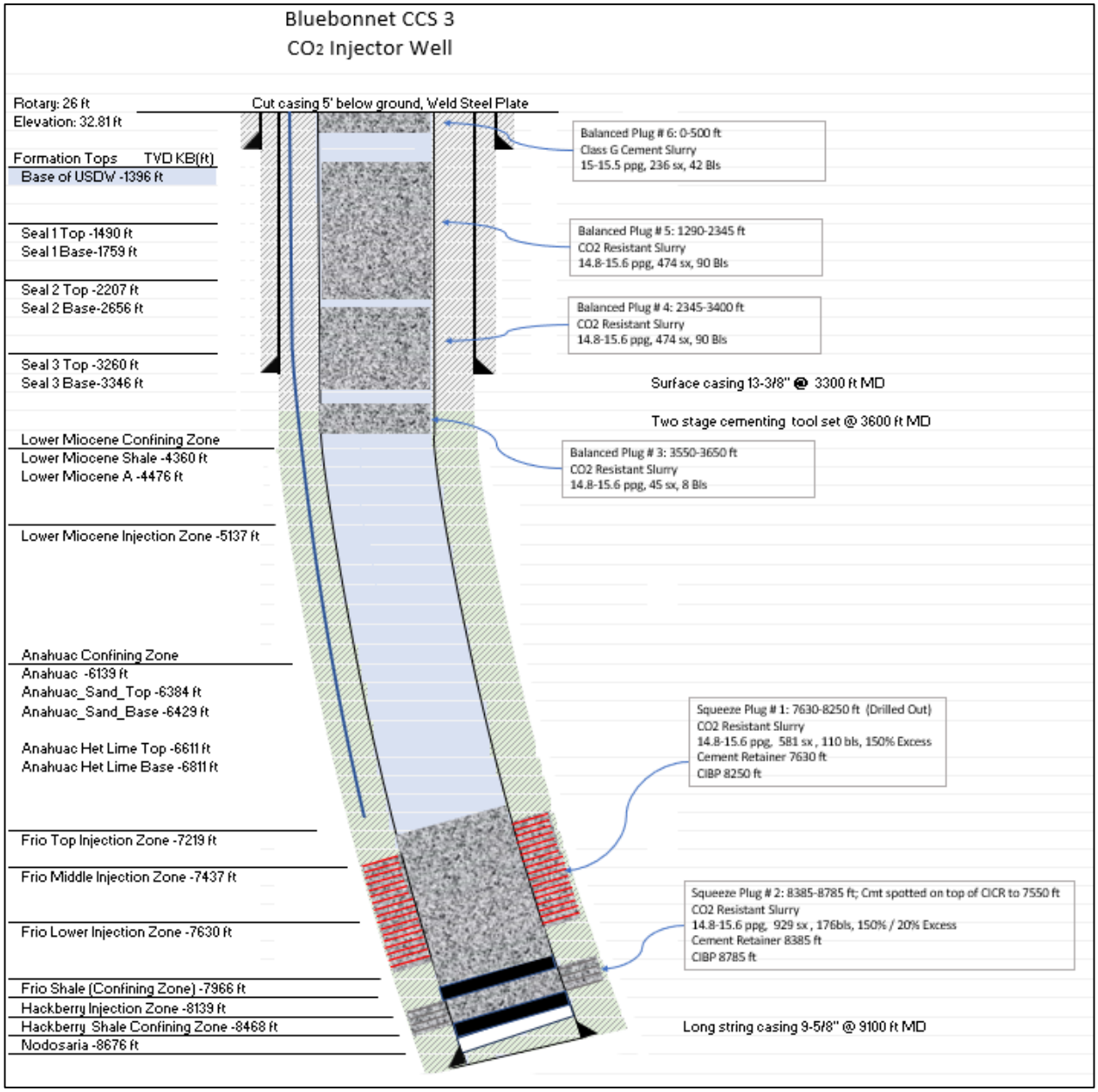


Figure PLG-3: Bluebonnet CCS 3 injection well plug schematic.

4.4 Bluebonnet CCS 5 Plug and Abandonment Details

Table PLG-4: Bluebonnet CCS 5 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	5450	6500	CO2 Resistant	14.8-15.5	1.06	150%	8.535	983
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2450	3500	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 4	Balanced Plug	1400	2450	CO2 Resistant	14.8-15.5	1.06	20%	8.535	472
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

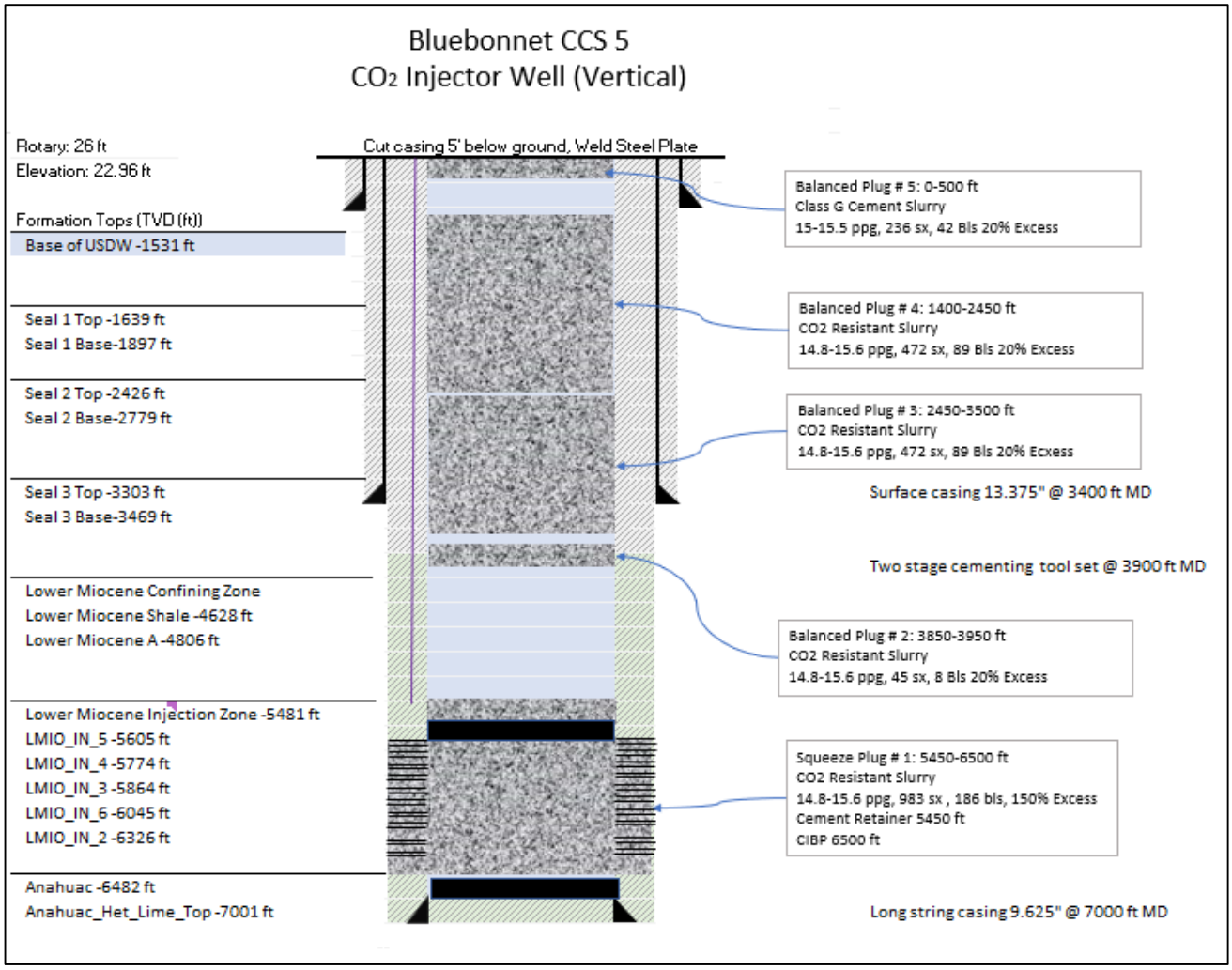


Figure PLG-4: Bluebonnet CCS 5 injection well plug schematic.

4.5 Bluebonnet CCS 6 Plug and Abandonment Details

Table PLG-5: Bluebonnet CCS 6 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	5500	6375	CO2 Resistant	14.8-15.5	1.06	150%	8.535	819
Plug # 2	Balanced Plug	3850	3950	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2400	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	449
Plug # 4	Balanced Plug	1400	2400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	449
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

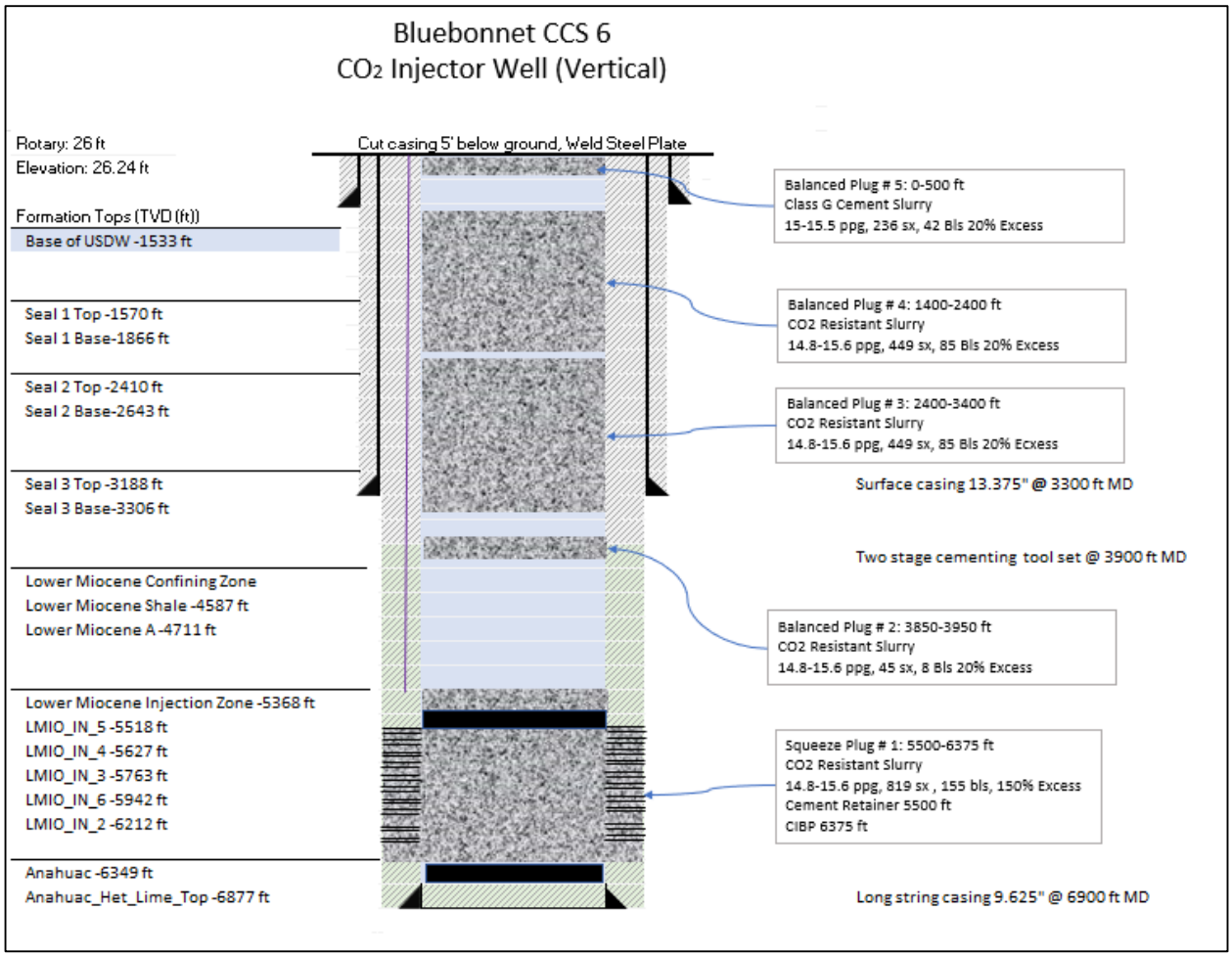


Figure PLG-5: Bluebonnet CCS 6 injection well plug schematic.

4.6 Bluebonnet CCS 7 Plug and Abandonment Details

Table PLG-6: Bluebonnet CCS 7 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	5150	6150	CO2 Resistant	14.8-15.5	1.06	150%	8.535	936
Plug # 2	Balanced Plug	3550	3650	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2325	3400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	483
Plug # 4	Balanced Plug	1250	2325	CO2 Resistant	14.8-15.5	1.06	20%	8.535	483
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by the EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

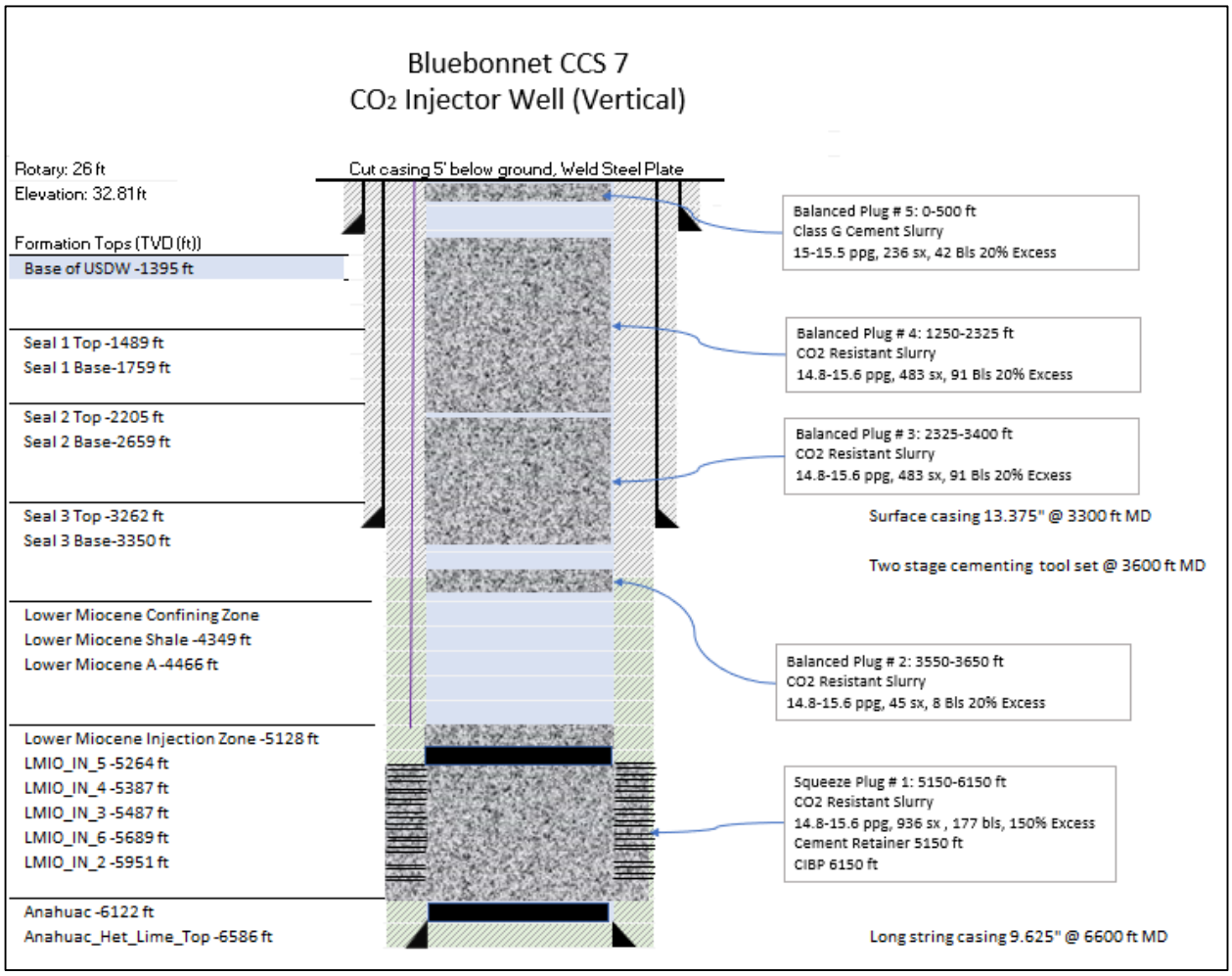


Figure PLG-6: Bluebonnet CCS 7 injection well plug schematic.

5.0 Narrative Description of Plugging Procedures for CO_2 Injector Wells

5.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), the Bluebonnet Sequestration Hub, LLC, will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

5.2 Bluebonnet CCS 1 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 1 site and rig up (RU). All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optic cables are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill/buffer fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before it is plugged and abandoned.
6. If both the casing and tubing are controlled, then nipple up the blowout preventers (BOPs).
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS/DAS temperature survey (no need for logging unit)

Rig down the logging unit.

10. Set a cast iron bridge plug (CIBP) at 8,980 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 8,740 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the Hackberry formations from 8,740-8,980 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from the top of the cement retainer to 7,867 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pull up out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,450-3,500 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,400-2,450 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.3 Bluebonnet CCS 2 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 2 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP

measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.

5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.

6. If both the casing and tubing are controlled, then nipple up the BOPs.

7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS / DAS temperature survey (no need for logging unit)

   Rig down the logging unit.

10. Set a CIBP at 8545 ft.

11. Trip in hole with the work string and cement retainer to the top of plug #1 at 7,980 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.

12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Frio formation from 7,980-8,545 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.

13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.

14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,450-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.

15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,500-2,450 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.4 Bluebonnet CCS 3 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 3 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

    a. Pulse neutron log
    b. Noise log
    c. Temperature log
    d. Fiber optic DTS

    Rig down the logging unit.

10. Set a CIBP at 8,250 ft.

11. Trip in hole with the work string with a cast iron cement retainer to the top of plug #1 at 7,630 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.

12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Frio formation from 7,630-8,250 ft. Disconnect from the retainer and check the flow. Pull out of the hole.

13. Pick up the bit and trip in hole to the cast iron cement retainer (CICR) at 7,630 ft. Wait for the cement from plug #1 to develop 1,000 psi compressive strength according to the laboratory test and drill out the CICR and cement down to the CIBP at 8,250 ft. Test the casing to 500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. If the casing fails the pressure test, re-squeeze plug #1.

14. Continue cleaning the well down to 8,785 ft. Circulate the well clean. Pull out of the hole and lay down the bit.

15. Set a CIBP at 8,785 ft.

16. Trip in hole with the work string and cement retainer to the top of plug #2 at 8,385 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.

17. Plug #2: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Hackberry formation from 8,385-8,785 ft. Disconnect from the retainer and check the flow. Spot 14.8-15.5 ppg CO_2-resistant slurry from top of the cement retainer to 7,550 ft. Pull up above the plug and circulate heavy mud 9.5-10.5 ppg. Pull out of the hole.

18. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,550-3,650 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.

19. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,345-3,400 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.

20. Plug #5: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,290-2,345 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
21. Plug #6: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
22. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.5 Bluebonnet CCS 5 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 5 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
    a. Pulse neutron log
    b. Noise log
    c. Temperature log
    d. DTS / DAS temperature survey (no need for logging unit)

    Rig down the logging unit.
10. Set a CIBP at 6,500 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,450 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Miocene formation from 5,450-6,500 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,450-3,500 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,400-2,450 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.6 Bluebonnet CCS 6 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 6 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.

3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log
   d. DTS / DAS temperature survey (no need for logging unit)

   Rig down the logging unit.
10. Set a CIBP at 6,375 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,500 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Miocene formation from 5,500-6,375 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,850-3,950 ft). Pull up above the plug and circulate. Wait for the cement to

develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.

14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,400-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,400-2,400 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

5.7 Bluebonnet CCS 7 Plugging Procedure

1. Move the rig onto the Bluebonnet CCS 7 site and rig up. All CO_2 pipelines will be marked and noted by the rig supervisor prior to moving in.
2. Conduct and document a safety meeting.
3. Record the BHP from the downhole gauge, perform a DTS survey through the fiber optic cable installed alongside the casing, and calculate the kill fluid density. If the fiber optics are not functioning, skip this step and proceed with the methods described above for mechanical integrity evaluation after the tubing is pulled.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid with the density determined using the BHP measurement. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below:
    a. Pulse neutron log
    b. Noise log
    c. Temperature log
    d. DTS / DAS temperature survey (no need for logging unit)

    Rig down the logging unit.
10. Set a CIBP at 6,150 ft.
11. Trip in hole with the work string and cement retainer to the top of plug #1 at 5,150 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zone of the Miocene formation from 5,150-6,150 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,550-3,650 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,325-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,250-2,325 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next plug stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

The proposed plugging and abandonment procedures and schematics for Bluebonnet IZM M1, Bluebonnet IZM M2, Bluebonnet IZM M3, Encanto 01, Bluebonnet PRDW F1, Bluebonnet PRDW F2, Bluebonnet DSW M2, Bluebonnet IZM FM1, Bluebonnet IZM FM2, Bluebonnet USDW 1, Bluebonnet USDW 2 and Bluebonnet USDW 8 are included in Appendix A.

All the monitoring wells that do not penetrate the base of usable quality water will be plugged according to the plan presented in Appendix A. (Certification added 04.07.25 to comply with Statewide Rule §5.203(k)(6))

Appendix A: Monitoring, Water Production and Water Disposal Well P&A

A.1 Bluebonnet IZM M1 Details

Table PLG-7: Bluebonnet IZM M1 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft3/sx)	Excess	ID (inch)	Sacks
Plug #1	Squeeze	2700	2800	CO2 Resistant	14.8-15	1.06	200%	4.892	234
Plug # 2	Balanced Plug	0	1500	Class A or C	15	1.01	20%	4.892	38

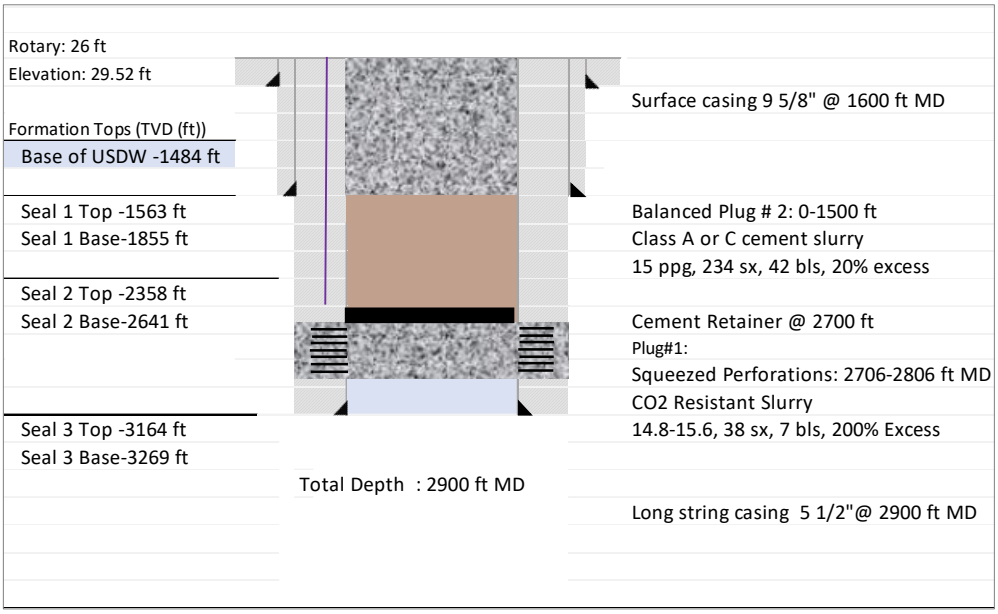


Figure PLG-7: Bluebonnet IZM M1 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Bluebonnet IZM M1 site and rig up.

2. Conduct and document a safety meeting.

3. Calculate the BHP from the downhole gauge or surface gauges and calculate the kill fluid density.

4. Test the pump and surface lines to 5,000 psi. Fill tubing and flush the well at least three times the tubing volume with kill fluid. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.

5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure.

   Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.

6. If both the casing and tubing are controlled, then nipple up the BOPs.

7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below in the event fiber optic cables are not functional:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log

   Rig down the logging unit.

10. Trip in hole with the work string and cement retainer to the top of plug #1 at 2,700 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations 2,706-2,806 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
12. Plug #2: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry to isolate the top of the surface casing (0-1,500 ft).
13. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.2 Bluebonnet IZM M2 Details

Table PLG-8: Bluebonnet IZM M2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft3/sx)	Excess	ID (inch)	Sacks
Plug #1	Balanced Plug	0	1400	Class A or C	15-15.5	1.01	20%	4.09	156

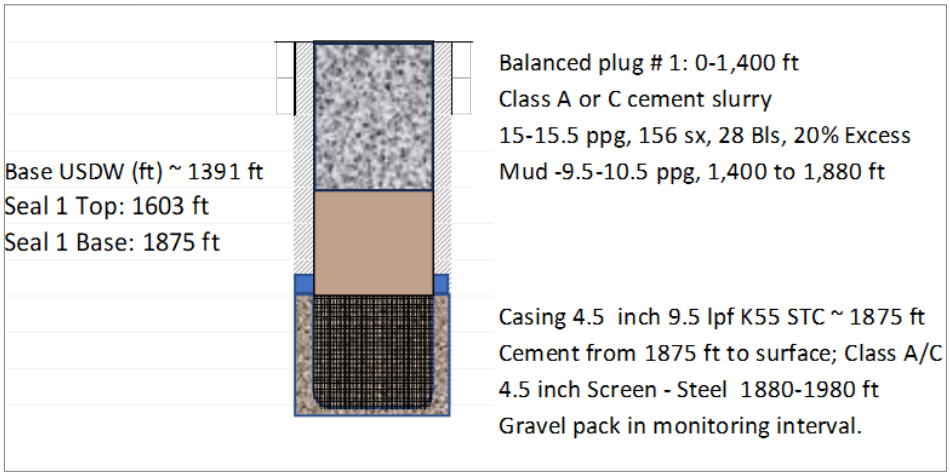


Figure PLG-8: Bluebonnet IZM M2 plug design and schematic.

Plugging procedure

1. Move the rig onto Bluebonnet IZM M2 site and rig up.
2. Conduct and document a safety meeting.
3. Record the surface pressure.
4. Test the pump and surface lines to 5,000 psi.
5. Kill the well if necessary.
6. Pull out of the hole and lay down tubing and pump.
7. Trip in hole with the work string to 1,875 ft.
8. Circulate heavy mud 9.5-10.5 ppg.
9. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-1,400 ft.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.3 Bluebonnet IZM M3 Details

Table PLG-9: Bluebonnet IZM M3 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft3/sx)	Excess	ID (inch)	Sacks
Plug #1	Balanced Plug	0	1300	Class A or C	15-15.5	1.01	20%	4.09	145

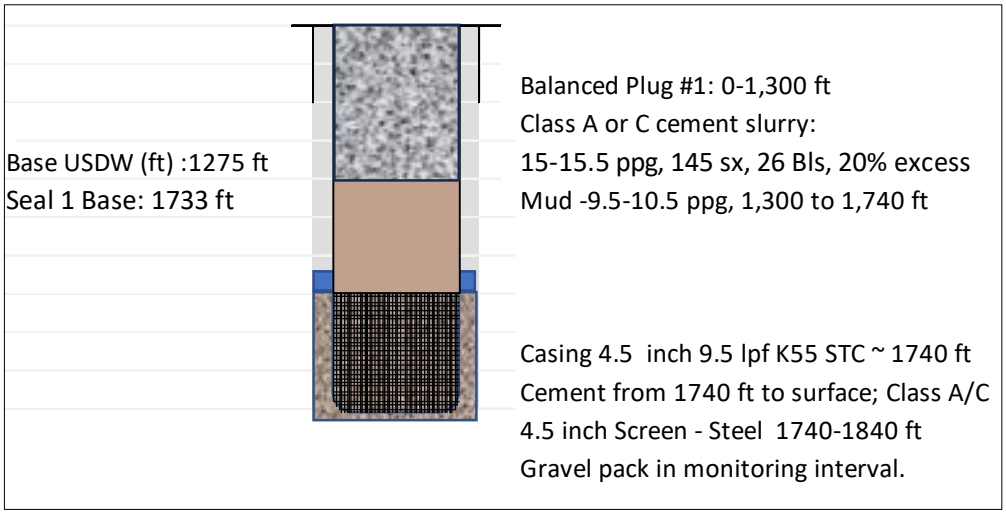


Figure PLG-9: Bluebonnet IZM M3 plug design and schematic.

Plugging procedure

1. Move the rig onto Bluebonnet IZM M3 site and rig up.
2. Conduct and document a safety meeting.
3. Record the surface pressure.
4. Test the pump and surface lines to 5,000 psi.
5. Kill the well if necessary.
6. Pull out of the hole and lay down tubing and pump.
7. Trip in hole with the work string to 1,740 ft.
8. Circulate heavy mud 9.5-10.5 ppg.
9. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-1,300 ft.
10. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.4 Encanto 01 Details

Table PLG-10: Bluebonnet Encanto 01 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7515	8400	CO2 Resistant	14.8-15.5	1.06	150%	4.778	260
Plug # 2	Squeeze	7058	7111	CO2 Resistant	14.8-15.5	1.06	150%	4.778	16
Plug # 3	Squeeze	5193	6175	CO2 Resistant	14.8-15.5	1.06	150%	4.778	288
Plug # 4	Balanced Plug	4068	4168	CO2 Resistant	14.8-15.5	1.06	20%	4.778	14
Plug # 5	Balanced Plug	2135	3220	CO2 Resistant	14.8-15.5	1.06	20%	4.778	153
Plug # 6	Balanced Plug	1050	2135	CO2 Resistant	14.8-15.5	1.06	20%	4.778	153
Plug # 7	Balanced Plug	0	500	Class G w/ additives	15-15.7	1.01	20%	4.778	74

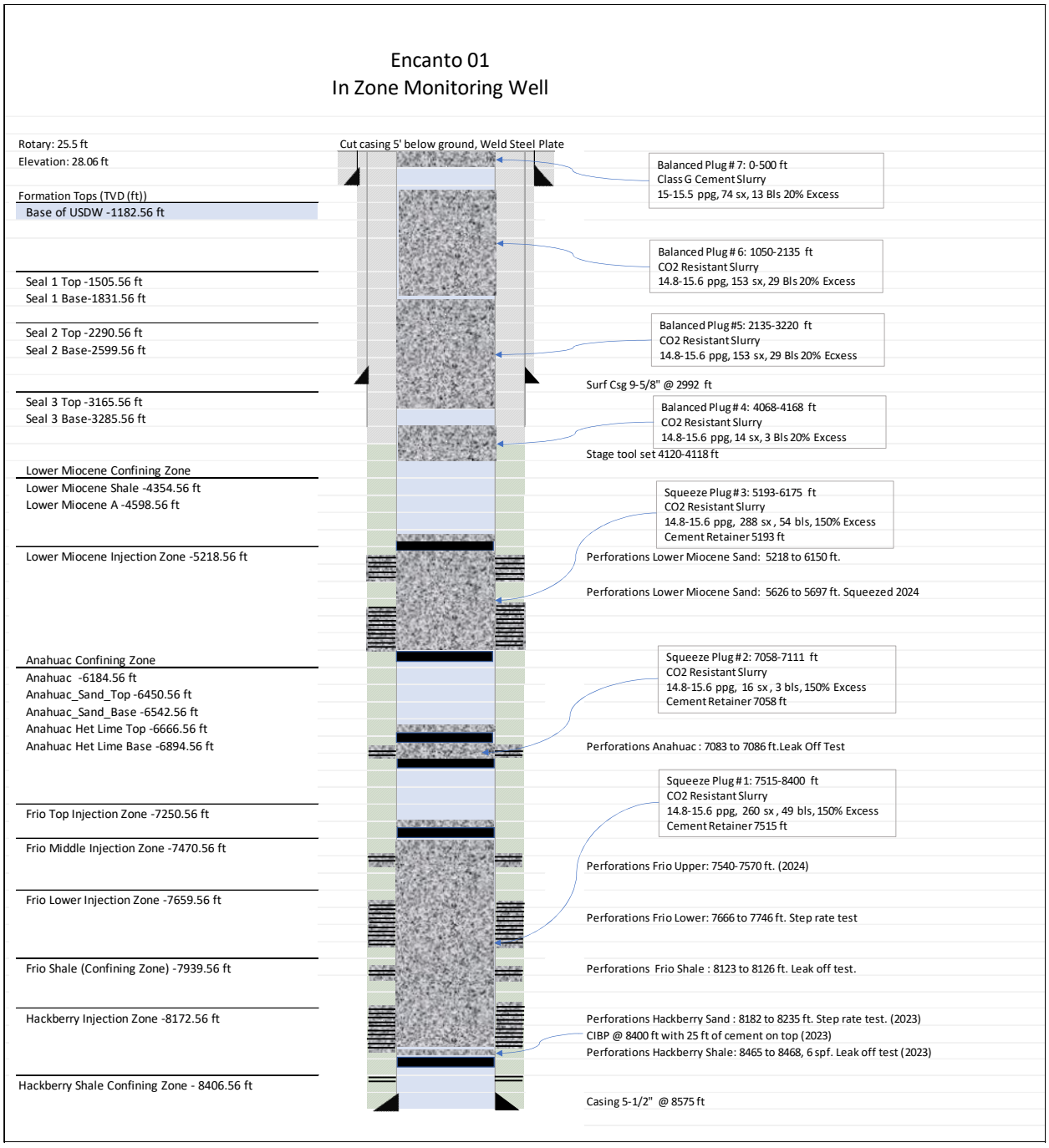


Figure PLG-10: Encanto 01 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Encanto 01 site and rig up.
2. Conduct and document a safety meeting.
3. Calculate the BHP from downhole or surface gauges and determine kill fluid density.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well with at least three times the tubing volume of kill fluid. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string out of the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with bit, drilling out the cast iron bridge plug (CIBP) at 6,184 ft and composite bridge plugs (CBP) at 7,650 ft, 8,100 ft, and 8,150 ft. Continue to trip in hole and tag CIBP at 8,375 ft (CIBP has ~25 ft of cement of top).
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below in the event fiber optic cables are not functional:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log

   Rig down the logging unit.
10. Trip in hole with the work string and cement retainer to the top of plug #1 at 7,515 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze perforations and seal the perforations in the injection zones of the Frio and Hackberry formations from 7,515-8,400 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
12. Set a CIBP at 7,111 ft.

13. Trip in hole with the work string and cement retainer to the top of plug #2 at 7,058 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
14. Plug #2: Mix and pump 14.8-15.5 ppg CO2-resistant slurry to squeeze perforations and seal the perforations in the Anahuac formation from 7,058-7,111 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
15. Set a CIBP at 6,175 ft.
16. Trip in hole with the work string and cement retainer to the top of plug #3 at 5,193 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
17. Plug #3: Mix and pump 14.8-15.5 ppg CO2-resistant slurry to squeeze perforations and seal the perforations in the Lower Miocene formation from 5,193-6,175 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
18. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO2-resistant slurry to cover the stage tool (4,068-4,168 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
19. Plug #5: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 3, the surface casing shoe and seal 2 (2,135-3,220 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag top of the plug.
20. Plug #6: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,050-2,135 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string to the next stage.
21. Plug #7: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
22. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.5. Bluebonnet PRDW F1 Details

Table PLG-11: Bluebonnet PRDW F1 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7380	7975	CO2 Resistant	14.8-15.5	1.06	150%	8.535	557
Plug # 2	Balanced Plug	3750	3850	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2320	3300	CO2 Resistant	14.8-15.5	1.06	20%	8.535	440
Plug # 4	Balanced Plug	1340	2320	CO2 Resistant	14.8-15.5	1.06	20%	8.535	440
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

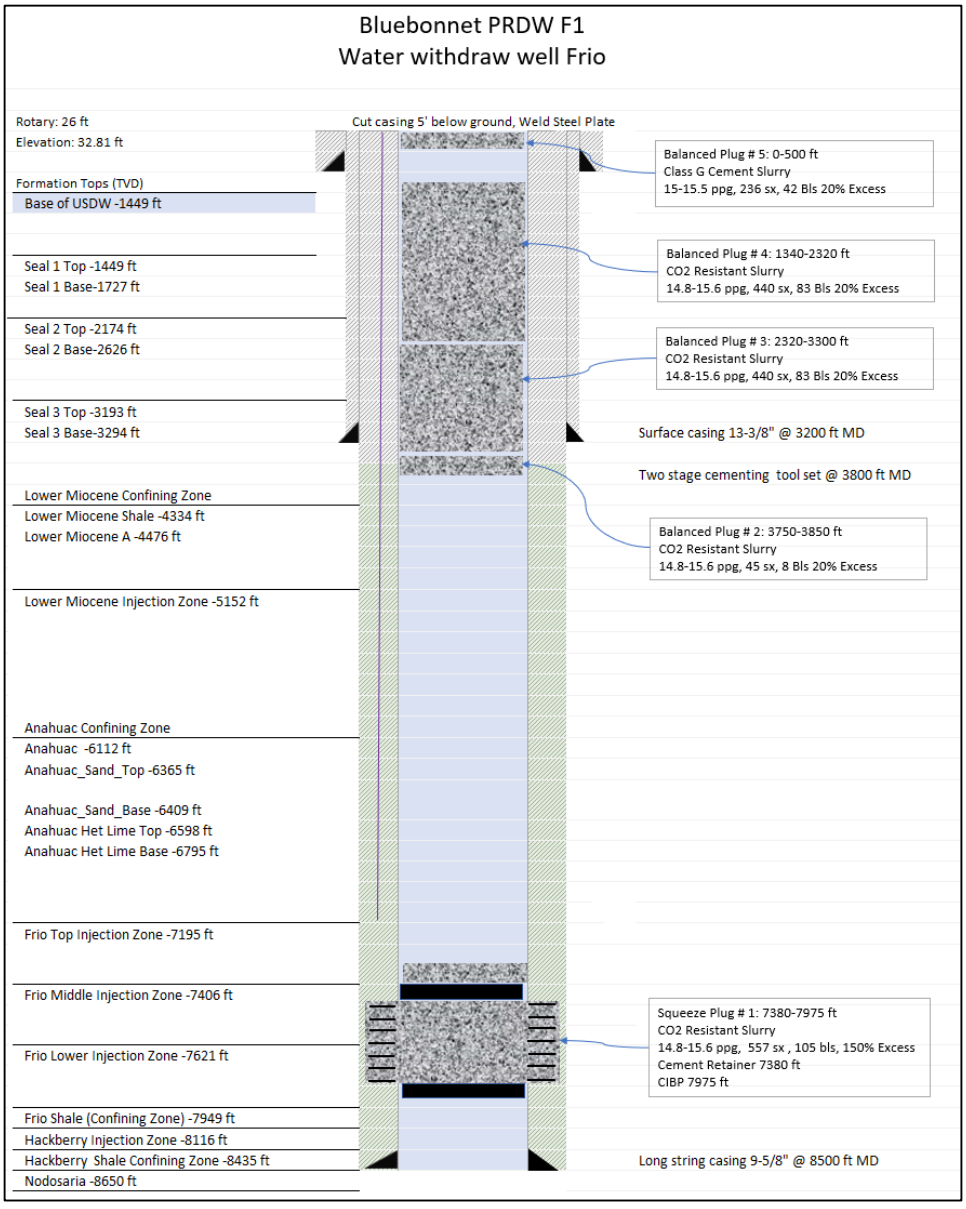


Figure PLG-11: Bluebonnet PRDW F1 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Bluebonnet PRDW F1 site and rig up.
2. Conduct and document a safety meeting.
3. Calculate the BHP using the downhole pressure from the ESP sensor and determine the kill fluid density.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well at least three times the tubing volume with kill fluid. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. If both the casing and tubing are controlled, then nipple up the BOPs.
6. Pull out of the hole and lay down the tubing and ESP.
7. Pick up the work string and trip in hole with the bit to condition the wellbore.
8. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below in the event the fiber optic cables are not functional:

    a. Pulse neutron log
    b. Noise log
    c. Temperature log

    Rig down the logging unit.
9. Set a CIBP at 7,975 ft.
10. Trip in hole with the work string with a cement retainer to the top of plug #1 at 7,380 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the Frio formation from 7,380-7,975 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
12. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,750-3,850 ft). Pull out above the plug and circulate. Wait for cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next plug stage.
13. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,320-3,300 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
14. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,340-2,320 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next stage.

15. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
16. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.6 Bluebonnet PRDW F2 Details

Table PLG-12: Bluebonnet PRDW F2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Squeeze	7650	8190	CO2 Resistant	14.8-15.5	1.06	150%	8.535	506
Plug # 2	Balanced Plug	3950	4050	CO2 Resistant	14.8-15.5	1.06	20%	8.535	45
Plug # 3	Balanced Plug	2370	3300	CO2 Resistant	14.8-15.5	1.06	20%	8.535	418
Plug # 4	Balanced Plug	1440	2370	CO2 Resistant	14.8-15.5	1.06	20%	8.535	418
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

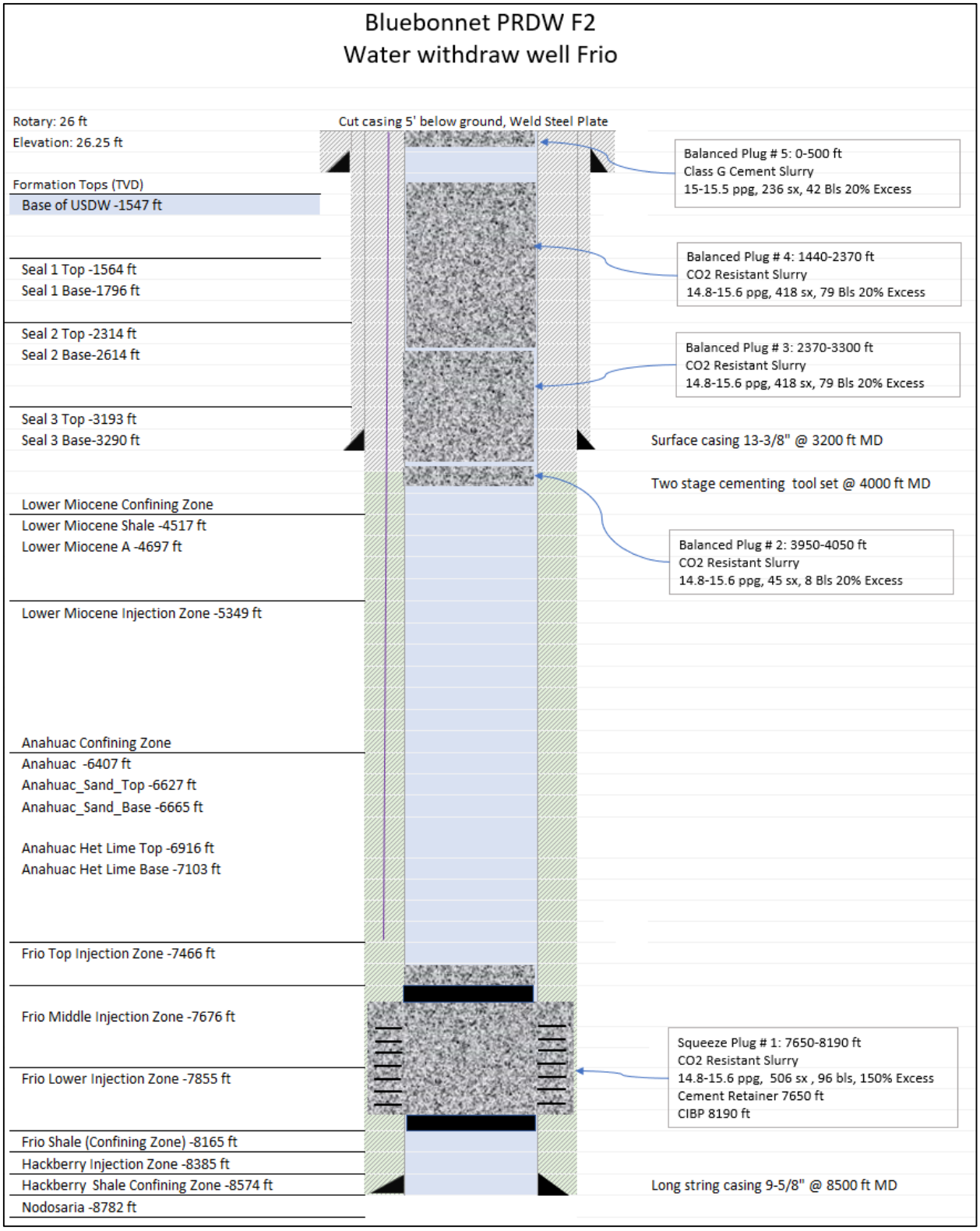


Figure PLG-12: Bluebonnet PRDW F2 plug design and schematic.

Plugging procedure

1. Move the rig onto the Bluebonnet PRDW F2 site and rig up.
2. Conduct and document a safety meeting.
3. Calculate the BHP using the downhole pressure from the ESP sensor and determine the kill fluid density.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well at least three times the tubing volume with kill fluid. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. If both the casing and tubing are controlled, then nipple up the BOPs.
6. Pull out of the hole and lay down the tubing and ESP.
7. Pick up the work string and trip in hole with the bit to condition the wellbore.
8. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below in the event fiber optic cable is not functional:

    a. Pulse neutron log
    a. Noise log
    b. Temperature log

    Rig down the logging unit.
9. Set a CIBP at 8,190 ft.
10. Trip in hole with the work string with a cement retainer to the top of plug #1 at 7,650 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zone of the Frio formation from 7,650-8,190 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
12. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,950-4,050 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next plug stage.
13. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,370-3,300 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
14. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,440-2,370 ft). Pull up above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next stage.

15. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
16. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.7 Bluebonnet DSW M2 Details

Table PLG-13: Bluebonnet DSW M2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1*	Squeeze	3200	4250	CO2 Resistant	14.8-15.5	1.06	150%	8.535	983
Plug # 2	Balanced Plug	1400	2400	CO2 Resistant	14.8-15.5	1.06	20%	8.535	449
Plug # 3	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	8.535	236

*Perfs. to be selected after well is drilled

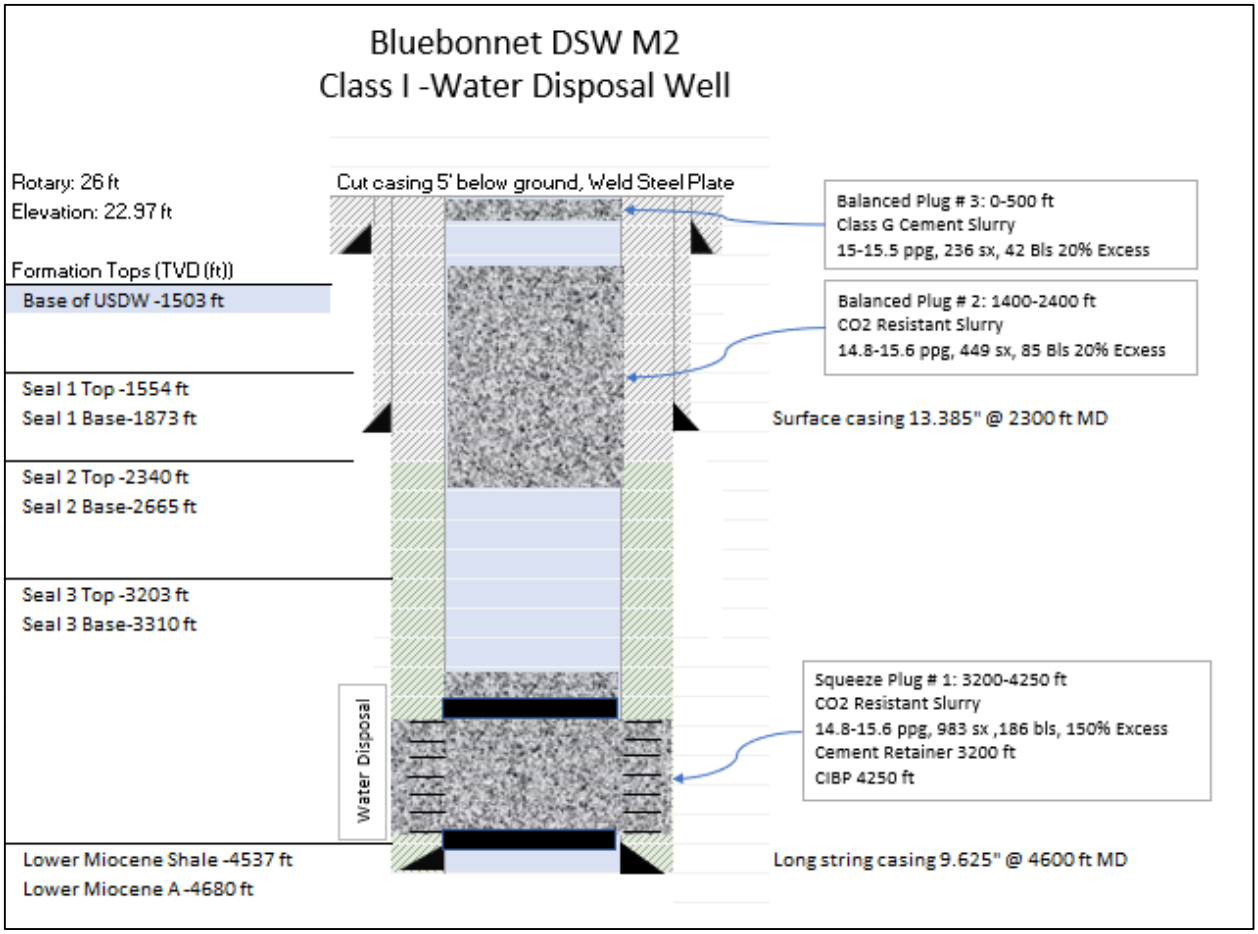


Figure PLG-13: Bluebonnet DSW M2 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Bluebonnet DSW M2 site and rig up.
2. Conduct and document a safety meeting.
3. Calculated the BHP from the downhole or surface gauges and calculate the kill fluid density.
4. Test the pump and surface lines to 5,000 psi.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric

line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string up the hole and proceed to recover the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Set a CIBP at 4,250 ft.
10. Trip in hole with the work string with a cement retainer to the top of plug #1 at 3,200 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
11. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the water disposal zone from 3,200-4,250 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
12. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 1 and the base of the USDW (1,400-2,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
13. Plug #3: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
14. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.8 Bluebonnet IZM FM1 Details

Table PLG-14: Bluebonnet IZM FM1 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1*	Squeeze	7220	8275	CO2 Resistant	14.8-15.5	1.06	150%	4.778	310
Plug # 2	Balanced Plug	3750	3850	CO2 Resistant	14.8-15.5	1.06	20%	4.778	14
Plug # 3	Balanced Plug	2300	3400	CO2 Resistant	14.8-15.5	1.06	20%	4.778	155
Plug # 4	Balanced Plug	1200	2300	CO2 Resistant	14.8-15.5	1.06	20%	4.778	155
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	4.778	74

*50-150 ft Net perfs. To be selected after well is drilled

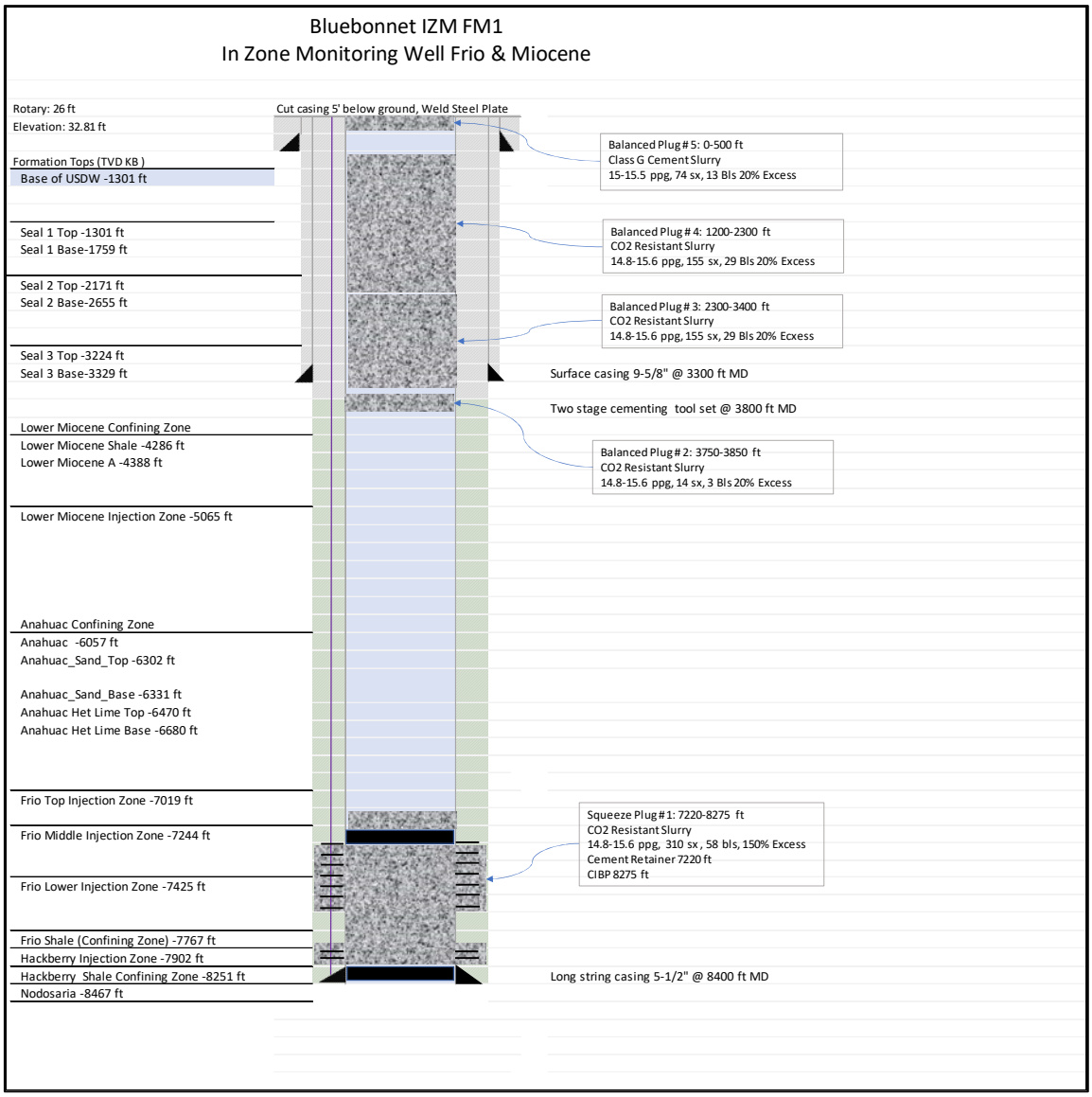


Figure PLG-14: Bluebonnet IZM FM1 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Bluebonnet IZM FM1 site and rig up.
2. Conduct and document a safety meeting.
3. Calculate the BHP from the downhole gauge or surface gauges and calculate the kill fluid density.
4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well at least three times the tubing volume with kill fluid. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing pressure and annular pressure continuously.
5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.
6. If both the casing and tubing are controlled, then nipple up the BOPs.
7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string up the hole and proceed to recover the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.
8. Pick up the work string and trip in hole with the bit to condition the wellbore.
9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below in the event the fiber optic cable is not functional:

   a. Pulse Neutron Log
   b. Noise Log
   c. Temperature Log

   Rig down the logging unit.
10. Set a CIBP at 8,275 ft.
11. Trip in hole with the work string with a cement retainer to the top of plug #1 at 7,220 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zones of the Frio and Hackberry formation from 7,220-8,275 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pullup the hole.

13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (3,750-3,850 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,300-3,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover Seal 1 and the base of the USDW (1,200-2,300 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.9 Bluebonnet IZM FM2 Details

Table PLG-15: Bluebonnet IZM FM2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1*	Squeeze	7800	8810	CO2 Resistant	14.8-15.5	1.06	150%	4.778	296
Plug # 2	Balanced Plug	4050	4150	CO2 Resistant	14.8-15.5	1.06	20%	4.778	14
Plug # 3	Balanced Plug	2400	3500	CO2 Resistant	14.8-15.5	1.06	20%	4.778	155
Plug # 4	Balanced Plug	1300	2400	CO2 Resistant	14.8-15.5	1.06	20%	4.778	155
Plug # 5	Balanced Plug	0	500	Class G w/ additives	15-15.5	1.01	20%	4.778	74

*50-150 ft Net perfs. To be selected after well is drilled

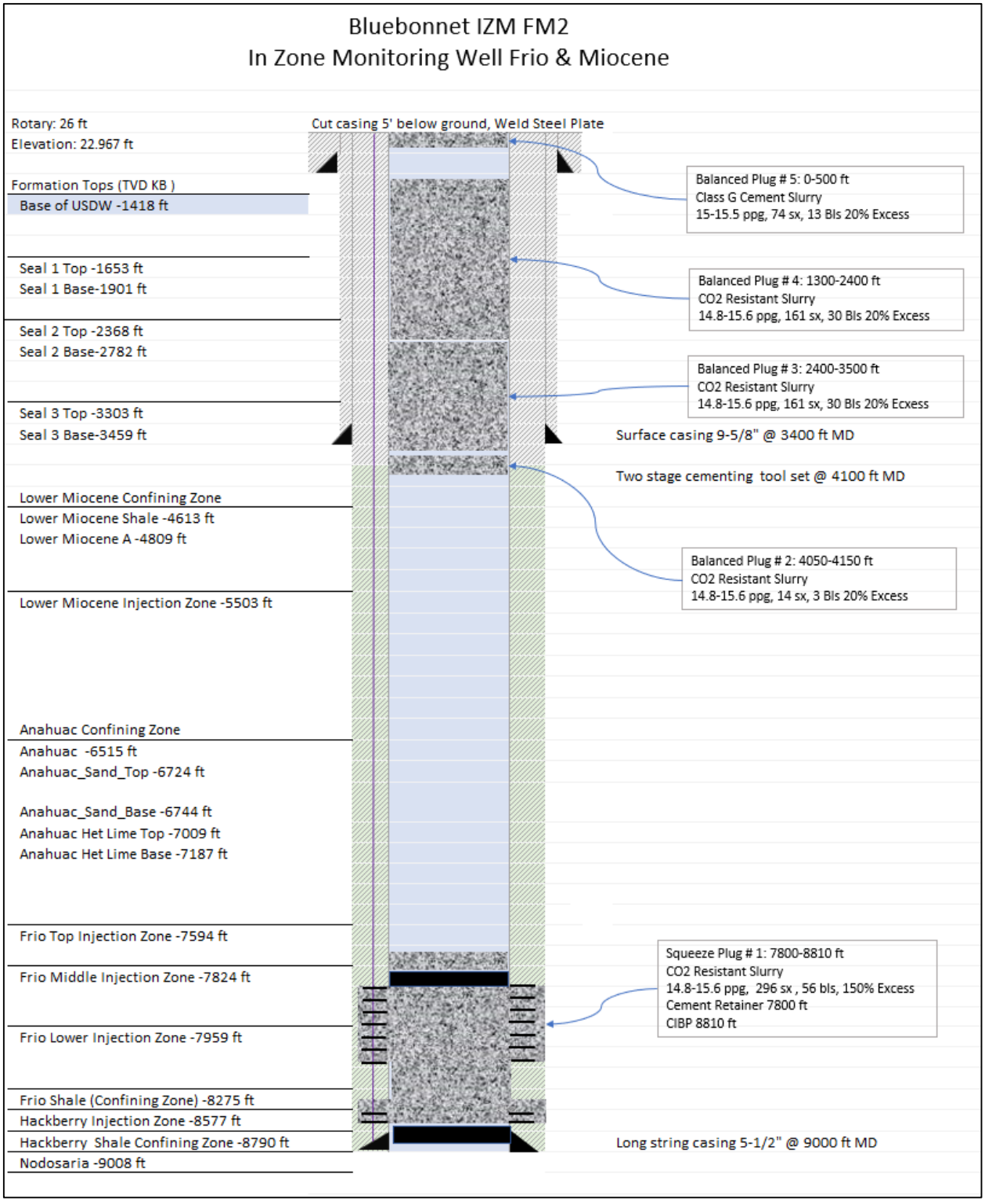


Figure PLG-15: Bluebonnet IZM FM2 plug design and schematic.

Plugging Procedure

1. Move the rig onto the Bluebonnet IZM FM2 site and rig up.

2. Conduct and document a safety meeting.

3. Calculate the BHP from the downhole or surface gauges and calculate the kill fluid density.

4. Test the pump and surface lines to 5,000 psi. Fill the tubing and flush the well at least three times the tubing volume with kill fluid. It may be necessary to bleed off occasionally to remove all air from the system. Monitor the tubing and annular pressures continuously.

5. Test the casing annulus to 500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed the pressure, check the surface lines and connections, and repeat the test. Then release the pressure. Note: If a failure in the long-string casing is identified, the Bluebonnet Hub will prepare a plan to repair the well before plugging and abandonment.

6. If both the casing and tubing are controlled, then nipple up the BOPs.

7. Pull out of the hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve the packer, rig up a lubricator and slickline and set a plug in the lower profile nipple below the packer. Rig up an electric line and make a cut on the tubing string just above the packer. The cut must be made at least 5–10 ft MD above the packer. Circulate with kill mud. Then pull the work string up the hole and proceed recovering the packer with the work string. If problems are noted, update the cement remediation plan. A cement retainer will be used to force the cement in case the packer cannot be removed.

8. Pick up the work string and trip in hole with the bit to condition the wellbore.

9. Pull out of the hole and rig up the logging unit. Confirm external mechanical integrity by running one of the tests listed below in the event fiber optic cable is not functional:

   a. Pulse neutron log
   b. Noise log
   c. Temperature log

   Rig down the logging unit.

10. Set a CIBP at 8,810 ft.

11. Trip in hole with the work string with a cement retainer to the top of plug #1 at 7,800 ft. Circulate the well, set the retainer, and perform an injectivity test. Rig up equipment for cementing operations.
12. Plug #1: Mix and pump 14.8-15.5 ppg CO_2-resistant slurry to squeeze and seal the perforations in the injection zones of the Frio and Hackberry formation from 7,800-8,810 ft. Disconnect from the retainer and check the flow. Circulate heavy mud (9.5-10.5 ppg). Pull out of the hole.
13. Plug #2: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the two-stage cementing tool (4,050-4,150 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next plug stage.
14. Plug #3: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover the surface casing shoe, seal 3, and seal 2 (2,400-3,500 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug.
15. Plug #4: Set a balanced plug with 14.8-15.5 ppg CO_2-resistant slurry to cover seal 1 and the base of the USDW (1,300-2,400 ft). Pull out above the plug and circulate. Wait for the cement to develop 500 psi compressive strength according to the laboratory test and tag the top of the plug. Pull the string up to the next stage.
16. Plug #5: Set a balanced plug with 15-15.5 ppg Class G cement slurry to isolate the top of the surface casing (0-500 ft).
17. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.10 Bluebonnet USDW 1 Details

Table PLG- 16: Bluebonnet USDW 1 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Balanced Plug	0	1370	Class A or C Cement	15	1.01	20%	4.950	217

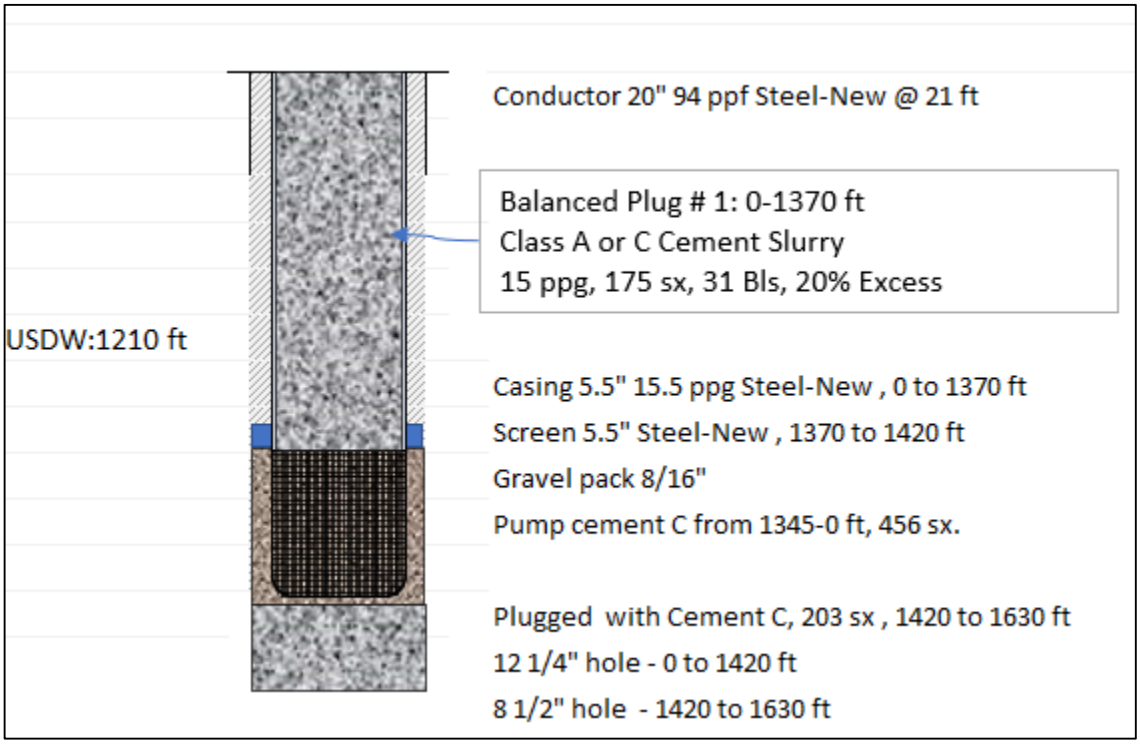


Figure PLG-16: Bluebonnet USDW 1 cement plug information.

Plugging procedure

11. Move the rig onto Bluebonnet USDW 1 site and rig up.
12. Conduct and document a safety meeting.
13. Record the surface pressure.
14. Test the pump and surface lines to 5,000 psi.
15. Kill the well if necessary.
16. Pull out of the hole and lay down tubing and pump.
17. Trip in hole with the work string to 1,370 ft.
18. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-1,370 ft.
19. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.11 Bluebonnet USDW 2 Details

Table PLG-17: Bluebonnet USDW 2 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft2/sx)	Excess	ID (inch)	Sacks
Plug # 1	Balanced Plug	0	1400	Class A or C Cement	15	1.01	20%	4.090	152

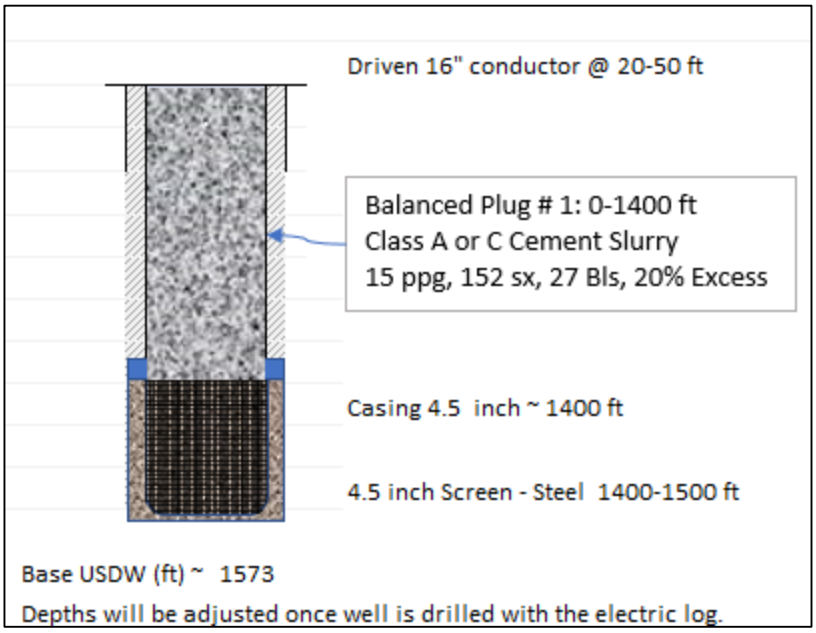


Figure PLG-17: Bluebonnet USDW 2 cement plug information.

Plugging Procedure

1. Move the rig onto Bluebonnet USDW 2 site and rig up.
2. Conduct and document a safety meeting.
3. Record the surface pressure.
4. Test the pump and surface lines to 5,000 psi.
5. Kill the well if necessary.
6. Pull out of the hole and lay down tubing and pump.
7. Trip in hole with the work string to 1,400 ft.
8. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-1,400 ft.
9. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

A.12 Bluebonnet USDW 8 Details

Table PLG-18: Bluebonnet USDW 8 cement plug information.

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Yield (ft3/sx)	Excess	ID (inch)	Sacks
Plug # 1	Balanced Plug	0	879	Class A or C Cement	15	1.01	20%	8.097	378

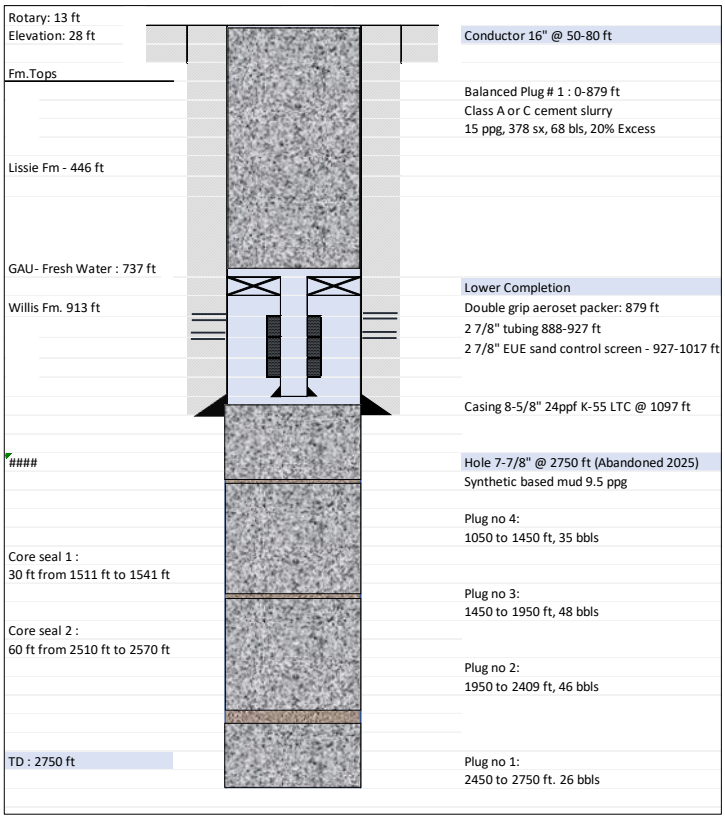


Figure PLG-18: Bluebonnet USDW 8 cement plug information.

Plugging Procedure

1. Move the rig onto Bluebonnet USDW 8 site and rig up.
2. Conduct and document a safety meeting.
3. Record the surface pressure.
4. Test the pump and surface lines to 5,000 psi.
5. Kill the well if necessary.

6. Pull out of the hole and lay down tubing and pump.
7. Trip in hole with the work string to 879 ft.
8. Plug #1: Set a balanced plug with 15-15.5 ppg Class A or C cement slurry 0-879 ft.
9. Lay down the work string. Rig down all equipment and move out. Cut the casing 5 ft below the ground. Clean the cellar so a plate can be welded with the required well information.

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

Appendix B: Example of CO_2 Resistant Cement Formulation for Plug and Abandonment.



Figure PLG-19: Example CO_2 resistant cement formulation for plug and abandonment. Additives such as WellLife and Microbond M may not be required for abandonment plugs.

POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Bluebonnet Sequestration Hub

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Plan revision number: 4
Plan revision date: 09/25/2025

1.0 Facility Information

Facility name: Bluebonnet CO_2 Sequestration Hub
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7 Wells.

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.93 this Post-Injection Site Care and Site Closure (PISC) Plan describes the activities that the Bluebonnet Sequestration Hub, LLC will take after injection ceases in the site until closure. The Bluebonnet Sequestration Hub, LLC will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years post injection. The Bluebonnet Sequestration Hub, LLC, may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the Underground Injection Control (UIC) Program Director. Following approval for site closure, the Bluebonnet Sequestration Hub, LLC, will plug all monitoring wells still active, restore the site in accordance with applicable law and good industry practice, and submit a site closure report and associated documentation.

2.0 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

2.1 Lower Miocene, Frio and Hackberry Pre- and Post-Injection Pressure Differential.

Based on the modeling of the pressure front as part of the AoR delineation, the magnitude and area of elevated pressure rapidly decreases over time after the end of injection reaching values close to original reservoir pressure in the first five years of the post-injection period.

The highest pressures are observed in the immediate vicinity of each CO_2 injector well. Table PISC-1 demonstrates the pressure differential at reference depth for Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3.

Table PISC-2 demonstrates the pressure differential at reference depth for Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7.

Table PISC-3 demonstrates the pressure differential at reference depth for each in zone monitoring well.

Figure PISC-1 and Figure PISC-2 show the bottomhole pressure versus time at reference depth for the CO_2 injector wells, Bluebonnet CCS 1, Bluebonnet CCS 2 , Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 and the in zone monitoring wells, Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01well in the Area of Review (AoR).

Table PISC-1: Pressure differential to pre-injection conditions at the CO_2 injector wells Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3.

Year From Injection	Pressure Differential (psi)		
	Bluebonnet CCS 1F	Bluebonnet CCS 2F	Bluebonnet CCS 3F
0	0	0	0
1	186 (Stage 1, measured at Frio Low)	241 (Stage 1, measured at Frio Low)	187 (Stage 1, measured at Hackberry)
2	183	227	194
3	184	223	199
4	186	224	203
5	189	225	206
6	192	227	210
7	195	231	213
8	199	234	216
9	211 (Stage 2, measured at Frio Mid)	220 (Stage 2, measured at Frio Mid)	227 (Stage 2, measured at Frio Low)
10	217	226	224
11	222	232	225
12	228	238	229
13	234	244	233
14	240	250	237
15	245	256	242
16	795 (Stage 3, measured at Hackberry)	124 (Shut in, measured at Frio Mid)	224 (Stage 3, measured at Frio Mid)
17	714	114	212
18	664	111	206
19	634	109	203
20	610	108	201
25	38	89	88
30	40	81	81
35	44	76	76
40	48	72	73
45	50	69	70
50	52	67	68
55	54	65	66
60	55	64	65
65	55	63	64
70	56	62	63

Table PISC-2: Pressure differential to pre-injection conditions at the CO_2 injector wells Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7

Year From Injection	Pressure Differential (psi)		
	Bluebonnet CCS 5	Bluebonnet CCS 6	Bluebonnet CCS 7
	(Ref 6,405 ft)	(Ref 6,289 ft)	(Ref 6,054 ft)
1	165.5	162.8	132.1
2	166.0	162.4	131.8
3	169.5	166.1	136.6
4	168.0	169.7	134.1
5	143.8	163.7	93.4
6	143.4	162.5	89.6
7	143.4	155.3	91.3
8	115.9	90.6	90.1
9	111.4	87.1	63.5
10	111.4	88.0	63.0
11	108.5	90.4	65.2
12	63.0	84.7	66.1
13	60.3	82.6	49.5
14	52.1	81.3	50.7
15	52.9	67.2	52.4
End of Injection			
16	31.8	34.9	41.4
17	25.5	28.4	35.8
18	22.9	25.7	33.7
19	21.3	24.1	32.9
20	20.4	23.1	32.6
25	18.2	21.1	32.1
30	16.2	20.7	31.7
35	15.4	21.1	31.5
40	16.0	21.5	31.5
45	16.6	21.8	31.5
50	17.1	22.0	31.5
55	17.4	22.2	31.5
60	17.7	22.3	31.5
65	17.8	22.4	31.5
70	18.0	22.5	31.5

Table PISC-3: Pressure differential to pre-injection conditions at the in zone monitoring well locations Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01.

Reference, ft, TVDSS	7,417	7,185	7,770	6,059*
Year From Injection	Pressure Differential (psi)			
	Encanto 01 (Frio)	Bluebonnet IZM FM 1	Bluebonnet IZM FM2	Encanto (Lower Miocene)
0	0	0	0	36
1	13	9	18	72
2	23	19	29	82
3	31	27	36	89
4	38	34	44	90
5	45	40	50	87
6	51	46	56	89
7	57	52	62	86
8	63	58	68	93
9	77	70	92	93
10	90	82	107	96
11	100	91	117	95
12	108	99	126	94
13	116	107	134	95
14	123	114	141	94
15 (End Injection Lower Miocene)	130	121	148	94
16	123	123	116	62
17	118	119	109	57
18	116	117	106	55
19	115	116	105	54
20 (End of Injection Hackberry/Frio)	114	116	104	53
25	89	88	88	50
30	82	81	80	49
35	77	76	76	49
40	74	73	72	48
45	71	70	70	48
50	69	68	68	48
55	67	67	66	48
60	66	65	65	47
65	65	64	64	47
70	64	63	63	47

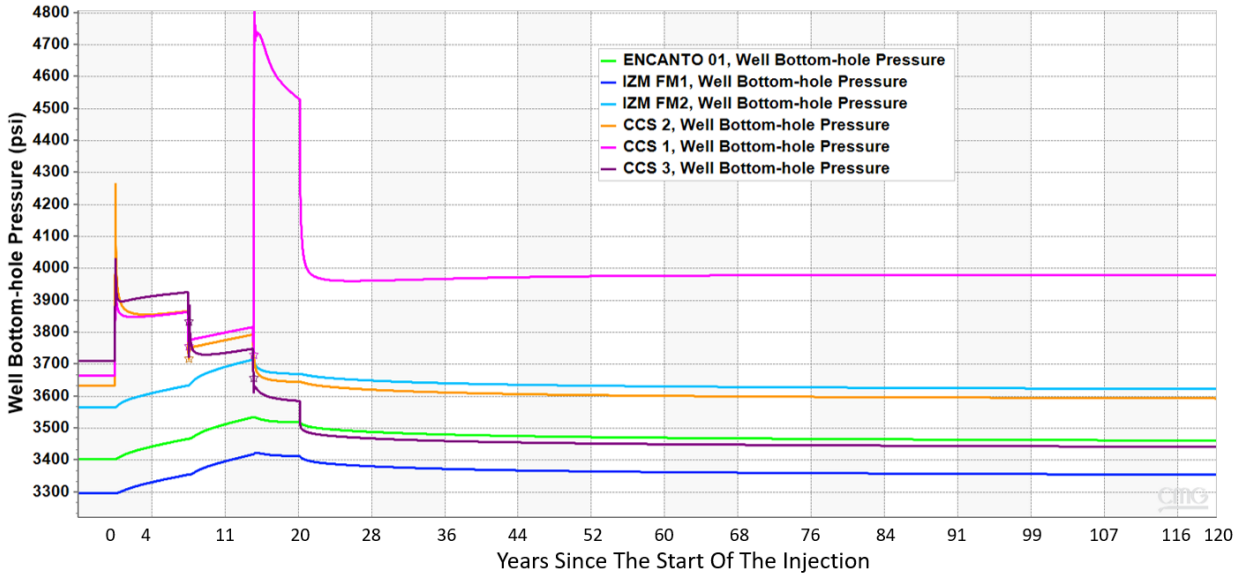


Figure PISC-1: Simulated pressure vs. time at reference depth in the Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3 injection and in the in zone monitoring wells Bluebonnet IZM FM1, Bluebonnet IZM FM2 and Encanto 01 wells*.

* Even though Encanto 01 will be completed as Lower Miocene monitoring well, the projected pressure differential in Frio is presented in figure PISC-1

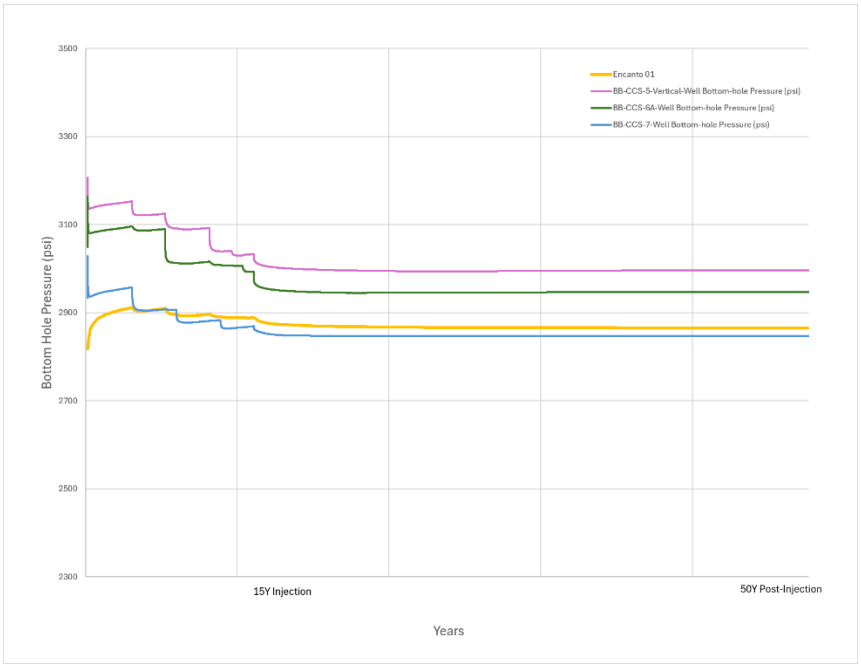


Figure PISC-2: Simulated pressure vs. time at reference depth in the Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injection and Encanto 01 well at reference depth.

Figure PISC-3, Figure PISC-4, and Figure PISC-5 show the simulated pressure differentials from the baseline at the reference point of the Lower Miocene, Frio Injection Zone, and the Hackberry Injection Zone at the highest pressure increase point respectively.

Figure PISC-6 shows the pressure differential 50 years post injection in the Lower Miocene Injection Zone. Figure PISC-7 shows the pressure differential 50 years post injection in the Frio Injection Zone. Figure PISC-8 shows the pressure differential 50 years post injection in the Hackberry Injection Zone. The pressure will have dissipated below the critical pressure in all areas of the site in the first 5 years of the post-injection period.

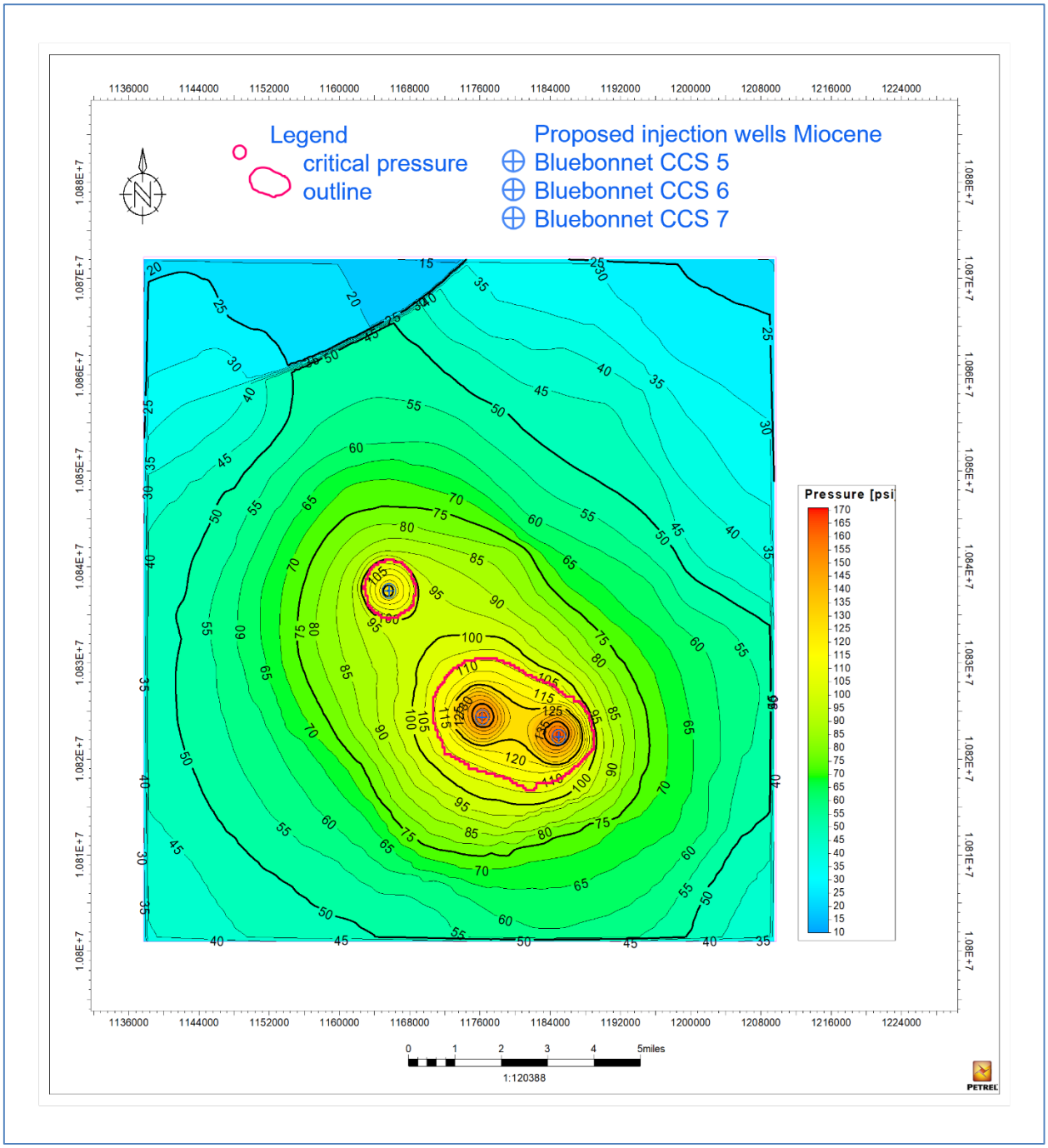


Figure PISC-3: Averaged aqueous pressure differentials from the baseline condition in the Lower Miocene Injection Zone (highest pressure increase point).

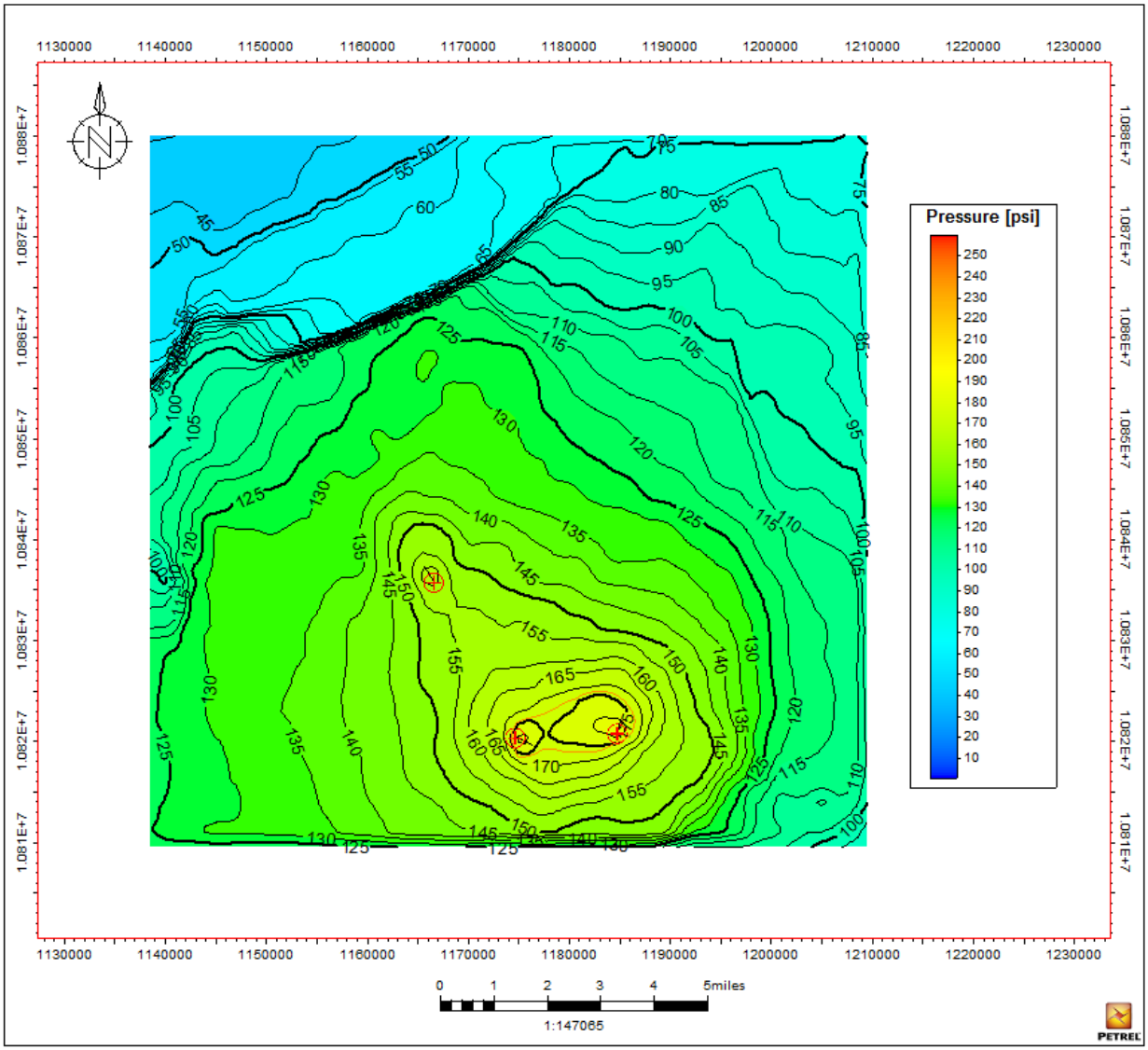


Figure PISC-4: Averaged aqueous pressure differentials from the baseline condition in the Frio Injection Zone (highest pressure increase point).

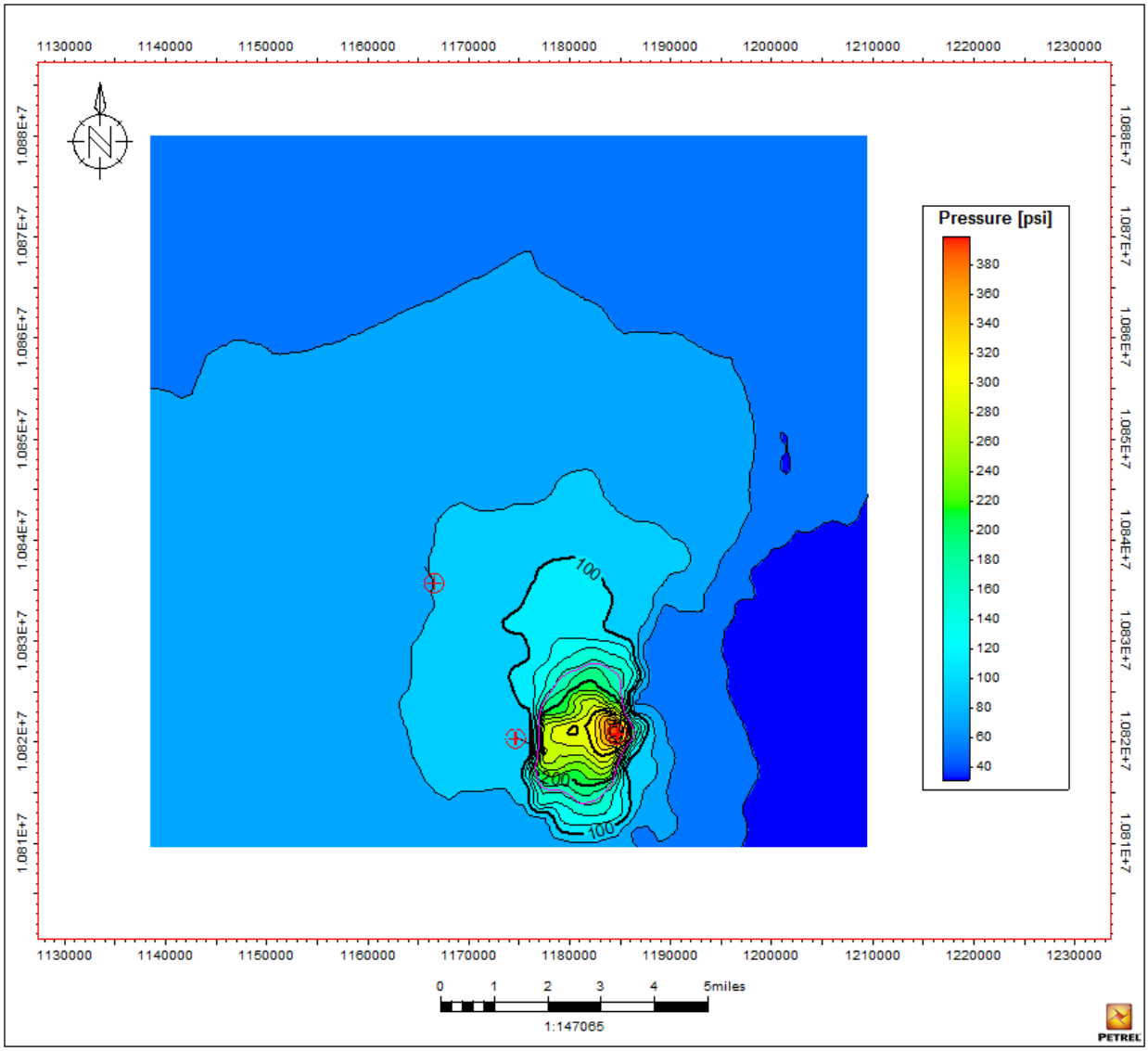


Figure PISC-5: Averaged aqueous pressure differentials from the baseline condition in the Hackberry Injection Zone (higher pressure increase point).

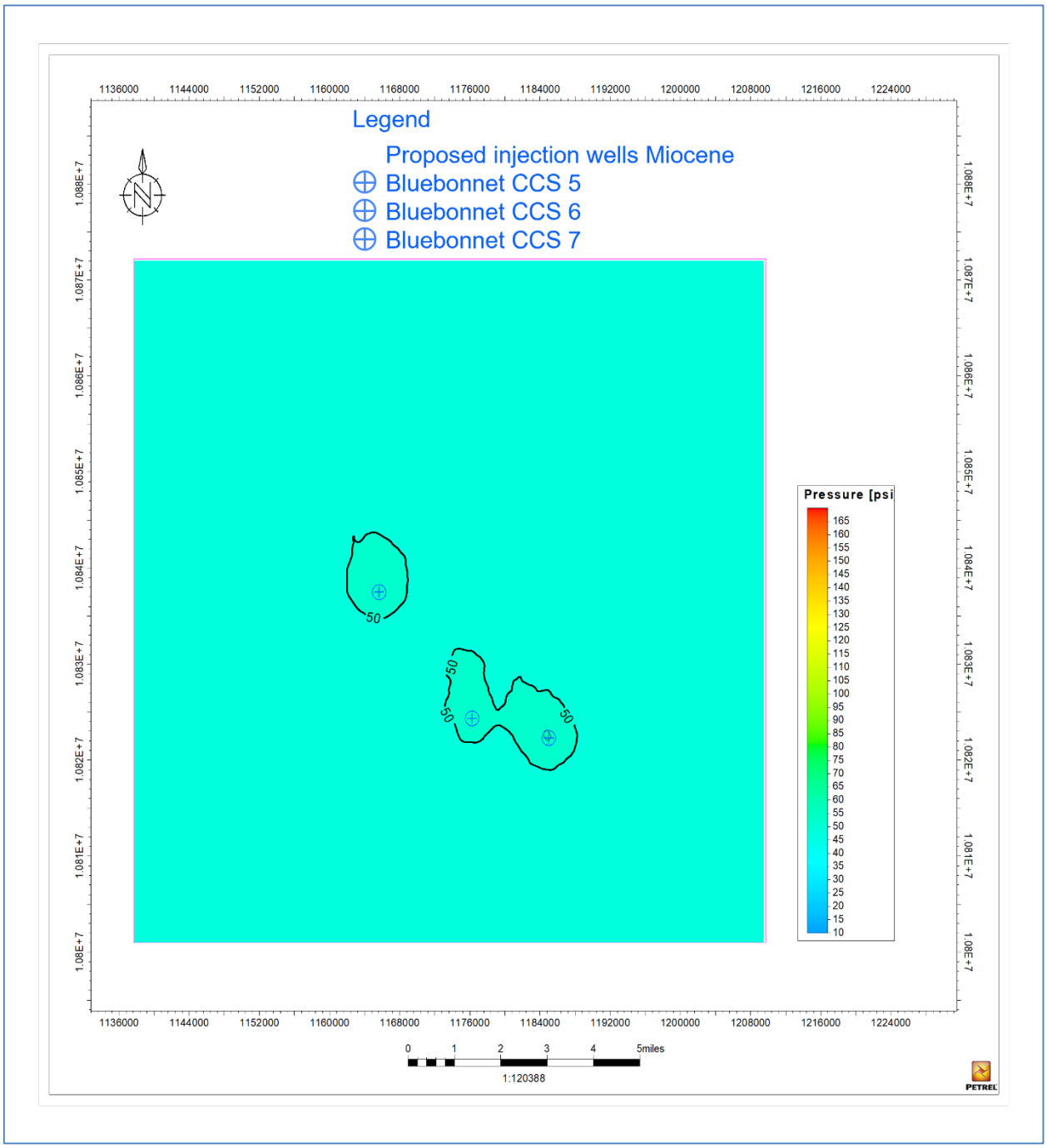


Figure PISC-6: Averaged aqueous pressure differentials from the baseline condition after 50 years post injection in the Lower Miocene Injection Zone

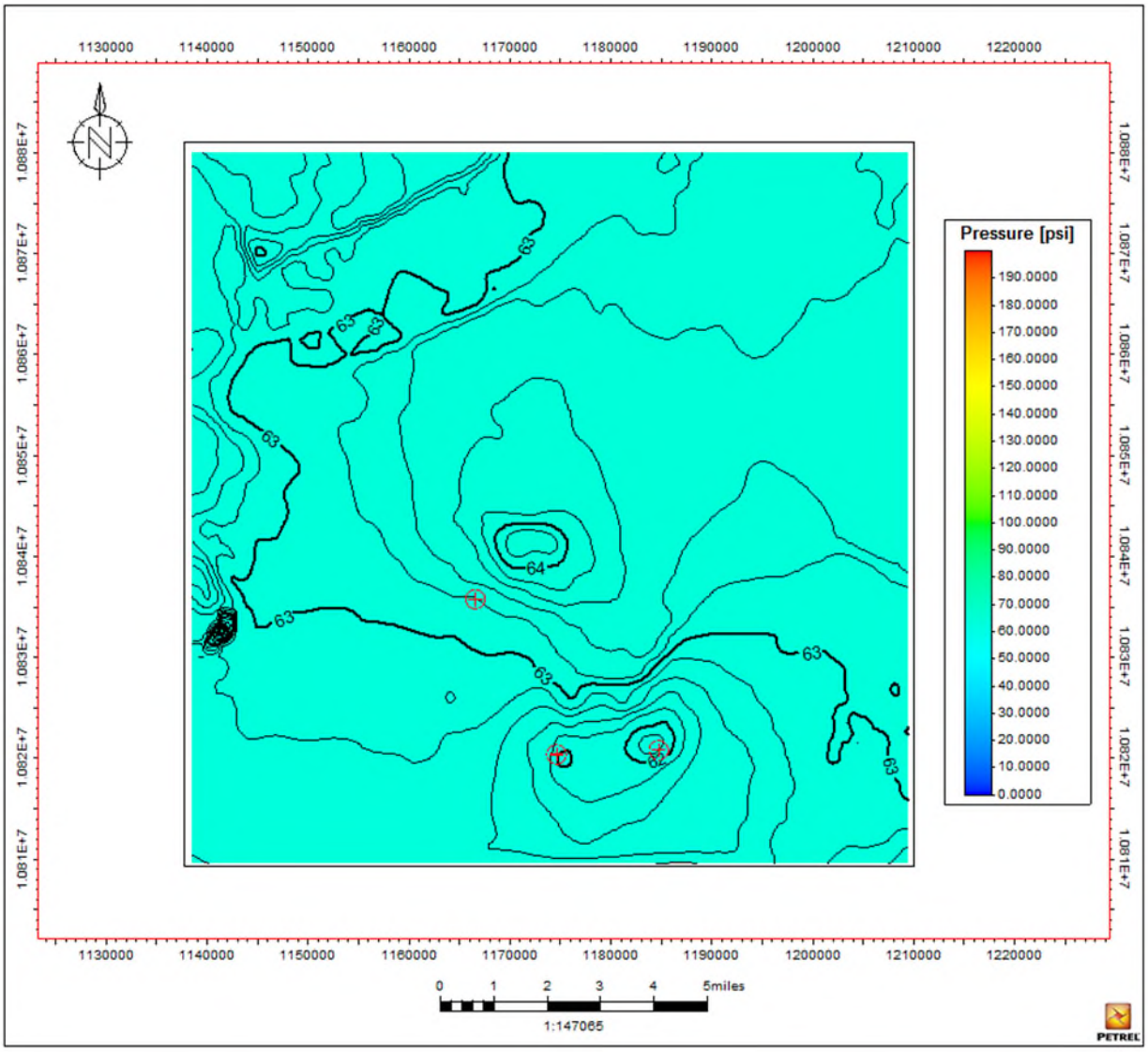


Figure PISC-7: Averaged aqueous pressure differentials from the baseline condition after 50 years post injection in the Frio Injection Zone.

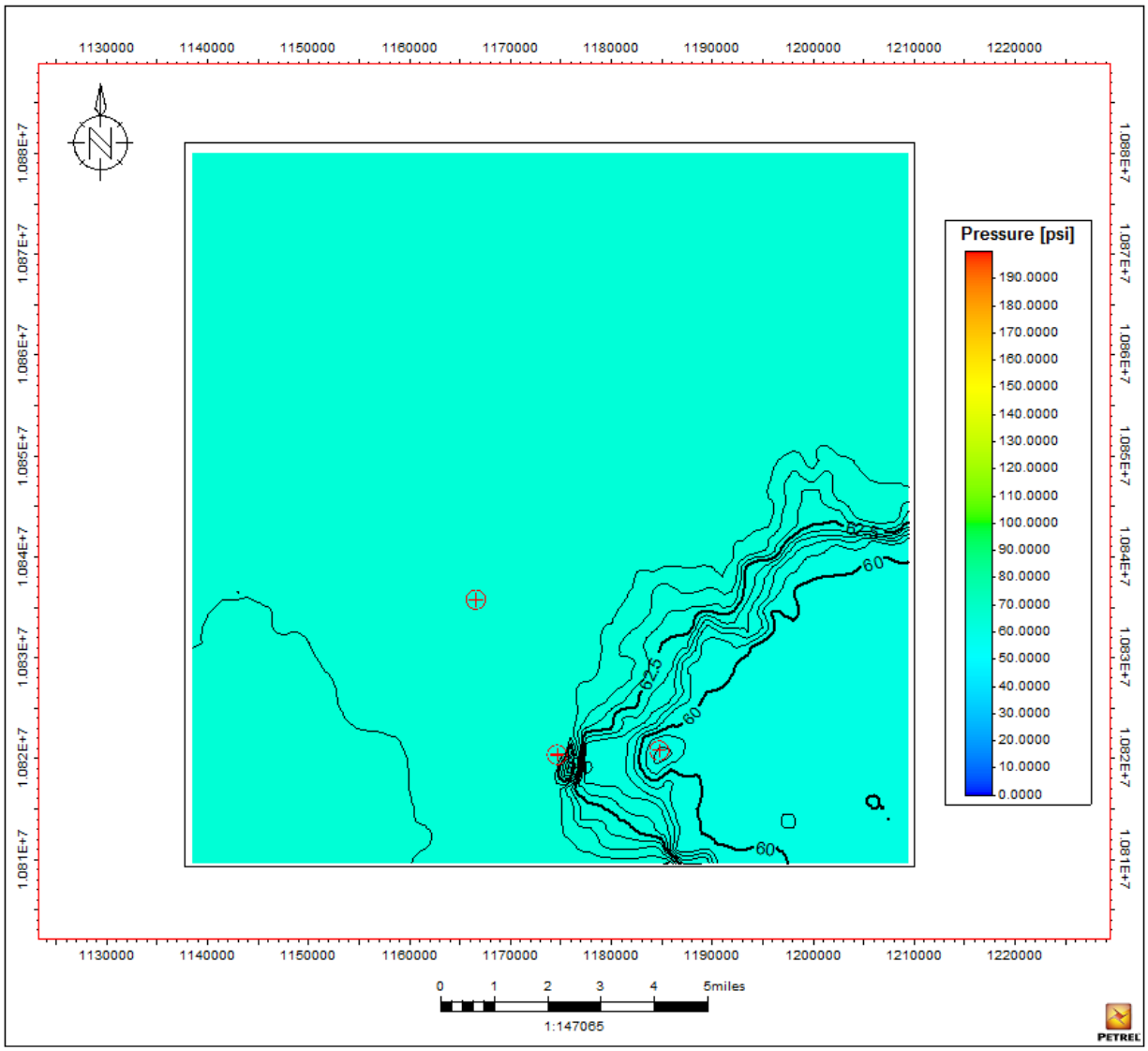


Figure PISC-8: Averaged aqueous pressure differentials from the baseline condition after 50 years post injection in the Hackberry Injection Zone.

3.0 Predicted Position of the CO_2 Plume and Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

3.1 Predicted Position of the CO_2 Plume and Pressure Front at Site Closure in Lower Miocene, Frio and Hackberry Injection Zones.

The reservoir simulation for Lower Miocene, Frio and Hackberry reservoirs indicates that, after injection ceases, the CO_2 plume remains within the Lower Miocene, Frio and Hackberry formations but continues to expand northward in the updip direction of the reservoir with time. The pressure front dissipated in the first years post injection as explain in the previous section. To be conservative, the sub AoR for Lower Miocene, Frio and Hackberry was defined by the combination of the pressure front at the end of injection and the plume shape and size after 100 years post-injection show in Figure PISC-9 (Lower Miocene Injection Zone), Figure PISC-10 (Frio Injection Zone), and Figure PISC-11 (Hackberry Injection Zone).

The colored area in Figure PISC-10 shows the CO_2 plume extent in year 70 (i.e., 50 years post-injection) and year 120 (100 years post injection) in the Frio Injection Zone. Figure PISC-11 shows CO_2 plume extent in year 70 (i.e., 50 years post-injection) and year 120 (100 years post injection) in the Hackberry Injection Zones.

Figure PISC-12 demonstrates the simulated plume in different years for the Lower Miocene Injection Zone. Figure PISC-13 demonstrates the simulated plume in different years for the Frio Injection Zone. Figure PISC-14 demonstrates the simulated plume at different years for the Hackberry Injection Zone.

The differences between the 50-year post-injection vertical extent and the 100-year post-injection vertical extent are almost negligible. The calculated plume size difference between year 70 and year 120 year is about 0.07 $mile^2$ in the Frio and 0.02 $mile^2$ in the Hackberry. This continued migration of the plume is due to buoyancy of the mobile supercritical phase CO_2, which moves along the strata in the updip direction.

Figure PISC-15, Figure PISC-16, Figure PISC-17, Figure PISC-18, Figure PISC-19, and Figure PISC-20 show a north-south cross section through wells Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7.

In addition, as previously shown in Figure PISC-6, Figure PISC-7, and Figure PISC-8, all pressures have been reduced to levels below the level of endangerment to USDWs in the first 5 years post injection for each well. Therefore, 50 years post injection is considered as the site closure date.

The maps are based on the final AoR delineation modeling results submitted, pursuant to 40 CFR §146.84.

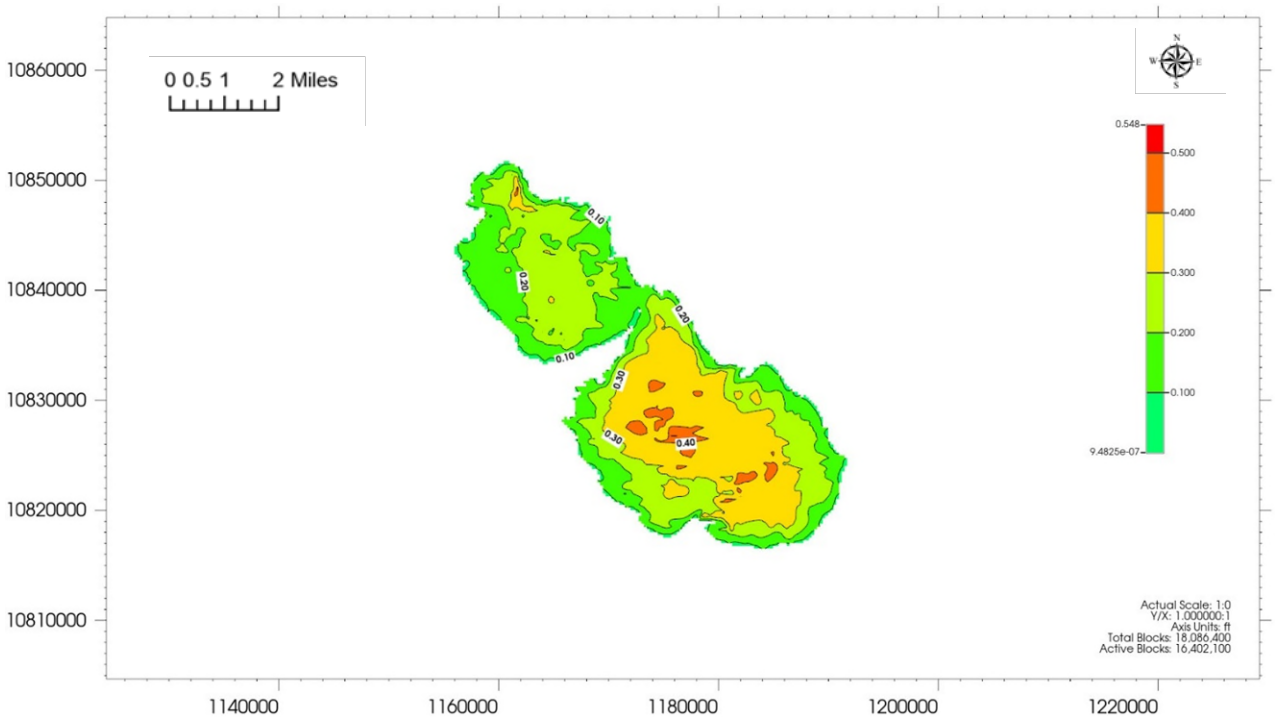


Figure PISC-9: Areal extent of the CO_2 plume after 100 years post injection in the Lower Miocene formation

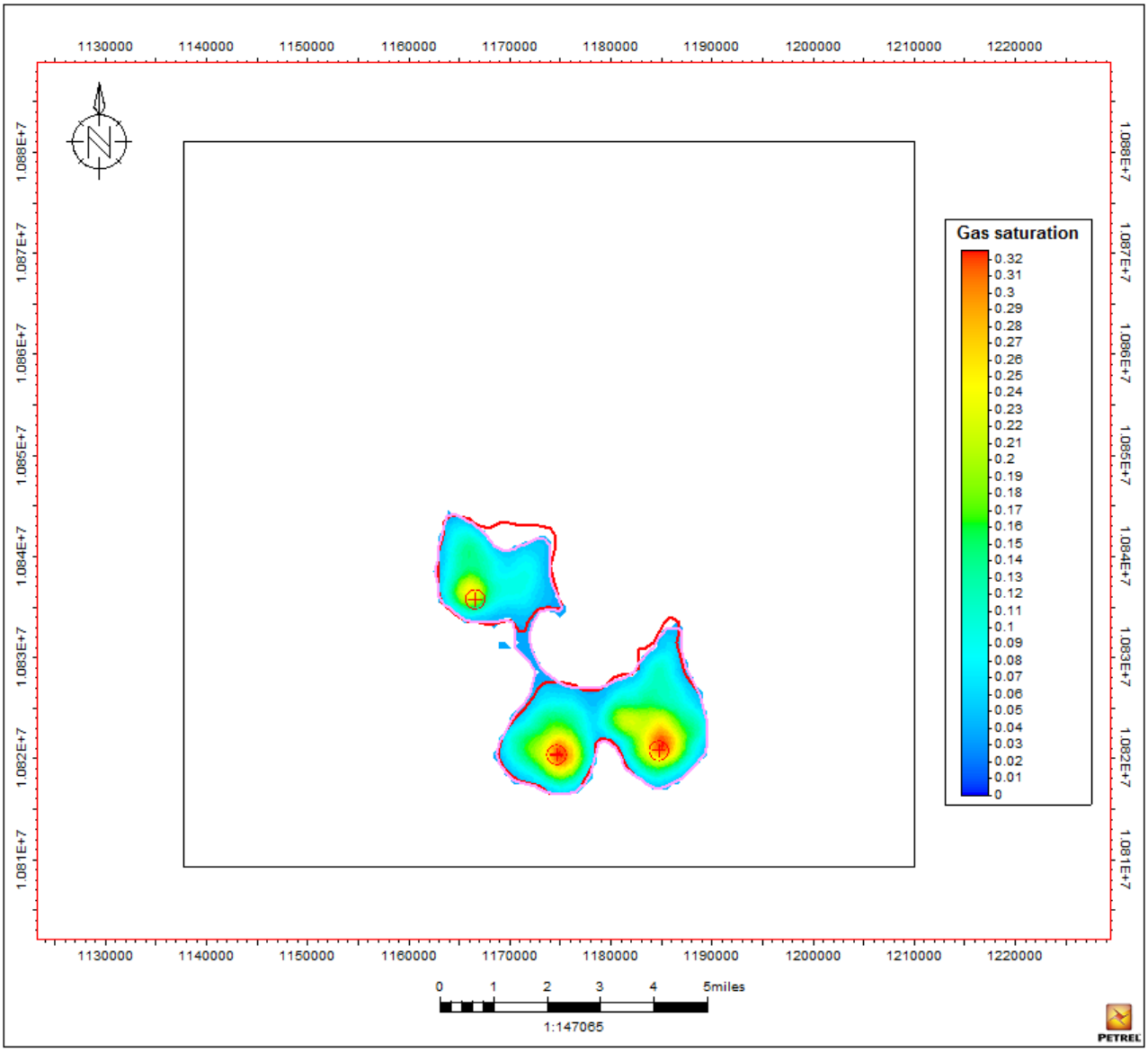


Figure PISC-10: Areal extent of the CO_2 plume at site closure 50 years post injection. The red outline represents the simulated CO_2 plume after 100 years post injection in the Frio formation.

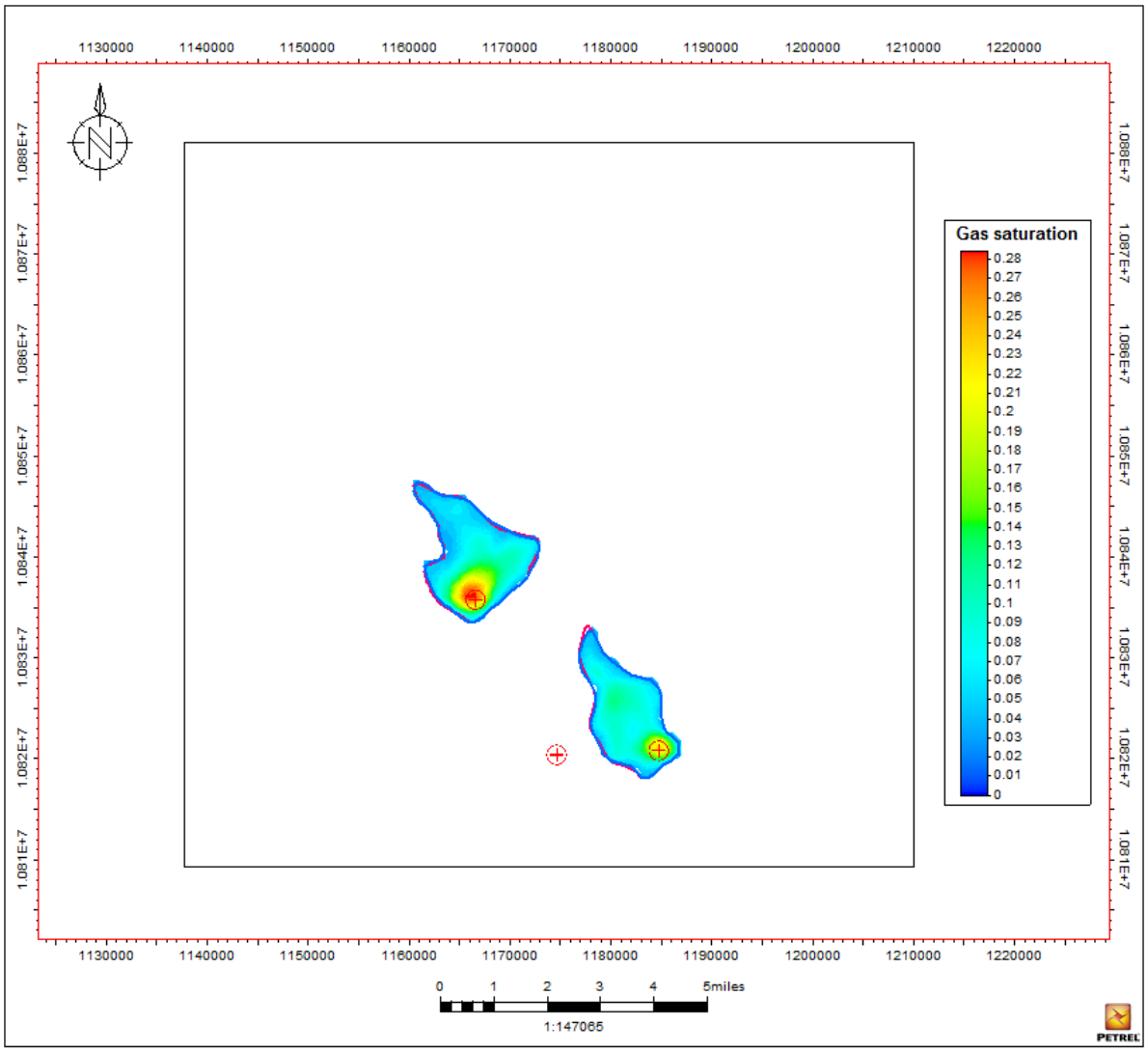


Figure PISC-11: Areal extent of the CO_2 plume at site closure 50 years post injection. The red outline represents the simulated CO_2 plume at 100 years post injection in the Hackberry formation.

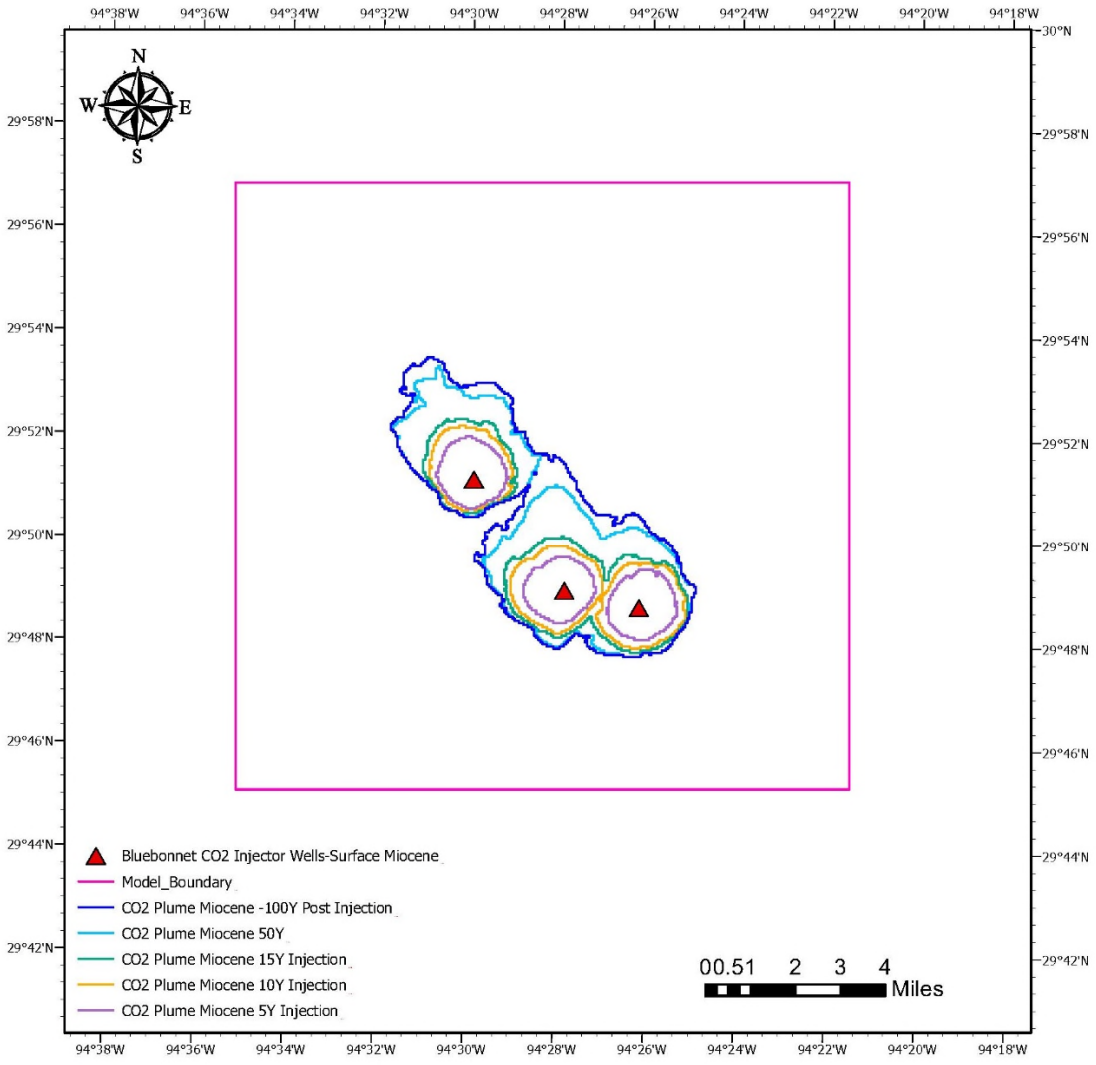


Figure PISC-12: Simulated areal extent of the CO_2 plume from injection startup to shut-in, then to 100 years post injection in the Lower Miocene formation.



Figure PISC-13: Simulated areal extent of the CO_2 plume from injection startup to shut-in, then to 100 years post injection in the Frio formation.

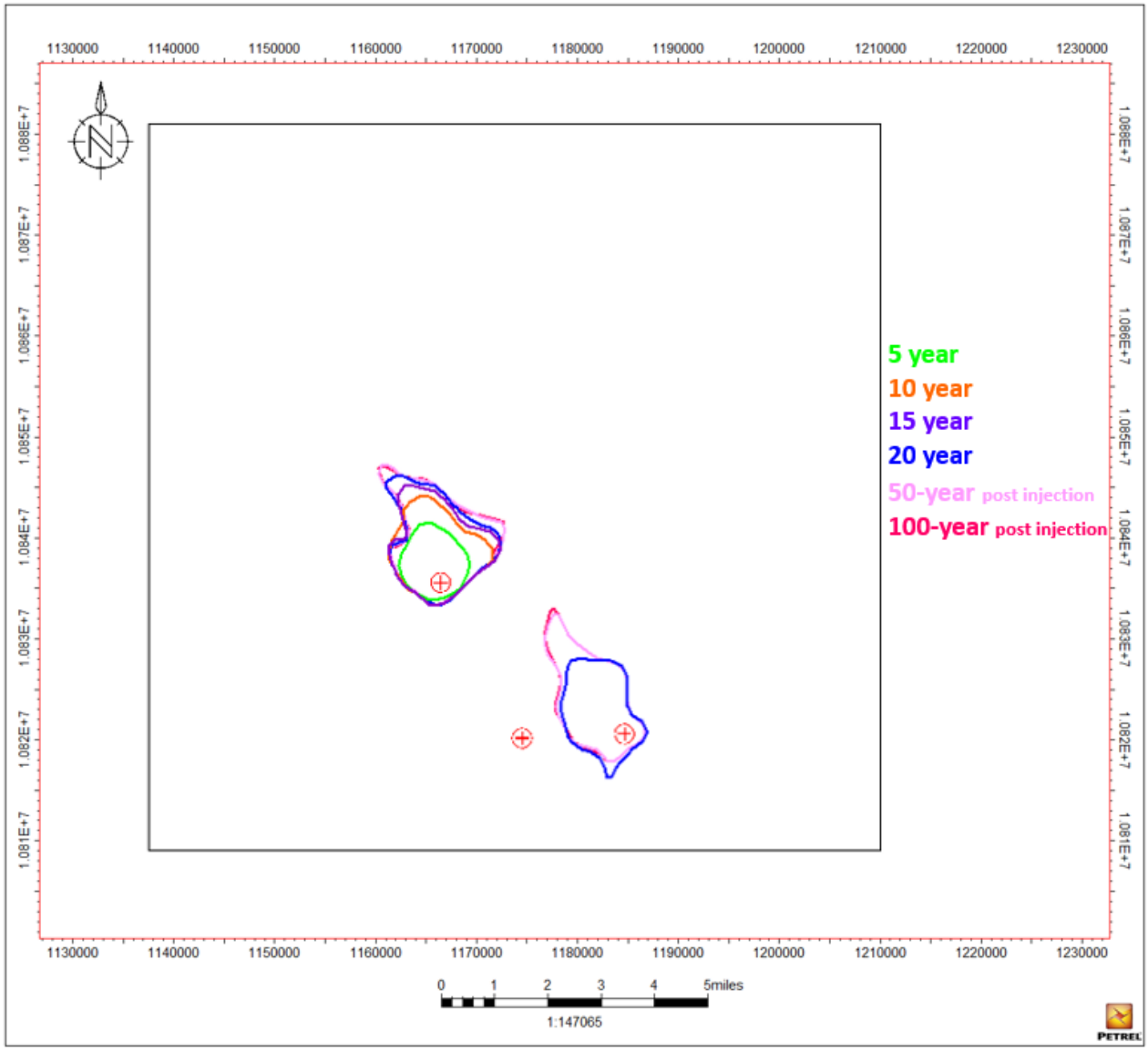


Figure PISC-14: Simulated areal extent of the CO_2 plume from injection start-up to shut-in, then to 100 years post injection in the Hackberry formation.

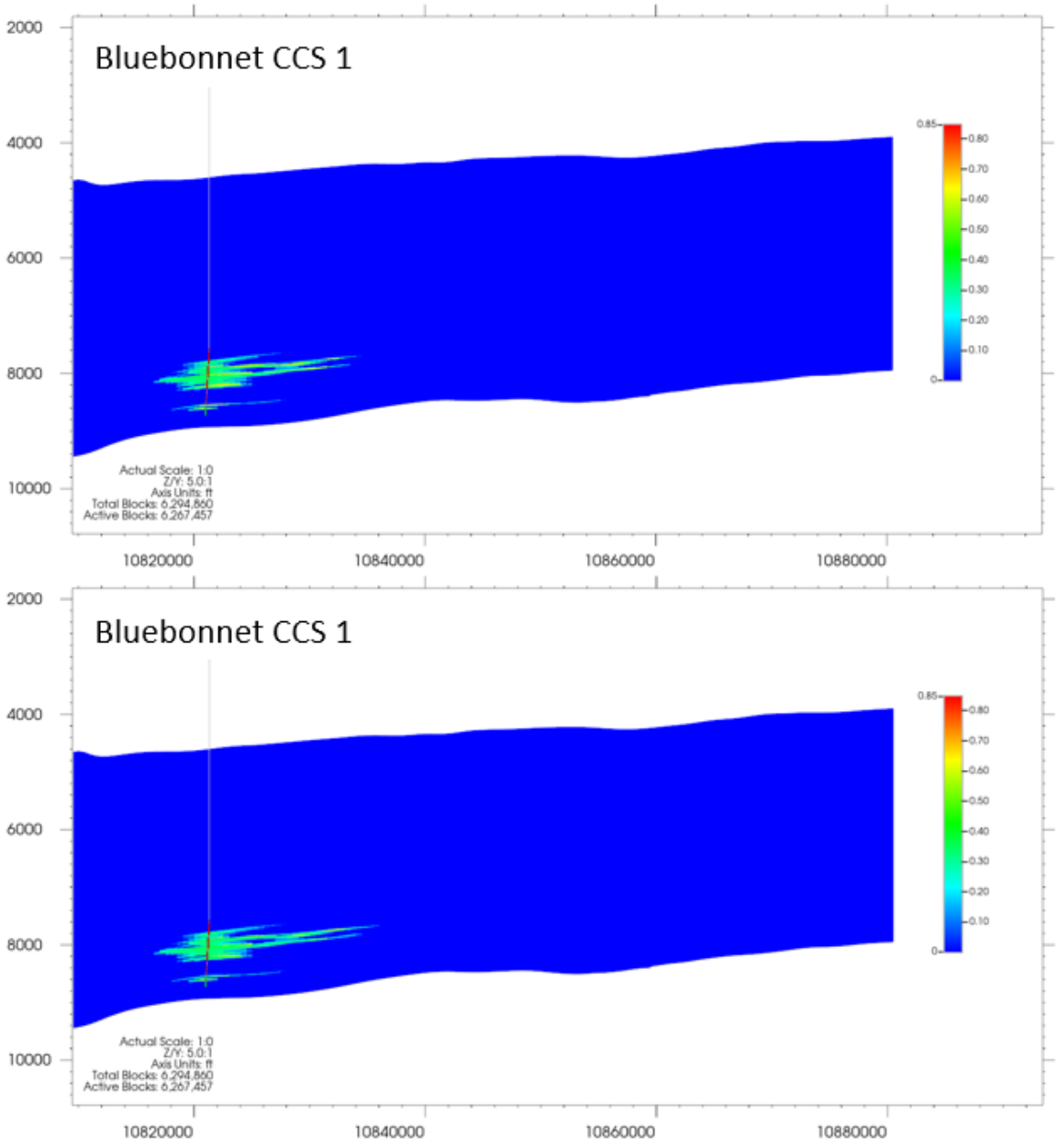


Figure PISC-15: North–south cross-section through well Bluebonnet CCS 1 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

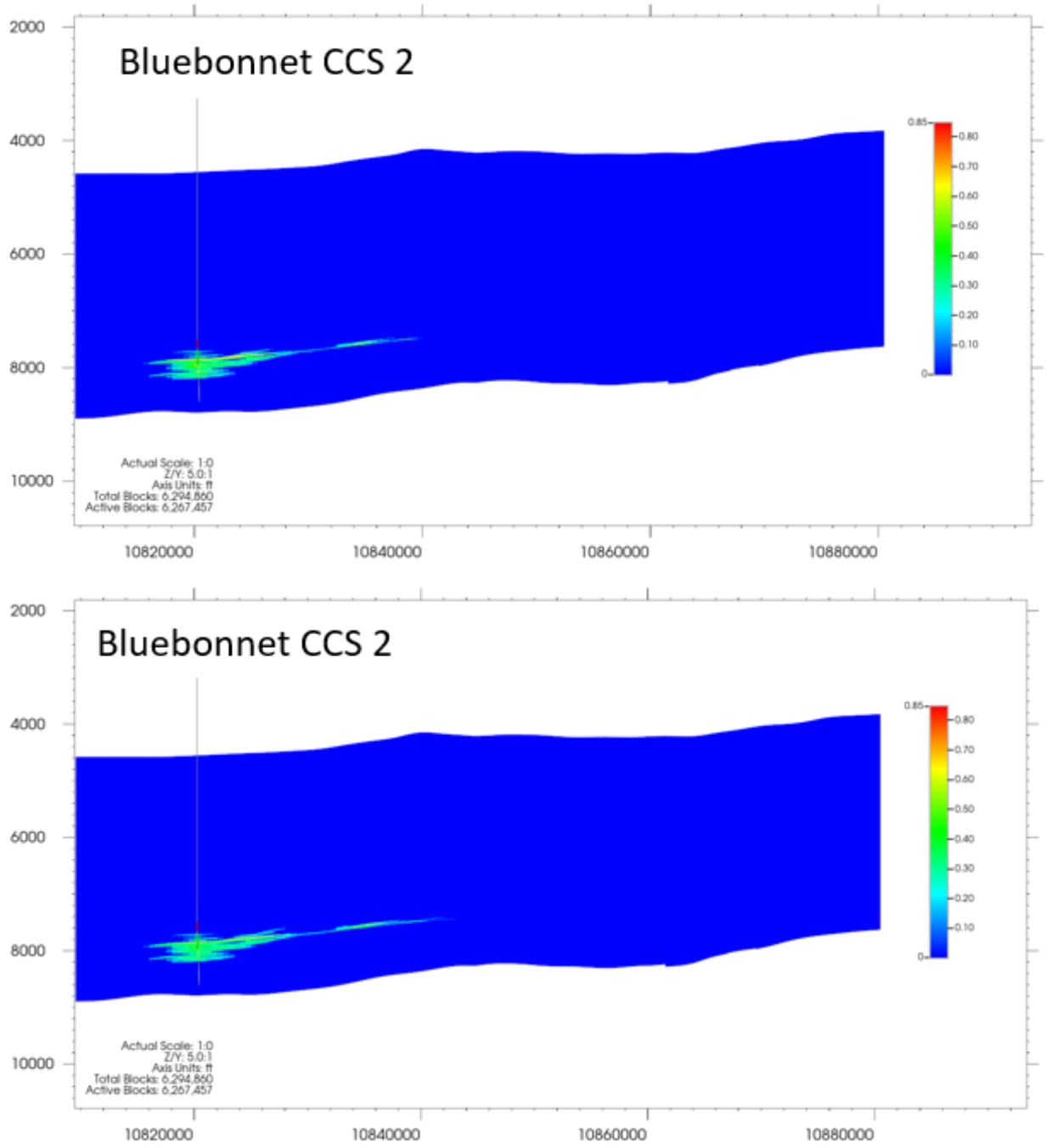


Figure PISC-16: North–south cross-section through well Bluebonnet CCS 2 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

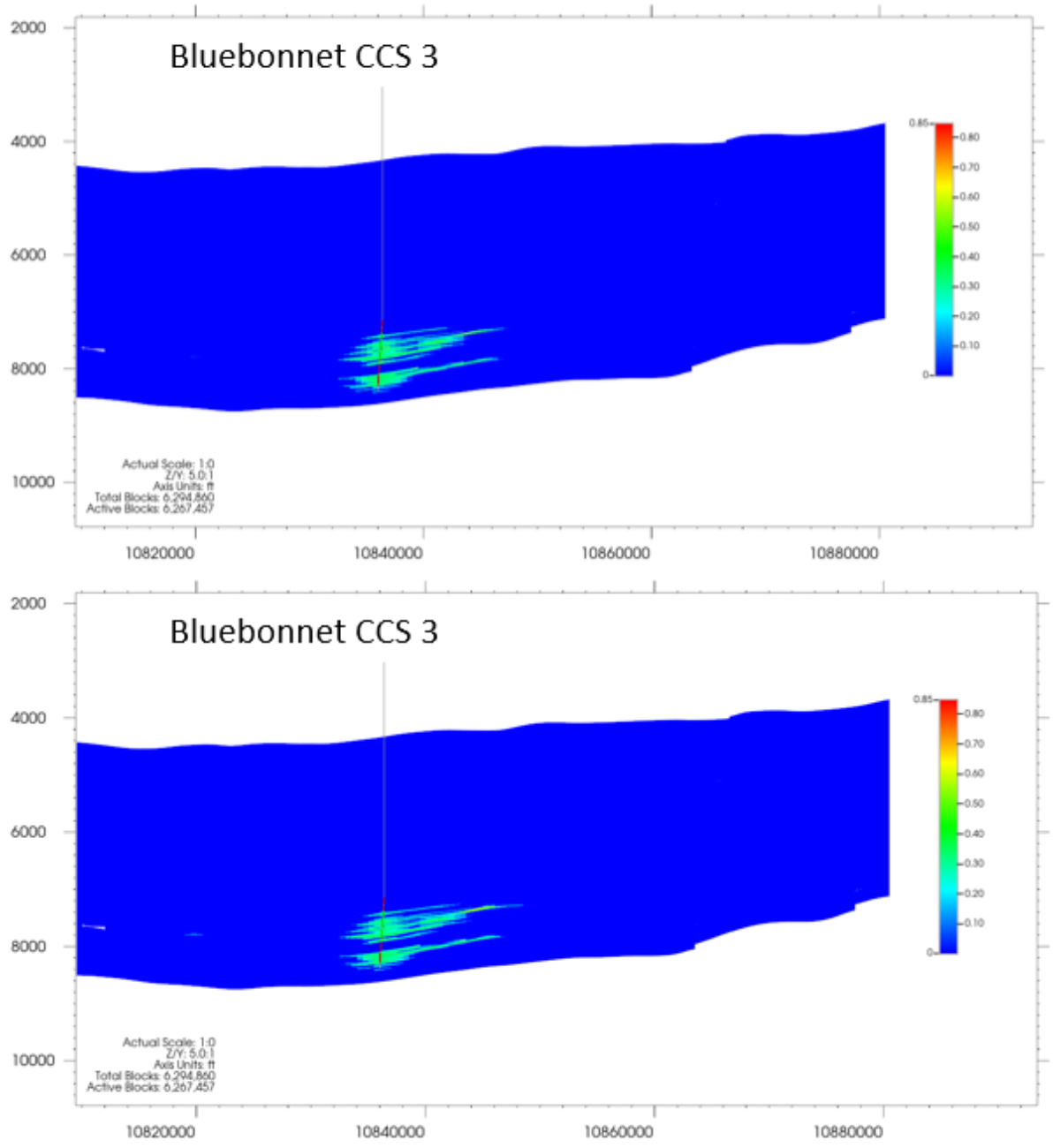


Figure PISC-17: North–south cross-section through well Bluebonnet CCS 3 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

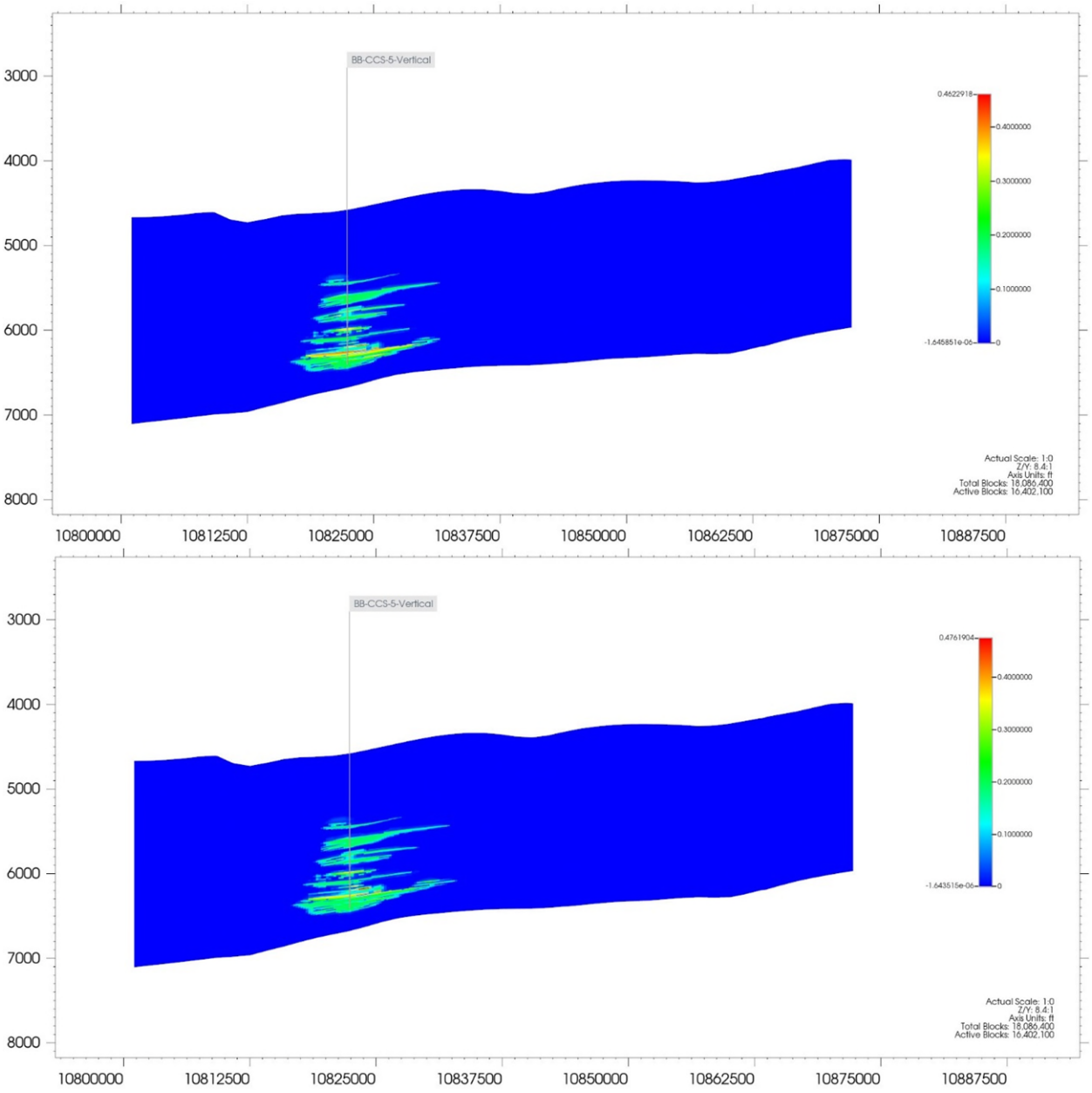


Figure PISC-18: North–south cross-section through well Bluebonnet CCS 5 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

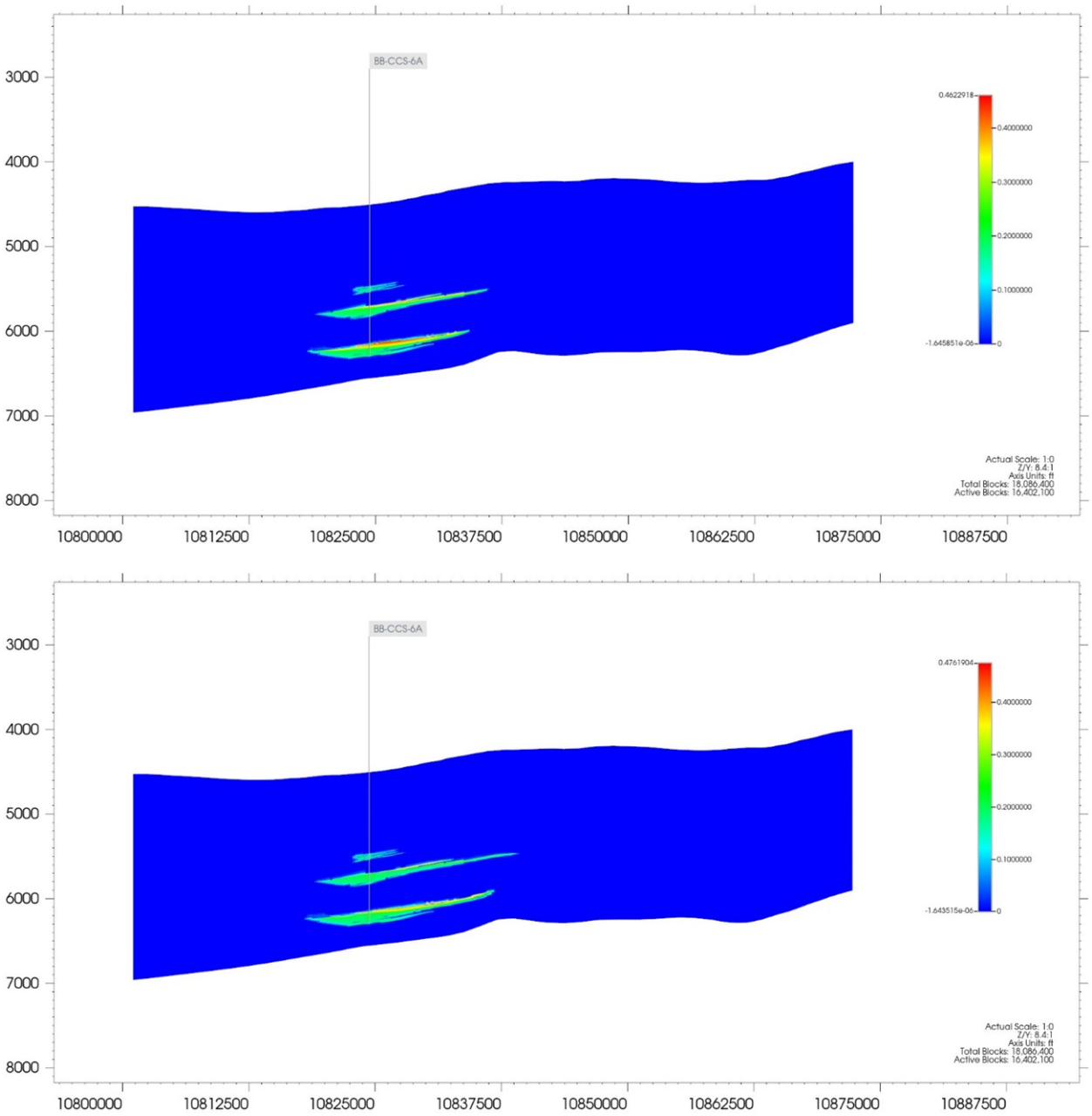


Figure PISC-19: North–south cross-section through well Bluebonnet CCS 6 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

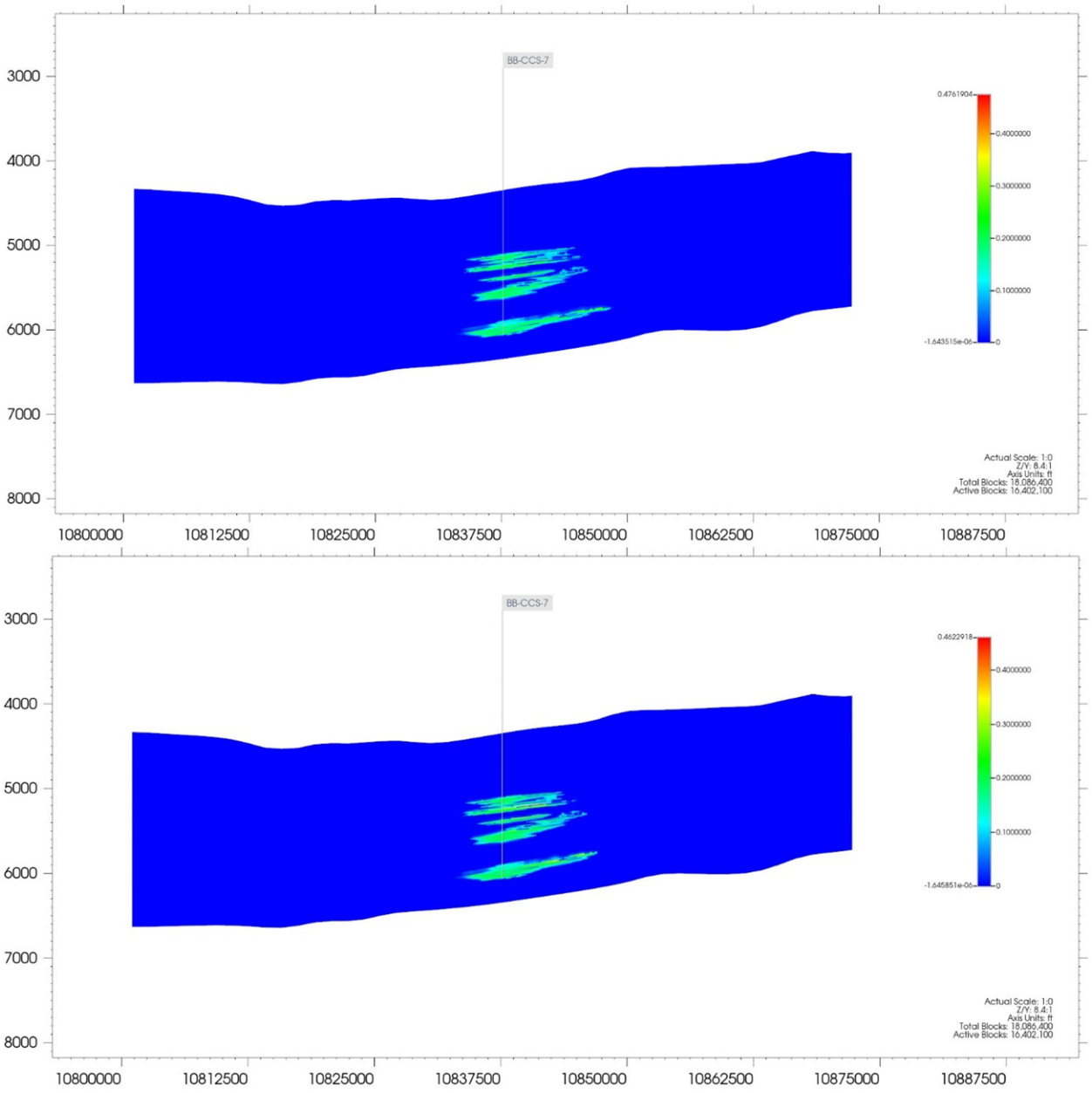


Figure PISC-20: North–south cross-section through well Bluebonnet CCS 7 showing simulated gas saturation at 50 years post injection and at 100 years post injection.

4.0 Post-Injection Monitoring Plan [40 CFR 146.93(a)(2)(iii)]

Performing groundwater quality monitoring and plume and pressure front tracking as described in the following sections during the post-injection phase will meet the requirements of 40 CFR §146.93(a)(2)(iii). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days of the anniversary of the date that injection ceases, as described under Section 4.3 Schedule for Submitting Post-Injection Monitoring Results.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided as a separate document of this permit.

After the injection ceases, the project will plug and abandon all the CO_2 injector wells according to the plugging procedure proposed in the Injection Well Plugging Plan of this permit.

The project will abandon the water production wells, Bluebonnet PRDW F1 and Bluebonnet PRDW F2 during the operative life of the project at year 15 of injection, or when the last recompletion in Frio formation is performed in the Bluebonnet CCS 3 well.

After injection ceases, the Project will keep operative Bluebonnet IZM FM1, Bluebonnet IZM FM2 Encanto 01, Bluebonnet IZM M1, Bluebonnet IZM M2, Bluebonnet IZM M3, Bluebonnet USDW 1, Bluebonnet USDW 2, Bluebonnet USDW 8 and Bluebonnet DSW during the post-injection period.

After injection cease the Project will repeat a 2D surface seismic survey to map the extension of the CO_2 plume. This survey will be repeated at year 5 and 10 post injection and before the site closure as a proof of non-endangerment to USDW.

During the post-injection period, the model predicts that, 10 years after the injection ceases, the pressure variation every 5 years will be less than 5%, as shown in Table PISC-4, while the CO_2 plume will continue to slightly migrate but in stable rate.

Table PISC-4: Modeled bottomhole pressure variation with time at the in-zone monitoring locations.

Reference, ft, TVDSS	7,417	7,185	7,770	6,059
Year From Injection	Differential Bottomhole Pressure Changes (psi)			
	Encanto 01 (Frio)	Bluebonnet IZM FM 1	Bluebonnet IZM FM2	Encanto 001 (Lower Miocene)
20 (End of Injection Frio/Hackberry)				
25	-22%	-24%	-15%	-44%
30	-8%	-8%	-9%	-1%
35	-6%	-6%	-5%	-1%
40	-4%	-4%	-5%	-1%
45	-4%	-4%	-3%	-1%
50	-3%	-3%	-3%	-1%
55	-3%	-1%	-3%	-1%
60	-1%	-3%	-2%	-1%
65	-2%	-2%	-2%	0
70	-2%	-2%	-2%	0

For the first 10 years of the post-injection period, the monitoring program will focus on demonstrating stabilization of the pressure and CO_2 plume migration and demonstration of non-endangerment to USDW.

After 10 years of the post-injection period, the Project will plug Bluebonnet IZM FM1, Bluebonnet IZM FM2, Bluebonnet IZM M1, Encanto 01 and Bluebonnet DSW M2 and will continue monitoring USWD groundwater and the Miocene Composite Confining Zone with Bluebonnet USDW 1, Bluebonnet USDW 2, Bluebonnet USDW 8, Bluebonnet IZM M2 and Bluebonnet IZM M3, in combination visual inspections, and soil gas monitoring, until the closure of the site.

Table PISC-5 describes the methods and techniques to be used while monitoring the site during the post-injection period. Locations and frequency for each method or technique are also presented in Table PISC-5.

Table PISC-5: Monitoring Plan for post-injection site care.

Description	Method	Location	Post-Injection period
Operations	Surface pressure and temperature measurements in tubing - gauges	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01 Bluebonnet DSW M2	Monthly until the wells are plugged.
	Visual inspections and handheld monitors (LEL, H_2S, CO_2)	General facilities	Quarterly until facilities are closed.
Mechanical Integrity	Pulse neutron, Temperature log, or Electromagnetic log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01	As required for plume monitoring, no minimum than every 5 years.
	Annular pressure test	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01 Bluebonnet DSW M2	Every 5 years until the wells are plugged.
Groundwater quality and geochemical monitoring	Water sampling and testing of USWD well.	Bluebonnet USWD 1 Bluebonnet USWD 2 Bluebonnet USWD 8 Bluebonnet IZM M1 Bluebonnet IZM M2 Bluebonnet IZM M3	Annually first 10 years of post-injection period, biannually from year 10 to site closure. Bluebonnet IZM M1 will be closed at year 10 of PISC.
CO_2 plume and pressure front tracking	Pulse Neutron Log	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01	Biannually first 10 years of post-injection period
	In-reservoir pressure and temperature measurement - downhole gauges	Bluebonnet IZM FM1 Bluebonnet IZM FM2 Bluebonnet IZM M1 Encanto 01	Monthly until the wells are plugged.

Description	Method	Location	Post-Injection period
	2D time lapsed surface seismic	AoR	At 5 years post injection, at 10 years post injection, and at site closure.
Near-Surface Monitoring	Process-based soil gas approach	AoR	Annually until site closure.

Specifics of the methods, techniques, and analytics to be tested as part of the proposed monitoring plan are described in detailed in the Testing and Monitoring Plan and in the QASP document.

5.0 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

During the PISC period, the monitoring reports will be prepared annually and submitted to the EPA Region 6 UIC Branch Office. These reports will summarize methods and results of groundwater quality monitoring, CO_2 storage zone pressure tracking, and indirect geophysical monitoring for CO_2 plume tracking.

The PISC and Site Closure Plan will be reviewed every 5 years during the PISC period. Results of the plan review will be included in the PISC monitoring reports. The operational and monitoring results will be reviewed for adequacy in relation to the objectives of the PISC. The monitoring locations, methods, and schedule will be analyzed in relation to the size of the CO_2 storage zone, pressure front, and protection of USDWs. In case of changes to the PISC plan, a modified plan will be submitted to the EPA Region 6 UIC Branch Office at least 30 days before the planned initiation of the changes.

6.0 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, the Bluebonnet Sequestration Hub, LLC, will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(1), (2) and (3).

The Bluebonnet Sequestration Hub LLC, will issue a report to the UIC Program Director that will demonstrate that the project poses no danger to the USDWs, based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections.

6.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

6.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan document and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91(e)] and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

6.3 Summary of Computational Modeling History

The computational modeling results used for the AoR delineation will be compared to monitoring data collected during the operational and PISC periods. Monitoring data will also be compared with data collected during site characterization, as per 40 CFR 146.82(a)(6) and 146.87(d)(3). The data will be used to update the computational model and monitor the site, and will include both direct (e.g., measurements of pressure, temperature, groundwater quality) and indirect (e.g., 2D seismic, pulse neutron logging) geophysical methods.

Data generated during the PISC period will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. The Bluebonnet Sequestration Hub, LLC, will demonstrate this degree of accuracy by comparing the monitoring data obtained during the operational and PISC period with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to represent the storage site accurately. The validation of the computational model with the large quantity of measured data will be a significant element to support the non-endangerment demonstration.

6.4 Evaluation of Reservoir Pressure

The Bluebonnet Sequestration Hub, LLC, will demonstrate non-endangerment to USDWs by showing that, during the PISC period, the pressure within the Lower Miocene, Frio, and Hackberry reservoir will have rapidly decreased to levels near its pre-injection static reservoir pressure. Because increased pressure is the primary driving force for fluid movement, which might endanger a USDW, the decay in the pressure differential provides strong justification that the injectant will no longer pose a risk to any USDWs.

The Bluebonnet Sequestration Hub, LLC, will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared with the pressure predicted by the computational model, which was previously shown in Figure PISC-1, Figure PISC-2, Figure PISC-3, and Figure PISC-4. Agreement between the actual and predicted values will validate the accuracy of the model and further demonstrate non-endangerment.

6.5 Evaluation of CO_2 Plume

The Bluebonnet Sequestration Hub, LLC, will use a combination of monitoring data, logs, geophysical surveys, and seismic methods to locate and track the movement of the CO_2 plume. The data produced by these activities will be compared with the modeled predictions (previously shown in Figure PISC-6 and Figure PISC-7) using statistical methods to validate the model's ability to represent the storage site accurately. The PISC monitoring data will show the stabilization of the separate-phase CO_2 plume as the reservoir pressure returns to its near pre-injection state.

6.6 Evaluation of Emergencies or Other Events

In addition to the CO_2 plume, mobilized fluids may also pose an ongoing risk to USDWs, as the reservoir fluids include brines high in total dissolved solids (TDS) and other drinking water contaminants. The geochemical data collected from USDW/above-confining-zone monitoring wells will be used to demonstrate that no mobilized fluids have moved above the confining formation, and therefore would not pose a risk to USDWs after the PISC period.

To demonstrate non-endangerment, the Bluebonnet Sequestration Hub, LLC, will compare the operational and PISC period samples of the lowermost USDW/above confining zone with the pre-injection characterization of the aquifers. This evaluation will demonstrate that no mobilized formation fluids have moved through the confining formation. In addition, this validation of confining zone integrity will demonstrate that the injectant and/or mobilized fluids will not represent an endangerment to any USDWs.

Other than the project and monitoring wells, other potential conduits for fluid movement or leakage pathways within the AoR will be adequately plugged and abandoned. Based on this information, the potential for fluid movement through artificial penetrations of the confining formation does not present a risk of endangerment to any USDWs.

7.0 Site Closure Plan

Pursuant 40 CFR §146.93(d), the Bluebonnet Sequestration Hub, LLC, will notify the UIC Program Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original Post-Injection Site Care and Site Closure Plan, Bluebonnet Hub will provide the revised plan to the Program Director for approval.

The Bluebonnet Sequestration Hub, LLC, will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Once the UIC Program Director has approved closure of the site, the Bluebonnet Sequestration Hub, LLC, will plug the remaining

monitoring wells in a manner that will not allow movement of injection or formation fluids that would endanger a USDW.

Bluebonnet Sequestration Hub, LLC, will submit a site closure report to UIC Program Director within 90 days of site closure [40 CFR 146.93(f)].

In addition to the EPA, the Texas Railroad Commission, Chambers County, the City of Winnie, and any other agencies governing the project at the time of site closure will be notified prior to the scheduled site closure. Currently, there are no federally recognized Native American Tribes located within the AoR; however, if a federally recognized Native American Tribe becomes known within the AoR at the time of site closure, that tribe (or tribes) will be notified of the site closure.

7.1 Plugging Monitoring Wells

Upon conclusion of the 50-year post-injection site care period, any remaining monitoring well will be plugged and capped below grade in accordance with the approved plugging and abandonment plans, which is included as Appendix A in the Injection Well Plugging Plan.

After completion of the plugging activities, a plugging report will be submitted to the UIC Program Director describing the methods used and tests performed on the well during plugging. This report will be submitted to the UIC Program Director within 60 days of completing the plugging activities.

7.2 Planned Remedial and Site Restoration Activities

At the end of the PISC phase, Bluebonnet Sequestration Hub, LLC, will ensure the site is reclaimed and returned to predevelopment condition.

Surface equipment decommissioning will occur in two phases: the first phase will occur after the active injection phase and the second phase will occur at the end of the PISC phase.

At the end of the active injection period, plume monitoring will continue, but there will be no further need for the pumping and control equipment. The process control building at the surface pumping facility will remain. This building will serve as a hub for control and monitoring of the well network, so it will remain operational. The pumping system and aboveground pipe, valves, and fittings at the surface pumping facility will be removed.

The injection wells will be plugged per the Injection Well Plugging Plan document of this permit. The process control building at the pumping facility site will act as the collection node for data from the plume-monitoring equipment. This building will contain the equipment required to receive real-time data from the monitoring wells and other monitoring stations and send the data via an internet connection to be analyzed offsite during post-injection monitoring period.

Surface facilities will be removed at the end of the PISC phase. The site will be reclaimed and returned to predevelopment condition except any facilities still in operation to serve other active projects (e.g., electrical supply serving other power users and roadways used or needed by surface landowners). Buried pipelines are expected to be idled and abandoned in place.

The soil will be backfilled around the monitoring and geophysical wells to bring the area around the wells back to the preinstallation grade. Any remaining surface facilities associated with the monitoring wells will be reclaimed and the area will be returned to the predevelopment condition. Gravel well pads will be removed, and the land will be reclaimed for preconstruction uses.

7.3 Site Closure Report [40 CFR 146.93(f)]

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of all injection and monitoring wells.
- Location of each well on a plat survey submitted to the local zoning authority.
- Notifications to State, local and Tribal authorities.
- Records regarding the nature, composition, and volume of CO_2 injected.
- Pre-injection, injection, and post-injection monitoring records.
- Certifications that all injection and storage activities have been completed.

Bluebonnet Sequestration Hub, LLC, will record a notation to the property's deed on which the CO_2 injection wells were located that will indicate the following:

- That the property was used for CO_2 sequestration.
- The name of the State agency, local authority and/or Tribe to which a plat of survey with injection well location was submitted.
- The volume of fluid injected.
- The formation into which the fluid was injected.
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by Bluebonnet Sequestration Hub, LLC, for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years, after which these records will be delivered to the UIC Program Director.

EMERGENCY AND REMEDIAL RESPONSE PLAN (ERRP)
40 CFR §146.94(a)

Bluebonnet Sequestration Hub

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.82(a)(19) and 40 CFR §146.94, this Emergency and Remedial Response Plan (ERRP) describes the actions that Bluebonnet Sequestration Hub, LLC, shall take to address movement of the injection or formation fluid in a manner that may endanger an Underground Source of Drinking Water (USDW) during the construction, operation, or post-injection site care periods of the Bluebonnet Sequestration Hub (the Project).

If the Bluebonnet Sequestration Hub, LLC, obtains evidence that the injected CO_2 stream and/or associated pressure front may endanger the USDW, the project must perform the following actions as required in 40 CFR §146.94(b):

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency Underground Injection Control (UIC) Program Director of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase “initiate shutdown plan” is used, the Bluebonnet Sequestration Hub, LLC, will immediately cease injection as quickly, technically, and safely possible. However, in some circumstances, Bluebonnet Sequestration Hub, LLC, in consultation with the UIC Program Director, will determine whether gradual cessation of injection is appropriate.

If the project demonstrates that the injection operation will not endanger USDWs, the UIC Director may allow the Bluebonnet Hub to resume injection prior to remediation 40 CFR §146.94(c).

2.0 Local Resources and Infrastructure

Resources in the vicinity of the Bluebonnet Sequestration Hub that may be affected due to an emergency event at the project site include groundwater (USDWs), surface riverine, freshwater ponds, lakes, estuarine, freshwater emergent wetlands, and palustrine farmed wetlands.

USDWs in the Gulf Coast includes the Chicot, Evangeline, and Jasper aquifers. In the Bluebonnet Hub site, the USDW has been identified within the Chicot aquifer, which is the main source of drinking water in the area. Site-specific base USDW (< 10,000 mg/l TDS) in the Bluebonnet Sequestration Hub proposed Area of Review (AoR) averages –1,356 TVDSS (true vertical depth subsea).

The physical geography of the AoR has the open water of the Rush Ditch, Spindletop Bayou, other unnamed ditches/riverine, and seasonally flooded rice or crawfish farming operations.

Figure ERR-1 shows the surface water features within the project AoR. The surface water features include palustrine, farmed wetlands, and riverine with limited freshwater ponds. The “Area of Review and Corrective Action Plan” document included in this permit application provides further details on the USDWs within the project area.

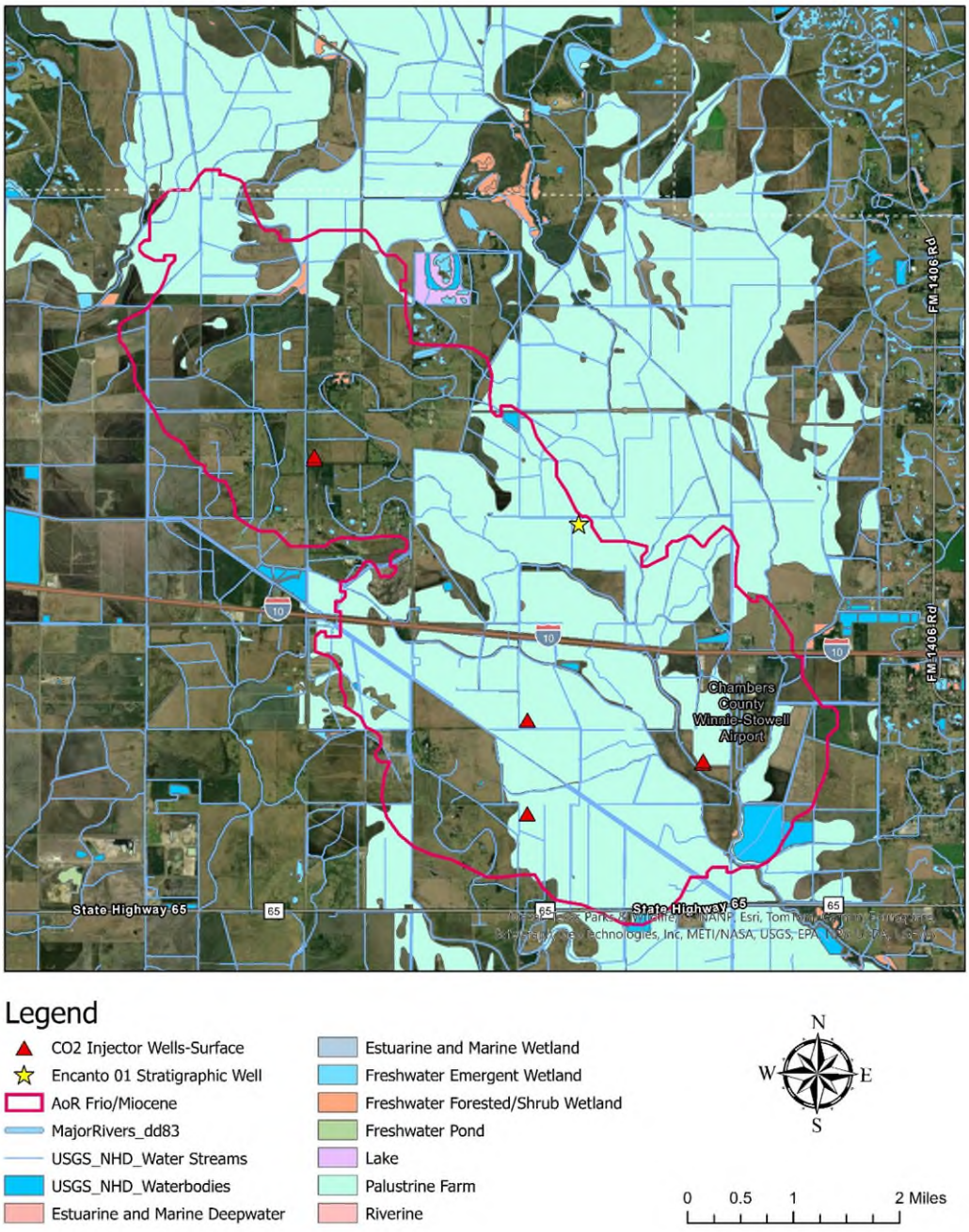


Figure ERR-1: Map of surface water features relatives to the proposed AoR.

Infrastructure in the vicinity of the Bluebonnet Hub that may be affected due to an emergency at the project site includes domestic residences, water wells, local farming operations, Winnie Stowell Airport (a small-craft airport in Chambers County), and a major roadway, Interstate-10.

The towns of Winnie and Stowell, Texas are approximately two miles from the injection site. As of the 2020 census, the population of Winnie was 3,162 while the population of Stowell was 1,743.


Claimed as PBI

3.0 Potential Risk Scenarios

The events related to the Bluebonnet Sequestration Hub operations that could potentially result in an emergency response have been identified in a risk assessment workshop and are included in Table ERR-1. This table lists the types of potential adverse incidents that could trigger response actions to protect USDWs and when they might occur (i.e., during the construction, injection, or post-injection site care periods). In addition, the risk assessment workshop identified the emergency or remedial actions that the Bluebonnet Sequestration Hub, LLC, will undertake in response to these incidents. The worst-case consequences of various scenarios have been developed to ensure that response plans are in place for all eventualities.

Table ERR-1: Potential adverse incidents.

Construction/Pre-Injection Period
• Well control event during drilling, completion, or workovers with loss of containment. • Contamination of the USDW with formation brine or drilling fluids during drilling operations. • Unauthorized access or activities to the site.
Injection Period
• Loss of mechanical well integrity in injection wells due to tubing or packer leak. • Loss of mechanical well integrity in monitoring, water production, and water disposal wells due to tubing or packer leak. • Loss of mechanical well integrity in injection wells due to casing leak. • Loss of mechanical well integrity in monitoring, water production, and water disposal wells due to casing leak. • Well monitoring equipment failure or malfunction. • Loss of mechanical integrity in the pipeline. • Vertical migration of CO_2 and brines due to loss of external mechanical integrity in CO_2 injection wells. • Vertical migration of CO_2 and brines due to loss of external mechanical integrity in monitoring, water production, and water disposal wells. • Migration of CO_2 from the injection zone through documented legacy wells or undocumented artificial penetrations within the defined AoR. • Migration of CO_2 from the injection zone through faults and fractures or failure of the confining zone. • Rapid and/or unexpected movement of CO_2 outside the defined AoR. • External impact to the surface infrastructure (pipeline and wells). • Induced seismic event. • A natural disaster. • Unauthorized access or activities to the site.
Post-Injection Site Care Period
• Loss of mechanical well integrity in monitoring wells due to tubing or packer leak. • Loss of mechanical well integrity in monitoring wells due to casing leak.

- Monitoring equipment failure or malfunction.
- Vertical migration of CO_2 and brines due to loss of external mechanical integrity in monitoring wells.
- Migration of CO_2 from the injection zone through documented legacy wells or undocumented artificial penetrations within the defined AoR.
- Migration of CO_2 from the injection zone through faults and fractures or failure of the confining zone.
- Rapid and/or unexpected movement of CO_2 outside the defined AoR.
- External impact to the surface infrastructure (pipeline and wells).
- Induced seismic event.
- A natural disaster.
- Unauthorized access or activities to the site.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table ERR-2.

Table ERR-2: Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Known release or indication of a potential incident that poses an immediate (acute) risk to human health, resources, or infrastructure. Response actions involving local authorities (evacuation, isolation of areas, or restrictions on water usage) should be initiated.
Serious emergency	Incidents/releases posing potential (chronic) risk to human health, resources, or infrastructure, if conditions worsen or no mitigative or remedial actions are taken.
Minor emergency	Incident poses a challenge to the confinement barrier, but it does not result in the immediate release of CO_2 or brine posing a risk to human health, resources, or infrastructure.

4.0 Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, controls and mitigations in place, and severity of the event. The avoidance measures and potential actions set forth below are for information purposes. In an emergency, response actions will be based on operational, technical, and safety conditions at the time of the emergency. Additionally, avoidance measures may change over time based on technical and operational advancement. Depending on the severity of the event, the Bluebonnet Sequestration Hub, LLC, will activate its corporate emergency response organization as appropriate. The potential risk scenarios listed in Table ERR-1 are detailed below.

4.1 Well Control Event During Drilling, Completion, or Workovers with Loss of Containment

A well control event could occur during drilling, completions, and workover operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well. A well control event could also occur due to encountering unexpected overpressure zones while drilling.

Severity: Minor

Timing of event: Construction/Pre-Injection/Injection

Avoidance measures: Blowout prevention (BOP) equipment, BOP testing protocol, kill fluid, well control training, kick drill, lubricators for wireline operations, and legacy well analysis.

Detection methods: flow sensor, pressure sensor, tank level indicator, tripping displacement practices, and mud weight control.

Potential response actions:

- During drilling:
  - Stop operations.
  - Close the BOP.
  - Clear the floor and secure the area.
  - Execute the well control procedure.

  - Evaluate drilling parameters and identify root cause.
  - Continue operations.

- During completion/workovers:
  - Stop operations.
  - Close the BOP.
  - Clear the floor and secure the area.
  - Execute the well control procedure.
  - Continue operations.

Response personnel: Rig crew, rig manager, field superintendent, and project manager

4.2 Contamination of the USDW with Formation Brine or Drilling Fluids During Drilling Operations

Movement of brine between formations during drilling operations could occur if there is a cross flow with losses to the USDW. Contamination with drilling mud could occur during lost circulation events if the formation is not able to support the column of fluids, during a packoff event, or due to swab surge events.

Severity: Minor

Timing of event: Construction/Pre-Injection

Avoidance measures: USDW covered with surface casing, surface section drilled with fresh water and gel, casing test after cementing surface casing to check integrity, and formation integrity test (FIT) test to verify shoe integrity.

Detection methods: tank level sensor, mud lab test, pressure sensors, flow tensors, and tripping sheets.

Potential response actions:

- Stop drilling.
- Check the well level to detect lost circulation or influx.
- In case of loss, treat the well with lost circulation material and evaluate mud weight and drilling parameters.
- In case of influx, control the well without compromising shoe integrity.
- In case the shoe is identified as leaking, squeeze to regain integrity.
- In case the surface casing is identified as leaking, squeeze or casing patch are options.

Response personnel: Rig crew, rig manager, and field superintendent.

4.3 Loss of Mechanical Integrity in CO_2 Injector due to Tubing or Packer Leak

Loss of mechanical integrity due to a tubing or packer leak in the CO_2 injector wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause communication of the formation fluids with the annulus between the casing and tubing and sustained casing pressure. There is no loss of containment in this scenario.

Severity: Minor

Timing of event: Injection

Avoidance measures: Coated tubing, inhibited packer fluid in annulus, corrosion monitoring plan, dry CO_2 injected, nickel-plated packers, HH trim on tubing hanger for CO_2 injector wellheads and tree, and CR or Inconel carrier for the sensors.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, annular pressure test, distributed temperature sensing (DTS) fiber optic capabilities, and CO_2 leak sensor on the wellhead.

Potential response actions:

- Follow protocol to close the well, stop operations, and vent or divert CO_2.
- Troubleshoot the well.
- If a tubing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, and rig crew

4.4 Loss of Mechanical Integrity in Monitoring Wells, Water Production Wells, and Water Disposal Wells Due to Tubing or Packer Leak

Loss of mechanical integrity due to a tubing or packer leak in the monitoring, water production, and water disposal wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause communication of the formation fluids with the annulus between the casing and tubing and sustained casing pressure. There is no loss of containment in this scenario.

Severity: Minor

Timing of event: Injection/Post Injection

Avoidance measures: Inhibited packer fluid in annulus, corrosion monitoring plan, nickel-plated packers, and CR or Inconel carrier for the sensors.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, annular pressure test, CO_2 leak sensor on the wellhead, DTS fiber installed alongside casing, pulse-activated neutron log, and electromagnetic inspection log.

Potential response actions:

- Troubleshoot the well.
- If a tubing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, and rig crew.

4.5 Loss of Mechanical Integrity in CO_2 Injection Wells Due to Casing Leak

Loss of mechanical integrity due to a casing leak in the CO_2 injection wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause a migration of CO_2 and brines through the casing, the cement sheet, and into a different formation in the injection target or USDW.

Severity: Minor

Timing of event: Injection

Avoidance measures: CO_2-resistant cement and metallurgy across injection zone, injection through tubing and packer, nickel-plated packers, CR or Inconel carrier sensors, inhibited packer fluid in the annulus, cement to surface, corrosion monitoring plan, Cement Bond Log (CBL) or Ultrasonic Image Tool (USIT) after installation, robust mechanical integrity plan, and USDW cover with surface casing cemented to surface.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, CO_2 leak sensor on the wellhead, real-time DTS fiber alongside of casing, flow rate monitoring, soil gas probes, neutron-activated logs, and USDW water monitoring.

Potential response actions:

- Follow protocol to stop operations and vent or divert CO_2.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to the USDW.
- If the USDW is affected, discuss remediation with the regulating authority.
- If a casing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.6 Loss of Mechanical Integrity in Monitoring Wells, Water Production Wells, and Water Disposal Wells Due to Casing Leak

Loss of mechanical integrity due to a casing leak in the monitoring, water production, and disposal wells could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause a migration of CO_2 and brines through the casing, the cement sheet, and into a different formation in the injection target or USDW.

Severity: Minor

Timing of event: Injection/Post Injection

Avoidance measures: CO_2-resistant cement across injection zone, nickel-plated packers, CR or Inconel carrier sensors, inhibited packer fluid in the annulus, cement to surface, corrosion monitoring plan, CBL/USIT after installation, and USDW cover with surface casing cemented to surface.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, casing inspection log, annular pressure test, DST capabilities, CO_2 leak sensor on the wellhead, soil gas probes, neutron-activated logs, and USDW water monitoring.

Potential response actions:

- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to the USDW.
- If the USDW is affected, discuss remediation with the regulating authority.
- If a casing leak is detected, discuss an action plan with the regulating authority.
- Schedule well service to repair the well.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.7 Well Monitoring Equipment Failure or Malfunction During Injection

A failure of the monitoring system or associated alarm devices may cause over pressurization of the system or reservoir beyond the design limits, which could cause reservoir fracture, leaks, failure of equipment and tubulars, and facilities damage.

Severity: Minor

Timing of event: Injection

Avoidance measures: Preventative maintenance program and periodic inspections

Detection methods: Real-time monitoring systems, redundancy, and field inspections.

Potential response actions:

- If a single surface-monitoring device (e.g., surface pressure transmitter) that has a redundant device (i.e., second pressure transmitter) still in operation fails, the operational response required is to repair the device. No change to operations will be immediately planned.
- If a downhole monitoring equipment fails, the project manager will assess the impact and prepare an action plan to be discussed with the UIC Director.

4.8 Vertical Migration of CO_2 and Brines Due to Loss of External Mechanical Integrity in CO_2 Injection Wells Due to Cement Failure

During the life of the injector wells, there are induced stresses and chemical reactions on the cement exposed to the CO_2 pressure and plume. These mechanics could lead to cracks, channels, or permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines or CO_2 potentially affecting the USDW.

Severity: Minor

Timing of event: Injection

Avoidance measures: CO_2-resistant cement and metallurgy across the injection zone, injection through tubing and packer, cement to surface, CBL/USIT after installation, and USDW covered as a section barrier with surface casing and surface cement sheet.

The injection zones in the Hackberry, Frio, and the Lower Miocene Formations are separated from the base of the USDW by more than 3,000 ft of shales and sand layers. The described base of the Hackberry, intraformational Frio, primary Anahuac, and secondary Lower Miocene Confining Zones as well as the additional Composite Confining Zones (five confining zones altogether) are in place to protect and dissipate any fluid migration outside the permitted Hackberry, Frio, and Lower Miocene Injection Zones to protect the USDW.

The injector wells will be plugged and abandoned at the end of the injection period in accordance with the Injection Well Plugging Plan included with this permit application.

Detection methods: CO_2 leak sensors on the wellhead, real-time DTS fiber alongside the casing, soil gas probes, USDW water monitoring, neutron-activated logs to be run for external MI, pressure gauges at the surface, and flow rate monitoring.

Potential response actions:

- Follow protocol to stop operations and vent or deviate CO_2.
- Troubleshoot the well.
- Evaluate if there is any movement of CO_2 or brine to the USDW.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary.
- Discuss plans to repair the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.9 Vertical Migration f CO_2 and Brines Due to Loss of External Mechanical Integrity in Monitoring Wells, Water Production Wells, and Water Disposal Wells Due to Cement Failure

During the life of the monitoring wells, water production wells, and water disposal wells, there are induced stresses and chemical reactions on the cement exposed to brines, the pressure plume, and CO_2. These mechanics could lead to cracks, cement deterioration, and/or channels or permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines or CO_2.

Severity: Minor

Timing of event: Injection and Post-Injection

Avoidance measures: CO_2-resistant cement across the injection zone, cement to surface, CBL/USIT after installation, and USDW is covered the surface casing and surface cement sheet as primary barrier. The water disposal wells and the above-confining-zone/USWD wells do not penetrate the CO_2 injection target.

Detection methods: CO_2 leak sensors on the wellhead, soil gas probes, USDW water monitoring, neutron-activated logs to be run for external MI, and pressure gauges at the surface. DST fiber installed alongside the casing in water production wells and in-zone monitoring wells.

Potential response actions:

- Troubleshoot the well.
- Evaluate if there is any movement of CO_2 or brine to the USDW.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary.
- Discuss plans to repair the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors

4.10 Migration of CO_2 From the Injection Zone through Documented Legacy Wells or Undocumented Artificial Penetrations within the Defined AoR

This event occurs if formation brines and CO_2 migrate through poor cement bonding, cement degradation, open hole abandonments, or cracking in the cement in existing legacy wells.

Severity: Serious

Timing of event: Injection and Post-Injection

Avoidance measures: Twenty-Five legacy wells were identified in the proposed AoR. The wells are or will be properly abandoned based on the leak assessment evaluation. CO_2-resistant cement will be used on wells that require a P&A program. An airborne magnetic survey will be conducted over the AoR before injection to identify potential undocumented wells.

Detection methods: Soil gas probes across the AoR, real-time pressure and temperature indication on monitoring wells, 2D surface seismic surveying, 3D VSP (vertical seismic profile) surveys, time-lapse pulse-neutron electromagnetic log, groundwater monitoring, and in-zone monitoring dedicated to measuring reservoir pressure to calibrate the model.

Potential response actions:

- Evaluate if there is any movement of CO_2 or brine to the USDW due to a leak in a legacy or plugged and abandoned well.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary
- Discuss plans to repair the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, and remediation contractors.

4.11 Migration of CO_2 from the Injection Zone Through Faults and Fractures or Failure of the Confining Zone

Migration of brine or CO_2 during injection could occur if the pressure of the injection zone exceeds the sealing capacity of the caprock or seal above or if fault or fracture features are reactivated. Brine or CO_2 could migrate to a shallower formation, including the USDW.

Severity: Minor

Timing of event: Injection/Post Injection

Avoidance measures: Seismic survey of the area shows no faults crossing the storage formation or the seal, injection is limited to 90% of the fracture gradient, and extensive characterization of the geology shows good sealing capacity. The injection zones in the Hackberry, Frio and the Lower Miocene Formations are separated from the base of the USDW by more than 3,000 ft of shales and sand layers. The described base of the Hackberry, intraformational Frio, primary Anahuac, and secondary Lower Miocene Confining Zones as well as the additional Composite Confining Zones (five confining zones altogether) are in place to protect and dissipate any fluid migration outside the permitted Hackberry, Frio, and Lower Miocene Injection Zones to protect the USDW.

Detection methods: Above-confining-zone/USDW water sampling and pressure monitoring, 2D surface seismic, 3D VSP surveys, neutron-activated logs in monitoring wells, soil gas monitoring, and reservoir pressure and temperature real-time monitoring with in-zone monitoring wells.

Potential response actions:

- Follow protocol to stop injection.
- Assess the root cause by reviewing monitoring data.
- If required, conduct a geophysical survey to delineate potential leak path.
- Evaluate if there is any movement of CO_2 or brine to the USDW due to a failure of confining rock, faults, or fractures.
- Discuss remediation options, action plan, and monitoring plan with the regulating authority, if necessary
- Take appropriate actions to restore injection, depending on the nature of the leak path and extension.

Response personnel: Monitoring staff, geologist, reservoir engineer, project manager, and remediation contractors

4.12 Rapid and/or Unexpected Movement of CO_2 Outside the Defined AoR

Lateral migration of CO_2 outside the defined AoR could occur during injection or post-injection if the plume moves faster or in an unexpected pattern and expands beyond the secure pore space and AoR for the project.

Severity: Serious

Timing of event: Injection/Post-Injection

Avoidance measures: Detailed geologic model with the stratigraphic well as a calibration, seismic survey integrated in the model, extensive characterization of the rocks and formation, AoR review and calibration at least every 5 years, and monitoring of the plume until stabilization.

Detection methods: 2D surface seismic, 3D VSP surveys, neutron-activated logs in monitoring wells, soil gas monitoring, and reservoir pressure and temperature real-time monitoring with in-zone monitoring wells.

Potential response actions:

- Injection

  - Review monitoring data and trends compared with simulation.
  - Discuss findings with the regulating authority and request to maintain injection during AoR evaluation if data shows no endangerment of USDWs.
  - Perform logging in monitoring wells.
  - Conduct geophysical survey as required to evaluate the AoR.
  - Recalibrate the model and simulate the new AoR.
  - Assess if additional corrective actions and additional pore space are needed.
  - Assess if remediation is needed: prepare an action plan and review with the regulating authority.
  - Present the AoR review to the regulating authority for approval and adjust the monitoring plan.
- Post-Injection
  - Review monitoring data and trends compared with simulation.
  - Discuss findings with the regulating authority.
  - Conduct a geophysical survey as required to evaluate the AoR.
  - Recalibrate model and simulate the new AoR.
  - Assess if additional corrective actions and pore space are needed.

Response personnel: Monitoring staff, geologist, reservoir engineer, and project manager

4.13 External Impact to the Infrastructure (Pipeline, Wells)

Surface impact may cause loss of containment during the follow scenarios:

- External impact to the wellhead of the CO_2 Injection wells.
- External impact to the wellhead of the monitoring wells, water production wells, and water disposal wells.
- External impact to the surface piping or buried pipelines

4.13.1 Loss of Containment; External Impact to the Wellhead of the CO_2 Injection Wells

This event could occur if the wellhead is hit by a massive object (such as a vehicle or other heavy equipment) while in operation. In this scenario, the object causes major damage to the equipment that results in the well separating from the pipeline and shut-off system and leads to a loss of containment of CO_2 and brine.

Severity: Major

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed and signage. A dispersion analysis was performed for this potential release event and did not identify any major public impact. This event is very unlikely to happen.

Detection methods: Real-time pressure and temperature at the wellhead and surface facilities, field inspections, and OGI (optical gas imaging) cameras.

Potential response actions:

- Automated shutdown will initiate; however, follow protocol to shutdown CO_2 delivery if the automated shutdown devices are not functional.
- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Contact the well control special team to execute blowout emergency plan that may include capping the well, drilling a relief well to kill the injector, repair the well, and/or abandon the well; discuss plan with the regulating authority.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system, as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, remediation contractors, and well control specialist

4.13.2 Loss of Containment; External Impact to the Wellhead of The Monitoring Wells, Water Production Wells and Water Disposal Wells

This event would occur if the wellhead of the deep monitoring well or water production well is hit by a massive object and causes major damage leading to a loss of containment. Since the well is open to the formation pressure at the CO_2 injection zone, formation fluids have the potential to flow and spill on the location and around the area.

Severity: Serious

Timing of event: Injection and Post-Injection

Avoidance measures: Fenced location and bollards installed, signage, and reduced pressure in the monitoring well compared with the injection well.

Detection methods: Field inspections and real-time pressure and temperature at the wellhead and surface facilities.

Potential response actions:

- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Contact the well control special team to execute blowout emergency plan that may include capping the well, drilling a relief well to kill the injector, repair the well, and/or abandon the well; discuss plan with the regulating authority.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system, as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew, remediation contractors, and well control specialist

4.13.3 Loss of Containment; External Impact to the Surface Piping or Buried Pipeline

External impact to the surface piping or buried pipeline due to heavy trucks or equipment could cause loss of containment of brine or CO_2, if the pipe is ruptured.

Severity: Major

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed to protect surface piping, field pipeline buried, pipeline Right-of-Way identified with signage, and One Call 811 Program. A dispersion analysis was performed for this potential release event and did not identify any public impact.

Detection methods: Real-time pressure, temperature, and flow measurements and field inspections.

Potential response actions:

- Automated shutdown will initiate; however, follow protocol to shutdown CO_2 delivery if the automated shutdown devices are not functional.
- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, and well control specialist

4.14 Earthquake

A major seismic event may disturb surface and/or subsurface facilities. Bluebonnet will develop and implement a site-based earthquake response plan. The purpose of the earthquake response plan is to identify the actions that will be taken to inspect for damage, mitigate and/or manage risk by modifying operations, and establish thresholds for suspension of injection activity.

- The earthquake response plan shall be filed with the Commission before injection activities begin.
- The operator will monitor TexNet and USGS earthquake catalogs.
- The earthquake response plan is triggered when a 3.5 M event is detected with a reported hypocenter within the 9.08 (5.6 miles) km AoR.
- The earthquake response plan shall identify the actions the operator will take when a 3.5 M event is detected with a reported hypocenter within the 9.08 (5.6 miles) km AoR.
- The operator shall notify the Commission within 24 hours of an earthquake that triggers the response plan.
- Within 30 days of an earthquake trigger, the operator shall file a report with the Commission documenting the event, response actions taken, and findings

Timing of event: Injection and Post-Injection

Avoidance measures: Shutoff valves are present to shutoff injection into the wells when abnormal operating parameters, particularly high or low pressures, are present in the pipeline delivering CO_2 to the injection site.

Detection methods: A geophone array located on the surface to monitor seismicity will detect naturally occurring major seismic events during the injection period, in addition to pipeline and wellhead real-time monitoring of pressures and flows.

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, and emergency teams

4.15 Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise from a natural disaster affecting the normal operation of the injection wells. If a natural disaster occurs that affects normal operation of an injection well, perform the following:

Severity: Dependent on severity of event, potentially Major

Timing of event: Injection and Post-Injection

Avoidance measures: Shutoff valves are present to shutoff injection into the wells when abnormal operating parameters, particularly high or low pressures, are present in the pipeline delivering CO_2 to the injection site.

Detection methods: The site will be equipped with real-time monitoring devices for pipeline and well operations. Daily surveillance of the site will allow forecasting natural events and start securing the site ahead of the event.

Potential response actions:

- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Follow protocol to stop injection in the event the site was not secured previously.
- Assess the mechanical integrity of the system and propose repair actions based on findings.
- If assessment allows for resuming injection safely, increase surveillance to validate effectiveness of actions.

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, and emergency teams

4.16 Induced Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 5.6-mile radius of an injection well and follow the actions described in the section 4.14.

A geophone array has been installed on the surface to monitor the area for seismicity.

Severity: Minor

Timing of event: Injection and Post Injection

Avoidance measures: Seismic survey of the storage complex shows no faults that could be reactivated, detailed geomechanical model created to evaluate the storage complex, and region is seismically stable. Shutoff valves are present to shutoff injection into the well.

Detection methods: Geophone array on surface

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, and emergency teams

4.17 Unauthorized access or activities on the Site. (Statewide Rule §5.203(I)(3)(B))

The Bluebonnet Hub primarily encompasses surface locations related to the CO_2 injection and monitoring wells, as well as the buster pads for the water and CO_2 pumps. Additionally, it is important to note that the majority of the CO_2 and water pipelines will be buried underground to ensure safety and efficiency.

Severity: Serious

Timing of event: Construction, Injection and Post Injection

Avoidance measures: During the construction phase, the locations and equipment will be under continuous surveillance by security guards stationed on the rigs and by construction crews. Once the equipment is installed, the locations will be fenced, and bollards will be set up to safeguard surface piping and the wellhead. During operation, a field supervisor will conduct regular visual inspections, and a 24/7 surveillance system will monitor operating parameters in real-time. The site is equipped with automatic shut-off devices to handle emergencies. Additionally, the field pipeline will be buried, the pipeline Right-of-Way will be marked with signage, and the One Call 811 Program will be implemented.

Detection methods: Real-time pressure, temperature, and flow measurements and field inspections.

Potential response actions:

- Automated shutdown will initiate; however, follow protocol to shutdown CO_2 delivery if the automated shutdown devices are not functional.
- If personnel are injured or property is damaged, contact the field superintendent to activate emergency evacuation and secure location.
- Clear the location and secure the perimeter.
- Evaluate environmental impact on soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, and well control specialist

5.0 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement the ERRP. Monitoring, control, and routine maintenance of the injection operations will be the responsibility of the Injection Operations Staff. Site personnel must include, at minimum, the positions listed below in Table ERR-3.

If an adverse event is discovered, the Operations Manager and Emergency Coordinator on duty will be notified immediately. The Emergency Coordinator will be responsible for notifying offsite emergency agencies and resources. The Operations Manager or their delegate will contact outside emergency response organizations, if the Emergency Coordinator is not available. The EPA (Environmental Protection Agency) Region 6 UIC Program Director will be notified within 24 hours, per 40 CFR §146.91(c) and 40 CFR §146.94(b)(3).

Table ERR-3: Operations staff descriptions.

Position	Function	Qualifications
Emergency Coordinator	Responsible for notification of offsite support agencies in accordance with written procedures. Responsible for coordination and overseeing contact with the media.	Trained in the Communications Plan and Emergency Notification Procedures requirements as contained in the ERRP.
Operations Manager	Serves as the Emergency Response Manager responsible for the overall management of the Incident Response Team. Manages facility operations and personnel during an emergency and is responsible for implementation of appropriate emergency procedures and their follow-up activities.	Trained in the requirements of the ERRP and facility operations.
Project Manager	Serves as the Emergency Response Coordinator responsible for the overall communication between Incident Response Team members. Directs facility operations during an emergency and is responsible for communication between on-site personnel and professional services. Implements emergency procedures and ensures documentation of follow-up activities.	Trained in the requirements of the ERRP and facility operations.
Senior Reservoir Engineer	Responsible for injection operation and monitoring. Lead incident response manager regarding injection and storage zone operation at the facility.	Experienced professional in reservoir dynamics and relevant monitoring interpretation.
Geologist/ Geophysicist	Professional serving to assist in operations, maintenance, and monitoring of the injection process. Conducts routine data management and interpretation. Assists in implementing response actions regarding injection zone integrity.	Experienced professional in geophysics or geology.
Operations Engineer	Oversees mechanical and fluid management operation of the injection wells, annulus pressure control system, and wellhead piping systems. Maintains and repairs injection-related equipment, including valves, instruments, and piping. Assists in mechanical and electronic control of the injection process.	Experienced professional in field operations, maintenance, monitoring systems. Trained in the requirements of the ERRP and facility operations.

A site-specific emergency contact list will be developed and maintained during the project's life. The Bluebonnet Sequestration Hub, LLC, will provide the current site-specific emergency contact list to the UIC Program Director.

A list of contacts for state agencies having jurisdiction within the AoR and key local emergency agencies is presented below in Table ERR-4.

There are no federally recognized Native American Tribes located within the AoR. If a federally recognized Native American Tribes were to exist in the AoR at the time of a site emergency, then that tribe(s) will be notified of the site emergency at that time.

Table ERR-4: Contact information for key local, state, and other authorities.

Agency/Service	Location	Phone
Chambers County – Emergency Mgt Office	Anahuac, TX	(409) 267-2445
Liberty County – Emergency Mgt Office	Liberty, TX	(936) 334-3219
Jefferson County – Emergency Mgt Office	Beaumont, TX	(409) 835-8757
Chambers County Sheriff — Main	Anahuac, TX	(409) 267-2500
Chambers County Sheriff (Office)	Anahuac, TX	(409) 267-3220
Winnie-Stowell Fire Dept. (District 1)	Winnie, TX	(409) 296-4133
Winnie-Stowell Volunteer EMS	Winnie, TX	(409) 296-9627
Jefferson County ESD No. 4	Beaumont, TX	(409) 796-1704
Riceland Hospital	Winnie, TX	(409) 730-8054
St. Elizabeth Hospital	Beaumont, TX	(409) 892-7171
Baptist Hospital	Beaumont, TX	(409) 212-5000
Medical Center Hospital	Beaumont, TX	(409) 724-7389
Texas Highway Patrol — Beaumont	Winnie/Beaumont, TX	(409) 924-5466
Texas Highway Patrol — Houston	Houston, TX	(281) 517-1220
US Geological Survey of Texas	Austin, TX	(512) 927-3500
Texas Railroad Commission (District 03)	Houston, TX	(713) 869-5001
Texas Railroad Commission (24-Hr Line)	Austin, TX	(844) 773-0305 or (512) 463-6788
TCEQ Region 12 — Houston	Houston, TX	(713) 767-3500
EPA Region 6	Dallas, TX	(214) 665-2294

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, the Bluebonnet Sequestration Hub, LLC, shall be responsible for its procurement.

6.0 Emergency Communications Plan

Bluebonnet Sequestration Hub, LLC, will communicate to the public about any event that requires an emergency response. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether there is any risk to human health or the environment or any impacts to drinking water, any impacts to the surrounding community, and current understanding of the event.

As may be required by any government agency with jurisdiction over the project, the Bluebonnet Sequestration Hub, LLC, will, to the extent known, communicate with appropriate stakeholders

what happened, current or potential impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long term (e.g., ongoing cleanups), the Bluebonnet Sequestration Hub, LLC, will provide appropriate periodic updates to the UIC Program Director on the progress of the response action(s).

The Bluebonnet Sequestration Hub, LLC, will also communicate with entities who need to be informed about or act in response to the event, including local water system operators, CO_2 source(s), pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

If a seismic event occurs, the Bluebonnet Sequestration Hub, LLC, will, to the extent it can be reasonably determined, provide information to the UIC Program Director about whether the event was naturally occurring or induced by the injection, whether any damage to the well or other structures in the area occurred, the investigative process, and what responses, if any, were taken by the Bluebonnet Sequestration Hub, LLC, or others.

7.0 Emergency and Remedial Response Plan Review

The project team will review the ERRP periodically and will comply with 40 CFR §146.94(d), including:

- At least once every five years following its approval by the permitting agency.
- Within one year of an AoR reevaluation.
- Within a prescribed period (to be determined by the permitting agency) following any significant changes to the injection process or injection facility or an emergency event
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, the project team will provide the permitting agency with the documentation supporting the “no amendment necessary” determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within six months following an event that initiates the ERRP review procedure.

8.0 Staff Training and Exercise Procedures

All operations employees will receive training related to health and safety, operational procedures, and emergency responses according to the roles and responsibilities of their work assignments. Initial training will be conducted by, or under, the operations manager or a designated representative's supervision. Trainers will be thoroughly familiar with the Operations Plan and ERRP.

Facility personnel will participate in annual training that teaches how to perform their duties in ways that prevent CO_2 discharge. The training will include familiarization with operating

procedures and equipment configurations appropriate to the job assignment and emergency response procedures, equipment, and instrumentation. New personnel will be instructed before beginning work.

Refresher training will be conducted at least annually for all operations personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and highlighted with recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

Only personnel who have been properly trained will participate in drilling, construction, operations, and equipment repair at the storage site. A record including the person's name, date of training, and instructor's signature will be maintained.

EMERGENCY AND REMEDIAL RESPONSE PLAN (ERRP) - Appendix A
40 CFR §146.94(a)

Bluebonnet Sequestration Hub Safety Plan

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1.0 Sites in scope

- All Bluebonnet Facilities and Wells.

2.0 Perimeter access – Gates & Locks:Hasp-and-key (no electronic access control).

- Keys issued under controlled inventory; duplication prohibited without written approval
- Maintain a key issuance/return log (person, role, date, key ID); lost/stolen keys require immediate notification and rekey/lock change as needed
- Lock/hasp integrity checks during routine site inspections; defects corrected before end of shift
- Key control owner: TBD

3.0 Lighting: Lighting: Area/security lighting only

- Conduct lighting functionality checks monthly and after power events; document repairs/replacements
- Lighting owner: TBD
- Security lead/contact: TBD (name, mobile, after-hours escalation). Leave blank until designated

4.0 Contractor access model:

- Default: Escorted access for visitors and vendors not formally approved
  Unescorted access is permitted for vendors who meet all of the following:
- Approved through the Supply Chain and Contractor Safety Management (CSM) procedure process and current in good standing

- Completed site-specific HSE/security orientation and acknowledged rules
- Hold a current work authorization (PTW/JSA as applicable) for the scope of work

5.0 Controls

- Access provisioning: issue only the minimum keys required; tag keys by ID and site
- Logging: record person, company, purpose, key ID, out/in time, escort (if any)
- Duration limits: default 24 hours unless otherwise authorized in writing
- Audits: spot-check unescorted vendors; reconcile key logs weekly
- Violations (tailgating, sharing keys, bypassing locks): remove from site; notify Supply Chain/HSE for CSM review

6.0 Incident & suspicious activity reporting

For emergencies, call 911 first. Immediately notify the Security Lead (when assigned) and report the event in Intelex according to the HSE Incident Reporting & Investigation Procedure. Maintain site control until relieved by authorities or the Incident Commander

7.0 Contact Numbers

Appendix B – External Contacts

Agency/Service	Location	Phone
Chambers County – Emergency Mgt Office	Anahuac, TX	(409) 267-2445
Liberty County – Emergency Mgt Office	Liberty, TX	(936) 334-3219
Jefferson County – Emergency Mgt Office	Beaumont, TX	(409) 835-8757
Chambers County Sheriff — Main	Anahuac, TX	(409) 267-2500
Chambers County Sheriff (Office)	Anahuac, TX	(409) 267-3220
Winnie-Stowell Fire Dept. (District 1)	Winnie, TX	(409) 296-4133
Winnie-Stowell Volunteer EMS	Winnie, TX	(409) 296-9627
Jefferson County ESD No. 4	Beaumont, TX	(409) 796-1704
Riceland Hospital	Winnie, TX	(409) 730-8054
St. Elizabeth Hospital	Beaumont, TX	(409) 892-7171
Baptist Hospital	Beaumont, TX	(409) 212-5000
Medical Center Hospital	Beaumont, TX	(409) 724-7389
Texas Highway Patrol — Beaumont	Winnie/Beaumont, TX	(409) 924-5466
Texas Highway Patrol — Houston	Houston, TX	(281) 517-1220
US Geological Survey of Texas	Austin, TX	(512) 927-3500
Texas Railroad Commission (District 03)	Houston, TX	(713) 869-5001
Texas Railroad Commission (24-Hr Line)	Austin, TX	(844) 773-0305 or (512) 463-6788
TCEQ Region 12 — Houston	Houston, TX	(713) 767-3500
EPA Region 6	Dallas, TX	(214) 665-2294

Internal Contacts (Complete & Maintain)

- Emergency Coordinator: Doug Fife, Phone: (713-366-5650)
- Operations Manager: William Campbell, Phone: (713-350-4823)
- Project Manager / PIO: Angie Contreras, Phone: (713-4972012)

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

Bluebonnet Sequestration Hub

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells.

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas

	Surface Coordinates		Bottom Hole Coordinates	
Well Name	Latitude (NAD27)	Longitude (NAD27)	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442	29.808132	-94.437235
Bluebonnet CCS 2	29.804552	-94.463937	29.806641	-94.469059
Bluebonnet CCS 3	29.852812	-94.498078	29.848655	-94.495108
Bluebonnet CCS 5	29.812133	-94.436456	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078	29.853222	-94.498078

Bluebonnet Sequestration Hub, LLC will be building the Bluebonnet Sequestration Hub (Bluebonnet Hub or the project) where it will construct CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, according to the procedures below. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, and pressure control systems, amongst others.

2.0 Overview

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

As mentioned, the Bluebonnet Sequestration Hub, LLC will drill six new CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS

6, and Bluebonnet CCS 7. These wells will target the Oligocene and Miocene formations, specifically the Lower Miocene, Frio, and Hackberry sands.

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

Bluebonnet Sequestration Hub LLC drilled the Bluebonnet USDW 1 well in 2024 to characterize the shallow aquifers. Subsequently, in 2025, the Bluebonnet USDW 8 well was drilled to obtain whole core and sidewall core samples from the intershales predominant within the Miocene Composite Confining Zone.

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

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

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

3.0 Design Considerations for CO_2 Injector Wells

Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 are designed to maximize the rate of injection and reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the frac gradient. A nodal analysis using PROSPER software performed sensitivities on the tubing size, rate of erosion, stresses, operating pressures, and potential movement of the tubulars. The injection rate will continue to be refined as the project acquires, processes, evaluates, and interprets additional data.

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

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

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

The operating conditions expected during the life of the CO2 injector wells are shown in Table CON-1.Table CON-2, Table CON-3, Table CON- 4, Table CON- 5, and Table CON- 6. Table CON-7 shows the CO_2 specifications of the Bluebonnet Hub.

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

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top - bottom (ft)	8,180-8,468	7,967-8,468	8,766-8,950
Perforation interval TVD[2], top - bottom (ft)	8,031-8,306	7,828-8,306	8,591-8,768
Maximum injection rate (metric tonnes per day)	6,850	6,850	1,370
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,3500	2,100-2,500	1,300-1,900
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,493	5,354	5,876
Surface temperature (°F)	60-90	60-90	60-90
Bottom hole temperature (°F) (top perfs)	164	162	170
Operating injection rate (metric tonnes per day)	5,480	5,480	1,370
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100	1,300-1,900
Minimum annulus/tubing differential pressure (psig)	100	100	100

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

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

Parameter/Completion	Completion 1	Completion 2
Perforation interval MD[1], top - bottom (ft)	8,237-8,514	8,009-8,514
Perforation interval TVD[2], top - bottom (ft)	7,974-8,230	7,766-8,230
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,454	5,276
Surface temperature (°F)	60-90	60-90
Bottomhole temperature (°F) (top perfs)	161	164
Operating injection rate (average) (metric tonnes per day)	4,660	4,660
Operating wellhead surface injection pressure (psig)	1,200-2,100	1,200-2,100
Minimum annulus/tubing differential pressure (psig)	100	100

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

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top - bottom (ft)	8,418-8,763	7,943-8,223	7,659-8,223
Perforation interval TVD[2], top - bottom (ft)	8,138-8,459	7,697-7,957	7,433-7,957
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,500	2,100-2,500	2,100-2,500
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	5,566	5,264	5,084
Surface temperature (°F)	60-90	60-90	60-90
Bottom hole temperature (°F) (top perfs)	165	161	158
Operating injection rate (average) (metric tonnes per day)	3,840	3,840	2,740
Operating wellhead surface injection pressure (psig)	1,000-1,800	1,000-1,800	1,000-1,600
Minimum annulus/tubing differential pressure (psig)	100	100	100

Table CON- 4: Operating design parameters for Bluebonnet CCS 5.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4	Completion 5
Perforation interval MD[1], top - bottom (ft)	6,330-6,464	6,053-6,181	5,820-5,975	5,646-5,734	5,481-5,502
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,330	4,140	3,980	3,860	3,750
Surface temperature (°F)	60-90	60-90	60-90	60-90	60-90
Bottom hole temperature (°F) (top perfs)	146	143	140	138	137
Operating injection rate (average) (metric tonnes per day)	5,095	5,095	5,095	5,095	5,095
Operating wellhead surface injection pressure (psig)	1000-1500	1000-1500	1000-1500	1000-1500	1000-1500
Minimum annulus/tubing differential pressure (psig)	100	100	100	100	100

Table CON- 5: Operating design parameters for Bluebonnet CCS 6.

Parameter/Completion	Completion 1	Completion 2	Completion 3
Perforation interval MD[1], top - bottom (ft)	6,218-6,347	5,760-5,869	5,523-5,584
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,250	3,940	3,780
Surface temperature (°F)	60-90	60-90	60-90
Bottom hole temperature (°F) (top perfs)	145	140	137
Operating injection rate (average) (metric tonnes per day)	4,465	4,465	4,465
Operating wellhead surface injection pressure (psig)	950-1500	950-1500	950-1500
Minimum annulus/tubing differential pressure (psig)	100	100	100

Table CON- 6: Operating design parameters for Bluebonnet CCS 7.

Parameter/Completion	Completion 1	Completion 2	Completion 3	Completion 4
Perforation interval MD[1], top - bottom (ft)	6,030-6,124	5,593-5,689	5,302-5,472	5,186-5,266
Maximum injection rate (metric tonnes per day)[3]	6,850	6,850	6,850	6,850
Wellhead surface injection pressure at maximum injection rate (psig)	2,100-2,300	2,100-2,300	2,100-2,300	2,100-2,300
Maximum bottomhole pressure at 90% of frac gradient (0.76 psi/ft) at top of perforations (psig)	4,125	3,825	3,630	3,550
Surface temperature (°F)	60-90	60-90	60-90	60-90
Bottom hole temperature (°F) (top perfs)	143	138	135	134
Operating injection rate (average) (metric tonnes per day)	3,808	3,808	3,808	3,808
Operating wellhead surface injection pressure (psig)	900-1,300	900-1,300	900-1,300	900-1,300
Minimum annulus/tubing differential pressure (psig)	100	100	100	100

Table CON-7: CO_2 Specification for Bluebonnet Hub.

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

4.0 Well Design Bluebonnet CCS 1 - CO_2 Injector Well

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

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

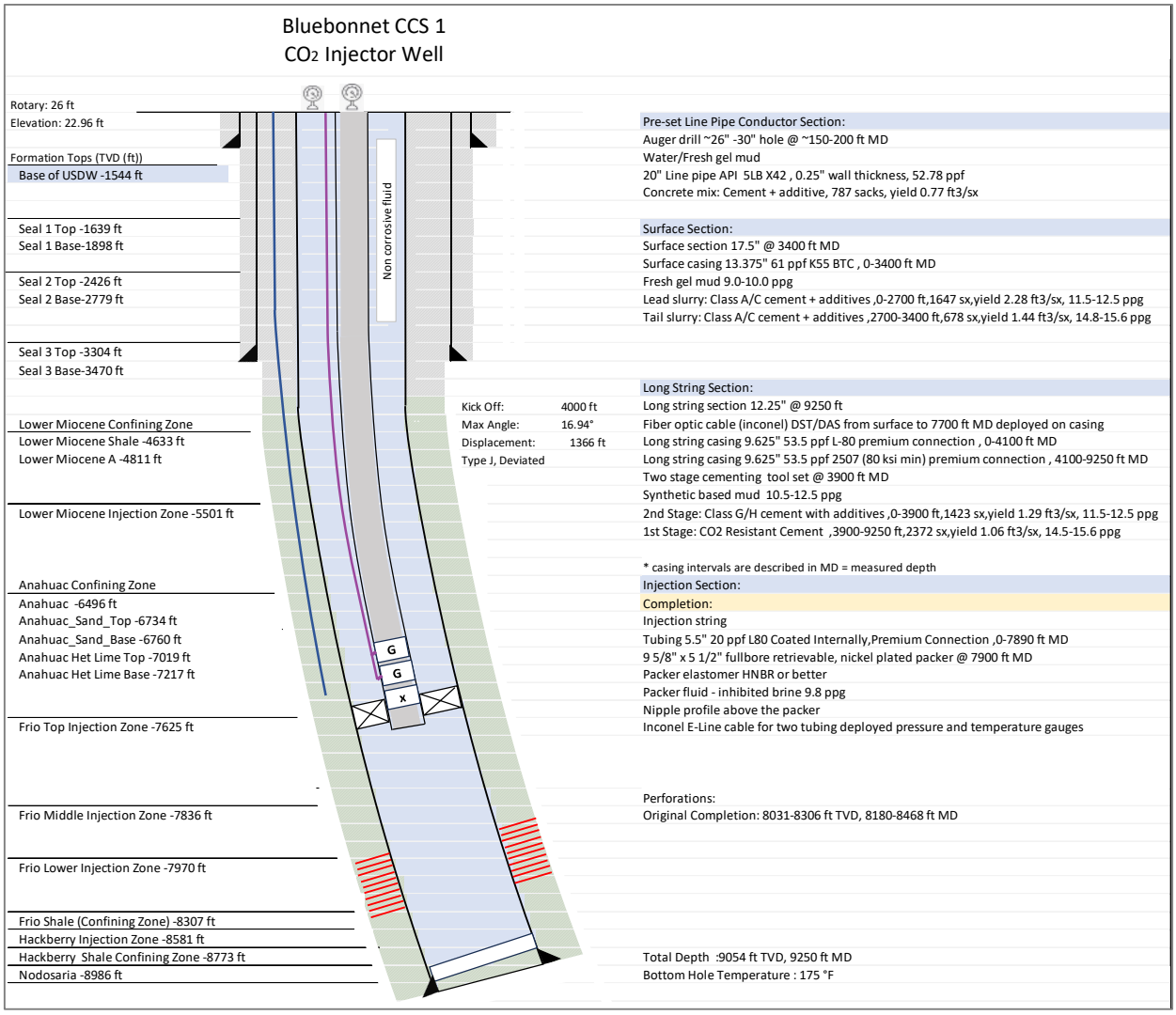


Figure CON-1: Bluebonnet CCS 1 well schematic – original completion.

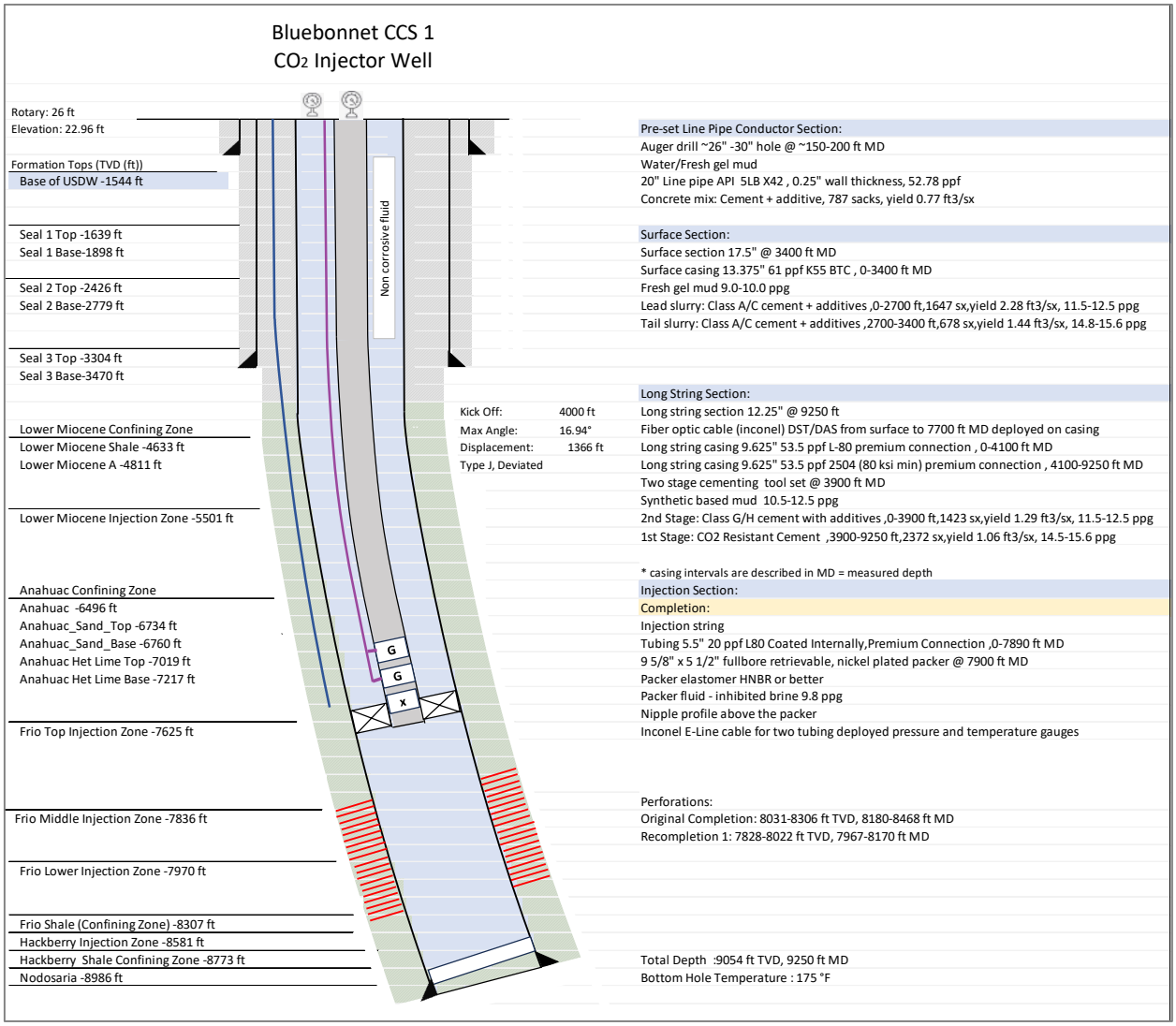


Figure CON-2: Bluebonnet CCS 1 well schematic – first recompletion.

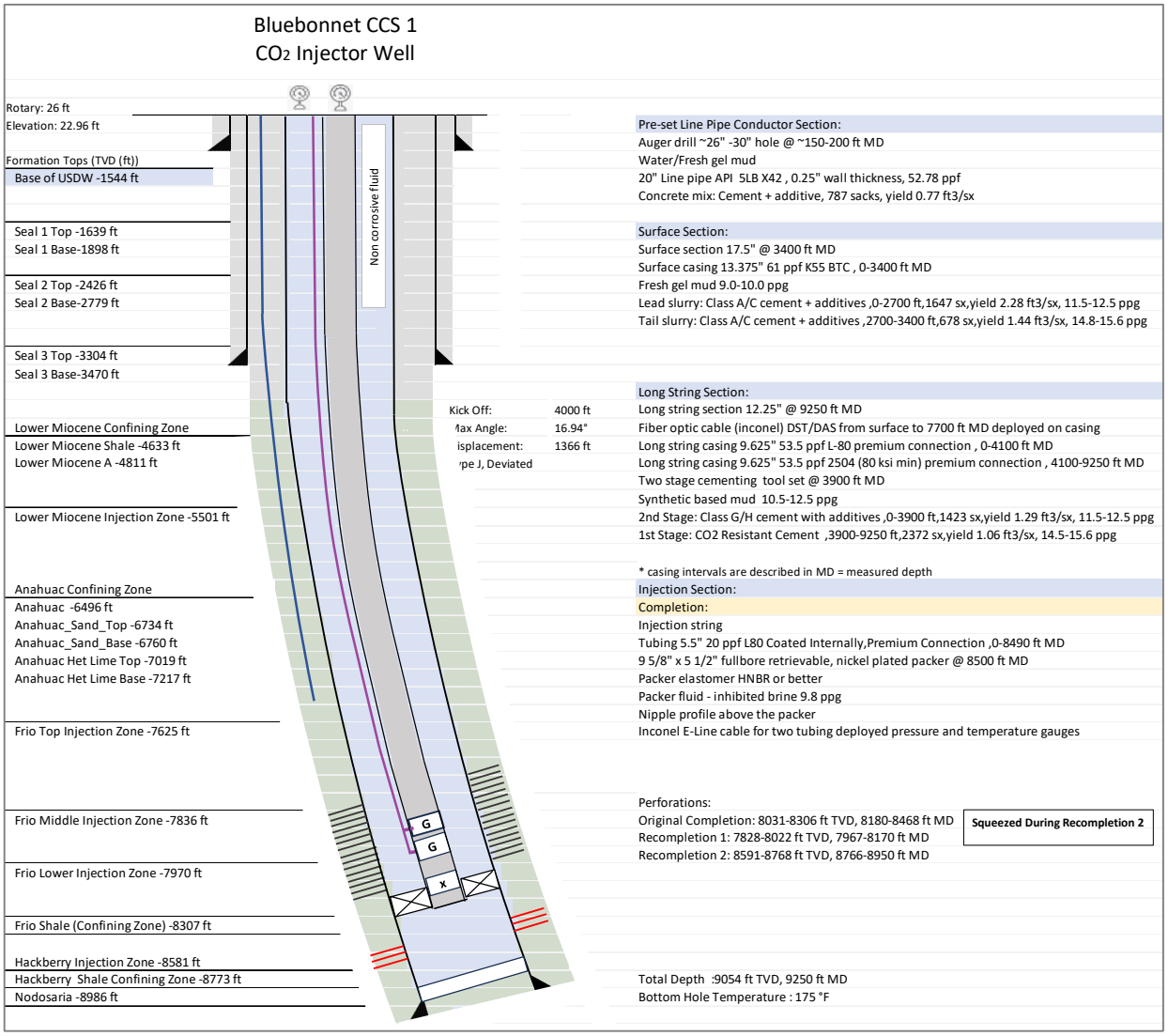


Figure CON-3: Bluebonnet CCS 1 well schematic – second recompletion.

4.1 Design Overview Bluebonnet CCS 1

4.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

4.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,400 ft to cover the base of the USDW, estimated at 1,544 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum of every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with a conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

4.1.3 Long String Section

Bluebonnet CCS 1 will be drilled directionally in a “J” type profile, with the kickoff point planned at 4,000 ft TVD, a maximum angle of 16.94°, and 1,366 ft displacement. The detailed trajectory is provided in Table CON-8.

A 12 ¼ in. directional wellbore will be drilled from 3,400 ft to total depth (MD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustical sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing

job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after it is drilled.

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

4.1.4 Completion

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

The 5 ½-in. tubing and packer completion will be run to approximately 7,900 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

4.2 Directional Plan Bluebonnet CCS 1

Table CON-8 summarizes the proposed trajectory for Bluebonnet CCS 1.

Table CON-8: Bluebonnet CCS 1 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
0	0	0	0	-48.96	0	0	0
4000	0	0	4000	3951.04	0	0	0
4050	0.75	191.42	4050	4001.04	-0.32	-0.06	0.33
4100	1.5	191.42	4099.99	4051.03	-1.28	-0.26	1.31
4150	2.25	191.42	4149.96	4101	-2.89	-0.58	2.94
4200	3	191.42	4199.91	4150.95	-5.13	-1.04	5.23
4250	3.75	191.42	4249.82	4200.86	-8.02	-1.62	8.18
4300	4.5	191.42	4299.69	4250.73	-11.54	-2.33	11.77
4350	5.25	191.42	4349.51	4300.55	-15.71	-3.17	16.02
4400	6	191.42	4399.27	4350.31	-20.51	-4.14	20.92
4450	6.75	191.42	4448.96	4400	-25.95	-5.24	26.48
4500	7.5	191.42	4498.57	4449.61	-32.03	-6.47	32.68

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
4550	8.25	191.42	4548.1	4499.14	-38.75	-7.83	39.53
4600	9	191.42	4597.54	4548.58	-46.1	-9.31	47.03
4650	9.75	191.42	4646.87	4597.91	-54.08	-10.92	55.17
4700	10.5	191.42	4696.09	4647.13	-62.7	-12.66	63.96
4750	11.25	191.42	4745.19	4696.23	-71.94	-14.53	73.39
4800	12	191.42	4794.16	4745.2	-81.82	-16.52	83.47
4850	12.75	191.42	4843	4794.04	-92.32	-18.65	94.19
4900	13.5	191.42	4891.7	4842.74	-103.45	-20.89	105.54
4950	14.25	191.42	4940.24	4891.28	-115.2	-23.27	117.53
5000	15	191.42	4988.62	4939.66	-127.58	-25.77	130.15
5050	15.75	191.42	5036.83	4987.87	-140.57	-28.39	143.41
5100	16.5	191.42	5084.86	5035.9	-154.18	-31.14	157.3
5129.57	16.94	191.42	5113.18	5064.22	-162.52	-32.82	165.81
5150	16.94	191.42	5132.72	5083.76	-168.36	-34	171.76
5200	16.94	191.42	5180.55	5131.59	-182.64	-36.89	186.33
5250	16.94	191.42	5228.38	5179.42	-196.93	-39.77	200.9
5300	16.94	191.42	5276.21	5227.25	-211.21	-42.66	215.47
5350	16.94	191.42	5324.04	5275.08	-225.49	-45.54	230.04
5400	16.94	191.42	5371.87	5322.91	-239.78	-48.42	244.62
5450	16.94	191.42	5419.7	5370.74	-254.06	-51.31	259.19
5500	16.94	191.42	5467.53	5418.57	-268.34	-54.19	273.76
5550	16.94	191.42	5515.36	5466.4	-282.62	-57.08	288.33
5600	16.94	191.42	5563.19	5514.23	-296.91	-59.96	302.9
5650	16.94	191.42	5611.02	5562.06	-311.19	-62.85	317.47
5700	16.94	191.42	5658.85	5609.89	-325.47	-65.73	332.05
5750	16.94	191.42	5706.68	5657.72	-339.76	-68.62	346.62
5800	16.94	191.42	5754.51	5705.55	-354.04	-71.5	361.19
5850	16.94	191.42	5802.34	5753.38	-368.32	-74.39	375.76
5900	16.94	191.42	5850.17	5801.21	-382.61	-77.27	390.33
5950	16.94	191.42	5898	5849.04	-396.89	-80.16	404.9
6000	16.94	191.42	5945.82	5896.86	-411.17	-83.04	419.47
6050	16.94	191.42	5993.65	5944.69	-425.46	-85.92	434.05
6100	16.94	191.42	6041.48	5992.52	-439.74	-88.81	448.62
6150	16.94	191.42	6089.31	6040.35	-454.02	-91.69	463.19
6200	16.94	191.42	6137.14	6088.18	-468.31	-94.58	477.76
6250	16.94	191.42	6184.97	6136.01	-482.59	-97.46	492.33
6300	16.94	191.42	6232.8	6183.84	-496.87	-100.35	506.9
6350	16.94	191.42	6280.63	6231.67	-511.15	-103.23	521.47
6400	16.94	191.42	6328.46	6279.5	-525.44	-106.12	536.05

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
6450	16.94	191.42	6376.29	6327.33	-539.72	-109	550.62
6500	16.94	191.42	6424.12	6375.16	-554	-111.89	565.19
6550	16.94	191.42	6471.95	6422.99	-568.29	-114.77	579.76
6600	16.94	191.42	6519.78	6470.82	-582.57	-117.66	594.33
6650	16.94	191.42	6567.61	6518.65	-596.85	-120.54	608.9
6700	16.94	191.42	6615.44	6566.48	-611.14	-123.42	623.48
6750	16.94	191.42	6663.27	6614.31	-625.42	-126.31	638.05
6800	16.94	191.42	6711.1	6662.14	-639.7	-129.19	652.62
6850	16.94	191.42	6758.93	6709.97	-653.99	-132.08	667.19
6900	16.94	191.42	6806.76	6757.8	-668.27	-134.96	681.76
6950	16.94	191.42	6854.59	6805.63	-682.55	-137.85	696.33
7000	16.94	191.42	6902.42	6853.46	-696.84	-140.73	710.9
7050	16.94	191.42	6950.25	6901.29	-711.12	-143.62	725.48
7100	16.94	191.42	6998.08	6949.12	-725.4	-146.5	740.05
7150	16.94	191.42	7045.91	6996.95	-739.68	-149.39	754.62
7200	16.94	191.42	7093.74	7044.78	-753.97	-152.27	769.19
7250	16.94	191.42	7141.56	7092.6	-768.25	-155.16	783.76
7300	16.94	191.42	7189.39	7140.43	-782.53	-158.04	798.33
7350	16.94	191.42	7237.22	7188.26	-796.82	-160.92	812.9
7400	16.94	191.42	7285.05	7236.09	-811.1	-163.81	827.48
7450	16.94	191.42	7332.88	7283.92	-825.38	-166.69	842.05
7500	16.94	191.42	7380.71	7331.75	-839.67	-169.58	856.62
7550	16.94	191.42	7428.54	7379.58	-853.95	-172.46	871.19
7600	16.94	191.42	7476.37	7427.41	-868.23	-175.35	885.76
7650	16.94	191.42	7524.2	7475.24	-882.52	-178.23	900.33
7700	16.94	191.42	7572.03	7523.07	-896.8	-181.12	914.91
7750	16.94	191.42	7619.86	7570.9	-911.08	-184	929.48
7800	16.94	191.42	7667.69	7618.73	-925.37	-186.89	944.05
7850	16.94	191.42	7715.52	7666.56	-939.65	-189.77	958.62
7900	16.94	191.42	7763.35	7714.39	-953.93	-192.66	973.19
7950	16.94	191.42	7811.18	7762.22	-968.21	-195.54	987.76
7966	16.94	191.42	7827	7778.04	-972.94	-196.49	992.58
8000	16.94	191.42	7859.01	7810.05	-982.5	-198.42	1002.33
8050	16.94	191.42	7906.84	7857.88	-996.78	-201.31	1016.91
8100	16.94	191.42	7954.67	7905.71	-1011.06	-204.19	1031.48
8150	16.94	191.42	8002.5	7953.54	-1025.35	-207.08	1046.05
8200	16.94	191.42	8050.33	8001.37	-1039.63	-209.96	1060.62
8250	16.94	191.42	8098.16	8049.2	-1053.91	-212.85	1075.19
8300	16.94	191.42	8145.99	8097.03	-1068.2	-215.73	1089.76

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
8350	16.94	191.42	8193.82	8144.86	-1082.48	-218.62	1104.33
8400	16.94	191.42	8241.65	8192.69	-1096.76	-221.5	1118.91
8450	16.94	191.42	8289.48	8240.52	-1111.05	-224.39	1133.48
8500	16.94	191.42	8337.31	8288.35	-1125.33	-227.27	1148.05
8550	16.94	191.42	8385.13	8336.17	-1139.61	-230.16	1162.62
8600	16.94	191.42	8432.96	8384	-1153.9	-233.04	1177.19
8650	16.94	191.42	8480.79	8431.83	-1168.18	-235.92	1191.76
8700	16.94	191.42	8528.62	8479.66	-1182.46	-238.81	1206.34
8750	16.94	191.42	8576.45	8527.49	-1196.74	-241.69	1220.91
8800	16.94	191.42	8624.28	8575.32	-1211.03	-244.58	1235.48
8850	16.94	191.42	8672.11	8623.15	-1225.31	-247.46	1250.05
8900	16.94	191.42	8719.94	8670.98	-1239.59	-250.35	1264.62
8950	16.94	191.42	8767.77	8718.81	-1253.88	-253.23	1279.19
9000	16.94	191.42	8815.6	8766.64	-1268.16	-256.12	1293.76
9050	16.94	191.42	8863.43	8814.47	-1282.44	-259	1308.34
9100	16.94	191.42	8911.26	8862.3	-1296.73	-261.89	1322.91
9150	16.94	191.42	8959.09	8910.13	-1311.01	-264.77	1337.48
9200	16.94	191.42	9006.92	8957.96	-1325.29	-267.66	1352.05
9250	16.94	191.42	9054.75	9005.79	-1339.58	-270.54	1366.62

4.3 Casing, Tubing and Completion Design Bluebonnet CCS 1

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

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

Table CON-9 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-9: Minimum safety factors for tubular design – Bluebonnet CCS 1.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,400	1.18	1.04	2.09	1.30
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.06	2.44	2.27	2.00
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-9,250	1.89	1.11	3.29	1.41
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,900	2.52	1.29	1.94	1.39

A detailed report of the loads and parameters used during the stress analysis of the tubulars is provided in Appendix D of this document. Safety factors for the second recompletion events are similar that the ones presented in Table CON-9.

Figure CON-4 shows the design limits envelope for the 5 ½-in. injection tubing used to validate the selection of the material. The analysis was developed with WELLCAT™ software from Landmark.

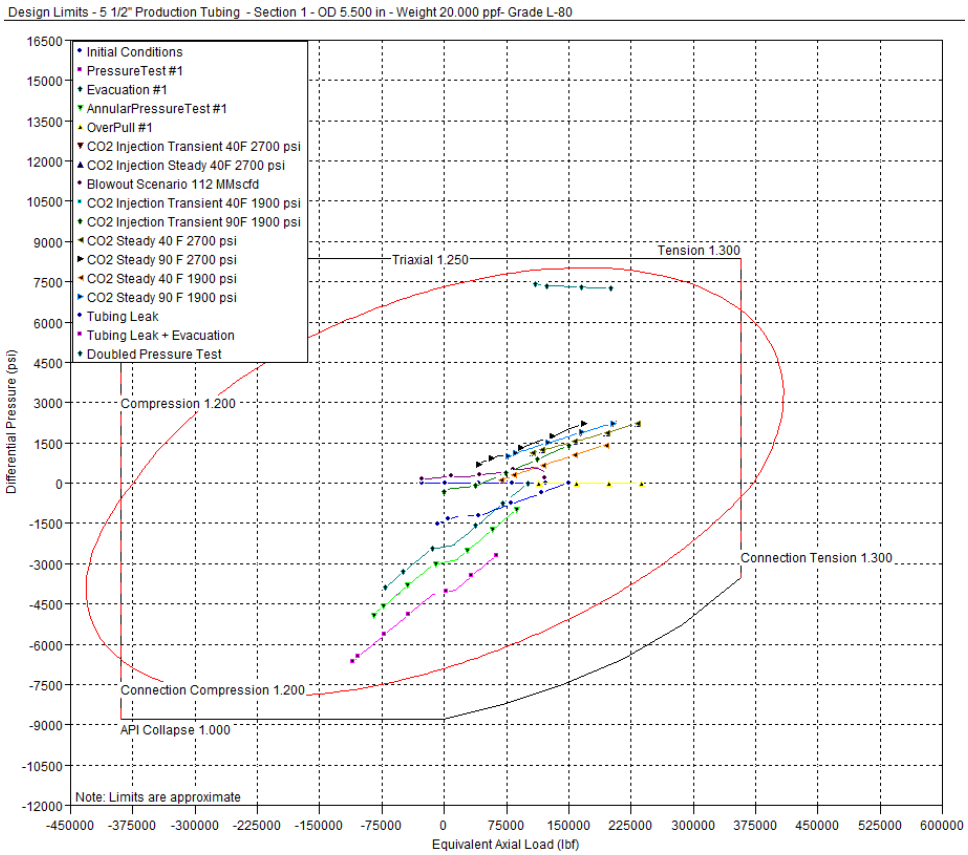


Figure CON-4: Bluebonnet CCS 1 injection tubing design limits.

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

The tables listed below provide further details regarding the Bluebonnet CCS 1 well. Table CON-10 contains the open hole diameters and intervals, Table CON-11 lists the casing specifications, Table CON-12 details the conductor material, and Table CON-13 details the casing material properties for Bluebonnet CCS 1.

Table CON-10: Open hole diameters and intervals - Bluebonnet CCS 1.

Name	Depth Interval (ft)	Open hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17 ½	Cover USDW
Long String Section	3,400 to 9,250	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,544 ft TVD.

Table CON-11: Casing specifications - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 9,250	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-12: Conductor material properties - Bluebonnet CCS 1.

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

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

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 61 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 9,250	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-14 and Table CON-15 contain the upper completion specifications for the original completion and first and second recompletions. Table CON-16 shows the specification of the 5 ½ in. tubing.

Table CON-14: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,890	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-15: Tubing material properties – second recompletion - Bluebonnet CCS 1.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 8,490	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-16: Tubing material properties - Bluebonnet CCS 1.

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

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-17 shows the specifications of the injection packer.

Table CON-17: Packer specifications - Bluebonnet CCS 1.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

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

Notes:

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

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

4.4 Cementing Program Bluebonnet CCS 1

Table CON-18 shows the cementing program details.

Table CON-18: Cementing program - Bluebonnet CCS 1.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,413	1.29	50%
	CO_2-Resistant Cement	3,900 to 9,250	14.5-15.6	2,372	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

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

4.5 Centralization Program Bluebonnet CCS 1

4.5.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

4.5.2 Long String Casing

Approximately 130-135 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

4.6 Fluids Program Bluebonnet CCS 1

Table CON-19 shows the mud program details for Bluebonnet CCS 1.

Table CON-19: Mud program - Bluebonnet CCS 1.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,400	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,400–9,250	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

4.7 Wellhead Schematic Bluebonnet CCS 1

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

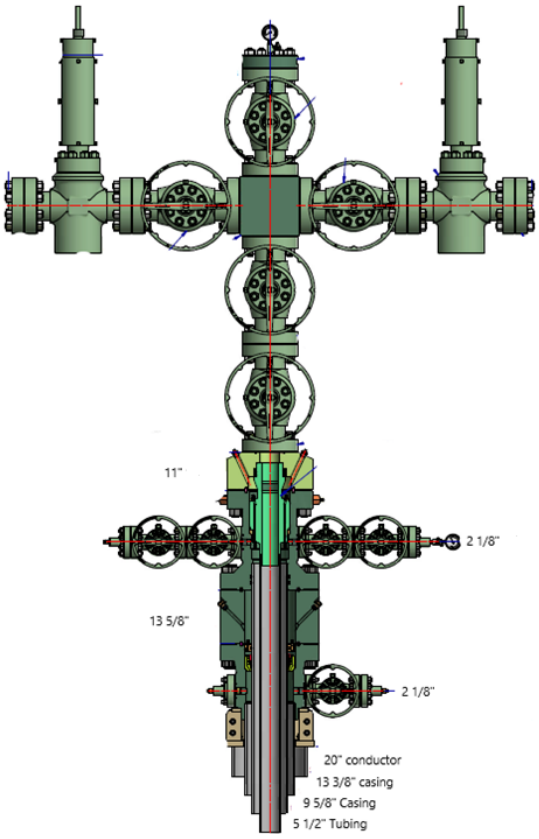


Figure CON-5: Schematic diagram of Bluebonnet CCS 1 well.

4.8 Bluebonnet CCS 1 Procedure

4.8.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

4.8.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi, BOPE to 3,000 psi.

4.8.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry as per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

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

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

4.8.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

5.0 Well Design Bluebonnet CCS 2 - CO_2 Injector Well

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

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

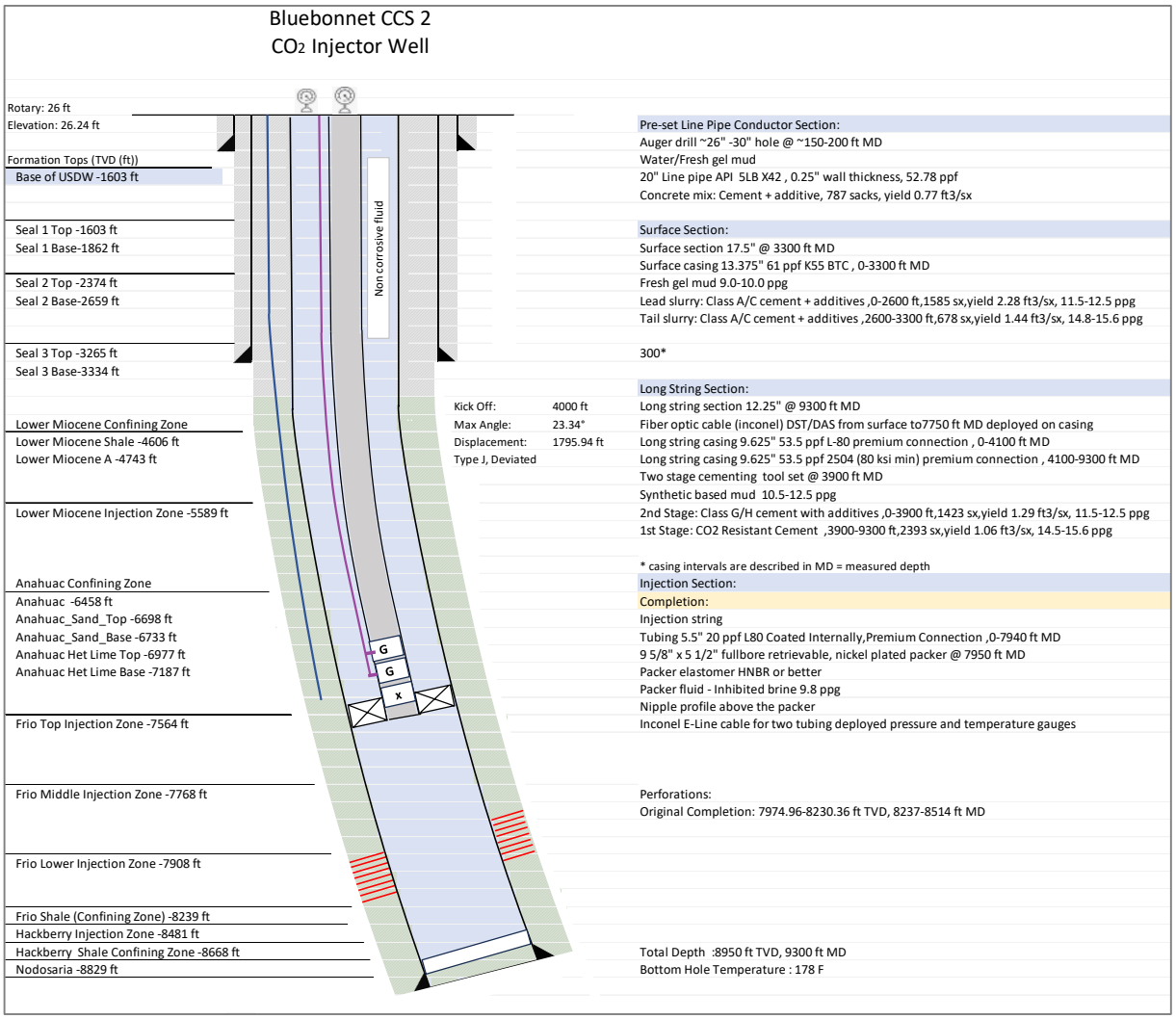


Figure CON-6: Bluebonnet CCS 2 well schematic – original completion.

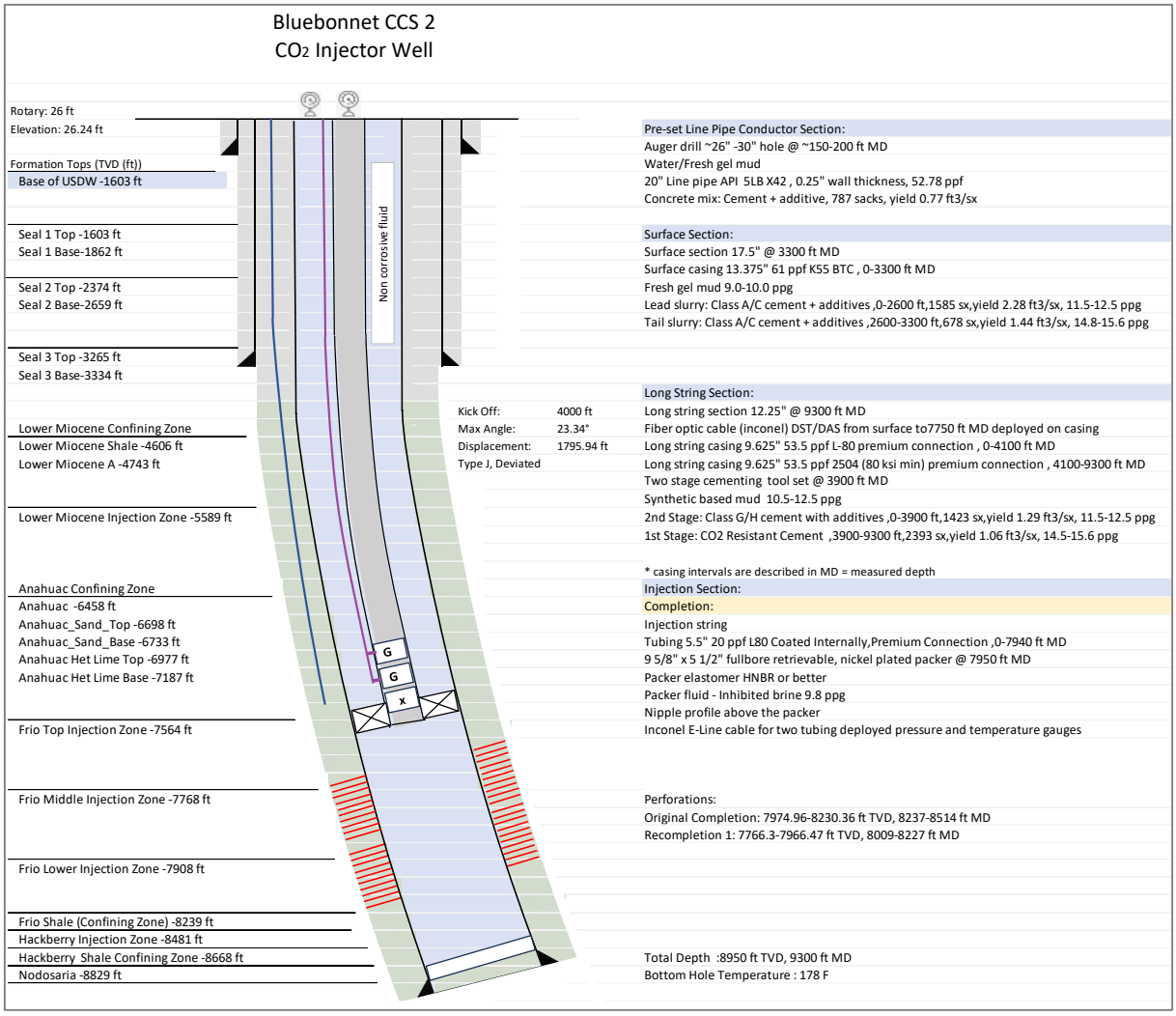


Figure CON-7: Bluebonnet CCS 2 well schematic – recompletion.

5.1 Design Overview Bluebonnet CCS 2

5.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

5.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,603 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling. This section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

5.1.3 Long String Section

Bluebonnet CCS 2 will be drilled directionally in a “J” type profile, with the kickoff point planned at 4,000 ft TVD, a maximum angle of 23.34°, and 1,795 ft displacement. The detailed trajectory is provided in Table CON-17.

A 12 ¼ in. directional wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The

depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

5.1.4 Completion

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

The 5 ½-in. tubing and packer completion will be run to approximately 7,950 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

5.2 Directional Plan Bluebonnet CCS 2

Table CON-20 summarizes the proposed trajectory for Bluebonnet CCS 2.

Table CON-20: Bluebonnet CCS 2 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
0	0	0	0	-52.25	0	0	0
4000	0	0	4000	3947.75	0	0	0
4050	0.75	295.79	4050	3997.75	0.14	-0.29	0.33
4100	1.5	295.79	4099.99	4047.74	0.57	-1.18	1.31
4150	2.25	295.79	4149.96	4097.71	1.28	-2.65	2.94
4200	3	295.79	4199.91	4147.66	2.28	-4.71	5.23
4250	3.75	295.79	4249.82	4197.57	3.56	-7.36	8.18
4300	4.5	295.79	4299.69	4247.44	5.12	-10.6	11.77
4350	5.25	295.79	4349.51	4297.26	6.97	-14.43	16.02
4400	6	295.79	4399.27	4347.02	9.1	-18.84	20.92
4450	6.75	295.79	4448.96	4396.71	11.52	-23.84	26.48
4500	7.5	295.79	4498.57	4446.32	14.22	-29.42	32.68

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
4550	8.25	295.79	4548.1	4495.85	17.2	-35.59	39.53
4600	9	295.79	4597.54	4545.29	20.46	-42.34	47.03
4650	9.75	295.79	4646.87	4594.62	24	-49.68	55.17
4700	10.5	295.79	4696.09	4643.84	27.83	-57.59	63.96
4750	11.25	295.79	4745.19	4692.94	31.93	-66.08	73.39
4800	12	295.79	4794.16	4741.91	36.32	-75.16	83.47
4850	12.75	295.79	4843	4790.75	40.98	-84.8	94.19
4900	13.5	295.79	4891.7	4839.45	45.92	-95.03	105.54
4950	14.25	295.79	4940.24	4887.99	51.13	-105.82	117.53
5000	15	295.79	4988.62	4936.37	56.63	-117.19	130.15
5050	15.75	295.79	5036.83	4984.58	62.39	-129.13	143.41
5100	16.5	295.79	5084.86	5032.61	68.43	-141.63	157.3
5150	17.25	295.79	5132.71	5080.46	74.75	-154.7	171.81
5200	18	295.79	5180.36	5128.11	81.34	-168.33	186.95
5250	18.75	295.79	5227.81	5175.56	88.19	-182.52	202.71
5300	19.5	295.79	5275.05	5222.8	95.32	-197.27	219.09
5350	20.25	295.79	5322.07	5269.82	102.72	-212.58	236.09
5400	21	295.79	5368.86	5316.61	110.38	-228.43	253.7
5450	21.75	295.79	5415.43	5363.18	118.31	-244.84	271.93
5500	22.5	295.79	5461.74	5409.49	126.5	-261.8	290.76
5550	23.25	295.79	5507.81	5455.56	134.96	-279.3	310.19
5556.05	23.34	295.79	5513.37	5461.12	136	-281.45	312.59
5600	23.34	295.79	5553.72	5501.47	143.57	-297.13	330
5650	23.34	295.79	5599.63	5547.38	152.19	-314.97	349.81
5700	23.34	295.79	5645.54	5593.29	160.81	-332.81	369.62
5750	23.34	295.79	5691.45	5639.2	169.43	-350.64	389.43
5800	23.34	295.79	5737.35	5685.1	178.05	-368.48	409.24
5850	23.34	295.79	5783.26	5731.01	186.67	-386.32	429.05
5900	23.34	295.79	5829.17	5776.92	195.28	-404.15	448.86
5950	23.34	295.79	5875.08	5822.83	203.9	-421.99	468.67
6000	23.34	295.79	5920.99	5868.74	212.52	-439.83	488.48
6050	23.34	295.79	5966.89	5914.64	221.14	-457.66	508.29
6100	23.34	295.79	6012.8	5960.55	229.76	-475.5	528.1
6150	23.34	295.79	6058.71	6006.46	238.38	-493.34	547.91
6200	23.34	295.79	6104.62	6052.37	247	-511.17	567.72
6250	23.34	295.79	6150.53	6098.28	255.62	-529.01	587.53
6300	23.34	295.79	6196.44	6144.19	264.23	-546.85	607.34
6350	23.34	295.79	6242.34	6190.09	272.85	-564.68	627.15
6400	23.34	295.79	6288.25	6236	281.47	-582.52	646.96

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
6450	23.34	295.79	6334.16	6281.91	290.09	-600.36	666.77
6500	23.34	295.79	6380.07	6327.82	298.71	-618.19	686.58
6550	23.34	295.79	6425.98	6373.73	307.33	-636.03	706.39
6600	23.34	295.79	6471.89	6419.64	315.95	-653.87	726.2
6650	23.34	295.79	6517.79	6465.54	324.56	-671.71	746.01
6700	23.34	295.79	6563.7	6511.45	333.18	-689.54	765.82
6750	23.34	295.79	6609.61	6557.36	341.8	-707.38	785.63
6800	23.34	295.79	6655.52	6603.27	350.42	-725.22	805.44
6850	23.34	295.79	6701.43	6649.18	359.04	-743.05	825.25
6900	23.34	295.79	6747.33	6695.08	367.66	-760.89	845.06
6950	23.34	295.79	6793.24	6740.99	376.28	-778.73	864.87
7000	23.34	295.79	6839.15	6786.9	384.9	-796.56	884.68
7050	23.34	295.79	6885.06	6832.81	393.51	-814.4	904.49
7100	23.34	295.79	6930.97	6878.72	402.13	-832.24	924.3
7150	23.34	295.79	6976.88	6924.63	410.75	-850.07	944.11
7200	23.34	295.79	7022.78	6970.53	419.37	-867.91	963.92
7250	23.34	295.79	7068.69	7016.44	427.99	-885.75	983.73
7300	23.34	295.79	7114.6	7062.35	436.61	-903.58	1003.54
7350	23.34	295.79	7160.51	7108.26	445.23	-921.42	1023.35
7400	23.34	295.79	7206.42	7154.17	453.84	-939.26	1043.16
7450	23.34	295.79	7252.33	7200.08	462.46	-957.09	1062.97
7500	23.34	295.79	7298.23	7245.98	471.08	-974.93	1082.78
7550	23.34	295.79	7344.14	7291.89	479.7	-992.77	1102.59
7600	23.34	295.79	7390.05	7337.8	488.32	-1010.61	1122.4
7650	23.34	295.79	7435.96	7383.71	496.94	-1028.44	1142.21
7700	23.34	295.79	7481.87	7429.62	505.56	-1046.28	1162.02
7750	23.34	295.79	7527.77	7475.52	514.18	-1064.12	1181.83
7793.81	23.34	295.79	7568	7515.75	521.73	-1079.74	1199.19
7800	23.34	295.79	7573.68	7521.43	522.79	-1081.95	1201.64
7850	23.34	295.79	7619.59	7567.34	531.41	-1099.79	1221.45
7900	23.34	295.79	7665.5	7613.25	540.03	-1117.63	1241.26
7950	23.34	295.79	7711.41	7659.16	548.65	-1135.46	1261.07
8000	23.34	295.79	7757.32	7705.07	557.27	-1153.3	1280.88
8050	23.34	295.79	7803.22	7750.97	565.89	-1171.14	1300.69
8100	23.34	295.79	7849.13	7796.88	574.51	-1188.97	1320.5
8150	23.34	295.79	7895.04	7842.79	583.12	-1206.81	1340.31
8200	23.34	295.79	7940.95	7888.7	591.74	-1224.65	1360.12
8250	23.34	295.79	7986.86	7934.61	600.36	-1242.48	1379.93
8300	23.34	295.79	8032.77	7980.52	608.98	-1260.32	1399.74

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
8350	23.34	295.79	8078.67	8026.42	617.6	-1278.16	1419.55
8400	23.34	295.79	8124.58	8072.33	626.22	-1295.99	1439.36
8450	23.34	295.79	8170.49	8118.24	634.84	-1313.83	1459.17
8500	23.34	295.79	8216.4	8164.15	643.46	-1331.67	1478.98
8550	23.34	295.79	8262.31	8210.06	652.07	-1349.51	1498.79
8600	23.34	295.79	8308.21	8255.96	660.69	-1367.34	1518.6
8650	23.34	295.79	8354.12	8301.87	669.31	-1385.18	1538.41
8700	23.34	295.79	8400.03	8347.78	677.93	-1403.02	1558.22
8750	23.34	295.79	8445.94	8393.69	686.55	-1420.85	1578.03
8800	23.34	295.79	8491.85	8439.6	695.17	-1438.69	1597.84
8850	23.34	295.79	8537.76	8485.51	703.79	-1456.53	1617.65
8900	23.34	295.79	8583.66	8531.41	712.4	-1474.36	1637.46
8950	23.34	295.79	8629.57	8577.32	721.02	-1492.2	1657.27
9000	23.34	295.79	8675.48	8623.23	729.64	-1510.04	1677.08
9050	23.34	295.79	8721.39	8669.14	738.26	-1527.87	1696.89
9100	23.34	295.79	8767.3	8715.05	746.88	-1545.71	1716.7
9150	23.34	295.79	8813.2	8760.95	755.5	-1563.55	1736.51
9200	23.34	295.79	8859.11	8806.86	764.12	-1581.38	1756.32
9250	23.34	295.79	8905.02	8852.77	772.74	-1599.22	1776.13
9300	23.34	295.79	8950.93	8898.68	781.35	-1617.06	1795.94

5.3 Casing, Tubing and Completion Design Bluebonnet CCS 2

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

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

Table CON-21 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-21: Minimum safety factors for tubular design - Bluebonnet CCS 2.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 68.0 ppf, K-55	Buttress	0-3,300	1.18	1.06	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.06	2.44	2.52	2.07
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-9,300	1.89	1.12	3.5	1.44
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,950	2.52	1.29	2.04	1.4

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

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 2 well. Table CON-22 contains the open hole diameters and intervals, Table CON-23 lists the casing specifications, Table CON-24 details the conductor material, and Table CON-25 details the casing material properties.

Table CON-22: Open hole diameters and intervals - Bluebonnet CCS 2.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 9,300	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,603 ft TVD.

Table CON-23: Casing specifications - Bluebonnet CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 9,300	9 ⅝	8.535	8.379	53.5	2507 Min. 80 ksi	Premium

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

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

Table CON-25: Casing material properties - Bluebonnet CCS 2.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 9,300	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-26 contains the upper completion specifications for the original completion. Table CON-27 shows the specification of the 5 ½ in. tubing.

Table CON-26: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 2.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,940	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-27: Tubing material properties - Bluebonnet CCS 2.

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

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-28 shows the specifications of the injection packer.

Table CON-28: Packer specifications - Bluebonnet CCS 2.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

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

Notes:

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

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

5.4 Cementing Program Bluebonnet CCS 2

Table CON-29 shows the cementing program details.

Table CON-29: Cementing program - Bluebonnet CCS 2.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	1,585	2.28	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,423	1.29	50%
	CO_2-Resistant Cement	3,900 to 9,300	14.5-15.6	2,393	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

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

5.5 Centralization Program Bluebonnet CCS 2

5.5.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

5.5.2 Long String Casing

Approximately 130-135 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

5.6 Fluids Program Bluebonnet CCS 2

Table CON-30 shows the mud program details for Bluebonnet CCS 2.

Table CON-30: Mud program - Bluebonnet CCS 2.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,300	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

5.7 Wellhead Schematic Bluebonnet CCS 2

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

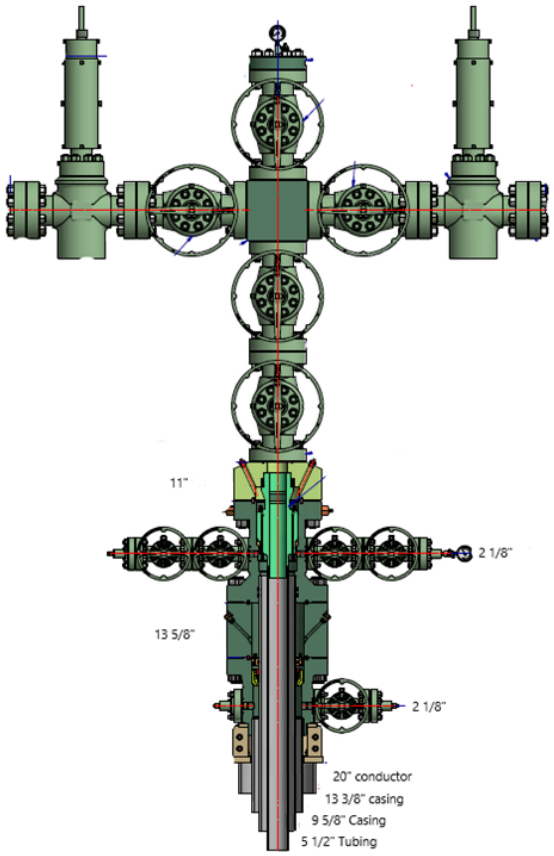


Figure CON-8: Schematic diagram of Bluebonnet CCS 2 well.

5.8 Bluebonnet CCS 2 Procedure

5.8.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

5.8.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

5.8.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing per program, coordinating running speed with the fiber optic installation.
- Once on the bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

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

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

5.8.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

6.0 Well Design Bluebonnet CCS 3 - CO_2 Injector Well

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

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

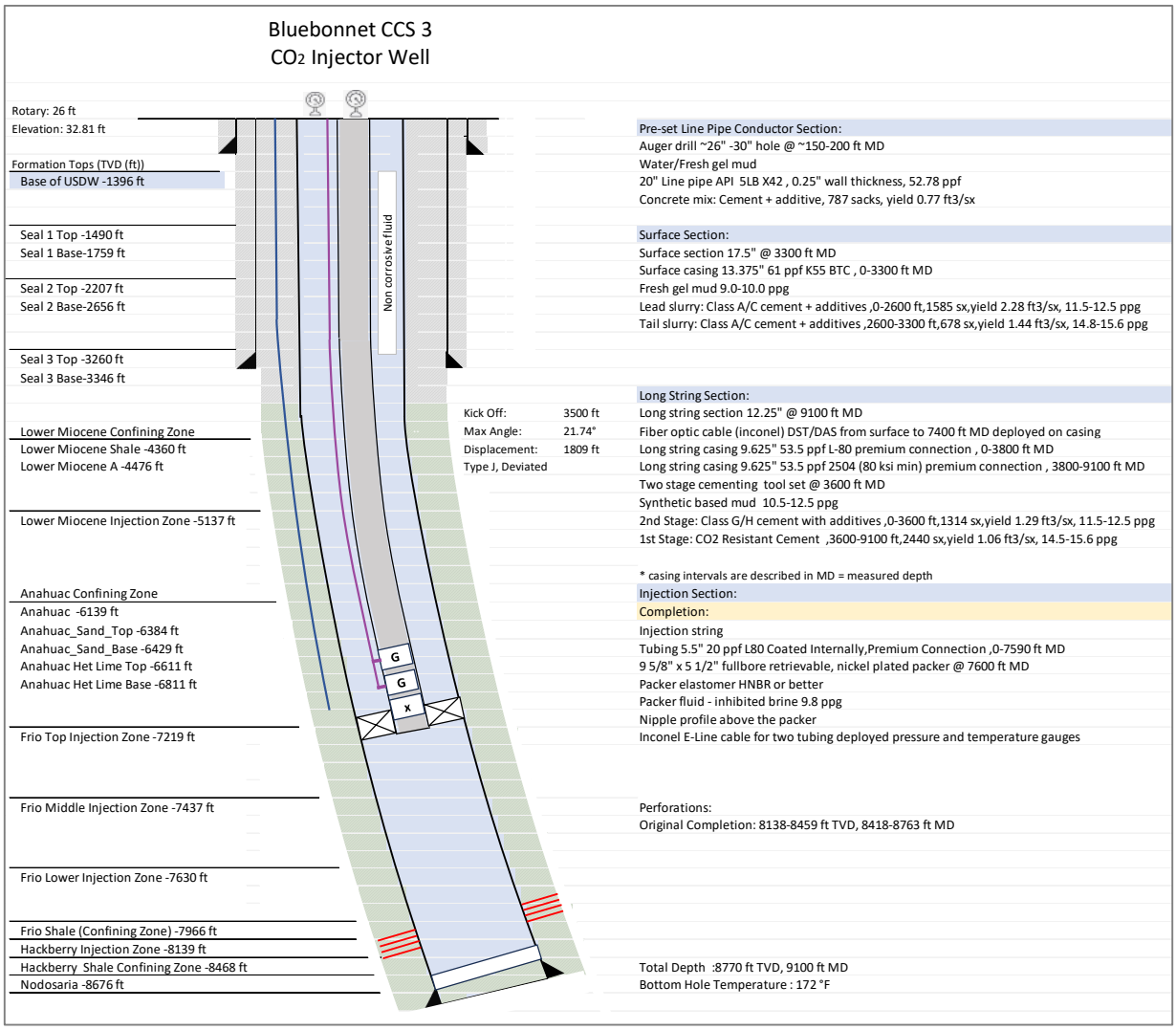


Figure CON-9: Bluebonnet CCS 3 well schematic – original completion.

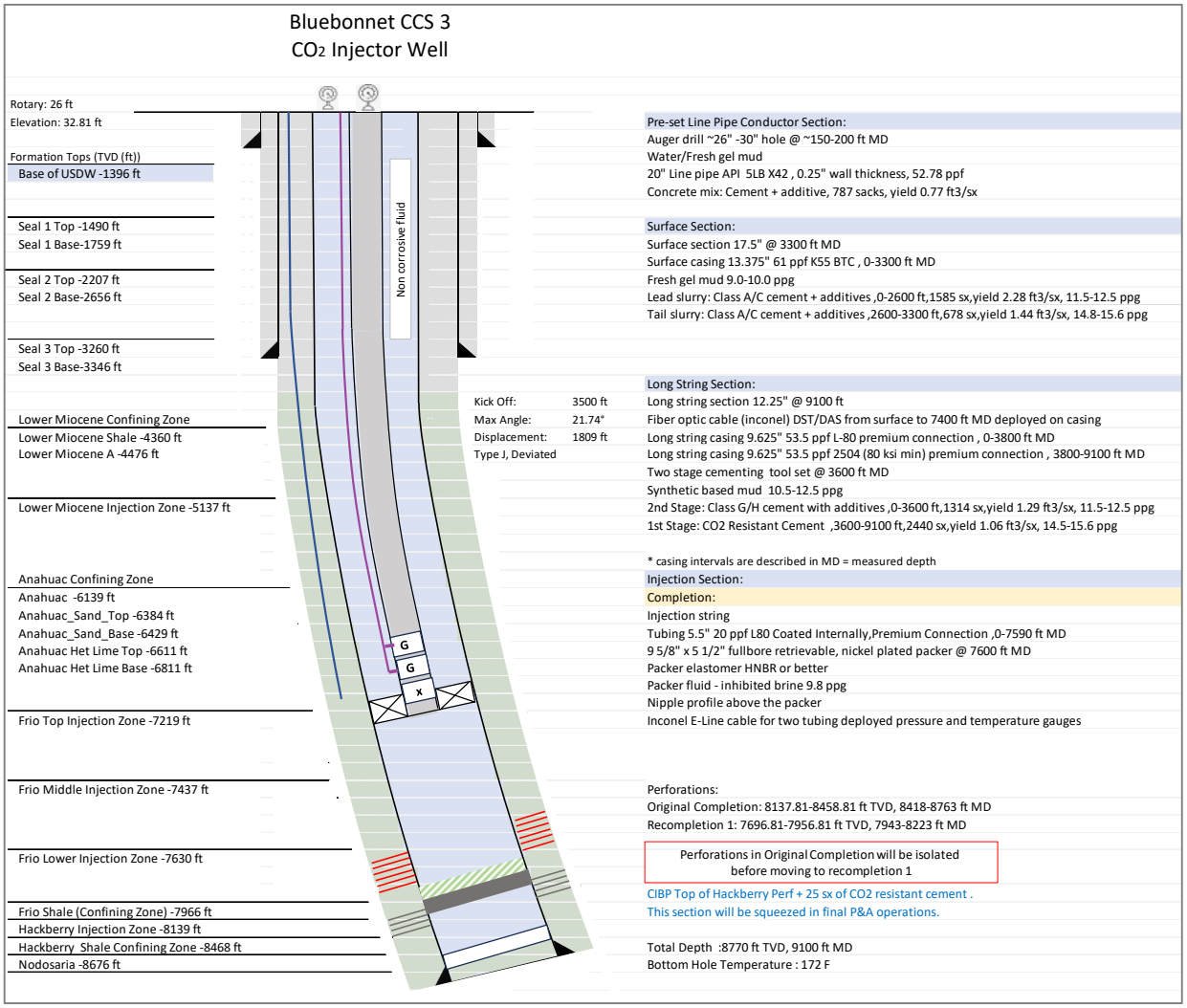


Figure CON-10: Bluebonnet CCS 3 well schematic – first recompletion.

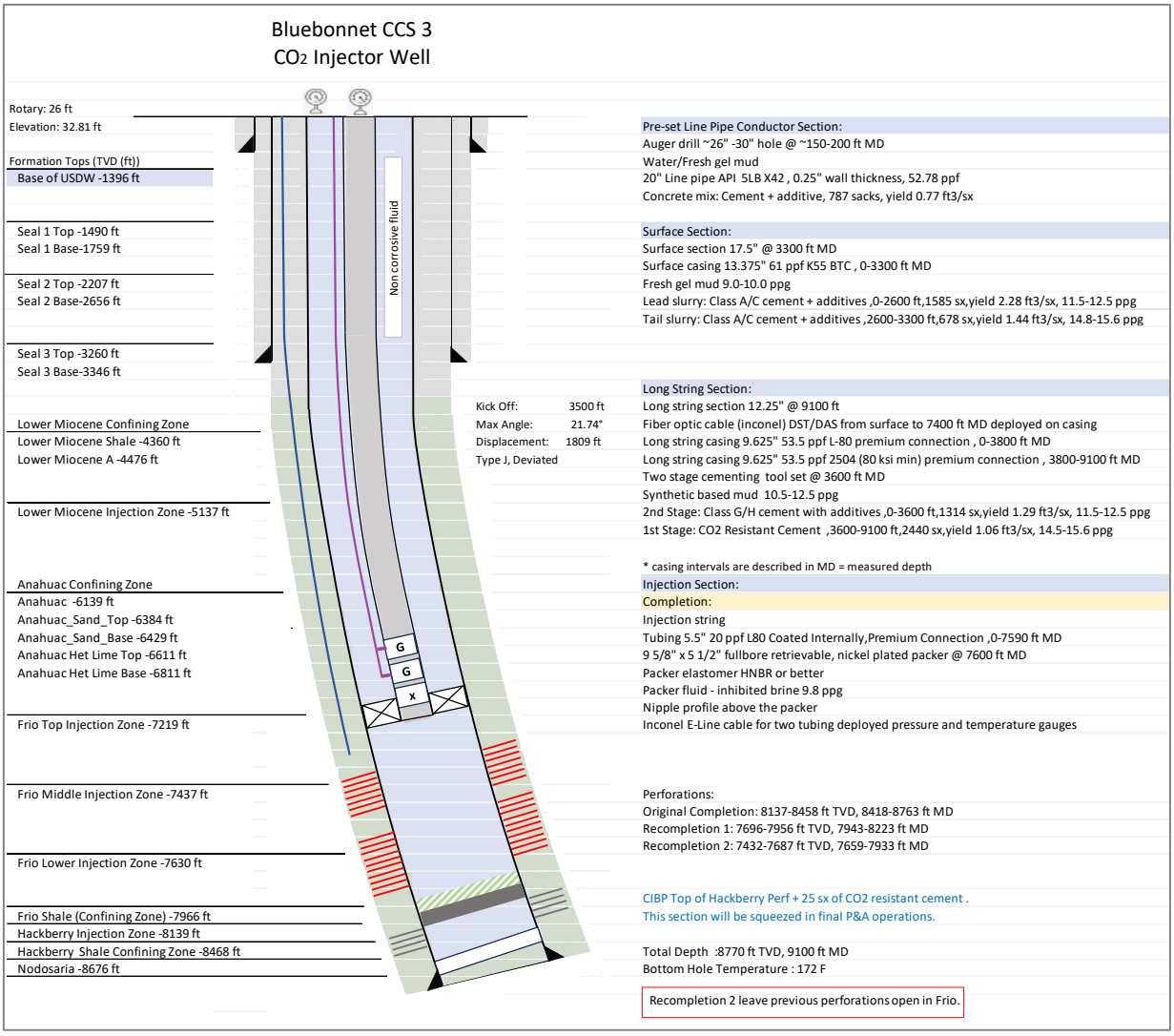


Figure CON-11: Bluebonnet CCS 3 well schematic – second recompletion.

6.1 Design Overview Bluebonnet CCS 3

6.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

6.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,396 ft TVD, and provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

6.1.3 Long String Section

Bluebonnet CCS 3 will be drilled directionally in a “J” type profile, with the kickoff point planned at 3,500 ft TVD, a maximum angle of 21.74°, and 1,809 ft displacement. The detailed trajectory is provided in Table CON-31.

A 12 ¼ in. directional wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

6.1.4 Completion

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

The 5 ½-in. tubing and packer completion will be run to approximately 7,600 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

6.2 Directional Plan Bluebonnet CCS 3

Table CON-31 summarizes the proposed trajectory for Bluebonnet CCS 3.

Table CON-31: Bluebonnet CCS 3 directional trajectory.

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
0	0	0	0	-58.81	0	0	0
3500	0	0	3500	3441.19	0	0	0
3550	0.75	148.83	3550	3491.19	-0.28	0.17	0.33
3600	1.5	148.83	3599.99	3541.18	-1.12	0.68	1.31
3650	2.25	148.83	3649.96	3591.15	-2.52	1.52	2.94
3700	3	148.83	3699.91	3641.1	-4.48	2.71	5.23
3750	3.75	148.83	3749.82	3691.01	-7	4.23	8.18
3800	4.5	148.83	3799.69	3740.88	-10.08	6.09	11.77
3850	5.25	148.83	3849.51	3790.7	-13.71	8.29	16.02
3900	6	148.83	3899.27	3840.46	-17.9	10.83	20.92
3950	6.75	148.83	3948.96	3890.15	-22.65	13.7	26.48
4000	7.5	148.83	3998.57	3939.76	-27.96	16.91	32.68
4050	8.25	148.83	4048.1	3989.29	-33.82	20.46	39.53
4100	9	148.83	4097.54	4038.73	-40.24	24.34	47.03
4150	9.75	148.83	4146.87	4088.06	-47.21	28.55	55.17

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
4200	10.5	148.83	4196.09	4137.28	-54.73	33.1	63.96
4250	11.25	148.83	4245.19	4186.38	-62.8	37.99	73.39
4300	12	148.83	4294.16	4235.35	-71.42	43.2	83.47
4350	12.75	148.83	4343	4284.19	-80.59	48.75	94.19
4400	13.5	148.83	4391.7	4332.89	-90.3	54.62	105.54
4450	14.25	148.83	4440.24	4381.43	-100.56	60.83	117.53
4500	15	148.83	4488.62	4429.81	-111.37	67.36	130.15
4550	15.75	148.83	4536.83	4478.02	-122.71	74.22	143.41
4600	16.5	148.83	4584.86	4526.05	-134.59	81.41	157.3
4650	17.25	148.83	4632.71	4573.9	-147.01	88.92	171.81
4700	18	148.83	4680.36	4621.55	-159.96	96.76	186.95
4750	18.75	148.83	4727.81	4669	-173.45	104.91	202.71
4800	19.5	148.83	4775.05	4716.24	-187.47	113.39	219.09
4850	20.25	148.83	4822.07	4763.26	-202.01	122.19	236.09
4900	21	148.83	4868.86	4810.05	-217.08	131.31	253.7
4949.52	21.74	148.83	4914.98	4856.17	-232.52	140.64	271.75
4950	21.74	148.83	4915.43	4856.62	-232.67	140.74	271.93
5000	21.74	148.83	4961.87	4903.06	-248.52	150.32	290.45
5050	21.74	148.83	5008.31	4949.5	-264.37	159.91	308.97
5100	21.74	148.83	5054.75	4995.94	-280.22	169.5	327.49
5150	21.74	148.83	5101.2	5042.39	-296.07	179.08	346.02
5200	21.74	148.83	5147.64	5088.83	-311.92	188.67	364.54
5250	21.74	148.83	5194.08	5135.27	-327.76	198.25	383.06
5300	21.74	148.83	5240.52	5181.71	-343.61	207.84	401.58
5350	21.74	148.83	5286.97	5228.16	-359.46	217.43	420.1
5400	21.74	148.83	5333.41	5274.6	-375.31	227.01	438.63
5450	21.74	148.83	5379.85	5321.04	-391.16	236.6	457.15
5500	21.74	148.83	5426.3	5367.49	-407.01	246.19	475.67
5550	21.74	148.83	5472.74	5413.93	-422.85	255.77	494.19
5600	21.74	148.83	5519.18	5460.37	-438.7	265.36	512.71
5650	21.74	148.83	5565.62	5506.81	-454.55	274.94	531.24
5700	21.74	148.83	5612.07	5553.26	-470.4	284.53	549.76
5750	21.74	148.83	5658.51	5599.7	-486.25	294.12	568.28
5800	21.74	148.83	5704.95	5646.14	-502.1	303.7	586.8
5850	21.74	148.83	5751.4	5692.59	-517.94	313.29	605.32
5900	21.74	148.83	5797.84	5739.03	-533.79	322.87	623.85
5950	21.74	148.83	5844.28	5785.47	-549.64	332.46	642.37
6000	21.74	148.83	5890.72	5831.91	-565.49	342.05	660.89
6050	21.74	148.83	5937.17	5878.36	-581.34	351.63	679.41

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
6100	21.74	148.83	5983.61	5924.8	-597.19	361.22	697.93
6150	21.74	148.83	6030.05	5971.24	-613.03	370.81	716.46
6200	21.74	148.83	6076.5	6017.69	-628.88	380.39	734.98
6250	21.74	148.83	6122.94	6064.13	-644.73	389.98	753.5
6300	21.74	148.83	6169.38	6110.57	-660.58	399.56	772.02
6350	21.74	148.83	6215.82	6157.01	-676.43	409.15	790.54
6400	21.74	148.83	6262.27	6203.46	-692.28	418.74	809.07
6450	21.74	148.83	6308.71	6249.9	-708.12	428.32	827.59
6500	21.74	148.83	6355.15	6296.34	-723.97	437.91	846.11
6550	21.74	148.83	6401.6	6342.79	-739.82	447.49	864.63
6600	21.74	148.83	6448.04	6389.23	-755.67	457.08	883.15
6650	21.74	148.83	6494.48	6435.67	-771.52	466.67	901.68
6700	21.74	148.83	6540.92	6482.11	-787.37	476.25	920.2
6750	21.74	148.83	6587.37	6528.56	-803.21	485.84	938.72
6800	21.74	148.83	6633.81	6575	-819.06	495.43	957.24
6850	21.74	148.83	6680.25	6621.44	-834.91	505.01	975.76
6900	21.74	148.83	6726.7	6667.89	-850.76	514.6	994.29
6950	21.74	148.83	6773.14	6714.33	-866.61	524.18	1012.81
7000	21.74	148.83	6819.58	6760.77	-882.46	533.77	1031.33
7050	21.74	148.83	6866.02	6807.21	-898.3	543.36	1049.85
7100	21.74	148.83	6912.47	6853.66	-914.15	552.94	1068.37
7150	21.74	148.83	6958.91	6900.1	-930	562.53	1086.9
7200	21.74	148.83	7005.35	6946.54	-945.85	572.12	1105.42
7250	21.74	148.83	7051.8	6992.99	-961.7	581.7	1123.94
7300	21.74	148.83	7098.24	7039.43	-977.55	591.29	1142.46
7350	21.74	148.83	7144.68	7085.87	-993.39	600.87	1160.98
7400	21.74	148.83	7191.12	7132.31	-1009.24	610.46	1179.51
7450	21.74	148.83	7237.57	7178.76	-1025.09	620.05	1198.03
7500	21.74	148.83	7284.01	7225.2	-1040.94	629.63	1216.55
7550	21.74	148.83	7330.45	7271.64	-1056.79	639.22	1235.07
7600	21.74	148.83	7376.89	7318.08	-1072.64	648.8	1253.59
7650	21.74	148.83	7423.34	7364.53	-1088.48	658.39	1272.11
7661.48	21.74	148.83	7434	7375.19	-1092.12	660.59	1276.37
7700	21.74	148.83	7469.78	7410.97	-1104.33	667.98	1290.64
7750	21.74	148.83	7516.22	7457.41	-1120.18	677.56	1309.16
7800	21.74	148.83	7562.67	7503.86	-1136.03	687.15	1327.68
7850	21.74	148.83	7609.11	7550.3	-1151.88	696.74	1346.2
7900	21.74	148.83	7655.55	7596.74	-1167.73	706.32	1364.72
7950	21.74	148.83	7701.99	7643.18	-1183.57	715.91	1383.25

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	TVDSS (ft)	NS (ft)	EW (ft)	VSEC (ft)
8000	21.74	148.83	7748.44	7689.63	-1199.42	725.49	1401.77
8050	21.74	148.83	7794.88	7736.07	-1215.27	735.08	1420.29
8100	21.74	148.83	7841.32	7782.51	-1231.12	744.67	1438.81
8150	21.74	148.83	7887.77	7828.96	-1246.97	754.25	1457.33
8200	21.74	148.83	7934.21	7875.4	-1262.82	763.84	1475.86
8250	21.74	148.83	7980.65	7921.84	-1278.66	773.42	1494.38
8300	21.74	148.83	8027.09	7968.28	-1294.51	783.01	1512.9
8350	21.74	148.83	8073.54	8014.73	-1310.36	792.6	1531.42
8400	21.74	148.83	8119.98	8061.17	-1326.21	802.18	1549.94
8450	21.74	148.83	8166.42	8107.61	-1342.06	811.77	1568.47
8500	21.74	148.83	8212.87	8154.06	-1357.91	821.36	1586.99
8550	21.74	148.83	8259.31	8200.5	-1373.75	830.94	1605.51
8600	21.74	148.83	8305.75	8246.94	-1389.6	840.53	1624.03
8650	21.74	148.83	8352.19	8293.38	-1405.45	850.11	1642.55
8700	21.74	148.83	8398.64	8339.83	-1421.3	859.7	1661.08
8750	21.74	148.83	8445.08	8386.27	-1437.15	869.29	1679.6
8800	21.74	148.83	8491.52	8432.71	-1453	878.87	1698.12
8850	21.74	148.83	8537.97	8479.16	-1468.84	888.46	1716.64
8900	21.74	148.83	8584.41	8525.6	-1484.69	898.04	1735.16
8950	21.74	148.83	8630.85	8572.04	-1500.54	907.63	1753.69
9000	21.74	148.83	8677.29	8618.48	-1516.39	917.22	1772.21
9050	21.74	148.83	8723.74	8664.93	-1532.24	926.8	1790.73
9100	21.74	148.83	8770.18	8711.37	-1548.09	936.39	1809.25

6.3 Casing, Tubing and Completion Design Bluebonnet CCS 3

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

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

Table CON-32 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-32: Minimum safety factors for tubular design - Bluebonnet CCS 3.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,300	1.18	1.08	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,800	2.06	2.63	2.56	2.06
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,800-9,100	1.90	1.14	3.56	1.47
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-7,600	2.56	1.32	2.09	1.44

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

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 3 well. Table CON-33 contains the open hole diameters and intervals, Table CON-34 lists the casing specifications, Table CON-35 details the conductor material, and Table CON-36 details the casing material properties.

Table CON-33: Open hole diameters and intervals - Bluebonnet CCS 3.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 9,100	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,396 ft TVD.

Table CON-34: Casing specifications - Bluebonnet CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,800	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,800 to 9,100	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

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

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

Table CON-36: Casing material properties - Bluebonnet CCS 3.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,800	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,800 to 9,100	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,600 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-37 contains the upper completion specifications for the original completion and recompletions. Table CON-38 shows the specification of the 5 ½ in. tubing.

Table CON-37: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 3.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 7,590	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-38: Tubing material properties - Bluebonnet CCS 3.

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

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-39 shows the specifications of the injection packer.

Table CON-39: Packer specifications - Bluebonnet CCS 3.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

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

Notes:

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

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

6.4 Cementing Program Bluebonnet CCS 3

Table CON-40 shows the cementing program details.

Table CON-40: Cementing program - Bluebonnet CCS 3.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	1,585	2.28	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,800	11.5-12.5	1,314	1.29	50%
	CO_2-Resistant Cement	3,800 to 9,100	14.5-15.6	2,440	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,600 ft, but the depth will be adjusted based on final drilling conditions.

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

6.5 Centralization Program Bluebonnet CCS 3

6.5.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

6.5.2 Long String Casing

Approximately 130-135 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the

field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,600 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

6.6 Fluids Program Bluebonnet CCS 3

Table CON-41 shows the mud program details for Bluebonnet CCS 3.

Table CON-41: Mud program - Bluebonnet CCS 3.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

6.7 Wellhead Schematic Bluebonnet CCS 3

Figure CON-12 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 3 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

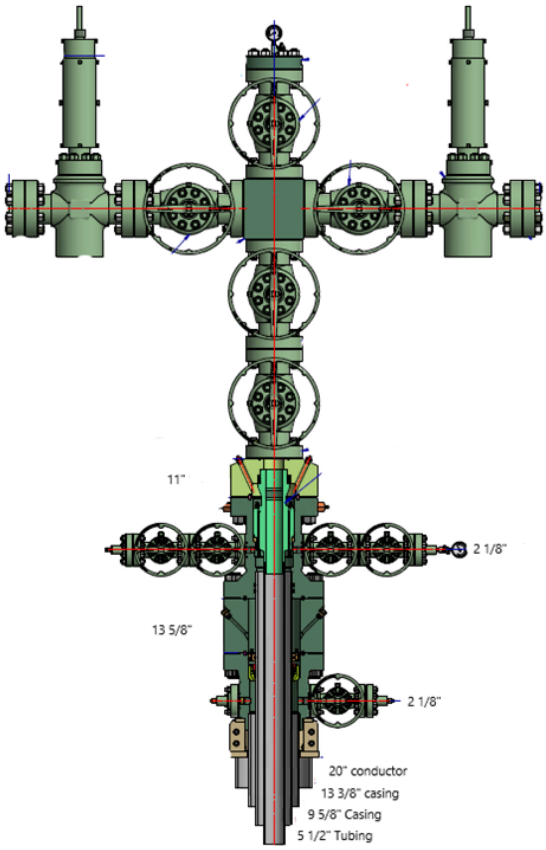


Figure CON-12: Schematic diagram of Bluebonnet CCS 3 well.

6.8 Bluebonnet CCS 3 Procedure

6.8.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

6.8.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).

- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting, and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

6.8.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

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

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

6.8.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

7.0 Well Design Bluebonnet CCS 5 - CO_2 Injector Well

The Bluebonnet CCS 5 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-13 shows the proposed well schematic for the Bluebonnet CCS 5 original completion.

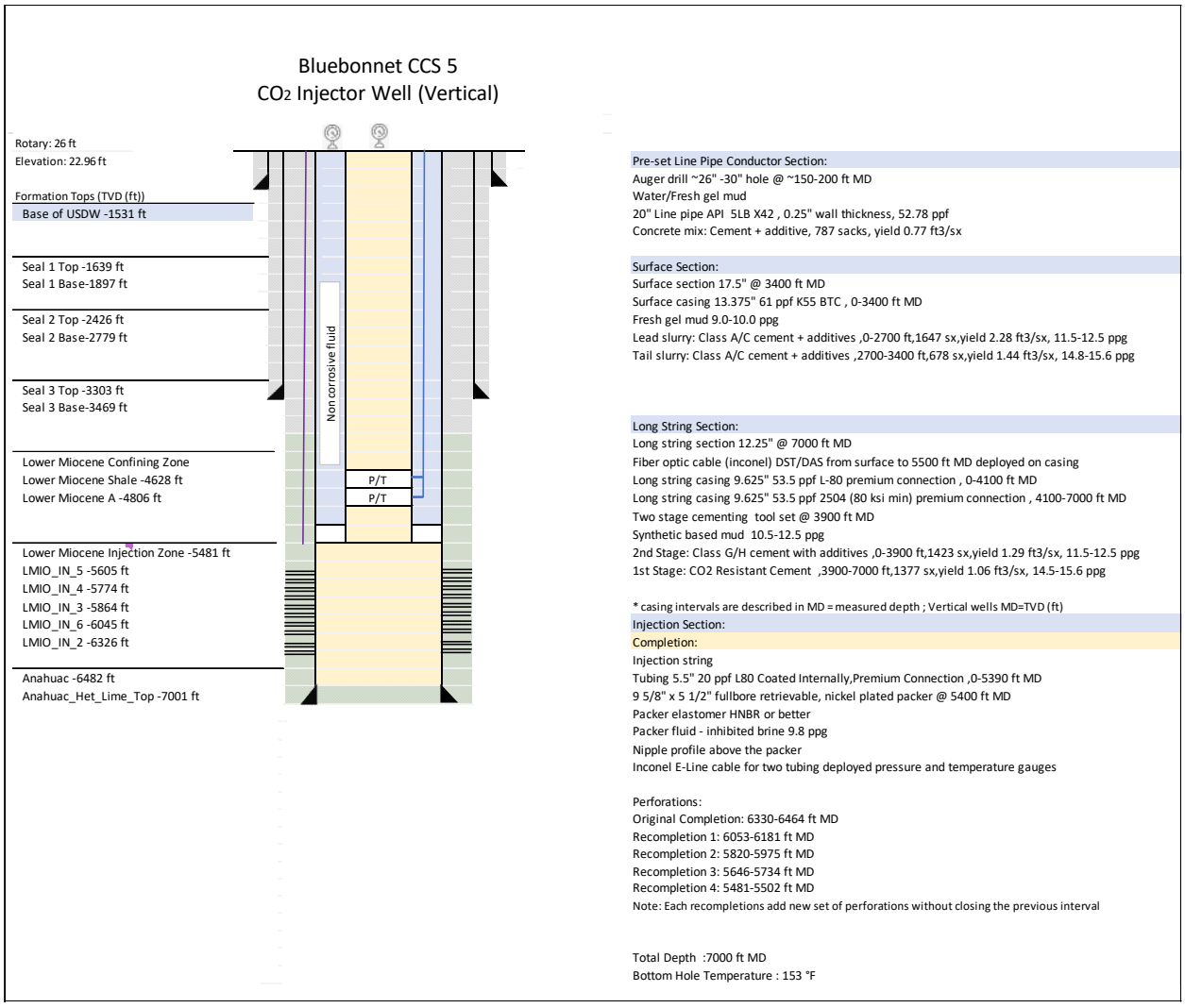


Figure CON-13: Bluebonnet CCS 5 well schematic.

7.1 Design Overview Bluebonnet CCS 5

7.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

7.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,400 ft to cover base of the USDW, estimated at 1,531 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

7.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,400 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

7.1.4 Completion

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

The 5 ½-in. tubing and packer completion will be run to approximately 5,400 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

7.2 Casing, Tubing and Completion Design Bluebonnet CCS 5

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

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

Table CON-42 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-42: Minimum safety factors for tubular design - Bluebonnet CCS 5.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,400	1.18	1.35	2.51	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.07	2.45	3.05	2.17
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-7,000	1.98	1.44	4.63	1.85
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,400	2.57	1.49	2.41	1.63

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

The WELLCAT^{TM} evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 5 well. Table CON-43 contains the open hole diameters and intervals, Table CON-44 lists the casing specifications, Table CON-45 details the conductor material, and Table CON-46 details the casing material properties.

Table CON-43: Open hole diameters and intervals - Bluebonnet CCS 5.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,400	17 ½	Cover USDW
Long String Section	3,400 to 7,000	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,531 ft TVD.

Table CON-44: Casing specifications - Bluebonnet CCS 5.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,400	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 7,000	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-45: Conductor material properties - Bluebonnet CCS 5.

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

Table CON-46: Casing material properties - Bluebonnet CCS 5.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,400	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 7,000	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-47 contains the upper completion specifications for the original completion and recompletions. Table CON-38 shows the specification of the 5 ½ in. tubing.

Table CON-47: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 5.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,390	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-48: Tubing material properties - Bluebonnet CCS 5.

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

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-49 shows the specifications of the injection packer.

Table CON-49: Packer specifications - Bluebonnet CCS 5.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

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

Notes:

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

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

7.3 Cementing Program Bluebonnet CCS 5

Table CON-50 shows the cementing program details.

Table CON-50: Cementing program - Bluebonnet CCS 5.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,627	2.28	100%
	Class A/C cement with additives	2,700 to 3,400	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,423	1.29	50%
	CO_2-Resistant Cement	3,900 to 7,000	14.5-15.6	1,377	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

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

7.4 Centralization Program Bluebonnet CCS 5

7.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

7.4.2 Long String Casing

Approximately 100-105 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the

field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

7.5 Fluids Program Bluebonnet CCS 5

Table CON-51 shows the mud program details for Bluebonnet CCS 5.

Table CON-51: Mud program - Bluebonnet CCS 5.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

7.6 Wellhead Schematic Bluebonnet CCS 5

Figure CON-14 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 5 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

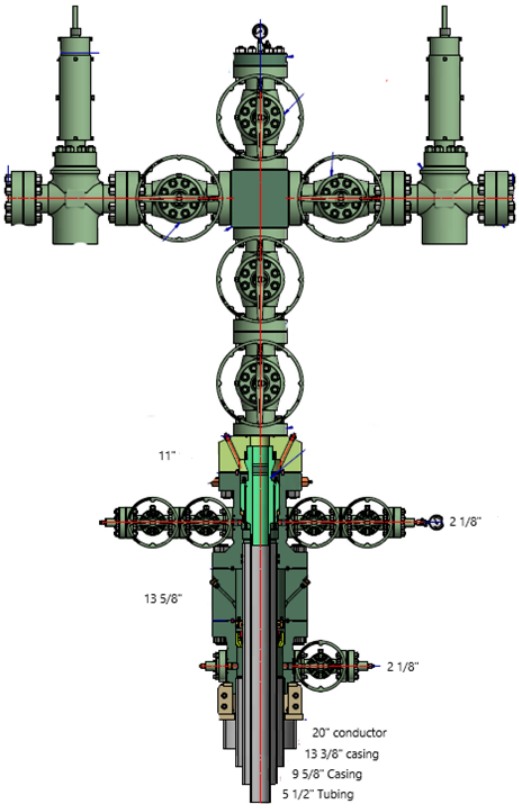


Figure CON-14: Schematic diagram of Bluebonnet CCS 5 well.

7.7 Bluebonnet CCS 5 Procedure

7.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

7.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.

- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.

- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

7.7.3 Long String Section

- Perform apre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.

- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

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

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

7.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.

- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

8.0 Well Design Bluebonnet CCS 6 - CO_2 Injector Well

The Bluebonnet CCS 6 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-15 shows the proposed well schematic for the Bluebonnet CCS 6 original completion.

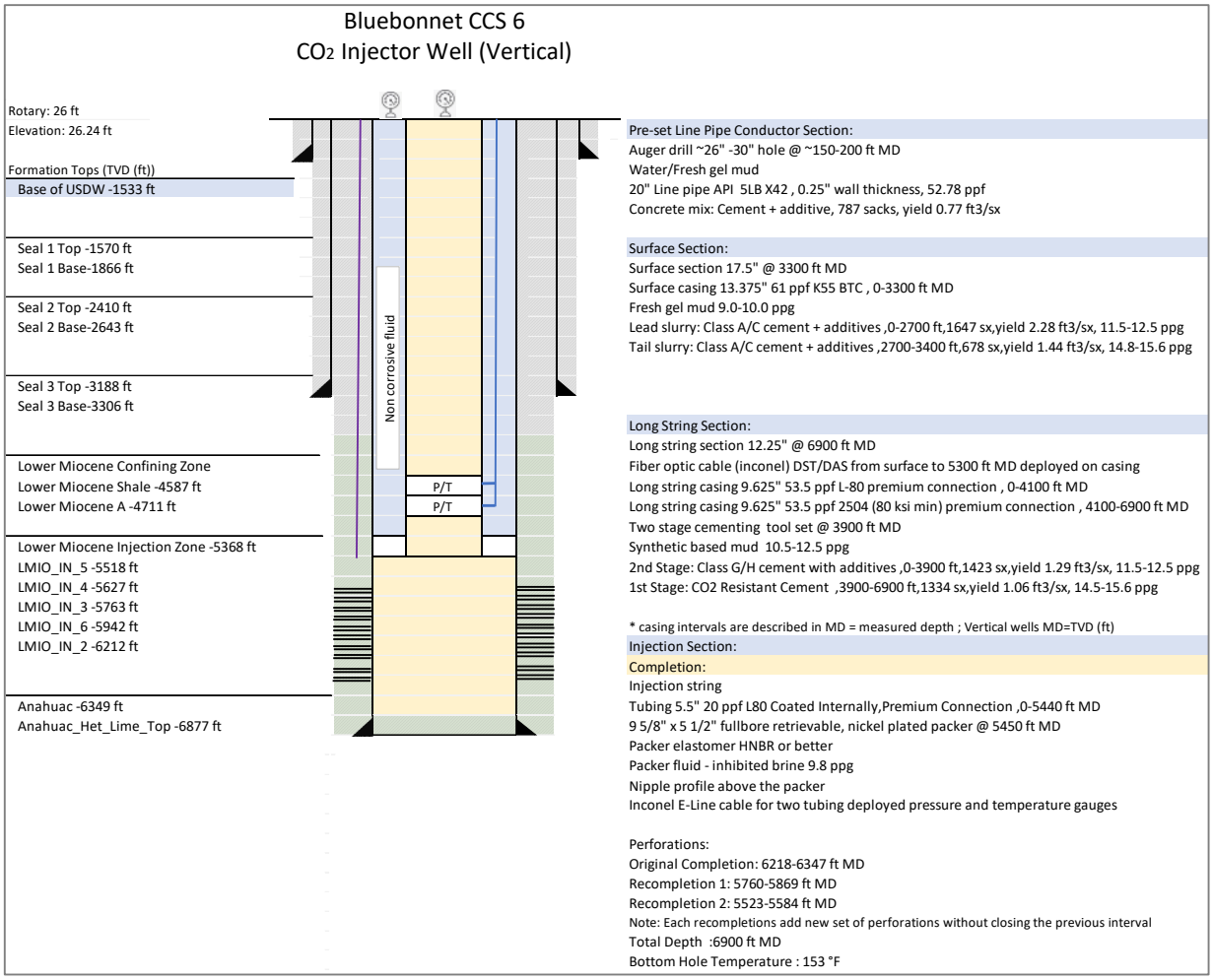


Figure CON-15: Bluebonnet CCS 6 well schematic.

8.1 Design Overview Bluebonnet CCS 6

8.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

8.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,533 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

8.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

8.1.4 Completion

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

The 5 ½-in. tubing and packer completion will be run to approximately 5,450 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

8.2 Casing, Tubing and Completion Design Bluebonnet CCS 6

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

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

Table CON-52 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-52: Minimum safety factors for tubular design - Bluebonnet CCS 6.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,300	1.18	1.37	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-4,100	2.07	2.45	3.09	2.18
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	4,100-6,900	1.99	1.46	4.66	1.88
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,450	2.57	1.49	2.41	1.63

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

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 6 well. Table CON-53 contains the open hole diameters and intervals, Table CON-54 lists the casing specifications, Table CON-55 details the conductor material, and Table CON-56 details the casing material properties.

Table CON-53: Open hole diameters and intervals - Bluebonnet CCS 6.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 6,900	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,533 ft TVD.

Table CON-54: Casing specifications - Bluebonnet CCS 6.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 4,100	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	4,100 to 6,900	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-55: Conductor material properties - Bluebonnet CCS 6.

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

Table CON-56: Casing material properties - Bluebonnet CCS 6.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 4,100	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	4,100 to 6,900	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,900 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-57 contains the upper completion specifications for the original completion and recompletions. Table CON-58 shows the specification of the 5 ½ in. tubing.

Table CON-57: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 6.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,440	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-58: Tubing material properties - Bluebonnet CCS 6.

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

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-59 shows the specifications of the injection packer.

Table CON-59: Packer specifications - Bluebonnet CCS 6.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

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

Notes:

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

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

8.3 Cementing Program Bluebonnet CCS 6

Table CON-60 shows the cementing program details.

Table CON-60: Cementing program - Bluebonnet CCS 6.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,700	11.5-12.5	1,647	2.28	100%
	Class A/C cement with additives	2,700 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,900	11.5-12.5	1,423	1.29	50%
	CO_2-Resistant Cement	3,900 to 6,900	14.5-15.6	1,334	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,900 ft, but the depth will be adjusted based on final drilling conditions.

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

8.4 Centralization Program Bluebonnet CCS 6

8.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

8.4.2 Long String Casing

Approximately 100-105 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

8.5 Fluids Program Bluebonnet CCS 6

Table CON-61 shows the mud program details for Bluebonnet CCS 6.

Table CON-61: Mud program - Bluebonnet CCS 6.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

8.6 Wellhead Schematic Bluebonnet CCS 6

Figure CON-16 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 6 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

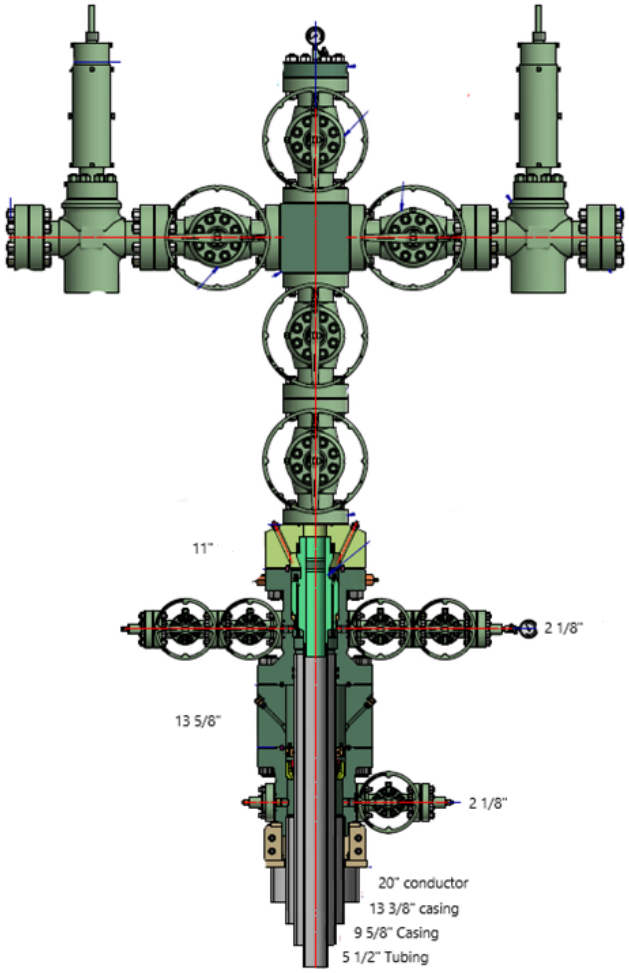


Figure CON-16: Schematic diagram of Bluebonnet CCS 6 well.

8.7 Bluebonnet CCS 6 Procedure

8.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

8.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.

- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.
- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

8.7.3 Long String Section

- Perform pre-section meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.

- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.
- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and casing slips and test the correct function of the tools.
- Rig up the spooler and equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing as per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.

- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer's recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

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

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

8.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.

- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.
- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform and injectivity test/step rate test and falloff test.

9.0 Well Design Bluebonnet CCS 7 - CO_2 Injector Well

The Bluebonnet CCS 7 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

Figure CON-17 shows the proposed well schematic for the Bluebonnet CCS 7 the original completion.

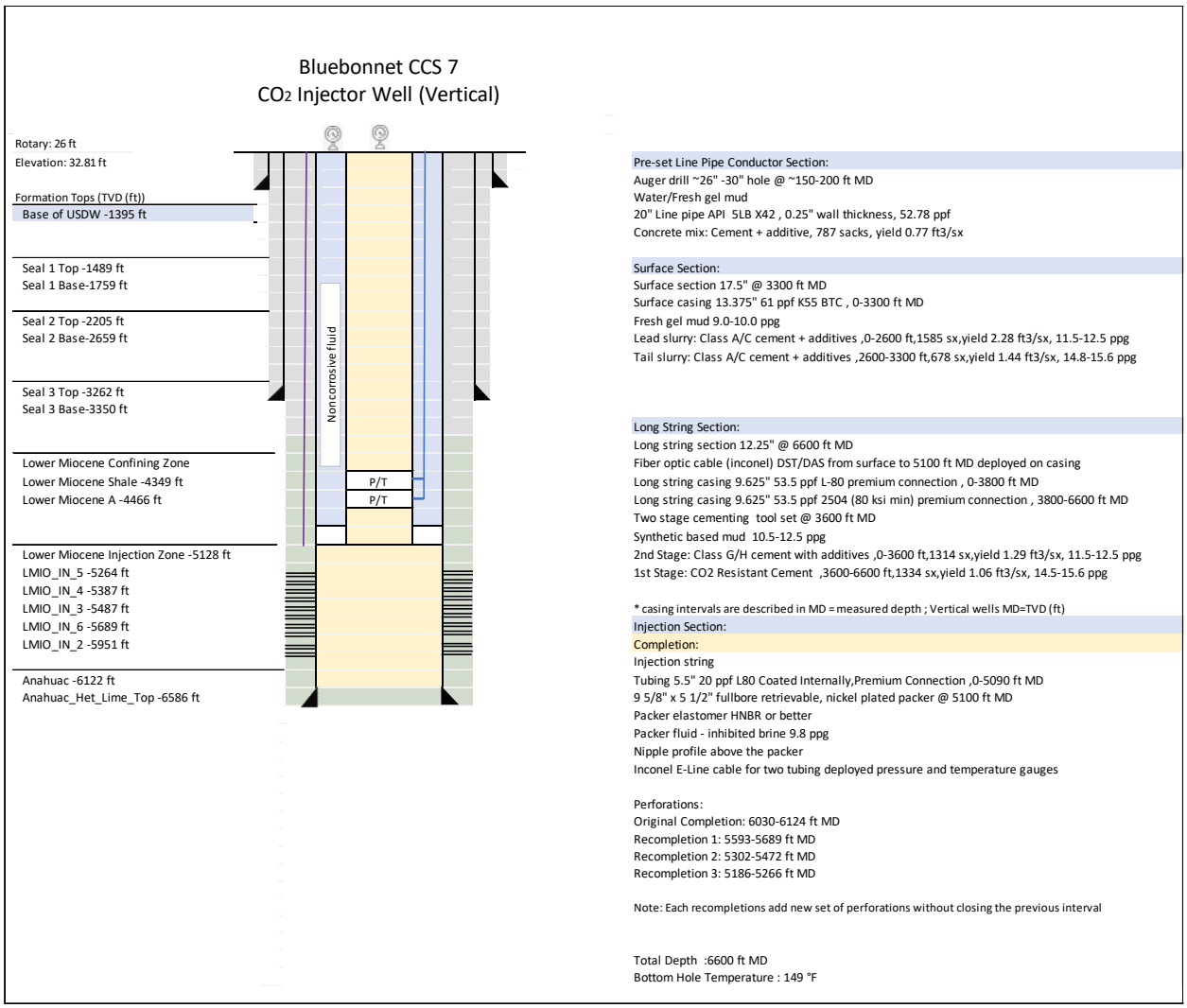


Figure CON-17: Bluebonnet CCS 7 well schematic.

9.1 Design Overview Bluebonnet CCS 7

9.1.1 Conductor

The 26 – 30 in. wellbore for the conductor casing will be drilled via auger to a depth approximately of 150 – 200 ft. The wellbore will be cased with a 20-in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

9.1.2 Surface Section

The 17 ½ in. vertical wellbore will be drilled to 3,300 ft to cover base of the USDW, estimated at 1,395 ft TVD, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operation Formation Testing Plan. Then, 13 3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the UIC Program Director. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

9.1.3 Long String Section

A 12 ¼ in. vertical wellbore will be drilled from 3,300 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Then, the long string of 9 5/8-in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO_2-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

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

9.1.4 Completion

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

The 5 ½-in. tubing and packer completion will be run to approximately 5,100 ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

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

9.2 Casing, Tubing and Completion Design Bluebonnet CCS 7

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

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

Table CON-62 shows the minimum safety factors calculated using Stress Check™ software from Landmark, based on the loads that the tubulars will experience during construction and injection operations. All the selected casing strings are within acceptable design limits.

Table CON-62: Minimum safety factors for tubular design - Bluebonnet CCS 7.

Section	Description	Connection	Depths	Burst	Collapse	Axial	Triaxial
Surface Casing	13 3/8-in., 61.0 ppf, K-55	Buttress	0-3,300	1.18	1.59	2.53	1.32
Long String Casing	9 5/8-in., 53.5 ppf, L-80	Premium, Gas Sealing	0-3,800	2.08	2.65	3.19	2.18
Long String Casing	9 5/8-in., 53.5 ppf, 2507, 80 ksi min	Premium, Gas Sealing	3,800-6,600	2.00	1.52	4.77	1.97
Tubing	5 ½-in., 20.0 ppf, L-80, Internally Coated	Premium, Gas Sealing	0-5,100	2.57	1.53	2.48	1.67

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

The WELLCATTM evaluation performed for Bluebonnet CCS 1 applies to the loads observed for Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 (Appendix E).

The tables listed below provide further details regarding the Bluebonnet CCS 7 well. Table CON-63 contains the open hole diameters and intervals, Table CON-64 lists the casing specifications, Table CON-65 details the conductor material, and Table CON-46 details the casing material properties.

Table CON-63: Open hole diameters and intervals - Bluebonnet CCS 7.

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor	0-200	26-30	Auger Drilled
Surface Section	0 to 3,300	17 ½	Cover USDW
Long String Section	3,300 to 6,600	12 ¼	To Total Depth

Note:

- The USDW depth will be confirmed with open hole logs. The USDW is estimated at 1,395 ft TVD.

Table CON-64: Casing specifications - Bluebonnet CCS 7.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Conductor	0-200	20	0.25-in. wall thickness, 19.5-in. ID		52.78	API 5LB X42	Welded
Surface String	0 to 3,300	13 ⅜	12.515	12.359	61	K55	BTC
Long String	0 to 3,800	9 ⅝	8.535	8.379	53.5	L80	Premium
Long String	3,800 to 6,600	9 ⅝	8.535	8.379	53.5	2507 Min 80 ksi	Premium

Table CON-65: Conductor material properties - Bluebonnet CCS 7.

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

Table CON-66: Casing material properties - Bluebonnet CCS 7.

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)	Max Allowed Bending °/100 ft	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
13 ⅜-in. 68 ppf K55 BTC	0 to 3,300	3,090	1,540	962	19°	26.2
9 ⅝-in. 53.5 ppf L80 Premium connection	0 to 3,800	7,930	6,620	1,244	38°	26.2
9 5/8-in. 53.5 ppf 2507 80 ksi Premium Connection	3,800 to 6,600	7,930	6,620	1,244	38°	8

Notes:

- A stage tool will be located at ~3,600 ft in the 9 5/8-in. casing to perform the two-stage cementing job.
- The DST/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program to the top of the injection interval. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

In addition, Table CON-67 contains the upper completion specifications for the original completion and recompletions. Table CON-68 shows the specification of the 5 ½ in. tubing.

Table CON-67: Upper completion specifications – initial completion and first recompletion - Bluebonnet CCS 7.

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Grade (API)	Coupling
Injection tubing (Coated TK-805)	0 to 5,090	5 ½	4.778	4.653	20	L80	Premium
Packer	Nickel-plated in all wetted surfaces / HNBR (RGD) Elastomers						

Table CON-68: Tubing material properties - Bluebonnet CCS 7.

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

Notes:

- Pressure and temperature gauges will be tubing-deployed above the packer, ported to the tubing and to the annulus. Cable material will be Inconel and gauge carriers will be CO_2-resistant material.
- The packer depth will be adjusted once the final perforation depth interval is known.

Table CON-69 shows the specifications of the injection packer.

Table CON-69: Packer specifications - Bluebonnet CCS 7.

Packer type and material	Nominal casing weight (ppf)	Packer main body outer diameter (in.)	Packer main body inner diameter (in.)	Temperature rating (°F)	Pressure rating (psi)
Full-bore retrievable, nickel-plated at all wet surfaces	47-53.5	8.35	4.575	40-325	10,000

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

Notes:

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

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

9.3 Cementing Program Bluebonnet CCS 7

Table CON-70 shows the cementing program details.

Table CON-70: Cementing program - Bluebonnet CCS 7.

Section	Type	Depths (ft)	Density (ppg)	Sacks (sx)	Yield ft^3/sx	Excess
Conductor	Concrete Mix	0-200				
Surface Section	Class A/C cement with additives	0 to 2,600	11.5-12.5	1,585	2.28	100%
	Class A/C cement with additives	2,600 to 3,300	14.8-15.6	678	1.44	100%
Long String Section	Portland cement with additives	0 to 3,600	11.5-12.5	1,314	1.29	50%
	CO_2-Resistant Cement	3,600 to 6,600	14.5-15.6	1,334	1.06	50%

Notes:

- The slurry design might change in cement type, density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the injection, confining, and USDW zones. The cementing stage tool is estimated at 3,600 ft, but the depth will be adjusted based on final drilling conditions.

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

9.4 Centralization Program Bluebonnet CCS 7

9.4.1 Surface Casing

Approximately 45-50 bow spring centralizers will be installed on the 13 3/8-inch surface casing. The centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar; and
- 1 Centralizer every other collar, up to the surface.

9.4.2 Long String Casing

Approximately 95-100 centralizers will be installed on the 9 5/8-inch long string casing. The type of centralizers and spacing will aim a minimum of 70% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions. As minimum program, the centralizers will be placed as follows:

- 1 Centralizer 10 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 10 feet above the float collar, straddling a stop collar;
- 1 Centralizer every other collar, to the multistage cement tool ~ 3,900 feet;
- 1 Centralizer below and above the multistage cement tool; and
- 1 Centralizer every other collar, from the stage tool to surface.

9.5 Fluids Program Bluebonnet CCS 7

Table CON-71 shows the mud program details for Bluebonnet CCS 7.

Table CON-71: Mud program - Bluebonnet CCS 7.

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lb/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½-in.	Freshwater Gel	0–3,300	9.0-10.0	12–14	14–18	40–50	n/a	5–7
12 ¼-in.	Synthetic-Based Mud	3,300–9,100	10.5-12.5	12–20	8–12	n/a	<5	<5

The space between the 5 ½-inch tubing and the 9 ⅝-inch casing will be filled with specially treated packer fluid. This packer fluid will be comprised of inhibited brine, weighted with either NaCl or KCl to a density of 10 pounds per gallon. Additionally, it will include various additives such as H_2S scavengers, O^2 scavengers, corrosion inhibitors, and biocides.

9.6 Wellhead Schematic Bluebonnet CCS 7

Figure CON-18 below is a basic mechanical drawing of the wellhead to be used for the Bluebonnet CCS 7 well. Details on blowout preventors (BOPs) and wellhead design are included in Appendix C.

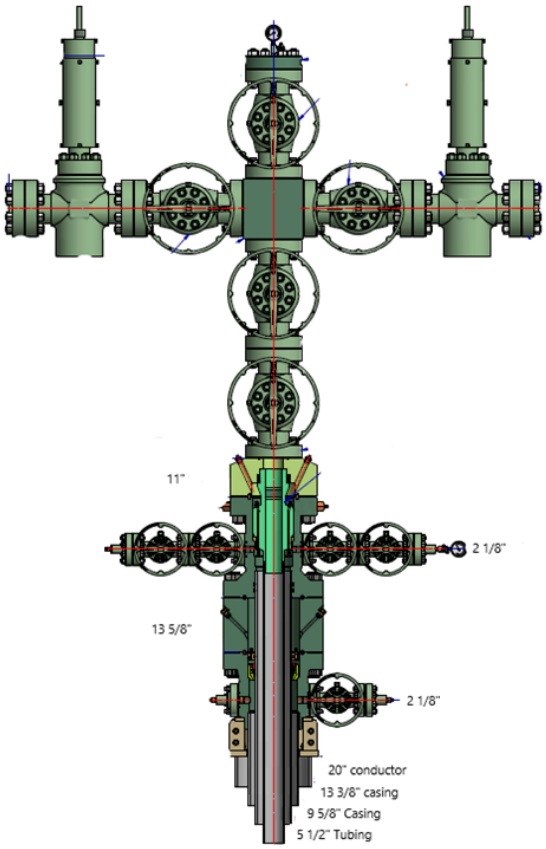


Figure CON-18: Schematic diagram of Bluebonnet CCS 7 well.

9.7 Bluebonnet CCS 7 Procedure

9.7.1 Conductor

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mobilize auger.
- Auger 26 in. – 30 in. hole to a depth of 150 – 200 ft.
- Set a 20 in. conductor on the bottom and pump cement.
- Move equipment off location and secure the site.

9.7.2 Surface

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.

- Rig up equipment.
- Perform rig inspection. Identify and correct any substandard conditions.
- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Mix and hydrate gel mud (freshwater-based). Ensure that all solid control equipment is installed and operating properly.
- Pick up 17-1/2 in. bottomhole assembly (BHA).
- Run in hole to base of conductor and drill out.
- Drill 17-1/2 in. surface hole to surface casing TD.
- Pump viscous pills and circulate until the well is clean, a minimum of two complete bottoms up.
- Perform wiper trip to surface to condition the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Circulate until the well is clean.
- Pull out of the hole and rack back drill pipe.
- Perform logging safety meeting and discuss operational plan and risks.
- Rig up logging unit and equipment.
- Run electric logs per program.
- Rig down logging unit and equipment.
- Condition the rig floor and prepare to run casing.
- Perform casing run safety meeting and discuss operational plan and risks.
- Make up shoe track and run 13-3/8 in. surface casing to TD.
- Circulate and prepare to cement surface casing.
- Hold a pre-cement meeting.
- Rig up cementing equipment and test lines at 250 psi and 5,000 psi. Secure the area while performing high-pressure operations.
- Pump 40-80 bbls of fresh water as a preflush.
- Mix and pump the cement slurries according to the cementing program. Take two samples of each slurry to check hardness and keep them for QAQC. Take one water sample.
- Drop the top plug. If a cementing head is used, make sure the plug indicator is functioning correctly. Displace the cement with fresh water. Check returns and measure the tank level before, during, and after the cementing operation.
- Reduce the displacement rate when at 10 bbls before bumping the plug.
- Test casing with 500 psi over the final displacing pressure. Hold the pressure for 5 minutes and release. Check the backflow to the pumping truck.
- Rig down cementing equipment.
- Wait on cement to reach 500 psi.

- While waiting on cement, perform pre-wellhead and nipple up safety meeting and discuss the operational plan and risks.
- Install wellhead A Section.
- Nipple up the 13 5/8 in. x 5,000 psi BOP stack.
- Perform pressure testing safety meeting and discuss operational plan and risks.
- Test casing to 1,500 psi and BOPE to 3,000 psi.

9.7.3 Long String Section

- Perform a pre-spud meeting and discuss the drilling procedure, emergency and response plans, and stop-work authority program.
- Change out pits from water-based mud (WBM) to synthetic-based mud (SBM). Ensure that all solid control equipment is installed and operating properly.
- Pick up 12.25 in. directional BHA.
- Run in hole to base of surface casing.
- Displace WBM for SBM and circulate the well.
- Conduct choke drill prior to drilling out.
- Drill out 13-3/8 in. surface casing shoe.
- Drill 10 ft of formation and conduct FIT.
- Drill 12-1/4 in. hole to TD based on the directional plan. Surveys must be taken minimum every 100 ft. Pump sweep pills to improve hole cleaning based on the hydraulic simulations. If signs of drag or hole-cleaning issues are observed, increase the frequency of pumping the sweep pills.
- Pump viscous pills and circulate a minimum of two bottoms up or until the returns of cuttings in the shaker are minimal and prepare to trip out of the hole.
- Perform a wiper trip to the surface casing shoe to condition the hole.
- Pull out of the hole and rack back drill pipe and BHA. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform logging safety meeting and discuss the operational plan and risks.
- Rig up logging truck and equipment.
- Execute logging and sampling operations as per program.
- Rig down logging truck.
- Perform clean out safety meeting and discuss the operational plan and risks.
- Pick up 12-1/4 in. cleanout BHA.
- Run in the hole to TD, circulating and reaming as hole conditions require.
- Circulate and prepare to trip out of the hole.
- Perform tripping safety meeting and discuss the operational plan and risks.
- Conduct flow check.

- Pull out of the hole. Keep a record of the fill volume and the level of the tanks to identify potential losses or influx.
- Perform casing run safety meeting and discuss the operational plan and risks.
- Rig up and install the casing running tool and the casing slips and test the correct function of the tools.
- Rig up the spooler and the equipment to run the fiber optic cable alongside the casing. Follow fiber optic provider recommendations to install the external centralizers, clamps, bands, and markers joints.

  Note: Run centralizers simulation with the final trajectory and caliper to adjust to final conditions of the well and target a minimum 70% standoff.

- Make up float equipment with two joints of shoe track.
- Run long string casing per program, coordinating running speed with the fiber optic installation.
- Once on bottom, start circulation with a low flow rate and increase it gradually to the target flow rate for the cementing job. Circulate at least two bottoms up or until the well is clean.
- Hold cementing safety meeting. Validate volumes by caliper and review the slurry test, thickening time, and time planned for the operation. Identify the person to keep track of the pumped volumes, tank levels, and returns.
- Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations. Start first stage of the cementing job.
- Pump cementing spacers. Mix and pump the cement slurry per program. Take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop the top plug and displace the cement. At 10 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase 500 psi over the circulating pressure. Hold the pressure for 5 minutes. Release pressure and check the backflow to the cementing unit.
- Drop the plug/bomb to open the stage tool according to manufacturer (follow specific procedure by provider and model of the tool). Circulate the annular.
- Wait on cement from the first stage. Waiting time will be based on slurry design and specific cementing program.
- Perform second stage of the cementing job. Test cementing lines at 250 psi and 5,000 psi, each for 5 minutes. Secure the area while executing high-pressure operations.
- Pump cementing spacers. Mix and pump the cement slurry per program, take two samples of the slurry for QAQC and two samples of the mixing water.
- Drop plug and displace the cement with inhibited brine. At 20 bbls before the plug reaches the float collar, reduce the rate. Bump the plug and increase the required pressure by the manufacturer’s recommendation over the circulating pressure to close the tool. Release pressure slowly and check the backflow to the cementing unit.

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

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

9.7.4 Original Completion

- Perform a field inspection of the location to identify any potential hazard during mobilization of the equipment (power lines, obstacles, road conditions, buried lines, etc.).
- Mobilize the rig to the location.
- Rig up equipment.
- Nipple up the BOP.
- Test the BOP.
- Pick up the work string and bit to clean cement.
- Run in the hole and tag the stage tool.
- Circulate with brine 9.8-10 ppg.
- Pressure and test casing to 300 psi for 5 minutes.
- Drill out the stage tool and clean the casing to the top of the float collar.
- Circulate brine.
- Test casing for 30 minutes with 1,000 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat the test. If the failure persists, the operator may require assessing the root cause and correcting it.
- Pull the BHA out of the hole.
- Perform safety meeting to discuss logging and perforating operations.
- Rig up logging unit.
- Run CBL/VDL or USIT as well as Casing Inspection Log as per program.
- Rig down logging unit.
- Rig up spooler and prepare rig floor to run upper completion.

- Run completion assembly per program.
- Circulate the well with inhibited packer fluid.
- Set packer as per program and test annulus to 1,000 psi.
- Install tubing sections, cable connector, and tubing hanger.
- Rig up logging unit and lubricator.
- Run cased hole logs through tubing by program.
- Run perforating guns, minimum of 6 shots per foot (spf). Perforation intervals will be defined with final log and correlation.
- Install backpressure valve.
- Rig down logging unit and surface equipment.
- Install injection tree.
- Rig down equipment.
- Perform an injectivity test/step rate test and falloff test.

References

1. Craig, B. D. and Rowe, A. X. 2023. Guidelines for the selection of corrosion resistant alloys for CCS and CCUS injection wells. International Journal of Greenhouse Gas Control, 129 (C) 103988 https://doi.org/10.1016/j.ijggc.2023.103988
2. Eiken, O. Ringrose, P., Christian, H. et al. 2011. Lessons Learned from 14 years of CCS Operations: Sleipner, In Salah and Snøhvit. Energy Procedia, (4), 5541-5548.
3. Trupp, M., Ryan, S. Mendoza, I. B. et al. 2021. Developing the world's largest CO_2 Injection System – a history of the Gorgon Carbon Dioxide Injection System. Presented at the 15th Greenhouse Gas Control Technologies Conference, Abu Dhabi, UAE. 15-18 March. 10.2139/ssrn.3815492
4. Matsuo, D., Arai, Y, Kanki, K. et al. 2022. Corrosion Resistance of Super Duplex Stainless Steel for CCS Usage under Supercritical CO_2 Conditions with Impurity Gas. Presented at the AMPP Annual Conference + Expo, San Antonio, Texas, USA. 6-10 March. AMPP-2022-17602.
5. Guideline for Materials Selection and Corrosion Control for CO_2 Transport and Injection, AMPP Guide 21532, Association of Materials Performance and Protection, Houston, TX. 2022.
6. Néel, G., Millet, C. Greenwood, J. et al. 2022. Material Selection for Anthropogenic CO_2 Injection, Mechanical and Corrosion Behavior of Steels under CO_2 with Impurities. Presented at the 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France. 23-27 October.

GENERAL DATA

Description:	Bluebonnet CCS 1 (Final)
Well Options, Deviated:	Yes
Well Options, Offshore:	No
Well TD (MD):	9250.00 ft
Reference Point:	OTR
Air Gap:	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	191.45 °

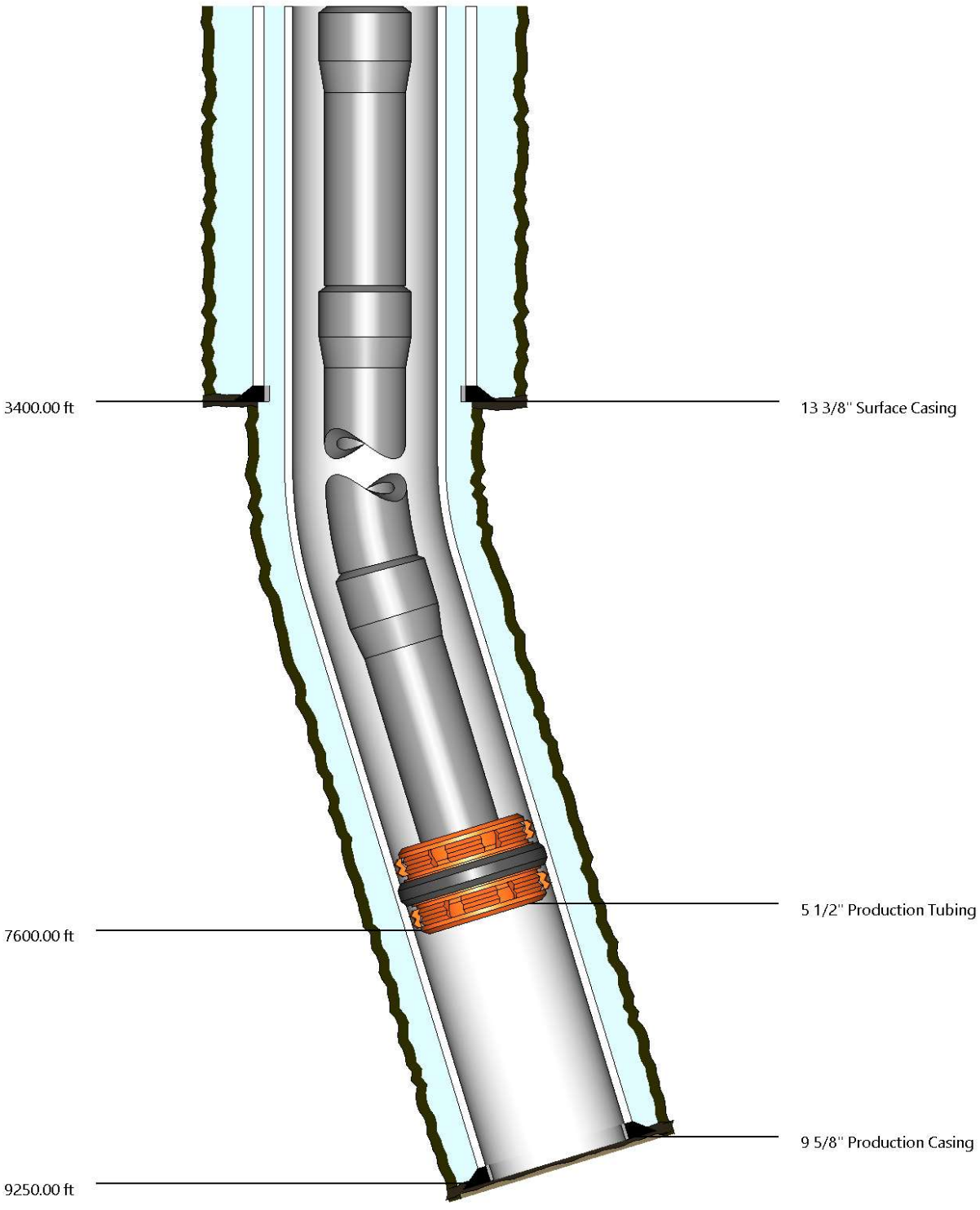
Comments:

Template to use when performing WT-Prod and WS-Tube calculations using the same well file.

WELL SUMMARY

	String	OD/Weight/Grade	Connection	MD Interval (ft)	Drift Dia. (in)	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V	Axial	Triaxial	
1	Surface Casing	13 3/8", 61.000 ppf, K-55	BTC, K-55	26.00-3400.00	12.359	1.18	1.04	2.09	1.30	94,695
2										Total = 94,695
3										
4	Production Casing	9 5/8", 53.500 ppf, L-80	Blue	26.00-4100.00	8.500 A	2.06	2.44	2.27	2.00	126,912
5		9 5/8", 53.500 ppf, L-80	Blue	4100.00-9250.00	8.500 A	1.89	1.11	3.29	1.41	160,431
6										Total = 287,343
7										
8	Production Tubing	5 1/2", 20.000 ppf, L-80	Blue	26.00-7600.00	4.653	2.52	1.29	1.94	1.39	75,222
9										Total = 75,222
10										
11										Total = 457,260
12	A Alternate Drift									
13	(V) Vector Collapse Safety Factor									

WELL SCHEMATIC (DEPTH - MD)



CASING AND TUBING SCHEME

	OD (in)	Name	Type	Hole Size (in)	Measured Depths (ft)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	13 3/8"	Surface	Casing	17.500	26.00	3400.00	26.00	10.00
2	9 5/8"	Production	Casing	12.250	26.00	9250.00	26.00	12.50
3	5 1/2"	Production	Tubing		26.00	7600.00		9.80

PRODUCTION DATA

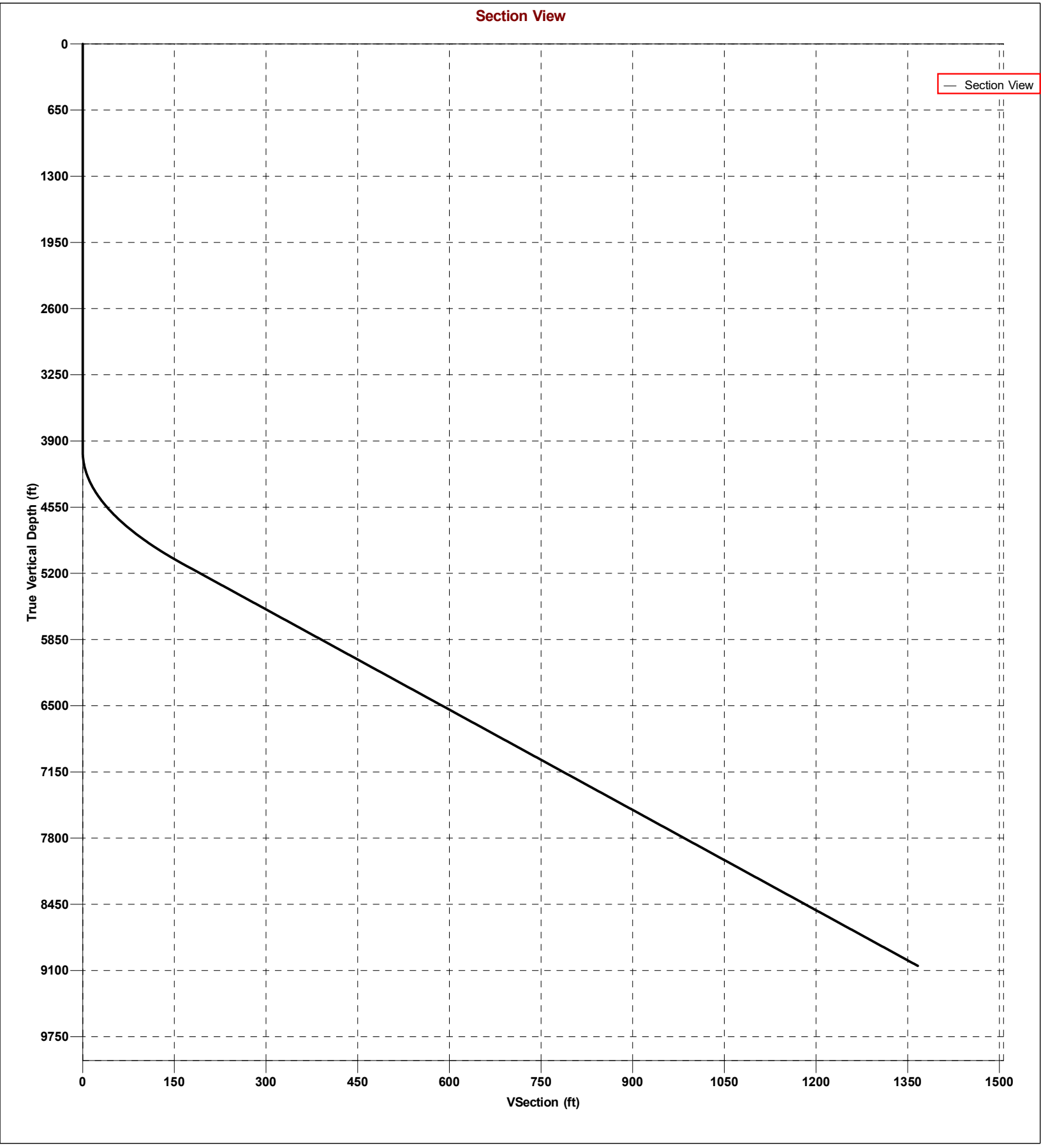
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7600.00 ft
Perforation Depth, MD:	8180.00 ft
Gas Gravity:	0.70

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.03	0.00			0.00	0.00
2	MD-INC-AZ	100.00	0.00	0.03	100.00	0.00	0.00	0.00	0.00
3	MD-INC-AZ	200.00	0.00	0.03	200.00	0.00	0.00	0.00	0.00
4	MD-INC-AZ	300.00	0.00	0.03	300.00	0.00	0.00	0.00	0.00
5	MD-INC-AZ	400.00	0.00	0.03	400.00	0.00	0.00	0.00	0.00
6	MD-INC-AZ	500.00	0.00	0.03	500.00	0.00	0.00	0.00	0.00
7	MD-INC-AZ	600.00	0.00	0.03	600.00	0.00	0.00	0.00	0.00
8	MD-INC-AZ	700.00	0.00	0.03	700.00	0.00	0.00	0.00	0.00
9	MD-INC-AZ	800.00	0.00	0.03	800.00	0.00	0.00	0.00	0.00
10	MD-INC-AZ	900.00	0.00	0.03	900.00	0.00	0.00	0.00	0.00
11	MD-INC-AZ	1000.00	0.00	0.03	1000.00	0.00	0.00	0.00	0.00
12	MD-INC-AZ	1100.00	0.00	0.03	1100.00	0.00	0.00	0.00	0.00
13	MD-INC-AZ	1200.00	0.00	0.03	1200.00	0.00	0.00	0.00	0.00
14	MD-INC-AZ	1300.00	0.00	0.03	1300.00	0.00	0.00	0.00	0.00
15	MD-INC-AZ	1400.00	0.00	0.03	1400.00	0.00	0.00	0.00	0.00
16	MD-INC-AZ	1500.00	0.00	0.03	1500.00	0.00	0.00	0.00	0.00
17	MD-INC-AZ	1600.00	0.00	0.03	1600.00	0.00	0.00	0.00	0.00
18	MD-INC-AZ	1700.00	0.00	0.03	1700.00	0.00	0.00	0.00	0.00
19	MD-INC-AZ	1800.00	0.00	0.03	1800.00	0.00	0.00	0.00	0.00
20	MD-INC-AZ	1900.00	0.00	0.03	1900.00	0.00	0.00	0.00	0.00
21	MD-INC-AZ	2000.00	0.00	0.03	2000.00	0.00	0.00	0.00	0.00
22	MD-INC-AZ	2100.00	0.00	0.03	2100.00	0.00	0.00	0.00	0.00
23	MD-INC-AZ	2200.00	0.00	0.03	2200.00	0.00	0.00	0.00	0.00
24	MD-INC-AZ	2300.00	0.00	0.03	2300.00	0.00	0.00	0.00	0.00
25	MD-INC-AZ	2400.00	0.00	0.03	2400.00	0.00	0.00	0.00	0.00
26	MD-INC-AZ	2500.00	0.00	0.03	2500.00	0.00	0.00	0.00	0.00
27	MD-INC-AZ	2600.00	0.00	0.03	2600.00	0.00	0.00	0.00	0.00
28	MD-INC-AZ	2700.00	0.00	0.03	2700.00	0.00	0.00	0.00	0.00
29	MD-INC-AZ	2800.00	0.00	0.03	2800.00	0.00	0.00	0.00	0.00
30	MD-INC-AZ	2900.00	0.00	0.03	2900.00	0.00	0.00	0.00	0.00
31	MD-INC-AZ	3000.00	0.00	0.03	3000.00	0.00	0.00	0.00	0.00
32	MD-INC-AZ	3100.00	0.00	0.03	3100.00	0.00	0.00	0.00	0.00
33	MD-INC-AZ	3200.00	0.00	0.03	3200.00	0.00	0.00	0.00	0.00
34	MD-INC-AZ	3300.00	0.00	0.03	3300.00	0.00	0.00	0.00	0.00
35	MD-INC-AZ	3400.00	0.00	0.03	3400.00	0.00	0.00	0.00	0.00
36	MD-INC-AZ	3500.00	0.00	0.03	3500.00	0.00	0.00	0.00	0.00
37	MD-INC-AZ	3600.00	0.00	0.03	3600.00	0.00	0.00	0.00	0.00
38	MD-INC-AZ	3700.00	0.00	0.03	3700.00	0.00	0.00	0.00	0.00
39	MD-INC-AZ	3800.00	0.00	0.03	3800.00	0.00	0.00	0.00	0.00
40	MD-INC-AZ	3900.00	0.00	0.03	3900.00	0.00	0.00	0.00	0.00
41	MD-INC-AZ	4000.00	0.00	0.03	4000.00	0.00	0.00	0.00	0.00
42	MD-INC-AZ	4100.00	1.50	191.45	4099.99	1.50	1.50	1.31	1.31
43	MD-INC-AZ	4200.00	3.00	191.45	4199.91	1.50	1.50	5.23	5.23
44	MD-INC-AZ	4300.00	4.50	191.45	4299.69	1.50	1.50	11.77	11.77
45	MD-INC-AZ	4400.00	6.00	191.45	4399.27	1.50	1.50	20.92	20.92
46	MD-INC-AZ	4500.00	7.50	191.45	4498.57	1.50	1.50	32.68	32.68
47	MD-INC-AZ	4600.00	9.00	191.45	4597.54	1.50	1.50	47.03	47.03
48	MD-INC-AZ	4700.00	10.50	191.45	4696.09	1.50	1.50	63.96	63.96
49	MD-INC-AZ	4800.00	12.00	191.45	4794.16	1.50	1.50	83.47	83.47
50	MD-INC-AZ	4900.00	13.50	191.45	4891.70	1.50	1.50	105.54	105.54
51	MD-INC-AZ	5000.00	15.00	191.45	4988.62	1.50	1.50	130.15	130.15
52	MD-INC-AZ	5100.00	16.50	191.45	5084.86	1.50	1.50	157.30	157.30
53	MD-INC-AZ	5129.57	16.94	191.45	5113.18	1.50	1.50	165.81	165.81
54	MD-INC-AZ	5200.00	16.94	191.45	5180.55	0.00	0.00	186.33	186.33
55	MD-INC-AZ	5300.00	16.94	191.45	5276.21	0.00	0.00	215.47	215.47
56	MD-INC-AZ	5400.00	16.94	191.45	5371.87	0.00	0.00	244.62	244.62
57	MD-INC-AZ	5500.00	16.94	191.45	5467.53	0.00	0.00	273.76	273.76
58	MD-INC-AZ	5600.00	16.94	191.45	5563.19	0.00	0.00	302.90	302.90
59	MD-INC-AZ	5700.00	16.94	191.45	5658.85	0.00	0.00	332.05	332.05
60	MD-INC-AZ	5800.00	16.94	191.45	5754.51	0.00	0.00	361.19	361.19
61	MD-INC-AZ	5900.00	16.94	191.45	5850.17	0.00	0.00	390.33	390.33
62	MD-INC-AZ	6000.00	16.94	191.45	5945.82	0.00	0.00	419.47	419.47
63	MD-INC-AZ	6100.00	16.94	191.45	6041.48	0.00	0.00	448.62	448.62
64	MD-INC-AZ	6200.00	16.94	191.45	6137.14	0.00	0.00	477.76	477.76
65	MD-INC-AZ	6300.00	16.94	191.45	6232.80	0.00	0.00	506.90	506.90
66	MD-INC-AZ	6400.00	16.94	191.45	6328.46	0.00	0.00	536.05	536.05
67	MD-INC-AZ	6500.00	16.94	191.45	6424.12	0.00	0.00	565.19	565.19
68	MD-INC-AZ	6600.00	16.94	191.45	6519.78	0.00	0.00	594.33	594.33
69	MD-INC-AZ	6700.00	16.94	191.45	6615.44	0.00	0.00	623.48	623.48
70	MD-INC-AZ	6800.00	16.94	191.45	6711.10	0.00	0.00	652.62	652.62
71	MD-INC-AZ	6900.00	16.94	191.45	6806.76	0.00	0.00	681.76	681.76
72	MD-INC-AZ	7000.00	16.94	191.45	6902.42	0.00	0.00	710.90	710.90
73	MD-INC-AZ	7100.00	16.94	191.45	6998.08	0.00	0.00	740.05	740.05
74	MD-INC-AZ	7200.00	16.94	191.45	7093.74	0.00	0.00	769.19	769.19
75	MD-INC-AZ	7300.00	16.94	191.45	7189.39	0.00	0.00	798.33	798.33
76	MD-INC-AZ	7400.00	16.94	191.45	7285.05	0.00	0.00	827.48	827.48
77	MD-INC-AZ	7500.00	16.94	191.45	7380.71	0.00	0.00	856.62	856.62

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
78	MD-INC-AZ	7600.00	16.94	191.45	7476.37	0.00	0.00	885.76	885.76
79	MD-INC-AZ	7700.00	16.94	191.45	7572.03	0.00	0.00	914.91	914.91
80	MD-INC-AZ	7800.00	16.94	191.45	7667.69	0.00	0.00	944.05	944.05
81	MD-INC-AZ	7900.00	16.94	191.45	7763.35	0.00	0.00	973.19	973.19
82	MD-INC-AZ	7966.54	16.94	191.45	7827.00	0.00	0.00	992.58	992.58
83	MD-INC-AZ	8000.00	16.94	191.45	7859.01	0.00	0.00	1002.33	1002.33
84	MD-INC-AZ	8100.00	16.94	191.45	7954.67	0.00	0.00	1031.48	1031.48
85	MD-INC-AZ	8200.00	16.94	191.45	8050.33	0.00	0.00	1060.62	1060.62
86	MD-INC-AZ	8300.00	16.94	191.45	8145.99	0.00	0.00	1089.76	1089.76
87	MD-INC-AZ	8400.00	16.94	191.45	8241.65	0.00	0.00	1118.91	1118.91
88	MD-INC-AZ	8500.00	16.94	191.45	8337.31	0.00	0.00	1148.05	1148.05
89	MD-INC-AZ	8600.00	16.94	191.45	8432.96	0.00	0.00	1177.19	1177.19
90	MD-INC-AZ	8700.00	16.94	191.45	8528.62	0.00	0.00	1206.34	1206.34
91	MD-INC-AZ	8800.00	16.94	191.45	8624.28	0.00	0.00	1235.48	1235.48
92	MD-INC-AZ	8900.00	16.94	191.45	8719.94	0.00	0.00	1264.62	1264.62
93	MD-INC-AZ	9000.00	16.94	191.45	8815.60	0.00	0.00	1293.76	1293.76
94	MD-INC-AZ	9100.00	16.94	191.45	8911.26	0.00	0.00	1322.91	1322.91
95	MD-INC-AZ	9200.00	16.94	191.45	9006.92	0.00	0.00	1352.05	1352.05
96	MD-INC-AZ	9250.00	16.94	191.45	9054.75	0.00	0.00	1366.62	1366.62
97									

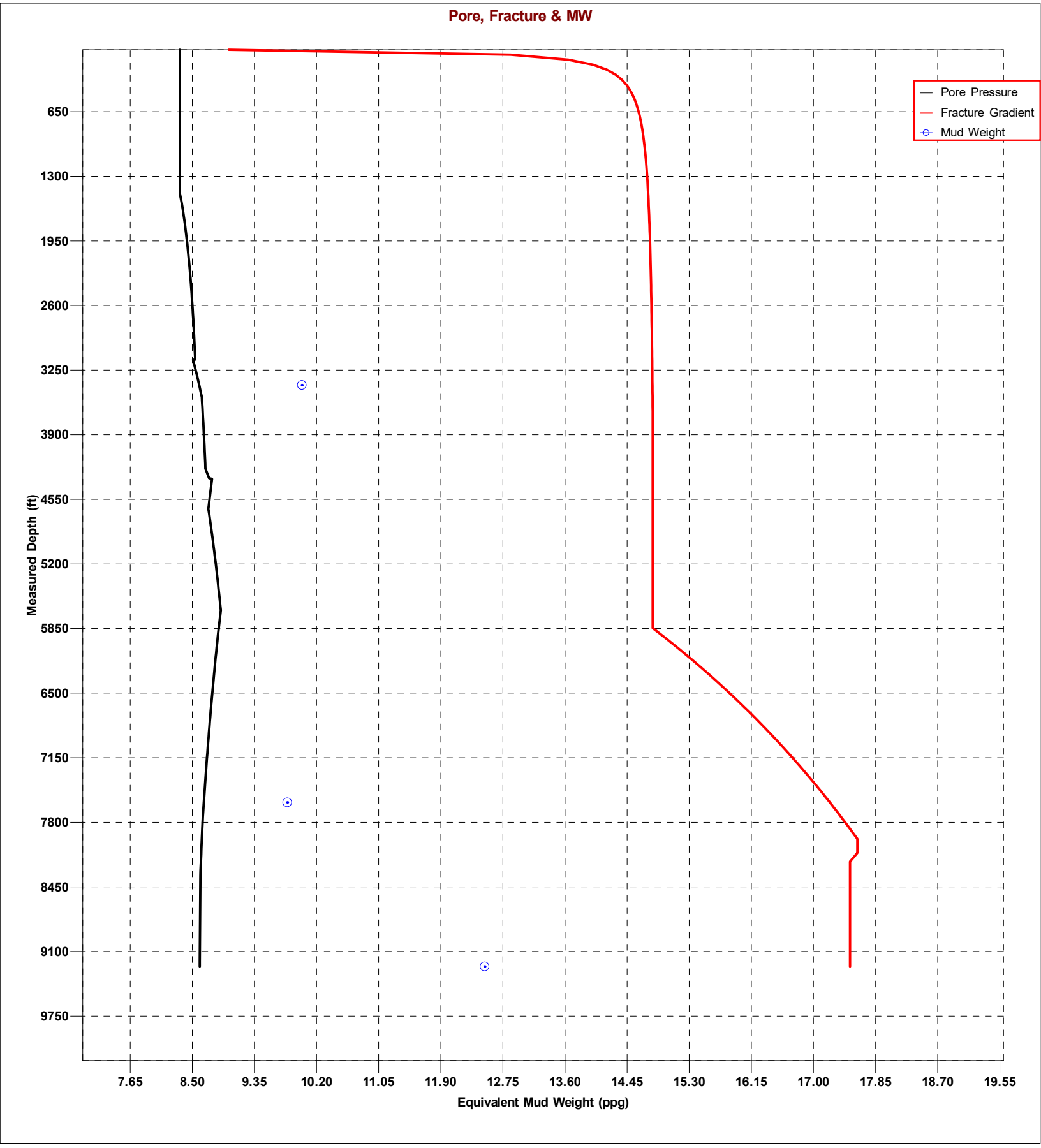

Section View
Section View
0
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
True Vertical Depth (ft)
0
150
300
450
600
750
900
1050
1200
1350
1500
VSection (ft)

PORE PRESSURE

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	0	8.33	No
2	1470.00	636	8.33	No
3	3144.00	1395	8.54	No
4	3146.00	1391	8.51	No
5	3521.00	1579	8.63	No
6	4240.00	1912	8.68	No
7	4337.00	1967	8.73	No
8	4344.00	1979	8.77	No
9	4643.00	2103	8.72	No
10	5626.00	2598	8.89	No
11	7666.00	3441	8.64	No
12	8182.00	3660	8.61	No
13	9260.00	4137	8.60	No

FRACTURE GRADIENT

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	0	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9260.00	8418	17.50


Pore, Fracture & MW
Pore Pressure
Fracture Gradient
Mud Weight
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
Measured Depth (ft)
7.65
8.50
9.35
10.20
11.05
11.90
12.75
13.60
14.45
15.30
16.15
17.00
17.85
18.70
19.55
Equivalent Mud Weight (ppg)

GEOTHERMAL GRADIENT DATA

Surface Ambient:	78 °F
Bottomhole Temperature - 9054.75 ft TVD:	175 °F
Bottomhole Gradient - 9054.75 ft TVD:	1.07 °F/100ft

DESIGN PARAMETERS DATA (13 3/8" Surface Casing)

Design Factor (Pipe) - Axial Tension:	1.400
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.400
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	12.250 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (13 3/8" Surface Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3400.00 ft	114 °F

BURST LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 3400.00 ft):	2612 psi
Mud/Water Interface, MD:	3400.00 ft
Mud Weight	7.82 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	9250.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	1.00 ppg
Maximum Mud Weight:	12.50 ppg
Kick Gas Gravity:	0.70 (0.1285 psi/ft @ 142 °F & 6350 psi)
Fracture at Shoe (MD= 3400.00 ft):	2612 psi
Drill Pipe OD:	5.500 in
Collar OD:	8.000 in
Collar Length:	300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	1500 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Fracture @ Shoe w/ Gas Gradient Above**
Gas Gravity:	0.70 (0.0756 psi/ft @ 123 °F & 2612 psi)
Shoe Depth, MD :	3400.00 ft
Fracture Pressure at Shoe:	2612 psi
Fracture Margin of Error:	0.00 ppg
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2600 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3400.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3400.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	9250.00 ft
Pore Pressure at Lost Returns Depth:	4046 psi
Pore Pressure Gradient at Lost Returns Depth:	8.60 ppg
Mud Weight:	12.50 ppg
Mud Drop Level, MD:	2823.84 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (13 3/8" Surface Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	2600 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Lost Returns (psi)	Gas Kick (psi)	Pressure Test (psi)	Fracture @ Shoe w/ Gas Gradient Above (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	1152	1303	1514	2364	2611	14	0
2	1470.00	1777	2046	2264	2469	3236	951	636
3	2700.00	2309	2679	2903	2560	3768	1750	1194
4	3144.00	2502	2907	3133	2593	3960	2114	1395
5	3146.00	2502	2908	3134	2593	3961	2116	1391
6	3400.00	2612	3039	3266	2612	4071	2324	1518

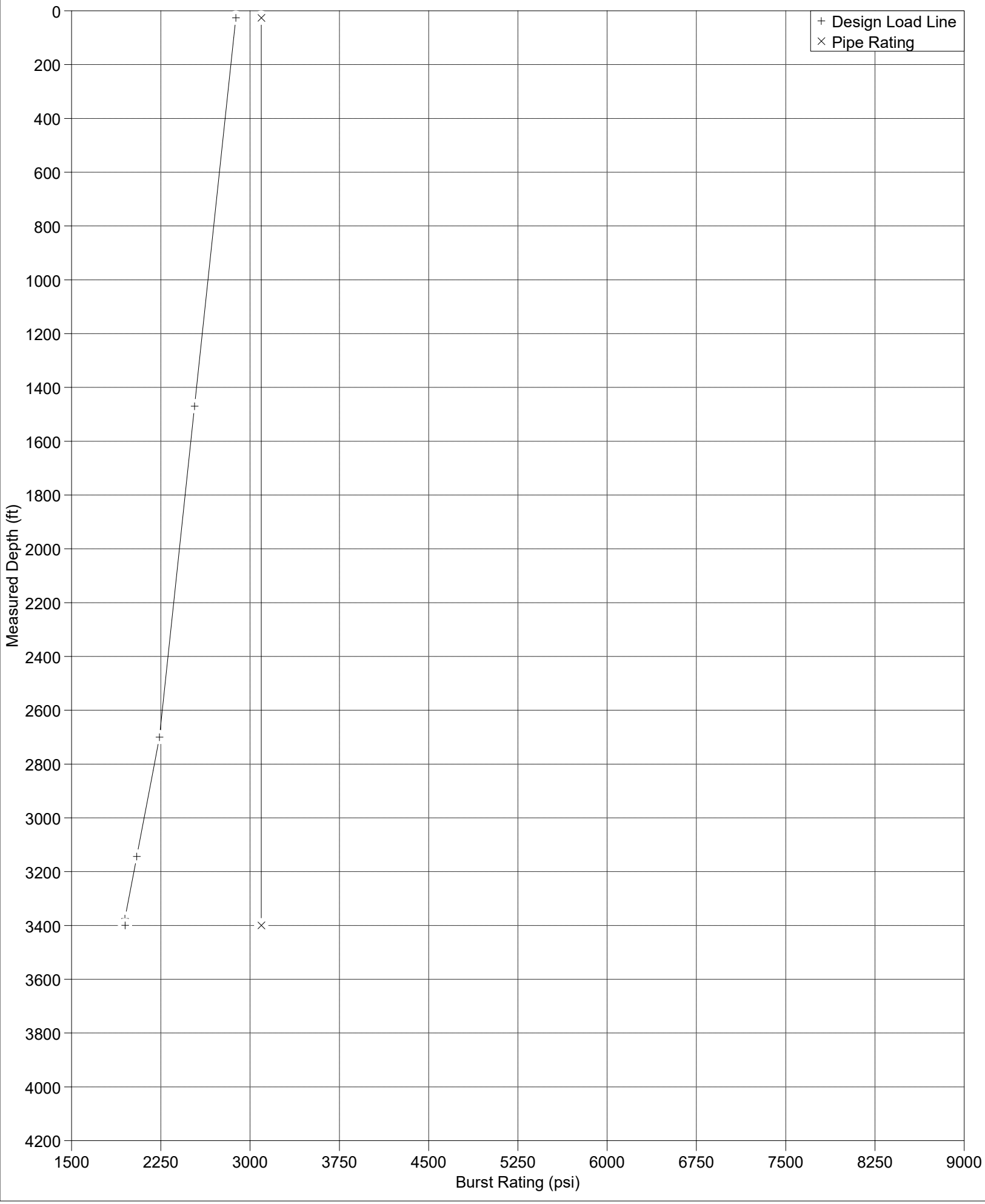
COLLAPSE PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Lost Returns (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	14	0	14
2	2700.00	1168	1750	0	1403
3	2823.84	1222	1852	0	1467
4	3400.00	1471	2324	374	1766

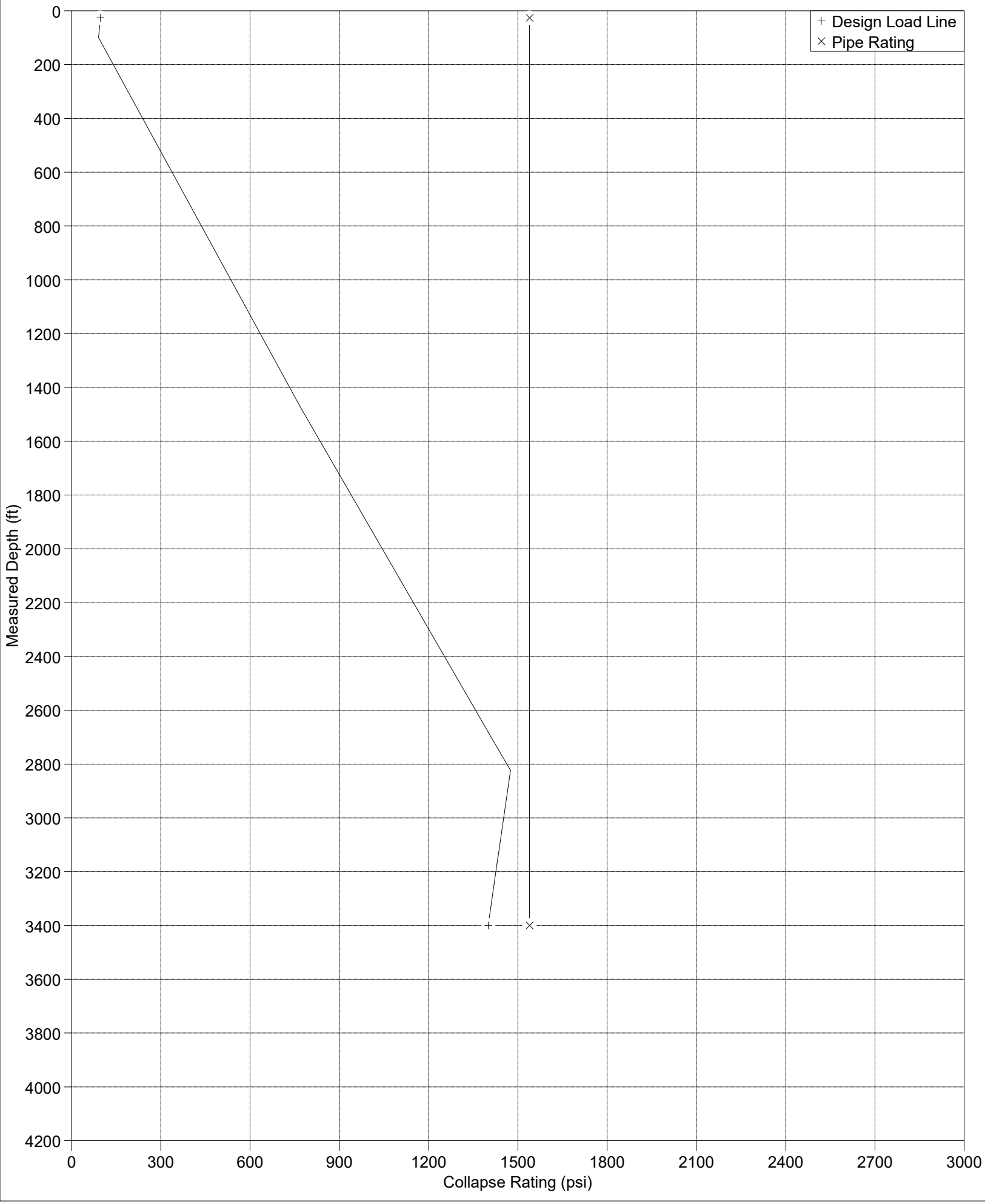
AXIAL LOADS TABLE (13 3/8" Surface Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	351646	275164	456536	380053	456536	380053
2	100.00	347804	271322	452022	375539	452022	375539
3	1470.00	276680	200197	368452	291969	368452	291969
4	2700.00	212823	136341	293422	216939	293422	216939
5	2823.84	206395	129912	285868	209385	285868	209385
6	3144.00	189773	113290	266338	189855	266338	189855
7	3146.00	189669	113187	266216	189733	266216	189733
8	3274.87	182979	106496	258354	181872	258354	181872

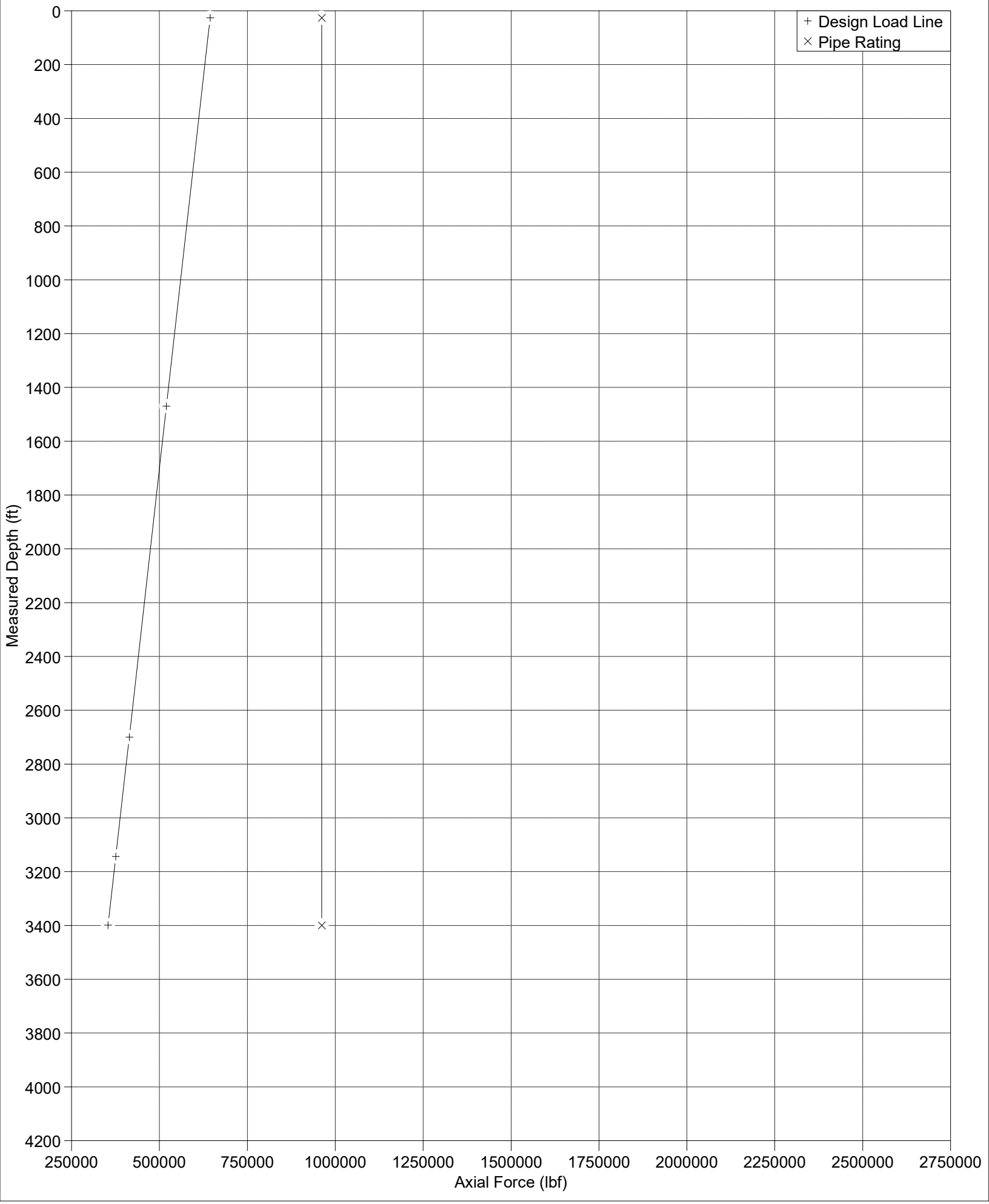
BURST DESIGN (13 3/8" Surface Casing)

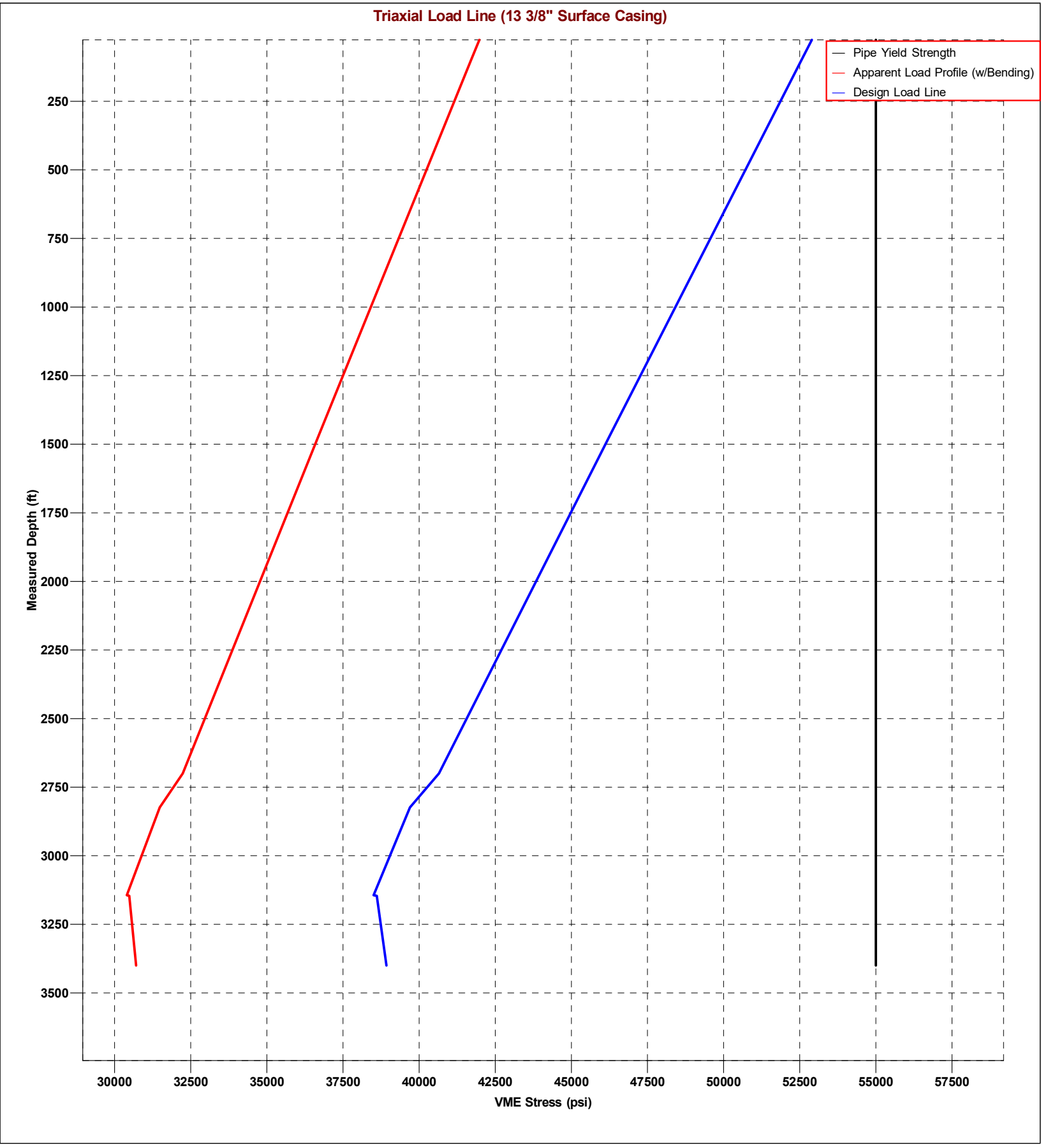


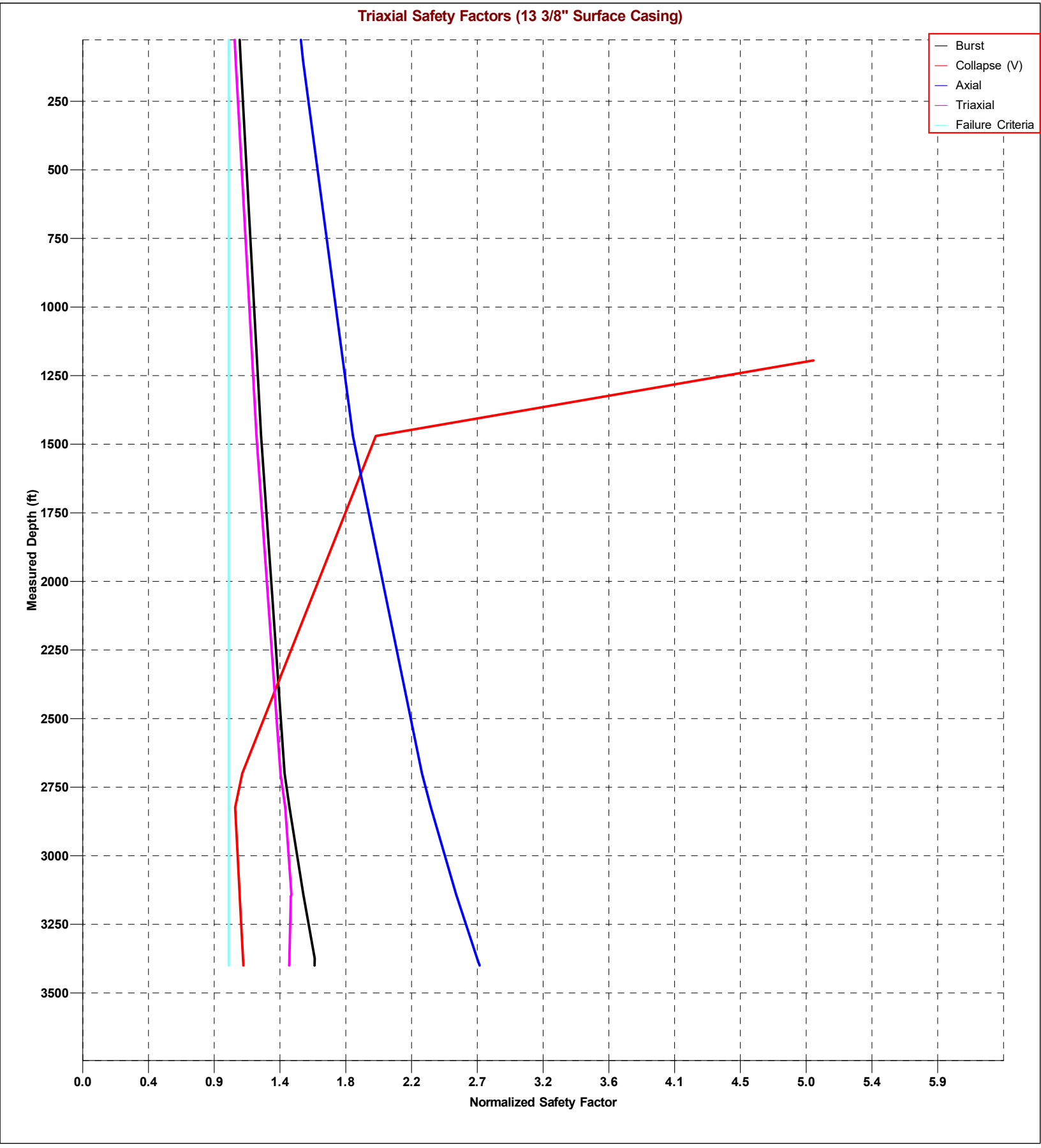
COLLAPSE DESIGN (13 3/8" Surface Casing)



AXIAL DESIGN (13 3/8" Surface Casing)




Triaxial Load Line (13 3/8" Surface Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
30000
32500
35000
37500
40000
42500
45000
47500
50000
52500
55000
57500
VME Stress (psi)


Triaxial Safety Factors (13 3/8" Surface Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	13 3/8", 61.000 ppf, K-55	BTC, K-55	1.18 B12	15.79 C2	2.09 A5	1.30 B12
2	100			1.19 B12	16.90 C2	2.11 A5	1.31 B12
3	1470			1.34 B12	2.01 C4	2.59 A5	1.49 B12
4	2700			1.52 B12	1.09 C4	3.25 A5	1.69 B12
5	2824			1.56 B12	1.04 C4	3.34 A5	1.73 B12
6	3144			1.66 B12	1.07 C4	3.58 A5	1.79 B5
7	3146			1.66 B12	1.07 C4	3.58 A5	1.78 B5
8	3374			1.75 B5	1.10 C4	3.78 A5	1.77 B5
9	3396			1.75 B5	1.10 C4	3.80 A5	1.77 B5
10	3399			1.75 B5	1.10 C4	3.80 A5	1.77 B5
11	3400			1.75 B5	1.10 C4	3.80 A5	1.77 B5
12							
13	B5	Pressure Test					
14	B12	Green Cement Pressure Test(Burst)					
15	C2	Cementing					
16	C4	Lost Returns with Mud Drop					
17	A5	Green Cement Pressure Test(Axial)					
18	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (13 3/8" Surface Casing)

	Depth (MD)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	13 3/8", 61.000 ppf, K-5	0.400 B12	0.088 C4	0.360 B12	6.9	79.6	16.3	0.030	0.342	0.070
2	100.00		0.398 B12	0.137 C4	0.358 B12	7.5	68.1	16.9	0.032	0.293	0.072
3	1470.00		0.352 B12	0.333 C4	0.313 B12	18.1	22.5	27.3	0.078	0.097	0.117
4	2700.00		0.311 B12	0.414 C4	0.277 B12	27.6	3.7	35.7	0.119	0.016	0.153
5	2823.84		0.304 B12	0.422 C4	0.270 B12	29.3	1.8	37.2	0.126	0.008	0.160
6	3144.00		0.285 B12	0.417 C4	0.260 B5	33.8	3.0	39.5	0.145	0.013	0.170
7	3146.00		0.285 B12	0.417 C4	0.261 B5	33.8	3.0	39.3	0.145	0.013	0.169
8	3374.50		0.271 B5	0.413 C4	0.263 B5	37.0	3.9	38.8	0.159	0.017	0.167
9	3396.45		0.271 B5	0.413 C4	0.263 B5	37.0	4.0	38.8	0.159	0.017	0.167
10	3399.18		0.271 B5	0.413 C4	0.263 B5	37.0	4.0	38.8	0.159	0.017	0.167
11	3400.00		0.271 B5	0.413 C4	0.263 B5	37.0	4.0	38.8	0.159	0.017	0.167
12											
13	B5	Pressure Test									
14	B12	Green Cement Pressure Test(Burst)									
15	C4	Lost Returns with Mud Drop									
16	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (13 3/8" Surface Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	604990
2	26	603641
3	26	603640
4	100	599798
5	262	591412
6	523	577834
7	785	564256
8	1000	553074
9	1046	550678
10	1308	537100
11	1569	523522
12	1831	509944
13	2000	501159
14	2092	496366
15	2354	482788
16	2615	469210
17	2877	455632
18	3000	449243
19	3138	442055
20	3374	429826
21	3400	* 430059
22		
23	* Based on Casing Strength	
24	Only. Running String not	
25	Included	

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Gas Kick Profile

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	112646	36164	114133	4373.6	2.26	2.34	N/A	8.43	111	1303	0	N/A	N/A
2	100	111863	35381	113926	4373.6	2.25	2.33	N/A	8.49	112	1341	33		
3	1470	97365	20883	110083	4373.6	2.07	2.16	N/A	9.74	116	2046	636		
4	2700	83032	6549	105564	4373.6	1.96	2.05	N/A	11.40	120	2679	1194		
5	2824	83379	6896	106926	4373.6	1.95	2.04	N/A	11.35	121	2742	1250		
6	3144	84274	7792	110451	4373.6	1.93	2.01	N/A	11.23	122	2907	1395		
7	3146	84695	8213	110808	4373.6	1.93	2.01	N/A	11.17	122	2908	1391		
8	3400	84391	7909	112788	4373.6	1.92	2.00	N/A	11.21	123	3039	1518		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Water

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	222058	145576	222729	4373.6	2.93	2.68	N/A	4.32	78	1152	0	N/A	N/A
2	100	221725	145243	222966	4373.6	2.93	2.68	N/A	4.32	78	1184	33		
3	1470	215552	139070	227360	4373.6	2.94	2.70	N/A	4.45	78	1777	636		
4	2700	208694	132211	230259	4373.6	2.99	2.76	N/A	4.59	78	2309	1194		
5	2824	209793	133310	232345	4373.6	2.99	2.77	N/A	4.57	78	2363	1250		
6	3144	212634	136152	237741	4373.6	2.99	2.79	N/A	4.51	78	2502	1395		
7	3146	213067	136584	238104	4373.6	2.98	2.78	N/A	4.50	78	2502	1391		
8	3400	214306	137824	241578	4373.6	3.01	2.82	N/A	4.47	78	2612	1518		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	248718	172236	249469	4373.6	2.23	2.04	N/A	3.86	78	1514	0	N/A	N/A
2	100	245981	169498	247354	4373.6	2.22	2.03	N/A	3.90	79	1552	33		
3	1470	195301	118819	208022	4373.6	2.00	1.89	N/A	4.89	94	2264	636		
4	2700	148484	72002	171353	4373.6	1.83	1.79	N/A	6.40	107	2903	1194		
5	2824	145560	69078	169456	4373.6	1.82	1.78	N/A	6.53	108	2967	1250		
6	3144	138001	61518	164545	4373.6	1.79	1.76	N/A	6.88	111	3133	1395		
7	3146	138368	61886	164848	4373.6	1.78	1.75	N/A	6.86	112	3134	1391		
8	3400	131356	54874	160129	4373.6	1.77	1.75	N/A	7.22	114	3266	1518		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Fracture @ Shoe w/ Gas Gradient Above

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	190933	114450	193453	4373.6	1.33	1.29	N/A	4.97	111	2364	0	N/A	N/A
2	100	187732	111250	190802	4373.6	1.35	1.31	N/A	5.06	112	2369	33		
3	1470	128565	52083	141742	4373.6	1.66	1.66	N/A	7.37	116	2469	636		
4	2649	-76485	-2	-56906	4373.6	2.07	2.20	N/A	(12.38)	120	2556	1171		
5	2649	-76486	-3	-56907	4373.6	2.07	2.20	N/A	(12.38)	120	2556	1171		
6	2700	-78721	-2238	-58772	4373.6	2.09	2.23	N/A	(12.03)	120	2560	1194		
7	2824	-82393	-5910	-61514	4373.6	2.15	2.31	N/A	(11.49)	121	2569	1250		
8	3144	-91880	-15398	-68598	4373.6	2.32	2.54	N/A	(10.30)	122	2593	1395		
9	3146	-91524	-15042	-68308	4373.6	2.32	2.53	N/A	(10.34)	122	2593	1391		
10	3400	-100060	-23577	-74743	4373.6	2.49	2.78	N/A	(9.45)	123	2612	1518		
11														
12	( )	Compression												
13	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	456536	380053	460477	4373.6	1.30	1.18	N/A	2.09	95	2611	14	N/A	N/A
2	100	452022	375539	456782	4373.6	1.31	1.19	N/A	2.11	95	2643	62		
3	1470	368452	291969	388335	4373.6	1.49	1.34	N/A	2.59	96	3236	951		
4	2700	293422	216939	326847	4373.6	1.69	1.52	N/A	3.25	97	3768	1750		
5	2824	285868	209385	321029	4373.6	1.73	1.56	N/A	3.34	97	3822	1852		
6	3144	266338	189855	305986	4373.6	1.85	1.66	N/A	3.58	97	3960	2114		
7	3146	266216	189733	305892	4373.6	1.85	1.66	N/A	3.58	97	3961	2116		
8	3399	250772	174289	293995	4373.6	1.95	1.76	N/A	3.80	97	4071	2324		
9	3400	250722	174239	293956	4373.6	1.95	1.76	N/A	3.80	97	4071	2324		
10														
11	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Mud Drop

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-137626	-61143	-139443	4373.6	6.59	N/A	+ 100.00	(6.90)	111	0	14	N/A	N/A
2	100	-141712	-65229	-143593	4373.6	6.64	N/A	29.50	(6.70)	112	0	52		
3	1470	-217355	-140872	-220549	4373.6	3.97	N/A	2.01	(4.36)	116	0	764		
4	2700	-285268	-208785	-289825	4373.6	2.38	N/A	1.09	(3.32)	120	0	1403		
5	2824	-290316	-213833	-294990	4373.6	2.28	N/A	1.04	(3.26)	121	0	1467		
6	3144	-288022	-211539	-289060	4373.6	2.35	N/A	1.07	(3.29)	122	208	1633		
7	3146	-288008	-211525	-289023	4373.6	2.35	N/A	1.07	(3.29)	122	209	1634		
8	3400	-286188	-209705	-284316	4373.6	2.40	N/A	1.10	(3.31)	123	374	1766		
9														
10	( )	Compression												
11	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	136701	60219	138009	4373.6	6.11	N/A	15.79	6.98	95	11	14	N/A	N/A
2	100	132187	55705	134025	4373.6	6.19	N/A	16.90	7.22	95	43	62		
3	1013	76505	22	84871	4373.6	6.82	N/A	7.03	12.47	95	438	654		
4	1014	-76510	-28	-69414	4373.6	12.31	N/A	7.10	(12.47)	95	439	655		
5	1470	-104348	-27865	-94011	4373.6	8.93	N/A	4.87	(9.14)	96	636	951		
6	2700	-179378	-102895	-160332	4373.6	5.10	N/A	2.64	(5.32)	97	1168	1750		
7	2824	-186932	-110449	-167011	4373.6	4.80	N/A	2.44	(5.10)	97	1222	1852		
8	3144	-206462	-129979	-184282	4373.6	4.16	N/A	2.04	(4.62)	97	1360	2114		
9	3146	-206584	-130101	-184390	4373.6	4.15	N/A	2.03	(4.62)	97	1361	2116		
10	3400	-222078	-145595	-198093	4373.6	3.74	N/A	1.80	(4.29)	97	1471	2324		
11														
12	( )	Compression												
13	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	351646	275164	354737	4373.6	2.38	N/A	N/A	2.71	95	14	14	N/A	N/A
2	100	347804	271322	351548	4373.6	2.40	N/A	N/A	2.74	95	52	52		
3	1470	276680	200197	292482	4373.6	2.91	N/A	N/A	3.45	96	764	764		
4	2700	212823	136341	239421	4373.6	3.57	N/A	N/A	4.48	97	1403	1403		
5	2824	206395	129912	234077	4373.6	3.66	N/A	N/A	4.62	97	1467	1467		
6	3144	189773	113290	220260	4373.6	3.90	N/A	N/A	5.02	97	1633	1633		
7	3146	189669	113187	220173	4373.6	3.90	N/A	N/A	5.03	97	1634	1634		
8	3399	176525	100043	209246	4373.6	4.11	N/A	N/A	5.40	97	1766	1766		
9	3400	176482	100000	209210	4373.6	4.11	N/A	N/A	5.40	97	1766	1766		
10														
11	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	456536	380053	460477	4373.6	1.30	1.18	N/A	2.09	95	2611	14	N/A	N/A
2	100	452022	375539	456782	4373.6	1.31	1.19	N/A	2.11	95	2643	62		
3	1470	368452	291969	388335	4373.6	1.49	1.34	N/A	2.59	96	3236	951		
4	2700	293422	216939	326847	4373.6	1.69	1.52	N/A	3.25	97	3768	1750		
5	2824	285868	209385	321029	4373.6	1.73	1.56	N/A	3.34	97	3822	1852		
6	3144	266338	189855	305986	4373.6	1.85	1.66	N/A	3.58	97	3960	2114		
7	3146	266216	189733	305892	4373.6	1.85	1.66	N/A	3.58	97	3961	2116		
8	3399	250772	174289	293995	4373.6	1.95	1.76	N/A	3.80	97	4071	2324		
9	3400	250722	174239	293956	4373.6	1.95	1.76	N/A	3.80	97	4071	2324		
10														
11	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (9 5/8" Production Casing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	7.970 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (9 5/8" Production Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5150.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
4000.00 ft	121 °F
4597.53 ft	127 °F
4891.69 ft	130 °F
5276.21 ft	134 °F
9006.92 ft	174 °F
9054.75 ft	175 °F
9054.75 ft	175 °F
9054.75 ft	175 °F

BURST LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Mud Weight:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7600.00 ft
Perforation Depth, MD:	8180.00 ft
Gas Gravity:	0.70 (0.0873 psi/ft @ 164 °F & 3596 psi)
Reservoir Pressure:	3596 psi
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Stimulation Surface Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7600.00 ft
Injection Pressure:	3500 psi
Injection Density:	8.33 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Injection Down Casing**
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	3500 psi
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5150.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	9250.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3400.00 ft
Mud Weight Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5150.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	9250.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Full Evacuation**
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3400.00 ft
Fluid Gradient Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	12.50 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (9 5/8" Production Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	3500 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Pressure Test (psi)	Tubing Leak (psi)	Stimulation Leak (psi)	Casing Injection (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	3513	2949	3511	3513	3511	17	17
2	3399.99	5231	4667	5229	5231	4971	2208	1489
3	3400.01	5231	4667	5229	5231	4971	2208	1518
4	3521.00	5293	4728	5291	5293	5024	2286	1579
5	3999.99	5536	4972	5534	5536	5231	2597	1801
6	4000.01	5536	4972	5534	5536	5231	2597	1801
7	4099.99	5587	5023	5585	5587	5274	2662	1847
8	4100.01	5587	5023	5585	5587	5274	2662	1847
9	4240.16	5659	5094	5657	5659	5335	2777	1912
10	4337.44	5708	5144	5706	5708	5377	2857	1967
11	4599.99	5841	5276	5839	5841	5489	3071	2084
12	4600.01	5841	5276	5839	5841	5489	3071	2084
13	4646.08	5864	5299	5862	5864	5509	3108	2103
14	4899.99	5990	5426	5988	5990	5617	3312	2228
15	4900.01	5990	5426	5988	5990	5617	3312	2228
16	5299.99	6186	5622	6184	6186	5783	3628	2422
17	5300.01	6186	5622	6184	6186	5783	3628	2422
18	5665.66	6364	5800	6362	6364	5935	3915	2598
19	7599.99	7306	6742	7304	7306	6735	5434	3362
20	7600.01	7306	3547	6735	7306	6735	5434	3362
21	7798.23	7403	3564	6817	7403	6817	5589	3441
22	8180.00	7589	3596	6975	7589	6975	5889	3596
23	9199.99	8085	4092	7398	8085	7398	6690	4025
24	9200.01	8085	4092	7398	8085	7398	6690	4025
25	9250.00	8110	4117	7418	8110	7418	6729	4046

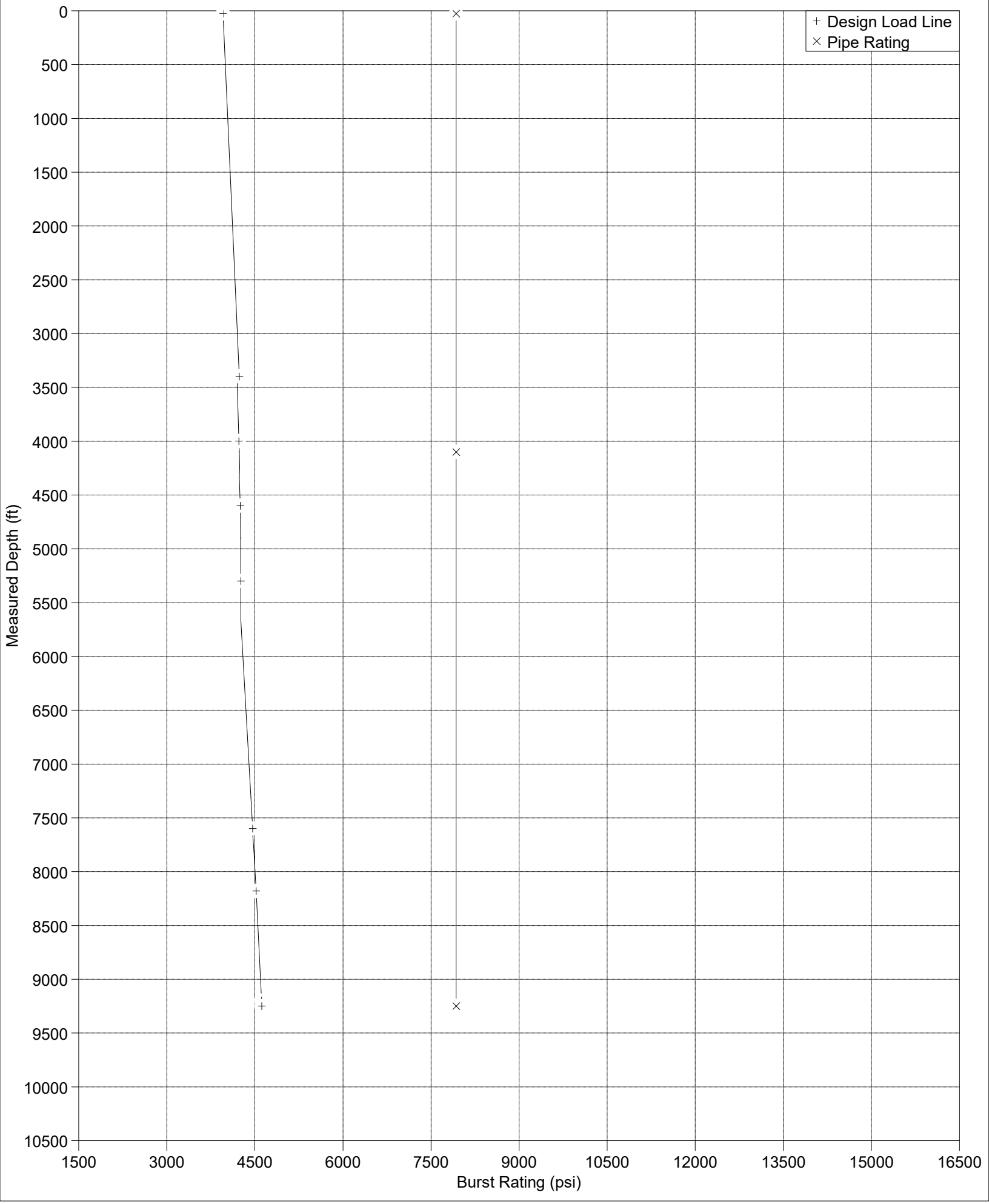
COLLAPSE PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Full Evacuation (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	17	0	17
2	3399.99	1471	2208	2	2208
3	3400.01	1471	2208	2	2208
4	3999.99	1731	2597	2	2597
5	4000.01	1731	2597	2	2597
6	4099.99	1774	2662	2	2662
7	4100.01	1774	2662	2	2662
8	4599.99	1989	3071	2	2985
9	4600.01	1989	3071	2	2985
10	4899.99	2117	3312	2	3176
11	4900.01	2117	3312	2	3176
12	5299.99	2283	3628	3	3426
13	5300.01	2283	3628	3	3426
14	7599.99	3235	5434	4	4855
15	7600.01	3235	5434	4	4855
16	8180.00	3475	5889	4	5215
17	9199.99	3898	6690	5	5849
18	9200.01	3898	6690	5	5849
19	9250.00	3918	6729	5	5880

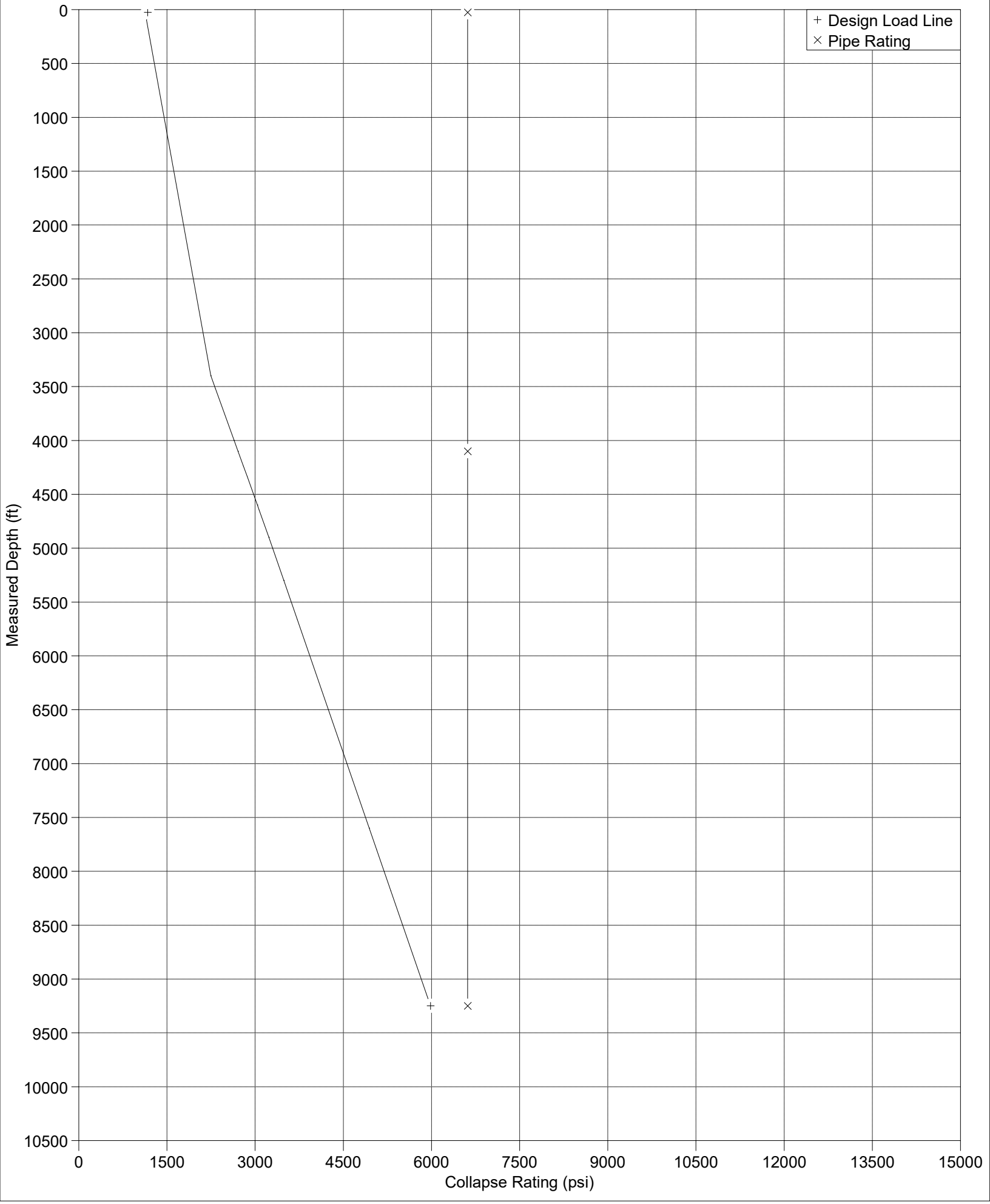
AXIAL LOADS TABLE (9 5/8" Production Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	540871	491941	466783	417853	466783	417853
2	100.00	537799	488868	462824	413894	462824	413894
3	3399.99	400781	351850	286275	237344	286275	237344
4	3400.01	400780	351849	286274	237343	361857	312926
5	3521.00	395756	346826	279801	230870	360670	311739
6	3999.99	375868	326938	254175	205244	356743	307813
7	4000.01	375867	326937	254174	205243	356743	307813
8	4099.99	371716	322786	248826	199895	355924	306993
9	4100.01	371715	322785	248824	199894	355924	306993
10	4240.16	365873	316943	241334	192404	355824	306893
11	4337.44	361784	312853	236145	187214	355317	306386
12	4599.99	350628	301697	222207	173276	355275	306345
13	4600.01	350627	301696	222206	173275	355275	306345
14	4646.08	348654	299724	219774	170843	355339	306408
15	4899.99	337721	288790	206469	157539	354728	305798
16	4900.01	337720	288790	206468	157537	354728	305798
17	5299.99	320380	271450	185898	136967	353784	304854
18	5300.01	320379	271449	185897	136966	353784	304854
19	5665.66	304508	255578	167183	118253	352926	303995
20	7599.99	220549	171619	68189	19258	355695	306764
21	7600.01	220548	171618	68188	19257	355695	306764
22	7798.23	211944	163014	58043	9113	355978	307048
23	8180.00	195374	146443	-59356	-10425	356348	307417
24	9121.14	154524	105593	-107521	-58591	356638	307707
25	9146.46	153425	104494	-108817	-59886	356645	307715
26	9199.99	151101	102171	-111557	-62626	356662	307731
27	9200.01	151100	102170	-111558	-62627	356662	-326050

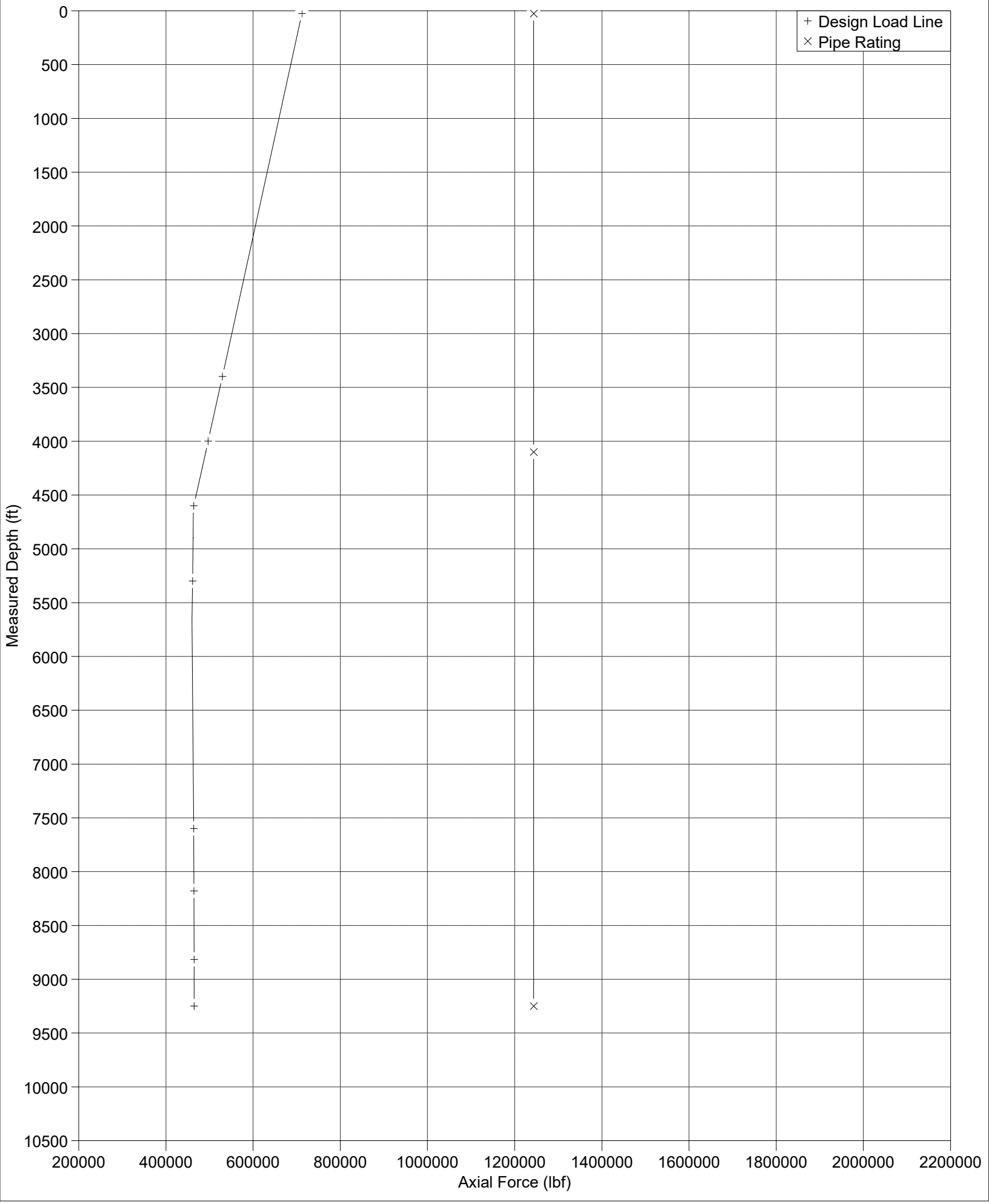
BURST DESIGN (9 5/8" Production Casing)

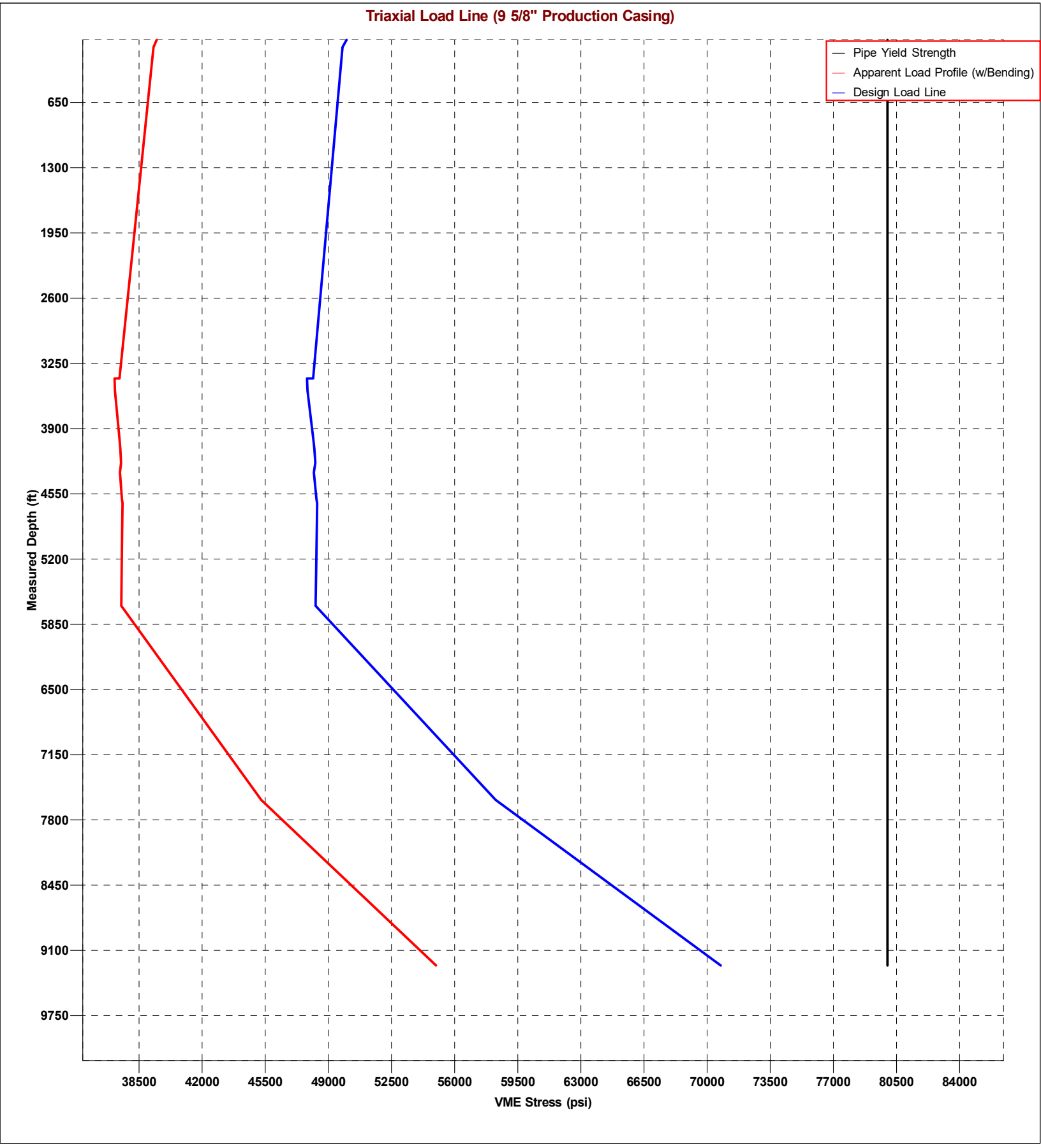


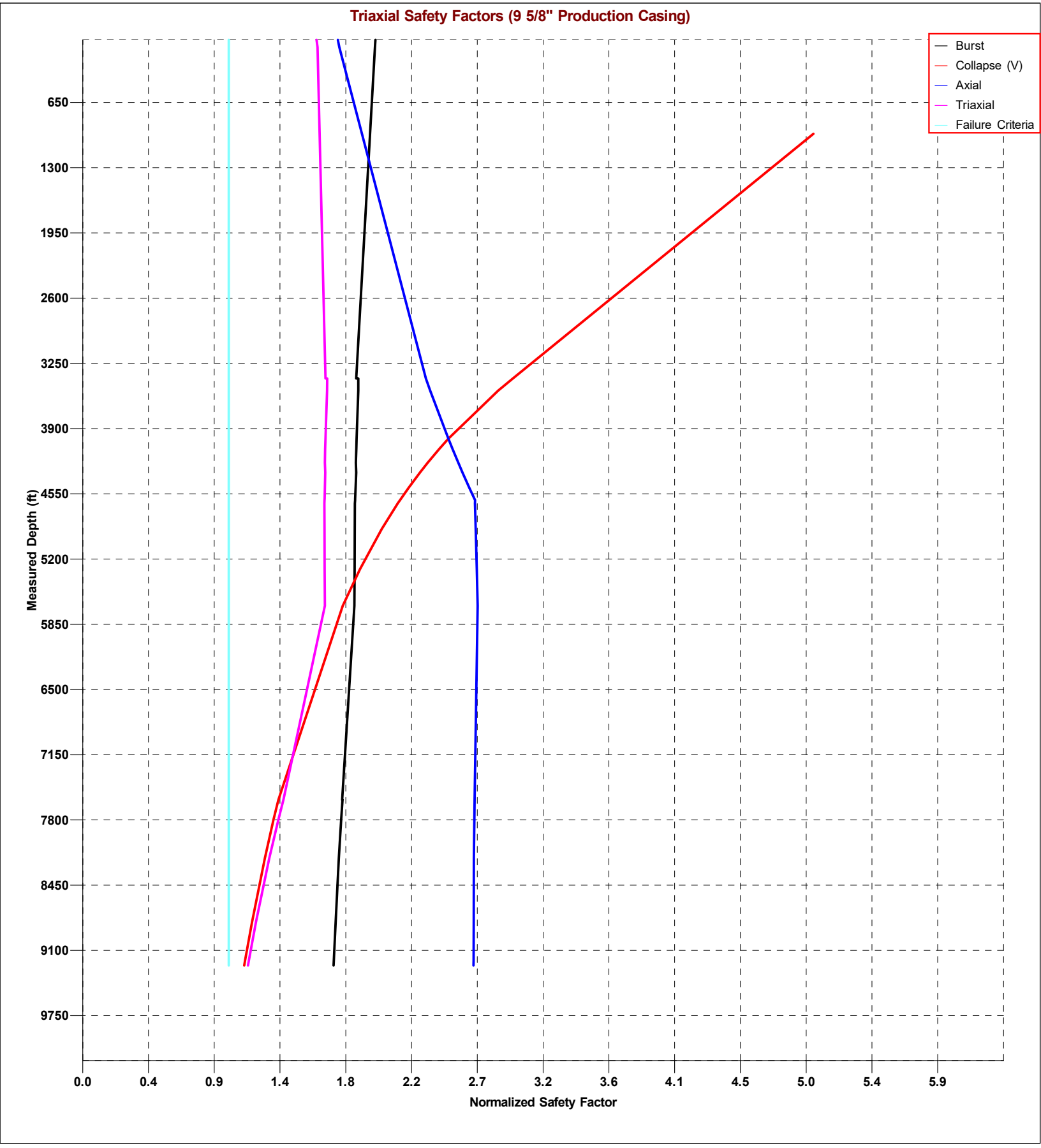
COLLAPSE DESIGN (9 5/8" Production Casing)



AXIAL DESIGN (9 5/8" Production Casing)




Triaxial Load Line (9 5/8" Production Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
38500
42000
45500
49000
52500
56000
59500
63000
66500
70000
73500
77000
80500
84000
VME Stress (psi)


Triaxial Safety Factors (9 5/8" Production Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	9 5/8", 53.500 ppf, L-80	Blue	2.20 B7	5.64 C2	2.27 A4	2.00 A4
2	100			2.20 B7	5.73 C2	2.28 A4	2.01 A4
3	3400			2.06 B7	2.94 C5	3.05 A4	2.08 B7
4	3400			2.07 B7	2.94 C5	3.05 A4	2.09 B7
5	3521			2.07 B7	2.84 C5	3.09 A4	2.09 B7
6	4000			2.06 B7	2.50 C5	3.25 A4	2.08 B7
7	4100			2.06 B7	2.44 C5	3.29 A4	2.07 B7
8	4100	9 5/8", 53.500 ppf, L-80	Blue	2.06 B7	2.44 C5	3.29 A4	2.07 B7
9	4240			2.06 B7	2.36 C5	3.34 A4	2.07 B7
10	4337			2.06 B7	2.31 C5	3.38 A4	2.07 B7
11	4490			2.05 B7	2.23 C5	3.44 A4	2.07 B7
12	4600			2.05 B7	2.18 C5	3.48 A4	2.07 B7
13	4613			2.05 B7	2.17 C5	3.49 A4	2.07 B7
14	4646			2.05 B7	2.16 C5	3.49 B8	2.07 B7
15	4900			2.05 B7	2.05 C5	3.50 B8	2.07 B7
16	5300			2.05 B7	1.90 C5	3.50 B8	2.07 B7
17	5666			2.05 B7	1.78 C5	3.51 B8	2.07 B7
18	7600			1.95 B7	1.34 C5	3.49 B8	1.72 C5
19	7600			1.96 B5	1.34 C5	3.49 B8	1.72 C5
20	7798			1.95 B5	1.31 C5	3.48 B8	1.67 C5
21	8180			1.93 B5	1.25 C5	3.48 B8	1.60 C5
22	8817			1.90 B5	1.16 C5	3.48 B8	1.48 C5
23	8818			1.90 B5	1.16 C5	3.48 B8	1.48 C5
24	9200			1.89 B5	1.11 C5	3.48 B8	1.42 C5
25	9249			1.89 B5	1.11 C5	3.48 B8	1.41 C5
26	9250			1.89 B5	1.11 C5	3.48 B8	1.41 C5
27							
28	B5	Pressure Test					
29	B7	Stimulation Surface Leak					
30	B8	Injection Casing					
31	C2	Cementing					
32	C5	Full Evacuation Production					
33	A4	Overpull Force					
34	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	9 5/8", 53.500 ppf, L-80	0.272 B7	0.092 C2	0.265 A4	50.1	83.1	51.4	0.273	0.453	0.280
2	100.00		0.273 B7	0.106 C5	0.263 A4	50.0	80.5	51.7	0.272	0.439	0.282
3	3399.99		0.291 B7	0.343 C5	0.284 B7	46.6	37.1	47.8	0.254	0.202	0.261
4	3400.01		0.289 B7	0.343 C5	0.282 B7	47.0	37.1	48.2	0.256	0.202	0.263
5	3521.00		0.289 B7	0.348 C5	0.282 B7	47.0	36.2	48.2	0.256	0.197	0.263
6	3999.99		0.291 B7	0.367 C5	0.285 B7	46.6	32.6	47.8	0.254	0.178	0.260
7	4000.01		0.291 B7	0.367 C5	0.285 B7	46.6	32.6	47.8	0.254	0.178	0.260
8	4099.99		0.291 B7	0.371 C5	0.285 B7	46.6	31.9	47.7	0.254	0.174	0.260
9	4100.01	9 5/8", 53.500 ppf, L-80	0.291 B7	0.371 C5	0.285 B7	46.6	31.9	47.7	0.254	0.174	0.260
10	4240.16		0.292 B7	0.377 C5	0.285 B7	46.5	30.8	47.6	0.253	0.168	0.260
11	4337.44		0.291 B7	0.381 C5	0.285 B7	46.6	30.1	47.7	0.254	0.164	0.260
12	4490.21		0.292 B7	0.387 C5	0.286 B7	46.4	29.0	47.6	0.253	0.158	0.259
13	4599.99		0.292 B7	0.391 C5	0.286 B7	46.4	28.2	47.5	0.253	0.154	0.259
14	4600.01		0.292 B7	0.391 C5	0.286 B7	46.4	28.2	47.5	0.253	0.154	0.259
15	4612.85		0.292 B7	0.392 C5	0.286 B7	46.3	28.1	47.5	0.253	0.153	0.259
16	4646.08		0.293 B7	0.393 C5	0.286 B7	46.3	27.9	47.5	0.252	0.152	0.259
17	4899.99		0.293 B7	0.403 C5	0.286 B7	46.3	26.0	47.5	0.252	0.142	0.259
18	4900.01		0.293 B7	0.403 C5	0.286 B7	46.3	26.0	47.5	0.252	0.142	0.259
19	5299.99		0.293 B7	0.419 C5	0.286 B7	46.2	23.2	47.5	0.252	0.126	0.259
20	5300.01		0.293 B7	0.419 C5	0.286 B7	46.2	23.2	47.5	0.252	0.126	0.259
21	5665.66		0.293 B7	0.430 C5	0.286 B7	46.2	21.1	47.5	0.252	0.115	0.259
22	7599.99		0.307 B7	0.479 C5	0.341 C5	43.7	12.2	37.4	0.238	0.066	0.204
23	7600.01		0.307 B5	0.479 C5	0.341 C5	43.8	12.2	37.4	0.238	0.066	0.204
24	7798.23		0.308 B5	0.483 C5	0.351 C5	43.5	11.3	35.7	0.237	0.062	0.194
25	8180.00		0.311 B5	0.493 C5	0.368 C5	42.9	9.5	32.4	0.234	0.052	0.177
26	8816.82		0.315 B5	0.509 C5	0.398 C5	42.2	6.6	26.9	0.230	0.036	0.147
27	8817.60		0.315 B5	0.509 C5	0.398 C5	42.2	6.6	26.9	0.230	0.036	0.147
28	9199.99		0.317 B5	0.519 C5	0.416 C5	41.8	4.8	23.6	0.228	0.026	0.129
29	9200.01		0.317 B5	0.519 C5	0.416 C5	41.8	4.8	23.6	0.228	0.026	0.129
30	9249.44		0.318 B5	0.520 C5	0.419 C5	41.7	4.6	23.2	0.227	0.025	0.126
31	9250.00		0.318 B5	0.520 C5	0.419 C5	41.7	4.6	23.2	0.227	0.025	0.126
32											
33	B5	Pressure Test									
34	B7	Stimulation Surface Leak									
35	C2	Cementing									
36	C5	Full Evacuation Production									
37	A4	Overpull Force									
38	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (9 5/8" Production Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	895336
2	26	894208
3	26	894207
4	100	890995
5	250	884485
6	500	873634
7	750	862782
8	1000	851931
9	1250	841080
10	1500	830229
11	1750	819377
12	2000	808526
13	2250	797675
14	2500	786824
15	2750	775973
16	3000	765121
17	3250	754270
18	3500	743419
19	3750	732568
20	4000	721717
21	4000	721716
22	4100	717377
23	4100	717376
24	4250	710873
25	4500	700076
26	4600	695781
27	4600	695780
28	4750	689372
29	4900	683013
30	4900	683012
31	5000	678806
32	5150	672551
33	5150	672550
34	5250	668399
35	5300	666323
36	5300	666322
37	5500	658019
38	5750	647638
39	6000	637258
40	6250	626878
41	6500	616498
42	6750	606118
43	7000	595737
44	7250	585357
45	7500	574977
46	7750	564597
47	8000	554217
48	8250	543836
49	8500	533456
50	8750	523076
51	9000	512696
52	9200	504392
53	9200	504391
54	9224	503395
55	9250	* 503682
56		
57	* Based on Casing Strength	
58	Only. Running String not	
59	Included	

TRIAXIAL RESULTS (9 5/8" Production Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	386753	337822	388183	3147.4	2.31	2.26	N/A	3.21	78	3513	17	N/A	N/A
2	100	383676	334745	385693	3147.4	2.32	2.26	N/A	3.23	79	3551	49		
3	3400	246461	197530	273417	3147.4	2.28	2.09	N/A	4.98	114	5231	1489		
4	3400	245204	196274	272597	3147.4	2.30	2.11	N/A	5.00	114	5231	1518		
5	3521	239834	190904	268212	3147.4	2.30	2.10	N/A	5.11	116	5293	1579		
6	4000	219348	170417	251325	3147.4	2.27	2.09	N/A	5.58	121	5536	1801		
7	4000	219347	170416	251325	3147.4	2.27	2.09	N/A	5.58	121	5536	1801		
8	4100	215071	166140	247794	3147.4	2.26	2.09	N/A	5.69	122	5587	1847		
9	4100	215070	166140	247793	3147.4	2.26	2.09	N/A	5.69	122	5587	1847		
10	4240	210130	161199	243909	3147.4	2.26	2.08	N/A	5.82	123	5659	1912		
11	4337	206269	157339	240930	3147.4	2.26	2.08	N/A	5.93	124	5708	1967		
12	4600	197221	148290	233783	3147.4	2.24	2.07	N/A	6.19	127	5841	2084		
13	4600	197220	148289	233783	3147.4	2.24	2.07	N/A	6.19	127	5841	2084		
14	4646	195712	146781	232581	3147.4	2.24	2.07	N/A	6.24	128	5864	2103		
15	4900	186503	137573	225371	3147.4	2.23	2.07	N/A	6.54	130	5990	2228		
16	4900	186503	137572	225371	3147.4	2.23	2.07	N/A	6.54	130	5990	2228		
17	5300	172265	123335	214200	3147.4	2.21	2.06	N/A	7.08	134	6186	2422		
18	5300	172265	123334	214199	3147.4	2.21	2.06	N/A	7.08	134	6186	2422		
19	5666	159313	110382	204013	3147.4	2.20	2.06	N/A	7.64	138	6364	2598		
20	7600	98108	49177	154569	3147.4	2.02	1.96	N/A	12.33	158	7306	3362		
21	7600	98107	49176	154569	3147.4	2.02	1.96	N/A	12.33	158	7306	3362		
22	7798	91835	42904	149468	3147.4	2.00	1.95	N/A	13.17	160	7403	3441		
23	8180	79578	30648	139508	3147.4	1.97	1.93	N/A	15.18	164	7589	3596		
24	9115	48941	11	114599	3147.4	1.90	1.89	N/A	24.60	174	8044	3989		
25	9115	48941	10	114598	3147.4	1.90	1.89	N/A	24.61	174	8044	3989		
26	9200	-51703	-2773	11229	3147.4	1.90	1.89	N/A	(23.28)	174	8085	4025		
27	9200	-51704	-2773	11228	3147.4	1.90	1.89	N/A	(23.28)	174	8085	4025		
28	9250	-53348	-4417	9872	3147.4	1.89	1.89	N/A	(22.56)	175	8110	4046		
29														
30	( )	Compression												
31	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Tubing Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	90611	41681	93577	3147.4	2.62	2.63	N/A	13.33	164	2949	17	N/A	N/A
2	100	90093	41162	93560	3147.4	2.61	2.62	N/A	13.41	164	2987	49		
3	3400	66971	18040	92803	3147.4	2.41	2.42	N/A	18.03	164	4667	1489		
4	3400	65715	16784	91971	3147.4	2.43	2.44	N/A	18.38	164	4667	1518		
5	3521	64528	15597	91718	3147.4	2.43	2.44	N/A	18.72	164	4728	1579		
6	4000	60602	11671	91230	3147.4	2.41	2.43	N/A	19.93	164	4972	1801		
7	4100	59782	10851	91128	3147.4	2.40	2.42	N/A	20.20	164	5023	1847		
8	4240	59682	10752	92064	3147.4	2.40	2.42	N/A	20.24	164	5094	1912		
9	4337	59175	10244	92423	3147.4	2.40	2.42	N/A	20.41	164	5144	1967		
10	4600	59134	10203	94261	3147.4	2.40	2.41	N/A	20.42	164	5276	2084		
11	4646	59197	10267	94629	3147.4	2.39	2.41	N/A	20.40	164	5299	2103		
12	4900	58587	9656	96005	3147.4	2.40	2.41	N/A	20.62	164	5426	2228		
13	5300	57643	8712	98132	3147.4	2.40	2.41	N/A	20.95	164	5622	2422		
14	5666	56784	7853	100068	3147.4	2.40	2.40	N/A	21.27	164	5800	2598		
15	7600	59553	10622	115153	3147.4	2.30	2.28	N/A	20.28	164	6742	3362		
16	7600	-147965	-99035	-98538	3147.4	9.80	41.61	N/A	(8.16)	164	3547	3362		
17	7798	-150432	-101501	-99825	3147.4	10.09	62.53	N/A	(8.03)	164	3564	3441		
18	8180	-155354	-106423	-102414	3147.4	10.62	N/A	N/A	(7.77)	164	3596	3596		
19	9200	-155040	-106109	-95219	3147.4	10.83	+ 100.00	N/A	(7.79)	164	4092	4025		
20	9200	-155040	-106109	-95218	3147.4	10.83	+ 100.00	N/A	(7.79)	164	4092	4025		
21	9250	-155031	-106100	-94870	3147.4	10.84	+ 100.00	N/A	(7.79)	164	4117	4046		
22														
23	( )	Compression												
24	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Stimulation Surface Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	109915	60984	113455	3147.4	2.23	2.20	N/A	10.99	164	3511	17	N/A	N/A
2	100	109396	60466	113438	3147.4	2.23	2.20	N/A	11.04	164	3549	49		
3	3400	86274	37344	112681	3147.4	2.08	2.06	N/A	14.00	164	5229	1489		
4	3400	85019	36088	111849	3147.4	2.09	2.07	N/A	14.21	164	5229	1518		
5	3521	83832	34901	111596	3147.4	2.09	2.07	N/A	14.41	164	5291	1579		
6	4000	79905	30975	111108	3147.4	2.08	2.06	N/A	15.12	164	5534	1801		
7	4100	79086	30155	111006	3147.4	2.07	2.06	N/A	15.27	164	5585	1847		
8	4240	78986	30055	111942	3147.4	2.07	2.06	N/A	15.29	164	5657	1912		
9	4337	78479	29548	112301	3147.4	2.07	2.06	N/A	15.39	164	5706	1967		
10	4600	78437	29507	114139	3147.4	2.07	2.05	N/A	15.40	164	5839	2084		
11	4600	78438	29507	114139	3147.4	2.07	2.05	N/A	15.40	164	5839	2084		
12	4646	78501	29570	114507	3147.4	2.07	2.05	N/A	15.39	164	5862	2103		
13	4900	77891	28960	115883	3147.4	2.07	2.05	N/A	15.51	164	5988	2228		
14	4900	77890	28960	115883	3147.4	2.07	2.05	N/A	15.51	164	5988	2228		
15	5300	76947	28016	118010	3147.4	2.07	2.05	N/A	15.70	164	6184	2422		
16	5300	76946	28016	118010	3147.4	2.07	2.05	N/A	15.70	164	6184	2422		
17	5666	76088	27157	119946	3147.4	2.07	2.05	N/A	15.87	164	6362	2598		
18	7600	78857	29926	135031	3147.4	1.99	1.95	N/A	15.32	164	7304	3362		
19	7600	59326	10396	114920	3147.4	2.30	2.28	N/A	20.36	164	6735	3362		
20	7798	59113	10182	115954	3147.4	2.30	2.28	N/A	20.43	164	6817	3441		
21	8180	58525	9594	117828	3147.4	2.30	2.28	N/A	20.64	164	6975	3596		
22	9200	56281	7351	122390	3147.4	2.32	2.28	N/A	21.46	164	7398	4025		
23	9250	56165	7235	122609	3147.4	2.32	2.28	N/A	21.50	164	7418	4046		
24														
25	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (9 5/8" Production Casing) - Injection Down Casing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	386753	337822	388183	3147.4	2.31	2.26	N/A	3.21	78	3513	17	N/A	N/A
2	100	386234	337304	388167	3147.4	2.31	2.26	N/A	3.21	78	3551	49		
3	3400	363112	314182	387429	3147.4	2.21	2.11	N/A	3.41	78	5231	1489		
4	3400	361857	312926	386619	3147.4	2.22	2.13	N/A	3.43	78	5231	1518		
5	3521	360670	311739	386372	3147.4	2.22	2.13	N/A	3.44	78	5293	1579		
6	4000	356743	307813	385897	3147.4	2.21	2.12	N/A	3.48	78	5536	1801		
7	4100	355924	306993	385798	3147.4	2.21	2.11	N/A	3.48	78	5587	1847		
8	4240	355824	306893	386710	3147.4	2.21	2.11	N/A	3.48	78	5659	1912		
9	4337	355317	306386	387059	3147.4	2.21	2.11	N/A	3.49	78	5708	1967		
10	4600	355275	306345	388850	3147.4	2.20	2.10	N/A	3.49	78	5841	2084		
11	4646	355339	306408	389208	3147.4	2.20	2.10	N/A	3.49	78	5864	2103		
12	4900	354728	305798	390548	3147.4	2.19	2.10	N/A	3.50	78	5990	2228		
13	5300	353784	304854	392620	3147.4	2.19	2.10	N/A	3.50	78	6186	2422		
14	5666	352926	303995	394506	3147.4	2.19	2.10	N/A	3.51	78	6364	2598		
15	7600	355695	306764	409200	3147.4	2.10	2.00	N/A	3.49	78	7306	3362		
16	7798	355978	307048	410706	3147.4	2.09	1.99	N/A	3.48	78	7403	3441		
17	8180	356348	307417	413491	3147.4	2.07	1.98	N/A	3.48	78	7589	3596		
18	9200	356662	307731	420500	3147.4	2.04	1.95	N/A	3.48	78	8085	4025		
19	9250	356671	307741	420839	3147.4	2.04	1.94	N/A	3.48	78	8110	4046		
20														
21	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	466783	417853	473211	3147.4	2.12	2.24	N/A	2.63	111	3511	17	N/A	N/A
2	100	462824	413894	469992	3147.4	2.14	2.25	N/A	2.65	112	3543	65		
3	3400	286275	237344	325953	3147.4	2.85	2.82	N/A	4.27	123	4971	2208		
4	3400	286274	237343	325952	3147.4	2.85	2.82	N/A	4.27	123	4971	2208		
5	3521	279801	230870	320652	3147.4	2.88	2.85	N/A	4.37	123	5024	2286		
6	4000	254175	205244	299659	3147.4	3.02	2.96	N/A	4.81	125	5231	2597		
7	4000	254174	205243	299658	3147.4	3.02	2.96	N/A	4.81	125	5231	2597		
8	4100	248826	199895	295274	3147.4	3.06	2.98	N/A	4.91	125	5274	2662		
9	4100	248824	199894	295273	3147.4	3.06	2.98	N/A	4.91	125	5274	2662		
10	4240	241334	192404	289511	3147.4	3.12	3.05	N/A	5.06	125	5335	2777		
11	4337	236145	187214	285519	3147.4	3.17	3.09	N/A	5.18	126	5377	2857		
12	4600	222207	173276	274791	3147.4	3.30	3.22	N/A	5.50	127	5489	3071		
13	4600	222206	173275	274790	3147.4	3.30	3.22	N/A	5.50	127	5489	3071		
14	4646	219774	170843	272917	3147.4	3.32	3.24	N/A	5.56	127	5509	3108		
15	4900	206469	157539	262671	3147.4	3.46	3.38	N/A	5.92	128	5617	3312		
16	4900	206468	157537	262670	3147.4	3.46	3.38	N/A	5.92	128	5617	3312		
17	5300	185898	136967	246817	3147.4	3.70	3.61	N/A	6.57	129	5783	3628		
18	5300	185897	136966	246816	3147.4	3.70	3.61	N/A	6.57	129	5783	3628		
19	5666	167183	118253	232384	3147.4	3.95	3.85	N/A	7.30	130	5935	3915		
20	7600	68189	19258	155862	3147.4	6.13	5.97	N/A	17.86	136	6735	5434		
21	7600	68188	19257	155861	3147.4	6.13	5.97	N/A	17.87	136	6735	5434		
22	7798	58043	9113	148003	3147.4	6.50	6.32	N/A	20.98	137	6817	5589		
23	7976	48948	17	140955	3147.4	6.87	6.68	N/A	24.88	137	6891	5729		
24	7977	-48942	-12	40983	3147.4	7.03	6.68	N/A	(24.88)	137	6891	5729		
25	8180	-59356	-10425	32891	3147.4	7.41	7.14	N/A	(20.51)	138	6975	5889		
26	9200	-111557	-62626	-7724	3147.4	9.67	10.95	N/A	(10.90)	141	7398	6690		
27	9200	-111558	-62627	-7725	3147.4	9.67	10.95	N/A	(10.90)	141	7398	6690		
28	9250	-114116	-65185	-9717	3147.4	9.78	11.25	N/A	(10.66)	142	7418	6729		
29														
30	( )	Compression												
31	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	266537	217606	270233	3147.4	4.05	N/A	5.64	4.61	111	11	17	N/A	N/A
2	100	262578	213647	266746	3147.4	4.09	N/A	5.73	4.67	112	43	65		
3	3400	86028	37098	110720	3147.4	5.95	N/A	7.44	14.22	123	1471	2208		
4	3400	86027	37097	110719	3147.4	5.95	N/A	7.44	14.22	123	1471	2208		
5	3521	79554	30624	104979	3147.4	6.01	N/A	7.37	15.37	123	1524	2286		
6	4000	53928	4998	82238	3147.4	6.17	N/A	7.03	22.67	125	1731	2597		
7	4000	53927	4997	82237	3147.4	6.17	N/A	7.03	22.67	125	1731	2597		
8	4093	48951	21	77819	3147.4	6.19	N/A	6.95	24.97	125	1771	2658		
9	4094	-48940	-9	-21774	3147.4	9.19	N/A	7.38	(24.98)	125	1771	2658		
10	4100	-49282	-352	-22078	3147.4	9.18	N/A	7.37	(24.80)	125	1774	2662		
11	4100	-49283	-353	-22079	3147.4	9.18	N/A	7.37	(24.80)	125	1774	2662		
12	4240	-56773	-7843	-28746	3147.4	8.75	N/A	6.94	(21.53)	125	1835	2777		
13	4337	-61963	-13032	-33366	3147.4	8.46	N/A	6.68	(19.72)	126	1877	2857		
14	4600	-75901	-26970	-45779	3147.4	7.77	N/A	6.05	(16.10)	127	1989	3071		
15	4600	-75902	-26972	-45780	3147.4	7.77	N/A	6.05	(16.10)	127	1989	3071		
16	4646	-78334	-29403	-47946	3147.4	7.65	N/A	5.95	(15.60)	127	2009	3108		
17	4900	-91639	-42708	-59803	3147.4	7.09	N/A	5.47	(13.33)	128	2117	3312		
18	4900	-91640	-42709	-59804	3147.4	7.09	N/A	5.47	(13.33)	128	2117	3312		
19	5300	-112210	-63280	-78147	3147.4	6.33	N/A	4.86	(10.88)	129	2283	3628		
20	5300	-112211	-63281	-78147	3147.4	6.33	N/A	4.86	(10.88)	129	2283	3628		
21	5666	-130924	-81994	-94847	3147.4	5.76	N/A	4.42	(9.32)	130	2435	3915		
22	7600	-229919	-180988	-183388	3147.4	3.85	N/A	2.97	(5.30)	136	3235	5434		
23	7600	-229920	-180989	-183389	3147.4	3.85	N/A	2.97	(5.30)	136	3235	5434		
24	7798	-240064	-191134	-192481	3147.4	3.72	N/A	2.87	(5.07)	137	3317	5589		
25	8180	-259602	-210672	-210003	3147.4	3.50	N/A	2.70	(4.69)	138	3475	5889		
26	9200	-311803	-262873	-256880	3147.4	3.00	N/A	2.34	(3.90)	141	3898	6690		
27	9200	-311804	-262874	-256881	3147.4	3.00	N/A	2.34	(3.90)	141	3898	6690		
28	9250	-314363	-265432	-259181	3147.4	2.98	N/A	2.32	(3.87)	142	3918	6729		
29														
30	( )	Compression												
31	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Full Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-108480	-59549	-111707	3147.4	10.49	N/A	+ 100.00	(11.13)	164	0	17	N/A	N/A
2	100	-110979	-62048	-114280	3147.4	10.58	N/A	+ 100.00	(10.88)	164	0	65		
3	3400	-222401	-173471	-228992	3147.4	3.76	N/A	2.94	(5.43)	164	2	2208		
4	3400	-222402	-173471	-228993	3147.4	3.76	N/A	2.94	(5.43)	164	2	2208		
5	3521	-226487	-177556	-233198	3147.4	3.64	N/A	2.84	(5.33)	164	2	2286		
6	4000	-242659	-193729	-249848	3147.4	3.23	N/A	2.50	(4.98)	164	2	2597		
7	4000	-242660	-193730	-249848	3147.4	3.23	N/A	2.50	(4.98)	164	2	2597		
8	4100	-246035	-197105	-253323	3147.4	3.15	N/A	2.44	(4.91)	164	2	2662		
9	4100	-246036	-197105	-253324	3147.4	3.15	N/A	2.44	(4.91)	164	2	2662		
10	4240	-249715	-200785	-257111	3147.4	3.05	N/A	2.36	(4.84)	164	2	2753		
11	4337	-252264	-203334	-259735	3147.4	2.98	N/A	2.31	(4.79)	164	2	2816		
12	4600	-259111	-210180	-266783	3147.4	2.81	N/A	2.18	(4.66)	164	2	2985		
13	4600	-259111	-210181	-266784	3147.4	2.81	N/A	2.18	(4.66)	164	2	2985		
14	4646	-260306	-211375	-268014	3147.4	2.78	N/A	2.16	(4.64)	164	2	3015		
15	4900	-266841	-217910	-274741	3147.4	2.64	N/A	2.05	(4.53)	164	2	3176		
16	4900	-266841	-217911	-274742	3147.4	2.64	N/A	2.05	(4.53)	164	2	3176		
17	5300	-276946	-228015	-285143	3147.4	2.44	N/A	1.90	(4.36)	164	3	3426		
18	5300	-276946	-228016	-285144	3147.4	2.44	N/A	1.90	(4.36)	164	3	3426		
19	5666	-286138	-237207	-294606	3147.4	2.29	N/A	1.78	(4.22)	164	3	3653		
20	7600	-334762	-285831	-344660	3147.4	1.72	N/A	1.34	(3.61)	164	4	4855		
21	7600	-334762	-285832	-344661	3147.4	1.72	N/A	1.34	(3.61)	164	4	4855		
22	7798	-339745	-290815	-349790	3147.4	1.67	N/A	1.31	(3.55)	164	4	4978		
23	8180	-349341	-300411	-359669	3147.4	1.60	N/A	1.25	(3.46)	164	4	5215		
24	9200	-374980	-326050	-386061	3147.4	1.42	N/A	1.11	(3.22)	164	5	5849		
25	9200	-374981	-326050	-386061	3147.4	1.42	N/A	1.11	(3.22)	164	5	5849		
26	9250	-376237	-327307	-387355	3147.4	1.41	N/A	1.11	(3.21)	164	5	5880		
27														
28	( )	Compression												
29	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	540871	491941	548278	3147.4	2.00	N/A	N/A	2.27	111	17	17	N/A	N/A
2	100	537799	488868	545963	3147.4	2.01	N/A	N/A	2.28	112	65	65		
3	3400	400781	351850	442371	3147.4	2.50	N/A	N/A	3.05	123	2208	2208		
4	3400	400780	351849	442370	3147.4	2.50	N/A	N/A	3.05	123	2208	2208		
5	3521	395756	346826	438559	3147.4	2.52	N/A	N/A	3.09	123	2286	2286		
6	4000	375868	326938	423461	3147.4	2.62	N/A	N/A	3.25	125	2597	2597		
7	4000	375867	326937	423460	3147.4	2.62	N/A	N/A	3.25	125	2597	2597		
8	4100	371716	322786	420307	3147.4	2.64	N/A	N/A	3.29	125	2662	2662		
9	4100	371715	322785	420306	3147.4	2.64	N/A	N/A	3.29	125	2662	2662		
10	4240	365873	316943	415860	3147.4	2.67	N/A	N/A	3.34	125	2753	2753		
11	4337	361784	312853	412736	3147.4	2.69	N/A	N/A	3.38	126	2816	2816		
12	4600	350628	301697	404167	3147.4	2.75	N/A	N/A	3.48	127	2985	2985		
13	4600	350627	301696	404166	3147.4	2.75	N/A	N/A	3.48	127	2985	2985		
14	4646	348654	299724	402644	3147.4	2.76	N/A	N/A	3.50	127	3015	3015		
15	4900	337721	288790	394170	3147.4	2.82	N/A	N/A	3.62	128	3176	3176		
16	4900	337720	288790	394170	3147.4	2.82	N/A	N/A	3.62	128	3176	3176		
17	5300	320380	271450	380616	3147.4	2.93	N/A	N/A	3.81	129	3426	3426		
18	5300	320379	271449	380615	3147.4	2.93	N/A	N/A	3.81	129	3426	3426		
19	5666	304508	255578	368177	3147.4	3.03	N/A	N/A	4.01	130	3653	3653		
20	7600	220549	171619	302229	3147.4	3.74	N/A	N/A	5.52	136	4855	4855		
21	7600	220548	171618	302228	3147.4	3.74	N/A	N/A	5.52	136	4855	4855		
22	7798	211944	163014	295456	3147.4	3.83	N/A	N/A	5.75	137	4978	4978		
23	8180	195374	146443	282406	3147.4	4.02	N/A	N/A	6.23	138	5215	5215		
24	9200	151101	102171	247490	3147.4	4.64	N/A	N/A	8.05	141	5849	5849		
25	9200	151100	102170	247489	3147.4	4.64	N/A	N/A	8.05	141	5849	5849		
26	9249	148955	100024	245795	3147.4	4.67	N/A	N/A	8.16	142	5879	5879		
27	9250	148931	100000	245776	3147.4	4.67	N/A	N/A	8.17	142	5880	5880		
28														
29	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	466783	417853	473211	3147.4	2.12	2.24	N/A	2.63	111	3511	17	N/A	N/A
2	100	462824	413894	469992	3147.4	2.14	2.25	N/A	2.65	112	3543	65		
3	3400	286275	237344	325953	3147.4	2.85	2.82	N/A	4.27	123	4971	2208		
4	3400	286274	237343	325952	3147.4	2.85	2.82	N/A	4.27	123	4971	2208		
5	3521	279801	230870	320652	3147.4	2.88	2.85	N/A	4.37	123	5024	2286		
6	4000	254175	205244	299659	3147.4	3.02	2.96	N/A	4.81	125	5231	2597		
7	4000	254174	205243	299658	3147.4	3.02	2.96	N/A	4.81	125	5231	2597		
8	4100	248826	199895	295274	3147.4	3.06	2.98	N/A	4.91	125	5274	2662		
9	4100	248824	199894	295273	3147.4	3.06	2.98	N/A	4.91	125	5274	2662		
10	4240	241334	192404	289511	3147.4	3.12	3.05	N/A	5.06	125	5335	2777		
11	4337	236145	187214	285519	3147.4	3.17	3.09	N/A	5.18	126	5377	2857		
12	4600	222207	173276	274791	3147.4	3.30	3.22	N/A	5.50	127	5489	3071		
13	4600	222206	173275	274790	3147.4	3.30	3.22	N/A	5.50	127	5489	3071		
14	4646	219774	170843	272917	3147.4	3.32	3.24	N/A	5.56	127	5509	3108		
15	4900	206469	157539	262671	3147.4	3.46	3.38	N/A	5.92	128	5617	3312		
16	4900	206468	157537	262670	3147.4	3.46	3.38	N/A	5.92	128	5617	3312		
17	5300	185898	136967	246817	3147.4	3.70	3.61	N/A	6.57	129	5783	3628		
18	5300	185897	136966	246816	3147.4	3.70	3.61	N/A	6.57	129	5783	3628		
19	5666	167183	118253	232384	3147.4	3.95	3.85	N/A	7.30	130	5935	3915		
20	7600	68189	19258	155862	3147.4	6.13	5.97	N/A	17.86	136	6735	5434		
21	7600	68188	19257	155861	3147.4	6.13	5.97	N/A	17.87	136	6735	5434		
22	7798	58043	9113	148003	3147.4	6.50	6.32	N/A	20.98	137	6817	5589		
23	7976	48948	17	140955	3147.4	6.87	6.68	N/A	24.88	137	6891	5729		
24	7977	-48942	-12	40983	3147.4	7.03	6.68	N/A	(24.88)	137	6891	5729		
25	8180	-59356	-10425	32891	3147.4	7.41	7.14	N/A	(20.51)	138	6975	5889		
26	9200	-111557	-62626	-7724	3147.4	9.67	10.95	N/A	(10.90)	141	7398	6690		
27	9200	-111558	-62627	-7725	3147.4	9.67	10.95	N/A	(10.90)	141	7398	6690		
28	9250	-114116	-65185	-9717	3147.4	9.78	11.25	N/A	(10.66)	142	7418	6729		
29														
30	( )	Compression												
31	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (5 1/2" Production Tubing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Temperature Deration:	Yes
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (5 1/2" Production Tubing)

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7600.00 ft
Perforation Depth, MD:	8180.00 ft
Packer Setting Method:	Set Mechanically
Pickup Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
4000.00 ft	121 °F
4597.53 ft	127 °F
4891.69 ft	130 °F
5276.21 ft	134 °F
7476.37 ft	158 °F

BURST LOADS DATA (5 1/2" Production Tubing)

Production Load:	**Shut-In**
Shut-in Bottom Hole Pressure:	4200 psi
Gas Gravity:	0.70 (0.0975 psi/ft @ 164 °F & 4200 psi)
Hot:	Yes
Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Internal Fluid Density:	9.80 ppg
Production Load:	**Tubing Injection**
Injection Pressure:	3500 psi
Injection Fluid Density:	10.00 ppg

COLLAPSE LOADS DATA (5 1/2" Production Tubing)

Drilling Load:	**Full/Partial Evacuation**
Mud Weight:	9.80 ppg
Mud Level, MD:	7600.00 ft
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7600.00 ft
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7600.00 ft
Perforation Depth, MD:	8180.00 ft
Gas Gravity:	0.70
Reservoir Pressure:	3596 psi
Production Load:	**Annular Pressure Test**
Fluid Density(Inside Tubing):	1.50 ppg
Wellhead Pressure (Annulus)	3500 psi
Fluid Density(Annulus)	9.80 ppg
Packer Depth, MD:	7600.00 ft

AXIAL LOADS DATA (5 1/2" Production Tubing)

Overpull Force:	100000 lbf
Service Loads:	Yes

BURST PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Pressure Test (Int) (psi)	Pressure Test (Ext) (psi)	Tubing Injection (Int) (psi)	Tubing Injection (Ext) (psi)	Shut-In (Int) (psi)	Shut-In (Ext) (psi)
1	26.00	3513	13	3514	13	3553	13
2	3999.99	5536	2036	5578	2036	3873	2036
3	4000.01	5536	2036	5578	2036	3873	2036
4	4599.99	5841	2341	5888	2341	3921	2341
5	4600.01	5841	2341	5888	2341	3921	2341
6	4899.99	5990	2490	6041	2490	3944	2490
7	4900.01	5990	2490	6041	2490	3944	2490
8	5299.99	6186	2686	6241	2686	3975	2686
9	5300.01	6186	2686	6241	2686	3975	2686
10	7599.99	7306	3806	7384	3806	4152	3806
11	7600.00	7306	3806	7384	3806	4152	3806

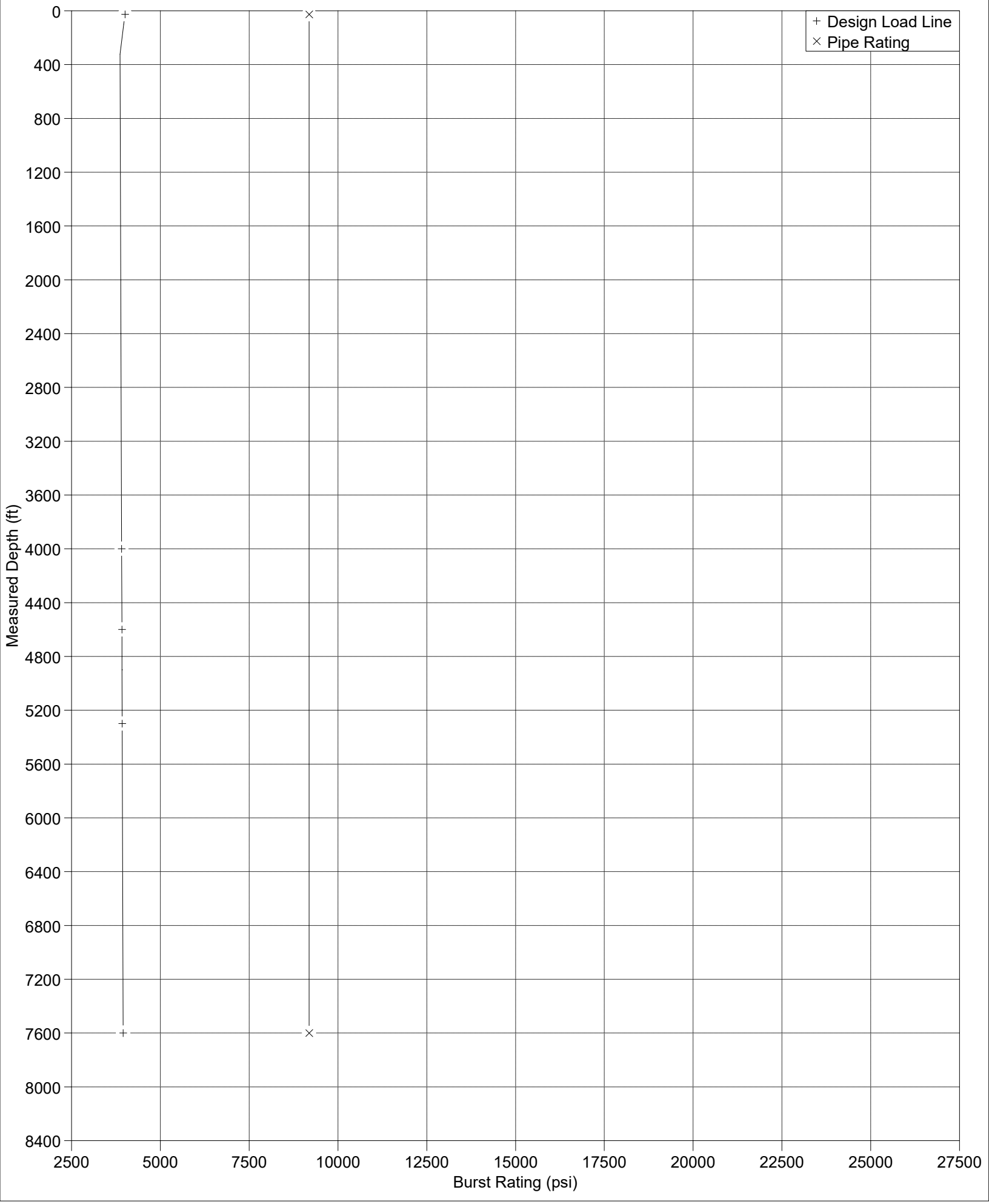
COLLAPSE PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Full/Partial Evacuation (Int) (psi)	Full/Partial Evacuation (Ext) (psi)	Tubing Leak (Int) (psi)	Tubing Leak (Ext) (psi)	Annular Pressure Test (Int) (psi)	Annular Pressure Test (Ext) (psi)
1	26.00	0	13	2949	2949	2	3513
2	3999.99	2	2036	3268	4972	312	5536
3	4000.01	2	2036	3268	4972	312	5536
4	4599.99	2	2341	3316	5276	358	5841
5	4600.01	2	2341	3316	5276	358	5841
6	4899.99	3	2490	3340	5426	381	5990
7	4900.01	3	2490	3340	5426	381	5990
8	5299.99	3	2686	3371	5622	411	6186
9	5300.01	3	2686	3371	5622	411	6186
10	7599.99	4	3806	3547	6742	583	7306
11	7600.00	4	3806	3547	6742	583	7306

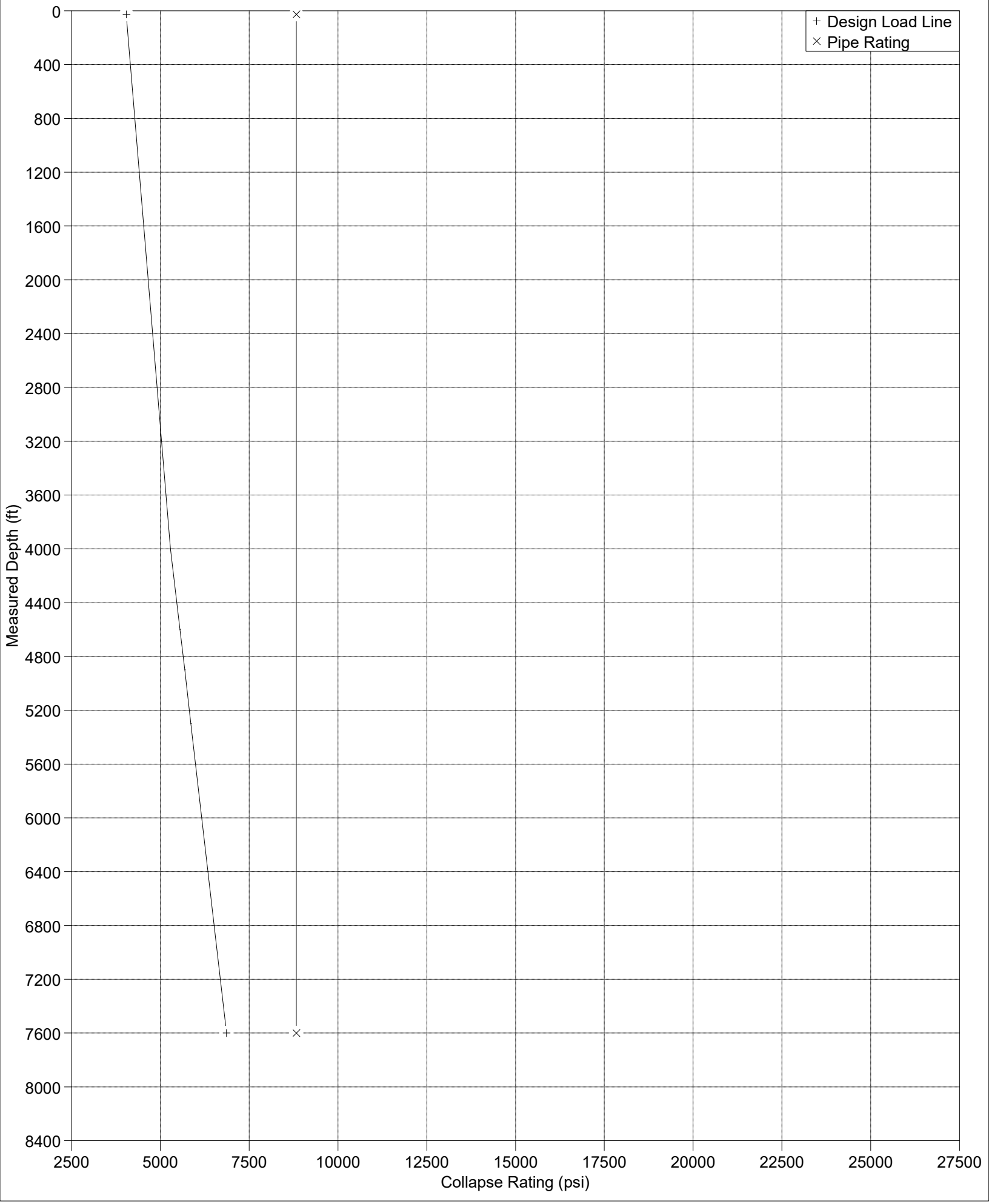
AXIAL LOADS TABLE (5 1/2" Production Tubing)

	Depth (MD) (ft)	Overpull Force (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	237403	226921	224163	213681
2	100.00	236197	225715	222683	212201
3	3999.99	171801	161319	144683	134201
4	4000.01	171800	161318	144682	134200
5	4599.99	161581	151099	132732	122250
6	4600.01	161581	151099	132732	122250
7	4899.99	156471	145989	126849	116367
8	4900.01	156471	145989	126849	116366
9	5299.99	149658	139176	119159	108677
10	5300.01	149658	139176	119158	108676
11	6670.63	126312	115830	92936	82454
12	7598.00	110516	100034	-115231	64711
13	7598.00	110516	100034	-115231	-104749

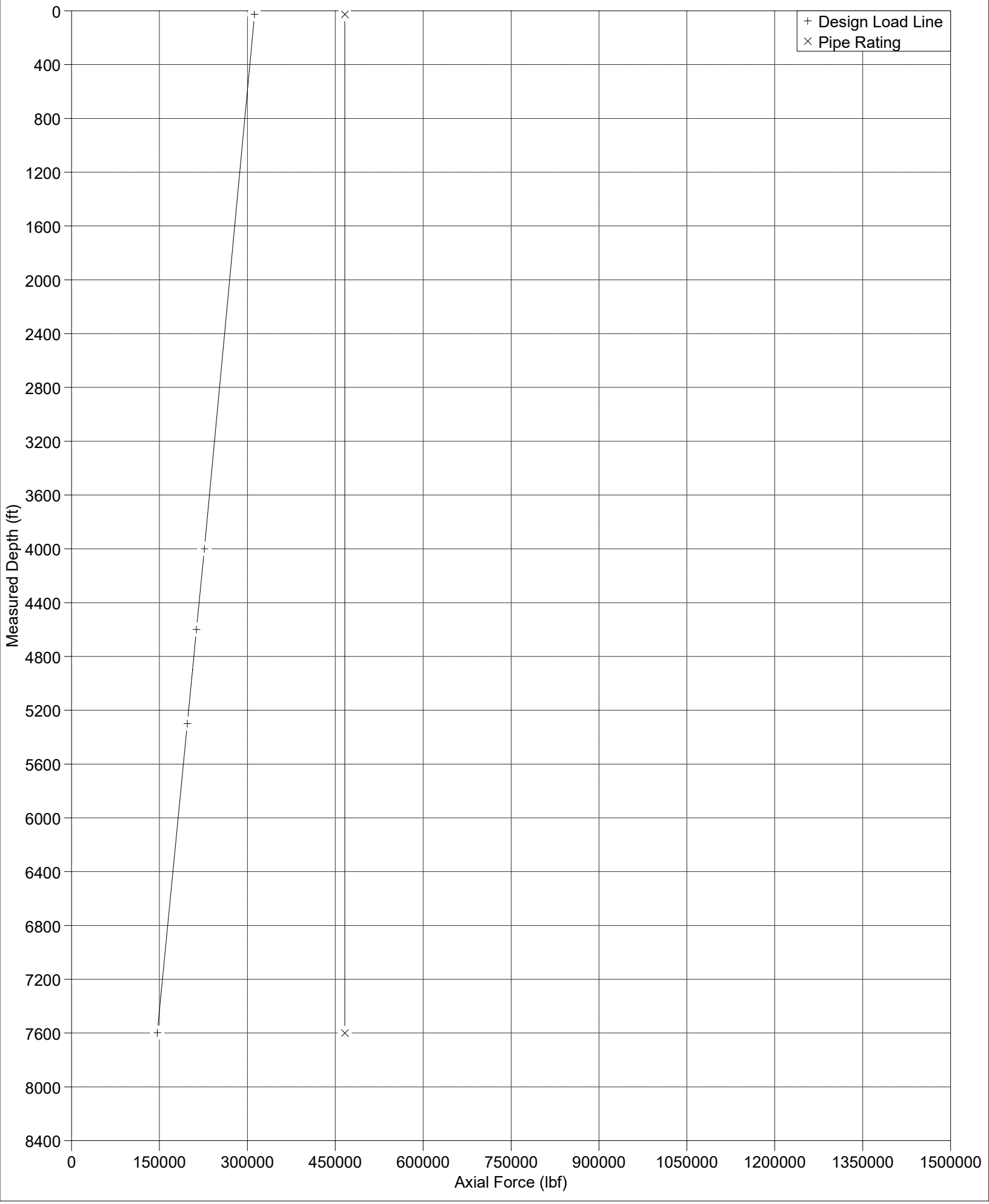
BURST DESIGN (5 1/2" Production Tubing)

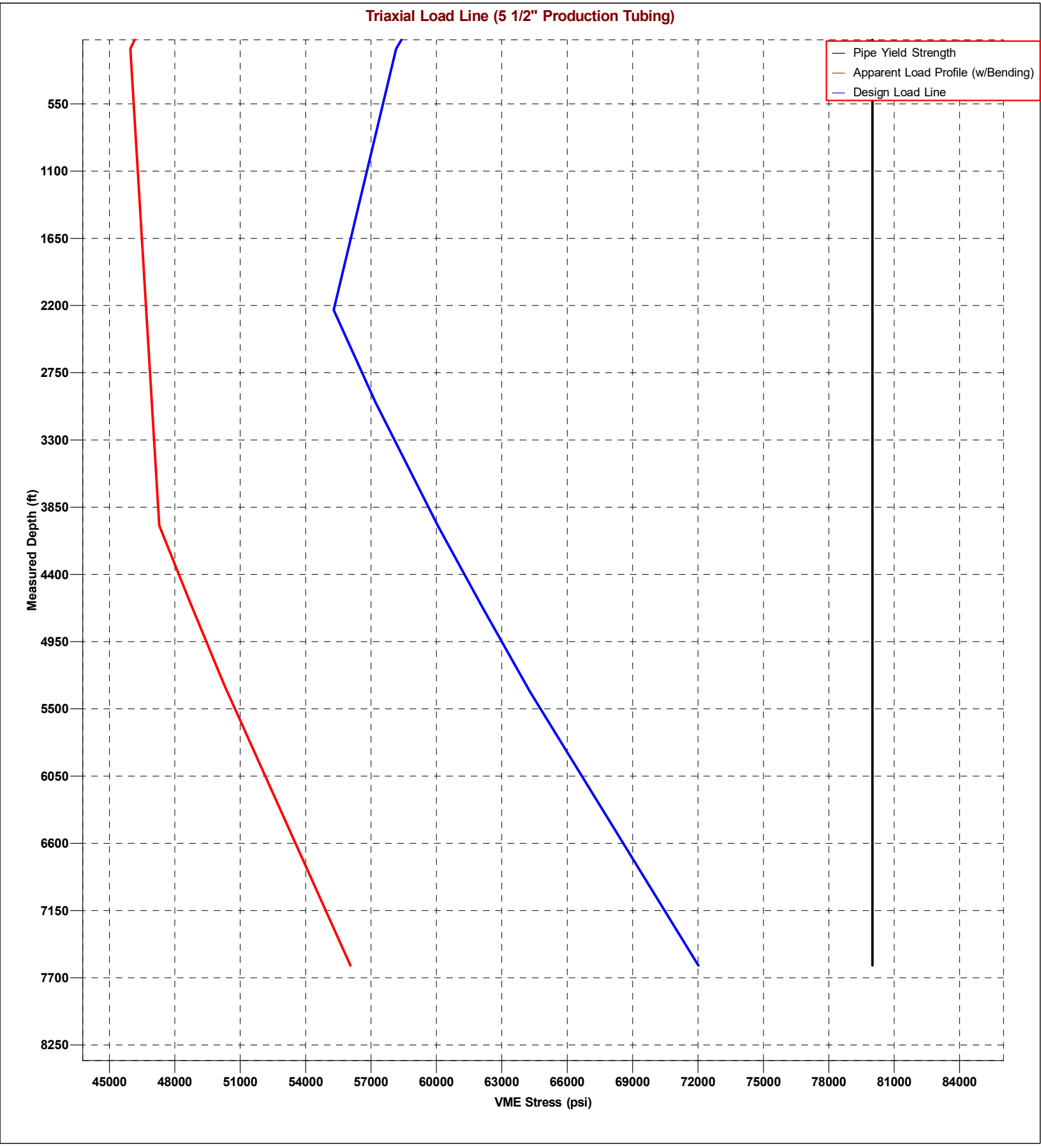


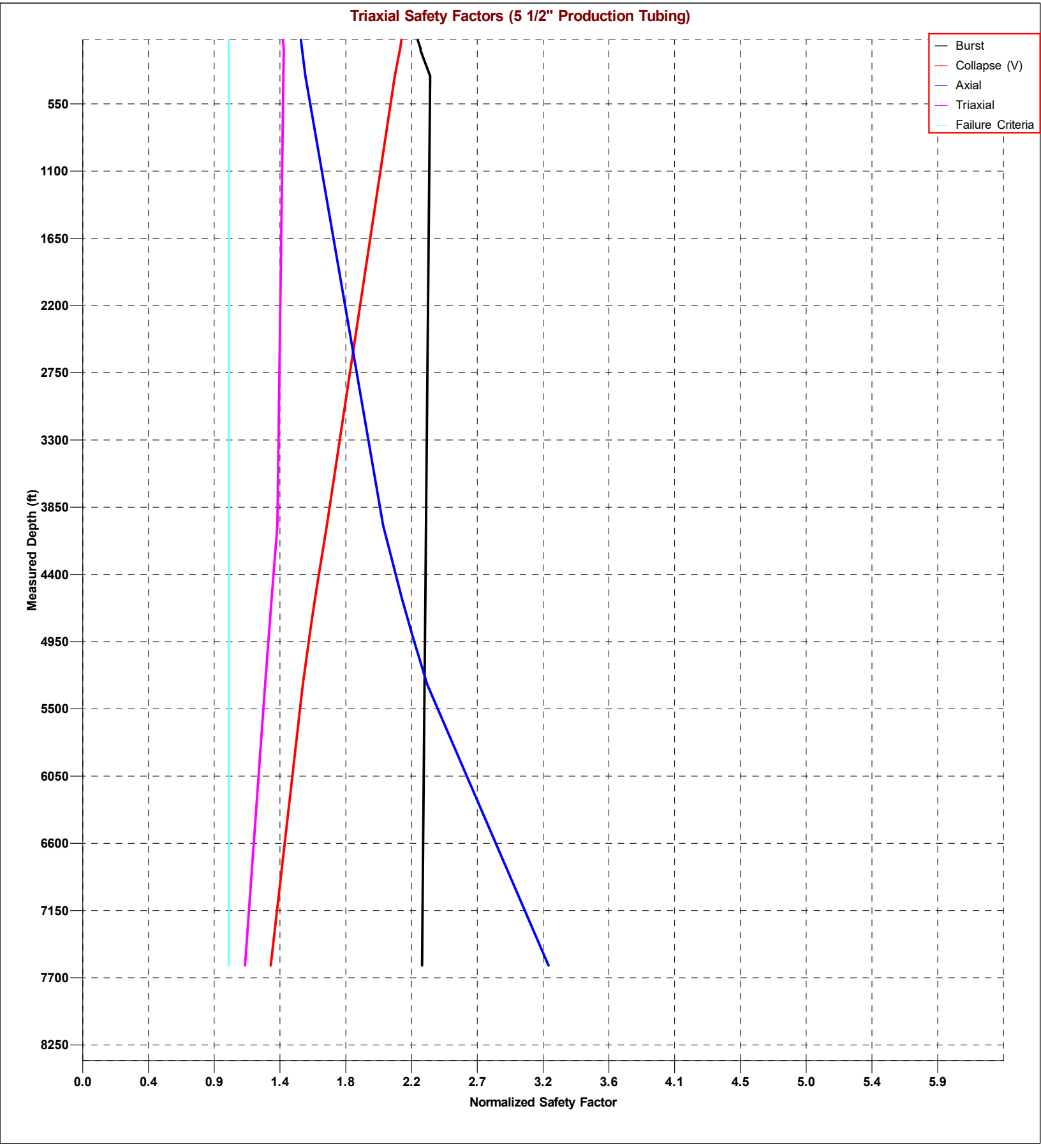
COLLAPSE DESIGN (5 1/2" Production Tubing)



AXIAL DESIGN (5 1/2" Production Tubing)




Triaxial Load Line (5 1/2" Production Tubing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
550
1100
1650
2200
2750
3300
3850
4400
4950
5500
6050
6600
7150
7700
8250
45000
48000
51000
54000
57000
60000
63000
66000
69000
72000
75000
78000
81000
84000
VME Stress (psi)


Triaxial Safety Factors (5 1/2" Production Tubing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
550
1100
1650
2200
2750
3300
3850
4400
4950
5500
6050
6600
7150
7700
8250
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	5 1/2", 20.000 ppf, L-80	Blue	2.52 B15	2.18 C19	1.94 A4	1.71 A4
2	100			2.54 B15	2.17 C19	1.95 A4	1.72 A4
3	117			2.54 B15	2.17 C19	1.95 A4	1.72 A4
4	324			2.62 B5	2.13 C19	1.98 A4	1.72 A4
5	4000			2.58 B5	1.67 C19	2.67 A4	1.67 C19
6	4600			2.58 B5	1.59 C19	2.84 A4	1.62 C19
7	4900			2.58 B5	1.55 C19	2.93 A4	1.59 C19
8	5300			2.57 B5	1.51 C19	3.06 A4	1.56 C19
9	7598			2.55 B5	1.29 C19	4.14 A4	1.39 C19
10	7599			2.55 B5	1.29 C19	4.14 A4	1.39 C19
11	7600			2.55 B5	1.29 C19	4.14 A4	1.39 C19
12							
13	B5	Pressure Test					
14	B15	Shut-In					
15	C19	Annular Pressure Test					
16	A4	Overpull Force					
17	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	5 1/2", 20.000 ppf, L-80	0.158 B15	0.245 C19	0.216 A4	56.4	32.2	40.1	0.203	0.116	0.145
2	100.00		0.156 B15	0.245 C19	0.215 A4	56.8	32.0	40.4	0.205	0.116	0.146
3	116.61		0.156 B15	0.246 C19	0.215 A4	56.8	32.0	40.5	0.205	0.115	0.146
4	323.59		0.152 B5	0.248 C19	0.212 A4	57.9	31.4	41.3	0.209	0.113	0.149
5	3999.99		0.154 B5	0.281 C19	0.232 C19	57.4	22.1	35.6	0.207	0.080	0.129
6	4000.01		0.154 B5	0.281 C19	0.232 C19	57.4	22.1	35.6	0.207	0.080	0.129
7	4599.99		0.154 B5	0.287 C19	0.240 C19	57.3	20.4	33.5	0.207	0.074	0.121
8	4600.01		0.154 B5	0.287 C19	0.240 C19	57.3	20.4	33.5	0.207	0.074	0.121
9	4899.99		0.154 B5	0.290 C19	0.244 C19	57.3	19.6	32.4	0.207	0.071	0.117
10	4900.01		0.154 B5	0.290 C19	0.244 C19	57.3	19.6	32.4	0.207	0.071	0.117
11	5299.99		0.154 B5	0.294 C19	0.249 C19	57.2	18.5	31.0	0.207	0.067	0.112
12	5300.01		0.154 B5	0.294 C19	0.249 C19	57.2	18.5	31.0	0.207	0.067	0.112
13	7598.00		0.155 B5	0.317 C19	0.282 C19	56.9	12.3	21.8	0.206	0.044	0.079
14	7599.08		0.155 B5	0.317 C19	0.282 C19	56.9	12.3	21.8	0.206	0.044	0.079
15	7599.99		0.155 B5	0.317 C19	0.282 C19	56.9	12.3	21.8	0.206	0.044	0.079
16	7600.00		0.155 B5	0.317 C19	0.282 C19	56.9	12.3	21.8	0.206	0.044	0.079
17											
18	B5	Pressure Test									
19	B15	Shut-In									
20	C19	Annular Pressure Test									
21	A4	Overpull Force									
22	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (5 1/2" Production Tubing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	343919
2	26	343476
3	100	342215
4	253	339604
5	507	335289
6	760	330974
7	1000	326886
8	1013	326659
9	1267	322344
10	1520	318029
11	1773	313714
12	2000	309853
13	2027	309399
14	2280	305084
15	2533	300769
16	2787	296454
17	3000	292820
18	3040	292139
19	3293	287824
20	3547	283509
21	3800	279194
22	4000	275787
23	4053	274879
24	4307	270569
25	4560	266283
26	4600	265609
27	4813	262038
28	4900	260599
29	5000	258948
30	5067	257854
31	5300	254050
32	5300	254049
33	5320	253724
34	5573	249596
35	5827	245468
36	6000	242644
37	6080	241341
38	6333	237213
39	6587	233085
40	6840	228957
41	7000	226350
42	7093	224830
43	7347	220702
44	7574	216998
45	7598	* 217080
46	7600	* 217086
47		
48	* Based on Casing Strength	
49	Only. Running String not	
50	Included	

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	174960	164478	175565	1798.5	2.28	2.62	N/A	2.66	78	3513	13	551	29
2	100	173480	162998	174343	1798.5	2.29	2.62	N/A	2.68	79	3551	51		
3	4000	95480	84998	109078	1798.5	2.72	2.58	N/A	4.81	121	5536	2036		
4	4600	83529	73047	98930	1798.5	2.75	2.58	N/A	5.48	127	5841	2341		
5	4900	77646	67164	93920	1798.5	2.77	2.58	N/A	5.89	130	5990	2490		
6	5300	69956	59474	87356	1798.5	2.78	2.57	N/A	6.53	134	6186	2686		
7	5300	69955	59473	87356	1798.5	2.78	2.57	N/A	6.53	134	6186	2686		
8	7598	26485	15509	50018	1883.4	2.69	2.55	N/A	17.13	158	7305	3805		
9	7600	26509	15470	50048	1894.0	2.68	2.55	N/A	17.11	158	7306	3806		
10	7600	26570	15470	50110	1904.4	2.68	2.55	N/A	17.07	158	7306	3806		
11														
12	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Shut-In

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	103687	93205	106851	1798.5	2.67	2.52	N/A	4.37	164	3553	13	22838	4076
2	100	102207	91725	105553	1798.5	2.69	2.54	N/A	4.43	164	3559	51		
3	4000	29011	13726	42095	2622.7	5.08	4.86	N/A	15.61	164	3873	2036		
4	4000	29011	13725	42095	2622.7	5.08	4.86	N/A	15.61	164	3873	2036		
5	4600	14820	1775	29308	2238.3	5.72	5.65	N/A	30.55	164	3921	2341		
6	4600	12256	1774	26668	1798.5	5.77	5.65	N/A	36.94	164	3921	2341		
7	4691	-10492	-10	3515	1798.5	5.87	5.79	N/A	(43.15)	164	3928	2386		
8	4691	-10493	-11	3515	1798.5	5.87	5.79	N/A	(43.15)	164	3928	2386		
9	4900	-14901	-4108	-398	1851.7	6.10	6.14	N/A	(30.39)	164	3944	2490		
10	4900	-14591	-4109	-79	1798.5	6.11	6.14	N/A	(31.03)	164	3944	2490		
11	5300	-23811	-11799	-8398	2061.0	6.49	6.92	N/A	(19.02)	164	3975	2686		
12	5300	-23251	-11799	-7822	1965.0	6.51	6.92	N/A	(19.47)	164	3975	2686		
13	7598	-84943	-55764	-64633	5006.5	5.77	25.75	N/A	(5.33)	164	4152	3805		
14	7600	-85012	-55802	-64698	5011.8	5.76	25.82	N/A	(5.33)	164	4152	3806		
15	7600	-85503	-55802	-65204	5096.0	5.73	25.82	N/A	(5.30)	164	4152	3806		
16														
17	( )	Compression												
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Injection

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	224163	213681	224917	1798.5	1.93	2.62	N/A	2.07	78	3514	13	0	0
2	100	222683	212201	223652	1798.5	1.94	2.62	N/A	2.09	78	3552	51		
3	4000	144683	134201	157024	1798.5	2.42	2.59	N/A	3.21	78	5578	2036		
4	4000	144682	134200	157023	1798.5	2.42	2.59	N/A	3.21	78	5578	2036		
5	4600	132732	122250	146815	1798.5	2.49	2.58	N/A	3.50	78	5888	2341		
6	4900	126849	116367	141790	1798.5	2.52	2.58	N/A	3.66	78	6041	2490		
7	4900	126849	116366	141789	1798.5	2.52	2.58	N/A	3.66	78	6041	2490		
8	5300	119159	108677	135221	1798.5	2.57	2.58	N/A	3.90	78	6241	2686		
9	5300	119158	108676	135220	1798.5	2.57	2.58	N/A	3.90	78	6241	2686		
10	7598	75193	64711	97665	1798.5	2.74	2.56	N/A	6.18	78	7383	3805		
11	7600	75155	64673	97632	1798.5	2.75	2.56	N/A	6.19	78	7384	3806		
12														
13	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Full/Partial Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	116574	106092	116926	1798.5	3.55	N/A	4.38	3.99	78	0	13	0	0
2	100	115094	104612	115470	1798.5	3.56	N/A	4.44	4.04	79	0	51		
3	4000	37095	26613	37705	1798.5	3.43	N/A	3.86	12.37	121	2	2036		
4	4000	37094	26612	37705	1798.5	3.43	N/A	3.86	12.37	121	2	2036		
5	4600	25144	14662	25614	1798.5	3.26	N/A	3.55	18.21	127	2	2341		
6	4900	19261	8779	19644	1798.5	3.17	N/A	3.41	23.75	130	3	2490		
7	4900	19260	8778	19644	1798.5	3.17	N/A	3.41	23.75	130	3	2490		
8	5300	11570	1088	11824	1798.5	3.05	N/A	3.23	39.49	134	3	2686		
9	5300	11570	1088	11823	1798.5	3.05	N/A	3.23	39.49	134	3	2686		
10	5357	10482	0	10715	1798.5	3.03	N/A	3.21	43.58	135	3	2714		
11	5357	-10482	-0	-10681	1798.5	3.03	N/A	3.21	(43.58)	135	3	2714		
12	7598	-53359	-42877	-54820	1798.5	2.41	N/A	2.28	(8.50)	158	4	3805		
13	7600	-53397	-42915	-54859	1798.5	2.41	N/A	2.28	(8.50)	158	4	3806		
14														
15	( )	Compression												
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Leak (Collapse)

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	54703	44221	74028	1798.5	5.82	N/A	7.37	8.28	164	2949	2949	0	0
2	100	53223	42741	72540	1798.5	5.88	N/A	7.55	8.51	164	2955	2987		
3	2237	10482	0	29558	1798.5	6.56	N/A	7.74	43.20	164	3127	4075		
4	2237	-10482	-0	7970	1798.5	6.56	N/A	9.11	(43.20)	164	3127	4075		
5	4000	-45741	-35259	-27488	1798.5	5.23	N/A	5.07	(9.90)	164	3268	4972		
6	4000	-45742	-35260	-27488	1798.5	5.23	N/A	5.07	(9.90)	164	3268	4972		
7	4600	-57692	-47210	-39506	1798.5	4.74	N/A	4.41	(7.85)	164	3316	5276		
8	4900	-63575	-53093	-45422	1798.5	4.51	N/A	4.14	(7.12)	164	3340	5426		
9	4900	-63576	-53093	-45423	1798.5	4.51	N/A	4.14	(7.12)	164	3340	5426		
10	5300	-71265	-60783	-53156	1798.5	4.23	N/A	3.84	(6.35)	164	3371	5622		
11	5300	-71266	-60784	-53156	1798.5	4.23	N/A	3.84	(6.35)	164	3371	5622		
12	7598	-115231	-104749	-97369	1798.5	3.01	N/A	2.71	(3.93)	164	3547	6741		
13	7600	-115269	-104787	-97408	1798.5	3.01	N/A	2.70	(3.93)	164	3547	6742		
14														
15	( )	Compression												
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Annular Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	69836	59354	70059	1798.5	1.96	N/A	2.18	6.66	78	2	3513	0	0
2	100	68356	57874	68625	1798.5	1.96	N/A	2.17	6.80	79	8	3551		
3	2994	10482	0	11993	1798.5	1.75	N/A	1.82	43.92	110	233	5024		
4	2994	-10482	-0	-9239	1798.5	1.75	N/A	1.83	(43.92)	110	233	5024		
5	4000	-30607	-20125	-29255	1798.5	1.67	N/A	1.67	(14.99)	121	312	5536		
6	4000	-30608	-20126	-29255	1798.5	1.67	N/A	1.67	(14.99)	121	312	5536		
7	4600	-42558	-32076	-41203	1798.5	1.62	N/A	1.59	(10.76)	127	358	5841		
8	4600	-42558	-32076	-41204	1798.5	1.62	N/A	1.59	(10.76)	127	358	5841		
9	4900	-48441	-37959	-47102	1798.5	1.59	N/A	1.55	(9.44)	130	381	5990		
10	4900	-48442	-37960	-47103	1798.5	1.59	N/A	1.55	(9.44)	130	381	5990		
11	5300	-56132	-45650	-54831	1798.5	1.56	N/A	1.51	(8.14)	134	411	6186		
12	5300	-56132	-45650	-54832	1798.5	1.56	N/A	1.51	(8.14)	134	411	6186		
13	7598	-100097	-89615	-99395	1798.5	1.39	N/A	1.29	(4.53)	158	582	7305		
14	7600	-100135	-89653	-99434	1798.5	1.39	N/A	1.29	(4.53)	158	583	7306		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	237403	226921	240339	1798.5	1.71	N/A	N/A	1.94	108	13	13	N/A	N/A
2	100	236197	225715	239356	1798.5	1.72	N/A	N/A	1.95	108	51	51		
3	4000	171801	161319	186510	1798.5	2.22	N/A	N/A	2.67	119	2036	2036		
4	4000	171800	161318	186509	1798.5	2.22	N/A	N/A	2.67	119	2036	2036		
5	4600	161581	151099	178023	1798.5	2.33	N/A	N/A	2.84	120	2341	2341		
6	4900	156471	145989	173762	1798.5	2.39	N/A	N/A	2.93	121	2490	2490		
7	4900	156471	145989	173761	1798.5	2.39	N/A	N/A	2.93	121	2490	2490		
8	5300	149658	139176	168052	1798.5	2.48	N/A	N/A	3.06	122	2686	2686		
9	7598	110516	100034	135146	1798.5	3.11	N/A	N/A	4.14	128	3805	3805		
10	7599	110498	100016	135130	1798.5	3.11	N/A	N/A	4.14	128	3806	3806		
11	7600	110482	100000	135117	1798.5	3.11	N/A	N/A	4.14	128	3806	3806		
12														
13	(V)	Vector Collapse Safety Factor												

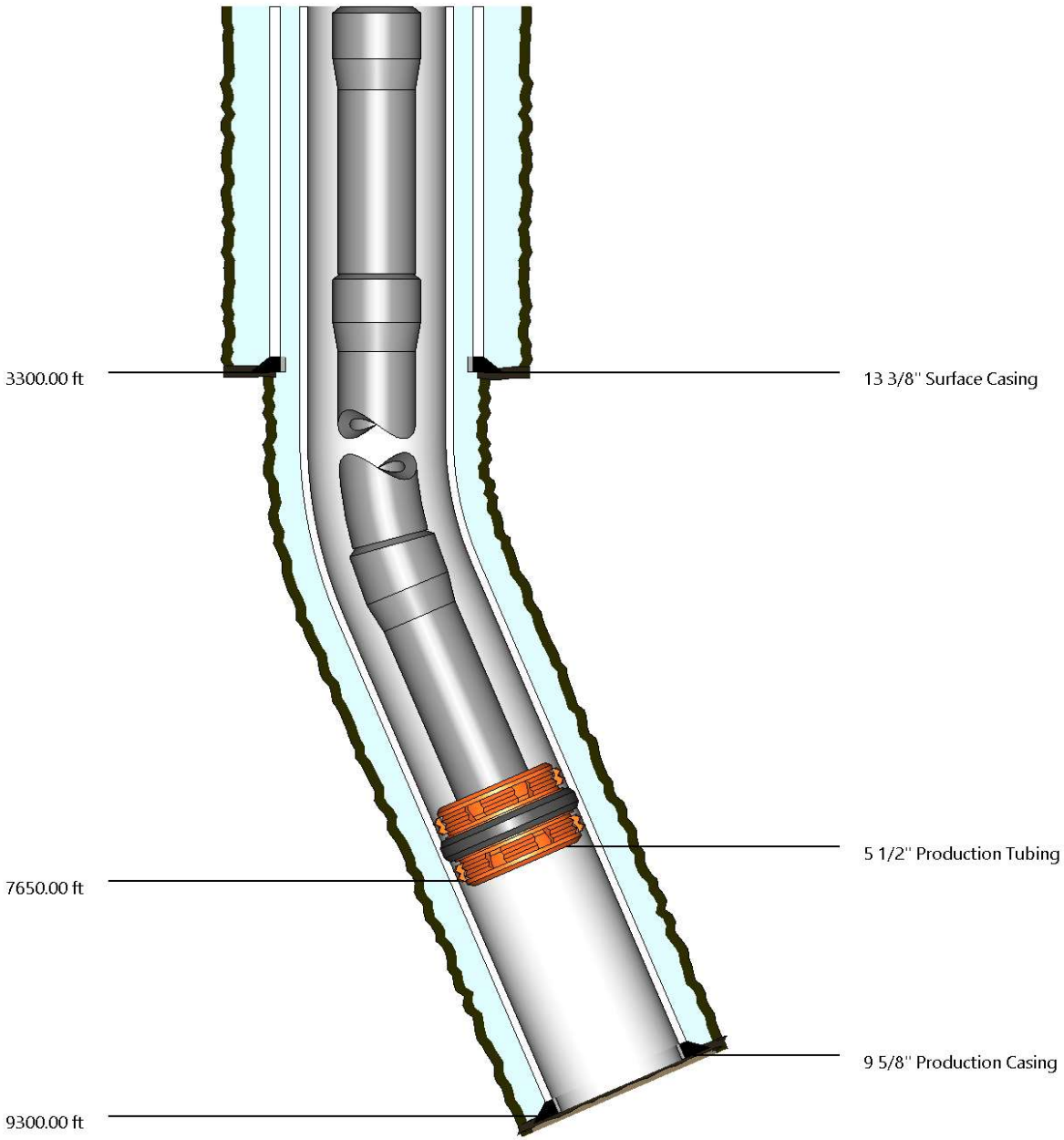
GENERAL DATA

Description:	Bluebonnet CCS 2 Final
Well Options, Deviated:	Yes
Well Options, Offshore:	No
Well TD (MD):	9300.00 ft
Reference Point:	OTR
Air Gap:	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	295.79 °

WELL SUMMARY

	String	OD/Weight/Grade	Connection	MD Interval (ft)	Drift Dia. (in)	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V	Axial	Triaxial	
1	Surface Casing	13 3/8", 61.000 ppf, K-55	BTC, K-55	26.00-3300.00	12.359	1.18	1.06	2.53	1.32	91,889
2										Total = 91,889
3										
4	Production Casing	9 5/8", 53.500 ppf, L-80	Blue	26.00-4100.00	8.500 A	2.06	2.44	2.52	2.07	126,912
5		9 5/8", 53.500 ppf, L-80	Blue	4100.00-9300.00	8.500 A	1.89	1.12	3.50	1.44	161,989
6										Total = 288,901
7										
8	Production Tubing	5 1/2", 20.000 ppf, L-80	Blue	26.00-7650.00	4.653	2.52	1.29	2.04	1.40	94,975
9										Total = 94,975
10										
11										Total = 475,765
12	A Alternate Drift									
13	(V) Vector Collapse Safety Factor									

WELL SCHEMATIC (DEPTH - MD)



CASING AND TUBING SCHEME

	OD (in)	Name	Type	Hole Size (in)	Measured Depths (ft)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	13 3/8"	Surface	Casing	17.500	26.00	3300.00	26.00	10.00
2	9 5/8"	Production	Casing	12.250	26.00	9300.00	26.00	12.50
3	5 1/2"	Production	Tubing		26.00	7650.00		9.80

PRODUCTION DATA

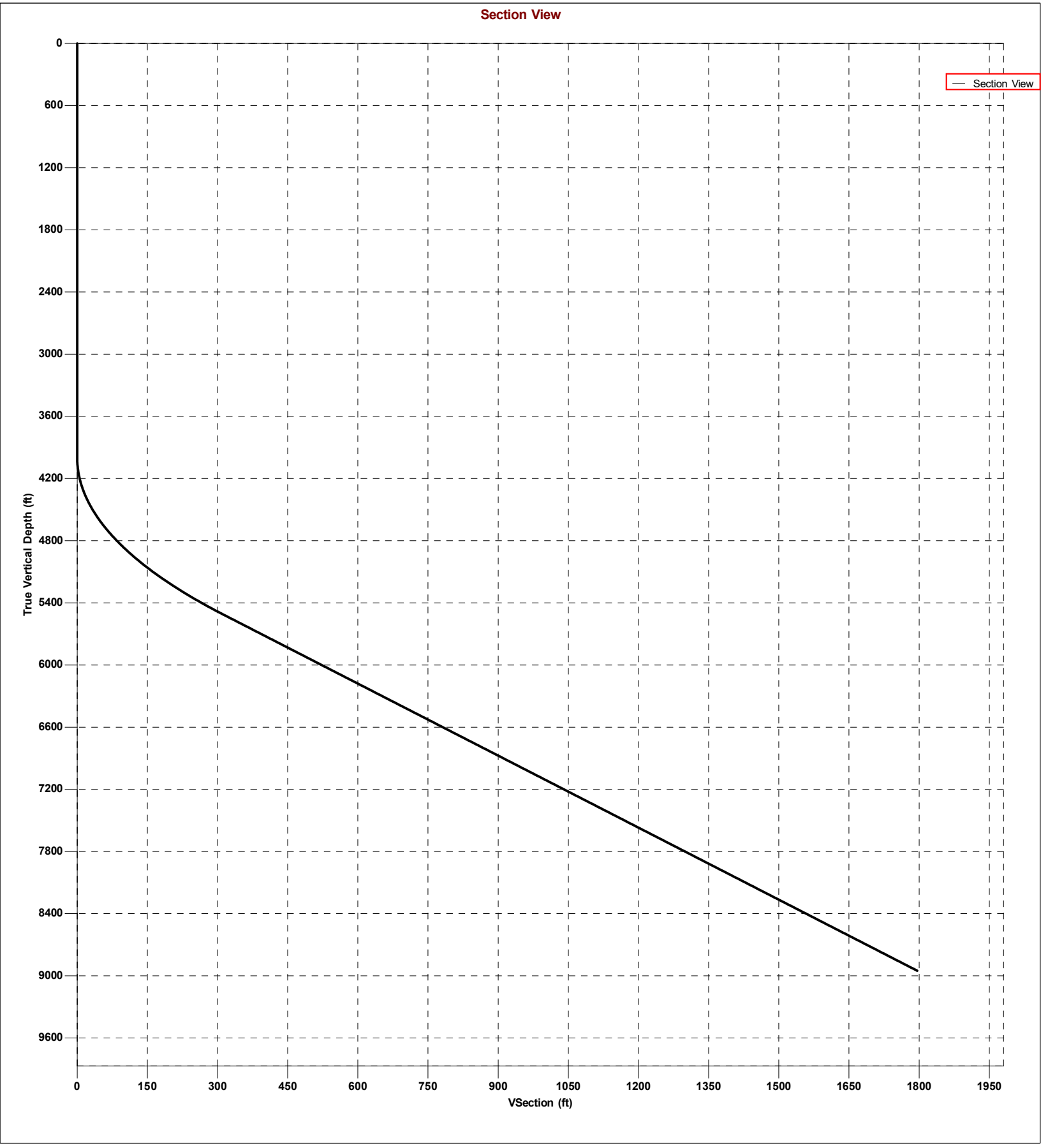
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7650.00 ft
Perforation Depth, MD:	8237.00 ft
Gas Gravity:	0.70

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.00	0.00			0.00	0.00
2	MD-INC-AZ	100.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00
3	MD-INC-AZ	200.00	0.00	0.00	200.00	0.00	0.00	0.00	0.00
4	MD-INC-AZ	300.00	0.00	0.00	300.00	0.00	0.00	0.00	0.00
5	MD-INC-AZ	400.00	0.00	0.00	400.00	0.00	0.00	0.00	0.00
6	MD-INC-AZ	500.00	0.00	0.00	500.00	0.00	0.00	0.00	0.00
7	MD-INC-AZ	600.00	0.00	0.00	600.00	0.00	0.00	0.00	0.00
8	MD-INC-AZ	700.00	0.00	0.00	700.00	0.00	0.00	0.00	0.00
9	MD-INC-AZ	800.00	0.00	0.00	800.00	0.00	0.00	0.00	0.00
10	MD-INC-AZ	900.00	0.00	0.00	900.00	0.00	0.00	0.00	0.00
11	MD-INC-AZ	1000.00	0.00	0.00	1000.00	0.00	0.00	0.00	0.00
12	MD-INC-AZ	1100.00	0.00	0.00	1100.00	0.00	0.00	0.00	0.00
13	MD-INC-AZ	1200.00	0.00	0.00	1200.00	0.00	0.00	0.00	0.00
14	MD-INC-AZ	1300.00	0.00	0.00	1300.00	0.00	0.00	0.00	0.00
15	MD-INC-AZ	1400.00	0.00	0.00	1400.00	0.00	0.00	0.00	0.00
16	MD-INC-AZ	1500.00	0.00	0.00	1500.00	0.00	0.00	0.00	0.00
17	MD-INC-AZ	1600.00	0.00	0.00	1600.00	0.00	0.00	0.00	0.00
18	MD-INC-AZ	1700.00	0.00	0.00	1700.00	0.00	0.00	0.00	0.00
19	MD-INC-AZ	1800.00	0.00	0.00	1800.00	0.00	0.00	0.00	0.00
20	MD-INC-AZ	1900.00	0.00	0.00	1900.00	0.00	0.00	0.00	0.00
21	MD-INC-AZ	2000.00	0.00	0.00	2000.00	0.00	0.00	0.00	0.00
22	MD-INC-AZ	2100.00	0.00	0.00	2100.00	0.00	0.00	0.00	0.00
23	MD-INC-AZ	2200.00	0.00	0.00	2200.00	0.00	0.00	0.00	0.00
24	MD-INC-AZ	2300.00	0.00	0.00	2300.00	0.00	0.00	0.00	0.00
25	MD-INC-AZ	2400.00	0.00	0.00	2400.00	0.00	0.00	0.00	0.00
26	MD-INC-AZ	2500.00	0.00	0.00	2500.00	0.00	0.00	0.00	0.00
27	MD-INC-AZ	2600.00	0.00	0.00	2600.00	0.00	0.00	0.00	0.00
28	MD-INC-AZ	2700.00	0.00	0.00	2700.00	0.00	0.00	0.00	0.00
29	MD-INC-AZ	2800.00	0.00	0.00	2800.00	0.00	0.00	0.00	0.00
30	MD-INC-AZ	2900.00	0.00	0.00	2900.00	0.00	0.00	0.00	0.00
31	MD-INC-AZ	3000.00	0.00	0.00	3000.00	0.00	0.00	0.00	0.00
32	MD-INC-AZ	3100.00	0.00	0.00	3100.00	0.00	0.00	0.00	0.00
33	MD-INC-AZ	3200.00	0.00	0.00	3200.00	0.00	0.00	0.00	0.00
34	MD-INC-AZ	3300.00	0.00	0.00	3300.00	0.00	0.00	0.00	0.00
35	MD-INC-AZ	3400.00	0.00	0.00	3400.00	0.00	0.00	0.00	0.00
36	MD-INC-AZ	3500.00	0.00	0.00	3500.00	0.00	0.00	0.00	0.00
37	MD-INC-AZ	3600.00	0.00	0.00	3600.00	0.00	0.00	0.00	0.00
38	MD-INC-AZ	3700.00	0.00	0.00	3700.00	0.00	0.00	0.00	0.00
39	MD-INC-AZ	3800.00	0.00	0.00	3800.00	0.00	0.00	0.00	0.00
40	MD-INC-AZ	3900.00	0.00	0.00	3900.00	0.00	0.00	0.00	0.00
41	MD-INC-AZ	4000.00	0.00	0.00	4000.00	0.00	0.00	0.00	0.00
42	MD-INC-AZ	4100.00	1.50	295.79	4099.99	1.50	1.50	1.31	1.31
43	MD-INC-AZ	4200.00	3.00	295.79	4199.91	1.50	1.50	5.23	5.23
44	MD-INC-AZ	4300.00	4.50	295.79	4299.69	1.50	1.50	11.77	11.77
45	MD-INC-AZ	4400.00	6.00	295.79	4399.27	1.50	1.50	20.92	20.92
46	MD-INC-AZ	4500.00	7.50	295.79	4498.57	1.50	1.50	32.68	32.68
47	MD-INC-AZ	4600.00	9.00	295.79	4597.54	1.50	1.50	47.03	47.03
48	MD-INC-AZ	4700.00	10.50	295.79	4696.09	1.50	1.50	63.96	63.96
49	MD-INC-AZ	4800.00	12.00	295.79	4794.16	1.50	1.50	83.47	83.47
50	MD-INC-AZ	4900.00	13.50	295.79	4891.70	1.50	1.50	105.54	105.54
51	MD-INC-AZ	5000.00	15.00	295.79	4988.62	1.50	1.50	130.15	130.15
52	MD-INC-AZ	5100.00	16.50	295.79	5084.86	1.50	1.50	157.30	157.30
53	MD-INC-AZ	5200.00	18.00	295.79	5180.36	1.50	1.50	186.95	186.95
54	MD-INC-AZ	5300.00	19.50	295.79	5275.05	1.50	1.50	219.09	219.09
55	MD-INC-AZ	5400.00	21.00	295.79	5368.86	1.50	1.50	253.70	253.70
56	MD-INC-AZ	5500.00	22.50	295.79	5461.74	1.50	1.50	290.76	290.76
57	MD-INC-AZ	5556.05	23.34	295.79	5513.37	1.50	1.50	312.59	312.59
58	MD-INC-AZ	5600.00	23.34	295.79	5553.72	0.00	0.00	330.00	330.00
59	MD-INC-AZ	5700.00	23.34	295.79	5645.54	0.00	0.00	369.62	369.62
60	MD-INC-AZ	5800.00	23.34	295.79	5737.35	0.00	0.00	409.24	409.24
61	MD-INC-AZ	5900.00	23.34	295.79	5829.17	0.00	0.00	448.86	448.86
62	MD-INC-AZ	6000.00	23.34	295.79	5920.99	0.00	0.00	488.48	488.48
63	MD-INC-AZ	6100.00	23.34	295.79	6012.80	0.00	0.00	528.10	528.10
64	MD-INC-AZ	6200.00	23.34	295.79	6104.62	0.00	0.00	567.72	567.72
65	MD-INC-AZ	6300.00	23.34	295.79	6196.44	0.00	0.00	607.34	607.34
66	MD-INC-AZ	6400.00	23.34	295.79	6288.25	0.00	0.00	646.96	646.96
67	MD-INC-AZ	6500.00	23.34	295.79	6380.07	0.00	0.00	686.58	686.58
68	MD-INC-AZ	6600.00	23.34	295.79	6471.89	0.00	0.00	726.20	726.20
69	MD-INC-AZ	6700.00	23.34	295.79	6563.70	0.00	0.00	765.82	765.82
70	MD-INC-AZ	6800.00	23.34	295.79	6655.52	0.00	0.00	805.44	805.44
71	MD-INC-AZ	6900.00	23.34	295.79	6747.33	0.00	0.00	845.06	845.06
72	MD-INC-AZ	7000.00	23.34	295.79	6839.15	0.00	0.00	884.68	884.68
73	MD-INC-AZ	7100.00	23.34	295.79	6930.97	0.00	0.00	924.30	924.30
74	MD-INC-AZ	7200.00	23.34	295.79	7022.78	0.00	0.00	963.92	963.92
75	MD-INC-AZ	7300.00	23.34	295.79	7114.60	0.00	0.00	1003.54	1003.54
76	MD-INC-AZ	7400.00	23.34	295.79	7206.42	0.00	0.00	1043.16	1043.16
77	MD-INC-AZ	7500.00	23.34	295.79	7298.23	0.00	0.00	1082.78	1082.78

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
78	MD-INC-AZ	7600.00	23.34	295.79	7390.05	0.00	0.00	1122.40	1122.40
79	MD-INC-AZ	7700.00	23.34	295.79	7481.87	0.00	0.00	1162.02	1162.02
80	MD-INC-AZ	7793.81	23.34	295.79	7568.00	0.00	0.00	1199.19	1199.19
81	MD-INC-AZ	7800.00	23.34	295.79	7573.68	0.00	0.00	1201.64	1201.64
82	MD-INC-AZ	7900.00	23.34	295.79	7665.50	0.00	0.00	1241.26	1241.26
83	MD-INC-AZ	8000.00	23.34	295.79	7757.32	0.00	0.00	1280.88	1280.88
84	MD-INC-AZ	8100.00	23.34	295.79	7849.13	0.00	0.00	1320.50	1320.50
85	MD-INC-AZ	8200.00	23.34	295.79	7940.95	0.00	0.00	1360.12	1360.12
86	MD-INC-AZ	8300.00	23.34	295.79	8032.77	0.00	0.00	1399.74	1399.74
87	MD-INC-AZ	8400.00	23.34	295.79	8124.58	0.00	0.00	1439.36	1439.36
88	MD-INC-AZ	8500.00	23.34	295.79	8216.40	0.00	0.00	1478.98	1478.98
89	MD-INC-AZ	8600.00	23.34	295.79	8308.21	0.00	0.00	1518.60	1518.60
90	MD-INC-AZ	8700.00	23.34	295.79	8400.03	0.00	0.00	1558.22	1558.22
91	MD-INC-AZ	8800.00	23.34	295.79	8491.85	0.00	0.00	1597.84	1597.84
92	MD-INC-AZ	8900.00	23.34	295.79	8583.66	0.00	0.00	1637.46	1637.46
93	MD-INC-AZ	9000.00	23.34	295.79	8675.48	0.00	0.00	1677.08	1677.08
94	MD-INC-AZ	9100.00	23.34	295.79	8767.30	0.00	0.00	1716.70	1716.70
95	MD-INC-AZ	9200.00	23.34	295.79	8859.11	0.00	0.00	1756.32	1756.32
96	MD-INC-AZ	9300.00	23.34	295.79	8950.93	0.00	0.00	1795.94	1795.94
97									

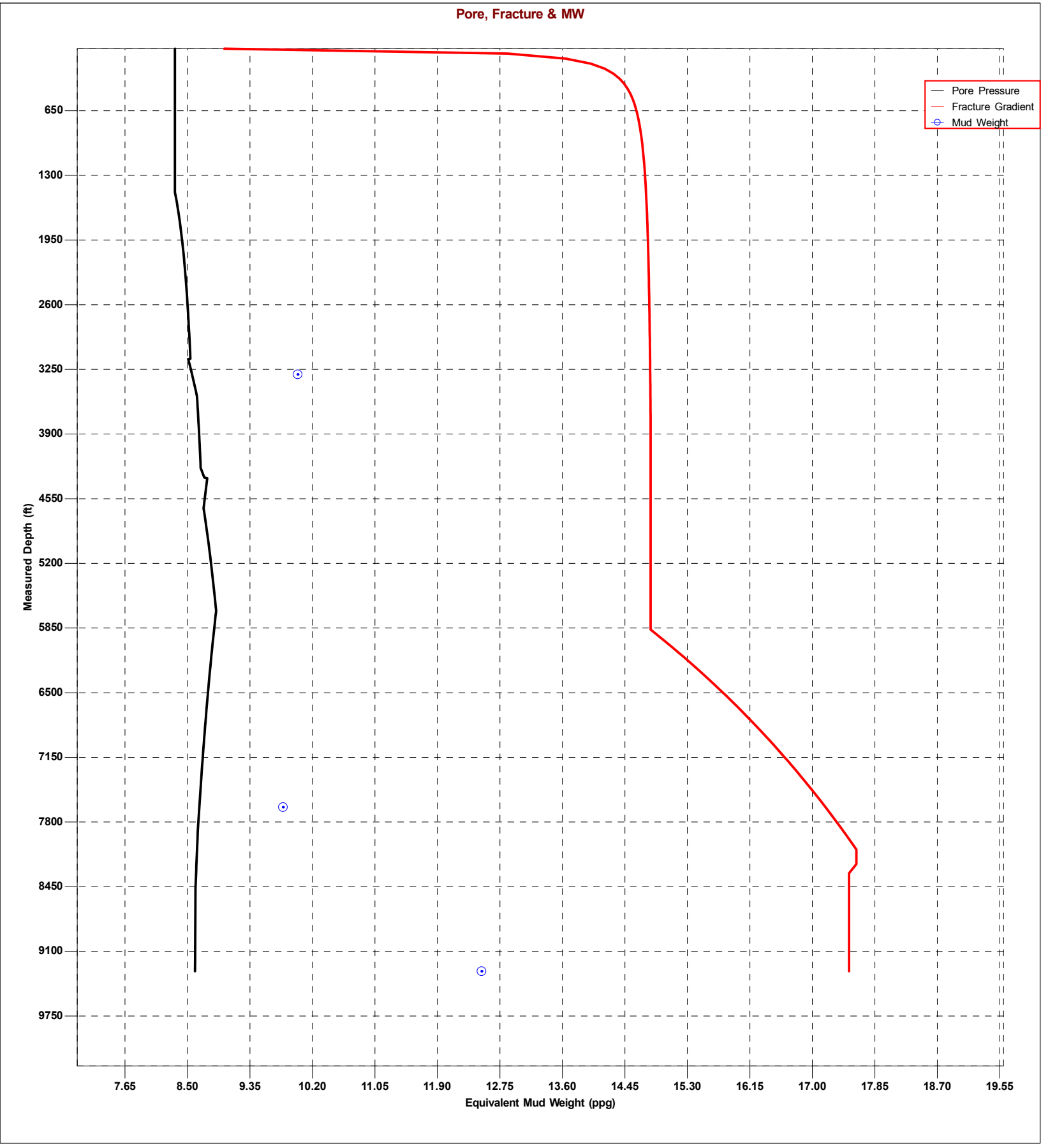

Section View
Section View
True Vertical Depth (ft)
0
600
1200
1800
2400
3000
3600
4200
4800
5400
6000
6600
7200
7800
8400
9000
9600
0
150
300
450
600
750
900
1050
1200
1350
1500
1650
1800
1950
VSection (ft)

PORE PRESSURE

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	0	8.33	No
2	1470.00	636	8.33	No
3	3144.00	1395	8.54	No
4	3146.00	1391	8.51	No
5	3521.00	1579	8.63	No
6	4240.00	1912	8.68	No
7	4337.00	1967	8.73	No
8	4344.00	1979	8.77	No
9	4643.00	2103	8.72	No
10	5626.00	2598	8.89	No
11	7666.00	3441	8.64	No
12	8182.00	3660	8.61	No
13	9300.00	4155	8.60	No

FRACTURE GRADIENT

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	0	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9300.00	8455	17.50


Pore, Fracture & MW
Pore Pressure
Fracture Gradient
Mud Weight
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
Measured Depth (ft)
7.65
8.50
9.35
10.20
11.05
11.90
12.75
13.60
14.45
15.30
16.15
17.00
17.85
18.70
19.55
Equivalent Mud Weight (ppg)

GEOTHERMAL GRADIENT DATA

Surface Ambient:	78 °F
Bottomhole Temperature - 8950.93 ft TVD:	174 °F
Bottomhole Gradient - 8950.93 ft TVD:	1.08 °F/100ft

DESIGN PARAMETERS DATA (13 3/8" Surface Casing)

Design Factor (Pipe) - Axial Tension:	1.400
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.400
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	12.250 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (13 3/8" Surface Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3300.00 ft	113 °F

BURST LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 3300.00 ft):	2535 psi
Mud/Water Interface, MD:	3300.00 ft
Mud Weight	7.82 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	9300.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	1.00 ppg
Maximum Mud Weight:	12.50 ppg
Kick Gas Gravity:	0.70 (0.1280 psi/ft @ 141 °F & 6277 psi)
Fracture at Shoe (MD= 3300.00 ft):	2535 psi
Drill Pipe OD:	5.500 in
Collar OD:	8.000 in
Collar Length:	300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	1500 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Fracture @ Shoe w/ Gas Gradient Above**
Gas Gradient:	0.1000 psi/ft
Shoe Depth, MD :	3300.00 ft
Fracture Pressure at Shoe:	2535 psi
Fracture Margin of Error:	0.00 ppg
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2600 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	9300.00 ft
Pore Pressure at Lost Returns Depth:	4000 psi
Pore Pressure Gradient at Lost Returns Depth:	8.60 ppg
Mud Weight:	12.50 ppg
Mud Drop Level, MD:	2790.65 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (13 3/8" Surface Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	2600 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Lost Returns (psi)	Gas Kick (psi)	Pressure Test (psi)	Fracture @ Shoe w/ Gas Gradient Above (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	1118	1298	1514	2208	2611	14	0
2	1470.00	1743	2037	2264	2352	3236	951	636
3	2600.00	2232	2615	2851	2465	3725	1685	1148
4	3144.00	2467	2894	3133	2519	3960	2131	1395
5	3146.00	2468	2895	3134	2519	3961	2133	1391
6	3300.00	2535	2973	3214	2535	4028	2259	1468

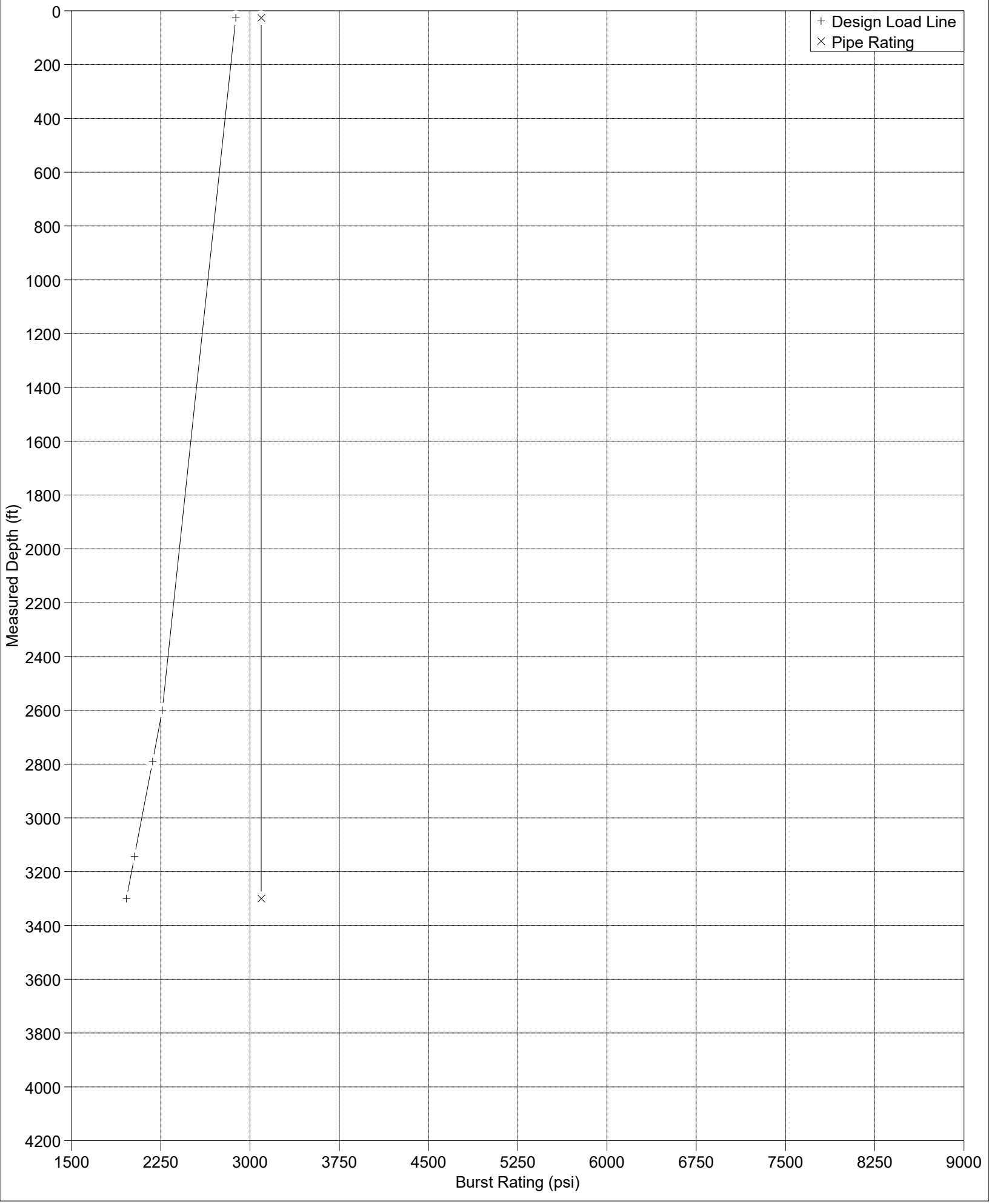
COLLAPSE PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Lost Returns (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	14	0	14
2	2600.00	1125	1685	0	1351
3	2790.65	1208	1841	0	1450
4	3300.00	1428	2259	331	1714

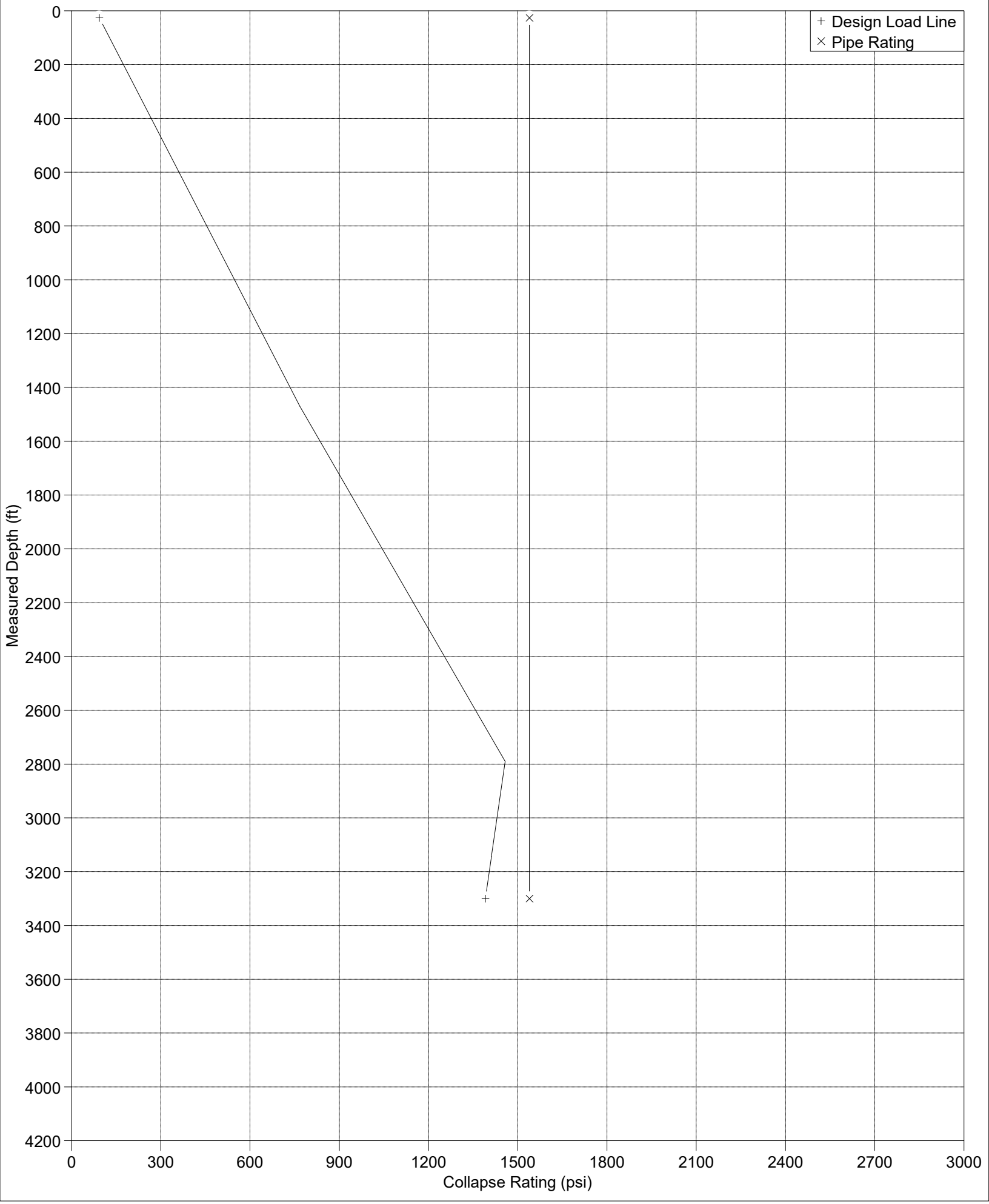
AXIAL LOADS TABLE (13 3/8" Surface Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	269972	269972	377753	377753	377753	377753
2	933.54	222856	222856	322393	322393	322393	322393
3	1470.00	195006	195006	289669	289669	289669	289669
4	2600.00	136341	136341	220739	220739	220739	220739
5	2790.65	126443	126443	209110	209110	209110	209110
6	3144.00	108099	108099	187555	187555	187555	187555
7	3146.00	107995	107995	187433	187433	187433	187433
8	3263.36	101902	101902	180274	180274	180274	180274

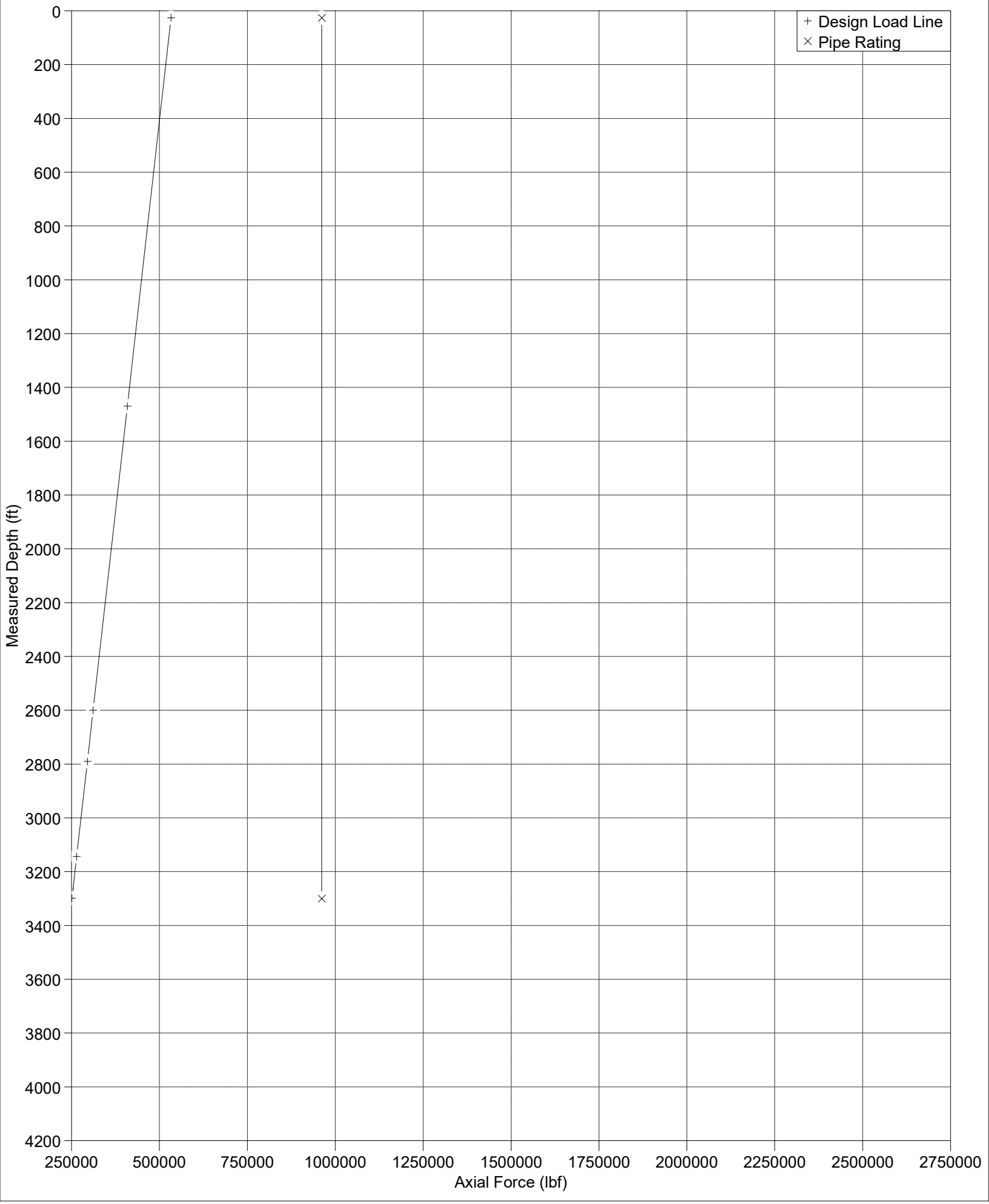
BURST DESIGN (13 3/8" Surface Casing)

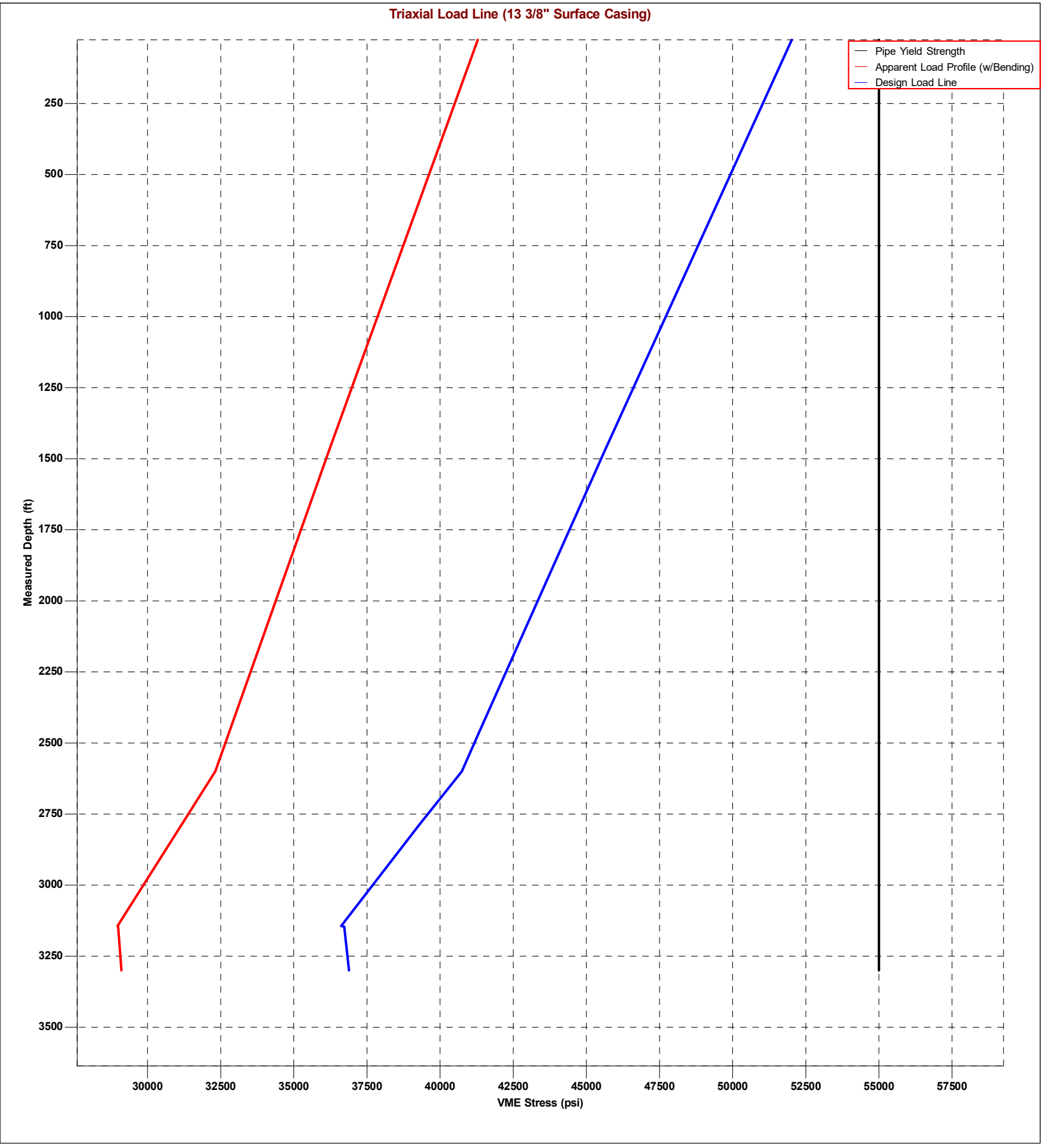


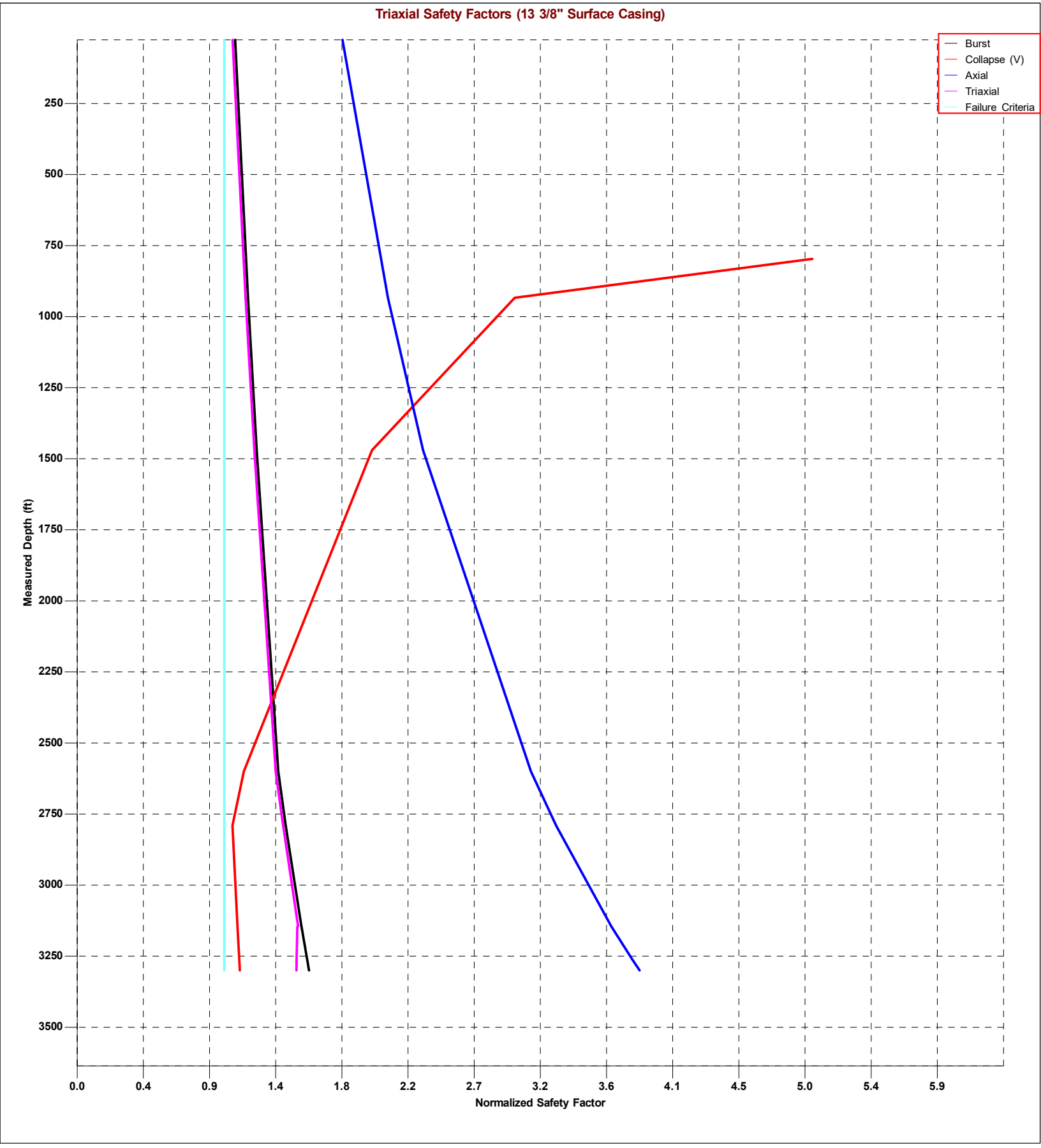
COLLAPSE DESIGN (13 3/8" Surface Casing)



AXIAL DESIGN (13 3/8" Surface Casing)




Triaxial Load Line (13 3/8" Surface Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
30000
32500
35000
37500
40000
42500
45000
47500
50000
52500
55000
57500
VME Stress (psi)


Triaxial Safety Factors (13 3/8" Surface Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	13 3/8", 61.000 ppf, K-55	BTC, K-55	1.18 B12	16.42 C2	2.53 B12	1.32 B12
2	934			1.28 B12	2.98 C4	2.96 B12	1.43 B12
3	1470			1.34 B12	2.01 C4	3.29 A5	1.51 B12
4	2600			1.50 B12	1.13 C4	4.32 A5	1.69 B12
5	2791			1.56 B12	1.06 C4	4.56 A5	1.75 B12
6	3144			1.68 B12	1.09 C4	5.08 A5	1.88 B5
7	3146			1.68 B12	1.09 C4	5.09 B12	1.87 B5
8	3263			1.72 B12	1.10 C4	5.29 B12	1.87 B5
9	3299			1.73 B12	1.11 C4	5.35 B12	1.86 B5
10	3299			1.73 B12	1.11 C4	5.35 A5	1.86 B5
11	3300			1.73 B12	1.11 C4	5.36 A5	1.86 B5
12							
13	B5	Pressure Test					
14	B12	Green Cement Pressure Test(Burst)					
15	C2	Cementing					
16	C4	Lost Returns with Mud Drop					
17	A5	Green Cement Pressure Test(Axial)					
18	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (13 3/8" Surface Casing)

	Depth (MD)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	13 3/8", 61.000 ppf, K-5	0.400 B12	0.088 C4	0.355 B12	6.9	79.6	17.4	0.030	0.342	0.075
2	933.54		0.370 B12	0.287 C4	0.327 B12	13.9	33.2	24.0	0.060	0.143	0.103
3	1470.00		0.352 B12	0.333 C4	0.311 B12	18.1	22.5	27.8	0.078	0.097	0.119
4	2600.00		0.315 B12	0.408 C4	0.277 B12	26.9	5.2	35.6	0.115	0.022	0.153
5	2790.65		0.303 B12	0.420 C4	0.267 B12	29.5	2.3	38.0	0.127	0.010	0.163
6	3144.00		0.282 B12	0.414 C4	0.251 B5	34.4	3.7	41.6	0.148	0.016	0.179
7	3146.00		0.282 B12	0.414 C4	0.252 B5	34.4	3.7	41.5	0.148	0.016	0.178
8	3263.36		0.275 B12	0.412 C4	0.253 B5	36.1	4.1	41.3	0.155	0.018	0.177
9	3298.97		0.273 B12	0.412 C4	0.253 B5	36.6	4.2	41.2	0.157	0.018	0.177
10	3299.20		0.273 B12	0.412 C4	0.253 B5	36.6	4.2	41.2	0.157	0.018	0.177
11	3300.00		0.273 B12	0.412 C4	0.253 B5	36.6	4.2	41.2	0.157	0.018	0.177
12											
13	B5	Pressure Test									
14	B12	Green Cement Pressure Test(Burst)									
15	C4	Lost Returns with Mud Drop									
16	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (13 3/8" Surface Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	681548
2	26	680199
3	26	680197
4	254	668369
5	508	655191
6	762	642012
7	1000	629632
8	1015	628833
9	1269	615655
10	1523	602476
11	1777	589297
12	2000	577716
13	2031	576119
14	2285	562940
15	2538	549762
16	2792	536583
17	3000	525800
18	3046	523404
19	3274	511576
20	3300	* 511808
21		
22	* Based on Casing Strength	
23	Only. Running String not	
24	Included	

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Gas Kick Profile

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	34203	34203	34652	0.0	2.45	2.35	N/A	27.76	111	1298	0	N/A	N/A
2	1470	18848	18848	30410	0.0	2.24	2.18	N/A	50.29	116	2037	636		
3	2600	5623	5623	26109	0.0	2.13	2.08	N/A	+ 100.00	120	2615	1148		
4	2791	6147	6147	28181	0.0	2.11	2.06	N/A	+ 100.00	120	2713	1235		
5	3144	7118	7118	32024	0.0	2.09	2.03	N/A	+ 100.00	121	2894	1395		
6	3146	7538	7538	32380	0.0	2.08	2.02	N/A	+ 100.00	121	2895	1391		
7	3300	7346	7346	33560	0.0	2.08	2.02	N/A	+ 100.00	122	2973	1468		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Water

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	140755	140755	141180	0.0	3.10	2.76	N/A	6.81	78	1118	0	N/A	N/A
2	1470	134317	134317	145880	0.0	3.13	2.79	N/A	7.14	78	1743	636		
3	2600	128069	128069	148595	0.0	3.19	2.85	N/A	7.49	78	2232	1148		
4	2791	129770	129770	151817	0.0	3.20	2.86	N/A	7.39	78	2314	1235		
5	3144	132922	132922	157788	0.0	3.22	2.88	N/A	7.21	78	2467	1395		
6	3146	133355	133355	158152	0.0	3.20	2.86	N/A	7.19	78	2468	1391		
7	3300	134114	134114	160265	0.0	3.23	2.89	N/A	7.15	78	2535	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	169936	169936	170449	0.0	2.28	2.04	N/A	5.64	78	1514	0	N/A	N/A
2	1470	116519	116519	128631	0.0	2.08	1.89	N/A	8.19	94	2264	636		
3	2600	73508	73508	94661	0.0	1.93	1.80	N/A	12.94	106	2851	1148		
4	2791	69007	69007	91694	0.0	1.91	1.78	N/A	13.77	108	2950	1235		
5	3144	60664	60664	86184	0.0	1.88	1.76	N/A	15.65	112	3133	1395		
6	3146	61031	61031	86486	0.0	1.87	1.75	N/A	15.55	112	3134	1391		
7	3300	56780	56780	83586	0.0	1.86	1.75	N/A	16.71	113	3214	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Fracture @ Shoe w/ Gas Gradient Above

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	101323	101323	102654	0.0	1.48	1.38	N/A	9.37	111	2208	0	N/A	N/A
2	1470	42088	42088	53990	0.0	1.86	1.78	N/A	22.52	116	2352	636		
3	2470	0	0	19347	0.0	2.28	2.24	N/A	+ 100.00	119	2452	1089		
4	2470	-0	-0	19346	0.0	2.28	2.24	N/A	(+ 100.00)	119	2452	1089		
5	2600	-5476	-5476	14834	0.0	2.34	2.31	N/A	(+ 100.00)	120	2465	1148		
6	2791	-10745	-10745	11019	0.0	2.46	2.44	N/A	(88.10)	120	2484	1235		
7	3144	-20512	-20512	3943	0.0	2.71	2.71	N/A	(46.14)	121	2519	1395		
8	3146	-20152	-20152	4237	0.0	2.70	2.70	N/A	(46.96)	121	2519	1391		
9	3300	-25024	-25024	656	0.0	2.84	2.85	N/A	(37.81)	122	2535	1468		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381014	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308844	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	2600	220739	220739	252338	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
4	2791	209110	209110	243379	0.0	1.75	1.56	N/A	4.56	96	3808	1841		
5	3144	187555	187555	226771	0.0	1.88	1.68	N/A	5.08	96	3960	2131		
6	3146	187433	187433	226677	0.0	1.88	1.68	N/A	5.09	96	3961	2133		
7	3299	178088	178088	219476	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219438	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Mud Drop

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-62752	-62752	-63577	0.0	13.69	N/A	+ 100.00	(15.13)	111	0	14	N/A	N/A
2	1470	-142254	-142254	-144335	0.0	4.40	N/A	2.01	(6.66)	116	0	764		
3	2600	-204468	-204468	-207696	0.0	2.53	N/A	1.13	(4.63)	120	0	1351		
4	2791	-212210	-212210	-215601	0.0	2.36	N/A	1.06	(4.46)	120	0	1450		
5	3144	-209623	-209623	-208971	0.0	2.43	N/A	1.09	(4.51)	121	229	1633		
6	3146	-209608	-209608	-208933	0.0	2.43	N/A	1.09	(4.51)	121	231	1634		
7	3300	-208480	-208480	-206042	0.0	2.47	N/A	1.11	(4.54)	122	331	1714		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	57919	57919	58581	0.0	14.35	N/A	16.42	16.47	94	11	14	N/A	N/A
2	975	43	43	7480	0.0	13.54	N/A	7.31	+ 100.00	95	422	630		
3	976	-6	-6	7437	0.0	13.53	N/A	7.30	(+ 100.00)	95	422	630		
4	1470	-30165	-30165	-19199	0.0	10.44	N/A	4.87	(31.62)	95	636	951		
5	2600	-99095	-99095	-80098	0.0	6.15	N/A	2.74	(9.62)	96	1125	1685		
6	2791	-110724	-110724	-90375	0.0	5.43	N/A	2.42	(8.61)	96	1208	1841		
7	3144	-132279	-132279	-109425	0.0	4.47	N/A	1.99	(7.21)	96	1360	2131		
8	3146	-132401	-132401	-109533	0.0	4.46	N/A	1.99	(7.20)	96	1361	2133		
9	3300	-141795	-141795	-117837	0.0	4.14	N/A	1.85	(6.72)	97	1428	2259		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	269972	269972	272370	0.0	3.10	N/A	N/A	3.53	94	14	14	N/A	N/A
2	1470	195006	195006	210089	0.0	4.05	N/A	N/A	4.89	95	764	764		
3	2600	136341	136341	161325	0.0	5.33	N/A	N/A	6.99	96	1351	1351		
4	2791	126443	126443	153095	0.0	5.63	N/A	N/A	7.54	96	1450	1450		
5	3144	108099	108099	137841	0.0	6.29	N/A	N/A	8.82	96	1633	1633		
6	3146	107995	107995	137754	0.0	6.29	N/A	N/A	8.83	96	1634	1634		
7	3299	100041	100041	131140	0.0	6.63	N/A	N/A	9.53	97	1714	1714		
8	3300	100000	100000	131105	0.0	6.63	N/A	N/A	9.54	97	1714	1714		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381014	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308844	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	2600	220739	220739	252338	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
4	2791	209110	209110	243379	0.0	1.75	1.56	N/A	4.56	96	3808	1841		
5	3144	187555	187555	226771	0.0	1.88	1.68	N/A	5.08	96	3960	2131		
6	3146	187433	187433	226677	0.0	1.88	1.68	N/A	5.09	96	3961	2133		
7	3299	178088	178088	219476	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219438	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (9 5/8" Production Casing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	7.970 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (9 5/8" Production Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5200.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
4000.00 ft	121 °F
4597.53 ft	127 °F
4891.69 ft	130 °F
5180.36 ft	133 °F
5461.74 ft	136 °F
8859.11 ft	173 °F
8950.93 ft	174 °F
8950.93 ft	174 °F
8950.93 ft	174 °F

BURST LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Mud Weight:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7650.00 ft
Perforation Depth, MD:	8237.00 ft
Gas Gravity:	0.70 (0.0870 psi/ft @ 164 °F & 3572 psi)
Reservoir Pressure:	3572 psi
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Stimulation Surface Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7650.00 ft
Injection Pressure:	3500 psi
Injection Density:	8.33 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Injection Down Casing**
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	3500 psi
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5200.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	9300.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Mud Weight Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5200.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	9300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Full Evacuation**
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Fluid Gradient Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	12.50 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (9 5/8" Production Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	3500 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Pressure Test (psi)	Tubing Leak (psi)	Stimulation Leak (psi)	Casing Injection (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	3513	2932	3511	3513	3511	17	17
2	3299.99	5180	4599	5178	5180	4928	2143	1446
3	3300.01	5180	4599	5178	5180	4928	2143	1468
4	3521.00	5293	4711	5291	5293	5024	2286	1579
5	3999.99	5536	4955	5534	5536	5231	2597	1801
6	4000.01	5536	4955	5534	5536	5231	2597	1801
7	4099.99	5587	5006	5585	5587	5274	2662	1847
8	4100.01	5587	5006	5585	5587	5274	2662	1847
9	4240.16	5659	5077	5657	5659	5335	2777	1912
10	4337.44	5708	5127	5706	5708	5377	2857	1967
11	4599.99	5841	5259	5839	5841	5489	3071	2084
12	4600.01	5841	5259	5839	5841	5489	3071	2084
13	4646.08	5864	5282	5862	5864	5509	3108	2103
14	4899.99	5990	5409	5988	5990	5617	3312	2228
15	4900.01	5990	5409	5988	5990	5617	3312	2228
16	5199.99	6137	5556	6135	6137	5742	3549	2374
17	5200.01	6137	5556	6135	6137	5742	3549	2374
18	5499.99	6281	5699	6279	6281	5863	3780	2515
19	5500.01	6281	5699	6279	6281	5863	3780	2515
20	5678.72	6364	5783	6362	6364	5935	3915	2598
21	7649.99	7286	6704	7284	7286	6718	5400	3346
22	7650.01	7286	3525	6718	7286	6718	5400	3346
23	7900.55	7403	3545	6817	7403	6817	5589	3441
24	8237.00	7560	3572	6951	7560	6951	5843	3572
25	9199.99	8010	4022	7334	8010	7334	6569	3960
26	9200.01	8010	4022	7334	8010	7334	6569	3960
27	9300.00	8057	4069	7373	8057	7373	6644	4000

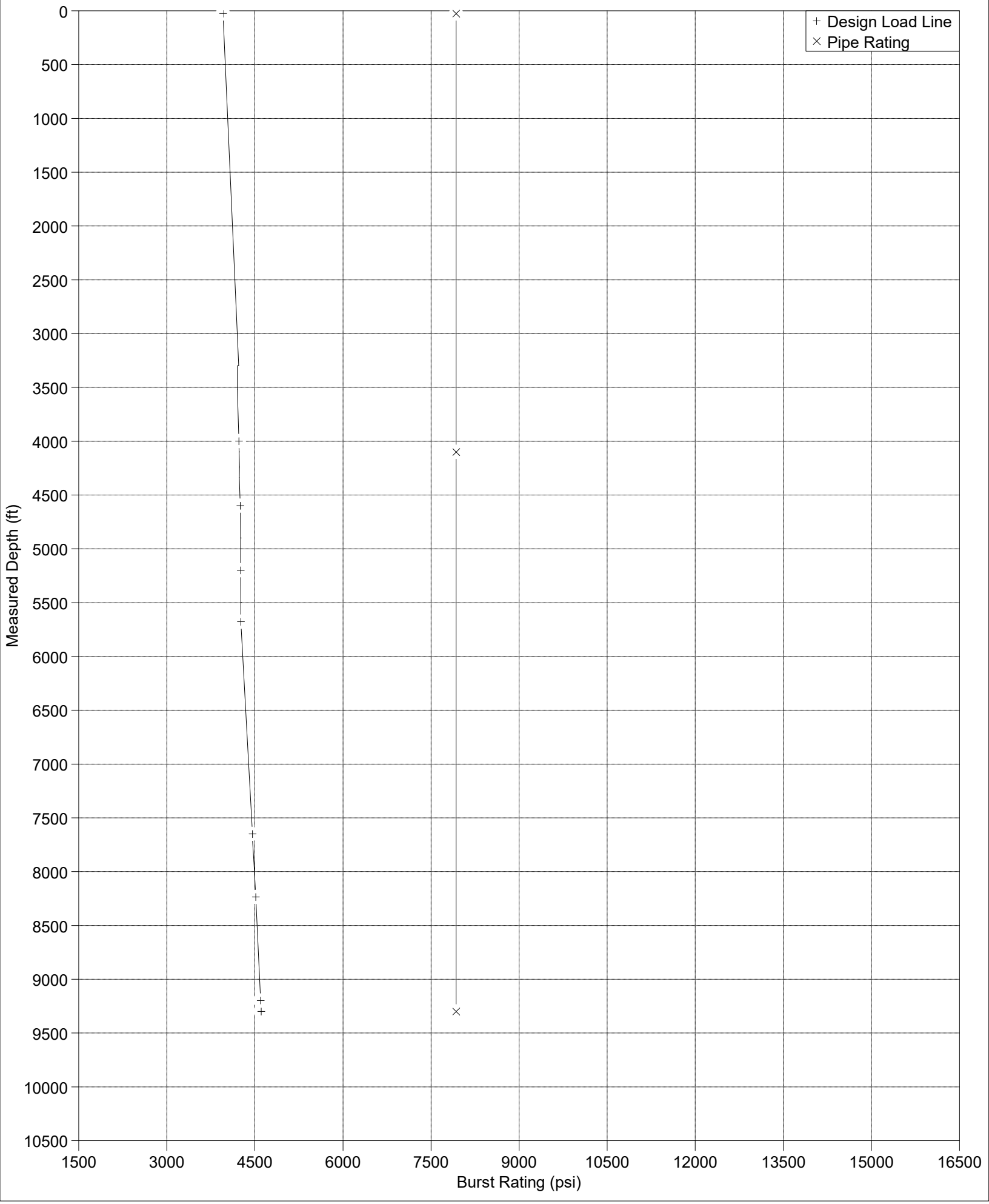
COLLAPSE PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Full Evacuation (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	17	0	17
2	3299.99	1428	2143	2	2143
3	3300.01	1428	2143	2	2143
4	3999.99	1731	2597	2	2597
5	4000.01	1731	2597	2	2597
6	4099.99	1774	2662	2	2662
7	4100.01	1774	2662	2	2662
8	4599.99	1989	3071	2	2985
9	4600.01	1989	3071	2	2985
10	4899.99	2117	3312	2	3176
11	4900.01	2117	3312	2	3176
12	5199.99	2242	3549	3	3364
13	5200.01	2242	3549	3	3364
14	5499.99	2363	3780	3	3547
15	5500.01	2363	3780	3	3547
16	7649.99	3218	5400	4	4829
17	7650.01	3218	5400	4	4829
18	8237.00	3451	5843	4	5179
19	9199.99	3834	6569	5	5753
20	9200.01	3834	6569	5	5753
21	9300.00	3873	6644	5	5812

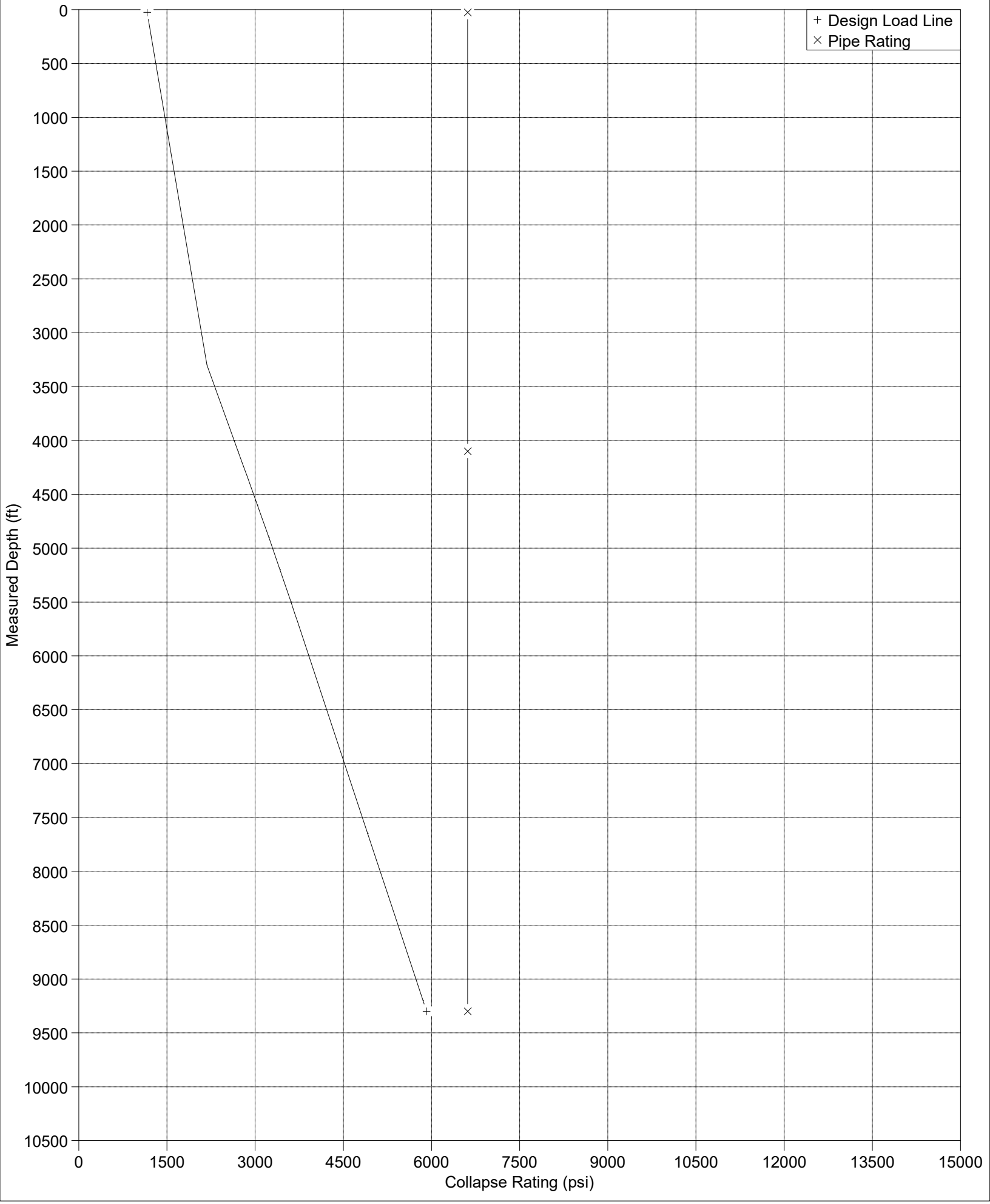
AXIAL LOADS TABLE (9 5/8" Production Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	487478	487478	415928	415928	415928	415928
2	1824.67	415796	415796	319699	319699	319699	319699
3	1824.67	415796	415796	319699	319699	319699	261108
4	3299.99	357000	357000	240770	240770	199764	199764
5	3300.01	356999	356999	240769	240769	312119	312119
6	3521.00	348192	348192	228946	228946	309960	309960
7	3999.99	328963	328963	203320	203320	306053	306053
8	4000.01	328962	328962	252249	203319	354984	306053
9	4099.99	324853	324853	246901	197970	354169	305238
10	4100.01	324852	324852	246900	197969	354169	305238
11	4240.16	319034	319034	239410	190479	354074	305144
12	4337.44	314959	314959	234220	185290	353571	304641
13	4599.99	303834	303834	220282	171351	353541	304610
14	4600.01	303833	303833	220281	171350	353541	304610
15	4646.08	301865	301865	217849	168919	353606	304676
16	4899.99	290950	290950	204545	155614	353006	304076
17	4900.01	290949	290949	204543	155613	353006	304076
18	5199.99	277960	277960	189101	140170	352310	303379
19	5200.01	277959	277959	189100	140169	352310	303379
20	5499.99	264939	264939	174047	125116	351630	302700
21	5500.01	264938	264938	174046	125115	351630	302700
22	5600.00	260598	260598	120195	120195	302478	302478
23	5678.72	257181	257181	116328	116328	302303	302303
24	7649.99	177982	171619	19496	19496	305087	305087
25	7650.01	177981	171618	19495	19495	305087	305087
26	7900.55	167943	160743	7188	7188	305441	305441
27	8237.00	154096	146139	-9339	-9339	305766	305766
28	9199.99	112890	104341	-56643	-56643	306141	306141
29	9200.01	112890	104340	-56644	-56644	306141	306141
30	9212.89	112331	103781	-57277	-57277	306144	306144
31	9241.30	111097	102548	-58672	-58672	306150	306150

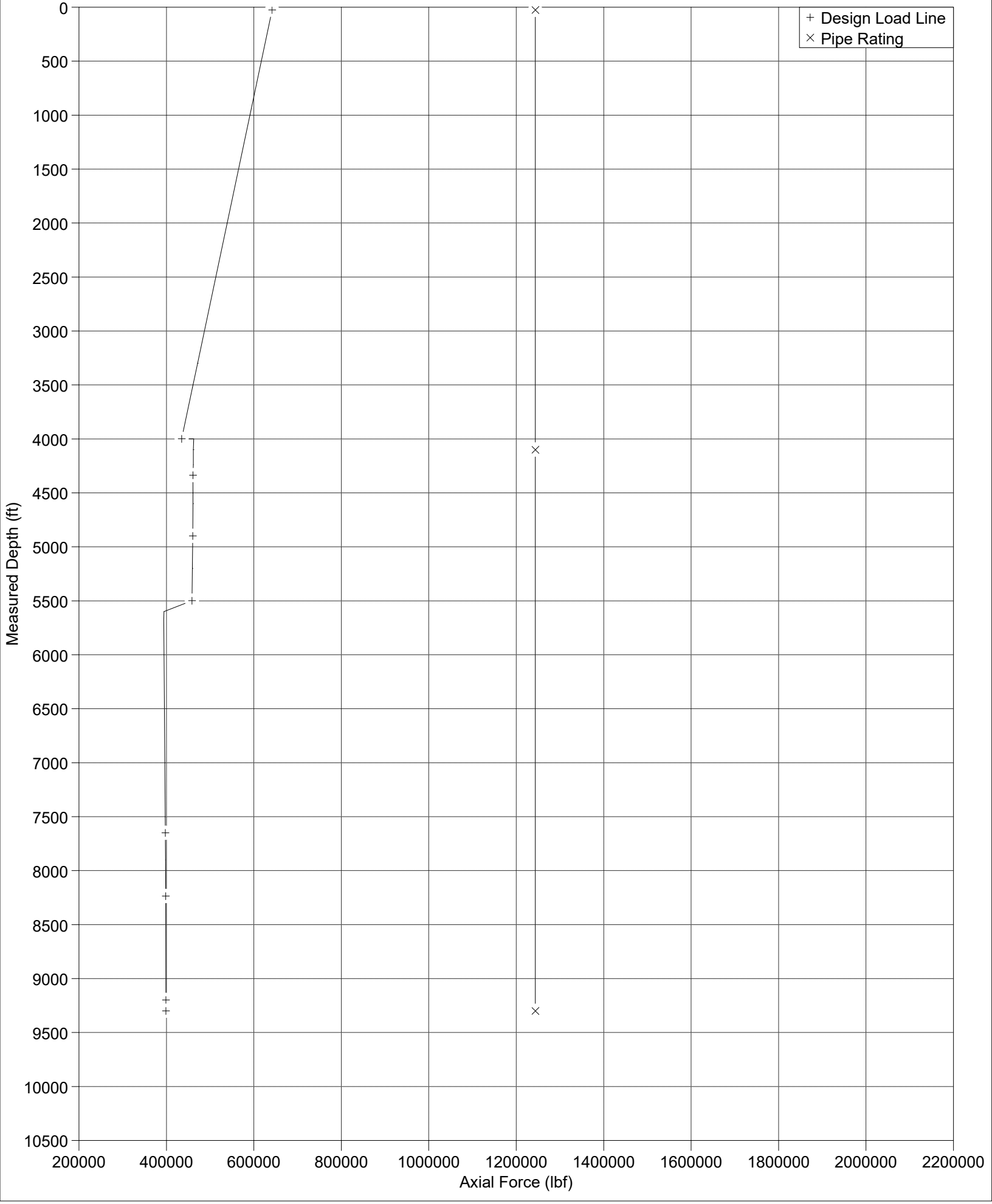
BURST DESIGN (9 5/8" Production Casing)

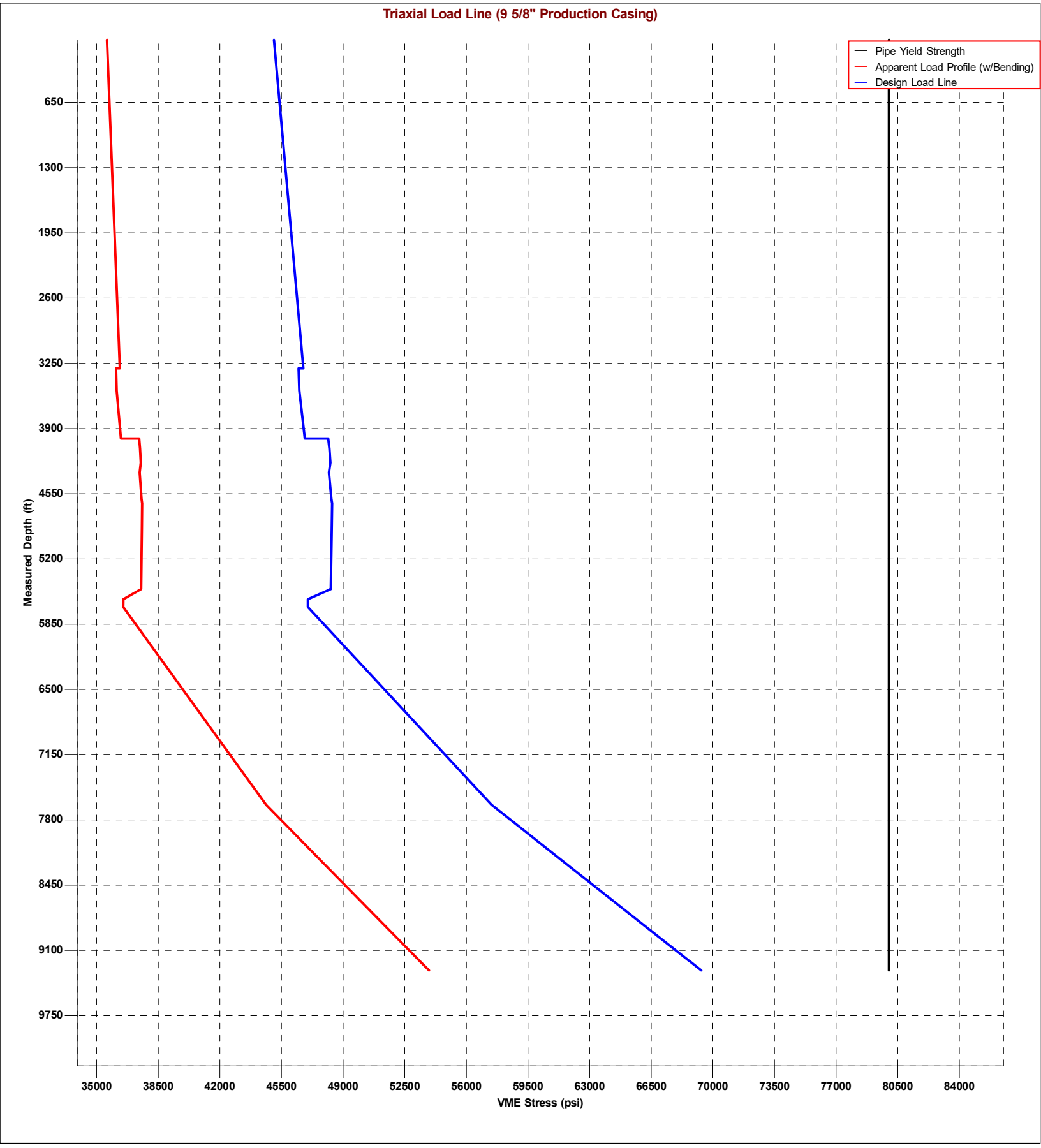


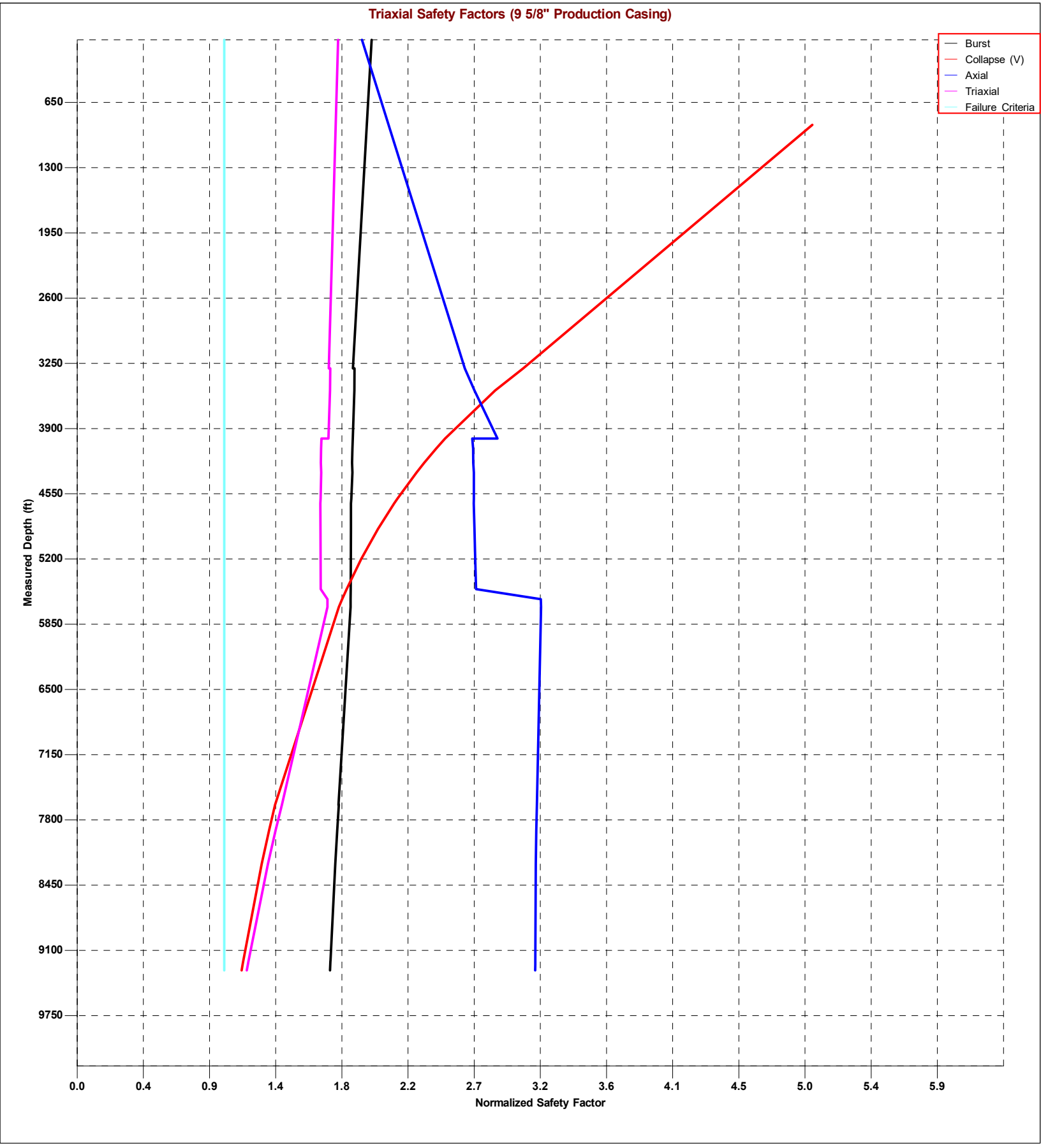
COLLAPSE DESIGN (9 5/8" Production Casing)



AXIAL DESIGN (9 5/8" Production Casing)




Triaxial Load Line (9 5/8" Production Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
35000
38500
42000
45500
49000
52500
56000
59500
63000
66500
70000
73500
77000
80500
84000
VME Stress (psi)


Triaxial Safety Factors (9 5/8" Production Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	9 5/8", 53.500 ppf, L-80	Blue	2.20 B7	5.69 C2	2.52 A4	2.22 B12
2	3300			2.06 B7	3.03 C5	3.43 A4	2.14 B7
3	3300			2.08 B7	3.03 C5	3.43 A4	2.15 B7
4	3521			2.07 B7	2.84 C5	3.51 A4	2.15 B7
5	4000			2.06 B7	2.50 C5	3.72 A4	2.14 B7
6	4000			2.06 B7	2.50 C5	3.49 B8	2.08 B7
7	4100			2.06 B7	2.44 C5	3.50 B8	2.07 B7
8	4100	9 5/8", 53.500 ppf, L-80	Blue	2.06 B7	2.44 C5	3.50 B8	2.07 B7
9	4240			2.06 B7	2.36 C5	3.50 B8	2.07 B7
10	4337			2.06 B7	2.31 C5	3.51 B8	2.08 B7
11	4600			2.05 B7	2.18 C5	3.51 B8	2.07 B7
12	4646			2.05 B7	2.16 C5	3.51 B8	2.07 B7
13	4900			2.05 B7	2.05 C5	3.51 B8	2.07 B7
14	5200			2.05 B7	1.93 C5	3.52 B8	2.07 B7
15	5500			2.05 B7	1.83 C5	3.53 B8	2.07 B7
16	5600			2.05 B7	1.80 C5	4.10 B8	2.13 B7
17	5679			2.05 B7	1.78 C5	4.10 B8	2.13 B7
18	7650			1.96 B7	1.35 C5	4.06 B8	1.74 C5
19	7650			1.96 B5	1.35 C5	4.06 B8	1.74 C5
20	7901			1.95 B5	1.31 C5	4.06 B8	1.69 C5
21	8237			1.93 B5	1.26 C5	4.06 B8	1.62 C5
22	9200			1.90 B5	1.13 C5	4.05 B8	1.46 C5
23	9213			1.89 B5	1.13 C5	4.05 B8	1.46 C5
24	9241			1.89 B5	1.13 C5	4.05 B8	1.45 C5
25	9299			1.89 B5	1.12 C5	4.05 B8	1.44 C5
26	9300			1.89 B5	1.12 C5	4.05 B8	1.44 C5
27							
28	B5	Pressure Test					
29	B7	Stimulation Surface Leak					
30	B8	Injection Casing					
31	B12	Green Cement Pressure Test(Burst)					
32	C2	Cementing					
33	C5	Full Evacuation Production					
34	A4	Overpull Force					
35	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	9 5/8", 53.500 ppf, L-80	0.272 B7	0.091 C2	0.262 A4	50.1	83.3	51.8	0.273	0.454	0.283
2	3299.99		0.291 B7	0.339 C5	0.278 B7	46.7	37.8	49.0	0.254	0.206	0.267
3	3300.01		0.289 B7	0.339 C5	0.277 B7	47.0	37.8	49.2	0.256	0.206	0.268
4	3521.00		0.289 B7	0.348 C5	0.277 B7	47.0	36.2	49.2	0.256	0.197	0.268
5	3999.99		0.291 B7	0.367 C5	0.279 B7	46.7	32.6	48.8	0.254	0.178	0.266
6	4000.01		0.291 B7	0.367 C5	0.285 B7	46.7	32.6	47.8	0.254	0.178	0.260
7	4099.99		0.291 B7	0.371 C5	0.285 B7	46.6	31.9	47.7	0.254	0.174	0.260
8	4100.01	9 5/8", 53.500 ppf, L-80	0.291 B7	0.371 C5	0.285 B7	46.6	31.9	47.7	0.254	0.174	0.260
9	4240.16		0.292 B7	0.377 C5	0.285 B7	46.5	30.8	47.6	0.253	0.168	0.260
10	4337.44		0.291 B7	0.381 C5	0.285 B7	46.6	30.1	47.7	0.254	0.164	0.260
11	4599.99		0.292 B7	0.391 C5	0.286 B7	46.4	28.2	47.5	0.253	0.154	0.259
12	4600.01		0.292 B7	0.391 C5	0.286 B7	46.4	28.2	47.5	0.253	0.154	0.259
13	4646.08		0.293 B7	0.393 C5	0.286 B7	46.3	27.9	47.5	0.252	0.152	0.259
14	4899.99		0.293 B7	0.403 C5	0.286 B7	46.3	26.0	47.5	0.252	0.142	0.259
15	4900.01		0.293 B7	0.403 C5	0.286 B7	46.3	26.0	47.5	0.252	0.142	0.259
16	5199.99		0.293 B7	0.415 C5	0.286 B7	46.3	23.9	47.5	0.252	0.130	0.259
17	5200.01		0.293 B7	0.415 C5	0.286 B7	46.3	23.9	47.5	0.252	0.130	0.259
18	5499.99		0.293 B7	0.426 C5	0.286 B7	46.2	21.9	47.5	0.252	0.119	0.259
19	5500.01		0.293 B7	0.426 C5	0.286 B7	46.2	21.9	47.5	0.252	0.119	0.259
20	5600.00		0.293 B7	0.428 C5	0.281 B7	46.2	21.5	48.5	0.252	0.117	0.264
21	5678.72		0.293 B7	0.430 C5	0.281 B7	46.2	21.1	48.5	0.252	0.115	0.264
22	7649.99		0.307 B7	0.477 C5	0.337 C5	43.7	12.4	38.1	0.238	0.068	0.208
23	7650.01		0.306 B5	0.477 C5	0.337 C5	43.8	12.4	38.1	0.239	0.068	0.208
24	7900.55		0.308 B5	0.483 C5	0.348 C5	43.5	11.3	36.1	0.237	0.062	0.197
25	8237.00		0.311 B5	0.492 C5	0.363 C5	43.0	9.8	33.4	0.234	0.053	0.182
26	9199.99		0.316 B5	0.515 C5	0.406 C5	42.0	5.5	25.5	0.229	0.030	0.139
27	9200.01		0.316 B5	0.515 C5	0.406 C5	42.0	5.5	25.5	0.229	0.030	0.139
28	9212.89		0.316 B5	0.515 C5	0.406 C5	41.9	5.5	25.4	0.229	0.030	0.139
29	9212.90		0.316 B5	0.515 C5	0.406 C5	41.9	5.5	25.4	0.229	0.030	0.139
30	9241.30		0.317 B5	0.516 C5	0.408 C5	41.9	5.4	25.2	0.228	0.029	0.137
31	9299.43		0.317 B5	0.517 C5	0.410 C5	41.9	5.1	24.7	0.228	0.028	0.135
32	9300.00		0.317 B5	0.517 C5	0.410 C5	41.9	5.1	24.7	0.228	0.028	0.135
33											
34	B5	Pressure Test									
35	B7	Stimulation Surface Leak									
36	C2	Cementing									
37	C5	Full Evacuation Production									
38	A4	Overpull Force									
39	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (9 5/8" Production Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	944321
2	26	943193
3	26	943192
4	251	933411
5	503	922502
6	754	911592
7	1000	900916
8	1005	900682
9	1257	889772
10	1508	878862
11	1759	867952
12	2000	857512
13	2011	857042
14	2262	846132
15	2514	835223
16	2765	824313
17	3000	814107
18	3016	813403
19	3268	802493
20	3519	791583
21	3770	780673
22	4000	770702
23	4000	770701
24	4022	769763
25	4100	766362
26	4100	766361
27	4273	758864
28	4524	748015
29	4600	744766
30	4600	744765
31	4776	737265
32	4900	731998
33	4900	731997
34	5000	727791
35	5027	726659
36	5200	719469
37	5200	719468
38	5278	716244
39	5500	707255
40	5530	706065
41	5600	703263
42	5781	696046
43	6000	687322
44	6032	686029
45	6284	676012
46	6535	665995
47	6786	655978
48	7000	647469
49	7038	645961
50	7289	635944
51	7541	625927
52	7792	615910
53	8000	607616
54	8043	605893
55	8295	595875
56	8546	585858
57	8797	575841
58	9000	567763
59	9049	565824
60	9200	559793
61	9200	559792
62	9274	556843
63	9300	* 557173
64		
65	* Based on Casing Strength	
66	Only. Running String not	
67	Included	

TRIAXIAL RESULTS (9 5/8" Production Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	335898	335898	337175	0.0	2.38	2.26	N/A	3.69	78	3513	17	N/A	N/A
2	3300	199764	199764	225302	0.0	2.30	2.09	N/A	6.14	113	5180	1446		
3	3300	198788	198788	224665	0.0	2.31	2.11	N/A	6.17	113	5180	1468		
4	3521	188979	188979	216622	0.0	2.31	2.10	N/A	6.49	116	5293	1579		
5	4000	168492	168492	199654	0.0	2.29	2.09	N/A	7.26	121	5536	1801		
6	4000	217422	168491	249373	3147.4	2.27	2.09	N/A	5.63	121	5536	1801		
7	4100	213146	164216	245841	3147.4	2.26	2.09	N/A	5.74	122	5587	1847		
8	4100	213146	164215	245841	3147.4	2.26	2.09	N/A	5.74	122	5587	1847		
9	4240	208205	159275	241956	3147.4	2.26	2.08	N/A	5.87	123	5659	1912		
10	4337	204345	155414	238976	3147.4	2.26	2.08	N/A	5.98	124	5708	1967		
11	4600	195296	146365	231828	3147.4	2.24	2.07	N/A	6.25	127	5841	2084		
12	4600	195295	146365	231828	3147.4	2.24	2.07	N/A	6.26	127	5841	2084		
13	4646	193787	144857	230626	3147.4	2.23	2.07	N/A	6.30	128	5864	2103		
14	4900	184579	135648	223414	3147.4	2.23	2.07	N/A	6.61	130	5990	2228		
15	4900	184578	135647	223414	3147.4	2.23	2.07	N/A	6.61	130	5990	2228		
16	5200	173890	124959	215029	3147.4	2.21	2.06	N/A	7.01	133	6137	2374		
17	5200	173889	124959	215028	3147.4	2.21	2.06	N/A	7.01	133	6137	2374		
18	5500	163471	114540	206839	3147.4	2.20	2.06	N/A	7.45	136	6281	2515		
19	5500	163470	114539	206839	3147.4	2.20	2.06	N/A	7.45	136	6281	2515		
20	5600	111134	111134	154183	0.0	2.23	2.06	N/A	10.96	137	6327	2562		
21	5679	108457	108457	152064	0.0	2.23	2.06	N/A	11.22	138	6364	2598		
22	7650	48589	48589	103394	0.0	2.07	1.96	N/A	24.91	158	7286	3346		
23	7650	48588	48588	103394	0.0	2.07	1.96	N/A	24.91	158	7286	3346		
24	7901	40980	40980	97166	0.0	2.05	1.95	N/A	29.51	160	7403	3441		
25	8237	30612	30612	88689	0.0	2.02	1.93	N/A	39.46	164	7560	3572		
26	9200	380	380	63957	0.0	1.96	1.90	N/A	+ 100.00	173	8010	3960		
27	9200	379	379	63957	0.0	1.96	1.90	N/A	+ 100.00	173	8010	3960		
28	9212	0	0	63646	0.0	1.96	1.89	N/A	+ 100.00	173	8016	3964		
29	9212	-0	-0	63646	0.0	1.96	1.89	N/A	(+ 100.00)	173	8016	3964		
30	9300	-2777	-2777	61369	0.0	1.95	1.89	N/A	(+ 100.00)	174	8057	4000		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Tubing Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	40784	40784	42261	0.0	2.73	2.64	N/A	29.62	164	2932	17	N/A	N/A
2	3300	17980	17980	41650	0.0	2.51	2.44	N/A	67.18	164	4599	1446		
3	3300	17005	17005	41004	0.0	2.53	2.46	N/A	71.04	164	4599	1468		
4	3521	14846	14846	40552	0.0	2.52	2.46	N/A	81.37	164	4711	1579		
5	4000	10940	10940	40084	0.0	2.50	2.44	N/A	+ 100.00	164	4955	1801		
6	4000	59870	10940	90463	3147.4	2.42	2.44	N/A	20.18	164	4955	1801		
7	4100	59055	10124	90365	3147.4	2.41	2.44	N/A	20.46	164	5006	1847		
8	4240	58961	10030	91307	3147.4	2.41	2.43	N/A	20.49	164	5077	1912		
9	4337	58458	9527	91670	3147.4	2.42	2.44	N/A	20.66	164	5127	1967		
10	4600	58427	9497	93519	3147.4	2.41	2.43	N/A	20.67	164	5259	2084		
11	4646	58493	9562	93889	3147.4	2.41	2.42	N/A	20.65	164	5282	2103		
12	4900	57893	8962	95275	3147.4	2.41	2.42	N/A	20.87	164	5409	2228		
13	5200	57196	8265	96884	3147.4	2.41	2.42	N/A	21.12	164	5556	2374		
14	5500	56517	7586	98453	3147.4	2.41	2.42	N/A	21.37	164	5699	2515		
15	5600	7364	7364	48587	0.0	2.49	2.42	N/A	+ 100.00	164	5746	2562		
16	5679	7190	7190	48990	0.0	2.50	2.42	N/A	+ 100.00	164	5783	2598		
17	7650	9974	9974	63822	0.0	2.38	2.29	N/A	+ 100.00	164	6704	3346		
18	7650	-99156	-99156	-48537	0.0	15.71	42.92	N/A	(12.18)	164	3525	3346		
19	7901	-102141	-102141	-50090	0.0	17.03	73.87	N/A	(11.83)	164	3545	3441		
20	8237	-106295	-106295	-52269	0.0	18.57	N/A	N/A	(11.36)	164	3572	3572		
21	9200	-105921	-105921	-45677	0.0	19.05	+ 100.00	N/A	(11.40)	164	4022	3960		
22	9300	-105899	-105899	-45004	0.0	19.09	+ 100.00	N/A	(11.41)	164	4069	4000		
23														
24	( )	Compression												
25	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Stimulation Surface Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	60675	60675	62740	0.0	2.30	2.20	N/A	19.91	164	3511	17	N/A	N/A
2	3300	37871	37871	62129	0.0	2.14	2.06	N/A	31.90	164	5178	1446		
3	3300	36896	36896	61483	0.0	2.15	2.08	N/A	32.74	164	5178	1468		
4	3521	34737	34737	61031	0.0	2.15	2.07	N/A	34.78	164	5291	1579		
5	4000	30830	30830	60564	0.0	2.14	2.06	N/A	39.18	164	5534	1801		
6	4000	79761	30830	110942	3147.4	2.08	2.06	N/A	15.14	164	5534	1801		
7	4100	78946	30015	110845	3147.4	2.07	2.06	N/A	15.30	164	5585	1847		
8	4240	78852	29921	111787	3147.4	2.07	2.06	N/A	15.32	164	5657	1912		
9	4337	78348	29418	112149	3147.4	2.08	2.06	N/A	15.42	164	5706	1967		
10	4600	78318	29387	113998	3147.4	2.07	2.05	N/A	15.42	164	5839	2084		
11	4646	78383	29453	114368	3147.4	2.07	2.05	N/A	15.41	164	5862	2103		
12	4900	77783	28853	115754	3147.4	2.07	2.05	N/A	15.53	164	5988	2228		
13	5200	77087	28156	117364	3147.4	2.07	2.05	N/A	15.67	164	6135	2374		
14	5500	76408	27477	118932	3147.4	2.07	2.05	N/A	15.81	164	6279	2515		
15	5500	76407	27477	118932	3147.4	2.07	2.05	N/A	15.81	164	6279	2515		
16	5600	27255	27255	69067	0.0	2.13	2.05	N/A	44.32	164	6325	2562		
17	5679	27080	27080	69470	0.0	2.13	2.05	N/A	44.61	164	6362	2598		
18	7650	29864	29864	84301	0.0	2.05	1.96	N/A	40.45	164	7284	3346		
19	7650	10440	10440	64302	0.0	2.38	2.28	N/A	+ 100.00	164	6718	3346		
20	7901	10191	10191	65566	0.0	2.37	2.28	N/A	+ 100.00	164	6817	3441		
21	8237	9706	9706	67165	0.0	2.37	2.28	N/A	+ 100.00	164	6951	3572		
22	9200	7763	7763	71370	0.0	2.38	2.28	N/A	+ 100.00	164	7334	3960		
23	9200	7763	7763	71371	0.0	2.38	2.28	N/A	+ 100.00	164	7334	3960		
24	9300	7543	7543	71796	0.0	2.38	2.28	N/A	+ 100.00	164	7373	4000		
25														
26	( )	Compression												
27	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Injection Down Casing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	335898	335898	337175	0.0	2.38	2.26	N/A	3.69	78	3513	17	N/A	N/A
2	3300	313094	313094	336580	0.0	2.26	2.12	N/A	3.96	78	5180	1446		
3	3300	312119	312119	335950	0.0	2.27	2.13	N/A	3.97	78	5180	1468		
4	3521	309960	309960	335510	0.0	2.27	2.13	N/A	4.00	78	5293	1579		
5	4000	306053	306053	335054	0.0	2.26	2.12	N/A	4.05	78	5536	1801		
6	4000	354984	306053	384133	3147.4	2.21	2.12	N/A	3.49	78	5536	1801		
7	4100	354169	305238	384038	3147.4	2.21	2.11	N/A	3.50	78	5587	1847		
8	4240	354074	305144	384956	3147.4	2.21	2.11	N/A	3.50	78	5659	1912		
9	4337	353571	304641	385309	3147.4	2.21	2.11	N/A	3.51	78	5708	1967		
10	4600	353541	304610	387110	3147.4	2.20	2.10	N/A	3.51	78	5841	2084		
11	4646	353606	304676	387470	3147.4	2.20	2.10	N/A	3.51	78	5864	2103		
12	4900	353006	304076	388821	3147.4	2.20	2.10	N/A	3.51	78	5990	2228		
13	5200	352310	303379	390388	3147.4	2.19	2.10	N/A	3.52	78	6137	2374		
14	5200	352310	303379	390389	3147.4	2.19	2.10	N/A	3.52	78	6137	2374		
15	5500	351630	302700	391917	3147.4	2.19	2.10	N/A	3.53	78	6281	2515		
16	5600	302478	302478	343338	0.0	2.24	2.10	N/A	4.10	78	6327	2562		
17	5679	302303	302303	343730	0.0	2.24	2.10	N/A	4.10	78	6364	2598		
18	7650	305087	305087	358179	0.0	2.14	2.01	N/A	4.06	78	7286	3346		
19	7901	305441	305441	360016	0.0	2.13	1.99	N/A	4.06	78	7403	3441		
20	8237	305766	305766	362385	0.0	2.12	1.98	N/A	4.06	78	7560	3572		
21	9200	306141	306141	368807	0.0	2.08	1.95	N/A	4.05	78	8010	3960		
22	9300	306162	306162	369463	0.0	2.08	1.95	N/A	4.05	78	8057	4000		
23														
24	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	415928	415928	421660	0.0	2.22	2.24	N/A	2.95	111	3511	17	N/A	N/A
2	3300	240770	240770	278608	0.0	2.94	2.80	N/A	5.08	122	4928	2143		
3	3300	240769	240769	278607	0.0	2.94	2.80	N/A	5.08	122	4928	2143		
4	3521	228946	228946	268917	0.0	3.01	2.85	N/A	5.34	123	5024	2286		
5	4000	203320	203320	247899	0.0	3.15	2.96	N/A	6.01	124	5231	2597		
6	4000	252249	203319	297671	3147.4	3.03	2.96	N/A	4.85	124	5231	2597		
7	4100	246901	197970	293287	3147.4	3.06	2.98	N/A	4.95	125	5274	2662		
8	4100	246900	197969	293286	3147.4	3.06	2.98	N/A	4.95	125	5274	2662		
9	4240	239410	190479	287525	3147.4	3.13	3.05	N/A	5.11	125	5335	2777		
10	4337	234220	185290	283532	3147.4	3.17	3.09	N/A	5.22	125	5377	2857		
11	4600	220282	171351	272804	3147.4	3.31	3.22	N/A	5.55	126	5489	3071		
12	4600	220281	171350	272803	3147.4	3.31	3.22	N/A	5.55	126	5489	3071		
13	4646	217849	168919	270931	3147.4	3.33	3.24	N/A	5.61	126	5509	3108		
14	4900	204545	155614	260684	3147.4	3.47	3.38	N/A	5.97	127	5617	3312		
15	4900	204543	155613	260683	3147.4	3.47	3.38	N/A	5.97	127	5617	3312		
16	5200	189101	140170	248783	3147.4	3.65	3.55	N/A	6.46	128	5742	3549		
17	5200	189100	140169	248782	3147.4	3.65	3.55	N/A	6.46	128	5742	3549		
18	5500	174047	125116	237176	3147.4	3.84	3.73	N/A	7.01	129	5863	3780		
19	5500	174046	125115	237175	3147.4	3.84	3.73	N/A	7.01	129	5863	3780		
20	5600	120195	120195	183528	0.0	4.09	3.80	N/A	10.16	129	5903	3856		
21	5679	116328	116328	180541	0.0	4.15	3.85	N/A	10.49	130	5935	3915		
22	7650	19496	19496	105604	0.0	6.44	5.90	N/A	62.49	136	6718	5400		
23	7650	19495	19495	105603	0.0	6.44	5.90	N/A	62.50	136	6718	5400		
24	7901	7188	7188	96059	0.0	6.92	6.32	N/A	+ 100.00	136	6817	5589		
25	8047	4	4	90486	0.0	7.23	6.60	N/A	+ 100.00	137	6875	5699		
26	8047	-23	-23	90465	0.0	7.23	6.60	N/A	(+ 100.00)	137	6876	5700		
27	8237	-9339	-9339	83236	0.0	7.68	7.00	N/A	(+ 100.00)	137	6951	5843		
28	9200	-56643	-56643	46487	0.0	11.04	10.14	N/A	(21.48)	140	7334	6569		
29	9200	-56644	-56644	46486	0.0	11.04	10.14	N/A	(21.48)	140	7334	6569		
30	9300	-61556	-61556	42667	0.0	11.54	10.63	N/A	(19.76)	141	7373	6644		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	215682	215682	218693	0.0	5.00	N/A	5.69	5.69	111	11	17	N/A	N/A
2	3300	40523	40523	63759	0.0	7.50	N/A	7.54	30.19	122	1428	2143		
3	3300	40522	40522	63758	0.0	7.50	N/A	7.54	30.19	122	1428	2143		
4	3521	28699	28699	53263	0.0	7.57	N/A	7.42	42.62	123	1524	2286		
5	4000	3073	3073	30499	0.0	7.62	N/A	7.06	+ 100.00	124	1731	2597		
6	4000	52003	3072	80272	3147.4	6.22	N/A	7.06	23.51	124	1731	2597		
7	4057	48936	5	77549	3147.4	6.24	N/A	7.02	24.98	124	1756	2635		
8	4058	-48956	-25	-22031	3147.4	9.28	N/A	7.45	(24.97)	124	1756	2635		
9	4100	-51207	-2276	-24034	3147.4	9.23	N/A	7.37	(23.87)	125	1774	2662		
10	4100	-51208	-2277	-24035	3147.4	9.23	N/A	7.37	(23.87)	125	1774	2662		
11	4240	-58698	-9767	-30701	3147.4	8.78	N/A	6.94	(20.82)	125	1835	2777		
12	4337	-63888	-14957	-35321	3147.4	8.49	N/A	6.68	(19.13)	125	1877	2857		
13	4600	-77826	-28895	-47733	3147.4	7.79	N/A	6.05	(15.70)	126	1989	3071		
14	4600	-77827	-28896	-47734	3147.4	7.79	N/A	6.05	(15.70)	126	1989	3071		
15	4646	-80259	-31328	-49901	3147.4	7.67	N/A	5.95	(15.22)	126	2009	3108		
16	4900	-93563	-44633	-61756	3147.4	7.10	N/A	5.47	(13.06)	127	2117	3312		
17	4900	-93564	-44634	-61757	3147.4	7.10	N/A	5.47	(13.06)	127	2117	3312		
18	5200	-109007	-60076	-75525	3147.4	6.52	N/A	5.00	(11.20)	128	2242	3549		
19	5200	-109008	-60077	-75526	3147.4	6.52	N/A	5.00	(11.20)	128	2242	3549		
20	5500	-124061	-75130	-88954	3147.4	6.02	N/A	4.62	(9.84)	129	2363	3780		
21	5500	-124062	-75131	-88955	3147.4	6.02	N/A	4.62	(9.84)	129	2363	3780		
22	5600	-80052	-80052	-43494	0.0	5.60	N/A	4.50	(15.25)	129	2403	3856		
23	5679	-83918	-83918	-46941	0.0	5.52	N/A	4.42	(14.55)	130	2435	3915		
24	7650	-180751	-180751	-133444	0.0	3.89	N/A	2.99	(6.74)	136	3218	5400		
25	7650	-180752	-180752	-133445	0.0	3.89	N/A	2.99	(6.74)	136	3218	5400		
26	7901	-193058	-193058	-144462	0.0	3.74	N/A	2.87	(6.31)	136	3317	5589		
27	8237	-209586	-209586	-159265	0.0	3.56	N/A	2.73	(5.81)	137	3451	5843		
28	9200	-256890	-256890	-201685	0.0	3.11	N/A	2.39	(4.74)	140	3834	6569		
29	9200	-256890	-256890	-201686	0.0	3.11	N/A	2.39	(4.74)	140	3834	6569		
30	9300	-261802	-261802	-206095	0.0	3.07	N/A	2.35	(4.65)	141	3873	6644		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Full Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-59859	-59859	-61630	0.0	18.15	N/A	+ 100.00	(20.18)	164	0	17	N/A	N/A
2	3300	-170268	-170268	-175281	0.0	3.94	N/A	3.03	(7.09)	164	2	2143		
3	3300	-170268	-170268	-175282	0.0	3.94	N/A	3.03	(7.09)	164	2	2143		
4	3521	-177721	-177721	-182952	0.0	3.70	N/A	2.84	(6.80)	164	2	2286		
5	4000	-193873	-193873	-199579	0.0	3.26	N/A	2.50	(6.23)	164	2	2597		
6	4000	-242804	-193874	-249958	3147.4	3.23	N/A	2.50	(4.98)	164	2	2597		
7	4100	-246175	-197245	-253428	3147.4	3.15	N/A	2.44	(4.91)	164	2	2662		
8	4100	-246176	-197245	-253429	3147.4	3.15	N/A	2.44	(4.91)	164	2	2662		
9	4240	-249849	-200919	-257210	3147.4	3.05	N/A	2.36	(4.83)	164	2	2753		
10	4337	-252395	-203464	-259829	3147.4	2.98	N/A	2.31	(4.79)	164	2	2816		
11	4600	-259230	-210299	-266865	3147.4	2.81	N/A	2.18	(4.66)	164	2	2985		
12	4600	-259231	-210300	-266865	3147.4	2.81	N/A	2.18	(4.66)	164	2	2985		
13	4646	-260423	-211493	-268093	3147.4	2.78	N/A	2.16	(4.64)	164	2	3015		
14	4900	-266948	-218017	-274809	3147.4	2.64	N/A	2.05	(4.53)	164	2	3176		
15	4900	-266949	-218018	-274809	3147.4	2.64	N/A	2.05	(4.53)	164	2	3176		
16	5200	-274522	-225591	-282604	3147.4	2.49	N/A	1.93	(4.40)	164	3	3364		
17	5200	-274522	-225592	-282605	3147.4	2.49	N/A	1.93	(4.40)	164	3	3364		
18	5500	-281905	-232974	-290203	3147.4	2.36	N/A	1.83	(4.29)	164	3	3547		
19	5500	-281905	-232975	-290204	3147.4	2.36	N/A	1.83	(4.29)	164	3	3547		
20	5600	-235388	-235388	-242309	0.0	2.34	N/A	1.80	(5.13)	164	3	3606		
21	5679	-237284	-237284	-244261	0.0	2.31	N/A	1.78	(5.09)	164	3	3653		
22	7650	-284771	-284771	-293137	0.0	1.74	N/A	1.35	(4.24)	164	4	4829		
23	7901	-290806	-290806	-299349	0.0	1.69	N/A	1.31	(4.15)	164	4	4978		
24	8237	-298911	-298911	-307690	0.0	1.62	N/A	1.26	(4.04)	164	4	5179		
25	9200	-322108	-322108	-331565	0.0	1.46	N/A	1.13	(3.75)	164	5	5753		
26	9200	-322108	-322108	-331566	0.0	1.46	N/A	1.13	(3.75)	164	5	5753		
27	9300	-324517	-324517	-334045	0.0	1.44	N/A	1.12	(3.72)	164	5	5812		
28														
29	( )	Compression												
30	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	487478	487478	494150	0.0	2.22	N/A	N/A	2.52	111	17	17	N/A	N/A
2	3300	357000	357000	396757	0.0	2.79	N/A	N/A	3.43	122	2143	2143		
3	3300	356999	356999	396756	0.0	2.79	N/A	N/A	3.43	122	2143	2143		
4	3521	348192	348192	390159	0.0	2.84	N/A	N/A	3.51	123	2286	2286		
5	4000	328963	328963	375707	0.0	2.96	N/A	N/A	3.72	124	2597	2597		
6	4000	328962	328962	375706	3147.4	2.96	N/A	N/A	3.72	124	2597	2597		
7	4100	324853	324853	372591	3147.4	2.98	N/A	N/A	3.76	125	2662	2662		
8	4100	324852	324852	372590	3147.4	2.98	N/A	N/A	3.76	125	2662	2662		
9	4240	319034	319034	368161	3147.4	3.02	N/A	N/A	3.83	125	2753	2753		
10	4337	314959	314959	365047	3147.4	3.05	N/A	N/A	3.88	125	2816	2816		
11	4600	303834	303834	356497	3147.4	3.12	N/A	N/A	4.02	126	2985	2985		
12	4600	303833	303833	356496	3147.4	3.12	N/A	N/A	4.02	126	2985	2985		
13	4646	301865	301865	354976	3147.4	3.14	N/A	N/A	4.05	126	3015	3015		
14	4900	290950	290950	346510	3147.4	3.22	N/A	N/A	4.20	127	3176	3176		
15	4900	290949	290949	346509	3147.4	3.22	N/A	N/A	4.20	127	3176	3176		
16	5200	277960	277960	336349	3147.4	3.32	N/A	N/A	4.39	128	3364	3364		
17	5200	277959	277959	336348	3147.4	3.32	N/A	N/A	4.39	128	3364	3364		
18	5500	264939	264939	326074	3147.4	3.43	N/A	N/A	4.61	129	3547	3547		
19	5500	264938	264938	326073	3147.4	3.43	N/A	N/A	4.61	129	3547	3547		
20	5600	260598	260598	322628	0.0	3.47	N/A	N/A	4.68	129	3606	3606		
21	5679	257181	257181	319914	0.0	3.50	N/A	N/A	4.75	130	3653	3653		
22	7650	177982	171619	258309	0.0	4.40	N/A	N/A	6.85	136	4829	4829		
23	7650	177981	171618	258309	0.0	4.40	N/A	N/A	6.85	136	4829	4829		
24	7901	167943	160743	250491	0.0	4.55	N/A	N/A	7.25	136	4978	4978		
25	8237	154096	146139	239613	0.0	4.77	N/A	N/A	7.90	137	5179	5179		
26	9200	112890	104341	206830	0.0	5.59	N/A	N/A	10.78	140	5753	5753		
27	9200	112890	104340	206829	0.0	5.59	N/A	N/A	10.78	140	5753	5753		
28	9299	108575	100025	203379	0.0	5.70	N/A	N/A	11.20	141	5812	5812		
29	9300	108550	100000	203360	0.0	5.70	N/A	N/A	11.21	141	5812	5812		
30														
31	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	415928	415928	421660	0.0	2.22	2.24	N/A	2.95	111	3511	17	N/A	N/A
2	3300	240770	240770	278608	0.0	2.94	2.80	N/A	5.08	122	4928	2143		
3	3300	240769	240769	278607	0.0	2.94	2.80	N/A	5.08	122	4928	2143		
4	3521	228946	228946	268917	0.0	3.01	2.85	N/A	5.34	123	5024	2286		
5	4000	203320	203320	247899	0.0	3.15	2.96	N/A	6.01	124	5231	2597		
6	4000	252249	203319	297671	3147.4	3.03	2.96	N/A	4.85	124	5231	2597		
7	4100	246901	197970	293287	3147.4	3.06	2.98	N/A	4.95	125	5274	2662		
8	4100	246900	197969	293286	3147.4	3.06	2.98	N/A	4.95	125	5274	2662		
9	4240	239410	190479	287525	3147.4	3.13	3.05	N/A	5.11	125	5335	2777		
10	4337	234220	185290	283532	3147.4	3.17	3.09	N/A	5.22	125	5377	2857		
11	4600	220282	171351	272804	3147.4	3.31	3.22	N/A	5.55	126	5489	3071		
12	4600	220281	171350	272803	3147.4	3.31	3.22	N/A	5.55	126	5489	3071		
13	4646	217849	168919	270931	3147.4	3.33	3.24	N/A	5.61	126	5509	3108		
14	4900	204545	155614	260684	3147.4	3.47	3.38	N/A	5.97	127	5617	3312		
15	4900	204543	155613	260683	3147.4	3.47	3.38	N/A	5.97	127	5617	3312		
16	5200	189101	140170	248783	3147.4	3.65	3.55	N/A	6.46	128	5742	3549		
17	5200	189100	140169	248782	3147.4	3.65	3.55	N/A	6.46	128	5742	3549		
18	5500	174047	125116	237176	3147.4	3.84	3.73	N/A	7.01	129	5863	3780		
19	5500	174046	125115	237175	3147.4	3.84	3.73	N/A	7.01	129	5863	3780		
20	5600	120195	120195	183528	0.0	4.09	3.80	N/A	10.16	129	5903	3856		
21	5679	116328	116328	180541	0.0	4.15	3.85	N/A	10.49	130	5935	3915		
22	7650	19496	19496	105604	0.0	6.44	5.90	N/A	62.49	136	6718	5400		
23	7650	19495	19495	105603	0.0	6.44	5.90	N/A	62.50	136	6718	5400		
24	7901	7188	7188	96059	0.0	6.92	6.32	N/A	+ 100.00	136	6817	5589		
25	8047	4	4	90486	0.0	7.23	6.60	N/A	+ 100.00	137	6875	5699		
26	8047	-23	-23	90465	0.0	7.23	6.60	N/A	(+ 100.00)	137	6876	5700		
27	8237	-9339	-9339	83236	0.0	7.68	7.00	N/A	(+ 100.00)	137	6951	5843		
28	9200	-56643	-56643	46487	0.0	11.04	10.14	N/A	(21.48)	140	7334	6569		
29	9200	-56644	-56644	46486	0.0	11.04	10.14	N/A	(21.48)	140	7334	6569		
30	9300	-61556	-61556	42667	0.0	11.54	10.63	N/A	(19.76)	141	7373	6644		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (5 1/2" Production Tubing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Temperature Deration:	Yes
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (5 1/2" Production Tubing)

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7650.00 ft
Perforation Depth, MD:	8237.00 ft
Packer Setting Method:	Set Mechanically
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
4000.00 ft	121 °F
4597.53 ft	127 °F
4891.69 ft	130 °F
5180.36 ft	133 °F
5461.74 ft	136 °F
7435.96 ft	158 °F

BURST LOADS DATA (5 1/2" Production Tubing)

Production Load:	**Shut-In**
Shut-in Bottom Hole Pressure:	4200 psi
Gas Gravity:	0.70 (0.0976 psi/ft @ 164 °F & 4200 psi)
Hot:	Yes
Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Internal Fluid Density:	9.80 ppg
Production Load:	**Tubing Injection**
Injection Pressure:	3500 psi
Injection Fluid Density:	10.00 ppg

COLLAPSE LOADS DATA (5 1/2" Production Tubing)

Drilling Load:	**Full/Partial Evacuation**
Mud Weight:	9.80 ppg
Mud Level, MD:	7650.00 ft
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7650.00 ft
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7650.00 ft
Perforation Depth, MD:	8237.00 ft
Gas Gravity:	0.70
Reservoir Pressure:	3572 psi
Production Load:	**Annular Pressure Test**
Fluid Density(Inside Tubing):	1.50 ppg
Wellhead Pressure (Annulus)	3500 psi
Fluid Density(Annulus)	9.80 ppg
Packer Depth, MD:	7650.00 ft

AXIAL LOADS DATA (5 1/2" Production Tubing)

Overpull Force:	100000 lbf
Service Loads:	Yes

BURST PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Pressure Test (Int) (psi)	Pressure Test (Ext) (psi)	Tubing Injection (Int) (psi)	Tubing Injection (Ext) (psi)	Shut-In (Int) (psi)	Shut-In (Ext) (psi)
1	26.00	3513	13	3514	13	3560	13
2	3999.99	5536	2036	5578	2036	3878	2036
3	4000.01	5536	2036	5578	2036	3878	2036
4	4599.99	5841	2341	5888	2341	3926	2341
5	4600.01	5841	2341	5888	2341	3926	2341
6	4899.99	5990	2490	6041	2490	3950	2490
7	4900.01	5990	2490	6041	2490	3950	2490
8	5199.99	6137	2637	6191	2637	3973	2637
9	5200.01	6137	2637	6191	2637	3973	2637
10	5499.99	6281	2781	6337	2781	3995	2781
11	5500.01	6281	2781	6337	2781	3995	2781
12	7649.99	7286	3786	7363	3786	4153	3786
13	7650.00	7286	3786	7363	3786	4153	3786

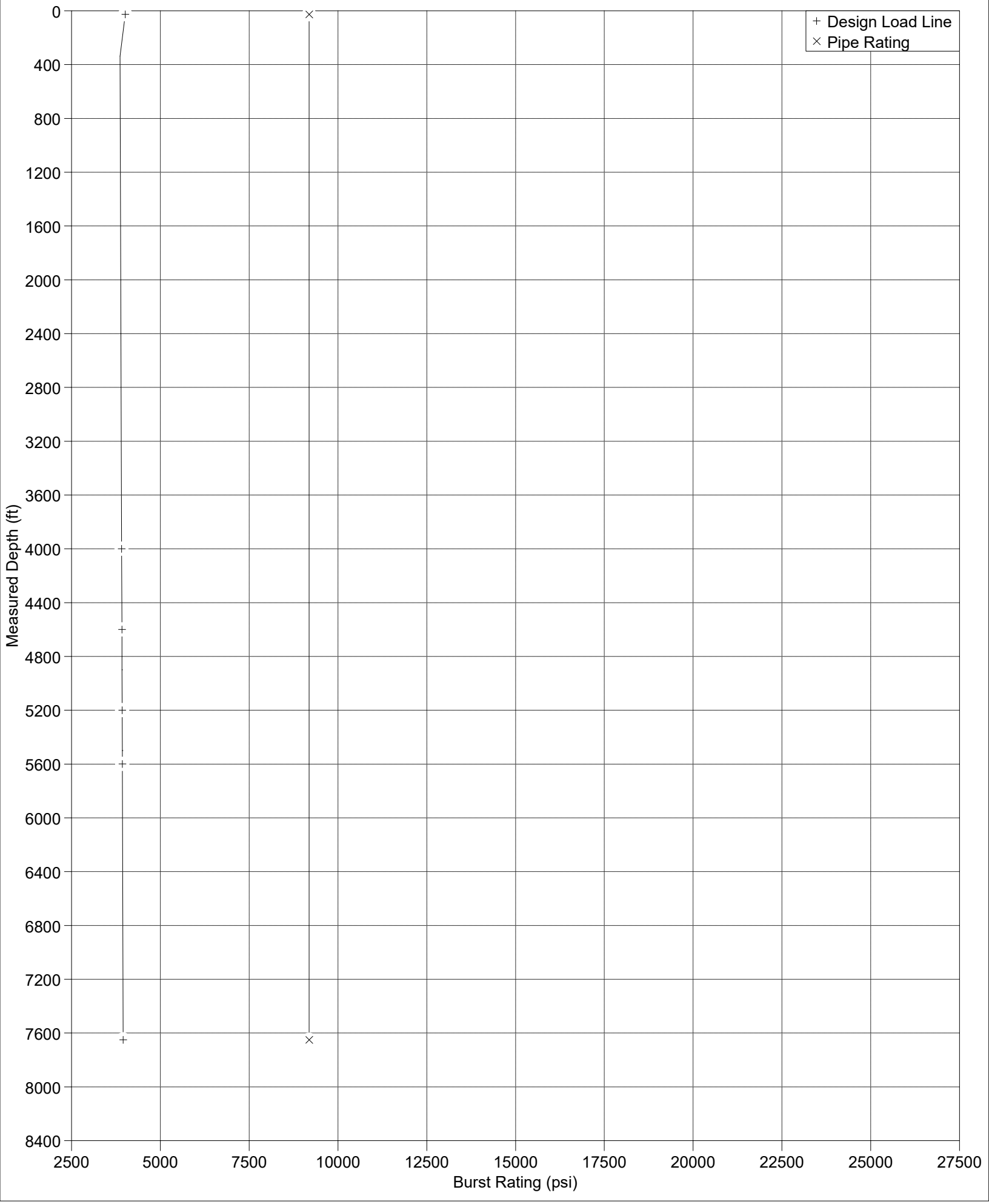
COLLAPSE PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Full/Partial Evacuation (Int) (psi)	Full/Partial Evacuation (Ext) (psi)	Tubing Leak (Int) (psi)	Tubing Leak (Ext) (psi)	Annular Pressure Test (Int) (psi)	Annular Pressure Test (Ext) (psi)
1	26.00	0	13	2932	2932	2	3513
2	3999.99	2	2036	3250	4955	312	5536
3	4000.01	2	2036	3250	4955	312	5536
4	4599.99	2	2341	3298	5259	358	5841
5	4600.01	2	2341	3298	5259	358	5841
6	4899.99	3	2490	3321	5409	381	5990
7	4900.01	3	2490	3321	5409	381	5990
8	5199.99	3	2637	3345	5556	404	6137
9	5200.01	3	2637	3345	5556	404	6137
10	5499.99	3	2781	3367	5699	426	6281
11	5500.01	3	2781	3367	5699	426	6281
12	7649.99	4	3786	3525	6704	579	7286
13	7650.00	4	3786	3525	6704	579	7286

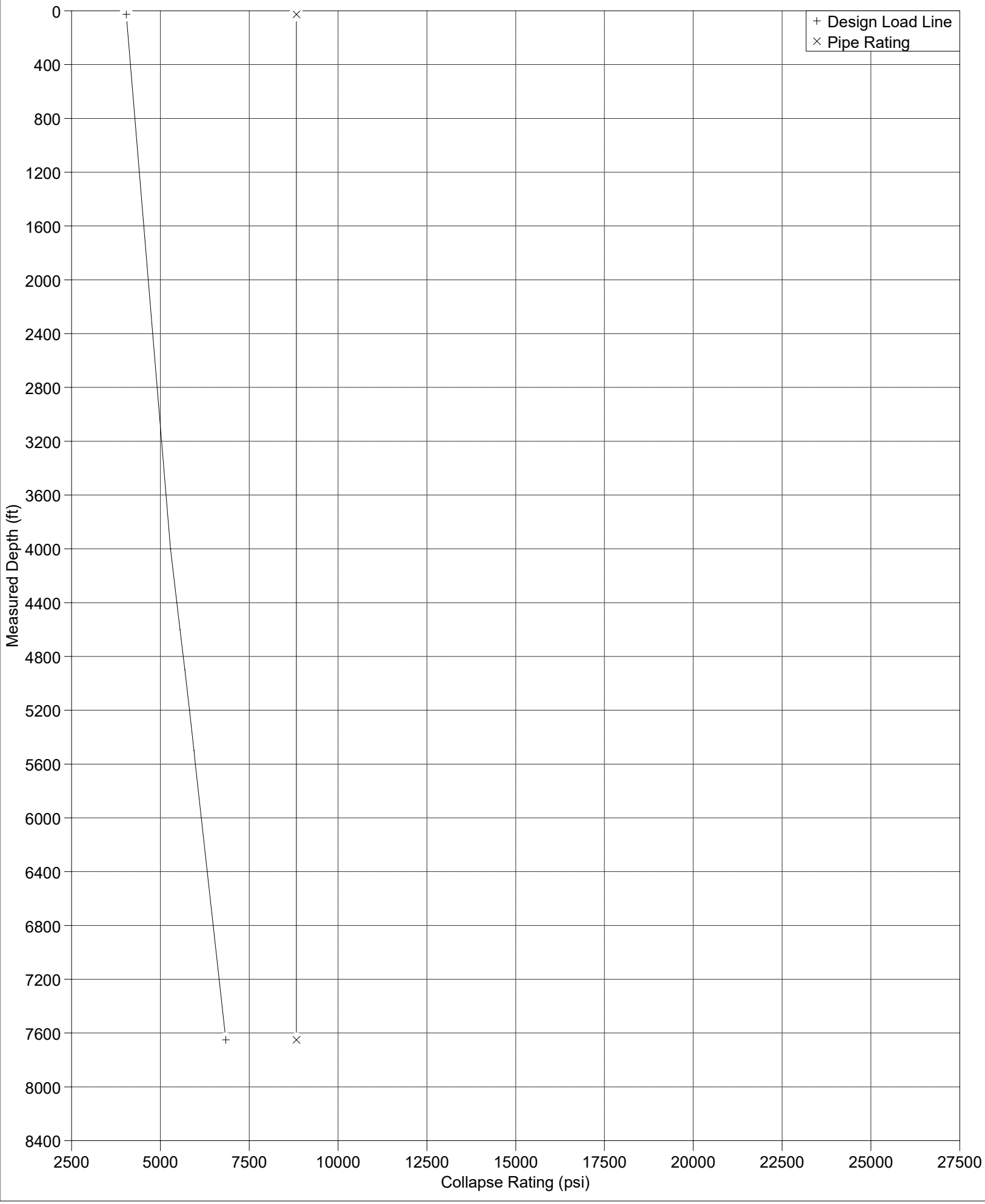
AXIAL LOADS TABLE (5 1/2" Production Tubing)

	Depth (MD) (ft)	Overpull Force (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	226249	226249	213195	213195
2	3999.99	162170	162170	133715	133715
3	4000.01	162170	162170	144197	133715
4	4599.99	151951	151951	132246	121764
5	4600.01	151950	151950	132246	121764
6	4899.99	146841	146841	126363	115881
7	4900.01	146840	146840	126363	115881
8	5199.99	141731	141731	120590	110108
9	5200.01	141730	141730	120589	110107
10	5499.99	136621	136621	114962	104480
11	5500.01	136621	136621	114962	104480
12	5600.00	134917	134917	102640	102640
13	6715.61	115915	115915	82154	82154
14	7648.00	100034	100034	-103825	65032
15	7648.00	100034	100034	-103825	-103825

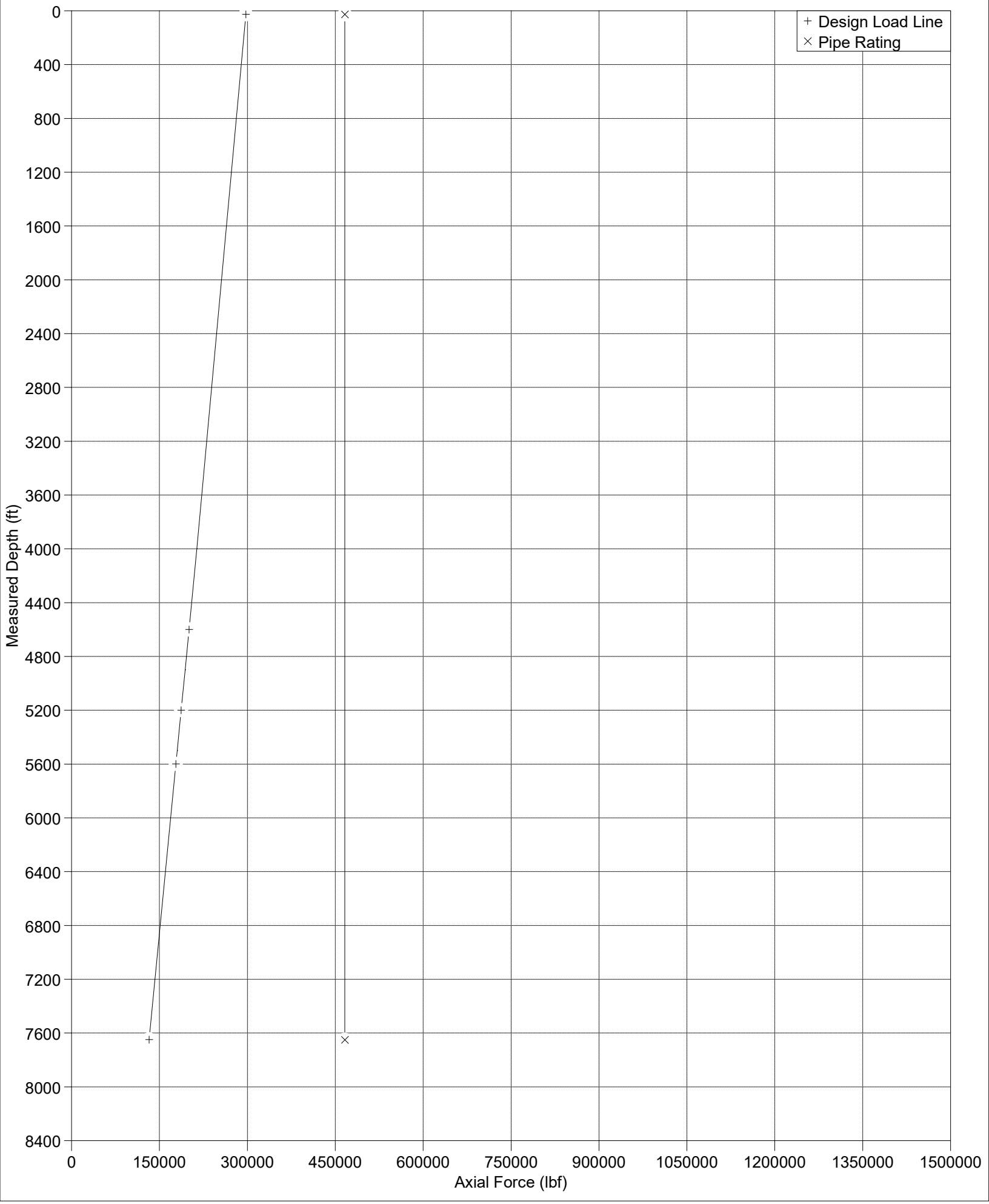
BURST DESIGN (5 1/2" Production Tubing)

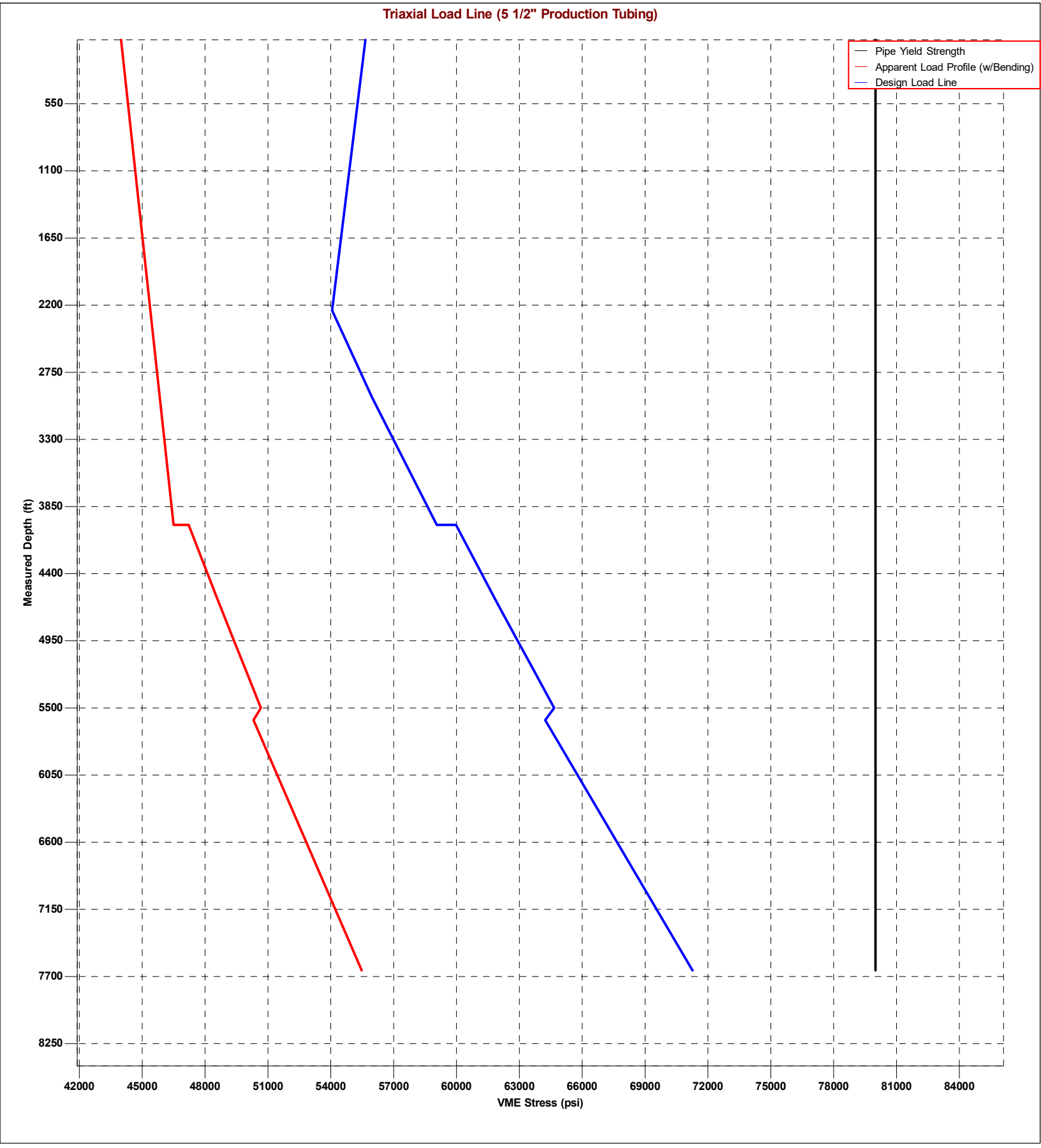


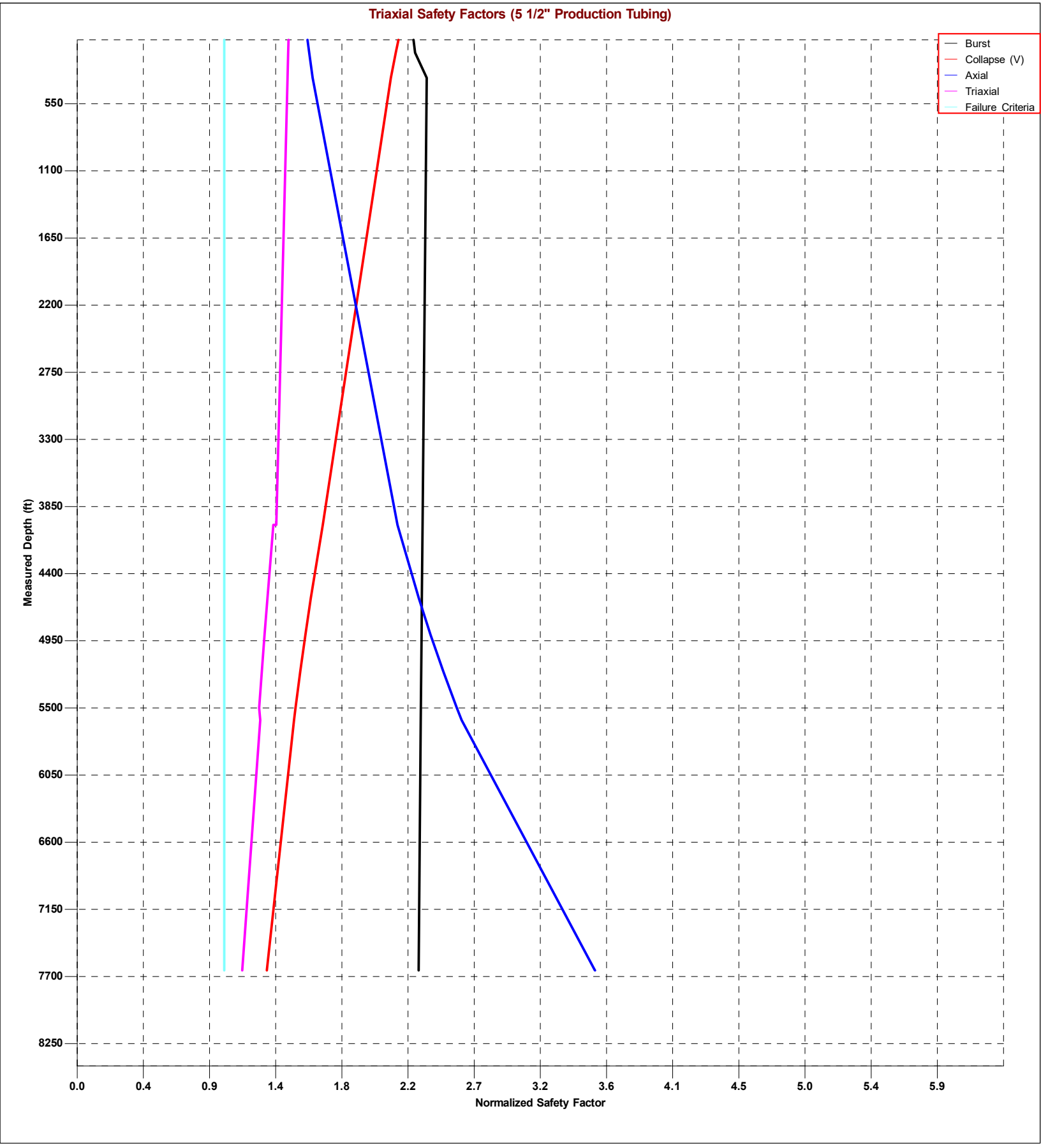
COLLAPSE DESIGN (5 1/2" Production Tubing)



AXIAL DESIGN (5 1/2" Production Tubing)




Triaxial Load Line (5 1/2" Production Tubing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
550
1100
1650
2200
2750
3300
3850
4400
4950
5500
6050
6600
7150
7700
8250
42000
45000
48000
51000
54000
57000
60000
63000
66000
69000
72000
75000
78000
81000
84000
VME Stress (psi)


Triaxial Safety Factors (5 1/2" Production Tubing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
550
1100
1650
2200
2750
3300
3850
4400
4950
5500
6050
6600
7150
7700
8250
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	5 1/2", 20.000 ppf, L-80	Blue	2.52 B15	2.18 C19	2.04 A4	1.80 A4
2	132			2.53 B15	2.17 C19	2.05 A4	1.79 A4
3	338			2.61 B5	2.13 C19	2.08 A4	1.79 A4
4	4000			2.58 B5	1.67 C19	2.83 A4	1.69 C19
5	4000			2.58 B5	1.67 C19	2.83 A4	1.67 C19
6	4600			2.58 B5	1.59 C19	3.02 A4	1.62 C19
7	4900			2.58 B5	1.55 C19	3.12 A4	1.59 C19
8	5200			2.57 B5	1.52 C19	3.24 A4	1.57 C19
9	5500			2.57 B5	1.49 C19	3.36 A4	1.55 C19
10	5600			2.57 B5	1.47 C19	3.40 A4	1.56 C19
11	7648			2.55 B5	1.29 C19	4.58 A4	1.40 C19
12	7649			2.55 B5	1.29 C19	4.58 A4	1.40 C19
13	7650			2.55 B5	1.29 C19	4.58 A4	1.40 C19
14							
15	B5	Pressure Test					
16	B15	Shut-In					
17	C19	Annular Pressure Test					
18	A4	Overpull Force					
19	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	5 1/2", 20.000 ppf, L-80	0.158 B15	0.245 C19	0.216 A4	56.3	32.2	40.3	0.203	0.116	0.145
2	131.96		0.156 B15	0.246 C19	0.214 A4	56.8	31.9	40.7	0.205	0.115	0.147
3	337.55		0.152 B5	0.248 C19	0.211 A4	57.9	31.4	41.5	0.209	0.113	0.150
4	3999.99		0.154 B5	0.281 C19	0.229 C19	57.4	22.1	36.5	0.207	0.080	0.132
5	4000.01		0.154 B5	0.281 C19	0.232 C19	57.4	22.1	35.7	0.207	0.080	0.129
6	4599.99		0.154 B5	0.287 C19	0.240 C19	57.3	20.4	33.6	0.207	0.074	0.121
7	4600.01		0.154 B5	0.287 C19	0.240 C19	57.3	20.4	33.6	0.207	0.074	0.121
8	4899.99		0.154 B5	0.290 C19	0.244 C19	57.3	19.6	32.5	0.207	0.071	0.117
9	4900.01		0.154 B5	0.290 C19	0.244 C19	57.3	19.6	32.5	0.207	0.071	0.117
10	5199.99		0.154 B5	0.293 C19	0.248 C19	57.3	18.8	31.4	0.207	0.068	0.113
11	5200.01		0.154 B5	0.293 C19	0.248 C19	57.3	18.8	31.4	0.207	0.068	0.113
12	5499.99		0.154 B5	0.296 C19	0.251 C19	57.2	18.0	30.3	0.207	0.065	0.110
13	5500.01		0.154 B5	0.296 C19	0.251 C19	57.2	18.0	30.3	0.207	0.065	0.110
14	5600.00		0.154 B5	0.297 C19	0.250 C19	57.2	17.8	30.7	0.207	0.064	0.111
15	7648.00		0.155 B5	0.316 C19	0.279 C19	56.9	12.4	22.6	0.206	0.045	0.082
16	7649.07		0.155 B5	0.316 C19	0.279 C19	56.9	12.4	22.6	0.206	0.045	0.082
17	7649.99		0.155 B5	0.316 C19	0.279 C19	56.9	12.4	22.6	0.206	0.045	0.082
18	7650.00		0.155 B5	0.316 C19	0.279 C19	56.9	12.4	22.6	0.206	0.045	0.082
19											
20	B5	Pressure Test									
21	B15	Shut-In									
22	C19	Annular Pressure Test									
23	A4	Overpull Force									
24	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (5 1/2" Production Tubing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	354408
2	26	353965
3	255	350065
4	510	345721
5	765	341378
6	1000	337375
7	1020	337034
8	1275	332691
9	1530	328348
10	1785	324004
11	2000	320342
12	2040	319661
13	2295	315317
14	2550	310974
15	2805	306631
16	3000	303309
17	3060	302287
18	3315	297944
19	3570	293600
20	3825	289257
21	4000	286277
22	4000	286276
23	4080	284914
24	4335	280578
25	4590	276267
26	4600	276099
27	4600	276098
28	4845	272001
29	4900	271088
30	5000	269437
31	5100	267798
32	5200	266172
33	5200	266171
34	5355	263678
35	5500	261379
36	5500	261378
37	5600	259812
38	5610	259656
39	5865	255668
40	6000	253556
41	6120	251680
42	6375	247692
43	6630	243704
44	6885	239716
45	7000	237917
46	7140	235728
47	7395	231740
48	7624	228159
49	7648	* 228256
50	7650	* 228264
51		
52	* Based on Casing Strength	
53	Only. Running String not	
54	Included	

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	163789	163789	164361	0.0	2.35	2.62	N/A	2.84	78	3513	13	0	0
2	4000	84309	84309	97729	0.0	2.75	2.58	N/A	5.44	121	5536	2036		
3	4000	94791	84309	108380	1798.5	2.72	2.58	N/A	4.84	121	5536	2036		
4	4600	82841	72359	98231	1798.5	2.76	2.58	N/A	5.53	127	5841	2341		
5	4600	82840	72358	98231	1798.5	2.76	2.58	N/A	5.53	127	5841	2341		
6	4900	76958	66475	93220	1798.5	2.77	2.58	N/A	5.94	130	5990	2490		
7	4900	76957	66475	93220	1798.5	2.77	2.58	N/A	5.95	130	5990	2490		
8	5200	71184	60702	88294	1798.5	2.78	2.57	N/A	6.42	133	6137	2637		
9	5200	71184	60702	88293	1798.5	2.78	2.57	N/A	6.42	133	6137	2637		
10	5500	65557	55075	83482	1798.5	2.79	2.57	N/A	6.97	136	6281	2781		
11	5500	65556	55074	83482	1798.5	2.79	2.57	N/A	6.97	136	6281	2781		
12	5600	53235	53235	71201	0.0	2.80	2.57	N/A	8.58	137	6327	2827		
13	7648	15627	15627	38730	0.0	2.72	2.55	N/A	29.03	158	7285	3785		
14	7650	15590	15590	38698	0.0	2.72	2.55	N/A	29.10	158	7286	3786		
15														
16	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Shut-In

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	93218	93218	96055	0.0	2.69	2.52	N/A	4.86	164	3560	13	19879	4092
2	4000	18600	13738	31370	834.3	5.19	4.85	N/A	24.35	164	3878	2036		
3	4000	29082	13737	42162	2632.8	5.06	4.85	N/A	15.57	164	3878	2036		
4	4600	14911	1787	29397	2251.8	5.69	5.63	N/A	30.37	164	3926	2341		
5	4600	12269	1787	26677	1798.5	5.75	5.63	N/A	36.91	164	3926	2341		
6	4691	-10493	-11	3516	1798.5	5.85	5.77	N/A	(43.16)	164	3933	2386		
7	4900	-14979	-4096	-478	1867.2	6.07	6.12	N/A	(30.23)	164	3950	2490		
8	4900	-14579	-4097	-66	1798.5	6.08	6.12	N/A	(31.06)	164	3950	2490		
9	5200	-21209	-9869	-6012	1945.7	6.38	6.68	N/A	(21.35)	164	3973	2637		
10	5200	-20352	-9870	-5129	1798.5	6.42	6.68	N/A	(22.25)	164	3973	2637		
11	5500	-27199	-15497	-11318	2007.7	6.68	7.35	N/A	(16.65)	164	3995	2781		
12	5500	-26563	-15497	-10664	1898.7	6.71	7.35	N/A	(17.05)	164	3995	2781		
13	5600	-18159	-17337	-1731	141.1	7.32	7.59	N/A	(24.94)	164	4003	2827		
14	7648	-70959	-54945	-50349	2747.8	6.93	24.21	N/A	(6.38)	164	4153	3785		
15	7650	-71007	-54981	-50392	2749.6	6.92	24.27	N/A	(6.38)	164	4153	3786		
16	7650	-71915	-54982	-51327	2905.4	6.83	24.27	N/A	(6.30)	164	4153	3786		
17														
18	( )	Compression												
19	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Injection

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	213195	213195	213916	0.0	1.99	2.62	N/A	2.18	78	3514	13	0	0
2	4000	133715	133715	146023	0.0	2.48	2.59	N/A	3.48	78	5578	2036		
3	4000	144197	133715	156536	1798.5	2.42	2.59	N/A	3.22	78	5578	2036		
4	4600	132246	121764	146328	1798.5	2.49	2.58	N/A	3.52	78	5888	2341		
5	4900	126363	115881	141302	1798.5	2.53	2.58	N/A	3.68	78	6041	2490		
6	5200	120590	110108	136371	1798.5	2.56	2.58	N/A	3.85	78	6191	2637		
7	5200	120589	110107	136370	1798.5	2.56	2.58	N/A	3.85	78	6191	2637		
8	5500	114962	104480	131564	1798.5	2.59	2.58	N/A	4.04	78	6337	2781		
9	5500	114962	104480	131563	1798.5	2.59	2.58	N/A	4.04	78	6337	2781		
10	5600	102640	102640	119478	0.0	2.65	2.58	N/A	4.53	78	6385	2827		
11	7648	65032	65032	87353	0.0	2.77	2.56	N/A	7.15	78	7362	3785		
12	7650	64996	64996	87322	0.0	2.77	2.56	N/A	7.15	78	7363	3786		
13														
14	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Full/Partial Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	105344	105344	105662	0.0	3.88	N/A	4.41	4.41	78	0	13	0	0
2	4000	25864	25864	26294	0.0	3.62	N/A	3.87	17.74	121	2	2036		
3	4000	36346	25864	36945	1798.5	3.45	N/A	3.87	12.62	121	2	2036		
4	4600	24395	13913	24852	1798.5	3.27	N/A	3.56	18.77	127	2	2341		
5	4900	18512	8030	18882	1798.5	3.18	N/A	3.42	24.71	130	3	2490		
6	4900	18512	8030	18881	1798.5	3.18	N/A	3.42	24.71	130	3	2490		
7	5200	12739	2257	13012	1798.5	3.09	N/A	3.28	35.88	133	3	2637		
8	5200	12739	2256	13011	1798.5	3.09	N/A	3.28	35.88	133	3	2637		
9	5320	-10501	-19	-10699	1798.5	3.05	N/A	3.23	(43.51)	135	3	2695		
10	5320	-10502	-20	-10700	1798.5	3.05	N/A	3.23	(43.51)	135	3	2695		
11	5500	-13853	-3371	-14127	1798.5	3.00	N/A	3.13	(32.96)	136	3	2781		
12	5600	-5211	-5211	-5304	0.0	3.06	N/A	3.08	(87.61)	137	3	2827		
13	7648	-42819	-42819	-43982	0.0	2.46	N/A	2.29	(10.60)	158	4	3785		
14	7650	-42855	-42855	-44019	0.0	2.46	N/A	2.29	(10.59)	158	4	3786		
15	7650	-42855	-42855	-44020	0.0	2.46	N/A	2.29	(10.59)	158	4	3786		
16														
17	( )	Compression												
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Leak (Collapse)

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	44337	44337	63242	0.0	6.73	N/A	7.37	10.21	164	2932	2932	0	0
2	2243	0	0	18658	0.0	7.27	N/A	7.73	+ 100.00	164	3109	4060		
3	2243	-0	-0	18658	0.0	7.27	N/A	7.73	(+ 100.00)	164	3109	4060		
4	4000	-35142	-35142	-16680	0.0	5.43	N/A	5.07	(12.89)	164	3250	4955		
5	4000	-45625	-35143	-27473	1798.5	5.23	N/A	5.07	(9.93)	164	3250	4955		
6	4600	-57575	-47093	-39490	1798.5	4.74	N/A	4.41	(7.87)	164	3298	5259		
7	4600	-57576	-47094	-39490	1798.5	4.74	N/A	4.41	(7.87)	164	3298	5259		
8	4900	-63458	-52976	-45405	1798.5	4.51	N/A	4.14	(7.14)	164	3321	5409		
9	4900	-63459	-52977	-45406	1798.5	4.51	N/A	4.14	(7.14)	164	3321	5409		
10	5200	-69232	-58750	-51211	1798.5	4.30	N/A	3.91	(6.54)	164	3345	5556		
11	5500	-74859	-64377	-56870	1798.5	4.10	N/A	3.70	(6.05)	164	3367	5699		
12	5500	-74860	-64378	-56870	1798.5	4.10	N/A	3.70	(6.05)	164	3367	5699		
13	5600	-66217	-66217	-47928	0.0	4.08	N/A	3.64	(6.84)	164	3374	5746		
14	7648	-103825	-103825	-85745	0.0	3.05	N/A	2.72	(4.36)	164	3525	6703		
15	7650	-103862	-103862	-85782	0.0	3.05	N/A	2.72	(4.36)	164	3525	6704		
16														
17	( )	Compression												
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Annular Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	58615	58615	58804	0.0	2.03	N/A	2.18	7.93	78	2	3513	0	0
2	2957	0	0	1360	0.0	1.79	N/A	1.83	+ 100.00	110	230	5005		
3	2957	-0	-0	1360	0.0	1.79	N/A	1.83	(+ 100.00)	110	230	5005		
4	4000	-20865	-20865	-19355	0.0	1.69	N/A	1.67	(21.99)	121	312	5536		
5	4000	-31347	-20865	-30007	1798.5	1.67	N/A	1.67	(14.64)	121	312	5536		
6	4600	-43297	-32815	-41957	1798.5	1.62	N/A	1.59	(10.58)	127	358	5841		
7	4600	-43298	-32816	-41957	1798.5	1.62	N/A	1.59	(10.58)	127	358	5841		
8	4900	-49181	-38699	-47857	1798.5	1.59	N/A	1.55	(9.30)	130	381	5990		
9	5200	-54954	-44472	-53658	1798.5	1.57	N/A	1.52	(8.32)	133	404	6137		
10	5500	-60582	-50100	-59323	1798.5	1.55	N/A	1.49	(7.54)	136	426	6281		
11	5500	-60582	-50100	-59324	1798.5	1.55	N/A	1.49	(7.54)	136	426	6281		
12	5600	-51939	-51939	-50472	0.0	1.56	N/A	1.47	(8.79)	137	433	6327		
13	7648	-89547	-89547	-88561	0.0	1.40	N/A	1.29	(5.07)	158	579	7285		
14	7650	-89584	-89584	-88599	0.0	1.40	N/A	1.29	(5.06)	158	579	7286		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	226249	226249	229047	0.0	1.80	N/A	N/A	2.04	107	13	13	N/A	N/A
2	4000	162170	162170	176724	0.0	2.35	N/A	N/A	2.83	118	2036	2036		
3	4000	162170	162170	176724	1798.5	2.35	N/A	N/A	2.83	118	2036	2036		
4	4600	151951	151951	168232	1798.5	2.47	N/A	N/A	3.02	120	2341	2341		
5	4600	151950	151950	168232	1798.5	2.47	N/A	N/A	3.02	120	2341	2341		
6	4900	146841	146841	163968	1798.5	2.54	N/A	N/A	3.12	121	2490	2490		
7	4900	146840	146840	163968	1798.5	2.54	N/A	N/A	3.12	121	2490	2490		
8	5200	141731	141731	159685	1798.5	2.61	N/A	N/A	3.24	122	2637	2637		
9	5200	141730	141730	159685	1798.5	2.61	N/A	N/A	3.24	122	2637	2637		
10	5500	136621	136621	155377	1798.5	2.68	N/A	N/A	3.36	123	2781	2781		
11	5600	134917	134917	153935	0.0	2.71	N/A	N/A	3.40	123	2827	2827		
12	7648	100034	100034	124338	0.0	3.38	N/A	N/A	4.58	128	3785	3785		
13	7649	100016	100016	124322	0.0	3.38	N/A	N/A	4.58	128	3785	3785		
14	7650	100000	100000	124309	0.0	3.38	N/A	N/A	4.58	128	3786	3786		
15														
16	(V)	Vector Collapse Safety Factor												

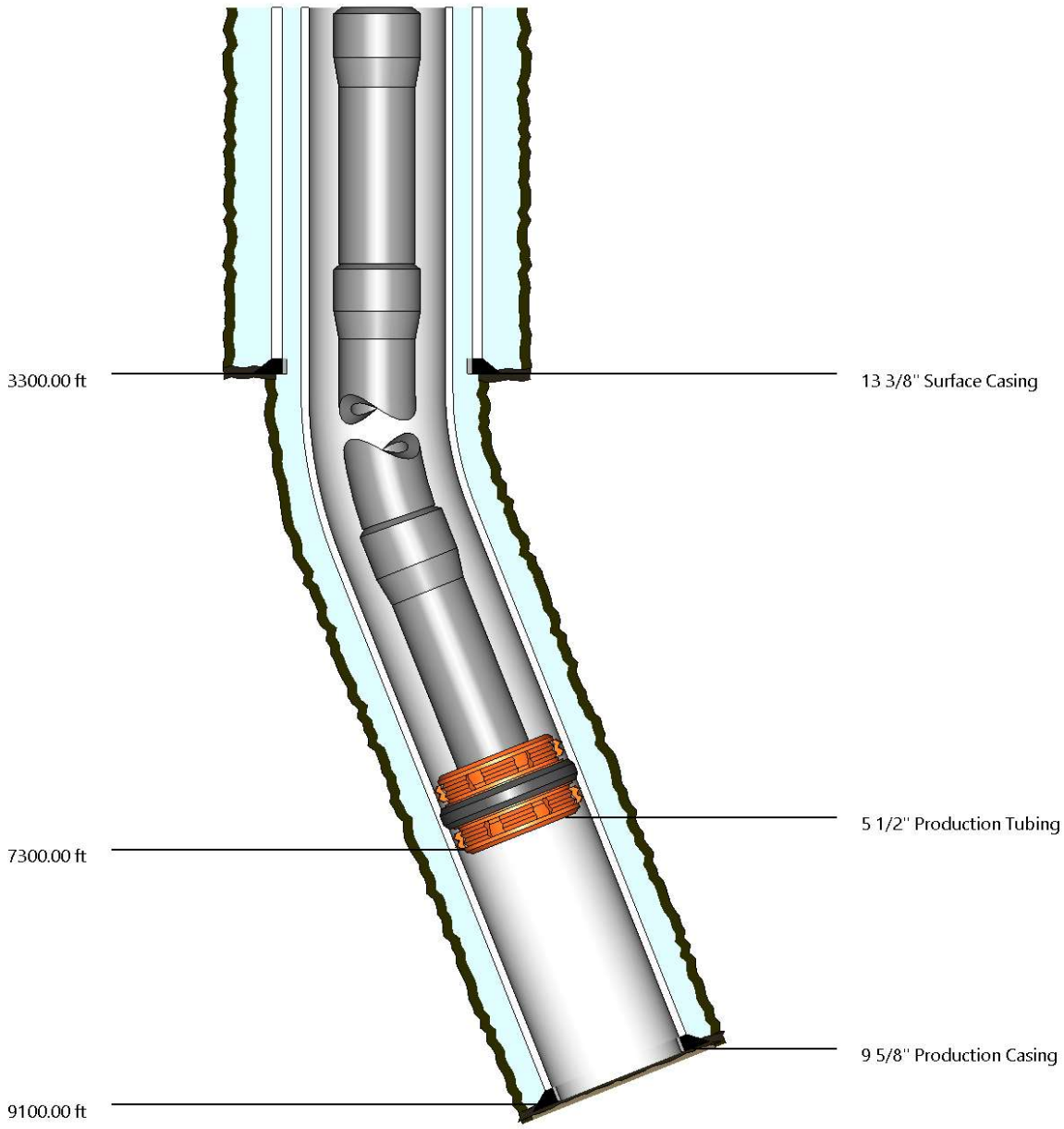
GENERAL DATA

Description:	Bluebonnet CCS 3
Well Options, Deviated:	Yes
Well Options, Offshore:	No
Well TD (MD):	9100.00 ft
Reference Point:	OTR
Air Gap:	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	148.83 °

WELL SUMMARY

	String	OD/Weight/Grade	Connection	MD Interval (ft)	Drift Dia. (in)	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V	Axial	Triaxial	
1	Surface Casing	13 3/8", 61.000 ppf, K-55	BTC, K-55	26.00-3300.00	12.359	1.18	1.08	2.53	1.32	91,889
2										Total = 91,889
3										
4	Production Casing	9 5/8", 53.500 ppf, L-80	blue	26.00-3800.00	8.500 A	2.06	2.63	2.56	2.06	117,567
5		9 5/8", 53.500 ppf, L-80	blue	3800.00-9100.00	8.500 A	1.90	1.14	3.56	1.47	165,104
6										Total = 282,671
7										
8	Production Tubing	5 1/2", 20.000 ppf, L-80	blue	26.00-7300.00	4.653	2.56	1.32	2.09	1.44	90,615
9										Total = 90,615
10										
11										Total = 465,175
12	A Alternate Drift									
13	(V) Vector Collapse Safety Factor									

WELL SCHEMATIC (DEPTH - MD)



CASING AND TUBING SCHEME

	OD (in)	Name	Type	Hole Size (in)	Measured Depths (ft)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	13 3/8"	Surface	Casing	17.500	26.00	3300.00	26.00	10.00
2	9 5/8"	Production	Casing	12.250	26.00	9100.00	26.00	12.50
3	5 1/2"	Production	Tubing		26.00	7300.00		9.80

PRODUCTION DATA

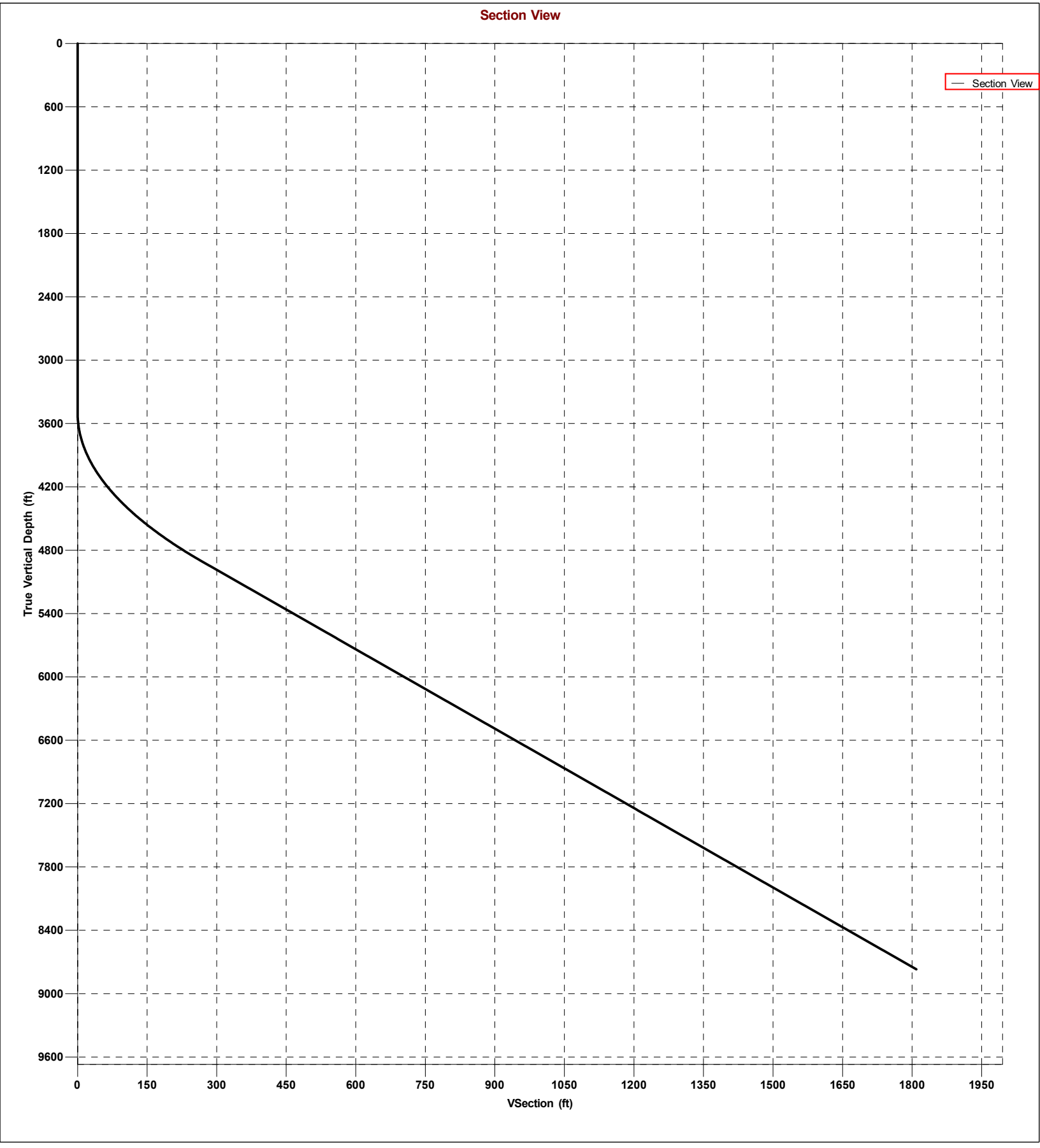
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7300.00 ft
Perforation Depth, MD:	8418.00 ft
Gas Gravity:	0.70

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.00	0.00			0.00	0.00
2	MD-INC-AZ	100.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00
3	MD-INC-AZ	200.00	0.00	0.00	200.00	0.00	0.00	0.00	0.00
4	MD-INC-AZ	300.00	0.00	0.00	300.00	0.00	0.00	0.00	0.00
5	MD-INC-AZ	400.00	0.00	0.00	400.00	0.00	0.00	0.00	0.00
6	MD-INC-AZ	500.00	0.00	0.00	500.00	0.00	0.00	0.00	0.00
7	MD-INC-AZ	600.00	0.00	0.00	600.00	0.00	0.00	0.00	0.00
8	MD-INC-AZ	700.00	0.00	0.00	700.00	0.00	0.00	0.00	0.00
9	MD-INC-AZ	800.00	0.00	0.00	800.00	0.00	0.00	0.00	0.00
10	MD-INC-AZ	900.00	0.00	0.00	900.00	0.00	0.00	0.00	0.00
11	MD-INC-AZ	1000.00	0.00	0.00	1000.00	0.00	0.00	0.00	0.00
12	MD-INC-AZ	1100.00	0.00	0.00	1100.00	0.00	0.00	0.00	0.00
13	MD-INC-AZ	1200.00	0.00	0.00	1200.00	0.00	0.00	0.00	0.00
14	MD-INC-AZ	1300.00	0.00	0.00	1300.00	0.00	0.00	0.00	0.00
15	MD-INC-AZ	1400.00	0.00	0.00	1400.00	0.00	0.00	0.00	0.00
16	MD-INC-AZ	1500.00	0.00	0.00	1500.00	0.00	0.00	0.00	0.00
17	MD-INC-AZ	1600.00	0.00	0.00	1600.00	0.00	0.00	0.00	0.00
18	MD-INC-AZ	1700.00	0.00	0.00	1700.00	0.00	0.00	0.00	0.00
19	MD-INC-AZ	1800.00	0.00	0.00	1800.00	0.00	0.00	0.00	0.00
20	MD-INC-AZ	1900.00	0.00	0.00	1900.00	0.00	0.00	0.00	0.00
21	MD-INC-AZ	2000.00	0.00	0.00	2000.00	0.00	0.00	0.00	0.00
22	MD-INC-AZ	2100.00	0.00	0.00	2100.00	0.00	0.00	0.00	0.00
23	MD-INC-AZ	2200.00	0.00	0.00	2200.00	0.00	0.00	0.00	0.00
24	MD-INC-AZ	2300.00	0.00	0.00	2300.00	0.00	0.00	0.00	0.00
25	MD-INC-AZ	2400.00	0.00	0.00	2400.00	0.00	0.00	0.00	0.00
26	MD-INC-AZ	2500.00	0.00	0.00	2500.00	0.00	0.00	0.00	0.00
27	MD-INC-AZ	2600.00	0.00	0.00	2600.00	0.00	0.00	0.00	0.00
28	MD-INC-AZ	2700.00	0.00	0.00	2700.00	0.00	0.00	0.00	0.00
29	MD-INC-AZ	2800.00	0.00	0.00	2800.00	0.00	0.00	0.00	0.00
30	MD-INC-AZ	2900.00	0.00	0.00	2900.00	0.00	0.00	0.00	0.00
31	MD-INC-AZ	3000.00	0.00	0.00	3000.00	0.00	0.00	0.00	0.00
32	MD-INC-AZ	3100.00	0.00	0.00	3100.00	0.00	0.00	0.00	0.00
33	MD-INC-AZ	3200.00	0.00	0.00	3200.00	0.00	0.00	0.00	0.00
34	MD-INC-AZ	3300.00	0.00	0.00	3300.00	0.00	0.00	0.00	0.00
35	MD-INC-AZ	3400.00	0.00	0.00	3400.00	0.00	0.00	0.00	0.00
36	MD-INC-AZ	3500.00	0.00	0.00	3500.00	0.00	0.00	0.00	0.00
37	MD-INC-AZ	3600.00	1.50	148.83	3599.99	1.50	1.50	1.31	1.31
38	MD-INC-AZ	3700.00	3.00	148.83	3699.91	1.50	1.50	5.23	5.23
39	MD-INC-AZ	3800.00	4.50	148.83	3799.69	1.50	1.50	11.77	11.77
40	MD-INC-AZ	3900.00	6.00	148.83	3899.27	1.50	1.50	20.92	20.92
41	MD-INC-AZ	4000.00	7.50	148.83	3998.57	1.50	1.50	32.68	32.68
42	MD-INC-AZ	4100.00	9.00	148.83	4097.54	1.50	1.50	47.03	47.03
43	MD-INC-AZ	4200.00	10.50	148.83	4196.09	1.50	1.50	63.96	63.96
44	MD-INC-AZ	4300.00	12.00	148.83	4294.16	1.50	1.50	83.47	83.47
45	MD-INC-AZ	4400.00	13.50	148.83	4391.70	1.50	1.50	105.54	105.54
46	MD-INC-AZ	4500.00	15.00	148.83	4488.62	1.50	1.50	130.15	130.15
47	MD-INC-AZ	4600.00	16.50	148.83	4584.86	1.50	1.50	157.30	157.30
48	MD-INC-AZ	4700.00	18.00	148.83	4680.36	1.50	1.50	186.95	186.95
49	MD-INC-AZ	4800.00	19.50	148.83	4775.05	1.50	1.50	219.09	219.09
50	MD-INC-AZ	4900.00	21.00	148.83	4868.86	1.50	1.50	253.70	253.70
51	MD-INC-AZ	4949.52	21.74	148.83	4914.98	1.50	1.50	271.75	271.75
52	MD-INC-AZ	5000.00	21.74	148.83	4961.87	0.00	0.00	290.45	290.45
53	MD-INC-AZ	5100.00	21.74	148.83	5054.75	0.00	0.00	327.49	327.49
54	MD-INC-AZ	5200.00	21.74	148.83	5147.64	0.00	0.00	364.54	364.54
55	MD-INC-AZ	5300.00	21.74	148.83	5240.52	0.00	0.00	401.58	401.58
56	MD-INC-AZ	5400.00	21.74	148.83	5333.41	0.00	0.00	438.63	438.63
57	MD-INC-AZ	5500.00	21.74	148.83	5426.30	0.00	0.00	475.67	475.67
58	MD-INC-AZ	5600.00	21.74	148.83	5519.18	0.00	0.00	512.71	512.71
59	MD-INC-AZ	5700.00	21.74	148.83	5612.07	0.00	0.00	549.76	549.76
60	MD-INC-AZ	5800.00	21.74	148.83	5704.95	0.00	0.00	586.80	586.80
61	MD-INC-AZ	5900.00	21.74	148.83	5797.84	0.00	0.00	623.85	623.85
62	MD-INC-AZ	6000.00	21.74	148.83	5890.72	0.00	0.00	660.89	660.89
63	MD-INC-AZ	6100.00	21.74	148.83	5983.61	0.00	0.00	697.93	697.93
64	MD-INC-AZ	6200.00	21.74	148.83	6076.50	0.00	0.00	734.98	734.98
65	MD-INC-AZ	6300.00	21.74	148.83	6169.38	0.00	0.00	772.02	772.02
66	MD-INC-AZ	6400.00	21.74	148.83	6262.27	0.00	0.00	809.07	809.07
67	MD-INC-AZ	6500.00	21.74	148.83	6355.15	0.00	0.00	846.11	846.11
68	MD-INC-AZ	6600.00	21.74	148.83	6448.04	0.00	0.00	883.15	883.15
69	MD-INC-AZ	6700.00	21.74	148.83	6540.92	0.00	0.00	920.20	920.20
70	MD-INC-AZ	6800.00	21.74	148.83	6633.81	0.00	0.00	957.24	957.24
71	MD-INC-AZ	6900.00	21.74	148.83	6726.70	0.00	0.00	994.29	994.29
72	MD-INC-AZ	7000.00	21.74	148.83	6819.58	0.00	0.00	1031.33	1031.33
73	MD-INC-AZ	7100.00	21.74	148.83	6912.47	0.00	0.00	1068.37	1068.37
74	MD-INC-AZ	7200.00	21.74	148.83	7005.35	0.00	0.00	1105.42	1105.42
75	MD-INC-AZ	7300.00	21.74	148.83	7098.24	0.00	0.00	1142.46	1142.46
76	MD-INC-AZ	7400.00	21.74	148.83	7191.12	0.00	0.00	1179.51	1179.51
77	MD-INC-AZ	7500.00	21.74	148.83	7284.01	0.00	0.00	1216.55	1216.55

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
78	MD-INC-AZ	7600.00	21.74	148.83	7376.89	0.00	0.00	1253.59	1253.59
79	MD-INC-AZ	7661.48	21.74	148.83	7434.00	0.00	0.00	1276.37	1276.37
80	MD-INC-AZ	7700.00	21.74	148.83	7469.78	0.00	0.00	1290.64	1290.64
81	MD-INC-AZ	7800.00	21.74	148.83	7562.67	0.00	0.00	1327.68	1327.68
82	MD-INC-AZ	7900.00	21.74	148.83	7655.55	0.00	0.00	1364.72	1364.72
83	MD-INC-AZ	8000.00	21.74	148.83	7748.44	0.00	0.00	1401.77	1401.77
84	MD-INC-AZ	8100.00	21.74	148.83	7841.32	0.00	0.00	1438.81	1438.81
85	MD-INC-AZ	8200.00	21.74	148.83	7934.21	0.00	0.00	1475.86	1475.86
86	MD-INC-AZ	8300.00	21.74	148.83	8027.09	0.00	0.00	1512.90	1512.90
87	MD-INC-AZ	8400.00	21.74	148.83	8119.98	0.00	0.00	1549.94	1549.94
88	MD-INC-AZ	8500.00	21.74	148.83	8212.87	0.00	0.00	1586.99	1586.99
89	MD-INC-AZ	8600.00	21.74	148.83	8305.75	0.00	0.00	1624.03	1624.03
90	MD-INC-AZ	8700.00	21.74	148.83	8398.64	0.00	0.00	1661.08	1661.08
91	MD-INC-AZ	8800.00	21.74	148.83	8491.52	0.00	0.00	1698.12	1698.12
92	MD-INC-AZ	8900.00	21.74	148.83	8584.41	0.00	0.00	1735.16	1735.16
93	MD-INC-AZ	9000.00	21.74	148.83	8677.29	0.00	0.00	1772.21	1772.21
94	MD-INC-AZ	9100.00	21.74	148.83	8770.18	0.00	0.00	1809.25	1809.25
95									

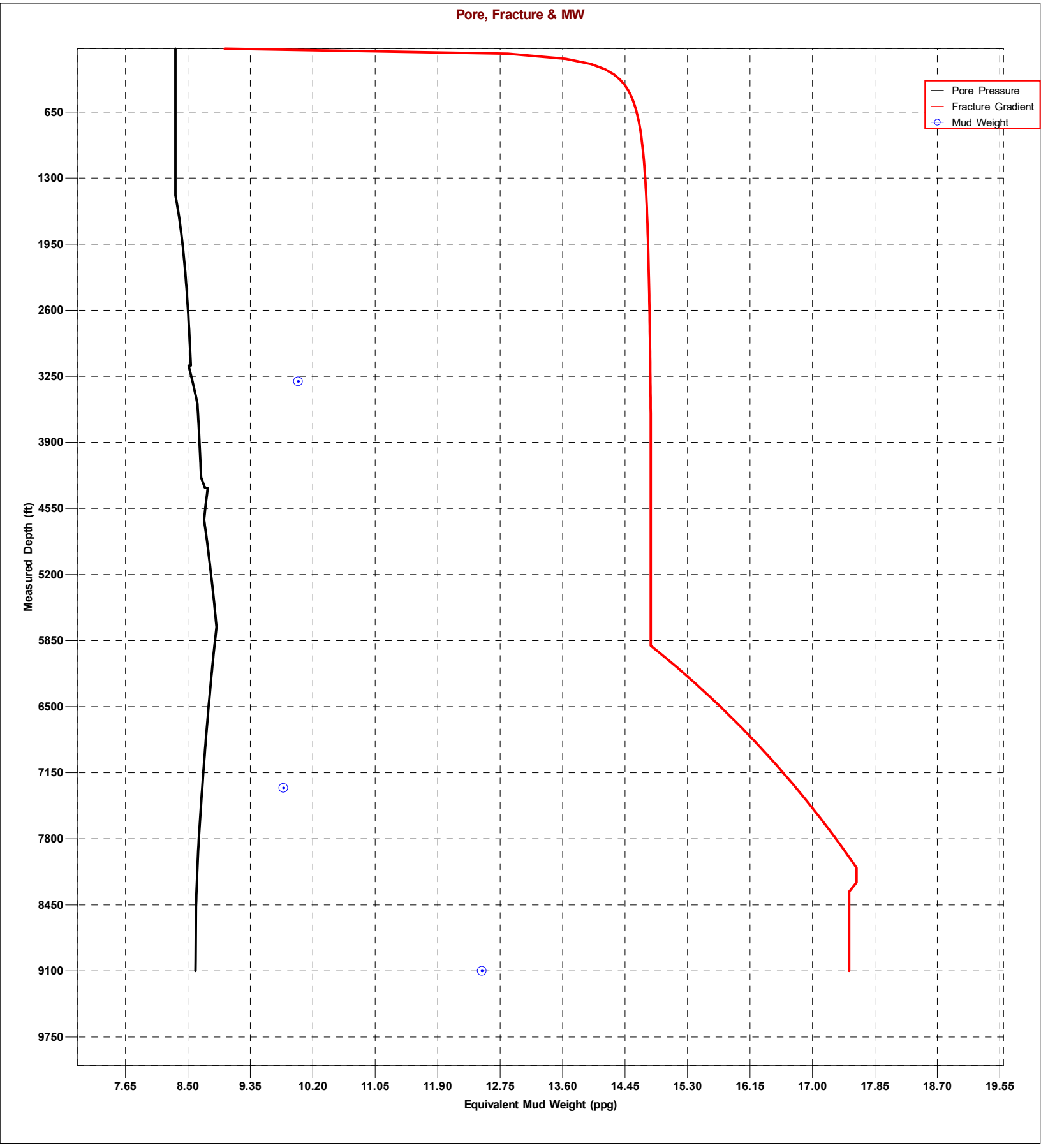

Section View
Section View
True Vertical Depth (ft)
0
600
1200
1800
2400
3000
3600
4200
4800
5400
6000
6600
7200
7800
8400
9000
9600
0
150
300
450
600
750
900
1050
1200
1350
1500
1650
1800
1950
VSection (ft)

PORE PRESSURE

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	11	8.33	No
2	1470.00	636	8.33	No
3	3144.00	1395	8.54	No
4	3146.00	1391	8.51	No
5	3521.00	1579	8.63	No
6	4240.00	1912	8.68	No
7	4337.00	1967	8.73	No
8	4344.00	1979	8.77	No
9	4643.00	2103	8.72	No
10	5626.00	2598	8.89	No
11	7666.00	3441	8.64	No
12	8182.00	3660	8.61	No
13	9260.00	4137	8.60	No

FRACTURE GRADIENT

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	12	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9260.00	8418	17.50


Pore, Fracture & MW
Pore Pressure
Fracture Gradient
Mud Weight
Measured Depth (ft)
650
1300
1950
2600
3250
3900
4550
5200
5850
6500
7150
7800
8450
9100
9750
7.65
8.50
9.35
10.20
11.05
11.90
12.75
13.60
14.45
15.30
16.15
17.00
17.85
18.70
19.55
Equivalent Mud Weight (ppg)

GEOTHERMAL GRADIENT DATA

Surface Ambient:	78 °F
Bottomhole Temperature - 8770.18 ft TVD:	172 °F
Bottomhole Gradient - 8770.18 ft TVD:	1.08 °F/100ft

DESIGN PARAMETERS DATA (13 3/8" Surface Casing)

Design Factor (Pipe) - Axial Tension:	1.400
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.400
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	12.250 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (13 3/8" Surface Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3300.00 ft	113 °F

BURST LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 3300.00 ft):	2536 psi
Mud/Water Interface, MD:	3300.00 ft
Mud Weight	7.82 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	9100.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	1.00 ppg
Maximum Mud Weight:	12.50 ppg
Kick Gas Gravity:	0.70 (0.1271 psi/ft @ 139 °F & 6151 psi)
Fracture at Shoe (MD= 3300.00 ft):	2536 psi
Drill Pipe OD:	5.500 in
Collar OD:	8.000 in
Collar Length:	300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	1500 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Fracture @ Shoe w/ Gas Gradient Above**
Gas Gradient:	0.1000 psi/ft
Shoe Depth, MD :	3300.00 ft
Fracture Pressure at Shoe:	2536 psi
Fracture Margin of Error:	0.00 ppg
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2600 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	9100.00 ft
Pore Pressure at Lost Returns Depth:	3920 psi
Pore Pressure Gradient at Lost Returns Depth:	8.60 ppg
Mud Weight:	12.50 ppg
Mud Drop Level, MD:	2733.32 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (13 3/8" Surface Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	2600 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Lost Returns (psi)	Gas Kick (psi)	Pressure Test (psi)	Fracture @ Shoe w/ Gas Gradient Above (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	1120	1289	1514	2209	2611	14	11
2	1470.00	1744	2027	2264	2353	3236	951	636
3	2600.00	2233	2604	2851	2466	3725	1685	1148
4	3144.00	2469	2882	3133	2521	3960	2131	1395
5	3146.00	2470	2883	3134	2521	3961	2133	1391
6	3300.00	2536	2961	3214	2536	4028	2259	1468

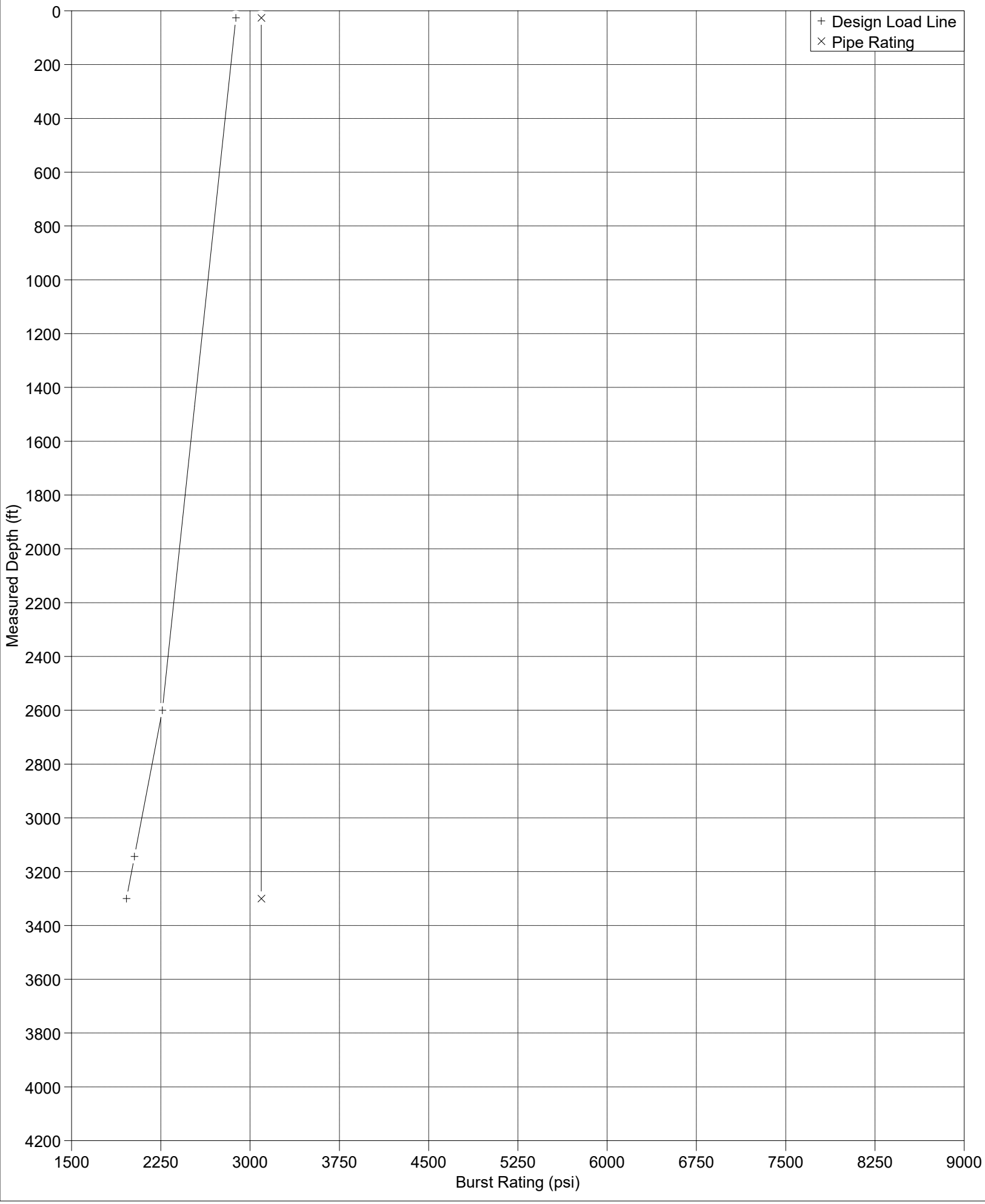
COLLAPSE PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Lost Returns (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	14	0	14
2	2600.00	1125	1685	0	1351
3	2733.32	1183	1794	0	1420
4	3300.00	1428	2259	368	1714

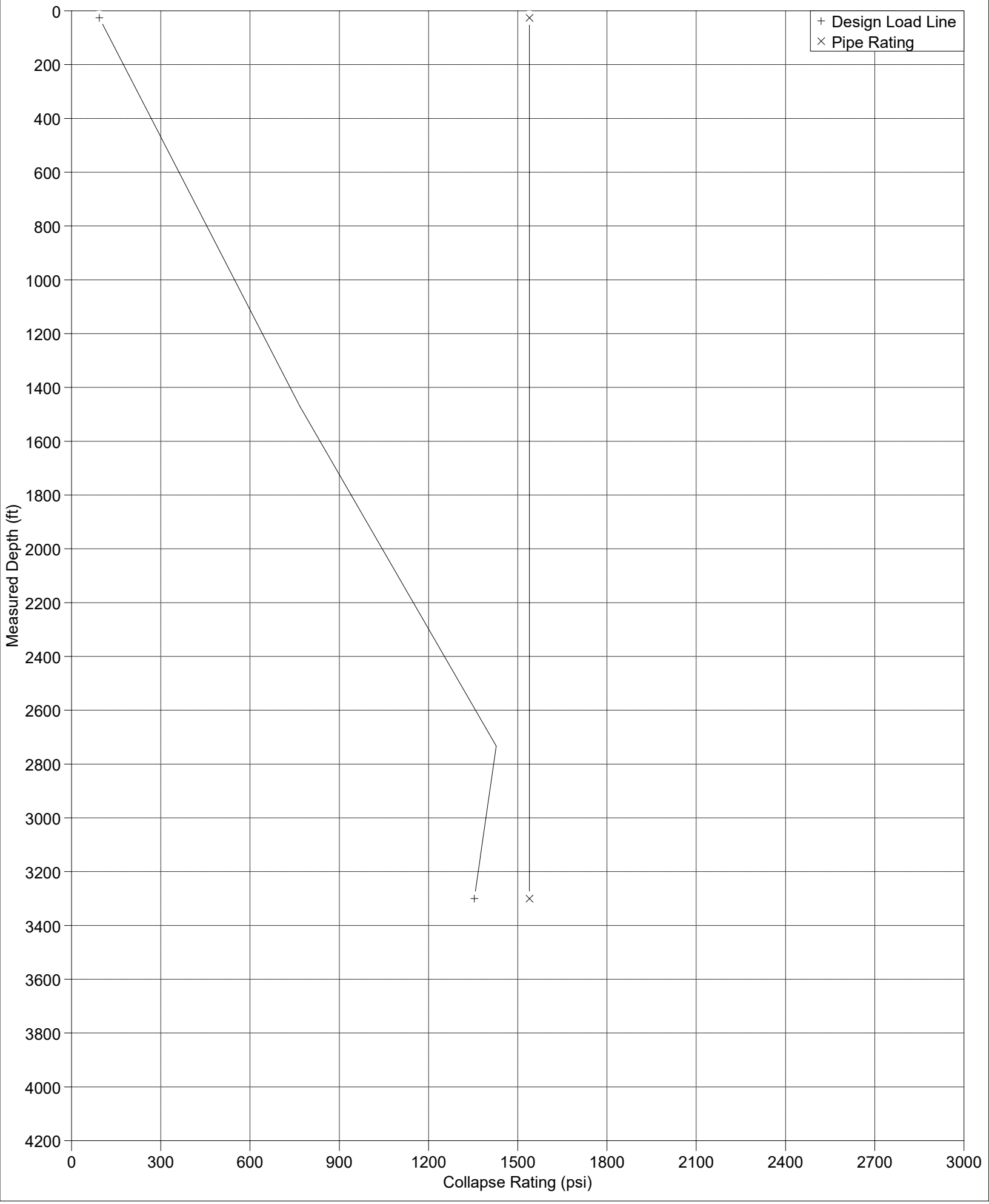
AXIAL LOADS TABLE (13 3/8" Surface Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	269972	269972	377753	377753	377753	377753
2	931.05	222986	222986	322545	322545	322545	322545
3	1470.00	195006	195006	289669	289669	289669	289669
4	2600.00	136341	136341	220739	220739	220739	220739
5	2733.32	129420	129420	212607	212607	212607	212607
6	3144.00	108099	108099	187555	187555	187555	187555
7	3146.00	107995	107995	187433	187433	187433	187433

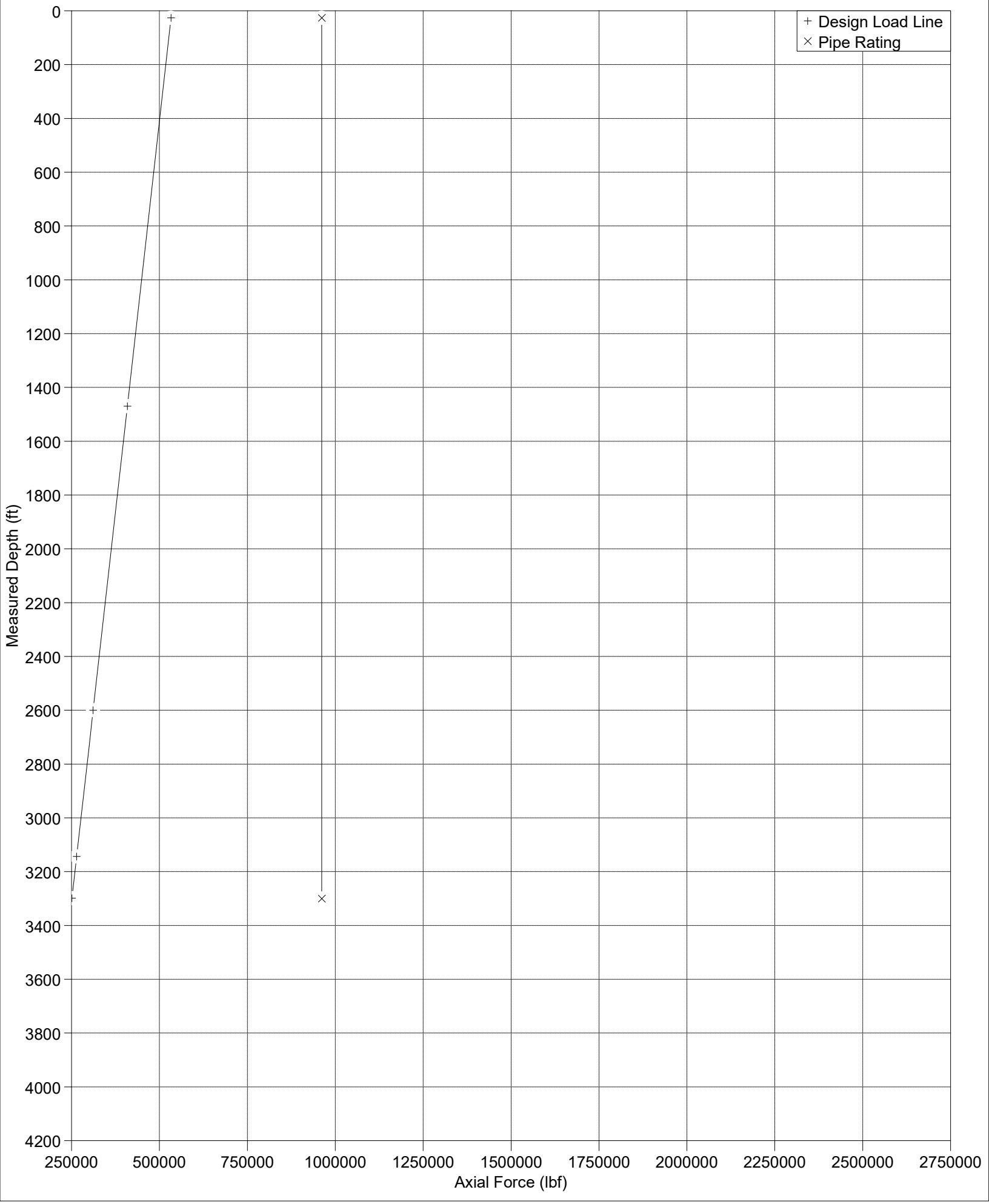
BURST DESIGN (13 3/8" Surface Casing)

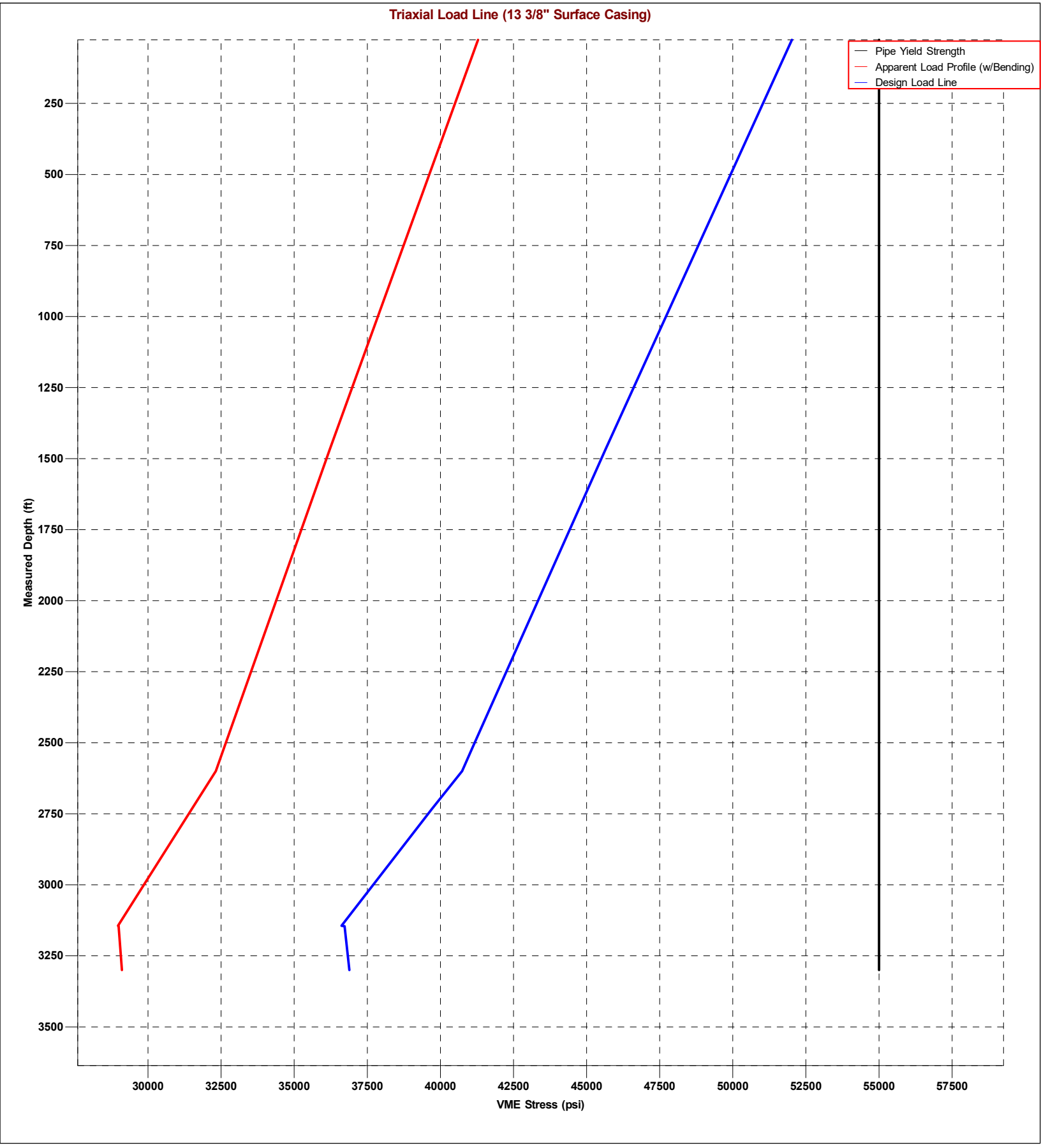


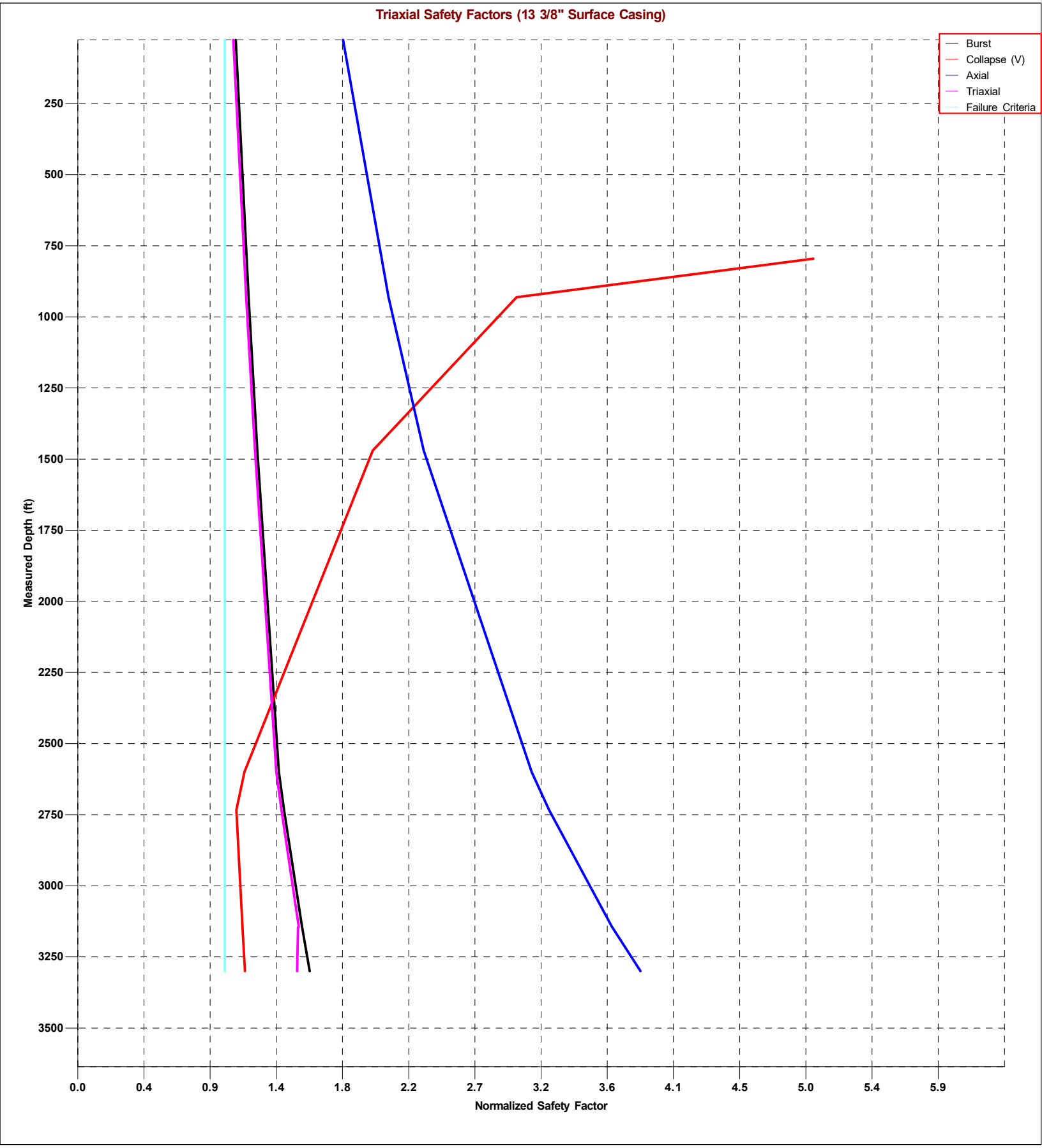
COLLAPSE DESIGN (13 3/8" Surface Casing)



AXIAL DESIGN (13 3/8" Surface Casing)




Triaxial Load Line (13 3/8" Surface Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
30000
32500
35000
37500
40000
42500
45000
47500
50000
52500
55000
57500
VME Stress (psi)


Triaxial Safety Factors (13 3/8" Surface Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	13 3/8", 61.000 ppf, K-55	BTC, K-55	1.18 B12	16.42 C2	2.53 B12	1.32 B12
2	931			1.28 B12	2.98 C4	2.96 B12	1.43 B12
3	1470			1.34 B12	2.01 C4	3.29 A5	1.51 B12
4	2600			1.50 B12	1.13 C4	4.32 A5	1.69 B12
5	2733			1.54 B12	1.08 C4	4.49 A5	1.73 B12
6	3144			1.68 B12	1.12 C4	5.08 A5	1.88 B5
7	3146			1.68 B12	1.12 C4	5.09 A5	1.87 B5
8	3299			1.73 B12	1.14 C4	5.35 A5	1.86 B5
9	3300			1.73 B12	1.14 C4	5.36 A5	1.86 B5
10							
11	B5	Pressure Test					
12	B12	Green Cement Pressure Test(Burst)					
13	C2	Cementing					
14	C4	Lost Returns with Mud Drop					
15	A5	Green Cement Pressure Test(Axial)					
16	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	13 3/8", 61.000 ppf, K-5	0.400 B12	0.088 C4	0.355 B12	6.9	79.6	17.4	0.030	0.342	0.075
2	931.05		0.370 B12	0.287 C4	0.327 B12	13.9	33.3	24.0	0.060	0.143	0.103
3	1470.00		0.352 B12	0.333 C4	0.311 B12	18.1	22.5	27.8	0.078	0.097	0.119
4	2600.00		0.315 B12	0.408 C4	0.277 B12	26.9	5.2	35.6	0.115	0.022	0.153
5	2733.32		0.307 B12	0.416 C4	0.270 B12	28.7	3.2	37.3	0.123	0.014	0.160
6	3144.00		0.282 B12	0.410 C4	0.251 B5	34.4	4.7	41.6	0.148	0.020	0.179
7	3146.00		0.282 B12	0.410 C4	0.252 B5	34.4	4.7	41.5	0.148	0.020	0.178
8	3299.20		0.273 B12	0.407 C4	0.253 B5	36.6	5.3	41.2	0.157	0.023	0.177
9	3300.00		0.273 B12	0.407 C4	0.253 B5	36.6	5.3	41.2	0.157	0.023	0.177
10											
11	B5	Pressure Test									
12	B12	Green Cement Pressure Test(Burst)									
13	C4	Lost Returns with Mud Drop									
14	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (13 3/8" Surface Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	681548
2	26	680199
3	26	680198
4	254	668370
5	508	655191
6	762	642012
7	1000	629632
8	1015	628834
9	1269	615655
10	1523	602477
11	1777	589298
12	2000	577717
13	2031	576119
14	2285	562941
15	2538	549762
16	2792	536583
17	3000	525801
18	3046	523405
19	3274	511576
20	3300	* 511809
21		
22	* Based on Casing Strength	
23	Only. Running String not	
24	Included	

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Gas Kick Profile

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	34085	34085	34728	0.0	2.49	2.39	N/A	27.86	111	1289	11	N/A	N/A
2	1470	19893	19893	31465	0.0	2.26	2.19	N/A	47.66	115	2027	636		
3	2600	6835	6835	27335	0.0	2.15	2.09	N/A	+ 100.00	119	2604	1148		
4	2733	7222	7222	28804	0.0	2.14	2.08	N/A	+ 100.00	119	2672	1209		
5	3144	8411	8411	33332	0.0	2.11	2.05	N/A	+ 100.00	121	2882	1395		
6	3146	8832	8832	33688	0.0	2.10	2.04	N/A	+ 100.00	121	2883	1391		
7	3300	8662	8662	34891	0.0	2.10	2.04	N/A	+ 100.00	121	2961	1468		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Water

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	139908	139908	140527	0.0	3.12	2.78	N/A	6.85	78	1120	11	N/A	N/A
2	1470	134384	134384	145947	0.0	3.12	2.78	N/A	7.14	78	1744	636		
3	2600	128110	128110	148637	0.0	3.19	2.84	N/A	7.48	78	2233	1148		
4	2733	129296	129296	150887	0.0	3.20	2.85	N/A	7.42	78	2291	1209		
5	3144	132951	132951	157817	0.0	3.21	2.87	N/A	7.21	78	2469	1395		
6	3146	133384	133384	158181	0.0	3.20	2.86	N/A	7.19	78	2470	1391		
7	3300	134139	134139	160290	0.0	3.23	2.89	N/A	7.15	78	2536	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	168988	168988	169695	0.0	2.30	2.05	N/A	5.67	78	1514	11	N/A	N/A
2	1470	116519	116519	128631	0.0	2.08	1.89	N/A	8.19	94	2264	636		
3	2600	73508	73508	94661	0.0	1.93	1.80	N/A	12.94	106	2851	1148		
4	2733	70360	70360	92586	0.0	1.92	1.79	N/A	13.51	107	2920	1209		
5	3144	60664	60664	86183	0.0	1.88	1.76	N/A	15.65	112	3133	1395		
6	3146	61031	61031	86485	0.0	1.87	1.75	N/A	15.55	112	3134	1391		
7	3300	56780	56780	83586	0.0	1.86	1.75	N/A	16.71	113	3214	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Fracture @ Shoe w/ Gas Gradient Above

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	101997	101997	103524	0.0	1.48	1.39	N/A	9.31	111	2209	11	N/A	N/A
2	1470	44013	44013	55935	0.0	1.86	1.78	N/A	21.54	115	2353	636		
3	2521	0	0	19755	0.0	2.31	2.26	N/A	+ 100.00	119	2458	1112		
4	2521	-0	-0	19754	0.0	2.31	2.26	N/A	(+ 100.00)	119	2458	1112		
5	2600	-3314	-3314	17027	0.0	2.35	2.31	N/A	(+ 100.00)	119	2466	1148		
6	2733	-6971	-6971	14388	0.0	2.43	2.40	N/A	(+ 100.00)	119	2480	1209		
7	3144	-18236	-18236	6254	0.0	2.71	2.70	N/A	(51.90)	121	2521	1395		
8	3146	-17876	-17876	6548	0.0	2.70	2.69	N/A	(52.95)	121	2521	1391		
9	3300	-22716	-22716	3001	0.0	2.84	2.85	N/A	(41.66)	121	2536	1468		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381014	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308843	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	2600	220739	220739	252337	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
4	2733	212607	212607	246072	0.0	1.73	1.54	N/A	4.49	96	3783	1794		
5	3144	187555	187555	226770	0.0	1.88	1.68	N/A	5.08	96	3960	2131		
6	3146	187433	187433	226676	0.0	1.88	1.68	N/A	5.09	96	3961	2133		
7	3299	178088	178088	219475	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219437	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Mud Drop

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-61230	-61230	-62026	0.0	14.04	N/A	+ 100.00	(15.51)	111	0	14	N/A	N/A
2	1470	-140430	-140430	-142461	0.0	4.41	N/A	2.01	(6.75)	115	0	764		
3	2600	-202408	-202408	-205566	0.0	2.53	N/A	1.13	(4.68)	119	0	1351		
4	2733	-207793	-207793	-211064	0.0	2.41	N/A	1.08	(4.56)	119	0	1420		
5	3144	-204700	-204700	-203268	0.0	2.50	N/A	1.12	(4.62)	121	267	1633		
6	3146	-204685	-204685	-203230	0.0	2.50	N/A	1.12	(4.62)	121	268	1634		
7	3300	-203526	-203526	-200306	0.0	2.54	N/A	1.14	(4.65)	121	368	1714		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	57919	57919	58581	0.0	14.35	N/A	16.42	16.47	94	11	14	N/A	N/A
2	975	43	43	7480	0.0	13.54	N/A	7.31	+ 100.00	95	422	630		
3	976	-6	-6	7437	0.0	13.53	N/A	7.30	(+ 100.00)	95	422	630		
4	1470	-30165	-30165	-19199	0.0	10.44	N/A	4.87	(31.62)	95	636	951		
5	2600	-99095	-99095	-80097	0.0	6.15	N/A	2.74	(9.62)	96	1125	1685		
6	2733	-107227	-107227	-87284	0.0	5.63	N/A	2.51	(8.89)	96	1183	1794		
7	3144	-132279	-132279	-109425	0.0	4.47	N/A	1.99	(7.21)	96	1360	2131		
8	3146	-132401	-132401	-109532	0.0	4.46	N/A	1.99	(7.20)	96	1361	2133		
9	3300	-141795	-141795	-117836	0.0	4.14	N/A	1.85	(6.72)	97	1428	2259		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	269972	269972	272370	0.0	3.10	N/A	N/A	3.53	94	14	14	N/A	N/A
2	1470	195006	195006	210088	0.0	4.05	N/A	N/A	4.89	95	764	764		
3	2600	136341	136341	161324	0.0	5.33	N/A	N/A	6.99	96	1351	1351		
4	2733	129420	129420	155569	0.0	5.54	N/A	N/A	7.37	96	1420	1420		
5	3144	108099	108099	137840	0.0	6.29	N/A	N/A	8.82	96	1633	1633		
6	3146	107995	107995	137754	0.0	6.29	N/A	N/A	8.83	96	1634	1634		
7	3299	100041	100041	131139	0.0	6.63	N/A	N/A	9.53	97	1714	1714		
8	3300	100000	100000	131105	0.0	6.63	N/A	N/A	9.54	97	1714	1714		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381014	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308843	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	2600	220739	220739	252337	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
4	2733	212607	212607	246072	0.0	1.73	1.54	N/A	4.49	96	3783	1794		
5	3144	187555	187555	226770	0.0	1.88	1.68	N/A	5.08	96	3960	2131		
6	3146	187433	187433	226676	0.0	1.88	1.68	N/A	5.09	96	3961	2133		
7	3299	178088	178088	219475	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219437	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (9 5/8" Production Casing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	7.970 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (9 5/8" Production Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5500.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3500.00 ft	115 °F
4097.53 ft	122 °F
4391.69 ft	125 °F
4680.36 ft	128 °F
4961.87 ft	131 °F
8677.29 ft	171 °F
8770.18 ft	172 °F
8770.18 ft	172 °F
8770.18 ft	172 °F

BURST LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Mud Weight:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7300.00 ft
Perforation Depth, MD:	8418.00 ft
Gas Gravity:	0.70 (0.0879 psi/ft @ 165 °F & 3640 psi)
Reservoir Pressure:	3640 psi
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Stimulation Surface Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7300.00 ft
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Injection Down Casing**
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	3500 psi
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5500.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	9100.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Mud Weight Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	5500.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	9100.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Full Evacuation**
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Fluid Gradient Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	12.50 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (9 5/8" Production Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	3500 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Pressure Test (psi)	Tubing Leak (psi)	Stimulation Leak (psi)	Casing Injection (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	3513	2981	3513	3513	3511	17	17
2	3299.99	5180	4648	5180	5180	4928	2143	1446
3	3300.01	5180	4648	5180	5180	4928	2143	1468
4	3499.99	5282	4749	5282	5282	5015	2273	1568
5	3500.01	5282	4749	5282	5282	5015	2273	1568
6	3521.00	5293	4760	5293	5293	5024	2286	1579
7	3600.00	5333	4800	5333	5333	5058	2338	1615
8	3799.99	5434	4902	5434	5434	5144	2502	1708
9	3800.01	5434	4902	5434	5434	5144	2502	1708
10	4099.99	5586	5054	5586	5586	5273	2746	1846
11	4100.01	5586	5054	5586	5586	5273	2746	1846
12	4244.71	5659	5126	5659	5659	5335	2863	1912
13	4343.85	5708	5175	5708	5708	5377	2943	1967
14	4399.99	5736	5203	5736	5736	5400	2987	1999
15	4400.01	5736	5203	5736	5736	5400	2987	1999
16	4660.78	5864	5331	5864	5864	5509	3194	2103
17	4699.99	5883	5350	5883	5883	5525	3224	2122
18	4700.01	5883	5350	5883	5883	5525	3224	2122
19	4999.99	6026	5494	6026	6026	5647	3455	2264
20	5000.01	6026	5494	6026	6026	5647	3455	2264
21	5715.00	6364	5832	6364	6364	5935	4001	2598
22	7299.99	7114	6581	7114	7114	6572	5209	3206
23	7300.01	7114	3550	7114	7114	6572	5209	3206
24	7911.25	7403	3599	7403	7403	6817	5675	3441
25	8418.00	7642	3640	7642	7642	7021	6061	3640
26	8999.99	7918	3916	7918	7918	7255	6505	3879
27	9000.01	7918	3916	7918	7918	7255	6505	3879
28	9100.00	7965	3963	7965	7965	7295	6581	3920

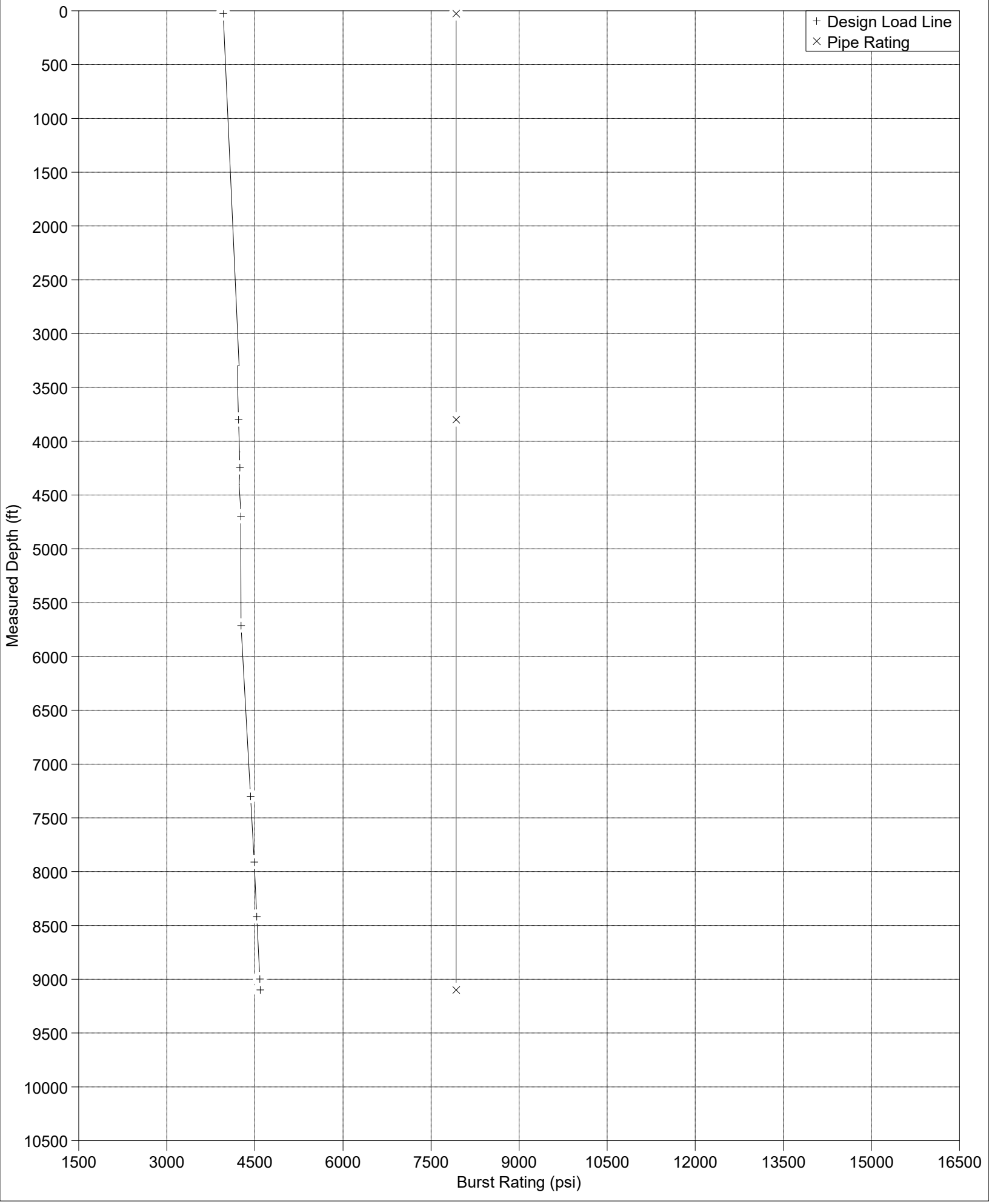
COLLAPSE PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Full Evacuation (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	17	0	17
2	3299.99	1428	2143	2	2143
3	3300.01	1428	2143	2	2143
4	3499.99	1515	2273	2	2273
5	3500.01	1515	2273	2	2273
6	3600.00	1558	2338	2	2338
7	3799.99	1644	2502	2	2467
8	3800.01	1644	2502	2	2467
9	4099.99	1773	2746	2	2661
10	4100.01	1773	2746	2	2661
11	4399.99	1900	2987	2	2852
12	4400.01	1900	2987	2	2852
13	4699.99	2025	3224	2	3039
14	4700.01	2025	3224	2	3039
15	4999.99	2147	3455	2	3222
16	5000.01	2147	3455	2	3222
17	7299.99	3072	5209	4	4609
18	7300.01	3072	5209	4	4609
19	8418.00	3521	6061	4	5284
20	8999.99	3755	6505	4	5635
21	9000.01	3755	6505	4	5635
22	9100.00	3795	6581	5	5695

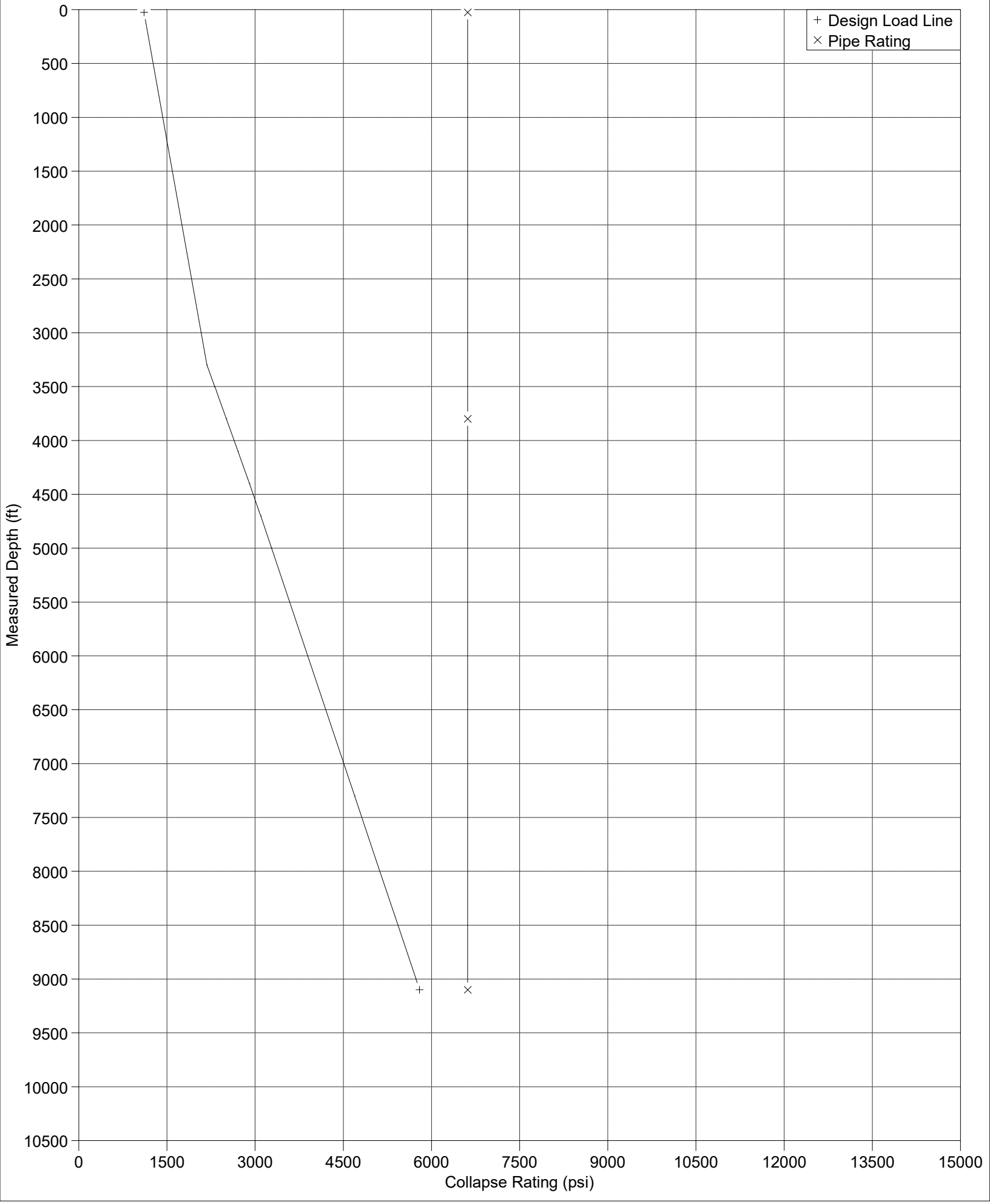
AXIAL LOADS TABLE (9 5/8" Production Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	479620	479620	406341	406341	406341	406341
2	1821.98	407212	407212	310256	310256	310256	310256
3	1821.98	407212	407212	310256	310256	310256	251633
4	3299.99	347623	347623	231182	231182	190176	190176
5	3300.01	347622	347622	231181	231181	302464	302464
6	3499.99	339560	339560	220482	220482	300506	300506
7	3500.01	342349	339559	269412	220481	349437	300506
8	3521.00	341502	338713	268289	219358	349231	300301
9	3600.00	338317	335528	264063	215132	348586	299655
10	3799.99	330254	327465	253379	204449	348447	299517
11	3800.01	330254	327464	253378	204448	348447	299517
12	4099.99	318159	315370	237445	188514	348241	299311
13	4100.01	318159	315369	237444	188513	348241	299311
14	4244.71	312325	309517	229822	180892	348143	299212
15	4343.85	308328	305463	224633	175702	347638	298707
16	4399.99	306064	303151	221707	172777	347309	298379
17	4400.01	306064	303150	221706	172776	347309	298379
18	4660.78	295550	292274	208262	159331	347666	298736
19	4699.99	293969	290621	206264	157333	347575	298645
20	4700.01	293968	290621	206263	157332	347575	298645
21	4999.99	281874	277853	142272	142272	297960	297960
22	5000.01	281873	277853	142271	142271	297960	297960
23	5715.00	253047	246926	106741	106741	296343	296343
24	7299.99	189145	178129	27977	27977	298577	298577
25	7300.01	189144	178128	27976	27976	298577	298577
26	7911.25	164366	151598	-2399	-2399	299439	299439
27	8418.00	143043	129602	-27582	-27582	299925	299925
28	8491.28	139882	126422	-31223	-31223	299944	299944
29	8999.99	117938	104341	-56503	-56503	300079	300079
30	9000.01	117937	104340	-56504	-56504	-328795	-328795
31	9026.22	116800	103202	-57806	-57806	-329434	-329434

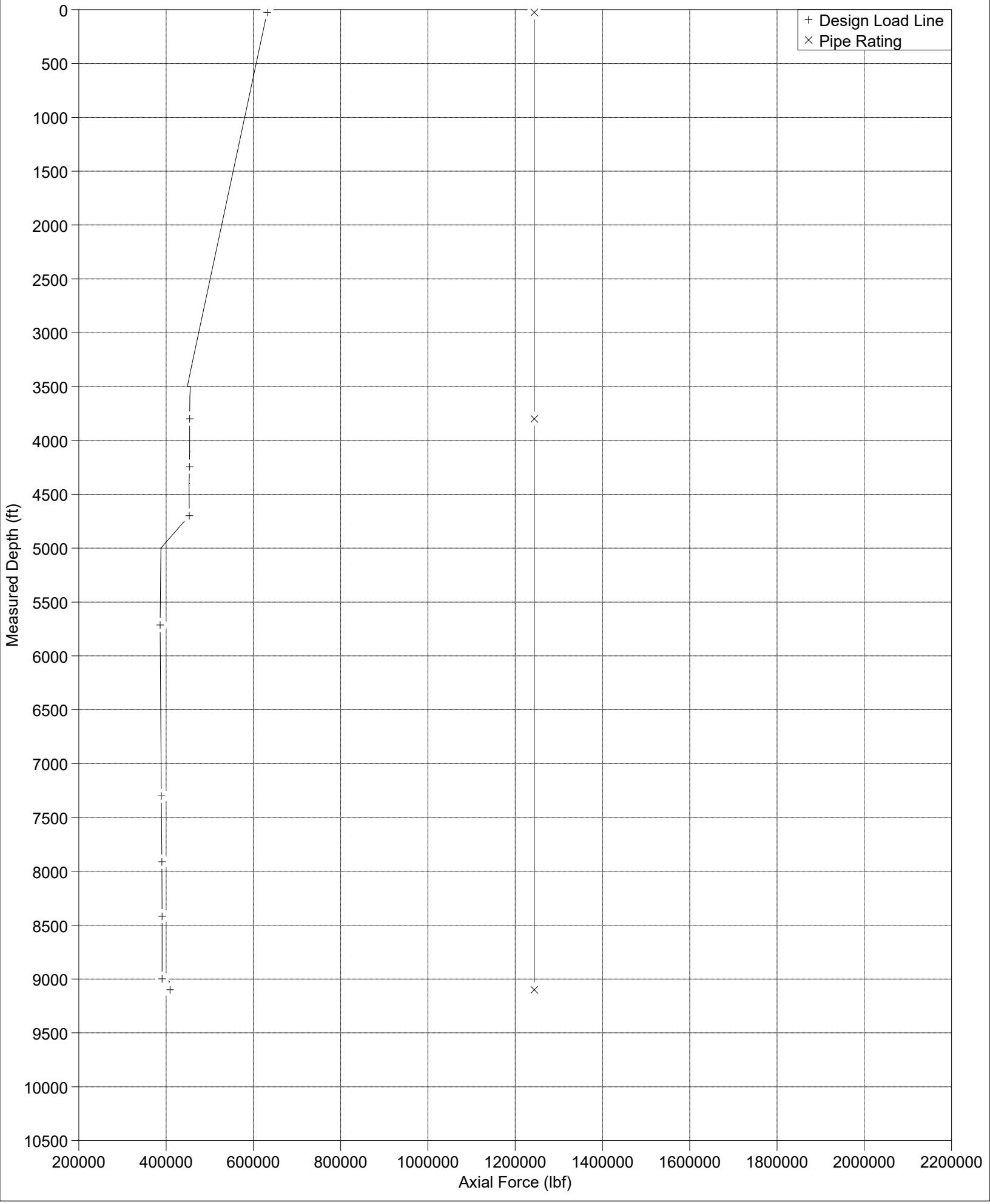
BURST DESIGN (9 5/8" Production Casing)

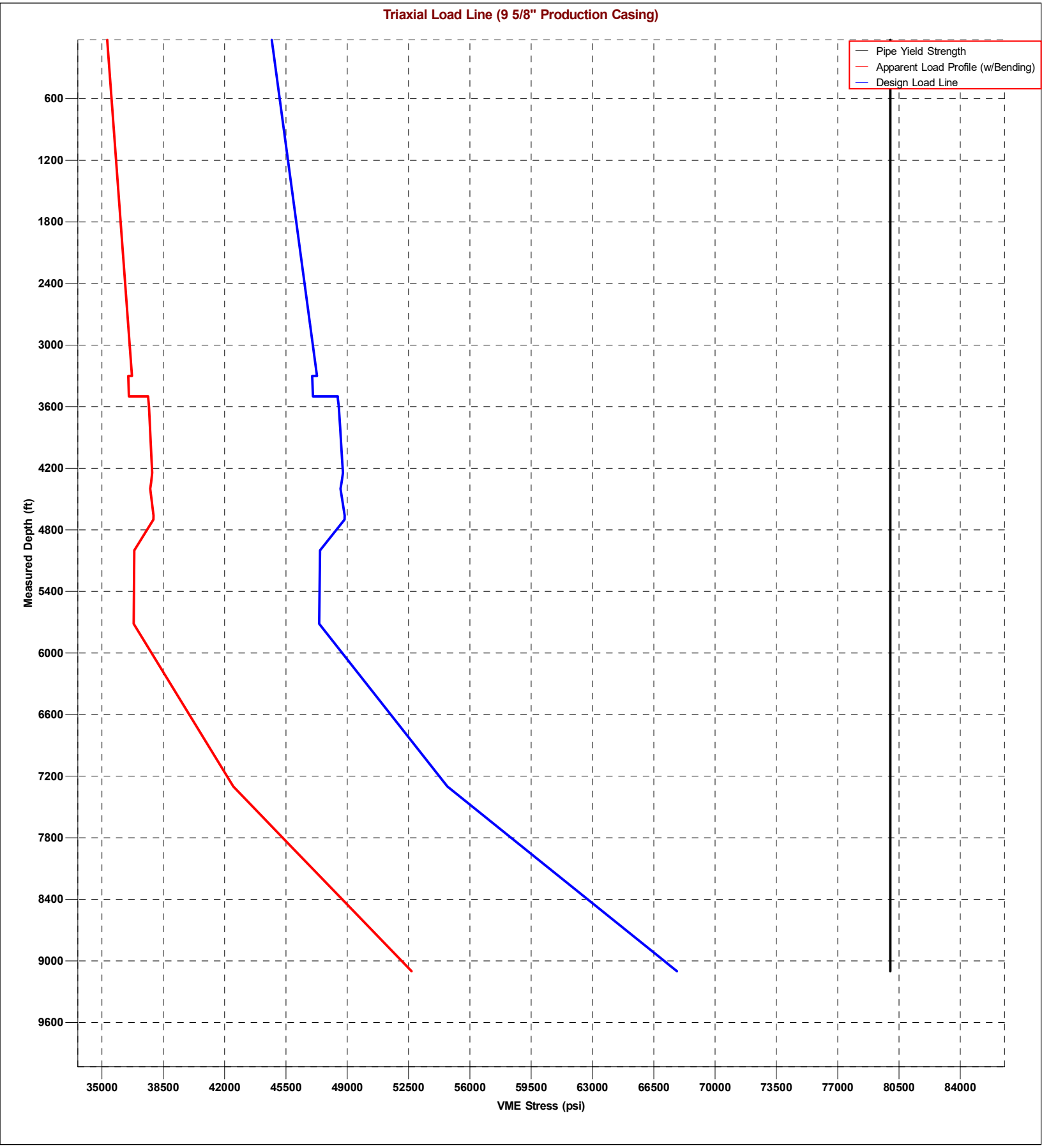


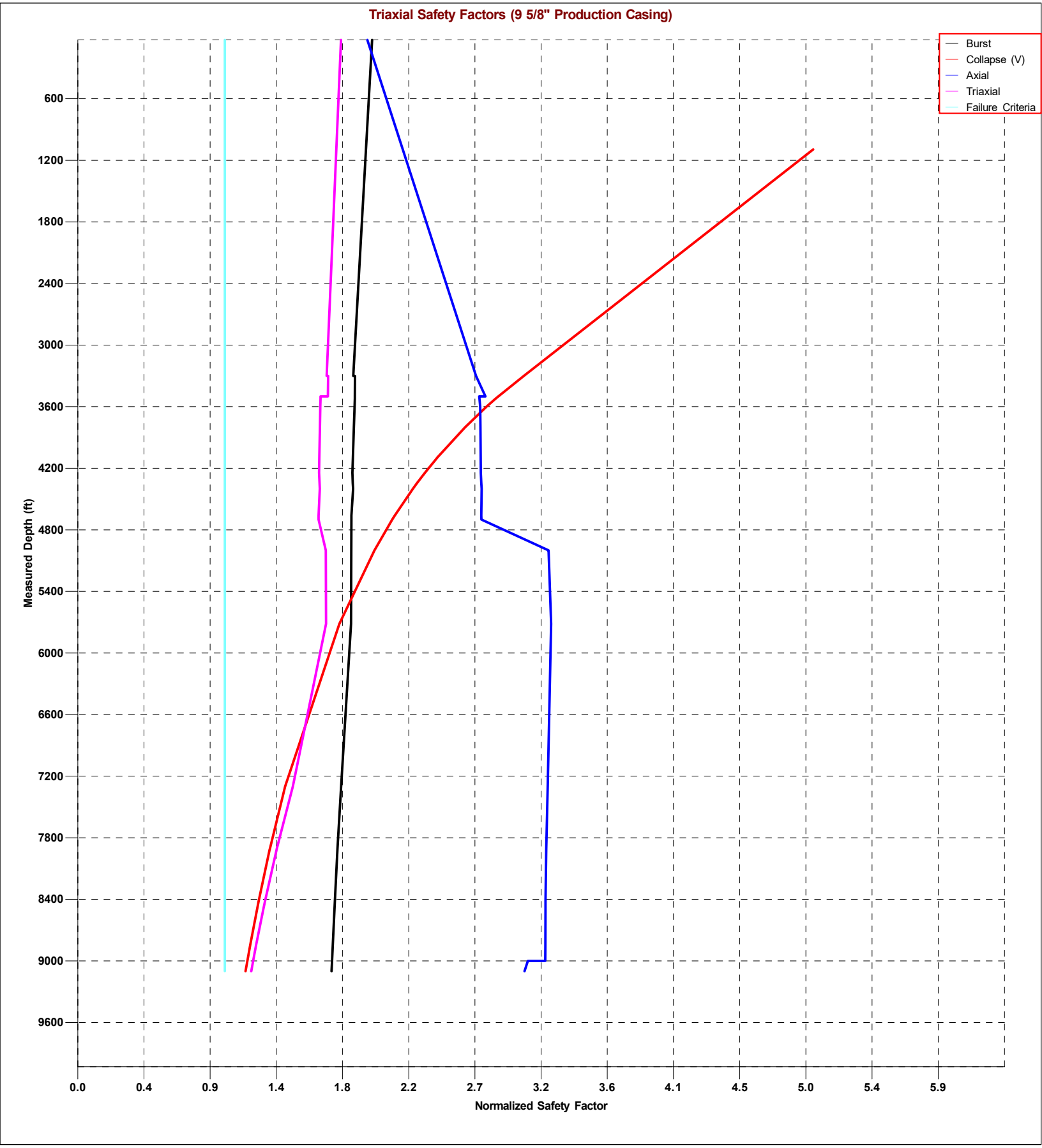
COLLAPSE DESIGN (9 5/8" Production Casing)



AXIAL DESIGN (9 5/8" Production Casing)




Triaxial Load Line (9 5/8" Production Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
600
1200
1800
2400
3000
3600
4200
4800
5400
6000
6600
7200
7800
8400
9000
9600
35000
38500
42000
45500
49000
52500
56000
59500
63000
66500
70000
73500
77000
80500
84000
VME Stress (psi)


Triaxial Safety Factors (9 5/8" Production Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
600
1200
1800
2400
3000
3600
4200
4800
5400
6000
6600
7200
7800
8400
9000
9600
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	9 5/8", 53.500 ppf, L-80	blue	2.20 B7	5.95 C2	2.56 A4	2.24 B12
2	3300			2.06 B7	3.03 C5	3.52 A4	2.12 B7
3	3300			2.07 B7	3.03 C5	3.52 A4	2.13 B7
4	3500			2.07 B7	2.86 C5	3.60 A4	2.13 B7
5	3500			2.07 B7	2.86 C5	3.55 B8	2.06 B7
6	3521			2.07 B7	2.84 C5	3.55 B8	2.06 B7
7	3600			2.07 B7	2.78 C5	3.56 B8	2.06 B7
8	3800			2.06 B7	2.63 C5	3.56 B8	2.06 B7
9	3800	9 5/8", 53.500 ppf, L-80	blue	2.06 B7	2.63 C5	3.56 B8	2.06 B7
10	4100			2.06 B7	2.44 C5	3.56 B8	2.05 B7
11	4245			2.05 B7	2.36 C5	3.56 B8	2.05 B7
12	4344			2.06 B7	2.31 C5	3.57 B8	2.05 B7
13	4400			2.06 B7	2.28 C5	3.57 B8	2.06 B7
14	4661			2.05 B7	2.16 C5	3.57 B8	2.05 B7
15	4700			2.05 B7	2.14 C5	3.57 B8	2.05 B7
16	5000			2.05 B7	2.02 C5	4.16 B8	2.11 B7
17	5715			2.04 B7	1.78 C5	4.18 B8	2.11 B7
18	7300			1.97 B7	1.41 C5	4.15 B8	1.83 C5
19	7911			1.94 B7	1.31 C5	4.14 B8	1.69 C5
20	7912			1.94 B7	1.31 C5	4.14 B8	1.69 C5
21	8418			1.92 B5	1.23 C5	4.13 B8	1.59 C5
22	8491			1.92 B5	1.22 C5	4.13 B8	1.58 C5
23	8846			1.91 B5	1.17 C5	4.13 B8	1.52 C5
24	9000			1.90 B5	1.15 C5	4.13 B8	1.49 C5
25	9000			1.90 B5	1.15 C5	(3.67) C5	1.49 C5
26	9026			1.90 B5	1.15 C5	(3.66) C5	1.49 C5
27	9099			1.90 B5	1.14 C5	(3.64) C5	1.47 C5
28	9100			1.90 B5	1.14 C5	(3.64) C5	1.47 C5
29							
30	B5	Pressure Test					
31	B7	Stimulation Surface Leak					
32	B8	Injection Casing					
33	B12	Green Cement Pressure Test(Burst)					
34	C2	Cementing					
35	C5	Full Evacuation Production					
36	A4	Overpull Force					
37	( )	Compression					
38	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	9 5/8", 53.500 ppf, L-80	0.272 B7	0.087 C2	0.261 B7	50.0	84.0	52.2	0.273	0.458	0.284
2	3299.99		0.291 B7	0.339 C5	0.282 B7	46.6	37.8	48.3	0.254	0.206	0.263
3	3300.01		0.289 B7	0.339 C5	0.280 B7	46.9	37.8	48.6	0.256	0.206	0.265
4	3499.99		0.289 B7	0.347 C5	0.281 B7	46.9	36.3	48.5	0.256	0.198	0.264
5	3500.01		0.289 B7	0.347 C5	0.286 B7	46.9	36.3	47.5	0.256	0.198	0.259
6	3521.00		0.289 B7	0.348 C5	0.286 B7	46.9	36.1	47.5	0.256	0.197	0.259
7	3600.00		0.290 B7	0.351 C5	0.287 B7	46.9	35.6	47.4	0.255	0.194	0.258
8	3799.99		0.290 B7	0.359 C5	0.287 B7	46.7	34.1	47.3	0.255	0.186	0.258
9	3800.01	9 5/8", 53.500 ppf, L-80	0.290 B7	0.359 C5	0.287 B7	46.7	34.1	47.3	0.255	0.186	0.258
10	4099.99		0.291 B7	0.371 C5	0.288 B7	46.5	31.9	47.1	0.254	0.174	0.257
11	4100.01		0.291 B7	0.371 C5	0.288 B7	46.5	31.9	47.1	0.254	0.174	0.257
12	4244.71		0.292 B7	0.377 C5	0.288 B7	46.4	30.8	47.1	0.253	0.168	0.257
13	4343.85		0.291 B7	0.381 C5	0.288 B7	46.5	30.1	47.1	0.254	0.164	0.257
14	4399.99		0.291 B7	0.383 C5	0.288 B7	46.6	29.7	47.2	0.254	0.162	0.257
15	4400.01		0.291 B7	0.383 C5	0.288 B7	46.6	29.7	47.2	0.254	0.162	0.257
16	4660.78		0.293 B7	0.393 C5	0.289 B7	46.2	27.8	46.9	0.252	0.152	0.256
17	4699.99		0.293 B7	0.395 C5	0.289 B7	46.2	27.6	46.9	0.252	0.150	0.256
18	4700.01		0.293 B7	0.395 C5	0.289 B7	46.2	27.6	46.9	0.252	0.150	0.256
19	4999.99		0.293 B7	0.406 C5	0.284 B7	46.2	25.5	48.0	0.252	0.139	0.261
20	5000.01		0.293 B7	0.406 C5	0.284 B7	46.2	25.5	48.0	0.252	0.139	0.261
21	5715.00		0.293 B7	0.430 C5	0.284 B7	46.2	21.1	48.0	0.252	0.115	0.261
22	7299.99		0.304 B7	0.469 C5	0.321 C5	44.1	14.0	41.2	0.241	0.076	0.224
23	7300.01		0.304 B7	0.469 C5	0.321 C5	44.1	14.0	41.2	0.241	0.076	0.224
24	7911.25		0.309 B7	0.484 C5	0.348 C5	43.4	11.3	36.2	0.236	0.061	0.197
25	7912.50		0.309 B7	0.484 C5	0.348 C5	43.4	11.3	36.2	0.236	0.061	0.197
26	8418.00		0.312 B5	0.496 C5	0.370 C5	42.8	9.0	32.0	0.233	0.049	0.175
27	8491.28		0.312 B5	0.498 C5	0.374 C5	42.7	8.7	31.4	0.233	0.047	0.171
28	8846.09		0.314 B5	0.506 C5	0.390 C5	42.3	7.1	28.5	0.231	0.039	0.155
29	8999.99		0.315 B5	0.510 C5	0.396 C5	42.2	6.4	27.3	0.230	0.035	0.149
30	9000.01		0.315 B5	0.510 C5	0.396 C5	42.2	6.4	27.3	0.230	0.035	0.149
31	9026.22		0.315 B5	0.511 C5	0.398 C5	42.1	6.3	27.0	0.230	0.034	0.147
32	9026.23		0.315 B5	0.511 C5	0.398 C5	42.1	6.3	27.0	0.230	0.034	0.147
33	9099.45		0.316 B5	0.513 C5	0.401 C5	42.1	6.0	26.4	0.229	0.032	0.144
34	9100.00		0.316 B5	0.513 C5	0.401 C5	42.1	6.0	26.4	0.229	0.032	0.144
35											
36	B5	Pressure Test									
37	B7	Stimulation Surface Leak									
38	C2	Cementing									
39	C5	Full Evacuation Production									
40	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (9 5/8" Production Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	944442
2	26	943314
3	26	943313
4	253	933470
5	506	922498
6	758	911527
7	1000	901037
8	1011	900555
9	1264	889583
10	1517	878611
11	1769	867639
12	2000	857632
13	2022	856668
14	2275	845696
15	2528	834724
16	2781	823752
17	3000	814227
18	3033	812780
19	3286	801809
20	3500	792525
21	3500	792524
22	3539	790837
23	3792	779877
24	3800	779517
25	3800	779516
26	4000	770884
27	4044	768973
28	4100	766589
29	4100	766588
30	4297	758172
31	4400	753821
32	4400	753820
33	4550	747522
34	4700	741292
35	4700	741291
36	4803	737068
37	5000	729073
38	5000	729072
39	5056	726833
40	5300	716978
41	5300	716977
42	5308	716642
43	5561	706450
44	5814	696259
45	6000	688756
46	6067	686068
47	6319	675877
48	6572	665685
49	6825	655494
50	7000	648439
51	7078	645303
52	7331	635112
53	7583	624921
54	7836	614729
55	8000	608122
56	8089	604538
57	8342	594347
58	8594	584156
59	8847	573964
60	9000	567805
61	9074	564822
62	9100	* 565140
63		
64	* Based on Casing Strength	
65	Only. Running String not	
66	Included	

TRIAXIAL RESULTS (9 5/8" Production Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	326310	326310	327558	0.0	2.39	2.26	N/A	3.80	78	3513	17	N/A	N/A
2	3300	190176	190176	215581	0.0	2.30	2.09	N/A	6.45	113	5180	1446		
3	3300	189200	189200	214944	0.0	2.31	2.11	N/A	6.48	113	5180	1468		
4	3500	180324	180324	207660	0.0	2.31	2.10	N/A	6.80	115	5282	1568		
5	3500	229254	180323	257297	3147.4	2.29	2.10	N/A	5.35	115	5282	1568		
6	3521	228322	179392	256535	3147.4	2.29	2.10	N/A	5.37	116	5293	1579		
7	3600	224944	176013	253751	3147.4	2.29	2.10	N/A	5.45	116	5333	1615		
8	3800	217897	168967	248224	3147.4	2.28	2.09	N/A	5.62	119	5434	1708		
9	3800	217897	168966	248223	3147.4	2.28	2.09	N/A	5.62	119	5434	1708		
10	4100	207387	158457	239966	3147.4	2.26	2.09	N/A	5.90	122	5586	1846		
11	4100	207387	158456	239965	3147.4	2.26	2.09	N/A	5.90	122	5586	1846		
12	4245	202360	153429	236010	3147.4	2.25	2.08	N/A	6.04	123	5659	1912		
13	4344	198499	149569	233028	3147.4	2.25	2.08	N/A	6.16	124	5708	1967		
14	4400	196279	147349	231317	3147.4	2.25	2.09	N/A	6.23	125	5736	1999		
15	4400	196279	147348	231317	3147.4	2.25	2.09	N/A	6.23	125	5736	1999		
16	4661	187942	139011	224671	3147.4	2.23	2.07	N/A	6.50	128	5864	2103		
17	4700	186559	137628	223588	3147.4	2.23	2.07	N/A	6.55	128	5883	2122		
18	4700	186558	137628	223588	3147.4	2.23	2.07	N/A	6.55	128	5883	2122		
19	5000	127204	127204	165539	0.0	2.25	2.07	N/A	9.59	131	6026	2264		
20	5715	102612	102612	146091	0.0	2.23	2.06	N/A	11.86	138	6364	2598		
21	7300	53915	53915	106518	0.0	2.09	1.98	N/A	22.47	154	7114	3206		
22	7300	53914	53914	106517	0.0	2.09	1.98	N/A	22.47	154	7114	3206		
23	7911	35134	35134	91153	0.0	2.04	1.95	N/A	34.42	160	7403	3441		
24	8418	19337	19337	78219	0.0	2.00	1.92	N/A	62.44	165	7642	3640		
25	9000	789	789	63047	0.0	1.96	1.90	N/A	+ 100.00	171	7918	3879		
26	9000	789	789	63046	0.0	1.96	1.90	N/A	+ 100.00	171	7918	3879		
27	9025	0	0	62400	0.0	1.96	1.90	N/A	+ 100.00	171	7929	3889		
28	9025	-0	-0	62400	0.0	1.96	1.90	N/A	(+ 100.00)	171	7929	3889		
29	9100	-2404	-2404	60430	0.0	1.96	1.90	N/A	(+ 100.00)	172	7965	3920		
30														
31	( )	Compression												
32	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Tubing Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	27444	27444	28542	0.0	2.65	2.60	N/A	43.99	165	2981	17	N/A	N/A
2	3300	4573	4573	27861	0.0	2.44	2.40	N/A	+ 100.00	165	4648	1446		
3	3300	3598	3598	27215	0.0	2.46	2.42	N/A	+ 100.00	165	4648	1468		
4	3500	1640	1640	26801	0.0	2.46	2.42	N/A	+ 100.00	165	4749	1568		
5	3500	50571	1640	77206	3147.4	2.37	2.42	N/A	23.87	165	4749	1568		
6	3521	50365	1435	77162	3147.4	2.37	2.42	N/A	23.97	165	4760	1579		
7	3600	49720	789	77084	3147.4	2.36	2.42	N/A	24.28	165	4800	1615		
8	3800	49581	651	78424	3147.4	2.36	2.41	N/A	24.35	165	4902	1708		
9	4100	49375	445	80423	3147.4	2.35	2.40	N/A	24.45	165	5054	1846		
10	4245	49277	346	81379	3147.4	2.35	2.39	N/A	24.50	165	5126	1912		
11	4313	-48931	-0	-19183	3147.4	2.35	2.40	N/A	(24.67)	165	5160	1950		
12	4344	-49090	-159	-19070	3147.4	2.36	2.40	N/A	(24.59)	165	5175	1967		
13	4400	-49418	-487	-18895	3147.4	2.36	2.40	N/A	(24.43)	165	5203	1999		
14	4661	-49061	-130	-16856	3147.4	2.35	2.38	N/A	(24.61)	165	5331	2103		
15	4700	-49152	-221	-16649	3147.4	2.35	2.38	N/A	(24.56)	165	5350	2122		
16	5000	-906	-906	35320	0.0	2.43	2.38	N/A	(+ 100.00)	165	5494	2264		
17	5715	-2523	-2523	39011	0.0	2.44	2.38	N/A	(+ 100.00)	165	5832	2598		
18	7300	-289	-289	51050	0.0	2.35	2.28	N/A	(+ 100.00)	165	6581	3206		
19	7300	-104344	-104344	-56140	0.0	11.62	22.39	N/A	(11.57)	165	3550	3206		
20	7911	-111716	-111716	-59979	0.0	13.90	48.56	N/A	(10.81)	165	3599	3441		
21	8418	-118042	-118042	-63298	0.0	15.62	N/A	N/A	(10.23)	165	3640	3640		
22	9000	-117888	-117888	-59320	0.0	15.87	+ 100.00	N/A	(10.24)	165	3916	3879		
23	9100	-117868	-117868	-58640	0.0	15.91	+ 100.00	N/A	(10.24)	165	3963	3920		
24														
25	( )	Compression												
26	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Stimulation Surface Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	45722	45722	47370	0.0	2.27	2.20	N/A	26.41	165	3513	17	N/A	N/A
2	3300	22851	22851	46690	0.0	2.12	2.06	N/A	52.84	165	5180	1446		
3	3300	21876	21876	46043	0.0	2.13	2.07	N/A	55.19	165	5180	1468		
4	3500	19918	19918	45629	0.0	2.13	2.07	N/A	60.62	165	5282	1568		
5	3500	68848	19918	96034	3147.4	2.06	2.07	N/A	17.54	165	5282	1568		
6	3521	68643	19712	95991	3147.4	2.06	2.07	N/A	17.59	165	5293	1579		
7	3600	67997	19067	95912	3147.4	2.06	2.07	N/A	17.76	165	5333	1615		
8	3800	67859	18928	97252	3147.4	2.06	2.06	N/A	17.79	165	5434	1708		
9	4100	67653	18722	99251	3147.4	2.05	2.06	N/A	17.85	165	5586	1846		
10	4245	67554	18624	100208	3147.4	2.05	2.05	N/A	17.87	165	5659	1912		
11	4344	67049	18119	100568	3147.4	2.05	2.06	N/A	18.01	165	5708	1967		
12	4400	66721	17790	100743	3147.4	2.06	2.06	N/A	18.10	165	5736	1999		
13	4400	66721	17791	100743	3147.4	2.06	2.06	N/A	18.10	165	5736	1999		
14	4661	67078	18147	102782	3147.4	2.05	2.05	N/A	18.00	165	5864	2103		
15	4700	66987	18056	102989	3147.4	2.05	2.05	N/A	18.02	165	5883	2122		
16	5000	17371	17371	54149	0.0	2.11	2.05	N/A	69.50	165	6026	2264		
17	5715	15755	15755	57839	0.0	2.11	2.04	N/A	76.63	165	6364	2598		
18	7300	17989	17989	69878	0.0	2.04	1.97	N/A	67.12	165	7114	3206		
19	7911	18850	18850	74521	0.0	2.02	1.94	N/A	64.05	165	7403	3441		
20	8418	19337	19337	78219	0.0	2.00	1.92	N/A	62.44	165	7642	3640		
21	9000	19491	19491	82198	0.0	1.99	1.91	N/A	61.94	165	7918	3879		
22	9100	19511	19511	82878	0.0	1.99	1.90	N/A	61.88	165	7965	3920		
23														
24	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (9 5/8" Production Casing) - Injection Down Casing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	326310	326310	327558	0.0	2.39	2.26	N/A	3.80	78	3513	17	N/A	N/A
2	3300	303439	303439	326896	0.0	2.27	2.12	N/A	4.09	78	5180	1446		
3	3300	302464	302464	326266	0.0	2.28	2.13	N/A	4.10	78	5180	1468		
4	3500	300506	300506	325864	0.0	2.28	2.13	N/A	4.13	78	5282	1568		
5	3500	349437	300506	374942	3147.4	2.24	2.13	N/A	3.55	78	5282	1568		
6	3521	349231	300301	374900	3147.4	2.24	2.13	N/A	3.55	78	5293	1579		
7	3600	348586	299655	374823	3147.4	2.23	2.13	N/A	3.56	78	5333	1615		
8	3800	348447	299517	376128	3147.4	2.23	2.12	N/A	3.56	78	5434	1708		
9	4100	348241	299311	378075	3147.4	2.22	2.11	N/A	3.56	78	5586	1846		
10	4245	348143	299212	379006	3147.4	2.22	2.11	N/A	3.56	78	5659	1912		
11	4344	347638	298707	379357	3147.4	2.22	2.11	N/A	3.57	78	5708	1967		
12	4400	347309	298379	379527	3147.4	2.22	2.11	N/A	3.57	78	5736	1999		
13	4661	347666	298736	381512	3147.4	2.21	2.10	N/A	3.57	78	5864	2103		
14	4700	347575	298645	381714	3147.4	2.21	2.10	N/A	3.57	78	5883	2122		
15	5000	297960	297960	334159	0.0	2.25	2.10	N/A	4.16	78	6026	2264		
16	5715	296343	296343	337752	0.0	2.24	2.10	N/A	4.18	78	6364	2598		
17	7300	298577	298577	349475	0.0	2.16	2.02	N/A	4.15	78	7114	3206		
18	7911	299439	299439	353995	0.0	2.14	1.99	N/A	4.14	78	7403	3441		
19	8418	299925	299925	357596	0.0	2.11	1.97	N/A	4.13	78	7642	3640		
20	9000	300079	300079	361470	0.0	2.10	1.96	N/A	4.13	78	7918	3879		
21	9100	300099	300099	362132	0.0	2.09	1.95	N/A	4.13	78	7965	3920		
22														
23	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	406341	406341	411894	0.0	2.24	2.24	N/A	3.02	111	3511	17	N/A	N/A
2	3300	231182	231182	268810	0.0	2.96	2.80	N/A	5.29	121	4928	2143		
3	3300	231181	231181	268809	0.0	2.96	2.80	N/A	5.29	121	4928	2143		
4	3500	220482	220482	260039	0.0	3.02	2.84	N/A	5.55	122	5015	2273		
5	3500	269412	220481	309777	3147.4	2.91	2.84	N/A	4.54	122	5015	2273		
6	3521	268289	219358	308857	3147.4	2.92	2.85	N/A	4.56	122	5024	2286		
7	3600	264063	215132	305396	3147.4	2.94	2.87	N/A	4.63	122	5058	2338		
8	3800	253379	204449	297185	3147.4	3.02	2.95	N/A	4.83	123	5144	2502		
9	3800	253378	204448	297184	3147.4	3.02	2.95	N/A	4.83	123	5144	2502		
10	4100	237445	188514	284931	3147.4	3.16	3.08	N/A	5.15	124	5273	2746		
11	4100	237444	188513	284930	3147.4	3.16	3.08	N/A	5.15	124	5273	2746		
12	4245	229822	180892	279067	3147.4	3.23	3.15	N/A	5.32	124	5335	2863		
13	4344	224633	175702	275073	3147.4	3.28	3.20	N/A	5.44	125	5377	2943		
14	4400	221707	172777	272822	3147.4	3.31	3.23	N/A	5.51	125	5400	2987		
15	4400	221706	172776	272821	3147.4	3.31	3.23	N/A	5.51	125	5400	2987		
16	4661	208262	159331	262470	3147.4	3.45	3.36	N/A	5.87	126	5509	3194		
17	4700	206264	157333	260932	3147.4	3.47	3.39	N/A	5.92	126	5525	3224		
18	4700	206263	157332	260931	3147.4	3.47	3.39	N/A	5.92	126	5525	3224		
19	5000	142272	142272	199519	0.0	3.81	3.55	N/A	8.59	127	5647	3455		
20	5000	142271	142271	199518	0.0	3.81	3.55	N/A	8.59	127	5647	3455		
21	5715	106741	106741	172089	0.0	4.34	4.02	N/A	11.44	129	5935	4001		
22	7300	27977	27977	111154	0.0	6.22	5.70	N/A	43.58	134	6572	5209		
23	7300	27976	27976	111153	0.0	6.22	5.70	N/A	43.58	134	6572	5209		
24	7863	12	12	89476	0.0	7.34	6.70	N/A	+ 100.00	135	6798	5638		
25	7863	-16	-16	89455	0.0	7.34	6.70	N/A	(+ 100.00)	135	6798	5638		
26	7911	-2399	-2399	87606	0.0	7.45	6.80	N/A	(+ 100.00)	136	6817	5675		
27	8418	-27582	-27582	68065	0.0	8.88	8.09	N/A	(44.16)	137	7021	6061		
28	9000	-56503	-56503	45598	0.0	11.27	10.35	N/A	(21.54)	139	7255	6505		
29	9000	-56504	-56504	45598	0.0	11.27	10.35	N/A	(21.54)	139	7255	6505		
30	9100	-61473	-61473	41735	0.0	11.80	10.87	N/A	(19.80)	139	7295	6581		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	206094	206094	208953	0.0	5.24	N/A	5.95	5.96	111	11	17	N/A	N/A
2	3300	30936	30936	54003	0.0	7.90	N/A	7.80	39.56	121	1428	2143		
3	3300	30935	30935	54002	0.0	7.90	N/A	7.80	39.56	121	1428	2143		
4	3500	20236	20236	44505	0.0	7.96	N/A	7.66	60.46	122	1515	2273		
5	3500	69165	20235	94242	3147.4	6.34	N/A	7.66	17.69	122	1515	2273		
6	3521	68042	19112	93246	3147.4	6.35	N/A	7.65	17.98	122	1524	2286		
7	3600	63816	14886	89498	3147.4	6.38	N/A	7.58	19.17	122	1558	2338		
8	3800	53133	4202	80018	3147.4	6.27	N/A	7.14	23.02	123	1644	2502		
9	3800	53132	4201	80017	3147.4	6.27	N/A	7.14	23.02	123	1644	2502		
10	3878	48951	21	76307	3147.4	6.22	N/A	6.97	24.99	123	1678	2566		
11	3879	-48939	-9	-23234	3147.4	9.21	N/A	7.37	(24.99)	123	1678	2566		
12	4100	-60663	-11732	-33664	3147.4	8.54	N/A	6.73	(20.16)	124	1773	2746		
13	4100	-60664	-11733	-33665	3147.4	8.54	N/A	6.73	(20.16)	124	1773	2746		
14	4245	-68285	-19355	-40448	3147.4	8.14	N/A	6.37	(17.90)	124	1835	2863		
15	4344	-73475	-24544	-45067	3147.4	7.88	N/A	6.14	(16.64)	125	1877	2943		
16	4400	-76401	-27470	-47672	3147.4	7.74	N/A	6.02	(16.00)	125	1900	2987		
17	4400	-76402	-27471	-47673	3147.4	7.74	N/A	6.02	(16.00)	125	1900	2987		
18	4661	-89846	-40915	-59646	3147.4	7.16	N/A	5.52	(13.60)	126	2009	3194		
19	4700	-91844	-42913	-61426	3147.4	7.07	N/A	5.46	(13.31)	126	2025	3224		
20	4700	-91845	-42914	-61427	3147.4	7.07	N/A	5.46	(13.31)	126	2025	3224		
21	5000	-57974	-57974	-25036	0.0	6.06	N/A	5.00	(21.07)	127	2147	3455		
22	5000	-57975	-57975	-25037	0.0	6.06	N/A	5.00	(21.07)	127	2147	3455		
23	5715	-93506	-93506	-56696	0.0	5.26	N/A	4.18	(13.06)	129	2435	4001		
24	7300	-172270	-172270	-127028	0.0	3.97	N/A	3.06	(7.08)	134	3072	5209		
25	7300	-172271	-172271	-127029	0.0	3.97	N/A	3.06	(7.08)	134	3072	5209		
26	7911	-202646	-202646	-154207	0.0	3.61	N/A	2.77	(6.01)	136	3317	5675		
27	8418	-227828	-227828	-176763	0.0	3.35	N/A	2.57	(5.35)	137	3521	6061		
28	9000	-256749	-256749	-202694	0.0	3.10	N/A	2.37	(4.74)	139	3755	6505		
29	9000	-256750	-256750	-202695	0.0	3.10	N/A	2.37	(4.74)	139	3755	6505		
30	9100	-261719	-261719	-207152	0.0	3.06	N/A	2.34	(4.65)	139	3795	6581		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Full Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-74880	-74880	-77136	0.0	14.45	N/A	+ 100.00	(16.12)	165	0	17	N/A	N/A
2	3300	-185356	-185356	-190915	0.0	3.92	N/A	3.03	(6.51)	165	2	2143		
3	3300	-185357	-185357	-190916	0.0	3.92	N/A	3.03	(6.51)	165	2	2143		
4	3500	-192104	-192104	-197866	0.0	3.70	N/A	2.86	(6.28)	165	2	2273		
5	3500	-241036	-192105	-248271	3147.4	3.62	N/A	2.86	(5.01)	165	2	2273		
6	3521	-241744	-192813	-249001	3147.4	3.60	N/A	2.84	(4.99)	165	2	2286		
7	3600	-244409	-195479	-251746	3147.4	3.53	N/A	2.78	(4.94)	165	2	2338		
8	3800	-249653	-200722	-257146	3147.4	3.36	N/A	2.63	(4.84)	165	2	2467		
9	3800	-249654	-200723	-257146	3147.4	3.36	N/A	2.63	(4.84)	165	2	2467		
10	4100	-257474	-208543	-265200	3147.4	3.14	N/A	2.44	(4.69)	165	2	2661		
11	4100	-257474	-208544	-265200	3147.4	3.14	N/A	2.44	(4.69)	165	2	2661		
12	4245	-261215	-212284	-269052	3147.4	3.04	N/A	2.36	(4.62)	165	2	2753		
13	4344	-263762	-214832	-271675	3147.4	2.97	N/A	2.31	(4.58)	165	2	2816		
14	4400	-265198	-216267	-273154	3147.4	2.94	N/A	2.28	(4.55)	165	2	2852		
15	4400	-265199	-216268	-273155	3147.4	2.94	N/A	2.28	(4.55)	165	2	2852		
16	4661	-271797	-222867	-279950	3147.4	2.79	N/A	2.16	(4.44)	165	2	3015		
17	4700	-272778	-223847	-280960	3147.4	2.76	N/A	2.14	(4.43)	165	2	3039		
18	4700	-272778	-223848	-280960	3147.4	2.76	N/A	2.14	(4.43)	165	2	3039		
19	5000	-231239	-231239	-238167	0.0	2.62	N/A	2.02	(5.22)	165	2	3222		
20	5000	-231240	-231240	-238168	0.0	2.62	N/A	2.02	(5.22)	165	2	3222		
21	5715	-248678	-248678	-256126	0.0	2.31	N/A	1.78	(4.86)	165	3	3653		
22	7300	-287335	-287335	-295934	0.0	1.83	N/A	1.41	(4.20)	165	4	4609		
23	7300	-287335	-287335	-295935	0.0	1.83	N/A	1.41	(4.20)	165	4	4609		
24	7911	-302242	-302242	-311286	0.0	1.69	N/A	1.31	(3.99)	165	4	4978		
25	8418	-314601	-314601	-324013	0.0	1.59	N/A	1.23	(3.84)	165	4	5284		
26	9000	-328795	-328795	-338629	0.0	1.49	N/A	1.15	(3.67)	165	4	5635		
27	9000	-328795	-328795	-338630	0.0	1.49	N/A	1.15	(3.67)	165	4	5635		
28	9100	-331234	-331234	-341141	0.0	1.47	N/A	1.14	(3.64)	165	5	5695		
29														
30	( )	Compression												
31	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	479620	479620	486127	0.0	2.26	N/A	N/A	2.56	111	17	17	N/A	N/A
2	3300	347623	347623	387150	0.0	2.86	N/A	N/A	3.52	121	2143	2143		
3	3300	347622	347622	387150	0.0	2.86	N/A	N/A	3.52	121	2143	2143		
4	3500	339560	339560	381083	0.0	2.91	N/A	N/A	3.60	122	2273	2273		
5	3500	342349	339559	383918	3147.4	2.89	N/A	N/A	3.57	122	2273	2273		
6	3521	341502	338713	383282	3147.4	2.89	N/A	N/A	3.58	122	2286	2286		
7	3600	338317	335528	380884	3147.4	2.91	N/A	N/A	3.62	122	2338	2338		
8	3800	330254	327465	374811	3147.4	2.96	N/A	N/A	3.70	123	2467	2467		
9	3800	330254	327464	374811	3147.4	2.96	N/A	N/A	3.70	123	2467	2467		
10	4100	318159	315370	365678	3147.4	3.04	N/A	N/A	3.84	124	2661	2661		
11	4100	318159	315369	365678	3147.4	3.04	N/A	N/A	3.84	124	2661	2661		
12	4245	312325	309517	361258	3147.4	3.08	N/A	N/A	3.91	124	2753	2753		
13	4344	308328	305463	358223	3147.4	3.11	N/A	N/A	3.96	125	2816	2816		
14	4400	306064	303151	356501	3147.4	3.12	N/A	N/A	3.99	125	2852	2852		
15	4400	306064	303150	356501	3147.4	3.12	N/A	N/A	3.99	125	2852	2852		
16	4661	295550	292274	348472	3147.4	3.20	N/A	N/A	4.14	126	3015	3015		
17	4700	293969	290621	347260	3147.4	3.21	N/A	N/A	4.16	126	3039	3039		
18	4700	293968	290621	347259	3147.4	3.21	N/A	N/A	4.16	126	3039	3039		
19	5000	281874	277853	337938	0.0	3.30	N/A	N/A	4.33	127	3222	3222		
20	5000	281873	277853	337937	0.0	3.30	N/A	N/A	4.33	127	3222	3222		
21	5715	253047	246926	315626	0.0	3.55	N/A	N/A	4.82	129	3653	3653		
22	7300	189145	178129	266062	0.0	4.26	N/A	N/A	6.45	134	4609	4609		
23	7300	189144	178128	266061	0.0	4.26	N/A	N/A	6.45	134	4609	4609		
24	7911	164366	151598	246770	0.0	4.62	N/A	N/A	7.41	136	4978	4978		
25	8418	143043	129602	229963	0.0	4.98	N/A	N/A	8.51	137	5284	5284		
26	9000	117938	104341	210012	0.0	5.50	N/A	N/A	10.32	139	5635	5635		
27	9000	117937	104340	210011	0.0	5.50	N/A	N/A	10.32	139	5635	5635		
28	9099	113622	100024	206573	0.0	5.60	N/A	N/A	10.71	139	5695	5695		
29	9100	113598	100000	206554	0.0	5.60	N/A	N/A	10.71	139	5695	5695		
30														
31	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	406341	406341	411894	0.0	2.24	2.24	N/A	3.02	111	3511	17	N/A	N/A
2	3300	231182	231182	268810	0.0	2.96	2.80	N/A	5.29	121	4928	2143		
3	3300	231181	231181	268809	0.0	2.96	2.80	N/A	5.29	121	4928	2143		
4	3500	220482	220482	260039	0.0	3.02	2.84	N/A	5.55	122	5015	2273		
5	3500	269412	220481	309777	3147.4	2.91	2.84	N/A	4.54	122	5015	2273		
6	3521	268289	219358	308857	3147.4	2.92	2.85	N/A	4.56	122	5024	2286		
7	3600	264063	215132	305396	3147.4	2.94	2.87	N/A	4.63	122	5058	2338		
8	3800	253379	204449	297185	3147.4	3.02	2.95	N/A	4.83	123	5144	2502		
9	3800	253378	204448	297184	3147.4	3.02	2.95	N/A	4.83	123	5144	2502		
10	4100	237445	188514	284931	3147.4	3.16	3.08	N/A	5.15	124	5273	2746		
11	4100	237444	188513	284930	3147.4	3.16	3.08	N/A	5.15	124	5273	2746		
12	4245	229822	180892	279067	3147.4	3.23	3.15	N/A	5.32	124	5335	2863		
13	4344	224633	175702	275073	3147.4	3.28	3.20	N/A	5.44	125	5377	2943		
14	4400	221707	172777	272822	3147.4	3.31	3.23	N/A	5.51	125	5400	2987		
15	4400	221706	172776	272821	3147.4	3.31	3.23	N/A	5.51	125	5400	2987		
16	4661	208262	159331	262470	3147.4	3.45	3.36	N/A	5.87	126	5509	3194		
17	4700	206264	157333	260932	3147.4	3.47	3.39	N/A	5.92	126	5525	3224		
18	4700	206263	157332	260931	3147.4	3.47	3.39	N/A	5.92	126	5525	3224		
19	5000	142272	142272	199519	0.0	3.81	3.55	N/A	8.59	127	5647	3455		
20	5000	142271	142271	199518	0.0	3.81	3.55	N/A	8.59	127	5647	3455		
21	5715	106741	106741	172089	0.0	4.34	4.02	N/A	11.44	129	5935	4001		
22	7300	27977	27977	111154	0.0	6.22	5.70	N/A	43.58	134	6572	5209		
23	7300	27976	27976	111153	0.0	6.22	5.70	N/A	43.58	134	6572	5209		
24	7863	12	12	89476	0.0	7.34	6.70	N/A	+ 100.00	135	6798	5638		
25	7863	-16	-16	89455	0.0	7.34	6.70	N/A	(+ 100.00)	135	6798	5638		
26	7911	-2399	-2399	87606	0.0	7.45	6.80	N/A	(+ 100.00)	136	6817	5675		
27	8418	-27582	-27582	68065	0.0	8.88	8.09	N/A	(44.16)	137	7021	6061		
28	9000	-56503	-56503	45598	0.0	11.27	10.35	N/A	(21.54)	139	7255	6505		
29	9000	-56504	-56504	45598	0.0	11.27	10.35	N/A	(21.54)	139	7255	6505		
30	9100	-61473	-61473	41735	0.0	11.80	10.87	N/A	(19.80)	139	7295	6581		
31														
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (5 1/2" Production Tubing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Temperature Deration:	Yes
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (5 1/2" Production Tubing)

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7300.00 ft
Perforation Depth, MD:	8418.00 ft
Packer Setting Method:	Set Mechanically
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
3500.00 ft	115 °F
4097.53 ft	122 °F
4391.69 ft	125 °F
4680.36 ft	128 °F
4961.87 ft	131 °F
7098.24 ft	154 °F

BURST LOADS DATA (5 1/2" Production Tubing)

Production Load:	**Shut-In**
Shut-in Bottom Hole Pressure:	4100 psi
Gas Gravity:	0.70 (0.0957 psi/ft @ 165 °F & 4100 psi)
Hot:	Yes

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Internal Fluid Density:	9.80 ppg

Production Load:	**Tubing Injection**
Injection Pressure:	3500 psi
Injection Fluid Density:	10.00 ppg

COLLAPSE LOADS DATA (5 1/2" Production Tubing)

Drilling Load:	**Full/Partial Evacuation**
Mud Weight:	9.80 ppg
Mud Level, MD:	7300.00 ft
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7300.00 ft

Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	7300.00 ft
Perforation Depth, MD:	8418.00 ft
Gas Gravity:	0.70
Reservoir Pressure:	3640 psi

Production Load:	**Annular Pressure Test**
Fluid Density(Inside Tubing):	1.50 ppg
Wellhead Pressure (Annulus)	3500 psi
Fluid Density(Annulus)	9.80 ppg
Packer Depth, MD:	7300.00 ft

AXIAL LOADS DATA (5 1/2" Production Tubing)

Overpull Force:	100000 lbf
Service Loads:	Yes

BURST PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Pressure Test (Int) (psi)	Pressure Test (Ext) (psi)	Tubing Injection (Int) (psi)	Tubing Injection (Ext) (psi)	Shut-In (Int) (psi)	Shut-In (Ext) (psi)
1	26.00	3513	13	3514	13	3440	13
2	3499.99	5282	1782	5318	1782	3720	1782
3	3500.01	5282	1782	5318	1782	3720	1782
4	4099.99	5586	2086	5629	2086	3768	2086
5	4100.01	5586	2086	5629	2086	3768	2086
6	4399.99	5736	2236	5781	2236	3792	2236
7	4400.01	5736	2236	5781	2236	3792	2236
8	4699.99	5883	2383	5931	2383	3815	2383
9	4700.01	5883	2383	5931	2383	3815	2383
10	4999.99	6026	2526	6078	2526	3838	2526
11	5000.01	6026	2526	6078	2526	3838	2526
12	7299.99	7114	3614	7187	3614	4010	3614
13	7300.00	7114	3614	7187	3614	4010	3614

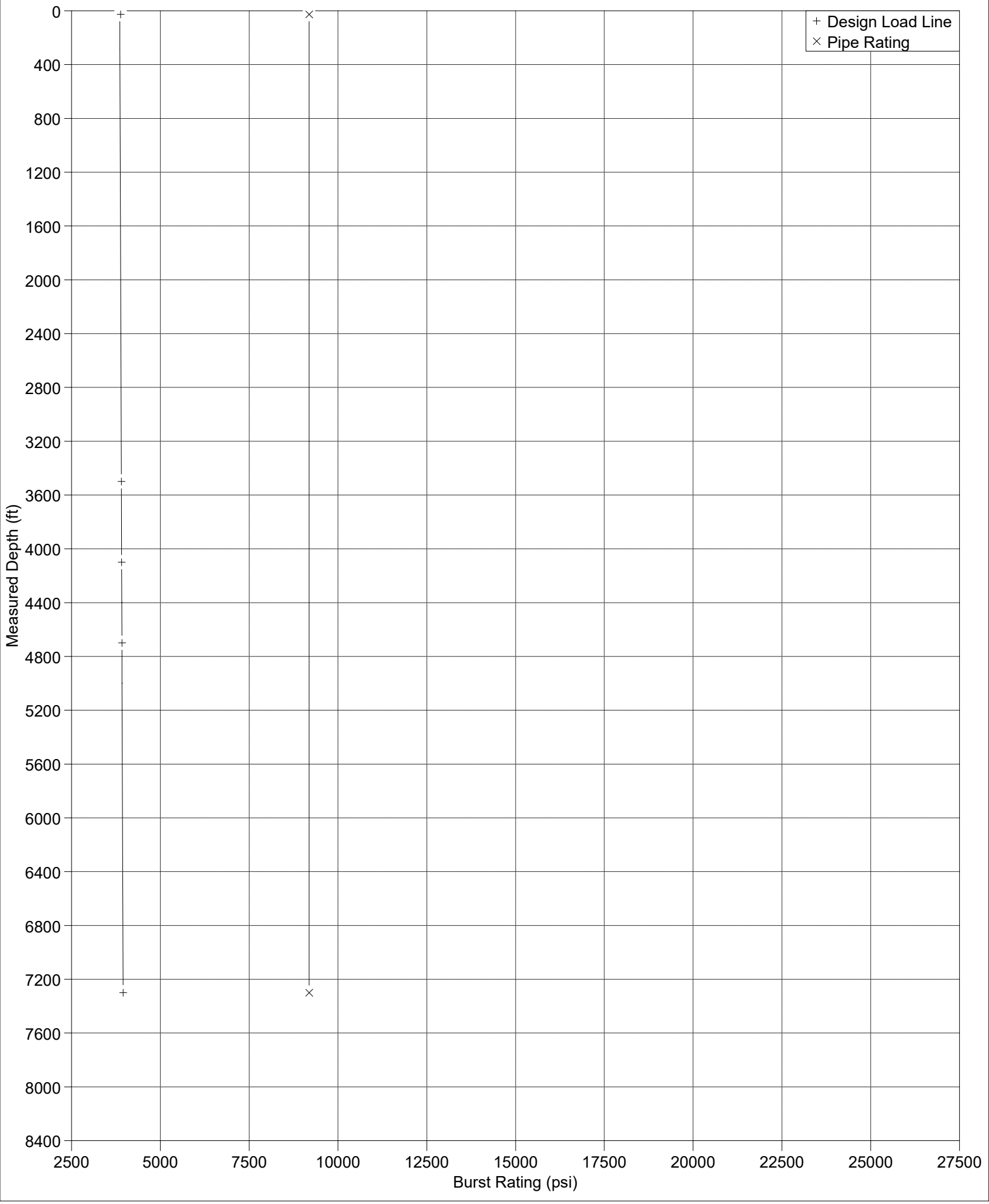
COLLAPSE PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Full/Partial Evacuation (Int) (psi)	Full/Partial Evacuation (Ext) (psi)	Tubing Leak (Int) (psi)	Tubing Leak (Ext) (psi)	Annular Pressure Test (Int) (psi)	Annular Pressure Test (Ext) (psi)
1	26.00	0	13	2981	2981	2	3513
2	3499.99	2	1782	3260	4749	273	5282
3	3500.01	2	1782	3260	4749	273	5282
4	4099.99	2	2086	3308	5054	319	5586
5	4100.01	2	2086	3308	5054	319	5586
6	4399.99	2	2236	3332	5203	342	5736
7	4400.01	2	2236	3332	5203	342	5736
8	4699.99	3	2383	3355	5350	365	5883
9	4700.01	3	2383	3355	5350	365	5883
10	4999.99	3	2526	3378	5494	387	6026
11	5000.01	3	2526	3378	5494	387	6026
12	7299.99	4	3614	3550	6581	553	7114
13	7300.00	4	3614	3550	6581	553	7114

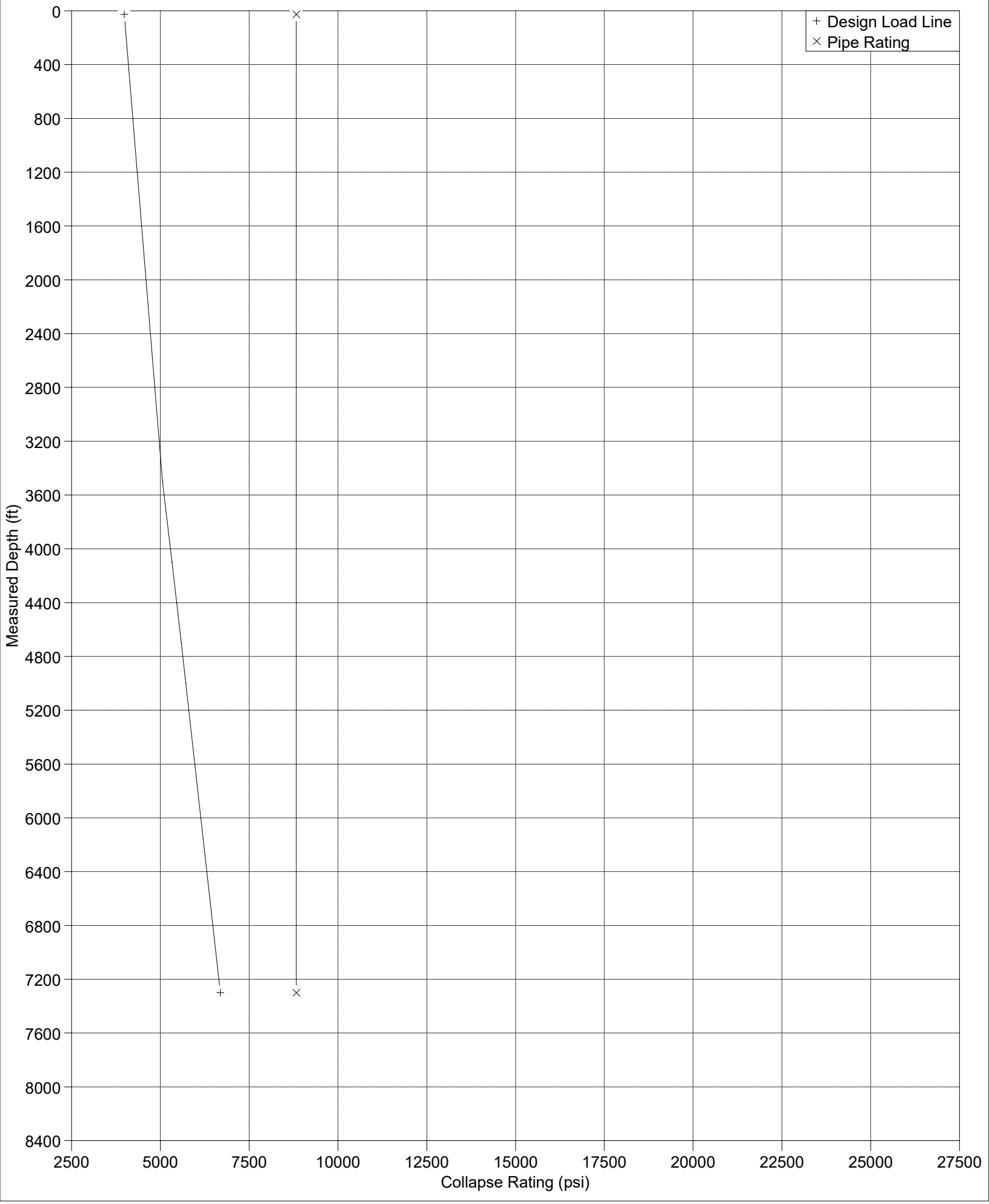
AXIAL LOADS TABLE (5 1/2" Production Tubing)

	Depth (MD) (ft)	Overpull Force (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	220492	220492	205092	205092
2	3499.99	164720	164720	135612	135612
3	3500.01	164720	164720	146094	135612
4	4099.99	154505	154505	134143	123661
5	4100.01	154505	154505	134143	123661
6	4399.99	149396	149396	128260	117778
7	4400.01	149395	149395	128260	117778
8	4699.99	144286	144286	122487	112005
9	4700.01	144285	144285	122487	112005
10	4999.99	139176	139176	106375	106375
11	5000.01	139176	139176	106374	106374
12	6267.14	117646	117593	82835	82835
13	7298.00	100131	100034	-106526	63684
14	7298.00	100131	100034	-106526	-106526

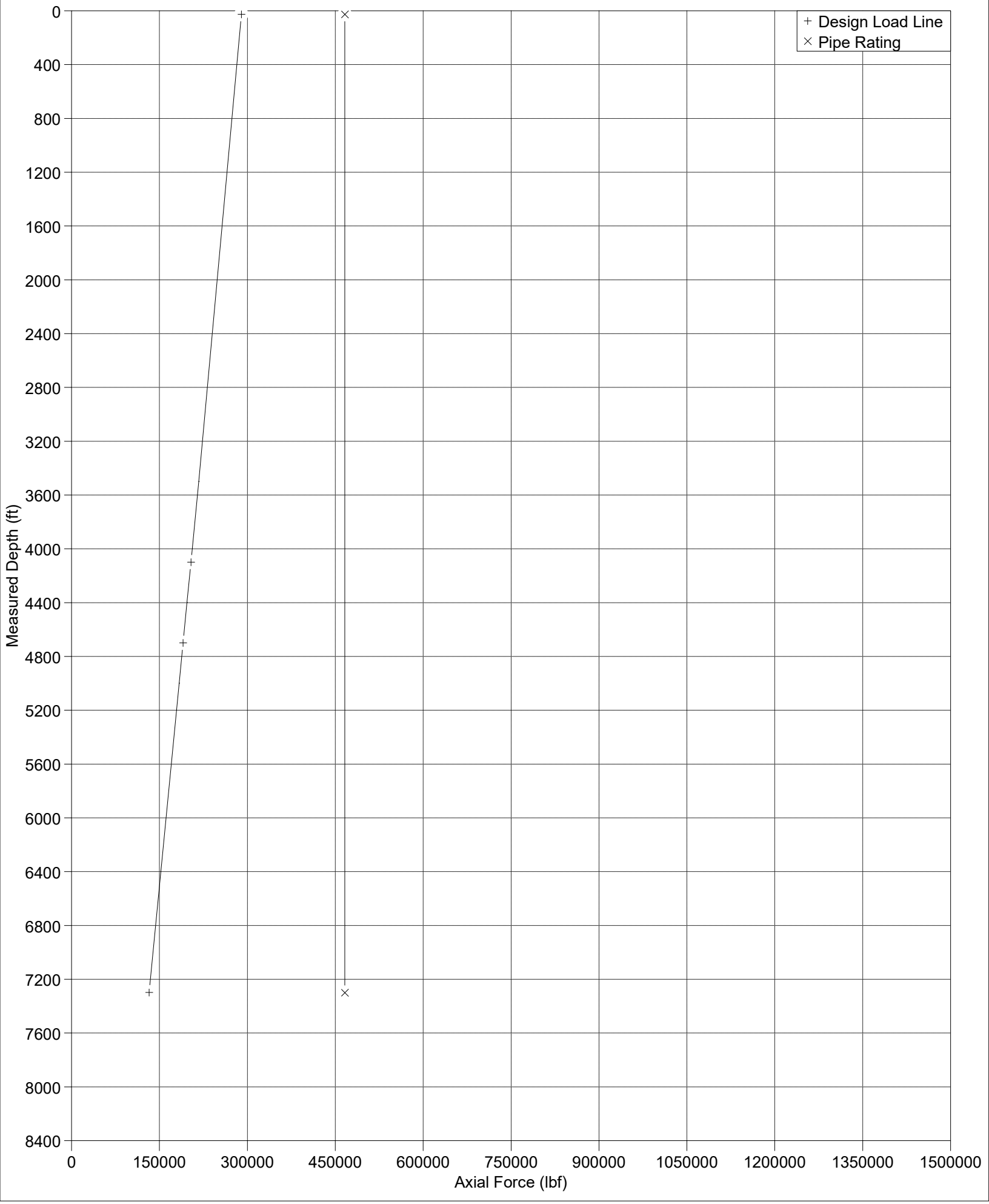
BURST DESIGN (5 1/2" Production Tubing)

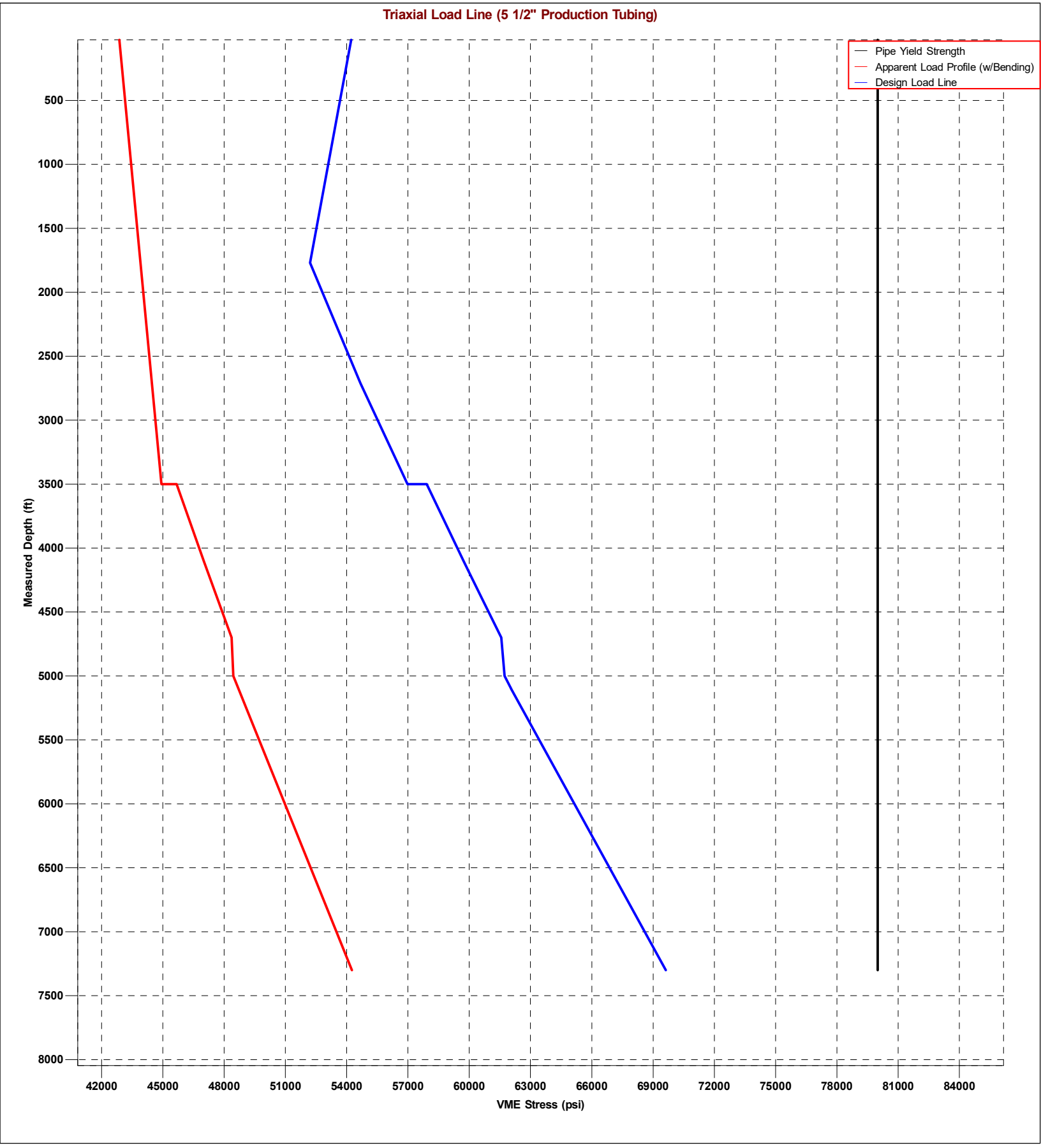


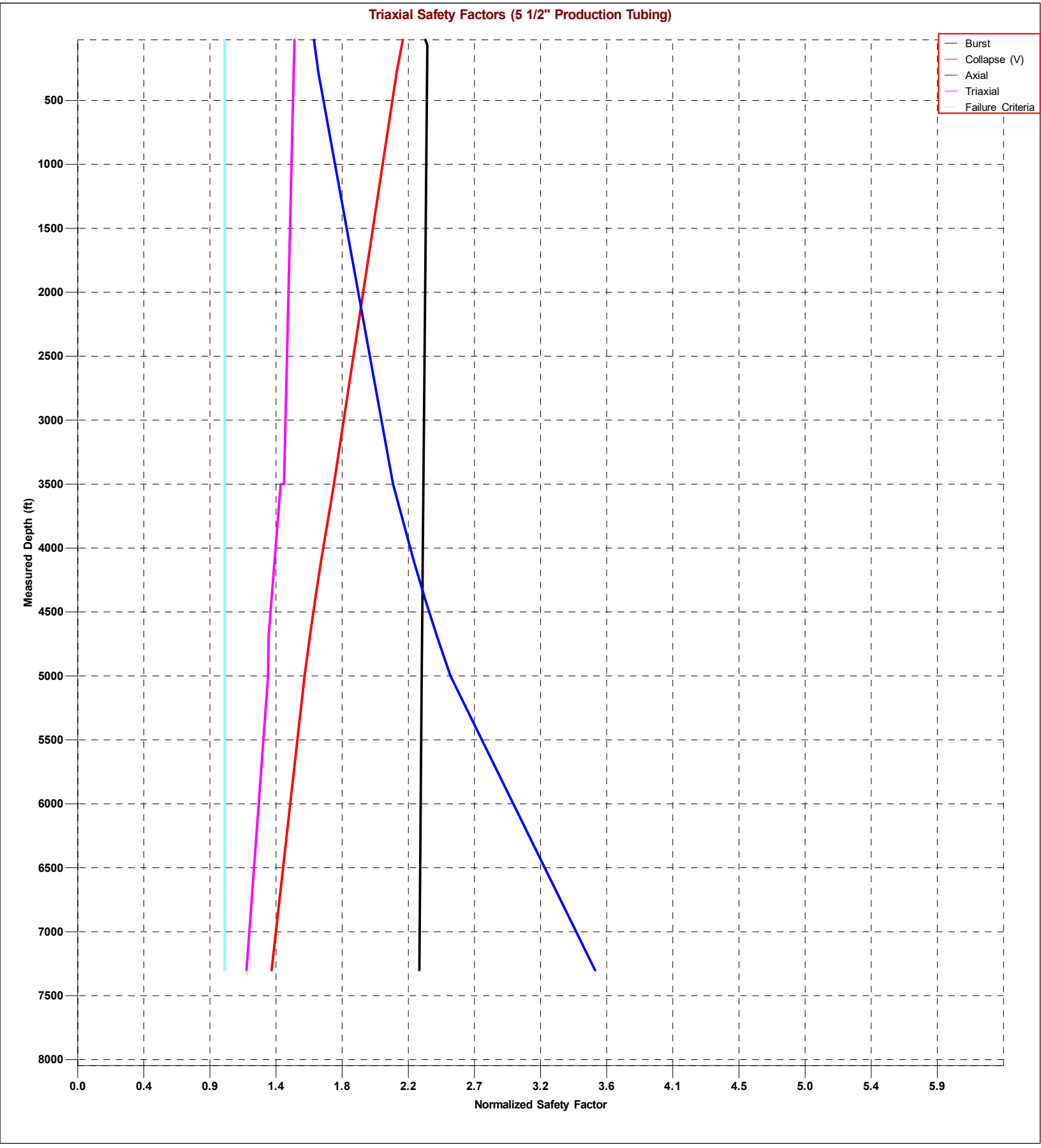
COLLAPSE DESIGN (5 1/2" Production Tubing)



AXIAL DESIGN (5 1/2" Production Tubing)




Triaxial Load Line (5 1/2" Production Tubing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
8000
42000
45000
48000
51000
54000
57000
60000
63000
66000
69000
72000
75000
78000
81000
84000
VME Stress (psi)


Triaxial Safety Factors (5 1/2" Production Tubing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
8000
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	5 1/2", 20.000 ppf, L-80	blue	2.60 B15	2.21 C19	2.09 A4	1.84 A4
2	69			2.62 B16	2.21 C19	2.10 A4	1.84 A4
3	277			2.62 B5	2.17 C19	2.13 A4	1.84 A4
4	3500			2.59 B5	1.74 C19	2.79 A4	1.76 C19
5	3500			2.59 B5	1.74 C19	2.79 A4	1.73 C19
6	4100			2.58 B5	1.66 C19	2.97 A4	1.67 C19
7	4400			2.58 B5	1.62 C19	3.07 A4	1.65 C19
8	4700			2.58 B5	1.58 C19	3.18 A4	1.62 C19
9	5000			2.58 B5	1.54 C19	3.30 A4	1.62 C19
10	7298			2.56 B5	1.32 C19	4.58 A4	1.44 C19
11	7299			2.56 B5	1.32 C19	4.58 A4	1.44 C19
12	7300			2.56 B5	1.32 C19	4.58 A4	1.44 C19
13							
14	B5	Pressure Test					
15	B15	Shut-In					
16	B16	Tubing Injection					
17	C19	Annular Pressure Test					
18	A4	Overpull Force					
19	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	5 1/2", 20.000 ppf, L-80	0.153 B15	0.244 C19	0.210 A4	57.7	32.3	41.9	0.208	0.117	0.151
2	69.39		0.152 B16	0.245 C19	0.209 A4	58.0	32.2	42.1	0.209	0.116	0.152
3	277.13		0.152 B5	0.247 C19	0.206 A4	57.9	31.7	42.9	0.209	0.114	0.155
4	3499.99		0.153 B5	0.276 C19	0.221 C19	57.5	23.5	38.9	0.208	0.085	0.140
5	3500.01		0.153 B5	0.276 C19	0.224 C19	57.5	23.5	38.1	0.208	0.085	0.137
6	4099.99		0.154 B5	0.282 C19	0.231 C19	57.4	21.8	36.0	0.207	0.079	0.130
7	4100.01		0.154 B5	0.282 C19	0.231 C19	57.4	21.8	36.0	0.207	0.079	0.130
8	4399.99		0.154 B5	0.285 C19	0.235 C19	57.4	21.0	34.9	0.207	0.076	0.126
9	4400.01		0.154 B5	0.285 C19	0.235 C19	57.4	21.0	34.9	0.207	0.076	0.126
10	4699.99		0.154 B5	0.288 C19	0.239 C19	57.3	20.2	33.9	0.207	0.073	0.122
11	4700.01		0.154 B5	0.288 C19	0.239 C19	57.3	20.2	33.9	0.207	0.073	0.122
12	4999.99		0.154 B5	0.291 C19	0.240 C19	57.3	19.4	33.5	0.207	0.070	0.121
13	5000.01		0.154 B5	0.291 C19	0.240 C19	57.3	19.4	33.5	0.207	0.070	0.121
14	7298.00		0.155 B5	0.313 C19	0.273 C19	57.0	13.4	24.5	0.206	0.048	0.088
15	7299.11		0.155 B5	0.313 C19	0.273 C19	57.0	13.4	24.5	0.206	0.048	0.088
16	7299.99		0.155 B5	0.313 C19	0.273 C19	57.0	13.4	24.5	0.206	0.048	0.088
17	7300.00		0.155 B5	0.313 C19	0.273 C19	57.0	13.4	24.5	0.206	0.048	0.088
18											
19	B5	Pressure Test									
20	B15	Shut-In									
21	B16	Tubing Injection									
22	C19	Annular Pressure Test									
23	A4	Overpull Force									
24	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (5 1/2" Production Tubing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	354504
2	26	354061
3	252	350216
4	503	345929
5	755	341641
6	1000	337471
7	1007	337354
8	1259	333066
9	1510	328778
10	1762	324491
11	2000	320438
12	2014	320203
13	2266	315916
14	2517	311628
15	2769	307340
16	3000	303405
17	3021	303053
18	3272	298765
19	3500	294889
20	3524	294478
21	3776	290194
22	4000	286397
23	4028	285931
24	4100	284711
25	4279	281707
26	4400	279701
27	4400	279700
28	4531	277540
29	4700	274784
30	4783	273448
31	5000	269989
32	5034	269443
33	5286	265461
34	5538	261478
35	5790	257496
36	6000	254168
37	6041	253513
38	6293	249531
39	6545	245548
40	6797	241565
41	7000	238347
42	7048	237583
43	7274	234012
44	7298	* 234105
45	7300	* 234113
46		
47	* Based on Casing Strength	
48	Only. Running String not	
49	Included	

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	158037	158037	158591	0.0	2.39	2.62	N/A	2.94	78	3513	13	0	0
2	3500	88557	88557	100372	0.0	2.75	2.59	N/A	5.19	115	5282	1782		
3	3500	99039	88557	111005	1798.5	2.71	2.59	N/A	4.64	115	5282	1782		
4	4100	87088	76606	100878	1798.5	2.75	2.58	N/A	5.27	122	5586	2086		
5	4400	81205	70723	95878	1798.5	2.77	2.58	N/A	5.64	125	5736	2236		
6	4700	75432	64950	90962	1798.5	2.78	2.58	N/A	6.07	128	5883	2383		
7	4700	75432	64949	90962	1798.5	2.78	2.58	N/A	6.07	128	5883	2383		
8	5000	59320	59320	75474	0.0	2.80	2.58	N/A	7.71	131	6026	2526		
9	5000	59319	59319	75474	0.0	2.80	2.58	N/A	7.71	131	6026	2526		
10	7298	16629	16629	38686	0.0	2.73	2.56	N/A	27.31	154	7113	3613		
11	7300	16592	16592	38654	0.0	2.73	2.56	N/A	27.37	154	7114	3614		
12														
13	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Shut-In

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	83115	83115	85699	0.0	2.81	2.60	N/A	5.45	165	3440	13	25503	4948
2	3500	20669	13636	31990	1206.8	4.88	4.60	N/A	21.90	165	3720	1782		
3	3500	31151	13635	42787	3005.3	4.75	4.60	N/A	14.53	165	3720	1782		
4	4100	17655	1685	30711	2740.1	5.26	5.30	N/A	25.64	165	3768	2086		
5	4100	15027	1684	28004	2289.3	5.32	5.30	N/A	30.12	165	3768	2086		
6	4186	-13573	-10	-1199	2327.0	5.39	5.42	N/A	(33.35)	165	3775	2129		
7	4186	-13256	-11	-872	2272.6	5.39	5.42	N/A	(34.14)	165	3775	2129		
8	4400	-18161	-4198	-5285	2395.7	5.56	5.73	N/A	(24.92)	165	3792	2236		
9	4400	-17543	-4199	-4648	2289.5	5.58	5.73	N/A	(25.80)	165	3792	2236		
10	4700	-24345	-9972	-10773	2466.1	5.80	6.23	N/A	(18.59)	165	3815	2383		
11	4700	-23318	-9972	-9715	2289.8	5.84	6.23	N/A	(19.41)	165	3815	2383		
12	5000	-19875	-15602	-5308	733.3	6.45	6.80	N/A	(22.77)	165	3838	2526		
13	5000	-19516	-15602	-4938	671.5	6.47	6.80	N/A	(23.19)	165	3838	2526		
14	7298	-78935	-58292	-59623	3541.9	6.00	22.48	N/A	(5.73)	165	4009	3613		
15	7300	-78975	-58329	-59658	3542.3	6.00	22.53	N/A	(5.73)	165	4010	3614		
16	7300	-79565	-58329	-60267	3643.6	5.96	22.53	N/A	(5.69)	165	4010	3614		
17														
18	( )	Compression												
19	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Injection

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	205092	205092	205788	0.0	2.04	2.62	N/A	2.27	78	3514	13	0	0
2	3500	135612	135612	146438	0.0	2.48	2.59	N/A	3.43	78	5318	1782		
3	3500	146094	135612	156951	1798.5	2.42	2.59	N/A	3.18	78	5318	1782		
4	4100	134143	123661	146743	1798.5	2.49	2.59	N/A	3.47	78	5629	2086		
5	4100	134143	123661	146742	1798.5	2.49	2.59	N/A	3.47	78	5629	2086		
6	4400	128260	117778	141717	1798.5	2.53	2.58	N/A	3.62	78	5781	2236		
7	4700	122487	112005	136786	1798.5	2.56	2.58	N/A	3.80	78	5931	2383		
8	4700	122487	112005	136785	1798.5	2.56	2.58	N/A	3.80	78	5931	2383		
9	5000	106375	106375	121463	0.0	2.64	2.58	N/A	4.37	78	6078	2526		
10	5000	106374	106374	121462	0.0	2.64	2.58	N/A	4.37	78	6078	2526		
11	7298	63684	63684	84996	0.0	2.77	2.56	N/A	7.30	78	7186	3613		
12	7300	63647	63647	84964	0.0	2.77	2.56	N/A	7.30	78	7187	3614		
13														
14	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Full/Partial Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	100562	100562	100866	0.0	4.07	N/A	4.62	4.62	78	0	13	0	0
2	3500	31083	31083	31543	0.0	3.91	N/A	4.24	14.79	115	2	1782		
3	3500	41564	31082	42176	1798.5	3.70	N/A	4.24	11.06	115	2	1782		
4	4100	29614	19132	30114	1798.5	3.52	N/A	3.90	15.49	122	2	2086		
5	4400	23731	13249	24159	1798.5	3.42	N/A	3.73	19.31	125	2	2236		
6	4400	23730	13248	24158	1798.5	3.42	N/A	3.73	19.31	125	2	2236		
7	4700	17958	7475	18303	1798.5	3.32	N/A	3.58	25.50	128	3	2383		
8	4700	17957	7475	18303	1798.5	3.32	N/A	3.58	25.50	128	3	2383		
9	5000	1845	1845	1897	0.0	3.34	N/A	3.43	+ 100.00	131	3	2526		
10	5099	0	0	17	0.0	3.30	N/A	3.39	+ 100.00	132	3	2573		
11	5099	-0	-0	16	0.0	3.30	N/A	3.39	(+ 100.00)	132	3	2573		
12	7298	-40845	-40845	-41907	0.0	2.58	N/A	2.40	(11.12)	154	4	3613		
13	7300	-40882	-40882	-41945	0.0	2.58	N/A	2.40	(11.11)	154	4	3614		
14														
15	( )	Compression												
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Leak (Collapse)

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	34881	34881	53828	0.0	7.96	N/A	8.66	12.98	165	2981	2981	0	0
2	1770	0	0	18739	0.0	8.74	N/A	9.34	+ 100.00	165	3121	3869		
3	1770	-0	-0	18739	0.0	8.74	N/A	9.34	(+ 100.00)	165	3121	3869		
4	3500	-34599	-34599	-16066	0.0	6.27	N/A	5.80	(13.08)	165	3260	4749		
5	3500	-45081	-34599	-26864	1798.5	6.01	N/A	5.80	(10.04)	165	3260	4749		
6	4100	-57031	-46549	-38886	1798.5	5.36	N/A	4.95	(7.94)	165	3308	5054		
7	4100	-57032	-46550	-38886	1798.5	5.36	N/A	4.95	(7.94)	165	3308	5054		
8	4400	-62915	-52432	-44804	1798.5	5.06	N/A	4.62	(7.19)	165	3332	5203		
9	4400	-62915	-52433	-44805	1798.5	5.06	N/A	4.62	(7.19)	165	3332	5203		
10	4700	-68688	-58206	-50612	1798.5	4.79	N/A	4.33	(6.59)	165	3355	5350		
11	5000	-63836	-63836	-45478	0.0	4.58	N/A	4.08	(7.09)	165	3378	5494		
12	7298	-106526	-106526	-88423	0.0	3.18	N/A	2.85	(4.25)	165	3550	6580		
13	7300	-106563	-106563	-88460	0.0	3.18	N/A	2.85	(4.25)	165	3550	6581		
14	7300	-106564	-106564	-88461	0.0	3.18	N/A	2.85	(4.25)	165	3550	6581		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Annular Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	53686	53686	53860	0.0	2.06	N/A	2.21	8.66	78	2	3513	0	0
2	2710	0	0	1246	0.0	1.83	N/A	1.87	+ 100.00	107	211	4880		
3	2710	-0	-0	1245	0.0	1.83	N/A	1.87	(+ 100.00)	107	211	4880		
4	3500	-15794	-15794	-14410	0.0	1.76	N/A	1.74	(29.10)	115	273	5282		
5	3500	-26276	-15794	-25044	1798.5	1.73	N/A	1.74	(17.49)	115	273	5282		
6	4100	-38227	-27745	-36964	1798.5	1.67	N/A	1.66	(12.00)	122	319	5586		
7	4400	-44110	-33628	-42849	1798.5	1.65	N/A	1.62	(10.39)	125	342	5736		
8	4400	-44110	-33628	-42850	1798.5	1.65	N/A	1.62	(10.39)	125	342	5736		
9	4700	-49883	-39401	-48636	1798.5	1.62	N/A	1.58	(9.18)	128	365	5883		
10	4700	-49883	-39401	-48637	1798.5	1.62	N/A	1.58	(9.18)	128	365	5883		
11	5000	-45031	-45031	-43605	0.0	1.62	N/A	1.54	(10.16)	131	387	6026		
12	5000	-45032	-45032	-43606	0.0	1.62	N/A	1.54	(10.16)	131	387	6026		
13	7298	-87722	-87722	-86744	0.0	1.44	N/A	1.32	(5.18)	154	553	7113		
14	7300	-87759	-87759	-86782	0.0	1.44	N/A	1.32	(5.18)	154	553	7114		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	220492	220492	223160	0.0	1.84	N/A	N/A	2.09	107	13	13	N/A	N/A
2	3500	164720	164720	177657	0.0	2.33	N/A	N/A	2.79	116	1782	1782		
3	3500	164720	164720	177657	1798.5	2.33	N/A	N/A	2.79	116	1782	1782		
4	4100	154505	154505	169174	1798.5	2.45	N/A	N/A	2.97	117	2086	2086		
5	4400	149396	149396	164912	1798.5	2.52	N/A	N/A	3.07	118	2236	2236		
6	4400	149395	149395	164912	1798.5	2.52	N/A	N/A	3.07	118	2236	2236		
7	4700	144286	144286	160631	1798.5	2.59	N/A	N/A	3.18	119	2383	2383		
8	4700	144285	144285	160631	1798.5	2.59	N/A	N/A	3.18	119	2383	2383		
9	5000	139176	139176	156326	0.0	2.66	N/A	N/A	3.30	120	2526	2526		
10	5000	139176	139176	156325	0.0	2.66	N/A	N/A	3.30	120	2526	2526		
11	7298	100131	100034	123311	0.0	3.41	N/A	N/A	4.58	125	3613	3613		
12	7299	100112	100015	123295	0.0	3.41	N/A	N/A	4.58	125	3613	3613		
13	7300	100097	100000	123282	0.0	3.41	N/A	N/A	4.58	125	3614	3614		
14														
15	(V)	Vector Collapse Safety Factor												

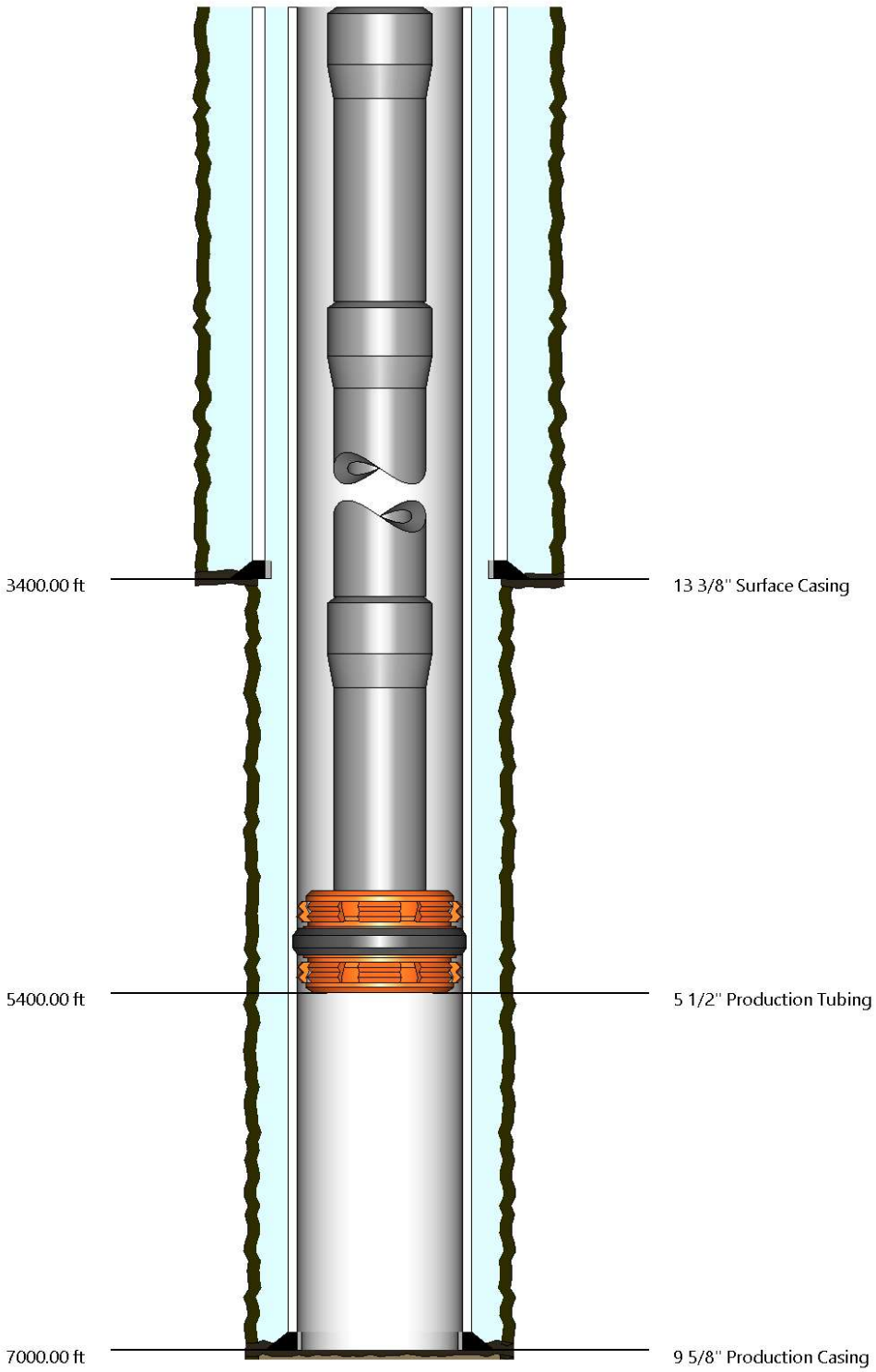
GENERAL DATA

Description:	Bluebonnet CCS 5 Final
Well Options, Deviated:	Yes
Well Options, Offshore:	No
Well TD (MD):	7000.00 ft
Reference Point:	OTR
Air Gap:	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	0.00 °

WELL SUMMARY

	String	OD/Weight/Grade	Connection	MD Interval (ft)	Drift Dia. (in)	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V	Axial	Triaxial	
1	Surface Casing	13 3/8", 61.000 ppf, K-55	BTC, K-55	26.00-3400.00	12.359	1.18	1.35	2.51	1.32	94,695
2										Total = 94,695
3										
4	Production Casing	9 5/8", 53.500 ppf, L-80	Blue	26.00-4100.00	8.500 A	2.07	2.45	3.05	2.17	126,912
5		9 5/8", 53.500 ppf, L-80	Blue	4100.00-7000.00	8.500 A	1.98	1.44	4.63	1.85	90,340
6										Total = 217,252
7										
8	Production Tubing	5 1/2", 20.000 ppf, L-80	Blue	26.00-5400.00	4.653	2.57	1.49	2.41	1.63	66,946
9										Total = 66,946
10										
11										Total = 378,893
12	A Alternate Drift									
13	(V) Vector Collapse Safety Factor									

WELL SCHEMATIC (DEPTH - MD)



CASING AND TUBING SCHEME

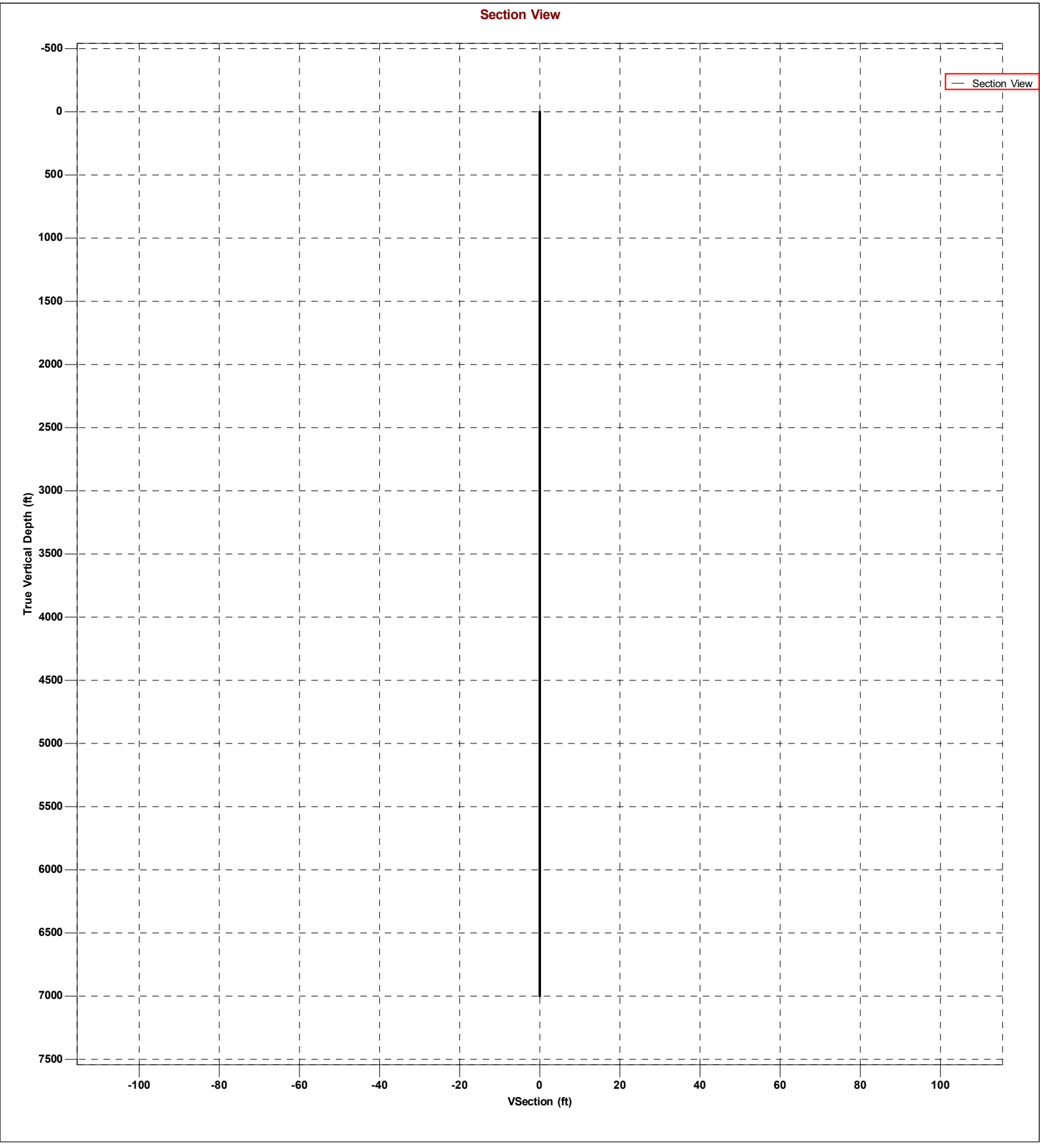
	OD (in)	Name	Type	Hole Size (in)	Measured Depths (ft)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	13 3/8"	Surface	Casing	17.500	26.00	3400.00	26.00	10.00
2	9 5/8"	Production	Casing	12.250	26.00	7000.00	26.00	12.50
3	5 1/2"	Production	Tubing		26.00	5400.00		9.80

PRODUCTION DATA

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6320.00 ft
Gas Gravity:	0.70

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.00	0.00			0.00	0.00
2	MD-INC-AZ	7000.00	0.00	0.00	7000.00	0.00	0.00	0.00	0.00

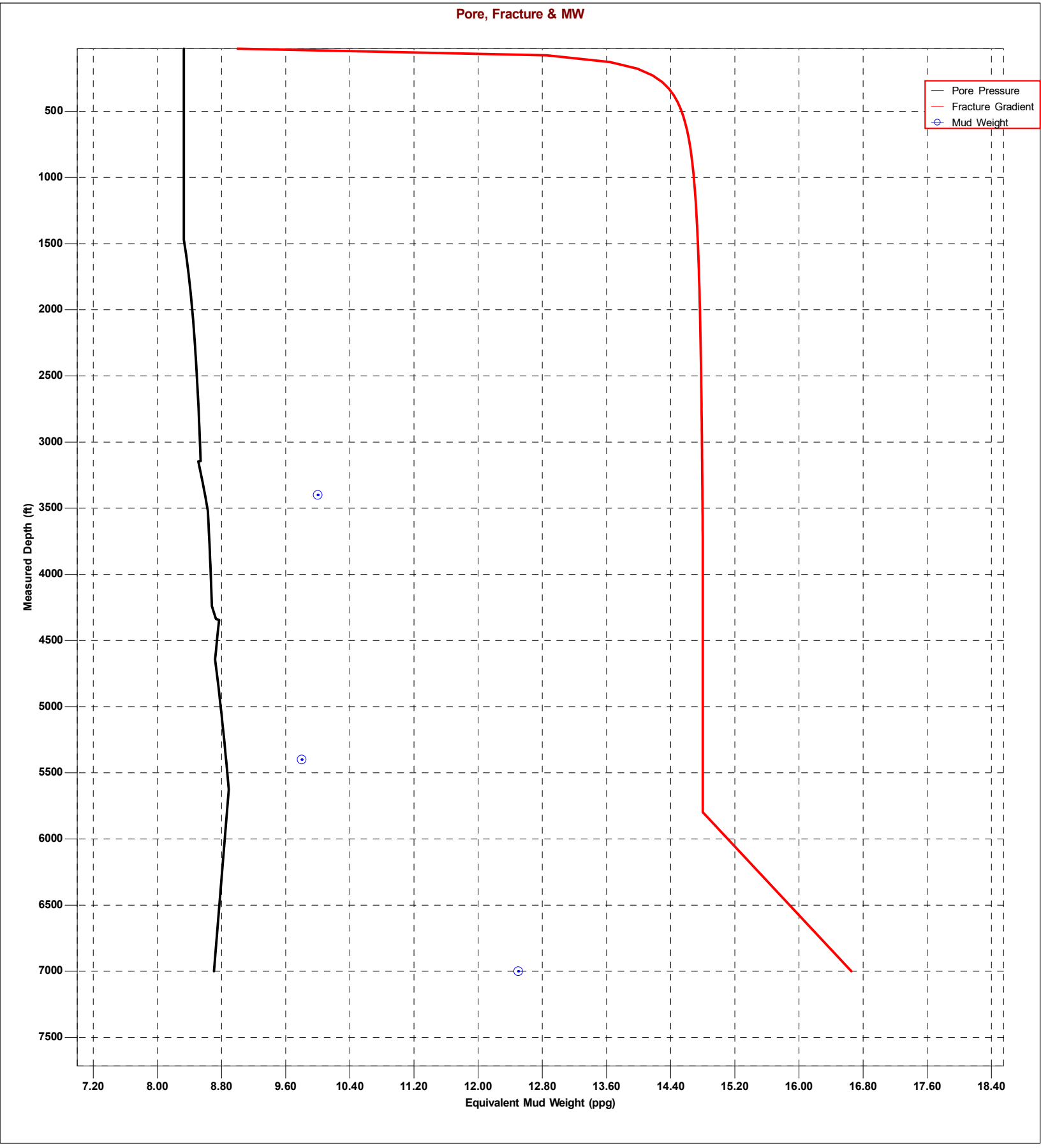

Section View
Section View
-500
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
True Vertical Depth (ft)
-100
-80
-60
-40
-20
0
20
40
60
80
100
VSection (ft)

PORE PRESSURE

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	0	8.33	No
2	1470.00	636	8.33	No
3	3144.00	1395	8.54	No
4	3146.00	1391	8.51	No
5	3521.00	1579	8.63	No
6	4240.00	1912	8.68	No
7	4337.00	1967	8.73	No
8	4344.00	1979	8.77	No
9	4643.00	2103	8.72	No
10	5626.00	2598	8.89	No
11	7666.00	3441	8.64	No
12	8182.00	3660	8.61	No
13	9300.00	4155	8.60	No

FRACTURE GRADIENT

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	0	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9300.00	8455	17.50


Pore, Fracture & MW
Pore Pressure
Fracture Gradient
Mud Weight
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
7.20
8.00
8.80
9.60
10.40
11.20
12.00
12.80
13.60
14.40
15.20
16.00
16.80
17.60
18.40
Equivalent Mud Weight (ppg)

GEOTHERMAL GRADIENT DATA

Surface Ambient:	78 °F
Bottomhole Temperature - 7000.00 ft TVD:	153 °F
Bottomhole Gradient - 7000.00 ft TVD:	1.08 °F/100ft

DESIGN PARAMETERS DATA (13 3/8" Surface Casing)

Design Factor (Pipe) - Axial Tension:	1.400
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.400
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	12.250 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (13 3/8" Surface Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3400.00 ft	114 °F

BURST LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 3400.00 ft):	2612 psi
Mud/Water Interface, MD:	3400.00 ft
Mud Weight	7.82 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	7000.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	1.00 ppg
Maximum Mud Weight:	12.50 ppg
Kick Gas Gravity:	0.70 (0.1167 psi/ft @ 124 °F & 4909 psi)
Fracture at Shoe (MD= 3400.00 ft):	2612 psi
Drill Pipe OD:	5.500 in
Collar OD:	8.000 in
Collar Length:	300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	1500 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Fracture @ Shoe w/ Gas Gradient Above**
Gas Gradient:	0.1000 psi/ft
Shoe Depth, MD :	3400.00 ft
Fracture Pressure at Shoe:	2612 psi
Fracture Margin of Error:	0.00 ppg
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2600 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3400.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3400.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	7000.00 ft
Pore Pressure at Lost Returns Depth:	3128 psi
Pore Pressure Gradient at Lost Returns Depth:	8.60 ppg
Mud Weight:	12.50 ppg
Mud Drop Level, MD:	2182.40 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (13 3/8" Surface Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	2600 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Lost Returns (psi)	Gas Kick (psi)	Pressure Test (psi)	Fracture @ Shoe w/ Gas Gradient Above (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	1152	1190	1514	2275	2611	14	0
2	1470.00	1777	1920	2264	2419	3236	951	636
3	2700.00	2309	2543	2903	2542	3768	1750	1194
4	3144.00	2502	2768	3133	2587	3960	2114	1395
5	3146.00	2502	2769	3134	2587	3961	2116	1391
6	3400.00	2612	2897	3266	2612	4071	2324	1518

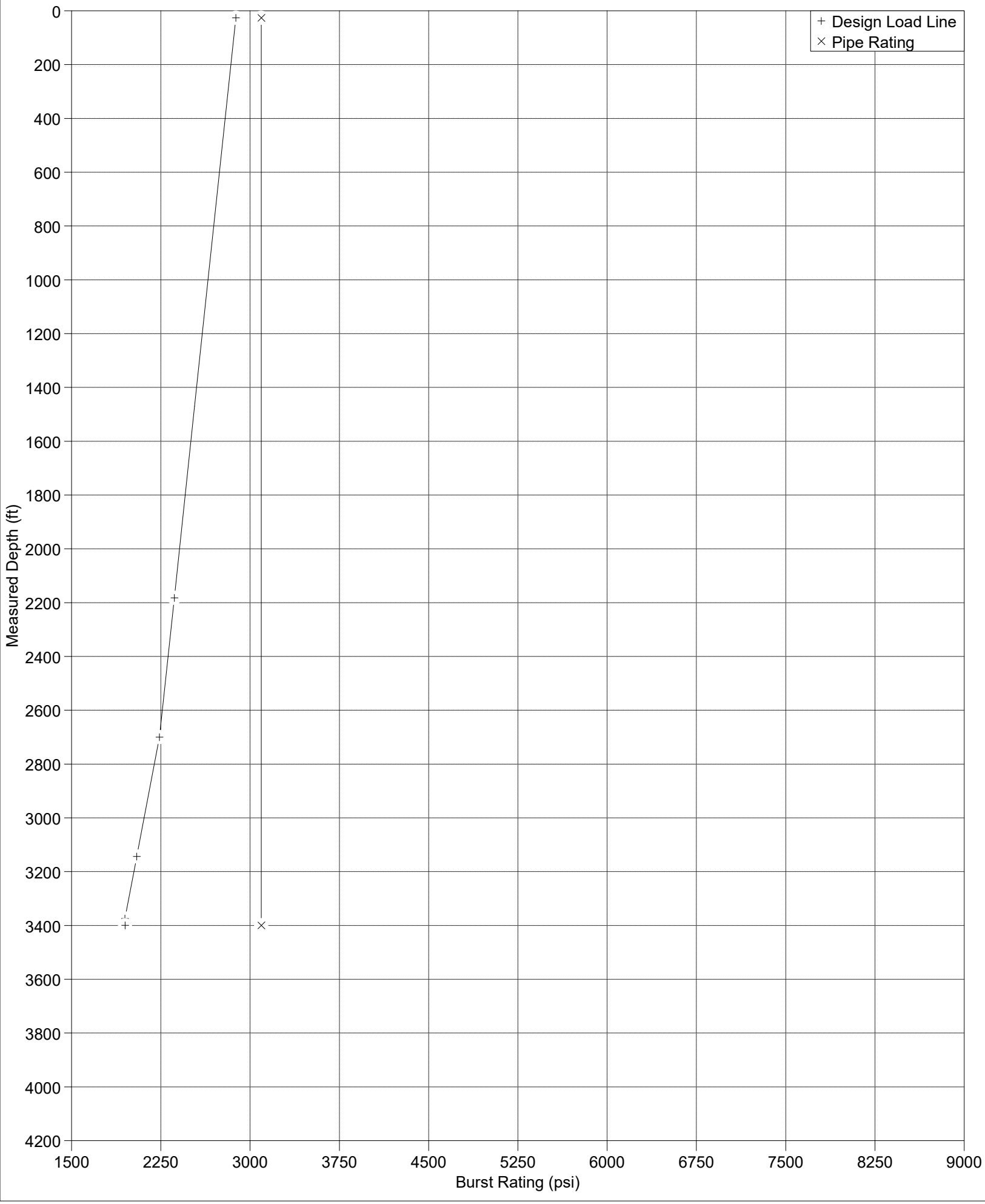
COLLAPSE PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Lost Returns (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	14	0	14
2	2182.40	944	1414	0	1134
3	2700.00	1168	1750	336	1403
4	3400.00	1471	2324	791	1766

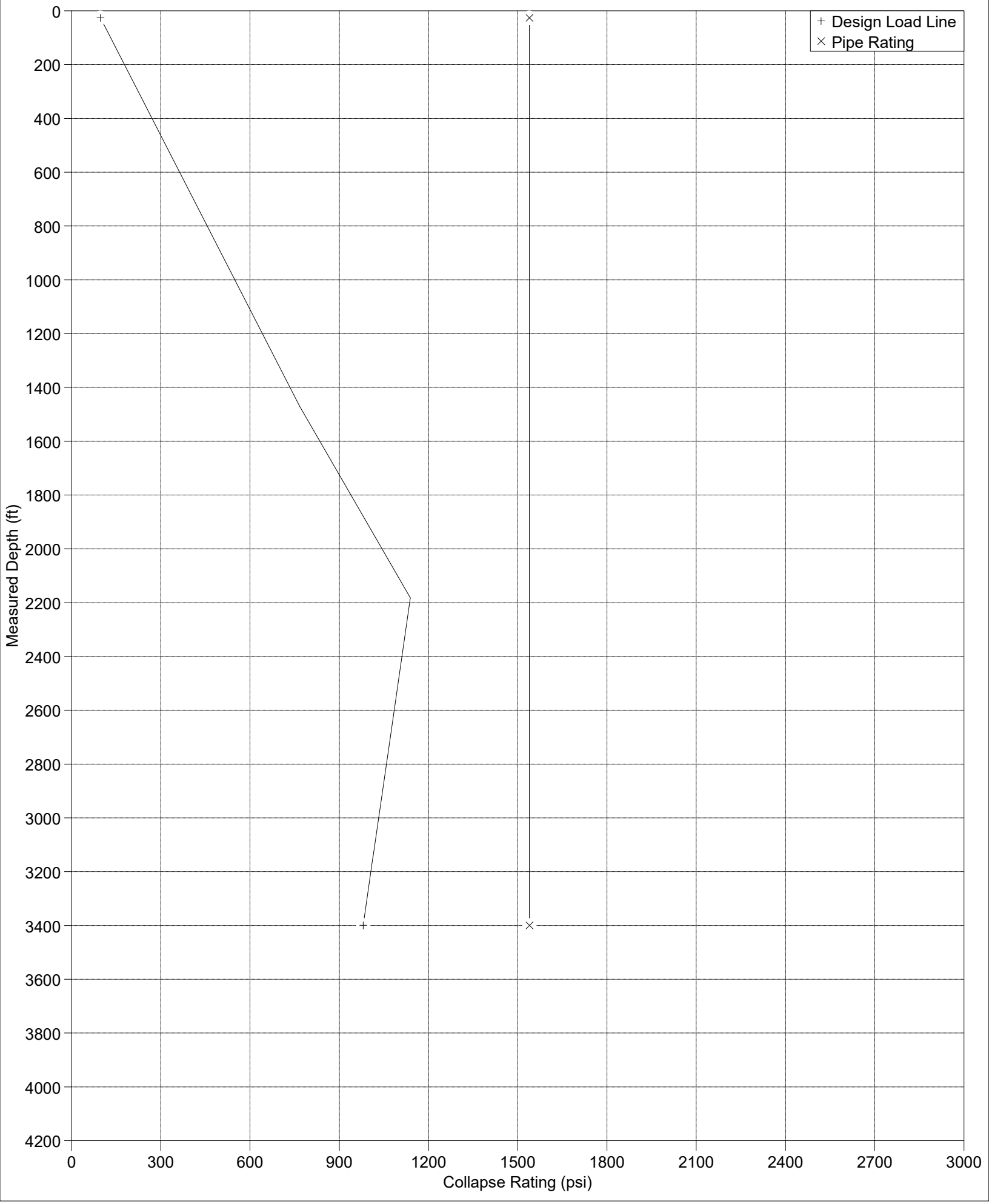
AXIAL LOADS TABLE (13 3/8" Surface Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	275164	275164	380053	380053	380053	380053
2	855.54	232098	232098	329451	329451	329451	329451
3	1470.00	200197	200197	291969	291969	291969	291969
4	2182.40	163213	163213	248513	248513	248513	248513
5	2700.00	136341	136341	216939	216939	216939	216939
6	3144.00	113290	113290	189855	189855	189855	189855
7	3146.00	113187	113187	189733	189733	189733	189733

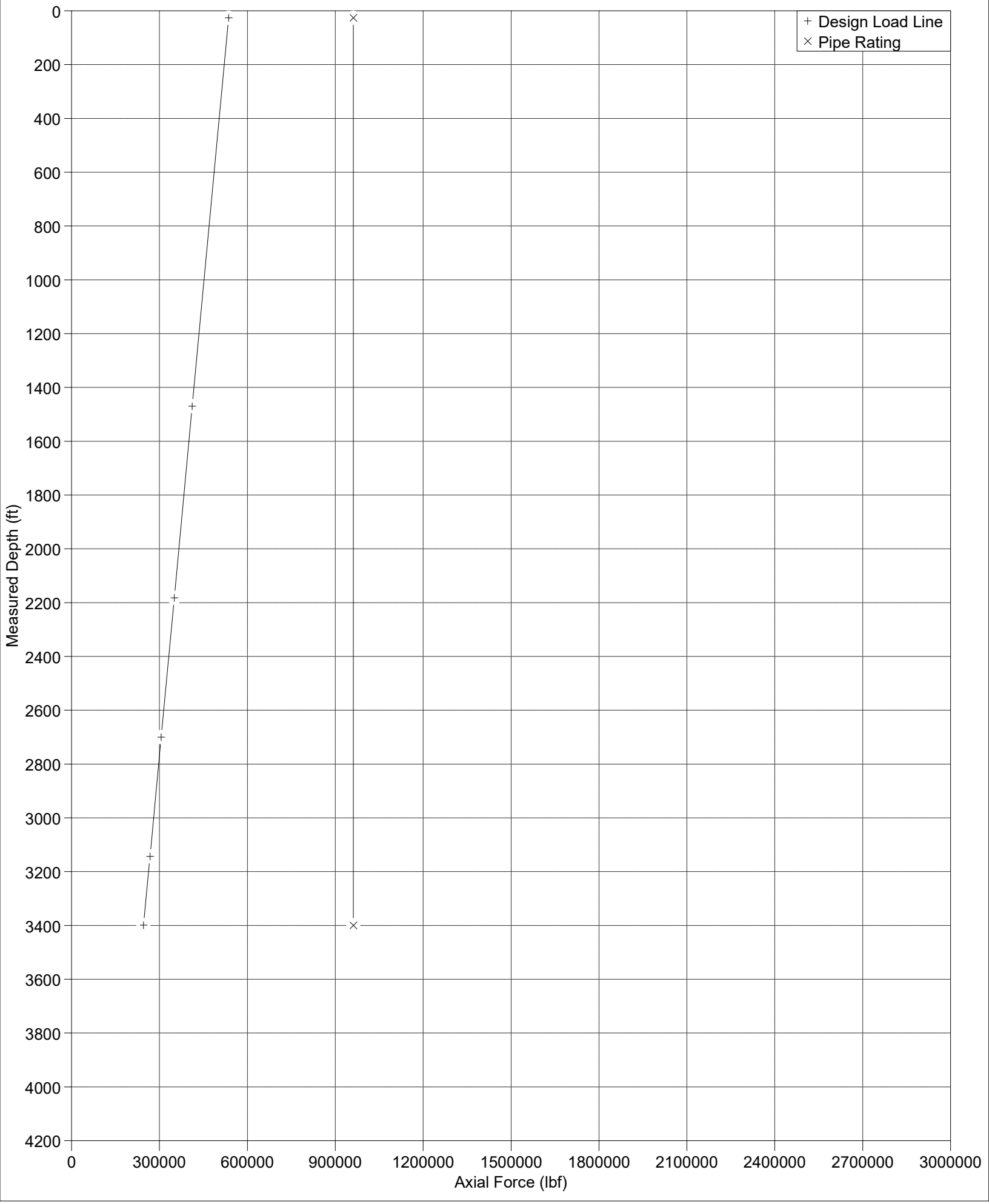
BURST DESIGN (13 3/8" Surface Casing)

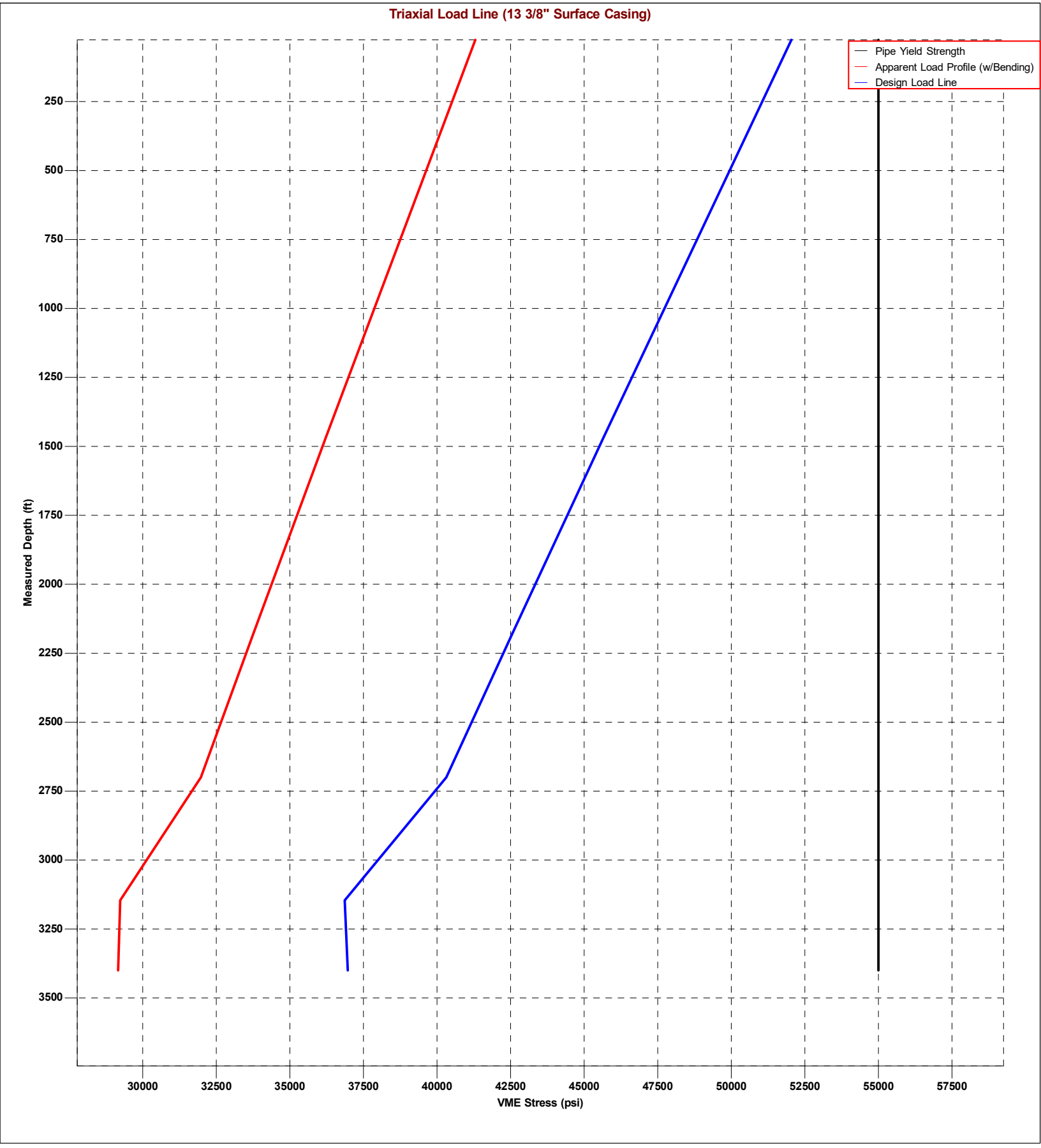


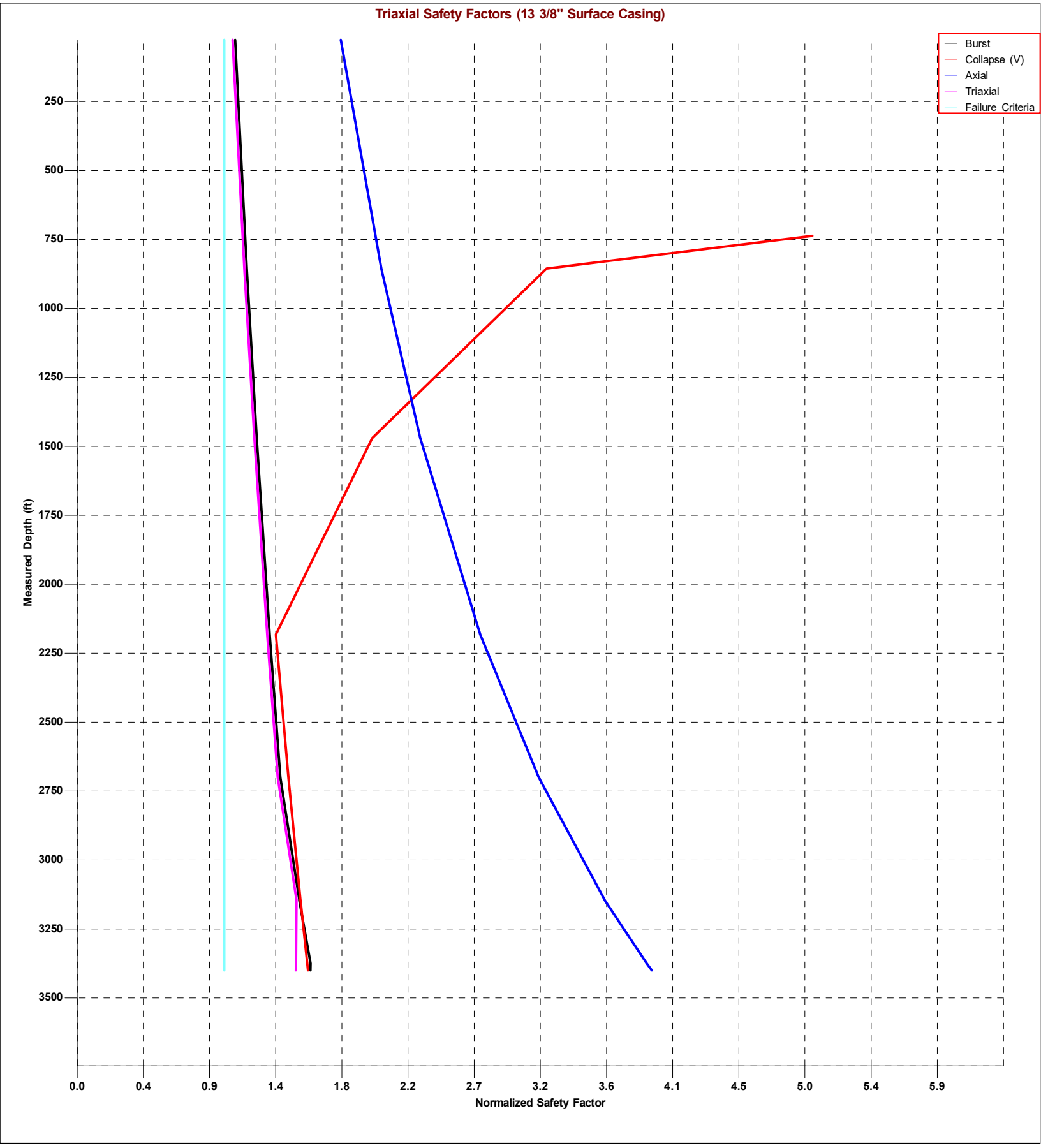
COLLAPSE DESIGN (13 3/8" Surface Casing)



AXIAL DESIGN (13 3/8" Surface Casing)




Triaxial Load Line (13 3/8" Surface Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
30000
32500
35000
37500
40000
42500
45000
47500
50000
52500
55000
57500
VME Stress (psi)


Triaxial Safety Factors (13 3/8" Surface Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	13 3/8", 61.000 ppf, K-55	BTC, K-55	1.18 B12	15.79 C2	2.51 B12	1.32 B12
2	856			1.27 B12	3.19 C4	2.90 B12	1.42 B12
3	1470			1.34 B12	2.01 C4	3.27 A5	1.51 B12
4	2182			1.44 B12	1.35 C4	3.84 A5	1.62 B12
5	2700			1.52 B12	1.44 C4	4.40 A5	1.71 B12
6	3144			1.66 B12	1.52 C4	5.02 A5	1.86 B12
7	3146			1.66 B12	1.52 C4	5.02 A5	1.86 B12
8	3375			1.75 B5	1.56 C4	5.42 A5	1.86 B5
9	3396			1.75 B5	1.57 C4	5.46 A5	1.86 B5
10	3399			1.75 B5	1.57 C4	5.47 A5	1.86 B5
11	3400			1.75 B5	1.57 C4	5.47 A5	1.86 B5
12							
13	B5	Pressure Test					
14	B12	Green Cement Pressure Test(Burst)					
15	C2	Cementing					
16	C4	Lost Returns with Mud Drop					
17	A5	Green Cement Pressure Test(Axial)					
18	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (13 3/8" Surface Casing)

	Depth (MD)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	13 3/8", 61.000 ppf, K-5	0.400 B12	0.088 C4	0.355 B12	6.9	79.6	17.4	0.030	0.342	0.075
2	855.54		0.373 B12	0.279 C4	0.329 B12	13.3	35.1	23.4	0.057	0.151	0.101
3	1470.00		0.352 B12	0.333 C4	0.311 B12	18.1	22.5	27.8	0.078	0.097	0.119
4	2182.40		0.328 B12	0.381 C4	0.289 B12	23.6	11.5	32.8	0.102	0.049	0.141
5	2700.00		0.311 B12	0.372 C4	0.274 B12	27.6	13.4	36.3	0.119	0.058	0.156
6	3144.00		0.285 B12	0.365 C4	0.251 B5	33.8	15.1	41.7	0.145	0.065	0.179
7	3146.00		0.285 B12	0.365 C4	0.251 B5	33.8	15.1	41.5	0.145	0.065	0.179
8	3374.51		0.271 B5	0.362 C4	0.253 B5	37.0	15.9	41.1	0.159	0.068	0.177
9	3396.45		0.271 B5	0.361 C4	0.253 B5	37.0	16.0	41.1	0.159	0.069	0.177
10	3399.18		0.271 B5	0.361 C4	0.253 B5	37.0	16.0	41.1	0.159	0.069	0.177
11	3400.00		0.271 B5	0.361 C4	0.253 B5	37.0	16.0	41.0	0.159	0.069	0.177
12											
13	B5	Pressure Test									
14	B12	Green Cement Pressure Test(Burst)									
15	C4	Lost Returns with Mud Drop									
16	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (13 3/8" Surface Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	681474
2	26	680125
3	26	680124
4	262	667896
5	523	654318
6	785	640740
7	1000	629559
8	1046	627162
9	1308	613584
10	1569	600007
11	1831	586429
12	2000	577643
13	2092	572851
14	2354	559273
15	2615	545695
16	2877	532117
17	3000	525727
18	3138	518539
19	3374	506311
20	3400	* 506543
21		
22	* Based on Casing Strength	
23	Only. Running String not	
24	Included	

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Gas Kick Profile

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	45892	45892	46427	0.0	2.72	2.57	N/A	20.72	106	1190	0	N/A	N/A
2	1470	33629	33629	45326	0.0	2.50	2.38	N/A	28.24	110	1920	636		
3	2182	26816	26816	44170	0.0	2.42	2.31	N/A	35.39	112	2281	959		
4	2700	21866	21866	43329	0.0	2.36	2.26	N/A	43.39	113	2543	1194		
5	3144	24037	24037	49114	0.0	2.33	2.22	N/A	39.45	114	2768	1395		
6	3146	24461	24461	49474	0.0	2.32	2.21	N/A	38.77	114	2769	1391		
7	3400	24688	24688	51969	0.0	2.33	2.21	N/A	38.41	115	2897	1518		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Water

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	145576	145576	146015	0.0	3.00	2.68	N/A	6.59	78	1152	0	N/A	N/A
2	1470	139126	139126	150703	0.0	3.03	2.70	N/A	6.89	78	1777	636		
3	2182	135181	135181	152410	0.0	3.07	2.74	N/A	7.09	78	2085	959		
4	2700	132315	132315	153650	0.0	3.10	2.76	N/A	7.25	78	2309	1194		
5	3144	136273	136273	161149	0.0	3.12	2.79	N/A	7.04	78	2502	1395		
6	3146	136706	136706	161513	0.0	3.11	2.78	N/A	7.01	78	2502	1391		
7	3400	137956	137956	164996	0.0	3.15	2.82	N/A	6.95	78	2612	1518		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	172236	172236	172756	0.0	2.29	2.04	N/A	5.57	78	1514	0	N/A	N/A
2	1470	118819	118819	130949	0.0	2.08	1.89	N/A	8.03	94	2264	636		
3	2182	91703	91703	109567	0.0	1.99	1.83	N/A	10.38	101	2634	959		
4	2700	72002	72002	93970	0.0	1.93	1.79	N/A	13.20	107	2903	1194		
5	3144	61518	61518	87049	0.0	1.88	1.76	N/A	15.43	112	3133	1395		
6	3146	61886	61886	87351	0.0	1.87	1.75	N/A	15.34	112	3134	1391		
7	3400	54874	54874	82568	0.0	1.86	1.75	N/A	17.28	114	3266	1518		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Fracture @ Shoe w/ Gas Gradient Above

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	125996	125996	127465	0.0	1.45	1.34	N/A	7.55	106	2275	0	N/A	N/A
2	1470	70451	70451	82621	0.0	1.83	1.71	N/A	13.48	110	2419	636		
3	2182	42285	42285	59846	0.0	2.10	1.99	N/A	22.44	112	2491	959		
4	2700	21821	21821	43283	0.0	2.36	2.26	N/A	43.48	113	2542	1194		
5	3144	10683	10683	35571	0.0	2.66	2.56	N/A	88.77	114	2587	1395		
6	3146	11048	11048	35870	0.0	2.66	2.55	N/A	85.84	114	2587	1391		
7	3400	3661	3661	30640	0.0	2.89	2.79	N/A	+ 100.00	115	2612	1518		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	380053	380053	383374	0.0	1.32	1.18	N/A	2.51	95	2611	14	N/A	N/A
2	1470	291969	291969	311208	0.0	1.51	1.34	N/A	3.27	96	3236	951		
3	2182	248513	248513	275588	0.0	1.62	1.44	N/A	3.84	96	3544	1414		
4	2700	216939	216939	249700	0.0	1.71	1.52	N/A	4.40	97	3768	1750		
5	3144	189855	189855	228832	0.0	1.86	1.66	N/A	5.02	97	3960	2114		
6	3146	189733	189733	228738	0.0	1.86	1.66	N/A	5.02	97	3961	2116		
7	3399	174289	174289	216836	0.0	1.97	1.76	N/A	5.47	97	4071	2324		
8	3400	174239	174239	216797	0.0	1.97	1.76	N/A	5.47	97	4071	2324		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Mud Drop

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-43055	-43055	-43557	0.0	20.23	N/A	+ 100.00	(22.08)	106	0	14	N/A	N/A
2	1470	-118868	-118868	-120392	0.0	4.48	N/A	2.01	(7.99)	110	0	764		
3	2182	-156270	-156270	-158364	0.0	3.02	N/A	1.35	(6.07)	112	0	1134		
4	2700	-158638	-158638	-154871	0.0	3.21	N/A	1.44	(5.98)	113	336	1403		
5	3144	-154253	-154253	-145365	0.0	3.39	N/A	1.52	(6.15)	114	624	1633		
6	3146	-154233	-154233	-145322	0.0	3.39	N/A	1.52	(6.15)	114	626	1634		
7	3400	-151725	-151725	-139881	0.0	3.51	N/A	1.57	(6.25)	115	791	1766		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	60219	60219	60906	0.0	13.81	N/A	15.79	15.84	95	11	14	N/A	N/A
2	1013	22	22	7751	0.0	13.02	N/A	7.03	+ 100.00	95	438	654		
3	1014	-28	-28	7706	0.0	13.02	N/A	7.02	(+ 100.00)	95	439	655		
4	1470	-27865	-27865	-16883	0.0	10.34	N/A	4.87	(34.23)	96	636	951		
5	2182	-71322	-71322	-55279	0.0	7.31	N/A	3.27	(13.37)	96	944	1414		
6	2700	-102895	-102895	-83184	0.0	5.92	N/A	2.64	(9.27)	97	1168	1750		
7	3144	-129979	-129979	-107126	0.0	4.57	N/A	2.04	(7.33)	97	1360	2114		
8	3146	-130101	-130101	-107234	0.0	4.56	N/A	2.03	(7.33)	97	1361	2116		
9	3400	-145595	-145595	-120933	0.0	4.03	N/A	1.80	(6.55)	97	1471	2324		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	275164	275164	277634	0.0	3.04	N/A	N/A	3.47	95	14	14	N/A	N/A
2	1470	200197	200197	215355	0.0	3.95	N/A	N/A	4.76	96	764	764		
3	2182	163213	163213	184614	0.0	4.64	N/A	N/A	5.84	96	1134	1134		
4	2700	136341	136341	162273	0.0	5.31	N/A	N/A	6.99	97	1403	1403		
5	3144	113290	113290	143104	0.0	6.05	N/A	N/A	8.42	97	1633	1633		
6	3146	113187	113187	143018	0.0	6.06	N/A	N/A	8.42	97	1634	1634		
7	3399	100043	100043	132086	0.0	6.59	N/A	N/A	9.53	97	1766	1766		
8	3400	100000	100000	132050	0.0	6.59	N/A	N/A	9.53	97	1766	1766		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	380053	380053	383374	0.0	1.32	1.18	N/A	2.51	95	2611	14	N/A	N/A
2	1470	291969	291969	311208	0.0	1.51	1.34	N/A	3.27	96	3236	951		
3	2182	248513	248513	275588	0.0	1.62	1.44	N/A	3.84	96	3544	1414		
4	2700	216939	216939	249700	0.0	1.71	1.52	N/A	4.40	97	3768	1750		
5	3144	189855	189855	228832	0.0	1.86	1.66	N/A	5.02	97	3960	2114		
6	3146	189733	189733	228738	0.0	1.86	1.66	N/A	5.02	97	3961	2116		
7	3399	174289	174289	216836	0.0	1.97	1.76	N/A	5.47	97	4071	2324		
8	3400	174239	174239	216797	0.0	1.97	1.76	N/A	5.47	97	4071	2324		
9														
10	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (9 5/8" Production Casing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	7.970 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (9 5/8" Production Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3100.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
7000.00 ft	153 °F

BURST LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Mud Weight:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6320.00 ft
Gas Gravity:	0.70 (0.0768 psi/ft @ 146 °F & 2885 psi)
Reservoir Pressure:	2885 psi
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Stimulation Surface Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Injection Pressure:	3500 psi
Injection Density:	8.33 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Injection Down Casing**
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	3500 psi
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3100.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	7000.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3400.00 ft
Mud Weight Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3100.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	7000.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Full Evacuation**
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3400.00 ft
Fluid Gradient Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	12.50 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (9 5/8" Production Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	3500 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Pressure Test (psi)	Tubing Leak (psi)	Stimulation Leak (psi)	Casing Injection (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	3513	2436	3511	3513	3511	17	17
2	3399.99	5231	4154	5229	5231	4971	2208	1489
3	3400.01	5231	4154	5229	5231	4971	2208	1518
4	3521.00	5293	4215	5291	5293	5024	2286	1579
5	3900.00	5485	4408	5483	5485	5188	2532	1754
6	4099.99	5587	4510	5585	5587	5274	2697	1847
7	4100.01	5587	4510	5585	5587	5274	2697	1847
8	4240.00	5659	4581	5657	5659	5335	2812	1912
9	4337.00	5708	4631	5706	5708	5377	2891	1967
10	4643.00	5864	4786	5862	5864	5509	3142	2103
11	5399.99	6249	5172	6247	6249	5837	3764	2484
12	5400.01	6249	2815	5837	6249	5837	3764	2484
13	5626.00	6364	2832	5935	6364	5935	3949	2598
14	6320.00	6717	2885	6235	6717	6235	4519	2885
15	7000.00	7064	3231	6529	7064	6529	5077	3166

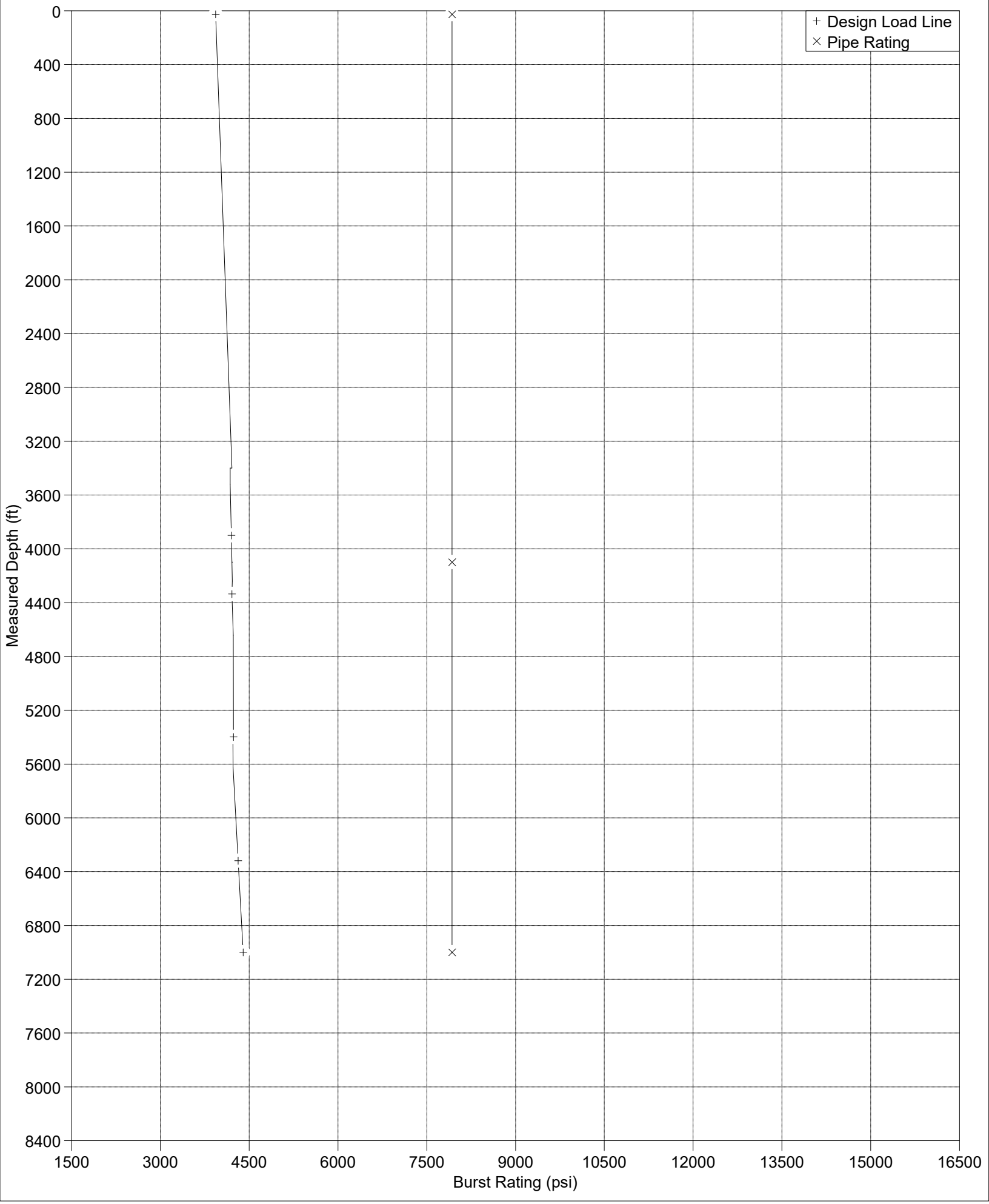
COLLAPSE PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Full Evacuation (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	17	0	17
2	3399.99	1471	2208	2	2208
3	3400.01	1471	2208	2	2208
4	3900.00	1688	2532	2	2532
5	4099.99	1774	2697	2	2662
6	4100.01	1774	2697	2	2662
7	5399.99	2337	3764	3	3506
8	5400.01	2337	3764	3	3506
9	6320.00	2735	4519	3	4104
10	7000.00	3029	5077	4	4545

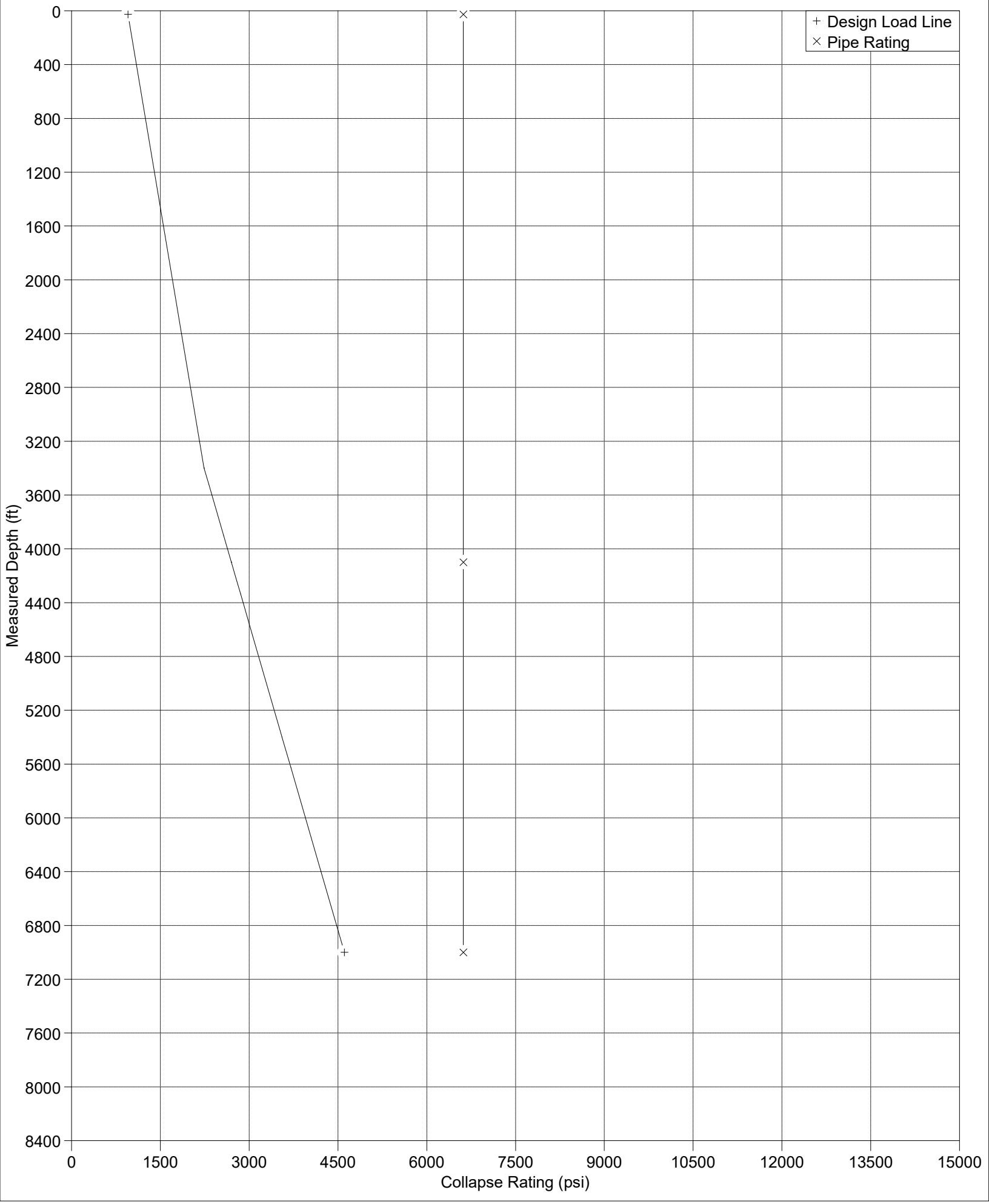
AXIAL LOADS TABLE (9 5/8" Production Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	402706	402706	377267	377267	377267	377267
2	1804.33	325517	325517	282126	282126	282126	282126
3	1804.33	325517	325517	282126	282126	282126	223293
4	3399.99	256258	256258	196759	196759	156945	156945
5	3400.01	256257	256257	196758	196758	272457	272457
6	3521.00	251006	251006	190285	190285	271275	271275
7	3900.00	234555	234555	170008	170008	268181	268181
8	4099.99	225875	225875	159309	159309	268045	268045
9	4100.01	225874	225874	159308	159308	268045	268045
10	4240.00	219797	219797	151818	151818	267950	267950
11	4337.00	215587	215587	146629	146629	267447	267447
12	4643.00	202305	202305	130258	130258	267480	267480
13	5399.99	169448	169448	89759	89759	265647	265647
14	5400.01	169447	169447	89758	89758	265647	265647
15	5626.00	159638	159638	77667	77667	265100	265100
16	5688.96	156905	156905	74299	74299	265197	265197
17	6320.00	129515	129515	40538	40538	266163	266163

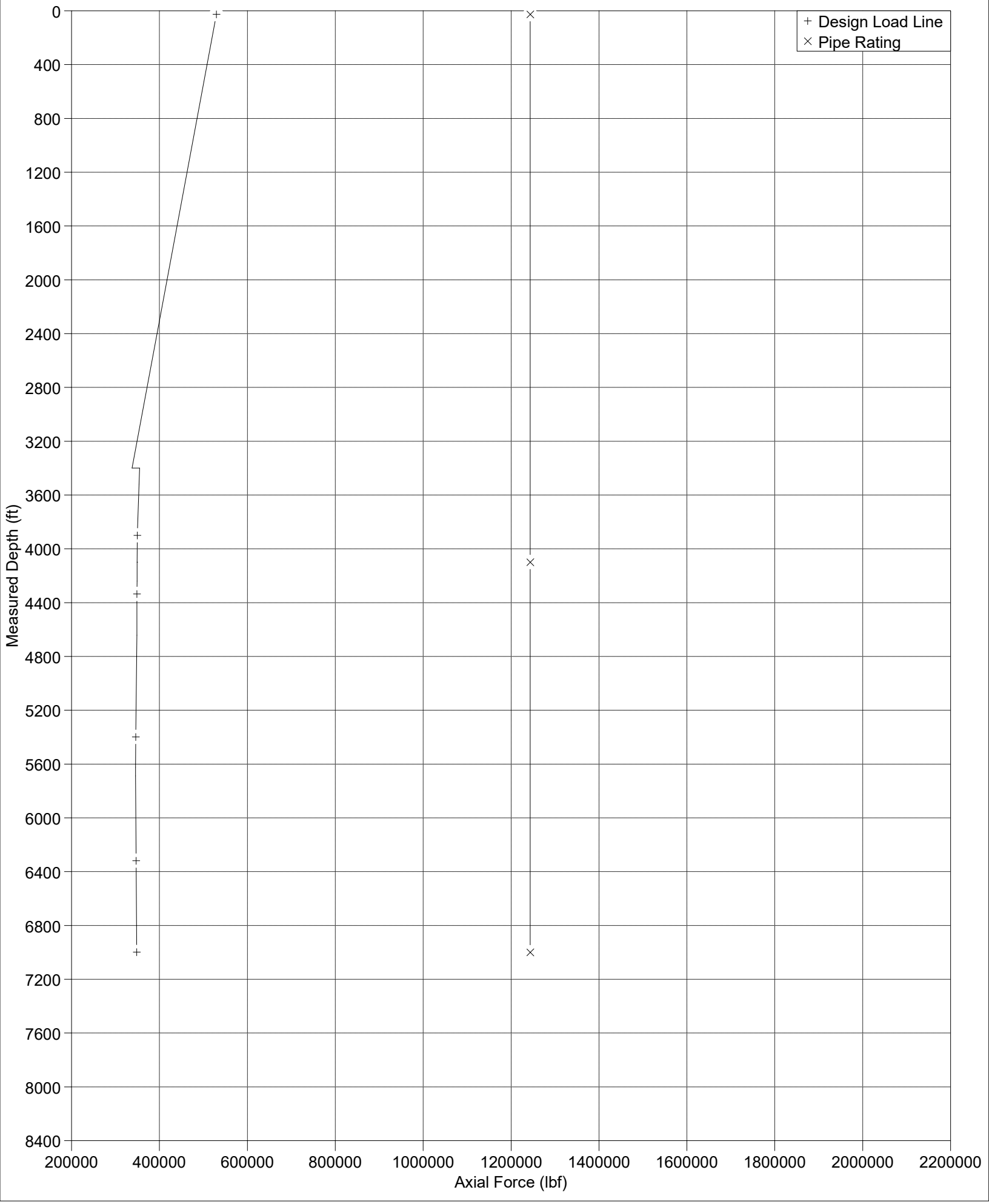
BURST DESIGN (9 5/8" Production Casing)

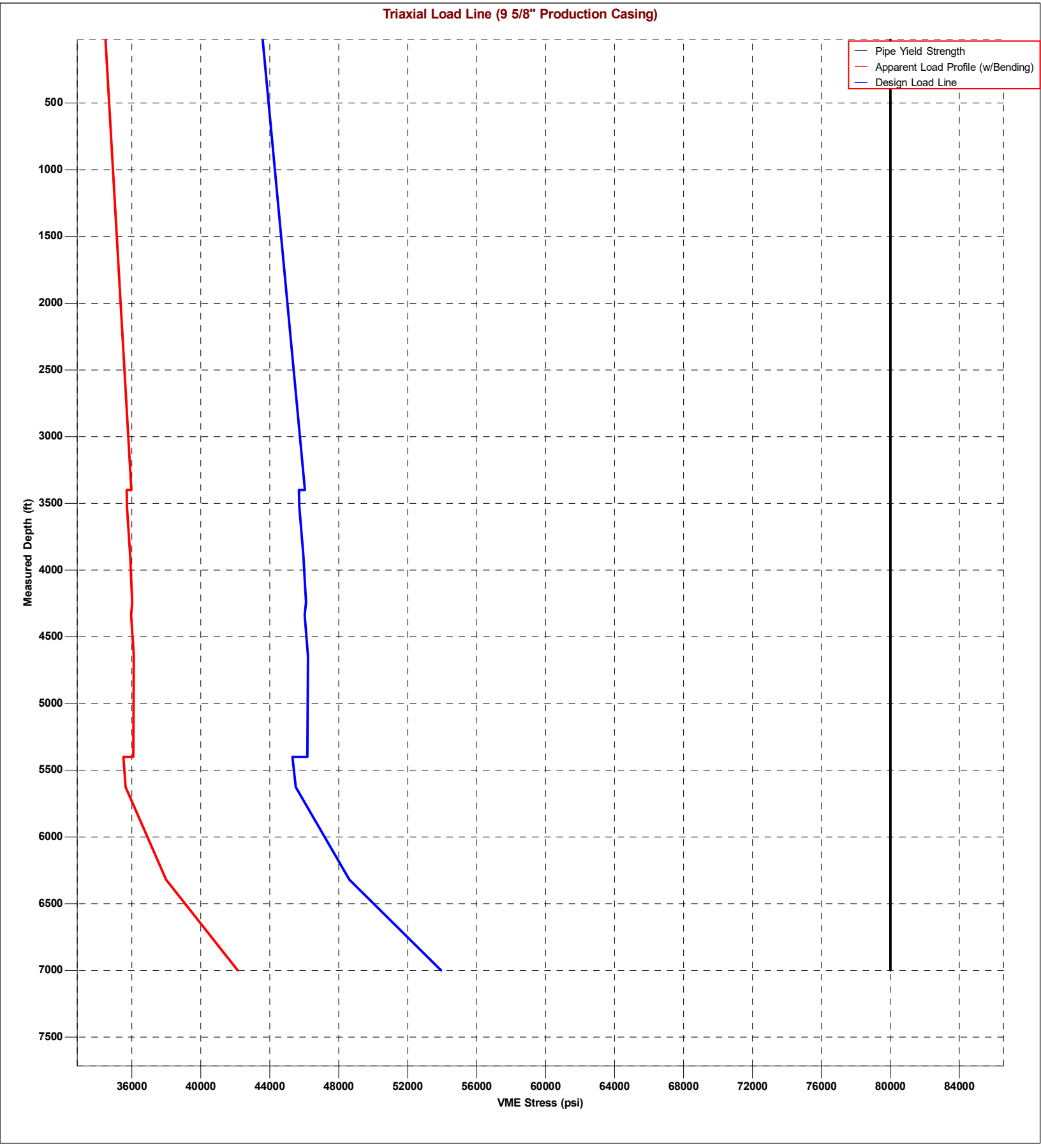


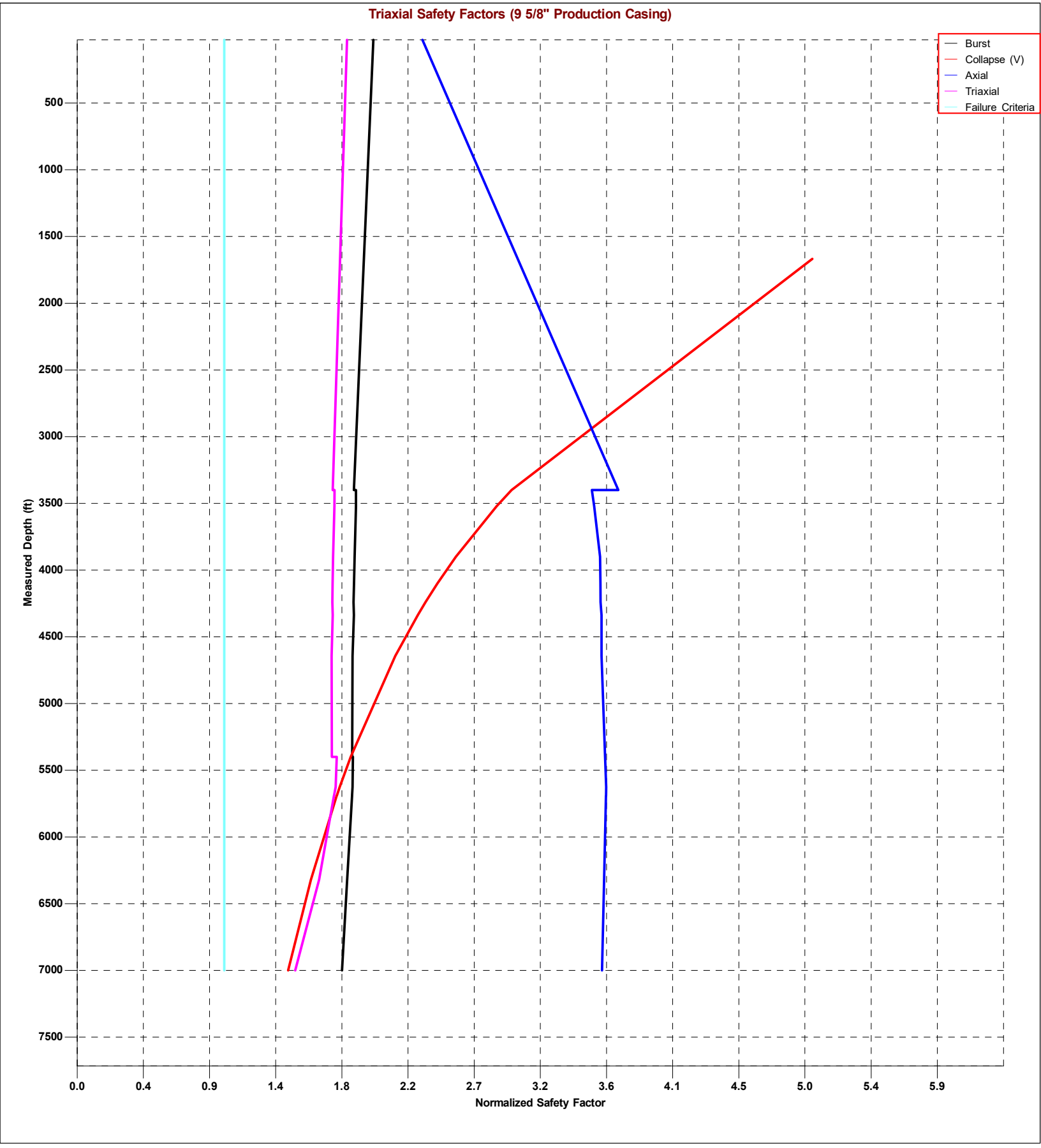
COLLAPSE DESIGN (9 5/8" Production Casing)



AXIAL DESIGN (9 5/8" Production Casing)




Triaxial Load Line (9 5/8" Production Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
36000
40000
44000
48000
52000
56000
60000
64000
68000
72000
76000
80000
84000
VME Stress (psi)


Triaxial Safety Factors (9 5/8" Production Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	9 5/8", 53.500 ppf, L-80	Blue	2.22 B7	6.94 C2	3.05 A4	2.29 B12
2	3400			2.07 B7	2.95 C5	4.78 A4	2.17 B7
3	3400			2.09 B7	2.95 C5	4.55 B8	2.19 B7
4	3521			2.09 B7	2.85 C5	4.57 B8	2.19 B7
5	3900			2.08 B7	2.58 C5	4.62 B8	2.18 B7
6	4100			2.07 B7	2.45 C5	4.63 B8	2.17 B7
7	4100	9 5/8", 53.500 ppf, L-80	Blue	2.07 B7	2.45 C5	4.63 B8	2.17 B7
8	4240			2.07 B7	2.37 C5	4.63 B8	2.17 B7
9	4337			2.07 B7	2.32 C5	4.64 B8	2.17 B7
10	4643			2.06 B7	2.16 C5	4.64 B8	2.16 B7
11	5400			2.06 B7	1.86 C5	4.67 B8	2.17 B7
12	5400			2.06 B5	1.86 C5	4.67 B8	2.21 B5
13	5626			2.06 B5	1.79 C5	4.68 B8	2.20 B5
14	5689			2.06 B5	1.77 C5	4.68 B8	2.18 B5
15	5692			2.06 B5	1.76 C5	4.68 B8	2.18 B5
16	6320			2.02 B5	1.59 C5	4.66 B8	2.06 C5
17	6999			1.98 B5	1.44 C5	4.64 B8	1.85 C5
18	7000			1.98 B5	1.44 C5	4.64 B8	1.85 C5
19							
20	B5	Pressure Test					
21	B7	Stimulation Surface Leak					
22	B8	Injection Casing					
23	B12	Green Cement Pressure Test(Burst)					
24	C2	Cementing					
25	C5	Full Evacuation Production					
26	A4	Overpull Force					
27	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	9 5/8", 53.500 ppf, L-80	0.271 B7	0.075 C2	0.253 B7	50.4	86.3	53.7	0.274	0.470	0.292
2	3399.99		0.290 B7	0.343 C5	0.274 B7	46.9	37.1	49.8	0.255	0.202	0.271
3	3400.01		0.287 B7	0.343 C5	0.272 B7	47.3	37.1	50.2	0.258	0.202	0.273
4	3521.00		0.287 B7	0.348 C5	0.272 B7	47.3	36.2	50.1	0.258	0.197	0.273
5	3900.00		0.289 B7	0.363 C5	0.273 B7	47.0	33.4	49.8	0.256	0.182	0.272
6	4099.99		0.289 B7	0.371 C5	0.274 B7	46.9	31.9	49.7	0.256	0.174	0.271
7	4100.01	9 5/8", 53.500 ppf, L-80	0.289 B7	0.371 C5	0.274 B7	46.9	31.9	49.7	0.256	0.174	0.271
8	4240.00		0.290 B7	0.377 C5	0.274 B7	46.8	30.9	49.6	0.255	0.168	0.271
9	4337.00		0.290 B7	0.380 C5	0.274 B7	46.9	30.2	49.7	0.255	0.165	0.271
10	4643.00		0.291 B7	0.393 C5	0.275 B7	46.6	28.0	49.5	0.254	0.152	0.270
11	5399.99		0.291 B7	0.423 C5	0.275 B7	46.5	22.4	49.5	0.254	0.122	0.270
12	5400.01		0.291 B5	0.423 C5	0.269 B5	46.7	22.4	50.6	0.254	0.122	0.276
13	5626.00		0.291 B5	0.430 C5	0.271 B5	46.6	21.2	50.3	0.254	0.115	0.274
14	5688.96		0.291 B5	0.431 C5	0.272 B5	46.5	20.9	50.2	0.254	0.114	0.273
15	5692.24		0.292 B5	0.431 C5	0.272 B5	46.5	20.8	50.2	0.253	0.114	0.273
16	6320.00		0.297 B5	0.448 C5	0.284 C5	45.5	17.8	47.9	0.248	0.097	0.261
17	6999.15		0.303 B5	0.466 C5	0.316 C5	44.5	14.6	42.0	0.242	0.079	0.229
18	7000.00		0.303 B5	0.466 C5	0.316 C5	44.5	14.6	42.0	0.242	0.079	0.229
19											
20	B5	Pressure Test									
21	B7	Stimulation Surface Leak									
22	C2	Cementing									
23	C5	Full Evacuation Production									
24	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (9 5/8" Production Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	945700
2	26	944572
3	26	944571
4	250	934848
5	500	923997
6	750	913146
7	1000	902295
8	1250	891444
9	1500	880592
10	1750	869741
11	2000	858890
12	2250	848039
13	2500	837187
14	2750	826336
15	2900	819826
16	2900	819825
17	3000	815485
18	3250	804634
19	3500	793783
20	3750	782931
21	4000	772080
22	4100	767740
23	4100	767739
24	4250	761229
25	4500	750378
26	4750	739526
27	5000	728675
28	5250	717824
29	5500	706973
30	5750	696122
31	6000	685270
32	6250	674419
33	6500	663568
34	6750	652717
35	6974	642994
36	7000	* 643237
37		
38	* Based on Casing Strength	
39	Only. Running String not	
40	Included	

TRIAXIAL RESULTS (9 5/8" Production Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	297237	297237	298397	0.0	2.43	2.26	N/A	4.17	78	3513	17	N/A	N/A
2	3400	156945	156945	182640	0.0	2.28	2.09	N/A	7.81	114	5231	1489		
3	3400	155688	155688	181819	0.0	2.30	2.11	N/A	7.88	114	5231	1518		
4	3521	150318	150318	177399	0.0	2.30	2.10	N/A	8.16	116	5293	1579		
5	3900	134108	134108	163928	0.0	2.28	2.09	N/A	9.13	120	5485	1754		
6	4100	127051	127051	158328	0.0	2.26	2.09	N/A	9.63	122	5587	1847		
7	4100	127050	127050	158328	0.0	2.26	2.09	N/A	9.63	122	5587	1847		
8	4240	122110	122110	154403	0.0	2.26	2.08	N/A	10.02	123	5659	1912		
9	4337	118250	118250	151395	0.0	2.26	2.08	N/A	10.34	124	5708	1967		
10	4643	107692	107692	142956	0.0	2.24	2.07	N/A	11.34	128	5864	2103		
11	5400	79662	79662	120749	0.0	2.21	2.06	N/A	15.29	136	6249	2484		
12	5400	79661	79661	120748	0.0	2.21	2.06	N/A	15.29	136	6249	2484		
13	5626	71293	71293	114097	0.0	2.20	2.06	N/A	17.08	138	6364	2598		
14	6320	48337	48337	95417	0.0	2.13	2.02	N/A	25.13	146	6717	2885		
15	7000	25845	25845	77030	0.0	2.07	1.98	N/A	46.89	153	7064	3166		
16														
17	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (9 5/8" Production Casing) - Tubing Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	42431	42431	43715	0.0	3.34	3.20	N/A	28.63	146	2436	17	N/A	N/A
2	3400	18907	18907	43065	0.0	3.01	2.91	N/A	64.24	146	4154	1489		
3	3400	17651	17651	42237	0.0	3.04	2.94	N/A	68.81	146	4154	1518		
4	3521	16468	16468	41990	0.0	3.04	2.94	N/A	73.76	146	4215	1579		
5	3900	13375	13375	41620	0.0	3.02	2.92	N/A	90.81	146	4408	1754		
6	4100	13239	13239	42957	0.0	3.01	2.91	N/A	91.75	146	4510	1847		
7	4240	13144	13144	43893	0.0	3.00	2.90	N/A	92.41	146	4581	1912		
8	4337	12641	12641	44253	0.0	3.01	2.91	N/A	96.09	146	4631	1967		
9	4643	12673	12673	46457	0.0	2.99	2.89	N/A	95.84	146	4786	2103		
10	5400	10841	10841	50649	0.0	3.00	2.88	N/A	+ 100.00	146	5172	2484		
11	5400	-70065	-70065	-32194	0.0	15.42	23.42	N/A	(17.34)	146	2815	2484		
12	5626	-73977	-73977	-34389	0.0	17.87	33.12	N/A	(16.42)	146	2832	2598		
13	6320	-83229	-83229	-39299	0.0	24.51	N/A	N/A	(14.59)	146	2885	2885		
14	7000	-82188	-82188	-33762	0.0	24.65	+ 100.00	N/A	(14.78)	146	3231	3166		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Stimulation Surface Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	79343	79343	81511	0.0	2.34	2.22	N/A	15.31	146	3511	17	N/A	N/A
2	3400	55819	55819	80861	0.0	2.17	2.07	N/A	21.76	146	5229	1489		
3	3400	54564	54564	80033	0.0	2.19	2.09	N/A	22.26	146	5229	1518		
4	3521	53381	53381	79786	0.0	2.19	2.09	N/A	22.75	146	5291	1579		
5	3900	50287	50287	79416	0.0	2.18	2.08	N/A	24.15	146	5483	1754		
6	4100	50152	50152	80753	0.0	2.17	2.07	N/A	24.22	146	5585	1847		
7	4240	50057	50057	81689	0.0	2.17	2.07	N/A	24.27	146	5657	1912		
8	4337	49553	49553	82049	0.0	2.17	2.07	N/A	24.51	146	5706	1967		
9	4643	49586	49586	84253	0.0	2.16	2.06	N/A	24.50	146	5862	2103		
10	5400	47754	47754	88445	0.0	2.17	2.06	N/A	25.44	146	6247	2484		
11	5400	33666	33666	74020	0.0	2.42	2.31	N/A	36.08	146	5837	2484		
12	5626	32527	32527	74665	0.0	2.43	2.32	N/A	37.34	146	5935	2598		
13	6320	31770	31770	78453	0.0	2.43	2.31	N/A	38.23	146	6235	2885		
14	7000	31029	31029	82165	0.0	2.42	2.30	N/A	39.15	146	6529	3166		
15														
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Injection Down Casing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	297237	297237	298397	0.0	2.43	2.26	N/A	4.17	78	3513	17	N/A	N/A
2	3400	273713	273713	297760	0.0	2.29	2.11	N/A	4.53	78	5231	1489		
3	3400	272457	272457	296950	0.0	2.31	2.13	N/A	4.55	78	5231	1518		
4	3521	271275	271275	296708	0.0	2.31	2.13	N/A	4.57	78	5293	1579		
5	3900	268181	268181	296345	0.0	2.30	2.12	N/A	4.62	78	5485	1754		
6	4100	268045	268045	297654	0.0	2.29	2.11	N/A	4.63	78	5587	1847		
7	4100	268045	268045	297655	0.0	2.29	2.11	N/A	4.63	78	5587	1847		
8	4240	267950	267950	298571	0.0	2.29	2.11	N/A	4.63	78	5659	1912		
9	4337	267447	267447	298924	0.0	2.29	2.11	N/A	4.64	78	5708	1967		
10	4643	267480	267480	301083	0.0	2.28	2.10	N/A	4.64	78	5864	2103		
11	5400	265647	265647	305189	0.0	2.27	2.10	N/A	4.67	78	6249	2484		
12	5626	265100	265100	306415	0.0	2.27	2.10	N/A	4.68	78	6364	2598		
13	6320	266163	266163	311950	0.0	2.23	2.06	N/A	4.66	78	6717	2885		
14	7000	267204	267204	317374	0.0	2.20	2.03	N/A	4.64	78	7064	3166		
15														
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377267	377267	381932	0.0	2.29	2.24	N/A	3.26	106	3511	17	N/A	N/A
2	3400	196759	196759	234404	0.0	3.05	2.83	N/A	6.23	115	4971	2208		
3	3400	196758	196758	234403	0.0	3.05	2.83	N/A	6.23	115	4971	2208		
4	3521	190285	190285	229098	0.0	3.09	2.85	N/A	6.44	115	5024	2286		
5	3900	170008	170008	212474	0.0	3.20	2.94	N/A	7.21	116	5188	2532		
6	4100	159309	159309	204238	0.0	3.30	3.03	N/A	7.69	117	5274	2697		
7	4100	159308	159308	204238	0.0	3.30	3.03	N/A	7.69	117	5274	2697		
8	4240	151818	151818	198471	0.0	3.37	3.10	N/A	8.07	117	5335	2812		
9	4337	146629	146629	194475	0.0	3.42	3.14	N/A	8.36	118	5377	2891		
10	4643	130258	130258	181864	0.0	3.60	3.30	N/A	9.40	118	5509	3142		
11	5400	89759	89759	150641	0.0	4.12	3.76	N/A	13.64	120	5837	3764		
12	5400	89758	89758	150640	0.0	4.12	3.76	N/A	13.64	120	5837	3764		
13	5626	77667	77667	141312	0.0	4.31	3.93	N/A	15.76	121	5935	3949		
14	6320	40538	40538	112643	0.0	4.99	4.54	N/A	30.18	123	6235	4519		
15	6999	4204	4204	84558	0.0	5.88	5.36	N/A	+ 100.00	124	6529	5076		
16	7000	4158	4158	84522	0.0	5.88	5.37	N/A	+ 100.00	124	6529	5077		
17														
18	( )	Compression												
19	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	177021	177021	179262	0.0	6.10	N/A	6.94	6.94	106	11	17	N/A	N/A
2	3334	31	31	22783	0.0	9.30	N/A	8.55	+ 100.00	115	1443	2165		
3	3335	-15	-15	22743	0.0	9.30	N/A	8.55	(+ 100.00)	115	1443	2166		
4	3400	-3488	-3488	19664	0.0	9.28	N/A	8.47	(+ 100.00)	115	1471	2208		
5	3400	-3489	-3489	19663	0.0	9.28	N/A	8.47	(+ 100.00)	115	1471	2208		
6	3521	-9962	-9962	13924	0.0	9.25	N/A	8.32	(+ 100.00)	115	1524	2286		
7	3900	-30238	-30238	-4061	0.0	9.04	N/A	7.76	(40.53)	116	1688	2532		
8	4100	-40938	-40938	-13555	0.0	8.52	N/A	7.11	(29.93)	117	1774	2697		
9	4100	-40939	-40939	-13556	0.0	8.52	N/A	7.11	(29.93)	117	1774	2697		
10	4240	-48428	-48428	-20204	0.0	8.18	N/A	6.71	(25.30)	117	1835	2812		
11	4337	-53618	-53618	-24811	0.0	7.95	N/A	6.46	(22.85)	118	1877	2891		
12	4643	-69989	-69989	-39350	0.0	7.28	N/A	5.78	(17.50)	118	2009	3142		
13	5400	-110488	-110488	-75346	0.0	5.94	N/A	4.59	(11.08)	120	2337	3764		
14	5400	-110489	-110489	-75347	0.0	5.94	N/A	4.59	(11.08)	120	2337	3764		
15	5626	-122579	-122579	-86102	0.0	5.62	N/A	4.32	(9.98)	121	2435	3949		
16	6320	-159708	-159708	-119153	0.0	4.79	N/A	3.67	(7.66)	123	2735	4519		
17	7000	-196088	-196088	-151573	0.0	4.18	N/A	3.20	(6.23)	124	3029	5077		
18														
19	( )	Compression												
20	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Full Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-41191	-41191	-42177	0.0	26.76	N/A	+ 100.00	(29.49)	146	0	17	N/A	N/A
2	3400	-154993	-154993	-158677	0.0	3.85	N/A	2.95	(7.84)	146	2	2208		
3	3400	-154994	-154994	-158678	0.0	3.85	N/A	2.95	(7.84)	146	2	2208		
4	3521	-159075	-159075	-162855	0.0	3.72	N/A	2.85	(7.64)	146	2	2286		
5	3900	-171858	-171858	-175941	0.0	3.36	N/A	2.58	(7.07)	146	2	2532		
6	4100	-177106	-177106	-181313	0.0	3.19	N/A	2.45	(6.86)	146	2	2662		
7	4100	-177107	-177107	-181314	0.0	3.19	N/A	2.45	(6.86)	146	2	2662		
8	4240	-180781	-180781	-185075	0.0	3.08	N/A	2.37	(6.72)	146	2	2753		
9	4337	-183326	-183326	-187680	0.0	3.01	N/A	2.32	(6.63)	146	2	2816		
10	4643	-191357	-191357	-195901	0.0	2.81	N/A	2.16	(6.35)	146	2	3015		
11	5400	-211223	-211223	-216236	0.0	2.41	N/A	1.86	(5.75)	146	3	3506		
12	5400	-211224	-211224	-216237	0.0	2.41	N/A	1.86	(5.75)	146	3	3506		
13	5626	-217155	-217155	-222307	0.0	2.31	N/A	1.79	(5.59)	146	3	3653		
14	6320	-235367	-235367	-240950	0.0	2.06	N/A	1.59	(5.16)	146	3	4104		
15	7000	-253212	-253212	-259216	0.0	1.85	N/A	1.44	(4.80)	146	4	4545		
16														
17	( )	Compression												
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	402706	402706	407667	0.0	2.69	N/A	N/A	3.05	106	17	17	N/A	N/A
2	3400	256258	256258	294759	0.0	3.77	N/A	N/A	4.78	115	2208	2208		
3	3400	256257	256257	294758	0.0	3.77	N/A	N/A	4.78	115	2208	2208		
4	3521	251006	251006	290698	0.0	3.83	N/A	N/A	4.88	115	2286	2286		
5	3900	234555	234555	277975	0.0	4.01	N/A	N/A	5.23	116	2532	2532		
6	4100	225875	225875	271258	0.0	4.12	N/A	N/A	5.43	117	2662	2662		
7	4100	225874	225874	271257	0.0	4.12	N/A	N/A	5.43	117	2662	2662		
8	4240	219797	219797	266554	0.0	4.19	N/A	N/A	5.57	117	2753	2753		
9	4337	215587	215587	263295	0.0	4.25	N/A	N/A	5.68	118	2816	2816		
10	4643	202305	202305	253010	0.0	4.43	N/A	N/A	6.05	118	3015	3015		
11	5400	169448	169448	227544	0.0	4.96	N/A	N/A	7.22	120	3506	3506		
12	5400	169447	169447	227543	0.0	4.96	N/A	N/A	7.22	120	3506	3506		
13	5626	159638	159638	219935	0.0	5.15	N/A	N/A	7.67	121	3653	3653		
14	6320	129515	129515	196553	0.0	5.81	N/A	N/A	9.44	123	4104	4104		
15	6999	100037	100037	173646	0.0	6.64	N/A	N/A	12.22	124	4545	4545		
16	7000	100000	100000	173617	0.0	6.64	N/A	N/A	12.23	124	4545	4545		
17														
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377267	377267	381932	0.0	2.29	2.24	N/A	3.26	106	3511	17	N/A	N/A
2	3400	196759	196759	234404	0.0	3.05	2.83	N/A	6.23	115	4971	2208		
3	3400	196758	196758	234403	0.0	3.05	2.83	N/A	6.23	115	4971	2208		
4	3521	190285	190285	229098	0.0	3.09	2.85	N/A	6.44	115	5024	2286		
5	3900	170008	170008	212474	0.0	3.20	2.94	N/A	7.21	116	5188	2532		
6	4100	159309	159309	204238	0.0	3.30	3.03	N/A	7.69	117	5274	2697		
7	4100	159308	159308	204238	0.0	3.30	3.03	N/A	7.69	117	5274	2697		
8	4240	151818	151818	198471	0.0	3.37	3.10	N/A	8.07	117	5335	2812		
9	4337	146629	146629	194475	0.0	3.42	3.14	N/A	8.36	118	5377	2891		
10	4643	130258	130258	181864	0.0	3.60	3.30	N/A	9.40	118	5509	3142		
11	5400	89759	89759	150641	0.0	4.12	3.76	N/A	13.64	120	5837	3764		
12	5400	89758	89758	150640	0.0	4.12	3.76	N/A	13.64	120	5837	3764		
13	5626	77667	77667	141312	0.0	4.31	3.93	N/A	15.76	121	5935	3949		
14	6320	40538	40538	112643	0.0	4.99	4.54	N/A	30.18	123	6235	4519		
15	6999	4204	4204	84558	0.0	5.88	5.36	N/A	+ 100.00	124	6529	5076		
16	7000	4158	4158	84522	0.0	5.88	5.37	N/A	+ 100.00	124	6529	5077		
17														
18	( )	Compression												
19	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (5 1/2" Production Tubing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Temperature Deration:	Yes
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (5 1/2" Production Tubing)

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6320.00 ft
Packer Setting Method:	Set Mechanically
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
5400.00 ft	136 °F

BURST LOADS DATA (5 1/2" Production Tubing)

Production Load:	**Shut-In**
Shut-in Bottom Hole Pressure:	3200 psi
Gas Gravity:	0.70 (0.0836 psi/ft @ 146 °F & 3200 psi)
Hot:	Yes
Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Internal Fluid Density:	9.80 ppg
Production Load:	**Tubing Injection**
Injection Pressure:	3500 psi
Injection Fluid Density:	10.00 ppg

COLLAPSE LOADS DATA (5 1/2" Production Tubing)

Drilling Load:	**Full/Partial Evacuation**
Mud Weight:	9.80 ppg
Mud Level, MD:	5400.00 ft
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6320.00 ft
Gas Gravity:	0.70
Reservoir Pressure:	2885 psi
Production Load:	**Annular Pressure Test**
Fluid Density(Inside Tubing):	1.50 ppg
Wellhead Pressure (Annulus)	3500 psi
Fluid Density(Annulus)	9.80 ppg
Packer Depth, MD:	5400.00 ft

AXIAL LOADS DATA (5 1/2" Production Tubing)

Overpull Force:	100000 lbf
Service Loads:	Yes

BURST PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Pressure Test (Int) (psi)	Pressure Test (Ext) (psi)	Tubing Injection (Int) (psi)	Tubing Injection (Ext) (psi)	Shut-In (Int) (psi)	Shut-In (Ext) (psi)
1	26.00	3513	13	3514	13	2751	13
2	5399.99	6249	2749	6305	2749	3130	2749
3	5400.00	6249	2749	6305	2749	3130	2749

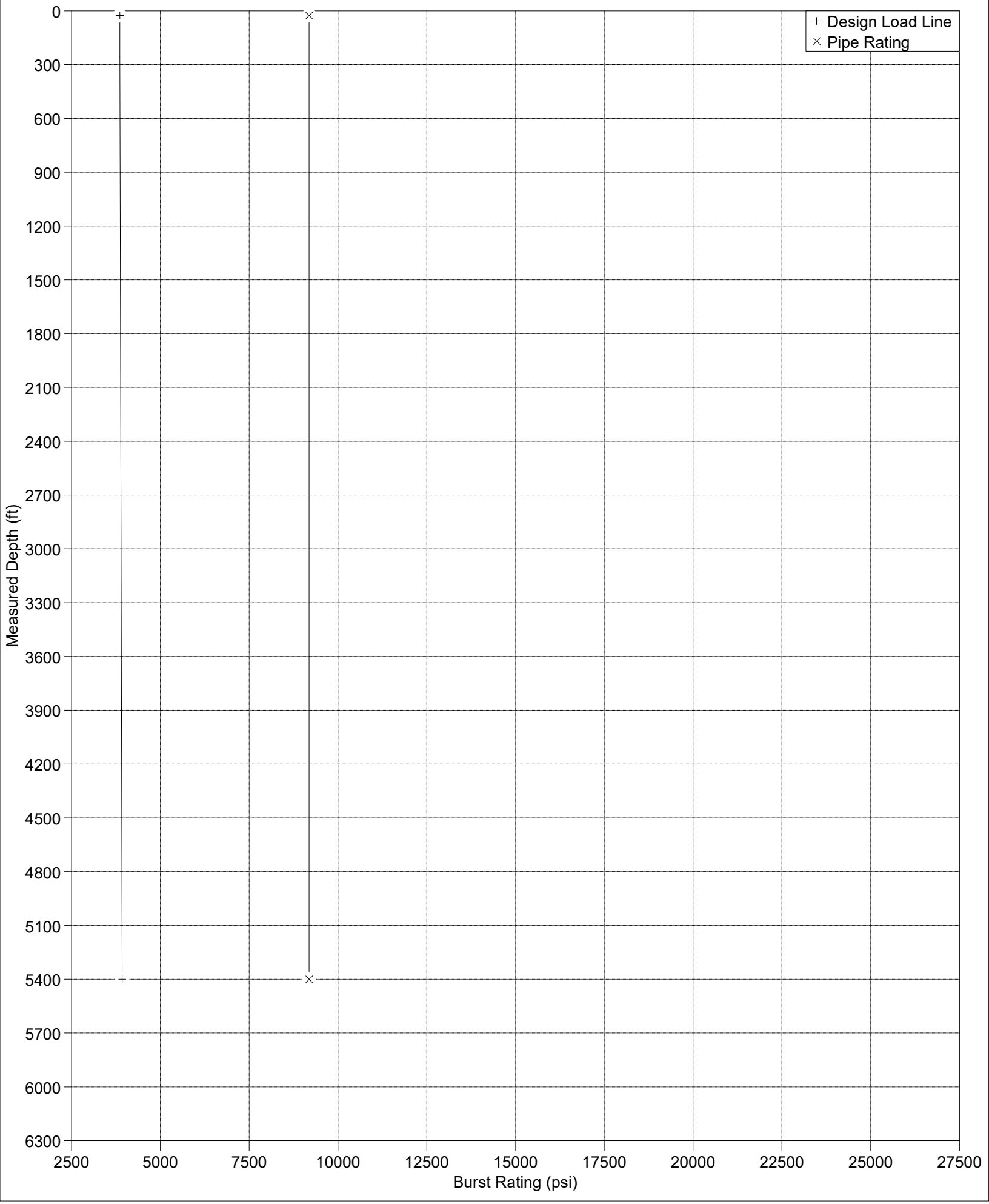
COLLAPSE PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Full/Partial Evacuation (Int) (psi)	Full/Partial Evacuation (Ext) (psi)	Tubing Leak (Int) (psi)	Tubing Leak (Ext) (psi)	Annular Pressure Test (Int) (psi)	Annular Pressure Test (Ext) (psi)
1	26.00	0	13	2436	2436	2	3513
2	5399.99	3	2749	2815	5172	421	6249
3	5400.00	3	2749	2815	5172	421	6249

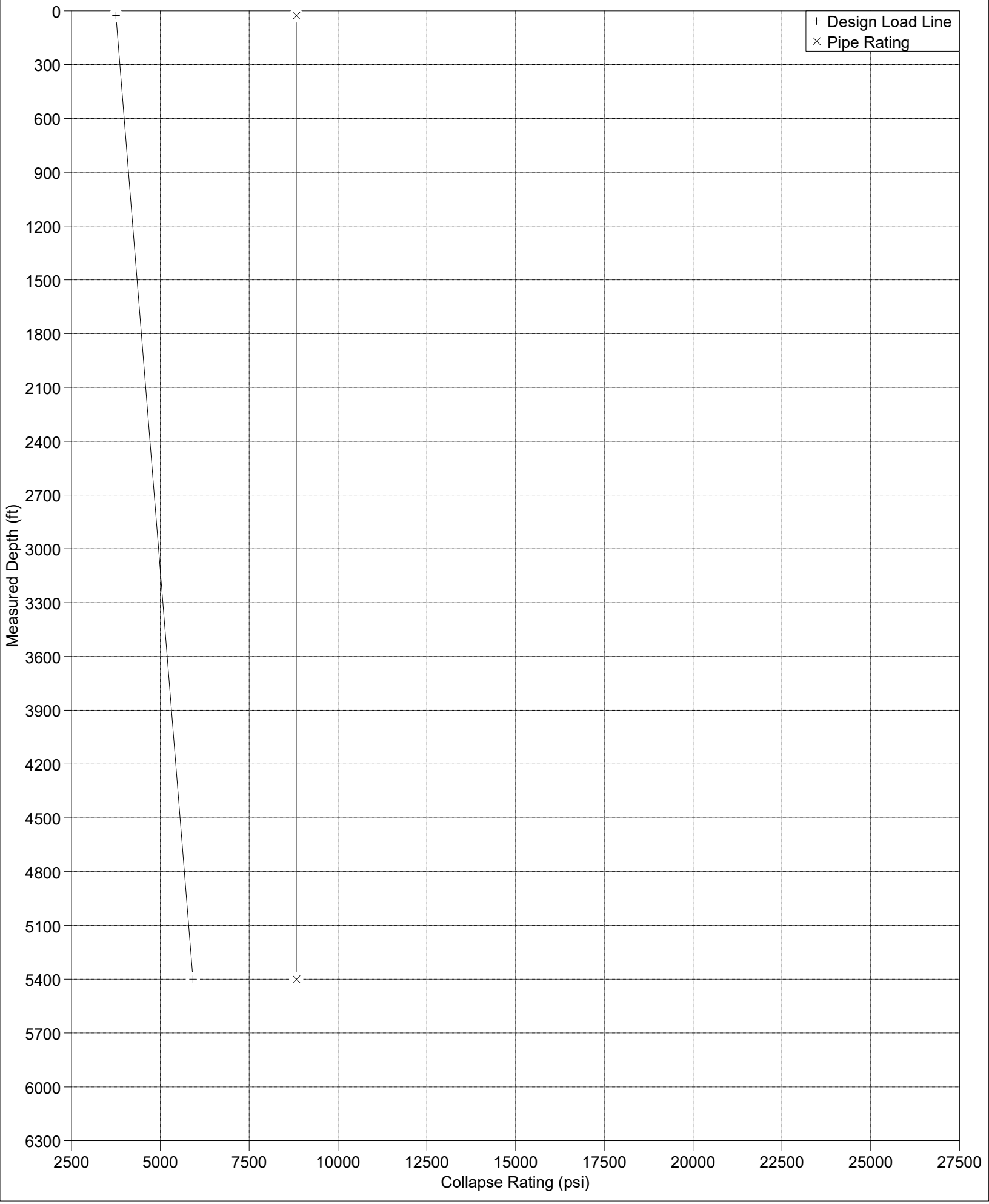
AXIAL LOADS TABLE (5 1/2" Production Tubing)

	Depth (MD) (ft)	Overpull Force (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	191535	191535	164276	164276
2	4836.10	109605	109605	-79082	68074
3	5398.00	100034	100034	-91095	56836
4	5398.00	100034	100034	-91095	-83685

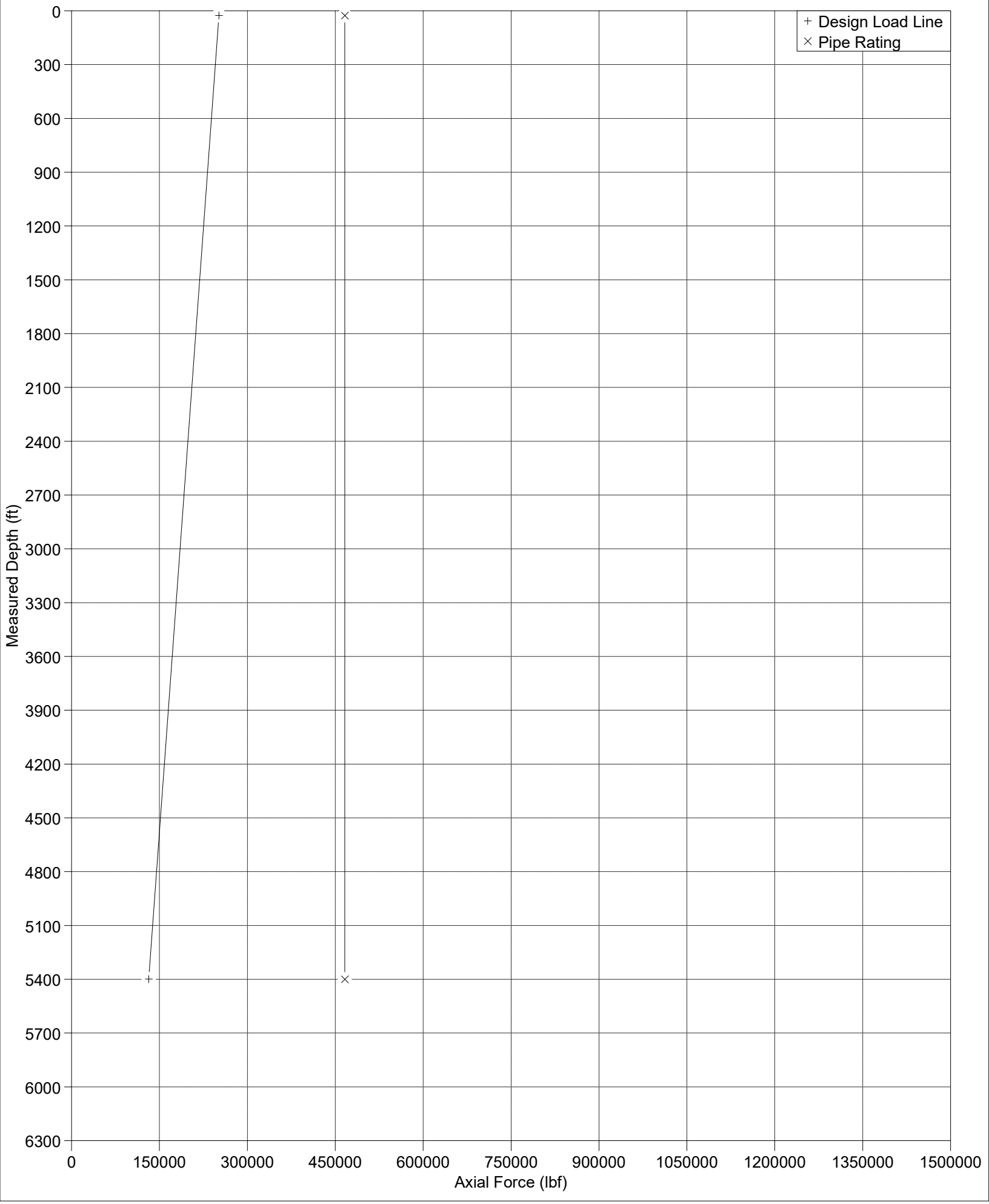
BURST DESIGN (5 1/2" Production Tubing)

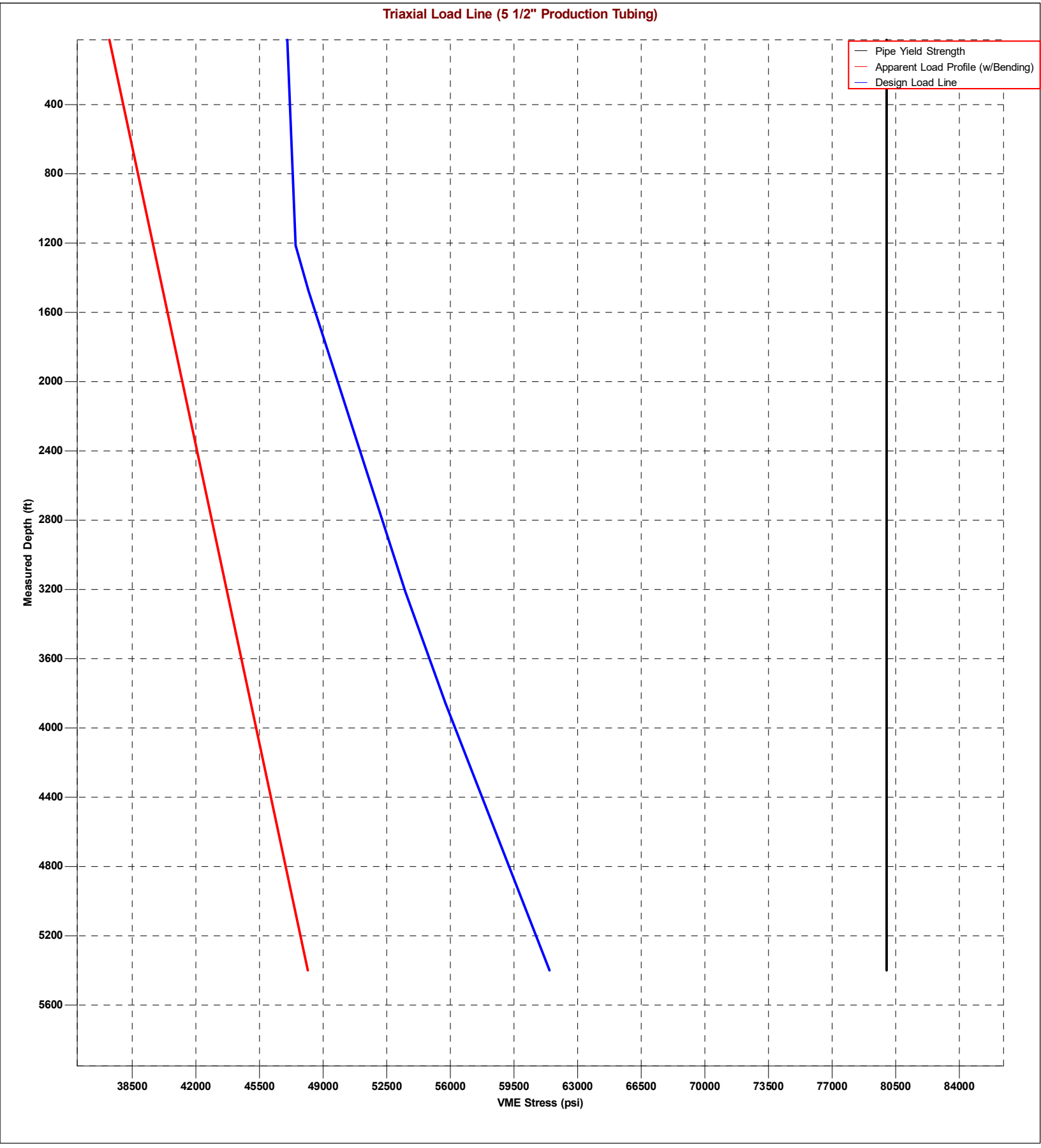


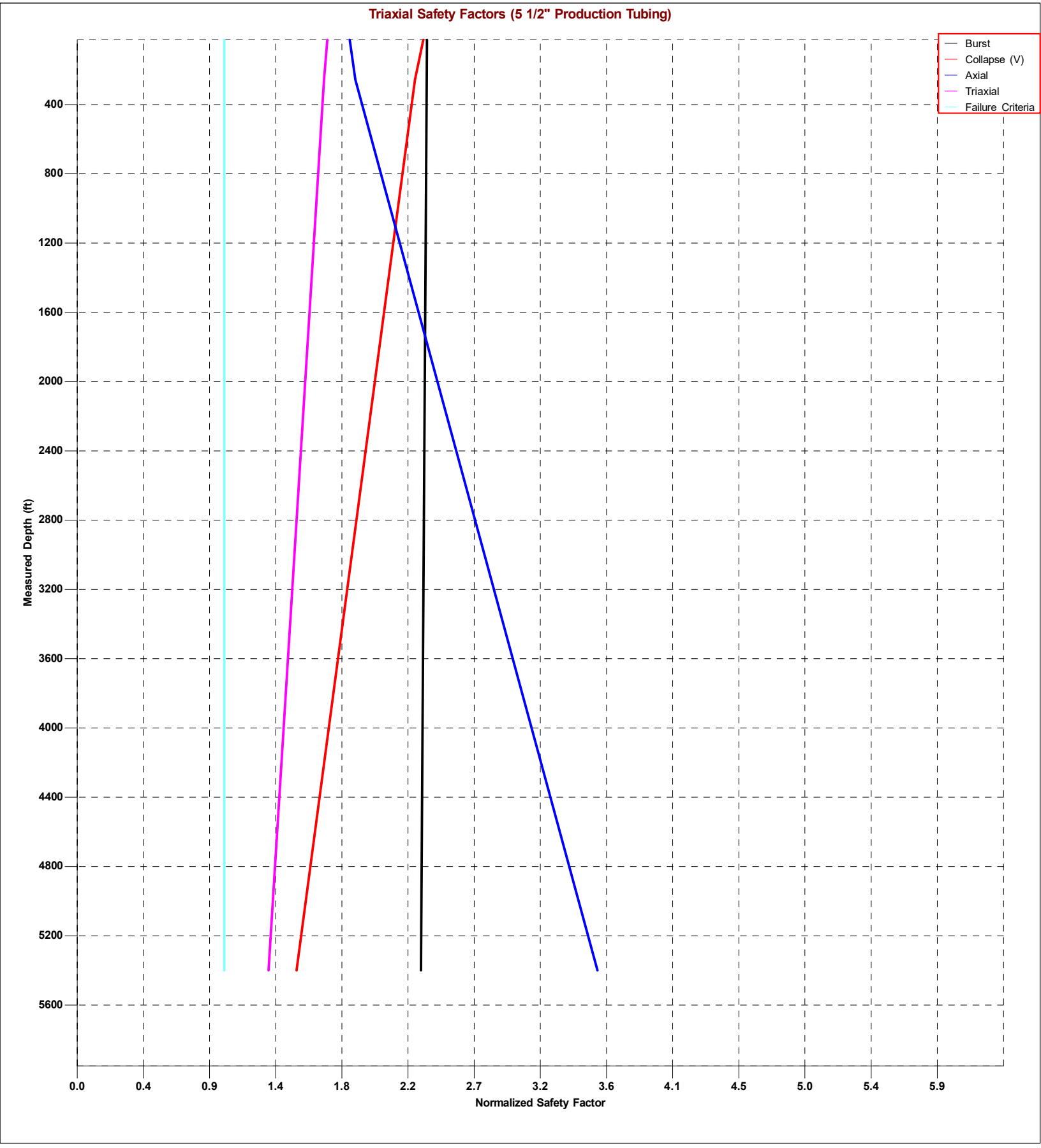
COLLAPSE DESIGN (5 1/2" Production Tubing)



AXIAL DESIGN (5 1/2" Production Tubing)




Triaxial Load Line (5 1/2" Production Tubing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
400
800
1200
1600
2000
2400
2800
3200
3600
4000
4400
4800
5200
5600
38500
42000
45500
49000
52500
56000
59500
63000
66500
70000
73500
77000
80500
84000
VME Stress (psi)


Triaxial Safety Factors (5 1/2" Production Tubing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
400
800
1200
1600
2000
2400
2800
3200
3600
4000
4400
4800
5200
5600
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	5 1/2", 20.000 ppf, L-80	Blue	2.62 B16	2.35 C19	2.41 A4	2.13 A4
2	256			2.62 B5	2.30 C19	2.46 A4	2.10 A4
3	5398			2.57 B5	1.49 C19	4.60 A4	1.63 C19
4	5399			2.57 B5	1.49 C19	4.60 A4	1.63 C19
5	5400			2.57 B5	1.49 C19	4.60 A4	1.63 C19
6							
7	B5	Pressure Test					
8	B16	Tubing Injection					
9	C19	Annular Pressure Test					
10	A4	Overpull Force					
11	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	5 1/2", 20.000 ppf, L-80	0.152 B16	0.243 C19	0.181 A4	58.0	32.7	49.9	0.209	0.118	0.180
2	256.29		0.152 B5	0.245 C19	0.177 A4	57.9	32.1	50.8	0.209	0.116	0.184
3	5398.00		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
4	5399.34		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
5	5399.99		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
6	5400.00		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
7											
8	B5	Pressure Test									
9	B16	Tubing Injection									
10	C19	Annular Pressure Test									
11	A4	Overpull Force									
12	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (5 1/2" Production Tubing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	355031
2	26	354588
3	257	350651
4	514	346272
5	771	341892
6	1000	337998
7	1029	337512
8	1286	333132
9	1543	328752
10	1800	324372
11	2000	320966
12	2057	319992
13	2314	315612
14	2571	311232
15	2829	306853
16	3000	303933
17	3086	302473
18	3343	298093
19	3600	293713
20	3857	289333
21	4000	286900
22	4114	284953
23	4371	280573
24	4629	276193
25	4886	271813
26	5000	269867
27	5143	267434
28	5374	263496
29	5398	* 263563
30	5400	* 263568
31		
32	* Based on Casing Strength	
33	Only. Running String not	
34	Included	

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	129728	129728	130197	0.0	2.60	2.62	N/A	3.58	78	3513	13	25102	1438
2	5398	38313	22288	55460	2749.5	2.69	2.57	N/A	11.92	136	6248	2748		
3	5400	38295	22248	55449	2753.3	2.69	2.57	N/A	11.93	136	6249	2749		
4	5400	38295	22248	55449	2753.4	2.69	2.57	N/A	11.93	136	6249	2749		
5														
6	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Shut-In

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	63721	63721	65326	0.0	3.54	3.28	N/A	7.15	146	2751	13	36854	3770
2	3212	9508	0	19494	1631.3	6.69	6.69	N/A	47.89	146	2976	1635		
3	3212	-9508	-0	23	1631.3	6.69	6.69	N/A	(47.89)	146	2976	1635		
4	5398	-66362	-43719	-51551	3885.2	6.93	23.50	N/A	(6.86)	146	3130	2748		
5	5400	-66414	-43758	-51598	3887.2	6.93	23.55	N/A	(6.86)	146	3130	2749		
6	5400	-66414	-43759	-51598	3887.2	6.93	23.55	N/A	(6.86)	146	3130	2749		
7														
8	( )	Compression												
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Injection

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	164276	164276	164849	0.0	2.35	2.62	N/A	2.83	78	3514	13	0	0
2	5398	56836	56836	73072	0.0	2.80	2.58	N/A	8.18	78	6304	2748		
3	5400	56796	56796	73038	0.0	2.80	2.58	N/A	8.18	78	6305	2749		
4														
5	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Full/Partial Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	76615	76615	76846	0.0	5.33	N/A	6.07	6.07	78	0	13	0	0
2	3857	0	0	12	0.0	4.35	N/A	4.45	+ 100.00	119	2	1963		
3	3857	-0	-0	12	0.0	4.35	N/A	4.45	(+ 100.00)	119	2	1963		
4	5398	-30825	-30825	-31449	0.0	3.41	N/A	3.17	(14.82)	136	3	2748		
5	5400	-30865	-30865	-31490	0.0	3.41	N/A	3.17	(14.80)	136	3	2749		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Leak (Collapse)

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	23755	23755	38860	0.0	11.08	N/A	12.00	19.17	146	2436	2436	11569	1235
2	1214	0	0	15037	0.0	12.11	N/A	12.97	+ 100.00	146	2520	3041		
3	1214	-0	-0	15037	0.0	12.11	N/A	12.97	(+ 100.00)	146	2520	3041		
4	5398	-91095	-83685	-76478	1271.3	4.07	N/A	3.68	(5.00)	146	2815	5171		
5	5400	-91147	-83725	-76530	1273.4	4.07	N/A	3.68	(5.00)	146	2815	5172		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Annular Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	28981	28981	29080	0.0	2.24	N/A	2.35	16.04	78	2	3513	0	0
2	1475	0	0	675	0.0	2.07	N/A	2.12	+ 100.00	94	115	4251		
3	1475	-0	-0	675	0.0	2.07	N/A	2.12	(+ 100.00)	94	115	4251		
4	5398	-78459	-78459	-77590	0.0	1.63	N/A	1.49	(5.82)	136	421	6248		
5	5400	-78499	-78499	-77630	0.0	1.63	N/A	1.49	(5.82)	136	421	6249		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	191535	191535	193573	0.0	2.13	N/A	N/A	2.41	102	13	13	N/A	N/A
2	5398	100034	100034	117604	0.0	3.56	N/A	N/A	4.60	112	2748	2748		
3	5399	100011	100011	117585	0.0	3.56	N/A	N/A	4.60	112	2749	2749		
4	5400	100000	100000	117576	0.0	3.56	N/A	N/A	4.60	112	2749	2749		
5	5400	100000	100000	117575	0.0	3.56	N/A	N/A	4.60	112	2749	2749		
6														
7	(V)	Vector Collapse Safety Factor												

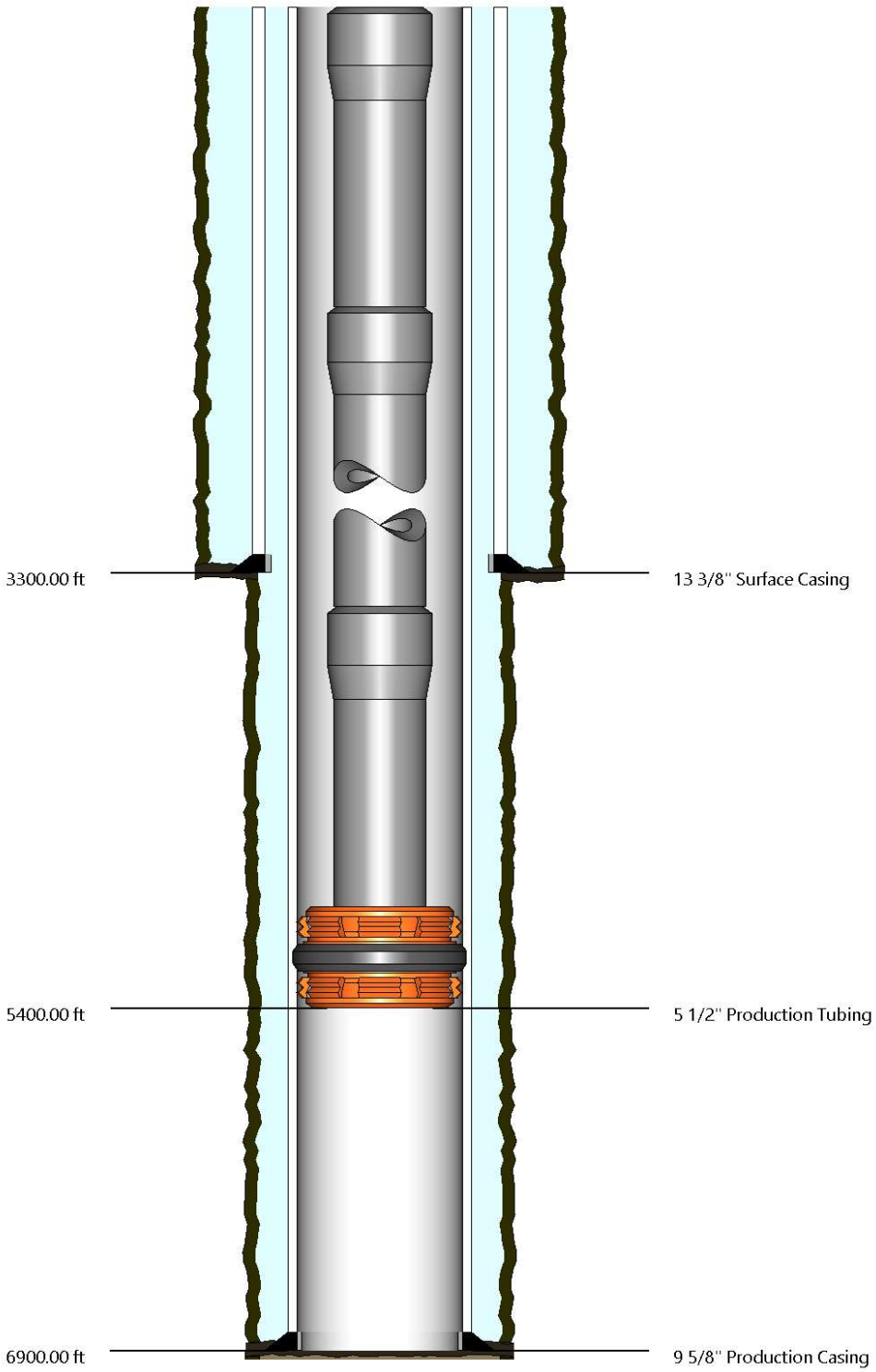
GENERAL DATA

Description:	Bluebonnet CCS 6 Final
Well Options, Deviated:	Yes
Well Options, Offshore:	No
Well TD (MD):	6900.00 ft
Reference Point:	OTR
Air Gap:	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	0.00 °

WELL SUMMARY

	String	OD/Weight/Grade	Connection	MD Interval (ft)	Drift Dia. (in)	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V	Axial	Triaxial	
1	Surface Casing	13 3/8", 61.000 ppf, K-55	BTC, K-55	26.00-3300.00	12.359	1.18	1.37	2.53	1.32	91,889
2										Total = 91,889
3										
4	Production Casing	9 5/8", 53.500 ppf, L-80	Blue	26.00-4100.00	8.500 A	2.07	2.45	3.09	2.18	126,912
5		9 5/8", 53.500 ppf, L-80	Blue	4100.00-6900.00	8.500 A	1.99	1.46	4.66	1.88	87,225
6										Total = 214,137
7										
8	Production Tubing	5 1/2", 20.000 ppf, L-80	Blue	26.00-5400.00	4.653	2.57	1.49	2.41	1.63	66,946
9										Total = 66,946
10										
11										Total = 372,972
12	A Alternate Drift									
13	(V) Vector Collapse Safety Factor									

WELL SCHEMATIC (DEPTH - MD)



CASING AND TUBING SCHEME

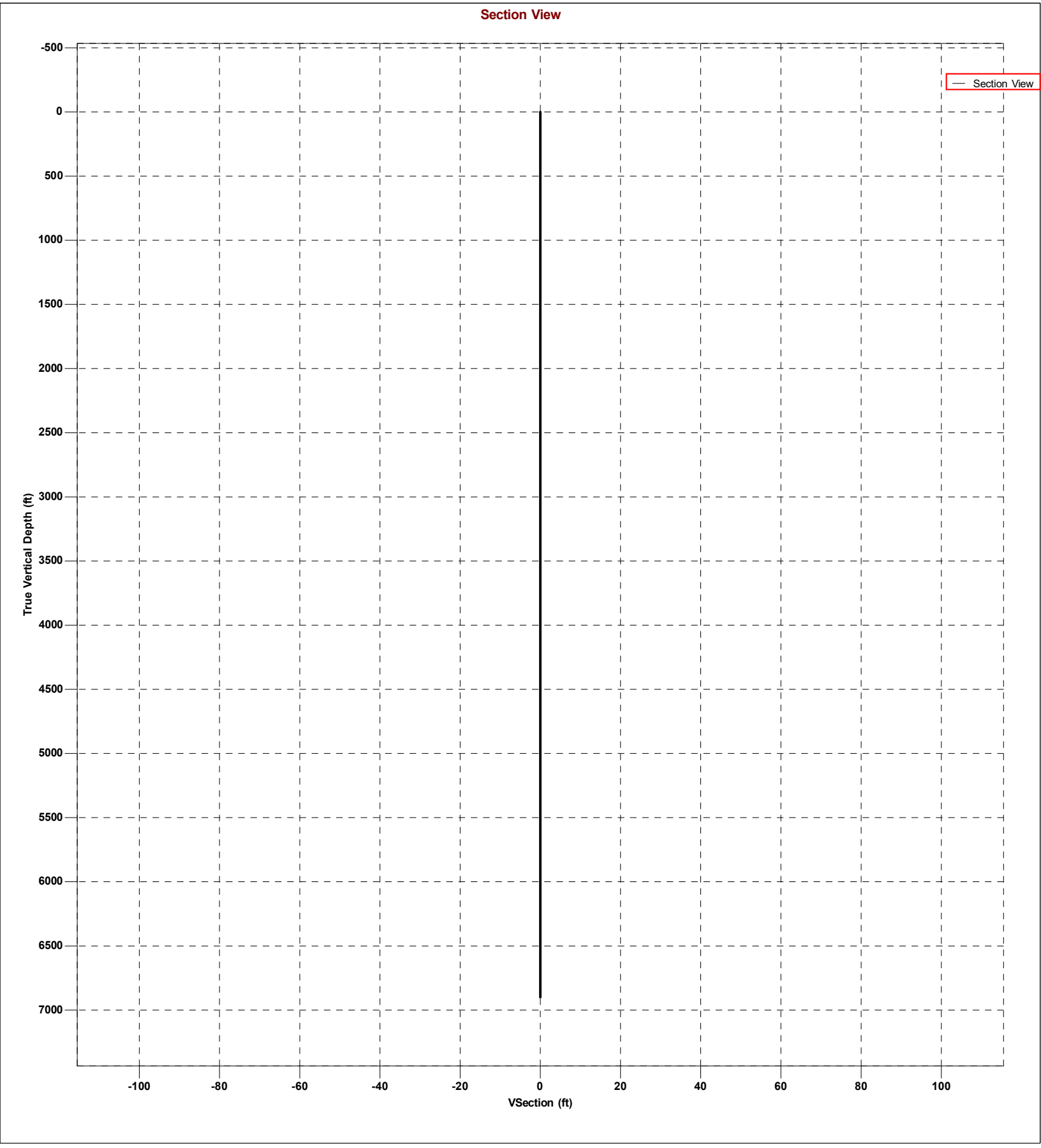
	OD (in)	Name	Type	Hole Size (in)	Measured Depths (ft)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	13 3/8"	Surface	Casing	17.500	26.00	3300.00	26.00	10.00
2	9 5/8"	Production	Casing	12.250	26.00	6900.00	26.00	12.50
3	5 1/2"	Production	Tubing		26.00	5400.00		9.80

PRODUCTION DATA

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6211.00 ft
Gas Gravity:	0.70

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.00	0.00			0.00	0.00
2	MD-INC-AZ	6900.00	0.00	0.00	6900.00	0.00	0.00	0.00	0.00

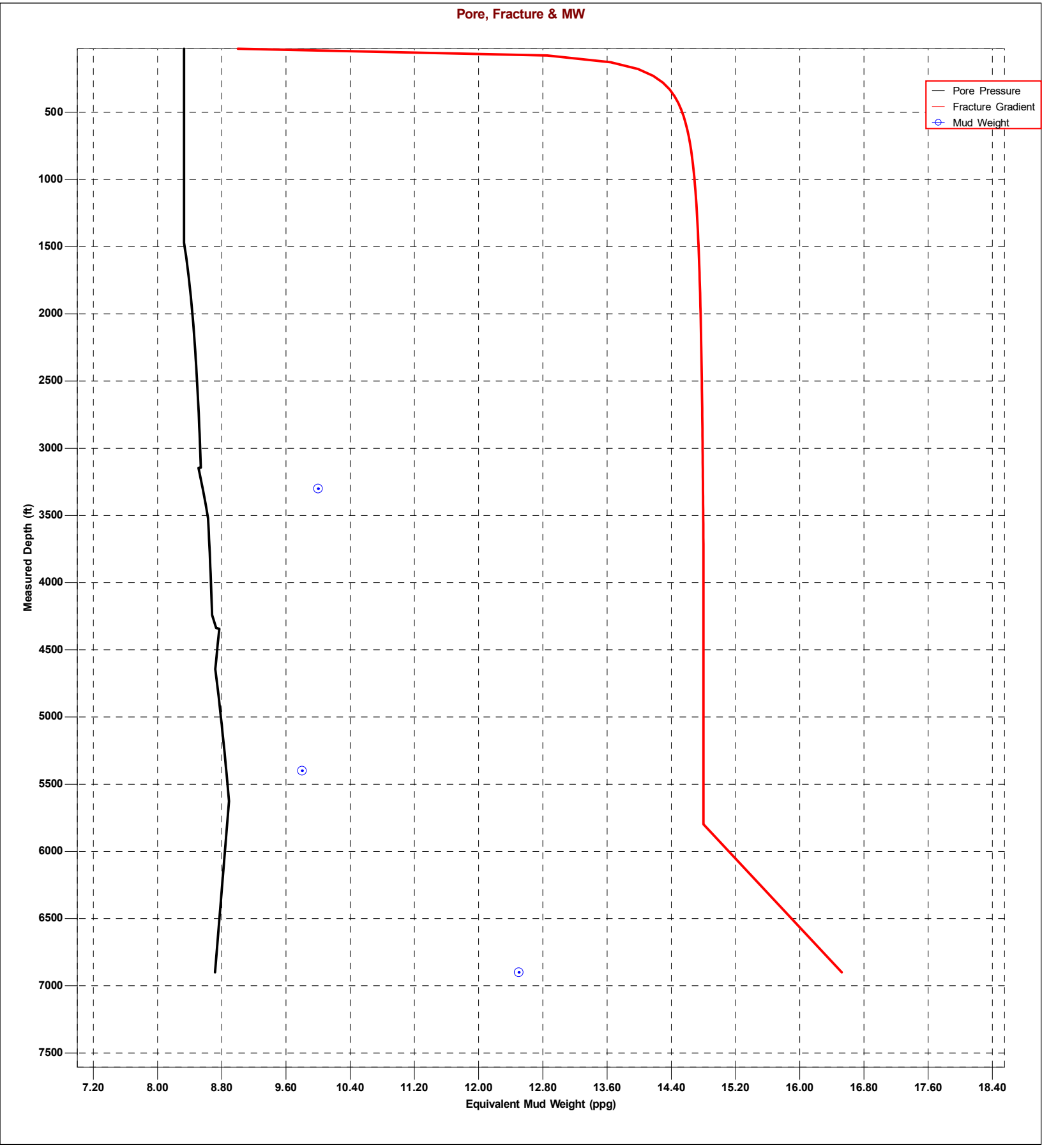

Section View
Section View
-500
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
True Vertical Depth (ft)
-100
-80
-60
-40
-20
0
20
40
60
80
100
VSection (ft)

PORE PRESSURE

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	0	8.33	No
2	1470.00	636	8.33	No
3	3144.00	1395	8.54	No
4	3146.00	1391	8.51	No
5	3521.00	1579	8.63	No
6	4240.00	1912	8.68	No
7	4337.00	1967	8.73	No
8	4344.00	1979	8.77	No
9	4643.00	2103	8.72	No
10	5626.00	2598	8.89	No
11	7666.00	3441	8.64	No
12	8182.00	3660	8.61	No
13	9300.00	4155	8.60	No

FRACTURE GRADIENT

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	0	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9300.00	8455	17.50


Pore, Fracture & MW
Pore Pressure
Fracture Gradient
Mud Weight
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
7.20
8.00
8.80
9.60
10.40
11.20
12.00
12.80
13.60
14.40
15.20
16.00
16.80
17.60
18.40
Equivalent Mud Weight (ppg)

GEOTHERMAL GRADIENT DATA

Surface Ambient:	78 °F
Bottomhole Temperature - 6900.00 ft TVD:	152 °F
Bottomhole Gradient - 6900.00 ft TVD:	1.08 °F/100ft

DESIGN PARAMETERS DATA (13 3/8" Surface Casing)

Design Factor (Pipe) - Axial Tension:	1.400
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.400
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	12.250 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (13 3/8" Surface Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3300.00 ft	113 °F

BURST LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 3300.00 ft):	2535 psi
Mud/Water Interface, MD:	3300.00 ft
Mud Weight	7.82 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	6900.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	1.00 ppg
Maximum Mud Weight:	12.50 ppg
Kick Gas Gravity:	0.70 (0.1160 psi/ft @ 124 °F & 4839 psi)
Fracture at Shoe (MD= 3300.00 ft):	2535 psi
Drill Pipe OD:	5.500 in
Collar OD:	8.000 in
Collar Length:	300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	1500 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Fracture @ Shoe w/ Gas Gradient Above**
Gas Gradient:	0.1000 psi/ft
Shoe Depth, MD :	3300.00 ft
Fracture Pressure at Shoe:	2535 psi
Fracture Margin of Error:	0.00 ppg
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2600 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	6900.00 ft
Pore Pressure at Lost Returns Depth:	3084 psi
Pore Pressure Gradient at Lost Returns Depth:	8.60 ppg
Mud Weight:	12.50 ppg
Mud Drop Level, MD:	2151.22 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (13 3/8" Surface Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	2600 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Lost Returns (psi)	Gas Kick (psi)	Pressure Test (psi)	Fracture @ Shoe w/ Gas Gradient Above (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	1118	1184	1514	2208	2611	14	0
2	1470.00	1743	1910	2264	2352	3236	951	636
3	2600.00	2232	2479	2851	2465	3725	1685	1148
4	3144.00	2467	2752	3133	2519	3960	2131	1395
5	3146.00	2468	2753	3134	2519	3961	2133	1391
6	3300.00	2535	2831	3214	2535	4028	2259	1468

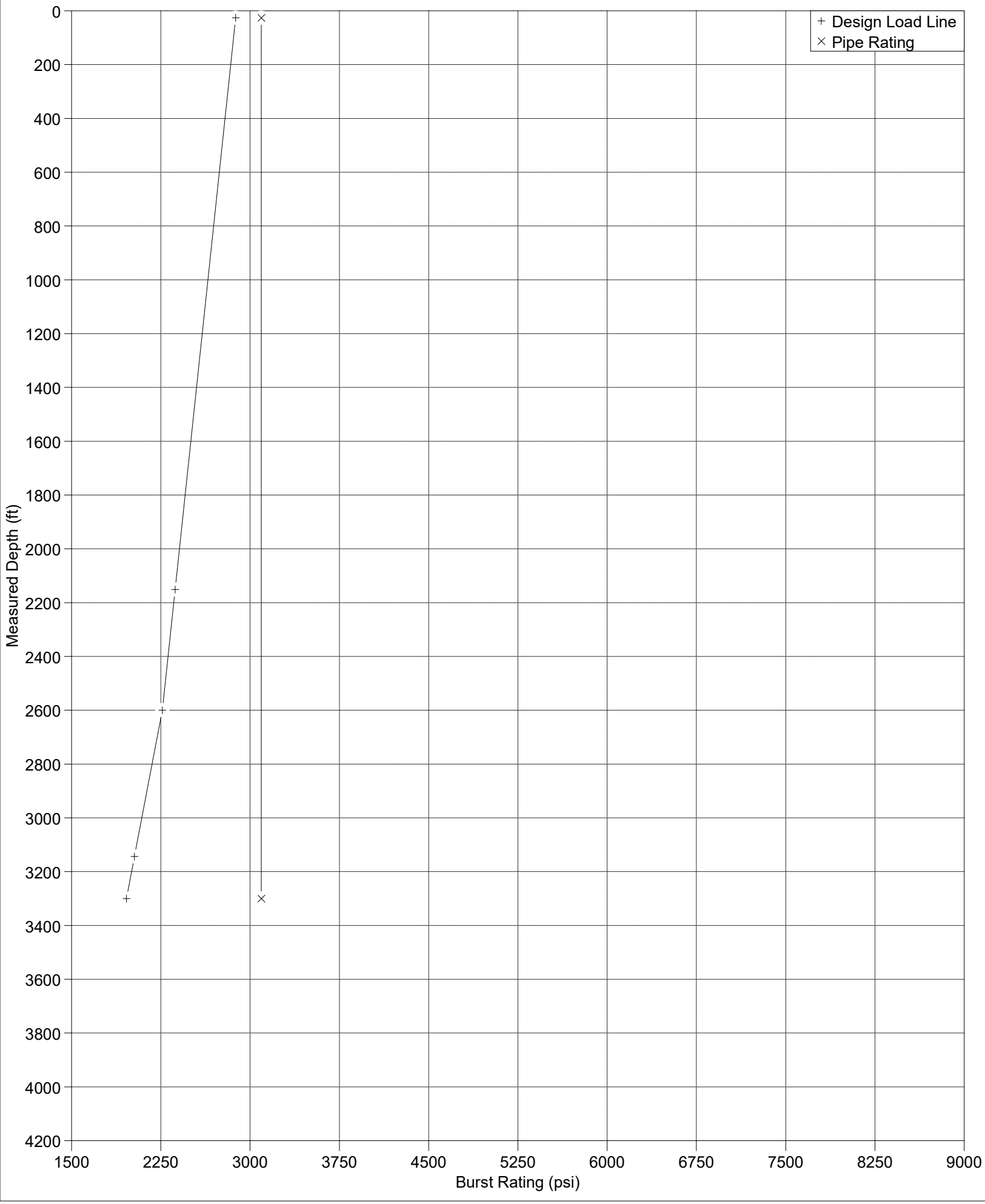
COLLAPSE PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Lost Returns (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	14	0	14
2	2151.22	931	1394	0	1118
3	2600.00	1125	1685	291	1351
4	3300.00	1428	2259	746	1714

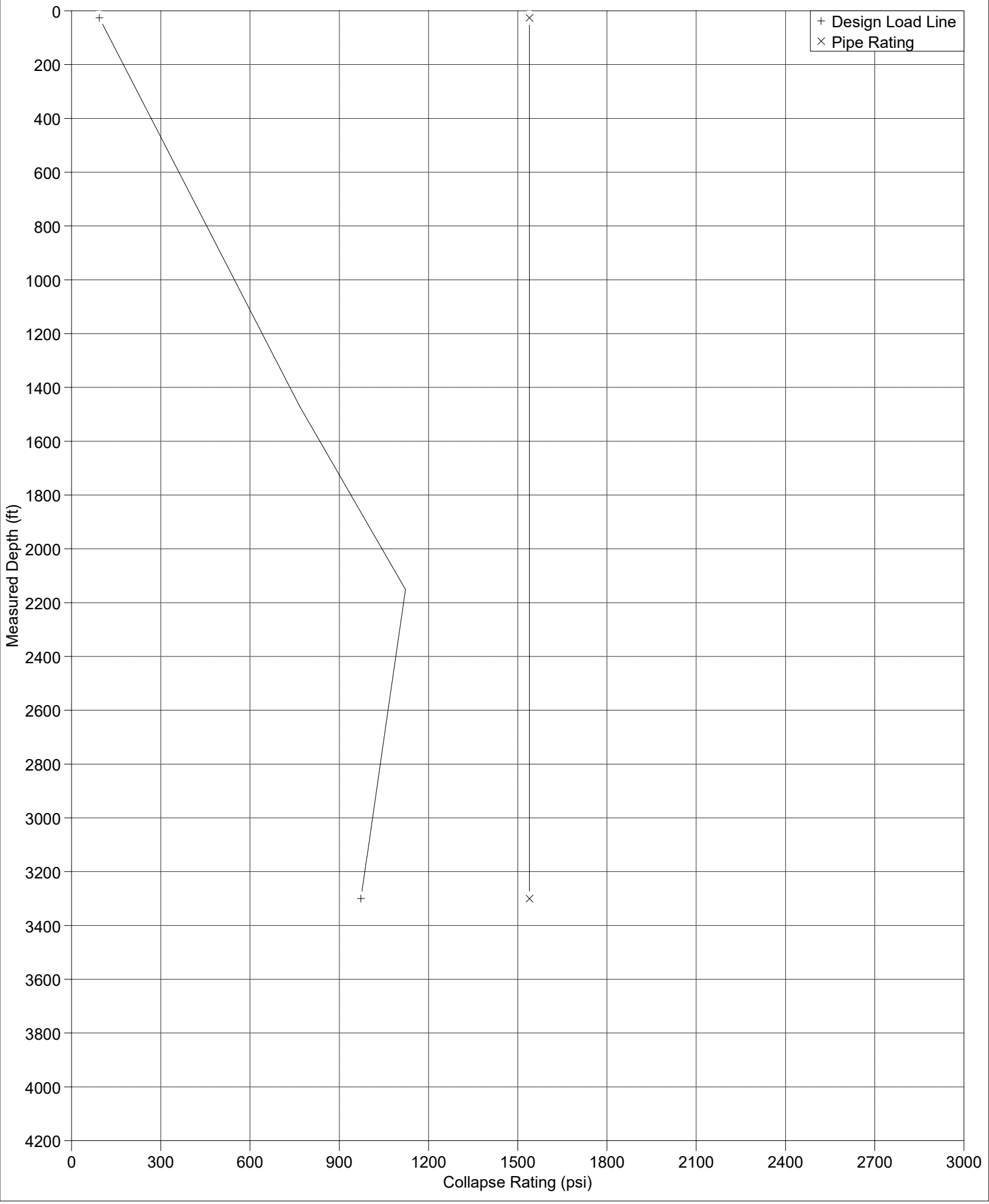
AXIAL LOADS TABLE (13 3/8" Surface Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	269972	269972	377753	377753	377753	377753
2	932.65	222903	222903	322448	322448	322448	322448
3	1470.00	195006	195006	289669	289669	289669	289669
4	2151.22	159640	159640	248115	248115	248115	248115
5	2600.00	136341	136341	220739	220739	220739	220739
6	3144.00	108099	108099	187555	187555	187555	187555
7	3146.00	107995	107995	187433	187433	187433	187433

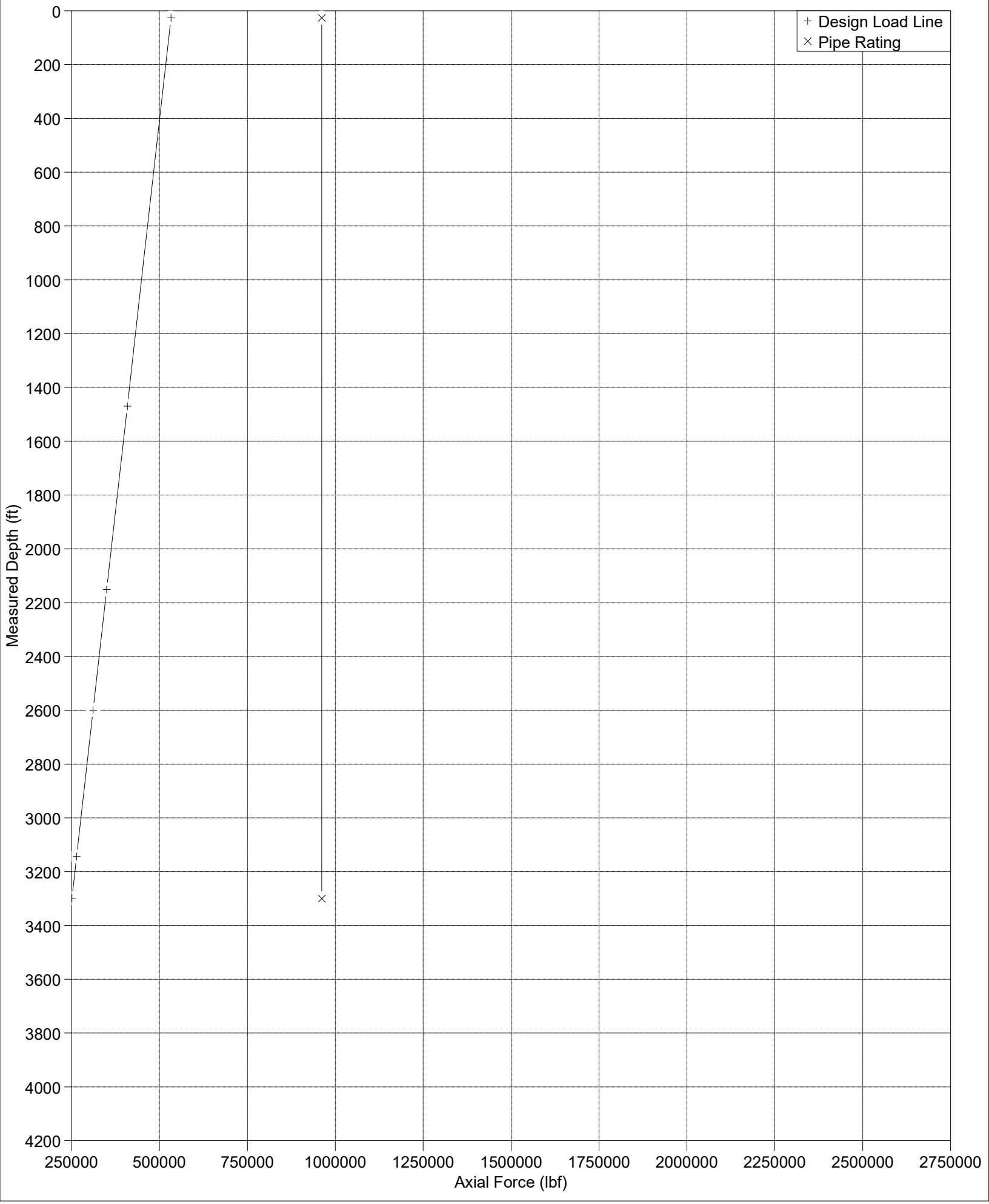
BURST DESIGN (13 3/8" Surface Casing)

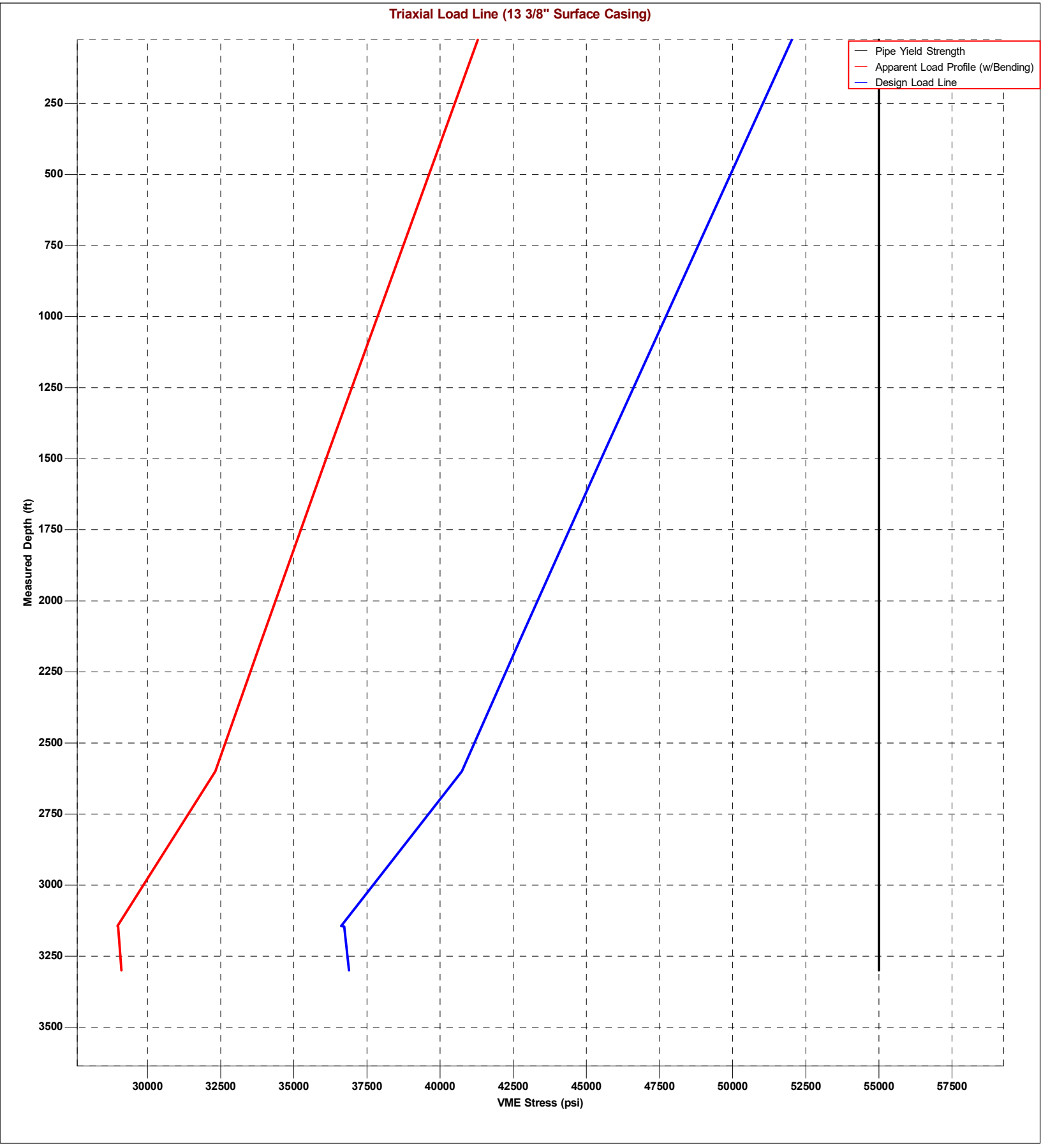


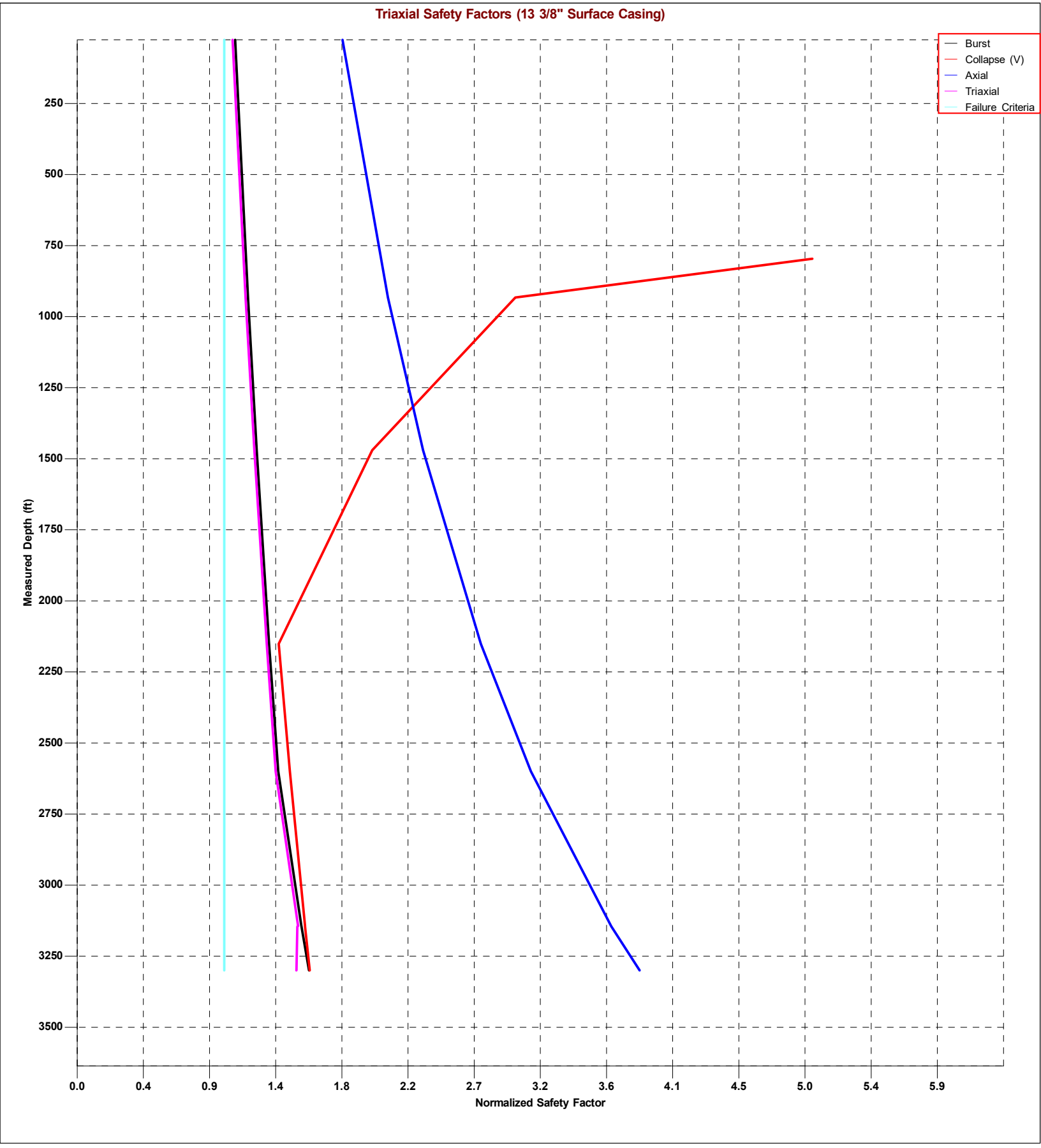
COLLAPSE DESIGN (13 3/8" Surface Casing)



AXIAL DESIGN (13 3/8" Surface Casing)




Triaxial Load Line (13 3/8" Surface Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
30000
32500
35000
37500
40000
42500
45000
47500
50000
52500
55000
57500
VME Stress (psi)


Triaxial Safety Factors (13 3/8" Surface Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	13 3/8", 61.000 ppf, K-55	BTC, K-55	1.18 B12	16.42 C2	2.53 B12	1.32 B12
2	933			1.28 B12	2.98 C4	2.96 B12	1.43 B12
3	1470			1.34 B12	2.01 C4	3.29 A5	1.51 B12
4	2151			1.44 B12	1.37 C4	3.84 A5	1.61 B12
5	2600			1.50 B12	1.45 C4	4.32 A5	1.69 B12
6	3144			1.68 B12	1.55 C4	5.08 A5	1.88 B5
7	3146			1.68 B12	1.55 C4	5.09 A5	1.87 B5
8	3299			1.73 B12	1.58 C4	5.35 A5	1.86 B5
9	3300			1.73 B12	1.58 C4	5.36 A5	1.86 B5
10							
11	B5	Pressure Test					
12	B12	Green Cement Pressure Test(Burst)					
13	C2	Cementing					
14	C4	Lost Returns with Mud Drop					
15	A5	Green Cement Pressure Test(Axial)					
16	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	13 3/8", 61.000 ppf, K-5	0.400 B12	0.088 C4	0.355 B12	6.9	79.6	17.4	0.030	0.342	0.075
2	932.65		0.370 B12	0.287 C4	0.327 B12	13.9	33.3	24.0	0.060	0.143	0.103
3	1470.00		0.352 B12	0.333 C4	0.311 B12	18.1	22.5	27.8	0.078	0.097	0.119
4	2151.22		0.329 B12	0.379 C4	0.290 B12	23.4	11.9	32.5	0.101	0.051	0.140
5	2600.00		0.315 B12	0.371 C4	0.277 B12	26.9	13.6	35.6	0.115	0.059	0.153
6	3144.00		0.282 B12	0.363 C4	0.251 B5	34.4	15.6	41.6	0.148	0.067	0.179
7	3146.00		0.282 B12	0.363 C4	0.252 B5	34.4	15.7	41.5	0.148	0.067	0.178
8	3299.20		0.273 B12	0.360 C4	0.253 B5	36.6	16.2	41.2	0.157	0.070	0.177
9	3300.00		0.273 B12	0.360 C4	0.253 B5	36.6	16.2	41.2	0.157	0.070	0.177
10											
11	B5	Pressure Test									
12	B12	Green Cement Pressure Test(Burst)									
13	C4	Lost Returns with Mud Drop									
14	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (13 3/8" Surface Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	681551
2	26	680201
3	26	680200
4	254	668372
5	508	655193
6	762	642015
7	1000	629635
8	1015	628836
9	1269	615658
10	1523	602479
11	1777	589300
12	2000	577719
13	2031	576122
14	2285	562943
15	2538	549764
16	2792	536586
17	3000	525803
18	3046	523407
19	3274	511578
20	3300	* 511811
21		
22	* Based on Casing Strength	
23	Only. Running String not	
24	Included	

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Gas Kick Profile

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	44069	44069	44579	0.0	2.73	2.58	N/A	21.57	106	1184	0	N/A	N/A
2	1470	31721	31721	43390	0.0	2.51	2.40	N/A	29.94	110	1910	636		
3	2151	25167	25167	42243	0.0	2.44	2.33	N/A	37.72	112	2253	945		
4	2600	20849	20849	41487	0.0	2.39	2.29	N/A	45.51	113	2479	1148		
5	3144	23477	23477	48541	0.0	2.36	2.25	N/A	40.40	114	2752	1395		
6	3146	23901	23901	48900	0.0	2.35	2.24	N/A	39.68	114	2753	1391		
7	3300	24030	24030	50404	0.0	2.35	2.24	N/A	39.46	114	2831	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Water

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	140755	140755	141180	0.0	3.10	2.76	N/A	6.81	78	1118	0	N/A	N/A
2	1470	134363	134363	145926	0.0	3.13	2.79	N/A	7.14	78	1743	636		
3	2151	130618	130618	147585	0.0	3.17	2.82	N/A	7.34	78	2038	945		
4	2600	128151	128151	148678	0.0	3.19	2.85	N/A	7.48	78	2232	1148		
5	3144	133022	133022	157888	0.0	3.22	2.88	N/A	7.21	78	2467	1395		
6	3146	133455	133455	158252	0.0	3.20	2.86	N/A	7.19	78	2468	1391		
7	3300	134218	134218	160370	0.0	3.23	2.89	N/A	7.14	78	2535	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	169936	169936	170449	0.0	2.28	2.04	N/A	5.64	78	1514	0	N/A	N/A
2	1470	116519	116519	128632	0.0	2.08	1.89	N/A	8.19	94	2264	636		
3	2151	90590	90590	108183	0.0	1.99	1.83	N/A	10.51	101	2618	945		
4	2600	73508	73508	94662	0.0	1.93	1.80	N/A	12.94	106	2851	1148		
5	3144	60664	60664	86184	0.0	1.88	1.76	N/A	15.65	112	3133	1395		
6	3146	61031	61031	86486	0.0	1.87	1.75	N/A	15.55	112	3134	1391		
7	3300	56780	56780	83587	0.0	1.86	1.75	N/A	16.71	113	3214	1468		
8														
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Fracture @ Shoe w/ Gas Gradient Above

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	119596	119596	120982	0.0	1.49	1.39	N/A	7.95	106	2208	0	N/A	N/A
2	1470	64303	64303	76387	0.0	1.89	1.78	N/A	14.77	110	2352	636		
3	2151	37489	37489	54728	0.0	2.18	2.07	N/A	25.32	112	2420	945		
4	2600	19824	19824	40447	0.0	2.42	2.32	N/A	47.86	113	2465	1148		
5	3144	6273	6273	31095	0.0	2.81	2.71	N/A	+ 100.00	114	2519	1395		
6	3146	6638	6638	31394	0.0	2.80	2.70	N/A	+ 100.00	114	2519	1391		
7	3300	2186	2186	28250	0.0	2.96	2.86	N/A	+ 100.00	114	2535	1468		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381012	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308845	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	2151	248115	248115	274785	0.0	1.61	1.44	N/A	3.84	96	3531	1394		
4	2600	220739	220739	252341	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
5	3144	187555	187555	226774	0.0	1.88	1.68	N/A	5.08	97	3960	2131		
6	3146	187433	187433	226680	0.0	1.88	1.68	N/A	5.09	97	3961	2133		
7	3299	178088	178088	219479	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219441	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Mud Drop

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-44478	-44478	-44994	0.0	19.56	N/A	+ 100.00	(21.38)	106	0	14	N/A	N/A
2	1470	-120039	-120039	-121567	0.0	4.48	N/A	2.01	(7.91)	110	0	764		
3	2151	-155686	-155686	-157752	0.0	3.07	N/A	1.37	(6.10)	112	0	1118		
4	2600	-157660	-157660	-154643	0.0	3.23	N/A	1.45	(6.02)	113	291	1351		
5	3144	-152192	-152192	-142900	0.0	3.46	N/A	1.55	(6.23)	114	645	1633		
6	3146	-152172	-152172	-142857	0.0	3.46	N/A	1.55	(6.23)	114	646	1634		
7	3300	-150624	-150624	-139531	0.0	3.54	N/A	1.58	(6.30)	114	746	1714		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	57919	57919	58581	0.0	14.35	N/A	16.42	16.47	94	11	14	N/A	N/A
2	975	43	43	7480	0.0	13.54	N/A	7.31	+ 100.00	95	422	630		
3	976	-6	-6	7437	0.0	13.53	N/A	7.30	(+ 100.00)	95	422	630		
4	1470	-30165	-30165	-19199	0.0	10.44	N/A	4.87	(31.62)	95	636	951		
5	2151	-71720	-71720	-55909	0.0	7.43	N/A	3.32	(13.30)	96	931	1394		
6	2600	-99095	-99095	-80098	0.0	6.15	N/A	2.74	(9.62)	96	1125	1685		
7	3144	-132279	-132279	-109427	0.0	4.47	N/A	1.99	(7.21)	97	1360	2131		
8	3146	-132401	-132401	-109534	0.0	4.46	N/A	1.99	(7.20)	97	1361	2133		
9	3300	-141795	-141795	-117838	0.0	4.14	N/A	1.85	(6.72)	97	1428	2259		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	269972	269972	272369	0.0	3.10	N/A	N/A	3.53	94	14	14	N/A	N/A
2	1470	195006	195006	210089	0.0	4.05	N/A	N/A	4.89	95	764	764		
3	2151	159640	159640	180695	0.0	4.74	N/A	N/A	5.97	96	1118	1118		
4	2600	136341	136341	161326	0.0	5.33	N/A	N/A	6.99	96	1351	1351		
5	3144	108099	108099	137842	0.0	6.29	N/A	N/A	8.82	97	1633	1633		
6	3146	107995	107995	137756	0.0	6.29	N/A	N/A	8.83	97	1634	1634		
7	3299	100041	100041	131142	0.0	6.63	N/A	N/A	9.53	97	1714	1714		
8	3300	100000	100000	131107	0.0	6.63	N/A	N/A	9.54	97	1714	1714		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381012	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308845	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	2151	248115	248115	274785	0.0	1.61	1.44	N/A	3.84	96	3531	1394		
4	2600	220739	220739	252341	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
5	3144	187555	187555	226774	0.0	1.88	1.68	N/A	5.08	97	3960	2131		
6	3146	187433	187433	226680	0.0	1.88	1.68	N/A	5.09	97	3961	2133		
7	3299	178088	178088	219479	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219441	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (9 5/8" Production Casing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	7.970 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (9 5/8" Production Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3000.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
6900.00 ft	152 °F

BURST LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Mud Weight:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6211.00 ft
Gas Gravity:	0.70 (0.0760 psi/ft @ 145 °F & 2840 psi)
Reservoir Pressure:	2840 psi
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Stimulation Surface Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Injection Pressure:	3500 psi
Injection Density:	8.33 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Injection Down Casing**
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	3500 psi
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3000.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	6900.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Mud Weight Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3000.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	6900.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Full Evacuation**
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Fluid Gradient Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	12.50 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (9 5/8" Production Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	3500 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Pressure Test (psi)	Tubing Leak (psi)	Stimulation Leak (psi)	Casing Injection (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	3513	2403	3511	3513	3511	17	17
2	3299.99	5180	4070	5178	5180	4928	2143	1446
3	3300.01	5180	4070	5178	5180	4928	2143	1468
4	3521.00	5293	4182	5291	5293	5024	2286	1579
5	3900.00	5485	4375	5483	5485	5188	2532	1754
6	4099.99	5587	4477	5585	5587	5274	2697	1847
7	4100.01	5587	4477	5585	5587	5274	2697	1847
8	4240.00	5659	4548	5657	5659	5335	2812	1912
9	4337.00	5708	4598	5706	5708	5377	2891	1967
10	4643.00	5864	4754	5862	5864	5509	3142	2103
11	5399.99	6249	5139	6247	6249	5837	3764	2484
12	5400.01	6249	2779	5837	6249	5837	3764	2484
13	5626.00	6364	2796	5935	6364	5935	3949	2598
14	6211.00	6662	2840	6188	6662	6188	4429	2840
15	6900.00	7013	3191	6486	7013	6486	4995	3124

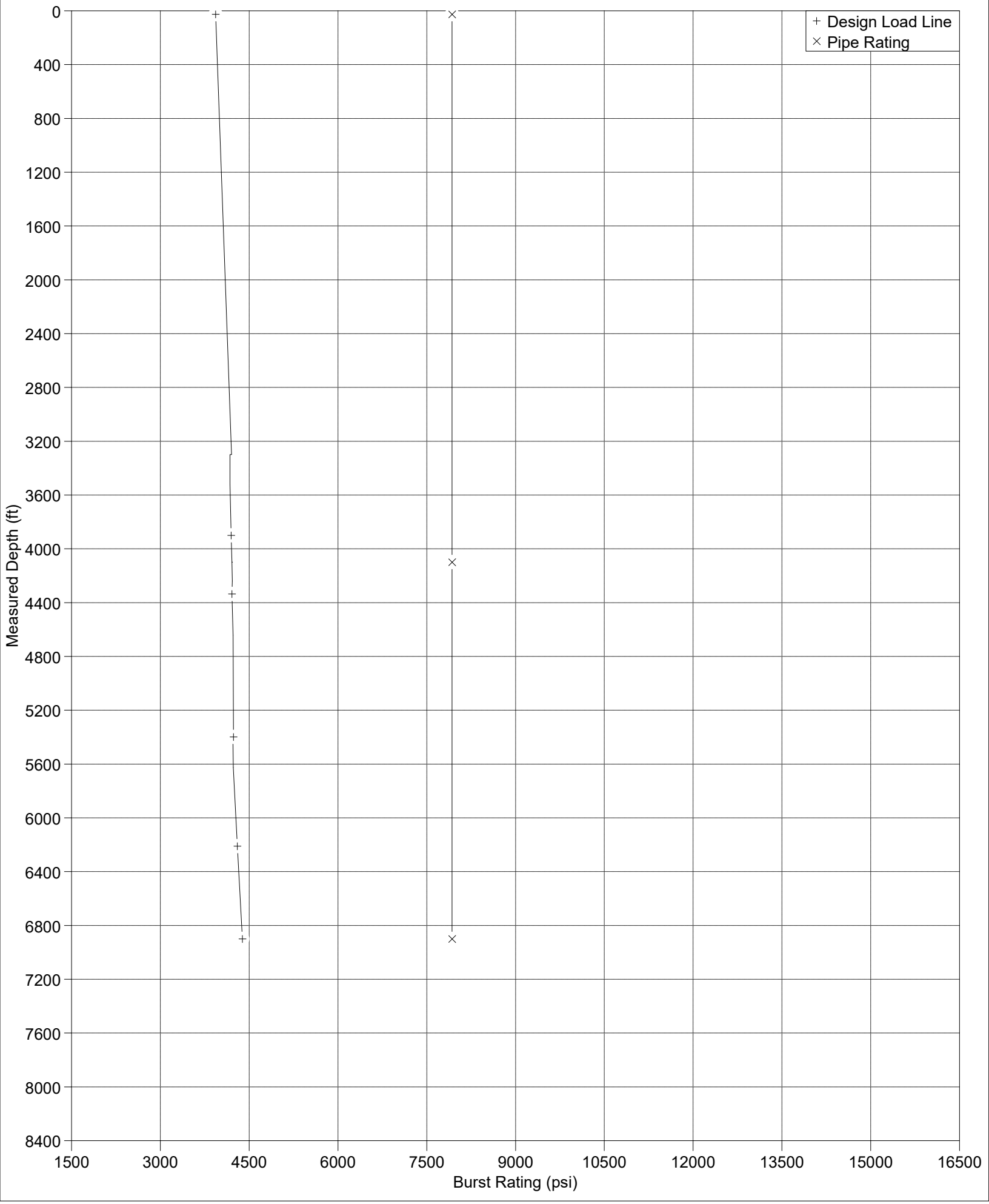
COLLAPSE PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Full Evacuation (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	17	0	17
2	3299.99	1428	2143	2	2143
3	3300.01	1428	2143	2	2143
4	3900.00	1688	2532	2	2532
5	4099.99	1774	2697	2	2662
6	4100.01	1774	2697	2	2662
7	5399.99	2337	3764	3	3506
8	5400.01	2337	3764	3	3506
9	6211.00	2688	4429	3	4033
10	6900.00	2986	4995	4	4481

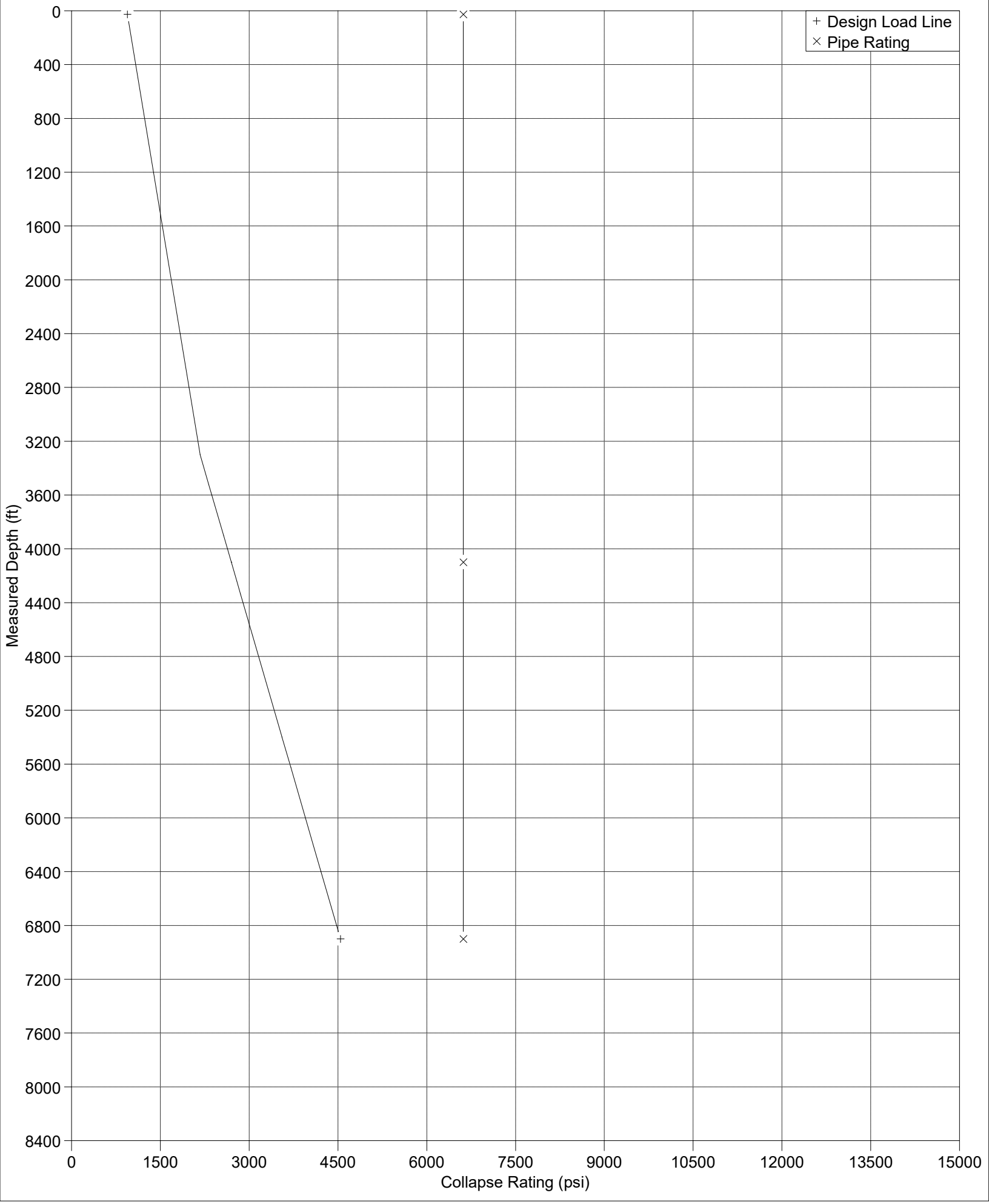
AXIAL LOADS TABLE (9 5/8" Production Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	398365	398365	375413	375413	375413	375413
2	1802.22	321268	321268	280385	280385	280385	280385
3	1802.22	321268	321268	280385	280385	280385	221527
4	3299.99	256258	256258	200255	200255	159249	159249
5	3300.01	256257	256257	200254	200254	271697	271697
6	3521.00	246665	246665	188431	188431	269544	269544
7	3900.00	230215	230215	168154	168154	266464	266464
8	4099.99	221534	221534	157455	157455	266335	266335
9	4100.01	221533	221533	157454	157454	266335	266335
10	4240.00	215457	215457	149964	149964	266245	266245
11	4337.00	211247	211247	144775	144775	265745	265745
12	4643.00	197965	197965	128404	128404	265789	265789
13	5399.99	165108	165108	87905	87905	263983	263983
14	5400.01	165107	165107	87904	87904	263983	263983
15	5626.00	155298	155298	75813	75813	263444	263444
16	5661.87	153741	153741	73894	73894	263500	263500
17	6211.00	129906	129906	44516	44516	264361	264361

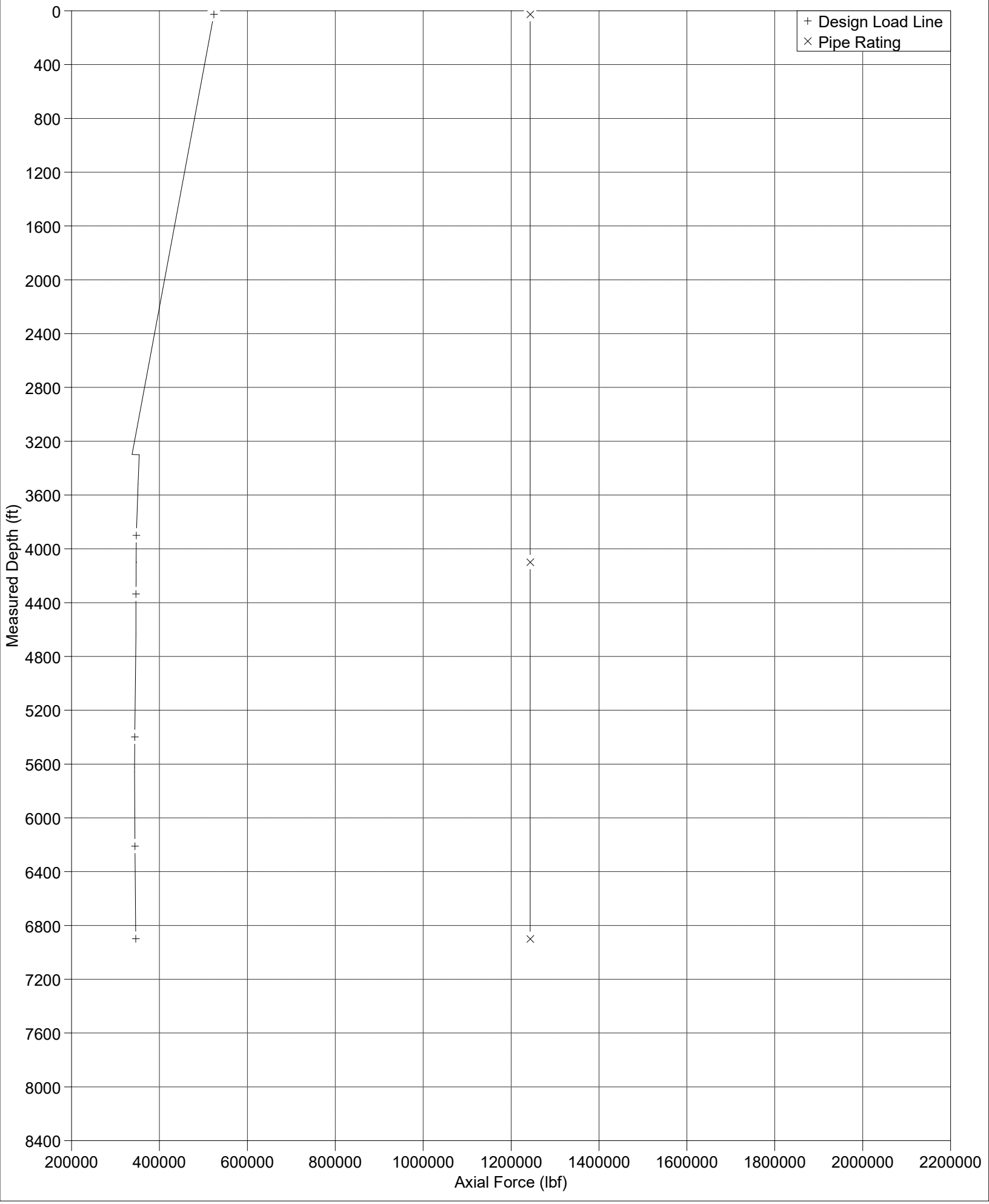
BURST DESIGN (9 5/8" Production Casing)

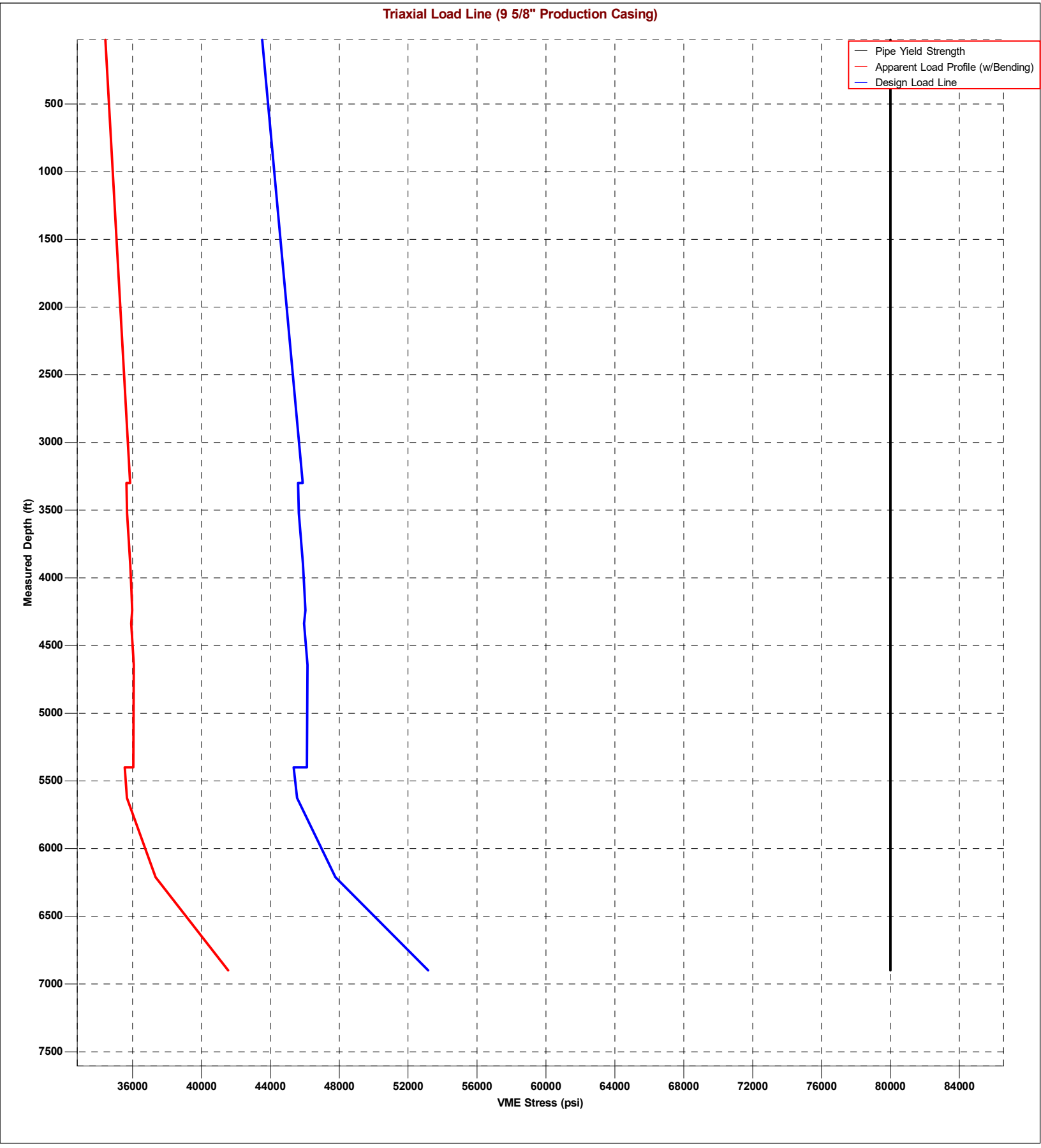


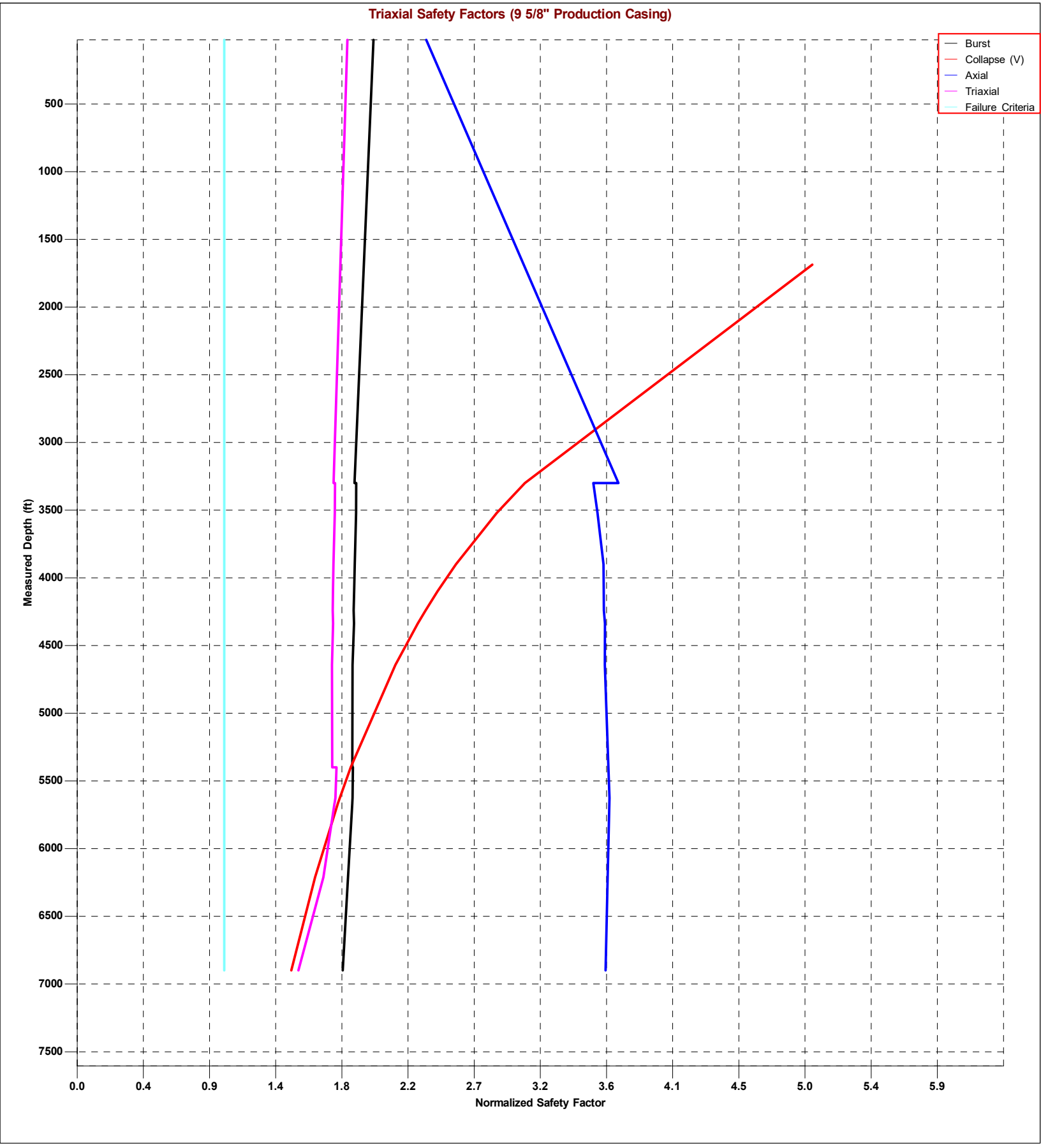
COLLAPSE DESIGN (9 5/8" Production Casing)



AXIAL DESIGN (9 5/8" Production Casing)




Triaxial Load Line (9 5/8" Production Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
36000
40000
44000
48000
52000
56000
60000
64000
68000
72000
76000
80000
84000
VME Stress (psi)


Triaxial Safety Factors (9 5/8" Production Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	9 5/8", 53.500 ppf, L-80	Blue	2.22 B7	7.01 C2	3.09 A4	2.30 B12
2	3300			2.07 B7	3.04 C5	4.79 A4	2.18 B7
3	3300			2.09 B7	3.04 C5	4.56 B8	2.19 B7
4	3521			2.09 B7	2.85 C5	4.60 B8	2.19 B7
5	3900			2.08 B7	2.58 C5	4.65 B8	2.18 B7
6	4100			2.07 B7	2.45 C5	4.66 B8	2.18 B7
7	4100	9 5/8", 53.500 ppf, L-80	Blue	2.07 B7	2.45 C5	4.66 B8	2.18 B7
8	4240			2.07 B7	2.37 C5	4.66 B8	2.17 B7
9	4337			2.07 B7	2.32 C5	4.67 B8	2.18 B7
10	4643			2.06 B7	2.16 C5	4.67 B8	2.17 B7
11	5400			2.06 B7	1.86 C5	4.70 B8	2.17 B7
12	5400			2.06 B5	1.86 C5	4.70 B8	2.20 B5
13	5626			2.06 B5	1.79 C5	4.71 B8	2.20 B5
14	5662			2.06 B5	1.77 C5	4.71 B8	2.19 B5
15	5665			2.06 B5	1.77 C5	4.71 B8	2.19 B5
16	6211			2.03 B5	1.62 C5	4.69 B8	2.09 C5
17	6899			1.99 B5	1.46 C5	4.67 B8	1.88 C5
18	6900			1.99 B5	1.46 C5	4.67 B8	1.88 C5
19							
20	B5	Pressure Test					
21	B7	Stimulation Surface Leak					
22	B8	Injection Casing					
23	B12	Green Cement Pressure Test(Burst)					
24	C2	Cementing					
25	C5	Full Evacuation Production					
26	A4	Overpull Force					
27	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	9 5/8", 53.500 ppf, L-80	0.270 B7	0.074 C2	0.252 B7	50.4	86.5	53.7	0.275	0.471	0.293
2	3299.99		0.289 B7	0.339 C5	0.273 B7	47.0	37.8	50.0	0.256	0.206	0.272
3	3300.01		0.287 B7	0.339 C5	0.271 B7	47.3	37.8	50.3	0.258	0.206	0.274
4	3521.00		0.287 B7	0.348 C5	0.271 B7	47.3	36.2	50.2	0.258	0.197	0.274
5	3900.00		0.289 B7	0.363 C5	0.273 B7	47.0	33.4	49.9	0.256	0.182	0.272
6	4099.99		0.289 B7	0.371 C5	0.274 B7	46.9	31.9	49.8	0.256	0.174	0.271
7	4100.01	9 5/8", 53.500 ppf, L-80	0.289 B7	0.371 C5	0.274 B7	46.9	31.9	49.8	0.256	0.174	0.271
8	4240.00		0.290 B7	0.377 C5	0.274 B7	46.8	30.9	49.7	0.255	0.168	0.271
9	4337.00		0.289 B7	0.380 C5	0.274 B7	46.9	30.2	49.8	0.256	0.165	0.271
10	4643.00		0.291 B7	0.393 C5	0.275 B7	46.6	28.0	49.6	0.254	0.152	0.270
11	5399.99		0.291 B7	0.423 C5	0.275 B7	46.6	22.4	49.5	0.254	0.122	0.270
12	5400.01		0.291 B5	0.423 C5	0.269 B5	46.7	22.4	50.6	0.254	0.122	0.276
13	5626.00		0.291 B5	0.430 C5	0.271 B5	46.6	21.2	50.3	0.254	0.115	0.274
14	5661.87		0.291 B5	0.431 C5	0.271 B5	46.6	21.0	50.2	0.254	0.114	0.274
15	5664.65		0.291 B5	0.431 C5	0.272 B5	46.6	21.0	50.2	0.254	0.114	0.273
16	6211.00		0.296 B5	0.445 C5	0.279 B5	45.7	18.4	48.8	0.249	0.100	0.266
17	6899.16		0.302 B5	0.463 C5	0.311 C5	44.6	15.1	42.9	0.243	0.082	0.234
18	6900.00		0.302 B5	0.463 C5	0.311 C5	44.6	15.1	42.9	0.243	0.082	0.234
19											
20	B5	Pressure Test									
21	B7	Stimulation Surface Leak									
22	C2	Cementing									
23	C5	Full Evacuation Production									
24	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (9 5/8" Production Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	945769
2	26	944641
3	26	944640
4	256	934677
5	511	923584
6	767	912492
7	1000	902364
8	1022	901400
9	1278	890307
10	1533	879215
11	1789	868123
12	2000	858959
13	2044	857030
14	2300	845938
15	2556	834846
16	2800	824236
17	2800	824235
18	2811	823753
19	3000	815554
20	3067	812661
21	3322	801568
22	3578	790476
23	3833	779384
24	4000	772150
25	4089	768291
26	4100	767810
27	4100	767809
28	4344	757199
29	4600	746107
30	4856	735014
31	5000	728745
32	5111	723922
33	5367	712830
34	5622	701737
35	5878	690645
36	6000	685340
37	6133	679552
38	6389	668460
39	6644	657368
40	6874	647404
41	6900	* 647647
42		
43	* Based on Casing Strength	
44	Only. Running String not	
45	Included	

TRIAXIAL RESULTS (9 5/8" Production Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	295383	295383	296538	0.0	2.43	2.26	N/A	4.20	78	3513	17	N/A	N/A
2	3300	159249	159249	184230	0.0	2.29	2.09	N/A	7.70	113	5180	1446		
3	3300	158273	158273	183593	0.0	2.30	2.11	N/A	7.75	113	5180	1468		
4	3521	148464	148464	175520	0.0	2.30	2.10	N/A	8.26	116	5293	1579		
5	3900	132254	132254	162047	0.0	2.27	2.09	N/A	9.26	120	5485	1754		
6	4100	125197	125197	156446	0.0	2.26	2.09	N/A	9.77	122	5587	1847		
7	4100	125196	125196	156446	0.0	2.26	2.09	N/A	9.77	122	5587	1847		
8	4240	120257	120257	152520	0.0	2.26	2.08	N/A	10.17	123	5659	1912		
9	4337	116396	116396	149512	0.0	2.26	2.08	N/A	10.50	124	5708	1967		
10	4643	105839	105839	141071	0.0	2.23	2.07	N/A	11.54	128	5864	2103		
11	5400	77808	77808	118858	0.0	2.20	2.06	N/A	15.66	136	6249	2484		
12	5400	77807	77807	118858	0.0	2.20	2.06	N/A	15.66	136	6249	2484		
13	5626	69439	69439	112205	0.0	2.20	2.06	N/A	17.53	138	6364	2598		
14	6211	50089	50089	96461	0.0	2.14	2.03	N/A	24.26	145	6662	2840		
15	6900	27299	27299	77839	0.0	2.07	1.99	N/A	44.41	152	7013	3124		
16														
17	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (9 5/8" Production Casing) - Tubing Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	43004	43004	44287	0.0	3.39	3.25	N/A	28.25	145	2403	17	N/A	N/A
2	3300	20293	20293	43775	0.0	3.06	2.95	N/A	59.88	145	4070	1446		
3	3300	19318	19318	43132	0.0	3.08	2.98	N/A	62.90	145	4070	1468		
4	3521	17165	17165	42689	0.0	3.08	2.97	N/A	70.79	145	4182	1579		
5	3900	14085	14085	42332	0.0	3.06	2.95	N/A	86.27	145	4375	1754		
6	4100	13956	13956	43676	0.0	3.05	2.94	N/A	87.06	145	4477	1847		
7	4240	13866	13866	44617	0.0	3.04	2.94	N/A	87.63	145	4548	1912		
8	4337	13366	13366	44980	0.0	3.05	2.94	N/A	90.91	145	4598	1967		
9	4643	13410	13410	47195	0.0	3.03	2.92	N/A	90.61	145	4754	2103		
10	5400	11604	11604	51412	0.0	3.04	2.92	N/A	+ 100.00	145	5139	2484		
11	5400	-69417	-69417	-31520	0.0	16.61	26.31	N/A	(17.50)	145	2779	2484		
12	5626	-73326	-73326	-33710	0.0	19.37	39.22	N/A	(16.57)	145	2796	2598		
13	6211	-81118	-81118	-37841	0.0	25.38	N/A	N/A	(14.98)	145	2840	2840		
14	6900	-80039	-80039	-32208	0.0	25.52	+ 100.00	N/A	(15.18)	145	3191	3124		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Stimulation Surface Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	81043	81043	83224	0.0	2.34	2.22	N/A	14.99	145	3511	17	N/A	N/A
2	3300	58332	58332	82711	0.0	2.18	2.07	N/A	20.83	145	5178	1446		
3	3300	57357	57357	82069	0.0	2.19	2.09	N/A	21.18	145	5178	1468		
4	3521	55204	55204	81626	0.0	2.19	2.09	N/A	22.01	145	5291	1579		
5	3900	52124	52124	81269	0.0	2.18	2.08	N/A	23.31	145	5483	1754		
6	4100	51996	51996	82613	0.0	2.18	2.07	N/A	23.37	145	5585	1847		
7	4240	51906	51906	83554	0.0	2.17	2.07	N/A	23.41	145	5657	1912		
8	4337	51405	51405	83917	0.0	2.18	2.07	N/A	23.64	145	5706	1967		
9	4643	51449	51449	86132	0.0	2.17	2.06	N/A	23.62	145	5862	2103		
10	5400	49644	49644	90349	0.0	2.17	2.06	N/A	24.48	145	6247	2484		
11	5400	35556	35556	75929	0.0	2.43	2.31	N/A	34.17	145	5837	2484		
12	5626	34425	34425	76582	0.0	2.44	2.32	N/A	35.30	145	5935	2598		
13	6211	33807	33807	79795	0.0	2.43	2.31	N/A	35.94	145	6188	2840		
14	6900	33081	33081	83580	0.0	2.43	2.30	N/A	36.73	145	6486	3124		
15														
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Injection Down Casing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	295383	295383	296538	0.0	2.43	2.26	N/A	4.20	78	3513	17	N/A	N/A
2	3300	272672	272672	296036	0.0	2.30	2.12	N/A	4.55	78	5180	1446		
3	3300	271697	271697	295406	0.0	2.31	2.13	N/A	4.56	78	5180	1468		
4	3521	269544	269544	294972	0.0	2.31	2.13	N/A	4.60	78	5293	1579		
5	3900	266464	266464	294623	0.0	2.30	2.12	N/A	4.65	78	5485	1754		
6	4100	266335	266335	295939	0.0	2.29	2.11	N/A	4.66	78	5587	1847		
7	4100	266335	266335	295940	0.0	2.29	2.11	N/A	4.66	78	5587	1847		
8	4240	266245	266245	296861	0.0	2.29	2.11	N/A	4.66	78	5659	1912		
9	4337	265745	265745	297217	0.0	2.29	2.11	N/A	4.67	78	5708	1967		
10	4643	265789	265789	299387	0.0	2.28	2.10	N/A	4.67	78	5864	2103		
11	5400	263983	263983	303520	0.0	2.28	2.10	N/A	4.70	78	6249	2484		
12	5626	263444	263444	304754	0.0	2.27	2.10	N/A	4.71	78	6364	2598		
13	6211	264361	264361	309441	0.0	2.24	2.07	N/A	4.69	78	6662	2840		
14	6900	265440	265440	314961	0.0	2.20	2.03	N/A	4.67	78	7013	3124		
15														
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	375413	375413	380028	0.0	2.30	2.24	N/A	3.27	106	3511	17	N/A	N/A
2	3300	200255	200255	236882	0.0	3.03	2.81	N/A	6.12	114	4928	2143		
3	3300	200254	200254	236881	0.0	3.03	2.81	N/A	6.12	114	4928	2143		
4	3521	188431	188431	227192	0.0	3.09	2.86	N/A	6.51	115	5024	2286		
5	3900	168154	168154	210568	0.0	3.20	2.94	N/A	7.29	116	5188	2532		
6	4100	157455	157455	202333	0.0	3.30	3.03	N/A	7.78	117	5274	2697		
7	4100	157454	157454	202332	0.0	3.30	3.03	N/A	7.78	117	5274	2697		
8	4240	149964	149964	196566	0.0	3.37	3.10	N/A	8.17	117	5335	2812		
9	4337	144775	144775	192570	0.0	3.42	3.14	N/A	8.46	117	5377	2891		
10	4643	128404	128404	179959	0.0	3.60	3.30	N/A	9.54	118	5509	3142		
11	5400	87905	87905	148738	0.0	4.12	3.76	N/A	13.93	120	5837	3764		
12	5400	87904	87904	148737	0.0	4.12	3.76	N/A	13.93	120	5837	3764		
13	5626	75813	75813	139409	0.0	4.31	3.93	N/A	16.15	120	5935	3949		
14	6211	44516	44516	115247	0.0	4.87	4.44	N/A	27.49	122	6188	4429		
15	6899	7699	7699	86796	0.0	5.72	5.23	N/A	+ 100.00	124	6485	4994		
16	6900	7654	7654	86761	0.0	5.73	5.23	N/A	+ 100.00	124	6486	4995		
17														
18	( )	Compression												
19	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	175167	175167	177373	0.0	6.17	N/A	7.01	7.02	106	11	17	N/A	N/A
2	3299	41	41	22553	0.0	9.40	N/A	8.65	+ 100.00	114	1428	2142		
3	3300	8	8	22524	0.0	9.39	N/A	8.64	+ 100.00	114	1428	2143		
4	3300	7	7	22523	0.0	9.39	N/A	8.64	+ 100.00	114	1428	2143		
5	3300	-4	-4	22513	0.0	9.39	N/A	8.64	(+ 100.00)	114	1428	2143		
6	3521	-11816	-11816	12042	0.0	9.33	N/A	8.36	(+ 100.00)	115	1524	2286		
7	3900	-32092	-32092	-5941	0.0	9.10	N/A	7.76	(38.19)	116	1688	2532		
8	4100	-42792	-42792	-15435	0.0	8.57	N/A	7.11	(28.64)	117	1774	2697		
9	4100	-42793	-42793	-15436	0.0	8.57	N/A	7.11	(28.64)	117	1774	2697		
10	4240	-50282	-50282	-22083	0.0	8.22	N/A	6.71	(24.37)	117	1835	2812		
11	4337	-55472	-55472	-26690	0.0	7.99	N/A	6.46	(22.09)	117	1877	2891		
12	4643	-71843	-71843	-41227	0.0	7.31	N/A	5.78	(17.05)	118	2009	3142		
13	5400	-112342	-112342	-77219	0.0	5.95	N/A	4.59	(10.90)	120	2337	3764		
14	5400	-112343	-112343	-77220	0.0	5.95	N/A	4.59	(10.90)	120	2337	3764		
15	5626	-124433	-124433	-87974	0.0	5.63	N/A	4.32	(9.84)	120	2435	3949		
16	6211	-155731	-155731	-115828	0.0	4.91	N/A	3.76	(7.86)	122	2688	4429		
17	6900	-192592	-192592	-148666	0.0	4.26	N/A	3.26	(6.35)	124	2986	4995		
18														
19	( )	Compression												
20	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Full Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-39491	-39491	-40422	0.0	27.95	N/A	+ 100.00	(30.77)	145	0	17	N/A	N/A
2	3300	-149805	-149805	-153313	0.0	3.97	N/A	3.04	(8.11)	145	2	2143		
3	3521	-157251	-157251	-160933	0.0	3.72	N/A	2.85	(7.73)	145	2	2286		
4	3900	-170021	-170021	-174001	0.0	3.36	N/A	2.58	(7.15)	145	2	2532		
5	4100	-175262	-175262	-179364	0.0	3.19	N/A	2.45	(6.93)	145	2	2662		
6	4100	-175263	-175263	-179365	0.0	3.19	N/A	2.45	(6.93)	145	2	2662		
7	4240	-178932	-178932	-183119	0.0	3.08	N/A	2.37	(6.79)	145	2	2753		
8	4337	-181474	-181474	-185720	0.0	3.01	N/A	2.32	(6.70)	145	2	2816		
9	4643	-189494	-189494	-193927	0.0	2.81	N/A	2.16	(6.41)	145	2	3015		
10	5400	-209333	-209333	-214228	0.0	2.41	N/A	1.86	(5.80)	145	3	3506		
11	5400	-209334	-209334	-214228	0.0	2.41	N/A	1.86	(5.80)	145	3	3506		
12	5626	-215257	-215257	-220289	0.0	2.31	N/A	1.79	(5.64)	145	3	3653		
13	6211	-230588	-230588	-235977	0.0	2.09	N/A	1.62	(5.27)	145	3	4033		
14	6900	-248645	-248645	-254453	0.0	1.88	N/A	1.46	(4.89)	145	4	4481		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	398365	398365	403246	0.0	2.72	N/A	N/A	3.09	106	17	17	N/A	N/A
2	3300	256258	256258	293679	0.0	3.78	N/A	N/A	4.79	114	2143	2143		
3	3300	256257	256257	293678	0.0	3.78	N/A	N/A	4.79	114	2143	2143		
4	3521	246665	246665	286262	0.0	3.89	N/A	N/A	4.97	115	2286	2286		
5	3900	230215	230215	273538	0.0	4.08	N/A	N/A	5.32	116	2532	2532		
6	4100	221534	221534	266821	0.0	4.19	N/A	N/A	5.53	117	2662	2662		
7	4100	221533	221533	266820	0.0	4.19	N/A	N/A	5.53	117	2662	2662		
8	4240	215457	215457	262117	0.0	4.27	N/A	N/A	5.69	117	2753	2753		
9	4337	211247	211247	258857	0.0	4.32	N/A	N/A	5.80	117	2816	2816		
10	4643	197965	197965	248571	0.0	4.51	N/A	N/A	6.19	118	3015	3015		
11	5400	165108	165108	223104	0.0	5.06	N/A	N/A	7.42	120	3506	3506		
12	5400	165107	165107	223103	0.0	5.06	N/A	N/A	7.42	120	3506	3506		
13	5626	155298	155298	215494	0.0	5.25	N/A	N/A	7.88	120	3653	3653		
14	6211	129906	129906	195786	0.0	5.82	N/A	N/A	9.42	122	4033	4033		
15	6899	100036	100036	172578	0.0	6.68	N/A	N/A	12.22	124	4480	4480		
16	6900	100000	100000	172550	0.0	6.68	N/A	N/A	12.23	124	4481	4481		
17														
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	375413	375413	380028	0.0	2.30	2.24	N/A	3.27	106	3511	17	N/A	N/A
2	3300	200255	200255	236882	0.0	3.03	2.81	N/A	6.12	114	4928	2143		
3	3300	200254	200254	236881	0.0	3.03	2.81	N/A	6.12	114	4928	2143		
4	3521	188431	188431	227192	0.0	3.09	2.86	N/A	6.51	115	5024	2286		
5	3900	168154	168154	210568	0.0	3.20	2.94	N/A	7.29	116	5188	2532		
6	4100	157455	157455	202333	0.0	3.30	3.03	N/A	7.78	117	5274	2697		
7	4100	157454	157454	202332	0.0	3.30	3.03	N/A	7.78	117	5274	2697		
8	4240	149964	149964	196566	0.0	3.37	3.10	N/A	8.17	117	5335	2812		
9	4337	144775	144775	192570	0.0	3.42	3.14	N/A	8.46	117	5377	2891		
10	4643	128404	128404	179959	0.0	3.60	3.30	N/A	9.54	118	5509	3142		
11	5400	87905	87905	148738	0.0	4.12	3.76	N/A	13.93	120	5837	3764		
12	5400	87904	87904	148737	0.0	4.12	3.76	N/A	13.93	120	5837	3764		
13	5626	75813	75813	139409	0.0	4.31	3.93	N/A	16.15	120	5935	3949		
14	6211	44516	44516	115247	0.0	4.87	4.44	N/A	27.49	122	6188	4429		
15	6899	7699	7699	86796	0.0	5.72	5.23	N/A	+ 100.00	124	6485	4994		
16	6900	7654	7654	86761	0.0	5.73	5.23	N/A	+ 100.00	124	6486	4995		
17														
18	( )	Compression												
19	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (5 1/2" Production Tubing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Temperature Deration:	Yes
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (5 1/2" Production Tubing)

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6211.00 ft
Packer Setting Method:	Set Mechanically
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
5400.00 ft	136 °F

BURST LOADS DATA (5 1/2" Production Tubing)

Production Load:	**Shut-In**
Shut-in Bottom Hole Pressure:	3100 psi
Gas Gravity:	0.70 (0.0818 psi/ft @ 145 °F & 3100 psi)
Hot:	Yes

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Internal Fluid Density:	9.80 ppg

Production Load:	**Tubing Injection**
Injection Pressure:	3500 psi
Injection Fluid Density:	10.00 ppg

COLLAPSE LOADS DATA (5 1/2" Production Tubing)

Drilling Load:	**Full/Partial Evacuation**
Mud Weight:	9.80 ppg
Mud Level, MD:	5400.00 ft
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft

Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5400.00 ft
Perforation Depth, MD:	6211.00 ft
Gas Gravity:	0.70
Reservoir Pressure:	2840 psi

Production Load:	**Annular Pressure Test**
Fluid Density(Inside Tubing):	1.50 ppg
Wellhead Pressure (Annulus)	3500 psi
Fluid Density(Annulus)	9.80 ppg
Packer Depth, MD:	5400.00 ft

AXIAL LOADS DATA (5 1/2" Production Tubing)

Overpull Force:	100000 lbf
Service Loads:	Yes

BURST PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Pressure Test (Int) (psi)	Pressure Test (Ext) (psi)	Tubing Injection (Int) (psi)	Tubing Injection (Ext) (psi)	Shut-In (Int) (psi)	Shut-In (Ext) (psi)
1	26.00	3513	13	3514	13	2663	13
2	5399.99	6249	2749	6305	2749	3039	2749
3	5400.00	6249	2749	6305	2749	3039	2749

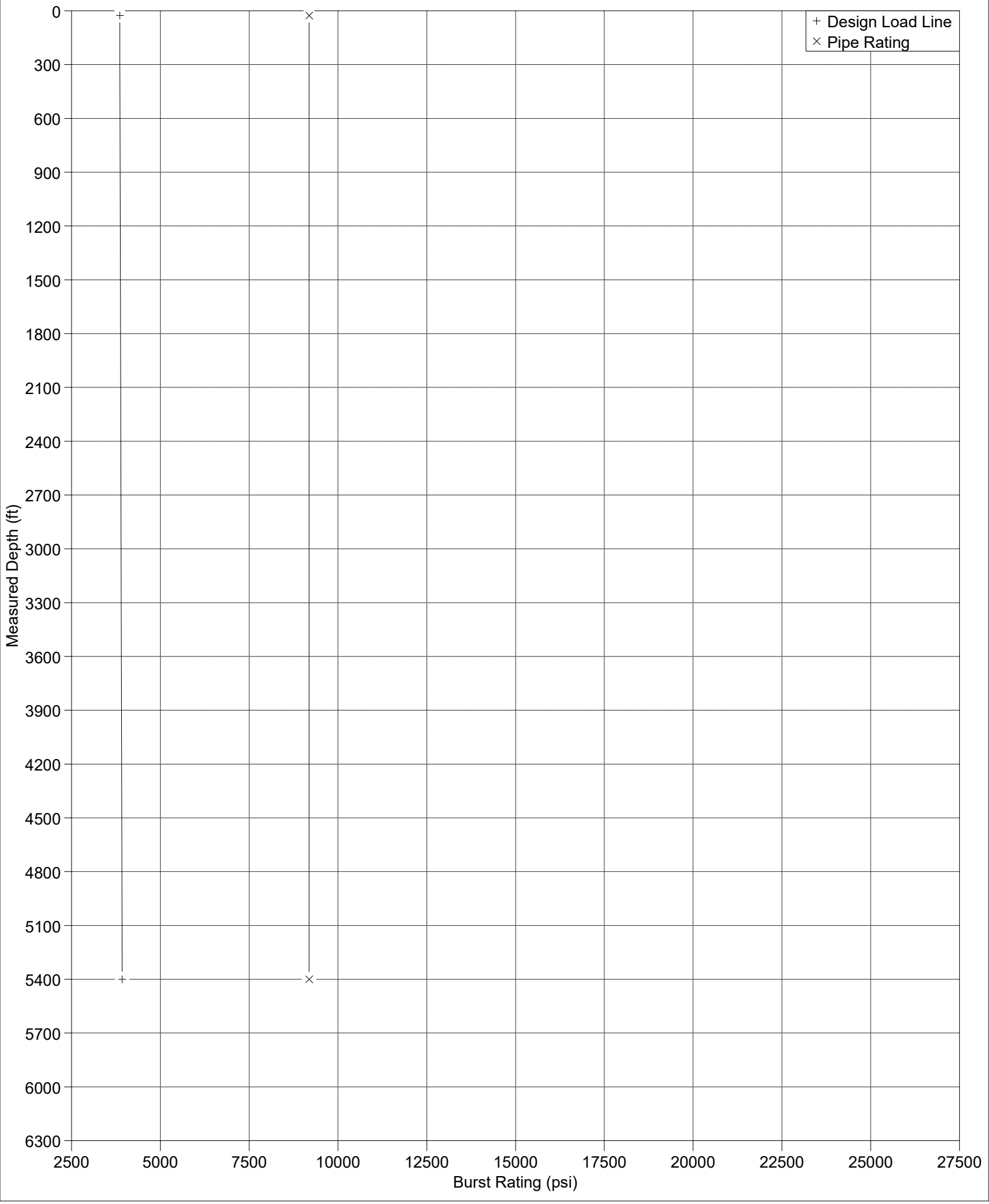
COLLAPSE PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Full/Partial Evacuation (Int) (psi)	Full/Partial Evacuation (Ext) (psi)	Tubing Leak (Int) (psi)	Tubing Leak (Ext) (psi)	Annular Pressure Test (Int) (psi)	Annular Pressure Test (Ext) (psi)
1	26.00	0	13	2403	2403	2	3513
2	5399.99	3	2749	2779	5139	421	6249
3	5400.00	3	2749	2779	5139	421	6249

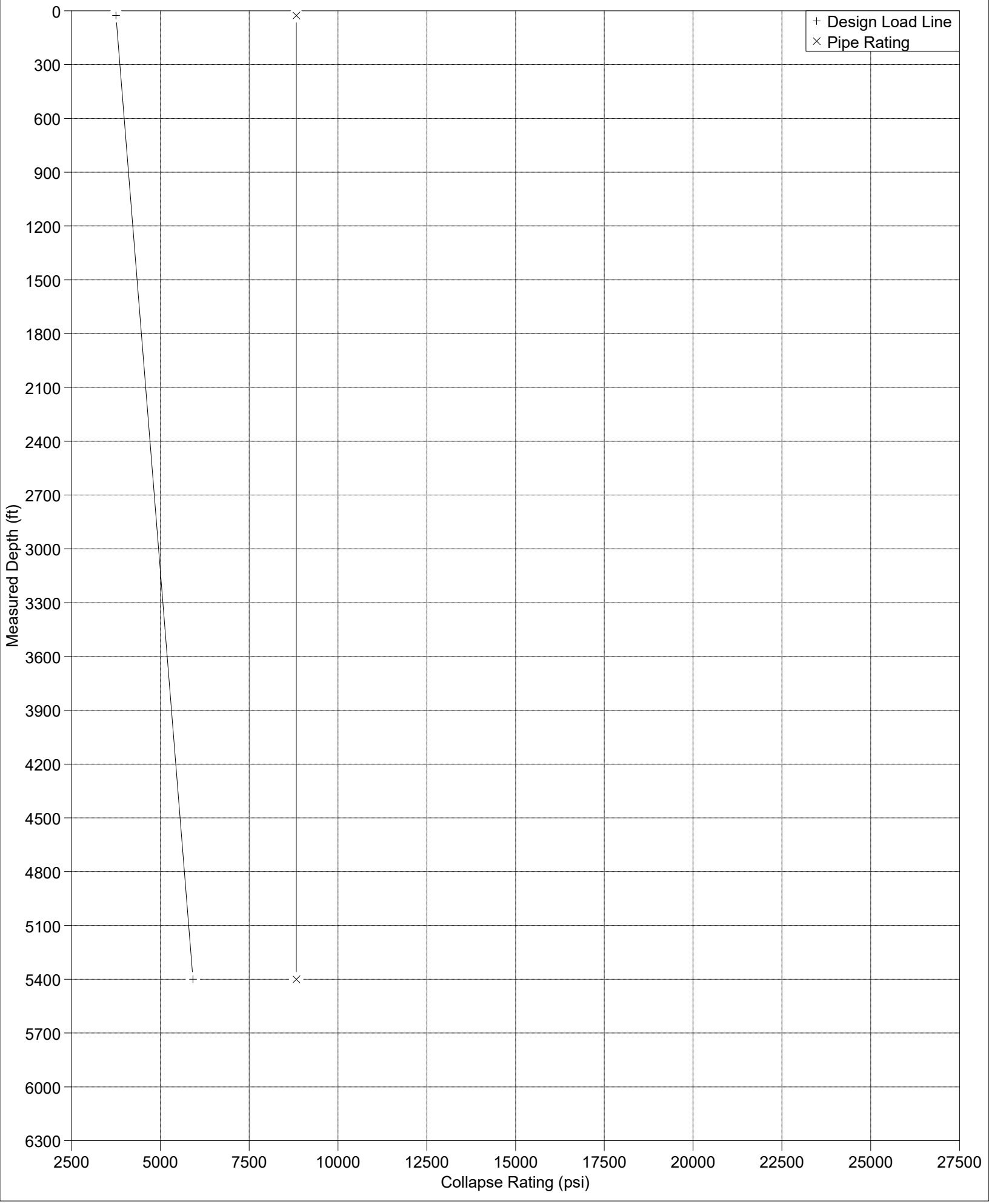
AXIAL LOADS TABLE (5 1/2" Production Tubing)

	Depth (MD) (ft)	Overpull Force (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	191535	191535	164312	164312
2	4871.83	108996	108996	-77676	67395
3	5398.00	100034	100034	-88843	56872
4	5398.00	100034	100034	-88843	-82273

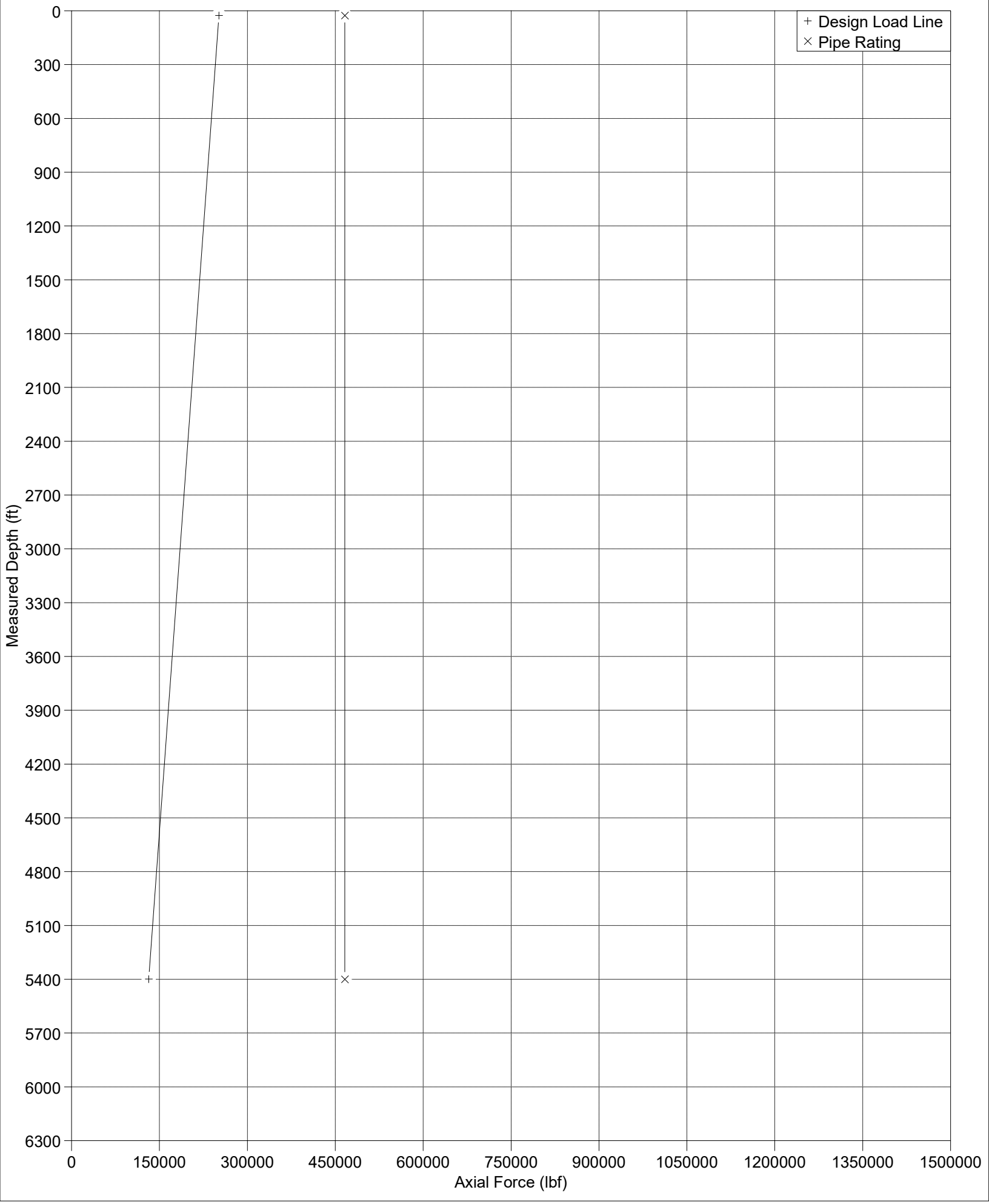
BURST DESIGN (5 1/2" Production Tubing)

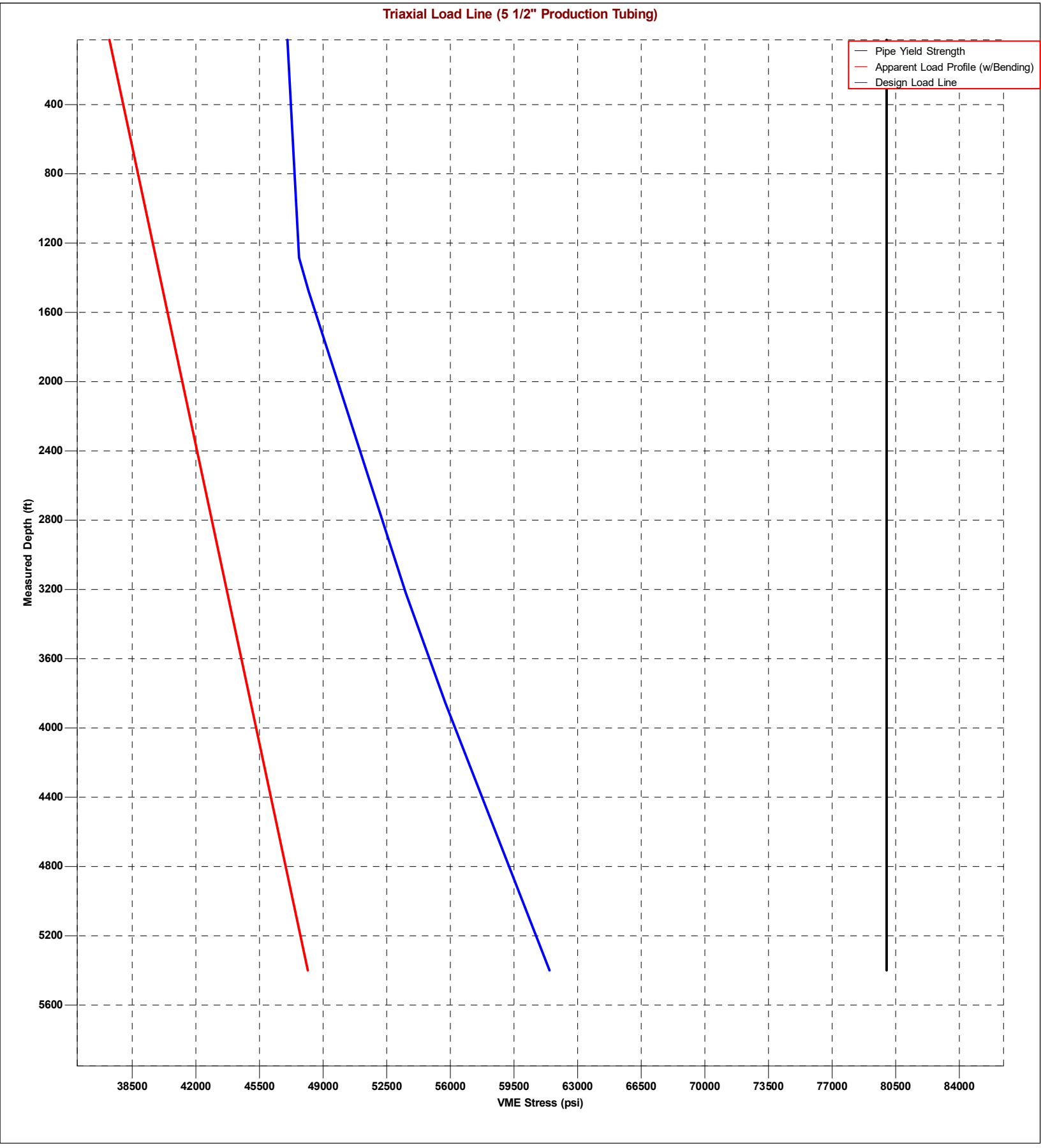


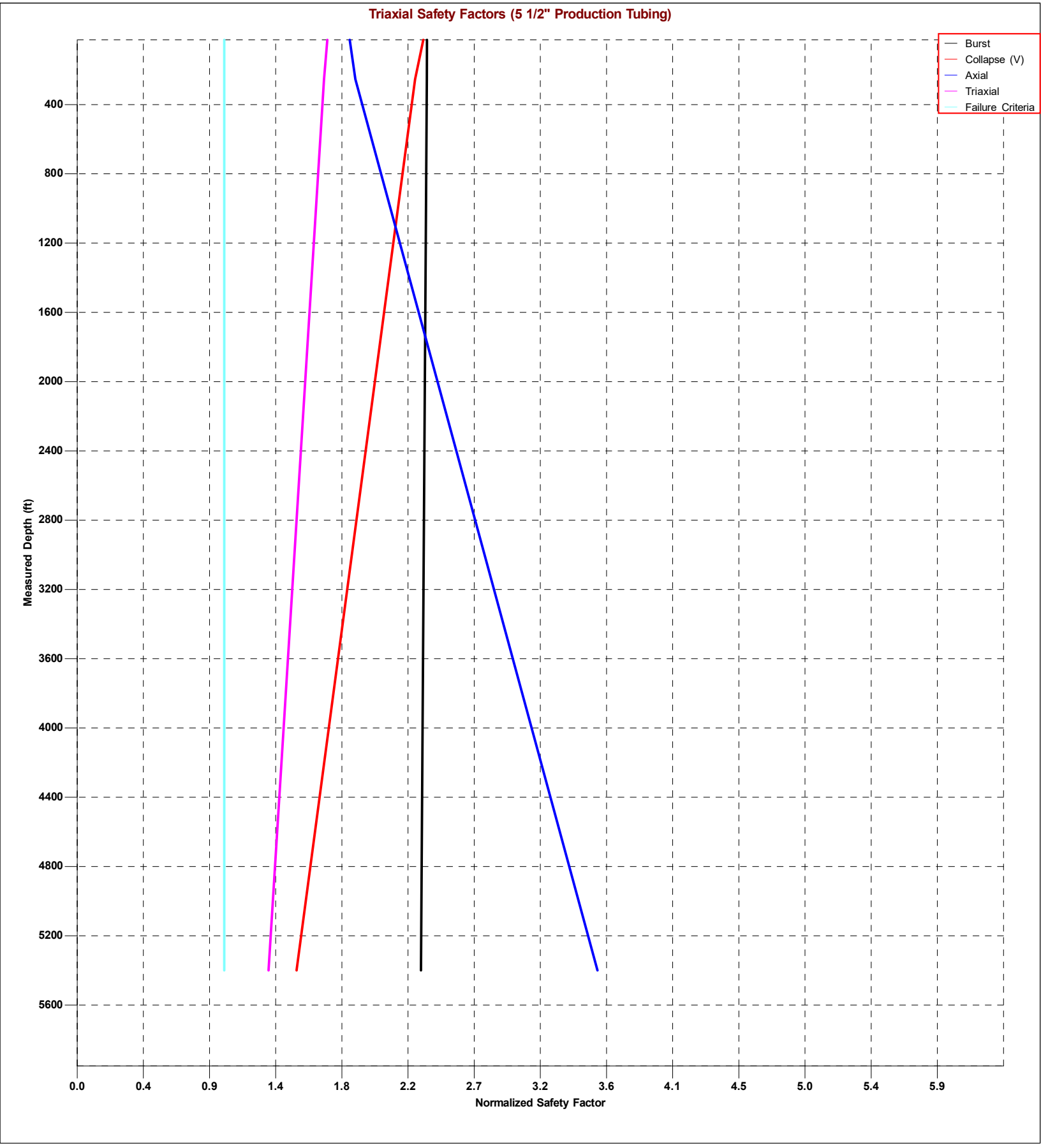
COLLAPSE DESIGN (5 1/2" Production Tubing)



AXIAL DESIGN (5 1/2" Production Tubing)




Triaxial Load Line (5 1/2" Production Tubing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
400
800
1200
1600
2000
2400
2800
3200
3600
4000
4400
4800
5200
5600
38500
42000
45500
49000
52500
56000
59500
63000
66500
70000
73500
77000
80500
84000
VME Stress (psi)


Triaxial Safety Factors (5 1/2" Production Tubing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
400
800
1200
1600
2000
2400
2800
3200
3600
4000
4400
4800
5200
5600
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	5 1/2", 20.000 ppf, L-80	Blue	2.62 B16	2.35 C19	2.41 A4	2.13 A4
2	254			2.62 B5	2.30 C19	2.46 A4	2.10 A4
3	5398			2.57 B5	1.49 C19	4.60 A4	1.63 C19
4	5399			2.57 B5	1.49 C19	4.60 A4	1.63 C19
5	5400			2.57 B5	1.49 C19	4.60 A4	1.63 C19
6							
7	B5	Pressure Test					
8	B16	Tubing Injection					
9	C19	Annular Pressure Test					
10	A4	Overpull Force					
11	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	5 1/2", 20.000 ppf, L-80	0.152 B16	0.243 C19	0.181 A4	58.0	32.7	49.9	0.209	0.118	0.180
2	253.96		0.152 B5	0.245 C19	0.178 A4	57.9	32.1	50.8	0.209	0.116	0.183
3	5398.00		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
4	5399.34		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
5	5399.99		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
6	5400.00		0.154 B5	0.295 C19	0.239 C19	57.2	18.2	33.8	0.207	0.066	0.122
7											
8	B5	Pressure Test									
9	B16	Tubing Injection									
10	C19	Annular Pressure Test									
11	A4	Overpull Force									
12	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (5 1/2" Production Tubing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	355029
2	26	354586
3	257	350649
4	514	346269
5	771	341889
6	1000	337996
7	1029	337509
8	1286	333129
9	1543	328749
10	1800	324370
11	2000	320963
12	2057	319990
13	2314	315610
14	2571	311230
15	2829	306850
16	3000	303930
17	3086	302470
18	3343	298090
19	3600	293710
20	3857	289330
21	4000	286897
22	4114	284951
23	4371	280571
24	4629	276191
25	4886	271811
26	5000	269864
27	5143	267431
28	5374	263494
29	5398	* 263560
30	5400	* 263566
31		
32	* Based on Casing Strength	
33	Only. Running String not	
34	Included	

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	129728	129728	130197	0.0	2.60	2.62	N/A	3.58	78	3513	13	25102	1438
2	5398	38313	22288	55461	2749.5	2.69	2.57	N/A	11.92	136	6248	2748		
3	5400	38295	22248	55450	2753.3	2.69	2.57	N/A	11.93	136	6249	2749		
4	5400	38295	22248	55450	2753.4	2.69	2.57	N/A	11.93	136	6249	2749		
5														
6	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Shut-In

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	63896	63896	65482	0.0	3.65	3.39	N/A	7.13	145	2663	13	34814	3577
2	3221	8390	0	18370	1439.6	7.24	7.20	N/A	54.29	145	2887	1640		
3	3221	-8390	-0	1194	1439.6	7.24	7.20	N/A	(54.29)	145	2887	1640		
4	5398	-65002	-43544	-50141	3681.7	7.37	30.87	N/A	(7.01)	145	3039	2748		
5	5400	-65054	-43584	-50188	3683.8	7.36	30.97	N/A	(7.00)	145	3039	2749		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Injection

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	164312	164312	164885	0.0	2.35	2.62	N/A	2.83	78	3514	13	0	0
2	5398	56872	56872	73108	0.0	2.80	2.58	N/A	8.17	78	6304	2748		
3	5400	56832	56832	73074	0.0	2.80	2.58	N/A	8.18	78	6305	2749		
4														
5	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Full/Partial Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	76615	76615	76846	0.0	5.33	N/A	6.07	6.07	78	0	13	0	0
2	3857	0	0	12	0.0	4.35	N/A	4.45	+ 100.00	119	2	1963		
3	3857	-0	-0	12	0.0	4.35	N/A	4.45	(+ 100.00)	119	2	1963		
4	5398	-30825	-30825	-31450	0.0	3.41	N/A	3.17	(14.82)	136	3	2748		
5	5400	-30865	-30865	-31491	0.0	3.41	N/A	3.17	(14.80)	136	3	2749		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Leak (Collapse)

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	25167	25167	40097	0.0	10.71	N/A	11.63	18.10	145	2403	2403	10236	1097
2	1284	0	0	14861	0.0	11.65	N/A	12.46	+ 100.00	145	2491	3044		
3	1284	-0	-0	14861	0.0	11.65	N/A	12.46	(+ 100.00)	145	2491	3044		
4	5398	-88843	-82273	-74362	1127.3	4.08	N/A	3.68	(5.13)	145	2779	5138		
5	5400	-88894	-82313	-74414	1129.3	4.08	N/A	3.68	(5.12)	145	2779	5139		
6	5400	-88895	-82313	-74414	1129.3	4.08	N/A	3.68	(5.12)	145	2779	5139		
7														
8	( )	Compression												
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Annular Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	28981	28981	29080	0.0	2.24	N/A	2.35	16.04	78	2	3513	0	0
2	1475	0	0	675	0.0	2.07	N/A	2.12	+ 100.00	94	115	4251		
3	1475	-0	-0	675	0.0	2.07	N/A	2.12	(+ 100.00)	94	115	4251		
4	5398	-78459	-78459	-77591	0.0	1.63	N/A	1.49	(5.82)	136	421	6248		
5	5400	-78499	-78499	-77632	0.0	1.63	N/A	1.49	(5.82)	136	421	6249		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	191535	191535	193574	0.0	2.13	N/A	N/A	2.41	102	13	13	N/A	N/A
2	5398	100034	100034	117605	0.0	3.56	N/A	N/A	4.60	112	2748	2748		
3	5399	100011	100011	117586	0.0	3.56	N/A	N/A	4.60	112	2749	2749		
4	5400	100000	100000	117577	0.0	3.56	N/A	N/A	4.60	112	2749	2749		
5														
6	(V)	Vector Collapse Safety Factor												

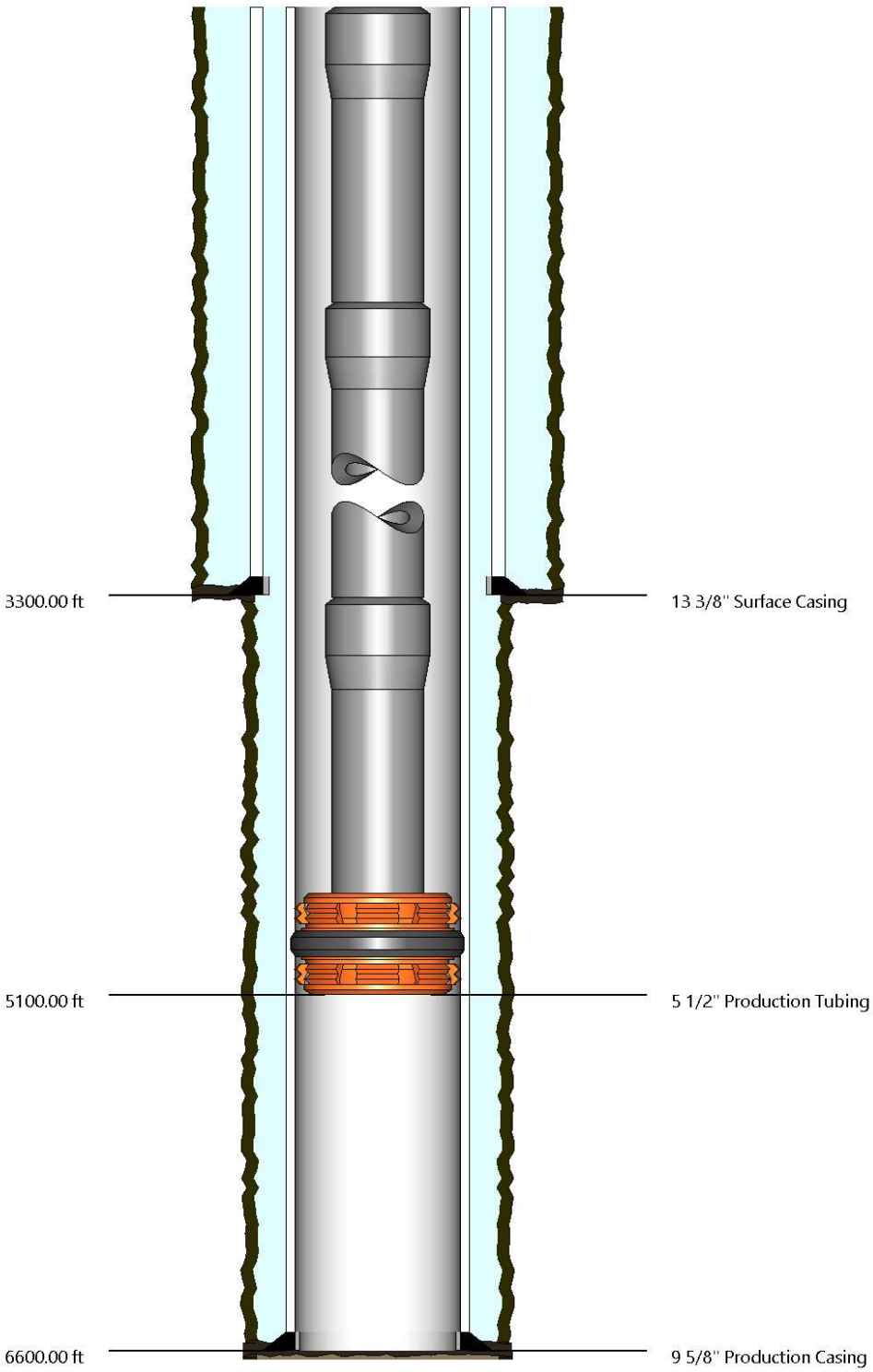
GENERAL DATA

Description:	Bluebonnet CCS 7 Final
Well Options, Deviated:	Yes
Well Options, Offshore:	No
Well TD (MD):	6600.00 ft
Reference Point:	OTR
Air Gap:	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	0.00 °

WELL SUMMARY

	String	OD/Weight/Grade	Connection	MD Interval (ft)	Drift Dia. (in)	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V	Axial	Triaxial	
1	Surface Casing	13 3/8", 61.000 ppf, K-55	BTC, K-55	26.00-3300.00	12.359	1.18	1.59	2.53	1.32	91,889
2										Total = 91,889
3										
4	Production Casing	9 5/8", 53.500 ppf, L-80	Blue	26.00-3800.00	8.500 A	2.08	2.65	3.19	2.18	117,567
5		9 5/8", 53.500 ppf, L-80	Blue	3800.00-6600.00	8.500 A	2.00	1.52	4.77	1.97	87,225
6										Total = 204,792
7										
8	Production Tubing	5 1/2", 20.000 ppf, L-80	Blue	26.00-5100.00	4.653	2.57	1.53	2.48	1.67	63,209
9										Total = 63,209
10										
11										Total = 359,890
12	A Alternate Drift									
13	(V) Vector Collapse Safety Factor									

WELL SCHEMATIC (DEPTH - MD)



CASING AND TUBING SCHEME

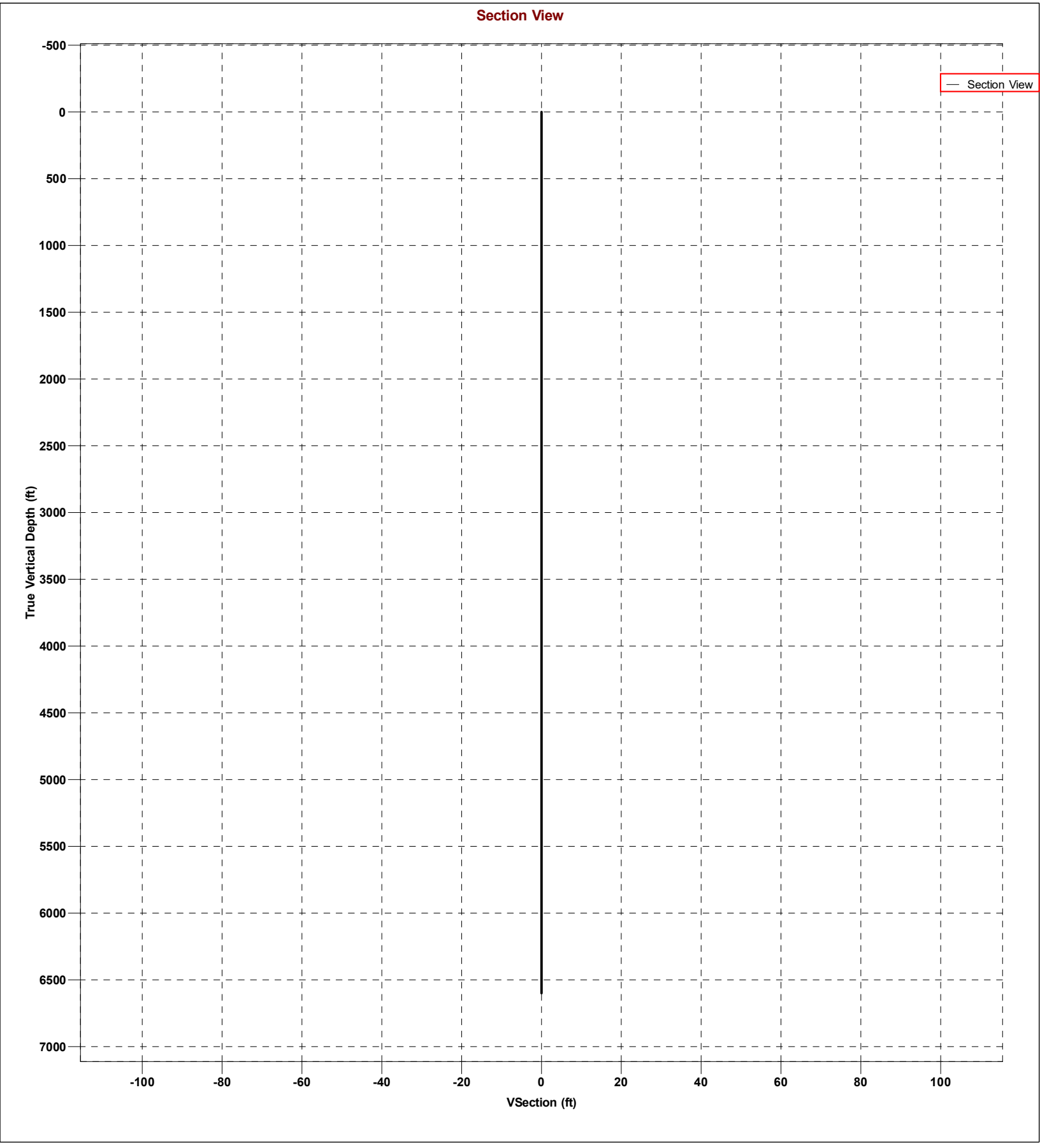
	OD (in)	Name	Type	Hole Size (in)	Measured Depths (ft)			Mud at Shoe (ppg)
					Hanger	Shoe	TOC	
1	13 3/8"	Surface	Casing	17.500	26.00	3300.00	26.00	10.00
2	9 5/8"	Production	Casing	12.250	26.00	6600.00	26.00	12.50
3	5 1/2"	Production	Tubing		26.00	5100.00		9.80

PRODUCTION DATA

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5100.00 ft
Perforation Depth, MD:	6019.00 ft
Gas Gravity:	0.70

WELLPATH EDITOR

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.00	0.00			0.00	0.00
2	MD-INC-AZ	6600.00	0.00	0.00	6600.00	0.00	0.00	0.00	0.00

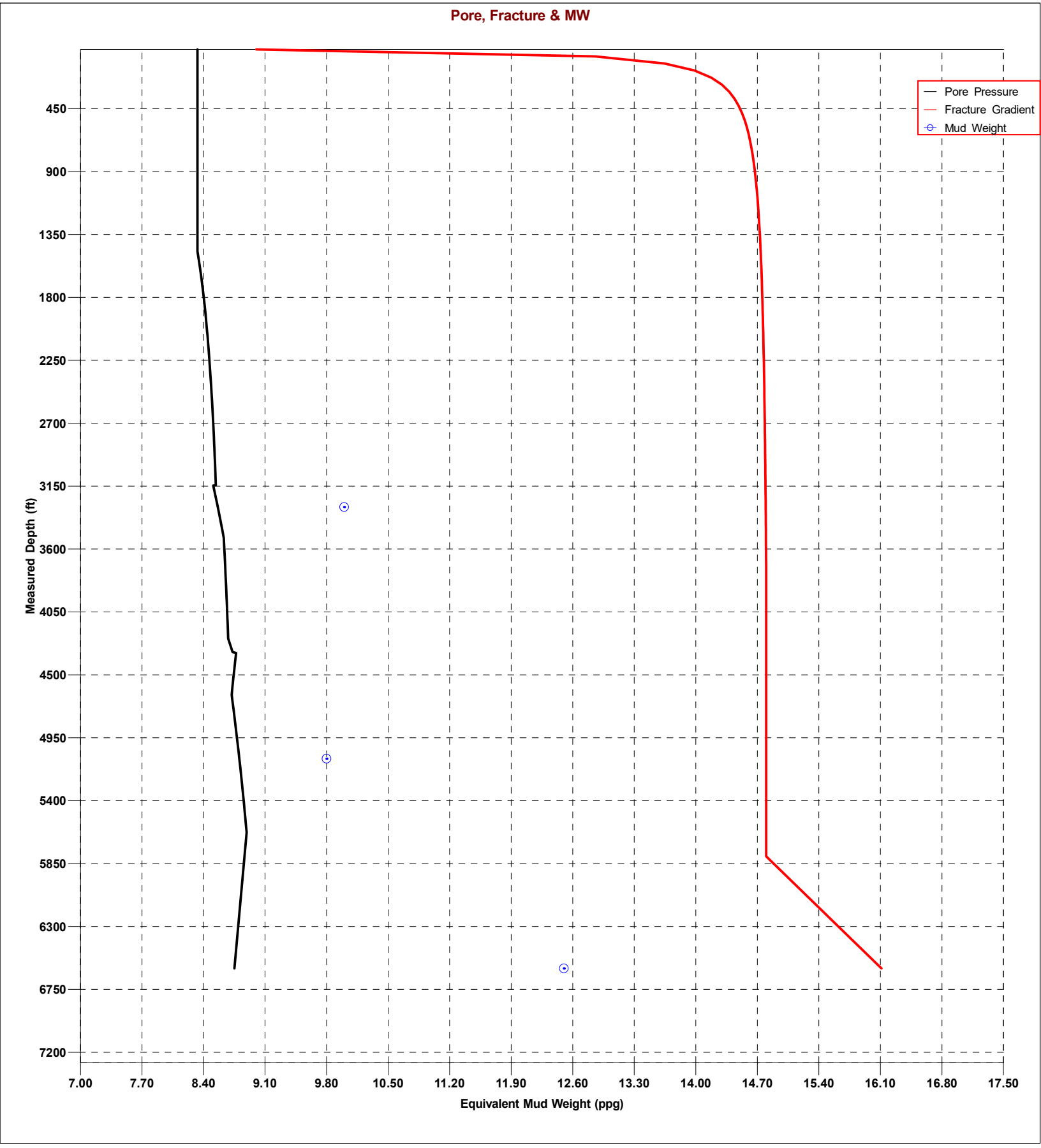

Section View
Section View
-500
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
True Vertical Depth (ft)
-100
-80
-60
-40
-20
0
20
40
60
80
100
VSection (ft)

PORE PRESSURE

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	0	8.33	No
2	1470.00	636	8.33	No
3	3144.00	1395	8.54	No
4	3146.00	1391	8.51	No
5	3521.00	1579	8.63	No
6	4240.00	1912	8.68	No
7	4337.00	1967	8.73	No
8	4344.00	1979	8.77	No
9	4643.00	2103	8.72	No
10	5626.00	2598	8.89	No
11	7666.00	3441	8.64	No
12	8182.00	3660	8.61	No
13	9300.00	4155	8.60	No

FRACTURE GRADIENT

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	0	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9300.00	8455	17.50


Pore, Fracture & MW
Pore Pressure
Fracture Gradient
Mud Weight
Measured Depth (ft)
450
900
1350
1800
2250
2700
3150
3600
4050
4500
4950
5400
5850
6300
6750
7200
7.00
7.70
8.40
9.10
9.80
10.50
11.20
11.90
12.60
13.30
14.00
14.70
15.40
16.10
16.80
17.50
Equivalent Mud Weight (ppg)

GEOTHERMAL GRADIENT DATA

Surface Ambient:	78 °F
Bottomhole Temperature - 6600.00 ft TVD:	149 °F
Bottomhole Gradient - 6600.00 ft TVD:	1.08 °F/100ft

DESIGN PARAMETERS DATA (13 3/8" Surface Casing)

Design Factor (Pipe) - Axial Tension:	1.400
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.400
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	12.250 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (13 3/8" Surface Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	**Temperature (°F)**
26.00 ft	78 °F
3300.00 ft	113 °F

BURST LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 3300.00 ft):	2535 psi
Mud/Water Interface, MD:	3300.00 ft
Mud Weight	7.82 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	6600.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	1.00 ppg
Maximum Mud Weight:	12.50 ppg
Kick Gas Gravity:	0.70 (0.1138 psi/ft @ 121 °F & 4629 psi)
Fracture at Shoe (MD= 3300.00 ft):	2535 psi
Drill Pipe OD:	5.500 in
Collar OD:	8.000 in
Collar Length:	300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	1500 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Fracture @ Shoe w/ Gas Gradient Above**
Gas Gradient:	0.1000 psi/ft
Shoe Depth, MD :	3300.00 ft
Fracture Pressure at Shoe:	2535 psi
Fracture Margin of Error:	0.00 ppg
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2600 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (13 3/8" Surface Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	700.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	3300.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	6600.00 ft
Pore Pressure at Lost Returns Depth:	3084 psi
Pore Pressure Gradient at Lost Returns Depth:	8.99 ppg
Mud Weight:	12.50 ppg
Mud Drop Level, MD:	1851.22 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	26.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	14 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (13 3/8" Surface Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	2600 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Lost Returns (psi)	Gas Kick (psi)	Pressure Test (psi)	Fracture @ Shoe w/ Gas Gradient Above (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	1118	1166	1514	2208	2611	14	0
2	1470.00	1743	1891	2264	2352	3236	951	636
3	2600.00	2232	2459	2851	2465	3725	1685	1148
4	3144.00	2467	2732	3133	2519	3960	2131	1395
5	3146.00	2468	2733	3134	2519	3961	2133	1391
6	3300.00	2535	2811	3214	2535	4028	2259	1468

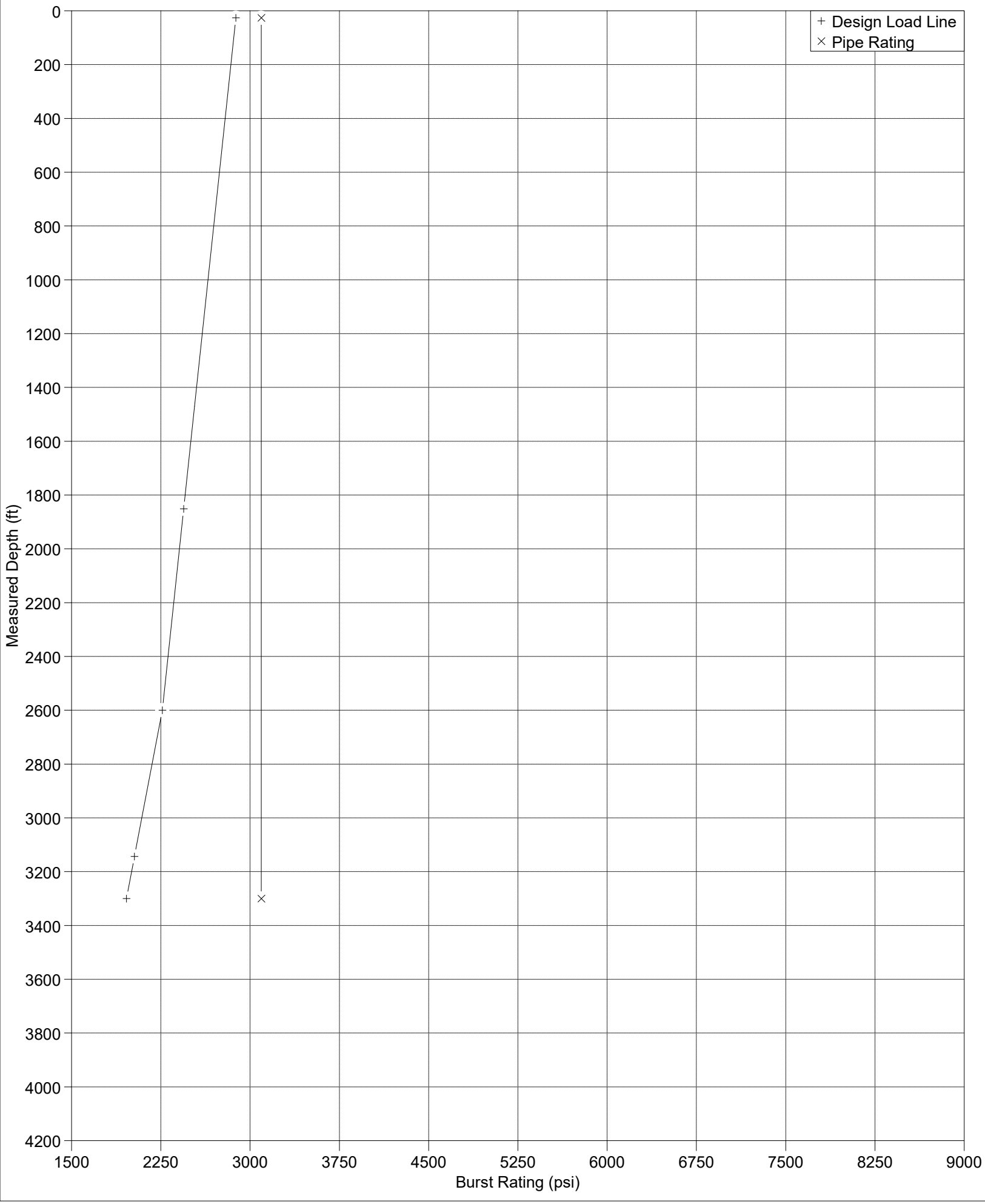
COLLAPSE PRESSURE PROFILES (13 3/8" Surface Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Lost Returns (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	14	0	14
2	1851.22	801	1199	0	962
3	2600.00	1125	1685	486	1351
4	3300.00	1428	2259	941	1714

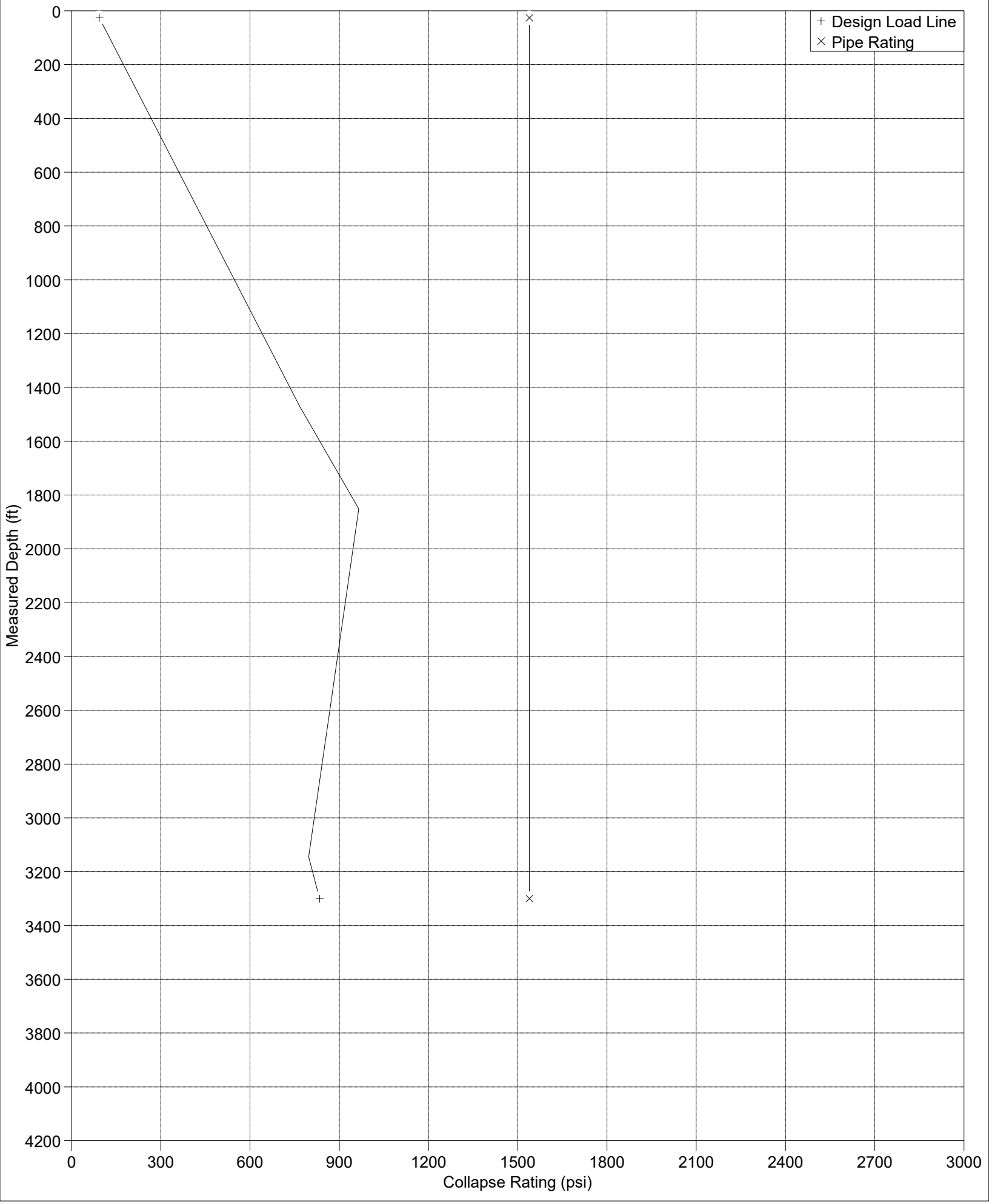
AXIAL LOADS TABLE (13 3/8" Surface Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	269972	269972	377753	377753	377753	377753
2	929.14	223085	223085	322662	322662	322662	322662
3	1470.00	195006	195006	289669	289669	289669	289669
4	1851.22	175214	175214	266415	266415	266415	266415
5	2600.00	136341	136341	220739	220739	220739	220739
6	3144.00	108099	108099	187555	187555	187555	187555
7	3146.00	107995	107995	187433	187433	187433	187433

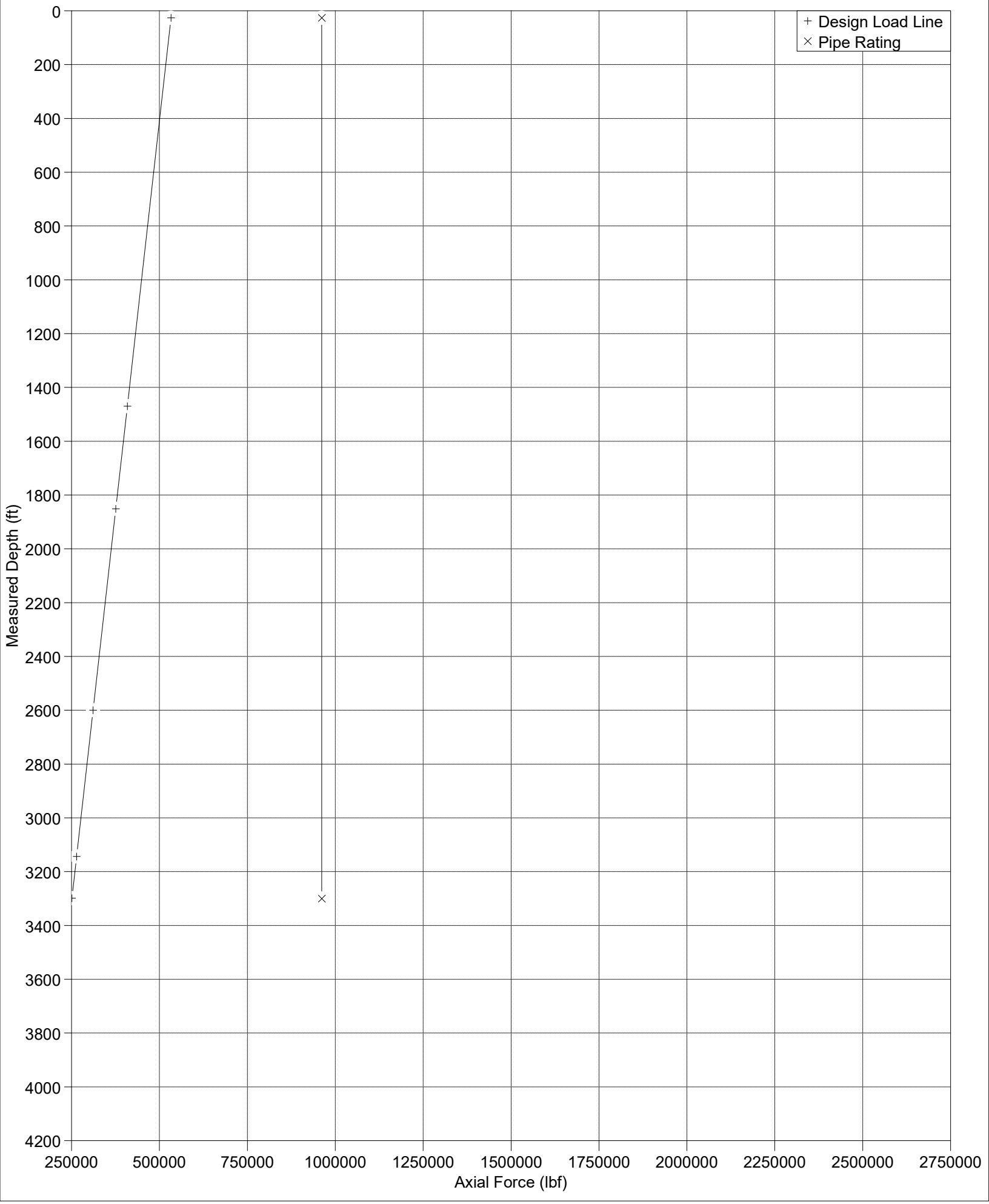
BURST DESIGN (13 3/8" Surface Casing)

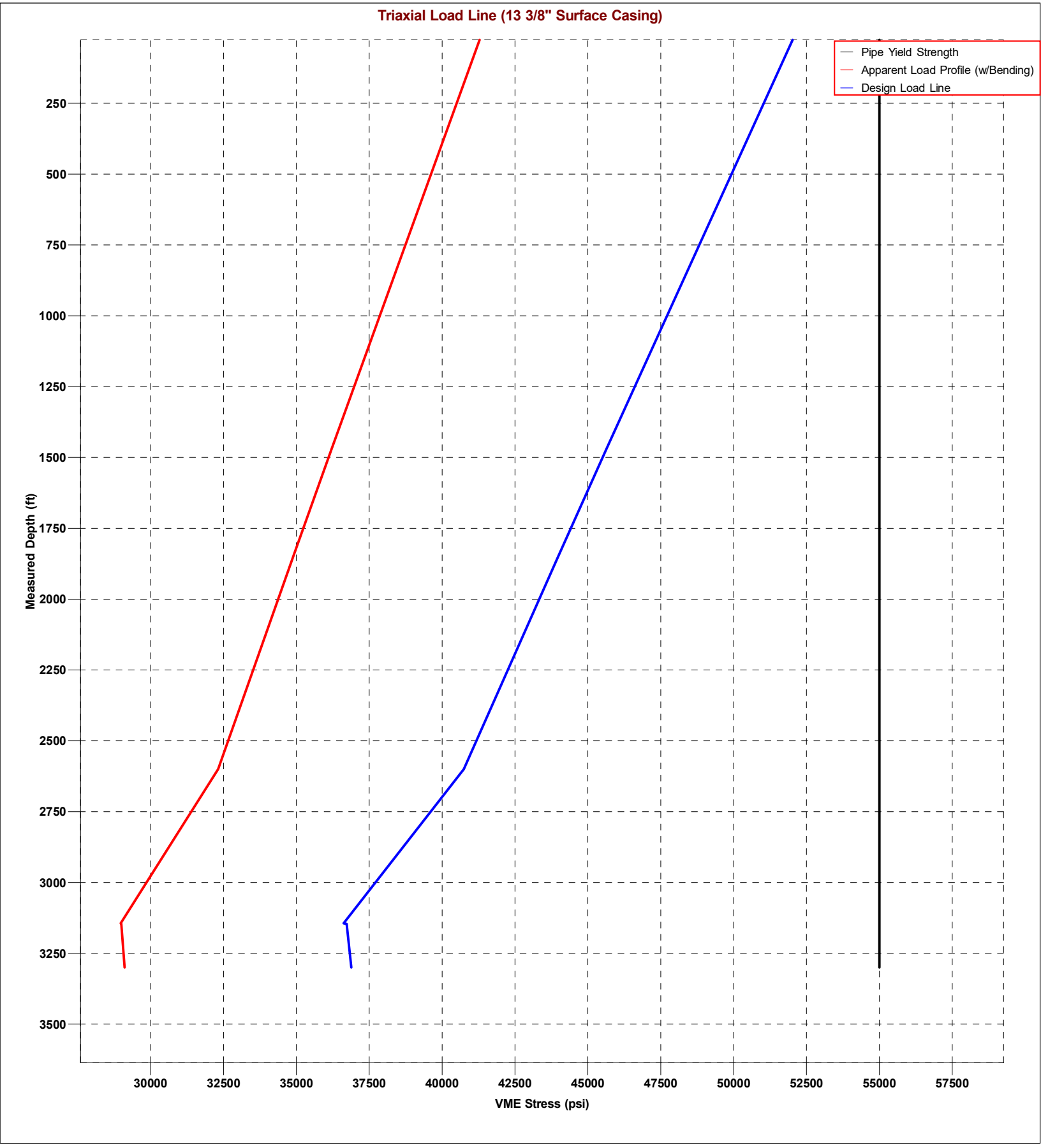


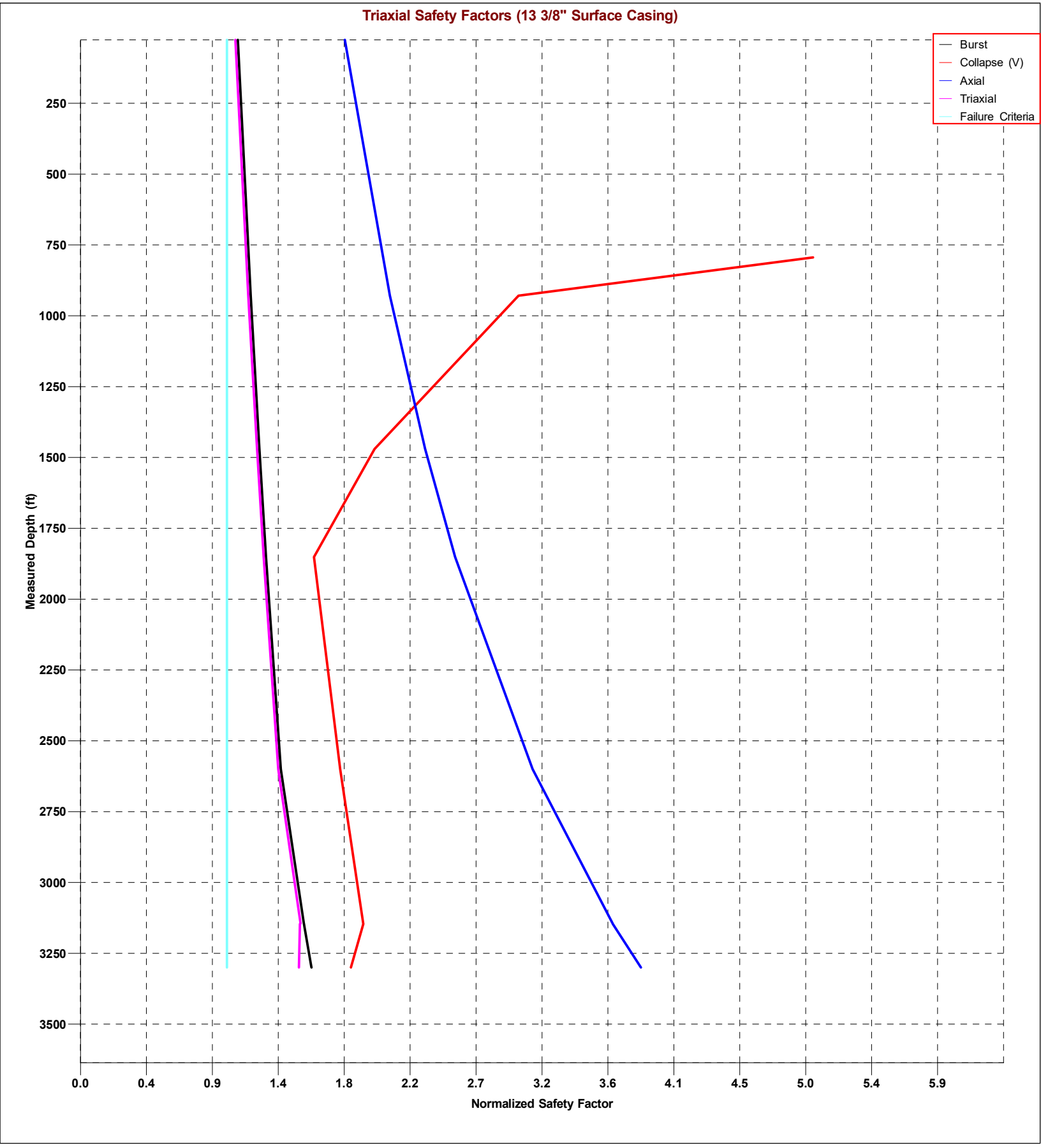
COLLAPSE DESIGN (13 3/8" Surface Casing)



AXIAL DESIGN (13 3/8" Surface Casing)




Triaxial Load Line (13 3/8" Surface Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
30000
32500
35000
37500
40000
42500
45000
47500
50000
52500
55000
57500
VME Stress (psi)


Triaxial Safety Factors (13 3/8" Surface Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
250
500
750
1000
1250
1500
1750
2000
2250
2500
2750
3000
3250
3500
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	13 3/8", 61.000 ppf, K-55	BTC, K-55	1.18 B12	16.42 C2	2.53 B12	1.32 B12
2	929			1.28 B12	2.99 C4	2.96 B12	1.43 B12
3	1470			1.34 B12	2.01 C4	3.29 A5	1.51 B12
4	1851			1.39 B12	1.59 C4	3.58 A5	1.56 B12
5	2600			1.50 B12	1.77 C4	4.32 A5	1.69 B12
6	3144			1.68 B12	1.93 C4	5.08 A5	1.88 B5
7	3146			1.68 B12	1.93 C4	5.09 A5	1.87 B5
8	3299			1.73 B12	1.85 C2	5.35 A5	1.86 B5
9	3300			1.73 B12	1.85 C2	5.36 A5	1.86 B5
10							
11	B5	Pressure Test					
12	B12	Green Cement Pressure Test(Burst)					
13	C2	Cementing					
14	C4	Lost Returns with Mud Drop					
15	A5	Green Cement Pressure Test(Axial)					
16	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (13 3/8" Surface Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	13 3/8", 61.000 ppf, K-5	0.400 B12	0.088 C4	0.355 B12	6.9	79.6	17.4	0.030	0.342	0.075
2	929.14		0.370 B12	0.287 C4	0.327 B12	13.9	33.3	23.9	0.060	0.143	0.103
3	1470.00		0.352 B12	0.333 C4	0.311 B12	18.1	22.5	27.8	0.078	0.097	0.119
4	1851.22		0.339 B12	0.359 C4	0.299 B12	21.1	16.4	30.5	0.091	0.071	0.131
5	2600.00		0.315 B12	0.347 C4	0.277 B12	26.9	19.3	35.6	0.115	0.083	0.153
6	3144.00		0.282 B12	0.337 C4	0.251 B5	34.4	21.5	41.6	0.148	0.093	0.179
7	3146.00		0.282 B12	0.337 C4	0.252 B5	34.4	21.5	41.5	0.148	0.093	0.178
8	3299.20		0.273 B12	0.343 C2	0.253 B5	36.6	20.3	41.2	0.157	0.087	0.177
9	3300.00		0.273 B12	0.343 C2	0.253 B5	36.6	20.3	41.2	0.157	0.087	0.177
10											
11	B5	Pressure Test									
12	B12	Green Cement Pressure Test(Burst)									
13	C2	Cementing									
14	C4	Lost Returns with Mud Drop									
15	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (13 3/8" Surface Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	681540
2	26	680191
3	26	680190
4	254	668361
5	508	655183
6	762	642004
7	1000	629624
8	1015	628825
9	1269	615647
10	1523	602468
11	1777	589290
12	2000	577708
13	2031	576111
14	2285	562932
15	2538	549754
16	2792	536575
17	3000	525793
18	3046	523397
19	3274	511568
20	3300	* 511800
21		
22	* Based on Casing Strength	
23	Only. Running String not	
24	Included	

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Gas Kick Profile

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	45386	45386	45902	0.0	2.78	2.62	N/A	20.95	105	1166	0	N/A	N/A
2	1470	33763	33763	45446	0.0	2.56	2.43	N/A	28.14	109	1891	636		
3	1851	30287	30287	44998	0.0	2.52	2.40	N/A	31.36	110	2083	809		
4	2600	23459	23459	44117	0.0	2.44	2.33	N/A	40.46	112	2459	1148		
5	3144	26359	26359	51447	0.0	2.40	2.28	N/A	35.99	113	2732	1395		
6	3146	26785	26785	51807	0.0	2.40	2.27	N/A	35.42	113	2733	1391		
7	3300	26991	26991	53388	0.0	2.40	2.27	N/A	35.15	113	2811	1468		
8														
9	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Water

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	140755	140755	141180	0.0	3.10	2.76	N/A	6.81	78	1118	0	N/A	N/A
2	1470	134545	134545	146109	0.0	3.13	2.79	N/A	7.13	78	1743	636		
3	1851	132498	132498	147086	0.0	3.15	2.81	N/A	7.24	78	1908	809		
4	2600	128476	128476	149004	0.0	3.19	2.85	N/A	7.46	78	2232	1148		
5	3144	133416	133416	158283	0.0	3.22	2.88	N/A	7.19	78	2467	1395		
6	3146	133849	133849	158647	0.0	3.20	2.86	N/A	7.16	78	2468	1391		
7	3300	134632	134632	160785	0.0	3.23	2.89	N/A	7.12	78	2535	1468		
8														
9	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	169936	169936	170449	0.0	2.28	2.04	N/A	5.64	78	1514	0	N/A	N/A
2	1470	116519	116519	128634	0.0	2.08	1.89	N/A	8.19	94	2264	636		
3	1851	102009	102009	117202	0.0	2.03	1.86	N/A	9.34	98	2462	809		
4	2600	73508	73508	94664	0.0	1.93	1.80	N/A	12.94	106	2851	1148		
5	3144	60664	60664	86187	0.0	1.88	1.76	N/A	15.65	112	3133	1395		
6	3146	61031	61031	86489	0.0	1.87	1.75	N/A	15.55	112	3134	1391		
7	3300	56780	56780	83590	0.0	1.86	1.75	N/A	16.71	113	3214	1468		
8														
9	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Fracture @ Shoe w/ Gas Gradient Above

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	122275	122275	123663	0.0	1.50	1.39	N/A	7.78	105	2208	0	N/A	N/A
2	1470	67763	67763	79868	0.0	1.90	1.78	N/A	14.02	109	2352	636		
3	1851	52963	52963	67963	0.0	2.05	1.93	N/A	17.93	110	2390	809		
4	2600	23895	23895	44559	0.0	2.43	2.32	N/A	39.72	112	2465	1148		
5	3144	10638	10638	35509	0.0	2.83	2.71	N/A	89.19	113	2519	1395		
6	3146	11004	11004	35809	0.0	2.82	2.70	N/A	86.22	113	2519	1391		
7	3300	6636	6636	32752	0.0	2.98	2.86	N/A	+ 100.00	113	2535	1468		
8														
9	( ) Compression													
10	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381018	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308851	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	1851	266415	266415	289791	0.0	1.56	1.39	N/A	3.58	96	3401	1199		
4	2600	220739	220739	252345	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
5	3144	187555	187555	226778	0.0	1.88	1.68	N/A	5.08	97	3960	2131		
6	3146	187433	187433	226684	0.0	1.88	1.68	N/A	5.09	97	3961	2133		
7	3299	178088	178088	219483	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219445	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V) Vector Collapse Safety Factor													

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Lost Returns with Mud Drop

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-41800	-41800	-42275	0.0	20.87	N/A	+ 100.00	(22.75)	105	0	14	N/A	N/A
2	1470	-116580	-116580	-118031	0.0	4.49	N/A	2.01	(8.15)	109	0	764		
3	1851	-136322	-136322	-138058	0.0	3.57	N/A	1.59	(6.97)	110	0	962		
4	2600	-139211	-139211	-132448	0.0	3.96	N/A	1.77	(6.82)	112	486	1351		
5	3144	-133449	-133449	-120399	0.0	4.31	N/A	1.93	(7.11)	113	839	1633		
6	3146	-133428	-133428	-120355	0.0	4.31	N/A	1.93	(7.11)	113	841	1634		
7	3300	-131797	-131797	-116942	0.0	4.42	N/A	1.98	(7.20)	113	941	1714		
8														
9	( )	Compression												
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	57919	57919	58582	0.0	14.35	N/A	16.42	16.47	94	11	14	N/A	N/A
2	975	43	43	7480	0.0	13.54	N/A	7.31	+ 100.00	95	422	630		
3	976	-6	-6	7437	0.0	13.53	N/A	7.30	(+ 100.00)	95	422	630		
4	1470	-30165	-30165	-19200	0.0	10.44	N/A	4.87	(31.62)	95	636	951		
5	1851	-53420	-53420	-39742	0.0	8.56	N/A	3.86	(17.85)	96	801	1199		
6	2600	-99095	-99095	-80100	0.0	6.15	N/A	2.74	(9.62)	96	1125	1685		
7	3144	-132279	-132279	-109429	0.0	4.47	N/A	1.99	(7.21)	97	1360	2131		
8	3146	-132401	-132401	-109536	0.0	4.46	N/A	1.99	(7.20)	97	1361	2133		
9	3300	-141795	-141795	-117840	0.0	4.14	N/A	1.85	(6.72)	97	1428	2259		
10														
11	( )	Compression												
12	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	269972	269972	272374	0.0	3.10	N/A	N/A	3.53	94	14	14	N/A	N/A
2	1470	195006	195006	210093	0.0	4.05	N/A	N/A	4.89	95	764	764		
3	1851	175214	175214	193644	0.0	4.41	N/A	N/A	5.44	96	962	962		
4	2600	136341	136341	161329	0.0	5.33	N/A	N/A	6.99	96	1351	1351		
5	3144	108099	108099	137845	0.0	6.29	N/A	N/A	8.82	97	1633	1633		
6	3146	107995	107995	137759	0.0	6.29	N/A	N/A	8.83	97	1634	1634		
7	3299	100041	100041	131144	0.0	6.63	N/A	N/A	9.53	97	1714	1714		
8	3300	100000	100000	131110	0.0	6.63	N/A	N/A	9.53	97	1714	1714		
9														
10	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (13 3/8" Surface Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	377753	377753	381018	0.0	1.32	1.18	N/A	2.53	94	2611	14	N/A	N/A
2	1470	289669	289669	308851	0.0	1.51	1.34	N/A	3.29	95	3236	951		
3	1851	266415	266415	289791	0.0	1.56	1.39	N/A	3.58	96	3401	1199		
4	2600	220739	220739	252345	0.0	1.69	1.50	N/A	4.32	96	3725	1685		
5	3144	187555	187555	226778	0.0	1.88	1.68	N/A	5.08	97	3960	2131		
6	3146	187433	187433	226684	0.0	1.88	1.68	N/A	5.09	97	3961	2133		
7	3299	178088	178088	219483	0.0	1.95	1.73	N/A	5.35	97	4028	2259		
8	3300	178039	178039	219445	0.0	1.95	1.73	N/A	5.36	97	4028	2259		
9														
10	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (9 5/8" Production Casing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Minimum Internal Drift Diameter:	7.970 in
Single External Pressure Profile:	No
Temperature Deration:	Yes
Limit to Fracture at Shoe:	No
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (9 5/8" Production Casing)

Mix-Water Density:	8.33 ppg
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3000.00 ft
Displacement Fluid Density:	8.33 ppg
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
6600.00 ft	149 °F

BURST LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Mud Weight:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5100.00 ft
Perforation Depth, MD:	6019.00 ft
Gas Gravity:	0.70 (0.0745 psi/ft @ 143 °F & 2761 psi)
Reservoir Pressure:	2761 psi
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Stimulation Surface Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5100.00 ft
Injection Pressure:	3500 psi
Injection Density:	8.33 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Injection Down Casing**
Injection Pressure:	3500 psi
Injection Density:	9.80 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	3500 psi
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3000.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	6600.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Mud Weight Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	8.40 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole:	Yes

COLLAPSE LOADS DATA (9 5/8" Production Casing)

Drilling Load:	**Cementing**
Mud Weight at Shoe:	12.50 ppg
TOC, MD:	26.00 ft
Lead Slurry Density:	12.50 ppg
Tail Slurry Density:	15.80 ppg
Tail Slurry Length:	3000.00 ft
Displacement Fluid Density:	8.33 ppg
Float Collar Depth, MD:	6600.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Production Load:	**Full Evacuation**
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	26.00 ft
Prior Shoe, MD:	3300.00 ft
Fluid Gradient Above TOC:	12.50 ppg
Fluid Gradient Below TOC:	12.50 ppg
Wellhead Pressure:	17 psi
Pore Pressure In Open Hole Below TOC:	No

AXIAL LOADS DATA (9 5/8" Production Casing)

Overpull Force:	100000 lbf
Green Cement Pressure Test:	3500 psi
Service Loads:	Yes

BURST PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Pressure Test (psi)	Tubing Leak (psi)	Stimulation Leak (psi)	Casing Injection (psi)	Green Cement Pres.Test (Int) (psi)	Green Cement Pres. Test (Ext) (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	3513	2345	3511	3513	3511	17	17
2	3299.99	5180	4012	5178	5180	4928	2143	1446
3	3300.01	5180	4012	5178	5180	4928	2143	1468
4	3521.00	5293	4125	5291	5293	5024	2286	1579
5	3600.00	5333	4165	5331	5333	5058	2338	1615
6	3799.99	5435	4267	5433	5435	5144	2502	1708
7	3800.01	5435	4267	5433	5435	5144	2502	1708
8	4240.00	5659	4491	5657	5659	5335	2863	1912
9	4337.00	5708	4540	5706	5708	5377	2943	1967
10	4643.00	5864	4696	5862	5864	5509	3194	2103
11	5099.99	6096	4928	6094	6096	5707	3569	2333
12	5100.01	6096	2693	5707	6096	5707	3569	2333
13	5626.00	6364	2731	5935	6364	5935	4001	2598
14	6019.00	6564	2761	6105	6564	6105	4323	2761
15	6600.00	6860	3056	6356	6860	6356	4800	3000

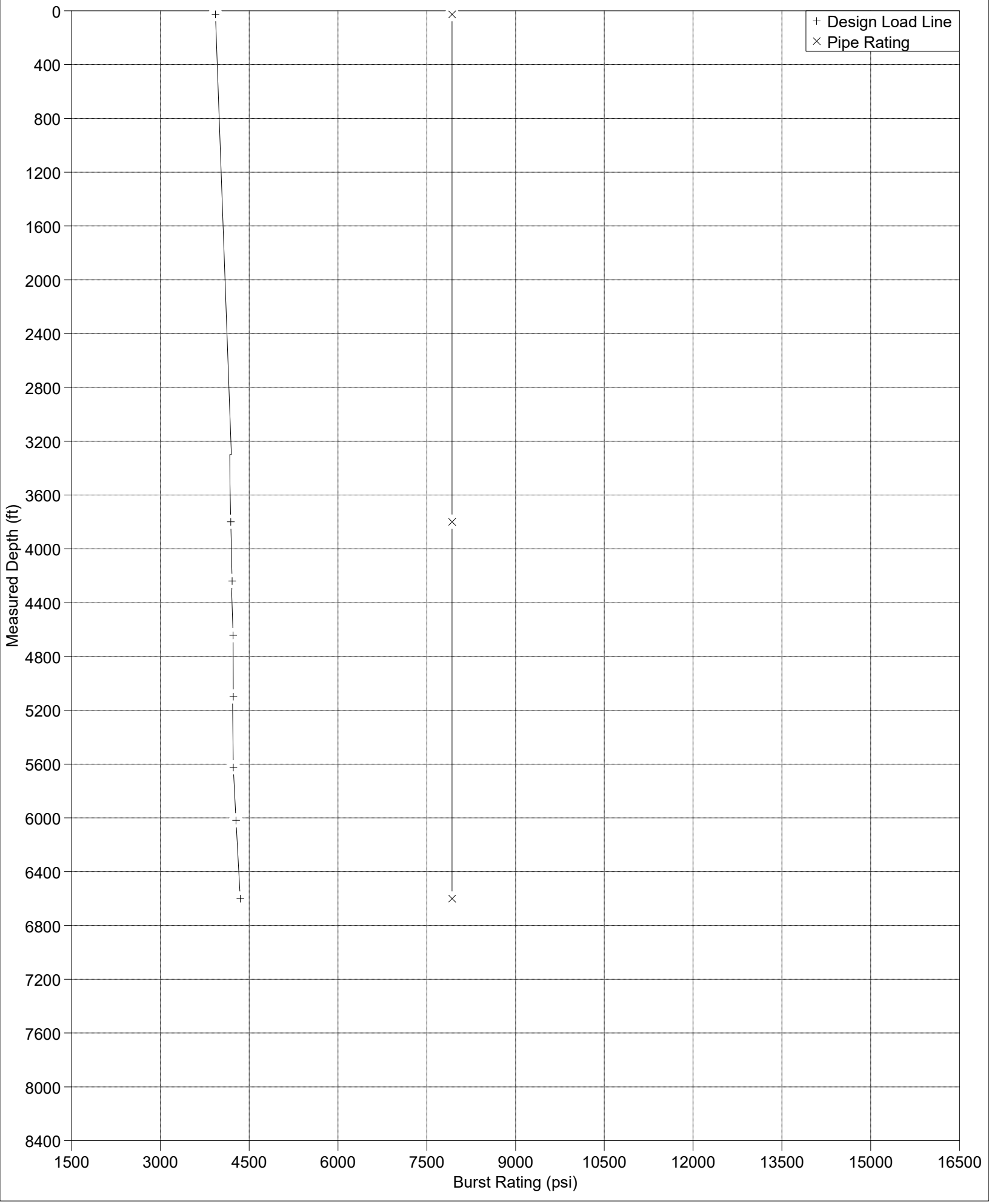
COLLAPSE PRESSURE PROFILES (9 5/8" Production Casing)

	Depth (MD) (ft)	Cementing (Int) (psi)	Cementing (Ext) (psi)	Full Evacuation (psi)	Fluid Gradients w/ Pore Press (psi)
1	26.00	11	17	0	17
2	3299.99	1428	2143	2	2143
3	3300.01	1428	2143	2	2143
4	3600.00	1558	2338	2	2338
5	3799.99	1644	2502	2	2468
6	3800.01	1644	2502	2	2468
7	5099.99	2207	3569	3	3312
8	5100.01	2207	3569	3	3312
9	6019.00	2605	4323	3	3908
10	6600.00	2856	4800	3	4286

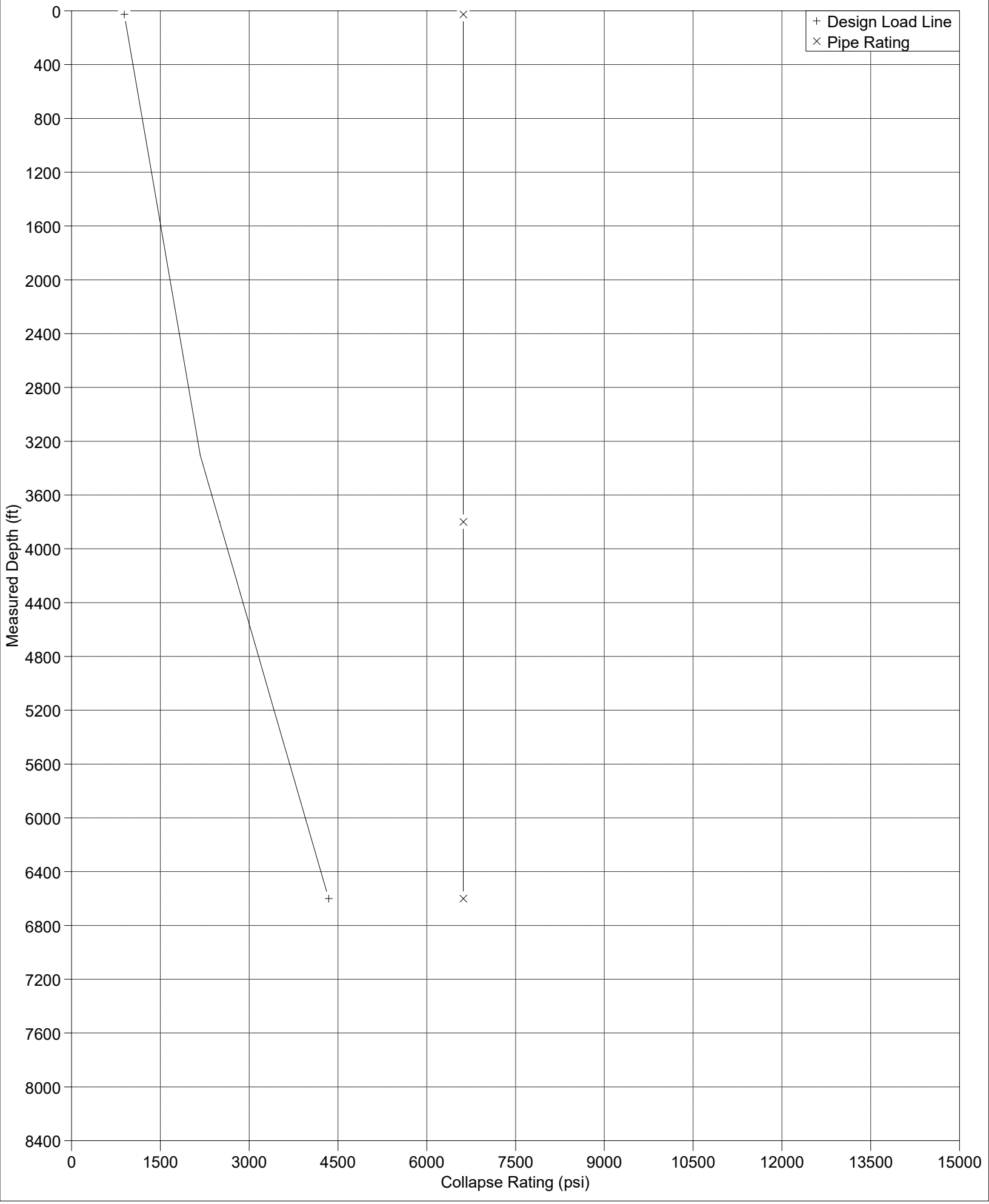
AXIAL LOADS TABLE (9 5/8" Production Casing)

	Depth (MD) (ft)	Overpull Force (lbf)		Green Cement Pressure Test (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	385344	385344	366110	366110	366110	366110
2	1794.44	308585	308585	271499	271499	271499	271499
3	1794.44	308585	308585	271499	271499	271499	212547
4	3299.99	243237	243237	190952	190952	149945	149945
5	3300.01	243236	243236	190950	190950	262761	262761
6	3521.00	233644	233644	179127	179127	260634	260634
7	3600.00	230215	230215	174901	174901	260000	260000
8	3799.99	221534	221534	164202	164202	259894	259894
9	3800.01	221533	221533	164200	164200	259894	259894
10	4240.00	202436	202436	140661	140661	259661	259661
11	4337.00	198225	198225	135471	135471	259171	259171
12	4643.00	184943	184943	119100	119100	259249	259249
13	5099.99	165108	165108	94651	94651	258211	258211
14	5100.01	165107	165107	94650	94650	258211	258211
15	5477.00	148744	148744	74482	74482	257354	257354
16	5626.00	142276	142276	66510	66510	257015	257015
17	6019.00	125218	125218	45484	45484	257675	257675

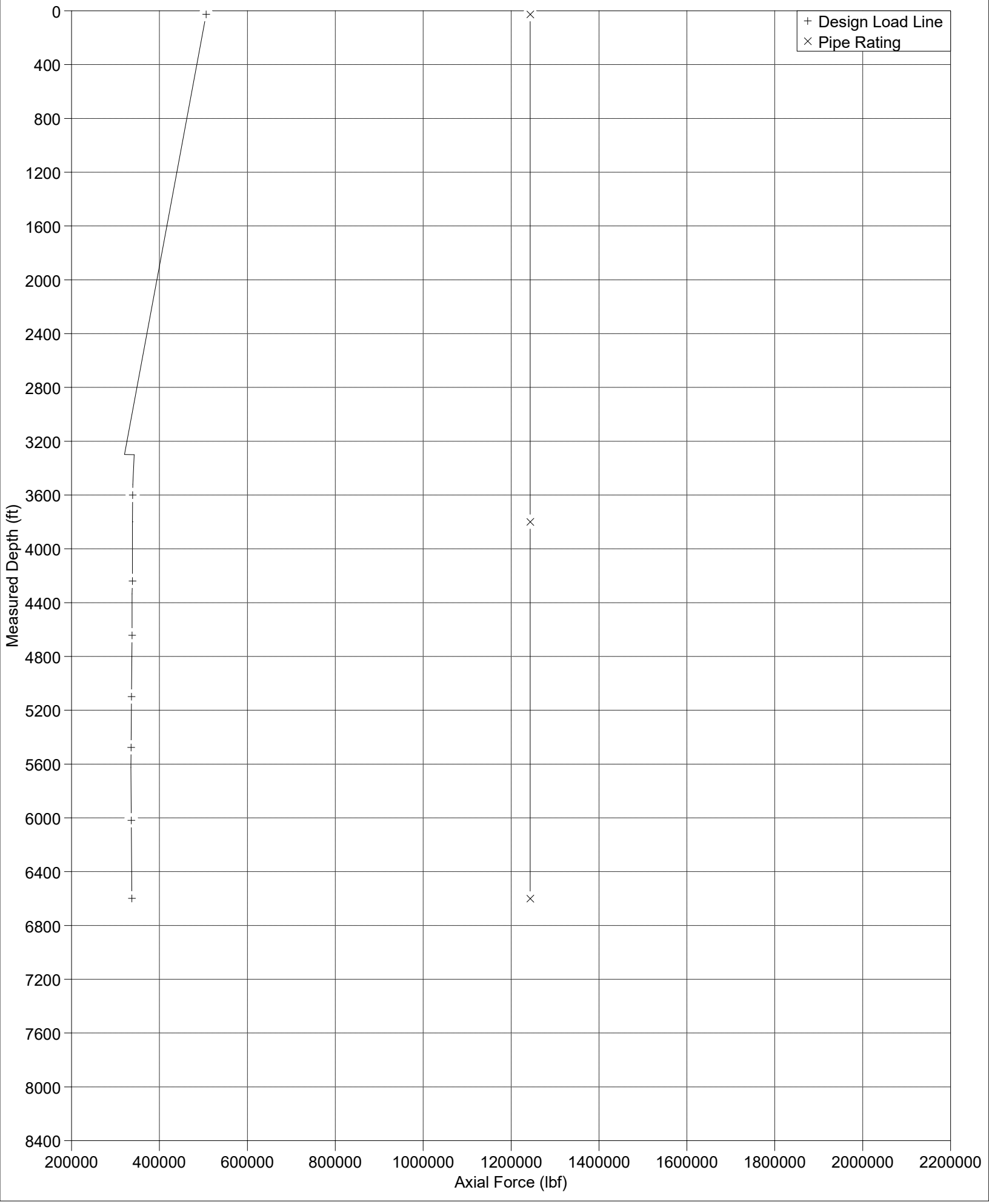
BURST DESIGN (9 5/8" Production Casing)

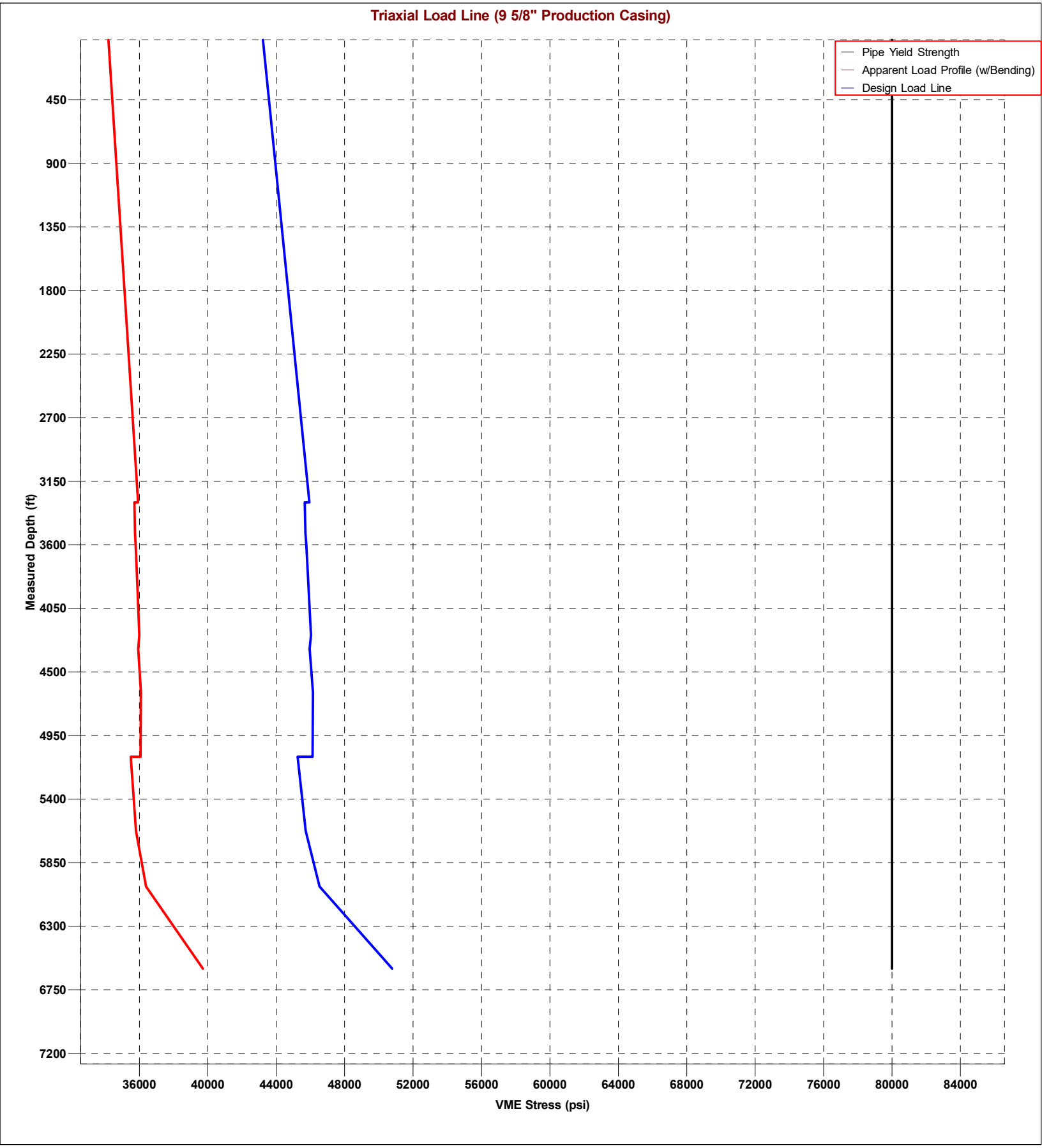


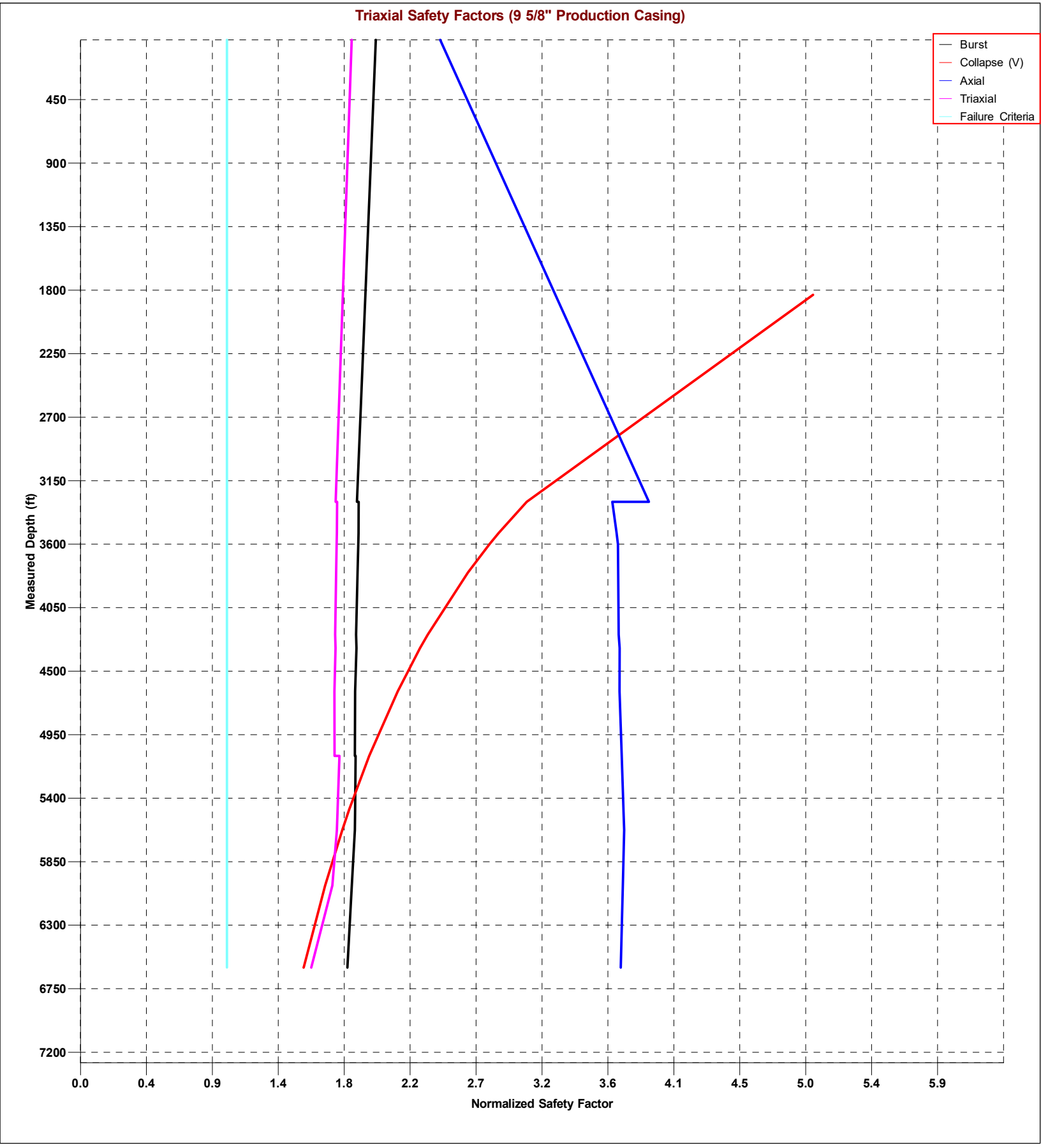
COLLAPSE DESIGN (9 5/8" Production Casing)



AXIAL DESIGN (9 5/8" Production Casing)




Triaxial Load Line (9 5/8" Production Casing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
450
900
1350
1800
2250
2700
3150
3600
4050
4500
4950
5400
5850
6300
6750
7200
36000
40000
44000
48000
52000
56000
60000
64000
68000
72000
76000
80000
84000
VME Stress (psi)


Triaxial Safety Factors (9 5/8" Production Casing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
450
900
1350
1800
2250
2700
3150
3600
4050
4500
4950
5400
5850
6300
6750
7200
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	9 5/8", 53.500 ppf, L-80	Blue	2.22 B7	7.41 C2	3.19 A4	2.31 B12
2	3300			2.08 B7	3.05 C5	5.04 A4	2.18 B7
3	3300			2.09 B7	3.05 C5	4.72 B8	2.19 B7
4	3521			2.09 B7	2.85 C5	4.76 B8	2.19 B7
5	3600			2.09 B7	2.79 C5	4.77 B8	2.19 B7
6	3800			2.08 B7	2.65 C5	4.77 B8	2.18 B7
7	3800	9 5/8", 53.500 ppf, L-80	Blue	2.08 B7	2.65 C5	4.77 B8	2.18 B7
8	4240			2.07 B7	2.37 C5	4.78 B8	2.17 B7
9	4337			2.07 B7	2.32 C5	4.78 B8	2.18 B7
10	4643			2.06 B7	2.16 C5	4.78 B8	2.17 B7
11	5100			2.06 B7	1.97 C5	4.80 B8	2.17 B7
12	5100			2.07 B5	1.97 C5	4.80 B8	2.21 B5
13	5477			2.06 B5	1.84 C5	4.82 B8	2.19 B5
14	5479			2.06 B5	1.83 C5	4.82 B8	2.19 B5
15	5626			2.06 B5	1.79 C5	4.82 B8	2.19 B5
16	6019			2.04 B5	1.67 C5	4.81 B8	2.15 B5
17	6599			2.00 B5	1.52 C5	4.79 B8	1.97 C5
18	6600			2.00 B5	1.52 C5	4.79 B8	1.97 C5
19							
20	B5	Pressure Test					
21	B7	Stimulation Surface Leak					
22	B8	Injection Casing					
23	B12	Green Cement Pressure Test(Burst)					
24	C2	Cementing					
25	C5	Full Evacuation Production					
26	A4	Overpull Force					
27	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (9 5/8" Production Casing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	9 5/8", 53.500 ppf, L-80	0.270 B7	0.070 C2	0.253 B7	50.4	87.2	53.6	0.275	0.475	0.292
2	3299.99		0.289 B7	0.339 C5	0.273 B7	47.0	37.8	49.9	0.256	0.206	0.272
3	3300.01		0.287 B7	0.339 C5	0.271 B7	47.3	37.8	50.2	0.258	0.206	0.274
4	3521.00		0.287 B7	0.348 C5	0.272 B7	47.3	36.2	50.1	0.258	0.197	0.273
5	3600.00		0.287 B7	0.351 C5	0.272 B7	47.3	35.6	50.1	0.258	0.194	0.273
6	3799.99		0.288 B7	0.359 C5	0.273 B7	47.1	34.2	50.0	0.257	0.186	0.272
7	3800.01	9 5/8", 53.500 ppf, L-80	0.288 B7	0.359 C5	0.273 B7	47.1	34.2	50.0	0.257	0.186	0.272
8	4240.00		0.290 B7	0.376 C5	0.274 B7	46.8	30.9	49.7	0.255	0.169	0.271
9	4337.00		0.289 B7	0.380 C5	0.274 B7	46.9	30.2	49.8	0.256	0.165	0.271
10	4643.00		0.291 B7	0.393 C5	0.275 B7	46.6	28.0	49.6	0.254	0.152	0.270
11	5099.99		0.291 B7	0.411 C5	0.275 B7	46.6	24.6	49.6	0.254	0.134	0.270
12	5100.01		0.290 B5	0.411 C5	0.269 B5	46.7	24.6	50.7	0.255	0.134	0.276
13	5477.00		0.291 B5	0.426 C5	0.271 B5	46.6	21.9	50.2	0.254	0.119	0.274
14	5479.43		0.291 B5	0.426 C5	0.271 B5	46.6	21.9	50.2	0.254	0.119	0.274
15	5626.00		0.291 B5	0.430 C5	0.272 B5	46.6	21.2	50.0	0.254	0.115	0.273
16	6019.00		0.294 B5	0.440 C5	0.278 B5	46.0	19.3	49.1	0.251	0.105	0.267
17	6599.20		0.299 B5	0.455 C5	0.297 C5	45.1	16.5	45.5	0.246	0.090	0.248
18	6600.00		0.299 B5	0.455 C5	0.297 C5	45.1	16.5	45.5	0.246	0.090	0.248
19											
20	B5	Pressure Test									
21	B7	Stimulation Surface Leak									
22	C2	Cementing									
23	C5	Full Evacuation Production									
24	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (9 5/8" Production Casing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	945981
2	26	944853
3	26	944852
4	254	934963
5	508	923945
6	762	912927
7	1000	902576
8	1015	901909
9	1269	890890
10	1523	879872
11	1777	868854
12	2000	859171
13	2031	857836
14	2285	846818
15	2538	835800
16	2792	824781
17	2800	824448
18	2800	824447
19	3000	815767
20	3046	813763
21	3300	802745
22	3554	791727
23	3800	781043
24	3800	781042
25	3808	780709
26	4000	772362
27	4062	769691
28	4315	758672
29	4569	747654
30	4823	736636
31	5000	728957
32	5077	725618
33	5331	714600
34	5585	703582
35	5838	692563
36	6000	685552
37	6092	681545
38	6346	670527
39	6574	660638
40	6600	* 660882
41		
42	* Based on Casing Strength	
43	Only. Running String not	
44	Included	

TRIAXIAL RESULTS (9 5/8" Production Casing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	286079	286079	287206	0.0	2.44	2.26	N/A	4.33	78	3513	17	N/A	N/A
2	3300	149945	149945	174804	0.0	2.28	2.09	N/A	8.18	113	5180	1446		
3	3300	148970	148970	174167	0.0	2.30	2.11	N/A	8.23	113	5180	1468		
4	3521	139161	139161	166087	0.0	2.29	2.10	N/A	8.81	116	5293	1579		
5	3600	135782	135782	163280	0.0	2.29	2.10	N/A	9.03	117	5333	1615		
6	3800	128725	128725	157685	0.0	2.28	2.09	N/A	9.51	119	5435	1708		
7	3800	128724	128724	157684	0.0	2.28	2.09	N/A	9.51	119	5435	1708		
8	4240	113198	113198	145349	0.0	2.25	2.08	N/A	10.80	124	5659	1912		
9	4337	109338	109338	142338	0.0	2.25	2.08	N/A	11.18	125	5708	1967		
10	4643	98780	98780	133890	0.0	2.23	2.07	N/A	12.36	128	5864	2103		
11	5100	81859	81859	120483	0.0	2.21	2.07	N/A	14.90	133	6096	2333		
12	5100	81858	81858	120482	0.0	2.21	2.07	N/A	14.90	133	6096	2333		
13	5626	62381	62381	105001	0.0	2.19	2.06	N/A	19.51	138	6364	2598		
14	6019	49382	49382	94421	0.0	2.15	2.04	N/A	24.62	143	6564	2761		
15	6600	30164	30164	78729	0.0	2.09	2.00	N/A	40.23	149	6860	3000		
16														
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Tubing Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	37691	37691	38826	0.0	3.46	3.33	N/A	32.26	143	2345	17	N/A	N/A
2	3300	15348	15348	38691	0.0	3.12	3.02	N/A	79.21	143	4012	1446		
3	3300	14373	14373	38049	0.0	3.14	3.05	N/A	84.59	143	4012	1468		
4	3521	12245	12245	37631	0.0	3.14	3.04	N/A	99.29	143	4125	1579		
5	3600	11612	11612	37566	0.0	3.13	3.04	N/A	+ 100.00	143	4165	1615		
6	3800	11506	11506	38932	0.0	3.13	3.03	N/A	+ 100.00	143	4267	1708		
7	4240	11272	11272	41938	0.0	3.11	3.01	N/A	+ 100.00	143	4491	1912		
8	4337	10783	10783	42312	0.0	3.12	3.01	N/A	+ 100.00	143	4540	1967		
9	4643	10861	10861	44560	0.0	3.10	2.99	N/A	+ 100.00	143	4696	2103		
10	5100	9822	9822	47158	0.0	3.10	2.99	N/A	+ 100.00	143	4928	2333		
11	5100	-66921	-66921	-31351	0.0	14.85	21.56	N/A	(18.17)	143	2693	2333		
12	5626	-75984	-75984	-36410	0.0	20.98	58.19	N/A	(16.00)	143	2731	2598		
13	6019	-81192	-81192	-39157	0.0	24.72	N/A	N/A	(14.97)	143	2761	2761		
14	6600	-80217	-80217	-34342	0.0	24.94	+ 100.00	N/A	(15.16)	143	3056	3000		
15														
16	( )	Compression												
17	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Stimulation Surface Leak

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	77718	77718	79774	0.0	2.34	2.22	N/A	15.64	143	3511	17	N/A	N/A
2	3300	55375	55375	79639	0.0	2.18	2.08	N/A	21.95	143	5178	1446		
3	3300	54400	54400	78997	0.0	2.19	2.09	N/A	22.35	143	5178	1468		
4	3521	52272	52272	78579	0.0	2.19	2.09	N/A	23.26	143	5291	1579		
5	3600	51639	51639	78514	0.0	2.19	2.09	N/A	23.54	143	5331	1615		
6	3800	51533	51533	79880	0.0	2.18	2.08	N/A	23.59	143	5433	1708		
7	4240	51299	51299	82886	0.0	2.17	2.07	N/A	23.70	143	5657	1912		
8	4337	50810	50810	83260	0.0	2.18	2.07	N/A	23.93	143	5706	1967		
9	4643	50888	50888	85508	0.0	2.17	2.06	N/A	23.89	143	5862	2103		
10	5100	49849	49849	88105	0.0	2.17	2.06	N/A	24.39	143	6094	2333		
11	5100	36548	36548	74499	0.0	2.41	2.30	N/A	33.26	143	5707	2333		
12	5626	33974	33974	76077	0.0	2.44	2.32	N/A	35.78	143	5935	2598		
13	6019	33603	33603	78280	0.0	2.44	2.32	N/A	36.18	143	6105	2761		
14	6600	33056	33056	81536	0.0	2.43	2.31	N/A	36.78	143	6356	3000		
15														
16	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Injection Down Casing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	286079	286079	287206	0.0	2.44	2.26	N/A	4.33	78	3513	17	N/A	N/A
2	3300	263737	263737	287073	0.0	2.30	2.12	N/A	4.70	78	5180	1446		
3	3300	262761	262761	286444	0.0	2.32	2.13	N/A	4.72	78	5180	1468		
4	3521	260634	260634	286034	0.0	2.31	2.13	N/A	4.76	78	5293	1579		
5	3600	260000	260000	285971	0.0	2.31	2.13	N/A	4.77	78	5333	1615		
6	3800	259894	259894	287310	0.0	2.31	2.12	N/A	4.77	78	5435	1708		
7	4240	259661	259661	290257	0.0	2.29	2.11	N/A	4.78	78	5659	1912		
8	4337	259171	259171	290624	0.0	2.30	2.11	N/A	4.78	78	5708	1967		
9	4643	259249	259249	292828	0.0	2.28	2.10	N/A	4.78	78	5864	2103		
10	5100	258211	258211	295375	0.0	2.28	2.10	N/A	4.80	78	6096	2333		
11	5626	257015	257015	298306	0.0	2.28	2.10	N/A	4.82	78	6364	2598		
12	6019	257675	257675	301498	0.0	2.26	2.08	N/A	4.81	78	6564	2761		
13	6600	258650	258650	306219	0.0	2.22	2.05	N/A	4.79	78	6860	3000		
14														
15	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	366110	366110	370534	0.0	2.31	2.24	N/A	3.36	105	3511	17	N/A	N/A
2	3300	190952	190952	227369	0.0	3.04	2.81	N/A	6.42	113	4928	2143		
3	3300	190950	190950	227368	0.0	3.04	2.81	N/A	6.42	113	4928	2143		
4	3521	179127	179127	217679	0.0	3.10	2.86	N/A	6.85	114	5024	2286		
5	3600	174901	174901	214215	0.0	3.13	2.87	N/A	7.01	114	5058	2338		
6	3800	164202	164202	205984	0.0	3.22	2.96	N/A	7.47	115	5144	2502		
7	3800	164200	164200	205983	0.0	3.22	2.96	N/A	7.47	115	5144	2502		
8	4240	140661	140661	187865	0.0	3.45	3.16	N/A	8.72	116	5335	2863		
9	4337	135471	135471	183869	0.0	3.50	3.21	N/A	9.05	116	5377	2943		
10	4643	119100	119100	171259	0.0	3.69	3.37	N/A	10.29	117	5509	3194		
11	5100	94651	94651	152417	0.0	4.00	3.65	N/A	12.94	118	5707	3569		
12	5100	94650	94650	152416	0.0	4.00	3.65	N/A	12.94	118	5707	3569		
13	5626	66510	66510	130713	0.0	4.43	4.04	N/A	18.41	119	5935	4001		
14	6019	45484	45484	114487	0.0	4.81	4.38	N/A	26.92	120	6105	4323		
15	6599	14444	14444	90513	0.0	5.49	5.01	N/A	84.72	121	6356	4799		
16	6600	14401	14401	90480	0.0	5.49	5.01	N/A	84.97	121	6356	4800		
17														
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Cementing

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	165863	165863	167924	0.0	6.51	N/A	7.41	7.41	105	11	17	N/A	N/A
2	3126	12	12	21331	0.0	9.92	N/A	9.13	+ 100.00	113	1353	2030		
3	3127	-31	-31	21293	0.0	9.92	N/A	9.13	(+ 100.00)	113	1353	2030		
4	3300	-9295	-9295	13084	0.0	9.87	N/A	8.88	(+ 100.00)	113	1428	2143		
5	3300	-9296	-9296	13083	0.0	9.87	N/A	8.88	(+ 100.00)	113	1428	2143		
6	3521	-21119	-21119	2604	0.0	9.75	N/A	8.55	(58.08)	114	1524	2286		
7	3600	-25346	-25346	-1143	0.0	9.69	N/A	8.41	(48.39)	114	1558	2338		
8	3800	-36045	-36045	-10630	0.0	9.12	N/A	7.65	(34.02)	115	1644	2502		
9	3800	-36046	-36046	-10631	0.0	9.12	N/A	7.65	(34.02)	115	1644	2502		
10	4240	-59586	-59586	-31514	0.0	7.96	N/A	6.38	(20.57)	116	1835	2863		
11	4337	-64775	-64775	-36119	0.0	7.73	N/A	6.15	(18.92)	116	1877	2943		
12	4643	-81146	-81146	-50653	0.0	7.07	N/A	5.53	(15.10)	117	2009	3194		
13	5100	-105595	-105595	-72370	0.0	6.23	N/A	4.81	(11.60)	118	2207	3569		
14	5100	-105596	-105596	-72371	0.0	6.23	N/A	4.81	(11.60)	118	2207	3569		
15	5626	-133737	-133737	-97385	0.0	5.46	N/A	4.18	(9.16)	119	2435	4001		
16	6019	-154762	-154762	-116088	0.0	4.98	N/A	3.81	(7.91)	120	2605	4323		
17	6600	-185846	-185846	-143758	0.0	4.40	N/A	3.37	(6.58)	121	2856	4800		
18														
19	( )	Compression												
20	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Full Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	-42816	-42816	-43801	0.0	25.74	N/A	+ 100.00	(28.39)	143	0	17	N/A	N/A
2	3300	-152762	-152762	-156250	0.0	3.97	N/A	3.05	(7.96)	143	2	2143		
3	3300	-152762	-152762	-156251	0.0	3.97	N/A	3.05	(7.96)	143	2	2143		
4	3521	-160183	-160183	-163841	0.0	3.72	N/A	2.85	(7.59)	143	2	2286		
5	3600	-162836	-162836	-166554	0.0	3.64	N/A	2.79	(7.47)	143	2	2338		
6	3800	-168055	-168055	-171891	0.0	3.45	N/A	2.65	(7.23)	143	2	2468		
7	3800	-168056	-168056	-171892	0.0	3.45	N/A	2.65	(7.23)	143	2	2468		
8	4240	-179538	-179538	-183634	0.0	3.09	N/A	2.37	(6.77)	143	2	2753		
9	4337	-182069	-182069	-186223	0.0	3.02	N/A	2.32	(6.68)	143	2	2816		
10	4643	-190055	-190055	-194390	0.0	2.81	N/A	2.16	(6.40)	143	2	3015		
11	5100	-201980	-201980	-206586	0.0	2.56	N/A	1.97	(6.02)	143	3	3312		
12	5100	-201981	-201981	-206586	0.0	2.56	N/A	1.97	(6.02)	143	3	3312		
13	5626	-215707	-215707	-220623	0.0	2.32	N/A	1.79	(5.64)	143	3	3653		
14	6019	-225962	-225962	-231111	0.0	2.16	N/A	1.67	(5.38)	143	3	3908		
15	6600	-241124	-241124	-246616	0.0	1.97	N/A	1.52	(5.04)	143	3	4286		
16														
17	( )	Compression												
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	385344	385344	389986	0.0	2.81	N/A	N/A	3.19	105	17	17	N/A	N/A
2	3300	243237	243237	280377	0.0	3.97	N/A	N/A	5.04	113	2143	2143		
3	3300	243236	243236	280377	0.0	3.97	N/A	N/A	5.04	113	2143	2143		
4	3521	233644	233644	272959	0.0	4.08	N/A	N/A	5.25	114	2286	2286		
5	3600	230215	230215	270307	0.0	4.12	N/A	N/A	5.33	114	2338	2338		
6	3800	221534	221534	263591	0.0	4.23	N/A	N/A	5.54	115	2468	2468		
7	3800	221533	221533	263590	0.0	4.23	N/A	N/A	5.54	115	2468	2468		
8	4240	202436	202436	248808	0.0	4.50	N/A	N/A	6.06	116	2753	2753		
9	4337	198225	198225	245548	0.0	4.56	N/A	N/A	6.18	116	2816	2816		
10	4643	184943	184943	235260	0.0	4.77	N/A	N/A	6.63	117	3015	3015		
11	5100	165108	165108	219887	0.0	5.13	N/A	N/A	7.42	118	3312	3312		
12	5100	165107	165107	219886	0.0	5.13	N/A	N/A	7.42	118	3312	3312		
13	5626	142276	142276	202179	0.0	5.61	N/A	N/A	8.61	119	3653	3653		
14	6019	125218	125218	188939	0.0	6.04	N/A	N/A	9.78	120	3908	3908		
15	6599	100035	100035	169379	0.0	6.79	N/A	N/A	12.23	121	4285	4285		
16	6600	100000	100000	169352	0.0	6.80	N/A	N/A	12.24	121	4286	4286		
17														
18	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (9 5/8" Production Casing) - Green Cement Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	366110	366110	370534	0.0	2.31	2.24	N/A	3.36	105	3511	17	N/A	N/A
2	3300	190952	190952	227369	0.0	3.04	2.81	N/A	6.42	113	4928	2143		
3	3300	190950	190950	227368	0.0	3.04	2.81	N/A	6.42	113	4928	2143		
4	3521	179127	179127	217679	0.0	3.10	2.86	N/A	6.85	114	5024	2286		
5	3600	174901	174901	214215	0.0	3.13	2.87	N/A	7.01	114	5058	2338		
6	3800	164202	164202	205984	0.0	3.22	2.96	N/A	7.47	115	5144	2502		
7	3800	164200	164200	205983	0.0	3.22	2.96	N/A	7.47	115	5144	2502		
8	4240	140661	140661	187865	0.0	3.45	3.16	N/A	8.72	116	5335	2863		
9	4337	135471	135471	183869	0.0	3.50	3.21	N/A	9.05	116	5377	2943		
10	4643	119100	119100	171259	0.0	3.69	3.37	N/A	10.29	117	5509	3194		
11	5100	94651	94651	152417	0.0	4.00	3.65	N/A	12.94	118	5707	3569		
12	5100	94650	94650	152416	0.0	4.00	3.65	N/A	12.94	118	5707	3569		
13	5626	66510	66510	130713	0.0	4.43	4.04	N/A	18.41	119	5935	4001		
14	6019	45484	45484	114487	0.0	4.81	4.38	N/A	26.92	120	6105	4323		
15	6599	14444	14444	90513	0.0	5.49	5.01	N/A	84.72	121	6356	4799		
16	6600	14401	14401	90480	0.0	5.49	5.01	N/A	84.97	121	6356	4800		
17														
18	(V)	Vector Collapse Safety Factor												

DESIGN PARAMETERS DATA (5 1/2" Production Tubing)

Design Factor (Pipe) - Axial Tension:	1.300
Design Factor (Pipe) - Axial Compression:	1.200
Design Factor (Coupling) - Axial Tension:	1.300
Design Factor (Coupling) - Axial Compression:	1.200
Design Factor (Pipe) - Burst:	1.100
Design Factor (Coupling) - Burst:	1.100
Design Factor (Pipe) - Collapse:	1.000
Design Factor (Pipe) - Triaxial:	1.250
Temperature Deration:	Yes
Buckling:	Yes
Use Burst Wall Thickness in Triaxial:	Yes
Use API RP1111 Collapse:	No
Collapse Strength Model:	API

INITIAL CONDITIONS (5 1/2" Production Tubing)

Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5100.00 ft
Perforation Depth, MD:	6019.00 ft
Packer Setting Method:	Set Mechanically
Slackoff Force:	0 lbf
Temperatures:	Default

Vertical Depth (ft)	Temperature (°F)
26.00 ft	78 °F
5100.00 ft	133 °F

BURST LOADS DATA (5 1/2" Production Tubing)

Production Load:	**Shut-In**
Shut-in Bottom Hole Pressure:	3000 psi
Gas Gravity:	0.70 (0.0800 psi/ft @ 143 °F & 3000 psi)
Hot:	Yes

Drilling Load:	**Pressure Test**
Test Pressure:	3500 psi
Internal Fluid Density:	9.80 ppg

Production Load:	**Tubing Injection**
Injection Pressure:	3500 psi
Injection Fluid Density:	10.00 ppg

COLLAPSE LOADS DATA (5 1/2" Production Tubing)

Drilling Load:	**Full/Partial Evacuation**
Mud Weight:	9.80 ppg
Mud Level, MD:	5100.00 ft
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5100.00 ft

Production Load:	**Tubing Leak**
Packer Fluid Density:	9.80 ppg
Packer Depth, MD:	5100.00 ft
Perforation Depth, MD:	6019.00 ft
Gas Gravity:	0.70
Reservoir Pressure:	2761 psi

Production Load:	**Annular Pressure Test**
Fluid Density(Inside Tubing):	1.50 ppg
Wellhead Pressure (Annulus)	3500 psi
Fluid Density(Annulus)	9.80 ppg
Packer Depth, MD:	5100.00 ft

AXIAL LOADS DATA (5 1/2" Production Tubing)

Overpull Force:	100000 lbf
Service Loads:	Yes

BURST PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Pressure Test (Int) (psi)	Pressure Test (Ext) (psi)	Tubing Injection (Int) (psi)	Tubing Injection (Ext) (psi)	Shut-In (Int) (psi)	Shut-In (Ext) (psi)
1	26.00	3513	13	3514	13	2585	13
2	5099.99	6096	2596	6149	2596	2932	2596
3	5100.00	6096	2596	6149	2596	2932	2596

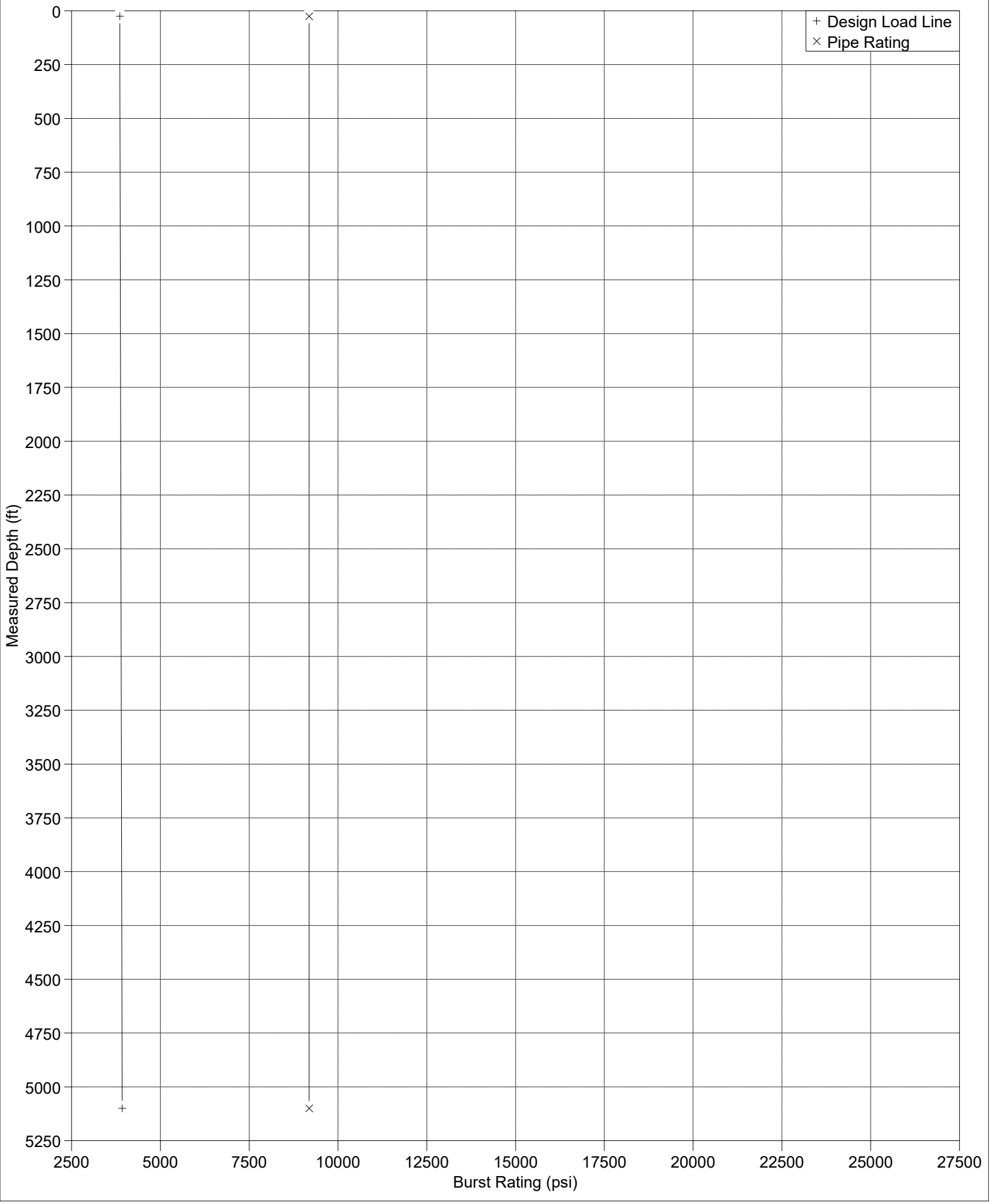
COLLAPSE PRESSURE PROFILES (5 1/2" Production Tubing)

	Depth (MD) (ft)	Full/Partial Evacuation (Int) (psi)	Full/Partial Evacuation (Ext) (psi)	Tubing Leak (Int) (psi)	Tubing Leak (Ext) (psi)	Annular Pressure Test (Int) (psi)	Annular Pressure Test (Ext) (psi)
1	26.00	0	13	2345	2345	2	3513
2	5099.99	3	2596	2693	4928	397	6096
3	5100.00	3	2596	2693	4928	397	6096

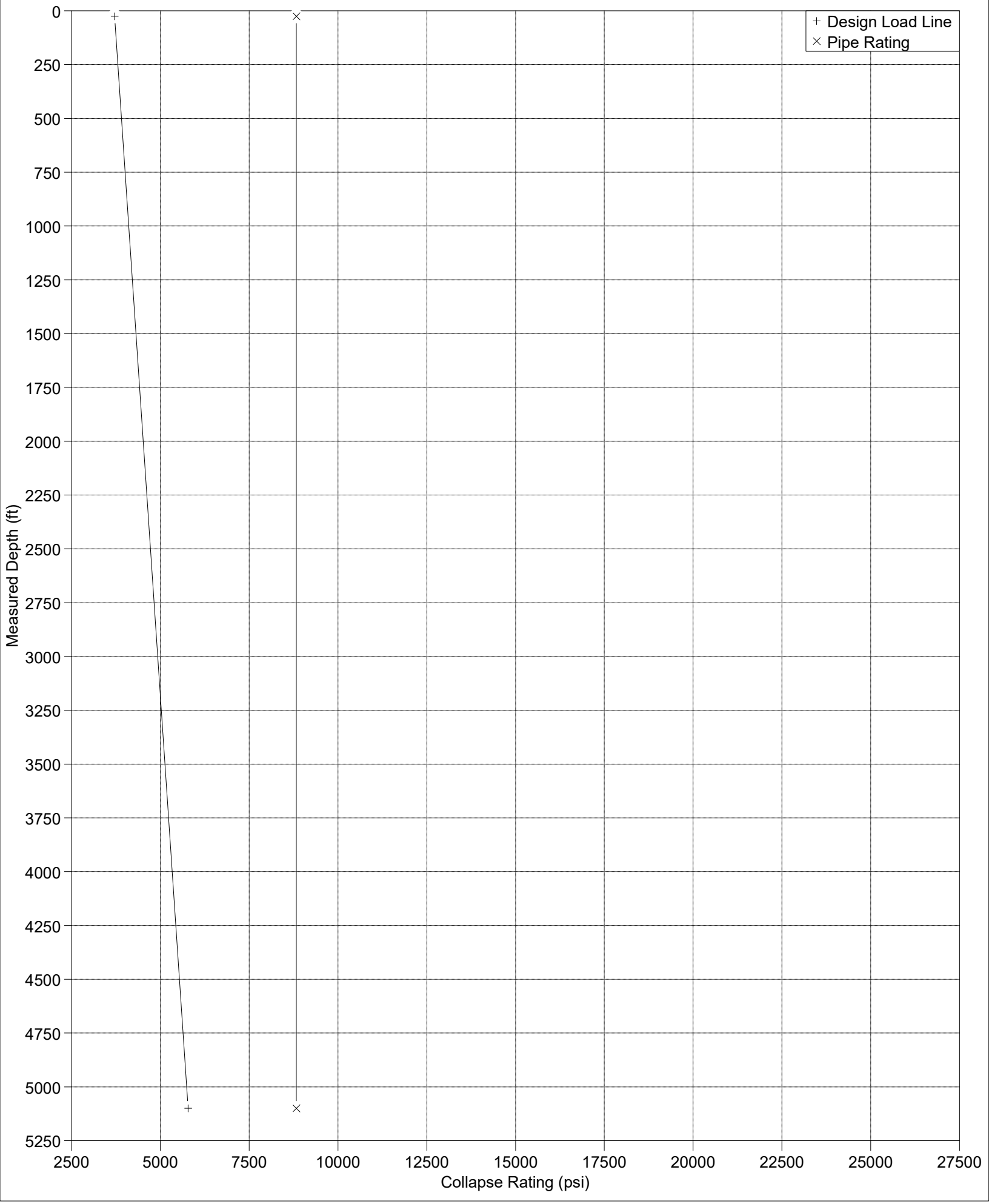
AXIAL LOADS TABLE (5 1/2" Production Tubing)

	Depth (MD) (ft)	Overpull Force (lbf)		Service Loads (lbf)	
		Apparent (w/Bending)	Actual (w/o Bending)	Apparent (w/Bending)	Actual (w/o Bending)
1	26.00	186425	186425	157344	157344
2	4601.18	108496	108496	-76764	65840
3	5098.00	100034	100034	-87423	55904
4	5098.00	100034	100034	-87423	-80044

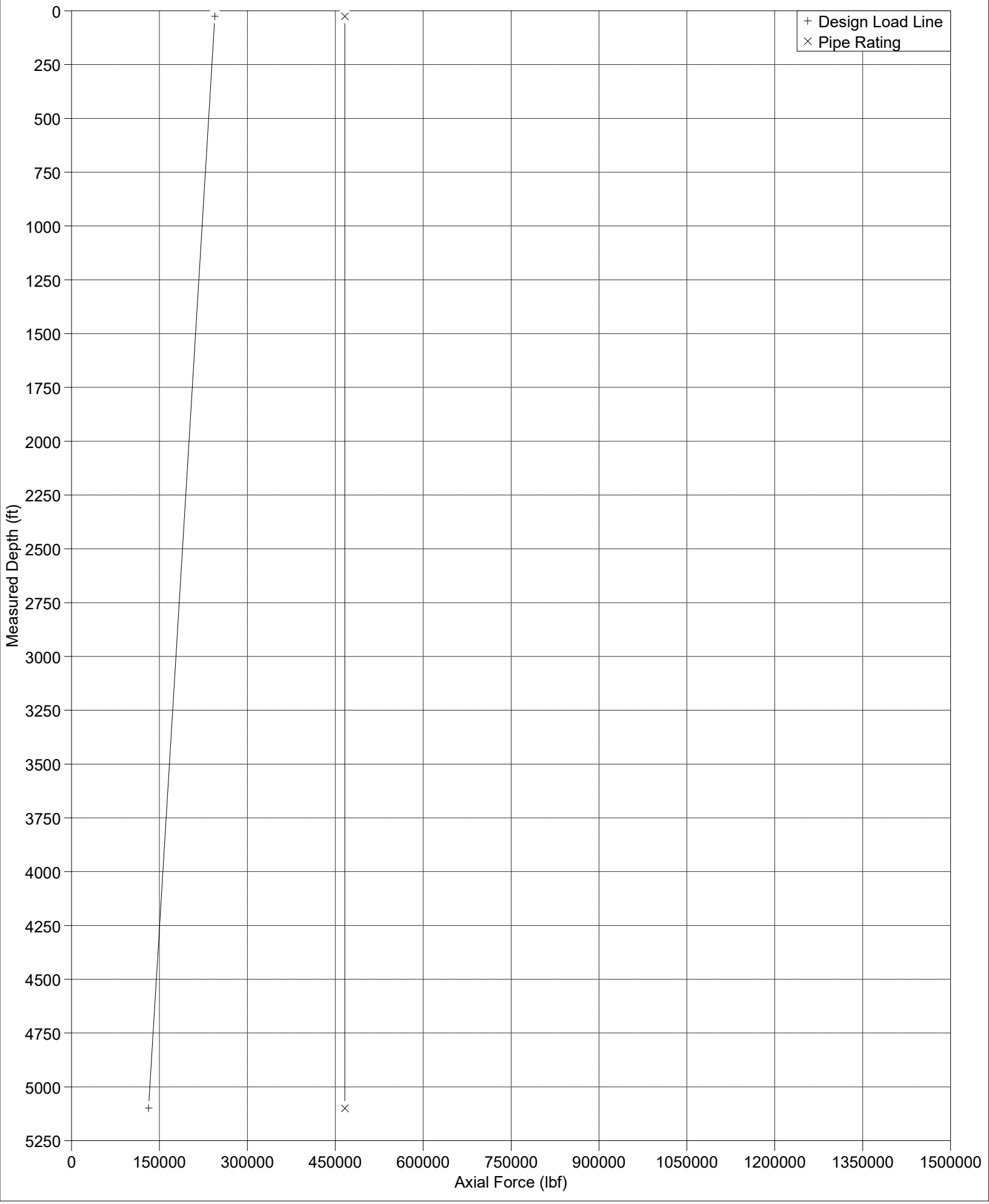
BURST DESIGN (5 1/2" Production Tubing)

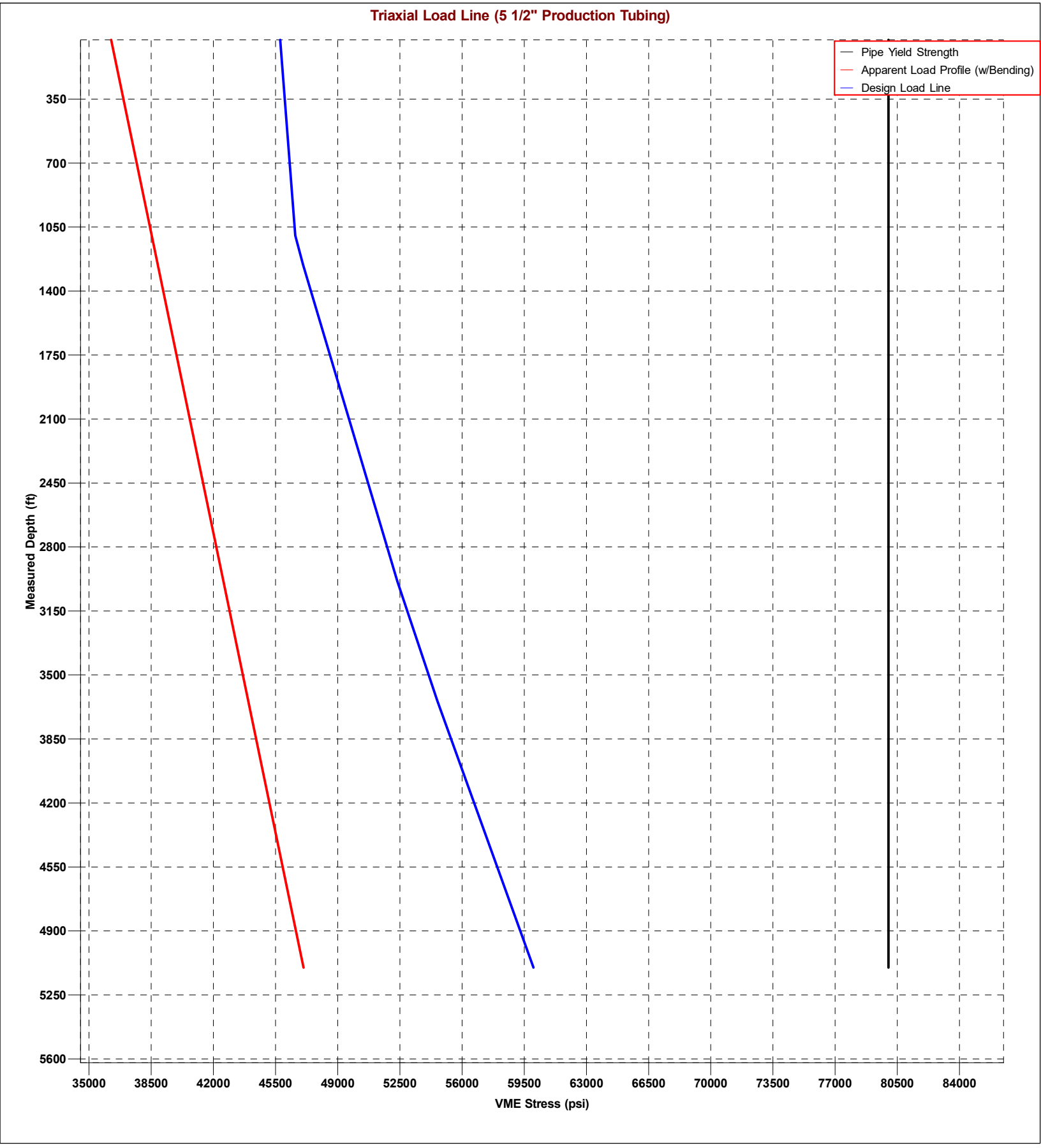


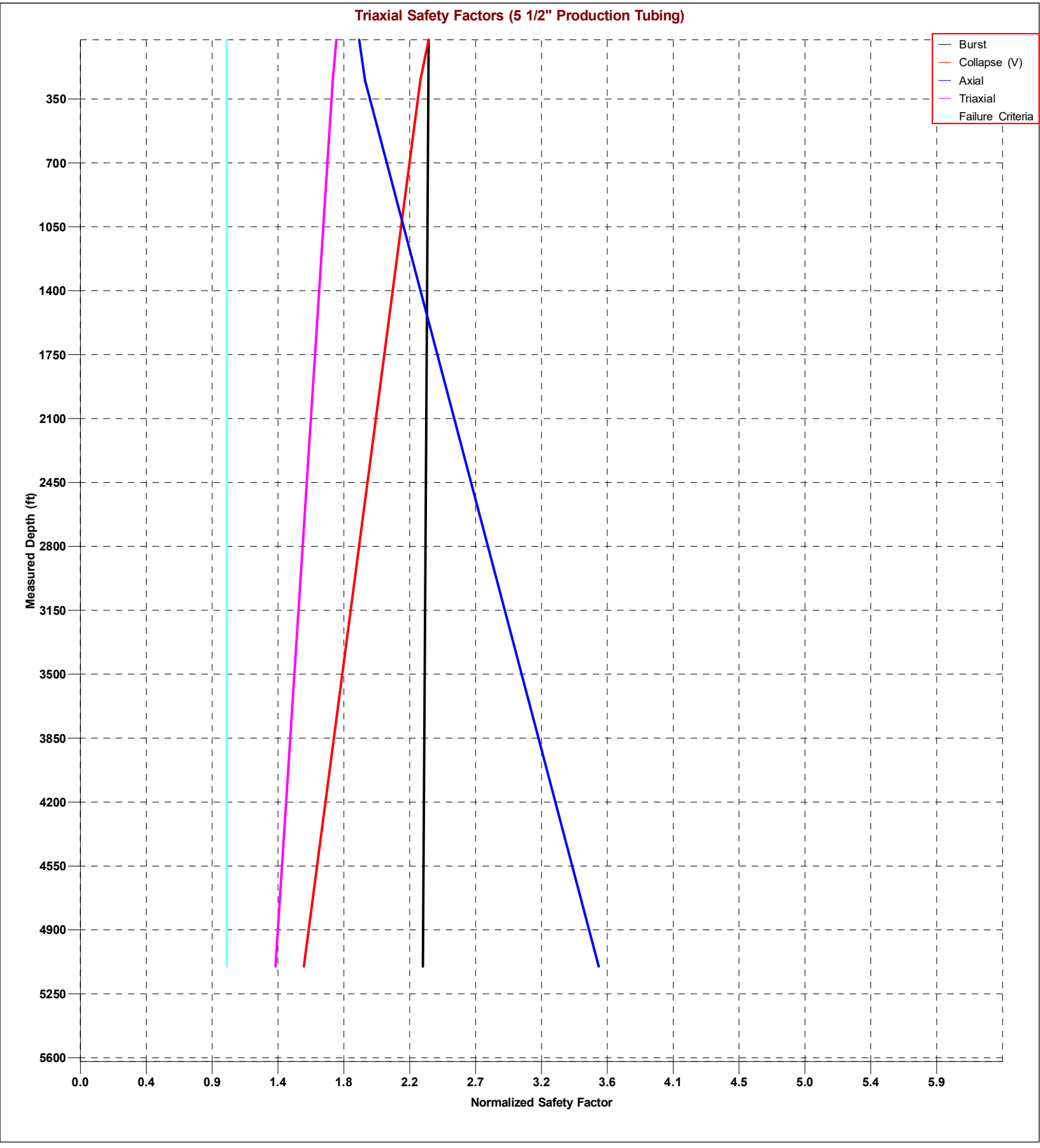
COLLAPSE DESIGN (5 1/2" Production Tubing)



AXIAL DESIGN (5 1/2" Production Tubing)




Triaxial Load Line (5 1/2" Production Tubing)
Pipe Yield Strength
Apparent Load Profile (w/Bending)
Design Load Line
Measured Depth (ft)
350
700
1050
1400
1750
2100
2450
2800
3150
3500
3850
4200
4550
4900
5250
5600
35000
38500
42000
45500
49000
52500
56000
59500
63000
66500
70000
73500
77000
80500
84000
VME Stress (psi)


Triaxial Safety Factors (5 1/2" Production Tubing)
Burst
Collapse (V)
Axial
Triaxial
Failure Criteria
Measured Depth (ft)
350
700
1050
1400
1750
2100
2450
2800
3150
3500
3850
4200
4550
4900
5250
5600
0.0
0.4
0.9
1.4
1.8
2.2
2.7
3.2
3.6
4.1
4.5
5.0
5.4
5.9
Normalized Safety Factor

MINIMUM SAFETY FACTORS (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Connection	Minimum Safety Factor (Abs)			
				Burst	Collapse (V)	Axial	Triaxial
1	26	5 1/2", 20.000 ppf, L-80	Blue	2.62 B16	2.38 C19	2.48 A4	2.19 A4
2	249			2.62 B5	2.32 C19	2.53 A4	2.16 A4
3	5098			2.57 B5	1.53 C19	4.60 A4	1.67 C19
4	5099			2.57 B5	1.53 C19	4.60 A4	1.67 C19
5	5100			2.57 B5	1.53 C19	4.60 A4	1.67 C19
6							
7	B5	Pressure Test					
8	B16	Tubing Injection					
9	C19	Annular Pressure Test					
10	A4	Overpull Force					
11	(V)	Vector Collapse Safety Factor					

MAXIMUM ALLOWABLE WEAR (5 1/2" Production Tubing)

	Depth (MD) (ft)	OD/Weight/Grade	Remaining Wall Thickness (in) - API			Max. Wear (% of Wall Thick.)			Max. Wear (in)		
			Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial	Burst	Collapse (V)	Triaxial
1	26.00	5 1/2", 20.000 ppf, L-80	0.152 B16	0.243 C19	0.176 A4	58.0	32.7	51.3	0.209	0.118	0.185
2	248.94		0.152 B5	0.245 C19	0.173 A4	57.9	32.1	52.2	0.209	0.116	0.188
3	5098.00		0.154 B5	0.292 C19	0.233 C19	57.3	19.0	35.4	0.207	0.069	0.128
4	5099.38		0.154 B5	0.292 C19	0.233 C19	57.3	19.0	35.4	0.207	0.069	0.128
5	5099.99		0.154 B5	0.292 C19	0.233 C19	57.3	19.0	35.4	0.207	0.069	0.128
6	5100.00		0.154 B5	0.292 C19	0.233 C19	57.3	19.0	35.4	0.207	0.069	0.128
7											
8	B5	Pressure Test									
9	B16	Tubing Injection									
10	C19	Annular Pressure Test									
11	A4	Overpull Force									
12	(V)	Vector Collapse Safety Factor									

MAXIMUM ALLOWABLE OVERPULL (5 1/2" Production Tubing)

	Running Depth (MD) (ft)	Max. Overpull (lbf)
1	0	355123
2	26	354681
3	255	350780
4	510	346437
5	765	342093
6	1000	338091
7	1020	337750
8	1275	333406
9	1530	329063
10	1785	324720
11	2000	321058
12	2040	320376
13	2295	316033
14	2550	311690
15	2805	307346
16	3000	304025
17	3060	303003
18	3315	298659
19	3570	294316
20	3825	289973
21	4000	286992
22	4080	285629
23	4335	281286
24	4590	276942
25	4845	272599
26	5000	269959
27	5074	268698
28	5098	* 268765
29	5100	* 268771
30		
31	* Based on Casing Strength	
32	Only. Running String not	
33	Included	

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	124653	124653	125106	0.0	2.63	2.62	N/A	3.73	78	3513	13	25102	1435
2	5098	39215	23213	55421	2745.6	2.70	2.57	N/A	11.66	133	6095	2595		
3	5100	39197	23173	55410	2749.4	2.70	2.57	N/A	11.66	133	6096	2596		
4	5100	39197	23173	55410	2749.5	2.70	2.57	N/A	11.66	133	6096	2596		
5														
6	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Shut-In

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	59194	59194	60635	0.0	3.78	3.49	N/A	7.70	143	2585	13	35415	3633
2	2986	9088	0	18360	1559.3	7.07	7.09	N/A	50.15	143	2787	1520		
3	2986	-9088	-0	-235	1559.3	7.07	7.09	N/A	(50.15)	143	2787	1520		
4	5098	-63977	-42246	-49974	3728.6	7.26	26.67	N/A	(7.12)	143	2932	2595		
5	5100	-64029	-42285	-50021	3730.7	7.26	26.74	N/A	(7.12)	143	2932	2596		
6	5100	-64029	-42286	-50022	3730.7	7.26	26.74	N/A	(7.12)	143	2932	2596		
7														
8	( )	Compression												
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Injection

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	157344	157344	157896	0.0	2.40	2.62	N/A	2.95	78	3514	13	0	0
2	5098	55904	55904	71244	0.0	2.81	2.58	N/A	8.32	78	6148	2595		
3	5100	55864	55864	71210	0.0	2.81	2.58	N/A	8.32	78	6149	2596		
4														
5	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Full/Partial Evacuation

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	72326	72326	72544	0.0	5.65	N/A	6.43	6.43	78	0	13	0	0
2	3642	0	0	12	0.0	4.61	N/A	4.71	+ 100.00	117	2	1854		
3	3642	-0	-0	11	0.0	4.61	N/A	4.71	(+ 100.00)	117	2	1854		
4	5098	-29114	-29114	-29677	0.0	3.62	N/A	3.36	(15.70)	133	3	2595		
5	5100	-29154	-29154	-29717	0.0	3.62	N/A	3.36	(15.68)	133	3	2596		
6	5100	-29154	-29154	-29718	0.0	3.62	N/A	3.36	(15.68)	133	3	2596		
7														
8	( )	Compression												
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Tubing Leak (Collapse)

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	21396	21396	35871	0.0	12.02	N/A	13.00	21.30	143	2345	2345	11535	1235
2	1096	0	0	14420	0.0	13.16	N/A	14.11	+ 100.00	143	2419	2890		
3	1096	-0	-0	14420	0.0	13.16	N/A	14.11	(+ 100.00)	143	2419	2890		
4	5098	-87423	-80044	-73380	1266.0	4.29	N/A	3.89	(5.21)	143	2693	4927		
5	5100	-87475	-80084	-73432	1268.1	4.28	N/A	3.88	(5.21)	143	2693	4928		
6														
7	( )	Compression												
8	(V)	Vector Collapse Safety Factor												

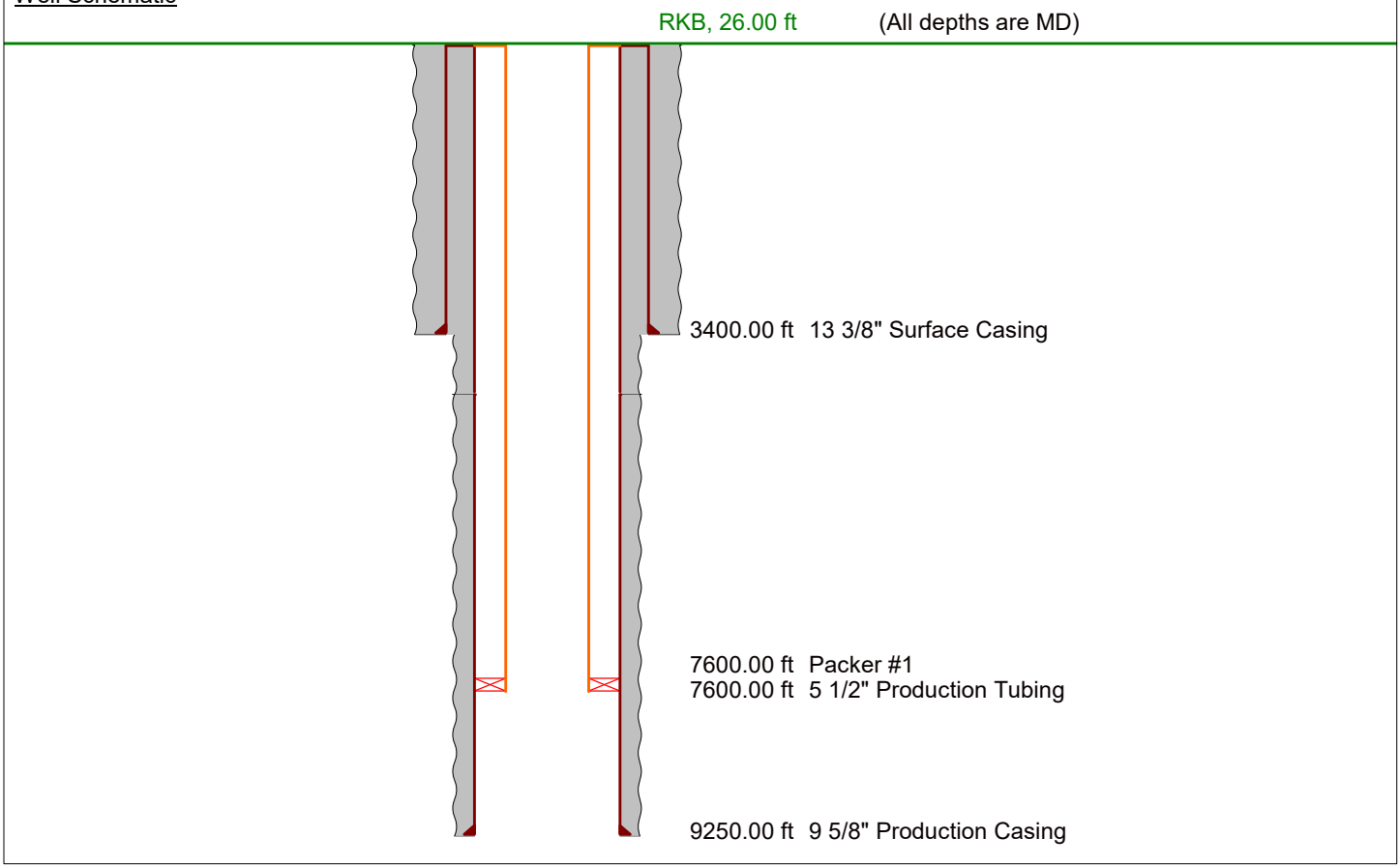
TRIAXIAL RESULTS (5 1/2" Production Tubing) - Annular Pressure Test

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	24567	24567	24653	0.0	2.27	N/A	2.38	18.92	78	2	3513	0	0
2	1254	0	0	574	0.0	2.13	N/A	2.17	+ 100.00	91	98	4139		
3	1254	-0	-0	573	0.0	2.13	N/A	2.17	(+ 100.00)	91	98	4139		
4	5098	-76873	-76873	-76040	0.0	1.67	N/A	1.53	(5.95)	133	397	6095		
5	5100	-76913	-76913	-76080	0.0	1.67	N/A	1.53	(5.94)	133	397	6096		
6	5100	-76913	-76913	-76081	0.0	1.67	N/A	1.53	(5.94)	133	397	6096		
7														
8	( )	Compression												
9	(V)	Vector Collapse Safety Factor												

TRIAXIAL RESULTS (5 1/2" Production Tubing) - Overpull Force

	Depth (MD) (ft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	26	186425	186425	188362	0.0	2.19	N/A	N/A	2.48	101	13	13	N/A	N/A
2	5098	100034	100034	116626	0.0	3.58	N/A	N/A	4.60	110	2595	2595		
3	5099	100011	100011	116606	0.0	3.58	N/A	N/A	4.60	110	2596	2596		
4	5100	100000	100000	116597	0.0	3.59	N/A	N/A	4.60	110	2596	2596		
5														
6	(V)	Vector Collapse Safety Factor												

Well Schematic



General Data

Well Name :	Bluebonnet CCS 1 (Final)
Well Type	
Location :	Onshore
Deviation :	Deviated
Well TD :	9250.00 ft
Reference Point :	RKB
Elevation :	26.00 ft
Origin N:	0.00 ft
Origin E:	0.00 ft
Azimuth:	191.45 °

Comments :
Template to use when performing WT-Prod and WS-Tube calculations using the same well file.

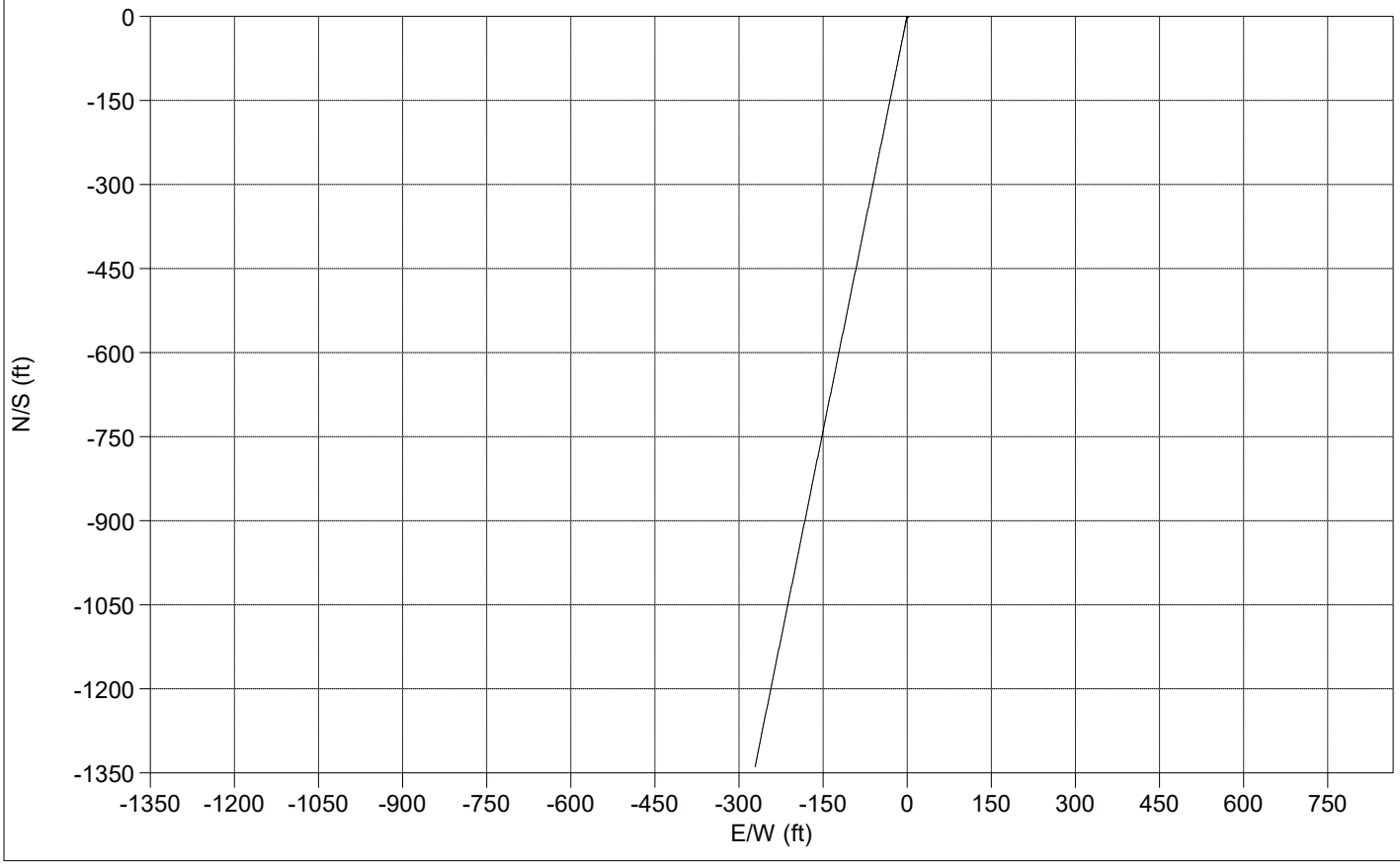
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	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
1	MD-INC-AZ	0.00	0.00	0.03	0.00			0.00	0.00
2	MD-INC-AZ	100.00	0.00	0.03	100.00	0.00	0.00	0.00	0.00
3	MD-INC-AZ	200.00	0.00	0.03	200.00	0.00	0.00	0.00	0.00
4	MD-INC-AZ	300.00	0.00	0.03	300.00	0.00	0.00	0.00	0.00
5	MD-INC-AZ	400.00	0.00	0.03	400.00	0.00	0.00	0.00	0.00
6	MD-INC-AZ	500.00	0.00	0.03	500.00	0.00	0.00	0.00	0.00
7	MD-INC-AZ	600.00	0.00	0.03	600.00	0.00	0.00	0.00	0.00
8	MD-INC-AZ	700.00	0.00	0.03	700.00	0.00	0.00	0.00	0.00
9	MD-INC-AZ	800.00	0.00	0.03	800.00	0.00	0.00	0.00	0.00
10	MD-INC-AZ	900.00	0.00	0.03	900.00	0.00	0.00	0.00	0.00
11	MD-INC-AZ	1000.00	0.00	0.03	1000.00	0.00	0.00	0.00	0.00
12	MD-INC-AZ	1100.00	0.00	0.03	1100.00	0.00	0.00	0.00	0.00
13	MD-INC-AZ	1200.00	0.00	0.03	1200.00	0.00	0.00	0.00	0.00
14	MD-INC-AZ	1300.00	0.00	0.03	1300.00	0.00	0.00	0.00	0.00
15	MD-INC-AZ	1400.00	0.00	0.03	1400.00	0.00	0.00	0.00	0.00
16	MD-INC-AZ	1500.00	0.00	0.03	1500.00	0.00	0.00	0.00	0.00
17	MD-INC-AZ	1600.00	0.00	0.03	1600.00	0.00	0.00	0.00	0.00
18	MD-INC-AZ	1700.00	0.00	0.03	1700.00	0.00	0.00	0.00	0.00
19	MD-INC-AZ	1800.00	0.00	0.03	1800.00	0.00	0.00	0.00	0.00
20	MD-INC-AZ	1900.00	0.00	0.03	1900.00	0.00	0.00	0.00	0.00
21	MD-INC-AZ	2000.00	0.00	0.03	2000.00	0.00	0.00	0.00	0.00
22	MD-INC-AZ	2100.00	0.00	0.03	2100.00	0.00	0.00	0.00	0.00
23	MD-INC-AZ	2200.00	0.00	0.03	2200.00	0.00	0.00	0.00	0.00
24	MD-INC-AZ	2300.00	0.00	0.03	2300.00	0.00	0.00	0.00	0.00
25	MD-INC-AZ	2400.00	0.00	0.03	2400.00	0.00	0.00	0.00	0.00
26	MD-INC-AZ	2500.00	0.00	0.03	2500.00	0.00	0.00	0.00	0.00
27	MD-INC-AZ	2600.00	0.00	0.03	2600.00	0.00	0.00	0.00	0.00
28	MD-INC-AZ	2700.00	0.00	0.03	2700.00	0.00	0.00	0.00	0.00
29	MD-INC-AZ	2800.00	0.00	0.03	2800.00	0.00	0.00	0.00	0.00
30	MD-INC-AZ	2900.00	0.00	0.03	2900.00	0.00	0.00	0.00	0.00
31	MD-INC-AZ	3000.00	0.00	0.03	3000.00	0.00	0.00	0.00	0.00
32	MD-INC-AZ	3100.00	0.00	0.03	3100.00	0.00	0.00	0.00	0.00
33	MD-INC-AZ	3200.00	0.00	0.03	3200.00	0.00	0.00	0.00	0.00
34	MD-INC-AZ	3300.00	0.00	0.03	3300.00	0.00	0.00	0.00	0.00
35	MD-INC-AZ	3400.00	0.00	0.03	3400.00	0.00	0.00	0.00	0.00
36	MD-INC-AZ	3500.00	0.00	0.03	3500.00	0.00	0.00	0.00	0.00
37	MD-INC-AZ	3600.00	0.00	0.03	3600.00	0.00	0.00	0.00	0.00
38	MD-INC-AZ	3700.00	0.00	0.03	3700.00	0.00	0.00	0.00	0.00
39	MD-INC-AZ	3800.00	0.00	0.03	3800.00	0.00	0.00	0.00	0.00
40	MD-INC-AZ	3900.00	0.00	0.03	3900.00	0.00	0.00	0.00	0.00
41	MD-INC-AZ	4000.00	0.00	0.03	4000.00	0.00	0.00	0.00	0.00
42	MD-INC-AZ	4100.00	1.50	191.45	4099.99	1.50	1.50	1.31	1.31
43	MD-INC-AZ	4200.00	3.00	191.45	4199.91	1.50	1.50	5.23	5.23
44	MD-INC-AZ	4300.00	4.50	191.45	4299.69	1.50	1.50	11.77	11.77
45	MD-INC-AZ	4400.00	6.00	191.45	4399.27	1.50	1.50	20.92	20.92
46	MD-INC-AZ	4500.00	7.50	191.45	4498.57	1.50	1.50	32.68	32.68
47	MD-INC-AZ	4600.00	9.00	191.45	4597.54	1.50	1.50	47.03	47.03
48	MD-INC-AZ	4700.00	10.50	191.45	4696.09	1.50	1.50	63.96	63.96
49	MD-INC-AZ	4800.00	12.00	191.45	4794.16	1.50	1.50	83.47	83.47
50	MD-INC-AZ	4900.00	13.50	191.45	4891.70	1.50	1.50	105.54	105.54
51	MD-INC-AZ	5000.00	15.00	191.45	4988.62	1.50	1.50	130.15	130.15
52	MD-INC-AZ	5100.00	16.50	191.45	5084.86	1.50	1.50	157.30	157.30
53	MD-INC-AZ	5129.57	16.94	191.45	5113.18	1.50	1.50	165.81	165.81
54	MD-INC-AZ	5200.00	16.94	191.45	5180.55	0.00	0.00	186.33	186.33
55	MD-INC-AZ	5300.00	16.94	191.45	5276.21	0.00	0.00	215.47	215.47
56	MD-INC-AZ	5400.00	16.94	191.45	5371.87	0.00	0.00	244.62	244.62
57	MD-INC-AZ	5500.00	16.94	191.45	5467.53	0.00	0.00	273.76	273.76
58	MD-INC-AZ	5600.00	16.94	191.45	5563.19	0.00	0.00	302.90	302.90
59	MD-INC-AZ	5700.00	16.94	191.45	5658.85	0.00	0.00	332.05	332.05
60	MD-INC-AZ	5800.00	16.94	191.45	5754.51	0.00	0.00	361.19	361.19
61	MD-INC-AZ	5900.00	16.94	191.45	5850.17	0.00	0.00	390.33	390.33
62	MD-INC-AZ	6000.00	16.94	191.45	5945.82	0.00	0.00	419.47	419.47
63	MD-INC-AZ	6100.00	16.94	191.45	6041.48	0.00	0.00	448.62	448.62
64	MD-INC-AZ	6200.00	16.94	191.45	6137.14	0.00	0.00	477.76	477.76
65	MD-INC-AZ	6300.00	16.94	191.45	6232.80	0.00	0.00	506.90	506.90
66	MD-INC-AZ	6400.00	16.94	191.45	6328.46	0.00	0.00	536.05	536.05
67	MD-INC-AZ	6500.00	16.94	191.45	6424.12	0.00	0.00	565.19	565.19
68	MD-INC-AZ	6600.00	16.94	191.45	6519.78	0.00	0.00	594.33	594.33
69	MD-INC-AZ	6700.00	16.94	191.45	6615.44	0.00	0.00	623.48	623.48
70	MD-INC-AZ	6800.00	16.94	191.45	6711.10	0.00	0.00	652.62	652.62

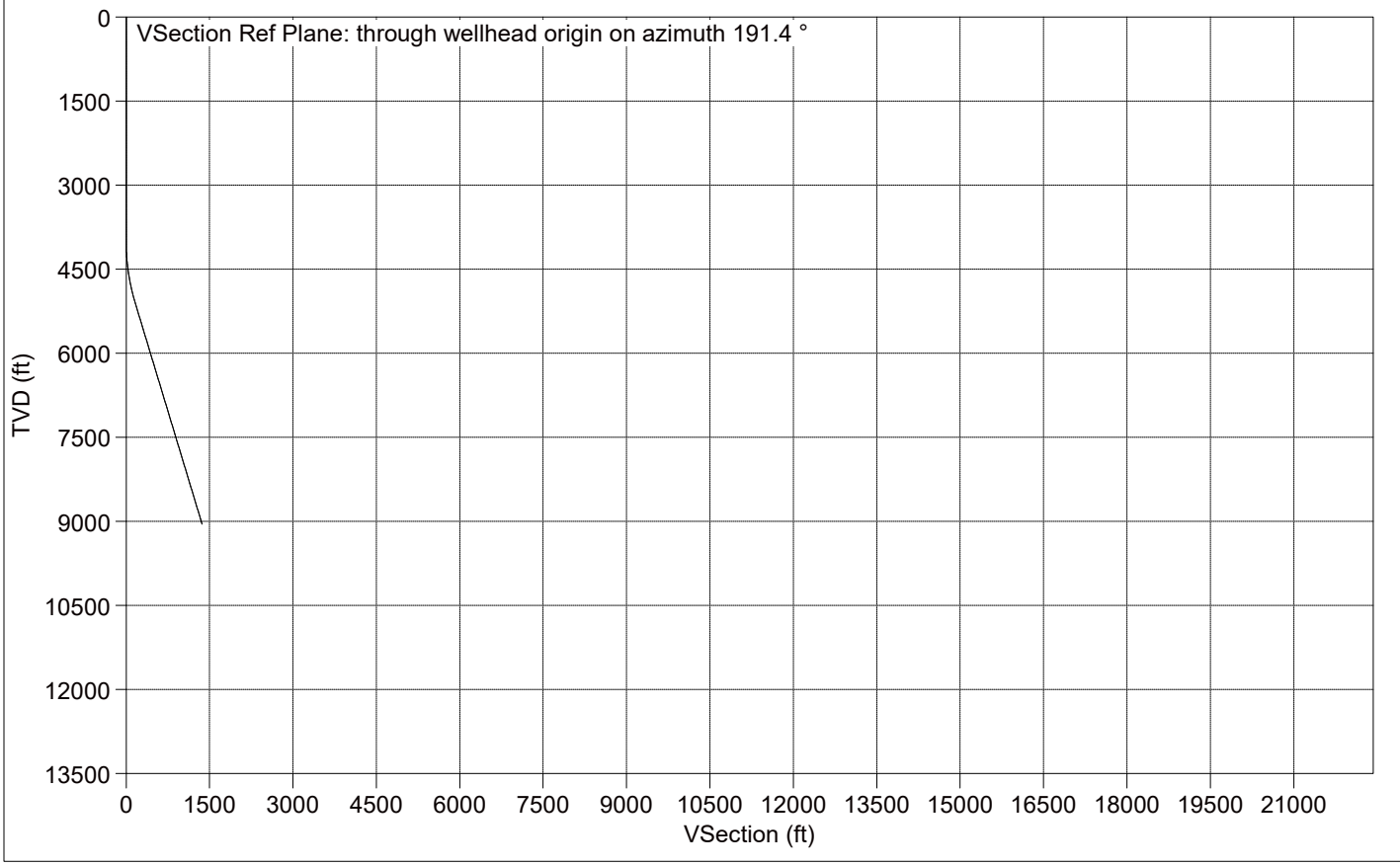
Wellpath Editor

	Data-Entry Mode	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	Max DLS (°/100ft)	Vsection (ft)	Departure (ft)
71	MD-INC-AZ	6900.00	16.94	191.45	6806.76	0.00	0.00	681.76	681.76
72	MD-INC-AZ	7000.00	16.94	191.45	6902.42	0.00	0.00	710.90	710.90
73	MD-INC-AZ	7100.00	16.94	191.45	6998.08	0.00	0.00	740.05	740.05
74	MD-INC-AZ	7200.00	16.94	191.45	7093.74	0.00	0.00	769.19	769.19
75	MD-INC-AZ	7300.00	16.94	191.45	7189.39	0.00	0.00	798.33	798.33
76	MD-INC-AZ	7400.00	16.94	191.45	7285.05	0.00	0.00	827.48	827.48
77	MD-INC-AZ	7500.00	16.94	191.45	7380.71	0.00	0.00	856.62	856.62
78	MD-INC-AZ	7600.00	16.94	191.45	7476.37	0.00	0.00	885.76	885.76
79	MD-INC-AZ	7700.00	16.94	191.45	7572.03	0.00	0.00	914.91	914.91
80	MD-INC-AZ	7800.00	16.94	191.45	7667.69	0.00	0.00	944.05	944.05
81	MD-INC-AZ	7900.00	16.94	191.45	7763.35	0.00	0.00	973.19	973.19
82	MD-INC-AZ	7966.54	16.94	191.45	7827.00	0.00	0.00	992.58	992.58
83	MD-INC-AZ	8000.00	16.94	191.45	7859.01	0.00	0.00	1002.33	1002.33
84	MD-INC-AZ	8100.00	16.94	191.45	7954.67	0.00	0.00	1031.48	1031.48
85	MD-INC-AZ	8200.00	16.94	191.45	8050.33	0.00	0.00	1060.62	1060.62
86	MD-INC-AZ	8300.00	16.94	191.45	8145.99	0.00	0.00	1089.76	1089.76
87	MD-INC-AZ	8400.00	16.94	191.45	8241.65	0.00	0.00	1118.91	1118.91
88	MD-INC-AZ	8500.00	16.94	191.45	8337.31	0.00	0.00	1148.05	1148.05
89	MD-INC-AZ	8600.00	16.94	191.45	8432.96	0.00	0.00	1177.19	1177.19
90	MD-INC-AZ	8700.00	16.94	191.45	8528.62	0.00	0.00	1206.34	1206.34
91	MD-INC-AZ	8800.00	16.94	191.45	8624.28	0.00	0.00	1235.48	1235.48
92	MD-INC-AZ	8900.00	16.94	191.45	8719.94	0.00	0.00	1264.62	1264.62
93	MD-INC-AZ	9000.00	16.94	191.45	8815.60	0.00	0.00	1293.76	1293.76
94	MD-INC-AZ	9100.00	16.94	191.45	8911.26	0.00	0.00	1322.91	1322.91
95	MD-INC-AZ	9200.00	16.94	191.45	9006.92	0.00	0.00	1352.05	1352.05
96	MD-INC-AZ	9250.00	16.94	191.45	9054.75	0.00	0.00	1366.62	1366.62

Plan View



Section View



Casing and Tubing Configuration

	Name	Type	OD (in)	MD (ft)			Hole Size (in)	Annulus Fluid
				Hanger	TOC	Base		
1	Surface	Casing	13 3/8	26.00	26.00	3400.00	17 1/2	Mud 10.00#
2	Production	Casing	9 5/8	26.00	26.00	9250.00	12 1/4	Mud 12.50#
3	Production	Tubing	5 1/2	26.00		7600.00		Brine 9.8

String Sections - 13 3/8" Surface Casing

	MD (ft)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (in)	Weight (ppf)	Grade	Pipe	Name	Grade	OD (in)	Material	Thickness
1	26.00	3400.00		13 3/8	61.000	K-55		BTC	K-55	14 3/8	None	0.000

String Sections - 9 5/8" Production Casing

	MD (ft)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (in)	Weight (ppf)	Grade	Pipe	Name	Grade	OD (in)	Material	Thickness
1	26.00	4100.00		9 5/8	53.500	L-80		Blue	L-80	10.626	None	0.000
2	4100.00	9250.00		9 5/8	53.500	L-80		Blue	L-80	10.626	None	0.000

String Sections - 5 1/2" Production Tubing

	MD (ft)		Pipe				Connection				Pipe Insulation	
	Top	Base	Type	OD (in)	Weight (ppf)	Grade	Pipe	Name	Grade	OD (in)	Material	Thickness
1	26.00	7600.00		5 1/2	20.000	L-80		Blue	L-80	6.102	None	0.000

Pore Pressure

	Vertical Depth (ft)	Pore Pressure/EMW		Permeable Zones
		(psi)	(ppg)	
1	26.00	0	8.33	NO
2	1470.00	636	8.33	NO
3	3144.00	1395	8.54	NO
4	3146.00	1391	8.51	NO
5	3521.00	1579	8.63	NO
6	4240.00	1912	8.68	NO
7	4337.00	1967	8.73	NO
8	4344.00	1979	8.77	NO
9	4643.00	2103	8.72	NO
10	5626.00	2598	8.89	NO
11	7666.00	3441	8.64	NO
12	8182.00	3660	8.61	NO
13	9260.00	4137	8.60	NO

Fracture Gradient

	Vertical Depth (ft)	Fracture Pressure/EMW	
		(psi)	(ppg)
1	26.00	0	9.00
2	3714.00	2855	14.80
3	5798.00	4458	14.80
4	7828.00	7157	17.60
5	7962.00	7280	17.60
6	8046.00	7315	17.50
7	9260.00	8418	17.50

Pore, Fracture & MW

	MD (ft)	Pore Pressure (ppg)	Equivalent Mud Weight (ppg)	Fracture Gradient (ppg)	Casing Scheme
1	26.00	8.33		9.00	
2	1470.00	8.33		14.74	
3	3144.00	8.54		14.79	
4	3146.00	8.51		14.79	
5	3400.00	8.59	10.00	14.80	13 3/8" (17 1/2")
6	3521.00	8.63		14.80	
7	3714.00	8.65		14.80	
8	4240.16	8.68		14.80	
9	4337.44	8.73		14.80	
10	4344.47	8.77		14.80	
11	4646.08	8.72		14.80	
12	5665.66	8.89		14.80	
13	5845.47	8.86		14.80	
14	7600.00	8.66	9.80	17.22	5 1/2" (7 7/8")
15	7798.23	8.64		17.43	
16	7967.58	8.63		17.60	
17	8107.66	8.62		17.60	
18	8195.48	8.62		17.50	
19	8337.65	8.61		17.50	
20	9250.00	8.60	12.50	17.50	9 5/8" (12 1/4")
21	9464.56	8.60		17.50	

Hole Profile - 13 3/8" Surface Casing

	MD(ft)		Hole Size (in)
	Top	Base	
1	26.00	3400.00	17 1/2

Hole Profile - 9 5/8" Production Casing

	MD(ft)		Hole Size (in)
	Top	Base	
1	3400.00	9250.00	12 1/4

Operations Data - CO2 Injection 40F Transient 2700 psi

Geometry
- Configuration : Production Tubing
- Use Drill String : No

5 1/2" Production Tubing
- Operation Type : Injection
- Primary Fluid : CO2 (EOS)
- Pressure : 2700 psi
  - Location : Wellhead
- Perforation Depth : 8180.00 ft
- Inlet Temperature : 40 °F
- Multi-Phase Correlation : Zhang Mechanistic
- Injection Rate :
  - Mass Rate: 5479.0000 Ton/day

Annulus
- Operation Type : Shut-In
- Pressure : 500 psi
  - Location : Wellhead
- Perforation Depth : 8180.00 ft

Transient Conditions
- Prior Operation : Undisturbed
- Duration
  - Time : 1.0 hr
- Model Permeable Layers : No

Operations Data - CO2 Injection 90F Transient 2700 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	2700 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	90 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Transient Conditions	
Prior Operation :	Undisturbed
Duration	
Time :	1.0 hr
Model Permeable Layers :	No

Operations Data - CO2 Injection 40F Steady 2700 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	2700 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	40 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Steady-State Conditions	
Model Permeable Layers :	No

Operations Data - CO2 Injection 90F Steady 2700 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	2700 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	90 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Steady-State Conditions	
Model Permeable Layers :	No

Operations Data - CO2 Injection 40F Transient 1900 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	1900 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	40 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Transient Conditions	
Prior Operation :	Undisturbed
Duration	
Time :	1.0 hr
Model Permeable Layers :	No

Operations Data - CO2 Injection 90F Transient 1900 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	1900 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	90 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Transient Conditions	
Prior Operation :	Undisturbed
Duration	
Time :	1.0 hr
Model Permeable Layers :	No

Operations Data - CO2 Injection 40F Steady 1900 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	1900 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	40 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Steady-State Conditions	
Model Permeable Layers :	No

Operations Data - CO2 Injection 90F Steady 1900 psi

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Injection
Primary Fluid	CO2 (EOS)
Pressure :	1900 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Inlet Temperature :	90 °F
Multi-Phase Correlation :	Zhang Mechanistic
Injection Rate :	
Mass Rate:	5479.0000 Ton/day
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Steady-State Conditions	
Model Permeable Layers :	No

Operations Data - CO2 Shut in

Geometry	
Configuration :	Production Tubing
Use Drill String :	No
5 1/2" Production Tubing	
Operation Type	Shut-In
Pressure :	200 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Annulus	
Operation Type	Shut-In
Pressure :	500 psi
Location :	Wellhead
Perforation Depth :	8180.00 ft
Transient Conditions	
Prior Operation :	CO2 Injection 40F Steady 2700 psi
Duration	
Time :	1.0 hr

Fluid Temperature - Tubing/Workstring

	MD (ft)	Temperatures (°F)									
		CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Shut	Undisturb
1	26.00	40	90	40	90	40	90	40	90	41	78
2	36.00	40	90	40	90	40	90	40	90	41	78
3	46.00	40	90	40	90	40	90	40	90	41	78
4	58.75	40	90	40	90	40	90	40	90	41	78
5	71.50	40	90	40	90	40	90	40	90	41	78
6	97.00	40	90	40	90	40	90	40	90	41	79
7	148.00	40	90	40	90	40	90	40	90	41	79
8	250.00	41	90	40	90	41	90	40	91	41	80
9	375.00	41	90	40	91	41	91	40	91	41	82
10	500.00	41	90	40	91	41	91	40	91	41	83
11	625.00	42	91	40	91	42	91	41	91	41	84
12	750.00	42	91	40	91	42	91	41	92	41	86
13	875.00	42	91	40	91	43	92	41	92	41	87
14	1000.00	43	91	40	91	43	92	41	92	41	88
15	1125.00	43	91	41	92	44	92	41	93	41	90
16	1250.00	44	91	41	92	44	93	41	93	42	91
17	1375.00	44	91	41	92	44	93	41	93	42	92
18	1500.00	45	92	41	92	45	93	41	93	42	94
19	1625.00	45	92	41	92	46	93	41	94	42	95
20	1750.00	46	92	41	92	46	94	41	94	42	97
21	1875.00	46	92	41	92	47	94	42	94	42	98
22	2000.00	47	92	41	93	47	94	42	94	42	99
23	2125.00	48	92	41	93	48	94	42	95	42	101
24	2250.00	48	93	41	93	49	95	42	95	42	102
25	2375.00	49	93	41	93	49	95	42	95	42	103
26	2500.00	50	93	41	93	50	95	42	95	42	105
27	2625.00	50	93	41	93	51	95	42	96	42	106
28	2750.00	51	93	41	93	51	96	42	96	42	107
29	2875.00	52	94	41	94	52	96	42	96	42	109
30	3000.00	53	94	41	94	53	96	42	96	42	110
31	3125.00	53	94	41	94	54	97	42	97	43	111
32	3250.00	54	94	41	94	55	97	42	97	43	113
33	3315.00	55	94	41	94	55	97	42	97	43	113
34	3347.50	55	95	41	94	55	97	42	97	43	114
35	3380.00	55	95	41	94	55	97	42	97	43	114
36	3400.00	55	95	41	94	56	97	43	97	43	114
37	3420.00	55	95	41	94	56	97	43	97	43	114
38	3460.00	56	95	41	94	56	97	43	97	43	115
39	3500.00	56	95	41	94	56	98	43	97	43	115
40	3562.50	57	95	41	94	57	98	43	97	43	116
41	3625.00	57	95	41	94	58	98	43	97	43	117
42	3750.00	58	96	41	94	58	98	43	98	43	118
43	3875.00	59	96	42	95	59	99	43	98	43	119
44	4000.00	60	96	42	95	60	99	43	98	43	121
45	4040.00	60	96	42	95	61	99	43	98	43	121
46	4080.00	61	96	42	95	61	99	43	98	43	122
47	4100.00	61	96	42	95	61	99	43	98	43	122
48	4120.00	61	96	42	95	61	99	43	98	43	122
49	4152.50	61	96	42	95	62	99	43	98	43	122
50	4185.00	62	97	42	95	62	99	43	98	43	123
51	4250.00	63	97	42	95	63	100	43	98	43	123
52	4375.00	64	97	42	95	64	100	43	99	43	125
53	4500.00	65	98	42	95	65	100	43	99	43	126
54	4625.00	66	98	42	95	66	101	43	99	43	127
55	4750.00	67	98	42	95	67	101	43	99	43	129
56	4875.00	68	99	42	95	68	102	43	99	43	130
57	5000.00	69	99	42	96	69	102	43	100	43	131
58	5125.00	71	100	42	96	71	103	43	100	43	133
59	5250.00	72	100	42	96	72	103	44	100	44	134
60	5375.00	73	101	42	96	73	104	44	100	44	135
61	5500.00	74	101	42	96	74	104	44	100	44	136
62	5625.00	76	102	42	96	75	105	44	100	44	138
63	5750.00	77	102	42	96	77	105	44	101	44	139
64	5875.00	78	103	42	96	78	106	44	101	44	140
65	6000.00	80	103	42	96	79	106	44	101	44	142
66	6125.00	81	104	42	96	81	107	44	101	44	143
67	6250.00	82	105	42	96	82	107	44	101	44	144
68	6375.00	84	105	42	97	83	108	44	101	44	145
69	6500.00	85	106	42	97	85	109	44	101	44	147
70	6625.00	86	107	42	97	86	109	44	102	44	148

Fluid Temperature - Tubing/Workstring

	MD (ft)	Temperatures (°F)									
		CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Shut	Undisturb
71	6750.00	87	107	42	97	87	110	44	102	44	149
72	6875.00	89	108	42	97	88	111	44	102	44	151
73	7000.00	90	109	42	97	90	111	44	102	44	152
74	7125.00	91	110	42	97	91	112	44	102	44	153
75	7250.00	93	110	42	97	92	113	44	102	44	154
76	7375.00	94	111	42	97	94	113	45	102	44	156
77	7500.00	95	112	42	97	95	114	45	103	44	157
78	7540.00	96	112	42	97	95	114	45	103	44	157
79	7580.00	96	112	42	97	96	115	45	103	44	158
80	7600.00	96	112	42	97	96	115	45	103	44	158
81	7620.00	97	113	42	97	96	115	45	103	43	158
82	7652.50	97	113	42	97	97	115	45	103	43	159
83	7685.00	98	113	42	97	97	115	45	103	43	159
84	7750.00	99	114	43	97	98	116	45	103	43	160
85	7875.00	100	115	43	98	99	117	45	103	43	161
86	8000.00	101	115	43	98	101	117	45	103	43	162
87	8090.00	103	116	43	98	102	118	45	103	43	163
88	8180.00	104	117	43	98	103	119	45	103	43	164

Fluid Temperature - Annulus

	MD (ft)	Temperatures (°F)									
		CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Shut	Undisturb
1	26.00	48	87	42	89	48	87	42	89	45	78
2	36.00	48	87	42	89	48	87	42	89	43	78
3	46.00	48	87	42	90	48	87	42	90	43	78
4	58.75	48	87	42	90	48	87	42	90	43	78
5	71.50	48	87	42	90	48	87	42	90	43	78
6	97.00	48	87	42	90	48	87	42	90	43	79
7	148.00	49	87	42	90	49	88	42	90	43	79
8	250.00	49	88	42	90	49	88	42	90	43	80
9	375.00	50	88	42	90	50	88	42	91	43	82
10	500.00	51	88	42	90	51	89	42	91	43	83
11	625.00	51	89	42	91	51	89	42	91	43	84
12	750.00	52	89	42	91	52	90	42	92	44	86
13	875.00	53	90	42	91	53	90	43	92	44	87
14	1000.00	53	90	42	91	53	91	43	92	44	88
15	1125.00	54	90	42	91	54	91	43	92	44	90
16	1250.00	55	91	43	92	55	92	43	93	44	91
17	1375.00	56	92	43	92	56	92	43	93	44	92
18	1500.00	56	92	43	92	56	93	43	93	44	94
19	1625.00	57	93	43	92	57	94	43	94	45	95
20	1750.00	58	93	43	92	58	94	43	94	45	97
21	1875.00	59	93	43	93	59	95	44	94	45	98
22	2000.00	60	94	43	93	60	95	44	95	45	99
23	2125.00	61	94	43	93	61	96	44	95	45	101
24	2250.00	62	95	43	93	62	96	44	95	45	102
25	2375.00	63	95	43	93	63	97	44	96	45	103
26	2500.00	64	96	43	94	64	97	44	96	45	105
27	2625.00	65	96	43	94	65	98	44	96	46	106
28	2750.00	66	97	44	94	66	98	44	96	46	107
29	2875.00	67	97	44	94	67	99	45	97	46	109
30	3000.00	68	97	44	94	68	99	45	97	46	110
31	3125.00	69	98	44	94	69	100	45	97	46	111
32	3250.00	70	98	44	95	70	100	45	97	46	113
33	3315.00	70	99	44	95	70	101	45	97	46	113
34	3347.50	71	99	44	95	70	101	45	98	46	114
35	3380.00	71	99	44	95	71	101	45	98	46	114
36	3400.00	71	99	44	95	71	101	45	98	46	114
37	3420.00	71	99	44	95	71	101	45	98	46	114
38	3460.00	72	99	44	95	72	101	45	98	46	115
39	3500.00	72	100	44	95	72	101	45	98	46	115
40	3562.50	73	100	44	95	72	102	45	98	47	116
41	3625.00	73	100	44	95	73	102	45	98	47	117
42	3750.00	75	101	44	95	74	103	45	98	47	118
43	3875.00	76	101	44	95	75	103	45	99	47	119
44	4000.00	77	102	44	96	76	104	46	99	47	121
45	4040.00	77	102	44	96	77	104	46	99	47	121
46	4080.00	78	102	44	96	77	104	46	99	47	122
47	4100.00	78	102	44	96	78	104	46	99	47	122
48	4120.00	78	102	44	96	78	104	46	99	47	122
49	4152.50	78	102	44	96	78	105	46	99	47	122
50	4185.00	79	103	44	96	78	105	46	99	47	123
51	4250.00	80	103	44	96	79	105	46	99	47	123
52	4375.00	81	104	45	96	80	106	46	100	47	125
53	4500.00	82	104	45	96	82	106	46	100	47	126
54	4625.00	83	105	45	96	83	107	46	100	48	127
55	4750.00	85	106	45	96	84	108	46	100	48	129
56	4875.00	86	106	45	97	85	108	46	100	48	130
57	5000.00	87	107	45	97	87	109	46	101	48	131
58	5125.00	89	108	45	97	88	110	46	101	48	133
59	5250.00	90	108	45	97	89	110	47	101	48	134
60	5375.00	91	109	45	97	91	111	47	101	48	135
61	5500.00	93	110	45	97	92	112	47	101	48	136
62	5625.00	94	111	45	97	93	113	47	102	48	138
63	5750.00	95	111	45	97	95	113	47	102	49	139
64	5875.00	97	112	45	98	96	114	47	102	49	140
65	6000.00	98	113	45	98	97	115	47	102	49	142
66	6125.00	99	114	45	98	98	116	47	102	49	143
67	6250.00	101	115	45	98	100	116	47	102	49	144
68	6375.00	102	116	46	98	101	117	47	103	49	145
69	6500.00	103	117	46	98	102	118	47	103	49	147
70	6625.00	105	117	46	98	104	119	48	103	49	148

Fluid Temperature - Annulus

	MD (ft)	Temperatures (°F)									
		CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Shut	Undisturb
71	6750.00	106	118	46	98	105	120	48	103	49	149
72	6875.00	107	119	46	98	106	121	48	103	49	151
73	7000.00	109	120	46	99	108	122	48	104	50	152
74	7125.00	110	121	46	99	109	123	48	104	50	153
75	7250.00	111	122	46	99	111	124	48	104	50	154
76	7375.00	113	123	46	99	112	124	48	104	50	156
77	7500.00	114	124	46	99	113	125	48	104	50	157
78	7540.00	114	124	46	99	114	126	48	104	50	157
79	7580.00	115	125	46	99	114	126	48	104	50	158
80	7600.00	115	125	46	99	114	126	48	104	50	158
81	7620.00	100	115	43	98	100	117	45	103	49	158
82	7652.50	101	115	43	98	100	117	45	103	49	159
83	7685.00	101	115	43	98	100	117	45	103	49	159
84	7750.00	102	116	43	98	101	118	45	103	49	160
85	7875.00	104	117	43	98	103	119	45	103	49	161
86	8000.00	105	118	43	98	104	119	45	103	49	162
87	8090.00	106	118	43	98	105	120	45	104	50	163
88	8180.00	107	119	43	98	106	121	45	104	50	164
89	8250.00	165	165	163	164	165	165	163	164	163	165
90	8500.00	167	167	167	167	167	167	167	167	167	167
91	8750.00	170	170	170	170	170	170	170	170	170	170
92	9000.00	172	172	172	172	172	172	172	172	172	172
93	9230.00	175	175	175	175	175	175	175	175	175	175
94	9250.00	175	175	175	175	175	175	175	175	175	175

Fluid Pressure - Tubing/Workstring

	MD (ft)	Pressures (psi)								
		CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Shut i
1	26.00	2700	2700	2700	2700	1900	1900	1900	1900	200
2	36.00	2704	2703	2704	2703	1903	1903	1903	1903	204
3	46.00	2707	2706	2707	2706	1907	1905	1907	1905	209
4	58.75	2712	2710	2712	2710	1911	1909	1911	1909	215
5	71.50	2716	2713	2716	2713	1916	1912	1916	1912	220
6	97.00	2726	2721	2726	2721	1925	1919	1925	1919	232
7	148.00	2744	2736	2744	2736	1942	1932	1942	1932	255
8	250.00	2780	2766	2781	2766	1977	1959	1977	1959	300
9	375.00	2825	2803	2826	2803	2021	1992	2021	1992	357
10	500.00	2870	2840	2871	2840	2064	2025	2064	2025	413
11	625.00	2915	2877	2916	2877	2107	2058	2108	2058	469
12	750.00	2960	2914	2961	2914	2150	2091	2151	2091	525
13	875.00	3005	2951	3006	2951	2194	2125	2195	2125	581
14	1000.00	3050	2989	3052	2988	2237	2159	2238	2158	637
15	1125.00	3096	3026	3097	3026	2280	2192	2282	2192	693
16	1250.00	3141	3064	3142	3063	2324	2226	2326	2226	749
17	1375.00	3186	3102	3188	3101	2367	2260	2370	2260	806
18	1500.00	3231	3139	3234	3139	2411	2294	2414	2294	862
19	1625.00	3276	3177	3279	3177	2454	2329	2458	2328	918
20	1750.00	3321	3215	3325	3215	2498	2363	2502	2362	974
21	1875.00	3366	3253	3371	3253	2541	2397	2546	2396	1030
22	2000.00	3412	3291	3417	3291	2585	2432	2591	2431	1087
23	2125.00	3457	3330	3463	3329	2628	2467	2635	2465	1143
24	2250.00	3502	3368	3509	3367	2672	2501	2679	2500	1199
25	2375.00	3547	3407	3555	3406	2715	2536	2724	2535	1255
26	2500.00	3592	3445	3601	3444	2759	2571	2768	2570	1311
27	2625.00	3637	3484	3647	3483	2802	2606	2813	2605	1368
28	2750.00	3683	3522	3694	3521	2846	2642	2858	2640	1424
29	2875.00	3728	3561	3740	3560	2889	2677	2903	2675	1480
30	3000.00	3773	3600	3787	3599	2933	2712	2948	2711	1536
31	3125.00	3818	3639	3833	3638	2976	2748	2993	2746	1593
32	3250.00	3863	3678	3880	3677	3019	2783	3038	2782	1649
33	3315.00	3886	3698	3904	3697	3042	2802	3061	2800	1678
34	3347.50	3898	3708	3916	3707	3053	2811	3073	2810	1693
35	3380.00	3910	3718	3928	3717	3065	2820	3085	2819	1708
36	3400.00	3917	3725	3936	3724	3071	2826	3092	2825	1717
37	3420.00	3924	3731	3943	3730	3078	2832	3099	2830	1726
38	3460.00	3938	3743	3958	3743	3092	2843	3114	2842	1744
39	3500.00	3953	3756	3973	3755	3106	2855	3128	2853	1762
40	3562.50	3975	3776	3997	3775	3128	2873	3151	2871	1790
41	3625.00	3998	3795	4020	3794	3149	2891	3173	2889	1818
42	3750.00	4043	3834	4067	3834	3193	2927	3219	2925	1874
43	3875.00	4087	3874	4114	3873	3236	2963	3264	2961	1931
44	4000.00	4132	3913	4161	3913	3279	2999	3310	2997	1987
45	4040.00	4146	3926	4176	3925	3293	3010	3324	3009	2005
46	4080.00	4161	3938	4191	3938	3306	3022	3339	3021	2023
47	4100.00	4168	3944	4199	3944	3313	3027	3346	3026	2032
48	4120.00	4175	3951	4206	3951	3320	3033	3354	3032	2041
49	4152.50	4187	3961	4218	3961	3331	3043	3365	3042	2056
50	4185.00	4198	3971	4231	3971	3343	3052	3377	3051	2070
51	4250.00	4221	3992	4255	3992	3365	3071	3401	3070	2100
52	4375.00	4266	4031	4302	4032	3408	3107	3446	3106	2156
53	4500.00	4310	4070	4349	4071	3450	3143	3492	3143	2212
54	4625.00	4353	4109	4395	4110	3492	3179	3537	3179	2268
55	4750.00	4397	4148	4442	4149	3534	3214	3582	3214	2323
56	4875.00	4440	4186	4488	4188	3575	3249	3626	3250	2378
57	5000.00	4482	4224	4533	4227	3616	3284	3670	3285	2433
58	5125.00	4524	4262	4578	4265	3656	3319	3714	3320	2487
59	5250.00	4566	4299	4624	4303	3696	3353	3758	3355	2542
60	5375.00	4607	4337	4669	4341	3736	3388	3802	3391	2596
61	5500.00	4649	4375	4714	4379	3776	3423	3845	3426	2650
62	5625.00	4690	4412	4759	4418	3816	3457	3889	3461	2704
63	5750.00	4732	4450	4805	4456	3856	3492	3933	3496	2758
64	5875.00	4773	4487	4850	4495	3896	3527	3977	3532	2812
65	6000.00	4814	4525	4896	4533	3935	3561	4022	3567	2866
66	6125.00	4855	4563	4941	4572	3975	3596	4066	3603	2920
67	6250.00	4896	4601	4987	4611	4014	3631	4110	3639	2974
68	6375.00	4937	4638	5032	4649	4054	3666	4154	3675	3028
69	6500.00	4978	4676	5078	4688	4093	3701	4198	3710	3082
70	6625.00	5019	4714	5124	4727	4133	3735	4243	3746	3136

Fluid Pressure - Tubing/Workstring

	MD (ft)	Pressures (psi)								
		CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Shut i
71	6750.00	5060	4751	5170	4766	4171	3770	4287	3782	3190
72	6875.00	5100	4789	5215	4805	4210	3805	4332	3818	3244
73	7000.00	5141	4827	5261	4844	4249	3840	4376	3855	3298
74	7125.00	5181	4864	5307	4883	4288	3875	4421	3891	3352
75	7250.00	5222	4902	5353	4923	4327	3909	4466	3927	3406
76	7375.00	5262	4940	5399	4962	4365	3944	4510	3964	3461
77	7500.00	5303	4977	5445	5001	4404	3979	4555	4000	3515
78	7540.00	5315	4989	5460	5014	4416	3990	4569	4012	3532
79	7580.00	5328	5001	5475	5026	4429	4001	4584	4023	3549
80	7600.00	5335	5007	5482	5033	4435	4007	4591	4029	3558
81	7620.00	5343	5015	5491	5040	4442	4014	4599	4037	3567
82	7652.50	5355	5027	5505	5053	4455	4026	4613	4049	3581
83	7685.00	5368	5039	5519	5066	4467	4037	4627	4061	3595
84	7750.00	5394	5064	5548	5091	4492	4061	4655	4085	3623
85	7875.00	5443	5110	5602	5140	4540	4105	4708	4131	3677
86	8000.00	5491	5157	5656	5188	4587	4150	4761	4177	3731
87	8090.00	5527	5191	5696	5223	4621	4182	4800	4211	3770
88	8180.00	5562	5225	5735	5259	4655	4214	4838	4244	3809

Fluid Pressure - Annulus

	MD (ft)	Pressures (psi)								
		CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Shut i
1	26.00	500	500	500	500	500	500	500	500	500
2	36.00	505	505	505	505	505	505	505	505	505
3	46.00	510	510	510	510	510	510	510	510	510
4	58.75	517	517	517	517	517	517	517	517	517
5	71.50	524	523	524	523	524	523	524	523	524
6	97.00	537	536	537	536	537	536	537	536	537
7	148.00	563	563	563	563	563	563	563	563	563
8	250.00	616	615	616	615	616	615	616	615	616
9	375.00	681	679	681	679	681	679	681	679	681
10	500.00	745	743	745	743	745	743	745	743	745
11	625.00	810	808	810	808	810	808	810	807	810
12	750.00	875	872	875	872	875	872	875	872	875
13	875.00	939	936	940	936	939	936	940	936	940
14	1000.00	1004	1000	1004	1000	1004	1000	1004	1000	1004
15	1125.00	1069	1064	1069	1064	1069	1064	1069	1064	1069
16	1250.00	1133	1129	1134	1128	1133	1129	1134	1128	1134
17	1375.00	1198	1193	1199	1193	1198	1193	1199	1193	1199
18	1500.00	1263	1257	1264	1257	1263	1257	1264	1257	1263
19	1625.00	1327	1321	1328	1321	1327	1321	1328	1321	1328
20	1750.00	1392	1386	1393	1385	1392	1385	1393	1385	1393
21	1875.00	1457	1450	1458	1450	1457	1450	1458	1449	1458
22	2000.00	1521	1514	1523	1514	1521	1514	1523	1514	1523
23	2125.00	1586	1578	1588	1578	1586	1578	1588	1578	1587
24	2250.00	1651	1643	1653	1642	1651	1642	1653	1642	1652
25	2375.00	1715	1707	1718	1707	1715	1707	1717	1706	1717
26	2500.00	1780	1771	1782	1771	1780	1771	1782	1771	1782
27	2625.00	1845	1835	1847	1835	1845	1835	1847	1835	1847
28	2750.00	1909	1899	1912	1899	1909	1899	1912	1899	1912
29	2875.00	1974	1964	1977	1964	1974	1963	1977	1963	1977
30	3000.00	2039	2028	2042	2028	2039	2028	2042	2027	2041
31	3125.00	2103	2092	2107	2092	2103	2092	2107	2092	2106
32	3250.00	2168	2156	2172	2157	2168	2156	2172	2156	2171
33	3315.00	2202	2190	2206	2190	2202	2189	2205	2189	2205
34	3347.50	2218	2207	2222	2207	2218	2206	2222	2206	2222
35	3380.00	2235	2223	2239	2223	2235	2223	2239	2223	2239
36	3400.00	2246	2234	2250	2234	2246	2233	2250	2233	2249
37	3420.00	2256	2244	2260	2244	2256	2243	2260	2243	2260
38	3460.00	2277	2264	2281	2265	2277	2264	2281	2264	2280
39	3500.00	2297	2285	2302	2285	2297	2284	2302	2285	2301
40	3562.50	2330	2317	2334	2317	2330	2317	2334	2317	2334
41	3625.00	2362	2349	2367	2349	2362	2349	2366	2349	2366
42	3750.00	2426	2413	2432	2414	2426	2413	2431	2413	2431
43	3875.00	2491	2478	2497	2478	2491	2477	2496	2477	2496
44	4000.00	2556	2542	2562	2542	2556	2541	2561	2542	2561
45	4040.00	2576	2562	2582	2563	2576	2562	2582	2562	2582
46	4080.00	2597	2583	2603	2584	2597	2582	2603	2583	2602
47	4100.00	2607	2593	2614	2594	2607	2593	2613	2593	2613
48	4120.00	2618	2604	2624	2604	2618	2603	2624	2603	2623
49	4152.50	2635	2620	2641	2621	2635	2620	2641	2620	2640
50	4185.00	2651	2637	2658	2638	2651	2636	2658	2637	2657
51	4250.00	2685	2670	2692	2671	2685	2670	2691	2670	2691
52	4375.00	2749	2734	2756	2735	2749	2734	2756	2734	2756
53	4500.00	2813	2798	2821	2799	2813	2798	2821	2798	2820
54	4625.00	2877	2862	2885	2863	2877	2861	2885	2862	2884
55	4750.00	2941	2925	2949	2926	2941	2924	2949	2925	2948
56	4875.00	3004	2988	3013	2989	3004	2987	3012	2988	3012
57	5000.00	3066	3050	3076	3052	3067	3049	3076	3050	3075
58	5125.00	3129	3112	3138	3113	3129	3111	3138	3112	3137
59	5250.00	3190	3173	3201	3175	3190	3172	3200	3174	3200
60	5375.00	3252	3235	3263	3237	3252	3234	3263	3235	3262
61	5500.00	3314	3296	3325	3298	3314	3295	3325	3297	3324
62	5625.00	3375	3358	3387	3360	3375	3357	3387	3358	3387
63	5750.00	3437	3419	3450	3422	3437	3418	3449	3420	3449
64	5875.00	3499	3481	3512	3483	3499	3480	3512	3482	3511
65	6000.00	3560	3542	3574	3545	3560	3541	3574	3543	3573
66	6125.00	3622	3603	3637	3607	3622	3602	3636	3605	3636
67	6250.00	3684	3665	3699	3668	3684	3664	3698	3666	3698
68	6375.00	3745	3726	3761	3730	3745	3725	3761	3728	3760
69	6500.00	3807	3788	3824	3791	3807	3787	3823	3790	3822
70	6625.00	3868	3849	3886	3853	3869	3848	3885	3851	3885

Fluid Pressure - Annulus

	MD (ft)	Pressures (psi)								
		CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Injection 40F	CO2 Injection 90F	CO2 Injection 40	CO2 Injection 90	CO2 Shut i
71	6750.00	3930	3910	3948	3915	3930	3909	3948	3913	3947
72	6875.00	3992	3972	4011	3976	3992	3971	4010	3974	4009
73	7000.00	4053	4033	4073	4038	4053	4032	4072	4036	4072
74	7125.00	4115	4095	4135	4100	4115	4093	4135	4098	4134
75	7250.00	4176	4156	4198	4162	4177	4155	4197	4159	4196
76	7375.00	4238	4217	4260	4223	4238	4216	4259	4221	4259
77	7500.00	4299	4279	4322	4285	4300	4277	4322	4283	4321
78	7540.00	4319	4298	4342	4305	4319	4297	4342	4302	4341
79	7580.00	4339	4318	4362	4325	4339	4317	4362	4322	4361
80	7600.00	4349	4328	4372	4334	4349	4326	4372	4332	4371
81	7620.00									4381
82	7750.00									4446
83	8000.00									4570
84	8180.00									4660

Wellbore Temperature - Tubing

	MD (ft)	Temperatures (°F)									
		CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Shut	Undisturb
1	26.00	42	90	40	90	42	90	40	90	44	78
2	36.00	42	90	40	90	42	90	40	90	43	78
3	46.00	42	90	40	90	42	90	40	90	43	78
4	58.75	42	90	40	90	42	90	40	90	43	78
5	71.50	42	90	40	90	42	90	40	90	43	78
6	97.00	42	90	40	90	42	90	40	90	43	79
7	148.00	42	90	40	90	42	90	40	90	43	79
8	250.00	42	90	40	90	42	90	40	91	43	80
9	375.00	43	90	40	90	43	90	40	91	43	82
10	500.00	43	90	40	91	43	91	41	91	43	83
11	625.00	44	90	40	91	44	91	41	91	43	84
12	750.00	44	90	41	91	44	91	41	92	43	86
13	875.00	45	91	41	91	45	92	41	92	43	87
14	1000.00	45	91	41	91	45	92	41	92	44	88
15	1125.00	46	91	41	92	46	92	41	93	44	90
16	1250.00	46	91	41	92	46	92	41	93	44	91
17	1375.00	47	91	41	92	47	93	41	93	44	92
18	1500.00	47	92	41	92	48	93	41	93	44	94
19	1625.00	48	92	41	92	48	93	42	94	44	95
20	1750.00	49	92	41	92	49	94	42	94	44	97
21	1875.00	49	92	41	92	50	94	42	94	44	98
22	2000.00	50	92	41	93	50	94	42	94	45	99
23	2125.00	51	93	41	93	51	95	42	95	45	101
24	2250.00	51	93	41	93	52	95	42	95	45	102
25	2375.00	52	93	41	93	52	95	42	95	45	103
26	2500.00	53	93	41	93	53	96	42	95	45	105
27	2625.00	54	94	41	93	54	96	42	96	45	106
28	2750.00	55	94	41	93	55	96	42	96	45	107
29	2875.00	56	94	41	94	56	97	42	96	45	109
30	3000.00	57	95	42	94	57	97	43	96	45	110
31	3125.00	57	95	42	94	58	97	43	97	46	111
32	3250.00	58	95	42	94	58	98	43	97	46	113
33	3315.00	59	95	42	94	59	98	43	97	46	113
34	3347.50	59	95	42	94	59	98	43	97	46	114
35	3380.00	59	96	42	94	59	98	43	97	46	114
36	3400.00	60	96	42	94	60	98	43	97	46	114
37	3420.00	60	96	42	94	60	98	43	97	46	114
38	3460.00	60	96	42	94	60	98	43	97	46	115
39	3500.00	60	96	42	94	61	98	43	97	46	115
40	3562.50	61	96	42	94	61	99	43	97	46	116
41	3625.00	62	96	42	94	62	99	43	98	46	117
42	3750.00	63	97	42	95	63	99	43	98	46	118
43	3875.00	64	97	42	95	64	100	43	98	46	119
44	4000.00	65	97	42	95	65	100	43	98	46	121
45	4040.00	65	98	42	95	65	100	43	98	46	121
46	4080.00	65	98	42	95	65	100	43	98	46	122
47	4100.00	66	98	42	95	66	100	43	98	46	122
48	4120.00	66	98	42	95	66	100	43	98	46	122
49	4152.50	66	98	42	95	66	101	43	98	47	122
50	4185.00	67	98	42	95	66	101	43	98	47	123
51	4250.00	67	98	42	95	67	101	43	99	47	123
52	4375.00	69	99	42	95	68	101	43	99	47	125
53	4500.00	70	99	42	95	69	102	43	99	47	126
54	4625.00	71	100	42	95	71	102	44	99	47	127
55	4750.00	72	100	42	95	72	103	44	99	47	129
56	4875.00	73	101	42	96	73	103	44	99	47	130
57	5000.00	75	101	42	96	74	104	44	100	47	131
58	5125.00	76	102	42	96	76	104	44	100	47	133
59	5250.00	77	102	42	96	77	105	44	100	47	134
60	5375.00	79	103	42	96	78	105	44	100	48	135
61	5500.00	80	103	42	96	79	106	44	100	48	136
62	5625.00	81	104	42	96	81	107	44	101	48	138
63	5750.00	83	105	42	96	82	107	44	101	48	139
64	5875.00	84	105	42	96	83	108	44	101	48	140
65	6000.00	85	106	43	96	85	109	44	101	48	142
66	6125.00	87	107	43	97	86	109	44	101	48	143
67	6250.00	88	107	43	97	87	110	44	101	48	144
68	6375.00	89	108	43	97	89	111	45	101	48	145
69	6500.00	91	109	43	97	90	111	45	102	48	147
70	6625.00	92	110	43	97	91	112	45	102	49	148

Wellbore Temperature - Tubing

	MD (ft)	Temperatures (°F)									
		CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Injection 40	CO2 Injection 90	CO2 Injection 4	CO2 Injection 9	CO2 Shut	Undisturb
71	6750.00	93	110	43	97	93	113	45	102	49	149
72	6875.00	95	111	43	97	94	113	45	102	49	151
73	7000.00	96	112	43	97	95	114	45	102	49	152
74	7125.00	97	113	43	97	97	115	45	102	49	153
75	7250.00	99	114	43	97	98	116	45	103	49	154
76	7375.00	100	115	43	97	99	117	45	103	49	156
77	7500.00	101	115	43	98	100	117	45	103	49	157
78	7540.00	102	116	43	98	101	118	45	103	49	157
79	7580.00	102	116	43	98	101	118	45	103	49	158
80	7600.00	103	116	43	98	102	118	45	103	49	158
81	7620.00										158
82	7652.50										159
83	7685.00										159
84	7750.00										160
85	7875.00										161
86	8000.00										162
87	8090.00										163
88	8180.00										164
89	8250.00										165
90	8500.00										167
91	8750.00										170
92	9000.00										172
93	9230.00										175
94	9250.00										175

Design Factors Data - 5 1/2" Production Tubing

Pipe Body	
Triaxial :	1.250
API Burst :	1.100
API Collapse :	1.000
Axial Tension:	1.300
Axial Compression :	1.200
Limit State Equation	
Rupture (Klever-Stewart) :	1.100
Collapse (Klever-Tamano) :	1.000
Connection	
Burst/Leak :	1.100
Tension :	1.300
Compression :	1.200
Envelope Burst :	1.000
Envelope Collapse :	1.000

Analysis Options - 5 1/2" Production Tubing

Enable Temperature Deration :	Yes
Enable Friction :	No
Collapse Strength Model :	API

Initial Conditions Data

5 1/2" Production Tubing	
Tubing Density Profile Data Source :	Casing and Tubing Configuration
Tubing Temperature Profile Data Source :	Undisturbed Temperatures
Annulus	
Annulus Density Profile Data Source :	Casing and Tubing Configuration
Annulus Temperature Profile Data Source :	Undisturbed Temperatures

Density Profile - Initial Conditions Data - 5 1/2" Production Tubing

	MD (ft)		Density (ppg)	Pressure Below Discontinuity (psi)
	Top	Base		
1	26.00	26.00	Hanger	0
2	26.00	7600.00	9.80	

Temperature Profile - Initial Conditions Data - 5 1/2" Production Tubing

	MD (ft)	Temperature (°F)
1	26.00	78
2	7600.00	158

Density Profile - Initial Conditions Data - Annulus

	MD (ft)		Density (ppg)	Pressure Below Discontinuity (psi)
	Top	Base		
1	26.00	26.00	Hanger	0
2	26.00	7600.00	9.80	

Temperature Profile - Initial Conditions Data - Annulus

	MD (ft)	Temperature (°F)
1	26.00	78
2	7600.00	158

Loads Data - PressureTest #1

5 1/2" Production Tubing	
Type :	Pressure Test
Pump Pressure :	0 psi
Fluid Inside Tubing :	Mud 0.01#
Annulus	
Wellhead Pressure :	1000 psi

Loads Data - Evacuation #1

5 1/2" Production Tubing	
Type :	Tubing Evacuation
Operation or Load :	Initial Conditions
Annulus	
Wellhead Pressure :	0 psi

Loads Data - AnnularPressureTest #1

5 1/2" Production Tubing	
Type :	Pressure Test
Pump Pressure :	0 psi
Fluid Inside Tubing :	CH4
Annulus	
Wellhead Pressure :	1000 psi

Loads Data - OverPull #1

5 1/2" Production Tubing	
Type :	Overpull
Overpull Force :	100000 lbf
Running Fluid :	Brine 9.8

Loads Data - CO2 Injection Transient 40F 2700 psi

5 1/2" Production Tubing	
Type :	Prod Link
Operation :	CO2 Injection 40F Transient 2700 psi
Annulus	
Wellhead Pressure :	500 psi

Loads Data - CO2 Injection Steady 40F 2700 psi

5 1/2" Production Tubing	
Type :	Prod Link
Operation :	CO2 Injection 40F Steady 2700 psi
Annulus	
Wellhead Pressure :	500 psi

Loads Data - Blowout Scenario 112 MMscfd

5 1/2" Production Tubing	
Type :	Custom
Tubing Density Profile Data Source :	Annulus Contents
Tubing Pressure Profile Data Source :	User-entered
Tubing Temperature Profile Data Source :	User-entered
Annulus	
Annulus Density Profile Data Source :	Annulus Contents
Annulus Pressure Profile Data Source :	Density Profile
Annulus Temperature Profile Data Source :	Initial Conditions

Density Profile - Blowout Scenario 112 MMscfd - 5 1/2" Production Tubing

	MD (ft)		Density (ppg)	Pressure Below Discontinuity (psi)
	Top	Base		
1	26.00	26.00	Hanger	0
2	26.00	7600.00	9.80	

Temperature Profile - Blowout Scenario 112 MMscfd - 5 1/2" Production Tubing

	MD (ft)	Temperature (°F)
1	26.00	-27
2	50.00	-1
3	100.00	16
4	150.00	26
5	200.00	30
6	300.00	42
7	400.00	57
8	500.00	66
9	600.00	72
10	700.00	78
11	800.00	83
12	900.00	86
13	1000.00	89
14	1500.00	96
15	2000.00	106
16	2500.00	113
17	3000.00	120
18	3500.00	126
19	4000.00	131
20	4500.00	136
21	5000.00	141
22	5500.00	146
23	6000.00	149
24	6500.00	153
25	7000.00	156
26	7600.00	160

Density Profile - Blowout Scenario 112 MMscfd - Annulus

	MD (ft)		Density (ppg)	Pressure Below Discontinuity (psi)
	Top	Base		
1	26.00	26.00	Hanger	0
2	26.00	7600.00	9.80	

Temperature Profile - Blowout Scenario 112 MMscfd - Annulus

	MD (ft)	Temperature (°F)
1	26.00	78
2	7600.00	158

Loads Data - CO2 Injection Transient 40F 1900 psi

5 1/2" Production Tubing

Type : Prod Link

Operation : CO2 Injection 40F Transient 1900 psi

Annulus

Wellhead Pressure : 500 psi

Loads Data - CO2 Injection Transient 90F 1900 psi

5 1/2" Production Tubing

Type : Prod Link

Operation : CO2 Injection 90F Transient 1900 psi

Annulus

Wellhead Pressure : 500 psi

Loads Data - CO2 Steady 40 F 2700 psi
5 1/2" Production Tubing
Type : Prod Link
Operation : CO2 Injection 40F Steady 2700 psi
Annulus
Wellhead Pressure : 500 psi

Loads Data - CO2 Steady 90 F 2700 psi
5 1/2" Production Tubing
Type : Prod Link
Operation : CO2 Injection 90F Steady 2700 psi
Annulus
Wellhead Pressure : 500 psi

Loads Data - CO2 Steady 40 F 1900 psi
5 1/2" Production Tubing
Type : Prod Link
Operation : CO2 Injection 40F Transient 1900 psi
Annulus
Wellhead Pressure : 500 psi

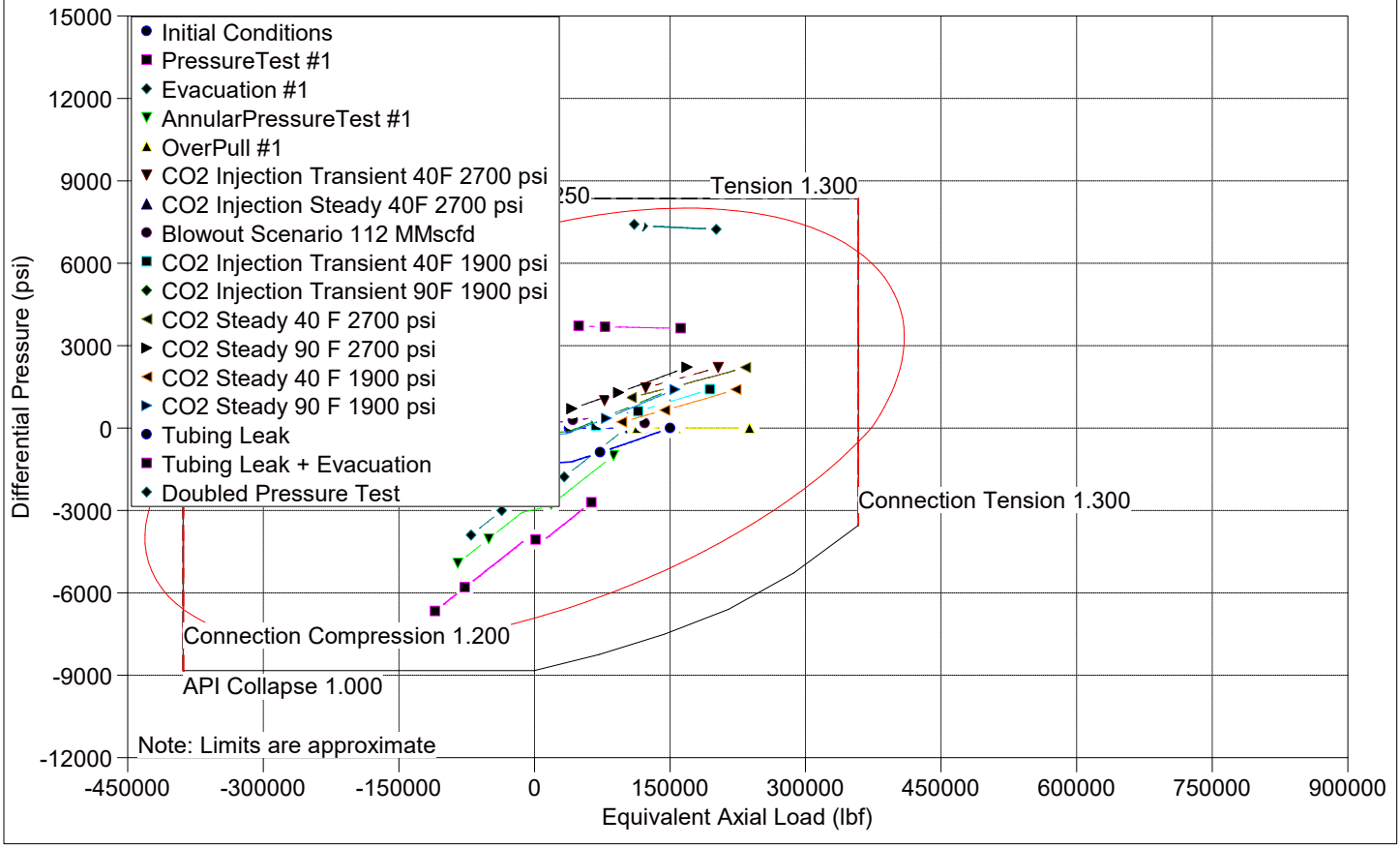
Loads Data - CO2 Steady 90 F 1900 psi
5 1/2" Production Tubing
Type : Prod Link
Operation : CO2 Injection 40F Transient 2700 psi
Annulus
Wellhead Pressure : 500 psi

Loads Data - Tubing Leak
5 1/2" Production Tubing
Type : Tubing Leak
Operation or Load : CO2 Injection 90F Steady 2700 psi
Annulus
Wellhead Pressure : 2700 psi

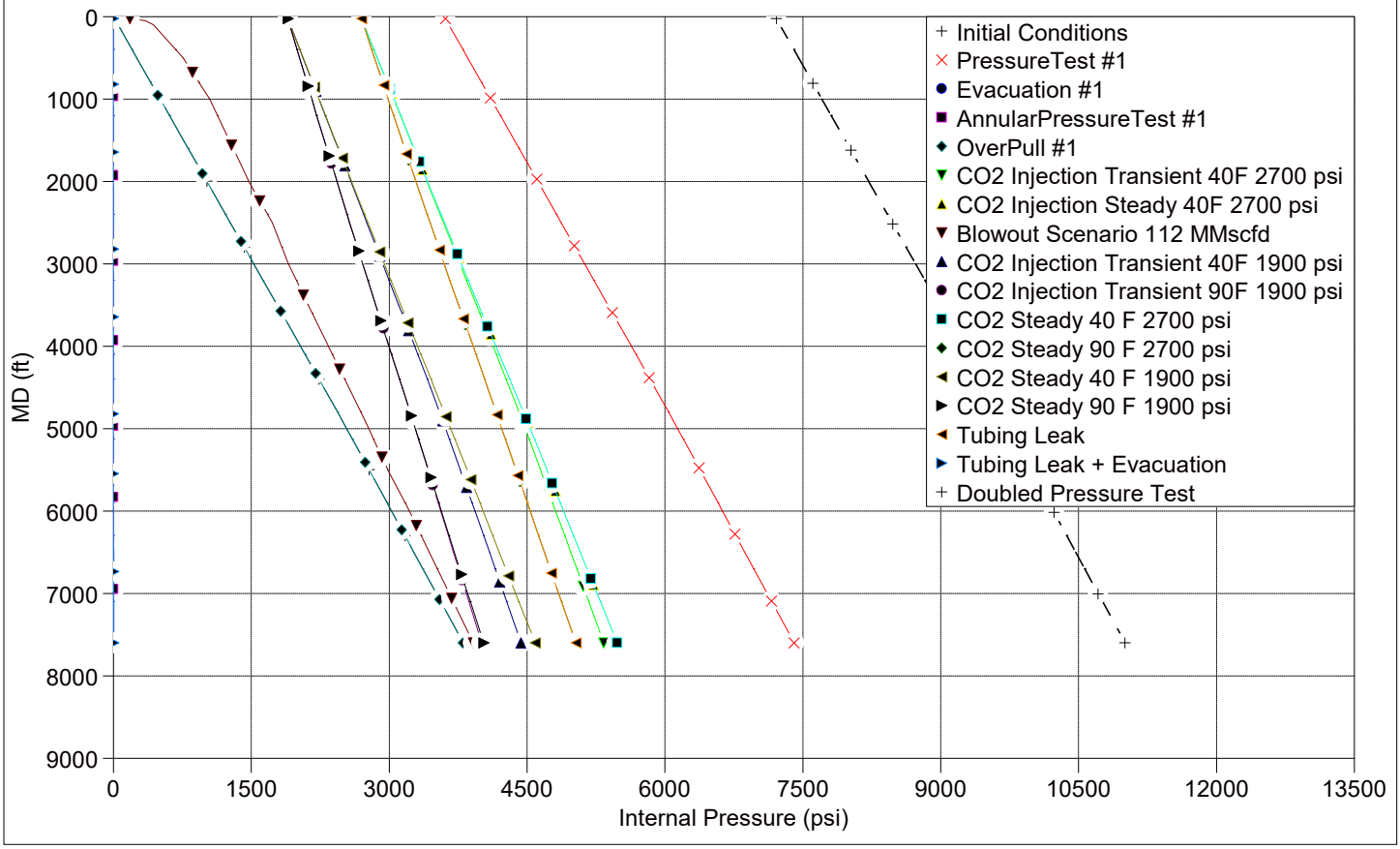
Loads Data - Tubing Leak + Evacuation
5 1/2" Production Tubing
Type : Tubing Evacuation
Operation or Load : Initial Conditions
Annulus
Wellhead Pressure : 2700 psi

Loads Data - Doubled Pressure Test
5 1/2" Production Tubing
Type : Pressure Test
Pump Pressure : 7200 psi
Fluid Inside Tubing : Brine 9.8
Annulus
Wellhead Pressure : 0 psi

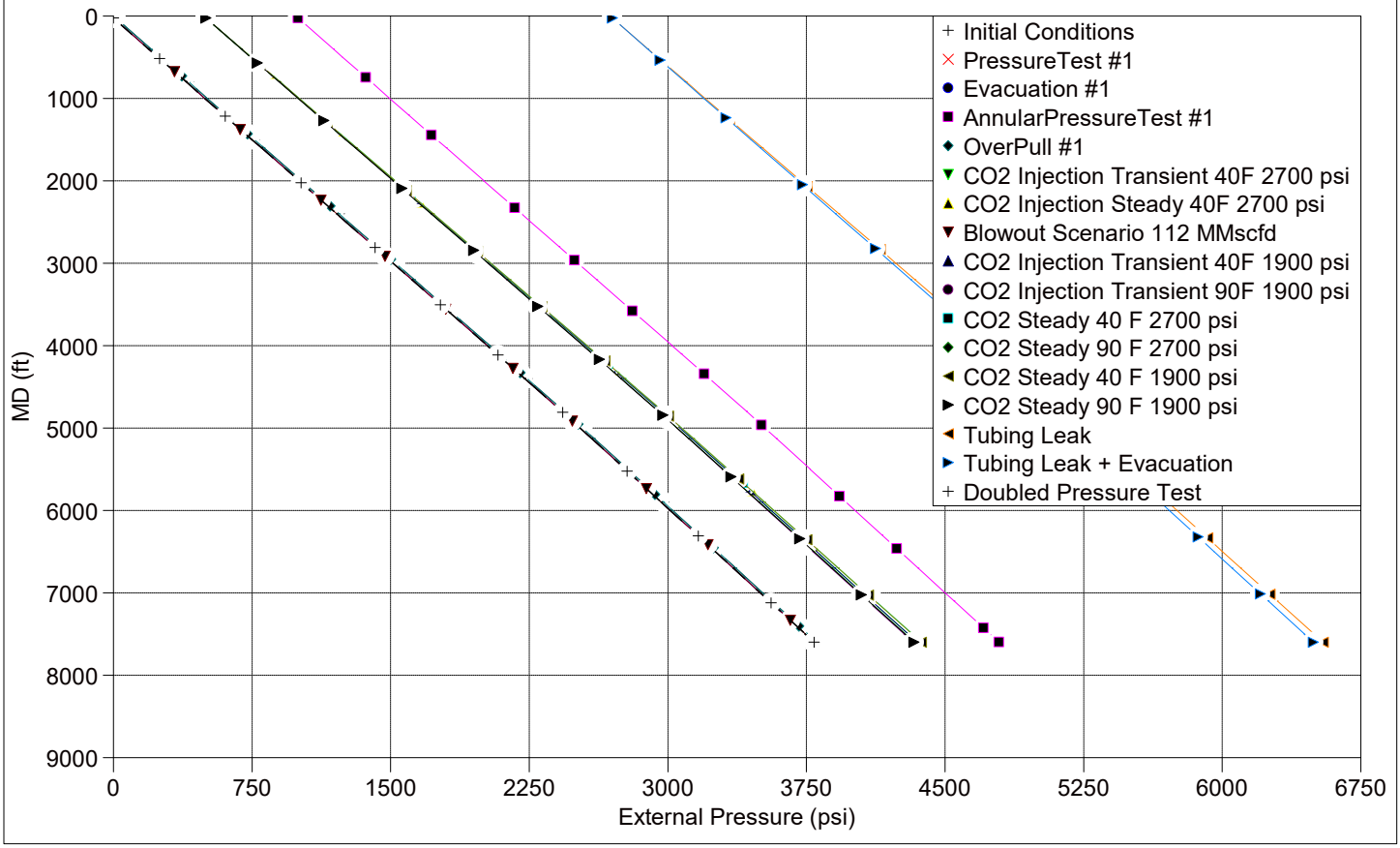
Design Limits - 5 1/2" Production Tubing - Section 1 - OD 5.500 in - Weight 20.000 ppf- Grade L-80



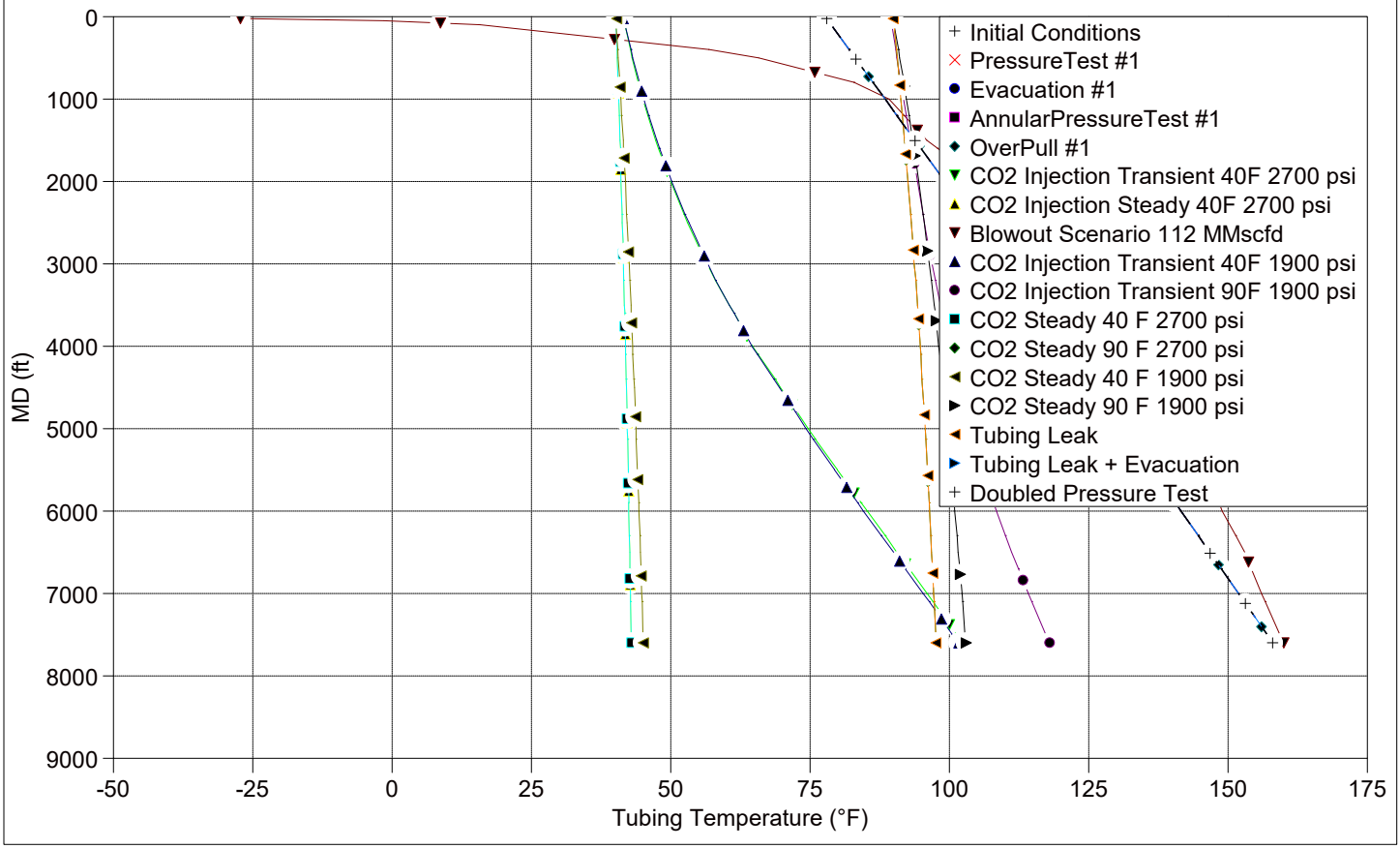
Internal Pressure - 5 1/2" Production Tubing



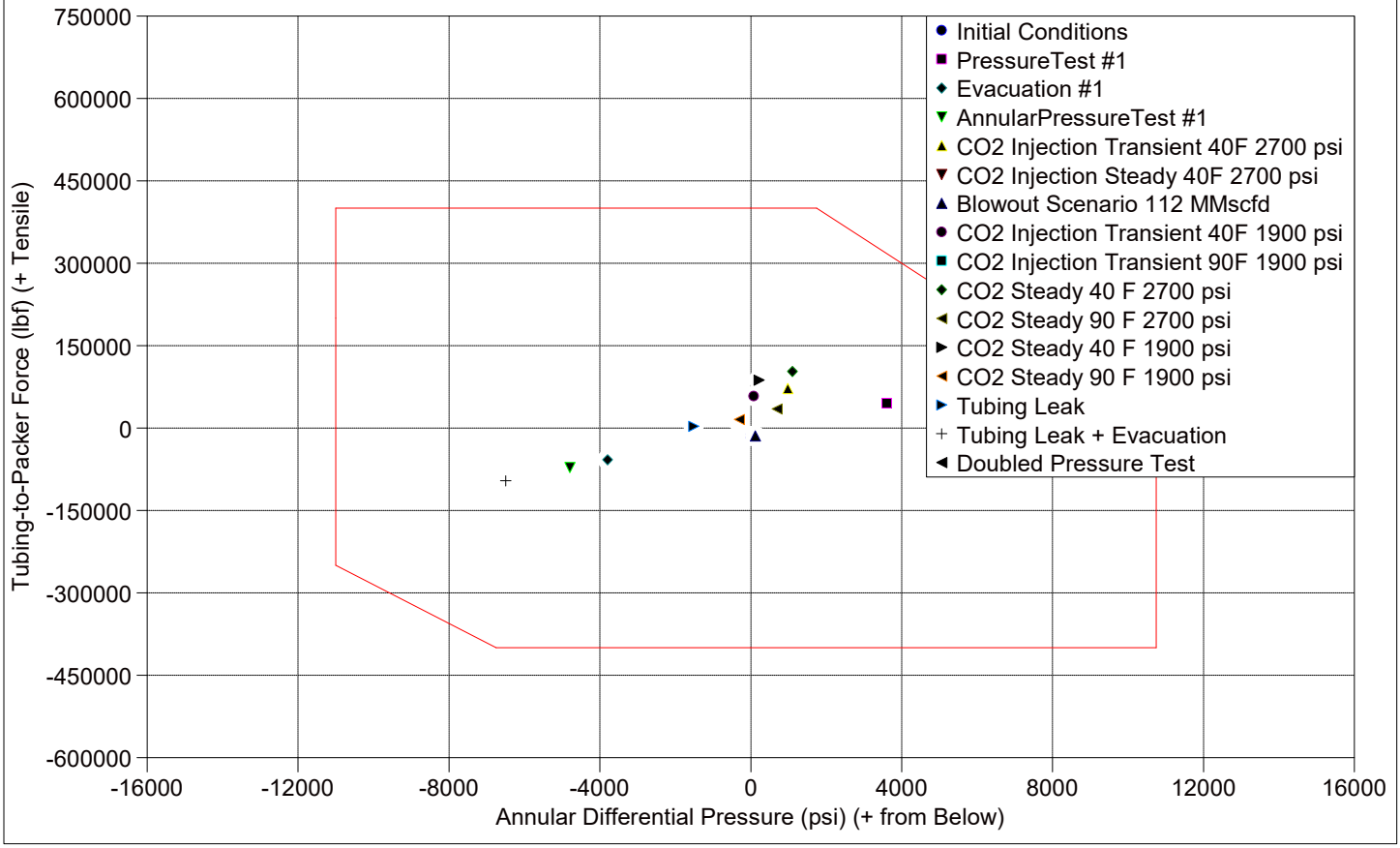
External Pressure - 5 1/2" Production Tubing



Tubing Temperature - 5 1/2" Production Tubing



Packer Operating Envelope - - 5 1/2" Production Tubing - Packer #1 (Packer @ 7600.00 ft MD)



Internal Pressure - 5 1/2" Production Tubing

	MD (ft)	Pressure (psi)																	
		Initial Co	Pressure	Evacuati	Annular	OverPull	CO2 Inje	CO2 Inje	Blowout	CO2 Inje	CO2 Inje	CO2 Ste	CO2 Ste	CO2 Ste	CO2 Ste	Tubing L	Tubing L	Doubled
1	26.10	13	3613	0	0	13	2700	2700	179	1900	1900	2700	2700	1900	1900	2700	0	7213
2	50.00	25	3625	0	0	25	2709	2709	349	1908	1906	2709	2707	1908	1906	2707	0	7225
3	100.00	51	3651	0	0	51	2727	2727	435	1926	1920	2727	2722	1926	1920	2722	0	7251
4	399.90	204	3804	0	0	204	2835	2836	679	2030	2000	2836	2811	2030	1999	2811	0	7404
5	400.00	204	3804	0	0	204	2835	2836	679	2030	2000	2836	2811	2030	1999	2811	0	7404
6	500.00	255	3855	0	0	255	2871	2872	760	2064	2026	2872	2841	2065	2026	2841	0	7455
7	799.90	407	4007	0	0	407	2979	2981	933	2168	2106	2981	2931	2170	2106	2931	0	7607
8	800.00	407	4007	0	0	407	2979	2981	933	2168	2106	2981	2931	2170	2106	2931	0	7607
9	1000.0	509	4109	1	0	509	3051	3053	1048	2238	2159	3053	2990	2240	2159	2990	1	7709
10	1199.9	611	4211	1	0	611	3123	3126	1133	2307	2213	3126	3050	2310	2212	3050	1	7811
11	1200.0	611	4211	1	0	611	3123	3126	1133	2307	2213	3126	3050	2310	2212	3050	1	7811
12	1500.0	764	4364	1	0	764	3231	3235	1261	2411	2295	3235	3139	2414	2294	3139	1	7964
13	1599.9	815	4414	1	0	815	3267	3271	1304	2446	2323	3271	3169	2449	2322	3169	1	8015
14	1600.0	815	4415	1	0	815	3267	3271	1304	2446	2323	3271	3169	2449	2322	3169	1	8015
15	1999.9	1018	4618	1	1	1018	3411	3417	1474	2585	2433	3417	3292	2592	2432	3292	1	8218
16	2000.0	1018	4618	1	1	1018	3411	3417	1474	2585	2433	3417	3292	2592	2432	3292	1	8218
17	2399.9	1222	4822	1	1	1222	3555	3566	1680	2723	2543	3566	3415	2734	2542	3415	1	8422
18	2400.0	1222	4822	1	1	1222	3555	3566	1680	2723	2543	3566	3415	2734	2542	3415	1	8422
19	2500.0	1273	4873	1	1	1273	3591	3603	1731	2758	2572	3603	3446	2770	2570	3446	1	8473
20	2799.9	1425	5025	1	1	1425	3699	3714	1835	2862	2657	3714	3538	2877	2655	3538	1	8625
21	2800.0	1425	5025	1	1	1425	3699	3714	1835	2862	2657	3714	3538	2877	2655	3538	1	8625
22	3000.0	1527	5127	2	1	1527	3771	3789	1904	2931	2714	3789	3600	2948	2712	3600	2	8727
23	3199.9	1629	5229	2	1	1629	3843	3863	1991	3001	2770	3863	3661	3020	2769	3661	2	8829
24	3200.0	1629	5229	2	1	1629	3843	3863	1991	3001	2771	3863	3661	3020	2769	3661	2	8829
25	3500.0	1782	5382	2	1	1782	3951	3974	2122	3105	2856	3974	3756	3129	2854	3756	2	8982
26	3599.9	1833	5433	2	1	1833	3987	4011	2166	3139	2884	4011	3788	3165	2883	3788	2	9033
27	3600.0	1833	5433	2	1	1833	3987	4012	2166	3139	2884	4012	3788	3165	2883	3788	2	9033
28	3999.9	2036	5636	2	1	2036	4131	4161	2340	3278	2999	4161	3914	3311	2998	3914	2	9236
29	4000.0	2036	5636	2	1	2036	4131	4161	2340	3278	2999	4161	3914	3311	2998	3914	2	9236
30	4099.9	2087	5687	2	1	2087	4167	4199	2384	3313	3028	4199	3946	3347	3027	3946	2	9287
31	4100.1	2087	5687	2	1	2087	4167	4199	2384	3313	3028	4199	3946	3347	3027	3946	2	9287
32	4399.9	2240	5840	2	1	2240	4274	4311	2517	3416	3114	4311	4040	3456	3114	4040	2	9440
33	4400.0	2240	5840	2	1	2240	4274	4311	2517	3416	3114	4311	4040	3456	3114	4040	2	9440
34	4500.0	2290	5890	2	1	2290	4309	4349	2561	3450	3143	4349	4072	3492	3143	4072	2	9490
35	4799.9	2441	6041	3	1	2441	4413	4460	2693	3550	3228	4460	4165	3600	3229	4165	3	9641
36	4800.0	2441	6041	3	1	2441	4413	4460	2693	3550	3228	4460	4165	3600	3229	4165	3	9641
37	5000.0	2540	6140	3	1	2540	4482	4534	2779	3616	3284	4534	4227	3671	3285	4227	3	9740
38	5129.5	2603	6203	3	1	2603	4525	4581	2833	3657	3321	4581	4267	3717	3322	4267	3	9803
39	5129.6	2603	6203	3	1	2603	4525	4581	2833	3657	3321	4581	4267	3717	3322	4267	3	9803
40	5499.9	2783	6383	3	2	2783	4647	4716	2985	3775	3424	4716	4381	3847	3427	4381	3	9983
41	5500.0	2783	6383	3	2	2783	4647	4716	2985	3775	3424	4716	4381	3847	3427	4381	3	9983
42	5899.9	2978	6578	3	2	2978	4779	4862	3174	3902	3535	4862	4504	3988	3540	4504	3	10178
43	5900.0	2978	6578	3	2	2978	4779	4862	3174	3902	3535	4862	4504	3988	3540	4504	3	10178
44	6000.0	3027	6627	3	2	3027	4812	4898	3221	3934	3562	4898	4535	4023	3569	4535	3	10227
45	6299.9	3173	6773	3	2	3173	4911	5007	3351	4030	3646	5007	4628	4129	3654	4628	3	10373
46	6300.0	3173	6773	3	2	3173	4911	5007	3351	4030	3646	5007	4628	4129	3654	4628	3	10373
47	6500.0	3270	6870	3	2	3270	4977	5080	3438	4093	3701	5080	4689	4200	3710	4689	3	10470
48	6699.9	3368	6968	3	2	3368	5043	5153	3525	4155	3757	5153	4751	4270	3768	4751	3	10568
49	6700.0	3368	6968	3	2	3368	5043	5153	3525	4155	3757	5153	4751	4270	3768	4751	3	10568
50	7000.0	3514	7114	4	2	3514	5141	5262	3655	4248	3840	5262	4844	4376	3855	4844	4	10714
51	7099.9	3563	7163	4	2	3563	5173	5298	3698	4279	3868	5298	4876	4412	3884	4876	4	10763
52	7100.0	3563	7163	4	2	3563	5173	5298	3698	4279	3868	5298	4876	4412	3884	4876	4	10763
53	7499.9	3757	7357	4	2	3757	5302	5445	3872	4404	3979	5445	5001	4555	4000	5001	4	10957
54	7500.0	3757	7357	4	2	3757	5302	5445	3872	4404	3979	5445	5001	4555	4000	5001	4	10957
55	7599.9	3806	7406	4	2	3806	5335	5482	3915	4435	4007	5482	5033	4591	4029	5033	4	11006

External Pressure - 5 1/2" Production Tubing

	MD (ft)	Pressure (psi)																	
		Initial Co	Pressure	Evacuati	Annular	OverPull	CO2 Inje	CO2 Inje	Blowout	CO2 Inje	CO2 Inje	CO2 Ste	CO2 Ste	CO2 Ste	CO2 Ste	Tubing L	Tubing L	Doubled
1	26.10	13	0	0	1000	13	500	500	0	500	500	500	500	500	500	2700	2700	0
2	50.00	25	12	12	1012	25	512	512	12	512	512	512	512	512	512	2712	2712	12
3	100.00	51	38	38	1038	51	538	538	38	538	538	538	538	538	538	2738	2738	38
4	399.90	204	190	190	1190	204	693	694	190	693	692	694	692	694	692	2893	2890	190
5	400.00	204	190	190	1190	204	693	694	190	693	692	694	692	694	692	2893	2890	190
6	500.00	255	241	241	1241	255	745	746	241	745	743	746	744	746	744	2945	2941	241
7	799.90	407	394	394	1394	407	900	902	394	900	898	902	898	902	898	3099	3094	394
8	800.00	407	394	394	1394	407	900	902	394	900	898	902	898	902	898	3100	3094	394
9	1000.0	509	496	496	1496	509	1004	1005	496	1004	1000	1005	1001	1005	1001	3203	3196	496
10	1199.9	611	598	598	1598	611	1107	1109	598	1107	1103	1109	1103	1109	1103	3306	3298	598
11	1200.0	611	598	598	1598	611	1107	1109	598	1107	1103	1109	1104	1109	1103	3306	3298	598
12	1500.0	764	750	750	1750	764	1262	1265	750	1262	1257	1265	1258	1265	1257	3461	3450	750
13	1599.9	815	801	801	1801	815	1314	1317	801	1314	1309	1317	1309	1317	1309	3512	3501	801
14	1600.0	815	801	801	1801	815	1314	1317	801	1314	1309	1317	1309	1317	1309	3513	3501	801
15	1999.9	1018	1005	1005	2005	1018	1521	1524	1005	1521	1514	1524	1515	1524	1514	3719	3705	1005
16	2000.0	1018	1005	1005	2005	1018	1521	1524	1005	1521	1514	1524	1515	1524	1514	3719	3705	1005
17	2399.9	1222	1209	1209	2209	1222	1728	1732	1209	1728	1719	1732	1720	1732	1720	3925	3909	1209
18	2400.0	1222	1209	1209	2209	1222	1728	1732	1209	1728	1720	1732	1720	1732	1720	3925	3909	1209
19	2500.0	1273	1259	1259	2259	1273	1780	1784	1260	1780	1771	1784	1772	1784	1771	3977	3959	1259
20	2799.9	1425	1412	1412	2412	1425	1935	1940	1412	1935	1925	1940	1926	1939	1925	4132	4112	1412
21	2800.0	1425	1412	1412	2412	1425	1935	1940	1412	1935	1925	1940	1926	1939	1925	4132	4112	1412
22	3000.0	1527	1514	1514	2514	1527	2038	2043	1514	2038	2028	2043	2029	2043	2028	4235	4214	1514
23	3199.9	1629	1616	1616	2616	1629	2142	2147	1616	2142	2130	2147	2132	2147	2131	4338	4316	1616
24	3200.0	1629	1616	1616	2616	1629	2142	2147	1616	2142	2130	2147	2132	2147	2131	4338	4316	1616
25	3500.0	1782	1769	1769	2769	1782	2297	2303	1769	2297	2285	2303	2286	2303	2285	4493	4469	1769
26	3599.9	1833	1819	1819	2819	1833	2349	2355	1819	2349	2336	2355	2337	2354	2336	4545	4519	1819
27	3600.0	1833	1819	1819	2819	1833	2349	2355	1820	2349	2336	2355	2337	2355	2337	4545	4519	1819
28	3999.9	2036	2023	2023	3023	2036	2555	2562	2023	2556	2541	2562	2543	2562	2542	4751	4723	2023
29	4000.0	2036	2023	2023	3023	2036	2556	2562	2023	2556	2541	2562	2543	2562	2542	4751	4723	2023
30	4099.9	2087	2074	2074	3074	2087	2607	2614	2074	2607	2593	2614	2594	2614	2593	4803	4774	2074
31	4100.1	2087	2074	2074	3074	2087	2607	2614	2074	2607	2593	2614	2594	2614	2594	4803	4774	2074
32	4399.9	2240	2226	2226	3226	2240	2762	2770	2226	2762	2747	2770	2748	2769	2747	4957	4926	2226
33	4400.0	2240	2226	2226	3226	2240	2762	2770	2226	2762	2747	2770	2748	2769	2747	4958	4926	2226
34	4500.0	2290	2277	2277	3277	2290	2813	2821	2277	2813	2798	2821	2799	2821	2798	5009	4977	2277
35	4799.9	2441	2427	2427	3427	2441	2966	2975	2427	2966	2949	2975	2951	2974	2950	5161	5127	2427
36	4800.0	2441	2427	2427	3427	2441	2966	2975	2427	2966	2949	2975	2951	2974	2950	5161	5127	2427
37	5000.0	2540	2526	2526	3526	2540	3066	3076	2526	3067	3049	3076	3052	3076	3050	5262	5226	2526
38	5129.5	2603	2590	2590	3590	2603	3131	3141	2590	3131	3113	3141	3116	3140	3114	5326	5290	2590
39	5129.6	2603	2590	2590	3590	2603	3131	3141	2590	3131	3113	3141	3116	3140	3114	5326	5290	2590
40	5499.9	2783	2770	2770	3770	2783	3313	3325	2770	3313	3295	3325	3298	3325	3297	5509	5470	2770
41	5500.0	2783	2770	2770	3770	2783	3313	3325	2770	3313	3295	3325	3298	3325	3297	5509	5470	2770
42	5899.9	2978	2965	2965	3965	2978	3510	3525	2965	3511	3492	3525	3496	3524	3494	5706	5665	2965
43	5900.0	2978	2965	2965	3965	2978	3510	3525	2965	3511	3492	3525	3496	3524	3494	5706	5665	2965
44	6000.0	3027	3014	3014	4014	3027	3560	3575	3014	3560	3541	3575	3545	3574	3543	5756	5714	3014
45	6299.9	3173	3160	3160	4160	3173	3708	3724	3160	3708	3688	3724	3693	3724	3691	5904	5860	3160
46	6300.0	3173	3160	3160	4160	3173	3708	3724	3160	3708	3688	3724	3693	3724	3691	5904	5860	3160
47	6500.0	3270	3257	3257	4257	3270	3806	3824	3257	3806	3786	3824	3792	3823	3790	6003	5957	3257
48	6699.9	3368	3355	3355	4355	3368	3905	3924	3355	3905	3884	3924	3890	3923	3888	6101	6055	3355
49	6700.0	3368	3355	3355	4355	3368	3905	3924	3355	3905	3884	3924	3890	3923	3888	6101	6055	3355
50	7000.0	3514	3501	3501	4501	3514	4053	4073	3501	4053	4032	4073	4038	4073	4036	6250	6201	3501
51	7099.9	3563	3549	3549	4549	3563	4102	4123	3549	4102	4081	4123	4088	4122	4085	6299	6249	3549
52	7100.0	3563	3549	3549	4549	3563	4102	4123	3549	4102	4081	4123	4088	4123	4085	6299	6249	3549
53	7499.9	3757	3744	3744	4744	3757	4299	4322	3744	4299	4277	4322	4285	4322	4283	6497	6444	3744
54	7500.0	3757	3744	3744	4744	3757	4299	4323	3744	4299	4277	4323	4285	4322	4283	6497	6444	3744
55	7599.9	3806	3793	3793	4793	3806	4348	4372	3793	4349	4326	4372	4334	4372	4332	6546	6493	3793

Triaxial Safety Factor - 5 1/2" Production Tubing

	MD (ft)	Absolute API Safety Factors																
		Initial Co	Pressure	Evacuati	Annular	OverPull	CO2 Inje	CO2 Inje	Blowout	CO2 Inje	CO2 Inje	CO2 Ste	CO2 Ste	CO2 Ste	CO2 Ste	Tubing L	Tubing L	Doubled
1	26.10	D 3.798	2.471	D 4.568	3.802	D 1.958	2.502	2.198	D 3.932	2.648	3.407	2.198	2.933	2.299	3.316	D 3.104	2.523	1.369
2	50.00	D 3.811	2.473	D 4.574	3.799	D 1.961	2.507	2.201	D 4.044	2.653	3.417	2.201	2.940	2.303	3.324	D 3.110	2.519	1.369
3	100.00	D 3.837	2.478	D 4.587	3.793	D 1.968	2.517	2.209	D 4.110	2.665	3.437	2.209	2.955	2.311	3.343	D 3.123	2.510	1.369
4	399.90	D 4.002	2.504	D 4.659	3.750	D 2.010	2.582	2.259	D 4.358	2.737	3.562	2.259	3.048	2.365	3.461	D 3.203	2.460	1.371
5	400.00	D 4.002	2.504	D 4.659	3.750	D 2.010	2.582	2.259	D 4.358	2.737	3.562	2.259	3.048	2.365	3.461	D 3.203	2.460	1.371
6	500.00	D 4.060	2.513	D 4.680	3.733	D 2.024	2.604	2.276	D 4.446	2.762	3.605	2.276	3.080	2.383	3.502	D 3.230	2.442	1.371
7	799.90	D 4.246	2.539	D 4.734	3.675	D 2.068	2.673	2.329	D 4.661	2.839	3.743	2.329	3.182	2.440	3.630	D 3.313	2.391	1.372
8	800.00	D 4.246	2.539	D 4.734	3.675	D 2.068	2.673	2.329	D 4.661	2.839	3.743	2.329	3.182	2.440	3.630	D 3.313	2.391	1.372
9	1000.00	D 4.380	2.555	D 4.762	3.631	D 2.099	2.721	2.366	D 4.823	2.893	3.840	2.366	3.253	2.480	3.721	D 3.371	2.356	1.372
10	1199.90	D 4.523	2.571	4.771	3.583	D 2.130	2.771	2.404	D 4.980	2.950	3.942	2.404	3.328	2.520	3.816	D 3.430	2.321	1.373
11	1200.00	D 4.523	2.571	4.771	3.583	D 2.130	2.771	2.404	D 4.980	2.950	3.942	2.404	3.328	2.520	3.816	D 3.430	2.321	1.373
12	1500.00	D 4.756	2.594	4.742	3.505	D 2.179	2.849	2.463	D 5.237	3.038	4.105	2.463	3.446	2.584	3.968	D 3.521	2.269	1.373
13	1599.90	D 4.839	2.601	4.726	3.478	D 2.196	2.876	2.483	D 5.328	3.069	4.162	2.483	3.488	2.606	4.021	D 3.552	2.252	1.373
14	1600.00	D 4.839	2.601	4.726	3.478	D 2.196	2.877	2.483	D 5.328	3.069	4.162	2.483	3.488	2.606	4.021	D 3.552	2.252	1.373
15	1999.90	D 5.203	2.628	4.637	3.364	D 2.267	2.990	2.568	D 5.727	3.197	4.407	2.568	3.662	2.697	4.248	D 3.684	2.184	1.372
16	2000.00	D 5.203	2.628	4.637	3.364	D 2.267	2.990	2.568	D 5.727	3.197	4.407	2.568	3.662	2.697	4.248	D 3.684	2.184	1.372
17	2399.90	D 5.629	2.652	4.510	3.244	D 2.342	3.113	2.658	D 6.233	3.337	4.680	2.658	3.855	2.795	4.500	D 3.822	2.117	N 1.371
18	2400.00	D 5.629	2.652	4.510	3.244	D 2.342	3.113	2.658	D 6.233	3.337	4.680	2.658	3.855	2.795	4.500	D 3.822	2.117	N 1.371
19	2500.00	D 5.746	2.657	4.473	3.214	D 2.362	3.146	2.682	D 6.374	3.374	4.754	2.682	3.907	2.821	4.568	D 3.858	2.100	N 1.370
20	2799.90	D 6.131	2.673	4.354	3.122	D 2.423	3.247	2.755	D 6.777	3.490	4.988	2.755	4.070	2.900	4.783	D 3.967	2.051	N 1.368
21	2800.00	D 6.131	2.673	4.354	3.122	D 2.423	3.247	2.755	D 6.777	3.490	4.988	2.755	4.070	2.900	4.783	D 3.967	2.051	N 1.368
22	3000.00	D 6.418	2.682	4.268	3.061	D 2.465	3.318	2.807	D 7.076	3.571	5.156	2.807	4.186	2.956	4.936	4.037	2.019	N 1.366
23	3199.90	D 6.733	2.690	4.179	3.000	D 2.510	3.393	2.860	D 7.430	3.656	5.336	2.860	4.309	3.013	5.100	4.105	1.988	N 1.364
24	3200.00	D 6.734	2.690	4.179	3.000	D 2.510	3.393	2.860	D 7.430	3.656	5.336	2.860	4.309	3.013	5.100	4.105	1.988	N 1.364
25	3500.00	D 7.271	2.700	4.040	2.910	D 2.579	3.510	2.943	D 8.035	3.792	5.627	2.943	4.507	3.104	5.364	4.210	1.941	N 1.361
26	3599.90	D 7.469	2.703	3.993	2.880	D 2.603	3.552	2.972	D 8.260	3.839	5.731	2.972	4.577	3.136	5.458	4.246	1.926	N 1.360
27	3600.00	D 7.470	2.703	3.993	2.880	D 2.603	3.552	2.972	D 8.260	3.839	5.731	2.972	4.577	3.136	5.458	4.246	1.926	N 1.360
28	3999.90	D 8.389	2.712	3.804	2.763	D 2.704	3.726	3.094	D 9.302	4.041	D 6.172	3.094	4.880	3.268	D 5.848	4.386	1.867	N 1.354
29	4000.00	D 8.389	2.712	3.804	2.763	D 2.704	3.726	3.094	D 9.303	4.041	D 6.172	3.094	4.880	3.268	D 5.848	4.386	1.867	N 1.354
30	4099.90	D 8.655	2.713	3.757	2.734	D 2.730	3.772	3.126	D 9.608	4.095	D 6.287	3.126	4.962	3.303	D 5.951	4.421	1.852	N 1.354
31	4100.10	D 8.656	2.713	3.757	2.734	D 2.731	3.773	3.126	D 9.608	4.095	D 6.287	3.126	4.962	3.303	D 5.951	4.421	1.852	N 1.354
32	4399.90	D 9.567	2.716	3.617	2.650	D 2.813	3.918	3.226	D 10.65	4.263	D 6.656	3.226	5.224	3.412	D 6.280	4.524	1.809	N 1.350
33	4400.00	D 9.568	2.716	3.617	2.650	D 2.813	3.918	3.226	D 10.65	4.263	D 6.656	3.226	5.225	3.412	D 6.281	4.524	1.809	N 1.350
34	4500.00	D 9.914	N 2.714	3.571	2.622	D 2.842	3.968	3.261	D 11.05	4.321	D 6.787	3.261	5.318	3.449	D 6.397	4.557	1.796	N 1.349
35	4799.90	D 11.11	N 2.705	3.438	2.543	D 2.931	4.124	3.368	D 12.44	4.502	D 7.208	3.368	5.617	D 3.564	D 6.769	4.655	1.755	N 1.345
36	4800.00	D 11.11	N 2.705	3.438	2.543	D 2.931	4.124	3.368	D 12.44	4.502	D 7.208	3.368	5.617	D 3.564	D 6.769	4.655	1.755	N 1.345
37	5000.00	D 12.08	N 2.698	3.352	2.492	D 2.992	4.234	3.443	D 13.57	D 4.626	D 7.511	3.443	5.832	D 3.642	D 7.035	4.716	1.729	N 1.342
38	5129.50	D 12.79	N 2.693	3.298	2.460	D 3.033	4.308	3.492	D 14.39	D 4.707	D 7.718	3.492	5.978	D 3.694	D 7.217	4.757	1.713	N 1.340
39	5129.60	D 12.79	N 2.693	3.298	2.460	D 3.033	4.308	3.492	D 14.39	D 4.707	D 7.718	3.492	5.978	D 3.694	D 7.217	4.757	1.713	N 1.340
40	5499.90	D 15.37	N 2.677	3.151	2.372	D 3.156	4.533	3.641	D 17.41	D 4.952	D 8.364	3.641	6.436	D 3.851	D 7.781	4.865	1.667	N 1.331
41	5500.00	D 15.37	N 2.677	3.151	2.372	D 3.156	4.533	3.641	D 17.41	D 4.952	D 8.364	3.641	6.436	D 3.850	D 7.781	4.865	1.667	N 1.331
42	5899.90	D 19.67	N 2.655	3.000	2.281	D 3.300	4.805	3.816	D 22.68	D 5.248	D 9.171	3.816	7.015	D 4.035	D 8.480	4.971	1.620	N 1.320
43	5900.00	D 19.67	N 2.655	3.000	2.281	D 3.300	4.805	3.816	D 22.68	D 5.248	D 9.171	3.816	7.015	D 4.035	D 8.480	4.971	1.620	N 1.320
44	6000.00	D 21.15	N 2.649	2.963	2.259	D 3.339	4.878	3.863	D 24.49	D 5.327	D 9.394	3.863	7.176	D 4.083	D 8.672	4.995	1.609	N 1.317
45	6299.90	D 27.32	N 2.630	2.858	2.196	D 3.459	5.111	4.009	D 31.92	D 5.579	D 10.11	4.009	7.705	D 4.236	D 9.289	5.062	1.575	N 1.308
46	6300.00	D 27.32	N 2.630	2.858	2.196	D 3.459	5.111	4.009	D 31.92	D 5.579	D 10.11	4.009	7.705	D 4.236	D 9.288	5.061	1.575	N 1.308
47	6500.00	D 33.94	N 2.617	2.790	2.154	D 3.545	5.280	4.113	DN 34.0	D 5.759	D 10.64	4.113	8.103	D 4.345	D 9.738	5.100	1.553	N 1.301
48	6699.90	DN 42.0	N 2.599	2.725	2.114	D 3.635	5.460	4.223	DN 28.5	D 5.950	D 11.20	4.223	8.543	D 4.459	D 10.22	5.134	1.532	N 1.295
49	6700.00	DN 42.0	N 2.599	2.725	2.114	D 3.635	5.460	4.223	DN 28.5	D 5.950	D 11.20	4.223	8.543	D 4.459	D 10.22	5.134	1.532	N 1.295
50	7000.00	DN 28.9	N 2.559	2.631	2.056	D 3.779	5.757	4.398	DN 22.7	D 6.260	D 12.13	4.398	9.295	D 4.641	D 11.02	5.178	1.500	N 1.284
51	7099.90	DN 26.2	N 2.546	2.601	2.038	D 3.830	5.864	4.460	DN 21.2	D 6.370	D 12.45	4.460	9.573	D 4.706	D 11.31	5.190	1.490	N 1.281
52	7100.00	DN 26.2	N 2.546	2.601	2.038	D 3.830	5.864	4.460	DN 21.2	D 6.369	D 12.45	4.460	9.573	D 4.706	D 11.31	5.190	1.490	N 1.281
53	7499.90	DN 19.0	N 2.487	2.486	1.965	D 4.047	6.332	4.725	DN 16.6	D 6.847	D 13.83	4.725	10.867	D 4.981	D 12.53	5.227	1.450	N 1.266
54	7500.00	DN 19.0	N 2.487	2.486	1.965	D 4.047	6.332	4.725	DN 16.6	D 6.847	D 13.83	4.725	10.867	D 4.981	D 12.53	5.226	1.450	N 1.266
55	7599.90	DN 17.7	N 2.471	2.458	1.948	D 4.106	6.461	4.797	DN 15.8	D 6.977	14.159	4.797	11.244	D 5.055	D 12.86	5.232	1.440	N 1.262
56																		
57	**Triaxial Design Factor = 1.250**																	
58																		
59	**Triaxial Flags**																	
60	**Default = Inner wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**																	

Differential Pressure - 5 1/2" Production Tubing

	MD (ft)	Pressure (psi)																
		Initial Co	Pressure	Evacuati	Annular	OverPull	CO2 Inje	CO2 Inje	Blowout	CO2 Inje	CO2 Inje	CO2 Ste	CO2 Ste	CO2 Ste	CO2 Ste	Tubing L	Tubing L	Doubled
1	26.10	0.00	3613.24	-0.04	-1000.04	0.00	2199.98	2199.98	178.66	1399.98	1399.98	2199.98	2199.98	1399.98	1399.98	-0.02	-2700.04	7213.24
2	50.00	0.00	3613.24	-12.20	-1012.20	0.00	2196.23	2196.26	336.78	1395.91	1394.06	2196.26	2194.81	1395.92	1394.05	-5.24	-2712.20	7213.24
3	100.00	0.00	3613.24	-37.62	-1037.64	0.00	2188.37	2188.45	397.33	1387.39	1381.69	2188.45	2184.01	1387.42	1381.66	-16.15	-2737.62	7213.24
4	399.90	0.00	3613.24	-190.14	-1190.23	0.00	2141.26	2141.66	488.32	1336.27	1307.49	2141.66	2119.20	1336.43	1307.34	-81.59	-2890.14	7213.24
5	400.00	0.00	3613.24	-190.19	-1190.28	0.00	2141.24	2141.64	488.35	1336.25	1307.46	2141.64	2119.18	1336.41	1307.31	-81.61	-2890.19	7213.24
6	500.00	0.00	3613.24	-241.05	-1241.16	0.00	2125.53	2126.04	518.69	1319.20	1282.72	2126.04	2097.57	1319.41	1282.53	-103.43	-2941.05	7213.24
7	799.90	0.00	3613.24	-393.57	-1393.75	0.00	2078.42	2079.25	538.75	1268.08	1208.52	2079.25	2032.77	1268.41	1208.21	-168.87	-3093.57	7213.25
8	800.00	0.00	3613.24	-393.62	-1393.80	0.00	2078.40	2079.23	538.76	1268.07	1208.49	2079.23	2032.74	1268.40	1208.18	-168.89	-3093.62	7213.25
9	1000.0	0.00	3613.23	-495.33	-1495.56	0.00	2046.98	2048.02	552.14	1233.98	1159.01	2048.02	1989.53	1234.39	1158.62	-212.53	-3195.33	7213.25
10	1199.9	0.00	3613.23	-596.99	-1597.27	0.00	2015.57	2016.83	535.53	1199.90	1109.55	2016.83	1946.33	1200.40	1109.08	-256.16	-3296.99	7213.25
11	1200.0	0.00	3613.23	-597.04	-1597.32	0.00	2015.56	2016.82	535.52	1199.88	1109.52	2016.82	1946.31	1200.38	1109.05	-256.18	-3297.04	7213.25
12	1500.0	0.00	3613.23	-749.61	-1749.96	0.00	1968.42	1970.01	510.59	1148.75	1038.08	1970.01	1881.48	1149.37	1037.05	-321.64	-3449.61	7213.25
13	1599.9	0.00	3613.23	-800.42	-1800.79	0.00	1952.73	1954.42	502.29	1131.72	1014.30	1954.42	1859.89	1132.39	1013.23	-343.44	-3500.41	7213.25
14	1600.0	0.00	3613.23	-800.47	-1800.84	0.00	1952.71	1954.41	502.28	1131.70	1014.27	1954.41	1859.87	1132.37	1013.21	-343.46	-3500.47	7213.25
15	1999.9	0.00	3613.23	-1003.84	-2004.31	0.00	1889.89	1892.86	469.05	1063.54	919.05	1892.86	1777.29	1067.36	917.86	-426.88	-3703.84	7213.26
16	2000.0	0.00	3613.23	-1003.89	-2004.37	0.00	1889.87	1892.84	469.04	1063.52	919.03	1892.84	1777.27	1067.34	917.83	-426.90	-3703.89	7213.26
17	2399.9	0.00	3613.23	-1207.26	-2207.84	0.00	1827.04	1833.84	471.01	995.36	823.80	1833.84	1694.69	1002.53	822.48	-510.33	-3907.26	7213.26
18	2400.0	0.00	3613.23	-1207.32	-2207.89	0.00	1827.03	1833.83	471.01	995.34	823.78	1833.83	1694.67	1002.52	822.46	-510.35	-3907.32	7213.26
19	2500.0	0.00	3613.23	-1258.17	-2258.77	0.00	1811.32	1819.08	471.50	978.29	800.81	1819.08	1674.02	986.31	798.61	-531.21	-3958.17	7213.26
20	2799.9	0.00	3613.22	-1410.69	-2411.36	0.00	1764.20	1774.83	422.58	927.17	731.92	1774.83	1612.09	937.71	729.79	-593.78	-4110.69	7213.26
21	2800.0	0.00	3613.22	-1410.74	-2411.41	0.00	1764.19	1774.81	422.57	927.16	731.90	1774.81	1612.07	937.69	729.77	-593.80	-4110.74	7213.26
22	3000.0	0.00	3613.22	-1512.45	-2513.17	0.00	1732.76	1745.31	389.95	893.07	685.96	1745.31	1570.77	905.27	683.87	-635.52	-4212.45	7213.27
23	3199.9	0.00	3613.22	-1614.11	-2614.88	0.00	1701.36	1715.82	375.34	858.99	640.05	1715.82	1529.49	872.88	637.99	-677.22	-4314.11	7213.27
24	3200.0	0.00	3613.22	-1614.16	-2614.93	0.00	1701.34	1715.80	375.33	858.97	640.02	1715.80	1529.47	872.86	637.97	-677.24	-4314.16	7213.27
25	3500.0	0.00	3613.22	-1766.73	-2767.57	0.00	1654.21	1671.54	353.40	807.84	571.12	1671.54	1470.08	826.00	569.12	-737.27	-4466.73	7213.27
26	3599.9	0.00	3613.22	-1817.54	-2818.40	0.00	1638.52	1656.80	346.10	790.81	548.17	1656.80	1450.30	810.51	546.19	-757.26	-4517.54	7213.27
27	3600.0	0.00	3613.22	-1817.59	-2818.45	0.00	1638.50	1656.79	346.09	790.79	548.15	1656.79	1450.28	810.50	546.17	-757.28	-4517.59	7213.27
28	3999.9	0.00	3613.22	-2020.96	-3021.92	0.00	1575.67	1598.81	316.86	722.63	457.28	1598.81	1371.11	748.51	455.70	-837.30	-4720.96	7213.28
29	4000.0	0.00	3613.22	-2021.01	-3021.97	0.00	1575.66	1598.80	316.85	722.61	457.26	1598.80	1371.09	748.49	455.68	-837.32	-4721.01	7213.27
30	4099.9	0.00	3613.22	-2071.79	-3072.77	0.00	1559.97	1584.58	310.36	705.59	434.81	1584.58	1351.33	733.01	433.41	-857.29	-4771.79	7213.28
31	4100.1	0.00	3613.22	-2071.89	-3072.87	0.00	1559.94	1584.55	310.35	705.56	434.77	1584.55	1351.29	732.98	433.37	-857.33	-4771.89	7213.28
32	4399.9	0.00	3613.22	-2224.03	-3225.08	0.00	1512.18	1541.94	290.89	653.83	367.53	1541.94	1292.06	686.61	366.66	-917.19	-4924.03	7213.28
33	4400.0	0.00	3613.22	-2224.08	-3225.13	0.00	1512.16	1541.93	290.89	653.81	367.50	1541.93	1292.04	686.59	366.64	-917.21	-4924.08	7213.28
34	4500.0	0.00	3613.22	-2274.54	-3275.62	0.00	1495.82	1527.80	284.43	636.16	345.20	1527.80	1272.40	671.21	344.51	-937.07	-4974.54	7213.28
35	4799.9	0.00	3613.21	-2424.86	-3426.00	0.00	1447.38	1485.46	265.22	583.85	278.77	1485.46	1213.72	625.16	278.48	-996.21	-5124.86	7213.28
36	4800.0	0.00	3613.21	-2424.91	-3426.05	0.00	1447.36	1485.45	265.22	583.83	278.74	1485.45	1213.70	625.14	278.46	-996.23	-5124.91	7213.28
37	5000.0	0.00	3613.22	-2523.77	-3524.96	0.00	1415.51	1457.87	252.58	549.43	235.20	1457.87	1175.03	595.19	234.97	-1035.13	-5223.77	7213.28
38	5129.5	0.00	3613.22	-2587.10	-3588.31	0.00	1394.31	1440.46	242.75	526.66	207.39	1440.46	1151.04	576.30	207.76	-1059.26	-5287.10	7213.28
39	5129.6	0.00	3613.22	-2587.14	-3588.36	0.00	1394.30	1440.44	242.74	526.64	207.37	1440.44	1151.03	576.28	207.74	-1059.28	-5287.14	7213.28
40	5499.9	0.00	3613.22	-2767.28	-3768.58	0.00	1334.00	1390.67	214.78	461.87	128.40	1390.67	1082.55	522.24	130.16	-1127.94	-5467.28	7213.27
41	5500.0	0.00	3613.22	-2767.33	-3768.63	0.00	1333.99	1390.66	214.77	461.85	128.38	1390.66	1082.53	522.22	130.14	-1127.96	-5467.33	7213.27
42	5899.9	0.00	3613.23	-2961.91	-3963.30	0.00	1268.85	1336.84	208.76	391.89	43.08	1336.84	1008.57	463.85	46.34	-1202.12	-5661.91	7213.27
43	5900.0	0.00	3613.23	-2961.95	-3963.35	0.00	1268.84	1336.83	208.76	391.87	43.05	1336.83	1008.55	463.83	46.32	-1202.14	-5661.95	7213.26
44	6000.0	0.00	3613.23	-3010.60	-4012.01	0.00	1252.55	1323.37	207.25	374.38	21.73	1323.37	990.07	449.24	25.37	-1220.68	-5710.60	7213.27
45	6299.9	0.00	3613.23	-3156.48	-4157.96	0.00	1203.72	1283.02	191.29	321.92	-42.23	1283.02	934.61	405.47	-37.46	-1276.28	-5856.48	7213.27
46	6300.0	0.00	3613.23	-3156.53	-4158.01	0.00	1203.70	1283.00	191.28	321.90	-42.25	1283.00	934.59	405.46	-37.48	-1276.30	-5856.53	7213.27
47	6500.0	0.00	3613.24	-3253.82	-4255.35	0.00	1171.14	1256.09	180.64	286.21	-84.90	1256.09	897.61	376.27	-79.38	-1313.38	-5953.82	7213.26
48	6699.9	0.00	3613.24	-3351.06	-4352.63	0.00	1138.59	1229.20	170.00	249.83	-127.53	1229.20	860.65	347.10	-119.93	-1350.44	-6051.06	7213.26
49	6700.0	0.00	3613.24	-3351.11	-4352.68	0.00	1138.57	1229.18	170.00	249.82	-127.55	1229.18	860.63	347.08	-119.95	-1350.46	-6051.11	7213.26
50	7000.0	0.00	3613.24	-3497.08	-4498.72	0.00	1087.76	1188.81	154.02	195.21	-191.55	1188.81	805.86	303.80	-180.82	-1405.38	-6197.08	7213.26
51	7099.9	0.00	3613.24	-3545.68	-4547.35	0.00	1070.83	1175.36	148.71	177.03	-212.86	1175.36	787.95	289.72	-201.09	-1423.34	-6245.68	7213.25
52	7100.0	0.00	3613.24	-3545.73	-4547.40	0.00	1070.82	1175.35	148.70	177.01	-212.88	1175.35	787.94	289.70	-201.11	-1423.36	-6245.73	7213.25
53	7499.9	0.00	3613.25	-3740.26	-4742.02	0.00	1003.09	1122.96	127.42	104.24	-298.16	1122.96	716.28	233.36	-282.23	-1495.22	-6440.26	7213.25
54	7500.0	0.00	3613.25	-3740.31	-4742.07	0.00	1003.08	1122.94	127.41	104.22	-298.18	1122.94	716.26	233.35	-282.25	-1495.24	-6440.31	7213.25
55	7599.9	0.00	3613.25	-3788.90	-4790.68	0.00	986.16	1109.97	122.10	86.04	-319.49	1109.97	698.36	219.27	-302.52	-1513.19	-6488.90	7213.25

Packer Operating Envelope - - 5 1/2" Production Tubing - Packer #1 (Packer @ 7600.00 ft MD)

	Load	Tubing-to-Packer Force (lbf)	Annular Differential Pressure (psi)
1	Initial Conditions	-15001	0
2	PressureTest #1	45038	3613
3	Evacuation #1	-57705	-3789
4	AnnularPressureTest #1	-71980	-4791
5	CO2 Injection Transient 40F 2700 psi	72088	986
6	CO2 Injection Steady 40F 2700 psi	103056	1110
7	Blowout Scenario 112 MMscfd	-14517	122
8	CO2 Injection Transient 40F 1900 psi	57907	86
9	CO2 Injection Transient 90F 1900 psi	11103	-319
10	CO2 Steady 40 F 2700 psi	103056	1110
11	CO2 Steady 90 F 2700 psi	34769	698
12	CO2 Steady 40 F 1900 psi	87306	219
13	CO2 Steady 90 F 1900 psi	15497	-303
14	Tubing Leak	3306	-1513
15	Tubing Leak + Evacuation	-96193	-6489
16	Doubled Pressure Test	105540	7213
17			
18	**The Force sign (+/-) represents the direction of the Tubing-to-Packer force against the packer. Negative forces are in the downward direction.**		

API Safety Factor Summary - Initial Conditions - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	20998.7	D 3.798	N/A	100+	4.156	C 3.801
2	1	100.00	79740.0	20782.7	D 3.837	N/A	100+	4.202	C 3.846
3	1	399.90	79663.0	19906.3	D 4.002	N/A	100+	4.402	C 4.043
4	1	400.00	79663.0	19906.0	D 4.002	N/A	100+	4.402	C 4.043
5	1	500.00	79636.5	19613.7	D 4.060	N/A	100+	4.472	C 4.114
6	1	799.90	79559.5	18737.3	D 4.246	N/A	100+	4.699	C 4.341
7	1	800.00	79559.4	18737.0	D 4.246	N/A	100+	4.699	C 4.341
8	1	1000.00	79506.5	18152.5	D 4.380	N/A	100+	4.864	C 4.506
9	1	1199.90	79456.0	17568.3	D 4.523	N/A	100+	5.041	C 4.686
10	1	1200.00	79455.9	17568.0	D 4.523	N/A	100+	5.041	C 4.686
11	1	1500.00	79378.9	16691.3	D 4.756	N/A	100+	5.333	C 4.984
12	1	1599.90	79352.4	16399.3	D 4.839	N/A	100+	5.437	C 5.092
13	1	1600.00	79352.4	16399.0	D 4.839	N/A	100+	5.438	C 5.092
14	1	1999.90	79248.9	15230.3	D 5.203	N/A	100+	5.903	C 5.576
15	1	2000.00	79248.9	15230.1	D 5.203	N/A	100+	5.903	C 5.576
16	1	2399.90	79145.4	14061.4	D 5.629	N/A	100+	6.457	C 6.164
17	1	2400.00	79145.4	14061.1	D 5.629	N/A	100+	6.458	C 6.165
18	1	2500.00	79118.9	13768.8	D 5.746	N/A	100+	6.613	C 6.332
19	1	2799.90	79041.9	12892.4	D 6.131	N/A	100+	7.128	C 6.893
20	1	2800.00	79041.8	12892.1	D 6.131	N/A	100+	7.129	C 6.893
21	1	3000.00	78988.9	12307.6	D 6.418	N/A	100+	7.520	C 7.327
22	1	3199.90	78938.4	11723.4	D 6.733	N/A	100+	7.958	C 7.820
23	1	3200.00	78938.3	11723.1	D 6.734	N/A	100+	7.958	C 7.821
24	1	3500.00	78861.3	10846.4	D 7.271	N/A	100+	8.721	C 8.700
25	1	3599.90	78834.8	10554.4	D 7.469	N/A	100+	9.008	C 9.039
26	1	3600.00	78834.8	10554.1	D 7.470	N/A	100+	9.009	C 9.040
27	1	3999.90	78731.3	9385.4	D 8.389	N/A	100+	10.383	C 10.713
28	1	4000.00	78731.3	9385.1	D 8.389	N/A	100+	10.383	C 10.714
29	1	4099.90	78704.8	9093.3	D 8.655	N/A	100+	10.795	C 11.234
30	1	4100.10	78704.8	9092.7	D 8.656	N/A	100+	10.796	C 11.235
31	1	4399.90	78627.8	8218.5	D 9.567	N/A	100+	12.254	C 13.151
32	1	4400.00	78627.8	8218.2	D 9.568	N/A	100+	12.255	C 13.152
33	1	4500.00	78601.3	7928.2	D 9.914	N/A	100+	12.830	C 13.942
34	1	4799.90	78526.7	7064.4	D 11.116	N/A	100+	14.921	C 16.984
35	1	4800.00	78526.7	7064.1	D 11.116	N/A	100+	14.922	C 16.985
36	1	5000.00	78476.1	6496.0	D 12.081	N/A	100+	16.716	C 19.836
37	1	5499.90	78350.9	5096.4	D 15.374	N/A	100+	23.775	C 33.876
38	1	5500.00	78350.9	5096.4	D 15.374	N/A	100+	23.774	C 33.876
39	1	5899.90	78252.2	3977.9	D 19.672	N/A	100+	35.934	CM 30.111
40	1	5900.00	78252.2	3978.0	D 19.671	N/A	100+	35.933	CM 30.111
41	1	6000.00	78228.1	3698.5	D 21.152	N/A	100+	41.210	CM 26.726
42	1	6299.90	78153.5	2859.8	D 27.328	N/A	100+	73.729	CM 19.980
43	1	6300.00	78153.5	2859.9	D 27.328	N/A	100+	73.726	CM 19.980
44	1	6500.00	78105.4	2300.8	D 33.947	N/A	100+	100+	CM 17.098
45	1	6699.90	78054.8	1857.0	DN 42.033	N/A	100+	100+	CM 14.940
46	1	6700.00	78054.8	1856.9	DN 42.034	N/A	100+	100+	CM 14.940
47	1	7000.00	77980.2	2695.8	DN 28.927	N/A	100+	100+	CM 12.558
48	1	7099.90	77956.1	2975.4	DN 26.200	N/A	100+	100+	CM 11.924
49	1	7100.00	77956.1	2975.4	DN 26.201	N/A	100+	100+	CM 11.924
50	1	7499.90	77857.4	4093.6	DN 19.019	N/A	100+	100+	CM 9.917
51	1	7500.00	77857.4	4093.5	DN 19.020	N/A	100+	100+	CM 9.917
52	1	7599.90	77833.4	4373.1	DN 17.798	N/A	100+	100+	CM 9.516
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - PressureTest #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	32280.5	2.471	N/A	2.536	100+	C 2.881
2	1	100.00	79740.0	32184.9	2.478	N/A	2.535	100+	C 2.907
3	1	399.90	79663.0	31809.0	2.504	N/A	2.532	100+	C 3.017
4	1	400.00	79663.0	31808.9	2.504	N/A	2.532	100+	C 3.017
5	1	500.00	79636.5	31687.9	2.513	N/A	2.532	100+	C 3.056
6	1	799.90	79559.5	31338.8	2.539	N/A	2.529	100+	C 3.179
7	1	800.00	79559.4	31338.6	2.539	N/A	2.529	100+	C 3.179
8	1	1000.00	79506.5	31117.3	2.555	N/A	2.527	100+	C 3.266
9	1	1199.90	79456.0	30905.6	2.571	N/A	2.526	100+	C 3.359
10	1	1200.00	79455.9	30905.5	2.571	N/A	2.526	100+	C 3.359
11	1	1500.00	79378.9	30605.9	2.594	N/A	2.523	100+	C 3.508
12	1	1599.90	79352.4	30511.1	2.601	N/A	2.523	100+	C 3.561
13	1	1600.00	79352.4	30511.0	2.601	N/A	2.523	100+	C 3.561
14	1	1999.90	79248.9	30156.8	2.628	N/A	2.519	100+	C 3.790
15	1	2000.00	79248.9	30156.7	2.628	N/A	2.519	100+	C 3.790
16	1	2399.90	79145.4	29844.1	2.652	N/A	2.516	100+	C 4.050
17	1	2400.00	79145.4	29844.1	2.652	N/A	2.516	100+	C 4.050
18	1	2500.00	79118.9	29772.6	2.657	N/A	2.515	100+	C 4.121
19	1	2799.90	79041.9	29574.4	2.673	N/A	2.513	100+	C 4.351
20	1	2800.00	79041.8	29574.3	2.673	N/A	2.513	100+	C 4.351
21	1	3000.00	78988.9	29455.9	2.682	N/A	2.511	100+	C 4.519
22	1	3199.90	78938.4	29348.7	2.690	N/A	2.509	100+	C 4.700
23	1	3200.00	78938.3	29348.7	2.690	N/A	2.509	100+	C 4.700
24	1	3500.00	78861.3	29209.0	2.700	N/A	2.507	100+	C 5.002
25	1	3599.90	78834.8	29168.2	2.703	N/A	2.506	100+	C 5.112
26	1	3600.00	78834.8	29168.2	2.703	N/A	2.506	100+	C 5.112
27	1	3999.90	78731.3	29033.7	2.712	N/A	2.503	100+	C 5.604
28	1	4000.00	78731.3	29033.7	2.712	N/A	2.503	100+	C 5.604
29	1	4099.90	78704.8	29007.3	2.713	N/A	2.502	100+	C 5.742
30	1	4100.10	78704.8	29007.3	2.713	N/A	2.502	100+	C 5.742
31	1	4399.90	78627.8	28945.9	2.716	N/A	2.500	100+	C 6.201
32	1	4400.00	78627.8	28945.9	2.716	N/A	2.500	100+	C 6.201
33	1	4500.00	78601.3	28959.3	N 2.714	N/A	2.499	100+	C 6.370
34	1	4799.90	78526.7	29025.9	N 2.705	N/A	2.496	100+	C 6.934
35	1	4800.00	78526.7	29025.9	N 2.705	N/A	2.496	100+	C 6.934
36	1	5000.00	78476.1	29084.6	N 2.698	N/A	2.495	100+	C 7.364
37	1	5499.90	78350.9	29273.7	N 2.677	N/A	2.491	100+	C 8.692
38	1	5500.00	78350.9	29273.6	N 2.677	N/A	2.491	100+	C 8.692
39	1	5899.90	78252.2	29472.4	N 2.655	N/A	2.488	100+	C 10.162
40	1	5900.00	78252.2	29472.4	N 2.655	N/A	2.488	100+	C 10.162
41	1	6000.00	78228.1	29527.9	N 2.649	N/A	2.487	100+	C 10.611
42	1	6299.90	78153.5	29711.7	N 2.630	N/A	2.484	100+	C 12.235
43	1	6300.00	78153.5	29711.6	N 2.630	N/A	2.484	100+	C 12.235
44	1	6500.00	78105.4	29845.4	N 2.617	N/A	2.483	100+	C 13.627
45	1	6699.90	78054.8	30030.3	N 2.599	N/A	2.481	100+	C 14.872
46	1	6700.00	78054.8	30030.3	N 2.599	N/A	2.481	100+	C 14.872
47	1	7000.00	77980.2	30468.2	N 2.559	N/A	2.479	100+	C 15.574
48	1	7099.90	77956.1	30623.9	N 2.546	N/A	2.478	100+	C 15.864
49	1	7100.00	77956.1	30623.9	N 2.546	N/A	2.478	100+	C 15.864
50	1	7499.90	77857.4	31309.5	N 2.487	N/A	2.475	100+	C 17.230
51	1	7500.00	77857.4	31309.5	N 2.487	N/A	2.475	100+	C 17.230
52	1	7599.90	77833.4	31496.2	N 2.471	N/A	2.474	100+	C 17.616
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - Evacuation #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	17460.6	D 4.568	N/A	100+	5.095	C 4.568
2	1	100.00	79740.0	17382.3	D 4.587	N/A	100+	5.126	C 4.634
3	1	399.90	79663.0	17097.6	D 4.659	N/A	100+	5.239	C 4.924
4	1	400.00	79663.0	17097.5	D 4.659	N/A	100+	5.239	C 4.925
5	1	500.00	79636.5	17014.9	D 4.680	N/A	100+	5.271	C 5.030
6	1	799.90	79559.5	16805.1	D 4.734	N/A	100+	5.352	C 5.374
7	1	800.00	79559.4	16805.0	D 4.734	N/A	100+	5.352	C 5.374
8	1	1000.00	79506.5	16697.6	D 4.762	N/A	100+	5.389	C 5.632
9	1	1199.90	79456.0	16653.3	4.771	N/A	100+	5.413	C 5.915
10	1	1200.00	79455.9	16653.3	4.771	N/A	100+	5.413	C 5.916
11	1	1500.00	79378.9	16739.8	4.742	N/A	100+	5.421	C 6.400
12	1	1599.90	79352.4	16789.6	4.726	N/A	100+	5.416	C 6.580
13	1	1600.00	79352.4	16789.7	4.726	N/A	100+	5.416	C 6.580
14	1	1999.90	79248.9	17091.6	4.637	N/A	100+	5.361	C 7.416
15	1	2000.00	79248.9	17091.7	4.637	N/A	100+	5.361	C 7.416
16	1	2399.90	79145.4	17550.6	4.510	N/A	100+	5.251	C 8.497
17	1	2400.00	79145.4	17550.8	4.510	N/A	100+	5.251	C 8.498
18	1	2500.00	79118.9	17688.7	4.473	N/A	100+	5.216	C 8.820
19	1	2799.90	79041.9	18154.8	4.354	N/A	100+	5.097	C 9.953
20	1	2800.00	79041.8	18155.0	4.354	N/A	100+	5.097	C 9.953
21	1	3000.00	78988.9	18507.2	4.268	N/A	100+	4.833	C 10.887
22	1	3199.90	78938.4	18890.2	4.179	N/A	100+	4.691	C 12.017
23	1	3200.00	78938.3	18890.4	4.179	N/A	100+	4.691	C 12.017
24	1	3500.00	78861.3	19519.2	4.040	N/A	100+	4.477	C 14.237
25	1	3599.90	78834.8	19742.1	3.993	N/A	100+	4.407	C 15.171
26	1	3600.00	78834.8	19742.3	3.993	N/A	100+	4.407	C 15.172
27	1	3999.90	78731.3	20696.2	3.804	N/A	100+	4.131	C 20.589
28	1	4000.00	78731.3	20696.5	3.804	N/A	100+	4.131	C 20.591
29	1	4099.90	78704.8	20949.0	3.757	N/A	100+	4.065	C 22.610
30	1	4100.10	78704.8	20949.5	3.757	N/A	100+	4.065	C 22.614
31	1	4399.90	78627.8	21737.2	3.617	N/A	100+	3.873	C 32.043
32	1	4400.00	78627.8	21737.4	3.617	N/A	100+	3.872	C 32.047
33	1	4500.00	78601.3	22008.4	3.571	N/A	100+	3.811	C 37.198
34	1	4799.90	78526.7	22841.8	3.438	N/A	100+	3.593	CM 31.414
35	1	4800.00	78526.7	22842.0	3.438	N/A	100+	3.593	CM 31.410
36	1	5000.00	78476.1	23410.0	3.352	N/A	100+	3.451	CM 24.778
37	1	5499.90	78350.9	24868.4	3.151	N/A	100+	3.143	CM 16.288
38	1	5500.00	78350.9	24868.9	3.151	N/A	100+	3.143	CM 16.288
39	1	5899.90	78252.2	26087.6	3.000	N/A	100+	2.934	CM 12.779
40	1	5900.00	78252.2	26088.1	3.000	N/A	100+	2.934	CM 12.779
41	1	6000.00	78228.1	26399.4	2.963	N/A	100+	2.886	CM 12.125
42	1	6299.90	78153.5	27347.1	2.858	N/A	100+	2.750	CM 10.509
43	1	6300.00	78153.5	27347.5	2.858	N/A	100+	2.750	CM 10.509
44	1	6500.00	78105.4	27990.7	2.790	N/A	100+	2.667	CM 9.651
45	1	6699.90	78054.8	28641.7	2.725	N/A	100+	2.588	CM 8.921
46	1	6700.00	78054.8	28642.1	2.725	N/A	100+	2.588	CM 8.921
47	1	7000.00	77980.2	29633.7	2.631	N/A	100+	2.478	CM 8.011
48	1	7099.90	77956.1	29967.3	2.601	N/A	100+	2.444	CM 7.747
49	1	7100.00	77956.1	29967.8	2.601	N/A	100+	2.444	CM 7.747
50	1	7499.90	77857.4	31319.4	2.486	N/A	100+	2.315	CM 6.844
51	1	7500.00	77857.4	31319.8	2.486	N/A	100+	2.315	CM 6.844
52	1	7599.90	77833.4	31661.2	2.458	N/A	100+	2.284	CM 6.650
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - AnnularPressureTest #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	20980.0	3.802	N/A	100+	4.272	C 5.313
2	1	100.00	79740.0	21023.0	3.793	N/A	100+	4.269	C 5.403
3	1	399.90	79663.0	21243.7	3.750	N/A	100+	4.246	C 5.802
4	1	400.00	79663.0	21243.8	3.750	N/A	100+	4.246	C 5.802
5	1	500.00	79636.5	21333.5	3.733	N/A	100+	4.235	C 5.949
6	1	799.90	79559.5	21649.4	3.675	N/A	100+	4.192	C 6.438
7	1	800.00	79559.4	21649.5	3.675	N/A	100+	4.192	C 6.439
8	1	1000.00	79506.5	21898.2	3.631	N/A	100+	4.155	C 6.813
9	1	1199.90	79456.0	22176.0	3.583	N/A	100+	4.113	C 7.233
10	1	1200.00	79455.9	22176.2	3.583	N/A	100+	4.113	C 7.234
11	1	1500.00	79378.9	22645.5	3.505	N/A	100+	4.040	C 7.974
12	1	1599.90	79352.4	22815.1	3.478	N/A	100+	4.013	C 8.256
13	1	1600.00	79352.4	22815.3	3.478	N/A	100+	4.013	C 8.256
14	1	1999.90	79248.9	23557.5	3.364	N/A	100+	3.737	C 9.618
15	1	2000.00	79248.9	23557.7	3.364	N/A	100+	3.737	C 9.619
16	1	2399.90	79145.4	24393.9	3.244	N/A	100+	3.560	C 11.526
17	1	2400.00	79145.4	24394.1	3.244	N/A	100+	3.560	C 11.526
18	1	2500.00	79118.9	24616.7	3.214	N/A	100+	3.516	C 12.129
19	1	2799.90	79041.9	25314.8	3.122	N/A	100+	3.385	C 14.386
20	1	2800.00	79041.8	25315.0	3.122	N/A	100+	3.385	C 14.387
21	1	3000.00	78988.9	25804.4	3.061	N/A	100+	3.300	C 16.430
22	1	3199.90	78938.4	26311.4	3.000	N/A	100+	3.217	C 19.152
23	1	3200.00	78938.3	26311.7	3.000	N/A	100+	3.217	C 19.153
24	1	3500.00	78861.3	27103.8	2.910	N/A	100+	3.096	C 25.505
25	1	3599.90	78834.8	27375.5	2.880	N/A	100+	3.056	C 28.676
26	1	3600.00	78834.8	27375.8	2.880	N/A	100+	3.056	C 28.679
27	1	3999.90	78731.3	28499.5	2.763	N/A	100+	2.889	CM 35.434
28	1	4000.00	78731.3	28499.7	2.763	N/A	100+	2.889	CM 35.429
29	1	4099.90	78704.8	28788.8	2.734	N/A	100+	2.840	CM 30.686
30	1	4100.10	78704.8	28789.4	2.734	N/A	100+	2.840	CM 30.678
31	1	4399.90	78627.8	29674.4	2.650	N/A	100+	2.704	CM 21.889
32	1	4400.00	78627.8	29674.7	2.650	N/A	100+	2.704	CM 21.887
33	1	4500.00	78601.3	29974.2	2.622	N/A	100+	2.662	CM 19.986
34	1	4799.90	78526.7	30882.5	2.543	N/A	100+	2.543	CM 15.873
35	1	4800.00	78526.7	30882.8	2.543	N/A	100+	2.543	CM 15.872
36	1	5000.00	78476.1	31492.7	2.492	N/A	100+	2.471	CM 13.977
37	1	5499.90	78350.9	33033.5	2.372	N/A	100+	2.308	CM 10.795
38	1	5500.00	78350.9	33033.9	2.372	N/A	100+	2.308	CM 10.795
39	1	5899.90	78252.2	34300.5	2.281	N/A	100+	2.193	CM 9.130
40	1	5900.00	78252.2	34301.0	2.281	N/A	100+	2.193	CM 9.130
41	1	6000.00	78228.1	34622.1	2.259	N/A	100+	2.165	CM 8.790
42	1	6299.90	78153.5	35595.1	2.196	N/A	100+	2.088	CM 7.907
43	1	6300.00	78153.5	35595.6	2.196	N/A	100+	2.088	CM 7.907
44	1	6500.00	78105.4	36252.4	2.154	N/A	100+	2.039	CM 7.410
45	1	6699.90	78054.8	36914.6	2.114	N/A	100+	1.993	CM 6.971
46	1	6700.00	78054.8	36915.1	2.114	N/A	100+	1.993	CM 6.971
47	1	7000.00	77980.2	37919.8	2.056	N/A	100+	1.927	CM 6.401
48	1	7099.90	77956.1	38256.9	2.038	N/A	100+	1.906	CM 6.231
49	1	7100.00	77956.1	38257.3	2.038	N/A	100+	1.906	CM 6.231
50	1	7499.90	77857.4	39618.8	1.965	N/A	100+	1.826	CM 5.632
51	1	7500.00	77857.4	39619.2	1.965	N/A	100+	1.826	CM 5.632
52	1	7599.90	77833.4	39962.2	1.948	N/A	100+	1.807	CM 5.500
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - OverPull #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	40730.1	D 1.958	N/A	100+	2.050	1.960
2	1	100.00	79740.0	40514.1	D 1.968	N/A	100+	2.061	1.972
3	1	399.90	79663.0	39637.7	D 2.010	N/A	100+	2.106	2.021
4	1	400.00	79663.0	39637.4	D 2.010	N/A	100+	2.106	2.021
5	1	500.00	79636.5	39345.1	D 2.024	N/A	100+	2.122	2.038
6	1	799.90	79559.5	38468.7	D 2.068	N/A	100+	2.171	2.092
7	1	800.00	79559.4	38468.4	D 2.068	N/A	100+	2.171	2.092
8	1	1000.00	79506.5	37883.9	D 2.099	N/A	100+	2.204	2.129
9	1	1199.90	79456.0	37299.7	D 2.130	N/A	100+	2.239	2.167
10	1	1200.00	79455.9	37299.4	D 2.130	N/A	100+	2.239	2.167
11	1	1500.00	79378.9	36422.7	D 2.179	N/A	100+	2.294	2.227
12	1	1599.90	79352.4	36130.7	D 2.196	N/A	100+	2.312	2.248
13	1	1600.00	79352.4	36130.5	D 2.196	N/A	100+	2.312	2.248
14	1	1999.90	79248.9	34961.8	D 2.267	N/A	100+	2.391	C 2.335
15	1	2000.00	79248.9	34961.5	D 2.267	N/A	100+	2.391	C 2.335
16	1	2399.90	79145.4	33792.8	D 2.342	N/A	100+	2.475	C 2.430
17	1	2400.00	79145.4	33792.5	D 2.342	N/A	100+	2.475	C 2.430
18	1	2500.00	79118.9	33500.2	D 2.362	N/A	100+	2.497	C 2.455
19	1	2799.90	79041.9	32623.8	D 2.423	N/A	100+	2.565	C 2.534
20	1	2800.00	79041.8	32623.5	D 2.423	N/A	100+	2.565	C 2.534
21	1	3000.00	78988.9	32039.0	D 2.465	N/A	100+	2.613	C 2.589
22	1	3199.90	78938.4	31454.8	D 2.510	N/A	100+	2.663	C 2.647
23	1	3200.00	78938.3	31454.5	D 2.510	N/A	100+	2.663	C 2.647
24	1	3500.00	78861.3	30577.8	D 2.579	N/A	100+	2.741	C 2.739
25	1	3599.90	78834.8	30285.8	D 2.603	N/A	100+	2.769	C 2.771
26	1	3600.00	78834.8	30285.5	D 2.603	N/A	100+	2.769	C 2.771
27	1	3999.90	78731.3	29116.8	D 2.704	N/A	100+	2.883	C 2.907
28	1	4000.00	78731.3	29116.6	D 2.704	N/A	100+	2.883	C 2.907
29	1	4099.90	78704.8	28824.8	D 2.730	N/A	100+	2.914	C 2.944
30	1	4100.10	78704.8	28824.2	D 2.731	N/A	100+	2.914	C 2.944
31	1	4399.90	78627.8	27949.9	D 2.813	N/A	100+	3.008	C 3.058
32	1	4400.00	78627.8	27949.6	D 2.813	N/A	100+	3.008	C 3.058
33	1	4500.00	78601.3	27659.6	D 2.842	N/A	100+	3.041	C 3.098
34	1	4799.90	78526.7	26795.8	D 2.931	N/A	100+	3.143	C 3.224
35	1	4800.00	78526.7	26795.5	D 2.931	N/A	100+	3.143	C 3.224
36	1	5000.00	78476.1	26227.4	D 2.992	N/A	100+	3.214	C 3.313
37	1	5499.90	78350.9	24827.8	D 3.156	N/A	100+	3.404	C 3.554
38	1	5500.00	78350.9	24827.8	D 3.156	N/A	100+	3.404	C 3.554
39	1	5899.90	78252.2	23709.3	D 3.300	N/A	100+	3.573	C 3.775
40	1	5900.00	78252.2	23709.4	D 3.300	N/A	100+	3.573	C 3.775
41	1	6000.00	78228.1	23429.9	D 3.339	N/A	100+	3.618	C 3.834
42	1	6299.90	78153.5	22591.2	D 3.459	N/A	100+	3.761	C 4.025
43	1	6300.00	78153.5	22591.3	D 3.459	N/A	100+	3.760	C 4.025
44	1	6500.00	78105.4	22032.2	D 3.545	N/A	100+	3.862	C 4.163
45	1	6699.90	78054.8	21473.1	D 3.635	N/A	100+	3.969	C 4.311
46	1	6700.00	78054.8	21473.1	D 3.635	N/A	100+	3.969	C 4.311
47	1	7000.00	77980.2	20634.3	D 3.779	N/A	100+	4.142	C 4.555
48	1	7099.90	77956.1	20354.6	D 3.830	N/A	100+	4.203	C 4.643
49	1	7100.00	77956.1	20354.7	D 3.830	N/A	100+	4.203	C 4.643
50	1	7499.90	77857.4	19236.5	D 4.047	N/A	100+	4.467	C 5.030
51	1	7500.00	77857.4	19236.6	D 4.047	N/A	100+	4.467	C 5.030
52	1	7599.90	77833.4	18957.0	D 4.106	N/A	100+	4.538	C 5.137
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Injection Transient 40F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	80000.0	31980.2	2.502	N/A	4.177	100+	2.327
2	1	50.00	80000.0	31916.9	2.507	N/A	4.184	100+	C 2.331
3	1	100.00	80000.0	31784.4	2.517	N/A	4.199	100+	C 2.343
4	1	399.90	80000.0	30989.7	2.582	N/A	4.291	100+	C 2.416
5	1	400.00	80000.0	30989.4	2.582	N/A	4.291	100+	C 2.416
6	1	500.00	80000.0	30724.5	2.604	N/A	4.323	100+	C 2.441
7	1	799.90	80000.0	29930.0	2.673	N/A	4.421	100+	C 2.520
8	1	800.00	80000.0	29929.8	2.673	N/A	4.421	100+	C 2.520
9	1	1000.00	80000.0	29400.1	2.721	N/A	4.489	100+	C 2.576
10	1	1199.90	80000.0	28870.7	2.771	N/A	4.559	100+	C 2.634
11	1	1200.00	80000.0	28870.5	2.771	N/A	4.559	100+	C 2.634
12	1	1500.00	80000.0	28076.2	2.849	N/A	4.668	100+	C 2.727
13	1	1599.90	80000.0	27811.8	2.876	N/A	4.706	100+	C 2.759
14	1	1600.00	80000.0	27811.5	2.877	N/A	4.706	100+	C 2.759
15	1	1999.90	80000.0	26753.4	2.990	N/A	4.862	100+	C 2.896
16	1	2000.00	80000.0	26753.1	2.990	N/A	4.862	100+	C 2.896
17	1	2399.90	80000.0	25695.4	3.113	N/A	5.029	100+	C 3.047
18	1	2400.00	80000.0	25695.1	3.113	N/A	5.030	100+	C 3.047
19	1	2500.00	80000.0	25430.7	3.146	N/A	5.073	100+	C 3.088
20	1	2799.90	80000.0	24638.0	3.247	N/A	5.209	100+	C 3.215
21	1	2800.00	80000.0	24637.7	3.247	N/A	5.209	100+	C 3.215
22	1	3000.00	80000.0	24109.3	3.318	N/A	5.303	100+	C 3.307
23	1	3199.90	80000.0	23581.2	3.393	N/A	5.401	100+	C 3.403
24	1	3200.00	80000.0	23581.0	3.393	N/A	5.401	100+	C 3.403
25	1	3500.00	80000.0	22788.9	3.510	N/A	5.555	100+	C 3.559
26	1	3599.90	80000.0	22525.2	3.552	N/A	5.608	100+	C 3.614
27	1	3600.00	80000.0	22524.9	3.552	N/A	5.608	100+	C 3.614
28	1	3999.90	80000.0	21470.0	3.726	N/A	5.832	100+	C 3.853
29	1	4000.00	80000.0	21469.7	3.726	N/A	5.832	100+	C 3.853
30	1	4099.90	80000.0	21206.5	3.772	N/A	5.891	100+	C 3.918
31	1	4100.10	80000.0	21206.0	3.773	N/A	5.891	100+	C 3.918
32	1	4399.90	79980.8	20416.2	3.918	N/A	6.075	100+	C 4.124
33	1	4400.00	79980.7	20416.0	3.918	N/A	6.075	100+	C 4.124
34	1	4500.00	79959.1	20153.2	3.968	N/A	6.140	100+	C 4.197
35	1	4799.90	79886.9	19371.1	4.124	N/A	6.340	100+	C 4.429
36	1	4800.00	79886.8	19370.8	4.124	N/A	6.340	100+	C 4.429
37	1	5000.00	79838.7	18856.7	4.234	N/A	6.479	100+	C 4.596
38	1	5499.90	79713.5	17584.8	4.533	N/A	6.864	100+	C 5.069
39	1	5500.00	79713.5	17584.8	4.533	N/A	6.864	100+	C 5.069
40	1	5899.90	79610.0	16569.3	4.805	N/A	7.207	100+	C 5.523
41	1	5900.00	79610.0	16569.3	4.805	N/A	7.207	100+	C 5.523
42	1	6000.00	79583.5	16315.6	4.878	N/A	7.298	100+	C 5.650
43	1	6299.90	79506.5	15555.0	5.111	N/A	7.587	100+	C 6.069
44	1	6300.00	79506.5	15555.0	5.111	N/A	7.587	100+	C 6.069
45	1	6500.00	79455.9	15048.3	5.280	N/A	7.793	100+	C 6.385
46	1	6699.90	79403.0	14542.0	5.460	N/A	8.010	100+	C 6.736
47	1	6700.00	79403.0	14542.0	5.460	N/A	8.010	100+	C 6.736
48	1	7000.00	79325.9	13778.5	5.757	N/A	8.377	100+	C 7.343
49	1	7099.90	79299.5	13524.1	5.864	N/A	8.506	100+	C 7.571
50	1	7100.00	79299.4	13524.1	5.864	N/A	8.506	100+	C 7.571
51	1	7499.90	79198.4	12507.9	6.332	N/A	9.069	100+	C 8.645
52	1	7500.00	79198.3	12507.9	6.332	N/A	9.069	100+	C 8.645
53	1	7599.90	79169.5	12254.1	6.461	N/A	9.221	100+	C 8.963
54									
55	**Burst and Axial Flags**								
56	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
57									
58	**Axial Flags**								
59	**Default = Tension, M = Compression**								
60									
61	**Triaxial Flags**								
62	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
63									
64	**Envelope Flags**								
65	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
66									
67	**Collapse Flags**								
68	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Injection Steady 40F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	80000.0	36404.7	2.198	N/A	4.177	100+	2.023
2	1	100.00	80000.0	36208.2	2.209	N/A	4.199	100+	2.036
3	1	399.90	80000.0	35410.8	2.259	N/A	4.291	100+	2.091
4	1	400.00	80000.0	35410.5	2.259	N/A	4.291	100+	2.091
5	1	500.00	80000.0	35144.7	2.276	N/A	4.322	100+	2.110
6	1	799.90	80000.0	34347.3	2.329	N/A	4.419	100+	2.169
7	1	800.00	80000.0	34347.0	2.329	N/A	4.419	100+	2.169
8	1	1000.00	80000.0	33815.3	2.366	N/A	4.487	100+	2.210
9	1	1199.90	80000.0	33283.8	2.404	N/A	4.556	100+	2.253
10	1	1200.00	80000.0	33283.5	2.404	N/A	4.556	100+	2.253
11	1	1500.00	80000.0	32485.9	2.463	N/A	4.664	100+	2.320
12	1	1599.90	80000.0	32220.3	2.483	N/A	4.702	100+	C 2.342
13	1	1600.00	80000.0	32220.0	2.483	N/A	4.702	100+	C 2.342
14	1	1999.90	80000.0	31157.4	2.568	N/A	4.855	100+	C 2.440
15	1	2000.00	80000.0	31157.2	2.568	N/A	4.855	100+	C 2.440
16	1	2399.90	80000.0	30096.5	2.658	N/A	5.011	100+	C 2.546
17	1	2400.00	80000.0	30096.2	2.658	N/A	5.011	100+	C 2.546
18	1	2500.00	80000.0	29831.0	2.682	N/A	5.052	100+	C 2.574
19	1	2799.90	80000.0	29035.6	2.755	N/A	5.177	100+	C 2.663
20	1	2800.00	80000.0	29035.3	2.755	N/A	5.178	100+	C 2.663
21	1	3000.00	80000.0	28504.9	2.807	N/A	5.265	100+	C 2.725
22	1	3199.90	80000.0	27974.8	2.860	N/A	5.356	100+	C 2.790
23	1	3200.00	80000.0	27974.6	2.860	N/A	5.356	100+	C 2.790
24	1	3500.00	80000.0	27179.1	2.943	N/A	5.497	100+	C 2.894
25	1	3599.90	80000.0	26914.2	2.972	N/A	5.546	100+	C 2.930
26	1	3600.00	80000.0	26913.9	2.972	N/A	5.546	100+	C 2.930
27	1	3999.90	80000.0	25854.4	3.094	N/A	5.747	100+	C 3.086
28	1	4000.00	80000.0	25854.2	3.094	N/A	5.748	100+	C 3.086
29	1	4099.90	80000.0	25589.9	3.126	N/A	5.799	100+	C 3.127
30	1	4100.10	80000.0	25589.4	3.126	N/A	5.799	100+	C 3.127
31	1	4399.90	80000.0	24797.6	3.226	N/A	5.959	100+	C 3.258
32	1	4400.00	80000.0	24797.4	3.226	N/A	5.959	100+	C 3.258
33	1	4500.00	80000.0	24534.8	3.261	N/A	6.015	100+	C 3.304
34	1	4799.90	80000.0	23752.7	3.368	N/A	6.186	100+	C 3.448
35	1	4800.00	80000.0	23752.5	3.368	N/A	6.186	100+	C 3.448
36	1	5000.00	80000.0	23238.5	3.443	N/A	6.303	100+	C 3.550
37	1	5499.90	80000.0	21973.6	3.641	N/A	6.608	100+	C 3.829
38	1	5500.00	80000.0	21973.7	3.641	N/A	6.608	100+	C 3.829
39	1	5899.90	80000.0	20963.3	3.816	N/A	6.874	100+	C 4.086
40	1	5900.00	80000.0	20963.3	3.816	N/A	6.874	100+	C 4.086
41	1	6000.00	80000.0	20710.9	3.863	N/A	6.944	100+	C 4.156
42	1	6299.90	80000.0	19953.7	4.009	N/A	7.162	100+	C 4.380
43	1	6300.00	80000.0	19953.7	4.009	N/A	7.162	100+	C 4.380
44	1	6500.00	80000.0	19449.1	4.113	N/A	7.316	100+	C 4.543
45	1	6699.90	80000.0	18944.6	4.223	N/A	7.476	100+	C 4.719
46	1	6700.00	80000.0	18944.7	4.223	N/A	7.476	100+	C 4.719
47	1	7000.00	80000.0	18188.1	4.398	N/A	7.730	100+	C 5.010
48	1	7099.90	80000.0	17935.9	4.460	N/A	7.818	100+	C 5.115
49	1	7100.00	80000.0	17936.0	4.460	N/A	7.818	100+	C 5.115
50	1	7499.90	80000.0	16929.9	4.725	N/A	8.183	100+	C 5.584
51	1	7500.00	80000.0	16929.9	4.725	N/A	8.183	100+	C 5.584
52	1	7599.90	80000.0	16678.7	4.797	N/A	8.279	100+	C 5.715
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - Blowout Scenario 112 MMscfd - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	80000.0	20344.0	D 3.932	N/A	51.433	100+	C 3.817
2	1	100.00	80000.0	19466.0	D 4.110	N/A	23.127	100+	C 3.864
3	1	399.90	80000.0	18357.3	D 4.358	N/A	18.818	100+	C 4.066
4	1	400.00	80000.0	18356.9	D 4.358	N/A	18.817	100+	C 4.066
5	1	500.00	80000.0	17994.0	D 4.446	N/A	17.716	100+	C 4.138
6	1	799.90	79641.4	17085.8	D 4.661	N/A	16.980	100+	C 4.351
7	1	800.00	79641.3	17085.5	D 4.661	N/A	16.980	100+	C 4.351
8	1	1000.00	79489.6	16483.0	D 4.823	N/A	16.537	100+	C 4.512
9	1	1199.90	79424.7	15948.7	D 4.980	N/A	17.035	100+	C 4.691
10	1	1200.00	79424.6	15948.4	D 4.980	N/A	17.036	100+	C 4.691
11	1	1500.00	79325.9	15146.6	D 5.237	N/A	17.845	100+	C 4.989
12	1	1599.90	79280.2	14879.6	D 5.328	N/A	18.130	100+	C 5.096
13	1	1600.00	79280.2	14879.4	D 5.328	N/A	18.130	100+	C 5.096
14	1	1999.90	79097.3	13810.6	D 5.727	N/A	19.370	100+	C 5.576
15	1	2000.00	79097.2	13810.3	D 5.727	N/A	19.370	100+	C 5.576
16	1	2399.90	78952.8	12666.8	D 6.233	N/A	19.254	100+	C 6.162
17	1	2400.00	78952.8	12666.5	D 6.233	N/A	19.254	100+	C 6.162
18	1	2500.00	78916.7	12381.5	D 6.374	N/A	19.225	100+	C 6.329
19	1	2799.90	78815.6	11629.9	D 6.777	N/A	21.423	100+	C 6.889
20	1	2800.00	78815.5	11629.6	D 6.777	N/A	21.424	100+	C 6.889
21	1	3000.00	78748.1	11129.2	D 7.076	N/A	23.196	100+	C 7.323
22	1	3199.90	78690.4	10590.8	D 7.430	N/A	24.081	100+	C 7.816
23	1	3200.00	78690.4	10590.5	D 7.430	N/A	24.082	100+	C 7.816
24	1	3500.00	78603.7	9782.6	D 8.035	N/A	25.548	100+	C 8.697
25	1	3599.90	78579.6	9513.6	D 8.260	N/A	26.079	100+	C 9.037
26	1	3600.00	78579.6	9513.4	D 8.260	N/A	26.080	100+	C 9.037
27	1	3999.90	78483.4	8436.9	D 9.302	N/A	28.451	100+	C 10.717
28	1	4000.00	78483.3	8436.6	D 9.303	N/A	28.451	100+	C 10.718
29	1	4099.90	78459.3	8166.3	D 9.608	N/A	29.038	100+	C 11.241
30	1	4100.10	78459.2	8165.8	D 9.608	N/A	29.039	100+	C 11.242
31	1	4399.90	78387.1	7356.4	D 10.656	N/A	30.952	100+	C 13.168
32	1	4400.00	78387.0	7356.1	D 10.656	N/A	30.953	100+	C 13.169
33	1	4500.00	78363.0	7087.8	D 11.056	N/A	31.645	100+	C 13.963
34	1	4799.90	78290.8	6289.3	D 12.448	N/A	33.907	100+	C 17.028
35	1	4800.00	78290.7	6289.0	D 12.449	N/A	33.907	100+	C 17.029
36	1	5000.00	78242.6	5764.6	D 13.573	N/A	35.582	100+	C 19.907
37	1	5499.90	78122.2	4486.8	D 17.411	N/A	41.779	100+	C 34.159
38	1	5500.00	78122.2	4486.9	D 17.411	N/A	41.781	100+	C 34.159
39	1	5899.90	78064.5	3441.9	D 22.681	N/A	42.953	100+	CM 29.743
40	1	5900.00	78064.4	3441.9	D 22.680	N/A	42.954	100+	CM 29.743
41	1	6000.00	78050.0	3186.2	D 24.496	N/A	43.257	100+	CM 26.432
42	1	6299.90	77992.2	2443.0	D 31.925	N/A	46.832	100+	CM 19.808
43	1	6300.00	77992.2	2443.0	D 31.925	N/A	46.833	100+	CM 19.807
44	1	6500.00	77953.7	2289.9	DN 34.042	N/A	49.569	100+	CM 16.969
45	1	6699.90	77924.8	2727.8	DN 28.567	N/A	52.651	100+	CM 14.842
46	1	6700.00	77924.8	2727.7	DN 28.568	N/A	52.653	100+	CM 14.842
47	1	7000.00	77881.5	3430.7	DN 22.701	N/A	58.080	100+	CM 12.490
48	1	7099.90	77864.6	3672.7	DN 21.201	N/A	60.144	100+	CM 11.863
49	1	7100.00	77864.6	3672.7	DN 21.201	N/A	60.146	100+	CM 11.863
50	1	7499.90	77802.1	4662.5	DN 16.687	N/A	70.137	100+	CM 9.878
51	1	7500.00	77802.0	4662.5	DN 16.687	N/A	70.140	100+	CM 9.878
52	1	7599.90	77785.2	4913.8	DN 15.830	N/A	73.178	100+	CM 9.481
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Injection Transient 40F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	80000.0	30216.2	2.648	N/A	6.564	100+	C 2.434
2	1	100.00	80000.0	30021.1	2.665	N/A	6.623	100+	C 2.453
3	1	399.90	80000.0	29230.0	2.737	N/A	6.877	100+	C 2.533
4	1	400.00	80000.0	29229.7	2.737	N/A	6.877	100+	C 2.533
5	1	500.00	80000.0	28966.1	2.762	N/A	6.966	100+	C 2.561
6	1	799.90	80000.0	28175.7	2.839	N/A	7.246	100+	C 2.648
7	1	800.00	80000.0	28175.5	2.839	N/A	7.247	100+	C 2.648
8	1	1000.00	80000.0	27648.7	2.893	N/A	7.447	100+	C 2.710
9	1	1199.90	80000.0	27122.6	2.950	N/A	7.658	100+	C 2.774
10	1	1200.00	80000.0	27122.3	2.950	N/A	7.658	100+	C 2.774
11	1	1500.00	80000.0	26333.3	3.038	N/A	7.999	100+	C 2.877
12	1	1599.90	80000.0	26070.7	3.069	N/A	8.120	100+	C 2.913
13	1	1600.00	80000.0	26070.4	3.069	N/A	8.120	100+	C 2.913
14	1	1999.90	80000.0	25020.2	3.197	N/A	8.640	100+	C 3.066
15	1	2000.00	80000.0	25019.9	3.197	N/A	8.640	100+	C 3.066
16	1	2399.90	80000.0	23971.3	3.337	N/A	9.232	100+	C 3.236
17	1	2400.00	80000.0	23971.1	3.337	N/A	9.232	100+	C 3.236
18	1	2500.00	80000.0	23709.1	3.374	N/A	9.393	100+	C 3.282
19	1	2799.90	80000.0	22924.3	3.490	N/A	9.911	100+	C 3.427
20	1	2800.00	80000.0	22924.0	3.490	N/A	9.911	100+	C 3.427
21	1	3000.00	80000.0	22401.3	3.571	N/A	10.289	100+	C 3.530
22	1	3199.90	80000.0	21879.3	3.656	N/A	10.698	100+	C 3.641
23	1	3200.00	80000.0	21879.1	3.656	N/A	10.698	100+	C 3.641
24	1	3500.00	80000.0	21096.9	3.792	N/A	11.375	100+	C 3.820
25	1	3599.90	80000.0	20836.8	3.839	N/A	11.620	100+	C 3.883
26	1	3600.00	80000.0	20836.5	3.839	N/A	11.620	100+	C 3.883
27	1	3999.90	80000.0	19797.0	4.041	N/A	12.716	100+	C 4.160
28	1	4000.00	80000.0	19796.8	4.041	N/A	12.717	100+	C 4.160
29	1	4099.90	80000.0	19537.7	4.095	N/A	13.023	100+	C 4.236
30	1	4100.10	80000.0	19537.2	4.095	N/A	13.024	100+	C 4.236
31	1	4399.90	79988.0	18763.3	4.263	N/A	14.052	100+	C 4.479
32	1	4400.00	79988.0	18763.0	4.263	N/A	14.053	100+	C 4.479
33	1	4500.00	79963.9	18507.4	4.321	N/A	14.438	100+	C 4.565
34	1	4799.90	79894.1	17747.2	4.502	N/A	15.718	100+	C 4.841
35	1	4800.00	79894.1	17747.0	4.502	N/A	15.718	100+	C 4.841
36	1	5000.00	79848.3	17262.4	D 4.626	N/A	16.693	100+	C 5.042
37	1	5499.90	79725.6	16098.1	D 4.952	N/A	19.827	100+	C 5.617
38	1	5500.00	79725.6	16098.2	D 4.952	N/A	19.828	100+	C 5.617
39	1	5899.90	79624.5	15173.0	D 5.248	N/A	23.338	100+	C 6.182
40	1	5900.00	79624.4	15173.1	D 5.248	N/A	23.339	100+	C 6.182
41	1	6000.00	79600.4	14942.7	D 5.327	N/A	24.422	100+	C 6.342
42	1	6299.90	79523.4	14253.9	D 5.579	N/A	28.375	100+	C 6.875
43	1	6300.00	79523.3	14254.0	D 5.579	N/A	28.376	100+	C 6.875
44	1	6500.00	79470.4	13798.8	D 5.759	N/A	31.893	100+	C 7.284
45	1	6699.90	79419.8	13347.6	D 5.950	N/A	36.514	100+	C 7.745
46	1	6700.00	79419.8	13347.7	D 5.950	N/A	36.517	100+	C 7.745
47	1	7000.00	79342.8	12675.3	D 6.260	N/A	46.686	100+	C 8.560
48	1	7099.90	79316.3	12452.4	D 6.370	N/A	51.465	100+	C 8.871
49	1	7100.00	79316.3	12452.5	D 6.369	N/A	51.470	100+	C 8.871
50	1	7499.90	79217.6	11569.0	D 6.847	N/A	87.294	100+	C 10.385
51	1	7500.00	79217.6	11569.1	D 6.847	N/A	87.310	100+	C 10.385
52	1	7599.90	79188.7	11350.3	D 6.977	N/A	100+	100+	C 10.848
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Injection Transient 90F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79482.4	23325.8	3.407	N/A	6.521	100+	C 3.146
2	1	100.00	79477.6	23124.5	3.437	N/A	6.607	100+	C 3.178
3	1	399.90	79460.7	22309.2	3.562	N/A	6.981	100+	C 3.314
4	1	400.00	79460.7	22308.9	3.562	N/A	6.981	100+	C 3.314
5	1	500.00	79455.9	22037.6	3.605	N/A	7.115	100+	C 3.362
6	1	799.90	79439.1	21225.8	3.743	N/A	7.550	100+	C 3.514
7	1	800.00	79439.1	21225.6	3.743	N/A	7.550	100+	C 3.514
8	1	1000.00	79427.0	20685.9	3.840	N/A	7.872	100+	C 3.623
9	1	1199.90	79415.0	20147.8	3.942	N/A	8.221	100+	C 3.740
10	1	1200.00	79415.0	20147.6	3.942	N/A	8.221	100+	C 3.740
11	1	1500.00	79398.1	19343.6	4.105	N/A	8.785	100+	C 3.930
12	1	1599.90	79390.9	19076.5	4.162	N/A	8.991	100+	C 3.997
13	1	1600.00	79390.9	19076.3	4.162	N/A	8.991	100+	C 3.997
14	1	1999.90	79366.9	18011.3	4.407	N/A	9.919	100+	C 4.293
15	1	2000.00	79366.9	18011.0	4.407	N/A	9.920	100+	C 4.293
16	1	2399.90	79342.8	16953.3	4.680	N/A	11.063	100+	C 4.635
17	1	2400.00	79342.8	16953.0	4.680	N/A	11.063	100+	C 4.635
18	1	2500.00	79338.0	16689.5	4.754	N/A	11.380	100+	C 4.730
19	1	2799.90	79318.7	15902.4	4.988	N/A	12.448	100+	C 5.038
20	1	2800.00	79318.7	15902.2	4.988	N/A	12.448	100+	C 5.038
21	1	3000.00	79304.3	15380.0	5.156	N/A	13.279	100+	C 5.267
22	1	3199.90	79289.8	14860.5	5.336	N/A	14.229	100+	C 5.517
23	1	3200.00	79289.8	14860.3	5.336	N/A	14.230	100+	C 5.517
24	1	3500.00	79268.2	14085.9	5.627	N/A	15.942	100+	C 5.941
25	1	3599.90	79260.9	13829.6	5.731	N/A	16.608	100+	C 6.097
26	1	3600.00	79260.9	13829.3	5.731	N/A	16.609	100+	C 6.098
27	1	3999.90	79229.6	12837.9	D 6.172	N/A	19.902	100+	C 6.814
28	1	4000.00	79229.6	12837.7	D 6.172	N/A	19.903	100+	C 6.815
29	1	4099.90	79222.4	12601.8	D 6.287	N/A	20.928	100+	C 7.021
30	1	4100.10	79222.4	12601.3	D 6.287	N/A	20.930	100+	C 7.021
31	1	4399.90	79193.5	11898.7	D 6.656	N/A	24.751	100+	C 7.721
32	1	4400.00	79193.5	11898.5	D 6.656	N/A	24.752	100+	C 7.722
33	1	4500.00	79186.3	11666.9	D 6.787	N/A	26.349	100+	C 7.986
34	1	4799.90	79157.4	10982.4	D 7.208	N/A	32.616	100+	C 8.893
35	1	4800.00	79157.4	10982.1	D 7.208	N/A	32.619	100+	C 8.893
36	1	5000.00	79138.1	10536.3	D 7.511	N/A	38.649	100+	C 9.611
37	1	5499.90	79085.2	9455.8	D 8.364	N/A	70.747	100+	C 11.999
38	1	5500.00	79085.2	9455.9	D 8.364	N/A	70.759	100+	C 11.999
39	1	5899.90	79037.0	8617.7	D 9.171	N/A	100+	100+	C 14.976
40	1	5900.00	79037.0	8617.8	D 9.171	N/A	100+	100+	C 14.976
41	1	6000.00	79025.0	8412.7	D 9.394	N/A	100+	100+	C 15.967
42	1	6299.90	78986.5	7810.1	D 10.113	N/A	100+	13.190	C 19.923
43	1	6300.00	78986.5	7810.2	D 10.113	N/A	100+	13.190	C 19.923
44	1	6500.00	78960.0	7420.9	D 10.640	N/A	100+	14.135	C 23.868
45	1	6699.90	78931.1	7043.2	D 11.207	N/A	100+	15.163	C 29.765
46	1	6700.00	78931.1	7043.4	D 11.206	N/A	100+	15.163	C 29.765
47	1	7000.00	78887.8	6503.6	D 12.130	N/A	100+	16.835	CM 40.841
48	1	7099.90	78873.4	6331.8	D 12.457	N/A	100+	17.413	CM 34.901
49	1	7100.00	78873.3	6331.9	D 12.456	N/A	100+	17.413	CM 34.901
50	1	7499.90	78813.2	5697.0	D 13.834	N/A	100+	19.630	CM 22.059
51	1	7500.00	78813.1	5697.1	D 13.834	N/A	100+	19.629	CM 22.059
52	1	7599.90	78796.3	5565.1	14.159	N/A	100+	20.104	CM 20.199
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Steady 40 F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	80000.0	36404.7	2.198	N/A	4.177	100+	2.023
2	1	100.00	80000.0	36208.2	2.209	N/A	4.199	100+	2.036
3	1	399.90	80000.0	35410.8	2.259	N/A	4.291	100+	2.091
4	1	400.00	80000.0	35410.5	2.259	N/A	4.291	100+	2.091
5	1	500.00	80000.0	35144.7	2.276	N/A	4.322	100+	2.110
6	1	799.90	80000.0	34347.3	2.329	N/A	4.419	100+	2.169
7	1	800.00	80000.0	34347.0	2.329	N/A	4.419	100+	2.169
8	1	1000.00	80000.0	33815.3	2.366	N/A	4.487	100+	2.210
9	1	1199.90	80000.0	33283.8	2.404	N/A	4.556	100+	2.253
10	1	1200.00	80000.0	33283.5	2.404	N/A	4.556	100+	2.253
11	1	1500.00	80000.0	32485.9	2.463	N/A	4.664	100+	2.320
12	1	1599.90	80000.0	32220.3	2.483	N/A	4.702	100+	C 2.342
13	1	1600.00	80000.0	32220.0	2.483	N/A	4.702	100+	C 2.342
14	1	1999.90	80000.0	31157.4	2.568	N/A	4.855	100+	C 2.440
15	1	2000.00	80000.0	31157.2	2.568	N/A	4.855	100+	C 2.440
16	1	2399.90	80000.0	30096.5	2.658	N/A	5.011	100+	C 2.546
17	1	2400.00	80000.0	30096.2	2.658	N/A	5.011	100+	C 2.546
18	1	2500.00	80000.0	29831.0	2.682	N/A	5.052	100+	C 2.574
19	1	2799.90	80000.0	29035.6	2.755	N/A	5.177	100+	C 2.663
20	1	2800.00	80000.0	29035.3	2.755	N/A	5.178	100+	C 2.663
21	1	3000.00	80000.0	28504.9	2.807	N/A	5.265	100+	C 2.725
22	1	3199.90	80000.0	27974.8	2.860	N/A	5.356	100+	C 2.790
23	1	3200.00	80000.0	27974.6	2.860	N/A	5.356	100+	C 2.790
24	1	3500.00	80000.0	27179.1	2.943	N/A	5.497	100+	C 2.894
25	1	3599.90	80000.0	26914.2	2.972	N/A	5.546	100+	C 2.930
26	1	3600.00	80000.0	26913.9	2.972	N/A	5.546	100+	C 2.930
27	1	3999.90	80000.0	25854.4	3.094	N/A	5.747	100+	C 3.086
28	1	4000.00	80000.0	25854.2	3.094	N/A	5.748	100+	C 3.086
29	1	4099.90	80000.0	25589.9	3.126	N/A	5.799	100+	C 3.127
30	1	4100.10	80000.0	25589.4	3.126	N/A	5.799	100+	C 3.127
31	1	4399.90	80000.0	24797.6	3.226	N/A	5.959	100+	C 3.258
32	1	4400.00	80000.0	24797.4	3.226	N/A	5.959	100+	C 3.258
33	1	4500.00	80000.0	24534.8	3.261	N/A	6.015	100+	C 3.304
34	1	4799.90	80000.0	23752.7	3.368	N/A	6.186	100+	C 3.448
35	1	4800.00	80000.0	23752.5	3.368	N/A	6.186	100+	C 3.448
36	1	5000.00	80000.0	23238.5	3.443	N/A	6.303	100+	C 3.550
37	1	5499.90	80000.0	21973.6	3.641	N/A	6.608	100+	C 3.829
38	1	5500.00	80000.0	21973.7	3.641	N/A	6.608	100+	C 3.829
39	1	5899.90	80000.0	20963.3	3.816	N/A	6.874	100+	C 4.086
40	1	5900.00	80000.0	20963.3	3.816	N/A	6.874	100+	C 4.086
41	1	6000.00	80000.0	20710.9	3.863	N/A	6.944	100+	C 4.156
42	1	6299.90	80000.0	19953.7	4.009	N/A	7.162	100+	C 4.380
43	1	6300.00	80000.0	19953.7	4.009	N/A	7.162	100+	C 4.380
44	1	6500.00	80000.0	19449.1	4.113	N/A	7.316	100+	C 4.543
45	1	6699.90	80000.0	18944.6	4.223	N/A	7.476	100+	C 4.719
46	1	6700.00	80000.0	18944.7	4.223	N/A	7.476	100+	C 4.719
47	1	7000.00	80000.0	18188.1	4.398	N/A	7.730	100+	C 5.010
48	1	7099.90	80000.0	17935.9	4.460	N/A	7.818	100+	C 5.115
49	1	7100.00	80000.0	17936.0	4.460	N/A	7.818	100+	C 5.115
50	1	7499.90	80000.0	16929.9	4.725	N/A	8.183	100+	C 5.584
51	1	7500.00	80000.0	16929.9	4.725	N/A	8.183	100+	C 5.584
52	1	7599.90	80000.0	16678.7	4.797	N/A	8.279	100+	C 5.715
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Steady 90 F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79472.8	27094.6	2.933	N/A	4.149	100+	C 2.809
2	1	100.00	79468.0	26891.6	2.955	N/A	4.179	100+	C 2.834
3	1	399.90	79458.3	26068.0	3.048	N/A	4.307	100+	C 2.941
4	1	400.00	79458.3	26067.7	3.048	N/A	4.307	100+	C 2.941
5	1	500.00	79453.5	25793.1	3.080	N/A	4.351	100+	C 2.979
6	1	799.90	79443.9	24969.4	3.182	N/A	4.489	100+	C 3.098
7	1	800.00	79443.9	24969.1	3.182	N/A	4.489	100+	C 3.098
8	1	1000.00	79439.1	24419.9	3.253	N/A	4.586	100+	C 3.183
9	1	1199.90	79431.8	23870.9	3.328	N/A	4.688	100+	C 3.273
10	1	1200.00	79431.8	23870.6	3.328	N/A	4.688	100+	C 3.273
11	1	1500.00	79422.2	23046.8	3.446	N/A	4.849	100+	C 3.418
12	1	1599.90	79419.8	22772.4	3.488	N/A	4.905	100+	C 3.469
13	1	1600.00	79419.8	22772.2	3.488	N/A	4.905	100+	C 3.469
14	1	1999.90	79407.8	21683.6	3.662	N/A	5.132	100+	C 3.689
15	1	2000.00	79407.8	21683.4	3.662	N/A	5.132	100+	C 3.689
16	1	2399.90	79395.7	20595.1	3.855	N/A	5.381	100+	C 3.940
17	1	2400.00	79395.7	20594.8	3.855	N/A	5.381	100+	C 3.940
18	1	2500.00	79393.3	20322.7	3.907	N/A	5.448	100+	C 4.008
19	1	2799.90	79386.1	19506.8	4.070	N/A	5.656	100+	C 4.227
20	1	2800.00	79386.1	19506.5	4.070	N/A	5.656	100+	C 4.227
21	1	3000.00	79381.3	18962.5	4.186	N/A	5.805	100+	C 4.388
22	1	3199.90	79374.1	18418.8	4.309	N/A	5.961	100+	C 4.560
23	1	3200.00	79374.1	18418.5	4.309	N/A	5.961	100+	C 4.560
24	1	3500.00	79366.9	17609.5	4.507	N/A	6.201	100+	C 4.846
25	1	3599.90	79364.5	17340.2	4.577	N/A	6.286	100+	C 4.950
26	1	3600.00	79364.5	17340.0	4.577	N/A	6.286	100+	C 4.950
27	1	3999.90	79354.8	16262.5	4.880	N/A	6.648	100+	C 5.413
28	1	4000.00	79354.8	16262.2	4.880	N/A	6.648	100+	C 5.413
29	1	4099.90	79352.4	15993.4	4.962	N/A	6.745	100+	C 5.542
30	1	4100.10	79352.4	15992.8	4.962	N/A	6.745	100+	C 5.542
31	1	4399.90	79347.6	15187.6	5.224	N/A	7.054	100+	C 5.970
32	1	4400.00	79347.6	15187.3	5.225	N/A	7.054	100+	C 5.970
33	1	4500.00	79345.2	14920.4	5.318	N/A	7.163	100+	C 6.127
34	1	4799.90	79338.0	14125.4	5.617	N/A	7.508	100+	C 6.647
35	1	4800.00	79338.0	14125.1	5.617	N/A	7.509	100+	C 6.647
36	1	5000.00	79333.2	13602.5	5.832	N/A	7.755	100+	C 7.040
37	1	5499.90	79323.5	12325.3	6.436	N/A	8.417	100+	C 8.241
38	1	5500.00	79323.5	12325.3	6.436	N/A	8.417	100+	C 8.241
39	1	5899.90	79316.3	11307.3	7.015	N/A	9.033	100+	C 9.542
40	1	5900.00	79316.3	11307.3	7.015	N/A	9.033	100+	C 9.542
41	1	6000.00	79313.9	11053.3	7.176	N/A	9.202	100+	C 9.934
42	1	6299.90	79309.1	10292.8	7.705	N/A	9.747	100+	C 11.331
43	1	6300.00	79309.1	10292.8	7.705	N/A	9.747	100+	C 11.331
44	1	6500.00	79306.7	9787.0	8.103	N/A	10.149	100+	C 12.503
45	1	6699.90	79301.9	9282.6	8.543	N/A	10.584	100+	C 13.946
46	1	6700.00	79301.9	9282.6	8.543	N/A	10.584	100+	C 13.946
47	1	7000.00	79297.0	8531.0	9.295	N/A	11.303	100+	C 16.866
48	1	7099.90	79294.6	8282.8	9.573	N/A	11.559	100+	C 18.132
49	1	7100.00	79294.6	8282.7	9.573	N/A	11.559	100+	C 18.132
50	1	7499.90	79287.4	7296.3	10.867	N/A	12.715	100+	C 25.907
51	1	7500.00	79287.4	7296.2	10.867	N/A	12.715	100+	C 25.907
52	1	7599.90	79287.4	7051.6	11.244	N/A	13.041	100+	C 29.020
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Steady 40 F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	80000.0	34803.4	2.299	N/A	6.564	100+	2.120
2	1	100.00	80000.0	34610.3	2.311	N/A	6.623	100+	2.135
3	1	399.90	80000.0	33827.3	2.365	N/A	6.876	100+	2.195
4	1	400.00	80000.0	33827.0	2.365	N/A	6.876	100+	2.195
5	1	500.00	80000.0	33566.1	2.383	N/A	6.965	100+	2.216
6	1	799.90	80000.0	32784.3	2.440	N/A	7.245	100+	2.281
7	1	800.00	80000.0	32784.0	2.440	N/A	7.245	100+	2.281
8	1	1000.00	80000.0	32263.1	2.480	N/A	7.444	100+	2.326
9	1	1199.90	80000.0	31742.9	2.520	N/A	7.655	100+	C 2.372
10	1	1200.00	80000.0	31742.6	2.520	N/A	7.655	100+	C 2.372
11	1	1500.00	80000.0	30962.8	2.584	N/A	7.995	100+	C 2.447
12	1	1599.90	80000.0	30703.3	2.606	N/A	8.115	100+	C 2.473
13	1	1600.00	80000.0	30703.1	2.606	N/A	8.115	100+	C 2.473
14	1	1999.90	80000.0	29662.3	2.697	N/A	8.609	100+	C 2.582
15	1	2000.00	80000.0	29662.1	2.697	N/A	8.609	100+	C 2.582
16	1	2399.90	80000.0	28622.9	2.795	N/A	9.166	100+	C 2.702
17	1	2400.00	80000.0	28622.6	2.795	N/A	9.166	100+	C 2.702
18	1	2500.00	80000.0	28363.0	2.821	N/A	9.317	100+	C 2.734
19	1	2799.90	80000.0	27585.4	2.900	N/A	9.800	100+	C 2.833
20	1	2800.00	80000.0	27585.1	2.900	N/A	9.800	100+	C 2.833
21	1	3000.00	80000.0	27067.2	2.956	N/A	10.151	100+	C 2.904
22	1	3199.90	80000.0	26550.1	3.013	N/A	10.527	100+	C 2.978
23	1	3200.00	80000.0	26549.8	3.013	N/A	10.528	100+	C 2.978
24	1	3500.00	80000.0	25772.4	3.104	N/A	11.125	100+	C 3.097
25	1	3599.90	80000.0	25513.6	3.136	N/A	11.337	100+	C 3.139
26	1	3600.00	80000.0	25513.3	3.136	N/A	11.338	100+	C 3.139
27	1	3999.90	80000.0	24478.9	3.268	N/A	12.277	100+	C 3.317
28	1	4000.00	80000.0	24478.7	3.268	N/A	12.277	100+	C 3.317
29	1	4099.90	80000.0	24220.8	3.303	N/A	12.536	100+	C 3.365
30	1	4100.10	80000.0	24220.3	3.303	N/A	12.537	100+	C 3.365
31	1	4399.90	80000.0	23448.6	3.412	N/A	13.383	100+	C 3.517
32	1	4400.00	80000.0	23448.3	3.412	N/A	13.384	100+	C 3.517
33	1	4500.00	80000.0	23192.8	3.449	N/A	13.690	100+	C 3.570
34	1	4799.90	80000.0	22449.4	D 3.564	N/A	14.699	100+	C 3.740
35	1	4800.00	80000.0	22449.2	D 3.564	N/A	14.699	100+	C 3.740
36	1	5000.00	80000.0	21966.1	D 3.642	N/A	15.439	100+	C 3.860
37	1	5499.90	80000.0	20776.4	D 3.851	N/A	17.596	100+	C 4.193
38	1	5500.00	80000.0	20776.5	D 3.850	N/A	17.596	100+	C 4.193
39	1	5899.90	80000.0	19828.7	D 4.035	N/A	19.811	100+	C 4.503
40	1	5900.00	80000.0	19828.8	D 4.035	N/A	19.811	100+	C 4.503
41	1	6000.00	80000.0	19592.3	D 4.083	N/A	20.455	100+	C 4.587
42	1	6299.90	80000.0	18883.9	D 4.236	N/A	22.663	100+	C 4.862
43	1	6300.00	80000.0	18883.9	D 4.236	N/A	22.663	100+	C 4.862
44	1	6500.00	80000.0	18412.7	D 4.345	N/A	24.421	100+	C 5.064
45	1	6699.90	80000.0	17942.1	D 4.459	N/A	26.474	100+	C 5.283
46	1	6700.00	80000.0	17942.2	D 4.459	N/A	26.475	100+	C 5.283
47	1	7000.00	80000.0	17236.6	D 4.641	N/A	30.248	100+	C 5.651
48	1	7099.90	80000.0	17000.7	D 4.706	N/A	31.717	100+	C 5.785
49	1	7100.00	80000.0	17000.8	D 4.706	N/A	31.719	100+	C 5.785
50	1	7499.90	80000.0	16060.6	D 4.981	N/A	39.377	100+	C 6.392
51	1	7500.00	80000.0	16060.7	D 4.981	N/A	39.379	100+	C 6.392
52	1	7599.90	80000.0	15826.2	D 5.055	N/A	41.907	100+	C 6.564
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - CO2 Steady 90 F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79472.8	23970.0	3.316	N/A	6.520	100+	C 3.057
2	1	100.00	79468.0	23769.6	3.343	N/A	6.607	100+	C 3.087
3	1	399.90	79448.7	22957.9	3.461	N/A	6.980	100+	C 3.215
4	1	400.00	79448.7	22957.6	3.461	N/A	6.981	100+	C 3.215
5	1	500.00	79443.9	22687.5	3.502	N/A	7.115	100+	C 3.260
6	1	799.90	79424.6	21879.6	3.630	N/A	7.551	100+	C 3.403
7	1	800.00	79424.6	21879.4	3.630	N/A	7.551	100+	C 3.403
8	1	1000.00	79415.0	21342.3	3.721	N/A	7.873	100+	C 3.506
9	1	1199.90	79403.0	20807.1	3.816	N/A	8.224	100+	C 3.615
10	1	1200.00	79403.0	20806.9	3.816	N/A	8.224	100+	C 3.615
11	1	1500.00	79388.5	20006.9	3.968	N/A	8.793	100+	C 3.792
12	1	1599.90	79381.3	19741.2	4.021	N/A	8.999	100+	C 3.855
13	1	1600.00	79381.3	19741.0	4.021	N/A	8.999	100+	C 3.855
14	1	1999.90	79362.0	18682.0	4.248	N/A	9.932	100+	C 4.129
15	1	2000.00	79362.0	18681.7	4.248	N/A	9.932	100+	C 4.129
16	1	2399.90	79342.8	17630.3	4.500	N/A	11.081	100+	C 4.445
17	1	2400.00	79342.8	17630.1	4.500	N/A	11.081	100+	C 4.445
18	1	2500.00	79338.0	17368.5	4.568	N/A	11.411	100+	C 4.532
19	1	2799.90	79325.9	16586.3	4.783	N/A	12.485	100+	C 4.815
20	1	2800.00	79325.9	16586.1	4.783	N/A	12.486	100+	C 4.815
21	1	3000.00	79316.3	16067.3	4.936	N/A	13.322	100+	C 5.023
22	1	3199.90	79306.7	15551.4	5.100	N/A	14.278	100+	C 5.251
23	1	3200.00	79306.7	15551.1	5.100	N/A	14.279	100+	C 5.251
24	1	3500.00	79294.6	14782.2	5.364	N/A	16.004	100+	C 5.634
25	1	3599.90	79289.8	14527.8	5.458	N/A	16.675	100+	C 5.775
26	1	3600.00	79289.8	14527.5	5.458	N/A	16.675	100+	C 5.775
27	1	3999.90	79275.4	13556.1	D 5.848	N/A	19.982	100+	C 6.415
28	1	4000.00	79275.4	13555.8	D 5.848	N/A	19.983	100+	C 6.415
29	1	4099.90	79270.6	13320.7	D 5.951	N/A	21.008	100+	C 6.598
30	1	4100.10	79270.6	13320.2	D 5.951	N/A	21.011	100+	C 6.598
31	1	4399.90	79258.5	12619.9	D 6.280	N/A	24.829	100+	C 7.213
32	1	4400.00	79258.5	12619.7	D 6.281	N/A	24.831	100+	C 7.213
33	1	4500.00	79256.1	12388.9	D 6.397	N/A	26.425	100+	C 7.444
34	1	4799.90	79244.1	11706.7	D 6.769	N/A	32.686	100+	C 8.226
35	1	4800.00	79244.1	11706.5	D 6.769	N/A	32.688	100+	C 8.227
36	1	5000.00	79236.9	11262.7	D 7.035	N/A	38.735	100+	C 8.838
37	1	5499.90	79220.0	10181.2	D 7.781	N/A	69.909	100+	C 10.819
38	1	5500.00	79220.0	10181.3	D 7.781	N/A	69.920	100+	C 10.819
39	1	5899.90	79208.0	9340.1	D 8.480	N/A	100+	100+	C 13.182
40	1	5900.00	79208.0	9340.2	D 8.480	N/A	100+	100+	C 13.182
41	1	6000.00	79205.6	9134.0	D 8.672	N/A	100+	100+	C 13.943
42	1	6299.90	79195.9	8526.2	D 9.289	N/A	100+	11.810	C 16.864
43	1	6300.00	79195.9	8526.3	D 9.288	N/A	100+	11.810	C 16.864
44	1	6500.00	79191.1	8132.0	D 9.738	N/A	100+	12.577	C 19.603
45	1	6699.90	79183.9	7742.1	D 10.228	N/A	100+	13.422	C 23.405
46	1	6700.00	79183.9	7742.3	D 10.227	N/A	100+	13.421	C 23.405
47	1	7000.00	79174.3	7178.8	D 11.029	N/A	100+	14.816	C 33.012
48	1	7099.90	79171.9	6997.5	D 11.314	N/A	100+	15.310	C 38.246
49	1	7100.00	79171.8	6997.7	D 11.314	N/A	100+	15.310	C 38.246
50	1	7499.90	79162.2	6313.7	D 12.538	N/A	100+	17.344	CM 27.861
51	1	7500.00	79162.2	6313.8	D 12.538	N/A	100+	17.343	CM 27.861
52	1	7599.90	79157.4	6154.6	D 12.862	N/A	100+	17.837	CM 24.975
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - Tubing Leak - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79472.8	25599.9	D 3.104	N/A	100+	3.341	C 3.471
2	1	100.00	79468.0	25443.0	D 3.123	N/A	100+	3.364	C 3.509
3	1	399.90	79458.3	24810.5	D 3.203	N/A	100+	3.461	C 3.676
4	1	400.00	79458.3	24810.3	D 3.203	N/A	100+	3.461	C 3.676
5	1	500.00	79453.5	24601.0	D 3.230	N/A	100+	3.494	C 3.735
6	1	799.90	79443.9	23978.3	D 3.313	N/A	100+	3.597	C 3.924
7	1	800.00	79443.9	23978.1	D 3.313	N/A	100+	3.597	C 3.924
8	1	1000.00	79439.1	23567.2	D 3.371	N/A	100+	3.668	C 4.062
9	1	1199.90	79431.8	23160.3	D 3.430	N/A	100+	3.741	C 4.209
10	1	1200.00	79431.8	23160.1	D 3.430	N/A	100+	3.741	C 4.209
11	1	1500.00	79422.2	22556.9	D 3.521	N/A	100+	3.854	C 4.452
12	1	1599.90	79419.8	22358.1	D 3.552	N/A	100+	3.892	C 4.539
13	1	1600.00	79419.8	22357.9	D 3.552	N/A	100+	3.892	C 4.539
14	1	1999.90	79407.8	21556.7	D 3.684	N/A	100+	4.055	C 4.924
15	1	2000.00	79407.8	21556.5	D 3.684	N/A	100+	4.055	C 4.924
16	1	2399.90	79395.7	20773.5	D 3.822	N/A	100+	4.225	C 5.382
17	1	2400.00	79395.7	20773.3	D 3.822	N/A	100+	4.225	C 5.382
18	1	2500.00	79393.3	20580.6	D 3.858	N/A	100+	4.269	C 5.510
19	1	2799.90	79386.1	20010.6	D 3.967	N/A	100+	4.404	C 5.933
20	1	2800.00	79386.1	20010.5	D 3.967	N/A	100+	4.404	C 5.933
21	1	3000.00	79381.3	19661.6	4.037	N/A	100+	4.496	C 6.253
22	1	3199.90	79374.1	19335.5	4.105	N/A	100+	4.589	C 6.610
23	1	3200.00	79374.1	19335.4	4.105	N/A	100+	4.589	C 6.610
24	1	3500.00	79366.9	18849.8	4.210	N/A	100+	4.735	C 7.229
25	1	3599.90	79364.5	18693.2	4.246	N/A	100+	4.784	C 7.462
26	1	3600.00	79364.5	18693.1	4.246	N/A	100+	4.784	C 7.462
27	1	3999.90	79354.8	18093.3	4.386	N/A	100+	4.984	C 8.567
28	1	4000.00	79354.8	18093.2	4.386	N/A	100+	4.984	C 8.567
29	1	4099.90	79352.4	17950.5	4.421	N/A	100+	5.034	C 8.896
30	1	4100.10	79352.4	17950.3	4.421	N/A	100+	5.034	C 8.897
31	1	4399.90	79347.6	17541.0	4.524	N/A	100+	5.185	C 10.053
32	1	4400.00	79347.6	17540.9	4.524	N/A	100+	5.185	C 10.053
33	1	4500.00	79345.2	17411.4	4.557	N/A	100+	5.235	C 10.506
34	1	4799.90	79338.0	17045.1	4.655	N/A	100+	5.381	C 12.135
35	1	4800.00	79338.0	17045.0	4.655	N/A	100+	5.381	C 12.136
36	1	5000.00	79333.2	16820.5	4.716	N/A	100+	5.476	C 13.514
37	1	5499.90	79323.5	16304.8	4.865	N/A	100+	5.704	C 18.765
38	1	5500.00	79323.5	16305.0	4.865	N/A	100+	5.704	C 18.765
39	1	5899.90	79316.3	15956.5	4.971	N/A	100+	5.871	C 27.219
40	1	5900.00	79316.3	15956.7	4.971	N/A	100+	5.871	C 27.219
41	1	6000.00	79313.9	15879.0	4.995	N/A	100+	5.909	C 30.673
42	1	6299.90	79309.1	15668.9	5.062	N/A	100+	5.791	CM 39.707
43	1	6300.00	79309.1	15669.1	5.061	N/A	100+	5.791	CM 39.707
44	1	6500.00	79306.7	15549.1	5.100	N/A	100+	5.799	CM 29.884
45	1	6699.90	79301.9	15445.3	5.134	N/A	100+	5.798	CM 23.957
46	1	6700.00	79301.9	15445.5	5.134	N/A	100+	5.798	CM 23.957
47	1	7000.00	79297.0	15315.6	5.178	N/A	100+	5.783	CM 18.462
48	1	7099.90	79294.6	15277.8	5.190	N/A	100+	5.775	CM 17.151
49	1	7100.00	79294.6	15278.0	5.190	N/A	100+	5.775	CM 17.151
50	1	7499.90	79287.4	15170.3	5.227	N/A	100+	5.725	CM 13.356
51	1	7500.00	79287.4	15170.4	5.226	N/A	100+	5.725	CM 13.356
52	1	7599.90	79287.4	15154.2	5.232	N/A	100+	5.708	CM 12.657
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - Tubing Leak + Evacuation - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	31616.2	2.523	N/A	100+	2.768	C 7.347
2	1	100.00	79740.0	31764.3	2.510	N/A	100+	2.750	C 7.521
3	1	399.90	79663.0	32389.2	2.460	N/A	100+	2.678	C 8.321
4	1	400.00	79663.0	32389.4	2.460	N/A	100+	2.677	C 8.321
5	1	500.00	79636.5	32605.9	2.442	N/A	100+	2.653	C 8.628
6	1	799.90	79559.5	33278.9	2.391	N/A	100+	2.581	C 9.701
7	1	800.00	79559.4	33279.1	2.391	N/A	100+	2.581	C 9.702
8	1	1000.00	79506.5	33746.7	2.356	N/A	100+	2.534	C 10.581
9	1	1199.90	79456.0	34228.4	2.321	N/A	100+	2.487	C 11.636
10	1	1200.00	79455.9	34228.6	2.321	N/A	100+	2.487	C 11.637
11	1	1500.00	79378.9	34977.0	2.269	N/A	100+	2.418	C 13.689
12	1	1599.90	79352.4	35232.7	2.252	N/A	100+	2.395	C 14.544
13	1	1600.00	79352.4	35233.0	2.252	N/A	100+	2.395	C 14.545
14	1	1999.90	79248.9	36287.5	2.184	N/A	100+	2.306	C 19.408
15	1	2000.00	79248.9	36287.8	2.184	N/A	100+	2.306	C 19.409
16	1	2399.90	79145.4	37388.4	2.117	N/A	100+	2.221	C 29.197
17	1	2400.00	79145.4	37388.7	2.117	N/A	100+	2.221	C 29.200
18	1	2500.00	79118.9	37670.6	2.100	N/A	100+	2.200	C 33.422
19	1	2799.90	79041.9	38531.4	2.051	N/A	100+	2.130	CM 34.970
20	1	2800.00	79041.8	38531.7	2.051	N/A	100+	2.130	CM 34.964
21	1	3000.00	78988.9	39117.9	2.019	N/A	100+	2.077	CM 26.804
22	1	3199.90	78938.4	39712.9	1.988	N/A	100+	2.028	CM 21.729
23	1	3200.00	78938.3	39713.2	1.988	N/A	100+	2.028	CM 21.727
24	1	3500.00	78861.3	40622.6	1.941	N/A	100+	1.957	CM 16.913
25	1	3599.90	78834.8	40929.6	1.926	N/A	100+	1.934	CM 15.750
26	1	3600.00	78834.8	40929.9	1.926	N/A	100+	1.934	CM 15.749
27	1	3999.90	78731.3	42178.5	1.867	N/A	100+	1.849	CM 12.344
28	1	4000.00	78731.3	42178.8	1.867	N/A	100+	1.849	CM 12.344
29	1	4099.90	78704.8	42495.2	1.852	N/A	100+	1.829	CM 11.710
30	1	4100.10	78704.8	42495.8	1.852	N/A	100+	1.829	CM 11.709
31	1	4399.90	78627.8	43454.4	1.809	N/A	100+	1.771	CM 10.148
32	1	4400.00	78627.8	43454.7	1.809	N/A	100+	1.771	CM 10.147
33	1	4500.00	78601.3	43776.0	1.796	N/A	100+	1.753	CM 9.717
34	1	4799.90	78526.7	44742.6	1.755	N/A	100+	1.700	CM 8.626
35	1	4800.00	78526.7	44742.9	1.755	N/A	100+	1.700	CM 8.626
36	1	5000.00	78476.1	45386.0	1.729	N/A	100+	1.667	CM 8.032
37	1	5499.90	78350.9	46993.1	1.667	N/A	100+	1.591	CM 6.865
38	1	5500.00	78350.9	46993.5	1.667	N/A	100+	1.591	CM 6.865
39	1	5899.90	78252.2	48299.7	1.620	N/A	100+	1.535	CM 6.148
40	1	5900.00	78252.2	48300.1	1.620	N/A	100+	1.535	CM 6.148
41	1	6000.00	78228.1	48629.5	1.609	N/A	100+	1.521	CM 5.992
42	1	6299.90	78153.5	49623.8	1.575	N/A	100+	1.482	CM 5.567
43	1	6300.00	78153.5	49624.3	1.575	N/A	100+	1.482	CM 5.567
44	1	6500.00	78105.4	50292.6	1.553	N/A	100+	1.458	CM 5.315
45	1	6699.90	78054.8	50964.5	1.532	N/A	100+	1.433	CM 5.084
46	1	6700.00	78054.8	50964.9	1.532	N/A	100+	1.433	CM 5.084
47	1	7000.00	77980.2	51980.8	1.500	N/A	100+	1.399	CM 4.773
48	1	7099.90	77956.1	52320.7	1.490	N/A	100+	1.387	CM 4.677
49	1	7100.00	77956.1	52321.2	1.490	N/A	100+	1.387	CM 4.677
50	1	7499.90	77857.4	53690.7	1.450	N/A	100+	1.344	CM 4.331
51	1	7500.00	77857.4	53691.1	1.450	N/A	100+	1.344	CM 4.331
52	1	7599.90	77833.4	54035.3	1.440	N/A	100+	1.334	CM 4.251
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

API Safety Factor Summary - Doubled Pressure Test - 5 1/2" Production Tubing

	String Section	MD (ft)	Yield Strength (psi)	VME Stress (psi)	Absolute API Safety Factors				
					Triaxial	Envelope	API Burst	API Collapse (V)	Axial
1	1	26.10	79759.2	58268.4	1.369	N/A	1.270	100+	2.315
2	1	100.00	79740.0	58238.7	1.369	N/A	1.270	100+	C 2.331
3	1	399.90	79663.0	58126.0	1.371	N/A	1.269	100+	C 2.401
4	1	400.00	79663.0	58126.0	1.371	N/A	1.269	100+	C 2.401
5	1	500.00	79636.5	58091.3	1.371	N/A	1.268	100+	C 2.425
6	1	799.90	79559.5	57996.1	1.372	N/A	1.267	100+	C 2.501
7	1	800.00	79559.4	57996.0	1.372	N/A	1.267	100+	C 2.501
8	1	1000.00	79506.5	57939.8	1.372	N/A	1.266	100+	C 2.554
9	1	1199.90	79456.0	57889.5	1.373	N/A	1.265	100+	C 2.610
10	1	1200.00	79455.9	57889.4	1.373	N/A	1.265	100+	C 2.610
11	1	1500.00	79378.9	57824.8	1.373	N/A	1.264	100+	C 2.699
12	1	1599.90	79352.4	57806.3	1.373	N/A	1.264	100+	C 2.730
13	1	1600.00	79352.4	57806.3	1.373	N/A	1.264	100+	C 2.730
14	1	1999.90	79248.9	57746.7	1.372	N/A	1.262	100+	C 2.862
15	1	2000.00	79248.9	57746.6	1.372	N/A	1.262	100+	C 2.862
16	1	2399.90	79145.4	57732.4	N 1.371	N/A	1.260	100+	C 3.007
17	1	2400.00	79145.4	57732.4	N 1.371	N/A	1.260	100+	C 3.007
18	1	2500.00	79118.9	57742.6	N 1.370	N/A	1.260	100+	C 3.046
19	1	2799.90	79041.9	57783.4	N 1.368	N/A	1.259	100+	C 3.168
20	1	2800.00	79041.8	57783.4	N 1.368	N/A	1.259	100+	C 3.168
21	1	3000.00	78988.9	57816.5	N 1.366	N/A	1.258	100+	C 3.256
22	1	3199.90	78938.4	57855.7	N 1.364	N/A	1.257	100+	C 3.348
23	1	3200.00	78938.3	57855.7	N 1.364	N/A	1.257	100+	C 3.348
24	1	3500.00	78861.3	57926.6	N 1.361	N/A	1.256	100+	C 3.498
25	1	3599.90	78834.8	57954.0	N 1.360	N/A	1.255	100+	C 3.551
26	1	3600.00	78834.8	57954.0	N 1.360	N/A	1.255	100+	C 3.551
27	1	3999.90	78731.3	58147.2	N 1.354	N/A	1.254	100+	C 3.654
28	1	4000.00	78731.3	58147.2	N 1.354	N/A	1.254	100+	C 3.654
29	1	4099.90	78704.8	58110.5	N 1.354	N/A	1.253	100+	C 3.842
30	1	4100.10	78704.8	58110.4	N 1.354	N/A	1.253	100+	C 3.842
31	1	4399.90	78627.8	58221.3	N 1.350	N/A	1.252	100+	C 4.040
32	1	4400.00	78627.8	58221.2	N 1.350	N/A	1.252	100+	C 4.041
33	1	4500.00	78601.3	58257.7	N 1.349	N/A	1.252	100+	C 4.111
34	1	4799.90	78526.7	58384.2	N 1.345	N/A	1.250	100+	C 4.337
35	1	4800.00	78526.7	58384.1	N 1.345	N/A	1.250	100+	C 4.337
36	1	5000.00	78476.1	58477.0	N 1.342	N/A	1.250	100+	C 4.500
37	1	5499.90	78350.9	58883.9	N 1.331	N/A	1.248	100+	C 4.666
38	1	5500.00	78350.9	58883.9	N 1.331	N/A	1.248	100+	C 4.666
39	1	5899.90	78252.2	59300.0	N 1.320	N/A	1.246	100+	C 4.769
40	1	5900.00	78252.2	59300.0	N 1.320	N/A	1.246	100+	C 4.769
41	1	6000.00	78228.1	59412.3	N 1.317	N/A	1.246	100+	C 4.798
42	1	6299.90	78153.5	59768.7	N 1.308	N/A	1.245	100+	C 4.884
43	1	6300.00	78153.5	59768.7	N 1.308	N/A	1.245	100+	C 4.884
44	1	6500.00	78105.4	60025.6	N 1.301	N/A	1.244	100+	C 4.945
45	1	6699.90	78054.8	60292.6	N 1.295	N/A	1.243	100+	C 5.007
46	1	6700.00	78054.8	60292.6	N 1.295	N/A	1.243	100+	C 5.007
47	1	7000.00	77980.2	60722.8	N 1.284	N/A	1.242	100+	C 5.102
48	1	7099.90	77956.1	60869.9	N 1.281	N/A	1.241	100+	C 5.136
49	1	7100.00	77956.1	60869.9	N 1.281	N/A	1.241	100+	C 5.136
50	1	7499.90	77857.4	61498.8	N 1.266	N/A	1.240	100+	C 5.276
51	1	7500.00	77857.4	61498.7	N 1.266	N/A	1.240	100+	C 5.276
52	1	7599.90	77833.4	61664.8	N 1.262	N/A	1.239	100+	C 5.313
53									
54	**Burst and Axial Flags**								
55	**Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection**								
56									
57	**Axial Flags**								
58	**Default = Tension, M = Compression**								
59									
60	**Triaxial Flags**								
61	**Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								
62									
63	**Envelope Flags**								
64	**EB = Envelope Burst, EC = Envelope Collapse, N/A = no ISO Connection**								
65									
66	**Collapse Flags**								
67	**(V) = Vector Collapse Safety Factor**								

Tubing Load Summary - Initial Conditions - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	111822	122756	1.50	0.0	0.0	78	13	13	None
2	1	100.00	110344	121522	1.50	0.0	0.0	79	51	51	None
3	1	399.90	104346	116510	1.50	0.0	0.0	82	204	204	None
4	1	400.00	104344	116508	1.50	0.0	0.0	82	204	204	None
5	1	500.00	102344	114836	1.50	0.0	0.0	83	255	255	None
6	1	799.90	96346	109811	1.50	0.0	0.0	86	407	407	None
7	1	800.00	96344	109809	1.50	0.0	0.0	86	407	407	None
8	1	1000.00	92344	106455	1.50	0.0	0.0	89	509	509	None
9	1	1199.90	88346	103094	1.50	0.0	0.0	91	611	611	None
10	1	1200.00	88344	103092	1.50	0.0	0.0	91	611	611	None
11	1	1500.00	82344	98043	1.50	0.0	0.0	94	764	764	None
12	1	1599.90	80346	96360	1.50	0.0	0.0	95	815	815	None
13	1	1600.00	80344	96358	1.50	0.0	0.0	95	815	815	None
14	1	1999.90	72346	89608	1.50	0.0	0.0	99	1018	1018	None
15	1	2000.00	72344	89606	1.50	0.0	0.0	99	1018	1018	None
16	1	2399.90	64346	82838	1.50	0.0	0.0	104	1222	1222	None
17	1	2400.00	64344	82837	1.50	0.0	0.0	104	1222	1222	None
18	1	2500.00	62344	81142	1.50	0.0	0.0	105	1273	1273	None
19	1	2799.90	56346	76051	1.50	0.0	0.0	108	1425	1425	None
20	1	2800.00	56344	76049	1.50	0.0	0.0	108	1425	1425	None
21	1	3000.00	52344	72650	1.50	0.0	0.0	110	1527	1527	None
22	1	3199.90	48346	69246	1.50	0.0	0.0	112	1629	1629	None
23	1	3200.00	48344	69244	1.50	0.0	0.0	112	1629	1629	None
24	1	3500.00	42344	64128	1.50	0.0	0.0	115	1782	1782	None
25	1	3599.90	40346	62423	1.50	0.0	0.0	116	1833	1833	None
26	1	3600.00	40344	62421	1.50	0.0	0.0	116	1833	1833	None
27	1	3999.90	32346	55582	1.50	0.0	0.0	121	2036	2036	None
28	1	4000.00	32344	55581	1.50	0.0	0.0	121	2036	2036	None
29	1	4099.90	30347	53871	1.50	0.0	0.0	122	2087	2087	None
30	1	4100.10	30343	53867	1.50	0.0	0.0	122	2087	2087	None
31	1	4399.90	24360	48735	1.50	0.0	0.0	125	2240	2240	None
32	1	4400.00	24358	48734	1.50	0.0	0.0	125	2240	2240	None
33	1	4500.00	22373	47030	1.50	0.0	0.0	126	2290	2290	None
34	1	4799.90	16462	41946	1.50	0.0	0.0	129	2441	2441	None
35	1	4800.00	16460	41944	1.50	0.0	0.0	129	2441	2441	None
36	1	5000.00	12572	38596	1.50	0.0	0.0	131	2540	2540	None
37	1	5499.90	2994	30328	1.50	0.0	0.0	137	2783	2783	None
38	1	5500.00	2994	30328	1.50	0.0	0.0	137	2783	2783	None
39	1	5899.90	-4660	2260	1.50	0.0	0.0	141	2978	2978	None
40	1	5900.00	-4660	2260	1.50	0.0	0.0	141	2978	2978	None
41	1	6000.00	-6573	595	1.50	0.0	0.0	142	3027	3027	None
42	1	6299.90	-12312	-4408	1.50	0.0	0.0	145	3173	3173	None
43	1	6300.00	-12312	-4408	1.50	0.0	0.0	145	3173	3173	None
44	1	6500.00	-16138	-7748	1.50	0.0	0.0	147	3270	3270	None
45	1	6699.90	-19964	-11093	1.50	0.0	0.0	149	3368	3368	None
46	1	6700.00	-19964	-11092	1.50	0.0	0.0	149	3368	3368	None
47	1	7000.00	-25705	-16119	1.50	0.0	0.0	152	3514	3514	None
48	1	7099.90	-27618	-17796	1.50	0.0	0.0	153	3563	3563	None
49	1	7100.00	-27618	-17796	1.50	0.0	0.0	153	3563	3563	None
50	1	7499.90	-35270	-24515	1.50	0.0	0.0	157	3757	3757	None
51	1	7500.00	-35270	-24515	1.50	0.0	0.0	157	3757	3757	None
52	1	7599.90	-37183	-26197	1.50	0.0	0.0	158	3806	3806	None

Tubing Load Summary - PressureTest #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	150879	161853	1.50	0.0	0.0	78	3613	0	None
2	1	100.00	149401	160630	1.50	0.0	0.0	79	3651	38	None
3	1	399.90	143403	155655	1.50	0.0	0.0	82	3804	190	None
4	1	400.00	143401	155653	1.50	0.0	0.0	82	3804	190	None
5	1	500.00	141401	153994	1.50	0.0	0.0	83	3855	241	None
6	1	799.90	135403	149007	1.50	0.0	0.0	86	4007	394	None
7	1	800.00	135401	149005	1.50	0.0	0.0	86	4007	394	None
8	1	1000.00	131401	145677	1.50	0.0	0.0	89	4109	496	None
9	1	1199.90	127403	142341	1.50	0.0	0.0	91	4211	598	None
10	1	1200.00	127401	142339	1.50	0.0	0.0	91	4211	598	None
11	1	1500.00	121401	137328	1.50	0.0	0.0	94	4364	750	None
12	1	1599.90	119403	135658	1.50	0.0	0.0	95	4414	801	None
13	1	1600.00	119401	135656	1.50	0.0	0.0	95	4415	801	None
14	1	1999.90	111403	128957	1.50	0.0	0.0	99	4618	1005	None
15	1	2000.00	111401	128956	1.50	0.0	0.0	99	4618	1005	None
16	1	2399.90	103403	122239	1.50	0.0	0.0	104	4822	1209	None
17	1	2400.00	103401	122238	1.50	0.0	0.0	104	4822	1209	None
18	1	2500.00	101401	120556	1.50	0.0	0.0	105	4873	1259	None
19	1	2799.90	95403	115504	1.50	0.0	0.0	108	5025	1412	None
20	1	2800.00	95401	115502	1.50	0.0	0.0	108	5025	1412	None
21	1	3000.00	91401	112129	1.50	0.0	0.0	110	5127	1514	None
22	1	3199.90	87403	108750	1.50	0.0	0.0	112	5229	1616	None
23	1	3200.00	87401	108749	1.50	0.0	0.0	112	5229	1616	None
24	1	3500.00	81401	103671	1.50	0.0	0.0	115	5382	1769	None
25	1	3599.90	79403	101979	1.50	0.0	0.0	116	5433	1819	None
26	1	3600.00	79401	101978	1.50	0.0	0.0	116	5433	1819	None
27	1	3999.90	71403	95190	1.50	0.0	0.0	121	5636	2023	None
28	1	4000.00	71401	95189	1.50	0.0	0.0	121	5636	2023	None
29	1	4099.90	69404	93492	1.50	0.0	0.0	122	5687	2074	None
30	1	4100.10	69400	93489	1.50	0.0	0.0	122	5687	2074	None
31	1	4399.90	63417	88396	1.50	0.0	0.0	125	5840	2226	None
32	1	4400.00	63415	88394	1.50	0.0	0.0	125	5840	2226	None
33	1	4500.00	61431	86704	1.50	0.0	0.0	126	5890	2277	None
34	1	4799.90	55519	81657	1.50	0.0	0.0	129	6041	2427	None
35	1	4800.00	55517	81655	1.50	0.0	0.0	129	6041	2427	None
36	1	5000.00	51629	78333	1.50	0.0	0.0	131	6140	2526	None
37	1	5499.90	42051	70129	1.50	0.0	0.0	137	6383	2770	None
38	1	5500.00	42051	70129	1.50	0.0	0.0	137	6383	2770	None
39	1	5899.90	34397	63553	1.50	0.0	0.0	141	6578	2965	None
40	1	5900.00	34397	63553	1.50	0.0	0.0	141	6578	2965	None
41	1	6000.00	32484	61907	1.50	0.0	0.0	142	6627	3014	None
42	1	6299.90	26745	56962	1.50	0.0	0.0	145	6773	3160	None
43	1	6300.00	26745	56963	1.50	0.0	0.0	145	6773	3160	None
44	1	6500.00	22919	53660	1.50	0.0	0.0	147	6870	3257	None
45	1	6699.90	19093	51391	1.64	0.2	0.0	149	6968	3355	Sinusoidal
46	1	6700.00	19093	51391	1.64	0.2	0.0	149	6968	3355	Sinusoidal
47	1	7000.00	13352	50872	2.26	2.2	0.0	152	7114	3501	Sinusoidal
48	1	7099.90	11439	50622	2.46	3.1	0.0	153	7163	3549	Sinusoidal
49	1	7100.00	11439	50622	2.46	3.1	0.0	153	7163	3549	Sinusoidal
50	1	7499.90	3787	49484	3.22	7.5	0.0	157	7357	3744	Sinusoidal
51	1	7500.00	3787	49484	3.22	7.5	0.0	157	7357	3744	Sinusoidal
52	1	7599.90	1874	49190	3.41	8.8	0.0	158	7406	3793	Sinusoidal
53											
54	**Additional Pickup to Prevent Buckling for Interval 0.00 ft - 7600.00 ft = 15784 lbf**										

Tubing Load Summary - Evacuation #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	91277	102072	1.50	0.0	0.0	78	0	0	None
2	1	100.00	89799	100614	1.50	0.0	0.0	79	0	38	None
3	1	399.90	83801	94688	1.50	0.0	0.0	82	0	190	None
4	1	400.00	83799	94686	1.50	0.0	0.0	82	0	190	None
5	1	500.00	81799	92709	1.50	0.0	0.0	83	0	241	None
6	1	799.90	75801	86769	1.50	0.0	0.0	86	0	394	None
7	1	800.00	75799	86767	1.50	0.0	0.0	86	0	394	None
8	1	1000.00	71799	82800	1.50	0.0	0.0	89	1	496	None
9	1	1199.90	67801	78828	1.50	0.0	0.0	91	1	598	None
10	1	1200.00	67799	78826	1.50	0.0	0.0	91	1	598	None
11	1	1500.00	61799	72857	1.50	0.0	0.0	94	1	750	None
12	1	1599.90	59801	70867	1.50	0.0	0.0	95	1	801	None
13	1	1600.00	59799	70865	1.50	0.0	0.0	95	1	801	None
14	1	1999.90	51801	62885	1.50	0.0	0.0	99	1	1005	None
15	1	2000.00	51799	62883	1.50	0.0	0.0	99	1	1005	None
16	1	2399.90	43801	54882	1.50	0.0	0.0	104	1	1209	None
17	1	2400.00	43799	54880	1.50	0.0	0.0	104	1	1209	None
18	1	2500.00	41799	52876	1.50	0.0	0.0	105	1	1259	None
19	1	2799.90	35801	46858	1.50	0.0	0.0	108	1	1412	None
20	1	2800.00	35799	46856	1.50	0.0	0.0	108	1	1412	None
21	1	3000.00	31799	42837	1.50	0.0	0.0	110	2	1514	None
22	1	3199.90	27801	38813	1.50	0.0	0.0	112	2	1616	None
23	1	3200.00	27799	38811	1.50	0.0	0.0	112	2	1616	None
24	1	3500.00	21799	32763	1.50	0.0	0.0	115	2	1769	None
25	1	3599.90	19801	30747	1.50	0.0	0.0	116	2	1819	None
26	1	3600.00	19799	30745	1.50	0.0	0.0	116	2	1819	None
27	1	3999.90	11801	22660	1.50	0.0	0.0	121	2	2023	None
28	1	4000.00	11799	22658	1.50	0.0	0.0	121	2	2023	None
29	1	4099.90	9802	20636	1.50	0.0	0.0	122	2	2074	None
30	1	4100.10	9798	20632	1.50	0.0	0.0	122	2	2074	None
31	1	4399.90	3815	14566	1.50	0.0	0.0	125	2	2226	None
32	1	4400.00	3813	14564	1.50	0.0	0.0	125	2	2226	None
33	1	4500.00	1829	12549	1.50	0.0	0.0	126	2	2277	None
34	1	4799.90	-4083	-14828	1.50	0.0	0.0	129	3	2427	None
35	1	4800.00	-4085	-14830	1.50	0.0	0.0	129	3	2427	None
36	1	5000.00	-7973	-18802	1.50	0.0	0.0	131	3	2526	None
37	1	5499.90	-17551	-28611	1.50	0.0	0.0	137	3	2770	None
38	1	5500.00	-17551	-28611	1.50	0.0	0.0	137	3	2770	None
39	1	5899.90	-25205	-36470	1.50	0.0	0.0	141	3	2965	None
40	1	5900.00	-25205	-36470	1.50	0.0	0.0	141	3	2965	None
41	1	6000.00	-27118	-38438	1.50	0.0	0.0	142	3	3014	None
42	1	6299.90	-32857	-44348	1.50	0.0	0.0	145	3	3160	None
43	1	6300.00	-32857	-44348	1.50	0.0	0.0	145	3	3160	None
44	1	6500.00	-36683	-48294	1.50	0.0	0.0	147	3	3257	None
45	1	6699.90	-40509	-52246	1.50	0.0	0.0	149	3	3355	None
46	1	6700.00	-40509	-52246	1.50	0.0	0.0	149	3	3355	None
47	1	7000.00	-46249	-58184	1.50	0.0	0.0	152	4	3501	None
48	1	7099.90	-48163	-60165	1.50	0.0	0.0	153	4	3549	None
49	1	7100.00	-48163	-60165	1.50	0.0	0.0	153	4	3549	None
50	1	7499.90	-55815	-68103	1.50	0.0	0.0	157	4	3744	None
51	1	7500.00	-55815	-68103	1.50	0.0	0.0	157	4	3744	None
52	1	7599.90	-57728	-70090	1.50	0.0	0.0	158	4	3793	None

Tubing Load Summary - AnnularPressureTest #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	77013	87764	1.50	0.0	0.0	78	0	1000	None
2	1	100.00	75535	86302	1.50	0.0	0.0	79	0	1038	None
3	1	399.90	69537	80363	1.50	0.0	0.0	82	0	1190	None
4	1	400.00	69535	80361	1.50	0.0	0.0	82	0	1190	None
5	1	500.00	67535	78379	1.50	0.0	0.0	83	0	1241	None
6	1	799.90	61537	72424	1.50	0.0	0.0	86	0	1394	None
7	1	800.00	61535	72422	1.50	0.0	0.0	86	0	1394	None
8	1	1000.00	57535	68446	1.50	0.0	0.0	89	0	1496	None
9	1	1199.90	53537	64464	1.50	0.0	0.0	91	0	1598	None
10	1	1200.00	53535	64462	1.50	0.0	0.0	91	0	1598	None
11	1	1500.00	47535	58478	1.50	0.0	0.0	94	0	1750	None
12	1	1599.90	45537	56484	1.50	0.0	0.0	95	0	1801	None
13	1	1600.00	45535	56481	1.50	0.0	0.0	95	0	1801	None
14	1	1999.90	37537	48482	1.50	0.0	0.0	99	1	2005	None
15	1	2000.00	37535	48480	1.50	0.0	0.0	99	1	2005	None
16	1	2399.90	29537	40460	1.50	0.0	0.0	104	1	2209	None
17	1	2400.00	29535	40458	1.50	0.0	0.0	104	1	2209	None
18	1	2500.00	27535	38449	1.50	0.0	0.0	105	1	2259	None
19	1	2799.90	21537	32417	1.50	0.0	0.0	108	1	2412	None
20	1	2800.00	21535	32415	1.50	0.0	0.0	108	1	2412	None
21	1	3000.00	17535	28385	1.50	0.0	0.0	110	1	2514	None
22	1	3199.90	13537	24352	1.50	0.0	0.0	112	1	2616	None
23	1	3200.00	13535	24350	1.50	0.0	0.0	112	1	2616	None
24	1	3500.00	7535	18288	1.50	0.0	0.0	115	1	2769	None
25	1	3599.90	5537	16267	1.50	0.0	0.0	116	1	2819	None
26	1	3600.00	5535	16265	1.50	0.0	0.0	116	1	2819	None
27	1	3999.90	-2463	-13152	1.50	0.0	0.0	121	1	3023	None
28	1	4000.00	-2465	-13154	1.50	0.0	0.0	121	1	3023	None
29	1	4099.90	-4462	-15188	1.50	0.0	0.0	122	1	3074	None
30	1	4100.10	-4466	-15192	1.50	0.0	0.0	122	1	3074	None
31	1	4399.90	-10449	-21294	1.50	0.0	0.0	125	1	3226	None
32	1	4400.00	-10451	-21296	1.50	0.0	0.0	125	1	3226	None
33	1	4500.00	-12436	-23323	1.50	0.0	0.0	126	1	3277	None
34	1	4799.90	-18347	-29367	1.50	0.0	0.0	129	1	3427	None
35	1	4800.00	-18349	-29369	1.50	0.0	0.0	129	1	3427	None
36	1	5000.00	-22237	-33351	1.50	0.0	0.0	131	1	3526	None
37	1	5499.90	-31815	-43183	1.50	0.0	0.0	137	2	3770	None
38	1	5500.00	-31815	-43183	1.50	0.0	0.0	137	2	3770	None
39	1	5899.90	-39469	-51062	1.50	0.0	0.0	141	2	3965	None
40	1	5900.00	-39469	-51062	1.50	0.0	0.0	141	2	3965	None
41	1	6000.00	-41382	-53034	1.50	0.0	0.0	142	2	4014	None
42	1	6299.90	-47121	-58959	1.50	0.0	0.0	145	2	4160	None
43	1	6300.00	-47121	-58959	1.50	0.0	0.0	145	2	4160	None
44	1	6500.00	-50947	-62913	1.50	0.0	0.0	147	2	4257	None
45	1	6699.90	-54773	-66875	1.50	0.0	0.0	149	2	4355	None
46	1	6700.00	-54773	-66875	1.50	0.0	0.0	149	2	4355	None
47	1	7000.00	-60514	-72828	1.50	0.0	0.0	152	2	4501	None
48	1	7099.90	-62427	-74814	1.50	0.0	0.0	153	2	4549	None
49	1	7100.00	-62427	-74814	1.50	0.0	0.0	153	2	4549	None
50	1	7499.90	-70079	-82771	1.50	0.0	0.0	157	2	4744	None
51	1	7500.00	-70079	-82771	1.50	0.0	0.0	157	2	4744	None
52	1	7599.90	-71992	-84762	1.50	0.0	0.0	158	2	4793	None

Tubing Load Summary - OverPull #1 - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	226822	238103	1.50	0.0	0.0	78	13	13	None
2	1	100.00	225344	236897	1.50	0.0	0.0	79	51	51	None
3	1	399.90	219346	231997	1.50	0.0	0.0	82	204	204	None
4	1	400.00	219344	231995	1.50	0.0	0.0	82	204	204	None
5	1	500.00	217344	230361	1.50	0.0	0.0	83	255	255	None
6	1	799.90	211346	225448	1.50	0.0	0.0	86	407	407	None
7	1	800.00	211344	225446	1.50	0.0	0.0	86	407	407	None
8	1	1000.00	207344	222168	1.50	0.0	0.0	89	509	509	None
9	1	1199.90	203346	218882	1.50	0.0	0.0	91	611	611	None
10	1	1200.00	203344	218880	1.50	0.0	0.0	91	611	611	None
11	1	1500.00	197344	213943	1.50	0.0	0.0	94	764	764	None
12	1	1599.90	195346	212298	1.50	0.0	0.0	95	815	815	None
13	1	1600.00	195344	212297	1.50	0.0	0.0	95	815	815	None
14	1	1999.90	187346	205698	1.50	0.0	0.0	99	1018	1018	None
15	1	2000.00	187344	205696	1.50	0.0	0.0	99	1018	1018	None
16	1	2399.90	179346	199080	1.50	0.0	0.0	104	1222	1222	None
17	1	2400.00	179344	199079	1.50	0.0	0.0	104	1222	1222	None
18	1	2500.00	177344	197423	1.50	0.0	0.0	105	1273	1273	None
19	1	2799.90	171346	192445	1.50	0.0	0.0	108	1425	1425	None
20	1	2800.00	171344	192444	1.50	0.0	0.0	108	1425	1425	None
21	1	3000.00	167344	189122	1.50	0.0	0.0	110	1527	1527	None
22	1	3199.90	163346	185793	1.50	0.0	0.0	112	1629	1629	None
23	1	3200.00	163344	185791	1.50	0.0	0.0	112	1629	1629	None
24	1	3500.00	157344	180789	1.50	0.0	0.0	115	1782	1782	None
25	1	3599.90	155346	179123	1.50	0.0	0.0	116	1833	1833	None
26	1	3600.00	155344	179121	1.50	0.0	0.0	116	1833	1833	None
27	1	3999.90	147346	172436	1.50	0.0	0.0	121	2036	2036	None
28	1	4000.00	147344	172434	1.50	0.0	0.0	121	2036	2036	None
29	1	4099.90	145347	170763	1.50	0.0	0.0	122	2087	2087	None
30	1	4100.10	145343	170760	1.50	0.0	0.0	122	2087	2087	None
31	1	4399.90	139360	165743	1.50	0.0	0.0	125	2240	2240	None
32	1	4400.00	139358	165741	1.50	0.0	0.0	125	2240	2240	None
33	1	4500.00	137373	164077	1.50	0.0	0.0	126	2290	2290	None
34	1	4799.90	131462	159103	1.50	0.0	0.0	129	2441	2441	None
35	1	4800.00	131460	159102	1.50	0.0	0.0	129	2441	2441	None
36	1	5000.00	127572	155829	1.50	0.0	0.0	131	2540	2540	None
37	1	5499.90	117994	147749	1.50	0.0	0.0	137	2783	2783	None
38	1	5500.00	117994	147749	1.50	0.0	0.0	137	2783	2783	None
39	1	5899.90	110340	141271	1.50	0.0	0.0	141	2978	2978	None
40	1	5900.00	110340	141271	1.50	0.0	0.0	141	2978	2978	None
41	1	6000.00	108427	139649	1.50	0.0	0.0	142	3027	3027	None
42	1	6299.90	102688	134778	1.50	0.0	0.0	145	3173	3173	None
43	1	6300.00	102688	134779	1.50	0.0	0.0	145	3173	3173	None
44	1	6500.00	98862	131524	1.50	0.0	0.0	147	3270	3270	None
45	1	6699.90	95036	128270	1.50	0.0	0.0	149	3368	3368	None
46	1	6700.00	95036	128270	1.50	0.0	0.0	149	3368	3368	None
47	1	7000.00	89295	123377	1.50	0.0	0.0	152	3514	3514	None
48	1	7099.90	87382	121743	1.50	0.0	0.0	153	3563	3563	None
49	1	7100.00	87382	121743	1.50	0.0	0.0	153	3563	3563	None
50	1	7499.90	79730	115201	1.50	0.0	0.0	157	3757	3757	None
51	1	7500.00	79730	115201	1.50	0.0	0.0	157	3757	3757	None
52	1	7599.90	77817	113562	1.50	0.0	0.0	158	3806	3806	None

Tubing Load Summary - CO2 Injection Transient 40F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	190002	203403	1.50	0.0	0.0	41	2700	500	None
2	1	100.00	188524	202148	1.50	0.0	0.0	42	2727	538	None
3	1	399.90	182526	197054	1.50	0.0	0.0	43	2835	693	None
4	1	400.00	182524	197052	1.50	0.0	0.0	43	2835	693	None
5	1	500.00	180524	195354	1.50	0.0	0.0	43	2871	745	None
6	1	799.90	174526	190260	1.50	0.0	0.0	44	2979	900	None
7	1	800.00	174524	190258	1.50	0.0	0.0	44	2979	900	None
8	1	1000.00	170524	186861	1.50	0.0	0.0	45	3051	1004	None
9	1	1199.90	166526	183466	1.50	0.0	0.0	46	3123	1107	None
10	1	1200.00	166524	183464	1.50	0.0	0.0	46	3123	1107	None
11	1	1500.00	160524	178369	1.50	0.0	0.0	47	3231	1262	None
12	1	1599.90	158526	176672	1.50	0.0	0.0	48	3267	1314	None
13	1	1600.00	158524	176670	1.50	0.0	0.0	48	3267	1314	None
14	1	1999.90	150526	169878	1.50	0.0	0.0	50	3411	1521	None
15	1	2000.00	150524	169876	1.50	0.0	0.0	50	3411	1521	None
16	1	2399.90	142526	163083	1.50	0.0	0.0	52	3555	1728	None
17	1	2400.00	142524	163082	1.50	0.0	0.0	52	3555	1728	None
18	1	2500.00	140524	161383	1.50	0.0	0.0	53	3591	1780	None
19	1	2799.90	134526	156289	1.50	0.0	0.0	55	3699	1935	None
20	1	2800.00	134524	156288	1.50	0.0	0.0	55	3699	1935	None
21	1	3000.00	130524	152890	1.50	0.0	0.0	57	3771	2038	None
22	1	3199.90	126526	149495	1.50	0.0	0.0	58	3843	2142	None
23	1	3200.00	126524	149493	1.50	0.0	0.0	58	3843	2142	None
24	1	3500.00	120524	144398	1.50	0.0	0.0	61	3951	2297	None
25	1	3599.90	118526	142701	1.50	0.0	0.0	61	3987	2349	None
26	1	3600.00	118524	142699	1.50	0.0	0.0	61	3987	2349	None
27	1	3999.90	110526	135907	1.50	0.0	0.0	65	4131	2555	None
28	1	4000.00	110524	135905	1.50	0.0	0.0	65	4131	2556	None
29	1	4099.90	108527	134209	1.50	0.0	0.0	66	4167	2607	None
30	1	4100.10	108523	134206	1.50	0.0	0.0	66	4167	2607	None
31	1	4399.90	102540	129156	1.50	0.0	0.0	69	4274	2762	None
32	1	4400.00	102538	129154	1.50	0.0	0.0	69	4274	2762	None
33	1	4500.00	100554	127503	1.50	0.0	0.0	70	4309	2813	None
34	1	4799.90	94642	122589	1.50	0.0	0.0	73	4413	2966	None
35	1	4800.00	94640	122587	1.50	0.0	0.0	73	4413	2966	None
36	1	5000.00	90752	119352	1.50	0.0	0.0	75	4482	3066	None
37	1	5499.90	81174	111370	1.50	0.0	0.0	80	4647	3313	None
38	1	5500.00	81174	111370	1.50	0.0	0.0	80	4647	3313	None
39	1	5899.90	73520	104978	1.50	0.0	0.0	84	4779	3510	None
40	1	5900.00	73520	104978	1.50	0.0	0.0	84	4779	3510	None
41	1	6000.00	71607	103379	1.50	0.0	0.0	85	4812	3560	None
42	1	6299.90	65868	98572	1.50	0.0	0.0	89	4911	3708	None
43	1	6300.00	65868	98572	1.50	0.0	0.0	88	4911	3708	None
44	1	6500.00	62042	95361	1.50	0.0	0.0	91	4977	3806	None
45	1	6699.90	58216	92148	1.50	0.0	0.0	93	5043	3905	None
46	1	6700.00	58216	92149	1.50	0.0	0.0	93	5043	3905	None
47	1	7000.00	52475	87318	1.50	0.0	0.0	96	5141	4053	None
48	1	7099.90	50562	85707	1.50	0.0	0.0	97	5173	4102	None
49	1	7100.00	50562	85707	1.50	0.0	0.0	97	5173	4102	None
50	1	7499.90	42910	79247	1.50	0.0	0.0	101	5302	4299	None
51	1	7500.00	42910	79248	1.50	0.0	0.0	101	5302	4299	None
52	1	7599.90	40997	77634	1.50	0.0	0.0	103	5335	4348	None

Tubing Load Summary - CO2 Injection Steady 40F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	220109	233510	1.50	0.0	0.0	40	2700	500	None
2	1	100.00	218631	232256	1.50	0.0	0.0	40	2727	538	None
3	1	399.90	212633	227165	1.50	0.0	0.0	40	2836	694	None
4	1	400.00	212631	227163	1.50	0.0	0.0	40	2836	694	None
5	1	500.00	210631	225466	1.50	0.0	0.0	40	2872	746	None
6	1	799.90	204633	220375	1.50	0.0	0.0	41	2981	902	None
7	1	800.00	204631	220373	1.50	0.0	0.0	41	2981	902	None
8	1	1000.00	200631	216978	1.50	0.0	0.0	41	3053	1005	None
9	1	1199.90	196633	213584	1.50	0.0	0.0	41	3126	1109	None
10	1	1200.00	196631	213583	1.50	0.0	0.0	41	3126	1109	None
11	1	1500.00	190631	208490	1.50	0.0	0.0	41	3235	1265	None
12	1	1599.90	188633	206794	1.50	0.0	0.0	41	3271	1317	None
13	1	1600.00	188631	206793	1.50	0.0	0.0	41	3271	1317	None
14	1	1999.90	180633	200004	1.50	0.0	0.0	41	3417	1524	None
15	1	2000.00	180631	200002	1.50	0.0	0.0	41	3417	1524	None
16	1	2399.90	172633	193214	1.50	0.0	0.0	41	3566	1732	None
17	1	2400.00	172631	193212	1.50	0.0	0.0	41	3566	1732	None
18	1	2500.00	170631	191515	1.50	0.0	0.0	41	3603	1784	None
19	1	2799.90	164633	186424	1.50	0.0	0.0	42	3714	1940	None
20	1	2800.00	164631	186422	1.50	0.0	0.0	42	3714	1940	None
21	1	3000.00	160631	183027	1.50	0.0	0.0	42	3789	2043	None
22	1	3199.90	156633	179634	1.50	0.0	0.0	42	3863	2147	None
23	1	3200.00	156631	179632	1.50	0.0	0.0	42	3863	2147	None
24	1	3500.00	150631	174539	1.50	0.0	0.0	42	3974	2303	None
25	1	3599.90	148633	172843	1.50	0.0	0.0	42	4011	2355	None
26	1	3600.00	148631	172842	1.50	0.0	0.0	42	4012	2355	None
27	1	3999.90	140633	166053	1.50	0.0	0.0	42	4161	2562	None
28	1	4000.00	140631	166052	1.50	0.0	0.0	42	4161	2562	None
29	1	4099.90	138634	164357	1.50	0.0	0.0	42	4199	2614	None
30	1	4100.10	138630	164353	1.50	0.0	0.0	42	4199	2614	None
31	1	4399.90	132647	159275	1.50	0.0	0.0	42	4311	2770	None
32	1	4400.00	132645	159273	1.50	0.0	0.0	42	4311	2770	None
33	1	4500.00	130660	157589	1.50	0.0	0.0	42	4349	2821	None
34	1	4799.90	124749	152573	1.50	0.0	0.0	42	4460	2975	None
35	1	4800.00	124747	152571	1.50	0.0	0.0	42	4460	2975	None
36	1	5000.00	120859	149273	1.50	0.0	0.0	42	4534	3076	None
37	1	5499.90	111281	141148	1.50	0.0	0.0	42	4716	3325	None
38	1	5500.00	111281	141149	1.50	0.0	0.0	42	4716	3325	None
39	1	5899.90	103627	134657	1.50	0.0	0.0	43	4862	3525	None
40	1	5900.00	103627	134657	1.50	0.0	0.0	42	4862	3525	None
41	1	6000.00	101714	133035	1.50	0.0	0.0	42	4898	3575	None
42	1	6299.90	95975	128167	1.50	0.0	0.0	43	5007	3724	None
43	1	6300.00	95975	128167	1.50	0.0	0.0	43	5007	3724	None
44	1	6500.00	92149	124922	1.50	0.0	0.0	43	5080	3824	None
45	1	6699.90	88323	121677	1.50	0.0	0.0	43	5153	3924	None
46	1	6700.00	88323	121677	1.50	0.0	0.0	43	5153	3924	None
47	1	7000.00	82582	116809	1.50	0.0	0.0	43	5262	4073	None
48	1	7099.90	80669	115186	1.50	0.0	0.0	43	5298	4123	None
49	1	7100.00	80669	115186	1.50	0.0	0.0	43	5298	4123	None
50	1	7499.90	73017	108696	1.50	0.0	0.0	43	5445	4322	None
51	1	7500.00	73017	108696	1.50	0.0	0.0	43	5445	4323	None
52	1	7599.90	71104	107073	1.50	0.0	0.0	43	5482	4372	None

Tubing Load Summary - Blowout Scenario 112 MMscfd - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	111671	122158	1.50	0.0	0.0	-27	179	0	None
2	1	100.00	110193	120900	1.50	0.0	0.0	16	435	38	None
3	1	399.90	104195	115792	1.50	0.0	0.0	57	679	190	None
4	1	400.00	104193	115790	1.50	0.0	0.0	57	679	190	None
5	1	500.00	102193	114087	1.50	0.0	0.0	66	760	241	None
6	1	799.90	96195	109469	1.50	0.0	0.0	83	933	394	None
7	1	800.00	96193	109467	1.50	0.0	0.0	83	933	394	None
8	1	1000.00	92193	106248	1.50	0.0	0.0	89	1048	496	None
9	1	1199.90	88195	102905	1.50	0.0	0.0	92	1133	598	None
10	1	1200.00	88193	102904	1.50	0.0	0.0	92	1133	598	None
11	1	1500.00	82193	97878	1.50	0.0	0.0	96	1261	750	None
12	1	1599.90	80195	96218	1.50	0.0	0.0	98	1304	801	None
13	1	1600.00	80193	96216	1.50	0.0	0.0	98	1304	801	None
14	1	1999.90	72195	89549	1.50	0.0	0.0	105	1474	1005	None
15	1	2000.00	72193	89548	1.50	0.0	0.0	106	1474	1005	None
16	1	2399.90	64195	82810	1.50	0.0	0.0	111	1680	1209	None
17	1	2400.00	64193	82808	1.50	0.0	0.0	112	1680	1209	None
18	1	2500.00	62193	81119	1.50	0.0	0.0	113	1731	1260	None
19	1	2799.90	56195	76038	1.50	0.0	0.0	117	1835	1412	None
20	1	2800.00	56193	76037	1.50	0.0	0.0	117	1835	1412	None
21	1	3000.00	52193	72641	1.50	0.0	0.0	120	1904	1514	None
22	1	3199.90	48195	69233	1.50	0.0	0.0	122	1991	1616	None
23	1	3200.00	48193	69231	1.50	0.0	0.0	122	1991	1616	None
24	1	3500.00	42193	64107	1.50	0.0	0.0	126	2122	1769	None
25	1	3599.90	40195	62394	1.50	0.0	0.0	127	2166	1819	None
26	1	3600.00	40193	62392	1.50	0.0	0.0	127	2166	1820	None
27	1	3999.90	32195	55526	1.50	0.0	0.0	131	2340	2023	None
28	1	4000.00	32193	55524	1.50	0.0	0.0	131	2340	2023	None
29	1	4099.90	30196	53807	1.50	0.0	0.0	132	2384	2074	None
30	1	4100.10	30192	53804	1.50	0.0	0.0	132	2384	2074	None
31	1	4399.90	24209	48653	1.50	0.0	0.0	135	2517	2226	None
32	1	4400.00	24207	48651	1.50	0.0	0.0	135	2517	2226	None
33	1	4500.00	22223	46941	1.50	0.0	0.0	136	2561	2277	None
34	1	4799.90	16311	41839	1.50	0.0	0.0	139	2693	2427	None
35	1	4800.00	16309	41838	1.50	0.0	0.0	139	2693	2427	None
36	1	5000.00	12421	38478	1.50	0.0	0.0	141	2779	2526	None
37	1	5499.90	2843	30184	1.50	0.0	0.0	146	2985	2770	None
38	1	5500.00	2843	30184	1.50	0.0	0.0	146	2985	2770	None
39	1	5899.90	-4811	2032	1.50	0.0	0.0	148	3174	2965	None
40	1	5900.00	-4811	2032	1.50	0.0	0.0	148	3174	2965	None
41	1	6000.00	-6724	363	1.50	0.0	0.0	149	3221	3014	None
42	1	6299.90	-12463	-4651	1.50	0.0	0.0	151	3351	3160	None
43	1	6300.00	-12463	-4650	1.50	0.0	0.0	151	3351	3160	None
44	1	6500.00	-16289	-7997	1.50	0.0	0.0	153	3438	3257	None
45	1	6699.90	-20115	-11345	1.50	0.0	0.0	154	3525	3355	None
46	1	6700.00	-20115	-11345	1.50	0.0	0.0	154	3525	3355	None
47	1	7000.00	-25855	-16373	1.50	0.0	0.0	156	3655	3501	None
48	1	7099.90	-27769	-18051	1.50	0.0	0.0	157	3698	3549	None
49	1	7100.00	-27769	-18051	1.50	0.0	0.0	157	3698	3549	None
50	1	7499.90	-35421	-24767	1.50	0.0	0.0	159	3872	3744	None
51	1	7500.00	-35421	-24766	1.50	0.0	0.0	159	3872	3744	None
52	1	7599.90	-37334	-26447	1.50	0.0	0.0	160	3915	3793	None

Tubing Load Summary - CO2 Injection Transient 40F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	181065	194466	1.50	0.0	0.0	41	1900	500	None
2	1	100.00	179587	193211	1.50	0.0	0.0	42	1926	538	None
3	1	399.90	173589	188117	1.50	0.0	0.0	43	2030	693	None
4	1	400.00	173587	188116	1.50	0.0	0.0	43	2030	693	None
5	1	500.00	171587	186417	1.50	0.0	0.0	43	2064	745	None
6	1	799.90	165589	181323	1.50	0.0	0.0	44	2168	900	None
7	1	800.00	165587	181321	1.50	0.0	0.0	44	2168	900	None
8	1	1000.00	161587	177924	1.50	0.0	0.0	45	2238	1004	None
9	1	1199.90	157589	174529	1.50	0.0	0.0	46	2307	1107	None
10	1	1200.00	157587	174527	1.50	0.0	0.0	46	2307	1107	None
11	1	1500.00	151587	169432	1.50	0.0	0.0	48	2411	1262	None
12	1	1599.90	149589	167735	1.50	0.0	0.0	48	2446	1314	None
13	1	1600.00	149587	167733	1.50	0.0	0.0	48	2446	1314	None
14	1	1999.90	141589	160941	1.50	0.0	0.0	50	2585	1521	None
15	1	2000.00	141587	160939	1.50	0.0	0.0	50	2585	1521	None
16	1	2399.90	133589	154147	1.50	0.0	0.0	53	2723	1728	None
17	1	2400.00	133587	154145	1.50	0.0	0.0	53	2723	1728	None
18	1	2500.00	131587	152446	1.50	0.0	0.0	53	2758	1780	None
19	1	2799.90	125589	147353	1.50	0.0	0.0	55	2862	1935	None
20	1	2800.00	125587	147351	1.50	0.0	0.0	55	2862	1935	None
21	1	3000.00	121587	143954	1.50	0.0	0.0	57	2931	2038	None
22	1	3199.90	117589	140558	1.50	0.0	0.0	58	3001	2142	None
23	1	3200.00	117587	140557	1.50	0.0	0.0	58	3001	2142	None
24	1	3500.00	111587	135461	1.50	0.0	0.0	61	3105	2297	None
25	1	3599.90	109589	133764	1.50	0.0	0.0	61	3139	2349	None
26	1	3600.00	109587	133763	1.50	0.0	0.0	61	3139	2349	None
27	1	3999.90	101589	126970	1.50	0.0	0.0	65	3278	2556	None
28	1	4000.00	101587	126968	1.50	0.0	0.0	65	3278	2556	None
29	1	4099.90	99590	125273	1.50	0.0	0.0	66	3313	2607	None
30	1	4100.10	99586	125269	1.50	0.0	0.0	66	3313	2607	None
31	1	4399.90	93603	120206	1.50	0.0	0.0	69	3416	2762	None
32	1	4400.00	93601	120204	1.50	0.0	0.0	69	3416	2762	None
33	1	4500.00	91617	118554	1.50	0.0	0.0	70	3450	2813	None
34	1	4799.90	85705	113629	1.50	0.0	0.0	72	3550	2966	None
35	1	4800.00	85703	113628	1.50	0.0	0.0	72	3550	2966	None
36	1	5000.00	81815	110384	1.50	0.0	0.0	74	3616	3067	None
37	1	5499.90	72237	102386	1.50	0.0	0.0	79	3775	3313	None
38	1	5500.00	72237	102386	1.50	0.0	0.0	79	3775	3313	None
39	1	5899.90	64583	95981	1.50	0.0	0.0	84	3902	3511	None
40	1	5900.00	64583	95981	1.50	0.0	0.0	84	3902	3511	None
41	1	6000.00	62670	94376	1.50	0.0	0.0	85	3934	3560	None
42	1	6299.90	56931	89561	1.50	0.0	0.0	88	4030	3708	None
43	1	6300.00	56931	89562	1.50	0.0	0.0	88	4030	3708	None
44	1	6500.00	53105	86348	1.50	0.0	0.0	90	4093	3806	None
45	1	6699.90	49279	83128	1.50	0.0	0.0	92	4155	3905	None
46	1	6700.00	49279	83128	1.50	0.0	0.0	92	4155	3905	None
47	1	7000.00	43538	78290	1.50	0.0	0.0	95	4248	4053	None
48	1	7099.90	41625	76676	1.50	0.0	0.0	96	4279	4102	None
49	1	7100.00	41625	76676	1.50	0.0	0.0	96	4279	4102	None
50	1	7499.90	33973	70205	1.50	0.0	0.0	101	4404	4299	None
51	1	7500.00	33973	70205	1.50	0.0	0.0	101	4404	4299	None
52	1	7599.90	32060	68588	1.50	0.0	0.0	102	4435	4349	None

Tubing Load Summary - CO2 Injection Transient 90F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	136755	151134	1.50	0.0	0.0	89	1900	500	None
2	1	100.00	135277	149879	1.50	0.0	0.0	90	1920	538	None
3	1	399.90	129279	144776	1.50	0.0	0.0	90	2000	692	None
4	1	400.00	129277	144774	1.50	0.0	0.0	90	2000	692	None
5	1	500.00	127277	143070	1.50	0.0	0.0	91	2026	743	None
6	1	799.90	121279	137965	1.50	0.0	0.0	91	2106	898	None
7	1	800.00	121277	137963	1.50	0.0	0.0	91	2106	898	None
8	1	1000.00	117277	134558	1.50	0.0	0.0	92	2159	1000	None
9	1	1199.90	113279	131154	1.50	0.0	0.0	92	2213	1103	None
10	1	1200.00	113277	131152	1.50	0.0	0.0	92	2213	1103	None
11	1	1500.00	107277	126040	1.50	0.0	0.0	93	2295	1257	None
12	1	1599.90	105279	124339	1.50	0.0	0.0	93	2323	1309	None
13	1	1600.00	105277	124337	1.50	0.0	0.0	93	2323	1309	None
14	1	1999.90	97279	117520	1.50	0.0	0.0	94	2433	1514	None
15	1	2000.00	97277	117519	1.50	0.0	0.0	94	2433	1514	None
16	1	2399.90	89279	110697	1.50	0.0	0.0	95	2543	1719	None
17	1	2400.00	89277	110695	1.50	0.0	0.0	95	2543	1720	None
18	1	2500.00	87277	108987	1.50	0.0	0.0	96	2572	1771	None
19	1	2799.90	81279	103870	1.50	0.0	0.0	96	2657	1925	None
20	1	2800.00	81277	103868	1.50	0.0	0.0	96	2657	1925	None
21	1	3000.00	77277	100456	1.50	0.0	0.0	97	2714	2028	None
22	1	3199.90	73279	97044	1.50	0.0	0.0	98	2770	2130	None
23	1	3200.00	73277	97043	1.50	0.0	0.0	98	2771	2130	None
24	1	3500.00	67277	91920	1.50	0.0	0.0	98	2856	2285	None
25	1	3599.90	65279	90214	1.50	0.0	0.0	99	2884	2336	None
26	1	3600.00	65277	90212	1.50	0.0	0.0	99	2884	2336	None
27	1	3999.90	57279	83381	1.50	0.0	0.0	100	2999	2541	None
28	1	4000.00	57277	83379	1.50	0.0	0.0	100	2999	2541	None
29	1	4099.90	55280	81672	1.50	0.0	0.0	100	3028	2593	None
30	1	4100.10	55276	81669	1.50	0.0	0.0	100	3028	2593	None
31	1	4399.90	49293	76559	1.50	0.0	0.0	102	3114	2747	None
32	1	4400.00	49291	76558	1.50	0.0	0.0	102	3114	2747	None
33	1	4500.00	47307	74860	1.50	0.0	0.0	102	3143	2798	None
34	1	4799.90	41395	69807	1.50	0.0	0.0	103	3228	2949	None
35	1	4800.00	41393	69805	1.50	0.0	0.0	103	3228	2949	None
36	1	5000.00	37505	66480	1.50	0.0	0.0	104	3284	3049	None
37	1	5499.90	27927	58285	1.50	0.0	0.0	106	3424	3295	None
38	1	5500.00	27927	58286	1.50	0.0	0.0	106	3424	3295	None
39	1	5899.90	20273	51733	1.50	0.0	0.0	108	3535	3492	None
40	1	5900.00	20273	51733	1.50	0.0	0.0	108	3535	3492	None
41	1	6000.00	18360	50094	1.50	0.0	0.0	108	3562	3541	None
42	1	6299.90	12621	44926	1.50	0.0	0.0	110	3646	3688	None
43	1	6300.00	12621	44926	1.50	0.0	0.0	110	3646	3688	None
44	1	6500.00	8795	41393	1.50	0.0	0.0	111	3701	3786	None
45	1	6699.90	4969	37858	1.50	0.0	0.0	112	3757	3884	None
46	1	6700.00	4969	37858	1.50	0.0	0.0	112	3757	3884	None
47	1	7000.00	-771	11280	1.50	0.0	0.0	114	3840	4032	None
48	1	7099.90	-2685	9506	1.50	0.0	0.0	115	3868	4081	None
49	1	7100.00	-2685	9506	1.50	0.0	0.0	115	3868	4081	None
50	1	7499.90	-10337	2403	1.50	0.0	0.0	117	3979	4277	None
51	1	7500.00	-10337	2403	1.50	0.0	0.0	117	3979	4277	None
52	1	7599.90	-12250	626	1.50	0.0	0.0	118	4007	4326	None

Tubing Load Summary - CO2 Steady 40 F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	220109	233510	1.50	0.0	0.0	40	2700	500	None
2	1	100.00	218631	232256	1.50	0.0	0.0	40	2727	538	None
3	1	399.90	212633	227165	1.50	0.0	0.0	40	2836	694	None
4	1	400.00	212631	227163	1.50	0.0	0.0	40	2836	694	None
5	1	500.00	210631	225466	1.50	0.0	0.0	40	2872	746	None
6	1	799.90	204633	220375	1.50	0.0	0.0	41	2981	902	None
7	1	800.00	204631	220373	1.50	0.0	0.0	41	2981	902	None
8	1	1000.00	200631	216978	1.50	0.0	0.0	41	3053	1005	None
9	1	1199.90	196633	213584	1.50	0.0	0.0	41	3126	1109	None
10	1	1200.00	196631	213583	1.50	0.0	0.0	41	3126	1109	None
11	1	1500.00	190631	208490	1.50	0.0	0.0	41	3235	1265	None
12	1	1599.90	188633	206794	1.50	0.0	0.0	41	3271	1317	None
13	1	1600.00	188631	206793	1.50	0.0	0.0	41	3271	1317	None
14	1	1999.90	180633	200004	1.50	0.0	0.0	41	3417	1524	None
15	1	2000.00	180631	200002	1.50	0.0	0.0	41	3417	1524	None
16	1	2399.90	172633	193214	1.50	0.0	0.0	41	3566	1732	None
17	1	2400.00	172631	193212	1.50	0.0	0.0	41	3566	1732	None
18	1	2500.00	170631	191515	1.50	0.0	0.0	41	3603	1784	None
19	1	2799.90	164633	186424	1.50	0.0	0.0	42	3714	1940	None
20	1	2800.00	164631	186422	1.50	0.0	0.0	42	3714	1940	None
21	1	3000.00	160631	183027	1.50	0.0	0.0	42	3789	2043	None
22	1	3199.90	156633	179634	1.50	0.0	0.0	42	3863	2147	None
23	1	3200.00	156631	179632	1.50	0.0	0.0	42	3863	2147	None
24	1	3500.00	150631	174539	1.50	0.0	0.0	42	3974	2303	None
25	1	3599.90	148633	172843	1.50	0.0	0.0	42	4011	2355	None
26	1	3600.00	148631	172842	1.50	0.0	0.0	42	4012	2355	None
27	1	3999.90	140633	166053	1.50	0.0	0.0	42	4161	2562	None
28	1	4000.00	140631	166052	1.50	0.0	0.0	42	4161	2562	None
29	1	4099.90	138634	164357	1.50	0.0	0.0	42	4199	2614	None
30	1	4100.10	138630	164353	1.50	0.0	0.0	42	4199	2614	None
31	1	4399.90	132647	159275	1.50	0.0	0.0	42	4311	2770	None
32	1	4400.00	132645	159273	1.50	0.0	0.0	42	4311	2770	None
33	1	4500.00	130660	157589	1.50	0.0	0.0	42	4349	2821	None
34	1	4799.90	124749	152573	1.50	0.0	0.0	42	4460	2975	None
35	1	4800.00	124747	152571	1.50	0.0	0.0	42	4460	2975	None
36	1	5000.00	120859	149273	1.50	0.0	0.0	42	4534	3076	None
37	1	5499.90	111281	141148	1.50	0.0	0.0	42	4716	3325	None
38	1	5500.00	111281	141149	1.50	0.0	0.0	42	4716	3325	None
39	1	5899.90	103627	134657	1.50	0.0	0.0	43	4862	3525	None
40	1	5900.00	103627	134657	1.50	0.0	0.0	42	4862	3525	None
41	1	6000.00	101714	133035	1.50	0.0	0.0	42	4898	3575	None
42	1	6299.90	95975	128167	1.50	0.0	0.0	43	5007	3724	None
43	1	6300.00	95975	128167	1.50	0.0	0.0	43	5007	3724	None
44	1	6500.00	92149	124922	1.50	0.0	0.0	43	5080	3824	None
45	1	6699.90	88323	121677	1.50	0.0	0.0	43	5153	3924	None
46	1	6700.00	88323	121677	1.50	0.0	0.0	43	5153	3924	None
47	1	7000.00	82582	116809	1.50	0.0	0.0	43	5262	4073	None
48	1	7099.90	80669	115186	1.50	0.0	0.0	43	5298	4123	None
49	1	7100.00	80669	115186	1.50	0.0	0.0	43	5298	4123	None
50	1	7499.90	73017	108696	1.50	0.0	0.0	43	5445	4322	None
51	1	7500.00	73017	108696	1.50	0.0	0.0	43	5445	4323	None
52	1	7599.90	71104	107073	1.50	0.0	0.0	43	5482	4372	None

Tubing Load Summary - CO2 Steady 90 F 2700 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	154443	168958	1.50	0.0	0.0	90	2700	500	None
2	1	100.00	152965	167703	1.50	0.0	0.0	90	2722	538	None
3	1	399.90	146967	162589	1.50	0.0	0.0	91	2811	692	None
4	1	400.00	146965	162587	1.50	0.0	0.0	91	2811	692	None
5	1	500.00	144965	160885	1.50	0.0	0.0	91	2841	744	None
6	1	799.90	138967	155769	1.50	0.0	0.0	91	2931	898	None
7	1	800.00	138965	155768	1.50	0.0	0.0	91	2931	898	None
8	1	1000.00	134965	152352	1.50	0.0	0.0	91	2990	1001	None
9	1	1199.90	130967	148943	1.50	0.0	0.0	92	3050	1103	None
10	1	1200.00	130965	148941	1.50	0.0	0.0	92	3050	1104	None
11	1	1500.00	124965	143821	1.50	0.0	0.0	92	3139	1258	None
12	1	1599.90	122967	142114	1.50	0.0	0.0	92	3169	1309	None
13	1	1600.00	122965	142112	1.50	0.0	0.0	92	3169	1309	None
14	1	1999.90	114967	135283	1.50	0.0	0.0	93	3292	1515	None
15	1	2000.00	114965	135282	1.50	0.0	0.0	93	3292	1515	None
16	1	2399.90	106967	128451	1.50	0.0	0.0	93	3415	1720	None
17	1	2400.00	106965	128449	1.50	0.0	0.0	93	3415	1720	None
18	1	2500.00	104965	126740	1.50	0.0	0.0	93	3446	1772	None
19	1	2799.90	98967	121612	1.50	0.0	0.0	94	3538	1926	None
20	1	2800.00	98965	121610	1.50	0.0	0.0	94	3538	1926	None
21	1	3000.00	94965	118191	1.50	0.0	0.0	94	3600	2029	None
22	1	3199.90	90967	114776	1.50	0.0	0.0	94	3661	2132	None
23	1	3200.00	90965	114774	1.50	0.0	0.0	94	3661	2132	None
24	1	3500.00	84965	109642	1.50	0.0	0.0	94	3756	2286	None
25	1	3599.90	82967	107933	1.50	0.0	0.0	94	3788	2337	None
26	1	3600.00	82965	107932	1.50	0.0	0.0	94	3788	2337	None
27	1	3999.90	74967	101090	1.50	0.0	0.0	95	3914	2543	None
28	1	4000.00	74965	101088	1.50	0.0	0.0	95	3914	2543	None
29	1	4099.90	72968	99380	1.50	0.0	0.0	95	3946	2594	None
30	1	4100.10	72964	99376	1.50	0.0	0.0	95	3946	2594	None
31	1	4399.90	66981	94254	1.50	0.0	0.0	95	4040	2748	None
32	1	4400.00	66979	94252	1.50	0.0	0.0	95	4040	2748	None
33	1	4500.00	64994	92554	1.50	0.0	0.0	95	4072	2799	None
34	1	4799.90	59083	87495	1.50	0.0	0.0	96	4165	2951	None
35	1	4800.00	59081	87493	1.50	0.0	0.0	95	4165	2951	None
36	1	5000.00	55193	84167	1.50	0.0	0.0	96	4227	3052	None
37	1	5499.90	45615	75968	1.50	0.0	0.0	96	4381	3298	None
38	1	5500.00	45615	75968	1.50	0.0	0.0	96	4381	3298	None
39	1	5899.90	37961	69415	1.50	0.0	0.0	96	4504	3496	None
40	1	5900.00	37961	69415	1.50	0.0	0.0	96	4504	3496	None
41	1	6000.00	36048	67778	1.50	0.0	0.0	96	4535	3545	None
42	1	6299.90	30309	62862	1.50	0.0	0.0	97	4628	3693	None
43	1	6300.00	30309	62863	1.50	0.0	0.0	97	4628	3693	None
44	1	6500.00	26483	59585	1.50	0.0	0.0	97	4689	3792	None
45	1	6699.90	22657	56309	1.50	0.0	0.0	97	4751	3890	None
46	1	6700.00	22657	56309	1.50	0.0	0.0	97	4751	3890	None
47	1	7000.00	16916	51391	1.50	0.0	0.0	97	4844	4038	None
48	1	7099.90	15003	49752	1.50	0.0	0.0	97	4876	4088	None
49	1	7100.00	15003	49753	1.50	0.0	0.0	97	4876	4088	None
50	1	7499.90	7351	43196	1.50	0.0	0.0	98	5001	4285	None
51	1	7500.00	7351	43197	1.50	0.0	0.0	98	5001	4285	None
52	1	7599.90	5438	41556	1.50	0.0	0.0	98	5033	4334	None

Tubing Load Summary - CO2 Steady 40 F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	209554	222956	1.50	0.0	0.0	40	1900	500	None
2	1	100.00	208076	221701	1.50	0.0	0.0	40	1926	538	None
3	1	399.90	202078	216610	1.50	0.0	0.0	41	2030	694	None
4	1	400.00	202076	216608	1.50	0.0	0.0	41	2030	694	None
5	1	500.00	200076	214911	1.50	0.0	0.0	41	2065	746	None
6	1	799.90	194078	209820	1.50	0.0	0.0	41	2170	902	None
7	1	800.00	194076	209818	1.50	0.0	0.0	41	2170	902	None
8	1	1000.00	190076	206423	1.50	0.0	0.0	41	2240	1005	None
9	1	1199.90	186078	203030	1.50	0.0	0.0	41	2310	1109	None
10	1	1200.00	186076	203028	1.50	0.0	0.0	41	2310	1109	None
11	1	1500.00	180076	197935	1.50	0.0	0.0	42	2414	1265	None
12	1	1599.90	178078	196239	1.50	0.0	0.0	42	2449	1317	None
13	1	1600.00	178076	196238	1.50	0.0	0.0	42	2449	1317	None
14	1	1999.90	170078	189449	1.50	0.0	0.0	42	2592	1524	None
15	1	2000.00	170076	189447	1.50	0.0	0.0	42	2592	1524	None
16	1	2399.90	162078	182659	1.50	0.0	0.0	42	2734	1732	None
17	1	2400.00	162076	182657	1.50	0.0	0.0	42	2734	1732	None
18	1	2500.00	160076	180959	1.50	0.0	0.0	42	2770	1784	None
19	1	2799.90	154078	175868	1.50	0.0	0.0	42	2877	1939	None
20	1	2800.00	154076	175867	1.50	0.0	0.0	42	2877	1939	None
21	1	3000.00	150076	172472	1.50	0.0	0.0	43	2948	2043	None
22	1	3199.90	146078	169078	1.50	0.0	0.0	43	3020	2147	None
23	1	3200.00	146076	169076	1.50	0.0	0.0	43	3020	2147	None
24	1	3500.00	140076	163984	1.50	0.0	0.0	43	3129	2303	None
25	1	3599.90	138078	162288	1.50	0.0	0.0	43	3165	2354	None
26	1	3600.00	138076	162286	1.50	0.0	0.0	43	3165	2355	None
27	1	3999.90	130078	155498	1.50	0.0	0.0	43	3311	2562	None
28	1	4000.00	130076	155496	1.50	0.0	0.0	43	3311	2562	None
29	1	4099.90	128079	153801	1.50	0.0	0.0	43	3347	2614	None
30	1	4100.10	128075	153797	1.50	0.0	0.0	43	3347	2614	None
31	1	4399.90	122092	148719	1.50	0.0	0.0	43	3456	2769	None
32	1	4400.00	122090	148717	1.50	0.0	0.0	43	3456	2769	None
33	1	4500.00	120106	147033	1.50	0.0	0.0	44	3492	2821	None
34	1	4799.90	114194	142017	1.50	0.0	0.0	44	3600	2974	None
35	1	4800.00	114192	142015	1.50	0.0	0.0	44	3600	2974	None
36	1	5000.00	110304	138717	1.50	0.0	0.0	44	3671	3076	None
37	1	5499.90	100726	130592	1.50	0.0	0.0	44	3847	3325	None
38	1	5500.00	100726	130592	1.50	0.0	0.0	44	3847	3325	None
39	1	5899.90	93072	124100	1.50	0.0	0.0	44	3988	3524	None
40	1	5900.00	93072	124100	1.50	0.0	0.0	44	3988	3524	None
41	1	6000.00	91159	122478	1.50	0.0	0.0	44	4023	3574	None
42	1	6299.90	85420	117610	1.50	0.0	0.0	45	4129	3724	None
43	1	6300.00	85420	117610	1.50	0.0	0.0	44	4129	3724	None
44	1	6500.00	81594	114365	1.50	0.0	0.0	45	4200	3823	None
45	1	6699.90	77768	111120	1.50	0.0	0.0	45	4270	3923	None
46	1	6700.00	77768	111120	1.50	0.0	0.0	45	4270	3923	None
47	1	7000.00	72028	106251	1.50	0.0	0.0	45	4376	4073	None
48	1	7099.90	70114	104628	1.50	0.0	0.0	45	4412	4122	None
49	1	7100.00	70114	104628	1.50	0.0	0.0	45	4412	4123	None
50	1	7499.90	62462	98138	1.50	0.0	0.0	45	4555	4322	None
51	1	7500.00	62462	98138	1.50	0.0	0.0	45	4555	4322	None
52	1	7599.90	60549	96515	1.50	0.0	0.0	45	4591	4372	None

Tubing Load Summary - CO2 Steady 90 F 1900 psi - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	141019	155444	1.50	0.0	0.0	90	1900	500	None
2	1	100.00	139541	154189	1.50	0.0	0.0	90	1920	538	None
3	1	399.90	133543	149091	1.50	0.0	0.0	91	1999	692	None
4	1	400.00	133541	149089	1.50	0.0	0.0	91	1999	692	None
5	1	500.00	131541	147386	1.50	0.0	0.0	91	2026	744	None
6	1	799.90	125543	142285	1.50	0.0	0.0	92	2106	898	None
7	1	800.00	125541	142283	1.50	0.0	0.0	92	2106	898	None
8	1	1000.00	121541	138874	1.50	0.0	0.0	92	2159	1001	None
9	1	1199.90	117543	135470	1.50	0.0	0.0	93	2212	1103	None
10	1	1200.00	117541	135469	1.50	0.0	0.0	93	2212	1103	None
11	1	1500.00	111541	130352	1.50	0.0	0.0	93	2294	1257	None
12	1	1599.90	109543	128652	1.50	0.0	0.0	94	2322	1309	None
13	1	1600.00	109541	128650	1.50	0.0	0.0	94	2322	1309	None
14	1	1999.90	101543	121827	1.50	0.0	0.0	95	2432	1514	None
15	1	2000.00	101541	121825	1.50	0.0	0.0	95	2432	1514	None
16	1	2399.90	93542	114998	1.50	0.0	0.0	95	2542	1720	None
17	1	2400.00	93540	114996	1.50	0.0	0.0	95	2542	1720	None
18	1	2500.00	91540	113288	1.50	0.0	0.0	96	2570	1771	None
19	1	2799.90	85542	108163	1.50	0.0	0.0	96	2655	1925	None
20	1	2800.00	85540	108161	1.50	0.0	0.0	96	2655	1925	None
21	1	3000.00	81540	104744	1.50	0.0	0.0	96	2712	2028	None
22	1	3199.90	77542	101327	1.50	0.0	0.0	97	2769	2131	None
23	1	3200.00	77540	101326	1.50	0.0	0.0	97	2769	2131	None
24	1	3500.00	71540	96194	1.50	0.0	0.0	97	2854	2285	None
25	1	3599.90	69542	94486	1.50	0.0	0.0	98	2883	2336	None
26	1	3600.00	69540	94484	1.50	0.0	0.0	98	2883	2337	None
27	1	3999.90	61542	87639	1.50	0.0	0.0	98	2998	2542	None
28	1	4000.00	61540	87637	1.50	0.0	0.0	98	2998	2542	None
29	1	4099.90	59544	85929	1.50	0.0	0.0	98	3027	2593	None
30	1	4100.10	59540	85925	1.50	0.0	0.0	98	3027	2594	None
31	1	4399.90	53556	80804	1.50	0.0	0.0	99	3114	2747	None
32	1	4400.00	53554	80802	1.50	0.0	0.0	99	3114	2747	None
33	1	4500.00	51570	79101	1.50	0.0	0.0	99	3143	2798	None
34	1	4799.90	45658	74040	1.50	0.0	0.0	99	3229	2950	None
35	1	4800.00	45656	74038	1.50	0.0	0.0	99	3229	2950	None
36	1	5000.00	41769	70708	1.50	0.0	0.0	100	3285	3050	None
37	1	5499.90	32190	62502	1.50	0.0	0.0	100	3427	3297	None
38	1	5500.00	32190	62502	1.50	0.0	0.0	100	3427	3297	None
39	1	5899.90	24536	55942	1.50	0.0	0.0	101	3540	3494	None
40	1	5900.00	24536	55942	1.50	0.0	0.0	101	3540	3494	None
41	1	6000.00	22623	54301	1.50	0.0	0.0	101	3569	3543	None
42	1	6299.90	16884	49160	1.50	0.0	0.0	101	3654	3691	None
43	1	6300.00	16884	49160	1.50	0.0	0.0	101	3654	3691	None
44	1	6500.00	13058	45632	1.50	0.0	0.0	102	3710	3790	None
45	1	6699.90	9232	42112	1.50	0.0	0.0	102	3768	3888	None
46	1	6700.00	9232	42112	1.50	0.0	0.0	102	3768	3888	None
47	1	7000.00	3492	36829	1.50	0.0	0.0	102	3855	4036	None
48	1	7099.90	1578	35067	1.50	0.0	0.0	102	3884	4085	None
49	1	7100.00	1578	35067	1.50	0.0	0.0	102	3884	4085	None
50	1	7499.90	-6074	6825	1.50	0.0	0.0	103	4000	4283	None
51	1	7500.00	-6074	6826	1.50	0.0	0.0	103	4000	4283	None
52	1	7599.90	-7987	5063	1.50	0.0	0.0	103	4029	4332	None

Tubing Load Summary - Tubing Leak - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	122979	150192	1.50	0.0	0.0	90	2700	2700	None
2	1	100.00	121501	148843	1.50	0.0	0.0	90	2722	2738	None
3	1	399.90	115503	143346	1.50	0.0	0.0	91	2811	2893	None
4	1	400.00	115501	143345	1.50	0.0	0.0	91	2811	2893	None
5	1	500.00	113501	141514	1.50	0.0	0.0	91	2841	2945	None
6	1	799.90	107503	136016	1.50	0.0	0.0	91	2931	3099	None
7	1	800.00	107501	136014	1.50	0.0	0.0	91	2931	3100	None
8	1	1000.00	103501	132344	1.50	0.0	0.0	91	2990	3203	None
9	1	1199.90	99503	128679	1.50	0.0	0.0	92	3050	3306	None
10	1	1200.00	99501	128677	1.50	0.0	0.0	92	3050	3306	None
11	1	1500.00	93501	123174	1.50	0.0	0.0	92	3139	3461	None
12	1	1599.90	91503	121340	1.50	0.0	0.0	92	3169	3512	None
13	1	1600.00	91501	121338	1.50	0.0	0.0	92	3169	3513	None
14	1	1999.90	83503	114021	1.50	0.0	0.0	93	3292	3719	None
15	1	2000.00	83501	114019	1.50	0.0	0.0	93	3292	3719	None
16	1	2399.90	75503	106700	1.50	0.0	0.0	93	3415	3925	None
17	1	2400.00	75501	106698	1.50	0.0	0.0	93	3415	3925	None
18	1	2500.00	73501	104867	1.50	0.0	0.0	93	3446	3977	None
19	1	2799.90	67503	99374	1.50	0.0	0.0	94	3538	4132	None
20	1	2800.00	67501	99372	1.50	0.0	0.0	94	3538	4132	None
21	1	3000.00	63501	95708	1.50	0.0	0.0	94	3600	4235	None
22	1	3199.90	59503	92049	1.50	0.0	0.0	94	3661	4338	None
23	1	3200.00	59501	92047	1.50	0.0	0.0	94	3661	4338	None
24	1	3500.00	53501	86564	1.50	0.0	0.0	94	3756	4493	None
25	1	3599.90	51503	84739	1.50	0.0	0.0	94	3788	4545	None
26	1	3600.00	51501	84737	1.50	0.0	0.0	94	3788	4545	None
27	1	3999.90	43503	77427	1.50	0.0	0.0	95	3914	4751	None
28	1	4000.00	43501	77425	1.50	0.0	0.0	95	3914	4751	None
29	1	4099.90	41504	75599	1.50	0.0	0.0	95	3946	4803	None
30	1	4100.10	41500	75596	1.50	0.0	0.0	95	3946	4803	None
31	1	4399.90	35517	70124	1.50	0.0	0.0	95	4040	4957	None
32	1	4400.00	35515	70122	1.50	0.0	0.0	95	4040	4958	None
33	1	4500.00	33531	68308	1.50	0.0	0.0	95	4072	5009	None
34	1	4799.90	27619	62902	1.50	0.0	0.0	96	4165	5161	None
35	1	4800.00	27617	62900	1.50	0.0	0.0	95	4165	5161	None
36	1	5000.00	23729	59345	1.50	0.0	0.0	96	4227	5262	None
37	1	5499.90	14151	50599	1.50	0.0	0.0	96	4381	5509	None
38	1	5500.00	14151	50599	1.50	0.0	0.0	96	4381	5509	None
39	1	5899.90	6497	43609	1.50	0.0	0.0	96	4504	5706	None
40	1	5900.00	6497	43609	1.50	0.0	0.0	96	4504	5706	None
41	1	6000.00	4584	41862	1.50	0.0	0.0	96	4535	5756	None
42	1	6299.90	-1155	15463	1.50	0.0	0.0	97	4628	5904	None
43	1	6300.00	-1155	15463	1.50	0.0	0.0	97	4628	5904	None
44	1	6500.00	-4981	11967	1.50	0.0	0.0	97	4689	6003	None
45	1	6699.90	-8807	8470	1.50	0.0	0.0	97	4751	6101	None
46	1	6700.00	-8807	8470	1.50	0.0	0.0	97	4751	6101	None
47	1	7000.00	-14547	3228	1.50	0.0	0.0	97	4844	6250	None
48	1	7099.90	-16461	1482	1.50	0.0	0.0	97	4876	6299	None
49	1	7100.00	-16461	1482	1.50	0.0	0.0	97	4876	6299	None
50	1	7499.90	-24113	-5500	1.50	0.0	0.0	98	5001	6497	None
51	1	7500.00	-24113	-5500	1.50	0.0	0.0	98	5001	6497	None
52	1	7599.90	-26026	-7246	1.50	0.0	0.0	98	5033	6546	None

Tubing Load Summary - Tubing Leak + Evacuation - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	52789	63467	1.50	0.0	0.0	78	0	2700	None
2	1	100.00	51311	62000	1.50	0.0	0.0	79	0	2738	None
3	1	399.90	45313	56037	1.50	0.0	0.0	82	0	2890	None
4	1	400.00	45311	56035	1.50	0.0	0.0	82	0	2890	None
5	1	500.00	43311	54045	1.50	0.0	0.0	83	0	2941	None
6	1	799.90	37313	48067	1.50	0.0	0.0	86	0	3094	None
7	1	800.00	37311	48065	1.50	0.0	0.0	86	0	3094	None
8	1	1000.00	33311	44073	1.50	0.0	0.0	89	1	3196	None
9	1	1199.90	29313	40076	1.50	0.0	0.0	91	1	3298	None
10	1	1200.00	29311	40074	1.50	0.0	0.0	91	1	3298	None
11	1	1500.00	23311	34067	1.50	0.0	0.0	94	1	3450	None
12	1	1599.90	21313	32064	1.50	0.0	0.0	95	1	3501	None
13	1	1600.00	21311	32062	1.50	0.0	0.0	95	1	3501	None
14	1	1999.90	13313	24032	1.50	0.0	0.0	99	1	3705	None
15	1	2000.00	13311	24030	1.50	0.0	0.0	99	1	3705	None
16	1	2399.90	5313	15978	1.50	0.0	0.0	104	1	3909	None
17	1	2400.00	5311	15976	1.50	0.0	0.0	104	1	3909	None
18	1	2500.00	3311	13959	1.50	0.0	0.0	105	1	3959	None
19	1	2799.90	-2687	-13325	1.50	0.0	0.0	108	1	4112	None
20	1	2800.00	-2689	-13327	1.50	0.0	0.0	108	1	4112	None
21	1	3000.00	-6689	-17387	1.50	0.0	0.0	110	2	4214	None
22	1	3199.90	-10687	-21449	1.50	0.0	0.0	112	2	4316	None
23	1	3200.00	-10689	-21451	1.50	0.0	0.0	112	2	4316	None
24	1	3500.00	-16689	-27558	1.50	0.0	0.0	115	2	4469	None
25	1	3599.90	-18687	-29594	1.50	0.0	0.0	116	2	4519	None
26	1	3600.00	-18689	-29596	1.50	0.0	0.0	116	2	4519	None
27	1	3999.90	-26687	-37761	1.50	0.0	0.0	121	2	4723	None
28	1	4000.00	-26689	-37763	1.50	0.0	0.0	121	2	4723	None
29	1	4099.90	-28686	-39805	1.50	0.0	0.0	122	2	4774	None
30	1	4100.10	-28690	-39809	1.50	0.0	0.0	122	2	4774	None
31	1	4399.90	-34673	-45935	1.50	0.0	0.0	125	2	4926	None
32	1	4400.00	-34675	-45937	1.50	0.0	0.0	125	2	4926	None
33	1	4500.00	-36660	-47971	1.50	0.0	0.0	126	2	4977	None
34	1	4799.90	-42571	-54039	1.50	0.0	0.0	129	3	5127	None
35	1	4800.00	-42573	-54041	1.50	0.0	0.0	129	3	5127	None
36	1	5000.00	-46461	-58038	1.50	0.0	0.0	131	3	5226	None
37	1	5499.90	-56039	-67909	1.50	0.0	0.0	137	3	5470	None
38	1	5500.00	-56039	-67909	1.50	0.0	0.0	137	3	5470	None
39	1	5899.90	-63693	-75819	1.50	0.0	0.0	141	3	5665	None
40	1	5900.00	-63693	-75819	1.50	0.0	0.0	141	3	5665	None
41	1	6000.00	-65606	-77798	1.50	0.0	0.0	142	3	5714	None
42	1	6299.90	-71345	-83746	1.50	0.0	0.0	145	3	5860	None
43	1	6300.00	-71345	-83746	1.50	0.0	0.0	145	3	5860	None
44	1	6500.00	-75171	-87716	1.50	0.0	0.0	147	3	5957	None
45	1	6699.90	-78997	-91693	1.50	0.0	0.0	149	3	6055	None
46	1	6700.00	-78997	-91693	1.50	0.0	0.0	149	3	6055	None
47	1	7000.00	-84738	-97669	1.50	0.0	0.0	152	4	6201	None
48	1	7099.90	-86651	-99663	1.50	0.0	0.0	153	4	6249	None
49	1	7100.00	-86651	-99663	1.50	0.0	0.0	153	4	6249	None
50	1	7499.90	-94303	-107651	1.50	0.0	0.0	157	4	6444	None
51	1	7500.00	-94303	-107651	1.50	0.0	0.0	157	4	6444	None
52	1	7599.90	-96216	-109650	1.50	0.0	0.0	158	4	6493	None

Tubing Load Summary - Doubled Pressure Test - 5 1/2" Production Tubing

	String Section	MD (ft)	Axial Force (lbf)	Equivalent Axial Load (lbf)	Dogleg (°/100ft)	Torque (ft-lbf)	Friction Force (lbf/ft)	Temperature (°F)	Pressure (psi)		Buckling Regime
									Internal	External	
1	1	26.10	190399	201493	1.50	0.0	0.0	78	7213	0	None
2	1	100.00	188921	200279	1.50	0.0	0.0	79	7251	38	None
3	1	399.90	182923	195342	1.50	0.0	0.0	82	7404	190	None
4	1	400.00	182921	195341	1.50	0.0	0.0	82	7404	190	None
5	1	500.00	180921	193695	1.50	0.0	0.0	83	7455	241	None
6	1	799.90	174923	188746	1.50	0.0	0.0	86	7607	394	None
7	1	800.00	174921	188744	1.50	0.0	0.0	86	7607	394	None
8	1	1000.00	170921	185442	1.50	0.0	0.0	89	7709	496	None
9	1	1199.90	166923	182132	1.50	0.0	0.0	91	7811	598	None
10	1	1200.00	166921	182130	1.50	0.0	0.0	91	7811	598	None
11	1	1500.00	160921	177157	1.50	0.0	0.0	94	7964	750	None
12	1	1599.90	158923	175501	1.50	0.0	0.0	95	8015	801	None
13	1	1600.00	158921	175499	1.50	0.0	0.0	95	8015	801	None
14	1	1999.90	150923	168852	1.50	0.0	0.0	99	8218	1005	None
15	1	2000.00	150921	168850	1.50	0.0	0.0	99	8218	1005	None
16	1	2399.90	142923	162186	1.50	0.0	0.0	104	8422	1209	None
17	1	2400.00	142921	162185	1.50	0.0	0.0	104	8422	1209	None
18	1	2500.00	140921	160517	1.50	0.0	0.0	105	8473	1259	None
19	1	2799.90	134923	155503	1.50	0.0	0.0	108	8625	1412	None
20	1	2800.00	134921	155501	1.50	0.0	0.0	108	8625	1412	None
21	1	3000.00	130921	152155	1.50	0.0	0.0	110	8727	1514	None
22	1	3199.90	126923	148802	1.50	0.0	0.0	112	8829	1616	None
23	1	3200.00	126921	148800	1.50	0.0	0.0	112	8829	1616	None
24	1	3500.00	120921	143762	1.50	0.0	0.0	115	8982	1769	None
25	1	3599.90	118923	142084	1.50	0.0	0.0	116	9033	1819	None
26	1	3600.00	118921	142082	1.50	0.0	0.0	116	9033	1819	None
27	1	3999.90	110923	139579	2.10	1.5	0.0	121	9236	2023	Helical
28	1	4000.00	110921	139578	2.10	1.5	0.0	121	9236	2023	Helical
29	1	4099.90	108924	133663	1.50	0.0	0.0	122	9287	2074	None
30	1	4100.10	108920	133659	1.50	0.0	0.0	122	9287	2074	None
31	1	4399.90	102937	128606	1.50	0.0	0.0	125	9440	2226	None
32	1	4400.00	102935	128604	1.50	0.0	0.0	125	9440	2226	None
33	1	4500.00	100951	126927	1.50	0.0	0.0	126	9490	2277	None
34	1	4799.90	95039	121919	1.50	0.0	0.0	129	9641	2427	None
35	1	4800.00	95037	121917	1.50	0.0	0.0	129	9641	2427	None
36	1	5000.00	91149	118620	1.50	0.0	0.0	131	9740	2526	None
37	1	5499.90	81571	116419	2.33	2.5	0.0	137	9983	2770	Sinusoidal
38	1	5500.00	81571	116419	2.33	2.5	0.0	137	9983	2770	Sinusoidal
39	1	5899.90	73917	115448	3.11	6.7	0.0	141	10178	2965	Sinusoidal
40	1	5900.00	73917	115448	3.11	6.7	0.0	141	10178	2965	Sinusoidal
41	1	6000.00	72004	115150	3.29	7.9	0.0	142	10227	3014	Sinusoidal
42	1	6299.90	66265	114318	3.86	12.0	0.0	145	10373	3160	Sinusoidal
43	1	6300.00	66265	114319	3.86	12.0	0.0	145	10373	3160	Sinusoidal
44	1	6500.00	62439	113746	4.24	15.0	0.0	147	10470	3257	Sinusoidal
45	1	6699.90	58613	113169	4.61	18.1	0.0	149	10568	3355	Sinusoidal
46	1	6700.00	58613	113169	4.61	18.1	0.0	149	10568	3355	Sinusoidal
47	1	7000.00	52873	112315	5.18	23.3	0.0	152	10714	3501	Sinusoidal
48	1	7099.90	50959	112018	5.36	25.1	0.0	153	10763	3549	Sinusoidal
49	1	7100.00	50959	112018	5.36	25.1	0.0	153	10763	3549	Sinusoidal
50	1	7499.90	43307	110793	6.11	32.6	0.0	157	10957	3744	Sinusoidal
51	1	7500.00	43307	110793	6.11	32.6	0.0	157	10957	3744	Sinusoidal
52	1	7599.90	41394	110490	6.29	34.6	0.0	158	11006	3793	Sinusoidal
53											
54	**Additional Pickup to Prevent Buckling for Interval 0.00 ft - 7600.00 ft = 41603 lbf**										

Packer Load Summary - Initial Conditions - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force (lbf)	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force (lbf)
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	15001	-37183		3806		158	---	15001
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - PressureTest #1 - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force (lbf)	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force (lbf)
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-45038	1874		3793		158	---	-165923
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - Evacuation #1 - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	57705	-57728		3793		158	---	184463
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - AnnularPressureTest #1 - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	71980	-71992		4793		158	---	232195
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - OverPull #1 - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	N/A	77817		3806		158	---	N/A
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Injection Transient 40F 2700 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-72088	40997		4348		103	---	-105083
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Injection Steady 40F 2700 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-103056	71104		4372		43	---	-140193
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - Blowout Scenario 112 MMscfd - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	14517	-37334		3793		160	---	10429
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Injection Transient 40F 1900 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-57907	32060		4349		102	---	-60788
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Injection Transient 90F 1900 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-11103	-12250		4326		118	---	-417
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Steady 40 F 2700 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-103056	71104		4372		43	---	-140193
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Steady 90 F 2700 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-34769	5438		4334		98	---	-58135
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Steady 40 F 1900 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-87306	60549		4372		45	---	-94645
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - CO2 Steady 90 F 1900 psi - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-15497	-7987		4332		103	---	-5378
2											
3	**Negative forces are in the upward direction.**										

Packer Load Summary - Tubing Leak - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-3306	-26026		6546		98	---	47315
2											
3	**Negative forces are in the upward direction.**										

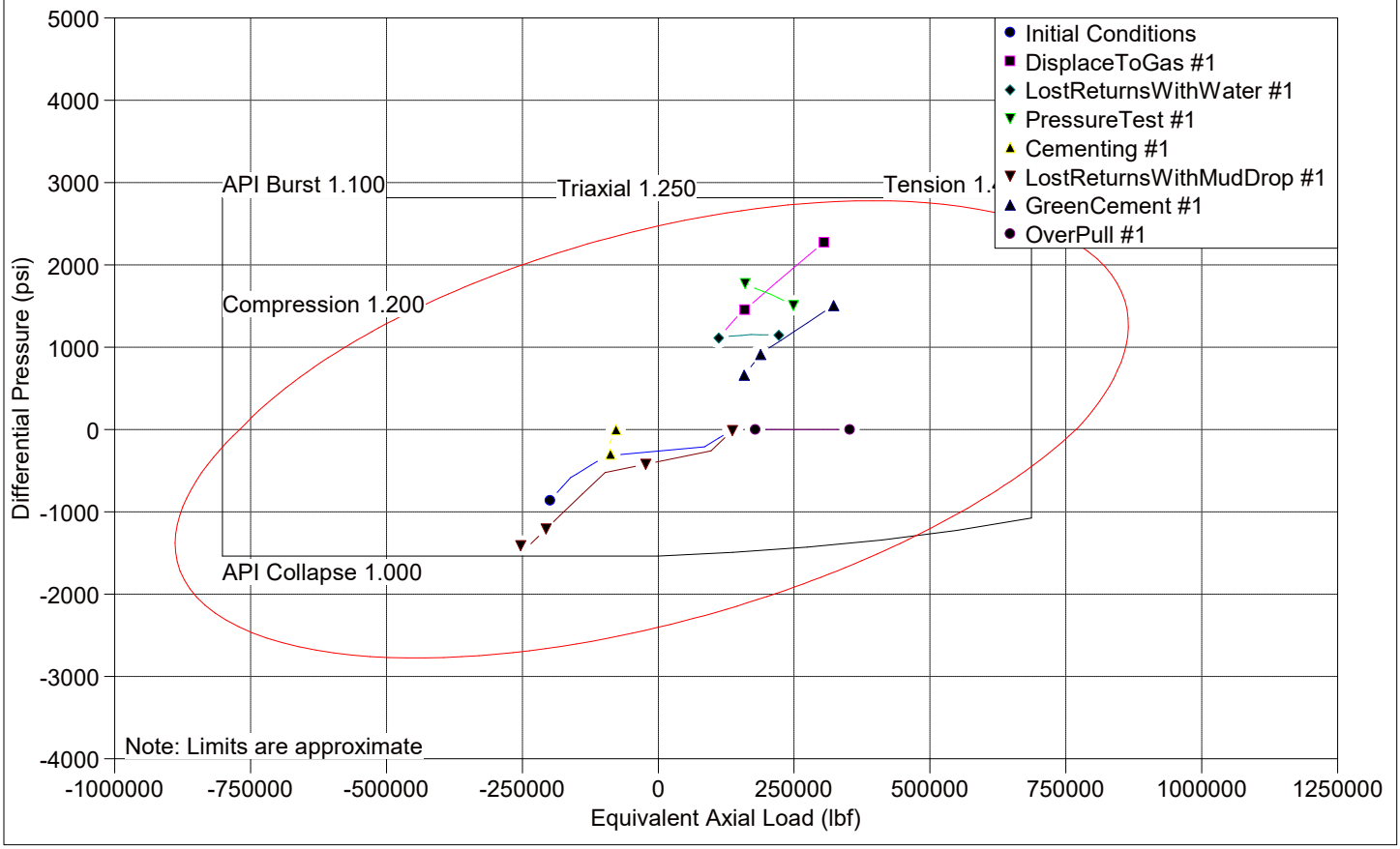
Packer Load Summary - Tubing Leak + Evacuation - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	96193	-96216		6493		158	---	313279
2											
3	**Negative forces are in the upward direction.**										

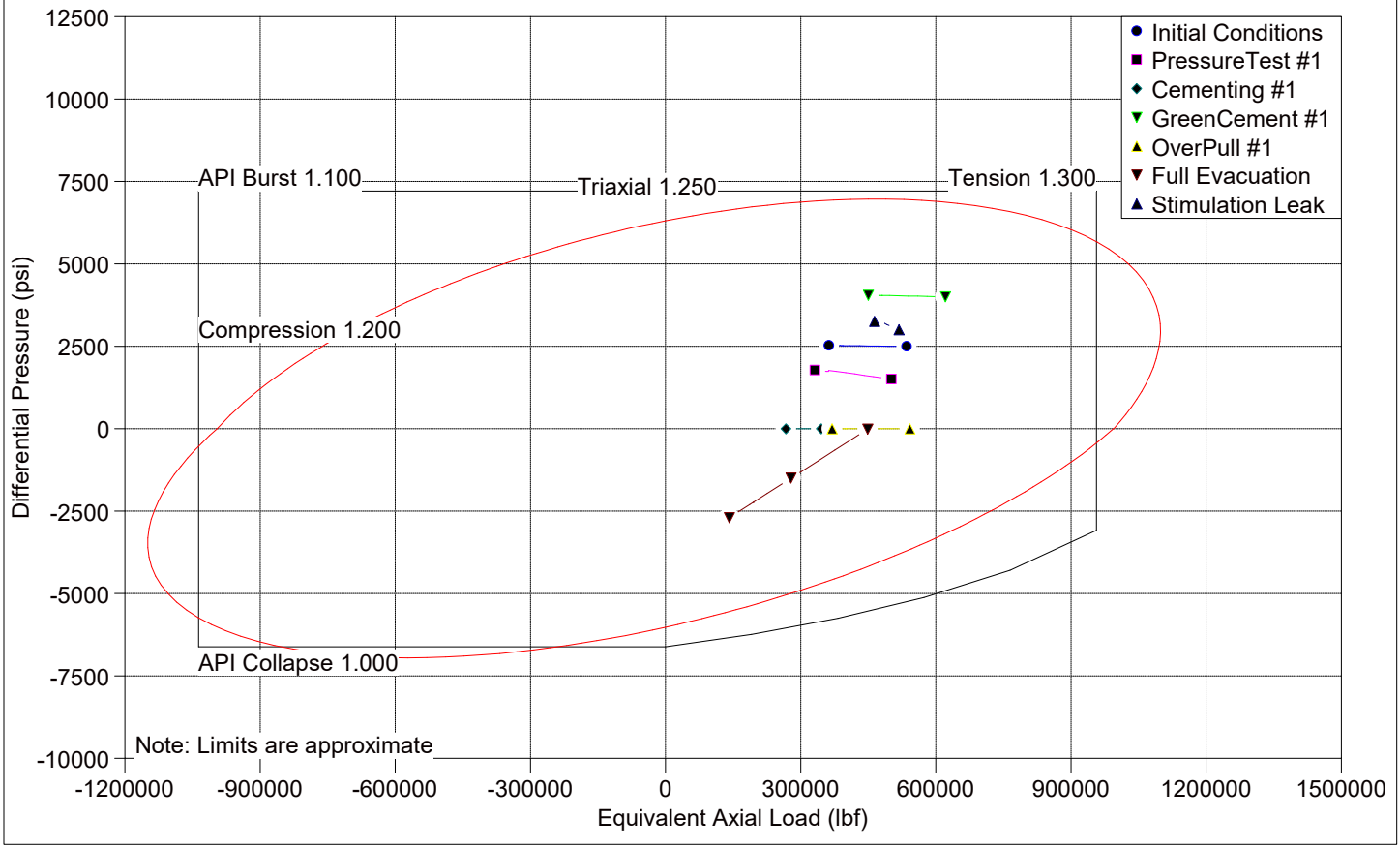
Packer Load Summary - Doubled Pressure Test - 5 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force
					Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Packer #1 (Pack	7600.00	1	-105540	41394		3793		158	---	-346862
2											
3	**Negative forces are in the upward direction.**										

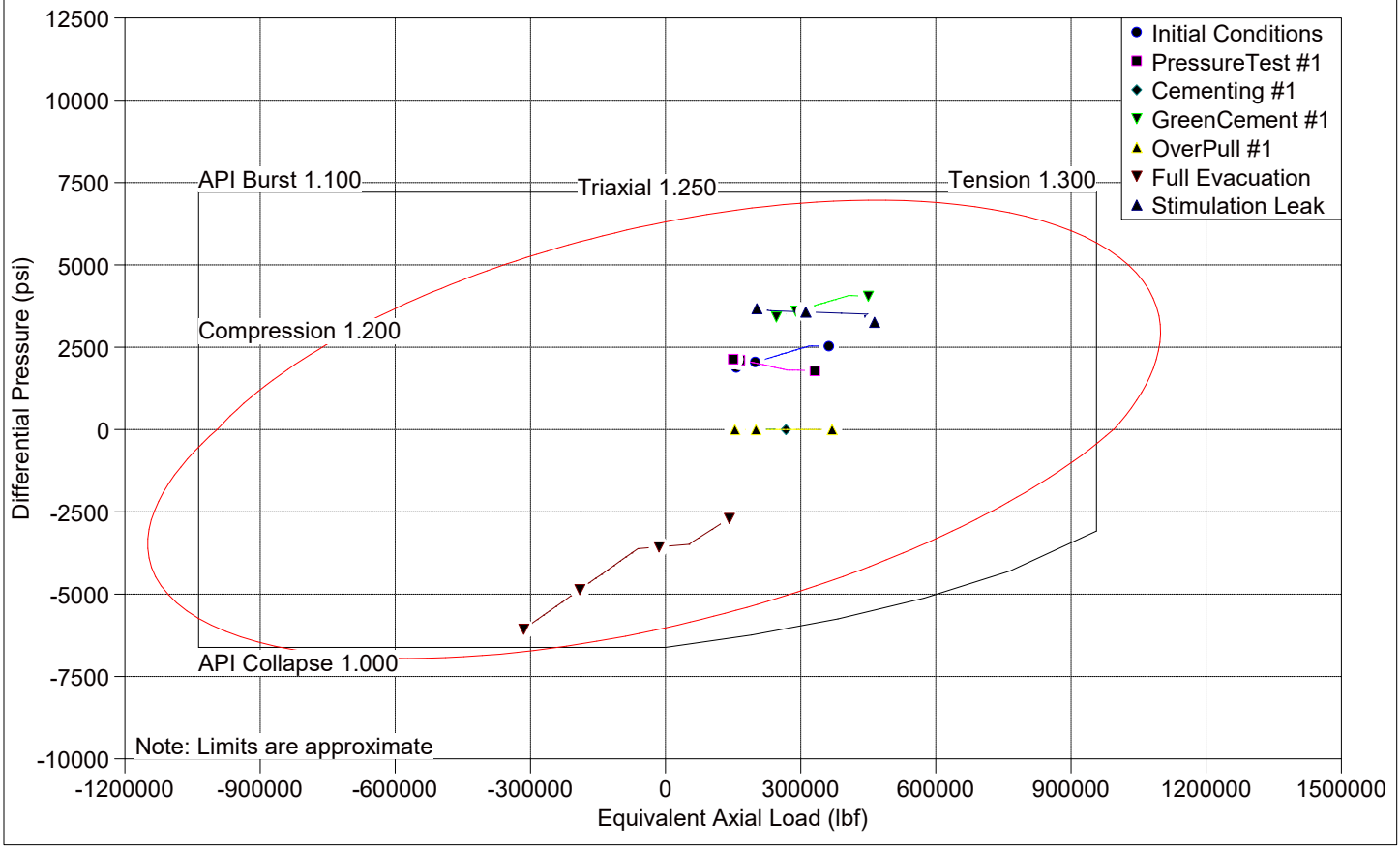
Design Limits - 13 3/8" Surface Casing - Section 1 - OD 13.375 in - Weight 61.000 ppf - Grade K-55



Design Limits - 9 5/8" Production Casing - Section 1 - OD 9.625 in - Weight 53.500 ppf - Grade L-80



Design Limits - 9 5/8" Production Casing - Section 2 - OD 9.625 in - Weight 53.500 ppf - Grade L-80



Triaxial Safety Factor - 13 3/8" Surface Casing

	MD (ft)	Absolute API Safety Factors							
		Initial Conditions	DisplaceToGas #	LostReturnsWith	PressureTest #1	Cementing #1	LostReturnsWith	GreenCement #1	OverPull #1
1	26.10	D 6.987	N 1.478	N 2.918	N 2.223	D 12.458	D 6.939	2.241	D 2.727
2	500.00	D 7.318	N 1.574	N 2.870	N 2.138	D 11.795	D 6.271	2.404	D 2.927
3	1000.00	D 7.361	N 1.688	N 2.815	N 2.053	D 10.977	4.856	2.605	D 3.175
4	1500.00	6.963	N 1.819	N 2.757	N 1.972	D 10.158	3.749	2.844	D 3.468
5	2000.00	6.266	N 1.980	N 2.716	N 1.906	D 9.392	2.995	N 3.106	D 3.824
6	2500.00	5.545	N 2.166	N 2.671	N 1.843	D 8.673	2.473	N 3.390	D 4.261
7	2700.00	5.272	N 2.250	N 2.653	N 1.819	D 8.394	2.309	N 3.514	D 4.466
8	2801.00	4.991	N 2.296	N 2.647	N 1.808	D 8.194	2.227	N 3.655	D 4.577
9	3000.00	4.510	N 2.396	N 2.638	N 1.788	7.770	2.260	N 3.968	D 4.814
10	3399.90	3.768	N 2.633	N 2.633	N 1.756	7.038	2.346	N 4.779	D 5.373
11									
12	**Triaxial Design Factor = 1.250**								
13									
14	**Triaxial Flags**								
15	**Default = Inner wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**								

Triaxial Safety Factor - 9 5/8" Production Casing

	MD (ft)	Absolute API Safety Factors						
		Initial Conditions	PressureTest #1	Cementing #1	GreenCement #1	OverPull #1	Full Evacuation	Stimulation Leak
1	26.10	2.445	2.764	D 3.594	1.859	D 2.293	D 2.760	2.345
2	500.00	2.513	2.869	D 3.692	1.886	D 2.380	D 2.811	2.349
3	1000.00	2.587	2.984	D 3.800	1.913	D 2.479	D 2.847	2.352
4	1500.00	2.662	3.104	D 3.915	1.940	D 2.588	2.844	2.354
5	2000.00	2.738	3.227	D 4.038	1.966	D 2.707	2.795	2.354
6	2500.00	2.815	3.353	D 4.170	1.991	D 2.838	2.717	2.353
7	3000.00	2.892	3.479	D 4.310	2.014	D 2.982	2.618	2.351
8	3399.90	2.953	3.579	D 4.431	2.031	D 3.110	2.527	2.349
9	3400.10	2.953	3.602	D 4.431	2.031	D 3.110	2.527	2.368
10	3500.00	2.968	3.633	D 4.461	2.035	D 3.143	2.504	2.371
11	4000.00	3.041	3.772	D 4.620	2.055	D 3.323	2.382	2.374
12	4099.90	3.056	3.800	D 4.652	2.058	D 3.361	2.357	2.375
13	4100.10	3.056	3.800	D 4.652	2.058	D 3.362	2.357	2.375
14	4199.90	3.070	3.827	D 4.691	2.062	D 3.401	2.333	2.376
15	4200.00	3.070	3.827	D 4.691	2.062	D 3.401	2.333	2.376
16	4240.20	3.076	3.838	D 4.704	2.064	D 3.417	2.323	2.376
17	4337.40	3.089	3.876	D 4.736	2.067	D 3.457	2.299	2.381
18	4344.50	3.090	3.886	D 4.738	2.067	D 3.459	2.297	2.386
19	4500.00	3.112	3.920	D 4.791	2.072	D 3.525	2.259	2.383
20	4599.90	3.125	3.941	D 4.830	2.076	D 3.568	2.234	2.381
21	4600.00	3.125	3.941	D 4.830	2.076	D 3.568	2.234	2.381
22	4646.10	3.131	3.950	D 4.846	2.077	D 3.588	2.223	2.380
23	4999.90	3.176	4.057	D 4.979	2.087	D 3.749	2.139	2.388
24	5000.00	3.176	4.057	D 4.979	2.087	D 3.749	2.139	2.388
25	5150.00	3.194	4.100	D 5.033	2.091	D 3.821	2.104	2.392
26	5299.90	3.234	4.136	D 5.073	2.106	D 3.895	2.069	2.393
27	5300.00	3.234	4.136	D 5.073	2.106	D 3.895	2.069	2.393
28	5499.90	3.287	4.182	D 5.119	2.126	D 3.998	2.022	2.394
29	5500.00	3.287	4.182	D 5.119	2.126	D 3.998	2.022	2.394
30	5665.70	3.333	4.220	D 5.164	2.142	D 4.089	1.984	2.396
31	5699.90	3.342	4.224	D 5.173	2.146	D 4.108	1.976	2.395
32	5700.00	3.342	4.224	D 5.173	2.146	D 4.108	1.976	2.395
33	5899.90	3.399	4.240	D 5.222	2.166	D 4.224	1.932	2.387
34	5900.00	3.399	4.240	D 5.222	2.166	D 4.224	1.932	2.387
35	6000.00	3.428	4.247	D 5.250	2.176	D 4.284	1.910	2.383
36	6099.90	3.457	4.254	D 5.278	2.186	D 4.346	1.889	2.380
37	6100.00	3.458	4.254	D 5.278	2.187	D 4.346	1.889	2.380
38	6299.90	3.518	4.264	D 5.328	2.207	D 4.476	1.847	2.372
39	6300.00	3.518	4.264	D 5.328	2.207	D 4.476	1.847	2.372
40	6499.90	3.579	4.270	D 5.387	2.228	D 4.615	1.806	2.365
41	6500.00	3.579	4.270	D 5.387	2.228	D 4.615	1.806	2.365
42	6699.90	3.643	4.273	D 5.439	2.250	D 4.762	1.767	2.357
43	6700.00	3.643	4.273	D 5.439	2.250	D 4.762	1.767	2.357
44	6899.90	3.709	4.273	D 5.500	2.271	D 4.920	1.729	2.349
45	6900.00	3.709	4.273	D 5.500	2.271	D 4.920	1.729	2.349
46	7000.00	3.742	4.271	D 5.524	2.282	D 5.002	1.710	2.345
47	7099.90	3.776	4.269	D 5.555	2.293	D 5.088	1.692	2.341
48	7100.00	3.776	4.269	D 5.555	2.293	D 5.088	1.692	2.341
49	7299.90	3.845	4.261	D 5.611	2.315	D 5.268	1.656	2.334
50	7300.00	3.845	4.261	D 5.611	2.315	D 5.268	1.656	2.334
51	7499.90	3.917	4.250	D 5.676	2.338	D 5.462	1.622	2.326
52	7500.00	3.917	4.250	D 5.676	2.338	D 5.462	1.622	2.326
53	7699.90	3.990	4.236	D 5.734	2.360	D 5.671	1.588	2.306
54	7700.00	3.990	4.236	D 5.734	2.360	D 5.671	1.588	2.306
55	7899.90	4.065	4.218	D 5.803	2.383	D 5.897	1.556	2.299
56	7900.00	4.065	4.218	D 5.803	2.383	D 5.897	1.556	2.299
57	7999.90	4.104	4.210	D 5.828	2.394	D 6.017	1.540	2.295
58	8000.00	4.104	4.210	D 5.828	2.394	D 6.017	1.540	2.295
59	8199.90	4.182	N 4.184	D 5.899	N 2.415	D 6.273	1.510	2.364
60	8200.00	4.182	N 4.184	D 5.899	N 2.415	D 6.273	1.510	2.364
61	8399.90	4.263	N 4.131	D 5.962	N 2.434	D 6.551	1.480	N 2.368
62	8400.00	4.263	N 4.131	D 5.962	N 2.434	D 6.551	1.480	N 2.368
63	8500.00	4.304	N 4.108	D 5.999	N 2.443	D 6.700	1.465	N 2.358
64	8599.90	4.345	N 4.084	D 6.036	N 2.452	D 6.856	1.451	N 2.349
65	8600.00	4.345	N 4.084	D 6.036	N 2.452	D 6.856	1.451	N 2.349
66	8799.90	N 4.403	N 4.035	D 6.102	N 2.470	D 7.191	1.423	N 2.332
67	8800.00	N 4.403	N 4.035	D 6.102	N 2.470	D 7.191	1.423	N 2.332
68	8999.90	N 4.459	N 3.985	D 6.180	N 2.489	D 7.561	1.396	N 2.315
69	9000.00	N 4.459	N 3.985	D 6.180	N 2.489	D 7.561	1.396	N 2.315
70	9199.90	N 4.513	N 3.934	D 6.249	N 2.507	D 7.972	1.370	N 2.298

Triaxial Safety Factor - 9 5/8" Production Casing

	MD (ft)	Absolute API Safety Factors						
		Initial Conditions	PressureTest #1	Cementing #1	GreenCement #1	OverPull #1	Full Evacuation	Stimulation Leak
71	9200.00	N 4.512	N 3.934	D 6.249	N 2.507	D 7.972	1.370	N 2.298
72	9249.90	N 4.525	N 3.921	D 6.269	N 2.511	D 8.081	1.363	N 2.293
73								
74	**Triaxial Design Factor = 1.250**							
75								
76	**Triaxial Flags**							
77	**Default = Inner wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending**							

Internal Pressure - 13 3/8" Surface Casing

	MD (ft)	Pressure (psi)							
		Initial Conditions	DisplaceToGas #	LostReturnsWithW	PressureTest #1	Cementing #1	LostReturnsWithMu	GreenCement #1	OverPull #1
1	26.10	11	2276	1153	1514	11	0	1511	14
2	500.00	216	2323	1358	1760	216	0	1716	260
3	1000.00	433	2373	1575	2019	433	0	1933	519
4	1500.00	649	2423	1791	2279	649	0	2149	779
5	2000.00	865	2473	2008	2539	865	0	2365	1039
6	2500.00	1082	2523	2224	2799	1082	0	2582	1299
7	2700.00	1168	2543	2310	2903	1168	0	2668	1403
8	2801.00	1212	2553	2354	2955	1212	0	2712	1455
9	3000.00	1298	2573	2440	3058	1298	120	2798	1558
10	3399.90	1471	2613	2613	3266	1471	374	2971	1766

Internal Pressure - 9 5/8" Production Casing

	MD (ft)	Pressure (psi)						
		Initial Conditions	PressureTest #1	Cementing #1	GreenCement #1	OverPull #1	Full Evacuation	Stimulation Leak
1	26.10	2500	1513	17	4000	17	0	3000
2	500.00	2808	1755	325	4308	325	0	3241
3	1000.00	3132	2009	649	4632	649	1	3496
4	1500.00	3457	2264	974	4957	974	1	3750
5	2000.00	3782	2518	1299	5282	1299	1	4005
6	2500.00	4106	2773	1623	5606	1623	1	4259
7	3000.00	4431	3027	1948	5931	1948	2	4514
8	3399.90	4691	3231	2208	6191	2208	2	4718
9	3400.10	4691	3231	2208	6191	2208	2	4718
10	3500.00	4756	3282	2273	6256	2273	2	4769
11	4000.00	5081	3536	2597	6581	2597	2	5023
12	4099.90	5145	3587	2662	6645	2662	2	5074
13	4100.10	5146	3587	2662	6646	2662	2	5074
14	4199.90	5210	3638	2727	6710	2727	2	5125
15	4200.00	5210	3638	2727	6710	2727	2	5125
16	4240.20	5236	3659	2753	6736	2753	2	5145
17	4337.40	5299	3708	2816	6799	2816	2	5195
18	4344.50	5304	3711	2821	6804	2821	2	5198
19	4500.00	5404	3790	2921	6904	2921	2	5277
20	4599.90	5468	3841	2985	6968	2985	2	5327
21	4600.00	5469	3841	2985	6969	2985	2	5327
22	4646.10	5498	3864	3015	6998	3015	2	5350
23	4999.90	5722	4040	3239	7222	3239	3	5526
24	5000.00	5722	4040	3239	7222	3239	3	5526
25	5150.00	5816	4113	3333	7316	3333	3	5600
26	5299.90	5909	4186	3426	7409	3426	3	5673
27	5300.00	5909	4186	3426	7409	3426	3	5673
28	5499.90	6033	4283	3550	7533	3550	3	5770
29	5500.00	6033	4283	3550	7533	3550	3	5770
30	5665.70	6136	4364	3653	7636	3653	3	5851
31	5699.90	6158	4381	3675	7658	3674	3	5868
32	5700.00	6158	4381	3675	7658	3675	3	5868
33	5899.90	6282	4478	3799	7782	3799	3	5965
34	5900.00	6282	4478	3799	7782	3799	3	5965
35	6000.00	6344	4527	3861	7844	3861	3	6014
36	6099.90	6406	4576	3923	7906	3923	3	6062
37	6100.00	6406	4576	3923	7906	3923	3	6062
38	6299.90	6530	4673	4047	8030	4047	3	6160
39	6300.00	6530	4673	4047	8030	4047	3	6160
40	6499.90	6655	4770	4171	8155	4171	3	6257
41	6500.00	6655	4770	4172	8155	4171	3	6257
42	6699.90	6779	4868	4296	8279	4296	3	6355
43	6700.00	6779	4868	4296	8279	4296	3	6355
44	6899.90	6903	4965	4420	8403	4420	4	6452
45	6900.00	6903	4965	4420	8403	4420	4	6452
46	7000.00	6965	5014	4482	8465	4482	4	6501
47	7099.90	7027	5063	4544	8527	4544	4	6549
48	7100.00	7027	5063	4544	8527	4544	4	6549
49	7299.90	7151	5160	4668	8651	4668	4	6647
50	7300.00	7152	5160	4668	8652	4668	4	6647
51	7499.90	7276	5257	4793	8776	4793	4	6744
52	7500.00	7276	5257	4793	8776	4793	4	6744
53	7699.90	7400	5355	4917	8900	4917	4	6842
54	7700.00	7400	5355	4917	8900	4917	4	6842
55	7899.90	7524	5452	5041	9024	5041	4	6939
56	7900.00	7524	5452	5041	9024	5041	4	6939
57	7999.90	7586	5501	5103	9086	5103	4	6988
58	8000.00	7586	5501	5103	9086	5103	4	6988
59	8199.90	7711	5598	5227	9211	5227	4	7085
60	8200.00	7711	5598	5227	9211	5227	4	7085
61	8399.90	7835	5696	5352	9335	5352	4	7182
62	8400.00	7835	5696	5352	9335	5352	4	7183
63	8500.00	7897	5744	5414	9397	5414	4	7231
64	8599.90	7959	5793	5476	9459	5476	4	7280
65	8600.00	7959	5793	5476	9459	5476	4	7280
66	8799.90	8083	5890	5600	9583	5600	4	7377
67	8800.00	8083	5891	5600	9583	5600	4	7377
68	8999.90	8207	5988	5724	9707	5724	5	7475
69	9000.00	8208	5988	5724	9708	5724	5	7475
70	9199.90	8332	6085	5849	9832	5849	5	7573

Internal Pressure - 9 5/8" Production Casing

	MD (ft)	Pressure (psi)						
		Initial Conditions	PressureTest #1	Cementing #1	GreenCement #1	OverPull #1	Full Evacuation	Stimulation Leak
71	9200.00	8332	6085	5849	9832	5849	5	7572
72	9249.90	8363	6110	5880	9863	5880	5	7596

External Pressure - 13 3/8" Surface Casing

	MD (ft)	Pressure (psi)							
		Initial Conditions	DisplaceToGas #	LostReturnsWithW	PressureTest #1	Cementing #1	LostReturnsWithMu	GreenCement #1	OverPull #1
1	26.10	12	11	11	11	14	14	12	14
2	500.00	319	216	216	216	260	260	319	260
3	1000.00	644	433	433	433	519	519	644	519
4	1500.00	969	650	650	650	779	779	969	779
5	2000.00	1293	876	876	876	1039	1039	1293	1039
6	2500.00	1618	1103	1103	1103	1299	1299	1618	1299
7	2700.00	1748	1194	1194	1194	1403	1403	1748	1403
8	2801.00	1831	1239	1239	1239	1455	1455	1831	1455
9	3000.00	1994	1330	1330	1330	1558	1558	1994	1558
10	3399.90	2322	1518	1518	1518	1766	1766	2322	1766

External Pressure - 9 5/8" Production Casing

	MD (ft)	Pressure (psi)						
		Initial Conditions	PressureTest #1	Cementing #1	GreenCement #1	OverPull #1	Full Evacuation	Stimulation Leak
1	26.10	17	17	17	17	17	17	17
2	500.00	325	224	325	325	325	325	222
3	1000.00	649	442	649	649	649	649	438
4	1500.00	974	660	974	974	974	974	655
5	2000.00	1299	878	1299	1299	1299	1299	871
6	2500.00	1623	1096	1623	1623	1623	1623	1087
7	3000.00	1948	1315	1948	1948	1948	1948	1304
8	3399.90	2208	1489	2208	2208	2208	2208	1477
9	3400.10	2208	1518	2208	2208	2208	2208	1518
10	3500.00	2273	1568	2273	2273	2273	2273	1568
11	4000.00	2597	1801	2597	2597	2597	2597	1801
12	4099.90	2662	1847	2662	2662	2662	2662	1847
13	4100.10	2662	1847	2662	2662	2662	2662	1847
14	4199.90	2727	1893	2727	2727	2727	2727	1893
15	4200.00	2727	1893	2727	2727	2727	2727	1893
16	4240.20	2753	1912	2753	2753	2753	2753	1912
17	4337.40	2816	1967	2816	2816	2816	2816	1967
18	4344.50	2821	1979	2821	2821	2821	2821	1979
19	4500.00	2921	2043	2921	2921	2921	2921	2043
20	4599.90	2985	2084	2985	2985	2985	2985	2084
21	4600.00	2985	2084	2985	2985	2985	2985	2084
22	4646.10	3015	2103	3015	3015	3015	3015	2103
23	4999.90	3239	2277	3239	3239	3239	3239	2277
24	5000.00	3239	2277	3239	3239	3239	3239	2277
25	5150.00	3333	2350	3333	3333	3333	3333	2350
26	5299.90	3451	2422	3426	3451	3426	3426	2422
27	5300.00	3451	2422	3426	3451	3426	3426	2422
28	5499.90	3608	2518	3550	3608	3550	3550	2518
29	5500.00	3608	2518	3550	3608	3550	3550	2518
30	5665.70	3738	2598	3653	3738	3653	3653	2598
31	5699.90	3765	2612	3675	3765	3674	3675	2612
32	5700.00	3765	2612	3675	3765	3675	3675	2612
33	5899.90	3922	2691	3799	3922	3799	3799	2691
34	5900.00	3922	2691	3799	3922	3799	3799	2691
35	6000.00	4000	2730	3861	4000	3861	3861	2730
36	6099.90	4079	2770	3923	4079	3923	3923	2770
37	6100.00	4079	2770	3923	4079	3923	3923	2770
38	6299.90	4236	2849	4047	4236	4047	4047	2849
39	6300.00	4236	2849	4047	4236	4047	4047	2849
40	6499.90	4393	2928	4171	4393	4171	4171	2928
41	6500.00	4393	2928	4172	4393	4171	4172	2928
42	6699.90	4550	3007	4296	4550	4296	4296	3007
43	6700.00	4550	3007	4296	4550	4296	4296	3007
44	6899.90	4707	3086	4420	4707	4420	4420	3086
45	6900.00	4707	3086	4420	4707	4420	4420	3086
46	7000.00	4785	3126	4482	4785	4482	4482	3126
47	7099.90	4864	3166	4544	4864	4544	4544	3166
48	7100.00	4864	3166	4544	4864	4544	4544	3166
49	7299.90	5021	3245	4668	5021	4668	4668	3245
50	7300.00	5021	3245	4668	5021	4668	4668	3245
51	7499.90	5178	3324	4793	5178	4793	4793	3324
52	7500.00	5178	3324	4793	5178	4793	4793	3324
53	7699.90	5335	3403	4917	5335	4917	4917	3403
54	7700.00	5335	3403	4917	5335	4917	4917	3403
55	7899.90	5492	3482	5041	5492	5041	5041	3482
56	7900.00	5492	3482	5041	5492	5041	5041	3482
57	7999.90	5571	3523	5103	5571	5103	5103	3523
58	8000.00	5571	3523	5103	5571	5103	5103	3523
59	8199.90	5728	3604	5227	5728	5227	5227	3604
60	8200.00	5728	3604	5227	5728	5227	5227	3604
61	8399.90	5885	3686	5352	5885	5352	5352	3686
62	8400.00	5885	3686	5352	5885	5352	5352	3686
63	8500.00	5963	3728	5414	5963	5414	5414	3728
64	8599.90	6042	3771	5476	6042	5476	5476	3771
65	8600.00	6042	3771	5476	6042	5476	5476	3771
66	8799.90	6199	3855	5600	6199	5600	5600	3855
67	8800.00	6199	3855	5600	6199	5600	5600	3855
68	8999.90	6356	3940	5724	6356	5724	5724	3940
69	9000.00	6356	3940	5724	6356	5724	5724	3940
70	9199.90	6513	4025	5849	6513	5849	5849	4025

External Pressure - 9 5/8" Production Casing

	MD (ft)	Pressure (psi)						
		Initial Conditions	PressureTest #1	Cementing #1	GreenCement #1	OverPull #1	Full Evacuation	Stimulation Leak
71	9200.00	6513	4025	5849	6513	5849	5849	4025
72	9249.90	6552	4046	5880	6552	5880	5880	4046

HALLIBURTON

iCem® Service

OXY INC

For:
Date: Saturday, June 29, 2024

Bluebonnet CCS 1
Case 1

Sincerely,

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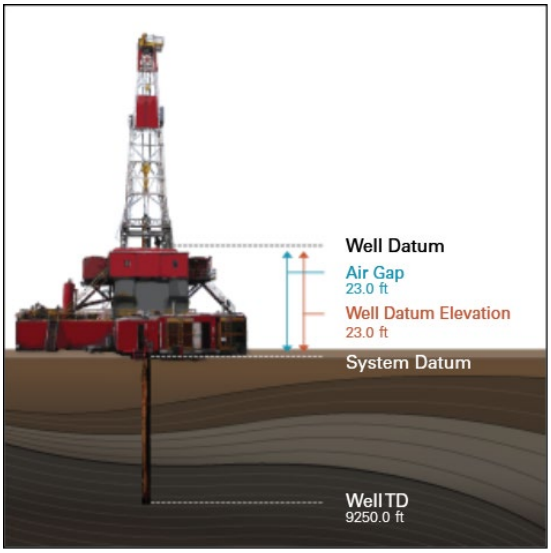
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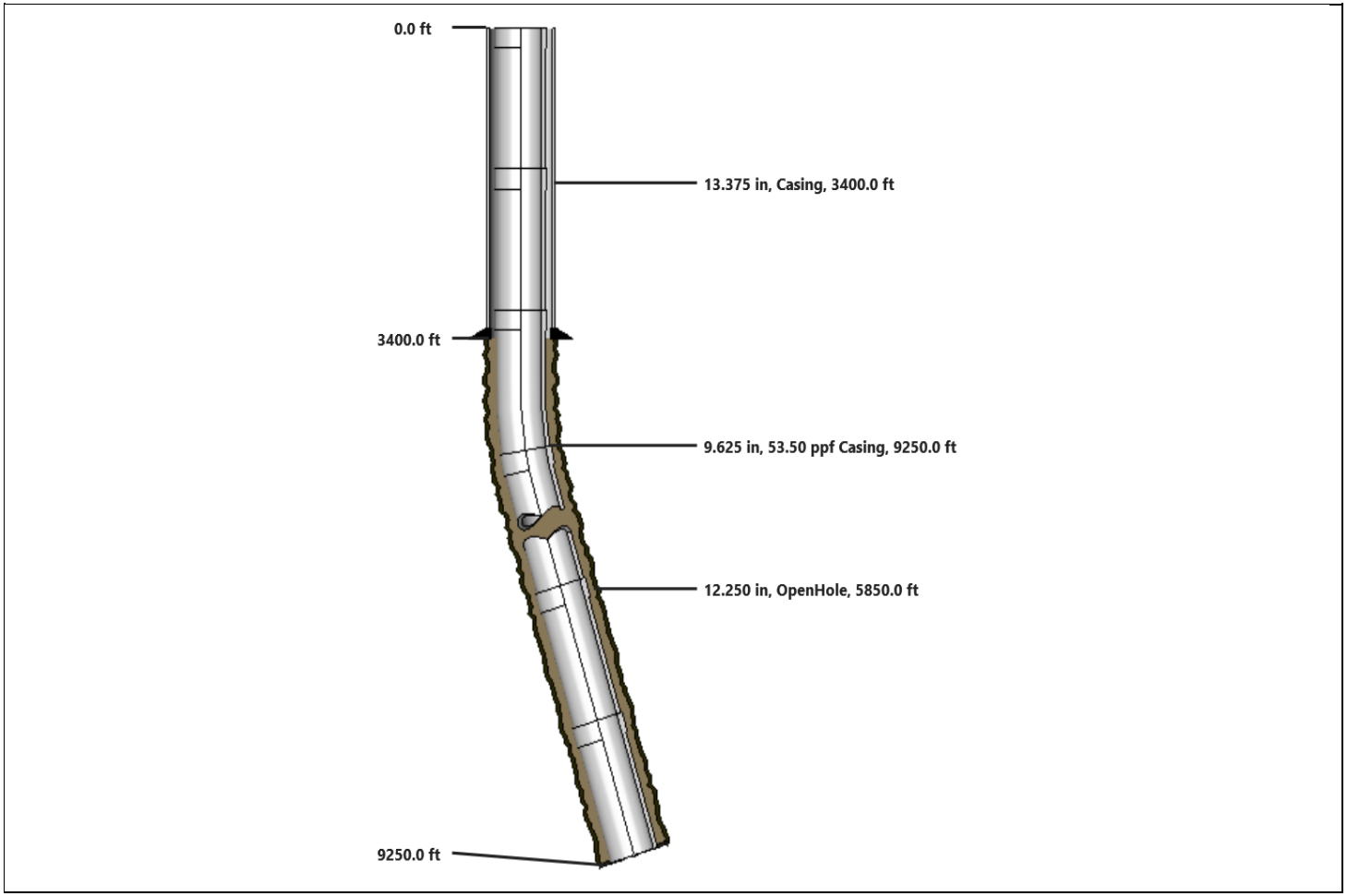
3D Displacement Efficiency - Default 28

1.0 Job Design

1.1 Overview

Job Type	Primary Cement Job
Injection Path	Casing/Conventional
Foam Job	No
Well Snapshot	
Simulations Performed	2D Hydraulics, Rheological Hierarchy, 3D Displacement

1.2 2D Wellbore Schematic



Casing Volume	654.57 *bbl*
Annulus Volume	537.65 *bbl*
Rathole Length	0.0 *ft*
Surface Volume	0.51 *bbl*
OH Volume	852.78 *bbl*
OH Equivalent ID	12.250 *in*

1.3 Job Parameters

Casing MD | TVD:	9,250.0 | 9,054.8 *ft*	**Drilling Fluid Type:**	BaraXcel™ 4 BASE
Max Deviation Angle:	16.94 °	**Drilling Fluid Density:**	12.50 *ppg*
Deviation Angle at TD:	16.94 °	**Compressible Mud:**	No
BHST	175.00 *°F*		

Fluids Top MD | BHCT*

Spacer/Flush 2	0.0 *ft* | 126.45 *°F*	Cement 3	0.0 *ft* | 125.26 *°F*

**BHCT = Max fluid placement temperature.*

1.4 Wellbore Geometry

Surface Lines

Length (ft)	Number in Parallel	Elevation Change (ft)	OD (in)	ID (in)
150.0	1	23.0	2.620	1.870

Outer Geometry

Top MD (ft)	Bottom MD (ft)	Length (ft)	OD (in)	ID (in)	Weight (ppf)	Grade	Annular Excess (%)
Casing/Liner							
0.0	3,400.0	3,400.0	13.375	12.515	61.00		N/A
Open Hole*							
3,400.0	9,250.0	5,850.0		12.250			0.00

**OH Equivalent ID = 12.250 in*

Inner Geometry

Type	Top MD (ft)	Bottom MD (ft)	Length (ft)	OD (in)	ID (in)	Weight (ppf)	Grade	AJL (ft)
Inner								
Casing	0.0	9,250.0	9,250.0	9.625	8.535	53.50	L80	42.0

1.5 Pump Schedule

Description	Stage No.	Batch Mix Time (min)	Safety Factor (min)	Density (ppg)	Rate (bbl/min)	Yield (ft^3/sack)	Water Req. (gal/sack)	Volume (bbl)	Bulk Cement (sacks)	Duration (min)	Duration (hh:mm)
SBM - 12.5# - 2779885.1	1			12.50	8.00			0.00		0.00	0:00
TPS (6,6,6) - 13.5 - 2781518.1	2			13.50	6.00			50.00		8.33	0:08
Bottom Plug											
CorrosaCem - 15.5# - 2779733.1	3		60.00	15.50	6.00	1.0573	2.107	543.31	2885.25	90.55	1:31
Top Plug/Start Displacement											
TPS (6,6,6) - 13.5 - 2781518.1	4			13.50	4.00			5.00		1.25	0:01
SBM - 12.5# - 2779885.1	5-1			12.50	8.00			630.08		78.76	1:19
SBM - 12.5# - 2779885.1	5-2			12.50	6.00			14.34		2.39	0:02
							Total:	**1,242.73**		**181.29**	**3:01**
			Min CorrosaCem - 15.5# - 2779733.1 Thickening Time - Stage 3:							**232.95**	**3:53**

**Pump schedule may include additional rows for displacement if "Automatic Rate Adjustment" was enabled and ECDs approached the fracture gradient.*

1.6 Pressure Schedule Inputs

Pressure Mode	Conventional

1.7 Pressure Schedule Table

Start *(Pump Volume in bbl)*	**End** *(Pump Volume in bbl)*	**Pressure** *(psi)*
0.00	End	0.00

1.8 Final 2D Fluid Positions Plot



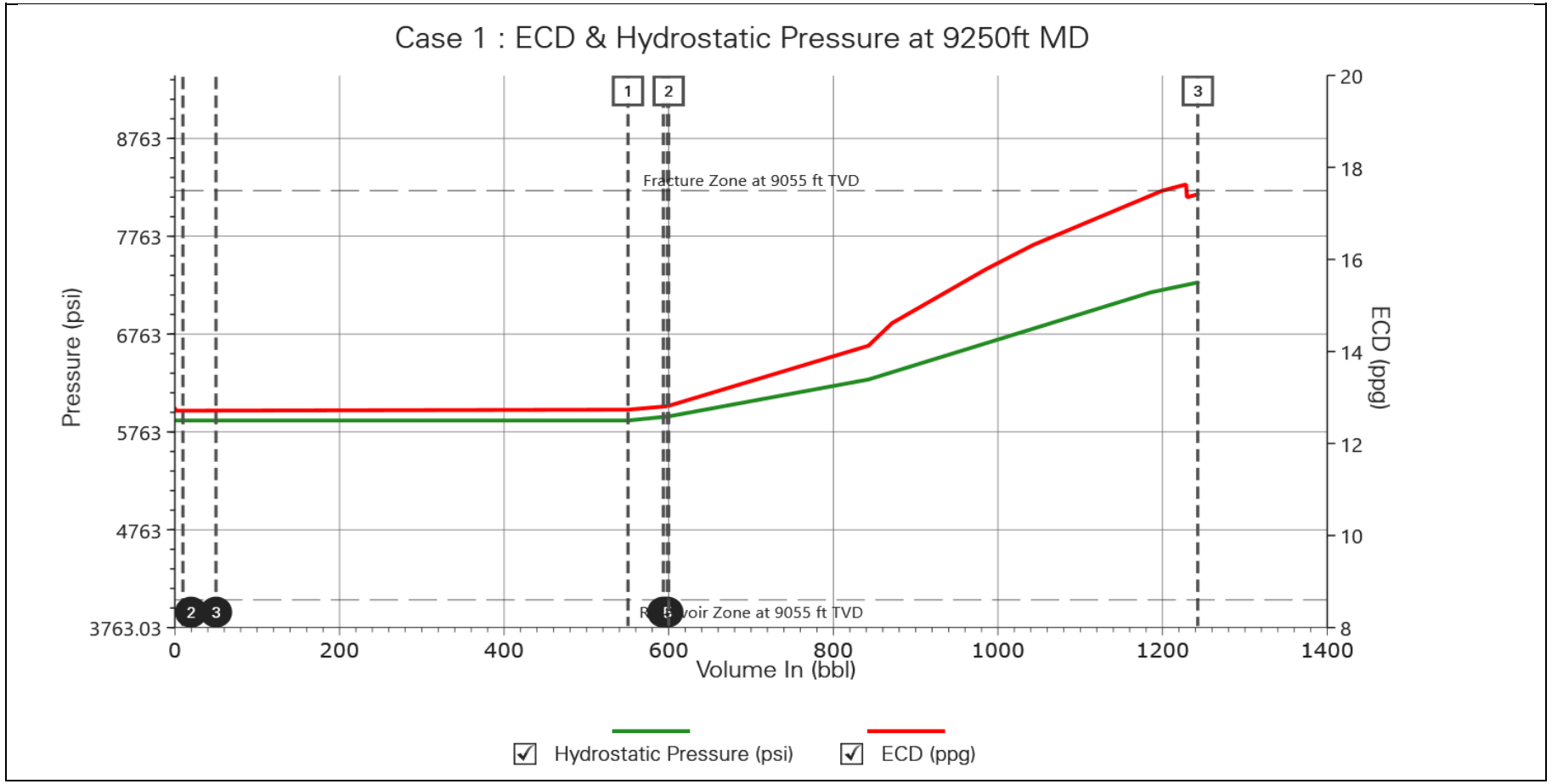
1.9 Final 2D Fluid Positions Table

Time	181.30 *min*
Volume In	1,242.73 *bbl*
Surface Pressure	2,809.42 *psi*
Rate In	6.00 *bbl/min*
Rate Out	6.00 *bbl/min*
Down Hole Depth	9,250.0 *ft*
Rate	6.00 *bbl/min*
Pressure	8,192.39 *psi*
ECD	17.42 *ppg*
Density	15.50 *ppg*

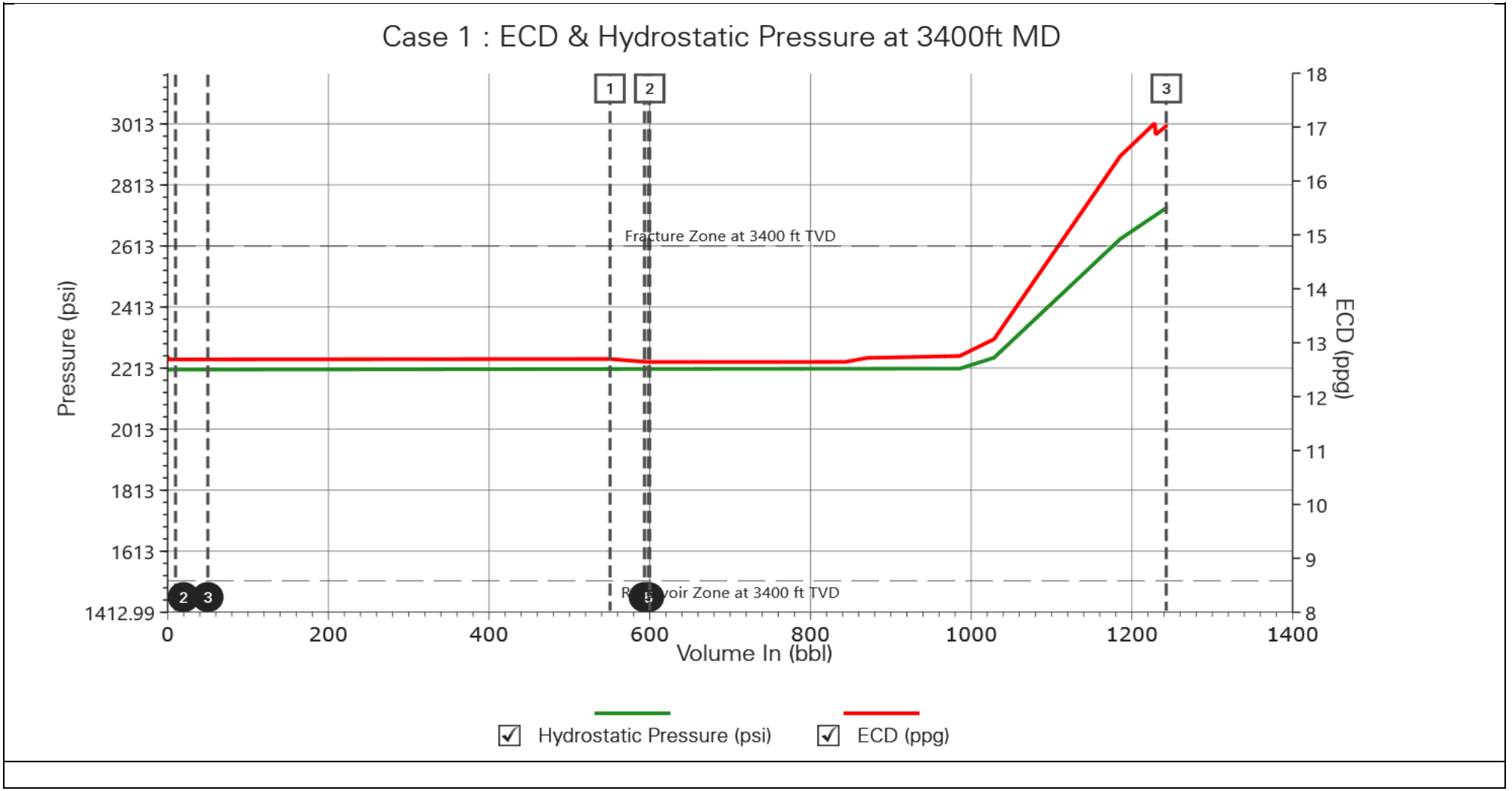
1.10 Fluids Pumped

TPS (6,6,6) - 13.5 - 2781518.1
CorrosaCem - 15.5# - 2779733.1
TPS (6,6,6) - 13.5 - 2781518.1
SBM - 12.5# - 2779885.1

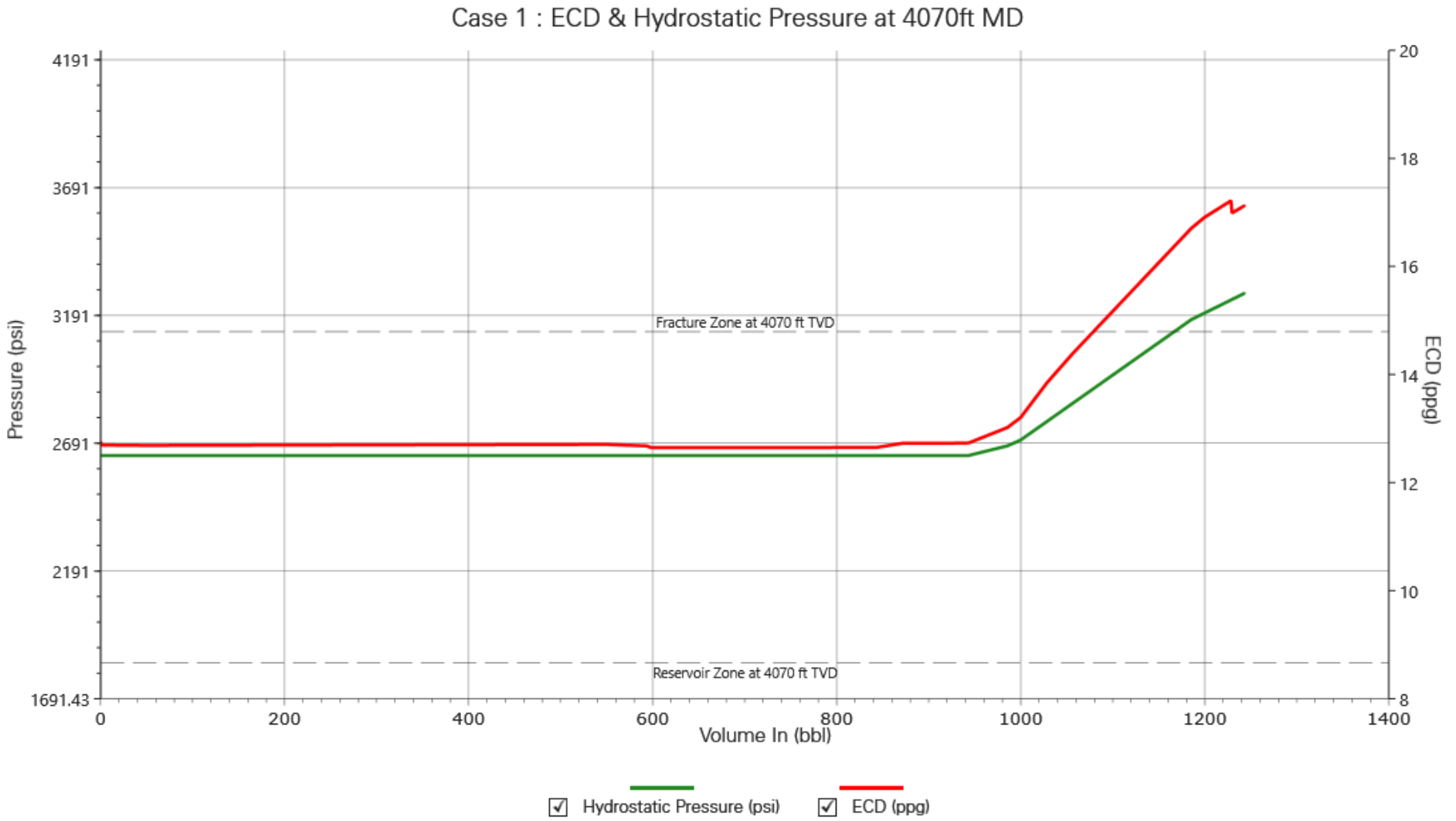
1.11 ECD & Hydrostatic Pressure Plot at Reservoir Zone



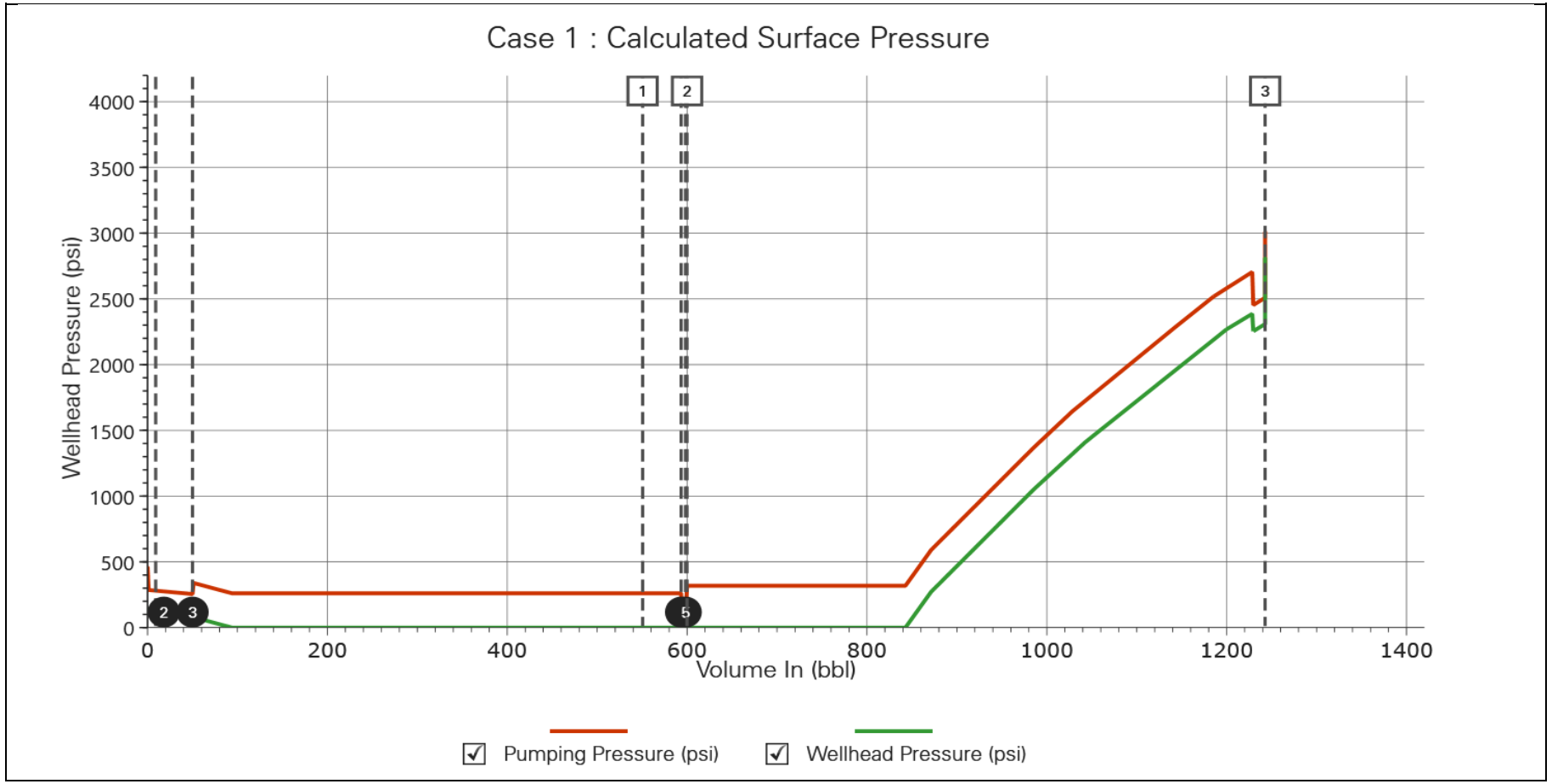
1.12 ECD & Hydrostatic Pressure Plot at Fracture Zone



1.13 ECD & Hydrostatic Pressure Plot at Fracture Zone

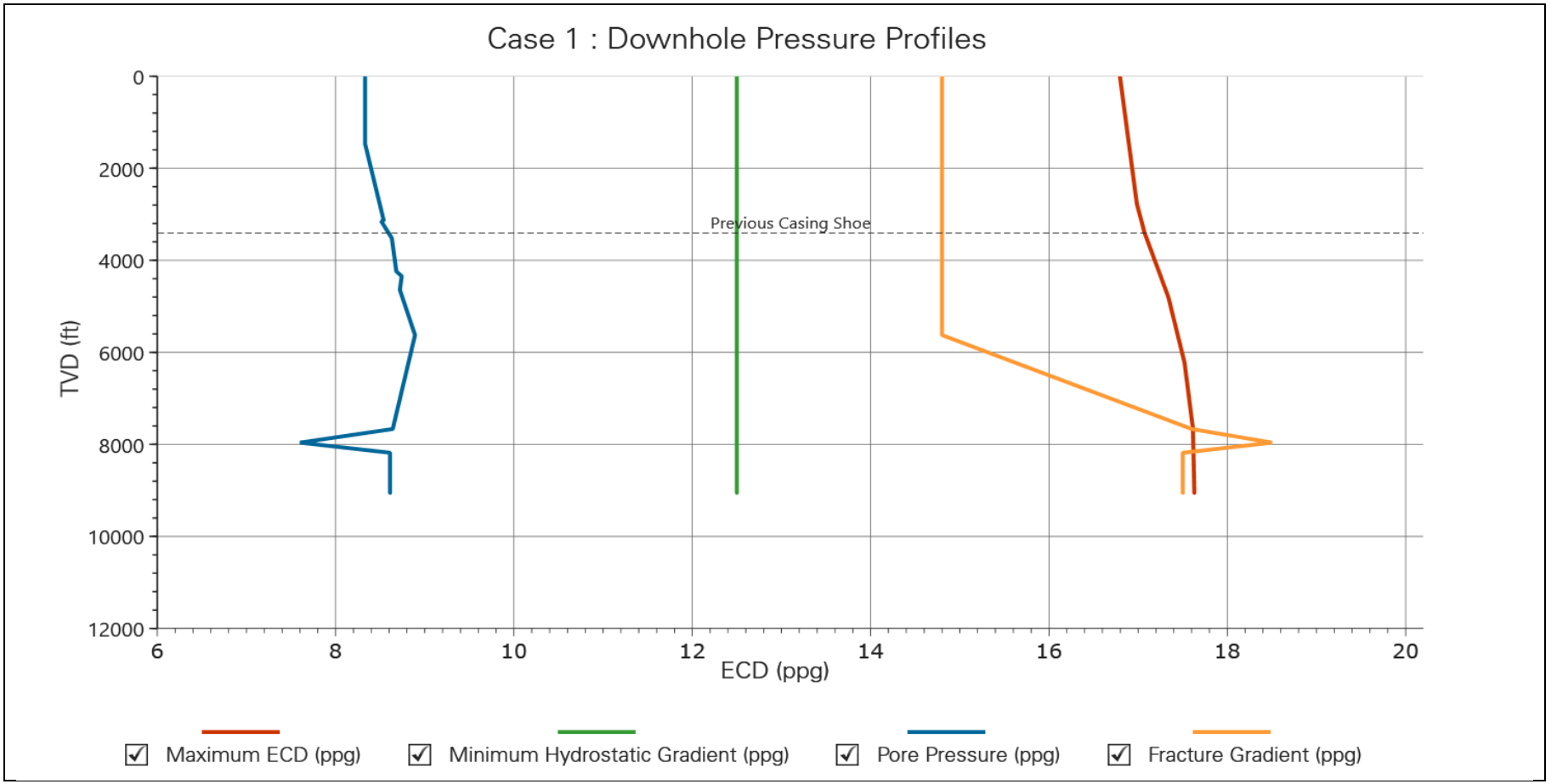


1.14 Calculated Surface Pressure Plot

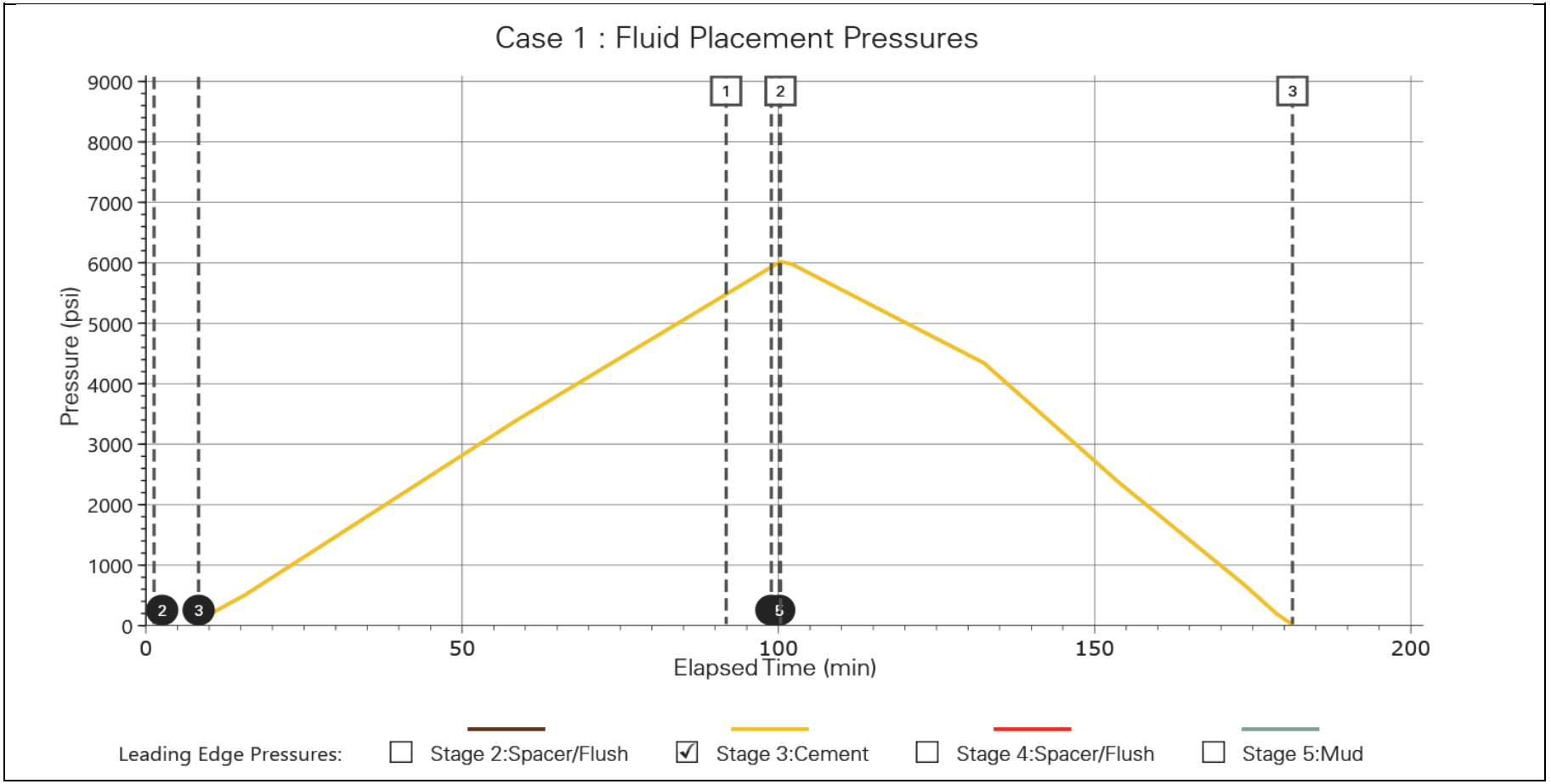


2.0 Hydraulics Summary

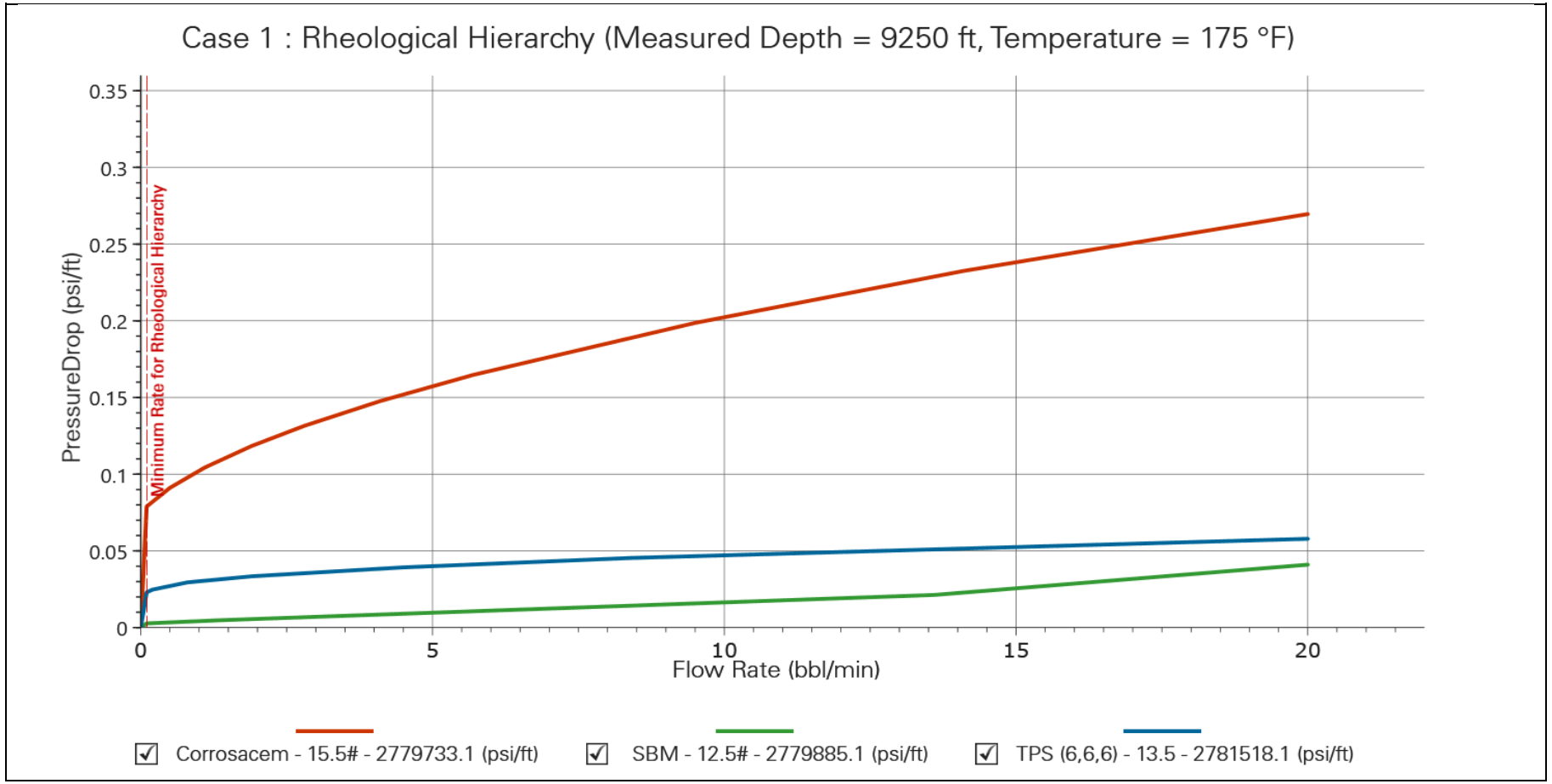
2.1 Downhole Pressure Profiles Plot



2.2 Fluid Placement Pressures Plot



2.3 Rheological Hierarchy Plot at Reservoir Zone

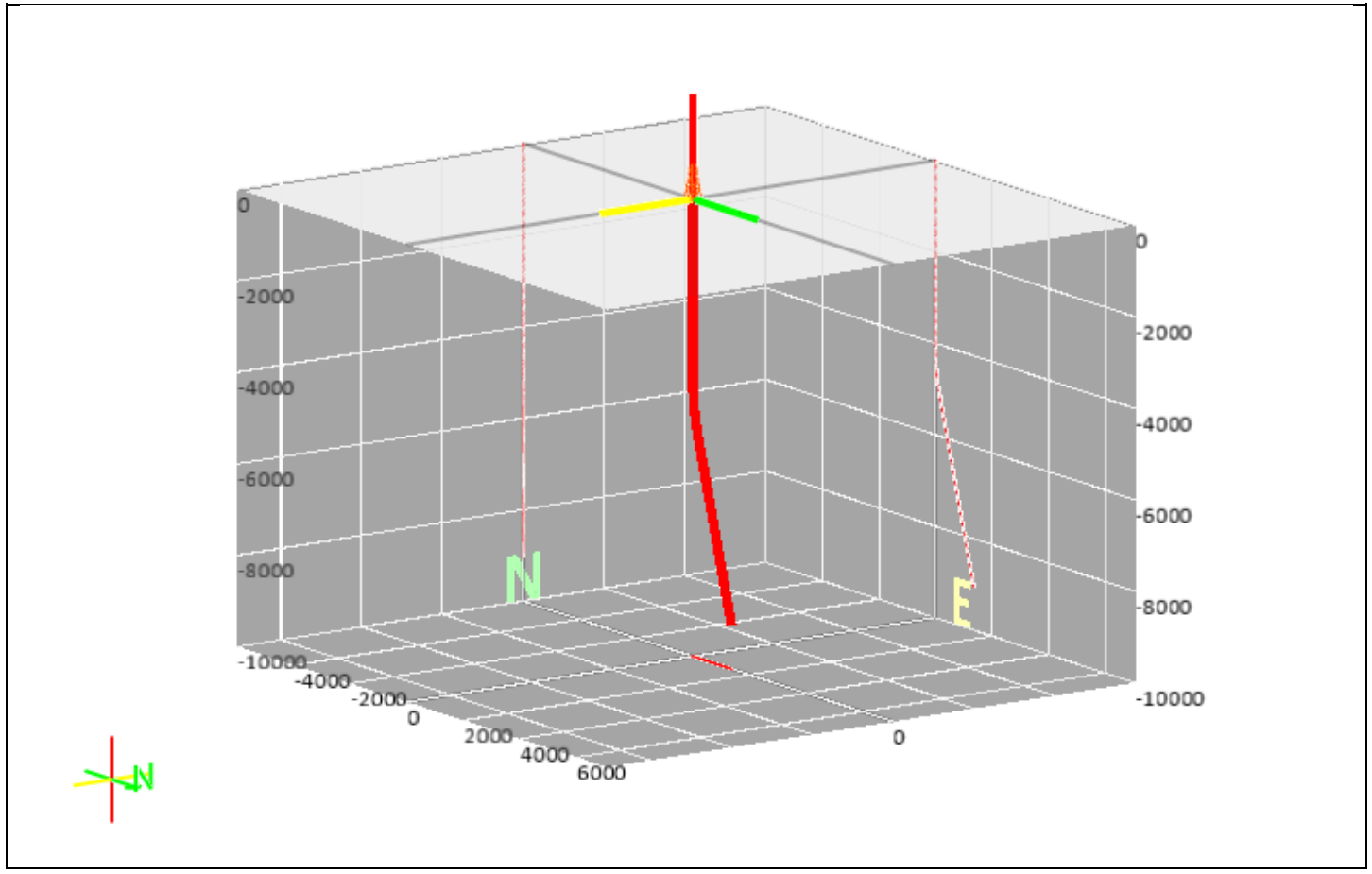


3.0 Appendix

3.1 Well Directional Data

Measured Depth (ft)	True Vertical Depth (ft)	Deviation (°)	Build Angle (°/100ft)	Azimuth (°)
0.0	0.0	0.00		0.00
4,200.0	4,199.9	3.00	1.50	0.00
4,450.0	4,449.0	6.75	1.50	0.00
4,700.0	4,696.1	10.50	1.50	0.00
4,950.0	4,940.2	14.25	1.50	0.00
5,150.0	5,132.7	16.94	0.00	0.00
5,400.0	5,371.9	16.94	0.00	0.00
5,650.0	5,611.0	16.94	0.00	0.00
5,900.0	5,850.2	16.94	0.00	0.00
6,150.0	6,089.3	16.94	0.00	0.00
6,400.0	6,328.5	16.94	0.00	0.00
6,650.0	6,567.6	16.94	0.00	0.00
6,900.0	6,806.8	16.94	0.00	0.00
7,150.0	7,045.9	16.94	0.00	0.00
7,400.0	7,285.1	16.94	0.00	0.00
7,650.0	7,524.2	16.94	0.00	0.00
7,900.0	7,763.4	16.94	0.00	0.00
8,100.0	7,954.7	16.94	0.00	0.00
8,350.0	8,193.9	16.94	0.00	0.00
8,600.0	8,433.0	16.94	0.00	0.00
8,850.0	8,672.2	16.94	0.00	0.00
9,100.0	8,911.3	16.94	0.00	0.00
9,250.0	9,054.8	16.94	0.00	0.00

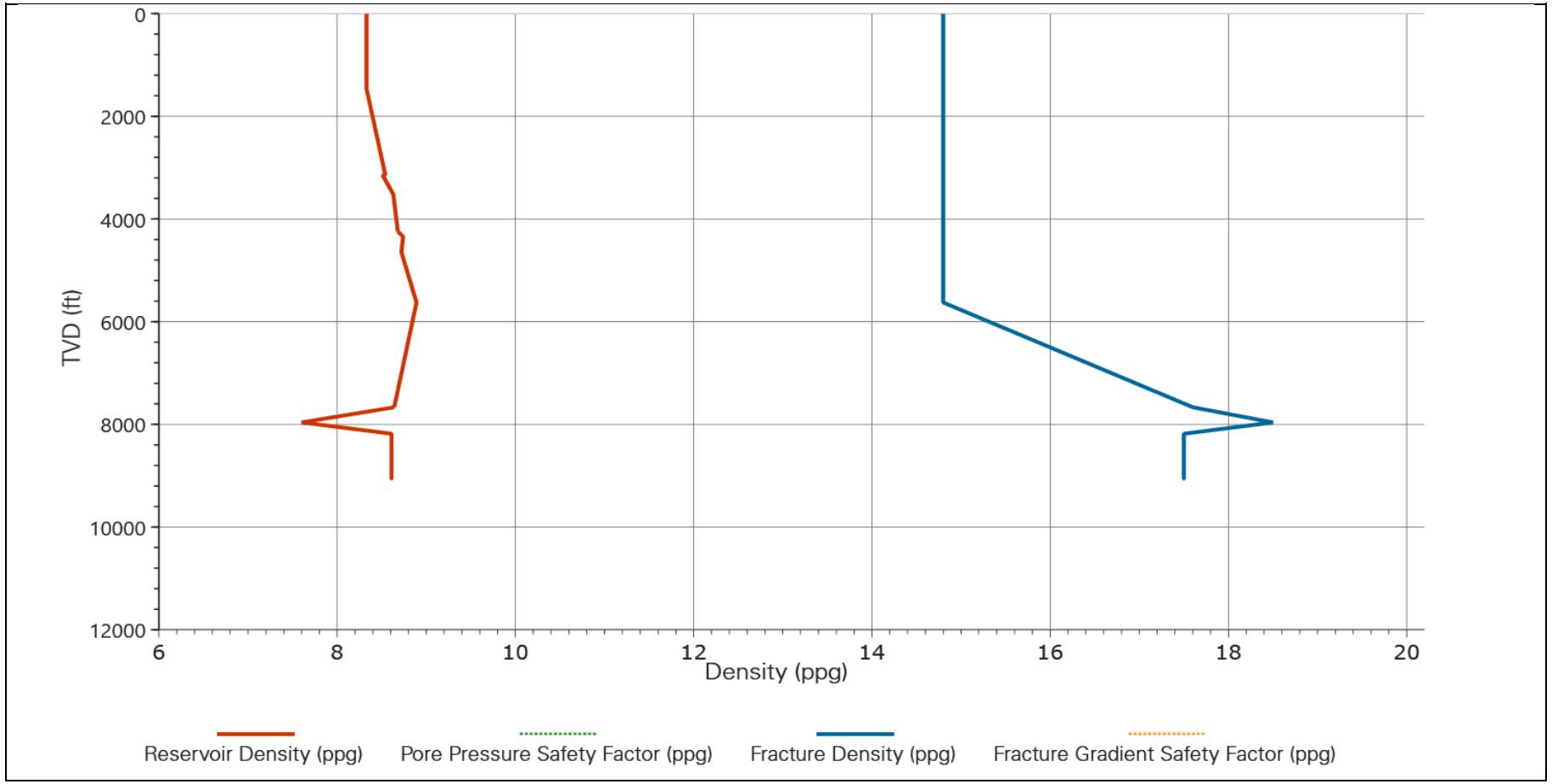
3.2 3D Wellbore Schematic



3.3 Formation Definitions

Measured Depth *(ft)*	True Vertical Depth *(ft)*	Pore Pressure *(psi)*	Reservoir Gradient *(psi/ft)*	Reservoir Density *(ppg)*	Fracture Pressure *(psi)*	Fracture Gradient *(psi/ft)*	Fracture Density *(ppg)*
	1,470.0	636.1	0.433	8.33	1,130.22	0.769	14.80
	3,144.0	1,394.8	0.444	8.54	2,417.30	0.769	14.80
	3,146.0	1,390.8	0.442	8.51	2,418.83	0.769	14.80
	3,521.0	1,578.6	0.448	8.63	2,707.16	0.769	14.80
	4,240.0	1,911.9	0.451	8.68	3,259.97	0.769	14.80
	4,337.0	1,966.9	0.454	8.73	3,334.55	0.769	14.80
	4,344.0	1,972.4	0.454	8.74	3,339.93	0.769	14.80
	4,643.0	2,103.3	0.453	8.72	3,569.82	0.769	14.80
	5,626.0	2,598.3	0.462	8.89	4,325.61	0.769	14.80
	7,666.0	3,440.9	0.449	8.64	7,009.18	0.914	17.60
	7,962.0	3,143.6	0.395	7.60	7,652.08	0.961	18.50
	8,182.0	3,659.7	0.447	8.61	7,438.46	0.909	17.50
	9,054.8	4,050.1	0.447	8.61	8,231.94	0.909	17.50

3.4 Formation Definitions Plot



3.5 Wellbore Geometry - Surface Lines

Length (ft)	Number in Parallel	Elevation Change (ft)	Fluid Friction Factor	Outer Diameter (in)	Inner Diameter (in)
150.0	1	23.0	1.00	2.620	1.870

3.6 Wellbore Geometry - Outer (Casing/Liners)

Top MD (ft)	Bottom MD (ft)	Length (ft)	Constant Friction Factor	Outer Diameter (in)	Inner Diameter (in)
0.0	3,400.0	3,400.0	0.25	13.375	12.515

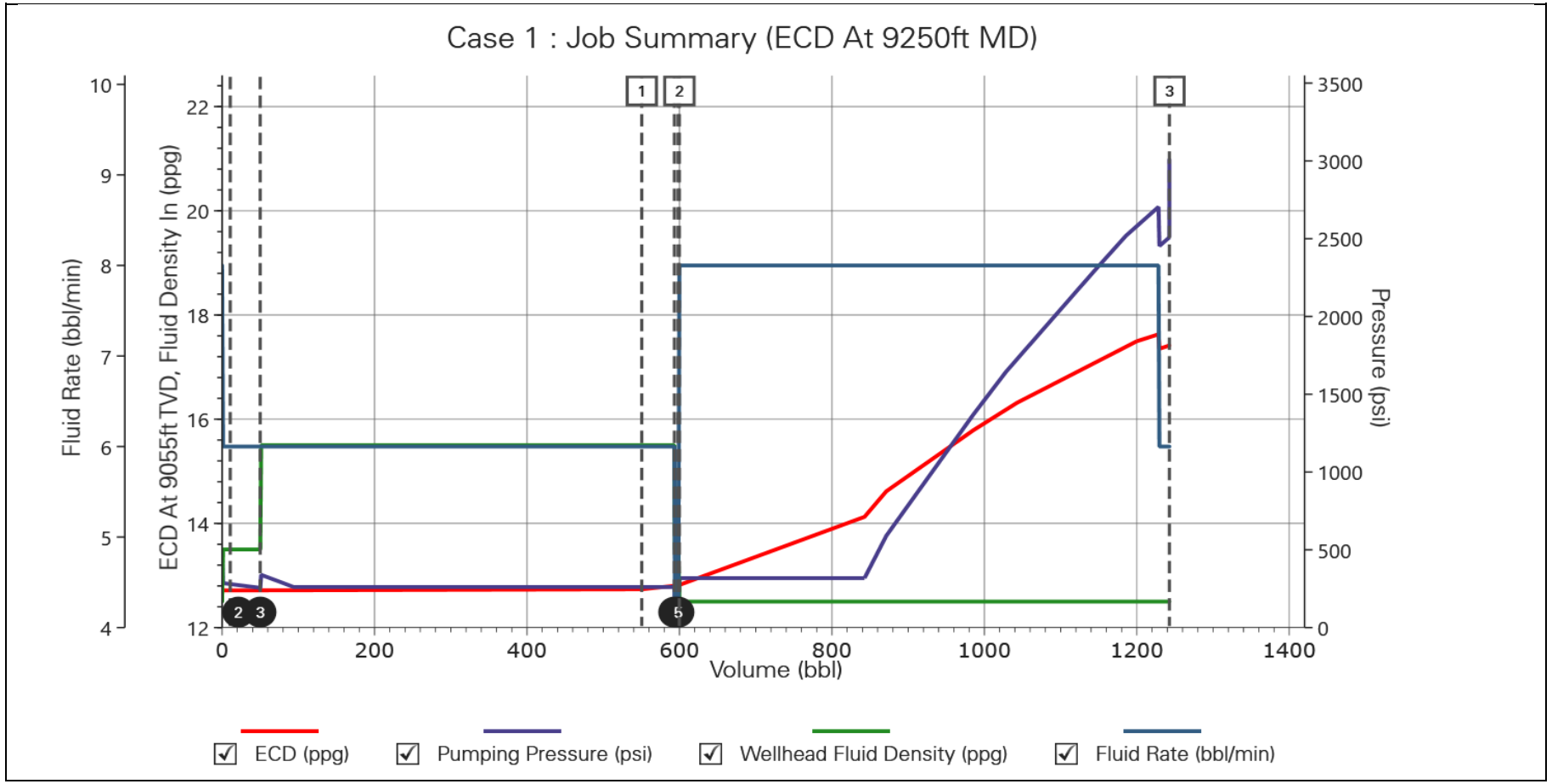
3.7 Wellbore Geometry - Outer (Open Hole)

Top MD (ft)	Bottom MD (ft)	Length (ft)	Constant Friction Factor	Inner Diameter (in)	Annular Excess (%)
3,400.0	9,250.0	5,850.0	0.30	12.250	0.00

3.8 Wellbore Geometry - Inner (Inner)

Type	Top MD (ft)	Bottom MD (ft)	Length (ft)	Outer Diameter (in)	Weight (ppf)	Grade	Inner Diameter (in)	Avg. Joint Length (ft)
Casing	0.0	9,250.0	9,250.0	9.625	53.50	L80	8.535	42.0

3.9 Job Summary at Reservoir Zone



3.10 Pure Fluid Viscometer Data

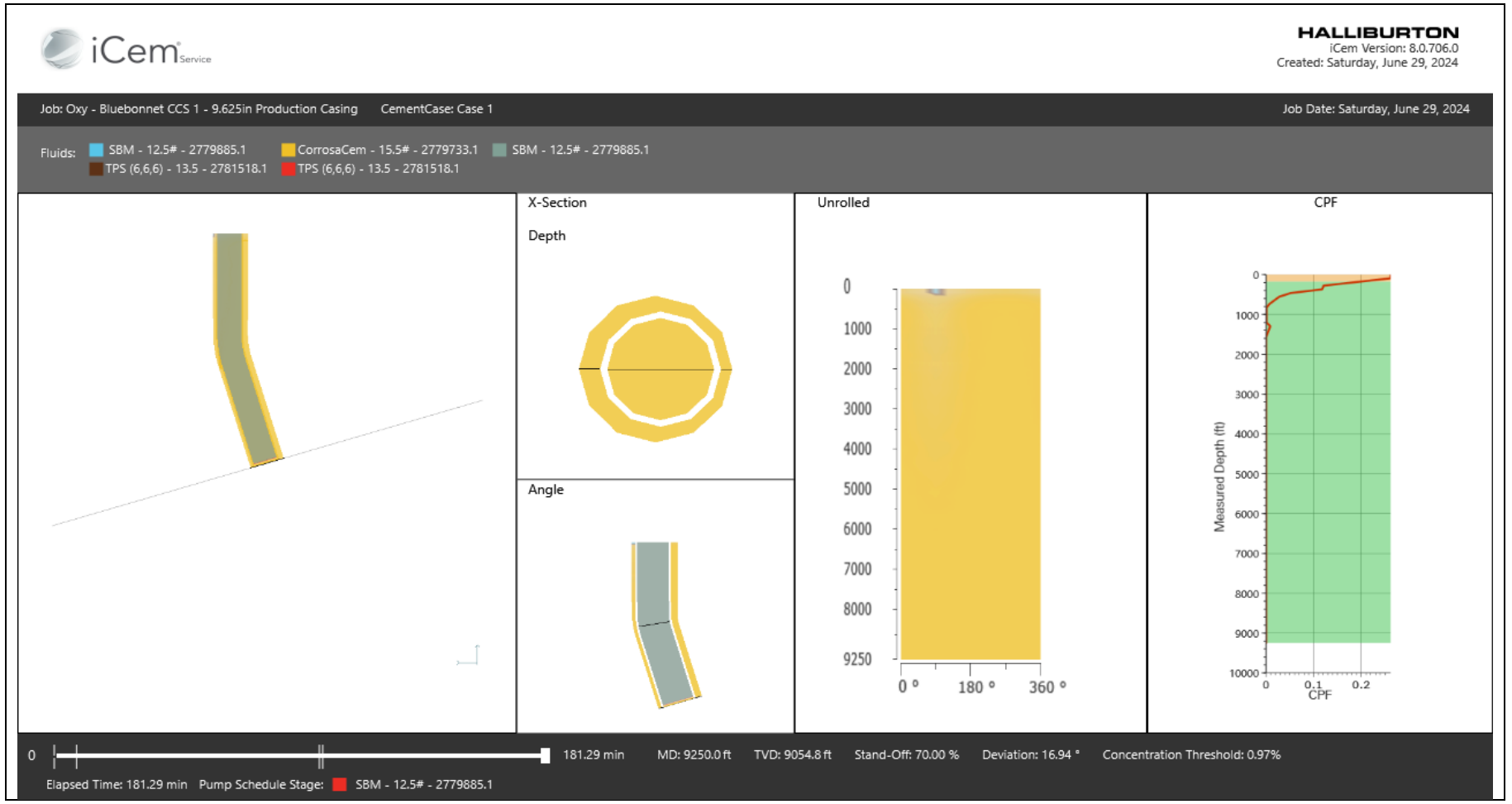
Fluid Name	Temp (°F)	P (psi)	600	300	200	100	60	30	20	10	6	6D	3	3D	2	1
SBM - 12.5# - 2779885.1	80.0		86	46	32	18	12	6	4	2	2		2			
SBM - 12.5# - 2779885.1	113.0		64	34	24	14	8	6	4	2	2		2			
SBM - 12.5# - 2779885.1	145.0		56	32	22	14	8	6	4	2	2		2			
TPS (6,6,6) - 13.5 - 2781518.1	80.0		82	56	46	36	30	26	24	22	20		18			
TPS (6,6,6) - 13.5 - 2781518.1	135.0		68	48	44	34	28	26	24	22	18		16			
TPS (6,6,6) - 13.5 - 2781518.1	190.0		72	56	46	38	34	28	26	22	20		16			
CorrosaCem - 15.5# - 2779733.1	80.0		154	86	60	34	24	16	12	10	8		6			
CorrosaCem - 15.5# - 2779733.1	145.0		310	260	190	132	108	86	84	76	72		54			
TPS (6,6,6) - 13.5 - 2781518.1	80.0		82	56	46	36	30	26	24	22	20		18			
TPS (6,6,6) - 13.5 - 2781518.1	135.0		68	48	44	34	28	26	24	22	18		16			
TPS (6,6,6) - 13.5 - 2781518.1	190.0		72	56	46	38	34	28	26	22	20		16			
SBM - 12.5# - 2779885.1	80.0		86	46	32	18	12	6	4	2	2		2			
SBM - 12.5# - 2779885.1	113.0		64	34	24	14	8	6	4	2	2		2			
SBM - 12.5# - 2779885.1	145.0		56	32	22	14	8	6	4	2	2		2			

**Foamed*

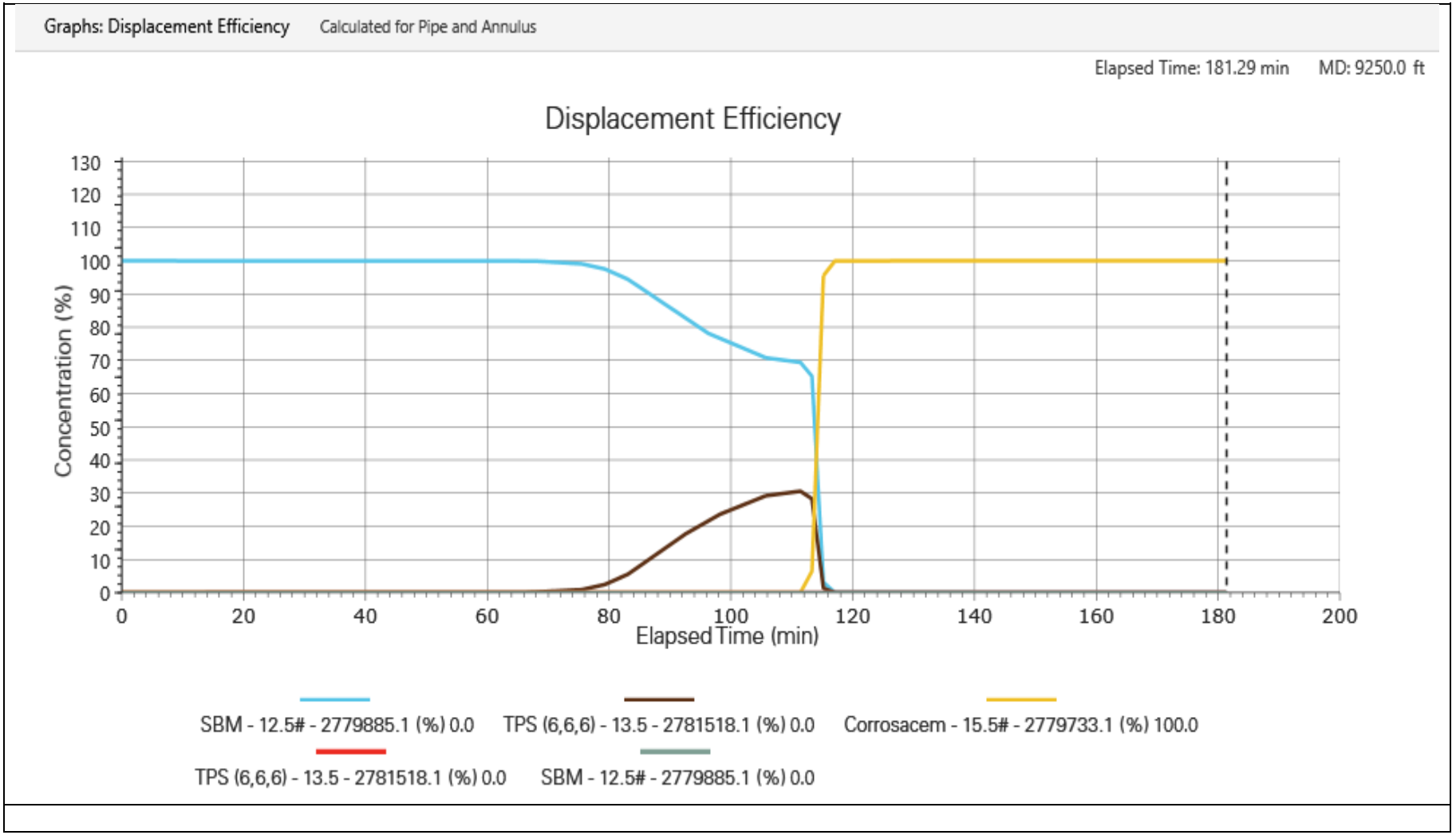
***Predicted values*

4.0 3D Visualizer - Default View

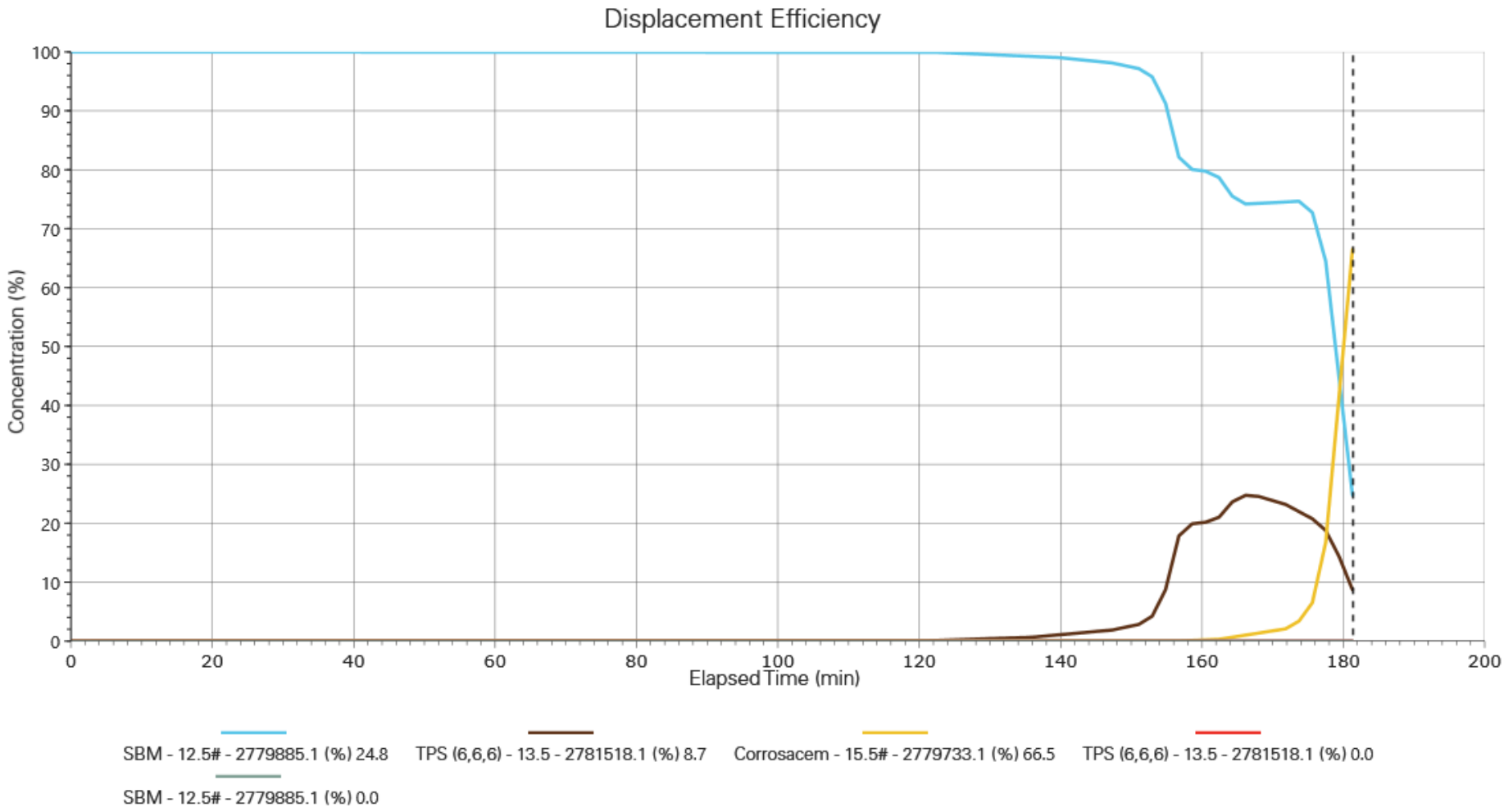
4.1 3D Visualizer - Default



4.2 3D Displacement Efficiency - Default



Displacement Efficincy at Surface



Claimed as PBI

Plan revision number: 5
Plan revision date: 09/25/2025

FINANCIAL ASSURANCE DEMONSTRATIO
In Satisfaction of 16 TAC 5.205 and 40 CFR 146.82(a)(14)

Bluebonnet Sequestration Hub

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2.0 Activities Requiring Financial Assurance 2
3.0 Instruments to Meet Financial Responsibility 2
4.0 Cost Estimate for Activities Covered by Financial Responsibility 2
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4.2 Plugging Injection Wells 3
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4.4 Site Closure 3
4.5 Emergency and Remedial Response 3

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub, LLC (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

The matter of financial assurance demonstration is relevant to the requirements of 16 TAC 5.205 and the Environmental Protection Agency (EPA) document 40 CFR Subpart H - Criteria and Standards applicable to Class VI Wells. The main topics covered in this attachment are activities

requiring financial assurance, instruments to meet financial responsibility, and the plan to be implemented by the Bluebonnet Sequestration Hub, LLC for the Bluebonnet Sequestration Project.

2.0 Activities Requiring Financial Assurance

Pursuant to TAC 5.205 and 40 CFR 146.85, the Bluebonnet Sequestration Hub, LLC is required to demonstrate financial ability to successfully complete all the tasks associated with performing well corrective action, injection well plugging, post-injection site care, site closure, and implementation of an emergency remedial response plan as specified in Table FA-1.

Table FA-1: List of project activities that require financial assurance.

Activity	Period of Performance
Performing corrective action	As needed
Plugging CO_2 injector wells	One time
Post-injection site care	Throughout the post-injection phase
Site closure	At closure
Emergency/remedial response	As needed

3.0 Instruments to Meet Financial Responsibility

Bluebonnet has reviewed the requirements of 16 TAC 5.205 and the extensive guidance, research, and analysis documents published by the EPA and proposes to utilize a letter of credit to demonstrate financial responsibility for all activities requiring financial assurance. The letter of credit will be issued by HSBC BANK USA, N.A that has (a) assets of at least Ten Billion Dollars ($10,000,000,000) and (b) has a Long-Term Credit Rating of at least “A-” by S&P and at least “A3” by Moody’s The letter of credit will be irrevocable, require the issuing institution to provide notice if it does not plan to reissue the letter of credit and will include a provision for automatic renewal. HSBC BANK USA, N.A maintains a "Certificate of Account Status," previously called "Certificates of Good Standing," with the Texas Comptroller of Public Accounts evidencing the status of its right to conduct financial transactions in Texas (which may be confirmed by entering HSBC at this link maintained by the Texas Comptroller: Taxable Entity (https://comptroller.texas.gov/taxes/franchise/account-status/search).Bluebonnet Sequestration Hub, LLC shall deposit funds as instructed by the Texas Railroad Commission. Bluebonnet Sequestration Hub, LLC may change the instrument(s) used to demonstrate financial assurance in accordance with 16 TAC 5.205 or 40 CFR 146.85.

4.0 Cost Estimate for Activities Covered by Financial Responsibility

The Bluebonnet Sequestration Hub, LLC will provide financial assurance sufficient to cover the costs identified in Table FA-2. Costs are to be in 2026 U.S. dollars. A detailed cost estimate is included in Appendix A.

The cost estimation provided in Appendix A is based on hiring a third party to perform the required activities (Statewide Rule §5.205(c)(2)(C)(i)).

In Accordance with 16 TAC §5.205(c)(2)(C)(ii), the preparation of the highest likely cost necessary to close the geologic storage facility have been supervised and reviewed by a qualified professional engineer licensed by the state of Texas.

Table FA-2: Cost estimate for activities covered by financial assurance.

Activity	Total Cost
Performing Corrective Action on Wells in AOR	Claimed as PBI
Plugging Injector Wells	
Post-injection Site Care	
Site Closure (Facilities and Monitoring Wells)	
Emergency and Remedial Response Actions	
Regulatory fee	
Total $	$ 35,925,514.00

4.1 Corrective Action

Twenty-five wells within the Area of Review (AoR) were determined to require corrective actions. Bluebonnet Hub will conduct corrective action as per schedule presented in the AoR attachment.

4.2 Plugging Injection Wells

Details of the well plugging plan are found in the Plugging Plan document of this permit. CO_2 injection wells will be plugged and abandoned when injection cease in the site.

4.3 Post-Injection Site Care

Details of the post-injection site and site closure plan are found in the Post Injection Site Care and Site Closure Plan document of this permit. The Post-Injection Site care costs were estimated from cessation of injection to site closure and account for activities included in the Post-Injection Site Care Plan.

4.4 Site Closure

Details of the site closure plan are found in the Post Injection Site Care and Site Closure Plan document of this permit. Monitoring wells and water extraction wells will be covered by the blank bond under Bluebonnet Sequestration Hub LLC P5. The water disposal well (Class I) will be covered through separate financial assurance document provided to the Texas Commission on Environmental Quality (TCEQ).

4.5 Emergency and Remedial Response

Details of the emergency and remedial response plan are found in the Emergency and Remedial Response plan document of this permit application.

The instrument values included in this document are based upon cost estimates by the Bluebonnet Sequestration Hub, LLC project team with input cost data from representative projects and service providers. Cost estimates provided during the permit process can be expected to change during the application approval process. The Bluebonnet Sequestration Hub, LLC will adjust the value of the financial instruments prior to securing them.

The Bluebonnet Project used a Carbon capture and Storage stochastic Monte Carlo model that has been tailored to reflect site-specific factors for emergency and remedial repose actions. This estimation approach is consistent with the U.S. EPA's Underground Injection Control (UIC) Program's Class VI regulatory requirements and is intended to inform the face value of financial assurance for the Bluebonnet Project. Details of this study are included in Appendix B.

CO_2 INJECTION WELL STIMULATION PLAN
40 CFR 146.82(a)(9)

Bluebonnet Sequestration Hub

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4.0 Ensuring Containment 8

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers County, Texas

Well Name	Latitude (°) (NAD27)	Longitude (°) (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
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Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.82 (a)(9), this CO_2 Injection Well Stimulation Plan describes the operations that Bluebonnet Sequestration Hub, LLC would execute in the CO_2 Injector Wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CC7 to enhance or regain injection capabilities.

Stimulation and cleanouts to enhance or regain the injection potential of the Lower Miocene, Frio and Hackberry Sandstones in the CO_2 Injector Wells include coil tubing cleanouts, stick pipe cleanouts, matrix acid stimulation, sand control and water flushes.

The need for stimulation and cleanouts will be determined once the characterization data from the Bluebonnet Sequestration Hub is completed, and the wells are available and have been evaluated (i.e., results of geophysical logs, core analyses, and hydrogeologic testing and operating conditions).

Bluebonnet Sequestration Hub, LLC will notify and submit the proposed stimulation or cleanout procedures in writing to the Underground Injection Control (UIC) Program Director at least 30 days in advance of performing the stimulation or workover in accordance with 40 CFR. § 146.91(d)(1) and 40 CFR § 146.91(d)(2). Bluebonnet Sequestration Hub, LLC will carry out the stimulation or cleanout according to the EPA approved procedures. The procedures will describe all fluids being pumped and demonstrate that there will be no loss of containment due to the stimulation.

While this CO_2 Injection Well Stimulation Plan sets forth the intended procedures for stimulation of the injection wells at the Bluebonnet Sequestration Hub, changes to the plan may be required based on technical, operational, or safety conditions encountered during operations. Bluebonnet

Sequestration Hub, LLC will notify the UIC Program Director if substantial deviations from this Plan are required.

2.0 Stimulation and Cleanout Procedures

If injection rates decline below or injection pressures increase above expected values during the project's life, the Bluebonnet Hub will investigate the cause to determine if a stimulation or cleanout may be required. Investigation activities include, without limitation, the following:

- Logging operations, including but not limited to, evaluation of the injection profile, mechanical spinner surveys, caliper logging, gauge runs, downhole camera investigation, distributed temperature sensing (DTS), distributed acoustic sensing (DAS), tracers and injection profile logging (IPL), etc.

- Collecting downhole samples when necessary or feasible with wireline, slickline, or coiled tubing conveyed sampling equipment, to be followed by analytical testing, as appropriate to determine remediation options.

The equipment to implement the stimulation procedures or cleanouts include, but is not limited to, coil tubing units, workover units, snubbing units, pumping units, wireline, and slickline, amongst others.

The following are standard procedures for matrix acid stimulations, water flush, and sand and solids clean out.

2.1 Matrix Acid Stimulation

- The maximum bottom hole pressure is 90% of the injection zone fracture pressure. Job will be pumped below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.
- Verify acid blend is correct before pumping.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Spot in acid pump truck, acid transport, and frac tanks.
4. Hook up tubing and pressure test lines to 5,000 psi.
5. Open well and pump pre-flush.
6. Pump acid blend.
7. Pump flush and close in well.
8. Rig down tubing.
9. Open injection line and resume injection.

2.2 Water Flush Treatment

- The maximum bottom hole pressure is 90% of the injection zone fracture pressure. Job will be pumped below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Spot in pump truck and frac tanks.
4. Hook up tubing and pressure test lines to 5,000 psi.
5. Open well.
6. Pump water with additives.
7. Close in well.
8. Rig down tubing.
9. Open injection line and resume injection.

2.3 Coil Tubing Cleanout

- The maximum bottom hole pressure is 90% of injection zone fracture pressure. The job will be performed below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up coil tubing unit.
4. Kill well, or if well is dead, pump buffer fluid.
5. Make up bottom hole assembly (BHA).
6. Run in hole (RIH) with BHA to just above top perforation.
7. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
8. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
9. Pull out of hole with coil tubing and BHA.
10. Rig down coil tubing unit.
11. Open injection line and resume injection.

2.4 Stick Pipe Cleanout

- The maximum bottom hole pressure is 90% of injection zone fracture pressure. The job will be performed below the maximum bottom hole pressure.
- Bottom hole pressure and/or surface pressure will be monitored throughout the job.
- Compatibility testing should be performed on all fluids prior to pumping to ensure compatibility with the formation and its fluids.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well and nipple up the blowout preventors (BOPs).
5. Make up bit on work string.
6. Run in hole (RIH) with bit to just above top perforation.
7. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
8. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
9. Pull out of hole with work string and bit. Lay down same.
10. Nipple down the BOPs.
11. Rig down pulling unit.
12. Open injection line and resume injection.

2.5 Sand Control

The requirement for sand control in Bluebonnet Class VI wells is very dependent upon the level of sand consolidation that is experienced during initial completion operations. Highly unconsolidated sand has an elevated risk of slumping or sloughing into the wellbore following perforating operations, during well intervention due to swabbing and surging forces, and during operations from pressure changes resulting from change in operating conditions.

1. Chemical consolidation

- Chemical treatment techniques are sometimes employed for sand control. These processes are designed to produce a chemical reaction with the formation sand for the purpose of inhibiting its mobility. Resin consolidation is the most common process and involves injecting chemical into the unconsolidated formation to provide grain-to-grain cementation creating a strong consolidated matrix that is subsequently flushed to clear the pore spaces and retain the best possible permeability.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well and nipple up the blowout preventors (BOPs).
5. Make up bit on work string.
6. Run in hole (RIH) with bit to just above top perforation.

7. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
8. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
9. Pull out of hole with work string and bit.
10. Pick up straddle packer assumbly and run in hole and isolate problem interval.
11. Establish injection rate then perform chemical squeeze followed by curing time.
12. Flush the perfs clean then pull out of hole and lay down tools.
13. Nipple down the BOPs.
14. Rig down pulling unit.
15. Open injection line and resume injection

2. Standalone Wire Wrapped or Premium Screen

- Conventional wire-wrapped or premium screens can be used stand-alone to control formation sand in cased holes. This type of design is most effective with medium to coarse grained, moderately uniform sands that will quickly build up a high permeability zone in the annular space between the casing and screen.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well, nipple down inj tree and flowlines and nipple up the blowout preventors (BOPs).
5. Pull out of hole with tubing and packer.
6. Make up bit on work string.
7. Run in hole (RIH) with bit to just above top perforation.
8. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
9. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
10. Pull out of hole with work string and bit.
11. Pick up sand screens and packer and RIH and set screens across perfs.
12. POOH with workstring.
13. Pick up and RIH with packer and tubing.
14. Set packer, land tubing
15. Nipple down the BOPs.
16. Nipple up Inj tree and flowlines.
17. Rig down pulling unit.
18. Open injection line and resume injection

3. Cased Hole Gravel Pack

Cased hole gravel packs are commonly used completion techniques where sized gravel is pumped into the wellbore and placed/ squeezed between the installed sandscreen and the formation matrix to produce a sand retention and filtration media. Prior to gravel placement large hole perforating charges are used to bypass the formation damage zone created during the drilling and cementing operation.

1. Conduct and document a safety meeting.
2. Close in injection line.
3. Move in and rig up pulling unit.
4. Kill well, nipple down inj tree and flowlines and nipple up the blowout preventors (BOPs).
5. Pull out of hole with tubing and packer.
6. Make up bit on work string.
7. Run in hole (RIH) with bit to just above top perforation.
8. Break circulation and wash down to plug back total depth (PBTD). Utilize gel sweeps as necessary to keep the hole clean.
9. Once PBTD is reached, circulate additional gel sweeps and bottoms up until returns are clean.
10. Pull out of hole with work string and bit.
11. Pick up sand screens, packer and gravel packing tools and RIH and set screens across perfs.
12. Pump and squeeze gravel pack into perforations, filling the annulus space and taking fluid returns back up the annulus.
13. Unsting out of packer assembly and POOH with workstring.
14. Pick up and RIH with packer and tubing.
15. Set packer, land tubing
16. Nipple down the BOPs.
17. Nipple up Inj tree and flowlines.
18. Rig down pulling unit.
19. Open injection line and resume injection

The proposed procedures could be modified to adjust to the actual condition of the well when the treatment is executed.

3.0 Stimulation and Cleanouts Fluids

At the Bluebonnet Hub, the project team may use acid blends for matrix stimulation or perforation cleanouts that are typical of the industry. These include, but are not limited to, mixtures of acetic, hydrochloric, hydrofluoric, and/or other organics acids. These blends have been historically proven to remove near-wellbore damage caused by mineral scales, drilling muds, completion fluids, and clay fines while minimizing negative impacts to permeability.

There is also potential for near-wellbore halite precipitation in the CO_2 Injector Wells, which may require remediation by periodic flushes with less saline water.

During the characterization of the site, the project team identified that the Frio and Hackberry injection zones tend to produce sand due to the unconsolidated condition of these formations. The project team plans to incorporate preventive and correctives cleanouts, as described in the previous section. During cleanout operations, the project team may use brines that might include a KCL and/or NACL solution to control the well along with a gelling additive to increase viscosities in the fluids and remove the sand from the wellbore.

All chemical treatments will be evaluated and selected for compatibility with the formation and installed equipment downhole.

Additives may be utilized with the stimulation fluids to aid matrix stimulation while mitigating corrosion of tubulars and potential damage to the sequestration zone. These additives include, but are not limited to, corrosion or acid inhibitors, scale inhibitors, clay stabilizers, biocides, demulsifiers, chelating agents, mutual solvents, iron sequestrants, retarders, and/or surfactants.

Brines and gelling additives will be included during wellbore cleanouts to improve efficiency while cleaning solids out of the wellbores.

Compatibility of these additives and stimulation fluids, with the installed tubulars and reservoir, will be confirmed prior to their use in any stimulation activities.

4.0 Ensuring Containment

Except during stimulation, the project team will ensure that injection pressure does not exceed 90 percent of the fracture pressure on the injection zone(s) to ensure that the injection will not initiate new fractures or propagate existing fractures in the injection zones(s). In no case will the injection pressure initiate fractures in the confining zones(s) or cause the movement of injected or formation fluids that endanger the USDW, 40 CFR §146.88 (a).

The injection pressure will be monitored continuously during stimulation operations. Chemicals and fluids used during stimulation or cleanouts will be selected to ensure no damage in downhole equipment and formation(s).

Bluebonnet Sequestration Hub

QUALITY ASSURANCE AND SURVEILLANCE PLAN
40 CFR §146.90(k)

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1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project) Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells.

Facility contacts: Claimed as PBI [redacted]

Well location: Chambers, Texas

Well Name	Latitude (°) (NAD27)	Longitude (°) (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

2.0 Project Management and Surveillance Process

Characterization of the Injection Zones, Confining Zones, and subsurface features has been done by experienced geoscience professionals using industry-recognized software and techniques. Further characterization of the features will be done using the latest logging and testing technologies during construction and operation of the CO_2 Injection wells.

Pipeline, surface equipment, and well designs comply with industry standards for CO_2 material selection and operating conditions to promote mechanical integrity of the system during the life of the project.

Monitoring programs for leak detection, corrosion, and surveillance have been tailored for the site to ensure protection of the underground sources of drinking water (USDWs) and environment, maintain mechanical integrity of the installation during operations, and maximize the storage life of the asset. These plans incorporate best practices and recommendations for Carbon Capture and Storage projects worldwide as well as Occidental's (Oxy's) decades of experience in the development of CO_2 enhanced oil recovery (EOR) fields.

As part of the quality control process during testing and surveillance, most of the samples collected and data gathered will be analyzed, processed, validated, or witnessed by third parties independent of the operations staff. For specialized data such as seismicity and distributed temperature sensing (DTS), the project will have additional support from the providers of the selected technologies in quality control, verification of the data, and system calibration.

Sensors, transducers, and controllers will be connected to a central platform to allow for monitoring of operating conditions, system upset alarming, and safety protocol initiation. System

data interfaces will be created and integrated into a unique surveillance platform. The operating parameters, monitoring values, laboratory results, and surveillance documents for the project will be stored in a central database to provide support for Area of Review (AoR) reviews, quality assurance programs, and reporting.

The project will establish key staffing positions for reliable operation, surveillance procedures, storage evaluation, and reporting. Some of the staff will be dedicated full time to the operation, while others will be assigned as required during AoR reviews, maintenance activities, and other project activities.

Once the project is in operation, the Bluebonnet Sequestration Hub, LLC will provide an updated contact list with the names of the individuals in each position. The list will then be updated upon request.

2.1. Project/Task Organization

2.1.1 Key Individuals and Responsibilities

A brief description of the project organization is below:

The Bluebonnet hub is supported by multidisciplinary teams from the Bluebonnet Sequestration Hub, LLC consultants, subcontractors, and government entities. Each team will provide technical expertise and economic input into the project to ensure a safe, successful, and efficient operation.

The project is led by the Vice President (VP) of Oxy Low Carbon Ventures, LLC (OLCV), the parent company of Bluebonnet Sequestration Hub, LLC, who is responsible for the overall execution of the project. Reporting to the VP are the Director Subsurface Evaluation and the Director Ops and Tech Support.

- **Director Subsurface Evaluation:** This director plays a critical role in the subsurface activities regarding the CO_2 sequestration site, including geological and reservoir modeling, petrophysics, and geophysics. This director is responsible for analyzing the site and ensuring subsurface safety based on various modeling assumptions regarding carbon capture and storage.

- **Director Operations and Technical Support:** This director plays a central role in implementing all data gathering and analysis for the CO_2 Storage Project. This director provides overall coordination and responsibility for organizational and administrative aspects of the project and is also responsible for the planning, funding, schedules, and controls needed to implement project plans and ensure that project participants adhere to the plan.

- **Director Commercial Development:** This director plays an important role in enlisting emitters to provide sources of CO_2 for sequestration. This individual negotiates contracts with the various parties and identifies the financial terms.

- **Project Manager:** The project manager is responsible for project implementation after pore space characterization and project commercial contracting is complete. This role is responsible for coordinating the Class VI permitting process, other environmental and

project permit approvals, drilling the wells, facility installation, and project commissioning and startup.

- **Facilities Engineer:** The role of the facilities engineer (FE) is to identify quality-affecting processes and monitor compliance with project requirements. The FE is responsible for establishing and maintaining the project quality assurance plans, monitoring project staff compliance with those plans, and ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements.

- **Drilling/Production Engineer**: The role of the drilling/production engineer is to design the injection and various monitoring wells, including obtaining budget pricing information, designing the wellbores, drilling the wells, and developing the monitoring programs for the wells involved. One additional responsibility is reviewing the wellbores within the proposed CO_2 plume and pressure front and provide a plan for remediation, as needed.

- **Reservoir Engineer:** The role of the reservoir engineer is to gather subsurface data and run the simulation model to predict the pressure front and CO_2 plume movement. This person must work closely with the other subsurface staff to achieve accurate results with the data available.

- **Geologist**: The role of the geologist is to define the subsurface storage area, to create a geologic model, and incorporate the seismic and petrophysical data into the model.

- **Geochemist:** The role of the geochemist is to evaluate fluid and gas data obtained from wells and integrate the information with the geologic, petrophysical, and reservoir engineering information to characterize fluid and gas compositional changes in the subsurface.
- **Petrophysicist:** The role of the petrophysicist is to analyze the available logs and generate porosity and permeability models for use in the subsurface model of the area.

- **Geophysicist**: The role of the geophysicist is to help define the subsurface storage area by analyzing the available 2D and 3D seismic images of the area and interpreting faults or other areas that could potentially be leakage pathways.

- **Subject Matter Experts/Task Leads:** Well testing and monitoring subject matter experts (SMEs) and task leads comprise both internal and external (subcontractor) geologists, hydrologists, chemists, atmospheric scientists, ecologists, etc. These SMEs help develop testing and monitoring plans, collect environmental data specified in those plans using best practices, and maintain and update those plans as needed.

2.1.2 Independence from Project QA Manager and Data Gathering

A majority of the physical samples collected, and data gathered as part of the monitoring program will be analyzed, processed, or witnessed by third parties independently and outside of the project management structure.

2.1.3 QA Project Plan Responsibility

The Bluebonnet Sequestration Hub, LLC will be responsible for maintaining and distributing official, approved QASP project plans. The Bluebonnet Sequestration Hub, LLC will periodically review the QASP and consult with the UIC Program Director if changes are recommended.

2.2. Data Verification and Validation

The project will establish a standardized program for data acquisition and validation methods. The program will verify that collected data is reasonable, processed and analyzed correctly, and reviewed for errors. Peer reviews or third-party consultants will serve as a quality control mechanism. Issues identified during a peer review will be addressed and corrected by the data owner. Errors identified in the data via validation will be corrected, and affected users will be notified. Corrective actions will be coordinated to mitigate and address any impacts from data errors.

2.3 Management of Change

The project will implement a management of change (MOC) procedure to communicate and document any deviation from policies, operational parameters, and standard operating procedures. The MOC procedure aims to mitigate deviations in cost and project scope.

2.4 Contractor Requirements

Each contractor will follow a qualification process before being authorized to execute work on site or in their shop. Each contractor providing service to the Bluebonnet hub must provide a copy of their quality assurance/quality control (QA/QC) and safety management program to qualify for performing the work. The contractors may be audited by the Bluebonnet Sequestration Hub, LLC, SMEs, and safety representatives. All contractors are required to comply with the Worker Safety Program and Operations policies at the work site. The Bluebonnet Sequestration Hub, LLC reserves the right to inspect and audit the contractor's operation and quality program to guarantee the safety and quality programs are being followed.

2.5 Special Training and Certificates

Wireline logging, indirect geophysical methods, and nonroutine sampling will be performed by trained, qualified, and certified personnel, according to the service company's requirements.

Routine injectant and groundwater sampling will be performed by trained personnel, but no specialized certifications are required. Some special training will be needed for project personnel, particularly in the areas of logging processing and interpretation, certain geophysical methods, certain data acquisition and transmission systems, and certain sampling technologies.

Training of project staff will be conducted by project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

2.6 Documentation, Records, and Reporting

All data and project records will be stored electronically on secure servers and will have routine backups. Reporting will comply with Class VI Underground Injection Control (UIC) requirements.

All testing and monitoring techniques and other procedures set forth below are subject to change, based on actual operations and technical, operational, and safety concerns encountered.

3.0 Testing and Monitoring Techniques

Calibration and quality control of the tools will follow the service provider's protocols and procedures.

3.1 Cement Bond Log and Variable Density Log

For cement quality evaluation, the testing and monitoring plan proposes using cement bond logs (CBL) and variable density logs (VDL). Table QASP-1 provides the basic data for some of the tools in the market.

3.1.1 Tool Specifications

Table QASP-1: Cement bond logging and variable density log specifications (CBL/VDL).

CBL/VDL Tool Specifications		
	Halliburton RBT-M	**SLB DSLT**
Recommended Logging Speed (ft/min)	30	30
Maximum Logging Speed (ft/min)	60	60
Maximum Temperature (°F)	350	302
Max OD (in)	2.75	3.625
Length (in)	9.375	20.63
Maximum Pressure (psi)	20,000	20,000
Minimum Csg/Tbg ID (in.)	3.50	5.50
Maximum Csg/Tbg OD (in.)	10.75	13.375
Weight (lbs)	116	313
Vertical Resolution (ft)	5	5
Borehole Fluid	Water, Oil	Water, Oil
Tool Positioning	Centralized	Centralized
Vertical Resolution (ft) - Sonic Waveform	5	5
Vertical Resolution (ft) - E_1 Peak Amp	3	3

These activities will be executed by specialized contractors with proven industry technology. Calibration and quality control of the tools will follow the service provider's protocols and procedures.

3.1.2 CBL/VDL Log Running Procedure Example.

1. Move in the wireline unit.
2. Ensure the wellbore is filled with treated water or brine.
3. Make sure the wellhead valve is in the closed position. Remove the top cap, then rig up 10K grease injection wireline pressure control equipment (PCE) for attachment to the wellhead. A crane will be required to rig up the wireline unit.
4. Rig up the CBL/VDL tool string.
5. Inspect all connections and accessories and conduct surface tool checks.
6. Lift the tool string into the PCE using wireline.
7. Connect the PCE to the wellhead and equalize the lubricator.
8. Open the wellhead valve and lower tools into wellbore.
9. Run in the hole to the desired depth.
10. Pressure casing up to 500 psi (optional).
11. Log up at vendor-recommended speed over the area of interest.
12. Pull out of the hole, bleed off the lubricator, and lay and rig down the CBL/VDL tool string.

3.2 Electromagnetic and Ultrasonic Cement and Casing Evaluation Tools

For mechanical integrity evaluation, the Testing and Monitoring Plan and Pre-Operational Formation Testing Plan propose using ultrasonic and electromagnetic tools to evaluate the conditions of the tubulars in the well and provide information about thickness, ovality, ruptures, potential corrosion, etc. Table QASP-2 provides the basic data for some of the proposed tools available in the market.

3.2.1 Tool Specifications

Table QASP-2: Tool data sheet summary for magnetic, sonic and ultrasonic tools.

Logging Type	Isolation Scanner	USIT	EM Pipe Xaminer	EM Pipe Scanner	CAST-XR
Acquisition	Real Time	Real Time	Real Time	Real Time	Real Time
Logging speed	2,700 ft/h	1,800 ft/h	900 ft/h	1,800 to 3,600 ft/h	3,600 ft/h
Thickness measurement accuracy				EM thickness 15%	+/- 0.05 in
Range of measurement	0 to 10 MRayl	0 to 10 MRayl		1.5 inch	0 to 10 MRayl
Mud type limitations	none	none	none	none	none
Temperature rating	350°F	350°F	350°F	302°F	350°F
Pressure rating	20,000 psi	20,000 psi	15,000 psi	15,000 psi	20,000 psi
Casing size minimum	4 ½ in.	4 ½ in.	2.38 in.	2 ⅞ in.	4.67 in.

Logging Type	Isolation Scanner	USIT	EM Pipe Xaminer	EM Pipe Scanner	CAST-XR
Casing size maximum	9 ⅝ in.	13 ⅜ in.	24 in.	13 ⅜ in.	20 in.
Outside diameter	3.37 in.	3.375 in.	1.69 in.	2.125 in.	3.625 in.
Length	19.73 ft	19.75 ft	17.34 ft	19.7 ft	17.9 ft
Weight	333 lb	333 lb	87 lb	110 lb	316 lb
1st Pipe defect detection accuracy			1%	± 0.05 in.	
1st Pipe (2Cs) accuracy			2% or 0.015 inch		
Total metal thickness 1.2 in. (3Cs) overall average			7%		
Total metal thickness 1.8 in. (4Cs) overall average			10%		

These activities will be executed by specialized contractors with proven industry technology. Calibration and quality control of the tools will follow the service provider's protocols and procedures.

3.2.2 Ultrasonic/Electromagnetic Log Running Procedure Example

1. Move in the wireline unit.
2. Ensure the wellbore is filled with treated water.
3. Make sure the wellhead valve is in the closed position. Remove the top cap, then rig up 10k grease injection wireline pressure control equipment (PCE) for attachment to the wellhead. A crane will be required to rig up the wireline unit.
4. Rig up the ultrasonic/electromagnetic tool string.
5. Inspect all connections and accessories and conduct surface tool checks.
6. Lift the tool string into the PCE using wireline.
7. Connect the PCE to the wellhead and equalize the lubricator.
8. Open the wellhead valve and lower tools into wellbore.
9. Run in the hole to the desired depth.
10. Log up at the vendor-recommended speed over the area of interest.
11. Pull out of the hole, bleed off the lubricator, and lay and rig down the ultrasonic/electromagnetic tool string.

3.3 Temperature Log

To help locate gas entries, detect casing leaks, and evaluate fluid movement behind the casing in the monitoring wells, the Testing and Monitoring Plan proposes using temperature logs as a potential method. Table QASP-3 provides an example of basic tool specification.

3.3.1 Tool Specifications

Table QASP-3: Halliburton BHPT-I (temperature) specifications.

Halliburton BHPT-I Specifications	
Maximum Temperature	350°F
Maximum Pressure	20,000 psi
Maximum OD	3.625 in.
Tool Length	6.77 ft
Minimum Hole ID	4.25 in.
Maximum Hole ID	24 in.
Borehole Fluids	Brine/Fresh/Oil/Air
Tool Positioning	Centralized/Eccentralized
Maximum Logging Speed	60 ft./min.
Pressure Measurement Range	0 - 20,000 psi
Temperature Measurement Range	32 - 350° F
Resistivity Measurement Range	0.01 - 25 Ohm-m
Pressure Resolution	1 psi
Temperature Resolution	.01° F
Resistivity Resolution	0.01 Ohm-m

These activities will be executed by specialized contractors with proven industry technology. Calibration and quality control of the tools will follow the service provider's protocols and procedures.

3.3.2 Temperature Log Running Procedure Example

1. Move in the wireline unit.
2. Make sure the wellhead valve is in the closed position. Remove the top cap, then rig up 10k grease injection wireline pressure control equipment (PCE) for attachment to the wellhead. A crane will be required to rig up the wireline unit.
3. Rig up the temperature tool string.
4. Inspect all connections and accessories and conduct surface tool checks.
5. Lift the tool string into the PCE using wireline.
6. Connect the PCE to wellhead and equalize the lubricator.
7. Open the wellhead valve and lower tools into the wellbore.
8. Run in the hole to the desired depth.
9. Log up at the vendor-recommended speed over the area of interest.
10. Pull out of the hole, bleed off the lubricator, and lay and rig down the temperature tool string.

3.4 Pulse Neutron Log

The pulsed neutron log is considered a proven technique to detect gas saturation in reservoirs. Advances in technology have improved the accuracy of the tool for tracking movement of CO_2 plumes in the reservoir and evaluating flow conformance. Table QASP-4 shows the basic specification of some of the tools in the market.

3.4.1 Tool Specifications

Table QASP-4: Basic tool specifications for pulse neutron.

Logging Type	Pulsar – Neutron (Schlumberger)	TMD3D Pulsed Neutron (Halliburton)
Acquisition	Real Time	Real Time
Logging speed	200 to 3,600 ft/h	60 to 1,800 ft/h
Depth of investigation		10 to 14 in.
Vertical resolution		24 in.
Range of measurement	0 to 60 pu	5 to 60 pu
Mud type limitations	none	none
Temperature rating	350°F	300°F
Pressure rating	15,000 psi	15,000 psi
Casing size minimum	2 ⅜ in.	2 in.
Casing size maximum	9 ⅝ in.	16 in.
Outside diameter	1.72 in.	1.69 in.
Length	18.3 ft	14.25 ft
Weight	88 lb	35 lb

These activities will be executed by specialized contractors with proven industry technology. Calibration and quality control of the tools will follow the service provider's protocols and procedures.

3.4.2 Pulse Neutron Log Running Procedures Example

1. Move in the wireline unit.
2. Make sure the wellhead valve is in the closed position. Remove top cap, then rig up 10k grease injection wireline pressure control equipment (PCE) for attachment to the wellhead. A crane will be required to rig up the wireline unit.
3. Equalizing: if possible, the lubricator should be equalized with a standalone CO_2 source/test pump rather than from the wellbore via needle valve.
4. Rig up the pulse neutron tool string.
5. Inspect all connections and accessories and conduct surface tool checks.
6. Lift the tool string into PCE using wireline.
7. Connect PCE to wellhead and equalize the lubricator.

8. Open the wellhead valve and lower tools into wellbore.
9. Function-test tools and conduct any calibrations while running in the hole.
10. Log over known wet zone first if one is available.
11. Proceed to Plugged Back True Depth (PBTD) with the tool string, being careful not to spud the tool string into the PBTD.
12. Upon reaching PBTD, log three passes the over area of interest at the vendor-recommended speed in C/O mode.
13. Proceed to PBTD with tool string, being careful not to spud tool string into PBTD.
14. Upon reaching PBTD, log one pass over the area of interest at the vendor-recommended speed in Sigma mode.
15. Pull out of the hole, bleed off the lubricator, and lay and rig down the pulse neutron tool string.

3.5 Mud Logging

Mud logging samples will be collected during drilling from the surface to final total depth (TD). Descriptions of the cuttings, Measure while Drilling / Logging While Drilling (MWD/LWD) gamma, and real-time drilling observations will be used to help call formation tops, influence rate of penetration (ROP) before core runs, and call or adjust core depths. Post-drill: cuttings and mud log documents will be used to further describe the subsurface.

3.5.1 Cuttings & IsoTube/Isojar Mudgas Collection

- Dry Cutting Samples
    - Collect unwashed, dry samples (30 grams) every 30 ft from the surface to TD.
- Wet Cutting Samples
    - Collect unwashed, wet samples (250 grams) every 30 ft from the surface to TD.
- Spare Cutting Samples
    - Collect washed, dry samples (30 grams) every 30 ft from the surface to TD (~10,900 ft).
    - Photograph magnified dry samples every 30 ft from the top of Anahuac to the base of the upper Frio (upper confining system and storage reservoir) and every 90 ft outside the previously mentioned interval from spud to TD except while coring.
    - Dispose of spare cutting samples on shakers after use.
- IsoTube/Isojar Mud Gas Collection
    - Collect mud gas samples from the provided manifold within each predetermined depth interval.

3.5.2 Mud Logger Requirements

- If the ROP is too high for the sampling rate, notify the project geologist.
- Contact the project geologist for approval to bring an additional crew member(s) on site to help catch samples at the requested rate.

- If going over the shakers or not using a bypass sluice box, it is the mud logger's responsibility to collect samples representative of the entire sample interval.
- Gas detection and analysis equipment (gas flow lines, filters, gas trap, antifreeze, etc.) shall be checked and/or calibrated at the beginning of each shift. The chromatograph should be calibrated to pentane. This should be noted on the mud log along with mud logger's name. Gas should be reported in parts per million (ppm).
- Do not dry cuttings with a heat lamp. Air dry or use a low-heat vacuum.
- Conduct oil cut and oil show analysis for the entirety of the well, regardless of mud system, for every sample. Photographs should be taken of oil shows under UV and white light in a dimple dish with the MD of each sample written under the respective sample.
- Photographs of cuttings should be taken of every 30-ft sample or as time permits, be magnified, and include a scale.
- All ditch and caving samples shall be examined on site and fully described on a Master Mud log at a scale of 1:100.

3.5.3 Mud Logging Reporting

- All deliverables (i.e., sample bags, IsoTubes, isojars, and AGI) sent out for analysis (wet cuttings, gas, or fluids) should be labelled clearly with a permanent marker, including well name, API number, and depth range in measured depth.
- Shipping containers (e.g., buckets and rice bags) should be clearly labelled with full well name, API number, and depth range of samples within container. Labels should be clearly visible on containers and written with water-resistant ink.
- Each container should include an inventory list of the cuttings within that container.
- Containers should be shipped in accordance with OSHA standards, and a tracking number should be provided to the project geologist once containers have been shipped.

3.6 Coring and SWC Sampling

The coring contractor must provide tools in good condition and according to the program discussed with the technical team. The Bluebonnet hub reserves the right to inspect the tools and request a replacement if substandard conditions are detected. The coring contractor must provide the tools to cut, retrieve, and stabilize the core to get the maximum possible recovery factor. All cores or sidewall cores (SWC) taken shall be placed in a standard core box and preserved according to the recommendation of the Bluebonnet hub SME.

3.7 CO_2 Threshold Entry Pressure Measurement

The core plugs will be loaded into core holders and the entire assemblies loaded into a temperature-controlled oven. Pore pressure, net overburden pressure, and temperature are matched to reservoir conditions. Specific permeability to synthetic formation brine is measured. Permeability is

monitored to ensure stability is reached. Supercritical CO_2 is then exposed to the inlet face of the plug.

Stepwise Injection Method: For low permeability samples, a series of differential pressures will be applied to observe the injection of CO_2. If no injection occurs after at least two days, the next pressure step is applied. After breakthrough occurs, the differential pressure will be maintained and then increased to the next step to verify if breakthrough occurs.

3.8 Analysis of Injected CO_2

3.8.1 CO2 Stream Analysis Protocol

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow. Quarterly samples will be collected and analyzed to track CO_2 composition and purity. Table QASP-5 below shows the list of constituents to be analyzed, based on the anticipated composition of the CO_2 stream.

Table QASP-5: CO_2 stream analysis.

Constituent	Frequency
Pressure	Continuous
Temperature	Continuous
Rate	Continuous
CO_2 (% mol)	Quarterly
Water (lb./MMCF)	Quarterly
Nitrogen (% mol)	Quarterly
Oxygen (% mol)	Quarterly
Hydrogen (% mol)	Quarterly
SOx (ppm by vol.)	Quarterly
NOx (ppm by vol.)	Quarterly
Hydrogen Sulfide (ppm by vol.)	Quarterly
HCN (ppm by vol.)	Quarterly
Hydrocarbons (% mol)	Quarterly
Carbon Monoxide (ppm by vol.)	Quarterly
Glycol (gal/MMSCF)	Quarterly
Ammonia (ppm by vol.)	Quarterly
Argon (%mol)	Quarterly
Sulfur (ppm by wgt)	Quarterly
Carbonyl Sulfide (ppmv)	Quarterly
Alcohols (ppmv)	Quarterly
δ13C of CO_2	During Characterization
14C of CO_2	During Characterization

3.8.2 Sampling and Custody

CO_2 sampling will be performed upstream or downstream of the flowmeter. Sampling procedures, including where the sampling will be performed, will be further refined during the front-end engineering and design (FEED) and will follow contractor protocols to ensure samples are representative of the injectant. Samples will be processed, packaged, and shipped to the contracted laboratory, following standard sample-handling and chain-of-custody guidance (EPA 540-R-09-03, or equivalent). Sample tubing, connectors, and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers. Once the samples are analyzed, the laboratory will be responsible for disposing of the containers and residues properly.

3.8.3 Equipment and Calibration

Sampling equipment in the field will be maintained, serviced, and calibrated per the manufacturer's recommendations. Spare parts that may be needed will be included in the supplies on hand during field sampling. Laboratory equipment supply, testing, calibration, inspection, and maintenance will be the responsibility of the analytical laboratory per its protocols and quality assurance (QA) program. The Bluebonnet hub reserves the right to review and audit the protocols and methods of the selected laboratory before awarding the work.

3.8.4 Personnel and Training

During initial operations, sampling will be performed by trained personnel from the laboratory. In addition, the field staff will be trained in the procedures and protocols to take the samples.

4.0 Analytical Methods

4.1 CO_2 Sampling

The operating temperature for the gas chromatography (GC) analytical method is from –10°C to 50°C. Also, the relative humidity should be 95% or less so there is no condensation.

Table QASP-6: Sampling methods summary.

Analytical Parameter	Analytical Method	Typical Precision/Accuracy
CO_2	GC/TCD	± 2% of full scale
Water	Stain Tube	± 10%
Nitrogen	GC/TCD	± 1% of full scale
Oxygen	GC/TCD	± 1% of full scale
Argon	GC/TCD	± 1% of full scale
Hydrogen	GC/TCD or GC/HID	± 1% of full scale

Analytical Parameter	Analytical Method	Typical Precision/Accuracy
HCN	GC	± 1% of full scale
Sulfur Dioxide	GC/SCD	± 2% of full scale
Nitrogen Dioxide	Colorimetric	± 20%
Nitric Oxide	Colorimetric	± 20%
Hydrogen Sulfide	GC/SCD	± 2% of full scale
Hydrocarbons	GC/FID	± 0.5% of full scale
Carbon Monoxide	GC/HID	± 0.5% of full scale
Glycol	GC/FID	± 10%
Sulfur	GC/SCD	± 2%
Carbonyl Sulfide	GC/SCD	± 2%
Alcohols	GC/FID	±5-10%

Notes:

- GC/TCD = gas chromatography with a thermal conductivity detector
- GC/FDP = gas chromatography with flame photometric detector
- GC/HID = gas chromatography with helium ionization detector
- GC/FID = gas chromatography with flame ionization detector
- Oxygen and Argon are reported together.

CO_2 samples will be also analyzed during the baseline period to identify isotopes (See Table QASP-7).

Table QASP-7: Isotopes Sampled for Identification

Hydrocarbons	Method
$\delta^{13}C$ and ^{14}C of CO_2	GC-IRMS, AMS for ^{14}C

Notes:

- GC-IRMS = Gas chromatography isotope ratio mass spectrometry
- AMS = Accelerator mass spectrometry

Gas samples will be analyzed by a third-party laboratory, which will be responsible for updating protocols and providing a quality control protocol.

If the CO_2 composition shows abnormal values during the testing period, a validation of the sampling process will be performed with a new sample collected by the laboratory technician and sent to the testing facilities for verification.

4.2 Corrosion Coupons

Injection-well material samples, called coupons, will be monitored for signs of corrosion to verify that the well components meet the standards for material strength and performance and identify well maintenance needs. The coupons shall be collected and sent quarterly to a third-party company for analysis, conducted in accordance with NACE Standard SP-0775-2018-SG, to determine and document corrosion wear rates based on mass loss.

4.2.1 Sampling and Custody

The following information must be recorded prior to coupon installation: coupon serial number, installation date, system location identification number (linked to SAP asset numbering), and coupon and holder orientation. The coupon should also be handled carefully to avoid contamination.

The field operator will collect the coupons and identify them by the serial number, date, company name, location identification number, and field operator name. The operator in the field will visually inspect the coupon for signs of erosion, pitting, scale, or other damage, and will take a picture before packing the sample. The coupon will be protected from oxidation and handling contamination by placing the coupon in a designated, moisture-proof envelope that is impregnated with a volatile corrosion inhibitor and shipped immediately to the laboratory for analysis.

As part of the training program, the field operator will be trained in best practices to mitigate coupon contamination.

4.2.2 Equipment Calibration

Preparation, cleaning, and evaluation of corrosion specimens will be handled by a certified third-party contractor following NACE RP0775-2005 or its equivalent. The contractor is responsible for calibrating and maintaining the measurement equipment as well as disposing of the samples when the analysis is finished.

Table QASP-8: Analytical methods.

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

Notes:

- NACE SP0775-2018-SC – Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

4.2.3 Quality Control

The Bluebonnet hub reserves the right to audit the QA/QC procedures before awarding the work to a contractor and during the execution of the service.

4.3 Soil Gas Sampling

The method for soil gas sampling is described in Section 8.1 of the Testing and Monitoring Plan. The samples will be sent to a specialized laboratory to determine gas composition and perform isotopic analysis to characterize the fluid and get a fingerprint for future appropriation.

4.3.1 Analytical Method

Compositional analysis of the gases includes chromatographic determination of the concentrations of fixed gases and hydrocarbons listed in Table QASP-9.

Table QASP-9: Soil gas analysis parameters.

Soil Gas Parameter	Analysis method	Detection Limit	Typical Precision/Accuracy
CO_2	GC/TCD	10 ppm	± 2% of full scale
N_2	GC/TCD	10 ppm	± 2% of full scale
O_2	GC/TCD	10 ppm	± 2% of full scale
CH_4, C_2-C_4	GC/FID	10 ppm	± 2% of full scale
C_5-C_6	GC/FID	10 ppm	± 2% of full scale
$\delta^{13}C$ of CO_2	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)	1000 ppm	± 1%
$\delta^{13}C$ of CH_4	Gas chromatography with combustion isotope ratio mass spectrometry (GC/C/IRMS)	1000 ppm	± 1%
δD of CH_4	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)	1000 ppm	± 1%

Notes:

- GC = Gas Chromatography
- IRMS = Isotope Ratio Mass Spectrometry
- AMS = Accelerator Mass Spectrometry

Isotopes are different forms of the same element, differing only in the number of neutrons in the nucleus of the atom. Although some isotopes are unstable and decay radioactively, most are stable. Isotopes are a valuable tool for distinguishing the source of the element and creating a fingerprint of the gas.

4.3.2 Equipment Calibration

Calibration will be performed by manufacturer using their protocol. Sampling will be performed by trained or specialized personnel from the lab at the beginning of the operation, and the field

operator will be trained in the process to be able to take samples and monitor gas composition with handheld devices as a part of routine operations.

5.0 Water Sampling

The following methodology will be used to collect ground water samples:

1. Purge the well to remove standing and/or stagnant water from the well casing. Purging also reduces chemical and biochemical artifacts caused by the materials used for well installation and construction and reactions occurring within an open borehole or annular space between a well casing and borehole wall.
2. At a minimum, purge three well-casing volumes while monitoring the temperature, pH, and conductivity until the readings have stabilized.
3. Record the well diameter, water level, well bottom depth, and purge volume on the field data sheet.
4. If the readings have stabilized after purging with three well volumes and meet the criteria in Table QASP-11, then proceed with sample collection.
5. If readings have not stabilized after three well volumes, continue to purge until they are stable, but do not exceed ten purge volumes before collecting samples.
6. Document those instances when the readings were not stable prior to sample collection.

- The measurement stability criteria in Table QASP 10 show the allowable variations among five or more field measurements.

Table QASP-10: Field measurement stability criteria.

Field Measurement	Stability Criteria
pH	± 0.1 standards units
Temperature, °C	± 0.5°C
Conductivity, mS/cm	± 5%

5.1 Equipment and Calibration

For groundwater sampling, field equipment will be maintained, serviced, and calibrated according to the manufacturers' recommendations. Spare parts that may be needed will be included in supplies on hand during field sampling. All laboratory equipment, testing, inspection, maintenance, and calibration will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program.

5.2 Personnel and Training

Water testing will be performed by certified laboratory personnel following the specific methods approved by the EPA or other applicable industry standard. The Bluebonnet hub reserves the right to audit the procedures and results of the selected laboratory with a third party to improve quality control. Field personnel should be trained to perform sampling collection following the laboratory's protocols.

5.3 Analytical Method

Where possible, methods are based on standard protocols from the EPA or standard methods for water analysis. Laboratories shall have standard operating procedures for the analytical methods performed.

Table QASP-11: Analytical method selected for various parameters.

Parameter	Analytical Method	Detection Limit	Typical Precision/ Accuracy
Cations: Al, Ba, B, Cd, Ca, Cu, Cr, Fe, Pb, Li, Mg, Mn, Ni, P, K, Si, Na Sr, Zn	ICP-OES, EPA Method 6010d, ICP-MS Method 200.8 or equivalent (ICP-OES)	< 0.1	± 1%
Other Metals: As, U, Co, Se, Pb, Mo, V	ICP-MS Method 200.8 or equivalent	< 0.1	± 1%
Mercury	EPA 245.7 CVAA, or equivalent (ICP-OES)	< 0.1	± 1%
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-, NO_2^-	Ion Chromatography, EPA Method 300.1 or similar	< 0.1	± 1%
Carbonate, bicarbonate, and hydroxide	Titration, ASTM D3875. IC	< 0.1	± 1%
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C, ASTM D5907 or equivalent	10 ppm	± 1%
Water Density	ASTM D5057, ASTM D4052 or equivalent	N/A	± 1%
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of Dissolved Inorganic Carbon DIC in Water	Gas Bench and CF-IRMS for $^{13/12}C$	N/A	3 reference standard comparison
Radiocarbon 14C of DIC in Water	AMS for ^{14}C	N/A	± 0.0007
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O	N/A	± 1%
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, ASTM 1945D, RSK 175 or equivalent	10 ppm per component	± 1%
pH	ASTM D1293, EPA 150.23 or equivalent	N/A	± 3%
Temperature	ASTM 2550		
Conductivity	ASTMD1125	10 microSiemens/centimeter	± 3%
Conductivity (field)	EPA 120.1		

ICP-OES = inductively coupled plasma optic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; GC/MS = gas chromatography–mass spectrometry; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: Cold Vapor Atomic Absorption;

Note: Isotopes will be analyzed only during the pre-injection baseline, and if required for appropriation based on other monitoring results.

5.4 Quality Control

Quality control of the sampling and results will follow the protocols established in the standard analytical method used for testing (See Table QASP-12). The Bluebonnet hub reserves the right to audit the laboratory procedures and protocols to validate that the methods are being followed, and results are accurate.

6.0 Continuous Recording of Injection Parameters

Injection pressure and temperature (P/T) will be measured continuously at the surface via real-time P/T instruments installed in the CO_2 flowline near the interface with the wellhead. The flow rate of CO_2 injected into the wellhead will be measured by flowmeter skids with a Coriolis meters. Automated shutoff devices will be used to stop injection, if injection parameters deviate outside operational limits.

Table QASP-12: Technical specification for surface pressure transducers.

Surface Pressure Transducer Specifications	
Parameter	**Specification**
Calibrated Working Pressure Range	0 to 3,000 psi
Pressure Accuracy	± 0.0065%
Pressure Resolution	0.001 psi
Type of Sensor	4-20 ma output transmitter; static measurement; 4-wire

Table QASP-13: Technical specification for surface temperature transducers.

Surface Temperature Transducer Specifications	
Parameter	**Specification**
Calibrated Working Temperature Range	0 to 150°F
Temperature Accuracy	± 0.0055%
Temperature Resolution	0.01°F
Type of Sensor	4-20 ma output; RTD

P/T gauges will be deployed on the tubing above and below the injection packer to monitor bottomhole conditions in real time. The gauges and cables will be selected to withstand CO_2 service conditions, and the data will be integrated into the SCADA system and surveillance platform. Table QASP-14 shows an example of the technical specifications for downhole gauges.

Table QASP-14: Technical specifications for downhole P/T sensors.

Downhole P/T Sensor Specifications	
Parameter	**Specification**
Pressure sensor	Quartz / Inconel Carriers
Pressure accuracy	± 0.02%
Pressure repeatability	≤ 0.01% of full scale
Temperature sensor	Quartz / Inconel Carriers
Temperature accuracy	± 0.5°C
Temperature resolution	0.005°C
Operating temperature ranges	-20°C to 200°C
Sample Rate	1 sec
Inconel cable	Required

The flow rate of CO_2 injected into the well will be measured by flowmeter skids with a Coriolis-type flowmeter. Table QASP-15 is an example of typical meter specifications.

Table QASP-15: Example of Coriolis meter specifications.

Parameter	Specification
Mass flow accuracy (Liquid)	±0.10% of rate (standard)±0.05% of rate (optional)
Mass flow repeatability (Liquid)	±0.05% of rate (standard)±0.025% of rate (optional)
Volume flow accuracy (Liquid)	±0.10% of rate (standard)±0.05% of rate (optional)
Volume flow repeatability (Liquid)	±0.05% of rate (standard)±0.025% of rate (optional)
Mass flow accuracy (Gas)	±0.35% of rate
Mass flow repeatability (Gas)	±0.20% of rate
Density accuracy (Liquid)	±0.0005 g/cm3 (±0.5 kg/m3) (standard)±0.0002 g/cm3 (±0.2 kg/m3) (optional)
Density repeatability (Liquid)	±0.0002 g/cm3 (±0.2 kg/m3) (standard)±0.0001 g/cm3 (±0.1 kg/m3) (optional)
Temperature accuracy	±1 °C ±0.5% of reading
Sensor maximum working pressure	2,855 psig (197 barg)

Automated shutdown valves will be used to stop the flow of CO_2 to the well in the event that operation parameters deviate from program operational limits. The valves are currently planned as ASME 1500 RF trunnion ball, full port, CS x SS, soft seated, gear operated, and NACE, with electrically operated actuator, but will be confirmed during detailed engineering of the surface facilities.

7.0 CO_2 Injection Well – Well Testing

7.1 Step Rate Test

A step rate test (SRT) is normally used to estimate fracture pressure in an injection well for given geologic formation. The test is conducted by injecting fluid into the formation at a series of increasing rates, allowing each rate to stabilize, and noting the stabilized injection pressure for each rate. The injection pressure is then plotted against the injection rate to identify the fracture pressure.

7.1.1 Equipment for Step Rate Test

The basic equipment required is as follows:

- A water supply truck capable of pumping the water downhole under increasing pressures.
- Surface monitoring equipment capable of measuring injection rate and pressure.
- Enough storage and volume of the water and additives to avoid interruption of the test.
- Bottomhole pressure (BHP) memory gauge or permanent pressure gauges installed in the well during original completions. It is recommended to use redundant pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality.

To convert surface pressure to BHP, the inside diameter and condition of the tubing must be known to compute frictional losses, and the density of the injected fluid must be known to compute the hydrostatic pressure. A BHP gauge should be used to measure BHP to provide two sources of pressure data for comparison.

7.1.2 Procedure for Step Rate Test

The following SRT procedure is recommended.

The test well should be shut in long enough, but not less than 48 hours, so that the BHP is near the shut-in formation pressure. The SRT should start at a suitably low rate such that at least two injection rate steps are below the formation fracture pressure and at least three rates are above the formation fracture pressure. A plot of the injection rate versus surface pressure and BHP will facilitate the determination of the formation fracture pressure. The point at which the slope of the lower fracture rates intersects the slope of the higher fracture rates is the formation fracture pressure, which can be expressed as a fracture gradient (psi/ft).

It is recommended that injection rate step is stable before proceeding to the next higher rate. The duration of each step will be at least 30 minutes since the permeabilities of the formations to test are greater than 10 mD. Each step should last exactly as long as the preceding step. Surface pressure and BHP measurements should be recorded at shut-in (instantaneous shut-in pressure or ISIP), after 5 minutes of shut-in, and after 10 minutes of shut-in.

It is recommended to use redundant pressure gauges during the test with one or more gauges serving as a backup, or for verification in cases of questionable data quality.

7.1.3 Analysis of Step Rate Test (SRT)

The SRT analysis consists of plotting the injection pressure at the end of each rate versus the injection rate. It is preferable to plot the BHP, but the surface pressure may be used if it is positive throughout the test and the friction effects are not significant. The plot should have two straight lines segments, as illustrated in the Figure QASP-1.



Figure QASP-1 Step Rate Data Plot Example

7.2 Injectivity Test

The injectivity test is pressure-transient testing during injection into a well. It is analogous to drawdown testing, for both constant and variable rates. This test and the analysis only apply to liquid-filled reservoirs with the mobility of the injected fluid similar to or equal to the mobility of the in-situ fluid (Robert Earlougher, 1997).

The test will be performed after the tubing and packer are installed in the CO_2 injection well and will be performed with water and clay inhibitors, if required to avoid formation damage. Before the injectivity test, an SRT will be conducted to validate fracture pressure values and identify the optimum injection rates. After the injectivity test is performed, the well will be shut in to proceed with the falloff test.

7.2.1 Equipment for Injectivity Test

The basic equipment required is as follows:

- A water supply truck capable of pumping the water downhole under increasing pressures.

- Enough storage and volume of the water and additives to avoid interruption of the test.
- Surface monitoring equipment capable of measuring injection rate and pressure.
- BHP memory gauge or permanent pressure gauges installed in the well during original completions. It is recommended to use redundant pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality.

7.2.2 Procedure for Injectivity Test

1. The well is initially shut in and pressure is stabilized at the initial reservoir pressure, pi.
2. Measure the initial reservoir pressure on the surface as well as downhole with the permanent gauges installed in the completion.
3. At time zero, injection starts at a constant rate established after the SRT is performed. The selected rate should be high enough to cause a pressure that is equal to the depth of the top of the tested zone times the 90% of the fracture gradient value identified during the SRT.
4. Continue injection until the pressure measurement is nearly stable unless this is impossible due to slow increase or high injection pressures. If the pressure is stable, inject enough fluid to reach modeled conditions to start the falloff test.
5. It is advisable to monitor the injection rate carefully to adjust the interpretation in case the rate varies significantly.
6. Shut in the well and start the falloff test.

7.3 Falloff Test

A falloff test is a pressure-transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff period is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing analysis provides transmissibility, skin factor, and well flowing and static pressures.

7.3.1 Equipment for Falloff Test

The basic equipment required is as follows:

- Pumping system (trucks or surface pump) and enough amount of the injectant to ensure an adequate test.
- Surface monitoring equipment capable of measuring injection rate and pressure.
- BHP memory gauge or permanent pressure gauges installed in the well during original completions. It is recommended to use redundant pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality.

7.3.2 General Considerations Falloff Test

- Adequate volume of the injectant should be ensured for the duration of the test.
- The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the injectivity and falloff portions of the test should be designed not only to

reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

- Offset wells completed in the same formation as the test well should be shut in, or, at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test.
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period.
- The condition of the well, junk in the hole, wellbore fill, or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period, and therefore, the shut-in time of the well.
- Accurate recordkeeping of injection rates is critical, including a mechanism to synchronize times reported for injection rate and pressure data. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

7.3.3 Site-Specific Pretest Planning

- Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
- Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
- Do not shut in two wells simultaneously or change the rate in an offset well during the test.
- The test well should be shut in at the wellhead to minimize wellbore storage and afterflow. If the well goes on vacuum, the wellhead should be opened to the atmosphere.
- Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
- Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.3.4 Evaluation of the Falloff Test

1. Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
2. Confirm pressure stabilization prior to shut-in of the test well.
3. Look for anomalous data, pressure drop at the end of the test, determine if the pressure drop is within the gauge resolution.

4. Prepare a log-log diagnostic plot of the pressure and semilog derivative. Identify the flow regimes present in the well test.
5. Use the appropriate time function, depending on the length of the injection period and variation in the injection rate preceding the falloff.
6. Mark the various flow regimes, particularly the radial flow period.
7. Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow).
8. If there is no radial flow period, attempt to type-curve match the data.
9. Prepare a semilog plot.
10. Use the appropriate time function, depending on the length of injection period and injection rate preceding the falloff.
11. Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line.
12. Calculate the transmissibility, kh.
13. Calculate the skin factor, s, and skin pressure drop, DP skin.
14. Calculate the radius of investigation, ri.
15. Explain any anomalous results.

8.0 Distributed Temperature Sensing

Distributed temperature sensing (DTS) uses fiber optic sensor cables, typically several kilometers in length, that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the well. DTS specifications are shown below in Table QASP-16 and fiber optic cable technical specifications are shown in Table QASP-17.

Table QASP-16: DTS Technical specifications.

Parameter	Value
Spatial Resolution	1 m (3.2 ft) across entire measurement range
Sampling Resolution	Down to 0.5 m (1.6 ft) across entire measurement range
Temperature Resolution	0.1°C (0.18°F)
Accuracy	±0.5°C (±0.9°F)
Measurement Range	Up to 12 Km
Measurement Temperature Range	-250°C to 400°C
Measurement Times	10 seconds to 24 hours
Dynamic Range	30 db
Operating Environment	-10°C to 60°C, humidity 0–95% non-condensing

Table QASP-17: Fiber optic cable technical specifications.

Parameter	Value
Tensile Strength	2,372 lbs
Yield Strength	2,018 lbs
Strain @ Yield	0.31%
Hydrostatic Pressure	23,872 psi
Burst Pressure	28,050 psi
Working Pressure	20,526 psi
Static Bend Radius	3 in.

9.0 Leak Detection

9.1 Optical Gas Imaging Camera

Optical Gas Imaging (OGI) cameras use unique spectral filters that enable them to detect a gas compound. The filter restricts the wavelengths of radiation allowed to pass through the detector to a very narrow band called band pass. OGI cameras will be used to identify fugitive emissions or other leaks of specified constituents from facilities, pipelines, wells, and other equipment at the project.

Table QASP- 18 FLIR Optical Gas Imaging Camera Specifications



SPECIFICATIONS

	Gx320	Gx620	G620	G343	G346	G304	G306	GF77	
Primary Gas Seen	Hydrocarbons (CxHx)	Hydrocarbons (CxHx)	Hydrocarbons (CxHx)	Carbon dioxide (CO_2)	Carbon monoxide (CO)	Refrigerants	Sulfur hexafluoride (SF_6), ammonia (NH_3)	LR lens: methane, R-134a, R-152a	HR lens: sulfur hexafluoride (SF_6), ammonia (NH_3), ethylene
Detector Type	Cooled InSb	Cooled InSb	Cooled InSb	Cooled InSb	Cooled QWIP	Cooled QWIP	Cooled QWIP	Uncooled microbolometer	
Spectral Range	3.2 µm to 3.4 µm	3.2 µm to 3.4 µm	3.2 µm to 3.4 µm	4.2 µm to 4.4 µm	4.52 µm to 4.67 µm	8.0 µm to 8.6 µm	10.3 µm to 10.7 µm	LR lens: 7 µm to 8.5 µm	HR lens: 9.5 µm to 12 µm
Resolution	320 × 240 (76,800 pixels)	640 × 480 pixels (307,200 pixels)	640 × 480 pixels (307,200 pixels)	320 × 240 (76,800 pixels)	320 × 240 (76,800 pixels)	320 × 240 (76,800 pixels)	320 × 240 (76,800 pixels)	320 × 240 (76,800 pixels)	
Quantification in Camera	Yes	Yes	Yes	No	No	No	No	No	
Thermal Sensitivity	<10 mK at 30°C (86°F)	20 mK at 30°C (86°F)	20 mK at 30°C (86°F)	15 mK at 30°C (86°F)	15 mK at 30°C (86°F)	15 mK at 30°C (86°F)	15 mK at 30°C (86°F)	25° lens: <25 mK at 30°C (86°F) 6° lens: <40 mK at 30°C (86°F)	
Accuracy	±1°C (±1.8°F) for temperature range (0°C, to 100°C, 32°F to 212°F) or ±2% of reading for temperature range (>100°C, >212°F)	±1°C (±1.8°F) for temperature range (0°C to 100°C, 32°F to 212°F) or ±2% of reading for temperature range (>100°C, >212°F)	±1°C (±1.8°F) for temperature range (0°C to 100°C, 32°F to 212°F) or ±2 % of reading for temperature range (>100°C, >212°F)	N/A	±1°C (±1.8°F) for temperature range (0°C to 100°C, 32°F to 212°F) or ±1 % of reading for temperature range (>100°C, >212	±1°C (±1.8°F) for temperature range (0°C, to 100°C, 32°F to 212°F) or ±2% of reading for temperature range (>100°C, >212°F)	±1°C (±1.8°F) for temperature range (0°C, to 100°C, 32°F to 212°F) or ±2 % of reading for temperature range (>100°C, >212°F)	±5°C (±9°F) for ambient temperatures 15°C to 35°C (59°F to 95°F)	
Noise Equivalent Concentration Length (NECL) [ΔT=10°C, Distance= 1 m]	Methane - 13 ppm-m	Methane - 29 ppm-m	Methane - 29 ppm-m	Carbon dioxide (CO_2) - 5.6 ppm-m	Carbon monoxide (CO) - 9 ppm-m	-	Sulfur hexafluoride (SF_6) - 0.3 ppm-m, Ethylene (C_2H_4) - 6.3 ppm-m	LR lens: CH_4: <100 ppm × m R-134a: <20 ppm × m R-152a: <100 ppm × m	HR lens: SF_6: <1 ppm × m C2H4: <20 ppm × m NH_3: <20 ppm × m
Minimum Laboratory Leak Rate (MLLR) [known gases]	Methane: 0.6 g/hr Propane: 0.6 g/hr Butane: 0.4 g/hr	Methane: 0.6 g/hr Propane: 0.6 g/hr	Methane: 0.6 g/hr Propane: 0.6 g/hr	-	-	-	Sulfur hexafluoride (SF_6): 0.026 g/hr Ammonia: 0.127 g/hr	Methane: 2.7 g/hr	Sulfur hexafluoride (SF_6): 0.74 g/hr
Temperature Range	-20°C to 350°C (-4°F to 662°F)	-20°C to 350°C (-4°F to 662°F)	-20°C to 350°C (-4°F to 662°F)	-	-20°C to 350°C (-4°F to 662 °F)	-20°C to 250°C (-4°F to 482°F)	-40°C to 500°C (-40°F to 932 °F)	-20°C to 80°C (-4°F to 176°F), 0°C to 250°C (32°F to 482 °F) 100°C to 500°C (212°F to 932 °F)	
Available Lenses	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm); 6° × 4.5° (92 mm)	24° × 18° (23 mm); 14.5° × 10.8° (38 mm)	
Zoom	1–8× continuous, digital zoom	1–8× continuous, digital zoom	1–8× continuous, digital zoom	1–8× continuous, digital zoom	1–8× continuous, digital zoom	1–8× continuous, digital zoom	1–8× continuous, digital zoom	1–6× continuous, digital zoom	
Focus	Manual	Manual	Autofocus, manual	Autofocus, manual	Autofocus, manual	Autofocus, manual	Autofocus, manual	Continuous (laser), one-shot (laser), one-shot contrast, manual	
Display									
Adjustable Viewfinder	4", 640 × 480 pixel rotatable, touchscreen LCD	4", 640 × 480 pixel rotatable, touchscreen LCD	4", 640 × 480 pixel rotatable, touchscreen LCD	4", 640 × 480 pixel rotatable, touchscreen LCD	4", 640 × 480 pixel rotatable, touchscreen LCD	4", 640 × 480 pixel rotatable, touchscreen LCD	4", 640 × 480 pixel rotatable, touchscreen LCD	Dragontrail® Touchscreen (QVGA), 640 × 480 pixels	
Visual Camera w/ Lamp	3.2 MP	3.2 MP	3.2 MP	3.2 MP	3.2 MP	3.2 MP	3.2 MP	5 MP	
Laser Pointer	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2 Semiconductor AlGaInP diode laser, 1 mW, 635 nm (red)	Class 2, dedicated button, used in focus and distance measurement	
Video Out	HDMI, DVI	HDMI, DVI	HDMI, DVI	HDMI, DVI	HDMI, DVI	HDMI, DVI	HDMI, DVI	DisplayPort over USB Type-C	
Certifications									
Hazardous Locations	ATEX/IECEx, Ex ic nC op is IIC T4 Gc II 3 G - ANSI/ISA-12.12.01-2013, Class I Division 2 - CSA 22.2 No. 213, Class I Division 2	ATEX/IECEx, Ex ic nC op is IIC T4 Gc II 3 G - ANSI/ISA-12.12.01-2013, Class I Division 2 - CSA 22.2 No. 213, Class I Division 2	-	-	-	-	-	-	
US EPA OOOOa	Yes	Yes	Yes	-	-	-	-	-	
Image Analysis	10 spots, 5 boxes with max/min/average, 1 line, Delta T, measurement corrections	10 spots, 5 boxes with max/min/average, 1 line, Delta T, measurement corrections	10 spots, 5 boxes with max/min/average, 1 line, Delta T, measurement corrections	-	10 spots, 5 boxes with max/min/average, 1 line, Delta T, measurement corrections	10 spots, 5 boxes with max/min/average, 1 line, Delta T, measurement corrections	10 spots, 5 boxes with max/min/average, 1 line, Delta T, measurement corrections	3 spot and boxes in live mode	
Annotations	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	Voice: 60 secs with Bluetooth on still images and video Text from predefined list or soft keyboard on touchscreen	
Communication Interfaces	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB 2.0, Bluetooth via headset, Wi-Fi, HDMI	USB2.0, Bluetooth, Wi-Fi, DisplayPort	
Data Storage	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	Removable SD card, cloud via FLIR Ignite	
File Format	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, MJEG, MPEG4, H.264, RTRR(.csq)	Standard JPEG, RTRR(.csq)	
MultiREC Recording	Record multiple files automatically in customizable order	Record multiple files automatically in customizable order	Record multiple files automatically in customizable order	Record multiple files automatically in customizable order	Record multiple files automatically in customizable order	Record multiple files automatically in customizable order	Record multiple files automatically in customizable order	-	
GPS	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS; data logging feature	Location data automatically added to every still image; first frame in video from built-in GPS	

For an overview of the specifications for the FLIR GF77a and G300a please visit FLIR.com

9.2 Atmospheric CO_2 Sensor

Table QASP-19: Infrared gas detector specifications.

Model	GF343
Detector Type	Focal plane array, cooled InSb
Spectral Range	4.2 – 4.4 µm
Resolution	320 x 240 pixels
Detector Pitch	30 µm
NETD/Thermal Sensitivity	< 15 mK @ +30°C (+86°F)
Sensor Cooling	Stirling Microcooler (FLIR MC-3)
Electronics / Imaging	
Image Modes	IR image, visual image, High Sensitivity Mode (HSM)
Frame Rate (Full Window)	60 Hz
Dynamic Range	14-bit
Video Recording / Streaming	Real-time non-radiometric recording: MPEG4/H.264 (up to 60 min./clip) to memory card Real-time non-radiometric streaming: RTP/MPEG4
Visual Video	MPEG4 (25 min./clip) to memory card
Visual Image	3.2 MP from integrated visible camera
GPS	Location data stored with every image
Camera Control	Remote camera control via USB
File Storage	
Storage Media	Removable SD or SDHC memory card; two card slots
Image Storage Capacity	> 1200 images (JPEG) with post-process capability per GB on memory card
Optics	
Camera f/number	f/1.5
Available Fixed Lenses	14.5° (38 mm), 24° (23 mm)
Focus	Automatic (one touch) or manual (electric or on the lens)
Image Presentation	
On-Camera Display	Built-in widescreen, 4.3 in. LCD, 800 x 480 pixels
Automatic Gain Control	Continuous/manual, linear, histogram
Menu Commands	Level/span, auto adjust continuous/manual/semi-automatic, zoom, palette, start/stop recording, store image, playback/recall image
Color palettes	Iron, Gray, Rainbow, Arctic, Lava, Rainbow HC
Zoom	1-8x continuous, digital zoom
General	
Operating Temperature Range	–20°C to +50°C (–4°F to +122°F)
Storage Temperature Range	–30°C to +60°C (–22°F to +140°F)
Encapsulation	IP 54 (IEC 60529)
Bump / Vibration	25 g (IEC 60068-2-27) / 2 g (IEC 60068-2-6)
Power	AC adapter 90-260 VAC, 50/60 Hz or 12 V from a vehicle
Battery System	Rechargeable Li-ion battery
Weight w/ Battery & Lens	2.48 kg (5.47 lb.)
Size (L x W x H) w/ Lens	306 × 169 × 161 mm (12.0 × 6.7 × 6.3 in.)
Mounting	Standard, 1/4"-20

The Bluebonnet hub will install infrared gas detectors close to the wellheads of the injector and monitoring wells. These sensors will interface with the surveillance system to set alarms and provide information on potential leaks at the surface.

Table QASP-20: Wellhead atmospheric CO_2 sensor specification example

Parameter	Specification
Detector Type	Infrared Absorption
Measuring Range	0 to 5000 ppm CO2
Accuracy @ 25° C	± 5% FS2500 ppm
Response Time With 5000 ppm CO2Applied	T50<7 seconds & T90<15 seconds
Operating Temperature Range	-40°F to +122°F -40°C to +50°C
Operating Humidity Range	5 to 100% Relative Humidity

10.0 Induced Seismicity Tracking

The Bluebonnet hub will deploy a seismometer monitoring network to determine the locations, magnitudes, and focal mechanisms of seismic events (if any).

10.1 Geophone Array for Seismicity

Based on the information provided by United States Geological Survey (USGS), the selected area does not show high seismic activity that could endanger the containment of the CO_2 in the storage complex or nearby infrastructure. Seismicity history is discussed in more detail in the Area of Review and Corrective Action Plan document of the permit.

Changes of in-situ stresses on existing faults caused by human activities (e.g., mining, dam impoundment, geothermal reservoir stimulation, wastewater injection, hydraulic fracturing, and CO_2 sequestration) may induce earthquakes on critically stressed fault segments. To monitor potentially induced seismicity due to the injection of CO_2 in the area, the project proposes deploying surface seismometer stations. While the historical seismicity of the project area indicates no earthquakes in the immediate vicinity, the Bluebonnet hub intends to monitor both the storage facility and adjacent infrastructure with a seismic monitoring system for the duration of the project. The seismic monitoring will be conducted with a surface array deployed to detect events above M_L1.0, with epicentral locations within 10 miles of the injection wells.

If an event is recorded by either the local private array or a public (national or state) array to have occurred within 5.6 miles of the injection wells, the Bluebonnet hub will implement its response plan subject to detected earthquake magnitude limits defined below to eliminate or reduce the magnitude and/or frequency of seismic events. A traffic light system is described in the Testing and Monitoring Plan Section 9.2.

10.1.1 Personnel

The design and installation of the station array will be performed by specialized contractors and will include the following activities:

- Project management support to design the seismometer array, model the network performance, coordinate permitting and equipment installation, conduct testing and maintenance, and ensure optimum execution of the project.
- Field operations to deploy seismic station instrumentation, run power and communication systems, monitor data quality, and perform commissioning.
- Data acquisition, system configuration, and process setup.
- Continuous support and monitoring for data verification and QA/QC.
- Continuous near-real-time reporting, including analyst reviews and alert notifications, for events at or above predetermined magnitude thresholds over the seismic area.

10.1.2 Equipment

The equipment proposed for seismic station includes:

- Broadband sensors
- Data logger
- Solar power system and backup battery
- Communication system
- Cabling
- Mounting equipment

Figure QASP-2 shows the technical specifications for broadband seismometer as a reference.

Figure QASP-3 shows an example of a setup for data acquisition, transfer, storage, and analysis.

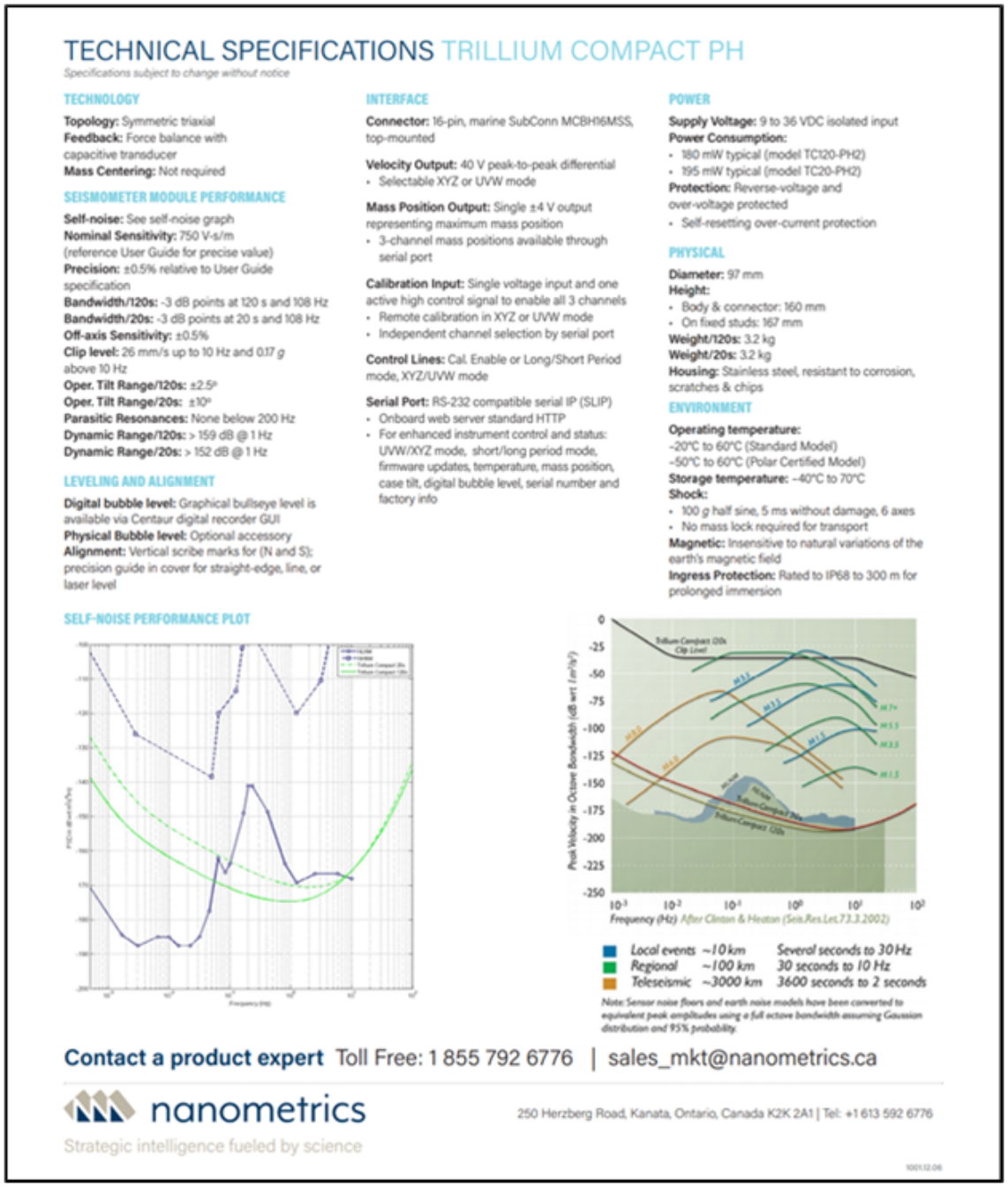


Figure QASP-2: Technical specification for a broadband seismometer.

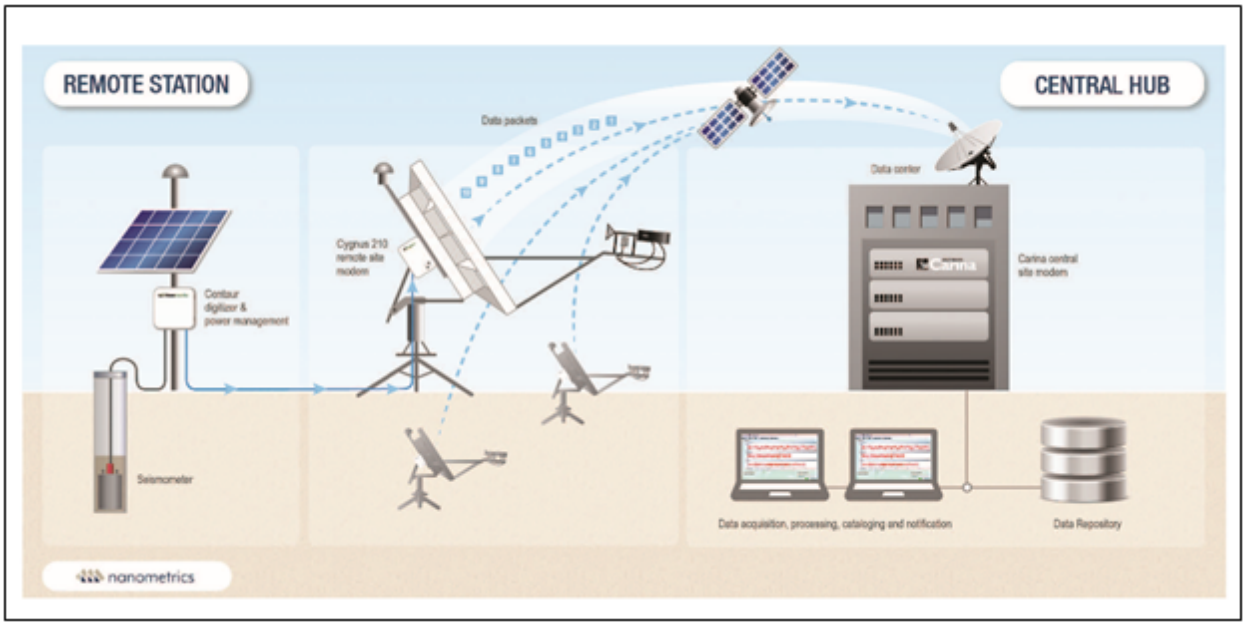


Figure QASP-3: Data acquisition setup example.

11.0 Open Hole and Cased Hole Wireline Logs Technical Specification and Procedures

See Appendix QASP-A.

12.0 References

- EPA Region 6 Falloff Guidelines
- SPE Monograph 5, “Advances in Well Test Analysis,” 1977, Robert Earlougher, Jr.

PRE-OPERATIONAL TESTING PLAN

Bluebonnet Sequestration Hub

1.0 Facility Information 1
2.0 Pre-Injection Test Plan – CO2 Injector Wells 6
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6.0 Pre-Injection Test Plan – Above-Confining-Zone/USDW Monitoring Wells 20
7.0 Pre-Injection Test Plan – Miocene Composite Confining Zone Monitoring Wells 20

1.0 Facility Information

Facility name: Bluebonnet Sequestration Hub (Bluebonnet Hub or the Project)
Bluebonnet CCS 1, Bluebonnet CCS 2, and Bluebonnet CCS 3,
Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 Wells

Facility contact: Claimed as PBI [redacted]

Well location: Chambers County, Texas

Well Name	Latitude (NAD27)	Longitude (NAD27)
Bluebonnet CCS 1	29.811792	-94.436442
Bluebonnet CCS 2	29.804552	-94.463937
Bluebonnet CCS 3	29.852812	-94.498078
Bluebonnet CCS 5	29.812133	-94.436456
Bluebonnet CCS 6	29.817417	-94.464104
Bluebonnet CCS 7	29.853222	-94.498078

Pursuant to 40 CFR §146.87, this plan describes the testing and logging activities proposed by Bluebonnet Sequestration Hub, LLC for the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, as well as the monitoring wells, water producer wells, and a water disposal well planned for the Bluebonnet Hub.

These testing and logging activities are restricted to the drilling, completion, and pre-injection phases of the project. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring Plan along with other non-well related pre-injection baseline activities, such as geophysical and geochemical monitoring.

As required by 40 CFR §146.87, all pre-injection testing procedures for logging, sampling, and testing will be submitted to the Underground Injection Control (UIC) Director for review. The results and data collected during the testing, sampling, and logging operations will be documented in a report and submitted to the UIC Director after the procedures are completed, but before the start of the CO_2 injection operations.

The Bluebonnet Sequestration Hub, LLC will notify the UIC director at least 30 days prior to conducting the tests. Notice and the opportunity to witness these test/logs shall be provided to the UIC Director at least 48 hours in advance of the given procedure.

A table of the wells described in this document is shown in Table POT-1.

Table POT-1: Bluebonnet Sequestration Hub wells.

Well Name	Purpose	Latitude (°)	Longitude (°)	Status
Bluebonnet CCS 1	CO_2 Injector	29.811792	-94.436442	To be drilled
Bluebonnet CCS 2	CO_2 Injector	29.804552	-94.463937	To be drilled
Bluebonnet CCS 3	CO_2 Injector	29.852812	-94.498078	To be drilled
Bluebonnet CCS 5	CO_2 Injector	29.812133	-94.436456	To be drilled
Bluebonnet CCS 6	CO_2 Injector	29.817417	-94.464104	To be drilled
Bluebonnet CCS 7	CO_2 Injector	29.853222	-94.498078	To be drilled
Bluebonnet PRDW F1	Water Producer	29.852293	-94.515401	To be drilled
Bluebonnet PRDW F2	Water Producer	29.810134	-94.497177	To be drilled
Bluebonnet DSW M2	Water Disposal	29.822235	-94.449624	To be drilled
Encanto 01	In-Zone Monitoring	29.844235	-94.456421	Drilled 2022
Bluebonnet IZM FM1	In-Zone Monitoring	29.869496	-94.500751	To be drilled
Bluebonnet IZM M1	Miocene Composite Confining Zone Monitoring	29.824174	-94.472579	To be drilled
Bluebonnet IZM FM2	In-Zone Monitoring	29.821144	-94.42333	To be drilled
Bluebonnet USDW 1	ACZ[1]/USDW[2] monitoring	29.844028	-94.456689	Drilled 2024
Bluebonnet IZM M2	Miocene Composite Confining Zone Monitoring	29.821141	-94.422738	To be drilled
Bluebonnet USDW 2	ACZ[1]/USDW[2] monitoring	29.80423	-94.463443	To be drilled
Bluebonnet IZM M3	Miocene Composite Confining Zone Monitoring	29.86918	-94.500983	To be drilled
Bluebonnet USDW 8	ACZ1/USDW2 monitoring	29.844026	-94.456309	Drilled 2025

(1) ACZ: Above Confining Zone
(2) USDW: Underground Source of Drinking Water

Figure POT-1 and Figure POT-2 show the location of the CO_2 injection wells, in-zone monitoring wells, Miocene Composite Confining Zone monitoring wells, water production wells, water disposal well, and USDW monitoring wells as proposed in the Bluebonnet Hub.

Well diagrams for the CO_2 Injection wells listed in Table POT-1 are presented in the Injector Wells Construction Details Plan of this permit. Well diagrams for the monitoring wells, water production wells, and water disposal well are presented in the Testing and Monitoring Plan.

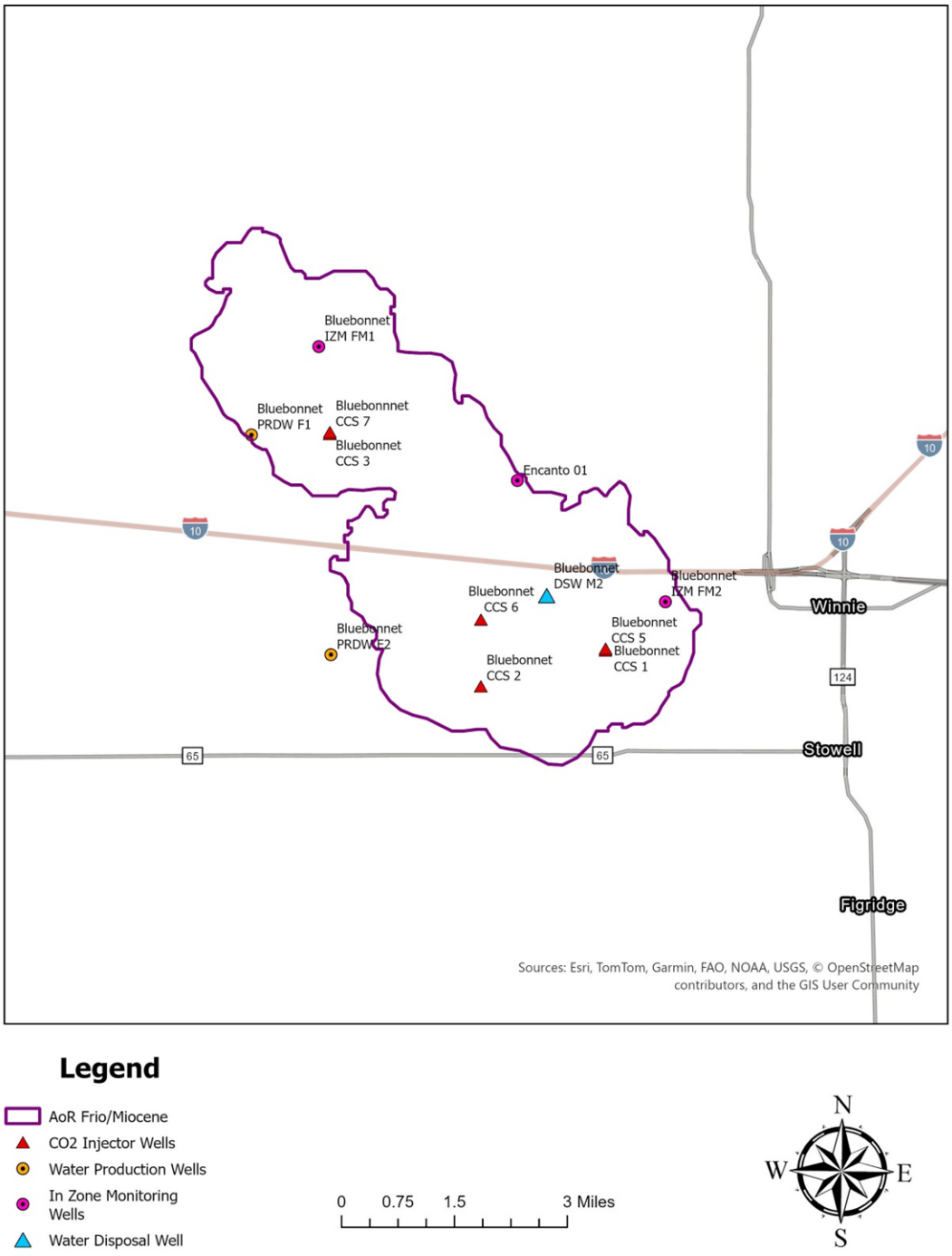


Figure POT-1: Location of CO_2 injector wells, in-zone monitoring wells, water production wells, and water disposal wells for the Bluebonnet Sequestration Hub.

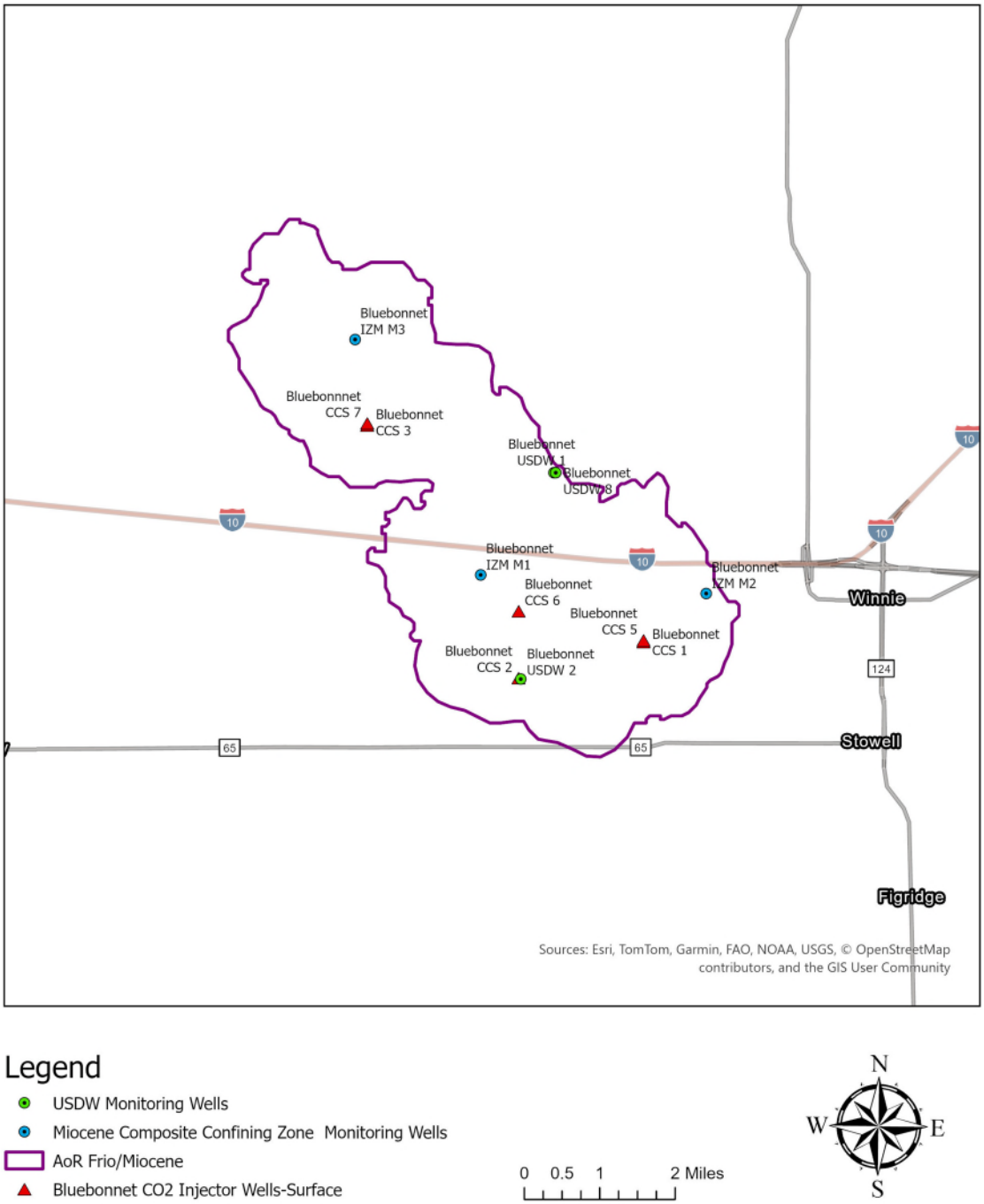


Figure POT-2: Location of CO2 injector wells, Miocene Composite Confining Zone monitoring wells and above-confining-zone/USDW monitoring wells for the Bluebonnet Sequestration Hub.

The Bluebonnet Sequestration Hub, LLC will construct six new CO_2 injection wells, Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CC 5, Bluebonnet CCS 6, and Bluebonnet CCS 7, targeting injection in the Lower Miocene, Frio, and Hackberry sands.

In addition to the injectors, the project will construct two new in-zone monitoring wells (Bluebonnet IZM FM1 and Bluebonnet IZM FM2) and will recomplete the stratigraphic well Encanto 01.

Oxy Low Carbon Ventures, LLC, the parent company of Bluebonnet Sequestration Hub, LLC, drilled the Encanto 01 stratigraphic well in 2022 and acquired advanced geophysical logs as well as 204 ft of full core and 22 sidewall cores (SWC). The project also performed step rate and falloff tests in the prospect reservoirs and leak-off tests in the proposed confining zones. The results and a summary of the data acquisition program for Encanto 01 are shown in Appendix A in the AoR attachment. In May 2024, Encanto 01 was reentered to collect additional water samples from the Frio reservoir. The Encanto 01 stratigraphic well was temporarily abandoned and will be re-completed as an in-zone monitoring well for the project.

The project plans to construct two water producer wells (Bluebonnet PRDW F1 and Bluebonnet PRDW F2) to extract water from the Frio formation as a technique to control the pressure front during the injection phase. These wells will be completed with pressure and temperature sensors downhole and pressure and temperature sensors on the surface.

The project defines the above-confining zone as the first permeable zone above the Miocene Composite Confining Zone. This first permeable formation is the base of the USDW as characterized by Encanto 01 stratigraphic well and mapped laterally though the storage complex.

In May 2024, the project drilled Bluebonnet USDW 1, targeting the shallow aquifers from the surface to 1,500 ft. The main objective of this well was to validate the base of the USDW and determine the water composition of the different flow units as part of the site characterization and baseline for injection operations. The detailed data acquired during Bluebonnet USDW 1 construction is provided in Appendix B in the AoR attachment. Bluebonnet USDW 1 will be used as monitoring well for the shallow aquifer to monitor changes in water composition during the injection and post-injection phases of the project.

In May 2025, the project drilled the Bluebonnet USDW 8 well, targeting the Miocene Composite Confining Zone intershales from the surface to a depth of 2,750 feet. The primary objective of this well was to acquire whole core samples (79 feet) and sidewall cores (35) from the intershales to further characterize the Miocene Composite Confining Zone and conduct sealing capabilities studies. The detailed data collected during the construction of Bluebonnet USDW 8 is currently being integrated and will be included as an appendix to the AoR. Additionally, Bluebonnet USDW 8 will serve as a monitoring well for the shallow aquifer, allowing us to track changes in water composition during both the injection and post-injection phases of the project. The project plans to construct one additional above-confining-zone/USDW monitoring wells (Bluebonnet USDW 2) and three Miocene Composite Confining Zone monitoring wells (Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3). These wells will be used to track changes in pressure, temperature as well as in water composition of the base of the USDW and within the Miocene Composite Confining Zone across the Hub.

The project also plans to drill one water disposal well (Bluebonnet DSW M2) targeting the sands of the Miocene formation above the Lower Miocene Confining Zone. This well will be used to dispose of the water extracted from the Frio formation as well as fluid generated during the construction and operation of the Bluebonnet site.

2.0 Pre-Injection Test Plan – CO_2 Injector Wells

The following tests and logs will be run during drilling, casing installation, and completion of the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injector wells in accordance with the testing required under 40 CFR §146.87(a), (b), (c), (d), and (e).

The CO_2 injection well testing program includes a combination of advanced logging, sidewall coring, fluid sampling, and formation hydrogeologic testing. This program is complemented with an extensive data acquisition program executed in the Encanto 01 stratigraphic well, as well as the data acquisition planned in the additional monitoring wells, water producer wells, and water disposal well.

The pre-operational testing program will measure the depth, fluid salinity, thickness, mineralogy, lithology, porosity, and permeability information of the injection zone, overlying confining zone, and other relevant geologic formations. This data acquisition program will be used to determine conformance with the injection well construction requirements and to establish accurate baseline data for future monitoring activities.

TablesPOT-2 and Table-3 list the logs, tests, and surveys proposed for the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells to comply with 40 CFR §146.87 (a).

Table POT-2: Logging, testing, and surveying plan for CO_2 injector wells – Part 1[(40 CFR 146.87 (a))].

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Open Hole Logs, Surveys, and Sampling During Construction							
Deviation survey [40 CFR §146.87 (a) (1)] – Every 100 ft while drilling, as a minimum	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline - Spontaneous Potential – Surface Casing [40 CFR §146.87 (a) (2) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Correlation log, volume of shale indicator, estimate salinity
Wireline - Resistivity – Surface Casing [40 CFR §146.87 (a) (2) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Fluid identification, estimate salinity, correlation log
Wireline - Density/neutron – Surface Casing [40 CFR §146.87 (a) (3) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Estimate porosity, mineralogical characterization.
Wireline - Sonic dipolar –Surface Casing [40 CFR §146.87 (a) (3) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - High-definition image – Surface Casing [40 CFR §146.87 (a) (3) (i)]	800 to 3,400 ft	800 to 3,300 ft	800 to 3,300 ft	n/a	800 to 3,300 ft	n/a	Identify fracture, structural information, minimum stress orientation
Wireline - Caliper – Surface Casing [40 CFR §146.87 (a) (2) (i)]	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	Identify borehole enlargement and calculate cement volume.

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Open Hole Logs, Surveys, and Sampling During Construction							
Wireline - Resistivity – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Fluid identification, estimate salinity, correlation log
Wireline - Caliper – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Define stratigraphy, correlation log, shale indicator
Wireline - Magnetic resonance image – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Estimate porosity, pore size distribution, permeability index
Wireline - Sonic dipolar – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Define uranium-rich formation, clay indicator
Wireline - Density / neutron – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Estimate porosity, mineralogical characterization.
Wireline - High-definition image – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Identify fracture, structural information, minimum stress orientation.

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Open Hole Logs, Surveys, and Sampling During Construction							
Wireline - Litho-scanner or equivalent – Long String Casing [40 CFR §146.87 (a) (3) (i)]	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Identify mineralogy.
Wireline - Formation pressure measurement – Long String Casing – Depths to be selected after drilling	5 points upper Miocene, 3-6 points in Lower Miocene Sands, 3-6 points in Frio Sands, 1-2 points in Hackberry Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands, 3-6 points in Frio Sand	5 points upper Miocene, 3-6 points in Lower Miocene Sands, 3-6 points in Frio Sands, 1-2 points in Hackberry Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands	5 points upper Miocene, 3-6 points in Lower Miocene Sands	Measure formation pressure.
Wireline - Mini Frac with MDT Tool in Confining Zones – Long String Casing	Upper Miocene Shales. Lower Miocene. Anahuac	Upper Miocene Shales. Lower Miocene. Anahuac	Upper Miocene Shales. Lower Miocene. Anahuac	n/a	Upper Miocene Shales. Lower Miocene	n/a	Measure frac gradient in the confining zones.
Mud Logging	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.

Table POT-3: Logging, testing and surveying plan for CO_2 injector wells – Part 2 [(40 CFR 146.87 (a))].

Method	Interval (ft)/Well						Purpose
	Bluebonnet CCS 1	**Bluebonnet CCS 2**	**Bluebonnet CCS 3**	**Bluebonnet CCS 5**	**Bluebonnet CCS 6**	**Bluebonnet CCS 7**	
Cased Hole Logs and Surveys Before Injection							
CBL-VDL-USIT-CCL - Surface Casing [40 CFR §146.87 (a)(2) (ii) - The surface cement log is run while running open hole logs in long string.	Surface to 3,400 ft	Surface to 3,300 ft	Surface to 3,300 ft	3,400 ft to TD	3,300 ft to TD	3,300 ft to TD	Cement bond, casing integrity. Validate external mechanical integrity
CBL-VDL-USIT-CCL - Long string casing [40 CFR §146.87 (a)(3) (ii)] – The well is logged during completions operations.	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long string casing [40 CFR §146.87 (a)(4) (i)]	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long-string, and packer.
Wireline - Activate pulsed neutron, through tubing – Long string casing [40 CFR §146.87 (a)(4) (ii)]	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long string casing [40 CFR §146.87 (a)(4) (iv)]	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.
Fiber Optic - DTS survey – Long-string casing [40 CFR §146.87 (a)(4) (iii)]	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Surface to the top of the shallowest injection zone	Measure the temperature profile on the well from the surface to the top of perforation. Define baseline for monitoring mechanical integrity.

Notes: Logging depths will be adjusted when the wells are drilled.

The long string sections of Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 will be drilled with synthetic based mud to ensure well stability while drilling, logging, and cementing. Therefore, spontaneous potential logs will not be possible to acquire. However, the project proposes additional new generation logs to improve reservoir and confining zone characterizations as described in Table POT-2 above.

The project will not collect full core while drilling the long string section in Bluebonnet CCS 01, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7**.** Only sidewall cores will be collected, as allowed by 40 CFR §146.87 (b). The project team will also collect water samples in the injection zones as shown in Table POT-4.

As part of the data acquisition program for the Bluebonnet Hub, the project acquired reservoir pressure and water samples in 2022 for the Miocene formation in Encanto 01 stratigraphic well as well as for the Frio formation. The water samples were deemed contaminated for the Frio reservoir. In 2024, the project re-entered Encanto 01 and collected four fluid samples from the Frio formation.

In 2024, the project also drilled water well Bluebonnet USWD 1 to acquire water samples in the first and second permeable zone below the shallowest seal, defined as the base of the USDW. In Bluebonnet USDW 1, water samples were collected at the base of the USDW and at the freshwater sands as part of the characterization. A detailed description of the baselines and data collected in Bluebonnet USDW 1 are provided in the AoR attachment in Appendix A.

Table POT-4: Sidewall Cores and Water Sampling for CO_2 Injector Wells (40 CFR 146.87 (b)).

Method	Interval (ft)	Samples	Purpose
Bluebonnet CCS 1 and Bluebonnet CCS 3			
Open Hole – Wireline - Sidewall core samples	Upper Miocene Shales, Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac, Frio Injection Zone, Frio Confining Zone, Hackberry Injection Zone.	20-35 samples at depths to be determined once the well is drilled.	Define porosity and permeability, mineralogy, CO_2 compatibility
Open Hole – Wireline - water samples	Injection zones: Frio and Hackberry	3-5 water samples. Depth to be defined once the well is drilled.	Define fluid temperature, formation pressure, water composition, pH, conductivity, mobility.
Bluebonnet CCS 2			
Open Hole – Wireline - Sidewall core samples	Upper Miocene Shales, Lower Miocene Confining Zone, Lower Miocene Injection Zone, Anahuac, Frio Injection Zone, Frio Confining Zone	20-35 samples at depths to be determined once the well is drilled.	Define porosity and permeability, mineralogy, CO_2 compatibility
Open Hole – Wireline - water samples	Injection zones: Frio	3-5 water samples. Depth to be defined once the well is drilled.	Define fluid temperature, formation pressure, water composition, pH, conductivity, mobility.
Bluebonnet CCS 5, Bluebonnet CCS 6 and Bluebonnet CCS 7			
Open Hole – Wireline - Sidewall core samples	Upper Miocene Shales, Lower Miocene Confining Zone, Lower Miocene Injection Zone	15-20 samples at depths to be determined once the well is drilled.	Define porosity and permeability, mineralogy, CO_2 compatibility
Open Hole – Wireline - water samples	Injection zones: Lower Miocene	3-5 water samples. Depth to be defined once the well is drilled.	Define fluid temperature, formation pressure, water composition, pH, conductivity, mobility.

The project team will record the fluid temperatures and reservoir pressures obtained from the wireline tool while taking the pressure points and water samples (40 CFR §146.87 (c)). The project team also plans to install downhole gauges that will allow us to determine original pressure and temperature at the top of the perforations.

The project team plans to perform the following analysis in the sidewall cores collected from CO_2 injection wells listed in Table POT-5.

Table POT-5: Core analysis to be performed in the rotary sidewall cores (RSWC) samples from CO_2 injector wells.

RSWC Testing
Standard CT scans
High Resolution Core Photography
X-ray Fluorescence
X-ray Diffraction - Bulk and Clay Analysis
Porosity and Permeability @ Net Confining Stress
Laser Particle Size Analysis
Thin Section Petrography
SEM (Scanning Electron Microscopy)
Source Rock Pyrolysis
Mercury Injection Capillary Pressure
High Resolution CT scans
CO_2 Threshold Entry Pressure

The project team will send the water samples to a third-party lab for a complete analysis, including pH, conductivity, major cations, major anions, trace metals, dissolved gases, density, and TDS, amongst others. Table POT-6 shows the minimum analytics to be characterized in the downhole water samples (40 CFR §146.87 (d)(3) and 40 CFR §146.87 (c)).

Table POT-6: Analyses and methods for water samples testing in the reservoir and overburden.

Parameter	Analytical Method
Cations: Al, Ba, B, Cd, Ca, Cu, Cr, Fe, Pb, Li, Mg, Mn, Ni, P, K, Si, Na Sr, Zn	ICP-OES, EPA Method 6010d, ICP-MS Method 200.8 or equivalent
Other Metals: As, U, Co, Se, Pb, Mo, V	ICP-MS Method 200.8 or equivalent
Mercury	EPA 245.7 CVAA, or equivalent
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-, $NO2^-$	Ion Chromatography, EPA Method 300.1 or similar
Carbonate, bicarbonate and hydroxide	Titration, ASTM D3875.
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C, ASTM D5907 or equivalent
Water Density	ASTM D5057, ASTM D4052 or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas Bench and CF-IRMS for $^{13/12}C$
Radiocarbon 14C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, ASTM 1945D, RSK 175 or equivalent
pH (lab)	ASTM D1293, EPA 150.23 or equivalent
Temperature (lab)	ASTM 2550
Conductivity (lab)	ASTM D1125
Conductivity (field)	EPA 120.1
ICP-OES = inductively coupled plasma optic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; GC/MS = gas chromatography–mass spectrometry; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: Cold Vapor Atomic Absorption; DIC: Dissolved Inorganic Carbon	

The static fluid level of the injection zones will be determined after well completion during the step rate test, injectivity tests, and falloff tests (40 CFR §146.87 (c)). The Bluebonnet Sequestration Hub, LLC will not acquire fluid samples though the open hole DST, by performing a pump off or swabbing after the well is completed, due to the potential for sand production when negative drawdown is applied to the reservoir, which could damage the well.

To comply with 40 CFR §146.87(d), the data to be acquired in the proposed Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 injection wells will include logging, formation pressure testing in the injection zones, mini frac test in the confining zones, rotary sidewall core sampling and analyses, and hydrogeologic testing to determine the physical and chemical characteristics of the injection and confining zones. This data will allow calibration of the data acquired in 2022 in the Encanto 01 stratigraphic test well during the initial site characterization and will further serve as a baseline prior to commencing CO_2 injection.

Upon completion and prior to injection in the Bluebonnet CCS 1, Bluebonnet CCS 2, Bluebonnet CCS 3, Bluebonnet CCS 5, Bluebonnet CCS 6, and Bluebonnet CCS 7 wells, the project team will conduct the tests described in Table POT-7 to verify hydrogeologic characteristics of the injection zone, define fracture pressure for the injection zone, and identify the maximum parameters for injection **(**40 CFR 146.87 (d) (1) and 40 CFR 146.87 (e))**.**

Table POT-7: Step rate test, injectivity test, and falloff test in CO_2 injectors.

Method	Comments
Step Rate Test (SRT) (Injection Target)	Determine the fracture pressure in the injection zone and define the rate of injection for the injectivity and falloff test.
Injectivity Test (Injection Target)	Evaluate injectivity on the well.
Pressure Falloff Test (Injection Target)	Determine transmissibility, skin factor, and well flowing and static pressures.

3.0 Pre-Injection Test Plan – In-Zone Monitoring Wells

3.1 In Zone Monitoring Wells – Bluebonnet IZM FM1 and Bluebonnet IZM FM2.

Bluebonnet IZM FM1 and Bluebonnet IZM FM2 will be new wells drilled as part of the project. Table POT-8 shows the proposed logging, survey, and mud log sampling for these wells.

Table POT-8: Logging, survey and sampling for in-zone monitoring wells.

Method	Interval (ft)		Purpose
	Bluebonnet IZM FM1	Bluebonnet IZM FM2	
Open Hole Logs, Surveys and Sampling During Construction			
Deviation Survey - every 100 ft while drilling as a minimum	Surface to TD	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline - Spontaneous Potential – Surface Casing	Surface to 3,300 ft	Surface to 3,400 ft	Correlation log, volume of shale indicator, estimate salinity.
Wireline - Resistivity – Surface Casing	Surface to 3,300 ft	Surface to 3,400 ft	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Surface Casing	Surface to 3,300 ft	Surface to 3,400 ft	Identify borehole enlargement and calculate cement volume.
Wireline - Resistivity – Long String Casing	3,300 ft to TD	3,400 ft to TD	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Long String Casing	3,300 ft to TD	3,400 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	3,300 ft to TD	3,400 ft to TD	Define stratigraphy, correlation log, shale indicator.
Wireline -Sonic Dipolar – Long String Casing	3,300 ft to TD	3,400 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Density/Neutron – Long String Casing	3,300 ft to TD	3,400 ft to TD	Estimate porosity, mineralogical characterization.
Mud Logging	Surface to TD (every 30 ft)	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and Surveys Before Injection			
CBL-VDL-USIT-CCL –Surface Casing - Surface casing will be logged while running open-hole logs in long string section.	Surface to 3,300 ft	Surface to 3,400 ft	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long String Casing - Long string casing will be logged during well completion.	Surface to TD.	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline - Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	Surface to TD	CO_2 saturation, baseline for monitoring.

Method	Interval (ft)		Purpose
	Bluebonnet IZM FM1	Bluebonnet IZM FM2	
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.
Fiber Optic - DTS Survey – Long String Casing	Surface to TD	Surface to TD	Measure temperature profile on the well from the surface to the top of the perforation. Define baseline for monitoring mechanical integrity.

Notes: Logging depths will be adjusted when the wells are drilled.

Original pressure and temperature in the reservoir will be measured with a downhole gauge installed in the tubing ported to the reservoir below the packer.

3.2 Encanto 01 – Recompletion as an In Zone Monitoring Well

As described in the previous section, the Encanto 01 stratigraphic well will be recompleted as an in-zone monitoring well. In addition to the data acquired during the stratigraphic campaign in 2022 and during the re-entry in May 2024, the well will be tested for mechanical integrity after the recompletion. A pulse neutron baseline will be acquired as well. Table POT-9 shows the logs and tests that will be performed during and after the recompletion of the well.

Table POT-9: Cased hole logs for Encanto 01.

Cased Hole Logs During and After Recompletion as an In-Zone monitoring well		
Method	**Interval (ft)**	**Purpose**
CBL-VDL-USIT-CCL - Long String Casing.	The log will be run after recompletion to validate the quality of the squeeze job proposed.	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline – Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.

The original pressure and temperature in the reservoir will be measured with a downhole gauge installed in the tubing ported to the reservoir below the packer.

4.0 Pre-Injection Test Plan – Water Production Wells

Bluebonnet PRDW F1 and Bluebonnet PRDW F2 will be new wells drilled as part of the project to withdraw water from the Frio Injection target as a technique to manage the pressure increases

in the reservoir. Table POT-10 shows the proposed logging, survey, and mud log sampling for these wells.

Table POT-10: Logging, survey, and sampling for water production wells.

Method	Interval (ft)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey - Every 100 ft while drilling, as a minimum.	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline- Spontaneous Potential – Surface Casing	Surface to 3,200 ft	Correlation log, volume of shale indicator, estimate salinity.
Wireline –Resistivity – Surface Casing	Surface to 3,200 ft	Fluid identification, estimate salinity, correlation log.
Wireline – Caliper – Surface Casing	Surface to 3,200 ft	Identify borehole enlargement and calculate cement volume.
Wireline –Resistivity – Long String Casing	3,200 ft to TD	Fluid identification, estimate salinity, correlation log.
Wireline – Caliper – Long String Casing	3,200 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	3,200 ft to TD	Define stratigraphy, correlation log, shale indicator.
Wireline - Sonic Dipolar – Long String Casing	3,200 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Density/Neutron – Long String Casing	3,200 ft to TD	Estimate porosity, mineralogical characterization.
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and surveys Before Injection		
CBL-VDL-USIT-CCL –Surface Casing - Surface casing will be logged while running open hole logs in the long string section.	Surface to 3,200 ft	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long String Casing - Long string casing will be logged during well completion.	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline – Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.

Note: Logging depths will be adjusted when the wells are drilled.

The original pressure and temperature in the reservoir zone will be measured with a downhole sensor, as part of the downhole completion.

5.0 Pre-Injection Test Plan – Water Disposal Well

The project plans to drill one new Class I well in order to dispose of the water production from the Frio Injection Zone, as well as the fluids generated or used during the construction and operation of the Hub. Bluebonnet DSW M2 will be the well, targeting the upper Miocene Sands located above the Lower Miocene Confining Zone. Table POT-11 shows the proposed logging, survey, and mud log sampling for this well.

Table POT-11: Logging, survey, and sampling for water disposal well.

Method	Bluebonnet DSW M2	
	Interval (ft)	Purpose
Deviation survey – Every 100 ft while drilling as a minimum.	Surface to TD	Define well trajectory, displacement, and tortuosity.
Wireline- Spontaneous Potential – Surface Casing	Surface to 2,300 ft	Correlation log, volume of shale indicator, estimate salinity.
Wireline –Resistivity – Surface Casing	Surface to 2,300 ft	Fluid identification, estimate salinity, correlation log.
Wireline - Density/Neutron – Surface Casing	Surface to 2,300 ft	Estimate porosity, mineralogical characterization.
Wireline - Sonic Dipolar –Surface Casing	Surface to 2,300 ft	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Caliper – Surface Casing	Surface to 2,300 ft	Identify borehole enlargement and calculate cement volume.
Wireline- Resistivity – Long String Casing	2,300 ft to TD	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Long String Casing	2,300 ft to TD	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	2,300 ft to TD	Define stratigraphy, correlation log, shale indicator.
Wireline - Magnetic Resonance Image – Long String Casing	2,300 ft to TD	Estimate porosity, pore size distribution, permeability index.
Wireline -Sonic dipolar – Long String Casing	2,300 ft to TD	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Spectral Gamma Ray – Long String Casing	2,300 ft to TD	Define uranium rich formation, clay indicator.
Wireline - Density/Neutron – Long String Casing	2,300 ft to TD	Estimate porosity, mineralogical characterization.
Wireline - High-Definition Image – Long String Casing	2,300 ft to TD	Identify fracture, structural information, minimum stress orientation.
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and Surveys Before Injection	Surface to 2,300 ft	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long string casing– The well is logged during completions operations.	Surface to TD	Cement bond, casing integrity. Validate external mechanical integrity.

Method	Bluebonnet DSW M2	
	Interval (ft)	Purpose
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string casing and packer.
Wireline - Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	CO_2 saturation, baseline for monitoring.
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.

Note: Logging depths will be adjusted when the wells are drilled.

The original pressure and temperature in the reservoir will be measured with a downhole gauge installed in the tubing ported to the reservoir below the packer.

6.0 Pre-Injection Test Plan – Above-Confining-Zone/USDW Monitoring Wells

Bluebonnet USDW 1 and Bluebonnet USDW 8 were completed to monitor the sands below and above the base of the USWD respectively. Bluebonnet USDW 2 will be used to monitor changes in pressure and the water composition of the USDW. Table POT-12 shows the proposed logging and survey for this well.

Table POT-12: Logging, survey, and sampling for above-confining-zone/USDW monitoring wells.

Method	Interval (ft)	Purpose
Open Hole Logs, Surveys, and Sampling During Construction		
Wireline- Spontaneous Potential – Surface Casing	Surface to TD	Correlation log, volume of shale indicator, estimate salinity.
Wireline –Resistivity – Surface Casing	Surface to TD	Fluid identification, estimate salinity, correlation log.

Note: Details, tools, and procedures for the logging, sampling and tests are described in the QASP attachment to this permit.

7.0 Pre-Injection Test Plan – Miocene Composite Confining Zone Monitoring Wells

Bluebonnet IZM M1, Bluebonnet IZM M2 and Bluebonnet IZM M3 will be used to monitor changes in pressure, temperature and the water composition within the Miocene Composite Confining Zone. Table POT-13 shows the proposed logging and survey for these wells.

Table POT-13: Logging, survey, and sampling for Miocene Composite Confining Zone Monitoring Wells.

Method	Interval (ft)			Purpose
	Bluebonnet IZM M1	**Bluebonnet IZM M2**	**Bluebonnet IZM M3**	
Open Hole Logs, Surveys and Sampling During Construction				
Deviation Survey - every 100 ft while drilling, or during completion	Surface to TD	n/a	n/a	Define well trajectory, displacement, and tortuosity.
Wireline - Spontaneous Potential – Surface Casing	Surface to 1,600 ft	n/a	n/a	Correlation log, volume of shale indicator, estimate salinity.
Wireline - Resistivity – Surface Casing	Surface to 1,600 ft	n/a	n/a	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Surface Casing	Surface to 1,600 ft	n/a	n/a	Identify borehole enlargement and calculate cement volume.
Wireline - Resistivity – Long String Casing	1,600 ft to TD	Surface to TD	Surface to TD	Fluid identification, estimate salinity, correlation log.
Wireline - Caliper – Long String Casing	1,600 ft to TD	n/a	n/a	Identify borehole enlargement and calculate cement volume.
Wireline - Gamma Ray – Long String Casing	1,600 ft to TD	Surface to TD	Surface to TD	Define stratigraphy, correlation log, shale indicator.
Wireline -Sonic Dipolar – Long String Casing	1,600 ft to TD	n/a	n/a	Estimate mechanical properties, validation of velocity model, well tie to seismic.
Wireline - Density/Neutron – Long String Casing	1,600 ft to TD	n/a	n/a	Estimate porosity, mineralogical characterization.
Mud Logging	Surface to TD (every 30 ft)	n/a	n/a	Identify lithology, hydrocarbon shows, gases composition.
Cased Hole Logs and Surveys Before Injection				
CBL-VDL-USIT-CCL – Surface Casing - Surface casing will be logged while running open-hole logs in long string section.	Surface to 1,600 ft	n/a	n/a	Cement bond, casing integrity. Validate external mechanical integrity.
CBL-VDL-USIT-CCL – Long String Casing - Long string casing will be logged during well completion.	1,600 to TD.	n/a	n/a	Cement bond, casing integrity. Validate external mechanical integrity.
Annulus Pressure Test - Long String Casing	Annular between tubing and long string.	n/a	n/a	Validate internal mechanical integrity between the tubing, long string, and packer.
Wireline - Activate Pulsed Neutron, Through Tubing – Long String Casing	Surface to TD	n/a	n/a	CO_2 saturation, baseline for monitoring.

Method	Interval (ft)			Purpose
	Bluebonnet IZM M1	**Bluebonnet IZM M2**	**Bluebonnet IZM M3**	
Wireline - Casing Inspection Tool - Long String Casing	Surface to TD	n/a	n/a	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring.
Fiber Optic - DTS Survey – Long String Casing	Surface to TD	n/a	n/a	Measure temperature profile on the well from the surface to the top of the perforation. Define baseline for monitoring mechanical integrity.