

AREA OF REVIEW AND CORRECTIVE ACTION PLAN**Magnolia Sequestration Project**

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1.0 Facility Information

Facility name: Magnolia Sequestration Project (Magnolia Hub)
Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 Wells

Facility contact: Kelly Watson, Project Manager
5 Greenway Plaza Houston, TX 77046
713-552-8613 kelly_watson@oxy.com

Well location: Allen Parish, Louisiana
Magnolia CCS 1
30° 40' 56.2474" N, 092° 50' 1.2244" W (NAD 27)
30° 40' 56.9387" N, 092° 50' 1.7707" W (NAD 83)
Magnolia CCS 2
30° 41' 40.1623"N, 092° 50' 23.1767"W (NAD 27)
30° 41' 40.8527" N, 092° 50' 23.7241" W (NAD 83)
Magnolia CCS 3
30° 41' 6.1794" N, 092° 50' 24.1145" W (NAD 27)
30° 41' 6.8705" N, 092° 50' 24.6617" W (NAD 83)
Magnolia CCS 4
30° 41' 38.4597" N, 092° 50' 23.1814" W (NAD 27)
30° 40' 39.1501" N, 092° 50' 23.7288" W (NAD 83)

2.0 Computational Modeling Approach

This plan deals with delineating the Area of Review (AOR) and provides corrective actions that are needed in the wells that penetrate the upper confining zone within the AOR. Delineation of the AOR is one of the key elements in Louisiana Class VI Rule to ensure USDWs surrounding the geologic sequestration project may not be endangered by the injection activity.

Both the CO₂ plume and the threshold pressure front are determined using a multiphase CO₂-brine transport model, which is constructed from a sophisticated geologic model that accounts for site-specific hydrogeology. The methods and approaches for developing this complex multiphase simulation model and delineating the AOR are defined below.

2.1 Model background***2.1.1 Model name and authors/institution***

The modeling software is GEM (v2024.10) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd.

2.1.2 Description of model

GEM is a commercially available, compositional, 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: a H₂O-rich phase (liquid), CO₂-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, enthalpy) of the H₂O and CO₂ phases and CO₂ solubility in H₂O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions, including temperature ranges between 12°C (53.6°F) and 150°C (302°F) and pressures up to 110 MPa (15,954.2 psi). Details of this method can be found in Collins et al. (1992), Thomas and Thurnau (1983), and Nghiem and Li (1989).

Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The CO₂-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).
- The CO₂ dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey, 1996).
- The brine density is specified at a reference pressure of 2,400 psi and corrected for local pressure variations using a specified water compressibility, $3.5 \times 10^{-6} \text{ psi}^{-1}$. It is then corrected for the dissolved CO₂ and ionic components using their partial molar volumes. The brine viscosity is calculated using the Kestin (1981) correlation. The details can be found in the publication by Kestin et al. (1981)
- Chemical equilibriums among H⁺, Ca²⁺, Mg²⁺, K⁺, Na⁺, Al³⁺, SiO₂, H₄SiO₄, HCO⁻, OH⁻, CO₃²⁻, CaOH⁺, MgHCO³⁺, 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 CO₂. 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 (Thibau, 2007) which were also used in a simulation study by Nghiem et al. (2004).
- The CO₂ 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:

$$P = \frac{RT}{(v - b_{\text{mix}})} - \frac{a_{\text{mix}}}{(v^2 + 2vb_{\text{mix}} - b_{\text{mix}}^2)} \quad \dots\dots\dots \text{(Equation 1)}$$

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 CO₂ and CH₄, based on Reid et al. (1977). No changes were made to the library components.

The transition between liquid and gaseous CO₂ 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 CO₂ region.

Because the compression facility controls the CO₂ delivery temperature to the injection well to keep it between 80°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 22 °C/km (0.0122 °F/ft) and a surface temperature of 86°F (Nicholson, 2012).

With respect to the time step selection, the software algorithm optimizes the time step duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the time step size ranged from 0.001 to 10 days. In all cases, the maximum solution change over a time step is monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of the saturation and pressure calculation results occur on successive iterations. New time steps are 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 CO₂ during injection periods. However, upon cessation of CO₂ injection, mineral precipitation (e.g., calcite) occurs over long timescales (100s of years). Results suggest geochemical reactions play a key role in long-term permanent (mineralized) sequestration of injected CO₂ as well as reduction in potential stray CO₂ migration due to porosity loss from mineralization in the reservoir.

2.2 Site geology and hydrology

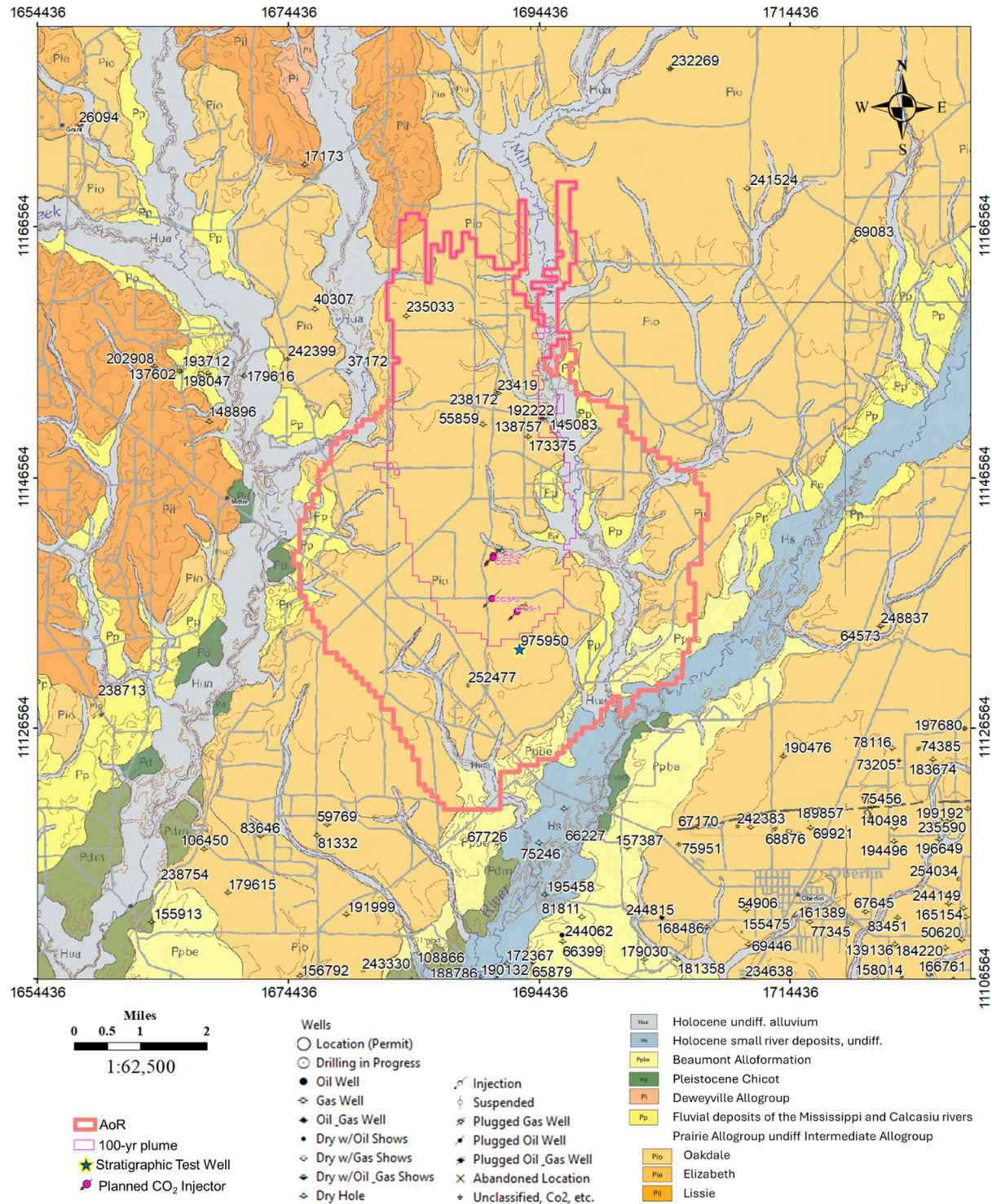
The Magnolia site subsurface characterization was initially conducted based on understanding of regional geology from published cross sections, papers, and publicly-available well data [e.g. Bebout and Gutierrez, 1982; see Narrative (NAR) for details]. Further evaluation has been conducted both regionally and locally for the area pertaining to the Magnolia Sequestration Project that includes the proposed Magnolia CCS 1, Magnolia CCS 2, Magnolia CCS 3, and Magnolia CCS 4 CO₂ injectors as well as the YAMS MLR 004 (SN 975950) Class V stratigraphic test well drilled in November 2022. The subsurface evaluation synthesizes information from published literature, publicly-available well data, Oxy-licensed 2D seismic data, and Oxy-proprietary petrophysical interpretation; the evaluation incorporates rock, formation, and fluid data collected from the YAMS MLR 004 (SN 975950) stratigraphic test well.

The Magnolia Sequestration Project is situated in the Gulf Coastal Plain, a low-relief region traversed by rivers draining the North American continental interior that navigate through and rework Holocene and Pleistocene sediment (Renkin, 1998). Hence, surface geology is dominated by alluvial and fluvial late Tertiary to Quaternary deposits of the Calcasieu River and its tributaries (USGS, 2023). Surface geology is characterized in the Ville Platte, Louisiana geologic quadrangle shown in Figure AOR-1. The majority of the site lies on top of the Oakdale alloformation Pleistocene-age alluvial deposits. On the Western side, Holocene age

undifferentiated alluvium deposits fill the valleys cut by Mill and Ten Mile Creeks. To the North lies an early Pleistocene age alluvial deposit known as the Elizabeth alloformation. Driller's logs from wells in the AOR (Research Labokay-01, SN 238172) report clay, fine sand, and pea gravel from 1 – 140 ft below ground level. Regional surface elevation averages 85 ft above mean sea level and dips gently southward towards the coastline.

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2.2.1 Stratigraphy and Depositional History

The Magnolia Sequestration Project targets strata of Oligocene through Early Miocene that are buried at a depth favorable for CO₂ sequestration: deeper than supercritical CO₂, not so deep as to be overpressured, and with thousands of feet of strata with sealing capabilities between the uppermost injection zone and base of underground sources of drinking water (USDW) (Figure AOR-2). The gross stratigraphic framework for subsurface zonation, shown in Figures AOR-3 and AOR-4, is based on published literature on Louisiana state geology and southwestern Louisiana hydrologic units (e.g. Bebout and Gutierrez, 1982, Swanson et al., 2013, LSU, 2020; USGS, 2023).

The storage complex is divided into (from bottom to top) the Vicksburg Lower Confining Zone, Frio Injection Zone, Anahuac Intermediate Zone, and Lower Miocene Upper Confining Zone.

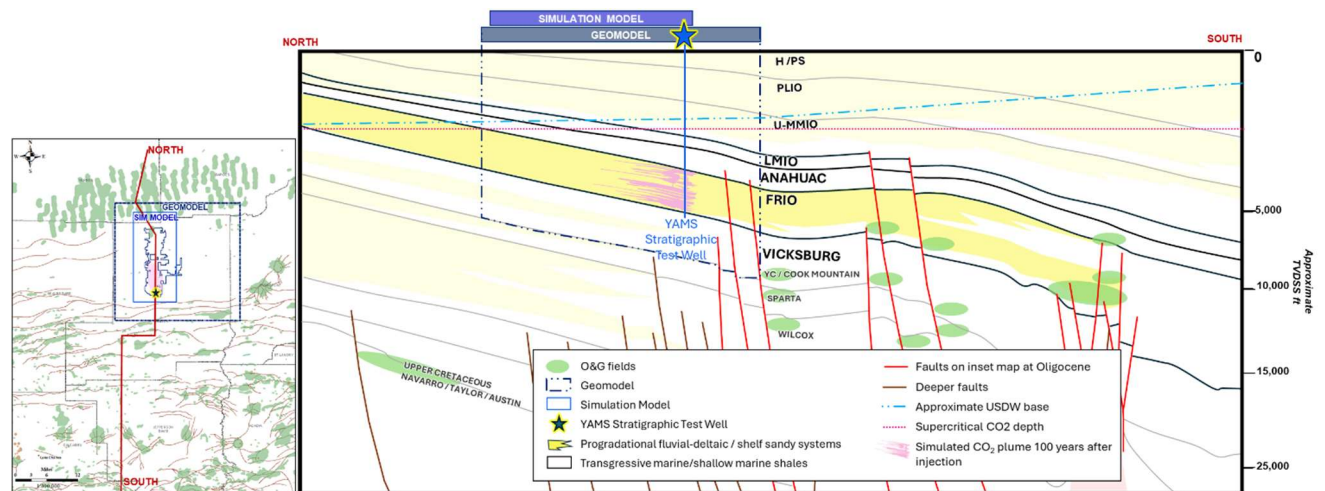
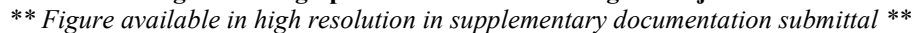


Figure AOR-2—Regional N-S dip line schematic through Magnolia Sequestration Hub shows regional stratigraphy and dip relative to supercritical CO₂ depth and base USDW. Interpreted from 2D seismic and published well tops.



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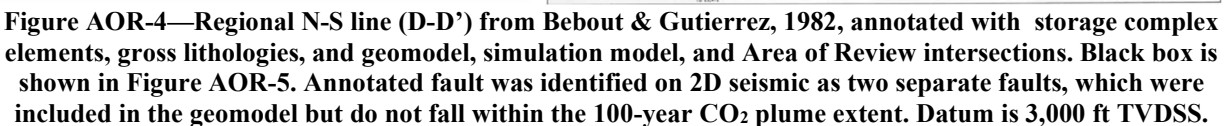


Figure AOR-5 shows that regional zonation (annotated in black all capitals) and local zonation (colorful labels) are in excellent agreement with the AOR, with the Frio injection zone subdivided into eight total parasequence-scale zones composed of basal shales coarsening up into sandy tops. The parasequence base shales correlate through the geomodel area, have low permeability, and are modeled as confining zones (2.3 and 2.4 and NAR Section 2.4). The base USDW was interpreted in the area using tops and the methodology published by DENR (2020) (now known as the Louisiana Department of Conservation and Energy or “C&E”) as described in NAR Section 2.2.8 (see figures NAR-41 and NAR-42 for a map and cross section of interpreted USDW base). Also shown is the top of overpressure from Bebout & Gutierrez (1982). Finally, the YAMS MLR 004 (SN 975950) well is projected into the section to show the regional correlatability of confining zones and injection targets. Faults 1 and 2, which were mapped on

2D seismic and included in the geomodel, are depicted on the southern end of the line. See Section 2.3.1 for additional discussion of how faults were incorporated into the model, and NAR Sections 2.1.3 and 2.2.1.1 for description of how faults were identified and tied to regional data.

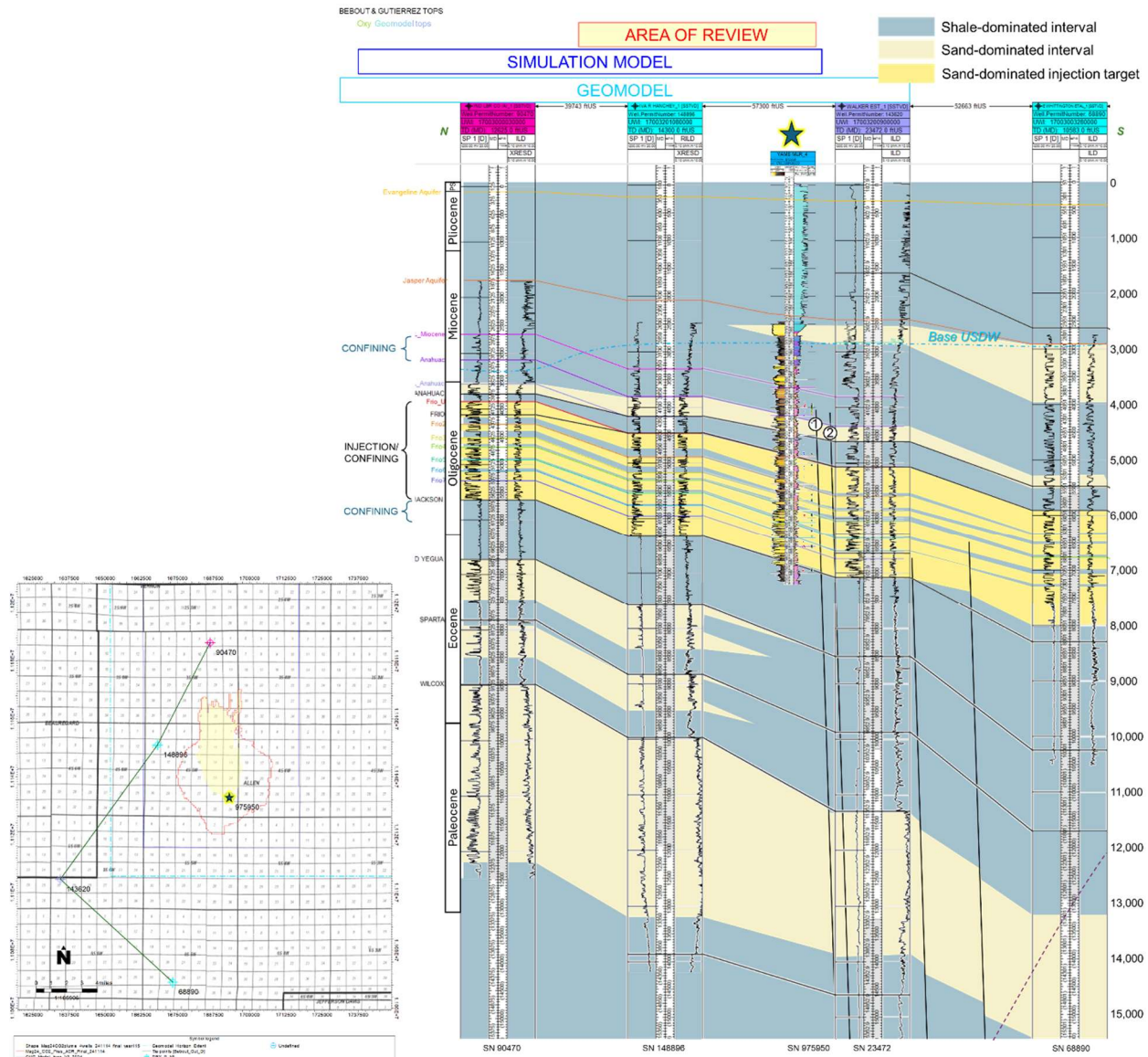


Figure AOR-5—Subregional N-S line recreated from northern end of Bebout & Gutierrez line D-D' (1982). Upper Confining, Injection/Confining, Base Confining zones are annotated, as is interpreted base USDW and top of overpressure from Bebout & Gutierrez, 1982. Geologic age listed on left side of figure next to published tops (black capital letters) and geomodel tops (colorful). Note Frio is annotated as both injection and confining due to presence of parasequence base shales. YAMS MLR 004 (SN 975950) stratigraphic well projected in from the east. Datum is 0 ft TVDSS.

**** Figure available in high resolution in supplementary documentation submittal ****

2.2.2 Deformational/tectonic history

A synthesis of regional and local data demonstrates that no through-going or transmissible faults are present within the storage complex across the calculated CO₂ plume extent. The Southern

edge of the AOR as defined by the threshold pressure front interacts with a through-going fault, however the maximum pressure increase calculated along the fault is an order of magnitude lower than calculated pressure increase required to induce shear failure (see Figures AOR-30 and AOR-31). Regional sources evaluated include published papers, consortia fault sets, and regional licensed databases.

See NAR Section 2.1.3 (Structural Geology) and NAR Section 2.2.1.1 (Faults) for details.

2.2.3 Geopressure

The USGS study of mudweight trends along the Gulf Coast (Burke et al., 2013) show that in the Magnolia Hub area, depth to top of overpressure is >11,000 ft TVDSS (Figure AOR-6). Published regional cross sections through the area annotated with top of overpressure identified on sonic/resistivity logs agree with this estimate (e.g., Figure AOR-4, Bebout & Gutierrez, 1982). The total depth (TD) of most wells within the Magnolia Hub are above this depth. Additionally, the wells do not show signs of a deflection in sonic and resistivity that suggest increase in pore pressure beyond hydrostatic. Modular Formations Dynamics Tester (MDT) pressure data collected in the YAMS MLR 004 (SN 975950) well show a pressure-depth trend following hydrostatic, albeit slightly underpressured. Figure AOR-7 shows a pressure-depth plot for the YAMS MLR 004 (SN 975950) well and mudweight data from wells in the area that were published in Burke et al., 2013. These mudweights show a conservative top of overpressure around 11,000 ft below ground level, which is approximately 4,000 feet deeper than the base injection zone.

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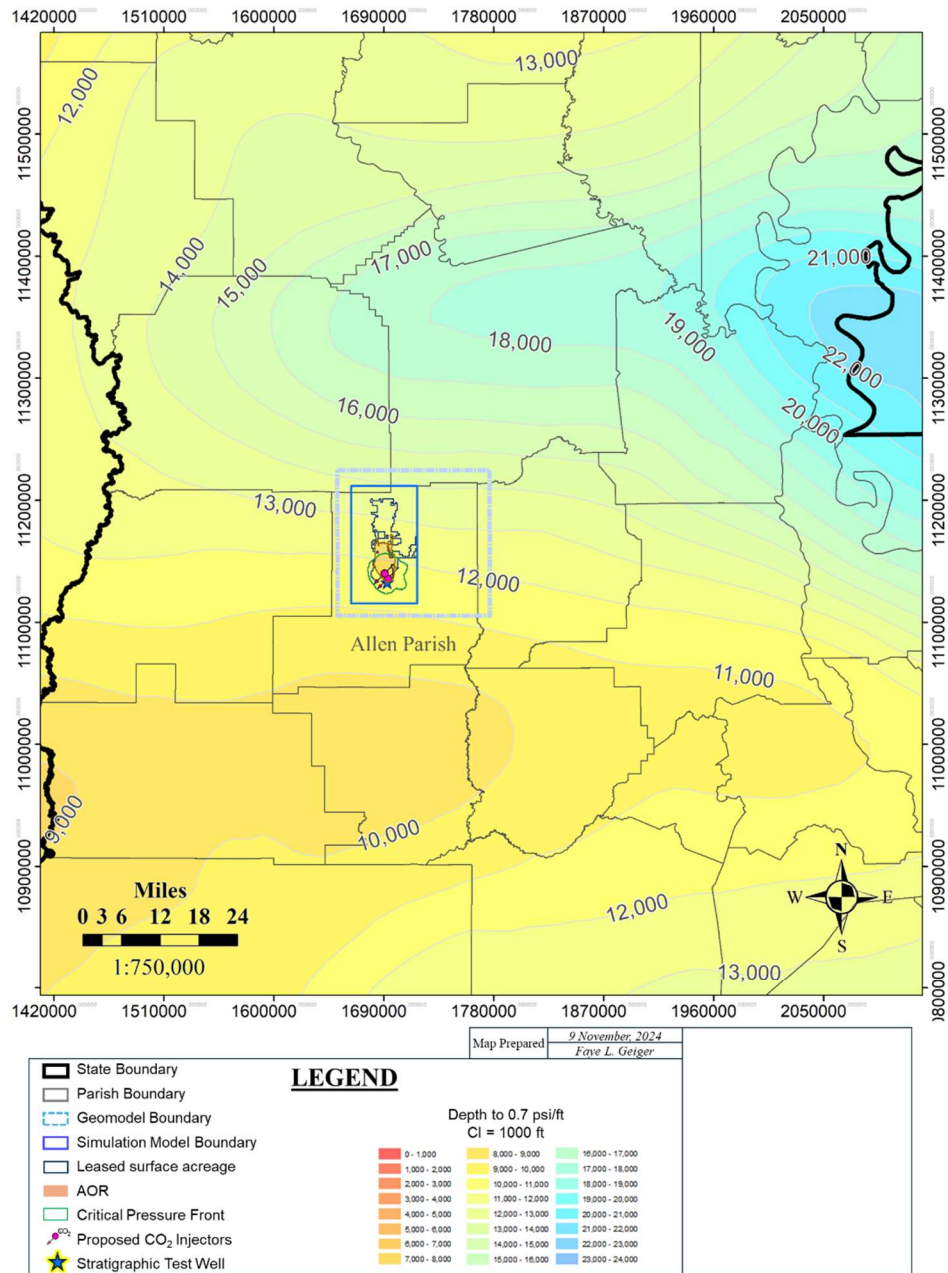


Figure AOR-6—Depth to 0.70 psi/ft mudweight density from USGS (Burke et al., 2013) The pressure gradient in the Magnolia Sequestration Project site reaches 0.70 psi/ft between 11,000 – 14,000 ft

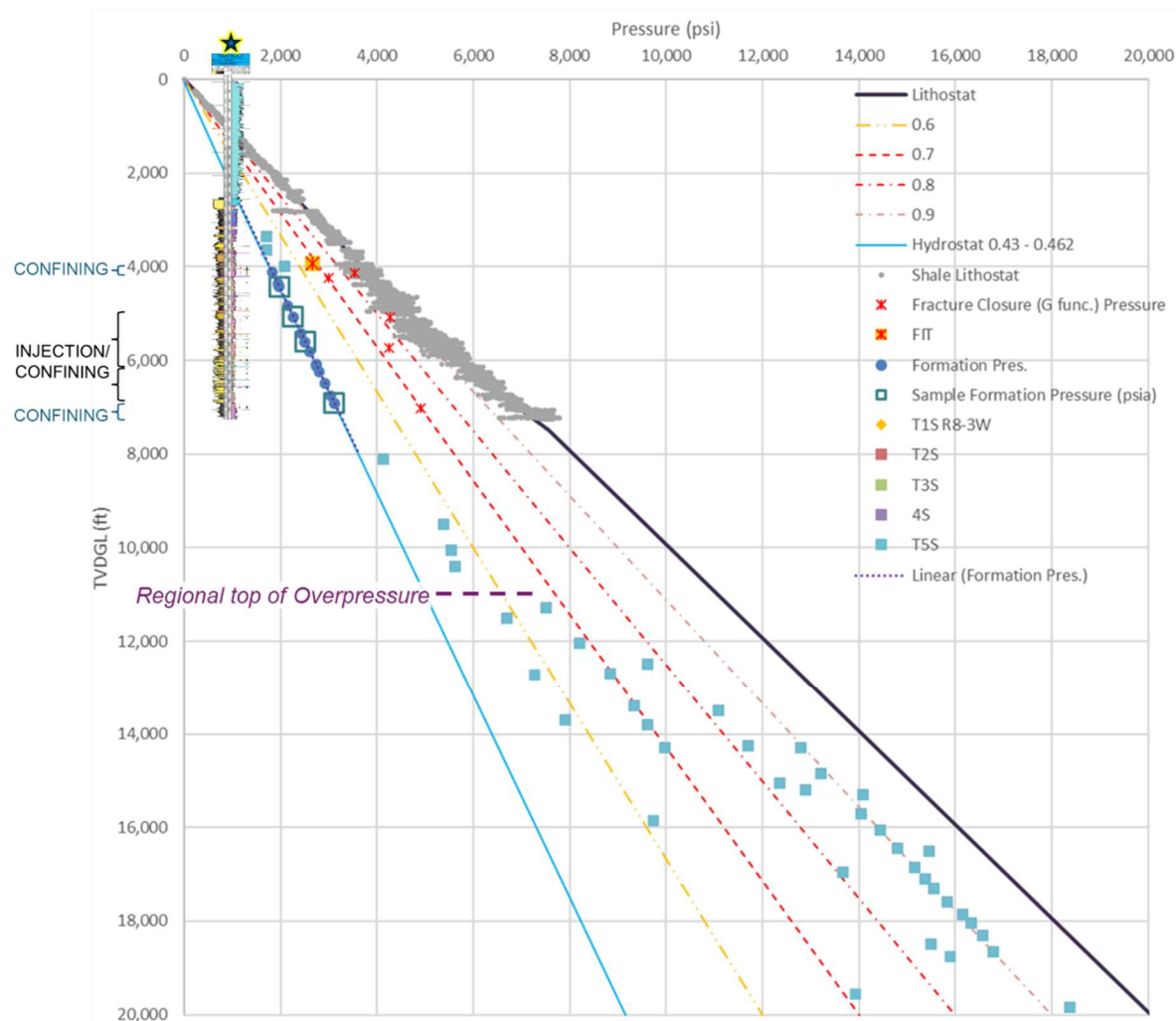


Figure AOR-7—Pressure-depth plot of data collected from the YAMS MLR 004 (SN 975950) well in context of regional mudweight data published by Burke et al., 2013. Shale-only density curve-based lithostat from YAMS MLR 004 (SN 975950) well is projected deeper using 1 psi/ft gradient. Hydrostat shown is combination of fresh (0.43 psi/ft from 0-2990' TVDGL) and saline (0.462 psi/ft >2990' TVDGL). Blue dots are formation pressures from MDT probe. Red stars defining approximate fracture gradient are fracture closure pressures and FIT pressure. Blue boxes are wells from T5S, R1W, 2W, 3W, 5W, 6W, 7W, and 9W (Burke et al, 2013).

2.2.4 Site Hydrology

Groundwater and surface water interactions occur near several major inland bodies of water found within Allen Parish (Figure AOR-8). The Calcasieu River runs from northeast to southwest across the Parish, passing near the southeastern side of the Magnolia Sequestration Project. Mill Creek runs north to south along the eastern margin of the Magnolia Sequestration Project site. Whiskey Chitto Creek and Ten Mile Creek are present along the western side of Magnolia Sequestration Project. No springs occur within the project site.

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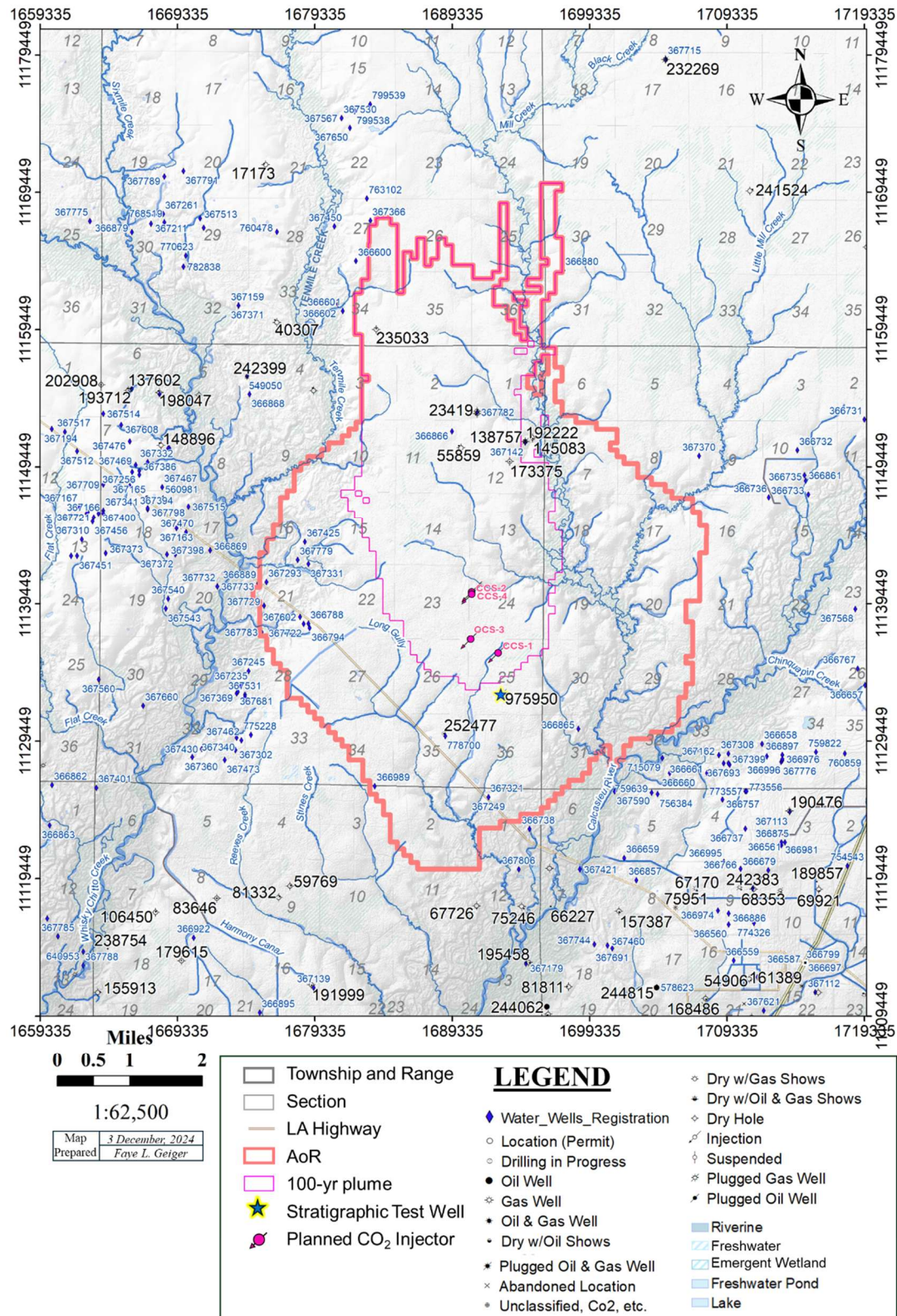


Figure AOR-8—Surface hydrology of the Magnolia Hub with a focus on Area of Review. Oil and gas wells are labeled with serial number in black; water wells are labeled with serial number in blue.

2.3 Model domain

To model supercritical CO₂ movement through the subsurface, a static geological model was created using Schlumberger Petrel (v2021) and dynamic simulations were completed in CMG on a subvolume large enough to model migration of the CO₂ plume during injection and post-injection. Figure AOR-9 shows the extent of the static geomodel and dynamic simulation model, the AOR, planned injector locations, YAMS MLR 004 (SN 975950) stratigraphic test well, and 201 wells for which the project team interpreted tops to understand regional zonation. These wells are also listed in AOR Table 28 in Appendix B.

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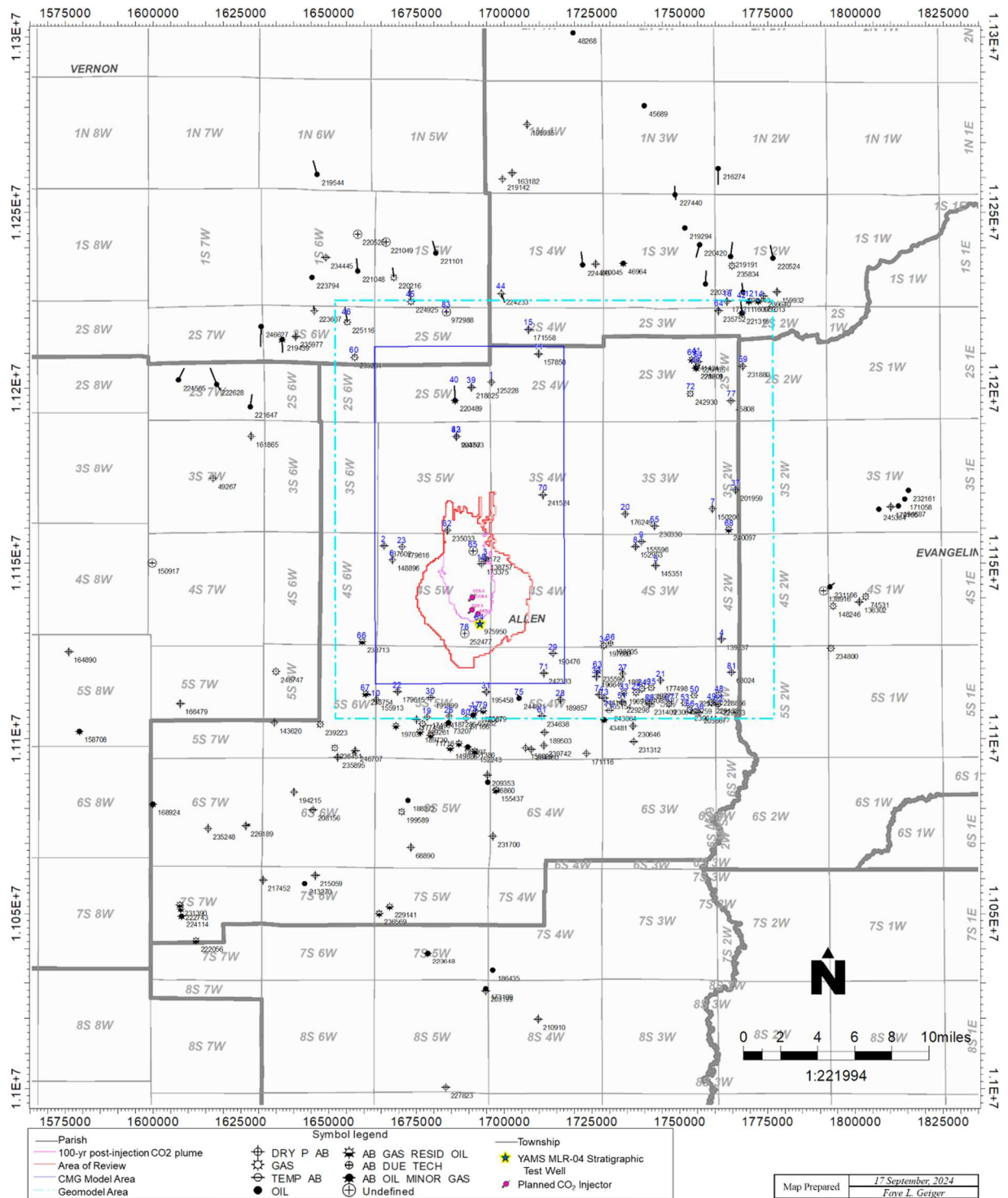


Figure AOR-9—Wells, labeled with state serial number, used in regional mapping to define zonation extend beyond the edges of the static geomodel, which itself is large enough to preclude edge effects in dynamic simulation model. All wells on map have tops that were used in regional correlation and are listed in Table AOR-29. Wells with blue label are a subset with tops that were used to define structural grids within the Geomodel, and are listed in Table AOR-31.

Geomodel creation was based on interpretation of publicly-available well log data; data collected from the YAMS MLR 004 (SN 975950) including log, whole rock, and fluid lab analyses; petrophysical interpretation of wells in the area; regional published studies; and in-house 2D seismic time data. Figure AOR-12 shows 2D seismic data that were used to interpret faulting in the area.

Figure AOR-10 depicts the 69 wells with digital log coverage and quality sufficient for petrophysical analysis; the 54 wells within the geomodel footprint had curves input to the model (Please see Appendix B: Tables of Wells Table 29 for a list of all wells with petrophysics).

Geomodel model dimensions are 22 miles north to south, 23.5 miles west to east, and approximately 3,500 feet from top to base. Grid cell size throughout the geomodeled area is 500 ft x 500 ft x 10 ft. The final geologic model is represented by a 250 x 233 x 313 grid in a Cartesian system with 250 grid cells in the I-direction, 233 grid cells in the J-direction, and 313 grid cells in the K-direction, for a total of 18.23 million active grid cells. Table AOR-1 summarizes the geomodel dimensions and coordinate reference system.

The dynamic simulations were carried out in 3D using full physics, an Equation of State, and a sector of the geologic model encompassing a 10.4×18.7 square mile area; the model dimensions and CRS are summarized in Table AOR-2. The dynamic reservoir simulation was performed with the same scale grid as the static geologic model (500 ft x 500 ft x 10 ft). A 6.8-million-cell sector model was then extracted with grid dimensions of 110 (I) x 197 (J) x 313 (K) grid cells. No upscaling was performed. Model domain coordinate reference system is summarized in Table AOR-2.

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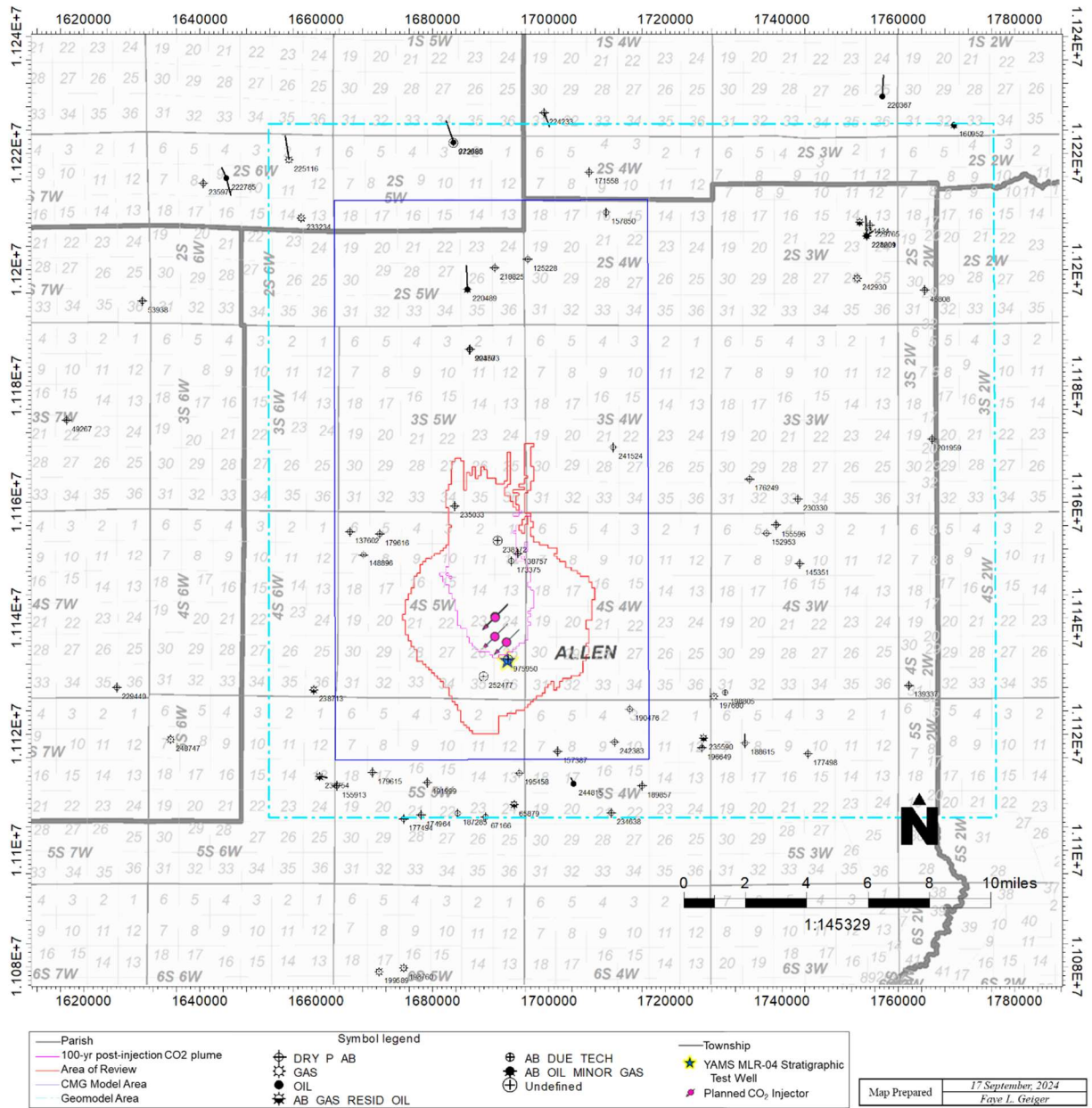


Figure AOR-10—Wells with petrophysical interpretation of V_{shale} and porosity logs, which were used for property distribution within the geomodel. Wells with petrophysical interpretation are listed in Table AOR-30.

Table AOR-1—Geologic Model Domain Information

Coordinate System	NAD 27 BLM Zone 15N		
Horizontal Datum	GCS North American 1927		
Coordinate System Units	ft US		
Zone	BLM Zone 15N		
FIPZONE	1702	ADZONE	4501
Coordinate of X min	1651575.74	Coordinate of X max	1776824.19
Coordinate of Y min	11105774.69	Coordinate of Y max	11225254.67
Elevation of top of domain	-1773	Elevation of bottom of domain	-7993

Note: FIPZONE is a geologic area defined by a Federal Information Processing Standard (FIPS) code

Table AOR-2—Dynamic Simulation Model Domain Information

Coordinate System	NAD 27 BLM Zone 15N		
Horizontal Datum	GCS North American 1927		
Coordinate System Units	ft US		
Zone	BLM Zone 15N		
FIPZONE	1702	ADZONE	4501
Coordinate of X min	1662625.12	Coordinate of X max	1718039.52
Coordinate of Y min	11111033.09	Coordinate of Y max	11212825.86
Elevation of top of domain	-2092	Elevation of bottom of domain	-7698

Note: FIPZONE is a geologic area defined by a Federal Information Processing Standard (FIPS) code

2.3.1 Model geologic structure

The structural framework of the geologic model was based on regional well data correlation (e.g. Figure AOR-9) that was refined and curated over the geomodel area with input from interpretation of licensed 2D seismic time data (see Figure AOR-12 for footprint). The gross framework defined by the Lower Miocene, Anahuac, Frio, and Vicksburg was refined by identifying parasequence sets composed of a sandy upper portion and shaley lower portion within the Anahuac and Frio. Careful correlation of these tops across 84 wells within the geomodel resulted in 19 horizons that defined the 18 zones within the geomodel, shown in Table AOR-3. Figure AOR-11 shows how horizons were correlated through the geomodel on an east-west cross section. Depth structure maps for these 19 input horizons are available in Appendix B of the Narrative.

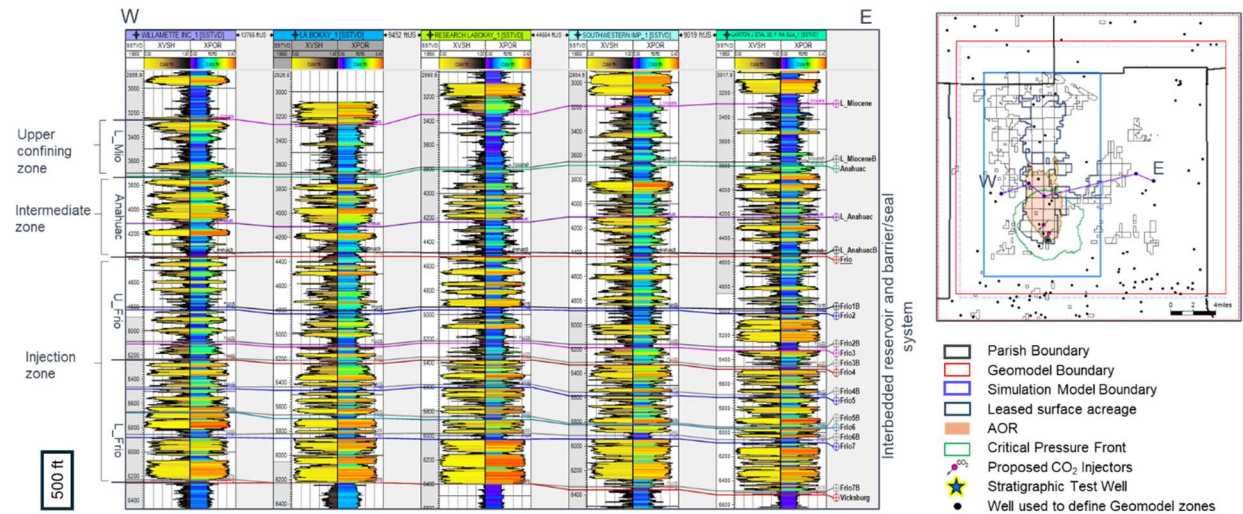


Figure AOR-11—West to East structural cross section demonstrating horizon correlation through the geomodel based on log character. Wells are shown as spaced evenly in the Figure; actual distances are noted between wells and vary from 9,000 to 45,000 ft.

**** Figure available in high resolution in supplementary documentation submittal ****

The 2D seismic data is of various sources and vintages acquired since the 1960s. Significant 2D line mis-ties were unable to be resolved and determined to likely result from navigation issues. The time-depth relationship was established with seismic well ties (shown in Figure NAR-22) and a regional velocity model was created using well-tied horizons to generate average velocities. The 2D line mis-ties resulted in structural artifacts in the depth-converted structure maps when attempting to incorporate depth converted 2D horizons. As such, the depth converted seismic horizons were not input to the model's structural framework. However, two correlatable faults were mapped in depth across multiple 2D lines that offset the storage complex within the Geomodel footprint and were incorporated into the model; these faults are shown in map view in Figure AOR-12 and in section view in Figure AOR-13. Faults 1 and 2 are located on the southern end of the geomodel and corroborate the regional faulting framework shown in Figure NAR-13. Both Faults 1 and 2 have offset from the base of the model through the Lower Anahuac. The Upper Anahuac and Lower Miocene do not have offset.

Figure AOR-13 shows how structural dip within the geomodel is nearly homoclinal down to the SSE; values range from 1.13 degrees in the Lower Miocene at the top of the model to 1.42 degrees for the Vicksburg, which defines the base of the model (Table AOR-3).

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**Table AOR-3—Tabulation of geomodel input horizon depth ranges, average structural dip and azimuth.
Average thickness of zones defined by horizons is last column.**

Regional Zone	Storage Element	Horizon Name	Horizon Depth Ranges (ft TVDSS)		Mean Dip Angle (°)	Mean Dip Azimuth (°)	Zone thickness (ft)
			Shallowest	Deepest			
Lower Miocene	Upper Confining	L_Miocene	1778	4468	1.13	167	537
		U_Anahuac	2327	4998	1.14	167	356
Anahuac	Intermediate	L_Anahuac	2640	5422	1.18	167	286
		L_Anahuac_B	2834	5888	1.25	165	36
Upper Frio	Injection	Frio1	2889	5934	1.25	165	384
	Confining	Frio1_B	3239	6220	1.23	166	34
	Injection	Frio2	3267	6248	1.23	166	250
	Confining	Frio2_B	3426	6619	1.30	167	23
	Injection	Frio3	3450	6642	1.29	167	122
	Confining	Frio3_B	3578	6780	1.31	167	24
	Injection	Frio4	3604	6804	1.30	167	220
	Confining	Frio4_B	3802	7129	1.34	166	22
	Injection	Frio5	3821	7163	1.33	166	209
	Confining	Frio5_B	4029	7398	1.35	165	21
Lower Frio	Injection	Frio6	4063	7425	1.35	166	132
	Confining	Frio6_B	4195	7530	1.35	165	26
	Injection	Frio7	4235	7565	1.32	166	269
	Confining	Frio7_B	4432	7723	1.36	165	91
		Vicksburg	4439	7793	1.42	167	

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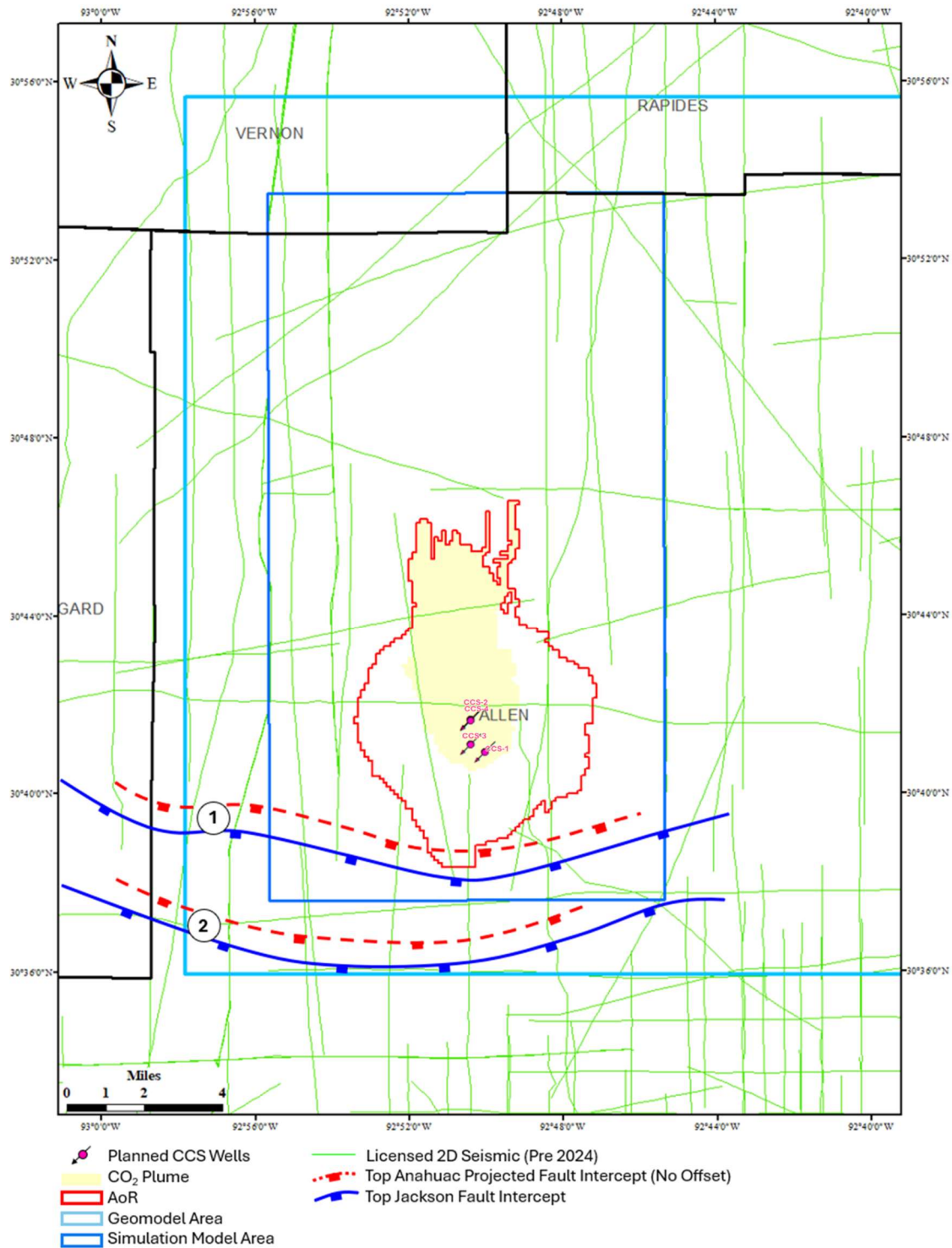


Figure AOR-12—2D seismic data set used for Geomodel fault mapping with faults incorporated into Geomodel labeled.

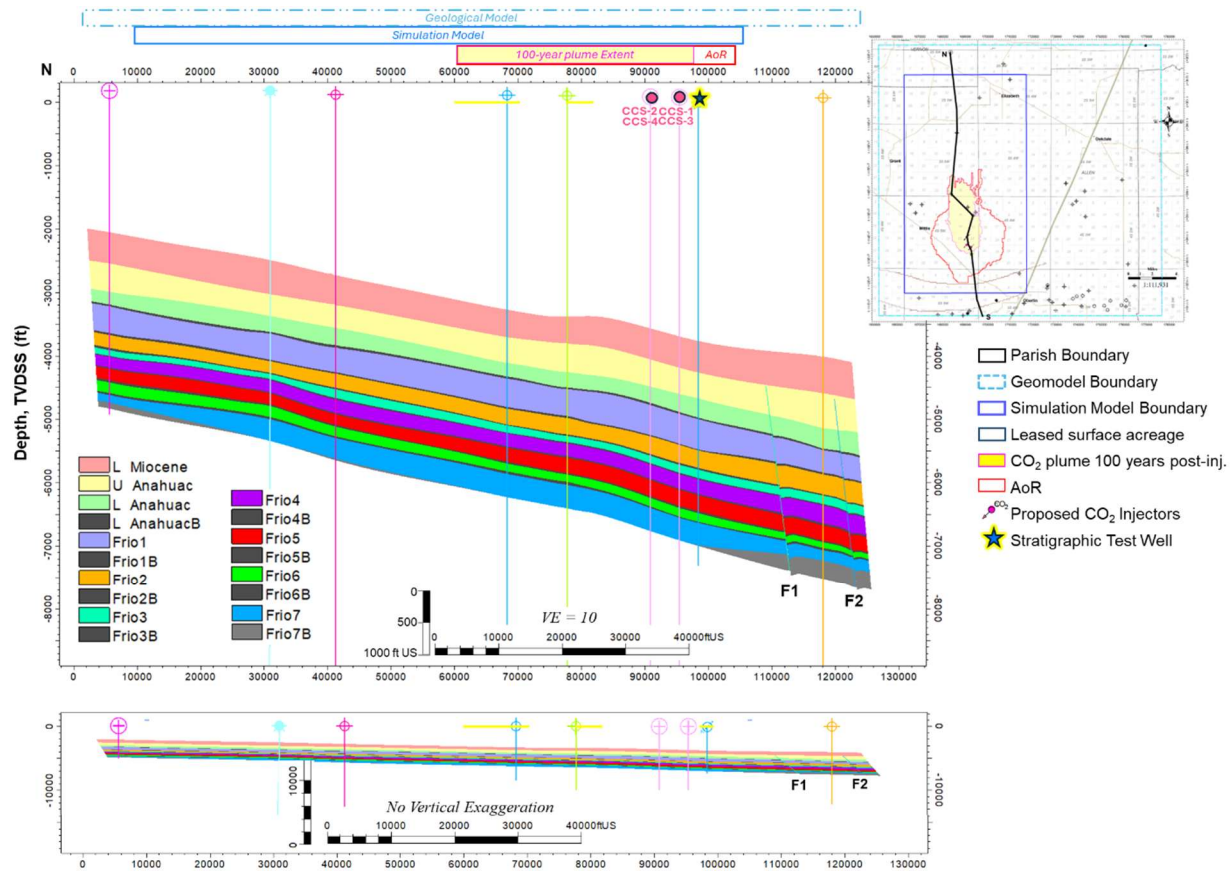


Figure AOR-13—View to ENE through 3D geologic model showing model layers and faults through full model (top), where offset on Faults 1 and 2 is observable through the Lower Anahuac. 100-year CO₂ plume is north of both faults. Bottom cross section is at no vertical exaggeration. Wells shown on cross section and map are a subset of those used to create geologic model structure.

**** Figure available in high resolution in supplementary documentation submittal ****

2.3.2 Geologic model zones and layering

Nineteen horizons were mapped that define 18 total model zones, which comprise five major stratigraphic zones. The L_Miocene zone comprises the Lower Miocene Upper Confining System; U_Anahuac L_Anahuac, and L_Anahuac_B comprise the Anahuac Intermediate/Confining Zone. The Frio1, Frio1B, Frio2, Frio2B, Frio3, Frio3B, Frio4, and Frio4b comprise the Upper Frio Injection/Confining Zone; Frio5, Frio5B, Frio6, Frio6B, Frio7 comprise the Lower Frio Injection/Confining Zone. The Frio7B is the top of the Lower Confining zone, which includes and is dominated by the Vicksburg shale. The 18 zones imported into CMG BUILDER are summarized in Table AOR-4. In several of the injection zones (Frio1, Frio4, Frio5, Frio6, and Frio7), very thin shales that did not map regionally, but are interpreted to be inherently part of the progradational/aggradational delta system, were represented in simulation by assigning a transmissibility multiplier between layers to mimic these baffling elements. For example, Figure AOR-14 shows dashed dark grey lines where intra-formational thin shales can be locally correlated; these are labeled with the suffix “ib”. Table AOR-4 enumerates where baffling shales were modeled with transmissibility multipliers.

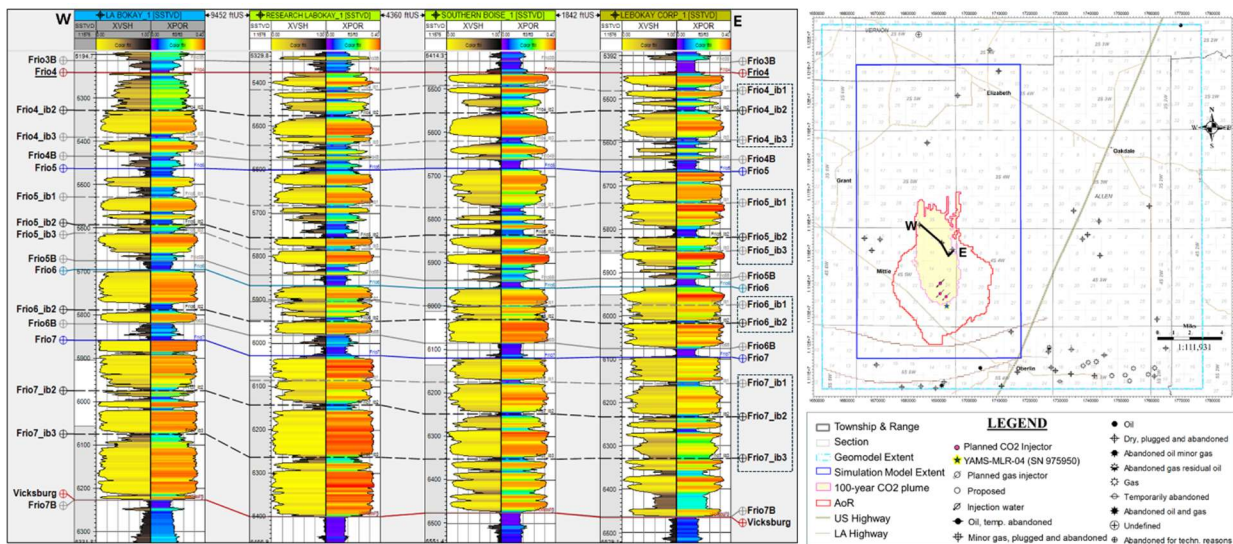


Figure AOR-14—Local west to east cross section showing baffling shales (those with suffix “_ib” that were captured in modeling with transmissibility multipliers in simulation.

**** Figure available in high resolution in supplementary documentation submittal ****

Table AOR-4—Dynamic Simulation Model Zone Information

Regional Zone	Storage Element	Name	Layers	K1	K2
Lower Miocene	Upper Confining	L_Miocene	50	1	50
Anahuac	Intermediate	U_Anahuac	40	51	90
		L_Anahuac	25	91	115
	Confining	L_AnahuacB	1	116	116
Upper Frio	Injection	Frio1_Upp	24	117	140
		Frio1_Lwr	21	141	161
	Confining	Frio1B	1	162	162
	Injection	Frio2	30	163	192
	Confining	Frio2B	1	193	193
	Injection	Frio3	15	194	208
	Confining	Frio3B	1	209	209
	Injection	Frio4	11	210	220
		Frio4_Lwr	14	221	234
	Confining	Frio4B	1	235	235
	Lower Frio	Injection	Frio5	15	236
Frio5_Lwr			10	251	260
Confining		Frio5B	1	261	261
Injection		Frio6	8	262	269
		Frio6_Lwr	7	270	276
Confining		Frio6B	1	277	277
Injection		Frio7	13	278	290
		Frio7_Mid	10	291	300
		Frio7_Lwr	12	301	312
Lower Confining System		Frio7B	1	313	313
Vicksburg	Vicksburg				

2.4 Porosity and permeability

A total of 69 wells were selected for petrophysical calculation of porosity, permeability, and clay volume that provided the best data quality and coverage of the Lower Miocene, Anahuac, Frio, and Vicksburg zones (see Figure AOR-15). **Error! Reference source not found.** A type well log from YAMS MLR 004 (SN 975950) with petrophysical interpretation is shown Figure AOR-16. The core and well-log data from the YAMS MLR 004 (SN 975950) stratigraphic test well was used to calibrate the petrophysical calculations.

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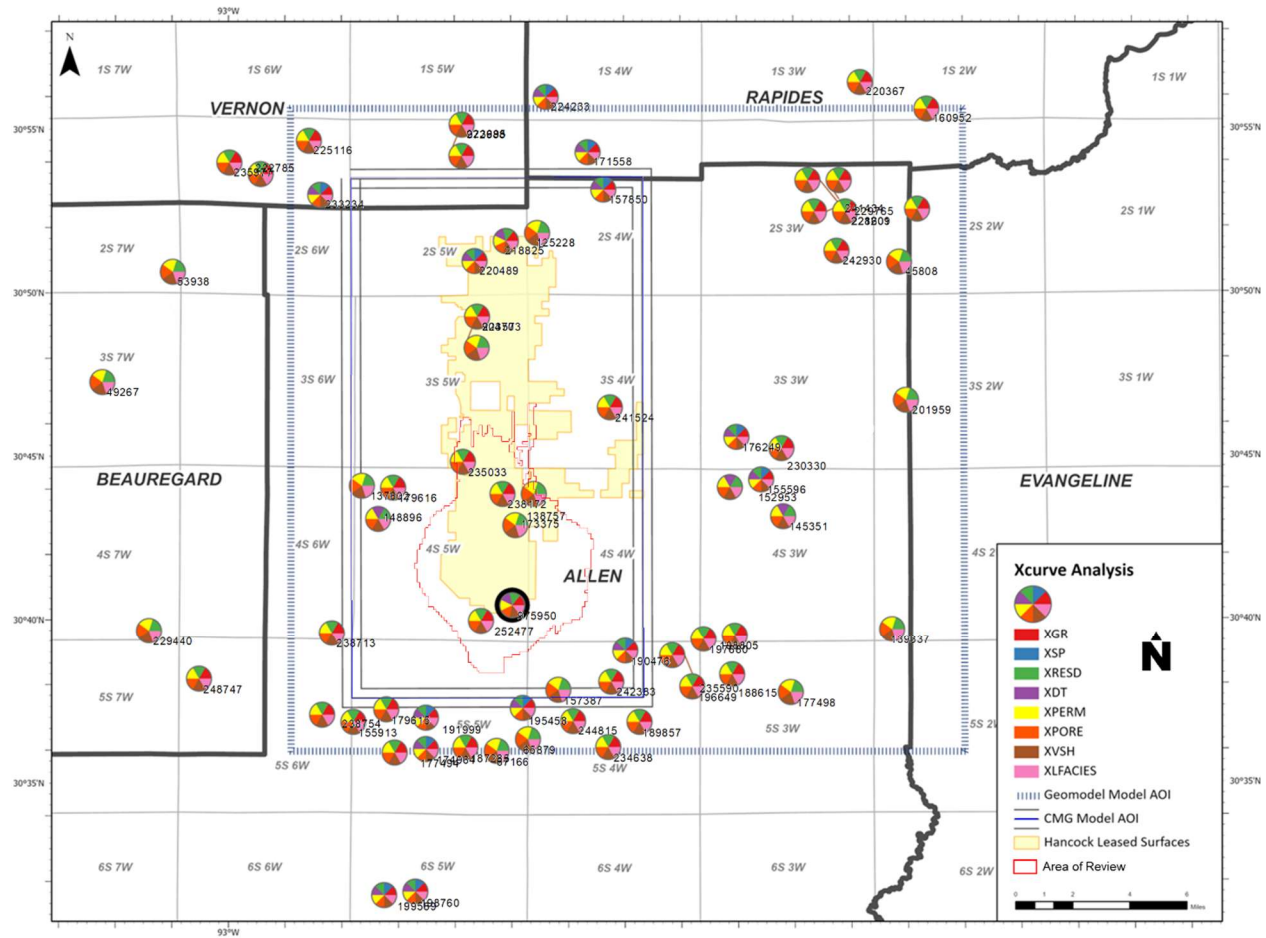


Figure AOR-15—Map representing petrophysical log interpretation for 69 control wells within and surrounding the Magnolia Sequestration Project area. The YAMS MLR 004 (SN 975950) stratigraphic test well is indicated by the black outline. Wells on map are listed in Appendix B Table AOR-30.

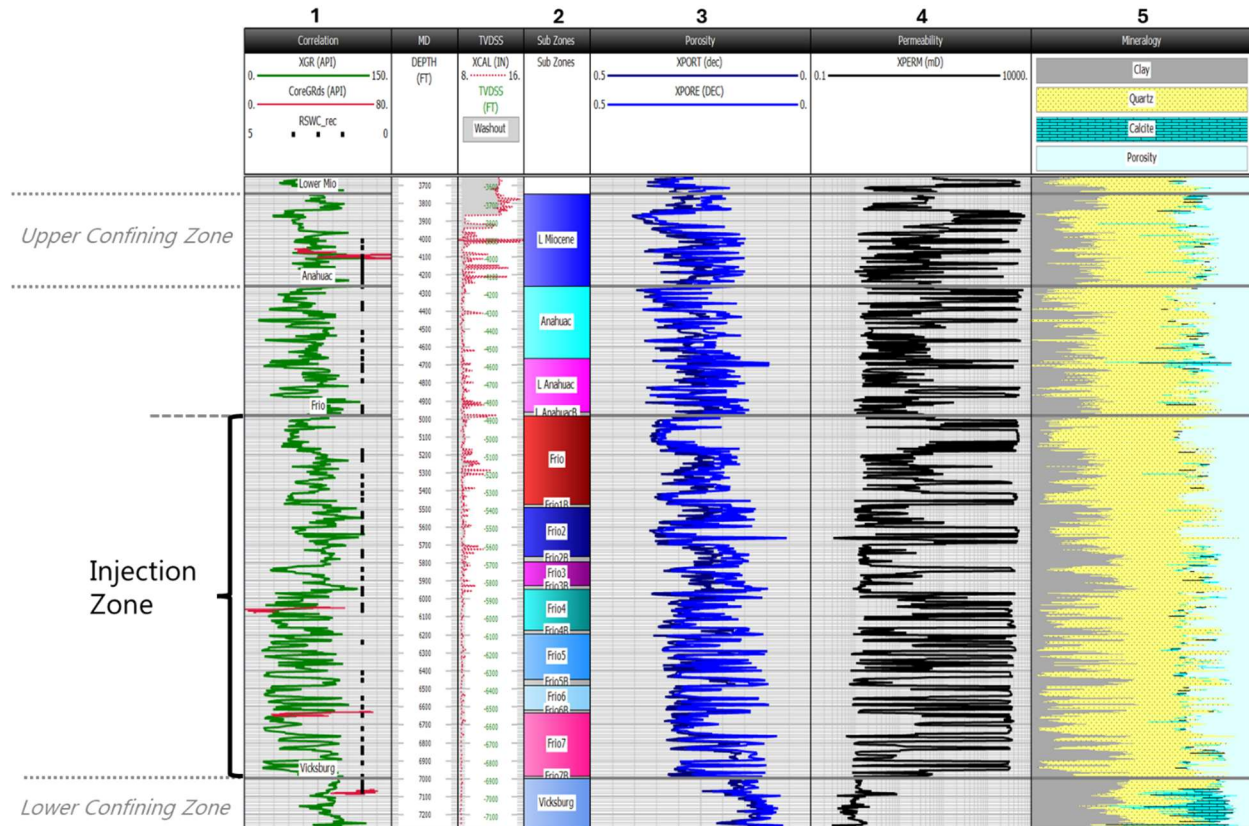


Figure AOR-16— Composite type well-log interpretation from YAMS MLR 004 (SN 975950). Track 1 in the Correlation column displays the Lower Miocene, Anahuac, Frio and Vicksburg major zones plus Fullcore (red line) and Rotary sidewall core intervals (black dots). Track 2 shows the differentiation of major zones into sub zonations. Track 3 displays XPORT (total porosity) and XPORE (effective porosity). Track 4 shows the XPERM (horizontal permeability). Track 5 represents the Mineralogy of quartz, clay, and calcite plus porosity.

Three lithofacies were defined based on Volume of shale (XVSH) and Effective Porosity (XPORE) curve cutoffs and their correlation to total porosity and permeability from core data, shown in Figure AOR-17. These facies are defined as:

Sandstone: $XVSH < 0.4$

Siltstone: $0.4 \leq XVSH < 0.7$ and $XPORE > 0.2$

Mudstone: $XVSH \geq 0.7$ or $XPORE \leq 0.2$

Lithofacies proportion maps were created based on the well point data, geologic interpretation of environment of deposition (EOD), zone isopach, log signature, and information gleaned from the YAMS MLR 004 (SN 975950) stratigraphic test well.

These facies proportion maps were incorporated into modeling as 2D trends. In zones with more complicated variation, vertical facies proportion curves and 3D trend models were generated to capture the variability. The facies logs were then upscaled into the model as hard data to be conditioned. Facies distribution was modeled using truncated Gaussian simulation or sequential

indicator simulation with defined variogram ranges depending on depositional sub-environment. Figure AOR-18 depicts facies distribution in the 3D model.

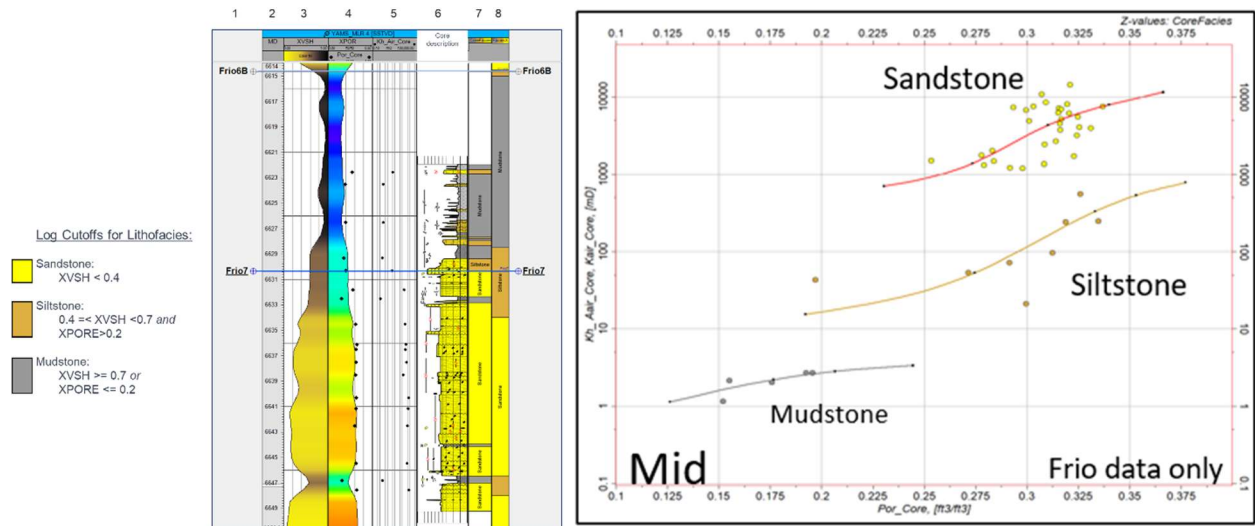


Figure AOR-17—Left: Lithofacies designation based on Vshale and porosity cutoffs was validated with core description. Track 1 is zone; track 2 is measured depth; track 3 is petrophysically-calculated Vshale; track 4 is petrophysically-calculated porosity with black dots signifying PHIT values from whole core plugs. Track 5 is permeability; track 6 is core description; track 7 is facies from core; track 8 is facies from log cutoffs. Right: Total porosity and permeability crossplot from core plugs taken from whole core in the Frio 4 and 7 in the YAMS MLR 004 (SN 975950) well shows three distinct trends that correlate to lithofacies identified at left.

**** Figure available in high resolution in supplementary documentation submittal ****

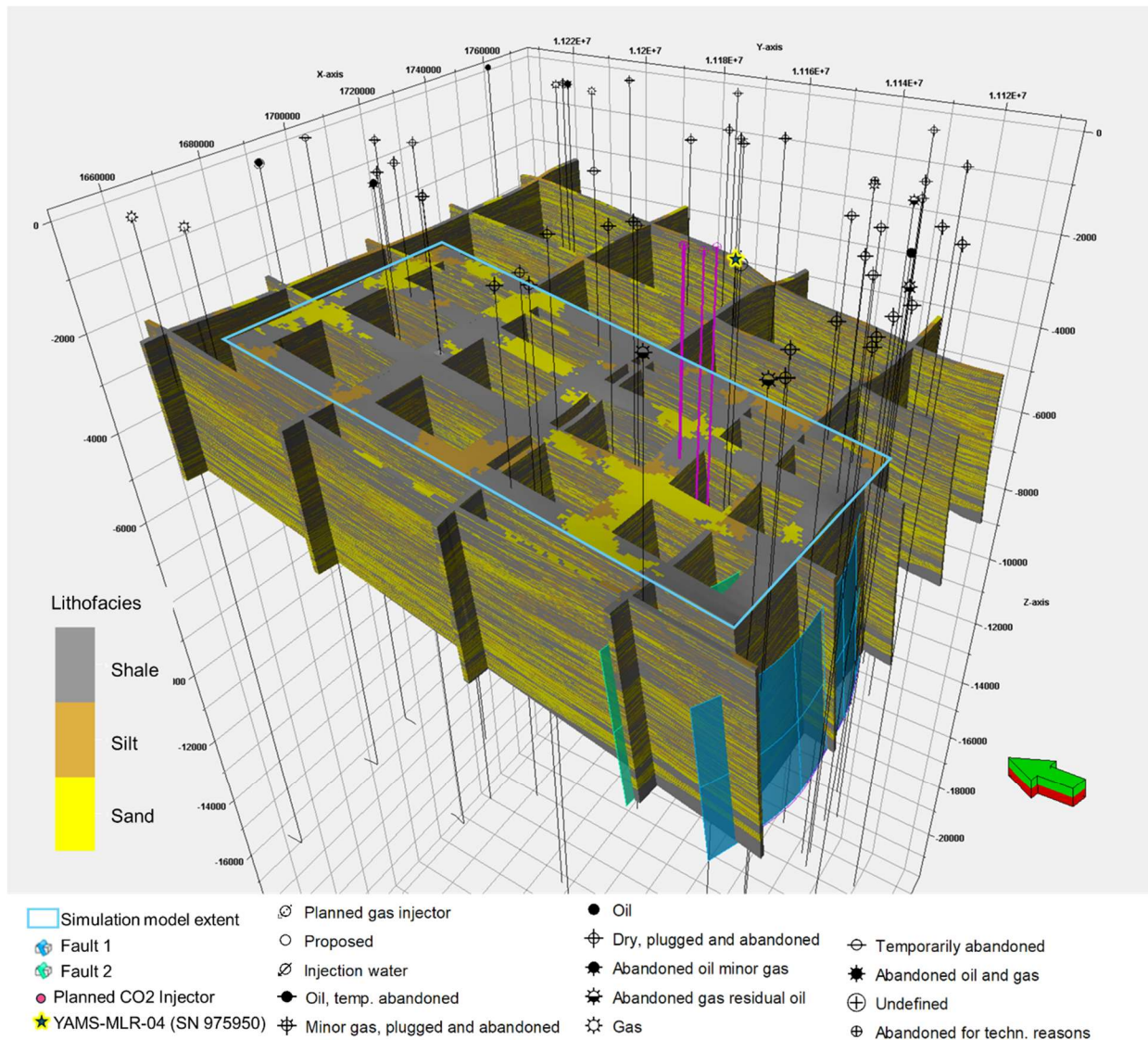


Figure AOR-18—3D model fence diagram showing lithofacies distribution through the geomodel and simulation model cutout. Black wells have porosity curves that anchored distribution; planned injectors in pink are labelled. Faults 1 and 2 are shown on southern end of model.

2.4.1 Porosity

A simultaneous, constrained inversion approach provided the solution of porosity, mineralogy, and fluid saturations using the Mineral Solver module in IP (Interactive Petrophysics Software). The software simultaneously solves a system of tool response equations, i.e., matrix algebra, by reconstructing the measured tool response using endpoint values specified for each mineral and fluid. The volume of clay (Msol:Vclay) is calculated using gamma ray, bulk density, and neutron. The volume of clay is calibrated against the volume fraction from x-ray diffraction (XRD)(Fullcore_XRD:VCLAY) (Figure AOR-19).

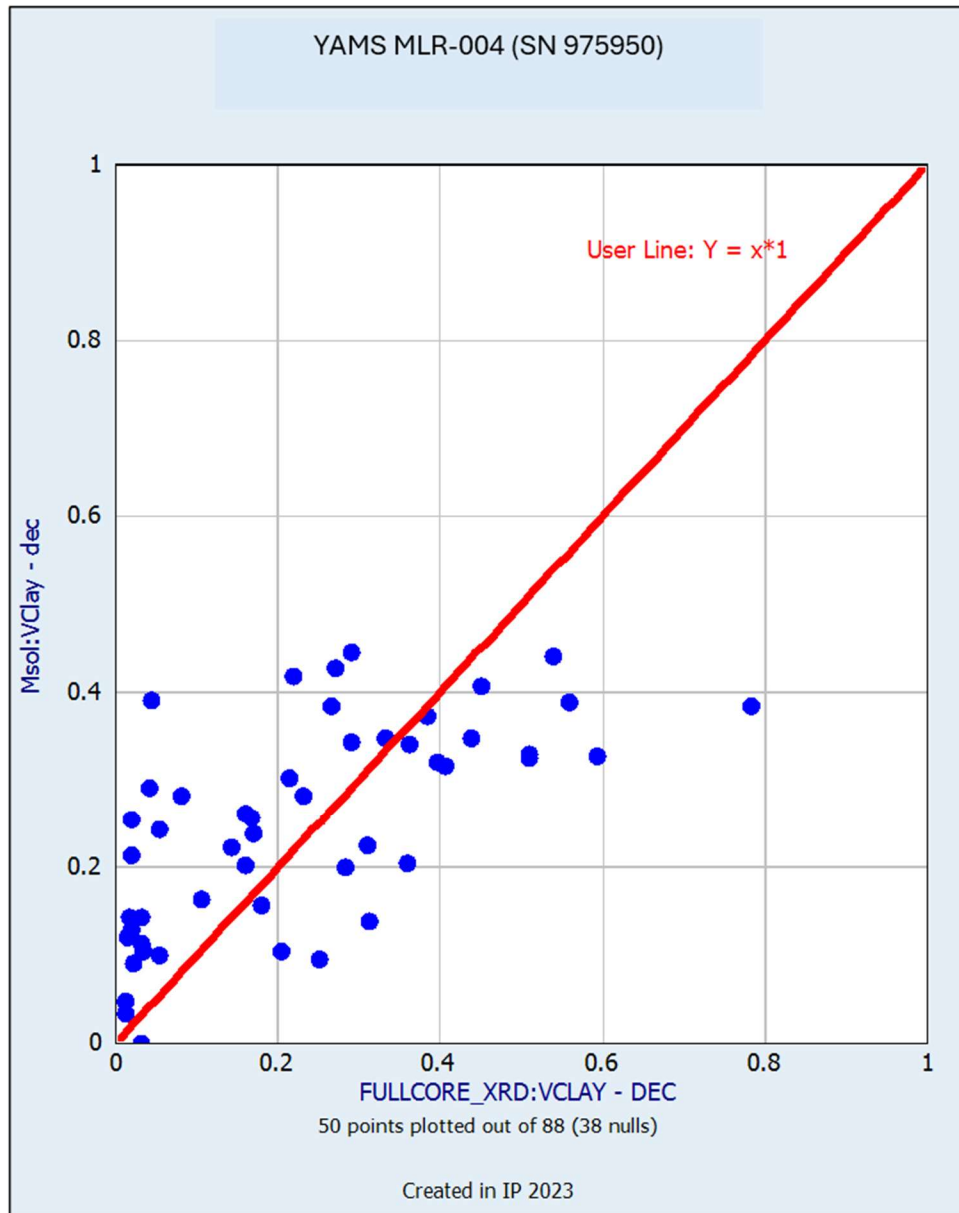


Figure AOR-19—Crossplot of XRD Clay volume (Fullcore_XRD:VCLAY)(decimal) on the x-axis and volume of clay (Msol:VClay)(decimal) determined from Mineral Solver in IP on the y-axis from the YAMS MLR 004 (SN 975950). The red line represents the 1:1 relationship between the two variables.

The total porosity (XPORT) and effective porosity (XPORE)(clay-corrected) is calculated from the neutron and bulk density porosity logs by defining the tool response endpoints for both minerals and fluids. Total porosity (XPORT) is then calibrated against the Vacuum-Dried porosity (CPHI) and effective porosity (XPORE) calibrated against Humidity-dried porosity (CPHI_H) from core data.

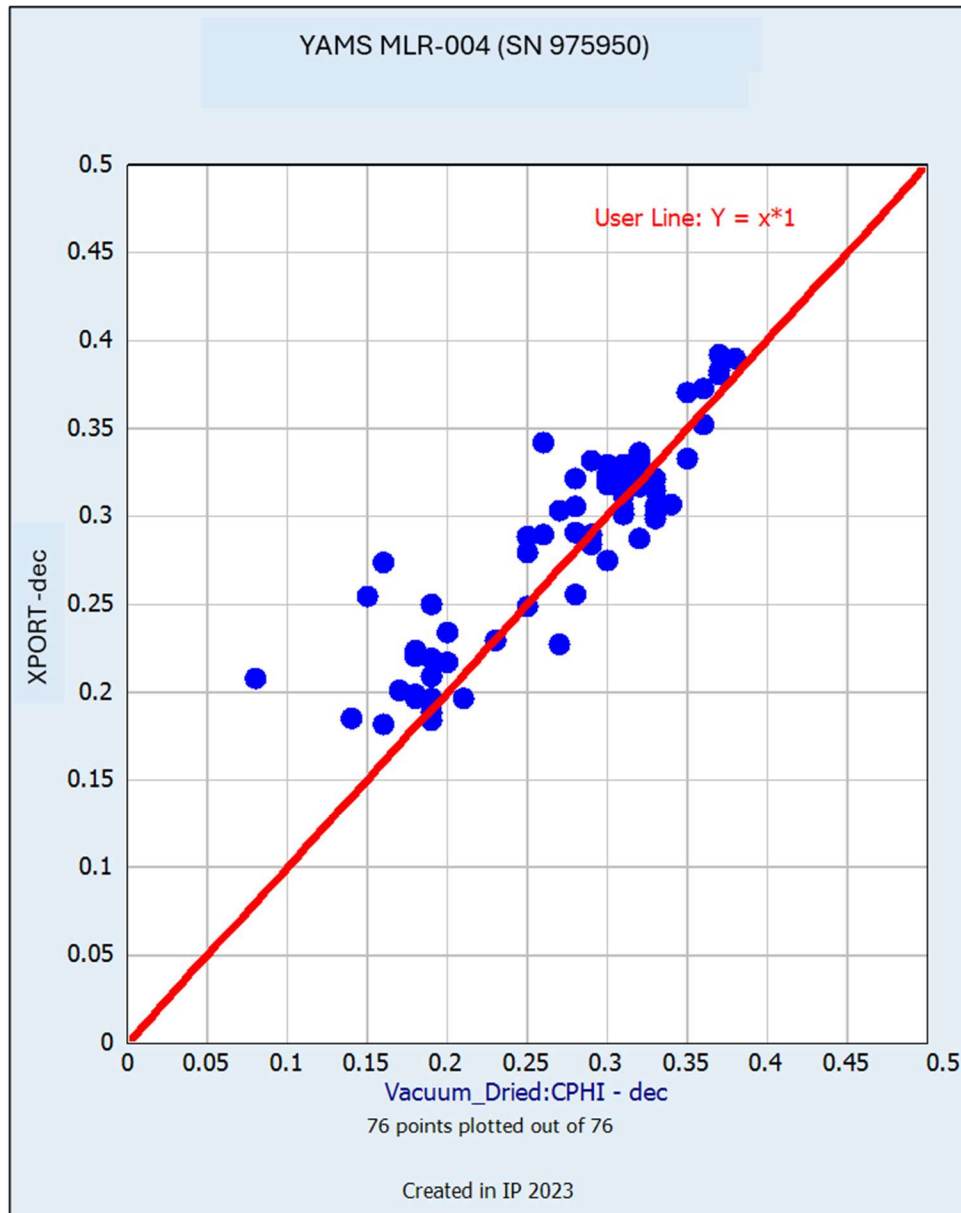


Figure AOR-20— Crossplot of Vacuum-dried core porosity (CPHI)(decimal) versus Total porosity (XPORT)(decimal) from Neutron and Density porosity log from the YAMS MLR 004 (SN 975950). The red line represents the 1:1 relationship between the two variables.

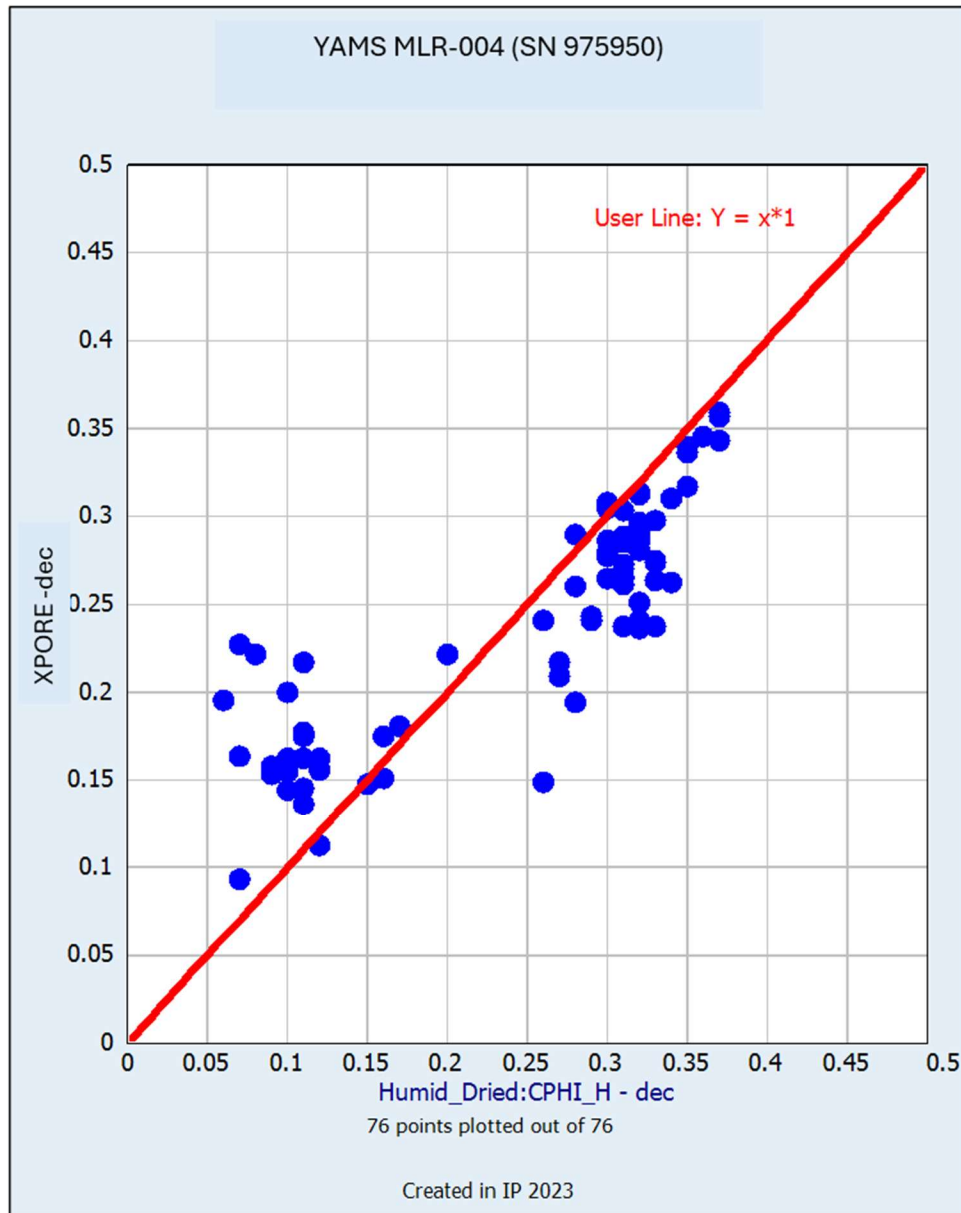


Figure AOR-21— Crossplot of Humidity-dried core porosity (CPHI_H)(decimal) versus Effective porosity (XPORE)(decimal) from Neutron and Density porosity log from the YAMS MLR 004 (SN 975950). The red line represents the 1:1 relationship between the two variables.

A linear correlation between volume of clay and effective porosity from the YAMS MLR 004 (SN 975950) is developed and the equation is used to calculate porosity on the remaining 70 wells (Figure AOR-22).

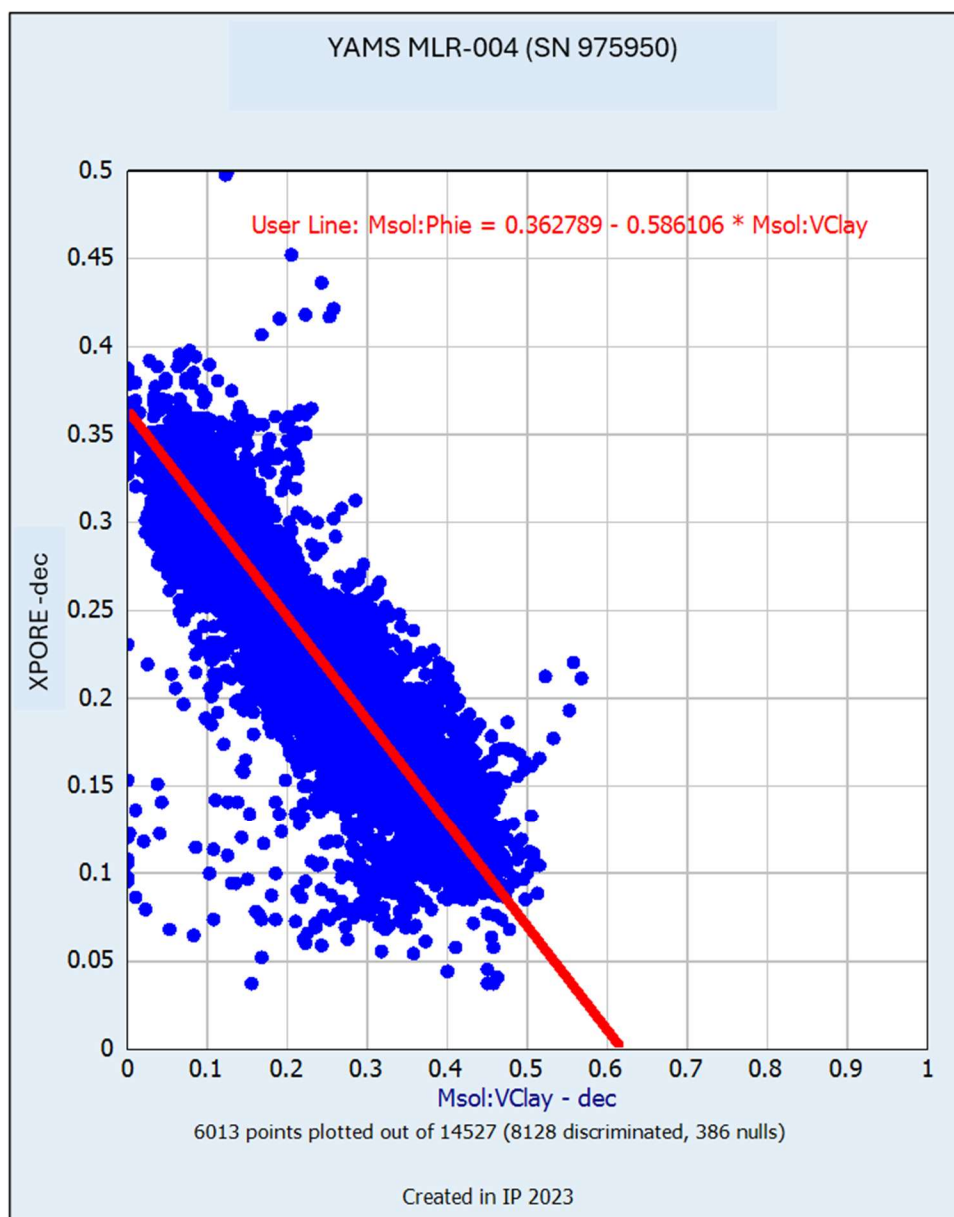


Figure AOR-22— Crossplot of the YAMS MLR 004 (SN 975950) with volume of clay (Msol:Vclay)(decimal) on the x-axis and Effective porosity (XPORE)(decimal) from Neutron and Density porosity logs on the y-axis. The red line represents the linear correlation between the two variables and the resultant equation used to calculate porosity in the remaining 70 wells.

The Frio injection zone is located at a depth of 4,982–6,994 ft with an average net reservoir thickness of 1,354 ft and an average porosity of 30%. The average porosity of the Lower Miocene Upper Confining Zone is 29%, and the average porosity of the Vicksburg Lower Confining zone is 14%. Intra-formational parasequence based shales within the Frio have an average porosity of 22%.

The porosity model was constructed by conditioning facies model and upscaled porosity logs. Based on well data analysis, distinctive porosity distribution was built for each lithofacies and the porosity property was distributed in 3D honoring the defined distribution using Gaussian random

function simulation (GRFS). Porosity was modeled independently for each zone. Figure AOR-23 shows a fence diagram from top of the Lower Miocene through the base of Frio7b with wells that were used to distribute porosity. The simulation model is indicated in wider bars.

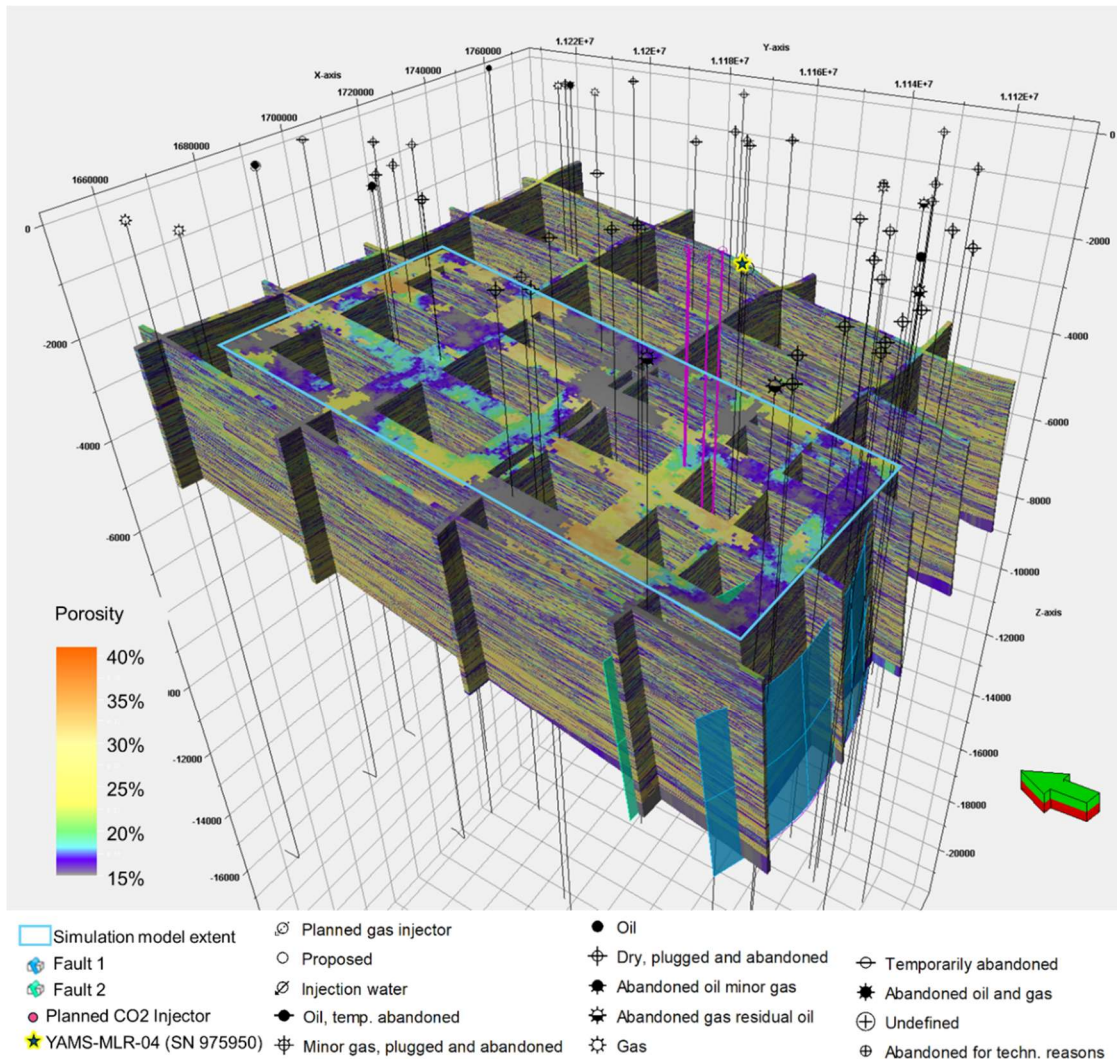


Figure AOR-23— 3D model fence diagram showing porosity distribution through the geomodel and simulation model cutout. Black wells have porosity curves that anchored distribution; planned injectors in pink are labelled. Faults 1 and 2 are shown on southern end of model.

2.4.2 Permeability

Horizontal permeability for the injection and confining zones is based on core analysis data from the YAMS MLR 004 (SN 975950) well. Permeability (XPERM) is calculated from multiple linear regressions with effective porosity (XPORE) for each facies as defined from the 3D Geologic model. Horizontal permeability was distributed through the model by facies using the regression relationships determined by porosity-permeability crossplot from core data shown in Figure AOR-17. Figure AOR-24 shows horizontal permeability distribution in the geomodel (thin fences) and simulation model cutout (thick fences).

In the YAMS MLR 004 (SN 975950), the distribution of permeability for the entire Frio injection interval ranges from 1920-2852 mD, with an average horizontal permeability of 2444 mD.

The average horizontal permeability for shales in the Lower Miocene Upper Confining zone is 2.4 mD and for the Vicksburg Lower Confining zone 1 mD. The average horizontal permeability of the parasequence base shales is 1.35 mD.

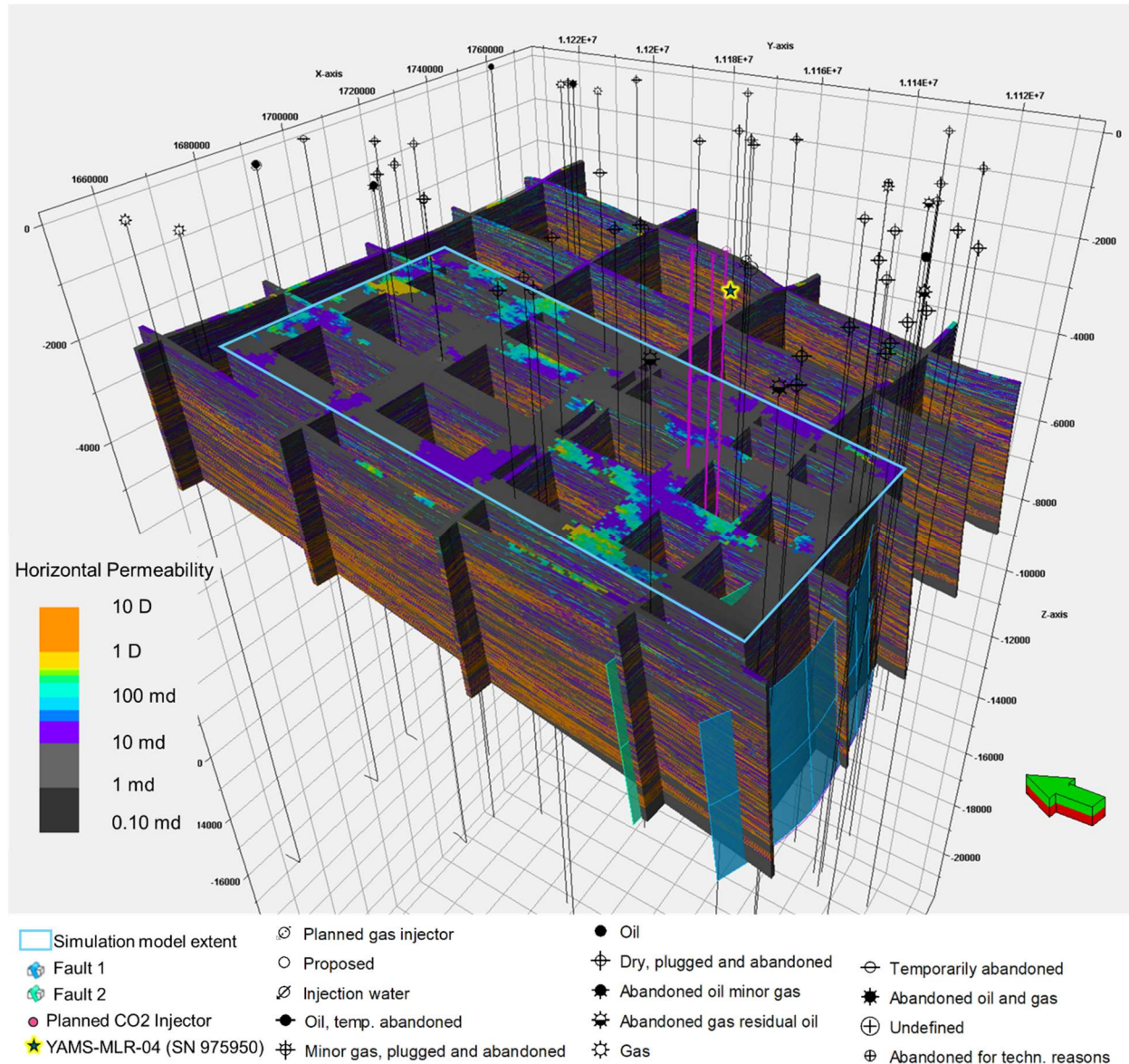


Figure AOR-24 – Horizontal permeability distribution in the geomodel (thin fences) and simulation model (thick fences). Simulation model is indicated with blue rectangle. Note position of Fault1 and Fault2.

Permeability measurements from co-located horizontal and vertical core plugs from the YAMS-MLR 004 well were used to determine Kv/Kh transform; Table AOR-5 details the core plug results.

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Table AOR-5—Vertical and Horizontal core plug RCA results from YAMS-MLR 004 (SN 975950)

	Sample #	Core Depth (ft)	Conf. Stress (psig)	Length (cm)	Diameter (cm)	Porosity (%)	Permeability (md)	Kv/Kh	Facies
1	55H	6050.50	2600	5.0	3.8	29	1200	0.25	Sandstone
	151V	6050.85-6051.00	2600	2.2	2.5	28	1470		
	56H	6052.50	2600	4.6	3.8	31	10800		
2	80H	6625.50	2800	4.2	3.7	31	2660	0.53	Sandstone
	162V	6625.65-6626.00	2800	6.1	2.5	32	1700		
	81H	6626.50	2800	4.8	3.7	32	3730		
3	82H	6627.50	2800	4.9	3.77	31	1350	1.66	Sandstone
	164V	6627.95-6628.30	2800	5.3	2.4	33	3910		
	83H	6628.30	2800	44.9	3.7	31	3360		
4	89H	6636.55	2800	4.6	3.7	32	7970	0.95	Sandstone
	167V	6636.95-6637.35	2800	2.1	2.4	34	7460		
	90H	6637.10	2800	4.1	3.7	31	7770		
5	94H	7054.50	3000	4.3	3.8	19	0.777	0.01	Mudstone
	184V	7055.00-7055.27	3000	2.3	2.5	21	0.007		
	97H	7059.50	3000	4.7	3.8	23	0.490		

Porosity and permeability averages by zone and lithofacies for the YAMS MLR 004 (SN 975950) well are summarized in Figure AOR-25.

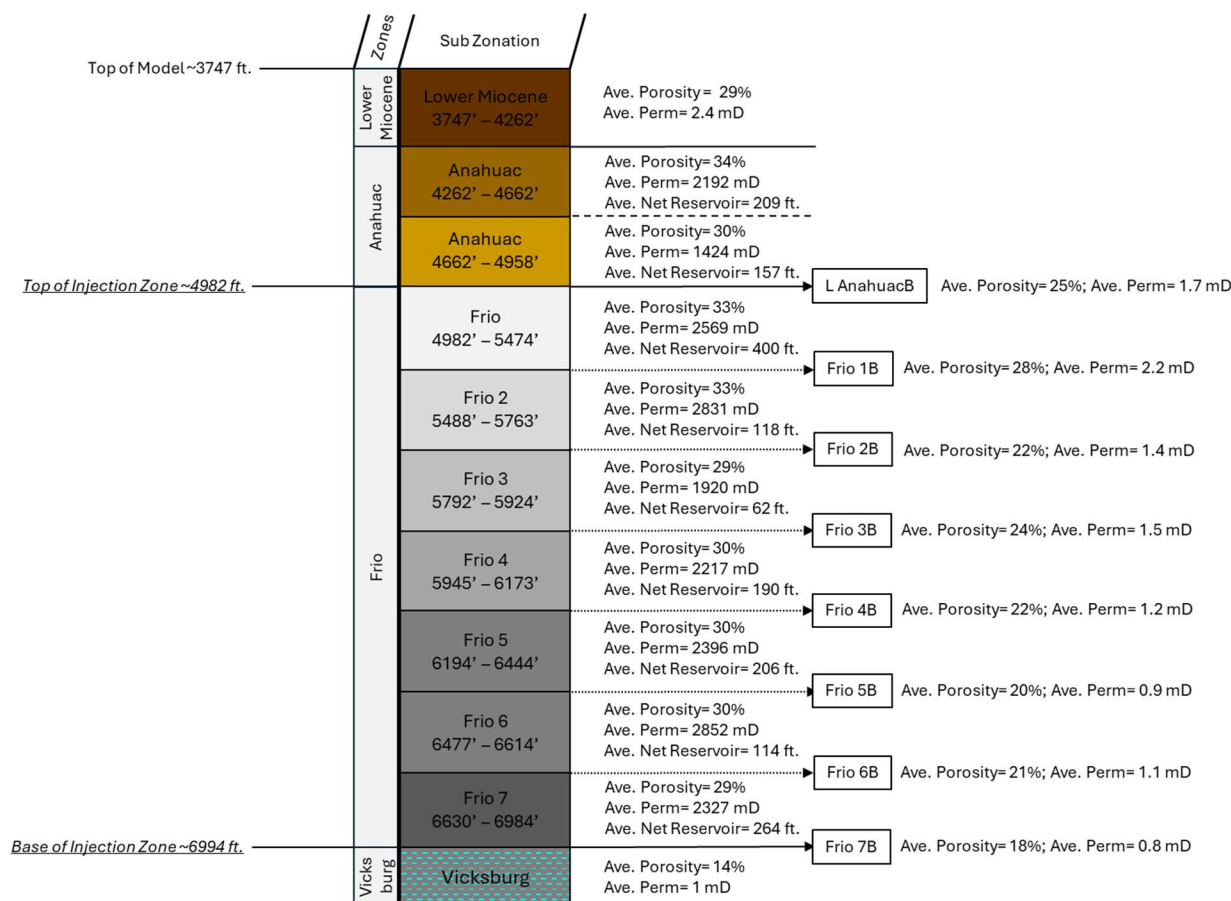


Figure AOR-25— Individual subzones with averages of porosity, permeability, and net reservoir thickness based on log analysis, along with approximate depth intervals at well YAMS MLR 004 (SN 975950). Average porosity and permeability values reported are for key lithofacies in zone, i.e. sands/silts in the Anahuac and Frio and shales in the Lower Miocene, Vicksburg, and parasequence base shales.

2.5 Constitutive relationships and other rock properties

All simulations runs were executed using the GEM simulator, as outlined in Section 2.1. The grid properties of porosity, horizontal permeability, and vertical permeability were directly imported from the static geomodel. The base vertical permeability (k_v) for each grid cell was calculated using the specified k_v/k_h ratio.

The water-gas relative permeability curves and capillary pressure data were constructed from analysis of available lab data from the YAMS MLR 004 (975950). Permeability curves and capillary pressure data was used for the 3 facies as identified from the petrophysical analysis. Endpoint values and Corey exponents used in modeling are from lab data analysis and shown in Table AOR-6.

Table AOR-6—Endpoint Values and Corey Exponents from Lab Data Analysis

Data	Sandstone	Siltstone	Mudstone
P_{c,max} (psi)	30	200	2500
Irreducible Water Saturation, S_{wirr}	0.06	0.26	0.36
Critical gas Saturation, S_{gc}	0.08	0.08	0.08
Trapped gas Saturation, S_{gt}	0.20	0.30	0.40
k_{rw} (at 100% S_w)	1	1	1
k_{rg} (at S_{wirr})	0.45	0.45	0.45
Corey Exponent For Water, N_w	4.50	4.50	4.50
Corey Exponent For Water, N_g	4.00	4.00	4.00

During the imbibition cycle (water displacing gas), trapped gas saturation (S_{gt}) values depend on the maximum gas saturation (S_{gh}) of the grid block. The trapped gas saturation used for the three facies are specified in Table AOR-6. These values are consistent with the values previously reported by Ghomian (2008).

2.6 Boundary conditions

No-flow boundary conditions were applied to the upper (top surface of Lower Miocene) and lower (base of Frio7b) boundaries of the model. The lateral extent of the formation was modeled numerically by a pore volume multiplier applied to the cells on the boundary of the model; pore volume multipliers ranged from 100 to 400 in the N-S direction and 150 – 600 in the E-W direction to mimic depositional trends along the Gulf Coast. To quantify its impact on AOR predictions, the horizontal boundary conditions were included as a sensitivity parameter. In Figure AOR-26, the dark green rectangle represents the low case boundary, the green rectangle represents the mid (base) case boundary, and the lime green rectangle represents the high case boundary, within which reservoir pore volumes were included to predict the pore pressure increases from CO₂ injection.

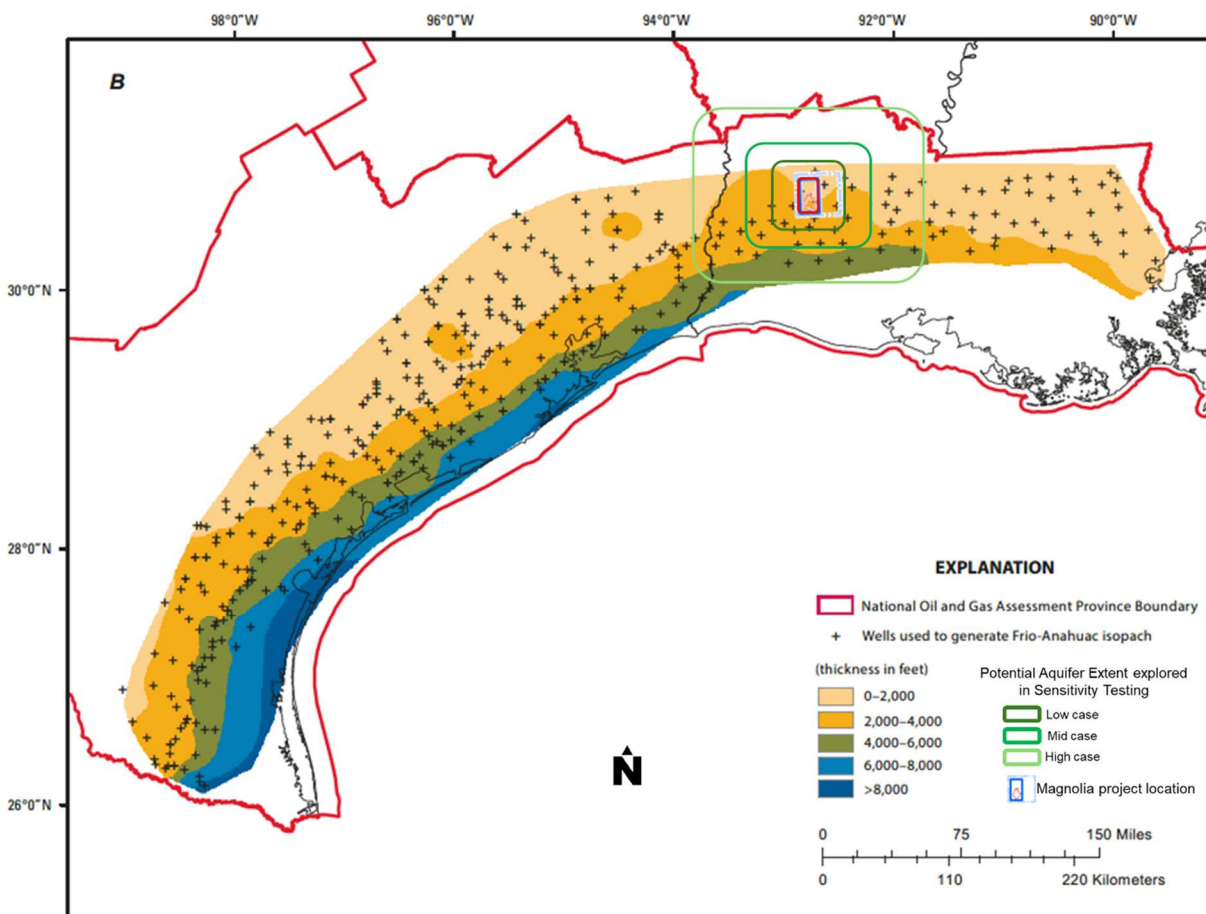


Figure AOR-26—A map showing Frio sand thickness in the Gulf Coast area and edge volumes added to the dynamic simulation model (Swanson, 2013).

2.7 Initial conditions

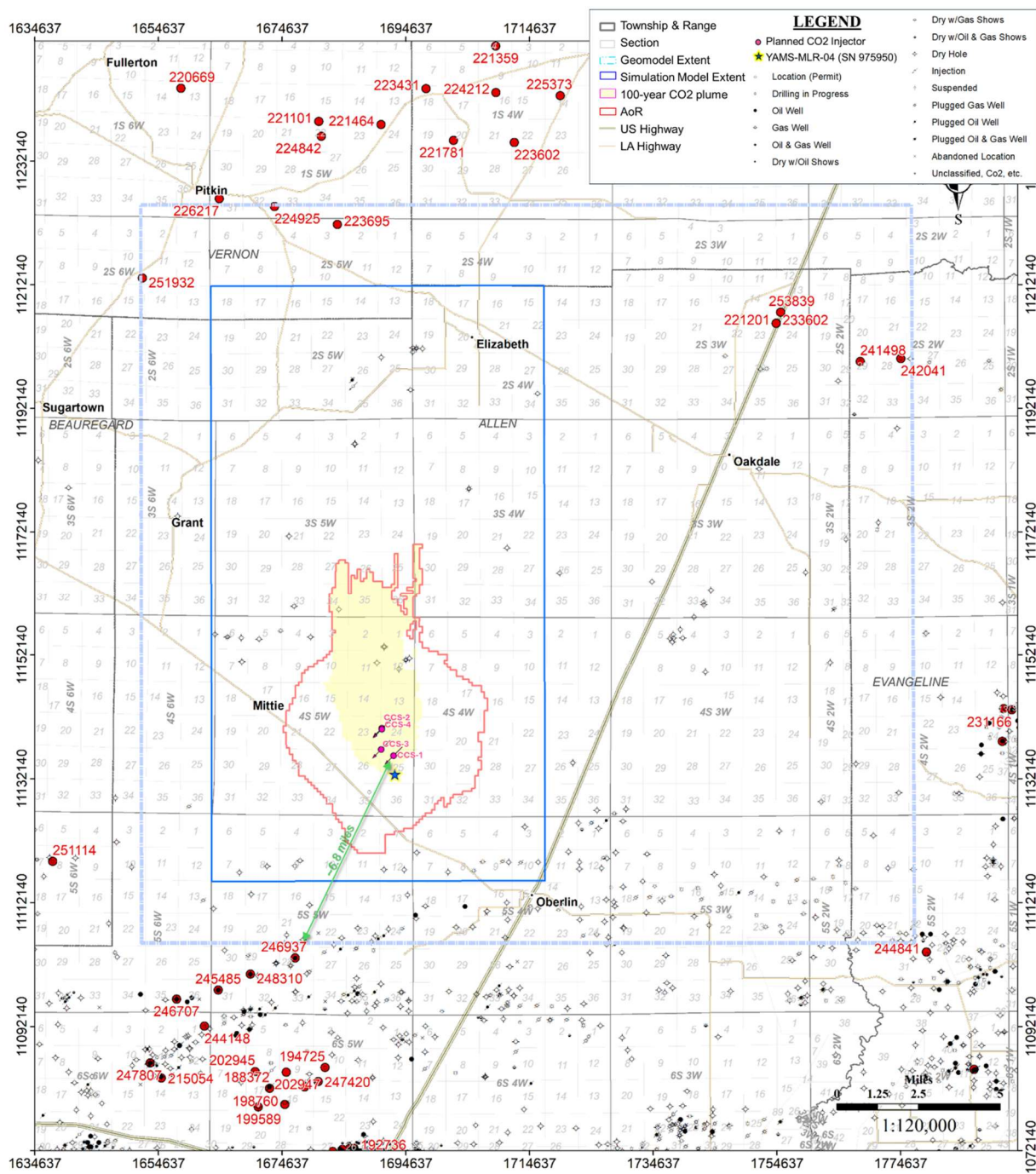
Initial conditions for the model are given in Table AOR-7.

Table AOR-7—Initial Conditions

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	125.5, 174.6	°F	-4000, -8000	MDT data, YAMS MLR 004 well
Reservoir pressure gradient (psi/ft)	0.445	psi/ft		MDT data, YAMS MLR 004 well
Formation pressure	2,225	psi	-5000 ft	MDT data, YAMS MLR 004 well
Fluid density	66.2	lb/ft ³	-6,935.98 ft MD	MDT data, YAMS MLR 004 well
Salinity	130,000	ppm	-6,935.98 ft MD	MDT data, YAMS MLR 004 well

Figure AOR-27 shows the active oil and gas wells near the Magnolia Sequestration project area from the SONRIS Database. There is no active oil or gas production within 6.8 miles of the project area, though several dry holes have been drilled targeting the Frio and overlying Miocene sands.

The closest active well is the SN 246937 (RICE LAND & LBR CO 002), indicated by the green arrow in Figure AOR-27. It is approximately 6.8 miles to the southwest of the CCS-1 injector well.



In this study, 2,225 psia was adopted as the Frio pressure at 5,000 ft (i.e., 0.445 psi/ft, as shown in Table AOR-7). For the modeled pressure gradient within the injection zone, a water density of

66.2 lb/ft³ (for 130,000 ppm TDS brine) was specified. The formation salinity of 130,000 TDS was determined from the approximate average of water samples in the Frio 1, 2, and 7 from the stratigraphic test well, YAMS MLR 004 (SN 975950). Figure AOR-28 shows how salinity ranges for the six samples from four depths from the Upper Anahuac through lowermost Frio from 134,519 mg/L to 98,721 mg/L. See Appendix C for the results of these water tests and samples from the Upper Anahuac.

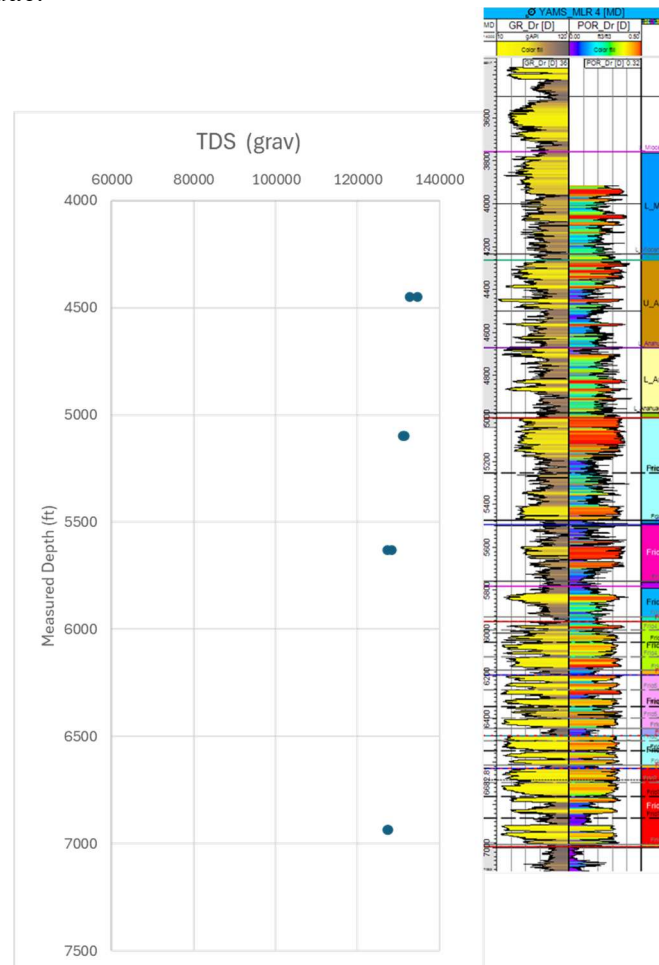


Figure AOR-28—Gravimetric TDS (mg/L) vs measured depth results from (at left) regional well data and (at right) open hole in-situ fluid samples collected at YAMS MLR 004 (SN 975950) stratigraphic test well. Test well is shown at right of figure with MD, GR, porosity, and zonation annotated. Samples are from Upper Anahuac, Frio1, Frio2, and Frio7.

The reservoir temperature was initialized using a linear temperature gradient representative of the regional subsurface of 22°C/km with reference temperatures of 52°C/125.5°F at 4,000 ft, and 79.2°C/174.6°F at 8,000 ft, as obtained from the YAMS MLR 004 (SN 975950) stratigraphic test well data.

2.8 Operational information

The model was initialized with hydrostatic conditions and run without active wells for 6 years to ensure equilibrium and no fluid movement. In Year 0, the Magnolia CCS 1 well begins injecting with a primary rate constraint of 105 MMscfd (2.0 million mta). A secondary bottom hole pressure

(BHP) constraint 4,100 psia (90% of the minimum estimated fracture gradient of 0.75 psi/ft) is set at the well reference depth of 6,550 ft total vertical depth subsurface (TVDSS). The injection stream composition is 100% CO₂. At the same time, Magnolia CCS 2 begins injecting with the same composition and rate constraint of 105 MMscfd (2.0 million mta), and a BHP constraint of 4,000 psia at 6,390 ft TVDSS. Both wells continue injection for 15 years. The base-case run continued for another 100 years post-injection to simulate CO₂ migration after post-injection site closure.

The injection target zones for CCS-1 and CCS-2 wells were the lower part of the Frio zones: Frio 5, Frio 6 & Frio 7. Magnolia CCS 1 and Magnolia CCS 2 are initially completed in the bottom most zone, Frio 7; injection continued for 7 years. Then, Frio 7 zone was plugged, and the wells were recompleted for injection in Frio 6 and Frio 5; injection continued for 8 years. The recompletion strategy provides higher CO₂ storage capacity by filling the bottom zones of the reservoir first.

Injection wells, CCS-3 and CCS-4 are the twin wells for injectors CCS-1 and CCS-2 respectively. The injection target zones for CCS-3 and CCS-4 wells were the upper part of the Frio zones: Frio 1, Frio 2, Frio 3 & Frio 4. A similar completion strategy was adopted for injection of CO₂ into the CCS-3 and CCS-4 wells. The wells were initially completed in the bottom most zone in the upper Frio interval, Frio 3 and 4, and CO₂ injection continued for 5½ years. The Frio 3 and 4 zone was then plugged, and the injection progressively moved upward to the shallower zones: Frio 2 and Frio 1. The injection sequence in the Magnolia CCS-1, Magnolia CCS-2, Magnolia CCS-3, and Magnolia CCS-4 CO₂ injection wells are furnished in the table below (Table AOR-8).

Table AOR-8—Injection Sequence of CO₂

Wells	Injection Target	Injection Zone	Start of Injection (yr)	End of Injection (yr)	Injection Duration (yr)
CCS 3 and CCS 4	Upper Frio	Frio 1	8.5	15	6.5
		Frio 2	5.5	8.5	3
		Frio 3	0	5.5	5.5
		Frio 4	0	5.5	5.5
CCS 1 and CCS 2	Lower Frio	Frio 5	10	15	5
		Frio 6	7	10	3
		Frio 7	0	7	7

Details on the injection operation are presented in Table AOR-9.

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Table AOR-9—Operating Details

Operating Information	CCS-1	CCS-2	CCS-3	CCS-4
Location (global coordinates)				
X	30.682291	30.694490	30.685050	30.694017
Y	-92.833673	-92.839771	-92.840032	-92.839773
Model coordinates (ft)				
X	1692684.539	1690761.962	1690684.539	1690761.796
Y	11135875.86	11140308.1	11136875.86	11140136.16
No. of perforated intervals	3	3	3	3
Perforated interval #1 (ft MSL)*				
Z top	6,550	6,390	5,675	5,569
Z bottom	6,896	6,740	6,036	5,921
Recompletion interval #2 (ft MSL)				
Z top	6,395	6,231	5,360	5,262
Z bottom	6,523	6,357	5,636	5,532
Recompletion interval #3 (ft MSL)				
Z top	6,110	5,950	4,872	4,769
Z bottom	6,354	6,194	5,330	5,230
Wellbore diameter (in.)*	8.4	8.4	8.4	8.4
Planned injection period				
Start	1-Jan-2028	1-Jan-2028	1-Jan-2028	1-Jan-2028
End	1-Jan-2043	1-Jan-2043	1-Jan-2043	1-Jan-2043
Injection duration (yrs)	15	15	15	15
Injection rate (t/day)	5,476	5,476	5,476	5,476

*Represents Z coordinates and diameter in the model, not final wellbore design

2.9 Fracture pressure and fracture gradient

The risk associated with formation breakdown and fracture generation during or after CO₂ injection is understood in the context of long-term pressure changes in the subsurface and the potential to induce fractures in the formation. The resolved normal and shear stresses acting on an existing fault surface are calculated and utilized in Mohr-Coulomb analysis to estimate the risk of failure during CO₂ injection. Uncertainties of inputs to the in-situ stress model increase the risk due to the decreased accuracy and precision of stress magnitudes and the injection pressures required to induce tensile or shear failure, collectively described as failure tendency. The increase in fluid pressure from CO₂ 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. Our 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:

$$\mu = \frac{\tau}{\sigma_n'} \quad (\text{Equation 2})$$

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:

$$\tau = \mu\sigma + S_o \quad (\text{Equation 3})$$

where S_o is cohesion and is a function of friction and unconfined compressive strength (UCS):

$$UCS = 2S_o(\sqrt{\mu^2 + 1} + \mu) \quad (\text{Equation 4})$$

Figure AOR-29 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) 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 the normal plane. In Figure AOR-28 the red circle represents the original state of effective stress. In the case of CO₂ 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 3. The dashed line would represent the failure limit of a pre-existing fault with comparatively little friction. While the friction of faults is not zero, it is small compared to the friction required to initiate fracture in the matrix.

As pore pressure increases during injection, the Mohr circle moves to the left along the X-axis and the boundary of the circle 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.

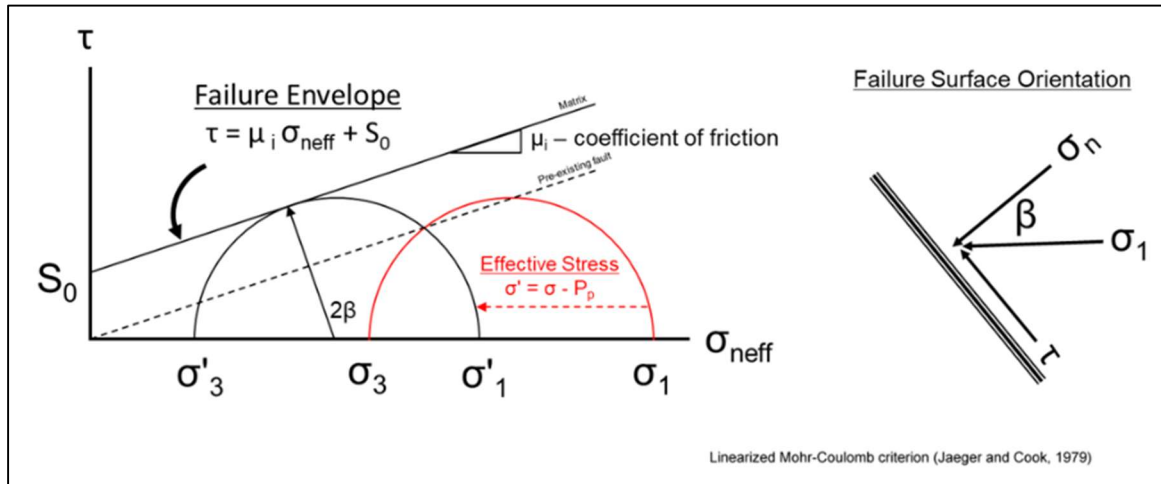


Figure AOR-29—Mohr-Coulomb Failure Criterion

Oxy Best Practices workflow was implemented for calculating pore pressure and the three principal stresses. 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:

$$Pp = \sigma v - \sigma v' \quad (\text{Equation 5})$$

An assumption was made that the pore pressure is hydrostatic in the shallow formations and follows the hydrostatic trend until the velocity data indicate that pressure deviates from that trend. Figure AOR-7 shows that this approach indicates formation pressure is hydrostatic until below the Frio formation in the LA BOKAY 1 (SN 235033) well.

The state of stress was modeled using the isotropic poroelastic uniaxial strain model shown in Equation 6.

$$\sigma_3 = \frac{\nu}{1-\nu} (\sigma v - \alpha Pp) + \alpha Pp \quad (\text{Equation 6})$$

where:

σ_3 = least horizontal principal stress

ν = Poisson's ratio

σ_v = maximum principal stress

α = Biot's coefficient

Pp = pore pressure

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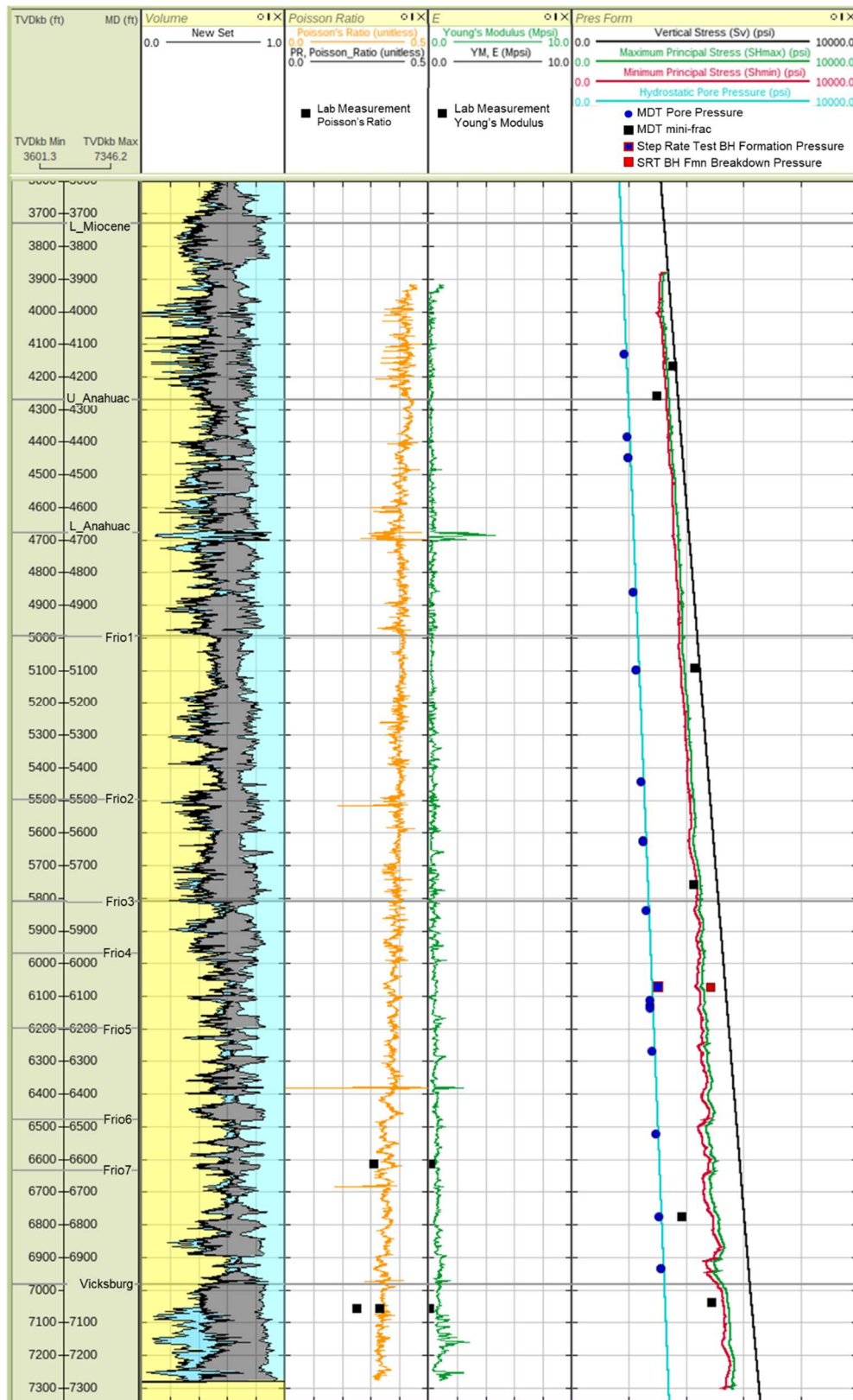


Figure AOR-30—Stress model YAMS MLR 004 (SN 975950) well.

The maximum principal stress is the overburden, or S_v , in this area, according to the geological interpretation that the area is in a normal faulting failure condition. Andersonian mechanics require that in normal faulting environments, the overburden is the maximum principal stress (Anderson, 1951). That interpretation is the strongest constraint available for this model. The overburden is calculated by integrating the density data over the interval from surface to the depth of interest at the bottom of the well. The overburden stress is represented by the black pressure profile in Figure AOR-30. At shallow depths, the state of stress converges such that all three principal stresses are equal. At the depth of the Frio in the Magnolia Sequestration Project site, we assume a minimum horizontal differential stress and the most conservative interpretation and creating the high risk potential. The minimum principal horizontal stress is calibrated to closure pressures interpreted from MDT measurements in the YAM MLR 004 (SN 975950) wellbore (black squares in AOR-30).

Figure AOR-31 shows the stress state in a Mohr circle graphical depiction. Figure AOR-31 is an indication that the Frio formation is not in a critical state of failure. It also shows that a 1500-psi increase in pressure is required to initiate tensile failure in the injection zone formation. Without a constraint on the tensile strength, we assume it to be zero as a conservative case. Under that assumption, a 1500-psi increase in formation pressure would cause tensile failure.

Mohr-Coulomb critical stress analysis on the YAMS MLR 004 (SN 975950) well was conducted using a pore pressure model that was calibrated to formation pressure interpretations from MDT borehole measurements. The pore pressure is hydrostatic with a pressure gradient of 0.465 psi/ft. The pressure gradient exhibits the effect of some salinity of the formation fluid compared to freshwater gradients and is in the established bounds of normal pressure gradients.

The minimum horizontal principal stress is calibrated to closure pressure interpreted from MDT pressure measurements in the borehole (Figure AOR-30, black squares). The horizontal differential stress is assumed to be minimal given the geological context. The results of the interpretation indicate that the mean tensile failure gradient is around 0.75 psi/ft in the Frio formation, indicating the reservoir could take up to 1500 psi of increase in formation pressure from injection of CO₂ before any risk of tensile failure in the formation matrix. An optimally oriented, pre-existing fault would require approximately 1100 psi of pressure increase from CO₂ injection to induce shear failure. Fault 1 is optimally oriented and interacts with the edge of the AoR as defined by the threshold pressure front (Figure AOR-32). The maximum increase in pressure calculated along the fault within the AOR is approximately 97 psi, or more than an order of magnitude lower than the calculated ~1100 psi pressure increase required to induce shear failure. Fracture gradient and maximum injection pressure values are summarized in Table AOR-10.

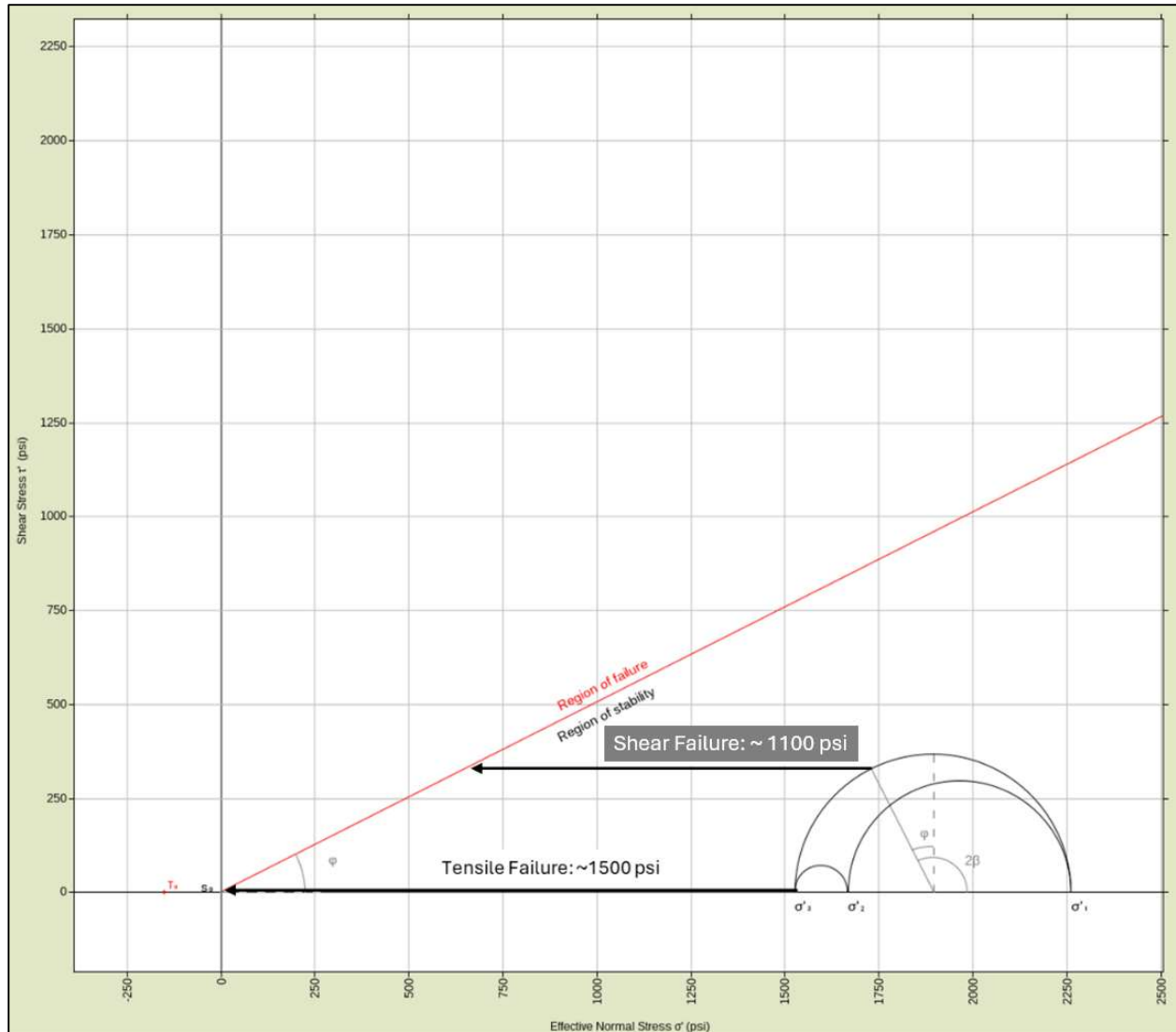


Figure AOR-31—Mohr circle depiction of the calibrated stress state in YAMS MLR 004 (SN 975950) The tensile failure line (~1500 psi) represents the pressure required to initiate tensile failure in the matrix of the injection zone formation. The shear failure line (~1100 psi) represents the pressure increase required to initiate shear failure on an optimally oriented, pre-existing fault in the injection zone formation.

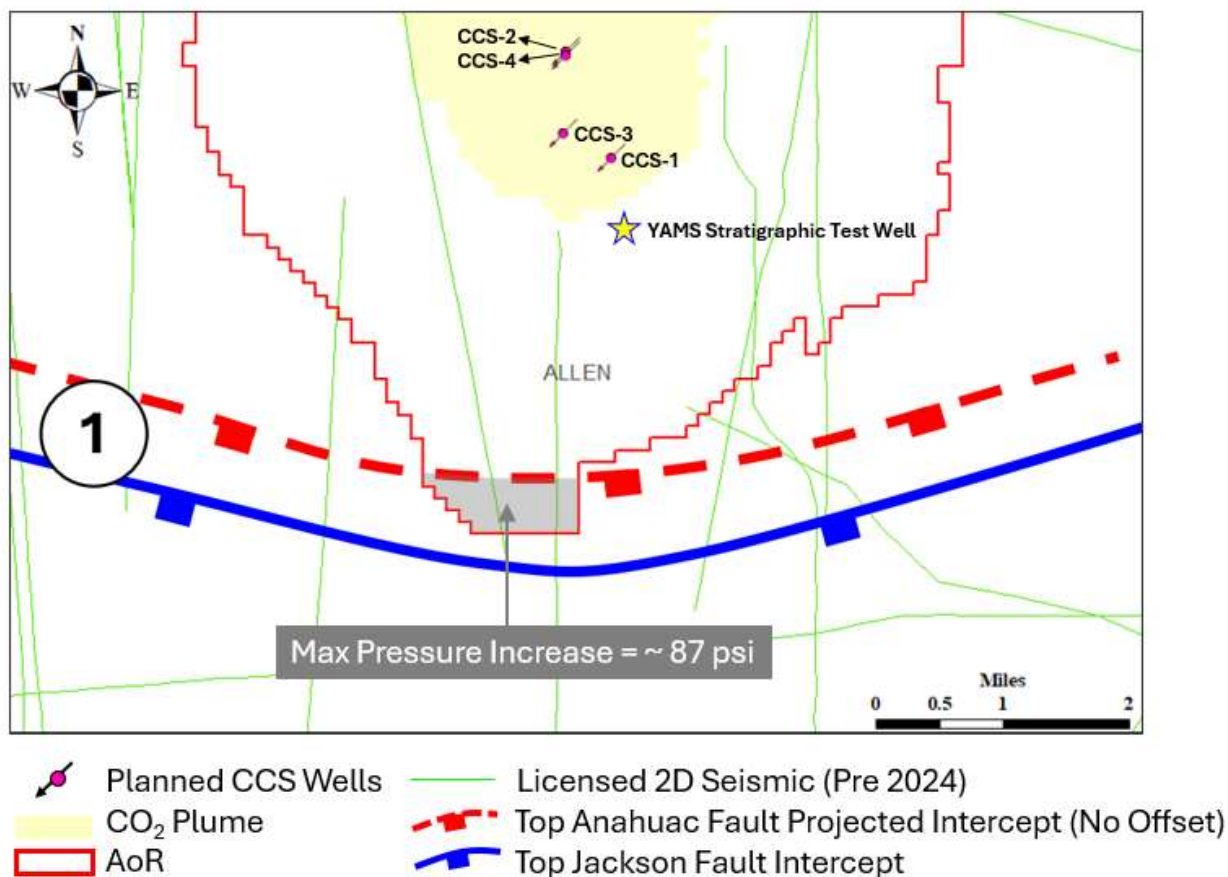


Figure AOR-32—Map view showing the interaction of the AR threshold pressure front with Fault 1.

Table AOR-10—Fracture and Injection Pressure Details

Injection Pressure Details	Magnolia CCS-1	Magnolia CCS-2	Magnolia CCS-3	Magnolia CCS-4
Fracture gradient (psi/ft)*	0.75	0.75	0.75	0.75
Perforation Interval MD ¹ , Shallowest Completion, top-bottom (ft)	6,222-6,466	6,064- 6,308	4,985- 5,443	4,883- 5,344
Perforation Interval TVD ² , Shallowest Completion, top-bottom (ft), top-bottom (ft)	6,222-6,466	6,064- 6,308	4,985- 5,443	4,883- 5,344
Bottomhole gauge depth MD ¹ /TVD ² (ft)	6120	6120	6120	6120
Calculated maximum injection pressure at the top of the perforated interval (psi)	4,200	4,093	3,365	3,296

Considering the perforation interval given in Table AOR-10 for the Magnolia CCS-1 to CCS-4 injection wells, the maximum bottom injection pressures at the top of perforation are calculated to be:

Magnolia CCS-1: $6,222 \text{ ft} \times 0.9 \times 0.75 \text{ psi/ft} = 4,200 \text{ psig}$

Magnolia CCS-2: $6,064 \text{ ft} \times 0.9 \times 0.75 \text{ psi/ft} = 4,093 \text{ psig}$

Magnolia CCS-3: $4,985 \text{ ft} \times 0.9 \times 0.75 \text{ psi/ft} = 3,365 \text{ psig}$

Magnolia CCS-4: $4,883 \text{ ft} \times 0.9 \times 0.75 \text{ psi/ft} = 3,296 \text{ psig}$

3.0 Computational Modeling Results

3.1 Predictions of system behavior

The simulated well rates and pressures are shown in Figure AOR-33. Wellhead pressures were calculated using a PROSPER-generated tubing table with 5.5-inch tubing. The maximum bottomhole pressure (BHP) for each CO₂ injection well is reported in Table AOR-11 and is below the operational constraint of 90% of fracture pressure at the corresponding depth. Step rate tests were performed in the Lower Frio. Each test exhibited injection rates equivalent to greater than 2 million tonnes per year (MMTPA) in each zone. The wellhead pressure for the injection wells predicted by the simulation model is reported in the Table AOR-11. Wellhead pressures for actual operation may vary due to completion and tubing design. See Summary of Operating Conditions and Injection Well Construction Plan documentation for additional details.

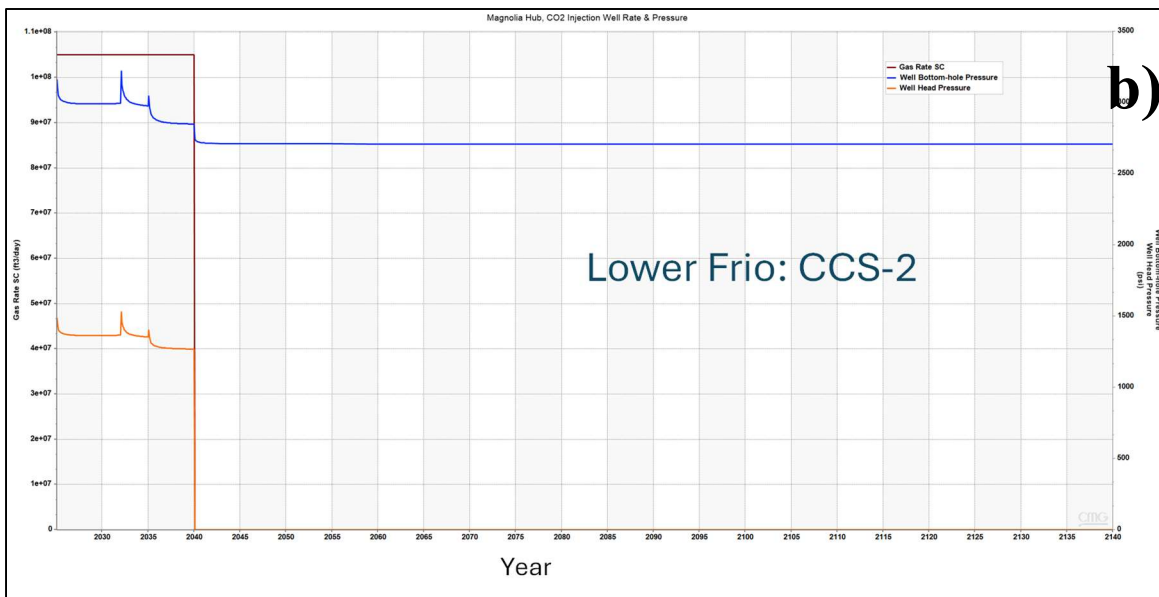
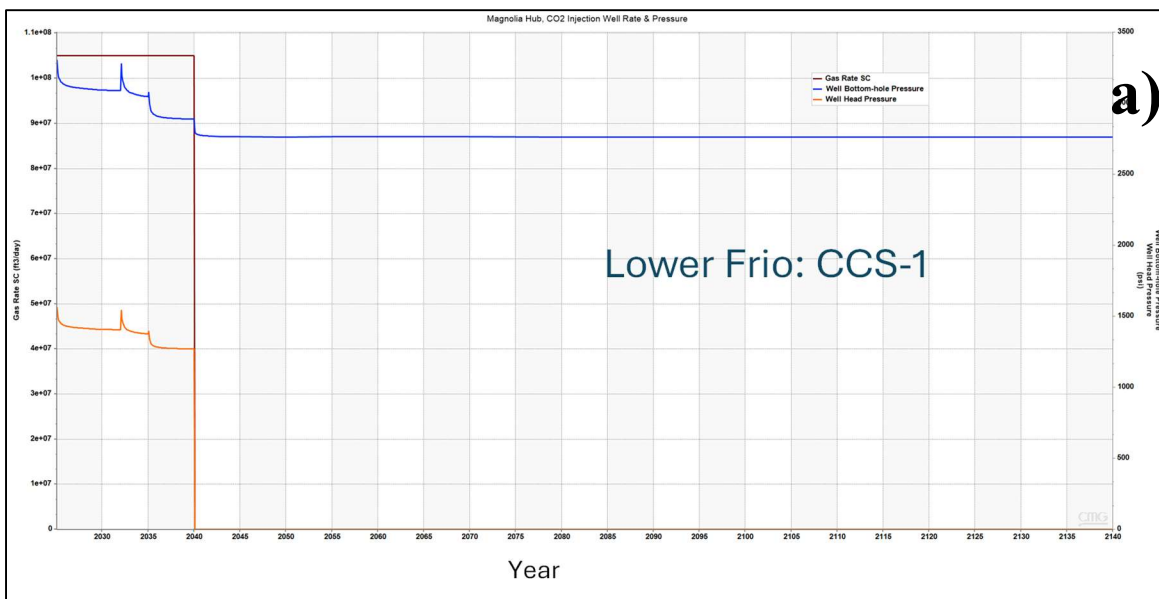
The resulting maximum extents of the CO₂ plume and the pressure front are discussed in in Section 4.0. The movement of the CO₂ plume and pressure front with time are shown in Section 5.3 and in the Post-Injection Site Care (PISC) Plan of this permit.

Table AOR-11—Injection well Maximum Bottom Hole Pressure (BHP) & Well Head Pressure (WHP)

Well	Maximum Bottom Hole Pressure (BHP), psig	Maximum Well Head Pressure (WHP), psig
CCS-1	3,305	1,565
CCS-2	3,224	1,533
CCS-3	2,934	1,629
CCS-4	2,854	1,565

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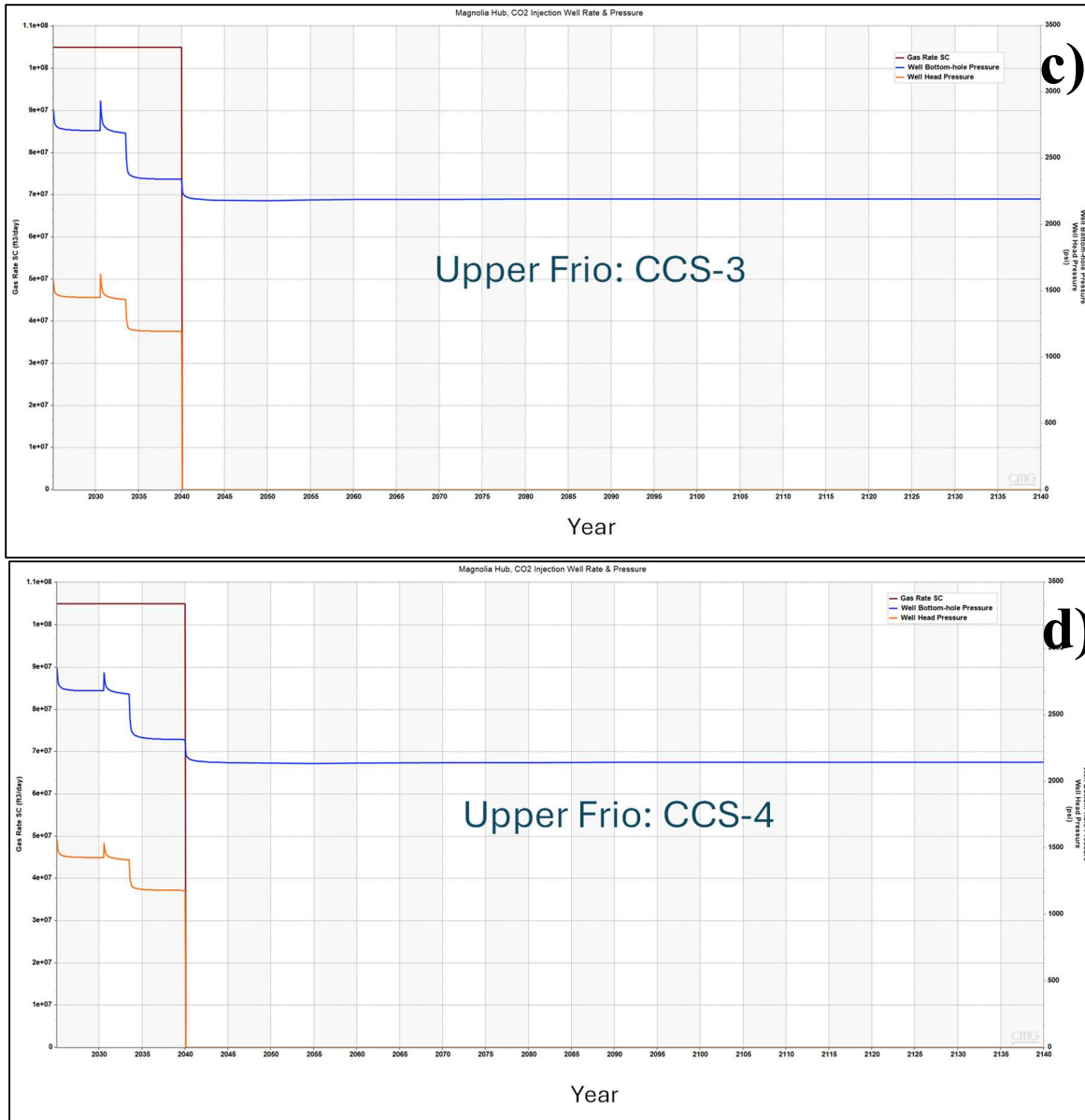


Figure AOR-33—Simulated well gas injection rates and corresponding wellhead and bottomhole pressures in (a) CCS 1, (b) CCS 2, (c) CCS 3, and (d) CCS 4.

3.2 Model calibration and validation

3.2.1 Sensitivity to input parameters

Any subsurface parameter estimated for use in dynamic modeling has some degree of uncertainty associated with it. Therefore, sensitivity of the results to subsurface uncertainties were explored.

The geomodel was built based on the interpretation of a diverse collection of publicly-available well log data; data collected from the YAMS MLR 004 (SN 975950) including log, whole rock and fluid lab analyses; petrophysical interpretation of wells in the area; regional published studies; and limited in-house 2D seismic time data. In spite of best efforts, uncertainties still exist in the

reservoir properties because of subsurface complexity, and complex flow dynamics. Additionally, the performance of the CO₂ plume can be changed by varying the operational variables such as well completion strategy, number of injection wells, etc. Therefore, sensitivity of the simulation results to these uncertainties were explored. These uncertainties included: sensitivity on the flow barriers, horizontal permeability, kv/kh ratio in the sand and shale, size of the boundary aquifers, porosity in the shale, irreducible water saturation, critical gas saturation, gas-water capillary pressure (P_c), trapped gas saturation, end point gas relative permeability, gas and water Corey exponents, variation of injection well completion strategy, and number of injection wells. These injection parameters were chosen as they have the potential to affect the plume migration.

Table AOR-12 summarizes the possible ranges of these subsurface inputs. Many simulation runs were made by varying these parameters one at a time and plotting the results to see their impacts. This approach to analyze uncertainty is often called as “one-variable-at-a-time (OVAT)” technique (see e.g., Ambastha, 2014). This is in contrast to uncertainty assessment using statistical design of experiment approach where many variables are changed together. The low and high values of the parameters were chosen to cover the expected range of uncertainty based on the current understanding of the subsurface and the field operations. The areal extent of the CO₂ plume was used as the basis to compare the different sensitivity runs.

Table AOR-12—Uncertainty Ranges of Reservoir Parameters

No.	Parameter	Low	Medium (Current Sim)	High
1	Barriers & Baffles	Intra-zone & Inter-zone transmissibility multipliers = 0	Inter-zone and intra-zone baffles	Intra-zone & Inter-zone transmissibility multipliers = 1
2	Horizontal Permeability	Mid case kh * 0.75	Base Case Perm (kh, kv)	Mid case kh * 1.50
3	kv/kh Ratio	Sand: 0.10	Sand: 0.30	Sand: 0.70
4	kv/kh Ratio	Shale: 0.001	Shale: 0.01	Shale: 0.1
5	Size of Boundary Aquifers	PV Multiplier: North/South: 100 East/West: 150	PV Multiplier: North/South: 200 East/West: 300	PV Multiplier: North/South: 400 East/West: 600
6	Porosity	Minimum 10%	Base case	Minimum 20%
7	Irreducible Water Saturation	Sand: 0.02	Sand: 0.06	Sand: 0.10
8	Critical Gas Saturation	4%	8%	10%
9	Gas-Water Capillary Pressure	No	Yes	Use Higher Pc
10	Trapped Gas Saturation	Sand: 0.15	Sand: 0.20	Sand: 0.30
11	Completion Location	Perf Upper	Perf Selective	Perf Lower
12	Injection Wells	8	4	
13	kr _g @Swirr	0.2	0.45	0.9
14	Corey Exponents for Gas (Ng)	Ng = 2.0	Ng = 4.0	Ng = 6.0
15	Corey Exponents for Water (Nw)	Nw = 2.5	Nw = 4.5	Nw = 6.5

The tornado charts of the CO₂ plume extent compared with the base case are shown in Figure AOR-34. The CO₂ plume migration is most sensitive to Corey exponent for gas (NG), gas relative permeability at irreducible water saturation and Corey exponent for water (NW). The plume behavior was found to be moderately sensitive to capillary pressure, trapped gas saturation and horizontal permeability. The CO₂ storage was found to be not very the vertical permeability on shale, size of the aquifer boundary and the porosity in the shale. The CO₂ plume migration in the saline aquifer is a complex interplay of various factors: reservoir structure, reservoir rock and fluid properties. Therefore, the results of the sensitivity analysis could vary based on the parameters selected for the base case and the low and high values for different parameters. With these limitations in mind, the following conclusions can be made from the dynamic model sensitivity analysis:

- 1) Relative permeability parameters, such as the relative permeability to gas and water and the end point gas relative permeability are the most influential parameters to determine the size of the CO₂ plume
- 2) The effect of the properties of the shale facies, such as vertical permeability and porosity, and the size of the aquifer extent were minimal

- 3) Horizontal and vertical permeability had a moderate effect on the final extent of the CO₂ plume.

The results of the sensitivity study suggest that reducing the uncertainty range of the relative permeability parameters and the horizontal permeability will reduce uncertainty on the CO₂ plume prediction.

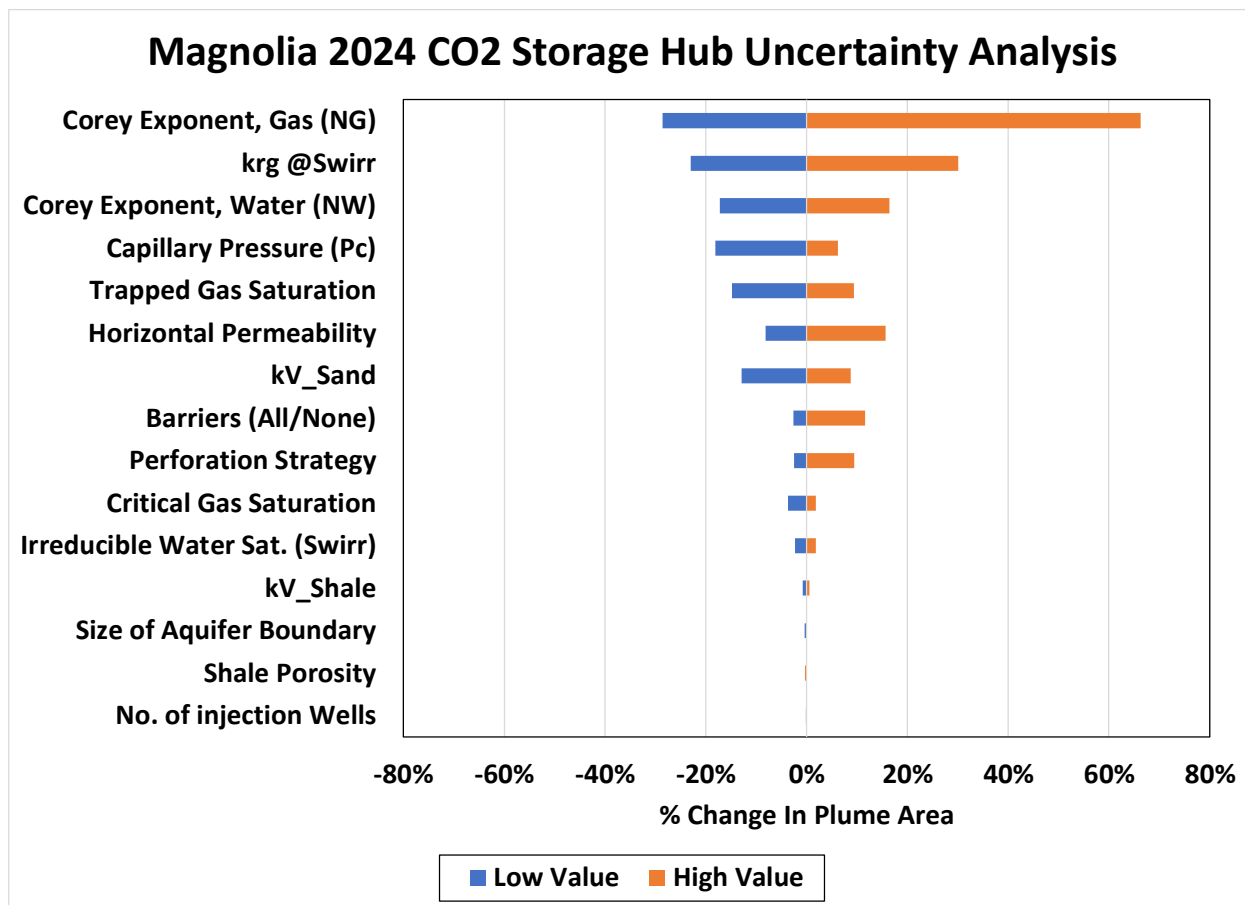


Figure AOR-34—Sensitivities of 100-year plume growth to various subsurface input parameters after 120 million mt CO₂ injection

4.0 Area of Review (AOR)

4.1 Threshold pressure calculations

To delineate the threshold 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. To cause reverse flow with fluid flow to the USDW, the pore pressure increase must be high enough to overcome the hydraulic head of the fluid in a hypothetical wellbore.

Literature presents varied methods to calculate the threshold pressure front. One such way is to calculate the threshold 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 threshold pressure threshold (ΔP_c) in the injection zone is given by Equation 8:

$$\Delta P_c = \frac{1}{2} * g * \xi * (z_u - z_i)^2 \dots\dots\dots \text{(Equation 8)}$$

where:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \dots\dots\dots \text{(Equation 9)}$$

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).

$$\frac{\Delta P}{g} = (z_v - z_I) \left(\frac{\lambda - \xi}{2} (z_v - z_I) + \rho_{I\lambda} - \rho_I \right) \dots\dots\dots \text{(Equation 10)}$$

Whether using uniform density approach or the equilibrium approach, it's assumed that the wellbore is open and filled with brine. However, based on Bump's study (2023), Texas Commission on Environment Quality (TCEQ) allows an assumption that the wellbore is filled with a 9 Pounds Per Gallon (PPG) mud and the mud develops a gel strength that increases with time. Based on Bump's recommendation, the calculated threshold pressure is the pressure due to mud column inside the wellbore and the pressure needed to overcome the gel strength subtract the initial pressure (pre-injection). This approach eliminates the need for determination of brine density from both USDW and injection zone.

Table AOR-13 –Threshold pressure Calculation

Description	Value	Source
Top of Injection Zone (ft) (See Note 1)	4,750	Completion depth
9 ppg mud to Top of Injection Zone (psig/ft)	0.468	Bump (2023)
Reservoir Pressure Gradient (psi/ft)	0.445	YAMS MLR 004 (SN 975950) MDT
Column pressure (psi)	$(4750-50)*0.468 = 2,199.6$	
Initial Pressure at Top of Injection Zone (psi)	$=4750*0.445 = 2,113.75$	YAMS MLR 004 (SN 975950) MDT
Gel Strength Pressure (psi)	10.44	Assumed gel strength and wellbore data
ΔP_c (psi)	$2,199.6-2,113.75+10.44 = \mathbf{96.29}$	

Note 1: Depth of the top of the injection zone is in reference to the completion depth at the CCS injection wells.

As illustrated Table AOR-13, the threshold pressure differential was calculated to be 96 psi.

4.2 AOR delineation

4.2.1 Threshold pressure front

Figure AOR-35 illustrates the propagation of the threshold pressure front at various times during the injection. The maximum threshold pressure front was observed 8½ years after the start of injection. The movement of the pressure front was evaluated at 5, 10, and 15 years after injection starts to align with regulatory requirements for AOR reviews every 5 years. Figure AOR-34 also gives the CO₂ plume 100 years after injection.

Figure AOR-36 illustrates the vertical extent of the maximum threshold pressure front as a cross-section through the model extent with the Magnolia CCS 3 location highlighted.

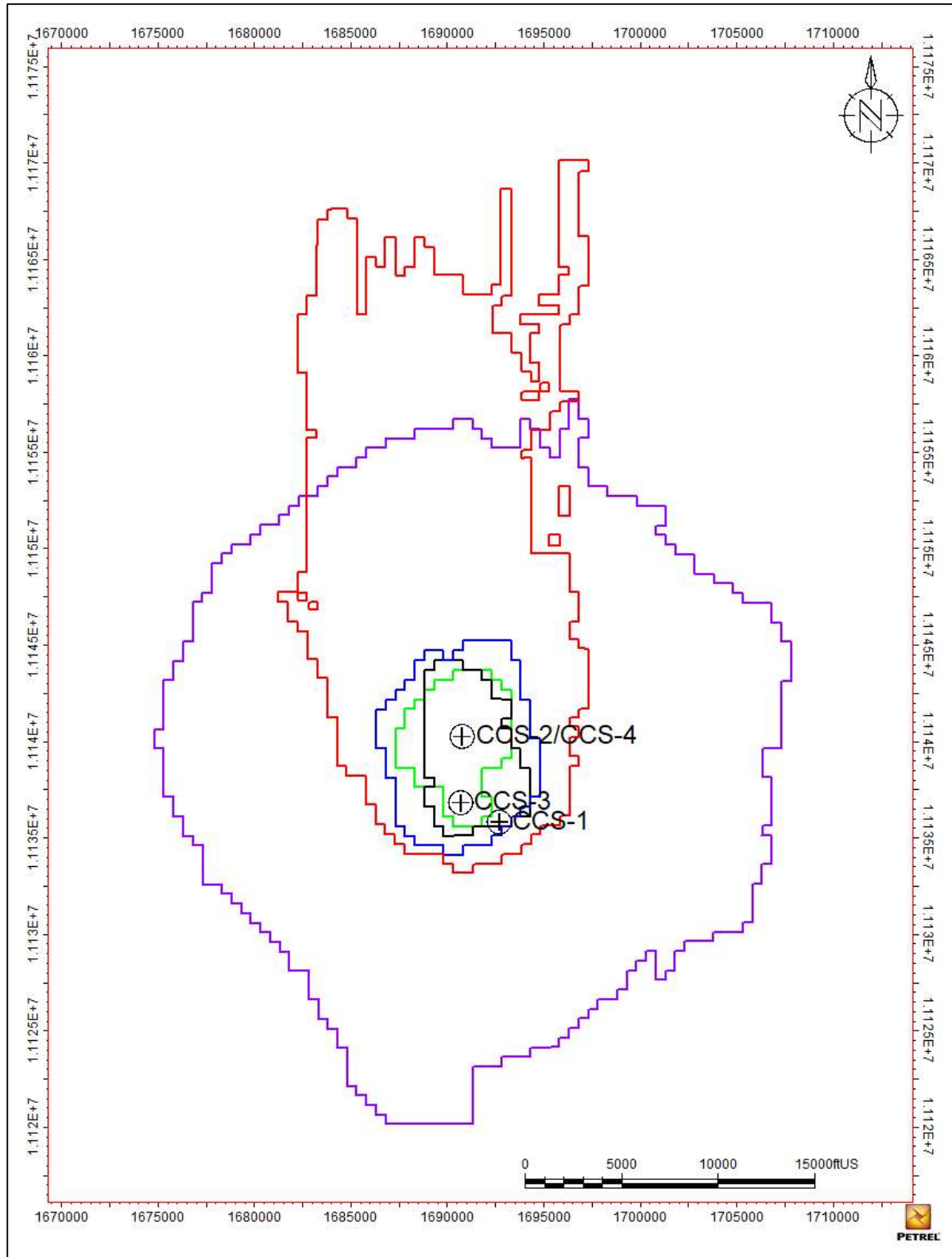


Figure AOR-35—Areal view of the threshold pressure front (>96 psi) at maximum areal extent (8½ years after start of injection), shown by the purple outline. The extent of the pressure front after 5, 10 and 15 years after start of injection is indicated by green, black and blue lines, respectively.

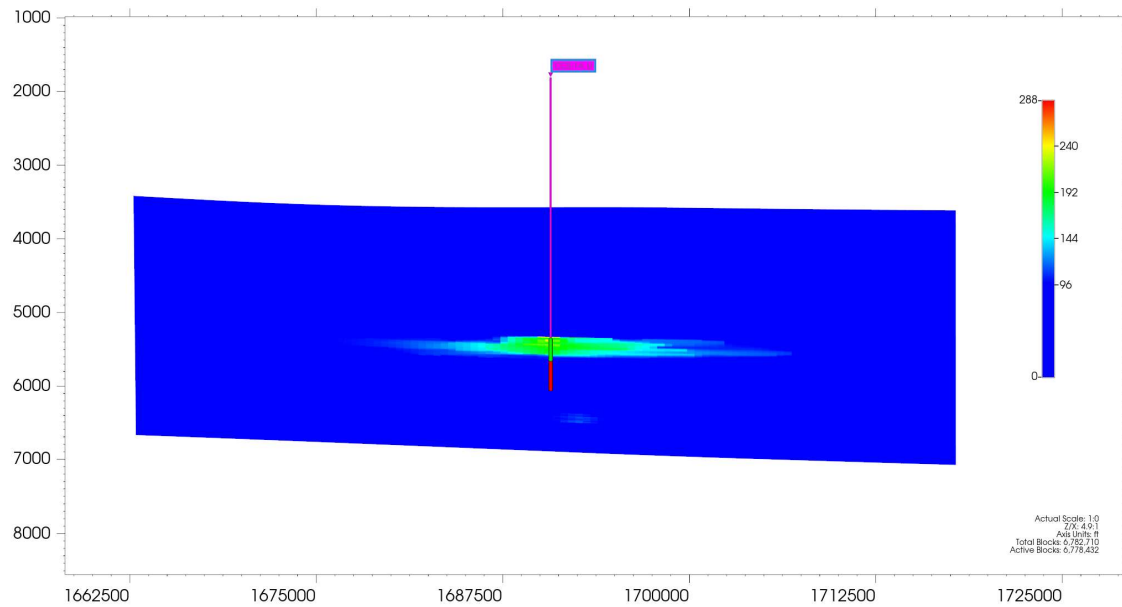


Figure AOR-36—S–N cross-section through injection well Magnolia CCS 3 showing the vertical extent of the pressure front at maximum differential pressure (8½ years after start of injection).

4.2.2 CO₂ plume extent

The injected CO₂ is concentrated near the injection wellbore, and the CO₂ concentration declines with distance away from the wellbore. A high-permeability layer in the model may result in a larger plume extent than is detectable by seismic monitoring. In addition, the grid size and numerical dispersion introduce uncertainty of ± 500 ft on the CO₂ plume edges. Therefore, Oxy chose to implement the method described by Zhang et al. (2015), which quantifies the CO₂ plume by a percentage of the total CO₂ mass.

A value of vertically integrated mass per unit area (VIMPA) is calculated for any area of the grid containing a mass of CO₂, then the cumulative percent mass and percent area of the CO₂ plume are plotted against the VIMPA value. This plot for the Magnolia injection site at 100 years after end of injection is shown in Figure AOR-37. The CO₂ plume for the Magnolia injection site is the area in which 99% of the CO₂ resides, designated by VIMPA₉₉. In Figure AOR-38, 99% of the CO₂ mass at 100 years after end of injection resides in approximately 62% of the total plume area. VIMPA is a vertically integrated value, which projects the CO₂ plume onto a 2-D surface. A different variable is required to view a cross-section of the plume. Figure AOR-39 shows a north-south cross-section through well Magnolia CCS 1 of gas-saturation > 0.01 fraction at 50 and 100-years post-injection. The plumes at the two time periods illustrate the increase in CO₂ saturation with time and the confinement of the CO₂ within the intended zones.

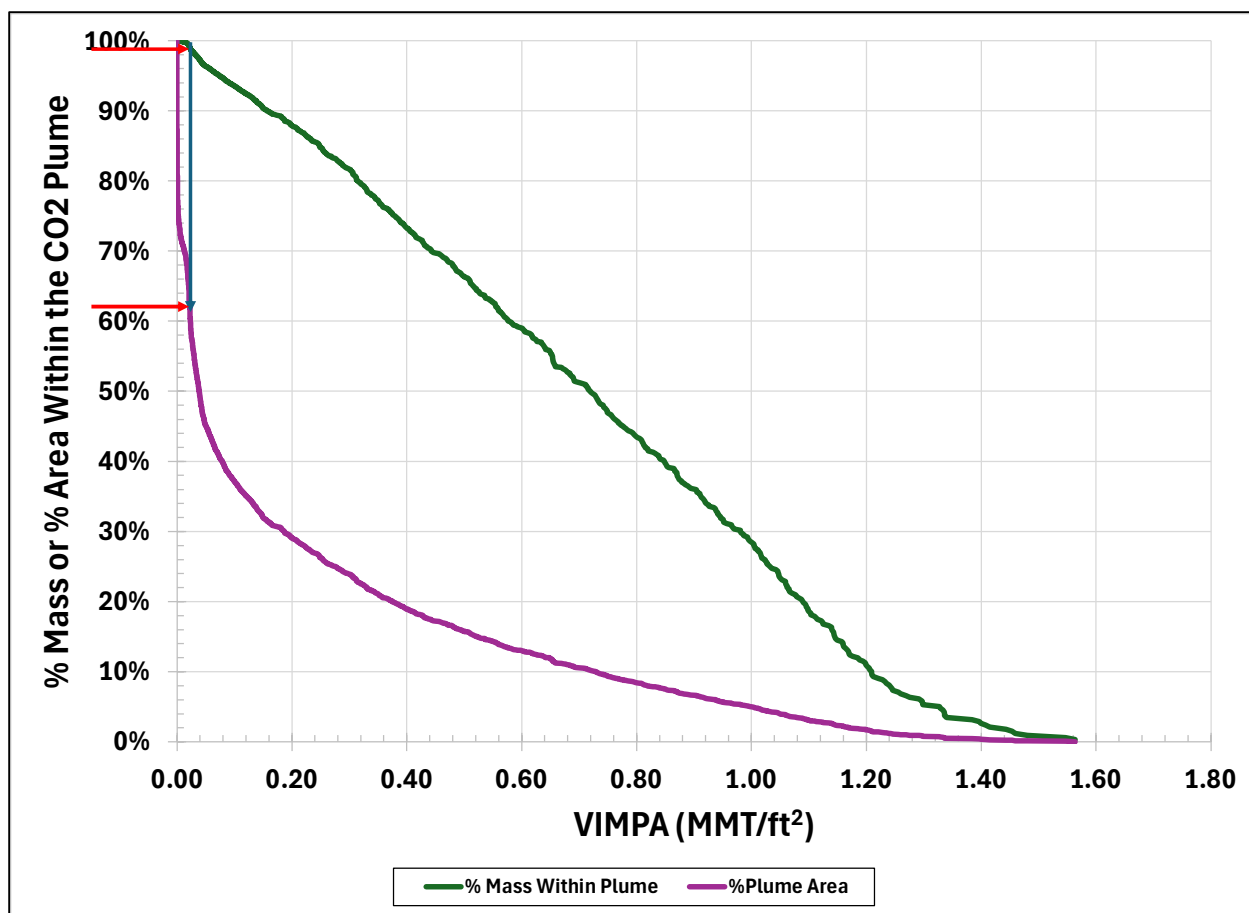


Figure AOR-37—Percent mass of CO₂ within the plume and percent of the plume area as a function of VIMPA.

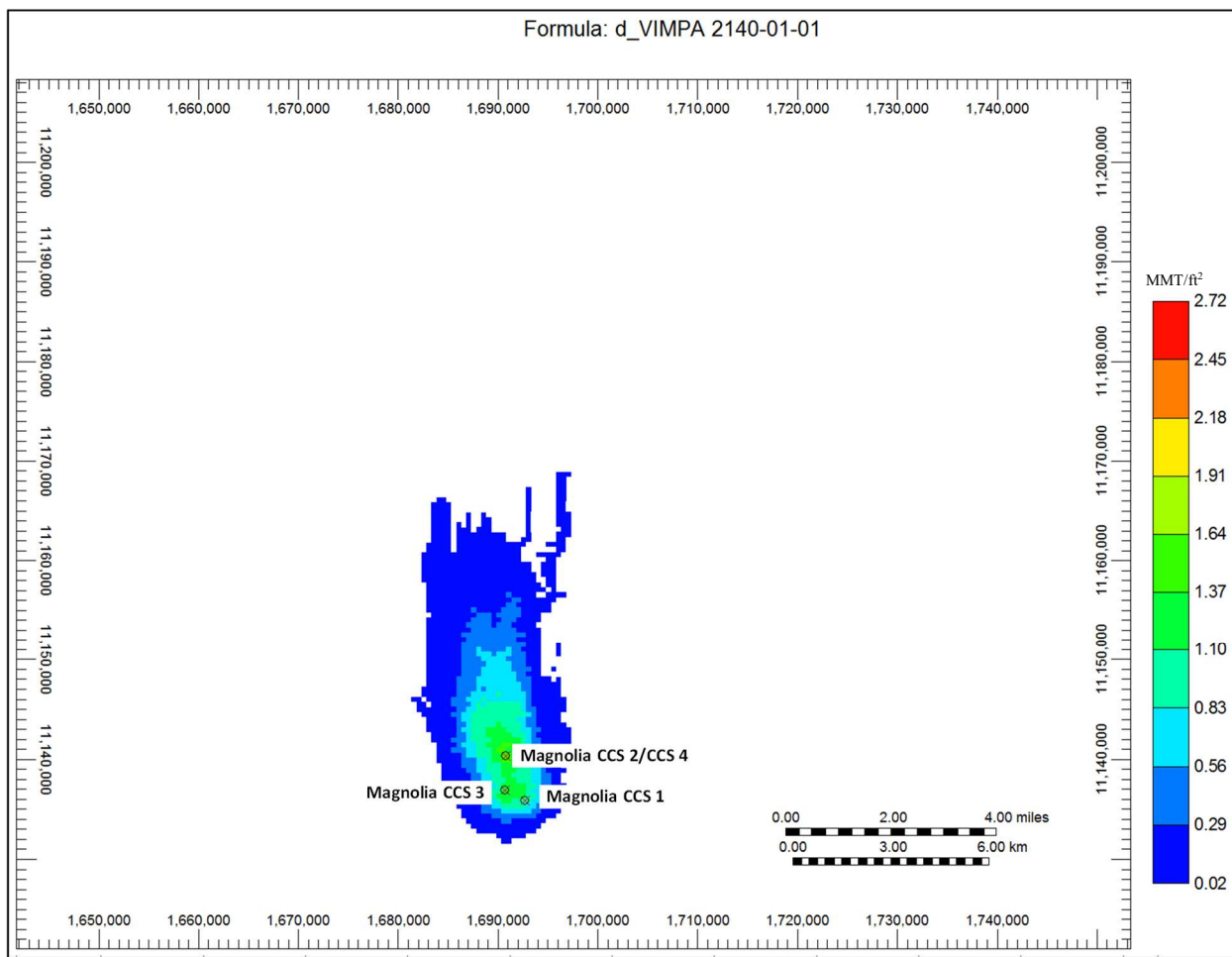


Figure AOR-38—CO₂ Plume defined by VIMPA₉₉ (MMT/ft²) at 100 years post-injection site closure (PISC).

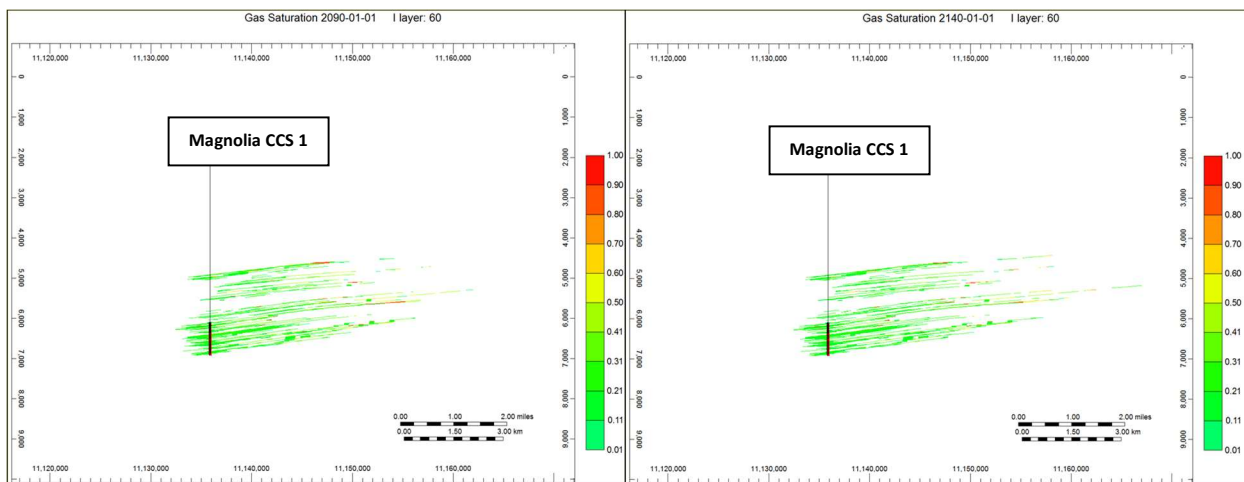


Figure AOR-39—South-North cross-section through well Magnolia CCS 1 showing simulated gas saturation in at 50 and 100 years PISC (simulation years 65 and 115).

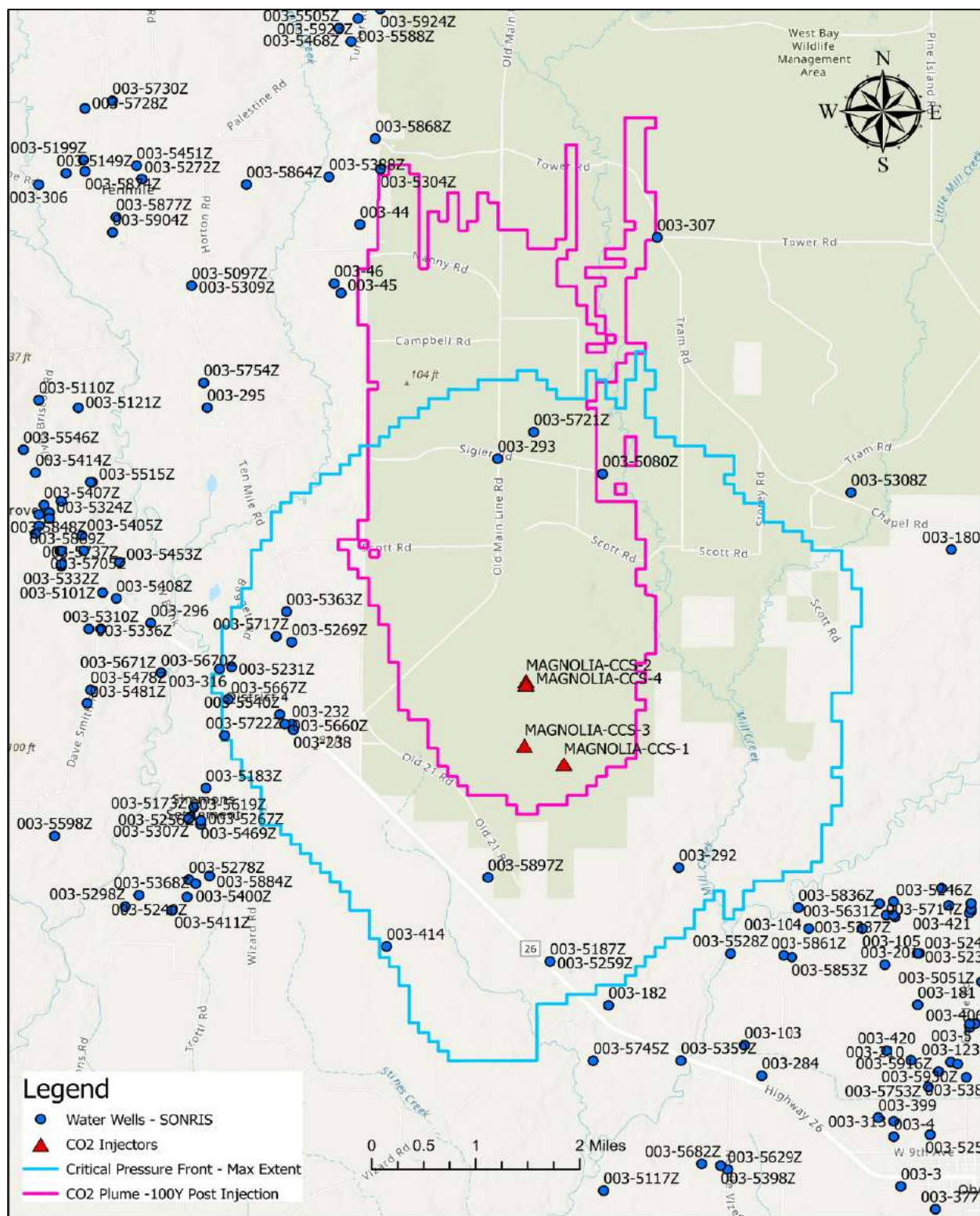
4.2.3 Combined area of review

The final AOR is the combination of the maximum pressure front and the maximum CO₂ plume and is shown on Figure AOR-40. The CO₂ plume is illustrated by the pink line, while the pressure front is shown by the light blue line. The predicted evolution of the CO₂ plume and pressure front relative to the monitoring locations is shown in the Testing and Monitoring Plan (TM) document and the Post-Injection Site Care and Site Closure Plan (PISC) document of this permit.



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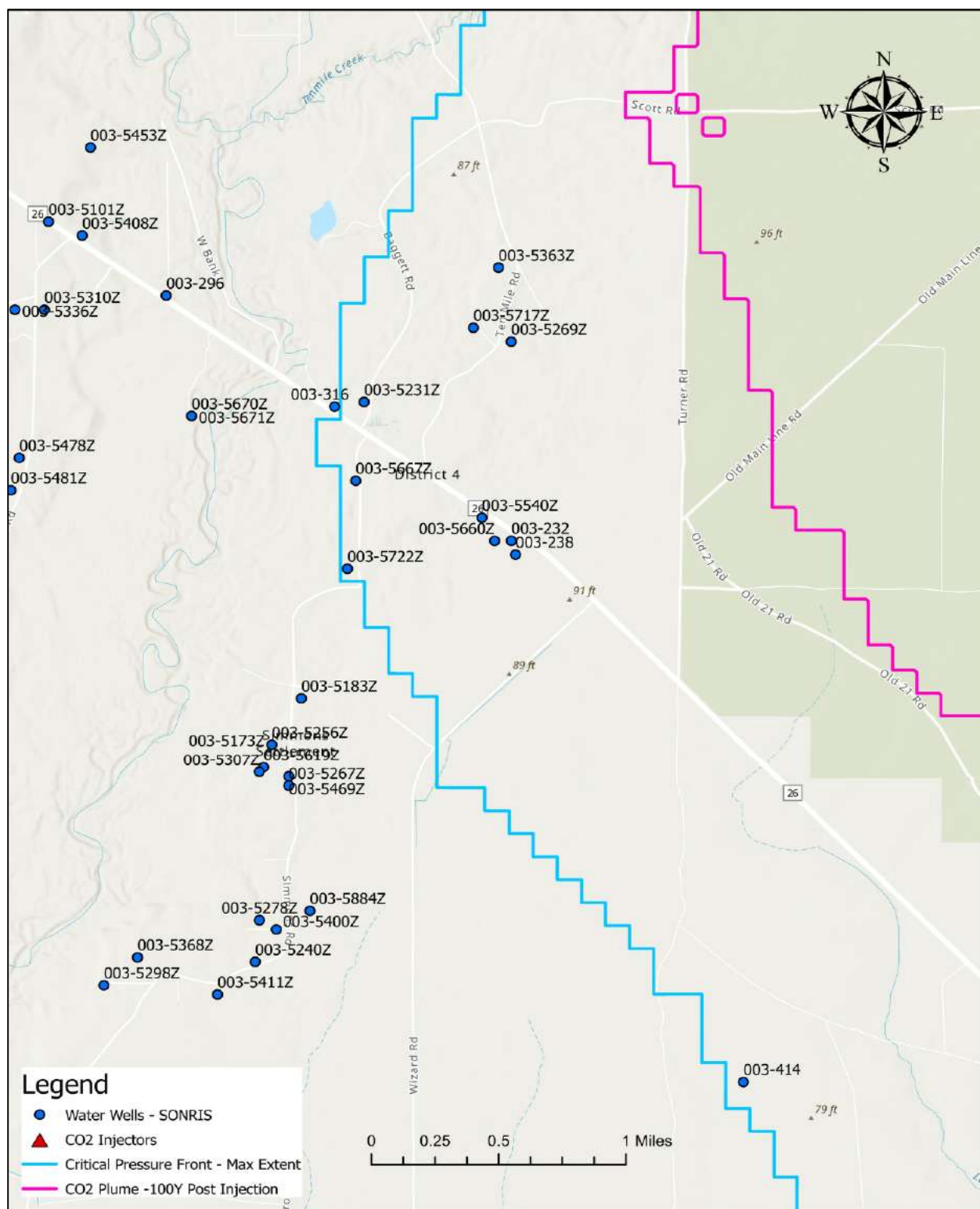


Figure AOR-42—Western edge of maximum threshold pressure front. Legacy water wells are indicated by the well number and symbol.

4.3 Fault Leakage Assessment

The southernmost portion of the Area of Review as defined by the threshold pressure front (96 psi increase) appears to interact with Fault 1 (Figure AOR-12), however the magnitude of pressure change (97 psi) predicted at the fault intersection is significantly below calculated pressure increase required to induce fault slip (1100 psi, explained in Section 2.9). Thus, effects resulting from this distal southern pressure front extent and the fault are expected to be negligible.

A synthesis of regional and local data demonstrates that no through-going or transmissible faults are present within the storage complex across the calculated CO₂ plume extent. See NAR Section 2.2.1.1 for a detailed discussion of fault delineation using 2D seismic data within the area—including data not available at the time of previous permit submittal.

4.4 Geochemical Modeling

4.4.1 Background and Literature Review

The main reactive-transport pathways in clastic reservoirs for CCS projects are: (1) carbonic gas dissolution into formation waters, (2) carbonic acid increase, (3) resulting mineral dissolution and precipitation, and (4) overall net CO₂ mineralization for long-term storage. Dissolution or precipitation of minerals can alter reservoir porosity and permeability, affecting sequestration storage capacity, well injectivity, and confining zone integrity. Quartz is the dominant mineral in the Upper and Lower Frio Injection Zones, and a mixture of quartz and clays are the dominant minerals in the Composite Confining Zone. Reactive-transport reservoir simulations of clastic reservoirs injected with CO₂ typically show negligible effects due to the dominance of nonreactive solid phases. Geochemical and reactive-transport literature review was performed to evaluate the lessons learned from previous projects and available site-specific data.

Approximately 1,600 tons of CO₂ was injected into the Frio Formation (sand) over 10 days in 2004 during the Frio-I pilot in southeast Texas. Post-injection measurements were acquired to evaluate short-term geochemical impacts such as injection and monitoring wells for fluid sampling, saturation logs, and pressure data collection. Publications showed attempts to interpret observed results in relation to reactive-transport modeling and main findings are described in the following paragraphs.

Hovorka et al. (2006) provided a comprehensive overview of the executed Frio-I pilot program with details on experimental design, reservoir characterization, well construction, injection and hydrogeological testing, seismic profiling, well logging, tracer tests, fluid sampling, modeling, and monitoring. Geochemical analysis, fluid sampling, modeling, and monitoring are regarded as most important. The authors reported issues with degassing effects and temperature changes that might have significantly affected fluid sampling data. Early time fluid samples showed high (93,000 mg/L) TDS and low CO₂ concentrations. Within hours of injection, fluid samples in the nearby monitoring well showed a sharp drop in pH (from 6.7 to 5.8) and a large increase in CO₂, bicarbonate, iron, calcium, and magnesium concentrations. After the injection period, fluid pH showed a tendency to steadily increase. Modeling showed acceptable agreement between observed data and simulations.

Kharaka et al. (2006) corroborated the findings provided by Hovorka et al. (2006), showing the same results for fluid sampling and monitoring in Frio-I. However, the authors provided a more

detailed interpretation of results. The authors showed pH is the most sensitive parameter to track subsurface CO₂ concentrations. In addition, the authors discussed pH values modeled prior to collecting field data was 3.0, much lower than values observed in the field. The higher pH values observed in the field were attributed to presence of carbonate minerals buffering the CO₂-carbonate system equilibria, in line with an earlier hypothesis by Hovorka et al. (2003).

Hovorka et al. (2009) reported the results of continued monitoring of the Frio-I pilot conducted in 2004, and a second injection test, called Frio-II, conducted in 2006. The subsequent Frio-II 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 and increase in alkalinity, iron, calcium, and magnesium in monitoring wells during CO₂ breakthrough. The authors discussed modeling limitations for observed iron concentrations increases that was not initially predicted. Increasing iron concentration was attributed to three causes: (1) combinations of various reactions, (2) dissolution of Fe-oxyhydroxides, and (3) corrosion of carbon steel tubing in contact with acidic environment. Kharaka et al. (2009) developed a detailed chemical model on possible dissolution of iron-bearing minerals using complex redox reactions. The authors concluded that no vertical leakage was observed from the Frio sand into the Anahuac shale formation. Both publications could not determine the origin of increased iron content at that time and considered materials corrosion in the subsurface as a reasonable source.

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 for initial assessments to consider batch equilibrium reactions in combination with reactive-transport simulations for improved results accuracy. In addition to primary mineral compositions (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. Xu et al. (2010) models also considered the unusual increase in iron concentrations observed at the monitoring well, assuming that materials corrosion was not a factor. Simulation results showed rapid carbonate mineral dissolution occurred during injection but was followed by carbonate reprecipitation upon cessation of injection. Results showed a strong tendency for kaolinite and illite precipitation and a stable suite of secondary minerals.

Results and interpretations from previous studies are not necessarily meant to represent site-specific behavior for the current project but serve as a valuable reference for expected geochemical reactions at carbon sequestration sites. Important differences exist between the Frio-I pilot and Magnolia Sequestration Project, such as brine and mineral compositions, reservoir conditions and quality, and cumulative CO₂ storage volumes. Therefore, geochemical equilibrium and reactive-transport simulation modeling was conducted for the Magnolia Sequestration Project 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.

4.4.2 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 the CO₂ compatibility with rocks and fluids in the reservoir and confining units. The modeling includes brines speciation, geochemical baseline prior injection, and CO₂ interaction with reservoir brine and minerals.

Table AOR-14 shows the brine compositions for the reservoir and confining system 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 insignificant concentration values and were not tracked during modeling. Table AOR-15 describes mineralogy used in geochemical equilibrium runs for the reservoirs and confining system. Values were obtained from XRD analysis of representative samples within each reservoir or confining system interval.

Table AOR-14—Brine chemical compositions used in geochemical and reactive-transport simulations.

Name	Description	Units	Composite Confining	Upper Frio	Lower Frio
Sample Depth	-	ft	4,450	5,100	6,936
Sample Pressure	-	psi	1,969	2,262	3,117
Sample Temp	-	°F	131	143	161
TDS	Gravimetric	mg/L	132,690	131,148	127,561
pH	Lab	SU	7.4	7.54	7.5
Sodium	Na ⁺	mg/L	33,018	35,103	34,637
Calcium	Ca ²⁺	mg/L	3,912	3,114	3,098
Magnesium	Mg ²⁺	mg/L	1,034	851	705
Potassium	K ⁺	mg/L	190	177	261
Strontium	Sr ²⁺	mg/L	197	202	255
Barium	Ba ²⁺	mg/L	125	82	61
Silica	SiO ₂ (aq)	mg/L	20	21	29
Aluminum	Al ³⁺	mg/L	1.0 x 10 ⁻³	1.0 x 10 ⁻³	1.0 x 10 ⁻³
Iron (II)	Fe ²⁺	mg/L	1.0 x 10 ⁻³	1.0 x 10 ⁻³	1.0 x 10 ⁻³
Chloride	Cl ⁻	mg/L	60,830	62,2E71	60,665
Total Alkalinity	Alkalinity	mg CaCO ₃ /L	116	120	152
Borate	B(OH) ₃ ⁻	mg/L	70	145	134
Bromide	Br ⁻	mg/L	71	84	72
Sulfate	SO ₄ ²⁻	mg/L	5.0	4.5	4.7

Table AOR-15—Solid-phase mineralogy from RSWC XRD data used in geochemical equilibrium and reactive-transport simulations.

Mineral (wt. %)	Composite Confining	Upper Frio	Lower Frio
Quartz	44.3	81.5	84.9
K-Feldspar	6.8	4.4	4.8
Plagioclase	8.8	6.0	3.0
Anatase	0.1	0.0	0.1
Calcite	0.6	0.2	0.1
Siderite	0.0	0.0	0.0
Pyrite	0.5	0.4	0.3
Illite/Smectite	38.1	7.2	6.2
Kaolinite	0.5	0.2	0.4
Chlorite	0.3	0.1	0.2

Although some chemical reactions are known to be time dependent, equilibrium assumptions were 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 CO₂ 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 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 CO₂ 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 0.044, 0.011, and 0.021 atm for the Composite Confining Zone, Upper Frio, and Lower Frio, 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, 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 CO₂ to represent the most

aggressive injection case. Table AOR-16 shows results the current fluid equilibrium state the reservoirs and confining system, respectively. 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. Confining system results suggest fluids are in equilibrium with the formation mineralogy including barite, calcite, dolomite, illite, kaolinite, k-feldspar, and quartz. Frio reservoir fluids are in equilibrium with barite, k-feldspar, and quartz, which suggest there is some limitation to vertical connectivity at recent timescales between the reservoir and confining system.

Modeled pH is noticeable lower in comparison to laboratory measured values. This result can be explained by CO₂ exsolving from fluids exposed to atmospheric conditions during analysis. Even rapid laboratory analytical result in CO₂ loss prior to measurements, resulting in a shift to more basic conditions (Appelo and Postma, 2005, page 14). Here, the confining system and Frio reservoirs show calculated pH values similar to those reported in the literature (Kharaka et al. 2009 and Xu et al., 2010).

Table AOR-16—Mineral saturation indexes and reservoir pH of formation waters in Composite Confining and Frio Reservoirs prior to CO₂ injection (baseline reservoir condition).

Model Results (SI)	Composite Confining	Upper Frio	Lower Frio
pH (SU)	6.4	7.1	7.1
Anhydrite	-3.0	-3.2	-2.9
Barite	0.2	0.0	-0.3
Calcite	-0.2	0.5	1.0
Celestite	-2.5	-2.5	-2.3
Dolomite	0.7	1.9	2.9
Gypsum	-3.1	-3.3	-3.2
Halite	-1.6	-1.6	-1.6
Illite	-0.8	-1.2	-2.2
Kaolinite	-0.6	-1.6	-2.8
K-Feldspar	0.0	0.25	-0.28
Plagioclase	-7.1	-7.1	-6.6
Quartz	0.29	0.34	0.19
Strontianite	0.84	1.67	2.00

Baseline (pre-injection) equilibrium modeling included the addition of formation mineralogy previously described in Table AOR-15. Similar mineral stability tendency is observed for the confining system and reservoirs (Table AOR-16). Pre-injection, formation waters are saturated with respect to calcite, dolomite, 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's 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-17—Mineral stability tendency and fluid pH of Composite Confining and Frio Formations in Equilibrium with Reservoir Mineralogy.

Model Results	Composite Confining	Upper Frio	Lower Frio
pH (SU)	6.4	6.7	6.5
Fluid TDS	Minor increase	Minor decrease	Minor decrease
Reservoir Porosity	Major Decrease	Minor Decrease	Minor Decrease
Anhydrite	Dissolution	Dissolution	Dissolution
Barite	Minor precipitation	Stable	Stable
Calcite	Precipitation	Precipitation	Precipitation
Celestite	Dissolution	Dissolution	Dissolution
Dawsonite	Dissolution	Dissolution	Dissolution
Dolomite	Precipitation	Precipitation	Precipitation
Gypsum	Dissolution	Dissolution	Dissolution
Halite	Dissolution	Dissolution	Dissolution
Illite	Stable	Stable	Stable
Kaolinite	Precipitation	Precipitation	Precipitation
K-Feldspar	Precipitation	Precipitation	Precipitation
Plagioclase	Dissolution	Dissolution	Dissolution
Pyrite	Stable	Stable	Stable
Quartz	Stable	Stable	Stable
Strontianite	Minor precipitation	Minor precipitation	Minor precipitation

Geochemical equilibrium modeling of formations fully saturated with CO₂ to simulate injection suggest CO₂ addition cause minor effects on mineral saturation states. CO₂ fugacity was assumed to be 2.08, 2.35, and 2.87 for 100% CO₂ gas at confining system, Upper Frio, and Lower Frio formation temperatures and pressures, respectively. Table AOR-18 shows the mineral stability tendency after equilibration for each sample in the confining system and Frio reservoirs.

Negligible changes for mineral saturation states were observed for most minerals when comparing results for existing (Table AOR-17) versus fully saturated (Table AOR-18) Values for pH are predicted to decrease approximately 1.0 standard units (SU). Minor precipitation of Dawsonite is predicted only in the Upper Frio reservoir. Minor dissolution of illite is predicted in this model, however, the model allows dolomite precipitation which consumes ions that would otherwise facilitate illite precipitation 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 CO₂ dissolved in water shifts the equilibria to more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite. However, dynamics in the reservoir during injection are more complicated as reactions are time dependent and calcite likely dissolves first at lower pH, reprecipitating at later times (equilibrium conditions).

Compared to the Frio reservoirs, the composite confining system shows low reactivity and a large porosity loss due to high proportions of clay minerals and mineral reprecipitation in the pore space. This finding corroborates the assumption that CO₂ 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-18—Change in mineral stability tendency and fluid pH of Composite Confining and Frio Formations in Equilibrium with Reservoir Mineralogy and Saturated CO₂.

Model Results	Composite Confining	Upper Frio	Lower Frio
pH (SU)	5.4	5.3	5.4
Fluid TDS	-	-	-
Reservoir Porosity	-	-	-
Anhydrite	-	-	-
Barite	-	-	-
Calcite	Inc. Precipitation	Inc. Precipitation	Inc. Precipitation
Celestite	-	-	-
Dawsonite		Precipitation	-
Dolomite	-	-	-
Gypsum	-	-	-
Halite	-	-	-
Illite	Minor dissolution	Minor dissolution	Minor dissolution
Kaolinite	-	-	-
K-Feldspar	-	-	-
Plagioclase	Inc. Dissolution	Inc. Dissolution	Inc. Dissolution
Pyrite	-	-	-
Quartz	-	-	-
Strontianite	-	-	-

4.4.3 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 are not included in simulations (e.g. pyrite) and are 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 CO₂ storage affect 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-9). In total, 14 aqueous species were initialized in reservoir connate water and allowed to flow with aqueous phase in the reactive-transport simulations. 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^+ , MgHCO_3^+ , and AlOH^{+2} . The selection of aqueous complexes was based on the simulation results from geochemical equilibrium runs with minerals and CO₂. 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.

Figure AOR-43 shows results for fluid pH values upon cessation of injection and 400 years post-injection, aggregated across all model layers. Reservoir fluid pH values pre- and post-injection are similar (compare 7.0 and 5.4) to equilibrium values obtained from equilibrium modeling (Table AOR-16; Table AOR-18).

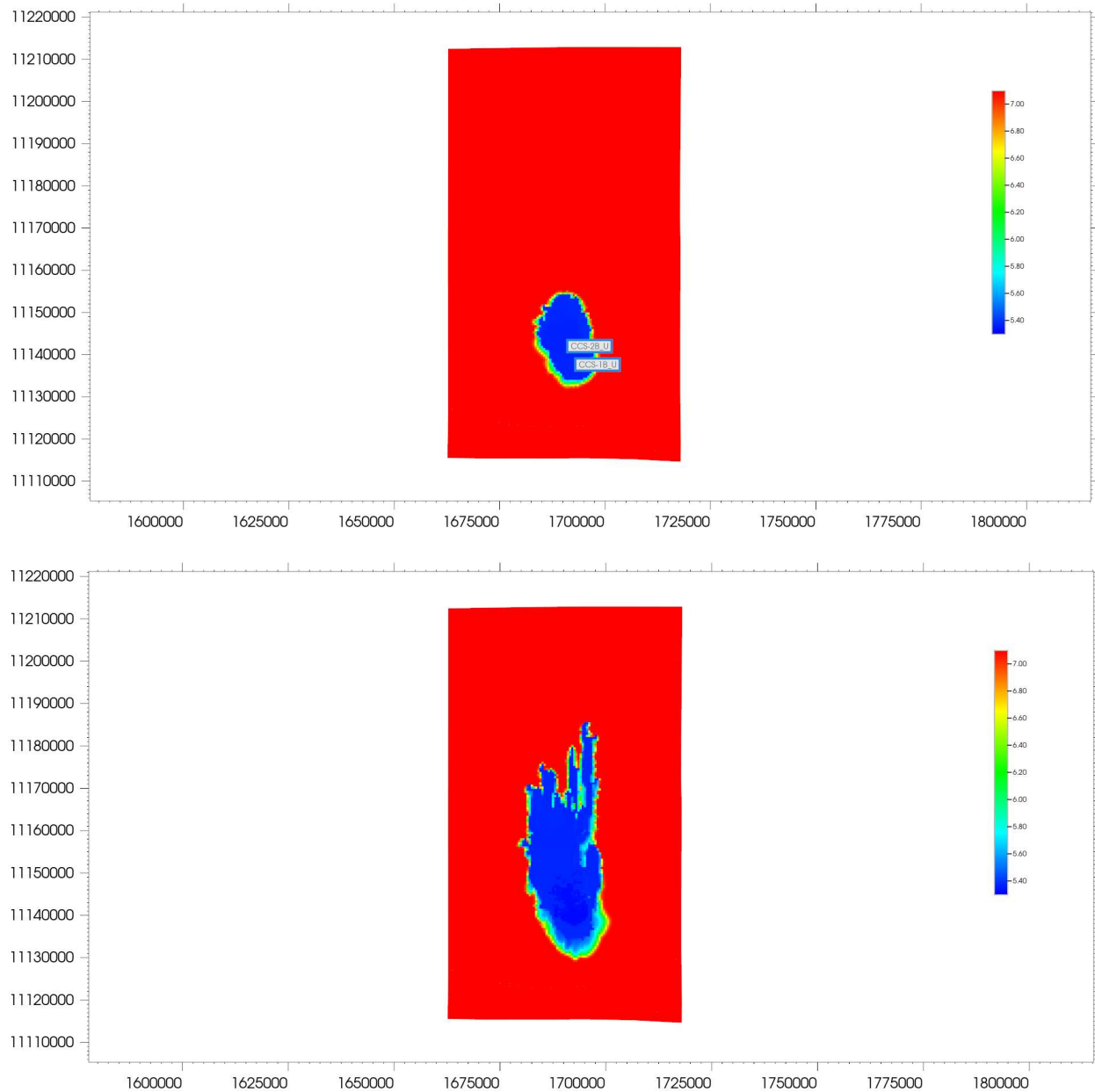


Figure AOR-43—Aggregate view for all model layers of modeled fluid pH at (top) 0-yr post-injection CO₂ and (bottom) 400-yr post-injection CO₂.

Figure AOR-44 shows the reservoir mineral volume change for calcite, plagioclase, kaolinite, illite, k-feldspar, dolomite and quartz from injection through 500 years post-injection. Dissolution of calcite and anorthite with precipitation of kaolinite is observed during injection. The initial dissolution of calcite is expected and been reported in several previous publications (Xu et al., 2010, Hovorka et al. 2009). Post-injection, plagioclase continues to dissolve while calcite starts to reprecipitate. Kaolinite and minor illite precipitation continue post-injection, related to dissolution of plagioclase which releases additional dissolved aluminum into formation waters. Calcite reprecipitation is attributed to excess dissolved calcium and bicarbonate from calcite dissolution during injection.

Modeled porosity changes due mineral dissolution and precipitation at end of the injection period and 400 years post-injection are shown in Figure AOR-45 and Figure AOR-46. Negative and positive values represent the amount of increase and decrease from the initial porosity, respectively. Mineral dissolution resulting in a porosity increase of a maximum of 0.2% in Frio reservoirs at the end of injection. Porosity remained unchanged for the confining system due to the presence of low-permeability shales that prevent vertical upward migration of CO₂-saturated fluids. Porosity decreases observed over longer timescales are related to calcite and kaolinite precipitation. Mineral precipitation caused a maximum decrease in porosity of about 2.2% in the region where the CO₂ plume contacted the reservoir at late time post-injection.

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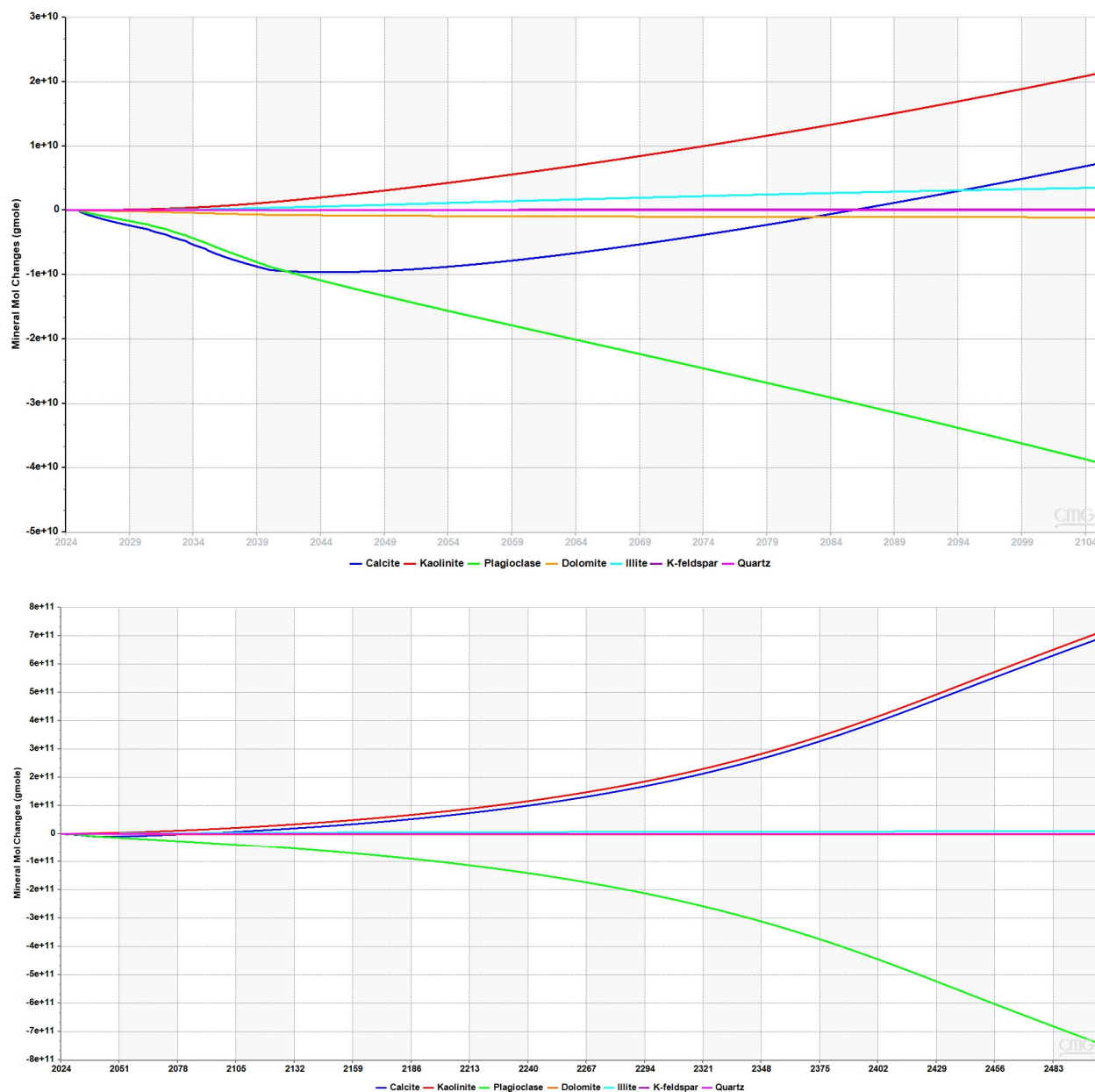


Figure AOR-44—Modeled molar change of minerals at (top) 0-yr post-injection CO₂ and (bottom) 500-yr post-injection CO₂.

AOR and CA Plan for Magnolia Sequestration Project

LA C&E Permit No. 45027, 45028, 45756, and 45757

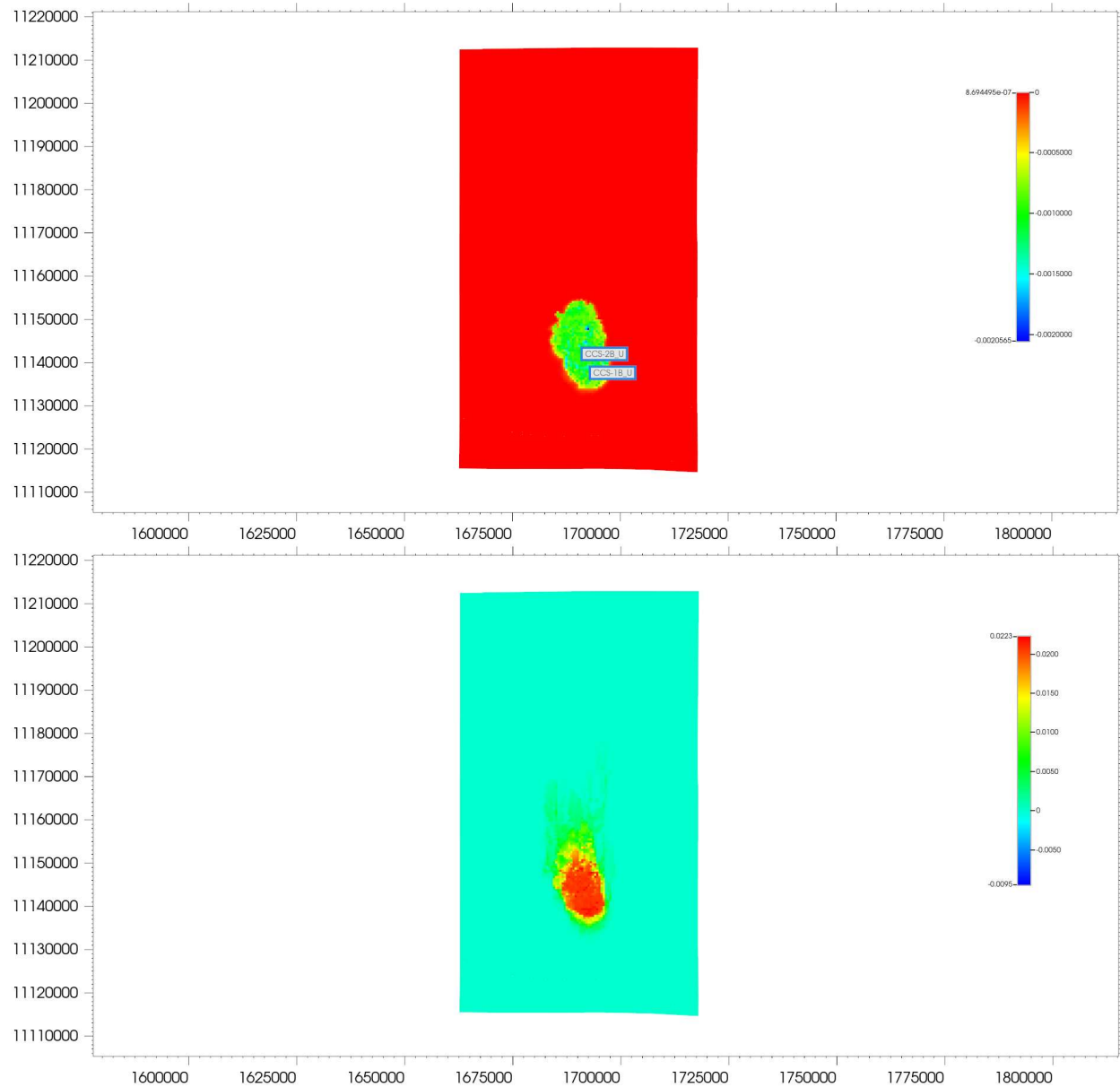


Figure AOR-45—Aggregate view for all model layers of modeled porosity changes due to (top) mineral dissolution at 0-yr post-injection CO₂ and (bottom) mineral precipitation at 400-yr post-injection CO₂.

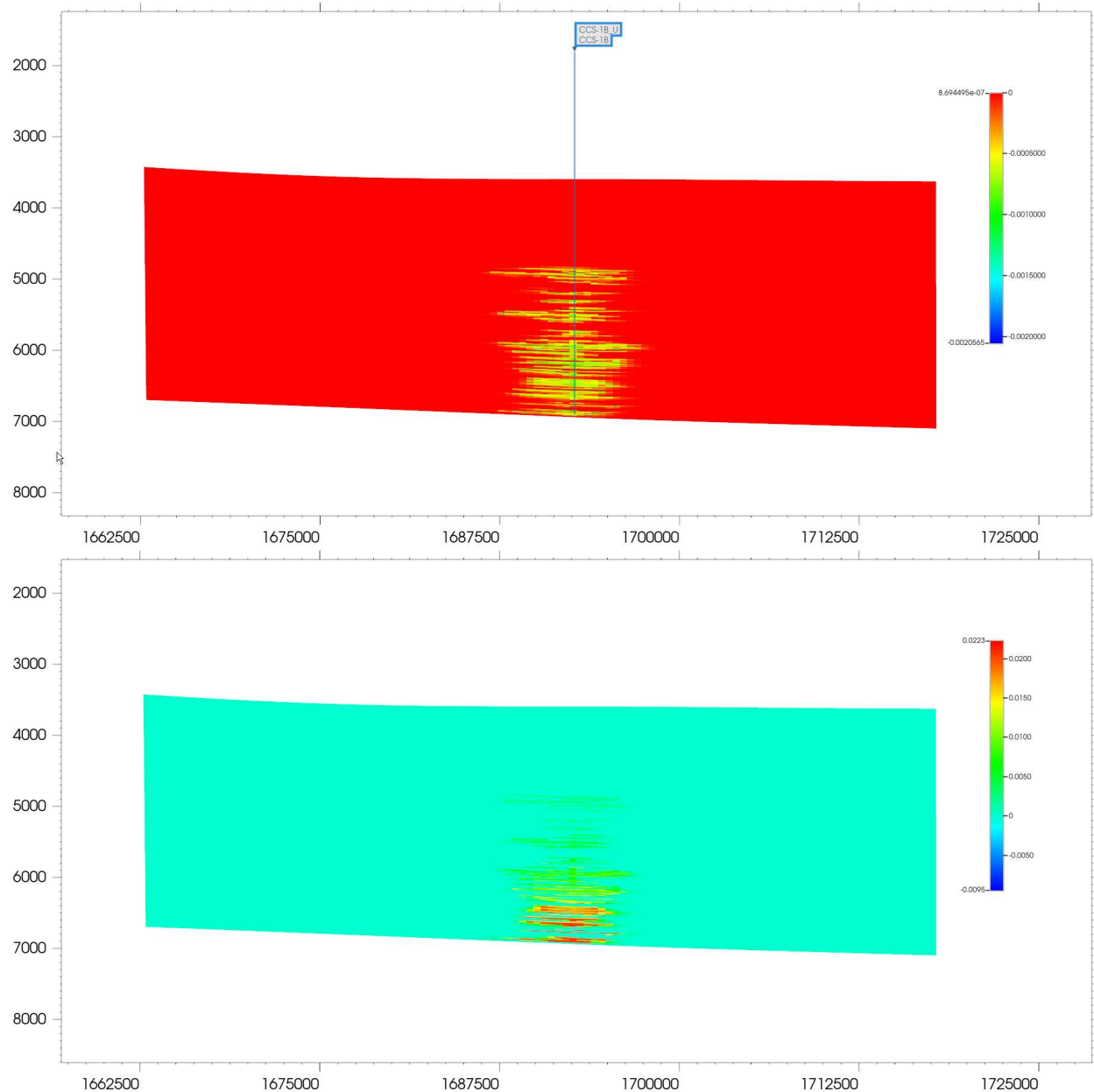


Figure AOR-46—Select E-W cross-section view of modeled porosity changes due to (top) mineral dissolution at 0-yr post-injection CO₂ and (bottom) mineral precipitation at 400-yr post-injection CO₂.

Modeled CO₂ trapping mechanisms (aqueous, dissolved in water, mineralization, super-critical mobile and trapped in residual phase) are shown in Figure AOR-47. Results show primary trapping mechanisms of injected CO₂ at injection timescales is the super-critical phase as mobile and trapped CO₂. Mineral CO₂ storage is negative during injection due to calcite dissolution and release of bicarbonate. CO₂ is primarily mainly trapped in residual phase for hundreds of years as CO₂ is slowly sequestered (mineralized) as calcite. Post-injection, super-critical mobile CO₂ slowly decreases over time, reaching close to zero at long timescales.

Compositional simulation commonly shows larger CO₂ plume compared to reactive transport simulation. The reason is for the reactive-transport simulations having smaller CO₂ plume, even with smaller pore volume, is due to part of the CO₂ being transferred from the super-critical state to two additional conditions that are not modeled using conventional runs: conversion in aqueous ions (e.g., HCO₃⁻) and precipitation as solid phase (e.g., kaolinite, calcite). Thus, compositional simulations (without geochemistry) typically provide the most conservative assessment of CO₂ plume extent.

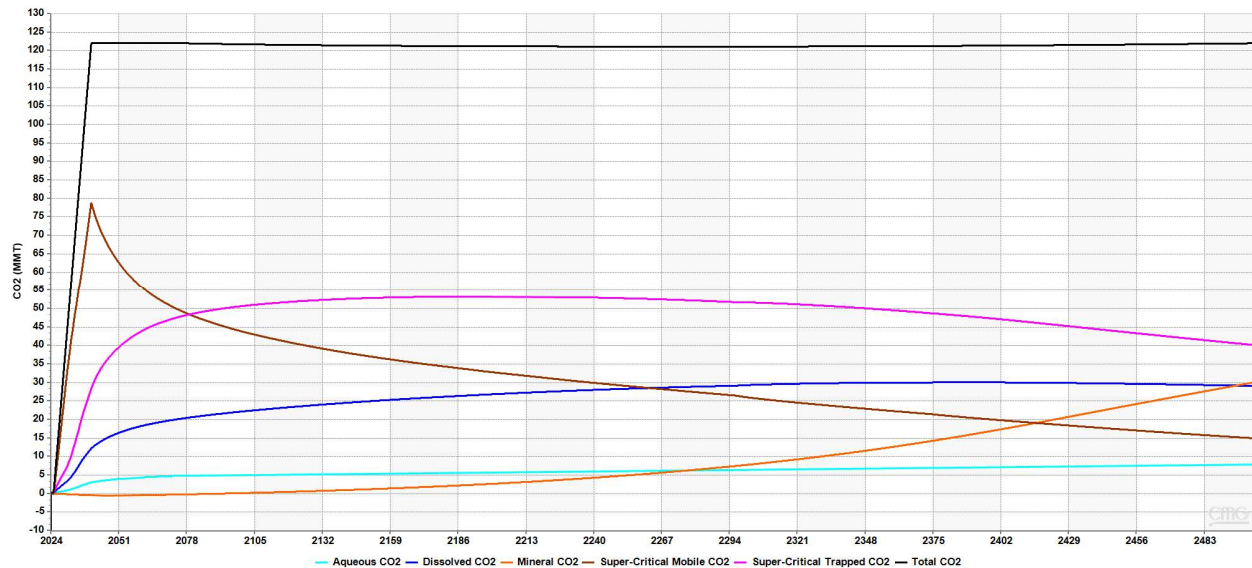


Figure AOR-47—CO₂ partitioning in reactive-transport model for 100 years post-injection.

5.0 Corrective Action

5.1 Tabulation of wells within the AOR

Pursuant to LAC 43:XVII.3607(C)(2)(d) and LAC 43:XVII.3607(C)(1)(a)(i) through (v), an exhaustive search using multiple methods is required to identify artificial penetrations (APs) in the Area or Review (AOR). Magnolia Sequestration Hub, LLC, used the following methods when evaluating the area:

- Public records searches
 - Strategic Online Natural Resources Information System (SONRIS) online records search and interactive Geographic Information System (GIS) viewer.
 - Third-party well databases licensed by Magnolia Sequestration Hub, LLC.
 - Review of historical aerial photos.
 - A hardcopy records search will be conducted in C&E central and regional offices following the magnetic survey
- Airborne magnetic survey
 - To be run before the start of injection to verify there are no unaccounted wellbores

The proposed AOR represents approximately 34 square miles of extension and includes nine legacy oil and gas wells and eighteen water wells, according to the records obtained from C&E. The location of these wells is shown in Figure AOR-48. The area is dedicated mostly to the lumber industry, recreational activities, and wildlife protection. 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 seven of the nine wells were classified as dry holes.

5.1.1 Water wells within the AOR

The eighteen water wells inside the AOR target the Chicot aquifer and are listed in Table AOR-19. The wells are mostly dedicated to domestic and irrigation activities, as well as supply for the lumber industry and the exploratory efforts of oil and gas companies. The measured depths range from 82 ft to 225 ft and target the Chicot aquifer system. Fifteen of these wells are still active, according to the C&E database. None of these eighteen wells penetrate the confining or injection zone or require any corrective action.

Table AOR-19—Water Wells within the Area of Review

Water Well Number	Well Depth, ft	Use Description	Well Status	Longitude	Latitude
003-232	225	Irrigation	Active	-92.8778	30.68833
003-292	124	Abandoned observation	Active	-92.8153	30.66722
003-5660Z	110	Institution public supply	Active	-92.8789	30.68833
003-5717Z	110	Domestic	Active	-92.8803	30.70111
003-5269Z	82	Domestic	Active	-92.8778	30.70028
003-293	84	Abandoned observation	Active	-92.8444	30.72694
003-5897Z	160	Oil/gas well rig supply	P&A	-92.8461	30.66583
003-5363Z	95	Domestic	Active	-92.8786	30.70472
003-238	171	Industrial lumber, wood products	Active	-92.8775	30.6875
003-5721Z	140	Plugged and abandoned rig supply	P&A	-92.8386	30.73083
003-5540Z	100	Domestic	Active	-92.8797	30.68972
003-5080Z	133	Oil/gas well rig supply	Active	-92.8275	30.72472
003-5187Z	90	Domestic	Active	-92.8361	30.65361
003-5667Z	90	Domestic	Active	-92.8881	30.69194
003-5722Z	115	Domestic	Active	-92.8886	30.68667
003-5231Z	90	Domestic	Active	-92.8875	30.69667
003-414	195	Irrigation	Active	-92.8625	30.65583
003-5259Z	93	Plugged and abandoned public supply	P&A	-92.8361	30.65361

5.1.2 Wells penetrating the confining zone within the AoR

The nine oil and gas wells within the Area of Review are listed in Table AOR-20. Well records for these wells are included as Appendix A. All oil and gas wells identified in the proposed AOR were drilled through the Lower Miocene upper confining zone into the Frio formation (injections Zone), with the deepest well reaching a total depth of 10,500 ft.

Seven of the nine oil and gas wells identified in the AOR were abandoned open holes and classified as dry holes. The exceptions are the LABOKAY CORP 1 (145083) and the YAMS MLR 004 (SN 975950).

The LABOKAY CORP 1 (SN 138757) was originally drilled through the Wilcox formation in 1972, abandoned open hole, and re-entered in 1984 targeting the Frio formation. The LABOKAY CORP 1 (SN 192222) re-entry has 5 ½" casing that is cemented at 5,800 ft. The perforated interval from 5,774 to 5,777 ft produced dry gas. In 1986 additional perforations were added from 5,876 to 5,880 ft without a significant increase in gas production. The well produced gas (117,857 Mscf cumulative) until it was plugged in 1990.

The YAMS MLR 004 (SN 975950) was the stratigraphic well drilled to collect data for the Magnolia project and will be converted to an in-zone monitoring well before the start of injection.

Table AOR-20—Oil and Gas Wells Inside Area of Review

Well Name (LA Serial No)	Status	MD (ft)	Field Name	Spud Date	P&A Date	Latitude	Longitude
INDUSTRIAL 1 (SN 23419)	D&A	10,305	WILDCAT	12/2/1939	1/23/1940	30.7304	-92.8389
INDUSTRIAL LBR CO INC 1 (SN 55859)	D&A	8,630	WILDCAT	3/13/1955	4/2/1955	30.7241	-92.8429
LABOKAY CORP 1 (SN 145083)	D&A	6,615	WILDCAT	6/26/1974	7/2/1974	30.7255	-92.8258
BOISE SOUTHERN 1 (SN 173375)	D&A	10,500	WILDCAT	5/26/1981	7/20/1981	30.7209	-92.8311
LABOKAY CORP 1 (Re-Entry) (SN 138757 & 192222)	P&A	13,488	MITTIE, EAST	1/7/1972	9/11/1990	30.7250	-92.8275
RESEARCH LABOKAY 1 (SN 238172)	D&A	10,000	WILDCAT	9/4/2008	9/29/2008	30.7310	-92.8386
QUATRE MINERAL LLC 1 (SN 252477)	D&A	5,806	WILDCAT	12/11/2020	12/20/2020	30.7310	-92.8386
YAMS MLR 004 (SN 975950)	WI- EOR	7,322	WILDCAT	11/1/2022		30.6741	-92.8328
LA BOKAY 1 (SN 235033)	D&A	8,500	WILDCAT	6/2/2007	7/16/2007	30.7472	-92.8618

5.2 Plan for site access

The project wells and the wells in the remediation plan are located inside the area negotiated for injection, and a perpetual servitude was granted for the project area to allow for all project activities during pre-construction, construction, injection and operations, post-injection site care, and site closure. There are already existing roads and infrastructure in place that will be used as-is or upgraded to provide access to project well sites.

5.3 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 formation are included in Appendix A.

The analysis was divided into two main categories to assess the risk and mitigations, based on the possible mechanism of failure:

- 1) **CO₂ 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 CO₂ 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/CO₂ leaks.
- 2) **Pressure front effect with brine contamination from deeper saline reservoirs to USDW aquifers and unauthorized zones.** This category includes wells that were not projected to be in contact with the CO₂ plume, but are inside the simulated pressure front. In this scenario, the wells were evaluated for proper hydraulic isolation between the injection zone and the 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, seven wells were identified that will require remedial actions to isolate the injection zone properly from the confining zone and USDW zones. These wells are listed in the Table AOR-21, along with the main mechanism of failure and the proposed schedule. The project plans to complement this evaluation with a magnetic survey in the proposed area before starting construction operations and injection, to adjust the corrective action schedule and program. If any additional wells that penetrated the confining zone are identified (i.e., if the AOR is re-delineated to cover a larger area because of an AOR reevaluation), a revised corrective action plan and schedule will be completed as needed pursuant to LAC 43:XVII.3615(C)(1).

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Table AOR-21—Wells to Be Remediated in the Proposed AOR

Well Name (LA Serial No)	Status	MD (ft)	Failure Mechanism	Schedule
INDUSTRIAL 1 (SN 23419)	D&A	10,305	CO ₂ Plume	Year 5
INDUSTRIAL LBR CO INC 1 (SN 55859)	D&A	8,630	CO ₂ Plume	Year 5
LABOKAY CORP 1 (SN 145083)	D&A	6,615	CO ₂ Plume	Year 15
BOISE SOUTHERN 1 (SN 173375)	D&A	10,500	CO ₂ Plume	Year 5
LABOKAY CORP 1 (Re-Entry) (SN 138757 & 192222)	P&A	13,488	CO ₂ Plume	Year 10
RESEARCH LABOKAY 1 (SN 238172)	D&A	10,000	CO ₂ Plume	Year 15
LA BOKAY 1 (SN 235033)	D&A	8,500	CO ₂ Plume	Year 15

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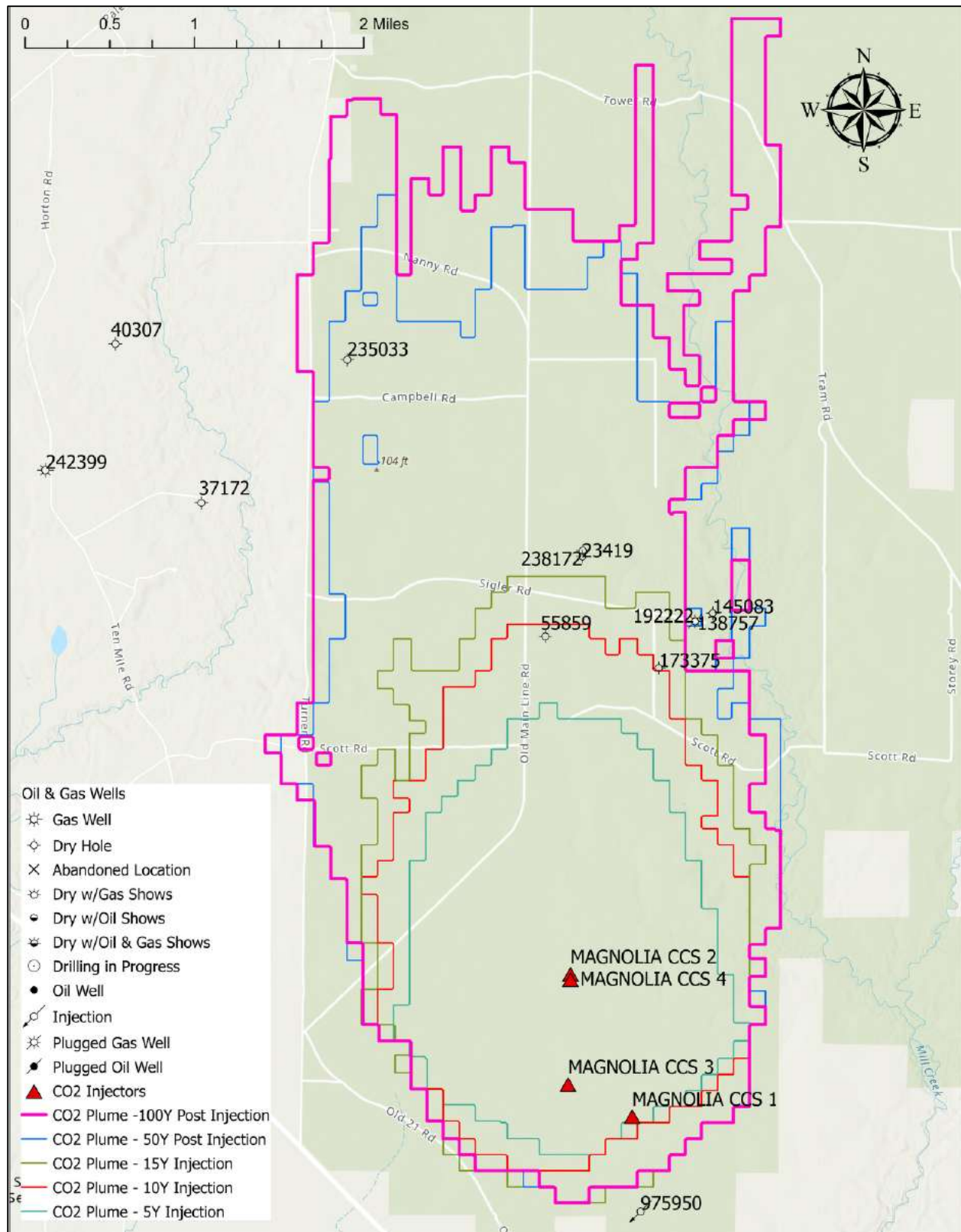


Figure AOR-48—Oil and gas wells and deep penetrations compared with CO₂ plume movement at 5 years, 10 years and 15 years of injection and 50 years and 100 years after injection.

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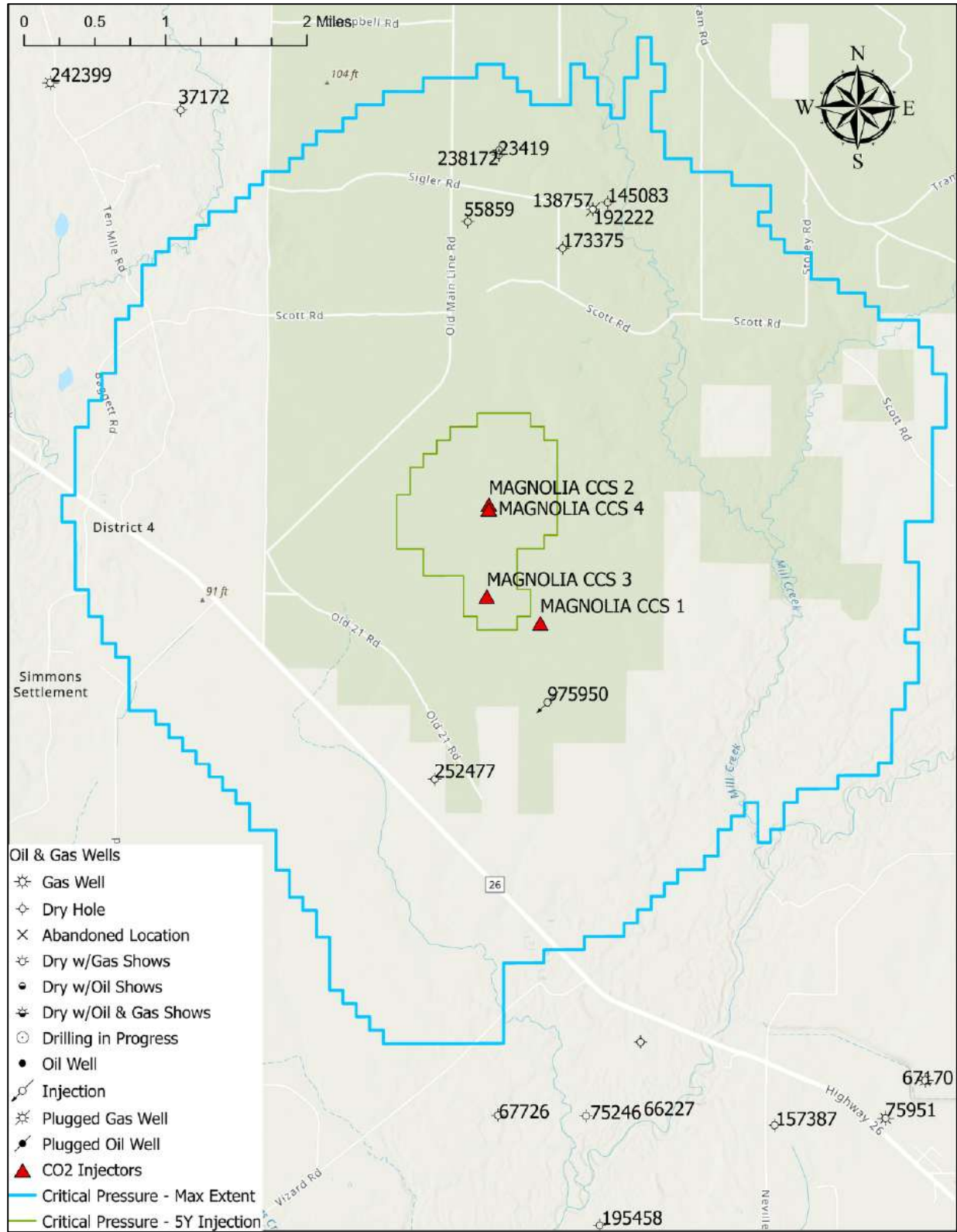


Figure AOR-49—Oil and gas wells and deep penetrations compared with the Threshold pressure at 5 years and the max Threshold pressure extent which occurs in year 8.

6.0 Re-evaluation Schedule and Criteria

6.1 AOR re-evaluation cycle

Magnolia Sequestration Hub, LLC will re-evaluate the AOR every five years during the injection and post-injection phases. In addition, monitoring and operational data will be reviewed periodically by Magnolia Sequestration Hub, LLC 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 CO₂ plume migration is consistent with the actual data. This includes data from the CO₂ injector wells, monitoring wells, geophysical surveys, and other sources. The monitoring activities to be conducted are described in the Testing and Monitoring (TM) Plan and the Post-Injection Site Care and Closure Plan (PISC).

Specific steps of this review and analysis include:

- Reviewing collected data on the position of the CO₂ plume and pressure front. This data will be collected from the CO₂ 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 Magnolia USDW monitoring wells and verify that there is no evidence of CO₂ 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 CO₂.
- 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.

6.2 Triggers for AOR reevaluations prior to the next scheduled re-evaluation

Unscheduled AOR reevaluations will be based on quantitative and material changes of the monitoring and operative parameters in CO₂ 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 pressure that are unexpected in timing or magnitude from those predicted by the model.
- **RST Saturation:** Increases in CO₂ saturation in the in-zone monitoring well that indicates a earlier breakthrough of CO₂.
- **Deep Groundwater Constituent Concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of CO₂ 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 in-zone monitoring well.
- **Induced Seismicity Monitoring:** Seismic monitoring data that indicates reactivation of a fault or structures due to pressurization of the reservoir because of the CO₂ injection. The project will review the monitoring data to discard naturally occurring events not related to the injection.

Oxy Low Carbon Ventures, LLC will discuss any such events with the Commissioner to determine if an AOR reevaluation is required. If an unscheduled re-evaluation is triggered, Oxy Low Carbon Ventures, LLC will perform the steps described in 6.1 AOR Re-evaluation Cycle.

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Appendix A: Schematics of legacy wells in the AOR and recommended corrective action

This appendix summarizes the evaluation of the legacy wells in the proposed AOR and the recommendations for corrective actions. All existing wellbore configuration and abandonment procedures are as reported in the SONRIS database.

INDUSTRIAL 1 (API 17003000910000, Serial 23419): D&A 1940

The Industrial 1 well is located inside the projected CO₂ plume after 15 years of CO₂ injection and inside the threshold pressure front between years 5 and 8. The well status is D&A, but there are no public records of the abandonment procedure. The surface casing does not cover the USDW, located at 3,000 ft, and most of the well was probably left open hole. The well will be scheduled for remedial action in Year 5 of injection.

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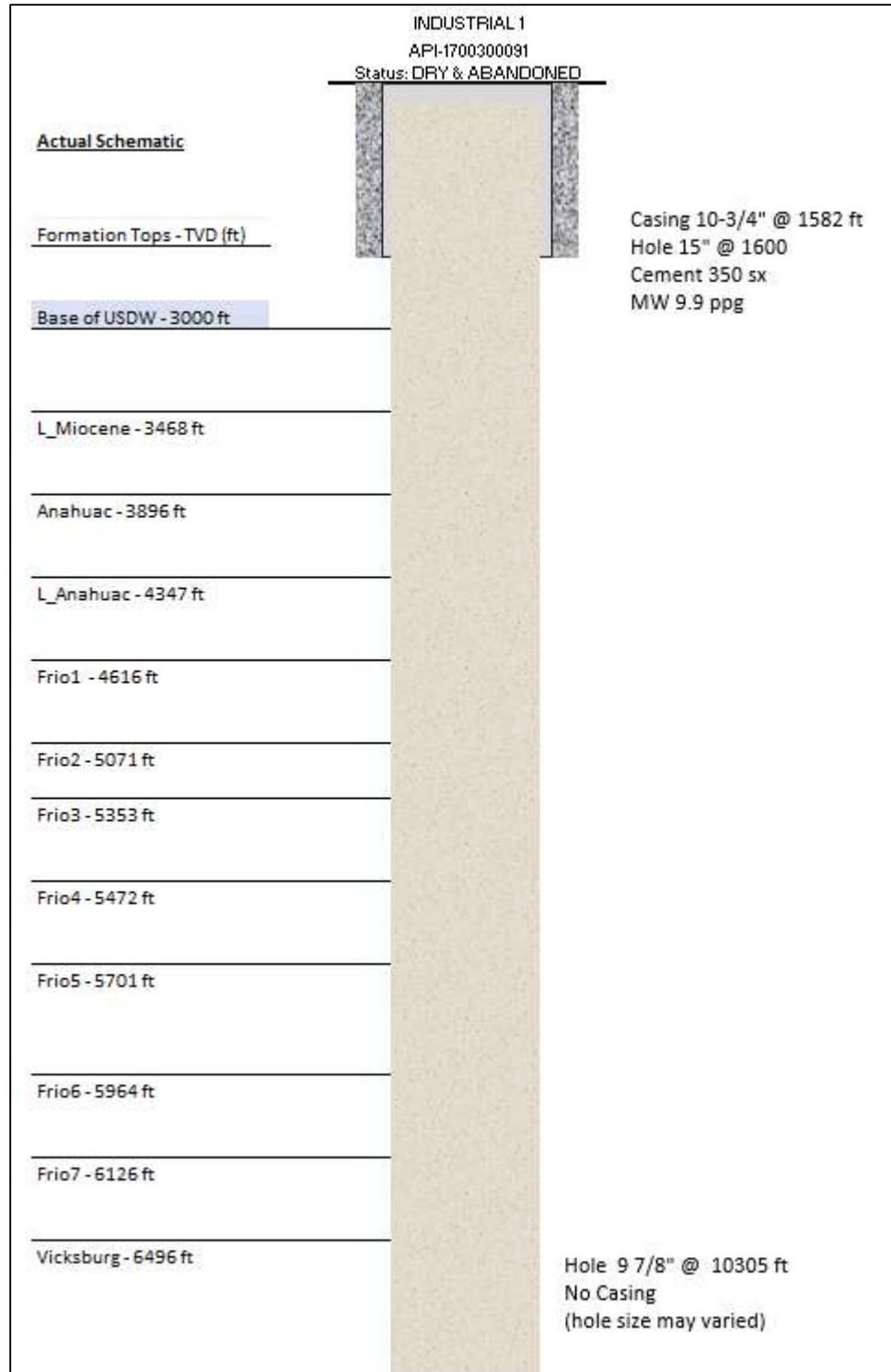


Figure AOR-50—Wellbore schematic of the Industrial 1 (SN 23419).



Table AOR-22—Plugging Plan for Industrial 1 (SN 23419)

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO ₂ Resistant	14.8-15.5	121	1.06	641
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	121	1.01	673
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	121	1.01	673

1. Move in rig onto Industrial 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up work string and 9-7/8" bit and run in hole (RIH) cleaning down to 3,600 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. RIH with work string to 3,600 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.
10. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.
11. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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.

Industrial LBR CO INC 1 (API 17003000930000, Serial 55859): D&A 1955

The Industrial LBR CO INC 1 well is located inside the projected CO₂ plume between years 5 and 10 years of CO₂ injection. The well status is D&A. The surface casing did not cover the USDW base located at 3,000 ft, but a cement plug was set from 2,950 to 3,050 ft; most of the well was left open hole. The well is properly abandoned to avoid fluid movement between the injection zone and USWD, but there's a risk of cement degradation once the CO₂ reaches the well. The well will be scheduled for remedial action in Year 5 of injection.

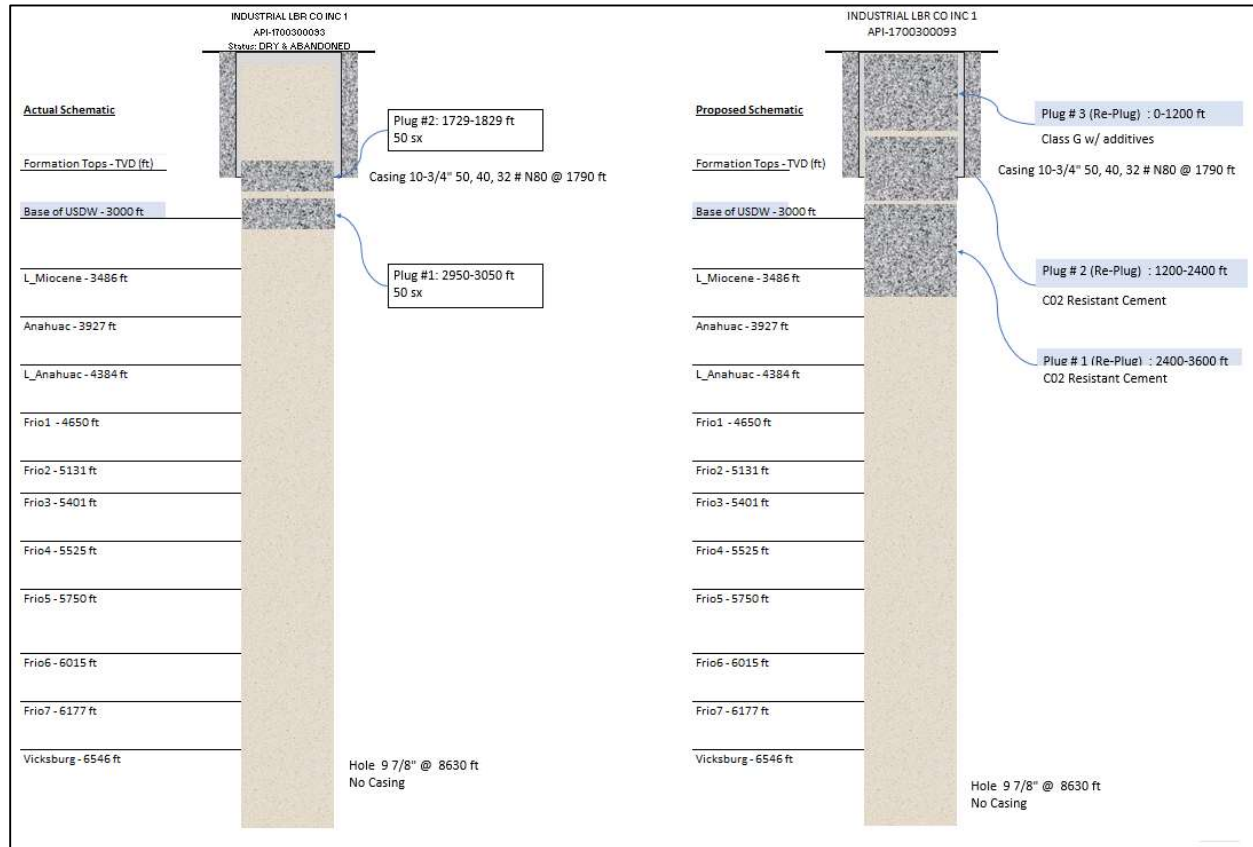


Figure AOR-52—Schematic of the existing wellbore and proposed repair of the Industrial LBR CO INC 1 (SN 55859).

Table AOR-23—Plugging Plan for Industrial LBR CO INC 1 (SN 55859)

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO ₂ Resistant	14.8-15.5	121	1.06	641
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	121	1.01	673
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	121	1.01	673

1. Move in rig onto Industrial LBR CO INC 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.

6. Pick up work string and a bit sized for 10-3/4 in. casing and run in hole (RIH) cleaning down to 3,600 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. RIH with work string to 3,600 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.
10. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.
11. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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.

Labokay Corp 1 (API 17003200940000, Serial 145083): D&A 1974

The Labokay Corp 1 is inside the projected CO₂ plume after year 15 of CO₂ injection. The surface casing did not cover the USDW at 2,615 ft, but during the abandonment process an isolating plug was placed from 2,520 to 2,720 ft. The well is properly abandoned to avoid fluid movement between the injection zone and USWD, but there's a risk of cement degradation once the CO₂ reaches the well. The well will be scheduled for remedial action in Year 15 of injection.

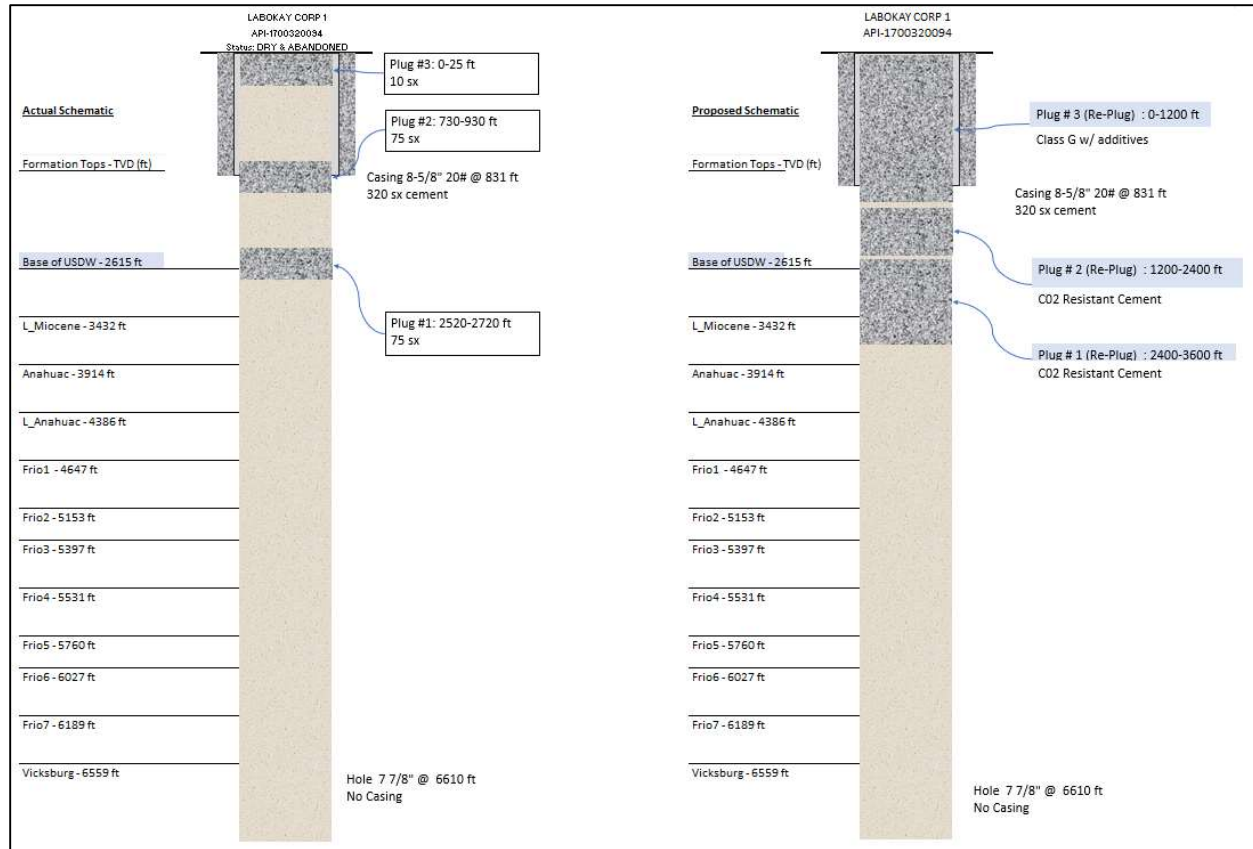


Figure AOR-53—Schematic of the existing wellbore and proposed repair of the Labokay Corp 1 (SN 145083).

Table AOR-24—Plugging Plan for Industrial Labokay Corp 1 (SN 145083).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bbls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO ₂ Resistant	14.8-15.5	79	1.06	420
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	79	1.01	441
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	79	1.01	441

1. Move in rig onto Labokay Corp 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up work string and a bit sized for 8-5/8 in. 20 ppf casing and run in hole (RIH) cleaning down to 3,600 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. RIH with work string to 3,600 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.

10. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.

11. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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.

Boise Southern 1 (API 17003202120000, Serial 173375): D&A 1981

The Boise Southern 1 is projected to be inside the CO₂ plume between years 10 and 15 of CO₂ injection and inside the threshold pressure front by year 8. The well does not have surface casing to the base of the official USDW at 2,945 ft, and the during the abandonment, the reported plug at the shoe covered from 2,516 to 2,766 ft. Therefore, the base of the USDW was left open. The well will be scheduled for remedial action in Year 5 of injection.

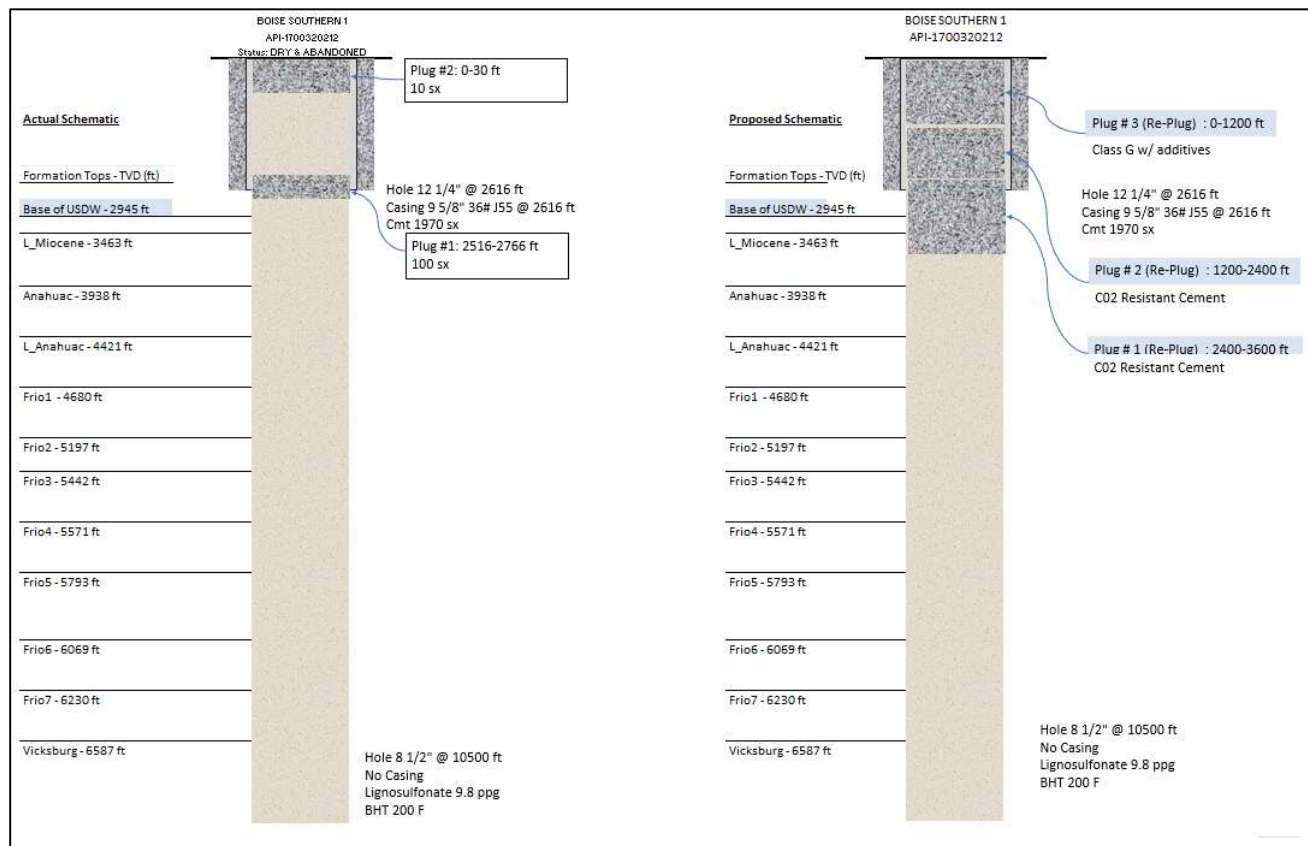


Figure AOR-54— Schematic of the existing wellbore and proposed repair of the Boise Southern 1 (SN 173375).

Table AOR-25—Plugging Plan for Boise Southern 1 (SN 173375).

Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO2 Resistant	14.8-15.5	93	1.06	491
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	93	1.01	515
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	93	1.01	515

1. Move in rig onto Boise Southern 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up work string and a bit sized for 9-5/8 in. 36 ppf casing and run in hole (RIH) cleaning down to 3,600 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. RIH with work string to 3,600 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.
10. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.
11. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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.

Labokay Corp 1 (API 17003200730000, Serial 192222): P&A 1990

The Labokay Corp 1 is projected to be inside the CO₂ plume after year 15 of CO₂ injection and inside the threshold pressure front by year 8. The well does not have surface casing to the base of the USDW at 2,753 ft. The 5-1/2 in. production casing was run to 5,800 ft during the reentry and cemented with 1500 sx of cement. The well will be scheduled for remedial action in Year 10 of injection.

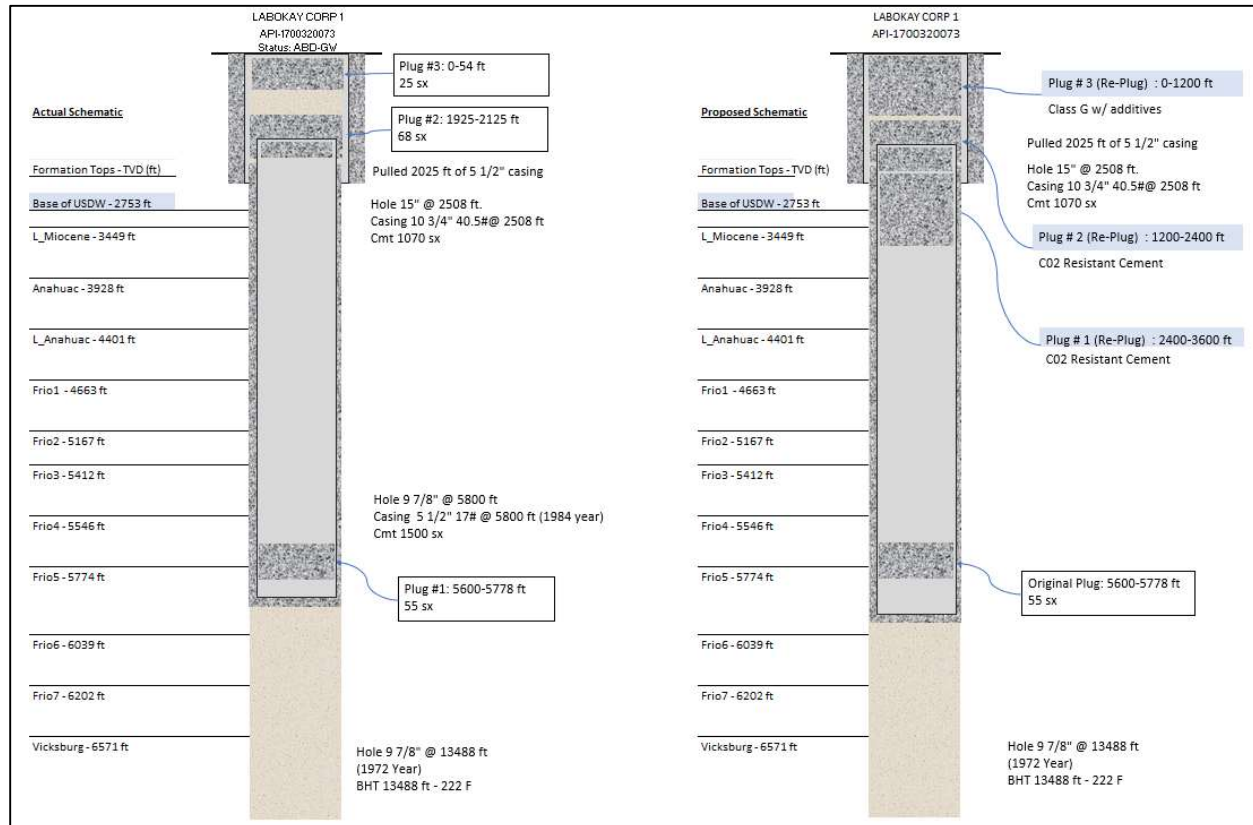


Figure AOR-55— Schematic of the existing wellbore and proposed repair of the Labokay Corp 1 (SN 192222).

Table AOR-26—Plugging Plan for Labokay Corp 1 (SN 192222).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO2 Resistant	14.8-15.5	28	1.06	148
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	121	1.01	673
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	121	1.01	673
Plug # 4 (TBD CBL)	Squeeze/Circ	TBD	TBD	CO2 Resistant	14.8-15.5	TBD	1.06	TBD

1. Move in rig onto Labokay Corp 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.

6. Pick up work string and a bit sized for 10-3/4 in. 40.5 ppf casing and run in hole (RIH) cleaning down to the top of the 5-1/2" production casing at 2,025 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. Run in the hole with mill and redress top of 5-1/2 in. casing. Pull out of the hole and lay down mill.
8. Run in the hole with bit sized for 5-1/2 in. casing and cleanout down to 3,600 ft. Circulate the well clean and pull out of the hole. Lay down the bit.
9. RIH with work string to 3,600 ft. Circulate the well clean.
10. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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.
11. Plug #2: Set a balanced plug 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.
12. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.
13. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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

Research Labokay 1 (API 17003205430000, Serial 238172): D&A 2008

The Research Labokay 1 is projected to be within the CO₂ plume after 15 years of CO₂ injection. The well status is D&A. The surface casing covered the USDW located at 3,021 ft, and a cement plug was set from 2900-3570 ft. The well is properly abandoned to avoid potential contamination of USDW with brine. The well will be scheduled for repair in Year 15 of injection.

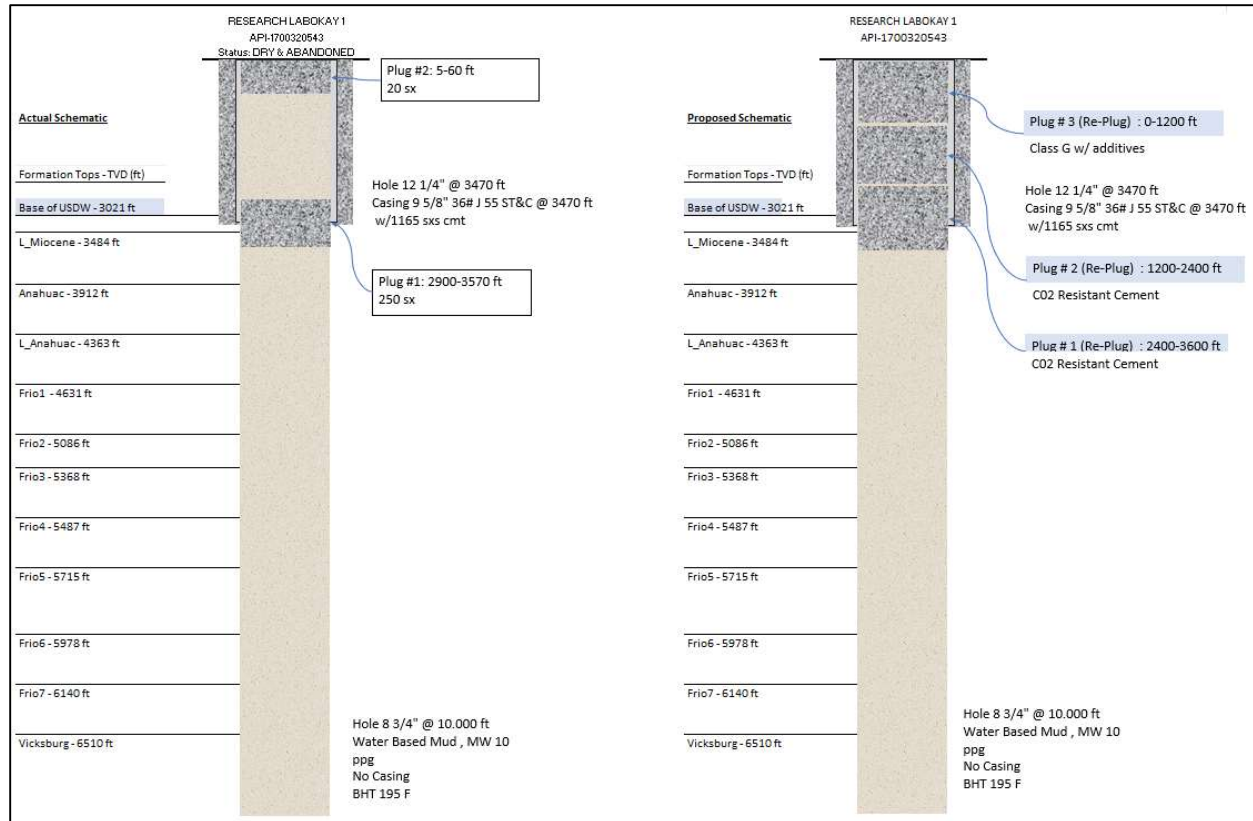


Figure AOR-56—Schematic of the existing wellbore and proposed repair of the Research Labokay 1 (SN 238172).

Table AOR-27—Plugging Plan for Research Labokay 1 (SN 238172).

Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO ₂ Resistant	14.8-15.5	93	1.06	491
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	93	1.01	515
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	93	1.01	515

1. Move in rig onto the Research Labokay 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up work string and a bit sized for 9-5/8 in. 36 ppg casing and run in hole (RIH) cleaning down to 3,600 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. RIH with work string to 3,600 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.

10. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.

11. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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.

Quatre Minerals 1 (API 17003205990000, Serial 252477): D&A 2020

The Quatre Minerals 1 well is located inside the projected pressure front. The well surface casing did not cover the USDW at 2,786 ft, but during the abandonment process an isolation plug was placed from 2,636 to 2,886 ft. An additional plug was set in the Anahuac formation, acting as a second barrier for the proposed injection zone. This well is not projected to be in contact with the CO₂ plume, which eliminates the risk of potential degradation of the cement plug. No remedial action is proposed.

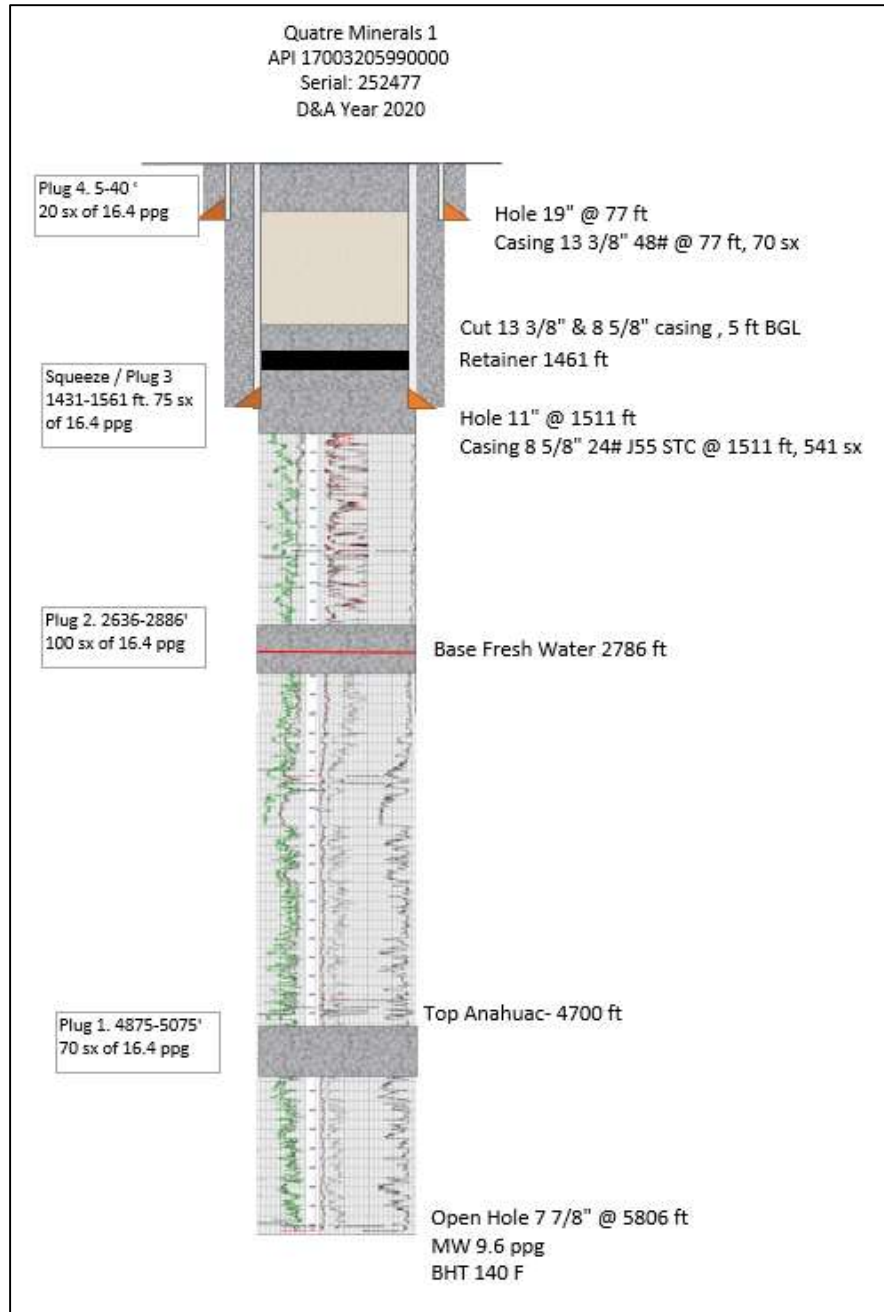


Figure AOR-57—Wellbore schematic of the Quatre Minerals 1 (252477).

LA BOKAY 1 (API 17003205340000, Serial 235033): D&A 2007

The LA BOKAY 1 is projected to be within the CO₂ plume after 15 years of CO₂ injection. The well status is D&A. The surface casing covered the USDW located at 3,097 ft, and a cement plug was set from 3243-3493 ft. The well is properly abandoned to avoid potential contamination of USDW with brine. The well will be scheduled for repair in Year 15 of injection.

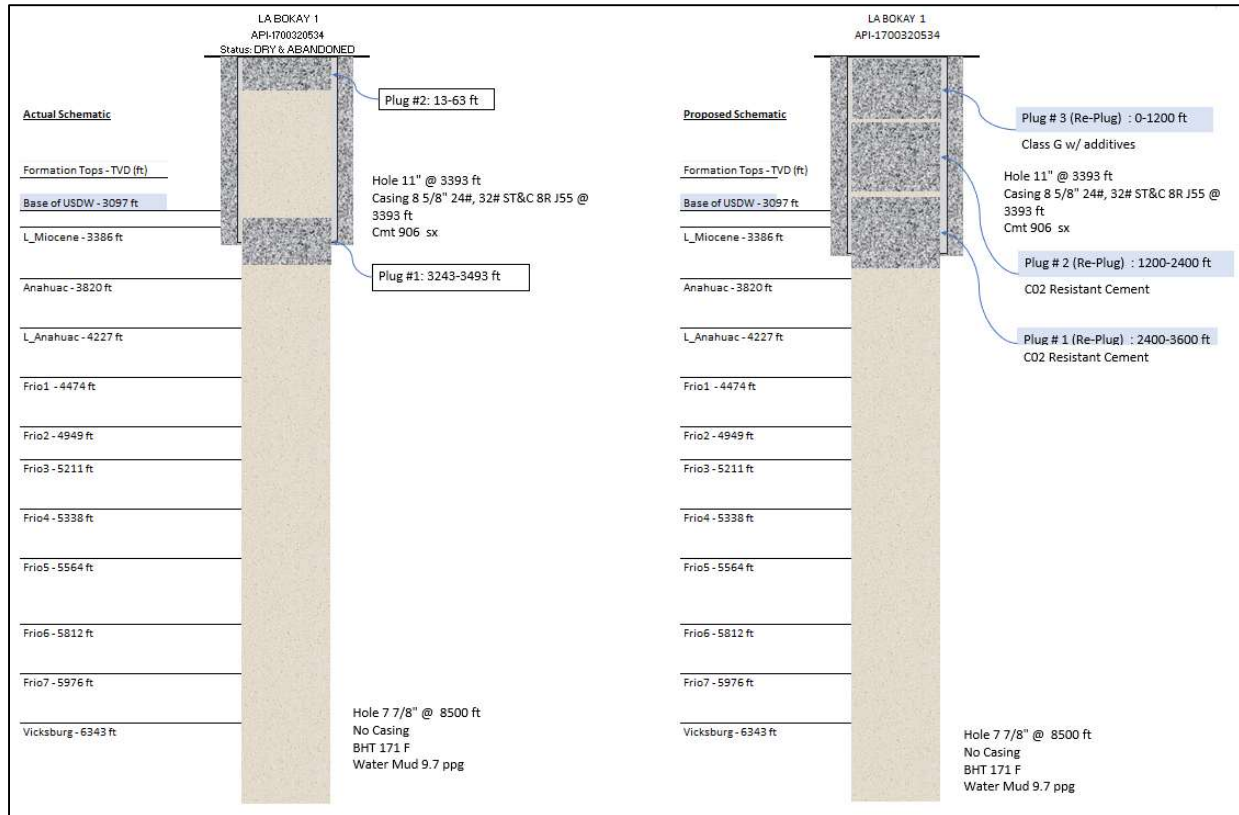


Figure AOR-58—Schematic of the existing wellbore and proposed repair of the LA BOKAY 1 (SN 235033).

Table AOR-28—Plugging Plan for LA BOKAY 1 (SN 235033).

Plug Description	Method	Top (ft)	Bottom (ft)	Cement Type	Density (ppg)	Volume (bbls)	Yield (ft ² /sx)	Sx
Plug # 1	Balanced Plug	2400	3600	CO ₂ Resistant	14.8-15.5	76	1.06	404
Plug # 2	Balanced Plug	1200	2400	Class G w/ additives	15-15.5	76	1.01	425
Plug # 3	Balanced Plug	0	1200	Class G w/ additives	15-15.5	76	1.01	425

1. Move in rig onto the LA BOKAY 1 site and rig up (RU).
2. Conduct and document safety meeting.
3. Check shut in casing pressure.
4. Test pump and lines to 5,000 psi and kill well if necessary.
5. Function test blowout preventers (BOPs) and nipple up.
6. Pick up work string and a bit sized for 8-5/8 in. casing and run in hole (RIH) cleaning down to 3,600 ft. Circulate hole clean and pull out of hole (POOH). Lay down bit.
7. RIH with work string to 3,600 ft. Circulate the well clean.
8. Plug #1: Set a balanced plug 2,400 – 3,600 ft with 14.8-15.5 ppg CO₂-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 1,200 – 2,400 ft with 15-15.5 ppg Class G cement. 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.

10. Plug #3: Set a balanced plug 0 – 1,200 ft with 15-15.5 ppg Class G cement.
11. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean the cellar to where 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: Tables of Wells

This appendix summarizes the wells and their associated well log data located within the geomodel and used for analysis of structure, thickness, and/ or reservoir characteristics used in the property model.

AOR and CA Plan for Magnolia Sequestration Project

LA C&E Permit No. 45027, 45028, 45756, and 45757

Table AOR-29—All wells with interpreted tops that were used to create regional framework

WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
125228	BOISE CASCADE	17003200310000	DRY_P_AB	9354	9510	WHITESTONE PETROLEUM	GL	156	30°51'49.4972"N	92°49'18.0185"W
125818	J A BENTLEY CO_1	17079201110000	DRY_P_AB	16037	16300	TEXACO INC	UNKNOWN	263	31°17'56.0400"N	92°48'42.4800"W
136302	C MILLER_1	17039200550000	DRY_P_AB	12298	12391	INEXCO OIL CO	KB	93	30°41'24.1810"N	92°29'18.9796"W
137602	CROSBY CHEMICALS_1	17003200670000	DRY_P_AB	10218	10305	MCCULLOCH OIL CORP	GL	87	30°44'6.1775"N	92°55'9.4308"W
138916	CROWELL LAND & MINERAL CORP_1	17039200630000	Undefined	14918	15000	FORMENTERA OPER LLC	KB	82	30°41'55.5171"N	92°31'15.7168"W
138757	LEBOKAY CORP_1	17003200730000	DRY_P_AB	13381	13488	BERNOS MILTON J JR	KB	107	30°43'28.9942"N	92°49'38.4476"W
139337	A MANUEL ETAL_1	17003200750000	DRY_P_AB	14756	14841	BURTON WM T INDST	GL	85	30°39'40.9782"N	92°36'49.4759"W
143620	WALKER EST_1	17003200900000	DRY_P_AB	23369	23472	TESORO PET&HALBOUY	KB	102.9	30°35'46.9454"N	93°01'7.2019"W
145351	POWELL LBR CO_1	17003200950000	DRY_P_AB	14367	14489	ANSCHUTZ CORP	KB	122	30°43'8.9900"N	92°40'23.4207"W
147697	WALTER LYLES_1	17003201030000	AB_GAS_RESID_OIL	14623	14705	CELERON O&G CO	KB	82	30°34'47.0569"N	92°51'6.1341"W
148246	PARDEE /F/_1	17039201290000	GAS	13139	13193	FORMENTERA OPER LLC	GL	54	30°41'12.6547"N	92°30'44.2941"W
148896	IVAR HANCHEY_1	17003201080000	DRY_P_AB	14200	14300	ANSCHUTZ CORP	KB	100	30°43'26.5174"N	92°54'42.3391"W
149886	POWELL LBR CO_1	17003201120000	AB_GAS_RESID_OIL	14228	14290	EL-OIL LTD	KB	62	30°34'34.3310"N	92°51'34.2468"W
150206	PINELANDS PETR CO_1	17003201140000	DRY_P_AB	13748	13875	WESTLAND OIL DEV CRP	KB	127	30°45'48.6831"N	92°37'17.3933"W
150331	CENTRAL COAL & COKE_1	17011202280000	DRY_P_AB	10375	10512	SOUTH LOUISIANA PROD	GL	137	30°39'57.9923"N	93°18'40.9664"W
150917	HENRY A FARRIS_1	17011202330000	Undefined	12942	13100	GOLDKING PROD CO	GL	158	30°43'17.2210"N	93°07'46.1210"W
151386	DALLAS COLE_1	17003201100000	AB_OIL_MINOR_GAS	12619	12695	CELERON O&G CO	KB	76	30°34'37.9488"N	92°50'36.9268"W
152243	DELLA BEL KRAUSE_1	17003201190000	AB_GAS_RESID_OIL	12598	12676	SOUTH LOUISIANA PROD	KB	78	30°34'25.4479"N	92°50'14.9366"W
152953	POWELL LBR CO_2	17003201220000	DRY_P_AB	21909	22025	ANSCHUTZ CORP	KB	116	30°44'2.5550"N	92°41'28.9315"W
155437	ALLEN J P 7-11_1	17003201330000	AB_GAS_RESID_OIL	14441	14475	AMOCO PROD CO	KB	34	30°32'35.4858"N	92°49'45.3022"W
155596	POWELL LBR CO /A/_1	17003201350000	DRY_P_AB	10697	10820	ANSCHUTZ CORP	KB	123	30°44'16.6305"N	92°41'9.7962"W
155913	NAVAL STORES CO INC_1	17003201360000	DRY_P_AB	12659	12710	WEWOKA EXPL CO	GL	51	30°36'51.9246"N	92°55'35.2350"W
157850	LABOKAY_1	17003201460000	DRY_P_AB	18514	18548	SHELL OIL CO	KB	34	30°53'8.8613"N	92°46'43.5119"W
158708	D MC PHERSON /L/_2	17011203140000	AB_OIL_MINOR_GAS	8845	8950	MCGOWN WORKING PRINR	KB	99	30°35'21.8191"N	93°11'14.3366"W
158829	JOHN A BEL ETAL_1	17003201520000	DRY_P_AB	13048	13110	HUNT ENERGY CORP	GL	62	30°34'34.7374"N	92°47'28.7771"W
159932	CARL L BUTLER ETAL_1	17079202560000	DRY_P_AB	11054	11230	SEVARG CO INC	UNKNOWN	176	30°56'1.8505"N	92°33'44.0032"W
160952	BENT-GLEN /A/_1	17079202590000	AB_OIL_MINOR_GAS	11033	11200	SEVARG CO INC	KB	167	30°55'35.8029"N	92°35'16.4122"W
161865	PINELANDS EDWARDS_1	17011203420000	DRY_P_AB	11332	11514	PINELANDS PET CO	KB	182	30°49'17.5774"N	93°02'23.5656"W
163182	SABINE ETAL_1	17079202660000	DRY_P_AB	16696	16910	AMOCO PROD CO	KB	214.4	31°01'39.0795"N	92°48'9.1935"W
164182	FORMAN ETAL_1	17039201930000	DRY_P_AB	19518	19538	SHELL OIL CO	KB	20	30°48'57.6803"N	92°17'21.7363"W
164890	EASON E M_1	17011203760000	DRY_P_AB	14283	14410	ANR PRODUCTION CO	GL	127	30°39'6.7409"N	93°12'17.3346"W
165154	A M MOORE_1	17003201760000	DRY_P_AB	12041	12115	EMERALD OIL&GAS-NORM	GL	74	30°36'54.9351"N	92°43'12.4377"W
165364	CROSBY CHEMICALS CO_1	17011203790000	DRY_P_AB	8680	8810	WEEKS PETROLEUM CORP	KB	130	30°34'52.8236"N	93°17'22.7409"W
166479	RAGLEY LBR CO_1	17011203880000	DRY_P_AB	8879	9000	LYONS PETROLEUM CO	GL	121	30°36'40.4578"N	93°06'13.7954"W
168924	BEL ESTATE_9	17003201890000	AB_OIL_MINOR_GAS	12455	12550	CXY ENERGY INC	KB	95	30°31'56.3435"N	93°07'42.9411"W
170105	CROWELL LAND & MINERAL_8	17039202210000	DRY_P_AB	13253	13338	INEXCO OIL CO	GL	85	30°45'52.0046"N	92°27'35.0435"W
171013	GLEN BENT_2	17079202930000	AB_OIL_MINOR_GAS	11076	11240	SEVARG CO INC	KB	164	30°55'35.9778"N	92°34'45.5185"W
171058	LAHAYE BROS ETAL_1	17039202230000	OIL	12499	12583	PETRO HARVESTER LLC	GL	84	30°46'13.8432"N	92°26'49.3332"W
171116	BEL J A ETAL_1	17003201980000	DRY_P_AB	5930	6000	SMITH PET CO	KB	70	30°34'18.8752"N	92°44'10.4137"W
171558	LABOKAY CORP/A/_1	17079202940000	DRY_P_AB	12440	12500	SHELL OIL CO	KB	60	30°54'17.4539"N	92°47'16.7438"W
173211	JOHNCO_1	17079202970000	DRY_P_AB	11031	11200	TRANSCONTNNTL OIL	KB	169	30°55'35.7936"N	92°36'27.5442"W
172367	VANCOUVER PLYWOOD_1	17003202030000	DRY_P_AB	9450	9510	TEE OIL INC	KB	60	30°36'19.0448"N	92°50'11.4625"W
173109	HEBERT RITA RICHARD_1	17053206920000	OIL	11294	11348	MIDCO ENERGY INC	KB	54	30°23'13.0099"N	92°49'39.8574"W
173375	SOUTHERN BOISE_1	17003202120000	DRY_P_AB	10390	10500	DANIEL OIL CO	KB	110	30°43'14.6234"N	92°49'51.4513"W
174964	RICE LAND & LUMBER_1	17003202200000	DRY_P_AB	9681	9750	PRUET PRODUCTION CO	GL	69	30°36'2.1149"N	92°52'49.6794"W
176249	SOUTHWESTERN IMP_1	17003202270000	DRY_P_AB	13895	14000	SHELL OIL CO	DF	105	30°45'34.7352"N	92°42'2.0535"W
177494	RICE LAND & LUMBER_2	17003202390000	DRY_P_AB	9644	9730	PRUET PRODUCTION CO	KB	86	30°35'55.6779"N	92°53'24.2248"W
177498	PRAIRIE LAND_1	17003202380000	DRY_P_AB	7728	7815	RIO BRAVO OIL CO	KB	87	30°37'45.1170"N	92°40'8.2590"W
177966	GOLDEN EST 20-13_1	17053207460000	DRY_P_AB	13534	13550	MARION CORP	GL	16	30°14'54.9247"N	92°42'8.7479"W
179615	RICE LAND & LUMBER_1	17003202450000	DRY_P_AB	12057	12132	CASHCO OIL CO	GL	75	30°37'14.7980"N	92°54'25.5243"W
179616	WILLAMETTE INC_1	17003202460000	DRY_P_AB	13412	13505	JUSTISS OIL CO INC	KB	93	30°44'2.6463"N	92°54'10.5884"W
183192	ADAMS HARVEY ETAL_1	17003202590000	GAS	9527	9600	FAULCONER VERNON E	GL	73	30°37'21.5989"N	92°41'8.9571"W
184408	ADAMS HARVEY ETAL_2	17003202720000	GAS	9545	9620	FAULCONER VERNON E	GL	75	30°37'10.7815"N	92°41'28.1926"W

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LA C&E Permit No. 45027, 45028, 45756, and 45757

WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
186435	POWELL LBR CO_2	17053208360000	OIL	9131	9200	E & B EQUIPMENT	KB	69	30°24'5.3409"N	92°49'17.2863"W
187285	QUATRE PARISH_1	17003202860000	DRY_P_AB	9537	9608	CENTURY MINERAL CORP	KB	71	30°36'4.8437"N	92°51'37.9059"W
188372	RICE LAND & LUMBER_1	17003202880000	OIL	14423	14500	ELYSIUM JENNINGS LLC	KB	77.3	30°32'7.1419"N	92°53'52.3208"W
188615	ADAMS L H ETAL_1	17003202890100	DRY_P_AB	10481	10750	RIO BRAVO OIL CO	KB	99	30°38'17.9141"N	92°42'12.3977"W
189261	RICE LAND & LUMBER CO A_1	17003202920000	GAS	9568	9600	LEEWARD OPERATORS LL	KB	32	30°35'43.1681"N	92°53'4.7122"W
189503	LEJEUNE N_1	17003202930000	DRY_P_AB	9726	9800	MATZINGER PET CO	KB	74	30°35'18.5740"N	92°46'27.2859"W
189730	RICE LAND & LUMBER CO_2	17003001080000	AB_GAS_RESID_OIL	9545	9600	CAMEX INC	GL	55	30°35'20.8392"N	92°53'12.6539"W
189857	LEBLANC GWIN N ETAL_1	17003202970000	DRY_P_AB	9510	9600	LGS EXPLORATION INC	KB	90	30°36'51.1798"N	92°45'34.9463"W
190476	DARBONNE C_1	17003203030000	DRY_P_AB	9392	9474	CABOT PETROLEUM CORP	GL	82	30°39'1.9163"N	92°45'58.7011"W
191999	FEAGIN - TUBB_1	17003203080000	DRY_P_AB	9407	9500	HAMON OIL CO	KB	93	30°36'57.4946"N	92°52'37.3900"W
193328	BENTLEY J A LBR_1	17079203650000	DRY_P_AB	16270	16470	SHELL WESTERN E&P	GL	200	31°15'51.1992"N	92°48'37.5624"W
194215	POWELL LBR_1	17003203130000	DRY_P_AB	13029	13100	MOORE MCCORMACK ENRG	KB	71	30°32'30.8607"N	93°00'3.3261"W
194687	CL & M; UWX RASU_17	17039202950000	OIL	10822	10903	FORMENTERA OPER LLC	GL	81	30°45'54.6083"N	92°27'10.0955"W
195458	BEL J A ESTATE_1	17003203160000	DRY_P_AB	12125	12200	CENERGY EXPL CO	GL	75	30°37'13.2542"N	92°49'36.2678"W
195935	BURTON WILLIAM T_1	17079203690000	DRY_P_AB	15800	16000	CHEVRON USA INC	UNKNOWN	200	31°03'55.5819"N	92°47'19.9092"W
196649	LETHA NAVARRE_2	17003203220000	DRY_P_AB	9315	9437	WOOLF & MAGEE INC	KB	84	30°37'55.7380"N	92°43'36.9481"W
196911	TATE VINEY MANUEL_1	17003203230000	AB_GAS_RESID_OIL	9557	9600	CARL OIL & GAS CO	KB	93	30°37'9.2441"N	92°42'7.6247"W
197037	RICE LAND & LUMBER CO_2	17003203250000	AB_GAS_RESID_OIL	9587	9650	LGS EXPLORATION INC	GL	63	30°35'37.0972"N	92°54'31.1239"W
197680	SONNIER MYRTLE_1	17003203280000	GAS	9205	9305	MISS LOU OPERATING L	KB	100	30°39'23.4095"N	92°43'12.9910"W
197727	HARVEY ADAMS ETAL_3	17003203290000	GAS	9554	9626	FAULCONER VERNON E	GL	72	30°37'23.6807"N	92°40'38.9231"W
198538	COLE FRANCES M H_1	17011207090000	DRY_P_AB	10333	10521	SANDEFER PETRO CO	KB	188	30°50'10.2895"N	93°15'25.3692"W
198805	DEAR EVELYN R_1	17003203350000	AB_DUE_TECH	9181	9275	WOOLF & MAGEE INC	KB	93.9	30°39'29.8610"N	92°42'51.1000"W
199589	GRAY MATILDA ESTATE_2	17003203390000	GAS	14606	14650	ELYSIUM JENNINGS LLC	GL	44	30°31'35.1300"N	92°54'12.7200"W
200088	BIBER HENRY_1	17053209470000	AB_OIL_MINOR_GAS	12832	12866	FIRST ENRGY DEV CORP	KB	32	30°10'18.1274"N	92°42'29.2295"W
201959	PINELANDS PETROLEUM CO FEE_1	17003203470000	DRY_P_AB	13366	13500	PINELANDS PET CO	KB	134	30°46'41.8013"N	92°36'2.0889"W
203199	HEBERT RICHARD RITA_1	17053209770000	DRY_P_AB	14669	14725	SPARTAN PETRO CORP	KB	56	30°23'7.0979"N	92°49'39.7699"W
203867	SMITH BENTON ETAL_1	17003203640000	DRY_P_AB	12931	13030	GERMANY EXPL CO	KB	99	30°36'13.2321"N	92°38'3.6928"W
204460	BEL JOHN A ESTATE_1	17003203240000	DRY_P_AB	9723	9800	LGS EXPLORATION INC	KB	77	30°34'30.5691"N	92°47'10.6597"W
208156	LABOKAY CORP_1	17003203810000	DRY_P_AB	10133	10200	OSULLIVAN&SCULLY ETA	KB	67	30°31'40.8094"N	92°59'1.6566"W
209353	COLE JASPER ETAL_1	17003203840000	DRY_P_AB	7756	7820	RIO BRAVO OIL CO	KB	64	30°33'18.3354"N	92°49'33.3818"W
210910	JEFFERSON DAVIS PARISH SCHOOL BOARD_1	17053210680000	DRY_P_AB	16757	16817	BHP PET(AMERICAS)INC	KB	60	30°21'47.2354"N	92°40'58.4988"W
211333	WINN EST_1	17053210600000	DRY_P_AB	17586	17630	PRIME NATURAL RESCS	KB	39	30°05'34.9980"N	92°42'45.9971"W
213270	WALKER; 10100 CF RA SU A_3	17003204090000	OIL	10259	10300	VAN WAY J P	KB	41	30°28'12.2725"N	92°59'28.7770"W
215059	WALKER LA PROPERTIES_1	17003204240000	DRY_P_AB	10184	10525	NICOR EXPL CO	KB	50	30°28'35.4140"N	92°58'54.3200"W
216274	MONROE A; AUS RA SUA_1	17079204160000	OIL	14660	19100	YUMA EXPL&PRD CO INC	GL	143	31°01'50.0000"N	92°36'55.0001"W
217452	LA BOKAY; 10 100 CF RA SU T_4	17003204420000	DRY_P_AB	10242	10300	SCANA PETR RESCS INC	KB	58	30°28'22.2739"N	93°01'43.7816"W
218825	LABOKAY_1	17003204500000	DRY_P_AB	4820	4995	SELMAN EXPL INC	KB	175.5	30°51'34.9579"N	92°50'23.3972"W
219142	LAWTON 31; AUS C RA SUU_1	17079204310000	DRY_P_AB	14075	14310	INDIGO MINERALS LLC	KB	232	31°01'21.8637"N	92°48'40.9358"W
219191	LORD 19; AUS C RA SUCC_1	17079204320000	OIL	14953	19315	CHESAPEAKE OPERG INC	KB	188	30°57'41.8990"N	92°36'14.9490"W
219294	MARTIN 11; AUS RA SUL_1	17079204340000	OIL	15025	15285	PERDIDO ENERGY LA LL	KB	170	30°59'2.8746"N	92°38'44.5170"W
219439	CROSBY LAND & RESOURCES 8_1	17115201050000	AB_OIL_MINOR_GAS	15219	18958	YUMA EXPL&PRD CO INC	KB	210	30°53'49.9736"N	93°00'42.1950"W
219544	SCOBEE 34_1	17115200720000	OIL	13778	17815	SONAT EXPL GOM INC	GL	245	31°01'35.5228"N	92°58'48.0413"W
220216	EXXON MINERALS 29_1	17115201240000	GAS	14743	17394	SONAT EXPL GOM INC	KB	217	30°56'45.1214"N	92°54'36.7463"W
220367	LORD 25; AUS C RA SULI_1	17079204460000	OIL	15284	18910	CHESAPEAKE OPERG INC	KB	190	30°56'24.9000"N	92°37'37.6299"W
220420	MURCHISON 24_1	17079204450000	OIL	14988	18958	PERDIDO ENERGY LA LL	KB	165.8	30°57'39.4600"N	92°38'7.9700"W
220443	WAHLDER 29; AUS C RA SUKK_1	17079204480000	OIL	15433	18900	CHESAPEAKE OPERG INC	KB	193	30°56'25.0943"N	92°35'38.1905"W
220489	LABOKAY 26; AUS C RA SUA_1	17003204550000	AB_OIL_MINOR_GAS	15986	20200	CHESAPEAKE OPERG INC	KB	192	30°50'58.1612"N	92°51'17.2654"W
220524	GILES 22; AUS C RA SUJJ_1	17079204630000	OIL	15114	18757	PERDIDO ENERGY LA LL	GL	150	30°57'36.9980"N	92°33'56.6791"W
220525	EXXON MINERALS 13_1	17115201310000	Undefined	11724	11950	SONAT EXPL GOM INC	KB	226	30°58'46.6100"N	92°56'34.9440"W
221048	DAUZAT 25_1	17115201490000	OIL	14553	18023	SONAT EXPL GOM INC	GL	171	30°57'2.8828"N	92°56'35.1761"W
221049	WISBY 18_1	17115201510000	Undefined	7080	7260	SONAT EXPL GOM INC	GL	180	30°58'24.7272"N	92°55'2.0076"W
221101	TEMPLE 22; AUS C RA SUG_1	17115201520000	OIL	14632	18112	PLANET RESOURCE OP	KB	229	30°57'53.5800"N	92°52'19.4300"W

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WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
221201	BLACKSTONE MINERALS 23_1	17003204580000	OIL	16015	19450	CHESAPEAKE OPERG INC	KB	168	30°52'27.7332"N	92°38'9.7081"W
221316	BENTLEY 5; AUS C RA SU69_1	17079204750000	AB_OIL_MINOR_GAS	15454	19069	CHESAPEAKE OPERG INC	KB	196	30°55'2.0000"N	92°35'39.0001"W
221565	TRIPLE R 20; AUS C RB SUA_1	17011209010000	OIL	15207	18862	PERDIDO ENERGY LA LL	KB	208	30°51'56.3056"N	93°06'21.1203"W
221647	CROSBY 36 A_1	17011209020000	OIL	15725	18964	TPETIGER LLC	KB	190	30°50'40.4961"N	93°02'26.1708"W
222056	DOROTHY STUCKEY ETAL_1	17003204590000	AB_GAS_RESID_OIL	7970	8014	HUNT OIL CO	KB	44	30°25'30.9047"N	93°05'22.2266"W
222628	MARTIN 22_1	17011209210000	OIL	15503	22230	YUMA EXPL&PRD CO INC	KB	189	30°52'27.3538"N	93°04'36.6468"W
222743	BEL JOHN A ETAL_1	17003204620000	AB_GAS_RESID_OIL	10627	10700	HUNT OIL CO	KB	72	30°27'0.1462"N	93°06'11.8711"W
223573	LABOKAY_1	17003204670000	DRY_P_AB	3372	3510	BASIN PROD PROPS LTD	KB	138	30°49'16.2428"N	92°51'12.0075"W
223607	CROSBY 4; AUS C RA SUR_1	17115201820000	DRY_P_AB	14971	16134	YUMA EXPL&PRD CO INC	GL	196	30°55'11.0000"N	92°58'57.0000"W
223648	ASHFORD PRESTON_1	17053212620000	AB_OIL_MINOR_GAS	9259	9310	HS RESOURCES INC	KB	51	30°24'55.1123"N	92°52'48.2163"W
223794	BEESON 28; AUS C RA_1	17115201840000	OIL	20124	20350	YUMA EXPL&PRD CO INC	KB	226	30°56'45.0012"N	92°59'4.6748"W
223867	BROUSSARD_001	17053212630000	GAS	14288	14650	LLOG EXPLORATION CO	KB	38	30°07'15.9995"N	92°42'25.9993"W
224114	AIRHART ALBERT ET UX_1	17003204690000	AB_OIL_MINOR_GAS	7185	7233	HUNT OIL CO	GL	48	30°26'40.3429"N	93°06'9.4243"W
224233	MARTIN ROY O LUMBERCO 31; AUS C RA SUXX_1	17079204960000	DRY_P_AB	15448	18195	SWIFT ENERGY CO	KB	188	30°55'58.8724"N	92°48'45.5432"W
224493	SWENCO B23; AUS C RA SU UU_1	17079204970000	OIL	14978	18460	PLANET RESOURCE OP	KB	182	30°57'19.5410"N	92°44'19.1691"W
224925	SWENCO 32; AUS C RA SUK_1	17115201870000	GAS	14954	18553	PLANET RESOURCE OP	KB	219.9	30°55'37.0000"N	92°53'41.0000"W
225116	CROSBY 2B_1	17115201880000	GAS	14973	19210	YUMA EXPL&PRD CO INC	KB	184	30°54'39.0000"N	92°57'9.0000"W
226189	BEL ESTATE_1	17003204770000	DRY_P_AB	9704	9930	HELMERICH & PAYNE	KB	77	30°30'55.8000"N	93°02'39.9363"W
227440	CARRUTH 3; AUS C RA SUG_1	17079204500000	OIL	14578	18581	PERDIDO ENERGY LA LL	KB	194	31°00'22.0000"N	92°39'14.0000"W
227823	BRUNER WALTER ETAL_1	17053213270000	DRY_P_AB	11329	11395	NOBLE ENERGY INC	KB	66	30°18'35.9834"N	92°51'49.9040"W
228609	BLACKSTONE 23_2	17003204940000	GAS	4517	4900	HUGHES EASTERN CORP	KB	149	30°52'27.7519"N	92°38'9.4786"W
228856	MTR_1	17003204990000	GAS	9752	9800	UNIT PETROLEUM CO	GL	48	30°37'3.0000"N	92°36'59.0004"W
229132	WALKER B; OBERLIN VUL_1	17003205030000	GAS	9767	9837	UNIT PETROLEUM CO	GL	70	30°36'42.0012"N	92°37'23.0015"W
229141	HAYES MINERALS 18; Y RA SUA_1	17003205040000	AB_GAS_RESID_OIL	10774	10800	ASPECT ENERGY LLC	GL	25	30°27'7.0000"N	92°54'52.0000"W
229253	WALKER C; VUJ_1	17003205050000	GAS	9840	9900	UNIT PETROLEUM CO	GL	60	30°37'1.9992"N	92°38'18.9996"W
229298	GRANGER; OBERLIN RA SUB_1	17003205060000	DRY_P_AB	9735	9810	UNIT PETROLEUM CO	KB	75	30°36'44.3654"N	92°42'14.1837"W
229653	MANUEL; OBERLIN RB SUE_1	17003205080000	DRY_P_AB	9770	9834	UNIT PETROLEUM CO	KB	64	30°36'36.0000"N	92°37'9.9984"W
229759	ADAMS A; VUK_1	17003205090000	GAS	9719	9810	UNIT PETROLEUM CO	KB	91	30°36'39.9996"N	92°38'49.9992"W
229765	BLACKSTONE 13_1	17003205100000	DRY_P_AB	4506	4650	HUGHES EASTERN CORP	KB	144	30°52'46.0000"N	92°38'3.0000"W
230330	LAWTON J ETAL 33; F RA SUA_1	17003205120000	DRY_P_AB	6628	6750	SMITH PRODUCTION CO	KB	122	30°45'0.3309"N	92°40'26.6378"W
230644	SMITH E; VUL_1	17003205130000	GAS	9735	9808	UNIT PETROLEUM CO	KB	73	30°36'21.2832"N	92°38'13.4897"W
230645	ADAMS B; VUM_1	17003205140000	GAS	9726	9810	UNIT PETROLEUM CO	KB	84	30°36'38.2860"N	92°39'40.4890"W
230646	BOWLES A; VUN_1	17003205150000	DRY_P_AB	9736	9810	UNIT PETROLEUM CO	KB	74	30°35'35.9000"N	92°41'38.2807"W
231166	PARDEE Q; RD U WX RA SU_1	17039204300000	OIL	11128	11540	FORMENTERA OPER LLC	KB	76	30°42'6.9383"N	92°30'54.9758"W
231312	MARTIN B_1	17003205180000	DRY_P_AB	9744	9805	UNIT PETROLEUM CO	GL	61	30°34'51.9553"N	92°41'36.5972"W
231390	L & H PARTNERSHIP 8; 10200 RA SUA_1-ALT	17003205190000	AB_GAS_RESID_OIL	10195	10270	HUNT OIL CO	KB	75	30°27'11.4676"N	93°06'15.0778"W
231409	SMITH F_1	17003205200000	DRY_P_AB	9729	9810	UNIT PETROLEUM CO	KB	81	30°36'38.2860"N	92°40'45.4872"W
231700	UNKEL C H ETAL_1	17003205210000	DRY_P_AB	10482	10550	NAVITAS RESOURCES LLC	KB	68	30°30'25.8420"N	92°49'16.1064"W
231880	MARTIN ROY O INC 20_2	17039204370000	DRY_P_AB	5169	5305	BRIDWELL OIL CO	KB	136	30°52'32.3561"N	92°35'36.8341"W
232161	ARDON L INC ETAL; WX RG SUA_1	17039204390000	OIL	12901	13025	PETRO HARVESTER LLC	KB	124	30°46'38.4328"N	92°26'37.2991"W
233234	CROSBY LAND & RESOURCES 14_1	17115201980000	GAS	4652	4800	PILOT RESOURCES INC	KB	148	30°52'59.9609"N	92°56'44.8900"W
234445	CROSBY LAND & RESOURCES 22_1	17115202030000	DRY_P_AB	3294	3464	PILOT RESOURCES INC	GL	170	30°57'41.3080"N	92°58'19.0572"W
234638	HEBERT KENNETH_1	17003205330000	DRY_P_AB	14552	14652	UNION GAS OPER CO	KB	100	30°36'5.2536"N	92°46'35.3754"W
234800	WEINSTEIN ETAL 6; SP RA SUB_1	17039204560000	GAS	10551	10600	NEUMIN PRODUCTION CO	GL	49	30°39'13.1805"N	92°30'52.4529"W
235033	LABOKAY_1	17003205340000	DRY_P_AB	8383	8500	BRIDWELL OIL MGT LLC	KB	117	30°44'49.9514"N	92°51'42.6065"W
235248	BEL MINERALS_1	17003205350000	DRY_P_AB	14413	14500	UNION GAS OPER CO	KB	87	30°30'47.6634"N	93°04'43.0601"W
235590	MEAUX CLAUDE_1	17003205370000	AB_GAS_RESID_OIL	9480	9503	UNION GAS OPER CO	KB	23	30°38'12.2888"N	92°43'33.4781"W
235752	LORD TIMBER LLC; F RA SUB_2	17079205240000	DRY_P_AB	4199	4350	WINDRUSH OPERATING	KB	151	30°55'9.0796"N	92°36'55.5953"W
235834	LORD TIMBER LLC; VUA_1	17079205250000	GAS	4348	4530	LAMAR OIL & GAS INC	KB	182	30°57'15.8296"N	92°36'10.5775"W
235895	MARCANTEL FARMS ETAL_1	17003205380000	DRY_P_AB	9643	9708	UNION GAS OPER CO	KB	65	30°34'9.3321"N	92°57'40.9749"W
235977	CROSBY LAND & RESOURCES 8_1	17115202060000	DRY_P_AB	4728	4900	PILOT RESOURCES INC	GL	172	30°53'59.1000"N	92°59'58.0000"W
236451	MARCANTEL FARMS ETAL_1	17003205390000	GAS	7917	8005	KASH OIL & GAS INC	KB	88	30°34'35.2800"N	92°57'50.4500"W
236569	KING MINERALS LLC ETAL_1	17003205410000	AB_GAS_RESID_OIL	10923	10972	SMITH PRODUCTION CO	KB	49	30°26'47.3312"N	92°55'26.0017"W

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WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
236640	BENTLY-GLENMORA LANDS INC_1	17079205270000	DRY_P_AB	10847	11021	RODESSA OPER CO INC	KB	174	30°55'50.2588"N	92°34'28.1163"W
238172	RESEARCH LABOKAY_1	17003205430000	Undefined	9890	10000	BRAMMER ENG INC	KB	110	30°43'50.8940"N	92°50'18.5600"W
238713	CROSBY LAND & RESOURCES_1	17003205460000	AB_GAS_RESID_OIL	5196	5300	UNION GAS OPER CO	KB	104	30°39'35.3627"N	92°56'20.7813"W
238754	FEAGIN ETAL_1	17003205470000	AB_GAS_RESID_OIL	6732	7166	UNION GAS OPER CO	KB	68	30°37'5.0423"N	92°55'54.4260"W
239223	PBAPROPERTIES_2	17003205480000	GAS	5507	5600	UNION GAS OPER CO	KB	93	30°35'42.1500"N	92°58'37.6000"W
239742	LEJEUNE C ETAL; VUA_1	17003205490000	DRY_P_AB	8025	8100	DYNAMIC EXP PRT LLC	KB	75	30°34'41.7848"N	92°46'29.2527"W
240045	BOM 24_1	17079205330000	DRY_P_AB	11703	11900	BRIDWELL OIL MGT LLC	KB	197	30°57'21.9364"N	92°43'36.7960"W
240097	INDIGO MINERALS 31_1	17003205510000	AB_GAS_RESID_OIL	5283	5400	LYMAC EXPL & PROD LLC	KB	117	30°44'49.6254"N	92°36'24.2598"W
241434	BLACKSTONE 14_1	17003205520000	AB_GAS_RESID_OIL	3928	4072	HUGHES EASTERN CORP	KB	144	30°52'51.1110"N	92°38'23.3720"W
241524	BLACKSTONE MINERALS 21_1	17003205530000	DRY_P_AB	4686	4802	LYMAC EXPL & PROD LLC	KB	116	30°46'29.4736"N	92°46'29.5377"W
242383	HAINS BEVERLY B ETAL_1	17003205580000	DRY_P_AB	9310	9400	KASH OIL & GAS INC	KB	90	30°38'5.7756"N	92°46'28.6596"W
242930	BSML PARTNERSHIP 26_1	17003205610000	GAS	4872	5010	TDX ENERGY LLC	KB	138	30°51'15.6239"N	92°38'28.3604"W
243064	BENTLEY J_1	17003205620000	TEMP_AB	10963	11050	GULF SOUTH OPER INC	KB	87	30°36'20.0340"N	92°42'55.6710"W
244149	SS&F FARM_1	17003205710000	DRY_P_AB	9713	9800	UNION GAS OPER CO	KB	87	30°37'5.2800"N	92°43'28.4701"W
244815	QUATRE MINERALS 17_1	17003205730000	OIL	15387	15575	MAGNOLIA PROD CO LLC	KB	96	30°36'54.9630"N	92°47'49.7317"W
245364	INDIGO 28_4	17039205630000	OIL	11582	11770	FORMENTERA OPER LLC	KB	117	30°45'38.9948"N	92°28'11.6877"W
246627	CROSBY 12; AUS C RA SUB_1	17115202260000	OIL	15071	20777	YUMA EXPL&PRD CO INC	KB	230	31°04'27.0000"N	93°01'51.0000"W
246707	LABOKAY CORPORATION; L CKFLD RA SUA_3-ALT	17003205800000	DRY_P_AB	9692	9905	EXTEX OPERATING CO	KB	69	30°34'27.5700"N	92°56'43.6800"W
246860	AMC; UWX RA SUFF_1	17003205810000	OIL	14528	14662	ELYSIUM JENNINGS LLC	KB	77	30°32'51.2505"N	92°49'29.0037"W
248747	MILLER S W; CF RA SUA_1	17011212120000	GAS	9594	9700	WILL-D RILL PROD CO	KB	106	30°38'11.0700"N	93°01'2.3600"W
252477	QUATRE MINERAL LLC_1	17003205990000	Undefined	5707	5806	PLANET OPER LLC	KB	99	30°39'57.9842"N	92°50'46.5301"W
32919	BENTLEY LBR CO_1	17079000040000	AB_OIL_MINOR_GAS	10795	11072	BURTON WMT INDST	DF	277	31°22'25.7178"N	92°53'24.9409"W
43481	LUMADARBONNE_1	17003000160000	AB_OIL_MINOR_GAS	15985	16066	RICHARDSON & BASS	DF	81	30°35'53.7098"N	92°43'12.6703"W
45689	LONG BELL PETR CO_1	17079006000000	OIL	10079	10300	CALIFORNIA CO THE	KB	220.7	31°04'47.6400"N	92°40'56.2800"W
45808	FOREST LBR CO_1	17003000050000	DRY_P_AB	12414	12542	CONTINENTAL OIL CO	DF	128	30°50'55.2532"N	92°36'15.7220"W
46964	CRWELL LD & MIN COR_1	17079006110000	AB_OIL_MINOR_GAS	12847	13003	RICHARDSON & BASS	DF	156	30°57'23.5698"N	92°42'6.1193"W
48268	HELLANDS INC_1	17079005980000	OIL	8728	8923	BUTLER-JOHNSON INC	DF	195	31°08'13.5600"N	92°44'49.2000"W
49267	LONG BELL LBR CO_1	17011001090000	DRY_P_AB	9333	9502	GENERAL CRUDE OIL CO	DF	169	30°47'16.3560"N	93°04'27.5828"W
65282	MARY A HODGES ETAL_1	17003001140000	AB_OIL_MINOR_GAS	9938	10004	HUNT H L	KB	66	30°36'7.9714"N	92°50'19.8471"W
65879	J A BEL ETAL/B/_1	17003001130000	AB_GAS_RESID_OIL	9890	9950	HUNT H L ETAL	DF	60	30°36'19.7183"N	92°49'46.6791"W
67166	POWELL LBR CO/C/_1	17003001120000	DRY_P_AB	9917	9966	HUNT H L EST	GL	49	30°35'58.5568"N	92°50'42.9181"W
68024	KELLY WEBER CO INC_1	17003000900000	DRY_P_AB	9806	9900	HUNT H L EST	DF	94	30°38'6.9714"N	92°36'17.2012"W
68890	E WHITTINGTON ETAL_1	17003003280000	DRY_P_AB	10532	10583	RELIANCE TRUSTS	DF	51	30°29'54.6148"N	92°53'43.0400"W
71716	RICE LAND & LUMBER CO_1	17003001060000	AB_GAS_RESID_OIL	9930	10004	PEAK TRADING CO	KB	74	30°35'11.1454"N	92°52'38.1545"W
73207	HILLYER ETAL_1	17003001160000	AB_OIL_MINOR_GAS	9604	9650	HUNT LAMAR	GL	46	30°35'46.5938"N	92°51'40.0021"W
74531	HATTIE HAAS_1	17039005210000	GAS	12137	12206	FAULCONER VERNON E	DF	69	30°41'39.1200"N	92°28'58.4400"W
90470	IND LBR CO /A/_1	17003000030000	DRY_P_AB	12500	12625	CONTINENTAL OIL CO	GL	125	30°49'16.0888"N	92°51'13.0503"W
972988	SWENCO 3 SWD_1	17115880450000	Undefined	4912	5100	SWIFT ENERGY CO	GL	188	30°55'7.6388"N	92°51'44.7295"W
975950	YAMS MLR_4	17003880130000	Undefined	7188	7300	OXY LOW CARBON VENT	KB	111.4	30°40'26.2233"N	92°49'59.0854"W

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Table AOR-30—Wells with petrophysically-interpreted VSH and Porosity

WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
45808	FOREST LBR CO_1	17003000050000	DRY_P_AB	12414	12542	CONTINENTAL OIL CO	DF	128	30°50'55.2532"N	92°36'15.7220"W
49267	LONG BELL LBR CO_1	17011001090000	DRY_P_AB	9333	9502	GENERAL CRUDE OIL CO	DF	169	30°47'16.3560"N	93°04'27.5828"W
53938	TEXAS CREOSOTING CO_1	17011001080000	DRY_P_AB	8500	8676	GLASSCOCK & WILSON	GL	176	30°50'38.7600"N	93°01'58.0800"W
65879	J A BEL ETAL/B/_1	17003001130000	AB_GAS_RESID_OIL	9890	9950	HUNTH L ETAL	DF	60	30°36'19.7183"N	92°49'46.6791"W
67166	POWELL LBR CO/C/_1	17003001120000	DRY_P_AB	9917	9966	HUNTH L EST	GL	49	30°35'58.5568"N	92°50'42.9181"W
90470	IND LBR CO /A/_1	17003000030000	DRY_P_AB	12500	12625	CONTINENTAL OIL CO	GL	125	30°49'16.0888"N	92°51'13.0503"W
125228	BOISE CASCADE CORP_1	17003200310000	DRY_P_AB	9354	9510	WHITESTONE PETROLEUM	GL	156	30°51'49.4972"N	92°49'18.0185"W
137602	CROSBY CHEMICALS_1	17003200670000	DRY_P_AB	10218	10305	MCCULLOCH OIL CORP	GL	87	30°44'6.1775"N	92°55'9.4308"W
138757	LEBOKAY CORP_1	17003200730000	DRY_P_AB	13381	13488	BERNOS MILTON J JR	KB	107	30°43'28.9942"N	92°49'38.4478"W
139337	A MANUEL ETAL_1	17003200750000	DRY_P_AB	14756	14841	BURTON WM T INDST	GL	85	30°39'40.9782"N	92°36'49.4759"W
145351	POWELL LBR CO_1	17003200950000	DRY_P_AB	14367	14489	ANSCHUTZ CORP	KB	122	30°43'8.9900"N	92°40'23.4207"W
148896	IVAR HANCHEY_2	17003201080000	DRY_P_AB	14200	14300	ANSCHUTZ CORP	KB	100	30°43'26.5174"N	92°54'42.3391"W
152953	POWELL LBR CO_2	17003201220000	DRY_P_AB	21909	22025	ANSCHUTZ CORP	KB	116	30°44'2.5550"N	92°41'28.9315"W
155596	POWELL LBR CO /A/_1	17003201350000	DRY_P_AB	10697	10820	ANSCHUTZ CORP	KB	123	30°44'16.6305"N	92°41'9.7962"W
155913	NAVAL STORES CO INC_1	17003201360000	DRY_P_AB	12659	12710	WEWOKA EXPL CO	GL	51	30°36'51.9246"N	92°55'35.2350"W
157387	QUATRE PARISH CO_1	17003201420000	DRY_P_AB	9364	9396	LOUISIANA LAND&EXPL	KB	32	30°37'50.1015"N	92°48'20.9450"W
157850	LABOKAY_1	17003201460000	DRY_P_AB	18514	18548	SHELL OIL CO	KB	34	30°53'8.8613"N	92°46'43.5119"W
160952	BENT-GLEN /A/_1	17079202590000	AB_OIL_MINOR_GAS	11033	11200	SEVARG CO INC	KB	167	30°55'35.8029"N	92°35'16.4122"W
171558	LABOKAY CORP /A/_1	17079202940000	DRY_P_AB	12440	12500	SHELL OIL CO	KB	60	30°54'17.4539"N	92°47'16.7438"W
173375	SOUTHERN BOISE_1	17003202120000	DRY_P_AB	10390	10500	DANIEL OIL CO	KB	110	30°43'14.6234"N	92°49'51.4513"W
174964	RICE LAND & LUMBER_1	17003202200000	DRY_P_AB	9681	9750	PRUET PRODUCTION CO	GL	69	30°36'2.1149"N	92°52'49.6794"W
176249	SOUTHWESTERN IMP_1	17003202270000	DRY_P_AB	13895	14000	SHELL OIL CO	DF	105	30°45'34.7352"N	92°42'2.0535"W
177494	RICE LAND & LUMBER_2	17003202390000	DRY_P_AB	9644	9730	PRUET PRODUCTION CO	KB	86	30°35'55.6779"N	92°53'24.2248"W
177498	PRAIRIE LAND_1	17003202380000	DRY_P_AB	7728	7815	RIO BRAVO OIL CO	KB	87	30°37'45.1170"N	92°40'8.2590"W
179615	RICE LAND & LUMBER_1	17003202450000	DRY_P_AB	12057	12132	CASHCO OIL CO	GL	75	30°37'14.7980"N	92°54'25.5243"W
179616	WILLAMETTE INC_1	17003202460000	DRY_P_AB	13412	13505	JUSTISS OIL CO INC	KB	93	30°44'2.6463"N	92°54'15.5884"W
187285	QUATRE PARISH_1	17003202860000	DRY_P_AB	9537	9608	CENTURY MINERAL CORP	KB	71	30°36'4.8437"N	92°51'37.9059"W
188615	ADAMS L H ETAL_1	17003202890100	DRY_P_AB	10481	10750	RIO BRAVO OIL CO	KB	99	30°36'17.9141"N	92°42'12.3977"W
189857	LEBLANC GWINN ETAL_1	17003202970000	DRY_P_AB	9510	9600	LGS EXPLORATION INC	KB	90	30°36'51.1798"N	92°45'34.9463"W
190476	DARBONNE C_1	17003203030000	DRY_P_AB	9392	9474	CABOT PETROLEUM CORP	GL	82	30°39'1.9163"N	92°45'58.7011"W
191999	FEAGIN - TUBB_1	17003203080000	DRY_P_AB	9407	9500	HAMON OIL CO	KB	93	30°36'57.4946"N	92°52'37.3900"W
195458	BEL J A ESTATE_1	17003203160000	DRY_P_AB	12125	12200	CENERGY EXPL CO	GL	75	30°37'13.2542"N	92°49'36.2678"W
196649	LETHA NAVARRE_2	17003203220000	DRY_P_AB	9315	9437	WOOLF & MAGEE INC	KB	84	30°37'55.7380"N	92°43'36.6481"W
197680	SONNIER MYRTLE_1	17003203280000	GAS	9205	9305	MISS-LOU OPERATING L	KB	100	30°39'23.4095"N	92°43'12.9910"W
198760	MATILDA GRAY EST_1	17003203320000	GAS	14570	14650	ELYSIUM JENNINGS LLC	KB	80	30°31'41.4971"N	92°53'24.1716"W
198805	DEAR EVELYN R_1	17003203350000	AB_DUE_TECH	9181	9275	WOOLF & MAGEE INC	KB	93.9	30°39'29.8610"N	92°42'51.1000"W
199589	GRAY MATILDA ESTATE_2	17003203390000	GAS	14606	14650	ELYSIUM JENNINGS LLC	GL	44	30°31'35.1300"N	92°54'12.7200"W
201959	PINELANDS PETROLEUM CO FEE_1	17003203470000	DRY_P_AB	13366	13500	PINELANDS PET CO	KB	134	30°46'41.8013"N	92°36'2.0889"W
218825	LABOKAY_1	17003204500000	DRY_P_AB	4820	4995	SELMAN EXPL INC	KB	175.5	30°51'34.9579"N	92°50'23.3972"W
220367	LORD 25; AUS C RA SULL_1	17079204460000	OIL	15284	18910	CHESAPEAKE OPERG INC	KB	190	30°56'24.9000"N	92°37'37.6289"W
220489	LABOKAY 26; AUS C RA SUA_1	17003204550000	AB_OIL_MINOR_GAS	15986	20200	CHESAPEAKE OPERG INC	KB	192	30°50'58.1612"N	92°51'17.2654"W
221201	BLACKSTONE MINERALS 23_1	17003204580000	OIL	16015	19450	CHESAPEAKE OPERG INC	KB	168	30°52'27.7332"N	92°38'9.7081"W
222785	CROSBY 9A; AUS C RA SUP_1	17115201780000	OIL	15116	20176	YUMA EXPL&PRD CO INC	GL	163.4	30°53'38.0000"N	92°59'4.0000"W
223573	LABOKAY_1	17003204670000	DRY_P_AB	3372	3510	BASIN PROD PROPS LTD	KB	138	30°49'16.2428"N	92°51'12.0075"W
223695	SWENCO MINERALS 3; AUS C RA SUL_1	17115201830000	OIL	15173	19062	PLANET RESOURCE OP	GL	200.5	30°55'8.3724"N	92°51'44.2631"W
224233	MARTIN ROYD LUMBER CO 31; AUS C RA SIOXX_1	17079204960000	DRY_P_AB	15448	18195	SWIFT ENERGY CO	KB	188	30°55'58.8724"N	92°48'45.5432"W
225116	CROSBY 2B_1	17115201880000	GAS	14973	19210	YUMA EXPL&PRD CO INC	KB	184	30°54'39.0000"N	92°57'9.0000"W
228609	BLACKSTONE 23_2	17003204940000	GAS	4517	4900	HUGHES EASTERN CORP	KB	149	30°52'27.7519"N	92°38'9.4786"W
229440	NORA MILLER COLE_1	17011009970000	DRY_P_AB	8418	8504	BRUXOIL INC	KB	86	30°39'39.6965"N	93°02'48.5046"W
229765	BLACKSTONE 13_1	17003205100000	DRY_P_AB	4506	4650	HUGHES EASTERN CORP	KB	144	30°52'46.0000"N	92°38'3.0000"W
230330	LAWTON J ETAL 33; F RA SUA_1	17003205120000	DRY_P_AB	6628	6750	SMITH PRODUCTION CO	KB	122	30°45'0.3309"N	92°40'26.6378"W
232324	CROSBY LAND & RESOURCES 14_1	17115201980000	GAS	4652	4800	PILOT RESOURCES INC	KB	148	30°52'59.9609"N	92°56'44.8900"W
234638	HEBERT KENNETH_1	17003205330000	DRY_P_AB	14552	14652	UNION GAS OPER CO	KB	100	30°36'5.2536"N	92°46'35.3754"W
235033	LABOKAY_1	17003205340000	DRY_P_AB	8383	8500	BRIDWELL OIL MGT LLC	KB	117	30°44'49.9514"N	92°51'42.6965"W
235590	MEAUX CLAUDE_1	17003205370000	AB_GAS_RESID_OIL	9480	9503	UNION GAS OPER CO	KB	23	30°38'12.2868"N	92°43'33.4781"W
235977	CROSBY LAND & RESOURCES 8_1	17115202060000	DRY_P_AB	4728	4900	PILOT RESOURCES INC	GL	172	30°53'59.1000"N	92°59'58.0000"W

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WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
238172	RESEARCH LABOKAY_1	17003205430000	Undefined	9890	10000	BRAMMER ENG INC	KB	110	30°43'50.8940"N	92°50'18.5600"W
238713	CROSBY LAND & RESOURCES_1	17003205460000	AB_GAS_RESID_OIL	5196	5300	UNION GAS OPER CO	KB	104	30°39'35.3627"N	92°56'20.7813"W
238754	FEAGIN ET AL_1	17003205470000	AB_GAS_RESID_OIL	6732	7166	UNION GAS OPER CO	KB	68	30°37'5.0423"N	92°55'54.4260"W
241434	BLACKSTONE 14_1	17003205520000	AB_GAS_RESID_OIL	3928	4072	HUGHES EASTERN CORP	KB	144	30°52'51.1110"N	92°38'23.3720"W
241524	BLACKSTONE MINERALS 21_1	17003205530000	DRY_P_AB	4686	4802	LYMAC EXPL & PROD LLC	KB	116	30°46'29.4736"N	92°46'30.5377"W
242383	HAINS BEVERLY B ETAL_1	17003205580000	DRY_P_AB	9310	9400	KASH OIL & GAS INC	KB	90	30°38'5.7756"N	92°46'28.6596"W
242930	BSML PARTNERSHIP 26_1	17003205610000	GAS	4872	5010	TDX ENERGY LLC	KB	138	30°51'15.6239"N	92°38'28.3604"W
244815	QUATRE MINERALS 17_1	17003205730000	OIL	15387	15575	MAGNOLIA PROD CO LLC	KB	96	30°36'54.9630"N	92°47'49.7317"W
248747	MILLER S W; CF RA SUA_1	17011212120000	GAS	9594	9700	WILL-DRILL PROD CO	KB	106	30°38'11.0700"N	93°01'2.3600"W
252477	QUATRE MINERAL LLC_1	17003205990000	Undefined	5707	5806	PLANET OPER LLC	KB	99	30°39'57.9842"N	92°50'46.5301"W
972988	SWENCO 3 SWD_1	17115880450000	Undefined	4912	5100	SWIFT ENERGY CO	GL	188	30°55'7.6388"N	92°51'44.7295"W
975950	YAMS MLR_4	17003880130000	Undefined	7188	7300	OXY LOW CARBON VENT	KB	111.4	30°40'26.2233"N	92°49'59.0854"W

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Table AOR-31 wells with top interpretation that were used to create structure and isopach maps. Arbitrary Class VI number at far left is labeled on maps.

Class VI Map Number	WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
1	125228	BOISE CASCADE CORP_1	17003200310000	DRY_P_AB	9354	9510	WHITESTONE PETROLEUM	GL	156	30°51'49.4972"N	92°49'18.0185"W
2	137602	CROSBY CHEMICALS_1	17003200670000	DRY_P_AB	10218	10305	MCCULLOCH OIL CORP	GL	87	30°44'6.1775"N	92°55'9.4308"W
3	138757	LEBOKAY CORP_1	17003200730000	DRY_P_AB	13381	13488	BERNOS MILTON JJR	KB	107	30°43'28.9942"N	92°49'38.4476"W
4	139337	A MANUEL ETAL_1	17003200750000	DRY_P_AB	14756	14841	BURTON WM T INDST	GL	85	30°39'40.9782"N	92°36'49.4759"W
5	145351	POWELL LBR CO_1	17003200950000	DRY_P_AB	14367	14489	ANSCHUTZ CORP	KB	122	30°43'8.9900"N	92°40'23.4207"W
6	148896	IVAR HANCHEY_1	17003201080000	DRY_P_AB	14200	14300	ANSCHUTZ CORP	KB	100	30°43'26.5174"N	92°54'42.3391"W
7	150206	PINELANDS PETR CO_1	17003201140000	DRY_P_AB	13748	13875	WESTLAND OIL DEV CRP	KB	127	30°45'48.6831"N	92°37'17.3933"W
8	152953	POWELL LBR CO_2	17003201220000	DRY_P_AB	21909	22025	ANSCHUTZ CORP	KB	116	30°44'2.5550"N	92°41'28.9315"W
9	155596	POWELL LBR CO /A_1	17003201350000	DRY_P_AB	10697	10820	ANSCHUTZ CORP	KB	123	30°44'16.6305"N	92°41'9.7962"W
10	155913	NAVAL STORES CO INC_1	17003201360000	DRY_P_AB	12659	12710	WEWOKA EXPL CO	GL	51	30°36'51.9246"N	92°55'35.2350"W
11	157850	LABOKAY_1	17003201460000	DRY_P_AB	18514	18548	SHELL OIL CO	KB	34	30°53'8.8613"N	92°46'43.5119"W
12	160952	BENT-GLEN /A_1	17079202590000	AB_OIL_MIN OR GAS	11033	11200	SEVARG CO INC	KB	167	30°55'35.8029"N	92°35'16.4122"W
13	165154	A M MOORE_1	17003201760000	DRY_P_AB	12041	12115	EMERALD OIL&GAS-NORM	GL	74	30°36'54.9351"N	92°43'12.4377"W
14	171013	GLEN BENT_2	17079202930000	AB_OIL_MIN OR GAS	11076	11240	SEVARG CO INC	KB	164	30°55'35.9778"N	92°34'45.5185"W
15	171558	LABOKAY CORP /A_1	17079202940000	DRY_P_AB	12440	12500	SHELL OIL CO	KB	60	30°54'17.4539"N	92°47'16.7438"W
16	172040	JOHNCO_1	17079202970000	DRY_P_AB	11031	11200	TRANSCNTNNTL OIL	KB	169	30°55'35.7936"N	92°36'27.5442"W
17	172367	VANCOUVER PLYWOOD_1	17003202030000	DRY_P_AB	9450	9510	TEE OIL INC	KB	60	30°36'19.0448"N	92°50'11.4625"W
18	173375	SOUTHERN BOISE_1	17003202120000	DRY_P_AB	10390	10500	DANIEL OIL CO	KB	110	30°43'14.6234"N	92°49'51.4513"W
19	174964	RICE LAND & LUMBER_1	17003202200000	DRY_P_AB	9681	9750	PRUET PRODUCTION CO	GL	69	30°36'2.1149"N	92°52'49.6794"W
20	176249	SOUTHWESTERN IMP_1	17003202270000	DRY_P_AB	13895	14000	SHELL OIL CO	DF	105	30°45'34.7352"N	92°42'2.0535"W
21	177498	PRAIRIE LAND_1	17003202380000	DRY_P_AB	7728	7815	RIO BRAVO OIL CO	KB	87	30°37'45.1170"N	92°40'8.2590"W
22	179615	RICE LAND & LUMBER_1	17003202450000	DRY_P_AB	12057	12132	CASHCO OIL CO	GL	75	30°37'14.7980"N	92°54'25.5243"W
23	179616	WILLAMETTE INC_1	17003202460000	DRY_P_AB	13412	13505	JUSTISS OIL CO INC	KB	93	30°44'2.6463"N	92°54'10.5884"W
24	183192	ADAMS HARVEY ETAL_1	17003202590000	GAS	9527	9600	FAULCONER VERNON E	GL	73	30°37'21.5989"N	92°41'8.9571"W
25	184408	ADAMS HARVEY ETAL_2	17003202720000	GAS	9545	9620	FAULCONER VERNON E	GL	75	30°37'10.7815"N	92°41'28.1926"W
26	187285	QUATRE PARISH_1	17003202860000	DRY_P_AB	9537	9608	CENTURY MINERAL CORP	KB	71	30°36'4.8437"N	92°51'37.9059"W
27	188615	ADAMS L H ETAL_1	17003202890100	DRY_P_AB	10481	10750	RIO BRAVO OIL CO	KB	99	30°38'17.9141"N	92°42'12.3977"W
28	189857	LEBLANC GWIN N ETAL_1	17003202970000	DRY_P_AB	9510	9600	LGS EXPLORATION INC	KB	90	30°36'51.1798"N	92°45'34.9463"W

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Class VI Map Number	WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
29	190476	DARBONNE C_1	17003203030000	DRY_P_AB	9392	9474	CABOT PETROLEUM CORP	GL	82	30°39'1.9163"N	92°45'58.7011"W
30	191999	FEAGIN - TUBB_1	17003203080000	DRY_P_AB	9407	9500	HAMON OIL CO	KB	93	30°36'57.4946"N	92°52'37.3900"W
31	195458	BEL J A ESTATE_1	17003203160000	DRY_P_AB	12125	12200	CENERGY EXPL CO	GL	75	30°37'13.2542"N	92°48'36.2678"W
32	196649	LETHA NAVARRE_2	17003203220000	DRY_P_AB	9315	9437	WOOLF & MAGEE INC	KB	84	30°37'55.7380"N	92°43'36.9481"W
33	196911	TATE VINEY MANUEL_1	17003203230000	AB_GAS_RE SID_OIL	9557	9650	CARLOIL & GAS CO	KB	93	30°37'9.2441"N	92°42'7.6247"W
34	197680	SONNIER MYRTLE_1	17003203280000	GAS	9205	9305	MISS-LOU OPERATING L	KB	100	30°39'23.4095"N	92°43'12.9910"W
35	197727	HARVEY ADAMS ETAL_3	17003203290000	GAS	9554	9626	FAULCONER VERNON E	GL	72	30°37'23.6807"N	92°40'38.9231"W
36	198805	DEAR EVELYN R_1	17003203350000	AB_DUE TE CH	9181	9275	WOOLF & MAGEE INC	KB	93.9	30°39'29.8610"N	92°42'51.1000"W
37	201959	PINELANDS PETROLEUM CO FEE_1	17003203470000	DRY_P_AB	13366	13500	PINELANDS PET CO	KB	134	30°46'41.8013"N	92°36'2.0889"W
38	203867	SMITH BENTON ETAL_1	17003203640000	DRY_P_AB	12931	13030	GERMANY EXPL CO	KB	99	30°36'13.2321"N	92°38'3.6928"W
39	218825	LABOKAY_1	17003204500000	DRY_P_AB	4820	4995	SELMAN EXPL INC	KB	175.5	30°51'34.9579"N	92°50'23.3972"W
40	220489	LABOKAY 26; AUS C RASUA_1	17003204550000	AB_OIL_MIN OR_GAS	15986	20200	CHESAPEAKE OPERG INC	KB	192	30°50'58.1612"N	92°51'17.2654"W
41	221201	BLACKSTONE MINERALS 23_1	17003204580000	OIL	16015	19450	CHESAPEAKE OPERG INC	KB	168	30°52'27.7332"N	92°38'9.7081"W
42	221316	BENTLEY 5; AUS C RASU69_1	17079204750000	AB_OIL_MIN OR_GAS	15454	19069	CHESAPEAKE OPERG INC	KB	196	30°55'2.0000"N	92°35'39.0001"W
43	223573	LABOKAY_1	17003204670000	DRY_P_AB	3372	3510	BASIN PROD PROPS LTD	KB	138	30°49'16.2428"N	92°51'12.0075"W
44	224233	MARTIN ROY O LUMBER CO 31; AUS C RASUX_1	17079204960000	DRY_P_AB	15448	18195	SWIFT ENERGY CO	KB	188	30°55'58.8724"N	92°48'45.5432"W
45	224925	SWENCO 32; AUS C RASUK_1	17115201870000	GAS	14954	18553	PLANET RESOURCE OP	KB	219.9	30°55'37.0000"N	92°53'41.0000"W
46	225116	CROSBY 2B_1	17115201880000	GAS	14973	19210	YUMA EXPL&PRD CO INC	KB	184	30°54'39.0000"N	92°57'9.0000"W
47	228609	BLACKSTONE 23_2	17003204940000	GAS	4517	4900	HUGHES EASTERN CORP	KB	149	30°52'27.7519"N	92°38'9.4786"W
48	228856	MTR_1	17003204990000	GAS	9752	9800	UNIT PETROLEUM CO	GL	48	30°37'3.0000"N	92°38'59.0004"W
49	229132	WALKER B; OBERLIN VUL_1	17003205030000	GAS	9767	9837	UNIT PETROLEUM CO	GL	70	30°36'42.0012"N	92°37'23.0015"W
50	229253	WALKER C; VUJ_1	17003205050000	GAS	9840	9900	UNIT PETROLEUM CO	GL	60	30°37'1.9992"N	92°38'18.9996"W
51	229298	GRANGER; OBERLIN RA SUB_1	17003205060000	DRY_P_AB	9735	9810	UNIT PETROLEUM CO	KB	75	30°36'44.3654"N	92°42'14.1837"W
52	229653	MANUEL; OBERLIN RB SUE_1	17003205080000	DRY_P_AB	9770	9834	UNIT PETROLEUM CO	KB	64	30°36'36.0000"N	92°37'0.9984"W

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Class VI Map Number	WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
53	229759	ADAMS A; VUK_1	17003205090000	GAS	9719	9810	UNIT PETROLEUM CO	KB	91	30°36'39.9996"N	92°38'49.9992"W
54	229765	BLACKSTONE 13_1	17003205100000	DRY_P_AB	4506	4650	HUGHES EASTERN CORP	KB	144	30°52'46.0000"N	92°38'3.0000"W
55	230330	LAWTON J ETAL 33; F RASUA_1	17003205120000	DRY_P_AB	6628	6750	SMITH PRODUCTION CO	KB	122	30°45'0.3309"N	92°40'26.6378"W
56	230644	SMITH E; VUL_1	17003205130000	GAS	9735	9808	UNIT PETROLEUM CO	KB	73	30°36'21.2832"N	92°38'33.4897"W
57	230645	ADAMS B; VUM_1	17003205140000	GAS	9726	9810	UNIT PETROLEUM CO	KB	84	30°36'38.2860"N	92°39'40.4890"W
58	231409	SMITH F_1	17003205200000	DRY_P_AB	9729	9810	UNIT PETROLEUM CO	KB	81	30°36'38.2860"N	92°40'45.4872"W
59	231880	MARTIN ROY O INC 20_2	17039204370000	DRY_P_AB	5169	5305	BRIDWELL OIL CO	KB	136	30°52'32.3561"N	92°35'36.8341"W
60	233234	CROSBY LAND & RESOURCES 14_1	17115201980000	GAS	4652	4800	PILOT RESOURCES INC	KB	148	30°52'59.9609"N	92°56'44.8900"W
61	234638	HEBERT KENNETH_1	17003205330000	DRY_P_AB	14552	14652	UNION GAS OPER CO	KB	100	30°36'5.2536"N	92°46'35.3754"W
62	235033	LABOKAY_1	17003205340000	DRY_P_AB	8383	8500	BRIDWELL OIL MGT LLC	KB	117	30°44'49.9514"N	92°51'42.6065"W
63	235590	MEAUX CLAUDE_1	17003205370000	AB_GAS_RE SID_OIL	9480	9503	UNION GAS OPER CO	KB	23	30°38'12.2868"N	92°43'33.4781"W
64	235752	LORD TIMBER LLC; F RASUB_2	17079205240000	DRY_P_AB	4199	4350	WINDRUSH OPERATING	KB	151	30°55'9.0796"N	92°36'55.5953"W
65	238172	RESEARCH LABOKAY_1	17003205430000	DRY_P_AB	9890	10000	BRAMMER ENG INC	KB	110	30°43'50.8940"N	92°50'18.5600"W
66	238713	CROSBY LAND & RESOURCES_1	17003205460000	AB_GAS_RE SID_OIL	5196	5300	UNION GAS OPER CO	KB	104	30°39'35.3627"N	92°56'20.7813"W
67	238754	FEAGIN ETAL_1	17003205470000	AB_GAS_RE SID_OIL	6732	7166	UNION GAS OPER CO	KB	68	30°37'5.0423"N	92°55'54.4260"W
68	240097	INDIGO MINERALS 31_1	17003205510000	AB_GAS_RE SID_OIL	5283	5400	LYMAC EXPL &PROD LLC	KB	117	30°44'49.6254"N	92°36'24.2598"W
69	241434	BLACKSTONE 14_1	17003205520000	AB_GAS_RE SID_OIL	3928	4072	HUGHES EASTERN CORP	KB	144	30°52'51.1110"N	92°38'23.3720"W
70	241524	BLACKSTONE MINERALS 21_1	17003205530000	DRY_P_AB	4686	4802	LYMAC EXPL &PROD LLC	KB	116	30°46'29.4736"N	92°46'30.5377"W
71	242383	HAINS BEVERLY B ETAL_1	17003205580000	DRY_P_AB	9310	9400	KASH OIL & GAS INC	KB	90	30°38'5.7756"N	92°46'28.6596"W
72	242930	BSML PARTNERSHIP 26_1	17003205610000	GAS	4872	5010	TDX ENERGY LLC	KB	138	30°51'15.6239"N	92°38'28.3604"W
73	243064	BENTLEY J_1	17003205620000	TEMP_AB	10963	11050	GULF SOUTH OPER INC	KB	87	30°36'20.0340"N	92°42'55.6710"W
74	244149	SSS&F FARM_1	17003205710000	DRY_P_AB	9713	9800	UNION GAS OPER CO	KB	87	30°37'5.2800"N	92°43'28.4701"W
75	244815	QUATRE MINERALS 17_1	17003205730000	OIL	15387	15575	MAGNOLIA PROD CO LLC	KB	96	30°36'54.9630"N	92°47'49.7317"W
76	252477	QUATRE MINERAL LLC_1	17003205990000	Undefined	5707	5806	PLANET OPER LLC	KB	99	30°39'57.9842"N	92°50'46.5301"W
77	45808	FOREST LBR CO_1	17003000050000	DRY_P_AB	12414	12542	CONTINENTAL OIL CO	DF	128	30°50'55.2532"N	92°36'15.7220"W
78	65282	MARY AHODGES ETAL_1	17003001140000	AB_OIL_MIN OR_GAS	9938	10004	HUNT H L	KB	66	30°36'7.9714"N	92°50'19.8471"W
79	65879	JABEL ETAL/B/_1	17003001130000	AB_GAS_RE SID_OIL	9890	9950	HUNT H L ETAL	DF	60	30°36'19.7183"N	92°49'46.6791"W

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Class VI Map Number	WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDSS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE
80	67166	POWELL LBR CO/C/_1	17003001120000	DRY_P_AB	9917	9966	HUNTH LEST	GL	49	30°35'58.5568"N	92°50'42.9181"W
81	68024	KELLY WEBER CO INC_1	17003000900000	DRY_P_AB	9806	9900	HUNTH LEST	DF	94	30°38'6.9714"N	92°36'17.2012"W
82	90470	IND LBR CO /A/_1	17003000030000	DRY_P_AB	12500	12625	CONTINENTAL OIL CO	GL	125	30°49'16.0888"N	92°51'13.0503"W
83	972988	SWENCO 3 SWD_1	17115880450000	Undefined	4912	5100	SWIFT ENERGY CO	GL	188	30°55'7.6388"N	92°51'44.7295"W
84	975950	YAMS MLR_4	17003880130000	Undefined	7188	7300	OXY LOW CARBON VENT	KB	0	30°40'26.7500"N	92°49'58.2240"W

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Table AOR-32—All wells with digital logs used to create petrophysical calculations and resulting curves

WELL PERMIT NUMBER	NAME	UWI	WELL SYMBOL	TD (TVDS)	TD (MD)	OPERATOR	WELL DATUM	DATUM VALUE	LATITUDE	LONGITUDE	XGR	XSP	XRES	XDT	XRHO	XPOR	XPERM	XVSH
45808	FOREST LBR CO_1	17003000050000	DRY_P_AB	12414	12542	CONTINENTAL OIL CO	DF	128	30°50'55.2532"N	92°36'15.7220"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
49267	LONG BELL LBR CO_1	17011001090000	DRY_P_AB	9333	9502	GENERAL CRUDE OIL CO	DF	169	30°47'16.3560"N	93°04'27.5888"W	No	Yes	Yes	No	No	Yes	Yes	Yes
53938	TEXAS CREOSOTING CO_1	17011001080000	DRY_P_AB	8500	8676	GLASSCOCK & WILSON	GL	176	30°50'36.7600"N	93°01'58.0800"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
65879	JABEL ETAL/B_1	17003001130000	DRY_P_AB	9890	9950	HUNT H L ETAL	DF	60	30°38'19.7183"N	92°49'46.6781"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
67166	POWELL LBR CO/C_1	17003001120000	DRY_P_AB	9917	9966	HUNT H L ETAL	GL	49	30°35'56.5568"N	92°50'42.9181"W	No	Yes	Yes	Yes	No	Yes	Yes	Yes
90470	IND LBR CO /A_1	17003000030000	DRY_P_AB	12500	12625	CONTINENTAL OIL CO	GL	125	30°49'16.0888"N	92°51'13.0503"W	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
125228	BOISE CASCADE CORP_1	17003200310000	DRY_P_AB	9354	9510	WHITESTONE PETROLEUM	GL	156	30°51'49.4872"N	92°49'18.0185"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
137602	CROSBY CHEMICALS_1	17003200670000	DRY_P_AB	10218	10305	MCCULLOCH OIL CORP	GL	87	30°44'6.1775"N	92°55'9.4308"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
138757	LEBOKAY CORP_1	17003200730000	DRY_P_AB	13381	13488	BERNOS MILTON J JR	KB	107	30°43'28.9942"N	92°49'38.4476"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
139337	A MANUEL ETAL_1	17003200750000	DRY_P_AB	14756	14841	BURTON WM T INDST	GL	85	30°39'40.9782"N	92°36'48.4759"W	No	Yes	Yes	No	No	Yes	Yes	Yes
145351	POWELL LBR CO_1	17003200950000	DRY_P_AB	14367	14489	ANSCHUTZ CORP	KB	122	30°45'8.9800"N	92°49'23.4007"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
148896	IVAR HANCHEY_1	17003201080000	DRY_P_AB	14200	14300	ANSCHUTZ CORP	KB	100	30°43'26.5174"N	92°54'42.3391"W	No	Yes	Yes	No	No	Yes	Yes	Yes
152953	POWELL LBR CO_2	17003201220000	DRY_P_AB	21909	22025	ANSCHUTZ CORP	KB	116	30°44'2.5550"N	92°48'28.9315"W	No	Yes	Yes	No	No	Yes	Yes	Yes
155596	POWELL LBR CO /A_1	17003201350000	DRY_P_AB	10697	10820	ANSCHUTZ CORP	KB	123	30°44'16.6305"N	92°41'9.7962"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
155913	NAVAL STORES CO INC_1	17003201360000	DRY_P_AB	12659	12710	WEWOKA EXPL CO	GL	51	30°38'51.9248"N	92°55'35.2390"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
157387	QUATRE PARISH CO_1	17003201420000	DRY_P_AB	9364	9396	LOUISIANA LAND&EXPL	KB	32	30°37'50.1015"N	92°48'20.9450"W	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
157850	LABOKAY_1	17003201460000	DRY_P_AB	18514	18548	SHELL OIL CO	KB	34	30°53'8.8813"N	92°46'43.5119"W	No	Yes	Yes	No	No	Yes	Yes	Yes
160952	BENT-GLEN /A_1	17079202590000	DRY_P_AB	11033	11200	SEVARG CO INC	KB	167	30°55'56.8029"N	92°36'18.4122"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
171558	LABOKAY CORP/A_1	17079202840000	DRY_P_AB	12440	12500	SHELL OIL CO	KB	60	30°54'17.4539"N	92°47'16.7438"W	Yes	No	Yes	No	Yes	Yes	Yes	Yes
173375	SOUTHERN BOISE_1	17003202120000	DRY_P_AB	10390	10500	DANIEL OIL CO	KB	110	30°43'14.6234"N	92°49'51.4513"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
174964	RICE LAND & LUMBER_1	17003202200000	DRY_P_AB	9681	9750	PRUET PRODUCTION CO	GL	69	30°36'2.1149"N	92°52'48.6794"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
176249	SOUTHWESTERN IMP_1	17003202270000	DRY_P_AB	13895	14000	SHELL OIL CO	DF	105	30°45'34.7352"N	92°42'2.0535"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
177494	RICE LAND & LUMBER_2	17003202390000	DRY_P_AB	9644	9730	PRUET PRODUCTION CO	KB	86	30°35'55.6779"N	92°53'24.2248"W	No	Yes	Yes	No	No	Yes	Yes	Yes
177498	PRAIRIE LAND_1	17003202380000	DRY_P_AB	7728	7815	RIO BRAVO OIL CO	KB	87	30°37'45.1170"N	92°48'8.2590"W	No	Yes	Yes	No	No	Yes	Yes	Yes
179615	RICE LAND & LUMBER_1	17003202450000	DRY_P_AB	12057	12132	CASHCO OIL CO	GL	75	30°37'14.7880"N	92°54'25.5243"W	No	Yes	Yes	No	No	Yes	Yes	Yes
179616	WILLAMETTE INC_1	17003202460000	DRY_P_AB	13412	13505	JUSTISS OIL CO INC	KB	93	30°44'2.6463"N	92°54'10.5884"W	No	Yes	Yes	No	No	Yes	Yes	Yes
187285	QUATRE PARISH_1	17003202860000	DRY_P_AB	9537	9608	CENTURY MINERAL CORP	KB	71	30°36'4.8437"N	92°51'37.9059"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
188615	ADAMS L H ETAL_1	17003202890100	DRY_P_AB	10481	10750	RIO BRAVO OIL CO	KB	99	30°38'17.9141"N	92°42'12.3977"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
189857	LEBLANC GWIN N ETAL_1	17003202970000	DRY_P_AB	9510	9600	LGS EXPLORATION INC	KB	90	30°36'51.1798"N	92°45'34.9463"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
190476	DARBONNE C_1	17003203030000	DRY_P_AB	9392	9474	CABOT PETROLEUM CORP	GL	82	30°38'1.9363"N	92°46'58.7011"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
191999	FEAGIN - TUBB_1	17003203080000	DRY_P_AB	9407	9500	HAMON OIL CO	KB	93	30°36'57.4946"N	92°52'37.3900"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
195458	BEL J A ESTATE_1	17003203160000	DRY_P_AB	12125	12200	CENERGY EXPL CO	GL	75	30°37'13.2542"N	92°49'36.2678"W	Yes	Yes	Yes	Yes	No	No	Yes	Yes
196649	LETHA NAVARRE_2	17003203220000	DRY_P_AB	9315	9437	WOOLF & MAGEE INC	KB	84	30°37'55.7380"N	92°43'36.9481"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
197680	SONNIER MYRTLE_1	17003203280000	GAS	9205	9305	MISS-LOU OPERATING L	KB	100	30°39'23.4095"N	92°43'12.9910"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
198760	MATILDA GRAY EST_1	17003203320000	GAS	14570	14650	ELYSIUM JENNINGS LLC	KB	80	30°31'41.4871"N	92°53'24.1718"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
198805	DEAR EVELYN R_1	17003203350000	DRY_P_AB	9181	9275	WOOLF & MAGEE INC	KB	93.9	30°39'29.8610"N	92°42'51.1000"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
199589	GRAY MATILDA ESTATE_2	17003203390000	GAS	14606	14650	ELYSIUM JENNINGS LLC	GL	44	30°31'35.1300"N	92°54'12.7200"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
201959	PINELANDS PETROLEUM CO FEE_1	17003203470000	DRY_P_AB	13366	13500	PINELANDS PET CO	KB	134	30°46'41.8013"N	92°36'2.0880"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
211825	LABOKAY_1	17003204500000	DRY_P_AB	4820	4995	SELMAN EXPL INC	KB	175.5	30°51'34.9579"N	92°50'23.3972"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
220367	LORO 25; AUS C RA SULA_1	17079204460000	OIL	15284	18910	CHESAPEAKE OPERG INC	KB	190	30°56'24.9000"N	92°37'37.6299"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
220489	LABOKAY 26; AUS C RA SUA_1	17003204550000	DRY_P_AB	15986	20200	CHESAPEAKE OPERG INC	KB	192	30°50'56.1612"N	92°51'17.2654"W	No	Yes	Yes	No	No	Yes	Yes	Yes
221201	BLACKSTONE MINERALS 23_1	17003204580000	OIL	16015	19450	CHESAPEAKE OPERG INC	KB	168	30°52'27.7332"N	92°38'9.7081"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
222785	CROSBY 9A; AUS C RA SUP_1	17115201780000	OIL	15116	20176	YUMA EXPL&PRD CO INC	GL	163.4	30°53'38.0000"N	92°59'4.0000"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
223573	LABOKAY_1	17003204670000	DRY_P_AB	3372	3510	BASIN PROD PROPS LTD	KB	138	30°49'16.2428"N	92°51'12.0075"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
223695	SWENCO MINERALS 3; AUS C RA SULA_1	17115201830000	OIL	15173	19062	PLANET RESOURCE OP	GL	200.5	30°50'8.3724"N	92°51'44.2631"W	No	Yes	Yes	No	No	Yes	Yes	Yes
224213	WATKINS LUMBER 31; AUS C RA SULA_1	17079204960000	DRY_P_AB	15448	18195	SWIFT ENERGY CO	KB	188	30°55'58.8724"N	92°48'45.5432"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
225136	CROSBY 2B_1	17115201880000	GAS	14973	19210	YUMA EXPL&PRD CO INC	KB	184	30°54'39.0000"N	92°57'9.0000"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
228609	BLACKSTONE 23_2	17003204940000	GAS	4517	4900	HUGHES EASTERN CORP	KB	149	30°52'27.7519"N	92°38'9.4786"W	Yes	No	Yes	No	Yes	Yes	Yes	Yes
229440	NORAMILLER COLE_1	17011009970000	DRY_P_AB	8418	8504	BRUXOIL INC	KB	86	30°39'39.6965"N	93°02'48.5046"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
229765	BLACKSTONE 13_1	17003205100000	DRY_P_AB	4506	4650	HUGHES EASTERN CORP	KB	144	30°52'46.0000"N	92°38'3.0000"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
230330	LAWTON J ETAL 33; FRA SUA_1	17003205120000	DRY_P_AB	6628	6750	SMITH PRODUCTION CO	KB	122	30°45'0.3309"N	92°40'26.6378"W	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
233234	CROSBY LAND & RESOURCES 14_1	17115201980000	GAS	4652	4800	PILOT RESOURCES INC	KB	148	30°52'59.9609"N	92°50'44.8900"W	Yes	No	Yes	No	No	Yes	Yes	Yes
234638	HEBERT KENNETH_1	17003205330000	DRY_P_AB	14552	14652	UNION GAS OPER CO	KB	100	30°36'5.2538"N	92°46'35.3754"W	No	Yes	Yes	No	No	Yes	Yes	Yes
235033	LABOKAY_1	17003205340000	DRY_P_AB	8383	8500	BRIDWELL OIL MGT LLC	KB	117	30°44'49.9514"N	92°51'42.6065"W	No	Yes	Yes	Yes	No	Yes	Yes	Yes
235590	MEALUX CLAUDE_1	17003205370000	DRY_P_AB	9480	9503	UNION GAS OPER CO	KB	23	30°38'12.2868"N	92°43'33.4781"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
235977	CROSBY LAND & RESOURCES 8_1	17115202060000	DRY_P_AB	4728	4900	PILOT RESOURCES INC	GL	172	30°53'59.1000"N	92°59'58.0000"W	No	Yes	Yes	Yes	No	Yes	Yes	Yes
238172	RESEARCH LABOKAY_1	17003205430000	Undefined	9890	10000	BRAMMER ENG INC	KB	110	30°43'50.8940"N	92°50'18.5600"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
238713	CROSBY LAND & RESOURCES_1	17003205460000	DRY_P_AB	5196	5300	UNION GAS OPER CO	KB	104	30°39'35.3627"N	92°56'20.7813"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
238754	FEAGIN ETAL_1	17003205470000	DRY_P_AB	6732	7166	UNION GAS OPER CO	KB	68	30°37'5.0423"N	92°55'54.4260"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
241434	BLACKSTONE 14_1	17003205520000	DRY_P_AB	3928	4072	HUGHES EASTERN CORP	KB	144	30°52'51.1110"N	92°38'23.3720"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
241524	BLACKSTONE MINERALS 21_1	17003205530000	DRY_P_AB	4686	4802	LYMAC EXPL & PROD LLC	KB	116	30°48'29.4736"N	92°46'30.5377"W	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
242383	HAINS BEVERLY B ETAL_1	17003205580000	DRY_P_AB	9310	9400	KASH OIL & GAS INC	KB	90	30°38'5.7756"N	92°46'28.6596"W	Yes	Yes	Yes	No	No	Yes	Yes	Yes
242930	BSML PARTNERSHIP 26_1	17003205610000	GAS	4872	5010	TDX ENERGY LLC	KB	138	30°51'15.6238"N	92°38'28.3604"W	Yes	No	Yes	No	Yes	Yes	Yes	Yes
244815	QUATRE MINERALS 17_1	17003205730000	OIL	15387	15575	MAGNOLIA PROD CO LLC	KB	96	30°36'54.9630"N	92°47'49.7317"W	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
248747	MILLER S W; CF RA SUA_1	17011212120000	GAS	9594	9700	WILL-DRILL PROD CO	KB	106	30°38'11.0700"N	93°01'2.3600"W	Yes	Yes	Yes	Yes				

Appendix C: Site-Specific Data and Procedures

Core data collected from the YAMS MLR 004 (SN 975950) Stratigraphic Test Well used for calibration of petrophysical calculations.

C.1 Core Analysis***C.1.1 Routine core analysis (RCA): Porosity & Permeability (P&P)*****Sample preparation and procedures (Core Lab)**

The selected samples were horizontal plugs extracted out of the Full core from the YAMS MLR-004 well (SN 975950) cleaned using Cool Solvent then Humidity-Dried at 40% relative humidity and Vacuum Oven Dried at 60 C to weight equilibrium. At a net-confining stress (NCS)(provided by OXY) most representative of subsurface conditions the porosity was determined using Boyle's Law and permeability to air was measured using the industry-standard gas steady-state method.

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Table AOR-33—Routine core analysis results.

Vacuum-Dried					Humidity-Dried				
Sample Number	Depth (ft)	Net Confining stress (psi)	Porosity (dec)	Permeability (mD)	Sample Number	Depth (ft)	Net Confining stress (psi)	Porosity (dec)	Permeability (mD)
2H	4054.24	1700	0.36	1680	2H	4054.24	1700	0.35	1830
5H	4056.99	1700	0.37	1640	5H	4056.99	1700	0.36	1920
6H	4057.99	1700	0.38	2580	6H	4057.99	1700	0.37	2970
11H	4062.99	1700	0.37	2720	11H	4062.99	1700	0.37	3010
15H	4067.04	1700	0.37	4250	15H	4067.04	1700	0.37	5070
17H	4068.99	1700	0.35	2910	17H	4068.99	1700	0.35	3370
25H	4084.1	1700	0.27	1.87	25H	4084.1	1700	0.20	2.03
29H	4088.4	1700	0.35	627	29H	4088.4	1700	0.33	575
31H	4090.55	1700	0.32	121	31H	4090.55	1700	0.30	107
34H	4094.7	1700	0.33	585	34H	4094.7	1700	0.32	542
37H	4097.55	1700	0.36	3020	37H	4097.55	1700	0.35	3350
40H	4100.95	1700	0.14	5.68	40H	4100.95	1700	0.12	4.58
41H	4101.7	1700	0.08	0.774	41H	4101.7	1700	0.07	0.767
43H	4104.05	1700	0.25	3.64	43H	4104.05	1700	0.16	2.92
44H	4104.8	1700	0.26	3.19	44H	4104.8	1700	0.15	2.56
45H	4105.65	1700	0.26	10.5	45H	4105.65	1700	0.17	7.03
141H	6043.59	2600	0.30	21.1	141H	6043.59	2600	0.27	17
47H	6044.79	2600	0.29	71.3	47H	6044.79	2600	0.26	87
48H	6045.74	2600	0.33	549	48H	6045.74	2600	0.32	568
49H	6046.94	2600	0.33	245	49H	6046.94	2600	0.33	233
148H	6049.39	2600	0.31	95.6	148H	6049.39	2600	0.30	86.6
52H	6049.94	2600	0.32	240	52H	6049.94	2600	0.31	233
53H	6050.94	2600	0.30	1190	53H	6050.94	2600	0.29	1180
54H	6051.94	2600	0.28	1310	54H	6051.94	2600	0.28	1430
150H	6053.74	2600	0.25	1500	150H	6053.74	2600	0.25	1480
55H	6053.94	2600	0.28	1200	55H	6053.94	2600	0.29	1200
56H	6055.94	2600	0.31	10800	56H	6055.94	2600	0.31	11500
58H	6058.89	2600	0.32	14200	58H	6058.89	2600	0.33	12700
59H	6059.94	2600	0.32	6090	59H	6059.94	2600	0.32	6150
60H	6061.19	2600	0.32	7140	60H	6061.19	2600	0.32	7660
61H	6062.94	2600	0.29	7320	61H	6062.94	2600	0.30	7740
63H	6064.94	2600	0.30	6770	63H	6064.94	2600	0.30	6930
64H	6065.94	2600	0.31	8500	64H	6065.94	2600	0.31	8440
176H	6066.6	2600	0.32	5520	176H	6066.6	2600	0.32	5660
66H	6067.94	2600	0.33	4040	66H	6067.94	2600	0.32	4020
67H	6069.94	2600	0.28	2020	67H	6069.94	2600	0.28	2000
68H	6071.44	2600	0.30	7510	68H	6071.44	2600	0.30	7480
69H	6072.44	2600	0.32	5170	69H	6072.44	2600	0.32	5130
70H	6622.55	2800	0.27	53.4	70H	6622.55	2800	0.26	48.2
71H	6623.5	2800	0.19	2.68	71H	6623.5	2800	0.11	1.3
73H	6626.5	2800	0.20	2.71	73H	6626.5	2800	0.11	1.86
75H	6629.3	2800	0.18	2.04	75H	6629.3	2800	0.10	1.33
158H	6630.3	2800	0.20	43	158H	6630.3	2800	0.16	38.3
159H	6631.8	2800	0.28	1750	159H	6631.8	2800	0.28	1650
78H	6632.5	2800	0.15	1.15	78H	6632.5	2800	0.06	1.37
79H	6634.5	2800	0.31	2420	79H	6634.5	2800	0.31	2350
161H	6636.1	2800	0.32	3180	161H	6636.1	2800	0.32	3230
80H	6636.5	2800	0.31	2660	80H	6636.5	2800	0.31	2590
81H	6637.5	2800	0.32	3730	81H	6637.5	2800	0.32	3660
82H	6638.5	2800	0.31	1350	82H	6638.5	2800	0.30	1390
83H	6639.3	2800	0.31	3360	83H	6639.3	2800	0.31	3330
84H	6640.3	2800	0.32	6910	84H	6640.3	2800	0.32	6910
165H	6641.15	2800	0.32	6230	165H	6641.15	2800	0.32	6490
86H	6642.5	2800	0.30	4890	86H	6642.5	2800	0.30	4880
87H	6645.45	2800	0.32	4510	87H	6645.45	2800	0.32	4620
88H	6646.8	2800	0.16	2.14	88H	6646.8	2800	0.08	1.62
89H	6647.55	2800	0.32	7970	89H	6647.55	2800	0.32	7880
90H	6648.1	2800	0.31	7770	90H	6648.1	2800	0.31	7720
92H	7059	3000	0.17	0.712	92H	7059	3000	0.07	0.767
93H	7060	3000	0.18	0.508	93H	7060	3000	0.09	0.248
94H	7061	3000	0.19	0.777	94H	7061	3000	0.09	0.489
97H	7066	3000	0.23	0.49	97H	7066	3000	0.10	0.204
98H	7067	3000	0.25	2.12	98H	7067	3000	0.07	0.383
188H	7067.62	3000	0.18	0.15	188H	7067.62	3000	0.11	0.052
101H	7070	3000	0.19	0.466	101H	7070	3000	0.11	0.25
102H	7070.9	3000	0.16	1.28	102H	7070.9	3000	0.10	0.933
108H	7079	3000	0.19	0.437	108H	7079	3000	0.11	0.294
109H	7080	3000	0.19	0.609	109H	7080	3000	0.12	0.942
110H	7080.9	3000	0.19	0.945	110H	7080.9	3000	0.11	0.5
111H	7084	3000	0.18	0.689	111H	7084	3000	0.10	0.989
112H	7084.7	3000	0.19	0.437	112H	7084.7	3000	0.12	0.285

C.1.2 High Pressure Mercury Injection Data (HPMI)

High Pressure Mercury Injection data from YAMS MLR 004 well (SN 975950) of 3 samples (2 in Lower Miocene Upper Confining zone and 1 in Vicksburg Lower Confining zone) converted to CO₂/Water System using input parameters and equations.

Table AOR-34—Input parameters for sealing capacity calculations.

	Lab	Reservoir	
Parameter	Hg/Air	CO ₂ / Water	
Interfacial Tension, σ	480	26.5	dynes/cm
Contact Angle, θ	140	60	degrees
water density, ρ_w	1.08		g/cc
CO ₂ density, ρ_{CO_2}	0.75		g/cc

The following equations were used to convert Hg/Air to CO₂/Water reservoir system,

$$P_{c_{CO_2/Water}} = 0.036 \times P_{c_{Hg/Air}}$$

And, from CO₂/Water reservoir system to sealing height capacity.

$$h = \frac{P_{c_{CO_2/Water}}}{(\rho_w - \rho_{CO_2}) \times 0.433}$$

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Table AOR-35—Capillary pressure data for 3 samples used in sealing capacity calculations.

Sample 44H_MICP Depth 4104.8			Sample 1-46R_MICPm Depth 4230			Sample 1-5R_MICP Depth 7015.01		
Pc, psi	Sw	Height, ft	Pc, psi	Sw	Height, ft	Pc, psi	Sw	Height, ft
2161.0262	0.107	15215.92	2161.026	0.085754	15215.92	1981.907	0.078247	13954.74
1975.4026	0.111	13908.94	1975.403	0.089932	13908.94	1744.079	0.1013	12280.17
1805.6604	0.116	12713.77	1805.66	0.096185	12713.77	1542.284	0.127781	10859.32
1651.1694	0.123	11625.99	1651.169	0.10454	11625.99	1362.111	0.158699	9590.709
1509.5023	0.131	10628.5	1509.502	0.114341	10628.5	1207.162	0.197086	8499.703
1379.8535	0.140	9715.636	1379.853	0.125715	9715.636	1066.627	0.248397	7510.185
1261.3460	0.151	8881.217	1261.346	0.138213	8881.217	944.1086	0.31263	6647.529
1153.0126	0.163	8118.435	1153.013	0.151876	8118.435	832.4011	0.390584	5860.989
1053.9478	0.174	7420.914	1053.948	0.166874	7420.914	735.1075	0.482865	5175.938
963.3773	0.187	6783.201	963.3773	0.183314	6783.201	652.2277	0.585832	4592.377
880.5806	0.201	6200.224	880.5806	0.20162	6200.224	576.5549	0.682079	4059.56
804.9033	0.219	5667.376	804.9033	0.222128	5667.376	508.089	0.762104	3577.487
735.6528	0.238	5179.778	735.6528	0.246074	5179.778	450.4335	0.814003	3171.531
672.3496	0.255	4734.056	672.3496	0.273267	4734.056	396.3815	0.849285	2790.947
614.5886	0.274	4327.358	614.5886	0.305699	4327.358	352.7795	0.872854	2483.943
561.6312	0.299	3954.481	561.6312	0.34523	3954.481	311.7	0.891749	2194.699
513.5491	0.328	3615.932	513.5491	0.393362	3615.932	275.6653	0.907003	1940.977
469.4600	0.365	3305.497	469.46	0.4499	3305.497	243.2341	0.919013	1712.627
429.0571	0.407	3021.018	429.0571	0.513062	3021.018	215.127	0.929208	1514.723
392.2174	0.460	2761.628	392.2174	0.579045	2761.628	190.9838	0.936985	1344.729
358.4705	0.523	2524.014	358.4705	0.644733	2524.014	169.363	0.943548	1192.496
327.6917	0.593	2307.298	327.6917	0.707827	2307.298	149.5439	0.94909	1052.948
299.5589	0.663	2109.213	299.5589	0.764261	2109.213	131.8869	0.953822	928.6242
273.7560	0.735	1927.534	273.756	0.811326	1927.534	116.0317	0.95855	816.9864
250.2500	0.798	1762.026	250.25	0.848663	1762.026	101.9781	0.961863	718.0346
228.6753	0.851	1610.118	228.6753	0.878466	1610.118	90.44705	0.964796	636.8434
208.9930	0.893	1471.533	208.993	0.901102	1471.533	79.99699	0.96732	563.2639
191.0330	0.923	1345.075	191.033	0.919523	1345.075	71.34867	0.969664	502.3705
174.5939	0.944	1229.326	174.5939	0.933095	1229.326	63.06069	0.971586	444.0143
159.5943	0.958	1123.714	159.5943	0.943767	1123.714	55.49341	0.9735	390.7326
146.0697	0.965	1028.486	146.0697	0.952887	1028.486	49.36751	0.975038	347.5998
133.5371	0.971	940.2435	133.5371	0.961044	940.2435	43.96231	0.97658	309.5414
122.0837	0.976	859.5988	122.0837	0.966099	859.5988	38.91745	0.977708	274.0203
111.5978	0.980	785.7669	111.5978	0.970115	785.7669	34.01674	0.978609	239.514
101.9880	0.983	718.1042	101.988	0.973571	718.1042	29.83672	0.979925	210.0822
93.2301	0.986	656.439	93.23009	0.977536	656.439	26.41342	0.980658	185.9786
85.2654	0.989	600.3594	85.26544	0.98123	600.3594	23.56668	0.981815	165.9345
77.9230	0.992	548.6609	77.92302	0.984246	548.6609	20.82805	0.98255	146.6516
71.1969	0.994	501.3018	71.19688	0.986132	501.3018	18.34165	0.983281	129.1447
65.0763	0.995	458.2065	65.07631	0.988099	458.2065	16.14354	0.984419	113.6677
59.5212	0.997	419.0928	59.52124	0.99011	419.0928	14.3418	0.984971	100.9815
54.3709	0.998	382.8287	54.37086	0.99184	382.8287	12.64817	0.985512	89.05659

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49.7173	0.999	350.0627	49.7173	0.993144	350.0627	11.20679	0.98647	78.90769
45.4313	0.999	319.8848	45.43132	0.994546	319.8848	9.909537	0.987022	69.77368
41.5327	0.999	292.4341	41.53266	0.995927	292.4341	8.684358	0.988166	61.14712
37.9614	1.000	267.2885	37.96139	0.99708	267.2885	7.675387	0.988925	54.04289
34.7039	1.000	244.3526	34.70393	0.998009	244.3526	6.846589	0.989503	48.20727
31.6947	1.000	223.1646	31.69473	0.998786	223.1646	6.053826	0.990672	42.62538
28.9573	1.000	203.8899	28.95726	0.99944	203.8899	5.261063	0.991206	37.04348
26.5314	1.000	186.8091	26.53138	0.999796	186.8091	4.720543	0.992207	33.23764
24.1929	1.000	170.3441	24.19295	1.000	170.3441	4.143988	0.99317	29.17808
22.1601	1.000	156.0304	22.16006	1.000	156.0304	3.675537	0.993749	25.87969
20.2033	1.000	142.2525	20.20327	1.000	142.2525	3.217897	0.995117	22.65742
18.5020	1.000	130.2736	18.50197	1.000	130.2736	2.843136	0.995262	20.0187
16.8688	1.000	118.7744	16.86882	1.000	118.7744	2.508014	0.995493	17.65908
15.5010	1.000	109.1436	15.50102	1.000	109.1436	2.205322	0.995635	15.52782
14.0940	1.000	99.23706	14.09404	1.000	99.23706	1.956683	0.996265	13.77713
12.8784	1.000	90.6775	12.87838	1.000	90.6775	1.718854	0.996431	12.10256
11.7322	1.000	82.6069	11.73216	1.000	82.6069	1.50625	0.996518	10.6056
10.7563	1.000	75.73582	10.7563	1.000	75.73582	1.293645	0.996779	9.108637
9.7988	1.000	68.99396	9.798798	1.000	68.99396	1.113472	0.996964	7.840024
8.9784	1.000	63.21781	8.978446	1.000	63.21781	0.918884	0.99701	6.469923
8.1801	1.000	57.59674	8.180119	1.000	57.59674	0.850418	0.998046	5.98785
7.4750	1.000	52.63207	7.475017	1.000	52.63207	0.735107	0.999023	5.175938
6.8524	1.000	48.24845	6.852439	1.000	48.24845	0.63421	1	4.465516
6.2374	1.000	43.91804	6.237416	1.000	43.91804	0.551331	1	3.881954
5.6801	1.000	39.99415	5.680129	1.000	39.99415	0.482865	1	3.399881
5.1846	1.000	36.50541	5.184645	1.000	36.50541	0.428813	1	3.019297
4.7550	1.000	33.48057	4.755045	1.000	33.48057	0.389175	1	2.740203
4.3494	1.000	30.62459	4.349427	1.000	30.62459	0.350978	1	2.471257
3.9501	1.000	27.81268	3.950069	1.000	27.81268	0.316745	1	2.230221
3.5906	1.000	25.28179	3.590621	1.000	25.28179	0.284674	1	2.004408
3.2926	1.000	23.18375	3.292649	1.000	23.18375	0.254405	1	1.791281
2.9818	1.000	20.99535	2.981844	1.000	20.99535	0.225577	1	1.588303
2.7362	1.000	19.26602	2.736238	1.000	19.26602	0.198191	1	1.395474
2.4909	1.000	17.53888	2.490942	1.000	17.53888	0.172966	1	1.217868
2.2783	1.000	16.04141	2.278266	1.000	16.04141	0.149904	1	1.055485
2.0769	1.000	14.62351	2.07689	1.000	14.62351	0.128644	1	0.905789
1.8913	1.000	13.31665	1.891284	1.000	13.31665	0.109185	1	0.768779
1.7334	1.000	12.20527	1.733441	1.000	12.20527	0.091528	1	0.644455
1.5855	1.000	11.16369	1.585512	1.000	11.16369	0.076033	1	0.535354
1.4014	1.000	9.867035	1.401356	1.000	9.867035	0.06234	1	0.43894
1.3034	1.000	9.177115	1.303371	1.000	9.177115	0.052611	1	0.370435
1.1463	1.000	8.07122	1.146307	1.000	8.07122	0.042161	1	0.296855
1.1223	1.000	7.901981	1.122271	1.000	7.901981	0.030269	1	0.213127

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1.0463	1.000	7.366972	1.046287	1.000	7.366972
0.9570	1.000	6.738083	0.95697	1.000	6.738083
0.8750	1.000	6.160583	0.874951	1.000	6.160583
0.7999	1.000	5.632139	0.799899	1.000	5.632139
0.7293	1.000	5.134994	0.729292	1.000	5.134994
0.6668	1.000	4.695198	0.666831	1.000	4.695198
0.6094	1.000	4.29111	0.609441	1.000	4.29111
0.5574	1.000	3.924932	0.557434	1.000	3.924932
0.5095	1.000	3.587533	0.509516	1.000	3.587533
0.4659	1.000	3.28053	0.465914	1.000	3.28053
0.4259	1.000	2.998886	0.425914	1.000	2.998886
0.3895	1.000	2.742557	0.389509	1.000	2.742557
0.3560	1.000	2.506884	0.356038	1.000	2.506884
0.3256	1.000	2.292664	0.325613	1.000	2.292664
0.2979	1.000	2.0974	0.297881	1.000	2.0974
0.2723	1.000	1.917439	0.272322	1.000	1.917439
0.2490	1.000	1.753326	0.249014	1.000	1.753326
0.2277	1.000	1.603236	0.227698	1.000	1.603236
0.2081	1.000	1.464922	0.208054	1.000	1.464922
0.1903	1.000	1.339833	0.190288	1.000	1.339833
0.1740	1.000	1.225471	0.174046	1.000	1.225471
0.1591	1.000	1.120198	0.159095	1.000	1.120198
0.1455	1.000	1.02435	0.145482	1.000	1.02435
0.1330	1.000	0.936269	0.132973	1.000	0.936269
0.1217	1.000	0.856606	0.121659	1.000	0.856606
0.1112	1.000	0.782946	0.111197	1.000	0.782946
0.1018	1.000	0.716759	0.101797	1.000	0.716759
0.0932	1.000	0.656031	0.093172	1.000	0.656031
0.0853	1.000	0.60055	0.085292	1.000	0.60055
0.0781	1.000	0.550023	0.078116	1.000	0.550023
0.0715	1.000	0.503715	0.07154	1.000	0.503715
0.0654	1.000	0.460829	0.065449	1.000	0.460829
0.0595	1.000	0.419035	0.059513	1.000	0.419035
0.0545	1.000	0.383853	0.054516	1.000	0.383853

C.1.3 XRD

Fullcore (FC) plugs, and rotary sidewall core (RSWC) samples were selected for whole-rock and clay-fraction X-Ray Diffraction (XRD) mineral analysis. XRD data have been converted to vol% internally.

Table AOR-36—Whole Rock XRD results.

			Volume % Mineralogy														
			Whole Rock Minerals							Total Clay							
Core Type	Sample	Depth (ft)	Quartz	K-Feldspar	Plagioclase	Calcite	Pyrite	Accessory Mineral	Mixed layer Illite/smectite	Kaolinite	Chlorite	Illite & Mica	Chlorite/Smectite	Sum Clay	Whole Mineral Sum		
FC	58H	6055.45	62.99211	2.227754	0.894583	0.462146	0	0	0.550512	0.21049	0.127798	0.202547		0	1.091347	67.66794045	
FC	89H	6636.55	62.9918	1.881675	0.757763	0.066091	0.071787	0	1.033313	0.42143	0.127934	0.337939		0	1.920616	67.68973665	
FC	63H	6061.50	63.86895	3.166898	1.494034	0.068257	0.074139	0	0.6403	0.217618	0.066063	0.209406		0	1.133388	69.80566256	
FC	87H	6634.45	60.89174	4.129816	1.452974	0.066381	0.072101	0	0.691892	0.352729	0.192741	0.203651		0	1.441014	68.05403138	
FC	66H	6064.50	57.5764	5.183527	2.596016	0.065543	0.071191	0	0.888111	0.417935	0.126873	0.335136		0	1.768055	67.26072946	
FC	37H	4095.35	39.49857	7.764	11.51162	2.183913	0.033887	0	0	0.198938		0.893344	2.066745	3.159027	64.15102142		
FC	83H	6628.30	63.40886	2.503713	1.767732	0.135678	0	0	0.777802	0.432574	0.065659	0.485626		0	1.761661	69.57764745	
FC	80H	6625.50	56.26122	6.102891	2.565534	0.133049	0.108385	0	1.456114	0.777682	0.193158	0.544244		0	2.971198	68.14227283	
FC	67H	6066.50	63.52244	3.28961	1.806474	0.138652	0.0753	0	1.445179	0.294703	0.067098	0.354478		0	2.161458	70.99393065	
FC	5H	4054.50	37.83063	7.814564	11.49084	0.857455	0	0	0	0.130179	0.177834	1.44057	3.319575	5.068159	63.06164242		
FC	159H	6620.80	63.74759	3.614888	2.260582	0.139924	0.075991	0	1.09383	0.297407	0.135427	0.286184		0	1.812848	71.65182051	
FC	55H	6050.50	60.97792	2.973378	2.867385	0.41265	0.112052	0	1.720431	0.438541	0.133129	0.773653		0	3.065754	70.40914149	
FC	48H	6042.30	53.92989	3.02445	4.076663	0.130373	0.141608	0.168564	3.940774	0.138553	0.063091	0.933274		0	5.075693	66.54724474	
RSWC	2-84R	4959.52	31.15431	4.931012	6.307679	0.412612	0.186737	0.035566	25.9475	0.365418	0.199675	1.336189		0	27.84878	70.8766969	
RSWC	2-85R	4950.02	53.42459	3.734754	2.626758	0.136224	0.036991	0	8.945177	0	0	1.044809		0	9.989986	69.94930405	
RSWC	1-32R	4928.95	43.70203	5.233053	6.681368	0.137853	0.037433	0	13.72195	0.219754	0.133422	1.127794		0	15.20292	70.99465192	
FC	31H	4088.35	28.8365	7.347695	13.98281	3.711983	0.070734	0	0	0.553669	0	4.728386	7.58219	12.86425	66.81396078		
FC	148H	6045.95	50.95864	3.982792	4.903779	0.198792	0.215922	0	4.213106	0.352108	0.32067	1.016462	1.596222	7.498568	67.75849328		
RSWC	2-100R	4094.51	28.34199	9.411194	11.89055	3.690792	0.036444	0.208231	0	0.356579	0	3.705733	10.97868	15.04099	68.62018794		
RSWC	1-70R	5177.01	39.159	3.413245	5.096684	0.137741	0.261818	0	0	0.219575	0.19997	1.338167	20.18468	21.94239	70.01087921		
FC	70H	6611.55	61.78374	3.559877	2.199251	0.070333	0.11459	0.036374	2.932335	0.298983	0.136144	0.791177		0	4.158639	71.92280515	
FC	158H	6619.30	52.77095	1.940456	1.838147	0	0.499697	0	13.50638	4.807702	1.113164	1.881876		0	21.30913	78.35837663	
RSWC	2-101R	4007.50	25.93093	7.279487	9.617053	4.115503	0.072099	0.137319	0	0.35272	0	2.172224	18.05536	20.5803	67.73269168		
RSWC	1-49R	4165.02	42.38826	4.895834	7.364219	0.201866	0	0	12.13343	0.429064	0.390754	1.582678		0	14.53592	69.38610159	
RSWC	2-87R	4784.00	32.30041	4.715875	6.482344	0.279516	0	0	0	0.22279	0	1.857988	25.38985	27.47063	71.24877326		
RSWC	1-61R	5367.00	34.28569	5.010654	7.704417	0.197992	0.716844	0	0	0.280553	0.127752	2.497186	16.03049	18.93598	66.85157577		
RSWC	1-7R	6985.00	40.12448	3.156328	1.939403	11.73038	0.527223	0	17.28598	4.986564	1.096184	1.82008		0	25.18881	82.66662885	
RSWC	1-66R	5881.98	43.99879	3.644347	4.92559	0.141064	0.22983	0	16.61468	0.899493	0.409591	1.514712		0	19.43847	72.37809295	
RSWC	2-95R	4192.53	38.18681	5.268554	8.702446	0.72316	0	0.17	12.12861	0.139734	0.190886	2.016909		0	14.47613	67.52710892	
RSWC	1-57R	4622.99	56.91771	1.623499	1.043098	0.615851	0	0	12.91837	2.863406	1.117605	1.968109		0	18.86748	79.06764744	
RSWC	1-43R	4260.00	26.2842	5.507436	9.598435	2.611459	0.223934	0.248792	22.85001	0.511242	0	2.740865		0	26.10211	70.57636461	
RSWC	1-63R	5522.02	42.51506	7.231091	7.147655	0.214298	0.038794	0	14.89095	0.227744	0.138273	1.241849		0	16.49881	73.64521733	
RSWC	1-59R	5225.98	23.28577	4.860156	7.672183	0	0.07472	0.071155	32.4096	0.438651	0.199743	2.110493		0	35.15848	71.12247227	
RSWC	1-44R	4250.02	18.07876	4.621866	6.243667	20.67361	0	0	22.6904	0.465812	0	2.241169		0	25.39738	75.01528366	
FC	44H	4102.60	14.32971	2.317767	2.720591	4.602126	0.820682	0.071048	36.79957	2.335946	1.196651	4.917056		0	45.24922	70.11114043	
RSWC	1-13R	6549.97	41.14929	4.227363	5.958353	0.296961	0.685421	0	18.64887	2.051361	0.646686	2.353557		0	23.70048	76.01785918	
FC	25H	4081.90	21.59091	3.576678	4.83413	12.11395	0.037594	0	18.47071	1.029923	0.401985	9.061102		0	28.96372	71.11697262	
RSWC	1-24R	5540.97	34.19116	5.0471	7.776758	0	0	0	0	-0.0748	0.272501	3.527088	21.19452	24.9193	71.93432128		
FC	111H	7077.50	23.52309	2.007891	3.096168	3.808325	0.744569	0.118174	33.02579	5.099571	1.621802	4.751352		0	44.49852	77.79673254	
FC	109H	7073.50	21.62973	1.186331	1.719876	12.22549	0.936861	0	28.92519	4.941962	1.742212	2.914645		0	38.52401	76.22229891	
FC	102H	7064.40	28.15302	1.845798	3.56607	14.00355	1.037064	0	26.20647	2.029391	0.539057	3.336051		0	32.11097	80.71646284	
FC	91H	7051.40	18.88135	1.20605	2.043659	23.52847	0.621152	0	27.24879	5.903904	1.106982	2.673466		0	36.93314	83.21382825	
RSWC	1-33R	4930.01	30.32803	5.685835	7.215159	0	0	0	29.54418	0.232315	0.211572	2.235481		0	32.22355	75.45257025	
FC	94H	7054.50	19.81831	2.200716	4.117577	1.639806	0.850076	0.115646	37.91278	4.515167	1.226394	3.887438		0	47.54178	76.28391084	
FC	98H	7060.50	3.957539	0.691649	0.820402	1.049469	0.320598	0	44.84867	0.209122	0	0.939077	14.54948	60.54635	67.3860097		
FC	108H	7072.50	23.16112	1.452289	2.631809	13.46658	1.121959	0.079143	27.51437	4.228409	1.258939	2.738646		0	35.74036	77.65326323	
RSWC	1-4R	7032.99	37.4313	1.316724	0.976148	0	0.296692	0.080725	20.58046	14.34874	3.323553	1.83565		0	40.08841	80.19000108	
RSWC	2-88R	4699.54	48.72568	1.008884	0.897519	42.76738	0.259803	0	2.193935	0.203359	0.092601	0.489214		0	2.979109	96.63837593	
FC	41H	4099.50	33.50911	6.948513	11.38451	36.01685	0.049023	0	2.728518	0.095932	0.087366	1.107739		0	4.019555	91.92755663	

C.1.4 Core Description

Core description was performed at CoreLab, Inc. with oversight from Oxy subject matter experts. Core description summaries are presented in Figures AOR-59 through 62. Tracks from left to right are: grain size & sedimentary structures, depth, lithology, bioturbation index, core photos, wraparound CT scan with fractures and beds annotated, glat slab CT, fracture type, CT K means, lithology, plug permeability, plug porosity, core description and remarks, depositional environment.

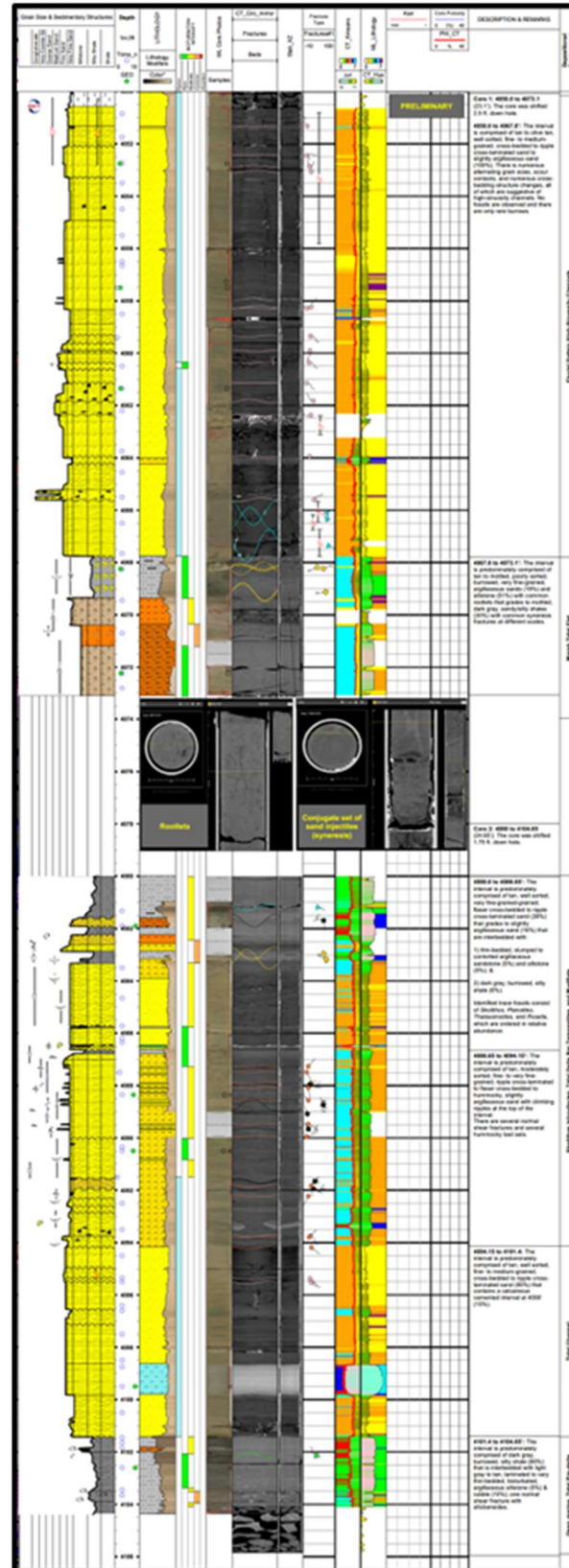


Figure AOR-59—Core description for Lower Miocene whole core.

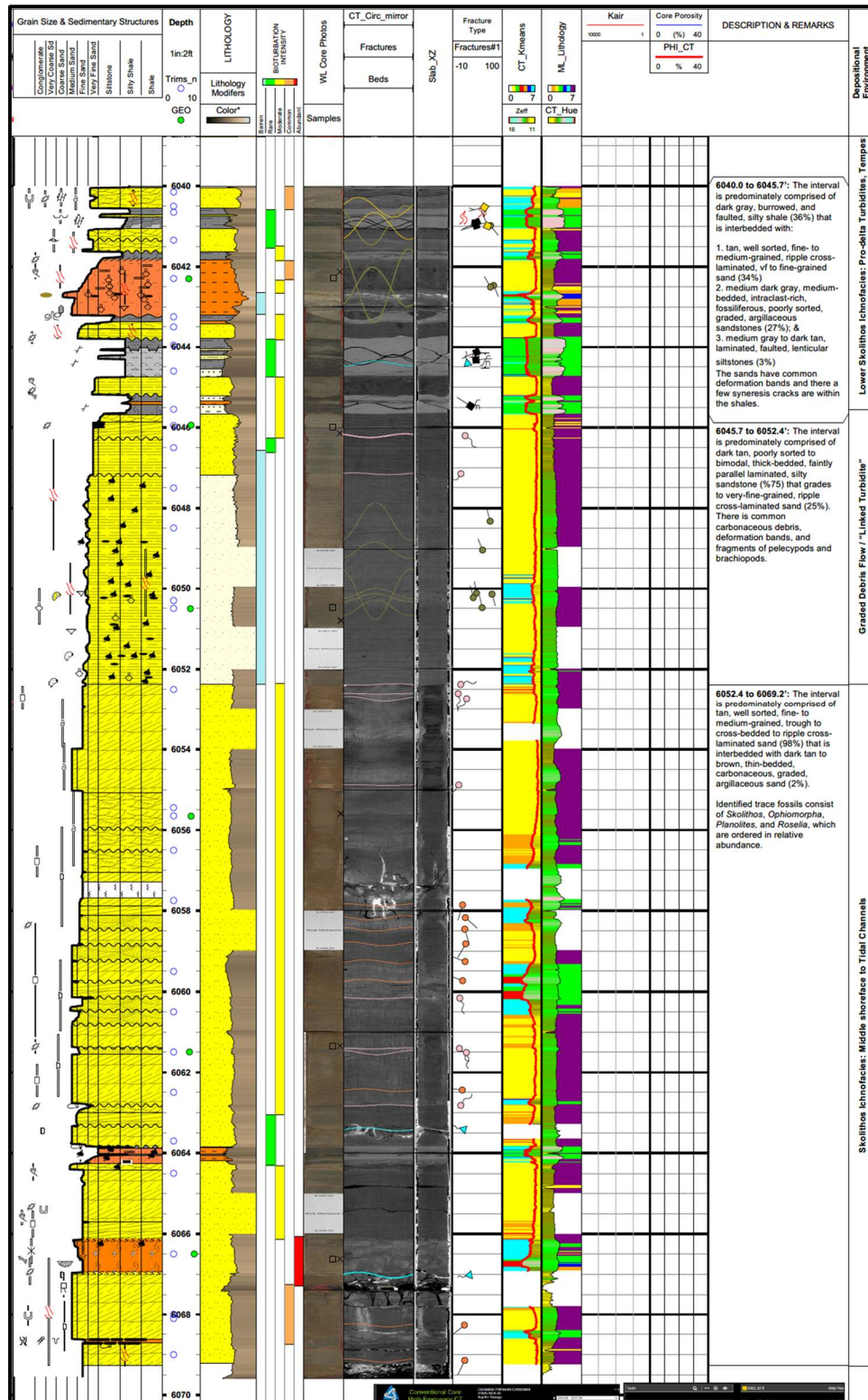


Figure AOR-60—Core description for Frio4 whole core.

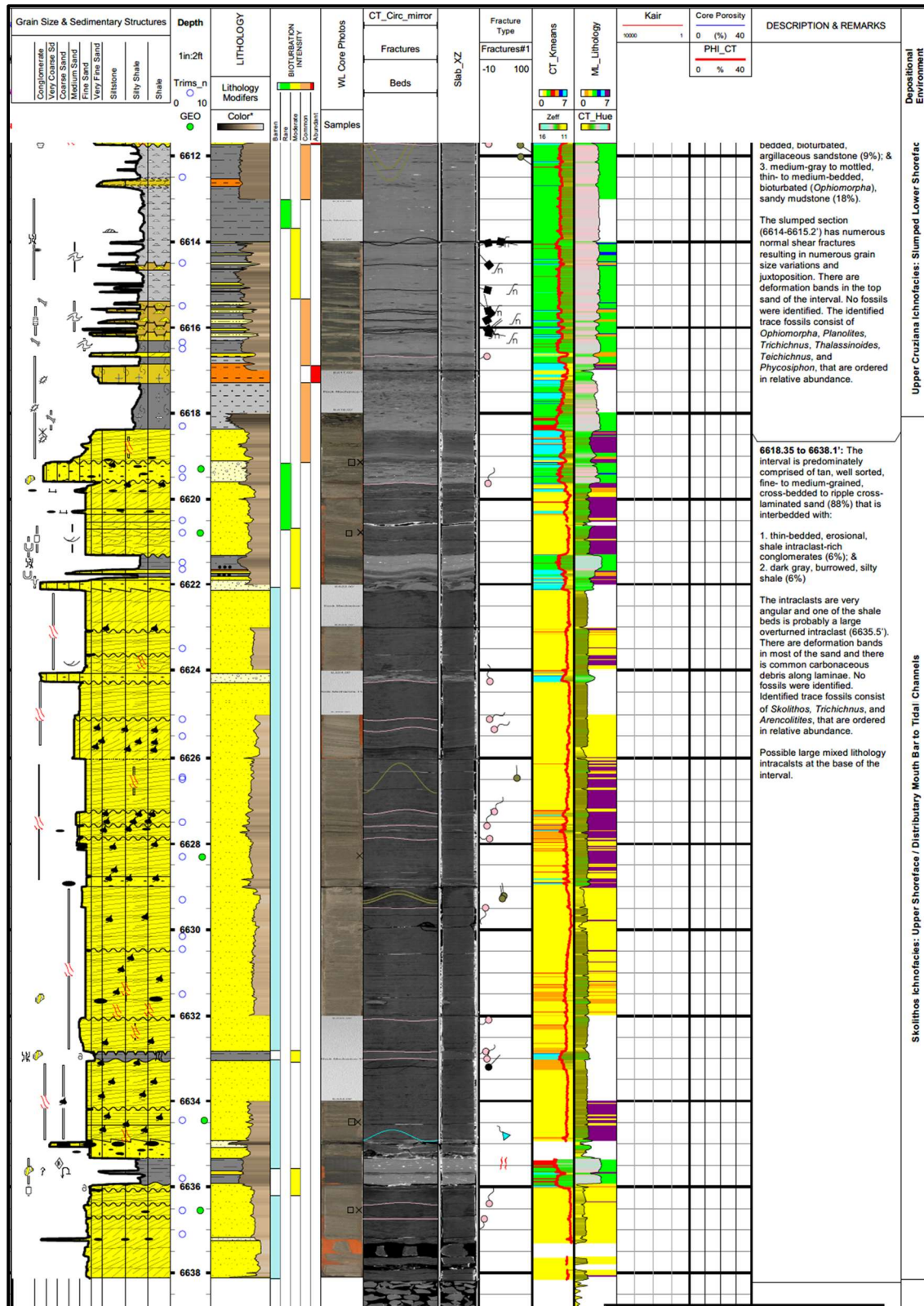


Figure AOR-61—Core description for Frio6B and Frio7 whole core.

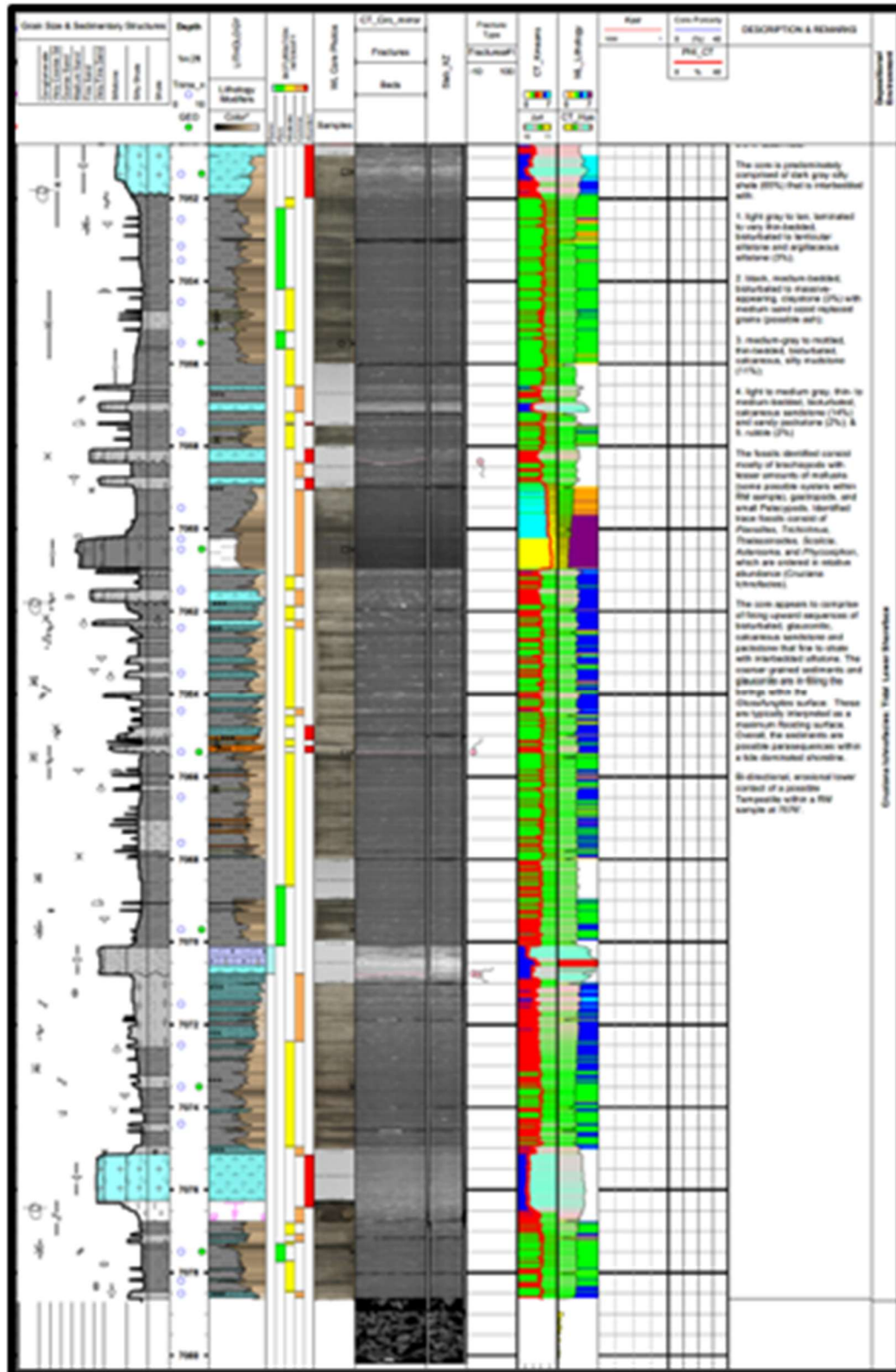


Figure AOR-62—Core description for Vicksburg whole core

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C.2 Modular Dynamic Test and Mini-frac

Modular Dynamic Test (MDT) was performed to get formation pressure measurements, Downhole Fluid Analysis measurements acquired while pumping out formation fluids for sampling and stress test.

MDT data acquisition consisted of 16 pretest stations, 3 sampling stations in run R2D, 2 pretest stations, 1 sampling station in R2E and 7 Stress testing stations in R2F. In both R2D & R2E, MDT string was configured with a large diameter probe, a 3D Saturn probe and a backup strain gauge. The InSitu Fluid Analyzer (IFA) was run as the DFA above the probes and the pump out module. A density and viscosity (DV-rod) sensor was run in the IFA module for density and viscosity measurements.

A total of 22 pretests were analyzed, which resulted in 18 high-quality formation pressures. An indicative water gradient of 1.066 g/cm³ (0.462 psi/ft) was constructed using all high-quality pressures of LD probe. The gradient is only indicative and should not be interpreted as vertical connectivity between zones. DFA was performed at 4 stations and a total of 8 water samples were captured in 420cc non compensated bottles. Table AOR-37 below summarizes the test points. Figure AOR-63 demonstrates an overall depth view of the formation tester acquisition program.

Table AOR-37—Summary Test Points

Run No.	Probe MD	Probe TVD	Pretest Status	Comments	Formation Pres.	DD Mobility	Mud Pres. Before	Mud Pres. After	Pretest Volume	Pretest Duration	Pretest Flowrate	Temp. Before	Temp. After
	ft	ft			psia	mD/cP	psia	psia	cm ³	s	cm ³ /s	degF	degF
R2D	4,132.99	4,132.09	Valid Test	Pretest built up & stabilized.	1,826.17	584.65	2,327.32	2,325.90	5.07	5.7	0.89	115.27	117.89
R2D	4,386.95	4,385.97	Valid Test	Pretest built up & stabilized.	1,939.97	1,111.29	2,487.75	2,481.02	10.07	6.6	1.53	118.58	119.57
R2D	4,861.94	4,860.87	Valid Test	Pretest built up & stabilized.	2,154.21	758.03	2,757.84	2,750.84	9.85	6.6	1.49	120.57	121.82
R2D	5,099.96	5,098.88	Valid Test	Pretest built up & stabilized.	2,262.05	969.90	2,874.66	2,883.53	10.10	6.9	1.46	126.03	127.32
R2D	5,444.97	5,443.87	Valid Test	Pretest built up & stabilized.	2,420.04	1,484.46	3,094.90	3,088.27	9.97	6.9	1.45	129.1	129.99
R2D	5,625.95	5,624.83	Valid Test	Pretest built up & stabilized. Spherical flow observed	2,504.14	1,283.97	3,177.75	3,176.22	10.04	6.6	1.52	133.06	134.02
R2D	5,841.00	5,839.87	Valid Test	Pretest built up & stabilized.	2,605.02	786.46	3,318.90	3,311.27	10.04	6.9	1.45	134.45	135.32
R2D	6,131.02	6,129.89	Valid Test	Pretest built up & stabilized.	2,743.29	1,532.25	3,456.63	3,454.94	10.14	7.2	1.41	142.27	143.8
R2D	6,272.03	6,270.90	Valid Test	Pretest built up & stabilized.	2,809.21	2,549.83	3,557.02	3,548.74	9.93	6.9	1.44	139.03	140.16
R2D	6,525.00	6,523.87	Valid Test	Pretest built up & stabilized.	2,927.84	2,114.16	3,678.09	3,671.60	10.11	6.6	1.53	143.06	144.1
R2D	6,779.02	6,777.88	Valid Test	Pretest built up & stabilized.	3,044.50	780.14	3,838.95	3,831.31	10.07	6.9	1.46	145.25	146.06
R2D	6,935.99	6,934.85	Valid Test	Pretest built up & stabilized.	3,116.73	5,229.89	3,904.40	3,899.90	10.08	6.6	1.53	147.32	148.15
R2D	6,935.98	6,934.84	Valid Test	Pretest before pumpout built up & stabilized.	3,117.35	301.00	3,900.54	3,918.65	179.49	76.5	2.35	127.12	161.23
R2D	6,137.98	6,136.84	Valid Test	Pretest before pumpout built up & stabilized. Radial flow observed	2,745.45	123.82	3,463.63	3,486.97	568.59	150.6	3.78	160.93	157.28
R2D	6,114.97	6,113.84	Valid Test	Pretest built up but not fully stabilized.	2,732.94	0.63	3,448.47	3,449.25	156.24	45.0	3.47	155.32	155.04
R2D	6,120.01	6,118.88	Unrecognizable	Drawdown did not go below formation pressure			3,453.04	3,452.60	103.02	27.6	3.73	154.93	154.92
R2D	5,629.99	5,628.88	Valid Test	Pretest before pumpout built up and stabilized. Minor leak observed	2,506.14	185.63	3,182.75	3,192.24	209.79	58.8	3.59	154.4	149.25
R2D	5,099.98	5,098.90	Valid Test	Pretest before pumpout built up & stabilized.	2,261.68	360.13	2,887.18	2,885.30	1771.83	457.5	3.87	148.56	142.71
R2D	4,450.02	4,449.02	Valid Test	Pretest before pumpout built up & stabilized.	1,968.30	106.24	2,682.66	2,520.92	572.34	145.2	3.94	139.66	134.52
R2E	4,387.04	4,386.06	No Seal	No seal.			2,489.70	2,487.33	6697.58	980.4	6.83	98.95	116.39
R2E	4,449.99	4,448.99	No Seal	No seal.			2,530.49	2,524.55	2125.80	126	16.87	117.44	121.11
R2E	4,450.23	4,449.22	Valid Test	Pretest built up & stabilized.	1,968.83	108.45	2,524.05	2,536.16	171.30	33.6	5.1	115.99	131.02

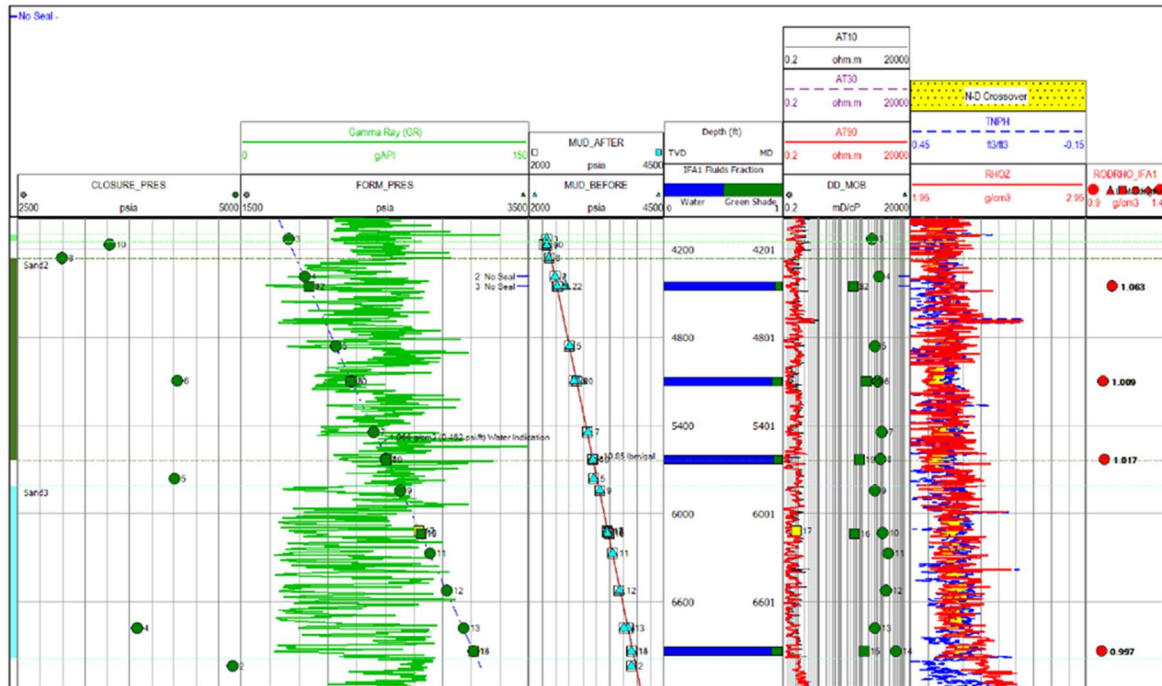


Figure AOR-63—An overall depth view of the formation tester acquisition program

Table AOR-38—MDT Mini-Frac Data

Run No.	File No.	Probe MD	Probe TVD	TVD GL	Date Time	Gauge Type	Frac Type	Formation Breakdown Pressure	Fracture Re-opening Pressure	Fracture Propagation Pressure	ISIP	Fracture Closure (SQRT) Pressure	Fracture Closure (G func.) Pressure	Rebound Pressure	Comments
		ft	ft	ft	mm-dd- yyyy HH:mm:ss			(psia)	(psia)	(psia)	(psia)	(psia)	(psia)	(psia)	
R2F	10	4,170.18	4,169.27	4,143.77	11-27- 2022 15:28:41	PAQP	Hydraulic	4,160.29	3,689.18	3,755.48	3,765.03	3,529.13	3,539.26	NA	3 Cycles
R2F	8	4,260.00	4,259.06	4,233.56	11-27- 2022 11:33:04	PAQP	Hydraulic	3,881.14	3,030.76	3,021.92	3,025.67	2,993.77	2,996.59	3,006.20	3 Cycles
R2F	6	5,095.04	5,093.96	5,068.46	11-27- 2022 07:26:46	PAQP	Hydraulic	4,703.76	4,161.36	4,507.82	4,504.41	4,286.83	4,272.21	3,628.21	3 Cycles
R2F	5	5,759.99	5,758.87	5,733.37	11-27- 2022 04:05:52	PAQP	Hydraulic	4,454.11	4,099.73	4,379.89	4,378.17	4,251.14	4,243.27	NA	3 Cycles
R2F	4	6,776.97	6,775.83	6,750.33	11-27- 2022 01:13:15	PAQP	Hydraulic	9,105.21	4,104.82	4,043.13	4,029.31	3,834.91	3,879.82	NA	5 Cycles
R2F	2	7,040.01	7,038.87	7,013.37	11-26- 2022 21:40:17	PAQP	Hydraulic	9,011.59	5,019.97	5,301.95	5,300.51	4,907.77	4,911.75	4,605.51	3 Cycles

C.3 Formation fluid sampling and analysis

Water Sample Experimental Preparation and Results

Four water samples were prepared and measured using the same procedures. Table AOR-39 below shows the sample depth, sampling pressure, temperature and opening pressure at 71.7 °F

Table AOR-39—Formation Water Samples Summary

Sample Number	Sample Label	Sampling Depth, ft	Sampling Pressure, psig	Sampling Temperature, °F	Opening Pressure psig@71.1 °F
WTC-22-009168-118	MPSR-1018	4450.23	1969	130.85	1853
WTC-22-009168-124	MPSR-3959	5099.98	2262	121.26	2464
WTC-22-009168-122	MPSR-1811	5629.99	2507	149.95	1205
WTC-22-009168-120	MPSR-30142	6935.98	3117	161.19	2888

Sample Preparation The opening pressure of the pressurized produced water sample was measured at ambient temperature (1853 psig at 71.1°F). The pressurized water sample was conditioned at the 160°F for 24 hours. Then the pressurized water sample was flashed to atmospheric pressure with the flashed gas and water collected for analysis.

Ion Chromatography (IC) of Anions The concentrations of bromide, chloride, fluoride, iodide, nitrate, nitrite, phosphate, and sulfate in the water sample were determined using a Dionex ICS 3000 Ion Chromatograph. The sample solution was diluted as required prior to analysis.

Inductivity Coupled Plasma Optical Emission Spectrometry (ICP-OES) The concentrations of aluminum, barium, boron, cadmium calcium, chromium, copper, iron, lead, lithium, magnesium, manganese, nickel, phosphorous, potassium, silicon, sodium, strontium, zinc, arsenic, molybdenum, selenium, uranium, and vanadium in the water sample were determined using inductively Coupled Plasma Spectroscopy. The sample solution was diluted as required prior to analysis.

Ion Chromatography (IC) of Organic Acids The concentrations of acetic acid, butyric acid, formic acid, glycolic acid, propionic acid in the water sample were determined using a Dionex ICS 3000 Ion Chromatograph. And the sample solution was diluted as required prior to analysis.

PH The pH of the water sample was determined following the procedure given in ASTM D1293.

Alkalinity The concentrations of carbonate, bicarbonate, and hydroxide in the water sample were determined by titration following the procedure given in ASTM D3875. The concentrations of carbonate and bicarbonate in the water sample were determined using a Dionex ICS 3000 Ion Chromatograph. And the sample solution was diluted as required prior to analysis.

Conductivity The conductivity/Resistivity of the water sample was determined following the procedure given in ASTM D1125.

Density The density of the water sample was determined following the procedure given in ASTM D4052.

Total Dissolved Solids The concentration of total dissolved solids in the water sample was determined following the procedure given in ASTM D5907.

Water Isotope Analysis (Hydrogen and Oxygen) Hydrogen isotopes were measured by Isotope Ratio Mass Spectrometry (IRMS) on hydrogen gas after equilibration of the water with the hydrogen. Oxygen isotopes were measured on carbon dioxide gas by IRMS after equilibration of the water with the carbon dioxide.

The water sample analysis results are shown in the following tables.

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Table AOR-40—Analysis of Water Sample Labeled MPSR1018, Depth 4450.23 ft**Analysis of Water Sample Labeled MPSR-1018, Depth 4450.23 ft**

Cations			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Aluminum	Al ³⁺	ICP	<0.1	27.0	3	9.0	n/a
2	Ammonium	NH ₄ ⁺	ICP	NT	18.0	1	18.0	n/a
3	Barium	Ba ²⁺	ICP	121.8	89.1	2	44.6	2.7
4	Boron	B ³⁺	ICP	13.3	10.8	3	3.6	3.7
5	Cadmium	Cd ²⁺	ICP	<0.1	112.4	2	56.2	n/a
6	Calcium	Ca ²⁺	ICP	3941.0	40.1	2	20.0	196.7
7	Copper	Cu ²⁺	ICP	<0.1	63.5	2	31.8	n/a
8	Chromium	Cr ³⁺	ICP	<0.1	52.0	3	17.3	n/a
9	Iron (total)	Fe ²⁺	ICP	<0.1	55.8	2	27.9	n/a
10	Lead	Pb ²⁺	ICP	<0.1	207.2	2	103.6	n/a
11	Lithium	Li ⁺	ICP	5.9	6.9	1	6.9	0.8
12	Magnesium	Mg ²⁺	ICP	1051.0	24.3	2	12.2	86.5
13	Manganese	Mn ²⁺	ICP	1.0	54.9	2	27.5	0.0
14	Nickel	Ni ²⁺	ICP	0.6	58.7	2	29.4	0.0
15	Phosphorus	P ³⁺	ICP	<0.1	31.0	3	10.3	n/a
16	Potassium	K ⁺	ICP	159.2	39.1	1	39.1	4.1
17	Silicon	Si ⁴⁺	ICP	11.0	28.1	4	7.0	1.6
18	Sodium	Na ⁺	ICP	33022.7	23.0	1	23.0	1436.4
19	Strontium	Sr ²⁺	ICP	199.0	87.6	2	43.8	4.5
20	Zinc	Zn ²⁺	ICP	0.7	65.4	2	32.7	0.0

Anions			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Acetate	CH ₃ COO ⁻	IC	0.5	59.0	1	59.0	0.0
2	Bicarbonate	HCO ₃ ⁻	IC	102.0	61.0	1	61.0	1.7
3	Bromide	Br ⁻	IC	70.8	79.9	1	79.9	0.9
4	Butyrate	CH ₃ CH ₂ CH ₂ CO ₂ ⁻	IC	< 0.5	88.1	1	88.1	n/a
5	Carbonate	CO ₃ ²⁻	IC	0.0	60.0	2	30.0	0.0
6	Chloride	Cl ⁻	IC	60001.5	35.5	1	35.5	1690.2
7	Fluoride	F ⁻	IC	0.2	19.0	1	19.0	0.0
8	Formate	HCOO ⁻	IC	0.9	45.0	1	45.0	0.0
9	Glycolate	OHCCOO ⁻	IC	< 0.5	76.1	1	76.1	n/a
10	Hydroxide	OH ⁻	Titration	0.0	17.0	1	17.0	0.0
11	Iodide	I ⁻	IC	12.3	126.9	1	126.9	0.6
12	Nitrate	NO ₃ ⁻	IC	< 0.5	62.0	1	62.0	n/a
13	Nitrite	NO ₂ ⁻	IC	< 0.5	46.0	1	46.0	n/a
14	Phosphate	PO ₄ ³⁻	IC	< 0.5	95.0	3	31.7	n/a
15	Propionate	CH ₃ CH ₂ CO ₂ ⁻	IC	< 0.5	73.1	1	73.1	n/a
16	Sulphate	SO ₄ ²⁻	IC	4.9	96.1	2	48.0	0.1

Total Cation Meq's	1737	Total Anion Meq's	1694
Ion Balance	1.026		

Stiff Diagram

pH	7.44	TDS (Calculated), mg/L	98,721
Conductivity, mS/cm @ 25 °C	157.2	TDS (Gravimetric), mg/L	134,519
Hardness, ppm	14,160	Resistivity, Ohm-cm @ 25 °C	6.36
Salinity, g/kg	134.5	Total Alkalinity, mg CaCO ₃ /L	120
Density (g/cm ³ @ 20 °C)	1.072	Concentration of carbonate by Titration, mg/L	0
SD H ₂ O (% vs VSMOW)	0.49	Concentration of bicarbonate by Titration, mg/L	146.4
SO H ₂ O (% vs VSMOW)	-4.47	Concentration of Vanadium, mg/L	4.15987
Strontium Isotopes (⁸⁷ Sr/ ⁸⁶ Sr)	NT	Concentration of Selenium, mg/L	<0.1
δ ¹⁴ C of DIC (% vs VPDB)	NT	Concentration of Arsenic, mg/L	<0.1
δ ¹³ C Content of DIC (% modern Carbon)	NT	Concentration of Molybdenum, mg/L	<0.1
Concentration of Mercury, mg/L	NT	Concentration of Uranium, mg/L	1.08214

ICP: Inductively Coupled Plasma IC: Ion Chromatography NT: Not Tested

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Table AOR-41—Analysis of Water Sample Labeled MPSR-3959, Depth 5099.98 ft
Analysis of Water Sample Labeled MPSR-3959, Depth 5099.98 ft

Cations			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Aluminium	Al ³⁺	ICP	<0.1	27.0	3	9.0	n/a
2	Ammonium	NH ₄ ⁺	ICP	N/T	18.0	1	18.0	n/a
3	Barium	Ba ²⁺	ICP	81.7	89.1	2	44.6	1.8
4	Boron	B ³⁺	ICP	25.3	10.8	3	3.6	7.0
5	Cadmium	Cd ²⁺	ICP	<0.1	112.4	2	56.2	n/a
6	Calcium	Ca ²⁺	ICP	3114.3	40.1	2	20.0	155.4
7	Copper	Cu ²⁺	ICP	<0.1	63.5	2	31.8	n/a
8	Chromium	Cr ³⁺	ICP	<0.1	52.0	3	17.3	n/a
9	Iron (total)	Fe ²⁺	ICP	<0.1	55.8	2	27.9	n/a
10	Lead	Pb ²⁺	ICP	<0.1	207.2	2	103.6	n/a
11	Lithium	Li ⁺	ICP	7.2	6.9	1	6.9	1.0
12	Magnesium	Mg ²⁺	ICP	850.5	24.3	2	12.2	70.0
13	Manganese	Mn ²⁺	ICP	1.0	54.9	2	27.5	0.0
14	Nickel	Ni ²⁺	ICP	0.3	58.7	2	29.4	0.0
15	Phosphorus	P ³⁺	ICP	<0.1	31.0	3	10.3	n/a
16	Potassium	K ⁺	ICP	176.8	39.1	1	39.1	4.5
17	Silicon	Si ⁴⁺	ICP	9.6	28.1	4	7.0	1.4
18	Sodium	Na ⁺	ICP	35102.6	23.0	1	23.0	1526.9
19	Strontium	Sr ²⁺	ICP	202.1	87.6	2	43.8	4.6
20	Zinc	Zn ²⁺	ICP	0.7	65.4	2	32.7	0.0

Anions			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Acetate	CH ₃ COO ⁻	IC	2.5	59.0	1	59.0	0.0
2	Bicarbonate	HCO ₃ ⁻	IC	100.0	61.0	1	61.0	1.6
3	Bromide	Br ⁻	IC	84.3	79.9	1	79.9	1.1
4	Butyrate	CH ₃ CH ₂ CH ₂ CO ₂ ⁻	IC	< 0.5	88.1	1	88.1	n/a
5	Carbonate	CO ₃ ²⁻	IC	0.0	60.0	2	30.0	0.0
6	Chloride	Cl ⁻	IC	62271.0	35.5	1	35.5	1754.1
7	Fluoride	F ⁻	IC	0.2	19.0	1	19.0	0.0
8	Formate	HCOO ⁻	IC	0.9	45.0	1	45.0	0.0
9	Glycolate	OHCCOO ⁻	IC	< 0.5	76.1	1	76.1	n/a
10	Hydroxide	OH ⁻	Titration	0.0	17.0	1	17.0	0.0
11	Iodide	I ⁻	IC	12.6	126.9	1	126.9	0.6
12	Nitrate	NO ₃ ⁻	IC	4.2	62.0	1	62.0	0.1
13	Nitrite	NO ₂ ⁻	IC	< 0.5	46.0	1	46.0	n/a
14	Phosphate	PO ₄ ³⁻	IC	< 0.5	95.0	3	31.7	n/a
15	Propionate	CH ₃ CH ₂ CO ₂ ⁻	IC	< 0.5	73.1	1	73.1	n/a
16	Sulphate	SO ₄ ²⁻	IC	4.5	96.1	2	48.0	0.1

Total Cation Meq's	1773	Total Anion Meq's	1758
Ion Balance	1.009		

Stiff Diagram

pH	7.54	TDS (Calculated), mg/L	102,052
Conductivity, mS/cm @ 25 °C	159.8	TDS (Gravimetric), mg/L	131,148
Hardness, ppm	11,270	Resistivity, Ohm-cm @ 25 °C	6.26
Salinity, g/kg	131.1	Total Alkalinity, mg CaCO ₃ /L	120
Density (g/cm ³ @ 20 °C)	1.0714	Concentration of carbonate by Titration, mg/L	0
SD H ₂ O (‰ vs VSMOW)	6	Concentration of bicarbonate by Titration, mg/L	146.4
SD H ₂ O (‰ vs VSMOW)	-2.31	Concentration of Vanadium, mg/L	2.67821
Strontium Isotopes (⁸⁷ Sr/ ⁸⁶ Sr)	NT	Concentration of Selenium, mg/L	<0.1
δ ¹³ C of DIC (‰ vs VPDB)	NT	Concentration of Arsenic, mg/L	<0.1
δ ¹³ C Content of DIC (‰ modern Carbon)	NT	Concentration of Molybdenum, mg/L	<0.1
Concentration of Mercury, mg/L	NT	Concentration of Uranium, mg/L	1.80869

ICP: Inductively Coupled Plasma IC: Ion Chromatography NT: Not Tested

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Table AOR-42—Analysis of Water Sample Labeled MPSR-1811, Depth 5629.99 ft**Analysis of Water Sample Labeled MPSR-1811, Depth 5629.99 ft**

Cations			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Aluminum	Al ³⁺	ICP	0.4	27.0	3	9.0	0.0
2	Ammonium	NH ₄ ⁺	ICP	N/T	18.0	1	18.0	n/a
3	Barium	Ba ²⁺	ICP	85.0	89.1	2	44.6	1.9
4	Boron	B ³⁺	ICP	24.9	10.8	3	3.6	6.9
5	Cadmium	Cd ²⁺	ICP	<0.1	112.4	2	56.2	n/a
6	Calcium	Ca ²⁺	ICP	2923.6	40.1	2	20.0	145.9
7	Copper	Cu ²⁺	ICP	<0.1	63.5	2	31.8	n/a
8	Chromium	Cr ³⁺	ICP	<0.1	52.0	3	17.3	n/a
9	Iron (total)	Fe ²⁺	ICP	0.3	55.8	2	27.9	0.0
10	Lead	Pb ²⁺	ICP	<0.1	207.2	2	103.6	n/a
11	Lithium	Li ⁺	ICP	5.0	6.9	1	6.9	0.7
12	Magnesium	Mg ²⁺	ICP	818.4	24.3	2	12.2	67.3
13	Manganese	Mn ²⁺	ICP	2.7	54.9	2	27.5	0.1
14	Nickel	Ni ²⁺	ICP	1.1	58.7	2	29.4	0.0
15	Phosphorus	P ³⁺	ICP	<0.1	31.0	3	10.3	n/a
16	Potassium	K ⁺	ICP	228.0	39.1	1	39.1	5.8
17	Silicon	Si ⁴⁺	ICP	9.4	28.1	4	7.0	1.3
18	Sodium	Na ⁺	ICP	35629.7	23.0	1	23.0	1549.8
19	Strontium	Sr ²⁺	ICP	179.9	87.6	2	43.8	4.1
20	Zinc	Zn ²⁺	ICP	0.5	65.4	2	32.7	0.0

Anions			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Acetate	CH ₃ COO ⁻	IC	< 0.5	59.0	1	59.0	n/a
2	Bicarbonate	HCO ₃ ⁻	IC	107.4	61.0	1	61.0	1.8
3	Bromide	Br ⁻	IC	75.9	79.9	1	79.9	1.0
4	Butyrate	CH ₃ CH ₂ CH ₂ CO ₂ ⁻	IC	< 0.5	88.1	1	88.1	n/a
5	Carbonate	CO ₃ ²⁻	IC	0.0	60.0	2	30.0	0.0
6	Chloride	Cl ⁻	IC	60744.1	35.5	1	35.5	1711.1
7	Fluoride	F ⁻	IC	0.4	19.0	1	19.0	0.0
8	Formate	HCOO ⁻	IC	< 0.5	45.0	1	45.0	n/a
9	Glycolate	OHCCOO ⁻	IC	< 0.5	76.1	1	76.1	n/a
10	Hydroxide	OH ⁻	Titration	0.0	17.0	1	17.0	0.0
11	Iodide	I ⁻	IC	12.5	126.9	1	126.9	0.6
12	Nitrate	NO ₃ ⁻	IC	< 0.5	62.0	1	62.0	n/a
13	Nitrite	NO ₂ ⁻	IC	< 0.5	46.0	1	46.0	n/a
14	Phosphate	PO ₄ ³⁻	IC	< 0.5	95.0	3	31.7	n/a
15	Propionate	CH ₃ CH ₂ CO ₂ ⁻	IC	< 0.5	73.1	1	73.1	n/a
16	Sulphate	SO ₄ ²⁻	IC	7.3	96.1	2	48.0	0.2

Total Cation Meq's	1784	Total Anion Meq's	1715
Ion Balance	1.040		

Stiff Diagram

pH	7.44
Conductivity, mS/cm @ 25 °C	161.8
Hardness, ppm	10,660
Salinity, g/Kg	128.3
Density (g/cm ³ @ 20 °C)	1.0724
δD H ₂ O (‰ vs VSMOW)	6.08
δO H ₂ O (‰ vs VSMOW)	-5.33
Strontium Isotopes (⁸⁷ Sr/ ⁸⁶ Sr)	NT
δ ¹³ C of DIC (‰ vs VPDB)	NT
δ ¹³ C Content of DIC (‰ modern Carbon)	NT
Concentration of Mercury, mg/L	NT

TDS (Calculated), mg/L	100,856
TDS (Gravimetric), mg/L	128,307
Resistivity, Ohm-cm @ 25 °C	6.18
Total Alkalinity, mg CaCO ₃ /L	108
Concentration of carbonate by Titration, mg/L	0
Concentration of bicarbonate by Titration, mg/L	131.8
Concentration of Vanadium, mg/L	3.09763
Concentration of Selenium, mg/L	<0.1
Concentration of Arsenic, mg/L	<0.1
Concentration of Molybdenum, mg/L	<0.1
Concentration of Uranium, mg/L	1.10037

ICP: Inductively Coupled Plasma IC: Ion Chromatography NT: Not Tested

AOR and CA Plan for Magnolia Sequestration Project

LA C&E Permit No. 45027, 45028, 45756, and 45757

Table AOR-43—Analysis of Water Sample Labeled MPSR-30142, Depth 6935.98 ft
Analysis of Water Sample Labeled MPSR-30142, Depth 6935.98 ft

Cations			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Aluminum	Al ³⁺	ICP	<0.1	27.0	3	9.0	n/s
2	Ammonium	NH ₄ ⁺	ICP	N/T	18.0	1	18.0	n/s
3	Barium	Ba ²⁺	ICP	60.9	89.1	2	44.6	1.4
4	Boron	B ³⁺	ICP	23.4	10.8	3	3.6	6.3
5	Cadmium	Cd ²⁺	ICP	<0.1	112.4	2	56.2	n/s
6	Calcium	Ca ²⁺	ICP	3098.1	40.1	2	20.0	154.6
7	Copper	Cu ²⁺	ICP	0.5	63.5	2	31.8	0.0
8	Chromium	Cr ³⁺	ICP	<0.1	52.0	3	17.3	n/s
9	Iron (total)	Fe ²⁺	ICP	<0.1	55.8	2	27.9	n/s
10	Lead	Pb ²⁺	ICP	<0.1	207.2	2	103.6	n/s
11	Lithium	Li ⁺	ICP	4.5	6.9	1	6.9	0.7
12	Magnesium	Mg ²⁺	ICP	705.3	24.3	2	12.2	58.0
13	Manganese	Mn ²⁺	ICP	1.0	54.9	2	27.5	0.0
14	Nickel	Ni ²⁺	ICP	<0.1	58.7	2	29.4	n/s
15	Phosphorus	P ³⁺	ICP	<0.1	31.0	3	10.3	n/s
16	Potassium	K ⁺	ICP	260.6	39.1	1	39.1	6.7
17	Silicon	Si ⁴⁺	ICP	13.4	28.1	4	7.0	1.9
18	Sodium	Na ⁺	ICP	34636.8	23.0	1	23.0	1506.6
19	Strontium	Sr ²⁺	ICP	254.7	87.6	2	43.8	5.8
20	Zinc	Zn ²⁺	ICP	2.0	65.4	2	32.7	0.1

Anions			Test Method	(mg/L)	MW	Valence	Factor	Meq/L
1	Acetate	CH ₃ COO ⁻	IC	1.8	59.0	1	59.0	0.0
2	Bicarbonate	HCO ₃ ⁻	IC	135.5	61.0	1	61.0	2.2
3	Bromide	Br ⁻	IC	71.6	79.9	1	79.9	0.9
4	Butyrate	CH ₃ CH ₂ CH ₂ CO ₂ ⁻	IC	< 0.5	88.1	1	88.1	n/s
5	Carbonate	CO ₃ ²⁻	IC	0.0	60.0	2	30.0	0.0
6	Chloride	Cl ⁻	IC	60664.5	35.5	1	35.5	1708.9
7	Fluoride	F ⁻	IC	0.4	19.0	1	19.0	0.0
8	Formate	HCOO ⁻	IC	0.5	45.0	1	45.0	0.0
9	Glycolate	OHCCOO ⁻	IC	< 0.5	76.1	1	76.1	n/s
10	Hydroxide	OH ⁻	Titration	0.0	17.0	1	17.0	0.0
11	Iodide	I ⁻	IC	14.8	126.9	1	126.9	0.6
12	Nitrate	NO ₃ ⁻	IC	< 0.5	62.0	1	62.0	n/s
13	Nitrite	NO ₂ ⁻	IC	< 0.5	46.0	1	46.0	n/s
14	Phosphate	PO ₄ ³⁻	IC	< 0.5	95.0	3	31.7	n/s
15	Propionate	CH ₃ CH ₂ CO ₂ ⁻	IC	< 0.5	73.1	1	73.1	n/s
16	Sulphate	SO ₄ ²⁻	IC	4.7	96.1	2	48.0	0.1

Total Cation Meq's	1742	Total Anion Meq's	1713
Ion Balance	1.017		

Stiff Diagram

pH	7.5
Conductivity, mS/cm @ 25 °C	157.8
Hardness, ppm	10,630
Salinity, g/Kg	127.6
Density (g/cm ³ @ 20 °C)	1.0722
δD H ₂ O (‰ vs VSMOW)	2.23
δO H ₂ O (‰ vs VSMOW)	-5.3
Strontium Isotopes (⁸⁷ Sr/ ⁸⁶ Sr)	NT
δ ¹³ C of DIC (‰ vs VPDB)	NT
δ ¹⁴ C Content of DIC (‰ modern Carbon)	NT
Concentration of Mercury, mg/L	NT

TDS [Calculated], mg/L	99,933
TDS [Gravimetric], mg/L	127,561
Resistivity, Ohm-cm @ 25 °C	6.34
Total Alkalinity, mg CaCO ₃ /L	152
Concentration of carbonate by Titration, mg/L	0
Concentration of bicarbonate by Titration, mg/L	185.4
Concentration of Vanadium, mg/L	2.90409
Concentration of Selenium, mg/L	<0.1
Concentration of Arsenic, mg/L	<0.1
Concentration of Molybdenum, mg/L	<0.1
Concentration of Uranium, mg/L	1.30931

ICP: Inductively Coupled Plasma IC: Ion Chromatography NT: Not Tested

C.2.2 Stress test

MDT stress testing was performed to determine the minimum stress magnitude. Stress orientation can also be obtained from the fracture trace at the borehole wall. Seven stress testing at R2F was performed in YAMS MLR 004 (SN 975950) well. Table AOR-44 below summarizes the fracture breakdown pressure, fracture propagation pressure and fracture closure pressure calculated from both SQR and G function.

Table AOR-44—Stress Test Summary

Run No.	Probe MD	Probe TVD	Frac Type	Formation Breakdown Pressure	Fracture Re-opening Pressure	Fracture Propagation Pressure	ISIP	Fracture Closure (SQR) Pressure	Fracture Closure (G func.) Pressure	Rebound Pressure	Comments
	ft	ft		(psia)	(psia)	(psia)	(psia)	(psia)	(psia)	(psia)	
R2F	4,170.18	4,169.27	Hydraulic	4,160.29	3,689.18	3,755.48	3,765.03	3,529.13	3,539.26	NA	3 Cycles
R2F	4,175.07	4,174.15	Hydraulic	NA	NA	NA	NA	NA	NA	NA	Leaky seal
R2F	4,260.00	4,259.06	Hydraulic	3,881.14	3,030.76	3,021.92	3,025.67	2,993.77	2,996.59	3,006.20	3 Cycles
R2F	5,095.04	5,093.96	Hydraulic	4,703.76	4,161.36	4,507.82	4,504.41	4,286.83	4,272.21	3,628.21	3 Cycles
R2F	5,759.99	5,758.87	Hydraulic	4,454.11	4,099.73	4,379.89	4,378.17	4,251.14	4,243.27	NA	3 Cycles
R2F	6,776.97	6,775.83	Hydraulic	9,105.21	4,104.82	4,043.13	4,029.31	3,834.91	3,879.82	NA	5 Cycles
R2F	7,040.01	7,038.87	Hydraulic	9,011.59	5,019.97	5,301.95	5,300.51	4,907.77	4,911.75	4,605.51	3 Cycles

C.4 Step Rate Test

The YAMS MLR 004 (SN 975950) well was perforated and tested in multiple zones for step-rate tests (SRT), followed by pressure fall-off tests. The tests were completed starting with the deepest zone. For the step-rate tests, two pressure and temperature gauges were run into the hole and placed slightly above the perforated interval. The step-rate test was performed at two intervals (6630 – 6760 ft, 6050 – 6100 ft) using a time interval of 5 minutes for each step. During Stage-1 Step-rate test (6630 – 6760 ft), well went in a vacuum and couldn't reach the fracture gradient after pumping 30 BPM water (43,300 bwpd). Step-rate test at the second stage (6050 – 6100 ft) shows the fracture gradient is 0.75 - 0.8 psi/ft.

After completion of step-rate test, the well was shut in for 3 hrs and monitored the pressure fall-off in the interval (6630-6760 ft) Frio Lower zone and 6 hrs to monitor the pressure fall-off in the interval (6050-6100 ft) in the Frio Lower. Fall-off analysis were done by PRB Reservoir Characterization. Below is a summary of the analysis.

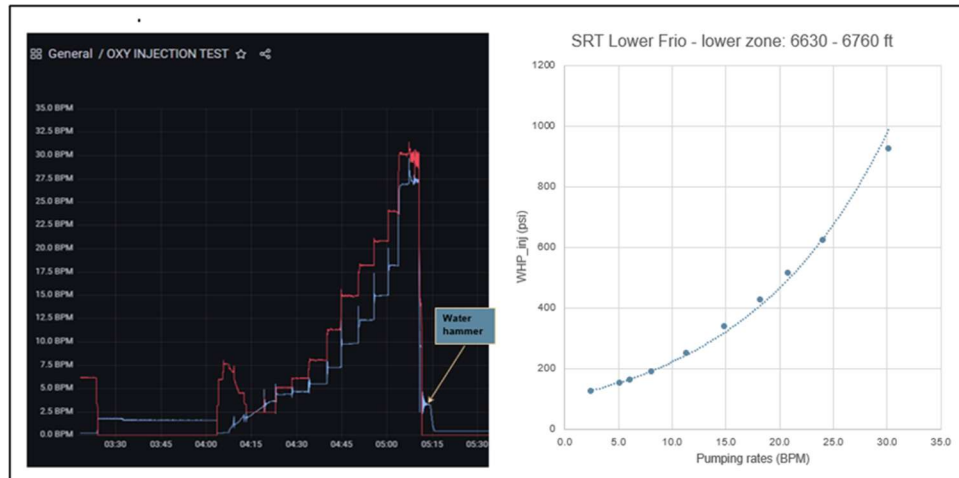


Figure AOR-64—Step Rate Test at Stage-1

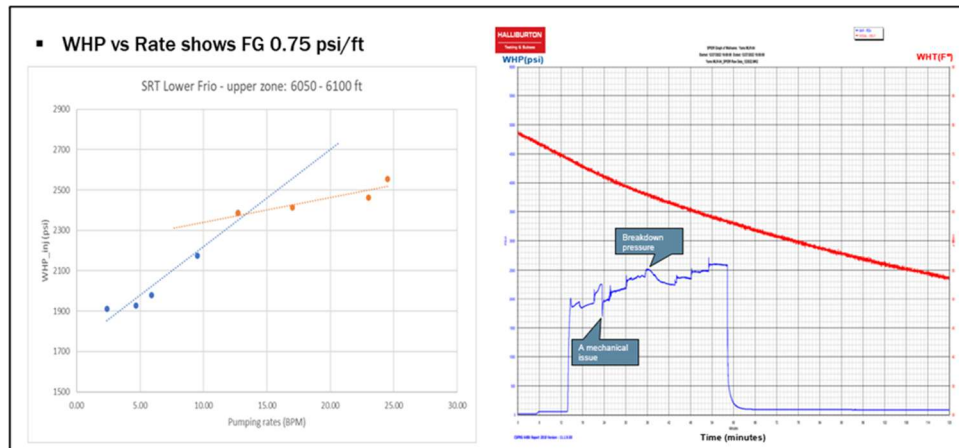


Figure AOR-65—Step Rate Test at Stage-2

C.5 Mudlogging, Sampling, and Analyses

The Magnolia project team selected Exlog to run the mud logging from surface to the total depth (TD). The mud log was used to monitor borehole gases, confirm lithology interpretation, and select core intervals along with running measure while drilling (MWD) and gamma ray (GR) logs. The mud loggers were also tasked with collecting cuttings and IsoTubes for further analysis. IsoTubes and cuttings were collected every 30 ft from the surface casing (2,998 ft) to TD.

Isotubes

68 mud gas samples between 1140' and 7322' were analyzed by Intertek for composition and 13 samples were selected for isotopic composition of methane, and two for CO₂. Gases were very dry and all are thought to be bacterial. CO₂ isotopic composition (-19.1‰ to -19.3‰), if reliable, is likely from oxidation of methane by bacteria.

Biostrat

Cuttings representing 30 to 90 feet of section were analyzed for foraminifera, nannofossil, and palynological data. Sample recovery was very poor above 4000' MD. Results are summarized in Figure AOR-46 below. At left are chronozone results for the 17 samples analyzed for pollen, spores, and dinoflagellate populations in palynological analysis. This analysis found evidence for early Miocene age from 4100 – 4350' MD, and possible Chattian (Late Oligocene) age from 5400 – 6850' MD. At right is zonation from nannofossil and microfossil (foraminifera) counts as well as interpreted zonation from Cretaceous coccolith counts. Probable nannofossil (blue) and foraminifera (pink) tops are annotated; black curve at far right shows total abundance for nannofossils; note absence of fossils through majority of well and maximum total count of ~40 samples at base of well. Zones with solid borders are interpreted to be high-confidence ages, whereas zones with dashed borders are inferred based on sparse age control or correlation with Cretaceous coccolith abundance curves by the paleontologist (Jiang et al, 1996).

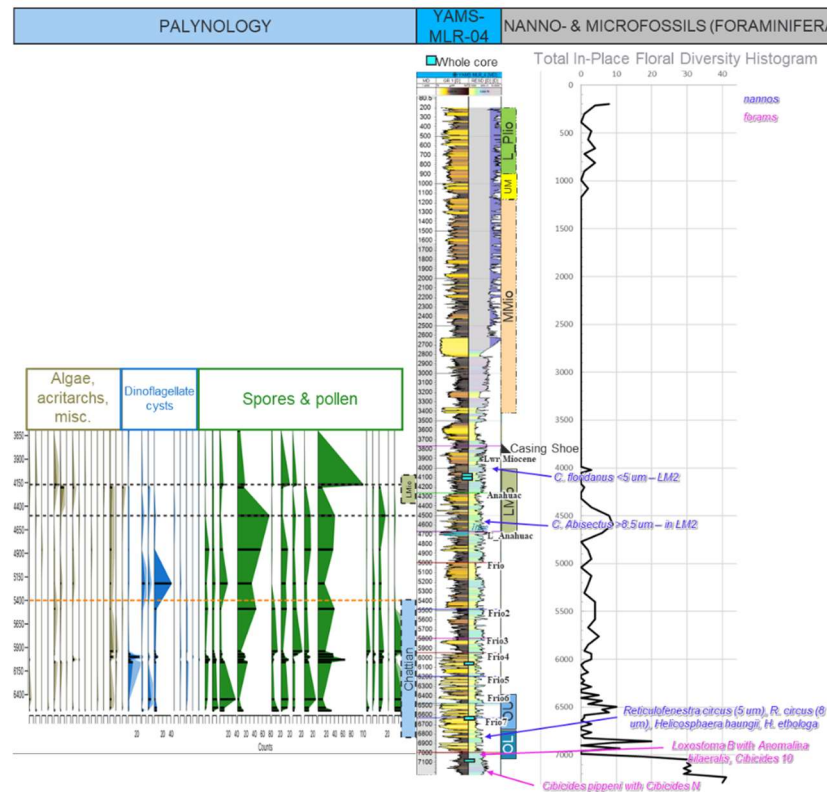


Figure AOR-66—YAMS MLR-4 (SN 975950) Gamma Ray and Deep Resistivity logs with chronostratigraphic zones from palynological analysis (left) and nannofossil/microfossil analysis (right) with key tops reported. Sample recovery for all types of analysis was low.