

Application No. 45079, 45080, 46169, 46170, and 46171

PROJECT NARRATIVE

Pelican Sequestration Project

Table of Contents

CLASS VI PERMIT APPLICATION NARRATIVE	1
1.0 Project Background and Contact Information	8
2.0 Site Characterization	8
2.1 Regional Geology, Hydrogeology, and Local Structural Geology	13
2.2 Maps and Cross Sections of the AoR	24
2.3 Faults and Fractures	31
2.4 Injection and Confining Zone Details	45
2.5 Geomechanical and Petrophysical Information	70
2.6 Seismic History	87
2.7 Hydrogeology	90
2.8 Geochemical Modeling	101
2.9. Geopressure	113
2.10 Site Suitability	115
3.0 Area of Review and Corrective Actions Plan	116
4.0 Financial Responsibility	117
5.0 Injection Well Construction Plan	118
5.1 Proposed Stimulation Program [LAC 43:XVII.3607(C)(2)(h)]	118
5.2 Construction Procedures [LAC 43:XVII.3607(C)(2)(k)]	119
6.0 Pre-Operational Testing Program	120
7.0 Well Operation	120
7.1 Operational Procedures [LAC 43:XVII.3607(C)(2)(i)]	120
7.2 Proposed Carbon Dioxide Stream [LAC 43:XVII.3607(C)(2)(f)(iii) and (iv)]	121
7.3 Reporting and Recordkeeping	121
8.0 Testing and Monitoring Plan	124
9.0 Injection Well Plugging Plan	125
10.0 Post-Injection Site Care (PISC) and Site Closure Plan	125
11.0 Emergency and Remedial Response Plan	125
12.0 Injection Depth Waiver and Aquifer Exemption Expansion	125

List of Figures

Figure NAR-1—Pelican Sequestration Hub location with respect to the Mississippi River Chemical Corridor.	9
Figure NAR-2—Satellite imagery highlighting the project area.	10
Figure NAR-3—LIDAR imagery highlighting surface topography, main river drainage, and surface-penetrating faults.	11
Figure NAR-4—Map of the Pelican CCS geomodel area (green polygon), Pelican Sequestration Project AOR (blue polygon), and legacy wells in the region.	12
Figure NAR-5—Pelican MLR 004 stratigraphic well data collection and test program summary.	13
Figure NAR-6—Schematic stratigraphic succession of the northern Gulf of America (Galloway, 2009).	15
Figure NAR-7—Paleogeography of the Oligocene Frio: a) Early Oligocene, b) Late Oligocene. Maps showing depositional system, sediment dispersal axes, generalized depocenters, and selected depositional and erosional features (Galloway, 2000).	17

Figure NAR-8—Paleogeography of the Miocene: a) Early Miocene, b) Late Miocene.	18
Figure NAR-9—Structural element map showing key structural features that developed during the Mesozoic and Cenozoic periods in the Gulf of America (Pitman, 2010).	19
Figure NAR-10—Regional structural cross section highlighting the location of the Pelican Sequestration Hub. Cross section location is shown on Figure NAR-9. (Created from Adams, 1997, Snedden and Galloway, 2019)	21
Figure NAR-11—Pelican Site Subsurface Data Control. Includes subsurface data control, area of investigation (AOI), and structural elements.	22
Figure NAR-12—Geological stratigraphic chart showing the project's storage complex.	23
Figure NAR-13—Structural cross section generated from Oxy-licensed 3D seismic data shows that faulting south of the acreage has little interaction with the Pelican Sequestration Project acreage.	24
Figure NAR-14—Structural Cross Section A-A'.....	26
Figure NAR-15—Structural Cross Section B-B'.....	27
Figure NAR-16—Top Confining Zone ANAH1 to ANAH3 Thickness Map.....	28
Figure NAR-17—Total Storage Zone ANAH3 to VKBG Thickness Map.....	29
Figure NAR-18—Basal Confining Zone: Vicksburg Thickness Map.....	30
Figure NAR-19—3D seismic survey footprint with wells used for velocity model and interpretation.	32
Figure NAR-20—Workflow diagram of geophysical input generation.	35
Figure NAR-21—Seismic well tie for Pelican MLR 004 stratigraphic test well.	36
Figure NAR-22—3D seismic survey footprint (dark gray polygon) with seismic interpreted fault intercepts at key horizon levels and the maximum plume at 100 years. Section lines labeled A-A' and B-B' shown in Figure NAR-23 and Figure NAR-24.	37
Figure NAR-23—Key dip line from 3D seismic through eastern project area showing storage complex, Pelican MLR 004 Stratigraphic Test Well, and faulting to the south of the CO ₂ plume.	38
Figure NAR-24—Key dip line from 3D seismic through western project area showing storage complex.....	39
Figure NAR-25—Mohr-Coulomb Failure Criterion from Jaeger and Cook, 1979).....	41
Figure NAR-26— Stress model (middle track) for the Pelican MLR 004 well.	43
Figure NAR-27—Mohr circle depiction of the stress state with two failure limits shown: a failure limit with 0 psi cohesion (red line), a typical value to represent the strength of existing faults/fractures and a failure limit with a modest estimate of matrix shear strength and tensile strength (blue lines).....	44
Figure NAR-28—Pelican Sequestration Hub stratigraphic framework defined by integrating log characteristics with results of a foraminiferal and calcareous nannofossil study for the Pelican MLR 004 stratigraphic test well.	48
Figure NAR-29—Marginal to shallow marine depiction of depositional settings (modified after Okosun, 2014). The red box approximates the environments defined by the biostratigraphy study.	49
Figure NAR-30—GBDS Regional Study control used to calibrate local geology.....	50
Figure NAR-31— Clastic depositional models and representative log facies characterization used to interpret EOD maps.	51

Figure NAR-32—Cross section across geomodel area illustrating stratigraphic framework interpretation for the Oligocene Storage Complex. This cross section is flattened on the top of the Anahuac Formation.....	52
Figure NAR-33—Log signature map example of the FRIO1 units. The left track shows the log stacking pattern (fining upward/blocky, coarsening upward, shale) and the right track shows petrophysical facies (sand, silty sand, shale, limestone).....	53
Figure NAR-34—FRIO1a gross thickness map generated from well and seismic interpretation. These maps helped define depositional trends and were used to refine polygons representing different EODS. The Red polylines represent changes in thickness trends that align with seismic attributes and log character.	55
Figure NAR-35—Workflow summary.	56
Figure NAR-36—FRIO1 Environment of Deposition (EOD) map was compiled using the stratigraphic framework and regional understanding. Two distinct EODs are interpreted: distributary channel with outer mouth bars and delta front. This final map was refined using seismic, well log stacking patterns, and thickness trends.	57
Figure NAR-37—Composite figure of EOD facies trends with systems tracts, dominate coastal process, and transportation direction defined.	58
Figure NAR-38—Vicksburg basal confining unit properties.	59
Figure NAR-39—Cross section zoomed in and flattened on the top of the Frio formation.....	61
Figure NAR-40—Frio storage unit environment of deposition (EOD) facies trend maps.....	62
Figure NAR-41—Cross section of the lower Anahuac storage units, flattened on the top of the ANAH3 (or base of the HETLM).	63
Figure NAR-42—Lower Anahuac log signature in Pelican MLR 004 (left) and storage units EOD defining facies trends and transportation direction (right).	64
Figure NAR-43—Top of the ANAH3 log signature in Pelican MLR 004 (left) and confining facies summary (right).	65
Figure NAR-44—HETLM and Anahuac Shale Confining Zone Cross Section (above) and thickness maps (below).	66
Figure NAR-45—HETLM log signature (left) and property summary (right) from samples in the Pelican MLR 004.	67
Figure NAR-46—Upper Anahuac and HETLM log signature in Pelican MLR 004 (left) and EOD Summary (right).	68
Figure NAR-47—Upper Anahuac (ANAH1 And ANAH2) log signature (left) and property summary from whole core samples (right) in the Pelican MLR 004.	69
Figure NAR-48—Anahuac Shale log signature in Pelican MLR 004 (left) and seal capacity summary (right).	70
Figure NAR-49—Composite type well-log interpretation of the Pelican MLR 4 (SN 975919). In track 1, the Correlation column displays the Anahuac, Frio, and Vicksburg formations along with the gamma ray (XGR), Full core (red line) and Rotary sidewall core intervals (black dots). Track 2 shows the breakdown of major zones into subzones. Track 3 displays total porosity (XPORT). In track 4 the XPERM is horizontal permeability and track 5 is the lithofacies model. Track 6 represents the Mineralogy of quartz, clay, and calcite plus porosity.	71
Figure NAR-50—Map representing petrophysical log interpretation for 101 control wells within and surrounding the Pelican Sequestration Project area. The Pelican MLR 004 (SN 975919) stratigraphic test well is indicated by the black outline. Wells on the map are listed in Project Narrative Appendix A, Table NAR-APPENDIX-A-1.	72

Figure NAR-51—Individual subzones with averages of porosity, permeability, and net reservoir thickness based on log analysis, along with approximate depth intervals at well Pelican MLR 004 (SN 975919). The column on the left lists the top of model at 5,740 ft, the top of Injection Zone at 6,135 ft, and the base of the Injection Zone at 7,708 ft.	73
Figure NAR-52—Crossplot of XRD Clay volume (Fullcore_XRD:VCLAY) on the x-axis and volume of clay (Msol:VClay)(decimal) determined from Mineral Solver in IP on the y-axis from the Pelican MLR 004 (SN 975919). The red line represents the 1:1 relationship between the two variables.	74
Figure NAR-53—Crossplot of vacuum-dried core porosity (CPHI) (decimal) on the x-axis and total porosity (XPORT) on the y-axis from the Pelican MLR 004 (SN 975919). The red line represents the 1:1 relationship between the two variables.	75
Figure NAR-54—Crossplot of shale volume (VSHAV)(decimal) and clay volume (Msol:VClay)(decimal) on the left graph and the right graph represents the correlation of the output XVCL using the equation from the Pelican MLR 004 (SN 975919) plus four additional interpreted wells. The red line on the right graph represents the 1:1 relationship between the two variables.	76
Figure NAR-55—Crossplot of the Pelican MLR 004 (SN 975919) plus four additional interpreted wells of modeled volume of clay (XVCL)(decimal) on the x-axis and total porosity (XPORT)(decimal) on the y-axis.	77
Figure NAR-56—Crossplot of the Pelican MLR 4 (SN 975919) core samples with vacuum-dried porosity on the x-axis and horizontal permeability on the y-axis differentiated by lithofacies and their corresponding regressions.	78
Figure NAR-57—Crossplot of vacuum-dried core permeability on the x-axis and calculated permeability on the y-axis from the Pelican MLR 004 (SN 975919). The red line represents the 1:1 relationship between the two properties.	79
Figure NAR-58—Well-log image plot of the ANAH1 Upper Confining Zone from the Pelican MLR 004 (SN 975919). Track 1 displays the wellbore geometry from the 4-arm caliper of the tool. Track 2 displays the gamma ray. Tracks 3 is the microresistivity. Tracks 4 and 5 are the static and dynamic microresistivity image plots of the near wellbore face. Track 6 displays the dip tadpoles and their associated classifications. Track 7 displays the bedding dip angle and dip azimuth on a group stereo net plot.	80
Figure NAR-59—Well-log image plot of the ANAH2 and HETLM2 from the Pelican MLR 004 (SN 975919). Track 1 displays the wellbore geometry from the 4-arm caliper of the tool. Track 2 displays the Gamma Ray. Tracks 3 is the microresistivity. Tracks 4 and 5 are the static and dynamic microresistivity image plots of the near wellbore face. Track 6 displays the dip tadpoles and their associated classifications. Track 7 displays the bedding dip angle and dip azimuth on a group stereo net plot.	81
Figure NAR-60—Well-log image plot of the Vicksburg from the Pelican MLR 004 (SN 975919). Track 1 displays the wellbore geometry from the 4-arm caliper of the tool. Track 2 displays the gamma ray. Tracks 3 is the microresistivity. Tracks 4 and 5 are the static and dynamic microresistivity image plots of the near wellbore face. Track 6 displays the dip tadpoles and their associated classifications. Track 7 displays the bedding dip angle and dip azimuth on a group stereo net plot.	82
Figure NAR-61—Well-log plot of the ANAH1 and HETLM2 Upper Confining Zones from the Pelican MLR 004 (SN 975919). The mineralogy track shows the samples selected for Confining Zone sealing integrity and sealing height capacity.	83

Figure NAR-62—Crossplot of water/CO ₂ saturation on the x-axis and capillary pressure on the y-axis converted into a CO ₂ -Water system from the Pelican MLR 004 (SN 975919). The red circles represent the seal entry pressure and CO ₂ saturation needed to initiate a continuous filament of CO ₂ in the interconnected pores. The purple square represents the maximum pressure and CO ₂ saturation at which CO ₂ would break through the seal.	84
Figure NAR-63—Crossplot of water/CO ₂ saturation on the x-axis and sealing height on the y-axis from the Pelican MLR 004 (SN 975919). The red squares at the ~10% saturation of CO ₂ represent the minimum column height of CO ₂ that can be held by the sealing shales. The purple square represents the maximum column height at which CO ₂ would break through the seal.	85
Figure NAR-64—Well log-based elastic and poroelastic properties used as input to the poroelastic stress models and the near isotropic state of stress.	87
Figure NAR-65—Seismic activity recorded by the USGS (2023), Appendix E: Historical Seismicity Data tabulates the recorded seismicity data and their locations. The concentric red circles have radii of 10, 20, 30, 40, and 50 miles centered on the injection locations.	89
Figure NAR-66—Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2024 Long-Term National Seismic Hazard Map (USGS, 2024). Seismic hazard potential in the study area is one of the lowest in the U. S.	90
Figure NAR-67—Location of Pelican Sequestration Hub overlain on a published summary of local Coastal Lowland Aquifer System (White and Prakken, 2016).	91
Figure NAR-68—Stratigraphic column summarizing the geohydrologic units of southeastern Louisiana.	92
Figure NAR-69—Generalized hydrogeologic cross section C–C'. Location shown on Figure NAR- 67. (modified from Griffith, 2003).	93
Figure NAR-70—Potentiometric surface of “400-foot” sand (Chicot equivalent aquifer) in southeastern Louisiana, January 2014-March 2015. Generalized groundwater flow directions shown with blue arrows (modified from Frederick, 2022).	94
Figure NAR-71—Water wells within the Pelican Sequestration Project, as recorded in the Louisiana state well register. Monitoring well in Evangeline equivalent aquifer (Li-52) shown in purple.	95
Figure NAR-72—Log plot from Pelican MLR 004 with base of USDW at 3,275 ft SSTVD.	99
Figure NAR-73—Structure map of the base of the USDW defined using 17 wells	100
Figure NAR-74—North to south cross section illustrating interpretation of the base USDW and structural dip toward the south.	101
Figure NAR-75—Aggregate view for all model layers of minimum values for modeled fluid pH after cessation of CO ₂ injection.	109
Figure NAR-76—Modeled molar change in minerals simulated to 2050.	110
Figure NAR-77—Aggregate view for all model layers of modeled maximum porosity changes from mineral precipitation and dissolution upon cessation of injection. Note negative and positive values represent increases and decreases in effective porosity, respectively.	111
Figure NAR-78—Aggregate view for all model layers of modeled maximum calcite dissolution (gmole) upon cessation of injection. Note largest mass of calcite dissolution is concentrated along edges of plume front.	111
Figure NAR-79—Aggregate view for all model layers of modeled maximum calcite precipitation (gmole) upon cessation of injection. Note spatiotemporal gradient of calcite precipitation occurring behind plume front.	112
Figure NAR-80—CO ₂ partitioning in reactive-transport model simulated to 2050.	113

Figure NAR-81—Schematic diagram of generalized pressure gradients and their associated pressure regime.	114
Figure NAR-82—Depth map for the onset of 0.6 psi/ft pressure gradient (Burke, 2013).	115
Figure NAR-83—CO ₂ plume area and storage capacity from dynamic simulation, from start of injection to 100 years post injection. Plume area is based on 99% of the vertically integrated mass per unit area (VIMPA) of CO ₂ in the reservoir.....	116

List of Tables

Table NAR-1—Wells used for velocity model and interpretation.	33
Table NAR-2—3D Seismic Acquisition Parameters.....	33
Table NAR-3—3D Seismic Processing Flow.....	34
Table NAR-4—Results of step rate, formation integrity, and leakoff tests on Pelican MLR 004 Well.....	40
Table NAR-5—Summary of subsurface characteristics.....	46
Table NAR-6—Average petrophysical properties for the Oligocene storage units in the Lower Anahuac and Frio formations.....	60
Table NAR-7—Four additional wells plus the Pelican MLR 004 (SN 975919) used in Mineral Solver module.	75
Table NAR-8—Sample selections for confining zones' hydrodynamic sealing capacity from the Pelican MLR 004 (SN 975919).	82
Table NAR-9—Summary of linear elastic and poroelastic properties. NT is not tested.....	86
Table NAR-10—Summary of Louisiana well registration records for water wells within Pelican Sequestration Project AOI	94
Table NAR-11—Brine chemical compositions for geochemical and reactive-transport simulations.	103
Table NAR-12—Solid-phase mineralogy from RSWC XRD data used in geochemical equilibrium and reactive-transport simulations.	104
Table NAR-13—Simulated fluid equilibrium in Frio Sand at reservoir conditions without minerals present.	105
Table NAR-14—Mineral stability tendency and fluid pH for Het Lime, Upper Anahuac and Frio in equilibrium with reservoir mineralogy (pre-injection baseline).	106
Table NAR-15—Change in mineral stability tendency and fluid pH of Het Lime, Upper Anahuac, and Frio formations in equilibrium with reservoir mineralogy and saturated CO ₂	107

1.0 Project Background and Contact Information

Facility name: Pelican Sequestration Project
Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, Pelican CCS 5 wells

Facility contact: Tyler Spoede, Project Manager
5 Greenway Plaza Houston, TX 77046
713-985-6954 william_spoede@oxy.com

Well location: Livingston Parish, Louisiana

Well Name	Longitude (NAD 27)	Latitude (NAD 27)	Longitude (NAD 83)	Latitude (NAD 83)
Pelican CCS 1	-90° 40' 55.76"	30° 35' 19.16"	-90° 40' 56.10"	30° 35' 19.83"
Pelican CCS 2	-90° 40' 58.83"	30° 34' 53.98"	-90° 40' 59.17"	30° 34' 54.66"
Pelican CCS 3	-90° 43' 50.13"	30° 36' 10.56"	-90° 43' 50.48"	30° 36' 11.24"
Pelican CCS 4	-90° 44' 29.72"	30° 36' 41.03"	-90° 44' 30.06"	30° 36' 41.70"
Pelican CCS 5	-90° 46' 30.21"	30° 37' 35.26"	-90° 46' 30.56"	30° 37' 35.93°

The Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 wells are part of the Pelican Sequestration Hub, LLC. The objective of the Pelican Sequestration Project is to demonstrate the technical feasibility of Carbon Capture and Storage (CCS) utilizing CO₂ from industrial emitters along the Louisiana Gulf Coast. Pelican Sequestration Hub, LLC has signed an offtake agreement with Blue Point Number One, LLC (Blue Point), a joint venture between subsidiaries of CF Industries Holdings, Inc. (CF), JERA Co., Inc., and Mitsui & Co., Ltd., to sequester approximately 2.3 million metric tons per annum (MMTPA) of CO₂ for 25 years. The advancement of CCS technology is critically important in addressing CO₂ emissions and global climate change concerns. The Pelican Sequestration Project is designed to demonstrate utility-scale integration of transport and permanent storage of captured CO₂ into a deep geologic formation (i.e., geologic sequestration). A commercial-scale CCS system will be designed, built, and operated with the capability of storing CO₂ gas.

The Pelican Sequestration Project will show that the geologic sequestration process can be done safely, ensuring that the injected CO₂ will be retained within the intended storage reservoir. By using safe and proven pipeline technology, the CO₂ will be transported to a storage site located near Livingston, Louisiana, where it will be injected into the Frio and Anahuac formations at a proposed rate of 2 million metric tons each year per well for a planned duration of 25 years. An injection depth waiver or aquifer exemption expansion is not being requested.

2.0 Site Characterization

The Pelican Sequestration Project encompasses 30,900 acres of deep saline aquifers for CO₂ storage in Livingston and St. Helena Parishes, Louisiana shown in Figure NAR-1 (Source: <https://netl.doe.gov/carbon-management/carbon-storage/atlas-data>). The Pelican Sequestration Project is 20 miles east of Baton Rouge, Louisiana, and is optimally located near many potential

Application No. 45079, 45080, 46169, 46170, and 46171

CO₂ source facilities along the Mississippi River Industrial Corridor identified by Department of Energy.

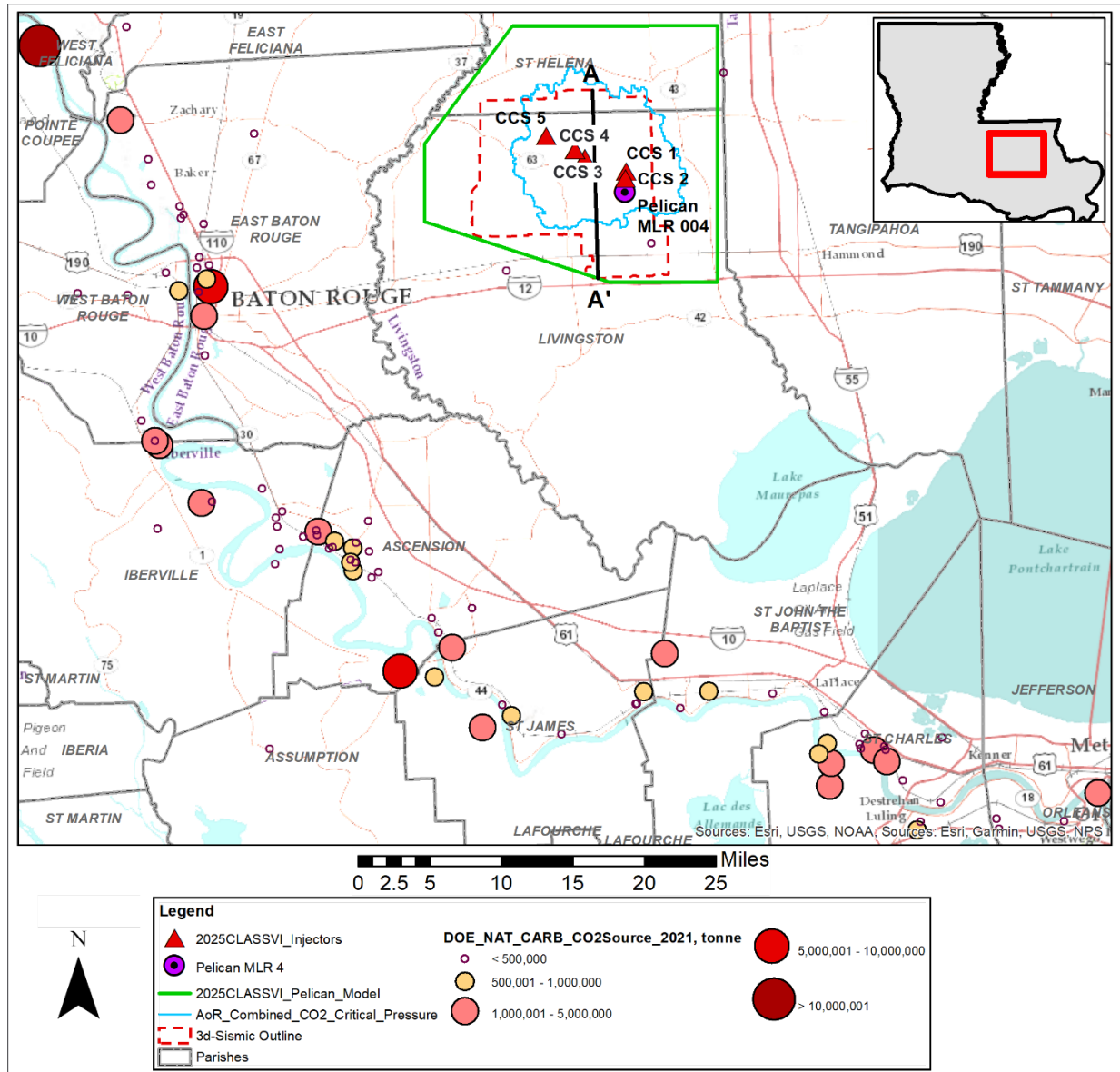


Figure NAR-1—Pelican Sequestration Hub location with respect to the Mississippi River Chemical Corridor.

The Pelican Sequestration Hub lies mostly within Livingston Parish, Louisiana. The area of investigation (AOI) straddles the parish line between Livingston and St. Helena Parishes. The surface geology is of Quaternary-age alluvium and terrace deposits. The Hub lies within forested acreage (Figure NAR-2). Populated areas near the AOI include Denham Springs (west and southwest), Livingston and Holden (south), and Hammond (southeast and east). The AOI lies in the Tickfaw River subbasin shown in Figure NAR-3 Imagery. The main drainage systems are the Tickfaw River and tributaries of the Hog Branch. Surface elevation in the area is between 150 and 40 ft above sea level, with a gentle dip of 0.09° toward the Gulf of America. Along the southern

Application No. 45079, 45080, 46169, 46170, and 46171

boundary of the AOI is the Denham Springs-Scotland Ville Fault, which has been interpreted on the 2009 LIDAR data (<https://maps.ga.lsu.edu/lidar2000>).

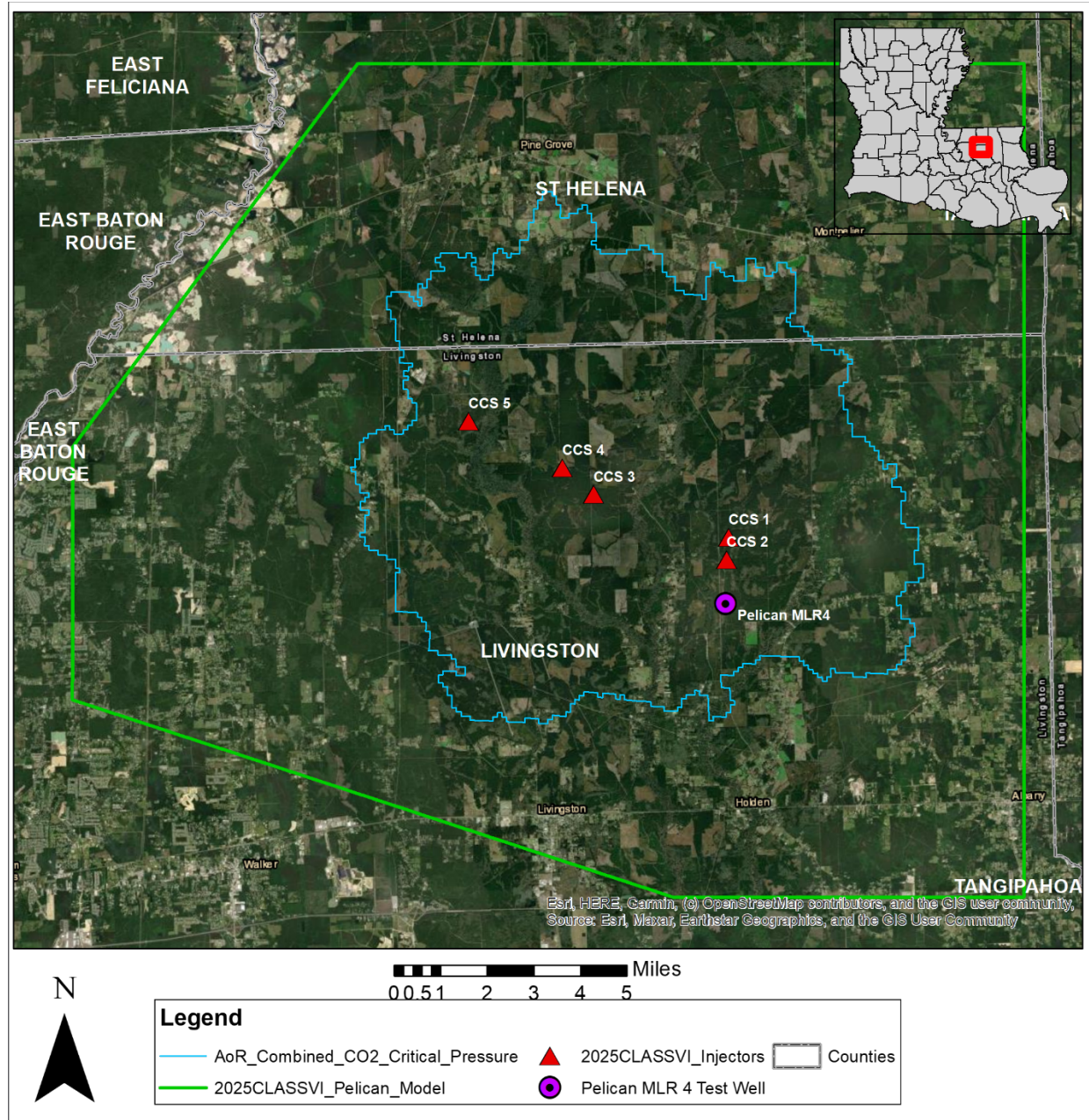


Figure NAR-2—Satellite imagery highlighting the project area.

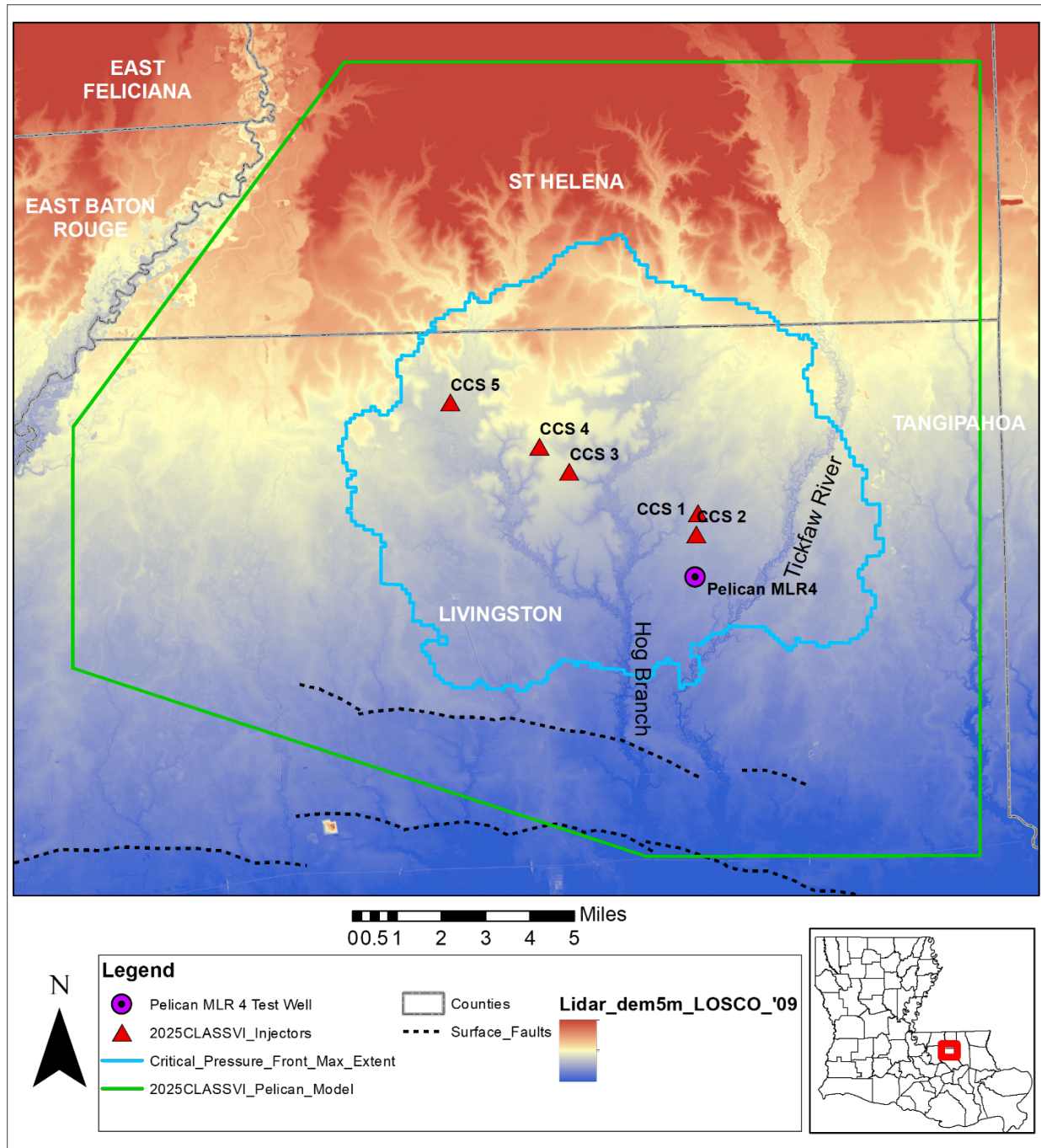


Figure NAR-3—LIDAR imagery highlighting surface topography, main river drainage, and surface-penetrating faults.

Figure NAR-4 displays the project AoR in northern Livingston and southern St. Helena Parishes, wells, (See Project Narrative - Appendix C), and the area for which a geomodel was built to quantify CCS potential and plan for site development. The active oil fields nearby include Beaver Dam Creek, Lockhart Crossing, and Livingston. All three produce from the deeper Wilcox or Tuscaloosa. CO₂ injection has been implemented in the Lockhart Crossing field (Wood, 2011). A

CO₂ enhanced oil recovery (EOR) pilot was planned in the Livingston field but was never implemented due to low oil prices (Hite, 2016).

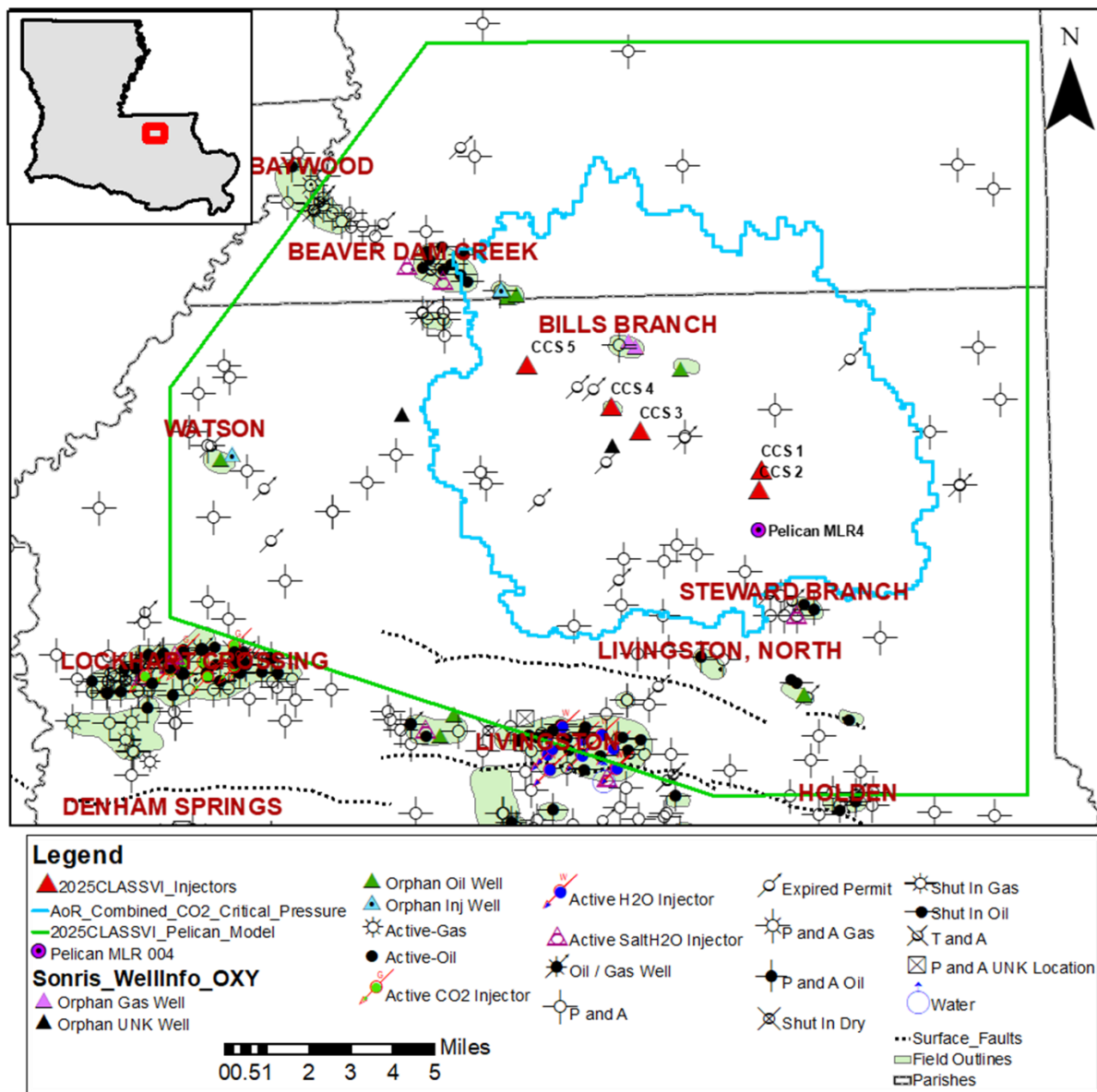
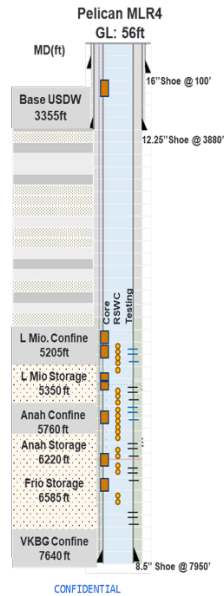


Figure NAR-4—Map of the Pelican CCS geomodel area (green polygon), Pelican Sequestration Project AOR (blue polygon), and legacy wells in the region.

The Pelican MLR 004 Stratigraphic Test well was drilled in August 2022 to address data gaps and collect data to minimize uncertainties in the Oligocene Storage Complex. Figure NAR-5 summarizes the data collected and lab analysis performed. Key findings, which were integrated into the site characterization, are: 1) the injection test confirmed expected injection rate of 2 MMTPA/injection well or more, 2) geomechanical analysis validated a high-pressure window to operate with low risk of fault activation, 3) borehole image analysis provided evidence for low likelihood for fractures in the brittle and unconsolidated formations, 4) cutting analysis for microbe

Application No. 45079, 45080, 46169, 46170, and 46171

and HC-detection provided evidence for vertical confinement of the primary confining unit, 5) log analysis indicated good porosity and net sand thickness supporting storage potential, and 6) pressure testing indicated good permeability.

Wellbore SummaryData Acquisition

Well Log		
Attempted	Recovered	Logs Acquired
Open Hole	0-3,894-ft	GR, Res, Neu, Den, Cali, DT, SP
Thru Bit	3,894-ft-7,785-ft	GR, Res, Neu, Den, Cali, DT, SP
Cased Hole	0-7,785-ft	CBL, Temp, PulseNeu, Imager, CIT

Conventional Core	
MD Depth, ft.	Recovered
3,050-6,750	156-ft

Rotary Cores	
MD Depth, ft.	Recovered
5271 - 6814	23-RSWC

Cuttings / Mudlog			
MD Depth, ft.	Interval	Amount	Analysis
0-TD	30ft	30g-dry	Biostratigraphy
		1-cup Wet	Biostratigraphy / Pyrolysis / XRF
		1-test tube	DNA Microbial Analysis
	72-samples	1-cup Wet	AGI Background Gas
	40-Samples	1-Isotube	Gas Analysis

Formation Testing	
MD Depth, ft.	Recovered
5500-6800ft	1-Fluid Sample
5300ft	1-LOT
5814-7425ft	2-FIT
6327-7070ft	3-SRT

Data Analysis

Analysis	
Routine	CoreGR, Slab, CT, Plug, Photo, XRD, Por/Perm, Crushed Rock Analysis
Special Core	NMR, MICP, CO ₂ -Threshold Entry Pres., Brine-Perm
Geomechanical	Static/Dynamic Anisotropy, Confining/Unconfining Strength, Poroelastic
Geological	Description, XRD, XRF, Thin Sec, SEM, Pore-Mapping, Paleo, Microb
Geochemical	Fluid / Gas Analysis, Mineralogy, Pyrolysis

Figure NAR-5—Pelican MLR 004 stratigraphic well data collection and test program summary.

2.1 Regional Geology, Hydrogeology, and Local Structural Geology

2.1.1 Regional Geology -- Stratigraphy

2.1.1.1 Paleozoic and Mesozoic

Analysis of the pre-Triassic basement rim around the Gulf of America provides provenance understanding for lithologic distribution in the Pelican Sequestration Project Oligocene Storage Complex. These rocks outcrop in the Appalachian and Ouachita Mountain belts northeast and north, respectively, of the northern Gulf of America basin. Predominant rock types in the Appalachian province are igneous (granite), metamorphic (marble and schist), and clastic rock (Devonian carbonates, Mississippi limestone, and Pennsylvanian coal). Rock types in the Ouachita Mountain belt are predominantly dark carbonates, black shales, cherts, and “flysch” (thinly bedded sandstone and shale) (Salvador, 1991).

The northern Gulf of America basin has more than 30,000 ft of sediment between the surface and basement (Adams, 1997). The oldest sediments are Triassic-aged sandstone and conglomerates that exist locally in rift basins. The Jurassic Louann salt sits unconformably over this unit, where it exists, or over Paleozoic basement (Figure NAR-6). The Louann salt resulted from the evaporation of very large, shallow, and hypersaline water bodies that periodically received water from nearby marine sources. The thickness and geographic extent of the deposit suggest long, gradual subsidence of the Gulf basin. Understanding the presence of the Louann salt and resulting

structures is key to understanding the geology of the Gulf of America basin. For example, it is the Louann salt that creates salt structures and related faults, acts as the deepest slip surface for passive growth faults and keeps basin temperatures suppressed.

During the rest of the Jurassic period, the Gulf experienced a long marine transgression as subsidence continued. In the northern Gulf of America, nonmarine nearshore and eolian sands of the Norphlet formation were conformably deposited over the Louann salt. Above this, the marine Smackover carbonate shale was deposited in restricted basins with equivalent up dip oolitic sands. The marine environment continued at the end of the Jurassic with the deposition of the Haynesville shale in a shallower marine setting. The close of the Jurassic was marked by the dark marine, fossiliferous Bossier shale, which grades north into the coarse sands of the Cotton Valley formation.

The Early Cretaceous in the northern Gulf of America basin consists predominantly of carbonates with occasional deposits of coarse-grained terrigenous clastics that were shed from the continental interior Appalachian and Ouachita Mountains. These sediments were deposited as subsidence in the basin continued. The Hosston formation unconformably overlies the Cotton Valley formation; it is a fine to coarse sandstone that interfingers and is overlain down dip by the argillaceous and fossiliferous limestones of the Sligo formation, which becomes a more massive, shallow-water, shelfal limestone. Overlying the Sligo are shales and thin limes of the Pearsall formation, which grades into terrigenous clastics up dip. This unit again is overlain by a series of shelf carbonates (Glen Rose, Fredericksburg, Washita, and Edwards-Stuart City formations) that grade basinward into deep marine calcareous shales (Atascocita formation). A prominent carbonate shelf margin was established at the end of the Early Cretaceous.

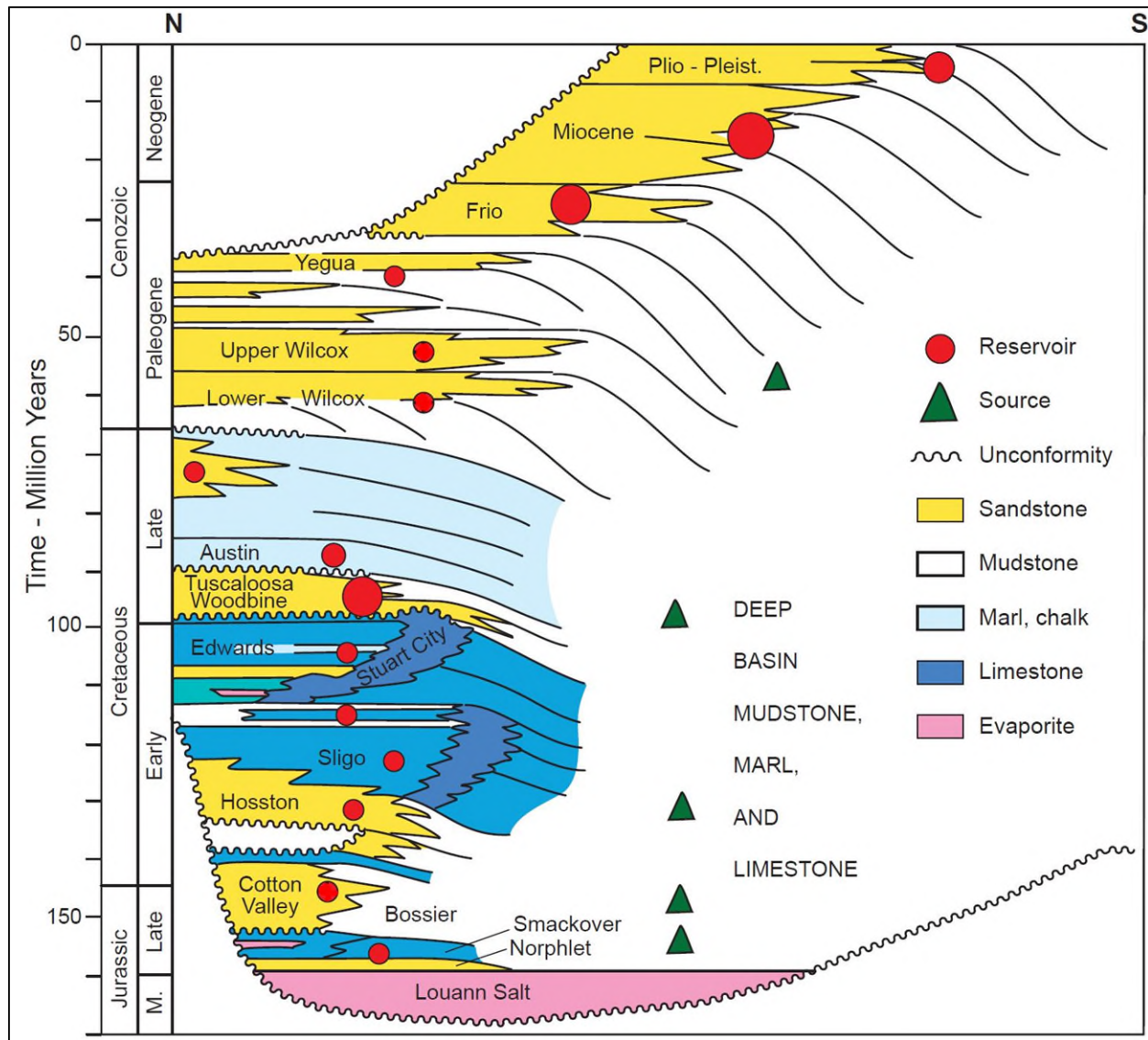


Figure NAR-6—Schematic stratigraphic succession of the northern Gulf of America (Galloway, 2009).

The Late Cretaceous was a time of oceanic highstand. Before the onset of the highstand, the terrigenous Tuscaloosa formation prograded basinward. It is divided into three intervals: the Lower Tuscaloosa, the Middle Tuscaloosa Shale, and the Upper Tuscaloosa. The Lower Tuscaloosa progrades to the shelf margin as sands were deposited in the basin through submarine channels. The Middle Tuscaloosa is a fossiliferous shale with interbedded calcareous sand that flooded the shelf and thickened downdip on the Early Cretaceous shelf margin. The Upper Tuscaloosa is medium- to coarse-grained and exists as an expanded section downdip of the Early Cretaceous shelf margin. The Tuscaloosa is the deepest formation penetrated (approximately 20,000 ft) in the Pelican Sequestration Hub area being investigated (AOI). After the deposition of the Tuscaloosa, ocean waters flooded the continental USA, depositing a series of carbonate mud and chalk layers in the northern Gulf of America (Austin Chalk, Taylor, and Navarro Groups). The position of the

Cretaceous shelf and platform greatly influenced the shape, size, rock type, and number of Cenozoic sediments deposited in the Gulf basin.

2.1.1.2 Cenozoic to Present

Cenozoic sedimentation was dominated by prograding terrigenous clastics shed from the Laramide orogeny in the western USA. The Midway formation is the first Paleocene rock to be deposited. It is a transgressive marine shale deposited before the major clastic progradation began. Overlying the Midway is the prograding wedge of the Paleocene to Eocene Wilcox formation. This formation is composed of coarse clastics that entered the basin through feeder systems in northeastern Louisiana and western Mississippi. The Middle and Upper Eocene is defined by a series of transgressive and regressive prograding events resulting in four thick prograding sand-rich wedges, each overlain by thin transgressive shaly marine deposits. The collection of this cyclicity is called the Claiborne Group, which conformably overlies the Wilcox formation. The final formation deposited before the Oligocene Storage Complex is the Jackson formation, which is a deepwater shale in the area of investigation.

The Pelican Sequestration Project will target Oligocene strata for CO₂ sequestration. The outer shelf Vicksburg shale was conformably deposited on the Jackson formation and is the basal seal. Above these are the clastics of the Frio and Lower Anahuac formations, which are the units identified for storage. In this location, the environment of deposition (EOD) of the storage units are sands deposited in a shore zone to carbonate marine shelf environment (Figure NAR-7, Galloway, 2000). The sediments deposited during this time are the Frio sands and shales and carbonate-dominated sediments with reworked sands and shales from the Anahuac maximum flooding event. The sands of the Frio formation represent coastal plain and delta sediments deposited as the Louisiana Delta prograded over the muddy Vicksburg shelf (Figure NAR-7a). The Frio depositional system was transgressed upon with the Anahuac Heterostegina Limestone (HET Lime) carbonate platform.

Figure NAR-7 maps show depositional system, sediment dispersal axes, generalized depocenters, and selected depositional and erosional features (modified from Galloway, 2000). Miocene sediments are dominated by shore-zone and mixed-load dominated fluvial sediments. The AOI is identified by a green/black polygon. During this time, the Louisiana delta shifted west and shoreward, resulting in the shrinkage of the delta and longshore reworking of platform delta sands by a tide-dominated shore-zone system (Figure NAR-7b). The end of the Oligocene time is marked by a regional maximum flooding event, which resulted in the deposition of the Anahuac Shale. The tight HET Lime and overlying Anahuac Shale are identified as the caprock for the Oligocene Storage Complex.

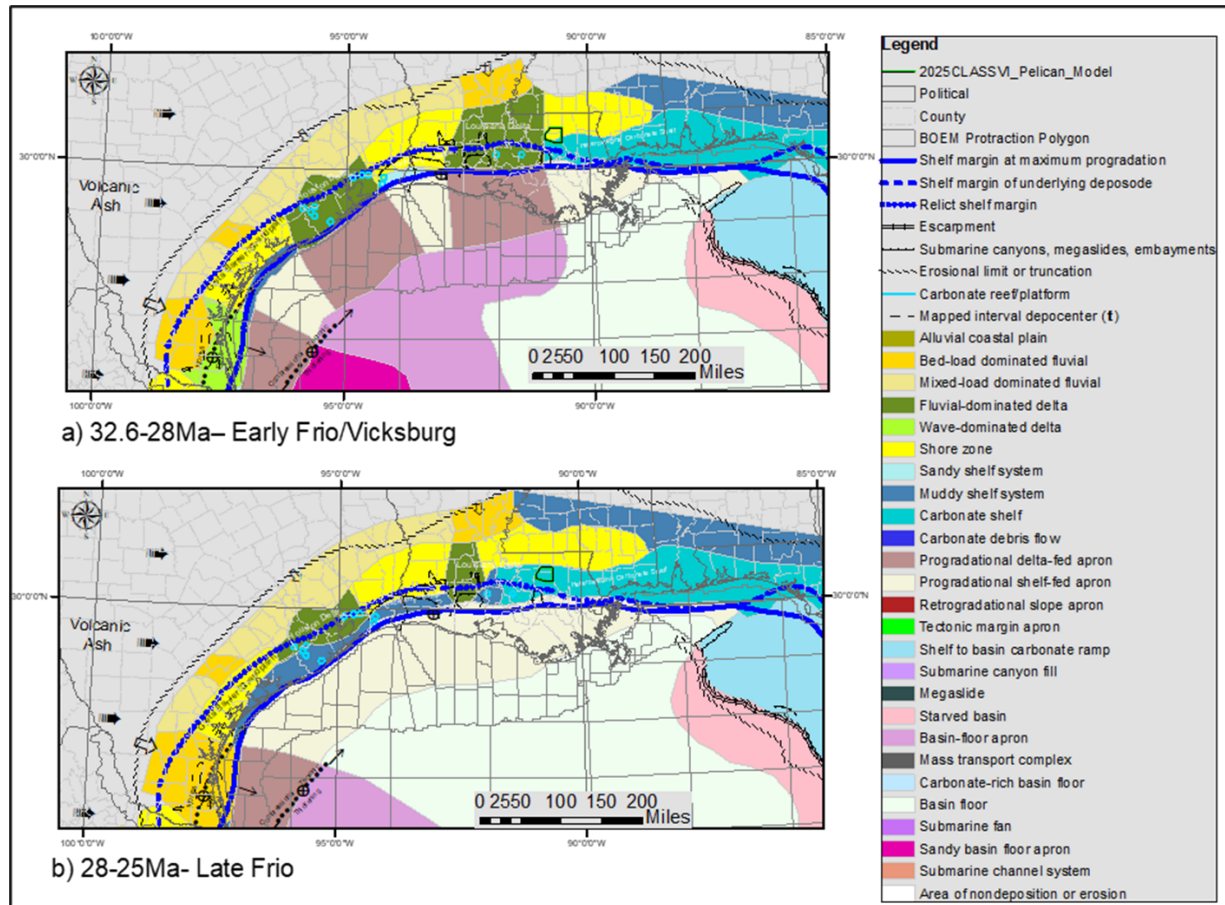


Figure NAR-7—Paleogeography of the Oligocene Frio: a) Early Oligocene, b) Late Oligocene. Maps showing depositional system, sediment dispersal axes, generalized depocenters, and selected depositional and erosional features (Galloway, 2000).

During the Lower Miocene, sedimentation into the Gulf basin shifted from the western Gulf of America (Rio Grande Valley) to the northern Gulf of America along the Calcasieu and Central Mississippi River delta systems (Figure NAR-8a, Galloway, 2000). Clastics in these delta systems were fed by rivers draining the Appalachian and basin and range provenances of the USA. Adjacent to and between these delta systems were wave-dominated shore-zone systems, where large volumes of sand and shales were deposited. The Pelican Sequestration Hub is located east of the Mississippi Delta system in a shore-zone environment, where fine- to medium-grained sands were deposited. The end of the Lower Miocene is identified by a maximum flooding event that deposited a continuous regional shale or mudstone bed.

Figure NAR-8 shows show depositional system, sediment dispersal axes, generalized depocenters, and selected depositional and erosional features (modified from Galloway, 2000). Miocene sediments are dominated by shore-zone and mixed-load dominated fluvial sediments. The AOI is identified by a green polygon. Sedimentation during the Middle and Upper Miocene was dominated by sands and shales of a mixed-load fluvial system of the Central Mississippi River (Figure NAR-8b, Galloway, 2002). The extreme amount of sedimentation delivered by this fluvial

system was accompanied by a delta-front “collapse margin,” resulting in slump scars, growth faults, and submarine canyons. The end of the Miocene is marked by a second maximum flooding event, which deposited a regionally extensive, clay-rich mudstone that acts as the lower confining unit for underground sources of drinking water (Goddard, 2003).

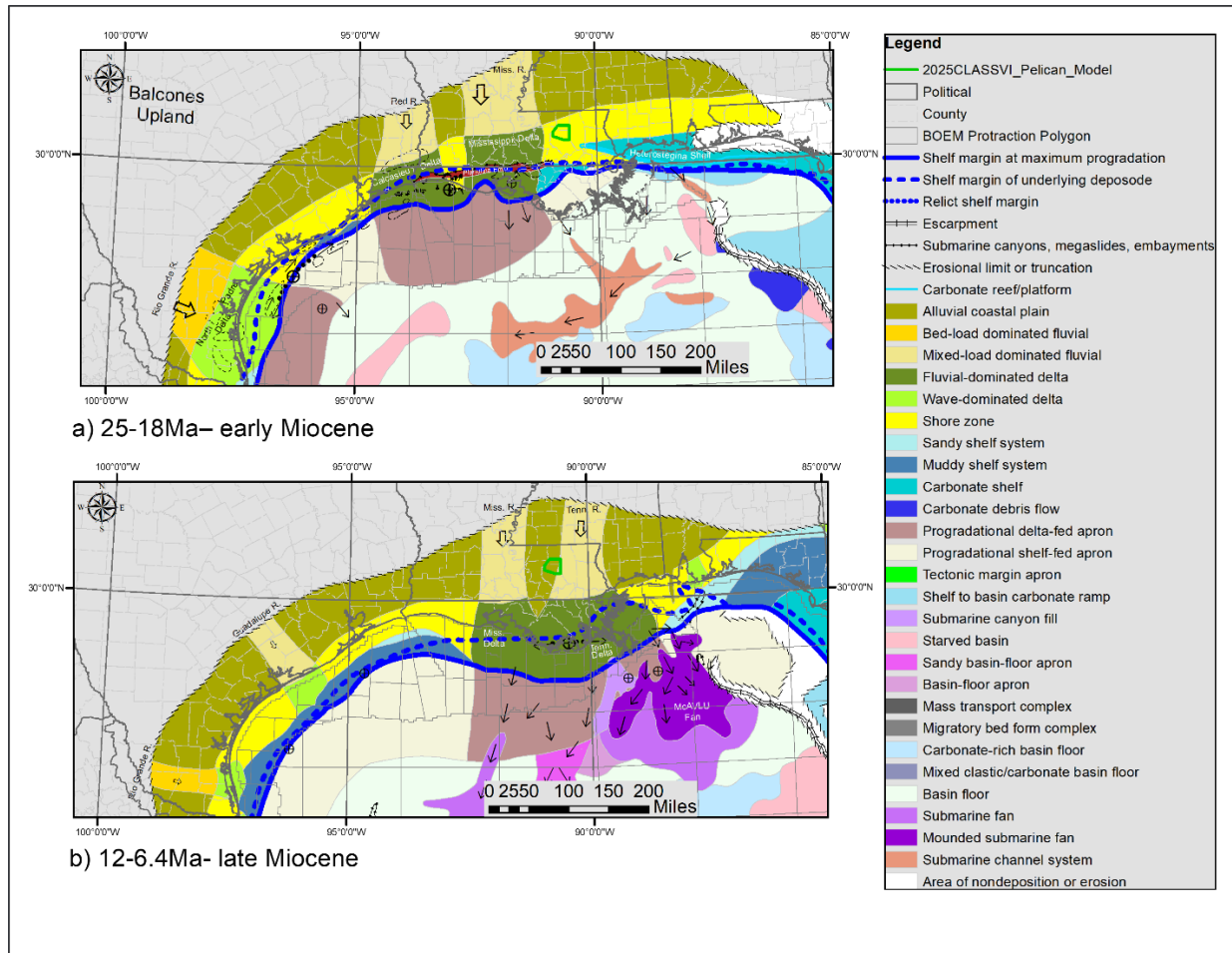


Figure NAR-8—Paleogeography of the Miocene: a) Early Miocene, b) Late Miocene.

Overlying the Upper Miocene confining clay unit are Mississippi River fluvial sediments of the Baton Rouge aquifer systems. These sands have complex geometries representing channel fill, floodplain, levee, and crevasse splay facies (Chamberlain, 2012). The USGS identifies these sands as an amalgamated zone of sand bodies with a high degree of connectivity, causing them to behave like one hydraulic unit.

2.1.2 Regional Geology -- Basin history and structure

2.1.2.1 Paleozoic and Mesozoic

The Gulf of America is an ocean basin that exists between the southern coast of the USA and Yucatan Peninsula, Mexico. During the Mesozoic, the Gulf basin underwent three phases of rift tectonics (pre-rift, syn-rift, and post-rift), followed by local rearrangement of basement features

Application No. 45079, 45080, 46169, 46170, and 46171

The pre-rift phase began after the continental plate collision that uplifted the Ouachita Mountains (360–310 million years ago [mya]). During pre-rifting, mantle plumes caused doming of the crust and deposition of the basin carbonates (Paleozoic, 310–250 mya). The continued doming stretched the crust and initiated the syn-rift phase in the late Triassic (225–200 mya).

Syn-rift tectonics are recorded in the Mississippi and North Louisiana Salt Basins and along the southern flanks of the Ouachita Mountains (Figure NAR-9). Rocks deposited during this phase are the red beds of the Eagle Mills formation. Crustal attenuation continued in the Middle Jurassic (180–160 mya). At this time, evaporation of seawater incurring into the region from the Pacific basin caused the Louann Salt to be deposited.

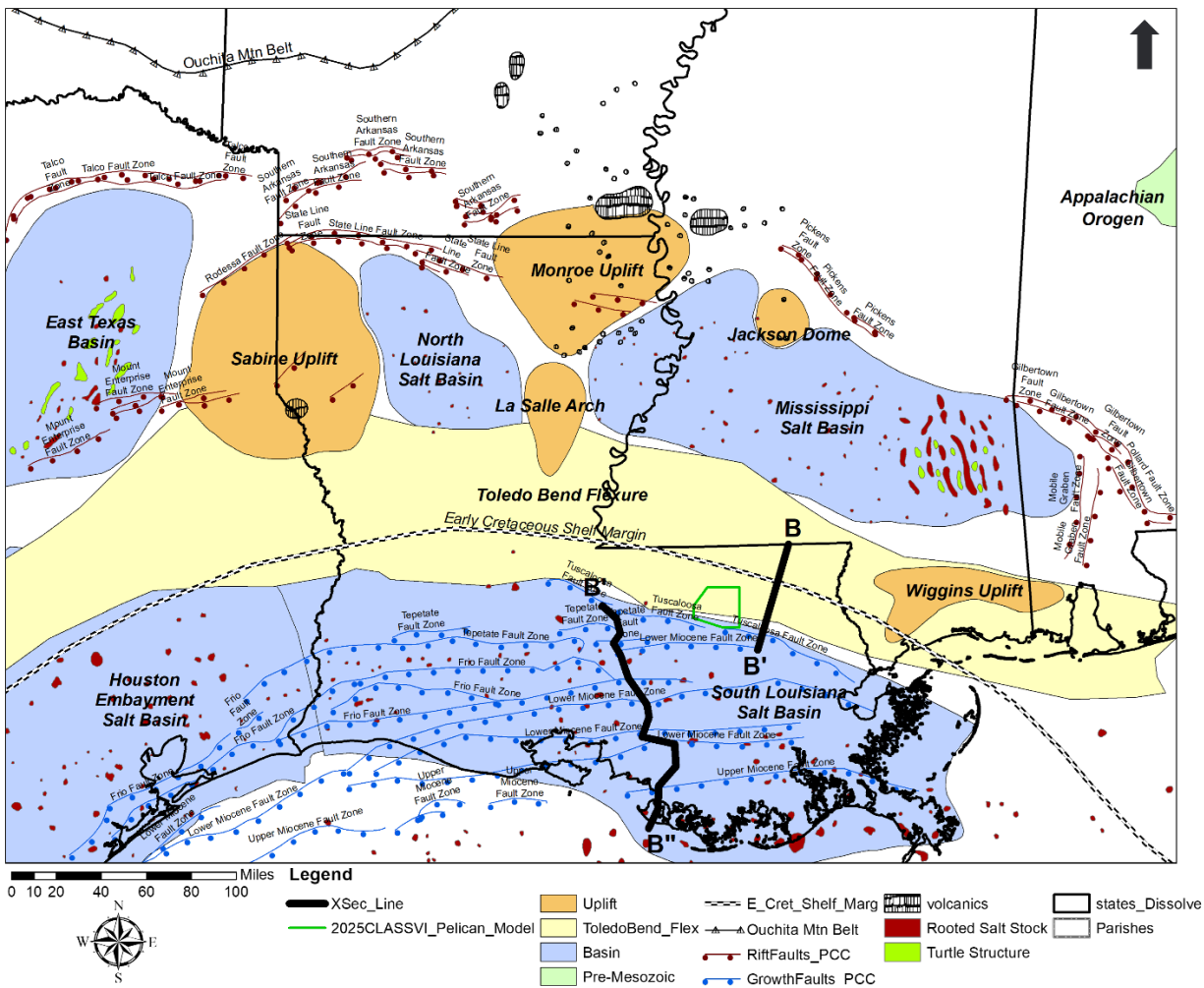


Figure NAR-9—Structural element map showing key structural features that developed during the Mesozoic and Cenozoic periods in the Gulf of America (Pitman, 2010).

Post-rift, passive margin sedimentation began in the northern Gulf of America with the onset of seafloor spreading in the central Gulf of America in the Late Jurassic (155–130 mya). During that time, the basin filled with a series of progradational (Norphlet and Cotton Valley) and retrogradational (Smackover, Haynesville) sequences. Central Gulf of America seafloor spreading

ceased during the Early Cretaceous (130–110 mya). This initiated basin subsidence and a stable shelf with a dip toward the south-southeast. The Early Cretaceous sediment sequence is of a prograding continental sediment wedge (Hosston formation) that was flooded by a carbonate platform, which set up a prominent and long-lived shelf margin (Figure NAR-9; Sligo, Glen Rose, and Edward formations).

The Middle Cretaceous (about 100 mya) marked the onset of igneous activity, corresponding to the Cordilleran thrust event, and a time of global sea-level fall. In the northern Gulf, basement highs were uplifted (Figure NAR-9, Sabine and Monroe Uplifts, Jackson Dome, and Wiggins Arch), small salt basins became isolated (North Louisiana, Mississippi, and South Louisiana Salt Basins), and the Cretaceous platform margin was exposed, creating a basinwide angular unconformity. The second major flooding event happened through the Late Cretaceous (96–86 mya), when the Tuscaloosa formation prograded over the Early Cretaceous shelf margin. At that time, the first series of down-to-the-basin normal faults developed to accommodate high sedimentation (Tuscaloosa Fault Zone, Figure NAR-9). As the sea level rose, the northern Gulf became flooded by another carbonate shelf (Austin Chalk, Taylor, and Navarro Groups). The end of the Cretaceous and start of the Cenozoic is defined by an unconformity that is associated with the Chicxulub meteor impact (Snedden and Galloway, 2019). The impact zone is about 700 miles south of the Pelican Sequestration Hub, along the northern coast of the Yucatan Peninsula. It is believed to have caused seismic waves and initiated tsunami-sized ocean waves, resulting in slump deposits that likely initiated widespread salt motions within the Gulf basin.

2.1.2.2 Cenozoic to Present

During the Cenozoic, the structural history of the northern Gulf of America is dominated by salt and gravitational tectonics that helped accommodate large amounts of prograding siliciclastic sediments. Growth faulting is the main type of structuration seen at the Pelican Sequestration Hub, which is just north of the South Louisiana Salt Basin, along the flank of the Toledo Bend Arch (Figure NAR-9). Ewing (1991) defines growth faults as:

Major strike-elongate zones of normal faulting, occurring entirely within the sedimentary column... These fault zones are intimately related in location and age to the prograding clastic shelf margin... The faults can cause tremendous expansion of the upper-slope and shelf-margin marine clastic deposits....

Three phases of growth faulting identified in the area are: 1) the Tuscaloosa Fault Zone, 2) the Tepehate Fault Zone, and 3) the Denham Springs Fault System (Figure NAR-9 and Figure NAR-10). The Tuscaloosa Fault Zone began to accommodate slope and deepwater sediments of the Middle Cretaceous Tuscaloosa formation, which is deeper than 14,000 ft in this area and does not affect the Oligocene or shallower sediments. The Tepehate Fault Zone was active during the deposition of the Eocene Wilcox to the Oligocene Frio formation (McCulloh et al., 2012). This system is present within the AOI with only one fault identified that penetrates the Frio injection sand but does not penetrate the Anahuac Confining Zone. The identified fault is south and downdip of the planned Sequestration Hub. The Denham Springs Fault System is a late-Pliocene to recent fault system (McCulloh, 2012) that developed to accommodate sedimentation created by deglaciation. The northernmost fault in this system is present along the southern boundary of the

Application No. 45079, 45080, 46169, 46170, and 46171

AOI (Figure NAR-9, and Figure NAR-10), is down dip of the Hub acreage, and does not penetrate the identified confining or injection targets.

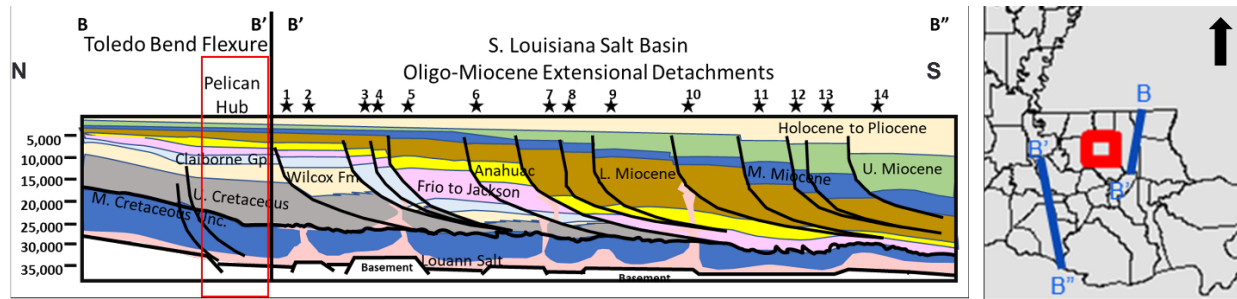


Figure NAR-10—Regional structural cross section highlighting the location of the Pelican Sequestration Hub. Cross section location is shown on Figure NAR-9. (Created from Adams, 1997, Snedden and Galloway, 2019)

2.1.3 Local Geology

A large body of data was used to characterize the Pelican Sequestration Project, including literature, remote sensing data (LIDAR), 2D and 3D seismic, and both licensed and public well data from SONRIS.com (Figure NAR-11). The well database includes 101 wells with petrophysical analysis shown in Table NAR-APPENDIX-A-1 out of which 82 wells inside the model area of interest with geological tops including stratigraphic test well (Pelican MLR 004) were used in static geological modeling. Details of static geological model can be found in Section 2.0 Computational Modeling Approach of the Area of Review and Corrective Action Plan document.

Application No. 45079, 45080, 46169, 46170, and 46171

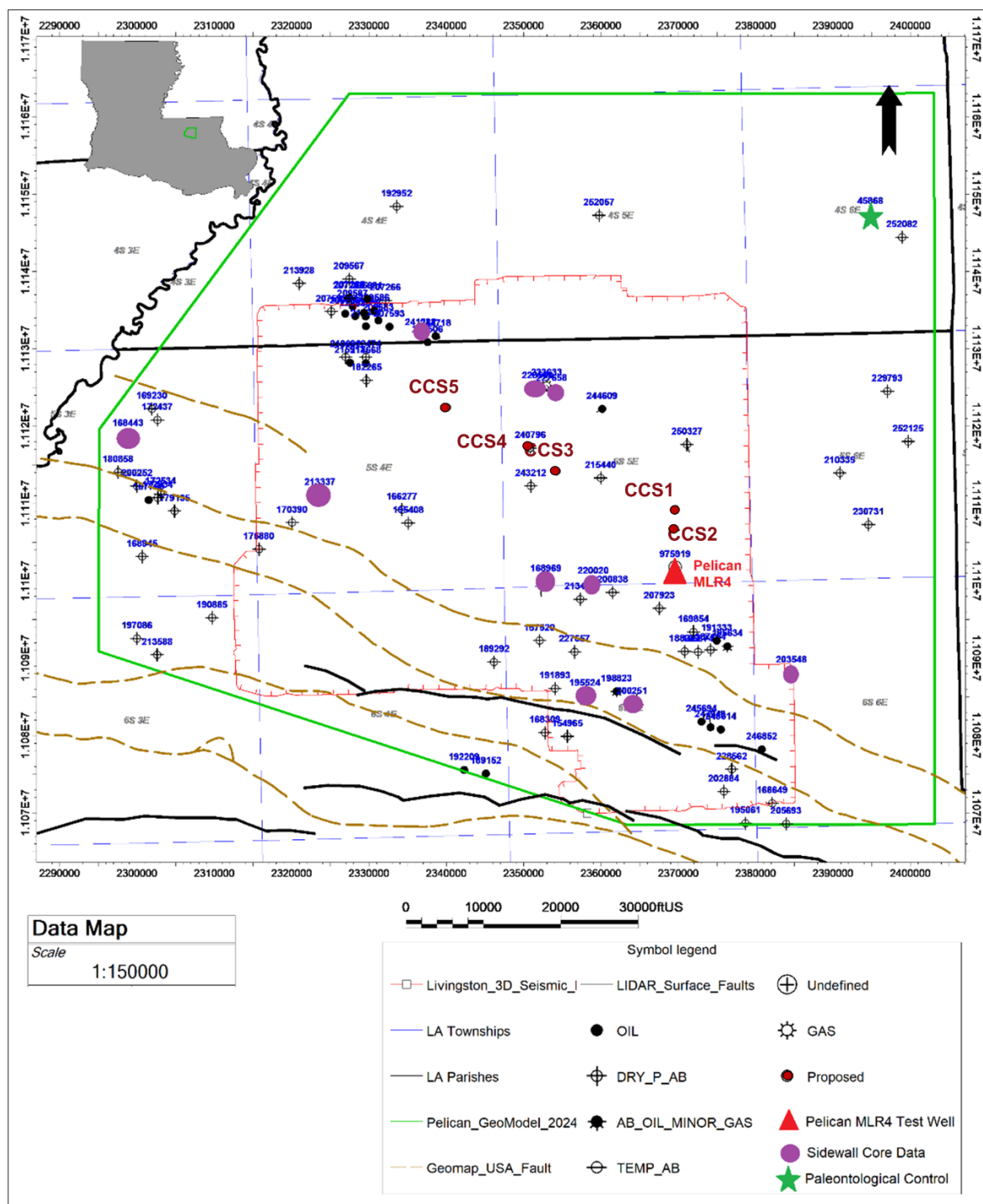


Figure NAR-11—Pelican Site Subsurface Data Control. Includes subsurface data control, area of investigation (AOI), and structural elements.

The storage complex for the Pelican Sequestration Project targets approximately 1,350 ft of Oligocene strata (Figure NAR-12) in the northern Gulf of America basin. The top of the Oligocene storage complex is approximately 5,400 ft true vertical subsea (TVDSS). Major confining units at the top of the Oligocene storage complex comprise shale and carbonate intervals of the

upper Anahuac Formation. Injection zones comprise the lower Anahuac and Frio Formations and consist of quartz-rich sands deposited in coastal plain and delta environments. The CCS 1 and CCS 2 injection wells are located along the eastern corridor of Pelican Sequestration Hub acreage and target thick sequences of high-quality clastic reservoirs. The Vicksburg Formation underlies the injection zones and consists of thick sequences of low-permeability shale.

The Oligocene storage complex is overlain by Miocene to present strata. The Lower Miocene consists of approximately 500 ft of channel and delta sand capped by 150 ft of marine shale. Approximately 1,700 ft of interbedded sands and low-permeability shales provide further vertical separation between the top of the Oligocene storage complex and interpreted base USDW. Here, base USDW is interpreted in the upper portions of the Jasper-equivalent aquifer sands (White, 2016). Jasper-equivalent aquifer sands are further separated from shallower overlying freshwater aquifers by thick unnamed confining shale units.

Series	Clastic Input	Stage	Aquifer System or Confining Unit	Project Storage Definitions
Pleistocene			Chicot equivalent aquifer system	Freshwater Aquifer
Pliocene		L	Evangeline equivalent aquifer system	Freshwater Aquifer
		E	Unnamed Confining Unit	Confining Clay / Base USDW
Miocene		L	Jasper equivalent aquifer sands	Saline Aquifer / Non-storage
		M	Unnamed Confining Unit	Saline Aquifer / Non-storage
		E	Fleming Formation Regional Start of Saline Aquifer	Confining Zone
	Sequestration Zone			
	Confining Zone			
Oligocene		L	Anahuac Formation	Sequestration Zone
		E	Frio Formation	Sequestration Zone
				Base Confining Zone

Figure NAR-12—Geological stratigraphic chart showing the project’s storage complex.

Structural history in the AOI during the Oligocene to present is dominated by passive margin growth faults accommodating large amounts of prograding sediments. These fault systems are located south and downdip of the Pelican Sequestration Project. Two phases of growth faulting, Eocene/Oligocene followed by Pliocene to present, intersect the storage complex in this general area. The Eocene/Oligocene Tepetate Fault Zone, active during early Frio deposition (McCulloh et al., 2012), penetrates the Frio injection sand, but not the Anahuac seal (Figure NAR-13). The Denham Springs Fault System is five miles south of the southern border of the acreage. A segment of this fault system is mappable on the 3D-seismic and defines the southern border of the model area.

Application No. 45079, 45080, 46169, 46170, and 46171

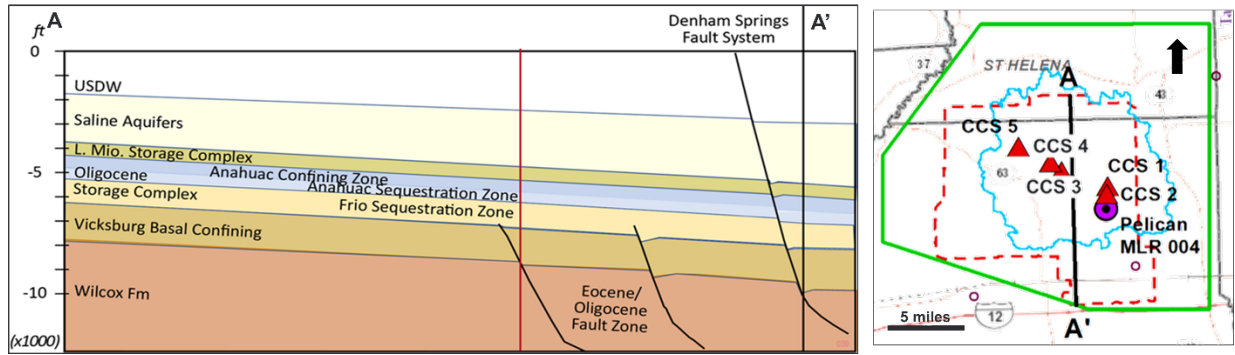


Figure NAR-13—Structural cross section generated from Oxy-licensed 3D seismic data shows that faulting south of the acreage has little interaction with the Pelican Sequestration Project acreage.

2.2 Maps and Cross Sections of the AoR

The Pelican Sequestration Hub is located updip of the Louisiana salt basin on the Cretaceous shelf edge (Figure NAR-10). The predominant regional geologic features in the area are down to the basin growth faults. The most updip series of growth faults in the area are late Eocene to Early Oligocene. In the AoR, this fault system penetrates the basal confining zone and storage zone but does not affect the Upper Confining Zone.

The lowest USDW averages 3,100 ft deep. The top of the confining zone for the Oligocene Storage Complex averages approximately 5,400 ft TVDSS. This provides approximately 2,300 ft of saline aquifers above the Oligocene Storage Complex (Figure NAR-14).

The proposed storage site is structurally benign. It has an average homoclinal dip to the southeast of 1.5°. The formations in (Frio and Lower Anahuac) are nearshore environments, which show variability and heterogeneity but are regionally present. The heterogeneity in the formation is considered favorable for containment.

The injection and confining formations are laterally continuous. The basal confining unit, the Vicksburg formation, is a homogeneous and laterally continuous marine shale with approximately 10% silt. The storage formations, Frio and Lower Anahuac, are broken into seven distinct units with an average of 1,600 ft of gross section and 480 ft of net sand (~30%NTG). These formations are laterally continuous throughout the proposed site but show heterogeneity typical of a delta and near shore environments. The upper confining unit consist of the Heterostegina Limestone (HETLM) and Upper Anahuac Shale, a marine siliciclastics. The HETLM is laterally continuous with a consistent thickness of about 100 ft of shelfal limestone. The Upper Anahuac marine shales are also laterally continuous. These units have a gross thickness of approximately 280 ft with about 25% sands that are present as compensationally stacked sand bodies. The Internal stratigraphy of the storage complex was determined by integrating 3D seismic and well data. The basic workflow entailed using log signature maps to spatially understand log characteristics, interpreted seismic sections and extractions to visualize depositional patterns, thickness maps to determine sediment fairways, and 3D visualization to understand interplay between paleo-topography and depositional patterns.

Application No. 45079, 45080, 46169, 46170, and 46171

There is approximately 2,300 ft of saline aquifer above the Oligocene Storage Complex before reaching the lowermost USDW. These are Miocene aged sediments. Paleontological control in the Pelican MLR 004 stratigraphic test well identifies two major flooding events that deposited high-quality Marine shales. These events are the *Amphistegina* B flood event at the top of the Lower Miocene and Cib Op flood event at the top of the Middle Miocene. These blanketed shales give confidence for additional containment via a secondary confining shale complex.

Application No. 45079, 45080, 46169, 46170, and 46171

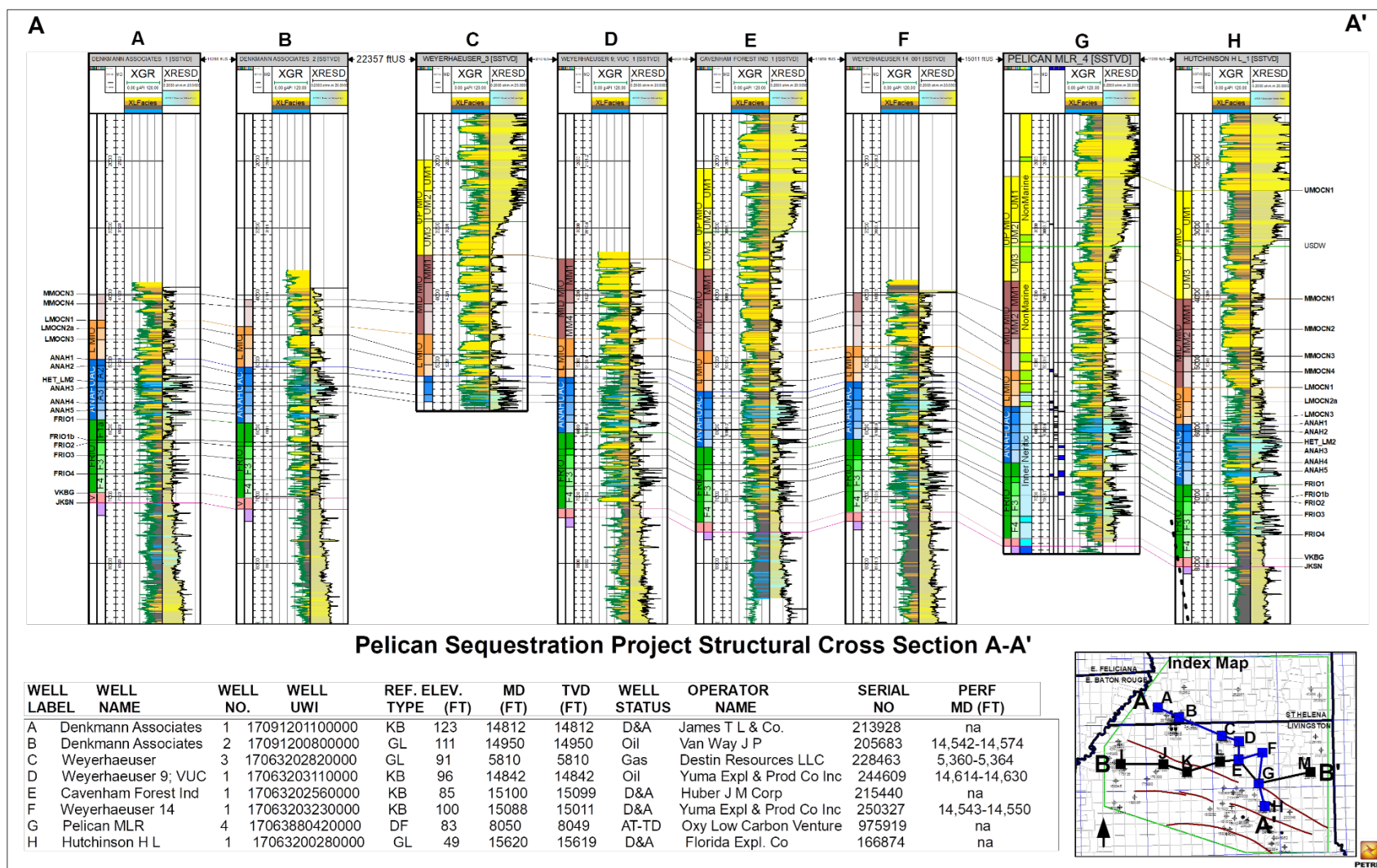


Figure NAR-14—Structural Cross Section A-A'.

Application No. 45079, 45080, 46169, 46170, and 46171

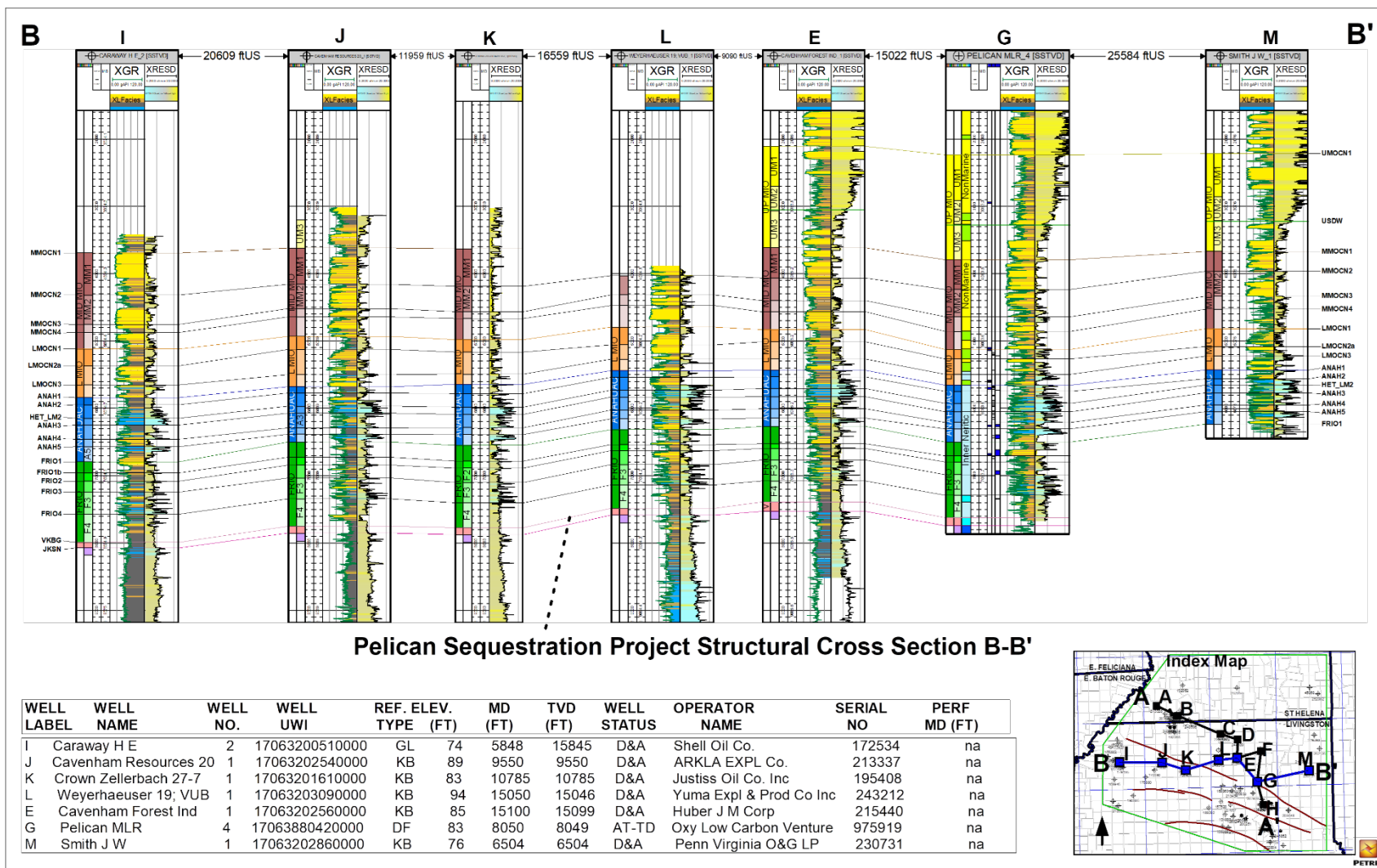


Figure NAR-15—Structural Cross Section B-B'.

Application No. 45079, 45080, 46169, 46170, and 46171

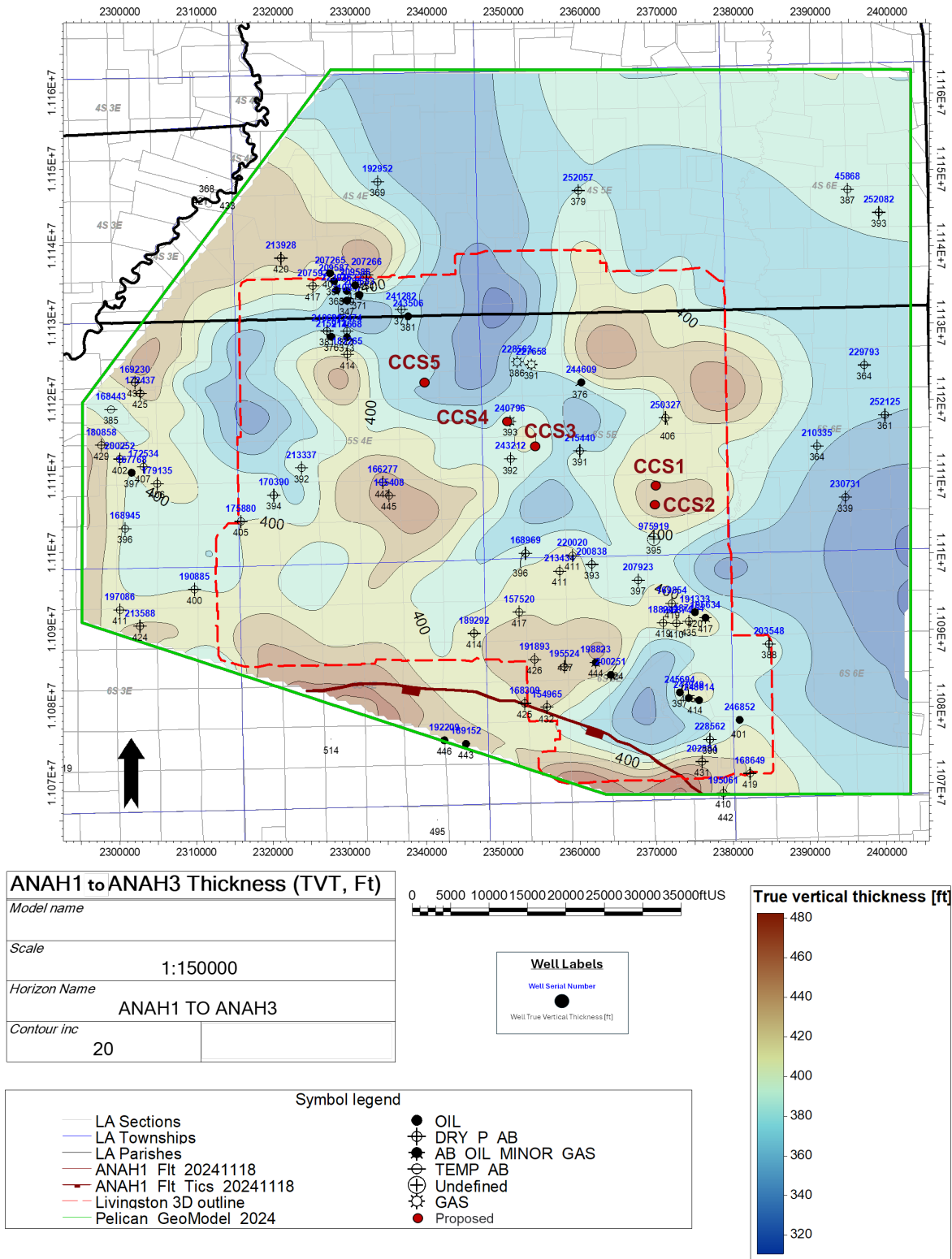


Figure NAR-16—Top Confining Zone ANAH1 to ANAH3 Thickness Map

Application No. 45079, 45080, 46169, 46170, and 46171

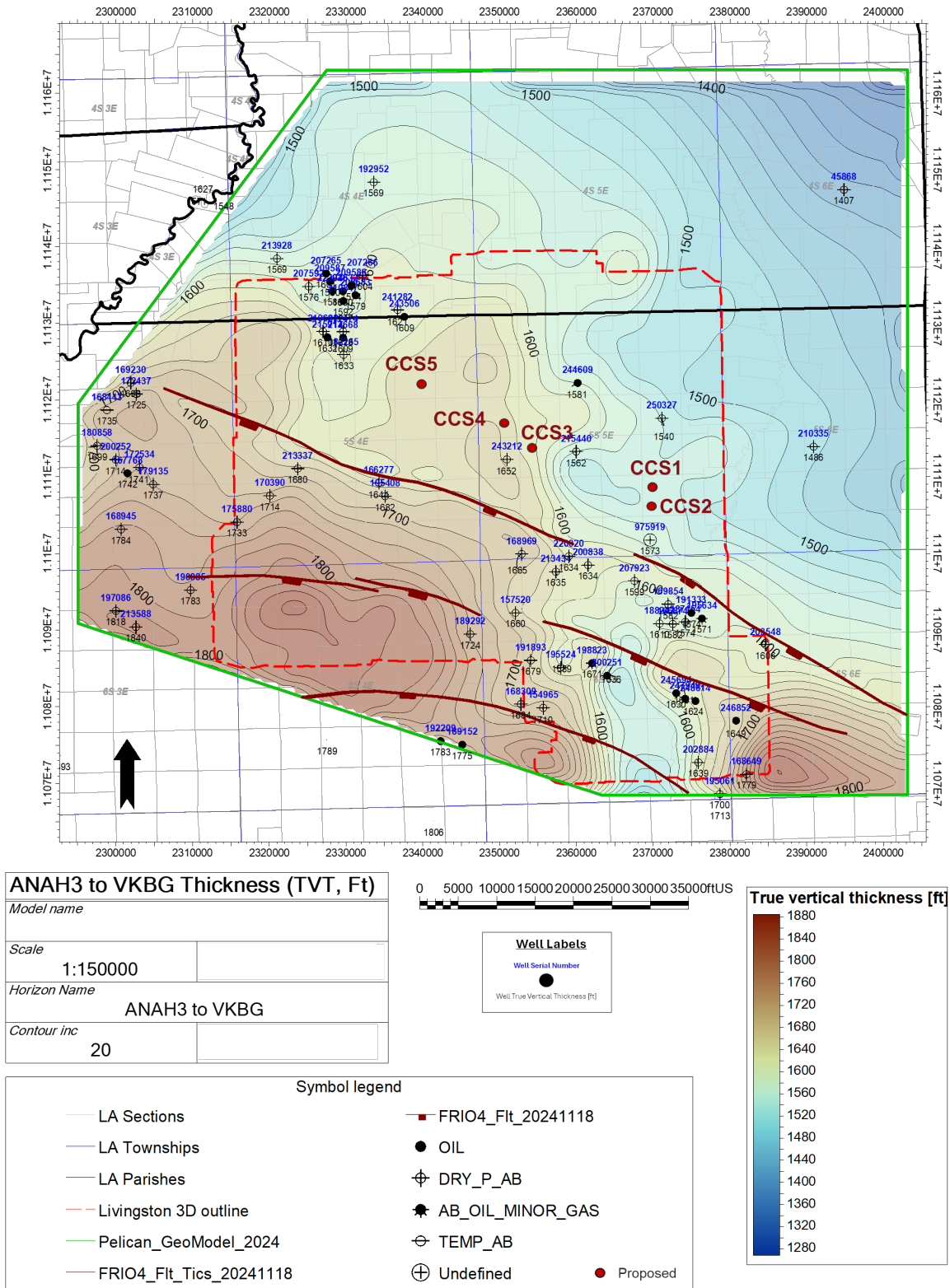


Figure NAR-17—Total Storage Zone ANAH3 to VKBG Thickness Map

Application No. 45079, 45080, 46169, 46170, and 46171

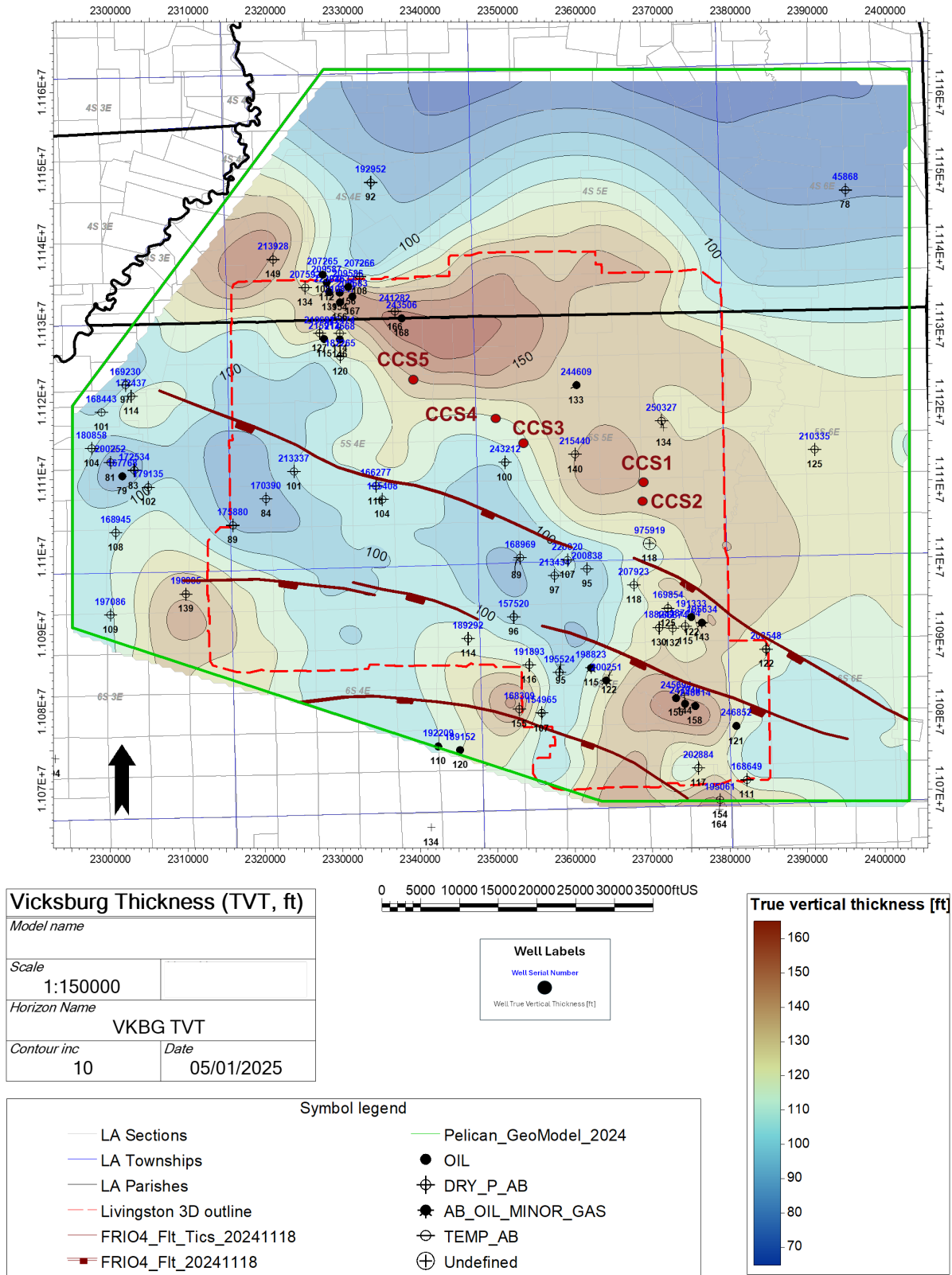


Figure NAR-18—Basal Confining Zone: Vicksburg Thickness Map

2.3 Faults and Fractures

2.3.1 Local Structure and Faulting

Approximately 137 square miles of legacy 3D seismic data was obtained, reprocessed, and used to generate the key geophysical inputs for the geomodel. The 3D seismic footprint, along with integrated well data, can be seen in Figure NAR-19 and Table NAR-1. As shown, the 3D seismic data covers the majority of the project area and extends significantly to the south to provide quality imaging of faulting south of the project area.

The legacy 3D seismic data was acquired by Yuma Exploration in 2009 and obtained by Oxy in 2022. It was acquired by CCG Veritas using the parameters listed in Table NAR-2. The 3D dataset underwent prestack time migration processing in 2009 by PGS and again in 2012 by Hardin. In 2012, Tricon performed a prestack depth migration on a subset of the full survey. Unfortunately, no documentation of the original processing workflow is known to be available to the project team. The field records from the original acquisition were sent to Earth Signal and reprocessed using modern Pre-Stack Time Migration methods in 2023 (Table NAR-3). Seismic resolution in the target zone was calculated to be approximately 90 ft, with a phase close to zero. Subsequently, numerous post-stack enhancement volumes were generated in-house to improve both structural and stratigraphic imaging. Figure NAR-20 presents a summary of the processes and workflows used to generate geomodel inputs from the 3D seismic data.

Robust and modern geophysical well logs were collected at the MLR 004 Stratigraphic Well Test. As such, the MLR 004 was used to anchor the seismic well tie interpretation and establish a time-depth relationship (Figure NAR-21). Key horizons that tie to significant well picks (shown as stars on Figure NAR-21) were identified from the seismic well tie and interpreted on the 3D time volumes.

Given the density of well data, the relatively simple geologic structure, and the lack of any velocity anomalies, a simple average velocity model leveraging tied time horizons and well picks yielded a robust depth conversion. This velocity model was used to convert the 3D seismic volumes and time horizons to depth. A detailed fault plane interpretation was then conducted on the depth-converted seismic volumes. The resulting depth horizons and fault planes were then used as input into the Geologic Structure Model.

Faulting within the 3D seismic area is characterized as listric normal faulting occurring in a coast-parallel WSW orientation. A map of fault-horizon intercepts is shown in Figure NAR-22, and interpreted seismic depth lines with faults and key horizons defining the storage complex are shown in Figure NAR-23 and Figure NAR-24. Faulting predominantly occurs south of the project area in the southern portion of the 3D survey, and faults become progressively younger in age from north to south. Figure NAR-23 demonstrates that faulting proximal to the eastern portion of project area extends vertically only slightly into the lower most portion of the storage complex, and that the majority of the Injection Zone and entirety of the Confining Zone are Figure NAR-24 shows faulting proximal to the southern edge of the western project area does extend through the storage complex; as such, the injection program proposed in this permit is designed specifically to avoid plume interaction with this fault segment.

The map displays the Pelican CCS area, highlighting the 3D seismic footprint (shaded gray) and wells with tops used for the velocity model (blue dots). Key features include:

- Geographic Labels:** Yuma, Livingston, ES.
- Scale:** 15,000 feet / 4,000 meters.
- Wells and Facilities:**
 - Pelican CCS 1, 2, 3, 4, 5:** Indicated by red star symbols.
 - Pelican MLR 4:** Indicated by a red star symbol.
 - Wells:** Numerous blue dots represent wells, including DENKMAN ASSOCIATES, CAVENHAM, WYERHAEUSER, CROWN ZELLERBACH, and others.
- Legend:**
 - 3D Seismic Footprint
 - Wells with Tops Used for Velocity Model

Figure NAR-19—3D seismic survey footprint with wells used for velocity model and interpretation.

Application No. 45079, 45080, 46169, 46170, and 46171

Table NAR-1—Wells used for velocity model and interpretation.

UWI	Common Well Name	UWI	Common Well Name	UWI	Common Well Name
17063201660000	AVERETT ELTON N_1	17063200460000	CZ /F/_1	17063201150000	HUTCHINSON H L_1
17063201620000	BALLARD F_1	17063201260000	CZ 25-6_1	17063201440000	HUTCHINSON_1
17063201950000	BANKSTON H R_1	17063201050000	CZ 29-16 SS_1	17063202930000	KINCHEN 25-4; LVG WX 1 RA SU_1
17063203100000	BLACKWELL DAVID 39; WX RB SUA_1	17063201130000	CZ 34-6 /EL/_1	17063202410000	KINCHEN ESTATE_1
17063200300000	CARAWAY H E_1	17091200870000	DENKMANN ASSOCIATES /A/_1	17063200760000	LANAT CORP_1
17063200510000	CARAWAY H E_2	17091200880000	DENKMANN ASSOCIATES /B/_1	17063203220000	NETTLES E G ET AL 39_1
17063202340000	CAVENHAM FOREST IND INC_1	17063202440000	DENKMANN ASSOCIATES /D/_1	17063880420000	PELICAN MLR_4
17063202640000	CAVENHAM FOREST IND_1	17063202700000	DENKMANN ASSOCIATES A_1	17063201910000	PONDER MINERAL CO_1
17091200740000	CAVENHAM FOREST INDUSTRIES_1	17063201380000	DENKMANN ASSOCIATES_1	17063201770000	REX TIMBER INC 10-4_1
17091200780000	CAVENHAM FOREST INDUSTRIES_2	17063202490000	DENKMANN ASSOCIATES_1	17091201060000	ROUCHON WALTER; L TUSC RA SUG_2
17063202540000	CAVENHAM RESOURCES 20_1	17063202630000	DENKMANN ASSOCIATES_1	17091200930000	ROUCHON WALTER_1
17063202810000	CEFALU & COMPANY INC_1	17091200790000	DENKMANN ASSOCIATES_1	17091201010000	ROUCHON_1
17063202580000	CLEMONS LORENAP_1	17091201000000	DENKMANN ASSOCIATES_1	17063201190000	SMITH C HEIRS 30-10_1
17091200810000	CLEMONS_1	17091201100000	DENKMANN ASSOCIATES_1	17063202550000	SMITH J W ETAL 5-8_1
17091200990000	CLEMONS_2	17091200800000	DENKMANN ASSOCIATES_2	17063202860000	SMITH J W_1
17091201040000	CLEMONS_3	17091200980000	DENKMANN ASSOCIATES_4	17063200410000	SMITH W H_1
17063201610000	CROWN ZELLERBACH 27-7_1	17091201630000	DENKMANN CC; MIO RA SUA_1	17063203120000	STARNS 38; WX RB SUB_1
17063202140000	CROWN ZELLERBACH 41-2_1	17091201640000	DENKMANN LNR; MIO RA SUA_1	17063201460000	WATTS 26-8_1
17063200370000	CROWN ZELLERBACH B_1	17063203250000	DENKMANN SLNR; MIO RA SUA_1	17091200560000	WEST M R_1
17063201790000	CROWN ZELLERBACH CORP_2	17063202900000	DUFFY 30-13; LVG WX 1 RA SU_1	17063203230000	WEYERHAEUSER 14_001
17063200380000	CROWN ZELLERBACH D_1	17063200350000	EASTERLY L P_1	17063203070000	WEYERHAEUSER 18; VUA_1
17063200630000	CROWN ZELLERBACH F_2	17063200700000	EASTERLY R D_1	17063203090000	WEYERHAEUSER 19; VUB_1
17063200630001	CROWN ZELLERBACH F_3	17091201230000	FOREST C IND; BVDC L TUSC RA SU_5	17091201460000	WEYERHAEUSER 57; VUB_3-ALT
17063200150000	CROWN ZELLERBACH_1	17091201030000	FOREST IND_4	17063203110000	WEYERHAEUSER 9; VUC_1
17063200260000	CROWN ZELLERBACH_1	17063200490000	GEORGIA PACIFIC_1	17063202750000	WEYERHAEUSER_1
17063201630000	CROWN ZELLERBACH_1B	17063201220000	HAUBERG J H ETAL_1	17063202790000	WEYERHAEUSER_1
17063200170000	CROWN ZELLERBACH_2	17063202290000	HENDERSON G LVG WX 1 RA SU_1	17063202820000	WEYERHAEUSER_3
17063200340000	CROWN ZELLERBACH_2	17063203130000	HUTCHINSON FLOYD; WX RC SUA_1	17063202870000	WHIDDON DEBRA B_1
17063201450000	CROWN ZELLERBACH_2	17063200280000	HUTCHINSON H L_1	17063201920000	WHITNEY ALT 15600 TUSC RA SUA_1

Table NAR-2—3D Seismic Acquisition Parameters.

Acquisition Parameter:	
Recording Template	45° Diagonal; 8 N-S receiver lines of 216 stations with SW-NE source lines
Receiver Geometry	220 ft stations at 1,760 ft lines (72.0/mi ²)
Source Geometry	220 ft stations at 1,980 ft lines (64.0/mi ²)
Trace Density	110,592/mi ²
Energy Source Type	Shot hole
Energy Source Details	5.5 lb GeoPrime buried at 80 ft
Recording Instruments	I/O RSR
Nominal Far Offset	24,644 ft (23,650 ft inline × 6,930 ft crossline)
Nominal Fold	48
Acquisition Bin Size	110 ft × 110 ft
Record Length	8 sec at 2 ms sample rate
Acquisition Period	March to April 2009

Application No. 45079, 45080, 46169, 46170, and 46171

Table NAR-3—3D Seismic Processing Flow.

• Reformat
• Geometry and QC
• Refraction Analysis
• Replacement Statics
• Exponential Scaling
• Trace Edits
• Geophone Inversion
• Anti-Aliasing Anti Leakage Fourier Filter (ALFF)
• Q Compensation
• Frequency Dependent Noise Attenuation (FDNA) – Shots
• Median Guided Ground Roll Removal – Offline
• SCAMPS
• Surface Consistent 5 Component Deconvolution – Supergroup Arrays
• First Break Equalization
• Residual ALFF
• Residual FDNA – Shots
• SCAMPS
• TPXY Noise Attenuation
• SCAMPS
• Trace Gather
• Processing Datum
• Preliminary Velocity Analysis
• Surface Consistent Statics
• Final Velocity Analysis
• Phase Stability Compensation
• Tau-P Multiple Attenuation
• 5D MWNI Interpolation - OVT
• SSA (Cadzow) Noise Reduction on OVT Gathers
• Final Mute
• Pre-Stack Azimuthal Kirchhoff Time Migration
• RMO Velocities
• Residual Trim Statics
• Stack
• Frequency Equalization
• SSA (Cadzow) Noise Reduction on Stack
• Final Time Variant Filter and Scaling

Application No. 45079, 45080, 46169, 46170, and 46171

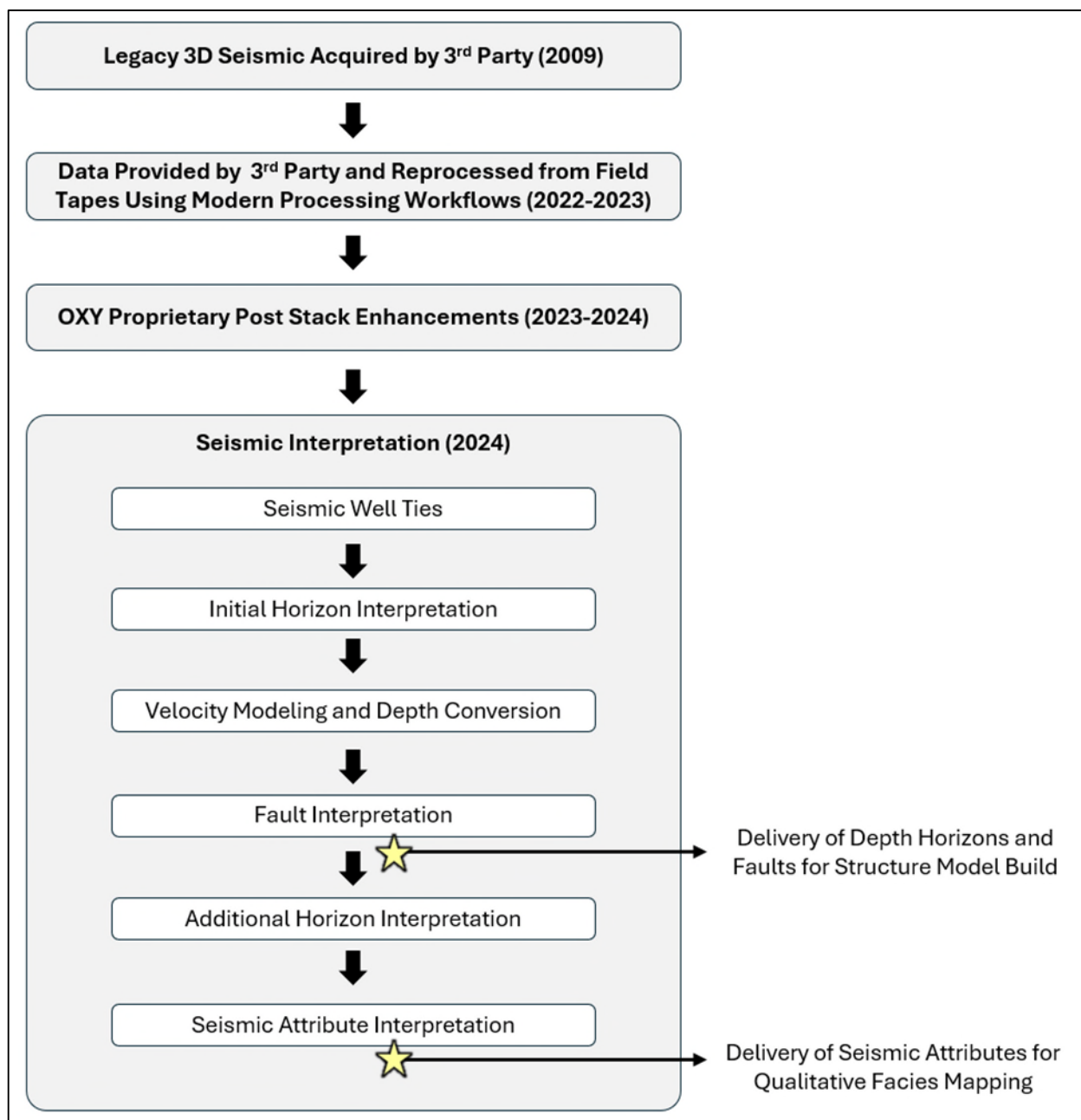


Figure NAR-20—Workflow diagram of geophysical input generation.

Application No. 45079, 45080, 46169, 46170, and 46171

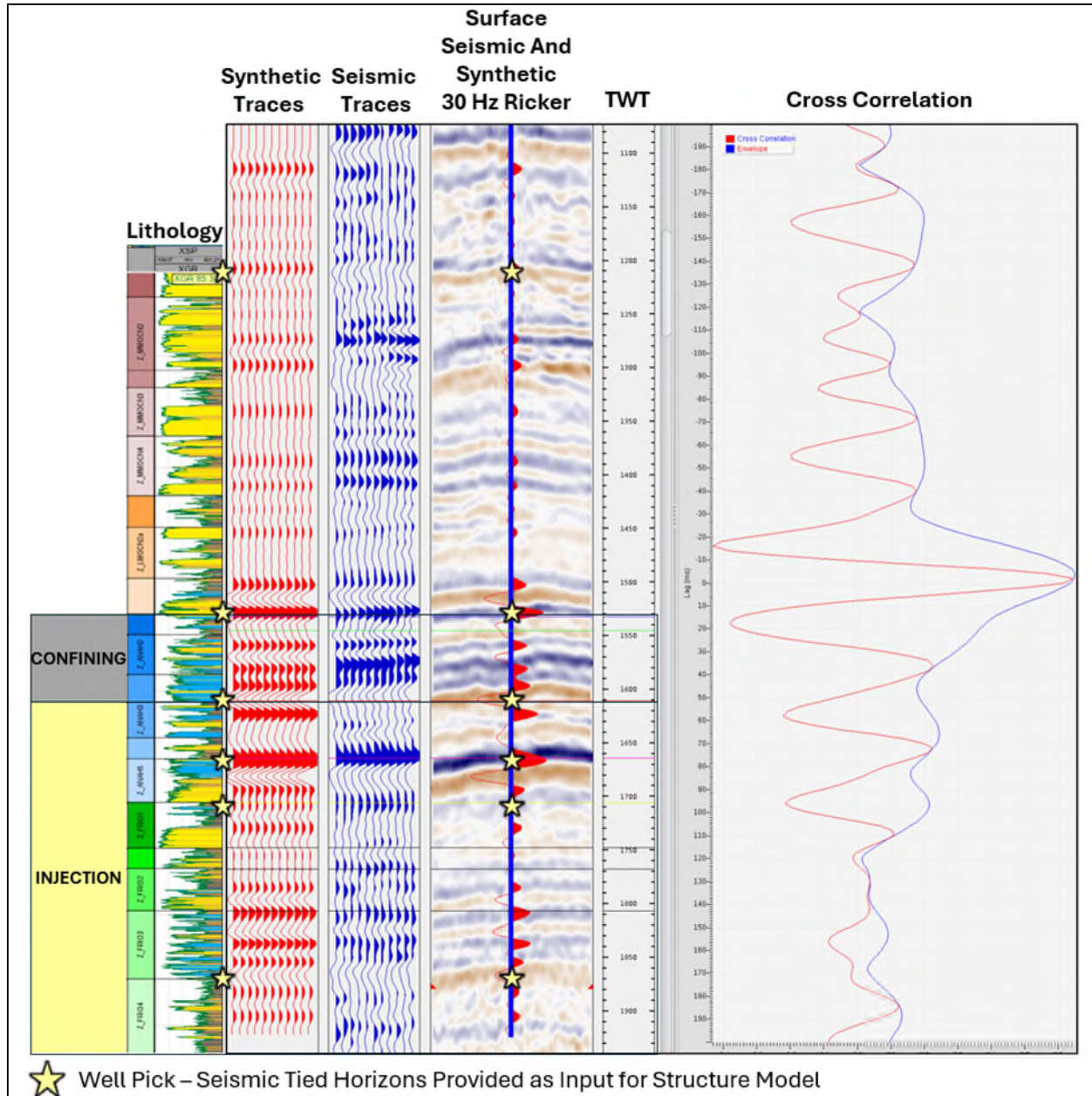


Figure NAR-21—Seismic well tie for Pelican MLR 004 stratigraphic test well.

Application No. 45079, 45080, 46169, 46170, and 46171

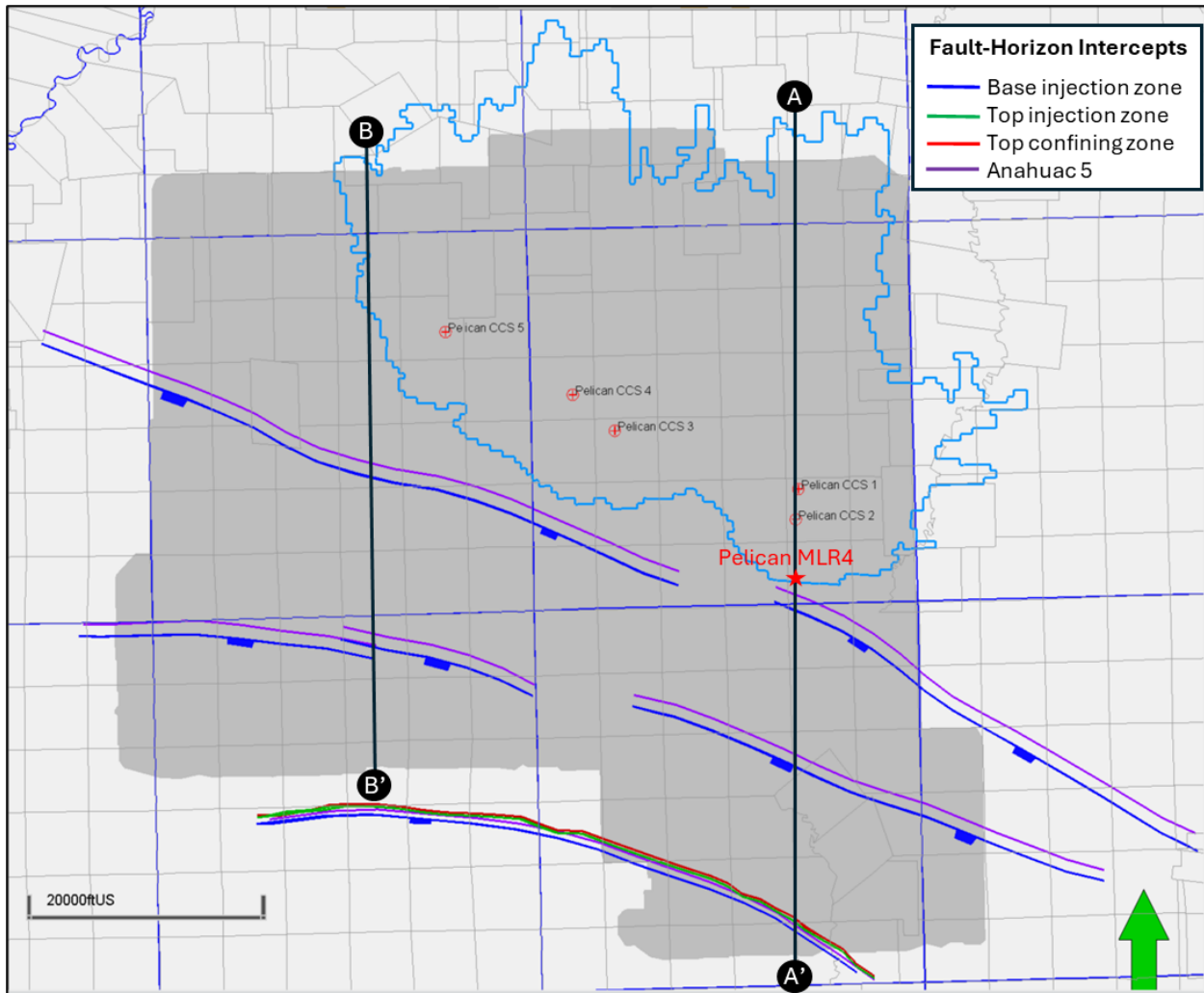


Figure NAR-22—3D seismic survey footprint (dark gray polygon) with seismic interpreted fault intercepts at key horizon levels and the maximum plume at 100 years. Section lines labeled A-A' and B-B' shown in Figure NAR-23 and Figure NAR-24.

Application No. 45079, 45080, 46169, 46170, and 46171

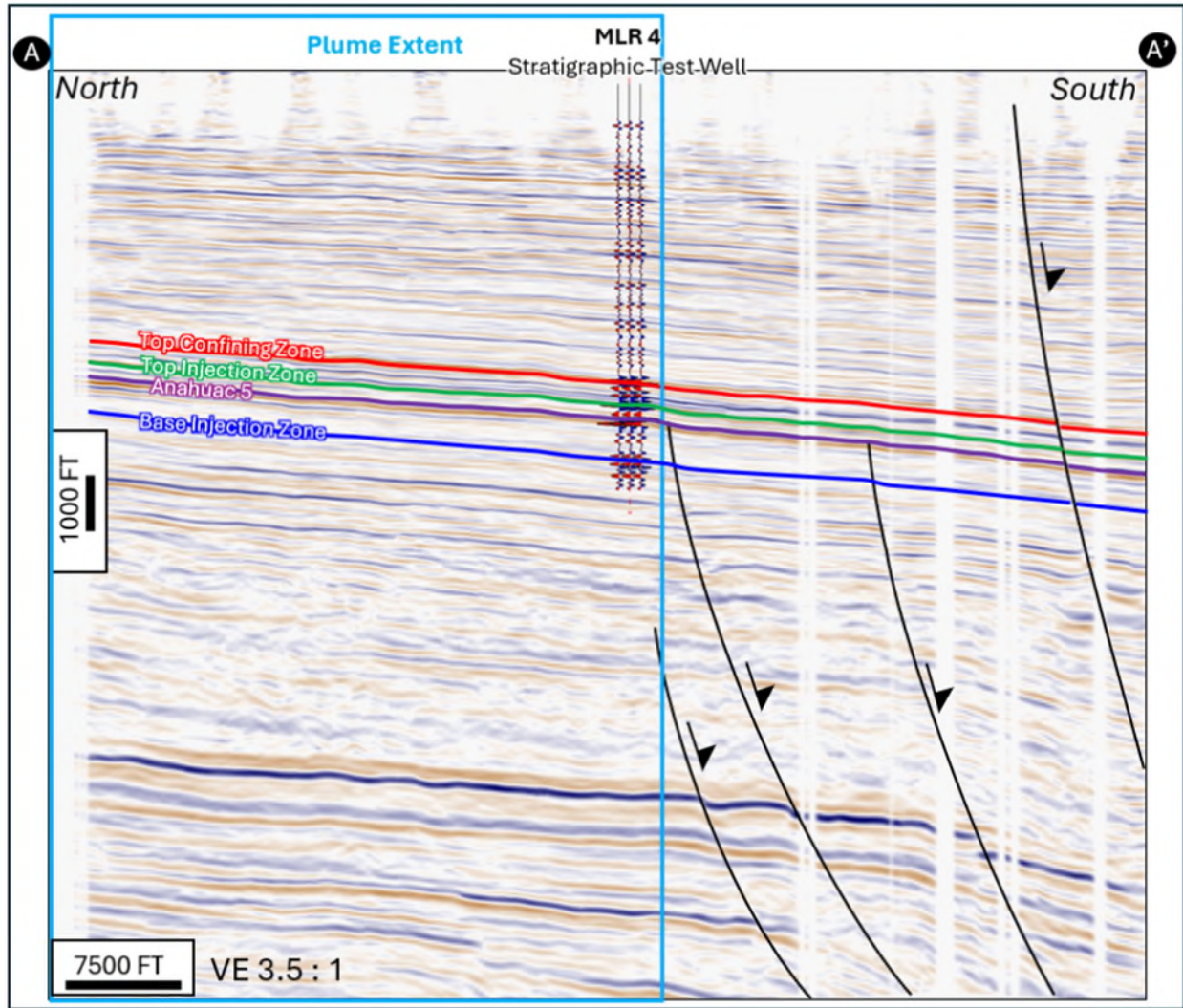


Figure NAR-23—Key dip line from 3D seismic through eastern project area showing storage complex, Pelican MLR 004 Stratigraphic Test Well, and faulting to the south of the CO₂ plume.

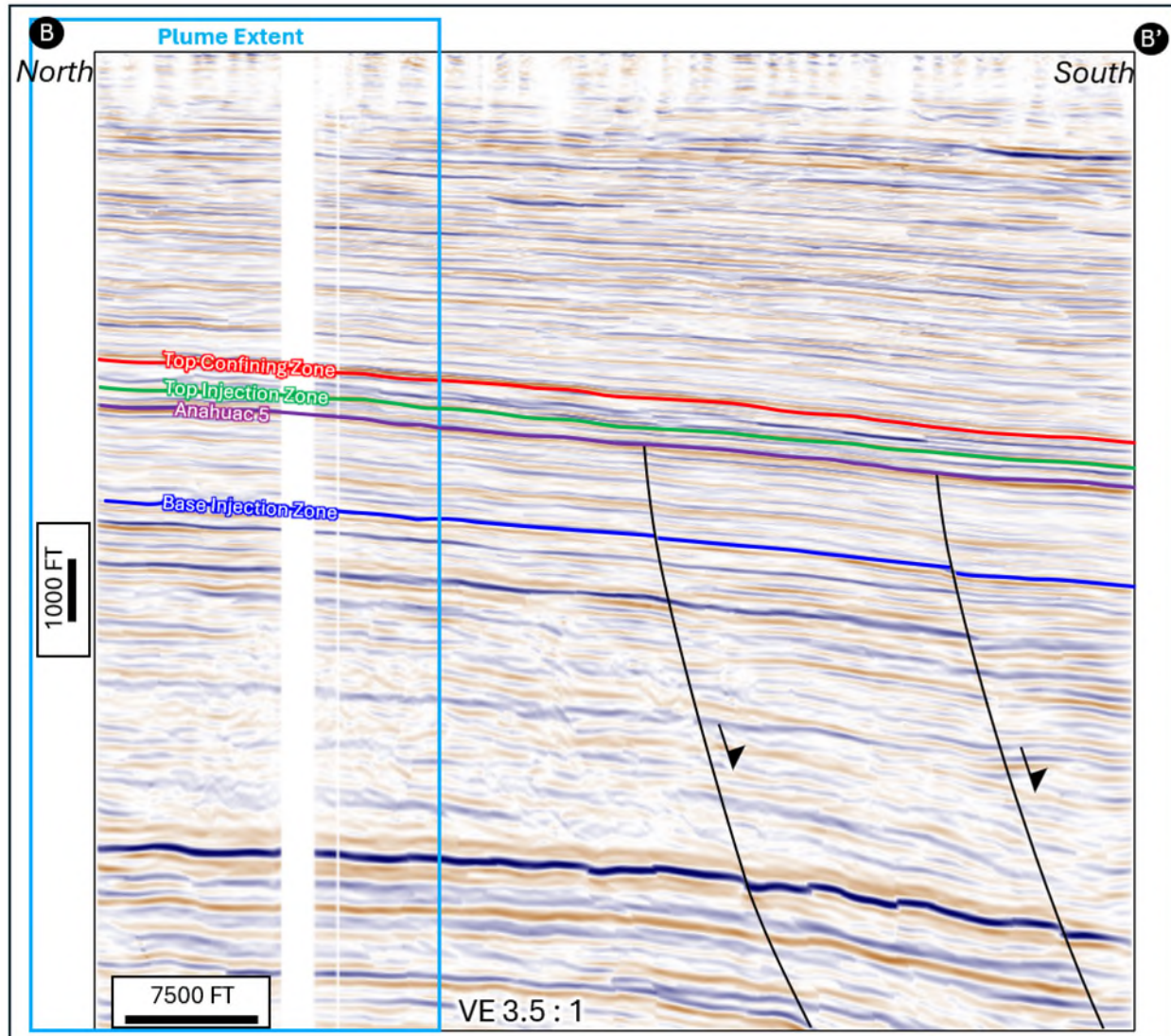


Figure NAR-24—Key dip line from 3D seismic through western project area showing storage complex.

2.3.3 Fault Reactivation Analysis

Table NAR-4 summarizes data gathered during well completion and testing of the MLR 004 stratigraphic well. Six tests were performed, including two formation integrity tests (FIT), three step rate tests (SRT), and one leakoff test (LOT). Details of the testing procedures and results are included in Project Narrative - Appendix D. The three SRTs performed in FRIO2, FRIO1, and ANAH4_SS did not indicate clear changes in pressure versus rate, so the formation was not fractured during the SRT. The values in the table indicate the ratio of maximum bottomhole pressure (BHP) reached (at the maximum rate) to the measured depth, so fracture gradients are higher than the tabulated values. During the LOT in the LMOCN1_SH, a fracture was created. The fracture gradient is captured in Table NAR-4.

Table NAR-4—Results of step rate, formation integrity, and leakoff tests on Pelican MLR 004 Well.

Zone Name	Test Interval (ft MD)	Test Method	Kh (mD-ft)	Skin	Pi (psia)	Fracture Gradient / Max Observed Gradient (psi/ft)	Max Inj. Rate (BWPD)
LMOCN1_SH	5,300-5,303	LOT				0.79	
ANAH1_SH	5,814-5,817	FIT				>0.91	
ANAH4_SS	6,327-6,355; 6,475-6,535	SRT/Falloff	176,932	76.6	2,930	>0.75	51,278
FRIO1	6,698-6,788	SRT/Falloff	806,161	25.6	3,046	>0.48	51,984
FRIO2	7,014-7,070	SRT/Falloff	647,820	289	3,185	>0.67	51,840
FRIO4	7,425-7,428	FIT				>0.89	

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 with the potential of inducing 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 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 preexisting faults and/or reactivation of the basement fault systems, producing induced seismicity. This analysis only includes the risk of failure initiation of the matrix.

Mohr-Coulomb analysis considers the ratio of shear stress (τ) and effective normal stress, defined as the total normal stress minus the pore pressure ($\sigma'_n = \sigma_n - P_p$), acting on a plane in any 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:

$$\mu = \tau / \sigma'_n \quad \mu = \tau / \sigma'_n \dots \dots \dots \text{(Equation 3)}$$

Using the Mohr-Coulomb failure criterion, failure is defined as conditions where the ratio of shear stress to effective normal stress acts on an optimally oriented plane and exceeds the failure limit defined by the relationship:

$$\tau = \mu \sigma + S_o \quad \dots \dots \dots \text{(Equation 4)}$$

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

$$UCS = 2S_o(\sqrt{\mu^2 + 1} + \mu) \quad \dots \dots \dots \text{(Equation 5)}$$

Application No. 45079, 45080, 46169, 46170, and 46171

Figure NAR-25 shows a graphical representation of the linear Mohr-Coulomb failure criterion. The state of stress is represented by the Mohr circle defined by the maximum (σ'_1) and minimum (σ'_3) effective principal stresses. Any plane orientation is defined along the boundary of the circle by an angle of 2β from σ'_1 to σ'_3 , where β is the angle between the σ'_1 and the normal plane. In Figure NAR-25, the red semicircle represents the original state of effective stress. In the case of CO_2 injection into the reservoir, pore pressure is estimated to increase while decreasing the magnitude of the effective principal stresses and moving the circle to the left on the x-axis. The failure limit shown is the sloped solid black line defined by Equation 4. The dashed line would represent the failure limit of a preexisting fault with comparatively little friction. While the friction of faults is not zero, it is small compared to the friction required to initiate 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.

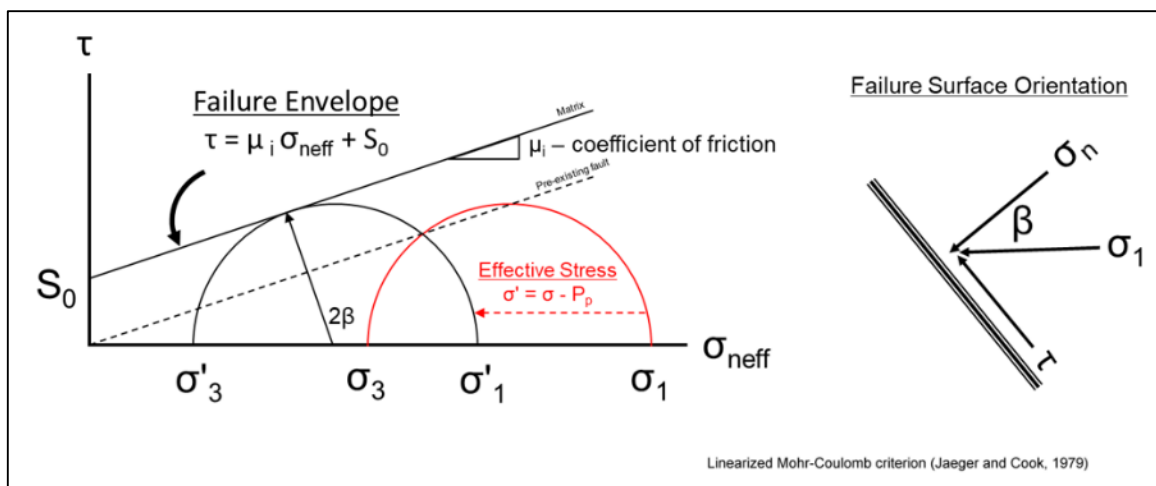


Figure NAR-25—Mohr-Coulomb Failure Criterion from Jaeger and Cook, 1979)

The Oxy Best Practices workflow has been 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 an estimate of effective stress such that:

$$P_p = \sigma_v - \sigma'_v \dots\dots\dots(\text{Equation 6})$$

An assumption was made that the pore pressure is hydrostatic in the shallow formations and follows the hydrostatic trend until the velocity data indicates that pressure deviates from that trend. Figure NAR-26 shows that this approach indicates formation pressure is hydrostatic until below the Frio formation in the Pelican MLR 004 well.

The state of stress was modeled using the isotropic poroelastic uniaxial strain model shown in Equation 7.

$$\sigma_3 = \frac{\nu}{1-\nu}(\sigma_v - \alpha P_p) + \alpha P_p \dots\dots\dots(\text{Equation 7})$$

where:

σ_3 = least horizontal principal stress

ν = Poisson's ratio

σ_v = maximum principal stress

α = Biot's coefficient

P_p = pore pressure

The overburden stress, S_v , is represented by the black pressure profile in Figure NAR-26 and is calculated by integrating the density data from surface utilizing bulk density log data and estimating a density trend from the top of data to the surface. The minimum principal stress (S_{hmin}) is calibrated to the closure pressure interpreted from leakoff tests and step rate tests in the Pelican MLR 004 well (see Table NAR-4). According to the geological interpretation, the area is in a normal faulting failure condition. Fault mechanics require the overburden to be the maximum principal stress, making S_{Hmax} the intermediate stress. The structural interpretation is the strongest constraint for the magnitude of S_{Hmax} . At shallow depths, the stress magnitudes converge such that all three principal stresses are close to equal. At the depth of the Frio in the Pelican Sequestration Project site, stress magnitudes are close to equal such that the state of stress is almost isotropic. The model results indicate enough stress differential to comply with the normal faulting interpretation.

Application No. 45079, 45080, 46169, 46170, and 46171

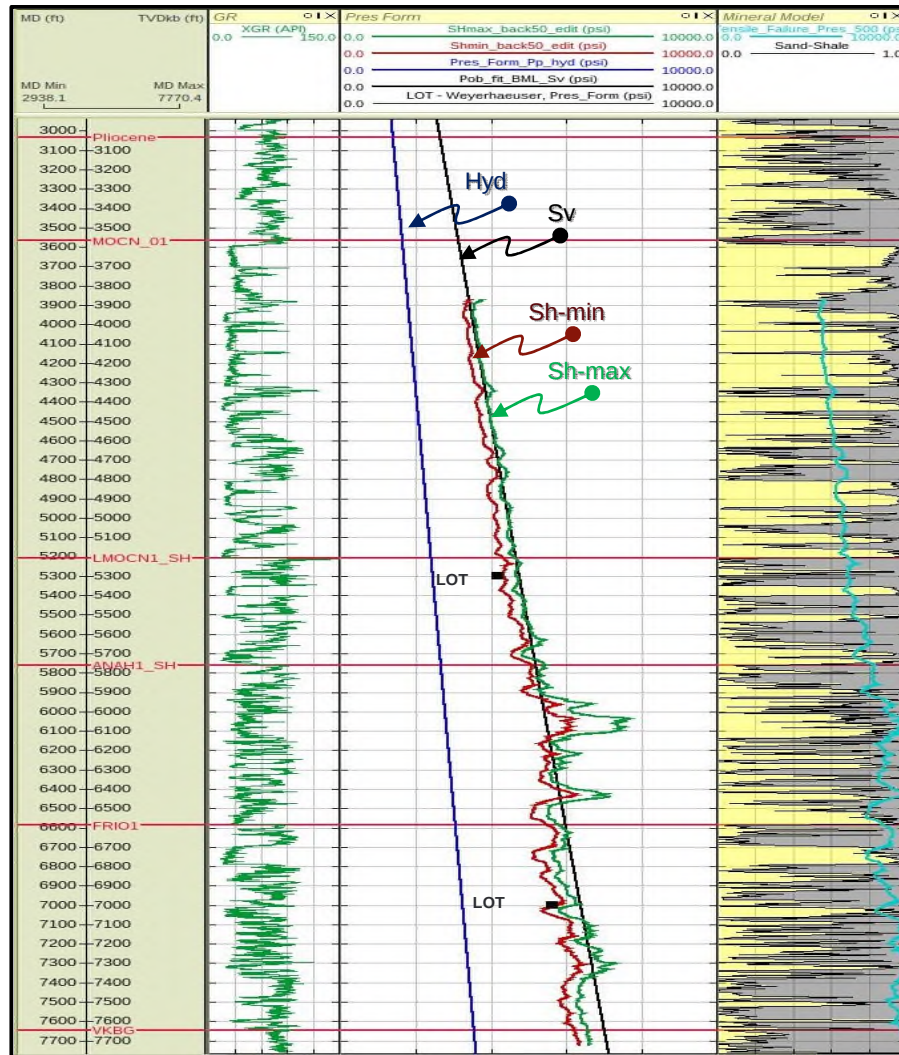


Figure NAR-26— Stress model (middle track) for the Pelican MLR 004 well.

Critical stress analysis (CSA) includes the assessment of shear or tensile failure of the formation. Failure is the generalized term used for the generation of induced fractures at the borehole wall or in the formation away from the borehole wall and/or reactivation of existing faults or fractures in the formation. The magnitude of stresses (as described above) is a necessary input for CSA, alongside the orientation of principal stresses and the orientation of existing and potential faults or fractures. In addition to stress characterization, rock and fault/fracture properties are necessary, such as compressive and tensile strength of the matrix formation, internal friction coefficients of the matrix and cohesion, and friction of fault and fracture surfaces. The rock properties are unconstrained in this analysis, so reasonable and customary assumptions are used for friction coefficient (0.6) for rock matrix and faults/fractures. The rationale and strategy for estimating rock and fault cohesion is described below.

CSA is the analysis of the potential for tensile or shear failure under those conditions and, in this case, a change in pressure from injection. Generally, it can be assumed that the minimum principal stress (S_{hmin}) is a good representation of the propagation pressure for optimally oriented existing

Application No. 45079, 45080, 46169, 46170, and 46171

faults or fractures. S_{hmin} is likely less than the propagation pressure and is less than the breakdown pressure required to generate new induced tensile fractures at the wellbore wall or in the matrix of the formation. As a result, the use of S_{hmin} as the upper limit of injection pressure incorporates a safety factor and is a conservative approach to assessing the risk of failure during injection and migration.

Table NAR-4 summarizes the data gathered from the formation integrity tests (FIT), step rate tests (SRT), and leakoff tests (LOT) on the MLR 004 stratigraphic well. The three SRT performed in FRIO2, FRIO1, and ANAH4_SS did not indicate clear changes in pressure versus rate, so the formation was not fractured during the SRT. The values in the table are the ratio of maximum BHP reached (at the maximum rate) to the measured depth, so the actual fracture gradients should be higher than the tabulated values. Three leakoff tests were conducted, with the recorded ranges of fracture gradients shown in Table NAR-4. In project simulations, the use of 0.8 psi/ft is supported by the geomechanical analyses described above. The maximum BHP was assigned based on a very conservative 0.56 psi/ft fracture gradient. Under this conservative BHP constraint, the model shows the well target rate of 2 MMTPA CO₂ per injector to be achievable.

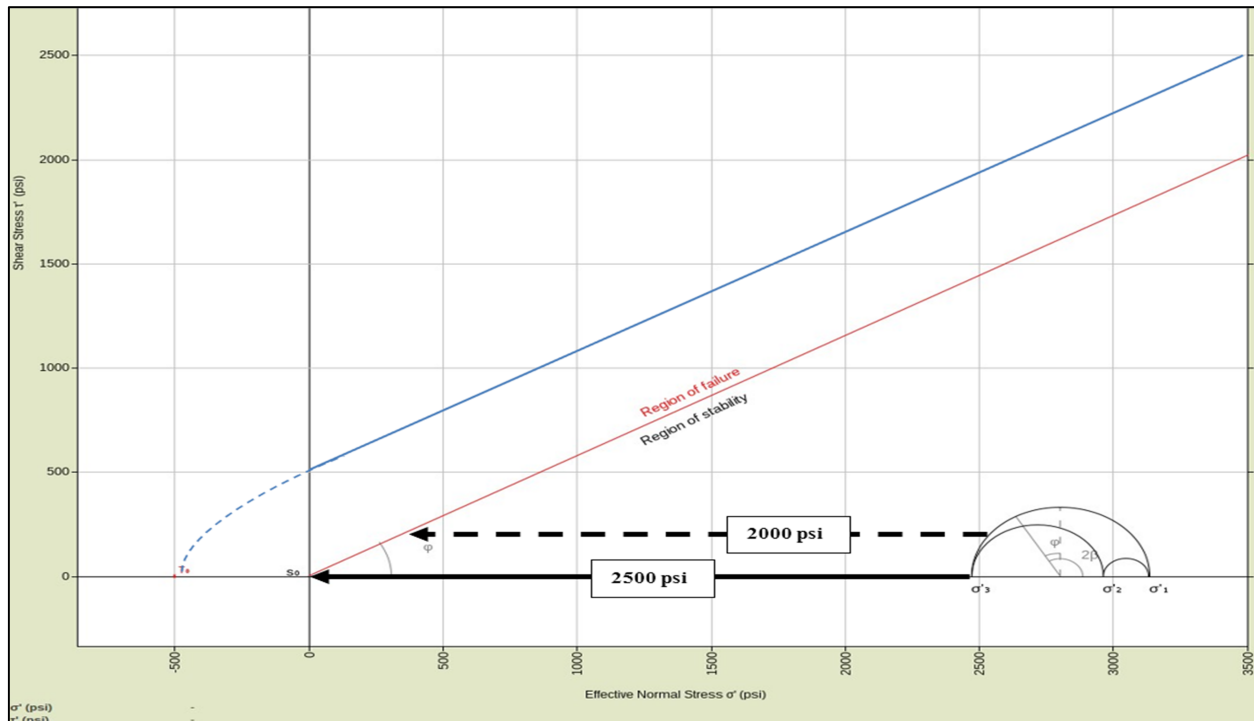


Figure NAR-27—Mohr circle depiction of the stress state with two failure limits shown: a failure limit with 0 psi cohesion (red line), a typical value to represent the strength of existing faults/fractures and a failure limit with a modest estimate of matrix shear strength and tensile strength (blue lines).

Figure NAR-27 shows the stress state in a Mohr circle graphical depiction. Two failure limits are shown in a similar fashion as Figure NAR-25. The red limit represents a material (rock or fault/fracture) with zero cohesive or tensile strength (the failure limit is typically used to represent existing faults and fractures). The blue limit represents a material with a modest cohesive strength (500 psi) and a reasonable tensile strength (500 psi). Since the material properties are

unconstrained, these scenarios are used to represent conservative estimates to show the highest risk conditions for injection.

Using the red failure limit as the conservative case, the analysis indicates that the Frio formation is not currently in a critical state of failure. It also shows that a 2,500-psi increase in pore pressure is required to move the Mohr circle into tensile stress (solid black arrow). In the event that optimally oriented, unobserved faults or fractures exist, a 2,000-psi pressure increase would be required to reactivate those structures in shear failure (dashed black arrow). Any consideration of tensile strength or cohesive shear strength of unobserved faults, fractures, or the matrix show that the pressures required to cause tensile or shear failure increase. The highest risk scenario is that unobserved, optimally oriented faults or fractures exist, and those experience a pore pressure increase of 2,000 psi from injection and are reactivated in shear failure.

2.4 Injection and Confining Zone Details

Within the Pelican Sequestration Hub AOI, 24 tops were interpreted within a well database including 82 wells (see Project Narrative - Appendix C). Petrophysical analysis assessed the injection and confining zone properties of the entire dataset. The distribution of the dataset was sufficient to characterize formation mineralogy and properties (Figure NAR-11). Details of the data used (e.g., well log, core) and analysis are documented in section 2.5.1 Petrophysics of this document. Additionally, 12 seismic horizons were interpreted on one 3D survey (Yuma Livingston Survey), which covers about 75% of the AOI. Details on the quality of the seismic cube and synthetic well ties are documented in section 2.3.1 Local Structure and Faulting. The well log and seismic interpretation were combined to build a Petrel-based geological model, which generated final structural, thickness, and property maps to understand formation depths, areal extent, and thickness of the injection and confining zones. Details on the geological model are described in section 2.0 Computational Modeling Approach of the Area of Review and Corrective Action Plan document. Table NAR-5 summarizes the average depths, thickness (gross and net), porosity, permeability, and orientation of the various zones in the storage complex zones. The areal extent of these properties will be discussed later in this section.

Application No. 45079, 45080, 46169, 46170, and 46171

Table NAR-5—Summary of subsurface characteristics.

Formation	Well Tops	Model Zone Name	Seismic Horizon Name	Storage Element	Top Avg. TVDss (ft.)	Base TVDss (ft.)	Avg. Dip (deg)	Avg. Dip Azi (deg)	Gross TVT (ft.)	NetRes TVT (ft)	Net Res PorT (frac.)	Net Res Kair (md)	NonNet TVT (ft)	NonNet PorT (frac.)	NonNet Kair (md)	FM GROSS TVT (Ft)	
Upper Miocene	UMOCN1			Fresh Aquifer	-2188	-2987	1	186	651	n/a	n/a	n/a	n/a	n/a	n/a	3103	
	UMOCN2				-2987	-3395	1	179	345	n/a	n/a	n/a	n/a	n/a	n/a		
	USDW_BASE				-3103				n/a	n/a	n/a	n/a	n/a	n/a			
	UMOCN3			Saline Aquifer	-3395	-3876	1	184	467	n/a	n/a	n/a	n/a	n/a	n/a	2312	
Middle Miocene	MMOCN1	(Top of Geological Model)			Additional Storage Potential	-3876	-3,964	1	184	459	n/a	n/a	n/a	n/a	n/a		n/a
	MMOCN2	MM2	YUMALIV_PEL24_MMOCN2			-3,964	-4,309	1.4	190	339	n/a	n/a	n/a	n/a	n/a		n/a
	MMOCN3	MM3	YUMALIV_PEL24_MMOCN3			-4,309	-4,459	1.5	191	146	n/a	n/a	n/a	n/a	n/a		n/a
	MMOCN4	MM4	YUMALIV_PEL24_MMOCN4	-4,459		-4,778	1.4	190	312	n/a	n/a	n/a	n/a	n/a	n/a		
Lower Miocene	LMOCN1	LM1	YUMALIV_PEL24_LMOCN1	Additional Storage Potential	-4,778	-4,976	1.4	189	193	n/a	n/a	n/a	n/a	n/a	n/a	387	
	LMOCN2a	LM2a			-4,976	-5,210	1.5	189	228	n/a	n/a	n/a	n/a	n/a	n/a		
	LMOCN3	LM3			-5,210	-5,382	1.5	190	168	n/a	n/a	n/a	n/a	n/a	n/a		
Upper Anahuac	ANAH1	A1	YUMALIV_PEL24_ANAH1	Oligocene Storage Complex	Top Confining	-5,382	-5,496	1.5	190	111	n/a	n/a	n/a	78	0.253	0.9	451
	ANAH2	A2	YUMALIV_PEL24_ANAH2			-5,496	-5,671	1.5	190	170	n/a	n/a	n/a	111	0.210	0.8	
	HET_LM2	HL2	YUMALIV_PEL24_HETLM2			-5,671	-5,780	1.5	192	106	n/a	n/a	n/a	98	0.125	0.3	
Lower Anahuac	ANAH3	A3			Oligocene Storage	-5,780	-5,985	1.5	192	200	53	0.307	2,773	n/a	n/a	n/a	1157
	ANAH4	A4	YUMALIV_PEL24_ANAH4			-5,985	-6,091	1.5	193	103	54	0.323	3,667	n/a	n/a	n/a	
	ANAH5	A5				-6,091	-6,243	1.6	193	148	50	0.311	3,262	n/a	n/a	n/a	
Frio	FRIO1	F1a				-6,243	-6,496	1.5	193	248	85	0.316	2,845	n/a	n/a	n/a	113
		F1b	YUMALIV_PEL24_FRIO1B			-6,496	-6,583	1.5	192	84	19	0.307	2,082	n/a	n/a	n/a	
	FRIO2	F2	YUMALIV_PEL24_FRIO2		-6,583	-6,778	1.5	193	191	68	0.317	2,773	n/a	n/a	n/a		
	FRIO3	F3	YUMALIV_PEL24_FRIO3		-6,778	-7,090	1.6	194	303	83	0.307	2,688	n/a	n/a	n/a		
	FRIO4	F4	YUMALIV_PEL24_FRIO4		-7,090	-7,433	1.7	194	331	69	0.307	1,955	n/a	n/a	n/a		
Vicksburg	VKBG	V			Basal Confining	-7,433	-7,548	1.8	194	113	n/a	n/a	n/a	112	0.281	1.1	113

The Oligocene Storage Complex consists of a basal confining unit, internal storage units, and top confining units. The basal confining unit is comprised of the laterally extensive marine shales of the Vicksburg Formation. The internal storage units are delta and near shore sands in the Frio and Lower Anahuac Formations. The top confining units are shelf limestones and marine shales in the Upper Anahuac Formation.

An in-depth study was undertaken to understand the stratigraphic framework and depositional environment of the Oligocene Storage Complex, focusing on the injection and confining zones. Log facies analysis and rock characterization from core and cuttings define the depositional setting of the Oligocene Storage Complex as a shallow marine environment. Biostratigraphic analysis integrated with regional studies (Galloway, 2009) and Eustasy Curve (Haq et al., 1987) establishes that the units in the Oligocene Storage Complex are regressing from a highstand during the Vicksburg to a lowstand at the top of the Lower Anahuac, then back to a highstand during the deposition of the Upper Anahuac. A closer look at the log stacking patterns reveals episodic progradation and retrogradation cycles.

2.4.1 Stratigraphic Framework Workflow

Many data types were interrogated and compiled to build a stratigraphic framework and understand the depositional environment of the Oligocene Storage Complex. These data and analysis include: 1) biostratigraphy analysis of the Pelican MLR 004 stratigraphic well, 2) regional study and log facies characterization, 3) log interpretation and log signature characterization, 4) modern analog investigation, 5) seismic characteristics from seismic sections and attribute maps, and 6) gross thickness trends from interpreted surfaces. This was conducted to characterize unit heterogeneity for representation in the geological model. The workflow is presented here using the FRIO1 unit as the example.

2.4.1.1 Biostratigraphic Analysis

Foraminiferal and calcareous nannofossils were studied on 66 cutting samples from 300 ft to 7,950 ft MD in the Pelican MLR 004 stratigraphic well. Biostratigraphic control identified the age of formations, major time boundaries, unconformities, maximum flood events, and depositional environments. Correlation with Eustasy and Gulf of America Depositional Episode Cycles helped define times of relevant sediment input.

Results of the paleontological study were integrated with log characteristics to define 24 tops to build the stratigraphic framework of the Oligocene and Miocene for the Pelican Sequestration Hub (Figure NAR-28).

Application No. 45079, 45080, 46169, 46170, and 46171

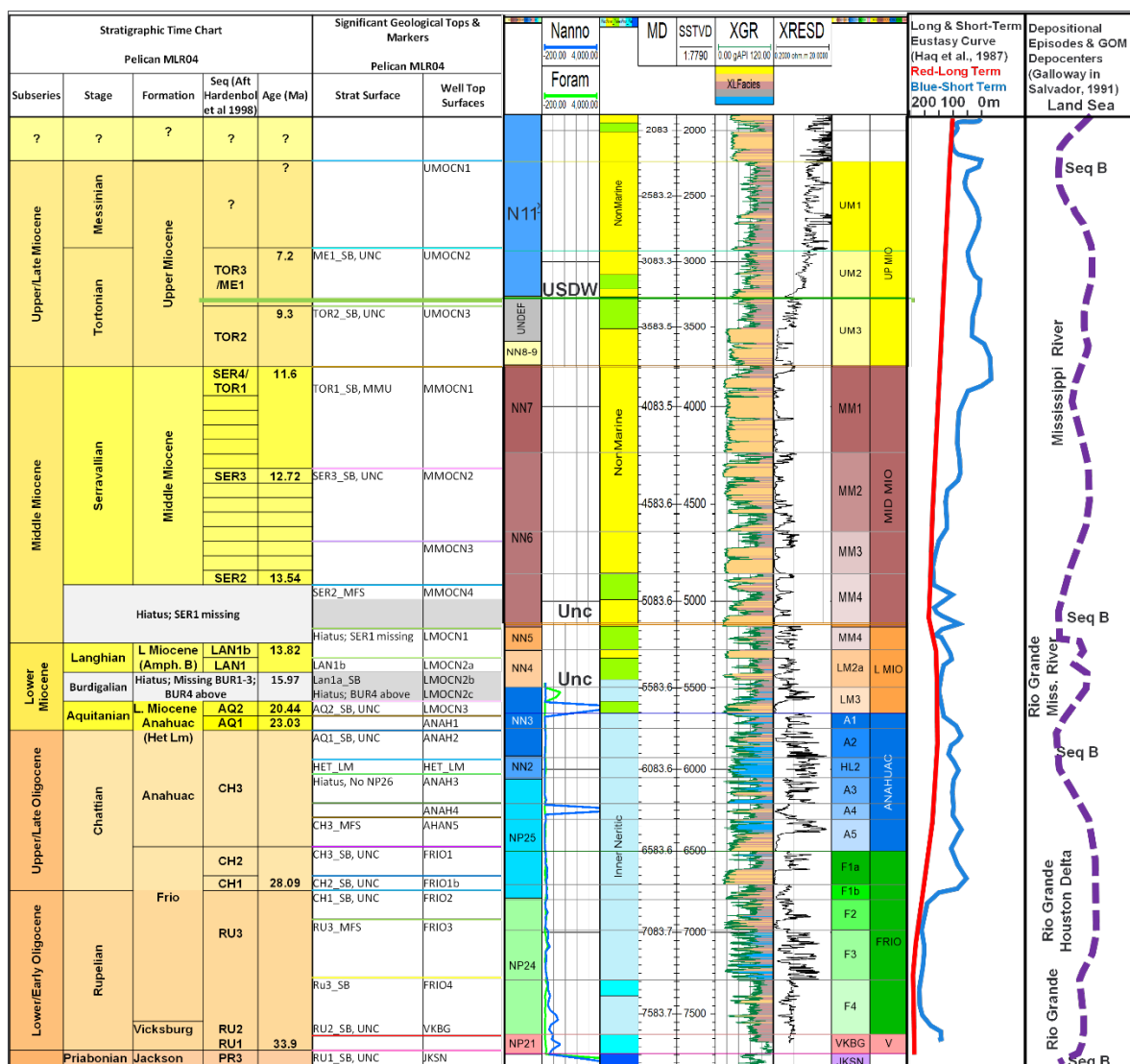


Figure NAR-28—Pelican Sequestration Hub stratigraphic framework defined by integrating log characteristics with results of a foraminiferal and calcareous nannofossil study for the Pelican MLR 004 stratigraphic test well.

Paleontology of the Oligocene Storage Complex represents shallow marine, middle-to-inner neritic environment (Figure NAR-29). Nanno and Foram fossils in the Jackson were deposited in a deep marine environment (Outer Neritic). Environments for the Vicksburg up to today become progressively shallower with episodic pulses of deepening. The Vicksburg to Anahuac sediments are interpreted to be deposited in an open shelf, pro-delta, and delta front environment.

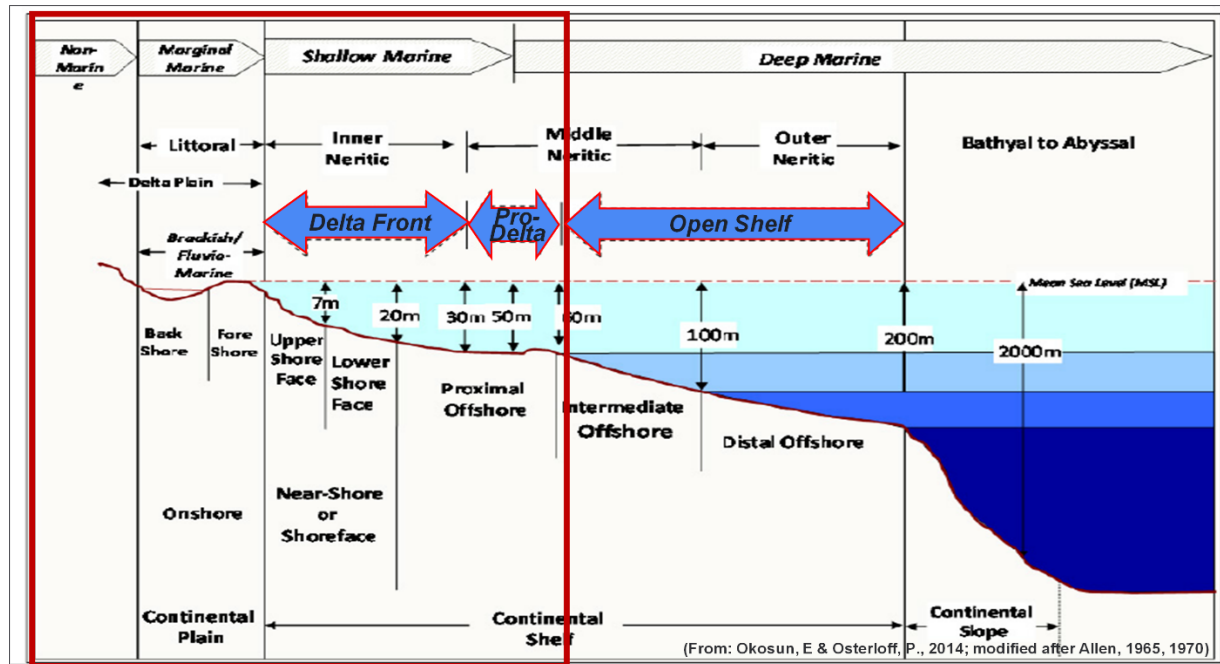


Figure NAR-29—Marginal to shallow marine depiction of depositional settings (modified after Okosun, 2014). The red box approximates the environments defined by the biostratigraphy study.

2.4.1.2 Regional Study and Log Facies Characterization

Literature review and regional studies provided the structural and depositional context to build local depositional understanding and mapping. From the Galloway, 2000 and GBDS-PHASE 14 study (<https://ig.utexas.edu/>) shown in Figure NAR-30a/b, the AOI (purple polygon) is defined to be in a shallow marine shore zone to carbonate shelf environment of deposition. This is consistent with the Biostratigraphy study (Figure NAR-28). A couple key observations near the AOI to point out are 1) the presence of a “submarine canyon, megaslide, or embayment” about 10-miles south to act as a downdip sediment pathway; 2) the shift of the Louisiana delta westward and shoreward during the late Frio, which would reduce delta sediment input and allow for greater tidal effects on sedimentation and cleaner water for carbonate growth; and 3) the presence of isolated “carbonate reefs/platforms” along the *Heterostegina* shelf, which could act as a backstop for onlapping sedimentation.

Application No. 45079, 45080, 46169, 46170, and 46171

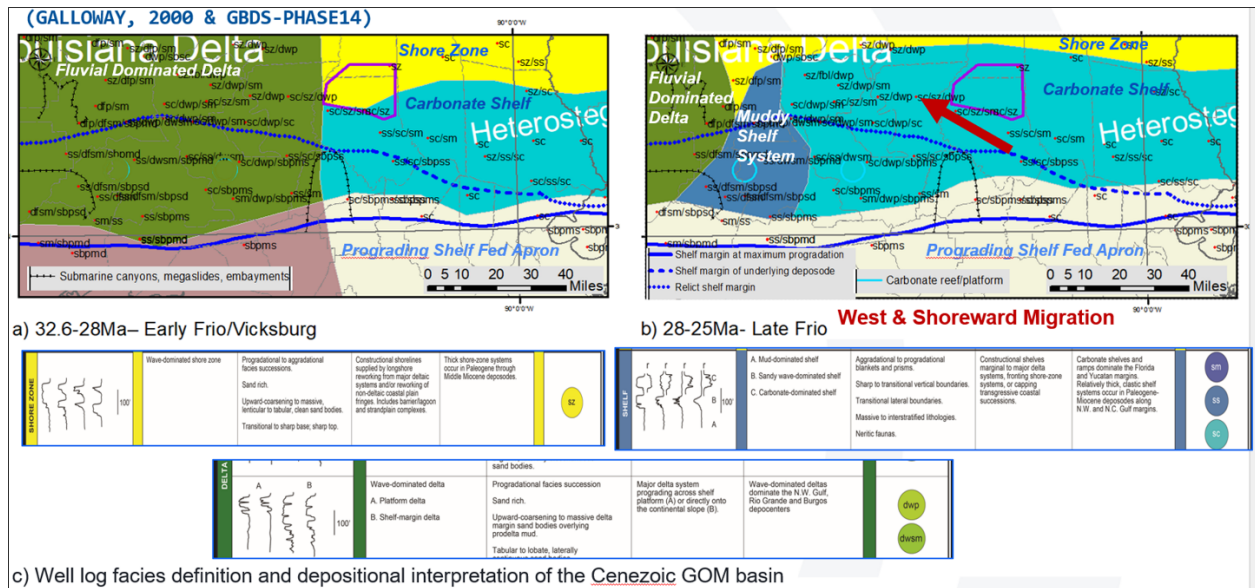


Figure NAR-30—GBDS Regional Study control used to calibrate local geology.

To understand site-specific geology into the regional context, log stacking patterns were interpreted based on the GBDS-Phase 14 log facies definition and depositional interpretation (Figure NAR-30c). This study defines sedimentation at the Pelican Sequestration Hub in the Oligocene as being deposited in a shore zone, shelf, and deltaic type environment. This is supported by the biostratigraphy as mentioned above. Scheihing & Atkinson, 1992, Lucia, 1992, and Boyd et al., 2006, were additional resources that provided additional understanding of expected log characteristics to help decipher spatial distribution of log variability. Figure NAR-31 highlights: a) major shoreface clastic depositional trends and associated log characteristics used to guide log stacking patterns, b) cartoon illustrating coastal depositional environments based on sediment input and power of waves and currents, c) example log stacking patterns from the Pelican Sequestration Hub illustrating local log characteristics.

The log stacking patterns of the clastic sediments (sands/silts/muds) were integrated with the results of the biostratigraphy study and stratigraphic framework. The patterns show a cyclical nature of sand/silt, mudstone, and limestone (Figure NAR-28 and Figure NAR-31). The log patterns of the sand and silt beds show 1) blocky, fining upward, 2) bell-shaped, fining upward, 3) funnel-shaped coarsening upward, and 4) serrated, mud-rich thin beds. These log patterns are diagnostic of distributary channels, bars, delta front, and pro-delta environments.

Application No. 45079, 45080, 46169, 46170, and 46171

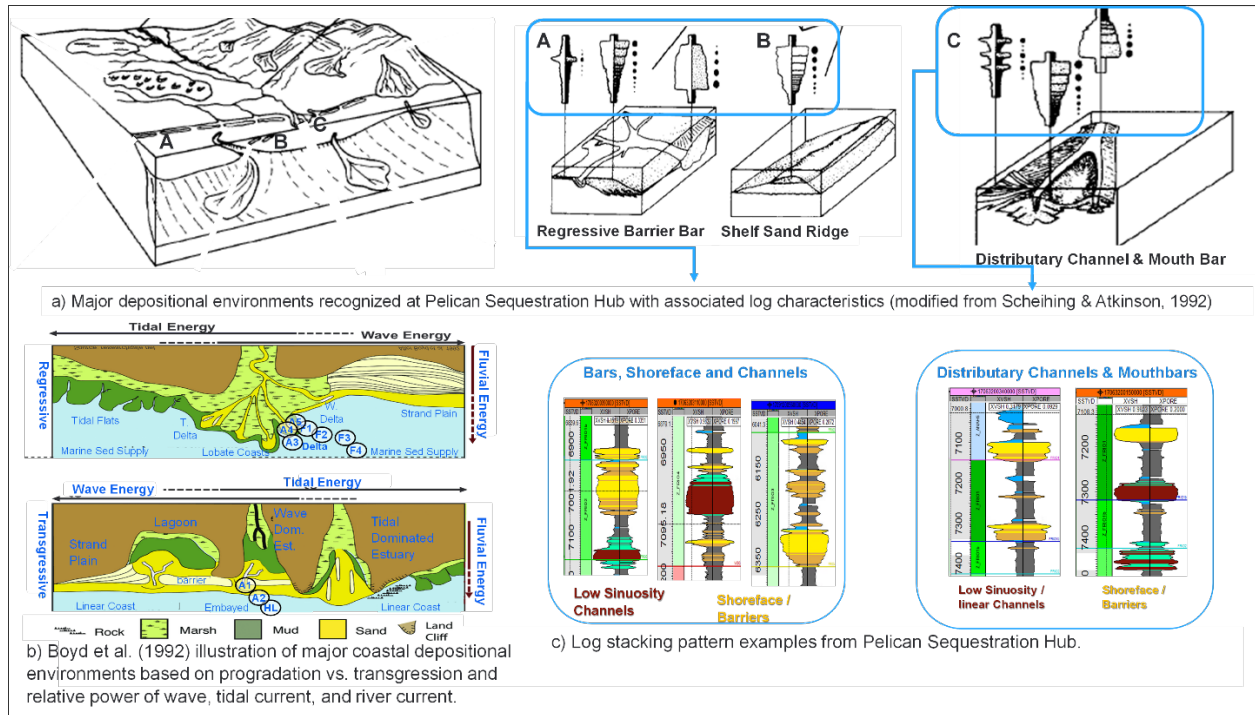


Figure NAR-31— Clastic depositional models and representative log facies characterization used to interpret EOD maps.

2.4.1.3 Well log interpretation and log signature characterization

Once the tops for the stratigraphic framework were defined based on sequence boundaries, unconformities, and Figure NAR-32). This interpretation was tied into the Yuma 3D seismic cube using synthetic well ties described in section 2.3.1 Local Structure and Faulting of this document. Figure NAR-32 is a NW-SE cross section through the acreage showing the correction.

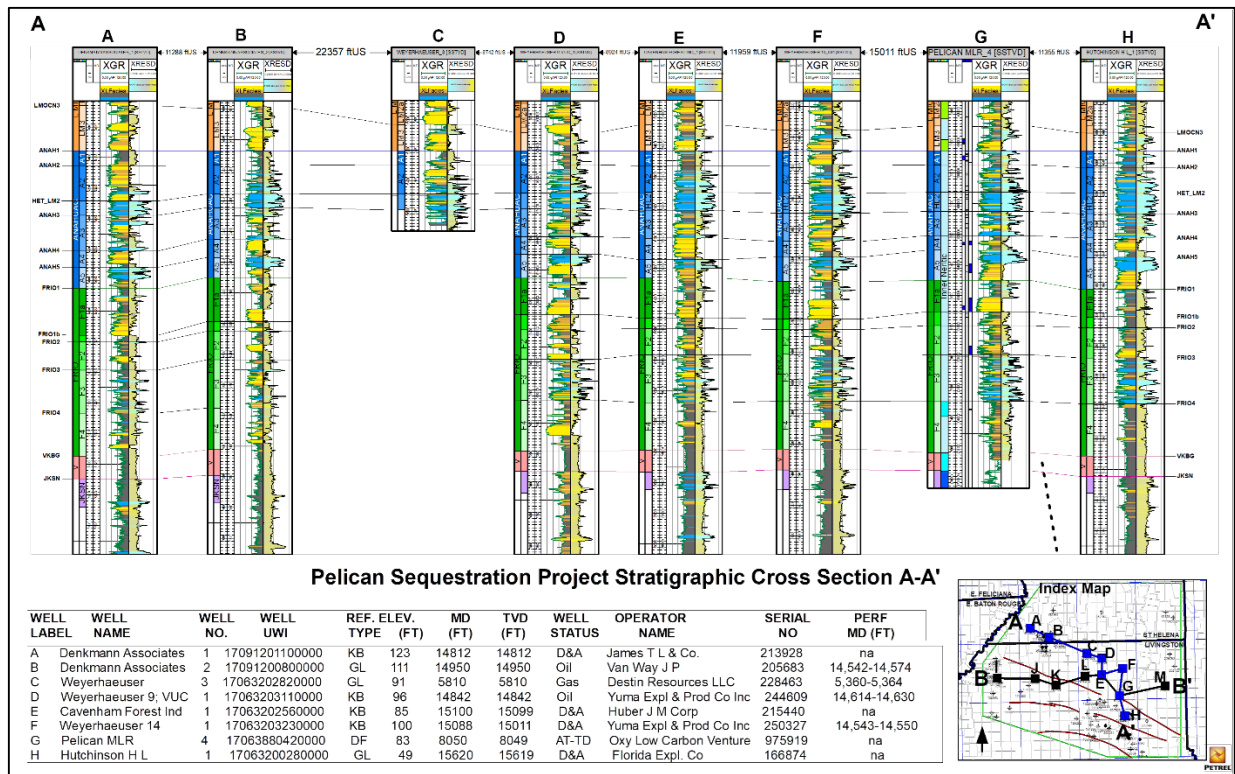


Figure NAR-32—Cross section across geomodel area illustrating stratigraphic framework interpretation for the Oligocene Storage Complex. This cross section is flattened on the top of the Anahuac Formation.

Within the Oligocene Storage Complex, 11 units were defined (VKBG, FRIO4, FRIO3, FRIO2, FRIO1(a/b), ANAH5, ANAH4, ANAH3, HETLM, ANAH2, and ANAH1). Log signature maps were generated for the storage and upper confining units, an example is shown in Figure NAR-33. These maps provide a spatial understanding of how lithology characteristics are changing. Understanding of the system and orientation of deposition were key inputs into the geological model for a correct representation of heterogeneity and more accurate understanding of CO₂ flow dynamics. Figure NAR-33 is a log signature map of the FRIO1 units and demonstrates how comprehensive this technique is for understanding and mapping unit changes across the AOI. Three distinct areas stand out on this map: 1) block/fining upward sand packages toward the northern part of the AOI; 2) mud-rich, thin beds toward the south of the AOI; and 3) a mud-rich, thin-bed cluster of wells at the western edge of the AOI.

Application No. 45079, 45080, 46169, 46170, and 46171

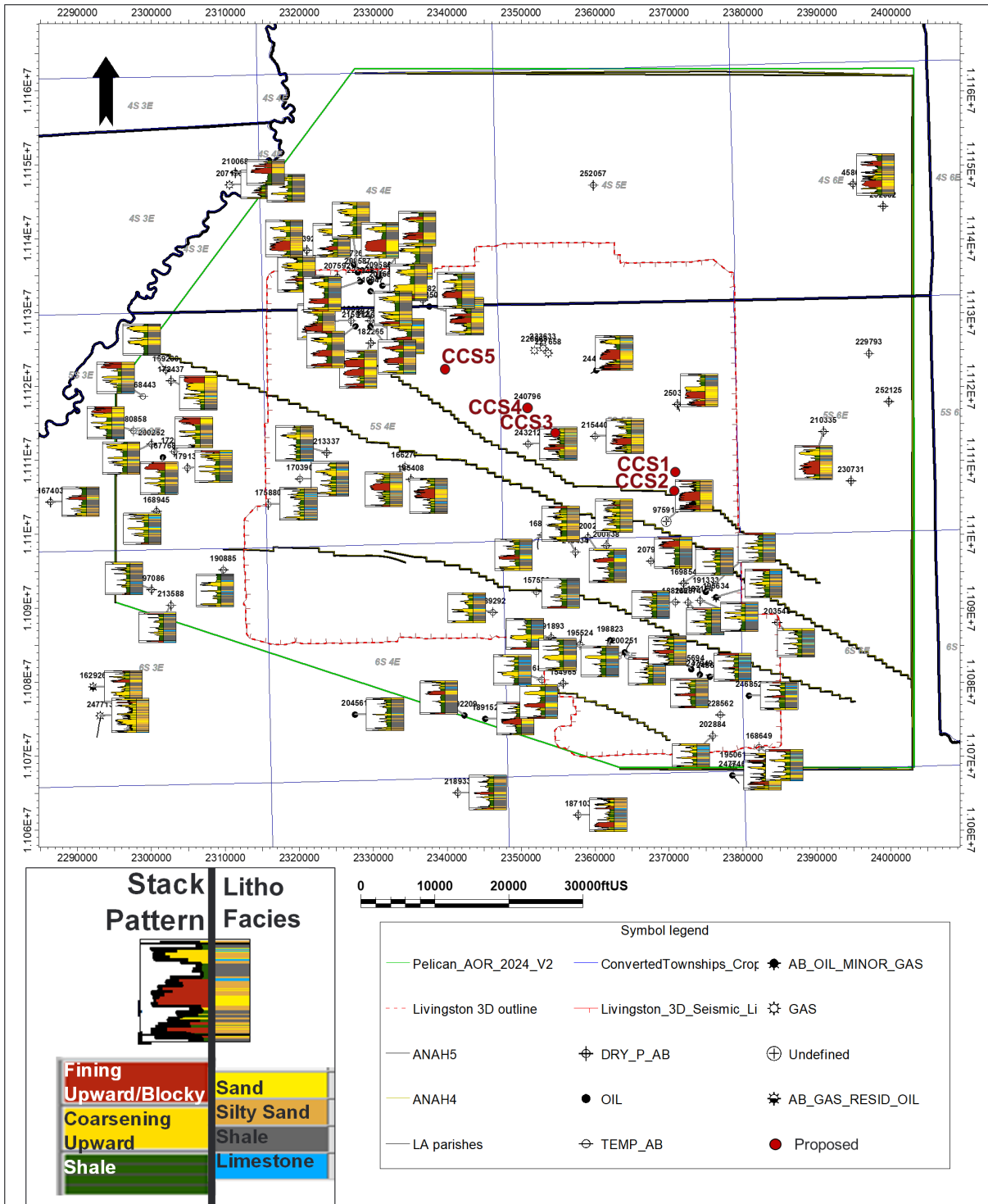


Figure NAR-33—Log signature map example of the FRIO1 units. The left track shows the log stacking pattern (fining upward/blocky, coarsening upward, shale) and the right track shows petrophysical facies (sand, silty sand, shale, limestone).

Application No. 45079, 45080, 46169, 46170, and 46171

2.4.1.5 Gross Thickness Trends

True vertical thickness (TVT) maps were interrogated and then integrated with seismic and log characteristics to refine boundaries between depositional environments. In the FRIO1a example (Figure NAR-34), a distinct change northeast to southwest aligns with the seismic amplitude extraction. It also mimics trends of sand-to-shale percentages seen in the well log characteristics. There is also a N-S thickness trend observed in the south-central part of the map and another thickness pattern in the SE-corner. These trends have a slightly higher sand percent with fining upward/blocky characteristics.

Application No. 45079, 45080, 46169, 46170, and 46171

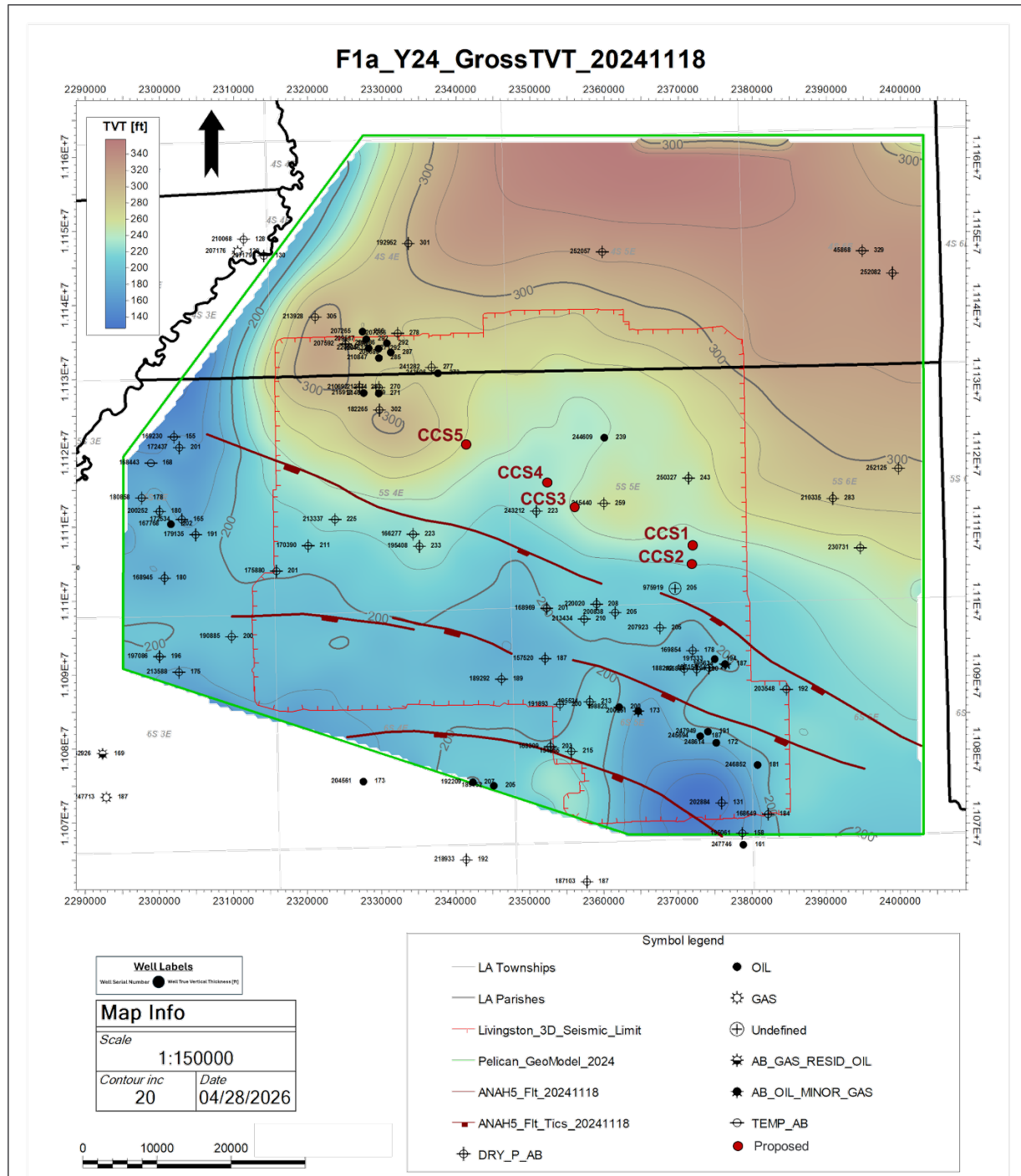


Figure NAR-34—FRIO1a gross thickness map generated from well and seismic interpretation. These maps helped define depositional trends and were used to refine polygons representing different EODS. The Red polylines represent changes in thickness trends that align with seismic attributes and log character.

Application No. 45079, 45080, 46169, 46170, and 46171

2.4.2 Final Integrated Sequence Strat and Environment of Deposition Interpretation

The final step in the workflow integrates regional and stratigraphic frameworks with the observations from the log signatures, seismic extractions, and TVT trend maps to understand the depositional environment and sediment transport orientation (Figure NAR-35).

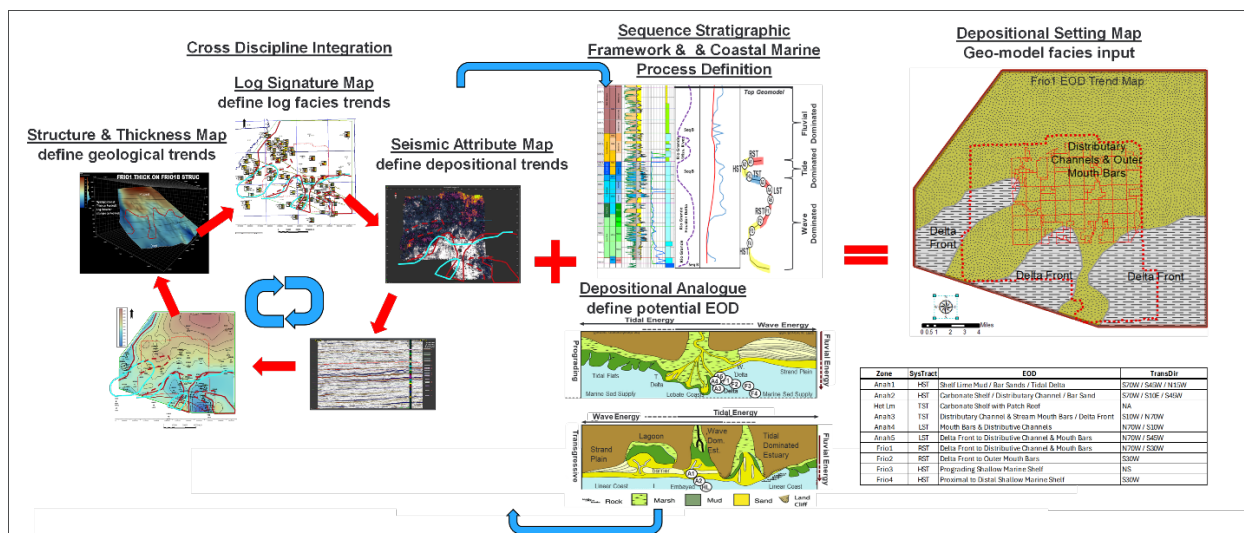


Figure NAR-35—Workflow summary.

The FRIO1a example has two distinct log signatures that are interpreted as 1) distributary channels with mouth bars and 2) delta front (Figure NAR-36). Thickness and seismic observations help refine the boundaries of these depositional environment polygons and the orientation of sedimentation is defined as approximately S30W with a shoreline of approximately N70W.

Application No. 45079, 45080, 46169, 46170, and 46171

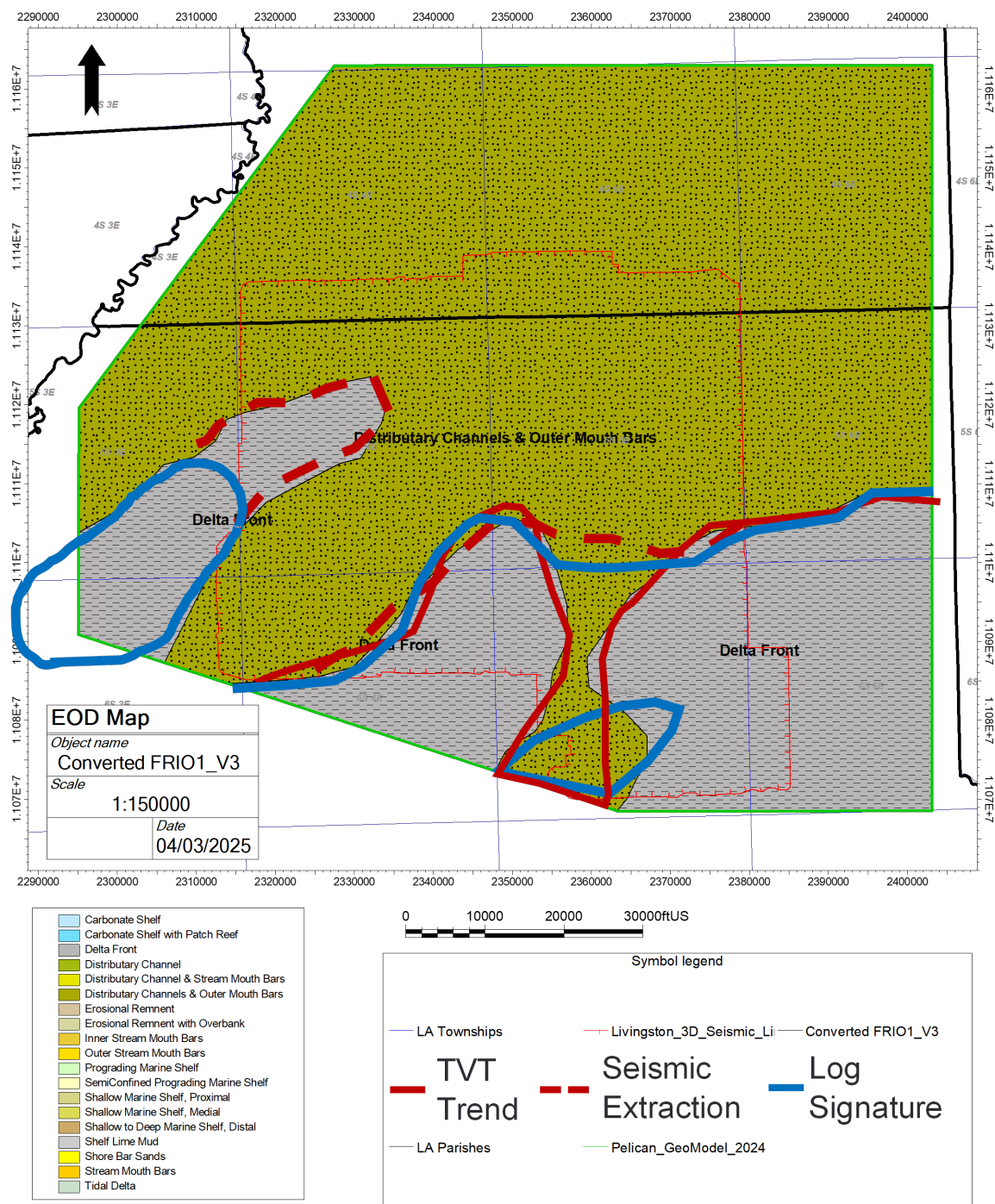


Figure NAR-36—FRI01 Environment of Deposition (EOD) map was compiled using the stratigraphic framework and regional understanding. Two distinct EODs are interpreted: distributary channel with outer mouth bars and delta front. This final map was refined using seismic, well log stacking patterns, and thickness trends.

Sequence Stratigraphic Framework

Frio and Anahuac Storage EOD, Facies Trend Maps

Anahuac Confining EOD, Facies Trend Maps

2.4.3 Basal Confining Units – Vicksburg Formation

The Vicksburg formation is a marine shale. Due to wellbore instability, only wellbore cuttings were extracted from the unit. Well log characteristics, paleo data, and cutting analysis show the Vicksburg to have very similar depositional environment and shale properties as the shales in the FRIO4 (Figure NAR-38). The cutting analysis defines both units as 100% non-calcareous, silica-rich shales. X-ray fluorescence (XRF) data show both units to have a 70% silica (SiO₂) makeup with aluminum oxide (Al₂O₃) as the dominant secondary element (approximately 10%). When solved for mineralogy, both units show a total framework makeup of mostly silicates and clays. This supports the conclusion that the shales in the FRIO4 can be used as an analog to measure the integrity of the Vicksburg.

Application No. 45079, 45080, 46169, 46170, and 46171

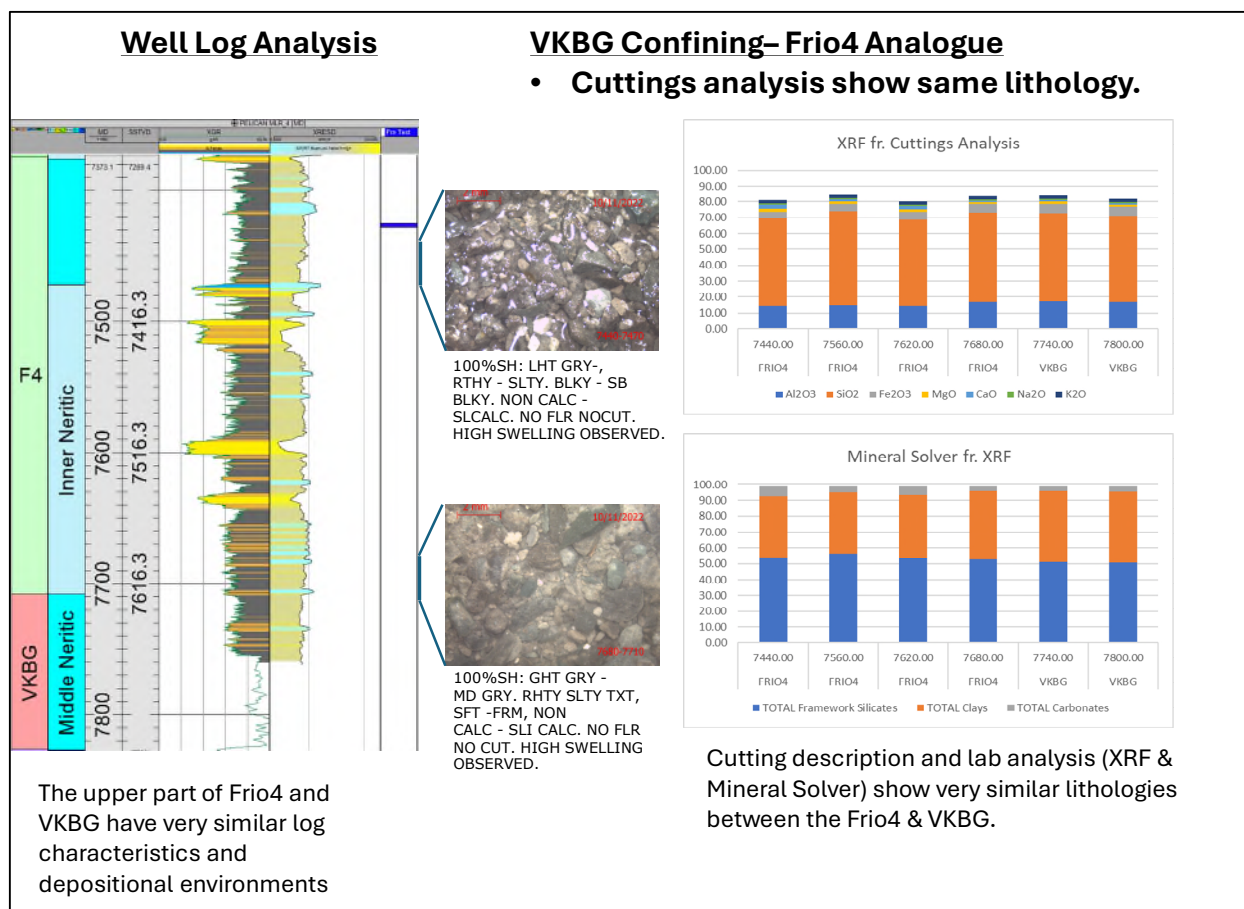


Figure NAR-38—Vicksburg basal confining unit properties.

2.4.4 Storage Units – Frio Formation and Lower Anahuac Sands

The Frio formation and lower Anahuac are the storage units and are interpreted to be inner neritic (shallow marine) delta front sands and shales. The Frio formation offers a series of cyclical, prograding marine shelf sands with heterogeneity observed between the wells.

Internally, some sands are thin and blanketing while others have channelized geometries for good heterogeneity and directional migration. The Lower Anahuac sands are delta and reworked bar sands that are less heterogeneous between the wells and offer excellent injectivity. The observed heterogeneity and sedimentary depositional geometries are expected to create a complex flow pattern for the injected CO₂.

The top of the Frio and lower Anahuac (ANAH3, ANAH4, FRIO1, FRIO2, FRIO3, and FRIO4) storage unit ranges from about 4,550 – 7,075 ft TVDSS (average 5,780 ft). The average gross thickness of the Frio and lower Anahuac (ANAH3, ANAH4, FRIO1, FRIO2, FRIO3, and FRIO4) storage units are 1,608 ft. (Table NAR-5). The units extend over the whole AOI and consist of unconsolidated sands and silt, mudstones, and mud-rich limestones. Average porosity and permeability values calculated with petrophysical techniques (See 2.5.1 Petrophysics of this report) are listed in Table NAR-6.

Application No. 45079, 45080, 46169, 46170, and 46171

Table NAR-6—Average petrophysical properties for the Oligocene storage units in the Lower Anahuac and Frio formations

Formation	Well Tops	Model Zone Name	Pelican MLR 004 Petrophysical Averages		
			Por (%)	Perm (mD)	Net Res. (ft)
Lower Anahuac	ANAH3	A3	22	3,532	37
	ANAH4	A4	30	1,769	40
	ANAH5	A5	30	2,560	119
Frio	FRIO1	F1a	30	4,109	106
	FRIO1b	F1b	29	2,307	55
	FRIO2	F2	27	2,210	98
	FRIO3	F3	27	1,319	83
	FRIO4	F4	24	1,436	103

2.4.3.1 Frio Formation

The average top of the Frio formation is 6,243 ft TVDSS, (Table NAR-5). Its average gross thickness is 1,157 ft TVT. Within the unit, an average net storage of about 325 ft is interbedded with limestone and shales (Figure NAR-39).

Storage within the Frio is variable. Heterogeneity within the Frio is captured in the environment of deposition (EOD) maps (Figure NAR-40). The four units in the Frio represent a progradational sequence of shelf clastics. Both FRIO4 and FRIO3 zones are the end of the highstand systems tract seen during the Vicksburg deposition. The FRIO4 is the most distal unit with correlative sheet-like sand bodies interbedded with silts and mudstones. These mudstones have a similar petrophysical characteristic as the Vicksburg Formation. This unit is deposited within a mid-to-inner neritic, proximal-to-distal shallow marine shelf environment. On average, there is about 70 ft net storage (21% NTG) within the unit. The FRIO3 has a series of well-developed, correlative sand beds that are interbedded with lime-rich mudstones (marls).

Application No. 45079, 45080, 46169, 46170, and 46171

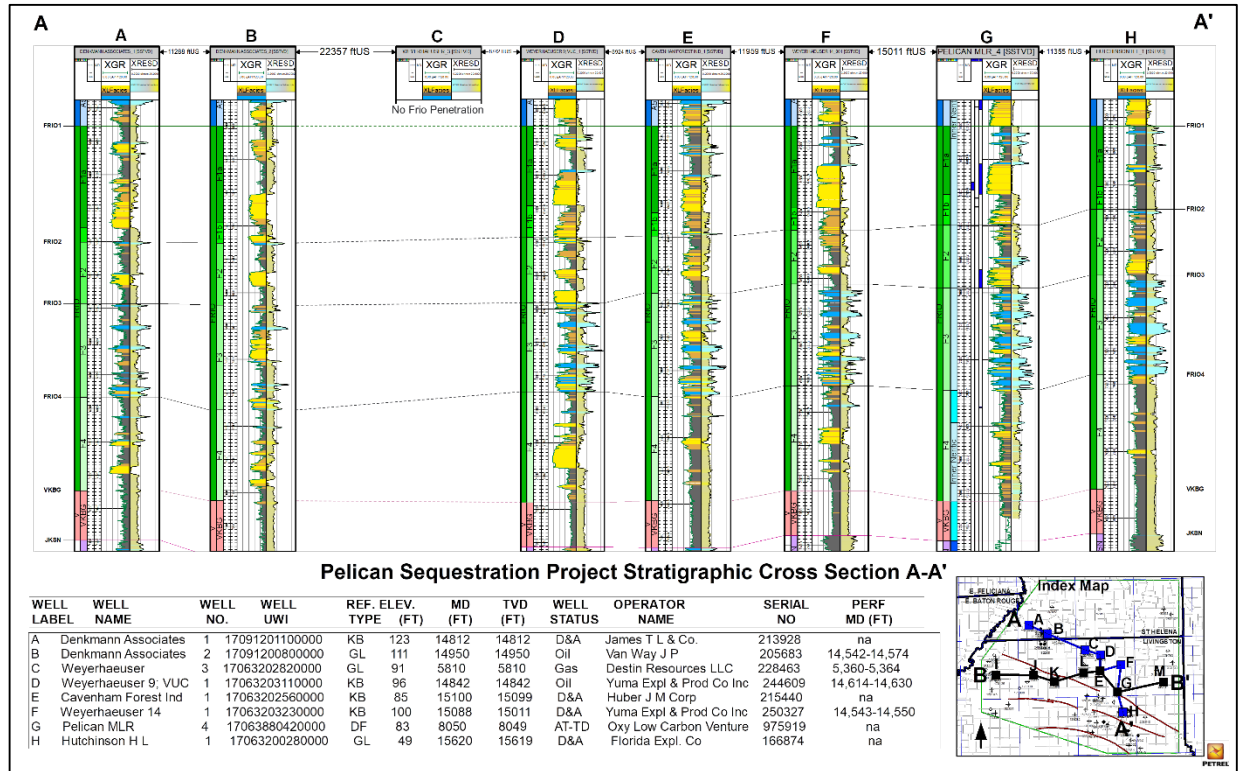


Figure NAR-39—Cross section zoomed in and flattened on the top of the Frio formation.

This unit is deposited within an inner neritic, shallow marine, pro-delta environment where sandy facies are better developed in the northern part of the AOI. Average net storage in this unit is about 85 ft (27%NTG). The FRI02 and FRI01 are interpreted to be a part of a regressive systems tract where more proximal delta front sediments are being deposited. The FRI02 is interpreted as being deposited in a delta front environment where stream mouth bars and distributary channels create heterogeneity, directionality, and baffles between sand bodies. Orientation of sedimentation is approximately N30W and average net storage is about 68 ft (36% NTG). The FRI01 is the most proximal unit where sand is best developed. This unit has about 105 ft average net storage (31% NTG). On well logs, individual sand units are thick and blocky. This log characteristic changes to more distal over the southern half of the AOI.

Application No. 45079, 45080, 46169, 46170, and 46171

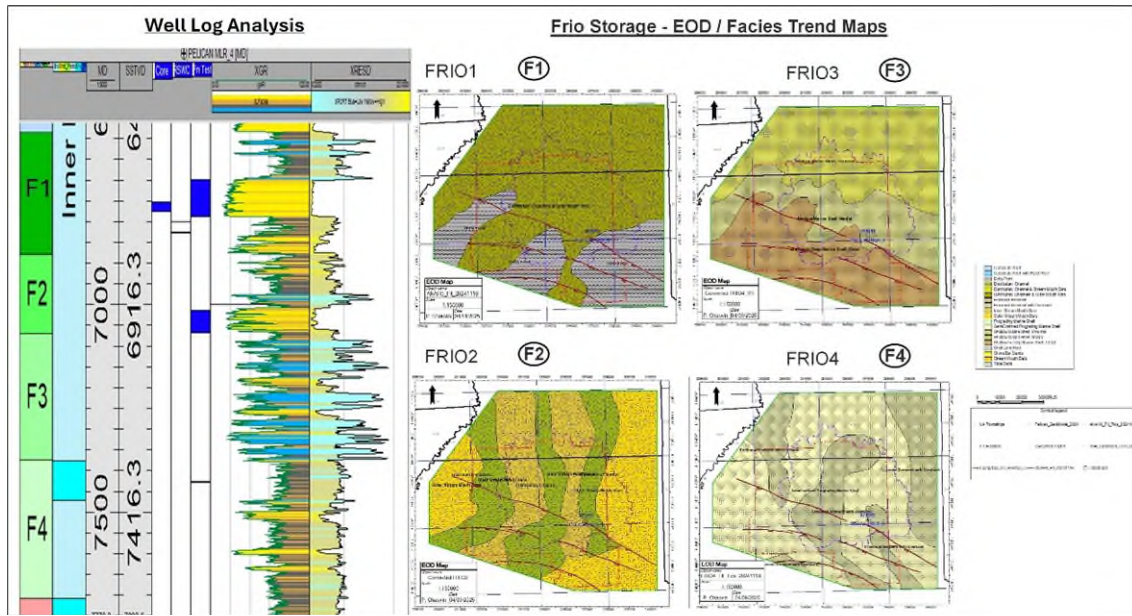


Figure NAR-40—Frio storage unit environment of deposition (EOD) facies trend maps.

2.4.3.2 Lower Anahuac Sandstones

The average top of the lower Anahuac sandstones (ANAH3, ANAH4, and ANAH5) is 5,780 ft TVDSS (Table NAR-2). Within the unit, an average net storage of 157 ft is interbedded with thick benches of limestone and shales (Figure NAR-41).

Application No. 45079, 45080, 46169, 46170, and 46171

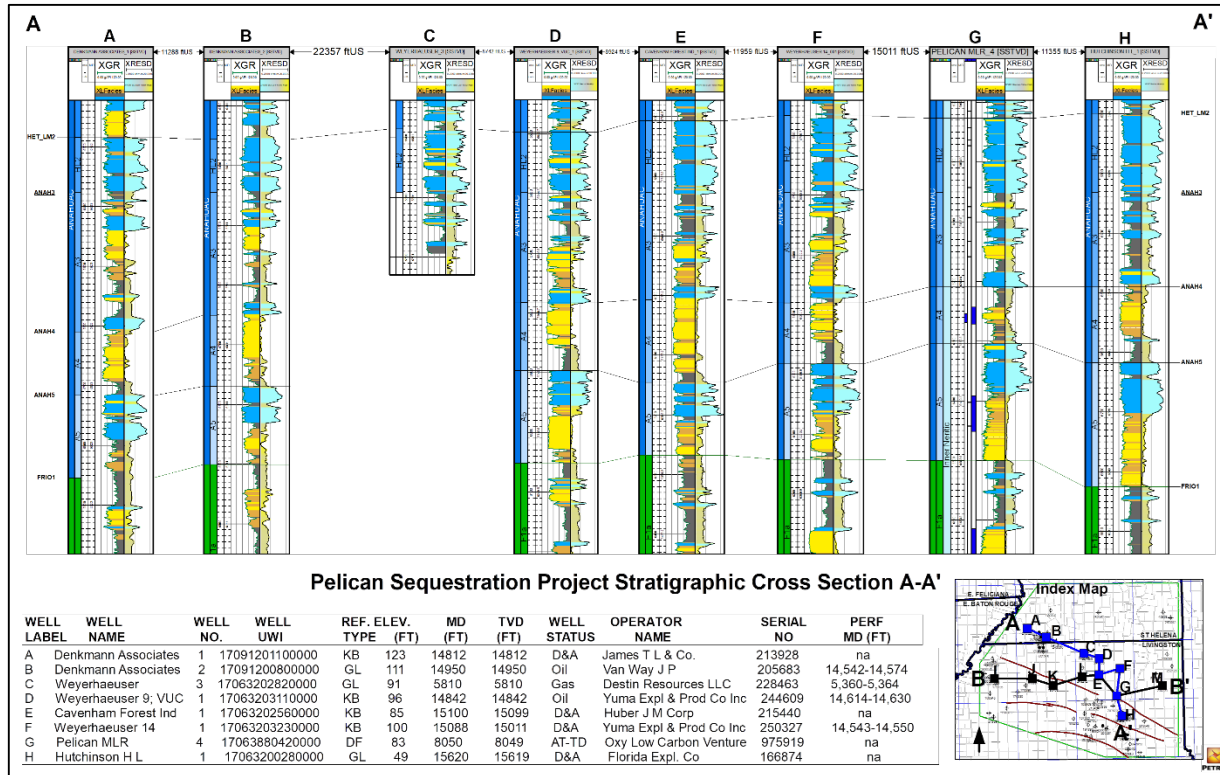


Figure NAR-41—Cross section of the lower Anahuac storage units, flattened on the top of the ANAH3 (or base of the HETLM).

Storage within the Anahuac sands is robust due to its unconsolidated nature, offering very high porosity and permeability. Log characteristics suggest channel, overbank, and bar deposits that come and go. These features are captured in EOD maps (Figure NAR-42). The three units in the Lower Anahuac are interpreted to be tidal influenced delta and delta front environments where sands are being reworked and deposited as clean sand bodies. These units appear to retrograde and show a maximum water depth in ANAH3 where the entire unit is capped by a marine shale. The ANAH4 and ANAH5 are the most proximal units with thick well-developed sands capped by thick limestone beds. The log signature on the sands varies from bell shaped to fining upward. This is interpreted to be a delta environment with distributary channels and stream mouth bars. This EOD mapping effort captures sand body trends which are critical control on CO₂ migration pattern in the model. The cyclical nature of shale/sand/limestone defines a time of short-term sea-level rise and falls. This time is defined as a transgressive system tract and is consistent with the Haq Eustacy Curve (Haq et al., 1987; Figure NAR-28). On average, there is about 105 ft net storage (41% NTG) within these units. The ANAH3 is more distal with thinner sand beds interbedded with shales and some limestones. Log signatures on the sands vary and show shaling out and stacking of sand bodies between wells. This unit is believed to cycle between deltaic distributary channels and stream mouth bars interbedded with delta front shales. On average, there is about 53 ft net storage (26% NTG) within this unit. This marine shale within this unit is expected to act as additional confinement for the Frio and Anahuac Storage units.



REV. 4/26

Application No. 45079, 45080, 46169, 46170, and 46171

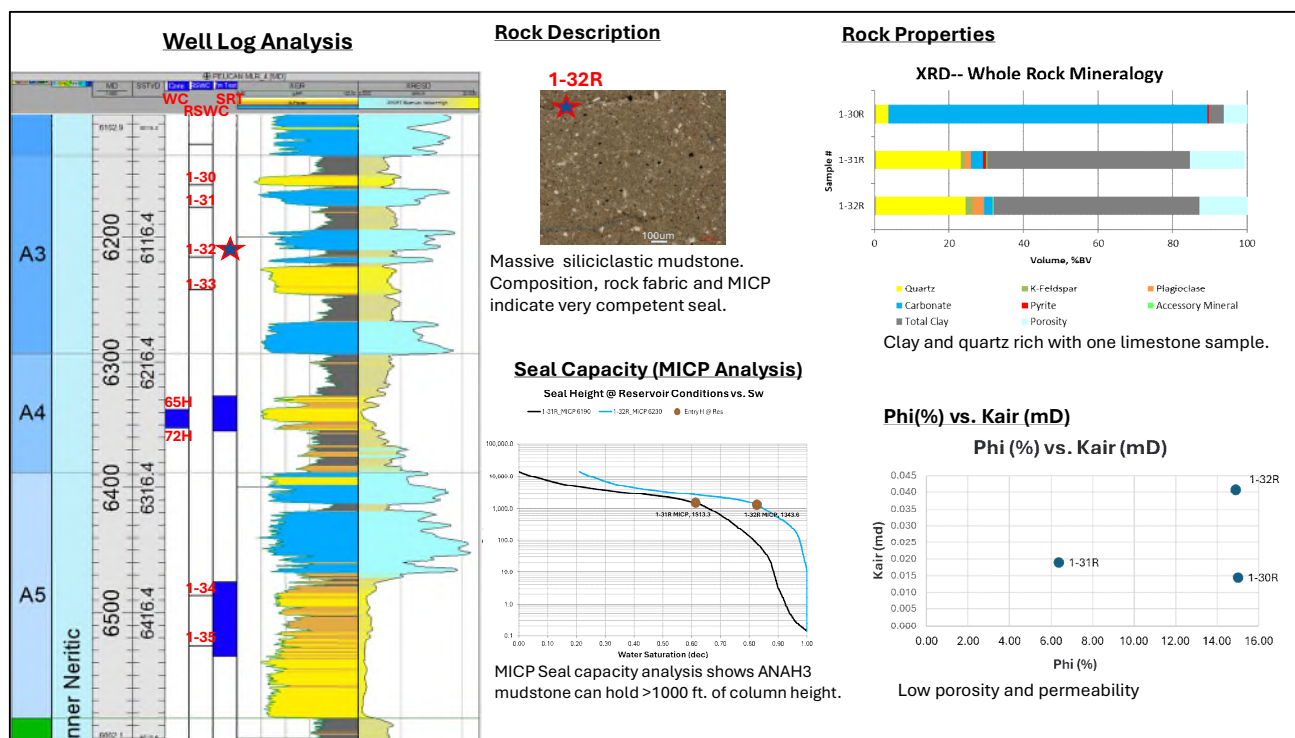
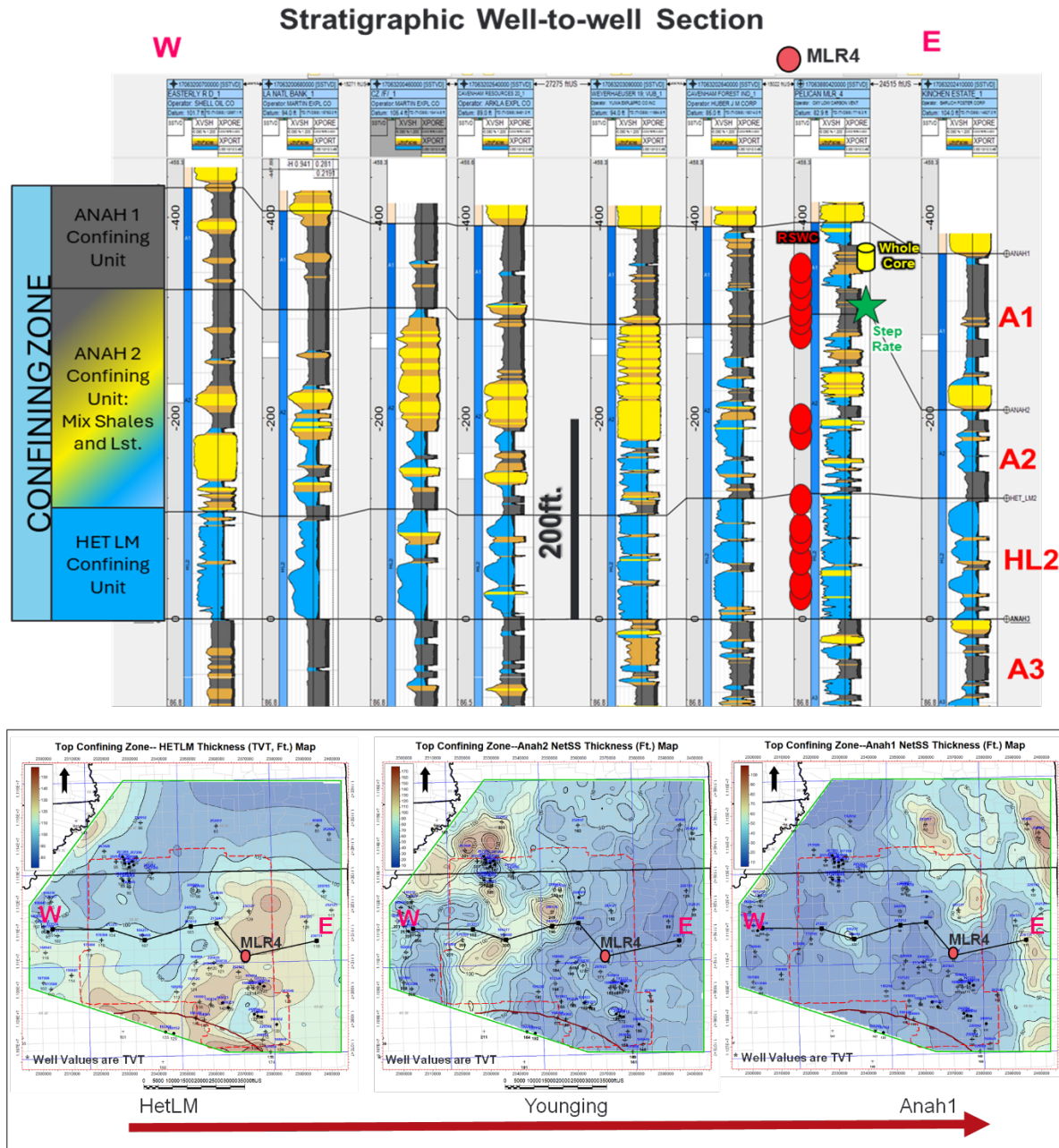


Figure NAR-43—Top of the ANAH3 log signature in Pelican MLR 004 (left) and confining facies summary (right).

2.4.5 Upper Confining Units—Heterostegina Limestone (HETLM) and Anahuac Shale

The top confining units (or caprock) are the Heterostegina Limestone (also called Het Lime) and upper Anahuac Shale. It is defined as a part of a highstand systems tract that was deposited in an inner neritic (shallow marine), near shore, tide-dominated, carbonate-rich environment. The unit consists of three zones (HETLM, ANAH2, and ANAH1) that are laterally continuous in the AOI (Figure NAR-44). The average gross thickness of the top confining unit is 387 ft (Table NAR-5). The porosity, permeability, and lithology of the three zones vary.

Application No. 45079, 45080, 46169, 46170, and 46171



2.4.5.1 Heterostegina Limestone (HETLM)

The Heterostegina Limestone (HETLM) is a regionally identified unit in the Anahuac Formation (average gross thickness ~100 ft.) Rotary sidewall core samples from the Pelican MLR 004 define this as a skeletal packstone that is predominately limestone with intraparticle pores and matrix porosity in micritic clays (Figure NAR-45). Some alteration has occurred, resulting in recrystallization to further reduce porosity and permeability. This thick, low porosity and

Application No. 45079, 45080, 46169, 46170, and 46171

permeability zone spans over the entire model area is a reliable confining zone for the Pelican Sequestration Hub.

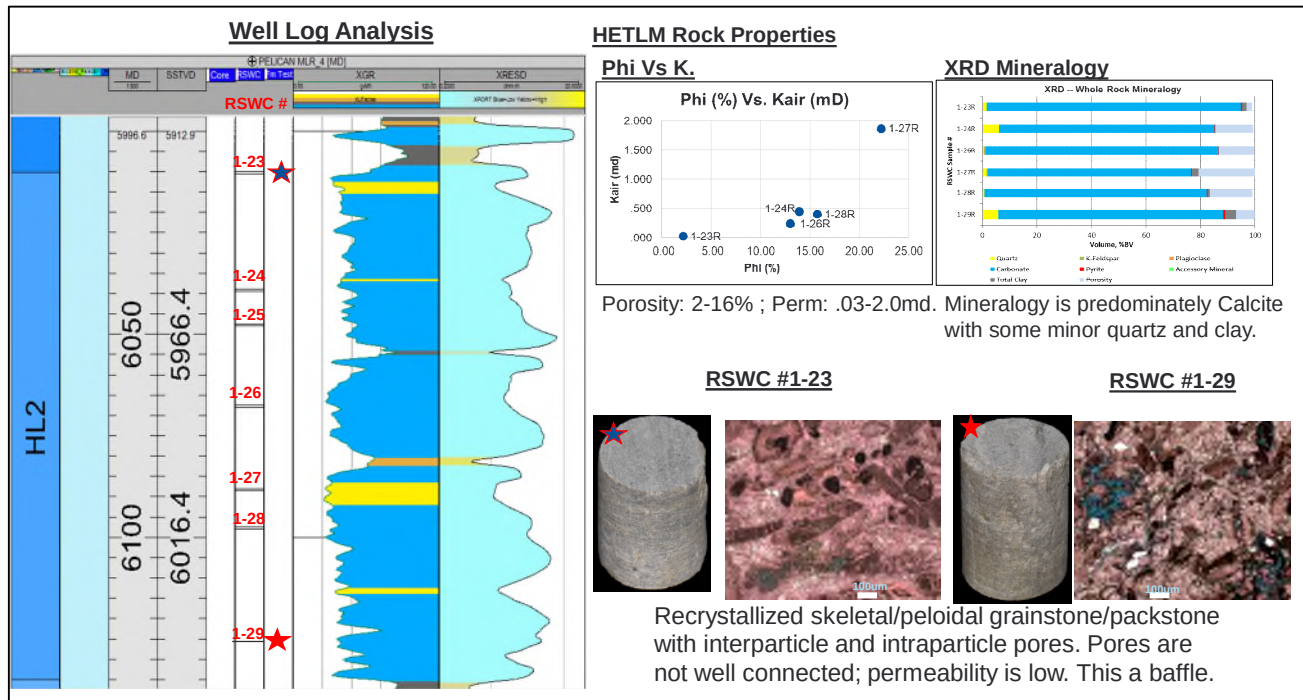


Figure NAR-45—HETLM log signature (left) and property summary (right) from samples in the Pelican MLR 004.

2.4.3.3 Anahuac Shale

The Anahuac Shale represents a time of marine transgression when the Heterostegina Limestone (HETLM) was deposited in an open marine shelf environment with patch reefs (Figure NAR-46). This unit is predominately limestone with very few shale and sand beds. Above this unit are two pulses of sedimentation (ANAH2 and ANAH1) exhibiting sediment geometries that appear as tide-dominated deltas, which are compensationally stacked in the AOI (Figure NAR-45). These units are a mix of muddy limestone, calcareous shales, and some sand. In Pelican MLR 004, 30 ft of whole core and 16 rotary sidewall core samples were collected. Additionally, a formation integrity test (FIT) performed in the shale facies of ANAH1 shows competent seal.

Application No. 45079, 45080, 46169, 46170, and 46171

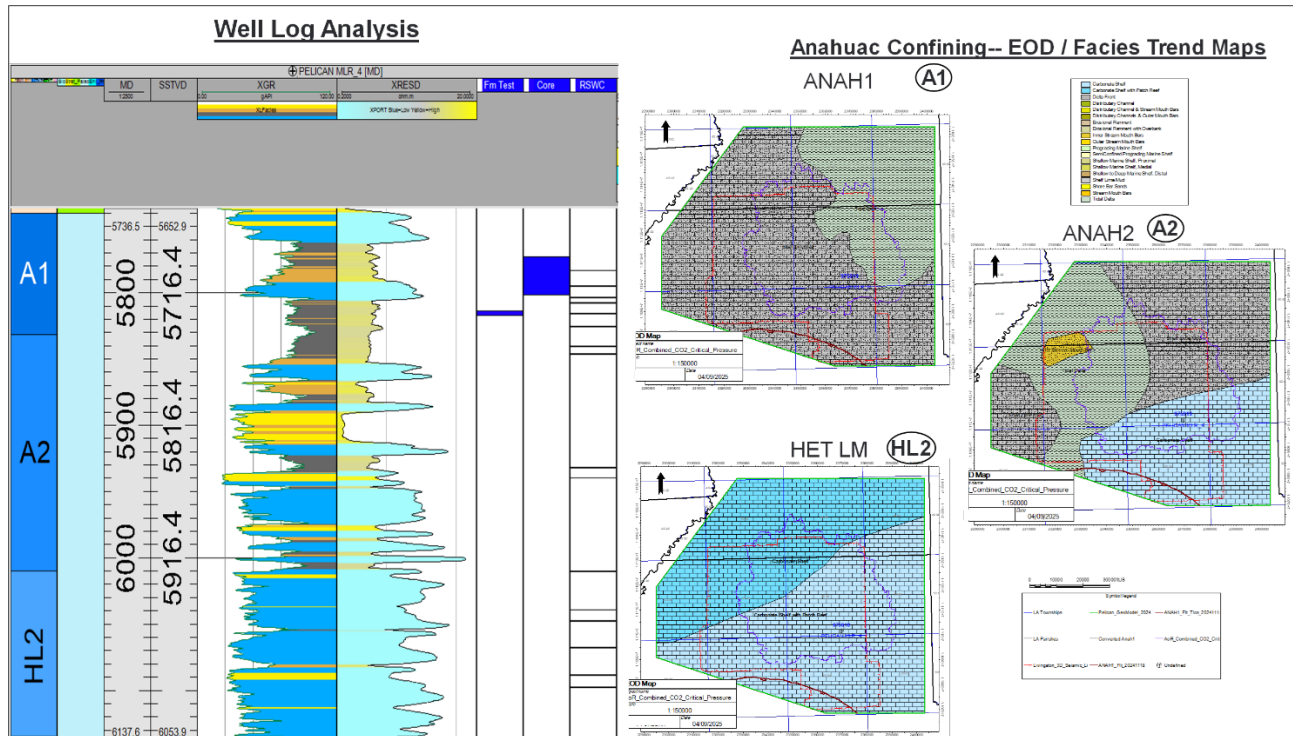


Figure NAR-46—Upper Anahuac and HETLM log signature in Pelican MLR 004 (left) and EOD Summary (right).

Overlying the HETLM are the ANAH1 and ANAH2. These zones were broken out due to a complex, compensational stacking pattern identified in seismic sections (Figure NAR-44). Log and rock facies within these 2-zones are very similar. There are three main rock types: limestone, mudstone, and sandstone. In the Pelican MLR 004, a thick limestone bed is seen at the base of the ANAH2. This limestone is thought to be a patch reef that is lapped onto by a sandy unit from the northwest that is interpreted to be a tidal influenced delta. At the Pelican MLR 004, the ANAH2 grades upward into a lime-rich mudstone and is interpreted as the ANAH1. This mudstone is easily correlated toward the northwest but becomes sandy to the north. This is a younger, separate lobe to the same tidal delta system as the ANAH2, which has avulsed eastward. The mudstones in these two zones are interpreted from biostratigraphy and log signature to be at the peak or just past the peak of a highstand system tract.

The top of the Anahuac Formation (top ANAH1) ranges from around 4,150 – 6,600 ft TVDSS. The ANAH1 and ANAH2 zones are present everywhere with a combined average thickness of 281 ft TVT (210 – 356 ft TVT). These units are made up of sandstone, siltstone, mudstone, and limestone (Figure NAR-47). Approximately 30 ft of continuous core was taken through a fining upward sequence of rock that allows close inspection of the various rock types that make up these zones. Porosity over the unit average 21% with permeability average 0.8 mD. The most competent sealing facies is a partially silicified argillaceous mudstone. The log characteristic of this rock facies is seen everywhere over the AOI and is expected to provide additional sealing capacity for the Upper Anahuac Top Confining Zone. Other sealing facies are present, such as argillaceous siltstones and sandy argillaceous skeletal packstones.

Application No. 45079, 45080, 46169, 46170, and 46171

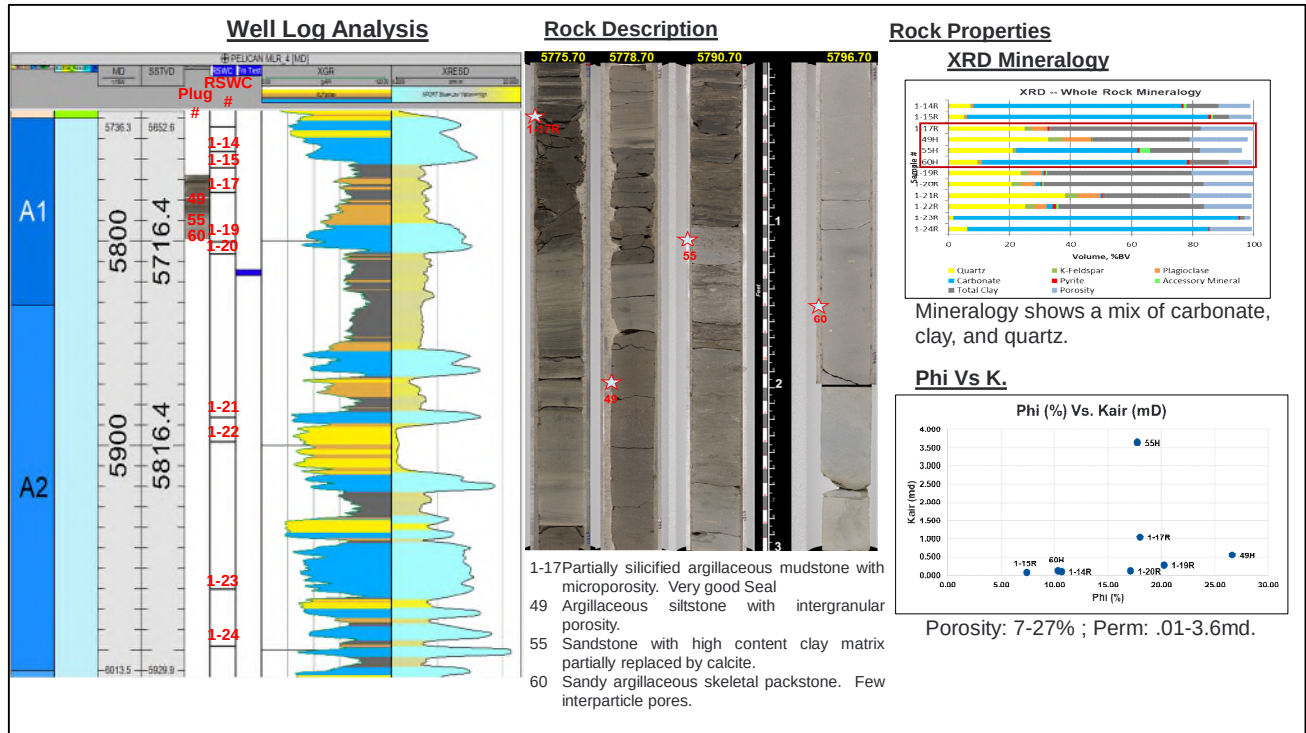


Figure NAR-47—Upper Anahuac (ANAH1 And ANAH2) log signature (left) and property summary from whole core samples (right) in the Pelican MLR 004.

The seal capacity of the Anahuac Shale was tested and validated in the field and with lab measurements. A FIT was performed on the mudstone facies of the ANAH1 at a depth of 5,814 – 5,817 ft MD (Project Narrative - Appendix D). This test shows a fracture gradient of >0.91 psi/ft with pressure building up to 2,750 psi without failure (Figure NAR-48). This confirms the ability for the shale to withstand pressures to achieve injection rates of 2 MMTPA. The MICP seal capacity analysis was performed in the lab demonstrating the shale facies able to hold >1,000 ft of column height. These tests, along with thin section and log measurements showing very low porosity and permeability due to micro- and moldic porosity, provide multiple lines of evidence to confirm the confining capacity of the upper Anahuac units (ANAH1 and ANAH2).

Application No. 45079, 45080, 46169, 46170, and 46171

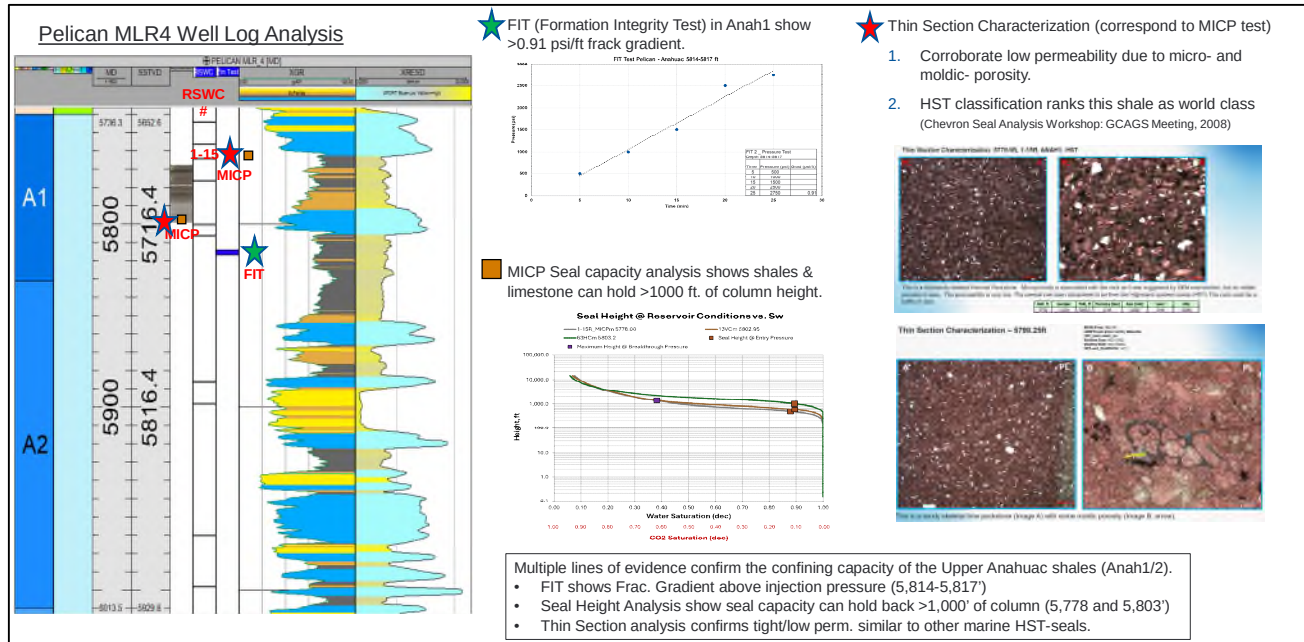


Figure NAR-48—Anahuac Shale log signature in Pelican MLR 004 (left) and seal capacity summary (right).

The combination of the Heterostegina Limestone shelf and Upper Anahuac siliciclastic flood events offers a laterally extensive top seal (caprock) for the Pelican Sequestration Hub's Oligocene Storage Complex. The many types of low porosity/low permeability rocks along with the complex stacking of the three units (HETLM, ANAH1, and ANAH2) introduce a level of tortuosity to flow that makes this a world class confining unit.

A complete understanding of seal competence, capillary pressure, and column height will be discussed in Section 2.5 Geomechanical and Petrophysical Information. Additionally, fault interpretation and seal continuity aspects are described in section 2.3.1 Local Structure and Faulting of this report. Geochemical reactions associated with the CO₂ stream are discussed in Section 2.8 Geochemical Modeling.

2.5 Geomechanical and Petrophysical Information

2.5.1 Petrophysics

The fluvial-deltaic Frio and Anahuac formations are composed of high-porosity and high-permeability sand layers with intermittent baffling limestones and shale layers. The ANAH1, ANAH2, and HETLM2 combined are the Upper Confining Zone. The ANAH3, ANAH4, ANAH5, FRIO1, FRIO1b, FRIO2, FRIO3, and FRIO4 are the Injection Zones. Underlying the Frio is the Vicksburg, that serves as the Lower Confining Zone. The core and well-log data from the Pelican MLR 004 (SN 975919) stratigraphic test well was used to calibrate the petrophysical calculations (see Figure NAR-49).

Application No. 45079, 45080, 46169, 46170, and 46171

A total of 101 wells (Project Narrative - Appendix A, Table NAR-APPENDIX-A-1) were selected for petrophysical calculation of porosity, permeability, clay volume, and net reservoir thickness that provided the best data quality and coverage of the Anahuac, Frio, and Vicksburg formations (see Figure NAR-50). Each formation and their subzones are provided in a summary with average properties displayed in Figure NAR-51.

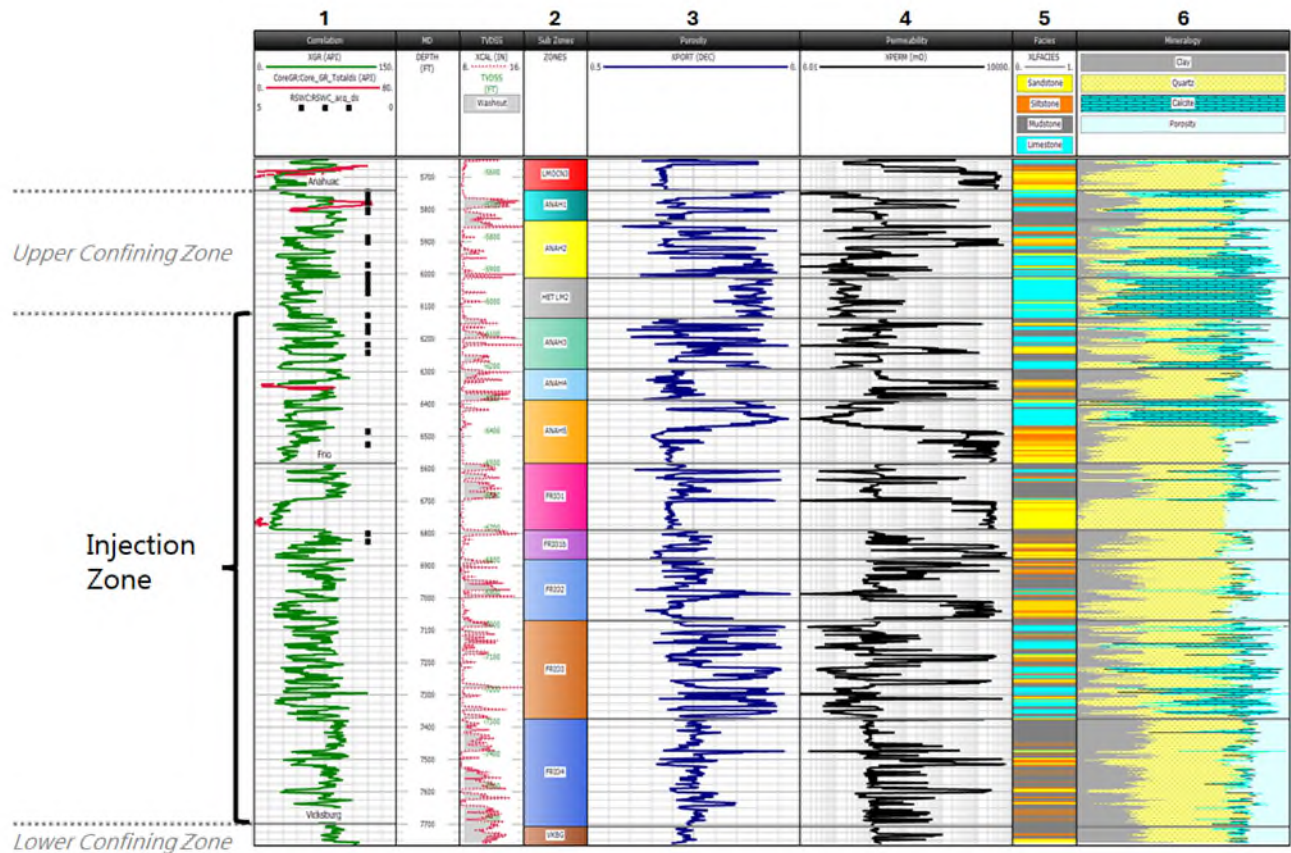


Figure NAR-49—Composite type well-log interpretation of the Pelican MLR 4 (SN 975919). In track 1, the Correlation column displays the Anahuac, Frio, and Vicksburg formations along with the gamma ray (XGR), Full core (red line) and Rotary sidewall core intervals (black dots). Track 2 shows the breakdown of major zones into subzones. Track 3 displays total porosity (XPORT). In track 4 the XPERM is horizontal permeability and track 5 is the lithofacies model. Track 6 represents the Mineralogy of quartz, clay, and calcite plus porosity.

Application No. 45079, 45080, 46169, 46170, and 46171

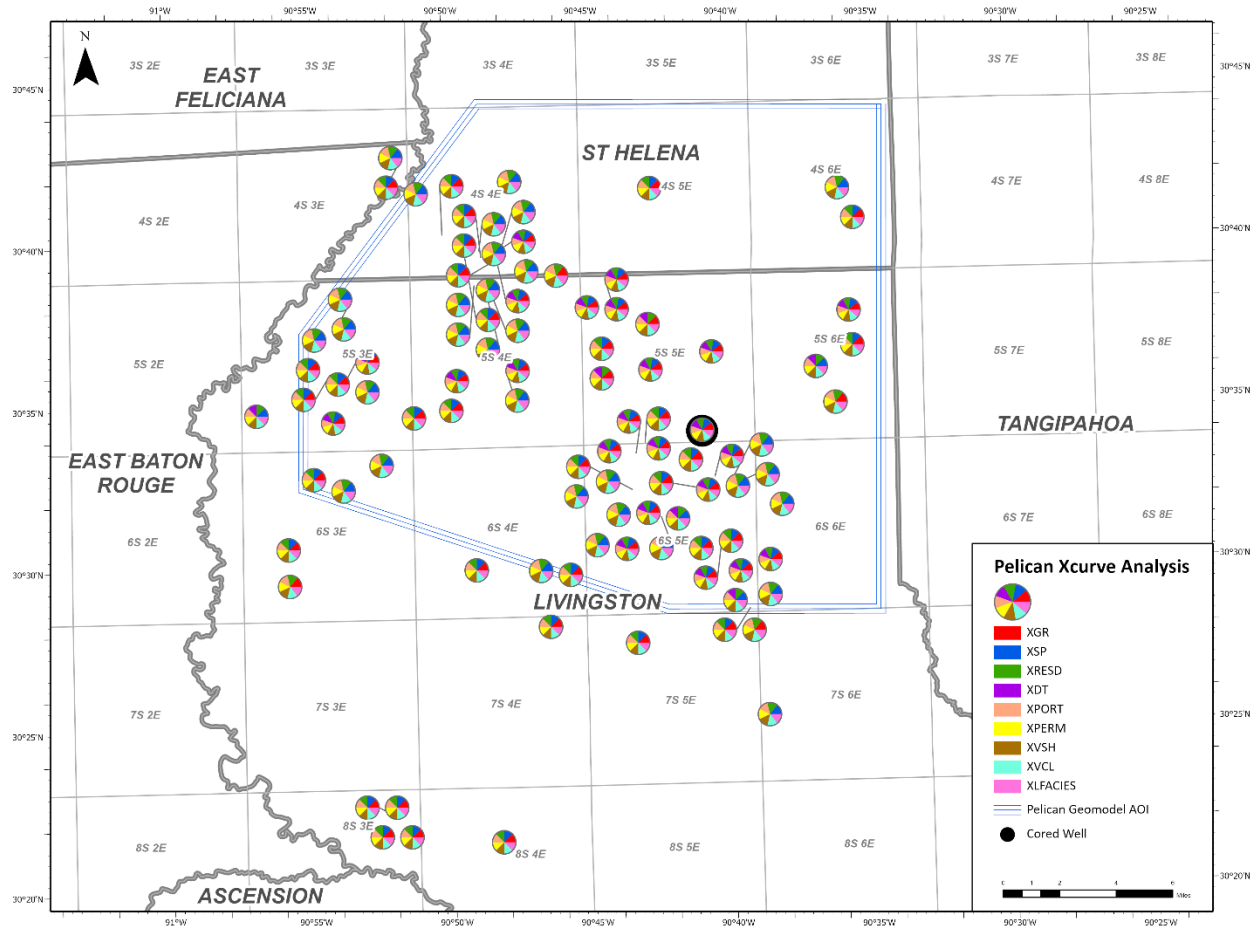


Figure NAR-50—Map representing petrophysical log interpretation for 101 control wells within and surrounding the Pelican Sequestration Project area. The Pelican MLR 004 (SN 975919) stratigraphic test well is indicated by the black outline. Wells on the map are listed in Project Narrative Appendix A, Table NAR-APPENDIX-A-1.

Application No. 45079, 45080, 46169, 46170, and 46171

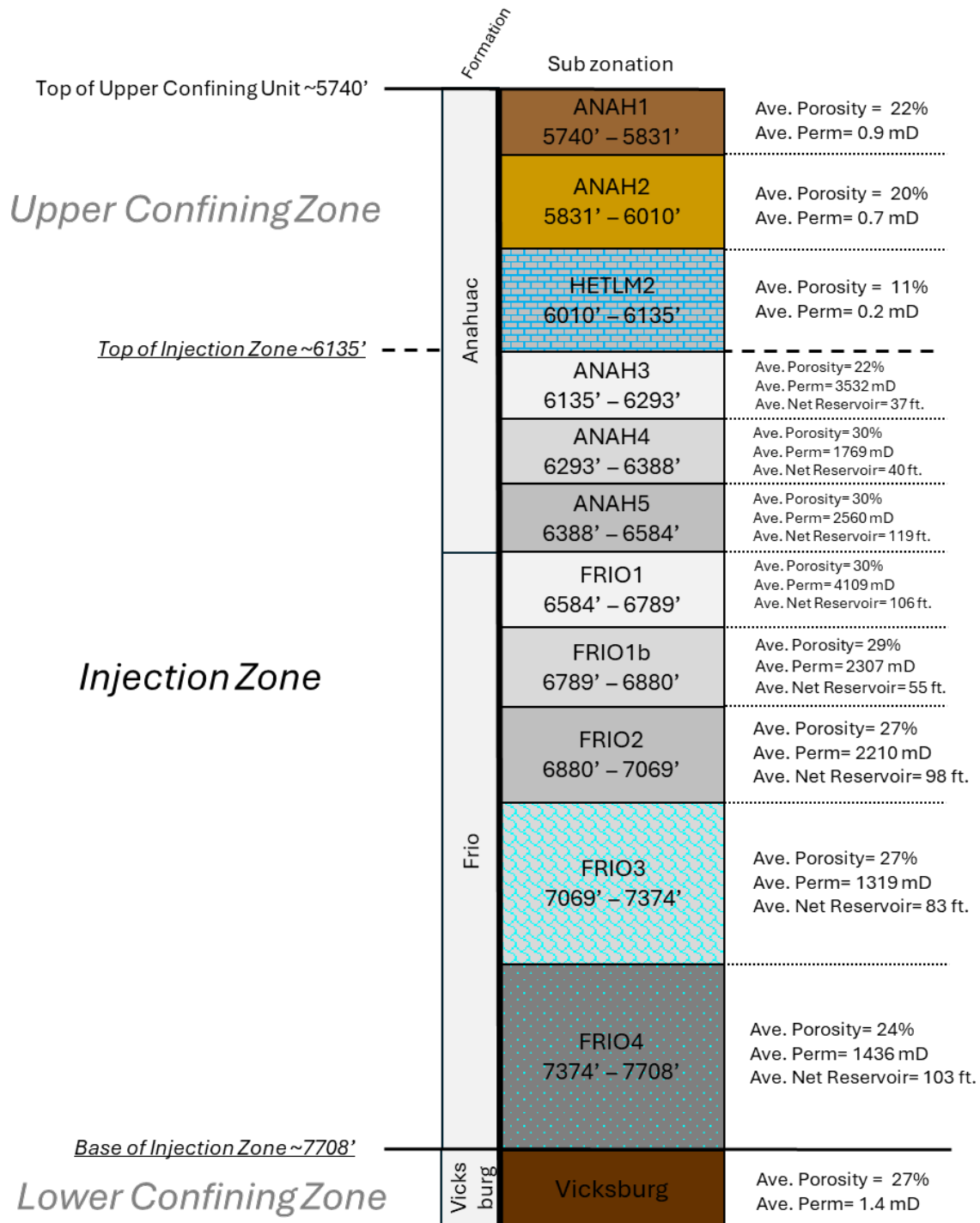


Figure NAR-51—Individual subzones with averages of porosity, permeability, and net reservoir thickness based on log analysis, along with approximate depth intervals at well Pelican MLR 004 (SN 975919). The column on the left lists the top of model at 5,740 ft, the top of Injection Zone at 6,135 ft, and the base of the Injection Zone at 7,708 ft.

2.5.2 Clay Volume and 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) on the Pelican MLR 004 (SN 975919). 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 of clay from X-ray diffraction (XRD)(Fullcore_XRD:VCLAY)(Project Narrative - Appendix B, Table NAR-APPENDIX-B-1)(Figure NAR-52).

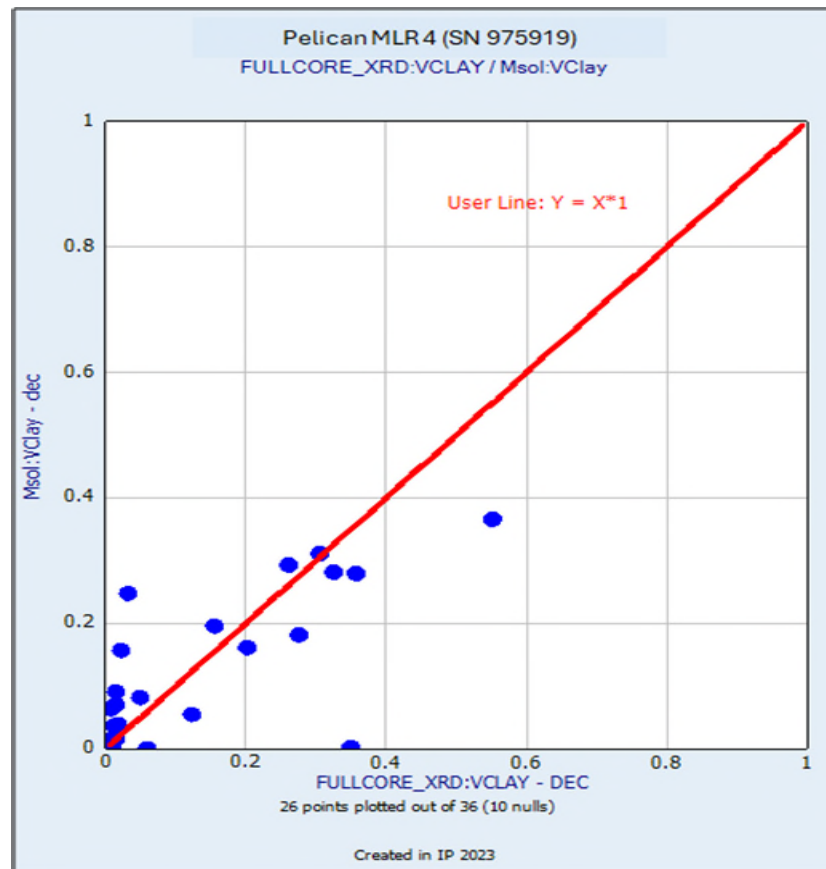


Figure NAR-52— Crossplot of XRD Clay volume (Fullcore_XRD:VCLAY) on the x-axis and volume of clay (Msol:VClay)(decimal) determined from Mineral Solver in IP on the y-axis from the Pelican MLR 004 (SN 975919). The red line represents the 1:1 relationship between the two variables.

The total porosity (XPORT) 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) from core data organized by lithofacies (XLFACIES) (see Figure NAR-53).

Application No. 45079, 45080, 46169, 46170, and 46171

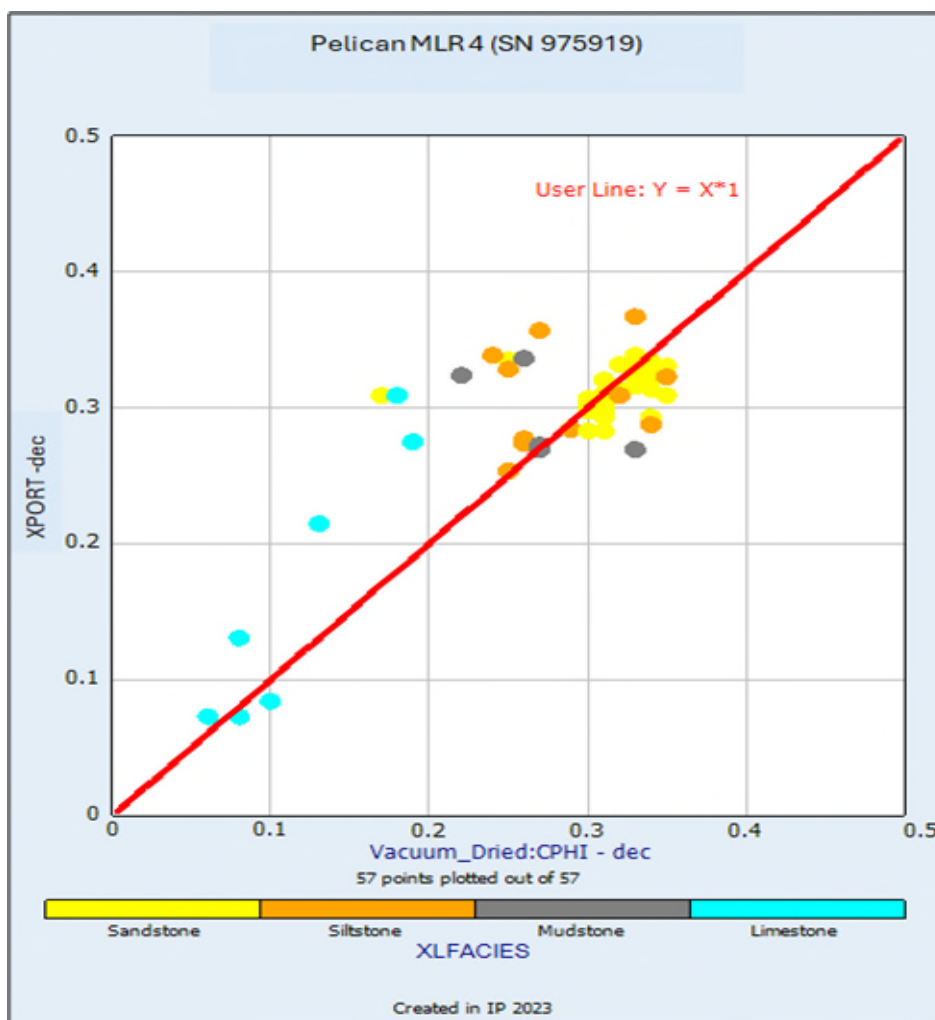


Figure NAR-53—Crossplot of vacuum-dried core porosity (CPHI) (decimal) on the x-axis and total porosity (XPORT) on the y-axis from the Pelican MLR 004 (SN 975919). The red line represents the 1:1 relationship between the two variables.

Four additional wells were selected for the Mineral Solver module and interpreted to reproduce the same outputs as the Pelican MLR 004 (SN 975919) (see Table NAR-7).

Table NAR-7—Four additional wells plus the Pelican MLR 004 (SN 975919) used in Mineral Solver module.

WellName	API	UWI	START	STOP
Pelican MLR 004	17063880420000	17063880420000	0	8050
WEYERHAEUSER 19 #1	17063203090000	17063203090000	3974	15010
MIO_RA_SUA_DENKMANN_SLNR_1	17063203250000	17063203250000	780	6100
MIO_RA_SUA_DENKMANN_LNR_1	17091201640000	17091201640000	494	5600
DENKMANN_CC_1	17091201630000	17091201630000	490	5700

Application No. 45079, 45080, 46169, 46170, and 46171

A linear correlation between volume of clay (Msol:VClay) and shale volume (VSHAV) was developed with the resultant equation (below) (see Figure NAR-54). This equation is then extrapolated to calculate clay volume (XVCL) in the remaining 96 wells.

$$XVCL = 0.398294 \times VSHAV$$

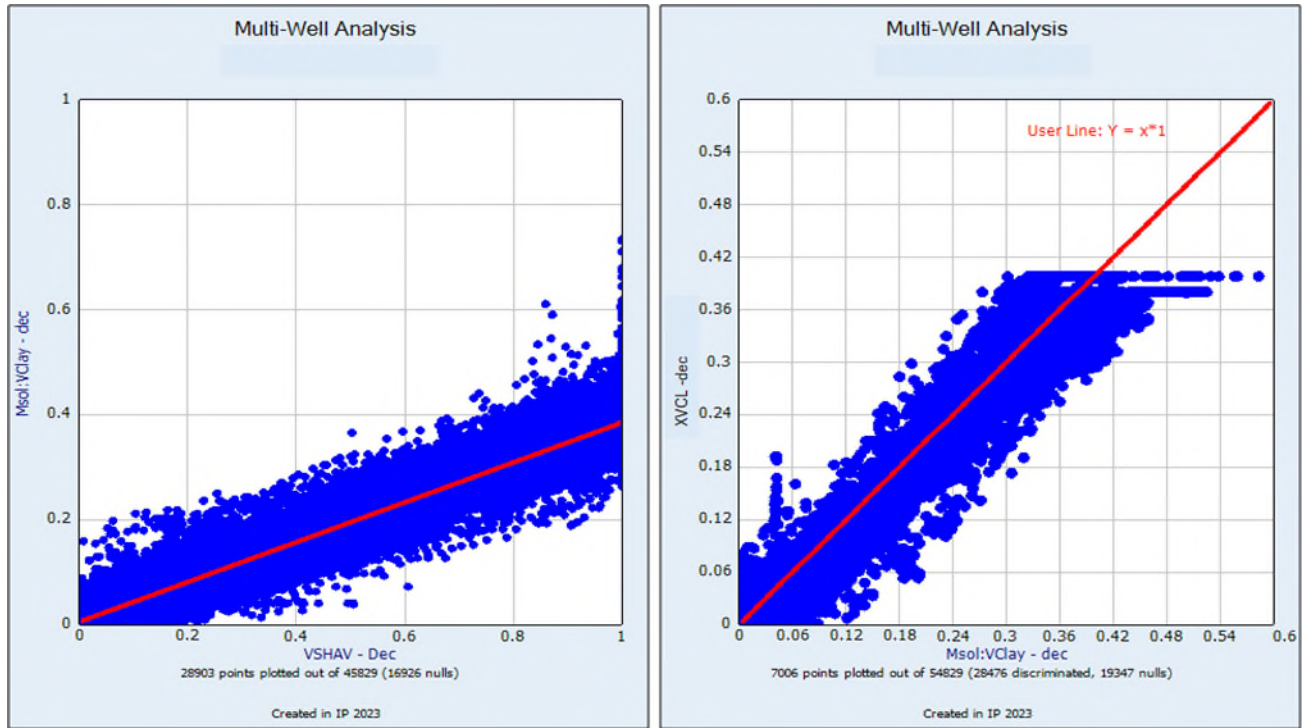


Figure NAR-54—Crossplot of shale volume (VSHAV)(decimal) and clay volume (Msol:VClay)(decimal) on the left graph and the right graph represents the correlation of the output XVCL using the equation from the Pelican MLR 004 (SN 975919) plus four additional interpreted wells. The red line on the right graph represents the 1:1 relationship between the two variables.

A linear correlation equation (below) between the modeled volume of clay (XVCL) and total porosity (XPORT) is then used to calculate a modeled total porosity (PHIT_model) using the Pelican MLR 004 (SN 975919) plus the four additional wells (Figure NAR-55). This equation is then extrapolated to calculate a modeled total porosity (PHIT_model) in the remaining 96 wells. The newly modeled total porosity can then be converted to the final XPORT curve and used for horizontal permeability computation.

$$PHIT_{Model} = 0.338833 - (0.156133 \times XVCL)$$

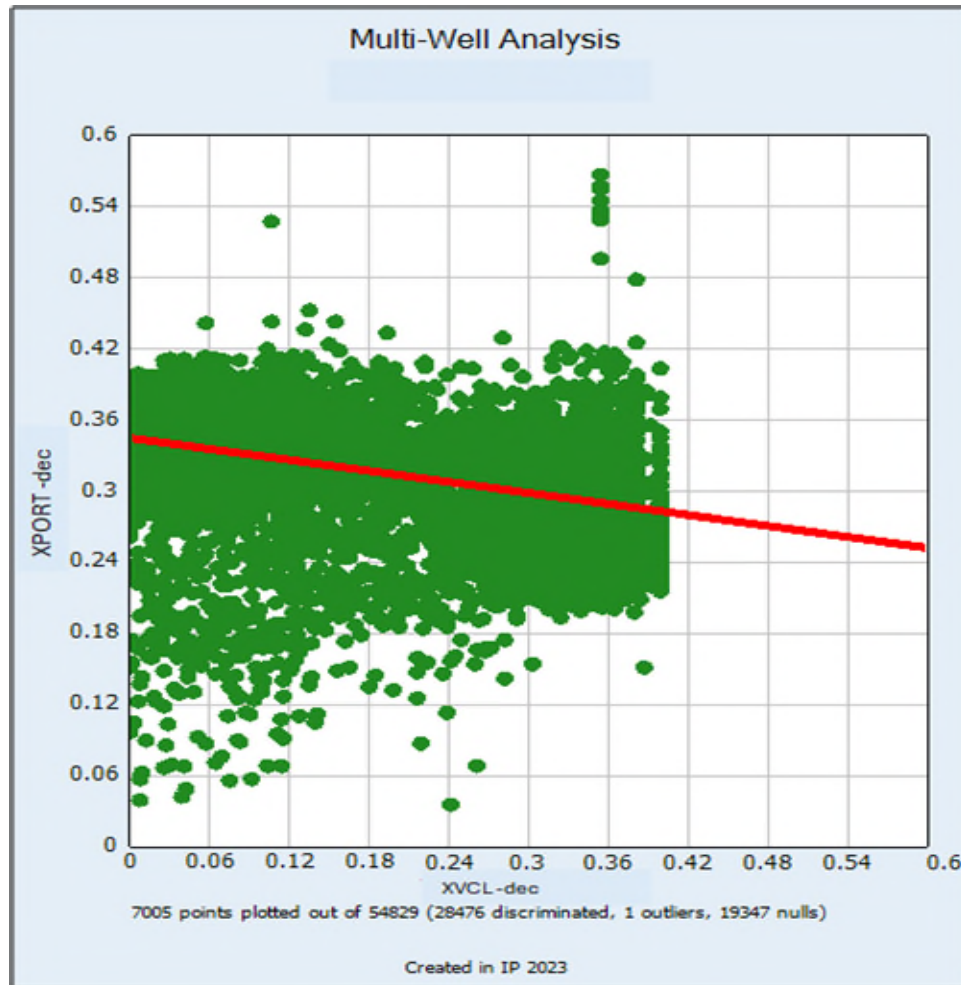


Figure NAR-55—Crossplot of the Pelican MLR 004 (SN 975919) plus four additional interpreted wells of modeled volume of clay (XVCL)(decimal) on the x-axis and total porosity (XPORT)(decimal) on the y-axis.

The Frio Injection Zone is located at a depth of 6,584 – 6,789 ft, with an average net reservoir thickness of 445 ft and average porosity of 27%. The Anahuac Injection Zone is located at a depth of 6,135-6,584 ft, with an average net reservoir thickness of 196 ft and average porosity of 27%. The average porosity of the Upper Confining Zone is 17% and average porosity of the Vicksburg Lower Confining Zone is 27%.

2.5.2.1 Lithofacies: Core to Well-log Facies

Four lithofacies (XLFACIES), sandstone, siltstone, mudstone, and limestone, were differentiated based on minimum and maximum cutoff values of core measured properties (X-ray diffraction and laser particle size analysis) (Project Narrative - Appendix B Table NAR-APPENDIX B-1). Lithofacies were then transposed onto well logs based on volume of clay (XVClay) corresponding to similar cutoffs derived from core measured properties. In addition, limestone lithofacies required using deep resistivity (XRESL) to differentiate limestone from sandstone and siltstone due to similar clay volumes. On well logs, these facies were differentiated using the below inputs:

Application No. 45079, 45080, 46169, 46170, and 46171

Sandstone: $XV_{Clay} \leq 0.1$ Siltstone: $0.1 \leq XV_{Clay} \leq 0.3$ Mudstone: $XV_{Clay} \geq 0.3$ Limestone: $X_{RES D} > 1.5 \text{ ohm-m}$

2.5.2.2 Horizontal Permeability

The horizontal permeability for the Injection Zone and Confining Zones was calculated from core analysis data acquired in the Pelican MLR 004 (SN 975919) well (Project Narrative - Appendix B, Table NAR-APPENDIX-B-2). Vacuum-dried porosity and permeability are crossplotted for each facies, then the data is fitted using a Power law function resulting in a permeability calculation specific to each lithofacies (see Figure NAR-56).

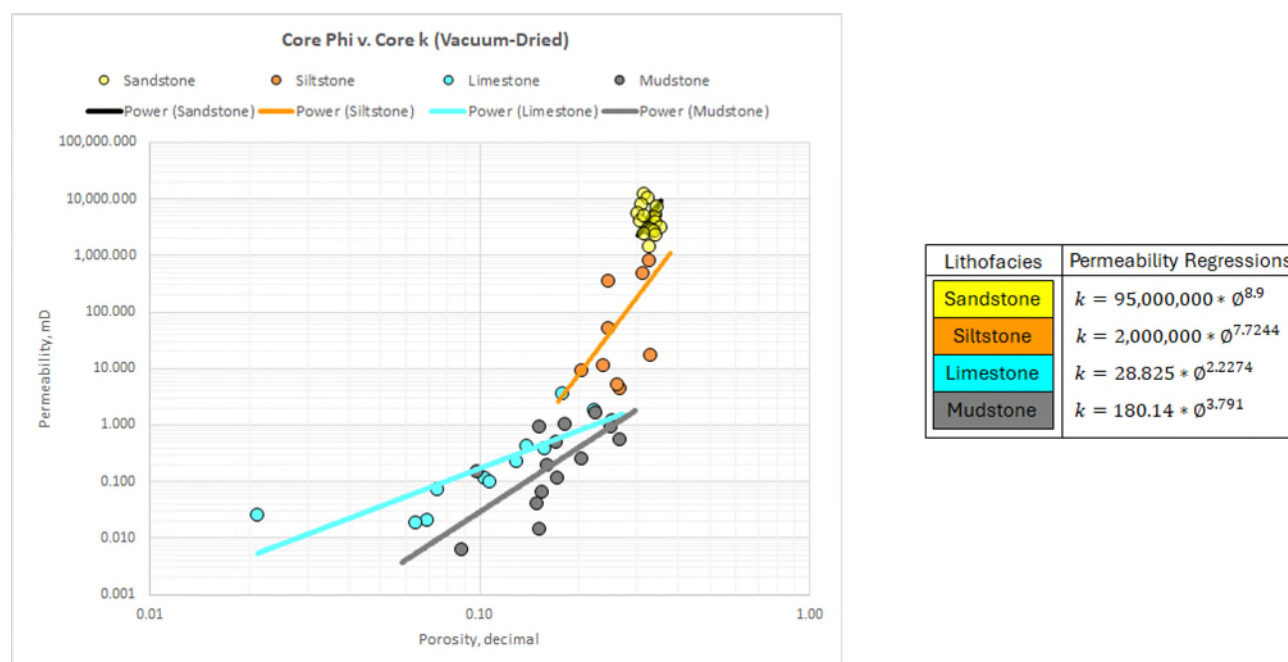


Figure NAR-56— Crossplot of the Pelican MLR 4 (SN 975919) core samples with vacuum-dried porosity on the x-axis and horizontal permeability on the y-axis differentiated by lithofacies and their corresponding regressions.

This permeability is then compared against the vacuum-dried permeability from core data (see Figure NAR-57). The equations are then applied to the well-log where each well has been populated with lithofacies every 0.5 ft. from the top of the Upper Confining Zone to the base of the Lower Confining Zone.

Application No. 45079, 45080, 46169, 46170, and 46171

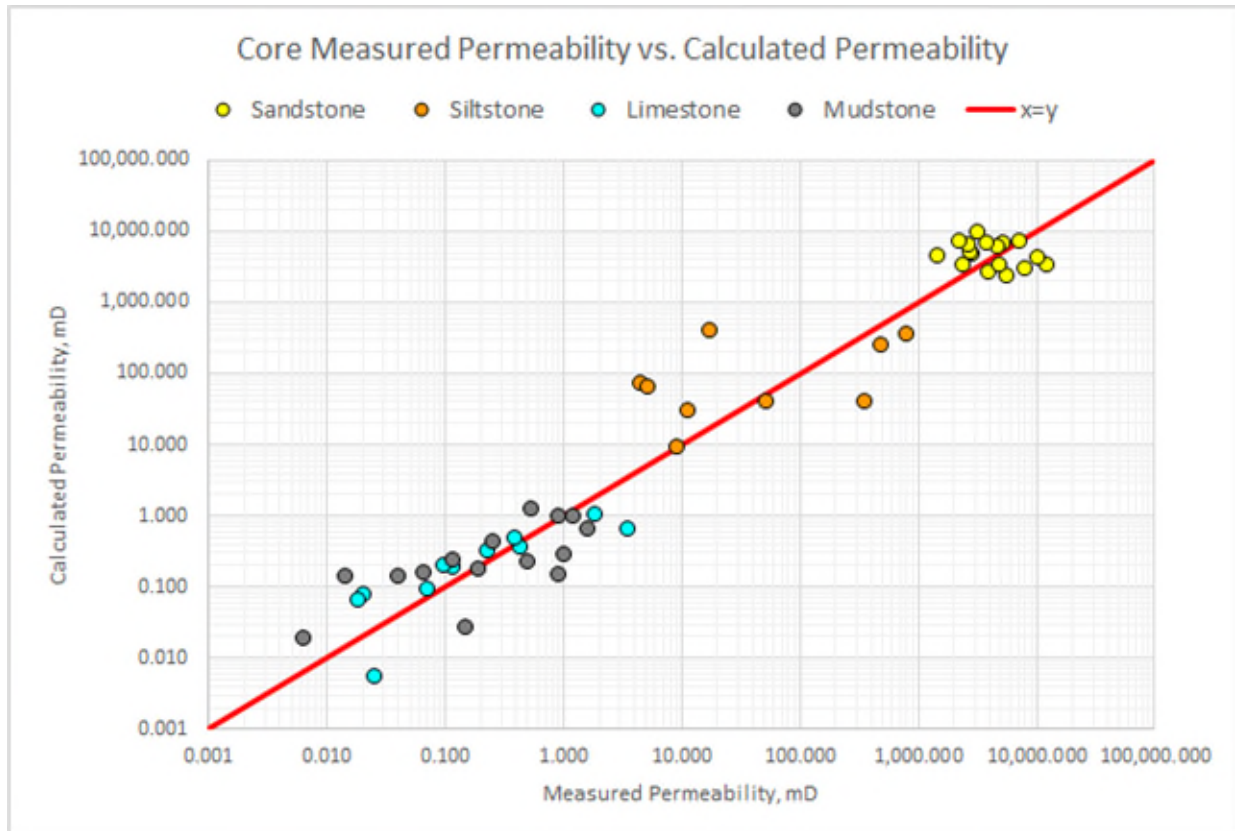


Figure NAR-57—Crossplot of vacuum-dried core permeability on the x-axis and calculated permeability on the y-axis from the Pelican MLR 004 (SN 975919). The red line represents the 1:1 relationship between the two properties.

Using this method, the distribution of permeability for the entire injection interval ranges from 1,319 – 4,109 mD, with an average horizontal permeability of 2,276 mD for the Frio and 2,620 mD for the Anahuac injection intervals.

The Upper and Lower Confining Zone permeabilities were developed from the core porosity-permeability transforms mentioned above, in conjunction with log-derived porosity. The average horizontal permeability for the Upper Confining Zone is 0.6 mD and Vicksburg Lower Confining Zone is 1.4 mD.

2.5.2.3 Confining Zones' Mechanical Integrity and Hydrodynamic Sealing Capacity

The confining zones' mechanical integrity was determined by structural characterization using the Schlumberger ThruBit Formation Borehole Image tool data logged in the Pelican MLR 004 (SN 975919). The interpretation consisted of identifying any fractures and/or microfaults in the Upper Confining Zones of the ANAH1, ANAH2, and HETLM2, and Vicksburg Lower Confining Zone that could contribute to mechanical instability and, consequently, CO₂ leakage (Figure NAR-58, Figure NAR-59, and Figure NAR-60, respectively). No shear fractures (faults), major fracture swarms, or high-density fracture sets were observed; however, one possible fracture was

Application No. 45079, 45080, 46169, 46170, and 46171

interpreted in the ANAH2. In that case, no damage zone was observed around or into the ANAH1 and HETLM2.

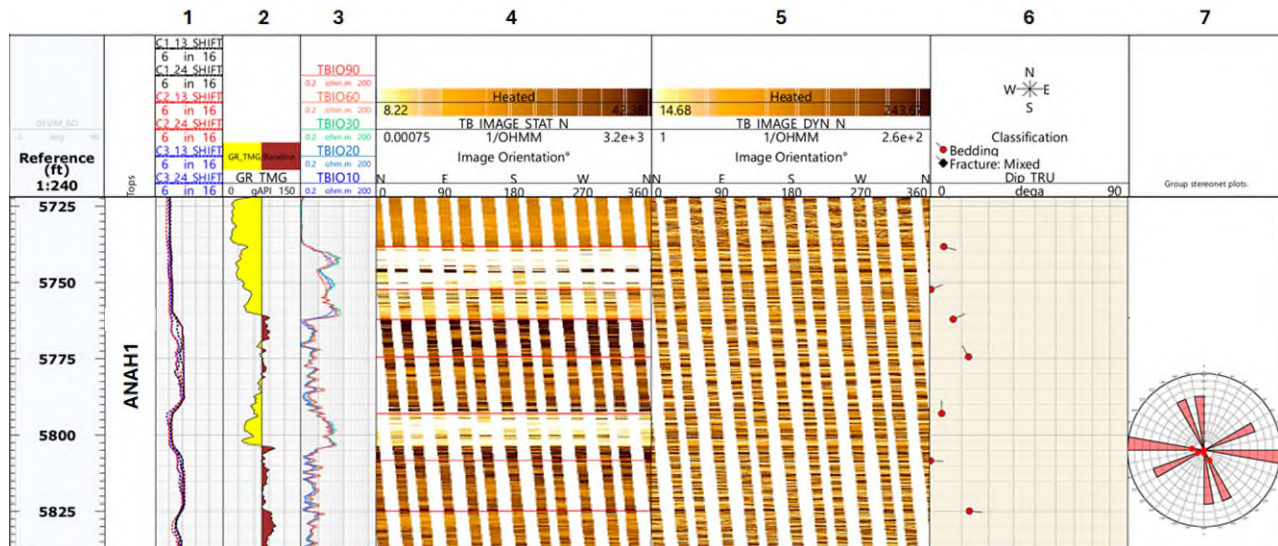


Figure NAR-58—Well-log image plot of the ANAH1 Upper Confining Zone from the Pelican MLR 004 (SN 975919). Track 1 displays the wellbore geometry from the 4-arm caliper of the tool. Track 2 displays the gamma ray. Tracks 3 is the microresistivity. Tracks 4 and 5 are the static and dynamic microresistivity image plots of the near wellbore face. Track 6 displays the dip tadpoles and their associated classifications. Track 7 displays the bedding dip angle and dip azimuth on a group stereo net plot.

Application No. 45079, 45080, 46169, 46170, and 46171

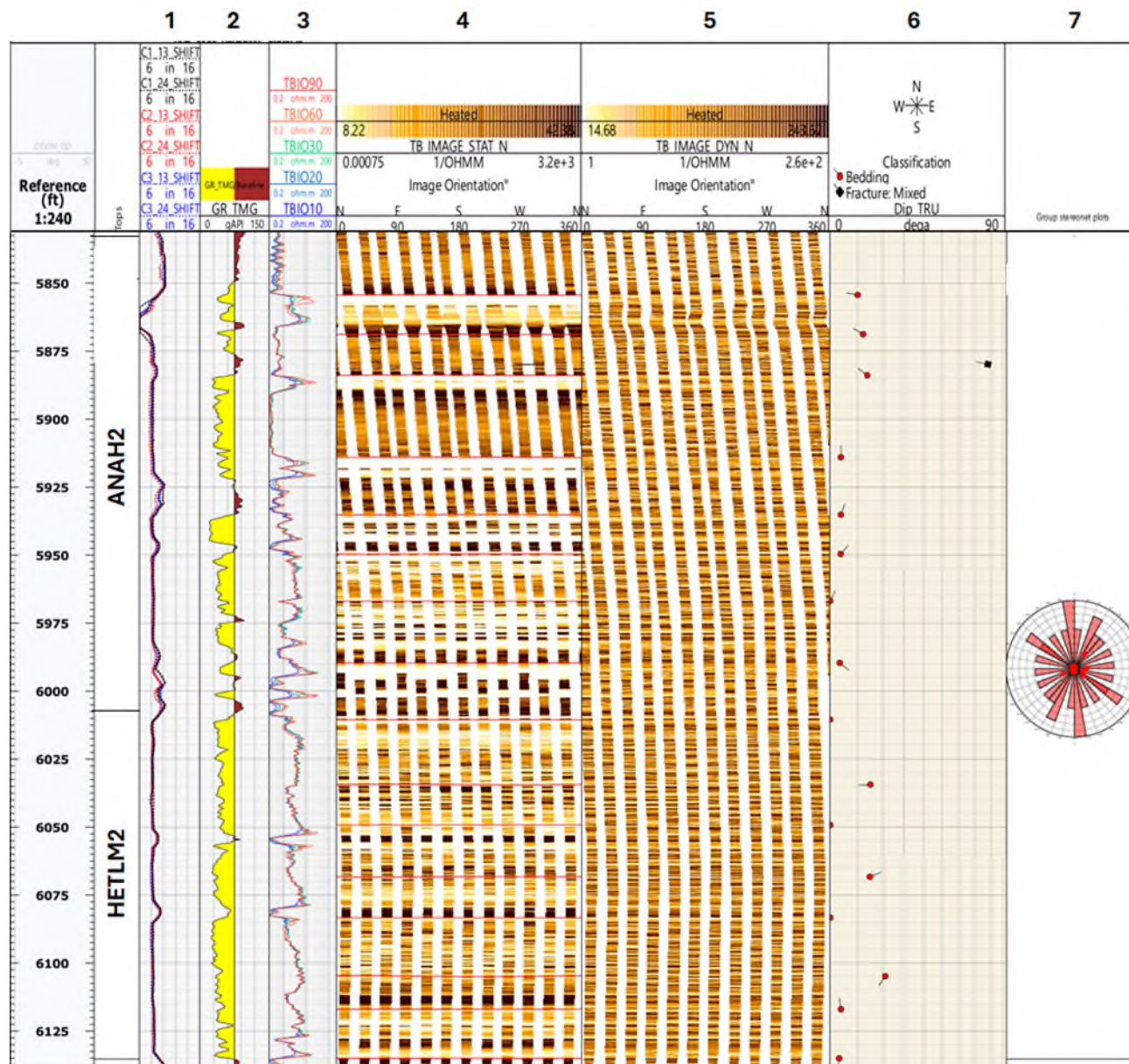


Figure NAR-59—Well-log image plot of the ANAH2 and HETLM2 from the Pelican MLR 004 (SN 975919). Track 1 displays the wellbore geometry from the 4-arm caliper of the tool. Track 2 displays the Gamma Ray. Tracks 3 is the microresistivity. Tracks 4 and 5 are the static and dynamic microresistivity image plots of the near wellbore face. Track 6 displays the dip tadpoles and their associated classifications. Track 7 displays the bedding dip angle and dip azimuth on a group stereo net plot.

Application No. 45079, 45080, 46169, 46170, and 46171

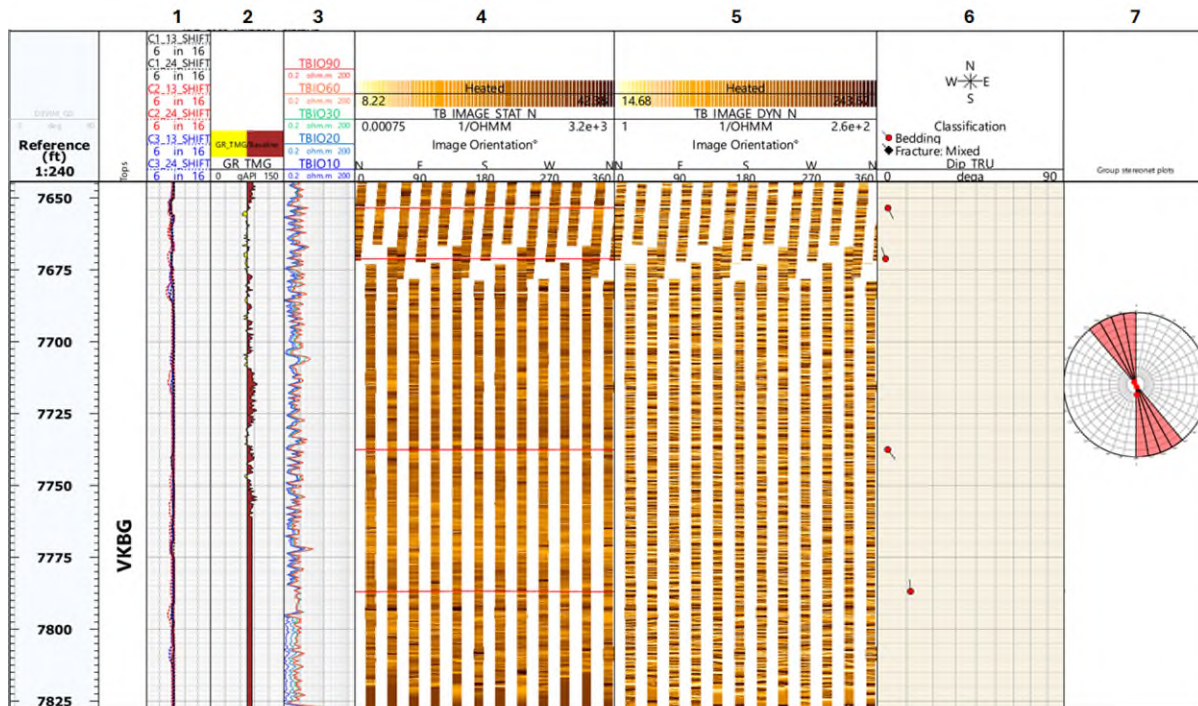


Figure NAR-60—Well-log image plot of the Vicksburg from the Pelican MLR 004 (SN 975919). Track 1 displays the wellbore geometry from the 4-arm caliper of the tool. Track 2 displays the gamma ray. Tracks 3 is the microresistivity. Tracks 4 and 5 are the static and dynamic microresistivity image plots of the near wellbore face. Track 6 displays the dip tadpoles and their associated classifications. Track 7 displays the bedding dip angle and dip azimuth on a group stereo net plot.

The confining zones' hydrodynamic sealing capacity was determined from four core high pressure mercury injection capillary pressure measurement samples converted into CO₂-water reservoir conditions and from one CO₂ Threshold Entry Pressure data sample (Project Narrative - Appendix B, Table NAR-APPENDIX-B-3). These samples were selected from sealing facies based on their very low permeability, very small pore throat radius, and depth locations in the ANAH1 and HETLM2 Upper Confining Zones. No core samples were acquired in the Vicksburg Lower Confining Zone due to wellbore instability.

Table NAR-8—Sample selections for confining zones' hydrodynamic sealing capacity from the Pelican MLR 004 (SN 975919).

Sample	Zone	Depth (ft)	Porosity (%)	Permeability (mD)	Pressure (psi)	CO2 Saturation (dec)	Water Saturation (dec)	Pore Throat Radius (microns)	Seal Height (ft)
1-15R_MICPm	ANAH1	5778.00	5.10	0.002	71.3	0.12	0.88	0.06	502
13VCm	ANAH1	5802.95	7.29	0.003	85.7	0.11	0.89	0.05	603
63HCm	ANAH1	5803.2	10.82	0.003	147.9	0.11	0.89	0.03	1041
1-29R_MICP	HetLm2	6126	6.30	0.013	20.9	0.10	0.90	0.20	147
*13V	ANAH1	5798.25-5798.5	n/a	**0.000007	***200	0.62	0.38	0.02	1408

*Denotes CO2 Threshold Entry Pressure Sample
 **Specific Permeability to Brine
 ***Pressure at which CO2 is observed at outlet of core sample

Application No. 45079, 45080, 46169, 46170, and 46171

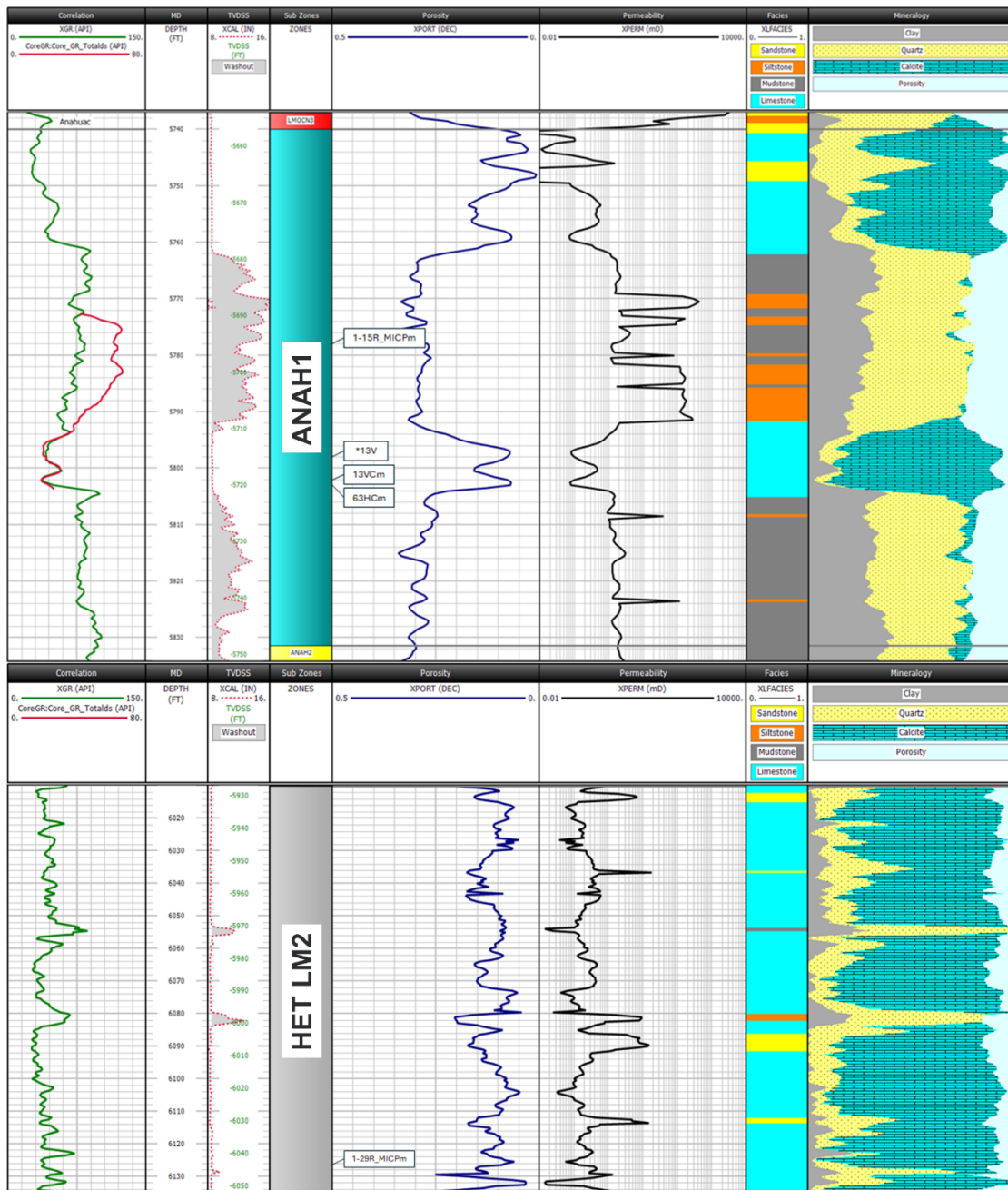


Figure NAR-61—Well-log plot of the ANAH1 and HETLM2 Upper Confining Zones from the Pelican MLR 004 (SN 975919). The mineralogy track shows the samples selected for Confining Zone sealing integrity and sealing height capacity.

The point at which CO₂ forms a connected filament within the interconnected pores of a sealing rock is at a minimum CO₂ saturation of ~10%. The pressure needed for ~10% CO₂ saturation is called the seal entry pressure. Schowalter, 1979, experimented on sandstones, shales, and chalks, and concluded that an average of 10% saturation is needed to establish a connected filament. This also suggests that if CO₂ saturation were to continue, thus an increasing buoyancy pressure, then more migration of CO₂ would extend through the interconnected pores. This can be seen on a

Application No. 45079, 45080, 46169, 46170, and 46171

capillary plateau from the range of ~10-50% where small pressure increases create substantial increases in CO₂ saturation. The sealing rock would eventually reach a maximum CO₂ saturation at a pressure where breakthrough of the seal would occur.

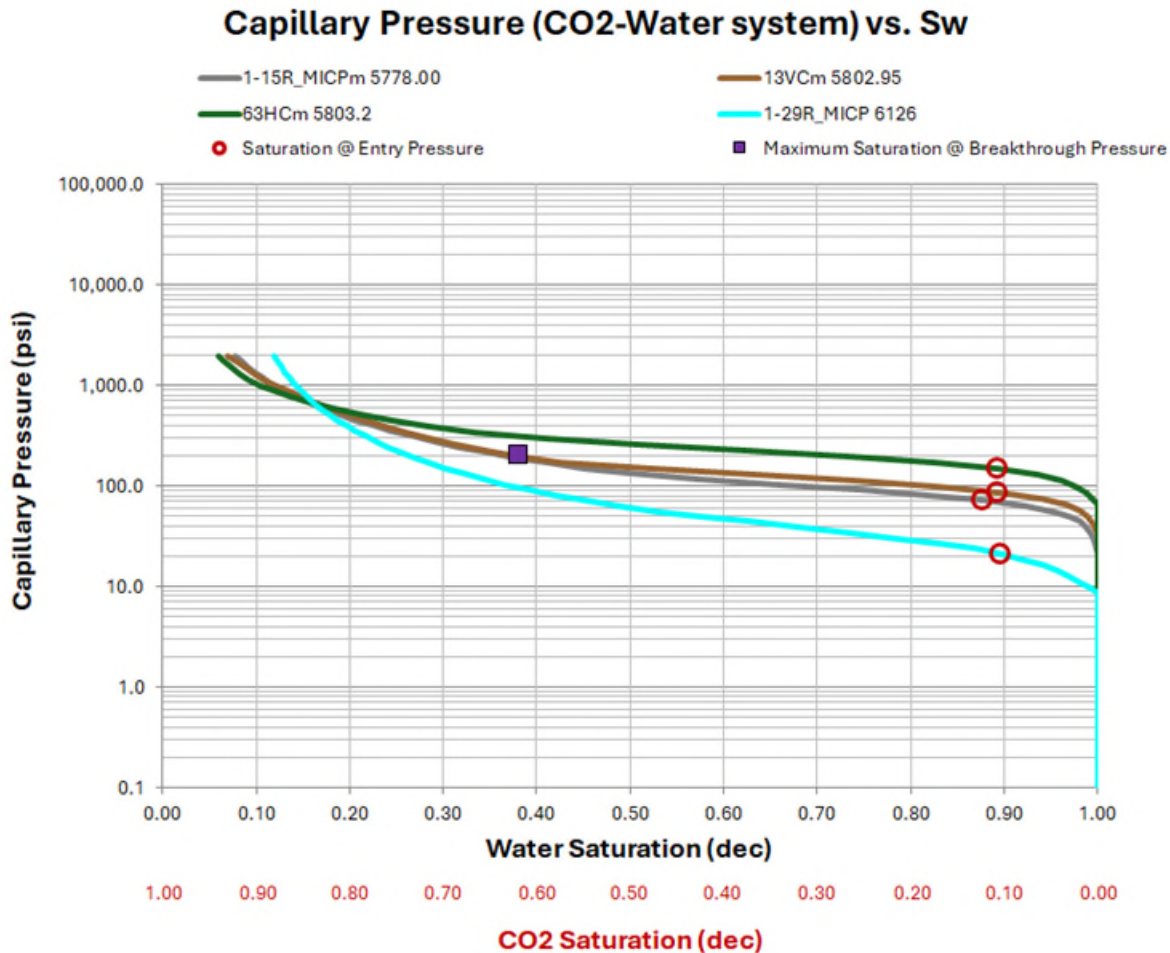


Figure NAR-62—Crossplot of water/CO₂ saturation on the x-axis and capillary pressure on the y-axis converted into a CO₂-Water system from the Pelican MLR 004 (SN 975919). The red circles represent the seal entry pressure and CO₂ saturation needed to initiate a continuous filament of CO₂ in the interconnected pores. The purple square represents the maximum pressure and CO₂ saturation at which CO₂ would break through the seal.

At the point of intersection between ~10% CO₂ saturation and seal entry pressure, an average minimum sealing height capacity can be calculated representing the CO₂ column height that an overlying seal can hold.

In this case, the estimated average CO₂ saturation and average seal entry pressure of the three core samples needed to initiate a connected filament of CO₂ in the overlying ANAH1 Upper Confining Zone is ~11% saturation and 81.5 psi (Figure NAR-62). The average minimum sealing height

Application No. 45079, 45080, 46169, 46170, and 46171

capacity at this point is 573 ft. (Figure NAR-63). The maximum sealing height capacity would be 1,408 ft. based on 200 psi and ~60% CO₂ saturation.

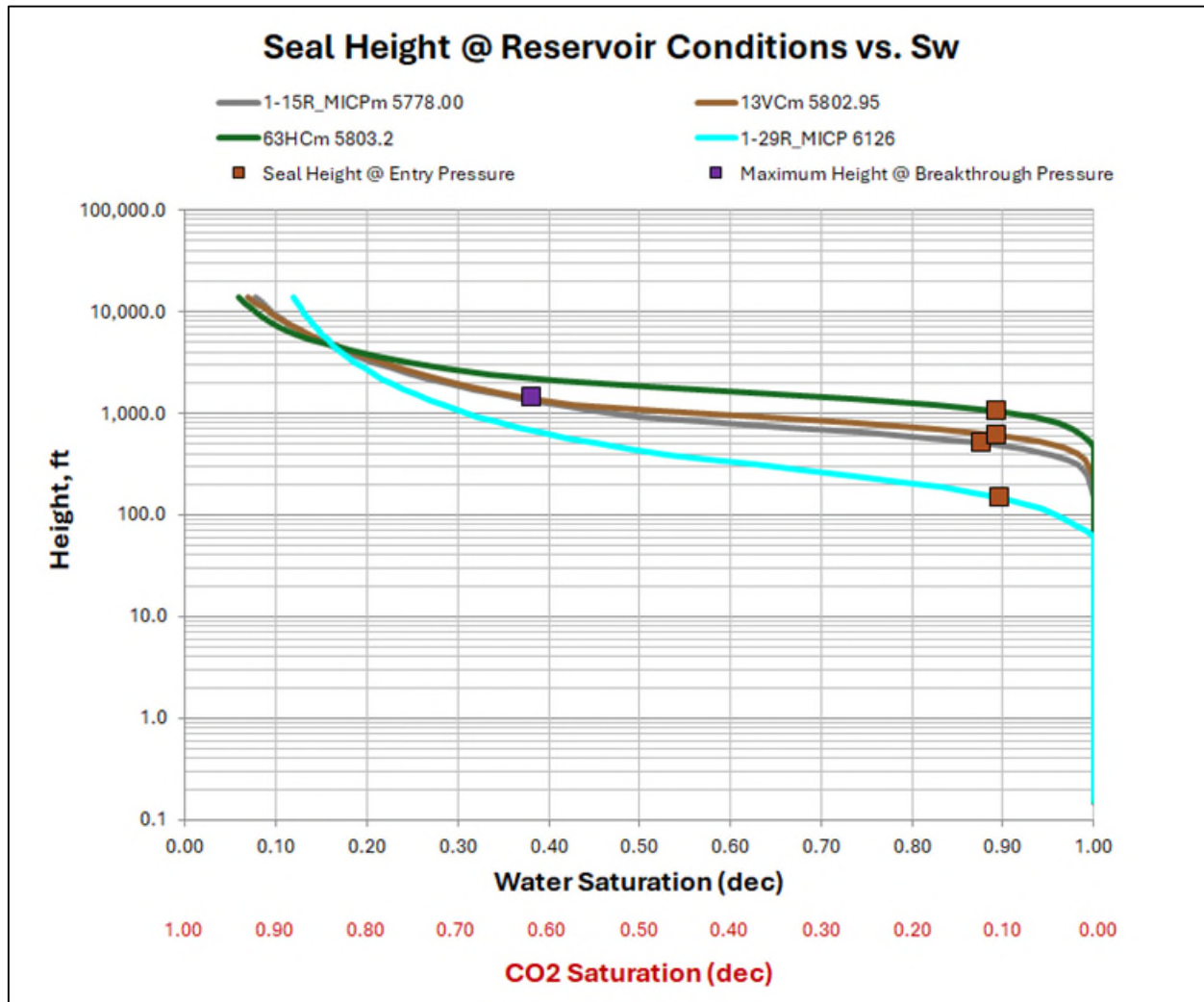


Figure NAR-63—Crossplot of water/CO₂ saturation on the x-axis and sealing height on the y-axis from the Pelican MLR 004 (SN 975919). The red squares at the ~10% saturation of CO₂ represent the minimum column height of CO₂ that can be held by the sealing shales. The purple square represents the maximum column height at which CO₂ would break through the seal.

2.5.3 Geomechanical Core Testing Summary and Implementation

The Project completed geomechanical testing on 11 samples from the Upper Miocene aquitard (UMOCN2), Lower Miocene Sand (LMOCN1), Upper Anahuac Shale (ANAH1), Lower Anahuac Sand (ANAH4), and Upper Frio Sand (FRIO1). Testing results are presented in Table NAR-9. The objective of the geomechanical testing was to capture the linear elastic strain response under confining stress and axial load determined by a preliminary estimate of the in-situ stress state. Subsequent testing measured the poroelastic property under varying confined stress and pore

Application No. 45079, 45080, 46169, 46170, and 46171

pressure. Finally, the shear strength was measured under unconfined conditions. The method employed was the single plug protocol and was conducted at New England Research (NER) laboratory. The linear elastic behavior was observed in the strain response and Young's modulus and Poisson's ratio were estimated accordingly. A deliberate method was subsequently applied to the samples to measure Biot's coefficient. Finally, all samples were subjected to final, destructive testing for unconfined compressive strength (UCS). In general, the samples exhibited low stiffness and shear strength. The samples all displayed time-dependent deformation and some exhibited orthotropic elastic responses to stress. The linear elastic properties, Young's modulus and Poisson's ratio, were reported and used to calculate log-based models that were input into the poroelastic stress models described in section 2.3.3 *Fault Reactivation Analysis*. Biot's coefficient was measured in each sample and used to calculate a log-based model for input into the poroelastic stress calculations (Figure NAR-64). Explanations for the complex deformation and apparent intrinsic orthotropy were pursued through multiple, repeated testing of sample RM-17. Results of those analyses were inconclusive due to time and material limitations. Analysis of the state of stress indicated that the time-dependent behavior presented as stress relaxation of the principal horizontal stresses. Given the near isotropic stress state, any stress relaxation would render very little change in the impact of application of that stress state to subsequent critical stress analysis. The resulting stress characterization was deemed sufficient for use for all geomechanical analyses going forward.

Table NAR-9—Summary of linear elastic and poroelastic properties. NT is not tested.

Sample	Depth (ft TVD)	Formation	Lithology	Young's modulus (Mpsi)	Poisson's ratio (unitless)	Biot's coefficient (unitless)	UCS (psi)
RM1	3023.52	UMOCN2	Silty mudstone	4.77	0.16	0.95	306.03
RM6	5210	LMOCN1	Calcareous siltstone	10.27	0.10	0.91	2728.16
RM7	5214.25	LMOCN1	Muddy siltstone	5.19	0.37	0.75	682.26
RM8	5663.1	LMOCN2	Argillaceous mudstone	4.62	0.29	0.77	NT
RM9	5668.6	LMOCN2	Silicified silty mudstone	5.06	0.22	0.86	NT
RM12	5693.1	LMOCN2	Medium grain sand	5.62	0.17	0.75	NT
RM13	5784.2	ANAH1	Argillaceous siltstone	5.01	0.19	0.88	385.80
RM14	5795.2	ANAH1	Lime packstone	29.32	0.18	0.73	11125.86
RM15	5799.2	ANAH1	Lime packstone	17.97	0.13	0.87	3002.29
RM17	6351.39	ANAH3	Sandy mudstone	12.45	0.37	0.22	NT
RM18	6754.48	FRIO1	Medium grain sand	19.42	0.18	0.04	NT

Application No. 45079, 45080, 46169, 46170, and 46171

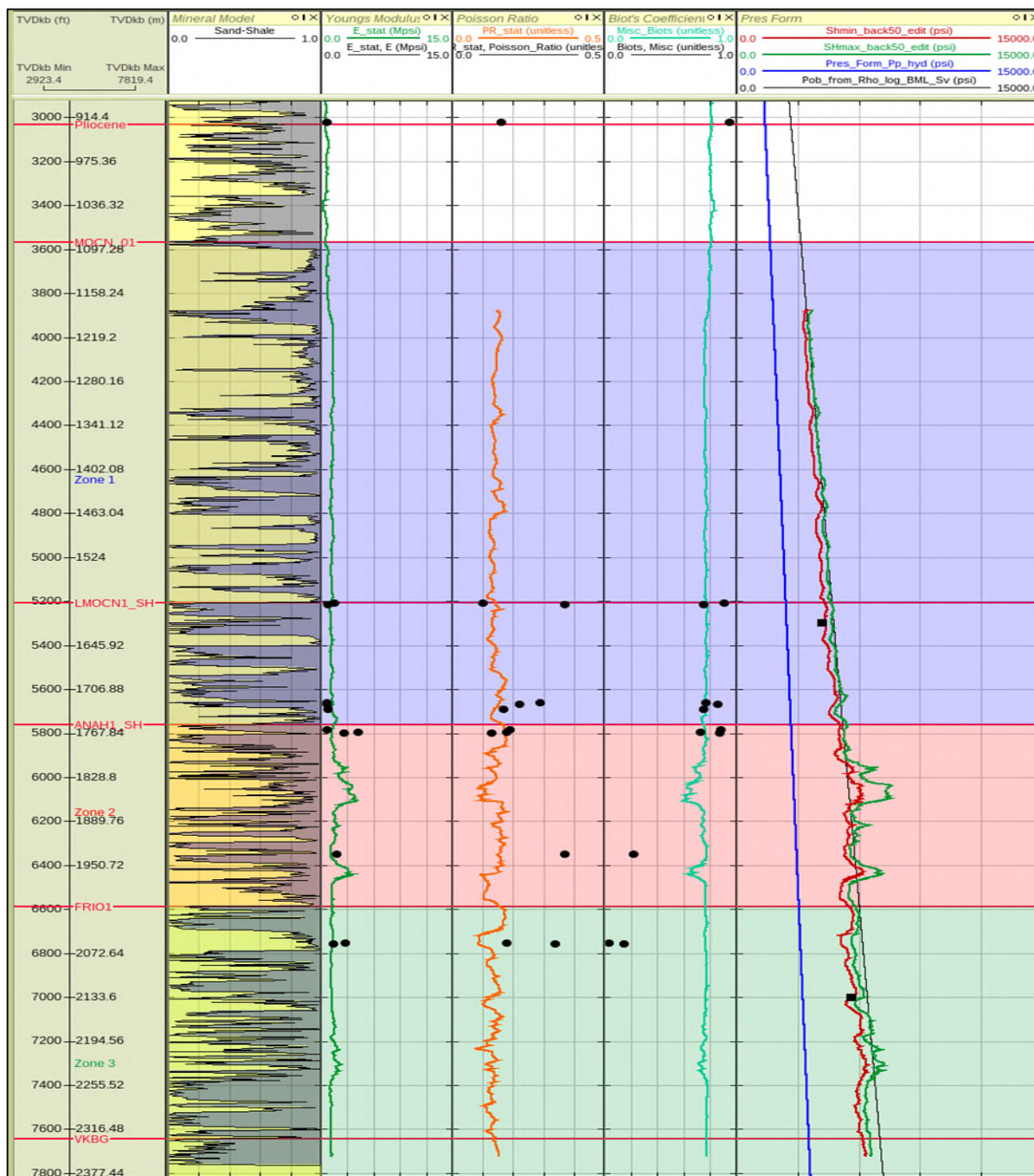


Figure NAR-64—Well log-based elastic and poroelastic properties used as input to the poroelastic stress models and the near isotropic state of stress.

2.6 Seismic History

As shown in Figure NAR-65, the proposed CCS site is situated in an area of central Louisiana with historically low seismic activity. Figure NAR-66 indicates that the area is also predicted to have

low future seismic potential. Regional earthquakes and locations were determined using the USGS online database and published data by the Louisiana Geological Survey. Five earthquakes have been recorded within 50 miles of the site, from the 18th century to the present day (Figure NAR-65). Three of these earthquakes have known magnitudes. Two of the three occurred within 30 miles with a magnitude of 3.0 and the third, occurring more than 40 miles away, had a magnitude 4.2. The USGS Long-Term Seismic Hazard Map (Figure NAR-66) indicates that this area is at relatively low risk of earthquake activity. The map is based on models looking at the fault-slip rates and frequency of earthquakes and represents the peak ground accelerations having a 2% probability of being exceeded in 50 years (USGS, 2024).

Several factors were considered in assessing the probability of seismic activity around the site, including distance from basement (>10,000 ft), distance from faults (using 3D seismic), and historical seismic activity. Additionally, model simulations show that the maximum pressure change in the reservoir will be significantly lower than the pressure change required to induce slip on faults, if they were present (refer to section 2.3.3). To further mitigate risks, a site-specific seismicity monitoring array will be deployed to lower the magnitude of completeness in the area.

Application No. 45079, 45080, 46169, 46170, and 46171

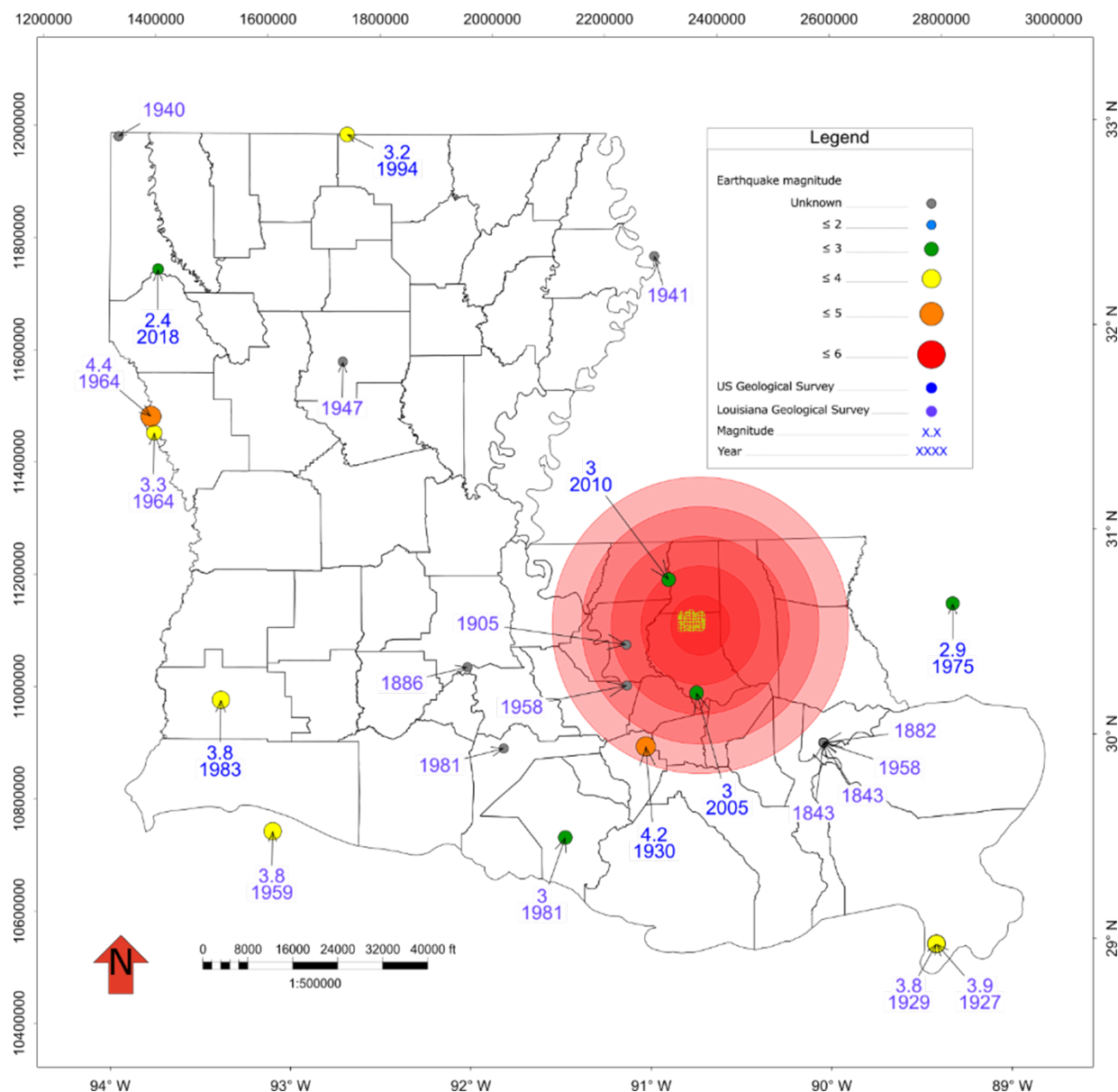


Figure NAR-65—Seismic activity recorded by the USGS (2023), Appendix E: Historical Seismicity Data tabulates the recorded seismicity data and their locations. The concentric red circles have radii of 10, 20, 30, 40, and 50 miles centered on the injection locations.

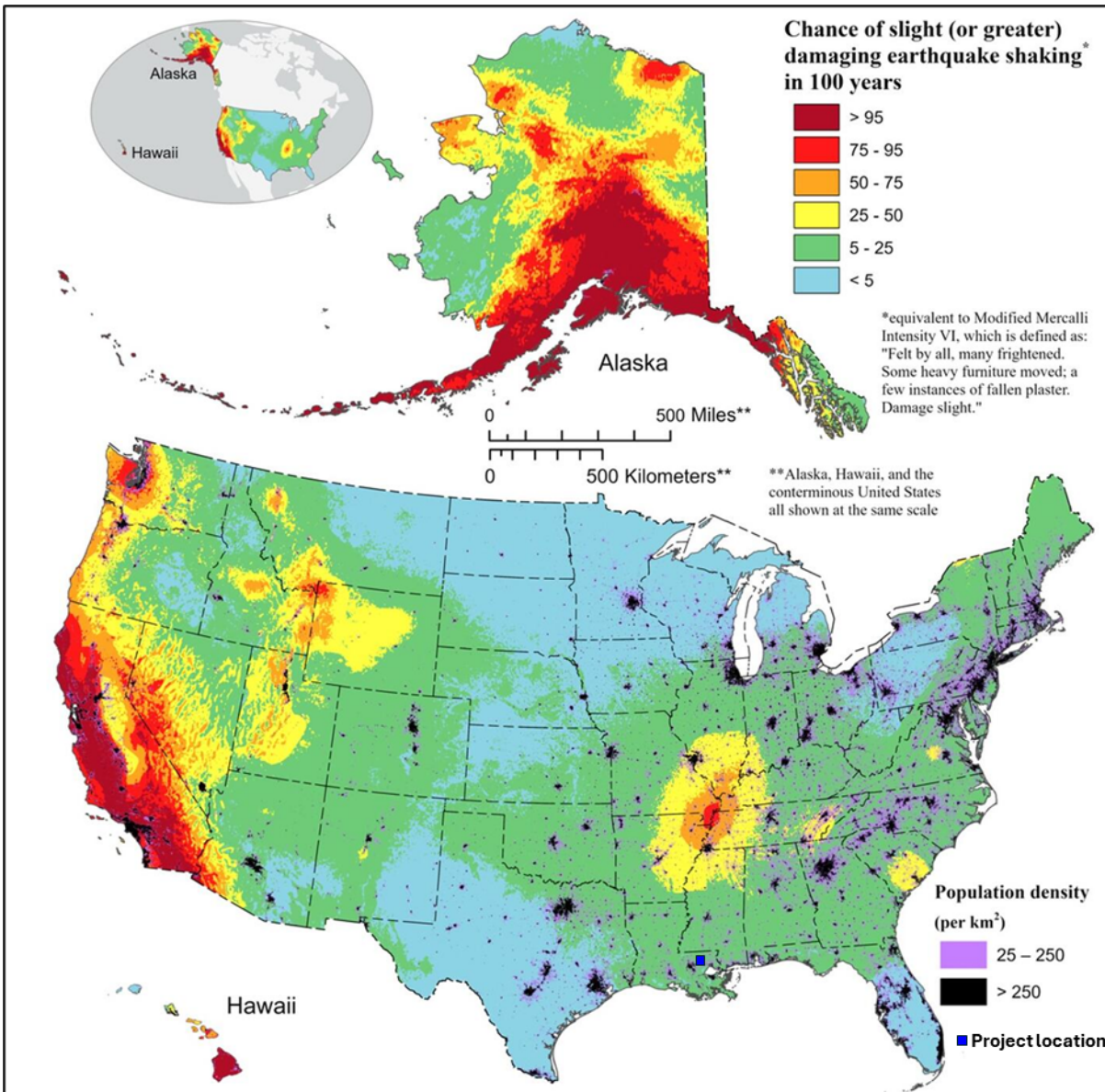


Figure NAR-66—Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2024 Long-Term National Seismic Hazard Map (USGS, 2024). Seismic hazard potential in the study area is one of the lowest in the U. S.

2.7 Hydrogeology

2.7.1 Freshwater Aquifers

The Pelican Sequestration Hub is located in the Tickfaw subbasin watershed and overlies the Coastal Lowlands aquifer system (Figure NAR-67). The Tickfaw subbasin extends from Lake Maurepas northward into Mississippi, and is drained by the Tickfaw River, which originates in Mississippi. Tributaries of the Tickfaw River in Livingston Parish include Hog Branch, Blood River, Natalbany River, and other small streams. The annual average streamflow of the Tickfaw River at Holden (site number 07376000) was 373 ft³/s during 1941–2014 from a drainage area of

Application No. 45079, 45080, 46169, 46170, and 46171

about 247 mi² (USGS 2015, White and Prakken, 2016). The Coastal Lowlands aquifer system yields large quantities of water for agricultural, public supply, domestic and commercial, and industrial uses. The Denham Springs-Scotlandville fault system, an east-west trending growth fault, lies south of the Pelican Sequestration Hub AOI and does not appear to influence groundwater hydrology (Figure NAR- 67; White and Prakken, 2016).

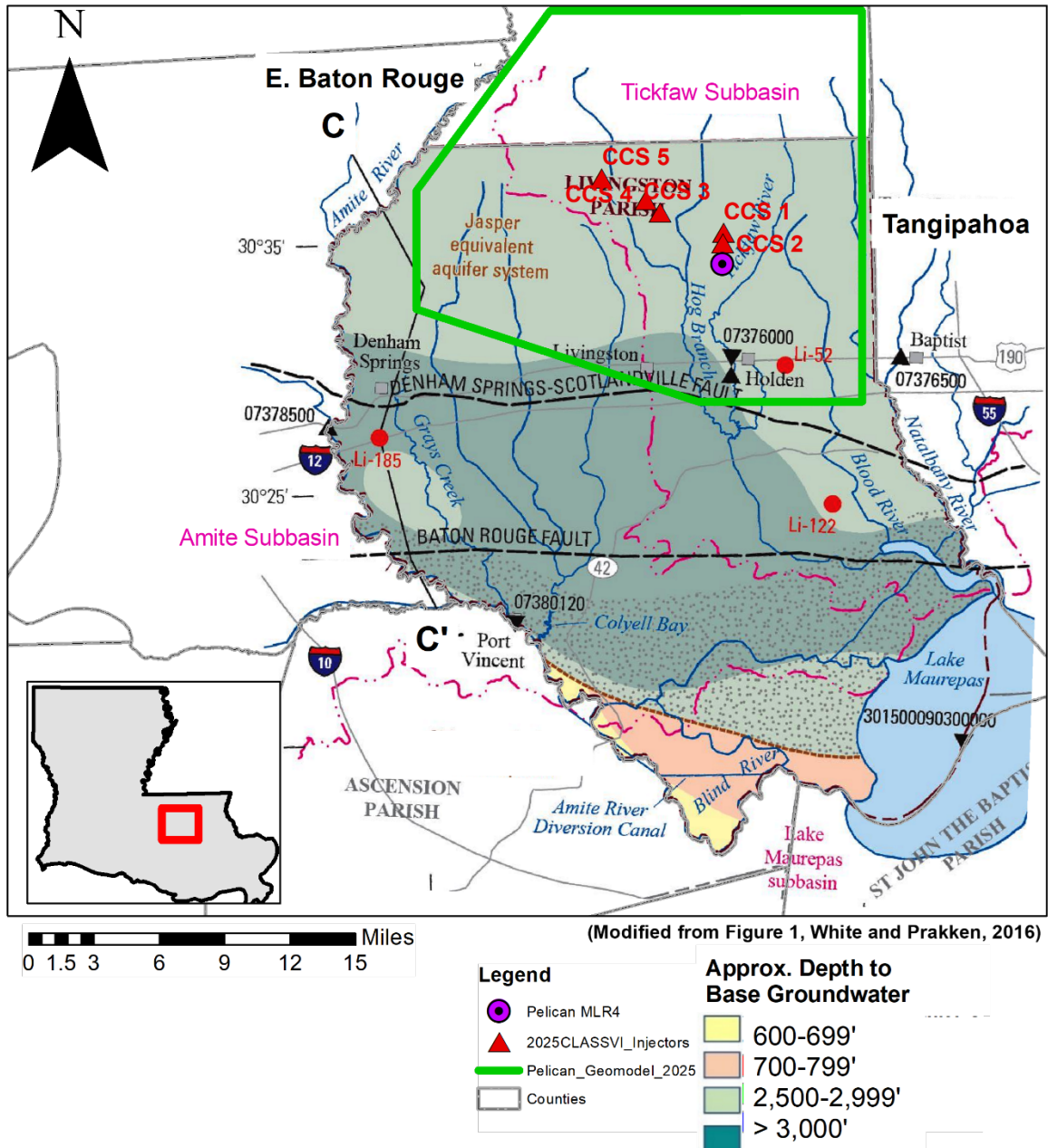


Figure NAR-67—Location of Pelican Sequestration Hub overlain on a published summary of local Coastal Lowland Aquifer System (White and Prakken, 2016).

Regionally, the Coastal Lowlands aquifer system underlies about 160,000 mi² in parts of Alabama, Florida, Louisiana, Mississippi, and Texas (Weiss, 1992). The aquifer system consists of a

heterogeneous, unconsolidated to poorly consolidated wedge of discontinuous beds of sand, silt, and clay. The wedge of sediment thickens gulfward, and ranges in age from Oligocene to Holocene (Renken, 1998). The average thickness of the sediments is about 6,000 feet, with a maximum thickness of more than 18,000 feet occurring offshore from southern Louisiana (Renken, 1998). Figure NAR-68 illustrates the gently south-southeast sloping nature of the aquifer system towards the Gulf of America.

Time (Ma)	Series	Stage	Clastic Supply	Aquifer System or Confining Unit
0			Low High	
	Pleistocene			Chicot equivalent aquifer system "400-foot" sand and "600-foot" sand
	Pliocene	L		Evangeline equivalent aquifer system "800-foot", "1000-foot", "1,200-foot", "1,500-foot", and "1,700-foot" sands
		E		
5				Unnamed Confining Unit
10	Miocene	L		Jasper equivalent aquifer sands "2,000-foot", "2,400-foot", "2,800-foot"
15		M		Unnamed Confining Unit
20		E		Regional Start of Saline Aquifer

Figure NAR-68—Stratigraphic column summarizing the geohydrologic units of southeastern Louisiana.

Given the regionally extensive nature of the Coastal Lowlands aquifers system, local aquifer names have been applied to describe different hydrogeologic units (Figure NAR-68). For example, in southwestern Louisiana, the Chicot, Evangeline, and Jasper aquifers comprise major hydrogeologic units of the Coastal Lowlands aquifer system (Lindaman, 2023). However, these aquifers do not extend into southeastern Louisiana as mappable hydrogeologic units. For this reason, some studies use “equivalent” aquifer nomenclature to subdivide major hydrogeologic units in southeastern Louisiana, including Chicot, Evangeline, and Jasper equivalent aquifers (Figure NAR-68; Griffith, 2003; Renken, 1998). Previous studies have referred to the Chicot equivalent aquifer system in the northern portion of Livingston County as the Upland terrace aquifer, due to the large proportion of sand and gravel deposits and hydraulic connection to major streams in the area (Walters, 1995; Frederick, 2022). Additional aquifer nomenclature at Pelican Sequestration Hub in southeastern Louisiana references depths at which major hydrogeologic units are encountered in industrial districts of Baton Rouge and New Orleans, such as “400-foot sand” and “2,800-foot sand” (Figure NAR-69; Griffith, 2003, Smoot, 1988; Renken, 1998). Although this aquifer nomenclature includes depth references, these hydrogeologic units are neither

Application No. 45079, 45080, 46169, 46170, and 46171

stratigraphically equivalent nor hydraulically interconnected to those described in New Orleans and Baton Rouge. The lack of regional hydraulic connectivity and stratigraphic correlation is due to the southward dip and displacement from faults the Coastal Lowlands aquifer system.

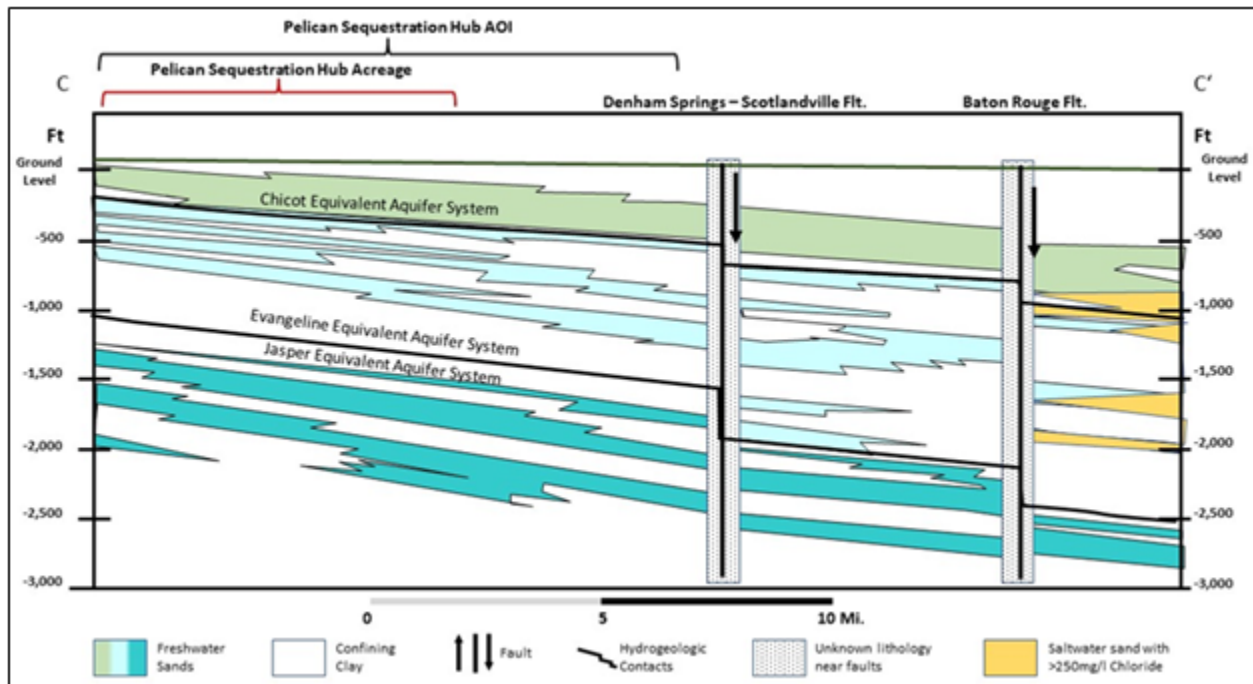


Figure NAR-69—Generalized hydrogeologic cross section C–C'. Location shown on Figure NAR- 67. (modified from Griffith, 2003)

The primary aquifers composing the Chicot equivalent aquifer system in Livingston Parish are shallow sands of the Baton Rouge area, the Gonzales-New Orleans aquifer, the Upland terrace aquifer, and the “400-foot” and “600-foot” sands of the Baton Rouge area (Griffith, 2003; White and Prakken, 2016). The Chicot equivalent aquifer exists under unconfined and confined conditions depending on presence of confining units, and a clay layer is generally present at the land surface. Localized confining units combine to retard the vertical movement of groundwater, facilitating confined conditions in deeper portions of the Chicot equivalent aquifer system. The base of the Chicot equivalent aquifer system ranges 300 ft bgs at the northern parish line to 1,200 ft bgs at the southern parish line (Figure NAR-67). The general direction of groundwater flow is south towards the gulf, and water levels range from surface to 25 ft bgs (Figure NAR-67; White and Prakken, 2016).

Application No. 45079, 45080, 46169, 46170, and 46171

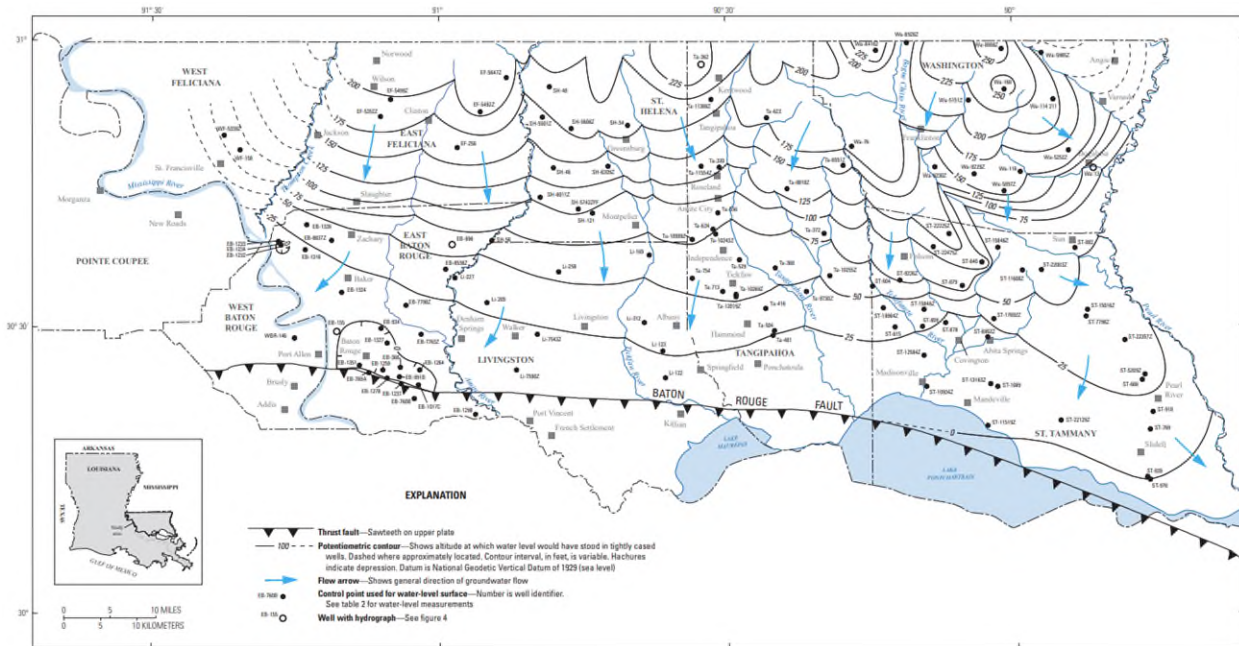


Figure NAR-70—Potentiometric surface of “400-foot” sand (Chicot equivalent aquifer) in southeastern Louisiana, January 2014-March 2015. Generalized groundwater flow directions shown with blue arrows (modified from Frederick, 2022)

State well records show 1,010 wells completed in the Chicot equivalent aquifer across the Pelican Sequestration Hub AOI (Table NAR-10; Figure NAR-69). Within the Pelican Sequestration Hub AOI well depths range from 10 to 550 ft bgs, with yields ranging from 2 to 500 gpm (C&E, 2015). The Chicot equivalent aquifer is the primary source for domestic water consumption, but also provides water for agriculture, public supply, oil and gas, and industrial usage. In 2010, withdrawals from the Chicot equivalent aquifer system in Livingston Parish totaled about 2.17 Mgal/d; approximately 88% of withdrawal volumes consisted of rural-domestic and public supply uses (White and Prakken, 2016).

Table NAR-10—Summary of Louisiana well registration records for water wells within Pelican Sequestration Project AOI .

	Chicot Surface Confining	Chicot Equivalent	Evangeline Equivalent	Jasper Equivalent
Depth Range	< 20 ft	10–550 ft	300–1,900 ft	1,600–2,950 ft
Aquifer Use				
Plug & Abandon		77	10	7
Domestic		847	16	2
Public Supply		21	10	8
Agriculture		37	3	
Oil/Gas		18		1
Industrial		10	2	
Test		3	4	
Monitor	6	1		

Application No. 45079, 45080, 46169, 46170, and 46171

	Chicot Surface Confining	Chicot Equivalent	Evangeline Equivalent	Jasper Equivalent
Well Count	6	1,014	45	18

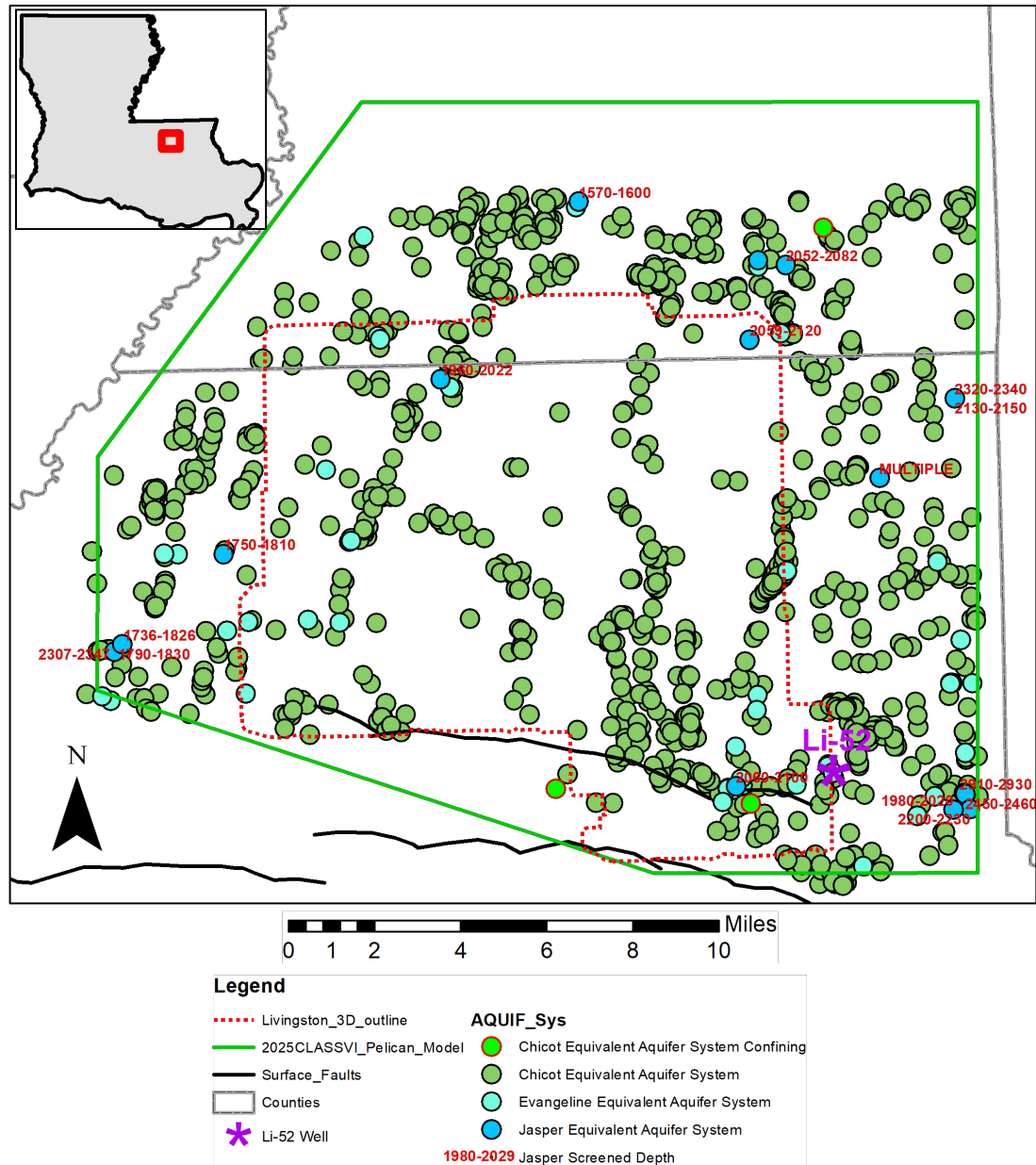


Figure NAR-71—Water wells within the Pelican Sequestration Project, as recorded in the Louisiana state well register. Monitoring well in Evangeline equivalent aquifer (Li-52) shown in purple.

The primary aquifers composing the Evangeline equivalent aquifer system in Livingston Parish are the “800-foot,” “1,000-foot,” “1,200-foot,” “1,500-foot,” and “1,700-foot” sands of the Baton Rouge area (Griffith, 2003; White and Prakken, 2016). The base of the Evangeline equivalent aquifer system ranges from 1,000 ft bgs at the northern parish line to 2,500 ft bgs at the southern

parish line (Figure NAR-67). The “1,500-foot” and “1,700-foot” sands typically have similar water levels, indicating that these sands are hydraulically connected (White and Prakken, 2016). The Evangeline equivalent aquifer is under confined conditions. The general direction of groundwater flow is southwest, and potentiometric heads range from near surface to 50 ft bgs (Figure NAR-74; White and Prakken, 2016). Monitoring well Li-52 completed in the Evangeline equivalent aquifer system, located near the Pelican Sequestration Hub AOI, measured potentiometric head at 29 ft above ground surface in 2016 (Figure NAR-67; White and Prakken, 2016).

State well records show 45 wells completed in the Evangeline equivalent aquifer across the Pelican Sequestration Hub AOI (Project Narrative – Appendix C Table NAR-APPENDIX-C-1; Figure NAR-69). Within the Pelican Sequestration Hub AOI well depths range from 300 to 1,900 ft bgs, with yields ranging from 10 to 1,900 gpm (C&E, 2015). The Evangeline equivalent aquifer is the major source for public supply consumption, but also provides water for agriculture, domestic, and industrial usage. In 2010, withdrawals from the Evangeline equivalent aquifer system in Livingston Parish totaled about 4.92 Mgal/d; approximately 99% of withdrawal volumes comprised public supply uses (White and Prakken, 2016).

The primary aquifers composing the Jasper equivalent aquifer system in Livingston Parish are the “2,000-foot,” “2,400-foot,” and “2,800-foot” sands of the Baton Rouge area (Griffith, 2003; White and Prakken, 2016). The base of the Jasper equivalent aquifer system is not well defined, and reasonable estimates are >2,000 ft bgs at the northern parish line to >3,400 ft bgs at the southern parish line (Griffith, 2003; Figure NAR-69). The Jasper equivalent aquifer exists under confined conditions. Poor water quality (saline to brine) is present in the lower sands of the aquifer system. The general direction of groundwater flow is west towards large groundwater withdrawal occurring near Baton Rouge. Few data for water levels are available, but one monitoring well (Li-185) located in western Livingston Parish measured water level at 62 ft bgs in 2016 (White and Prakken, 2016).

State well records show 18 wells completed in the Jasper equivalent aquifer across the Pelican Sequestration Hub AOI (Table NAR-10; Figure NAR-68). Within the Pelican Sequestration Hub AOI well depths range from 1,600 to 2,950 ft bgs, with yields ranging from 10 to 1,934 gpm (C&E, 2015). The Jasper equivalent aquifer is a major source for public supply but also provides water for agriculture and industrial usage. In 2010, withdrawals from the Jasper equivalent aquifer system in Livingston Parish totaled about 6.46 Mgal/d; approximately 99% of withdrawal volumes consisted of public supply use (White and Prakken, 2016).

Hydraulic characteristics of the Coastal Lowlands aquifer system are heavily influenced by sand and clay proportions, and connectivity is often poorly understood due to constrained lateral and vertical boundaries with gradational contacts. Moderately high hydraulic conductivities (100 to 120 ft/day) are associated with higher sand percentages (Renken, 1998). Low values (<5 ft/d) for hydraulic conductivity are associated with prodelta deposits dominated by interbedded silt, mud, and very fine sand (<10%) (Renken, 1998). Interdistributary deposits tend to be more permeable than prodelta deposits, but hydraulic conductivities are often low to moderate (5 to 100 ft/d) (Renken, 1998).

Water quality in the Coastal Lowlands aquifer system in Livingston Parish is predominately fresh and total dissolved solids (TDS) concentrations typically range from 50 to 350 mg/l TDS, but some water quality analyses have reported dissolved chloride concentrations up to 1,200 mg/l (USGS 2015; White and Prakken, 2016). The dominant water type is calcium bicarbonate and hardness (mg/l as CaCO₃) ranges from 0.5 to 57 mg/l as CaCO₃. Locally, concentrations of iron and manganese can greatly exceed EPA Secondary Maximum Contaminant Levels (White and Prakken, 2016). Water quality in the Coastal Lowlands aquifer system is directly related to groundwater flow and tends to become increasingly saline as it flows gulfward due to several factors including: (1) increasing distance from landward recharge areas, (2) increasing mineral dissolution, and (3) commingling with seawater intrusion (Renken, 1998). Groundwater transitions from calcium bicarbonate water type to sodium bicarbonate type along flow paths towards the gulf as calcium ions are exchanged for sodium ions in clay minerals. Deep portions of the Coastal Lowlands aquifer system (i.e., lower sands in the Jasper equivalent aquifer system) can contain poor water quality (saline to brine) and is likely associated with long flow paths (Renken, 1998).

2.7.2 Base of underground source of drinking water (USDW)

Publicly available literature for southeastern Louisiana commonly describes base to freshwater (TDS <1,000 mg/L) but does not typically report depth of base USDW as defined by USEPA (depth at which formation water contains less than 10,000 mg/L TDS). The formal definition of a USDW, as found in the Louisiana UIC Regulations, Statewide Order No. 29-N-1 (LAC 43:XVII.101(A)) matches that of the EPA Class VI regulation and reads as follows:

Underground source of drinking water (USDW) means an “aquifer” or its portion;

- a) 1) Which supplies any public water system; or*
- 2) Which contains a sufficient quantity of ground water to supply a public water system;*
- and*
- i) currently supplies drinking water for human consumption; or*
- ii) contains fewer than 10,000 mg/l total dissolved solids and*
- b) Which is not “exempted aquifer.”*

Here, site-specific interpretation for base USDW was completed using deep resistivity readings from open hole logs. Deep resistivity methodology followed Louisiana Department of Conservation and Energy (C&E) guidelines. C&E methodology was applied to wells within and outside of the AOR. Results from C&E method were compared to publicly available groundwater quality and water supply well information to confirm base USDW. The C&E methodology was conducted under the following guidance:

“The C&E typically uses the deep induction curve on an e-log to define the base of the USDW. The following guidelines are used: (1) ground surface to 1,000 feet: 3 ohms or greater is considered USDW; 2) from 1,000 feet to 2,000 feet: 2 ½ ohms or greater is considered USDW; and 3) 2,000 feet and deeper: 2 ohms or greater is considered USDW. The base of the USDW is established at the base of the sand unit that contains the lowermost USDW with an isolating shale beneath it (C&E, 2022).”

One concern with deep resistivity readings is that, in addition to resistivity responses from formation fluid salinity, resistivity responds to pore fluids such as hydrocarbons, gases, and drilling

Application No. 45079, 45080, 46169, 46170, and 46171

fluids, as well as cementation effects in tight sandstones. Here, care was taken by technical staff to consistently select clean basal sandstones with high water saturations for formation water salinity estimation. In addition, the SONRIS database used by C&E for interpretation of USDW from deep resistivity curves was compared to site-specific logs (Louisiana UIC, 2020). The sand base below 2-ohm methodology was used to extend interpretation and the resulting tops were gridded. In total, 17 wells were selected for base USDW picks. Pelican Sequestration Hub drilled and completed stratigraphic test well MLR 004 which facilitated a site-specific base USDW pick from modern open hole logs.

Figure NAR-72 shows the interpreted base USDW at MLR 004 of 3,275 ft TVDSS, located in the Upper Miocene (UM3 Zone). Figure NAR-73 shows the resulting mapped base USDW depths in TVDSS, trended with a Digital Elevation Model. Base USDW mapping shows a deepening of the USDW from approximately 2,800 ft TVDSS in the north to approximately 3,400 ft TVDSS in the south. Figure NAR-74 is a structural N-S cross-section that depicts average vertical separation of 2,500 ft between the Anahuac confining units and base USDW across the Pelican Sequestration Hub.

Application No. 45079, 45080, 46169, 46170, and 46171

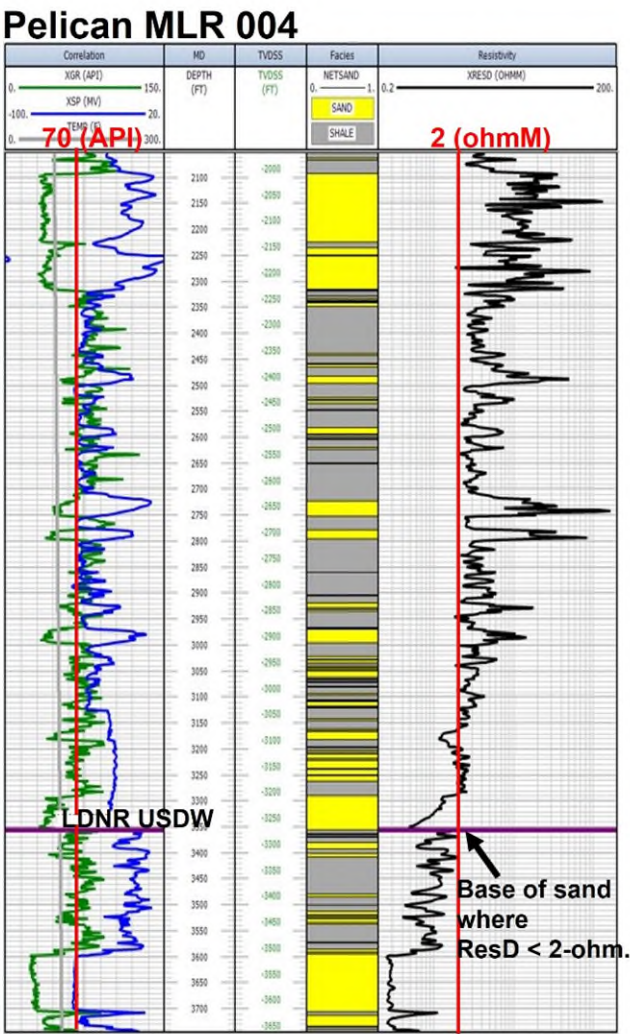


Figure NAR-72—Log plot from Pelican MLR 004 with base of USDW at 3,275 ft SSTVD.

Application No. 45079, 45080, 46169, 46170, and 46171

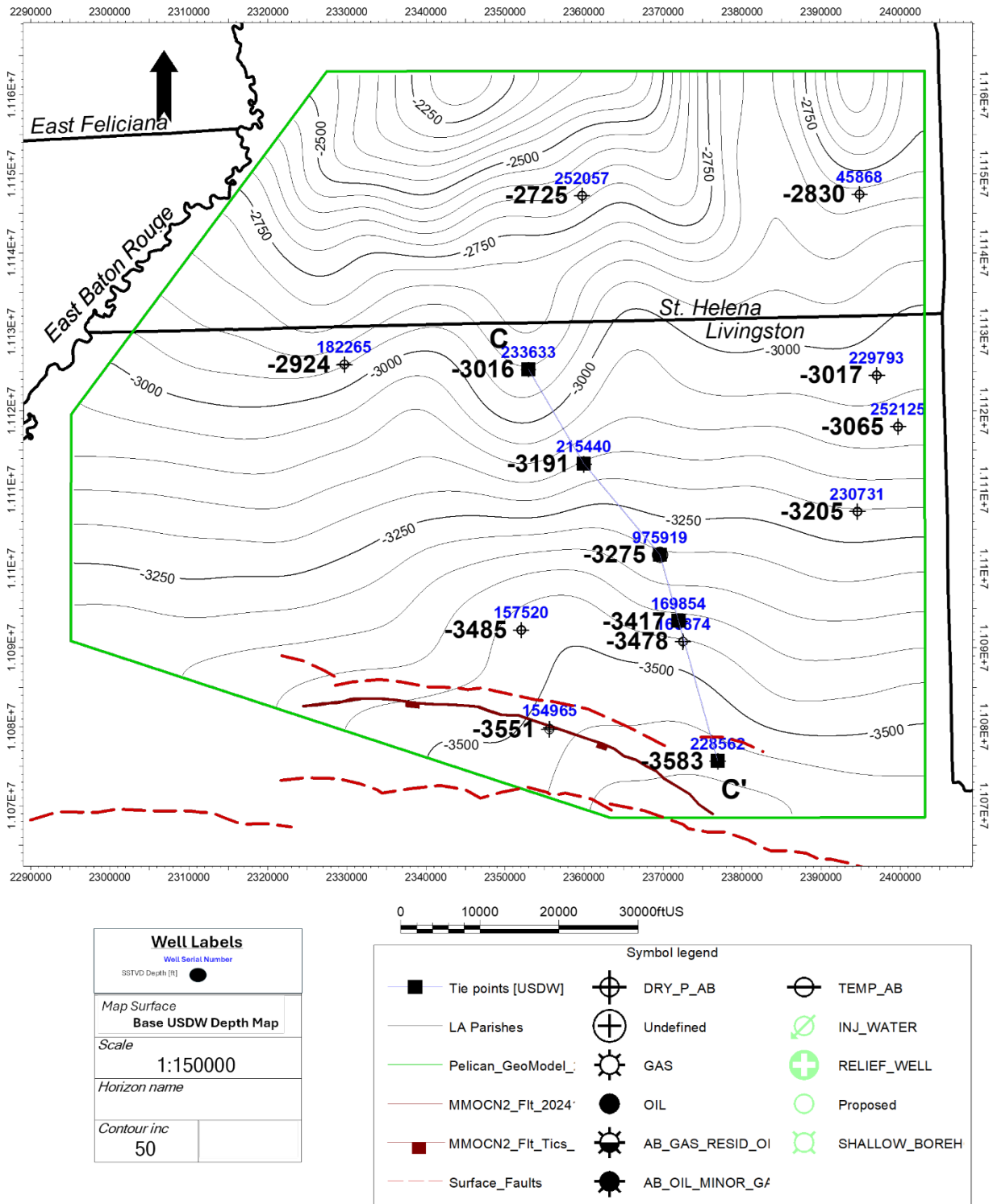


Figure NAR-73—Structure map of the base of the USDW defined using 17 wells

Application No. 45079, 45080, 46169, 46170, and 46171

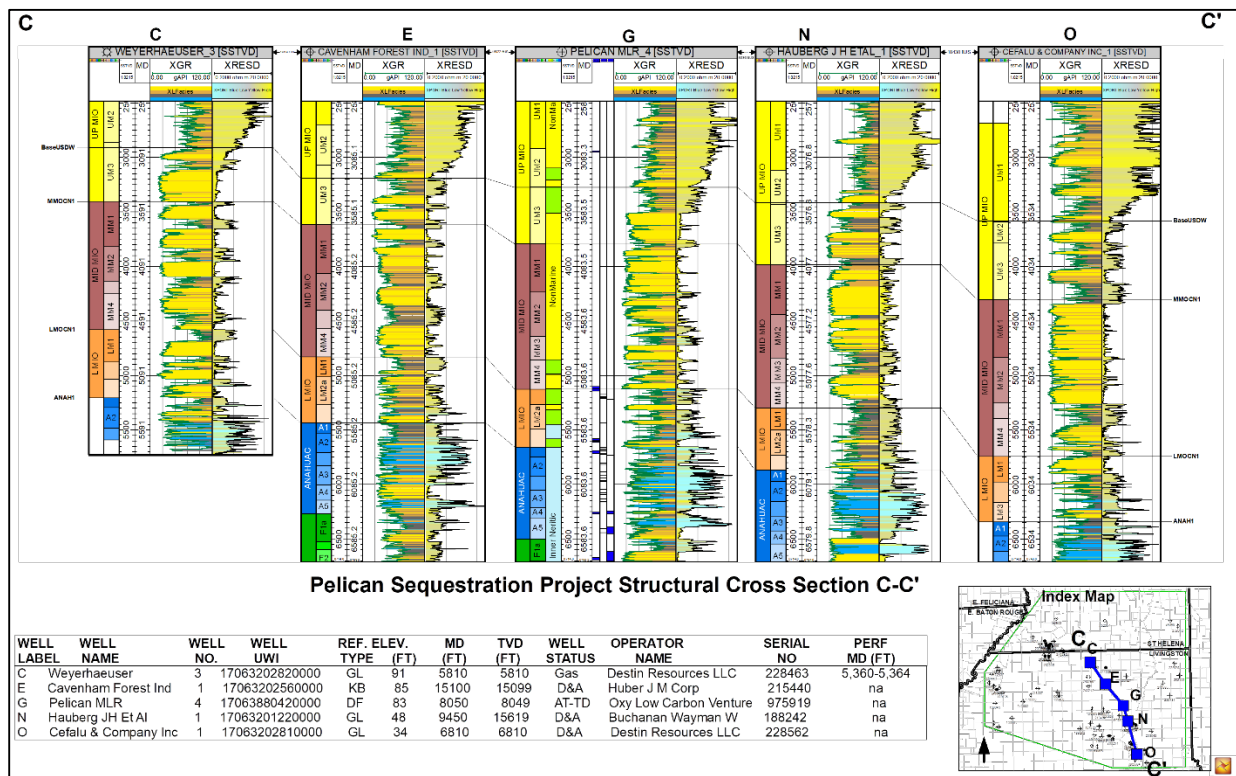


Figure NAR-74—North to south cross section illustrating interpretation of the base USDW and structural dip toward the south.

2.8 Geochemical Modeling

2.8.1 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. Here, quartz is the dominant mineral in Lower Anahuac and Frio injection zones; dominant minerals in the overlying confining system include quartz and clays in the Upper Anahuac and calcite in the Heterostegina Limestone (“Het Lime”). 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 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 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 concentration increases that were 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 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 wells, 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 Pelican 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 Pelican 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.

2.8.2 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 NAR-11 shows brine composition used for both reservoir and confining units in geochemical simulations. Brine chemical composition is from production fluid samples collected during a Frio reservoir well test. 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 NAR-11—Brine chemical compositions for geochemical and reactive-transport simulations.

Name	Description	Units	Frio Sand
Sample Depth	-	ft	6,707
Sample Pressure	-	psi	2,985
Sample Temp	-	°F	143
TDS	Sum of Ions	mg/L	120,013
pH	Lab	SU	6.56
Sodium	Na ⁺	mg/L	42,032
Calcium	Ca ²⁺	mg/L	2,876
Magnesium	Mg ²⁺	mg/L	905
Potassium	K ⁺	mg/L	195
Strontium	Sr ²⁺	mg/L	226

Application No. 45079, 45080, 46169, 46170, and 46171

Name	Description	Units	Frio Sand
Barium	Ba ²⁺	mg/L	60.1
Silica	SiO ₂ (aq)	mg/L	20
Aluminum	Al ³⁺	mg/L	1.0 x 10 ⁻³
Iron (II)	Fe ²⁺	mg/L	26.9
Chloride	Cl ⁻	mg/L	73,218
Total Alkalinity	Alkalinity	mg CaCO ₃ /L	177
Borate	B(OH) ₃ ⁻	mg/L	123
Bromide	Br ⁻	mg/L	95
Sulfate	SO ₄ ²⁻	mg/L	6.0

Table NAR-12 describes mineralogy used in geochemical equilibrium runs for the reservoirs and confining system. Values were obtained from a mineral model that utilizes SCAL and XRD analyses of representative samples from the reservoir and confining units.

Table NAR-12—Solid-phase mineralogy from RSWC XRD data used in geochemical equilibrium and reactive-transport simulations.

Mineral (Rock Vol. %)	Het Lime	Upper Anahuac	Frio Sand
Porosity	6.4	15.2	30.6
Plagioclase	0.0	1.7	0.3
Calcite	85.6	3.3	0.2
Dolomite	0.0	0.0	0.0
Pyrite	0.4	0.9	0.1
Illite	3.2	47.4	0.7
K-Feldspar	0.0	1.0	0.3
Kaolinite	0.9	7.4	0.1
Quartz	3.5	23.0	67.7

Although some chemical reactions are known to be time dependent, equilibrium assumption was first modeled to represent the most conservative approach. The equilibrium approach allows minerals to dissolve or precipitate instantaneously and achieve final stage of interaction with other solid phase and aqueous species. This approach can simulate expected late time fluid-rock interactions anticipated in permanent 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 more suitable for the brines analyzed for this site. Besides the ion-size parameters, the extended terms based on ionic strength have been fit for main ions in chloride-dominated waters (Truesdell and Jones, 1974) such as calcium, magnesium, sulfate, potassium, and carbonate species. In addition, the Pitzer approach has limited parametrization for iron and aluminum species as pointed out by Krupka et al. (2010). These aqueous components are very important for brines in equilibrium with clay-type minerals because they modify the ions activity, having critical impact on minerals solubility product (Appelo and Postma, 2005).

Application No. 45079, 45080, 46169, 46170, and 46171

Equilibrium simulations were conducted for the reservoir (Frio sand) and confining units (Upper Anahuac shale, Het Lime). Initial porosity for the Frio sand, Upper Anahuac, and Het Lime was 30.6%, 15.2%, and 6.4%, respectively. Initial CO₂ concentration was retrieved using flashed gas composition and the fugacity was calculated at reservoir pressure and temperature. Calculated pre-injection fugacity is 0.025. Secondary mineral phases were included in the simulation even though they are not present in measured XRD data (e.g., dolomite, anhydrite, gypsum, barite, strontianite, and celestite) to evaluate their precipitation tendency. In addition, plagioclase is assumed to be anorthite phase.

Three geochemical scenarios were modeled at reservoir conditions: (1) fluid equilibrium without minerals present, (2) current (pre-injection) baseline equilibrium between existing formation fluids and mineralogy, and (3) equilibrium between existing formation fluids and mineralogy with fully saturated CO₂ to represent the most aggressive injection case. Table NAR-13 shows results for the current fluid equilibrium state of the Frio sand reservoir. Positive and negative saturation index numbers (SI) indicate supersaturated or undersaturated conditions with respect to each mineral. 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. Reservoir fluids are in equilibrium with barite, K-feldspar, and quartz; and saturated with respect to calcite, dolomite, and strontianite.

Modeled pH is noticeably larger in comparison to laboratory measured values. This discrepancy between modeled and measured fluid pH can be explained by CO₂ exsolving from solution prior to flashed gas sampling. This explanation is reasonable considering samples were production fluid samples and were not collected *in-situ* and preserved at reservoir conditions. Even rapid laboratory analytical results in CO₂ loss prior to measurements, resulting in a shift to more basic conditions (Appelo and Postma, 2005, page 14). Here, the Frio reservoir fluid chemistry is similar to literature values (Kharaka et al., 2009 and Xu et al., 2010).

Table NAR-13—Simulated fluid equilibrium in Frio Sand at reservoir conditions without minerals present.

Model Results (SI)	Frio Sand
pH (SU)	7.0
Anhydrite	-3.0
Barite	-0.2
Calcite	0.7
Celestite	-2.4
Dolomite	2.5
Gypsum	-3.2
Halite	-1.4
Illite	-2.1
Kaolinite	-2.3
K-Feldspar	-0.4
Plagioclase	-7.1
Quartz	0.2
Strontianite	1.8

Application No. 45079, 45080, 46169, 46170, and 46171

Baseline (pre-injection) equilibrium modeling included the addition of formation mineralogy previously described in Table NAR-12. Overall, similar mineral stability tendency is observed for the Frio sand, Upper Anahuac, and Het Lime (Table NAR-14). Pre-injection, formation waters in equilibrium with reservoir mineralogy are saturated with respect to calcite, dolomite, kaolinite, K-feldspar, pyrite, witherite, and strontianite. Calcite precipitation at equilibrium and associated removal of bicarbonate ions is likely the cause of pH values observed with fluid-rock equilibrium models. Formation waters in equilibrium with reservoir mineralogy show quartz, illite, and analcime as stable phases. Clay minerals, including kaolinite, are highly sensitive to dissolved aluminum concentrations and lab measurements were below detection limit and an assumed value of 1.0×10^{-3} mg/l was used. Despite predicted kaolinite supersaturation, it is likely that both kaolinite and illite are stable at existing reservoir conditions considering rapid kinetics of clay mineral precipitation. Witherite and strontianite are predicted to precipitate, however their precipitate mass is negligible. Quartz, pyrite, and dolomite are considered stable phases initially present in the reservoir due to their respective slow kinetics. Plagioclase is unstable at pre-injection reservoir conditions and predicted to dissolve at existing reservoir conditions.

Table NAR-14—Mineral stability tendency and fluid pH for Het Lime, Upper Anahuac and Frio in equilibrium with reservoir mineralogy (pre-injection baseline).

Model Results	Het Lime	Upper Anahuac	Frio Sand
pH (SU)	6.6	6.6	6.6
Fluid TDS	Increase	Increase	Increase
Porosity	Decrease	Decrease	Decrease
Anhydrite	Dissolve	Dissolve	Dissolve
Barite	Dissolve	Dissolve	Dissolve
Calcite	Precipitate	Precipitate	Precipitate
Celestite	Dissolve	Dissolve	Dissolve
Dawsonite	Dissolve	Dissolve	Dissolve
Dolomite	Precipitate	Precipitate	Precipitate
Gypsum	Dissolve	Dissolve	Dissolve
Halite	Dissolve	Dissolve	Dissolve
Illite	Stable	Stable	Stable
Kaolinite	Precipitate	Precipitate	Precipitate
K-Feldspar	Precipitate	Precipitate	Precipitate
Plagioclase	Dissolve	Dissolve	Dissolve
Pyrite	Precipitate	Precipitate	Precipitate
Quartz	Stable	Stable	Stable
Siderite	Dissolve	Dissolve	Dissolve
Witherite	Precipitate	Precipitate	Precipitate
Strontianite	Precipitate	Precipitate	Precipitate
Analcime	Stable	Stable	Stable

Geochemical equilibrium modeling of formations fully saturated with CO₂ to simulate injection suggests CO₂ addition causes minor effects on mineral saturation states. CO₂ fugacity was assumed to be 2.46 for 100% CO₂ gas at formation temperature and pressure. Table NAR-15 shows the mineral stability tendency after equilibration for each sample in the reservoir and confining units.

Negligible changes for mineral saturation states were observed for most minerals when comparing results for existing (Table NAR-14) versus fully saturated (Table NAR-15) Values for pH are predicted to decrease approximately 1.3 to 1.4 SU. Precipitation of dawsonite is predicted to occur in the reservoir and confining units, however precipitated mass is small. Saturation with respect to illite, analcime, and siderite is predicted to decrease at equilibrium with fully saturated CO₂; minerals that were considered relatively stable prior to interaction with CO₂. Dolomite is considered stable, and precipitation is suppressed due to slow reaction kinetics associated with dolomite. Therefore, quartz, pyrite, and dolomite likely remain the most stable phases initially present. Plagioclase dissolution will increase as larger amount of CO₂ dissolved in water shifts the equilibria to more acidic environment. In addition, a substitution process occurs by precipitation of calcite and kaolinite; enhanced further under CO₂-saturated reservoir conditions. However, dynamics in the reservoir during injection are more complicated as reactions are time dependent and calcite likely dissolve first at lower pH, reprecipitating at later times (equilibrium conditions).

Het Lime and Upper Anahuac confining units show minimal effects from saturation with 100% CO₂, and equilibrium conditions have significant (~3.0%) porosity loss due to high proportions of clay minerals and calcite mineral reprecipitation. Although some degree of initial dissolution may occur in the overlying carbonate confining unit, reservoir pore fluids are buffered by the presence of carbonate minerals, limiting dissolution. At equilibrium conditions (late time), pore fluids in reservoir and confining units are saturated with respect to calcite, resulting in calcite precipitation. 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 microfractures that might have been formed due to pressure increase (*i.e.*, mechanical deformation), as proposed by Hangx et al. (2009), further enhancing long-term integrity of the confining system.

Table NAR-15—Change in mineral stability tendency and fluid pH of Het Lime, Upper Anahuac, and Frio formations in equilibrium with reservoir mineralogy and saturated CO₂.

Model Results	Het Lime	Upper Anahuac	Frio Sand
pH (SU)	5.3	5.2	5.3
Fluid TDS	Increase	Increase	Increase
Porosity	Decrease	Decrease	Decrease
Anhydrite	-	-	-
Barite	-	-	-
Calcite	-	-	-
Celestite	-	-	-

Application No. 45079, 45080, 46169, 46170, and 46171

Model Results	Het Lime	Upper Anahuac	Frio Sand
Dawsonite	Precipitate	Precipitate	Precipitate
Dolomite	-	-	-
Gypsum	-	-	-
Halite	-	-	-
Illite	Minor Dissolution	Minor Dissolution	Minor Dissolution
Kaolinite	-	-	-
K-Feldspar	-	-	-
Plagioclase	Inc Dissolution	Inc Dissolution	Inc Dissolution
Pyrite	-	-	-
Quartz	-	-	-
Siderite	Inc Dissolution	Inc Dissolution	Inc Dissolution
Witherite	-	-	-
Strontianite	-	-	-
Analcime	Minor Dissolution	Minor Dissolution	Minor Dissolution

2.8.2 Reactive-Transport Simulations

Reactive-transport simulations were conducted using CMG-GEM. This section provides an evaluation of geochemical influences on reservoir storage capacity and long-term trapping mechanisms. The extended Debye-Hückel equation (“Bdot”) is used for consistency with geochemical equilibrium simulations. Calcite, plagioclase (anorthite), kaolinite, and illite are minerals considered in dynamic simulations. Minerals present in the XRD considered non-reactive (*e.g.*, quartz, pyrite) are not included in simulations and are lumped with a nonreactive fraction.

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 long-term CO₂ storage affects reservoir properties within a reasonable computational time.

The effect of mineral dissolution and precipitation on porosity is also included to evaluate its impact on reservoir storage capacity. The model is based on the simple correlation that the amount of mineral change will directly impact the solid volume using the respective mineral mass, mineral molar weight, and mineral density to calculate the new void volume (porosity) over time. The modified Kozeny-Carman equation was included to model the effect of porosity changes in rock permeability.

The model is initialized into two regions, confining and reservoir, with identical initial fluid chemical compositions (Table NAR-11). Here, the Het Lime is considered of more interest than Upper Anahuac due to high proportion of carbonate. Therefore, reservoirs are modeled using Frio sand mineralogy and confining units are modeled using Het Lime mineralogy (Table NAR-12). In total, 11 aqueous species were initialized in reservoir connate water and allowed to flow with aqueous phase in the reactive-transport simulations. The aqueous species modeled are H^+ , Ca^{2+} , Mg^{2+} , K^+ , Na^+ , Al^{3+} , SiO_2 , HCO_3^- , OH^- , CO_3^{2-} , $CaOH^+$. The selection of aqueous complexes was based on the simulation results from geochemical equilibrium runs with minerals and CO_2 . Aqueous species that were not originally in the complete water analysis were assumed to have trace concentration. The reservoir is allowed to equilibrate prior to simulation start. Preliminary reactive-transport simulation results are described below, and multiple parameter sets are still being considered to understand current model observations and improve simulation runtimes.

Figure NAR-75 shows minimum value results for fluid pH values at end of the injection period, aggregated across all model layers. Reservoir fluid pH values pre- and post-injection are similar (compare 6.7 and 4.7) to equilibrium values obtained from equilibrium modeling (Table NAR-14, Table NAR-15).

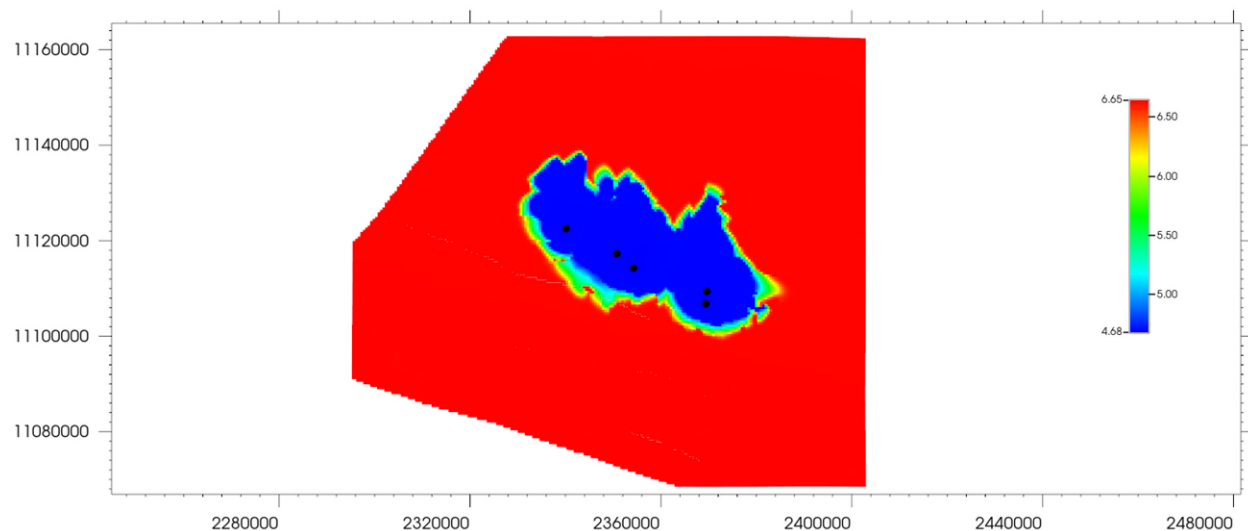


Figure NAR-75—Aggregate view for all model layers of minimum values for modeled fluid pH after cessation of CO_2 injection.

Figure NAR-76 shows reservoir mineral volume change for calcite, plagioclase, kaolinite, and illite throughout injection. Kaolinite precipitation occurs steadily throughout the duration of injection. Illite is relatively stable during injection and shows negligible dissolution as predicted

Application No. 45079, 45080, 46169, 46170, and 46171

from equilibrium models. Dissolution of calcite and plagioclase occurs early time, however there is a shift to net calcite precipitation following several years of injection. Late time calcite precipitation is attributed to several modeled factors including high initial values for dissolved calcium and bicarbonate concentrations in formation waters and reservoir temperatures, which result in a supersaturation of formation waters with respect to calcite during injection. Post-injection, it is expected that plagioclase continues to dissolve while calcite and kaolinite continue to precipitate (Xu et al., 2010, Hovorka et al. 2009). Kaolinite precipitation is associated with plagioclase dissolution, which releases additional dissolved aluminum into formation waters.

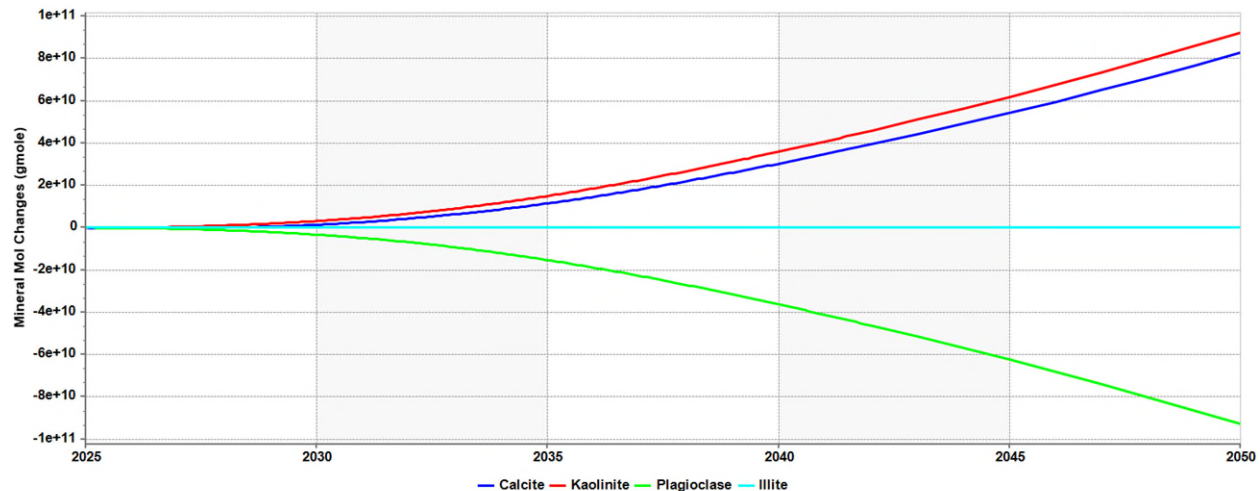


Figure NAR-76—Modeled molar change in minerals simulated to 2050.

Modeled porosity changes due to net mineral dissolution and precipitation at end of the injection period are shown in Figure NAR-77. Negative and positive values represent the increase or decrease from initial porosity, respectively. Maximum porosity changes at the end of injection across all model layers were approximately 0.1% (decrease). Porosity remained unchanged for the Het Lime and Upper Anahuac shale confining system due to the presence of low-permeability units that prevent vertical upward migration of CO₂-saturated fluids. Reservoir porosity is expected to continue decreasing overtime post injection as calcite and kaolinite continue to precipitate.

Figure NAR-78 and Figure NAR-79 show the dissolution and precipitation of calcite mass across all model layers. There are minimal proportions of calcite in the Frio sand reservoir, and they likely comprise the initial dissolution of calcite along the advancing edge of the CO₂ plume as pH changes. Precipitation of calcite occurs behind the plume front as CO₂ gas saturations decrease in formation waters that are supersaturated with respect to calcite. Although mineral dissolution and precipitation are occurring on injection timescales, changes in calcite mass are relatively small compared to total mineral mass, as shown by negligible porosity alteration (Figure NAR-80).

Application No. 45079, 45080, 46169, 46170, and 46171

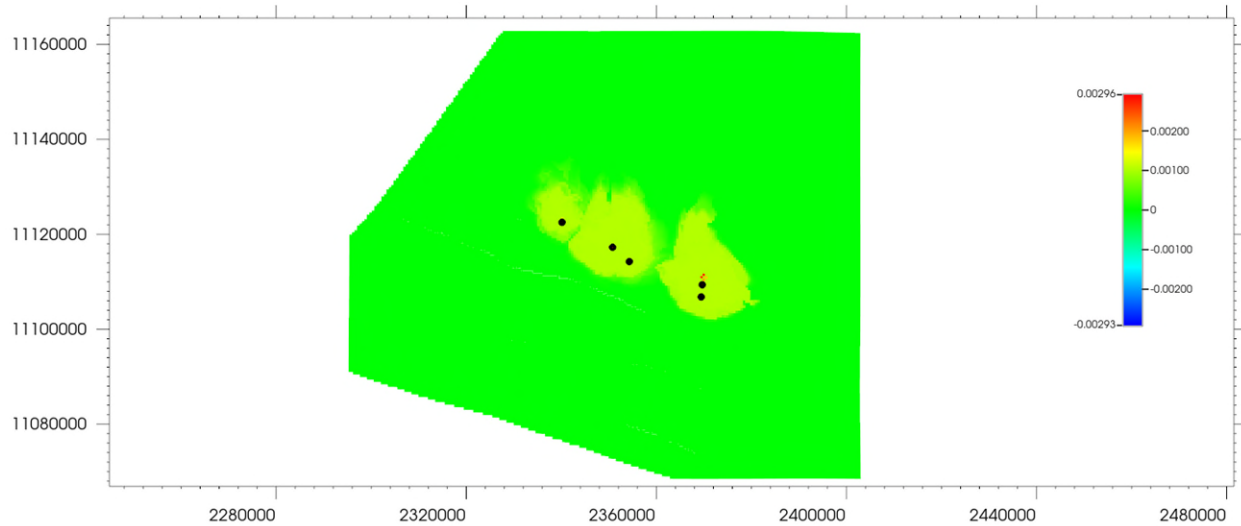


Figure NAR-77—Aggregate view for all model layers of modeled maximum porosity changes from mineral precipitation and dissolution upon cessation of injection. Note negative and positive values represent increases and decreases in effective porosity, respectively.

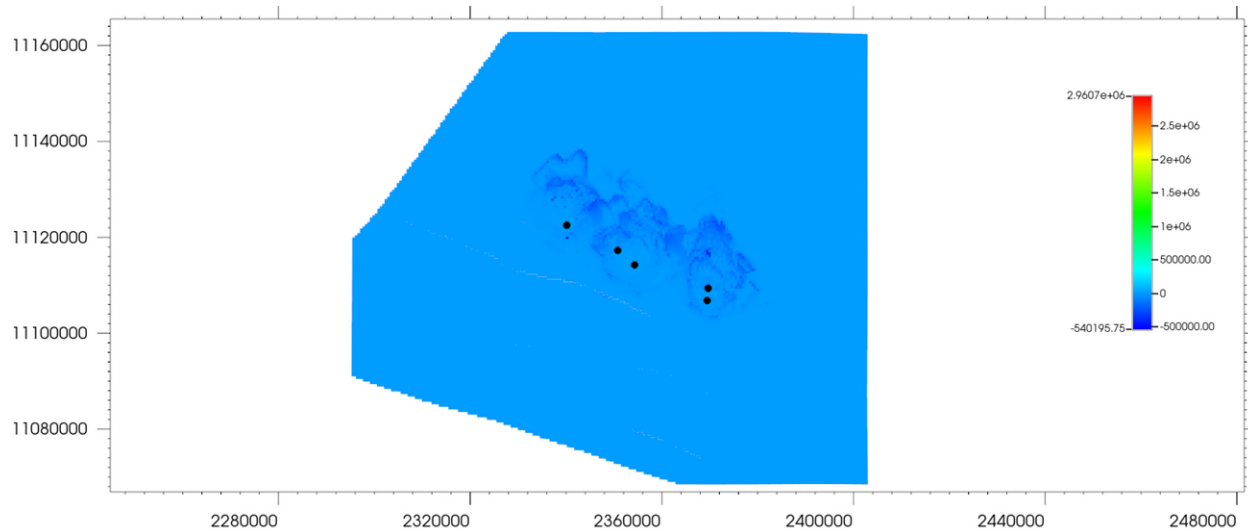


Figure NAR-78—Aggregate view for all model layers of modeled maximum calcite dissolution (gmole) upon cessation of injection. Note largest mass of calcite dissolution is concentrated along edges of plume front.

Application No. 45079, 45080, 46169, 46170, and 46171

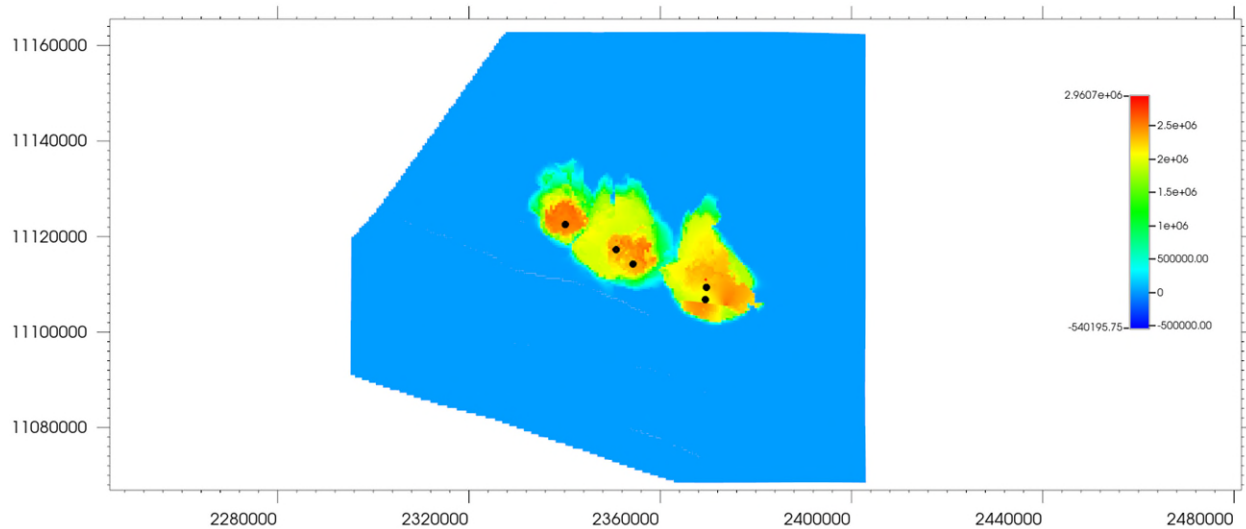


Figure NAR-79—Aggregate view for all model layers of modeled maximum calcite precipitation (gmole) upon cessation of injection. Note spatiotemporal gradient of calcite precipitation occurring behind plume front.

Modeled CO₂ trapping mechanisms (aqueous, dissolved in water, mineralization, super-critical mobile, and trapped in residual phase) are shown in Figure NAR-80. Results show the primary trapping mechanisms of injected CO₂ at injection timescales is the super-critical phase as mobile and trapped CO₂. Mineral CO₂ storage is positive during injection due to calcite precipitation. Mineralization (permanent sequestration) of injected CO₂ as calcite is expected to continue post-injection, eventually becoming a dominant trapping mechanism at long timescales.

Compositional simulation commonly shows a larger CO₂ plume compared to reactive transport simulation. The reason for the reactive-transport simulations showing a 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, the compositional simulations (without geochemistry) typically provide the most conservative assessment of CO₂ plume extent.

Application No. 45079, 45080, 46169, 46170, and 46171

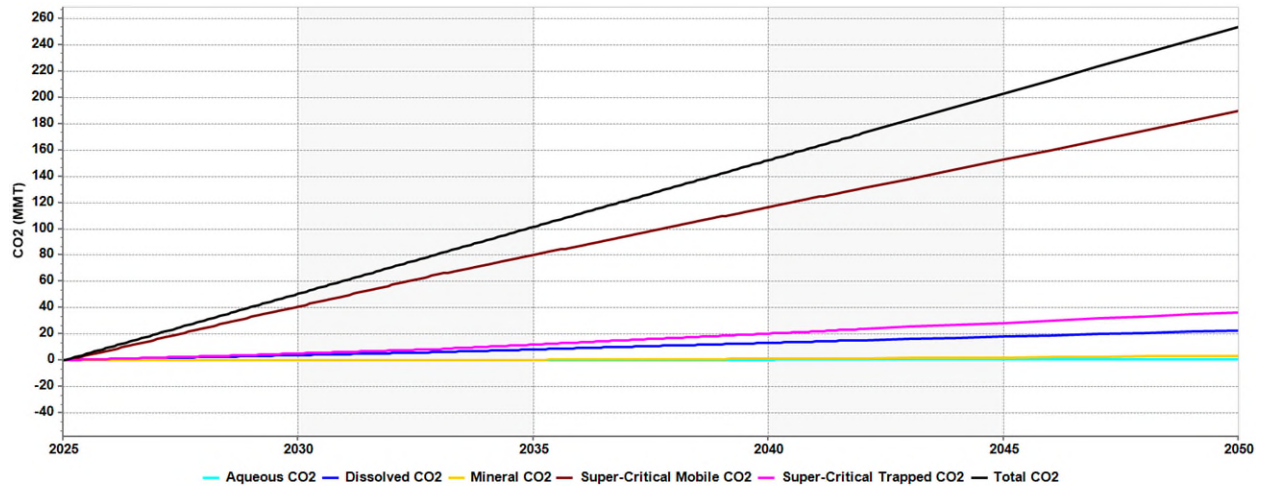


Figure NAR-80—CO₂ partitioning in reactive-transport model simulated to 2050.

2.9. Geopressure

A typical saline formation in the Gulf of America basin has approximately 100,000 ppm dissolved solids and a hydrostatic pressure gradient of 0.465 psi/ft (Schlumberger, 2012). With depth, this transitions to overpressure at 0.7 psi/ft, and the onset of overpressure starts at about 0.6 psi/ft (Figure NAR-81). The onset of overpressure in the AOI is between 12,000 ft and 15,000 ft based on the USGS study published by Burke (2013, Figure NAR-82). The base of the Oligocene Storage Complex is shallower than 9,000 ft (Figure NAR-82).

Application No. 45079, 45080, 46169, 46170, and 46171

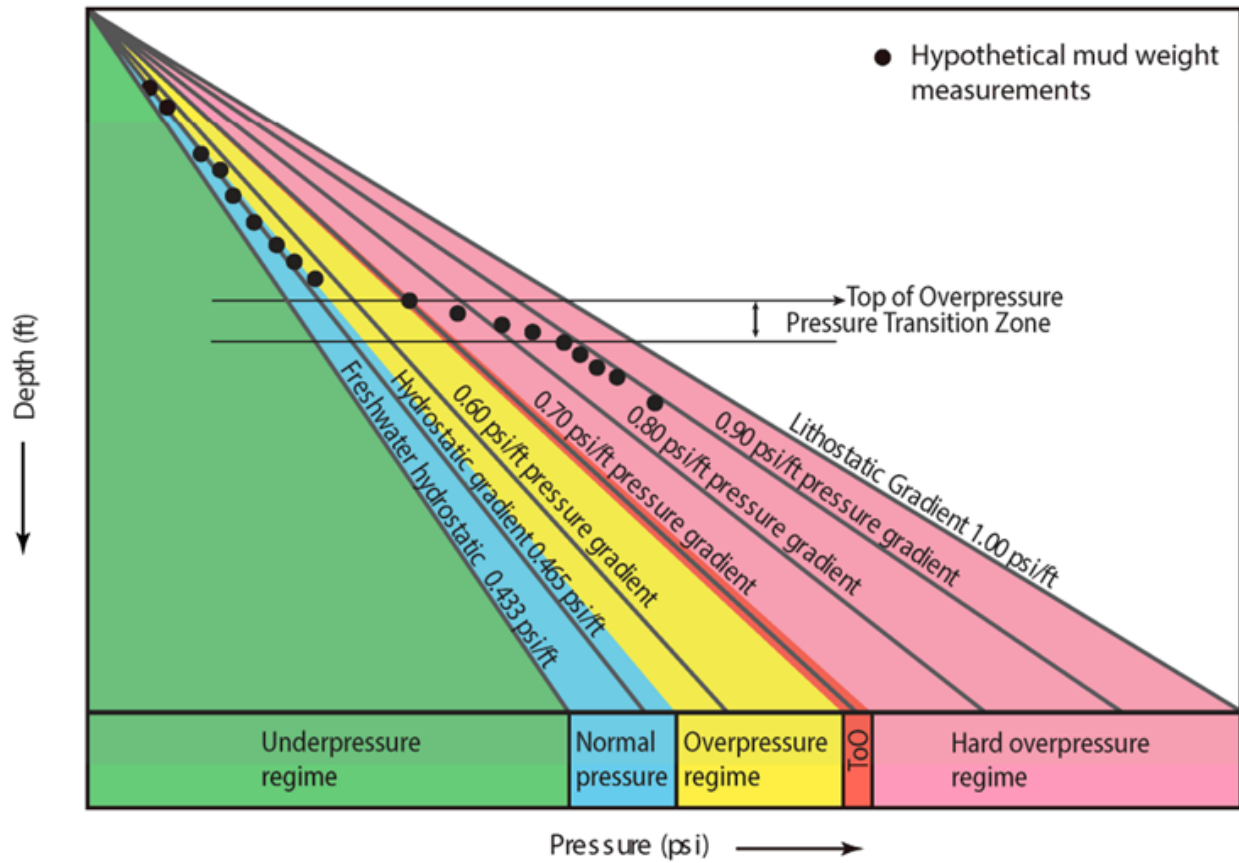


Figure NAR-81—Schematic diagram of generalized pressure gradients and their associated pressure regime.

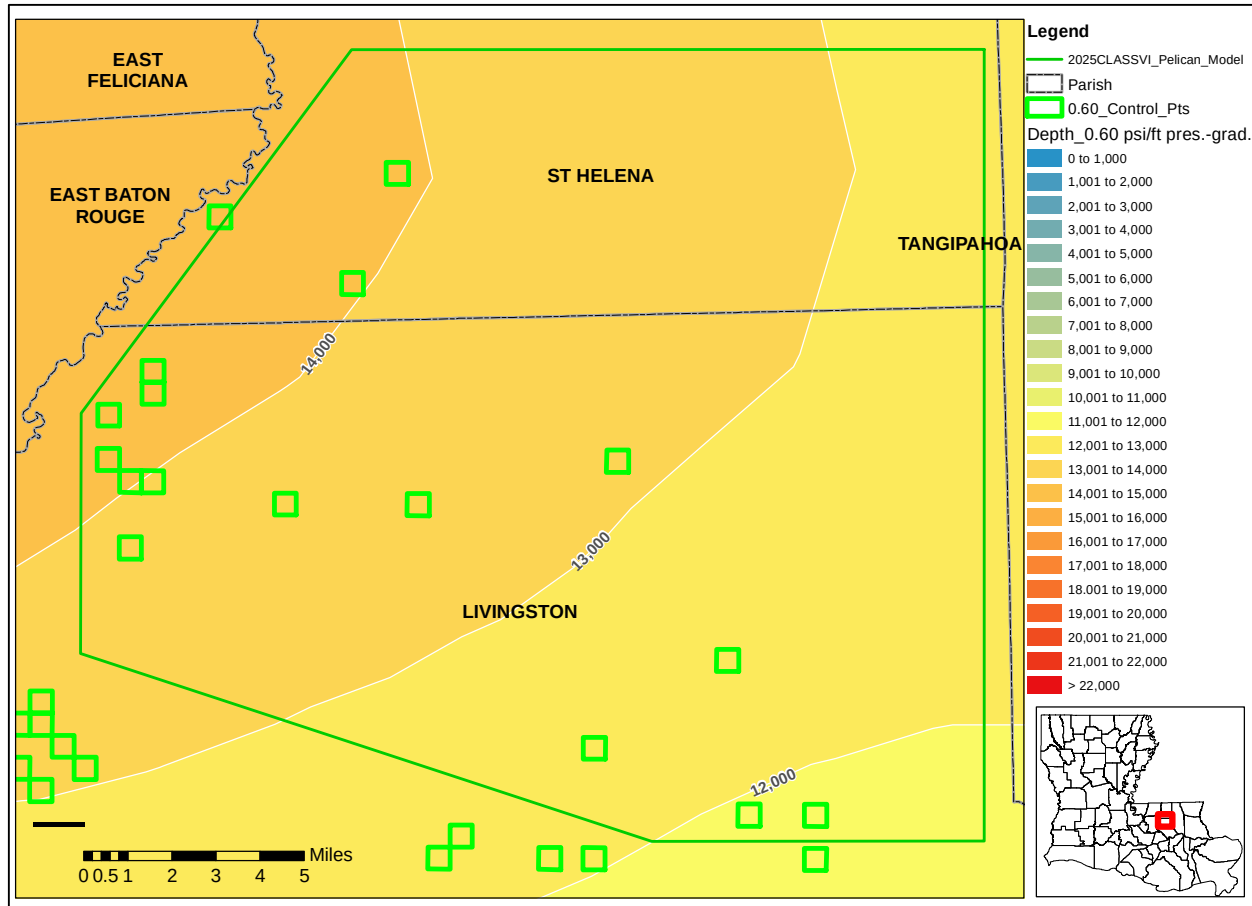


Figure NAR-82—Depth map for the onset of 0.6 psi/ft pressure gradient (Burke, 2013).

2.10 Site Suitability

The dynamic simulation model provides an advanced method for determining the storage capacity. The GEM (v2024.10) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd., was used in this study. The construction and physics of the base case dynamic model are described in detail in 4.2 CO₂ Plume Extent of the Area of Review and Corrective Action Plan document. The base case model includes CO₂ dissolved in the aqueous phase or as free or trapped supercritical CO₂ but does not model trapping due to mineralization. Figure NAR-83 shows the change in storage capacity and CO₂ plume area with time from the dynamic simulation, forecasted for 100 years after end of injection. The storage capacity will reach a peak at the end of the injection period at about 8.5 million MT/mi², then decline to a value of 4.9 million MT/mi² at 100 years after the end of injection. The plume is based on the area in which 99% of the injected CO₂ resides, determined by vertical integration of the mass per unit area (VIMPA). The storage capacity on a per-area basis from dynamic modeling is ultimately higher near the injector than at the outer edges of the plume due to the heterogeneity of the storage formation and the CO₂ migration updip but is averaged over the entire area.

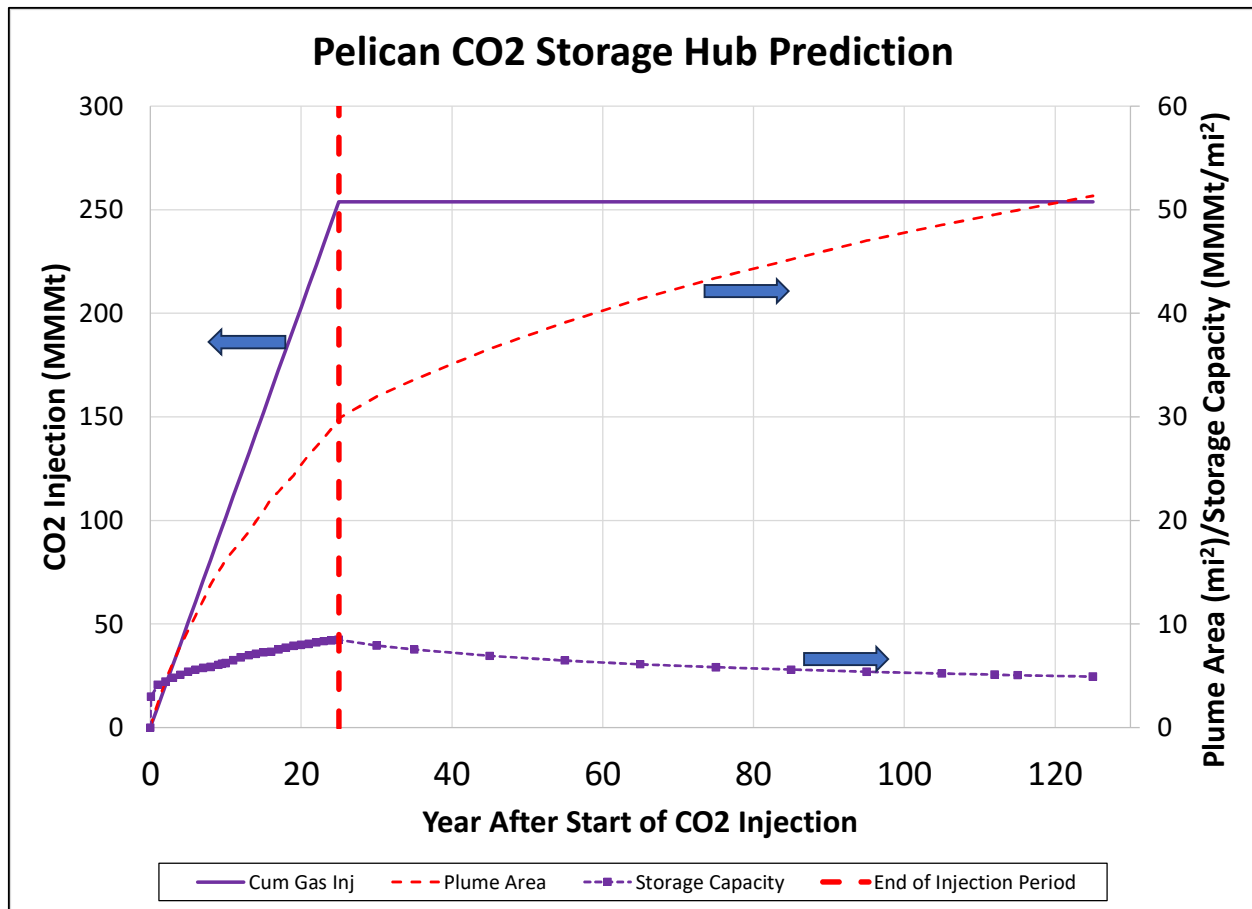


Figure NAR-83—CO₂ plume area and storage capacity from dynamic simulation, from start of injection to 100 years post injection. Plume area is based on 99% of the vertically integrated mass per unit area (VIMPA) of CO₂ in the reservoir.

3.0 Area of Review and Corrective Actions Plan

The Area of Review and Corrective Actions Plan document meets the requirements of C&E Criteria and Standards Applicable to Class VI Wells. The key challenges are detailed characterization of the injection and confining zones, delineation of all underground sources of drinking water, and development of corrective actions to be implemented on existing wells within the AoR. The Area of Review and Corrective Actions Plan describes the subsurface characterization, computational modeling, current AoR delineation, corrective action plan and schedule, wells requiring corrective action, and future AoR reevaluation plan and schedule.

The corrective action plan delineates the AoR and provides for any corrective action needed in the wells that penetrate the Upper Confining Zone within the AoR. Delineation of the AOR is one of the key elements of Class VI Rule LAC 3615.B to ensure USDWs in the region surrounding the geologic sequestration project will not be endangered by the injection activity.

At a fixed frequency specified in the Area of Review and Corrective Actions Plan or more frequently when monitoring and operational conditions warrant, Pelican Sequestration Hub, LLC, must reevaluate the AoR and perform any required corrective action in the manner specified in

LAC 43:XVII.3615(B) and (C). Pelican Sequestration Hub, LLC, must also update the Area of Review and Corrective Actions Plan or demonstrate to the Commissioner that no update is needed.

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

4.0 Financial Responsibility

Pelican Sequestration Hub, LLC, shall maintain financial responsibility and resources to meet the requirements of LAC 43:XVII.3609(C) and conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The approved financial assurance mechanisms are found in the Financial Assurance Plan document of this permit. The financial instrument(s) must be sufficient to cover the cost of:

- Corrective action [meeting the requirements of LAC 43:XVII.3615(B) and (C)];
- Injection well plugging [meeting the requirements of LAC 43:XVII.3631(A)];
- Post-injection site care and site closure [meeting the requirements of LAC 43:XVII.3633(A)];
- Emergency and remedial response [meeting the requirements of LAC 43:XVII.3623(A)].

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

Pelican Sequestration Hub, LLC, shall provide notification to meet the requirements of LAC 43:XVII.3609(C) and conditions of this permit.

- Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, within 60 days after the increase, Pelican Sequestration Hub, LLC, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such an increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after Pelican Sequestration Hub, LLC, has received written approval from the Commissioner.
- Pelican Sequestration Hub, LLC, must notify the Commissioner by certified mail and in an electronic format of adverse financial conditions, such as bankruptcy, that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and

any applicable ongoing actions under the Corrective Action and/or Emergency and Remedial Response.

- o If Pelican Sequestration Hub LLC, or third-party provider of a financial responsibility instrument is going through a bankruptcy, Pelican Sequestration Hub, LLC, must notify the Commissioner by certified mail and in an electronic format of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code, which names Pelican Sequestration Hub, LLC, as the debtor, within 10 days after commencement of the proceeding.
- o A guarantor of a corporate guarantee must make such a notification, if he or she is named as debtor, as required under the terms of the guarantee.
- o A permittee who fulfills the requirements of financial assurance by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy, will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee (or issuing institution) or suspension/revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

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

5.0 Injection Well Construction Plan

The Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 injection wells are designed with the highest standards and best practices for drilling and well construction. The operational parameters and material selection are intended to ensure mechanical integrity in the system and to optimize the operation during the life of the project.

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

5.1 Proposed Stimulation Program [LAC 43:XVII.3607(C)(2)(h)]

Pelican Sequestration Hub, LLC, may stimulate the Injection Zone in the CO₂ injector wells Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 to enhance or regain injection capabilities.

Stimulation and cleanouts to enhance or regain the injection potential of the Frio and Anahuac formations in the CO₂ injector wells may include, but are not limited to: coil tubing cleanouts, stick pipe cleanouts, matrix acid stimulation, and water flushes.

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

5.2 Construction Procedures [LAC 43:XVII.3607(C)(2)(k)]

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

The 17-1/2 in. vertical wellbore will be drilled at least 100 ft below the base of the USDW into a competent shale and will provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken minimum every 100 ft while drilling and this section will be drilled with freshwater mud. Once the final depth is reached, the well will be circulated and conditioned to run open-hole electric logs according to the Pre-Operational Testing (POT) Program. Then, 13-3/8 in. casing will be run and cemented to surface via circulation with conventional Portland cement plus additives slurry. If there are no cement returns to the surface, the project will inform C&E, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Commissioner. After the tail cement reaches at least 500 psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing according to Louisiana Statutes and Regulations LAC 43:XVII.3617(A)(3) requirements and pick up the drilling assembly. After drilling out the shoe track, an additional 10 to 15 ft of new formation will be drilled to execute a formation integrity test (FIT).

A 12-1/4 in. vertical wellbore will be drilled from the surface casing shoe to the total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Testing Program. Then, the long string of 9-5/8 in. casing will be deployed with the DTS/DAS fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of CO₂-resistant and conventional cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The stage tool or cementing stage tool depth will be adjusted based on actual conditions of the well after drilled.

After the cementing is complete, Section B of the wellhead will be installed, and the DTS/DAS cable will be threaded through the slips and packoff. The team will install the rest of the wellhead to prepare for completions operations. The casing will be tested per LAC 43:XVII.3617(A)(3) requirements.

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

The 5-1/2 in. tubing and packer completion will be run to just above the planned top perforation for the first completion, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the Injection Zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO₂ injection.

6.0 Pre-Operational Testing Program

The Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and CCS 5 well testing program aims to obtain the chemical and physical characteristics of the injection and confining zone(s). This program includes a combination of logging, sidewall coring, formation hydrogeologic testing, and other activities performed during the drilling and construction of the CO₂ injection well, monitoring well(s), and any stratigraphic characterization well(s).

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

Specific details on the proposed pre-operational logging and testing program are found in the Pre-Operation Testing Program.

7.0 Well Operation

The CO₂ injector wells are designed to maximize the rate of injection and to reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the fracture gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and to ensure continuous surveillance of external integrity and conformance through the external fiber optic cable. The design allows for other logs to be periodically run, (e.g., pulse neutron).

7.1 Operational Procedures [LAC 43:XVII.3607(C)(2)(i)]

The operational procedures detailed below describe how Pelican Sequestration Hub, LLC, will initiate injection and conduct startup-specific monitoring of the Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 injection wells.

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

after the initial startup will follow the Testing and Monitoring Plan (TM) document of this application.

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

Additional operational parameters are detailed in the Summary of Operating Conditions document of this permit.

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

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

Pelican Sequestration Hub, LLC, shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO₂ stream and/or associated pressure front may cause an endangerment to a USDW.

7.2 Proposed Carbon Dioxide Stream [LAC 43:XVII.3607(C)(2)(f)(iii) and (iv)]

The proposed CO₂ stream composition is given in the Testing and Monitoring Plan. No injectant other than that identified in this permit shall be injected into the well except fluids used for stimulation, rework, and well tests as approved by the Commissioner.

7.3 Reporting and Recordkeeping

Electronic reports, submittals, notifications, and records made and maintained by Pelican Sequestration Hub, LLC, under this permit will be in an electronic format approved by C&E. The permittee shall electronically submit all required reports to the Commissioner.

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

- Any changes to the physical, chemical, and other relevant characteristics of the CO₂ stream from the proposed operating data;
- Monthly average, maximum, and minimum values for injection pressure; flow rate and daily volume; temperature; and annular pressure;

Application No. 45079, 45080, 46169, 46170, and 46171

- A description of any event that exceeds operating parameters for the annulus or injection pressure specified in the permit;
- A description of any event that triggers the required shutoff systems and the responses taken;
- The monthly volume and/or mass of the CO₂ stream injected over the reporting period and volume and/or mass injected cumulatively over the life of the project;
- Monthly annulus fluid volume added or produced; and
- Results of the continuous monitoring required, including:
 - A tabulation of the (1) daily maximum injection pressure, (2) daily minimum annulus pressure, (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure, (4) daily volume, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and
 - Graph(s) of the continuous monitoring required or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Commissioner; and
- Results of any additional monitoring identified in the Testing and Monitoring Plan

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

- Pelican Sequestration Hub, LLC, shall report to the Commissioner any permit noncompliance, which may endanger human health or the environment, and/or any events that require implementation of actions in the Emergency and Remedial Response Plan (ERRP). Any information shall be provided verbally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:
 - Any evidence that the injected CO₂ stream or associated pressure front may have caused an endangerment to a USDW or any monitoring or other information, which indicates that any contaminant may have caused endangerment to a USDW;
 - Any noncompliance with a permit condition or malfunction of the injection system that may have caused fluid migration into or between USDWs;
 - Any triggering of the shutoff system;
 - Any failure to maintain mechanical integrity;
 - Pursuant to compliance with the requirement at LAC 43:XVII.3625(A)(8) for surface air/soil gas monitoring or other monitoring technologies, if required by the Commissioner, any release of CO₂ to the atmosphere or biosphere; and
 - Actions taken to implement appropriate protocols outlined in the ERRP.
- A written submission shall be provided to the Commissioner in an electronic format within five days of the time Pelican Sequestration Hub, LLC, becomes aware of the circumstances. The submission shall contain a description of the noncompliance and its cause; the period of noncompliance (including the exact dates and times); and if the noncompliance has not been corrected, then the anticipated time it is expected to

Application No. 45079, 45080, 46169, 46170, and 46171

continue, as well as actions taken to implement appropriate protocols outlined in the ERRP. This submission should also include the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

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

The following items require advance notification from the permittee to the Commissioner:

- Well Tests – Pelican Sequestration Hub, LLC, shall give at least 30 days advance written notice to the Commissioner in an electronic format of any planned workover, stimulation, or other well test.
- Planned Changes – Pelican Sequestration Hub, LLC, shall give written notice to the Commissioner in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid shall be submitted to the Commissioner for review and written approval at least 30 days prior to injection. This approval may result in a permit modification.
- Anticipated Noncompliance – Pelican Sequestration Hub, LLC, shall give at least 14 days advance written notice to the Commissioner in an electronic format of any planned changes in the permitted facility or activity that may result in noncompliance with the permit requirements.

Other reporting requirements are as follows:

- Compliance Schedules – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit, shall be submitted in an electronic format Pelican Sequestration Hub, LLC, no later than 30 days following each scheduled date.
- Transfer of Permits – This permit is not transferable to any person except after notice is sent to the Commissioner in an electronic format at least 30 days prior to the transfer and requirements of LAC 43:XVII.3613(C)(2) have been met. Pursuant to the requirements at LAC 43:XVII.3613(C)(2), the Commissioner will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary.
- Other Noncompliance – Pelican Sequestration Hub, LLC, shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report.
- Other Information – When Pelican Sequestration Hub, LLC, becomes aware of a failure to submit any relevant facts in the permit application or incorrect information has been submitted in a permit application or in any report to the Commissioner, the permittee shall submit such facts or corrected information in an electronic format, within 10 days in accordance with LAC 43:XVII.3609(L)(9).

Application No. 45079, 45080, 46169, 46170, and 46171

- Report on Permit Review – Within 30 days of receipt of this permit, Pelican Sequestration Hub, LLC, shall certify to the Commissioner in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

The following guidelines are provided for recordkeeping:

- Pelican Sequestration Hub, LLC, shall retain records and all monitoring information, including all calibration and maintenance records and original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) according to LAC 43:XVII.3615(C)(4) and 3629(A)(6) for a period of at least 10 years from collection.
- Pelican Sequestration Hub, LLC, shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and re-evaluations and plan modifications) according to LAC 43:XVII.3615(C)(4) and 3629(A)(6) for a period of at least 10 years after site closure.
- Pelican Sequestration Hub, LLC, shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.
- The retention periods may be extended at any time by a request from the Commissioner. Pelican Sequestration Hub, LLC, shall continue to retain records after the specified retention period of this permit, or any requested extension thereof expires, unless the permittee delivers the records to the Commissioner or obtains written approval from the Commissioner to discard the records.
- Records of monitoring information shall include:
 - The date, exact place, and time of sampling or measurements;
 - The name(s) of the individual(s) who performed the sampling or measurements;
 - A precise description of both the sampling methodology and handling of samples;
 - The date(s) analyses were performed;
 - The name(s) of the individual(s) who performed the analyses;
 - The analytical techniques or methods used; and
 - The results of such analyses.

8.0 Testing and Monitoring Plan

The Testing and Monitoring Plan document of this permit describes how Pelican Sequestration Hub, LLC, will monitor the Pelican Sequestration Project site pursuant to LAC 43:XVII.3625(A). In addition to demonstrating that the well is operating as planned, the CO₂ plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO₂ within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

9.0 Injection Well Plugging Plan

Upon the end of life for the Pelican CCS injection wells, the injection wells will be plugged and abandoned relevant to the requirements of C&E Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of CO₂ with water mixtures, and protect any underground sources of drinking water (USDWs).

10.0 Post-Injection Site Care (PISC) and Site Closure Plan

The Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Pelican Sequestration Hub, LLC, will perform to meet the requirements of LAC 43:XVII.3633(A). Pelican Sequestration Hub, LLC, may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by C&E pursuant to LAC 43:XVII.3633(A)(2)(c). Following approval for site closure, Pelican Sequestration Hub, LLC, will plug all remaining monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

11.0 Emergency and Remedial Response Plan

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

If Pelican Sequestration Hub, LLC, obtains evidence that the injected CO₂ stream and/or associated pressure front may cause an endangerment to a USDW, Pelican Sequestration Hub, LLC, will initiate shutdown plan for the injection well, take all steps reasonably necessary to identify and characterize any release, notify the permitting agency (C&E) of the emergency event, and implement applicable portions of the approved ERRP.

12.0 Injection Depth Waiver and Aquifer Exemption Expansion

Injection depth waivers are not requested in this permit application.