Longleaf CCS Hub

Longleaf CCS, LLC

Application Narrative

40 CFR 144.31(e), 40 CFR 144.32(a), 40 CFR 146.82 (a), and 40 CFR 146.83

<u>Facility Information</u>

Facility Name:	Longleaf CCS Hub
Facility Contact:	Longleaf CCS, LLC 14302 FNB Parkway Omaha, NE 68154
Well Locations:	Mobile County, Alabama LL#1: Latitude: 31.071303° N Longitude: -88.094703° W LL#2: Latitude: 31.070774° N Longitude: -88.074523° W LL#3: Latitude: 31.0447129° N Longitude: -88.0736318° W LL#4: Latitude: 31.0569516° N Longitude: -88.1047433° W

Table of Contents

List of Figures

List of Tables

List of Definitions

Injection zone: stratigraphic units between the base of the primary confining zone and the top of the lower confining zone.

Injection interval: formation where CO_2 will be injected.

List of Acronyms

AOB	Above-zone monitoring well
AoR	Area of Review
ADEM	Alabama Department of Environmental Management
AOGB	Alabama Oil and Gas Board
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
ft	Feet
GSA	Geological Survey of Alabama
HPF	Hatters Pond Fault
IOB	In-zone monitoring well
LL	Longleaf
MASP	Maximum allowable surface pressure
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
NMR	Nuclear Magnetic Resonance
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
RCA	Routine core analysis
SGR	Shale gouge ratio
SS	Sub- Sea
TD	Total Depth
TDS	Total dissolved solids
TMS	Tuscaloosa Marine Shale
TVD	True Vertical Depth

UIC	Underground Injection Control
UOB	Deep USDW monitoring well
USDW	Underground Source of Drinking Water

A. PROJECT BACKGROUND AND CONTACT INFORMATION

GSDT Submission - Project Background and Contact Information

GSDT Module: Project Information Tracking
Tab(s): General Information tab; Facility Information and Owner/Operator Information tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

A.1. The Longleaf CCS Hub

Longleaf CCS, LLC, an affiliate of Tenaska, Inc. (Tenaska), is proposing development of an industrial scale carbon capture and storage (CCS) hub in Mobile County, Alabama. The Longleaf CCS Hub (the "project") area is located 27 miles north of the city of Mobile, Alabama and 8 miles east of the city of Citronelle, Alabama (**Figure 1**). The center of the project area is located 6 miles northwest of Alabama Power's James M. Barry electrical generation plant (Plant Barry), a major 2.6-Gigawatt capacity electric power generating plant and one of the possible sources of CO_2 for the project. The Longleaf CCS Hub covers a 58,000-acre (90-square mile) area located east of the Mobile Graben and west of the Citronelle Dome, two prominent geologic features in this area (**Figure 2**). The project is seeking to permit and drill up to four injection wells, five in-zone monitoring wells, two above-zone monitoring wells, and four deep underground source of drinking water (USDW) monitoring wells. These wells will be drilled on ten well pads. Shallow groundwater monitoring wells (not shown) will be drilled on nine of the well pads. The location of each well pad and its associated injection and/or monitoring well is shown in **Figure 2**.

The area surrounding the project contains both shallow water supply wells and deeper wells related to oil and gas production and wastewater disposal. However, within the project's area of review (AoR), there are only shallow water wells. The location of these shallow water wells within the AoR are shown in **Figure 3.** The well number, latitude, longitude, well type (i.e., public, domestic), and depth of the 12 water supply wells within or near the AoR are provided in **Table 1**.

There are several notable surface features in and around the project area. **Figure 2** shows the location of all surface bodies of water, city limits for the cities of Citronelle and Mt. Vernon, numerous roads, land containing residential buildings, the MOWA Choctaw State Reservation tribal boundary three miles north of the AoR, the Chastang Landfill adjacent to the eastern boundary of the AoR, and Plant Barry. There are no springs, state or EPA subsurface cleanup sites, surface or subsurface mines, or quarries identified in and around the AoR.

The subsurface within and around the AoR has been well studied, initially from oil and gas resource development assessments (Eaves, 1976; Mancini and Benson, 1985; Mancini et al., 1985; Esposito and King, 1987; Mancini et al., 1987; Bolin et al., 1986; Raymond, 1995; Pashin et al., 2000; Kopaska-Merkel, 2002). More recent investigations, conducted as part of the DOE/NETL and Southern States Energy Board sponsored "Integrated Anthropogenic CO_2 Storage Project", targeted the deep saline Paluxy Formation at the Citronelle Dome, located west of the project area. This work, along with the prior studies noted above, have shown that the area has attractive geologic properties and large potential for safely and permanently storing CO_2 in the deep saline reservoirs below the project area. (Esposito et al., 2008; Pashin et al., 2008; Esposito et al., 2010; Koperna et al., 2012).

No depth waiver or aquifer exemption is requested for the project since the proposed injection interval is 8,750 feet deeper than the deepest USDW in the area and the reservoir fluid in the proposed injection interval is highly saline, with total dissolved solids (TDS) greater than 100,000 mg/L.

Monitoring protocols have been designed to allow Longleaf CCS, LLC to track the areal and vertical extent of the CO_2 plume, the development of the elevated pressure front, and changes in pressure, saturations, and fluid composition above the confining zone. These protocols will also provide input data to periodic reevaluation of the AoR through computational modeling of CO_2 plume and reservoir pressures as well as changes in above injection interval conditions to ensure containment of the injectant CO_2.

The project will provide safe, secure, and long-term CO_2 storage for CO_2 emissions from key sources including the above noted Plant Barry, as well as the Williams Gas Processing Facility and the AM/NS Calvert Steel Finishing Plant. In future years, the project could also provide a viable storage option for CO_2 captured from other industrial facilities in the region.

A.2. Proposed CO_2 Source and Mass/Volume of Injection.

The three sources of CO_2 for the project are estimated to provide up to 5 Mt of captured CO_2 per year for 30 years (150 Mt total). The four injection wells will be capable of storing 13,700 metric tons / day, which is equivalent to 90% of the total emissions from the above three sources over 30 years.

A.3. Project Scope and Timeframe

The characterization of the project draws on the prior logging and core analyses work at the DOE/NETL SECARB Phase III Anthropogenic Test Site at Citronelle conducted from 2011 through 2018. This work has been supplemented by additional log analyses and seismic assessments for the project.

Four proposed injection wells will be permitted and drilled in the center of the project with each well located approximately 1.25 miles apart. Computational reservoir modeling work shows that the four injection wells will be able to safely inject the proposed volume of CO_2 provided from Plant Berry and the other four sources.

With this application, Longleaf CCS, LLC is requesting permits to construct four injection wells: LL#1, LL#2, LL#3, and LL#4. After issuance of the permits by the UIC Program Director, Longleaf CCS, LLC plans to start construction of the injection wells within 5 years but additionally requests two options to extend the permit term by 4 years. The reason for this request is that the project relies on the installation of capture equipment at the emitter and construction of pipeline infrastructure to the emitter, both of which may be delayed for reasons outside the control of Longleaf CCS, LLC. The proposed construction schedule for the injection and monitoring wells is in Table 1 of Appendix A to this Application Narrative.

After submittal of required documentation to the UIC Program Director and receiving authorization to inject and once the emitter is ready to operate their CO_2 capture equipment, Longleaf CCS, LLC will initiate injection. This application assumes that the 30-year injection period will start in approximately 2025, end in 2055, and be followed by a 20-year post-injection site care period, taking the project to 2075. Start of injections could vary by 1 to 5 years.

A.4. Partners/Collaborators/Stakeholders

Tenaska has made major, corporate-level commitments toward the development of the project. Tenaska is a privately held, independent power company based in Omaha, Nebraska. Established in 1987, Tenaska has a generating fleet over 7,500 MW, is one of the largest gas marketing companies in North America and has balance sheet equity of $2.9 billion. Longleaf CCS, LLC, an affiliate of Tenaska, will serve as the project owner and will assume liability for the project development, finance, and operation. The project will be conducted entirely within the State of Alabama in Mobile County. No tribal or territory boundaries will be impacted per 40 CFR 146.82(a)(20). The key contacts are:

Longleaf CCS, LLC
Ryan Choquette, Sr. Project Manager
Project Mailing Address:
Tenaska Inc, 14302 FNB Parkway, Omaha, NE 68154
402-691-9500 (Main Office)

Advanced Resources International, Inc.
Vello A. Kuuskraa, President
Advanced Resources International, 4501 Fairfax Dr., Suite 910, Arlington, VA 22203
703-528-8420 (Main Office)

The State of Alabama Oil and Gas Board
Berry H. (Nick) Tew, Jr., State Geologist & Oil and Gas Supervisor
AL OGB - Tuscaloosa, 420 Hackberry Lane, Tuscaloosa, AL 35401
205-247-3679

A.5. Other Permit Information Required Under 40 CFR 144.31(e)

<u>Applicable SIC Codes</u>

Per ***40 CFR 144.31(e)(3)***, the SIC codes applicable to the Longleaf CCS Hub are:

1. 49530300 Nonhazardous waste disposal sites – primarily engaged in collection and disposal of refuse by processing or destruction or in operation of incinerators/waste treatment plants/landfills/other sites for disposal of such materials.
2. 51690203 Carbon Dioxide – primarily engaged in wholesale distribution of CO_2
3. 4619 Pipelines, not elsewhere classified – primarily engaged in pipeline transportation of commodities except petroleum and natural gas.

<u>Permits and Authorizations</u>

The permits and authorizations under ***40 CFR 144.31(e)(6)*** that will likely be required for the wells at the Longleaf CCS Hub, the permit/authorization jurisdictions, and the associated project development activities are provided in **Table 2**.

The remainder of this page intentionally left blank.

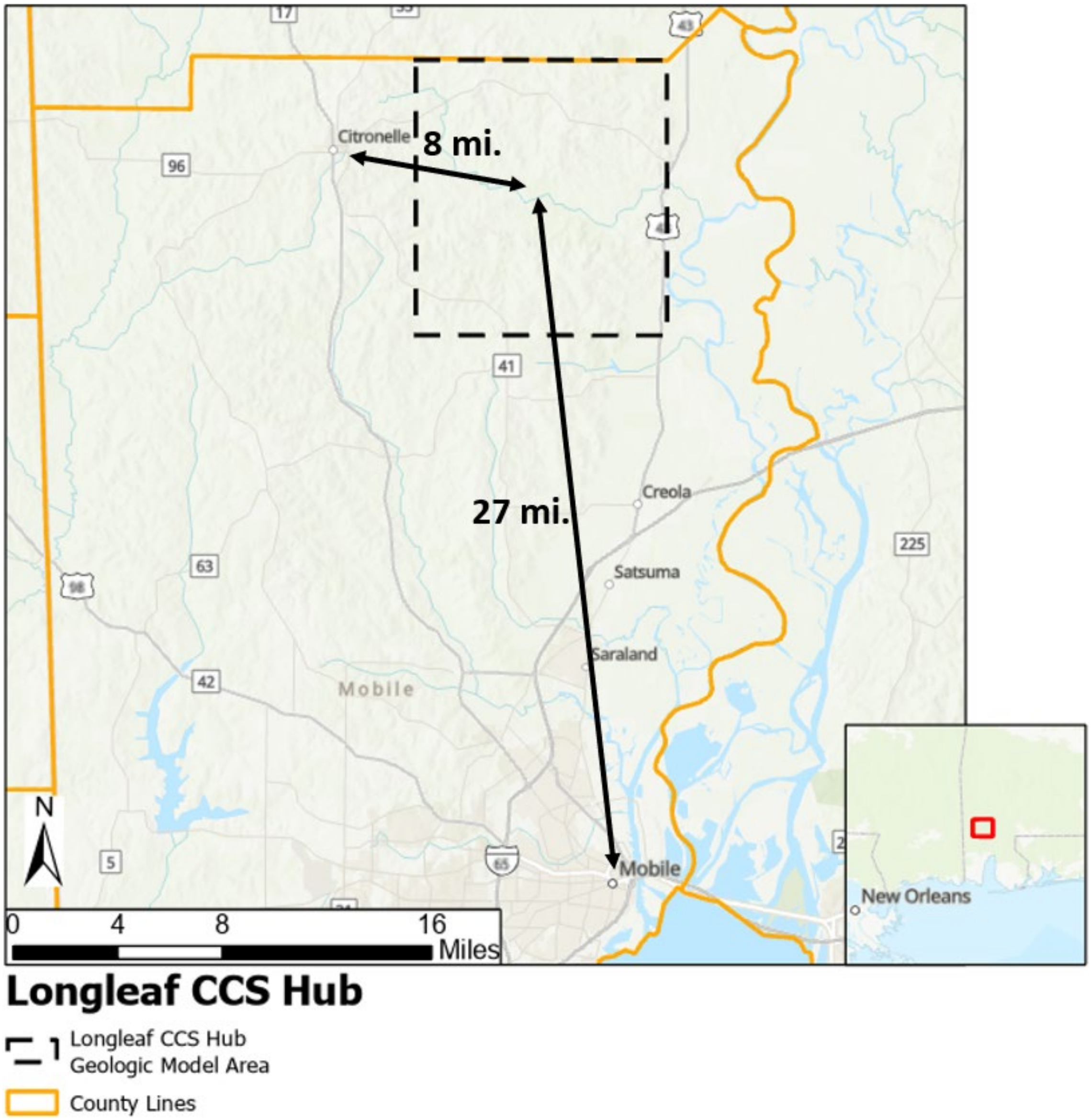


Figure 1. Location of the Longleaf CCS Hub in Southwestern Alabama.

The remainder of this page intentionally left blank.

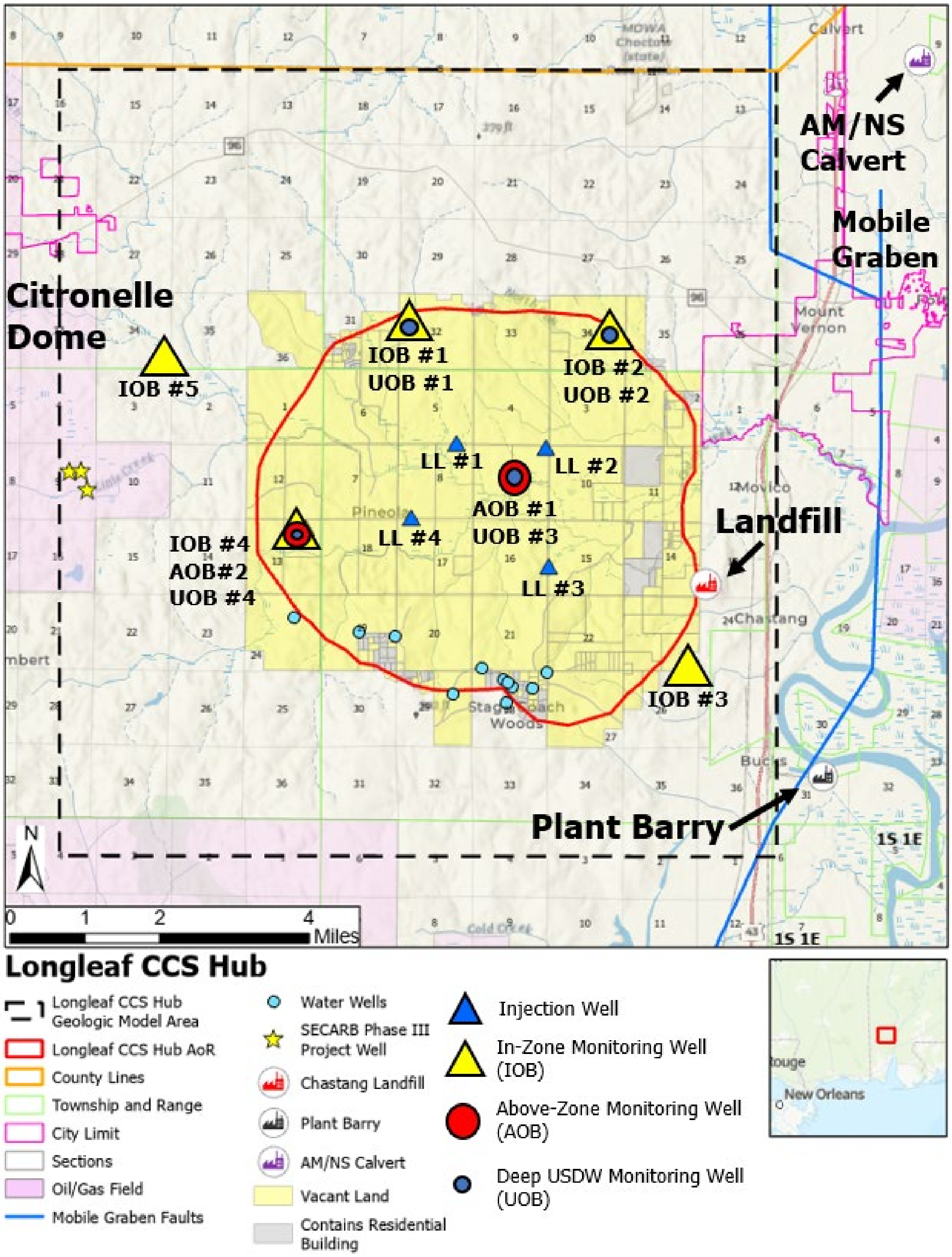


Figure 2. Surface feature map of the Longleaf CCS Hub and its AoR. Well spots with multiple symbols will have co-located wells on the same well pad. Note: Williams Gas Processing Facility (not shown) located 45 mi south of Longleaf CCS Hub.

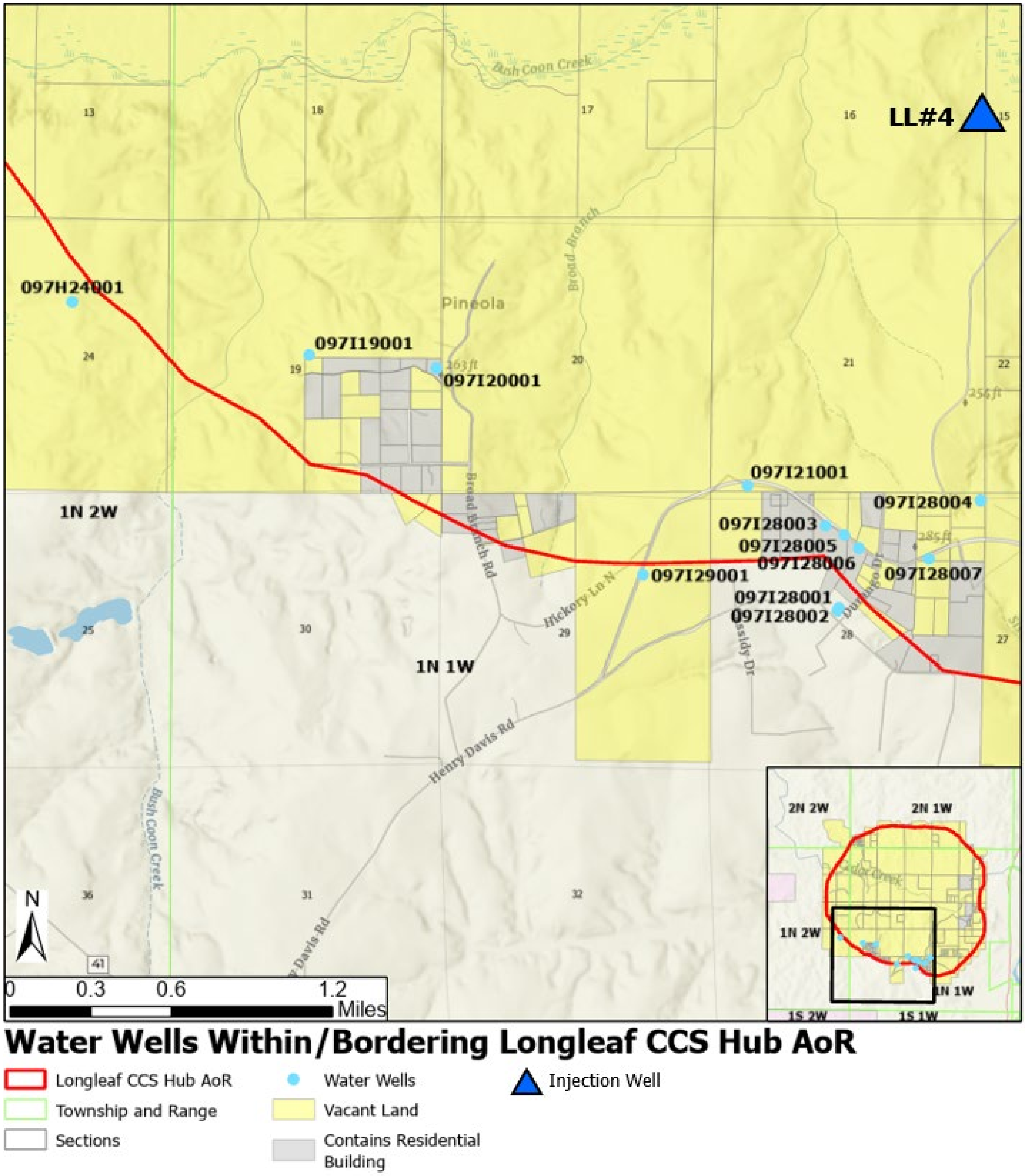


Figure 3. Large Scale map of water wells within and bordering the AoR. Twelve water wells within 600 feet of the AoR are shown, and details including water well type, Latitude/Longitude location, and depth are provided in Table 1.

Table 1. List of Shallow Water Wells within or bordering the Longleaf CCS Hub AoR.

Well Name	Type	Latitude	Longitude	Well Depth (ft)
097I28004	Domestic	31.02662	-88.073916	95
097I19001	Domestic	31.03413	-88.1161078	140
097I28005	Domestic	31.0247	-88.0824543	145
097I28007	Domestic	31.02344	-88.0770718	63
097I28006	Domestic	31.02393	-88.081495	115
097I21001	Domestic	31.02730	-88.0885148	120
097I20001	Domestic	31.03346	-88.108117	90
097B35001	Domestic	31.08952	-88.0484472	125
097I29001	Domestic	31.022405	-88.095012	115
097H24001	Domestic	31.036907	-88.131019	120
097I28001	Domestic	31.020733	-88.082707	92
097I28002	Domestic	31.020588	-88.082824	81

Table 2. Permits and authorizations to be obtained for the development of the Longleaf CCS Hub wells.

Permit/Authorization	Activity	Jurisdiction
UIC Class VI Injection Well Permit to Construct	Drilling of Injection Wells	Federal
UIC Class VI Injection Well Authorization to Inject	Injecting CO_2	Federal
Greenhouse Gas Rule Subpart RR Monitoring, Reporting, and Verification Plan Approval	Injecting CO_2	Federal
Section 404 Nationwide Permit	Temporary impacts to jurisdictional waters	Federal
State Drilling Permits	Drilling of monitoring wells	State
NPDES General Permit for Water Discharge from Construction Activities	Management of stormwater during construction	State
Mobile County Development Permit	Development of project on land within Mobile County	County

B. GEOLOGIC SITE CHARACTERIZATION

B.1. Regional Geologic Structure and Hydrogeologic Properties [40 CFR 146.82(a)(3)]

B.1.1 Data Used for Geologic Characterization

The data used to develop the geologic model of the Longleaf CCS Hub includes existing data from the DOE/NETL SECARB Phase III Anthropogenic CO_2 injection demonstration, data from nearby oil and gas resource exploration and development, and new data generated for this UIC Class VI permit application. The DOE/NETL SECARB Phase III 'Anthropogenic Test' CO_2 injection demonstration was an active resource characterization and CO_2 injection project conducted from 2011 to 2018 in the Southeast Unit of Citronelle Dome. The project injected CO_2 into the Paluxy Formation above the oil producing Rodessa Formation and used the Basal Shale of the Washita-Fredericksburg (Wash-Fred) interval as the confining unit (ADEM permit numbers ALSI9949664 and ALSI9949665).

Three wells were drilled as part of the Anthropogenic Test project: the characterization and observation well D-9-8 #2, the injection well D-9-7 #2, and a backup injection well D-9-9 #2 (**Figure 4**). These three wells were drilled under supervision of the Alabama Department of Environmental Management (ADEM) and the permit information for wells D-9-7 #2 and D-9-9 #2 is included in **Table 3.** Well D-9-8 #2 was a monitoring well and not issued a specific ADEM permit number. The wells D-9-7 #2 and D-9-8 #2 were plugged and abandoned under the jurisdiction of ADEM, while D-9-9 #2 was transferred to Alabama Oil and Gas Board (AOGB), issued an API number, and is currently shut-in. All available well records, including plugging reports and well schematics, are attached as **Appendix A Table 3** to the **Area of Review and Corrective Action Plan**. The data collected from these wells located about ½ mile from the western boundary of the geologic model area are representative of the reservoir properties within the Longleaf CCS Hub and include a full suite of geophysical well logs including gamma ray, bulk density, dipole sonic, and porosity (**Figure 5**) and whole core. These logs were used to pick formation tops, interpret lithologies, develop synthetic seismic traces to tie depth to two-way travel time, and create 3D porosity and permeability data for the geologic model of the injection and confining zones.

Table 3. ADEM Permit Information and Current Status for SECARB Phase III Anthropogenic Test Wells

Well	ADEM Permit No.	Activity	Status
D-9-7 #2	ALSI9949664 (State Class V UIC Well Permit) Issued: 11/22/2011 Terminated: 05/11/2018	Experimental CO_2 injection	Plugged 12/11/2017
D-9-8 #2	Covered under monitoring well requirements in ADEM Permit No. ALSI9949664 (ASR 335-6-8-.10)	Monitoring well for experimental CO_2 injection	Plugged 07/26/2016
D-9-9 #2	ALSI9949665 (State Class V UIC Well Permit) Issued: 11/22/2011 Expired: 11/21/2016	Backup well for experimental CO_2 injection (never completed)	Transferred to AOGB jurisdiction on 5/7/2018; Issued API #: 01-097-20396; Currently shut-in

One hundred eighty-six feet of whole core was collected from the Paluxy Formation, the injection interval for this permit application, in the D-9-7 #2 well, the D-9-8 #2 well, and the D-9-9 #2 well. This core was evaluated to further define the sand-shale sequences and create porosity-permeability transforms for the Paluxy. The core samples were also used to perform mineralogical analyses such as X-ray diffraction and thin section analysis. The depths cored in each well are provided in **Table 4**.

The remainder of this page intentionally left blank.

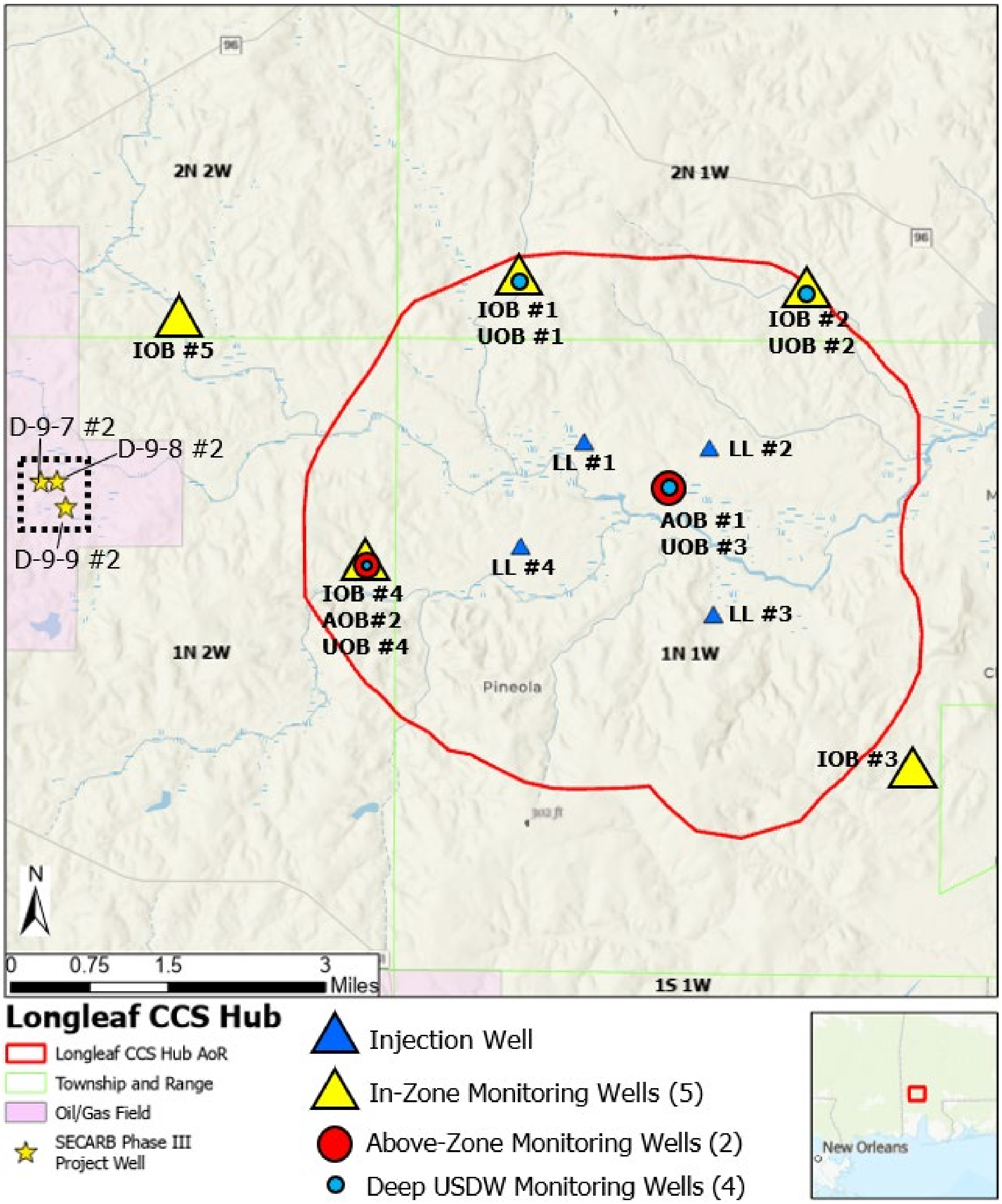


Figure 4. Map of the Longleaf CCS Hub with the location of the proposed injection and monitoring wells and the SECARB Phase III project wells

The remainder of this page intentionally left blank.

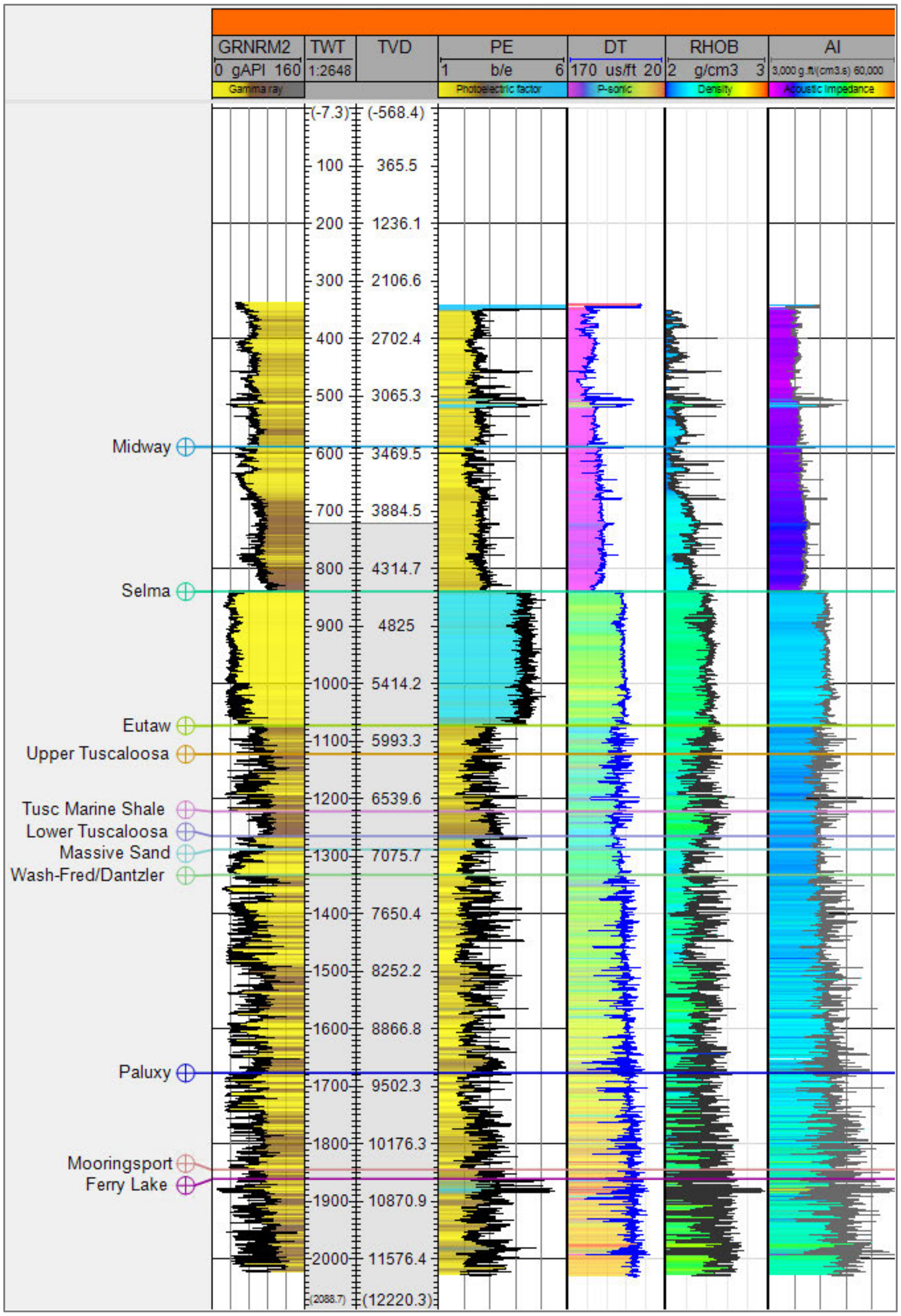


Figure 5. Geophysical logs from the D-9-8 #2 well used for site specific geologic characterization.
Gamma ray is plotted in track 1, sonic is plotted in track 3, bulk density is plotted in track 4, acoustic impedance is plotted in track 5. Depth tracks shown in Two-way time (TWT) and True Vertical Depth (TVD).

Table 4. Depths of Whole Core Acquired from the SECARB Phase III Project Wells

Well	Formation Cored	Interval Cored	Retrieved Core
D-9-7 #2	Upper Paluxy Sandstone	9,568-9,636 ft.	62 Ft.
D-9-8 #2	Upper Paluxy Sandstone	9,400-9,461 ft.	53 Ft.
	Lower Paluxy Sandstone	10,430-10,465 ft.	28 Ft.
D-9-9 #2	Upper Paluxy Sandstone	9,404-9,448 ft.	43 Ft.

Reservoir fluid samples from the Paluxy Formation at the SECARB Phase III test site provided baseline geochemical characteristics including total dissolved solids (TDS), major cations and anions, dissolved carbonate-bicarbonate, and pH. Further discussion of the fluid samples gathered from the Paluxy Formation can be found in **Section B.9. Baseline Geochemical Data**.

In addition to assembling and further analyzing the wealth of reservoir characterization data gained from the DOE/NETL SECARB Phase III Anthropogenic CO_2 injection demonstration, Tenaska licensed 38.6 miles of existing 2D seismic lines that transect the Longleaf CCS Hub (**Figure 6**). This data was used to interpret site-specific and regional geologic structure, to determine lateral continuity, and build the geologic inputs used for computational modeling. The seismic data included six lines: four oriented east-west and two oriented north-south. These 2D seismic lines provided data to refine the structural interpretation of the Longleaf CCS Hub, specifically defining the structural dip and the location of the Hatters Pond Fault bounding the western edge of the Mobile Graben which is located to the east of the project area. Additionally, seismic data was used to confirm the lateral continuity of the injection and confining zones.

The 2D seismic lines were tied to sonic measurements taken in the D-9-8 #2 well (**Figure 5**) to correlate the structural interpretation of the Longleaf CCS Hub to the porosity and permeability model developed using the well log data. Together, these data sets were used to build a 3D Static Earth Model in the Petrel geological modeling software suite representative of the geologic and petrophysical characteristics within the Longleaf CCS Hub (Petrel is trademarked by and licensed from SLB Corporation). The areal extent of the 3D Static Earth Model is shown in **Figure 6**.

To provide additional data on regional structure and stratigraphy surrounding the Longleaf CCS Hub, 207 digital gramma ray logs from legacy wells were acquired and loaded into the Kingdom geologic interpretation software (Kingdom is trademarked by and licensed from S&P Global). Eighty of these logs covered the entire injection zone and primary confining unit (**Figure**

7). Well log cross sections, shown later in this application narrative, were created using a subset of these logs along with the geophysical logs from the D-9-7 #2, D-9-8 #2, and D-9-9 #2. All of the wells with digital logs covering the injection zone in the model area are plugged and abandoned. Information on the deep oil and gas wells in the modeled area is provided in **Table 3** of **Application Narrative Appendix A**.

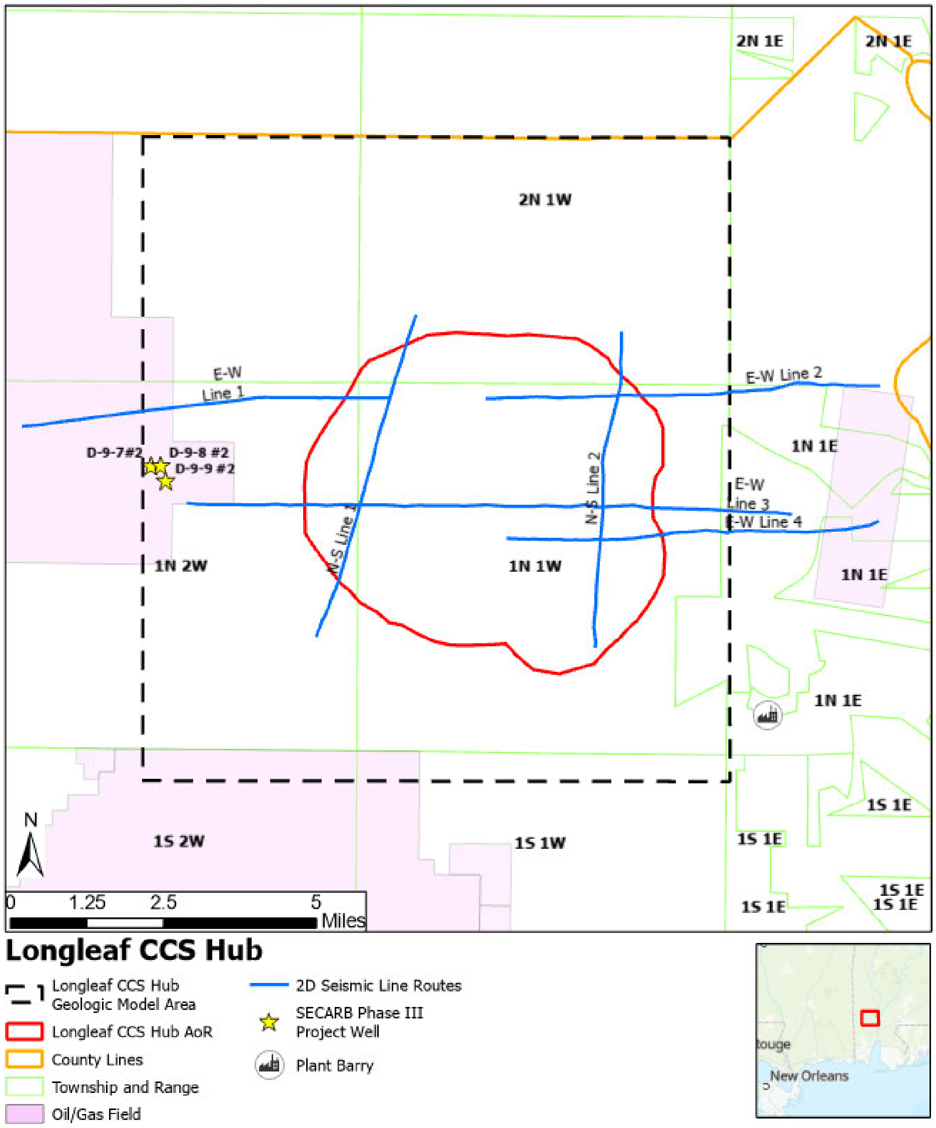


Figure 6. Map of 2D seismic coverage used to create the 3D Static Earth Model of the Longleaf CCS Hub (geologic model area indicated by black dashed line).

Acoustic logs from well D-9-8 #2 were tied to E-W Line 1 (northeastern most line) to convert time to depth.

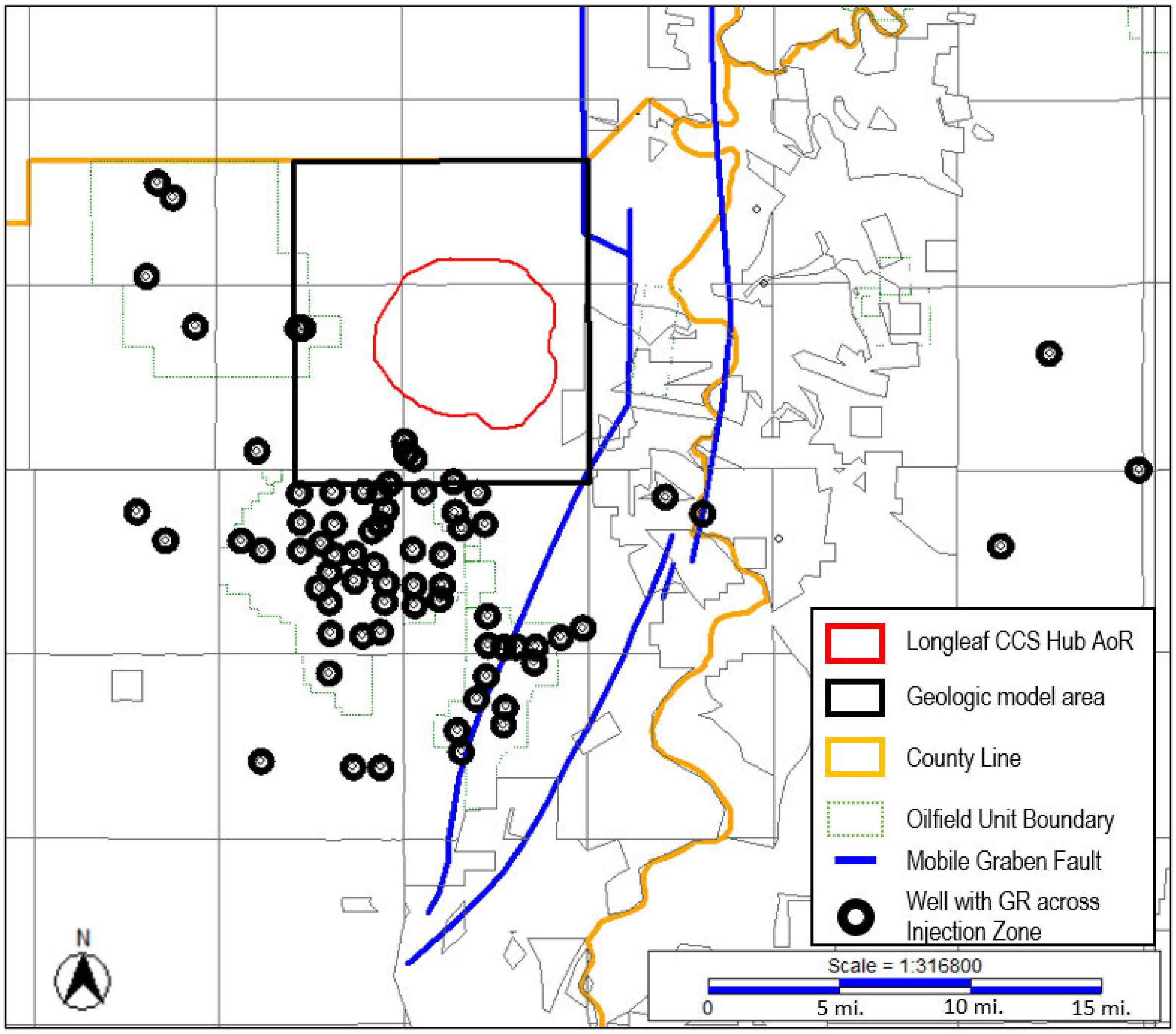


Figure 7. Wells with gamma ray logs across the Paluxy Formation and Tuscaloosa Marine Shale used in regional geologic study, including the 3 DOE/NETL SECARB Phase III Anthropogenic CO_2 injection test wells and 80 existing deep exploration wells.

B.2. Maps and Cross Sections of the Longleaf CCS Hub Model Area [40 CFR 146.82(a)(3)(i)]

B.2.1. Stratigraphic Column of the Longleaf CCS Hub

The Longleaf CCS Hub will consist of several key regulatory zones. The uppermost zone will be the primary confining zone, the Tuscaloosa Marine Shale (TMS). The lowermost zone is the lower confining zone, comprised of the combination of the Mooringsport Formation and Ferry Lake Anhydrite. The primary injection zone for this permit application is the Paluxy Formation. The Washita-Fredericksburg Group Dantzler Sand and the Lower Tuscaloosa Group Pilot Sand and Massive Sand in aggregate are considered the secondary injection zone containing porous and permeable sands that may provide future expansion opportunities, but injection is not currently proposed for these formations within the Longleaf CCS Hub. The following paragraphs provide details on the primary injection zone (Paluxy), the lower confining zone (Ferry Lake Anhydrite/Mooringsport), and the primary confining zone (TMS).

The primary CO_2 injection zone for the Longleaf CCS Hub is the lower Cretaceous Paluxy Formation. This formation contains a series of thick sandstones and interbedded mudstones and conglomerates and is located at 10,080 to 11,220 ft. subsea (10,160 to 11,300 ft below ground surface) within the Longleaf CCS Hub (**Figure 8**). The Paluxy Formation has favorable reservoir properties, such as a thick 473 ft package of porous sands giving it high storage resource potential and sufficient permeability (see **Section B.4**) to support high rates of CO_2 injectivity per well below 90% of the fracture pressure (See **Section B.6**).

The Paluxy Formation is overlain by a 144-foot-thick transgressive shale at the base of the Washita-Fredericksburg Group (the Wash-Fred Basal Shale). The Wash-Fred Basal Shale served as a confining zone for the DOE/NETL SECARB Phase III CO_2 injection demonstration at Citronelle Dome (ADEM permit numbers ALSI9949664 and ALSI9949665) and prevented the migration of CO_2 from the Paluxy during that demonstration. However, the volumes injected for this demonstration (100,000 mt total) were much lower than are proposed at the Longleaf CCS Hub, and so there is uncertainty regarding its potential as a confining zone for commercial scale storage that will require additional data to be collected and assessed during testing discussed in the **Pre-Operational Testing Plan**. Currently available data for the Wash-Fred Basal Shale are discussed in **Section B.5.2** below.

Beneath the Paluxy, from approximately 11,220 to 11,570 ft., is the Mooringsport Formation and the Ferry Lake Anhydrite. These two formations contain low permeability silty limestone and anhydrite, respectively, and serve as the lower confining units for the Longleaf CCS Hub.

The primary and secondary injection zones are overlain by the 300-foot-thick TMS at approximately 7,250 ft subsea that will serve as the primary confining zone for the Longleaf CCS Hub (**Figure 8**). The TMS is overlain by silty sandstones in the upper Tuscaloosa Group that would serve as the above zone monitoring interval for the project. Petrophysical properties of the TMS indicating its sealing capacity are discussed in **Section B.5.1** below.

In addition to the TMS, the primary and secondary injection zones are overlain by extensive low permeability intervals that separate the lowest USDW in the Chickasawhay

Formation from the Paluxy CO_2 injection interval. These include the Selma and Midway Groups at approximately 5,000 to 7,000 ft. of depth that contain a 2,000-foot-thick package of low-permeability chalks and clays (**Figure 8**).

In total, about 8,380 ft. of strata separate the top of the primary injection zone in the Paluxy at 10,080 ft. and the deepest USDW, the Chickasawhay Formation, located at a depth of approximately 1,700 ft. (**Figure 8**). These formations are further described in **Table 5**. Porosity, permeability, and thickness of these formations is discussed in Section B.4 for the injection interval and Section B.5 for the confining zones.

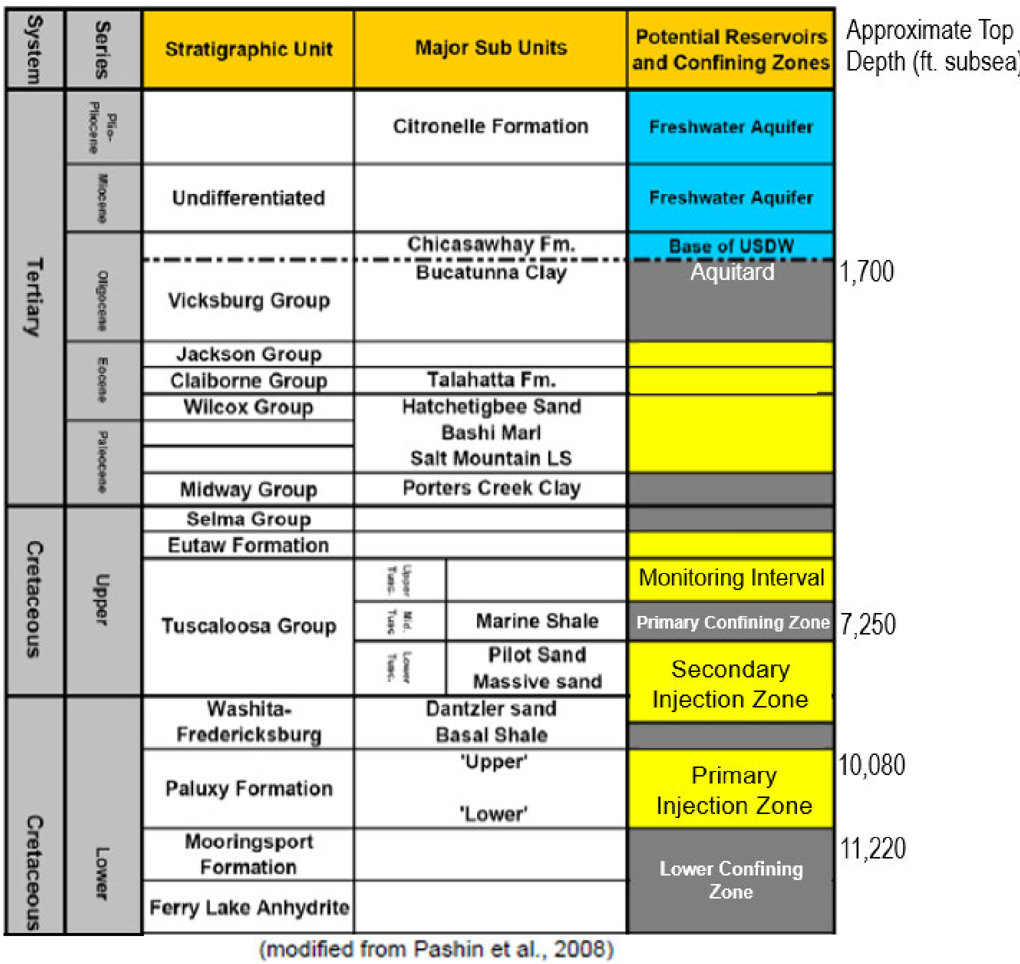


Figure 8. Stratigraphic column identifying the storage reservoir, confining zones, and the deepest USDW addressed in this permit for the Longleaf CCS Hub.

Table 5. Formations comprising the Longleaf CCS Hub

Regulatory Interval	Formation Name	Expected Depth Interval (ft. subsea)
Primary Confining Zone	Tuscaloosa Marine Shale (TMS)	7,250–7,550
Primary Injection Zone	Paluxy Formation	10,080–11,220
Injection Zone Subunits	Upper Paluxy Sandstones	10,080–10,915
	Lower Paluxy Sandstones	10,915–11,220
Lower Confining Zone	Mooringsport (limestone) / Ferry Lake (anhydrite) Interval	11,220–11,570

B.2.2. Regional Structural Setting of the Longleaf CCS Hub

The Longleaf CCS Hub is in the eastern margin of the Mississippi Interior Salt Basin which formed during the Triassic-Jurassic rift-to-drift sequence associated with the opening of the Gulf of Mexico (Pashin et al., 2008). Structural deformation in the area is primarily driven by movement of the Jurassic-aged Louann Salt, the basal stratigraphic unit within the basin (Pashin et al., 2014).

Figure 9 shows a structural cross section view through the geologic model of the Longleaf CCS Hub. The Longleaf CCS Hub sits down dip and to the east of the Citronelle Dome, a prominent salt cored anticline that hosts oil accumulations in reservoirs below the Ferry Lake Anhydrite (Esposito et al., 2008). The cross section shows the subsurface structure in the project from the Selma Group (upper Confining Zone) to the base of the Mooringsport Formation.

The Paluxy Formation shown in **Figure 9** is informally separated into two intervals, the Upper Paluxy which contains several thick, amalgamated sandstone bodies, and the Lower Paluxy which contains predominantly shale, vertically isolated sandstones, and a regionally continuous basal sandstone unit overlying the Mooringsport Formation.

The remainder of this page intentionally left blank.

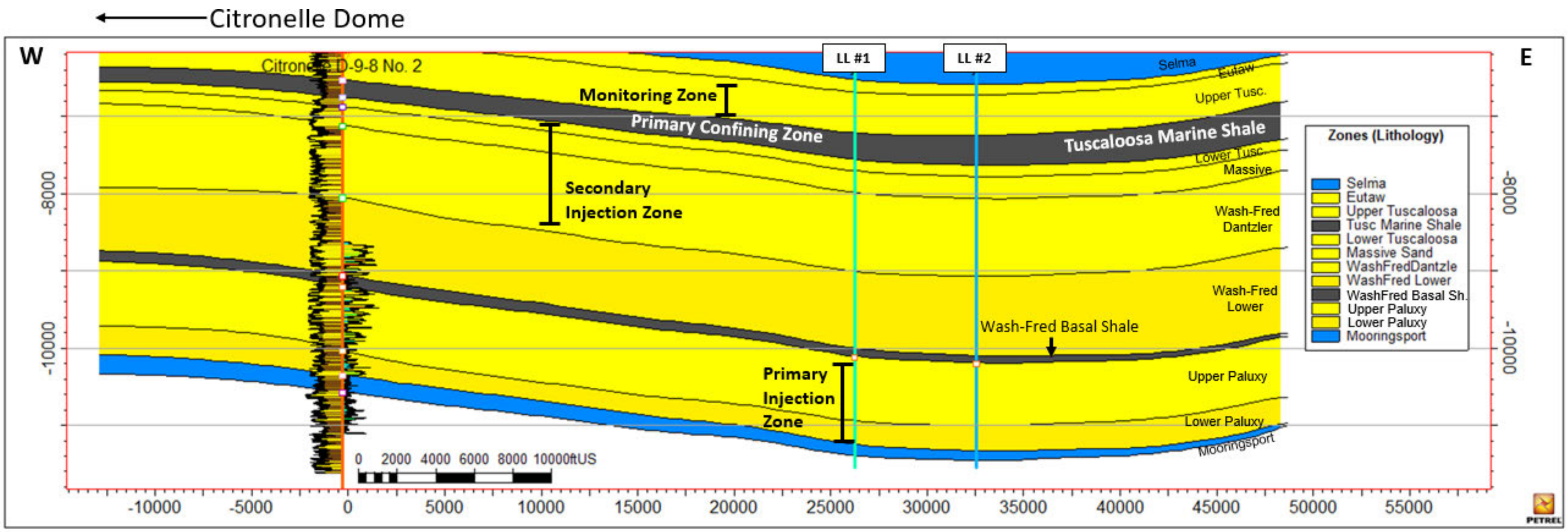


Figure 9. Cross sectional view through the 3D static earth model of the Longleaf CCS Hub from the Selma Group to the base of the Mooringsport.

The upper Tuscaloosa Group, the above zone monitoring interval, is annotated above the Tuscaloosa Marine Shale, the primary confining zone (upper black shale zone). The Wash-Fred Basal Shale is the lower black shale zone above the upper Paluxy injection interval. The log shown is the D-9-8 #2 with gamma ray plotted to the left and effective porosity (PHIE) plotted to the right.

B.3. Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

The closest fault to the Longleaf CCS Hub, and only fault near the project, is the Hatters Pond Fault (HPF) that forms the western edge of the Mobile Graben. The HPF trends north-south, dips to the east, and lies approximately five miles east of the center of the proposed injection wells (**Figure 10**). The Graben is about 3.5 miles wide in the upper part of the Cretaceous section and narrows considerably downward in section between the opposed normal faults which dip approximately 65°. The faults on either side of the Graben have maximum displacement in the Jurassic section, and displacement dies out in the upper part of the Tertiary section. The HPF does not crop out at the surface, and no core data has been recovered from the fault rocks; therefore, the degree of cataclasis or diagenetic cementation along the fault plane is unknown. In addition, no wells with pressure data occur within the area near the fault so pressure compartmentalization cannot be determined.

A 2D seismic line was acquired and interpreted that intersects the HPF and Movico Dome which are two prominent structures in the area. Geologic horizons of the Selma Chalk and Ferry Lake Anhydrite have high acoustic impedance contrasts and were interpreted across the seismic image (**Figure 11)**. The 2D seismic line indicates the HPF to the east with approximately 760 feet of displacement along the hanging wall of the normal fault (**Figure 11)**. However, a large shot point gap occurs above the HPF where a swamp inhibited seismic data collection. The interpreted seismic image indicates the presence of the Movico Dome by the interpreted geologic horizons that dip gently to the west from the footwall of the HPF.

Using the fault displacement value that was interpreted from seismic, an Allan chart was constructed following Knipe (1997) and Knipe et al. (1998) to determine which units contact each other across the HPF surface. The Allan chart indicates the different high porosity sandstone or shale lithologies that are juxtaposed against one another along line AA' which represents a constant fault displacement of 760 feet across the HFP (**Figure 12)**. With a fault displacement of 760 feet, the upper Paluxy Formation in the hanging wall of the HPF is juxtaposed against the shales and sandstones of the lower Paluxy Formation in the footwall. In addition, sandstones of the lower Washita-Fredericksburg in the hanging wall are juxtaposed against sandstones of the upper Paluxy Formation in the footwall. These high porosity sand on sand contacts could allow lateral migration of CO_2 across the fault plane. This is the assumption used in the baseline computational model.

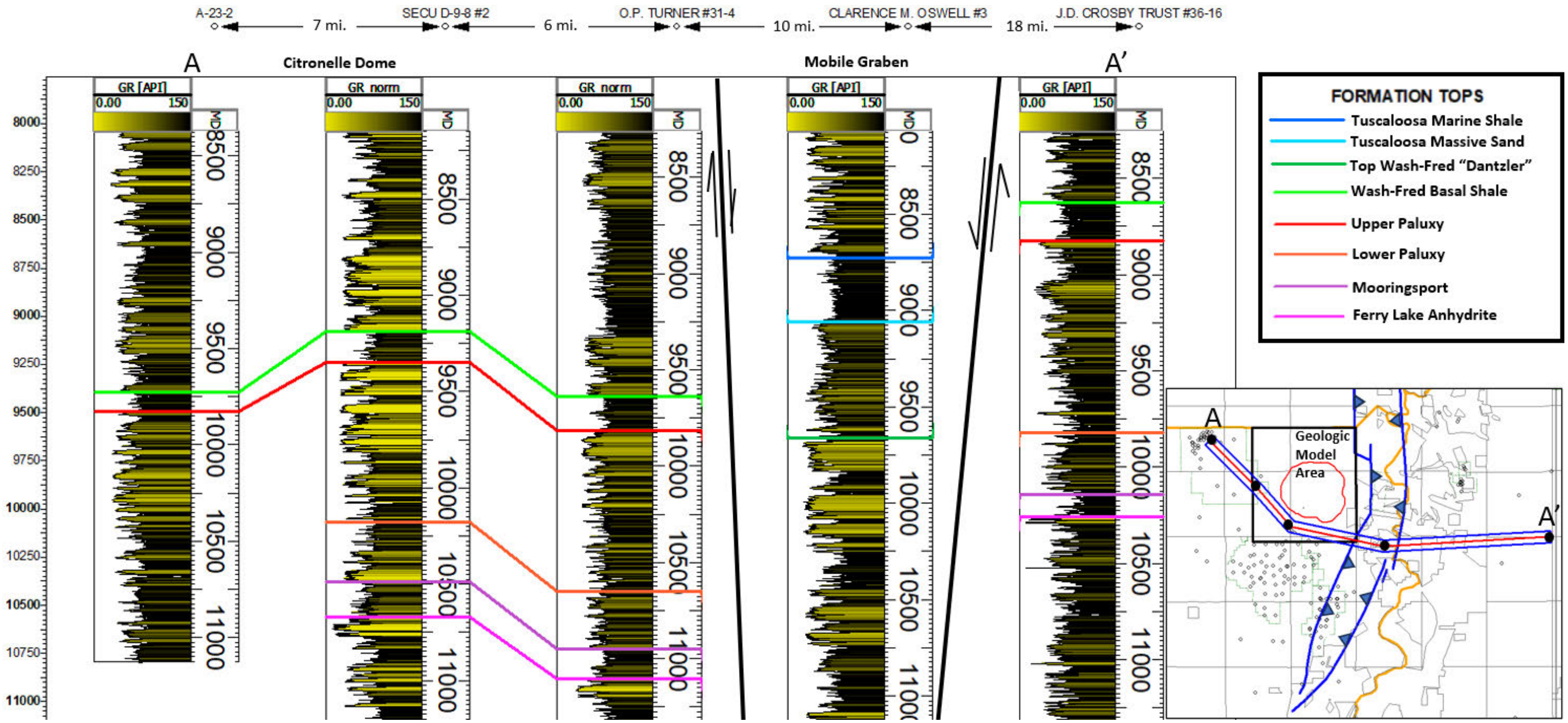


Figure 10. Regional structural cross section of the Wash-Fred Basal Shale, Paluxy injection interval, and Mooringsport/Ferry Lake interval through northeastern Mobile County and northwestern Baldwin County showing two prominent geologic structures in the region, the Citronelle Dome and the Mobile Graben.

Claimed as PBI

[redacted]

Figure 11. Interpreted Post Stack Time Migrated (PTSM) west-east 2D seismic line interpretation that intersects the AoR and HPF along the western edge of the Mobile Graben. The structural high point of Movico Dome is also indicated adjacent to the HPF along the footwall of the fault. The locations of in-zone monitoring wells IOB#2 and IOB#3 were projected onto the 2D seismic line. The Selma Chalk and Ferry Lake Anhydrite are also interpreted on the seismic image.

The remainder of this page intentionally left blank.

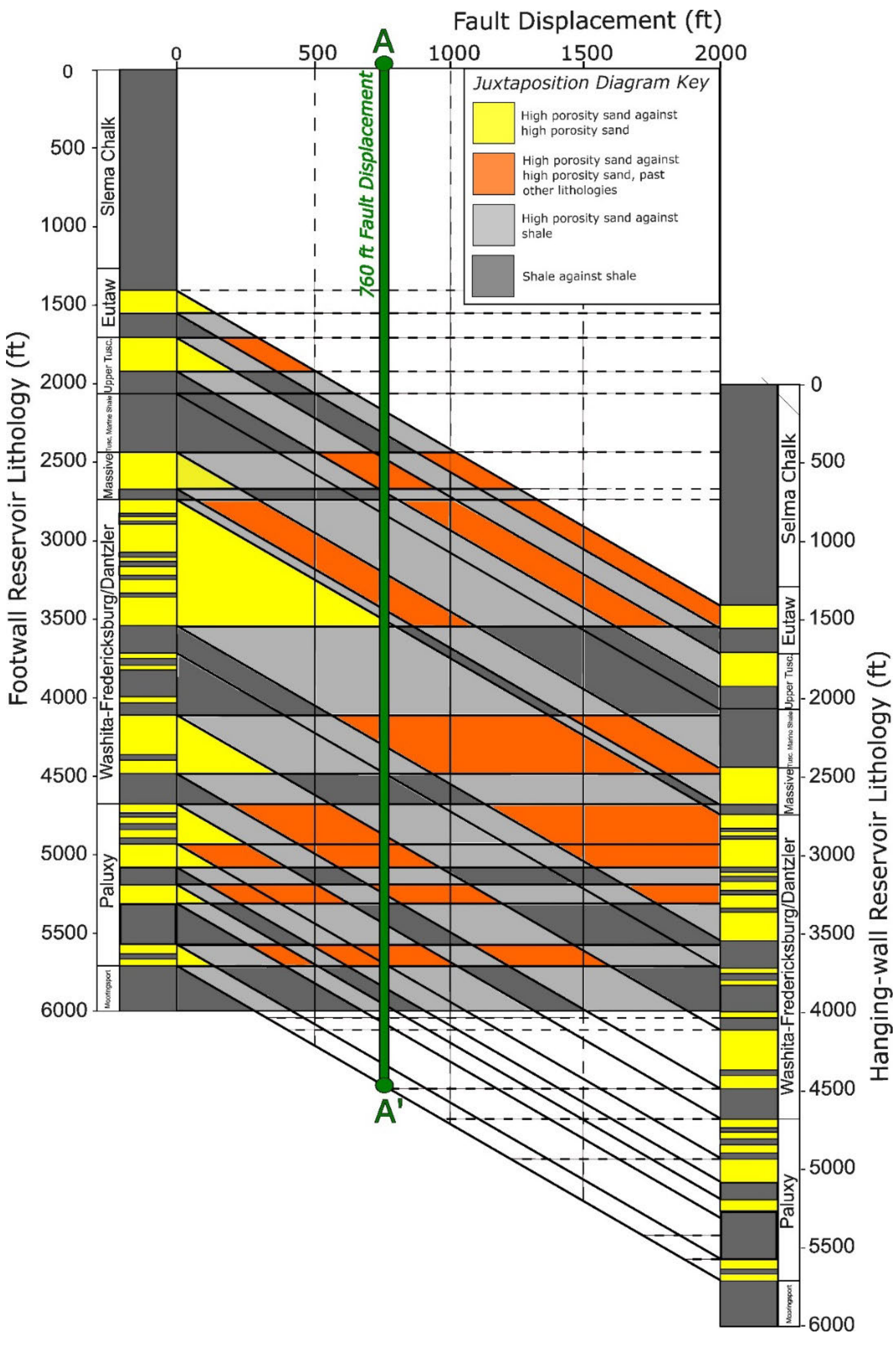


Figure 12. Allan chart indicating constant displacement of 760 feet along line AA' for the HPF.

The Wash-Fred Basal Shale (with an average shale volume of 0.70) directly overlies the top of the Paluxy Formation. Areas of fault planes where high porosity sandstones are juxtaposed against one another and occur just below a clay rich shale in the footwall or hanging wall have high potential for enhanced sealing by clay smearing (Knipe, 1997). The Wash-Fred Basal Shale may provide clay smear that extends down the HPF from the footwall intersection of the Wash-Fred Basal Shale across the Paluxy Formation in the footwall. This clay smear along the fault plane sourced from the Wash-Fred Basal Shale may provide a vertical seal for the HPF across the Paluxy Formation. In addition, the clay-rich TMS in the hanging wall of the HPF is juxtaposed against the sandstones and shales of the upper portion of the Washita-Fredericksburg Formation which provides good vertical sealing potential.

If the fault acts as a lateral seal either due to juxtaposition of the injection zone against low permeability units or the fault plane itself has sealing properties (e.g., resulting from clay smearing or cataclasis), the fault plane would act as a pressure boundary (Meckel, 2007). Simulation of the eastern boundary of the model being hydraulically closed is one of the sensitivity cases presented and discussed in more detail in **Section C.1** of the **Post-Injection Site Care and Site Closure Plan**.

To further evaluate the potential for vertical leakage along the HPF, we used two approaches. First, we looked at analog hydrocarbon traps which use the fault plane as a structural trap. Located to the east of the project is the Movico Field. Now abandoned, the Movico Field is a faulted anticline butted up against the HPF producing from the Jurassic Smackover formation at approximately -17,000 ft below sea level. The field's trap is created by the fault and juxtaposition with salt to the east of the HPF (Galicki, 1986). The larger Hatter's Pond Field to the south of the storage field has a similar trapping mechanism (Benson et al., 1981). The fact that these oilfields were butted up against the HPF provides evidence that it did not allow for vertical migration of buoyant hydrocarbon out of the Smackover.

There are no hydrocarbon pools along the HPF in the Cretaceous section above the Ferry Lake Anhydrite, likely due to the evaporite's impedance of vertical hydrocarbon migration. This is the case in the Citronelle oilfield, a giant salt-cored anticline with four-way closure to the west of the Longleaf CCS Hub (Esposito et al., 2008.). To determine the vertical sealing potential of the HPF above the confining zone, we used petroleum industry approaches developed for quantitative prediction of fault sealing potential (Meckel, T.A., 2007). One of these approaches, described by Yielding et al (1997), defines and uses a shale gouge ratio (SGR) to predict if faults may be sealing. In geologic units dominated by clay or shale beds, clay- and shale-rich smears can be formed on the fault plane, impeding vertical flow of buoyant fluids. SGR is defined as the cumulative thickness of shale in a unit divided by fault throw. The higher the SGR, the greater the potential for fault sealing. For example, using a global database of clastic reservoirs at less than 3 kilometers depth, Yielding et al. (2010) showed that faults with SGR below 20% have reduced sealing capacity and essentially leak over geologic time. Those with an SGR greater than 20% are likely sealing.

As mentioned, the HPF offset decreases up section. The existing 2D seismic lines that transect the HPF indicate an offset of approximately 760 ft at the top of the Selma Group. Directly overlying the Selma Group is the Porters Creek Clay unit of the Midway Group, which is a 500 ft thick, nearly 100% clay rich interval (Figure 8). The Porters Creek Clay is an oilfield seal in the Gilbertown Oil Field in Choctaw County, Alabama, approximately 60 miles to the north of the Longleaf CCS Hub (GSA Bulletin 168). Using the calculation described above, an SGR of 66% is calculated for the Porters Creek Clay interval (500 ft shale thickness divided by a fault throw of 760 ft). Thus, the HPF is likely a seal across this interval.

Using two methods, the Allan Chart and the SGR calculation, the HPF is not expected to impact CO2 containment within the AoR. The Allan Chart suggests that sand on sand juxtaposition should prevent the buildup of pressure on the fault. Additionally, the presence of hydrocarbon traps in deeper formations below the injection zone along with SGR calculated of 66% in the Porters Creek Clay (which would be juxtaposed against the shallowest portion of the injection zone, the lower Tuscaloosa) suggest that the HPF is vertically sealing and would prevent the migration of CO_2 out of the injection zone.

B.4. Primary Injection Zone — Paluxy Formation

The Paluxy Formation contains a series of braided fluvial sandstones, conglomerates, and interfluvial mudstones that are present across the Gulf of Mexico Basin (Folaranmi, 2015) (**Figure 13).** The top of the Paluxy occurs at 10,080 ft subsea within the Longleaf CCS Hub (**Figure 14**). It is 1,140 ft thick with 473 ft of net sandstone thickness into two main subunits: the Upper Paluxy, consisting primarily of thick sandstones with thin shale interbeds, and the Lower Paluxy that contains predominantly shale with two thick sandstone sections (**Figure 15**).

Assessing the Paluxy Formation and its surrounding strata in well logs was done first in the D-9-8 #2 well where gamma ray, resistivity and porosity logs were available. The Ferry Lake Anhydrite serves as a marker horizon for picking the base of the Paluxy in well logs. The Ferry Lake has an especially low gamma ray and high resistivity response (**Figure 16**). The lower

Paluxy sandstone is the first low gamma ray and resistivity signature above the Ferry Lake Anhydrite. The top of the Paluxy was picked based on the transition from a series of low gamma ray and resistivity signatures representing the thick sandstone bodies to a 144-foot-thick high gamma ray and resistivity signature interpreted as the Wash-Fred Basal Shale.

The remainder of this page intentionally left blank.

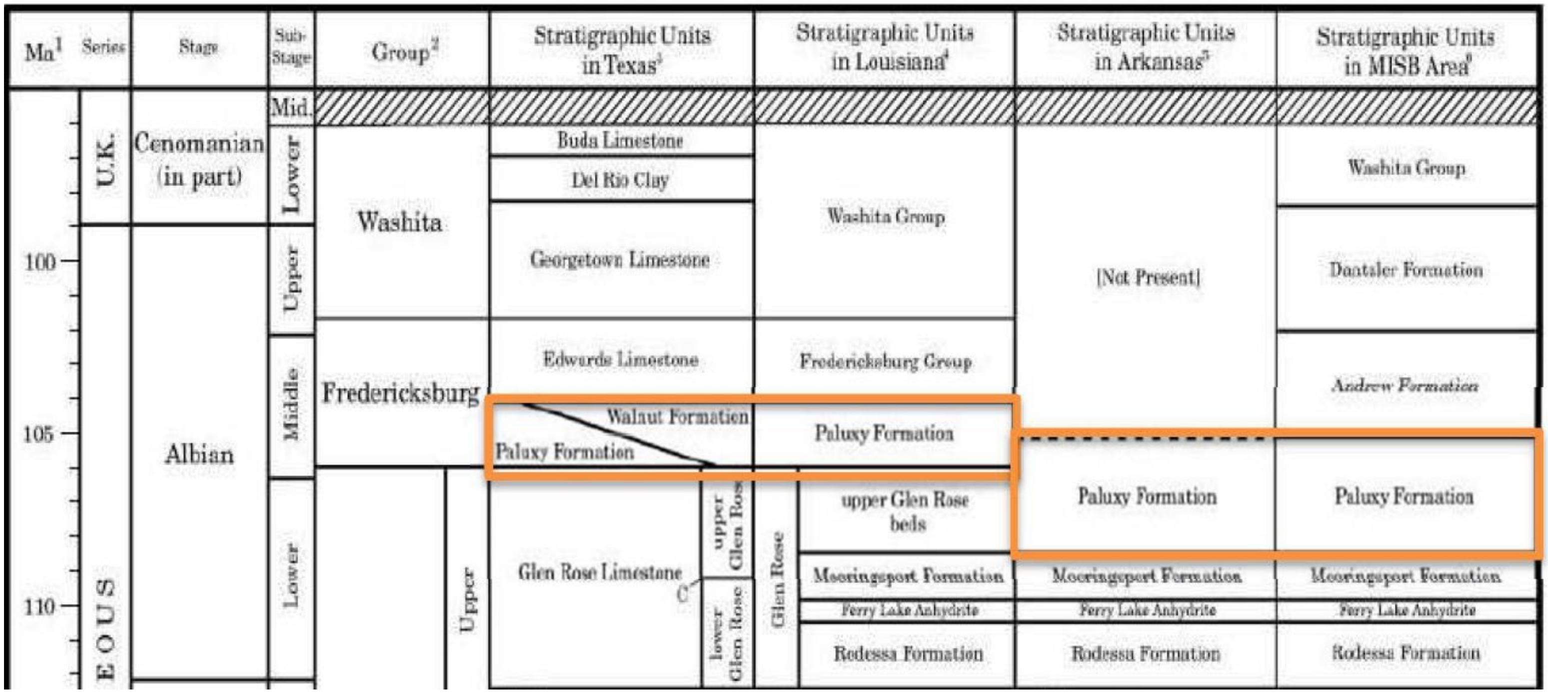


Figure 13. Stratigraphic columns across the continental Gulf of Mexico Basin indicating lateral continuity of the Paluxy Formation.

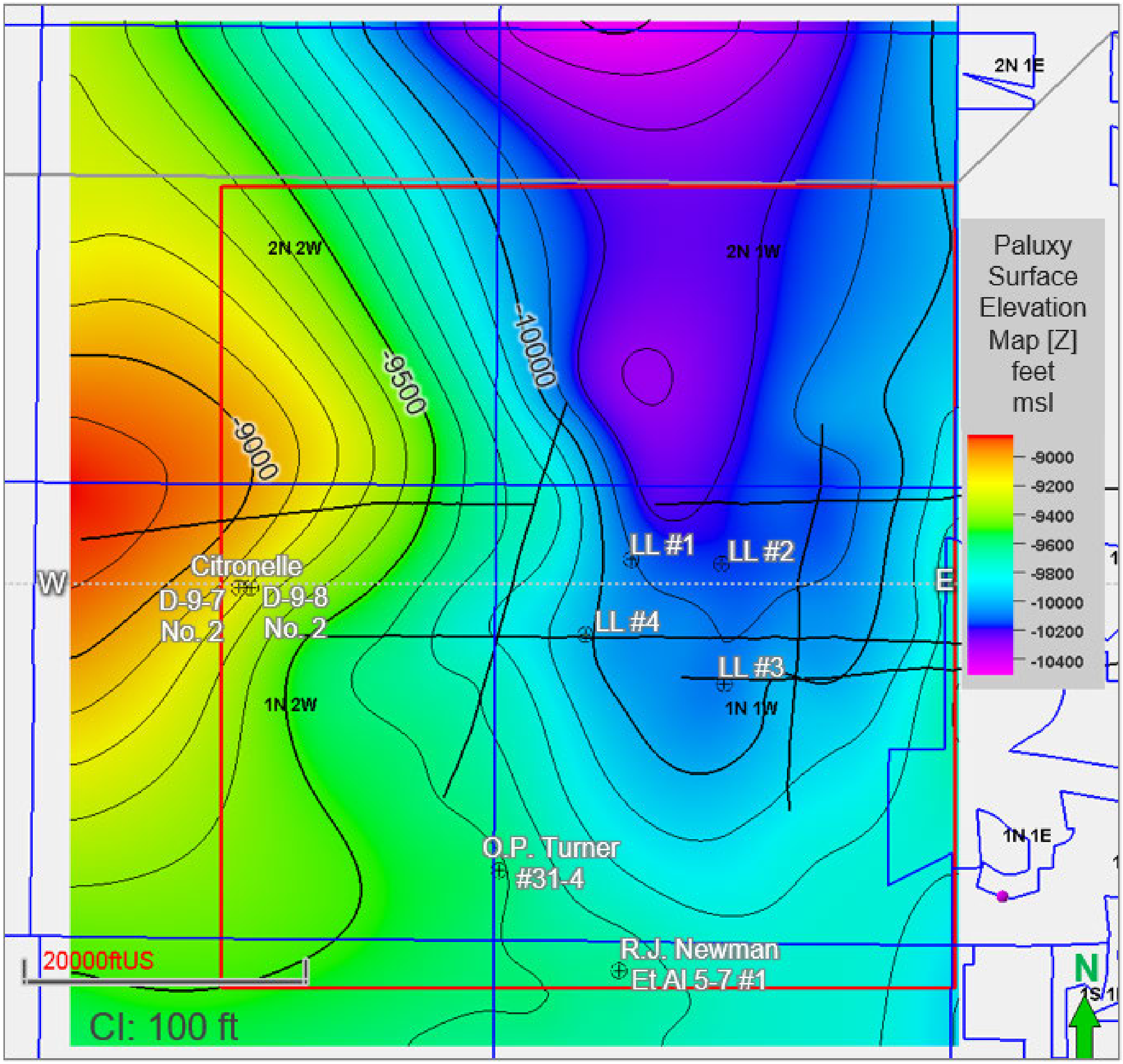


Figure 14. Structure contour map on the top of the Paluxy Formation in northeastern Mobile County. Datum is elevation in feet subsea. Contour interval: 100 ft. Black lines indicate surface track of 2D seismic lines.

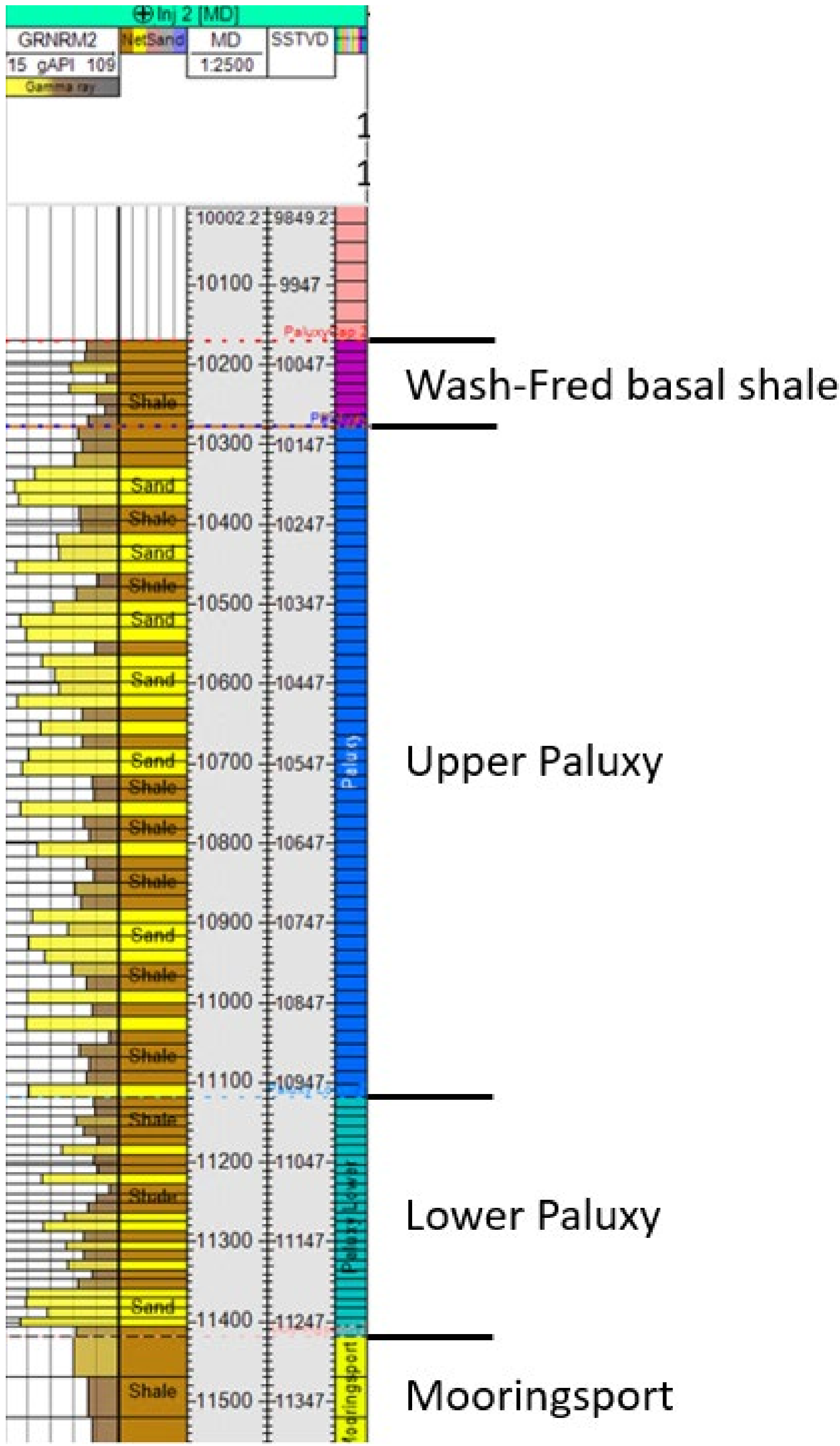


Figure 15. Net sand log derived from the 3D Static Earth Model at planned Injection well LL#1 with 473 ft. of net sand in the Paluxy Formation.

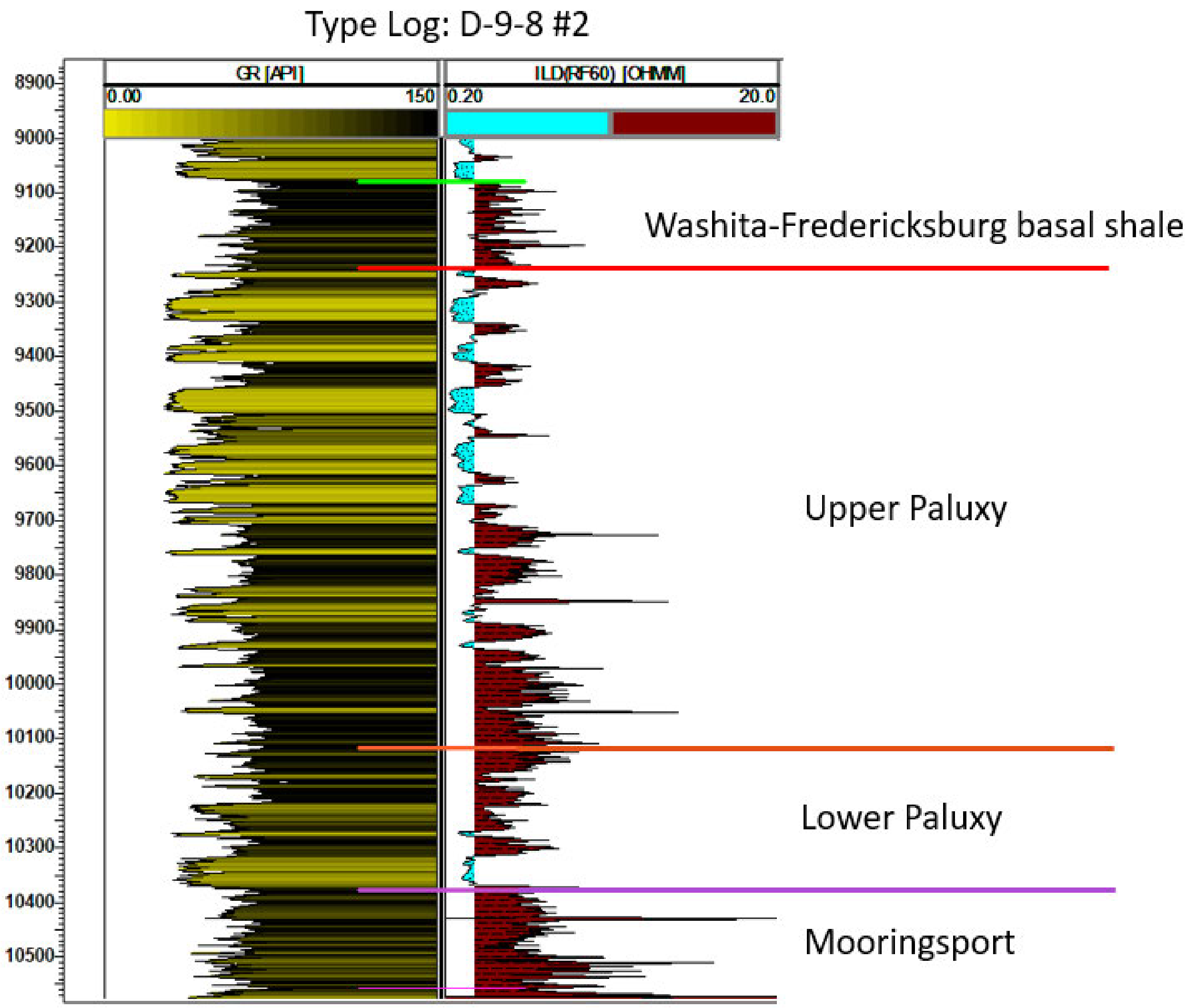


Figure 16. Gamma ray and resistivity logs from the Paluxy Formation type log, the D-9-8 #2 well, used to pick formation tops.

A deep resistivity cutoff of 2 ohms, that coincides with a decrease in gamma ray, indicates the approximate sand/shale cutoff. Blue shading on the resistivity log indicates net sand.

The Paluxy Formation is comprised of three lithofacies: the conglomerate lithofacies (**Figure 17**), the sandstone lithofacies (**Figure 18**), and the mudstone lithofacies (**Figure 19**) (Folaranmi, 2015). The sandstone lithofacies are the target for CO_2 injection in the Paluxy.

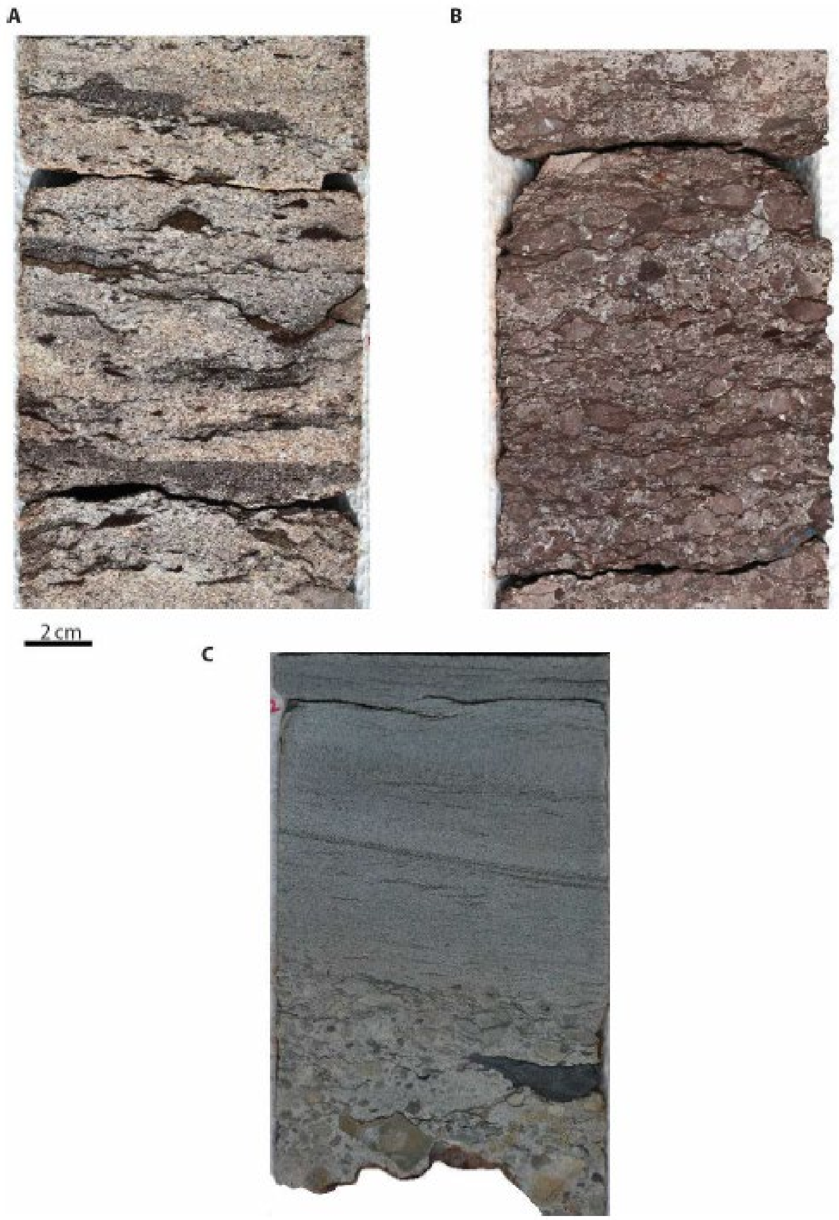


Figure 17. Core photos of the Paluxy conglomerate facies.

A: Well D-9-7 #2 at 9,624.5 ft. showing conglomeratic sandstone with platy shale intraclasts in a sandstone matrix. B: Well D-9-9 #2 at 9,419 ft. showing a clast-supported conglomerate containing clay-coated caliche clasts. C: Well D-9-9 #2 at 9,422 ft. showing argillaceous and dolomitic mudstone clasts overlain by siltstone.

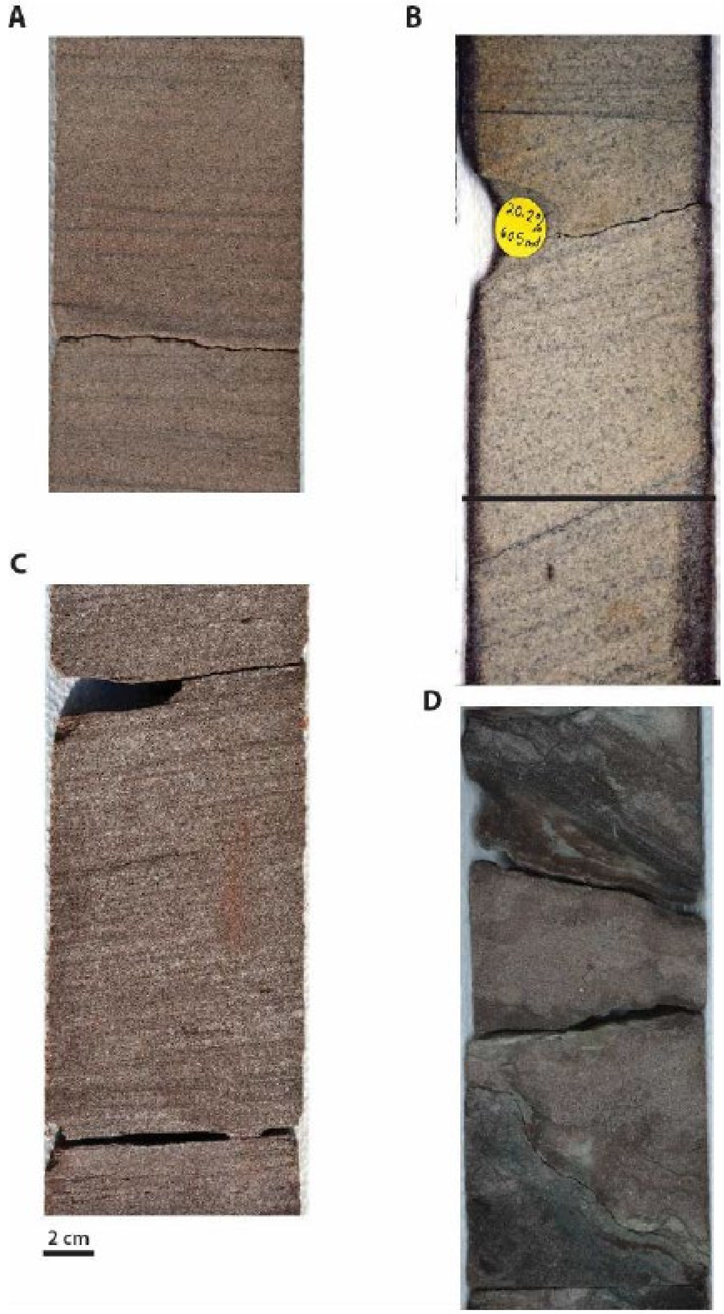


Figure 18. Core photos of the Paluxy sandstone facies.

A: Well D-9-7 #2 at 9,614 ft. showing horizontally laminated sandstone with thin micaceous laminae. B: Well D-9-8 #2 at 9,449 ft. showing planar cross-bedded sandstone. C: Well D-9-7 #2 at 9,582 ft. showing tangential cross bedding. D: Well D-9-8 #2 at 9,436 ft. showing fine-grained sandstone with convoluted beds.

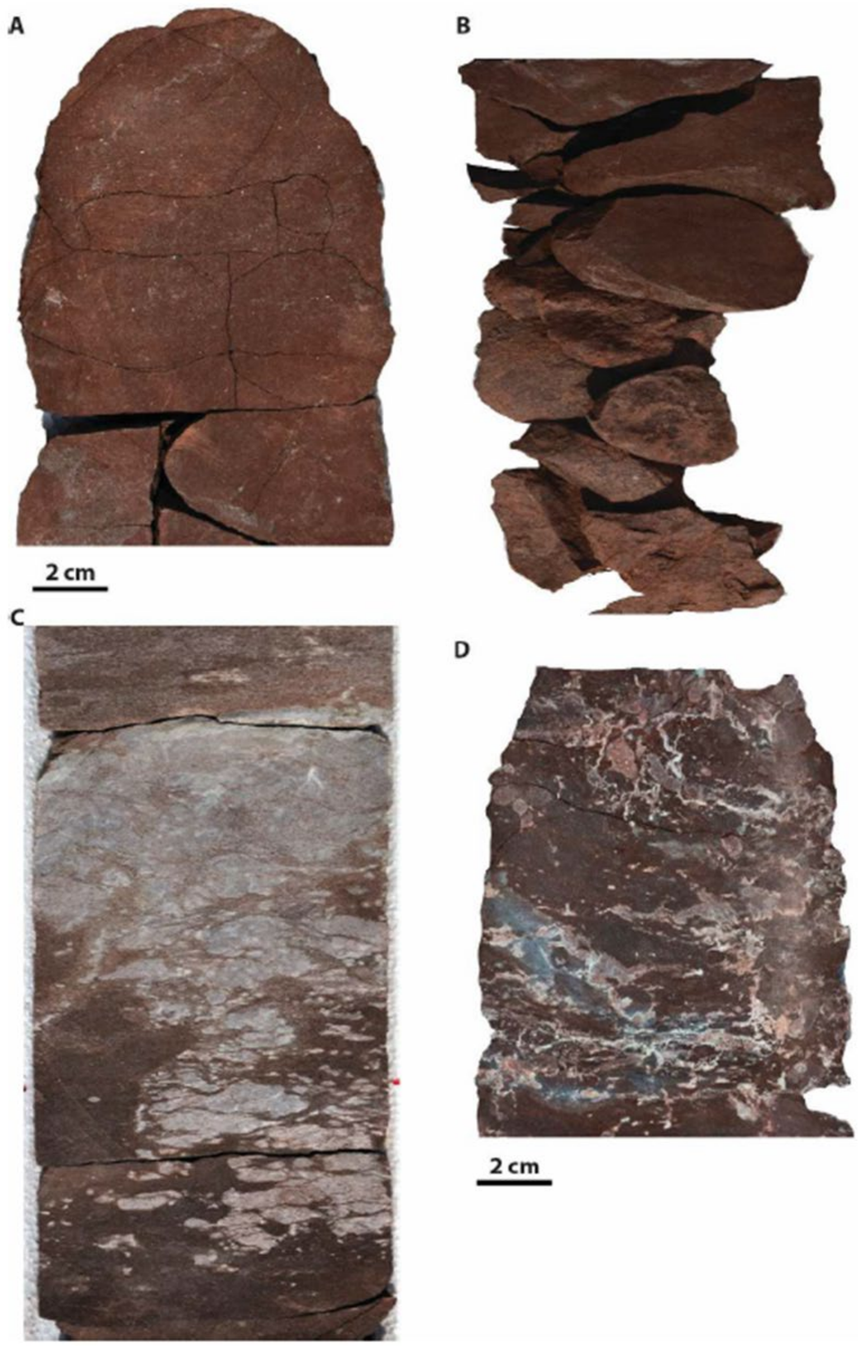


Figure 19. Core photos of the Paluxy mudstone facies.

A: Well D-9-7 #2 at 9,634 ft. showing blocky mudstone with horizontal and vertical cracks. B: Well D-9-7 #2 at 9,635 ft. showing mudstone with pedogenic slickensides and blocky peds. C: Well D-9-7 #2 at 9,590.5 ft. showing mottled mudstone with abundant calcareous nodules. D: Well D-9-9 #2 at 9,424.5 ft. showing Mudstone with calcite-filled cracks and small caliche nodules.

Mineralogy

The Paluxy sandstone is composed of quartz, feldspar, and lithic fragments, and is classified as a subarkosic, feldspathic litharenite according to the Folk (1980) classification system (**Figure 20**) (Pashin et al., 2020). Quartz grains are mostly monocrystalline, occasionally polycrystalline, and sub-angular to sub-rounded and slightly elongate to spherical (**Figure 21**). Quartz content ranges from 65-95% with roughly equal proportions of feldspar and lithic fragments. Orthoclase and plagioclase feldspar are both present and are commonly partially dissolved or vacuolized resulting in secondary porosity. Traces of accessory minerals include biotite and muscovite micas, and trace amounts of zircon grains, calcite cement, and kaolinite exist within pore spaces (**Figure 22**). XRD analysis indicated that clay minerals within the Paluxy are predominantly illite and kaolinite (Folaranmi, 2015). This composition is low in reactive minerals, such as calcite, and therefore is compatible with CO_2 injection.

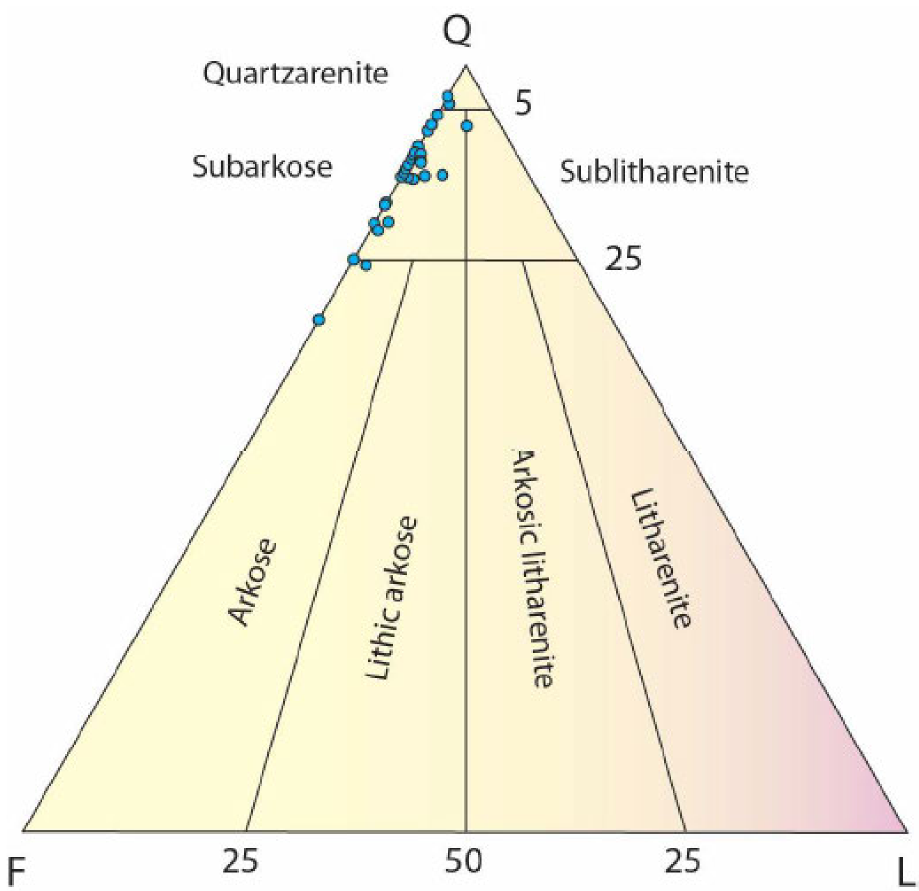


Figure 20. QFL diagram for sandstones in the Paluxy Formation (modified from Folk, 1980). The core data from the Paluxy sandstones plot predominantly as subarkosic sandstones.

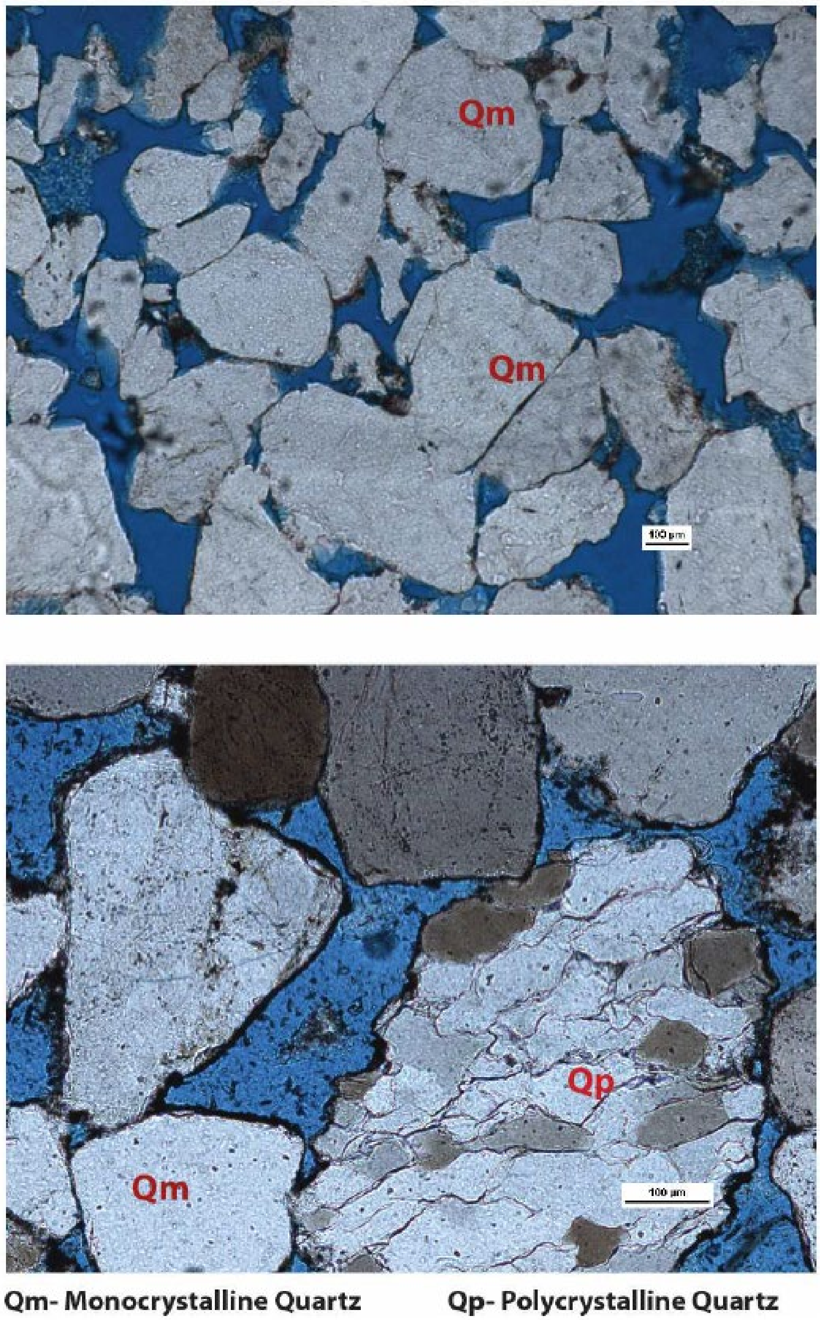


Figure 21. Thin section photomicrograph of Paluxy sandstone subangular and subrounded grains showing the dominance of monocrystalline quartz and an example of a polycrystalline grain.

Dark coating on grains is clay coating. From well D-9-7 #2, top photo at 9,604.35 ft; bottom photo at 9,600 ft.

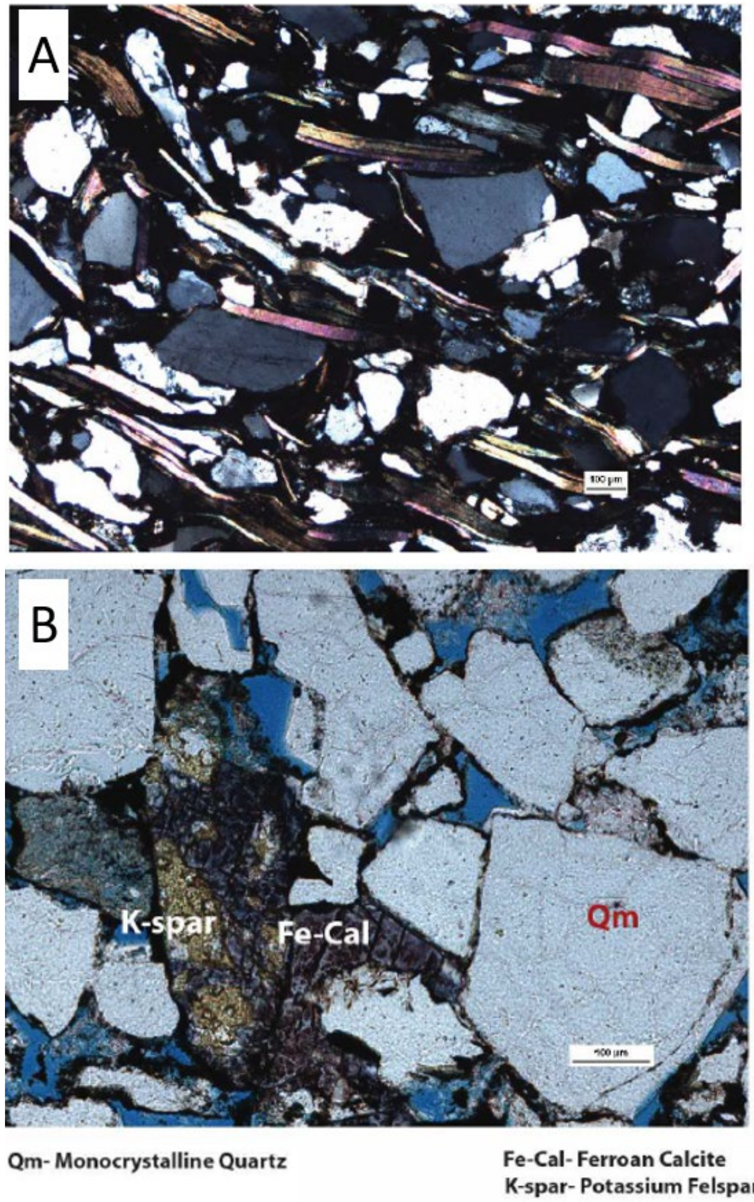


Figure 22. Thin section photomicrograph of Paluxy sandstone grains.

A: from well D-9-8 #2 at 10,455 ft. showing cross-polarized light sample with birefringent biotite grains mixed with equant quartz and feldspar grains. B: from well D-9-7 #2 at 9,575.5 ft. showing clay coating on grains (dark brown), partially vacuolized potassium feldspar, and ferroan calcite cement replacing a vacuolized potassium feldspar grain.

Porosity and Permeability

Routine Core Analysis (RCA) was conducted on whole core obtained from the D-9-8 #2 well from a depth of 9,400 ft to 9,461 ft, a thick Upper Paluxy sandstone interval. **Figure 23** provides core photos and descriptions of a portion of the core collected that is representative of the Upper Paluxy sandstones, from 9,430 ft to 9,460 ft.

RCA was conducted on 10-foot intervals from 9,400 ft to 9,461 ft to calculate an average porosity and permeability for each interval. Sandstone porosity ranged from 8% to 19%, and permeability ranged from 26 millidarcies (mD) to 437 mD. A porosity-permeability relationship was calculated by fitting an exponential trendline to a cross plot of porosity and permeability values from the geologic model (**Figure 24**).

The remainder of this page intentionally left blank.

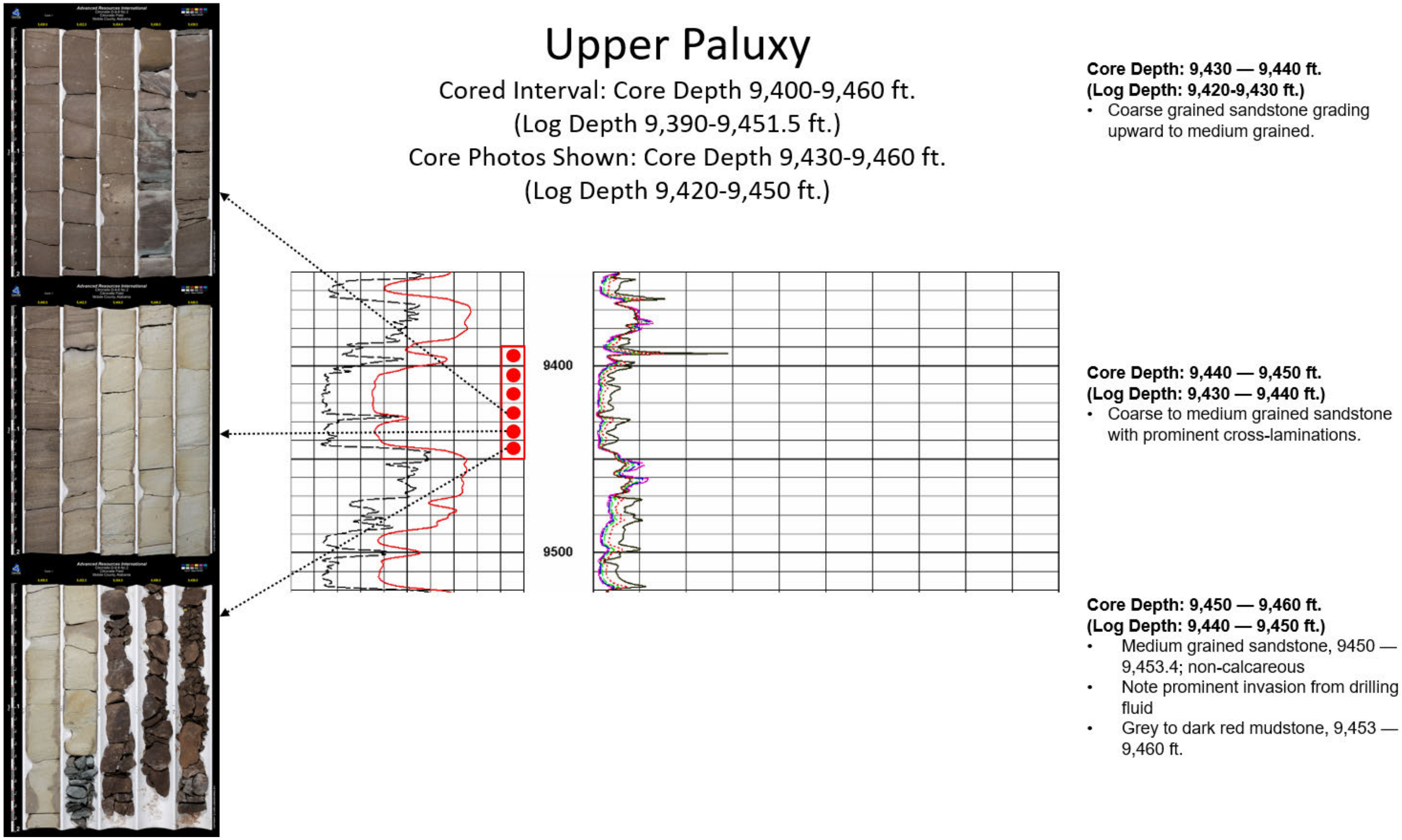


Figure 23. Whole core photos from the upper Paluxy Formation (9,400 ft. to 9,460 ft.) correlated to log signatures. Each photo contains 10 ft. of core. Lithologic descriptions of the core are to the right of the log.

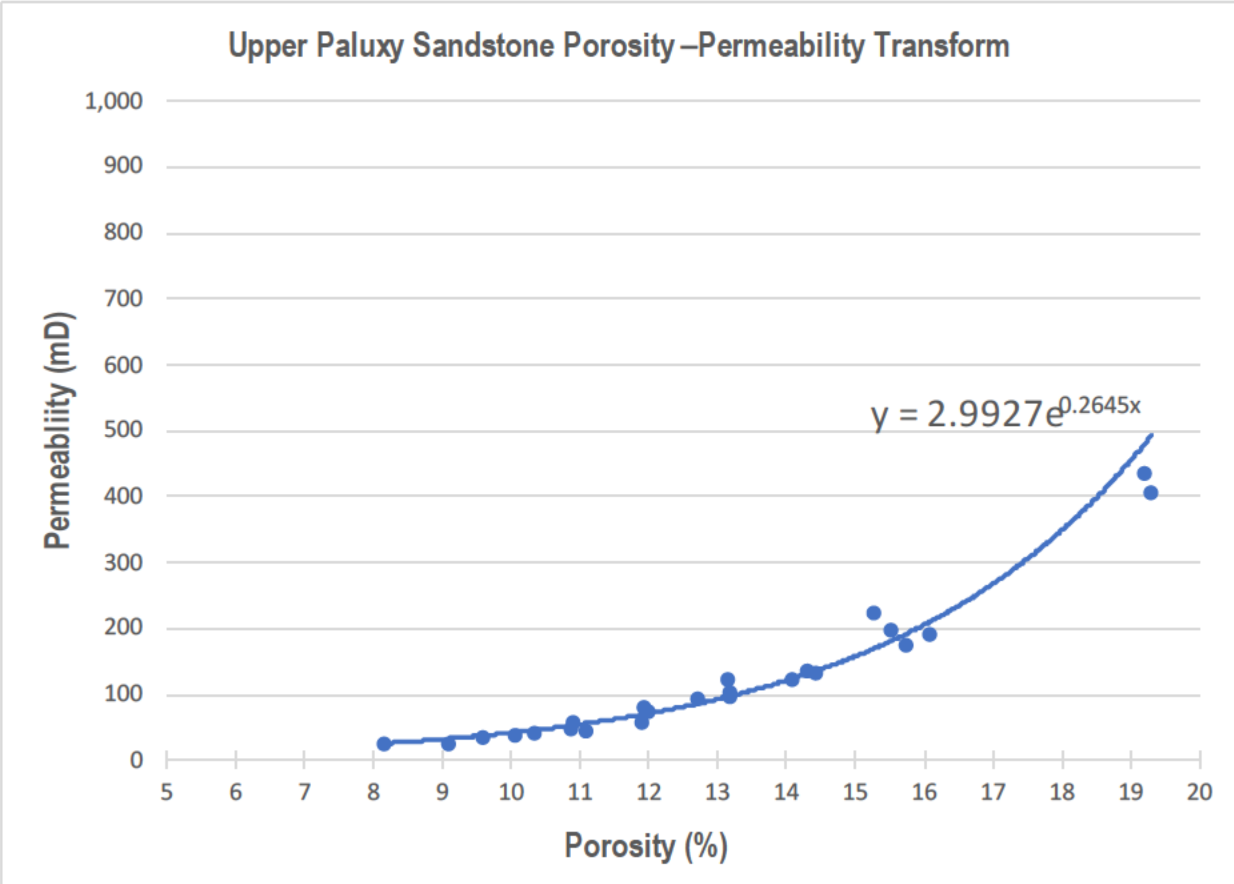


Figure 24. Porosity-permeability cross plot based on modeled upper Paluxy porosity and permeability values from the geologic model.

The whole core acquired from the Lower Paluxy sandstone interval was recovered from a depth of 10,430 ft to 10,465 ft. Core photos from the Lower Paluxy sandstones from 10,440 ft to 10,465 ft. (core depth) are shown in **Figure 25** (Note: Core depths 10,460 ft to 10,465 ft contain discontinuous core segments). Average sandstone porosity ranged from 8% to 16%, and average sandstone permeability ranged from 24 mD to 115 mD, with the higher permeability in the coarser grained sandstones at the base of the Lower Paluxy. A porosity-permeability relationship was calculated by fitting an exponential trendline to a cross plot of porosity and permeability values from the geologic model (**Figure 26**).

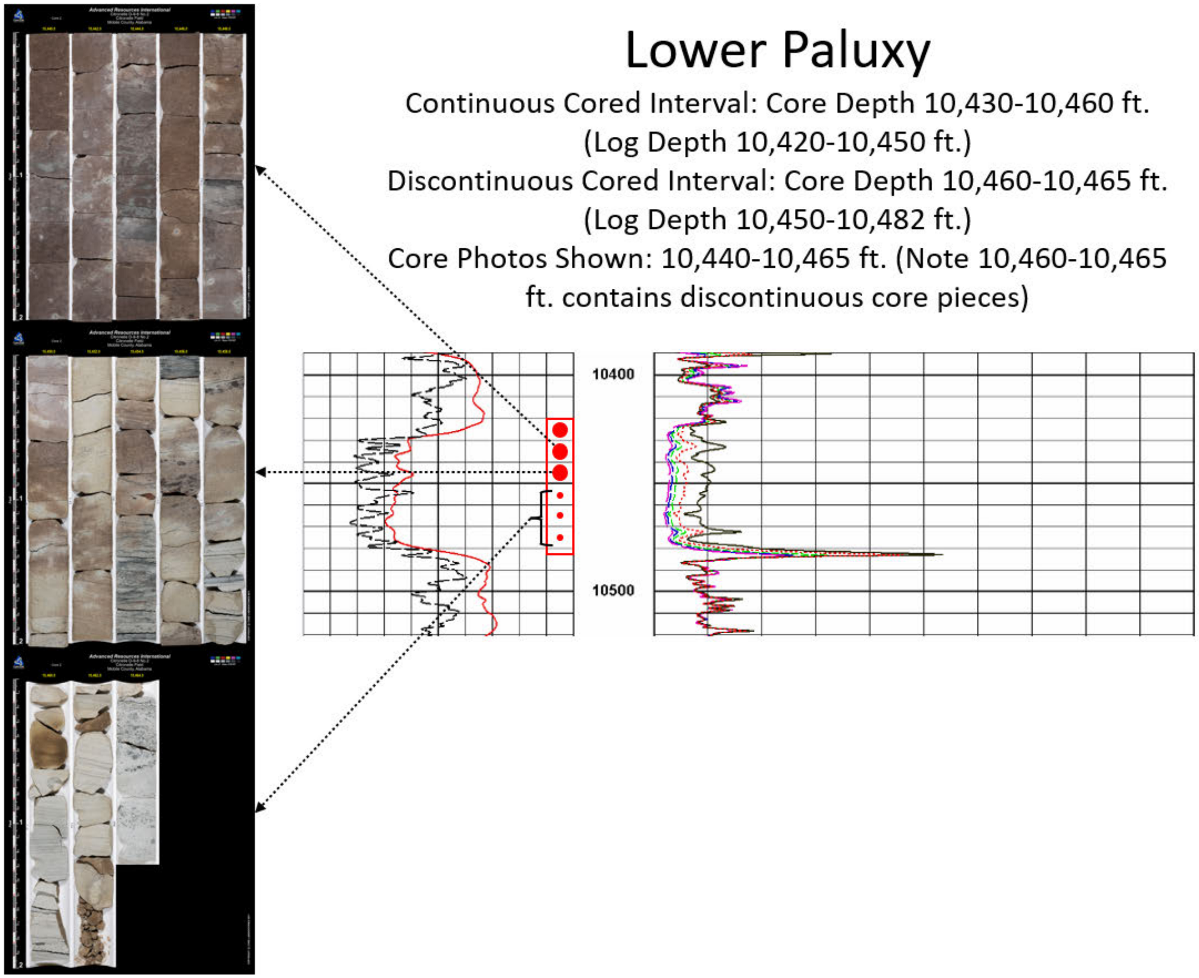


Figure 25. Whole core photos from the lower Paluxy Formation (10,430 ft. to 10,482 ft.) correlated to log signatures. Each photo contains 10 ft. of core. Lithologic descriptions of the core are to the right of the log.

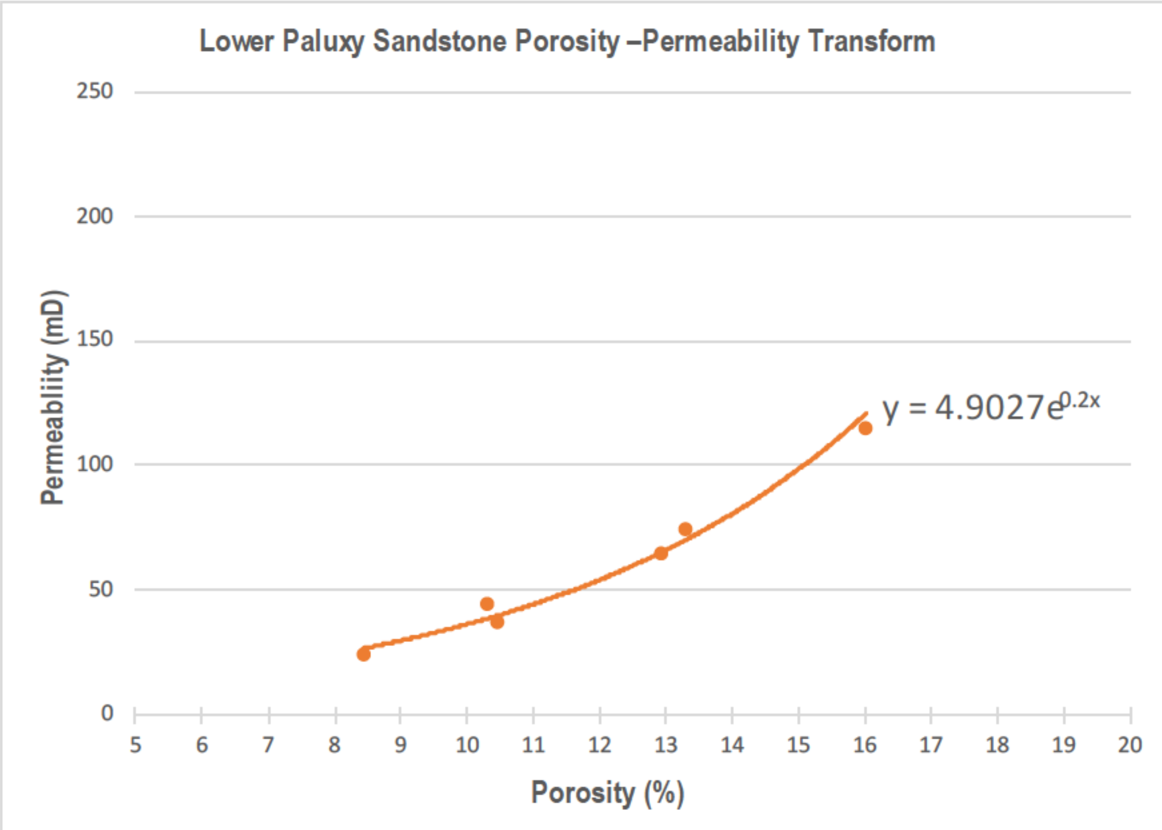


Figure 26. Porosity-permeability cross plot based on modeled lower Paluxy porosity and permeability values from the geologic model.

The porosity-permeability transforms shown in these plots are representative of the relationship between porosity and permeability in the dynamic reservoir simulation discussed in the **Area of Review and Corrective Action Plan**. Figure 27 displays these transforms compared to regional Paluxy core data. The model transforms have a similar slope to the regional Paluxy core data but lower porosity values for similar permeabilities. This observation reflects the model's use of effective porosity, while the regional core data is shown in total porosity. The use of effective porosity accounts for fine scale heterogeneities within portions of the reservoir from clay content that are prevalent in fluvial depositional systems. The use of a conservative estimate for effective porosity and pore space leads to the calculation of an aerially larger baseline AoR.

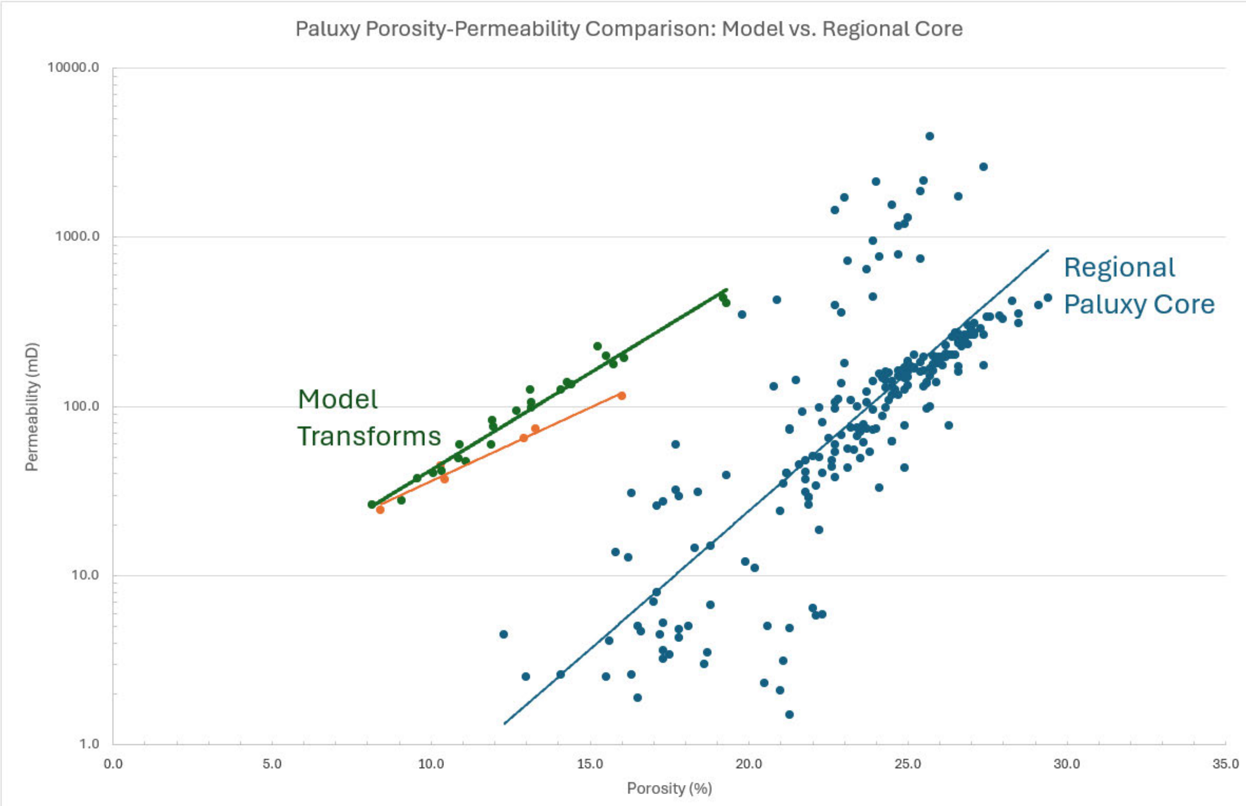


Figure 27. Comparison of Paluxy porosity-permeability transforms between model layer data and regional core data.

<ins>Reservoir Pressure</ins>

The reservoir pore pressure gradient was calculated using data from downhole monitoring equipment in the D-9-8 #2 well. The baseline pore pressure in the Paluxy was recorded in the shallowest upper Paluxy sandstone interval with a top gauge at 9,416 ft. and a bottom gauge at 9,441 ft. The baseline pressure at the top gauge was 4,369 psi, and at the bottom gauge was 4,385 psi, which provided a calculated pressure gradient of 0.463 psi/ft (**Figure 28**).

The remainder of this page intentionally left blank.

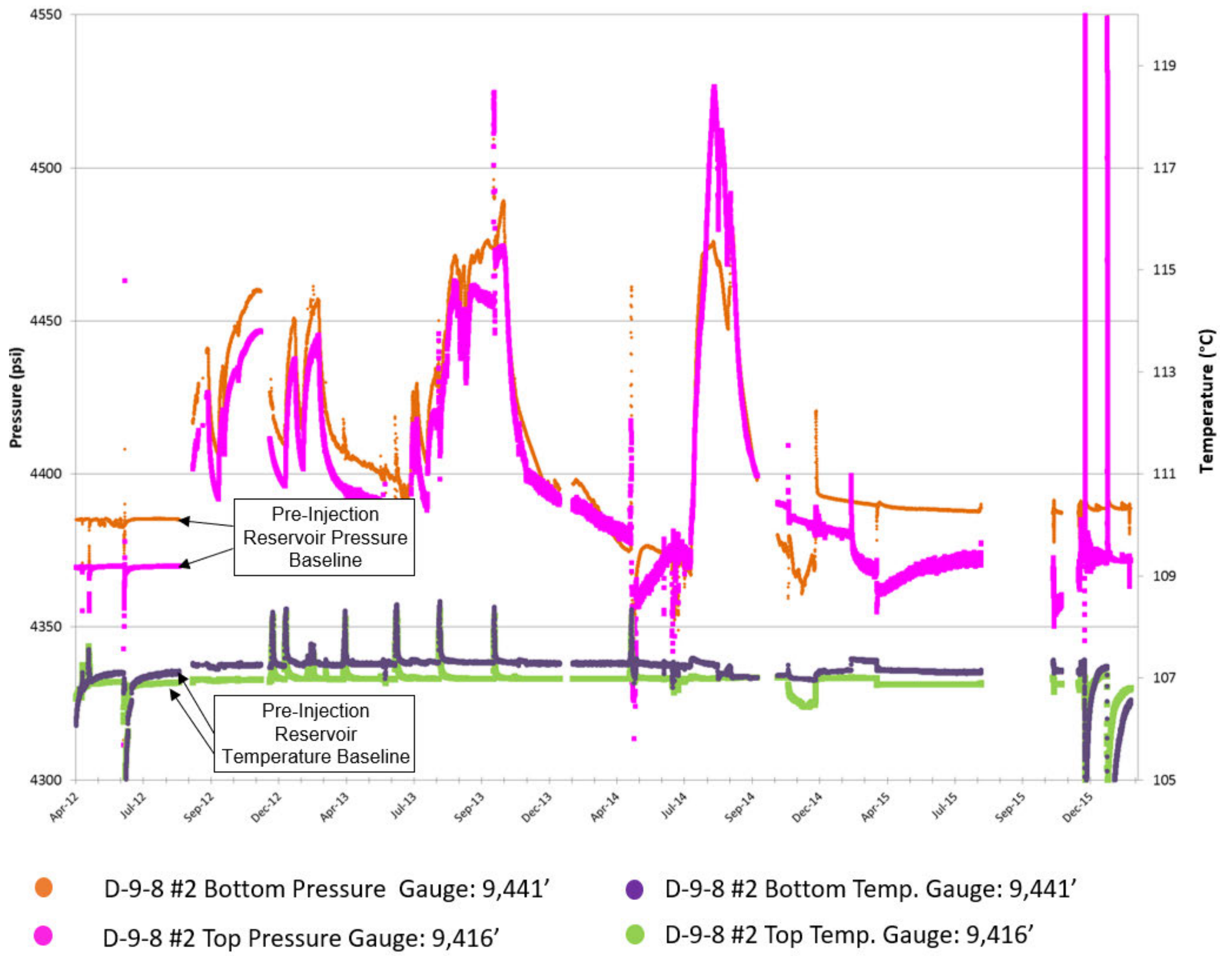


Figure 28. Pressure and temperature gauge data from the D-9-8 #2 Paluxy in-zone monitoring well. Pre-injection baseline data used to calculate pressure and temperature gradients for the Paluxy is annotated.

<u>Reservoir Temperature</u>

Temperature data was also recorded from gauges in the D-9-8 #2 well. The pre-injection baseline reservoir temperature for the Paluxy at the top gauge was 106.9°C (224.4°F) and at the bottom gauge was 107.1°C (224.8°F) (**Figure 28**). Salt domes, such as the Citronelle Dome, may exert an effect on surficial heat flow and thereby higher than normal temperatures (Dees and Smith, 1982). The domes can function as a heat sink at their bases and as a heat source at their tops, causing high geothermal gradients in the overlying sedimentary rock units. This could be the case for the elevated temperatures sometimes encountered in south Alabama within the Mississippi Interior Salt Basin. Based on temperature gauge readings, an elevated temperature gradient of 1.65 °F/100 ft. is assumed in our geologic modeling of the Longleaf CCS Hub. Data gathered from the first monitoring well, which will serve as the characterization well for the

Longleaf CCS Hub, will determine if an elevated temperature gradient exists to the east of the Dome where CO_2 will be injected.

Capillary Pressure

Capillary pressure injection data for the Paluxy Formation will be acquired as part of the **Pre-Operational Testing Plan** provided with this application under a separate cover.

Static Storage Resource Potential

Based on these petrophysical and reservoir characteristics, the P10, P50, and P90 Static Storage Potential for the Paluxy Formation was calculated at 2.3, 4.3, and 7.4 Mt per square mile, respectively (Goodman et al., 2011). A summary of the calculations for the Upper Paluxy, Lower Paluxy, and Total Paluxy is provided in **Table 6a**. For comparison, static storage resource calculations for the Secondary Injection Zone are shown in Table 6b.

Table 6a: Estimate of Static CO_2 Storage Resource Potential for the Paluxy Formation

Estimate of Static CO_2 Storage Resource Potential—Primary Injection Zone (Paluxy Formation)				
Producing Interval		U. Paluxy Total	L. Paluxy Total	Total/Average
Net Thickness (ft)		395	78	473
Avg Porosity (%)		13%	11%	–
Avg Pressure (psi)		4,878	5,215	–
Reservoir Temperature (°F)		240	251	–
CO_2 Density (lb/ft^3)		40.5	40.7	–
Storage Potential (Mt/mi.^{2})	P10 (7.4% Efficiency)	1.9	0.4	2.3
	P50 (14% Efficiency)	3.7	0.7	4.3
	P90 (24% Efficiency)	6.3	1.1	7.4

Table 6b: Estimate of Static CO_2 Storage Resource Potential for the Secondary Injection Zone

Estimate of Static CO_2 Storage Resource Potential—Secondary Injection Zone				
Producing Interval		Pilot/Massive Sand	Wash Fred Dantzler	Total/Average
Net Thickness (ft)		210	708	918
Avg Porosity (%)		21%	18%	
Avg Pressure (psi)		3,577	3,674	
Reservoir Temperature (°F)		195	199	
CO_2 Density (lb/ft^3)		39.2	39.3	
Storage Potential (Mt/mi.^{2})	P10 (7.4% Efficiency)	1.6	4.8	3.2
	P50 (14% Efficiency)	3.0	9.1	6.0
	P90 (24% Efficiency)	5.2	15.5	10.4

B.5. Confining Zones

B.5.1. Primary Confining Zone - Tuscaloosa Marine Shale

The TMS occurs at a depth of approximately 7,250 ft subsea in the Longleaf CCS Hub (**Figure 29**) and is about 300 ft thick (**Figure 30**). This shale is persistent across the Gulf of Mexico Basin, serving as the principal reservoir seal for oil and gas accumulations in the Lower Tuscaloosa Group (Petrusak et al., 2009).

The remainder of this page intentionally left blank.

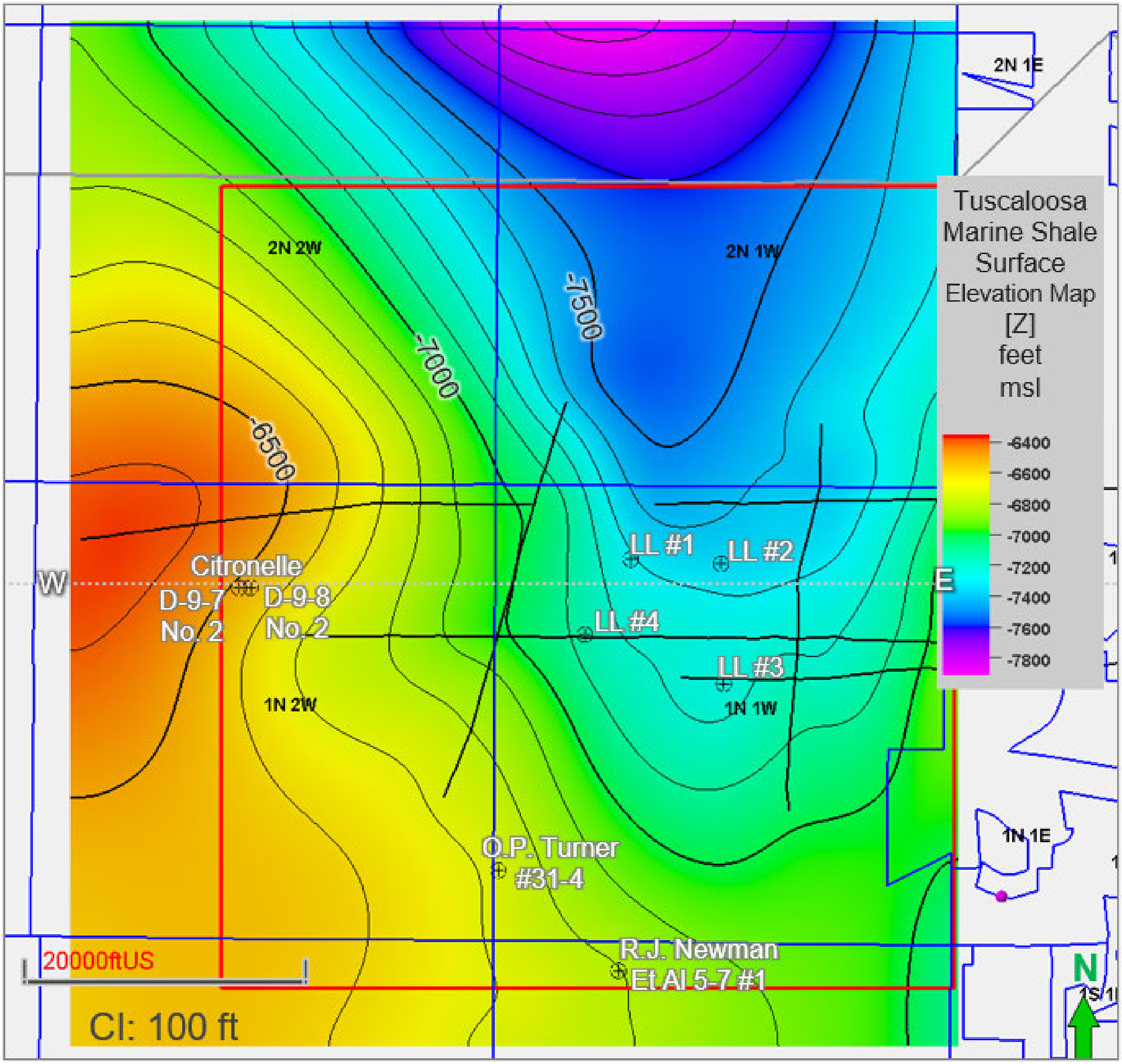


Figure 29. Structure contour map on the top of the Tuscaloosa Marine Shale in northeastern Mobile County. Datum is shown in feet subsea. Contour interval: 100 ft. Black lines indicate surface track of 2D seismic lines.

The remainder of this page intentionally left blank.

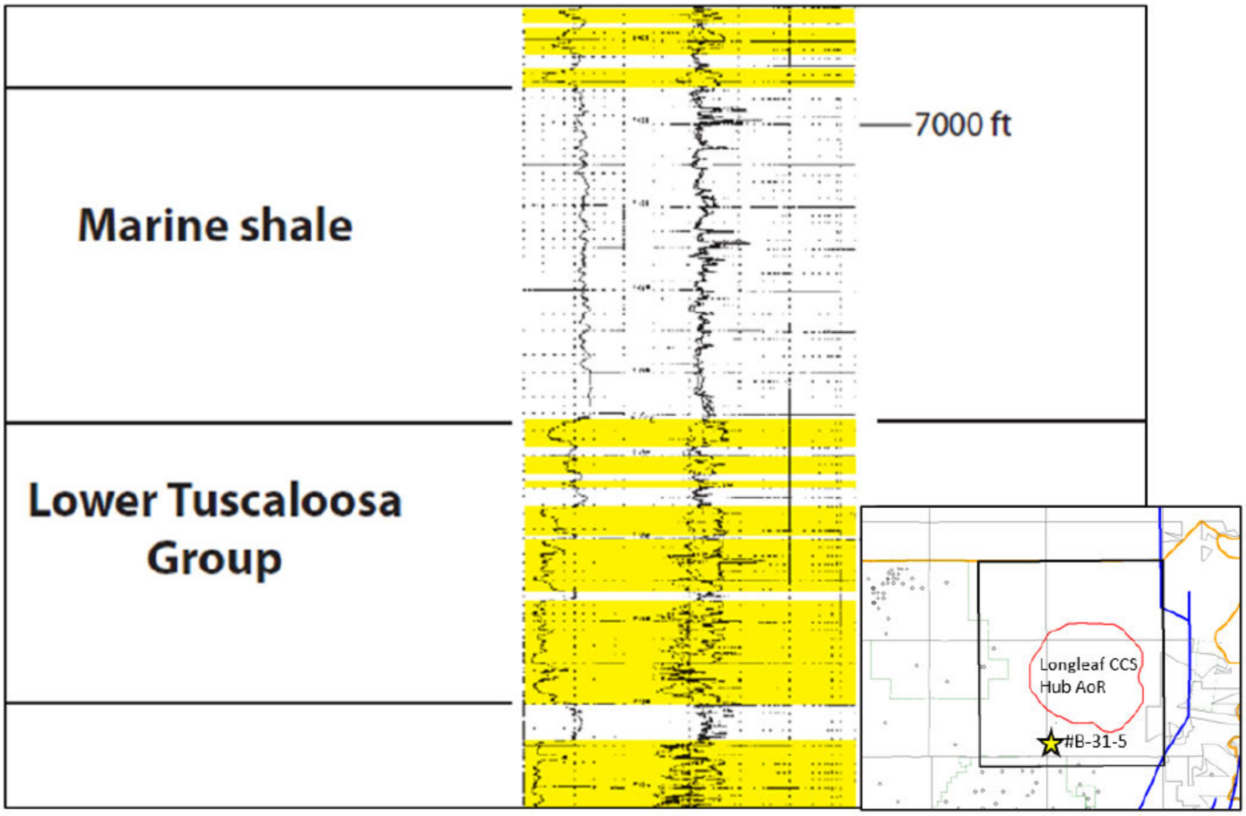


Figure 30. Type log for the Tuscaloosa Marine Shale in the Longleaf CCS Hub from well #B-31-5.

In southwest Alabama, the TMS is predominantly gray to black mudstone grading into siltstone and very fine-grained sandstone at the top (Petrusak et al., 2009). **Figure 31** shows a whole core sample collected from a 30-foot section of the TMS in Jackson County, Mississippi approximately 40 miles from the Longleaf CCS Hub.

Mercury capillary pressure tests were performed on select samples from the whole core under ambient (surface) and overburden pressure (subsurface) conditions. Results from samples under overburden pressure conditions show low effective porosity (1–2%) and low permeabilities at the microdarcy to nanodarcy scale, indicating favorable sealing characteristics (**Table 7**).

Table 7: Summary of Tuscaloosa Marine Shale core from the Mississippi Power Co. #11-1, Jackson County, MS.

Core Depth (ft.)	Effective Core Porosity (%)	Core permeability (mD)
7,914 - 7,916	2.0	1.27×10^{-5}
7,923 - 7,926	1.5	8.08×10^{-6}
7,928 - 7,931	1.2	2.07×10^{-5}

B.5.2.Washita-Fredericksburg Basal Shale

The Wash-Fred Basal Shale overlying the Paluxy Formation occurs at 9,990 ft subsea within the Longleaf CCS Hub (**Figure 32**) and ranges from 96 to 172 ft. thick (**Figure 33**). This shale, while apparently present across the Longleaf CCS Hub, is less regionally significant, and therefore confidence in its suitability as a confining zone is uncertain.

Mud log descriptions from the D-9-8 #2 well indicate the Wash-Fred Basal Shale is a gray, brick red, and red-brown mottled shale with traces of silty- to very fine-grained sand and limestone streaks (**Figure 34**). Renken et al. (1989) and Pashin et al. (2008) suggested that the Wash-Fred Basal Shale contains interfluvial redbeds, and this interpretation is supported by the mud log descriptions from the D-9-8 #2 well.

An integrated mineralogical and petrophysical interpretation from the DOE/NETL SECARB Phase III demonstration at the SE Citronelle Unit indicates an effective porosity across the Wash-Fred Basal Shale of approximately 1% (**Figure 35**). This petrophysical interpretation also estimated permeability of the Wash-Fred Basal Shale using the Power Law function, indicating 145 ft of shale with average permeability of 6.5 x 10^{-6} mD (**Figure 36**).

The remainder of this page intentionally left blank.

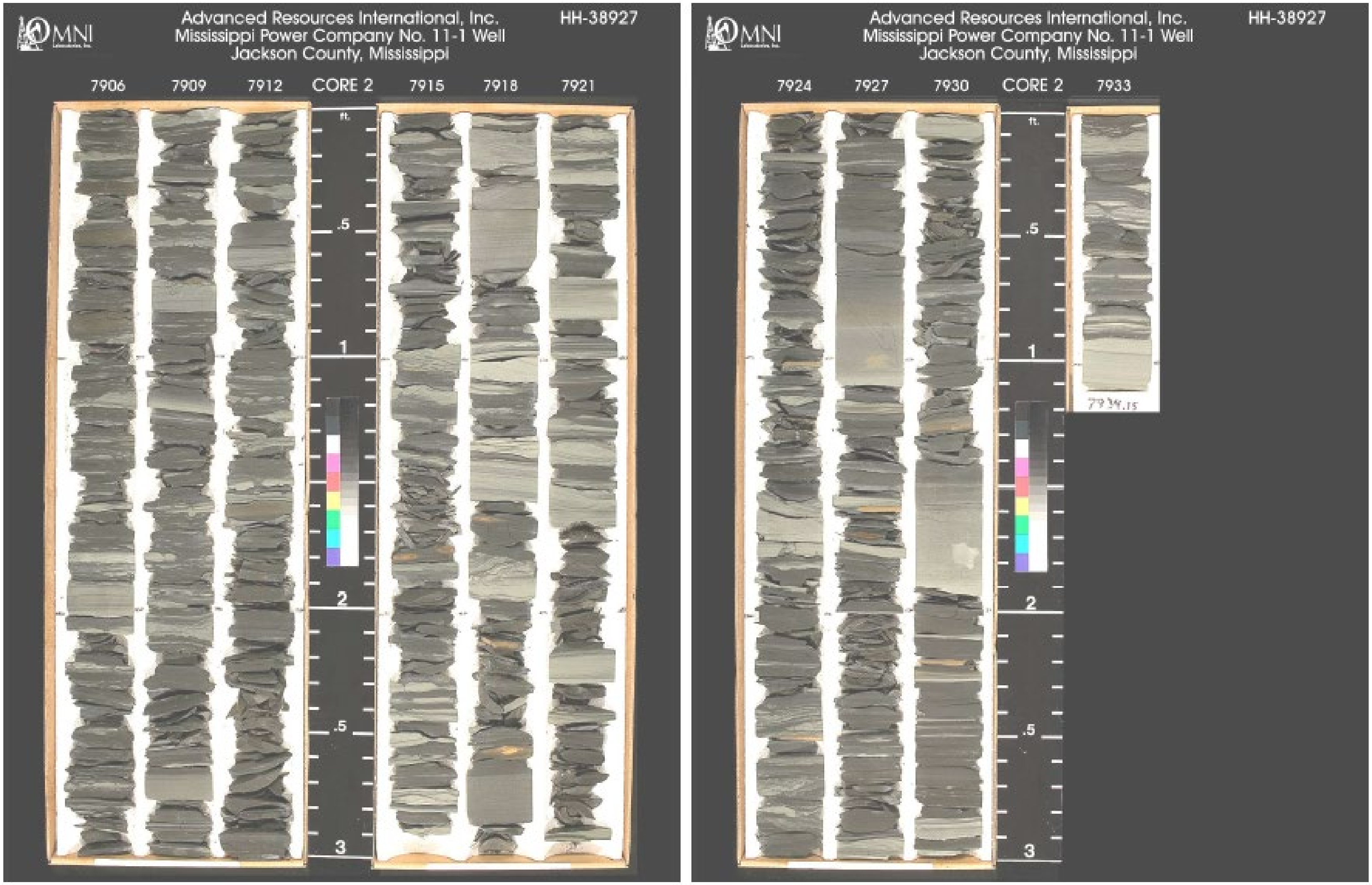


Figure 31. Tuscaloosa Marine Shale whole core photos from the Mississippi Power Co. #11-1 well (from Petrusak et al., 2009).

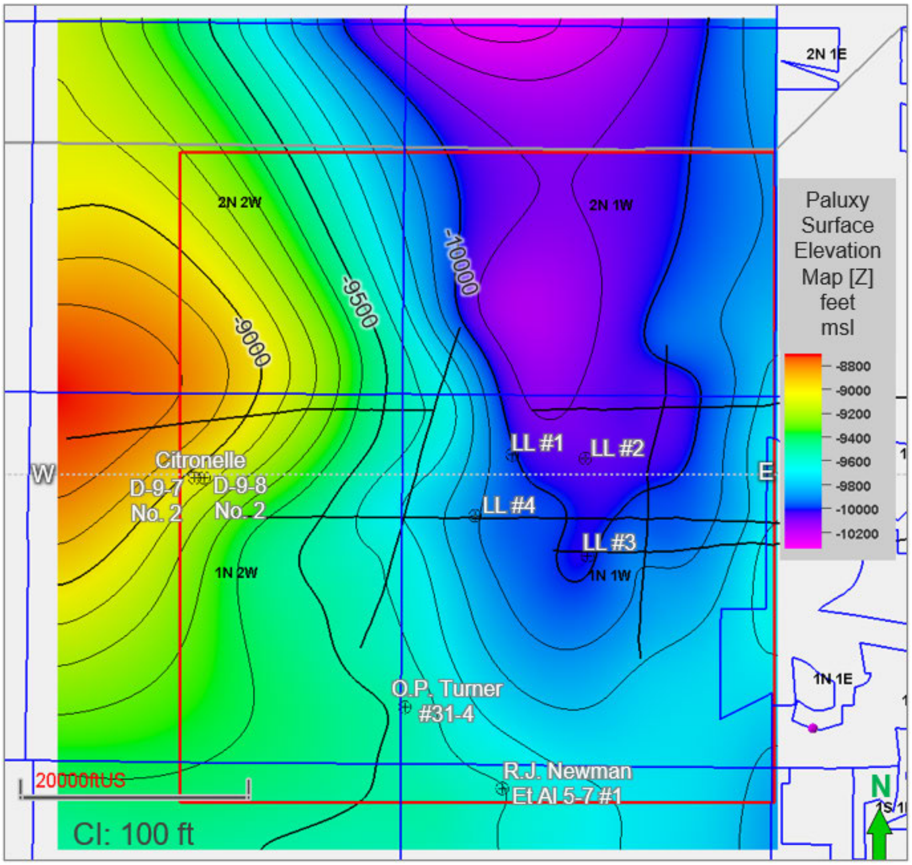


Figure 32. Structure contour map on the top of the Washita-Fredericksburg Basal Shale. Datum is elevation subsea (ft.). Contour interval: 100 ft.

The remainder of this page intentionally left blank.

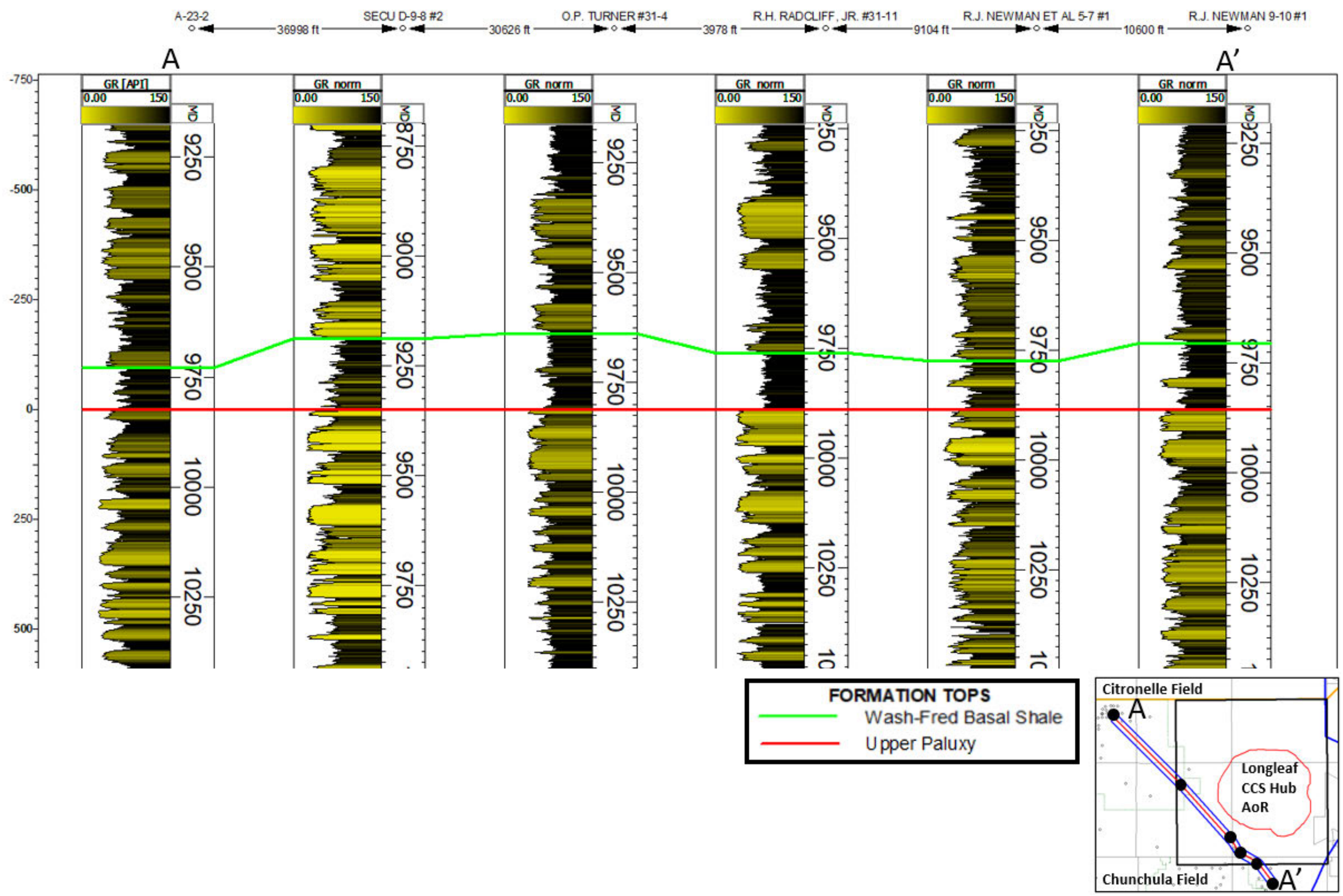


Figure 33. Stratigraphic cross section of the Washita-Fredericksburg Basal Shale through wells west and south of the Longleaf CCS Hub AoR.

Thickness ranges between 96 ft in the A-32-2 well on the northern edge of the Citronelle Dome and 172 ft in the O.P. Turner #31-4 well located at the southern edge of the geologic model area.

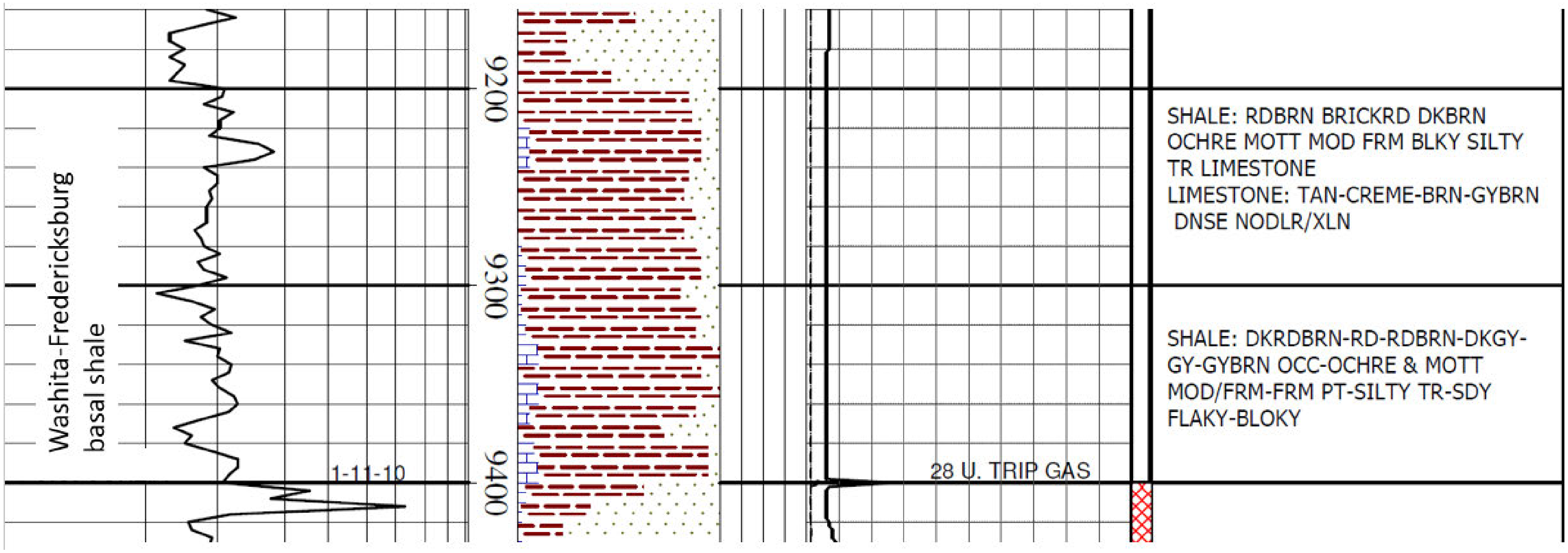


Figure 34. Mud log with lithology descriptions from the Washita Fredericksburg Basal Shale.

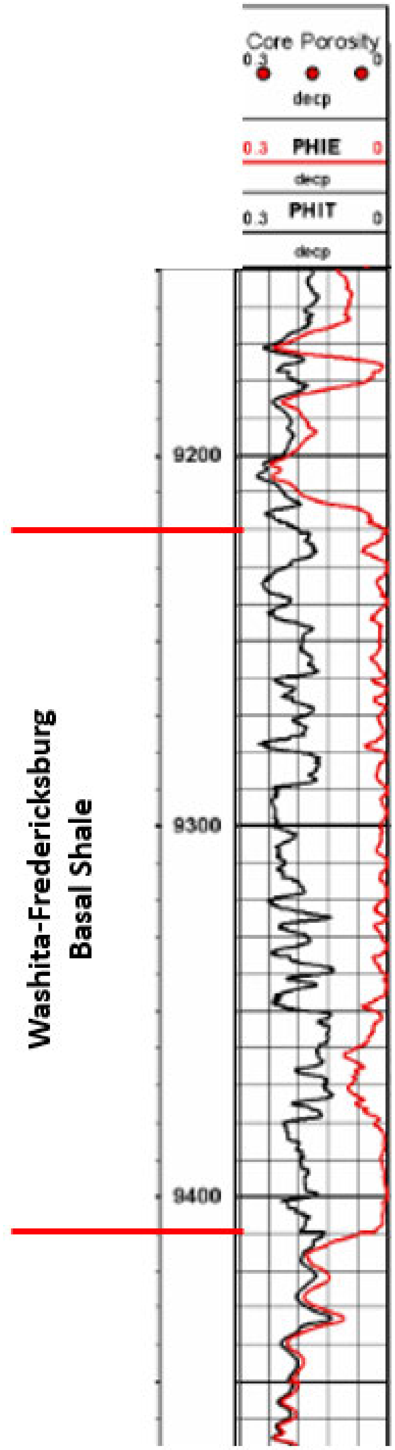
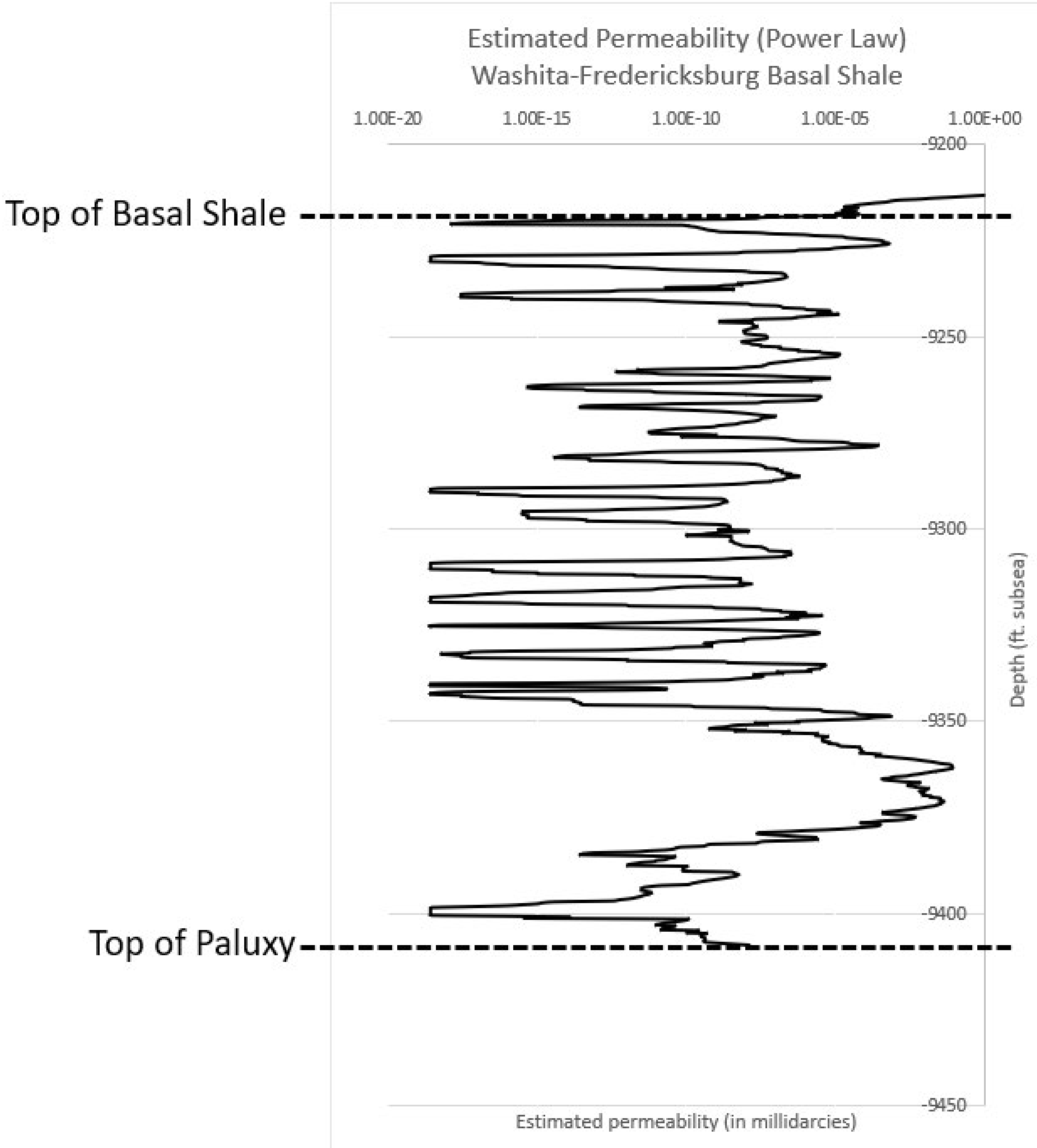


Figure 35. Porosity log from the D-9-7 #2 well over the Washita-Fredericksburg Basal Shale showing the total porosity (PHIT) in black and effective porosity (PHIE) in red.

Porosity logs were generated using the Halliburton GEM™ elemental analysis tool.



Permeability plotted on X-axis; depth (ft. subsea) plotted on Y-axis.

Figure 36. Logarithmic scale plot of the Power Law estimated permeability log from the D-9-7 #2 well across the Washita-Fredericksburg Basal Shale. Values have not yet been confirmed by core data.

B.5.3. Additional Low Permeability Intervals Above the Injection Zones

Above the primary confining zone, the TMS, there are additional strata that provide protection against CO_2 plume migration into USDWs. The combined Selma and Midway Groups form a 2,000 ft thick interval above the TMS and below the base of USDW. The depth and thickness of these formations are shown in **Table 8**.

Table 8: Summary of additional confining zones above the Tuscaloosa Marine Shale.

Formation Name	Lithology	Formation Top Depth (ft. subsea)	Thickness (ft.)	Depth Below Base of USDW (ft.)
Selma Group	Chalk	5,500	1,500	3,800
Midway Group	Clay	5,000	500	3,300

B.5.3a. Selma Group

The Upper Cretaceous Selma Group, with a thickness of 1,500 ft, consists of low permeability chalk, marl, and limestone that is the primary seal for oil accumulations in the underlying Eutaw Formation in Alabama, demonstrating its ability to prevent the upward migration of buoyant fluids (Pashin et al., 2000; Pashin et al., 2008). The Selma is predominantly bioturbated and fossiliferous chalk with significant quantities of marl and grain-supported limestone (Pashin et al., 2008). The upper Selma is mainly chalk, while the lower Selma consists of transitionary strata between the chalk and underlying Eutaw Formation siliciclastic sediments. In the Longleaf CCS Hub, the top of the Selma Group occurs at approximately 4,500 ft subsea. **Figure 37** shows the structure of the Selma Group in Alabama and Mississippi, and **Figure 38** shows gross thickness of the Selma.

A whole core sample from the Selma Group was recovered from the Mississippi Power Co. #11-1 well in Jackson County, Mississippi, the same well from which the Tuscaloosa Marine Shale core was acquired.

Core photos from the Selma show the unit contains very fine-grained, burrowed to bioturbated, fossiliferous limestone and chalk (**Figure 39**). Dissolution along laminations with siltstones and clays contains concentrated silt and mud grains in coalescing dissolution seams. Ambient pressure condition tests were conducted on the Selma core samples, which showed porosity ranging from 12.5 to 16.7% and core plug permeability ranging from 0.012 mD to 0.108 mD; the porosity and permeability of the Selma chalks under overburden pressure conditions are expected to be several orders of magnitude lower.

B.5.3b. Midway Group

Directly overlying the Selma Group is the Midway Group, consisting of about 500 ft. of dark brown to black marine clay that is regionally extensive across the Mississippi Interior Salt Basin (Mancini et al., 1999).

The remainder of this page intentionally left blank.

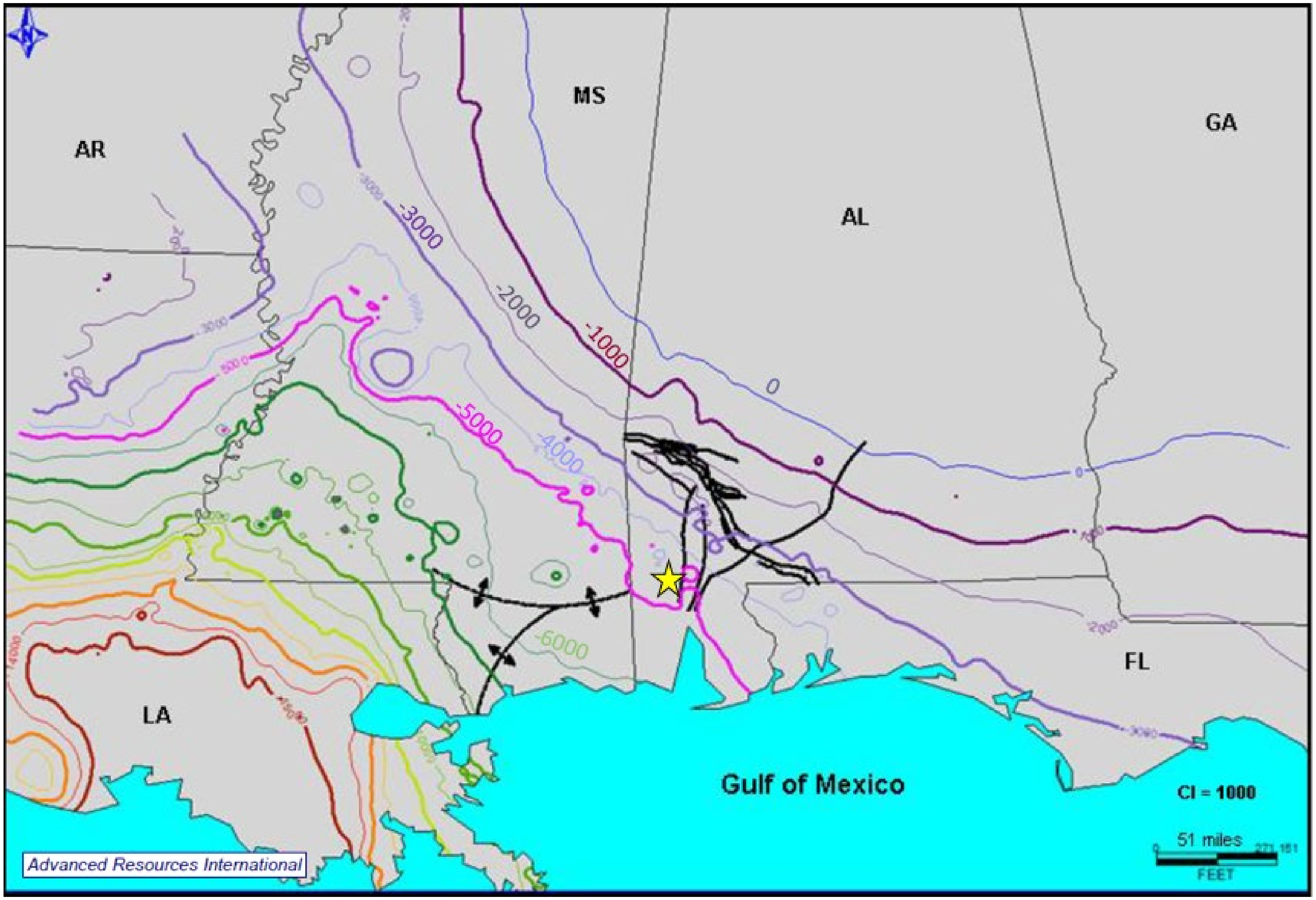


Figure 37. Regional structure contour map on the top of the Selma Group (modified from Petrusak et al., 2009). Datum is elevation in ft. subsea. Location of the Longleaf CCS Hub is starred.

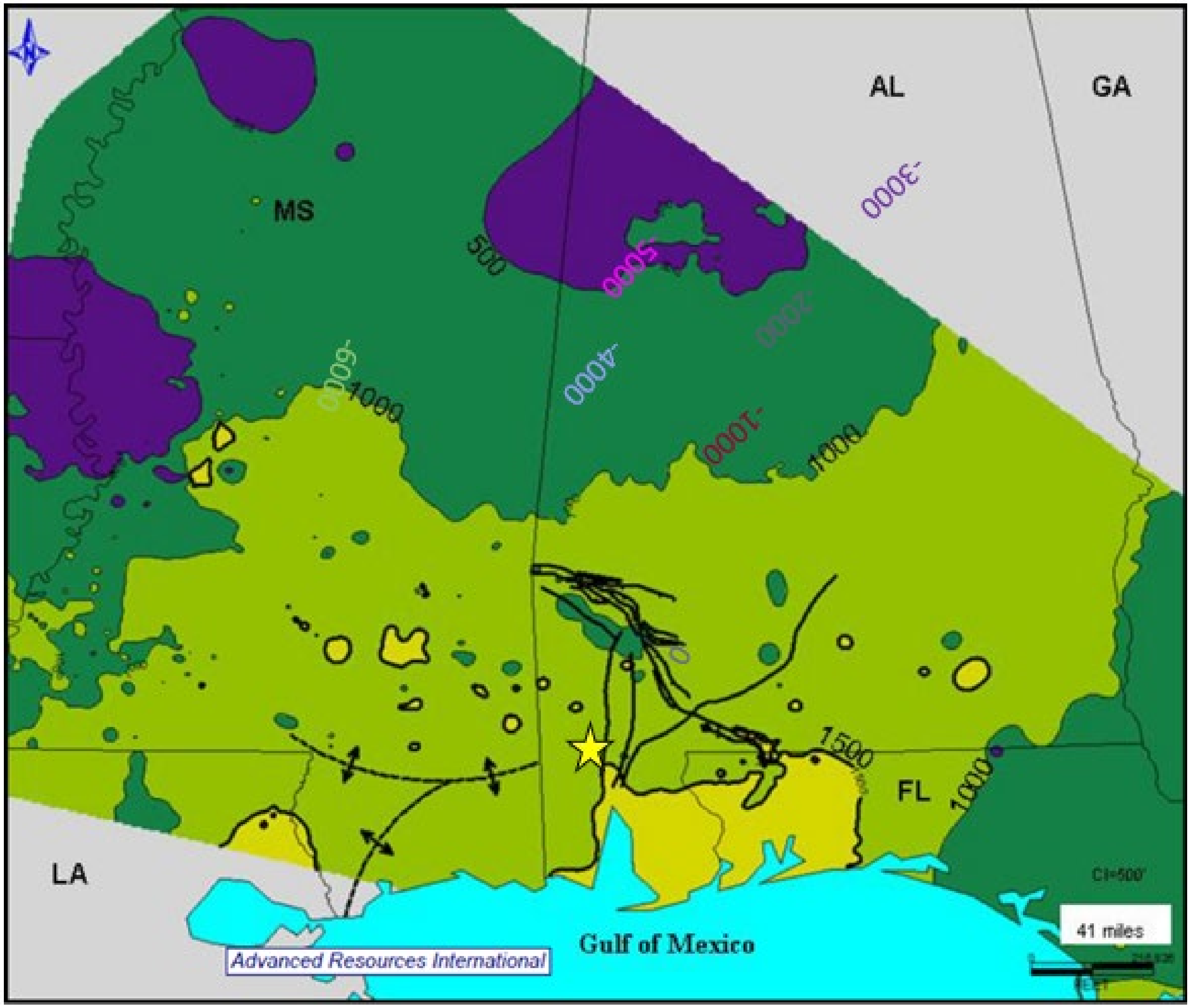


Figure 38. Regional gross isopach map of the Selma Group. In southwest Alabama, the Selma Group is consistently 1,000–1,500 ft. thick (from Petrusak et al., 2009). Location of the Longleaf CCS Hub is starred.

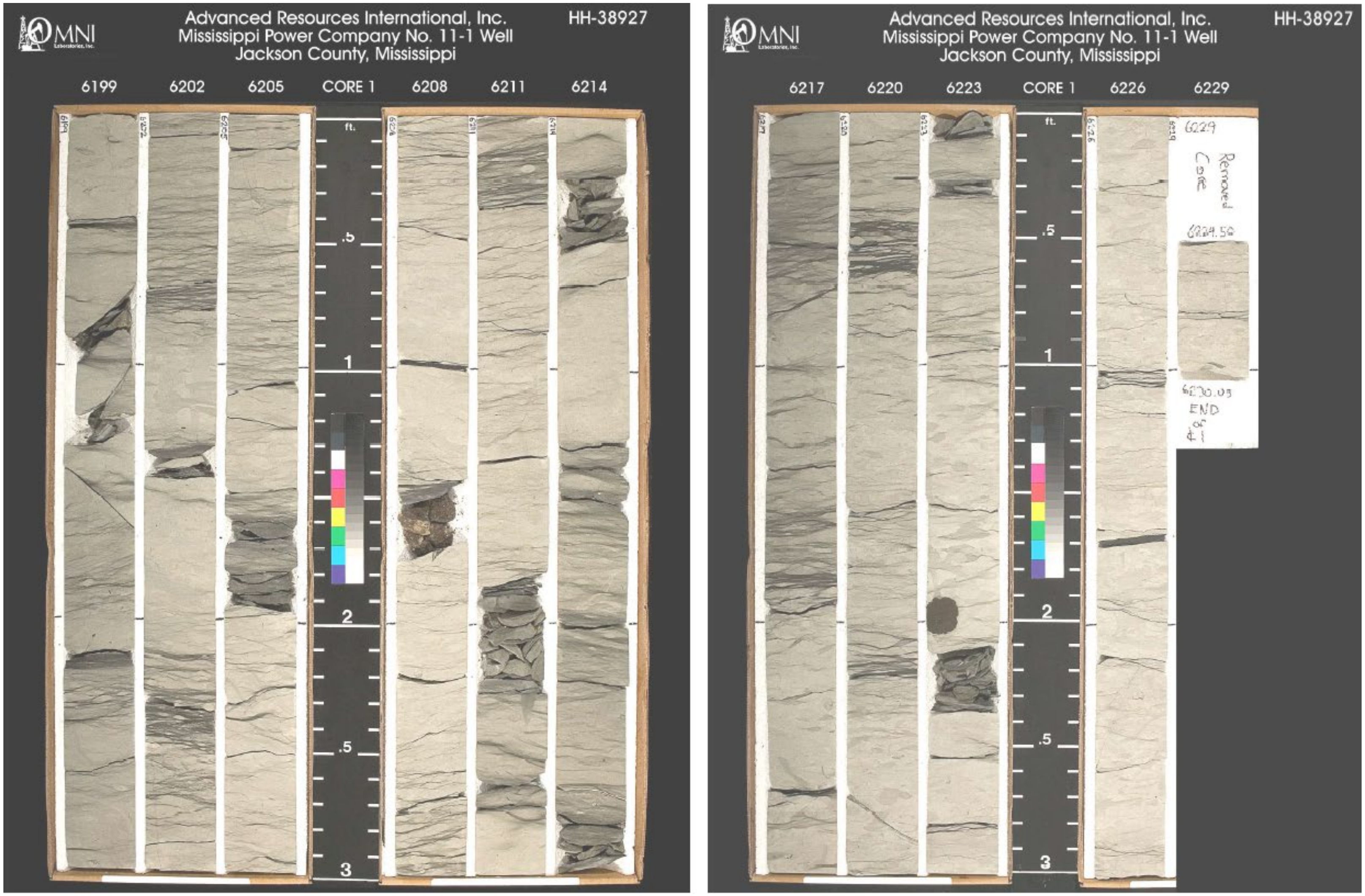


Figure 39. Core photos from the Selma Group in the Mississippi Power Co. #11-1 located approximately 40 miles from the Longleaf CCS Hub (from Petrusak et al., 2009).

B.6. Geomechanical and Petrophysical Information of the Confining Zones [40 CFR 146.82(a)(3)(iv)]

Alabama Gulf Coast region clastic reservoirs typically have moderate fracture pressure gradients, with conservative regional fracture pressure gradient estimates of 0.7 to 0.75 psi per foot (Eaton 1969). Modeling work in support of this permit application used 90% of the regional fracture gradient of 0.63 psi/ft. Note that pressure gauges installed at 9,355 ft (bottom of injection tubing) in the D-9-7 #2 well during the Phase III SECARB CO_2 injection demonstration reached sustained pressures of 5,850 psig (0.625 psi/ft) with no issues observed in terms of reservoir geomechanical impact. The **AoR and Corrective Action Plan** details current assumptions regarding formation temperature, pressure, and pore pressure gradient. The resulting computational modeling used 0.63 psi/ft as the maximum allowable downhole pressure gradient to determine the CO_2 injection rate, the surface CO_2 injection pressure, and the CO_2 mass that can be injected at the Longleaf CCS Hub.

A site-specific geomechanical characterization effort is planned with the use of micro-image logs, wireline well tests, and laboratory core tests as detailed in the **Pre-Operational Testing Plan**. Acquisition of this data will be undertaken during the construction of new monitoring and injection wells in the storage area. Physical properties that will be determined from samples collected from these wells include bulk density, porosity, permeability, Young's modulus, Poisson's ratio, and failure strength, to determine:

- Fracture/parting pressure of the sequestration zone and primary confining layer, and the corresponding fracture gradients are determined via step rate or leak-off tests.
- Rock compressibility, or measure of rock strength, for the confining layer(s) and sequestration zone.
- Rock strength and the ductility of the confining layer(s).
- Unconfined compressive strength (UNC) of the confining layer as measured from intact samples.

B.7. Seismic History [40 CFR 146.82(a)(3)(v)]

The Longleaf CCS Hub sits within a tectonically stable passive margin with no known sources of natural seismicity in the AoR or region. Southwestern Alabama is in a region of low natural seismicity, and any earthquakes that do occur are of low magnitude. No earthquakes above Intensity VII on the Modified Mercalli Scale (severe damage to older structures, slight damage elsewhere) have occurred in Alabama during historical times (Bolt, 1993). **Figure 40** illustrates the peak ground acceleration (as a percentage of the gravity constant 9.8 m/s^2) with a

2% likelihood of being exceeded within a 50-year period in Alabama. The peak ground acceleration for Mobile County is estimated to be 4 to 6 percent gravity which would correlate to a Modified Mercalli Intensity of VI or less causing only slight damage to older structures.

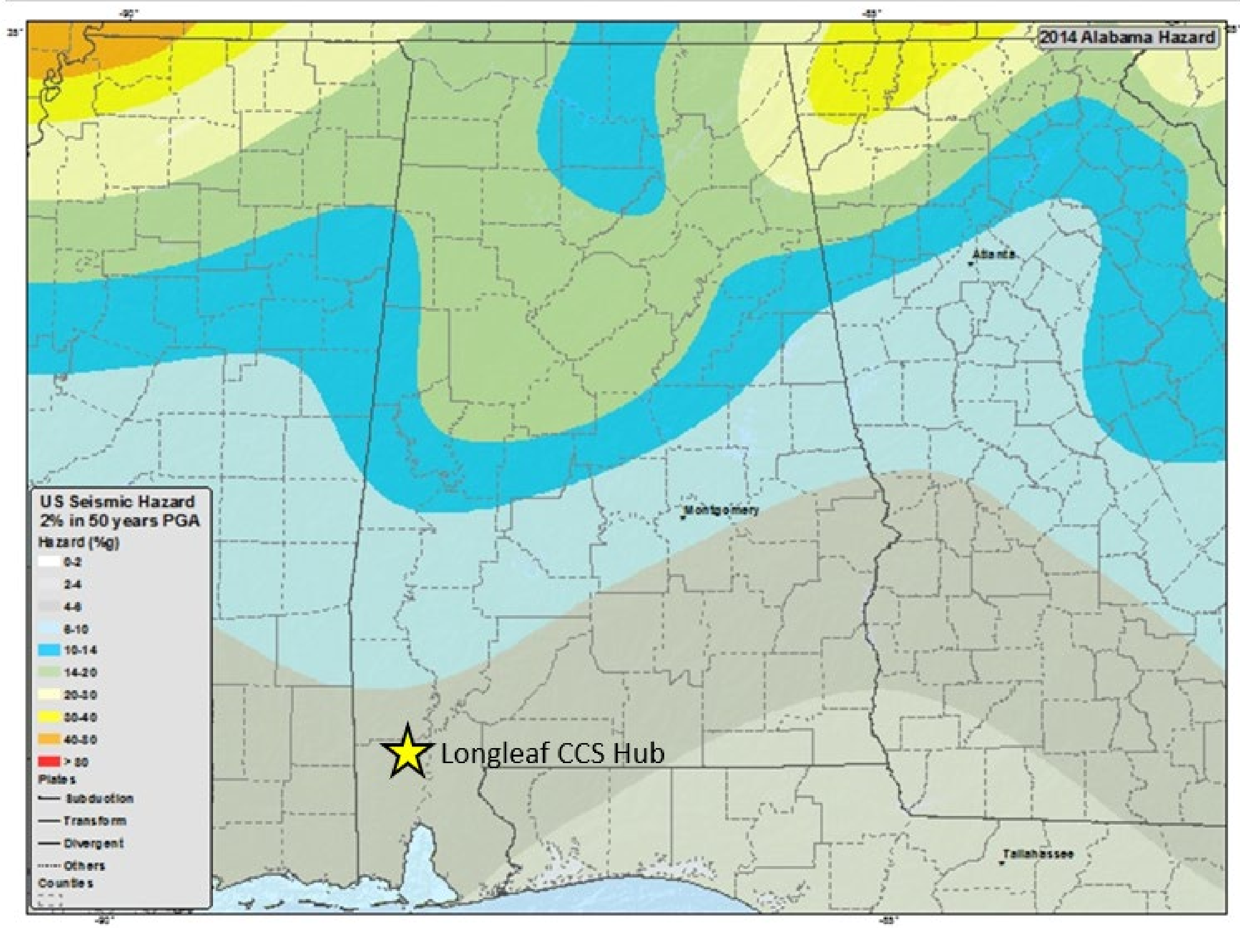


Figure 40. 2014 Seismic Hazard Map of Alabama from the USGS National Seismic Hazard Maps illustrating the peak ground acceleration with a 2% likelihood of being exceeded within a 50-year period (US Geological Survey, 2014).

The largest earthquake in Alabama's history occurred on October 18, 1916, in Irondale, Jefferson County (approx. 190 mi. NE of the Longleaf CCS Hub) and had an estimated magnitude of 5.1 on the Richter scale (Mercalli index of VII). A map of earthquakes in adjacent counties to the Longleaf CCS Hub is shown in Figure 41. The largest earthquake in south Alabama occurred in Escambia County in 1997 along the Bahamas Fracture Seismic Zone (approx. 45 mi. from the Longleaf CCS Hub), measuring 4.9 on the Richter scale (Mercalli index of VI). It has been suggested that this earthquake may have been non-tectonic, instead triggered as a poroelastic response of the crust to the extraction of hydrocarbons or associated wastewater injection in the area (Gomberg and Wolf, 1999). The injection of wastewater into the Eutaw and Tuscaloosa Groups near this earthquake occurred within an existing fault zone at pressures between 725 psi and as high as 1450 psi, much higher than the proposed injection pressure (max 450 psi) at the Longleaf CCS Hub. Given that the Longleaf CCS Hub will operate at lower injection pressures and that the closest fault to the injection wells is several miles to the east, it is highly unlikely that the proposed CO_2 injection would induce a seismic event.

No seismic events have occurred within 25 miles of the AoR. The closest seismic events to the AoR were two earthquakes in Mobile County in 1929 and 2012 with magnitudes of 3.2 and 2.7, respectively (Figure 41). Both were over 25 miles from the Longleaf CCS Hub (Figure 38). Thus, the likelihood of an earthquake capable of causing considerable damage within the storage area (Mercalli index of IX/Magnitude 6.0+—ground cracks, pipes break, foundations shift) is very low.

The remainder of this page intentionally left blank.

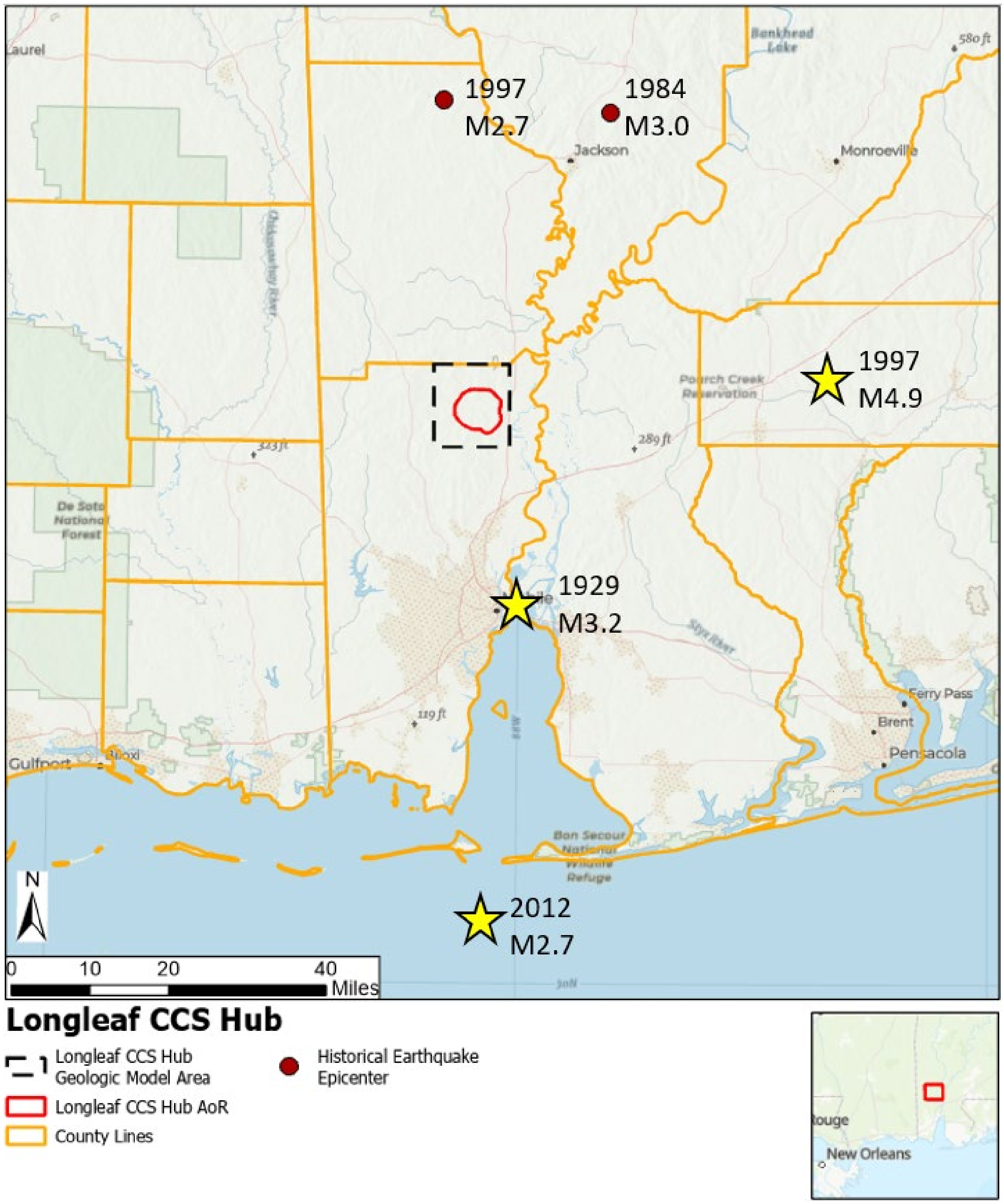


Figure 41. Map of Recorded Earthquake Epicenters in nearby counties to Longleaf CCS Hub. Nearby events discussed in Section B.7 are starred.

B.8. Hydrogeologic Information/Maps and Cross Sections of USDWs [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

B.8.1. Base of USDW

EPA defines protected USDWs as aquifers with a TDS content less than 10,000 mg/L. Only limited information on the composition of deep groundwater is available at the Longleaf CCS Hub; no data could be found on TDS concentration or resistivity in the aquifers. However, the

Stauffer Chemical Company's plugged and abandoned Class I injection well located in Bucks, Alabama about six miles south from center of the Longleaf CCS Hub identified the Chickasawhay Limestone at 1,440 ft., a fossiliferous, arenaceous, and glauconitic limestone, as the deepest USDW in northern Mobile County (Tucker and Kidd, 1973; Class One Injection Well Survey, 1986; Mancini et al., 1999).

Limited data on the depth of the Chickasawhay in the Longleaf CCS Hub is available, but the deepest USDW data point, located in the northeastern part of the of the geologic model area, occurs at depth of approximately 1,605 ft. based on Geological Survey of Alabama (GSA) published maps (**Figure 42**) (Gillett et al., 2000).

Considering the uncertainty in the depth of the base of the Chickasawhay, a conservative estimate for the base of USDW across the storage area is 1,700 ft. The Chickasawhay Formation and shallower aquifers are separated from underlying saline reservoirs by the Bucatunna Clay in the Byram Formation within the Vicksburg Group. This aquitard serves as an additional level of protection for USDWs for the project. Based on five data points in the surrounding area, the Bucatunna Clay is on average 142 ft. thick, ranging from 50 ft to 216 ft. (Dixon 2015), and is considered an effective confining unit separating deeper saline water from the deepest USDW in the Chickasawhay (**Figure 43**) (Alverson, 1970).

The remainder of this page intentionally left blank.

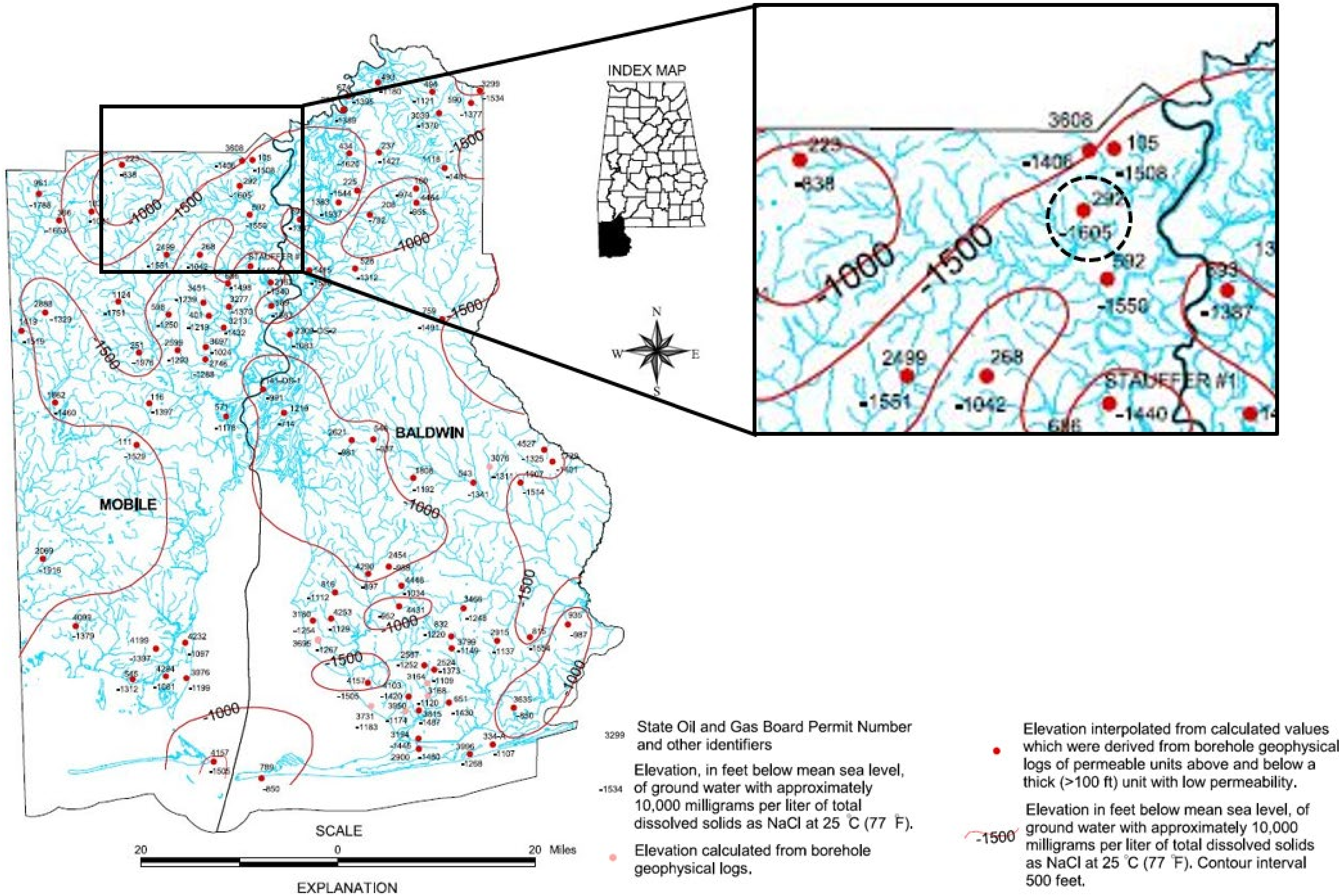


Figure 42. GSA published map (Gillett et al., 2000) of the base of USDW defined as 10,000 mg/L TDS or less. Inset map shows deepest data point near the Longleaf CCS Hub at 1,605 ft below sea level (dashed circle).

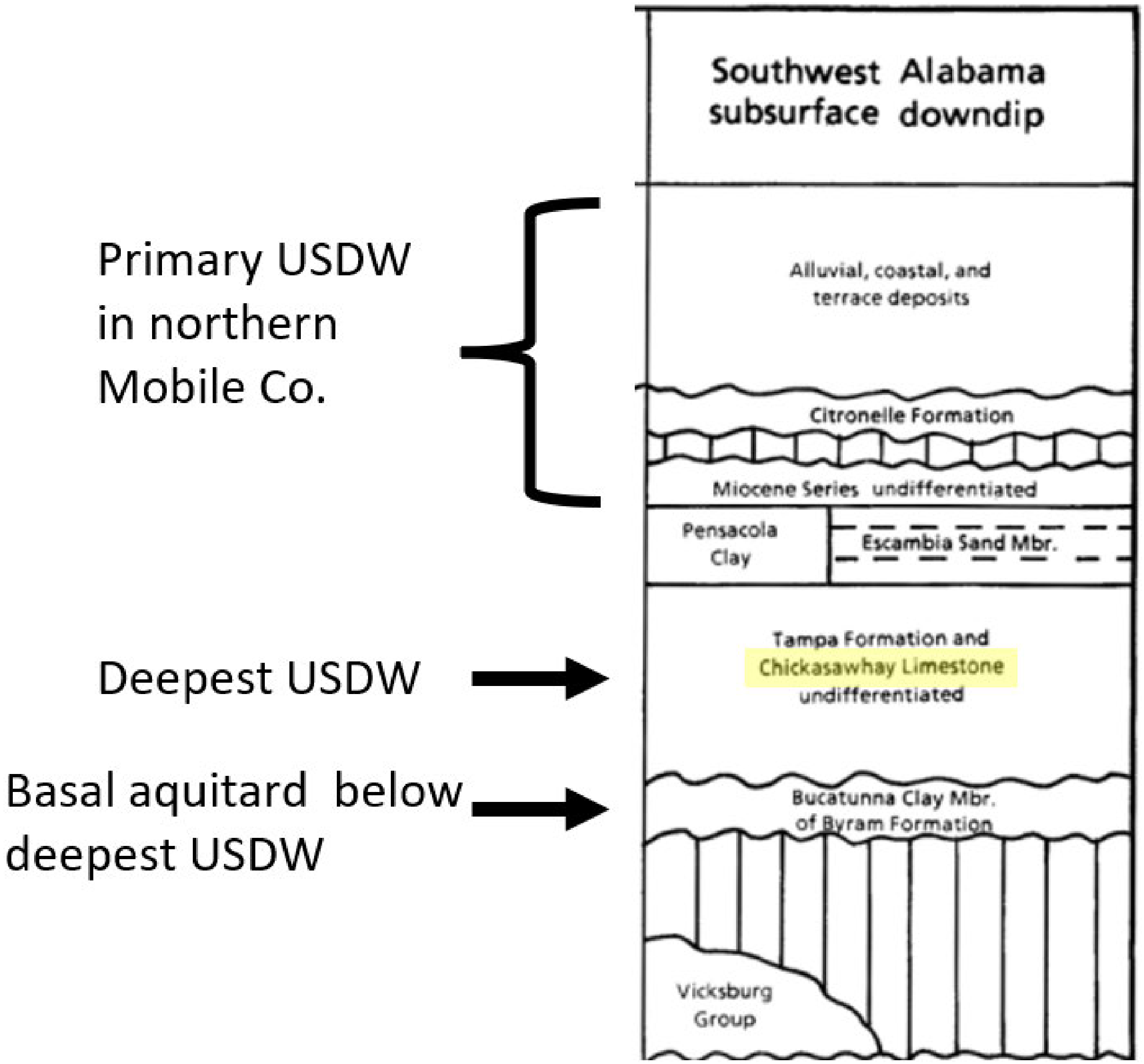


Figure 43. Stratigraphic column of USDW and the basal aquitard protecting USDW in southwest Alabama (modified from Raymond et al., 1988).

Below the Chickasawhay Formation, all aquifers in the area are saline with TDS content exceeding 10,000 mg/L (Pashin et al. 2008). These deep saline reservoirs include sandstones in the Claiborne Group, Wilcox Group, Eutaw Formation, Tuscaloosa Group, Wash-Fred undifferentiated, and the Paluxy Formation.

The saline reservoirs in the Claiborne and Wilcox Groups contain prolific aquifers up dip to the north. In Washington County, about 20 miles north of the Longleaf CCS Hub, the Claiborne and Wilcox Groups may contain potable water and are referred to as the Pearl River Aquifer by the USGS (**Figure 44**) (USGS, 1998).

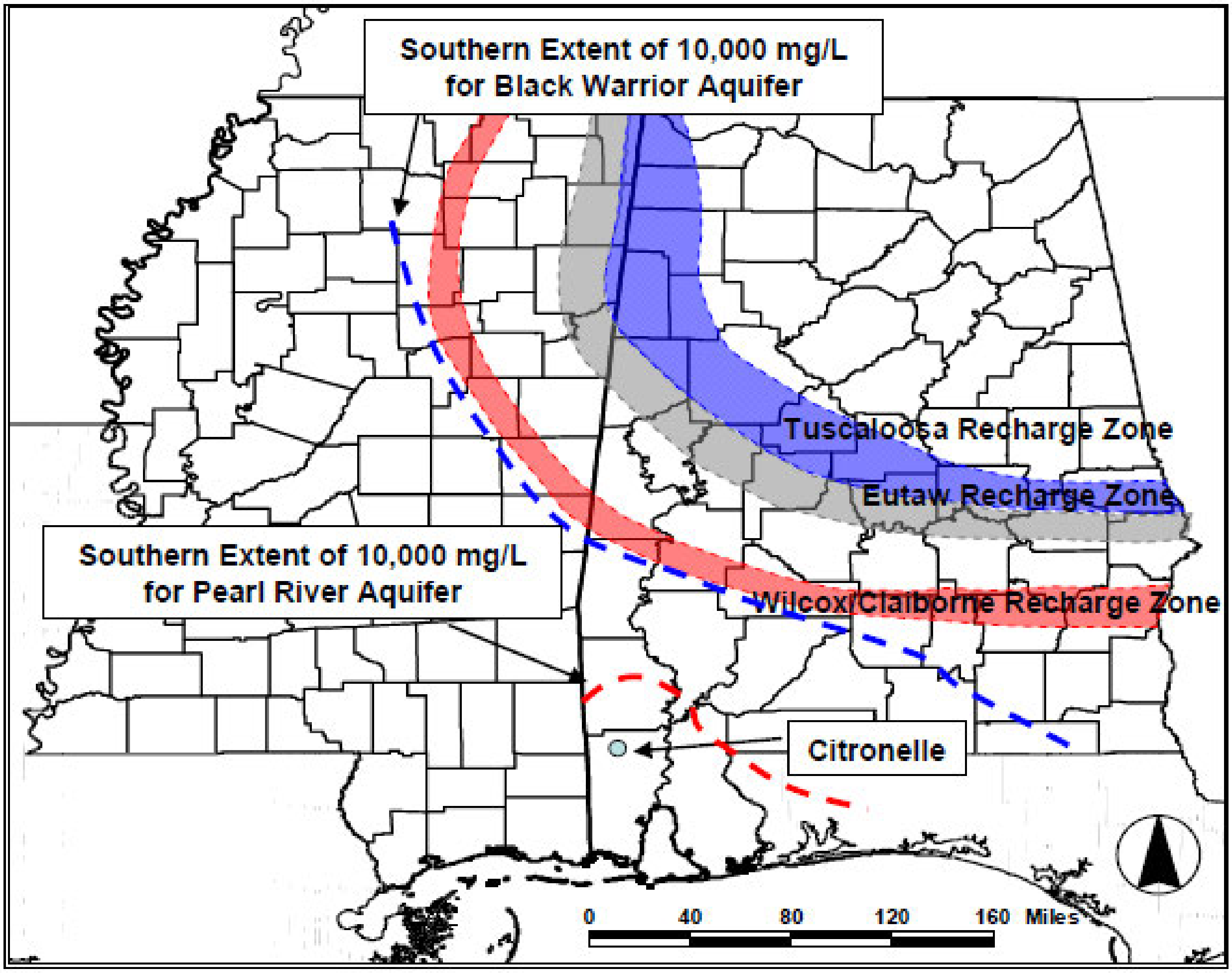


Figure 44. Map of downdip freshwater extent of the Claiborne/Wilcox-aged Pearl River and Eutaw/Tuscaloosa-aged Black Warrior River Aquifers (Modified from USGS, 1998).

The next major aquifer system is the Eutaw-Tuscaloosa "Black Warrior River" aquifer (USGS, 1998). The Black Warrior River aquifer contains potable water in portions of central Alabama, becoming a USDW about 80 miles north of the Longleaf CCS Hub (**Figure 44**).

None of the deeper saline aquifers, including those in the Wash-Fred and the Paluxy Formations, are used as sources of freshwater in Alabama (Raymond et al., 1988), and since the lower Cretaceous subcrops in the eastern Gulf of Mexico Basin, they do not have a surface freshwater recharge zone in the region.

B.8.2. Regional Hydrogeologic Information

The primary water supply within northern Mobile County is from the Plio-Pleistocene, Miocene, and Oligocene-aged units, including the Plio-Pleistocene Watercourse Aquifer and the Miocene-Pliocene Aquifer (Gillett et al., 2000). Lithologic and hydrologic descriptions of these aquifers are provided in **Table 9**. Interpretation of individual aquifer units in the subsurface has proven difficult, however the GSA indicates that the thickness of Miocene undifferentiated aquifers is approximately 850 ft, with the overlying Citronelle formation ranging from 5 to 40 ft thick, where present (GSA 2018). The water in the Miocene-Pliocene Aquifer and the Watercourse Aquifer is generally low in dissolved solids in northern Mobile County but may contain iron concentrations in excess of 0.3 mg/L (Gillet et al., 2000). The project plans to acquire more detailed water quality information as detailed in the **Pre-Operational Testing Plan**.

Large capacity wells tapping the Miocene-Pliocene Aquifer in Mobile County typically range from 150 to 800 feet deep and may yield one million gallons of water per day or more. Additionally, many residential and agricultural users obtain water from the shallow Watercourse Aquifer, which is a water-table (unconfined) aquifer consisting of interbedded sand, gravel, and clay. Wells screened in the Watercourse Aquifer are typically less than 150 feet deep and yield on the order of 100 gallons per minute.

A USGS flow model of the Wilcox aquifer along the eastern Gulf Coast suggests that groundwater migrates down dip from recharge zones located to the north (where the strata outcrop) and becomes parallel to the coast moving eastward in southern Mississippi (USGS Open-File Report 91-451). The model results suggest that Gulf Coast saline reservoirs such as the Wilcox have a maximum velocity of 1 to 10 ft per year. The hydrologically sheltered Paluxy saline formation is expected to have substantially lower groundwater velocities.

Figure 45 shows a generalized cross section of the principal freshwater formations in southwest Alabama. The municipal water source in the area is lower Miocene sands, which are shallower than 900 ft. within the Longleaf CCS Hub. Based on this regional study and the structural dip of the formations, we expect groundwater flow to move to the south-southwest towards the Gulf of Mexico through the AoR (**Figure 46**).

Table 9. Description of aquifers in Mobile and Baldwin Counties, southwestern Alabama (from GSA report, Gillet et al., 2000)

Hydrogeologic unit	Unit character		Aquifers		
	Lithologic	Hydrologic	Walter & Kidd, 1979	Chandler & others, 1985	This report
Pleistocene (?)-Holocene	Sand, white to pale-orange, fine- to coarse-grained; silt; clay; and sea-shell hash. Finer grained sediments predominant in lower part of unit as dis- continuous layers.	Predominantly medium-grained sands in upper 20 to 60 feet of unit comprise principal aquifer. The aquifer is a water-table aquifer and is a potential source of more than 100 gpm of water per well.	Beach sand aquifer	A1	Watercourse aquifer
Pleistocene-shallow Miocene	Sand, white to light-gray, fine- to very coarse-grained, gravelly and carbonaceous in places, interbedded with sandy silty clay.	Sand and gravel in unit comprise major aquifers. The lower aquifers are generally semiconfined. Potential source of 100 to more than 100 gpm of water per well.	Gulf Shores aquifer	A 2	Miocene-Pliocene aquifer
Deep Miocene	Same as A2, except sediments form more persistent and traceable layers in the sub- surface. The siliciclastics im- mediately overlie the Pensacola Clay.	Major aquifers are semi-confined or confined and yield water to wells under low-head artesian pressure. Potential source of more than 1,500 gpm of water per well.	350- and 500-foot aquifers	A 3	

The remainder of this page intentionally left blank.

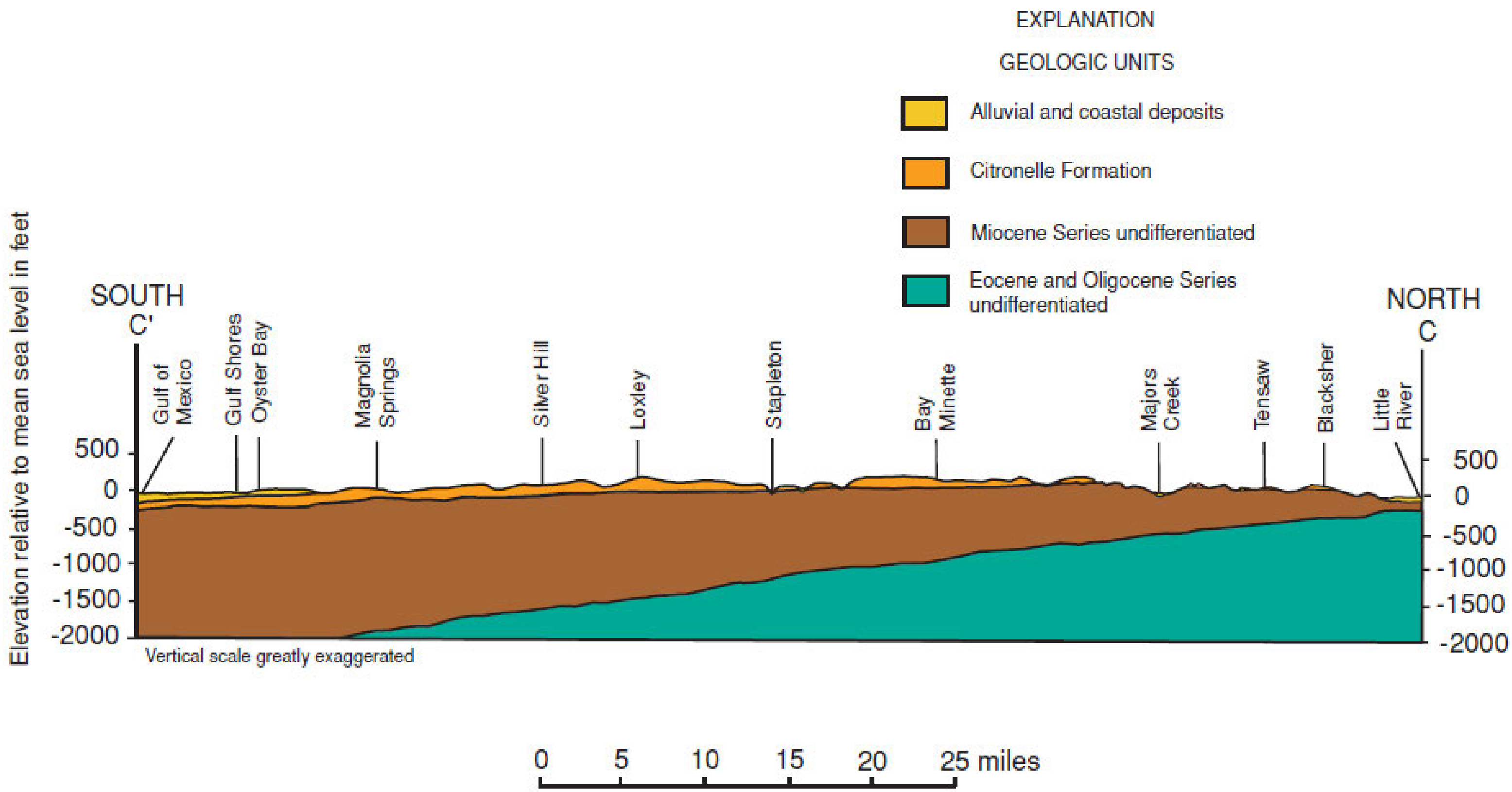


Figure 45. Generalized cross section of freshwater formations within southwest Alabama from the Geological Survey of Alabama (Gillett et al., 2000).

Cross section C-C' is oriented North to South through western Baldwin County; the Longleaf CCS Hub is located approximately 20 miles west of Major's Creek.

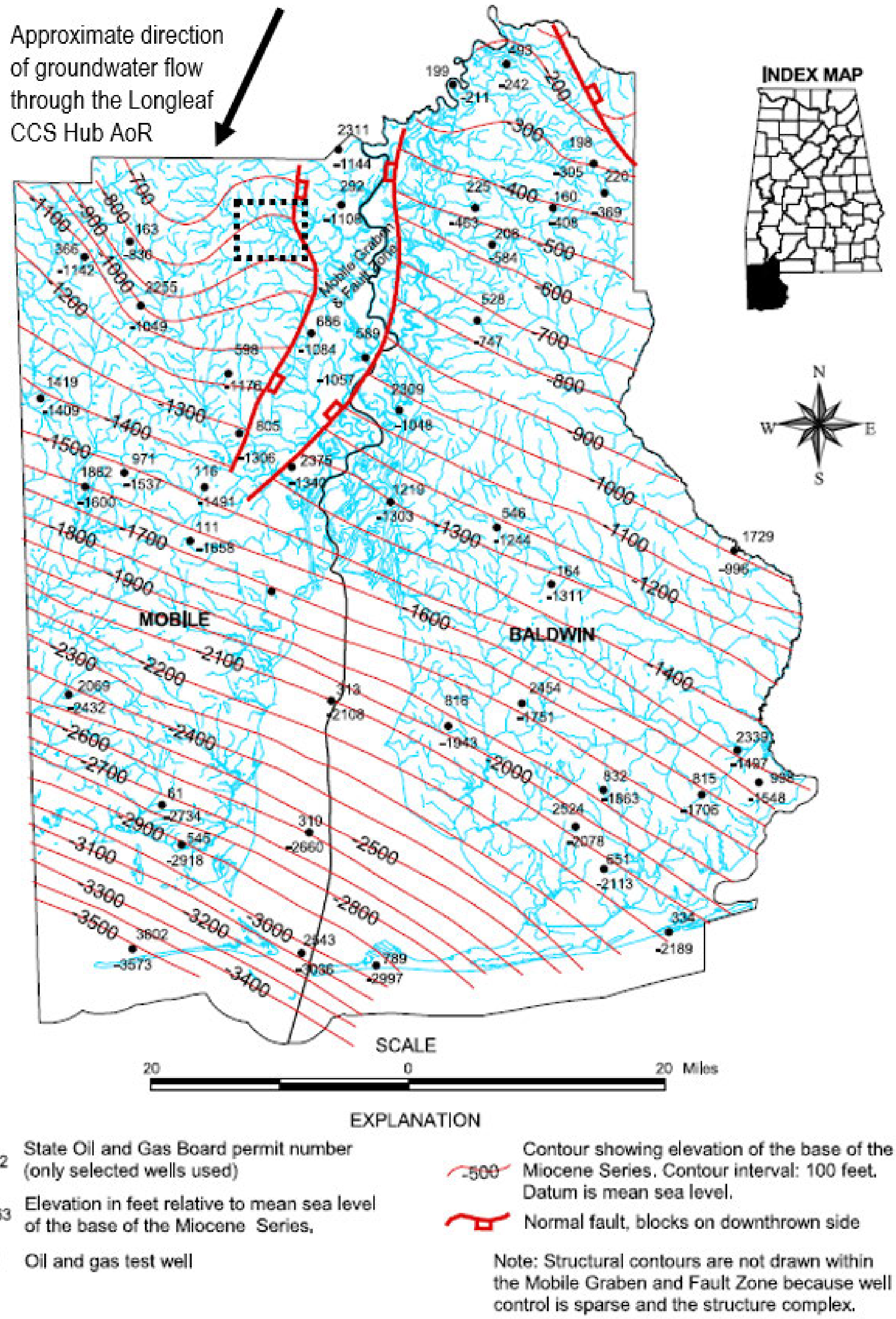


Figure 46. Structure contour map on the base of the Miocene series from the GSA (Gillett et al., 2000). The dashed black box is the approximate location of the Longleaf CCS Hub.

B.8.3. Water Wells within the Longleaf CCS Hub

Within the Longleaf CCS Hub, only the Watercourse and Miocene-Pliocene Aquifers are used for groundwater. A total of 61 water wells (12 of which are in or border the AoR) are drilled within the project (modeled) area and are completed in either the Miocene undifferentiated sands or the Citronelle Formation (**Figure 47**). According to the GSA Risk-Based Data Management System-Environmental (RBDMS-ENV), all water wells in the area are drilled to 1,000 ft. or shallower. All municipal water wells are completed between 700 and 800 ft. or shallower, separated by the underlying Bucatunna Clay from deeper reservoir intervals. A list of the 61 water wells in the modeled area is provided in **Appendix A Table 2** of this Application Narrative.

The remainder of this page intentionally left blank.

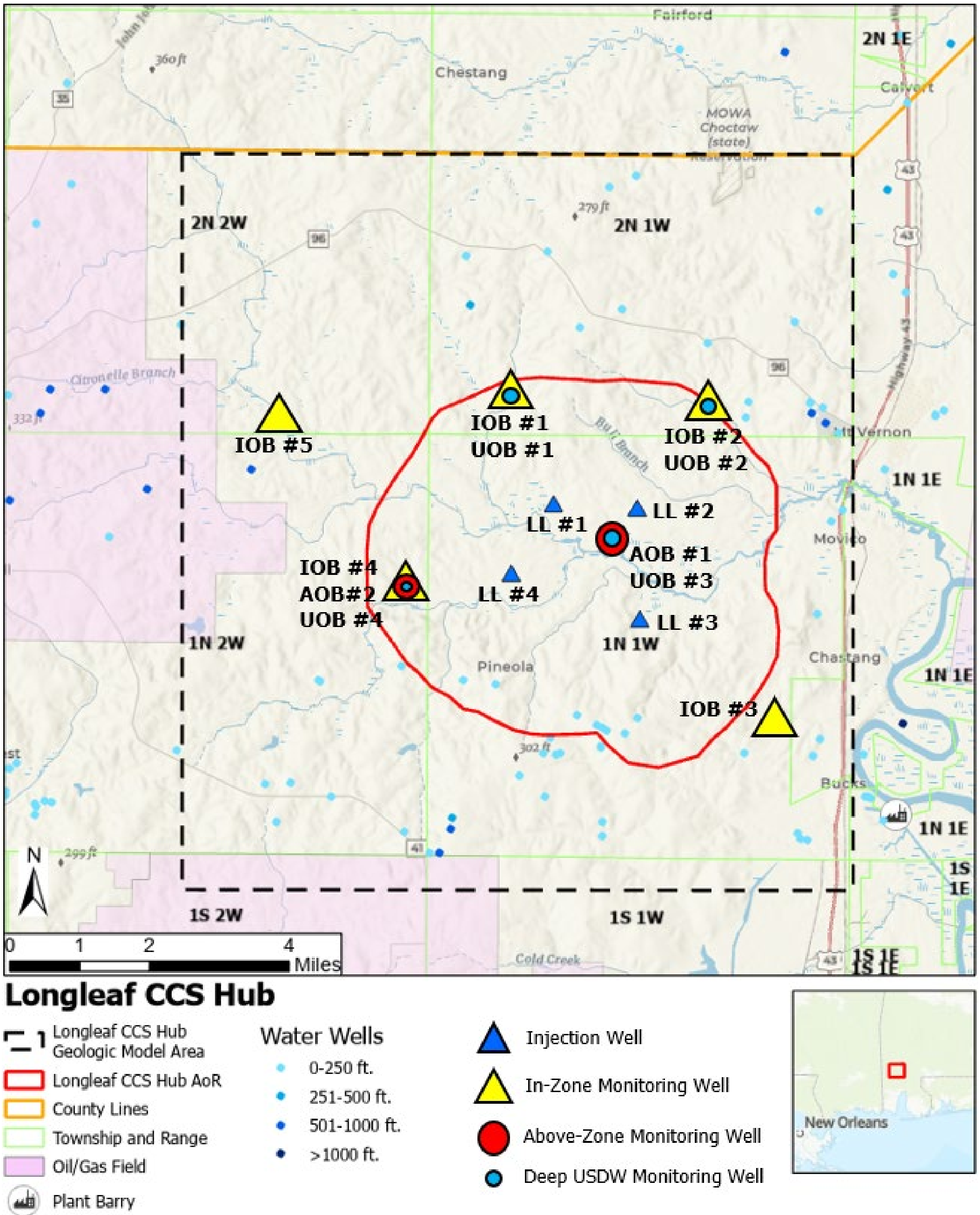


Figure 47. Map of groundwater wells around the Longleaf CCS Hub.

Water well location data from the Geological Survey of Alabama Risk-Based Data Management System-Environmental (RBDMS-ENV).

B.9. Baseline Geochemical Data [40 CFR 146.82(a)(6)]

Reservoir fluid samples from the Upper Paluxy at 9,400 ft to 9,430 ft were gathered as part of the SECARB Phase III CO_2 injection demonstration at Citronelle Dome, approximately five miles from the project's injections wells, and thus should be representative of the Paluxy reservoir fluids at the Longleaf CCS Hub due to continuity of the Paluxy in this region (see **Section B.4**). This work showed that TDS in the Paluxy ranged from 185,000 to 203,000 mg/L (Conaway et al., 2016).

Additional fluid-phase geochemical data will be collected as part of the **Pre-Operational Testing Plan**. Specifically, fluid samples will be collected from the Chickasawhay Formation, the lower-most USDW in the area, as well as the Paluxy, Tuscaloosa, and Eutaw formations to provide site-specific measurements of fluid geochemistry.

Solid-phase petrological analyses for the Paluxy Formation are discussed in detail in **Section B.2.** Additional formation mineralogy data for the Tuscaloosa Marine Shale and the Wash-Fred Basal Shale will be obtained from logs and core samples collected during injection and monitoring well drilling at the Longleaf CCS Hub.

B.10. Site Suitability [40 CFR 146.83]

The geologic site characterization of the Longleaf CCS Hub in northern Mobile County, Alabama along with information assembled by other studies show that the project area provides a geologically favorable setting for safe, long-term storage of CO_2 (Esposito et al., 2008; Pashin et al., 2008; Esposito et al., 2010; Koperna et al., 2012). The primary CO_2 injection interval within the lower Cretaceous strata is the Paluxy Formation that contains a series of thick and porous fluvial sandstones and interbedded floodplain mudstones.

The Paluxy Formation has previously demonstrated the capability for geologic sequestration of CO_2, serving as the primary injection interval for the SECARB Phase III CO_2 injection demonstration at Citronelle Dome, five miles from the center of the proposed injection wells. Data collected from that project combined with other information indicate there is 473 ft of high porosity and permeability saline reservoir sandstone that will be perforated for CO_2 injection in the planned injection wells for the Longleaf CCS Hub. These injection intervals are separated into two zones, the Upper and Lower Paluxy. Average porosity for the sandstone intervals to be perforated in the Upper Paluxy is 13%, ranging from 8 to 19%, and average permeability is 125 mD ranging from 26 to 437 mD. For the Lower Paluxy, average porosity is 12% ranging from 8 to 16%, and average permeability is 60 mD ranging from 24 to 115 mD. Based on these characteristics, the estimated static storage resource of the Paluxy Formation at the Longleaf CCS Hub is 2.3, 4.3, and 7.4 Mt per mi.^{2} for storage efficiency factors of 7.4%, 14%, and 24%, respectively. Geochemical modeling to evaluate compatibility of the CO_2 injectate with Paluxy

Formation has not been performed and plans to conduct this analysis are addressed in the **Pre-Operational Testing Plan**.

The primary confining zone for the Longleaf CCS Hub will be the Tuscaloosa Marine Shale. This 300 ft thick shale has an average effective porosity of less than 2% and permeability at the microdarcy to nanodarcy scale. The low permeability and absence of reactive minerals (e.g., Calcite) provides effective sealing characteristics to prevent the vertical migration of CO_2 into overlying formations. The Selma Group and Midway Group serve as additional confining units that will provide supplemental security for USDWs in the area. In total, 8,380 ft of strata separate the top of the primary injection interval and the base of the deepest USDW at 1,700 ft.

Below the Paluxy, the Mooringsport Formation and Ferry Lake Anhydrite, the caprock for petroleum accumulations in the underlying Rodessa Formation at Citronelle Dome, form a 350 ft thick section of low porosity and permeability interval that serves as the lower confining unit for the storage interval.

Further, the lack of faults and existing wellbores in the AoR, and lack of strong natural seismicity in southwestern Alabama make the presence of CO_2 migration pathways into USDW highly unlikely.

The characteristics of the injection and confining units suggest that the lower Cretaceous Paluxy strata of northern Mobile County, Alabama is compatible with the long-term storage of CO_2. Highly porous and permeable sandstones, overlain and underlain by thick intervals of proven sealing units, ensure the prevention of vertical migration of CO_2 out of the Paluxy Formation. Additionally, the regional continuity of the primary and other confining units demonstrate that the CO_2 plume will be confined to the Paluxy injection interval.

C. SUMMARY OF OTHER PLANS

C.1 AOR and Corrective Action Plan

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

The information and files submitted in the ***Area of Review and Corrective Action Plan*** satisfy the requirements of **40 CFR 146.84(b).** This plan addresses how the Area of Review (AoR) will be delineated and uses corrective action techniques to address all deficient artificial penetrations and other features that compromise the integrity of the confining zone above the injection zone. The AoR encompasses the entire region surrounding the Longleaf CCS Hub where USDWs may be endangered by injection activity. The AoR is delineated by the lateral and vertical migration extent of the CO_2 plume, formation fluids, and pressure front in the subsurface. A computational model was built to model the subsurface injection of CO_2 into the Paluxy Formation in the Longleaf CCS Hub. The *GEM* simulator is used to assess the development of the CO_2 plume, the pressure front, and the long-term fate of the injection. The AoR is delineated by the full lateral and vertical extent of the CO_2 plume in the subsurface and used to monitor where USDWs may be compromised by injection activity. This plan details the computational modelling, assumptions that are made, and site characterization data that the model is based on to satisfy the requirements of **40 CFR 146.84(c).**

Per **40 CFR 146.82(a)(4)**, wells that penetrate the injection or confining zone within the AoR must be tabulated. There are no existing wellbores that penetrate the primary confining unit within the AoR. In Section B.2 of the ***Area of Review and Corrective Action Plan*** is a listing of the five nearest wellbores to the AoR that penetrate the primary confining unit. Three of these wells may require corrective action if CO_2 migrates beyond the baseline modeled AoR, and the corrective action plan to remediate those wellbores is provided in Section B.4 of the ***Area of Review and Corrective Action Plan***.

C.2 Financial Responsibility

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

The ***Financial Responsibility Plan*** demonstrates the financial responsibility for injection well plugging/conversion, Post-Injection Site Care (PISC), site closure, and emergency and remedial response according to requirements of **40 CFR 146.85**. As mentioned earlier, no corrective action is anticipated at the Longleaf CCS Hub as there are no penetrations into the confinement interval currently. The ***Financial Responsibility Plan*** includes financial instruments to cover the costs of: (1) one emergency leakage event as discussed in the ***Emergency and Remedial Response Plan***, (2) well plugging as discussed in the ***Injection Well Plugging Plan***, (3) 20 years of PISC, and (4) site closure as discussed in the ***Posts-Injection Site Care (PISC) and Site Closure Plan***. For more details, refer directly to the ***Financial Responsibility Plan*** where the financial instruments are outlined and costs are presented in more detail.

C.3 Pre-Operational Testing Plan

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

The ***Pre-Operational Testing Plan*** is designed to establish an accurate baseline dataset of pre-injection site conditions, verify depths and physical characteristics of geologic formations germane to the injection and confining zones, and ensure that injection well construction satisfies requirements outlined in **40 CFR 146.86**.

During the drilling and construction phase of the project, appropriate log suites, surveys, and tests will be deployed to verify the depth, thickness, porosity, permeability, and lithology of pertinent geologic formations, as well as the salinity of formation fluids within them. Deviation checks will be performed during drilling at frequent intervals to keep track of the borehole location in the subsurface and serve as a reference for steering purposes to achieve as near to vertical wellbore as possible. These checks will also assist in assuring that avenues for vertical fluid movement are not created in the form of diverging holes while drilling. Mudlogs will be acquired throughout the drilling process. When the well reaches 1,800 ft., resistivity, spontaneous potential, and caliper logs will be run before surface casing is run. A cement bond log will be run to evaluate radial cement quality once the casing is cemented in place.

Once the well is drilled to total depth (TD), resistivity and spontaneous potential logs, porosity, caliper, gamma ray, nuclear magnetic resonance, sonic, and formation micro imager logs will be run prior to the installation of the long string casing. Cement bond, variable density, and temperature logs will be run after long string casing is cemented in place to verify the quality of the cement job. Internal and external mechanical integrity of the injection wells will be tested to demonstrate the absence of leaks in the wellbore that could result in migration of CO_2 out of the injection zone. An annular pressure test will be performed within 24 hours of cementing casing.

Core samples will be taken from the confining and injection zones while drilling the first monitoring well, in-zone monitoring well IOB#1. Analysis of these cores will be correlated to analysis of well logs as part of the pre-operational geologic site characterization updates. Fluid samples will be collected from the injection zone in the proposed injection wells to establish baseline measurements for fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone. Fracture pressure will be determined using the formation testing tool and minifrac tests in IOB#1. Fracture pressure tests will not be conducted in the injection wells to prevent borehole rugosity and washouts and ensure mechanically sound cement jobs.

Upon completion and before operation, hydrogeologic characteristics of the injection zone will be determined by performing a composite injectivity evaluation test in the injection interval to determine the large-scale transmissivity through the reservoir. Reports detailing the results and interpretations of all testing operations will be provided to the UIC Program Director following conclusion of analysis.

C.4 Testing and Monitoring Plan

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

The ***Testing and Monitoring Plan*** is designed to ensure that injection and storage of CO_2 at the Longleaf CCS Hub is done safely, without endangerment to local USDWs or communities, and satisfies the requirements under **40 CFR 146.90**. A ***Quality Assurance and Surveillance Plan*** is attached as an Appendix to the ***Testing and Monitoring Plan***.

Data collected during the implementation of this Plan will be used to confirm that injection procedures are operating as planned, that USDWs are protected, and that the CO_2 plume and pressure front are developing as predicted. The monitoring data will also be used to validate and update geologic and reservoir simulation models. These models, being the primary method of forecasting the position, pressure, and saturation of the injected CO_2 within the Longleaf CCS Hub, will ultimately support and demonstrate the safe and permanent storage of CO_2 throughout the project. **Table 10** summarizes the well-based testing and monitoring activities at the Longleaf CCS Hub.

Longleaf CCS, LLC expects multiple sources of CO_2 from the Mobile, Alabama region, with additional sources to be added throughout the life of the project. As such, Longleaf CCS, LLC will continuously monitor the CO_2 stream with a gas chromatograph to ensure the physical and chemical characteristics of the CO_2 stream are as anticipated. Corrosion monitoring will occur quarterly by analyzing coupons of materials used to construct the CO_2 flowlines, long string casing, injecting tubing, well head, and packer that are exposed to the CO_2 stream while injection is occurring.

Table 10: Summary of Testing and Monitoring Activities to be Conducted at the Longleaf CCS Hub.

Monitoring Activity/Test		Location	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
Pulsed Neutron Capture Log (PNC)		LL#1-4, IOB#1-5, AOB#1-2	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Mechanical Integrity Tests		LL#1-4, IOB#1-5	Once before injection	Annually	Annually
		AOB#1-2, UOB#1-4	Once before injection	Every 5yrs	Every 5yrs
Pressure Transient Test		LL#1-4	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Bottomhole Pressure Monitoring		LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous surface read-out	Continuous surface read-out
Wellhead Pressure Monitoring	Tubing	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Annulus	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
Injection Rate and Volume Monitoring		LL#1-4	N/A	Continuous	N/A
Fluid Sampling		LL#1-4	Once during well construction	N/A	N/A
		AOB#1-2	At least 3 sampling events prior to injection	Quarterly for first yr; Annually thereafter	Annually
		UOB#1-4, All Shallow Groundwater Wells (10)	At least 3 sampling events prior to injection	Annually	Annually

LL#1-4: injection wells
AOB#1-2: above-zone monitoring wells
IOB#1-5: in-zone monitoring wells
UOB#1-4: deep USDW monitoring wells

Longleaf CCS, LLC will use continuous recording devices to monitor the injection pressure, rate, and volume; the pressure of the annulus between the long string casing; and the annulus fluid volume added. The downhole annulus pressure will be maintained at a pressure greater than the operating injection pressure during periods of injection. Fiber optic cable installed on the outside of the long string casing for all injection, in-zone monitoring, and above-zone monitoring wells will conduct continuous geophysical monitoring through distributed acoustic sensing (DAS) and distributed temperature sensing (DTS).

Longleaf CCS, LLC will conduct an annulus pressure test in all injection and in-zone monitoring wells annually to confirm mechanical integrity. DTS will occur continuously, and a temperature log will be run 3 years after injection begins and every 5 years thereafter in conjunction with pulsed neutron capture (PNC) logging. Longleaf CCS, LLC will perform pressure falloff tests in all injection wells once before injection begins, 3 years after injection begins, and every 5 years thereafter in order to verify that the injection zone and pressure are responding as predicted.

Longleaf CCS, LLC will conduct fluid sampling and geochemistry testing in above-zone, deep USDW, and shallow groundwater monitoring wells to detect fugitive CO_2 and ensure USDWs are protected. Longleaf CCS, LLC chose the locations for above-zone and deep USDW monitoring wells based on the expected pressure and CO_2 plume development.

Longleaf CCS, LLC will utilize direct and indirect methods to track the extent of the pressure and CO_2 plume throughout the life of the project. Continuous downhole pressure monitoring will be performed in all injection wells and in-zone and above-zone monitoring wells with real-time surface read-out capabilities. Indirect CO_2 plume monitoring will occur using PNC logs and vertical seismic profiles in conjunction with DAS to monitor formation fluid saturations (including the presence of CO_2) and track the movement of the CO_2 plume. These monitoring data will allow Longleaf CCS, LLC to ensure the injection zone pressure and CO_2 plume are behaving as expected and validate the reservoir model with real pressure and saturation data.

Monitoring reports will be submitted to the UIC Program Director semi-annually.

C.5 Injection Well Construction Designs

Injection Well Construction Plan GSDT Submissions
GSDT Module: Project Information Tracking *Tab(s):* Initial Permit Application tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Description of the Casing and Cement *[40 CFR 146.82(a)(11, 12) and 146.86(b)]* ☒ Description of the Tubing and Packer *[40 CFR 146.86(c)]* ☒ Continuous Recording Devices and Automatic Shutoff Devices *[40 CFR 146.88(e)]*

The ***Injection Well Construction Designs*** illustrates the comprehensive analysis performed to comply with and exceed federal Class VI UIC well standards in 40 CFR 146.86(a) regarding the design of the casing, cement, and wellhead for the four injection wells at the Longleaf CCS Hub.

The injection wells have been designed to accommodate the mass of CO_2 that will be delivered to the storage site, considering key characteristics of the CO_2 storage reservoir that affect the well design. Assuming an injection rate of 1.25 MT/y and an expected wellhead pressure of 1500 psia, the injection well design will include the following casing strings: a 20-inch-diameter conductor casing string set at a depth of approximately 60 feet below ground surface (BGS) inside a 26-inch borehole; a 13.375-inch diameter surface casing string set at a depth of approximately 1,800 feet BGS inside a 16-inch borehole; a 9.625-inch diameter long casing string set at a depth of approximately 11,400 feet BGS inside a 12.25-inch borehole; and a 6.625-inch diameter deep (injection) tubing string set at an approximate depth of 10,950 feet BGS. The 6.625-inch tubing will then crossover to a 5.5-inch diameter tubing string set to a depth of 11,360 feet BGS and be equipped with two sliding sleeves run in series, corresponding with the two injection zones. The conductor, surface casing, and deep casing will be cemented to the surface in accordance with requirements at 40 CFR 146.86(b)(3). To protect from potential CO_2 corrosion, the entire tubing string and the portion of the long string casing from TD through the primary confining zone will be composed of L-80 grade steel with 13% chrome type (13Cr-L80). Additionally, CO_2 resistant cement will be used from TD to the top of the primary confining zone.

The outside of the long-string casing will be equipped with a DAS/DTS fiber optic cable to continuously monitor zonal pressures, temperatures, and seismic activity in compliance with the ***Testing and Monitoring Plan*** and mechanical integrity testing requirements. The long-string casing will be perforated across the Paluxy Sandstone with deep-penetrating shaped charges. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The planned perforation intervals will be set between 10,269 feet and 11,347 feet with 6 shots-per-foot and 60-degree phasing.

The injection tubing will be secured within the long-string casing with a packer made of CO_2 resistance material, such as 13Cr steel. The annular space above the packer between the long-string casing and the injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be controlled during injection operations (See **Section *D.2.2.* of the *Testing and Monitoring Plan*** for a full description of the injection well annulus monitoring system). Added to the hydrostatic pressure of the fluid column, this will ensure that the annular pressure downhole will be greater than injection pressure. Annular and downhole injection pressure will be monitored with pressure/temperature gauges set both above and below the packer.

The wellhead and Christmas tree will be composed of materials that are designed to be compatible with the injection fluid. Critical components that encounter the CO_2 injection fluid will be made of a corrosion-resistant alloy such as stainless steel.

C.6 Injection Well Operations Plan

Injection Well Operations Plan GSDT Submissions
GSDT Module: Project Information Tracking ***Tab(s):*** Initial Permit Application tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Planned well operations [***40 CFR 146.82(a)(7)]***

The ***Injection Well Operations Plan*** describes the operational design developed to adhere to 40 CFR 146.82(a)(7) and 40 CFR 146.88 and provides a plan for safely injecting an average rate of 1.25 Mt/y of CO_2 into each of four injection wells at the Longleaf CCS Hub. The CO_2 will be sourced from industrial and power plants located in the Mobile, Alabama area and transported in liquid or supercritical phase by pipeline to the Longleaf CCS Hub where it will transition to a supercritical phase and be injected deep underground into the Paluxy formation at approximately 10,269 feet.

The four injection well designs were modeled with SLB *PIPESIM* software to confirm the average annual injection rate of 1.25 Mt/y and maximum instantaneous injection rate of 1.50 Mt/y could be achieved. SLB *PIPESIM* software is a steady-state multi-phase flow simulator that accounts for pressure-volume-temperature (PVT) properties of CO_2, friction pressures of wellbore tubulars, hydrostatic effects, and fluid velocity.

During the initial start-up period of injection, Longleaf CCS, LLC will perform a series of 24-hour injection rate tests to look for any evidence of pressure anomalies and to confirm wellbore integrity. At no point during these tests will the injection pressure exceed the maximum permitted bottomhole injection pressure which is 90% of the Paluxy Formation fracture pressure.

These wells will be continually monitored for injection pressure, rate, volume, temperature of the CO_2 stream, tubing/casing annulus pressure, and external mechanical integrity in compliance with 40 CFR 146.88(e)(2).

Each injection well will have a wellhead pressure gauge (tubing and annular pressure) and flow computer tied into the injection control system and set to trigger an alarm at the project control room and shut down injection if: (1) the maximum allowable surface pressure (MASP) is reached; (2) the CO_2 injection rate exceeds maximum permitted rate; or (3) the tubing/casing annulus pressure drops below the injection pressure.

All automatic shutdowns will be investigated prior to returning to CO_2 injection to ensure that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, Longleaf CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown.

C.7 Injection Well Plugging Plan

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

The ***Injection Well Plugging Plan*** describes the process that Longleaf CCS, LLC will follow to plug the four injection wells at the Longleaf CCS Hub in accordance with federal requirements at 40 CFR 146.92 and 40 CFR 146.93(e) and state requirements at ASR 400-1-4-.15 - .16. After the 30-year injection period, the injection wells will be plugged or converted to monitoring wells to ensure containment of the CO_2 in the injection zone. Upon completion of operations, the final bottom-hole pressure of the injection wells will be measured, and a buffered fluid (brine) will be used to flush and fill the wells to maintain pressure control. The injection tubing strings, packers, and gauges will be removed from the wells. The mechanical integrity of the wells will be determined to ensure no communication has been established between the injection zone and the USDWs or ground surface (per **40 CFR 146.92**). Finally, the entire wellbore will then be filled with cement, from the total depth to surface. CO_2 resistant cement will be squeezed into the perforations to seal and fill the wellbore up to the Tuscaloosa Marine Shale. The remaining wellbore will be filled with standard cement to surface. The casing will then be cut at least 5 feet below ground level and sealed with a welded steel plate.

The remainder of this page intentionally left blank.

C.8 Post-Injection Site Care and Site Closure Plan

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

The ***Post-Injection Site Care and Site Closure Plan*** describes the activities that Longleaf CCS Hub, LLC will perform to meet the requirements of 40 CFR 146.93. The Post-Injection Site Care (PISC) timeframe will begin when all CO_2 injection ceases and ends with site closure. Longleaf CCS, LLC proposes a 20-year PISC timeframe based on results from computational modeling as discussed in the ***AoR and Corrective Action Plan*** as well as the ***Post-Injection Site Care and Site Closure Plan***. Per 40 CFR 146.93(b), Longleaf CCS, LLC will monitor the project site for CO_2 plume movement and pressure fall-off to demonstrate non-endangerment of USDWs throughout the PISC timeframe. The plan describes the post-injection period computational modeling that was completed to determine the pressure differential, position of the CO_2 plume, and prediction of CO_2 migration. Additionally, the plan provides a detailed description of the post-injection monitoring plan and the site-closure activities. The numerical reservoir model used for calculating the AoR was also used for the PISC and site-closure analysis.

The predicted positions of the CO_2 storage zone and pressure front at the end of 30 years of injection and 20 years post-injection were simulated in the model. The simulation indicates that the CO_2 plume would remain within 2.3 miles from LL#1 at the time of site closure. Most of the CO_2 mass is concentrated around the four injection wells with some CO_2 extending outward from the injection wells, primarily in the up-dip directions to the northwest, southwest, and southeast. Based on the model, it is estimated that there is not sufficient hydrostatic pressure in the injection zone to push fluids into or interact with the lowermost USDW, which is the Chickasawhay formation.

Following the cessation of injection, some of the injection wells may be converted to monitoring wells to contribute to the collection of data as part of the Longleaf CCS, LLC monitoring program. The post-injection phase will include monitoring for gas leaks in the wellheads and valves, external mechanical well integrity testing, groundwater sampling, direct pressure and temperature measurements, indirect and direct plume tracking, surface and near surface CO_2 leak monitoring, and seismicity monitoring for induced and natural seismic events.

Once Longleaf CCS, LLC demonstrates plume and pressure stabilization, as well as non-endangerment of local USDWs, well plugging and abandonment of the remaining active injection wells will commence. Abandonment will be performed to preclude the movement of injection or formation fluids out of the storage complex. Prior to well plugging, the mechanical integrity of the wells will be verified by the DTS and DAS fiber optic systems emplaced in the monitoring wells. The well plugging and abandonment will follow the methodology described in the ***Injection Well Plugging Plan***.

C.9 Emergency and Remedial Response Plan

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

The ***Emergency and Remedial Response Plan*** details actions that Longleaf CCS, LLC will take to address movement of the injection fluid or formation fluid in a manner that may endanger a USDW during the construction, operation, or post-injection site care periods, pursuant to 40 CFR 146.82(a)(19) and 146.94(a). Examples of potential risks include: (1) injection or monitoring well integrity failure, (2) injection well monitoring and/or surface equipment failure, (3) natural disaster, (4) fluid leakage into a USDW, (5) CO_2 leakage to USDW or land surface, or (6) an induced seismic event. In the case of one of the listed risks, site personnel, project personnel, and local authorities will be relied upon to implement this plan. Longleaf CCS, LLC will communicate to the public any major emergency, as described in the plan, to ensure that the public understands what happened and whether there are any environmental or safety implications. This will include a detailed description of what happened, any impacts to the environment or other local resources, how the event was investigated, what actions were taken, and the status of the remediation.

The emergency contact list in Appendix B of the plan will be updated annually at a minimum, and the plan will be reviewed at least once every five years following its approval as well as within one year of an AoR reevaluation and following any significant changes to the injection process or the injection facility or an emergency event. Periodic training will be provided to well operators, plant safety and environmental personnel, the operations manager, plant superintendent, and corporate communications to ensure that the responsible personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the plan.

The remainder of this page intentionally left blank.

REFERENCES

A Class One Injection Well Survey, Phase I Report: Survey of Selected Sites. Prepared for the Underground Injection Practices Council. Prepared by CH2M Hill. 1986.

Alverson, R. M., “Deep Well Disposal Study for Baldwin, Escambia, and Mobile Counties”, Alabama, Geological Survey of Alabama, Circular 58, 1970.

Benson, J., Mancini, E.A., and Wilkerson, R.P. Hatter's Pond Field: Complex Combination Trap in Smackover and Norphlet Formations (Upper Jurassic), Southwest Alabama, AAPG Bulletin (1981) 65 (5): 899

Bolin, D.E., Mann, S.D., Burroughs, D., Moore, H.E. Jr., and Powers, T.L., Petroleum Atlas of Southwest Alabama, Alabama Geological Survey Atlas 23, 1986.

Bolt, B. A., “Abridged Modified Mercalli Intensity Scale, Earthquakes – Newly Revised and Expanded”, Appendix C, W.H. Freeman and Co., 331 pp., 1993.

Conway, C.H., Thordsen, J.J., Manning, M.A., Cook, P.J., Trautz, R.C., Thomas, B., and Kharaka, Y.K., “Comparison of geochemical data obtained using four brine sampling methods at the SECARB Phase III Anthropogenic Test CO2 injection site, Citronelle Oil Field, Alabama” International Journal of Coal Geology, v.162, p.85-95, 2016.

Dees, W.T and Smith, D.L. (1982): Heat Flow in the Gulf Coastal Plain. Journal of geophysical research, vol. 87, NO. B9, pp. 6787-7693.

Dixon, J., 2015, DS926 Digital surfaces and thicknesses of selected hydrogeologic units of the Floridan aquifer system in Florida and parts of Georgia, Alabama, and South Carolina -- Revised Hydrogeologic Framework of the Floridan aquifer system in Florida and Parts of Georgia, Alabama, and South Carolina, U.S. Geological Survey Professional Paper 1807: U.S. Geological Survey data release, https://doi.org/10.5066/P92NJL6Q.

Eaton, B., “Fracture Gradient Prediction and Its Application in Oilfield Operations”, Journal of Petroleum Technology, v.21 (10), p. 1353-1360, 1969.

Eaves, E., “American Association of Petroleum Geologists Memoir 24”, p.259-275, 1976.

Ebersole, S., “Earthquakes in Alabama Brochure”, Geological Survey of Alabama and Alabama Emergency Management Agency, 2007.

Esposito, R.A., and King, D.T., “Facies Analysis, Sea Level History and Platform Evolution of the Jurassic Smackover Formation, Conecuh Basin, Escambia County, Alabama” Gulf Coast Association of Geological Societies Transactions, v. 37, p. 335-346, 1987

Esposito, R. A., Pashin, J. C., and Walsh, P. M., “Citronelle Dome: A Giant Opportunity for Multizone Carbon Storage And Enhanced Oil Recovery In The Mississippi Interior Salt Basin Of Alabama”, Environmental Geosciences, v. 15, p. 53-62, 2008.

Folaranmi, Ayobami T. “Geologic Characterization of a Saline Reservoir for Carbon Sequestration: The Paluxy Formation, Citronelle Dome, Gulf of Mexico Basin, Alabama [unpublished master’s thesis]. Oklahoma State University, 2015.

Galicki, S.J., Movico Field Mobile County, Alabama, Mesozoic-Paleozoic Producing Areas of Mississippi and Alabama, Volume III, 1986, 105-107

Geological Survey of Alabama, 2018, Assessment of groundwater resources in Alabama, 2010-16: Alabama Geological Survey Bulletin 186, 426 p., plus separately bound volume of 105 plates.

Geological Survey of Alabama Circular 47, “Geology of the Alabama Coastal Plain”, 1968.

Gillett, B., Raymond, D.E., Moore, J.D., and Tew, B.H. Hydrogeology and Vulnerability to Contamination of Major Aquifers in Alabama: Area 13. Prepared by the Geological Survey in Alabama in cooperation with the Alabama Department of Environmental Management, 2000.

Gomberg, J. and Wolf, L., “Possible cause for an improbable earthquake: The 1997 Mw 4.9 southern Alabama earthquake and hydrocarbon recovery”, Geology, v.27, p.367-370, 1999.

Goodman, A., Hakala, A., Bromahl, G., Deel, D., Rodosta, T., Frailey, S., Small, M., Allen, D., Romanov, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, B., and Guthrie, G., “U.S. DOE methodology for development of geologic storage potential for carbon dioxide at the national and regional scale.” International Journal of Greenhouse Gas Control, v.5, p. 952-965, 2011.

Guoqing Xiao, et al, “CO2 corrosion behaviors of 13Cr steel in the high-temperature steam environment,” Petroleum, Volume 6, Issue 1, 2020, Pages 106-113.

Kopaska-Merkel, D.C., Jurassic Cores from the Mississippi Interior Salt Basin, Alabama, Alabama Geological Survey Circular 200, 2002.

Koperna, G., Reistenberg, D., Kuuskraa, V., Rhudy, R., Truatz, R., Hill, G.R., and Esposito, R., 2012. The SECARB Anthropogenic Test: A US Integrated CO2 Capture, Transportation, and Storage Test, International Journal of Clean Coal and Energy, 1, pg. 13-26.

Mancini, E.A., and Benson, D.J., “Regional Stratigraphy of the Upper Jurassic Smackover Carbonates of Southwest Alabama.” Gulf Coast Association of Geologic Societies Transactions, v.30, p. 151-165, 1985.

Mancini, E.A., Mink, R.M., Bearden, B.L., and Wilkerson, R.P., “Norphlet Formation (Upper Jurassic) of Southwestern Alabama” AAPG Bulletin, v. 71, p. 1128-1142, 1985.

Mancini, E. A., Mink, R. M., Payton, J. W., and Bearden, B. L., “Environments of Deposition and Petroleum Geology of Tuscaloosa Group (Upper Cretaceous), South Carlton and Pollard Fields, Southwestern Alabama”, American Association of Petroleum Geologists Bulletin, V71, No 10, p 1128-1142, 1987.

Mancini, E. A., Puckett, T. M., Parcell, W. C., and Panetta, B. J., “Basin Analysis of the Mississippi Interior Salt Basin and Petroleum System Modeling of the Jurassic Smackover Formation, Eastern Gulf Coastal Plain”, Topical Reports 1 and 2. Work performed for the National Petroleum Technology Office, Office of Fossil Energy, U.S. Department of Energy under DOE Award Number DE-FG22-96BC14946, 425 p.,1999.

Mancini, E. A. and Puckett, T. M., “Jurassic and Cretaceous Transgressive-Regressive Cycles, Northern Gulf of Mexico, U.S.A.”, Stratigraphy, v. 2, p.30-47, 2005.

Meckel, T.A., Considering faults in CCS: presented at the Outreach Working Group (OWG) for the regional carbon sequestration partnerships, teleconference, June 14, 2007. GCCC Digital Publication Series #07-04.

Pashin, J. C., Raymond, D. E., Alabi, G. G., Groshong, R. H., Jr., and Guohai Jin;, “Revitalizing Gilbertown Oilfield: Characterization of Fractured Chalk and Glauconitic Sandstone Reservoirs in an Extensional Fault System”, Alabama Geological Survey Bulletin 168, 81 p., 2000.

Pashin, J. C, McIntyre, M. R., Grace, R. L. B., Hills, D. J., “Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III, Final Report”, Report to Advanced Resources International by Geological Survey of Alabama, Tuscaloosa, September 12, 2008.

Pashin, J. C., Kopaska-Merkel, D. C., and Hills, D. J., “Reservoir geology of the Donovan sandstone in Citronelle Field”, in Walsh, P. M., ed., Carbon dioxide enhanced oil production from the Citronelle oil field in the Rodessa Formation, South Alabama: Final Scientific/Technical Report, U.S. Department of Energy Award DEFC26-06-NT43029, p. 13-65, 2014.

Petersen, M. D., et al., “2008 United States National Seismic Hazard Maps”, U.S. Geological Survey Fact Sheet 2008–3018, 2 p., 2008.

Petrusak, R. L., Goad, P. G., Koperna, G. J., and Riestenberg, D. E., “FY2008 Annual Report Geologic Characterization Task Southeast Regional Carbon Sequestration Partnership (SECARB) on Geologic Characterization of the Lower Tuscaloosa Formation for the Phase II Saline Reservoir Injection Pilot Test”, Jackson County, Mississippi, 2009.

Raymond, D. E., Osborne, W. E., Copeland, C. W., and Neathery, T. L.; “Alabama Stratigraphy”, Geological Survey of Alabama, Circular 140, 1988.

Raymond, D.E. The Lower Cretaceous Ferry Lake Anhydrite in Alabama, Including Supplemental Information on the Overlying Mooringsport Formation and Petroleum Potential of the Lower Cretaceous, Alabama Geological Survey Circular 183, 1995.

Tucker, W.E., and Kidd, R.E., “Deep-Well Disposal in Alabama”, Geological Survey of Alabama, Bulletin 104, 1973

U.S. Environmental Protection Agency, 2012. Underground Injection Control (UIC) Program Class VI Well Construction Guidance. Published May 2012.

U. S. Geological Survey; “Groundwater Atlas of the United States”, http://capp.water.usgs.gov/gwa/, 1998.

U. S. Geological Survey, “2014 Seismic Hazard Map-Alabama”, https://www.usgs.gov/media/images/2014-seismic-hazard-map-alabama , 2014.

Yielding, G., Freeman, B. and Needham, D.T. Quantitative fault seal prediction. AAPG Bulletin (1997) 81: 897–917

Yielding, G., Bretan, P. and Freeman, B. Fault seal calibration: a brief review. Geological Society, London, Special Publications (2010), 347, 243–255

Appendix A – Supplemental Tables

Table 1. List of Longleaf Project Wells including planned use and spud date timing.

Well	Drilling Order	Use	Well Spud Timing		
			Early date	Target date	Late date
IOB-1	1	Strat well and in-zone monitoring	May, 2025	June, 2025	August, 2025
UOB-1	2	Deep groundwater monitoring well	July, 2027	2028	2032
LL-1	3	Injection well	August, 2027	2028	2032
LL-2	4	Injection well	October, 2027	2028	2032
AOB-1	6	Above zone monitoring well	November, 2027	2028	2032
UOB-3	7	Deep groundwater monitoring well	January, 2028	2028	2032
IOB-2	8	In-zone monitoring well	February, 2028	2029	2032
UOB-2	9	Deep groundwater monitoring well	March, 2028	2029	2032
IOB-3	10	In-zone monitoring well	April, 2028	2030	2035
LL-3	11	Injection well	June, 2028	2030	2035
IOB-4	12	In-zone monitoring well	August, 2028	2030	2035
AOB-2	13	Above zone monitoring well	September, 2028	2031	2038
UOB-4	14	Deep groundwater monitoring well	November, 2028	2031	2038
LL-4	15	Injection well	November, 2028	2031	2038
IOB-5	16	In-zone monitoring well	January, 2029	2031	2038

Table 2. List of water wells in the modeled area.

Well Name	Type	Latitude	Longitude	Well Depth
097I29003	Domestic	31.01885	-88.0935325	100
097I28004	Domestic	31.02662	-88.073916	95
097I31004	Public	30.99828	-88.121286	960
097H27001	Domestic	31.01209	-88.1634116	125
097H36001	Domestic	31.00252	-88.1297846	110
097I21001	Domestic	31.02731	-88.0885148	120
097I36002	Domestic	31.00299	-88.0351673	80
097I12001	Domestic	31.06787	-88.0274657	70
097I29004	Domestic	31.0146	-88.1021994	84
097I29005	Domestic	31.01915	-88.09249	105
097H34001	Domestic	31.00436	-88.1608181	75
097I19001	Domestic	31.03413	-88.1161078	140
097I29001	Domestic	31.0224	-88.0950116	115
097I31001	Domestic	30.99824	-88.1238619	150
097H24001	Domestic	31.03691	-88.131019	120
097I28006	Domestic	31.02394	-88.081495	115
097I29006	Domestic	31.01015	-88.0960036	81
097I29007	Domestic	31.01918	-88.0964432	108
097I31002	Industrial	31.00553	-88.1184381	368
097B36003	Public	31.09045	-88.0325	685
097I28001	Domestic	31.02073	-88.0827067	92
097I28003	Domestic	31.02521	-88.0836203	150
097I33001	Domestic	31.00199	-88.0820889	70
097B16001	Domestic	31.13682	-88.082114	85
097B36005	Domestic	31.0916	-88.0299088	93
097B20001	Public	31.12346	-88.096863	222
097I12003	Observation	31.07033	-88.024965	901
097I13001	Domestic	31.04859	-88.0309296	55
097I40002	Public	31.02281	-88.029777	234
097I28005	Domestic	31.0247	-88.0824543	145
097I28007	Domestic	31.02344	-88.0770718	63
097B35002	Domestic	31.09255	-88.0479792	90
097I20001	Domestic	31.03346	-88.108117	90
097I26001	Domestic	31.01971	-88.0480245	110

Well Name	Type	Latitude	Longitude	Well Depth
097H35001	Domestic	31.00963	-88.1477503	110
097I36001	Domestic	31.00171	-88.0327704	83
097I36003	Domestic	31.00184	-88.0342784	85
097B36001	Industrial	31.08628	-88.026111	240
097B19001	Domestic	31.12236	-88.1164607	166
097B25001	Domestic	31.10931	-88.0369994	80
097B27001	Domestic	31.10466	-88.0579211	100
097B16002	Domestic	31.13938	-88.0755593	190
097B36002	Public	31.08851	-88.029166	728
097B28001	Domestic	31.11164	-88.0787906	47
097B28002	Domestic	31.1077	-88.088657	116
097I12002	Public	31.07033	-88.024961	200
097H26001	Domestic	31.01262	-88.1575365	90
097I40001	Domestic	31.0192	-88.0316538	60
097I31003	Industrial	31.00336	-88.1187973	861
097I31005	Observation	30.99829	-88.121284	955
097H03001	Industrial	31.07748	-88.1676035	530
097H23002	Domestic	31.03379	-88.1508215	106
097B30001	Public	31.11215	-88.1153719	310
097A36001	Domestic	31.09258	-88.0331053	68
097B35001	Domestic	31.08952	-88.0484472	125
097H23001	Domestic	31.03372	-88.1505421	112
097I28002	Domestic	31.02059	-88.0828235	81
097I33002	Domestic	31.00506	-88.082056	165
097B13001	Industrial	31.13229	-88.0313	163
097B36004	Domestic	31.0924	-88.0330664	58
097B36006	Domestic	31.0915	-88.029749	110

Table 3. List of deep (oil and gas) wells in modeled area.

Well Name	Well API	Elevation (ft)	Elevation Measured From	Latitude	Longitude	Operator	Total Depth (ft)	Status
ALABAMA STATE HOSPITALS "B" #1	01097195280000	210	KB	31.09098	-88.02893	GULF REFINING	11014	P&A
CITRONELLE SE UNIT #D-10-12	01097199400000	146	KB	31.06106	-88.17384	JP OIL ALABAMA, LLC	11328	P&A
CITRONELLE SE UNIT #D-10-4	01097199380000	118	KB	31.06861	-88.17388	JP OIL ALABAMA, LLC	11330	P&A
CITRONELLE SE UNIT #D-10-5	01097199290000	131	KB	31.06487	-88.17386	JP OIL ALABAMA, LLC	11295	P&A
CITRONELLE SE UNIT #D-4-15	01097199270000	131	KB	31.07228	-88.18285	JP OIL ALABAMA, LLC	11717	P&A
CITRONELLE SE UNIT #D-4-7	01097199300000	138	KB	31.07966	-88.18338	JP OIL ALABAMA, LLC	11639	P&A
CITRONELLE SE UNIT #D-9-1	01097199170000	124	KB	31.06938	-88.17793	JP OIL ALABAMA, LLC	11260	P&A
CITRONELLE SE UNIT #D-9-10	01097198560000	171	KB	31.06126	-88.18279	JP OIL ALABAMA, LLC	11261	P&A
CITRONELLE SE UNIT #D-9-15	01097198670000	162	KB	31.05788	-88.18229	JP OIL ALABAMA, LLC	11450	P&A
CITRONELLE SE UNIT #D-9-2	01097198790000	138	KB	31.0693	-88.182787	JP OIL ALABAMA, LLC	11600	P&A
CITRONELLE SE UNIT #D-9-9	01097199210000	156	KB	31.06143	-88.17843	JP OIL ALABAMA, LLC	11228	P&A
CITRONELLE SE UNIT D-9-9 #2	01097203960000	183	KB	31.06136	-88.17794	JP OIL ALABAMA, LLC	11780	P&A
CITRONELLE UNIT (B-33-1) #1	01097199260000	152	KB	31.0983	-88.17885	JETT DRILLING	11692	P&A
CITRONELLE UNIT (D-4-16) #1	01097199850000	138	KB	31.07227	-88.17912	JETT DRILLING	11316	P&A
CITRONELLE UNIT D-9-7	01097198660000	166	KB	31.06519	-88.18172	AMERICAN EXPLORATION COMPANY	11206	P&A
D-9-7#2	01000000070000	162	GL	31.06486	-88.18201	Denbury Onshore, LLC.	11777.5	P&A

Well Name	Well API	Elevation (ft)	Elevation Measured From	Latitude	Longitude	Operator	Total Depth (ft)	Status
DR. MONTE L. MOORE FOUNDATION TRUST 3-6	01097201340000	199	KB	31.07874	-88.17081	ROACH, RALPH H.	18828	P&A
INTERNATIONAL PAPER CO. 36-14 #1	01097201730000	232	KB	31.00117	-88.13714	MARION CORPORATION	18652	P&A
LAMBERT HEIRS #1	01097200300000	264	KB	31.04317	-88.15742	STATES OIL COMPANY, INC.	11961	P&A
MATTIE J. TURNER 1-7 #1	01097200730000	283	KB	30.9912	-88.13171	CHEVRON	18631	P&A
NO. 1 CITRONELLE UNIT D-9-8	01097198980000	121	KB	31.06533	-88.17842	JP OIL ALABAMA, LLC	11214	P&A
NO. 4 M. L. MOORER ESTATE D-10-6	01097199460000	126	KB	31.06494	-88.16957	JP OIL ALABAMA, LLC	11321	P&A
O.P. TURNER #31-4	01097202090000	222	KB	31.01112	-88.1235	SANDEFER PETROLEUM CO.	18675	P&A
PRATT TURNER LAND CO.#B-31-5	01097201330000	247	KB	31.00563	-88.1224	TURNER & HICKOX, INC.	12140	P&A
R.H. RADCLIFF ET AL #1	01097195270000	296	KB	30.99213	-88.10501	MORGAN, HARRY I. & BORDEN, S.P.	8232	P&A
R.H. RADCLIFF, JR. #31-11	01097200160000	318	KB	31.00303	-88.11798	CHEVRON	18755	P&A
R.J. NEWMAN ET AL 5-7 #1	01097201720000	256	KB	30.99213	-88.0965	CHEVRON	18575	P&A
SECU D-9-8 #2	01000000080000	109.5	GL	31.06496	-88.17938	Denbury Onshore, LLC.	11810	P&A
STATE OF ALABAMA & ALABAMA STATE HOSPITA	01097199660000	79	KB	31.08051	-88.02464	CITMOCO SERVICES, INC	12503	P&A
TENSAW 33-2 #1	01097203950000	189	KB	31.09709	-88.18323	J-BREX ALABAMA, LLC	12050	P&A
TENSAW LAND & TIMBER CO. 13-14 #1	01097203900000	124	KB	31.13229	-88.0313	FORT APACHE ENERGY	12002	P&A

Well Name	Well API	Elevation (ft)	Elevation Measured From	Latitude	Longitude	Operator	Total Depth (ft)	Status
TENSAW LAND & TIMBER CO. B-39-13 #1	01097201960000	215	KB	31.01347	-88.12139	TURNER & HICKOX, INC.	2478	P&A
UNIT D-4-10	01097199390000	135	KB	31.07589	-88.18336	I N HICKOX	11204	P&A