CLASS VI PERMIT APPLICATION NARRATIVE

STRATEGIC BIOFUELS
LOUISIANA GREEN FUELS, PORT OF COLUMBIA FACILITY

Prepared By:
GEOSTOCK SANDIA, LLC

Revision No. 3
May 2025

TABLE OF CONTENTS

LIST OF TABLES

Section 2.0 – Site Characterization

Section 3.0 – Area of Review and Corrective Action

Section 4.0 – Financial Demonstration

Section 5.0 – Injection Well Construction

LIST OF FIGURES

Section 2.0 – Site Characterization

Section 5.0 – Injection Well Construction

LIST OF APPENDICES

** Reference technical papers and other support material that are confidential (subject to copyright, etc.) has been placed in a separate folder (Module A > 5 CBI Documents > CBI References)*

INDEX OF SUBMITTED APPLICATION PLANS

GSDT Module	Report Plan Name
Module A - Summary of Requirements	A.1 – Project Narrative
Module B – Area of Review & Corrective Action Plan	B.1 – Area of Review and Corrective Action Plan
Module C – Financial Demonstration	C.1 – Financial Demonstration Plan
Module D – Pre-Operational Testing	D.1 – Pre-Operation Testing Plan
Module E – Project Plan Submission	E.1 – Testing and Monitoring Plan
	E.2 – Injection Plugging Plan
	E.3 – Post-Injection Site Care and Site Closure Plan
	E.4 – Emergency and Remedial Response Plan

1.0 PROJECT BACKGROUND AND CONTACT INFORMATION

1.1 FACILITY INFORMATION

Facility Name:	Louisiana Green Fuels, Port of Columbia Facility Three Class VI Injection Wells
Facility Contact:	Bob Meredith, COO 303 Wall St., Columbia, LA 71418 (318) 649-6401 bobmeredith@strategicbiofuels.com
Well Locations:	Port of Columbia, Caldwell Parish, Louisiana **Name: Latitude / Longitude** Well 1 (W-N1): 32.18812141510 / -92.10986101060 Well 2 (W-N2): 32.18686691570 / -92.05915551900 Well 3 (W-S2): 32.1639375970 / -92.08754320370

1.2 PROJECT GOALS

The issuance of permits for Class VI wells is integral to the construction and operation of a planned deeply carbon negative renewable fuel facility (or biorefinery) that will be powered with its own onsite generated green power, where the carbon dioxide (CO_2) generated from both the biorefinery and its adjacent biomass power plant is captured, compressed to a supercritical state, and safely sequestered deep underground. Forestry waste products from sustainable forests in the surrounding area will provide the feedstocks for both renewable fuel production and power generation.

The primary feedstocks used to create the facility's renewable fuel are Renewable Fuel Standard compliant pre-commercial thinnings from the region's sustainable, managed hundred-year-old pine forest plantation industry. Typically, at planting, 500 to 700 pine seedlings are planted per acre. These young trees compete for sunlight, nutrients, and water.

Over the 30 to 35 – year crop cycle, several planned thinnings are implemented by the forest plantation owner to reduce the number of trees and allow the remaining ones to grow to sufficient diameter and height more quickly for harvesting and the subsequent production of lumber and other forest products. Virtually all the carbon in the harvested trees was captured from CO_2 in the atmosphere via photosynthesis; thus, all the carbon reconstituted from the forestry waste (mostly the roundwood thinnings) used to create the renewable fuel, and all the CO_2 that is captured and geologically sequestered from the refining operation, originated in the atmosphere.

The feedstock for the renewable power is predominantly sawmill waste. This waste consists of the bark, chips, and sawdust that are the residuals from the harvesting and subsequent processing of the fully grown pine trees. The bark comprises the outer ten to fifteen percent of each pine tree; together with the accompanying wood chips and sawdust created by sawmill operations, this biomass "waste" can total up to 30% of the total mass of a mature pine tree. The sawmill waste is combusted in a boiler to generate steam which drives a steam turbine used to generate electricity. Approximately 95% of the carbon dioxide produced by this on-site power generation is captured using an amine-based chemical process. As with the biorefinery feedstock, all the carbon in the sawmill waste was captured by the trees directly from the atmosphere, and all the CO_2 captured and geologically sequestered from the power generation operations originated in the atmosphere.

The biorefinery is capable of producing about 32 million gallons per year of renewable fuel (87% Sustainable Aviation Fuel ("SAF") or, alternatively, synthetic diesel; and 13% naphtha) from forestry waste. The feedstock is converted via gasification and partial oxidation to synthesis gas ("syngas"; carbon monoxide and hydrogen). Approximately 90% of the carbon dioxide is removed from the gas stream using a chilled methanol process. The syngas is then converted to paraffinic oil and wax via the Fischer-Tropsch process, and those materials are subsequently hydrocracked to create the finished products. The biorefinery will be initially designed to produce SAF.

A detailed life cycle analysis of the renewable fuel to be produced by the biorefinery (by Life Cycle Associates, an independent third-party consultant) scored its carbon intensity (CI) at **-294** gCO2e/MJ, or a 394% reduction in carbon footprint relative to fossil diesel (scored at +100 CI). This appears to be the lowest CI of any renewable fuel plant in the U.S., and likely the world.

The project is located within Louisiana's Fifth US Congressional District, the seventh poorest congressional district in the country, with an average household income of just $36,000. The project site in Caldwell Parish has an even lower average household income of just $32,000 per year. The project is expected to create 151 full-time jobs at the facility site – sourced from the surrounding communities – with an average salary of about $70,000 per year plus benefits.

It is estimated that the ongoing operation of the facility will create another 750 indirect jobs in the surrounding communities, which will benefit from the increased demand for goods and services. The project has a planned 31-month construction schedule, during which an average of 635 workers will be employed with peak construction employment approaching 1,500 workers.

1.3 PARTNERS AND COLLABORATORS

The Louisiana Green Fuels facility project at the Port of Columbia is being developed and sponsored by Strategic Biofuels LLC, sometimes referred to herein as the Applicant. Partners and collaborators in the project are the hundreds of private investors who have funded the project thus far and the world-class technical team assembled by Applicant that is actively designing and will build the facility. Among the project accomplishments as of the date of this application are (1) completion of the Class V stratigraphic test well and evaluation of the data collected to confirm geologic suitability for the carbon dioxide Sequestration Complex, (2) site acquisition for the planned renewable fuels facility from the Port and significant additional adjacent privately-owned real estate, (3) completion of the first two of three phases of engineering design of the facility and commencement of the third and final phase, (4) allocation thus far of $450 million of tax-exempt bonds from the State of Louisiana with additional volumes pending, (5) initiation by the Port of Columbia of several infrastructure improvement projects at the Port site including the rebuilding of the primary access road and the construction of a high capacity railroad spur, (6) completion of an Independent Engineer's Report confirming the technological and economic soundness of the project, (7) approval of the Louisiana Dept. of Transportation & Development for U.S. Highway interchanges and a railroad overpass, (8) receipt from the Louisiana Dept. of Environmental Quality of a minor source Air Permit, (9) recognition by the leading life cycle consulting firm in the US that the project CI will be **-294**, which will make its fuel the most deeply carbon negative renewable fuel in the world, (10) completed studies by two leading firms in the US indicating the availability within the immediate proximity of the plant site of several multiples of the needed forestry waste feedstock, (11) a pending $1.6 billion DOE loan application that is in the second stage of review, (12) enactment of favorable legislation, specific to the Louisiana Green Fuels project, significantly enhancing the project's ability to acquire the needed pore space for sequestration in accordance with the drilling prohibition requirements of the California Air Resources Board (CARB) Low Carbon Fuel Standards (LCFS), (13) development of an adjacent biomass-fired green power plant fully dedicated to powering the biorefinery, and (14) a unanimous formal expression of project support by the local government, including for the carbon sequestration component of the project, and the broader voiced support of the community. These project milestones have been achieved with the input of the leading industrial engineering design and construction firms in the world, pre-eminent geotechnical experts in the region, the unqualified governmental support of the project at the local, state and federal level, international financial firms, and the financial commitment and confidence of hundreds of individual investors.

1.4 PROJECT TIMEFRAME

The Applicant expects to reach Final Investment Decision or FID in 2025, signaling the commencement of construction of the renewable fuels facility. Plant construction will require 30 to 36 months with the first renewable fuel (SAF / naphtha) production and the first CO_2 for compression, injection, and sequestration to commence in early 2027. Construction of the Sequestration Complex, including the drilling and completion of the three initial proposed Class VI wells, the construction and installation of CCS components of the facility, and the CO_2 pipeline transport to offsite injection wells, will be accomplished simultaneously with facility construction.

1.5 PROJECT CO_2 PRODUCTION DETAILS

Approximately 1.36 million metric tons of carbon dioxide will be captured and geologically sequestered from the combined fuel production refinery and its associated power generation plant on an annual basis. The Applicant drilled a Class V Stratigraphic Test Well (SN975841) about 1 mile southeast of the proposed biorefinery site in 2021 and conducted a series of freshwater injection / flowback tests in the proposed injection zones in the Stratigraphic Test Well, which was also extensively cored and logged with a full suite of petrophysical and geomechanical tools.

This substantial data acquisition and injection testing of multiple planned sequestration reservoirs increased the accuracy of the Dynamic and Static Models used to model CO_2 plume growth.

Following detailed analysis and modeling, Applicant has determined that the best approach to sequestering the CO_2 to be generated by the facility would be to implement the drilling of three Class VI injection wells and the conversion of the Stratigraphic Test Well and five additional dry holes to monitor wells, such that a total of six (7) monitor (five In-Zone and one Above-Confining Zone ("ACZMI")) wells will be completed within the Injection Zone. An additional shallow ACZMI monitor well will be completed at a depth just above the Secondary Upper Confining Zone, the Midway Shale, on site. Two sequestration reservoir intervals grouped within the Injection Zone have been identified. The primary targets for injection are the multiple sandstones of the Upper Tuscaloosa and Paluxy Formations. The Basal Sand of the Lower Tuscaloosa was tested in the Stratigraphic Test Well for its injection potential, however it is not considered an injection target for this project. The shallow USDW is well protected from the CO_2 injected into the sequestration reservoirs by the thick Primary Upper Confining Zone, the Austin Chalk "Equivalent" / Upper Eagleford interval, and the Secondary Upper Confining Zone, the thick Midway Shale. The Lower Cretaceous Ferry Lake Anhydrite represents a regionally extensive Lower Confining Zone.

The injection wells will sequester supercritical CO_2 within the multiple sandstones of the Upper Tuscaloosa and Paluxy Formations. Modeling indicates that the injected CO_2 plume will reach the converted Stratigraphic Test Well (located in the middle of the three injection wells) within five (5) years; a second monitor well within twenty (20) years; and a third monitor well during the post-injection closure migration period. The modeled plume does not reach the other two monitor wells (or any other legacy wells that penetrate the Injection Zone) within the Area of Review (AoR). The plan for managing the CO_2 sequestration process is to operate the three injection wells at injection pressures (and rates) **far below** their regulatory maximum allowable injection pressures. With that normal operating condition, when any one of the three wells is temporarily removed from service for maintenance, the other two wells together will have more than sufficient available injection pressure (and rate) capacity to accept the volume of CO_2 from the well that is offline, maintaining full and undiminished CCS operations from both the biorefinery and the power plant.

2.0 SITE CHARACTERIZATION

The geologic suitability of a specific stratigraphic interval for the injection and confinement of CO_2 is determined primarily by the following criteria:

- Lateral extent, thickness, interconnected porosity, permeability, and geomechanical properties of the injection zone;
- Lateral extent, thickness, minimal porosity, impermeability, and geomechanical properties of the overlying confining zone;
- Hydrogeologic compatibility of the injected supercritical carbon dioxide with the various rock formation material (sandstones, in this instance) and *in-situ* brines;
- Faulting or fracturing of the injection zone, overlying aquiclude, and confining zone, if any; and
- Seismicity risk.

These criteria can be adequately evaluated using the regional and local depositional and structural histories of the geologic section.

In the following sections, the depositional and structural framework of the sedimentary column (Figure 2-1) utilized for the sequestration of CO_2 for the project at the Louisiana Green Fuels, Port of Columbia Facility in Caldwell Parish is outlined. Information is obtained from the regional and local data interpretations and conclusions of the AoR study, and from the drilling and completion of the Class V Stratigraphic Test Well (SN975841) in 2021, one mile southeast of the proposed biorefinery site. A detailed Composite Type Log of the subsurface formations beneath the site using the log from the Class V Stratigraphic Test Well (SN975841) and two other wells within the AoR (SN57466; SN165305) is included as Figure 2-2. The key regulatory intervals are reported in depths below ground elevation. Geologic maps and cross sections illustrating the regional geology, hydrogeology, and the geologic structure of the local area have been prepared to meet the requirements under Louisiana Statewide Order No. 29-N-6 [LAC 43:XVII §3607 (C)]. All geological and geophysical maps and required cross sections that have been included by Applicant extend at least two (2) miles beyond the principal Upper Tuscaloosa / Paluxy AoR [§3607 (C)(1)].

2.1 REGIONAL GEOLOGY

In Figure 2-3, the series of cross sections showing evolutionary stages in the development of the northern region of the Gulf of Mexico and East Texas Basin between the Lower Triassic and Lower Cretaceous periods provide the background knowledge necessary to understand the regional geological setting. The earliest record of sedimentation in the Gulf of Mexico Basin occurred during the Early Mesozoic, between 200 and 160 million years ago. At this time, the early phases of continental rifting resulted in the deposition of non-marine red beds and deltaic sediments (shales, siltstones, sandstones, and conglomerates) that comprised the Eagle Mills Formation in a series of restricted, graben fault-block basins. These sediments were subsequently overlain by a thick sequence of evaporites, predominantly halite, forming the Werner Anhydrite and Louann Salt, deposited during the Early to Middle Jurassic time.

The deposition of the Louann Salt was localized within major basins that were defined by the major structural elements in the Gulf Coast Basin. The clastic Norphlet Formation (consisting of thin shales overlain by arkosic sandstones and conglomerates, as well as thick eolian sandstones) overlies the Louann Salt and can exceed 1,000 feet thick in Mississippi and Alabama but thins westward to a sandstone and siltstone across southern Arkansas and northern Louisiana and into Texas. Norphlet conglomerates (arkosic granite wash) were deposited in coalescing alluvial fans adjacent to Appalachian sources and grade downdip into seif dune ergs and interdunal siltstone deposited across a broad desert plain (Mancini et al., 1985). Although the Norphlet Formation is essentially devoid of fossils, based on the dating of the overlying and underlying sequences, the Norphlet Formation is probably late Middle Jurassic (Callovian) in age (Todd and Mitchum, 1977).

The marine transgression that marked the encroachment of the Lower Smackover Sea led to the subsequent deposition of the shallow-water carbonates, evaporites, and clastic rocks of the Smackover, Haynesville-Buckner, and Cotton Valley Formations, a series of progressively younger Jurassic rocks that were deposited atop the Norphlet Formation. Thick oolitic shoals and calcareous muds accumulated on a ramp-type shelf with thrombolitic buildups developed atop subtle topographic highs (Baria et al., 1982). A massive influx of terrigenous clastics in eastern Louisiana and Mississippi occurred during the deposition of the Haynesville Formation, diminishing westward into East Texas where the clastic facies (predominantly shale) grades laterally into the Gilmer Limestone. The top of the Cotton Valley Group, and the end of the Jurassic, is demarcated at the (Lower) Cretaceous / Jurassic unconformity, atop which thick basal conglomerates of the Lower Cretaceous Hosston / Travis Peak Formation were deposited. The lengthy lower to middle Cretaceous period was a time of regional stability for the Gulf Coast area, permitting the development of extensive, shelf-edge reef complexes (Baria et al., 1982).

During the Late Cretaceous (especially during the Laramide Orogeny, between 70 to 80 million years ago), tectonism in the western and south-central United States as well as northern Mexico resulted in the influx of terrigenous sands and muds into the Gulf of Mexico Basin that contributed to the deposition of the Tuscaloosa Formation. A dramatic rise in sea level during Campanian through Maastrichtian time gave rise to the deposition of thick pelagic chalks including the Austin Chalk and younger Selma Chalk. Following the end of the Cretaceous, the rate of terrigenous sediment influx was greater than the rate of basin subsidence in the Gulf of Mexico, resulting in the significant progradation of the continental shelf margin (Figure 2-4).

The uppermost stage of the Late Cretaceous Epoch, the Maastrichtian Age, marked a time when large regional uplifts like the Sabine Uplift and Monroe / Sharkey Platform began actively moving upward in the onshore (northern) Gulf Coast area, resulting in the formation of extensive regional angular unconformities (Ewing, 2009). The movement of the Sabine Uplift and Monroe / Sharkey Platform profoundly impacted the sediments of the East Texas Salt Basin - North Louisiana Salt Basin and the Interior Salt Basin of Mississippi, respectively (Figure 2-5). The Mesozoic igneous activity of the onshore Northern Gulf of Mexico Basin, which peaked during Campanian time, has been studied and discussed in several studies and local reports. The largest volume of intrusive and extrusive rocks and the greatest compositional diversity in the Northern Gulf of Mexico Basin has been attributed to the genesis and movement of the Monroe / Sharkey Platform; at least four major igneous rock groups were defined so far atop that broad uplift, including: i) intermediate rocks; ii) alkaline rocks; iii) basalts; and iv) lamprophyres (Ewing, 2009; Kidwell,1951). There appears to be a direct correlation between the substantive regional upwarping and the onset of igneous activity in the greater Monroe / Sharkey Platform area (Salvador, 1991; Kidwell, 1951).

During the Cenozoic era, the geometry of the deposition in the Gulf of Mexico Basin was primarily controlled by the interaction of the following factors:

1. Changes in the location and rates of sediment input, resulting in major shifts in the location of areas of maximum sedimentation.

2. Changes in the relative position of sea level, resulting in the development of a series of large-scale depositional cycles throughout Cenozoic time.

3. Diapiric intrusion of salt and shale in response to sediment loading and buoyancy.

4. Flexures and growth faults due to sediment loading and gravitational instability.

Early Tertiary sediments are thickest in the Rio Grande Embayment of Texas, reflecting the role of the ancestral Rio Grande and Nueces Rivers as sediment sources to the Gulf of Mexico (Figure 2-6). By Oligocene time, the thickest sediment deposition had shifted to the northeast, suggesting that the ancestral Colorado, Brazos, Sabine, and Mississippi Rivers were increasing in importance. The onset of Miocene time is marked by an abrupt decrease in the amount of sediment supply entering the Rio Grande Embayment, with a coincident increase in the rate of sediment supply in southeast Texas, Louisiana, and Mississippi. Throughout the Pliocene and Pleistocene epochs, large depocenters of sedimentation were deposited by the Mississippi River and developed offshore of Louisiana and Texas.

Tertiary sediments accumulated to great thickness where the continental platform began to build toward the Gulf of Mexico, beyond the underlying Mesozoic shelf margin. Rapid loading of sand on water-saturated prodeltaic and continental slope muds resulted in contemporaneous listric growth faulting (Loucks et al., 1986). The effect of this syndepositional faulting was a significant expansion of the sedimentary section on the downthrown side of the faults. Sediment loading also led to salt diapirism and the movement of allochthonous salt, with its associated faulting and formation of large salt withdrawal basins (Galloway et al., 1982a).

The sediments of the Tertiary progradational wedges were deposited in continental, marginal marine, nearshore marine, shelf, and basinal environments and present a complex depositional system along the Texas Gulf Coast. Overlying the Tertiary progradational wedges along the Texas Gulf Coast are the Pleistocene and Holocene sediments of the Quaternary Period. Pleistocene sedimentation occurred during a period of complex glacial activity and corresponding sea level changes. As the glaciers made their final retreat, Holocene sediments were being deposited under the influence of an irregular, but rising, sea level. Quaternary sedimentation along the Texas Gulf Coast occurred in fluvial, marginal marine, and marine environments.

2.1.1 Regional Maps and Cross Sections

Following this brief summary of the principal tectonic and depositional events attributable to the formation of the Gulf of Mexico and the filling of its associated basins, the regional geology of the proposed sequestration site can be described in further detail.

The understanding of the regional geology for the proposed sequestration site is based upon the detailed geological and geophysical mapping of the area, published reports, maps and cross sections, and published regional studies. The data evaluated covers the Gulf Coast Region and the State of Louisiana, with the focal area being the northeast sector of the State. The published regional maps are contained as “Figures” referenced within their respective description sections. A published north-south oriented regional cross section H-H’ (Figure 2-7), from Eversull (1984), illustrates the influence of the Monroe / Sharkey Platform uplift on its updip (left) side and the increasingly thicker Mesozoic formations that expand in thickness as southern regional dip increases towards the Gulf of Mexico.

2.1.2 Regional Stratigraphy

The general stratigraphy of the region is depicted on the Stratigraphic Column shown in Figure 2-1. The regional stratigraphy is well documented and extensive throughout northern Louisiana. The following sections only describe the regional formations that may be penetrated or consist of the regulatory intervals at the Port of Columbia site. These formations are described in ascending order, beginning with the Lower Cretaceous-aged Trinity Group.

For the proposed sequestration site in Caldwell Parish, the proposed injection intervals are the sandstones of the Upper Tuscaloosa and Paluxy Formations. The regional upper confining unit is defined as the Austin Chalk Equivalent / Upper Eagleford interval and the lower confining unit is defined as the Ferry Lake Anhydrite of the Trinity Group. Both confining units are thick and well developed across the AoR. Details on the proposed confining and injection zones are further discussed in Section 2.3.

2.1.2.1 Trinity Group

The Trinity Group is a lower Cretaceous-aged geologic group that extends from Mississippi to New Mexico, and northwards into Oklahoma and Arkansas. It consists of facies varying from fluvial sands to marginal marine limestones and shales to lagoonal evaporites that extend over the interior portions of the northern Gulf Coast region.

The Ferry Lake Anhydrite is a geological unit that is comprised of alternating carbonate and evaporite beds (predominantly anhydrite). It extends from east Texas through northern Louisiana, throughout southern Mississippi and southwestern Alabama, and into northwestern Florida. In north Louisiana, the Ferry Lake Anhydrite is essentially truncated along an angular unconformity on the southern flank of the Monroe Uplift, well north of the northern perimeter of the AoR; within and across the AoR, the Ferry Lake Anhydrite is thick and well-developed. The evaporites were deposited in an arid back-reef lagoonal environment, which preserved sufficient levels of calcium sulphate for the deposition of extensive beds of gypsum (Forgotson, 1963). Over time, compaction, pressures, and temperatures increased in the strata and the gypsum underwent dehydration to form anhydrite. The evaporites of the Ferry Lake Anhydrite are interlaminated with thin interbeds of alternating limestone and mudstone, indicating cyclical variations in climate. The anhydrite facies has been described in published literature as dense, off-white, soft, and finely crystalline.

Overlying the anhydrite is the Mooringsport Formation, also known as the Rusk Member. The terrigenous facies of the Mooringsport are comprised of dark grey shales, lenticular (channel) sandstones, and some varicolored mudstones with red and white limestone nodules. As one moves in a coastward (southwesterly) direction, the Mooringsport transitions to more marine facies, with increasing volumes of calcareous shale (Devery, 1982). This transition from terrigenous siliciclastics to a more marine environment is best observed in east Louisiana and southwest Mississippi. The lack of depositional variation in the Mooringsport strata of northeast Texas and northwest Louisiana suggests a calm, offshore neritic environment (Forgotson, 1963).

2.1.2.2 Washita Fredericksburg Group

In the western U.S. Gulf Coast region, the Washita / Fredericksburg Group generally consist of back-reef carbonates; however, further east the formations include a full range of laminated limestones, shales, mudstones, and sands (Nunnally and Fowler, 1954). Shallow water platform deposition occurred during Washita / Fredericksburg time over most of the northern Gulf Coast area. Within the AoR, the Washita / Fredericksburg facies consist predominantly of buff-to-white colored dense limestones interlaminated with dark gray calcareous shales. In northeastern Louisiana, including the AoR, the Washita / Fredericksburg Group is increasingly truncated by the Upper Cretaceous angular unconformity as one approaches the the crest of the Monroe Uplift, located just north of the AoR (Granata, 1963).

The Paluxy Formation underlies the Washita / Fredericksburg Group and extends from northeast Texas, across Louisiana, to southern Mississippi. The Paluxy is a progradational unit associated with fluvial and marginal marine depositional environments (Caughey, 1977, Mancini and Puckett, 2000). The top of the Paluxy Formation is arbitrarily placed at the base of the lowest limestone of the Washita / Fredericksburg Group (Nunnally and Fowler, 1954). The Paluxy trends northwest and southeast through Caddo Parish and northern DeSoto Parish in Northern Louisiana. The end of Comanchean (Lower Cretaceous) time was characterized by uplift and erosion across east Texas, southern Arkansas, north Louisiana, and across into west-central portions of Mississippi (Granata, 1963). This period of erosion is manifested by the substantial UK / LK Unconformity, where the basal (Lower) Tuscaloosa Formation of the Upper Cretaceous truncates, in an updip succession, first the Washita / Fredericksburg Group, followed by the underlying Paluxy.

Within the AoR, the Paluxy Formation can be further characterized as a thick interval of alternating calcareous quartzitic sandstones, thin limestones, and silty/sandy calcareous mudstones deposited in a depositional environment that transitions cyclically from fluvial deltaic to marginal marine sediments as the shoreline advanced and retreated episodically across the area over time. A number of thick distributary channels and estuaries have been encountered by wells drilled through the Paluxy interval; these lenticular channels and estuaries are typically dip-oriented (trend from north to south) and can be as much as 80 feet thick and 4,000 to 5,000 feet in width. Most such channels and estuaries, representing cycles of more temperate climate (with higher rainfall) during Paluxy time, are isolated both laterally and vertically by thick impermeable shales such that the typical Paluxy penetration within the AoR encounters anywhere from three to ten such channel or estuary deposits separated commonly by as much as 100 feet of shale. The lenticularity of the channel and estuary deposits further isolates each such reservoir laterally; wells drilled east or west of each other will rarely encounter the same channel or estuary if spaced more than a mile apart.

The mudstones of the Paluxy Formation are typically characterized as being very hard, moderately calcareous, impermeable, and multi-colored (predominantly gray, brown and red). The shales and mudstones often contain appreciable amounts of silt and bioclastic debris. The red (iron-rich) shale facies are interpreted to reflect cycles of increased arid climate and decreased current energy.

The lateral distribution of the Paluxy sandstones that are candidates for injection is best visualized by a review of the stratigraphic and structural cross sections contained in Figures A.13, A.14, and A.15. Cross Section A – A' (Figures A.13 and A.14) trends northwest to southeast across the northern third of the AoR. Cross Sections B – B' and C-C' (Figure A.15) trend south to north and west to east, respectively, across the central part of the AoR. The cross sections reveal that a number of Paluxy sandstones have been encountered in the deeper wells drilled within the AoR. Most are separated vertically from each other by 50 to over 100 feet of impermeable shale. Strategic Biofuels has created isoliths for five of the more prominent Paluxy sandstones, which include the "P-2" and "P-3" Sands encountered in Strategic Biofuels' Class V Stratigraphic Test Well and three deeper sandstones applicant has designated the "P-4", "P-5", and "P-6" Sands. All of these sandstone isoliths exhibit dip-oriented channel-sand geometries, ranging from 3,000 feet to 5,000 feet in interpreted width; and are illustrated in composite form on Figures A.22 and A.23. Although these five Paluxy sandstones have been mapped as described, the isoliths from only two mapped Paluxy sandstones (encountered in the Class V Stratigraphic Test Well, AP 137) were included in the Static Model calculations for the Paluxy interval. These were: Paluxy "P-2" Sand

(Permeability Layer 18, Figure A.22), and Paluxy "P-3" Sand (Permeability Layer 19, Figure A.23).

Because of the lenticular nature of the Paluxy channel sands and the currently limited number of Paluxy penetrations within the AoR, there is some uncertainty as to which Paluxy channel sands will be encountered in each subsequently drilled injection well, or deepened In-Zone monitor well. At the end of the proposed construction, three new injection wells and three deepened monitor wells will more than double the number of Paluxy penetrations within the AoR and provide much more clarity as to the aerial extent and geometry of each Paluxy channel sand. For this reason, Strategic Biofuels will remap the Paluxy and provide new or updated structure / isolith maps for each Paluxy sandstone targeted for injection, which will be provided with the application to inject.

2.1.2.3 Tuscaloosa Group

The period of Tuscaloosa deposition is characterized by a full transgressive / regressive depositional cycle that was initiated at the beginning of the Late Cretaceous (Pair, 2017) and ended with the marine transgression of the Campanian Austin Chalk Equivalent. The Tuscaloosa interval is informally subdivided into three formations: the Upper Tuscaloosa, the Middle Tuscaloosa, and the Lower Tuscaloosa. In southern Mississippi and the north central – eastern Louisiana area, the Lower Tuscaloosa Formation unconformably overlies the Washita-Fredericksburg group at the UK / LK boundary. Regional differences in stratigraphic nomenclature have led to different names (Eutaw, Eagleford) having been assigned to portions of the Upper Tuscaloosa in different areas of the Gulf Coast; in addition, much of the sand-rich facies of the Upper Tuscaloosa grades laterally into what are called the upper shales of the Middle Tuscaloosa, and in the updip areas of Alabama, Mississippi and Louisiana, the three units coalesce into an undifferentiated sand/shale sequence that is simply referred to as the Tuscaloosa Formation.

In the northeast Louisiana area, this coalescence into one undifferentiated Tuscaloosa sand/shale sequence occurs approximately ten miles north of the AoR.

2.1.2.3.1 Lower Tuscaloosa

In south/central Mississippi and east/central Louisiana, the Lower Tuscaloosa Formation transitions from an updip terrigenous facies to a laterally equivalent, downdip marine facies (Berg and Cook, 1968; Chasteen, 1983; Hearne and Lock, 1985; Stancliffe and Adams, 1986; Shirley, 1987). The Lower Tuscaloosa may then be further subdivided into two sections, from oldest to youngest: the basal transgressive Massive Sand member, considered to represent a series of thick braided stream sediments deposited atop the UK / LK Unconformity; and the overlying Stringer Sand interval, which includes several meander belt point-bar complexes that transitioning downdip into deltaic / intertidal sediments. The Stringer Sand interval in the subject area is noteworthy for its interfingering of such fluvial/deltaic and intertidal deposits in a near-shore environment.

The basal Lower Tuscaloosa "Massive" Sand, which was not deposited in northeastern Louisiana, is comprised of a series of stacked massive quartzitic sandstones. Chert gravels / conglomerates are commonly present at the base of the unit, associated with the onset of erosion and deposition at the end of the Lower Cretaceous (Chasteen, 1983). The stacking of channel sandstones with basal conglomerates is typical of a braided-stream environment. Regional isopach maps of the braided-stream unit indicate a sheet-like geometry with thick sand areas corresponding to persistent drainage patterns where major streams existed (Chasteen, 1983). The Massive Sand was deposited in portions of south Alabama, south Mississippi, and southeast Louisiana, but as noted previously, the unit was not deposited in northeast Louisiana; in that area, the lowest units of the younger Stringer Sand interval are encountered atop the UK/LK unconformity.

The overlying Stringer Sand interval is comprised of three fluvial-deltaic / intertidal marine depositional sequences. These Stringer Sand sequences are identified by industry as the Lower Tuscaloosa "A", "B", and "C" Sands of south Mississippi, where they were first exploited.

Later, as the Lower Tuscaloosa producing trend expanded into adjacent states, variations in the local nomenclature were adopted in those states. In Alabama, the stratigraphic equivalent of the Lower Tuscaloosa "A" Sand was called the Lower Tuscaloosa Pilot Sand; similarly, in east Louisiana, the stratigraphic equivalent of the Lower Tuscaloosa "A" Sand was called the Lower Tuscaloosa Stringer Sand, while the stratigraphic equivalents of the Lower Tuscaloosa "B" and

"C" Sands were called the Lower Tuscaloosa "Upper Basal Sand and "Lower Basal Sand", respectively.

Updip, the sandstones of the Stringer Sand interval consist of numerous fluvial meander-belt systems that exhibit sinuous patterns on sand isolith maps (Devery, 1980). These fluvial sandstones typically contain appreciable amounts of chlorite and kaolinite clay, contributed by the widespread vulcanism occurring along the Monroe / Sharkey Platform at that time. As one progresses further to the south / southwest, the fluvial depositional environment transitions to a tide-dominated littoral setting, and in this marginal marine environment many of the intertidal sandstones exhibit intense bioturbation. The chlorite and kaolinite clays are winnowed out by intertidal reworking and are typically replaced by varying amounts of glauconite. In addition, cores and sample logs commonly record the presence of oysters as solitary and bedded forms in calcareous shales, which would support a shallow-water marine (intertidal / littoral) origin for the unit (Chasteen, 1983).

2.1.2.3.2 Middle Tuscaloosa Shale

A marine transgression caused by a global rise in sea level during the early Late Cretaceous inundated the near-shore facies of the Lower Tuscaloosa Stringer Sand interval, leading to the deposition of the Middle Tuscaloosa Shale (Vail et al., 1977; Stancliffe and Adams, 1986). The Middle Tuscaloosa Shale is composed almost entirely of a grey to black, fissile, and sometimes sandy shale that thickens and transitions downdip to a calcareous, brittle, organic-rich marine shale (John et al., 1997). This downdip marine unit is commonly called the Tuscaloosa Marine Shale, and it represents the inundated stage of the depositional cycle, otherwise known as the end transgressive systems tract (John et al., 1997). The upper portion of the Middle Tuscaloosa Shale is considered the time equivalent of the basal portion of the Upper Tuscaloosa, which grades laterally into shale as one moves downdip.

The marine shales of the Tuscaloosa Marine Shale (TMS) unit contain a diverse assemblage of macrofossils, including ammonites, gastropods, inoceramids, other bivalves, and a rich assemblage of planktonic foraminifera and calcareous nannofossils typical of Cretaceous open-shelf environments (Mancini et al., 1987). A microfauna analysis of TMS samples from Liberty Field in Amite County, Mississippi indicates a vertical change from fauna dominated by the agglutinated species *Ammobaculites* and *Trochammina* to those characterized by the calcareous species *Heterohelix* and *Lenticulina* (Stancliffe and Adams, 1986). This faunal succession suggests a transition over time from restricted marine to open marine neritic conditions for Middle and time-equivalent Upper Tuscaloosa shales (Stancliffe and Adams, 1986).

The deposition of terrigenous shale within the Middle Tuscaloosa was confined to updip areas of the northern Gulf of Mexico Basin, including the AoR (Chasteen, 1983). The TMS facies was not deposited and is thus not present within the AoR.

2.1.2.3.3 Upper Tuscaloosa

The Upper Tuscaloosa Formation consists of interlaminated sandstones and shales deposited in an alternating fluvial-deltaic / intertidal (near-shore) environment. Sandstones deposited in the intertidal (near-shore) environment are typically glauconitic, fossiliferous, and intensely bioturbated. Conversely, the Upper Tuscaloosa fluvial-deltaic sandstones are devoid of glauconite and fossils, are not bioturbated, and typically exhibit more lenticularity. With an average thickness of approximately 400 feet, the Upper Tuscaloosa is a southward thinning wedge of fluvial-deltaic clastics which complements the northward thinning wedge of Middle Tuscaloosa Shale (Spooner, 1964) in lateral facies change previously described in this report. The Upper and Lower Tuscaloosa coalesce into one undifferentiated clastic unit in central Mississippi prior to its outcrop along the east flank of the Mississippi Embayment in extreme east Mississippi and west Alabama; similarly, the Upper and Lower Tuscaloosa coalesce into one undifferentiated clastic unit in northern Louisiana, but that unit is subcropped by the Midway Shale at the Cretaceous-Paleogene (KPg) boundary (which is a major unconformity) along the crest of the Monroe / Sharkey Platform, about 10-15 miles north of the AoR.

2.1.2.4 Eagle Ford Group

The Eagle Ford Group of Texas, also known as the "Eagleford", is generally considered to be the time-stratigraphic equivalent of the Middle and Upper Tuscaloosa of east and north Louisiana. In Mississippi, the Eagleford is considered to be the time-stratigraphic equivalent of the Eutaw Formation, which grades into micaceous, calcareous, glauconitic, fine-grained sandstone near its updip marine margin (Mancini et al., 1987). The interchangeable use of the term Eutaw Formation in Mississippi and Upper Tuscaloosa Formation in north and east Louisiana is a confusing practice that generally describes the same stratigraphic interval. Where present, the Eagleford Formation is interpreted to be a truncated wedge of deep-water shale deposited out in front of the Middle / Upper Tuscaloosa shelf margin. In these locations, the top of the Eagleford Group is an unconformity overlain by the Austin Chalk, which was deposited in deeper water. Within the AoR, the Upper Eagleford Formation is interpreted to comprise the thin (10 – 35 foot-thick) marine shale that is encountered beneath the base of the Austin Chalk Equivalent Formation, as defined below) and above the top of the Upper Tuscaloosa Formation.

2.1.2.5 Austin Group

The Upper Cretaceous-aged Austin Group is a thick layer of carbonate strata, predominantly pelagic chalks, deposited across most of the northern perimeter of the Gulf of Mexico, extending from east Texas to Mississippi to the panhandle of Florida and further offshore. In Texas, the group is comprised of the Brownstone and Tokio Formations, which were deposited in a shallow marine environment. In certain areas of regional uplift (Sabine Uplift; Monroe / Sharkey Platform), the Austin Group as well as most of (if not all) of the entire Upper Cretaceous have been removed by subsequent erosion (Adams and Carr, 2010), followed by the deposition of the thick Paleocene Midway Shale.

Depositional environments across Louisiana transition from fluvial-deltaic to shallow marine, with the latter exhibiting shoreface to barrier or beach complexes and marshes or tidal flats and channels. Bioturbation, storm deposits, soft-sediment deformation, rip-up clasts, volcanic clasts, and glauconite are all present (Clark, 1995). Vulcanism, common in the central Texas, northern Louisiana, and west-central Mississippi areas, contributed large volumes of volcaniclastics to the Austin Chalk Equivalent strata, especially in the form of thick water-lain, clay-rich volcaniclastic sediments.

The Austin Chalk Equivalent interval ranges in thickness from 150 feet (updip) to 800 feet (downdip) and has been generally subdivided into three main units: a lower chalk, a middle marl, and an upper chalk. In south Louisiana, the upper and lower chalks contain less clay and are more micritic, and therefore more brittle, leading to higher fracture densities (Hovorka and Nance, 1994). However, in northeast Louisiana (including the AoR), proximity to the vulcanism associated with the Campanian uplift of the Monroe / Sharkey Platform has contributed so much volcaniclastics that very few "clean" carbonate layers exist in the Austin Chalk interval, which is otherwise predominantly argillaceous, very ductile, and not prone to any substantive fracturing whatsoever. Because of its marked difference in lithology from its South Louisiana counterparts, within the AoR the interval is referred to as the Austin Chalk "Equivalent" facies.

The lower chalk interval is characterized as having thin limestones that transition into thinly laminated organic-rich mudstones. The mudstones contain pyrite and high organic content suggesting deposition in a dysaerobic basin during a transgressive cycle. The limestone units were most likely deposited during highstand periods of the Austin Chalk Equivalent depositional cycle. The middle marl contains alternating layers of volcaniclastic clay and bioturbated chalk. The older strata thus appear to have been deposited during a regressive phase while the younger units were deposited a transgressive phase (Hovarka and Nance, 1994). Relative to the lower Austin Chalk Equivalent interval, the middle marl facies typically exhibit higher clay concentrations. The Austin Chalk Equivalent interval contains cyclic layers of thin limestones and mudstones within the AOR and surrounding area. Where present, the limestones were deposited during a highstand and trace fossil assemblages from the interval indicate normal marine waters (Hovarka and Nance, 1994).

This laminated lithology of thin limestones and mudstones in the Austin Chalk Equivalent interval is resistant to vertical fracture propagation because of the principal of mechanical stratigraphy, which refers to rocks with similar mechanical behaviors properties that, in a laminated (bedded) environment, respond similarly – to stress (Fu, 2022). However, the response to stress is completely different for ductile rock layers vs. brittle rock layers. Ductile mudstone layers resist fracturing and absorb fracture energy. Brittle layers are prone to fracturing, but alternating layers of ductile and brittle strata serve to absorb and disperse stress laterally while impeding vertical fracture propagation (Su, 2023). Because the Austin Chalk Equivalent consists predominantly of ductile mudstones interspersed with six thin brittle limestones, conditions are ideal for suppressing vertical fracture propagation.

In the Whitetail #1 LGF Class V Stratigraphic Test Well, Core #2 was cut in the Austin Chalk Equivalent and recovered 9 feet of core that consisted predominantly of silty calcareous mudstone (the ductile facies). Soft sediment deformation, observed in the core, is another indicator of ductility. This cored interval is correlative to a high gamma ray (shaley) interval on the log.

To further characterize the Austin Chalk Equivalent facies within the AoR, Strategic Biofuels intends to cut whole cores across selected, variable intervals of the Austin Chalk Equivalent facies in each of its proposed Class VI injection wells. In one of the wells, a 60-foot core will be attempted to be cut across a portion of the upper Austin Chalk Equivalent interval. In a second injection well, a 60-foot core will be attempted to be cut across a portion of the middle Austin Chalk Equivalent interval. In the third injection well, two consecutive 60-foot cores will be attempted to be cut, as follows: beginning approximately ninety feet above the base of the (lower) Austin Chalk Equivalent interval, one 60-foot core will be attempted to be cut; then the core bit and barrel will be immediately run back in the hole to attempt to cut a second 60-foot interval, intended to core (i) the remaining 30 feet of the basal Austin Chalk Equivalent interval; (ii) the thin (approximately 10 – 35 foot-thick) Upper Eagleford Shale encountered beneath the basal Austin Chalk Equivalent interval and atop the Upper Tuscaloosa Formation; and (iii) approximately 15 to 20 feet of the underlying, uppermost sediments of the Upper Tuscaloosa Formation. This second cored interval should greatly aid in the characterization of the Primary Confining Zone / Primary Injection Zone interface, at the top of the Upper Tuscaloosa Formation.

2.1.2.6 Taylor Group

The Late Cretaceous global rise in sea level reached its maximum extent in Maastrichtian time, near the end of the Late Cretaceous. Much of the Gulf Coast (including most of Louisiana and Mississippi) was inundated and remained well below sea level through the end of Cretaceous time.

The Taylor Group is separated from the Austin Chalk Equivalent by a regional disconformity at the base of the unit. The Lower Taylor Group is comprised of calcareous claystone, and argillaceous limestone, indicating deposition in a deepwater marine environment. Outcrops in Arkansas record glauconite, shells, and phosphorite which are characteristic of a condensed zone. Though the sea levels were relatively high, there were episodic, short-lived fluctuations in sea level.

During such episodic, short-lived episodes where sea level fell, a renewed influx of sandy terrigenous sediment in a shallow shelf and shoreface environment led to the deposition of glauconite-rich marine sands such as the Annona Sand of the AoR (Galloway, 2008).

In the Ark-La-Tex area, including northern Louisiana, sedimentation took place on the submerged Lower Cretaceous shelf during the Campanian. This time period included the deposition of several chalk – rich layers (Ozan, Annona, and Marlbrook Formations) that comprise the Taylor Group and are extensive throughout central and northern Louisiana. The Taylor Group transitions upward into the Navarro Group with a gradation of chalks to marls, which corresponds with the episodic changes of sea level during time of deposition. However, most of the Gulf Coast remained inundated and below sea level through the end of Cretaceous time.

2.1.2.7 Navarro Groups

The Uppermost Cretaceous-aged Navarro Group overlies the Taylor Group and is bound at the base by a maximum flooding surface, recording the end of a marine transgression, and bound at the top by the highly significant KPg unconformity. During times of falling sea level, the Navarro Group records a forward stepping progradational and shoaling event dominated by siliciclastic material provided from the Olmos Delta and Nacatoch clastic system (Figure 2-8) in northeast Texas, southwest Arkansas, and northwest Louisiana. Lag deposits on the bounding erosional surface consist of shell debris, fish, shark teeth, and mud clasts indicate deposition in a nearshore to inner shelf paleoenvironment (Galloway, 2008). The Nacatoch delta and shore-zone system provided a clastic pulse to northeast Texas, southwest Arkansas, and northwest Louisiana areas, while the larger Olmos delta prograded across the Rio Grande embayment from northern Mexico (Galloway, 2008). However, these clastic pulses did not reach the northeast Louisiana area.

The Navarro Group extends through East Texas, Louisiana, and south Arkansas and contains interbedded layers of sandstone, calcareous mudstone, chalks, and marls. In northeast Texas, from oldest to youngest, the Navarro Group is comprised of the Neylandville Marl, the Nacatah Sand, and the Kemp Clay Formation. The Neylandville Formation is a gray marl containing calcareous sands that has a varying thickness of 50 to 400 feet. The Nacatoch Formation consists of massive calcareous sandstones and mudstones, sourced from the East Texas Embayment, and can range in thickness from 100 to 200 feet in East Texas, and 400 feet in south Arkansas (Esker, 1968; Adkins, 1933). The Kemp Clay Formation (the equivalent of the Arkadelphia Marl in Louisiana) is characterized as greenish-gray silty calcareous mudstone that contains glauconite (Martin, 2014).

In Arkansas and Louisiana, the Navarro Group is subdivided, in ascending order, into the Saratoga Chalk (in south Arkansas), the Nacatoch Sand, and the Arkadelphia Marl, which is the lateral equivalent of the Selma Chalk of northeast-central Louisiana, Mississippi and Alabama. The Selma Chalk Formation is laterally extensive throughout northeast and central Louisiana and was deposited in an epicontinental sea of varying water depths; lithologically, it consists of chalks, marls, thin calcareous shales, and thin sandstone lenses. The Late Cretaceous Sea inundated most of the Gulf Coast area during Maastrichtian time, with sedimentation and subsidence in near equilibrium.

2.1.2.8 Midway Group

The Paleocene-aged Midway Group sediments were deposited atop the KPg boundary, a significant unconformity, during the first major Tertiary regressive cycle. The Midway Shale is regional in extent, thickening from the perimeter of the Gulf of Mexico towards its central area. The Midway Group predominantly consists of a thick terrigenous clay member (the Porters Creek Clay) deposited atop a thin calcareous marl (the Clayton Formation) atop the KPg unconformity. The faunal succession across the Paleogene / Upper Cretaceous boundary shows a sharp break in both macro-fauna and micro-fauna types, making it possible to accurately determine the base of the Paleogene (the KPg unconformity) in the Gulf Coast Basin (Rainwater, 1964a). At the beginning of the Paleogene, a shallow epicontinental sea transgressed across most of the Mississippi Embayment, resulting in the Clayton Formation (“Marl”) being deposited in an open marine environment. The Clayton Marl is generally less than 50 feet thick and is comprised of thin marls, argillaceous chalk, and calcareous clays (Rainwater, 1964a).

As the Paleogene epicontinental sea receded within the Mississippi Embayment, the thick terrigenous Porters Creek Clay was deposited atop the Clayton Marl. The Porters Creek Formation is composed mainly of massively bedded montmorillonitic clay. Open marine circulation was later re-established in the Mississippi Embayment during the deposition of the shallow marine

Matthews Landing Formation. The Matthews Landing Formation (or its equivalent) was deposited above the Porters Creek clay in a shallow marine environment, and is composed primarily of fossiliferous, glauconitic shales with minor sandstone beds (Rainwater, 1964a).

A major regression marks the deposition of the late Paleocene Naheola Formation that overlies the Matthews Landing Formation. Uplift in the sediment source areas of the Rocky Mountains, Plains, and Appalachian regions supplied an abundance of coarse-grained fluvial sediments for the first time in the Tertiary. Sedimentation rates along the Gulf Coast exceeded subsidence rates and produced the first major regressive cycle in the Tertiary. Fluvial environments dominated throughout most of Naheola time. The Naheola Formation consists of alternating sand, silt, and shale, with lignite interbeds near the top of the unit (Rainwater, 1964a).

The upper contact of the Naheola Formation with the overlying Wilcox Group is typically gradational. Wood and Guervara (1981) defined the top of the Midway as the base of the last Wilcox sand greater than 10 feet thick. In outcrop, much further updip of the AoR, the Midway Group is subdivided into the Wills Point and Kincaid Formations (Wood and Guevara, 1981).

The Midway Group comprises a very low-permeability hydrologic unit in the Area of Review that is approximately 600 feet thick. Within the AoR, wells that have penetrated the entire interval have encountered all three formations that comprise the Midway Group (Clayton, Porters Creek Clay, and Naheola) but the Naheoloa Formation is thin in this area of northeast Louisiana. The fact that the Naheola Formation is thin in the AoR does not materially impact the effectiveness of the overall Midway Group interval as a containment interval, since the Naheola Formation is deposited atop the thick (~500 foot-thick) Porters Creek Clay, the most effective barrier to vertical migration. The thick Midway Group interval serves as a very effective aquiclude, isolating the shallower Eocene aquifers from the deeper saline flow systems except, in certain instances, at fault zones and along the flanks of some salt diapirs where vertical conduits for brine flow may exist (Fogg and Kreitler, 1983); neither of which appear to exist within the AoR.

In a regional published map from Hosman, 1996 (Figure 2-9) the Midway Group continues to thicken to greater than 2,000 feet towards the approximate center of the Gulf of Mexico at depths exceeding 14,000 feet. Outcrops of the Midway Group in the Gulf Coast area occur in north-central Alabama, southwestern Tennessee, and southeastern Arkansas.

2.1.2.9 Wilcox Group

The Wilcox Group, an upper Paleocene / Lower Eocene – aged sand/shale sequence, represents a thick clastic succession that flanks the margin of the Gulf Coast Basin. This stratigraphic unit contains stacked fluvial-deltaic channel-fill sand bodies distributed complexly in a matrix of lower permeability inter-channel sands, silts, clays, and lignites. Most of the sands are distributed in a dendritic pattern, indicating a predominately fluvial depositional environment (Fogg et al., 1983). The clays of the underlying Midway Group grade upward into the fluvial and deltaic sediments of the Wilcox, which are typically comprised of interbedded lenticular sandstone bodies, interbedded shales, and lignites (Fogg and Kreitler, 1982).

The Wilcox Group is informally divided into the Lower, Middle, and Upper intervals. The semi-regional Yoakum Shale divides the Upper and Middle Wilcox in Texas, while the Big Shale Marker separates the Middle and Lower Wilcox strata further east. During Wilcox Group deposition, the Laramide Orogeny displaced the Paleocene shelf eastward from the relict Lower Cretaceous reef and formed Laramide uplands which sourced the majority of the sediment in Texas (Galloway et al., 2000; Galloway et al., 2011). The East Texas Basin ceased to be a marine basin during the Tertiary and Quaternary Periods, when major Eocene, Oligocene, Pliocene, and Pleistocene depocenters shifted toward the Gulf of Mexico.

The thick sediments of the Lower Wilcox were transported via two ancestral fluvial-dominated delta systems in the central Gulf, the Houston Delta and the Holly Springs Delta (Ewing and Galloway, 2019). This represented a major Gulf Coast prograding delta system located primarily in the ancestral Mississippi River synclinal trough that encompassed the Mississippi Embayment of central Louisiana and southern Mississippi (Galloway, 1968). The Houston Delta, supplied by a bed-load fluvial system, was the largest and was sand-dominated. East of the Houston Delta, shore-zone facies deposits separated the Houston Delta from the smaller Holly Springs Delta system. The Holly Springs Delta was the first Cenozoic Delta to be aligned with the axis of the later Central Mississippi fluvial-delta system. The very high rate of sediment influx (150,000 km^3/Ma) rapidly prograded the delta and shore-zone deposits towards the shelf edge, off-lapping onto the continental slope (Galloway et al., 2000; Galloway et al., 2011).

Two transgressive events bound the Middle Wilcox interval at its base and top. The early transgressive event deposited the Big Shale, and the later transgressive episode deposited the Yoakum Shale. During Middle Wilcox deposition (Late Paleocene-Early Eocene), the LaSalle wave-dominated delta and the fluvially-dominated Calvert delta supplied sufficient sediment to prograde the ancestral Gulf shelf (Galloway et al., 2000). Relative to the Lower Wilcox, the Middle Wilcox sedimentation rate was roughly half (Galloway et al., 2000; Galloway et al., 2011).

During Upper Wilcox deposition, a wave-dominated delta in the southern axis of the Mississippi Embayment prograded onto the central Gulf shelf. Reworking shifted the delta westward and deposited shelf and shoreline sands covering the central Gulf of Mexico. An increase in the carbonate content and glauconite content in the sediments of the upper Wilcox suggests an increase in marine conditions compared to the middle and lower Wilcox intervals. An examination of Wilcox hydrocarbon producing trends in Louisiana and Mississippi led Paulson (1972) to conclude that the upper Wilcox is a transgressive sequence.

Figure 2-10 provides a published regional isopach and configuration map of the Wilcox Group from Hosman, 1996 as presented in the USGS Report 1416. The composite thickness of the Wilcox Group is about 3,000 feet in east-central Louisiana (Galloway, 1968) and thickens to the south and can reach a maximum thickness of 4,000 feet (Lowry, 1988). Thickness trends mimic the perimeter of the Mississippi Embayment in the northeast updip areas and thicken to the south and southwest at the front of the Holly Springs Delta System.

2.1.2.10 Claiborne Group

The Claiborne Group in the Gulf Coastal Plain is widely considered to be a classic example of strata produced by alternating marine-nonmarine depositional cycles (Hosman,1996). There are multiple sand and shale units that have been identified across the region that comprise the Claiborne Group. These are (in ascending order) the Cane River Formation, the Sparta Formation, the Cook Mountain Formation, and the Cockfield Formation. These units are also the hydrostratigraphic units for north central Louisiana (See Section 2.4 for details).

Cane River Formation

The Cane River Formation represents the most extensive marine transgression to have occurred during Claiborne time. In the central part of the Mississippi Embayment (Arkansas, Louisiana, and Mississippi), the formation is composed of marine clays and shales. It is glauconitic and calcareous in part, as well as containing sandy clay, marl, and thin beds of fine sand. Well-developed sand bodies within the Cane River Formation are found only around the margins of the Mississippi Embayment. Regionally, the sand percentage decreases markedly to the south and southwest, so that in southeastern Arkansas, southwestern Mississippi, and all of Louisiana, the Cane River Formation contains virtually no sand. Along the flanks of the Mississippi embayment and over the Wiggins arch area the formation is generally 200 to 350 feet thick (Payne, 1972), and its basal unit is known as the Tallahatta Marl. The Cane River Formation ranges in thickness from 200 feet to 600 feet and deepens towards the Gulf of Mexico. The Cane River is absent of the regional Sabine Uplift structure in the northwestern part of Louisiana (Figure 2-11). In the northern Louisiana region, the Cane River Formation acts as an additional regional aquitard isolating the overlying Sparta Aquifer from the deeper brine-bearing sandstones of the Wilcox Formation.

Sparta Formation

The Sparta Formation is one of the Gulf Coastal Plain's most recognized geologic units. Overlying the Cane River Formation, the Sparta extends northward to the central part of the Mississippi Embayment, where it is also known as the "Kosciusko Sand". Deposited in a deltaic to shallow marine environment, the thick sandstones of the Sparta Formation are comprised of fine to medium grained unconsolidated quartzitic sand that is ferruginous in places, occasionally forming limonitic orthoquartzite ledges. The Sparta Formation ranges in thickness from less than 100 feet at its outcrop to more than 1,000 feet near the southern axis of the Mississippi Embayment (Hosman, 1996, Figure 2-12). The important Memphis Sand aquifer is the equivalent of the Kosciusko (Sparta) Sand in southeastern Arkansas and southwestern Tennessee. Outcrops of the Sparta Formation occur in north-central Louisiana along the perimeter of the Sabine Uplift (considerably west of the Area of Review, in western Louisiana).

Cook Mountain Formation

The Cook Mountain Formation is predominantly a marine deposit that is present throughout the Gulf Coastal Plain. It is generally less than 200 feet thick in the upper Mississippi Embayment but thickens in southern Louisiana and Texas to a thickness in excess of 900 feet (Figure 2-13). Along the central and Eastern Gulf Coastal Plain, the Cook Mountain Formation is composed of two lithologic units. The lower unit is a glauconitic, calcareous, fossiliferous, sandy marl or limestone. The upper unit consists of sandy carbonaceous shale than can be locally glauconitic. As the Cook Mountain Formation thickens downdip, the carbonaceous shale facies of the upper unit gradually increase as the predominant lithologic type.

Cockfield Formation

Lithologically similar to the Wilcox Group, the Cockfield Formation is present throughout most of the Gulf Coastal Plain, but less expansive in the interior than other units of the Claiborne Group (Figure 2-14). It is composed of discontinuous and lenticular beds of lignitic to carbonaceous, fine to medium quartz sand, silt, and clay. The lower part of the Cockfield Formation is generally sandier than the upper part. The formation is non-marine in origin and represents the youngest continental deposits of the Eocene Series in the Gulf Coastal Plain. The Cockfield is thickest in the west-central part of Mississippi, with thicknesses ranging from 10 to 550 feet as it thins to the east and southeast. It outcrops in the western portion of Caldwell Parish, adjacent to the AoR, as well as along strike further to the southwest in Louisiana and south Texas and in central Mississippi.

2.1.2.11 Jackson Group

The Eocene-aged Jackson Group was deposited during a regional transgressive episode which flooded the Gulf and retracted the ancestral Fayette delta landward. This landward shift of the Fayette delta reduced basinal sediment supply and disseminated clay-rich shelf deposits extending from the Central Gulf to the Mississippi Embayment (Galloway et al., 2000). The Jackson Group extends from Texas to western Alabama in the Gulf Coast. The northern and southern terrigenous facies of the lower Jackson Group was formed as a destructional shelf facies by the reworking of the upper surface of the Claiborne delta systems (Dockery, 1977). In Louisiana, the source material was from deposits transported into the Mississippi Embayment.

With the transgressive / regressive shoreline movement and the decrease in terrigenous clastic influx, the depositional environment transitioned to nearshore marine, leading to the deposition of carbonates alternating with calcareous mudstones and clays. This transgression represents the most recent maximum extent of sea level within the Mississippi Embayment. As a result, most of the Jackson Group sediments are of marine or nearshore origin.

The Moodys Branch Formation ("Marl") comprises the basal part of the Jackson Group and consists of fossiliferous, glauconitic sands, calcareous clays, and some limestones (Dockery, 1977). Multiple Eocene-aged fossils specific to these deposition cycles are found within the Moodys Branch Marl. Overlying the Moodys Branch Marl are the thick montmorillonitic clays of the Yazoo Clay Formation. The Yazoo Clay is primarily argillaceous, containing thin discontinuous sand lenses that are not regionally extensive. The clays have been described as fossiliferous and highly calcareous. The formations of the Jackson Group, named for their prominent outcrops in the greater Jackson, Mississippi area, are not present in the AoR.

2.1.2.12 Vicksburg Group

The Vicksburg Formation lies within the Tertiary depositional wedge of the Texas Gulf Coastal Plain. Alluvial sands were funneled through broad valleys and grade seaward into deltaic sands and shales, transitioning to prodeltaic siltstones and clays. These sediments were deposited during periods of marine transgression, separated by thicker sections deposited during period of regression in the early Oligocene. The shoreline advanced and retreated in response to both changes in the rates of subsidence and sediment supply. Rapid downdip thickening occurs along the syndepositional Vicksburg Flexure fault zone of south Texas, especially on the downthrown sides of the listric faults that characterize that fault trend.

The contact between the underlying Eocene-aged Jackson Group and the Oligocene-aged Vicksburg Group is almost indistinguishable in most of the Gulf Coast area. The lower part of the Vicksburg Group is marine and the lithology changes between the two groups are based upon paleontological breaks, which are rarely distinguishable on electric logs. For this reason, the two groups are combined into one larger mega-group (the so-called "Jackson-Vicksburg Group") in many regional literary references. As was the case with the underlying Jackson Group, the sediments of the Vicksburg Group are not present within the AoR. The Jackson-Vicksburg Group as mapped across the Gulf Coast region (Figure 2-15) shows that the strike of the outcrops of strata within the aggregate unit trends almost parallel with the current Gulf of Mexico coastline. Viewed separately, the unit thickness of the Vicksburg Group in Louisiana ranges from 200 feet thick in the southeastern part of the state to 800 feet in the western Louisiana area.

2.1.2.13 Catahoula Formation

The Catahoula Formation consists of soft claystone containing lenticular beds of friable sandstone and siltstone (Paine and Meyerhoff, 1968). The two principal units of the Catahoula Formation are the Oligocene Frio Formation and the overlying Anahuac Shale. The deposition of the progradational Frio sedimentary wedge was initiated by a major fall in global sea level, with subsequent Frio sediments being deposited under the influence of a slowly rising sea level (Galloway et al., 1982b). The Frio Formation is thus comprised of a series of deltaic and marginal-marine sandstones and shales that represent the downdip equivalent of the continental Lower Catahoula Formation (Galloway et al., 1982b.) In southeast Texas and southwest Louisiana, a transgressive deepwater shale and sandstone unit referred to as the Hackberry Formation occurs in the middle part of the Frio Formation (Bornhauser, 1960; Paine, 1968). The Frio is regionally overlain by the Anahuac Formation, an onlapping, transgressive marine shale that occurs in the subsurface of Texas, Louisiana, and southwestern Mississippi (Galloway et al., 1982b).

In the updip depositional area of the Frio Formation, a time-equivalent Catahoula Formation facies that accumulated on the progradational continental platform was derived from the erosion of older Cockfield, Jackson, and Vicksburg sediments (Galloway et al., 1982b). Volcaniclastics are common in the sandstone composition of the Catahoula Formation and their presence reflects the nature of transport of such volcanic debris and the distance from the volcaniclastic source. East Texas / west Louisiana sample cuttings from the Catahoula typically contain heavy mineral assemblages including ultra-stable, polycyclic and igneous minerals such as zircon, sphene, tourmaline, staurolite, kyanite, apatite, rutile, sillimanite, and garnet (Ledger et al. 1984). South Texas sample cuttings often contain abundant hornblende, zircon, apatite, and biotite (Ledger et al., 1984). The Trans-Pecos volcanic area is the probable source for the volcaniclastic material found in the Catahoula Formation (Ledger et al., 1984) of Texas.

As sea level continued to rise during the late Oligocene, the underlying Frio progradational platform flooded. Wave-dominant reworking of sediments along the encroaching shoreline produced thick, time-transgressive blanket sands at the top of the Frio Formation and the base of the overlying Anahuac Formation. A transgressive Anahuac marine shale was deposited conformably atop the blanket sands throughout the Texas and Louisiana coastal region.

The Anahuac Shale was deposited in an open-shelf environment and is typically composed of calcareous marine shales with localized, lenticular, micritic limestone units. The Anahuac Shale is regional in extent, thickening from its inshore margin to nearly 2,000 feet of thickness in the offshore sector of the Gulf of Mexico (Galloway et al., 1982b). The Catahoula Formation is not present within the AoR.

2.1.2.14 Miocene-aged Formations

The Miocene strata of the Gulf Coastal Plain contain more transgressive-regressive cycles than any other epoch. Rainwater (1964) has interpreted the Middle Miocene as a major delta-forming interval comparable to the present-day Mississippi Delta system. The Middle Miocene is representative of most of the entire Miocene interval, with only the depo-center location changing in response to various transgressions and regressions. The result is a complex of deltaic sands, silts, and clay deposits, restricted marine clays, and interbedded shallow neritic clays.

The Miocene sediments of the Fleming Group of Louisiana are equivalent to the Oakville and Lagarto Formations of Texas, and to the Catahoula, Hattiesburg, and Pascagoula Formations of south Mississippi.

Along the northeastern boundary of Texas, the Newton Fluvial System supplied sediment to the Calcasieu Delta system of southeast Texas and southwest Louisiana. Sands of the Newton Fluvial System are typically fine - medium-grained, with thick, vertically, and laterally amalgamated sand lithosome geometries typical of meander-belt fluvial systems (Galloway, 1985). Depositional patterns within the Oakville Formation (lower Fleming equivalent) of southeast Texas exhibit facies assemblages typical of a delta-fringing strand plain system (Galloway, 1985). The Calcasieu Delta system is optimally developed in southeast Texas in the Lagarto Formation equivalent of the upper Fleming Group. The delta system consists of stacked delta-front, coastal-barrier, and interbedded delta-destructional shoreline sandstones that comprise the principal part of the delta system, with interbedded prodelta mudstones and progradational sandy sequences deposited along the distal margin of the delta (Galloway, 1985).

Per Hosman, 1996, the complexity and heterogeneity of the myriad of facies comprising the Miocene strata preclude the correlation of regionally continuous horizons and have thus frustrated attempts at regional differentiation. Much of the Miocene correlations in southern Louisiana rely upon local or even well-specific nomenclature for the Miocene sands that is informally based upon the depth each such sand was encountered in the subsurface at a particular location (i.e., a Miocene sandstone encountered at a depth of 6,400 feet would typically be called the "6,400-Foot Sand"). For this reason, various sandstones within the Fleming Formation may be locally mapped and understood on a local rather than a regional basis. Figure 2-16 indicates the Miocene Formation outcrops in a strike-oriented belt that begins in the general Rapides Parish area and continues along strike to the southwest into Texas; the Miocene also crops out across most of south Mississippi and south Alabama but extends to depths well below 8,000 feet along the southeastern portion of Louisiana and into the Gulf of Mexico. The Miocene Formation is not present within the AoR.

2.1.2.15 Pliocene Formations

Pliocene Age formations in Louisiana, although informally separated into upper and lower units, are mostly undifferentiated and unnamed. Much of the Pliocene and younger sediments were deposited offshore of the present coastline. Nearer shore, sediments were deposited under predominantly fluvial-deltaic conditions and exist as a complex of channel sands, splays, and overbank flood plain marsh deposits. Further south along the coastline in southern Plaquemines Parish, the Pliocene section is approximately 6,000 feet thick (Everett et al., 1986). At the AoR, Pliocene-aged formations are not present. See Figure 2-17 for the regional extent of the Pliocene Formation.

2.1.2.16 Pleistocene and Holocene Formations

Pleistocene sediments were deposited during a period of fluctuating sea level and represent a fluvial sequence of post-glacial erosion and deposition. The formations were deposited in both fluvial and deltaic environments, and they thicken in a southeastward dip direction as well as along strike toward the southwest. Pleistocene sediments thicken along the Texas / Louisiana border and in a downdip direction where there was significant deposition along the downthrown sides of listric growth faults during Pleistocene sea level lowstands (Aronow and Wesselman, 1971). The thickest portions of the Pleistocene Formation are observed in the offshore sector of the Gulf of Mexico, where the Pleistocene sediments are relatively shallow (~2,000 feet deep) and up to 5,000 feet thick. Pleistocene sediments grade conformably into the overlying Holocene depositional units. At the Area of Review, such Pleistocene-aged formations are not present.

With the retreat of the Pleistocene glaciers, sea level began a final irregular rise to its present-day level, and Holocene sediments were deposited following the final retreat of glacial ice. The slow rise of the Holocene sea level heralded the beginning of the recent geologic processes that have created and shaped the present Texas and Louisiana coastal zone. During recent times, sediment compaction, slow basin subsidence, and minor glacial fluctuations have resulted in relatively insignificant changes in sea level. The coastal zone in Louisiana has evolved to its present condition through the continuing processes of erosion, deposition, compaction, and subsidence. The Holocene sediments in Caldwell Parish unconformably overlie the Eocene-aged Claiborne Group, representing an extended period of time of non-deposition and erosion. Within the AoR, such Holocene deposits are represented as a thin layer of alluvium at the surface, which is typically 250 to 300 feet thick.

2.1.3 Regional Structural Geology

The interaction between sediment accumulation, gravity, and differential loading and compaction has played a major part in the contemporaneous and post-depositional deformation of Tertiary strata. However, the continental margins and deep ocean basin regions of the Gulf of Mexico represent relatively stable areas (Foote et al., 1984). During the Late Triassic to Early Jurassic, large volumes of eroded material were deposited in areas of regional subsidence, and isolated salt basins formed where the Louann Salt thickened into those areas. Considering the regional influence of the Mississippi Embayment, the sediments deposited within the Gulf Coast Basin generally dip and thicken southward towards depocenters located in the Gulf of Mexico (Murray, 1957).

Structurally positive regions in the northern Louisiana area include the Sabine Uplift, the Monroe / Sharkey Platform (also known as the Monroe Uplift), the Richland-Caldwell Paleohigh (RCP), and the LaSalle Arch (Figure 2-18). Structurally negative regions in the area include the North Louisiana Salt Basin and the Interior Salt Basin of Mississippi, which are separated by the Richland-Caldwell Paleohigh, a southwest-plunging Paleozoic horst block (Walkinshaw, 2020). The RCP was an emergent structural ridge that formed during Late Paleozoic time; the Louann Salt that fills the synclinal salt basins on either side of the RCP appears to have not been deposited – or is very thin – atop the ridge, which appears to have been drowned during upper Cotton Valley time. Because of the lack of Louann Salt atop the RCP (which trends through the AoR), differential loading, salt movement and faulting is minimal in the subject area.

The Mississippi Interior Salt Basin is by far the largest interior extensional salt basin underlying the onshore sector of the Gulf Coastal Plain. This extensional basin is associated with late Triassic rifting linked with wrench faulting and was an actively subsiding depocenter throughout the Mesozoic and into the Cenozoic. Figure 2-18 only shows the westernmost portion of the basin, which is bounded to the west by the RCP. The Mississippi Interior Salt Basin covers most of south Mississippi and southwest Alabama.

The North Louisiana Salt Basin is a roughly rectangular structural trough some 100 miles long and 30 to 50 miles wide, centered in Webster, Bienville, and Winn Parishes Louisiana. The basin is situated between the Sabine and Monroe Uplifts and is located to the northwest of the proposed sequestration site on the other side of the RCP.

The Monroe Uplift is a large domal structure that spans across northeastern Louisiana and extends into southeastern Arkansas and western Mississippi. The core of the Uplift is inferred to be a large horst block that began moving upward episodically during the Late Cretaceous and especially at the end of the Cretaceous (*i.e.* immediately following the deposition of the Maastrichtian

Cretaceous strata), creating two significant angular unconformities: an exacerbated regional erosional event that beveled off much of the Lower Cretaceous at the UK/LK boundary (in an off-flank position), and a younger erosional event that truncated the entire Cretaceous and much of the underlying Jurassic strata at the KPg boundary (Lower Paleocene time) in the crestal area near the city of Monroe (Kose, 2013). Therefore, the Paleocene Midway Group is encountered atop the KPg unconformity directly overlying Jurassic rocks as old as Cotton Valley. The Midway Shale has demonstrated its efficacy as a regional upper seal for all strata truncated beneath the KPg unconformity, having trapped over 7 TCF of gas in the Monroe Gas Field atop the Monroe Uplift.

The LaSalle Arch, a southerly extension of the RCP, also serves to divide the Mississippi and Lousiana Salt Basins, and its core is also a relict Paleozoic horst block (Lawless and Hart, 1990). The eastern limb of the Arch formed by regional tilting to the east and the western limb formed from differential subsidence to the southwest. (Lawless and Hart, 1990). The northernmost extent of this feature is in northern LaSalle Parish, approximately 15 miles southwest of the AoR. Unlike the RCP, later movement caused Upper Cretaceous strata to thin over the crest of the LaSalle Arch.

2.1.4 Regional Groundwater Flow in the Injection Zone

Natural aquifer flows are well documented in shallow aquifers, but reliable data for deep, confined aquifers has generally not been available. Many of the studies for flow rates in deep saline aquifers were derived from the search for nuclear waste isolation sites. These studies show sluggish circulation to nearly static conditions in the deep subsurface (Clark, 1987). Studies in other areas, such as for the Mt. Simon Formation by Nealon (1982) and Clifford (1973), and the Frio Formation on the Texas Gulf Coast by Kreitler et al. (1988), demonstrate the complexities of the problem and the limitations of conventional hydrological methods.

Another issue pertains to the difference between strata exposed at a formation outcrop and the equivalent-aged strata buried at depth in a given downdip area. For example, Late Cretaceous-aged sediments outcrop in the northwest area of Alabama, along the broad eastern flanks of the Mississippi Embayment; however, in most instances, the strata that outcrop represent the youngest (uppermost) or coalesced portion of the exposed strata, not necessarily the stratigraphic unit that is the subject of interest deeper in the subsurface. Regarding the Tuscaloosa, as described earlier in this report, as one moves further updip the Lower Tuscaloosa Formation thins and has coalesced with the Upper Tuscaloosa into one undifferentiated stratigraphic unit that eventually crops out; accordingly, the Lower Tuscaloosa as a separate and distinct unit is not represented in the northern extent of the coalesced Tuscaloosa outcrop in northwest Alabama.

A southern (downdip) direction of regional flow established for section is consistent with the theory of deep basin flows and the physical mechanisms (topographic relief near outcrops and deep basin compaction) identified as contributing to natural formation drift (Bethke et al, 1988; Clark, 1988; Kreitler, 1986). Studies indicate the general directional flow of groundwater through a reservoir, as indicated by Kreitler et al. (1988), can be locally modified (changed) by the production of a substantial volume of oil, gas, and formation brine. However, since the AoR is largely devoid of production from the contemplated sequestration intervals (all of which are much deeper than the Wilcox), any such local modifications to the general directional flow of groundwater in the project site are unlikely. Lateral facies changes and sand pinch-outs are known to have occurred in some of the targeted sequestration reservoirs in the general direction of the recharge area (updip), therefore, background hydraulic gradients in those Injection Zone reservoirs are likely to be highly restricted.

While conservative estimates of regional background hydraulic gradients for Cretaceous-aged sequestration reservoirs are not available, extrapolations of test measurements of Miocene-aged sediments can be derived from previous studies and the results can be reasonably applied to the Cretaceous-aged sequestration reservoirs underlying the proposed Caldwell Parish site.

Data published by Clifford (1973 and 1975), Slaughter (1981), and Bently (1983) provide estimated natural hydraulic gradients from three Miocene aquifers that are approximately 3,000 feet deep. The natural horizontal hydraulic gradient in these aquifers ranged from 0.021 feet/yr. to 1.58 feet/yr., averaging 0.70 feet/yr. For deeper Frio (Oligocene) aquifers in the Texas Gulf Coast area, within the depth range of approximately 6,000 feet below ground, the natural hydraulic gradient is estimated to be much smaller and, as indicated by Kreitler et al. (1988), to move at only a geologic time scale.

Clark (1988) found similar sluggish circulation in the Oligocene Frio Formation in the greater Houston area, with annual groundwater velocities expected to measure in the few inches to a few feet in scale. The original formation pressure gradient data for Class I wells completed in the Frio Formation in the east Houston area substantiates the lack of a large hydraulic gradient within those deeper sandstones. Original formation pressure gradients from injection wells in the Houston Ship Channel area – the Sasol Plant Well No. 1 (WDW147), from the Lyondell Chemical Company, Plant Well No. 1 (WDW148), and from the Equistar Plant Well No. 1 (WDW036) – are nearly identical (+0.001 psi/feet). Therefore, based on this information, estimates for the horizontal natural background reservoir velocity in the Injection Zone reservoirs are calculated at a few inches to feet per year, in a downdip direction.

The actual value for the natural hydraulic gradients in the proposed Injection Zone reservoirs of the Caldwell Parish site are expected to be less than 1.0 foot / year. There are no obvious natural sinks for the formation fluid except in regions where salt domes are being dissolved, which is not applicable to this project area. According to Miller (1989), flow due to dissolution of salt domes is expected to be on the order of a few centimeters per year, or substantially less than 1.0 foot / year, at distances greater than one mile from the source of dissolution. Therefore, the estimate of 1.0 foot / year in the southeasterly (downdip) direction for the natural hydraulic gradient near the proposed sequestration site is believed to represent a very conservative estimate.

2.2 LOCAL GEOLOGY OF THE LOUISIANA GREEN FUELS, PORT OF COLUMBIA FACILITY

The Louisiana Green Fuels, Port of Columbia Facility is located approximately 5.5 miles north of the town of Columbia (the parish seat of Caldwell Parish). The plant site, part of a larger 171-acre industrial parcel owned by the Columbia Port Commission, a political subdivision of the State of Louisiana, is a Louisiana Economic Development Certified Site and is located on the eastern side of the Ouachita River, adjacent to the Port of Columbia. Topographically, the region is relatively flat with local relief of less than 15 feet at the project site, with surface elevations ranging from 52 feet above sea level at the Ouachita River to over 67 feet in the vicinity of the Facility (Figure 2-19). The following sections detail the geology on a locally affected scale, specific to the delineated AoR encompassing the proposed Louisiana Green Fuels, Port of Columbia Facility.

2.2.1 Data Sets Used for Site Evaluation

Multiple sets of geological and geophysical data were used to evaluate and characterize the subsurface geology for the Louisiana Green Fuels sequestration site. Data sets included existing (legacy) offset well data, reprocessed 2D seismic data, regional geological literature derived from multiple sources of academic and technical data, and the extensive site-specific data acquired during the drilling and testing of the Whitetail Operators LLC, Louisiana Green Fuels No. 1 (SN975841) stratigraphic test well, which occurred during April to June of 2021.

2.2.1.1 Offset Well Logs

Open-hole well log data has been acquired for those oil and gas test wells located within a 100 square-mile area surrounding the proposed Louisiana Green Fuels sequestration site. Formation tops were correlated across the area and used to develop subsurface structure and isopach maps, as well as structural and stratigraphic cross sections. The southern half of the map area encompasses several shallow gas fields, including the Riverton Gas Field, an abandoned field that produced methane from two lignite bed which are deposited stratigraphically in the lower Wilcox at an average depth of 2,800 feet subsea. While most of the Wilcox gas wells in Riverton Field bottomed in the upper 100 feet of the underlying Paleocene Midway Shale (the Secondary Upper Confining Zone, which averages 600 feet in thickness in the AoR), most of the shallow Wilcox test wells drilled outside of the Riverton Gas Field area within the AoR reached total depth in the lower Wilcox and did not penetrate the Midway Shale. Within the AoR, no oil or gas has been produced from formations deeper than the Wilcox Formation, and only a limited number of wells penetrated the entirety of the Secondary Upper Confining Zone and/or Primary Upper Confining Zone in the immediate vicinity of the proposed Louisiana Green Fuels sequestration site.

There are eighteen penetrations extending deeper than the top of the Selma Chalk (base of the Upper Confining Zone) in the 100 square-mile area that surrounds the plant site. Of these eighteen wells, only thirteen such penetrations are located within the AoR. This limited deeper well control includes an even smaller subset of wells that penetrated the Upper Tuscaloosa Formation, which comprises most of the Primary Injection Zone. These legacy wells (dry holes) were used to provide information on the lateral extent and continuity of the proposed Confining and Injection Zones.

Well logs for the project were downloaded from the LDENR SONRIS (state agency database) and/or from commercial log libraries that market similar downloads of digital and raster well log data. Correlations of the formations and intervals of interest and the maps and cross sections were performed and prepared by Steven S. Walkinshaw (Louisiana Professional Geoscientist No. 65).

Published data for the formations of interest in the AoR are listed alphabetically in Section 14.0 - References. The sources of the published data include the American Association of Petroleum Geologists, the Gulf Coast Association of Geological Societies, the United States Geological Survey, and various state agencies.

2.2.1.2 Seismic Data

In order to map the subsurface structure at several important levels and to investigate the presence or absence of faulting in the area, all of the commercially available (non-exclusive) seismic data available for licensing that crosses the AoR was reviewed (as of the date of this report, there is no three-dimensional (3D) seismic data across the area). Over the past 60 years, many two-dimensional (2D) seismic lines shot in the area have been acquired by various third parties for the purposes of oil and gas exploration; the number of 2D seismic lines that transect the AoR and are available for licensing was determined to be more than sufficient to provide good seismic coverage across the AoR. The 2D seismic lines that have been acquired were licensed from Seismic Exchange, Inc. The licensed 2D seismic data was quality checked and determined to be of sufficient fold and quality to be utilized in a seismic interpretation.

Due to recent technological advances in processing and the vintage of the licensed 2D seismic data, the seismic lines were reprocessed prior to their interpretation. The principal objective of the reprocessing effort was to derive pre-stack time migration iterations of each of the 2D seismic lines. Time-depth control was initially provided by a composite time-depth table created and previously utilized in a neighboring area, which was subsequently supplanted by the Vertical Seismic Profile (VSP) survey acquired in the recently drilled Whitetail Operators LLC, Louisiana Green Fuels No. 1 (SN975841) stratigraphic test well. The processed VSP, displayed using a conventional synthetic seismogram format, indicates good positive impedance contrasts (peak events) are generated at the Top Chalk and Top Washita-Fredericksburg levels (the lithology of both strata being relatively high-velocity limestone), displayed in normal polarity; and the Top Annona Sand and Top Paluxy exhibit good negative impedance constrasts (trough events), as expected (the top of the Paluxy being the base of the higher-velocity Washita-Fredericksburg limestones). When compared to their peak and trough event counterparts as exhibited on the seismic data, these impedance contrast events exhibited an excellent correlation to those observed on the seismic data, especially the strong peak event at the Top Chalk level. The VSP synthetic seismogram plot is shown on both Figures A.19a. and A.19b. These highly-correlative sources of acoustic subsurface time-depth relationships proved sufficiently accurate for use within the AoR. The time-depth chart created as a derivative of the VSP acquisition proved to be very useful in demonstrating the excellent ties between the formation tops picked in each Chalk penetration within the AoR that intersected or were close to the 2D seismic lines, and the 2D seismic data set.

Fifteen licensed seismic lines located (all or in part) within the AoR (Figures A.19a and A.19b) were loaded into an S&P Kingdom workstation project using the NAD27 Louisiana North State Plane 1701 projection, which is the industry-standard State Plane cartesian projection utilized in North Louisiana. The Kingdom geophysical software utilized in the interpretation of the seismic data has been upgraded over time and, as of the date of this report, is Version 2024 HF4. Cultural and digital well data covering the AoR was acquired from a commercial source of such data and cross-checked for accuracy by comparing the digital cultural data with that shown on USGS topographic maps.

2D Seismic Lines Licensed by Strategic Biofuels That Are Located (All or in Part) Within the AoR (Total 15 2D Lines)									
LINE NAME	YEAR SHOT	SHOT BY / FOR	ENERGY	FOLD*	GROUP INT.	SP INT.	REPR.?	PROCESSOR**	DATE REP.
7678-RA4	1966	Sun	Dynamite	6	110	220	Yes	Geo-Seis	2021
78-174-378	1978	Shell	Dynamite	15	150	600	Yes	Geo-Seis	2021
82-202-1084	1982	Shell	Dynamite	30	200	400	Yes	AGT	2024
82-202-1085	1982	Shell	Dynamite	30	200	400	Yes	Geo-Seis	2021
82-202-1086	1982	Shell	Dynamite	30	200	400	Yes	Geo-Seis	2022
AH79-EA1-H107	1979	Hunt	Dynamite	24	330	330	Yes	AGT	2024
F66RAY-R-4-CLDL	1966	Mobil	Dynamite	6	220	440	Yes	Geo-Seis	2022
F78DEL-LD-78-1	1980	Mobil	Dynamite	12	330	660	Yes	Geo-Seis	2021
F78DEL-LD-78-2A	1980	Mobil	Dynamite	12	330	660	Yes	Geo-Seis	2021
F-HOM-17021-1	1979	Houston O&M	Dynamite	12	330	660	Yes	Geo-Seis	2021
JOD-21	1978	Amoco	Dynamite	24	165	330	Yes	Geo-Seis	2022
JOD-23	1978	Amoco	Dynamite	24	165	330	Yes	Geo-Seis	2022
JOD-24	1978	Amoco	Dynamite	24	165	330	Yes	AGT	2024
JOD-25	1977	Amoco	Dynamite	24	165	330	Yes	AGT	2024
JOD-114	1968	Amoco	Dynamite	6	660	1320	Yes	AGT	2024

** Reprocessing results: the resolution of the 2D data was improved as a consequence of using better filtering and pre-stack migration; the original fold remained the same*

*** The owner of Geo-Seis retired in 2023, which necesitated the selection of Advanced Geophysical Technologies (AGT) to reprocess additional 2D lines licensed in 2023*

Note: all 2D data listed was licensed from Seismic Exchange, Inc. ("SEI") from 2020 - 2023.

Minor two-way time mis-ties between certain 2D lines were corrected with bulk time shifts on an as-needed basis. A key reprocessed 2D line, Line 82-202-1086, crosses the center of the AoR close to Strategic Biofuels' #1 Louisiana Green Fuels Class V Stratigraphic Test Well (AP Number 137, 1,270' northwest); remarkably, Line 82-202-1086 tied the VSP synthetic seismogram acquired in the #1 Louisiana Green Fuels so well that no bulk shift to tie the VSP data was required. The multiple line ties of Line 82-202-1086 with other 2D lines crossing the AoR permitted the subsequent tying of the reprocessed data to that line (and thus the VSP) with very little bulk shift correction from line to line. Because of the relative lack of surface anomalies and only moderate subsurface dip rates, the reprocessed 2D data was observed to tie fairly well at the 2D line intersections within the AoR. Interpretations of the principal seismic events were made in the time domain; because the seismic data set consisted entirely of 2D seismic data of several vintages, it was decided that the reprocessing of the data would not include any attempt to derive pre-stack depth migration (PSDM) iterations. This decision was further supported by the fact that the primary objective of the seismic mapping effort was to map the subsurface structure of the principal seismic events in the AoR and to determine the **presence or absence of faulting** in the zones of interest. After the interpretations of the seismic data had been completed, maps of the two most important time horizons mapped within the AoR (the top of the Upper Cretaceous Selma Chalk and the Lower Cretaceous Ferry Lake Anhydrite, both peak events) were created. Mapping included the procedure to mathematically interpolate a spatial distribution of data samples between 2D planar horizons in the area illuminated by the seismic data. For a given set of 2D seismic data, the interpolation between the 2D lines closely conforms to the aerial extent of the 2D data; as such, most 2D seismic areas are constrained by the geospatial distribution of the data. The 2D line density within the AoR was deemed adequate.

Within the AoR the most reliable time horizons mapped were the positive impedance events (peak events, given the display of normal polarity, zero phase seismic data) generated at the top of the Upper Cretaceous Selma Chalk and the top of the Lower Cretaceous Ferry Lake Anhydrite. The peak event generated by the positive impedance contrast at the top of the Selma Chalk is especially important because the top of this formation is also interpreted to represent the base of the Secondary Upper Confining Zone, the Midway Shale. The thin basal Paleocene Clayton Marl is an argillaceous, calcareous unit deposited directly atop the KPg unconformity in northeastern Louisiana and represents a thin layer of marine Paleocene strata that underlies the Midway Shale and overlies the Selma Chalk. However, because of the thin nature and slower velocity of the Clayton Marl, the peak event generated by the positive impedance contrast at the top of the Selma Chalk is considered to represent the seismic delineation of the base of the Midway Shale.

The peak event generated by the positive impedance contrast at the top of the Ferry Lake Anhydrite is another identifiable datum in the seismic data. This peak event is generated at the top of a thick layer of evaporites that were deposited across the entire North Louisiana area during the Albian Stage of the Lower Cretaceous. The Ferry Lake Anhydrite represents the ultimate bottom seal (Lower Confining Zone) for the geologic strata targeted for sequestration within the AoR.

Since the peak event generated by the positive impedance contrast at the top of the Upper Cretaceous Selma Chalk represents the base of the Upper Confining Zone and the peak event generated by the positive impedance contrast at the top of the Lower Cretaceous Ferry Lake Anhydrite represents the top of the Lower Confining Zone, seismically mapping these two events provides an excellent assessment of the structure and continuity (i.e., lack of faulting) of the entire stratigraphic interval containing the proposed Injection Zone sequestration reservoirs within the greater project area. On dip-oriented 2D seismic lines, a visual observation of the two south-dipping peak events also provides a clear understanding of the southward-expanding wedge of Cretaceous sediments that include the proposed Injection Zone intervals.

With regard to the individual sandstone reservoirs proposed for sequestration within the principal Upper Tuscaloosa and Paluxy Formations, those reservoirs are generally considered to be too closely spaced in depth (and thus, 2-way time) and too similar in velocity within their respective interlaminated sand/shale sequences to be individually resolved by either 2D or 3D seismic data. For this reason, the proposed sequestration relies upon the interpretation of the interpolated 2D seismic time horizons derived from mapping the base of the Secondary Upper Confining Zone and the top of the Lower Confining Zone to assess subsurface structure and continuity, while extensive subsurface geological mapping of the individual sandstone reservoirs targeted for sequestration has also been utilized to provide an in-depth analysis of those proposed Injection Zone intervals.

The optimal seismic interpretations that have been derived from the 2D data licensed across the AoR are the seismic time horizons derived from mapping the base of the Midway Shale, the base of the Secondary Upper Confining Zone, and the top of the Ferry Lake Anhydrite, the top of the Lower Confining Zone. The Top Chalk 2D seismic time horizon map is included in Figure A.19.

2.2.1.3 Stratigraphic Test Well

In the late Spring of 2021, the Whitetail Operators LLC, Louisiana Green Fuels No. 1 (SN 975841) stratigraphic test well was drilled to acquire site-specific data in the vicinity of the proposed Louisiana Green Fuels facility. The well is located in Section 44, Township 14N, Range 4E (Figure 2-20), which is approximately five miles north of the city of Columbia and approximately 1.1 miles from the planned location of the facility. Whitetail Operators LLC was the contract operator that oversaw the drilling and completion of the well. The stratigraphic test well was drilled to a driller’s depth of 6,200 feet and reached total depth in the upper part of the Paluxy Formation.

The stratigraphic test well was designed to be a dual-purpose well with the initial objective of acquiring investigative geological and petrophysical data of the subsurface formations penetrated by the well. Once that data had been collected, the second objective was to set casing to bottom and perforate and test the proposed Cretaceous Injection Zone intervals that were encountered. It is proposed that this well be converted to an In-Zone monitoring well as part of the testing and monitoring plan for the facility. Industry standard technology was used to characterize the geologic formations encountered by the wellbore, and consisted of mudlogging (including wet and dry sample collection); the cutting and retrieval of five whole cores cut across targeted confining and injection zones; a robust open-hole well logging program, including the running of dipole sonic (Sonic Scanner), combinable magnetic resonance (CMR), elemental capture spectroscopy (ECS), and triaxial induction (Rt Scanner) tools; the acquisition of 22 formation pressures using the XPT (pressure sampling) tool; the acquisition of 25 sidewall rotary cores, with excellent recoveries; and, following the setting of casing to total depth, the acquisition of a zero-offset vertical seismic profile (VSP) survey, followed by the injection testing of the Upper Cretaceous Annona Sand and various sandstones and intervals within the Upper Tuscaloosa and upper Paluxy Formations.

Five 30-foot whole cores were acquired, along with 25 rotary sidewall cores, in the Stratigraphic Test well. Three of the five whole cores were cut in **confining layers**, as follows:

Whole Core No. 1: cut in the lower Midway Shale from 3,600 ft to 3,630 ft (driller's depth). The Midway Shale is the Secondary Upper Confining Zone.

Whole Core No. 2: cut in the Austin Chalk Equivalent (part of the Primary Upper Confining Zone) from 4,690 ft to 4,720 ft (driller's depth). While the targeted interval was cored, only 9 feet of the core was recovered (the only cored interval with poor recovery; such poor recovery is believed to have occurred because of the very argillaceous lithology of the cored interval). Fortunately, the portion of the cored interval that was recovered was the primary objective of this coring effort: the retrieval of a silty/sandy calcareous mudstone that is believed to be representative of the laminated mudstone/marl lithology that typifies the very argillaceous, alternating ductile/brittle nature of this important (but secondary / ancillary) confining layer. In northeast Louisiana, proximity to vulcanism occurring during Austin time along the Monroe / Sharkey Platform (just north of the AoR) led to the introduction of large volumes of volcaniclastics to the sediments that were deposited, resulting in the deposition of such argillaceous strata that differ markedly from the much "cleaner" chalks and micrites typical of the equivalent Austin Chalk interval in south Louisiana.

Whole Core No. 5: cut in the upper Paluxy Formation "red shale" sequence a short distance beneath the base of the upper Paluxy "P-3" Sand. The targeted interval was a very hard and dense red (terrigenous) shale known to exist in the area in the lower portion of the Upper Paluxy. Sample cuttings transitioned to dense red shale just above 5,900 ft (driller's depth) in the Upper Paluxy, at which point Core No. 5 was cut. Core recovery was excellent (29.2 feet recovered from 30 feet cut). In addition to standard core analysis, portions of the core were subsequently analyzed for vertical permeability. When drilling resumed below Core No. 5, two very hard and dense limestones were drilled, providing excellent evidence of the existence of more confining layers deposited within the Paluxy Formation.

Unfortunately, during the open-hole logging that followed, Schlumberger's Platform Express AIT/LDT/CNL tool could not log below the base of Core No. 5 at a depth of 5,930 feet, where a suspected bridge (obstruction) was encountered in the wellbore (however, several other logging tools were subsequently able to get past the bridge and reach the total depth of the well). It should be noted that all of the Injection Zone and the Primary and Secondary Upper Confining Zones encountered in this well were shallower in depth than the partial obstruction encountered at 5,930 feet in the subject well; accordingly, a full suite of logs was acquired across the Primary Upper Confining Zone and the proposed Injection Zone encountered in the stratigraphic test well.

The open-hole logging program was very comprehensive and established several baseline log curve responses. In addition, during the injection testing, water samples were acquired from many of the zones of interest and provided a good baseline for formation fluid salinity. Abundant baseline reservoir pressure data was acquired in both open hole (via wireline XPT pressure measurements) and cased hole (static and flowing bottomhole pressure measurements).

Open hole logs run in the Louisiana Green Fuels No. 1 stratigraphic test well (SN 975841) included the AIT/LDT/CNL/GR, ECS, CMR, Rt Scanner, and Sonic Scanner (dipole sonic) logs. Following the successful acquisition of that suite of logs, the XPT tool was then run in the hole, sampling reservoir pressures in the Primary Injection Zone, the Upper Tuscaloosa, as well as the overlying Annona Sand, the first porous reservoir above the Primary Upper Confining Zone, the Austin Chalk Equivalent / Upper Eagleford interval. Twenty-five rotary cores were then cut across various sandstone reservoirs in the Upper Tuscaloosa and the overlying Annona Sand (the first porous reservoir above the Austin Chalk Equivalent) and subsequently analyzed by Stratum Reservoir, which also analyzed the five whole cores cut in the well and the sample cuttings collected across the Paluxy Formation. Finally, the zero-offset VSP was run in cased hole prior to the perforation and testing of the stratigraphic test well.

The injection testing conducted in the stratigraphic test well aided in the determination of the likely size of the available reservoirs (capacity), the maximum rate of supercritical carbon dioxide injection (injectivity), and the projected expansion of the sequestered plume over time. With regard to the projected plume expansion, the extensive whole coring, logging, rotary coring and sample collection provided a wealth of reservoir data considered optimal for developing and adjusting the Static and Dynamic Models that have been utilized in such projections.

2.2.2 Local Stratigraphy

The injection and confinement system present beneath the Louisiana Green Fuels site is comprised of sediments that range in age from Lower Cretaceous (Ferry Lake Anhydrite – Lower Confining Zone) to Paleocene (Midway Shale – Secondary Upper Confining Zone). Above the top of the Midway Shale, a succession of progressively younger Cenozoic rocks has been deposited within the AoR. Recent regional downwarping and erosion has deposited Holocene-aged alluvium unconformably atop the upper Eocene strata at an approximate depth of 250 feet subsea. The local stratigraphy is established on the type log (Figure 2-2) and used as a basis for correlating with the offset well data.

The correlation of the logs run in the stratigraphic test well with those of the legacy (pre-existing) offset dry holes that penetrated the Upper Confining and Injection Zones facilitated a good understanding of the local geology in the vicinity of the proposed Louisiana Green Fuels plant site. Using these correlations, the following local stratigraphic formations have been evaluated:

- Lower Cretaceous Paluxy Formation
- Lower Cretaceous Washita-Fredericksburg Group
- Upper Cretaceous Tuscaloosa Group
- Upper Cretaceous Austin Chalk (Equivalent) Group and Upper Eagleford Shale
- Upper Cretaceous Selma / Annona Group

- Paleocene Midway Group
- Paleocene – Lower Eocene Wilcox Formation
- (Upper) Eocene Claiborne Group
- Holocene Group (consisting of various near-surface undifferentiated alluvial sandstones)

The Secondary Upper Confining Zone, the impermeable Paleocene Midway Shale, averages 600 feet in gross thickness across the area in the vicinity of Louisiana Green Fuels' proposed plant site. Underlying the Midway Shale beneath the KPg unconformity is approximately 300 feet of impermeable, hard, Upper Cretaceous Selma Chalk. In aggregate, the total thickness of the confining layers above the top of the Annona Sand (a porous glauconitic reservoir deposited at the base of the Selma Chalk) is approximately 900 feet. An additional 700 feet of impermeable strata extends beneath the base of the Annona Sand to the top of the Upper Tuscaloosa Formation, which contains most of the proposed Injection Zone. The lower 200-300 feet of this lower Chalk / Eagleford interval is comprised of the impermeable micrites and calcareous shales of the Austin Chalk Equivalent / Upper Eagleford interval, the Primary Confining Zone, and this interval thickens to over 500 feet in gross thickness in the extreme southern portion of the AoR. This means that for much (and possibly all) of the operating life of the project, an aggregate thickness of ~1,600 feet of overlying impermeable rock will effectively confine the injected supercritical CO_2 as well as any other minor volumes of waste gases authorized to be simultaneously injected into the proposed Injection Zone.

All proposed injection operations are projected to be confined between the subsurface depths of 4,300 feet (the approximate shallowest depth of the top of the Upper Tuscaloosa Formation within the AoR) and 7,000 feet, the proposed total depth of the planned injection (and monitor) wells. There has been no production of oil or gas from any of the Cretaceous intervals beneath the Midway Shale in the AoR.

Additionally, there are very few exploration wells that have been drilled deep enough beneath the Midway Shale to encounter the Paluxy Formation, which harbors the deepest proposed reservoirs in the Injection Zone. The analyses of the data acquired in the stratigraphic test well have been used as the basis for defining the parameters used for modeling the sequestration and monitoring strategies for the facility. The stratigraphic test well, as described above, will be recompleted as a monitor well as identified in the "*E.1 - Testing and Monitoring Plan*" contained in Module E.

The following discussion defines and briefly describes the formations that underlie the surface in the project area, beginning with the Middle Eocene Sparta Formation and ending with the base of the Ferry Lake Formation of the Lower Cretaceous. Maps referenced in this discussion are contained in Appendix A – Local Geologic Maps (see Table 2-1).

Sparta Formation **-** In the northeastern portion of Caldwell Parish, including the Port of Columbia area, the Middle Eocene Sparta Formation represents the deepest freshwater aquifer, and the base of the Sparta has been designated by the LDNR to be the base of the USDW in the area. However, it should be noted that, while they are used for agricultural purposes (irrigation), the sands of the Sparta Formation **are not currently used as a source of public drinking water in the AoR**. The Sparta Formation is overlain in the AoR by a thin veneer of upper Eocene (upper Claiborne) Cook Mountain and/or Cockfield sediments, which in turn are unconformably overlain by the Holocene Mississippi River alluvial aquifer (locally, the point bars and other fluvial deposits of the Ouachita River floodplain), which represents the source of public drinking water for communities located in the project area (extending from the surface to an approximate depth of 250-300 feet). The thickness of the Sparta aquifer locally ranges from 600 to 800 feet, and its confining units (where present) are the overlying Cook Mountain and underlying Cane River Formations.

Cane River Formation (Base of the lowermost USDW), Figure A.1 **-** In north-central Louisiana, the term "Cane River" is given to the predominantly shale unit underlying the basal sandstone of the Sparta Formation (the base of which is the USDW). It ranges in thickness from 100 to 200 feet in the project area. The impermeable middle Eocene/Lower Claiborne Cane River Formation serves as the adjacent, underlying confining unit (aquitard) for the overlying Sparta Formation, which only contains fresh or brackish water in the northeastern area of Caldwell Parish.

Tallahatta Formation **-** The middle Eocene / lower Claiborne Tallahatta Formation directly overlies the Wilcox Formation and underlies the Cane River Formation (however, it is stratigraphically considered part of the Cane River Formation in Texas, and is also referred to as the "Carrizo" Formation in Texas and portions of western Louisiana). The Tallahatta Formation is comprised of an interlaminated series of marls, hard quartzitic lenses, and calcareous shales that are typically poor in porosity and very poor in permeability. The Tallahatta ranges in thickness from 50 to 60 feet in the project area.

Wilcox Formation - The lower Eocene / upper Paleocene Wilcox Formation is comprised of a thick series of sandstones, lignites, and shales that ranges in thickness from 1,300 feet in the most northern part of the project area to over 1,900 feet in the southeasternmost part of the project area. This significant change in isopachous thickness is attributable to both the influence of the Monroe Uplift, to the north, and a general coastward (southern) downwarping of the area during the Paleogene period. The depositional setting for the formation is continental, with lignite beds generally increasing in number in the Lower Wilcox. Methane generated from these lignites is believed to have been the source of gas that has been produced from Wilcox sands as well as from the lignites themselves in adjacent coal bed methane fields (e.g., Riverton Gas Field). Because of its thick sand/shale sequences, the Wilcox Formation is considered to represent an interlaminated saline aquifer / shale baffle interval; the highly porous nature of the numerous stacked Wilcox sandstones means that there are multiple vertical brine-filled reservoirs separated by shale baffles that can absorb any extraneous injectate that (in an improbable scenario) may find its way uphole, and serve to effectively dissipate the pressure associated with any such upward movement of such fluids or gases before they can reach the USDW, still separated by approximately 200 feet of additional impermeable strata (predominantly Cane River shale) above the top of the Wilcox Formation.

Midway Group, Figures A.2 and A.3 - The Paleocene Midway Group separates the overlying Wilcox Formation from the underlying Upper Cretaceous Selma Chalk. Accordingly, it represents a significant and highly effective regional confining unit. The Midway Group is approximately 600 feet thick across the project area. The lower 50-100 feet of the unit is generally known as the Clayton Marl in eastern Louisiana and southern Mississippi and consists of generally impermeable calcareous shales and marls. The basal Paleocene Clayton Marl was deposited unconformably atop the Upper Cretaceous Selma Chalk at the KPg boundary. The Porters Creek Shale directly overlies the Clayton Marl and, as the principal member of the Midway Group, typically consists of a thick, dense, gray-black terrigenous shale. This impermeable terrigenous shale transitions in the uppermost portion of the Porters Creek / Midway Shale to a slightly calcareous gray shale (Naheola equivalent). The 600 foot-thick Midway Shale serves as a very effective Secondary Upper Confining Zone for the proposed sequestration project.

Upper Cretaceous (Selma) Chalk Formation, Figure A.4 - The Maastrichtian-aged Upper Cretaceous Chalk interval is the youngest Cretaceous formation, being located just beneath the KPg boundary (unconformity). Within the AoR, the interval is comprised of a slightly sandy, impermeable upper chalk member (the Selma Chalk), followed by a glauconitic sandstone (the Annona), an argillaceous middle chalk member, and a basal, more argillaceous, calcareous unit that is the regional equivalent of the Austin Chalk. The entire Top Selma - Base Austin Chalk Equivalent interval ranges in thickness from 600 feet in the most northern part of the project area to over 1,200 feet in the southeastern most part of the AoR, a consequence of the regional influence of the Monroe Uplift, centered approximately 20 miles north of the subject area, as well as the general basinward expansion of the Cretaceous in the surrounding area.

Approximately 300 feet from the top of the Upper Cretaceous Chalk (i.e., the top of the Selma Chalk member), a glauconitic, shallow marine sandstone locally named the “Annona Sand" was deposited. This generally porous and permeable sandstone, considered to be of Taylor age, ranges in thickness from approximately 90 feet in the southeasternmost part of the AoR to less than 20 feet in its northernmost area, pinching out entirely within the basal Selma Chalk a short distance north of the AoR. Aside from some thin lenses of discontinuous clastic porosity erratically developed within the overlying Selma Chalk, the Annona Sand represents the only porous reservoir developed within the Upper Cretaceous Chalk that exhibits substantive aerial extent and reservoir volume. The Annona Sand has been extensively studied within the AoR (Figures A.5, A.6 and A.20). The argillaceous middle chalk (lower Taylor) member and the basal, more calcareous, argillaceous unit that is the local equivalent of the Austin Chalk are noteworthy in that their ductility has the appropriate characteristics (i.e., mechanical stratigraphy) to limit the upward propagation of vertical fractures that might form beneath the base of the Austin Chalk Equivalent interval.

Austin Chalk Equivalent / Upper Eagleford Interval, Figures A.28, A.29, A.30) - There are only a few thin, dense and impermeable limestones developed within the argillaceous Austin Chalk Equivalent within the AoR (six of the most prominent thin limestones deposited across the entirety of the AoR, labeled "AE 'A' Limestone", "AE 'B' Limestone", "AE 'C' Limestone", "AE 'D' Limestone", "AE 'E' Limestone", and "Basal Austin Chalk Equivalent", are identified on the cross sections (Figures A.13, A.14, A.15, and A.31) provided). This entire interval is extremely poor in porosity, interlaminated with argillaceous sediments, and essentially impermeable, as further characterized in Figure A.28. Underlying the Austin Chalk Equivalent is the Upper Eagleford Shale, an impermeable calcareous shale deposited between the Austin Chalk Equivalent and the top of the Upper Tuscaloosa, which thickens from ~10 feet to ~100 feet from north to south across the AoR. This aggregate Primary Confining Zone represents 200 to 500 feet of impermeable strata that is deposited directly atop the Primary Injection Zone.

Upper Tuscaloosa Formation, Figures A.7, A.8, A.9) - The Upper Tuscaloosa Formation, the Primary Injection Zone for the proposed sequestration project, represents the regressive phase of the greater Tuscaloosa depositional cycle. Most of the Upper Tuscaloosa Formation is considered to be the stratigraphic (lateral facies) equivalent of the Eagleford Formation of Texas. It averages ~640 feet in gross thickness across the project area. The Upper Tuscaloosa consists of gray-colored shales and some multicolored (red, green, and purple) mudstones interlaminated with fine to coarse-grained sandstones and siltstones. In north-central Louisiana, the Upper Tuscaloosa thins and transitions to a marine shale sequence as one moves in a southeasterly direction; conversely, the older underlying Middle Tuscaloosa Shale interval thickens in that same direction. Upper Tuscaloosa sandstones typically average 20% to 25% porosity in the north-central Louisiana area, with the best reservoir rock approaching 30% porosity. For the purposes of this narrative, minor regional disagreements between geologists regarding the correlation of the uppermost beds of the Upper Tuscaloosa to either those of the Eutaw Formation (in southeast Louisiana and Mississippi) or the equivalent of the basal Austin

Chalk (West Louisiana / East Texas) Formation have been set aside in favor of the use of a simple correlative electric log marker identified at the top of the first well-developed sandstone encountered beneath the base of the Austin Chalk Equivalent / Upper Eagleford interval within the AoR, which is a readily correlated log marker across the greater project area.

The sandstones and their interlaminated gray shales of the Upper Tuscaloosa become more calcareous (marine) as one approaches the top of the unit. The uppermost sandstones of the Upper Tuscaloosa are typically bioturbated, indicating a shallow marine / littoral depositional environment. The base of the Upper Tuscaloosa (Figure A.7) is not as distinct but generally conforms to the base of a correlative sandstone at the top of the Middle Tuscaloosa Formation, which is generally represented by a thin shale in the AoR.

One of the reasons the correlative base of the Upper Tuscaloosa is not as distinct is the lateral stratigraphic change that occurs in that interval as one progressively moves south of the project area. The sandstones of the basal Upper Tuscaloosa interval are the first to transition laterally into what are correlated to be Middle Tuscaloosa shales in south-central Louisiana. The Middle Tuscaloosa shale interval grades from essentially nil thickness in northern Caldwell Parish and southern Richland Parish area to over 500 feet in thickness in the Florida Parishes area of southeast Louisiana.

Most of the apparent southward thickening of the Middle Tuscaloosa shale interval thus represents the lateral facies change of the Upper Tuscaloosa as it grades from sandstones and siltstones in northern Louisiana to Middle Tuscaloosa shales as one moves south across central Louisiana. As these lateral facies changes occur, principally from the bottom up, the top of the Middle Tuscaloosa shale appears to rise stratigraphically within the greater Tuscaloosa interval. Because of its relatively uniform thickness (~640 feet; Figure A.9) and appreciable content of coarse grained, highly porous, and permeable clastics, the Upper Tuscaloosa Formation represents an optimal Injection Zone interval for the sequestration complex.

Dip-oriented stratigraphic cross sections indicate the Upper Tuscaloosa can be generally viewed as three approximately 200-foot-thick intervals, each separated by a predominantly shale interval that is typically 30 to 50 feet thick. The sandstones of the lowest (basal) third of the unit exhibit the most lateral discontinuity, for the reasons stated above. The sandstones of the middle third of the unit are more correlative but still exhibit considerable lateral discontinuity. As one approaches the upper 200 feet of the Upper Tuscaloosa (the upper third of the interval), greater lateral continuity of the sandstone reservoirs is generally observed. This culminates with the virtual sheet-sand geometry of the bi-lobed, reworked, shallow marine sandstone encountered at the very top of the Upper Tuscaloosa in the project area; the gross thickness of this sandstone can range as high as 60 feet.

Of the eleven legacy oil and gas test wells (dry holes) that were drilled deep enough to encounter all or a portion of the Upper Tuscaloosa within the 100-square mile project area prior to the drilling of the stratigraphic test well (SN975841), only one density-neutron porosity log run across the Upper Tuscaloosa in the Bass Enterprises No. 1 Jack L. Keahy well (SN165305, located in Section 8-T14N-R4E), was available.

Many of the legacy wells were drilled 60 to 80 years ago, prior to the advent of modern porosity logging tools. For those wells drilled later, the open-hole log filing requirements of the State of Louisiana required only the filing of an induction-electrical correlation log by the operator. Some well files maintained by the State are missing even the required correlation log; in those instances, every effort has been made to obtain at least a copy of the correlation log from another data source (commercial data broker sites such as IHS Markit, TGS, etc.). Having been noted, there are a few instances where the logs run across the Upper Tuscaloosa within the project area well are simply not available. This very rare absence of well log data for a particular well is noted on the maps that are provided with this narrative; it should be noted that a correlation log is available for the vast majority of the subject wells.

The updip limit of the Upper Tuscaloosa is characterized by the truncation of the interval to the north of Caldwell Parish, in the Ouachita and Richland Parishes area. This truncation is attributable to erosional events that represent significant unconformities associated locally with episodic upward movement of the regional Monroe Uplift, centered approximately 20 miles north of the proposed Louisiana Green Fuels plant site area. The older unconformity that impacts the Upper Tuscaloosa is that of the transgressing Selma Chalk Sea, which represents the youngest (Maastrichtian) unit of the Upper Cretaceous. Representing a period wherein global sea levels rose an estimated 400-500 feet in the North Louisiana area, the shallow Selma Chalk Sea drowned the area following a period of significant erosion that began in Maastrichtian time. The thin limestones and chalks of Selma age deposited atop this unconformity were later subjected to subaerial exposure and intensive leaching following the end of the Cretaceous. This leaching formed the porous "Gas Rock" facies of the Monroe Uplift, which hosts a large gas reservoir in the Monroe, Louisiana area. The porous Selma-aged Gas Rock facies of the Monroe Uplift does not extend southward to even the northernmost perimeter of the AoR.

The end of the Cretaceous is distinguished by a second, much more significant unconformity at the KPg boundary that resulted in the deposition of the Paleocene Clayton Marl and the overlying, thick Porters Creek member of the Midway Shale (the latter across almost all of the entire onshore U.S. Gulf Coast area). These vertically impermeable units of the Midway Group effectively served as an efficient vertical barrier to fluid and gas migration at the Cenozoic / Mesozoic unconformity. Twenty miles north of the AoR, at the broad crest of the Monroe Uplift (where even the Selma Chalk facies was removed by erosion), the deposition and compaction of the thick Paleocene Midway Shale interval effectively sealed all Mesozoic strata that had been uplifted and subjected to erosion at either (or both) unconformity surfaces.

The top seal for the Upper Tuscaloosa is best described as follows: in those areas south of the older Selma unconformity surface, the top seal consists of the impermeable shales, marls and calcareous beds (chalks and limestones) of the overlying Upper Cretaceous, especially that thick interval that extends from the base of the Annona Sand to the base of the Austin Chalk Equivalent / Upper Eagleford interval, directly atop the Upper Tuscaloosa Formation. In those areas north (updip) of the older Selma unconformity surface, the impermeable marls, and shales of the 600-foot-thick Paleocene Midway Shale (the base of which is atop the KPg Boundary) effectively form a very effective secondary regional top seal for the entire Tuscaloosa interval, as well as all other Mesozoic strata truncated by the KPg Unconformity (or any other local angular unconformity). The effectiveness of this thick and effective secondary top seal is demonstrated, for example, by the giant accumulations of oil and gas trapped beneath the Midway Shale at Delhi and Monroe Fields in the Morehouse, Ouachita, and Richland Parish areas, well north of the AoR in Caldwell Parish.

The adjacent parish that borders Caldwell Parish on its eastern side is Franklin Parish. Steven S. Walkinshaw, the Louisiana Licensed Professional Geoscientist who contributed to this report, was responsible for the drilling and evaluation of several Lower Tuscaloosa oil and gas test wells drilled in the adjoining Franklin Parish over the past 15 years and has personally supervised the drilling and logging of the Tuscaloosa interval in each of those wells. This experience has provided insights into the petrophysical characteristics of the Upper Tuscaloosa sandstone reservoirs targeted for CO_2 sequestration within the AoR.

Notwithstanding the relative lack of porosity log data in the project area, a careful review of the logs from the legacy Upper Tuscaloosa penetrations indicates the following general empirical observations about reservoir porosity can be made:

1. On the electrical correlation logs for the oldest wells, typically good spontaneous potential curve deflection appears associated with the optimally porous Upper Tuscaloosa sandstone reservoirs encountered in those wells.

2. The limited range of investigation of older resistivity tools means that virtually all of the older logged wells exhibit only the resistivity of the near-wellbore flushed/invaded zone, which (given the fresh water native muds used to drill said wells) is of only limited utility in petrophysical analysis. An improvement in the range of investigation of the resistivity tools over time, as well as the use of generally better drilling fluids, reveals the existence of certain reservoirs within the Upper Tuscaloosa sandstones that harbor excellent porosity and exhibit extremely low (less than 0.6 ohm-meter) resistivity. This correlation between high porosity and very low resistivity, in a brine-filled environment, is logical and straightforward and confirmed by the petrophysical analysis of the Bass No. 1 Keahy log (SN165305), where a density/neutron porosity log (run on limestone matrix) across the Upper Tuscaloosa is available.

Middle Tuscaloosa Formation - Within the AoR, the Middle Tuscaloosa Formation is a thin (60 to 100 feet thick) dark gray shale that thickens to the south because of the coastward expansion of the greater Tuscaloosa sedimentary wedge. Additionally, the increase in formation thickness is also due to the lateral facies transition of the overlying basal Upper Tuscaloosa sandstones and siltstones to their stratigraphic equivalents that are shales virtually indistinguishable from their underlying Middle Tuscaloosa counterparts. The shale of the Middle Tuscaloosa Formation is the first (ancillary) confining layer beneath the Upper Tuscaloosa Formation; although generally dark gray in color, this interval also contains many thin laminated layers of reddish-brown shale. The gray shales facies are hard and impermeable and typically splinter into shards when drilled. The Middle Tuscaloosa shale contains many silt lenses (especially in its upper half) and, while generally non-calcareous within the AoR, can contain one or more thin limestones near its basal contact with the underlying Lower Tuscaloosa.

Lower Tuscaloosa Formation - The thickness of the Lower Tuscaloosa Formation in the project area is similar (60 to 100 feet). Two fluvial-deltaic sandstone systems - the Basal Sand and the overlying Stringer Sand - were deposited within the Lower Tuscaloosa Formation in the north-central Louisiana area. Because of their limited, lenticular, fluvial-deltaic geomorphology, a well drilled in the area might encounter either sand, both sands, or no sand. The Basal Sand is more prevalent in the project area and is typically deposited directly atop the significant UK/LK Unconformity. Stringer and Basal sandstones of the Lower Tuscaloosa contain appreciable volumes of chlorite and kaolinite and are very sensitive to drilling and completion practices and fluids (Weedman, 1996; Berg et al, 1980). Within the AoR, the percentage of chlorite deposited in the Basal Sand can total over 9% of the total reservoir matrix; at those concentrations, the effective permeability of the Basal Sand is severely impacted, with the chlorite clay occluding the pore throats. For this reason, the Lower Tuscaloosa Basal Sand is not considered to represent a viable sequestration reservoir objective within the AoR.

Washita-Fredericksburg Formation - Throughout most of the AoR, the Washita member of the Washita-Fredericksburg Formation is the first Lower Cretaceous formation encountered directly beneath the UK/LK Unconformity. Prior to the deposition of the Upper Cretaceous, the Lower Cretaceous strata in the area were exposed along a low angle angular unconformity (at the UK/LK boundary) and subjected to substantial erosion. Consequently, the thickness of the Washita-Fredericksburg interval is progressively reduced from over 1,200 feet in southwest Mississippi and the Florida Parishes of the East Louisiana to an updip "zero" line (complete truncation) demarcation that includes, among other areas, portions of the northern Caldwell Parish area, immediately north of the AoR (Spooner, 1964) (see Figure A.15, Cross Section B-B').

The Washita-Fredericksburg Formation is readily recognized on mudlogs and electrical logs as a series of dark gray calcareous fossiliferous shales interbedded with typically thin gray, brown, or buff-white dense crystalline limestones. Some thin fine-grained calcareous sandstones are also present but are very limited in aerial extent, appearing to represent marine bars. Because of their distinctive (highly resistive) log character, the limestones of the Washita-Fredericksburg interval can often be correlated across a large geographic area, south of their truncation at the UK/LK Unconformity. Where it is present – across an area that includes almost all the AoR – the Washita-Fredericksburg represents an excellent containment interval for both the Upper Tuscaloosa and the underlying sandstones of the Paluxy Formation.

Paluxy Formation, Figure A.10 - Like the overlying Washita-Fredericksburg Formation, the Paluxy Formation was also exposed along a low-angle angular unconformity (at the UK/LK boundary) and subjected to substantial erosion in the northeast Louisiana area. However, in north-central Louisiana, the Paluxy Formation is considerably thicker than the Washita-Fredericksburg Formation and is not fully truncated by the Selma and/or Midway unconformities until it approaches the crest of the Monroe Uplift, approximately 20 miles north of the project area. The top of the Paluxy Formation is generally noted on electrical logs and mud logs as that sand and shale sequence that directly underlies the last (basal) limestone of the Washita-Fredericksburg. Most of the sandstones encountered within the Paluxy Formation in the project area are lenticular channel sands with limited aerial extent. The Paluxy Formation is typically 700 to 1,000 feet thick in the greater Caldwell Parish area.

Mooringsport Formation - The Mooringsport Formation underlies the Paluxy Formation and typically consists of dense, calcareous, impermeable shales and limestones containing lenticular sandstones that are similar in size and thickness to the channel sands encountered in the overlying Paluxy Formation. In the project area, the Mooringsport Formation is approximately 500 feet thick and represents another excellent (lower) containment interval beneath the Paluxy. The top of the Mooringsport is generally encountered approximately 1,000 feet below the base of the Injection Zone in the AoR.

Ferry Lake Formation - The Ferry Lake Anhydrite Formation is well developed in the project area and comprised of regionally extensive evaporites and tight carbonate facies that were deposited in a broad, shallow-subtidal hypersaline lagoonal environment (Loucks, 1987) . The evaporitic beds of the Massive Ferry Lake Anhydrite are approximately 200 feet thick in the Caldwell Parish area. Another evaporite layer, the 60 foot-thick Lower Ferry Lake Anhydrite Stringer, is typically encountered approximately 80 feet beneath the base of the Massive Anhydrite interval. The sedimentary layer separating the base of the Massive Anhydrite from the top of the Lower Ferry Lake Anhydrite Stringer is a very hard impermeable dark gray calcareous shale interbedded with thin layers of red calcareous splintery shale, very thin tight limestones, and very thin laminar beds of anhydrites. The Lower Ferry Lake Anhydrite Stringer consists of approximately 30 feet of anhydrite and an equivalent thickness of dense anhydritic limestone. The overall interval from the top of the Massive Anhydrite to the base of the Lower Anhydrite Stringer is approximately 350 feet thick. The Massive Anhydrite represents (on an impermeability basis) the most effective confining unit in the north Louisiana area. The top of the formation is generally encountered approximately 1,600 feet below the base of the Upper Tuscaloosa Injection Zone in the AoR.

2.2.3 *Local Structure*

The Port of Columbia site is located on the southwestern flank of the Monroe Uplift, a regionally large anticlinal structure that, as described previously, moved episodically upward, especially at the end of the Cretaceous (Figure 2-18). The Monroe Uplift is centered in extreme northeastern Louisiana, approximately 20 miles north of the project site, and is principally defined based on subsurface log data. It is bounded by the North Louisiana Salt Basin and the Mississippi Salt Basin on the southwest and southeast sides, respectively (Ewing, 1991). The RCP, a Paleozoic ridge that separates the two salt basins, was first described by Steven S. Walkinshaw in 2018 and its presence was cited in a paper published in 2020 (Walkinshaw). The RCP underlies most of the AoR and accounts for the thinning or non-deposition of the Permo-Triassic Louann Salt across most of the greater Caldwell Parish area.

The upward movement of the Monroe Uplift is also associated with a period of Late Cretaceous (Campanian) igneous activity. Igneous rocks have been encountered in nearly 100 boreholes drilled across the Monroe Uplift, including granite, syenite, pyroxenite, dolerite, basalt, nepheline syenite, phonolite, lamprophyres and pyroclastics[1]. The Monroe Uplift developed as a discrete structural feature in Late Cretaceous time when regional upwarping resulted in the erosion of as much as two miles of Mesozoic strata from the crest of the anticline. The upwarping associated with the Monroe Uplift ceased at the end of the Cretaceous and the feature was subsequently buried by the deposition of thick Paleogene sediments. In the AoR, normal sequential deposition of Upper Cretaceous and Paleocene strata, albeit thinning to the north in the direction of the crest of the Monroe Uplift, appears to have occurred. Depending on the area of investigation, some of the uppermost Cretaceous strata in that area may be absent (either not deposited or subsequently eroded by either the Selma-aged or KPg unconformities). Taken in a regional context, the Monroe Uplift thus had an impact upon the subsurface Mesozoic structure of the AoR, resulting generally in an increase in the angle of dip of the uniformly dipping Mesozoic strata to the south-southwest.

Local structure maps prepared for the project and are contained in Appendix A include:

- Top of Eocene Cane River/Base of Sparta (lowermost USDW) – Figure A.1
- Top of the Paleocene Midway Shale – Figure A.2
- Top of the Upper Cretaceous Selma Chalk – Figure A.4
- Top of the Upper Cretaceous Annona Sand – Figure A.5
- Top of the Upper Cretaceous Austin Chalk Equivalent – Figure A.30
- Top of the (Upper Cretaceous) Upper Tuscaloosa Formation – Figure A.7

[1] https://alkcarb.myrocks.info/node/1194

- Top of the (Lower Cretaceous) Paluxy Formation – Figure A.10

Additionally, 237.112 linear miles of 2D seismic data covering the AoR has been licensed, interpreted and evaluated for both structure and the presence or absence of any faulting in the Cretaceous intervals shallower than the Ferry Lake Anhydrite.

2D seismic time structure maps were prepared for the project and include the following horizons:

- Top of the Ferry Lake Anhydrite Peak Event (2D Time Horizon) – Figure A.11
- Top of the Upper Cretaceous Chalk Peak Event (2D Time Horizon) – Figure A.12

The 2D seismic time structure maps and 2D data (Figure A.19) exhibit good conformance with the subsurface structure maps (Figure A.11 also includes the subsurface structure map of the Top Ferry Lake Anhydrite). These interpretations indicate a consistent south-southeast dip with very minor structural undulations that are typical for this area. It should also be noted that some of the minor structural undulations are probably the result of inconsequential 2D seismic mis-ties.

Most importantly, a detailed analysis of the 2D seismic data indicates there is no faulting within the AoR that impacts Cretaceous strata and could possibly create a potential CO_2 injectate leak path or disrupt reservoir continuity and compartmentalize the proposed Injection Zone intervals (either the multiple sandstones of the Upper Tuscaloosa Formation or the Paluxy Formation).

Additional structure maps are contained in Appendix A for:

- Top of the Lower Cretaceous / Washita-Fredericksburg Formation – Figure A.16
- Base of the upper Paluxy "P-3" Sand – Figure A.17

The overall thickness of the entire Injection Interval is presented in Figure A.18.

2.2.4 Absence of Faulting Within the Area of Review

Within the AoR, no faults, fracture systems, or anticlinal structures that impact Cretaceous strata located above the Lower Confining Zone have been identified, as evidenced by the provision of three (dip and strike – oriented) cross sections that transect the AoR. Cross section A-A' is displayed using both structural and stratigraphic datums (Figures A.13 and A.14 contained in Appendix A), while the dual structural cross section B-B' / C-C' exhibit (Figure A.15) contains a dip-oriented structural cross section B-B' that transects the injection site area and a strike-oriented structural cross section C-C' that also transects the injection site area. This exhibit also includes the composite type log and annotated Platform Express log presentations of the stratigraphic test well, which is one of the wells featured on both cross sections B-B' and C-C'.

The cross section exhibits also integrate, as sidebar exhibits, images of arbitrary 2D seismic lines created from the 2D seismic database that are designed to run as close to parallel as possible to the lines of cross section. These arbitrary 2D seismic lines confirm the absence of faults along the correlative lines of cross section, which meets the Siting Criteria set forth in LAC 43:XVII §3615 (A)(1) and (A)(2). The cross sections also serve to illustrate the thickness and continuity of the various confining zones, containment intervals, and sequestration zones within the AoR.

A total of fifteen 2D seismic lines are located either totally or partially within the AoR. All of these 2D seismic lines have been recently reprocessed (2021 – 2024) and interpreted. Figures A.19.a and A.19.b are seismic montages that display that portion of each of the 15 seismic lines that are located within the AoR. The gridded mapped time horizons picked on the Top Chalk (Figure A.19.a) and Top Ferry Lake Anhydrite (Figure A.19.b) peak events are shown in the center of each seismic montage. On each seismic line "panel", the Top Chalk and Top Ferry Lake Anhydrite horizons are visible as blue and magenta – colored time horizons; the Top Chalk horizon attributable to the blue time horizon (average 2-way time around 1.0 seconds), and the Top Ferry Lake Anhydrite horizon attributable to the magenta time horizon (average 2-way time around 1.7 seconds). These interpretations indicate uninterrupted monoclinal dip on each of the 15 2D seismic lines. A visual inspection of the mapped horizons as interpreted on each 2D seismic line corroborates the assertion that no substantive faulting impacts the strata from the surface to the Lower Confining Zone, the Ferry Lake Anhydrite. A synthetic seismogram generated from acoustic data acquired in the Class V Stratigraphic Test Well (combined with velocity and time-depth data obtained from the VSP run in that well) is shown on Line 82-202-1086 at that projected wellbore intersection; it demonstrates excellent correlations with the two mapped horizons.

Additionally, as evidenced by the structure and isopach maps prepared for the proposed sequestration site [LAC 43:XVII §3607 (C)(1)], there is no subsurface evidence of faults or fracture systems that extend upward into and impact the Cretaceous strata above the Ferry Lake Anhydrite within the 91 square-mile AoR.

Based upon all the mapping performed, a diligent published literature search, and the interpretation of the site-specific seismic data, Applicant has concluded there is no faulting indicated within the AoR that could potentially create a CO_2 injectate leak path or compartmentalize the underlying Upper Tuscaloosa / Paluxy Injection Zone. The Confining and Injection Zones within the AoR are all laterally continuous and free of transecting, transmissive faults or fractures that could possibly facilitate the upward movement of injectate fluids or gases from the Injection Zone into the USDW or any other freshwater aquifer.

2.3 DESCRIPTION OF THE CONFINING AND INJECTION ZONES

This section contains the information on the confining and injection zones for the proposed sequestration site per the LAC 43:XVII §3607 (C)(2)(a) standard. Details pertaining to the formation characteristics, lateral and vertical extent, and mineralogy are identified for each zone of interest. Demonstration of security for injection includes a geologic containment demonstration and the absence of vertically transmissive faults that could form breaches of the containment system.

The Confining Zone is defined as "a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement". For the Louisiana Green Fuels, Port of Columbia Facility AoR, the regionally extensive Austin Chalk Equivalent / Upper Eagleford interval has been identified as the Primary Upper Confining Zone, located in the interval between 4,637 feet and 4,911 feet (measured log depths) as depicted on the on the SLB Platform Express / GR / SP / Caliper Log (Run 3) for the Louisiana Green Fuels stratigraphic test well. It should be noted that additional thick confining layers, consisting primarily of the Selma and Middle Chalks, intervals occupy much of the stratigraphic interval extending from the top of the Austin Chalk Equivalent / Upper Eagleford interval to the top of the Secondary Upper Confining Zone, the Midway Shale. These containment intervals will act as additional effective barriers to vertical flow. Mudstones and limestones of the Washita-Fredericksburg Group, as well as those within the underlying Paluxy Formation, will provide several lower containment intervals. Further beneath the Paluxy Formation, the thick impermeable limestones of the Mooringsport represent yet another containment interval, and the thick evaporites (anhydrites) of the Ferry Lake Anhydrite Formation represent an optimal and regionally extensive bottom seal (the Lower Confining Zone).

The Injection Zone is defined as "the geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a geologic sequestration project". Injection targets are identified as formations below a depth of 3,000 feet, which defines the top of the supercritical window for carbon dioxide sequestration. Two sequestration reservoir intervals have been identified.

From the shallowest to the deepest formation, they are as follows: (1) the multiple sandstones of the Upper Cretaceous (UK) Upper Tuscaloosa Formation, between 4,911 feet and 5,514 feet; and (2) the multiple sandstones of the Lower Cretaceous (LK) Paluxy Formation, between 5,771 feet and 7,000 feet (the depth of the base of the deepest Paluxy sandstone reservoir (the "P-3 Sand") encountered in the stratigraphic test well at 5,846 feet). The stratigraphic test well bottomed at 6,200 feet, which is fully 800 feet above the proposed total depth of the injection and most monitor wells (all measured log depths below the Top Selma Chalk as described above are shown based upon the Composite Type Log (Figure 2-2) as being associated with the log from the stratigraphic test well). Each of the reservoir intervals described within the proposed Injection Zone contains multiple sandstones with the necessary characteristics to be effective sequestration reservoirs at the Louisiana Green Fuels, Port of Columbia Facility and are located more than 3,000 feet below the lowermost aquifer that meets the criteria for being a USDW (less than 10,000 mg/l total dissolves solids content), identified locally as the basal sandstone of the Eocene Sparta Formation.

With regard to the Paluxy Formation, additional potential sequestration reservoirs (comprised of stratigraphically deeper, porous and permeable siliciclastic sandstones) have been identified in adjacent deeper oil and gas dry holes drilled within the AoR; these reservoirs will also be targeted by the proposed injection and most monitor wells, which are to be drilled to a total depth of 7,000 feet. A representative section of the entire Paluxy interval is shown on the Composite Type Log.

2.3.1 Confining and Containment Zones

Demonstration of security for injection includes a geologic containment with impermeable, laterally extensive strata and the absence of vertically transmissive faults that could form breaches of the containment system. In accordance with LAC 43:XVII §3607 (C)(2)(a), the Confining Zone is a laterally extensive layer that restricts the vertical flow of injectate due to sufficiently low porosity and permeability. Within the Louisiana Green Fuels proposed site, the identified Primary Upper Confining Zone is the 240-370 foot-thick interval of Austin Chalk Equivalent / Upper Eagleford interval, topped by thick (200-450 foot-thick) calcareous shales of the regionally extensive Middle Chalk.

In addition to the Primary Upper Confining Zone, the upper 300 feet of the Selma Chalk and the overlying 600 foot-thick Secondary Upper Confining Zone, the Midway Shale, have been identified as additional upper containment intervals that will also serve as effective barriers to potential vertical migration, providing a further measure of safety. The Lower Cretaceous formations encountered beneath the UK / LK Unconformity also contain numerous containment intervals; the impermeable mudstones and limestones of the Washita-Fredericksburg Group are encountered just below the UK / LK Unconformity within the AoR, while interspersed and beneath the multiple sandstones (potential sequestration reservoirs) of the Paluxy Formation, thick mudstones and limestones of the Paluxy and Mooringsport Formations represent additional containment intervals, and beneath the Mooringsport, the thick evaporites of the Ferry Lake Anhydrite Formation comprise a very effective Lower Confining Zone. Finally, in addition to the overlying Primary Upper Confining Zone, the targeted sandstones of the Upper Tuscaloosa and Paluxy Formations are interlayered with impermeable mudstones that are expected to provide additional intraformational confinement for the individual sandstone layers.

Abundant site-specific core data was collected during the drilling and logging of the stratigraphic test well (SN975841) and analyzed by Stratum Reservoir in Houston, Texas. Measurements were performed to characterize the mineral composition and petrophysical characteristics of the Midway Shale (the Secondary Upper Confining Zone) and the Austin Chalk Equivalent / Upper Eagleford interval (the Primary Upper Confining Zone), as well as several Upper Paluxy Shale containment layers (presented in Tables 2-2, 2-3, and 2-4). Along with published literature data, this test data has been used to develop model parameters and inputs for the sequestration site.

2.3.1.1 Secondary Upper Confining Zone – Midway Shale

Mudstones of the Midway Group represent the Secondary Upper Confining Zone for the Louisiana Green Fuels, Port of Columbia project site. The Midway Group is a thick and predominantly terrigenous (non-calcareous) clay unit, which on a regional basis might contain minor amounts of sand (Barnes, 1965). However, in the project area, the matrix of the Midway Group is almost completely shale. The top of the Midway Group is observed at approximately 3,128 feet (measured log depths based upon the Composite Type Log (Figure 2-2) and is approximately 600 to 650 feet thick (Figure A.3 in Appendix A). The Midway Group underlies the Paleocene-Eocene Wilcox

Formation, creating a regionally extensive seal that extends across all north Louisiana. In the greater Caldwell Parish area, the thick shales of the Midway Group are neither faulted nor fractured. Accordingly, the Midway Group has sufficient areal extent, thickness, and integrity to confine any proposed supercritical CO_2 or other injectate that might escape the Primary Upper Confining Zone.

A conventional whole core was obtained from the Midway Group in the lower Porters Creek Clay over the depth range of 3,600 feet to 3,628.75 feet during the drilling of the stratigraphic test well. Although 28 feet of core was successfully recovered, the suitability of the core for sampling (i.e., the cutting of suitable core plugs) for laboratory measurements was compromised by the presence of the swelling clays (mostly smectites) that comprise the predominant clay type. This lithology caused the Midway Shale core to degrade somewhat during the retrieval operations despite significant precautions made to decrease potential swelling (i.e., low water loss drilling fluid, slow retrieval, etc.). Three plug samples were obtained from the whole core to determine near-site specific parameters for the Secondary Upper Confining Zone and are included in Table 2-2. The analysis of whole core samples acquired from the lower Midway Group (Porters Creek Formation; obtained in Core No. 1) was augmented by the supplemental petrophysical data provided by the acquisition of the open hole logs run across the Midway Shale in the stratigraphic test well and older offset wells within the surrounding area, which serve to characterize the well-established sealing and confinement properties of the Midway Group. Data from whole cores to be acquired during the drilling of the proposed injection wells will provide additional physical data to further characterize the sealing and confinement properties of the Midway Group.

2.3.1.1.1 Formation Characteristics

The core acquired from the Porters Creek member of the Midway Group consists almost entirely of dark gray mudstone that is silty in part. This lower Midway mudstone lithofacies is dominantly massive, but vague, faint planar to wavy laminations are also present. Several thin, very fine-grained sandstone planar to wavy laminations occur in the core. Other features observed from the whole core include soft sediment deformation structures, flame structures, phosphatic nodules, and *Planolites* and *Skolithos* burrow traces. These observations support the interpretation of the lower Midway stratigraphic equivalent as having been deposited in a marginal marine environment dominated by the accumulation of fine-grained, terrigenous sediment. As one progresses upward through the Midway Shale, the mudstone facies grades into a more terrigenous (non-marine) facies.

Permeability – especially vertical permeability – is a crucially important consideration for assessing the suitability of a geologic formation to prevent vertical fluid migration. The matrix permeability of the lower Midway Group mudstones was determined using crushed rock analysis. As expected, the matrix permeabilities measured for the lower Midway Group samples were extremely low, ranging from 0.0000262 to 0.0000977 mD (Table 2-2). These measurements are consistent with the clay-rich, very fine-grained character of the samples (Figure 2-21) and further demonstrate why the thick and regionally extensive Midway Group has historically been recognized as a very effective upper seal and confinement layer for oil and gas accumulations trapped beneath the Midway Shale in north Louisiana (and elsewhere).

2.3.1.1.2 Mineralogy and Petrophysics

X-Ray Diffraction (XRD) measurements were acquired from three samples taken from the cored mudstones of the lower Midway Group. These samples confirm that clays overwhelmingly dominate the mineralogy of this interval (Table 2-3). The total clay content for these samples ranges from 63.8 weight percent to 65.4 weight percent. The clay component is comprised of mixed layer illite/smectite clays, ranging from 30.0 weight percent to 32.6 weight percent in the three samples, and illite/mica, ranging from 17.3 weight percent to 22.4 weight percent. Modest amounts of chlorite and kaolinite clays were also present in each sample.

While the Midway Group mineralogy is dominated by clays, tectosilicates are noticeably elevated in the three measurements (Table 2-3). Quartz is the dominant tectosilicate present, ranging from 26.3 weight percent to 27.1 weight percent. Minor amounts of potassium feldspar and plagioclase are also present. The examination of the thin sections taken from the cores acquired from the lower Midway Group confirms the extremely fine grained, somewhat silty character of these lower Paleocene mudstones (Figure 2-22). It is noteworthy that no carbonate minerals were detectable using XRD for any of the Midway Group samples.

In addition to XRD measurements, elemental data was acquired using X-Ray Fluorescence (XRF) to further investigate the composition of the lower Midway Group mudstones (Table 2-4). Silica is the dominant element present, with SiO_2 abundance ranging from 56.1% to 63.8%. The preponderance of silica is consistent with the observations from the XRD measurements and is an indication of the influx of a substantial volume of terrigenous siliciclastic sediment (as both quartz and clay) during Midway deposition. These samples also include modest amounts of Al_2O_3, ranging from 15.4% to 17.8%, and Fe_2O_3, ranging from 5.3% to 5.8%. When considered together, this elemental data confirms the elevated clay content observed in the XRD measurements. The CaO abundance obtained from XRF is negligible, ranging from 0.3% to 0.4%. These data confirm that the silty mudstones sampled from the core cut in the lower Midway Group consist predominantly of terrigenous sediments.

2.3.1.2 Lower Confining Zone – Ferry Lake Formation; Other Lower Containment Intervals

Silty mudstones and limestones of the Washita-Fredericksburg Formation comprise a containment interval encountered a short distance below the Upper Tuscaloosa Injection Zone. The Washita-Fredericksburg is the first Lower Cretaceous unit encountered beneath the angular unconformity at the UK / LK Boundary (Unconformity). The unit has a thickness of 92 feet, extending from 5,628 feet to 5,744 feet (Figure A.16 in Appendix A) as observed in the stratigraphic test well (Figure 2-2). The majority of the interval consists of hard and impermeable buff-white limestones. While core samples were not obtained over this interval, an examination of the open hole logs indicates a lack of porous and permeable layers throughout this unit. While the same logs indicate the presence of three porous and permeable sandstones in the underlying Paluxy Formation, those Paluxy sandstones are in turn interbedded with shales with extremely low to negligible permeability. This was confirmed by laboratory analysis of Core No. 5, cut in the shale interval below the lowest (P-3) of the three Paluxy sandstones encountered in the stratigraphic test well.

The Washita-Fredericksburg Formation is fully truncated by the UK / LK angular unconformity just north of the northern perimeter of the AoR. Where it is present, the generally impermeable nature of the Washita-Fredericksburg Formation, combined with the limited porosity data from the available open hole logs, supports the viability of this unit as an additional containment interval that segregates the Injection Zone intervals of the (UK) Upper Tuscaloosa Formation from the Injection Zone intervals of the (LK) Paluxy Formation. Additional core and log measurements may be acquired in the future to further characterize the potentially significant Washita-Fredericksburg containment interval.

The Paluxy Formation underlies the Washita-Fredericksburg Formation and, depending on where it is penetrated, is approximately 700 to 900 feet thick, as indicated on the open hole logs for the Bass No.1 Keahey (SN165305; also shown on the Composite Type Log, Figure 2-2), which is located in the northern sector of the AoR. The upper half of the interval is characterized by fluvial and fluvial-deltaic sandstones that can have porosities as high as 22%. The interbedded shales, as noted earlier, are very hard and contribute to the local confinement of any injectate sequestered in the adjacent sandstones. Beneath the deepest upper Paluxy sandstone reservoir encountered in the stratigraphic test well (the upper Paluxy “P-3” Sand), the facies transitions from a continental environment to a marginal marine environment. The deepest whole core cut in the stratigraphic test well (No. 5) was recovered from the transitional base of the continental environment facies.

Beneath the Paluxy Formation lies the Mooringsport Formation, which consists of a series of interbedded calcareous mudstones, argillaceous limestones, and in rare instances, calcareous sandstones that can range up to 50 feet in thickness. The Mooringsport Formation typically averages 400 feet in thickness, as indicated on the open hole logs for the Bass No.1 Keahey (SN165305). Directly underlying the Mooringsport are the evaporites (predominantly anhydrites) of the Ferry Lake Anhydrite Formation. These laterally continuous evaporites constitute the densest, most optimal bottom seal beneath the proposed Injection Zone, and average 200 to 300 feet in thickness throughout the AoR. As such, the Ferry Lake Anhydrite Formation will act as a highly effective Lower Confining Zone throughout the AoR.

2.3.1.2.1 Formation Characteristics – Paluxy (Interbedded Containment Layers)

A whole core (Core No. 5) was acquired from the Paluxy Formation in the stratigraphic test well over the depth interval of 5,900 feet to 5,929 feet. This interval consists primarily of fine to very fine, argillaceous sandstones interlayered with silty mudstones. The main sedimentary structures observed in the argillaceous sandstones include ripples and wavy laminations, and burrow traces are abundant. The sandstones exhibit a brownish red color, most likely due to elevated concentrations of hematite and iron oxide resulting from prolonged subaerial exposure. The silty mudstones are planar laminated but also include abundant, thin very fine sandstone laminations. Fluid escape structures, herringbone cross bedding, and abundant trace burrows are also observed in the silty mudstones. These observations are consistent with deposition in a continental environment, with the sand deposited as fluvial bedload while silt and mud accumulated in an interfluvial setting.

The porosity and permeability of four samples acquired from the whole core were determined using the crushed rock technique and provided confirmation of the containment efficacy of such interbedded shales within the Paluxy Formation (Table 2-2). Dry helium porosity ranges from 9.0% to 10.5%, while permeability is extremely low for all measured samples, ranging from 0.0000048 mD to 0.0000390 mD (average 0.0000203 mD). These measurements are consistent with the fine grained, clay-rich character of these samples as observed in the SEM (Figure 2-23) and thin section (Figure 2-24).

2.3.1.2.2 Mineralogy and Petrophysics (Interbedded Containment Layers)

The mineralogy of the argillaceous Paluxy interval cored in the stratigraphic test well is dominated by quartz and clay (Table 2-2). Quartz content ranges from 39.3 weight percent to 46.9 weight percent, and clay content ranges from 35.4 weight percent to 36.9 weight percent. Relatively minor amounts of potassium and plagioclase feldspar are also present. The clay component is dominated by illite/mica, which ranges from 22.7 weight percent to 24.5 weight percent. Carbonates represent a relatively insignificant component of the overall mineral assemblage and are present mainly in the form of cements (ranging from 1.9 weight percent to 11.0 weight percent). The XRD data confirms that hematite percentages are elevated in the argillaceous sandstone facies, ranging from 4.1 weight percent to 8.6 weight percent. Elemental data acquired using XRF confirm that SiO_2 and Al_2O_3 dominate these samples (Table 2-4). The occurrence of CaO is insignificant, ranging from 1.5% to 5.9%. These data confirm that the facies consist predominantly of terrigenous sediment that was subjected to prolonged subaerial exposure.

A single sample was acquired from the whole core from the silty mudstone lithofacies. Clay (67.1 weight percent) is the most abundant mineral type for these facies (Table 2-2). The most abundant clay type is illite/mica, but the percentage of mixed illite/smectite is also elevated in this sample.

The quartz content is relatively low (23.1 weight percent). The elemental data acquired from XRF indicates SiO_2 at 53.5% and Al_2O_3 at 14.4%, again confirming the terrigenous character of these sediments (Table 2-4).

2.3.1.3 Primary Upper Confining Zone – Austin Chalk Equivalent / Upper Eagleford

Additional impermeable fluid flow barriers exist between the Primary Upper and Lower Confining Zones. These additional containment layers include the Middle Tuscaloosa Shale, the Washita-Fredericksburg Formation (where present), and the intraformational shales separating the channel sandstones within the Paluxy Formation. Above the Primary Upper Confining Zone, the Upper (Selma) Chalk interval above the Annona Sand extends from 3,733 feet to 4,144 feet as shown on the Composite Type Log (Figure 2-2). Beneath the base of the Annona Sand, the argillaceous Middle Chalk (Taylor equivalent) has been identified as an additional impermeable layer that extends from 4,195 feet to 4,637 feet in the stratigraphic test well (Figure 2-2).

An analyzed sample from the whole core cut and retrieved from the Austin Chalk Equivalent in the stratigraphic test well exhibited a matrix permeability measurement of 0.0000403 mD using the crushed rock technique (Table 2-2). This exceedingly low permeability measurement is consistent with fine grained, poorly sorted, clay-rich matrix of the Austin Chalk Equivalent as observed in thin section (Figure 2-25). The Austin Chalk Equivalent and the underlying Upper Eagleford Shale are thick and laterally extensive across the AoR; in aggregate these formations comprise the Primary Upper Confining Zone. Five regionally-continuous limestone beds ("Austin Chalk Equivalents "A" through "E") can be readily mapped across the AoR (as indicated on Cross Section Figures A.13, A.14 and A.15); these interbedded limestones are dense and impermeable and represent excellent intraformational seals distributed evenly throughout the Austin Chalk Equivalent interval. Figure A.28, a confining layer characterization exhibit, illustrates these strata.

Interbedded shales of the Upper Tuscaloosa Formation also have the potential to serve as additional intraformational containment layers. An examination of the open hole logs acquired from the stratigraphic test well indicates the Upper Tuscaloosa sandstones proposed as Injection Zone reservoirs for this project are interlayered with numerous mudstone layers. While additional core data will be required to fully evaluate their confinement potential, an analysis of the open hole logs indicates these interbedded shales are impermeable. Many of these individual mudstone layers exceed 20 feet in thickness, and these interbedded containment intervals will impede or prevent any upward migration of injectate from individual sequestration intervals (sandstone reservoirs) within the Upper Tuscaloosa Formation.

2.3.2 Injection Zones

The Injection Zone is defined as "the geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a geologic sequestration project". Upper Cretaceous – aged sandstones of the Upper Tuscaloosa Formation and Lower Cretaceous – aged sandstones of the Paluxy Formation have the necessary reservoir characteristics to be effective sequestration reservoirs at the Louisiana Green Fuels, Port of Columbia Facility. The Injection Zone intervals have been designated as follows: Upper Tuscaloosa Sands (Primary), Paluxy Sands (Secondary). As discussed in the previous section, in addition to the Primary Upper and Lower Confining Zones, the Upper Tuscaloosa sandstones and the deeper Paluxy sandstones of the Lower Cretaceous are interlayered with thick, impermeable mudstones. All characteristics for the proposed Injection Zones are discussed in the following sections. A ternary diagram for the injection zones based upon the results of the stratigraphic test well is shown in Figure 2-26.

2.3.2.1 Primary Injection Zone – Upper Tuscaloosa Sands; Paluxy Sands

The multiple sandstones of the Upper Cretaceous (UK) Upper Tuscaloosa Formation are proposed as the primary supercritical carbon dioxide sequestration zones (reservoirs) for this project. The Upper Tuscaloosa Formation, as indicated by the open hole logs run in the stratigraphic test well, comprises the interval from 4,911 feet to 5,514 feet and consists of numerous sandstone layers ranging between 5 to 60 feet in thickness alternating with impermeable mudstone layers (shales) that range between 5 to 50 feet in thickness (Figure 2-2).

2.3.2.1.1 Formation Characteristics

Two 30-foot whole cores were attempted within the Upper Tuscaloosa interval in the Stratigraphic Test Well. One core was cut in the upper half of the interval from 4,911 feet to 4,941 feet (driller's depth; 4,921 feet to 4,951 feet log depth), while the second core was cut in the lower half of the interval from 5,250 feet to 5,280 feet (driller's depth; 5,257 feet to 5,287 feet log depth). Core recovery was good with most of the cored intervals being successfully retrieved. The analyses and descriptions of these two whole cores and 20 high-quality sidewall rotary cores subsequently sampled from the interval following open-hole logging were used to contribute to the definition of the petrophysical characteristics and general depositional setting for the Upper Tuscaloosa Formation. The numerous sandstone layers encountered within the Upper Tuscaloosa are comprised of alternating fluvial-deltaic and intertidal (reworked shallow marine / littoral) deposits. The fluvial-deltaic deposits include distributary channels, crevasse splays, levee and overbank deposits, and the channel facies often exhibit sharp basal contacts with evidence of erosion, including incorporation of mud clasts into the sandstone matrix. These fluvial-deltaic deposits exhibit little or no intertidal reworking.

This contrasts with the alternating deposition of sediments that were clearly subjected to intertidal deposition and/or reworking, in a very low energy littoral environment. The coarser-grained sandstones encountered within the facies are interpreted to consist of reworked estuarine deposits and shallow marine bar sands. The marine bar sand facies consist of amalgamated packages of fine to coarse grained, argillaceous, and calcareous sandstones that typically exhibit a coarsening upward grain size trend. Several of these marine bar sands exhibit intensive bioturbation. Wavy and ripple laminations, trace burrows, and soft sedimentation deformation are commonly observed in sedimentary structures. The interlayered silty mudstones are planar to wavy laminated and burrowed and contain phosphatic nodules. The presence of glauconite confirms the shallow marine deposition of the littoral bar sands. However, the occurrence of faint iron oxidation on some detrital grains observed from adjacent, less glauconitic sandstone layers indicates deposition in an oxidizing environment with periodic subaerial exposure. These observations are consistent with the accumulation of terrigenous sediment in a tide-dominated, shallow marine environment, including tidal flats, estuaries, thin beaches, and marine bars. The older (Lower Cretaceous) sandstones of the Paluxy Formation are considered to represent important secondary injection layers and will be perforated for injection at the same time the younger (Upper Cretaceous) sandstones of the Upper Tuscaloosa are perforated for injection. The lenticular (channel) sandstones frequently encountered in the deeper portion of the Paluxy Formation were not penetrated by the Stratigraphic Test Well but comprehensive open-hole log data was acquired from the three upper Paluxy sandstones that were encountered. Cuttings recovered from those sandstones were sampled every ten feet and are of high quality. Four thin sections were prepared using sample cuttings from the Paluxy sandstones: (1) one from the 10-foot sample interval 5,760' – 5,770' ("P1" Sand; driller's depth; 5,770' – 5,780' log depth), (2) one from the 10-foot sample interval 5, 800' – 5,810' ("P2" Sand; driller's depth; 5,810' – 5,820' log depth); (3) one from the 10-foot sample interval 5, 820' – 5,830' ("P3" Sand; driller's depth; 5,830' – 5,840' log depth); and the 10-foot sample interval 5, 830' – 5,840' (basal portion of "P3" Sand; driller's depth; 5,840' – 5,850' log depth). The thin sections indicate the cuttings from the intervals sampled consisted predominantly of individual quartz grains, angular to subrounded in appearance; this is an empirical indicator of good porosity and permeability, because sample cuttings from tightly cemented (low porosity / low permeability) sands typically consist of "clumps" of quartz grains still tightly cemented to each other despite the shearing action of a modern PDC bit. The two thickest upper Paluxy Sands (the "P-2" and "P-3" Sands) were perforated and tested for injection capacity.

Sample cuttings and open-hole log analysis indicate the Paluxy sandstones encountered to be porous and permeable fluvial and fluvial-deltaic (inferred channel) sandstones, relatively devoid of clay, with abrupt upper and lower gamma ray curve boundaries and crossplot porosities as high as 23.7%, as indicated on the density-neutron log and listed in the following table

Paluxy "P-1 Sand"

5770	0.1527
5770.5	0.1416
5771	0.1403
5771.5	0.1385
5772	0.1305
5772.5	0.1121
5773	0.107
5773.5	0.1154
5774	0.1353
5774.5	0.1402
5775	0.1372
5775.5	0.1298
5776	0.1327
5776.5	0.1411
5777	0.1757
5777.5	0.2255
5778	**0.2371**
5778.5	0.2058
Average	**0.1499**

SLB Crossplot Porosity (PXND_HILT.CFCF)
Source: SLB LAS File
Platform Express Log Run #3
Whitetail (LGF) #1 LGF Class V
Stratigraphic Test Well (5/4/21)

Paluxy "P-2 Sand"

5808.5	0.1937
5809	0.2115
5809.5	0.216
5810	0.2142
5810.5	0.2198
5811	0.2199
5811.5	0.2144
5812	0.2169
5812.5	0.2171
5813	0.2207
5813.5	0.2234
5814	**0.2277**
5814.5	0.2099
5815	0.2076
5815.5	0.2039
5816	0.1925
5816.5	0.1748
5817	0.1698
5817.5	0.175
5818	0.1866
5818.5	0.1916
5819	0.1819
5819.5	0.1639
5820	0.1438
5820.5	0.1251
Average	**0.1969**

Paluxy "P-3 Sand"

5834.5	0.1294
5835	0.1381
5835.5	0.1356
5836	0.1477
5836.5	0.1515
5837	0.1637
5837.5	0.1709
5838	0.1794
5838.5	0.1815
5839	0.1841
5839.5	0.1923
5840	0.1974
5840.5	0.1981
5841	0.19
5841.5	0.186
5842	0.1788
5842.5	0.1842
5843	0.1935
5843.5	**0.2023**
5844	0.2011
5844.5	0.1972
5845	0.1838
5845.5	0.1526
Average	**0.1756**

While the sandstones that were penetrated and tested in the upper portion of the Paluxy interval were relatively thin (up to 14 feet in gross thickness), the logs from other legacy Paluxy penetrations drilled within the AoR that penetrated the entire Paluxy interval indicate such channel sandstones can attain a gross thickness in excess of 50 feet.

2.3.2.1.2 Mineralogy and Petrophysics

The mineralogy of the Upper Tuscaloosa sandstones is dominated by quartz, with quartz abundance determined from XRD ranging from 62.6 weight percent to 95.0 weight percent (average 80.5 weight percent) (Figure 2-29 and Table 2-6). Minor (<5 weight percent) amounts of potassium and plagioclase feldspar are also present. Clay content ranges from 2.2 weight percent to 32.8 weight percent (averaging 11.5 weight percent). Dickite, a form of kaolin clay, is the most common clay species present in the Upper Tuscaloosa sandstones (average 5.8 weight percent), followed by illite/mica (3.7 weight percent). Siderite, an iron carbonate, is the most common carbonate mineral, ranging as high as 11.3 weight percent in some samples (average 2.8 weight percent).

Porosity and permeability data were acquired using conventional analysis of 71 samples taken from the two 30-foot whole cores and from the 20 sidewall rotary core samples cut in the Upper Tuscaloosa (Tables 2-7 and 2-8). A net confining stress of 1,900 psi was applied to 28 of those samples over the depth range 4,911.5 feet to 5,158.0 feet. The net confining stress was increased to 2,000 psi for the remaining 43 samples over the depth range 5,175.0 feet to 5,608.0 feet (it should be noted that the deepest two sidewall rotary cores cut and analyzed were taken from the underlying Lower Tuscaloosa Basal Sand, which is a separate clastic reservoir that is not included in the proposed Upper Tuscaloosa sequestration interval). Setting aside the mudstone facies cored in the two whole cores, the measured porosity of the whole-cored Upper Tuscaloosa sandstones ranges from 15% to 22.7%, with an average of 18%. Measured air permeability ranged from 0.476 mD to 1,080 mD (average 111.5 mD).

For the twenty high-quality Upper Tuscaloosa sidewall rotary core samples – which were specifically targeted to sample intervals of optimal reservoir quality following the open-hole logging of the well – the measured porosity of the rotary-cored Upper Tuscaloosa sandstones ranges from 14.4% to 26.6%, with an average of 21.6%, and the measured air permeability ranged from 0.398 mD to 718 mD (average 326.9 mD). This data indicates that while Upper Tuscaloosa sandstones span a wide spectrum of injection zone quality, they include layers with excellent reservoir characteristics. Thin section analyses for these layers indicate the samples with elevated permeability are associated with abundant, large intergranular and intragranular porosity occurring in clean sandstones (Figure 2-29 and 2-30).

Sandstones encountered within the deeper portion of the older (Lower Cretaceous) Paluxy Formation can attain thicknesses more than 50 feet with porosities as high as 22% and, although generally lenticular, appear to extend laterally over considerable distances. By drilling the proposed injection wells 800 feet deeper than the total depth of the stratigraphic test well (7,000 feet vs. 6,200 feet), it is projected that several additional porous and permeable sandstones will be encountered, contributing significantly to the sequestration capacity of the Primary Injection Zone. In that event, each additional potential sequestration target will be thoroughly evaluated with open hole logs and sidewall rotary cores in preparation for including those additional deeper reservoirs in the updated modeling that will be performed. Those additional reservoirs will then be incorporated into the proposed authorized zones for injection.

2.3.2.1.3 Expected Zone Capacity

Based upon the current understanding of its porosity, permeability, thickness, and lateral extent, the sands of the Upper Tuscaloosa and Paluxy Formation, are projected to have the capacity to sequester an injected volume of 38.44 MMT over a 20-year injection period (or 1.922 MMT per a year). The injectate pressure front and plume boundary projected using the current modeling iterations have been reported and illustrated in the relevant figures included within Appendix A. The Upper Tuscaloosa / Paluxy Sand Injection Interval is projected on Figure A.21 in Appendix A.

The injection rates and storage capacity are estimated based upon the current understanding of porosity, permeability, thickness, and lateral extent and will be calibrated to the actual Injection Wells after site-specific data collection. Specific modeling parameters related to the relative permeability, saturation curves, and compressibility of the formation and injectate characteristics are contained in the *"Area of Review and Corrective Action Report"* submitted with this permit application in Module B.

2.4 GEOMECHANICS AND PETROPHYSICS

This section details the mechanical rock properties and in-situ fluid pressures per the LAC 43:XVII §3607 (C)(2)(b) standard and includes information on ductility, stress, pore pressures, and fracture gradients of the sequestration complex. Mechanical rock properties describe the behavior of the framework rock matrix and pore space under applied stresses. Mechanical rock properties are described by elastic properties (Young, Shear, and Bulk Modulus as well as Poisson's ratio) and inelastic properties (Fracture Pressure and Formation Strength).

Changes in *in-situ* stresses and strains, ground surface deformation, and potential risks, such as new caprock fracture initiation and propagation of pre-existing fault openings and slippage are crucial geomechanical aspects of large-scale and long-term CO_2 storage (Rutqvist, 2012). Therefore, it is necessary to assess the geomechanical stability risks before commencing the operations associated with CO_2 sequestration. Although many of the processes involved are not always fully understood, the integration of all available data, such as ground surveys, geological conditions, micro-seismicity, and ground level deformation has led to many insights into the rock mechanical response to CO_2 injection (Pan et al., 2016).

Site-specific data will be collected during the drilling and testing of the project Injection Wells. Geomechanical data across the Primary Injection Zone intervals and the Primary and Secondary Upper Confining Zones will be collected, along with laboratory analyses of recovered core samples. Details for the data acquisition program are contained in the "*Pre-operational Testing and Logging Plan*" contained in Module D.

2.4.1 Available Data Used for Analysis

Whole core data acquired from the Stratigraphic Test Well (La SN: 975841) has been utilized to determine the rock mechanical properties of the Upper Tuscaloosa sands within the Primary Injection Zone. The integrity of the Primary Upper Confining Zone (Austin Chalk Equivalent / Upper Eagleford interval) and the Secondary Upper Confining Zone (Midway Group) was also evaluated with well logs and additional whole coring. A combination of mineralogical analysis and dynamic elastic properties estimates was used for seal characterization in this initial application.

Five different sets of rock samples are commonly used for laboratory rock mechanical testing to characterize the range of geological facies expected in the injection units. The following suites of tests were conducted on whole core samples (laboratory report is contained in Appendix B).

- *Azimuthal or Circumferential Acoustic Velocity measurements (Radial Velocity Anisotropy) at ambient temperature and unstressed*: The stress memory property of rock, observed from studying and quantifying the strain recovery of the rock recovered in the whole cores, allows for an in-situ estimation of stress (and sample alignment) using the measurement of Radial Velocity Anisotropy (i.e., the difference in compressional (P) and shear (S) velocities as measured at radial increments along a circumferential plane). The acquisition of azimuthal velocity is performed by mounting the sample (either a portion of the whole core, or a competent plug cut from the whole core) on a rotary table, then transmitting P and/or S waves across the sample to a receiver on the other side. The rock sample is rotated every ten degrees (10º) and P and S wave velocities are recorded each time the rock has been rotated. The minimum and maximum velocities are then determined and compared to that recorded in other samples, facilitating the correlative azimuthal orientation of the rock samples for consistency during subsequent rock mechanical testing.

- *Multistage Triaxial (MST) Compressive Strength test:* The compressional testing of vertical and horizontal samples yields an estimation of compressive strength, static Young's Modulus, static Poisson's ratio, residual strength, and other mechanical properties from measured stress-strain data. Acoustic velocity is measured simultaneously to provide dynamic elastic properties for dynamic to static model calibration. The acoustic measurements are performed throughout the duration of the test. The MST test is used to obtain the parameters necessary for a Mohr-Coulomb analysis using a single sample. This test is similar to a single stage triaxial test; however, the sample is only compressed to the point of failure during the very last step of testing.

  To conduct the MST test, the sample is placed under confinement within a suitable pressure vessel. A pore pressure is applied, targeting a specific deviatoric stress (axial – pore pressure) depending on the test design. The axial deviatoric stress is increased to an automated observed yield point or until the positive point of dilation (PPD) or manually unloading just before failure. The PPD is reached when the derivative of the volumetric strain reaches zero. Once the unload point is reached, the deviatoric stress is unloaded and the confining pressure is ramped to the next desired value. The same loading/unloading procedure is repeated for a minimum of four cycles. During the last cycle, the sample is subjected to maximum confining until failure occurs to obtain a maximum compressive strength value.

- *Uniaxial Pore Volume Compressibility*: The volumetric deformation of rock is largely a result of uniaxial stress; this is attributed to the lateral confinement by the adjacent bounding strata. A uniaxial pore volume compressibility (UPVC) experiment is performed in the lab to estimate the matrix and pore volume compressibility under uniaxial deformation, by maintaining zero lateral strain conditions. The drained uniaxial pore volume compressibility (UPVC) is measured under zero radial strain condition ($\Delta\varepsilon\_t$=0) and constant overburden stress conditions. The Biot Coefficient is determined from UPVC measurements and is used in the estimation of the fracture pressure.

Laboratory rock mechanical testing was conducted on selected whole core samples (Table 2-9) from the Stratigraphic Test Well (La SN: 975841) Stratigraphic Test Well. These tests results have been used to determine the fracture gradient for the Upper Tuscaloosa Injection Zone within the AoR.

2.4.2 Ductility

Ductility refers to the capacity of a rock to deform in response to large strains without macroscopic fracturing. Ductile deformation is typically characterized by diffuse deformation (i.e., lacking a discrete fault plane) and is accompanied on a stress-strain plot by a steady-state sliding at failure, compared to the sharp stress drop observed during brittle failure. In other words, when a material behaves in a ductile manner, it exhibits a linear stress vs. strain relationship past the elastic limit.

Unconsolidated sediments are mechanically weaker than lithified rocks, but their ductility provides certain advantages for carbon storage. The ductility of a shale top seal is a function of compaction. Lower-density shales are extremely ductile and can thus accommodate significant strain without undergoing brittle failure and loss of top seal integrity. Conversely, highly compacted, deeply-buried, dense shales are extremely brittle and may undergo sudden brittle failure and loss of top seal integrity with very small amounts of strain. Figure 2-31 shows the relationship between ductility and density observed for 68 shales as presented in Hoshino et al. (1972).

The smectite-rich shales of the Midway Group, especially the thick terrigenous shales of the Porters Creek Formation (which comprises most of the unit), are buried to a relatively shallow depth in the AoR, from 2,300 feet to 3,600 feet subsea. Core No. 1 cut in the lower Midway (Porters Creek Clay) interval in the stratigraphic test well exhibits soft-sediment deformation (a manifestation of ductility) and a complete lack of vertical fracturing. Depth of burial and abundant smectite content indicates the shales of the Midway Group are ductile shales averaging 600 feet in thickness that are not brittle and do not exhibit any fracturing within the AoR. This ductile nature is further evidenced by the effective sealing and confinement of over seven trillion cubic feet of methane below the Midway Shale in the giant Monroe Gas Field, located a short distance north of the AoR. In the Monroe Field area, the Midway Shale is draped over the crest of the Monroe Uplift and has been subjected to much higher tectonic stress than that associated with the gentle, monoclinal south dip of Midway strata within the AoR; despite the higher tectonic stress, no fracturing has been observed in the Midway strata across the Monroe Field area (or in the AoR).

The analysis of Core No. 1 also indicates the calcite / carbonate content of the cored Midway interval is very low; calcite / carbonate content is one lithological factor that is directly associated with brittleness in shales. The higher the calcite / carbonate content, the more brittle most compacted (and deeply buried) shales become; conversely, the lower the calcite / carbonate content, the less brittle. The predominantly terrigenous smectite-rich shales of the Midway Group (especially the thick Porters Creek Clay member) would thus be characterized as lacking the calcite / carbonate content to be brittle while being sufficiently ductile to impede the initiation or propagation of fracturing.

Other parameters are expected to influence ductility, such as confining pressure and time. The mechanical behavior of rock formations is not constant but changes with various conditions, such as progressive burial as the top seal is converted from a mud to a more competent material, thus developing higher strength. Compaction decreases ductility while confining pressure increases ductility. Compaction is typically related to depth. Figure 2-32 from Hoshino et al (1972) shows density and ductility vs. brittleness against depth. Ductile samples are displayed as gray circles and brittle samples are displayed as black circles. Ductile shales did not fracture whereas brittle shales did fracture during the experiment. According to the figure, a low-density shale at a depth of 500 m is more ductile than a highly compacted shale at a depth of 5,000 m. Finally, ductility varies not only with depth of burial but also with time.

Holt et al (2020) emphasizes the importance of characterizing the extent to which shales may fail in a brittle or ductile manner, and in the case of ductile shales, the creation of permanent sealing barriers. Triaxial tests, creep tests, and other tests tailored to follow the failure envelope under simulated borehole conditions were performed on two soft shales. The more ductile shale was proved to form barriers both in the laboratory and in the field. By comparing their behavior, the authors noticed that the ductile shale exhibits normally compacted behavior while the more brittle shale is over-compacted. This points to the stress history and possibly the grain cementation as keys in determining the failure mode. Porosity, clay content, ultrasonic velocities, unconfined compressive strength, and friction angle may be used as other indicators of brittle or ductile failure behavior.

Shale ductility has proven to be useful in assessing the quality of sealing barriers. Successful natural shale barriers have been reported, where the annulus between casing and formation has closed after drilling, forming an efficient seal (Williams et al., 2009; Kristiansen et al., 2018).

Additionally, ductile formations have a higher propensity to creep than brittle ones under the same loading conditions. Creep is the tendency of solid material to deform permanently under a certain load, depending on time and temperature. Typically, creep is divided into three distinct stages, which are: (1) primary creep (transient elastic deformation with decreasing strain rate), (2) secondary creep (plastic deformation with constant strain rate), and (3) tertiary creep (plastic deformation with accelerating strain rate), as summarized in Figure 2-33 from Brendsdal (2017) (see also Fjaer et al., 2008; Hosford, 2005). Unless stresses are reduced, tertiary creep will eventually lead to brittle failure.

The following factors have the potential to increase or enhance creep (Kristiansen et al., 2018):

- High clay content, especially smectite,
- High shear stresses,
- Thermal deformation from heating,
- Shale/brine interaction effects.

According to Chang and Zoback (2009), the amount of creep strain in shales is significantly larger than that in sands with less clay, which corroborates previous observations that creep strain increases with clay content. Microscopic inspections show that creep in shales appears to generate a packing of clay minerals and a progressive collapse of pore spaces. Chang and Zoback (2009) observed a loss of porosity and an increase of dynamic moduli in shales during creep.

Strain in unconsolidated and un-compacted sediments is typically accommodated by creep behavior which may be enhanced by a high clay content that induces self-sealing properties (Meckel and Trevino, 2017; Zoback, 2010; Ostermeier, 2001; Hart et al., 1995). This has major implications on the suitability of confining zones because ductile deformation of mudstone seals potential leakage pathways to the surface. Such leakage pathways would include natural pathways such as faults and man-made pathways such as boreholes (Clark, 1987).

Loizzo et al. (2017) discusses how certain important parameters, such as the *in-situ* stress and creep properties, can be measured or estimated from geophysical logs, geological and geomechanical information, and active well tests. Any sedimentary formation with a clay matrix predominantly composed of smectite is a good candidate for the formation of a natural barrier. Sloughing shales encountered during drilling are excellent real-time indicators of this phenomenon, but the acquisition of petrophysical data across such formations, such as that provided by logging while drilling or wireline logging, is recommended at the initial characterization stage. Multi-arm wireline-conveyed caliper tools can directly detect creep as well as stress anisotropy. The acquisition of density, neutron porosity, and spectral gamma ray data can aid in clarifying the mineralogical composition; such petrophysical data is routinely acquired as part of a "triple combo" (multi-tool) log run in the wellbore, while dipole sonic tools can record both P and S wave velocities. These logs will be included in the formation evaluation program for all of the Injection Wells for the Louisiana Green Fuels site (subject to open hole wellbore conditions at time of logging). Further processing of such log data to aid in the identification of facies, various petrophysical and mineralogical properties, and estimated rock strength will also be performed. Defining the maximum operating pressure of the natural barrier requires the knowledge of its mechanical properties and far-field stresses. The characterization of rock mechanical properties (elastic properties, anisotropy, and non-linearity) has been well documented for measurements, protocols, and practices. Young's modulus and Poisson's ratio can be estimated from the compressional and shear wave velocities and density values obtained from the offset sonic logs, using standard rock physics equations.

Finally, cement evaluation logs are also very effective in identifying creeping shales. In fact, they precisely measure the ultimate effect of creep, i.e., the annulus bridging by a natural barrier. A cement evaluation log run immediately after cementing and another cement evaluation log run approximately a week later can help distinguish between cement and the encroachment of creeping shale in the annulus.

2.4.2.1 Ductility of Clay / Shales in Gulf Coast Examples

The ductility of clay/shales both in the Injection Zone and in the Upper Primary and Secondary Confining Zones is a function of compaction state. Low-density shales are extremely ductile and can thus accommodate large amounts of strain without undergoing brittle failure and loss of integrity. However, highly compacted, dense, deep shales may be extremely brittle and undergo brittle failure and loss of integrity with very small amounts of strain. As noted earlier, Figure 2-31 shows the relationship between ductility and density for 68 shales from the literature. All samples were deformed in compression.

Gulf Coast shales are known to exhibit viscoelastic deformational behavior that causes natural fractures to close rapidly under the action of *in-situ* compressive stresses (Aumman, 1966; Neuzil, 1986; Bowden and Curran, 1984; Collins, 1986). Evidence of this includes rapid borehole closure often encountered while drilling and running casing in oil and gas wells along the Gulf Coast (Johnston and Knape, 1986; Clark et al., 1987). Furthermore, older abandoned boreholes have been observed to heal (close) across such shale sections to the extent that the re-entry of such boreholes for the purposes of testing deeper intervals requires the drilling of a new borehole through such viscoelastic shales (Clark et al., 1987).

This property of viscoelastic deformation behavior will cause any fractures and/or faults to close rapidly in response to *in-situ* compressive stresses, even leading to the extrusion of highly viscoelastic shale into the fault plane from both sides. This well-known ductile (or plastic) behavior of the geologically young Cenozoic Gulf Coast shales is amply demonstrated by the presence of shale diapir structures and the natural closure of uncased boreholes with time (Johnston and Greene, 1979; Gray et al., 1980; Davis, 1986; Clark et al., 1987; Warner and Syed, 1986; and Warner, 1988). Jones and Haimson (1986) have found that due to the very plastic nature of Gulf Coast shales, faults will seal across shale-to-shale contacts, allowing no vertical fluid movement along the fault plane.

In 1991, the DuPont Borehole Closure Test Well was drilled and tested as an integral part of a demonstration project in support of DuPont's EPA No-Migration Petition for the DuPont Sabine River Works (now known the INVISTA Orange chemical plant), located near the city of Orange in southeast Texas. The objective was to test the natural healing of boreholes through clay/shale sections due to clay swelling and creep and to quantify natural borehole closure (Clark et al., 2005). A test well was drilled to provide additional information on the sealing effectiveness of viscoelastic Cenozoic shales in a simulated abandoned borehole located on the flanks of Orange Dome (a salt diapir), which is also located near the INVISTA Orange chemical plant.

For the testing, a worst-case strategy was evaluated, where the mechanism of swelling and plastic creep of the clay/shales was simulated by allowing the clay/shale to heal over a week's duration and then injecting fluids into the lower test sand while monitoring pressure in the next sand vertically in the section (upper monitor sand), similar to a vertical interference test. The upper gauge in the shallow monitor sand showed no change during the testing, indicating that there was no out-of-zone movement across the 90-foot thick, healed clay/shale bed. The lack of out-of-zone movement was confirmed via the Schlumberger Water Flow Log® that showed no migration of fluids vertically along the walls of the borehole in the healed clay/shale section.

2.4.2.2 Site Specific Ductility of the Upper Confining Zones

To date, the site-specific brittleness or ductility/creep measurements available for the Primary Confining Zone – the Upper Cretaceous Austin Chalk Equivalent / Upper Eagleford interval, the Secondary Confining Zone – the Paleocene Midway Group, or the other micritic or argillaceous containment intervals of the Upper Cretaceous Selma and Middle (Taylor-aged) Chalk strata within the project area are limited to those measurements and analyses obtained from the analyses of whole cores #1 (cut in the lower Midway) and #2 (cut in the Austin Chalk Equivalent) taken in the stratigraphic test well (SN975841). Assumptions regarding brittleness or ductility have also been made by referencing the drilling and completion history of the legacy Cretaceous penetrations (and their available density/neutron or sonic logs) located within the AoR as well as the published literature discussed above. Ductility is assessed by measuring sample strains under applied stresses at representative reservoir conditions (*e.g.,* injection or depletion). Elastic moduli are often used as an indicator of rock creep compliance and strength, which can be related to mineral rock composition (Lund Snee and Zoback, 2013).

Site-specific geomechanical data will be acquired from analyses of cores collected during the drilling of the Injection Wells and those Monitor Wells that will be re-entered and deepened to 7,000 feet (see Module D for the "*Pre-Operational Testing and Logging Plan*"). The ductility of the confining layers will be assessed using potential calculations as follows:

1. Brittleness Index (BRI):

$$BRI = \frac{UCS}{UCS_{NC}}$$

Where:

UCS is the unconfined compressive strength of the confining unit as measured from intact samples, and

UCS_{NC} is the compressive strength if the confining layer was normally consolidated, as measured from remolded samples that are normally consolidated.

2. Pressure Velocity (Vp):

$$\log(UCS) = -6.36 + \log(0.86V_p - 1172)$$

This calculation would be performed through intact samples or measured in-situ within the wellbore.

3. Effective Vertical Stress (σ′):

$$UCS_{NC} = 0.5\sigma¢$$

If BRI < 2, the confining layer will be sufficiently ductile to anneal any discontinuities.

2.4.3 Stresses and Rock Mechanics

In-situ stress and strain are basic concepts in the geomechanics discipline. Stress is defined as a force over an area. If a force is perpendicular to a planar surface, the resulting stress is called normal stress. If a force is applied parallel to a planar surface, it is called a shear stress. Normal stress is called either a tensile stress if the stress is pulling the material apart or a compressive stress if the stress is compressing the material. In geomechanics, compressive stresses are conventionally shown as positive. Strain is the deformation of the rock material in response to a change in the corresponding effective stress. A normal strain is defined as the change in length (caused by the change in normal effective stress) divided by its original length. A shear strain is the ratio of the change in length to its original length perpendicular to the principal stress axes of the element due to shear stress. A volume (or volumetric) strain is the ratio of the change in volume to its original volume, also called a bulk strain, when all-around change in effective confining stress is applied. These stress and strain concepts are illustrated in Figure 2-34 (Han, 2021).

The Gulf Coast Basin is generally considered as a passive margin with an extensional (normal faulting) stress regime. In a normal faulting stress regime, the vertical stress is the greatest stress (maximum principal stress) and is typically referred to as the rock overburden. Regional literature from Eaton, 1969, indicates that the overburden stress gradient for normally compacted Gulf Coast Sediments ranges from about 0.85 psi/ft near the surface to about 1.00 psi/ft at depths of about 20,000 feet. Sedimentary rocks along the central portion of the Gulf Coastal Plain experience predominantly normal faulting, with a maximum horizontal stress oriented sub-parallel to the coastline (Lund Snee and Zoback, 2020) and a minimum horizontal stress (i.e., the least principal stress) oriented orthogonal to the coastline.

Published data has been used to set the orientation of the principal horizontal stresses (Meckel et al., 2017; Nicholson, 2012; Zoback and Zoback, 1980) using regional fault-strike statistics (Figure 2-35). Geomechanical assumptions for the rock properties estimated at the Louisiana Green Fuels site are contained in Table 2-10. The geomechanical properties of the Secondary Upper Confining Zone, the Midway Group, will be further measured during the drilling and completion of the project's proposed injection wells.

Vertical Stress: S_v

The overburden stress, S_v, for normal-faulting stress regimes is assumed to have an average gradient of 1.0 psi/ft (Nicholson, 2012). This is equivalent to the lithostatic pressure exerted by rock with an average density of 2.3 g/cm^3 (Hovorka, 2018). Meckel, 2017, assumed a value of 1.00 psi/ft for the Lower Miocene in the Texas Gulf of Mexico.

For the Louisiana Green Fuels site, the S_v is estimated using the bulk density measurements from the lab. The S_v gradient is approximately 0.95 psi/ft.

Minimum Horizontal Stress (S_{hmin}):

Minimum horizontal stress values are estimated using Eaton's method (Eaton 1969) and analogue Biot coefficients. The Biot coefficient is the ratio of the volume of fluid change, divided by the change in bulk volume (assumption that port pressure remains constant).

$$Sh_{min} = K * (\sigma_v - \alpha P_P) + \alpha P_P$$

Where:

Sh_{min} = the minimum horizontal stress,

K = the stress ratio (for Eaton's method, K is estimated using Poisson's Ratio),

σ_V = the vertical stress

α = the Biot coefficient (*assumed to be 1*)

P_p = the pore pressure.

The range of Sh_{min} in the geomechanically tested sands resulted in calculated values that ranged from 0.55 to 0.63 psi/ft. These values fall well within the same range assumed in the region of 0.74 x 0.9 psi/ft = 0.66 psi/ft, per Ramos (1994).

Maximum Horizontal Stress (Sh_{max}):

Maximum horizontal stress values were estimated by averaging the gradients of the total vertical and minimum horizontal stresses (0.80 psi/ft).

Young's Modulus (E):

The Young's Modulus is an inelastic mechanical property that describes the relation of tensile stress to tensile strain (i.e., the ability of a material to deform).

$$E = \frac{\sigma}{\in}$$

Where:

E = Young's Modulus (pressure units)

σ = Uniaxial stress – or force per unit surface (pressure units)

$\in$ = Strain, or proportional deformation (dimensionless)

The Young's Modulus was calculated in the laboratory using the available core data. Results range from 1.75 x 10^6 psi to 3.75 x 10^6 psi and are considered representative of the tested Cretaceous strata. It should be noted that the derivation of the Young's Modulus subsequently impacts the calculation of the fracture gradient (as discussed in further sections).

Shear Modulus (G):

The Shear Modulus is a mechanical property that describes the response of a material to shear deformation and provides insight into how resistant a material is to shearing deformation (such resistance also being known as the material's rigidity). The Shear Modulus will be smaller than the Young's Modulus and is derived from the following basic equation:

$$G = \frac{t_{xy}}{g_{xg}}$$

Where:

G = Shear Modulus (pressure units)

t_{xy} = Shear stress in xy direction

g_{xy} = Shear strain

The Shear Modulus was calculated in the laboratory using the available core data. Results range from 1.10 x 10^6 psi to 1.56 x 10^6 and are considered representative of the tested Cretaceous strata. It should be noted that the Shear Modulus is related to the viscosity of the material; however, it is insensitive to temperature and composition of the material (Rajput et al., 2016).

Bulk Modulus (*k*):

The Bulk Modulus is a mechanical property that describes the ability of a material to withstand a change in volume due to compression from all directions. The Bulk Modulus can be defined by the following equation:

$$K = -V \frac{dP}{dV},$$

Where:

K = Bulk Modulus (pressure units)

P = Pressure

V = initial volume of a substance

The Bulk Modulus was calculated in the laboratory using the available core data. Results range from 1.30 x 10^6 psi to 2.68 x 10^6 and are considered representative of the tested Cretaceous strata. It should be noted that the Bulk Modulus can also be derived if the Young's Modulus and the Poisson's Ratio are known.

Poisson's Ratio (*v*):

Poisson's Ratio is a constant that is used to determine the stress and deflection property of a material. It is a measure of the deformation of a material perpendicular to the load direction. Poisson's Ratio is also calculated from density, P-wave and S-wave velocities using standard Rock Physics equations.

$$v = \frac{d \in_{trans}}{d \in_{axial}}$$

Where:

v = Poisson Ratio (dimensionless)

$\in_{trans}$ = transverse strain

$\in_{axial}$ = axial strain

Poisson’s Ratio was calculated in the laboratory using the available core data. It should be noted that the Poisson’s Ratio of most materials will fall within a range between 0.0 and 0.5. Lower Poisson’s Ratio values indicate less deformation of the material when exposed to strain, and higher values indicate greater deformation when exposed to strain. A higher Poisson’s Ratio would also indicate that the subject material would be harder to fracture. Results for the tested samples ranged from 0.20 – 0.27 and are considered representative for the Cretaceous strata for the project site.

The preliminary dynamic elastic properties are estimated from sonic and density logs obtained from the stratigraphic test well (SN975841). This log-derived data was later calibrated with laboratory measurements of core samples from the Upper Tuscaloosa Formation. The difference between the dynamic (log-derived) elastic properties and the static (core-derived) elastic property measurements is correlative to the difference in the magnitude of strain measured during the data acquisition process; log-derived elastic property measurements rely upon micro-strains exerted on the formation during the logging process, while core-derived elastic property measurements physically test the material strength limit in the laboratory, including the limit of material strength at its physical point of structural failure.

Sonic logs provide dynamic elastic properties in the small strain region ($<10^{-6}$), while laboratory measurements use unloading and reloading tri-axial stress paths until the rock is failed, achieving large strains ($> 10^{-3}$). The range of uncertainty is captured for the elastic properties, subject to the range of facies that were available for testing. Additional rock mechanical facies identified from logs were accounted for in the model by testing additional uncertainty in the input parameters.

2.4.4 Pore Pressures

Additional pore pressure profiles for the Louisiana Green Fuels, Port of Columbia Facility will be evaluated after the installation and testing of the Injection Wells (and its associated monitor wells). The pore pressures in the targeted injection intervals will be collected for each well to establish the baseline formation pressure for the Injection Zone intervals. A testing procedure for obtaining formation pressures is detailed in "*D– Pre-Operational Testing Plan*" submitted in Module D.

Formation pressure measurements are available from several legacy wells that have been drilled within or near the project AoR. These legacy wells include:

- Bass Enterprises, J. L. Keahey No. 1 (SN165305) – located approximately 2.4 miles northeast of the proposed Louisiana Green Fuels Facility (in Section 8 – Township 14N, Range 4 East, Caldwell Parish, Louisiana)

- Samson Contour Energy EP, Blackstone Minerals No. 2 (SN232452) – located approximately 7.7 miles to the northwest of the proposed Louisiana Green Fuels Facility (in Section 31 – Township 15N, Range 3 East, Caldwell Parish, Louisiana)

- G. Lea & Franks Petroleum Co. Olinkraft No. 1 (SN122331) – located approximately 9.3 miles to the northwest of the proposed Louisiana Green Fuels Facility (in Section 24 – Township 15N, Range 2 East, Caldwell Parish, Louisiana)

Formation pressure measurements taken in the Samson Contour Energy EP, Blackstone Minerals 2 (SN232452) include 14 pressure measurements from strata in the Lower Cretaceous Hosston Formation, exhibits an average pressure gradient close to 0.46 psi/feet in that deeper formation (the Hosston being substantially deeper than either the proposed Injection Zone or the Lower Confining Zone). Formation pressure measurements taken in the Bass Enterprises, J. L. Keahey No. 1 (SN165305) pressures are from strata in the Mooringsport and Hosston Formations (the latter being deeper than the Lower Confining Zone). The average calculated pressure gradient measurement in the strata sampled in the Keahey well is about 0.468 psi/ft. Formation pressure measurements taken in the G. Lea & Franks Petroleum Co. Olinkraft 1 (SN122331) pressures are from the uppermost Rodessa and Hosston Formations (again, both deeper than the Lower

Confining Zone). The average calculated pressure gradient measurement in the strata sampled in the Olinkraft well is approximately 0.466 psi/ft. In summary, all the above-noted pressure gradient data was derived from formations substantially deeper than the Lower Confining Zone and the Primary Injection Zone.

During the open hole logging of the stratigraphic test well (SN975841), 22 formation pressure measurements were obtained between 4,154 feet and 5,608 feet (measured log depths) using Schlumberger's "*PressureXpress*" (XPT) tool. This wireline formation pressure data was acquired across porous intervals in the Upper Cretaceous Annona Sand and various sandstones within the Upper Cretaceous Upper Tuscaloosa Formation, as well as the Basal Sand of the Lower Tuscaloosa Formation, the latter of which will not be an injection zone sequestration reservoir. The resulting XPT-derived pressure measurements were plotted with the regional pressure data cited above in Figure 2-36. All of these site-specific formation pressures measured from the sampled intervals in the stratigraphic test well clearly indicate the Annona Sand and Upper Tuscaloosa reservoirs are normally-pressured brine-filled reservoirs. The XPT pressures have been used to estimate the formation pressure gradient of 0.45 psi/feet, which is displayed as the trendline on the graph.

Following the casing of the stratigraphic test well to total depth, a series of step-rate and constant-rate injection tests were conducted via perforations across the targeted Injection Zone reservoirs in cased hole. These pressure transient tests and analyses (contained in Appendix C) are fully described in the Injection Test Report prepared by Geostock Sandia, LLC in July 2021.

The static pre-injection bottomhole pressure recorded prior to each step-rate and injection test and the final pressures recorded at the end of each falloff period is plotted for the pressure gauge measured depths of 4,149 feet (Annona Sand), 4,913 feet (in a sandstone near the stratigraphic top of the **upper test interval** within the Upper Tuscaloosa Formation), 5,052 feet (in a sandstone informally named the Upper Tuscaloosa "5,050 Foot Sand"), and 5,250 feet (in a sandstone near the stratigraphic top of the **lower test interval** within the Upper Tuscaloosa Formation). It should be noted that the measured pre-injection bottomhole pressure data was consistently lower than the final formation pressures recorded at the completion of the fall-off testing indicating that the pressures from the fall-off test have not completed a full relaxation stage, even 24 hours following cessation of injection, confirming the containment integrity of the Injection Zone. This data is also presented in Figure 2-36.

With normal compaction typifying both the Primary Upper Confining Zone and the Primary Injection Zone in the project site, the pore pressures across the Austin Chalk Equivalent / Upper Eagleford Zone are expected to be gradational between the overlying Selma and Middle (Taylor) Chalks and the underlying Upper Tuscaloosa Formation. Additional pore pressure data will be acquired both above and below the Primary Upper Confining Zone and below the Secondary Upper Confining Zone (the Midway Group) during the drilling and completion of the proposed injection and monitor wells.

2.4.5 Calculated Fracture Gradient

The injection pressure envelope (safe operating injection limit) is determined from the fracture gradient. The fracture gradient for the Louisiana Green Fuels Port of Columbia site was estimated using standard published equations as show below (Jaeger et al. 2007):

$$Pr = \frac{1}{2}\frac{\left({V_P}/{V_S}\right)^2 - 2}{\left({V_P}/{V_S}\right)^2 - 1}$$

$$E = 2\rho V_S^2(1 + Pr)$$

$$\sigma_v = g\int_0^z \rho(z)dz$$

$$\sigma_h = \frac{Pr}{1 - Pr}(\sigma_v - \alpha PP) + \alpha P_0$$

Where:

Pr = Poisson's ratio (provided in its dynamic expression in the above-noted equation)

V_P = Compressional wave velocity (inverse of log-derived compressional wave slowness)

V_S = Shear wave velocity (inverse of log-derived shear wave slowness)

E = Young's Modulus (provided in its dynamic expression in the above-noted equation)

ρ = Rock density

σ_v = Overburden stress

g = Acceleration due to gravity

z = Depth

σ_h = Minimum horizontal stress

α = Poroelastic coefficient (or Biot's constant)

P_0 = Pore pressure (or formation pressure)

The fracture gradient is then estimated using the Kirsch Solution for the formation breakdown pressure, as defined in Zhang and Roegiers (2010):

$$P_{FPmax} = 3\sigma_{min} - \sigma_H - p - \sigma_T - T_O$$

Where:

P_{FPmax} is the upper bound of the fracture pressure,

σ_H is the maximum horizontal stress,

σ_{min} is the minimum horizontal stress,

p is the pore pressure,

σ_T is the thermal stress and

T_O is the tensile strength of the rock.

The minimum stress is the minimum principal in-situ stress and typically equal to the fracture closure pressure (Zhang and Roegiers, 2010). Therefore, the following approximation for the estimate of fracture pressure is:

$$FG = K * (\sigma_v - \alpha P_P) + \alpha P_P$$

Where:

FG is the fracture gradient,

K is the stress ratio (for Eaton it is estimated using Poisson's ratio),

σ_V is the vertical stress,

α is the biot coefficient, and

Pp is the pore pressure.

The vertical stress (σ_V) for the above calculation is determined from the following equation:

$$\sigma_V = \int_0^z \rho(z).g.dz$$

The Biot coefficient (α) calculation is determined from the following equation:

$$\alpha = 1 - \frac{C_g}{C_b}$$

Where:

α is the Biot coefficient,

C_g is the grain compressibility; and

C_b is the bulk compressibility.

No indications of pre-existing fractures were in the stratigraphic test well borehole. Data supporting the lack of such fractures was provided by the analysis of the recovered whole core samples and from the behavior of the pressure transient falloff test data observed during the post-completion water injection well tests. The analysis of the injection pressure versus the injection rate data as plotted from the step-rate testing during the active injection testing period, and the observed behavior / slope of the fall-off pressure data, clearly indicates injection confined to the matrix of each perforated sandstone reservoir, with no indication of formation breakdown.

Following the methodology presented by Zhang and Roegiers (2010), the lack of known pre-existing fractures validates the use of the Kirsch Solution equation for calculating the fracture breakdown pressure. This calculation of fracture breakdown pressure was then utilized as the assumed base case for the reservoir model at the Louisiana Green Fuels Port of Columbia site. Specifically, the fracture breakdown pressure derived from the Kirsch Solution equation was directly measured in the laboratory using tests conducted on four representative samples (core plugs) taken from whole cores cut in the Upper Tuscaloosa Formation. The results are presented in Table 2-11.

2.5 SEISMICITY

An earthquake is a sudden shaking of the ground caused by the passage of seismic waves through the Earth after two blocks of rock material suddenly slip past one another beneath the Earth's surface. The plane where they slip is called the fault. The location below the Earth's surface where the earthquake starts is called the hypocenter, and the location directly above it at the surface of the Earth is called the epicenter. Seismic waves are elastic and travel at the speed of sound. These waves may be felt by humans and can produce significant damage far away from the epicenter.

The size of an earthquake is typically expressed by either its intensity or magnitude. The magnitude of an earthquake is an instrumental recording related to the energy released by the earthquake, while the intensity of the earthquake describes the severity of its effects.

> **Intensity** - Number describing the severity of an earthquake evaluated from the effects observed at the Earth's surface on humans, structures, and natural features. Several scales exist, but the Rossi-Forel scale (before 1931) and the Modified Mercalli scale (after 1931) are the most used in the US. Intensity observations are employed to construct isoseismal maps wherein areas of equal shaking effects are contoured.

> **Magnitude** - Instrumental measure of an earthquake by a seismograph which records the vibrations and movements of the Earth at seismic stations which are expected to all provide

the same determination of the same event since adjustments are made for distance and instrumental constants. The magnitude scale was devised by Dr. Charles F. Richter in 1935. Several iterations are available, depending on the type of seismic waves, distance to the epicenter, and other factors.

Instrumental seismology is equally as important as historic records. Instrumentation allows determination of seismic events much smaller than those which can be felt at the Earth's surface. Thus, a catalog of seismic events may contain a wide range of events that are instrumentally recorded but not felt by humans. Also, since seismic waves attenuate with distance and because all regions cannot be adequately covered by seismographs, many small events are felt, but not always detected.

The Richter magnitude scale was developed in 1935 by Charles F. Richter of the California Institute of Technology as a mathematical device to compare the size of earthquakes. The magnitude of an earthquake is determined from the logarithm of the amplitude of waves recorded by seismographs. Adjustments are included for the variation in the distance between the various seismographs and the epicenter of the earthquakes. On the Richter Scale, magnitude is expressed in whole numbers and decimal fractions. For example, a magnitude 5.3 might be computed for a moderate earthquake, and a strong earthquake might be rated as magnitude 6.3. Because of the logarithmic basis of the scale, each whole number increase in magnitude represents an approximate tenfold increase in measured amplitude; as an estimate of energy, each whole number step in the magnitude scale corresponds to the release of about 31 times more energy than the amount associated with the preceding whole number value.

At first, the Richter Scale could be applied only to the records from instruments of identical manufacture. Now, instruments are carefully calibrated with respect to each other. Thus, magnitude can be computed from the record of any calibrated seismograph.

Earthquakes with magnitude of about 2.0 or less are usually referred to as micro-earthquakes; they are not commonly felt by people and are generally recorded only on local seismographs. Events with magnitudes of about 4.5 or greater (there are several thousand such shocks annually) are strong enough to be recorded by sensitive seismographs all over the world. Great earthquakes, such as the 1964 Good Friday earthquake in Alaska, have magnitudes of 8.0 or higher. On average, one earthquake of such size occurs somewhere in the world each year. The Richter Scale has no upper limit.

Recently, another scale called the moment magnitude scale has been devised for more precise study of great earthquakes. The moment magnitude scale is the measure of an earthquake's magnitude (strength) based on its seismic moment. It was defined by Thomas C. Hanks and Hiroo Kanamori in 1979. The moment magnitude scale is similar to the local magnitude scale defined by Richter in 1935 in that it also uses a logarithmic scale; for this reason, small earthquakes have approximately the same magnitudes on both scales.

The effect of an earthquake on the Earth's surface is called the intensity. The intensity scale consists of a series of certain key responses such as people awakening, movement of furniture, damage to chimneys, and finally, total destruction. Although numerous intensity scales have been developed over the last several hundred years to evaluate the effects of earthquakes, the one currently used in the United States is the Modified Mercalli Intensity (MMI) Scale. It was developed in 1931 by the American seismologists Harry Wood and Frank Neumann. This scale, composed of 12 increasing levels of intensity that range from imperceptible shaking to catastrophic destruction, is designated by Roman numerals. It does not have a mathematical basis; instead, it is an arbitrary ranking based on observed effects.

The MMI Scale (Figure 2-37) value assigned to a specific site after an earthquake has a more meaningful measure of severity to the nonscientist than the magnitude because intensity refers to the effects experienced at that place. After the occurrence of widely felt earthquakes, the Geological Survey mails questionnaires to postmasters in the disturbed area requesting the information so that intensity values can be assigned. The results of this postal canvass and information furnished by other sources are used to assign an intensity within the felt area. The maximum observed intensity generally occurs near the epicenter.

The lower numbers of the intensity scale generally deal with the manner in which the earthquake is felt by people. The higher numbers of the scale are based on observed structural damage. Structural engineers usually contribute information for assigning intensity values of VIII or above.

The following section detail the regional and local seismicity impacts for the Louisiana Green Fuels Caldwell Parish site per the LAC 43:XVII §3607 (C)(2)(c) standard.

2.5.1 Regional Seismic Activity

Seismically, the Gulf Coastal Plain is one of the least active seismic regions of North America (Figure 2-38) as defined by seismicity hazard. Caldwell Parish and the greater region of adjacent Parishes has an extremely low rating for seismicity as determined via the USGS. Natural seismicity in the Gulf Coastal Plain is attributed primarily to flexure of sediments along hinge-lines that parallel the coast. This flexure is due to compression and down warping of the immature Gulf of Mexico basin sediments in response to extreme sediment loading. Structural features such as salt domes and growth faults, although capable of storing and releasing some seismic energy, are weak and ineffective in generating even modest ground motion.

Salt domes are created by buoyant masses of autochthonous or allochthonous halite that cause doming in the overlying sedimentary layers. Most such overlying sediments exhibit low density, poor cementation, and low shear strength; such physical properties typically are associated with a low shear modulus. For this reason, it is unlikely that tectonic stress attributable solely to compaction or movement over a salt dome would cause earthquake events with a magnitude greater than 3.0 on the Richter Scale. Such small earthquakes may be felt locally but are unlikely to propagate damaging ground motions. As indicated in Section 2.2.3 , the sequestration site is not located near any known salt diapirs. In fact, the Louann Salt, the primary source of autochthonous and/or allochthonous halite in Louisiana, is understood to be very thin or even non-existent in the AoR because of the presence of the underlying Paleozoic horst block, the Richland-Caldwell Paleohigh (RCP), in much of the AoR. Accordingly, local tectonic stress associated with the presence or movement of salt is considered highly unlikely.

The largest earthquake occurrence in Louisiana is the 1983 event recorded in the Lake Charles area in extreme southwest Louisiana, over 150 miles from the Louisiana Green Fuels site, which originated at a depth of more than 14+ kilometers (>8.4 miles) with a rated Mercalli magnitude of approximately IV (light shaking and dishes rattling). This depth of origination is located much deeper in the subsurface than the proposed injection depths beneath the Louisiana Green Fuels sequestration site.

A database search of the National Earthquake Information Center for earthquakes in Louisiana and the bordering states was conducted in September 2022. Table 2-12 presents a summary of these results and is keyed to Figure 2-39. The search shows that since 1900, 42 reported earthquakes with magnitudes greater than 2.5 on the Richter Scale were recorded within the State of Louisiana. The blue circle represents a 100-kilometer (62 mile) radius from the Louisiana Green Fuels sequestration site; within this blue circle, no seismic events have been recorded. The closest recorded earthquakes are located more than 100 kilometers northwest of the proposed sequestration site, in southern Arkansas. The largest ground motion experienced in Louisiana was from the Lake Charles earthquake of October 16, 1983 (No. 40 on Table 2-12) as discussed above.

2.5.2 Seismic Risk of the Site

A preliminary seismicity risk evaluation has been conducted for the project area AoR. The proposed sequestration area is located within Caldwell Parish, in an area indicated to have no substantive faulting or salt dome movement. Overall seismicity risk is rated ***very low*** based upon:

- *Extremely* low frequency of earthquakes in the northeast Louisiana region;
- The lack of reported natural earthquake events with a 100-kilometer radius of the AoR;
- The very low population density in the area, which limits the exposures and potential impacts;
- The lack of recorded or suspected injection-induced seismicity in all Class I or Class II wells that have operated in the area in the past;
- The lack of any large-scale oil and/or gas production in the area; and
- No substantive faults identified from the 2D seismic data or the subsurface well log information obtained within the delineated AoR or the extended reviewed area.

Typical geologic structures characterizing this province are gently southerly dipping and thickening sedimentary strata. Significant structural features such as salt domes and growth faults are not present near the sequestration site. Therefore, seismic events typically attributable to such structural features is not anticipated.

The frequency and magnitude of seismic activity in this part of the Gulf Coastal Plain is among the lowest in the United States (Figure 2-38). Structural features such as salt diapirs and growth faults, although capable of storing and releasing some seismic energy, are weak and ineffective in generating even modest ground motion. None of these features are located near the AoR. It should also be noted that none of the modest earthquake events that have been reported in Louisiana have been attributed to movement along any specific fault.

Evaluations have been performed to determine the possible effects of natural events on (1) the integrity of well construction materials; and (2) the integrity of both the Injection and Confining Zones beneath the Louisiana Green Fuels sequestration site. A review of the USGS National Earthquake Information Center (NEIC) (http://earthquake.usgs.gov/contactus/golden/neic.php) website indicates that Caldwell Parish area has a very low potential for seismic activity. In 1989, David J. Leeds, a certified geophysicist and engineering geologist, conducted a regional evaluation on seismicity. Leeds (1989) identified seismogenic sources, modeled a design earthquake and discussed the effects of the design earthquake on potential Injection and Confining Zones. The natural seismicity studied by Leeds indicates that seismicity is not expected to be a significant issue at the project site.

At the proposed Louisiana Green Fuels sequestration site, the likelihood of an earthquake caused by natural forces or induced by fluid injection is considered very remote. The planned injection of supercritical carbon dioxide into the highly porous reservoirs within the Injection Zone intervals will occur at relatively low pressures (the highest being within the injection wellbores, at less than 80% of the fracture pressure for each such reservoir) and the injected plume(s) of supercritical carbon dioxide will expand unimpeded over time at decreasing pressure (with increasing distance from the wellbore) within reservoirs that are typically extensive over a broad, unfaulted area.

Accordingly, the probability of the occurrence of a natural or induced earthquake event of sufficient intensity to damage the injection system, the injection wells, or the confining layers is considered to be extremely low.

2.5.3 Induced Seismicity and Regional Case Studies

Induced seismicity related to fluid injection normally results from salt or wastewater disposal activity involving the injection of very large volumes of water at high pressures near known faults. This injection activity increases the pore pressure within the reservoirs receiving the injected fluids, which reduces frictional resistance and reactivates slippage along the existing fault planes. As noted earlier, there is no record of any injection-induced seismicity having ever been linked to any Class I or Class II injection well located in Caldwell Parish or any adjoining parish.

Conversely, significant fluid withdrawal has caused land subsidence and earthquakes as the affected sediments are dewatered and subjected to uneven differential compaction. Earthquakes of magnitude 3.4 to 4.3 on the Richter scale appear to have been caused by fluid withdrawal near some oil fields in east Texas (Davis et al., 1987), such as Sour Lake, Mexia, and Wortham Fields.

Factors that may lead to the creation of an induced earthquake event include the distance of an injection well from a fault, the pre-existing stress state of that fault, and along with the injection of a sufficiently large volume of fluids at a sufficiently high pressure and for a sufficient period of time to initiate movement (slippage) along the fault (Ohio Department of Natural Resources, 2012).

Since 2010, the occurrence of earthquakes with a magnitude greater than 3.0 has increased from 20 events per a year (1967-2000) to over 100 events per a year (2010-2013) in certain areas of the central and eastern United States (Ellsworth, 2013). This increased rate of occurrence in previously inactive seismic areas has been, in many cases, correlated with the increased use of salt or wastewater disposal injection wells located near faults. This mechanism has been used to explain the best-known cases of injection-induced seismicity which was first studied in the Rocky Mountain Arsenal near Denver in the 1960's. More current case studies have increased awareness of the consequences of the use of injection wells to dispose of the large volumes of carry agents (fracture fluids) associated with hydraulic fracturing methods. At many sites, smaller seismic occurrences have been demonstrated to be the precursors of larger events. Since the Rocky Mountain study, the abundance of more recent research has led to a better understanding of the factors and processes associated with induced seismicity.

A hydraulic conduit from the injection zone to a fault may also induce earthquakes (Ellsworth, 2013). The largest injection-induced events are associated with faulting that is deeper than the injection interval, suggesting that the increased pressure transferred deeper into the basement via such conduits increases the potential for inducing earthquakes (Ellsworth, 2013). In all known cases, fault slippage has been reactivated at or in close proximity to Class II injection sites. In some cases, previously unknown faults have been discovered. No induced earthquakes have been known or are postulated to have been caused by Class I injection operations (Davis et al., 1987).

One of the most notable regional cases of induced seismicity associated with injection wells was recently recorded in Youngstown, Ohio. In 2011, twelve low-magnitude seismic events occurred in the Youngstown area along a previously unknown fault line (Ohio Department of Natural Resources, 2012). These events occurred less than a mile from the disposal of large volumes of wastewater in a Class II injection well, the Northstar I well. Prior to the injection of large volumes of wastewater in the subject well, the area had been seismically inactive; the reported earthquake events began to occur a few months afterward. A review of its well history indicated the injection pressure in the Northstar I disposal well had been increased twice over a six-month time period (Ohio Department of Natural Resources, 2012); this increase in injection pressure may have contributed to a reduction in the effective stress on the fault, reactivating slippage along the fault plane. After the Northstar I disposal well was shut down by the Ohio Department of Natural Resources, the seismic activity in the area declined. As a result of this case, pre-injection and post-injection seismic monitoring has become commonly required in such Class II injection sites.

Another case study in the Dallas-Fort Worth (DFW) area tied small seismic events to a Class II injection well. Eleven hypocenters have been observed at a focal depth of 4.4 km and 0.5 km in the vicinity of the deep saltwater disposal (SWD) well (Frohlich et al., 2010). Injection at this well began 8 weeks prior to the first recorded seismic event. A northeast trending normal fault was identified as transecting the same approximate location (Frohlich et al., 2010). It appears that due to the injection of large volumes of wastewater into the disposal well, the stress upon the nearby fault had been reduced, reactivating slippage along the fault plane (Frohlich et al., 2010). All the reported seismic events associated with the DFW focus area were events of small magnitude (less than 3.3) that occurred shortly after the initial injection of large volumes of water.

In north-central Arkansas, multiple earthquakes may have been triggered by the injection of large volumes of wastewater into one or more Class II injection wells. Since the operation of the disposal well in 2009, the site has experienced an increase from 2 seismic events in 2008 to 157 such events in 2011 (Horton, 2012). These events were also believed to be linked to the discovery of a new, nearly vertical fault in the vicinity of the disposal well. Most of the earthquake events in this area have occurred within 6 kilometers (~2.5 miles) of one of three wastewater disposal wells (Horton, 2012). The depth of the earthquake foci occurred between 6.7 to 7.6 kilometers (4 to 4.6 miles) beneath the surface. The injection of wastewater had occurred at a depth of 2.6 kilometers (1.6 miles). At this disposal site, an east-west trending normal fault (the "Enders Fault") was known to have cut the reservoir into which the wastewater was being injected, thus acting as a probable conduit to the deeper, recently detected, near-vertical fault at the depth of 6.7 to 7.6 kilometers (Horton, 2012). Following the shutdown of the subject disposal wells in 2011 by the Arkansas Oil and Gas Commission, the occurrence and magnitude of the earthquakes in the area steadily decreased over time (Horton, 2012).

2.5.3.1 Induced Seismicity Analysis at the Sequestration Site

Real world examples that are more comparable for evaluation of this sequestration project are available from Class I injection well sites located along the Texas-Louisiana-Mississippi Gulf Coast, roughly extending from Corpus Christi in South Texas to Pascagoula, Mississippi. These sites include both hazardous and nonhazardous fluid effluent disposal wells that typically operate in the +/- 300 to 500 gallons per minute (gpm) injection range, with maximum injection approaching 1,000 gpm. Many of these sites have been operating since the 1970s and a few as far back as the 1950s. There is no known evidence of injection-induced seismicity or suspected injection-induced seismicity at or near any of these Class I injection facilities, many of which are near high-population areas.

Assessment of the potential for induced seismicity at these locations follows the methodology outlined below, using the very conservative zero-cohesion Mohr-Coulomb failure criterion recommended by the USGS (Wesson and Nicholson, 1987). These analyses indicate very low potential for induced seismicity caused by pressures resulting from injection activities. Examples are available, such as long-term Class I injection operations at sites like Chemours Delisle, Denka

Pontchartrain, INV-Orange, Lyondell Channelview, Rubicon Geismar, etc., among others, which are all regulated by the EPA. Additionally, this sequestration project proposes the injection of supercritical carbon dioxide into individual sandstones interbedded with impermeable shales within the Upper Tuscaloosa and Paluxy Formations, which are located many thousands of feet above the crystalline basement complex. Injection into strata near or at the basement (an operation that will not occur within this project's AoR), with activation of pre-existing faults, has been identified as contributing to induced seismicity in those parts of the country where deep injection occurs. Despite the long history of Class I and Class II disposal along the Texas-Louisiana Gulf Coast, there has been no regional-scale or operational trends associated with induced seismicity attributed to those wells or in similar hydro-mechanical areas such as those documented in Skoumal et al. (2018, 2021) and Weingarten et al., (2015).

Finally, as mentioned in Section 2.5.1, characteristics of the typical regional geologic structures of the Gulf Coast include gently coastward dipping and thickening sedimentary strata of Tertiary to Cretaceous age that are disrupted by radial faults originating from salt or shale piercement domes, syndepositional growth faults, regional fault systems, and post-depositional faults. However, within the AoR of the proposed sequestration site, there are no known faults or salt structures that would impact the integrity of the Injection Zone or have the potential for fault reactivation due to injection operations.

2.5.4 Seismic Risk Models

The purpose of an earthquake model is to evaluate any potential effects of natural earthquakes on subsurface geological structures associated with the sequestration project. In general, a source mechanism is required when designing a model earthquake. In these cases, it is usual to have a known active fault system with a measured strain or stress field. In more active regions of the earth, faults with strain (movement across the fault without a rupture) develop at a rate of up to 5 centimeters per year, or more (Leeds, 1989). As a meter or more of strain develops, stress accumulates and eventually the system releases this stored strain energy in the form of elastic waves (e.g., an earthquake). Although the Texas/Louisiana Gulf Coast contains several geological features capable of storing and releasing stored energy, all are weak or ineffective in terms of generating even modest ground motion (Leeds, 1989).

Growth faults have also developed along the Texas/Louisiana Gulf Coast which may be responsible for seismic activity. Considering the Gulf Coast as a whole, a level of Mb=4.2 is considered an upper level for this kind of source in this area (Leeds, 1989). The several low magnitude events within about 50 miles of the coastline are probably attributable to this mechanism.

The possibility that growth faults may be triggered by faults in the basement is suggested by Stevenson and Agnew (1985) in their discussion of the Lake Charles Earthquake. Details of the event were developed from recordings of Department of Energy (DOE) supported microseismic networks deployed for monitoring geothermal experiments (withdrawal and injection) in southern Louisiana. The interpreted depths of 14+ km for these events are even deeper than have previously been reported and well beneath anticipated injection depths for the sequestration project. Additionally, none of the events were attributable to the geothermal extraction/reinjection operations (Stevenson (personal communication), in Leeds, 1989).

2.5.4.1 Design Earthquake Model

For the evaluation of the potential impact of seismicity on a Class VI injection well facility, like the proposed Louisiana Green Fuels Port of Columbia Facility, a modeled seismic event with a body-wave magnitude Mb of 4.2 ±0.2 can be used as a conservative working model for the design earthquake. It is presumed that the seismic source area would be along one of the east-west trending growth faults located far south of the proposed sequestration site area, in south-central Louisiana (Leeds and Associates, 1989). Another assumption is that the maximum ground motion at the surface generated by the design earthquake would be within the range of MMI = V, which equates to a horizontal surface acceleration of 0.05g (Leeds and Associates, 1989). The empirical correlation between intensity and acceleration has a wide spread of data range, with recordings varying from horizontal accelerations of 0.025g to 0.150g for an MMI = V event. This is the same value used for an Operating Basis Earthquake (OBE) for certain Gulf Coast nuclear power plant electric generating stations. For example, the Nuclear Regulatory Commission's estimate for the risk each year of an earthquake intense enough to cause core damage to the reactor at River Bend (north of Baton Rouge) was 1 in 40,000, according to an NRC study published in August 2010 (Hiland, 2010).

The OBE is defined by US Federal Regulations 10 CFR 100, Appendix A, as follows:

"The Operating Basis Earthquake is that earthquake which, considering the regional and local geology and seismology and specific characteristics of local subsurface material, could reasonably be expected to affect the plant site during the operating life of the plant; it is that earthquake which produces the vibratory ground motion for which those features of the nuclear power plant necessary for continued operation without undue risk to the health and safety of the public are designed to remain functional."

The design earthquake in this study is based on the empirical data of normal shallow focus (<20 km) earthquakes on soft sites (Leeds, 1989). It is also assumed that in the Gulf Coastal seismic environment, the release of energy from less competent materials than usual would result in longer surface rise times; therefore, the ground motion would be biased to longer periods (lower frequencies) than usual, and result in low accelerations, large displacements, and long durations.

Over the years, studies of the effect of depth on seismic ground motion have all noted a clear attenuation. Observations in deep mines and boreholes have confirmed this phenomenon. Data strongly indicates the dampening of amplitude with depth to an average of one-half, or less, of the ground motion. The motion may become as low as one-fifth of ground motion while for small motions, where the materials remain completely elastic, the amplitude may be diminished to as small as one-tenth of the original amplitude (Leeds, 1989).

The primary kinetic impact of ground motion on saturated granular soils is a sudden increase in pore water pressure. If the water table is located near the surface (within about 15 to 20 feet), if the sands are reasonably well sorted and clean (free of clay), and if accelerations exceed about 0.25g, soil liquefaction can occur (Leeds, 1989). Liquefaction causes a loss of shear strength of the soil and may result in the ejection of sand and water to the surface (sand boils) and the collapse of the foundations of structures supported by such soil. In extreme cases, multistory buildings have toppled (Niigata, Japan Earthquake in 1964) and buried tanks have floated to the surface (Leeds, 1989). Settlement and densification of the soil follow liquefaction. Because of the lack of seismicity in the Caldwell Parish area, and its significant distance from any known seismic source area, the proposed Louisiana Green Fuels sequestration site area does not meet the conditions expected to trigger liquefaction since the predicted acceleration levels (0.05g) would only be about one-fifth of that required to cause liquefaction (Leeds and Associates, 1989).

Ground motion attenuates with depth. While pore pressures may increase, the soil matrix is not required to support the lithostatic sediment column. Additionally, within the short duration of shaking, there is neither sufficient pore space nor time for the fluids within the deeper strata to move. Consequently, fluids trapped within deeper, more consolidated strata are considered to be incompressible. Leeds (1989) concludes that possible interactions between sedimentary horizons due to casing penetration and cement are minimal since there are only minor differential movements as the propagated seismic waves pass through the matrix. They conclude that there might be only several centimeters of displacement over the wavelength of the seismic waves and that the normal elasticity of the well casing and tubing is sufficient to accommodate the strain (Leeds, 1989).

It is only in the most extreme cases, such as that recorded in 1952 in Kern County, California, where surface accelerations can reach 0.50g and many miles of surface rupture can occur, that existing wells may be impacted. During the 1952 event in California, approximately 2% of the wells in the area exhibited some form of surface damage due to the settlement of surficial soils (Leeds, 1989). This event caused some subsurface damage including collapsed tubing near the surface due to the sharp rise in casing pressure that accompanied the shock. However, all affected wells were capable of being returned to operational status within 2 or 3 weeks of the event (Leeds, 1989).

After reviewing data from the largest historic events of the province and modeling a design earthquake, the hypothetical modeling results show an event with little damage to engineered structures or facilities. Ground motion due to seismic activity is attenuated with depth. The low-magnitude limited events in the Gulf Coast region have resulted in only minimal ground movement, further attenuated with depth. Therefore, in the highly unlikely scenario of a seismic event occurring in the Caldwell Parish area, damage to the well systems within the AoR would not be anticipated.

2.5.4.2 Induced Seismicity Model

In the construction of its induced seismicity model, Strategic Biofuels has employed conservative assumptions to the causative mechanisms of induced seismicity and the geomechanical conditions associated with the proposed Louisiana Green Fuels sequestration site. The potential for induced seismicity at the proposed injection site can be evaluated using the very conservative zero-cohesion Mohr-Coulomb failure criterion, recommended by the USGS (Wesson and Nicholson, 1987). This method is based on the following equation:

$$P_{crit} = \frac{S_v(3\alpha - 1)}{2} \tag{1}$$

Where:

P_{crit} = the critical injection zone fluid pressure required to initiate slippage along faults and fractures

S_v = the total overburden stress (which is the maximum principal stress in the Gulf Coast region)

α = the ratio of the minimum principal stress (horizontal in the Gulf Coast region) to the maximum principal stress (overburden stress)

Inherent in Equation (1) are several conservative assumptions that appear guaranteed to produce a "worst-case" lower bound to the critical fluid pressure for inducing seismicity. These are:

1) It neglects the cohesive strength of the sediments.

2) It assumes that a fault or fracture is oriented at the worst possible angle.

3) It assumes a worst-case value of 0.6 for the coefficient of friction of the rock (see Figure 4 of Wesson and Nicholson, 1987).

For present purposes, Equation (1) can be expressed in a more convenient form by introducing the so-called matrix stress ratio (K_i) (Matthews and Kelly, 1967; Eaton, 1969), which is defined as the ratio of the minimum to the maximum effective principal stresses. Eaton (1969) provides a plot of the effective overburden stress (S_v) as a function of depth for locations along the Gulf Coast. This plot indicates S_v values exceed 0.90 psi/ft for the injection interval reservoirs. Matthews and Kelly (1967) provide a plot of the matrix stress ratio (K_i) for tectonically relaxed reservoir sediments along the Louisiana and Texas Gulf Coast.

Effective principal stress is equal to actual principal stress minus fluid pore pressure (p_o). Thus:

$$K_i = \frac{\alpha S_v - p_o}{S_v - p_o} \tag{2}$$

Substituting the Equation (2) into Equation (1) yields:

$$\Delta P_{crit} = \left(\frac{3K_i - 1}{2}\right)\left(S_v - p_o\right) \tag{3}$$

where ΔP_{crit} is the critical injection zone pressure build-up required to induce seismicity, such as:

$$P_{crit} = p_o + \Delta P_{crit} \tag{4}$$

Equation (3) was used to evaluate the induced seismicity risk at the proposed Louisiana Green Fuels sequestration site.

The analysis of the pore pressure data in Section 2.4.4 determined a regional formation pressure gradient (of brine-filled reservoirs) of 0.450 psi/ft for the targeted Injection Zone. Eaton (1969) provides a plot of the effective overburden stress (S_v) as a function of depth for locations along the Gulf Coast. This plot indicates S_v values exceed 0.90 psi/ft for the Injection Zone reservoirs. Matthews and Kelly (1967) provide a plot of the matrix stress ratio (K_i) for tectonically relaxed reservoir sediments along the Louisiana and Texas Gulf Coast.

The conservatively calculated critical pressure increases required to induce seismicity on a pre-existing fault for the Upper Tuscaloosa Injection Zone interval at the Louisiana Green Fuels sequestration site are contained in Table 2-13. These critical pressures are incrementally less than the pressures modeled at the end of injection (Upper Tuscaloosa (Upper Interval) – 95%). Therefore, Strategic Biofuels will monitor injection pressure to ensure the actual injected pressure **does not** exceed the calculated critical pressure. Regardless, the absence of any known fault or fractures that impact the Cretaceous rocks within the AoR for this project indicates induced seismicity is highly unlikely to ever occur at the proposed sequestration site.

2.6 HYDROGEOLOGY

The primary regulatory focus of the US EPA injection well program is the protection of human health and the environment, including the protection of known or potential Underground Source of Drinking Water (USDW). A USDW is defined by the EPA as an aquifer which supplies any public water system and contains fewer than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS). The following sections describe in detail the regional and local hydrogeology and hydrostratigraphy [LAC 43:XVII §3607 (C)(1)(b)].

2.6.1 Regional Hydrogeology

The predominant aquifers of Louisiana by location, presented in Figure 2-40, typically occur within Eocene and younger formations that contain usable quality water (<3,000 mg/L TDS) and potentially usable quality water (<10,000 mg/L TDS), which is defined as the base of the lowermost USDW. These aquifer systems regionally crop out in bands parallel to the perimeter of the Mississippi Embayment and dip and thicken towards the south/southeast.

There are two major regional aquifer systems of importance in north-central Louisiana (Figure 2-40):

- the Eocene-aged Cockfield and Sparta Aquifer System; and
- the Quaternary-aged Mississippi River Valley Alluvial (MRVA) Aquifer System.

Figure 2-41 contains a hydrostratigraphic column for the State of Louisiana. This column denotes the focused aquifer units for the project site (as highlighted by the red box outline). Not all of these aquifer units are present throughout all of Louisiana. The deeper Eocene-aged aquifers of the

Cockfield and Sparta Formations only contain fresh water (above the USDW) in the northernmost portion of the state, generally that area that encompasses the proposed sequestration site and those lands located further north. In the central area of Louisiana, these same aquifers transition with depth to saline reservoirs as the rate of formation dip increases towards the Gulf of Mexico. Once the salinity of the water in these reservoirs increases with depth beyond the USDW standards they no longer represent potential sources of groundwater supply.

Groundwater moves through aquifer systems from areas of high hydraulic head to areas of lower hydraulic head. Local groundwater withdrawal by industrial and municipal water systems has been documented to have impacted (locally changed) the direction of groundwater flow through the impacted aquifer(s). Where available, published potentiometric maps for the aquifers of the subject region have been provided and are discussed in the hydrostratigraphic section. The direction of groundwater flow, unimpacted by local water usage, is typically downgradient at 90 degrees to the potentiometric contours, at right angles. The most heavily used aquifer system in the northern region of the state is the MRVA system, the use of which accounts for 22 percent of all groundwater withdrawal in the state.

The following subsections focus on the regional hydrostratigraphy for north-central Louisiana.

2.6.1.1 Sparta Aquifer System

The Sparta Aquifer (also known as the "Kosciusko Aquifer" in western Mississippi) extends from northeast Texas to central Mississippi and is comprised of highly porous and permeable Eocene-aged sandstone reservoirs. It is a major source of freshwater in the north-central part of Louisiana and Arkansas and its depositional geomorphology parallels the structural strike of the ancestral Mississippi Embayment (Figure 2-42). The Sparta Aquifer is recharged at its outcrop through the direct infiltration of rainfall, the movement of water through overlying terrace and alluvial deposits, and in certain limited areas, vertical leakage from the Cockfield and Wilcox aquifers. The Sparta Aquifer consists of a series of fine- to coarse-grained, loosely consolidated, quartzitic sands that range in thickness from 100 to 900 feet in the updip areas of the Mississippi Embayment where it contains freshwater (Rollo, 1960). The Sparta Aquifer thins over the significant structural arches of the local region, most notably the LaSalle Arch and the Monroe Uplift.

The Sparta Aquifer predominantly consists of sandstones of continental origin in the updip areas of the Mississippi Embayment, where it contains freshwater. However, in certain paleocoastal areas, brief transgressions of the Gulf of Mexico sea during Eocene time episodically inundated the littoral areas of the Sparta coastline (Payne, 1968). Such minor marine transgressions are evidenced by the occasional appearance of marine fossils and glauconite in locally reworked sands deposited within the Sparta stratigraphic interval. The lateral equivalents of the Sparta sandstones are hydraulically connected in certain areas but do not necessarily represent regionally extensive (sheet-like) reservoirs.

In northeast Louisiana, the regional flow direction for the Sparta Aquifer is generally eastward, towards the axis of the Mississippi Embayment. The Sparta Aquifer is an artesian aquifer system that is confined by the overlying impermeable clays of the lower Cook Mountain Formation and the underlying clays of the Cane River Formation, which serves as an aquitard for the USDW.

The Sparta Aquifer is an important source of usable groundwater for fifteen parishes in north-central Louisiana, primarily for public supply and industrial purposes (McGee and Brantly, 2015). For the Sparta Aquifer, the hydraulic conductivity generally ranges from 10 to 200 feet per day (feet/d) with an average of about 70 feet/d over the extent of the Mississippi Embayment (Hosman and others, 1968).

2.6.1.2 Mississippi River Valley Aquifer

This MRVA is comprised of Pleistocene and Holocene-aged sediments. The Pleistocene deposits consist of a wedge of fluvial-deltaic sediments that thicken into the Mississippi Embayment (and in a general coastward direction). A relatively thin veneer of Holocene-aged deposits form stream terraces and alluvial valley fills (Rollo, 1960). These near-surface deposits are surficial and recharge to the system is predominately by the abundant rainfall associated with the temperate climate of the Gulf Coastal Plain. The MRVA system typically contains a series of gravel to coarse-grained sandstones at its base, transitioning upward into finer-grained sandstones and siltstones that in turn continue to diminish in grain size (fining upwards) until the lithology transitions to clay. In some localized areas, the surface is covered by such impermeable clays.

The MRVA is a major source of freshwater in the northern-northeastern part area of Louisiana and into the adjacent western area of Mississippi. The recharge is derived primarily from precipitation rainfall and, to a lesser degree, by leakage from underlying sediments such as those of the underlying Cockfield aquifer and Sparta Formations, where the MRVA unconformably subcrops those older Eocene aquifers of the region (Prakken and White, 2014). The alluvial aquifer discharge and recharge patterns of the MRVA are also controlled by surface water features that may cross through the seasonal influx and movement of surface waters through the rivers and streams that are in hydraulic communication with the porous strata of the unit.

The MRVA can thus be generally separated into two hydrogeologic units: an upper confining unit of poorly permeable or impermeable silt, clay, and fine sand that impedes the downward movement of water and a lower aquifer unit comprised of a series of exceptionally porous and permeable, recently deposited, coarse-grained sands and gravels (Martin and Whiteman, 1985). The important lower aquifer unit of the aquifer MRVA ranges in depth thickness from 60 to 260 feet in the northeast Louisiana areas and contains fresh water.

The MRVA is used as a primary drinking water aquifer in twenty-seven parishes in central Louisiana and represents the youngest depositional unit of the Mississippi Embayment. The geomorphology of the MRVA is oriented along the axis of the Embayment in a north to south orientation, parallel to and associated with the floodplain of the Mississippi River. The MRVA is hydraulically connected to the Mississippi River and its tributaries and groundwater within the Mississippi River floodplain; accordingly, groundwater within the MRVA flows generally flows in a southerly direction, from high to low hydraulic head. For the MRVA aquifer, hydraulic conductivity generally varies between 10 to 530 feet per day (feet/d). In 2015, withdrawals from the MRVA aquifer totaled 384.60 Mgal/d (Collier and Sargent, 2015) with the majority of the usage for agricultural irrigation (especially rice cultivation) and industry. A potentiometric map published from the USGS in 2016 is presented in Figure 2-43.

2.6.2 Local Hydrogeology

The Louisiana Green Fuels facility is situated in Caldwell Parish in northeastern Louisiana, along the eastern bank of the Ouachita River in the Port of Columbia industrial site. Excluding the

MRVA, the aquifers of the Sparta and Cockfield Formations that underlie the Louisiana Green Fuels project site comprise the major sources of groundwater in southern Arkansas, northern and north-central Louisiana, western and central Mississippi, and portions of northeast Texas. The principal aquifers of Louisiana are presented in Figure 2-44 and a localized hydrogeologic stratigraphic column, developed for the AoR, is illustrated in Figure 2-45.

The hydrostratigraphic units of local importance at the Louisiana Green Fuels proposed sequestration site are of the Eocene-aged Claiborne Group strata and the Quaternary-aged surficial aquifer (MRVA). These are presented in descending order, from oldest to youngest:

- Cane River Formation – the lower containment interval, below the Sparta Formation;
- Sparta Aquifer (series of massive porous and permeable sandstones);
- Cook Mountain Formation – the containment interval deposited above the Sparta Aquifer;
- Cockfield Aquifer (series of thin, porous and permeable sandstones); and
- Mississippi River Valley Alluvial Aquifer (MRVA).

Within this stratigraphic interval there are two principal drinking water – quality aquifers of local importance for the northern Caldwell Parish area: the Cockfield and MRVA aquifers (the Sparta Aquifer is also present but contains more brackish water in most areas). For the project site, the base of the lowermost USDW (as defined by the LDNR) is the base of the lowest (basal) sandstone of the Sparta Formation, which directly overlies the shales of the regionally extensive and generally impermeable Cane River Formation. Because of the considerably higher quality and lower salinity of the groundwater in the overlying Cockfield and MRVA aquifers, the deeper Sparta Aquifer is not currently used as a primary source of drinking water in Caldwell Parish.

The following sections provide details on the local expanse and parameters pertaining to the hydrostratigraphy of the defined systems, from deepest to shallowest intervals. There are no known springs within the local area and there are no upper bedrock or lower bedrock aquifers. The surficial aquifer system within the area is the Holocene-aged MRVA. A regional north-south cross section through the parish from Prakken and White (2014) is presented in Figure 2-46. It should be noted that this line of cross section is located west of the sequestration site, out of the Ouachita River floodplain, and consequently does not show the MVRA. Being located just within the Ouachita River floodplain, Louisiana Green Fuels Port of Columbia site occupies a geographic position that straddles the freshwater surficial extent of the Cockfield and MRVA. Within the Ouachita River floodplain (i.e., east of the Ouachita River), the MRVA is the primary aquifer, while outside of the Ouachita River floodplain (west of the Ouachita River), the Cockfield Aquifer is the primary aquifer. Because of its location, both aquifers are of importance at the proposed Louisiana Green Fuels sequestration site.

2.6.2.1 Cane River Formation – Aquitard

The Cane River Formation is a regionally extensive poorly permeable to impermeable layer (aquitard) comprised primarily of marine clay that directly underlies the Sparta Aquifer. This fossiliferous clay contains glauconite and some very thin, poorly permeable siltstones. The Cane River Formation hydraulically separates the Sparta Aquifer from the deeper Wilcox Formation, which is comprised of a thick interval of interlaminated brine-filled sandstones and shales. The brine-filled sandstones of the Wilcox Formation have been utilized for saltwater disposal from oilfield operations in the northern Louisiana area. The top of the Cane River Formation (i.e., the first shale or clay encountered beneath the base of the basal sandstone of the overlying Sparta Aquifer) has been defined by the LDENR as the base of the lowermost USDW within the greater Louisiana Green Fuels sequestration site AoR.

2.6.2.2 Sparta Aquifer

The gross thickness of the Sparta Aquifer ranges from 600 to 800 feet throughout Caldwell Parish, except in the southeastern corner where the gross thickness ranges from 800 to 1,000 feet (Ryals, 1984). In the northern Caldwell Parish area, the Sparta Aquifer is a confined aquifer that contains usable ground water that is of lesser quality (<3,000 mg/L) than that pumped from the shallower Cockfield and MRVA Aquifers. The formation was deposited in what has been interpreted to be a fluvial-deltaic braided stream environment. The lower half of the Sparta Aquifer generally consists of fine to medium grained sand; the beds in the upper half of the Sparta interval are typically comprised of layers of sand and clay, with occasional thin lignite deposits (McGee and Brantly, 2015). In Caldwell Parish, the direction of groundwater flow in the Sparta aquifer (as measured in 2012) is northward toward a localized pressure sink caused by the pumping of large volumes of groundwater from the Sparta Aquifer in that area, especially in the vicinity of the city of Monroe in the adjoining Ouachita Parish (Figure 2-47).

2.6.2.3 Cook Mountain Formation

The Cook Mountain Formation extends from north-central Louisiana eastwards into west-central Mississippi and northward into southern Arkansas. The formation ranges in thickness from about 100 feet in northeastern Louisiana, to about 300 feet in central Louisiana, where it dips to the southeast towards the axis of the Mississippi Embayment (Rollo, 1960). In the project area, the Cook Mountain Formation is comprised primarily of impermeable clays and some thin, discontinuous, fine-grained sandstones and siltstones that do not represent commercially important groundwater reservoirs.

2.6.2.4 Cockfield Aquifer

The Cockfield Aquifer is considered an aquifer of minor importance within much of Louisiana. However, it is a primary aquifer for northern Caldwell Parish west of the Ouachita River and its floodplain. The Cockfield Aquifer thickness ranges from less than 200 feet along the northwestern parish line to between 600 to 800 feet in the southeastern corner of the parish (Ryals, 1984). Beneath the Ouachita River, much of the Cockfield Aquifer has been eroded and replaced by the alluvial sands and gravels of the MRVA (Collier and Sargant, 2015).

2.6.2.5 MRVA

The MRVA is an important source of groundwater east of the Ouachita River (in the floodplain). The aquifer is relatively shallow in Caldwell Parish from surface to depths around 250 to 300 feet. Recharge to the MRVA is primarily from precipitation and, to a lesser degree, by leakage from underlying sediments such as the Cockfield aquifer (Prakken and White, 2014). Natural discharge occurs by seepage into streams (Whitfield, 1975). Details on MRVA groundwater usage in the Parish are discussed in the following sections.

2.6.3 Determination of the Lowermost USDW

The most accurate method for determining formation fluid properties is through the analysis of formation fluid samples. In the absence of formation fluid sample analyses, spontaneous potential and formation resistivity data obtained from the analysis of open-hole geophysical well logs can be used to calculate formation fluid salinity by determining the resistivity of the formation fluid (R_w) and converting that resistivity value to a salinity value. The two primary methods used to derive formation fluid salinity from geophysical logs are the "Spontaneous Potential Method" and the "Resistivity Method". The Spontaneous Potential Method derives the formation fluid salinity from the measured resistivity of the mud filtrate and the magnitude of the deflection of the spontaneous potential response, which is the electrical potential produced by the interaction of the typically freshwater based (low salinity) drilling fluid, the varying saline content of the formation water, and the shale content of the formation surveyed. The Resistivity Method determines formation fluid resistivity from the logged resistivity of the formation (R_t) and the calculation of a formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987).

2.6.3.1 Spontaneous Potential Method

The spontaneous potential (SP) curve on an open-hole geophysical well log records the electrical potential (voltage) produced by the interaction of the connate formation water, conductive drilling fluid, and certain ion-selective rocks (clays and shales). Opposite shale beds, the spontaneous potential curve usually trends as a straight line (called the shale baseline), while opposite permeable formations, the spontaneous potential curve exhibits excursions (deflections) away from the shale baseline. The deflection may be to the left (negative) or to the right (positive), depending primarily on the relative salinities of the formation water and the drilling mud filtrate. When formation salinities are greater than the drilling mud filtrate salinity, the deflection is to the left (negative), which is usually the case for porous formations logged below the USDW. For the reverse salinity contrast (i.e., usually for shallower porous reservoirs that are freshwater bearing), the deflection, to the extent there is sufficient contrast with the salinity of the drilling fluid, is to the right (positive). When the salinities of the formation fluid and the drilling mud filtrate are similar, no spontaneous potential deflection opposite a permeable bed will occur, and the response will be roughly equivalent to that of the shale baseline.

The deflection of the spontaneous potential curve away from the shale baseline in a clean sand is related to the equivalent resistivities of the formation water (r_{we}) and the drilling mud filtrate (r_{mf}) by the following formula:

$$SP = -K\ Log\ \left(\frac{r_{mf}}{r_{we}}\right) \qquad \text{Equation (1)}$$

For NaCl solutions, K = 71 at 77°F and varies in direct proportion to temperature by the following relationship:

$$K = 61 + 0.133\ T° \qquad \text{Equation (2)}$$

From the above equations, by knowing the formation temperature, the resistivity of the mud filtrate, and the spontaneous potential deflection away from the shale baseline, the resistivity of the formation water can be calculated (Figure 2-48). From the formation water resistivity and the formation temperature, the salinity of the formation water can then be calculated (Figure 2-49).

2.6.3.2 Resistivity Method

As noted above, the Resistivity Method determines formation fluid resistivity from the true resistivity of the formation (R_t) and the calculation of a formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987). The resistivity of a formation (R_t in ohm-meters) is a function of: 1) the resistivity of the formation water, 2) the amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (infinitely high resistivity) with the exception of some clay minerals, and therefore is not generally a factor in the resistivity log response.

Induction geophysical logging techniques determine resistivity or true resistivity (R_t) by inducing electrical current into the formation and measuring its conductivity (the reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and the invaded zone (Schlumberger, 1987). Therefore, the induction log can measure the true resistivity of the formation

(Schlumberger, 1987). The inverse of the conductivity measured on the induction log is the most accurate resistivity measurement for resistivity under 2 ohm-meters. Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988).

In general, brine-filled highly porous sediments with open, well-connected pores exhibit lower resistivity, and low-porosity sediments with sinuous and constricted system of pores exhibit higher resistivity. It has been established experimentally that the resistivity of a clean, saltwater-bearing formation (i.e., one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w} \qquad \text{Equation (3)}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, lower salinity, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given (saline) formation water, the greater the porosity of the formation, the lower the resistivity of the formation (R_t) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G. E. Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m} \qquad \text{Equation (4)}$$

Where:

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor m is assumed to be 2, but can vary from 1.2 to 2.2 (Stolper, 1994). In the shallower sandstones, as sorting, cementation, and compaction decrease, the cementation factor m can also decrease (Stolper, 1994). Experience over the years has shown that the following modified form of Archie's Law generally holds for sands in the Gulf Coast and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^m} \qquad \text{Equation (5)}$$

By combining the equations for the Humble relationship and the determination of the formation factor, the resistivity of the formation water (R_{we}) can be related to the formation resistivity (R_t) by the following formula:

$$R_t = \frac{R_{we} \: x \: 0.81}{\phi^m} \qquad \text{Equation (6)}$$

2.6.3.3 Methodology Used in the Site Evaluation

To determine the formation water resistivity in a particular reservoir, the resistivity of the drilling mud filtrate (obtained from the log header) at the depth of the reservoir must first be determined. Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically shown in the form of a nomograph for computational ease (Figure 2-48). From this Figure, the resistivity of the drilling mud filtrate can be corrected to the temperature of the zone of interest. A shale baseline is next established on the spontaneous potential curve and the deflection away from the shale baseline is measured. A chart containing the graphic solution of the spontaneous potential Equation (1) (Figure 2-49) gives the solution for the ratio between the resistivity of the mud filtrate and the formation water (R_{mf}/R_{we}) based on the measured spontaneous potential curve deflection. The resistivity of the formation water at formation temperature can be determined from the R_{mf}/R_{we} ratio and converted to the equivalent NaCl concentration from Figure 2-48. Once the base of the lowermost USDW is established, a formation resistivity (R_t) cut-off on the deep induction log can be established using Equation (6). This formation resistivity cut-off, used by LDENR for the state, has been used to establish the base of the lowermost USDW, which corresponds with the base of the Sparta Aquifer in the Louisiana Green Fuels proposed sequestration site area.

By using Figures 2-48 and 2-49, a formation water resistivity of 0.35 ohm-m corresponds to a salinity of 10,000 mg/l TDS. However, using a temperature of approximately 90 °F, a formation water resistivity value of 0.45 ohm-m corresponds to a salinity of 10,000 mg/l TDS. Therefore, deeper intervals with higher temperatures are expected to have a higher resistivity cut off for analysis.

Using a water resistivity value and an estimate of formation porosity, a formation resistivity (R_t) cut-off can be calculated. For the Louisiana Green Fuels site, the USDW is relatively shallow (compared to injection depths), and thus a formation water resistivity of 0.35 ohm-m is used. From Equation (6), using an assumed formation porosity of 34 percent (shallow unconsolidated sands), a formation resistivity (R_t) cut-off can be calculated as follows:

$$R_t = \frac{0.35\ ohm - m\ x\ 0.81}{0.34^2} = 2.45\ ohm - m$$

Therefore, it is conservatively calculated that porous sands with a formation resistivity greater than 2.0 ohm-m were considered to be above the USDW. This methodology is in agreement with DENR guidance: (http://www.dnr.louisiana.gov/assets/OC/im_div/uic_workshop/2_USDW.pdf), which indicates that the USDW should fall between:

- Ground surface to 1,000 feet: 3 ohm-meters or greater
- 1,000 feet to 2,000 feet: 2 ½ ohm-meters or greater
- 2,000 feet and deeper: 2 ohm-meters or greater

USDW values and depths have been reported through LDENR's Strategic Online Natural Resources Information System (SONRIS), and these were compared against the depths measured using shallow well logs in the proposed sequestration site area. To be conservative in the current analysis, the base of the lowest USDW as observed on all of the logs from wells drilled within the AoR was correlated from well to well and placed at the base of the deepest Sparta sand (or its stratigraphic equivalent) exhibiting a deep resistivity of 2 ohm-meters, which consistently represents the stratigraphic equivalent of the base of the Sparta Aquifer (Figure 2-50).

2.6.3.4 Base of Lowermost USDW

The lowermost USDW is defined by the marked decrease of resistivity (to the Cane River Formation shale baseline) that occurs at the base of the deepest (basal) sand deposited within the Sparta Formation. The lowermost USDW is separated from the top of the Wilcox Formation by approximately 200 feet to 250 feet of Cane River Formation, which is a regional aquitard consisting predominantly of shale between the shallowest freshwater sands of the Sparta Formation and the deeper saline sands of the upper Wilcox Formation.

For the Louisiana Green Fuels site, the USDW is found to occur at a depth range of approximately 850 feet to 1,100 feet (measured log depth), based upon the methodology presented above and as verified by the correlative USDW depth values reported by SONRIS. The base of the lowermost USDW is presented in **Figure A.1** in Appendix A. The map shows the depth of the USDW ranges from ~500 feet below ground level (at the northeast corner of the map) to over 1,200 feet (in the south / southwest sector of the map).

The USDW is approximately 1,070 to 1,100 feet below ground level, which has been established by the historical drilling and open hole logging records within the shallow Riverton Field as well as the recently drilled stratigraphic test well (SN975841). This depth correlates to the stratigraphic equivalent of the base of the Sparta Aquifer. However, as noted, the Sparta Aquifer is not currently used as a source of drinking water within the AoR.

2.6.4 Local Water Usage

In Caldwell Parish, which has a current population of approximately 9,700 people, the main source of drinking water comes from the Cockfield and MRVA Aquifers. Currently, there are 11 public water systems in the Parish that rely upon pumped shallow groundwater as a source of fresh water.

The USGS, in cooperation with the Louisiana Department of Transportation and Development (DOTD), produced a "*Water Resources of Caldwell Parish*" fact sheet with data up until 2010. The supply of water for public use was divided between surface water use (61%) and groundwater use (39%). The majority of the Parish's surface water is supplied from the Ouachita and Bouef Rivers and Bayou Lafourche, with a very minor additional volume supplied by Caster Creek and

Beaucoup Creek. With regard to groundwater supply, the 2010 USGS statistics showed that 1.73 Mgal/d of groundwater was supplied from the three local aquifers, in the following proportions: (1) the MRVA provided 0.61 Mgal/d, (2) the Cockfield Aquifer provided 1.09 Mgal/d, and (3) the Sparta Aquifer provided 0.02 Mgal/d.

The nearest drinking water producer to the proposed sequestration site is the East Columbia Water District (ECWD). The ECWD is one of two systems providing service to Caldwell Parish east of the Ouachita River; the other nine systems are located west of the river. The ECWD supplies groundwater from two wells completed within the MRVA aquifer system for the eastern portion of the Parish nearest the river along its entire course through the Parish, including all surface operational areas of the proposed Louisiana Green Fuels sequestration site. The source wells, treatment facility and storage tanks are on the same location and are within the AoR for the sequestration site. The other system east of the river is distant to the northeast, far outside the AoR, and is separately sourced. The ECWD reports that it provides service to 940 customers and a total population of approximately 2,820. Usage in 2020 was 51 million gallons averaging 140,000 gal/day, and the total tank storage capacity is 300,000 gallons.

2.6.5 Water Wells and Data Sets

Water well data was gathered from the online database of the LDENR, specifically the online GIS website SONRIS (https://www.sonris.com). A water well search was performed through SONRIS in March 2024. LDENR registered water well locations within the AoR are shown on many of the maps provided and on Figure 2-51 (shown as blue squares labeled "W") and keyed to Table 2-14. Additionally, these water wells are also depicted on all the geologic maps provided in Appendix A. Figure 2-51 also illustrates surface water bodies in the local area. The Ouachita River, which is located just west of the proposed sequestration site, runs generally north-south from southern Arkansas through northern Louisiana and eventually empties into the Red River. It is approximately 605 miles long. There are also multiple branches and creeks, which are seasonally intermittent. There are no quarries or subsurface mines within the study area.

A total of 186 water wells have been identified as having been drilled for sources of water (Table 2-14) and extend from depths of 28 feet to 845 feet (Figure 2-52). Of those 186 wells, 133 water wells are still active, the remaining 53 water wells are plugged. These active wells are proportionately completed in the MRVA (63%), the Cockfield Aquifer (24%), the Sparta Aquifer (8%), and minor completions in other smaller systems (Figure 2-53).

The available public data (note: some wells are missing data) indicates the water well usage within a 4-mile radius of the proposed project site is primarily attributable to agricultural irrigation and domestic consumption (Figure 2-54). The remaining water wells for which usage data is available are used for commercial and industrial purposes or were drilled to provide temporary drilling water in support of nearby oil and gas drilling well activity. Of the 133 active water wells, six wells are currently being used for municipal public water supply.

No Class I injection wells have ever been operated within Caldwell Parish. There are currently no active Class II injection wells (saltwater disposal wells for oil and gas operations) located within the AoR. Previously active Class II wells in the local area injected brine well below the USDW into the saline reservoirs of the Upper Wilcox formation at depths between 1,300 feet to 2,500 feet. It should be noted that all such previously active Class II saltwater disposal wells injected brine into Upper Wilcox sandstone reservoirs that are well above the top of the Secondary Upper Confining Zone, the Paleocene Midway Group. Those wells have since been plugged.

2.6.6 Injection Depth Waiver

The Injection Zone proposed by Strategic Biofuels for its proposed Louisiana Green Fuels sequestration site is more than 3,000 feet deeper than the base of the lowermost USDW. Accordingly, Strategic Biofuels does not request an injection depth waiver.

2.7 GEOCHEMISTRY

The proposed data collection program (submitted in "*Pre-Operational Testing*" in Module D) has been designed and implemented to determine the mineralogy of the Injection Zone intervals, the numerous intraformational Containment Intervals, and the Primary and Secondary Upper Confining Zones, as well as to characterize the interstitial fluids in each of these zones of interest.

Below the base of the lowermost USDW and throughout the entire interval of interest, all rock formations contain brines of varying salinity in their pore spaces. Open hole logging methods, such as the wireline recording of spontaneous potential, formation resistivity, and formation nuclear magnetic resonance tool measurements, along with their interpretations, can be used to define the vertical distribution of saline brine concentrations. The salinity of brines within such formations increases with depth under normal (i.e., non-geopressured / dewatered) conditions. For additional accuracy, fluid samples will be collected *in-situ* during the initial completion of the injection wells and brought to the surface to be analyzed by an LDNR accredited laboratory, in a manner similar to that recently employed during the testing of the stratigraphic test well (SN975841). These different sources of data will be integrated and compared to existing data available in the region through published literature papers and state and/or federal regulatory agency databases.

The deep resistivity log data acquired in the stratigraphic test well borehole and fluid samples collected using various methods and tools have been used to characterize the formation fluid's geochemical properties and assess potential compatibility issues between the supercritical CO_2 to be injected and the native fluids and the mineralogy of the sandstones of the Injection Zone.

2.7.1 Formation Brine Properties

During cased-hole testing, formation fluid samples were collected from the stratigraphic test well for each tested injection interval and the samples were subsequently analyzed by Stratum Reservoir in Houston, Texas. The data obtained from the analysis of the formation fluid samples was used to establish the model parameters and data inputs for the proposed sequestration reservoirs within the AoR.

The resistivity of each formation fluid sample as measured in the laboratory was then compared to the downhole water resistivity recorded by the deep induction resistivity curve logged in the stratigraphic test well. The salinity of the samples measured in the lab was also compared to the salinity derived from the resistivity curve measurements and the calculated formation water resistivities. Overall, the laboratory results were in excellent agreement with the properties estimated using the wireline logging tools. Fluid viscosities were then calculated from the temperature, pressure, and salt concentrations of the formation fluid samples, as was the pH of the fluid, which is also discussed in this section for each injection interval. The site-specific test results are summarized in Table 2-15.

Additional samples were collected from the stratigraphic test well during testing operations and maintained in pressurized conditions for flashed gas composition measurements at the surface. These datasets reveal the non-negligible presence of native CO_2 in the subsurface, mostly in the sandstones of the Upper Tuscaloosa Injection Zone, as detailed in Table 2-16.

2.7.1.1 Temperature

The formation temperature gradient can be estimated from temperature measurements previously recorded in offset wellbores drilled to various depths within the AoR. The radius (rugosity) of the borehole, the temperature of the drilling fluid, and the extent of mud filtrate invasion (from the drilling fluid) can influence the temperature measured in the borehole, although such influence generally attenuates (lessens) over time (Poulsen et al., 2012). The measured borehole temperature is thus affected by the length of time between the end of drilling fluid circulation and the time the wireline logging tool takes to reach the drilled bottom of the well and begin logging up. As such, borehole temperature measurements recorded by wireline-conveyed thermometers at a given depth in a borehole are likely to be lower than the actual formation temperature at that depth, because the temperature of the mud column in the borehole (at time of logging) has not had sufficient time to reach equilibrium with the actual formation temperature.

In Figure 2-36, the bottomhole temperatures recorded in 58 offset wells drilled within a radius of 20 miles from the stratigraphic test well are combined with the temperatures recorded by the cased hole Differential Temperature Survey run in the stratigraphic test well 24 hours after the injection tests were completed. Also displayed for reference are the mean annual surface temperature and the bottomhole temperature immediately measured prior to open hole logging. The data are fitted by a linear trend which indicates a temperature gradient of 1.53 °F/100 feet.

The subsurface temperature for each injection interval can then be estimated from the temperature gradient and the mean annual surface temperature (see also Table 2-15, which summarizes the water formation properties analyzed from the fluid samples tested in the lab):

1) 129 °F – Annona Sand (Intraformational Chalk Reservoir) (log depth of 4,166 ft)

2) 145 °F for Primary Injection Zone – Upper Tuscaloosa Interval (depth of 5,166 ft)

3) 151 °F – Lower Tuscaloosa "Basal Sand" (depth of 5,612 feet; note – the Lower Tuscaloosa Basal Sand is a low-permeability reservoir not targeted for injection)

The temperatures of the confinement and containment intervals can also be calculated, such as:

1) 119 °F for Secondary Upper Confining Zone – Midway Shale (3,469 feet)

2) 145 °F for Primary Upper Confining Zone – Austin Chalk Equivalent (depth of 4,800 feet)

3) 155 °F for Lower Containment Interval – Paluxy Shale (depth of 5,846 feet)

2.7.1.2 Salinity

Much of the methodology for salinity determination is identical to the Resistivity Method used for USDW determination detailed in Section 2.6.3, including the use of Equations (3), (4), (5) and (6). For clarity, that analysis is repeated in full in this Section.

The general theory associated with the determination of water quality in "clean" saltwater-bearing reservoirs relies upon the resistivity of the native formation water (R_w), which can be calculated by using the Archie Equation (Archie, 1942). The use of the Archie Equation assumes that the reservoir for which water resistivity is to be determined is 100% water saturated and does not contain any appreciable volume of clay or shale. The Archie Equation further assumes that the subject reservoir is sufficiently thick so that the deep investigation resistivity measurements have not been affected by either shoulder beds or by mud filtrate invasion.

The general form of the water saturation equation is:

$$S_w^n = \frac{R_w}{(\phi^m R_t)}$$

where:

S_w is the water saturation of the uninvaded formation

n is the *saturation* exponent, which varies from 1.8 to 4.0 but is normally assumed to be 2.0

R_w is the formation water resistivity at formation temperature

Φ is the porosity

m is the *cementation* exponent, which varies from 1.7 to 3.0 but is normally assumed to be 2.0

R_t is the true resistivity of the formation, corrected for invasion, borehole, thin bed, and other environmental effects

In shaley (clay-rich) reservoirs, Archie's Equation tends to overestimate the water saturation. Many models have been developed that attempt to take into consideration the volume of clay or shale (Vshale) in the formation matrix to account for the overestimation of water saturation. As an example, the Simandoux Equation (Simandoux, 1963) is among the most frequently used shaley sand water saturation equations, and one that reduces mathematically to the Archie Equation when the subject reservoir is clean (*i.e.*, when Vshale = 0).

In the case of a fully saturated formation, the true resistivity of the formation (R_t, expressed in ohm-meters) is a function of the resistivity of the formation water, the amount and type of fluids present, and the pore structure geometry. The rock matrix itself generally has zero conductivity and therefore is not generally a factor in the resistivity log response unless the logged strata have zero porosity. Induction logging determines near-wellbore resistivity by inducing an electrical current into the formation and measuring the formation's conductivity (the reciprocal of resistivity). The induction logging tool investigates deeply into the formation and is tailored to minimize the influences of borehole effects, surrounding formations, and invaded zones (Schlumberger, 1987). Modern versions of the induction logging tool are considered capable of measuring the R_t of the formation (Schlumberger, 1987). In other words, modern induction resistivity logging represents the most accurate resistivity measurement for resistivities under 2 ohm-meters.

Electrical conductivity in porous rocks almost always results from the transport of ions in the pore-filled formation water and is dependent upon the volume and type of fluids present as well as the pore space geometry (Schlumberger, 1988). In general, high-porosity sediments with open, well-connected pores exhibit higher conductivity and lower resistivity whereas low-porosity sediments with sinuous and constricted porous systems exhibit lower conductivity and higher resistivity . It has been established experimentally that the resistivity of a clean, water-bearing formation (i.e., a reservoir containing no appreciable clay or hydrocarbons) is directly proportional to the resistivity of the formation water, R_w (Schlumberger, 1988). This constant of proportionality is called the formation resistivity factor (F), such as:

$$F = \frac{R_t}{R_w}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given formation fluid, the greater the porosity of a formation, the lower the resistivity of the formation (R_t) and the lower the formation factor (F). Therefore, the formation factor is inversely related to the formation porosity. In 1942, Archie proposed the following relationship between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m}$$

where:

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor *m* is generally assumed to be 2.0 but can vary from 1.2 to 2.2. In near-surface sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease. Experience over the years has shown that the following form of Archie's Law is generally accurate when applied to such shallow sandstones, especially in the U.S. Gulf Coast area, and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^2}$$

By combining the two expressions:

$$\frac{R_t}{R_w} = \frac{0.81}{\emptyset^2}$$

The above equation was applied to calculate the formation water resistivity in the Stratigraphic Test Well (La SN: 975841) from the deep resistivity curve measurements (Figure 2-55).

Resistivities of reservoir brines vary as a function of NaCl concentration and formation temperature. The relationship between formation temperature, NaCl concentration, and formation resistivity are typically shown in the form of a nomograph for computational ease (Figure 2-48). This nomograph (or its algorithmic expression) can be used to estimate the water salinity in the proposed Injection Zone intervals.

Empirical methods exist to determine the salinity of the formation water, but the most accurate method is the direct physical analysis of formation fluid samples collected *in-situ.* Table 2-15 presents a summary of the major chemical constituents and physical properties of the eight formation water samples collected during the injection testing of the stratigraphic test well by swabbing operations that immediately followed the perforation of the prospective sequestration reservoirs. *In-situ* samples were collected from their representative formations as follows:

- Annona Sand (intraformational reservoir above Primary Confining Zone) (4,149-4,184 ft)
- Upper Tuscaloosa Formation (5 samples collected between 4,913 and 5,484 ft)
- Lower Tuscaloosa Basal Sand (5,597-5,628 ft) (note – see previous comments; the Lower Tuscaloosa Basal Sand is a low-permeability reservoir not targeted for injection)
- Paluxy "P-2" and "P-3" Sands (commingled interval: 5,810-5,846 ft)

The measurement of TDS, which indicates the salinity of the formation water, was measured in the lab by (1) the summation of the major ion constituents and (2) derived (estimated) from the observed conductivity of the formation fluid sample. The first method is preferred because the ion constituents are directly measured from the fluid samples. Table 2-15 provides the results for both calculations.

Since the dominant cation in each of the eight fluid analyses is sodium (Na^+), and the dominant anion is chlorine (Cl^-), the TDS can be compared to the sodium chloride (NaCl) concentration (which is also a proxy for salinity) estimated from the resistivity measurements performed in the lab at a temperature of 77 °F, using the nomograph provided in Figure 2-48. The TDS can also be compared to the NaCl concentration estimated from the formation water resistivity (R_w) computed from the resistivity well log (R_t), plotted in Figure 2-55 for the proposed Injection Zone, again using the nomograph for the corresponding downhole temperatures. The NaCl concentrations exhibit a near-perfect match between the two methods. However, it should be noted that a discrepancy of -4% to +16% with the TDS calculated as the sum of the major ions and a discrepancy of -18% to -13% with the TDS calculated from the sample conductivity was observed.

For subsequent calculations, the TDS obtained as the sum of the major ions in the fluid samples will be used as the reference.

The water salinity / quality measured in the stratigraphic test well can be summarized as follows:

1) 96,000 mg/l – Annona Sand (Upper Point of Reference) (sample depth 4,166 feet)

2) 126,000 mg/l – Upper Sands Interval of the Upper Tuscaloosa Formation (Primary Injection Zone) (sample depth 5,166 feet)

In addition, as a Deeper Point of Reference, the salinity of the brine of the Basal Sand of the Lower Tuscaloosa Formation was also measured and determined to be:

3) 104,000 mg/l for the Basal Sand of the Lower Tuscaloosa Interval (at a depth of 5,612 feet; note – see previous comments; the Lower Tuscaloosa Basal Sand is a low-permeability reservoir not targeted for injection)

Overall, the water quality measurements indicate lower salinities in the Annona Sand (95,000-100,000 mg/l) and in the Lower Tuscaloosa Basal Sand (100,000-105,000 mg/l) than in the Upper Tuscaloosa interval. As one would expect, the highest salinity is observed in the deeper commingled Paluxy "P-2" and "P-3" Sand interval, with an expected range between approximately 130,000 and 145,000 mg/l. For the sandstones of the Upper Tuscaloosa, the general trend seems to be towards increasing formation fluid salinity with depth, ranging from about 120,000 to 130,000 mg/l. However, one formation fluid sample from the top of the Upper Tuscaloosa interval (near 4,930 feet) yielded an analysis of 130,000 mg/l, suggesting brine salinities throughout the Upper Tuscaloosa may be relatively consistent, regardless of the sample depth within the unit.

2.7.1.3 Viscosity

Viscosity is a measure of a fluid's resistance to flow. At subsurface conditions, the formation brine viscosity can be determined using a Microsoft Excel spreadsheet correlation developed by Douglas M. Boone in 1993 which estimates the viscosity as a function of pressure, temperature, and NaCl concentration. Viscosity tends to increase with pressure and salt concentration whereas it decreases when temperature increases.

Table 2-15 includes the viscosity calculated for the fluid samples tested in the lab.

The formation brine viscosity measured in the stratigraphic test well can be summarized as follows:

1) 0.62 cP for the Upper Point of Reference – Annona Sand (sample depth 4,166 feet)

2) 0.59 cP for the upper half of the Primary Injection Zone – the Upper Sands Interval of the Upper Tuscaloosa Formation (sample depth of 5,166 feet)

3) 0.53 cP for the Deeper Point of Reference – the Basal Sand of the Lower Tuscaloosa Interval (sample depth 5,612 feet; note – see previous comments; the Lower Tuscaloosa Basal Sand is a low-permeability reservoir not targeted for injection)

As expected, viscosity decreases with depth as formation temperature increases. However, this tendency for viscosity to decrease with depth may be offset by the higher salinities that also tend to increase with depth. In such higher salinity reservoirs, the formation water becomes more viscous (by way of example, note the higher viscosity of the formation brine recovered from the commingled Paluxy "P-2" and "P-3" Sand interval).

2.7.1.4 pH Measurements

The pH scale, historically denoting potential of hydrogen (or power of hydrogen), is a scale used to specify the acidity or basicity of an aqueous solution. Acidic solutions (solutions with higher concentrations of H^+ ions) have lower pH values than basic or alkaline solutions. The pH scale is logarithmic and inversely indicates the concentration of H^+ ions in the solution. At 25 °C (i.e., 77 °F), solutions with a pH less than 7 are acidic, and solutions with a pH greater than 7 are basic. Solutions with a pH of 7 at this reference temperature are considered neutral (e.g., pure fresh water).

Table 2-14 documents the pH measured in the lab for the eight fluid samples collected *in-situ* from the Stratigraphic Test Well. All samples have a pH lower than 7, indicating slightly acidic solutions. The highest (most basic) pH value of 6.4 was measured from the fluid sample collected from the Annona Sand. For the Upper Sands Interval of the Upper Tuscaloosa Formation (Primary Injection Zone), the pH varies within a narrow range of acidity, i.e., between 5.8 and 6.2. The most acidic values were measured from brine collected from the Lower Tuscaloosa Basal Sand (pH = 2.6; the Basal Sand is not targeted for injection) and the commingled Paluxy "P-2" and "P-3" Sand interval (pH = 4.9).

2.7.1.5 Gas Analysis

Fluid samples were conditioned at reservoir temperature and pressure for a minimum of 24 hours prior to measuring the gas/water ratio and flashed gas composition using gas chromatography methods. The analyses were performed by Stratum Reservoir laboratories in Houston, Texas. Table 2-16 presents the results for the eight samples collected between 4,134 feet and 5,808 feet in the stratigraphic test well. The shallowest sample was collected from the Annona Sand. Two fluid samples were collected from perforations across the Upper Tuscaloosa "5,050-Foot Sand", an optimal sequestration target stratigraphically located within the Upper Sands Interval of the Upper Tuscaloosa Formation (Primary Injection Zone). Another two fluid samples were collected from the Lower Tuscaloosa Basal Sand, which as earlier noted is a low-permeability sandstone that is not a candidate for sequestration. The deepest two samples were from the commingled Paluxy “P-2” and “P-3” Sand interval.

The measured gas/water ratio (GWR) indicates higher amounts of gas were present in the Lower Tuscaloosa Basal Sand reservoir (19.0 and 21.7 scf/stb; the Basal Sand is not targeted for injection) than in the Upper Tuscaloosa “5,050-Foot Sand” reservoir (4.9 and 6.2 scf/stb). There is a non-negligible amount of native CO_2 in the Lower Tuscaloosa Basal Sand (74.2 mol% and 88.0 weight% on average) and in the Upper Tuscaloosa “5,050-Foot Sand” (22.0 mol% and 40.6 weight% on average). Significantly lower amounts of CO_2 were also present in the Annona Sand (2.6 mol% and 6.5 weight%) and in the commingled Paluxy “P-2” and “P-3” Sand reservoir interval (10.9 mol% and 22.9 weight%).

It is also worth noting that two gas collection bags were filled with gas emanating from certain three-foot segments of the whole cores cut in the Stratigraphic Test Well, after the (aluminum inner core) barrels had been transported to Stratum Reservoir’s Houston laboratory for analysis (the end caps of those sealed three-foot core barrel segments had been observed to be distended (bulging) outward by pressure from a buildup in gas within those segments). When the distended end caps of those segments were pierced, the slightly pressured gas trapped inside those barrel segments was extracted and collected in the two bags and subsequently analyzed by Isotech Technology (an affiliate of Stratum Reservoir).

The molecular content of the gas collected in those bags, while mostly methane, was confirmed to also include the presence of CO_2: 100% of the non-hydrocarbon gases present in the gas collected from an Austin Chalk Equivalent core barrel segment (Whole Core No. 2) was CO_2, which equates to 0.092% of the gas collected from that three-foot core barrel segment; and 96% of the non-hydrocarbon gases present in the gas collected from a core barrel segment cut in the upper portion of the Upper Tuscaloosa interval (Whole Core No. 3) was CO_2, which equates to 0.015% of the gas collected from that three-foot core barrel segment.

2.7.2 Compatibility of the CO_2 with Subsurface Fluids and Minerals

Interactions between carbon dioxide and the formation brine and matrix materials in the subsurface can be categorized as those that occur during the period of active injection (or in the immediate period following injection), and those that occur over the longer term of carbon dioxide plume migration and permanent storage. While interactions occurring during injection and in the early phase of carbon dioxide sequestration can be (and have been) directly studied and evaluated, the longer-term interactions over tens to hundreds of years can only be evaluated through modeling and other forms of prediction. In general, geologic materials are not overly reactive, or very slowly reactive, with acids such as carbonic acid. Carbonic acid (H_2CO_3) is a weak acid that dissociates into a proton (H^+ cation) and a bicarbonate ion (HCO_3^- anion).

Because the permeability of the confining zones and adjacent containment intervals (shales) is expected to be several orders of magnitude lower than the permeability of the Primary Injection Zone (sandstones), in a practical sense, the sequestered supercritical carbon dioxide has a much higher potential to contact and react with the rocks and fluids in the Primary Injection Zone. Additionally, because of the extremely low permeability of the aquitard shales, only reactions near or at the shale/sand interface are likely to occur.

Injection operations elevate pressure within the injection interval during the period of active injection and for a period of time afterwards (during pressure recovery). This elevated pressure provides the driving force for the potential vertical permeation of injected fluids and formation brines into the overlying aquitards. Buoyance of the sequestered supercritical carbon dioxide also provides an additive driving force. Permeation is greatest immediately adjacent to the wellbore where the pressure buildup is large and involves primarily the injected fluids. With increasing distance from the well, the permeation force drops off significantly with decreasing elevated formation pressure. In addition, with increasing distance from the well, the mix of affected fluids subject to the permeation force is comprised of decreasing concentrations of injected fluids. At a considerable distance from the injection well, the vertical permeation force declines to the point where it may only affect either the original formation brine or the injected fluids, depending on the extent of the injected carbon dioxide plume.

Occasionally, fluids may move into the base of the overlying aquitard from the injection interval below and compress some of the native brines immediately above it. This compression raises the pressure within the lower portion of the aquitard and expands the pores immediately above the interface. Aquitard materials, such as clay/shales, are known to exhibit significant pore expansion (Neuzil, 1986). The combined effects of native brine compression and aquitard pore expansion provides the necessary space to accommodate / store the entering fluids. This process does not occur uniformly throughout the thickness of the aquitard; rather, it is confined to a narrow region very close to the lower aquitard boundary. Throughout the remainder of the aquitard, there is virtually no indication that any changes have taken place. This narrow region near the base of the aquitard is referred to as the compression boundary layer. It contains new fluids that have entered since the beginning of the injection, as well as original formation brines that have been pushed upward into the expanded pores and compressed by the entering fluids. The vast majority of the fluids within this layer are typically the original formation brines.

With continued injection, the compression boundary layer increases in thickness and may eventually encompass the entire aquitard thickness. Native fluids originally present at the top of the aquitard may then begin seeping out into the next overlying permeable layer. The time for this to occur is proportional to the square of the aquitard thickness and inversely proportional to the hydraulic diffusivity of the aquitard material (Bredehoeft and Pinder, 1970). Because the hydraulic diffusivity of many aquitard materials (such as shales) is very low (Neuzil, 1986; Neuman and Witherspoon, 1969a and 1969b; and Hantush, 1964), the time is in the order of decades (Chen and Herrera, 1982) which is comparable to the operational lifetime of many underground sequestration facilities. Thus, compressive storage effects in the aquitard layers are important when modeling injection-induced permeation into an aquitard during injection and shortly after the cessation of operation of the injection facility. When injection is discontinued, some of the injectate may seep back into the injection interval from the aquitard. This reverse permeation phenomenon always occurs when the pressure in the injection interval decreases.

The vertical permeation distance reaches an absolute maximum either during injection (typically at the end of the injection period) or after an infinite time has passed since injection operations have stopped. The time necessary to attain the maximum distance depends on the compressive storage properties of the aquitard. For aquitards with high compressive storage capabilities, the maximum permeation distance occurs at the end of the injection period. For aquitards with low storage capabilities, the maximum permeation will occur at a much later time.

After injection operations have stopped, the driving force (i.e., pressure) for vertical permeation usually will begin to dissipate, along with the compressive storage of fluids in the aquitard. The pressure-driven rate of fluid movement into the overlying aquitard decreases to zero, leaving only the residual buoyance force. Before the carbonic acid from the sequestered carbon dioxide can react with the clay/shales of the aquitard, it must first migrate from the injection interval strata into the base of the overlying aquitard. During the movement within the injection interval, the acid can be partially or totally neutralized by the carbonates, clays, and other silicates (e.g., feldspars) in the formation. This neutralization halts any further dissolution of carbonate minerals, so that the fraction of dissolved carbonates (relative to the amount of pre-injection carbonate mineral that was present) is extremely small.

The modeling of strong acids injected into Class I wells presented by DuPont indicates that:

- During injection, injected acids react with at most 2 inches per year of shale in the overlying arresting aquiclude layer. This rate drops to less than 0.1 inch per year if the waste is injected at least five feet below the base of the arresting shale.
- After injection ceases, injected acids react with at most an additional two feet of the overlying arresting aquiclude layer for all eternity.
- In the unlikely event that the overlying arresting aquiclude shale layer contains a vertical streak of highly reactive material, such as calcite, the acid could at most migrate 26 inches into this streak: 16 inches during a 60-year period of injection and an additional 10 inches for all eternity post-closure.
- Permeation through the arresting shale due to pressure buildup during injection is more important than shale-acid reactions in determining how far injected fluids can migrate into the overlying arresting aquiclude shale.

Therefore, interactions of the sequestered carbon dioxide and the formation fluids and materials are the most critical within the injection intervals.

At the pressure and temperature conditions typical of supercritical carbon dioxide sequestration projects, carbon dioxide is soluble to a limited degree. The dissolved carbon dioxide transforms the native formation brine into a carbonic acid, such as:

$$CO_2 \text{ (aqueous phase)} + H_2O = H^+ + HCO_3^- \text{ (aqueous phase)}$$

Carbonic acid can react with and dissolve certain minerals in the matrix, which acts to neutralize the lower pH. The sequestration process includes both short-term and long-term geochemical impacts. Short-term CO_2-water-rock interactions can affect injection over the operational time period (decades), such as dry-out and salt precipitation in the near-wellbore area from formation fluid evaporation. In addition, at first contact with CO_2 (i.e., at the leading edge of the sCO_2 plume), carbonic acid is formed via sCO_2 dissolution in the native formation brine. This triggers dissolution of carbonate minerals. As a consequence of this chemical reaction, the carbonic acid is quickly neutralized, and a new equilibrium is rapidly established between the elevated sCO_2 concentration and the carbonate minerals. The new equilibrium is already established after only a small amount of carbonate dissolution has occurred, such that porosity and permeability changes are negligible.

Behind the advancing leading edge of the sCO_2 plume (where the formation brine has already been neutralized), no further carbonate dissolution takes place. Long-term reactions can lead to the permanent entrapment of the carbon dioxide via mineral trapping. The long-term geochemical processes consist of a combination of slow dissolution and precipitation reactions. Significant long-term dissolution without simultaneous co-precipitation is impossible because it would lead to unrealistic supersaturation levels in the formation brine. In most systems, precipitation dominates over dissolution, resulting in a gradual decrease of porosity and permeability and a gradual mineral entrapment of CO_2.

The extent of secondary trapping mechanisms within the injection interval is highly site-specific and depends on the geology, structure, and hydrology of each reservoir. For instance, increasing pore fluid salinity decreases carbon dioxide solubility (Gunter et al., 1993). The purity of the injected carbon dioxide also affects the storage capacity of the reservoir (Talman, 2015). In such sedimentary settings, the injected carbon dioxide may remain mobile for centuries and entrapment would be attributable to the impermeability of the overlying confining layer(s) and sealing faults (if present; there are no known faults within the AoR that would impact the mobility of the sCO2). Large and extensive saline aquifers are essentially hydrodynamic traps, where the injected carbon dioxide is expected to move rapidly through the pore space, interacting with a larger volume of the reservoir. This interaction increases the extent of all secondary mechanisms (National Academies of Sciences Engineering Medicine, 2019).

The carbonic acid created by the dissolution and dissociation of the sCO2 into the formation brine can readily react with calcium carbonate and hydroxide minerals, which in turn would reduce the acidity of the formation brine. In addition to the precipitation of carbonates, a host of other fluid-rock reactions can take place within the injection zone. Silicate minerals in arkoses and shales display textures in experiments indicating those minerals are reacting with carbonic acid (Kaszuba et al., 2002). Acid reacts with feldspars in a manner similar to its reaction with clays. However, the overall rate is slower with feldspars than with clays because in typical rock matrix, the feldspar is present as large particles, so the relative surface area available for feldspar to react is much smaller than that for clay particles.

Silica can be solubilized by an acid as follows:

$$SiO_2 + H_2O + H^+ \rightarrow Si(OH)^{3+}$$

The rate of dissolution of silica is generally quite slow but becomes faster as the hydroxyl concentration increases. Note also that the rate of dissolution is 10,000 times faster at a pH of 8.5 than at a pH of 3.0 (Iler, 1979).

Mineral compatibility from CO_2-brine-rock interaction experiments conducted in support of basin characterization projects sponsored by the Department of Energy suggests that feldspars (plagioclase and albite-K-spar system) are destabilized by the drop in pH associated with carbon dioxide dissolution in the formation brine water, favoring the formation of minerals such as kaolinite, muscovite, and paragonite (LBNL, 2014).

The principal effect of acid on clays is to leach metal ions from the clay lattice sites, leaving behind a silica framework. In experiments which monitored the x-ray diffraction pattern of the clays as the metal ions were leached out by acid, the pattern remained very similar to the original clay x-ray pattern even when 50% of the aluminum had been extracted from the mineral (Matthews et al., 1955). There are two types of sites in clays where metal ions can be located. The largest fraction of metal ions is located within the octahedral sites of the clay structure. These are part of the alumina sheet in the mineral structure and are coordinated to six oxygens. A smaller fraction of the metal ions occupies the tetrahedral sites. These are part of the silica sheet and are coordinated to four oxygens. Octahedrally coordinated aluminum leached out at a faster rate than tetrahedrally coordinated aluminum (Turner, 1964).

At the BEG Frio Brine Pilot Test (in the Texas Gulf Coast Region), following carbon dioxide breakthrough, samples from the monitoring well exhibited sharp drops in pH, pronounced increases in alkalinity and iron content, and significant shifts in the isotopic compositions of formation waters, dissolved inorganic carbon, and methane (Kharaka et al., 2006). Geochemical modeling of the Frio Brine Pilot indicates that brine pH would have decreased further but was buffered by the dissolution of carbonate and iron oxyhydroxides (Kharaka et al., 2006). The dissolution of minerals, especially iron oxyhydroxides, and the leaching of the clays could mobilize metals and organic compounds in formations containing residual hydrocarbons or other organic compounds (Kharaka et al., 2006). It should be noted that whole core and rotary core analysis, as well as an extensive petrophysical analysis of the Stratigraphic Test Well (and surrounding older wells) indicate there is essentially nil residual hydrocarbons in the targeted Injection Zone within the AoR.

The experimental and modeling analyses suggest that mineral precipitation and dissolution reactions (within the targeted Injection Zone intervals) are not expected to lead to significant changes to the underground hydrologic system over time frames (approximately 30 years) that are typically relevant for such injection operations.

2.7.3 Site Specific Geochemical Modeling

Injection of supercritical CO_2 into a reservoir leads to the dissolution and dissociation of CO_2 in the formation water, causing the pH to decline and changing the geochemical equilibrium. As a result, the dissolution and precipitation of minerals will take place until a new geochemical equilibrium is reached. This process may take hundreds of years due to the slow rate at which some minerals react. Mineral reactions, speciation reactions, and gas dissolution reactions are quantified and coded in public geochemical databases (*e.g.,* Thermoddem developed by BRGM), which can be used by the simulation code PHREEQC to compute geochemical equilibria and kinetic rates. PHREEQ is a C and C++ model software designed to solve various aqueous calculations and is available as open-source code through the USGS.

For the Louisiana Green Fuels project, evaluations of the geochemical reactions, especially those related to redox reactions and hydrogen sulfide will be performed in an effort to reduce model prediction uncertainties. A follow-up study is planned to be undertaken once more accurate data (mineralogical and formation fluid compositions) has been obtained from the site-specific acquisition of such data in the proposed injection wells as well as the composition of the actual sCO_2 injection stream. Such follow-up work should include a 1D and/or 2D modeling study to assess the reactive transport effects of CO_2, the quantification of uncertainty (the impact of physiochemical model input parameter uncertainties like mineral dissolution / precipitation kinetic rates), and the geochemical impact of contaminants present in the reaction stream. The future geochemical modeling will also evaluate the potential for the clogging (occlusion) of the pore throats in the near-wellbore area, which could lead to loss of injectivity, caused by water evaporation (dry-out) in the injected CO_2 and salt precipitation in the reservoir. Such salt accumulation could be exacerbated as a result of the capillary backflow of brine from the aquifer into the dried-out area during lengthy periods of non-injection.

The sampling program that will be implemented during the drilling and completion of each proposed injection well has been designed to include additional sampling of relevant formation fluids and formation materials so that tests on both injection interval and the confining layer(s) can be made (see *"Pre-Operational Testing and Logging Plan"* submitted in Module D). The interactions between carbon dioxide, formation brines, and formation minerals will be further analyzed using geochemical and reactive transport models to evaluate changes in formation water chemistry, mineral precipitation, and dissolution reactions, as well as any potential impact upon formation permeability.

2.8 ECONOMIC GEOLOGY OF THE AREA

Historically, Riverton Gas Field, formerly occupying much of the area where the AoR is located, was once a producer of low volumes of natural gas in Caldwell Parish, with methane production supplied from the so-called Reynolds "Coal Seam" (actually, two separate lower Wilcox lignite beds), at depths between 2,400 feet and 3,100 feet. However, coalbed methane production from Riverton Gas Field has significantly declined in production since 2008, and all the formerly producing gas wells (and saltwater disposal wells) have been plugged and abandoned.

The thick shales of the Midway Group (the Secondary Upper Confining Zone) directly underlie the Wilcox Formation and act as a very effective lower confining zone for the shallower gas-bearing lignite reservoirs within the AoR (i.e., within the greater Riverton Field area). Most of the wells drilled within a six-mile radius of the Port of Columbia site are shallow Wilcox test wells that did not penetrate deeper than 3,300 feet, and therefore did not penetrate very far (if at all) into the 600 foot-thick Midway Shale Secondary Upper Confining Zone. As such, these shallow Wilcox wells will not be affected by the deeper CO_2 injection operations at the project site and do not represent potential vertical leak conduits; furthermore, all wells within the AoR have been plugged and abandoned.

Within Caldwell Parish, certain sandstones within the upper portion of the Wilcox Formation (from 1,350 feet to 1,800 feet) have been used by operators for the disposal of produced saltwater. Eight such SWD wells have been drilled within four miles of the Port of Columbia location. All of the saltwater disposal wells located within the AoR have been plugged and abandoned. The historical well documentation indicates that there is a sufficient barrier of a minimum 100 feet between the shallow disposal operations and the base of the lowermost USDW. Therefore, the Cane River Formation has been demonstrated as a good seal (aquitard) separating the historical SWD operations within the upper Wilcox from the overlying lowermost USDW in the Sparta.

Detailed information on wells within the designated AoR is contained in the "*Area of review and Corrective Action Plan Report"* submitted in **Module B**.

There are no sources of pressure, induced pressure sinks, or other critical operations involving either the confining or injection zones in the local site area or region that will have an impact on sCO_2 sequestration operations at the Louisiana Green Fuels, Port of Columbia Facility.

2.9 SHALLOW SURFACE GEOLOGY

The project area is dominated by complex surface conditions including tree and grass-dominated high areas, intermittently flooded freshwater wetland, and riparian zones. The area is expected to be dynamic in terms of seasonal carbon dioxide production and uptake from active environments, including wetland bottom sediments, intermittently saturated soils, plant and animal activities, and other activities which are likely to change over time. The determination of the baseline spatial distribution of atmospheric and soil gas monitoring stations will be determined on a site-specific basis and will consist of repeat measurements at several fixed and variable sites, and over a period of at least one year, to capture any seasonal or diurnal variations (LCFS Protocol Subsection C.4.1).

Atmospheric monitoring across the AoR will be conducted utilizing a single, broad-range eddy covariance system and a portable gas meter to define natural background variability, including seasonal and diurnal trends, and to detect potential atmospheric carbon dioxide leakage and/or potential movement of carbon dioxide that may endanger the local USDW (LCFS Protocol Subsection C.4.3.2.2(a)).

The sampling program that will be implemented during the testing and monitoring for the Louisiana Green Fuels project is provided in *"E.1 – Testing and Monitoring Plan"* submitted in **Module E**.

2.10 SITE SUITABILITY SUMMARY

The Strategic Biofuels, Louisiana Green Fuels site is suitable for injection of supercritical CO_2 as per LAC 43:XVII §3615 (A) standards for the Confining and Injection Zones. The key factors driving site suitability are summarized:

- Only a very limited number of artificial penetrations (legacy wells drilled in search of oil and gas; all dry holes) drilled within the project AoR have completely penetrated the Secondary Upper Confining Zone (the 600 foot-thick shales of the Paleocene Midway Group) and/or the Primary Upper Confining Zone (the 250 to 300 foot-thick impermeable limestones and shales of the Austin Chalk Equivalent / Upper Eagleford interval), reducing associated CO_2 containment risk.

- The proposed Primary Injection Zone is deeper than 4,000 feet, a depth that is associated with sufficient pressure and temperature to be favourable for supercritical CO_2 injection, which increases site efficiency (injecting denser supercritical CO_2 means more carbon dioxide can be stored in an equivalent pore space volume).

- The project AoR is interpreted to be devoid of faults and high-relief salt structures that reach or breach the Lower Confining Zone, substantially reducing risk of vertical migration of injectate out of the proposed Injection Zone via potential natural conduits.

- Structural dips are approximately less than 1.5 to 2 degrees, which is generally favorable for migration-assisted supercritical carbon dioxide sequestration in a saline aquifer.

- There are two vertically stacked Primary Injection Zone intervals: the multiple sandstones of the Upper Tuscaloosa Formation, and the multiple sandstones of the Paluxy Formation, both of which contribute to the capacity of the storage complex and thus improve the storage efficiency of the proposed sequestration site.

- The Primary Upper Confining Zone consists of the 250 to 300 foot-thick impermeable limestones and shales of the Austin Chalk Equivalent / Upper Eagleford interval, which directly overlies the Primary Injection Zone (the Upper Tuscaloosa Formation), and is laterally extensive throughout north-central Louisiana. The Austin Chalk Equivalent / Upper Eagleford interval meets or exceeds all the standards of an upper confining zone in accordance with the definitions set forth by the LAC 43:XVII §3601 (A) standard. Secondary containment intervals internal to the sequestration complex, being located above the Primary Upper Confining Zone (the Austin Chalk Equivalent / Upper Eagleford interval), include the 450 foot-thick Taylor (Middle) Chalk, the 300 foot-thick Selma (Upper) Chalk, and the 600 foot-thick Midway Group (Secondary Upper Confining Zone); these provide an additional and very substantial measure of safety.

- The Lower Confining Zone is comprised of the thick evaporites of the regionally extensive Lower Cretaceous Ferry Lake Anhydrite Formation. Numerous secondary containment intervals that are internal to the basal Sequestration Complex, being located between the base of the Secondary Injection Zone interval (the multiple sandstone reservoirs of the Paluxy Formation) and the top of the Lower Confining Zone (the Ferry Lake Anhydrite) include thick impermeable shales within the Paluxy and Mooringsport Formations, which in turn provide an additional and very substantial measure of safety. The regionally extensive thick evaporites of the Lower Cretaceous Ferry Lake Anhydrite Formation also meet the definition of the Lower Confining Zone as specified by the Low Carbon Fuel Standard (LCFS) regulations promulgated by the California Air Resources Board (CARB).

The heterogeneity and distribution of the sand and shale facies of the Upper Tuscaloosa and Paluxy Formations, as well as their correlative intra-reservoir baffles and containment intervals, serve to provide substantial local immobilization and effective containment of the proposed volumes of supercritical CO_2 to be injected within the AoR. Substantial volumes of supercritical CO_2 can thus be safely sequestered in the pore spaces by capillary forces and dissolved within the *in-situ* brine of the targeted Injection Zone.

The mineralogy of the targeted Injection Zone and its Upper and Lower Confining Zones, as well as the internal containment intervals within the sequestration project, along with the native formation fluids (brines) present in the targeted Injection Zone intervals, are not expected to be reactive in any substantive manner with the injected supercritical CO_2 stream. This lack of reactivity will be confirmed with future data analysis and compatibility testing of the supercritical CO_2 stream.

3.0 AOR AND CORRECTIVE ACTION PLAN

Strategic Biofuels has uploaded the "*Area of Review and Corrective Action Plan*" technical report [LAC 43:XVII §3615 (B) and (C) via **Module B** of the GSDT portal. The report contains the details of the computational modeling [LAC 43:XVII §3615 (B)(1)]which includes pressure and plume maps at 5-year intervals for the simulated 20-year sequestration operation period. The report also includes a tabulation of all wells within the delineated AoR [per §3607 (C)(2)(d)] and is presented in Table 3-1 and is keyed to Figure A.26 contained in Appendix A.

The tabulation includes the well construction and plugging details (if applicable). All supporting well records and construction documentation have been submitted as part of Module B. Well records and logs were collected through multiple agencies such as Louisiana's online state portal (SONRIS), as well as through hardcopy searches at the state's central and regional file rooms. These data were then compiled and organized into one PDF file per artificial penetration (AP). A thorough evaluation of each of these wells, using well records, scout tickets, and logs was performed to determine if a corrective action plan was warranted. There are a total of 263 legacy wells, referred to as Artificial Penetrations (APs), within the delineated AoR. However, only thirteen wells are deep enough to penetrate through the entirety of the Secondary Upper Confining Zone (Midway Shale). These are highlighted in "pink" on Table 3-1. One of these wells, AP No. 229, does not penetrate the Primary Injection Zone. AP No. 129 penetrates just through the top of the Annona Sand but does not reach the Austun Chalk. The 11 remaining AP's have been evaluated based on their 1) proximity to the plume extent, and 2) proximity within the pressure front.

Out of the thirteen wells, four are located within the plume front, with the remining nine only located within the pressure front extent. The (three) wells that penetrated the Primary Upper Confining Zone (Austin Chalk Equivalent / Upper Eagleford) within the area underlain by the modeled supercritical carbon dioxide plume are:

- AP No. 69 – Bradford Brown Trust – Shipp No. 1 (SN137738)
- AP No. 76 – Bass Enterprises – Keahy No. 1 (SN165305)
- AP No. 137 – Whitetail Operators – Louisiana Green Fuels Test Well (SN975841)

These three wells (out of the four wells within the plume extent; AP Nos. 69, 76, and 137) are planned to be re-entered and recompleted as In-Zone monitoring wells. The fourth well, AP No. 129 – Magnolia Petroleum – Reynolds No. 1 (SN57466), was not drilled deep enough to penetrate the Primary Confining Zone (having reached total depth just below the Annona Sand); that well will also be re-entered and recompleted as an Above-Confining-Zone (ACZMI) Monitoring Well.

Wells that penetrated the Primary Upper Confining Zone (Austin Chalk Equivalent / Upper Eagleford interval) within the area underlain by the modeled Pressure Front (**outside** of the modeled plume areas) are:

- AP No. 3 – J. S. Neilson – Simmons No. 1 (SN40405)
- AP No. 77 – Houston Oil & Mineral – C. O. Howard No. 1 (SN172767)
- AP No. 79 – D. E. Vasser – Howard No. 1 (SN48382)
- AP No. 101 – Southern Carbon – USA No. 1 (SN34225)
- AP No. 147 – Ouachita Exploration – Alama F. Jones No. 1 (SN137572)
- AP No. 276 – C. H. Murphy – Meredith No. 1 (SN38817)
- AP No. 280 – J. F. Magale – Kellog Bros. No. 1 (SN31012)

All wells within the pressure front passed an evaluation for movement of fluid in the borehole due to incremental pressure buildup. Notwithstanding, two out of these nine wells are planned to be re-entered and recompleted as In-Zone monitoring wells: AP Nos. 101 and 276.

Two wells drilled within the pressure front penetrated the Secondary Upper Confining Zone (Midway Group) but were not drilled deep enough to penetrate the Primary Upper Confining Zone:

- AP No. 81 – Southern Carbon – Vollie Howard No. 1 (SN26071) (did not reach PCZ)
- AP No. 229 –Myers / Storms – Olin No. 1 / 1-D (SN125019 / 125975) (did not reach PCZ)

Each of the two wells targeted for re-entry and recompletion as In-Zone monitoring wells (AP Nos. 101 and 276) will be deepened to 7,000 feet and completed across the entire Upper Tuscaloosa / Paluxy interval. Details on their current construction and planned recompletions are presented in Section 7.2 of **Module B.**

The remaining wells do not penetrate the entirety of the Secondary Upper Confining Zone (the Midway Group) and are not located within the extent of the sCO_2 plume front. Therefore, no additional wells require corrective action.

A re-evaluation schedule for AoR delineation is set at 5-year intervals during injection operations. The re-evaluation will use the injection and operational data to date to first calibrate the model, then project the model, and finally match and/or compare to the initial submitted model. At this time, the Project Plans such as "Testing and Monitoring Plan" and "Post-Injection Site Closure and Site Care Plan" may be updated to accurately reflect a newly demonstrated Area of Review.

This plan will be updated as the project is developed to be consistent with the geological, testing, and operational data derived from the injection wells and monitor wells as they are constructed and tested, and subsequently updated once injection has been initiated.

4.0 FINANCIAL RESPONSIBILITY

Strategic Biofuels has submitted a Financial Responsibility Demonstration (FRD) that covers activities identified in the corrective action plan, injection plugging plan, post-injection site care and closure, and the emergency and remedial response plan. Additionally, it covers the monitoring and reporting activities during injection and closure operations.

Cost estimates (Table 4-1) for the activities were provided by independent third-party contractors per LAC 43:XVII §3609 (C)(4)(h)(i). A third party is defined as a party that is not within the corporate structure of the owner or operator of the wells [LAC 43:XVII §3601 (A)]. Therefore, the cost estimates include project management, administrative costs, overhead, and contingency.

Detailed cost estimates for each plan with supporting documentation have been uploaded on the "Cost Estimates" Tab in Module C of the GSDT Tool. Values may change due to inflation of costs or additional changes to the final project. If the costs estimate change, Strategic Biofuels will adjust the value of the FRD and it will be submitted to the authorized regulatory body for review and approval on an "as needed" basis. Detailed information and supporting documents have been submitted through the GSDT through "*Module C – Financial Responsibility Demonstration*".

5.0 INJECTION WELL CONSTRUCTION

Strategic Biofuels is requesting permits for three Class VI carbon dioxide sequestration wells (Well Nos. 1, 2, & 3) for use with its Louisiana Green Fuels renewable fuels facility to be constructed at the Port of Columbia in Caldwell Parish, Louisiana. These wells will be completed in the Primary Injection Zone, the multiple sandstones of the Upper Tuscaloosa / Paluxy.

The following sections address the procedures to drill, sample, complete, operate, and test the proposed injection wells, as well as specifications of the construction materials. Specification of maximum instantaneous rate of injection, average rate of injection, and the total monthly and annual volumes to be injected are also included. All construction data for the injection wells and wellheads meet the requirements for Class VI wells under LAC 43:XVII §3617. Procedures for the plugging and abandonment of the injection wells meet the standards set forth under LAC 43:XVII §3631 and are contained in "*E.2 – Injection Plugging Plan*" submitted in Module E.

All phases of well construction will be supervised by qualified individuals acting under the responsible charge of licensed professional engineers who are knowledgeable and experienced in practical drilling and completion operations and who are familiar with the special conditions and requirements of Class VI CO_2 injection well construction [LAC 43:XVII §3617 (A)(1)].

5.1 PROPOSED STIMULATION PROGRAM

A detailed stimulation plan has been proposed for the Class VI wells at the Louisiana Green Fuels facility, which will be employed after drilling and completion [LAC 43:XVII §3607 (C)(2)(h)]. Well stimulations can be comprised of but not limited to as defined by LAC 43:XVII §3601:

- Well Surging;
- Jetting;
- Blasting;
- Acidizing; or
- Hydraulic fracturing.

For Strategic Biofuels, the proposed stimulation program will consist of acidization and wellbore flowback (utilizing nitrogen on coiled tubing) to remove formation skin damage due to invasion of solids during drilling and completion operations. This plan is based upon successful historical uses of the same method for Class I UIC (hazardous and non-hazardous) Injection Wells in the Gulf Coast region. The proposed acid stimulation fluids have been demonstrated to not impact the ductile shales used for confinement in Louisiana. The acid treatment will most likely consist of the following acids, with specific treatment chemicals and actual volumes to be determined based upon core analysis, evaluation of open hole logs, and footage of the interval to be treated at the time of placement. An initial project stimulation plan proposed is the following:

- 15% Hydrochloric Acid (HCl)
- 7.5% HCl + 1.5% Hydrofluoric (HF) Acid

Best practices for recommended volumes for acid stimulations generally range from 25 to 100 gallons per foot of perforations, depending on the suspected severity of the near wellbore formation damage. Chemicals will be added to the acid blends to limit clay swelling, reduce emulsions, and inhibit reaction to the completion equipment. The type and quantity of these chemicals will be determined based on formation characteristics determined from core and wireline log evaluation. All stimulation fluids that may be used will be verified to confirm there is no adverse reaction that could affect the confinement integrity of the reservoir [per §3607 (C)(2)(h)].

Additional acids and the use of diverter fluids may be considered at the time of placement. The acid fluids will be displaced from the wellbore using non-hazardous treating water or brine.

Additional stimulation treatment may be necessary if the injection performance of the well remains unacceptable following treatment. Per §3621 (A)(1), the stimulation procedures will follow all standards set forth in §3607 (C)(2)(h) and the program will be approved by the commissioner as part of the permit application.

5.2 CONSTRUCTION DETAILS

Strategic Biofuels is requesting permits for three Class VI sCO_2 Sequestration Wells (Nos. 1, 2, & 3) for its Louisiana Green Fuels facility. Each injection well will be completed into the Upper Tuscaloosa / Paluxy Injection Zone between the approximate depths of 4,900 and 7,000 feet. One injection well will be located within the Louisiana Green Fuels renewable fuels facility site and the other two wells will be located nearby, off site, on the surrounding acreage. Well depths and completion intervals will be adjusted based on the actual formation tops encountered during the drilling operations. The wells will be constructed in accordance with LAC 43:XVII §3617 and LCFS Protocol Subsection C.3.1 standards for Class VI Injection Wells. Unless otherwise specified, all depths are relative to ground level.

The proposed well completion schematics are included as Figures 5-1, 5-2, and 5-3 and are designed to prevent movement of fluids into or between USDWs or into any unauthorized zones [LAC 43:XVII §3617 (A)(1)(a)] Each of the injection wells will be planned and constructed with the same general specifications, allowing for appropriate correlative depth shifts depending on geographic placement. The schematic includes well casing specifications and setting depths, cementing data, and completion details. As each of these wells are currently proposed, the final specific details will be updated with "*as-built*" for each injection well with the finalized drilling and completion details.

Normal plant and area safety rules and regulations will be in force during construction of each of the injection wells. Prior to well construction, the ground surface will be graded to level. An all-weather wellsite pad and road will be installed for site access. Additional reinforcement will be placed under the rig substructure area to support the rig and peripheral heavy equipment. The rig contractor will provide power for the rig and associated drilling equipment. Access to the construction site will be actively controlled to prevent entry by unauthorized personnel. Non-hazardous wellbore solids and fluids will be handled in accordance with all state and federal regulations and established safe oilfield practice, including the use of a closed loop system during drilling operations with offsite disposal of all waste materials to a regulated facility. Personal protective equipment in accordance with all regulations will be worn by onsite workers when handling wellbore solids and fluids.

All phases of well construction will be supervised by qualified individuals acting under the responsible charge of engineers who are knowledgeable and experienced in practical drilling and completion operations and who are familiar with the special conditions and requirements of Class VI injection well construction [per LAC 43:XVII §3617 (A)(1)].

5.2.1 Casing String Details

Casing specifications for the proposed injection wells are detailed in Tables 5-1, 5-2, and 5-3. Tubular stress calculations for all well casing and tubing are included in Appendix D. All components of the conductor, surface, intermediate and protection casings will be manufactured to API standards and are designed as appropriate for the proposed injection life of the well (approximately 30 years), and the sequestration reservoir monitoring life (100 years) based on the materials of construction and their environment of use. The casing and cementing program have been designed to ensure long-term wellbore mechanical integrity and that there is no movement of fluids from the Primary Injection Zone through the Primary and Secondary Upper Confining Zones and into the shallow subsurface where it could eventually reach the atmosphere.

Carbon steel (for non-CO_2 stream contact usage) will be used for the conductor/drive pipe, potable water, and surface casings. A mixed string of carbon steel and 13CR stainless steel (for those portions of the intermediate casing which might eventually come into contact with CO_2 stream contact) will be utilized for the intermediate casing. The protection casing will consist of a mixed string of carbon steel and 22CR stainless steel (for those portions with CO_2 stream contact). The CO_2 injection stream from the Louisiana Green Fuels facility will be 99.8% pure CO_2 and CO_2 in its pure form is non-corrosive to steel. The 22CR steel (will be used for the protection casing where it will be in contact with the injection stream) is highly corrosion-resistant and will provide proven protection from corrosive fluids in the unlikely event any water vapor, in whatever small amounts, eludes the highly efficient capture system that will be in use at the Louisiana Green Fuels facility. Additionally, all casing strings will be fully cemented to surface (with cementing stage tools for multiple cementing stages for the intermediate and protection strings), which will provide additional isolation and protection of the casing strings from external formation fluids along the full length of the wellbore.

Prior to running the casing in the hole, each string will be fully inspected during procurement and each string will be drifted and visually inspected onsite to check for damage during the shipping and handling. The connections will be cleaned, and the manufacturer's recommended thread compound will be applied to the pin of each connection before make-up.

Casing design considered factors listed under LAC 43:XVII §3617 (A)(2)(a) and LCFS Protocol Subsection C.3.1(b).

5.2.2 Tubing and Packer Details

Tubing specifications for the proposed injection wells are detailed in Table 5-4, 5-5, and 5-6. Tubular stress calculations for all well casing and tubing are included in Appendix D. Consistent with LAC 43:XVII §3617 (A)(4) and LCFS Protocol Subsection C.3.1(c), each well will be completed with 22CR steel injection tubing to provide resistance to corrosion from CO_2 injection. The tubing will extend from the surface (wellhead) to the deepest injection packer, with a slip-and-seal assembly installed to provide engagement with the surface wellhead.

Prior to running the tubing in the hole, each string will be fully inspected onsite and drifted to ensure that no defects are present. The connections will be cleaned, and the manufacturer's recommended thread compound will be applied to the pin of each connection before make-up. Each connection of the injection tubing will be externally pressure tested to ensure no leaks exist upon makeup.

The injection packers will be visually inspected to ensure no defects are present. A pressure test of the annulus will be conducted after installation of the packers to confirm proper setting and absence of leaks.

5.2.3 Centralizers

Each casing string will have hinged bow type centralizers attached to the casing at intervals along the entire well path. Centralizers will be placed to maximize the casing standoff from the well bore to enhance the cementing of the wells. The centralizers will be placed as shown below.

On the 24-inch Potable Water Casing:

- 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
- 1 Centralizer on the first joint above the float shoe;
- 1 Centralizer every other joint to surface; and
- 1 Centralizer 10 feet below ground level.

On the 18-5/8-inch Surface Casing:

- 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
- 1 Centralizer on the first joint above the float shoe;
- 1 Centralizer every other joint to surface; and
- 1 Centralizer 10 feet below ground level.

On the 13-3/8-inch Intermediate Casing:

- 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 8 feet above the float collar, straddling a stop collar;
- 1 Centralizer every joint to the cementing-stage tool at approximately 3,000 feet;
- 1 Centralizer above and below each cementing stage tool, straddling a stop collar;
- 1 Centralizer above and below the stage collar, straddling a stop collar;
- 1 Centralizer every other joint to surface; and
- 1 Centralizer 10 feet below ground level.

On the 9-5/8-inch Protection Casing:

- 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
- 1 Centralizer 8 feet above the float collar, straddling a stop collar;
- 1 Centralizer every joint across planned perforated intervals to 4,800 feet;
- 1 Centralizer every other joint across planned non-perforated intervals to 4,800 feet;

- 1 Centralizer every other joint from 4,800 feet to the stage collar at approximately 3,000 feet
- 1 Centralizer above and below the stage collar, straddling a stop collar;
- 1 Centralizer every third joint from 3,000 feet to surface; and
- 1 Centralizer 10 feet below ground level.

Actual placement of centralizers will be determined once the drilling of each well section is completed, and logs have been reviewed. Additional centralizers may be used as needed to provide the highest quality cementing job possible.

5.2.4 Annular Fluid

The permanent packer fluid designed for the 5-1/2-inch x 9-5/8-inch annulus for these wells is 9.0 lb/gal (1.08 Specific Gravity) sodium chloride brine with corrosion inhibitor and oxygen scavenger additives or equivalent as approved by the commissioner [LAC 43:XVII §3621 (A)(3)]. An annulus monitoring and pressurization system such as a seal pot (or equivalent system) will always maintain the annulus at a pressure greater than the injection tubing pressure. Per LAC 43:XVII §3621 (A)(4), the annulus pressure will exceed the operating injection tubing pressure. The pressure and volume of the annulus system will be continuously monitored per LAC 43:XVII §3625 (A)(2).

5.2.5 Cement Details

The conductor/drive pipe will be set to approximately 100 feet or to the point of drive pipe refusal. The potable water, surface, intermediate, and protection casing strings will be cemented using current cementing technology and practices. Cementing standards detailed in LAC 43:XVII §3617 (A)(2) will be used during the construction of the well. The wells will use both standard cement (Class A or Class H) and CO_2 resistant cement (e.g., SLB's Evercrete™, or equivalent) to ensure the longevity of the wellbore. All casing strings will be fully cemented to surface, which will provide additional isolation of the casing strings from external formation fluids along the borehole path (LAC 43:XVII §3617 (A)(2)(d) and LCFS Protocol Subsection C.3.1(b)). For the intermediate and protection casing strings, the CO_2 resistant cement will be brought near the top of the Midway Shale Secondary Upper Confining Zone in each well. A copy of the cementing report indicating returns at the surface will be submitted to the commissioner.

Expected downhole temperature at total depth is 158°F at 7,000 feet, which is not considered detrimental to the cement. The cement will increase in hardness over time and reach a value close to its maximum compressive strength soon after setting.

5.3 PROPOSED DRILLING PROGRAM

Normal plant and area safety rules and regulations will be in force during installation of the wells. Prior to well construction, the ground surface will be graded to level. An all-weather location will be installed, with additional reinforcement placed under the rig substructure area. The rig contractor will provide power for the rig and associated equipment. The construction site will be barricaded to prevent entry by unauthorized personnel. Normal handling of the wellbore solids and fluids is anticipated during the drilling phases of the work and completion phases of the work.

All phases of well construction will be supervised by qualified individuals acting under the responsible charge of a licensed professional engineer who is knowledgeable and experienced in practical drilling engineering and who is familiar with the special conditions and requirements of Class VI CO_2 injection well construction [LAC 43:XVII §3617 (A)(1)].

5.3.1 Injection Well No. 1 (W-N1)

The drilling program for Injection Well No. 1 (W-N1) at the Louisiana Green Fuels facility includes a conductor/drive pipe, potable water hole, surface hole, intermediate hole, and protection hole. All depths in the outlined procedure are referenced to the kelly bushing (KB) elevation, which is estimated at 20.0 feet above ground level. A casing seat test will be performed for each casing string, but the pressures used in the tests will not exceed the fracture gradient of the geologic formation [LAC 43:XVII §3617 (A)(3)].

5.3.1.1 Proposed Drilling Procedures

Conductor/Drive Pipe

1. Prepare surface location and mobilize drilling rig. Drill mousehole and rathole.

2. Pick up casing hammer and drive 30-inch conductor pipe to approximately 100 feet or until 100 blows per foot penetration rate is reached. (Alternatively, auger the "drive pipe" hole and grout the casing to ensure a setting depth below 100 feet to avoid washout in unconsolidated sands while drilling large diameter conductor hole).

3. Cut off drive pipe and install bell nipple to drill conductor hole.

Potable Water Hole

4. Pick up 28-inch drilling assembly and drill conductor hole to 300 feet (+/-) using drilling fluid as detailed in the Drilling Fluids section of this procedure.

> ***28-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN***
>
> Should lost circulation occur (expected) while drilling the 28-inch borehole from the base of conductor/drive pipe to the potable water casing point, paper, cottonseed hulls, or other forms of standard lost circulation material may be used to remedy the loss condition. A cement truck may be mobilized to location and placed on "standby" to minimize "wait time" if severe loss of circulation is encountered.
>
> ***28-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN***
>
> If an overpressured zone is encountered (which is **not** expected) while drilling the 28-inch surface casing borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.
>
> ***28-INCH BOREHOLE DEVIATION CONTINGENCY PLAN***
>
> Take borehole inclination surveys at a minimum every 150 feet and at TD. A maximum recommended deviation from vertical is 2 degrees, and the targeted deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

5. Run 24-inch casing to 300 feet (+/-). Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

6. Cement the casing in place using the stab-in method. Refer to Section 5.3.1.4 – Cement Details.

7. If no cement returns are observed at surface, grout the un-cemented annular space to the surface if necessary.

8. After waiting on cement for a minimum of 12 hours, cut off the drive pipe and potable

water casing and install bell nipple on the conductor pipe to drill surface hole.

Surface Hole

9. Pick up 22-inch drilling assembly, lower in the well, and drill the float shoe. Drill surface hole to a sufficient depth to set 1,200 feet of surface casing using drilling fluid as detailed in the Drilling Fluids section of this procedure. Configure the bottom hole assembly and follow established industry practice to ensure a vertical hole. Take deviation surveys every 300 feet. Maximum deviation from vertical should be no more than 2 degrees.

22-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

Should lost circulation occur (expected) while drilling the 22-inch borehole from the base of potable water casing to the surface casing point, paper, cottonseed hulls, or other forms of standard lost circulation material may be used to remedy the loss condition. A cement truck may be mobilized to location and placed on "standby" to minimize "wait time" if severe loss of circulation is encountered.

24-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (which is **not** expected) while drilling the 26-inch surface casing borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

24-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys at a minimum every 300 feet and at TD. A maximum allowable deviation from vertical is 2 degrees, and the targeted deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

10. Run open hole electric logs as listed in "*Module D – Pre-Operational Testing"* from total depth to 300 feet (setting depth of 24-inch casing. Continue logging the gamma ray log to surface.

11. Run 18-5/8-inch surface casing to a minimum of 1,200 feet. Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

12. Cement the casing in place using the using the two-plug method with a minimum of 100% excess cement over the hole size. Refer to Section 5.3.1.4 – Cement Details.

13. If no cement returns are observed at surface, a temperature or similar diagnostic survey will be run to determine the top of cement. Grout the un-cemented annular space to the surface if necessary and prior to proceeding to the next step.

14. After waiting on cement for a minimum of 12 hours, cut off the surface and potable water casings and install a 20-1/4-inch x 3,000 psi x 18-5/8-inch SOW casing head on the surface casing and pressure test.

15. Nipple up 20-1/4-inch, 3,000 psi Blowout Preventers (BOP) and ancillary equipment and pressure test to a low pressure of 250 psig and a maximum pressure of 2,000 psig.

16. Rig up wireline unit and log differential temperature survey and cement bond log.

17. Pressure test (and record) the surface casing to 500 psig for one hour [LAC 43:XVII §3617 (A)(3)(a)]. Casing test pressures will never exceed the rates burst or collapse pressures of the casing string.

Intermediate Hole

18. Pick up a 17-1/2-inch drilling assembly and trip into the wellbore.

19. Displace the spud mud with a potassium-based drilling fluid to improve hole cleaning and stability. The drilling fluid system might be modified to use a different mud system. Drill out casing float equipment and 10 feet of new formation.

20. Perform a Casing Seat Test to a minimum of 1,000 psig for one hour. The casing seat pressures will never exceed the calculated fracture gradient of the formation [LAC 43:XVII §3617 (A)(3)(b)].

21. Once the Casing Seat Test is secured (allowable loss is limited to 5 percent of the test pressure over stabilized test duration), will proceed to drill a 17-1/2-inch intermediate hole from surface casing point to 3,900 feet (+/-) into the top of the Selma Chalk, using drilling fluid as detailed in the Drilling Fluids section of this procedure. Take deviation surveys every 500 feet. To the extent possible, maintain deviation from vertical at should be no more than 2 degrees or less.

22. In one or more of the injection wells, attempt to collect a 60-foot conventional core from the Midway Shale Secondary Upper Confining Zone. Refer to Module D – Pre-Operational Testing for details on the coring program.

17 1/2-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

If circulation is lost (not expected) while drilling the 17-1/2-inch borehole, lost circulation material pills will be pumped to re-establish circulation. Depending upon the severity of lost circulation encountered, lost circulation material may need to be blended with the drilling fluid in concentrations dictated by hole conditions to maintain circulation to the surface casing point.

17-1/2-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (which is **not** expected) while drilling the 17-1/2-inch borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

17-1/2-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys ~~at~~ 500 feet intervals and at TD. To the extent possible, maintain deviation from vertical of 2 degrees or less, and deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

23. Run open hole electric logs as listed in "*Module D – Pre-Operational Testing*".

24. Run 13-3/8-inch intermediate casing to 3,900 feet (+/-) into the top of the Selma Chalk. Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

25. Rig up cementing equipment and cement the intermediate casing in place. Cement will be placed in three stages with the lower cement stage from the casing shoe to the top of the Midway Shale Secondary Upper Confining Zone, being CO_2 resistant cement (Evercrete™ or equivalent). The upper two cement stages will be circulated through cementing stage tools placed at approximately 3,000 feet and 1,450 feet. The cement slurries for each stage will consist of a lead lightweight cement blend and tail slurry of standard cement. Refer to Section 5.3.1.4 – Cement Details.

26. If no cement returns are observed at surface, a temperature log or similar diagnostic survey will be run to determine the top of cement. Grout will be applied to the un-cemented annular space to the surface if necessary and prior to proceeding to the next step.

27. After completing the third stage cementing, immediately pick up the BOP, set the 13-3/8-inch casing slips, cut off the 13-3/8-inch casing, nipple down the BOPs, and install a 21-1/4-inch 3,000 psi x 13-5/8-inch 3,000 psi casing spool and pressure test.

28. Nipple up 13-5/8-inch 3,000 psi BOPs and ancillary equipment and pressure test to a low pressure of 250 psig and a maximum pressure of 3,000 psig.

29. Pick up 12-1/4-inch bit and lower in the well on the drilling assembly. Drill out the two 13-3/8-inch cement stage tools, trip in the well to the float collar, and circulate clean.

30. Wait on cement to cure and temperature to stabilize for approximately 24 hours.

31. Rig up wireline unit and log differential temperature survey and cement bond log. Analyze cement bond log results and confirm adequate isolation before proceeding. If necessary, the cement bond log will be repeated under pressure.

32. Pressure test (and record) the intermediate casing to 1,000 psig for one hour [LAC 43:XVII

§3617 (A)(3)(a)]. Casing test pressures will never exceed the rates burst or collapse pressures of the casing string.

Protection Hole

33. Pick up a 12-1/4-inch drilling assembly and trip into the wellbore.

34. Displace the fresh water from cement with a potassium-based drilling fluid to improve hole cleaning and stability. The drilling fluid system might be modified to use a different mud system. Drill out the shoe track cement and float equipment and drill 10 feet of formation.

35. Perform a Casing Seat Test to a minimum of 1,000 psig for one hour. The casing seat pressures in the test will never exceed the calculated fracture gradient of the formation [LAC 43:XVII §3617 (A)(3)(b)].

36. Once the Casing Seat Test is secured (allowable loss is limited to 5 percent of the test pressure over stabilized test duration), proceed forward and drill a 12-1/4-inch protection hole from intermediate casing point to 7,000 feet. To the extent possible, maintain deviation from vertical at 2 degrees or less. The actual total depth of the well will be contingent on the "rathole" depth beneath the base of the deepest sandstone encountered in the Paluxy Formation. Take inclination surveys every 500 feet to monitor wellbore drift.

37. Attempt to acquire conventional whole cores at selected geologic intervals within the Austin Chalk Equivalent / Upper Eagleford and the Upper Tuscaloosa / Paluxy in the injection wells. Refer to *Module D – Pre-Operational Testing* for coring program details.

28-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

If circulation is lost (not expected) while drilling the 12-1/4-inch borehole, lost circulation material pills will be pumped to re-establish circulation. Depending upon the severity of lost circulation encountered, lost circulation material may need to be blended with the drilling fluid in concentrations dictated by hole conditions to maintain circulation to the intermediate casing point.

12-1/4-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (not expected) while drilling the 12-1/4-inch borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

12-1/4-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys at 500 feet intervals and at TD. To the extent possible, maintain deviation from vertical of 2 degrees or less, and deviation between surveys to 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

38. Run electric wireline logs and collect rotary sidewall core samples (if needed) over the open hole interval. Refer to Module D – Pre-Operational Testing for details.

39. Run 9-5/8-inch casing (mixed string), with casing packer and DV stage tool, (and fiber optic cable: DTS/DAS, and perforation markers, if required) to the planned casing point (7,000 feet). Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

Note: Louisiana Green Fuels is evaluating "smart well" completion technologies to monitor Differential Temperature, Acoustic, and Bottomhole Pressure.

40. Rig up cementing equipment and cement the protection casing in place. Cement will be placed in stages with the lower cement stage from total depth to the top of the Midway Shale Secondary Upper Confining Zone being CO_2 resistant cement. The second stage will be circulated through a cementing stage tool at approximately 3,000 feet. The second stage cement will consist of lead slurry of a lightweight cement blend and tail slurry of standard cement. Refer to Section 5.3.1.4 – Cement Details.

41. After completing the second stage cementing, pick up the BOP, set the 9-5/8-inch casing slips, cut the 9-5/8-inch casing above the slips, and remove the BOP's. Install the 13-5/8-inch 3,000 psi x 11-inch 5,000 psi casing/tubing spool and test the seals.

42. In the event cement returns are not observed at the surface, a temperature or similar diagnostic survey will be run to determine the top of cement. After the cement top is located, a procedure to grout in the uncemented annular space will be provided.

43. Set night cap and secure well.

44. Rig down the drilling rig, and associated equipment and move out.

General Notes:

- ***All depths referenced are approximate and are based on the expected log depth.***
- ***Actual depths may vary based on lithology of local formations.***

5.3.1.2 Proposed Completion Procedure

The completion procedure has been developed to utilize the Upper Tuscaloosa / Paluxy Primary Injection Zone for sCO_2 sequestration. It is anticipated that the full interval in the Upper Tuscaloosa will be utilized in each well completion and selected sandstones within the Paluxy will be perforated based on results from the open hole logging program. The following is a proposed completion procedure for the Louisiana Green Fuels facility for Injection Well No. 1 (W-N1).

1. Move in and rig up the completion rig and associated equipment.
2. Check for pressure, remove the night cap and nipple up and test the 11-inch 5,000 psi BOP from 250 low to 5000 psi high.
3. Pick up an 8-1/2-inch bit and casing scraper for 9-5/8-inch casing and trip into the wellbore picking up completion work string.
4. Drill out the cementing stage tool plugs at ±3,000 feet and the float shoe and cement in the casing to ±6,990 feet (15 feet above the casing shoe).
5. Rig up and run differential temperature and radial cement bond and casing evaluation logs as detailed in the Module D – Pre-Operational Testing.
6. Pressure-test (and record) the casing string to 1,000 psig for one hour.
7. Displace the drilling fluid in the wellbore with filtered completion fluid.
8. Rig up wireline unit and if fiber optics were installed on the casing, directionally perforate (to avoid fiber optic cable) selected intervals of the 9-5/8-inch casing within the overall geologic formation intervals in the following table:

Perforation Interval	Formation/Lithology
± 4,910 feet to 5,210 feet	Upper Interval of the Upper Tuscaloosa
± 5,250 feet to 5,630 feet	Lower Interval of the Upper Tuscaloosa
± 5,900 feet to 6,990 feet	Various Permeable Sandstones in Paluxy

(Note: Perforating depths are approximate and will be determined after review of open hole logs. Note, oriented perforating will be required if DTS/DAS cable run on casing through the Injection Zone)

9. Go in hole with the workstring to the bottom of the protection casing and circulate filtered completion fluid.

10. Prepare all completed intervals for injection, including washing perforations and performing acid stimulation as necessary. The final stimulation program will be based on the open hole logs and the injection interval core material collected during the drilling.

11. Remove the workstring from the well while laying down the workstring and downhole tools.

12. Install the two 9-5/8-inch x 5-1/2-inch injection packers with an adjustable sliding sleeve flow control valve between the packers, and 5-1/2-inch injection tubing to surface. The system will be installed on a single trip, spaced out, and hydraulically set. The installation will include two downhole surface readout (SRO) pressure gauges on a single electric line. The lower pressure gauge will monitor the injection pressure in the Lower Interval of the Upper Tuscaloosa Injection Zone and the Paluxy Injection Zone between approximately 5,250 feet and 6,990 feet. The lower gauge will be installed below the low injection packer. The upper pressure gauge will be installed below the upper packer and clamped to 5-1/2-inch spacer tubing between the two packers to monitor the pressure in the Upper Interval of the Upper Tuscaloosa Injection Zone between approximately 4,910 feet and 5,210 feet. A general description of the completion equipment as picked up and lowered into the well (deepest to surface) is presented below:

    - 9-5/8-inch x 5-1/2-inch hydraulically set lower injection packer with 22CR or higher wetted surfaces with 10 foot long 5-1/2-inch 20 lb/ft, 22CR65 tail pipe below with wireline reentry guide. The lower SRO gauge will be strapped to the 5-1/2-inch tail pipe below the packer and the gauge electric line will be connected to the gauge and the electric line will go through the packer pass through.

    - 5-1/2-inch Spacer Tubing, 5-1/2-inch Adjustable Sliding Sleeve Flow Control Valve, Upper SRO Pressure Gauge, two ¼-inch Hydraulic Control Lines for the

Adjustable Sliding Sleeve Flow Control Valve, and Electric Line for the two Pressure Gauges. A 5-1/2-inch, 20 lb/ft, 22CR65 Spacer Tubing will be installed with integral connections to the top of the lower packer and the bottom of the upper packer. The 5-1/2-inch Adjustable Sliding Sleeve Flow Control Valve will be installed in the 5-1/2-inch Spacer Tubing at approximately 5,400 feet (Actual setting depth will be determined later). The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will be strapped to the 5-1/2-inch Spacer Tubing. The Upper SRO Pressure Gauge for monitoring the injection pressure in the Upper Tuscaloosa Injection interval will be set at approximately 5,300 feet (Actual setting depth will be determined later).

- 9-5/8 x 5-1/2-inch hydraulically set upper injection packer with 22CR or higher wetted surfaces will be made up/connected to the 5-1/2-inch spacer tubing below the packer and the 5-1/2-inch 20 lb/ft, 22CR65 Injection Tubing will be make up to the top of the packer. The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will feed through the passthrough in the packer. The packer will be spaced out and hydraulically set at approximately 4,800 feet.
- The 5-1/2-inch 20 lb/ft, 22CR65 Injection Tubing will be installed from the top of the upper injection packer at approximately 4,800 feet to surface. The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will be strapped to the 5-1/2-inch Injection Tubing.

13. The 5-1/2-inch Injection Tubing will be spaced to position the equipment correctly. Inhibited packer fluid will be circulated/pumped down the tubing-casing annulus until inhibited brine is fully displaced to the top packer.
14. The two ¼-inch hydraulic control lines and the electric line for the two SRO pressure gauges will be feed through the 5-1/2-inch tubing hanger, secured, and terminated. The 5-

1/2-inch tubing hanger will be positioned in the wellhead. The two completion packers will be hydraulically set per the suppliers' specifications.

15. Top out the 5-1/2-inch x 9-5/8-inch casing annulus with inhibited packer fluid. Conduct preliminary pressure test to verify proper installation with a test pressure of 2,500 psi.
16. Nipple down well control equipment and install tubing head adapter and the wellhead tree section.
17. Rig down completion rig and demobilize from site.
18. Rig up coiled tubing and displace tubing and rathole with non-formation-damaging fluid for undetermined period to await CO_2 source from the Louisiana Green Fuels facility.

General Notes:

- ***All depths referenced are approximate and are based on the expected log depth.***
- ***Actual depths may vary based on lithology of local formations.***

5.3.1.3 Proposed Well Fluids Program

Lost circulation material (LCM) will be on location to treat for fluid losses in top hole sands above the potential injection intervals. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones. High-viscosity sweeps will be used to assist hole cleaning. Sodium chloride (NaCl) is planned for use as the completion fluid. The fluid weight will be maintained slightly over-balanced to contain reservoir pressures. Table 5-7 is provided to show the proposed fluids per hole.

5.3.1.4 Proposed Cementing Program

The potable water, surface, intermediate, and protection casing strings will be cemented using current cementing technology and practices. Cementing standards defined in LAC 43:XVII §3617 (A)(2) will be used during the construction of the well. The wells will use both standard cement (Class A or Class H) and CO_2 resistant cement (SLB Evercrete ™, or equivalent) to ensure the longevity of the wellbore. All casing strings will be fully cemented to surface, which will provide additional isolation of the casing strings from external formation fluids along the borehole path (LAC 43:XVII §3617 (A) and LCFS Protocol Subsection C.3.1(b)). For the intermediate and protection casing strings, the top of the CO_2 resistant cement will be above the top of the Midway Shale Secondary Upper Confining Zone in each injection well. The final cementing programs for each of the casing will be revised based on the wellbore conditions during drilling and the cementing contractors' recommendations.

5.3.1.4.1 Potable Water Casing

The following cementing program (Table 5-8) is proposed for installation of the surface casing string:

- 24-inch in a 28-inch borehole at 300 feet;
- Float shoe;
- Cement to surface;
- Cement volumes are estimated 100% excess over bit size in open hole interval;
- Procedure might be modified to use the inner string method with a stab-in float shoe; and,
- In the event that hole issues are observed, 150 percent of the annular space between the casing and drilled wellbore will be used for calculating cement volume for that section of the wellbore.

5.3.1.4.2 Surface Casing

The following cementing program (Table 5-9) is proposed for installation of the surface casing string:

- 18-5/8-inch in a 22-inch borehole at 1,200 feet
- Float shoe;
- Float Collar, 1 joint above the float shoe;
- Cement to surface;
- Cement volumes are estimated 100% excess over bit size in open hole interval;
- Actual volume to be calculated from caliper log plus 20% excess; and,

- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.1.4.3 Intermediate Casing

The following cementing program (Table 5-10) is proposed for installation of the intermediate casing string:

- 13-3/8-inch in a 17-1/2-inch borehole at 3,900 feet
- Float shoe;
- Float Collar, 2 joint above the float shoe;
- Three-stage cement job with cement to surface and cementing stage tools at 3,000 feet and 1,450 feet;
- Cement volumes are estimated 50% excess over bit size in open hole interval;
- Actual volume to be calculated from caliper log plus 20% excess in the open hole intervals; and,
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.
- caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.1.4.4 Protection Casing

The following cementing program (Table 5-11) is proposed for installation of the protection casing string:

- 9-5/8-inch in a 12-1/4-inch hole at 7,000 feet;
- Two-stage cement job with cement to surface, with stage tool and external casing packer;
- estimated 50% excess over bit size in open hole sections;

- actual volume to be calculated from caliper log plus 20% excess; and
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.1.5 Casing Cementing Equipment

Potable Water Casing

24-inch Cementing Equipment

1. Float shoe with receptacle for stab-in cementing technique
2. Six hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer straddling the first casing collar above the float shoe; and
    - 1 Centralizer every other collar, up to the surface.

Surface Casing

18-5/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 1 joint above the float shoe
3. Approximately 50 hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
    - 1 Centralizer ever other casing collar to surface.

Intermediate Casing

13-3/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 1 joint above the float shoe
3. Two cementing Stage Tools spaced at approximately 3,000 feet and 1,450 feet
4. Approximately 45 hinged bow spring centralizers placed in accordance with Section 5.2.3.
   - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
   - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
   - 1 Centralizer above and below each stage collar, straddling a stop collar;
   - 1 Centralizer every other joint, to 1,200 feet;
   - 1 Centralizer every third joint, from 1,200 feet to the surface; and
   - 1 Centralizer approximately 10 feet below ground level.

Protection Casing

9-5/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 2 joints above the float shoe
3. Cementing Stage Tool at approximately 3,000 feet
4. Approximately 59 hinged bow spring centralizers placed in accordance with Section 5.2.3.
   - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
   - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
   - 1 Centralizer every other joint, to 3,900 feet;
   - 1 Centralizer every third joint, from 3,900 feet to the surface; and
   - 1 Centralizer approximately 10 feet below ground level.

5.3.1.6 Well Logging, Coring, and Testing Program

Details on the proposed logging program are contained in the "*Pre-Operational Testing and Logging Plan*" submitted in Module D. All tools will be run on a wireline and will be compatible with open hole and cased hole diameters, allowing for successful testing runs (LAC 43:XVII §3617 (B) and LCFS Protocol Subsection C.2.3.1 standards).

5.3.1.7 Wellhead Schematic

The proposed wellhead for Injection Well No. 1 (W-N1) will be with a similar trim that is resistant to the CO_2 stream and impurities. A proposed wellhead schematic is presented in Figure 5-4. The well head will be surrounded by an enclosed diked, impermeable pad to protect the ground surface from spills and releases from the wellhead and ancillary equipment [§3621 (A)(8)(a)]. Pressure gauges will be installed on the wellhead to show the tubing and tubing-casing annulus pressure and be calibrated and maintained in good working order. The pressure gauges will read in 10 psig increments [§3621 (A)(10)].

Signs will be posted at the wellhead and include the operators name and number, the state well serial number, section-township-range and will be comprised of durable weather materials and kept in legible condition [§3621 (A)(8)(b)].

5.3.2 Injection Well No. 2 (W-N2)

The drilling program for Injection Well No. 2 (W-N2) at the Louisiana Green Fuels facility includes a conductor/drive pipe, potable water hole, surface hole, intermediate hole, and protection hole. All depths in the outlined procedure are referenced to the 186 Kelly bushing (KB) elevation, which is estimated at 20.0 feet above ground level. A casing seat test will be performed for each casing string, but the pressures used in the tests will not exceed the fracture gradient of the geologic formation [LAC 43:XVII §3617 (A)(3)].

5.3.2.1 Proposed Drilling Procedures

Conductor/Drive Pipe

1. Prepare surface location and mobilize drilling rig. Drill mousehole and rathole.

2. Pick up casing hammer and drive 30-inch conductor pipe to approximately 100 feet or until 100 blows per foot penetration rate is reached. (Alternatively, auger the “drive pipe” hole and grout the casing to ensure a setting depth below 100 feet to avoid washout in unconsolidated sands while drilling large diameter conductor hole).

3. Cut off drive pipe and install bell nipple to drill conductor hole.

Potable Water Hole

4. Pick up 28-inch drilling assembly and drill conductor hole to 300 feet (+/-) using drilling fluid as detailed in the Drilling Fluids section of this procedure.

> ***28-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN***
>
> Should lost circulation occur (expected) while drilling the 28-inch borehole from the base of conductor/drive pipe to the potable water casing point, paper, cottonseed hulls, or other forms of standard lost circulation material may be used to remedy the loss condition. A cement truck may be mobilized to location and placed on “standby” to minimize “wait time” if severe loss of circulation is encountered.
>
> ***28-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN***
>
> If an overpressured zone is encountered (which is **not** expected) while drilling the 28-inch surface casing borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.
>
> ***28-INCH BOREHOLE DEVIATION CONTINGENCY PLAN***
>
> Take borehole inclination surveys at a minimum every 150 feet and at TD. A maximum recommended deviation from vertical is 2 degrees, and the targeted deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

5. Run 24-inch casing to 300 feet (+/-). Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

6. Cement casing in place using the stab-in method. Refer to Section 5.3.2.4 – Cement Details.

7. If no cement returns are observed at surface, grout the uncemented annular space to the surface if necessary.

8. After waiting on cement for a minimum of 12 hours, cut off the drive pipe and potable water casing and install bell nipple on the conductor pipe to drill surface hole.

Surface Hole

9. Pick up 22-inch drilling assembly, lower in the well, and drill the float shoe. Drill surface hole to a sufficient depth to set 1,200 feet of surface casing using drilling fluid as detailed in the Drilling Fluids section of this procedure. Configure the bottom hole assembly and follow established industry practice to ensure a vertical hole. Take deviation surveys every 300 feet. Maximum deviation from vertical should be no more than 2 degrees.

> ***22-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN***
>
> Should lost circulation occur (expected) while drilling the 22-inch borehole from the base of potable water casing to the surface casing point, paper, cottonseed hulls, or other forms of standard lost circulation material may be used to remedy the loss condition. A cement truck may be mobilized to location and placed on "standby" to minimize "wait time" if severe loss of circulation is encountered.
>
> ***24-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN***
>
> If an overpressured zone is encountered (which is **not** expected) while drilling the 26-inch surface casing borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.
>
> ***24-INCH BOREHOLE DEVIATION CONTINGENCY PLAN***
>
> Take borehole inclination surveys at a minimum every 300 feet and at TD. A maximum allowable deviation from vertical is 2 degrees, and the targeted deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

10. Run open hole electric logs as listed in "*Module D – Pre-Operational Testing*" from total depth to 300 feet (setting depth of 24-inch casing. Continue logging the gamma ray log to surface.

11. Run 18-5/8-inch surface casing to a minimum of 1,200 feet. Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

12. Cement the casing in place using the using the two-plug method with a minimum of 100% excess cement over the hole size. Refer to Section 5.3.2.4 – Cement Details.

13. If no cement returns are observed at surface, a temperature or similar diagnostic survey will be run to determine the top of cement. Grout the un-cemented annular space to the surface if necessary and prior to proceeding to the next step.

14. After waiting on cement for a minimum of 12 hours, cut off the surface and potable water casings and install a 20-1/4-inch x 3,000 psi x 18-5/8-inch SOW casing head on the surface casing and pressure test.

15. Nipple up 20-1/4-inch, 3,000 psi Blowout Preventers (BOP) and ancillary equipment and

pressure test to a low pressure of 250 psig and a maximum pressure of 2,000 psig.

16. Rig up wireline unit and log differential temperature survey and cement bond log.
17. Pressure test (and record) the surface casing to 500 psig for one hour [LAC 43:XVII §3617 (A)(3)(a)]. Pressures will never exceed the burst or collapse pressures of the casing string.

Intermediate Hole

18. Pick up a 17-1/2-inch drilling assembly and trip into the wellbore.
19. Displace the spud mud with a potassium-based drilling fluid to improve hole cleaning and stability. The drilling fluid system might be modified to use a different mud system. Drill out casing float equipment and 10 feet of new formation.
20. Perform a Casing Seat Test to a minimum of 1,000 psig for one hour. Casing seat pressures will never exceed the calculated formation fracture gradient [LAC 43:XVII §3617 (A)(3)(b)].
21. Once the Casing Seat Test is secured (allowable loss is limited to 5 percent of the test pressure over stabilized test duration), will proceed to drill a 17-1/2-inch intermediate hole from surface casing point to 3,900 feet (+/-) into the top of the Selma Chalk, using drilling fluid as detailed in the Drilling Fluids section of this procedure. Take deviation surveys every 500 feet. To the extent possible, maintain deviation from vertical at should be no more than 2 degrees or less.
22. In one or more of the injection wells, attempt to collect a 60-foot conventional core from the Midway Shale Secondary Upper Confining Zone. Refer to Module D – Pre-Operational Testing for details on the coring program.

17 1/2-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN
If circulation is lost (not expected) while drilling the 17-1/2-inch borehole, lost circulation material pills will be pumped to re-establish circulation. Depending upon the severity of lost circulation encountered, lost circulation material may need to be blended with the drilling fluid in concentrations dictated by hole conditions to maintain circulation to the surface casing point.

17-1/2-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN
If an overpressured zone is encountered (which is **not** expected) while drilling the 17-1/2-inch borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

17-1/2-INCH BOREHOLE DEVIATION CONTINGENCY PLAN
Take borehole inclination surveys ~~at~~ 500 feet intervals and at TD. To the extent possible, maintain deviation from vertical of 2 degrees or less, and deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

23. Run open hole electric logs as listed in “*Module D – Pre-Operational Testing*”.

24. Run 13-3/8-inch intermediate casing to 3,900 feet (+/-) into the top of the Selma Chalk. Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

25. Rig up cementing equipment and cement the intermediate casing in place. Cement will be placed in three stages with the lower cement stage from the casing shoe to the top of the Midway Shale Secondary Upper Confining Zone, being CO_2 resistant cement (Evercrete™ or equivalent). The upper two cement stages will be circulated through cementing stage tools placed at approximately 3,000 feet and 1,450 feet. The cement slurries for each stage will consist of a lead lightweight cement blend and tail slurry of standard cement. Refer to Section 5.3.2.4 – Cement Details.

26. If no cement returns are observed at surface, a temperature log or similar diagnostic survey will be run to determine the top of cement. Grout will be applied to the un-cemented annular space to the surface if necessary and prior to proceeding to the next step.

27. After completing the third stage cementing, immediately pick up the BOP, set the 13-3/8-inch casing slips, cut off the 13-3/8-inch casing, nipple down the BOPs, and install a 21-1/4-inch 3,000 psi x 13-5/8-inch 3,000 psi casing spool and pressure test.

28. Nipple up 13-5/8-inch 3,000 psi BOPs and ancillary equipment and pressure test to a low pressure of 250 psig and a maximum pressure of 3,000 psig.

29. Pick up 12-1/4-inch bit and lower in the well on the drilling assembly. Drill out the two 13-3/8-inch cement stage tools, trip in the well to the float collar, and circulate clean.

30. Wait on cement to cure and temperature to stabilize for approximately 24 hours.

31. Rig up wireline unit and log differential temperature survey and cement bond log. Analyze cement bond log results and confirm adequate isolation before proceeding. If necessary, the cement bond log will be repeated under pressure.

32. Pressure test (and record) the intermediate casing to 1,000 psig for one hour [LAC 43:XVII §3617 (A)(3)(a)]. Casing test pressures will never exceed the rates burst or collapse pressures of the casing string.

<u>Protection Hole</u>

33. Pick up a 12-1/4-inch drilling assembly and trip into the wellbore.

34. Displace the fresh water from cement with a potassium-based drilling fluid to improve hole cleaning and stability. The drilling fluid system might be modified to use a different mud system. Drill out the shoe track cement and float equipment and drill 10 feet of formation.

35. Perform a Casing Seat Test to a minimum of 1,000 psig for one hour. The casing seat pressures in the test will never exceed the calculated fracture gradient of the formation [LAC 43:XVII §3617 (A)(3)(b)].

36. Once the Casing Seat Test is secured (allowable loss is limited to 5 percent of the test pressure over stabilized test duration), proceed forward and drill a 12-1/4-inch protection hole from intermediate casing point to 7,000 feet into the Paluxy Formation. To the extent possible, maintain deviation from vertical at 2 degrees or less. The actual total depth of the well will be contingent on the "rathole" depth beneath the base of the deepest sandstone encountered in the Paluxy Formation. Take inclination surveys every 500 feet to monitor wellbore deviation.

37. Attempt to collect conventional whole cores at selected geologic intervals within the Austin Chalk Equivalent and Upper Tuscaloosa / Paluxy Injection Zone in one or more of the injection wells. Refer to *Module D – Pre-Operational Testing* for details on the coring program.

28-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN
If circulation is lost (not expected) while drilling the 12-1/4-inch borehole, lost circulation material pills will be pumped to re-establish circulation. Depending upon the severity of lost circulation encountered, lost circulation material may need to be blended with the drilling fluid in concentrations dictated by hole conditions to maintain circulation to the-intermediate casing point.
12-1/4-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN
If an overpressured zone is encountered (which is **not** expected) while drilling the 12-1/4-inch borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.
12-1/4-INCH BOREHOLE DEVIATION CONTINGENCY PLAN
Take borehole inclination surveys at 500 feet intervals and at TD. To the extent possible, maintain deviation from vertical of 2 degrees or less, and deviation between surveys to 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

38. Run electric wireline logs and collect rotary sidewall core samples (if needed) over the open hole interval. Refer to Module D – Pre-Operational Testing for details.

39. Run 9-5/8-inch casing (mixed string), with casing packer and DV stage tool, (and fiber

optic cable: DTS/DAS, and perforation markers, if required) to the planned casing point (7,000 feet). Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

Note: Louisiana Green Fuels is evaluating "smart well" completion technologies to monitor Differential Temperature, Acoustic, and Bottomhole Pressure.

40. Rig up cementing equipment and cement the protection casing in place. Cement will be placed in stages with the lower cement stage from total depth to the top of the Midway Shale Secondary Upper Confining Zone being CO_2 resistant cement. The second stage will be circulated through a cementing stage tool at approximately 3,000 feet. The second stage cement will consist of lead slurry of a lightweight cement blend and tail slurry of standard cement. Refer to Section 5.3.2.4 – Cement Details.

41. After completing the second stage cementing, pick up the BOP, set the 9-5/8-inch casing slips, cut the 9-5/8-inch casing above the slips, and remove the BOP's. Install the 13-5/8-inch 3,000 psi x 11-inch 5,000 psi casing/tubing spool and test the seals.

42. In the event cement returns are not observed at the surface, a temperature or similar diagnostic survey will be run to determine the top of cement. After the cement top is located, a procedure to grout in the un-cemented annular space will be provided.

43. Set night cap and secure well.

44. Rig down the drilling rig, and associated equipment and move out.

General Notes:

- ***All depths referenced are approximate and are based on the expected log depth.***
- ***Actual depths may vary based on lithology of local formations.***

5.3.2.2 Proposed Completion Procedure

The completion procedure has been developed to utilize the Upper Tuscaloosa / Paluxy Injection Zone for sequestration of the injected CO_2. It is anticipated that the full interval in the Upper Tuscaloosa will be utilized in each well completion and selected sandstones in the Paluxy will be perforated based on results from the open hole logging program. The following is a proposed completion procedure for the Louisiana Green Fuels facility for Injection Well No. 1 (W-N2).

1. Move in and rig up the completion rig and associated equipment.
2. Check for pressure, remove the night cap and nipple up and test the 11-inch 5,000 psi BOP from 250 low to 5000 psi high.
3. Pick up an 8-1/2-inch bit and casing scraper for 9-5/8-inch casing and trip into the wellbore picking up completion work string.
4. Drill out the cementing stage tool plugs at ±3,000 feet and the float shoe and cement in the casing to ±6,990 feet (15 feet above the casing shoe).
5. Rig up and run differential temperature and radial cement bond and casing evaluation logs as detailed in the Module D – Pre-Operational Testing.
6. Pressure-test (and record) the casing string to 1,000 psig for one hour.
7. Displace the drilling fluid in the wellbore with filtered completion fluid.
8. Rig up wireline unit and if fiber optics were installed on the casing, directionally perforate (to avoid fiber optic cable) selected intervals of the 9-5/8-inch casing within the overall geologic formation intervals in the following table:

Perforation Interval	**Formation/Lithology**
± 4,910 feet to 5,210 feet	Upper Interval of the Upper Tuscaloosa
± 5,250 feet to 5,630 feet	Lower Interval of the Upper Tuscaloosa
± 5,900 feet to 6,990 feet	Various Permeable Sandstones in Paluxy

(Note: Perforating depths are approximate and will be determined after review of open hole

logs. Note, oriented perforating will be required if DTS/DAS cable run on casing through the Injection Zone)

9. Go in hole with the workstring to the bottom of the protection casing and circulate filtered completion fluid.

10. Prepare all completed intervals for injection, including washing perforations and performing acid stimulation as necessary. The final stimulation program will be based on the open hole logs and the injection interval core material collected during the drilling.

11. Remove the workstring from the well while laying down the workstring and downhole tools.

12. Install the two 9-5/8-inch x 5-1/2-inch injection packers with an adjustable sliding sleeve flow control valve between the packers, and 5-1/2-inch injection tubing to surface. The system will be installed on a single trip, spaced out, and hydraulically set. The installation will include two downhole surface readout (SRO) pressure gauges on a single electric line. The lower pressure gauge will monitor the injection pressure in the Lower Interval of the Upper Tuscaloosa Injection Zone and the Paluxy Injection Zone between approximately 5,250 feet and 6,990 feet. The lower gauge will be installed below the low injection packer. The upper pressure gauge will be installed below the upper packer and clamped to 5-1/2-inch spacer tubing between the two packers to monitor the pressure in the Upper Interval of the Upper Tuscaloosa Injection Zone between approximately 4,910 feet and 5,210 feet. A general description of the completion equipment as picked up and lowered into the well (deepest to surface) is presented below:

    - 9-5/8-inch x 5-1/2-inch hydraulically set lower injection packer with 22CR or higher wetted surfaces with 10 foot long 5-1/2-inch 20 lb/ft, 22CR65 tail pipe below with wireline reentry guide. The lower SRO gauge will be strapped to the 5-1/2-inch tail pipe below the packer and the gauge electric line will be connected to the gauge and the electric line will go through the packer pass through.

    - 5-1/2-inch Spacer Tubing, 5-1/2-inch Adjustable Sliding Sleeve Flow Control Valve, Upper SRO Pressure Gauge, two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve, and Electric Line for the two Pressure Gauges. A 5-1/2-inch, 20 lb/ft, 22CR65 Spacer Tubing will be installed with integral connections to the top of the lower packer and the bottom of the upper packer. The 5-1/2-inch Adjustable Sliding Sleeve Flow Control Valve will be installed in the 5-1/2-inch Spacer Tubing at approximately 5,400 feet (Actual setting depth will be determined later). The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will be strapped to the 5-1/2-inch Spacer Tubing. The Upper SRO Pressure Gauge for monitoring the injection pressure in the Upper Tuscaloosa Injection Zone will be set at approximately 5,300 feet (Actual setting depth will be determined later).

- 9-5/8-inch x 5-1/2-inch hydraulically set upper injection packer with 22CR or higher wetted surfaces will be made up/connected to the 5-1/2-inch spacer tubing below the packer and the 5-1/2-inch 20 lb/ft, 22CR65 Injection Tubing will be make up to the top of the packer. The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will feed through the passthrough in the packer. The packer will be spaced out and hydraulically set at approximately 4,800 feet.
- The 5-1/2-inch 20 lb/ft, 22CR65 Injection Tubing will be installed from the top of the upper injection packer at approximately 4,800 feet to surface. The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will be strapped to the 5-1/2-inch Injection Tubing.

13. The 5-1/2-inch Injection Tubing will be spaced to position the equipment correctly. Inhibited packer fluid will be circulated/pumped down the tubing-casing annulus until inhibited brine is fully displaced to the top packer.
14. The two ¼-inch hydraulic control lines and the electric line for the two SRO pressure gauges will be feed through the 5-1/2-inch tubing hanger, secured, and terminated. The 5-1/2-inch tubing hanger will be positioned in the wellhead. The two completion packers will be hydraulically set per the suppliers' specifications.

15. Top out the 5-1/2-inch x 9-5/8-inch casing annulus with inhibited packer fluid. Conduct preliminary pressure test to verify proper installation with a test pressure of 2,500 psi.
16. Nipple down well control equipment and install tubing head adapter and the wellhead tree section.
17. Rig down completion rig and demobilize from site.
18. Rig up coiled tubing and displace tubing and rathole with non-formation-damaging fluid for undetermined period to await CO_2 source from the Louisiana Green Fuels facility.

General Notes:

- ***All depths referenced are approximate and are based on the expected log depth.***
- ***Actual depths may vary based on lithology of local formations.***

5.3.2.3 Proposed Well Fluids Program

Lost circulation material (LCM) will be on location to treat for fluid losses in top hole sands above the potential injection intervals. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones. High-viscosity sweeps will be used to assist hole cleaning. Sodium chloride (NaCl) is planned for use as the completion fluid. The fluid weight will be maintained slightly over-balanced to contain reservoir pressures. Table 5-12 is provided to show the proposed well fluids per hole.

5.3.2.4 Proposed Cementing Program

The potable water, surface, intermediate, and protection casing strings will be cemented using current cementing technology and practices. Cementing standards defined in LAC 43:XVII §3617 (A)(2) will be used during the construction of the well. The wells will use both standard cement (Class A or Class H) and CO_2 resistant cement (SLB Evercrete ™, or equivalent) to ensure the longevity of the wellbore. All casing strings will be fully cemented to surface, which will provide additional isolation of the casing strings from external formation fluids along the borehole path (LAC 43:XVII §3617 (A) and LCFS Protocol Subsection C.3.1(b)). For the intermediate and protection casing strings, the top of the CO_2 resistant cement will be above the top of the Midway Shale Secondary Upper Confining Zone in each injection well. The final cementing programs for each of the casing will be revised based on the wellbore conditions during drilling and the cementing contractors' recommendations.

5.3.2.4.1 Potable Water Casing

The following cementing program (Table 5-13) is proposed for installation of the surface casing string:

- 24-inch in a 28-inch borehole at 300 feet;
- Float shoe;
- Cement to surface;
- Cement volumes are estimated 100% excess over bit size in open hole interval;
- Procedure might be modified to use the inner string method with a stab-in float shoe; and,
- In the event that hole issues are observed, 150 percent of the annular space between the casing and drilled wellbore will be used for calculating cement volume for that section of the wellbore.

5.3.2.4.2 Surface Casing

The following cementing program (Table 5-14) is proposed for installation of the surface casing string:

- 18-5/8-inch in a 22-inch borehole at 1,200 feet
- Float shoe;
- Float Collar, 1 joint above the float shoe;
- Cement to surface;
- Cement volumes are estimated 100% excess over bit size in open hole interval;
- Actual volume to be calculated from caliper log plus 20% excess; and,

- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.2.4.3 Intermediate Casing

The following cementing program (Table 5-15) is proposed for installation of the intermediate casing string:

- 13-3/8-inch in a 17-1/2-inch borehole at 3,900 feet
- Float shoe;
- Float Collar, 2 joint above the float shoe;
- Three-stage cement job with cement to surface and cementing stage tools at 3,000 feet and 1,450 feet;
- Cement volumes are estimated 50% excess over bit size in open hole interval;
- Actual volume to be calculated from caliper log plus 20% excess in the open hole intervals; and,
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.
- caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.2.4.4 Protection Casing

The following cementing program (Table 5-16) is proposed for installation of the protection casing string:

- 9-5/8-inch in a 12-1/4-inch hole at 7,000 feet;
- Two-stage cement job with cement to surface, with stage tool and external casing packer;
- estimated 50% excess over bit size in open hole sections;

- actual volume to be calculated from caliper log plus 20% excess; and
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.2.5 Casing Cementing Equipment

Potable Water Casing

24-inch Cementing Equipment

1. Float shoe with receptacle for stab-in cementing technique.
2. Six hinged bow spring centralizers placed in accordance with Section 5.2.3.
   - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
   - 1 Centralizer straddling the first casing collar above the float shoe; and
   - 1 Centralizer every other collar, up to the surface.

Surface Casing

18-5/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 1 joint above the float shoe
3. Approximately 50 hinged bow spring centralizers placed in accordance with Section 5.2.3.
   - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
   - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
   - 1 Centralizer ever other casing collar to surface.

Intermediate Casing

13-3/8-inch Cementing Equipment

1. Float shoe

2. Float collar, 1 joint above the float shoe
3. Two cementing Stage Tools spaced at approximately 3,000 feet and 1,450 feet
4. Approximately 45 hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
    - 1 Centralizer above and below each stage collar, straddling a stop collar;
    - 1 Centralizer every other joint, to 1,200 feet;
    - 1 Centralizer every third joint, from 1,200 feet to the surface; and
    - 1 Centralizer approximately 10 feet below ground level.

<u>Protection Casing</u>

9-5/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 2 joints above the float shoe
3. Cementing Stage Tool at approximately 3,000 feet
4. Approximately 59 hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
    - 1 Centralizer every other joint, to 3,900 feet;
    - 1 Centralizer every third joint, from 3,900 feet to the surface; and
    - 1 Centralizer approximately 10 feet below ground level.

5.3.2.6 Well Logging, Coring, and Testing Program

Details on the proposed logging program are contained in the "*Pre-Operational Testing and Logging Plan*" submitted in Module D. All tools will be run on a wireline and will be compatible with open hole and cased hole diameters, allowing for successful testing runs (LAC 43:XVII §3617 (B) and LCFS Protocol Subsection C.2.3.1 standards).

5.3.2.7 Wellhead Schematic

The proposed wellhead for Injection Well No. 2 (W-N2) will be with a similar trim that is resistant to the CO_2 stream and impurities. A proposed wellhead schematic is presented in Figure 5-5. The well head will be surrounded by an enclosed diked, impermeable pad to protect the ground surface from spills and releases from the wellhead and ancillary equipment [§3621 (A)(8)(a)]. Pressure gauges will be installed on the wellhead to show the tubing and tubing-casing annulus pressure and be calibrated and maintained in good working order. The pressure gauges will read in 10 psig increments [§3621 (A)(10)].

Signs will be posted at the wellhead and include the operators name and number, the state well serial number, section-township-range and will be comprised of durable weather materials and kept in legible condition [§3621 (A)(8)(b)].

5.3.3 Injection Well No. 3 (W-S2)

The drilling program for Injection Well No. 3 (W-S2) at the Louisiana Green Fuels facility includes a conductor/drive pipe, potable water hole, surface hole, intermediate hole, and protection hole. All depths in the outlined procedure are referenced to the kelly bushing (KB) elevation, which is estimated at 20.0 feet above ground level. A casing seat test will be performed for each casing string, but the pressures used in the tests will not exceed the fracture gradient of the geologic formation [LAC 43:XVII §3617 (A)(3)].

5.3.3.1 Proposed Drilling Procedures

Conductor/Drive Pipe

1. Prepare surface location and mobilize drilling rig. Drill mousehole and rathole.

2. Pick up casing hammer and drive 30-inch conductor pipe to approximately 100 feet or until 100 blows per foot penetration rate is reached. (Alternatively, auger the "drive pipe" hole

and grout the casing to ensure a setting depth below 100 feet to avoid washout in unconsolidated sands while drilling large diameter conductor hole).

3. Cut off drive pipe and install bell nipple to drill conductor hole.

Potable Water Hole

4. Pick up 28-inch drilling assembly and drill conductor hole to 300 feet (+/-) using drilling fluid as detailed in the Drilling Fluids section of this procedure.

28-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

Should lost circulation occur (expected) while drilling the 28-inch borehole from the base of conductor/drive pipe to the potable water casing point, paper, cottonseed hulls, or other forms of standard lost circulation material may be used to remedy the loss condition. A cement truck may be mobilized to location and placed on "standby" to minimize "wait time" if severe loss of circulation is encountered.

28-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (which is **not** expected) while drilling the 28-inch surface casing borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

28-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys at a minimum every 150 feet and at TD. A maximum recommended deviation from vertical is 2 degrees, and the targeted deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

5. Run 24-inch casing to 300 feet (+/-). Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

6. Cement the casing in place using the stab-in method. Refer to Section 5.3.3.4 – Cement Details.

7. If no cement returns are observed at surface, grout the un-cemented annular space to the surface if necessary.

8. After waiting on cement for a minimum of 12 hours, cut off the drive pipe and potable water casing and install bell nipple on the conductor pipe to drill surface hole.

Surface Hole

9. Pick up 22-inch drilling assembly, lower in the well, and drill the float shoe. Drill surface hole to a sufficient depth to set 1,200 feet of surface casing using drilling fluid as detailed in the Drilling Fluids section of this procedure. Configure the bottom hole assembly and follow established industry practice to ensure a vertical hole. Take deviation surveys every 300 feet.

Maximum deviation from vertical should be no more than 2 degrees.

22-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

Should lost circulation occur (expected) while drilling the 22-inch borehole from the base of potable water casing to the surface casing point, paper, cottonseed hulls, or other forms of standard lost circulation material may be used to remedy the loss condition. A cement truck may be mobilized to location and placed on "standby" to minimize "wait time" if severe loss of circulation is encountered.

24-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (which is **not** expected) while drilling the 26-inch surface casing borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

24-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys at a minimum every 300 feet and at TD. A maximum allowable deviation from vertical is 2 degrees, and the targeted deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

10. Run open hole electric logs as listed in "*Module D – Pre-Operational Testing"* from total depth to 300 feet (setting depth of 24-inch casing. Continue logging the gamma ray log to surface.
11. Run 18-5/8-inch surface casing to a minimum of 1,200 feet. Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.
12. Cement the casing in place using the using the two-plug method with a minimum of 100% excess cement over the hole size. Refer to Section 5.3.3.4 – Cement Details.
13. If no cement returns are observed at surface, a temperature or similar diagnostic survey will be run to determine the top of cement. Grout the un-cemented annular space to the surface if necessary and prior to proceeding to the next step.
14. After waiting on cement for a minimum of 12 hours, cut off the surface and potable water casings and install a 20-1/4-inch x 3,000 psi x 18-5/8-inch SOW casing head on the surface casing and pressure test.
15. Nipple up 20-1/4-inch, 3,000 psi Blowout Preventers (BOP) and ancillary equipment and pressure test to a low pressure of 250 psig and a maximum pressure of 2,000 psig.
16. Rig up wireline unit and log differential temperature survey and cement bond log.
17. Pressure test (and record) the surface casing to 500 psig for one hour [LAC 43:XVII §3617 (A)(3)(a)]. Casing test pressures will never exceed the rates burst or collapse pressures of the casing string.

Intermediate Hole

18. Pick up a 17-1/2-inch drilling assembly and trip into the wellbore.

19. Displace the spud mud with a potassium-based drilling fluid to improve hole cleaning and stability. The drilling fluid system might be modified to use a different mud system. Drill out casing float equipment and 10 feet of new formation.

20. Perform a Casing Seat Test to a minimum of 1,000 psig for one hour. The casing seat pressures will never exceed the calculated fracture gradient of the formation [LAC 43:XVII §3617 (A)(3)(b)].

21. Once the Casing Seat Test is secured (allowable loss is limited to 5 percent of the test pressure over stabilized test duration), will proceed to drill a 17-1/2-inch intermediate hole from surface casing point to 3,900 feet (+/-) into the top of the Selma Chalk, using drilling fluid as detailed in the Drilling Fluids section of this procedure. Take deviation surveys every 500 feet. To the extent possible, maintain deviation from vertical at should be no more than 2 degrees or less.

22. In one or more of the injection wells, attempt to collect a 60-foot conventional core from the Midway Shale Secondary Upper Confining Zone. Refer to Module D – Pre-Operational Testing for details on the coring program.

17 1/2-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

If circulation is lost (not expected) while drilling the 17-1/2-inch borehole, lost circulation material pills will be pumped to re-establish circulation. Depending upon the severity of lost circulation encountered, lost circulation material may need to be blended with the drilling fluid in concentrations dictated by hole conditions to maintain circulation to the surface casing point.

17-1/2-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (which is **not** expected) while drilling the 17-1/2-inch borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

17-1/2-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys ~~at~~ 500 feet intervals and at TD. To the extent possible, maintain deviation from vertical of 2 degrees or less, and deviation between surveys is 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

23. Run open hole electric logs as listed in "*Module D – Pre-Operational Testing*".

24. Run 13-3/8-inch intermediate casing to 3,900 feet (+/-) into the top of the Selma Chalk. Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

25. Rig up cementing equipment and cement the intermediate casing in place. Cement will be

placed in three stages with the lower cement stage from the casing shoe to the top of the Midway Shale Secondary Upper Confining Zone, being CO_2 resistant cement (Evercrete™ or equivalent). The upper two cement stages will be circulated through cementing stage tools placed at approximately 3,000 feet and 1,450 feet. The cement slurries for each stage will consist of a lead lightweight cement blend and tail slurry of standard cement. Refer to Section 5.3.3.4 – Cement Details.

26. If no cement returns are observed at surface, a temperature log or similar diagnostic survey will be run to determine the top of cement. Grout will be applied to the un-cemented annular space to the surface if necessary and prior to proceeding to the next step.

27. After completing the third stage cementing, immediately pick up the BOP, set the 13-3/8-inch casing slips, cut off the 13-3/8-inch casing, nipple down the BOPs, and install a 21-1/4-inch 3,000 psi x 13-5/8-inch 3,000 psi casing spool and pressure test.

28. Nipple up 13-5/8-inch 3,000 psi BOPs and ancillary equipment and pressure test to a low pressure of 250 psig and a maximum pressure of 3,000 psig.

29. Pick up 12-1/4-inch bit and lower in the well on the drilling assembly. Drill out the two 13-3/8-inch cement stage tools, trip in the well to the float collar, and circulate clean.

30. Wait on cement to cure and temperature to stabilize for approximately 24 hours.

31. Rig up wireline unit and log differential temperature survey and cement bond log. Analyze cement bond log results and confirm adequate isolation before proceeding. If necessary, the cement bond log will be repeated under pressure.

32. Pressure test (and record) the intermediate casing to 1,000 psig for one hour [LAC 43:XVII §3617 (A)(3)(a)]. Casing test pressures will never exceed the rates burst or collapse pressures of the casing string.

Protection Hole

33. Pick up a 12-1/4-inch drilling assembly and trip into the wellbore.

34. Displace the fresh water from cement with a potassium-based drilling fluid to improve hole cleaning and stability. Drilling fluid system might be modified to use a different mud

system. Drill out the shoe track cement and float equipment and drill 10 feet of formation.

35. Perform a Casing Seat Test to a minimum of 1,000 psig for one hour. The casing seat pressures in the test will never exceed the calculated fracture gradient of the formation [LAC 43:XVII §3617 (A)(3)(b)].

36. Once the Casing Seat Test is secured (allowable loss is limited to 5 percent of the test pressure over stabilized test duration), proceed forward and drill a 12-1/4-inch protection hole from intermediate casing point to 7,000 feet into the Paluxy Formation. To the extent possible, maintain deviation from vertical at 2 degrees or less. The actual total depth of the well will be contingent on the "rathole" depth beneath the base of the deepest sandstone encountered in the Paluxy Formation. Take inclination surveys every 500 feet to monitor wellbore deviation.

37. Attempt to collect conventional whole cores at selected geologic intervals within the Austin Chalk Equivalent and Upper Tuscaloosa / Paluxy Injection Zone in one or more of the injection wells. Refer to *Module D – Pre-Operational Testing* for details on the coring program.

28-INCH BOREHOLE LOST CIRCULATION CONTINGENCY PLAN

If circulation is lost (not expected) while drilling the 12-1/4-inch borehole, lost circulation material pills will be pumped to re-establish circulation. Depending upon the severity of lost circulation encountered, lost circulation material may need to be blended with the drilling fluid in concentrations dictated by hole conditions to maintain circulation to the intermediate casing point.

12-1/4-INCH BOREHOLE OVERPRESSURED ZONE CONTINGENCY PLAN

If an overpressured zone is encountered (which is **not** expected) while drilling the 12-1/4-inch borehole, drilling fluid pump rate down the drill pipe will be increased while the drill fluid density is increased. The increased pumping rate will continue until the well stops flowing.

12-1/4-INCH BOREHOLE DEVIATION CONTINGENCY PLAN

Take borehole inclination surveys at 500 feet intervals and at TD. To the extent possible, maintain deviation from vertical of 2 degrees or less, and deviation between surveys to 1 degree or less. If the maximum recommended deviation is exceeded, an evaluation will be made to determine whether remedial action is necessary.

38. Run electric wireline logs and collect rotary sidewall core samples (if needed) over the open hole interval. Refer to Module D – Pre-Operational Testing for details.

39. Run 9-5/8-inch casing (mixed string), with casing packer and DV stage tool, (and fiber optic cable: DTS/DAS, and perforation markers, if required) to the planned casing point (7,000 feet). Refer to Section 5.2.1 – Casing String Details for a detailed description of the casing.

Note: Louisiana Green Fuels is evaluating "smart well" completion technologies to monitor Differential Temperature, Acoustic, and Bottomhole Pressure.

40. Rig up cementing equipment and cement the protection casing in place. Cement will be placed in stages with the lower cement stage from total depth to the top of the Midway Shale Secondary Upper Confining Zone being CO_2 resistant cement. The second stage will be circulated through a cementing stage tool at approximately 3,000 feet. The second stage cement will consist of lead slurry of a lightweight cement blend and tail slurry of standard cement. Refer to Section 5.3.3.4 – Cement Details.
41. After completing the second stage cementing, pick up the BOP, set the 9-5/8-inch casing slips, cut the 9-5/8-inch casing above the slips, and remove the BOP's. Install the 13-5/8-inch 3,000 psi x 11-inch 5,000 psi casing/tubing spool and test the seals.
42. In the event cement returns are not observed at the surface, a temperature or similar diagnostic survey will be run to determine the top of cement. After the cement top is located, a procedure to grout in the un-cemented annular space will be provided.
43. Set night cap and secure well.
44. Rig down the drilling rig, and associated equipment and move out.

General Notes:

- ***All depths referenced are approximate and are based on the expected log depth.***
- ***Actual depths may vary based on lithology of local formations.***

5.3.3.2 Proposed Completion Procedure

The completion procedure has been developed to utilize the Tuscaloosa/Paluxy Injection Zone for sequestration of the injected CO_2. It is anticipated that the full interval in the Tuscaloosa will be utilized in each well completion and select sandstones in the Paluxy will be perforated based on results from the open hole logging program. The following is a proposed completion procedure for the Louisiana Green Fuels facility for Injection Well No. 1 (W-N1).

1. Move in and rig up the completion rig and associated equipment.

2. Check for pressure, remove the night cap and nipple up and test the 11-inch 5,000 psi BOP from 250 low to 5000 psi high.

3. Pick up an 8-1/2-inch bit and casing scraper for 9-5/8-inch casing and trip into the wellbore picking up completion work string.

4. Drill out the cementing stage tool plugs at ±3,000 feet and the float shoe and cement in the casing to ±6,990 feet (15 feet above the casing shoe).

5. Rig up and run differential temperature and radial cement bond and casing evaluation logs as detailed in the Module D – Pre-Operational Testing.

6. Pressure-test (and record) the casing string to 1,000 psig for one hour.

7. Displace the drilling fluid in the wellbore with filtered completion fluid.

8. Rig up wireline unit and if fiber optics were installed on the casing, directionally perforate (to avoid fiber optic cable) selected intervals of the 9-5/8-inch casing within the overall geologic formation intervals in the following table:

Perforation Interval	**Formation/Lithology**
± 4,910 feet to 5,210 feet	Upper Interval of the Upper Tuscaloosa
± 5,250 feet to 5,630 feet	Lower Interval of the Upper Tuscaloosa
± 5,900 feet to 6,990 feet	Various Permeable Sandstones in Paluxy

(Note: Perforating depths are approximate and will be determined after review of open hole logs. Note, oriented perforating will be required if DTS/DAS cable run on casing through the Injection Zone)

9. Go in hole with the workstring to the bottom of the protection casing and circulate filtered completion fluid.

10. Prepare all completed intervals for injection, including washing perforations and performing acid stimulation as necessary. The final stimulation program will be based on the open hole logs and the injection interval core material collected during the drilling.

11. Remove the workstring from the well while laying down the workstring and downhole tools.

12. Install the two 9-5/8-inch x 5-1/2-inch injection packers with an adjustable sliding sleeve flow control valve between the packers, and 5-1/2-inch injection tubing to surface. The system will be installed on a single trip, spaced out, and hydraulically set. The installation will include two downhole surface readout (SRO) pressure gauges on a single electric line. The lower pressure gauge will monitor the injection pressure in the Lower Interval of the Upper Tuscaloosa Injection Zone and the Paluxy Injection Zone between approximately 5,250 feet and 6,990 feet. The lower gauge will be installed below the low injection packer. The upper pressure gauge will be installed below the upper packer and clamped to 5-1/2-inch spacer tubing between the two packers to monitor the pressure in the Upper Interval of the Upper Tuscaloosa Injection Zone between approximately 4,910 feet and 5,210 feet. A general description of the completion equipment as picked up and lowered into the well (deepest to surface) is presented below:

    - 9-5/8-inch x 5-1/2-inch hydraulically set lower injection packer with 22CR or higher wetted surfaces with 10 foot long 5-1/2-inch 20 lb/ft, 22CR65 tail pipe below with wireline reentry guide. The lower SRO gauge will be strapped to the 5-1/2-inch tail pipe below the packer and the gauge electric line will be connected to the gauge and the electric line will go through the packer pass through.

    - 5-1/2-inch Spacer Tubing, 5-1/2-inch Adjustable Sliding Sleeve Flow Control Valve, Upper SRO Pressure Gauge, two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve, and Electric Line for the two Pressure Gauges. A 5-1/2-inch, 20 lb/ft, 22CR65 Spacer Tubing will be installed with integral connections to the top of the lower packer and the bottom of the upper packer. The 5-1/2-inch Adjustable Sliding Sleeve Flow Control Valve will be installed in the 5-1/2-inch Spacer Tubing at approximately 5,400 feet (Actual setting depth will be determined later). The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will be strapped to the 5-1/2-inch Spacer Tubing. The Upper SRO Pressure Gauge for monitoring the injection pressure in the Upper Tuscaloosa

Injection Zone will be set at approximately 5,300 feet (Actual setting depth will be determined later).

- 9-5/8-inch x 5-1/2-inch hydraulically set upper injection packer with 22CR or higher wetted surfaces will be made up/connected to the 5-1/2-inch spacer tubing below the packer and the 5-1/2-inch 20 lb/ft, 22CR65 Injection Tubing will be make up to the top of the packer. The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will feed through the passthrough in the packer. The packer will be spaced out and hydraulically set at approximately 4,800 feet.
- The 5-1/2-inch 20 lb/ft, 22CR65 Injection Tubing will be installed from the top of the upper injection packer at approximately 4,800 feet to surface. The two ¼-inch Hydraulic Control Lines for the Adjustable Sliding Sleeve Flow Control Valve and Electric Line for the two Pressure Gauges will be strapped to the 5-1/2-inch Injection Tubing.

13. The 5-1/2-inch Injection Tubing will be spaced to position the equipment correctly. Inhibited packer fluid will be circulated/pumped down the tubing-casing annulus until inhibited brine is fully displaced to the top packer.
14. The two ¼-inch hydraulic control lines and the electric line for the two SRO pressure gauges will be feed through the 5-1/2-inch tubing hanger, secured, and terminated. The 5-1/2-inch tubing hanger will be positioned in the wellhead. The two completion packers will be hydraulically set per the suppliers' specifications.
15. Top out the 5-1/2-inch x 9-5/8-inch casing annulus with inhibited packer fluid. Conduct preliminary pressure test to verify proper installation with a test pressure of 2,500 psi.
16. Nipple down well control equipment and install tubing head adapter and the wellhead tree section.
17. Rig down completion rig and demobilize from site.
18. Rig up coiled tubing and displace tubing and rathole with non-formation-damaging fluid for undetermined period to await CO_2 source from the Louisiana Green Fuels facility.

General Notes:

- ***All depths referenced are approximate and are based on the expected log depth.***
- ***Actual depths may vary based on lithology of local formations.***

5.3.3.3 Proposed Well Fluids Program

Lost circulation material (LCM) will be on location to treat for fluid losses in top hole sands above the potential injection intervals. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones. High-viscosity sweeps will be used to assist hole cleaning. Sodium chloride (NaCl) is planned for use as the completion fluid. The fluid weight will be maintained slightly over-balanced to contain reservoir pressures. Table 5-17 is provided to show the proposed fluids per hole.

5.3.3.4 Proposed Cementing Program

The potable water, surface, intermediate, and protection casing strings will be cemented using current cementing technology and practices. Cementing standards defined in LAC 43:XVII §3617 (A)(2) will be used during the construction of the well. The wells will use both standard cement (Class A or Class H) and CO_2 resistant cement (SLB Evercrete ™, or equivalent) to ensure the longevity of the wellbore. All casing strings will be fully cemented to surface, which will provide additional isolation of the casing strings from external formation fluids along the borehole path (LAC 43:XVII §3617 (A) and LCFS Protocol Subsection C.3.1(b)). For the intermediate and protection casing strings, the top of the CO_2 resistant cement will be above the top of the Midway Shale Secondary Upper Confining Zone in each injection well. The final cementing programs for each of the casing will be revised based on the wellbore conditions during drilling and the cementing contractors' recommendations.

5.3.3.4.1 Potable Water Casing

The following cementing program (Table 5-18) is proposed for installation of the surface casing string:

- 24-inch in a 28-inch borehole at 300 feet
- Float shoe;

- Cement to surface;
- Cement volumes are estimated 100% excess over bit size in open hole interval;
- Procedure might be modified to use the inner string method with a stab-in float shoe; and,
- In the event that hole issues are observed, a 150 percent of the annular space between the casing and drilled wellbore will be used for calculating cement volume for that section of the wellbore.

5.3.3.4.2 Surface Casing

The following cementing program (Table 5-19) is proposed for installation of the surface casing string:

- 18-5/8-inch in a 22-inch borehole at 1,200 feet
- Float shoe;
- Float Collar, 1 joint above the float shoe;
- Cement to surface;
- Cement volumes are estimated 100% excess over bit size in open hole interval;
- Actual volume to be calculated from caliper log plus 20% excess; and,
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.3.4.3 Intermediate Casing

The following cementing program (Table 5-20) is proposed for installation of the intermediate casing string:

- 13-3/8-inch in a 17-1/2-inch borehole at 3,900 feet;
- Float shoe;

- Float Collar, 2 joint above the float shoe;
- Three-stage cement job with cement to surface and cementing stage tools at 3,000 feet and 1,450 feet;
- Cement volumes are estimated 50% excess over bit size in open hole interval;
- Actual volume to be calculated from caliper log plus 20% excess in the open hole intervals; and,
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.
- caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.3.4.4 Protection Casing

The following cementing program (Table 5-21) is proposed for installation of the protection casing string:

- 9-5/8-inch in a 12-1/4-inch hole at 7,000 feet;
- Two-stage cement job with cement to surface, with stage tool and external casing packer;
- estimated 50% excess over bit size in open hole sections;
- actual volume to be calculated from caliper log plus 20% excess; and
- In the event the hole diameter exceeds the scale of a 2-dimensional caliper, a minimum of 150 percent of the annular space between the casing and the maximum caliper reading will be used for calculating cement volume for that section of the wellbore.

5.3.3.5 Casing Cementing Equipment

Potable Water Casing

24-inch Cementing Equipment

1. Float shoe with receptacle for stab-in cementing technique
2. Six hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer straddling the first casing collar above the float shoe; and
    - 1 Centralizer every other collar, up to the surface.

Surface Casing

18-5/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 1 joint above the float shoe
3. Approximately 50 hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
    - 1 Centralizer ever other casing collar to surface.

Intermediate Casing

13-3/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 1 joint above the float shoe
3. Two cementing Stage Tools spaced at approximately 3,000 feet and 1,450 feet
4. Approximately 45 hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;

- 1 Centralizer 8 feet above the float collar, straddling a stop collar;
- 1 Centralizer above and below each stage collar, straddling a stop collar;
- 1 Centralizer every other joint, to 1,200 feet;
- 1 Centralizer every third joint, from 1,200 feet to the surface; and
- 1 Centralizer approximately 10 feet below ground level.

Protection Casing

9-5/8-inch Cementing Equipment

1. Float shoe
2. Float collar, 2 joints above the float shoe
3. Cementing Stage Tool at approximately 3,000 feet
4. Approximately 59 hinged bow spring centralizers placed in accordance with Section 5.2.3.
    - 1 Centralizer 8 feet above the float shoe, straddling a stop collar;
    - 1 Centralizer 8 feet above the float collar, straddling a stop collar;
    - 1 Centralizer every other joint, to 3,900 feet;
    - 1 Centralizer every third joint, from 3,900 feet to the surface; and
    - 1 Centralizer approximately 10 feet below ground level.

5.3.3.6 Well Logging, Coring, and Testing Program

Details on the proposed logging program are contained in the "*Pre-Operational Testing and Logging Plan*" submitted in Module D. All tools will be run on a wireline and will be compatible with open hole and cased hole diameters, allowing for successful testing runs (LAC 43:XVII §3617 (B) and LCFS Protocol Subsection C.2.3.1 standards).

5.3.3.7 Wellhead Schematic

The proposed wellhead for Injection Well No. 3 (W-S2) will be with a similar trim that is resistant to the CO_2 stream and impurities. A proposed wellhead schematic is presented in Figure 5-6. The well head will be surrounded by an enclosed diked, impermeable pad to protect the ground surface from spills and releases from the wellhead and ancillary equipment [§3621 (A)(8)(a)]. Pressure gauges will be installed on the wellhead to show the tubing and tubing-casing annulus pressure and be calibrated and maintained in good working order. The pressure gauges will read in 10 psig increments [§3621 (A)(10)].

Signs will be posted at the wellhead and include the operators name and number, the state well serial number, section-township-range and will be comprised of durable weather materials and kept in legible condition [§3621 (A)(8)(b)].

6.0 PRE-OPERATIONAL LOGGING AND TESTING

Strategic Biofuels has designed the sequestration project using three injection wells. These wells will be completed into one or more of the project Injection Zone intervals described above. All injection wells will follow the LAC 43:XVII §3617 (B) standards for logging and testing requirements. Each phase of the well completions will have open and cased hole logs. Coring will be adaptive and based upon well spatial variability, wellbore conditions, core recovery, and core quality as each project well is drilled. All wells will demonstrate mechanical integrity prior to receiving authorization to inject.

The data obtained in this plan will be used to validate and update, if necessary, the "*Area of Review and Corrective Action Plan*" (submitted in **Module B**), to define and reduce uncertainties with the site characterization, revise the "*E.1-Testing and Monitoring Plan*" (submitted in **Module E),** and determine final operational procedures and limits.

A detailed plan with coring and logging has been uploaded in **Module D**:

"D. Pre-Operations Testing and Logging Plan"

A pre-operational report detailing all the logging and testing details will be provided for each well per [LAC 43:XVII §3619 (A)(7)].

7.0 INJECTION WELL OPERATIONS

Strategic will operate the injection wells at the Caldwell Parish site per the operating requirements in accordance with LAC 43:XVII §3621. No injection operations will occur between the outermost casing and the USDW per LAC 43:XVII §3621 (A)(2). Operating the well in this fashion will prevent the movement of fluids that could result in the pollution of a USDW and will prevent leaks from any of the subject injection wells into unauthorized zones.

The annulus pressure will be maintained that exceeds the operating injection tubing pressure to prevent leaks from the well into unauthorized zones and to detect well malfunctions [LAC 43:XVII §3621 (A)(4)] The annulus will be filled with a non-corrosive fluid that is approved by the commissioner [LAC 43:XVII §3621 (A)(3)].

During injection operations, continuous measurements will be taken at the wellhead for injection pressure, rate, volume, and temperature of the CO_2 stream [LAC 43:XVII §3621 (A)(6)(ii)]. The maximum injection pressure is governed by the fracture gradient. The planned maximum injection pressure will be set at 80% of the calculated fracture gradient values (see Section 2.4.5 for value determination). The maximum 80% of calculated fracture pressure threshold, which is lower than that specified for a Class VI permitted well, is derived from the rules for carbon sequestration of the California Air Resources Board (CARB), which has an overlapping regulatory authority on other matters affecting the Louisiana Green Fuels project. Specific *in-situ* fracture gradients will be determined during the drilling and testing of the Class VI Injection Wells for the primary and secondary proposed Injection Zone intervals.

The source of the CO_2 will be from the generation of biofuels and energy production from the carbon negative renewable fuel facility. This facility will generate fuels and power using the biomass waste from the forestry industry. A detailed analysis of the CO_2 waste stream composition and characteristics will be performed prior to initiating injection operations. The CO_2 composition is expected to be 99.5% pure CO_2, with minor additional constituents, but will remain as a non-hazardous classification.

If there are major changes to the operational stream (density changes, composition, etc.) or a new source, Strategic Biofuels may reevaluate and adjust the operating pressures with approval from the Commissioner.

Under routine operations, injection pressures that approach the limits shown below will trigger notifications or a full system shutdown (if limits are close to exceedance). Well conditions will then be monitored to decide on steps to return to full rate injection. In cases where return to full injection is not possible, additional troubleshooting steps may be required.

- Table 7-1 for Injection Well No. 1 (W-N1)
- Table 7-2 for Injection Well No. 2 (W-N2)
- Table 7-3 for Injection Well No. 3 (W-S2)

The final operational values will be updated based upon data collected from the drilling of the injection wells and used in the final model simulations and delineated Area of Review.

8.0 TESTING AND MONITORING

In accordance with LAC 43:XVII §3625, Strategic Biofuels has developed a testing and monitoring plan for the lifetime of injection operations. In addition to demonstrating that the injection wells will be operating as expected, that the carbon dioxide plume and pressure front are moving as predicted, and there is no endangerment to USDWs, the monitoring data will be used to validate and guide any required adjustments to the geologic and dynamic models used to predict the distribution of carbon dioxide within the storage complex, supporting AoR evaluations and a non-endangerment demonstration. Additionally, the testing and monitoring components include a leak detection plan to monitor and account for any movement of the carbon dioxide outside of the sequestration project.

Strategic Biofuels has designed the program with two Above-Confining-Zone-Monitoring (ACZMI) wells [LAC 43:XVII §3625 (A)(4)] The initial ACZMI Monitoring Zone Well for the sequestration project will be the re-entered and recompleted AP No. 129 well, to be completed in the permeable Annona Sand, the first porous sandstone overlying (~450 feet above) the Primary Upper Confining Zone, located at the base of the Selma Chalk Formation. In addition, adjacent to the on-site injection well (W-N1), a second shallower ACZMI well will be drilled to monitor the basal sandstone of the Wilcox Formation encountered directly above the top of the Secondary Upper Confining Zone, the Midway Group. This second ACZMI Monitoring well will be located near the point of carbon dioxide injection (in the W-N1 Well), where the elevated formation pressure within the sequestration complex is expected to be the greatest. Both ACZMI wells will be completed with a real-time, continuously recording downhole pressure/temperature gauge.

Direct in-zone monitoring at the injection wells will confirm that the wells are performing as intended; delivering the carbon dioxide to the authorized sequestration reservoirs; not exceeding safe injection pressures and measuring the pressure response in the Injection Zone intervals (a key model match parameter). Downhole pressure gauges and injection logging in the constructed injection wells will be used for data collection.

Multiple In-Zone pressure (IZ) monitoring wells, located away from the injection site (up and down dip), will validate the dynamic model, calibrating both the growth of sequestered carbon dioxide plume and pressure front over time. Downhole pressure gauges and logging in the constructed monitoring wells will be used to collect real-time, continuous data. Monitor wells will be located initially outside of the carbon dioxide plume and will primarily monitor the pressure changes due to the developing pressure front. These wells are installed as part of the direct monitoring plan as set forth by LAC 43:XVII §3625 (A)(7).

Additionally, as part of the CARB LCFS Protocol Subsection C.4.1(a)(11), the surface and near-surface of the site will also be monitored. The primary objective of the surface and near-surface monitoring program is to confirm containment of carbon dioxide within the deep subsurface to 1) demonstrate no endangerment to public health or the environment, 2) confirm conformance with the proposed injection plan, and 3) validate calculations of total sequestered carbon dioxide in the deep subsurface.

Accordingly, the proposed surface and near-surface program includes the following elements: i) determine baseline physical and chemical conditions and natural background variability at the surface above the storage complex, ii) detect changes in conditions that might be indicative of an environmental impact and therefore warrant further investigation, iii) attribute those changes to either natural variability or actual anthropogenic impacts, and iv) if needed, assist in the quantification and subsequent remediation of the potential carbon dioxide leak.

The proposed surface and near-surface monitoring program consists of three key monitoring components during the baseline and/or operational phases of the project: 1) atmospheric monitoring, 2) ecosystem stress monitoring, and/or 3) soil gas monitoring.

The monitoring plan has been uploaded in **Module E** – Project Plan Submission as Report:

"E.1 – Testing and Monitoring Plan"

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to LAC 43:XVII §3625 (A)(11) is provided in Appendix 1 – Quality Assurance and Surveillance Plan (QASP) to the Testing and Monitoring Plan.

9.0 INJECTION WELL PLUGGING

The Injection Well Plugging Plan has been developed using the GSDT Template and meets the requirements under LAC 43:XVII §3631. It contains testing prior to closure and plugging plans and schematics for each injection well in this application. Mechanical integrity of each injection well will be verified prior to closure. A final bottomhole reservoir pressure will be determined prior to commencing injection well plugging operations [LAC 43:XVII §3631 (A)(2) and LCFS Protocol Subsection C.5.1(d)(1)]. The Injection Wells will be plugged using acid resistant cement across the completion zones by squeezing cement through a retainer. Plugs will be set across the surface casing shoe and at surface using the balanced method and premium type of cement.

In compliance with LAC 43:XVII §3631 (A)(4) and LCFS Protocol Subsection C.5.1(h), Strategic Biofuels will notify the authorized regulatory agency with a Notice of Intent to plug by submitting a UIC-17, or successor form, to the commissioner. Strategic Biofuels will receive written approval from the commissioner before commencing plugging operations.

The report will include records for any unreported newly constructed or previously unidentified wells within the Area of Review that penetrate the Primary Confining Zone, the Austin Chalk Equivalent / Upper Eagleford interval.

When plugging and abandonment is complete, Strategic Biofuels will submit certification to the authorized regulatory body (by the plant and by a licensed, professional engineer with current registration, who is knowledgeable and experienced in practical drilling engineering and who is familiar with the special conditions and requirements of injection well construction) that the injection well(s) has been closed in accordance with the regulations. Plugging reports will be submitted within 30 days of well plugging. The report will include records for any unreported newly constructed or previously unidentified wells within the Area of Review that the Primary Confining Zone, the Austin Chalk Equivalent / Upper Eagleford interval. Strategic Biofuels will retain a copy of the plugging report for a minimum of 10 years following site closure [§3631 (A)(5) and LCFS Protocol Subsection C.5.1(k)].

It has been uploaded in **Module E** – Project Plan Submission as Report:

"E.2 – Injection Well Plugging Plan"

The Injection Plugging Plan will be updated as the project develops to be consistent with the Injection Well "*as built*" details after construction.

10.0 POST INJECTION SITE CARE (PISC) AND SITE CLOSURE

The Post Injection Site Care (PISC) and Site Closure Plan has been developed using the GSDT Template and meets the requirements under LAC 43:XVII §3633 and 5.2(a)(2) for LCFS standards. It has been uploaded in **Module E** – Project Plan Submission as Report:

"E.3 – Post Injection Site Care and Closure Plan"

Strategic Biofuels plans to implement a PISC over a 100-year timeframe (exceeding Louisiana designated Class VI timeframe of 50-years) to demonstrate conformance and containment with 5.2 (a)(2) of the LCFS standards. Data will be gathered to track the position of the CO_2 plume, declining pressure front and to demonstrate that the USDW is not endangered, using an adaptive, sustainable, risk-based monitoring approach.

Based on the modeling of the pressure front as part of the Area of Review delineation, the pressure at each injection well is expected to decrease to values approaching pre-injection levels. Figures 1, 2, and 3 in the PISC Plan represent the pressure differentials in each Injection Zone interval. Additionally, Figures 4 and 5 project the maximum plume extent (Saturation Front Boundary) at the end of the 100-year observation period.

Prior to receiving authorization for site closure, Strategic Biofuels will demonstrate that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs as per LAC 43:XVII §3633 (A)(2)(b).

At time of site closure, Strategic Biofuels will submit a closure report which will be submitted within 90 days of closure [§3631 (A)(6)]. Strategic Biofuels will retain a copy of the plugging report for a minimum of 10 years following site closure.

Any amendments to the PISC and Site Closure plan, if required at time of cessation of injection, will be approved by the Commissioner [LAC 43:XVII §3633 (A)(1)(c)].

11.0 EMERGENCY AND REMEDIAL RESPONSE

The Emergency and Remedial Response Plan (ERRP) has been developed using the GSDT Template and meets the requirements under [LAC 43:XVII §3623].

If Strategic Biofuels obtains evidence that the injected sCO_2 stream and/or associated pressure front may cause an endangerment to the USDW, Strategic Biofuels will perform the following actions per LAC 43:XVII §3623 (A)(2):

1. Initiate shutdown plan for the injection well(s).
2. Take all steps reasonably necessary to identify and characterize the nature of any release.
3. Notify the permitting agency (Commissioner) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: Strategic Biofuels will immediately cease injection. However, in some circumstances, Strategic Biofuels will, in consultation with the Commissioner, determine whether gradual cessation of injection (using the parameters set forth in the Summary of Requirements of the Class VI permit) is safe and appropriate.

Details pertaining to specific events and procedures have been submitted in the GSDT **Module E** – Project Plan Submission as Report:

"E.4 – Emergency and Remedial Response Plan"

The ERRP Plan will be updated and further developed to meet the project's needs throughout three phases of development: 1) Construction; 2) Operation; and 3) Post-Injection Site Closure. This ERRP shall be reviewed and potentially revised after per the following:

- At least once every five (5) years following its approval by the permitting agency [per LAC 43:XVII §3623 (A)(4)];
- Within one (1) year of any Area of Review (AOR) re-evaluation [per LAC 43:XVII §3623 (A)(4)(a)];

- Following any significant changes to the injection process or the injection facility, or an emergency event [per LAC 43:XVII §3623 (A)(4)(b)]; or
- As required by the commission [per LAC 43:XVII §3623 (A)(4)(c)].

Revisions will be drafted and annotated with date of submittal and submitted to the Commissioner for review prior to implementation.

12.0 INJECTION DEPTH WAIVER AND AQUIFER EXEMPTION EXPANSION

Strategic Biofuels is not requesting an Injection Depth Waiver or an Aquifer Exemption Expansion. Therefore, this Section is not applicable.

13.0 OPTIONAL ADDITIONAL PROJECT INFORMATION

In conjunction with these permit applications, Strategic Biofuels has applied for Class VI UIC-60 Injection Well Permits. This is a state level permit that is required for all such wells in Louisiana. Three Form UIC-60 have been submitted to the Louisiana DENR and each permit application contains the owner and applicant information, well location and construction details, proposed injection formations, proposed injection rates and volumes, and lists any other site permits relevant to the project that have been applied for or received. Additionally, a plat location of the proposed wells, a listing of water wells identified for baseline sampling measurements, and answers related to the environmental analysis as required by LA R.S. 30:1104 have been concurrently submitted.

Strategic Biofuels is also applying to the California Air Resources Board (CARB) for site certification using more stringent parameters (such as designing the project with injection pressures below 80% fracture gradient) to qualify for that state's Low Carbon Fuel Standard (LCFS) credits. That application will be submitted in tandem with this Class VI permit application. The CARB LCFS application will be for certification purposes only and will be unrelated to any State regulatory authorization to inject.

Strategic Biofuels will apply to LDENR for drilling permits for the re-entering and conversion of four legacy (previously plugged and abandoned) wells (all dry holes) to In-Zone monitor wells identified within the AoR; the re-entering and conversion of a fifth legacy well (AP No. 129) to a "deep" ACZMI monitor well completed in the Annona Sand ~450 feet above the Primary Upper Confining Zone, the Austin Chalk Equivalent / Upper Eagleford interval (as described above); and the drilling of a new grass-roots "shallow" ACZMI monitor well (located on the renewable fuels facility site, adjacent to Well W-N1) to the basal sandstone of the Wilcox Formation just above the Midway Group Secondary Upper Confining Zone. These permits will be obtained from the LDENR.

As noted elsewhere in this application, the Louisiana Green Fuels, Port of Columbia project plans for two of the three proposed Injection Wells to be located offsite to the renewable fuels plant that will be the source of the CO_2. This will require a bifurcated pipeline approximately 3.5 miles in total length (intrastate) to transport sCO_2 to the two offsite wells for downhole injection. The sCO_2

pipeline is integral to the project and considered part of this Class VI permit application. Its construction and operation will be subject to the safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or Carbon Dioxide in accordance with the US Department of Transportation – Pipeline and Hazardous Materials Safety Administration (PHMSA) (49 CFR Part 195). The safety standards and enforcement responsibility will be under the jurisdiction of the Pipeline Division of the LDENR in accordance with Title 33, Environmental Quality, Part V. Hazardous Waste and Hazardous Materials, Subpart 1. Louisiana Department of Environmental Quality – Hazardous Waste, and Subpart 3. Natural Resources promulgated by the LDENR – Pipeline Division (49 CFR Part 195). The sCO_2 pipeline will also require a Section 404 permit from the US Army Corps of Engineers to cross those tracts along the pipeline route designated as wetlands, as well as the approval of the Louisiana Department of Transportation and Development to cross beneath US Highway 165 and LA Highway 847.

Pursuant to LAC 33:III.503, Strategic Biofuels (through its subsidiary Louisiana Green Fuels) has applied for and received an Air Permit (Minor Source) from the Louisiana Department of Environmental Quality (LDEQ) that pertains to the planned operations of the sCO_2-generating renewable fuels facility. The LDEQ Air Permit is not related to carbon capture and sequestration operations.

Construction of the renewable fuels' facility will require several Section 404 permits from the US Army Corps of Engineers where wetlands are encountered at the facility site.

A draft Environmental Assessment (EA) of the site of the renewable fuels plant associated with this Class VI application, has been completed. An expanded EA covering the planned offsite wells and pipeline will be completed and submitted for review and acceptance prior to the commencement of sCO2 injection operations.

Within the AoR, there are two privately-owned residential structures identified to be on the National Register of Historic Places and subject to the National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq. Synope Plantation House (circa 1857) is located approximately 2,300 ft from the nearest proposed injection well. Breston Plantation House (circa 1835) is located approximately 4100' from the nearest proposed injection well and 2600' from the nearest proposed monitor well. Neither of the sites have been assessed to be impacted by the project. In the case of the Synope Plantation House, its current owner sold the adjacent injection well site for that purpose. There are no other structures or sites within the AoR known or believed to be eligible for listing on the National Register.

The Ouachita River traverses the AoR. It is not listed as a "wild and scenic" river and is not subject to the Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq. It is a navigable river controlled and regulated by the U.S. Army Corps of Engineers with multiple lock and dam structures but has been assessed to not be impacted by the planned carbon dioxide sequestration operations, with all well sites and pipelines located beyond artificial levees. The sCO_2-generating renewable fuels facility itself will have raw water intake and wastewater discharge operations directly affecting the river (unrelated to this application) which will require permitting and be subject to regulation by the LDEQ as well as the US Army Corps of Engineers.

The draft EA has not identified any endangered or threatened species at or near the renewable fuels facility and no similar identifications are anticipated from the planned expanded EA covering the Injection Wells and pipeline routes located offsite to the renewable fuels facility that may be subject to the Endangered Species Act, 16 U.S.C. 1531 et seq.

The project site is located far inland from the Gulf of Mexico and is not within an area subject to the Coastal Zone Management Act, 16 U.S.C. 1451 et seq.

14.0 OTHER RELEVANT INFORMATION

No additional information or documents have been requested by the Commissioner to date for this Class VI Permit Application for the Louisiana Green Fuels, Port of Columbia Facility in Caldwell Parish.

However, Strategic Biofuels has performed an initial assessment using the Environmental Justice Screening and Mapping Tool (EJScreen Tool) in February 2023. Reports applicable to the project are contained in Appendix E to this Project Narrative.

14.1 COMMUNITY OUTREACH AND DEVELOPMENT PROGRAMS

Strategic Biofuels is engaged in a multifaceted approach to foster community outreach and development programs within the greater Caldwell Parish area. The company, together with several of its major contractors and partners, has focused on local education and training, especially STEM programs, through its supportive relationships with Caldwell Parish Jr. High School, Caldwell Parish High School, and Louisiana Delta Community College.

For example, Strategic Biofuels and Hatch Engineering sponsored the first Robotics Team at Caldwell Parish High School, which competed in its first (the 74^{th}) Annual Senior BETA Club State Convention in Baton Rouge, Louisiana in 2023, winning Fourth Place in the Robotics Showcase Competition.

The Caldwell Parish Junior High School Robotics Team, also sponsored by Strategic Biofuels and Hatch Engineering, also excelled in their first competition. The Jr. High School Robotics Team competed in the Lego League Regional Division Qualifiers Tournament in Shreveport, Louisiana in 2023, and won first place in its division. This allowed the Robotics Team to advance to the State Championship held in New Orleans.

This demonstrates the success of the company's investment in local STEM programs and the educational nurturing of the children who quickly thrived and excelled in Robotics competition.

Strategic Biofuels is also working to establish internships and apprenticeships focused on collaborative vocational training for students and graduates of Louisiana Delta Community College. The company is encouraging more of its partners and major contractors to join it in establishing additional community outreach and development programs, with the goal of training workers from the Parish to acquire the skills necessary to be employed at the proposed facility and other ancillary employers in the surrounding community. Local business leaders have already voiced their support for such efforts; without the jobs and local tax income created by such innovative facilities, many workers in the local community have, in the past, been forced to leave Caldwell Parish to find gainful employment. The proposed Louisiana Green Fuels biorefinery and power plant represents a potentially powerful economic engine that will enable local workers to remain in the area, stay gainfully employed, and focus on raising their families while contributing to the local community.

14.2 COMMUNITY TAX BENEFITS

The proposed Louisiana Green Fuels biorefinery and power plant will bring good paying permanent and construction jobs to Caldwell Parish and the surrounding parishes. The company estimates that the plant will have 151 onsite full-time employees once it is operational. This in turn is expected to create over 700 additional full-time indirect jobs in Caldwell Parish and the surrounding region. Long term employment opportunities include the need for unskilled labor, technicians, operators, maintenance, engineers, and plant managers. During the construction phase of the Project, the company expects to create an average of 635 construction jobs. These construction jobs will employ many workers from the local community and the surrounding areas. The proposed Louisiana Green Fuels plant will also invigorate the regional logging industry, requiring the delivery of over 200 truckloads per day of feedstock for the combined biorefinery and power plant.

The economic benefits to the local communities and the tax base will be transformative. Notwithstanding the tax incentives currently in place, it is estimated that the tax benefits produced once the plant is operational will be reflected by an almost doubling of the tax income to the Parish, and consequently, the local school budgets. This tax benefit should only increase over time.

REFERENCES

Adams, R.L. and Carr, J.P., 2010, Regional depositional systems of the Woodbine, Eagle Ford, and Tuscaloosa of the U.S. Gulf Coast, Gulf Coast Association of geological Societies Transactions, v. 60, p. 3-27

Adkins, W. S., 1933, The Mesozoic systems in Texas, The geology of Texas; v. 1, Stratigraphy; University of Texas Bulletin 3232 p. 239-517

Archie, G. E., 1942, The electrical resistivity log as an aid in determining some reservoir characteristics, Petroleum Transactions of the AIME, v. 146, p. 54-62.

Aronow, S. and Wesselman, J. B., 1971, Groundwater Resources of Chambers and Jefferson Counties, Texas: Texas Water Development Board Report No. 133.

Aumman, H. H., 1966, Experimental study of the effect of stress on the creep in shales: Exxon Production Research Report, (private communication to R. E. Collins, DuPont consultant)

Baria, L. R., Stoudt, D. L., Victoria, P. M. and Crevello, P. D., 1982, Upper Jurassic reefs of Smackover Formation, United States Gulf Coast: Am. Assoc. Petroleum Geologists Bull., v. 66, n. 10, p. 1449-1482.

Bentley, C. B., 1983, Preliminary Report of the Geohydrology Near Cypress Creek and Richton Salt Domes, Perry County, Mississippi: Water-Resources Investigations Report 83-4169, U. S. G. S., Jackson, MS.

Berg, R. B. and Cook, B. C., 1968, Petrography and origin of Lower Tuscaloosa sandstones, Mallalieu Field, Lincoln County, Mississippi: Gulf Coast Association of Geological Societies Transactions, v. 18, 242-255.

Bethke, C. M., Harrison, W. J., Upson, C. and Altaner, S. P., 1988, Super computer analysis of sedimentary basins: Science, v. 239, Washington, D. C.

Bornhauser, M., 1960, Depositional and structural history of Northeast Hartburg field, Newton County, Texas: AAPG Bulletin, v. 44, no. 4, p. 458-470

Bowden R K, Curran J H, 1984. Time-dependent behaviour of joints in Shale. In: Dowding C H, Singh M M (eds). Rock mechanics in productivity and production: proceedings of the 25th U.S. Symposium on Rock Mechanics, Northwestern University, Evanston, Illinois, 25–27 June 1984. Littleton: Society of Mining Engineers, pp 320–327.

Bredehoeft, J.D., & Pinder, G.F., 1970, Digital Analysis of Areal Flow in Multiaquifer Groundwater Systems: A Quasi Three-Dimensional Model. Water Resources Research, 6, 883-888.

Brendsdal, A.O.E., 2017, The capacity of creeping shale to form an annular barrier, Master Thesis, Norwegian University of Science and Technology, Department of Geoscience and Petroleum.

Caughey, C. A., 1977, Depositional systems of the Paluxy Formation, The University of Texas at Austin, Bureau of Economic Geology Geological Circular 77–8.

Chang, C. and Zoback, M.D., 2009, Viscous creep in room-dried unconsolidated Gulf of Mexico shale (I): Experimental results. Journal of Petroleum Science and Engineering, 69, 239-246

Chasteen, H. R., 1983, Reevaluation of the lower Tuscaloosa and Dantzler Formations Mid-Cretaceous with emphasis on depositional environments and time-stratigraphic relationships: Gulf Coast Association of Geological Societies Transactions, v. 33, 31-40

Chen-Charpentier, B. and Herrera I.R., 1982, Numerical Treatment of Leaky Aquifers in the Short Time Range. Water Resources Research. 18. 557-562

Clark, J. E., 1987, Groundwater flow in deep saline aquifers: Special Session on the Hydrologic and Geochemical Processes Involved in Deep Injection of Liquid Wastes, Groundwater Committee of the American Geophysical Union and the International Association of Hydrogeologists, Baltimore, Maryland.

Clark, J. E., Howard, M. R., and Sparks, D. K., 1987, Factors that can Cause Abandoned Wells to Leak as Verified by Case Histories from Class II injection, Texas Railroad Commission files: International Symposium on Subsurface Injection of Oilfield Brines, Underground Injection Practices Council, New Orleans, LA., p. 166-223.

Clark, J. E., 1988, Groundwater flow in deep saline aquifers: Special Session on the Hydrologic and Geochemical Processes Involved in Deep Injection of Liquid Wastes, Groundwater Committee of the American Geophysical Union and the International Association of Hydrogeologists, Baltimore, Maryland.

Clark, W. J., 1995, Depositional environments, diagenesis and porosity of Upper Cretaceous volcanic-rich Tokio sandstone reservoirs, Haynesville field, Claiborne Parish Louisiana: Transactions—Gulf Coast Association of Geological Societies, v. 45, p. 127–134.

Clark J. E., Bonura, D. K., Papadeas, P. W., McGowen, R., 2005, Gulf Coast Borehole-Closure-Test Well Near Orange, Texas: Developments in Water Science, v. 52, p. 157-166.

Clifford, H. J., 1973, Hydrodynamics of the Mt. Simon Sandstone, Ohio and Adjacent Areas: in Underground Waste Management and Artificial Recharge Vol. l, American Association of Petroleum Geologists, Tulsa, OK.

Clifford, H. J., 1975, Subsurface Liquid Waste Injection in Ohio: Ohio Geological Survey Information Circ., n. 43.

Collier, A.L and Sargent, B.P., 2015, Water use in Louisiana 2015, Department of Transportation and Development, Water Resources Special Report No. 18

Collins, R. E., 1986, Potential Breaches in the Confining Layer Near Injections Wells on the Gulf Coastal Plain. Report to E.I. du Pont de Nemours & Co. Inc.

Davis, K. E., 1986, Factors Effecting the Area of Review for Hazardous Waste Disposal Wells: Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Association, Dublin, OH, p. 148-194.

Davis, S. D., Pennington, W. D. and Carlson, S. M., 1987, A compendium of earthquake activity in Texas: Bureau of Economic Geology Circular, The University of Texas at Austin, Austin, Texas, in press.

Devery, D. M., 1982, Subsurface Cretaceous strata of Mississippi: Mississippi Department of Natural Resources, Bureau of Geology and Energy Resources Information Series, v. 82, no. 1, p. 1–24

Dockery, D. T., 1977, Mollusca of the Moodys Branch Formation, Mississippi. Mississippi Geological, Economic and Topographical Survey, Bulletin 120.

Eaton, B. A., 1969, Fracture Gradient Prediction And its Application in Oilfield Operations, Journal of Petroleum Technology, volume 21: 1353 – 1360.

Ellsworth, W.L., 2013, Injection-induced earthquakes: Science, v.341, p. 6142-6148

Esker, G. C., 1968, Biostratigraphy of the Cretaceous-Tertiary Boundary in the East Texas Embayment Based on Planktonic Foraminifera, LSU Historical Dissertations and These. 1484.

Everett, A. G., Anderson, J. J. and Shakoor, A., 1986, Factors Affecting the Integrity of Confining Beds for Injected Waste Reservoirs: A Review: Underground Injection Committee Modeling Work Group, Chemical Manufacturers Association, Inc., Vol. II, pp 1-60.

Eversull, L.G., 1984, Regional Cross Sections North Louisiana, Louisiana Geological Survey, Folio Series No. 7

Ewing, T. E. and Lopez, J. A., 1991, Principal structural features, Gulf of Mexico basin: in A. Salvador, ed., The Gulf of Mexico Basin: The Geological Society of America, The Geology of North America, v. J., plate 2, 1 sheet.

Ewing, T. E., 2009, The Ups and Downs of the Sabine Uplift and Northern Gulf of Mexico Basin; Jurassic Basement Blocks, Cretaceous Therman Upfits and Cenozoic Flexure: Gulf Coast Association of Geological Societies Transactions, v. 59, p. 253-269

Ewing, T. E. and Galloway, W. E., 2019, Evolution of the Northern Gulf of Mexico Sedimentary Basin, in Miall, A. D., ed., Sedimentary Basins of the United States and Canada, Second Edition: The Netherlands, Elsevier, p. 627-694

Fjær, E., Holt, R. M., Raaen, A., 2008, Chapter 1 – Elasticity: Petroleum Related Rock Mechanics, Second Edition: The Netherlands, Elsevier, p. 1-54

Fogg, G. E. and Kreitler, C. W., 1982, Groundwater hydraulics and hydrochemical facies in Eocene aquifers of the East Texas Basin: University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 127, 75 p.

Fogg, G. E., Seni, S. J. and Kreitler, C. W., 1983, Three-dimensional ground-water modeling in depositional systems, Wilcox Group, Oakwood Salt Dome area, East Texas: Texas Bureau of Economic Geology Report of Investigations 133, Austin, 55 p.

Foote, R.Q., 1984, Open-File Report Vol. 1984 (84-339), Summary report on the regional geology, petroleum potential, environmental consideration for development, and estimates of undiscovered recoverable oil and gas resources of the United States Gulf of Mexico Continental Margin in the area of proposed oil and gas lease sales nos. 81 and 84. US Geological Survey Open-File Report 84-339, p. 1-193.

Forgotson, J. M., 1963, Depositional history and paleotectonic framework of Comanchean Cretaceous Trinity stage, Gulf Coast area: AAPG Bulletin, v. 47, no. 1, p. 69-103.

Frohlich, C., Potter, E., Hayward, C., and Stump, B., 2010, Dallas-Fort Worth earthquakes coincident with activity associated with natural gas production: The Leading Edge, v. 29, p. 270-275.

Galloway, W. E., 1968, Depositional systems of the lower Wilcox Group, north-central Gulf Coast Basin: Gulf Coast Association of Geological Societies Transactions, v. 18, p. 275–289.

Galloway, W. E., Hobday, D. K. and Magara, K., 1982(a), Frio Formation of the Texas Gulf of Mexico Basin-depositional systems, structural framework and hydrocarbon origin, migration, distribution, and exploration potential: Bureau of Economic Geology, Report of Investigations No. 122, The University of Texas at Austin, Austin, Texas, p. 78.

Galloway, W. E., Henry, C. G. and Smith, G. E., 1982(b), Depositional framework, hydrostratigraphy and uranium mineralization of the Oakville sandstone Miocene Texas Coastal Plain: Bureau of Economic Geology, Report of Investigations No. 113, The University of Texas at Austin, Austin, Texas, 59 p.

Galloway, W. E., 1985, Depositional framework of the lower Miocene (Fleming) episode Northwest Gulf Coast Basin: Gulf Coast Association of Geologists Society Transactions, v. 35, pp. 67-73.

Galloway, W. E., 2008, Depositional evolution of the Gulf of Mexico sedimentary basin, in Hsü, K. J., ed., Sedimentary basins of the world, Volume 5, The sedimentary basins of the United States and Canada, Miall, A. D., ed.: The Netherlands, Elsevier, p. 505–549.

Galloway, W. E., Ganey-Curry, P. E., Li, X. and Buffler, R. T., 2000, Cenozoic depositional history of the Gulf of Mexico basin: AAPG Bulletin, v. 84, no. 11, p. 1743-1774.

Galloway, W. E., Whiteaker, T. L. and Ganey-Curry, P., 2011, History if Cenozoic North American Drainage basin evolution, sediment yield and accumulation in the Gulf of Mexico Basin, Geosphere, August 211; v. 7; no. 4; p. 938-

Granata, W.H., 1963, Cretaceous stratigraphy and structural development of the Sabine Uplift Area, Texas and Louisiana: Reference Report of the Shreveport Geological Society, v. 5, p. 50-96.

Gray, G. R., H. C. H. Darley, and W. F. Rodgers, 1980, Composition and Properties of Oil Well Drilling Fluids: Gulf Publishing Company, Houston, Texas.

Gunter, W., Perkins, E. and McCann, T., 1993, Aquifer disposal of CO2-rich gases: Reaction design for added capacity: Energy Conversion and Management. 34. 941-948.

Han, H. X., 2021, Effects of transient borehole deformation on rock stress and rock properties analysis: University of Waterloo Doctoral Thesis

Hantush, M. S., 1964, Hydraulics of Wells: Advances in Hydroscience, Vol. 1, Ed.: V. T. Chow, Academic Press, New York, pp. 281–432.

Hart, B. S., Flemings, P. B., & Deshpande, A., 1995, Porosity and pressure: Role of compaction disequilibrium in the development of geopressures in a Gulf Coast Pleistocene basin. *Geology*, *23*(1), 45-48.

Hearne, J. H. and Lock, B. E., 1985, Diagenesis of the Lower Tuscaloosa as seen in the du Pont de Nemours No. 1 Lester Earnest, Harrison County, Mississippi: Gulf Coast Association of Geological Societies Transactions, v 35, 387-393.

Hiland, P., 2010, Memo to Brian W. Sheron – Director Office of Nuclear Regulatory Research, Subject: Safety/Risk Assessment results for the Generic Issue 199, "Implications of

Updated Probabilistic Seismic Hazard Estimated in Central and Eastern United States on Existing Plants.: see also US Nuclear Regulatory Commission.

Holt, R.M., Larsen, I., Fjær, E. and Stenebraten, J.F., 2020, Comparing mechanical and ultrasonic behaviour of a brittle and a ductile shale: Relevance to prediction of borehole stability and verification of shale barriers, J. of Petroleum Science and Engineering, 187, 106746.

Horton, S., 2012, Disposal of hyrofracking waste fluid by injection into subsurface aquifers triggers earthquake swarm in central Arkansas with potential for damaging earthquake: Seismological Research Letters, v. 83, no. 2, p. 250-260.

Hosford, W. F., 2005, Mechanical Behavior of Materials. United Kingdom: Cambridge University Press.

Hoshino, K., Koide, H., Inami, K., Iwamura, S., Mitsui, S., 1972, Mechanical properties of Japanese Tertiary sedimentary rocks under high confining pressures: Geological Survey of Japan Report 244, 200 p.

Hosman, R.L., Long, A.T., Lambert, T.W., and others, 1968, Tertiary aquifers in the Mississippi embayment, with discussions of quality of the water, by Jeffery, H.G.: U.S. Geological Survey Professional Paper 448-D, 29 p.

Hosman, R. L., 1996, Regional Stratigraphy and subsurface geology of Cenozoic deposits. Gulf Coastal Plain, South-Central United States: U. S. Geological Survey professional paper; 1416-G

Hovorka, S. D. and Nance, H. S., 1994, Dynamic depositional and early diagenetic processes in a deep-water shelf setting, Upper Cretaceous Austin Chalk, north Texas: Transactions—Gulf Coast Association of Geological Societies, v. 44, p. 269–276.

Hovorka, S.D., Tutton, P., and Trevino, R.H., 2018, Feasibility study of CO_2 storage in saline formations in the region of the planned Lake Charles Methanol Plant, Final Report, Gulf Coast Carbon Center, Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin, July 30, 2018.

Iler, R. K., 1979, The Chemistry of Silica: New York, Wiley and Sons, pp. 34-40.

Jackson, M. P. A. and Galloway, W. E., 1984, Structural and depositional styles of Gulf Coast Tertiary continental margins: Application to hydrocarbon exploration: Am. Assoc. Petroleum Geologists, Continuing Education Course Note Series No. 25, p. 147, 215.

Jaeger, J.C., Cook, N.G., and Zimmerman, R.W., 2007, Fundamentals of Rock Mechanics, 4th edition. Blackwell Publishing, Oxford, pp 197-204

John, C.J., Jones, B.L., Moncrief, J.E., Bourgeois, R., Harder, B.J., 1997. An Unproven Unconventional Seven Billion Barrel Oil Resource-The Tuscaloosa Marine Shale. BRI Bulletin. V. 7, pp. 1-22

Johnston, O. C. and Greene, C. J., 1979, Investigation of Artificial Penetrations in the Vicinity of Subsurface Disposal Wells: Texas Department of Water Resources.

Johnston, O. C., and Knape, B. K., 1986, Pressure effects of the static mud column in abandoned wells: Texas Water Commission LP 86-06, 106 p.

Jones, T. A. and Haimson, J. S., 1986, Demonstration of Confinement: An Assessment of Class 1 Wells in the Great Lakes and Gulf Coast Regions: Journal of the Underground Injection Practices Council, Number 1, pp. 279-317.

Kaszuba, J.P., Janecky, D.R. and Snow, M., 2005, Experimental evaluation of mixed fluid reactions between supercritical carbon dioxide and a NaCl brine: relevance to the integrity of a geologic carbon repository. Chemical Geology, vol 217, p 277-293

Kharaka Y.K., Cole D.R., Hovorka S.D., Gunter W.D., Knauss K.G., Freifeld B.M. (2006) Gas–water–rock interactions in Frio Formation following CO2 injection: implications for the storage of greenhouse gases in sedimentary basins. Geology 34(7):577–580

Kidwell, A. L., 1951, Mesozoic igneous activity in the northern Gulf Coastal Plain: GCAGS Trans., v. 1, p. 182-199.

Kose, S. G., 2013, Crustal Architecture, Cretaceous Rise and Igneous Activity of Sabine, Monroe and Jackson Uplifts, Northern Gulf of Mexico Basin, Master's Thesis, University of Houston

Kreitler, C. W., 1986, Hydrogeology of sedimentary basins as it relates to deep-well injection of chemical wastes, Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Assoc., Dublin, Ohio, pp. 398-416.

Kreitler, C. W., Akhter, M. S., Donnelly, A. C. A. and Wood, W. T., 1988, Hydrogeology of formations used for deep-well injection, Texas Gulf Coast: Prepared for the U. S. Environmental Protection Agency under Cooperative Agreement ID No. CR812786-01-0, The University of Texas at Austin, Bureau of Economic Geology Austin, Texas, 215 p.

Kristiansen, T.G., Dyngeland, T., Kinn, S., Flatebø, R. and Aarseth, N.A., 2018, Activating shale to form well barriers: Theory and field examples, SPE-191607-MS.

Lawless, P. N. and Hart, G. F., 1990, The LaSalle Arch and its Effects on Lower Paleogene Genetic Sequence Stratigraphy, Nebo-Hemphill Field, LaSalle Parish, Louisiana. Gulf Coast Association of Geological Societies Transactions, v. 40, p. 459-473

LBNL, 2014, Final report on experimental and numerical modeling activities for the Newark Basin: Lawrence Berkeley National Laboratory, Berkeley California, 130 p.

Ledger, E. B., Tieh, T. T. and Rowe, M. W., 1984, An evaluation of the Catahoula Formation as a uranium source rock in East Texas: Gulf Coast Association of Geologists Society. Transactions, v. 34, pp. 99-108.

Leeds and Associates, 1989, Seismic Effects/DuPont DeLisle Plant, Mississippi.

Leeds and Associates, 1989, Seismic Effects/DuPont Sabine River Works, DuPont Sabine River Work.

Loizzo, M., Lecampion B., Mogilevskaya S., 2017, The role of geological barriers in achieving robust well integrity. Energy Procedia. Pp. 5193-5205

Lowry, P., 1988, Stratigraphic Framework and Sedimentary Facies of a Clastic Shelf Margin: Wilcox Group Paleocene-Eocene, Central Louisiana; Louisiana State University and Agricultural and Mechanical College, PhD Dissertation

Lund Snee, JE., Zoback, M.D., 2020(b), Multiscale variations of the crustal stress field throughout North America. *Nat Commun* **11**, 1951 (2020). https://doi.org/10.1038/s41467-020-15841-5

Mancini, E. A., Mink, R. M., Bearden, B. L. and Wilkerson, R. P., 1985, Norphlet Formation Upper Jurassic of southwestern and offshore Alabama: environments of deposition and petroleum geology: Am. Assoc. Petroleum Geologists Bull., v. 69, n. 6, p. 881-889.

Mancini, E. A., Mink, R. M., Payton, J. W. and Bearden, B. L., 1987, Environments of deposition and petroleum geology of Tuscaloosa Group Upper Cretaceous, South Carlton and Pollard Fields, Southwestern Alabama: American Association of Petroleum Geologists Bulletin, v. 71, 1128-1142.

Martin, A. and Whiteman, C.D., 1985, Geohydrology and regional groundwater flow of the coastal lowlands aquifer system in parts of Louisiana, Mississippi, Alabama, and Florida – a preliminary analysis, U.S. Geological Survey, Water Resources Investigations Report 88-4100

Martin, A. T., 2014, Depositional History and Stratigraphic Framework of Upper Cretaceous Campanian to Maastrichtian Strata in the Minerva-Rockdale Oil Field of Milam County and Adjacent Counties, Texas, Graduate Theses and Dissertations, University of Arkansas, Fayetteville

Matthews, A. C., Weed, S. B., Coleman, N. T.1955, The Effect of Acid and Heat Treatment on Montmorillonite: National Academy of Sciences, Washington DC.

Matthews, W. R. and Kelly, J., 1967, How to predict formation pressure and fracture gradient from electric and sonic logs: The Oil and Gas Journal, Figure 3, ADT 21

McGee, B.D. and Brantly, J.A., 2015, Potentiometric surface, 2012, and water-level differences, 2005–12, of the Sparta Aquifer in north-central Louisiana: U.S. Geological Survey Scientific Investigations Map 3313, 2 sheets

Meckel, T., and Trevino, R., 2014, Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect: Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin.

Meckel, T.A., Nicholson, A.J., and Trevino, R.H., 2017, Capillary Aspects of Fault-Seal Capacity for CO2 Storage, Lower Miocene, Texas Gulf of Mexico", in Geological CO_2

Sequestration Atlas of Miocene Strata, Offshore Texas State Waters, Bureau of Economic Geology, 2017.

Miller, C., Hales C., Clark, J. E. and Collins, G., 1989, Density drive flow near salt domes: Underground Injection Practices Council Winter Meeting, San Antonio, Texas

Murray, 1957, Hydrocarbons in Gulf Coastal Province of the United States: Gulf Coast Association of Geological Societies, Transactions, Vol. VII, and p. 254.

National Academies of Sciences, Engineering, and Medicine, 2019, Sequestration of Supercritical CO2 in Deep Sedimentary Geological Formations; Synthesis in Negative Emissions Technologies and Reliable Sequestration: A Research Agenda, Washington, DC: The National Academies Press. pp. 319 – 401

Nealon, D. J., 1982, A Hydrological Simulation of Hazardous Waste Injection in Mt. Simon, Ohio: Ohio State University, Master's Thesis, 279 p.

Neuman, S. P. and Witherspoon, P. A., 1969a, Theory of flow in a confined two aquifer system, Water Resources. Res., 5, 4, 803-816.

Neuzil, C. E., 1986, Groundwater flow in low permeability environments: Water Resources Research, v. 22, no. 8, p. 1163-1195

Nicholson, A., J., 2012, Empirical Analysis of Fault Seal Capacity for CO_2 sequestration, Lower Miocene, Texas Gulf Coast: Master's Thesis, The University of Texas at Austin, 100 p.

Nunnally, J.D. and Fowler, H.F., 1954, Lower Cretaceous Stratigraphy of Mississippi; Mississippi Geological Survey, Bulletin 79, 45 p.

Ohio Department of Natural Resources, 2012, Executive Summary: Preliminary report on the Northstar I Class II injection well and the seismic events in the Youngstown, Ohio area: State Report, p 1- 23, Columbus, Ohio.

Ostermeier, R. M. 2001, Compaction effects on porosity and permeability: Deepwater Gulf of Mexico turbidite. Journal of Petroleum Technology, 53(02), 68-74.

Paine, W. R., 1968, Stratigraphy and sedimentation of subsurface Hackberry wedge and associated beds of southwestern Louisiana: AAPG Bulletin, v. 52, no. 2, p. 322-342

Paine, W.R., and Meyerhoff, A.A, 1968, Catahoula Formation of western Louisiana and thin-section criteria for fluviatile depositional environment, Journal of Sedimentary Research, v.38(1), p. 92-113

Pair, Jessica D., 2017, The Tuscaloosa Marine Shale: Geologic History, Depositional Analysis, and Exploration Potential. Electronic Theses and Dissertations. 68.

Pan, P., Wu, Z., Feng, X. and Yan, F., 2016, Geomechanical modeling of CO_2 geological storage: A review. Journal of Rock Mechanics and Geotechnical Engineering, 8, p. 936-947

Paulson Jr, O. L. 1972, Various factors influence Wilcox deposits in the Golden Triangle. Oil Gas Journal.; United States, vol. 70(25), p 86

Payne, J. N., 1968, Hydrologic significance of the lithofacies of the Sparta Sand in Arkansas, Louisiana, Mississippi, and Texas: USGS Professional Paper 569-A, p. 17

Payne, J. N., 1972, Hydrogeologic significance of lithofacies of the Cane River Formation or equivalents of Arkansas, Louisiana, Mississippi, and Texas: Geological Survey Professional Paper 569-C, 17 p

Poulsen, S. E., Nielsen, S. B., Balling, N., 2012, Estimating the equilibrium formation temperature in the presence of bore fluid invasion, Geophysical Journal International, vol. 190, Issue 3, pp. 1551–1561.

Prakken, L., and White, V. 2014, Water Resources of Caldwell Parish, Louisiana: U.S. Geological Survey Fact Sheet 2014-3044, 6p.

Rainwater, E. H., 1964, Regional stratigraphy of the Gulf Coast Miocene: GCAGS Trans., v. 14, p. 81-124.

Rainwater, E. H., 1964(a), Regional Stratigraphy of the Midway and Wilcox in Mississippi: Mississippi Geological Economic and Topographical Survey, Bulletin No. 102, 9-31 pp.

Rollo, J.R., 1960, Ground water in Louisiana: Louisiana Department of Conservation and Department of Public Works, Water Resources Bulletin 1, 84 p

Ryals, G.N., 1984, Regional geohydrology of the northern Louisiana salt dome basin, part II, geohydrology maps of the tertiary aquifers and related confining layers; U.S. Geological Survay, Water-Resources Investigations Report 83-4135

Salvador, A., 1991, Triassic–Jurassic, in A. Salvador, ed., The Gulf of Mexico basin: Boulder, Colorado, Geological Society of America, The Geology of North America, v. J, p. 131–180.

Schlumberger, 1987, Log Interpretation Principles/Applications: Schlumberger Educational Services, Houston, Texas, 198 p.

Schlumberger, 1988, Archie's Law: Electrical conduction in clean, water-bearing rock: The Technical Review, v. 36, n. 3, Schlumberger Educational Services, Houston, Texas, p. 4-13.

Shirley, K., 1987, Valuable tool for Tuscaloosa; trend spins seismic success story: American Association of Petroleum Geologists Explorer, v. 8, no. 10, p. 14,25.

Simandoux, P., 1963, Dielectric measurements of porous media: application to measurement of water saturations, study of the behavior of argillaceous formations: Revue de L'Institut Français du Petrole 1B, Supplementary Issue, p. 193-215.

Skoumal, R. J., Ries, R., Brudzinski, M., Barbour, A., & Currie, B. 2018, Earthquakes induced by hydraulic fracturing are pervasive in Oklahoma. Journal of Geophysical Research, 123, pp. 10,918– 10,935.

Skoumal, R. J., Kaven J. O., Barbour A. J., Wicks, C., Brudzinski M. R., Cochran E. S., Rubinstein, J. L., 2021, The Induced Mw 5. 0 March 2020 West Texas Seismic Sequence: JGR Solid Earth, Volume 126, Issue 1, p. 17.

Slaughter, G.M., 1981, Analysis of ground-water flow times near seven salt domes in the Gulf Interior Region: Prepared by Law Engineering Testing Company for Battelle Memorial Institute, Office of Nuclear Waste Isolation, 88 p

Sone, H. and Zoback, M., 2013, Mechanical properties of shale-gas reservoir rocks — Part 2: Ductile creep, brittle strength, and their relation to the elastic modulus. Geophysics, Vol. 78, No. 5 (September-October 2013); p. D393–D402.

Spooner, H. V., 1964, Basal Tuscaloosa sediments, east-central Louisiana: American Association of Petroleum Geologist Bulletin, v. 48, p. 1-21

Stancliffe, R. J. and Adams, R. E. 1986, Lower Tuscaloosa fluvial channel styles at Liberty Field, Amite County, Mississippi: Transactions - Gulf Coast Association of Geological Societies., v. 36, 305-313

Stevenson, D., and Agnew J. D., 1988, Lake Charles, Louisiana, Earthquake of 16 October 1983: Bulletin of the Seismological Society of America, Vol. 78, No. 4, pp. 1463-1474

Stolper, K., 1994, Calculate a More Accurate Water Salinity by Visually Estimating "m": Houston Geological Society Bulletin, September 1994, p. 34.

Talman, S., 2015, Subsurface geochemical fate and effects of impurities contained in a CO2 stream injected into a deep saline aquifer: What is known: International Journal of Greenhouse Gas Control 40, p. 267 - 291.

Todd, E. G. and Mitchum, R. M., 1977, Seismic sequences and global changes in sea level, part 8: Identification of Upper Triassic, Jurassic, and Lower Cretaceous seismic sequences in Gulf of Mexico and offshore West Africa: in Seismic Stratigraphy – Applications to Hydrocarbon Exploration , Payton, C. E., ed., American Association of Petroleum Geologists Memoir 26, p. 145-163.

Turner, R., 1964, Kinetic studies of Acid Dissolution of Montmorillonite and Kaolinite: Ph.D. thesis, Univ. of Calif. Davis, p. 140.

Vail, P. R., Mitchum, R. M. and Thompson, S., 1977, Seismic stratigraphy and global changes in sea-level, Part 4: global cycles of relative changes in sea-level, in Seismic Stratigraphy-Applications to Hydrocarbon Exploration, Payton, C. E., ed., American Association of Petroleum Geologists Memoir 26, pp. 83-98.

Walkinshaw, S., 2020, The Lower Smackover Brown Dense Limestone: Its Potential as a Hybrid Unconventional Resource Play, extended abstract and oral presentation, 2020 GeoGulf Convention (October 2020), Lafayette, Louisiana

Warner, D. L., 1988, Abandoned oil and gas industry wells and their environmental implications: Underground Injection Practices Council, 1988 Summer Meeting; prepared for the American Petroleum Institute, pp. 69-90.

Warner, D. L. and Syed, T., 1986, Confining layer study-supplemental report: prepared for U. S. EPA Region V, Chicago, Illinois.

Weingarten, M., Ge S., Godt, J. W., Bekins B. A. and Rubinstein, J. L., 2015, High-rate injection is associated with the increase in U. S. mid-continent seismicity: Science vol. 348, Issue 6241, pp. 1336-1340.

Wesson, R. L., and Nicholson, C., 1987, Earthquake hazard associated with deep well injection: U.S. Geological Survey Open-File Report 87-331, p. 108

Whitfield, M.S., Jr., 1975, Geohydrology and water quality of the Mississippi River alluvial aquifer, northeastern Louisiana: Louisiana Department of Public Works Water Resources Technical Report no. 10, 29 p.

Williams S., Carlsen T., Constable K., Guldahl A., 2009, Identification and qualification of shale annular barriers using wireline logs, presentation for SPE/IADC Drilling Conference and Exhibition, Amsterdam, The Netherlands, p. 20.

Wood, D. H. and Guevara, E. H., 1981, Regional Structural cross sections and general stratigraphy, East Texas basin: University of Texas at Austin, Bureau of Economic Geology, 21 p.

Zhang, J. and Roegiers, J. C., 2010, Integrating borehole-breakout dimensions, strength criteria and leak-off test results, to constrain the state of stress across the Chelungpu Fault, Taiwan. Tectonophysics, Volume 492, Issues 1-4, p. 295–298.

Zoback, M. L. and Zoback, M., 1980, State of Stress in the Conterminous United States. Journal of Geophysical Research, v. 85, no. B11, pp. 6113-6156