Underground Injection Control – Class VI Permit Application
for
Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

Prepared for
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Spring, TX

By
Lonquist Sequestration, LLC
Austin, TX

July 2023

FOREWORD

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) plans to develop a carbon sequestration facility in Vermilion Parish, Louisiana. The Pecan Island Carbon Capture and Sequestration (CCS) Project will collect concentrated carbon dioxide streams from third-party atmospheric emission points in southern Louisiana and route them to a suitable long-term sequestration site. This site is ideally suited for the sequestration of CO_2 with thick intervals of stacked sand and shale sequences of Miocene-aged rock that are high in porosity and permeability. Additionally, ExxonMobil wholly owns the Pecan Island acreage for surface, pore space, and minerals.

The following application will fully detail and characterize the geology of the proposed well locations, evaluate the formations for properties necessary to contain the sequestered CO_2 permanently, and describe the engineering design and safety considerations for both well. The application will also discuss the proposed monitoring system that will be used to compare actual injectate plume migration to reservoir modeling and simulation of the anticipated plume.

The application has been developed to meet all the requirements of both Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82** through **§146.95** and the Louisiana Code LAC 43:XVII Chapter 6, Statewide Order (SWO) 29-N-6. Both codes detail the regulations for Underground Injection Control Class VI wells. Once the permit has been issued, in accordance with the requirements of 40 CFR **§144.36(a)** and SWO 29-N-6 **§3607.M.1,** the permit will be updated every five years thereafter for the active injection life of the wells.

CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

27 JULY 2023

Edward E. Graham
Vice President, ExxonMobil Low Carbon Solutions,
New Assets

CERTIFIED BY:
Lonquist Sequestration, LLC
Louisiana Registration No. EF7423

I, William H. George, certify that this application was prepared by me or under my direct supervision and that the information and analyses presented herein are true and accurate to the best of my knowledge.

William H. George, P.E.
Vice President/Principal Engineer
Louisiana License No. 45286
Date Signed: 07/25/2023

CERTIFIED BY:
Lonquist Sequestration, LLC
Louisiana Registration No. EF7423

I, Stephen L. Pattee, certify that this application was prepared by me or under my direct supervision and that the information and analyses presented herein are true and accurate to the best of my knowledge.

Stephen L. Pattee, P.G.
Vice President/Regulatory Manager
Louisiana License No. 1001
Date Signed: 07/25/2023

ELECTRONIC VERSION CERTIFICATION

This document is an electronic version of the application titled "Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002" dated July 28, 2023. This electronic version is an exact duplicate of the paper copy submitted in three volumes to the Louisiana Office of Conservation.

Stephen L. Pattee, P.G.
Vice President / Regulatory Manager
Louisiana License No. 1001

ACRONYMS AND ABBREVIATIONS

Note: All terms are written as used in the text.

§45Q	IRS Tax Code §45Q
AAPG	American Association of Petroleum Geologists
AOR	area of review
API	American Petroleum Institute
ASCII	American Standard Code for Information Interchange
ASTM	American Society for Testing and Materials
AZMI	above-zone monitoring interval
bbl	barrel(s)
BHP	bottomhole pressure
bp	bridge plug
bph	barrels per hour
bpm	barrels per minute
CBG	Cell Block Group
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and sequestration
CEQ	Center for Environmental Quality
Chicot EAS	Chicot Equivalent Aquifer System
CFR	U.S. Code of Federal Regulations
CIL	casing inspection log
CMG	Computer Modelling Group
DAS	distributed acoustic sensing
DSA	double-studded adaptor
DTS	distributed temperature sensing
DV	diverter valve
EEHC	Exxon Equity Holding Company

EJ	environmental justice
EOS	equation of state
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
GHG	greenhouse gas emissions
GR	gamma ray
GS	geologic sequestration
HDIL	high-definition induction log
HNBR	hydrogenated nitrile rubber
ID	inner diameter
ILD	deep induction log
IMD	Injection and Mining Division
kb	kelly bushing
kbd	thousand barrels per day
LAS	Log *American Standard Code for Information Interchange* (ASCII) Standard
lbm	pounds per square mass
LCZ	lower confining zone
LDNR	Louisiana Department of Natural Resources
LEPC	Local Emergency Planning Committee
LWIA	Legacy Wells Integrity Assessment
mD	millidarcy
MD	measured depth
mg/l	milligrams per liter
Mgal/d	million gallons per day
MIT	mechanical integrity test
MMI	Modified Mercalli Intensity
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
MT	metric tons

MT	metric tons
MMT/yr	million metric tons per year
MMTA	million metric tons annually (or per annum)
MWD	measurement while drilling
m.y.	million year
NGVD 29	National Geodetic Vertical Datum of 1929
NEPA	National Environmental Policy Act
NRC	National Response Center
NSHM	National Seismic Hazard Model
OBM	oil-based mud
OD	outer diameter
OEC	other end connector
OH	open hole
P&A	plug and abandonment
PBTD	plugged back total depth
PHIT	total porosity
PISC	post-injection site care
P&M	preventive and mitigative
ppg	pounds per gallon
ppm	parts per million
ppmv	parts per million by volume
psi	pounds per square inch
psia	pounds per square inch absolute
PSDM	Pre-Stack Depth Migration
PSTM	Pre-Stack Time Migration
P/T	pressure/temperature
QA/QC	quality assurance/quality control
RAPID	Reservoirs Applied Petrophysical Integrated Data
RDT	Reservoir Description Tool

RSWC	rotary sidewall core
SAU	storage assessment unit
SCADA	Supervisory Control and Data Acquisition
scf/D	standard cubic feet per day
SIC	Standard Industrial Classification
SHmax	maximum horizontal stress
SMCL	Secondary Maximum Contaminant Level
SONRIS	Strategic Online Natural Resources Information System
SOW	slip-on weld
SP	spontaneous potential
SPE	Society of Petroleum Engineers
SRK	Soave-Redlich-Kwong (method)
SWO	Statewide Order
TD	total depth
TDS	total dissolved solids
TEC	tubing encapsulated conductor
Title 40	U.S. Code of Federal Regulations, Title 40
TOC	top of cement
TVD	true vertical depth
TVDSS	true vertical depth subsea
UCZ	upper confining zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
VSP	vertical seismic profile
WAG	water-alternating-gas
WHP	wellhead pressure
XOM-RQFM	ExxonMobil Reservoir Quality Forward Model
XRD	X-Ray Diffraction

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82	Required Class VI permit information			
		§3605.G	Certification. Any person signing a document under §3605.E shall make the following certification on the application: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.”	Master Documents
		§ 3605.C.1.b	the electronic version of the application shall contain the following certification statement: This document is an electronic version of the application titled (Insert Document Title) dated (Insert Application Date). This electronic version is an exact duplicate of the paper copy submitted in (Insert the Number of Volumes Comprising the Full Application) to the Louisiana Office of Conservation.	Electronic Document Certification
§146.91(e)	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	§3629.A.3	Regardless of whether the State of Louisiana has primary permit and enforcement authority (primacy) for Class VI wells, owners or operators of Class VI wells, or applicants for Class VI wells must submit all required submittals, reports, and notifications under §§3605, 3607, 3615, 3617, 3619, 3621, 3623, 3625, 3627, 3629, 3631, and 3633 to the USEPA in an electronic format approved by the USEPA.	Electronic Document Certification

Introduction

§146.82(a)(1)	Information required in §144.31(e)(1) through (6) of this chapter;			#N/A

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§144.31(e)(8)	A brief description of the nature of the business.	§3607.B.6	a brief description of the nature of the business associated with the activity;	Introduction (Project Overview & Injectate Information)
§144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§3607.B.7	the activity or activities conducted by the applicant which require the applicant to obtain a permit under these regulations;	Introduction (Project Overview and Additional Permits)
§146.82(a)(7)(iii)	The source(s) of the carbon dioxide stream; and	§3607.C.2.f.iii	source(s) of the carbon dioxide stream; and	Introduction (Project Overview)
§146.82(a)(7)(iv)	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	§3607.C.2.f.iv	analysis of the chemical and physical characteristics of the carbon dioxide stream.	Introduction (Injectate Information)
§144.31(e)(2)	Name, mailing address, and location of the facility for which the application is submitted.	§3607.B.3	the name and mailing address of the applicant and the physical address of the sequestration well facility;	Introduction (General Application Information)
§144.31(e)(3)	Up to four SIC codes which best reflect the principal products or services provided by the facility.	§3607.B.8	up to four SIC Codes which best reflect the principal products or services provided by the facility;	Introduction (General Application Information)
§144.31(e)(4)	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	§3607.B.4	the operator's name, address, telephone number, and email address;	Introduction (General Application Information)

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§144.31(e)(5)	Whether the facility is located on Indian lands.	§3607.B.10	acknowledgment as to whether the facility is located on Indian lands or other lands under the jurisdiction or protection of the federal government, or whether the facility is located on state water bottoms or other lands owned by or under the jurisdiction or protection of the state of Louisiana;	Intro (General Application Information)
§144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§3607.B.7	the activity or activities conducted by the applicant which require the applicant to obtain a permit under these regulations;	Introduction (Additional Permits)
§144.31(e)(6)	A listing of all permits or construction approvals received or applied for under any of the following programs:	§3607.B.9	a listing of all permits or construction approvals that the applicant has received or applied for under any of the following programs or which specifically affect the legal or technical ability of the applicant to undertake the activity or activities to be conducted by the applicant under the permit being sought:	Introduction (Additional Permits)
§144.31(e)(6)(i)	Hazardous Waste Management program under RCRA.	§3607.B.9.a	the Louisiana Hazardous Waste Management;	Introduction (Additional Permits)
§144.31(e)(6)(ii)	UIC program under SDWA.	§3607.B.9.b	this or any other underground injection control program;	Introduction (Additional Permits)
§144.31(e)(6)(iii)	NPDES program under CWA.	§3607.B.9.c	NPDES program under the Clean Water Act;	Introduction (Additional Permits)
§144.31(e)(6)(iv)	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§3607.B.9.d	prevention of significant deterioration (PSD) program under the Clean Air Act;	Introduction (Additional Permits)
§144.31(e)(6)(v)	Nonattainment program under the Clean Air Act.	§3607.B.9.e	nonattainment program under the Clean Air Act;	Introduction (Additional Permits)
§144.31(e)(6)(vi)	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.	§3607.B.9.f	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act;	Introduction (Additional Permits)
§144.31(e)(6)(vii)	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.	§3607.B.9.g	ocean dumping permit under the Marine Protection Research and Sanctuaries Act;	Introduction (Additional Permits)
§144.31(e)(6)(viii)	Dredge and fill permits under section 404 of CWA.	§3607.B.9.h	dredge or fill permits under section 404 of the Clean Water Act; and	Introduction (Additional Permits)
§144.31(e)(6)(ix)	Other relevant environmental permits, including State permits.	§3607.B.9.i	other relevant environmental permits including, but not limited to any state permits issued under the Louisiana Coastal Resources Program, the Louisiana Surface Mining Program or the Louisiana Natural and Scenic Streams System;	Introduction (Additional Permits)

Section 1 - Site Characterization & Appendix B, C

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82(a)(3)	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	§3607.C.1.b	information on the geologic structure and hydrogeologic properties of the proposed sequestration site and overlying formations, to include:	Sections 1.2, 1.3, 1.8,1.10, 1.11, App B
§146.82(a)(3)(ii)	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	§3607.C.1.b.iii	the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Section 1.10, 2.4.2, Appendix I
§146.82(a)(3)(iii)	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	§3607.C.2.a	data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions	Sections 1.3, Appendix B
§146.82(a)(3)(iv)	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	§3607.C.2.b	geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	
§146.82(a)(3)(v)	Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	§3607.C.2.c	information on the region’s seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Section 1.10
§146.82(a)(3)(vi)	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	§3607.C.1.b.i	geologic and topographic maps and cross-sections illustrating regional geology, geologic structure, and hydrology.	Sections 1.3, 1.8, 3.3, App B1-B5
§146.82(a)(5)	Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	§3607.C.2.d.iv	maps and stratigraphic cross-sections showing the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their position relative to the injection zone(s) and the direction of water movement, if known	Sections 1.8, 3.3.4
§146.82(a)(6)	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	§3607.C.2.e	baseline geochemical data on subsurface formations, including injection zones, confining zones and all USDWs in the area of review;	Section 1.6, 1.7, 1.8, 4.2, App E
§146.83(a)	Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	§3615.A	Minimum Criteria for Siting. Applicants, owners, or operators of Class VI wells must demonstrate to the satisfaction of the commissioner that the wells will be sited in areas with a suitable geologic system. The demonstration must show that the geologic system comprises:	Sections 1.5, 1.11, 2.2.1, 2.4.3, 2.5.2, 2.6, 2.7.1, 2.8, 2.9
§146.83(a)(1)	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	§3615.A.1	an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Sections 1.3.1, 1.3.4, 1.77, 3.1, App B

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.83(a)(2)	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	§3615.A.2	confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids, and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Sections 1.3, 1.4, 1.5, App B
§146.83(b)	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	§3615.A.2.a	The commissioner may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	
§146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	§3615.B.3	Area of Review Boundary Delineation. Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	
§146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§3615.B.3.a	predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the commissioner. The model must:	Section 0, 2.8, 2.9, 2.10, 3.3, 3.4, 3.5, 5.5.5,App C
§146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§3615.B.3.a.i	be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Section 1.3.4, Appendix B
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	§3617.A.2.a.vii	lithology of injection and confining zone(s);	Section 1.3.3

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(c)(1)(vii)	A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	§3633.A.3.a.vii	a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	Section 1.3, 1.7, 1.10, 1.11
§146.93(c)(1)(x)	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	§3633.A.3.a.x	the distance between the injection zone and the nearest USDW above the injection zone; and	Section 1.8.1, 1.83, 7.4, App B-19 and B20

Section 2 - Plume Model

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.84(a)	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	§3615.B.1	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data	Sections 2.9, 2.10, 3.2, 3.3.2
§146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	§3615.B.3	Area of Review Boundary Delineation. Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	
§146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§3615.B.3.a	predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the commissioner. The model must:	Section 2.8.1.1, Section 3.2, Section 3.3.2
§146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§3615.B.3.a.i	be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	Sections 2.4 - 2.5, Section 3.3.3

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Sections 2.4 - 2.5
§146.93(c)(1)(iii)	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	§3633.A.3.a.iii	the predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	Section 2.8.1.1, Section 3.2, Section 3.3.2
§146.93(c)(1)(iv)	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	§3633.A.3.a.iv	a description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	Section 2.3

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(c)(1)(v)	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	§3633.A.3.a.v	the predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	Section 2.3
§146.82(a)(7)(ii)	Average and maximum injection pressure;	§3607.C.2.f.ii	average and maximum injection pressure;	Section 2.7.1, Tables 2-9 - 2-10, Figures 2-32 - 2-35

Section 3 - AOR & Appendix C

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82(a)(1)	Information required in § 144.31(e)(1) through (6) of this chapter;	§3607.B.12	names and addresses of all property owners within the area of review of the Class VI well or project.	Appendix A
§146.82(a)(2)	A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	§3607.C.1	Maps and Related Information	Appendix C
§146.82(a)(2)		§3607.C.1.a	map(s) showing property boundaries of the facility, the location of the proposed Class VI well, and the applicable area of review consistent with §3615.B and §3615.C. USGS topographic maps with a scale of 1:24,000 may be used. The map boundaries must extend at least two miles beyond the area of review and include as applicable:	Appendix C
§146.82(a)(2)		§3607.C.1.a.i	the section, township and range of the area where the activity is located and any parish, city, municipality, state, and tribal boundaries	Appendix C
§146.82(a)(2)		§3607.C.1.a.ii	within the area of review, the map(s) must identify all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or USEPA-approved subsurface cleanup sites, surface bodies of water, springs, surface and subsurface mines, quarries, water wells, other pertinent surface features including structures intended for human occupancy, and roads.	Appendix C-6
§146.82(a)(2)		§3607.C.1.a.iii	only information of public record is required to be included on the map(s), however, the applicant is required to make a diligent search to locate all wells not listed in the public record.	Section 3.3.4

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§146.82(a)(2)	map;	§3607.C.1.a.iv	for water wells on the facility property and adjacent property, submit a tabulation of well depth, water level, owner, chemical analysis, and other pertinent data. If these wells do not exist, submit this information for a minimum of three other wells in the area of review or a statement why this information was not included	Section 3.3.4
§146.82(a)(2)		§3607.C.1.a.v	the protocol followed to identify, locate, and ascertain the condition of all wells within the area of review that penetrate the injection or confining zone.	Section 3.3.4
§146.82(a)(3)(i)	Maps and cross sections of the area of review;			
§146.82(a)(4)	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	§3607.C.2.d	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	Appendix C8.5, C10.5, C12.5
§146.82(a)(13)	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	§3607.C.2.l	proposed area of review and corrective action plan that meets the requirements under §3615.B and §3615.C;	Section 3.4
§146.82(a)(20)	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	§3607.C.2.s	a list of contacts, submitted to the commissioner for those states and tribes identified to be within the area of review based on information provided in §3607.C.1.a.i; and	Section 8.6
§146.84(a)	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	§3615.B.1	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data	Sections 2.9-2.10, Section 3.2, Section 3.3.2

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§146.84(b)	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	§3615.B.2	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for the proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of these regulations and is acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application, the owner or operator must submit an area of review and corrective action plan that includes the following information:	Section 3.2, Section 3.3.2, Section 3.5.1
§146.84(b)(1)	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	§3615.B.2.a	the method for delineating the area of review that meets the requirements of §3615.B.3, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sections 2.4 - 2.5, Section 3.3.4, Section 3.4, Appendix C2 - C5
§146.84(b)(2)	A description of:	§3615.B.2.b	a description of:	N/A
§146.84(b)(2)(i)	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	§3615.B.2.b.i	the minimum fixed frequency—not to exceed five years—at which the owner or operator proposes to reevaluate the area of review;	Section 3.5.1
§146.84(b)(2)(ii)	The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	§3615.B.2.b.ii	the monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in §3615.B.2.b.i.	Section 3.5.1
§146.84(b)(2)(iii)	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	§3615.B.2.b.iii	how monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	Section 3.5.1

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§146.84(b)(2)(iv)	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§3615.B.2.b.iv	how corrective action will be conducted to meet the requirements of §3615.C, including what corrective action will be performed prior to injection and what, if any, portions of the area of review the operator proposes to have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	Section 3.4
§146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	§3615.B.3	Area of Review Boundary Delineation. Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	
§146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§3615.B.3.a	predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the commissioner. The model must:	Section 2.8.1.1, Section 3.2, Section 3.3.2
§146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§3615.B.3.a.i	be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	Sections 2.4 - 2.5, Section 3.3.3
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Sections 2.4 - 2.5

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§146.84(c)(1)(iii)	Consider potential migration through faults, fractures, and artificial penetrations	§3615.B.3.a.iii	consider potential migration through faults, fractures, and artificial penetrations.	Section 2.4
§146.84(c)(2)	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	§3615.B.3.b	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	Section 3.3.4, Section 3.4, Appendix C2 - C5
§146.84(c)(3)	Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	§3615.B.3.c	determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	Section 3.4
§146.84(d)	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	§3615.C.1	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	Section 3.4

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§146.84(e)	At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	§3615.C.2	At the minimum fixed frequency—not to exceed five years—as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	Section 3.5.1
§146.84(e)(1)	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	§3615.C.2.a	reevaluate the area of review in the same manner specified in §3615.B.3.a;	Section 3.5.1
§146.84(e)(2)	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	§3615.C.2.b	identify all wells in the reevaluated area of review that require corrective action in the same manner specified in §3615.B.3;	
§146.84(e)(3)	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	§3615.C.2.c	perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in §3615.C.1; and	
§146.84(e)(4)	Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§3615.C.2.d	submit an amended area of review and corrective action plan or demonstrate to the commissioner through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate.	
§146.84(g)	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	§3615.C.4	All modeling inputs and data used to support area of review reevaluations under §3615.C.2 shall be retained for at least 10 years.	Section 3.3.2

Section 4 - Construction & Appendix F

§146.82(c)(5)	Final injection well construction procedures that meet the requirements of § 146.86;	§3619.A.5	final injection well construction procedures that meet the requirements of §3617.A;	Section 4
§146.86	Injection well construction requirements.			N/A

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§146.86(a)	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§3617.A.1	General. All phases of Class VI well construction shall be supervised by a person knowledgeable and experienced in practical drilling engineering and is familiar with the special conditions and requirements of injection well construction. All materials and equipment used in the construction of the well and related appurtenances shall be designed and manufactured to exceed the operating requirements of the specific project, including flow induced vibrations. The owner or operator must ensure that all wells are constructed and completed to:	Sections 1.4.3 - 1.4.4, Section 1.7, Section 4.2, Section 4.3.4, Section 4.4, Section 5.5.4 Appendix D
§146.86(a)(1)	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	§3617.A.1.a	prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Sections 4.2.1.1 - 4.2.1.5, Appendix D
§146.86(a)(2)	Permit the use of appropriate testing devices and workover tools; and	§3617.A.1.b	allow the use of appropriate testing devices and workover tools; and	Section 4.2
§146.86(a)(3)	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	§3617.A.1.c	allow for continuous monitoring of the annulus space between the injection tubing and long string casing.	Section 4.2
§146.86(b)	Casing and cementing of Class VI wells.	§3617.A.2	Casing and Cementing of Class VI Wells	Sections 4.2.1.1 - 4.2.1.5, Appendix D
§146.86(b)(1)	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	§3617.A.2.a	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids that the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the commissioner. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the commissioner to evaluate casing and cementing requirements, the owner or operator must provide the following information:	
§146.86(b)(1)(i)	Depth to the injection zone(s);	§3617.A.2.a.i	depth to the injection zone(s);	Section 4.4, Table 4-33
§146.86(b)(1)(ii)	Injection pressure, external pressure, internal pressure, and axial loading;	§3617.A.2.a.ii	injection pressure, external pressure, internal pressure, and axial loading;	Sections 4.2.1.1 - 4.2.1.5, Section 4.4, Appendix D
§146.86(b)(1)(iii)	Hole size;	§3617.A.2.a.iii	hole size;	Sections 4.2.1.1 - 4.2.1.5, Appendix D
§146.86(b)(1)(iv)	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	§3617.A.2.a.iv	size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Sections 4.2.1.1 - 4.2.1.5, Appendix D
§146.86(b)(1)(v)	Corrosiveness of the carbon dioxide stream and formation fluids;	§3617.A.2.a.v	corrosiveness of the carbon dioxide stream and formation fluids;	Section 1.7.1,

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§146.86(b)(1)(vi)	Down-hole temperatures;	§3617.A.2.a.vi	down-hole temperatures;	Section 1.7
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	§3617.A.2.a.vii	lithology of injection and confining zone(s);	Sections 1.3.2 & 1.3.4, Sections 1.5.2 & 1.5.4, Section 1.7.8
§146.86(b)(1)(viii)	Type or grade of cement and cement additives; and	§3617.A.2.a.viii	type or grade of cement and cement additives including slurry weight (lb/gal) and yield (cu. ft./sack); and	Sections 4.2.1.1 - 4.2.1.5, Appendix D
§146.86(b)(1)(ix)	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§3617.A.2.a.ix	quantity, chemical composition, and temperature of the carbon dioxide stream.	Section 0 - Injectate Information
§146.86(b)(2)	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	§3617.A.2.b	The surface casing of any Class VI well must extend into a confining bed—such as a shale—below the base of the deepest formation containing a USDW. The casing shall be cemented with a sufficient volume of cement to circulate cement from the casing shoe to the surface. The commissioner will not grant an exception or variance to the surface casing setting depth.	Sections 4.2.1.2
§146.86(b)(3)	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	§3617.A.2.c	At least one long string casing, using a sufficient number of centralizers, shall be utilized in the well. If the casing is to be perforated for injection, then the approved casing shall extend through the base of the injection zone. If an approved alternate construction method is used, such as the setting of a screen, the casing shall be set to the top of the injection interval. Regardless of the construction method utilized, the casings shall be cemented by circulating cement from the casing shoe to the surface in one or more stages.	Sections 4.2.1.4
§146.86(b)(4)	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	§3617.A.2.d	Circulation of cement may be accomplished by staging. Circulated to the surface shall mean that actual cement returns to the surface were observed during the primary cementing operation. A copy of the cementing company's job summary or cementing tickets indicating returns to the surface shall be submitted as part of the pre operating requirements	Sections 4.2.1.4
§146.86(b)(5)	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	§3617.A.2.e	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Sections 4.2.1.4
§146.86(c)	Tubing and packer.	§3617.A.4	Tubing and Packer	Sections 4.2.1.6 - 4.2.1.7

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§146.86(c)(1)	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	§3617.A.4.a	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids that the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the commissioner.	Sections 4.2.1.6 - 4.2.1.7
§146.86(c)(2)	All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director	§3617.A.4.b	Injection into a Class VI well must be through tubing with a packer set at a depth opposite an interval of cemented casing at a location approved by the commissioner.	Sections 4.2.1.6 - 4.2.1.7
§146.86(c)(3)	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	§3617.A.4.c	In order for the commissioner to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	Sections 4.2.1.6 - 4.2.1.7
§146.86(c)(3)(i)	Depth of setting;	§3617.A.4.c.i	depth of setting;	Sections 4.2.1.6 - 4.2.1.7
§146.86(c)(3)(ii)	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	§3617.A.4.c.ii	characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Section 0 - Injectate Information, Sections 1.7 - 1.8
§146.86(c)(3)(iii)	Maximum proposed injection pressure;	§3617.A.4.c.iii	maximum proposed injection pressure;	Section 4.4
§146.86(c)(3)(iv)	Maximum proposed annular pressure;	§3617.A.4.c.iv	maximum proposed annular pressure;	Section 4.4
§146.86(c)(3)(v)	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	§3617.A.4.c.v	proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	Section 4.4
§146.86(c)(3)(vi)	Size of tubing and casing; and	§3617.A.4.c.vi	size of tubing and casing; and	Sections 4.2.1.6 - 4.2.1.7
§146.86(c)(3)(vii)	Tubing tensile, burst, and collapse strengths.	§3617.A.4.c.vii	tubing tensile, burst, and collapse strengths.	Sections 4.2.1.6 - 4.2.1.7
§146.82(a)(7)	Proposed operating data for the proposed geologic sequestration site:	§3607.C.2.f	proposed operating data:	Section 4.4
§146.82(a)(7)(i)	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	§3607.C.2.f.i	average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4.4
§146.82(a)(7)(ii)	Average and maximum injection pressure;	§3607.C.2.f.ii	average and maximum injection pressure;	Section 4.4
§146.82(a)(8)	Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	§3607.C.2.g	proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at §3617.B;	Section 4.3
§146.82(a)(9)	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	§3607.C.2.h	proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	TBD
§146.82(a)(10)	Proposed procedure to outline steps necessary to conduct injection operation;	§3607.C.2.i	proposed injection operation procedures;	Section 4.4
§146.82(a)(11)	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	§3607.C.2.j	schematics or other appropriate drawings of the surface (wellhead and related appurtenances) and subsurface construction details of the well;	Appendix D

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§146.82(a)(12)	Injection well construction procedures that meet the requirements of § 146.86;	§3607.C.2.k	injection well construction procedures that meet the requirements of §3617.A;	Appendix D
		§3617.A.3	Casing and Casing Seat Tests. The owner or operator shall monitor and record the tests using a surface readout pressure gauge and a chart or a digital recorder. All instruments shall be calibrated properly and in good working order. If there is a failure of the required tests, the owner or operator shall take necessary corrective action to obtain a passing test.	Appendix D
		§3617.A.3.a	Casing. After cementing each casing, but before drilling out the respective casing shoe, all casings shall be hydrostatically pressure tested to verify casing integrity and the absence of leaks. For surface casing, the stabilized test pressure applied at the surface shall be a minimum of 500 pounds per square inch gauge (PSIG). The stabilized test pressure applied at the surface for all other casings shall be a minimum of 1,000 PSIG. All casing test pressures shall be maintained for one hour after stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.	Appendix D
		§3617.A.3.a.i	Casing test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix D
		§3617.A.3.b	Casing Seat. The casing seat and cement of any intermediate and injection casings shall be hydrostatically pressure tested after drilling out the casing shoe. At least 10 feet of formation below the respective casing shoes shall be drilled before the test. The test pressure applied at the surface shall be a minimum of 1,000 PSIG. The test pressure shall be maintained for one hour after pressure stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.	Appendix D
		§3617.A.3.b.i	Casing seat test pressures shall never exceed the known or calculated fracture gradient of the appropriate subsurface formation.	Appendix D
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EXXONMOBIL PECAN ISLAND INJECTION WELLS NO. 001 and NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(a)	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	§3617.B.1	During the drilling and construction of a Class VI well, appropriate logs, surveys and tests must be run to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements of §3617 and to establish accurate baseline data against which future measurements may be compared. The well operator must submit to the commissioner a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Sections 4.3.2 - 4.3.3, Appendix D
§146.87(a)(1)	Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	§3617.B.1.a	deviation checks during drilling of all boreholes constructed by drilling a pilot hole, which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling;	Appendix D
§146.87(a)(2)	Before and upon installation of the surface casing:	§3617.B.1.b	before and upon installation of the surface casing:	Section 4.3.2
§146.87(a)(2)(i)	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§3617.B.1.b.i	resistivity, gamma-ray, spontaneous potential, and caliper logs before the casing is installed; and	Section 4.3.2
§146.87(a)(2)(ii)	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	§3617.B.1.b.ii	a cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented	Section 4.3.2
§146.87(a)(3)	Before and upon installation of the long string casing:	§3617.B.1.c	before and upon installation of intermediate and long string casing:	Section 4.3.2
§146.87(a)(3)(i)	Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	§3617.B.1.c.i	resistivity, gamma-ray, spontaneous potential, porosity, caliper, fracture finder logs, and any other logs the commissioner requires for the given geology before the casing is installed; and	Section 4.3.2

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§146.87(a)(3)(ii)	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	§3617.B.1.c.ii	a cement bond and variable density log, and a temperature log after the casing is set and cemented.	Section 4.3.2
§146.87(a)(4)	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	§3617.B.1.d	a series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	Section 4.3.2, Section 5.4.2
§146.87(a)(4)(i)	A pressure test with liquid or gas;	§3617.B.1.d.i	a pressure test with liquid or gas;	Section 5.4.2
§146.87(a)(4)(ii)	A tracer survey such as oxygen-activation logging;	§3617.B.1.d.ii	a tracer-type survey to detect fluid movement behind casing such as a radioactive tracer or oxygen activation logging, or similar tool	Section 4.3.2
§146.87(a)(4)(iii)	A temperature or noise log;	§3617.B.1.d.iii	a temperature or noise log;	Section 4.3.2
§146.87(a)(4)(iv)	A casing inspection log; and	§3617.B.1.d.iv	a casing inspection log	Section 4.3.2
§146.87(a)(5)	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	§3617.B.1.e	any alternative methods that provide equivalent or better information and that are required by and approved by the commissioner.	Section 4.3.2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(b)	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	§3617.B.2	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the commissioner a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. The commissioner may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The commissioner may require the owner or operator to core other formations in the borehole.	Section 4.3.1
§146.87(c)	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§3617.B.3	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Section 4.3.3
§146.87(d)	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	§3617.B.4	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	Section 4.3.4
§146.87(d)(1)	Fracture pressure;	§3617.B.4.a	fracture pressure;	Section 4.3.4
§146.87(d)(2)	Other physical and chemical characteristics of the injection and confining zone(s); and	§3617.B.4.b	other physical and chemical characteristics of the injection and confining zone(s); and	Sections 4.3.3 - 4.3.4
§146.87(d)(3)	Physical and chemical characteristics of the formation fluids in the injection zone(s).	§3617.B.4.c	physical and chemical characteristics of the formation fluids in the injection zone(s).	Section 4.3.3
§146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	§3617.B.5	Upon completion, but before operating, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	Section 4.3.4, Section 5.4.4
§146.87(e)(1)	A pressure fall-off test; and,	§3617.B.5.a	a pressure fall-off test; and,	

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(e)(2)	A pump test; or	§3617.B.5.b	a pump test; or	Section 4.3.4, Section 5.4.4
§146.87(e)(3)	Injectivity tests.	§3617.B.5.c	injectivity tests.	
§146.87(f)	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	§3617.B.6	The owner or operator must notify the Office of Conservation at least 72 hours before conducting any wireline logs, well tests, or reservoir tests	Section 4.X, Appendix D
§146.88	Injection well operating requirements			
§146.88(a)	Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	§3621.A.1	Injection Pressure. Except during stimulation, the injection well shall be operated so that the injection-induced pressure in the injection zone(s) does not exceed 90 percent of the fracture pressure of the injection zone(s). This shall ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at NATURAL RESOURCES Louisiana Administrative Code September 2022 170 §3607.C.2.h, all stimulation programs must be approved by the commissioner as part of the permit application and incorporated into the permit.	Section 4.4, Table 4-33
§146.88(b)	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	§3621.A.2	Injection between the outermost casing protecting USDWs and the wellbore is prohibited.	Section 4.4

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.88(c)	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	§3621.A.3	The owner or operator must fill the annulus between the tubing and the long string casing with a non corrosive fluid approved by the commissioner or a fluid containing a corrosion inhibitor approved by the commissioner.	Section 4.2, Drilling and Completion Design
§146.88(d)	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	§3621.A.5	The owner or operator must maintain mechanical integrity of the injection well at all times, except when doing well workovers, well maintenance, or well remedial work approved by the commissioner.	Section 4.2

Section 5 - Testing and Monitoring

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	§3617.B.5	Upon completion, but before operating, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	Section 4.3.4, Section 5.4.4
§146.87(e)(1)	A pressure fall-off test; and,	§3617.B.5.a	a pressure fall-off test; and,	
§146.87(e)(2)	A pump test; or	§3617.B.5.b	a pump test; or	
§146.87(e)(3)	Injectivity tests.	§3617.B.5.c	injectivity tests.	

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90	The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	§3625.A	Testing and Monitoring Requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be included with the permit application and must include a description of how the owner or operator will meet these requirements— including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must include, at a minimum:	Section 5
§146.90(a)	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	§3625.A.1	analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 0, Injectate Information, Section 5.2, Sections 5.5.1 - 5.5.2, Table 5-1

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§146.90(b)	Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	§3625.A.2	installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the tubing-casing annulus; and the annulus fluid volume added. Continuous monitoring is not required during well workovers as defined in §3621.A.5;	Sections 5.5.1 - 5.5.2
§146.90(c)	Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:	§3625.A.3	corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in §3617.A.2, by:	Section 5.5.3
§146.90(c)(1)	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	§3625.A.3.a	analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	
§146.90(c)(2)	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	§3625.A.3.b	routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	
§146.90(c)(3)	Using an alternative method approved by the Director;	§3625.A.3.c	using an alternative method approved by the commissioner;	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90(d)	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	§3625.A.4	periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Sections 5.5.4 - 5.5.6, Table 5-2
§146.90(d)(1)	The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	§3625.A.4.a	the location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	
§146.90(d)(2)	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	§3625.A.4.b	the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under §3607.C.2.e and on any modeling results in the area of review evaluation required by §3615.B.3.	
§146.90(e)	A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	§3625.A.5	a demonstration of external mechanical integrity pursuant to §3627.A.3 at least once every 12 months until the injection well is permanently plugged and abandoned; and, if required by the commissioner, a casing inspection log pursuant to requirements at §3627.A.4 at a frequency established in the testing and monitoring plan;	Section 5.4.3
§146.90(f)	A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	§3625.A.6	a pressure fall-off test at least once every five years unless more frequent testing is required by the commissioner based on site-specific information;	Section 5.4.4

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90(g)	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	§3625.A.7	testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Section 5.5.8
§146.90(g)(1)	Direct methods in the injection zone(s); and,	§3625.A.7.a	direct methods in the injection zone(s); and	Section 5.5.8
§146.90(g)(2)	Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	§3625.A.7.b	indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the commissioner determines that such methods are not appropriate, based on site-specific geology;	Section 5.5.8
§146.90(h)	The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	§3625.A.8	The commissioner may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW	
§146.90(h)(1)	Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;	§3625.A.8.a	Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;	
§146.90(h)(2)	The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under §3603.D;	§3625.A.8.b	The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under §3603.D;	

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.90(h)(3)	If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;	§3625.A.8.c	If an owner or operator demonstrates that monitoring employed under 40 CFR 98.440 to 98.449 accomplishes the goals of §3625.A.8.a. and b., and meets the requirements pursuant to §3629.A.1.c.v, a regulatory agency that requires surface air/soil gas monitoring must approve the use of monitoring employed under 40 CFR 98.440 to 98.449. Compliance with 40 CFR 98.440 to 98.449 pursuant to this provision is considered a condition of the Class VI permit;	
§146.90(i)	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	§3625.A.9	Any additional monitoring, as required by the commissioner, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under §3615.B.3 and to determine compliance with standards under §3619;	
§146.90(j)	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	§3625.A.10	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under §3625, operational data collected under §3621, and the most recent area of review reevaluation performed under §3615.C.2. In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the commissioner that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:	Section 5.3
§146.90(j)(1)	Within one year of an area of review reevaluation;	§3625.A.10.a	within 12 months of an area of review reevaluation;	Section 5.3
§146.90(j)(2)	Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	§3625.A.10.b	following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the commissioner; or	Section 5.3
§146.90(j)(3)	When required by the Director.	§3625.A.10.c	when required by the commissioner.	Section 5.3
§146.90(k)	A quality assurance and surveillance plan for all testing and monitoring requirements.	§3625.A.11	a quality assurance and surveillance plan for all testing and monitoring requirements.	TBD
§146.89(a)	A Class VI well has mechanical integrity if:	§3627.A.1	A Class VI well has mechanical integrity if:	N/A
§146.89(a)(1)	There is no significant leak in the casing, tubing, or packer; and	§3627.A.1.a	there is no significant leak in the casing, tubing, or packer; and	N/A

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§146.89(a)(2)	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	§3627.A.1.b	there is no significant fluid movement into a USDW through channels adjacent to the injection wellbore.	N/A
§146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§3627.A.2	To evaluate the absence of significant leaks, owners or operators must:	N/A
		§3627.A.2.a	perform an annulus pressure test:	Section 5.4.2
		§3627.A.2.a.i	after initial well construction or conversion as part of the pre-operating requirements;	Section 5.4.2
No equivalent federal requirement	No equivalent federal requirement	§3627.A.2.a.ii	at least once every 12 months witnessed by an agent of the Office of Conservation; and	Section 5.4.2
		§3627.A.2.a.ii	after performing any well remedial work that involves unseating the tubing or packer.	N/A
§146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§3627.A.2.b	continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing;	Section 5.5.1
§146.89(c)	At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	§3627.A.3	At least once every 12 months, use one of the following methods to determine the absence of significant fluid movement:	Section 5.4.3
§146.89(c)(1)	An approved tracer survey such as an oxygen-activation log; or	§3627.A.3.a	an approved tracer-type survey such as a radioactive tracer, oxygen-activation log, or similar tool; or	Section 5.4.3
§146.89(c)(2)	A temperature or noise log.	§3627.A.3.b	a temperature or noise log	Section 5.4.3

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§146.89(d)	If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	§3627.A.4	If required by the commissioner, run a casing inspection log at a frequency specified in the testing and monitoring plan at §3625 to determine the presence or absence of corrosion in the long-string casing.	N/A
§146.89(e)	The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	§3627.A.5	The commissioner may require other tests to evaluate well mechanical integrity	N/A
		§3627.A.5.a	The commissioner may allow the use of a test to demonstrate mechanical integrity other than those listed above with written approval of the USEPA. To obtain approval for the use of a new mechanical integrity test, the owner or operator must submit a written request to the commissioner with details of the proposed test and all technical data supporting its use, and the commissioner will submit a written request to the USEPA.	N/A
§146.89(f)	In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	§3627.A.6	In conducting and evaluating the tests enumerated in this section to be allowed by the commissioner, the owner or operator and the commissioner must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the commissioner, a description of the test(s) and the method(s) used must be included. In making the evaluation, the commissioner must review monitoring and other test data submitted since the previous evaluation.	Sections 5.4.2 - 5.4.3
§146.89(g)	The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	§3627.A.7	The commissioner may require additional or alternative tests if the mechanical integrity test results presented are not satisfactory to the commissioner to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity.	N/A
§146.91	The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	§3629.A.1	The owner or operator must provide, at a minimum, the following reports to the commissioner, and the USEPA as specified in §3629.A.3, for each permitted Class VI well:	Section 5.2
§146.91(a)	Semi-annual reports containing:	§3629.A.1.a	semi-annual reports containing:	Section 5.2

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EXXONMOBIL PECAN ISLAND INJECTION WELLS NO. 001 and NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.91(a)(1)	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	§3629.A.1.a.i	any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	Section 5.2
§146.91(a)(2)	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	§3629.A.1.a.ii	monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	Section 5.2, Section 5.5.1
§146.91(a)(3)	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	§3629.A.1.a.iii	a description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	Section 5.2
§146.91(a)(4)	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	§3629.A.1.a.iv	a description of any event which triggers a shut-off device required by §3621 and the response taken;	Section 5.2
§146.91(a)(5)	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	§3629.A.1.a.v	the monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	Section 5.2
§146.91(a)(6)	Monthly annulus fluid volume added; and	§3629.A.1.a.vi	monthly annulus fluid volume added;	Section 5.2
§146.91(a)(7)	The results of monitoring prescribed under § 146.90.	§3629.A.1.a.vii	the results of monitoring prescribed under §3625; and	Section 5.2
§146.91(b)	Report, within 30 days, the results of:	§3629.A.1.b	report, within 30 days or as specified by permit, the results of:	Section 5.2
§146.91(b)(1)	Periodic tests of mechanical integrity;	§3629.A.1.b.i	periodic tests of mechanical integrity;	Section 5.2

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EXXONMOBIL PECAN ISLAND INJECTION WELLS NO. 001 and NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.91(b)(2)	Any well workover; and,	§3629.A.1.b.ii	any well workover; and	Section 5.2
§146.91(b)(3)	Any other test of the injection well conducted by the permittee if required by the Director.	§3629.A.1.b.iii	any other test of the injection well conducted by the permittee if required by the commissioner;	Section 5.2
§146.91(c)	Report, within 24 hours:	§3629.A.1.c	report, within 24 hours:	Section 5.2
§146.91(c)(1)	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	§3629.A.1.c.i	any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	Section 5.2
§146.91(c)(2)	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	§3629.A.1.c.ii	any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Section 5.2
§146.91(c)(3)	Any triggering of a shut-off system (i.e., down-hole or at the surface);	§3629.A.1.c.iii	any triggering of a shut-off system (i.e., down hole or at the surface);	Section 5.2
§146.91(c)(4)	Any failure to maintain mechanical integrity; or.	§3629.A.1.c.iv	any failure to maintain mechanical integrity; or	Section 5.2
§146.91(c)(5)	Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	§3629.A.1.c.v	any release of carbon dioxide to the atmosphere or biosphere pursuant to compliance with the requirement at §3625.A.8 for surface air/soil gas monitoring or other monitoring technologies, if required by the commissioner;	Section 5.2
§146.91(d)	Owners or operators must notify the Director in writing 30 days in advance of:	§3629.A.2	Owners or operators must notify the commissioner in writing in advance of doing any well work or formation testing as required in §3621.A.9	Section 5.2
§146.91(d)(1)	Any planned well workover;			Section 5.2
§146.91(d)(2)	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and			Section 5.2
§146.91(d)(3)	Any other planned test of the injection well conducted by the permittee.			Section 5.2
§146.91(e)	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	§3629.A.3	Regardless of whether the State of Louisiana has primary permit and enforcement authority (primacy) for Class VI wells, owners or operators of Class VI wells, or applicants for Class VI wells must submit all required submittals, reports, and notifications under §§3605, 3607, 3615, 3617, 3619, 3621, 3623, 3625, 3627, 3629, 3631, and 3633 to the USEPA in an electronic format approved by the USEPA.	
§146.91(f)	Records shall be retained by the owner or operator as follows:	§3629.A.4	Records shall be retained by the owner or operator as follows:	Section 5.2

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.91(f)(1)	All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	§3629.A.4.a	all data collected for Class VI permit applications in §3607 and §3619 shall be retained throughout the life of the geologic sequestration project and at least 10 years following site closure.	Section 5.2
§146.91(f)(2)	Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.	§3629.A.4.b	data on the nature and composition of all injected fluids collected under §3625.A.1.a shall be retained at least 10 years after site closure. The commissioner may require the owner or operator to deliver the records to the commissioner at the conclusion of the retention period.	Section 5.2
§146.91(f)(3)	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	§3629.A.4.c	monitoring data collected under §3625.A.2 through §3625.A.9 shall be retained at least 10 years after it is collected.	Section 5.2
§146.91(f)(4)	Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.	§3629.A.4.d	well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §3633.A.6 and §3633.A.8 shall be retained at least 10 years following site closure.	Section 5.2
§146.91(f)(5)	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	§3629.A.4.e	The commissioner may require the owner or operator to retain any records required under these regulations for longer than 10 years after site closure.	Section 5.2
§146.88(e)(1)	Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	§3621.A.6.a	continuous recording devices shall monitor:	Sections 5.5.1 - 5.5.2
		§3621.A.6.a.i	surface injection or bottom-hole pressure;	Sections 5.5.1 - 5.5.2
		§3621.A.6.a.ii	flow rate, volume and/or mass, and temperature of the carbon dioxide stream;	Sections 5.5.1 - 5.5.2
		§3621.A.6.a.iii	tubing-casing annulus pressure and annulus fluid volume; and	Sections 5.5.1 - 5.5.2
No equivalent federal requirement	No equivalent federal requirement	§3621.A.6.a.iv	any other data specified by the commissioner.	Sections 5.5.1 - 5.5.2
		§3621.A.6.b	continuous recordings shall consist of digital recordings. Instruments shall be weatherproof or housed in weatherproof enclosures when located in areas exposed to climatic conditions.	Sections 5.5.1 - 5.5.2

Section 6 - Plugging Plan

§146.92(a)	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	§3631.A.2	Before well plugging, the owner or operator must flush each Class VI well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Section 6.2.1.1, Section 6.2.2.1

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EXXONMOBIL PECAN ISLAND INJECTION WELLS NO. 001 and NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.92(b)	Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§3631.A.3	Well Plugging Plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application, must be designed in a way that will prevent the movement of fluids into or between USDWs or outside the injection zone, and must include the following minimum information:	Section 6.2.2, Section 6.3, Section 7.7.2
§146.92(b)(1)	Appropriate tests or measures for determining bottomhole reservoir pressure;	§3631.A.3.a	appropriate tests or measures for determining bottomhole reservoir pressure;	Section 6.2.1.1(2), Section 6.2.2.1(2)
§146.92(b)(2)	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	§3631.A.3.b	appropriate testing methods to ensure external mechanical integrity as specified in §3627;	Section 6.2.1.1(2), Section 6.2.2.1(2)
	NEQFR	§3631.A.3.c	a description of the size and amount of casing, tubing, or any other well construction materials to be removed from the well before well closure;	Section 6.2.2.2 (Table 6-1)
	NEQFR	§3631.A.3.d	that prior to the placement of plugs, the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method;	Section 6.2.2.2
§146.92(b)(3)	The type and number of plugs to be used;	§3631.A.3.e	the type and number of plugs to be used;	Section 6.2.2.3 (Table 6-2, Table 6-3, Table 6-4, Table 6-5)
§146.92(b)(4)	The placement of each plug, including the elevation of the top and bottom of each plug;	§3631.A.3.f	the placement of each plug, including the elevation of the top and bottom of each plug;	Section 6.2.2.3 (Table 6-2, Table 6-3, Table 6-4, Table 6-5)
§146.92(b)(5)	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	§3631.A.3.g	the type, grade, yield, and quantity of material, such as cement, to be used in plugging. The material must be compatible with the carbon dioxide stream;	Section 6.2.2.3 (Table 6-2, Table 6-3, Table 6-4, Table 6-5)
§146.92(b)(6)	The method of placement of the plugs.	§3631.A.3.h	the method of placement of the plugs;	Section 6.2.2.3 (Table 6-2, Table 6-3, Table 6-4, Table 6-5)

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.92(c)	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§3631.A.4	Notice of Intent to Plug. The owner or operator must submit the Form UIC-17, or successor form, to the commissioner and receive written approval from the commissioner before beginning actual well plugging operations. The form must contain information on the procedures to be used in the field to plug and abandon the well.	Section 6.2.1.1(1), Section 6.2.2.1(1), Section 6.3.1(1-2)
§146.92(d)	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	§3631.A.5	Well Closure Report. The owner or operator shall submit a closure report to the commissioner within 30 days after well plug and abandonment. The report shall be certified as accurate by the owner or operator and by the person charged with overseeing the closure operation (if other than the owner or operator). The owner or operator shall retain the well closure report at least 10 years following site closure. The report shall contain the following information:	Section 6.3.4.1, Page 25, Paragraph 1
§146.82(a)(16)	Proposed injection well plugging plan required by § 146.92(b);	§3607.C.2.o	proposed injection well plugging plan required by §3631;	Section 6.2.2, Section 6.3

Section 7 - Post Injection Site Care and Closure Plan

§146.93	#N/A	#N/A	#N/A	
§146.82(a)(17)	Proposed post-injection site care and site closure plan required by § 146.93(a);	§3607.C.2.p	proposed post-injection site care and site closure plan required by §3633.A.3;	Section 7
§146.82(a)(18)	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	§3607.C.2.q	at the commissioner’s discretion, a demonstration of an alternative post-injection site care timeframe required by §3633.A.3;	Section 7
§146.93(a)	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§3633.A.1	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of §3633.A.1.b and is acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 7
§146.93(a)(1)	The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	§3633.A.1.a	The owner or operator must submit the post injection site care and site closure plan as a part of the permit application.	Section 7
§146.93(a)(2)	The post-injection site care and site closure plan must include the following information:	§3633.A.1.b	The post-injection site care and site closure plan must include the following information:	Section 7

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(a)(2)(i)	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	§3633.A.1.b.i	the pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Section 7.2, Table 7-1, Figure 7-1, Figure 7-2
§146.93(c)	Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.	§3633.A.3	Demonstration of Alternative Post-Injection Site Care Timeframe. The commissioner may approve, in consultation with the USEPA, an alternative post-injection site care timeframe other than the 50-year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site specific data and information including all data and information collected pursuant to §3607 and §3615, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post injection site care timeframe.	Section 7.6
§146.93(c)(1)	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	§3633.A.3.a	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	Section 7.2, Table 7-1, Figure 7-1, Figure 7-2, Section 7.6
§146.93(c)(1)(i)	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	§3633.A.3.a.i	the results of computational modeling performed pursuant to delineation of the area of review under §3615.B and §3615.C;	Section 3.3, Section 3.5, Section 7.2, Table 7-1, Figure 7-1, Figure 7-2, Section 7.6
§146.93(c)(1)(ii)	The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	§3633.A.3.a.ii	the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	Section 7.2, Table 7-1, Figure 7-1, Figure 7-2, Section 7.6
§146.93(c)(1)(ix)	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	§3633.A.3.a.ix	a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	Section 3.4, Section 4.2, Section 7.7.2, Appendix C, Appendix D, Appendix H
§146.93(c)(1)(viii)	The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	§3633.A.3.a.viii	the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	Section 3.4, Section 4.2, Section 7.3, Section 7.7.2, Appendix C, Appendix D, Appendix H
§146.93(c)(2)	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	§3633.A.3.b	Information submitted to support the demonstration in §3633.A.3.a must meet the following criteria:	N/A
§146.93(c)(2)(i)	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	§3633.A.3.b.i	all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	N/A

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(c)(2)(ii)	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	§3633.A.3.b.ii	estimation techniques must be appropriate and USEPA-certified test protocols must be used where available;	N/A
§146.93(c)(2)(iii)	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	§3633.A.3.b.iii	predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	Section 7.6
§146.93(c)(2)(iv)	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	§3633.A.3.b.iv	predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	Section 7.6
§146.93(c)(2)(v)	Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	§3633.A.3.b.v	reasonably conservative values and modeling assumptions must be used and disclosed to the commissioner whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	N/A
§146.93(c)(2)(vi)	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	§3633.A.3.b.vi	an analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration	N/A
§146.93(c)(2)(vii)	An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	§3633.A.3.b.vii	an approved quality assurance and quality control plan must address all aspects of the demonstration; and	N/A
§146.93(c)(2)(viii)	Any additional criteria required by the Director.	§3633.A.3.b.viii	any additional criteria required by the commissioner.	Section 7.6
§146.93(a)(2)(ii)	The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);	§3633.A.1.b.ii	the predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under §3615.B.3.a;	Section 7.3

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(a)(2)(iii)	A description of post-injection monitoring location, methods, and proposed frequency;	§3633.A.1.b.iii	a description of post-injection monitoring location, methods, and proposed frequency;	Sections 5.5.4 - 5.5.9, Section 7.4, Section 7.5, Table 7-2
§146.93(a)(2)(iv)	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	§3633.A.1.b.iv	a proposed schedule for submitting post injection site care monitoring results to the commissioner and to the USEPA pursuant to §3629.A.3; and,	Section 7.5, Table 7-2
§146.93(a)(2)(v)	The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	§3633.A.1.b.v	the duration of the post-injection site care timeframe and, if approved by the commissioner, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	Sections 7.4 - 7.6, Table 7-2
§146.93(a)(3)	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§3633.A.1.c	**Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post injection site care and site closure plan or demonstrate to the commissioner through monitoring data and modeling results that no amendment to the plan is needed**. Any amendments to the post-injection site care and site closure plan must be approved by the commissioner, be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate.	Section 7.4
§146.93(a)(4)	At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	§3633.A.1.d	At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the commissioner's approval within 30 days of such change.	Section 7.4
§146.93(b)	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	§3633.A.2	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	Section 7.4

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EXXONMOBIL PECAN ISLAND INJECTION WELLS NO. 001 and NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(b)(1)	Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	§3633.A.2.a	Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the commissioner-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the commissioner pursuant to requirements in §3633.A.3, unless the owner or operator makes a demonstration under §3633.A.2.b. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under §3633.A.2.b is submitted and approved by the commissioner.	Sections 7.4 - 7.6
§146.93(b)(2)	If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	§3633.A.2.b	If the owner or operator can demonstrate to the satisfaction of the commissioner before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the commissioner may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where the owner or operator has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	Section 7.6
§146.93(b)(3)	Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	§3633.A.2.c	Prior to authorization for site closure, the owner or operator must submit to the commissioner for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs	Section 7.6

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§146.93(b)(4)	If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	§3633.A.2.d	If the demonstration in §3633.A.2.c cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the commissioner does not approve the demonstration, the owner or operator must submit to the commissioner a plan to continue post-injection site care until a demonstration can be made and approved by the commissioner.	N/A
§146.93(d)	Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	§3633.A.4	Notice of Intent for Site Closure. The owner or operator must notify the commissioner in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The commissioner may allow for a shorter notice period.	Section 7.7.1
§146.93(e)	After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	§3633.A.5	After the commissioner has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	Section 7.7.2, Section 7.7.4
§146.93(f)	The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	§3633.A.6	The owner or operator must submit a site closure report to the commissioner within 90 days after site closure, which must also be retained by the owner or operator for at least 10 years. The report must include:	Section 7.7.4
§146.93(f)(1)	Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;	§3633.A.6.a	documentation of appropriate injection and monitoring well plugging as specified in §3631 and §3633.A.5. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the commissioner. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the USEPA as in §3629.A.3;	Section 6.3.1, Section 7.7.4
§146.93(f)(2)	Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	§3633.A.6.b	documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	Section 7.7.4

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.93(f)(3)	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	§3633.A.6.c	records reflecting the nature, composition, and volume of the carbon dioxide stream	Section 7.7.4
§146.93(g)	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	§3633.A.7	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	Section 7.7.4
§146.93(g)(1)	The fact that land has been used to sequester carbon dioxide;	§3633.A.7.a	the fact that land has been used to sequester carbon dioxide;	Section 7.7.4
§146.93(g)(2)	The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and	§3633.A.7.b	the name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the USEPA Regional Office to which it was submitted; and	Section 7.7.4
§146.93(g)(3)	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	§3633.A.7.c	the volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	Section 7.7.4
§146.93(h)	The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	§3633.A.8	The owner or operator must retain for at least 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the commissioner at the conclusion of the retention period, and the records must thereafter be retained in a form and manner and at a location designated by the commissioner.	Section 7.7.4

Section 8 - Emergency Response

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.82(a)(19)	Proposed emergency and remedial response plan required by § 146.94(a);	§3607.C.2.r	proposed emergency and remedial response plan required (contingency plans for well failures or breaches) by §3623;	Section 8.3
§146.84(f)	The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	§3615.C.3	The emergency and remedial response plan (as required by §3623) and the demonstration of financial responsibility (as described by §3609.C must account for the area of review delineated as specified in §3615.B.3.a or the most recently evaluated area of review delineated under §3615.C.2, regardless of whether or not corrective action in the area of review is phased.	Section 8.2, Appendix G
§146.88(e)(2)	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	§3621.A.7.a.i	for onshore wells, alarms and automatic surface shut-off valves or—at the discretion of the commissioner—down-hole shut-off systems (e.g., automatic shut-off, check valves) or, other mechanical devices that provide equivalent Protection; and	Section 8.2
§146.88(e)(3)	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	§3621.A.7.a.ii	for offshore wells, alarms and automatic down hole shut-off systems designed to alert the operator and shut in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges or gradients specified in the permit.	N/A
§146.88(f)	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	§3621.A.7.b	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, the owner or operator must:	Section 8.3.2.4
§146.88(f)(1)	Immediately cease injection;	§3621.A.7.b.i	immediately cease injection;	Section 8.3.2.4
§146.88(f)(2)	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	§3621.A.7.b.ii	take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	Section 8.3.2.4
§146.88(f)(3)	Notify the Director within 24 hours;	§3621.A.7.b.iii	notify the commissioner within 24 hours;	Section 8.3.2.4
§146.88(f)(4)	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	§3621.A.7.b.iv	restore and demonstrate mechanical integrity to the satisfaction of the commissioner prior to resuming injection; and	Section 8.3.2.4
§146.88(f)(5)	Notify the Director when injection can be expected to resume.	§3621.A.7.b.v	notify the commissioner when injection can be expected to resume.	Section 8.3.2.4
§146.94	Emergency and remedial response		Emergency Response	Section 8.3

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.94(a)	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§3623.A.1	As part of the permit application, the owner or operator must provide the commissioner with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 8.3, Section 8.5
§146.94(b)	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	§3623.A.2	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	Section 8.3.1, Section 8.3.2
§146.94(b)(1)	Immediately cease injection;	§3623.A.2.a	immediately cease injection;	Section 8.3.1, Section 8.3.2
§146.94(b)(2)	Take all steps reasonably necessary to identify and characterize any release;	§3623.A.2.b	take all steps reasonably necessary to identify and characterize any release;	Section 8.3.1, Section 8.3.2
§146.94(b)(3)	Notify the Director within 24 hours; and	§3623.A.2.c	notify the commissioner within 24 hours; and	Section 8.3.1, Section 8.3.2
§146.94(b)(4)	Implement the emergency and remedial response plan approved by the Director.	§3623.A.2.d	implement the emergency and remedial response plan approved by the commissioner.	Section 8.3, Section 8.6
§146.94(c)	The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	§3623.A.3	The commissioner may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	N/A
§146.94(d)	The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	§3623.A.4	The owner or operator shall review the emergency and remedial response plan developed under §3623.A.1 at least once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the commissioner that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:	Section 8.1, Section 8.8
§146.94(d)(1)	Within one year of an area of review reevaluation;	§3623.A.4.a	within one year of an area of review reevaluation;	Section 8.1, Section 8.8

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§146.94(d)(2)	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	§3623.A.4.b	following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the commissioner; or	Section 8.1, Section 8.8
§146.94(d)(3)	When required by the Director.	§3623.A.4.c	when required by the commissioner.	Section 8.1, Section 8.8

Section 9 - Financial Assurance

No equivalent federal requirement	No equivalent federal requirement	§3607.B.11	documentation of financial responsibility or documentation of the method by which proof of financial responsibility will be provided as required in §3609.C. Before making a final permit decision, final (official) documentation of financial responsibility must be submitted to and approved by the Office of Conservation;	Section 9.3
§146.82(a)(14)	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§3607.C.2.m	demonstration, satisfactory to the commissioner, that the applicant has met the financial responsibility requirements under §3609.C;	TBD
No equivalent federal requirement	No equivalent federal requirement	§3609.C.2	The amount of funds available in the financial instrument shall be no less than the amount identified in the cost estimate of the closure plan and any required post injection site care and site closure, and must be approved by the commissioner	Section 9.3
§146.85(a)(6)(ii)	When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	§3609.C.3	Any financial instrument filed in satisfaction of the financial responsibility requirements shall be issued by and drawn on a bank or other financial institution authorized under state or federal law to operate in the State of Louisiana.	TBD
§146.84(f)	The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	§3615.C.3	The emergency and remedial response plan (as required by §3623) and the demonstration of financial responsibility (as described by §3609.C must account for the area of review delineated as specified in §3615.B.3.a or the most recently evaluated area of review delineated under §3615.C.2, regardless of whether or not corrective action in the area of review is phased.	Section 9.4
§146.85	Financial responsibility			

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.85(a)	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	§3609.C.1	The permit shall require the permittee to maintain financial responsibility and resources to close, plug, and abandon the underground injection wells and, where necessary, related surface facility, and for post-injection site care and site closure in a manner prescribed by the commissioner. Class VI well operators must also comply with §3609.C.4. The permittee must show evidence of financial responsibility to the commissioner by the submission of:	Section 9.3
§146.85(a)(1)	The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	N/A	*** The full language at 40 CFR 146.85(a)(1) will not be adopted since 3609.C.1 introduces the list of the qualifying instruments	N/A
No equivalent federal requirement	No equivalent federal requirement	§3609.C.1.a	a certificate of deposit issued in sole favor of the Office of Conservation in a form prescribed by the commissioner. A certificate of deposit may not be withdrawn, canceled, rolled over or amended in any manner without the approval of the commissioner;	N/A
§146.85(a)(1)(ii)	Surety Bonds.	§3609.C.1.b	a performance bond (surety bond) in sole favor of the Office of Conservation in a form prescribed by the commissioner;	N/A
§146.85(a)(1)(iii)	Letter of Credit.	§3609.C.1.c	a letter-of-credit in sole favor of the Office of Conservation in a form prescribed by the commissioner;	N/A
§146.85(a)(1)(i)	Trust Funds.	§3609.C.1.d	site-specific trust account, or	N/A
§146.85(a)(1)(vii)	Any other instrument(s) satisfactory to the Director.	§3609.C.1.e	any other instrument of financial assurance acceptable to the commissioner.	Section 9.3
§146.85(a)(2)	The qualifying instrument(s) must be sufficient to cover the cost of:	§3609.C.4.a	Qualifying financial responsibility instruments must be sufficient to cover the cost of meeting the requirements of:	Sections 9.3 - 9.7
§146.85(a)(2)(i)	Corrective action (that meets the requirements of § 146.84);	§3609.C.4.a.i.(a)	corrective action of §3615.C;	Section 9.4
§146.85(a)(2)(ii)	Injection well plugging (that meets the requirements of § 146.92);	§3609.C.4.a.i.(b)	injection well plugging of §3631;	Section 9.5

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§146.85(a)(2)(iii)	Post injection site care and site closure (that meets the requirements of § 146.93); and	§3609.C.4.a.i.(c)	post-injection site care and site closure of §3633; and	Section 9.6
§146.85(a)(2)(iv)	Emergency and remedial response (that meets the requirements of § 146.94).	§3609.C.4.a.i.(d)	emergency and remedial response of §3623.	Section 9.7
§146.85(a)(3)	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	§3609.C.4.b	Financial responsibility instruments must be sufficient to address endangerment of underground sources of drinking water.	Sections 9.3 - 9.7
§146.85(a)(4)	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	§3609.C.4.c	Qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable:	N/A
§146.85(a)(4)(i)	Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.			N/A

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§146.85(a)(4)(i)(A)	Cancellation - for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.	§3609.C.4.c.i	cancellation: an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the commissioner. The cancellation must not be final for 120 days after receipt of the cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the commissioner;	N/A
§146.85(a)(4)(i)(B)	Renewal - for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	§3609.C.4.c.ii	renewal: owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument;	N/A
§146.85(a)(4)(i)(C)	Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	§3609.C.4.c.iii	cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration the commissioner deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the commissioner or a court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	N/A
§146.85(a)(5)	The qualifying financial responsibility instrument(s) must be approved by the Director.	§3609.C.4.d	Qualifying financial responsibility instruments must be approved by the commissioner:	N/A

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§146.85(a)(5)(i)	The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).	§3609.C.4.d.i	the commissioner shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project before issuing any authorization to begin geologic sequestration of carbon dioxide in a Class VI well;	N/A
§146.85(a)(5)(ii)	The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.	§3609.C.4.d.ii	the owner or operator must provide any updated information related to their financial responsibility instrument(s) annually and if there are any changes, the commissioner must evaluate the financial responsibility demonstration to confirm that the instrument(s) used remain adequate. The owner or operator must maintain financial responsibility requirements regardless of the status of the commissioner's review of the financial responsibility demonstration;	Section 9.3, Paragraph 4
§146.85(a)(5)(iii)	The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.	§3609.C.4.d.iii	the commissioner may disapprove the use of a financial instrument if he determines it is not sufficient to meet the financial responsibility requirements.	N/A
§146.85(a)(6)	The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.	§3609.C.4.e	The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project:	N/A
§146.85(a)(6)(i)	In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	§3609.C.4.e.i	in the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance, for example trust funds, certificates of deposit, surety bonds guaranteeing payment into a trust fund, and letters of credit. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	N/A
§146.85(b)(1)	The owner or operator must maintain financial responsibility and resources until:	§3609.C.4.f	The requirement to maintain adequate financial responsibility and resources is directly enforceable NATURAL RESOURCES Louisiana Administrative Code September 2022 158 regardless of whether the requirement is a condition of the permit. The owner or operator must maintain financial responsibility and resources until:	N/A

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.85(b)(1)(i)	The Director receives and approves the completed post-injection site care and site closure plan; and	§3609.C.4.f.i	the commissioner receives and approves the completed post-injection site care and site closure plan; and	N/A
§146.85(b)(1)(ii)	The Director approves site closure.	§3609.C.4.f.ii	the commissioner approves site closure.	N/A
§146.85(c)	The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.	§3609.C.4.h	The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response:	Sections 9.4 - 9.7
§146.85(c)(1)	The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.	§3609.C.4.h.i	the cost estimate must be performed for each phase separately and must be based on the costs to the Office of Conservation of contracting a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator;	N/A
§146.85(c)(2)	During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).	§3609.C.4.h.ii	during the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days before the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the commissioner. The owner or operator must also provide the commissioner written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and remedial response plan;	N/A
§146.85(c)(3)	The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.	§3609.C.4.h.iii	the commissioner must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the commissioner has approved the request to modify the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and response plan, if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the commissioner. Any decrease to the value of the financial assurance instrument must first be approved by the commissioner. The revised cost estimate must be adjusted for inflation as specified at §3609.C.4.h.ii. above;	N/A

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 36	LA 43:XVII.Chapter 36 Description	Permit Application
§146.85(c)(4)	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.	§3609.C.4.h.iv	whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the commissioner, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the commissioner.	N/A
§146.85(d)	The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.	§3609.C.4.i	The owner or operator must notify the commissioner by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure:	N/A
§146.85(d)(1)	In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	§3609.C.4.i.i	in the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the commissioner by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	N/A
§146.85(e)	The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94).	§3609.C.4.j	The owner or operator must provide the commissioner with an adjustment of the cost estimate within 60 days of notification by the commissioner, if the commissioner determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response	N/A
§146.85(f)	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	§3609.C.4.k	The commissioner must approve the use and length of pay-in-periods for trust funds or escrow accounts.	N/A

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

INTRODUCTION

July 2023

SECTION 0 – INTRODUCTION

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Project Overview

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) proposes a Carbon Capture and Sequestration (CCS) Project to collect concentrated carbon dioxide (CO_2) streams from third-party atmospheric emission points in southern Louisiana and route them to a suitable long-term, underground sequestration site located in Vermilion Parish, LA (Pecan Island Area Project). This CCS project will prevent the release of these greenhouse gas (GHG) emissions into the atmosphere.

The Pecan Island Area Project will use a phased approach, initially capturing a limited number of CO_2 streams, then expanding the collection network as additional industrial emitters are identified and agreements established to capture their CO_2 streams. The full network capacity will be designed to collect, transport, and sequester up to 10 million metric tons annually (MMTA).

The initial phase of this project is based on signed agreements with CF Industries and Nucor Corporation (Nucor) for sources of the CO_2 and with EnLink Midstream (EnLink) to provide a portion of the midstream service. CO_2 will be captured by CF Industries, transported by both ExxonMobil and EnLink, and ultimately sequestered underground in Vermilion Parish on acreage owned by ExxonMobil[1]. For the Nucor scope, CO_2 will be captured by ExxonMobil and transported and stored using the same infrastructure as with respect to CF Industries[2].

This permit application is for two injection wells considered as the initial phase of the Pecan Island Area Project. ExxonMobil plans to sequester 3.2 MMTA (1.6 MMTA per well) of CO_2 over the life of these two wells. ExxonMobil will also use these two wells as a template for further project phases.

The South Louisiana coastal area subsurface geologic environment provides an ideal CO_2 sequestration environment. The stacked sand-shale sequences of the Miocene-age rock are high in both porosity and permeability, which creates the ideal storage-and-trapping mechanism for the CO_2 to be permanently sequestered in this project.

During the selection process, other sites were considered for ExxonMobil's initial Louisiana CCS project. ExxonMobil ultimately selected its Vermilion Parish acreage for CO_2 sequestration because of its ideal subsurface geology and proximity to existing EnLink infrastructure.

[1] https://corporate.exxonmobil.com/news/news-releases/2022/1012_landmark-emissions-reduction-project-in-louisiana-announced
[2] https://corporate.exxonmobil.com/news/news-releases/2023/0601_lcs-nucor-agreement

Project Key Attributes

- Thick [redacted] storage reservoir in the Miocene-age rock consisting of stacked sand shale sequences with excellent permeability and porosity
- Single ownership by ExxonMobil of the surface, pore space, and minerals
- Proximity to planned EnLink pipeline to gather CO_2 and transport it to the sequestration facility in Vermilion Parish
- Executed agreements to off-take CO_2 from CF Industries and Nucor industrial facilities
- CO_2 storage capacity of [redacted], aligned with CF Industries and Nucor contracts, with infrastructure expansion potential to 10 MMTA of CO_2

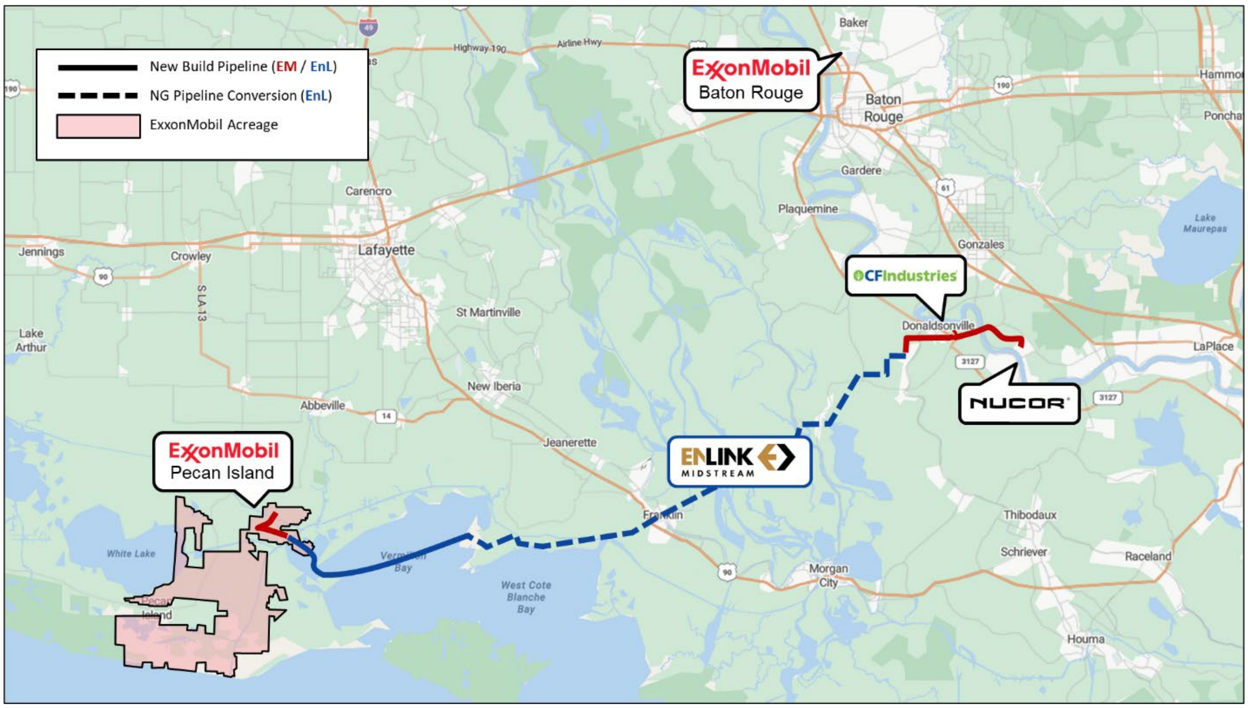

Figure 0-1 – Project Area Map

Pore Space Discussion

The acreage considered for sequestration for the Pecan Island Area Project has been owned by ExxonMobil since 1958, including surface and mineral rights. ExxonMobil has a long-term surface use lease with Vermilion Corporation for purposes of outdoor recreation. Vermilion Corporation, as surface use Lessee, has been actively engaged in the site-selection and overall project-planning process.

Proposed CO_2 Sequestration System Discussion

Collection lines will bring the CO_2 from each customer's location to a common transport line to be built and operated by ExxonMobil. The combined CO_2 stream will transfer custody to EnLink's planned pipeline, the majority of which will be repurposed from natural gas service. Repurposing an existing pipeline will reduce the environmental impacts associated with the CO_2 transportation network. EnLink will also build additional pipeline segments and a new compressor station near Vermilion Bay to boost the CO_2 stream from vapor phase to dense phase, and further transport the stream to the proposed sequestration facility. ExxonMobil will retake custody of the CO_2 stream and finish transporting it to a central facility, then distribute the CO_2 to individual wells for injection and sequestration.

Injectate Information

Each of the Pecan Island Area Project injection wells is designed to inject [redacted]. The CO_2 streams from different emitters along the Mississippi River Valley (*i.e.*, CF Industries and Nucor) will be combined and will meet the overall thresholds shown in Table 0-1.

Table 0-1 – CO_2 Injection Stream Composition

Component	Value
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

*ppmv – parts per million by volume
**MMCF - million cubic feet

Surface Facility Details

As the dense phase (supercritical) CO_2 is delivered to the Pecan Island Area Project area, a booster station may be installed to pump the CO_2 to the final required pressure for injection. Then the CO_2 will be delivered to each injection well via permanently-installed distribution lines. ExxonMobil will install a monitoring system to ensure that the CO_2 is properly monitored over the life of the project and that the Underground Sources of Drinking Water (USDWs) are protected.

Site Suitability

ExxonMobil's acreage in Vermilion Parish is well-suited for the location of the planned sequestration project due to its location relative to CO_2 sources, its subsurface geology able to store large volumes of CO_2, and its proximity to planned EnLink infrastructure. In addition, ownership by ExxonMobil eliminates concerns about land ownership and access. The surface location was picked based on geologic subsurface feasibility studies, and access to those locations was adjusted to reduce surface impacts. Water-depth data, soil data, and site-specific marsh conditions were analyzed to identify the shortest and most efficient path to provide access to the injection wells, while reducing the amount of dredging and other impacts to the water bottoms.

In compliance with the applicable regulations, an evaluation of the proposed site ("Site Suitability") was conducted by considering factors such as:

- Location of the proposed project site relative to potential emitters and pipelines
- Consideration of the project area relative to federal sites, buildings, and facilities.
- Threatened and endangered species surveys
- Flood zone
- Existing infrastructure, surface, and subsurface mines or quarries
- Faults or fractures in the project area based on seismic analysis or geophysical well-log characterization
- State or federal subsurface cleanup sites within the project area
- Environmental justice issues
- Artificial penetrations in the project area
- USDWs in the project area

These site-specific questions are answered throughout the permit application. The result of this evaluation was the selection of the site for the proposed injection wells and associated facilities.

Summary

Pecan Island Injection Wells No. 001 and No. 002 are planned for the Pecan Island Area Project as part of the initial phase of an overall project. This phase will support 3.2 MMTA of CO_2 sequestration and storage. ExxonMobil's overall project goal is to ultimately sequester 10 MMTA of CO_2. This permit application includes details of the geologic investigation, reservoir model, design of the Class VI well, and all the associated components required as part of Statewide Order (SWO) 29-N-6 [Title 40, U.S. Code of Federal Regulations (40 CFR) Part 146 Subpart H].

This permit application is comprised of 10 sections that will address the regulatory requirements of the permit application.

Required Administrative Information

General Application Information

Injection Well Information:

Well Name and Number	Pecan Island Injection Well No. 001
Parish	Vermilion

[redacted]

Well Name and Number	Pecan Island Injection Well No. 002
Parish	Vermilion

[redacted]

Applicant:

Name	ExxonMobil Low Carbon Solutions Onshore Storage LLC
Address	22777 Springwoods Village Parkway Spring, TX 77389

[redacted]

Ownership Status	Limited Liability Company
Entity Status	Public

Standard Industrial Classification (SIC) Codes:

- 4953 – Refuse Systems (nonhazardous waste disposal sites)

This project is not located on Federal, State, or Indian lands.

Additional Permits

Table 0-2 – Additional Required Permits

Agency	Permit & Authorization	Filing Date	Anticipated Receipt Date	Status
[redacted]				

*Anticipated

ExxonMobil

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 1 – SITE CHARACTERIZATION

July 2023

LONQUIST SEQUESTRATION LLC

SECTION 1 – SITE CHARACTERIZATION

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1.1 Overview

This site characterization for ExxonMobil's Pecan Island Project was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3607.C.2.m** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(3)**]. This section describes the regional and site geology for the proposed location. The site characterization incorporates analysis from multiple data types from public, proprietary, and licensed datasets, including well logs, 3D seismic, academic and professional publications, and existing core-sample analyses.

1.2 Regional Geology

The proposed Pecan Island Project is located in southern Louisiana within the Gulf of Mexico basin. The area relative to present coastal boundaries is displayed in Figure 1-1. The basin contains successive strata from the Jurassic to the Holocene, up to 20 km thick. A generalized stratigraphic column of the northern Gulf of Mexico basin is shown in Figure 1-2 (modified from Mattson, 2019).

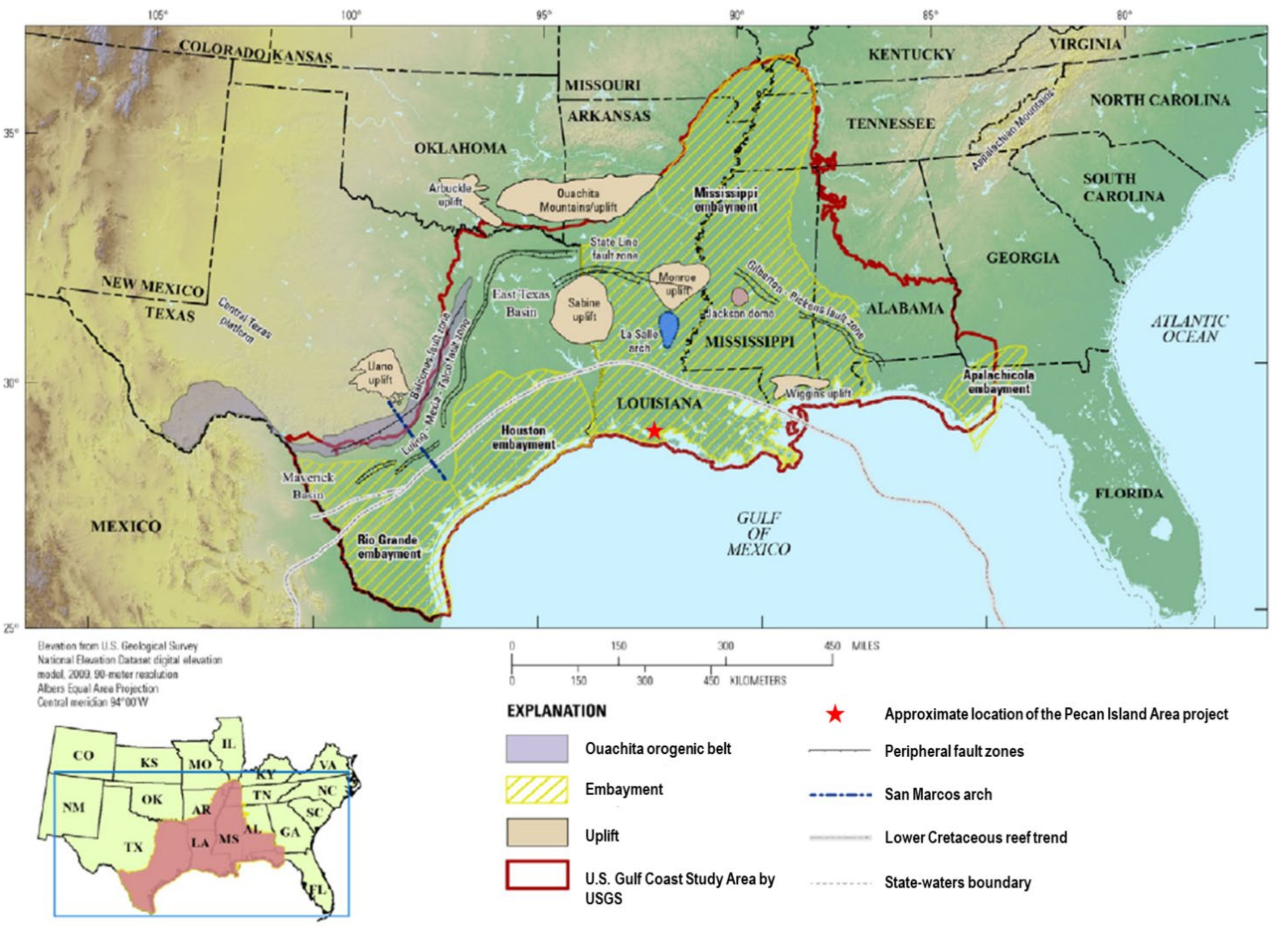

Figure 1-1 – Regional Project Location Map (modified from Roberts-Ashby et al., 2012)

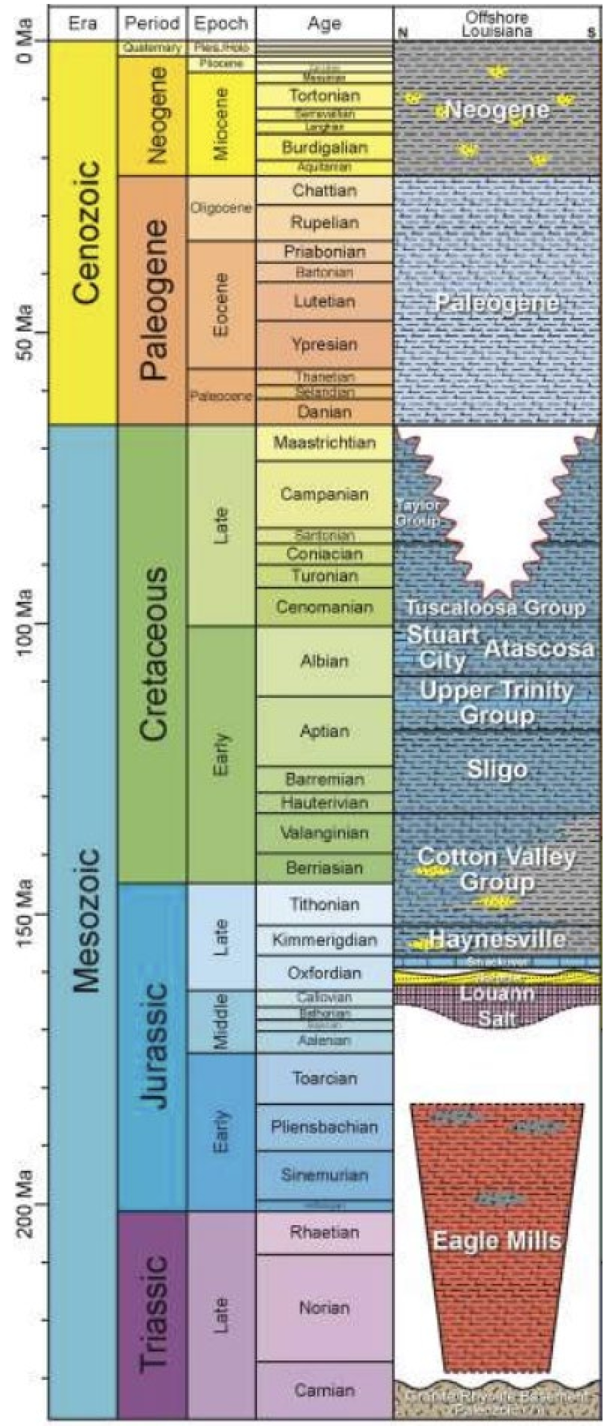

Figure 1-2 – Gulf of Mexico Stratigraphic Column (Mattson, 2019)

The Gulf of Mexico basin was created by extensional rifting events throughout the Mesozoic period that were responsible for breaking apart Pangea (Galloway, 2008). The earliest deposits occurred during the Late Triassic to Early Jurassic in graben structures produced by rifting. This graben fill is composed of non-marine Eagle Mills formation red beds and volcanics. During the

Middle Jurassic, large-scale deposition of Louann Salt and associated evaporites began to accumulate (Galloway, 2008). These substantial evaporitic deposits (up to 4 km thick) became a defining characteristic for later structural evolution of the basin. Salt deposition ceased at the end of the Late Jurassic, as continued rifting produced oceanic crust.

By the Early Cretaceous, the outline and morphology of the present-day Gulf of Mexico basin was sculpted by subsidence and rimming carbonate platforms (Galloway, 2008). The Cenozoic depositional episodes along the northwestern Gulf of Mexico basin are fluvial-deltaic and shore-zone dominated—and reflect major phases of adjacent North American basins (Galloway, 2008).

Five North American tectonic phases have influenced the Gulf of Mexico basin's deposition: (1) Laramide uplift, (2) the mid-Cenozoic thermal phase, (3) basin and range tectonism, (4) southern Appalachian and Cumberland Plateau uplift and erosion, and (5) Rocky Mountain plateau tectonic uplift. The southern Appalachian and Cumberland Plateau uplift during the Miocene shifted the center of deposition from the northwest basin margin to the east, including present-day Louisiana (Galloway, 2008).

The combination of subsidence and rapid sediment loading upon a thick salt substrate resulted in significant gravity tectonics. Some of these gravity tectonic structures include growth faults, allochthonous salt bodies, salt welds, listric normal faults, salt diapirs with their related synclines and mini-basins, and basin-floor compressional fold-belts (Galloway, 2008). Figure 1-3 is a profile of the Gulf of Mexico basin structure along a regional seismic line (Peel et al., 1995). The red star approximates the location of the Pecan Island Project site.

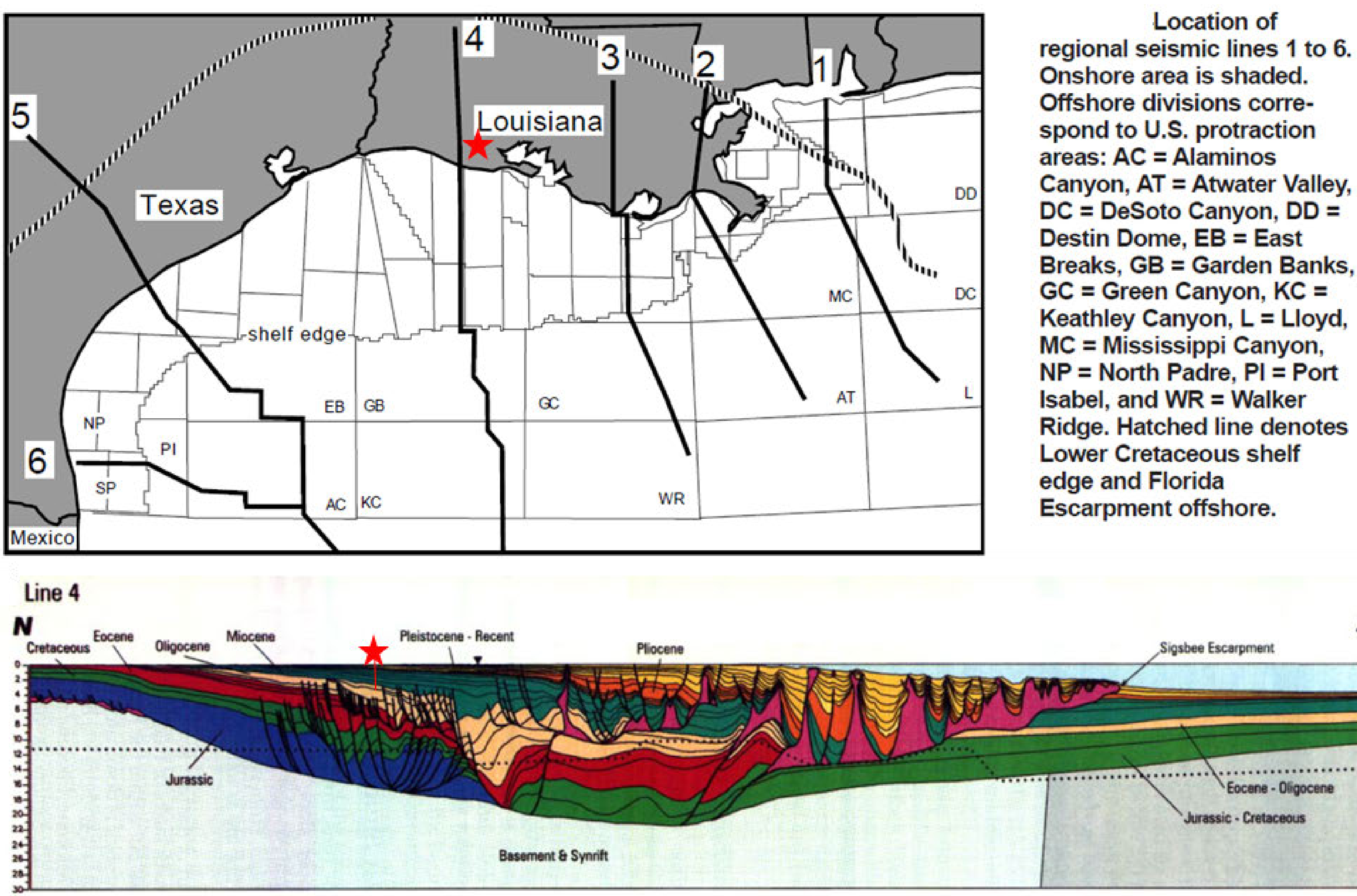

Figure 1-3 – Gulf of Mexico Basin Cross Section (modified from Peel et al., 1995)

1.2.1 Major Stratigraphic Units

The targeted formations for this study are Miocene age deposits. Figure 1-4 is a stratigraphic column of Gulf of Mexico basin Tertiary depositional episodes, and a detailed Miocene coastal onlap curve with associated key biochronozone markers (modified from Trevino & Rhatigan, 2017). Stratigraphic intervals of interest to this project are highlighted according to the associated function during injection operations. The Miocene strata decrease in age basinward, and the Miocene interval records a period of rapid subsidence and abundant deposition. Along the Gulf Coast of Louisiana, the Miocene is separated by biostratigraphic assemblages into lower II, lower I, middle, and upper series. It is characterized generally “as a thick wedge of regressive deltaic sands, silts, and clays” (Bearb, 2014) interspersed with transgressive marine-shale tongues. The deposition of these units mainly occurred on the broadening continental slope and underwent subsequent reworking by shallow marine and mass-wasting processes during periods of regression when sea levels decreased (Bearb, 2014). The stratigraphic units of interest within the area of review (AOR), as defined by plume extents outlined in *Section 2.10*, include middle and upper Miocene. The lower I and lower II sections in the project area are considered too deep and possibly overpressured, and thus were excluded from the storage interval.

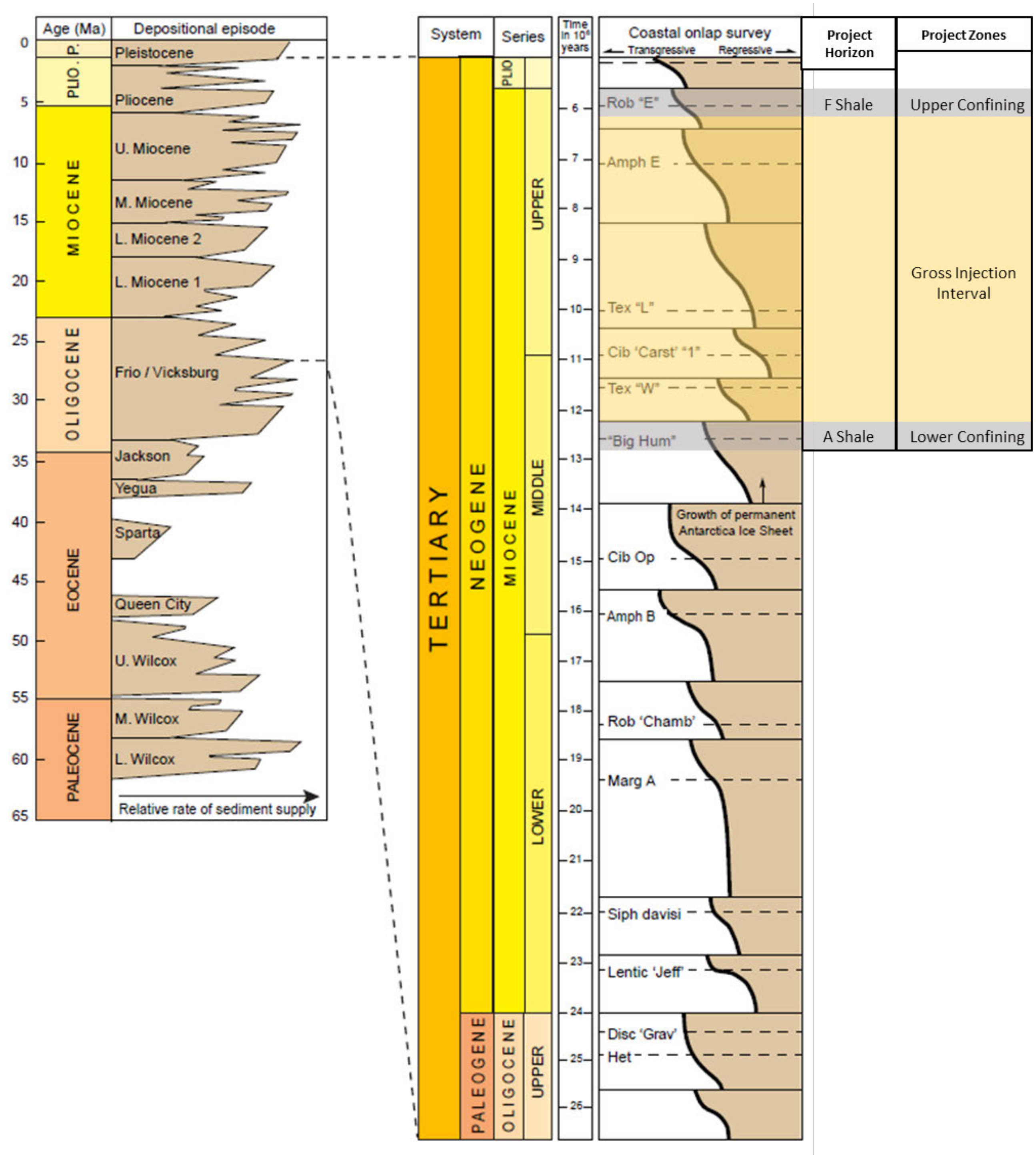

Figure 1-4 – Stratigraphic column of Cenozoic depositional episodes in the Gulf of Mexico basin relating Miocene sea-level fluctuations, with associated biochronozones, project horizons, and zones (modified from Trevino & Rhatigan, 2017).

The middle Miocene depositional episode records a 3-million-year (m.y.) span within the 5.5 m.y. middle Miocene interval. This sequence is bounded at the base by *Amphistegina B* (Amph B) and the top by *Textularia stapperi/wareni* (Tex W) benthic markers, both of which are areally extensive, transgressive marine shales (Galloway, 2008). The fine-grained, regionally deposited transgressive marine units in both the Amph B and Tex W are considered by the U.S. Geological Survey (USGS) National Assessment of Carbon Dioxide Storage Resources as good sealing units, and therefore the middle Miocene interval is “self-sealing” (Roberts-Ashby et al., 2012).

The upper Miocene section contains roughly 6.5 m.y. of rapidly deposited sediment in a progradational continental margin. Upper Miocene deposition begins following the Tex W maximal flooding surface and is bounded at the top by the *Robulus E* (Rob E) biostratigraphic marker, associated with a regional flooding event. The Miocene epoch contains 21.9% of the petroleum resources in the Gulf of Mexico, of which the upper Miocene accounts for 40%, demonstrating that the interval reliably forms seals over geologic time (Wu and Galloway, 2002). As with the middle Miocene interval, the USGS CO_2 storage assessment classifies the upper Miocene storage assessment unit (SAU) to be “self-sealing” (Roberts-Ashby et al., 2012).

The lower confining zone is the “A Shale,” explained below, projected to correspond to the biostratigraphic marker *Bigenerina humblei* (Big Hum). The gross injection interval is comprised of interbedded sandstones and shales from the middle and upper Miocene. The upper and middle Miocene series are similar in lithology and possess comparable reservoir characteristics across the Pecan Island Project region, and for the purposes of this permit application, are defined as a single injection zone. Only clean sand beds within the gross injection zone were modeled to store CO_2. Above the upper and middle Miocene gross injection zone is the F Shale Complex, which serves as the upper confining zone, and is projected to correspond to the Rob E biochronozone marker.

Lower Confining Zone: A Shale

The regionally deposited A Shale associated with the Big Hum biostratigraphic marker acts as the lower confining zone for this permit. The maximal flooding surface associated with the Big Hum coincides with high accumulations of fine-grained sediment, causing a significant progradation of the continental shelf. A decrease in sand-to-shale ratios on the shelf during this time suggests that sand was preferentially deposited away from the shelf and into deeper waters, and high sand accumulations in deeper basin fans in the Mississippi Canyon area are consistent with this suggestion (Fillon & Lawless, 2000).

Injection Zone: Upper and Middle Miocene Sandstones

Upper Miocene deposition was driven primarily by the ancestral Mississippi and Tennessee river systems. These deposits were fluvial-dominated along the Central Gulf of Mexico and prograded onto the continental slope, advancing the shelf edge by as much as 40–90 km (Galloway, 2008). The upper Miocene SAU, as defined by the USGS, covers an area of 1.9 million acres. Gross sandstone thickness in the upper Miocene SAU is estimated to be 5,400 ± 1000 ft and net sandstone thickness is 1,500 ± 400 ft (Roberts-Ashby et al., 2012). The USGS used the Nehring Associates' production database (2010) to determine porosity and permeability. From this database, porosity was determined from 432 petroleum-reservoir averages to be approximately 28 ± 4%. From that same database, permeability was estimated from 259 petroleum reservoirs along the coastal plain and found to be an average 500 millidarcys (mD) (Roberts-Ashby et al., 2012). As with other geologic formations, permeability can vary significantly, and individual reservoirs in the dataset exhibited permeability as low as 20 mD to as high as 8,000 mD.

Middle Miocene sandstones along the central Gulf of Mexico were fluvial-dominated deposits that extended the shelf basin-ward up to 70 km (Galloway, 2008). According to the USGS, the middle Miocene SAU has an area of 3.6 million acres. Gross sandstone thickness is estimated to be an average of 3,200 ± 900 ft, with net sandstone thickness estimated to be 480 ± 140 ft. As with the upper Miocene, porosity and permeability were calculated from Nehring Associates' dataset and were found to be 28% ± 4% and 500 mD.

Upper Confining Zone: F Shale Complex

The so-called F Shale Complex mapped across the Pecan Island Project area corresponds to the Rob E biomarker, which indicates the transition between the Miocene and Pliocene epochs. The F Shale Complex serves as the upper confining zone for this project. The Rob E biomarker is associated with a maximal flooding surface that deposited fine-grained sediments onto the continental shelf. As stated previously, the upper Miocene is responsible for 40% of all oil-equivalent production in the Miocene epoch, which demonstrates that the Rob E shale is a proven regional sealing body (Wu and Galloway, 2002). This statement is confirmed by the USGS CO_2 storage assessment, which refers to the upper Miocene as "self-sealing" (Roberts-Ashby et al., 2012).

Regional Shale Beds

The middle Miocene is capped by the regionally deposited transgressive marine shale Tex W, which marks the boundary between the middle and upper Miocene and is mapped in this project as "B shale." A regionally deposited marine shale within the upper Miocene is associated with the biostratigraphic marker *Bigenerina Floridana*, mapped in this project as "BF shale."

1.3 Site Geology

[redacted]

[redacted]

Figure 1-5 – Overview Map of Pecan Island Project Area of Review

ExxonMobil proposes to augment initial interpretations of site characteristics from the research conducted over the project area with two stratigraphic test wells at the locations of the proposed injection wells. [redacted] Site-specific subsurface information will be gathered during the drilling of the proposed stratigraphic test wells to update the data obtained from these investigative efforts.

A list of wireline logs planned during the drilling of the proposed well is provided in Table 1-1 and includes projected top and base depths designed to provide specific data pertinent to the site characterization application. Data collection during drilling may alter the top and base depths of investigation, in order to analyze the proposed target formations. Table 1-2 lists anticipated intervals of coring operations planned during the drilling of the proposed well to obtain mineralogical, petrophysical, mechanical, and geochemical data to provide data specific to this site characterization.

The stratigraphic test wells drilled prior to the issuance of the Class VI permit are planned to collect site-specific data to update this site characterization and associated models. Upon issuance of the Class VI order to construct, the stratigraphic test wells will be converted to the authorized injection wells.

Table 1-1 – Planned Geophysical Wireline Log Intervals

Geophysical Log Suite	Top Log Interval	Base Log Interval	Use
Gyro Survey	[redacted]	[redacted]	Directional survey
Gamma Ray	[redacted]	[redacted]	Lithology identification
HDIL** (Resistivity)	[redacted]	[redacted]	Fluid identification
Spontaneous Potential (SP)	[redacted]	[redacted]	Lithology/indication of permeability
Caliper	[redacted]	[redacted]	Borehole breakout direction identification
Sonic/Acoustic	[redacted]	[redacted]	Synthetic seismogram tie, rock property identification
Bulk Density/Density Porosity	[redacted]	[redacted]	Rock property identification
Neutron Porosity	[redacted]	[redacted]	Rock property identification
Magnetic Resonance	[redacted]	[redacted]	Reservoir storage potential
Resistivity Imaging	[redacted]	[redacted]	Dip analysis, fracture identification
Ultrasonic Imaging	[redacted]	[redacted]	Structural analysis, stress analysis, reservoir texture
Elemental Capture Spectroscopy	[redacted]	[redacted]	In situ mineralogy

*TD – total depth
**HDIL – high-definition induction log

Table 1-2 – Planned Core Intervals

Well No.	Interval Top (ft)	Interval Bottom (ft)	Stratigraphic Unit	Zone
[redacted]				

Reservoir characteristics and geological properties of the injection and confining intervals are drawn from proprietary, licensed, subscribed, and public data sources including LDNR Strategic Online Natural Resources Information System (SONRIS), Texas Bureau of Economic Geology, IHS LogNet, Enverus, TGS R360, Core Laboratories' Reservoirs Applied Petrophysical Integrated Data (RAPID) service, and published research. General geologic setting and lithological attributes are described regionally from publications and, when available, supported with offset wellbore and core data. Anticipated conditions across the proposed sequestration project site are estimated from petrophysical analyses of 481 wells with wireline logs, including 321 wells with Log *American Standard Code for Information Interchange* (ASCII) Standard (LAS) logs, and production data of wellbores adjacent to the proposed well site.

[redacted]

Table 1-3 – Injection and Confining Zones as Encountered in Well [redacted]

System	Group/Formation Name	Injection/Confining	Formation Top-Bottom (ft)	Thickness (ft)
[redacted]				

[redacted]

Figure 1-6 – Stratigraphic Column from [redacted]

[redacted]

Table 1-4 – Injection and Confining Zones as Encountered in Well [redacted]

System	Group/Formation Name	Injection/Confining	Formation Top-Bottom (ft)	Thickness (ft)
[redacted]				

[redacted]

Figure 1-7 – Stratigraphic Column from [redacted]

1.3.1 Injection Zone

The injection zone is composed of sediments deposited during the middle and upper Miocene, including two mapped shales associated with maximum flooding surfaces: *Bigenerina Floridana/Bigenerina A* and *Textularia wareni* as identified in (Olariu, DeAngelo, Dunlap and Trevino, 2019). Figure 1-8 relates the injection zone to the stratigraphic chart in the referenced publication.

The Mississippi River delta is the sediment source for the entire injection interval. The two ages of rock (middle and upper Miocene) vary slightly in proximity to paleoshoreline and position within the delta. Figure 1-9 relates the Pecan Island Project location to the paleogeographic setting during the upper and middle Miocene. During the middle Miocene, the sediment depocenter shifted eastward as the Tennessee River met the Mississippi River along the Louisiana shoreline, forming the Mississippi-Tennessee Delta System. The middle Miocene deposits at the AOR remained sourced within the Mississippi River delta, with minor changes as the Mississippi River advanced basinward and the delta plain shifted closer to the AOR. The western edge of the Mississippi-Tennessee Delta System shifted eastward during the upper Miocene and placed the proposed well-site location within the shore zone, along the western edge of the delta system. Longshore currents transported sediment westward from the adjacent Mississippi-Tennessee Delta System to the AOR.

Due to a shared sediment source and depositional setting, mineralogy of the whole injection interval will be similar. Miocene-aged sediments are primarily composed of interbedded sandstones, siltstones, and shale. Shales in this section are claystones rich in smectite. Detrital calcareous grains, often in the form of fossiliferous debris, are present throughout the interval. The sediments have undergone minimal diagenesis during burial and compaction.

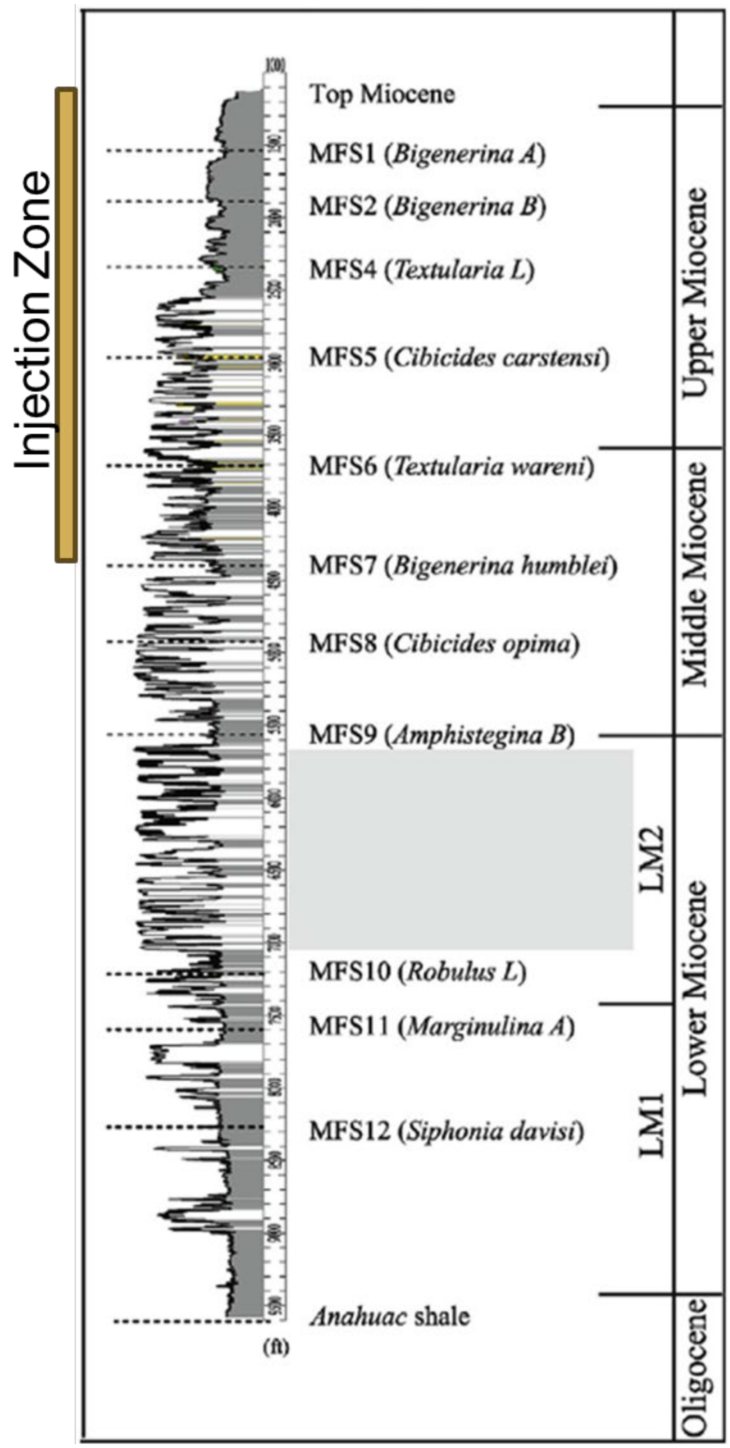

Figure 1-8 – Injection Zone in the Gulf of Mexico, Miocene Stratigraphic Section (modified from Olariu, DeAngelo, Dunlap and Trevino, 2019)

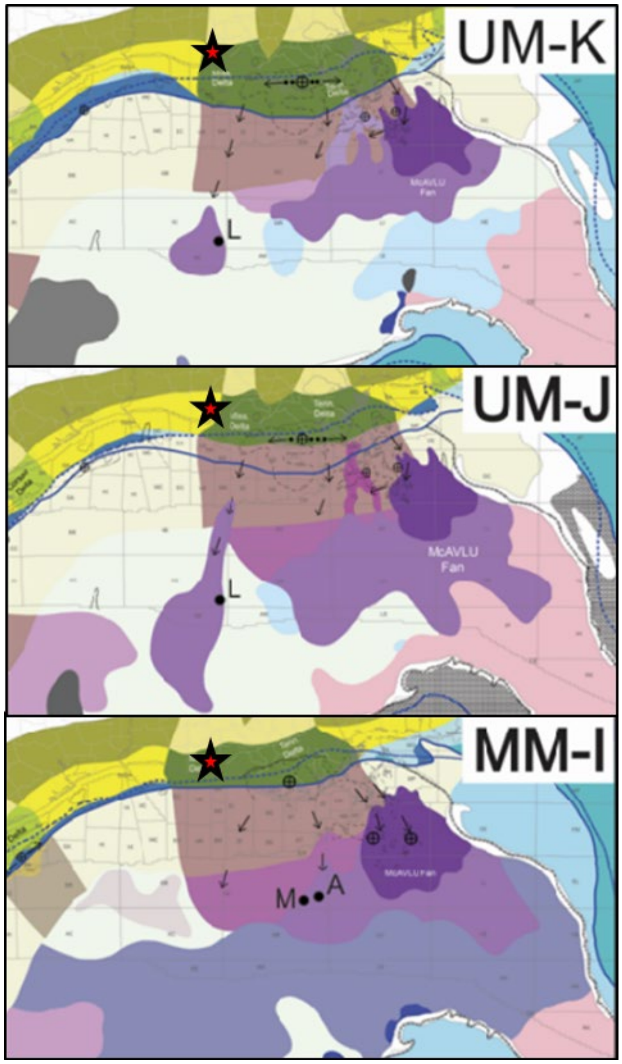

Figure 1-9 – Gulf of Mexico paleogeography during the upper and middle Miocene, increasing in age toward the bottom (modified from Combellas-Bigott & Galloway, 2005). The red star denotes the project location.

[redacted]

[redacted]

Figure 1-10 – Core Description of [redacted]

[redacted]

Figure 1-11 – Core Photographs from [redacted]

[redacted]

Figure 1-12 – Core Description of [redacted]

[redacted]

[redacted]

[redacted]

Figure 1-13 -Thin Section Microphotographs from [redacted]

[redacted]

Figure 1-14 -Thin Section Microphotographs from [redacted]

[redacted]

[redacted]

Figure 1-15 -Petrographic Point Count by % Bulk Volume from Wel [redacted]

[redacted]

Figure 1-16 – Averages of Petrographic Point Counts by % Bulk Volume from Well [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 1-17 – Whole Rock XRD from [redacted]

[redacted]

[redacted]

[redacted]

Figure 1-18 – Open-hole log of offset well [redacted] depicting the proposed injection interval.

1.3.2 Upper Confining Zone

The Upper Miocene depositional episode terminated with a regional flooding event associated with the Rob E biochronozone. Currently, no core analyses of the upper confining shale beds are found in public databases or published research. Core in the upper confining zone (UCZ) is planned to occur during the drilling of a stratigraphic test well. Once the data from the core is received, this permit application will be updated with the results of the analysis. The upper confining shales are anticipated to be similar in composition to fine-grained sedimentary rocks in clastic basins: mixtures of smectite and illite, with variable amounts of quartz, feldspar, kaolinite, and chlorite (Totten, Hanan, Knight, & Borges, 2002).

Three regionally mapped shale beds are included in the F Shale Complex UCZ: F shale, F secondary shale, and F tertiary shale. The F shale is denoted by the correlation marker TOP_F_SHALE to TOP_F_SANDS; the F secondary shale is defined by the markers TOP_F_SEC and TOP_F_SAND_SEC; and the F tertiary shale is bounded by markers TOP_F_TERTIARY and TOP_F_SAND_TERTIARY. Figure 1-19 displays the UCZ from the same offset well as above [redacted] The SP_NORM curve in the left track is an SP curve calibrated to other SP well logs in the project geocellular model, shaded to represent sand content, and the ILD curve in the right track is the measured deep-resistivity log. The deflection of the SP_NORM curve to the right and corresponding increase in deep resistivity over the mapped confining beds indicate fine-grained units—in this case, clay-rich shale.

[redacted]

[redacted]

Figure 1-19 – Open-hole log of offset well [redacted] depicting the proposed UCZ.

1.3.3 Lower Confining Zone

The lower confining A Shale is associated with a regional flooding event corresponding with the Big Hum biochronozone, a marker noted in nearby West White Lake Field as "a major shale break" (Steinhoff, 1964). Currently, no core analyses of the lower confining shale beds are found in public databases or published research. The lower confining shales are anticipated to be similar in composition to the UCZ shales, with a higher illite to smectite ratio corresponding with the deeper burial depths (Totten, Hanan, Knight, & Borges, 2002) (Dixon, 2005).

The A Shale confining zone is bounded at the top by the TOP_LOWER_CONF marker and at the base by the BASE_A_SHALE marker. Figure 1-20 displays the UCZ from the same offset well as above [redacted] The SP_NORM curve in the left track is an SP curve calibrated to other SP well logs in the project geocellular model, shaded to represent sand content, and the ILD curve in the right track is the measured deep-resistivity log. The deflection of the SP_NORM curve to the right and corresponding increase in deep resistivity over the mapped confining beds indicate fine-grained units—in this case, clay-rich shale.

[redacted]

[redacted]

Figure 1-20 – Open-hole log of offset well [redacted] depicting proposed lower confining zone.

1.3.4 Geologic Structure

Structural dips of sedimentary strata within the injection interval were mapped utilizing well control and 3D seismic data (Figure 1-21). Structure maps, cross sections, and isochor maps with further detail are included in *Appendix B*.

1.3.4.1 <u>Reflection Seismic Profiles</u>
Approximately 183 square miles (sq mi) of 3D surface seismic data was licensed by ExxonMobil Exploration Company and used for this interpretation. The analyzed dataset is a portion of the 182 sq mi from the "Catapult Merge 3D (2014 Merged Processing)," licensed by Seismic Exchange Inc., and 331 sq mi from "Cameron-Vermilion Depth 1," licensed by Geophysical Pursuit, Inc.

[redacted]

[redacted]

Figure 1-21 – Location of 3D Seismic Surveys

The resulting 3D reflection profiles, which image the subsurface based on velocity and density contrasts, were combined with geologic formation tops from subsurface well control, to map the proposed injection and confining intervals. The resulting maps represent formation depths and any discontinuities such as faults, shown in Figures 1-22 and 1-23.

[redacted]

[redacted]

[redacted]

Figure 1-22 – Structure Map of [redacted]

[redacted]

Figure 1-23 – Structure Map of Top Injection Interval

1.3.4.2 Velocity Control and Synthetic Seismogram

[redacted]

[redacted]

Figure 1-24 – Location of well with a checkshot velocity survey (indicated by blue circle), with wells used for synthetic ties to seismic (green circles). The yellow stars indicate the locations of proposed injection wells.

[redacted]

Figure 1-25 – Synthetic Seismogram Showing Well Calibration

[redacted]

Figure 1-26 - Seismic Line with Synthetic Well Ties

1.4 <u>Geomechanics</u>

1.4.1 Local Stress Conditions

Local formation stresses will be calculated by integrating mechanical rock properties from an X-dipole open-hole log, calibrated with geomechanical core tests. Details regarding the logging plan and relevant tests can be found in *Section 4 – Engineering Design and Operating Strategy*. According to published maps of crustal-stress orientation along the northern coast of the Gulf of Mexico basin, the maximum horizontal stress (SHmax) orientation is primarily parallel to the coast in an east-northeast direction near the AOR (Yassir and Zerwer, 1997) (Heidbach et al., 2016).

1.4.1.1 <u>Determination of Vertical Stress (S_v) from Density Measurements</u>

The vertical stress can be characterized by the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth (Aird, 2019). The average bulk density for the entire injection zone was assumed to be 2.21 grams per cubic centimeter (g/cm^3), which is an acceptable value for porous sandstone at this depth (Galloway W. E., Ganey-Curry, Li, & Buffler, 2000). The average bulk density of confining zones was assumed to be 2.23 and 2.34 g/cm^3 based on a nearby bulk-density log. A general overburden pressure gradient was chosen as 1.1 pound per square inch per foot (psi/ft), based on industry standards for onshore drilling (Zhang, 2019). Tables 1-5 and 1-6 shows the overburden gradient, vertical stress, and average densities of the upper confining, injection, and lower confining zones, respectively, for the two injection wells (Galloway W. E., Ganey-Curry, Li, & Buffler, 2000).

Table 1-5 – Calculated Vertical Stresses For Pecan Island Injection Well No. 001

Formation	Depth (ft)	Avg Density (g/cm^3)	Avg Density (lb/ft^3)	Vertical Stress (psi)	Gradient (psi/ft)
[redacted]	[redacted]	2.23	139.24	[redacted]	1.1
[redacted]	[redacted]	2.21	137.97	[redacted]	1.1
[redacted]	[redacted]	2.34	147.95	[redacted]	1.1

Table 1-6 – Calculated Vertical Stresses For Pecan Island Injection Well No. 002

Formation	Depth (ft)	Avg Density (g/cm^3)	Avg Density (lb/ft^3)	Vertical Stress (psi)	Gradient (psi/ft)
[redacted]	[redacted]	2.23	139.24	[redacted]	1.1
[redacted]	[redacted]	2.21	137.97	[redacted]	1.1
[redacted]	[redacted]	2.34	147.95	[redacted]	1.1

1.4.2 Elastic Moduli and Fracture Gradient

Elastic moduli, including inputs for Eaton's equation, will be determined from laboratory analysis of core samples and log data where applicable. Core samples are not available at this time and will be recovered during the drilling of the stratigraphic test well(s); the results of mechanical tests will be included in future permit updates. The core samples will undergo triaxial compressive strength testing to provide the geomechanical properties listed in Tables 1-7 and 1-8. The Poisson's ratios for the upper confining zone and the injection zone have been estimated based on literature and will be updated when laboratory results are available (Jin and Boahua, 2014) (Molina, Vilarrasa, and Zeidouni, 2016).

Table 1-7 – Triaxial Compressive Strength Test Results For Pecan Island Injection Well No. 001

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
[redacted]							

Table 1-8 – Triaxial Compressive Strength Test Results For Pecan Island Injection Well No. 002

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
[redacted]							

1.4.3 Injection Zone Fracture Gradient Calculation

The fracture pressure gradient was estimated using Eaton's equation. This method was created for Gulf Coast sands to determine the fracture pressure of the rock. Eaton's equation is commonly accepted as the standard practice for the estimation of fracture gradients (Eaton, 1969). The calculation requires Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) to determine the required pressure to fracture the injection zone, shown in Table 1-9. These variables can be changed to match the site-specific injection zone.

Through literature review and industry standards, the expected fracture gradient (Zhang, 2019) can be determined. A 1.1 psi/ft and 0.475 psi/ft were assumed for both the overburden and pore gradients, respectively. These values are considered best-practice values when there are no site-specific numbers available. Sandstones have a wide range of possible Poisson's ratios (0.1 – 0.4). Therefore, the literature focused primarily on sandstones that more closely represent the unconsolidated nature of the Miocene sands. Soft sandstones typically have a range of 0.2 – 0.35 (Molina, Vilarrasa, and Zeidouni, 2016).

In 2014, a case study was done to model fracture initiation in poorly consolidated sandstone. The Poisson's ratio for this rock was determined to be 0.24 (Jin and Boahua, 2014). From these papers, it was determined that a Poisson's ratio of 0.24 would be representative of poorly consolidated Miocene sands. Using these values in the equation below, a fracture gradient of 0.67 psi/ft was calculated. As a safety factor, a 10% reduction was then applied to this number, resulting in a maximum allowed bottomhole pressure of 0.60 psi/ft. This approach was used to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

$$FG = \frac{\nu}{1-\nu}(OBG - PG) + PG$$

$$FG = \frac{0.24}{1-0.24}(1.1 - 0.475) + 0.475 = 0.67\ psi/ft$$

$$FG\ with\ SF = 0.67\ \times 90\% = \mathbf{0.60\ psi/ft}$$

1.4.4 Confining Zone Fracture Gradient

Eaton's equation was employed to approximate the fracture gradient of the confining zones, as outlined in Tables 1-9 and 1-10. The pore and overburden gradients were assumed to be 0.475 psi/ft and 1.1 psi/ft, respectively. The confining zones, which are comprised of clay-rich shales situated above and below the injection zone, exhibit a Poisson's ratio with a typical range of 0.28–0.43, as reported by (Molina, Vilarrasa, and Zeidouni, 2016). As shown in Figure 1-27, clay content greater than 0.2 tends to raise the Poisson's ratio of the rock to above a value of 0.2 (Zhang & Bentley, 2005).

A value of 0.24 was selected as an estimate for Poisson's ratio of the confining intervals because the shales are classified as "clay-rich." These values were utilized in the equation below to arrive at a fracture gradient of 0.67 psi/ft. Applying a 10% safety margin yields a maximum allowable pressure of 0.61 psi/ft.

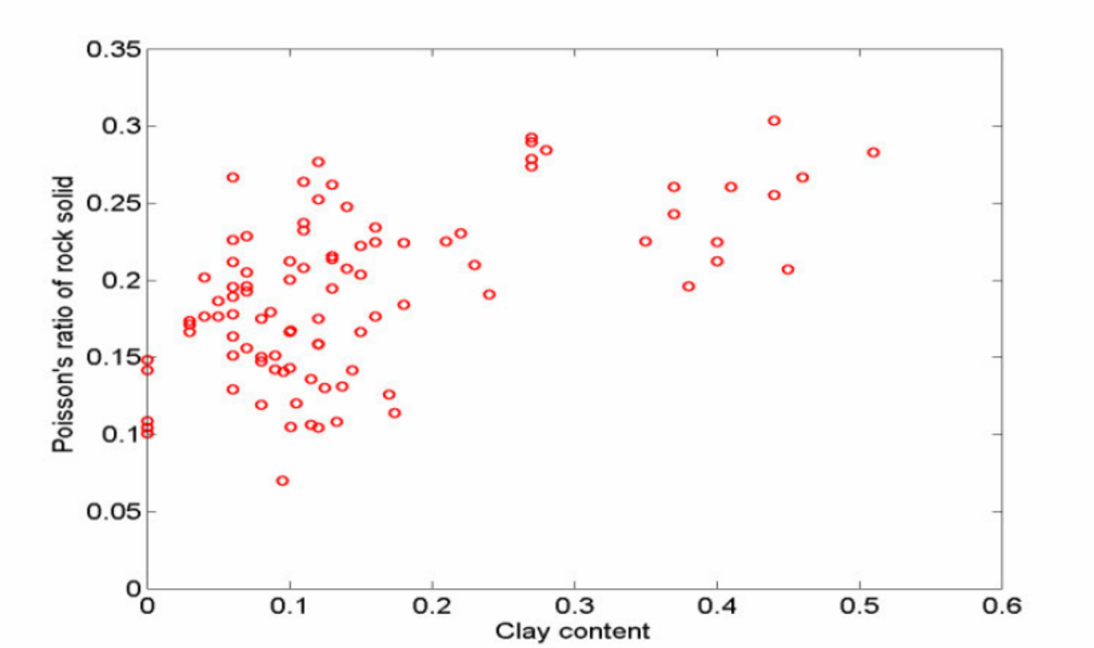

Figure 1-27 – Clay Content vs. Poisson's Ratio of Solid Rock (Zhang & Bentley 2005)

Table 1-9 – Confining Zone Fracture Gradients Calculated Using Triaxial Test Results or Eaton's Equation for Pecan Island Injection Well No. 001

Depth (ft)	Zone	Member	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
[redacted]			1.1	0.475	0.24	0.67
[redacted]			1.1	0.4755	0.24	0.67

Table 1-10 – Confining Zones' Fracture Gradient Calculated Using Triaxial Test Results or Eaton's Equation for Pecan Island Injection Well No. 002

Depth (ft)	Zone	Member	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
[redacted]				0.475	0.24	0.67
				0.4755	0.24	0.67

1.5 Porosity and Permeability

Distribution of porosity and permeability in the Cenozoic sandstone deposits of the Gulf of Mexico basin are influenced by deposition and diagenesis. The environments of deposition of injection-interval analogs, discussed in *Section 1.3.1*, are associated with highly porous and permeable sands. The transgressive marine environment in which the upper and lower confining intervals were deposited is associated with fine-grained sediment rich in swelling clay, such as smectite.

Both sand and clay lose porosity during the mechanical process of compaction, driven chiefly by overburden loading. During compaction, grains are reoriented and become more densely packed, while water is expelled from the pore space (Ulmer-Scholle, Scholle, Schieber, & Raine, 2014). In general, the porosity relationship is nonlinear but increases with depth, as shown in Figure 1-28.

As cementation may further reduce the pore volume between grains, the degree of cementation and potential impact on injectivity is analyzed in this section. In Figure 1-26 (*Section 1.3.4.2*), the pink shaded region between the pink compaction curve and purple cementation curve represents the range of porosity a sandstone may possess at a general burial depth. Gulf of Mexico sediments heated to temperatures above 100°C (212°F) are transformed by cementation and mineral alteration (Land, Milliken, & McBride, 1987). Quartz cement is primarily responsible for porosity occlusion in Miocene sediments of the Gulf of Mexico (Ajdukiewicz and Lander, 2010).

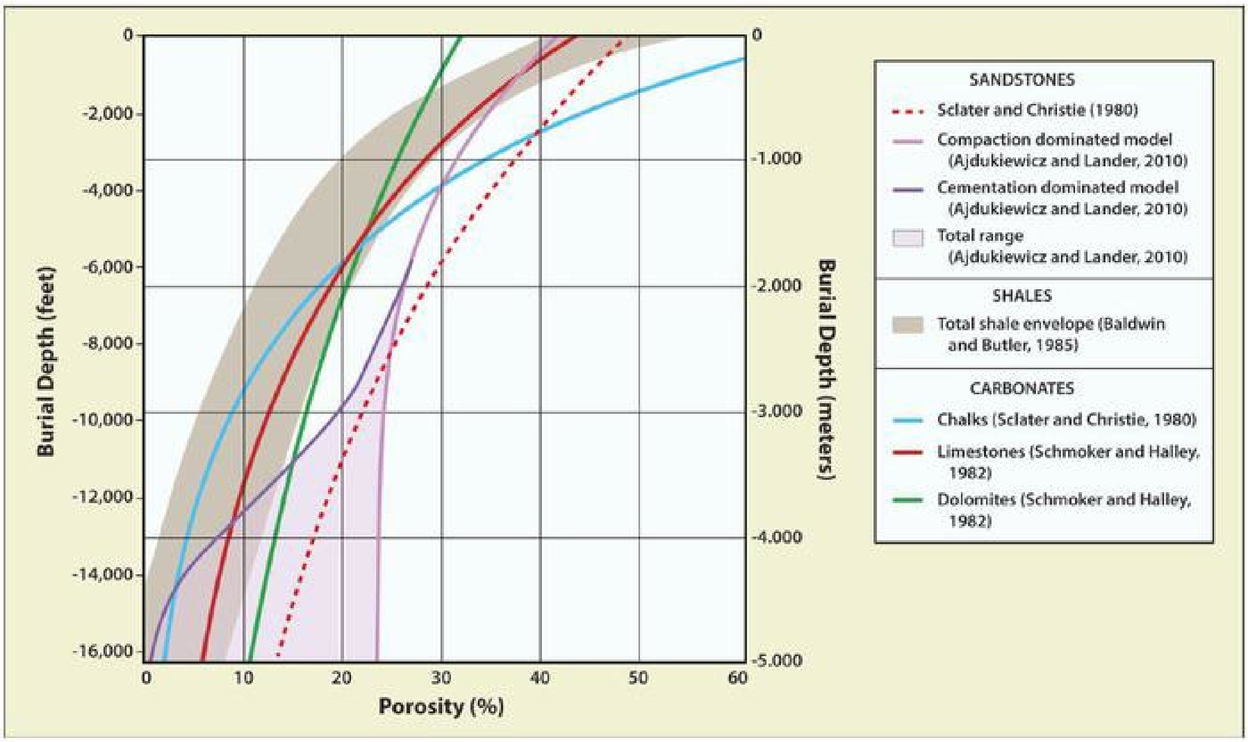

Figure 1-28 – General statistically derived porosity-depth curves for sandstones, shales, and carbonate rocks (Ulmer-Scholle, Scholle, Schieber, & Raine, 2014).

Globally, shales have, on average, about 12% total porosity but are full of water very tightly bound to individual clay minerals via surface tension and Van der Waals bonds. Pushing the water molecules out of these pores is very difficult and usually takes quite a bit of capillary pressure to do so in conventional oil and gas fields. As there is no difference in fluid-phase density in saline reservoirs that have 100% water saturation, no capillarity occurs to drive the bound water out, most often rendering the clay pores completely ineffective. Clay-bound pores are very small, which generate ample grain surface area to bind water and yield very high, irreducible water-saturation values. The bound water leaves shales with little to no effective porosity, despite the measured total-porosity values.

Porosity and permeability over the injection intervals were predicted using the ExxonMobil Reservoir Quality Forward Model (XOM-RQFM), a proprietary coupled effect-oriented compaction-and-cementation model that will be refined using data collected during appraisal. Effect-oriented compaction-and-cementation models are valid where compaction is an important mechanism of porosity loss, and where diagenetic alterations within the reservoir primarily involve insoluble aluminosilicates. [redacted]

[redacted]

1.5.1 Reservoir Quality Forward Modeling

RQFM is a prediction tool developed at ExxonMobil that uses analog data, a suite of diagenetic and petrophysical models, and stochastic modeling capabilities to (1) quantify the processes that control clastic reservoir quality at well locations, and (2) extrapolate and predict reservoir quality elsewhere in the basin. The primary data used to make model predictions are a detailed description of the *reservoir properties* (grain mineralogy, grain size, detrital clay content) and *burial history information* (temperature and effective stress history).

The most important controls on reservoir-rock quality at the Pecan Island Project site are grain mineralogy and texture (grain size and sorting, and rigid grain content). Figure 1-29 displays the results of multiple linear-regression modeling on the reservoir-quality dataset. Porosity and permeability are related, as evidenced in both properties' results. [redacted]

[redacted]

Figure 1-29 – Multiple linear-regression modeling of reservoir-quality dataset for (A) core porosity and (B) permeability.

1.5.1.1 Burial History

The burial history used for forward modeling is a high-resolution 1D burial, thermal, and pressure model. Figure 1-28 presents the results of the burial history model. The pseudo well on the right side of the burial plot is shaded to correspond with the included temperature-scale bar. [redacted]

[redacted]

Figure 1-30 – 1D basin model of a Pecan Island pseudo well indicating the injection interval and projected zone of quartz cementation.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

rate[redacted]*e*[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 1-31 Model Calibration Results

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 1-32 – Porosity and Permeability Plot with Transform Equation

Vshale is a ratio of shale volume calculated using the gamma ray log by the equation:

$$Vshale = \frac{(GR - GR_{sand})}{(GR_{shale} - GR_{sand})}$$

Where:

Vshale = shale volume, in percentage

GR = value of gamma ray curve

GR_{sand} = baseline sandstone gamma ray curve value

GR_{shale} = baseline shale gamma ray curve value

Total porosity (PHIT) is a measure of the void pace in a rock. Total porosity was estimated from existing open-hole logs, including neutron, density, and sonic or acoustic logs. Quality assurance was performed to verify LAS log data matched to original raster log data. Bulk density logs were examined for washouts (e.g., an increased hole size that causes a loss of contact between the padded density tool and the borehole, which overestimates porosity values). Washouts were excluded from trend lines and total porosity curves.

Effective porosity (PHIE) is a measure of the volume of connected void space, or pore space available for fluid movement, in a rock. As discussed above, shales have an average of 12% porosity but often a very low effective porosity. Effective porosity is calculated using Vshale and total porosity:

$$\emptyset_{eff} = \emptyset_{total} * (1 - Vshale)$$

Where:

Φ_{eff} = baseline shale gamma ray curve value

Φ_{total} = value of gamma ray curve

Vshale = shale volume, in percentage

1.5.2 Upper Confining Zone

[redacted]

[redacted]

Figure 1-33 – Log display of [redacted] calculated shale volume, porosity, and calculated permeability of the UCZ.

[redacted]

Figure 1-34 – Volume (%) of Facies Within Upper Confining F Shale Complex

1.5.2.1 Upper Confining Zone Porosity

Table 1-9 displays the average total and effective porosities for each of the UCZ complex confining beds. These values are not filtered by facies; the total porosity values greater than [redacted]

Table 1-8 – Upper Confining Zone Porosity Values

Confining Bed	Average Total Porosity (%)	Average Effective Porosity (%)
[redacted]		

Figure 1-35 is a set of histograms of total porosity in the confining bed and total porosity in the shale facies of the confining bed for each confining F shale.

[redacted]

Figure 1-35 – Histograms of confining beds within the [redacted]

1.5.2.2 Upper Confining Zone Permeability

Displayed in Figure 1-33, the permeability log values in the confining beds correspond to permeability calculated at the [redacted] Core analyses of the confining shale will be performed on samples taken from the test wells at the Pecan Island Project site, and this assumed value will be updated with measured data in future permit updates.

1.5.3 Injection Zone

[redacted]

[redacted]

[redacted]

Figure 1-36 – Log display of [redacted] calculated shale volume, porosity, and calculated permeability of the injection interval.

[redacted]

Figure 1-37 Volume (%) of Facies Within Gross Injection Interval

1.5.3.1 Injection Zone Porosity

Figure 1-38 is a set of histograms of (a) total porosity over the entire gross interval and (b) total porosity in the injection interval sand facies. [redacted]

[redacted]

Figure 1-38 – Histograms of PHIT Over the Injection Interval (a) All Facies and (b) Sand Facies

1.5.3.2 Injection Zone Permeability

[redacted] Core analyses at the Pecan Island Project site will calibrate the measured data to log data and refine the current model.

1.5.4 Lower Confining Interval

[redacted]

[redacted]

[redacted]

Figure 1-39 – Log display of [redacted] calculated shale volume, porosity, and calculated permeability of the lower confining interval.

[redacted]

Figure 1-40 – Volume (%) of Facies in Lower Confining Interval

1.5.4.1 Lower Confining Zone Porosity

[redacted]

[redacted]

Figure 1-41 – Histograms of lower confining interval, (a) all PHIT values and (b) PHIT filtered to shale facies.

1.5.4.2 <u>Lower Confining Zone Permeability</u>

Displayed in Figure 1-39, most permeability log values in the lower confining zone correspond to permeability calculated at the [redacted] Core analyses of the confining shale will be performed on samples taken from the test wells at the Pecan Island Project site and the permit's assumed values will be updated with measured data in future permit updates.

1.6 <u>Injection Zone Water Chemistry</u>

1.6.1 Injection Zone Water Chemistry

Results of fluid analyses measuring the total dissolved solids (TDS) and concentrations of ions and cations from water samples taken from a stratigraphic test well, once drilled, will be provided. However, to have a preliminary understanding of the regional variability in the water chemistry, both USGS publicly available data and ExxonMobil internal data are reviewed prior to upcoming water data from the test well. Regional water chemistry is examined from publicly available data from the USGS National Produced Waters Geochemical Database v.2.3. In addition, internal ExxonMobil brine chemistry data from the Pecan Island area (Table 1-10) is used for the geochemical modeling in *Section 1.7*. The main difference is in the TDS concentrations between the USGS and ExxonMobil datasets. To examine a potential regional relationship between TDS and depth, data was filtered by latitude and longitude, (29.4000, -92.45000) to (30.1000, -91.95000), respectively, in the Vermilion and Lafayette parishes; South Marsh Island; and offshore Vermilion for the USGS dataset. The TDS for the ExxonMobil brine chemistry is based on the average of six brines. The USGS data are plotted in Figure 1-42; the injection interval, indicated by the horizontal, red-dashed lines, is added for reference.

Table 1-9 – Formation Brine Chemstry

Species	Concentration	Units
TDS	[redacted]	mg/L
Sp. Grav	[redacted]	g/cm3
Ca	[redacted]	mg/L
Fe	[redacted]	mg/L
Mg	[redacted]	mg/L
Mn	[redacted]	mg/L
K	[redacted]	mg/L
Na	[redacted]	mg/L
SiO_2	[redacted]	mg/L
Cl	[redacted]	mg/L
HCO_3	[redacted]	mg/L
SO_4	[redacted]	mg/L

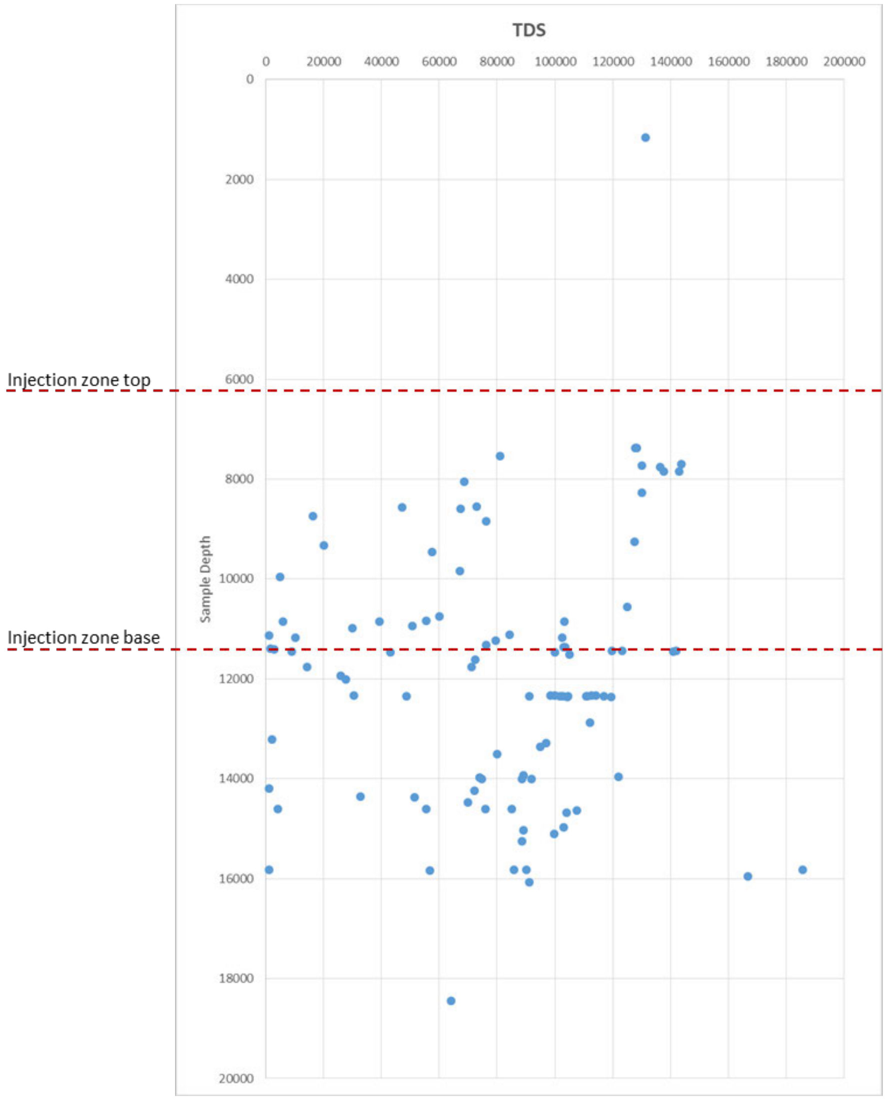

Figure 1-42 – Plot of TDS vs. Depth (ft)

Figure 1-43 is a plot of salinity vs. depth over a six-parish region in Southwest Louisiana including Vermilion Parish. The dashed line represents salinity of seawater, and the two horizontal solid lines represent the depth range to the top of overpressure in the region (Szalkowski, 2003). Figure 1-42 indicates that salinity varies significantly; however, Szalkowski et al. suggest a general decrease in salinity with depth in Allen and Vermilion parishes. The highly variable range in TDS throughout the region requires further data from the planned test well to reduce the uncertainty.

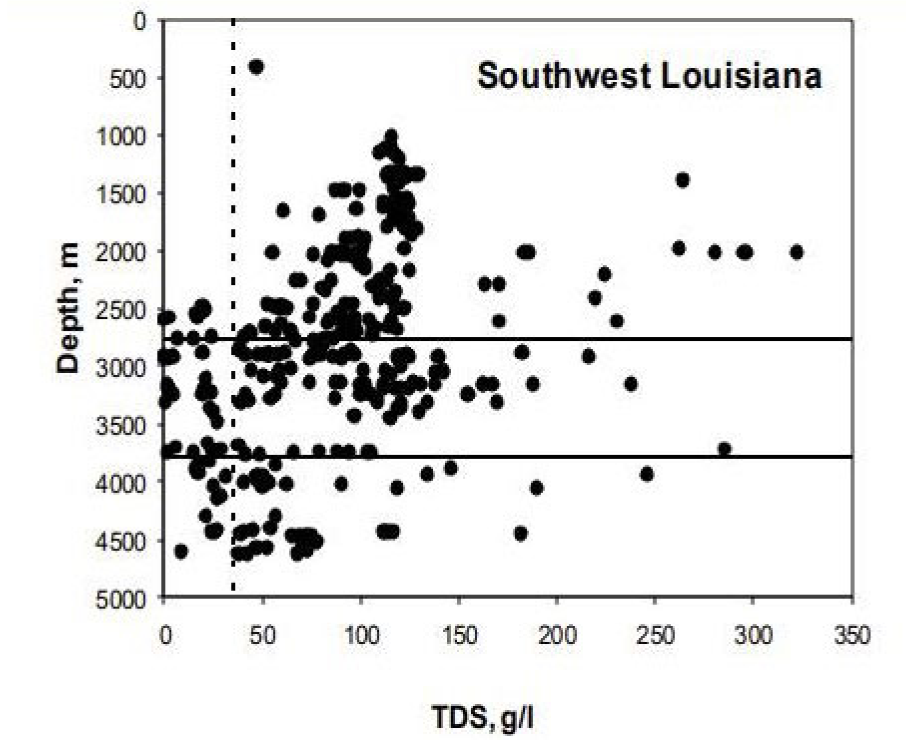

Figure 1-43 – Regional Plot of Depth (meters) vs. TDS (g/L) (Szalkowski, 2003)

In neighboring Iberia parish, a salinity profile of a single wellbore (SN 202104) is plotted in the modified Figure 1-44 (Ausburn, 2013). As indicated in the left plot of total dissolved solids versus depth, salinity above the zone of overpressure ranges from 35,000 to over 200,000 ppm. Ausburn notes that above the overpressure zone “salinities exhibit significant variability with no systemic change with depth” (Ausburn, 2013). The injection interval at the Pecan Island Project site is above the overpressure zone, and salinity is anticipated to vary over the interval, as also illustrated in Figure 1-42. Fluid samples to test salinity for the injection interval will be collected and measured during the drilling of the stratigraphic test wells.

Given the current lack of data specific to the Pecan Island area, a preliminary review of regional data provides insights into highly variable TDS with depth over the six-parish area in southeast Louisiana. Upcoming data from the test wells will provide the specific data needed to reduce the uncertainty in the geochemical characteristics of the brine at the Pecan Island site.

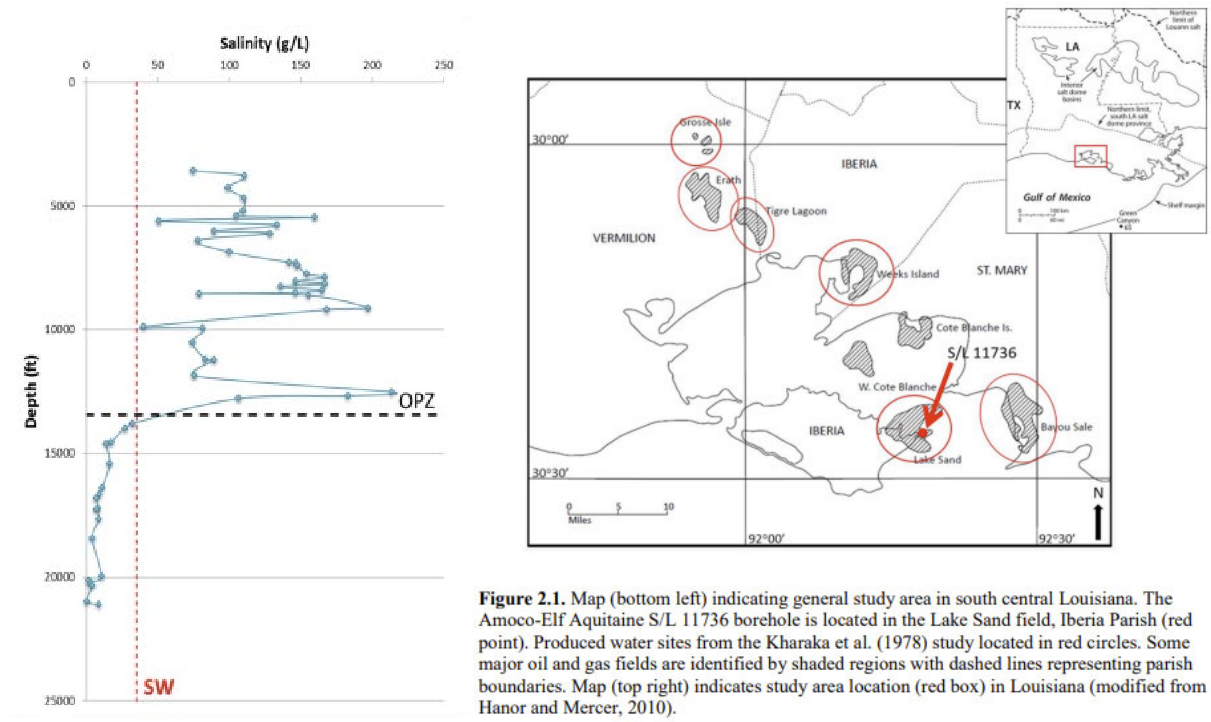

Figure 2.1. Map (bottom left) indicating general study area in south central Louisiana. The Amoco-Elf Aquitaine S/L 11736 borehole is located in the Lake Sand field, Iberia Parish (red point). Produced water sites from the Kharaka et al. (1978) study located in red circles. Some major oil and gas fields are identified by shaded regions with dashed lines representing parish boundaries. Map (top right) indicates study area location (red box) in Louisiana (modified from Hanor and Mercer, 2010).

Figure 1-44 – Salinity profile with depth over Amoco-Elf Aquitaine S/L 11736 (SN 202104) in Lake Sand Field, aside the well's location map (Ausburn, 2013).

To establish the baseline water chemistry of analogous saline aquifers closest to the AOR, available USGS water chemistry data was constrained by latitude and longitude (29.6000, -92.42000) to (30.0000, -92.02000), respectively, at samples between 6,200 and 11,500 ft deep in a sandstone lithology. A minimum filter of 35,000 ppm was applied, as a minimum of 35,000 ppm is expected in southwestern Louisiana above the depths of overpressure (Ausburn, 2013). The resulting table is displayed in *Appendix B* with an accompanying map.

1.7 <u>Baseline Geochemistry</u>

As part of the pre-drill assessment of the impact of CO_2 sequestration on the subsurface, the brine-mineral-CO_2 interactions are modeled to assess the potential alteration of both the reservoir and the sealing lithologies following CO_2 injection. The injection of CO_2 will result in disequilibrium in the brine-mineral-CO_2 system, with subsequent mineral dissolution and precipitation reactions occurring to restore equilibrium with the altered brine chemistry. Geochemical modeling, field observations, and laboratory experiments show that these reactions are driven by the specific mineralogy of the formation, the chemistry of the brine, the temperature, and the pressure of the formation. A set of reaction-path models from the host reservoir and the seal facies is presented to evaluate the impact of CO_2 sequestration on the mineralogy of the target formations.

1.7.1 Methods

Simple batch reaction-path models were developed using Geochemist's Workbench® (GWB; Bethke and Yeakel, 2012) for the reservoir and sealing formations. The model used the parameters in Table 1-11 for the brine chemistry, the mineralogy data in Table 1-12 for the reservoir formation, and Table 1-13 for the seal (shale) formation. The seal lithology is assumed to be shale and is subsequently referred to as "seal (shale)" in the text.

For the GWB model, the initial pH is 6.85 and the reservoir temperatures are 65°C and 95°C. Using the data in Tables 1-13, the thermo.dat database, and the CO_2 solubility of brines determined by Duan and Sun (2003), initial equilibrium models between the host lithology and the brine were modeled using the Spec8 and React modules of GWB. These results were used as the basis for the reaction path models during CO_2 injection.

There are multiple ways in GWB to simulate CO_2 injection. It is possible to either (1) set the fugacity of the CO_2 (g) as a single step and model the brine-mineral interactions, or (2) set a sliding scale of CO_2 input from the starting conditions to the final gas concentrations. Since these are preliminary models to evaluate both the reactions that will occur and the overall precipitation and dissolution of minerals, a discrete injection of CO_2 is used in the model. The CO_2 fugacity was set at 90 (approximately 130 bar) for the reaction-path model.

All data used in these preliminary models may be revised following further data acquisition, after additional wells are drilled in the area.

1.7.2 Brine Geochemistry

The brine composition used in the model was derived from internal ExxonMobil data from the Pecan Island area and is generally consistent with regional data provided in *Section 1.6*. The data are provided in Table 1-11. The TDS composition is an average of a set (n = 6) of brines in the area. The cation and anion data are from a comprehensive oilfield water analyses performed at an existing ExxonMobil Pecan Island producing well, from an interval equivalent to the targeted injection formation. The brine chemistry was equilibrated with the targeted reservoir formation and the sealing formation prior to injecting CO_2. The models were run at two separate temperatures, 65°C and 95°C, to capture the temperature variability at the upper and lower confining zones and throughout the reservoir.

Table 1-10 – Brine geochemistry data from the Pecan Island Project region used in the GWB reaction-path modeling.

Species	Concentration	Units
pH	[redacted]	
Temp		°C
TDS		mg/L
Sp. Grav		g/cm3
Ca		mg/L
Fe		mg/L
Mg		mg/L
Mn		mg/L
K		mg/L
Na		mg/L
SiO_2		mg/L
Cl		mg/L
HCO_3		mg/L
SO_4		mg/L

1.7.3 Reservoir Mineralogy

Specific reservoir-target mineralogy is not currently available for the Pecan Island Project site. Therefore, XRD data from a nearby location was used as an analogue for this study. The mineralogy for 12 samples representing the target reservoir is characterized by the minerals present in Table 1-12. Also included in the table are the minerals used as a substitution basis for the GWB modeling when multiple minerals, or solid-solution series, are available. The average values were used for the reaction-path models.

Table 1-11 – Reservoir Target Minerology Data

Mineral	Range (relative %)	Average (%)	Substitution
[redacted]			

1.7.4 Seal Mineralogy

Currently, little shale mineralogy exists for the targeted seal formation at the Pecan Island Project site. Therefore, as a proxy in the model, an average shale composition based on Yaalon (1961) was used—defined there as general mineral groups (i.e., clays, feldspar, carbonates, etc.). These are shown in Table 1-13 along with the minerals used to represent those categories for the reaction-path models. These models will be updated with appropriate data, once a project-specific, appropriate Pecan Island appraisal well is drilled and samples collected. However, these analogue datasets represent the dominant reactive mineral phases and are therefore appropriate for reaction-path models. Like the approach for the reservoir mineralogy, the minerals used for the substitution basis for the GWB model were included in Table 1-12. The average value was used for the reaction-path models.

Table 1-12 – Seal (Shale) Target Mineralogy Used in the GWB Models

General Mineralogy	Range (relative %)	Average (%)	Substitution
[redacted]			

1.7.5 Models

Two sets of GWB reaction-path models were created using the targeted-reservoir mineralogy in Table 1-12 and the seal (shale) mineralogy in Table 1-13 at 65° and 95°C. The models used the same formation-water chemistry, and each set of minerals was equilibrated with the appropriate mineralogy prior to CO_2 injection. The reaction-path model was used to simulate the possible geochemical reactions in the brine-mineral-CO_2 system. Initially, these models are established at equilibrium and then disturbed by the addition to CO_2. The subsequent geochemical reactions between the minerals and the new CO_2-brine conditions will result in the precipitation and dissolution of the minerals as the new equilibrium is established. Ultimately, the reaction-path model is a simulation to predict not only how the subsurface will react, but also the changes to porosity and permeability that may occur.

1.7.6 Results

The first step of the modeling was to equilibrate the formation brine with the mineral phases present. These equilibrium conditions were then reacted with CO_2 set at a fugacity of 90 (130 bar) at 65° and 95°C. The results of the two models are summarized in Figures 1-45 (reservoir) and 1-46 (seal). The total dissolution and precipitation amount of the minerals are displayed by tracking the change in volume (ΔVolume (%)) throughout the reaction. A value of greater than 0 for ΔVolume (%) indicates the precipitation of the mineral, and a value of less than 0 indicates dissolution relative to the equilibrium brine-mineral chemistry prior to CO_2 injection.

1.7.7 Reservoir Model

In the reservoir model, it appears that muscovite and quartz show minor amounts of precipitation, and K-Feldspar and albite show a similar amount of dissolution—whereas dolomite, calcite, and annite remain unchanged. Overall, there may be slightly greater dissolution relative to precipitation in the reservoir, but it is essentially balanced—with no significant change in pore-space volume, as shown in Figure 1-45.

[redacted]

Figure 1-45 – Reaction-path model results for the reservoir mineralogy at 65°C (A) and 95°C (B).

1.7.8 Upper and Lower Confining Shale

In the upper and lower confining shale models, most minerals appear to exhibit some degree of dissolution, including calcite, siderite, illite, smectite, quartz, and K-feldspar. The overall dissolution represents less than 0.01 volume % change, relative to the initial conditions for both the 65°C and 95°C conditions. The siderite and calcite remain relatively unchanged. Compared to the reservoir model, the relative ΔVolume (%) is minimal, but instead of quartz precipitation there is proposed quartz dissolution with no overall significant change in pore-space volume, as shown in Figure 1-46.

[redacted]

Figure 1-46 – Reaction-path model results for the sealing shale mineralogy at 65°C (A) and 95°C (B).

1.7.9 Baseline Geochemistry Summary

The reaction-path models provide initial modeling insights into the ways the subsurface target formations will respond to CO_2 sequestration. The mineralogies and brine-chemistry model inputs capture the major geochemical constituents to adequately model porosity changes caused by CO_2 injection. Results show that the variations in mineralogy among target zones will impact the subsurface response to CO_2 sequestration. However, the current model conditions indicate there will be no major changes in pore space due to dissolution or precipitation. The datasets will be updated as new data are collected from the test wells at the Pecan Island Site.

1.8 Hydrology

The following hydrologic review of Vermilion Parish was conducted for the Pecan Island Project area to properly characterize and protect potential Underground Source of Drinking Water (USDW) resources in the State of Louisiana. The study reviewed publicly available material published by the LDNR, the USGS, and literature from peer-reviewed journals. The LDNR online database supplied helpful documents regarding water-well and groundwater information. USGS studies contributed to the hydrologic evaluation and were utilized to source figures included in this section.

The average water withdrawal from Vermilion Parish, according to a 2010 report, is approximately 93.6 million gallons per day (Mgal/d), sourced from both groundwater (31.75 Mgal/d) and surface-water resources (61.86 Mgal/d) (White and Prakken, 2014). The Chicot Equivalent Aquifer System (Chicot EAS) is present across most of Vermilion Parish and represents the primary source of fresh groundwater for public, industrial, and rural domestic supply; rice, livestock, and general irrigation; and aquaculture uses. "In 2010, all reported groundwater withdrawals in Vermilion parish came from Chicot EAS" (31.75 Mgal/d). Surface-water contributions within the parish occur from the Vermilion River (20.18 Mgal/d), Bayou Queue de Tortue (20.18 Mgal/d), and other miscellaneous streams (21.50 Mgal/d) (White & Prakken, 2014).

1.8.1 Base of USDW Determination

A USDW structure map at the Pecan Island Project site and associated cross sections are included in *Appendix B.* Figure 1-47 is a structure map on the base of the USDW for Vermilion Parish, with a red star signifying the approximate location of the Pecan Island Project. The base of said USDW occurs within the Chicot EAS and generally ranges from less than 300 ft below the National Geodetic Vertical Datum of 1929 (NGVD 29) in southwestern Vermilion Parish, to roughly 1,000 ft below NGVD 29 in northeastern Vermilion Parish. No fresh groundwater is anticipated in the Chicot EAS south of White Lake, as designated by the grey shading in the southwestern portion of Figure 1-43 (White & Prakken, 2014).

[redacted]

[redacted]

Figure 1-47 – Base of USDW altitude map for Vermilion Parish, LA (White & Prakken, 2014). The red star represents the approximate location of Exxon's Pecan Island Project.

1.8.2 Stratigraphy of the Chicot Equivalent Aquifer System

The Chicot EAS consists of a series of shallow Pleistocene deposits that span roughly 9,000 square miles across southwestern Louisiana into portions of the Texas coastal lowlands. Aquifers are present within silt, sand, and gravel deposits interbedded with clay and sandy clay that dip and thicken toward the Gulf of Mexico (Hill, Kress, & Lindaman, 2022)). Moving south, deposits tend to grade from coarse sand and gravel to finer sediments that are increasingly subdivided by clay intervals (Lovelace, Fontenot, & Frederick, 2002). In Vermilion Parish, the Chicot EAS is comprised of shallow sand, upper sand, and lower sand intervals overlain by a surficial confining layer of silt and clay (White & Prakken, 2014).

Shallow Sand Interval

Shallow sand deposits occur as discontinuous sand streaks, lenses, and layers within the surficial confining unit. Shallow sand deposits are less than 100 ft thick in most of the parish but thicken to 250 ft south of Abbeville. Where this deposition occurs, overlying confinement thins to less than 20 ft thick, underlying confinement thins to less than 5 ft thick, and shallow sand deposits are saltwater saturated (White & Prakken, 2014). In 2010, there were 2,429 active water wells screened in the shallow sand (White & Prakken, 2014). Reported water-well depths ranged from 12 to 350 ft below land surface and reported yields varied from 2 to 3,600 gallons per minute (gal/min).

Upper Sand Interval

The upper sand underlies the surficial confining unit and contains some degree of freshwater throughout most of Vermilion Parish. The upper sand is generally freshwater bearing in northern parts of the parish but contains freshwater underlain by saltwater across most of the parish. In southwestern Vermilion Parish, the upper sand is completely saturated with saltwater as indicated by the gray shading in Figure 1-47 (White & Prakken, 2014). The upper sand is stratigraphically equivalent to the “200-foot” sand in the Lake Charles area (Lovelace, Fontenot, & Frederick, 2002).

“The top of the upper sand ranges from less than 200 ft to more than 600 ft below NGVD 29,and the base extends to about 1,200 ft or more below NGVD 29 within the parish” (White & Prakken, 2014). According to the USGS Water Resources of Vermilion Parish, there were 2,701 active water wells screened in the upper sand in 2010. Reported water-well depths ranged from 60 to 716 ft below land surface, with a median depth of 170 ft. Reported yields from the upper sand varied from 2 to 5,975 gal/min.

Lower Sand Interval

The lower sand is stratigraphically equivalent to the “500-foot” and “700-foot” sands in the Lake Charles area and is separated from the upper sand by a clay interval that ranges from 5 to 200 ft thick (Lovelace, Fontenot, & Frederick, 2002) (White & Prakken, 2014). The lower sand is generally saltwater bearing in Vermilion Parish, except for the extreme northeastern corner along the borders of the Lafayette and Acadia Parishes. Freshwater is present in the northeastern corner to a depth greater than 1,000 ft, but south of this area the lower sand is completely saturated with saltwater (White & Prakken, 2014). The USGS Water Resources of Vermilion Parish (2010) did not report any active wells screened in the lower sand.

The schematic cross section displayed in Figure 1-48 portrays individual sand intervals referenced herein and provides visual clarification of stratigraphic relationships within the Chicot EAS. The stratigraphic column displayed in Figure 1-49 clarifies Chicot stratigraphic nomenclatures among regions.

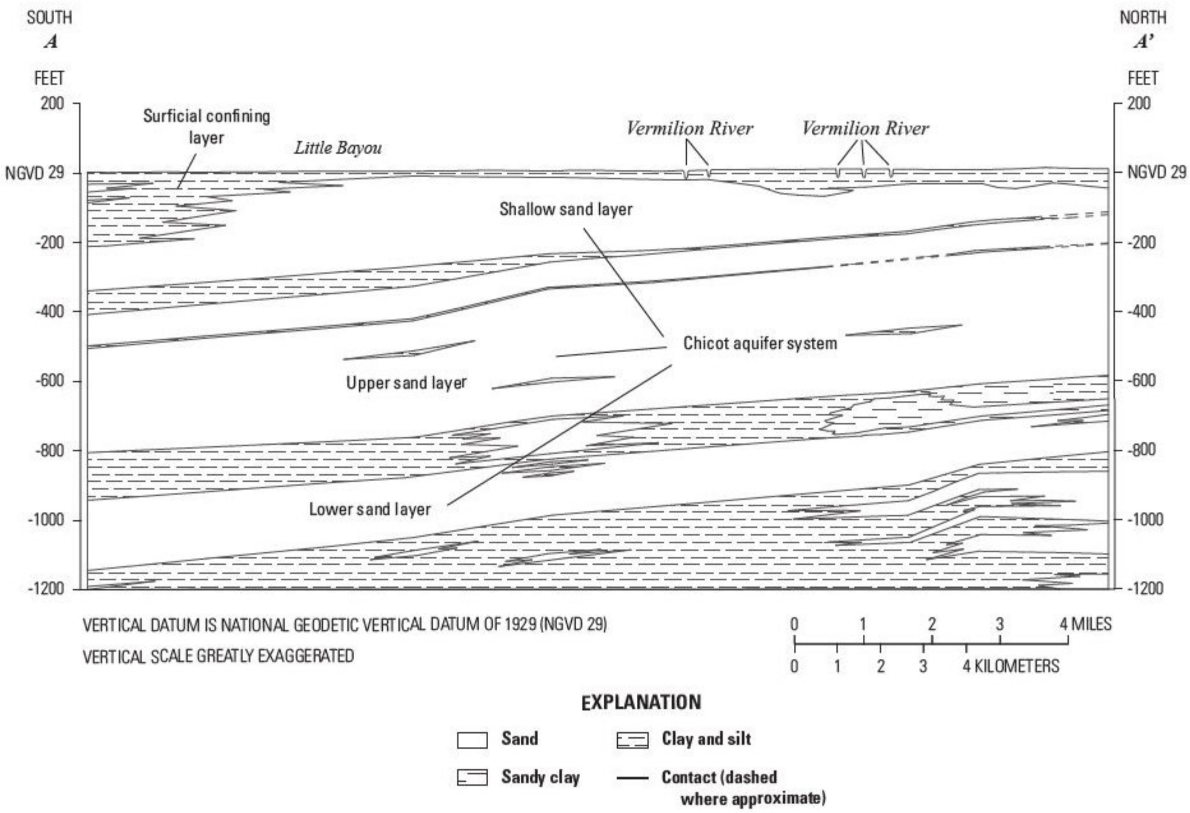

Figure 1-48 – Schematic cross section of sand layers of the Chicot aquifer system, Vermilion Parish (White & Prakken, 2014)—the line of section shown on Figure 1-47.

System	Series	Aquifer system	Aquifer	
			Lake Charles area	Rice-growing area
Quaternary	Pleistocene	Chicot aquifer system	"200-foot" sand of Lake Charles area	Chicot aquifer, upper sand unit
			"500-foot" sand of Lake Charles area "700-foot" sand of Lake Charles area	Chicot aquifer, lower sand unit

Figure 1-49 – Stratigraphic column displaying Chicot aquifer system nomenclatures (Lovelace, Fontenot, & Frederick, 2002).

1.8.3 Characteristics of the Chicot Aquifer System

Recharge and discharge

The primary source of recharge to the Chicot EAS is from direct "infiltration of precipitation where the aquifer system outcrop in the Allen, Beauregard, Evangeline, Rapides, and Vernon Parishes" (White & Prakken, 2014). Additional recharge to the aquifer is supplied from the east, where the system is laterally adjacent and hydraulically connected to alluvial deposits associated with the Atchafalaya River (Lovelace, Fontenot, & Frederick, 2002). The primary source of discharge from the aquifer system is from water-well withdrawals (White & Prakken, 2014).

Potentiometric surface and groundwater flow direction

Groundwater moves within aquifers from areas of higher hydraulic head to areas of lower hydraulic head, and the flow direction is generally perpendicular to potentiometric surface contours. A potentiometric surface map of the Chicot EAS published by the USGS (Figure 1-50) demonstrates that groundwater should flow north/northwest near the Pecan Island Project.

Groundwater within the Chicot EAS was once consistent across southwestern Louisiana, with a general flow direction from the north toward the coast, but large withdrawals of groundwater lowered water levels enough to form a cone of depression that affected flow direction in the region (Lovelace, Fontenot, & Frederick, 2002). Water levels within the Chicot EAS fluctuate seasonally by 1 to 3 ft, depending on water demands (White & Prakken, 2014).

[redacted]

Figure 1-50 – Potentiometric surface map of the Chicot aquifer system in southwest Louisiana (Lovelace, Fontenot, & Frederick, 2002). The red star approximates the location of the Pecan Island Project.

Water quality

Table 1-13 displays a statistical summary of water-quality characteristics from the 2010 USGS report discussing Water Resources of Vermilion Parish. The study sourced data from 196 wells screened in the Chicot EAS in Vermilion Parish. The median hardness is 200 milligrams per liter (mg/L), classifying Chicot EAS water as very hard. The iron and manganese concentrations were deemed generally too high, exceeding the EPA's Secondary Maximum Contaminant Levels (SMCLs) for drinking water. The pH of water collected from the Chicot EAS falls within the SMCL range of 6.5–8.5 standard units (White & Prakken, 2014).

Table 1-13 – Water-quality characteristics for freshwater from the Chicot aquifer system in Vermilion Parish (White & Prakken, 2014).

	Temperature (°C)	Color (PCU)	Specific Conductance Field, (µS/cm at 25 °C)	pH, Field (SU)	Hardness (as CaCO3)	Chloride, filtered (as Cl)	Iron, filtered (µg/L as Fe)	Manganese, filtered (µg/L as Mn)	Dissolved Solids, filtered
Chicot aquifer system (196 wells)									
Median	22	5	802	7.4	200	62	1,200	140	438
10th percentile	21	0	532	7.0	150	18	390	64	280
90th percentile	23	24	1,110	7.8	270	180	2,000	330	598
Number of samples	109	34	145	76	104	190	50	50	65
Percentage of samples that do not exceed SMCLs	NA	82	NA	99	NA	100	8	8	71
SMCL's									
	NA	15	NA	6.5-8.5	NA	250	300	50	500

[Values are in milligrams per liter, except as noted. °C, degrees Celsius; PCU, platinum cobalt units; µS/cm, microsiemens per centimeter; SU, standard units; CaCO3, calcium carbonate; µg/L, micrograms per liter; SMCL, Secondary Maximum Contaminant Level established by the U.S. Environmental Protection Agency (2012); NA, not applicable]

1.9 Site Evaluation of Mineral Resources

1.9.1 Active Mines Near the Proposed Injection Location

A search using public data was conducted. No active surface mines were identified near the proposed site of the geologic storage project. No surface mineral impacts from will occur from Pecan Island Project activities.

1.9.2 Underground Mineral Resources

A search for subsurface mineral production was conducted using publicly available data from the LDNR (SONRIS and Document Access) and subscription-based data (Enverus). The data was used to locate current and historical production zones within a 10-mile radius of the proposed well locations.

The collected data were pooled from a 10-mile radial search from the proposed locations. The data included locations, perforations, production history, current well status, and radial distance from the proposed project location. A total of 926 wells was identified. Table 1-15 summarizes the status count of the wells within the 10-mile investigation radius.

Table 1-14 – Ten-Mile Well Count by Status

Well Status	Total
ACT 404 ORPHAN WELL-ENG GAS	9
ACT 404 ORPHAN WELL-ENG NO PRODUCT SPECIFIED	10
ACT 404 ORPHAN WELL-INJECTION AND MINING NO PRODUCT SPECIFIED	4
ACTIVE - PRODUCING GAS	5
ACTIVE - PRODUCING OIL	8
ACTIVE- INJECTION COMMUNITY SALT WATER DISPOSAL	2
ACTIVE- INJECTION PRODUCED SALT WATER	8
DRY AND PLUGGED NO PRODUCT SPECIFIED	421
PA-35 TEMPORARY INACTIVE WELL TO BE OMITTED FROM PROD.REPORT GAS	8
PERMIT EXPIRED	70
PLUGGED AND ABANDONED DRY GAS	1
PLUGGED AND ABANDONED GAS	143
PLUGGED AND ABANDONED NO PRODUCT SPECIFIED	131
PLUGGED AND ABANDONED OIL	65
REVERTED TO SINGLE COMPLETION NO PRODUCT SPECIFIED	7
SHUT-IN PRODUCTIVE -FUTURE UTILITY GAS	16

SHUT-IN PRODUCTIVE -FUTURE UTILITY OIL	11
UNABLE TO LOCATE WELL-NO PLUGGED AND ABANDONED GAS	1
UNABLE TO LOCATE WELL-NO PLUGGED AND ABANDONED NO PRODUCT SPECIFIED	6
Grand Total	926

Sections 1.9.3 to *1.9.11* identify wells and their production intervals. The areas of investigation are subdivided into producing zones above the injection zone, producing intervals within the injection interval, and producing intervals below the injection zone. The investigation zones included a 2-mile radius, wells that were drilled within the plume, wells that were drilled and were not perforated, and nearby active production.

1.9.3 Distribution of Perforated Intervals

Figures 1-51 and 1-52 plot the distributions of perforation depth and distance from Wells No. 001 and No. 002. [redacted] The dark vertical line marks the 2-mile lateral extent from the proposed surface location. The area between these two limits identifies the nearest possible production zones within this study's review area. As can be observed, there is little producing activity within the radial extent.

[redacted]

Figure 1-51 – Well No. 001 Perforation and Depth Distribution

[redacted]

Figure 1-52 – Well No. 002 Perforation and Depth Distribution

1.9.4 Nearby Production Above the Injection Zone

The perforation intervals within 2 miles of the proposed locations and above the confining zone for Injection Well No. 001 were located. Table 1-16 includes the wells within the specified area of investigation—all of which were properly abandoned and will not be impacted by the Pecan Island Project.

Table 1-15 – Oil and Gas Wells Within 2 Miles of Injection Well No. 001 with Perforations Above the Confining Zone

Serial Number	API Num	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

The perforation intervals within 2 miles of the proposed locations and above the confining zone for Injection Well No. 002 were located. Table 1-17 includes the wells within the specified area of investigation—all of which were properly abandoned and will not be impacted by the Pecan Island Project.

Table 1-16 – Oil and Gas Wells Within Two Miles of Injection Well No. 002 with Perforations Above the Confining Zone

Serial Number	API	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

Historical files of the [redacted] and is plugged and abandoned. The wells located above the injection interval and above the confining zone will not be impacted by Pecan Island Project operations.

1.9.5 Nearby Production in the Injection Zone

The perforated intervals within 2 miles of the proposed well location for Injection Well No. 001 and in the injection zone were located. The wells in the investigation zone are listed on Table 1-18. The wells identified in the zone were all properly abandoned and will not be impacted by the Pecan Island Project.

Table 1-17 – Well No. 001 Oil and Gas Wells Within 2 Miles, with Perforations, in the Injection Zone

Serial Number	API Num	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

The perforated intervals within 2 miles of the proposed well locations for Well No. 002 and in the injection zone were located. The wells in the investigation zone are listed on Table 1-19. The wells identified in the zone were all properly abandoned and will not be impacted by the Pecan Island Project.

Table 1-18 – Well No. 002 Oil and Gas Wells Within 2 Miles, with Perforations, in the Injection Zone

Serial Number	API	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

A historical review of the [redacted]

1.9.6 Nearby Production Below the Injection Zone

The perforated intervals within 2 miles of the proposed locations and below the confining zone are listed in Tables 1-20 and 1-21. The wells listed in the table are plugged and abandoned and lie outside the projected plume and pressure front. The proposed Pecan Island Project will not impact the potential production of the nearby minerals.

Table 1-19 – Well No. 001 Oil and Gas Wells with Perforations, Below the Injection Zone

Serial Number	API Num	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

Table 1-20 – Well No. 002 Oil and Gas Wells with Perforations, Below the Injection Zone

Serial Number	API	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

It is not expected that nearby mineral production will be affected by the Pecan Island Project.

1.9.7 Wells Drilled in the Area without Perforations

Table 1-22 lists wells within 2 miles of Injection Well No. 001 that were drilled but not produced. The well files were reviewed to identify any productive intervals that were not identified during the search for perforations. All wells were plugged and abandoned; therefore, the Pecan Island Project will not affect any mineral production.

Table 1-21 – Well No. 001 Oil and Gas Wells Within Two Miles Drilled, Not Produced

Serial Number	API	Well Name	Surface Lat (NAD 83)	Surface Long (NAD 83)	Status	MD (ft)
[redacted]						

[redacted]

All wells identified in the table are plugged and abandoned. [redacted]

Table 1-22 lists wells within 2 miles of Well No. 002 that were drilled but not produced. The well files were reviewed to identify any productive intervals that were not identified during the search for perforations. All wells were plugged and abandoned; therefore, the Pecan Island Project will not affect any mineral production.

Table 1-22 – Well No. 002 Oil and Gas Wells Within 2 Miles Drilled, Not Produced

Serial Number	API	Well Name	Surface Lat (Nad83)	Surface Long (Nad83)	Status	MD (ft)
[redacted]						

[redacted]

All wells identified in the table are plugged and abandoned.

1.9.8 Wells Located above the Plume Location

Wells within the region that are above the predicted CO_2 plume extent were identified and are listed in Table 1-24. Figure 1-53 displays the location of the wells within the plume. A review of the history of the wells lists any existing wellbores that may be affected by the Pecan Island Project. This analysis revealed that all wells were plugged and abandoned. Intervals with historical production will not be affected by the Pecan Island Project.

Table 1-23 – Regional Wells Above the Predicted CO_2 Plume Extent

Serial Number	API	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

[redacted]

Historical well files for the [redacted] No interference with possible production was identified.

[redacted]

Figure 1-53 – Oil and Gas Wells in the AOR

1.9.9 Active Production Near the Proposed Injection

Figure 1-54 plots the perforation depths for active wells and the distance from the Well No. 001 location. The nearest active production occurs approximately [redacted] from the proposed location. Wells identified are provided in Table 1-25. The expected plume and pressure front are not expected to extend and interact with any of the active producing activity. This distance confirms that the Pecan Island Project will not have any effect on the nearby mineral production.

[redacted]

Figure 1-54 – Well No. 001 Perforation Depths vs. Distance for Active Producing Wells

Table 1-24 – Well No. 001 Oil and Gas Wells Within 6 Miles of Proposed Project Location

Serial Number	API	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

[redacted]

Figure 1-55 plots the perforation depths for active wells and the distance from the Well No. 002 location. The nearest active production occurs approximately [redacted] from the proposed location. Wells identified are provided in Table 1-26. The expected plume and pressure front are not expected to extend and interact with any of the active producing activity. This distance confirms that the Pecan Island Project will not have any effect on the nearby mineral production.

[redacted]

Figure 1-55 – Well No. 002 Perforation Depths vs. Distance for Active Producing Wells Within 6 Miles

Table 1-25 – Well No. 002 Oil and Gas Wells Within 6 Miles of Proposed Project Location

Serial Number	API	Well Name	Status	Upper Perfs (ft)	Lower Perfs (ft)	MD (ft)
[redacted]						

[redacted]

1.9.10 Nearby Active Production in the Current Producing Injection Interval

The nearest producing interval below the depth of the Well No. 001 proposed confining interval occurs at [redacted] The Pecan Island Project is not anticipated to interfere with this mineral production.

The nearest producing interval below the depth of the Well No. 002 proposed upper confining interval occurs at [redacted]. The Pecan Island Project is not anticipated to interfere with this mineral production.

1.9.11 Nearby Active Production Below the Confining Zone

The nearest producing interval below the Well No. 001 proposed confining interval occurs at [redacted]

[redacted] The Pecan Island Project is not anticipated to interfere with this mineral production.

The nearest producing interval below the Well No. 002 proposed lower-confining-interval depths occurs at [redacted] The Pecan Island Project is not anticipated to interfere with this mineral production.

1.10 Seismic History

An important consideration in the design and development of all new injection-well projects is the determination for the potential of injection activities to induce a seismic event. This section complies with the Class VI Rule, at 40 CFR 146.82(a)(3)(v). A four-step approach is conducted, including:

1. Identification of historical seismic events within proximity to the project
2. Faulting and determination of operational influences of nearby faults
3. Performance of a fault-slip potential (FSP) simulation model
4. Review of seismic hazards

1.10.1 Identification of Historical Seismic Events

An area of interest (AOI) with a 9.08-kilometer radius[1] was used for the historical seismic data investigation. This data is based on seismographic recordings from a global network of seismological stations. According to the USGS Earthquake Archive Search, no seismic events greater than a 2.0 magnitude[2] were recorded within the Pecan Island Project area (Figure 1-56). Further research was conducted on the National Centers for Environmental Information (NCEI), Texas Seismological Network and Seismology Research (TexNet), Northern California Earthquake Data Center (NCEDC), and Volcano Discovery seismic catalogs, which supported the USGS results. Although Louisiana is in an area of low seismic risk, a few earthquakes caused by natural seismicity or induced seismicity have occurred in the state, shown in Figure 1-57. The closest known earthquake to have occurred around the proposed location was a magnitude 4.2 earthquake (unknown depth) in 1930, in Assumption Parish, LA, 75 miles away from the Pecan Island Project area (Figure 1-57, indicated by the green dot).

[1] Railroad Commission of Texas FSP Area of Interest (AOI) Standard, adopted in this report.
[2] The magnitude of an earthquake is reported using the Richter scale, which measures the amount of energy (amplitude) generated at the source of an earthquake.

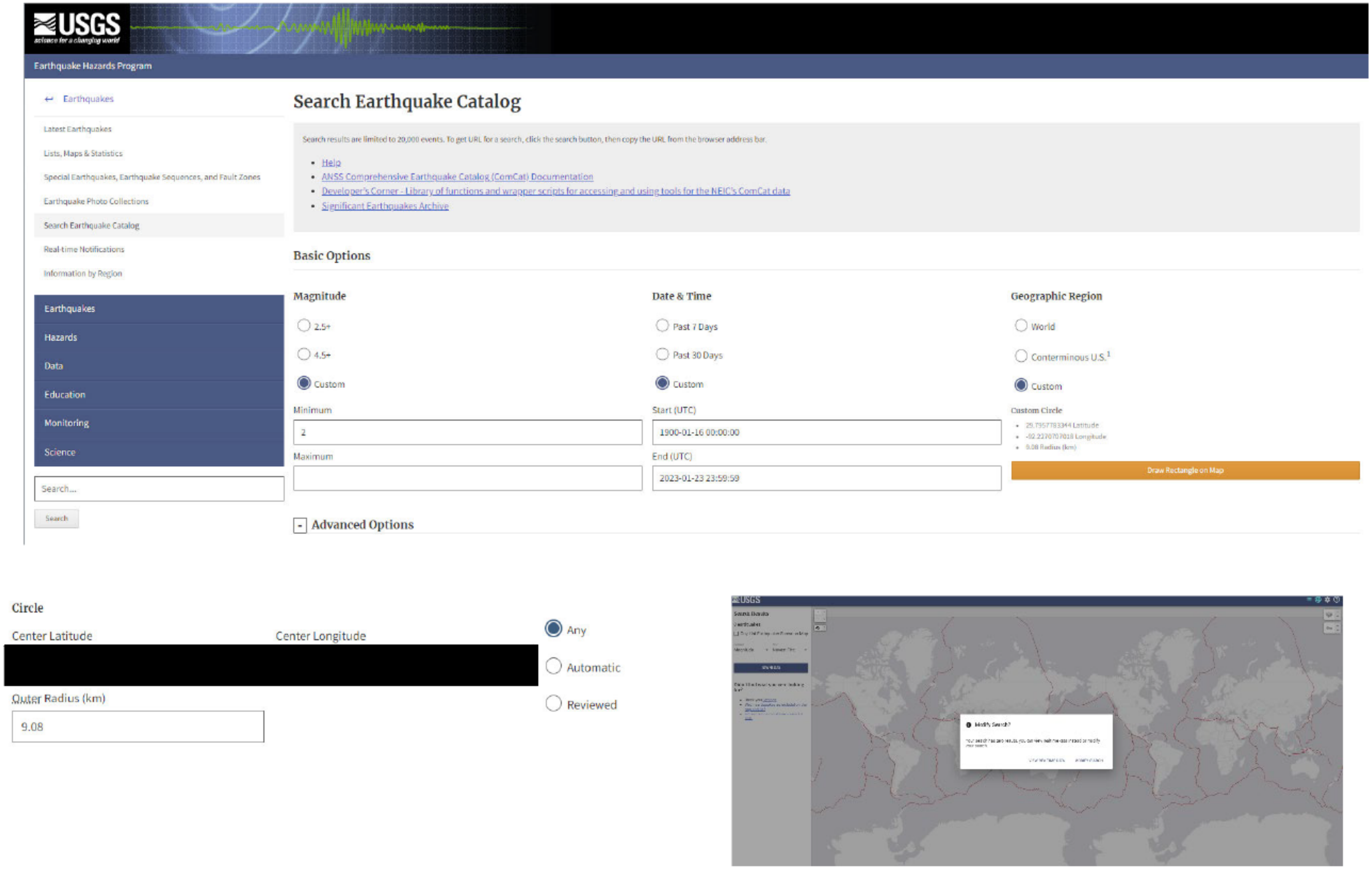

Figure 1-56 – Earthquake Search Parameters and Results from USGS Website

[redacted]

Figure 1-57 – All USGS- registered earthquakes inland and offshore LA. The red star is the location of the proposed project, the red circle is the 9.08 km radius around the project, and the green dot is the closest earthquake.

1.10.2 Faults and Influence

The USGS has developed a database with detailed information on faults and related folds across the United States (Figure 1-58). Regionally, the USGS catalogs the faults in southwest Louisiana as “Class B,” as most of the faults are in sediments and poorly lithified rocks—which are unable to sustain the forces necessary for the propagation of large seismic ruptures that could result in harmful ground motions. Also, there is a possibility that the post-rift sequence and its band of normal faults along the Gulf of Mexico margin are mechanically separated from the underlying crust, reducing the risk of a significant earthquake[3] (Crone & Wheeler, 2000). *Section 2 – Plume Model* discusses CO_2 and pressure plume results, demonstrating that multiple faults are adjacent to, but not breached by, injection operations for the Pecan Island Project.

[3] The USGS defines a Significant Earthquake to be > 600, a number derived by magnitude, number of Did You Feel It responses, and PAGER alert level.

[redacted]

Figure 1-58 – USGS Quaternary Fault and Fold Database of Louisiana and location of the proposed project (indicated by the red star) (USGS U.S. Quaternary Faults, 2023)

1.10.3 Fault-Slip Potential Model

The fault slip potential (FSP) model calculates the cumulative likelihood of a known fault exceeding Mohr-Coulomb slip criteria due to fluid injection. Pressure variations at the prospective site should be characterized to prevent fault reactivation or hydraulic fracture of the seal (Meckel & Trevino, 2014). Since faults were observed near the anticipated CO_2 and pressure plume extents, but no historical seismic activity data was found in the study area, the projected induced seismic risk is assumed to be low. Nevertheless, an FSP model was completed. The results and data used, including assumptions and uncertainty, are discussed in *Appendix I* of this application. The FSP demonstrated a low probability of injection-induced seismicity.

1.10.4 Seismic Hazard

The USGS's 2018 National Seismic Hazard Model (NSHM) Project and derived maps are recommended by the EPA as tools to assess seismic hazards. This model integrated and updated the 2014 NSHM including: fault models, seismic catalogs, ground-motion models, soil-amplification factors, amplified shaking estimates of long-period ground motions, population density, and seismic-hazard calculation. The 2018 Modified Mercalli Intensity[4] (MMI) earthquake hazard map (Figure 1-59) shows peak ground accelerations having a 2% probability of exceedance in 50 years, for a firm rock site. Figure 1-59 also predicts that southwestern Louisiana will most likely encounter a Class IV[5] or V[6] earthquake in the 50 years following the model, which was performed in 2018. The AOI is in the Class IV hazard region. Figure 1-60 illustrates the chance of a minor damaging earthquake occurring in 100 years over the conterminous United States, which shows southwest Louisiana to have a 4–19% chance of having a class VI[7] earthquake. Over a forecast period of 10,000 years, Figure 1-61 predicts fewer than two damaging earthquakes[8] to occur in southwestern Louisiana.

Based on the NSHM and the location of the proposed project, some earthquakes may occur in the future. The shake of these potential earthquakes is anticipated as Class IV–VI, causing furniture to be moved, and possible minor[9] damage to structures. Furthermore, according to the

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[4] The MMI scale ranges from I to XII. The following descriptions are from the Public Domain USGS Earthquake Hazards Program (originally abridged by Wood and Neumann, 1931).
[5] Class IV. "light; Felt indoors by many, outdoors by few during the day: At night, some are awakened. Dishes, windows, and doors are disturbed; walls make cracking sounds. Sensations are like a heavy truck striking a building. Standing vehicles are rocked noticeably."
[6] Class V. "moderate; Felt by nearly everyone; many awakened: Some dishes and windows are broken. Unstable objects are overturned. Pendulum clocks may stop."
[7] Class VI. "strong; Felt by all, and many are frightened. Some heavy furniture is moved; a few instances of fallen plaster occur. Damage is slight."
[8] Damaging earthquake shaking; meaning a level VI or higher earthquake causing structures failure.
[9] Minor damages; structural stable building, but some fallen plaster could occur.

NSHM, violent class IX[10] earthquakes are unlikely near the location of the AOI. In terms of natural hazards[11], Vermilion Parish is considered "Moderate" based on the National Risk Index, as hurricanes, landslides, riverine flooding, droughts, tornados, or ice storms could occur (Figure 1-62). However, communities are rated "Relatively High" in the ability to prepare for impending natural disasters (National Risk Index FEMA, 2023).

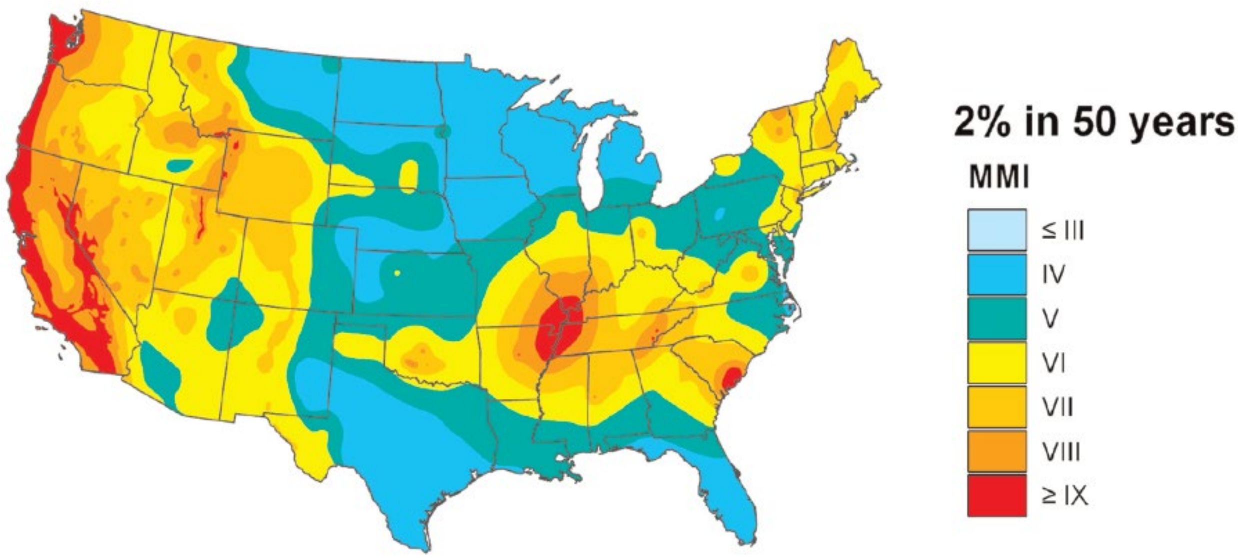

Figure 1-59 – Total mean hazard maps for 2% probability of exceedance in 50 years and location (indicated by the red star) of the proposed project (Petersen, et al., 2019, p. 33).

[10] MMI Class IX. "violent; Damage is considerable in specially designed structures; well-designed frame structures are thrown off-kilter. Damage is great in substantial buildings, with partial collapse. Buildings are shifted off foundations. Liquefaction occurs. Underground pipes are broken."

[11] Natural Hazard; 18 natural hazards: Avalanche, Coastal Flooding, Cold Wave, Drought, Earthquake, Hail, Heat Wave, Hurricane, Ice Storm, Landslide, Lightning, Riverine Flooding, Strong Wind, Tornado, Tsunami, Volcanic Activity, Wildfire, and Winter Weather.

[redacted]

Figure 1-60 – Location of the proposed project (indicated by the red star) plus population density, and the risk of a Class VI earthquake shaking in 100 years (Petersen, et al., 2019, p. 7).

[redacted]

Figure 1-61 – Predicted damaging earthquakes shaking around the U.S and the location of the proposed project (indicated by the red star) ("Frequency of Damaging Earthquake Shaking Around the U.S", retrieved 2023).

[redacted]

Figure 1-62 – The National Risk Index Map of natural hazards and the location of the proposed project, noted with a green star (National Risk Index FEMA, 2023).

1.11 Conclusion

The site characterization of the proposed injection wells, Pecan Island Injection Wells No. 001 and No. 002 indicates the upper and middle Miocene sandstones contain sufficient porosity, permeability, and lateral continuity and are of sufficient depth and thickness to store the proposed amount of CO_2. The F Shale Complex at the project site has low enough permeability and sufficient thickness and lateral continuity of the constituent mudstone beds to serve as the upper confining zone. The A Shale at the project site has low enough permeability and sufficient thickness and lateral continuity of its constituent mudstone beds to serve as the lower confining zone. No known faults are present within the AOR that may serve as potential CO_2 migration pathways in the upper and middle Miocene injection zones. Faults outside of the AOR are identified, mapped, and reviewed for potential migration pathways and are determined to be of low risk. Upon issuance of the Class V Order to Construct the stratigraphic test wells, additional data will be collected and assessed to ensure the site remains low risk for CO_2 injection and storage.

The following attachments are in *Appendix B:*

- Appendix B-1 SW-NE Structural Cross Section
- Appendix B-2 NW-SE Structural Cross Section
- Appendix B-3 SW-NE Stratigraphic Cross Section
- Appendix B-4 NW-SE Stratigraphic Cross Section
- Appendix B-5 Cross Section Reference Map
- Appendix B-6 Top Upper Confining Structure
- Appendix B-7 Top Injection Interval Structure
- Appendix B-8 Top Lower Confining Structure
- Appendix B-9 Top Regional Shale Structure (BF Shale)
- Appendix B-10 Top Regional Shale Structure (D Shale)
- Appendix B-11 Top Regional Shale Structure (B Shale)
- Appendix B-12 Upper Confining Isochore
- Appendix B-13 Injection Interval Isochore
- Appendix B-14 Lower Confining Isochore
- Appendix B-15 Upper Confining Net Shale
- Appendix B-16 Injection Interval Net Sand
- Appendix B-17 Lower Confining Net Shale
- Appendix B-18 Offset Produced Water Sample Composition and Map
- Appendix B-19 USDW to Injection Interval Cross Section (SW-NE)
- Appendix B-20 USDW to Injection Interval Cross Section (NW-SE)
- Appendix B-21 USDW Structure/Cross Section Reference Map
- Appendix B-22 USGS Potentiometric Surface Report
- Appendix B-23 USGS Potentiometric Surface Map

1.12 References

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Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 2 – PLUME MODEL

July 2023

SECTION 2 – PLUME MODEL

TABLE OF CONTENTS

Figures

Tables

2.1 Introduction

The following discussion of the plume model used for Pecan Island Injection Wells No. 001 and No. 002 was prepared to meet the requirements of Statewide Order (SWO) 29-N-6, **§3615.31** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84**]. This section describes the key details of the reservoir model. The plume defines the pore space rights, area of review (AOR) for the well, monitoring plans, corrective action plan as necessary, and overall viability of the project. Both *Section 3 – AOR and Corrective Action Plan* and *Section 5 – Testing and Monitoring Plan* use the forecasted plume to help determine the best strategies and plans to minimize the impact of carbon sequestration.

The primary objectives of the plume model are to do the following:

1. Select the strategically best well locations for CO_2 storage.
2. Optimize the available pore space for supercritical CO_2 storage.
3. Minimize the impact of offset injection through completion-strategy implementation and well design.
4. Assess CO_2 migration and pressure increase to avoid adverse impact on major subsurface structures.

2.2 Project Summary

The Pecan Island Project is located on ExxonMobil's property in South Louisiana. This property, known as Pecan Island, covers approximately [redacted] acres of land that may be used for carbon capture and storage (CCS). While the entire property may be used for CCS operations, this permit, and the plume modeling as discussed, is focused on Pecan Island Injection Wells No. 001 and No. 002, located in the northeast corner of Pecan Island. The northeast portion of the property encompasses approximately [redacted] acres available for CCS activities. The two injection wells currently planned for the project were included in the reservoir model to capture their interaction with each other. Each well injects [redacted] million metric tons annually (MMTA). Injection Well No. 001 is planned to inject for [redacted] years, resulting in [redacted] million metric tons (MMT) of supercritical CO_2 being safely sequestered. Injection Well No. 002 is planned to inject for [redacted] years, resulting in [redacted] MMT of supercritical CO_2 being safely sequestered. The two wells will collectively inject approximately [redacted] MMT over the planned injection periods. Figure A-4 in *Appendix A* provides a detailed description of the property.

2.2.1 Software

2.2.1.1 Petrel™ Software Suite

Schlumberger's Petrel™ Software was chosen to create a detailed geologic model for the CCS site. This state-of-the-art software is used worldwide and combines information from logs and seismic data to build an accurate representation of the underground reservoir. The Petrel™-developed geologic model shows the different layers of the site, including the F Shale Complex formation (upper seal), Upper and Middle Miocene Sands (injection zone), and Big Hum Shale (lower seal). Using Petrel™, the permeability and porosity properties of the injection were distributed, considering well-log analysis and established methods. These methodologies ensure a more precise depiction of the reservoir in the model.

2.2.1.2 Computer Modelling Group's (CMG) Software Suite

The geologic model developed in Petrel™ was used as an input into CMG's GEM **2022.10** (GEM) simulator. GEM is a widely recognized tool for modeling compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state (EOS) algorithms to evaluate compositional, chemical, and geochemical processes to produce a reliable simulation for CCS. The software can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

2.2.1.3 ExxonMobil Reservoir Quality Forward Model

A porosity-permeability relationship over the injection intervals was predicted using the ExxonMobil Reservoir Quality Forward Model (XOM-RQFM), a proprietary, coupled effect-oriented compaction-and-cementation model, and will be refined using data collected during appraisal. Porosity was first determined using well-log data, then this relationship was applied to determine the permeability across the injectable sands. Effect-oriented compaction-and-cementation models are valid where compaction is an important mechanism of porosity loss, and where diagenetic alterations within the reservoir primarily involve insoluble aluminosilicates. These conditions are consistent with observations from offset wells in the Miocene sands of Louisiana (Core Laboratories, 2023). This category of RQFM is widely employed across industry, proven to provide credible pre-drill predictions of porosity, permeability, and other rock properties (Taylor et al., 2015; Wojcik et al., 2016; Chudi et al., 2016; etc.).

2.2.2 Data Sources

The data sources needed to build the geologic and dynamic model include 3D seismic data, offset well logs, core data, and publicly available literature such as Society of Petroleum Engineers (SPE) and American Association of Petroleum Geologists (AAPG) peer-reviewed papers.

Public databases and literature were initially reviewed at both a regional and site-specific level. The regional review identified the major trends in the project area and the surrounding region. These trends were compared to more site-specific data to provide a higher confidence of the reservoir properties. Reservoir salinity and temperature trends were identified in Vermilion Parish. Regional data also indicated analogous reservoirs for use in the model. Properties such as rock compressibility and relative permeability were derived from public literature. These assumptions are further discussed in *Section 2.5.2*.

Offset well log analysis was conducted to further characterize the reservoir and populate the geologic model. Open-hole log data included various analyses such as gamma-ray, spontaneous potential, resistivity, porosity (sonic, neutron, density), photoelectric factor, caliper, and other related analyses. These well logs helped determine formation tops, rock properties, and temperature gradients. Petrophysical analysis was performed on 18 wells in the Project vicinity to appraise the target injection zone and subsequent confining layers.

To enhance the characterization of the reservoir, 3D seismic data was used in conjunction with formation tops identified through log analysis—to identify major structural horizons as seen in Figure 2-1. 3D seismic data also allows for greater clarity of subsurface, such as faults, salt domes, or any other structural changes in the subsurface. This data enhanced the accuracy of the geologic model by providing a clearer understanding of the targeted stratigraphy.

[redacted]

Figure 2-1 – Major Stratigraphic Units in the Geologic Model

Analogous core data was used in XOM-RQFM to determine the porosity-permeability relationship in the Upper and Middle Miocene. The core data comes from the Lower Miocene and was taken from the Pecan Island Project area. This data is discussed in greater detail in *Section 2.3* (on the conceptual site model).

Site-specific data will be collected after submittal of this permit application. A stratigraphic test well is planned to gather core, fluid samples, and geophysical logs. The inclusion of the additional data will further increase the accuracy of the model.

2.3 Trapping Mechanisms

In a CCS project, four primary trapping mechanisms exist that sequester the supercritical CO_2, schematically represented in Figure 2-2. Structural and stratigraphic, residual, solubility, and mineral trapping mechanisms—all except for mineral trapping are present in the current model—are discussed in the sections following.

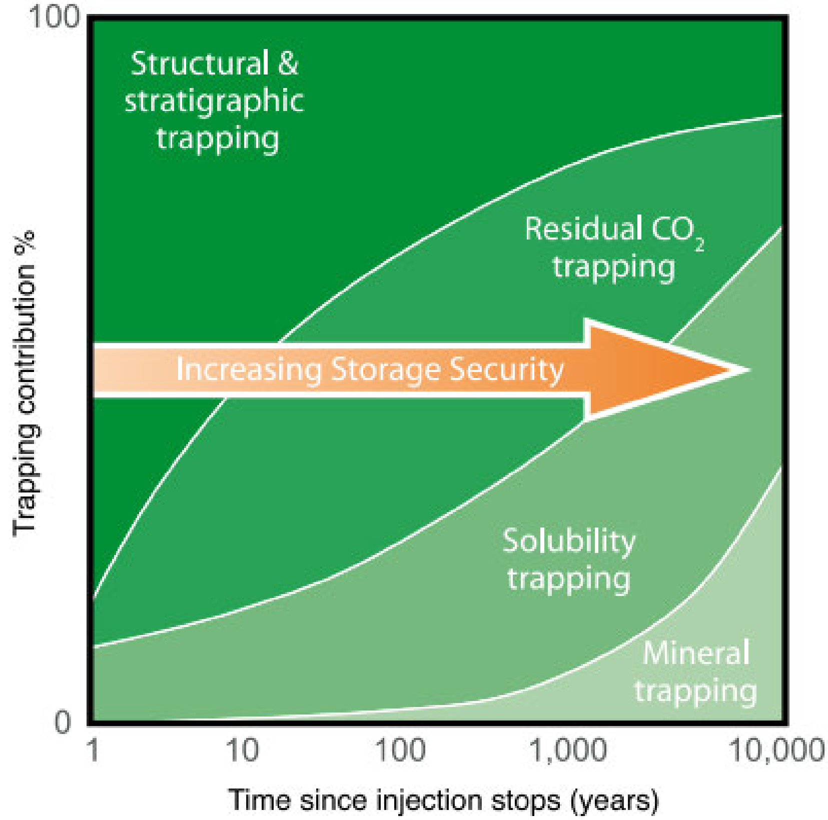

Figure 2-2 – CO_2 Storage Mechanisms (Metz et al. 2005)

2.3.1 Structural Trapping

Structural trapping is a physical form of trapping where injected CO_2 is immobilized by the presence of sealing faults, pinchouts, or other forms of geologic traps. Like naturally occurring hydrocarbon reservoirs, CO_2 can commonly be stored in anticlinal folds. Supercritical CO_2 is a low-viscosity fluid, less dense than the surrounding brine found in the injection zone. CO_2 will continue to rise until its buoyant forces are no longer greater than the capillary-entry pressure of the caprock. For this model, the CO_2 mass density ranges between 43.8 lb/ft^3 in the shallowest injection interval and 45.7 lb/ft^3 in the deepest intervals. The surrounding brine density is 68.4 lb/ft^3.

EOS calculations are performed to determine the phase of CO_2. These formulae can predict the density of the injected fluid at any location based on pressure and temperature. GEM uses several well-known EOS formulas, including the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) method. The EOS implemented within the plume model was the Peng-Robinson method, due to its widely accepted use for volumetric and phase equilibria.

2.3.2 Residual Gas Trapping

Residual gas trapping is a form of physical trapping. Small amounts of CO_2 are left behind in the pore space as the plume continues to migrate. As water is displaced in the rock, the CO_2 fills the space. However, depending on the movement of CO_2 and the aqueous phase through saturation and capillary forces, CO_2 will remain residually trapped within the pore space.

Hysteresis modeling is used in the model to accurately predict the amount of residually trapped supercritical CO_2. GEM offers several methods to determine residual gas trapping, such as the Carlson and Land model and the Larsen and Skauge model. The Carlson and Land model was implemented for this simulation due to (1) its use being validated for water-alternating-gas (WAG) injection and (2) its ability to model a two-phase system. The critical parameter, trapped gas saturation, will be discussed in *Section 2.5.3*.

2.3.3 Solubility Trapping

Solubility trapping is a form of chemical trapping between supercritical CO_2 and surrounding brine. CO_2 is highly soluble in brine, resulting in a solution that has a higher density than the connate brine. This action causes the higher density brine to sink within the formation and traps the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. The salinity, pressure, and temperature of the surrounding brine all affect the solubility of CO_2.

For solubility modeling, GEM offers the options of the Harvey and Li-Ngheim's methods. The Li-Ngheim method was selected for its accuracy in modeling CO_2 solubility at high salinities. This method can also include solubility parameters specific to CO_2, as defined by Henry's Law constant correlations.

2.3.4 Mineral Trapping

Mineral, or geochemical, trapping is another form of chemical trapping that occurs due to reactions between CO_2 and the geochemistry of the formation. During injection of CO_2 into the reservoir, four primary drivers interact with each other: (1) CO_2 in supercritical phase, (2) in situ hydrochemistry of the connate brine, (3) aqueous CO_2, and (4) the geochemistry of the formation rock. These components interact with each other, resulting in CO_2 often being precipitated out as a new mineral. This new mineral is typically $Ca\text{-}CO_3$, or calcium carbonate (i.e., limestone).

Mineral trapping can also occur due to the adsorption of CO_2 onto clay minerals. Once hysteresis and solubility trapping are included in the model, geochemical formulae can be added through an internal geochemistry database to describe mineral-trapping reactions. For aqueous reactions, the following formulae were used:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

These three reactions are common ionic reactions that can occur in the reservoir between water and CO_2. The following formulae show the mineral reactions used within the model. Each mineral is commonly found within sandstone in an underground aquifer and causes the precipitation of carbon oxides in a solid state:

$$Anthorite\ (CaAl_2Si_2O_8) + 8H^+ = 4H_2O + Ca^{2+} + 2Al^{2+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO_3^-$$
$$Kaolinite\ (Al_2Si_2O_5(OH_4)) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

While geochemical trapping can have a greater impact on CO_2 over hundreds or thousands of years, the short-term effects of these trapping mechanisms are small, and fluid movement is predominated by hydrodynamic and solubility trapping. Due to the current limitations in data for the compositions of these minerals and components in the reservoir, as well as the computational stress added to the software, the geochemical trapping mechanisms were not assumed in the current model. As more data are received on the geochemical properties of the reservoir, sensitivities could be run to determine the applicability of these traps.

2.3.5 Trapping Summary

Figure 2-3 shows the breakdown of the trapping mechanism. Once injection stops (Year [redacted]), the mobile CO_2 quickly decreases as gaseous phase CO_2 migrates through pore space and is trapped. Over the life of the project, residual trapping of supercritical CO_2 has the greatest effect among the trapping mechanisms. Approximately [redacted] of the injected fluid is safely sequestered by residual trapping within the pore space. The solubility of CO_2 into the connate brine will safely store approximately [redacted] of the CO_2. The remaining [redacted] of the injectate is structurally and hydrodynamically trapped.

[redacted]

Figure 2-3 – Modeled Trapping Mechanisms (red line designating end of injection)

2.4 Conceptual Site Model

2.4.1 Geologic Model Development

[redacted] A horizontal cell dimension of 400 ft x 400 ft was applied. Sixteen well-top markers and stratigraphic layering averaging 20 ft were then included to define the 15 zones and finer resolution of the vertical dimension of the cells. Lithofacies were then interpreted from the well logs and scaled up to the 3D grid. Next, the data was analyzed using geostatistics to help define the vertical and lateral continuity and orientation of the facies. These results were used to populate the facies well control throughout the 3D model, using the Sequential Indicator Simulation algorithm. The results were used to condition the distribution of the porosity model and to obtain the porosity model. The geologic model is referenced to the North American Datum of 1927 (NAD27) and projected in the State Plane Louisiana - South (LA-S, FIPS 1702) before being exported to GEM.

The data sources incorporated into the geologic model were seismic surveys and well data such as locations, elevations, deviation, well tops, and well logs. Seismic-survey and well logs were used for interpretation and for the depth-conversion process.

2.4.2 Structural Framework

[redacted]

[redacted]

Figure 2-4 – Map of the project area showing acreage outline (indicated in pink) in the [redacted] of the acreage and the 3D geomodel outline (in black).

[redacted]

Figure 2-5 – Structural model displayed in a 3D view as seen from a [redacted].

Figures 2-6 and 2-7 illustrate the faults for the Top F Shale Tertiary and top lower confining surfaces. The key faults trend northeast-southwest, with the closest fault being 2 miles away from the proposed location. [redacted] The seismically mapped horizons are the F Shale, BF Shale, and B Shale. Sixteen formation tops were used to further define the zones. These tops included the Top F Tertiary, Top F Sand Tertiary, Top F Sec, Top F Sand Sec, Top F Shale, Top F Sands, Top D2 SH, Top D SD, Top BF Shale, Top BF SD, Top C Shale, Top C Sand, Top B Shale, Top B SA, Top Lower Conf, and Top NE SD3. The structural grid's horizontal resolution is 400 ft x 400 ft, while finer-scale stratigraphic layering results in a vertical resolution averaging 20 ft.

[redacted]

Figure 2-6 – Structural map for Top F Shale Tertiary surface (faults shown in brown).

[redacted]

Figure 2-7 – Structural map for Top Lower Confining surface (faults shown in brown).

2.4.3 Rock Property Distribution

Lithofacies Distribution

Lithofacies were interpreted for 58 wells with spontaneous potential (SP) or gamma-ray (GR) logs. Figures 2-8 and 2-9 display the strike and dip well sections showing the SP log and interpreted facies. If an SP log was not available, GR was used. A shale baseline was selected for each SP or GR log based on log character for individual wells. This baseline was used to separate the sand from the shale. The cut-off values varied since they were chosen according to the shale baseline determined for each well. The interpreted facies logs based on the results obtained were then upscaled into the 3D grid and distributed to create a facies model using geostatistics.

Figure 2-10 shows the location of the 58 wells used for the lithofacies interpretation.

[redacted]

Figure 2-8 – [redacted] displaying SP logs and interpreted lithofacies results (map location shown in Figure 2-11).

[redacted]

Figure 2-9 – [redacted] displaying SP logs and interpreted lithofacies results (map location shown in Figure 2-11)

[redacted]

Figure 2-10 – Base map displaying well [redacted] (from Figures 2-8 and 2-9). The 58 wells used for the lithofacies interpretation and the Pecan Island Injection Wells No. 001 and No. 002 are indicated with a cross and circle symbol.

The geostatistical analysis included the generation of vertical, major, and minor variograms from upscaled facies logs derived from the defined SP/GR cutoffs. The variograms were calculated for each one of the zones in the model. An example of a typical variogram from this study is shown in Figure 2-11, displaying the vertical, major, and minor variograms for the BF Sand. The anisotropy observed has an azimuth of 200. This northeast-southwest trend is observed in most of the intervals above the B Sand. Underlying zones show a major trend with a northwest-southeast azimuth. Table 2-1 displays the variogram ranges and target-facies fractions for each of the sand intervals in the project. The target-facies fractions are derived from the upscaled-facies log.

[redacted]

Figure 2-11 – Typical vertical and horizontal variograms, calculated in this study for the BF SD interval.

Table 2-1 – Facies Variograms and Target Percentages from Well Logs

Zone	Vertical Range (ft)	Major Range (ft)	Minor Range (ft)	Facies Fraction
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The Sequential Indicator Simulation algorithm was used to populate the facies distribution, using the variograms and target facies fractions listed in Table 2-12. The vertical-facies proportions from the upscaled log were also used to capture the vertical trends.

The facies model is observed in Figure 2-12, and a northeast-southwest cross section through the model is shown in Figure 2-13. Sand lithofacies are represented in yellow and shale in gray.

[redacted]

Figure 2-12 – Facies model in a 3D window. The location of the cross section from Figure 2-13 is represented by the blue plane.

[redacted]

Figure 2-13 – [redacted] cross-section through the facies model shown in Figure 2-12.

<u>Permeability/Porosity Distribution</u>

A porosity model was also generated using 18 porosity log curves that were upscaled to the 3D grid. The values were distributed using the sequential Gaussian-simulation algorithm conditioned to the facies model. Figure 2-14 shows the location for the wells with porosity logs, while Figure 2-15 shows the resulting porosity model and a northeast-southwest section through the injector location. The results of the porosity-distribution histogram are shown in Figure 2-16.

[redacted]

Figure 2-14 – Base map showing the location of the 18 wells with porosity logs included in the distribution of the porosity model.

[redacted]

Figure 2-15 – [redacted] through the porosity model. The location of the section is represented by the polygon in Figure 2-14.

[redacted]

Figure 2-16 – Histogram comparing porosity from raw logs, upscaled cells, and porosity property model.

A porosity-permeability relationship was derived from offset core samples. Using these samples and XOM-RQFM, a relationship was identified as displayed in Figure 2-17. This relationship was then applied to the porosity model to determine the permeability of the Upper and Middle Miocene sands. *Section 1.5.1* provides a more detailed explanation of this relationship.

[redacted]

Figure 2-17 – XOM-RQFM porosity-permeability relationship implemented into the geologic model.

A regression equation was derived from Figure 2-19 and used to calculate the permeability property:

[redacted] e [redacted]

Where:
K is the resulting permeability model
ϕ *is the porosity property discussed above converted to percentage instead of fractions*

All properties, facies, porosity, and permeability were exported to GEM for simulation.

2.5 Dynamic Plume Model

2.5.1 Model Orientation and Gridding Parameters

Spatial Conditions

As discussed earlier, CMG uses the Petrel™ geologic model as an input. The geologic model encompasses approximately 32,900 acres (approximately 51 sq mi). At its greatest extent, the grid extends 124 grid cells in the x-direction, 92 grid cells in the y-direction, and 448 grid cells in the z-direction. Roughly 6.1 million blocks are modeled, where each cell size was kept the same at 400 ft by 400 ft by 20 ft.

To improve computational efficiency, the grid was reduced by approximately 1.6 million blocks (approximately 27%) as Figure 2-18 shows. The nulled-out portion of the model was chosen because of the distance from the injection wells and location on the opposite side of a large fault. The updated grid covers 23,900 acres (approximately 37 sq mi) and contains around 4.5 million cells. At its greatest extent, the grid extends 105 grid cells in the x-direction, 66 grid cells in the y-direction, and 448 grid cells in the z-direction.

[redacted]

Figure 2-18 – Model Resizing for Improved Efficiency

The model is further refined laterally around the injection wellbores to 200 by 200 ft grid cells. It extends 1,000 ft in diameter around each wellbore location. To refine the cells, a cartesian sub-grid is created within the model as displayed in Figure 2-19. Implementing the sub-grid greatly reduced numerical convergence errors and resulted in a more accurate simulation prediction.

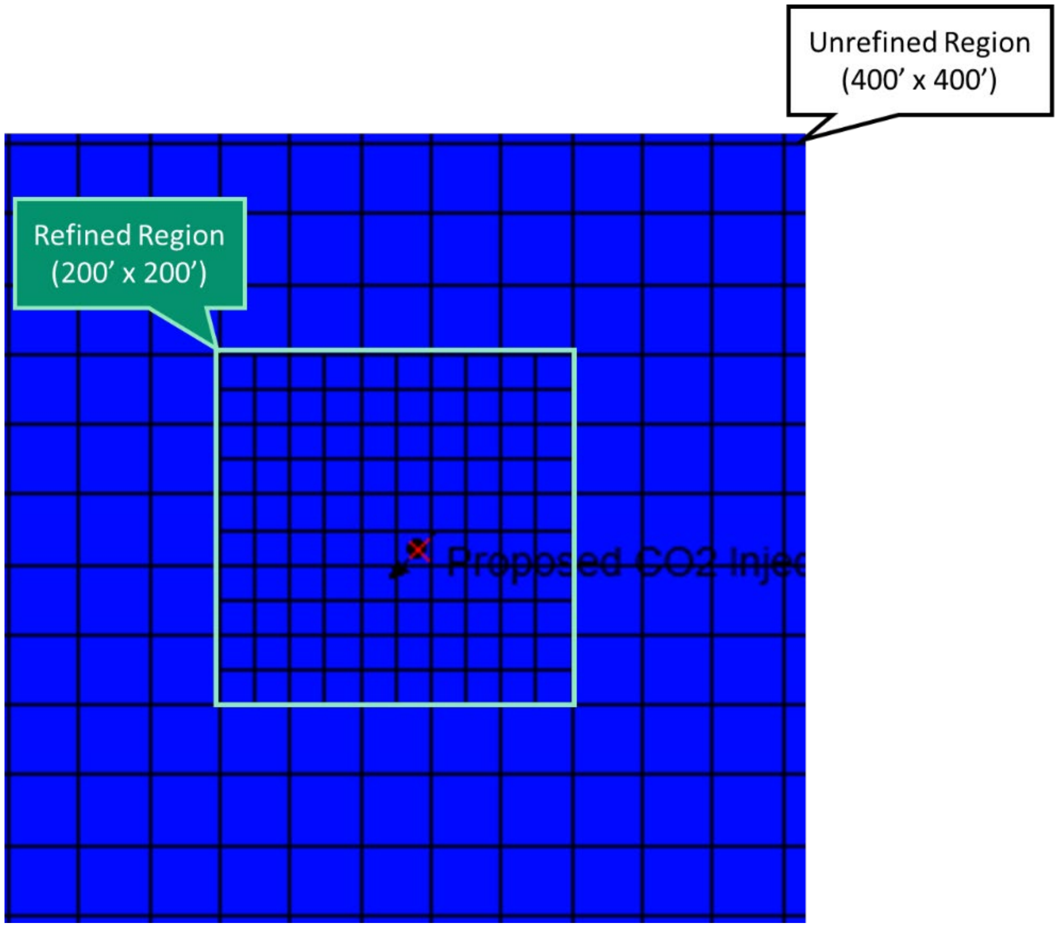

Figure 2-19 – Local Grid Refinement Around Pecan Island Injection Well No. 001

Multiple distinct sand packages are identified as potential targets for supercritical CO_2 injection. Each package is separated by interbedded shales and shale baffles that may act as barriers that impede CO_2 movement. These sand packages are then combined into five "completion stages" or bundles of combined sands. To represent the sand packages more accurately between large gaps of well data and further validate the geologic model, 3D seismic was used.

Boundary Conditions

The Miocene sands in the Gulf Coast are highly connected throughout the region. Thus, an infinite-acting reservoir is implemented to accurately model the pressure response due to supercritical CO_2 injection. The use of "volume modifiers" along the edges of the grid creates this effect. Volume modifiers change the gross volume of a grid block by adding a multiplier to the original volume. A value of 10,000 is applied uniformly along the edge of the grid as Figure 2-20 illustrates. The volume modifiers provide an additional 577 trillion cubic feet of pore space to the aquifer. This model represents a reservoir highly connected throughout the region. Additionally, the upper and lower confines are impermeable to allow for the largest possible AOR. Any nearby faults were assumed to be transmissive, to ensure that no CO_2 migration would be artificially constrained at the fault location.

[redacted]

Figure 2-20 – Volume modifiers (indicated in red) applied to create an infinite-acting reservoir.

Model Time Frame

The model encompasses a total of 520 years, including 15 years of active injection and 505 years of density drift. This time frame allows sufficient time to capture the stabilized plume. The model results are further discussed in *Section 2.7*.

2.5.2 Initial Conditions

The geologic model was used as an input to help build the dynamic plume model. The assumptions in Table 2-2 were also used to initialize the model. [redacted] The pore and fracture pressure gradients were calculated to be 0.475 psi/ft and 0.67 psi/ft, respectively. A regional and well-log review estimated the temperature gradient to be 1.25 Fahrenheit per 100 ft (°F/100 ft). Salinity was determined to be around 130,000 parts per million (ppm), as discussed in the Brine Salinity subsection.

Table 2-2 – Initial-Conditions Inputs Summary

Inputs	Values
Average Porosity (%)	[redacted]
Average Permeability (mD)	[redacted]
Average Kv/Kh Ratio	[redacted]
Pore Pressure Gradient (psi/ft)	0.475
Frac Pressure Gradient (psi/ft)	0.67
Mean Surface Temperature (°F)	72
Temperature Gradient (°F/100 ft)	1.25
Salinity (ppm)	130,000

Porosity/Permeability Discussion

As discussed in *Section 2.4*, porosity is determined through the analysis of open-hole logs, and permeability is calculated using a porosity-permeability relationship (Figure 2-17) derived from core data taken from the Lower Miocene. The XOM-RQFM software is then used to create this relationship.

Porosity is geostatistically distributed throughout the model. The porosity-permeability equation is then applied to all grid cells to determine the reservoir permeability. [redacted] Shales are expected to be clay-rich in this depositional environment. Clay-rich shales show permeability values in the range of 0.1 to 100 nano-darcy (Backeberg et al., 2017). In the model, a permeability value of [redacted] mD is assumed. These distributions are shown in west-to-east (W-E) (Figure 2-21) and south-to-north (S-N) (Figure 2-22) cross sections. A summary of the porosity and permeability values for each major stratigraphic horizon is also provided in Table 2-3.

[redacted]

Figure 2-21 – Porosity (Upper) and Permeability (Lower) Distribution, [redacted]

[redacted]

Figure 2-22 – Porosity (Upper) and Permeability (Lower) Distribution, [redacted]

Table 2-3 – Permeability and Porosity Ranges for Each Major Stratigraphic Zone

Zone	Porosity (%)	Permeability (mD)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Vertical permeability is applied to the model using a vertical-to-horizontal permeability (K_V/K_H) ratio. This ratio was derived from public literature using a best-fit equation of a line to derive the ratio from the porosity of the rock. Figure 2-23 provides K_V/K_H to porosity relations, where the lower and upper bounds imposed in the model are [redacted], respectively. An average ratio of approximately [redacted] was applied throughout the model.

[redacted]

Figure 2-23 – K_V/K_H vs. Porosity Relationship (Hovorka et al., 2003)

Pressure Gradients Discussion

A 100% brine-filled reservoir is assumed for the Pecan Island reservoir-simulation model. The formation is assumed to be in hydrostatic conditions. McCain's correlation was used to estimate the pore gradient. A salinity of 130,000 ppm was used in this correlation, resulting in a 68.4 lb/ft^3 gradient. The pressure used in this model is 0.475 psi/ft, which correlates to the calculated density. This value is used to help initialize GEM's reservoir model to internally calculate the fluid density across the entire modeled area.

Fracture Gradient Calculation

Eaton's method (Eaton, 1968) was used to calculate the pressure required to fracture the injectable rock. This method was developed using Gulf Coast sands to determine the fracture pressure of the rock. Eaton's equation is commonly accepted as the standard practice for the determination of fracture gradients. The method requires Poisson's ratio (v), overburden gradient (OBG), and pore gradient (PG) to be 0.475 psi/ft, to determine the fracture gradient. Table 2-4 provides the values of each input.

Table 2-4 – Fracture Gradient Calculation Assumptions – Eaton's Method

Inputs	Values
Poisson's Ratio	0.24
Overburden Gradient (psi/ft)	1.1
Pore Gradient (psi/ft)	0.475

Poisson's ratio was determined through an extensive literature review on unconsolidated sandstones. Literature suggests that sandstones can have a wide range of potential Poisson's ratios (0.1–0.4). The review primarily focused on sandstones that closely resemble the unconsolidated nature of the Miocene sands. In 2014, a case study was done to model fracture initiation in poorly consolidated sandstone, resulting in a ratio of 0.27 (Sun et al., 2015). Further research shows that soft sandstones can have a range of 0.2–0.35 (Molina, Vilarras, and Zeidouni, 2017). A value of 0.24 was chosen to be the most representative of the Miocene sands, based on the literature. Per accepted industry practices, a value of 1.1 psi/ft was chosen for the OBG. A PG of 0.475 psi/ft was calculated from the salinity of the connate brine.

With the inputs, it is possible to calculate a fracture gradient (FG). Equation 1 highlights the necessary steps for calculating the gradient. Per SWO 29-N-6, **§3621.A.1** [40 CFR **§146.88(a)**], the well may not exceed 90% of the FG during injection operations. Therefore, the model applied a pressure constraint of 0.6 psi/ft to all injectors.

(Eq. 1)
$$FG = \frac{\nu}{1-\nu}(OBG - PG) + PG$$

$$FG = \frac{0.24}{1-0.24}(1.1 - 0.475) + 0.475$$

$$FG = 0.67\, psi/ft$$

$$FG\ with\ Safety\ Factor = 0.67 \times 0.9 = 0.6\, psi/ft$$

<u>Reservoir Fluid Properties Analysis</u>

Reservoir Temperature

A review of nearby well logs and regional literature was conducted to estimate the reservoir temperature. Reservoir temperature was input into the model at a 1.25°F/100 ft gradient. Nearby wells were drilled into a deeper overpressurized regime, resulting in temperatures that may not be characteristic of the depth of interest for this project. A literature review was used to determine this estimate. This data will be confirmed upon collection of additional data as the wells are drilled.

Figure 2-24 shows the geothermal gradient map from the literature. The map shows the geothermal gradient between 5,000 ft and 10,000 ft within each parish in Louisiana (Carlson and McCulloh, 2006). The Pecan Island Injection Wells No. 001 and No. 002 are in Vermilion Parish, where the regional geothermal gradient was found to be 1.03°F/100 ft. The density of CO_2 decreases as temperature increases, resulting in a larger plume area. For this reason, the more conservative value of 1.25°F/100 ft was chosen for the entire model area. This gradient lies in between the range created by the regional and deep well-log data. This gradient is added onto an assumed surface temperature of 72°F, which is the mean annual surface temperature.

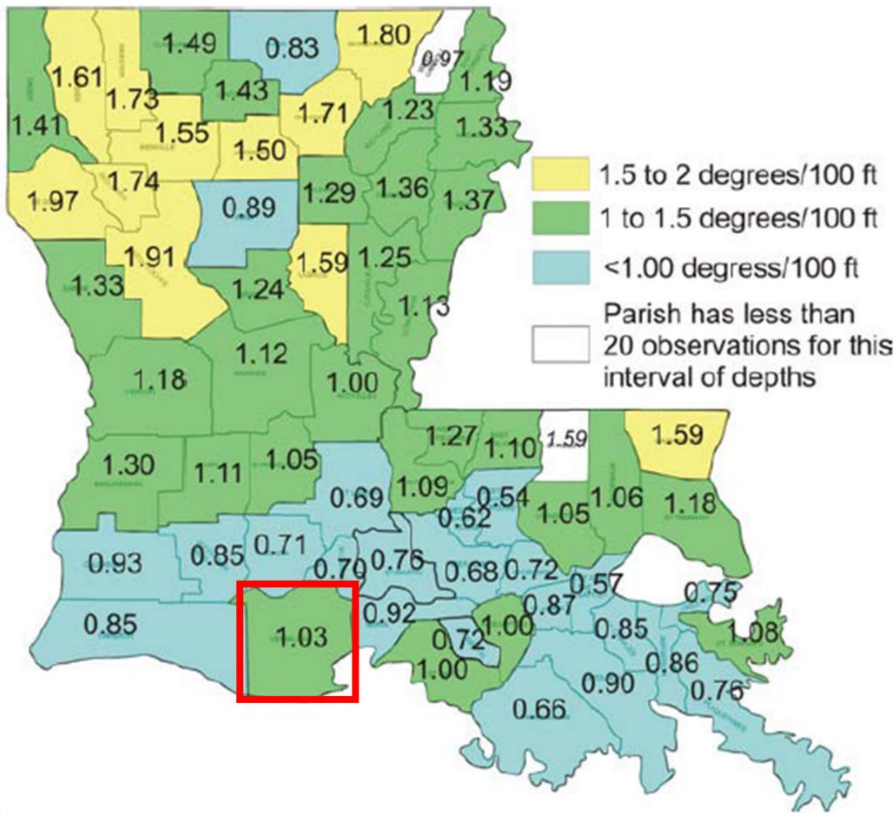

Figure 2-24 – Geothermal Gradients in Louisiana Parishes from Depths of 5,000 ft to 10,000 ft (Carlson and McCulloh, 2006)

Brine Salinity

A regional review of publicly available fluid samples was done to determine the salinity of the reservoir. Data was taken from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database, the public online database that stores numerous water samples to help understand regional hydrogeology. Fluid samples taken around the Vermilion and Cameron Parishes were used to discover any trends within the injection zone. Figure 2-25 provides the total dissolved solids (TDS) content of each sample and shows that the salinity can vary significantly within the injection zone. However, most of the data suggests the salinity is between

100,000 ppm and 150,000 ppm. Taking an average of all samples within similar depths of the injection zone results in a salinity of 127,835 ppm.

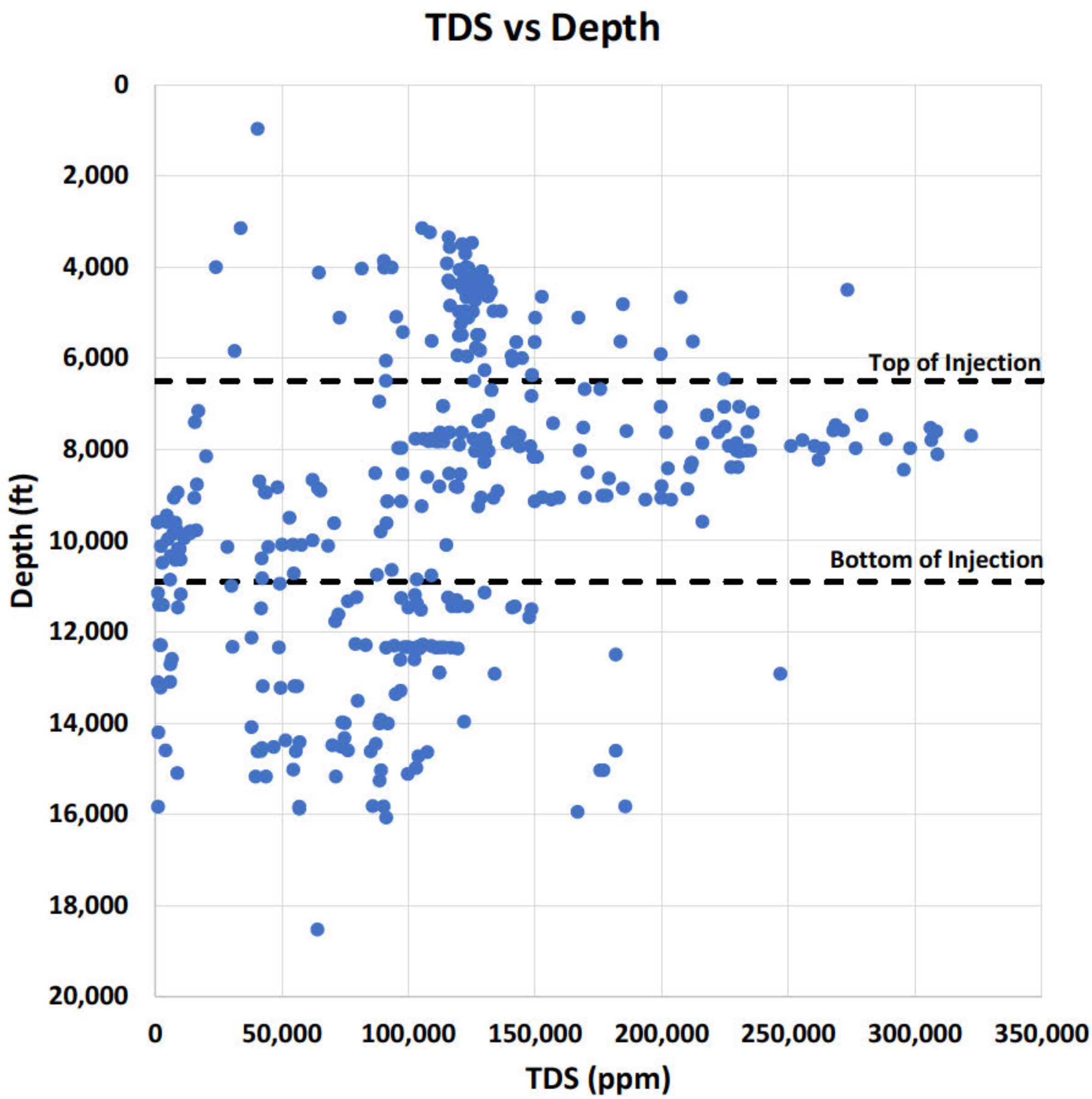

Figure 2-25 – Produced Water Samples from Vermilion and Cameron Parishes

Seven of the nearest available fluid samples were also considered. These wells represent the most accurate representation of the fluid composition of the reservoir. An average of 113,000 ppm was estimated from these samples. Table 2-5 provides a list of each well that the sample was taken from, along with its corresponding TDS content. Based off the data, a conservative value of 130,000 ppm was chosen to represent the formation salinity. Higher salinity brines reduce the amount of CO_2 that can be trapped in the surrounding brine. Therefore, a larger TDS value was chosen to represent the fluid across the entire injection interval.

Table 2-5 – Closest Fluid Samples to Injection Site

API	USGS ID	Average Depth (ft)	TDS (ppm)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

2.5.3 Rock Properties Hysteresis Modeling

Rock Compressibility

A literature review was conducted to determine the rock compressibility of the Miocene sands. A lack of regional data resulted in an expanded search for data into poorly sorted, unconsolidated sandstones. The research suggests that this type of formation can have compressibility values that range from 10 to 40 microsips as highlighted in Figure 2-26. For the purposes of this simulation, a value of 20 microsips was chosen. This assumption will be updated as needed based on data collected from the stratigraphic test well.

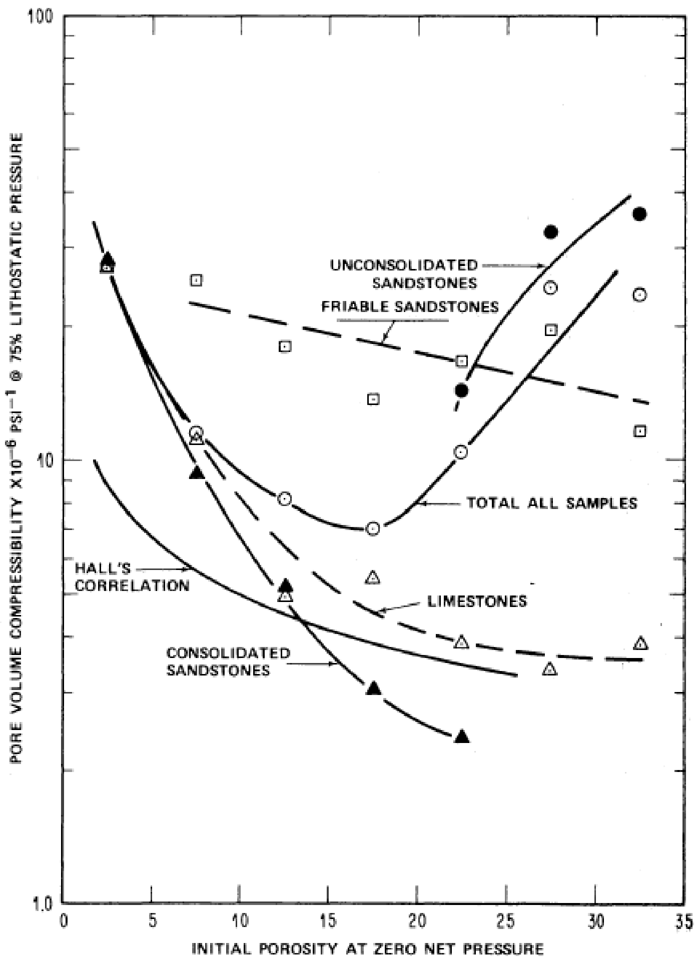

Figure 2-26 – Pore-Volume Compressibility vs. Initial Sample Porosity (Newman 1973)

Residual Gas Saturation

An extensive literature review was conducted to determine the maximum residual-gas saturation (S_{gr}). Numerous studies were reviewed to find a value that most accurately represents the target formation. One report (Holt, 2005) was able to derive a relationship between porosity and S_{gr}. A chart showing the relationship between porosity and the maximum residual-gas saturation for unconsolidated sands in the Miocene is displayed in Figure 2-27 (Holt, 2005). On average, the modeled sands have a porosity of [redacted]. Using this relationship, the S_{gr} is calculated to be [redacted], which is implemented into the model.

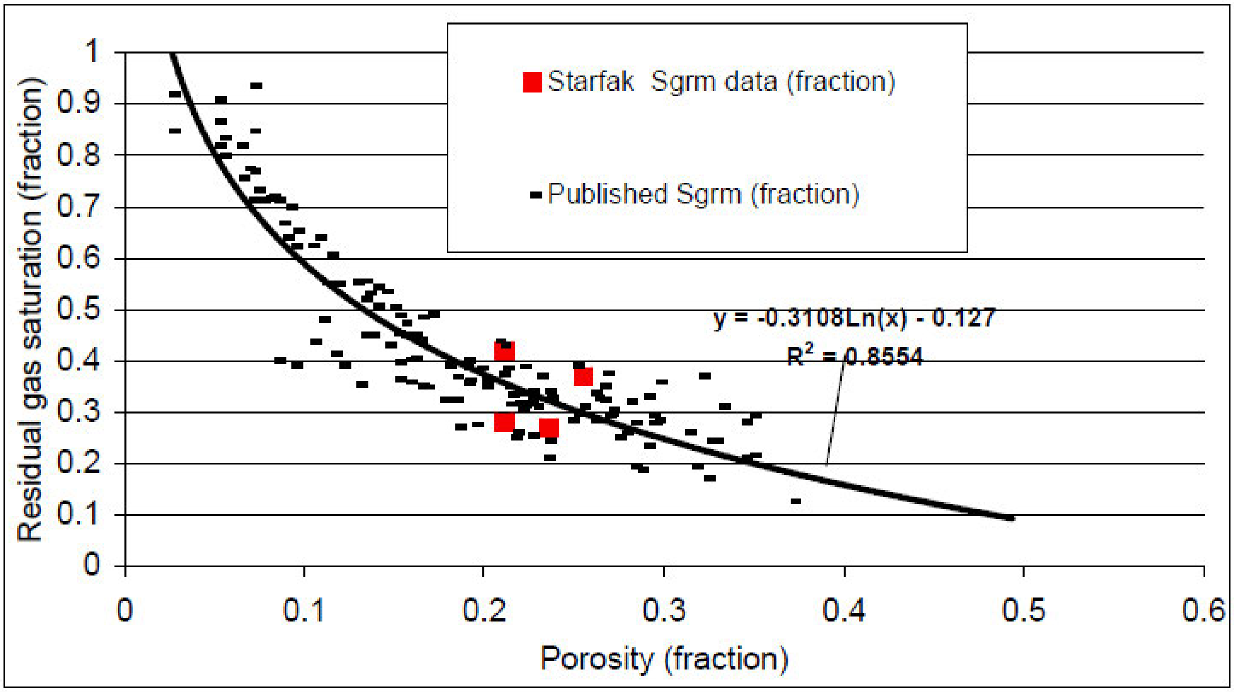

Figure 2-27 – Porosity vs. Residual Gas Saturation Relationship (Holt, 2005)

Relative Permeability Curves

Due to lack of site-specific data, relative permeable curves were generated based on research of analogous depositional environments. Traditional core testing has difficulty accurately measuring the endpoints of the curves, resulting in high irreducible water saturations and low CO_2 endpoints (Benson, 2015). In the drainage CO_2-brine relative-permeability experiments, as the water saturation decreases, the capillary forces become larger (i.e., capillary pressure (Pc) values increase rapidly in the approach to the irreducible water saturation). During the experiment, the increase in capillary forces limits further reduction in water saturation (i.e., the viscous force is too small relative to the capillary force). This causes the experimental relative-permeability measurements to end at water saturations higher than the actual irreducible water saturation. For this reason, it is recommended to fit a Corey-Brooks expression to the experimental data and to extrapolate the curve to a representative value of irreducible water saturation.

In a recent study conducted by researchers at the University of Texas, a Corey-Brooks function was fitted to experimental data to generate relative-permeability curves at a lower irreducible water saturation (Chen et al., 2017). Using similar methodologies and experimental data provided by public literature (Bachu, 2012; Krevor et al., 2012), relative permeability curves were generated.

[redacted]

[redacted]. The geologic model permeability property is based on absolute gas permeability. The laboratory-measured relative-permeability curves were referenced to the starting point of the test—in this case, the absolute water-phase permeability. Because it has been observed that the absolute brine permeability is less than the absolute gas permeability, the relative-permeability curves input into the reservoir simulation were adjusted by multiplying each value by the ratio of the absolute brine permeability to the absolute gas permeability. Figure 2-28 is the final product implemented into the model; the relative permeability is referenced to the absolute gas permeability and begins at a value less than 1 due to the absolute brine/gas permeability effect mentioned above.

[redacted]

Figure 2-28 – Two-phase relative permeability curves implemented in the model.

Site-specific core is planned both with a stratigraphic test well and upon completion of the subject injection well. The model and subsequent curves will be updated after the core data has been analyzed.

2.6 Well Operations Setup

For the Pecan Island Project, the wellbores were set up using the latest wellbore schematics along with some assumptions as provided in Table 2-6. Three primary constraints were imposed in GEM to limit the pressure response and plume growth: (1) a maximum injection rate of [redacted] MM

MMTA, (2) a maximum bottomhole pressure (BHP) gradient of 0.60 psi/ft, and (3) an injection period of [redacted] years for Pecan Island Injection Well No. 001 and [redacted] years for Injection Well No. 002. A skin factor of zero was applied to the wellbore to simulate that the formation has returned to in situ conditions. [redacted] This design was considered when calculating the wellhead pressure (WHP).

Table 2-6 – Well Hydraulics Input Summary

Inputs	Well No. 001 Values	Well No. 002 Values
Max Injection Rate (MMTA)	[redacted]	[redacted]
Pressure Constraint Gradient (psi/ft)	0.6	0.6
Injection Duration (yrs)	[redacted]	[redacted]
Tubing Inner Diameter (in.)	[redacted]	[redacted]
	[redacted]	[redacted]
Tubing Setting Depth (ft)	[redacted]	[redacted]
	[redacted]	[redacted]
Roughness Factor	0.0006	0.0006
Compressor Outlet Temperature (°F)	75	75

The injection well is divided into multiple completion intervals to optimize the usage of available pore space. Each completion stage represents a portion of the reservoir that will be injected into at a given time. Figure 2-29 provides a theoretical depiction of the completion strategy planned for carbon sequestration. At each new completion, the pressure constraint is updated based on the upper perforation depth. This is done to ensure that the BHP never exceeds the calculated fracture gradient. [redacted] A general description of the completion strategies is summarized in Tables 2-7 and 2-8.

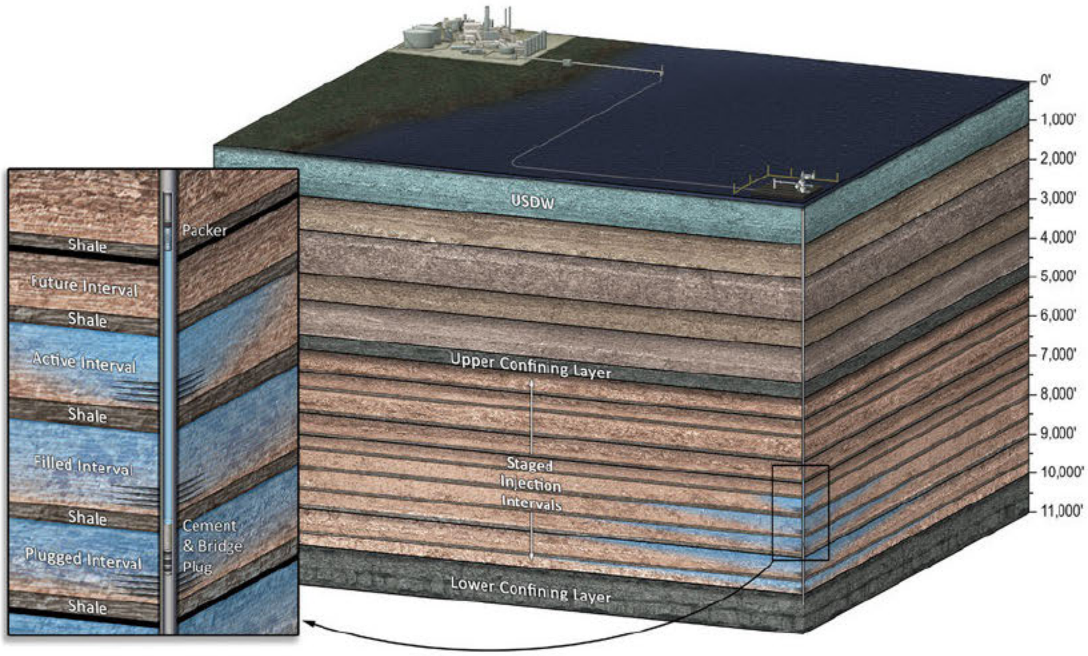

Figure 2-29 – Depiction of Completion Strategy

Table 2-7 – Summary of Completion Intervals for Pecan Island Injection Well No. 001

[redacted]

Table 2-8 – Summary of Completion Intervals for Pecan Island Injection Well No. 002

[redacted]

Both proposed CO_2 injectors are considered in this analysis. [redacted] The injection stages for the two wells were staggered to mitigate the increase in pressure. This strategy led to a staggering of the two wells, which will inject into separate intervals at the same time. This resulted in Injection Well No. 002 only injecting into the upper half of the B sands and reducing its injection period t[redacted] years.

2.7 Model Results

2.7.1 Active Injection Operations of Proposed CO_2 Injector

During the life of the CO_2 injectors, the BHP and injection rate are simulated for each completion interval. Figures 2-30 and 2-31 depict the injection rates and BHP responses during operational activities. The rates are held at a constant rate of [redacted] MMTA for the injection periods for both wells, and the BHP never exceeds 90% of the fracture gradient. Because of the relative permeability, the BHP "spikes" at the start of each stage of injection. Once gas flow is established, reservoir pressure declines to the expected values.

[redacted]

Figure 2-30 – Modeled BHP and Injection Rate for Pecan Island Injection Well No. 001

[redacted]

Figure 2-31 – Modeled BHP and Injection Rate for Pecan Island Injection Well No. 002

WHP is calculated separately using fanning friction equations to estimate the pressure drop through a tapered string. The calculations used BHP outputs from GEM to estimate the WHP.

The maximum expected BHP of Pecan Island Injection Well No. 001 is estimated to be [redacted]. On average, the BHP of the well will be [redacted] The maximum WHP is calculated to be [redacted] with an average of approximately [redacted]. Table 2-9 highlights the outputs for the injection well as modeled in GEM.

Table 2-9 – Pecan Island Injection Well No. 001 Model Outputs

[redacted]

The maximum expected BHP of Injection Well No. 002 is estimated to be [redacted] during the life of the project, evaluated at [redacted] ft. On average, the BHP of the well will be [redacted]. The maximum WHP is calculated to be [redacted] with an average of approximately [redacted]. Table 2-10 provides the outputs for this injection well as modeled in GEM.

Table 2-10 – Pecan Island Injection Well No. 002 Model Outputs

[redacted]

Reservoir pressure is expected to increase from initial conditions during the active injection period. The highest increase is expected at the wellbore and then propagates throughout the formation rock, resulting in a general increase of pressure within the aquifer region. This pressure-increase phenomenon is referred to as "pressure buildup." The pressure buildup is monitored by the rise of reservoir pressure as well as its associated gradient based on the top of the perforated interval.

Figures 2-32 and 2-33 represent the maximum pressure-buildup at the well, which is the BHP result—which represents the maximum pressure seen within the reservoir at any given time. In addition, since these pressure values are retrieved at different depths, the pressure gradient is also calculated as pressure divided by depth, thereby the pressure gradient. The greatest buildup is experienced in the first completion interval of Pecan Island Injection Well No. 001, resulting in a [redacted] pressure increase. As shown in Figures 2-32 and 2-33, the pressure gradient never exceeds the constraint (90% of FG) imposed on the well, to allow for the safe injection of supercritical CO_2.

[redacted]

Figure 2-32 – Pressure Buildup for Pecan Island Injection Well No. 001 During Active Injection Operations

[redacted]

Figure 2-33 – Pressure Buildup for Pecan Island Injection Well No. 002 During Active Injection Operations

The elevated pressure in the saline aquifer quickly dissipates once active-injection operations cease. [redacted] after both wells are shut in, the reservoir pressure stabilizes to [redacted] above the in situ conditions. Figures 2-34 and 2-35 show the pressure buildup throughout the life of the project.

[redacted]

Figure 2-34 – Pressure Buildup for the Life of Pecan Island Injection Well No. 001

[redacted]

Figure 2-35 – Pressure Buildup for the Life of Pecan Island Injection Well No. 002

2.8 CO_2 Plume Migration for AOR Delineation

According to SWO 29-N-6 **§3615.A** [40 CFR **§146.84**], the AOR must be determined by the maximum extent of either the supercritical CO_2 plume or critical-pressure front—or both. The first review starts with the extent of the CO_2 plume. Both injection wells that are part of the Pecan Island Project were used to determine the plume extent. Injection of CO_2 into the two injection wells results in a combined supercritical CO_2 plume.

Because of the geologic structure of the reservoir and presence of channels, the CO_2 plume may migrate in different directions. Channels may act as a high permeability conduit that CO_2 can migrate further through. Figure 2-36 provides a 3D view of the plume in the year [redacted] highlighting the different directions the plume migrates to. Therefore, the largest plume is determined by the maximum saturation experienced in all the modeled layers at a specified point in time.

[redacted]

Figure 2-36 – 3D Representation of Supercritical CO_2 Plume in [redacted], Colored by Gas Saturation

The CO_2 plume migrates primarily to the northwest for both injection wells. Figures 2-37 through 2-40 show the cross-sectional view of the plumes and highlight how the shape and size of the plumes vary in each sand package. Between each sand package, interbedded clay rich shales exist that help structurally trap CO_2 and inhibit vertical migration. The current completion strategy is designed to use these interbedded shales, to help permanently sequester CO_2 between completion intervals while minimizing the footprint of the plume.

[redacted]

Figure 2-37 – [redacted] View at Pecan Island Injection Well No. 001, Colored by Gas Saturation

[redacted]

Figure 2-38 – [redacted] View at Pecan Island Injection Well No. 002, Colored by Gas Saturation

[redacted]

Figure 2-39 – [redacted] View at Pecan Island Injection Well No. 001, Colored by Gas Saturation

[redacted]

Figure 2-40 – [redacted] View at Pecan Island Injection Well No. 002, Colored by Gas Saturation

The CO_2 plume in Figure 2-41 is delineated from the maximum gas saturation seen in each layer of the model. The plume extent is taken in [redacted] (approximately 50 years after injection), a total of [redacted] after the start of injection. The supercritical CO_2 plume covers approximately [redacted] of land owned by ExxonMobil. From Pecan Island Injection Well No. 001, the plume's greatest extent is approximately [redacted] to the northwest. The carbon front migrates about [redacted] to the northwest from Pecan Island Injection Well No. 002 as well. Structural trapping can also be seen in Figure 2-36. Interbedded shale baffles act as traps for the supercritical CO_2 and prevent any further movement.

[redacted]

Figure 2-41 – Aerial View of Supercritical CO_2 Front in [redacted], Colored by Gas Saturation

2.8.1.1 Stabilized Plume

Plume stabilization is considered to occur when the rate or growth or positional change has slowed to a nearly imperceptible change per year. At that point in time, the CO_2 plume is considered hydrodynamically trapped within the pore space. This stabilization point is determined by the model output, where the areal growth rate is less than 0.25% per year.

The plume model determines that plume stabilization occurs by year [redacted] or [redacted] years after the wells cease injection. By [redacted], the plume growth rate is reduced to approximately 0.25% per year while continuing to decline. The plume continues to migrate very slowly, approximately 0.6 acres per year on average, and may be considered hydrodynamically trapped. While incidental plume movement may occur after this period, the reservoir model indicates that the plume will continue to remain on ExxonMobil-owned property. Figure 2-42 demonstrates that the rate of plume movement decreases to less than 0.25% within [redacted] after the cessation of injection into that well.

[redacted]

Figure 2-42 – Plume Growth Over Time

2.9 Critical Pressure Front for AOR Delineation

In accordance with SWO 29-N-6 **§3615.A** [40 CFR **§146.84**], the AOR was delineated by the critical-pressure front created by the injection of supercritical CO_2 into a saline aquifer. Critical pressure is the increase in reservoir pressure that may push in situ fluids out of the injection zone and into the lowermost USDW, in the presence of a bridging conduit such as an unplugged borehole. The first step to predict the pressure front is to calculate the critical pressure for each completion stage. Once critical pressure is determined, a numerical simulation is used to predict the size and shape of the critical-pressure front.

The EPA has outlined three potential methodologies to calculate the critical pressure. EPA Method 2, which uses Nicot's method to calculate the critical pressure, was used in this model. Nicot assumes that the reservoir is in hydrostatic equilibrium, neither under- nor overpressurized, and that a direct path between the two zones exists. This path could be in an incorrectly plugged and abandoned wellbore or some other subsurface feature.

For the purposes of the critical-pressure calculations, the base of the USDW was conservatively assumed to be at 850 ft true vertical depth (TVD). The critical pressure was calculated for each completion of each injection well, with the top of injection ranging from [redacted]. The fluid in the injection zone is assumed to be brine, with 130,000 ppm TDS, which results in a 0.475 psi/ft pressure gradient. The fluid within the USDW was assumed to be fresh water (less than 10,000 ppm) with a pressure gradient of 0.436 psi/ft. The inputs used in the calculation are provided in Table 2-11.

Table 2-11 – Critical-Pressure Calculation Parameters

Parameter	Symbol	Value
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The coefficient (ξ) is first calculated in Equation 2 using the pressure gradients and depths for the base of the USDW and top of injection zone.

(Eq. 2) $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

The critical pressure rise (ΔP_c) is then calculated using Equation 3. The inputs include the coefficient (ξ) calculated in Equation 2 and the depths for the base of USDW (D_u) and top of injection (D_i).

(Eq. 3) $$\Delta P_c = \frac{1}{2} * \xi * (D_i - D_u)^2$$

[redacted]

The resulting critical pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by approximately [redacted] psi, without risk of fluid migration to the USDW. The calculated critical-pressure rise for each of the completion stages for both injection wells is included in Tables 2-12 and 2-13.

Table 2-12 – Pecan Island Injection Well No. 001 Critical-Threshold Pressure for Each Completion Interval

[redacted]

Table 2-13 – Pecan Island Injection Well No. 002 Critical-Threshold Pressure for Each Completion Interval

[redacted]

Due to the complex nature of the reservoir, the critical-pressure front may propagate in different directions. The critical-pressure front is delineated by the maximum extent of the plume from each completion interval. The largest extent is experienced in the first completion interval. The critical-pressure front also considered offset CO_2 injectors to delineate the AOR. The AOR is, in part, determined by the critical-pressure fronts for both injection wells, to form one continuous front. This area covers approximately [redacted] ([redacted] Figure 2-43 provides a snapshot of the largest extent of the critical-pressure front experienced in the model.

[redacted]

Figure 2-43 – Greatest Extent of Critical Pressure Front

2.10 Final AOR

The maximum CO_2 plume and pressure fronts delineate the AOR. The AOR determines the necessary evaluation of and potential corrective action needed for any offset wells. The CO_2 saturation front is determined by the greatest extent of the fluid in any direction throughout the injection zone. [redacted]. The critical-pressure front was determined from the greatest areal extent of all completion intervals for both injection wells. Figure 2-44 provides the final AOR outlines for the project.

[redacted]

Figure 2-44 – Pecan Island Area Project Final AOR

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Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

July 2023

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Facility Information

Facility name: **ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) – Pecan Island**

Injection Well Information:

Well Name and Number	Pecan Island Injection Well No. 001
Parish	Vermilion
[redacted]	[redacted]

Well Name and Number	Pecan Island Injection Well No. 002
Parish	Vermilion
[redacted]	[redacted]

3.2 Computational Modeling

Model Name: **GEM (Version No. 2022.30)**

Model Authors/Institution: Computer Modelling Group (CMG), Ltd.

Description of Model: Equation-of-state (EOS) reservoir simulator for compositional, chemical, and unconventional reservoir modeling.

Model Inputs and Assumptions: The parameters for CMG's GEM are summarized in Table 3-1:

Table 3-1 – Model Input Parameters and Assumptions

Input	Value
Injection Rate (MT/yr*)	[redacted]
Porosity Range (%)	[redacted]
Permeability Range (mD**)	[redacted]
Temperature Gradient (°F/100 ft)	1.25
Fracture Gradient (psi/ft)	0.67
Brine Salinity (ppm)	130,000
Injected Fluid Composition	100% CO_2

*MT/yr – metric tons per year

**mD – millidarcy

3.3 Area of Review Discussion

Statewide Order (SWO) 29-N-6, **§3615.B** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] requires that an Area of Review (AOR) investigation be conducted for a Class VI carbon-sequestration well application. The EPA defines the AOR as the greater of either (1) the maximum extent of the separate-phase plume (pore occupancy plume) or (2) the pressure front—where the pressure buildup is of sufficient magnitude (*i.e.*, pressure front plume) to force fluids from the injection zone into the formation matrix of an Underground Source of Drinking Water (USDW). The Pecan Island Project AOR was determined under both definitions.

3.3.1 Area of Review: Pore Occupancy Plume

The pore occupancy plume area is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data. This modeling effort is discussed at length in *Section 2 – Plume Model* and defines the pore occupancy plume area. Three primary details have been identified and evaluated in connection with the pore occupancy plume AOR investigation: (1) artificial penetrations, (2) subsurface features, and (3) pore space rights.

Artificial penetrations (e.g, wellbores) found within this AOR have been evaluated for appropriate completions, plugging strategies, and construction materials. In accordance with the Class VI regulations, these wellbores are required to be constructed and/or plugged using materials appropriate to support the long-term storage of carbon oxides. The majority of legacy wells in the project area were not constructed with the storage of CO_2 in mind. As such, all of the wellbores found within the pore occupancy plume, which penetrate the gross injection zone, require a corrective action or contingency plan to ensure that these penetrators do not act as a conduit for stored gases or reservoir fluids to escape containment. Wellbores found within this AOR boundary that do not penetrate the gross injection zone were determined to have no effect on the integrity of containment and therefore are not considered in any corrective action or contingency plans.

Subsurface features found within this AOR will be evaluated as to their impact to the gross injection zone. These features would include, but are not limited to, structures such as faults, mapped fractures, folds, steeply-dipping formations, and salt diapirs. Some of these features can act as barriers and serve as no-flow boundaries, which will aid in containing the stored CO_2. Conversely, some of these subsurface features could act as a conduit out of the containment zone. However, ExxonMobil has determined that any such structures should not allow CO_2 to escape to the surface.

Reservoir modeling simulations indicate that the CO_2 plume growth and extent will remain on ExxonMobil-owned fee acreage at Pecan Island. Accordingly, ExxonMobil will not need additional pore space rights with respect to the modeled plume.

3.3.2 Area of Review: Pressure Front

The second AOR to be evaluated is the pressure front created when injecting fluids into a reservoir previously in equilibrium. The pressure-front plume AOR is defined by both calculation and simulation modeling. The value of pressure buildup that could cause potential fluid migration is determined for either insufficiently plugged and abandoned artificial penetrations or subsurface features that are found to penetrate the upper confining zone (UCZ) of the gross injection interval.

ExxonMobil determined that the worst-case scenario for moving reservoir fluids to the USDW would be through an open or incorrectly plugged and abandoned wellbore that is open in both the top of the injection interval and the base of the USDW. The pressure at which this scenario can occur is referred to as the *critical pressure*. The injection zone was assumed to be in hydrostatic equilibrium (*i.e.*, not under- or over-pressured). The methodology for finding critical pressure was sourced from EPA guidance for calculations based on displacing fluid initially present in the borehole in the hydrostatic case.

The base of the USDW is expected to be at 850 ft. as observed on offset logs as discussed in *Section 1.8*. The critical pressure was calculated for each of the injection intervals, with the top depth of each interval ranging from [redacted] As discussed in detail in Section 2 – Plume Model (Section 2.5.2), the fluid in the injection zone is assumed to be brine with 130,000 parts per million (ppm) total dissolved solids, which results in a 0.475 pounds per square inch (psi)/ft pressure gradient. The fluid within the USDW was assumed to be fresh water with a pressure gradient of 0.436 psi/ft. Table 3-2 summarizes the calculation inputs.

Table 3-2 – Inputs for Critical Pressure Calculation

Inputs for Critical Pressure Calculation				
Depth to Base of USDW	(D_u)	=	850	
[redacted]	[redacted]	[redacted]	[redacted]	
Gradient of USDW	(G_u)	=	0.436	
Gradient of Injection Zone	(G_i)	=	0.475	

The calculations for the uppermost stage are shown in detail below as an example. The coefficient (ξ) is first calculated in Equation 1 using the pressure gradients and depths for the base of the USDW and top of injection zone.

(Eq. 1) $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

The critical pressure rise (ΔP_c) is then calculated using Equation 2. The inputs include the coefficient (ξ) calculated in Equation 1 and the depths for the base of the USDW (D_u) and top of injection (D_i).

(Eq. 2) $$\Delta P_c = \frac{1}{2} * \xi * (D_i - D_u)^2$$

[redacted]

The resulting critical-pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by 110 psi without risk of fluid migration to the USDW. The calculated critical-pressure rise for each of the completion stages for both wells is included in Tables 3-3 and 3-4.

Table 3-3 – Pecan Island Injection Well No. 001 Critical-Threshold Pressure for Each Completion Interval

[redacted]

Table 3-4 – Pecan Island Injection Well No. 002 Critical-Threshold Pressure for Each Completion Interval

[redacted]

The complete AOR for the Pecan Island Project includes the total area covered by both pore space and pressure-front areas. Any feature identified within either zone was evaluated for appropriate protection of the USDW and, if deemed insufficient, included in the corrective action or contingency plan discussed in Section 3.4.

[redacted]

Figure 3-1 – Critical Pressure Front

As previously discussed, the AOR was determined with three primary purposes in mind:

1) Identification of any artificial penetrations or man-made structures that may influence the ability to store sequestered gases for an indefinite length of time;
2) Identification of any subsurface geological features that may influence the ability to store sequestered gases for an indefinite length of time; and
3) Identification of pore space rights impacted by the extent of the injection plume over the modeled time period.

In accordance with SWO and EPA requirements, ExxonMobil will reevaluate the AOR at each of the following intervals:

- Minimum frequency of 5 years
- Detection of a significant change in the plume
- As otherwise warranted by routine monitoring or operational conditions

Wells identified requiring corrective action within the reevaluated AOR will be addressed with an amended AOR and corrective action plan that will be submitted to the Underground Injection Control (UIC) Program Director (UIC Director) for approval. All amendments and corrective action plans will be approved, incorporated into the permit, and subject to permit modification requirements per 40 CFR **§144.39.**

Upon reevaluation, if no additional wells are impacted, ExxonMobil will demonstrate to the UIC Director, through monitoring-data support and modeling results, that no changes are needed. All modeling inputs and data used to support AOR reevaluations will be retained for 10 years.

3.3.3 Operating Strategies Influencing Reservoir Modeling Results

To keep the plume growth and migration from encountering artificial penetrations or adverse subsurface features, a robust completion and operating strategy is required in the Miocene sands of the Gulf Coast depositional environment. The Pecan Island Project employs strategies to achieve these goals, as discussed in *Section 2 – Plume Model*.

For this project, approximately [redacted] net feet of usable sand formations are targeted for injection. These Miocene-age sand formations will be accessed in discrete completions, staged out over the proposed active life of the project. Each of these sand packages is separated by shale layers that will allow for the sequestered carbon to be contained within each of the discrete injection zones.

The goal of this completion strategy is to both create multiple plumes—stacked on top of each other and separated by shale beds—and control the lateral extent of the resultant plumes, thereby keeping them within controlled pore space. The GEM model produced the following outputs to this reservoir management program. Figures 3-2 and 3-3 show a cross section for each well, and Figure 3-4 shows the oblique cross section of these stacked injection layers as modeled by GEM.

[redacted]

Figure 3-2 – [redacted] View at Pecan Island Injection Well No. 001, Colored by Gas Saturation

[redacted]

Figure 3-3 – [redacted] View at Pecan Island Injection Well No. 002, Colored by Gas Saturation

[redacted]

Figure 3-4 – GEM Plume Model Results, Oblique Cross Section View

Figure 3-5 depicts the shape and lateral extent of the largest of the stacked injection plumes. This extent was used to define the initial AOR for both proposed wells.

[redacted]

Figure 3-5 – GEM Plume Model Results – Plan View Maximum Extents

This plume extent was digitized from the GEM output and imported into ArcGIS to define the area of influence from which the AOR for the Pecan Island Project was performed. Per SWO **§3615.B.1 [40 CFR §146.84]**, a review was conducted to determine if any artificial penetrations or other features exist that may endanger the lowermost USDW as a result of injection activity or operations. This review consisted of creating maps depicting the AOR and any man-made structures found within that AOR. Any artificial penetrations or other artifacts were then evaluated for depth of completion, construction details, and plugging and abandonment practices to determine if these penetrations could affect the containment integrity of the storage intervals.

[redacted].

[redacted]

Figure 3-6 – Final AOR Map

3.3.4 Area of Review Results

A comprehensive multi-database analysis was performed to search for artificial penetrations into the injection interval within the AOR. The ExxonMobil Legacy Wells Integrity Assessment (LWIA) was proactively applied to ensure a robust evaluation of the potential storage site. This workflow provides a fit-for-purpose, early-stage screening of existing wells in the storage area and focuses on understanding the potential impact on the ability of the project to safely store CO_2 in the subsurface formations.

Oil-and-gas-well data for the AOR is primarily gathered from the Louisiana Department of Natural Resources (LDNR) Strategic Online Natural Resources Information System (SONRIS). Supplemental well data from additional databases are then incorporated and assessed to reduce potential historical well omissions and data inaccuracies. All water-well data is accessed directly from the LDNR statewide water-well registration database. A review of the LDNR "microfilm/microfiche" records was also conducted, ensuring that a complete assessment of all available historical data was accomplished.

In addition to the historical well-review efforts, magnetometer data for this area was obtained and analyzed, looking for unknown wellbores and penetrations into the injection interval. From this data, multiple anomalies were identified and then thoroughly investigated with on-the-ground survey activities to confirm that no additional penetrations exist outside of the public data. The magnetometer analysis is provided in *Appendix C-13*.

As stated in *Section 0 – Introduction*, the proposed location of the Pecan Island Injection Wells No. 001 and No. 002 is ideally suited for carbon sequestration. The results of the AOR evaluation yielded three artificial penetrations within the pore occupancy AOR boundaries. The pressure-front AOR evaluation yielded the same three artificial penetrations. All three of these wells will require corrective action because they are located inside the CO_2 plume. As shown in Section 1.3.4, while faults near the project area exist, no faults or other geologic features were found within either AOR that may affect the integrity of the disposal intervals from keeping the sequestered fluid permanently contained.

No existing water wells have been found within the AOR. A map showing the nearest offset water wells is included in *Appendix E*.

3.4 <u>Corrective Action Plan and Schedule</u>

The proper containment of CO_2 and other resulting fluids involved in a carbon sequestration project is the primary objective of this corrective action plan. This plan is designed to ensure that no CO_2 or other formation fluids will migrate from the injection interval past the impermeable shale of the upper confinement layer.

Three wells identified within the CO_2 plume and pressure-front boundaries need corrective action and are planned for remediation prior to the start of injection. Since these existing wellbores penetrate the UCZ, a re-entry and plugging operation is proposed. A combination of CO_2-compatible cement and traditional plugging techniques will be used to seal the wellbore and ensure containment of reservoir fluids.

The wells requiring re-entry and additional plugging are listed in Table 3-5.

Table 3-5 – Corrective Action Well List

Well Name	Well No.	Serial Number	Location	Planned Corrective Action Method	Planned Date of Corrective Action
[redacted]					

The growth and extent of the CO_2 plume will be constantly monitored and periodically evaluated. A reassessment will occur after 5 years and, if deemed necessary, the corrective action plan will be amended to include additional wells.

3.4.1 General Re-Entry Process

Each historical well was located using the documented coordinates from public data, combined with the magnetometer analysis and ground-penetrating radar. Each well in the AOR was physically tagged with a self-jetting probe to verify its location and depth. Operation plans were developed based on information in the public historical well files, including casing details, cement information, and previous plugging-and-abandonment activities.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted].

Current and proposed wellbore schematics for each well that requires corrective action are provided in Figures 3-7 to 3-12.

3.4.2 In-Depth Review of Wells Needing Corrective Action

Well Name: [redacted]
Serial Number: [redacted]
API Number: [redacted]

[redacted]

Figure 3-7 – [redacted] Current State Schematic

[redacted]

Figure 3-8 – [redacted] Corrective Action Schematic

Well Name: [redacted]
Serial Number: [redacted]
API Number: [redacted]

[redacted]

Figure 3-9 – [redacted] Current State Schematic

[redacted]

Figure 3-10 – [redacted] Corrective Action Schematic

Well Name: [redacted]
Serial Number: [redacted]
API Number: [redacted]

[redacted]

Figure 3-11 – [redacted] Current State Schematic

[redacted]

Figure 3-12 – [redacted] Corrective Action Schematic

3.5 Area of Review Reevaluation Plan and Schedule

3.5.1 Proposed Reevaluation Cycle

ExxonMobil will reevaluate the AOR at least every 5 years, per SWO 29-N-6 **§3615.B.2.b.i** [40 CFR **§146.84(b)(2)(i)**]. The periodic monitoring of the plume growth and migration may require a reevaluation of the AOR more frequently than every 5 years.

Periodic surveys will be conducted to allow ExxonMobil to adjust the discrete sand formations being injected into, thereby influencing the development of the plume throughout the injection life of the wells. After a time, the migration model and measured plume surveys will likely coincide with one another and allow for less frequent surveys. The surveys will be performed at least once every 5 years from the commencement of injection operations.

If the injection rates do not reach the capacity modeled, the anticipated measured plume migration could be less than the extents modeled. In this case, the life of each discrete completion zone would be extended without impacting the AOR. However, if the measured plume behavior extends beyond the modeled limits, the model will be updated and the AOR will be reevaluated.

Table 3-6 lists some of the possible triggers for an AOR reevaluation.

Table 3-6 – Triggers for AOR Reevaluations

Reevaluation Trigger	Measure to be Taken	Schedule for Reevaluation
SWO 29-N-6 **§3615.B.2.b.i** [40 CFR **146.84(b)(2)(i)**]	Reevaluate the AOR as required by statute.	At least once every 5 years
Annual plume migration survey identifies a greater extent than modeled.	Re-run the reservoir plume model with new data. Reevaluate the AOR.	Within 1 month of detection
Annual plume migration survey identifies the plume direction is different than modeled.	Re-run the reservoir plume model with new data. Reevaluate the AOR.	Within 1 month of detection
<u>Operational Change</u>: Injection rate increases to a rate greater than modeled.	Re-run the reservoir plume model with new data. If plume extents increase, reevaluate the AOR.	Within 1 month of rate change
<u>Operational Change</u>: Injectate composition changes to a new mixture.	Re-run the reservoir plume model with new data. If plume extents increase, reevaluate the AOR.	Within 1 month of composition change

New site-characterization data is produced.	Re-run the reservoir plume model with new data. If plume increases in extents, reevaluate the AOR.	Within 1 month of data production
New operations are being brought online within or near the plume extents.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AOR.	Within 1 month of commencement of new operations
Seismic event or other emergency occurs.	Perform a plume migration survey. If plume increases in shape or extents, reevaluate the AOR.	Within 1 month of event

The following AOR maps and resultant tables are included in *Appendix C* in large-scale format for ease of detailed review.

- Appendix C-1 USDW Determination AOR Map
- Appendix C-2 Oil and Gas Wells AOR Map
- Appendix C-3 Oil and Gas Wells AOR List
- Appendix C-4 Freshwater Wells AOR Map
- Appendix C-5 Freshwater Wells AOR List
- Appendix C-6 Site Review AOR Map
- Appendix C-7 SN: [redacted] Current State Schematic
- Appendix C-8 SN: [redacted] Corrective Action Schematic
- Appendix C-9 SN: [redacted] Current State Schematic
- Appendix C-10 SN: [redacted] Corrective Action Schematic
- Appendix C-11 SN: [redacted] Current State Schematic
- Appendix C-12 SN: [redacted] Corrective Action Schematic
- Appendix C-13 Magnetometer Survey Results
- Appendix C-14 Magnetometer Anomalies Investigation

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

July 2023

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

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Figures

Tables

4.1 Introduction

The following section describes the engineering design details and operational strategies employed during the planning of the proposed Pecan Island Injection Well No. 001 and Pecan Island Injection Well No. 002. The engineering design details meet the requirements of Statewide Order (SWO) 29-N-6 **§3617.A** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**.

The design, construction, and operation of injection wells fall under the jurisdiction of the EPA Underground Injection Control (UIC) program. Class VI injection wells are designed for the sole purpose of injection and storage of CO_2, safely targeted in injection zones, and contained within those zones—to ensure protection of all Underground Sources of Drinking Water (USDWs).

The Pecan Island Project is proposing wells centrally located to various surrounding industrial companies that produce CO_2 as a by-product at high levels at their facilities. The environment and these companies will benefit from capture of the CO_2 by-product and its safe and permanent injection into formations having the proper geology and rock qualities. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) proposes to inject CO_2 into upper and middle Miocene sands. The formation properties of this reservoir make it an excellent candidate for injection of CO_2. It is a highly porous, highly permeable, saline-filled sand zone that contains approximately 5,000 ft of gross vertical thickness of sands, interbedded with shale layers to help isolate each potential zone of injection.

The specific requirements for the design of a carbon capture and sequestration (CCS) Class VI well are described in the following sections.

4.2 Engineering Design

The primary concern for the design of a Class VI CO_2 sequestration well is to ensure the protection of the USDW from any CO_2 injectate contamination. The design parameters for such a well consider injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid.

The combination of CO_2 mixed with formation fluids and other injectate components, including H_2S, can be corrosive. As a result, a proposed CO_2 sequestration well is designed to withstand the corrosive environment to which the well components, including casing, tubing, wellhead equipment, and downhole tools, will be exposed. The engineering design also considers the cement used in the well. The cement design and products selected are designed to fill the annulus in order to create a good bond between the casing and formations and withstand the nature of the corrosive fluids. The production casing, cementing, tubing, packer, and other well components are designed to prevent the migration of CO_2 above the upper confining zone (UCZ).

The CO_2 injectate will be sequestered in the Miocene sands, bound by the upper and lower confining zones discussed in *Section 1 – Site Characterization*. Additionally, intermittent layers of shales are present throughout the injection interval and will act as additional vertical barriers. The sands in the project area are located below [redacted] thick. The sands are porous, permeable, and unconsolidated, which make them favorable for CO_2 injection and storage.

[redacted] Upon installation of the completion assembly, injection will start at the deepest sand interval per the current model plan. The CO_2 plume will be monitored during and after injection to ensure that the plume follows the model expectations. An extensive monitoring program is included in *Section 5 – Testing and Monitoring Plan*.

At the end of injection for a given zone, the injection interval will be plugged back to isolate that zone. The next injection interval will then be accessed through the screen assembly by perforating the inner string, establishing communication to the reservoir. The injectate will then be injected and sequestered into that new zone until the end of injection life for that interval. The above process will be repeated until the uppermost injection interval below the UCZ is reached, as shown in Table 4-1 and Table 4-2 for the Pecan Island Injection Wells No. 001 and 002, respectively.

Table 4-1 – Pecan Island Injection Well No. 001 Operational Strategy

Stage	Top Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]				

Table 4-2 – Pecan Island Injection Well No. 002 Operational Strategy

Stage	Top Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]				

[redacted]

[redacted]

This design also allows for continuous monitoring of the casing and tubing annulus to ensure wellbore and mechanical integrity are maintained.

Figures 4-1 and 4-2 show the proposed wellbore designs for the Pecan Island Project. Figures 4-3 and 4-4 show the certified well-location plats.

[redacted]

Figure 4-1 – Pecan Island Injection Well No. 001 Wellbore Schematic

[redacted]

Figure 4-2 – Pecan Island Injection Well No. 002 Wellbore Schematic

[redacted]

Figure 4-3 – Plat for Pecan Island Injection Well No. 001

[redacted]

Figure 4-4 – Plat for Pecan Island Injection Well No. 002

The drilling and completion design for the Pecan Island Injection Well No. 001 is as follows:

- Drive Pipe
  - [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of open-hole logging during the drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is [redacted] TVD.
  - [redacted] hole size
  - [redacted] outer diameter (OD) casing
  - Cemented to surface
- [redacted]roduction Casing
  - [redacted]
  - Cemented back to surface
    - Cement to be comprised of:
      - CO_2-compatible cement from TD through the UCZ, designed to be from [redacted]
- Injection Tubing
  - [redacted] tubing at [redacted].

- Tubing annulus will be filled with a non-corrosive fluid.
- Packer
  - [redacted]
- Wellhead
  - [redacted]

The drilling and completion design for the Pecan Island Injection Well No. 002 is as follows:

- Drive Pipe
  - [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of open-hole logging during the drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is [redacted]
  - [redacted]
  - [redacted]
  - Cemented to surface
- [redacted]

[redacted]

- Cemented back to surface
  - Cement to be comprised of:
    - CO_2-compatible cement blend from TD through the UCZ, designed to be from [redacted]

[redacted]

- Injection Tubing

[redacted]

  - Tubing annulus will be filled with a non-corrosive fluid.
- Packer

[redacted]

- Wellhead

[redacted]

A detailed drilling-and-completion prognosis is included in *Appendix D*.

4.2.1 Detailed Discussion of Injection Well Design

ExxonMobil plans to inject a maximum volume of captured carbon gas of [redacted] per year (MMTA) into each of the proposed wells. This translates to a rate of approximately [redacted]. The tubing design, including size, weight, and grade, is based on the properties of the injectate, rate of injection, and injection pressures determined during the detailed reservoir modeling. Table 4-3 shows the standard conditions of CO_2 used in the modeling and flow calculations.

Table 4-3 – CO_2 Inlet Conditions

Temperature °F	Pressure psia*	Density lbm**/ft^3	Enthalpy Btu/lbm	Entropy Btu/lbm-°R
60	14.7	0.11666	214.18	0.64759

*psia – pounds per square inch absolute

**lbm – pounds mass

A tubing design sensitivity was run that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. Bottomhole pressures (BHP) were calculated from detailed reservoir-engineering model runs as shown in Figures 4-5 and 4-6. The data identify when the maximum BHP occurs during the life of the project, and the resulting maximum flowing pressure at surface, allowing for proper design of the casing, tubing, and wellhead configurations.

[redacted]

Figure 4-5 – Injection Pressure Plot for Well No. 001

[redacted]

Figure 4-6 – Injection Pressure Plot for Well No. 002

For the reservoir model, a conservative value of 100% CO_2 was used for the injectate stream. The anticipated chemical composition of the pipeline CO_2 is outlined in Table 4-4.

Table 4-4 – Injectate Parameters

[redacted]

The input injection parameters from the model are shown in Table 4-5. The calculated injection parameters are shown in Table 4-6 for Well No. 001 and in Table 4-7 for Well No. 002.

Table 4-5 – Input Injection Parameters for Injection Well No. 001

Inputs	Well No. 001	Well No. 002
Max Injection Rate (MMTA)	[redacted]	
Pressure Constraint Gradient (psi/ft)		
Injection Duration (yrs)		
[redacted]		
Absolute Roughness Factor		
Wellhead Temperature (°F)		

Table 4-6 – Calculated Injection Parameters for Well No. 001

Stage	Date	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Table 4-7 – Calculated Injection Parameters for Well No. 002

Stage	Date	Max Rate (MMT/yr)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)	Avg WHP (psi)
[redacted]							

Based on the inputs and the results from the model, [redacted] through the injection interval is the appropriate size necessary to move the desired volumes of supercritical CO_2 in each well. The model also verified that the CO_2 would remain in supercritical state in each wellbore.

Based on appropriate bit-size selection, pipe-clearance considerations, and recommended annular spacing for assurance of proper cementing, the following casing sizes are appropriate to accommodate the [redacted] completion design.

[redacted]

4.2.1.1 Drive Pipe

Because of the loose, unconsolidated nature of the sediments found immediately beneath the waterline, drive pipe will be needed to ensure that the hole integrity is maintained during the initial drilling of the Pecan Island Injection Wells No. 001 and No. 002. [redacted] drive pipe will be used to accommodate this need in both wells and driven to [redacted] blows per foot of advancement) by a hydraulic ram.

The drive pipe size was selected to facilitate the desired bit size for drilling of the surface casing borehole. A[redacted]. bit will be used to drill the next section of the well through the [redacted] of the drive pipe.

Once the drive pipe is established, the inner portions of the pipe will be flushed out and cleaned, and drilling will commence.

4.2.1.2 Surface Casing

The surface hole will be drilled below the USDW with a [redacted] bit, to casing set [redacted] for each of the injection wells. A string of [redacted] casing will be run and cemented with the casing centered in the open hole with centralizers. Being centralized, the size of the annulus chosen will provide a consistent thickness of cement between the casing and open hole. Cement will be circulated to surface. If the cement level falls after the cement is circulated to surface, a top-job will be performed if needed. This ensures a good cement bond from the surface casing shoe to surface and protects the critical USDW. After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole.

Summaries of engineering calculations for the surface casing are displayed in Tables 4-8 to 4-10. The engineering calculations for both injection wells in this project were performed assuming the same wellbore conditions and setting depth for surface casing.

Table 4-8 – Surface Casing Engineering Calculations – Wells No. 001 and 002

Surface Casing – Kick Load (Burst)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl**/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Surface Casing – Casing Pressure Test (Burst)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Surface Casing – Cementing Casing (Collapse)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

*ppg – pounds per gallon
**bbl – barrels

Table 4-9 – Surface Casing Cement Summary

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
[redacted]			

Table 4-10 – Surface Casing Volume Calculations

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]				

To ensure that cement returns to surface are achieved, 100% excess of open-hole volumes were used to calculate cement volume.

4.2.1.3 Intermediate Liner

The intermediate hole will be drilled with a [redacted] above the UCZ for both wells. A string of [redacted] being centered in the open hole with centralizers. Being centralized, the size of the annulus chosen will provide a consistent thickness of cement between the casing and open hole to approximately [redacted]

Summaries of engineering calculations for the intermediate casing for the two injection wells are shown in Tables 4-11 to 4-14.

Table 4-11 – Intermediate Liner Engineering Calculations for Well No. 001

Intermediate Casing – Kick Load (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Casing Pressure Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Pressure [redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Cementing Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

*OBM – oil-based mud

**OH – Open Hole

Table 4-12 – Intermediate Liner Engineering Calculations for Well No. 002

Intermediate Casing – Kick Load (Burst)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Casing Pressure Test (Burst)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Intermediate Casing – Cementing Casing (Collapse)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Table 4-13 – Intermediate Liner Cement Summary for Well No. 001

Section	Top (ft)	Bottom (ft)	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]						

Table 4-14 – Intermediate Liner Cement Calculations for Well No. 002

Section	Top (ft)	Bottom (ft)	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
[redacted]						

An excess of 15% of the open-hole volumes was used to calculate cement volume.

4.2.1.4 Production Casing

The production casing, or long-string casing, is the final, permanently-cemented string of casing installed in the well. The production casing will be run from the surface to TD and cemented back to the surface. The key design criteria for the long string includes the use of:

- [redacted] from above the UCZ through the injection interval to TD;
- fiber optic cable along the exterior of the casing terminating above UCZ; and
- CO_2-compatible cement systems from [redacted] above the UCZ through the injection interval to TD.

A detailed metallurgical analysis was performed that considered the chemical composition of the injectate and downhole conditions as shown in Table 4-3 and included in *Appendix E*. The injectate stream is made up of [redacted]. Based on the analysis of the injectate stream and downhole conditions, the production casing will be [redacted] material to prevent corrosion and downhole failures, should any fluids enter the wellbore from the reservoir.

To prevent CO_2 migration out of the injection interval, CO_2-compatible cement will be run from TD to 400 ft above the UCZ, to provide a good barrier across the UCZ. By using CO_2-compatible material, the cement is protected from carbonic acid, maintaining integrity throughout the life of the project. Figures 4-1 and 4-2 (*Section 4.2*) illustrate the production casing design for both wells.

The Miocene sand for the Pecan Island Injection Wells No. 001 and Well No. 002 is approximately [redacted] thick. The sand is interbedded with layers of shale above each sand layer that will act as barriers to confine the CO_2 injectate below the UCZ. Given the unconsolidated nature of the reservoir, [redacted] The completion strategy for the wells is designed to start injection at the lowest sand interval selected. The CO_2 injectate will be injected for the predetermined amount of time or volume derived from the reservoir-injection plume modeling. When that interval has reached the predetermined time or volume, a plug will be set above that injection interval. Injection into the upper zones will be achieved [redacted] This strategy allows for an efficient and economic method for performing the work, since a workover rig is not necessary to perform the work. This process will repeat throughout the life of each well until the uppermost sand interval is completed.

Throughout the life of each well, the project will have a continual monitoring system in place. The system is designed to measure and record downhole temperatures from above the UCZ to surface, as well as to perform vertical seismic profile (VSP) surveys of the CO_2 plume, as discussed in *Section 5 – Testing and Monitoring Plan*. Monitoring systems will include a fiber optic cable with distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) outside of the [redacted] The fiber optic cable will be installed above the UCZ, ending at the [redacted], and cemented into place when the casing-cementing job is performed.

The engineering and design parameters for the production casing are summarized in Tables 4-15 through 4-22.

Table 4-15 – Production Casing Engineering Calculations – Well No. 001

Production Casing – Casing Test (Burst)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Production Casing – Fully Evacuated Casing (Collapse)								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			

[redacted]								
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Table 4-16 – Production Casing Engineering Calculations – Well No. 002

Production Casing – Casing Test (Burst)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			

[redacted]								
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Production Casing – Fully Evacuated Casing (Collapse)								
Description	**Casing Wt. (lb/ft)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]			
[redacted]			[redacted]	[redacted]	[redacted]			

Table 4-17 – Production Casing Annular Geometry

			Well No. 001			Well No. 002	
Section	**ID (in.)**		**Top (ft)**	**Bottom (ft)**		**Top (ft)**	**Bottom (ft)**
[redacted]							

Table 4-18 – Production Casing Specifications

						Well No. 001			Well No. 002	
Section	**OD (in.)**	**ID (in.)**	**Drift (in.)**	**Weight (lb/ft)**		**Top (ft)**	**Bottom (ft)**		**Top (ft)**	**Bottom (ft)**
[redacted]										

Table 4-19 – Production Casing Cement Summary – Well No. 001

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
[redacted]			

Table 4-20 – Production Casing Cement Summary – Well No. 002

System	Top (ft)	Bottom (ft)	Cement Volume (ft^3)
[redacted]			

Table 4-21 – Production Casing Detail Cement Calculations – Well No. 001

Hole Section (Casing / Hole Section)	Top (ft)	Bottom (ft)	Footage	Capacity (ft^3/ft)	% Excess	Cement Volume Stage 1	Cement Volume Stage 2
[redacted]							

Table 4-22 – Production Casing Detail Cement Calculations – Well No. 002

Hole Section (Casing / Hole Section)	Top (ft)	Bottom (ft)	Footage	Capacity (ft^3/ft)	% Excess	Cement Volume Stage 1	Cement Volume Stage 2
[redacted]							

An excess of 15% of open-hole volumes was used to calculate cement volume.

4.2.1.5 Centralizers

Centralizer selection and installation for the Pecan Island Injection Wells No. 001 and 002 serve two functions. [redacted] The recommended centralizer placement for both wells is shown in Table 4-23.

Table 4-23 – Surface Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Well No. 001		Well No. 002	
		Depth (ft)	Qty	Depth (ft)	Qty
[redacted]					

Centralizer placement for the [redacted] The recommended centralizer placement is shown in Table 4-24.

Table 4-24 – Intermediate Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Well No. 001		Well No. 002	
		Depth (ft)	Qty	Depth (ft)	Qty
[redacted]					

Centralizer placement for the [redacted] is designed to accommodate the installation of the fiber optic cable. Clamp centralizers and eccentric centralizers, of the same alloy as the production casing, will be used to ensure that the fiber optic cable is not damaged. The recommended placement of centralizers through the production casing is shown in Table 4-25.

Table 4-25 – Production Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Well No. 001		Well No. 002	
		Depth (ft)	Qty	Depth (ft)	Qty
[redacted]					

4.2.1.6 Injection Tubing

The [redacted] injection tubing size and material were selected for use in both wells based on injection volumes, rates, and injectate composition. Like the casing string, the injectate and the potential for a corrosive environment are important considerations when selecting the metallurgy of the tubing. The planned design offers protection from the potential corrosive environment of the injectate stream and potential for influx of reservoir brine. A complete summary of the metallurgical analysis is included in *Appendix E*.

Taking into consideration the possibility of a water-and-CO_2 mixture resulting in the presence of carbonic acid, [redacted] material or better is recommended for the tubing string and will be utilized. Additionally, fiber optic cable and a pressure gauge array will be run during the completion and installed across each injection interval in both wells. A single pressure and temperature gauge will be installed above the packer to monitor CO_2 injection through the tubing. Throughout the life of each well, this system will monitor all the data from all zones that will be plugged, and from each new injection zone that is completed.

Tables 4-26 and 4-27 provide the design calculations for Wells No. 001 and 002.

Table 4-26 – Tubing Engineering Design Calculations – Well No. 001

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID
[redacted]								

Table 4-27 – Tubing Engineering Design Calculations – Well No. 002

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID
[redacted]								

The tubing will be installed using premium connections.

4.2.1.7 Packer Discussion

The proposed packer for both wells is a [redacted] Figure 4-7 provides a schematic of the planned packer.

[redacted]

Figure 4-7 – [redacted] Packer Schematic

The packer will be run with the [redacted] injection tubing. Prior to setting the packer, the tubing annulus will be filled with a non-corrosive fluid. The packer will be set by applying surface pressure against a plug set below the packer, previously installed via slickline.

4.2.1.8 Safety Injection Valve

A safety injection valve will be installed in the [redacted] tubing. The injection valve will prevent fluid backflow into the upper completion tubing and will keep the reservoir pressurized until equilibrium is achieved. Additionally, the safety injection valve will maintain the CO_2 below the valve in a supercritical state when closed. This design will minimize cross-flow events and reduce sand influx into the wellbore. The safety injection valve will be manufactured out of a 25SCr material or equivalent, to sustain the corrosive environment.

The safety injection valve will be run on wireline [redacted] The valve is designed to the American Petroleum Institute (API) 14A standard. The operation of the valve consists of a variable orifice that actively adjusts the instantaneous injection flow to maintain a consistent low-back pressure without a flapper or flow tube.

The valve will be retrieved each time an intervention is required to isolate an injection zone or perforate the [redacted]. inner string. Figure 4-8 provides a schematic and specifications for the safety injection valve.

[redacted]

Figure 4-8 – [redacted]

[redacted]

[redacted]

Figure 4-9 – [redacted]

[redacted]

[redacted]

Figure 4-10 – [redacted]

Downhole Pressure and Temperature Gauge

A single pressure and temperature gauge will be run above the injection packer in both wells, to provide real-time bottomhole injection information. The gauge will be ported to the tubing only, and data will be fed to the surface using the installed TEC line.

[redacted]

[redacted]

Fiber Optic

In addition to the fiber optic line run on the production casing, there will be one run on the exterior of the production tubing and through the lower completion for both wells. This fiber optic line will provide a secondary DAS for plume monitoring purposes and DTS for injection conformance. In the upper completion, the DTS functionality will be used to monitor mechanical integrity of the tubing and casing.

Pressure Gauge Array

A pressure gauge will be installed across each reservoir interval to provide continuous data in real time for reservoir monitoring purposes. A TEC line will be installed on the exterior of the tubing completion to power the gauges and provide communication to surface for both wells.

4.2.1.9 Wellhead Discussion

The wellhead is designed to combat working pressures and corrosion complications. The wellhead equipment will be manufactured with a combination of stainless-steel components across the hanger and casing spool. Inconel lining will be placed across trims, stems, gates, vales, etc. The wellhead will be configured as illustrated in Figure 4-11.

[redacted]

Figure 4-11 – ExxonMobil Pecan Island Injection Wells No. 001 and No. 002 Preliminary Wellhead Design

4.3 Testing and Logging During Drilling and Completion Operations

4.3.1 Coring Plan

The drilling procedure in *Appendix D-1* discusses the coring procedures for the Pecan Island Injection Wells No. 001 and No. 002. [redacted]

Coring depths, formations, and footages for full core samples are shown in Table 4-28.

Table 4-28 – Full Core Sample Depths

Formation	Well #1 Depth (ft)	Well #2 Depth (ft)	Footage
[redacted]			

[redacted]

4.3.2 Logging Plan

An extensive suite of electric logs will be run in the open-hole sections and in each string of casing. The open-hole logging plan is detailed in Table 4-29. The cased-hole logging plan is detailed in Table 4-30.

Table 4-29 – Open-Hole Logging Plan

Section	Open Hole Logs	Well No. 001	Well No. 002
[redacted]	Gyro Survey Gamma Ray Resistivity Spontaneous Potential Caliper	[redacted]	[redacted]
[redacted]	Gyro Survey Gamma Ray	[redacted]	[redacted]

	Resistivity Sonic Caliper		
[redacted]	Gyro Survey – from measurement while drilling (MWD) Gamma Ray Resistivity Density Neutron Magnetic Resonance Elemental Capture Spectroscopy Dipole Sonic Resistivity Imaging Ultrasonic Imaging Caliper RSWC Pressure and Fluid Sampling	[redacted]	[redacted]

Table 4-30 – Cased Hole Logging Plan

Section	Cased Hole Logs	Well No. 001 (ft)	Well No. 002 (ft)
[redacted]			

*CBL – cement bond log
**GR – gamma ray
***CCL – casing collar locator
^PBTD – plugged back total depth

4.3.3 Formation Fluid Testing

Prior to setting the production casing string, samples of the formation fluid will be obtained with an open-hole fluid recovery tool. Recovery sections will be determined based on open-hole evaluations.

4.3.4 Injection Falloff / Step-Rate Test

- A non-hazardous fluid, approved by the Louisiana Department of Natural Resources (LDNR) Injection and Mining Division (IMD) will be used during the injection test.
- Injection falloff test
  - The purpose of this test is to evaluate the injectivity index, skin, and permeability (kH) of the injection interval.
  - Inject at a rate of 20,000 bbls per day (13.9 bbls per minute) for three hours. The total volume to be injected is estimated to be 2,500 bbls.
  - Shut in well and record pressure falloff for at least three hours with downhole gauges. The injection falloff test parameters are detailed in Table 4-31.

Table 4-31 – Injection Falloff Test

Injection Falloff Test (per zone)				
Duration (hr)	Rate (kbd)	Rate (bph)	Rate (bpm)	Volume (bbl)
3	20	833.3	13.9	2,500

- Step-rate injection test
  - The purpose of this test is to evaluate the fracture pressure of the injection interval.
  - Step duration
    - Minimum step duration is 5 minutes.
    - Maximum step duration is 30 minutes.
    - Actual step duration will be established based on the time required for pressure stabilization during the initial step, and this step duration will be held for all additional steps.
  - Maximum planned injection rate is 50% above the operating injection rate.
  - Attempt to record three steps below and above the fracture.
  - The proposed steps are listed in Table 4-32.

Table 4-32 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (kbd*)	Rate (bph**)	Rate (bpm***)	Volume (bbl)
1	5	10	416.7	6.9	35
2	5	20	833.3	13.9	69
3	5	30	1,250	20.8	104
4	5	40	1,667	27.8	139
5	5	50	2,083	34.7	174
6	5	60	2,500	41.7	208
Total	30				729

*kbd – thousand barrels per day
**bph – barrels per hour
***bpm – barrels per minute

4.4 Injection Well Operating Strategy

ExxonMobil plans to inject [redacted] of CO_2 into each of the Pecan Island Project injection wells. The CO_2 will be injected and remain in a supercritical state through the life of the project. The reservoir properties of the Miocene sands with high porosity and high permeability allow for a pseudo-infinite-acting reservoir, with the ability to absorb the injected CO_2 and relieve pressure quickly. The operator parameters for the injection wells are provided in Table 4-33.

Table 4-33 – Injection Parameters

Parameter	Well No. 001	Well No. 002
Gross Injection Interval	[redacted]	
Maximum Injection Volume		
Average Injection Volume		
Maximum Increase in BHP		
Maximum Allowed Surface Pressure (90% of Estimated Fracture Gradient)		
Modeled Maximum Surface Pressure Injection		
Maximum Annular Pressure		

Surface injection pressures will be limited so that the BHP does not exceed 90% of the fracture pressure of the injection reservoir. The anticipated surface and bottomhole injection pressures and injection rates over time for the wells are shown in Tables 4-34 and 4-35.

Table 4-34 – Injection Pressures and Volumes by Stage – Well No. 001

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowable Bottomhole Pressure (psi)
[redacted]				

Table 4-35 – Injection Pressures and Volumes by Stage – Well No. 002

Completion Stage	Completion Date	Top Depth (TVD ft)	Fracture Pressure (psi)	Maximum Allowable Bottomhole Pressure (psi)
[redacted]				

To maximize the use of the available pore space, multiple injection intervals will be used. Each discrete injection interval was selected to maximize the utilization of the pore space and collectively maximize the usage of the acreage position for CO_2 sequestration. A summary of the planned injection strategy is listed in Table 4-36 for Well No. 001 and in Table 4-37 for Well No. 002.

Table 4-36 – Injection Intervals – Well No. 001

Completion Stage	Completion Date	Injection Duration (years)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
[redacted]					

Table 4-37 – Injection Intervals – Well No. 002

Completion Stage	Completion Date	Injection Duration (years)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
[redacted]					

Typical densities for the injectate range from 43.8 lb/ft^3 in the shallowest injection interval to 45.7 lb/ft^3 in the deepest injection interval. This is compared to approximately 68 lb/ft^3 for the connate brine in the same formations. This density difference and the high vertical permeability in the Miocene sands allow the CO_2 to migrate vertically to the top of each discrete injection interval and laterally under the confining layer of that injection interval.

The result is a significant "mushroom cap" effect, with the top of the mushroom expanding outwardly from the injection well (Figure 4-12).

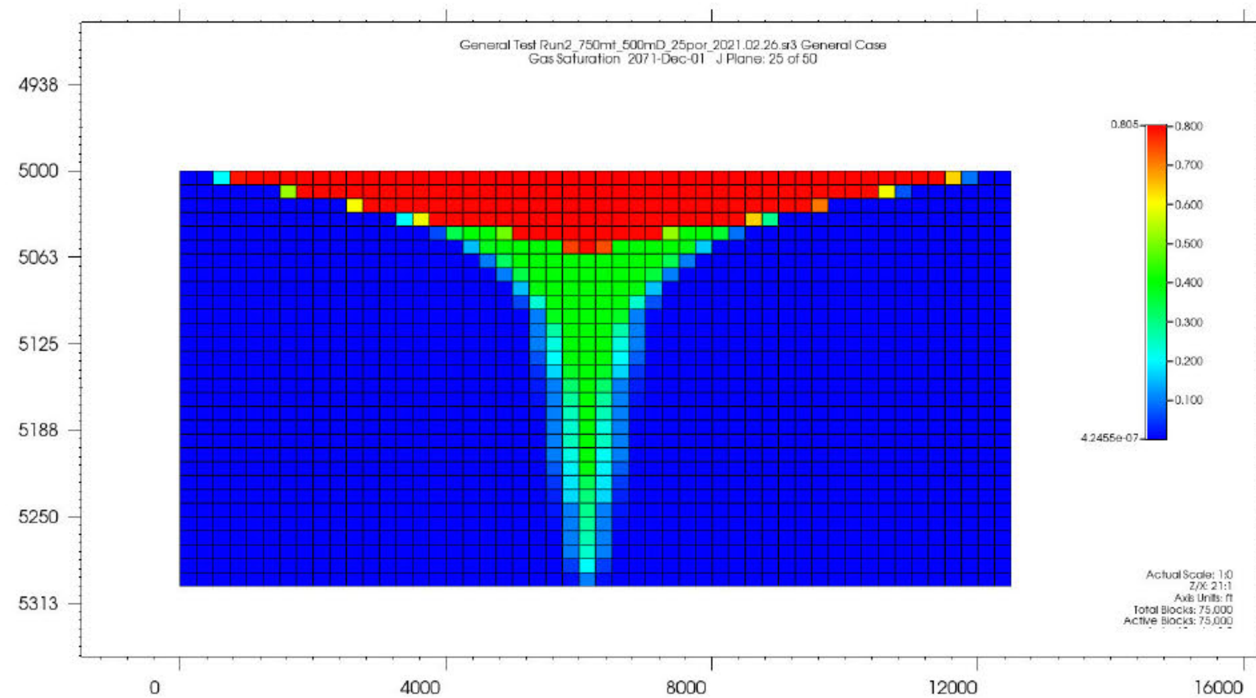

Figure 4-12 – Typical Plume Profile in High Permeability Formations

Reservoir management is important for sequestration wells in thick, high permeability, unconsolidated sand formations. At the end of each injection interval, wireline operations will be executed to recomplete into a new interval. A plug will be set to isolate the previous interval, and the [redacted] will be perforated to access the next interval for injection.

Figure 4-13 depicts this process in a general form.

[redacted]

Figure 4-13 – Operational Completion Strategy

The actual injection intervals, injection time frame, injection rate, and injection volume were displayed in Table 4-33 for both wells.

4.5 Injection Well Construction and Operation Summary

The proposed well design is engineered to address the potential hazards and risks associated with Class VI wells, including protection of the USDW. Casing setting points, materials, and cement meet and exceed the requirements for this classification of injection well. All requirements and regulations are satisfied by the well design. Additionally, efforts have been made to efficiently maximize use of the available pore space with the completion strategy and to mitigate issues with sand control while still allowing pressure monitoring throughout the injection interval.

The location for this project is ideally situated for carbon sequestration. Combining the best engineering practices in the design of the well with a state-of-the-art monitoring system and a robust reservoir management strategy, this well will safely serve the State of Louisiana for years to come.

Appendix D – Well Construction Schematics and Procedures

- Appendix D-1 Drilling and Completion Prognoses
- Appendix D-2 Drilling Phase Wellbore Schematics
- Appendix D-3 Completion Phase Wellbore Schematics
- Appendix D-4 Injection Phase Wellbore Schematics
- Appendix D-5 Plug and Abandonment Phase Wellbore Schematics
- Appendix D-6 Pecan Island Injection Well No. 001 Cement Program
- Appendix D-7 Pecan Island Injection Well No. 002 Cement Program

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 5 – TESTING AND MONITORING PLAN

July 2023

SECTION 5 – TESTING AND MONITORING PLAN

TABLE OF CONTENTS

Figures

Tables

5.1 Introduction

This section includes the proposed Testing and Monitoring plan for the Pecan Island Injection Wells No. 001 and No. 002. The plan includes robust testing and monitoring programs that satisfy the requirements of Statewide Order (SWO) 29-N-6 **§3625.A** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**]. This plan will start before the injection of CO_2 commences. Monitoring strategies are designed to ensure and verify protection of the Underground Sources of Drinking Water (USDWs). These strategies consider, but are not limited to, the injection-stream composition, wellhead conditions, bottomhole operating parameters, seismic imaging for plume evolution, well integrity, and the above-zone confinement conditions. The location and information for all new monitoring wells are included, as are the parameters to be measured at each location. An in-depth summary of plume-growth monitoring, using time-lapse seismic imaging technology, is presented. The monitoring activities described in this plan will be carried out during the entirety of the life of the injection wells, including the post-injection site care (PISC) phase. The monitoring activities will follow a predetermined timeline tailored toward verifying that the observed plume development is according to modeling expectations, as well as demonstrating that the injected CO_2 is not endangering a USDW.

5.2 Reporting Requirements

In compliance with SWO 29-N-6 **§3629.A** [40 CFR **§146.91**], ExxonMobil will provide routine reports to the Underground Injection Control (UIC) program director (UIC Director). The report contents and submittal frequencies are described below:

- Any noncompliance with a permit condition, or malfunction of the injection system that may cause fluid migration into or between USDWs
    - Verbal Notification – Reported within 24 hours of event
- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW
    - Verbal Notification – Reported within 24 hours of event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of event
- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
    - Written Notification – Reported within 72 hours of composition change
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 72 hours of event
- Description of any event that triggers a shut-off device either downhole or at the surface and the response taken
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 72 hours of event

Semiannual Reports:

Reports will include all contents and situations listed above, in addition to the following:

- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure
- Monthly volume and/or mass of the CO_2 stream injected over the reporting period, and the volume injected cumulatively over the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring as described here, throughout *Section 5*

Reports to be submitted within 30 days after the following events:

- Any well workover
- Any test of the injection well conducted, if required by the UIC Director

Notification to the UIC Director, in writing, 30 days in advance of:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of an injection well

ExxonMobil will submit all reports, submittals, and notifications to both the EPA and the Louisiana Department of Natural Resources (LDNR) and ensure that all records are retained throughout the life of the project. In accordance with SWO 29-N-6 **§3629.A.4.c** [40 CFR **§146.91(f)**], records will be retained for a 10-year period after site closure. Additionally, injected-fluid data, including nature and composition, will also be retained for the 10-year period following site closure. Monitoring data will be retained for a minimum of 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

In accordance with SWO 29-N-6 **§3625.A.10** [40 CFR **§146.90(j)**], the Testing and Monitoring Plan will be reviewed and revised as necessary, at a minimum of every 5 years to incorporate collected monitoring data. Plan amendments will also be submitted within 1 year of an area of review (AOR) reevaluation, following significant facility changes—such as the development of offset monitoring wells or newly-permitted injection wells within the AOR, or as the UIC Director requires.

5.4 Testing Strategies

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO_2 injection, ExxonMobil will conduct a step-rate injectivity test to measure the fracture gradient of Pecan Island Injection Wells No. 001 and No. 002 in compliance with SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**] and SWO 29-N-6 **§3617.B.5.c** [40 CFR **§146.87(e)(3)**]. The details of the step-rate test are provided in *Section 4.3.4*.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with SWO 29-N-6 **§3627.A.2** [40 CFR **§146.89(b)**], ExxonMobil will ensure the mechanical integrity of each injection well by performing annulus pressure tests after the well has been completed, prior to injection, and annually afterwards. This annular pressure test specifically verifies the integrity of the annulus between casing and tubing above the packer. During well construction, prior to completion, the casing will also be pressure tested to the maximum anticipated annulus-surface pressure to verify its integrity. The annual pressure tests must be witnessed by an agent of the Louisiana Office of Conservation.

The annular pressure tests are designed to demonstrate mechanical integrity of the casing, tubing, and packer. These tests are conducted by pressuring the annulus to a minimum of 500 pounds per square inch (psi) surface pressure. A block valve is then used to isolate the test-pressure source from the test-pressure gauge upon test initiation, with all ports into the casing annulus closed except the one monitored by the test-pressure gauge. The test pressure will be monitored and recorded for a minimum duration of 30 minutes, using a pressure gauge with sensitivities that can indicate a loss of 5%. A lack of mechanical integrity is indicated by any loss of test pressure exceeding 5% during a minimum elapsed period of 30 minutes.

All annulus pressure test results will be submitted to the Injection and Mining Division (IMD) on Form UIC-5 within 30 days of completion.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times. More details regarding continuous monitoring are described in *Section 5.5.1 and 5.5.2.*

5.4.3 External Mechanical Integrity Testing

Following the requirements of SWO 29-N-6 **§3627.A.3** [40 CFR **§146.89(c)**], ExxonMobil will perform an annual external mechanical integrity test (MIT). A noise log will be run to meet this requirement using the distributed acoustic sensing (DAS) interrogator and fiber cables installed in the well. The aim of this measurement is to detect the sound generated by the movement of fluid through a leak or channel behind the casing. One of the benefits of this approach is that measurements can be obtained while the well is operating, unlike an approach based exclusively on temperature measurements. One anticipated challenge of measuring noise during injection conditions is the competing noise from the injection stream. If the noise interference reduces the diagnostic power of the noise logs below acceptable levels, then the noise measurements will be repeated when the well is shut in.

[redacted]

[redacted]

As a contingency, ExxonMobil can revert to a determination using one or more of the following methods: a temperature log, data collected using DTS, a wireline, or an oxygen-activation log.

All logs recorded during the external MIT will be submitted to the UIC Director within 30 days of log-run completion.

5.4.4 Pressure Fall-Off Testing

The injection interval is several thousand feet thick and is partitioned into multiple injection stages [redacted]. Each injection stage is instrumented with multiple downhole pressure gauges. After the end of injection for a given stage, it will be plugged back to isolate that stage. The next injection stage [redacted].

ExxonMobil will perform a required pressure fall-off test at the end of every injection stage or every 5 years, whichever is more frequent, to meet the requirements of SWO 29-N-6 **§3625.A.6** [40 CFR **§146.90(f)**]. After an injection stage is permanently abandoned, the pressure gauges clamped to the tubing within each injection stage will measure the natural pressure decay after injection ceases in that stage. The objective of the pressure fall-off test would be automatically satisfied by the continued measurements in the abandoned zone. When a pressure fall-off test is conducted in an injection stage and injection continues in that stage after the test, the test procedure in *Section 5.4.4.1* would be followed. This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

5.4.4.1 <u>Testing Method</u>

The CO_2 injection rate and pressure will be held as constant as possible prior to the beginning of the fall-off test, and data will be continuously recorded during testing. After the well is shut in, continuous pressure measurements will be taken with a downhole pressure gauge array installed across each injection stage. This array consists of a tubing encapsulated conductor (TEC) cable equipped with pressure gauges. The fall-off period will end once the pressure-decay data plotted on a semi-log plot is a straight line, indicating radial-flow conditions have been reached.

5.4.4.2 <u>Analytical Methods</u>

Near-wellbore conditions, such as the prevailing flow regimes, well skin, and hydraulic property and boundary conditions, will be determined through standard diagnostic plotting. This determination is accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by comparing pressure fall-off tests performed prior to initial injection with later tests. The effects of two-phase flow effects will also be considered. These well parameters resulting from fall-off testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary.

All pressure fall-off test results will be submitted to the IMD within 30 days of test completion.

5.4.4.3 <u>Quality Assurance/Quality Control</u>

All surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results. Further validation of the test results will be justified by extended collection of pressure data from the plugged and abandoned injection stages. The continuation of pressure monitoring in deeper, inactive stages allows for recording of the naturally occurring pressure decay. Pressure communication between stages can be detected with this system.

5.4.5 Cement Evaluation and Casing Inspection Logs

A cement bond log will be run after the casing installation and the required cement-hardening time to understand the quality of the cement. [redacted]

[redacted]

- [redacted].
- The UIC Director requests it.

[redacted] can be analyzed to identify and localize casing corrosion, addressing SWO 29-N-6 **§3627.A.4** [40 CFR **§146.89(d)**].

5.5 Monitoring Programs

5.5.1 Continuous Injection Stream Physical Monitoring

ExxonMobil will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with SWO 29-N-6 **§3625.A.2** [40 CFR **§146.90(b)**]. A Supervisory Control and Data Acquisition (SCADA) system facilitates the operational data collection and monitoring for the full sequestration site, consisting of the pipeline, the injection wells, and the above-zone monitoring interval (AZMI) monitoring wells.

The injected CO_2 stream pressure will be continuously monitored in the CO_2 piping near the pipeline-wellhead interface. The annulus pressure will also be continuously recorded at the wellhead. The injection interval is thousands of feet thick and is vertically partitioned into multiple injection stages. Each stage is several hundred feet thick and has continuous-recording downhole pressure and temperature gauges installed. Combined with the wellhead-pressure measurements, it is therefore possible to continuously characterize the injection stream in detail. This analysis can be further supplemented on demand by DTS and DAS measurements from the fiber optic cable on the tubing, using a permanently available interrogator of each type. If necessary, this enables more detailed flow characterization along the entire length of the well, including the pipeline between the wells and the central platform. At the central platform, there is a high-accuracy Coriolis flow meter to measure the mass flow rate in the pipeline that connects to the injection wells. Each of the injection wells also has its own Coriolis flow meter to quantify the partitioning of the flow between the two injectors.

5.5.1.1 <u>Analytical Methods</u>

ExxonMobil will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination of trends to help determine a need for equipment maintenance or calibration. Semiannual reports of the monitoring data will be submitted to the UIC Director.

5.5.2 Continuous Injection Stream Composition Monitoring

Under SWO 29-N-6 **§3625.A.1** [40 CFR **§146.90(a)**], ExxonMobil will determine the chemical composition of the injection stream with the objective of understanding potential interactions between CO_2 and other injectate components, as well as with the wellbore materials. This determination is accomplished by quarterly sampling of the injection stream and subsequent laboratory analysis.

5.5.2.1 Sampling Methods

The quarterly measurements are obtained by extracting samples from the injection stream at a location where the composition is representative for the injection well. The samples are subsequently sent to a laboratory for analysis.

5.5.2.2 Parameters Measured

Table 5-1 lists the injection stream parameters that will be measured, plus the frequency and methods used.

Table 5-1 – Injection Stream Measurements

Parameter/Analyte	Frequency	Method
Pressure	Continuous	Pressure gauges at wellhead (downstream of choke) and downhole
Temperature	Continuous	Temperature gauges at platform and downhole
pH	Quarterly	Lab analysis
Water (lb/mmscf*)	Quarterly	Lab analysis
Oxygen (%)	Quarterly	Lab analysis
Methane (%)	Quarterly	Lab analysis
Other Hydrocarbons (%)	Quarterly	Lab analysis
Hydrogen Sulfide (ppm**)	Quarterly	Lab analysis

*mmscf – million standard cubic feet
**ppm – parts per million

5.5.3 Corrosion Coupon Monitoring

Monitoring of corrosion to the well tubing and casing materials will be conducted in adherence to SWO 29-N-6 **§3625.A.3** [40 CFR **§146.90(c)**]. A quarterly evaluation of a corrosion coupon monitoring system, implemented by ExxonMobil, will be performed to meet this requirement. A corrosion coupon station or rack is provided as part of well-materials integrity monitoring. Multiple coupons will be exposed to the stream composition to provide ongoing evaluation of materials compatibility. Results will be reported to the UIC Director semiannually.

5.5.3.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection tubing and production casing, will be exposed to the conditions of the pipeline's CO_2 flow. The coupons will be removed on a quarterly schedule and examined for corrosion per American Society for Testing and Materials (ASTM) standards for corrosion testing evaluation. The coupons, once removed, will be visually inspected for signs of corrosion, including pitting, and measured for weight and size each time they are removed. The corrosion rate will be estimated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

5.5.4 Fluid Quality Monitoring

Fluid samples will be taken periodically from the USDW and AZMI monitoring wells.

The USDW monitoring wells target the deepest USDW formation, and the initial sampling frequency is quarterly. This sampling frequency is for both the pre-injection phase and the first 3 years of injection. This quarterly sampling characterizes any potential seasonal fluctuation in this USDW. [redacted]

One example of these complementary leakage-detecting monitoring measurements is the deep fluid sampling provided by the AZMI monitoring wells. This type of well targets the first permeable formation above the UCZ. This formation is referred to as the AZMI. This interval is a deep formation [redacted] in which no seasonal variation is expected. Therefore, sampling this formation annually from the start of the project will provide sufficient resolution for analysis. The first (and therefore deepest) injection stage of the project is [redacted] deeper than the AZMI and is separated by multiple continuous shales.

Table 5-2 summarizes the parameters analyzed and the planned sampling frequency, which apply to all USDW and AZMI wells. Anomalous measurements will initiate further studies, including a more detailed analysis of existing data to understand the potential cause of the variation. This analysis could take the form of geochemical modeling and review of trends observed in samples collected from all wells prior to the anomalous measurement.

These studies could also include integration with other measurements, such as time-lapse seismic and AZMI pressure measurements, as described later in *Sections 5.5.8* and *5.5.6*, respectively. If this study does not satisfactorily rule out the leakage scenario, further contingency data acquisition will be considered. The options include acquiring another fluid sample to verify the original measurement, or complementary measurements, such as a repeat cased-hole wireline log in the injector—or AZMI monitoring wells to independently detect the presence of CO_2. Details of the USDW and AZMI sample-collection strategies are discussed in *Sections 5.5.5*. and *5.5.6*, respectively.

Table 5-2 – USDW and AZMI Monitoring Well Sampling Program During the Injection Phase

Parameter/Analyte	USDW Well Frequency	AZMI Well Frequency
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	[redacted]	[redacted]
Gas composition (CO_2, CH_4, C_{2+}, O_2, N_2)		
Dissolved cations (i.e., Ba, Ca, Fe, Mg, Mn, Na, other relevant metals)	[redacted]	
Dissolved anions (i.e., HCO_3 Br, Cl, F, SO_4)		

Measurements are performed on gases collected from the fluid samples by depressurizing them to atmospheric conditions in a controlled laboratory environment.

5.5.4.1 Analytical Methods

ExxonMobil will test the fluid samples and maintain results for the parameters listed in Table 5-2. If results indicate the existence of impurities in the injection stream, the diagnostic power of these constituents will be assessed to determine if they should be included in the analysis of the water samples. Testing results will be stored in an electronic database.

Potential geochemical signs that fluid may be leaking from the injection interval may be detected upon observation of the following trends:

- Change in total dissolved solids (TDS)
- Change in signature of major cations and anions
- Increase in carbon dioxide concentration
- Decrease in pH
- Increase in concentration of injectate impurities
- Increase in concentration of leached constituents

5.5.4.2 Laboratory to be Used/Chain of Custody Procedures

The analysis of the fluid samples will be submitted to the IMD through a state-approved laboratory. ExxonMobil will observe standard chain-of-custody procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

5.5.4.3 Quality Assurance and Surveillance Measures

ExxonMobil will collect replicate samples and sample blanks for quality assurance/quality control purposes. The samples will be used to validate test results, if needed.

5.5.4.4 Plan for Guaranteeing Access to All Monitoring Locations

Placement of the well locations is optimized to be accessible from roads or, for more remote locations, preexisting dredged channels.

5.5.5 USDW Monitoring Wells

To comply with SWO 29-N-6 **§3625.A.4** [40 CFR **§146.90(d)**], five USDW monitoring wells will be drilled into the deepest USDW sand to support the sequestration project. The deepest USDW formation is defined by salinity and is currently estimated to occur at a depth of approximately 850 ft at Pecan Island Injection Wells No. 001 and No. 002. When the injection wells and USDW monitoring wells are drilled, the USDW depth will be confirmed in each well through the collection of open-hole wireline-resistivity logs.

These five USDW monitoring wells surround the injection wells and provide USDW-quality verification for the sequestration project. Hydrological modeling predicts that USDW flow is toward the north to northwest, which is why three of the five USDW monitoring wells (Wells No. 003, No. 004, and No. 005) are placed in that direction. The remaining two USDW monitoring wells (Wells No. 001 and 002) are in the upstream direction (south to southeast). Water samples will be collected from the USDW monitoring wells to monitor for signs of CO_2 or brine leakage. Figure 5-1 (*Section 5.5.5.1*) displays the monitoring well locations, which are also listed in Table 5-3 (also in *Section 5.5.5.1*).

The USDW monitoring wells are positioned to maximize the value of the information collected, using knowledge of the local hydrology and subsurface features that could potentially act as leakage pathways. USDW Monitoring Wells No. 001 and No. 002 are north (*i.e.*, downstream) of a noteworthy surface-going fault plane. These monitoring wells are therefore optimally positioned to detect any change in fluid chemistry caused by movement of either CO_2 or formation brines along the fault into the USDW. Reservoir simulations predict that CO_2 will never get close to this fault plane, and time-lapse seismic will provide valuable information to validate the model prediction. USDW Monitoring Wells No. 001 and No. 002 serve as early detection in the event of unanticipated CO_2 leakage along the fault. Simulation models also predict that the pressures at the fault plane do not increase to levels that would allow brines to be pushed up along the fault and into the USDW, but these two wells would verify these predictions.

In addition to being downstream of the USDW hydrology, Monitoring Wells No. 003, No. 004, and No. 005 are also in the preferential growth direction (*i.e.*, updip) of the injected CO_2. These monitoring wells are therefore more likely to encounter CO_2 or its effects on the USDW chemistry if a leak does occur. USDW Monitoring Well No. 003 is also adjacent to a legacy oil-and-gas wellbore. While this legacy wellbore will be remediated to minimize any potential leak through the confining zone, a nearby USDW measurement from Monitoring Well No. 003 will provide extra certainty. AZMI Monitoring Well No. 001 further reduces the likelihood of undetected leakage through the adjacent legacy wellbore. This reduced risk is accomplished by including the legacy wellbore in the cone-shaped area of the subsurface that can be monitored with the DAS time-lapse seismic-monitoring methodology, as described in *Section 5.5.8*. USDW Monitoring Well No. 004 is also downstream of two oil-and-gas legacy wells in the vicinity of Injection Well No. 002. While both wells will be remediated to minimize the risk of leaks through the confining zone, this well will provide further verification. While USDW Monitoring Well No. 005 is the farthest away from the injection well—and therefore the least likely to see the effects of any leak during the life of the project—it is also the well downstream to most legacy wellbores and therefore able to detect most potential leakage signatures.

5.5.5.1 Fluid Sampling Methods

Water samples will be collected from the USDW monitoring wells at the surface. Two well volumes will be purged to collect a pristine sample that represents the USDW water rather than water that has resided for a significant time in the wellbore. These water samples will be analyzed in the field for a variety of physical parameters, including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity, as these parameters are sensitive to alteration over time. Additional analyses include TDS, concentrations of cations, anions, CO_2, and CH_4. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

The fluid-sampling parameters and frequencies for the groundwater monitoring wells are shown in Table 5-2. Details regarding sampling techniques and processes are explained in *Section 5.5.4*.

[redacted]

Figure 5-1 – Location of USDW Monitoring Wells Surrounding the Two Injection Wells

Table 5-3 – USDW Monitoring Well Details

Monitoring Well Location Info	USDW Monitoring Well No. 001	USDW Monitoring Well No. 002	USDW Monitoring Well No. 003	USDW Monitoring Well No. 004	USDW Monitoring Well No. 005
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A detailed wellbore schematic for USDW Monitoring Well No. 001 is shown in Figure 5-2 as a representative example of such wells. Wellbore schematics of USDW Monitoring Wells No. 001 through No. 005 are provided in *Appendix F*.

[redacted]

Figure 5-2 – USDW Monitoring Well No. 001 Schematic

5.5.6 AZMI monitoring wells

Two monitoring wells will be drilled to a depth corresponding to the first permeable formation above the UCZ, which is referred to as AZMI. These two wells monitor both injection wells in this project. Each well is directly updip from one of the project's two injection wells. These monitoring wells are located on ExxonMobil Low Carbon Solutions Onshore Storage LLC's property as shown in Figure 5-3, with the location details provided in Table 5-4.

[redacted]

Figure 5-3 – Pecan Island Project AZMI Monitoring Wells and the Two Injection Wells

Table 5-4 – AZMI Monitoring Well Location Details

Monitoring Well Location Info	AZMI Monitoring Well No. 001	AZMI Monitoring Well No. 002
NAD83 (2011) Latitude	[redacted]	[redacted]
NAD83 (2011) Longitude	[redacted]	[redacted]
NAD27 Easting	[redacted]	[redacted]
NAD27 Northing	[redacted]	[redacted]

Datum	[redacted]	[redacted]
Total Depth	[redacted]	[redacted]
Type	[redacted]	[redacted]

5.5.6.1 Fluid Sampling Methods

[redacted] The residual fluid will be analyzed for the physical parameter and geochemical species provided in Table 5-2. Sample collection will occur before the start of injection, to characterize the original chemical composition of the formation fluids. As discussed in *Section 5.5.4*, unexpected changes in the fluid chemistry in the AZMI may be caused by a leakage or other processes and would result in further studies to determine if a leak is present.

5.5.6.2 Pressure Monitoring

Although not required by Class VI regulations, ExxonMobil will continuously monitor the pressure of the first permeable formation identified above the UCZ in the AZMI monitoring wells using a downhole pressure gauge. Deviations from baseline pressures after the start of injection will initiate further review in the area. This review includes a study to rule out sensor drift, and a comparison to the pressure trend observed prior to injection. This comparison would provide insights into potential far-field activities in the same zone. Furthermore, pressure increase in the injection interval causes those sands to physically expand, which may compress the overlying formations and increase pore-fluid pressure without any leakage path being present. This benign effect would also be modeled and compared against observations to further assess the likelihood of the pressure response indicating leakage.

5.5.6.3 Seismic Imaging

A fiber optic cable will be cemented in the annulus of the long casing string. The fiber optic cable gives ExxonMobil the ability to use DAS with time-lapse vertical seismic profile (VSP) surveys to detect CO_2 in the injection sands below the confining zone, as well as any CO_2 that has leaked upward in the vicinity of the wellbore. These time-lapse DAS-VSP surveys are also sensitive to changes in pore pressure, but this effect is anticipated to be minor compared to the sensitivity to changes in CO_2 saturation. A baseline survey will be established at each injection well and AZMI monitoring well for future survey reference and plume tracking. Further details of the seismic program are discussed in *Section 5.5.8*.

A detailed wellbore schematic for AZMI Monitoring Well No. 001 is shown in Figure 5-3 as a representative example of both AZMI monitoring wells. Wellbore schematics of AZMI Monitoring Wells No. 001 and No. 002 are displayed in *Appendix F*.

[redacted]

Figure 5-4 – AZMI Monitoring Well No. 001 Schematic.

5.5.7 Injection Interval Monitoring

The injection interval will be monitored through measurements taken from the injection wells themselves. Each well will continuously monitor pressure and temperature in all injection stages of the injection interval, including previously injected-into stages. These stages will continue to be monitored for the life of the well.

This project includes two injection wells targeting the same sand formations. The pressure measurements taken from the two wells will allow the wells to monitor each other within the injection interval. The fiber optic cables installed in the injection and AZMI monitoring wells facilitate time-lapse seismic imaging of the CO_2 plume in the injection sands with the VSP geometry. These time-lapse seismic images are also capable of detecting potential leakage into the overburden and are described in more detail in *Section 5.5.8.*

5.5.8 Injection Plume Monitoring

ExxonMobil proposes a two-tiered system for plume and pressure-front tracking per the operational monitoring requirements of SWO 29-N-6 **§3625.A.7** [40 CFR **§146.90(g)**]. Plume calculations based on continuously recorded pressures and temperatures will be used as a direct monitoring approach. The fiber optic cables in the injection and monitoring wells will be used as recording devices to indirectly monitor the plume with time-lapse seismic imaging, using the DAS-VSP acquisition geometry.

- <u>Direct method, targeting injection zone pressure</u>: Using the multiple downhole pressure gauges installed in both injection wells.

- <u>Indirect method, targeting CO_2 presence</u>: Using DAS-VSP surveys.

This two-tiered system will serve two purposes: first, to verify reservoir conditions during injection; and second, to track plume migration and validate the plume model. Continuous pressure and temperature monitoring of the injection reservoir will allow for continuous monitoring of the reservoir conditions and calculations. The actual plume migration will be determined by VSP surveying. The VSP will be run prior to injection initiation and periodically as needed, with a detailed discussion of timing in *Section 5.5.8.2.*

5.5.8.1 <u>Direct Monitoring: Pressure</u>

The two injection wells are instrumented with many downhole pressure gauges to continuously monitor the pressure in the multiple injection sands. The pressure response recorded by any gauge would not only be a representation of the injection through that well, but would also be affected by the far-field pressure response from the other injection well. This response effectively empowers one injection well to function as the in-zone pressure monitoring well of the other. These recorded time series provide insight into the reservoir connectivity between the two injectors. These measurements are sufficient for pressure monitoring when both injection wells inject in the same sands of an injection stage, and also in those occasions when the injectors may target separate injection stages. In the latter case, the absence of simultaneous injection in a stage means that the recorded pressure response is exclusively the far-field pressure response of the other injector. This case corresponds to the most conventional understanding of a pressure-monitoring well.

The reservoir model built during the site-evaluation phase may be used to predictively monitor the reservoir conditions during injection operations. Continual monitoring of bottomhole pressures and temperatures, combined with known reservoir parameters, will be used to derive reservoir conditions throughout the injection stages. In addition to the bottomhole measurements from this injection well, the second injection well will collect relevant data to assist with tracking plume development. The two wells will work in conjunction with each other to monitor both plumes.

Any periods of shut-in of the well can be observed and treated as a fall-off test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continual measurements obtained during regular operating conditions, will aid in updating models and forecasts.

5.5.8.2 Indirect Monitoring: Vertical Seismic Profile

ExxonMobil will use a time-lapse VSP as the first method to monitor the CO_2 plume extent and development to meet the operation monitoring requirements specified in SWO 29-N-6 **§3625.A.7.b** [40 CFR **§146.90(g)(2)**]. A VSP is a seismic survey where the seismic sources are spaced out over the surface of the earth, with the recording devices placed in the wellbore. Like previous exploration seismic surveys that cover the acreage, the seismic sources are explosive charges buried at sufficient depth to ensure good coupling of the acoustic energy with the subsurface and to avoid environmental damage. These sound waves travel through the subsurface and partially reflect whenever they encounter contrasts in acoustic properties, in a process very similar to echoes observed from the acoustic contrast between the air and a wall. Through this dependence on acoustic properties, these reflected sound waves contain information about the structure of the subsurface, including the fluid properties.

The recording devices in a VSP survey are placed on fiber optic cables in the well, using DAS technology. From a functional perspective, DAS converts the entire fiber optic cable into an array of microphones closely spaced (in tens of feet) that can capture the sound waves along the length of the well from the seismic sources. These recordings can then be used to form an image of the subsurface around the wellbore. Figure 5-5 illustrates the concept of a DAS-VSP.

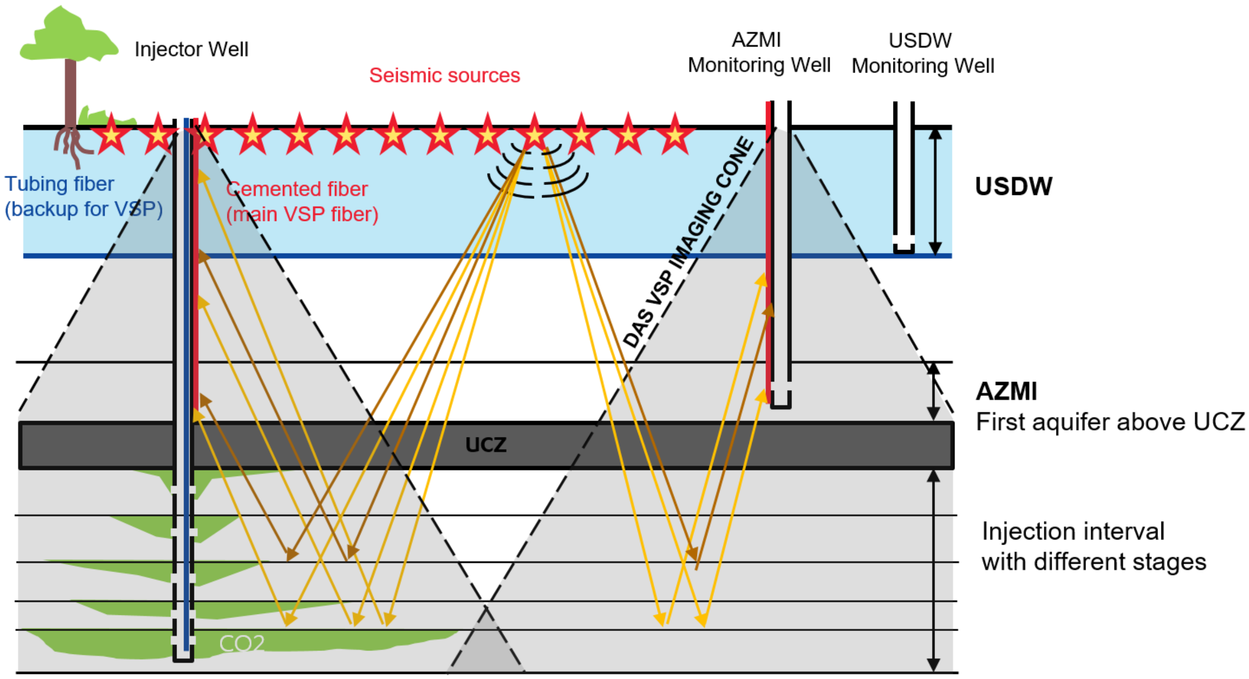

Figure 5-5 – Illustration of a DAS Vertical Seismic Profile

In Figure 5-5, the stars represent the buried seismic sources, and the red line along the injector and AZMI monitoring wells is the primary imaging fiber cemented up to the UCZ. An additional fiber, represented by the blue line, is installed on the injector tubing and is also capable of recording the same seismic waves, although likely with higher noise. One seismic source is highlighted. The energy traveling out from this source reflects on all acoustic contrasts (*e.g.*, layers) in the earth, with two layers highlighted using sets of orange arrows.

It is possible to acquire DAS-VSP multiple times during the life of the project, a process known as time-lapse DAS-VSP. The seismic waves are sensitive to the fluid in the pores of the rock. When CO_2 replaces the original formation brines, it changes the acoustic impedance of the rock, which in turn changes the amplitude of the reflection in the repeat survey. The seismic velocity of the rock is also impacted. The seismic waves traveling through the CO_2 will be delayed compared to earlier seismic surveys, where the rocks were still filled with brine. By comparing the changes in amplitude and delays in arrival time between the repeated seismic surveys, it is possible to trace in 3D where the CO_2 plume is, in a cone-shaped volume around the wellbores.

ExxonMobil performed time-lapse seismic modeling, using logs from offset wellbores, to estimate the magnitude of the time-lapse seismic response due to CO_2 replacing brine. The modeled response is significant, which is consistent with expectations for the level of consolidation in these sands. In addition, the seismic rock properties are also sensitive to changes in pore pressure due to injection. This time-lapse seismic methodology has a decades-long track record for oil-and-gas exploration, and the DAS-VSP configuration is a subset of this. That configuration has seen a significant uptick in usage in the last decade, with improvement in fiber optic sensing technology.

ExxonMobil proposes the following DAS-VSP monitoring schedule:

- The first baseline DAS-VSP survey is acquired prior to injection, because the seismic recordings represent a well-understood initial state of the subsurface fluids (*i.e.*, brine filled).

- [redacted]

- [redacted] Survey timing may be more frequent, depending upon the currently undetermined moment of transition of one injection stage to the next. The objective of earlier surveys is predominantly to establish conformance to reservoir models. Containment risk is limited, especially in the early phase of the project, because the injection stages are still much deeper than the UCZ—and there are multiple baffles/seals below the UCZ that would impede any unexpected upwards migration of CO_2. The timing of these monitor surveys will be refined in future updates of the monitoring plan according to 40 CFR **§146.90(j)**.

- [redacted]

[redacted] cemented fiber optic cables are expected to provide data of the highest quality, because of (1) cement providing better coupling to the formation, (2) fewer external casing strings distorting the seismic waves, and (3) partial shielding from the noise of CO_2 flowing through tubing. In addition, the quality of the seismic data recorded by the tubing fiber is analyzed in the first two surveys to understand if the increased recording depth provides imaging uplift. If not, then these tubing-fiber recordings will be dropped in following surveys. Regardless, the expectation is that DAS and DTS recordings on this tubing fiber will be useful for external MIT (described in *Section 4.4.3*) and injection-flow profiling.

Table 5-5 – Fiber Cable Arrays Used in DAS-VSP

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

- [redacted]

[redacted]

- [redacted]

- [redacted]

- [redacted]

Figure 5-6 shows the acquisition design and modeling details for the baseline (left column) and monitor (right column) surveys. The pre-injection baseline survey is important, because it represents a known subsurface saturation state (*i.e.*, brine), and monitor surveys can therefore be compared against it to determine the extent of the CO_2 plume. This baseline survey is very conservative and contains source points that may not be necessary for adequate imaging of the plume (Figure 5-6(a)). Examples of why some of these baseline source points may not contribute to the time-lapse monitoring are (1) the seismic-wave reflection angle potentially being larger than desirable for plume imaging for the faraway sources, and (2) the plume potentially not migrating far enough during the life of the project to require imaging with those source points. Including these sources in the pre-injection baseline maximizes both flexibility and the ability to meet the indirect plume-monitoring objectives of 40 CFR **§146.90 (g)(2)**.

[redacted]

Figure 5-6(f) shows that, at these depths, the imaging cones of the two injectors and two monitoring wells merge and provide almost continuous coverage. This placement includes significant coverage toward the north, the direction where the plume is expected to preferentially move due to subsurface dip. Even the shallowest injection stage, reached at the end of the project, is expected to have seismic imaging coverage of [redacted]

[redacted] away from the wellbore, as Figure 5-6(d) shows. Outside of this black circle, the fold rapidly decreases, and the range of seismic reflection angles usable for imaging becomes limited. While it may still be possible to form a time-lapse image beyond this black circle, noise will become limiting at a wellbore distance that depends on factors such as the repeatability of the seismic survey.

In addition to indirect monitoring of the movement of the CO_2 in the injection stages, the DAS-VSP is also sensitive to any potential leaks through the UCZ. This further increases the safety of the storage operation.

[redacted]

[redacted]

Figure 5-6 – DAS-VSP Program Details

5.5.9 Monitoring Conclusion

The contents of this Testing and Monitoring Plan have been designed to satisfy SWO 29-N-6 **§3625.A** [40 CFR **§146.90**]. Reporting and reevaluation requirements will be executed by ExxonMobil for the life of the project, including post-injection. Monitoring strategies are included for the injection stream composition and wellhead CO_2 conditions using pressure and temperature gauges, as well as mass flowmeters, to allow for continuous reading of data. Bottomhole operating parameters are monitored by the pressure gauges array that extend the full length of the injection interval. Well integrity is confirmed by the execution of annual tests. Above-zone confinement is monitored by multiple new wells equipped with pressure sensors and periodic fluid sampling. USDW safety is ensured by monitoring multiple groundwater wells that are distributed in a manner that allow for effective sampling of the bottomhole fluids. The appropriate well equipment and its related use is explained within the respective sub-sections of this application.

The individual injection stages of the injection wells are also instrumented with pressure and temperature gauges, which enable direct monitoring of the formation pressure. Furthermore, these pressure gauges verify the pressure decay toward pre-injection levels after injection in each stage is finished.

A significant part of the plan is the monitoring and tracking of the injected CO_2 in the subsurface. The fiber optic cables in both the injection wells and AZMI monitoring wells enable time-lapse DAS-VSP surveys, which are indirect measurements of changes in the injection formation. Such surveys are sensitive to both the presence of CO_2 and, to a lesser extent, the formation pressure. Even though the cemented fiber optic cables used for imaging terminate above the UCZ, modeling shows that imaging below the UCZ is viable.

Time-lapse DAS-VSP surveys have been used around the world for both oil and gas operations and CO_2 monitoring. For ExxonMobil, using offset petrophysical data modeling results has generated a modeled differential in compressional velocity and density likely to produce detectable changes in the reservoir, where the connate fluid has been replaced by carbon dioxide. [redacted].

This method eliminates the need for additional penetrations within the injection formations for monitoring purposes beyond what is proposed in this plan. This approach minimizes the risk of inadvertently forming a leakage path through the upper confining zone.

The contents of this plan will be carried out during the entirety of the life of the injection wells, including post-injection monitoring following a predetermined timeline, based on both updated plume growth and observed well conditions at the time of planned injection cessation.

Table 5-6 summarizes the various measurements discussed in the Testing and Monitoring Plan.

Table 5-6 – Testing and Monitoring Plan Measurements

Equipment / Measurement	Regulation	Comment	Frequency
Coriolis flow meter	§3625.A.2 §146.90b	Measures mass flow rate	Continuously
Corrosion coupon	§3625.A.3 §146.90c	Measures corrosion levels on the types of metal used in the project	Quarterly
Injection stream sampling	§3625.A.1 §146.90a	Provides more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central platform temperature gauge	§3625.A.1 §146.90a	Measures temperature of the total injection stream at the platform before partitioning to both injectors	Continuously
Injector wellhead tubing P gauge	§3625.A.1 §146.90a	Measures downstream of choke	Continuously
Injector wellhead annulus P gauge	§3625.A.2 §146.90b	Verifies annulus pressure maintained	Continuously
Injector annulus pressure test	§3627.A.2 §146.89b	Verifies absence of leak in annulus	Annually
Injector downhole P&T gauges on sand screens of individual injection stages	§3625.A.2 §146.90b	Measures downhole pressure and temperature (P&T) as close as possible to formation (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	§3625.A.6 §146.90f	Measures fall-off of pressure after abandoning injection stage and initiating injection in next stage above	At the end of every injection stage or every 5 years, whichever is more frequent
	§3625.A.7.a §146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injectors, especially when injection intervals are staggered between wells	Continuously
[redacted]	[redacted]	[redacted]	[redacted]

		[redacted]	
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Injector casing-inspection log	§3625.A.5 §146.90e	[redacted]	[redacted]
AZMI monitoring well downhole P/T gauge	Redundant measurement, no direct regulatory link	Potential to detect pressure anomaly in AZMI in case of leakage; will require careful analysis due to false positive potential from sensor drift, geomechanical effects, and preexisting pressure trends due to potential far-field activities	Continuously
AZMI monitoring well fluid sampling	§3625.A.4 §146.90d	Above UCZ fluid collection is recommended by guidelines	Annually

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Appendix F – Testing and Monitoring

- Appendix F-1 USDW Monitoring Well Plan Map
- Appendix F-2 AZMI Monitoring Well Plan Map
- Appendix F-3 USDW Monitoring Well No. 001 Schematic
- Appendix F-4 USDW Monitoring Well No. 002 Schematic
- Appendix F-5 USDW Monitoring Well No. 003 Schematic
- Appendix F-6 USDW Monitoring Well No. 004 Schematic
- Appendix F-7 USDW Monitoring Well No. 005 Schematic
- Appendix F-8 AZMI Monitoring Well No. 001 Schematic
- Appendix F-9 AZMI Monitoring Well No. 002 Schematic

5.6 References

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Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 6 – INJECTION WELL PLUGGING PLAN

July 2023

SECTION 6 – INJECTION WELL PLUGGING PLAN

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6.1 Introduction

The plugging plan for ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) Pecan Island Injection Well No. 001 and Injection Well No. 002 was prepared to meet the requirements of Statewide Order (SWO) 29-N-6, **§3631** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**]. This section provides a general description of the steps that will be taken to plug and abandon each well in the project. For the injection wells, this plan will include the proposed stages of well development through final abandonment. The plugging and abandoning of each monitoring well is also covered in this section. Complete plugging and abandonment prognoses are included in *Appendix H*.

6.2 Injection Well Zonal Isolation and Final Plug and Abandonment

As described in *Section 4 – Engineering Design and Operating Strategy*, the injection wells will be completed in multiple intervals within the gross injection zone. Each injection interval will be used for a discrete period as identified in the plume model. Once that period has been completed, the current injection interval will be isolated to prevent crossflow conditions between the new and old injection intervals. Once an injection stage is isolated, a new injection horizon will be opened. This process will repeat until the entire gross injection interval is fully developed. After approximately [redacted] years of injection, the uppermost plug will be set, and the wells will continue to be used for monitoring purposes until the plume monitoring is no longer required. After that, the wells will be permanently plugged. The plugging and abandonment procedures for the injection wells are designed to prevent CO_2 or formation fluids in the injection interval from migrating to the Underground Sources of Drinking Water (USDW).

The following details outline the procedures for both types of plugs to be installed in the injection wells. The two types of plugs are:

- Isolation of the active injection section via recompletion operations
- Final plug and abandonment of the wellbore

6.2.1 Zonal Isolation of Injection Zone / Intermediate Plugback Plan

When the current, active injection zone has reached the end of its injection period, that zone will be isolated and abandoned. The general procedure for zonal isolation includes:

6.2.1.1 Pre-Zonal Isolation Activities

1. ExxonMobil will comply with all reporting and notification provisions.
    a. ExxonMobil will notify the Underground Injection Control (UIC) Program Director (UIC Director) 60 days before planned plugging efforts. [40 CFR ***§146.92(c)***]
    b. Notice of Intent to Plug will be communicated to the Louisiana Department of Natural Resources (LDNR) by submitting Form UIC-17 with detailed plans. (SWO 29-N-6 **§3631.A.4**)

2. Bottomhole reservoir pressure will be measured using the externally mounted pressure-sensing array installed in the tubing casing annulus as discussed in *Section 5 – Testing and Monitoring Plan*. (SWO 29-N-6 **§3631. A.2** [40 CFR ***§*146.92(a)**])
3. External mechanical integrity will be demonstrated through approved monitoring methods described in *Section 5*. (SWO 29-N-6 **§3631.A.2** [40 CFR ***§*146.92(a)**])

Figures 6-1 and 6-2 show schematics of the first intermediate isolation plans for Pecan Island Injection Wells No. 001 and No. 002.

[redacted]

Figure 6-1 – First Plugging Schematic for Pecan Island Injection Well No. 001

[redacted]

Figure 6-2 – First Plugging Schematic for Pecan Island Injection Well No. 002

6.2.1.2 Zonal Isolation Activities

1. A CO_2-compatible barrier will be set above the injection zone to be isolated.
2. The plug will be confirmed by conducting a successful pressure test.
3. To allow for pressure monitoring of the isolated zone during the life of the storage project, the perforations will not be squeezed.

The design of the wells does not require any well components to be removed during zonal-isolation operations in the permitted injection zone. All intermediate plugging operations can be conducted with wireline services to allow a more efficient and safe recompletion process.

6.2.2 Final Plug and Abandonment

After injection operations cease, and after the available pore space has been depleted, the injection wells will be prepared for final plug and abandonment (P&A). The general final P&A procedures will include:

6.2.2.1 Pre-Plugging Activities

1. ExxonMobil will comply with all reporting and notification provisions.
   a. ExxonMobil will notify the UIC Director 60 days before planned plugging efforts. [40 CFR **§146.92(c)**)]
   b. Notice of Intent to Plug will be communicated to the LDNR by submitting Form UIC-17 with detailed plans. (SWO 29-N-6 **§3631.A.4**)
2. Bottomhole reservoir pressure will be measured using the fiber optic pressure-sensing array installed in the tubing casing annulus as discussed in *Section 5 – Testing and Monitoring Plan*. (SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])
3. External mechanical integrity will be demonstrated through approved testing methods described in *Section 5*. (SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])
4. The injection well will be flushed with a buffer fluid prior to pulling the injection tubing and packer. (SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])
5. All uncemented, non-permanent components of the well will be removed, as described in Table 6-1.
6. Casing inspection and cement bond logs will be performed before plugging.

Table 6-1 – Description of Casing, Tubing, and Other Well-Construction Materials to be Removed

Well Component	Size	Well No. 001 Amount	Well No. 002 Amount	Notes / Comments
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6.2.2.2 Plugging Procedure, Injection Well No. 001

1. Check tubing and casing pressures; verify that the lower safety valve is functional. Determine bottomhole pressure (BHP) with sensor and record all annuli pressures. [40 CFR **§146.92(a)**]
    a. Verify the annulus integrity and positive pressure on the annulus.
2. Pump kill-weight brine (buffer fluid compatible with CO_2) for a minimum of two times the wellbore volume.
3. Rig up slickline unit, run in hole with injection safety valve retrieval tool. Pull out of hole with the injection valve from [redacted]
    a. Note: The injection tool mandrel has a slight restriction, [redacted]
4. Run in hole with [redacted].
5. Move in and rig up workover unit.
6. Run in hole with jet cutter to 15 ft above the packer top. Cut [redacted]
7. Trip out of hole and lay down 5-1/2 in. tubing and cables.
8. [redacted]
    a. Evaluate cement bond behind production casing.
    b. Adjust procedure as necessary.
9. Trip in hole with workstring.
10. Pump a balanced cement plug from [redacted] from the packer across the intermediate casing shoe with CO_2-compatible cement or equivalent. [40 CFR **§146.92(b)**]
11. Wait on cement. Tag and test to confirm placement.
12. Pump balanced cement plug at the base of surface casing with 500-ft Portland cement plug from [redacted] [40 CFR **§146.92(b)**]
13. Wait on cement. Tag and test to confirm placement.
14. Pump balanced cement plug across the base of the USDW with 200-ft Portland cement plug from [redacted] [40 CFR **§146.92(b)**]
15. Wait on cement. Tag and test to confirm placement.
16. Pump surface cement plug with at least 30 ft of Portland cement. (SWO 29-B **§137(F)(3)(g)**)
17. Cut and cap casing to a minimum of 15 ft below the mud line. (SWO 29-B **§137(F)(3)(j)**)
18. Rig down and move off location.
19. Perform site closure requirements. [40 CFR **§146.93(a)**]

6.2.2.3 Plug Details, Injection Well No. 001

Tables 6-2 and 6-3 provide the plugging details for Injection Well No. 001.

Table 6-2 – Plug Details for Plugs [redacted] Injection Well No. 001

[redacted]

Table 6-3 – Plug Details for [redacted] Injection Well No. 001

[redacted]

Figure 6-3 shows the final plugged schematic for Pecan Island Injection Well No. 001.

[redacted]

Figure 6-3 – Final Plugging Schematic for Pecan Island Injection Well No. 001

6.2.2.4 <u>Plugging Procedure, Injection Well No. 002</u>

1. Check tubing and casing pressures; verify that the lower safety valve is functional. Determine BHP with sensor and record all annuli pressures. [40 CFR **§146.92(a)**]
    a. Verify the annulus integrity and positive pressure on the annulus.
2. Pump kill-weight brine (buffer fluid compatible with CO_2) for a minimum of two times the wellbore volume.
3. Rig up slickline unit, run in hole with retrieval tool, or equivalent. Pull out of hole with the injection valve from [redacted].
    a. Note: The injection tool mandrel has a slight restriction, [redacted].
4. Run in hole with [redacted].
5. Move in and rig up workover unit.
6. Run in hole with jet cutter to [redacted] KB. [redacted].
7. Trip out of hole and lay down [redacted] in. tubing and cables.
8. Run cement-bond log and casing-inspection log on [redacted].
    a. Evaluate cement bond behind production casing.
    b. Adjust procedure as necessary.
9. Trip in hole with workstring.
10. Pump a balanced cement plug from [redacted] across the intermediate casing shoe with CO_2 resistant cement or equivalent (40 CFR **§146.92(b)**).
11. Wait on cement. Tag and test to confirm placement.
12. Pump balanced cement plug at the base of surface casing with 500-ft Portland cement plug from [redacted]. [40 CFR **§146.92(b)**]
13. Wait on cement. Tag and test to confirm placement.
14. Pump balanced cement plug across the base of the USDW with 200-ft Portland cement plug from [redacted] [40 CFR **§146.92(b)**]
15. Wait on cement. Tag and test to confirm placement.
16. Pump surface cement plug with at least 30 ft of Portland cement. (SWO 29-B **§137(F)(3)(g)**)
17. Cut and cap casing to a minimum of 15 ft below the mud line. (SWO 29-B **§137(F)(3)(j)**)
18. Rig down and move off location.
19. Perform site closure requirements. [40 CFR **§146.93(a)**]

6.2.2.5 Plug Details, Injection Well No. 002

Tables 6-4 and 6-5 provide the plugging details for Injection Well No. 002.

Table 6-4 – Plug Details for [redacted] Injection Well No. 002

[redacted]

Table 6-5 – Plug Details for [redacted], Injection Well No. 002

[redacted]

[redacted]

Figure 6-4 shows the final plugged schematic for Pecan Island Injection Well No. 002.

[redacted]

Figure 6-4 – Final Plugging Schematic for Pecan Island Injection Well No. 002

6.3 Monitoring Wells Plugging and Abandonment Plans

The following sections will outline the plan for the plugging and abandonment of the monitoring wells associated with the Pecan Island Injection Wells No. 001 and No. 002.

6.3.1 Pre-Plugging Activities for All Wells

ExxonMobil will comply with all reporting and notification provisions.

1. The UIC Director will be notified 60 days in advance of planned plugging efforts. [40 CFR **§146.92(c)**]
2. Notice of Intent to Plug will be communicated to the Louisiana DNR by submitting Form UIC-17 with detailed plans. [SWO 29-N-6 **§3631.A.4**]

6.3.2 USDW Monitoring Well Plugging Procedure (USDW Wells No. 1–5)

Each of the five monitoring wells will be plugged by pulling and removing the submersible pump and tubing. Portland cement will then be placed along the entire casing string through a workstring. The plugging schematics for the five wells are provided in Figures 6-5 to 6-9.

6.3.2.1 Final P&A Wellbore Schematics – USDW Monitoring Wells No. 001- 005

[redacted]

Figure 6-5 – Final Plugging Schematic for USDW Monitoring Well No. 001

[redacted]

Figure 6-6 – Final Plugging Schematic for USDW Monitoring Well No. 002

[redacted]

Figure 6-7 – Final Plugging Schematic for USDW Monitoring Well No. 003

[redacted]

Figure 6-8 – Final Plugging Schematic for USDW Monitoring Well No. 004

[redacted]

Figure 6-9 – Final Plugging Schematic for USDW Monitoring Well No. 005

6.3.3 AZMI Monitoring Well No. 001

6.3.3.1 <u>Plugging Procedure, Above-Zone Monitoring Interval (AZMI) Monitoring Well No. 001</u>

1. Move in and rig up workover unit.
2. Check casing and annulus pressures. Record all annuli pressures.
3. Run in hole with workstring.
4. Section-mill [redacted] across the surface casing shoe, circulate hole clean.
5. Pump viscous reactive pill to base of milled section.
6. Pump a balanced cement plug from [redacted] across the section-milled casing with Portland cement.
7. Wait on cement. Tag and test to confirm placement.
8. Section-mill [redacted], circulate hole clean.
9. Pump viscous reactive pill to base of milled section.
10. Pump a balanced cement plug from [redacted] across the section-milled casing with Portland cement.
11. Wait on cement. Tag and test to confirm placement.
12. Pump surface cement plug with at least 30 ft of Portland cement. (SWO 29-B **§137(F)(3)(g)**)
13. Cut and cap casing to a minimum of 15 ft below the mud line. (SWO 29-B **§137(F)(3)(j)**)
14. Rig down and move off location.
15. Perform site closure requirements.

Figure 6-10 shows the plugging schematic for AZMI Monitoring Well No. 001.

[redacted]

Figure 6-10 – Final Plugging Schematic for AZMI Monitoring Well No. 001

6.3.4 AZMI Monitoring Well No. 002

6.3.4.1 <u>Plugging Procedure, AZMI Monitoring Well No. 002</u>

1. Move in and rig up workover unit.
2. Check casing and annulus pressures. Record all annuli pressures.
3. Run in hole with workstring.
4. Section-mill [redacted] across the surface casing shoe, circulate hole clean.
5. Pump viscous reactive pill to base of milled section.
6. Pump a balanced cement plug from [redacted] across the section-milled casing with Portland cement.
7. Wait on cement. Tag and test to confirm placement.
8. Section-mill [redacted], circulate hole clean.
9. Pump viscous reactive pill to base of milled section.
10. Pump a balanced cement plug from [redacted] across the section-milled casing with Portland cement.
11. Wait on cement. Tag and test to confirm placement.
12. Pump surface cement plug with at least 30 ft of Portland cement. (SWO 29-B **§137(F)(3)(g)**)
13. Cut and cap casing to a minimum of 15 ft below the mud line. (SWO 29-B **§137(F)(3)(j)**)
14. Rig down and move off location.
15. Perform site closure requirements.

Figure 6-11 shows the plugging schematic for AZMI Monitoring Well No. 002.

[redacted]

Figure 6-11 – Final Plugging Schematic for AZMI Monitoring Well No. 002

For each well in the project, final plugging reports—certified by the operator and the person who performed the plugging operation—will be submitted to the UIC Director within 60 days after plugging. Detailed plugging procedures are included in *Appendix H*.

The detailed schematics and procedures in *Appendix H* contain the following:

- Appendix H-1 Injection Wells No. 001 and No. 002 Zonal Isolation Schematics
- Appendix H-2 Injection Well No. 001 Detailed Plugging Procedure
- Appendix H-3 Injection Well No. 002 Detailed Plugging Procedure
- Appendix H-4 Injection Wells No. 001 and No. 002 Final P&A Schematic
- Appendix H-5 Above-Zone Monitoring Wells No. 001 and No. 002 – Final P&A Procedures
- Appendix H-6 Above-Zone Monitoring Wells No. 001 and No. 002 – Final P&A Schematic

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Vermilion Parish, Louisiana

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the Pecan Island Injection Wells No. 001 and No. 002 was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3633.A.1** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93(a)**]. This plan describes the various activities that will occur once injection has ceased and during the site closure. This plan will be implemented once ExxonMobil demonstrates that no additional monitoring is needed to ensure that this project poses no further endangerment to Underground Sources of Drinking Water (USDWs).

7.2 Pre- and Post-Injection Pressure Differentials

To meet the requirements of SWO 29-N-6 **§3633.A.1.b** [40 CFR **§146.93(a)(2)**], the following table shows the expected pressure differential between pre- and post-injection pressures in the injection zone, as determined by the plume model described in *Section 2 – Plume Model*. As discussed there and in *Section 4 – Engineering Design and Operating Strategy*, both Pecan Island injection wells will inject into sequentially shallower intervals over the life of the project, resulting in separate pressure profiles for each interval. The highest pressure differential for Well No. 001 occurs in Year 1, which is part of Completion Stage 1 and is predicted to reach [redacted] pounds per square inch (psi). The highest pressure differential for Well No. 002 occurs in Year 1, which is part of Completion Stage 1 and is predicted to reach [redacted] psi. Once injection ceases in each stage, the pressure drops down to near in situ pressures. Table 7-1 shows the maximum pressure differential at the wellbore predicted in each year modeled.

Table 7-1 – Maximum Pressure Differential by Year

Year	Max Pressure Differential (psi) Well No. 001	Max Pressure Differential (psi) Well No. 002
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Figures 7-1 and 7-2 present graphical representations of the data in Table 7-1, showing the differential pressure over the life of both injection wells. The dark green line represents the buildup from in situ pressure, and the light green line represents the maximum pressure gradient. The light green dashed line shows the maximum bottomhole pressure constraint, indicating that the model does not surpass this maximum pressure.

[redacted]

Figure 7-1 – Maximum Pressure Differential Over Time for Pecan Island Injection Well No. 001

[redacted]

Figure 7-2 – Maximum Pressure Differential Over Time for Pecan Island Injection Well No. 002

7.3 CO_2 Plume Position and Pressure Front at End of Closure

The area of review (AOR) consists of both the CO_2 plume and critical-pressure maximum extent. Figure 7-3 shows the AOR and its subcomponents. The CO_2 plumes are indicated by the black polygons, based on the maximum extent of all the differing plume layers in the model, extracted at 50 years post-injection. The hatch area represents the pressure front that combines the farthest extent of the calculated critical-pressure fronts from all stages at both injection Wells. The CO_2 plumes and pressure front AOR consider both CO_2 injection wells (Pecan Island Injection Wells No. 001 and No. 002). Once injection has ceased, the pressure in the injection interval will quickly revert to near reservoir pressure (Table 7-1).

[redacted]

Figure 7-3 – 50-Year Maximum Combined Plume

7.4 Post-Injection Monitoring Plan

As required by SWO 29-N-6 **§3633.A.2** [40 CFR **§146.93(b)**], ExxonMobil will continue to monitor the site for 50 years or until it is demonstrated that the project no longer poses an endangerment to the USDW, as described in *Section 7.6*. The reservoir model will continue to be updated throughout the project using monitoring observations. Upon cessation of injection, an amended PISC—if needed per the updated model—will be submitted to the Underground Injection Control Program Director (UIC Director).

7.5 Post-Injection Monitoring Activities

During the monitoring period, the testing and monitoring activities, as described in *Section 5 – Testing and Monitoring Plan,* will be performed and reported at the frequency shown in Table 7-2.

Table 7-2 – Post-Injection Monitoring and Reporting Frequency

Testing/Monitoring Activity	Frequency	Reporting Schedule	Comment
USDW monitoring well fluid sampling and analysis	Every 5 years	Within 30 days after data collection and analysis	
Above-zone monitoring interval (AZMI) monitoring well-fluid sampling and analysis	Every 5 years	Within 30 days after data collection and analysis	
AZMI pressure measurements	Continuously	Annually	
Injection well wellhead pressure monitoring (tubing and annulus)	Continuously	Annually	
Injection well in-zone pressure/temperature (P/T) monitoring	Continuously, using P/T gauges in individual injection stages	Annually	[redacted] [redacted]

Indirect Plume Monitoring (VSP)	Every 5 years for the first 10 years	Within 30 days after time-lapse seismic processing has finished	[redacted]
Direct plume calculations based on P/T data	Annually	Annually	

*DAS – distributed acoustic sensing; VSP – vertical seismic profile

All testing and monitoring activities listed will be performed and analyzed as discussed in *Section 5*, including quality assurance/quality control (QA/QC) measures.

7.6 Demonstration of Non-Endangerment of USDW

The primary mechanism through which the USDWs are protected is the upper confining zone (UCZ), which comprises three separate, continuous sealing layers to provide redundancy. The monitoring data that will be collected after injection ceases verifies that the UCZ is functioning as expected and that the USDW is not endangered.

The monitoring data will also be used to calibrate the simulation model and further improve its ability to accurately predict the movement of CO_2. These calibrated simulation-model predictions are used to identify any UCZ-penetrating features with which the CO_2 plume may interact prior to final stabilization. Examples of these features of concern are legacy wellbores and fault planes. Any legacy wellbores with which the CO_2 plume is modeled to interact will be assessed to determine if they are adequately abandoned. This effort ensures that (1) legacy wellbores do not compromise the integrity of the UCZ and (2) the USDW is not endangered. The calibrated simulation-model predictions are also used to verify that the CO_2 does not reach fault planes cutting through the UCZ.

Prior to the approval of the site-closure authorization, as required by SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(c)**], ExxonMobil will provide documentation that the USDW is not at risk of further endangerment from the CO_2 plume. While the PISC duration is 50 years, it may be possible to demonstrate USDW non-endangerment earlier. [redacted] ExxonMobil will submit a report to the UIC Director demonstrating the non-endangerment of the USDW, including site-specific conditions, updated plume model, predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model.

7.7 Site Closure Plan

To meet the requirements of SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(e)**], the following site-closure activities will be performed: plugging of all wells, site closure, and submittal of final site-closure reports.

7.7.1 Pre-Closure

Notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

7.7.2 Plugging Activities

The Pecan Island Injection Wells No. 001 and No. 002, AZMI Monitoring Wells No. 001 and No. 002, and all five USDW monitoring wells will be plugged as discussed in *Section 6 – Plugging Plan*. The plugging and abandonment procedures for the injectors are designed to prevent CO_2 or formation fluids in the injection interval from migrating to the USDW. Prior to plugging the injection and AZMI wells, the mechanical integrity of those wells will be verified. Plugging schematics and procedures are provided in *Appendix H*.

7.7.3 Site Restoration

Once the injection and monitoring wells are plugged and capped below grade, all surface equipment will be decommissioned.

7.7.4 Documentation of Site Closure

Within 90 days of site closure, a final report must be submitted to the UIC Director, per the requirements of SWO 29-N-6 **§3633.A.6** [40 CFR **§146.93(f)**], and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats;
- Documentation of well-plugging report to the Louisiana Department of Natural Resources (LDNR); and
- Records of the nature, composition, and volume of the CO_2 stream over the injection period.

A record of notation in the facility property deed will be added to provide, in perpetuity, any potential purchaser of the property the following information:

- The fact that the land was used to sequester carbon dioxide;
- The name of the state agency (LDNR) with which the survey plat was filed, and the EPA or state agency to which it was submitted; and
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which injection occurred.

ExxonMobil will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, ExxonMobil will deliver all records to the UIC Director for retention at a location designated by the UIC Director for that purpose.

ExxonMobil

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

July 2023

LONQUIST SEQUESTRATION LLC

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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Figures

None included in this section.

Tables

8.1 Introduction

This Emergency and Remedial Response Plan (ERRP) for Pecan Island Injection Wells No. 001 and No. 002 (the Pecan Island Project) was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3623** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.94**]. The plan describes potential adverse events that could occur in the development, operation, and post-closure phases of the project and the actions to be taken in the event of such an emergency. This plan will be reviewed and updated annually. Any change in key personnel will also cause the ERRP to be updated immediately.

8.2 Resources/Infrastructure in Area of Review

The Pecan Island Project is located [redacted], Louisiana, and approximately [redacted] Louisiana. The proposed location is approximately 2 miles from the nearest freshwater drinking water well. There are no permanent structures located within the predicted area of review (AOR), but there are seasonally-used camp sites in the AOR. [redacted] plugged wellbores exist within the AOR. These wells will be remediated to ensure protection against any possible migration of CO_2 as discussed in *Section 3 – Area of Review and Corrective Action Plan*. Additionally, two above-zone monitoring wells will be installed in the AOR, as discussed in *Section 5 – Testing and Monitoring Plan*. These monitoring wells will be constructed in a manner to prevent migration of CO_2 into the Underground Source of Drinking Water (USDW) and surface atmosphere.

The lowermost USDW in the AOR is estimated to be found at a depth of approximately [redacted] ft in this area.

8.3 Resources/Infrastructure – Specific Events and Response Plans

The following scenarios represent a high-level concept of potentially significant adverse events, methods of prevention and detection, and likely remedial responses.

8.3.1 Event Category – Water Quality Impact

8.3.1.1 Specific Event Description – Leakage of CO_2 outside permitted area into freshwater aquifer

Risk Assessment Matrix, Sections 1.1 and 1.3 (Appendix I-2)

While this event should not happen during operations of the injection facility, ExxonMobil cannot wholly eliminate the risk of CO_2 leakage. Similarly, analysis and modeling should avoid instances of the plume reaching faults or fractures that allow CO_2 migration into another zone, including the USDW, or to the surface. Likewise, there is a nonzero risk that the confining zone fails and such failure allows CO_2 to migrate into the USDW.

Likelihood: Rare

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- The well is specifically designed and constructed to prevent the likelihood of a CO_2 leak.

Potential Response Actions:

- Lower the injection rate or stop the injection and notify the Underground Injection Control (UIC) Program Director (UIC Director) within 24 hours.
- Use vertical seismic profile (VSP) surveys to assess the location and degree of CO_2 movement, as described in *Section 5 – Testing and Monitoring Plan*.
- Resume injection at a reduced rate if possible to do so.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted:
  - Pump CO_2-impacted groundwater to the surface and aerate it to remove the CO_2.
  - Apply "pump and treat" methods to remove trace elements.
  - Drill wells that intersect the accumulations in groundwater and extract CO_2.
  - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If surface water is impacted:
  - Shallow lakes will quickly release dissolved CO_2 back into the atmosphere.
  - Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection interval.

8.3.1.2 Specific Event Description – Leakage of drilling fluid into freshwater aquifer

Risk Assessment Matrix, Section 1.2 (Appendix I-2)

It is possible, albeit highly unlikely, that drilling fluid could leak during drilling of the well. In the unlikely event drilling fluid leaks, it may impact the freshwater aquifer.

Likelihood: Remote

Prevention and Detection:

- Select a proper drilling-fluids program including freshwater-based muds.
- The well is specifically designed to prevent the likelihood of this occurring.

Potential Response Actions:

- If groundwater/USDW is impacted:
  - Apply "pump and treat" methods to remove trace elements.
  - Extract and treat affected water at an above-ground treatment facility.
  - Provide an alternative water supply if groundwater-based public water supplies are impacted.

8.3.1.3 ***Specific Event Description – Seismic event occurs in project area resulting in plume leakage into USDW***

Risk Assessment Matrix, Section 1.4 (Appendix I-2)

If a seismic event were to occur in the project area that creates or opens faults or fractures, such an event could provide a pathway for CO_2 migration into another zone, including the USDW, or to the surface. Failure of the confining zone caused by a seismic event could also cause CO_2 to migrate and contaminate the USDW.

Likelihood: Remote

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- The chosen project location is both a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- The well and operating strategy are designed to prevent the likelihood of this occurring.

Potential Response Actions:

- Lower the injection rate or stop the injection and notify the UIC Director within 24 hours.
- Use VSP surveys to assess the location and degree of CO_2 movement, as described in *Section 5 – Testing and Monitoring Plan*.
- Resume injection, if possible, at a reduced rate.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted:
    - Pump CO_2-impactted groundwater to the surface and aerate it to remove the CO_2.
    - Apply “pump and treat” methods to remove trace elements.
    - Drill wells that intersect the accumulations in groundwater and extract CO_2.
    - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If surface water is impacted:
    - Shallow lakes will quickly release dissolved CO_2 back into the atmosphere.
    - Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection interval.

8.3.2 Event Category – CO_2 Release to or at the Surface

<u>8.3.2.1 Specific Event Description – Overpressurization (i.e., induced)</u>

Risk Assessment Matrix, Section 2.1 (Appendix I-2)

Although unlikely, overpressurization during injection-facility operations or by operating equipment over designed pressures could cause CO_2 to be released to the surface. This situation could also occur if the maximum allowable operating parameters change due to depreciation or corrosion of equipment and the changes are not accounted for.

Likelihood: Remote

Prevention and Detection:

- Proper operation and preventive maintenance of all surface facility equipment will be implemented.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- Surface wellhead tree will be regularly maintained and tested for integrity.
- Subsurface safety valve will be regularly tested.

Potential Response Actions:

- Shut in flow line upon any detection of CO_2 at the surface.
- Stop the injection and notify the UIC Director within 24 hours.
- Activate downhole safety valve.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

<u>8.3.2.2 Specific Event Description – Caprock/reservoir failure</u>

Risk Assessment Matrix, Section 2.2 (Appendix I-2)

Unforeseen geological complications could result in release of CO_2 to the surface.

Likelihood: Rare

Prevention and Detection:

- Due diligence will be exercised when collecting information from offset wells in the AOR.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5*.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- CO_2 detectors will be utilized to continuously monitor ambient air.

Potential Response Actions:

- Shut in flow line upon any detection of CO_2 at the surface.
- Stop the injection and notify the UIC Director within 24 hours.
- Activate downhole safety valve.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5.*
- Notify the UIC Director when injection can be expected to resume.

8.3.2.3 Specific Event Description – Well blowout during drilling or loss of mechanical integrity of the well pressure equipment

Risk Assessment Matrix, Section 2.3 (Appendix I-2)

Although highly unlikely, a well blowout could occur during wellbore drilling if unexpected changes in reservoir pressures cause a sudden release of hydrocarbons, water, and/or pressure from the subsurface formations.

Likelihood: Remote

Prevention and Detection:

- Maintain appropriate mud weights as required based on offset well data.
- Monitor the rate of drilling-fluid returns vs. rates pumped, penetration rates, pump pressures, etc.
- Proper wellbore design, including proper cement and metallurgy of the casing and tubing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5*.

Potential Response Actions:

- Stop drilling.
- Close the blowout preventer; insert rams into the well.

- Read and record stabilized shut-in pressures.
- Stop injection and notify the UIC Director within 24 hours.
- Kill the well by pumping fluid down the wellbore that is heavier than the current fluid until the well stops flowing.

8.3.2.4 <u>Specific Event Description – Well seal failure of CO_2 sequestration well</u>

Risk Assessment Matrix, Sections 2.4 and 2.5 (Appendix I-2)

A well seal failure could occur due to the failure of the cement behind the casing, an improperly seated packer, or a tubing leak. This event could also occur due to the corrosive nature of the CO_2 stream causing a break through the casing, allowing for an escape to surface.

Likelihood: Remote

Prevention and Detection:

- Proper wellbore design, including proper cement and metallurgy of the casing and tubing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan*.
- Routine cement bond logs and casing inspection logs.

Potential Response Actions:

- Stop the injection and notify the UIC Director within 24 hours.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer.
- Install chemical-sealant barrier and or attempt cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

8.3.2.5 <u>Specific Event Description – Major mechanical failure of flowlines or distribution system</u>

Risk Assessment Matrix, Section 2.6 (Appendix I-2)

Although highly unlikely, a major mechanical failure of the CO_2 flowlines and distribution system is possible during injection-facility operations by operating equipment (1) outside designed operating parameters, (2) beyond recommended preventive maintenance cycles, or (3) improperly.

Likelihood: Remote

Prevention and Detection:

- Operate a closely-monitored facility with competent management of operations.
- Ensure controls are in place to prevent overpressure and release.

- Proper operation and preventive maintenance of all surface-facility equipment will be carried out.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- Surface wellhead tree will be regularly maintained and tested for integrity.

Potential Response Actions:

- Shut in the flow line upon any detection of CO_2 at the surface.
- Stop the injection and notify the UIC Director within 24 hours.
- Activate downhole safety valve.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

8.3.2.6 <u>Specific Event Description – Well seal failure of adjacent wells (i.e., P&A wells, monitoring wells) or orphan wells (i.e., wells not identified prior to injection)</u>

Risk Assessment Matrix, Sections 2.7 and 2.8 (Appendix I-2)

It is possible that well seals in adjacent well could fail due to the failure of improper materials in adjacent wellbores, such as cement inside and behind casing, casing and equipment metallurgy, and plugging materials. This event could also occur due to undiscovered orphan wells that create leak paths to the surface due to improper plugging.

Likelihood: Occasional

Prevention and Detection:

- Perform proper corrective action review and design, including appropriate cement and metallurgy of the plugging materials.
- Perform magnetic surveying to discover undocumented/unknown wellbores.
- Continuous pressure monitoring at surface and downhole will highlight potential issues.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan*.
- Operate closely-monitored facility and surrounding area with competent management of operations.

Potential Response Actions:

- Stop the injection and notify the UIC Director within 24 hours.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Perform any well reentry and corrective action as necessary to regain isolation of injectate/formation fluids.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

8.3.2.7 Specific Event Description – Sabotage/terrorist attack

Risk Assessment Matrix, Section 2.9 (Appendix I-2)

This event could theoretically happen during injection-facility operations by any person or organization wishing to cause harm to life, property, or environment. This facility is not of strategic or cultural importance; therefore, this event has a very low risk.

Likelihood: Remote

Prevention and Detection:

- Stay current with recent events in the local area, country, and globally that could potentially warrant a threat to the facility.
- Properly secure the facility and surrounding area.
- Proper operation and preventive maintenance of all surface-facility equipment will be carried out.
- Surface wellhead tree will be regularly maintained and tested for integrity.
- Subsurface safety valve will be regularly tested.

Potential Response Actions:

- Shut in the flow line upon any detection of CO_2 at the surface.
- Stop the injection and notify the UIC Director within 24 hours.
- Activate downhole safety valve.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.

- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

8.3.2.8 Specific Event Description – Induced seismicity directly caused by injection, resulting in leakage

Risk Assessment Matrix, Section 2.10 (Appendix I-2)

Although highly unlikely, the process of injection could induce a seismic event that causes the plume to reach faults or fractures that allow CO_2 migration to the surface.

Likelihood: Remote

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5*.
- The chosen project location is both a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- The well and operating strategy are designed to prevent the likelihood of this occurring.

Potential Response Actions:

- Lower the injection rate or stop the injection and notify the UIC Director within 24 hours.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Use VSP surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Resume injection, if possible, at a reduced rate.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection interval.

8.3.3 Event Category – CO2 Migration

8.3.3.1 <u>Specific Event Description – Injected plume migrates into adjacent pore space</u>

Risk Assessment Matrix, Section 3.1 (Appendix I-2)

This event could occur if the plume expands beyond what the reservoir model predicts and migrates off controlled acreage into neighboring pore space not controlled by the operator.

Likelihood: Rare

Prevention and Detection:
- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- Model the AOR to confirm ownership and/or control of pore space within AOR.

Potential Response Actions:
- Lower the injection rate or stop the injection and notify the UIC Director within 24 hours.
- Use VSP surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Restart the injection, if possible, at a reduced rate.
- Possibly recomplete into a new, shallower injection interval.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If migration off of ExxonMobil pore space is detected or identified to be likely:
    - Negotiate with neighboring landowner to acquire rights to store within the affected pore space.
    - Drill wells that intersect the accumulations within controlled pore space and extract the CO_2.

8.3.3.2 <u>Specific Event Description – Migration of CO_2 by others/competitors on Pecan Island</u>

Risk Assessment Matrix, Section 3.2 (Appendix I-2)

This event could occur if the pore space controlled by the operator is migrated upon by others or competitors.

Likelihood: Remote

Prevention and Detection:
- The CO_2 plume will be monitored as described in *Section 5*.
- Strategically locate the injection operations in an area devoid of other carbon sequestration or injection operations.

Potential Response Actions:
- If migration is detected or identified to be likely:
    - Obtain control of additional pore space through outright ownership or lease

agreements.

- Lower injection rates or stop the injection and notify the UIC Director within 24 hours.
- Use VSP surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Restart the injection, if possible, at a reduced rate.
- Possibly recomplete into a new, shallower injection interval.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.

8.3.4 Event Category – Entrained Contaminant (Non-CO_2) In Injection Stream

8.3.4.1 <u>Specific Event Description – Change in CO_2 composition/properties from its source</u>

Risk Assessment Matrix, Sections 5.1 and 5.2 (Appendix I-2)

This event could occur due to changes in contamination levels in the CO_2 source. The sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity.

Likelihood: Remote

Prevention and Detection:

- Samples of the CO_2 stream will be collected from the injection-source pipeline. The samples will represent injection conditions and be sent to a third-party laboratory for analysis. The analysis will be used to indicate contaminant levels.

Potential Response Actions:

- Lower the injection rate or stop the injection.
- Notify the UIC Director within 24 hours.
- Determine the cause of contaminants.
- Investigate downhole issues.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce the effect of contaminants.
- Replace tubing and packer if necessary.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

8.3.4.2 ***<u>Specific Event Description – Microbial activity initiated by injection process or composition, allowing possible production of H_2S</u>***

Risk Assessment Matrix, Section 5.3 (Appendix I-2)

This event could occur due to changes in contamination levels in the CO_2 source that allow microbial activity for possible production of H_2S gas. These sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity.

Likelihood: Remote

Prevention and Detection:

- Samples of the CO_2 stream will be collected from the injection-source pipeline. The samples will represent injection conditions and be sent to a third-party laboratory for analysis. The analysis will be used to indicate contaminant levels.

Potential Response Actions:

- Lower the injection rate or stop the injection.
- Notify the UIC Director within 24 hours.
- Determine the cause of contaminants.
- Investigate downhole issues.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce effect of contaminants.
- Replace tubing and packer if necessary.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

8.3.5 Event Category – Accidents/Unplanned Events (Typical Insurable Events)

8.3.5.1 ***<u>Specific Event Description – Surface infrastructure damage</u>***

Risk Assessment Matrix, Section 6.1 (Appendix I-2)

Unforeseen events, such as surface infrastructure damage, pipeline leak, compressor failure, boater or animal damage, or weather-related events, may occur while operating Pecan Island Injection Well No. 001 or No. 002.

Likelihood: Remote

Prevention and Detection:

- Equipment will be maintained regularly to prevent or minimize damage.
- Damage prevention infrastructure will be installed, and markers placed to alert the public of the potential hazards. The markers will include the name of the operator and telephone number.

- Barricades will be installed to prevent accidental damage to any equipment, and to prevent animals from entering the facility.
- Weather will be continuously monitored and, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Stop the injection and notify the UIC Director within 24 hours.
- Activate the downhole safety valve, if necessary.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

8.3.5.2 <u>Specific Event Description – Hurricane</u>

Risk Assessment Matrix, Section 6.2 (Appendix I-2)

Unforeseen weather-related events, such as a hurricane, are likely to occur while operating Pecan Island Injection Wells No. 001 and No. 002.

Likelihood: Imminent

Prevention and Detection:

- Equipment will be maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed and markers placed to alert the public of the potential hazards. The markers will include the name of the operator and telephone number.
- Weather will be continuously monitored and, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Stop the injection and notify the UIC Director within 24 hours.
- Activate the downhole safety valve, if necessary.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

The following tables (8-1 to 8-3) outline the risk assessment process discussed above.

8.4 <u>Risk Activity Matrix</u>

Table 8-1 – Risk Activity Matrix

Section	Risk (Feature, Event, or Process)	**Likelihood**	**Severity** Safety	Environmental	Financial		
			40%	40%	20%		
		1-Remote, 5-Imminent	1-Harmless, 5-Destructive				
		Assigned	Assigned	Assigned	Assigned	Estimated Costs	Total Score
1	**Water Quality Impact**	[redacted]					
2	**Storage Rights Migration**						
3	**Entrained Contaminant (Non-CO^2) Releases**						
4	**Accidents/Unplanned Events (Typical Insurable Events)**						
	Total						

Table 8-2 – Risk Mitigation and Threat Scores

THREAT SCORES	RISK MITIGATION
≥15	Avoid. Mitigate through immediate responsive action to reduce likelihood to an acceptable level.
10.0-14.9	Preventive and mitigative (P&M) measures required.
3.5-9.9	P&M measures are optional. Monitoring required.
0-3.4	No P&M measures are required. Monitor situation.

Table 8-3 – Risk Assessment Scores

Risk Assessment Scores							
LIKELIHOOD	5	Almost Certain	5	10	15	20	25
	4	Likely	4	8	12	16	20
	3	Occasional	3	6	9	12	15
	2	Rare	2	4	6	8	10
	1	Remote	1	2	3	4	5
			1	2	3	4	5
			SEVERITY				

8.5 Training

Personnel will be trained in their duties and responsibilities related to these facilities during annual on-site or table-top training exercises. All plant personnel, visitors, and contractors must attend a plant overview orientation before entering any of the facilities. A refresher course on this training is required annually for all personnel.

ExxonMobil will provide a copy of the ERRP to local first responders that includes potential response scenarios.

8.6 Communications Plan and Emergency Notification Procedures:

Table 8-4 – Emergency Services – CALL 911

Agency	Telephone Number
Vermilion Parish Fire Department Pecan Island Vol. Fire Department Seventh Ward Vol. Fire Department	911 or (337) 737-2501 (337) 893-8023
Vermilion Parish Sheriff	911 or (337) 893-0871
Vermilion Parish Health Unit	(337) 893-1443
Vermilion Parish Office of Emergency Preparedness	(337) 898-4308
Louisiana Emergency Preparedness Office	(225) 763-3535
Louisiana State Police	(504) 310-7000
Louisiana State Police – Hazardous Material Hotline	(877) 925-6595
Louisiana Department of Fish and Wildlife Service	(225) 765-2800

Table 8-5 – Government Agency Notification

Agency	Telephone Number
EPA Region 6	(214) 665-2200
Class VI Contact	(214) 665-8473
Louisiana Department of Natural Resources	(225) 342-5515
Injection Well Incidents	(225) 342-5515
Vermilion Parish Local Emergency Planning Committee (LEPC)	(337) 898-4308
National Response Center (NRC)	(800) 424-8802
Louisiana State Police – Hazardous Material Hotline	(877) 925-6595

Table 8-6 – Internal Call List

Name	Title	Telephone Number
[redacted]		

As appropriate, ExxonMobil will communicate with the public regarding events that require an emergency response, including the impact of the event on drinking water or the severity of the event, actions taken or planned to address the event, and other information needed to protect the public during the event.

8.7 Flood Hazard Risk

Due to its location near the coast, the Pecan Island Injection Wells No. 001 and No. 002 and surrounding area are designated as a mixture of FEMA flood hazard Zone VE and flood hazard zone AE. Flood hazard zone "VE" corresponds to a coastal area within the 1% annual chance flood event, with additional hazards due to storm-induced velocity-wave action. Flood hazard zone "AE" corresponds to an area within the 1% annual chance of flood event. Both zones are subject to a 26% chance of flooding over a 30-year lifespan. Floodplain management standards apply. The well locations and FEMA flood zones are shown in *Appendix I-3*.

8.8 Emergency and Remedial Response Plan Review and Updates

This ERRP will be reviewed and updated annually. Any amendments to the plan must be approved by the UIC Director and will be incorporated into the permit:

- Within 1 year of an AOR evaluation;
- Following any significant changes to the facility, such as addition of injection or monitoring wells;
- After a change in key personnel; or
- As required by the UIC Director.

The following attachments are in *Appendix G*:

- Appendix G-1 Resources and Infrastructure in AOR Map
- Appendix G-2 Complete Risk Assessment Matrix
- Appendix G-3 FEMA Flood Zone Hazards Map
- Appendix G-4 Emergency Operations Plan

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 9 – FINANCIAL ASSURANCE

July 2023

SECTION 9 – FINANCIAL ASSURANCE

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9.1 Facility Information

Facility Name:	ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) – Pecan Island
Facility Contact:	Okwudiri Onyedum, Treasurer ExxonMobil Low Carbon Solutions Onshore Storage LLC
Project Site Name:	Pecan Island
Project Location:	Vermilion Parish, Louisiana Pecan Island Injection Well No. 001 [redacted] Pecan Island Injection Well No. 002 [redacted]

9.2 Introduction

Under Statewide Order (SWO) 29-N-6 **§3609.C** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.85**], owners or operators of geologic sequestration (GS)[1] wells are required to demonstrate financial responsibility for GS activities. ExxonMobil plans to construct two Class VI injection wells for the purpose of sequestering up to 3.2 MMTA of CO_2 at ExxonMobil's Pecan Island property. Consistent with these regulatory requirements, ExxonMobil has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Pecan Island storage site (Pecan Island Site).

The sections that follow summarize the Pecan Island Site's GS activities, as well as the qualifying financial instrument that ExxonMobil proposes to use, to demonstrate financial responsibility for the following GS project phases: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care and Site Closure; and (4) Emergency and Remedial Response.

9.3 Financial Assurance Demonstration

Per 40 CFR **§146.85(a)(1)(vii)**, ExxonMobil requests approval from the Underground Injection Control Program Director (UIC Director), or their designee, [redacted] for purposes of demonstrating financial responsibility for Corrective Action, Injection Well Plugging, Post-Injection Site Care (PISC) and Site Closure, as well as Emergency and Remedial Response (ERR). [redacted]

[1] "Geologic sequestration" (GS) is "carbon capture and storage" (CCS) by another name, the former predominant in LA and EPA regulations, hence the use here.

[redacted].

In support of the financial assurance demonstration, [redacted] satisfies both Part 1 and Part 2 of the corporate financial test criteria in **§146.85(a)(6)(v)**.

Table 9-1 – [redacted]

[redacted]

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[2] U.S. EPA. *Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Financial Responsibility Guidance* (July 2011). PA 816-R-11-005. B-22 Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates). https://www.epa.gov/system/files/documents/2022-11/uicfinancialresponsibilityguidancefinal072011v_0.pdf

[redacted]

Appendix J-3 is a completed letter fro [redacted] that demonstrates the company's ability to meet the requisite financial coverage and threshold criteria. Appendix J-3 is consistent in form to the "Letter from Chief Financial Officer" included in Appendix B of EPA's July 2011 guidance document.[4]

Consistent with the EPA's July 2011 guidance, ExxonMobil provides this demonstration of financial responsibility with the understanding that the financial instruments referenced herein will be updated and verified no less than annually. As each GS activity phase is initiated for the Pecan Island Site, ExxonMobil will ensure that the coverage limits provided by the respective financial responsibility instruments are sufficient to cover the corresponding project costs prior to initiating the GS project phase.

Estimated Coverage Amounts

The total current cost estimate for all GS activities necessitating financial assurance at the Pecan Island Site is [redacted] in 2023 dollars. This total cost estimate assumes the hiring of independent, third-party contractors for each GS activity, and it can be separated into the following GS project phases[5]:

1. Corrective Action: (completed prior to initial injection);
2. Well Plugging[6]: [redacted]
3. Post-Injection Site Care: [redacted] Site Closure [redacted] and
4. Emergency and Remedial Response: [redacted]

Table 9-2 summarizes the total estimated project costs by GS activity, along with the timeline for which financial assurance coverage is expected to be needed. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the permit application process and assume the hiring of third-party contractors to perform the services or to procure the goods associated with the performance of each GS activity. These values are subject to change during the project to account for inflation of costs and changes to the project that may affect the cost of covered activities. Per SWO 29-N-6 **§3609.C.4(h)** [40 CFR **§146.85(c)**], ExxonMobil will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its demonstration of financial responsibility to the UIC Director or their designee for review and approval. ExxonMobil will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Director, or their designee.

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[4] *Ibid*. See B-19 Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates).
[5] Assumes receipt of permit in 2025, start of injection in 2025, 18 years of injection for Well No. 001, and 15 years of injection for Well No. 002.
[6] Financial responsibility coverages for well plugging reflect the current estimated cost for plugging all injection and monitoring wells related to the Pecan Island site.

Table 9-2 – Summary of GS Activity Project Costs

Activity	Cost
Corrective Action	[redacted]
Well Plugging	
Post-Injection Site Care and Site Closure	
Emergency and Remedial Response	
TOTAL	

9.4 Corrective Action

The Corrective Action Plan is discussed in detail in *Section 3 – Area of Review and Corrective Action Plan*. The plan specifically outlines both a plugging plan for the wells found within the critical pressure front and CO_2 pore-occupancy plume and the recompletion schedule whereby the wellbore modifications will have been completed.

For the planned GS activities at the Pecan Island Site, workovers on all wells requiring plugging modifications will have been completed prior to injection. As such, there is no financial risk for these recompleted wells.

The area of review (AOR) will be reevaluated every 5 years to determine if any additional penetrations will be impacted.

9.5 Well Plugging

9.5.1 Injection Well Plugging

Plug and abandonment (P&A) of the injection wells at the Pecan Island Site will meet the requirements of SWO 29-N-6 **§3631** [40 CFR **§146.92**]. The P&A of the injection wells will be designed as such that no movement of fluids will occur from the injection interval. A more detailed P&A plan is discussed in *Section 6 – Plugging Plan*. These funds include costs for logs/wireline to be run in the wellbore before cementing occurs. CO_2 compatible cement will be used in the initial plug for the well, to ensure the cement does not react with the injected fluid—resulting in a potentially higher cement expense than usual. All expenses relating to personnel and equipment have been accounted for in Table 9-3. Pressure test costs are also included to account for proving the integrity of the well.

9.5.2 Monitoring Well Plugging

P&A of the monitoring wells associated with the Pecan Island Site will also meet the requirements of SWO 29-N-6 **§3631** [40 CFR **§146.92**]. The P&A of these shallow monitor wells will be designed as such that no movement of fluids will occur from the injection interval, nor will fresh and treatable water found within the USDW be threatened. A more detailed P&A plan is discussed in *Section 6 – Plugging Plan*. Because these wells will be completed above the uppermost confining geologic interval, conventional plugging procedures will be utilized. These funds include costs for logs and wireline to be run in the wellbore before cementing occurs. All expenses relating to personnel and equipment have been accounted for in Table 9-3. Pressure test costs are also included to account for proving the integrity of the well.

Table 9-3 – Summary of Well Plugging Costs Associated with Financial Security

Activity	Cost	Total
Injection Well Plugging (two wells)	[redacted]	
Workover Rig		
Kill/Buffer Fluid		
Personnel		
Wireline		
Downhole Tools		
Other Services		
Cement & Pumping Services		
Equipment Rentals		
Deep, Above-Zone Monitoring Well Plugging (two wells)		
Workover Rig/Barge		
Kill/Buffer Fluid		
Personnel		
Wireline		
Downhole Tools		
Other Services		
Cement & Pumping Services		
Equipment Rentals		
USDW Monitoring Well Pluggin (five wells)		
Workover Rig/Barge		
Cement Services		
TOTAL		

9.6 Post-Injection Site Care and Site Closure

The PISC and Site Closure Plan will be designed to meet the requirements of SWO 29-N-6 **§3633** [40 CFR **§146.93**]. The costs associated with the plan are highlighted in Table 9-4, while the plan itself is discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

9.6.1 Post-Injection Monitoring

As discussed in *Section 5 – Testing and Monitoring Plan*, vertical seismic profile (VSP) monitoring will be conducted after the end of injection to ensure the integrity of the well and to track the migration of the plume.

9.6.2 Site Closure

Site closure will occur when the UIC Director has released the owner from all PISC duties. The costs estimated in Table 9-4 reflect the expected amount to decommission and close the site.

Table 9-4 – Summary of PISC/Site Closure Costs Associated with Financial Security

Activity	Cost	Total
Post-Injection Monitoring	[redacted]	
Indirect Plume Monitoring (VSP) x 2		
Other Monitoring (e.g., fluid sampling and analysis, pressure/temperature monitoring)		
Site Closure		
TOTAL		

9.7 Emergency and Remedial Response

The Emergency and Remedial Response Plan (ERRP) is discussed in *Section 8 – Emergency and Remedial Response Plan* and designed to be in compliance with SWO 29-N-6 **§3623.A.1** [40 CFR **§146.94**].

The resultant cost for the ERRP is [redacted] in 2023 dollars. This cost assumes coverage for the Pecan Island Site, including the following risks: water quality contamination, storage rights infringement–form of mineral rights infringement (trespass), mineral rights infringement (trespass), entrained contaminant (non-CO_2) in injection stream, and accidents/unplanned events (typical insurable events). Details regarding these cost estimates are explained in *Section 8*.

9.8 Conclusion

Appendix J contains the following documents:

- Appendix J-1: [redacted]
- Appendix J-2:
- Appendix J-3:

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

SECTION 10 – ENVIRONMENTAL JUSTICE IMPACT REPORT

July 2023

SECTION 10 – ENVIRONMENTAL JUSTICE IMPACT REPORT[1]

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[1] Note: Applicant is including this analysis due to its commitment to, and the importance of, community engagement in the Class VI well permitting process, as well as existing federal guidance. Applicant reserves the right in the future to revise this analysis if interpretation or implementation of federal law or regulation should change.

10.1 Introduction

ExxonMobil anticipates that activities supporting the development of the Pecan Island Injection Wells No. 001 and No. 002 and surrounding area (Study Area) will be supportive of the environmental and economic needs of the communities in which it operates. ExxonMobil's integrated environmental and socioeconomic management approach supports the early identification of potential project-related impacts and opportunities, as well as the planning and implementation of measures to address them. ExxonMobil engagement practices are guided by the goals of universally recognized human rights principles and an integrated approach to identifying and mitigating potential human rights impacts. This Environmental Justice (EJ) Impact Report (EJ Report) is based on a process that identifies potential benefits, impacts, and risk mitigation related to the Study Area.

This assessment is intended to be a baseline that will continue to develop and be refined in conjunction with the Underground Injection Control (UIC) Director or appointed representatives throughout the project. The EJ Report identifies vulnerabilities and other factors to track and guide engagement as the project is planned, permitted, built, and operated. At a minimum, ExxonMobil will engage with stakeholders, including but not limited to local leaders, residents, economic developers, environmental organizations, tribal entities, and others. Engagement materials will take into consideration diversity, access, and inclusion principles such as language, barriers to internet access, and transportation. A stakeholder grievance process is under development that will allow stakeholders to have access to ExxonMobil throughout the project life cycle.

10.2 Methodology

Environmental Protection Agency (EPA) guidance (2016) does not prescribe a methodology for determining EJ impact assessments. The EPA provides guidance for environmental justice considerations for the Class VI Injection Well Permitting Process.[2] In its Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide, EPA recognizes that "there is no singular approach to conducting an EJ analysis[,]"[3] and intends for its implementation manual and Quick Reference Guide to assist with any necessary EJ analysis during the permitting process. The Quick Reference Guide provides seven steps to incorporate EJ in a Class VI Permit Application Review.[4] ExxonMobil has a socioeconomic standard process, which assesses environmental,

[2]https://www.epa.gov/sites/default/files/2015-07/documents/uic-quick-reference-guide_public-participation_final-508.pdf

[3] Id. at 1.

[4] (1) Work with applicant to initiate discussions with the public, which may help assess whether EJ issues are present for a particular permit review; (2) Review site characterization data to determine if EJ communities reside within the area of review or may be impacted; (3) Ask EJ related questions and consider EJ impacts on communities; (4) Evaluate EJ communities for environmental hazards, exposure impacts and vulnerable sub-populations, including consideration of maps and geological considerations, drinking water, other permitted facilities in the area and other multiple or cumulative exposure risks; (5) Implement an inclusive public participation process; (6) Consider potential mitigation measures; (7) Evaluate and document EJ analysis.

socioeconomic, and health considerations throughout a project. That process and this EJ Analysis meet the seven steps set forth in the Quick Reference Guide. While no particular methodology is required, ExxonMobil has applied a combination of quantitative and qualitative methods to conduct this EJ analysis. As ExxonMobil's understanding of the local environment evolves, internal EJ assessments will be refreshed throughout the project lifecycle.

The EPA's EJScreen tool (version 2.2) was used to examine demographic and environmental variables in a 2-mile radius around the injection wells. While ExxonMobil's approach to identifying and managing issues does not depend only on the EJScreen, factors that rose to the 80th percentile are noted in tables by bold type and gray shading; these were used as one starting point for identifying geographic areas that warrant further consideration, analysis, or engagement. Other sources highlighted in this report are census data and primary data from field interviews.

Census Tract (CT) 9511 Block Group (BG) 2 was identified as a community within the Study Area with a disproportionate burden of low income (Figure 10-1). Together with CT9511 BG2, the adjacent Census Block Group (CBG)—CT9511 BG1—incorporates the location of Pecan Island Injection Wells No. 001 and No. 002 and ExxonMobil leased lands. The Study Area is sufficiently large to include the wells and the surrounding 2-mile radius.

This report is based on EJScreen data (version 2.2) retrieved on July 19, 2023 (results included in *Appendix K*). ExxonMobil understands that further updates to the EPA EJScreen tool can be expected throughout the life of the project.

In accordance with the EPA guidance (2016, 2022), this report uses demographic and socioeconomic data to determine if minority and low-income populations are present. The U.S. Council on Environmental Quality (CEQ) states that a minority population is potentially present where one is "meaningfully greater" than the minority population of an appropriate unit of geographic analysis, or a reference population (CEQ, 1997). For measurement against a reference population, CEQ recommends using an "appropriate unit of geographic analysis" that does not "artificially dilute or inflate" the population (CEQ, 1997). While "meaningfully greater" is not explicitly defined in the CEQ's guidance, federal guidelines suggest that 10% greater than a reference population is considered a reasonable threshold for "meaningfully greater" (Federal EJ IWG and NEPA Committee, 2019). To identify minority populations in this report, the corresponding parish (Vermilion) was used as the reference population.

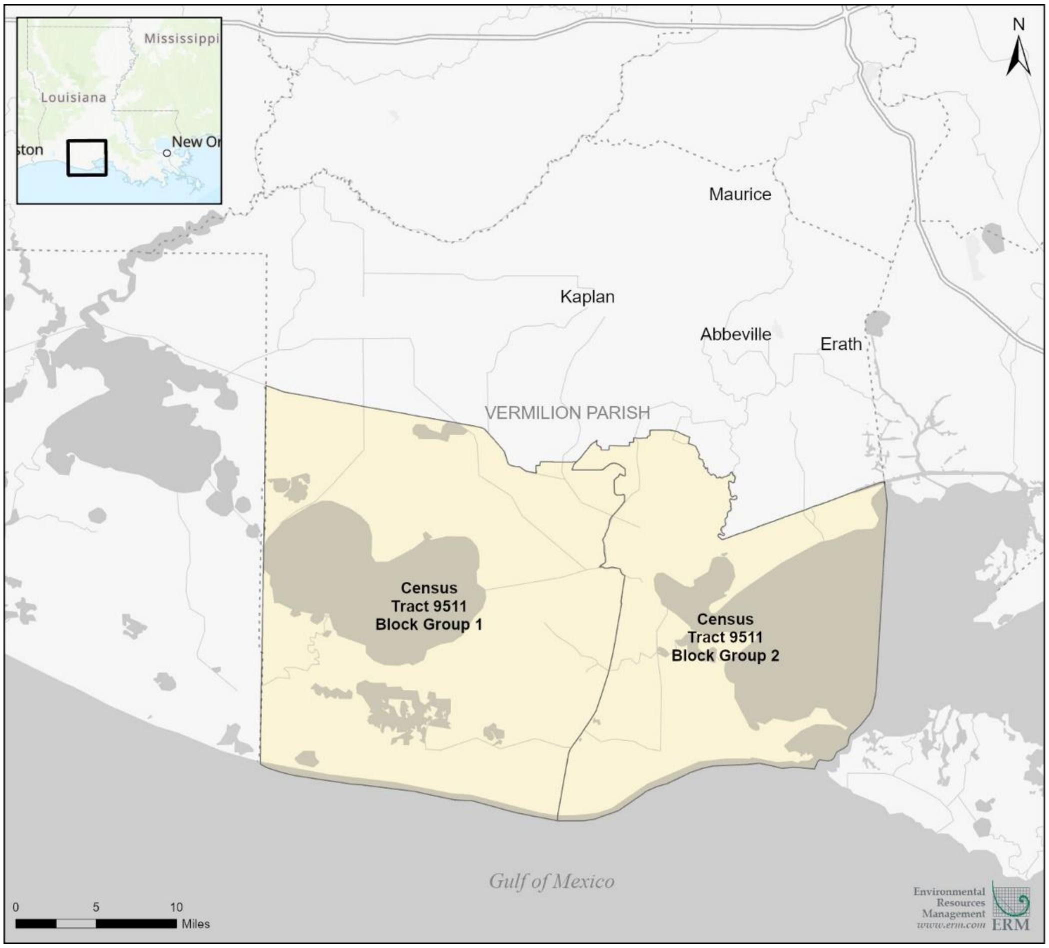

Figure 10-1 – Study Area (CT9511 BG1 and CT9511 BG2) in Relation to Proposed Wells

Guidelines for identifying low-income populations differ depending on federal or state agencies. Low-income populations can be identified using either (1) the U.S. Census Bureau poverty thresholds, (2) local data sources on poverty, or (3) the U.S. Department of Health and Human Services poverty guidelines. Additionally, communities can be identified by using the "meaningfully greater" analysis, the percent of *individuals* below the poverty level, percent of *households* below the poverty level, and/or percent of families with children below the poverty level (Federal EJ IWG and NEPA Committee, 2019). The National Environmental Policy Act (NEPA) uses the "meaningfully greater" analysis to identify low-income populations.

For this report, potential minority and low-income populations are identified using the following guidelines:

<u>Racial composition</u>:

- Share of nonwhites is more than 50%.
- Share of nonwhites is at least 10% higher than the county/parish or state share.

Poverty rate:

- Share of households in poverty is at least greater than the county/parish share.

10.3 Demographic Indicators[5]

The EJ assessment used the EJScreen tool (version 2.2) to consider a wide array of demographic factors and indicators in relation to the two CBGs that encompass the Study Area, shown in Figures 10-2 and 10-3. The Study Area CBGs are indicated in light green shading with percentile ranking colors overlaid for People of Color and Low-Income Households (see corresponding “map contents” charts for color keys). As illustrated, the locations of the two injection wells are indicated by the orange dots. Both CBGs have low populations of people of color compared to the overall parish population (Tables 10-1 and 10-2). Table 10-3 (page 10) combines the two block groups and compares them with Vermilion Parish averages. The Full EJScreen reports for the two block groups retrieved July 19, 2023, are provided in *Appendix K.*

Additionally, CT9511 BG1 (Table 10-2) also has a low percentage of low-income residents when compared to Vermilion Parish, whereas CT9511 BG2 (Table 10-1) is in the 84th percentile for low-income populations nationally and in the 71st percentile for low-income populations compared to the State of Louisiana.

Both injection wells are located in CT9511 BG2. Using the suggested percentile screening, indicators above the 80th percentile nationally appear for this block in the demographic indicator categories and include:

- Low income (84th)
- Less than high school education (83rd)
- Under age 5 (82nd)

[5] The discussion of demographic indicators satisfies step two of the Quick Reference Guide.

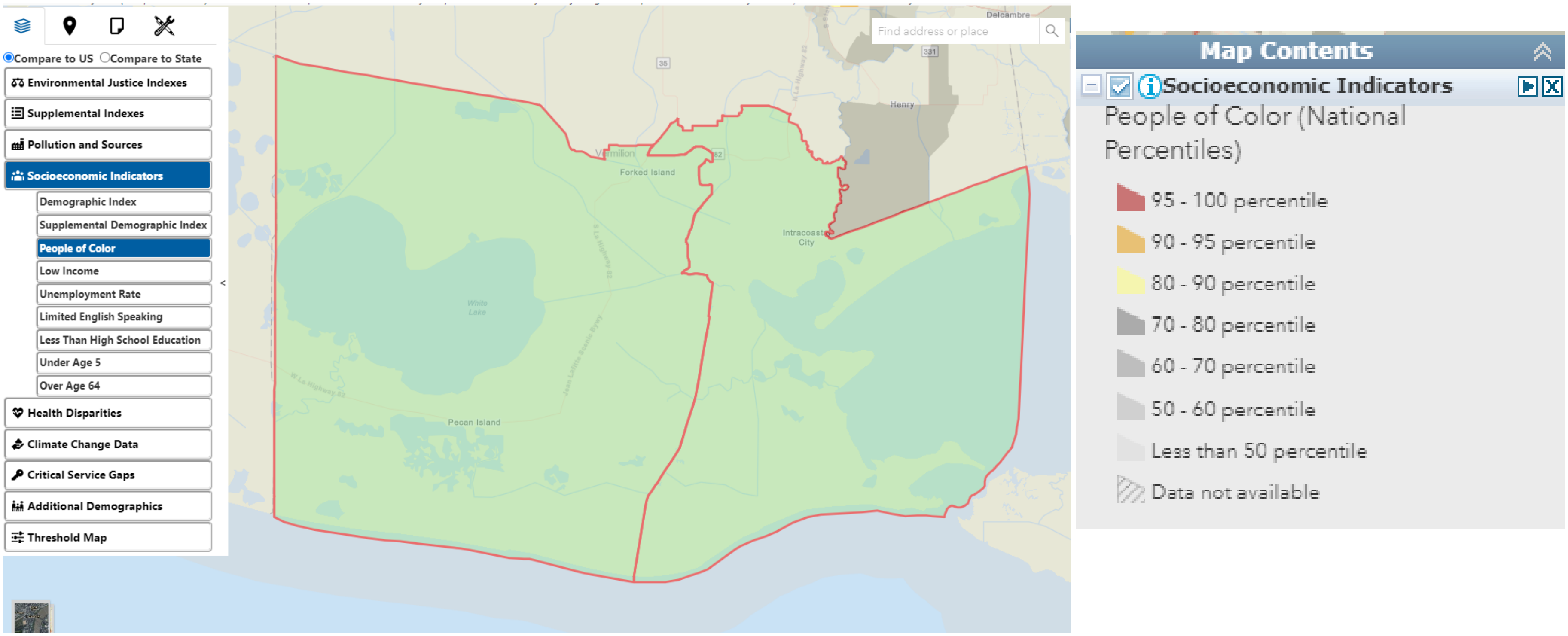

Figure 10-2 – People of Color in the Study Area – Socioeconomic Indicator Percentiles

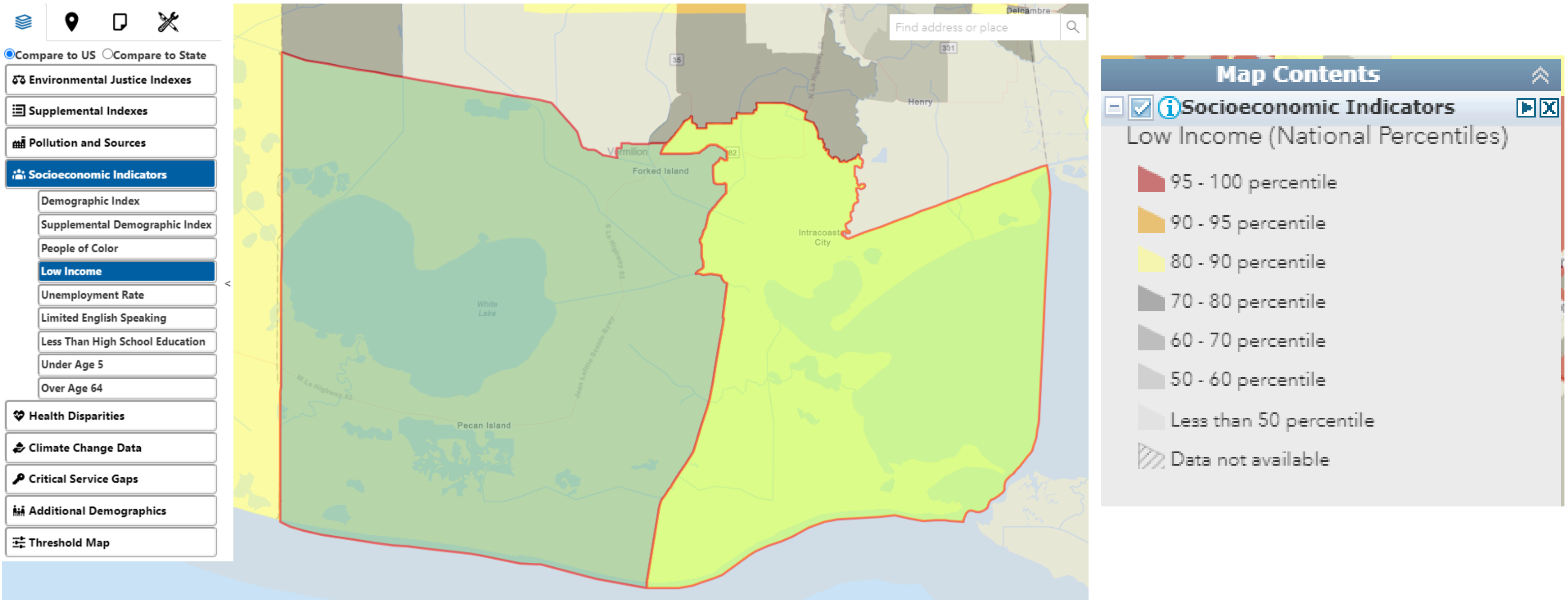

Figure 10-3 – Low-Income Households in the Study Area – Socioeconomic Indicator Percentiles

Table 10-1 – EJScreen Results for Census Tract 9511 Block Group 2

Category	Selected Variables	Value	State Avg.	Percentile in State	U.S. Avg.	Percentile in U.S.
Demographic	Demographic Index	36%	41%	48	35%	60
Demographic	Supplemental Demographic Index	20%	17%	65	14%	78
Demographic	People of Color	18%	43%	30	39%	35
Demographic	Low Income	54%	40%	71	31%	**84**
Demographic	Unemployment Rate	3%	7%	47	6%	46
Demographic	Limited English Speaking	0%	2%	0	5%	0
Demographic	Population with Less than High School Education	21%	15%	74	12%	**83**
Demographic	Population Under Age 5	9%	6%	77	6%	**82**
Demographic	Population Over Age 64	10%	17%	27	17%	27
Demographic	Low Life Expectancy	20%	22%	29	20%	60

Blockgroup 221139511002, LOUISIANA, EPA Region 6 (Population: 976). ***.*** *Values above the 80th percentile are shown in bold and shaded dark gray.*

Table 10-2 – EJScreen Results for Census Tract 9511 Block Group 1

Category	Selected Variables	Value	State Avg.	Percentile in State	U.S. Avg.	Percentile in U.S.
Demographic	Demographic Index	15%	41%	14	35%	21
Demographic	Supplemental Demographic Index	15%	17%	44	14%	63
Demographic	People of Color	0%	43%	0	39%	0
Demographic	Low Income	30%	40%	38	31%	55
Demographic	Unemployment Rate	0%	7%	0	6%	0
Demographic	Limited English Speaking	3%	2%	**83**	5%	68
Demographic	Population with Less than High School Education	24%	15%	79	12%	**85**
Demographic	Population Under Age 5	2%	6%	26	6%	20
Demographic	Population Over Age 64	20%	17%	68	17%	66
Demographic	Low Life Expectancy	20%	22%	29	20%	60

Blockgroup 221139511001, LOUISIANA, EPA Region 6 (Population: 518). Values above the 80th percentile are shown in bold and shaded dark gray.

Census Tract 9511 BG1 does not contain injection wells; however, the models show that the area of review (AOR) of the Pecan Island Project may extend to the BG1 area. Indicators above the 80th percentile nationally, as displayed in Table 10-2, appear for this CBG in secondary demographic indicator categories and include:

- Less than a high school education (85th)
- Population with limited English (83rd percentile for the State of Louisiana and 68th percentile when compared nationally)

Table 10-3 uses the "meaningfully greater" methodology to compare the CBGs to Vermilion Parish. Census Tract 9511 BG2 has "meaningfully greater" percentages in the Demographic Index (36%), Supplemental Demographic Index (20%), Low-Income (54%), Population with Less than a High School Education (21%), and Population Under Age 5 (5%). Census Tract 9511 BG1 has "meaningfully greater" population percentages for Limited English Speakers (3%), Population with Less than a High School Education (24%), and Population Over Age 64 (20%).

Most of the indicators that are higher than the Vermilion Parish percentiles match national percentile rankings above the 80th percentile, with the exceptions of the Demographic Index in CT9511 BG2, and the Limited English and Population Over Age 64 indicators in CT9511 BG1.

Table 10-3 – EJScreen Demographic Results for the Study Area Compared to Vermilion Parish Results

Category	Selected Variables	Vermilion Parish	CT9511 BG2	CT9511 BG1
Demographic	Demographic Index	30%	**36%**	15%
Demographic	Supplemental Demographic Index	17%	**20%**	15%
Demographic	People of Color	22%	18%	0%
Demographic	Low Income	37%	**54%**	30%
Demographic	Unemployment Rate	6%	3%	0%
Demographic	Limited English Speaking	2%	0%	**3%**
Demographic	Population with Less than High School Education	17%	**21%**	**24%**
Demographic	Population Under Age 5	6%	**9%**	**2%**
Demographic	Population Over Age 64	15%	10%	**20%**
Demographic	Low Life Expectancy	21%	20%	20%

Census Block Group percentages above the Vermilion Parish percentages are shown in bold and shaded dark gray.

Importantly, the proposed wells, located in a sparsely populated area, will have impacts on very few people. The population numbers, square miles, and population density of CT9511 BG1 and

CT9511 BG2 compared to Vermilion Parish are set forth in Table 10-4 below.

Table 10-4 – EJScreen Population Density Results for the Study Area Compared to Vermilion Parish Results

Population Statistics	Vermilion Parish	CT9511 BG2	CT9511 BG1
Total Population	57,775	976	518
Square Miles	1542.21	315.79	482.70
Population Density (persons/square mile)	37.46	3.09	1.07

10.4 Environmental Indicators[6]

Environmental indicators from the EJScreen tool for both CBGs in the Study Area, including the numerical values as well as the percentile rankings, are displayed in Tables 10-5 and 10-6. The full EJScreen reports for the two CBGs are provided as *Appendix K.*

In addition to the primary indicators in the demographic category (minority and low-income), the EJScreen tool also uses 13 “EJ indexes” reflecting environmental indicators combined with socioeconomic information. The EJ index highlights block groups with the highest intersection of low-income populations, people of color, and a given environmental indicator.

As detailed in Table 10-5, the Study Area results for CT9511 BG2 rank above the 80th percentile nationally in one EJScreen category: Wastewater Discharge (illustrated in Figure 10-4). However, when socioeconomic conditions are factored into the formula to calculate the EJ index, BG2 has a lower percentile (49th percentile). The indicator for Ozone is in the 82nd percentile statewide (Figure 10-5) while only in the 50th percentile nationally.

[6] The Environmental Indicators section satisfies steps three and four of the Quick Reference Guide.

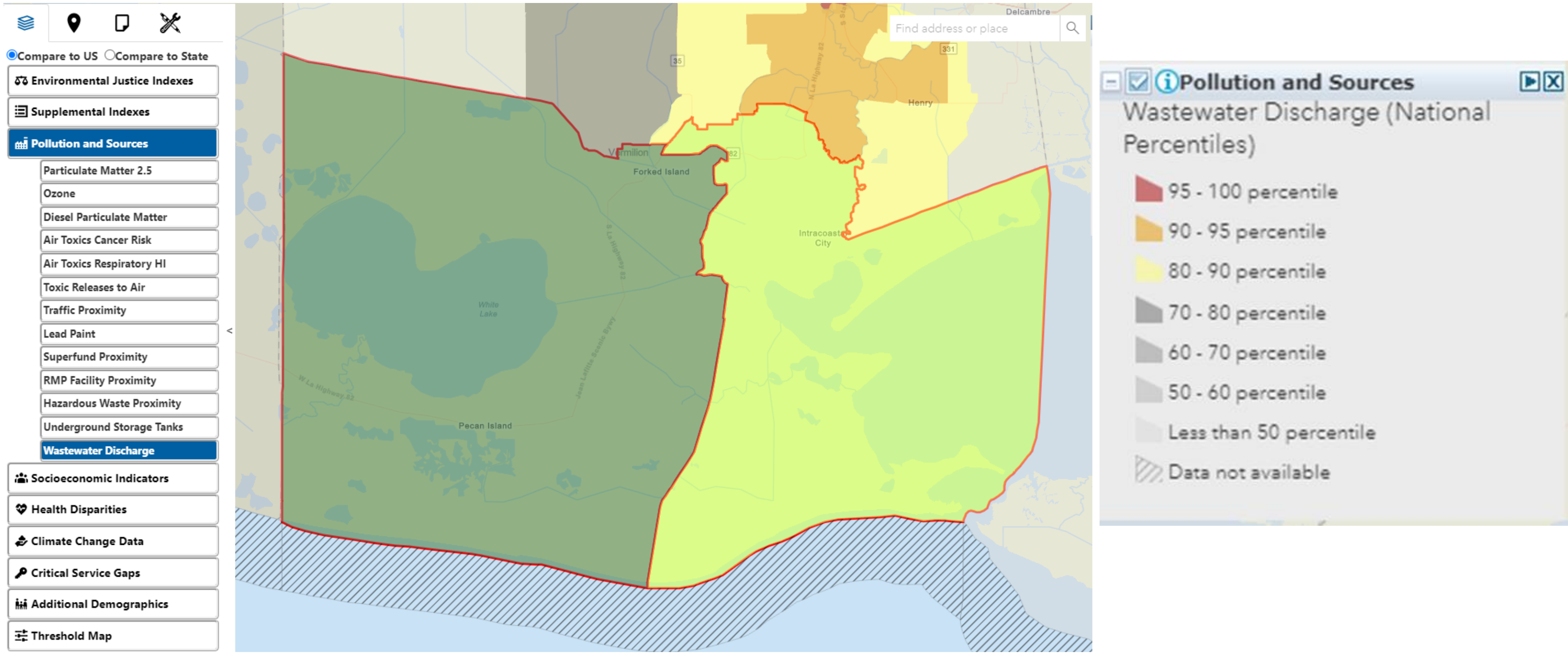

Figure 10-4 – Environmental Indicator Percentiles for Wastewater Discharge in the Study Area

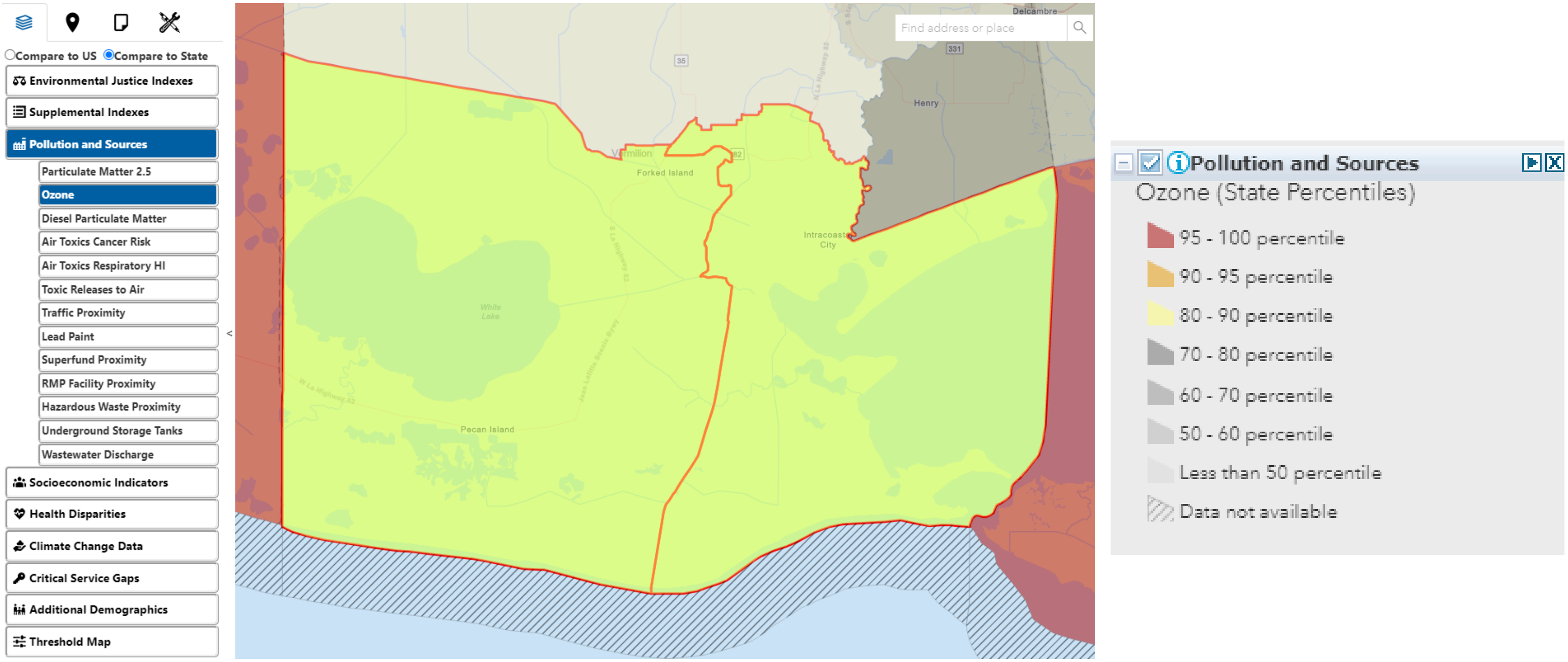

Figure 10-5 – Environmental Indicator Percentiles for Ozone in the Study Area

Table 10-5 – EJ Screen Environmental Results for Census Tract 9511 BG2

Category	Selected Variables	Value	State Avg.	Percentile in State	U.S. Avg.	Percentile in U.S.
Environmental	Particulate Matter (PM 2.5 in micrograms per cubic meter (ug/m3))	7.52	8.62	1	8.08	32
Environmental	Ozone (parts per billion (ppb))	61.2	59.8	**82**	61.6	50
Environmental	Diesel PM (ug/m3)	0.078	0.247	4	0.261	9
Environmental	Air Toxics Cancer Risk (risk per lifetime per million (MM))	30	40	2	28	35
Environmental	Air Toxics Respiratory Hazard Index	0.3	0.38	1	0.31	31
Environmental	Toxic Releases to Air	130	15,000	15	4,600	27
Environmental	Traffic Proximity and Volume (daily traffic count/distance to road)	0.41	86	2	210	1
Environmental	Lead Paint Indicator (% pre-1960s housing)	0.24	0.22	67	0.3	53
Environmental	Superfund Proximity (site count/km distance)	0.02	0.076	27	0.13	17
Environmental	Risk Management Plan (RMP) Proximity (facility count/km distance)	0.3	0.62	56	0.43	67
Environmental	Hazardous Waste Proximity (facility count/km distance)	0.086	1.1	18	1.9	17
Environmental	Underground Storage Tank Indicator	0.0016	2.2	0	3.9	0
Environmental	Wastewater Discharge Indicators (toxicity-weighted concentration/km distance)	0.2	49	**90**	22	**85**

Blockgroup 221139511002, LOUISIANA, EPA Region 6 (Population: 976). Values above the 80th percentile are shown in bold and shaded dark grey.

Using the established percentile screening for CT9511 BG2 (where both injection wells are located), environmental indicators above the 80th percentile appear for this block as follows, as displayed in Table 10-5:

- Ozone ppb (82nd percentile statewide)
- Wastewater discharge indicators (85th percentile nationally, 90th percentile statewide)

Table 10-6 presents the environmental indicators for CT9511 BG1.
While CT9511 BG1 does not contain injection wells, as discussed earlier, the models show that the AOR of the Pecan Island Project may extend to the area of that CBG. Environmental indicators above the 80th percentile appear for this block as follows, as displayed in Table 10-6:

- Ozone ppb (82nd percentile statewide)
- Wastewater Discharge (85th percentile statewide)

Table 10-6 – EJScreen Environmental Results for Census Tract 9511 BG1

Category	Selected Variables	Value	State Avg.	Percentile in State	U.S. Avg.	Percentile in U.S.
Environmental	PM 2.5 in ug/m3	7.52	8.62	1	8.08	32
Environmental	Ozone (ppb)	61.2	59.8	**82**	61.6	50
Environmental	Diesel PM (ug/m3)	0.078	0.247	4	0.261	9
Environmental	Air Toxics Cancer Risk (risk per lifetime per MM)	30	40	52	28	35
Environmental	Air Toxics Respiratory Hazard Index	0.3	0.38	1	0.31	31
Environmental	Toxic Releases to Air	31	15,000	4	4,600	14
Environmental	Traffic Proximity and Volume (daily traffic count/distance to road)	0.024	86	0	210	0
Environmental	Lead Paint Indicator (% pre-1960s housing)	0.24	0.22	67	0.3	52
Environmental	Superfund Proximity (site count/km distance)	0.02	0.076	30	0.13	18
Environmental	RMP Proximity (facility count/km distance)	0.14	0.62	32	0.43	42

Environmental	Hazardous Waste Proximity (facility count/km distance)	0.043	1.1	7	1.9	7
Environmental	Underground Storage Tank Indicator	0.0023	2.2	0	3.9	0
Environmental	Wastewater Discharge Indicators (toxicity-weighted concentration/km distance)	0.05	49	**85**	22	78

Blockgroup 221139511001, LOUISIANA, EPA Region 6 (Population: 518). Values above the 80th percentile are shown in bold and shaded dark gray.

10.5 Critical Services

Critical services such as broadband internet subscription, “food deserts” (i.e., areas with limited access to affordable and nutritious foods), lack of health insurance, housing burden and transportation access were also assessed. Census Tract 9511 BG2 has households with limited broadband in the 88th percentile when compared to the U.S. average, as shown in Figure 10-6.

Both CBGs are in food desert areas, lack health insurance in the 56th and 57th percentile nationally, face housing burden in the 14th percentile, and lack transportation access in the 76th percentile, as shown in Figures 10-7 through 10-10.

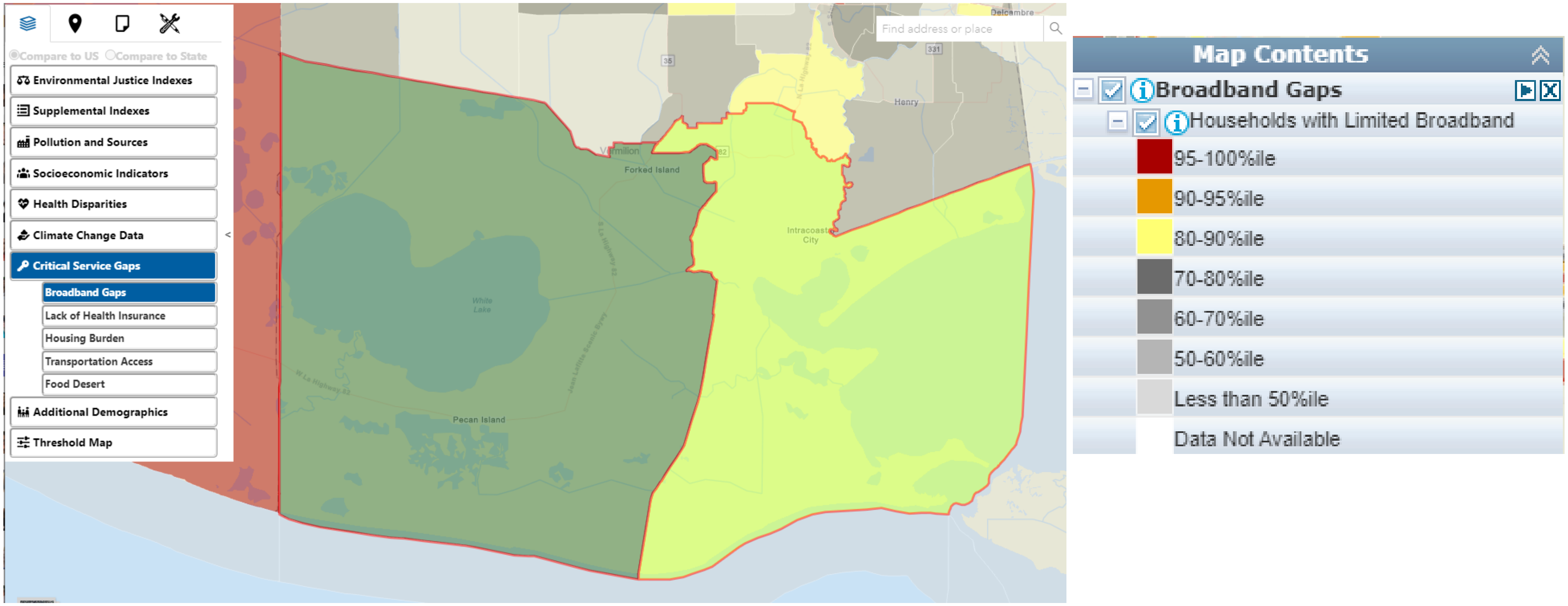

Figure 10-6 – Critical Service Gap: Broadband Gaps in the Study Area

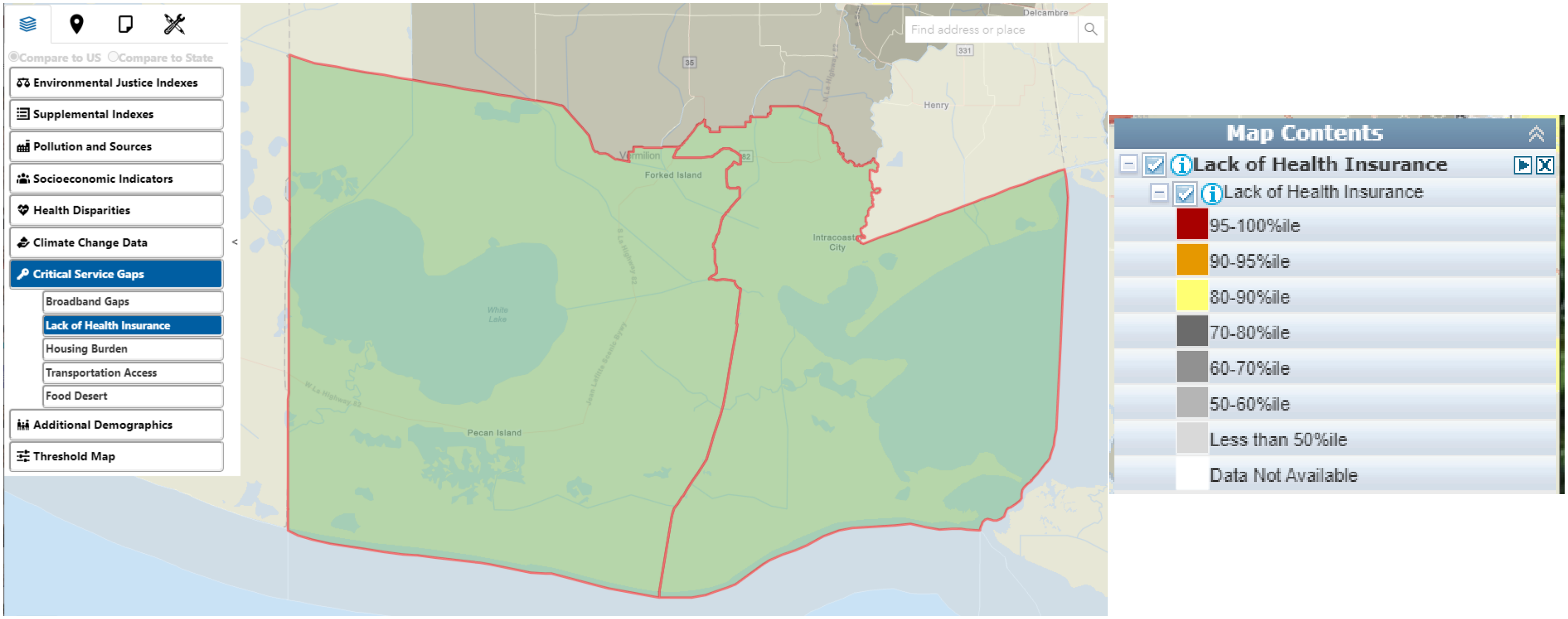

Figure 10-7 – Critical Service Gap: Lack of Health Insurance in the Study Area (BG1 and BG2)

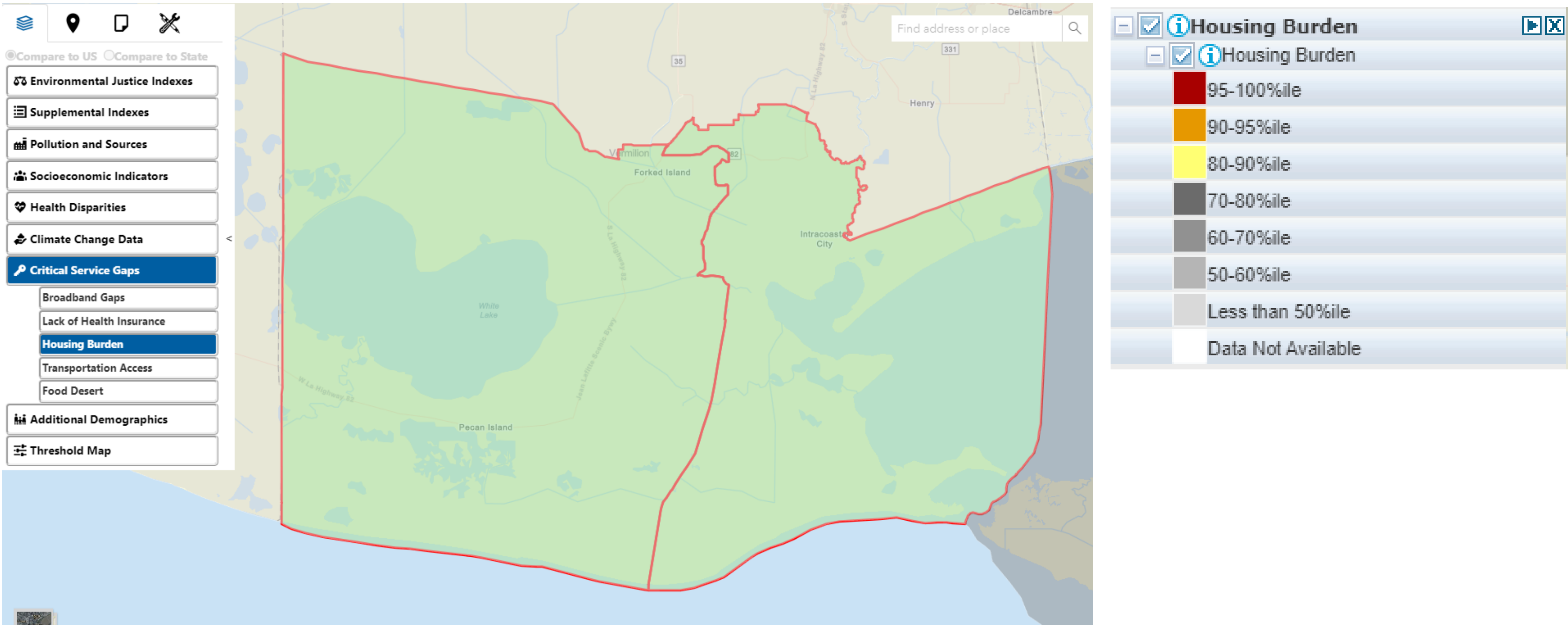

Figure 10-8 – Critical Service Gap: Housing Burden in the Study Area (BG1 and BG2)

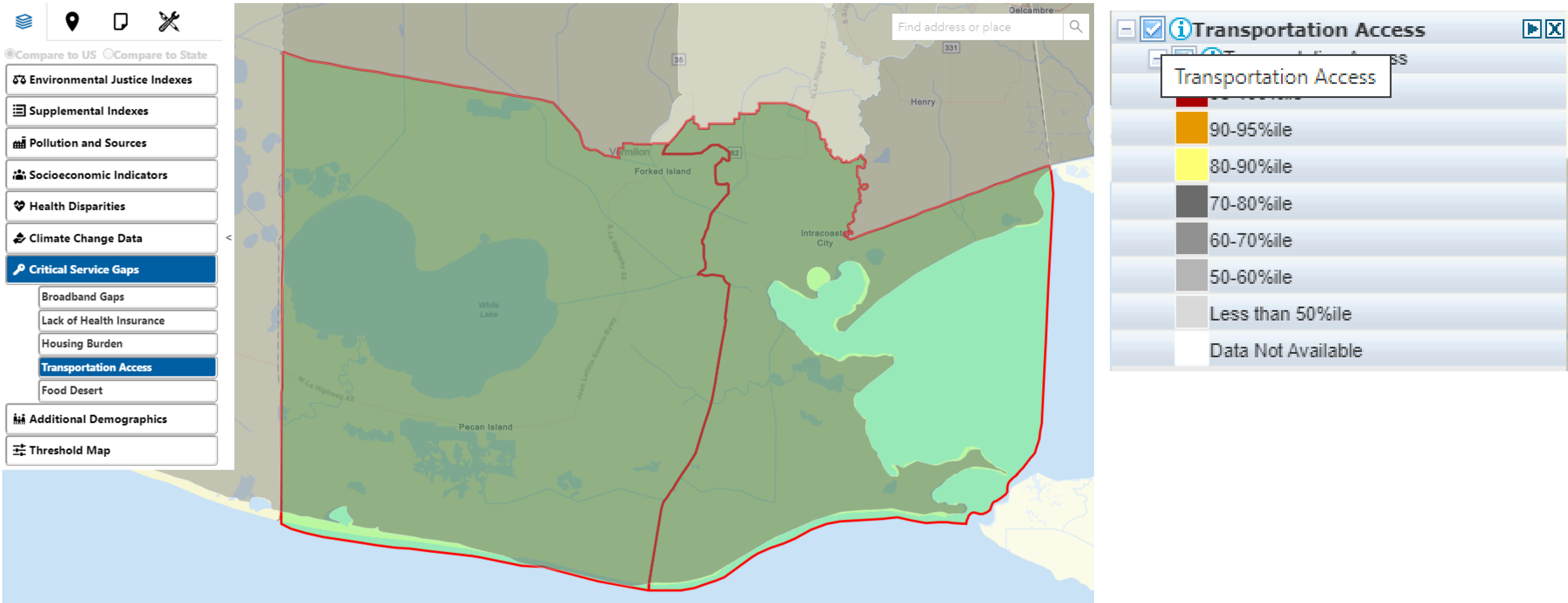

Figure 10-9 – Critical Service Gap: Transportation Access in the Study Area (BG1 and BG2)

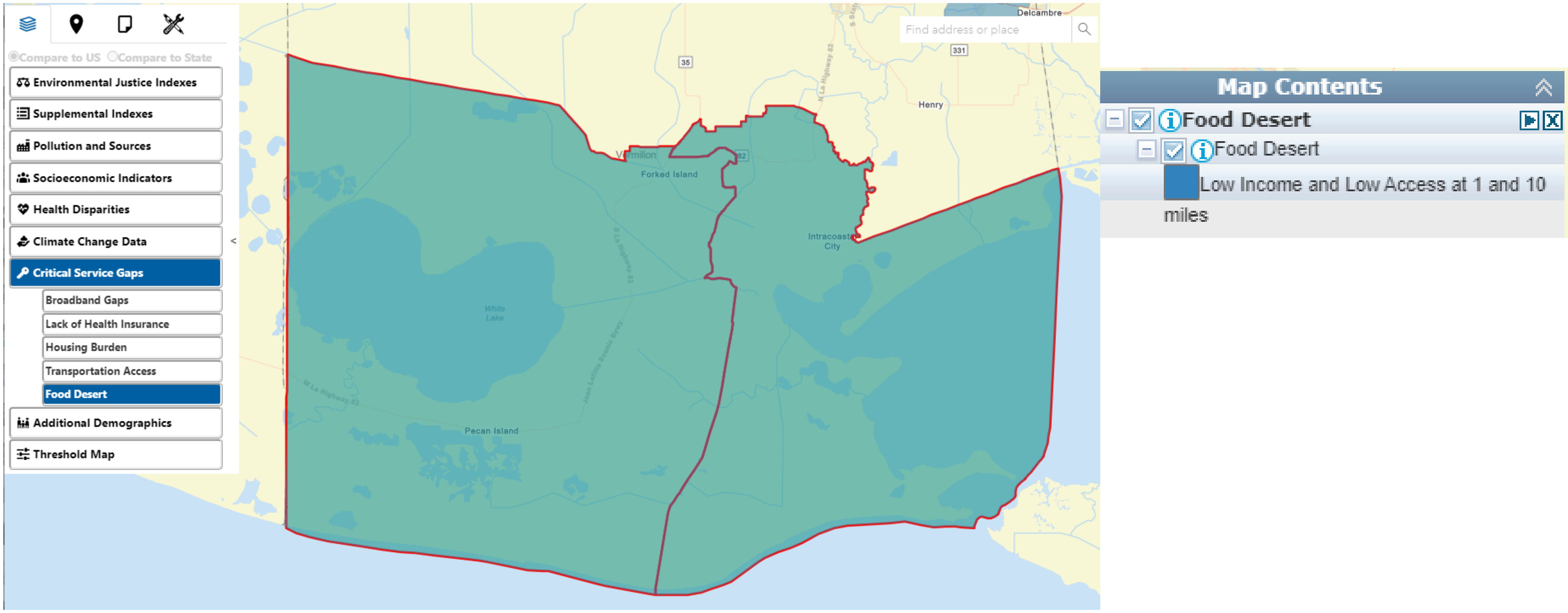

Figure 10-10 – Critical Service Gap: Food Deserts in the Study Area

In summary, EJScreen data indicate that CT9511 BG2 has a significant low-income population (54%) (Table 10-3). In addition, BG2 ranks above the 80th percentile in ozone and wastewater discharge (Table 10-5). The block group also shows gaps in critical services including rates of broadband adoption, food deserts and transportation access.

CT9511 BG1 does not have primary demographic indicators beyond the parish average. It does, however, have environmental indicators above the 80th percentile for ozone and wastewater discharge (Table 10-6). It has critical service gaps similar to BG2.

Both block groups have population densities far lower than Vermilion Parish.

10.6 Preliminary EJ and Stakeholder Engagement[7]

In accordance with internal socioeconomic standard procedures and in addition to census data and the EJScreen tool, ExxonMobil conducted field interviews in Abbeville (the parish seat to the north of the Study Area) and Erath, Louisiana, in April 2023. The interviews were conducted over four days with individuals representing a diverse range of stakeholders, such as mayors, police chiefs, nongovernment organizations, church leaders, tourism officials, educators, and farmers.

Initial observations from the interviews informed the baseline understanding of potential EJ and socioeconomic dynamics that may impact the Pecan Island Project area. Considerations related to EJ, local economic development, workforce development, and grievance will continue to be measured and assessed throughout the project.

10.7 EJ and Socioeconomic Observations

The population of Vermilion Parish is primarily Caucasian and African American, with other populations including Asian (Vietnamese and Laotian) and Latin American. Distribution of socioeconomic factors varies across the parish. For example, while the overall percentage of African Americans is 14% parish-wide, the population in Abbeville is 43% African American and in Erath is 11%.

The following primary findings, based on interviewee input, are qualitative — categorized by Regional Challenges, Socioeconomic Factors, Affordable Housing, Jobs, Health, and Education.

Regional Challenges

- Vermilion Parish has felt the impacts of recent natural disasters—having been particularly affected by Hurricane Rita in 2005. Significant changes in the region are related to "pre-Rita" and "post-Rita" socioeconomic factors.

- The Pecan Island Project area was particularly impacted by Hurricane Rita. Once described as vibrant and thriving pre-Rita, with a high school and several grocery stores, the area saw the high school close in 2007, and only one grocery store remains.
- The parish experienced a northward migration due to the Federal Emergency Management Agency (FEMA) flood buyout program, in which the government purchased voluntary sellers' properties damaged by floods, doing so at pre-flood values then demolishing the properties. The rising cost of flood insurance has been linked to people moving north of Louisiana Highway 14 (LA 14).
- The northward migration and consequent depopulation in some southern parts of the parish have created challenges for communities who derive identity and sociocultural nuances from where they live. The attachment is specific to the towns where their families are located and does not extend to the next town. Many people are unwilling or unable to relocate, despite the challenges of remaining.
- In Vermilion Parish, many services for low-income or vulnerable groups are in the northern area of the parish whereas those served live in the south. Public transportation is a barrier to access to services in the northern part of the parish.

<u>Socioeconomic Factors</u>

- The western block of the Study Area (BG1) is 30% low income and less than 1% people of color; the eastern block (BG2) is 54% low income and 18% people of color. These are rural areas, with a 2022 population of 518 residents in BG1 and 1,976 in BG2.
- Limited opportunities for childcare and access to the Head Start program impact the parish. Childcare for children under the age of 3 is limited. Children between the ages of 3 and 5 are eligible for Head Start; however, there is a wait list to enter the program, and once children age out and are in school, access to affordable after-school care is a challenge.
- Single-parent households are common in the parish low-income communities.
- Crime among teenagers is increasing in some communities.

<u>Affordable Housing</u>

- Several factors impact access to quality, affordable housing, including but not limited to the following: higher post-pandemic rents; investor purchasing of available single-family dwellings; increased rental-property fees, such as those for background checks and applications; and increased cost of utilities. Vulnerable populations such as the elderly on fixed incomes, those on disability, and those who rely on Section 8 housing may be disproportionately impacted.

- Interviewees reported that the rising cost of housing has increased rates of homelessness. One of these interviewees noted that there is a single homeless shelter serving Vermilion and Iberia Parishes.

Jobs

- The Vermilion Parish economy is primarily driven by oil and gas, agriculture, and aquaculture, with tourism also playing a role. Sugar cane, cattle, and Tabasco pepper farming are the main agricultural activities, while crawfishing, shrimping, and seafood manufacturing drive the aquaculture industry.
- Residents are impacted by the loss of oil-and-gas industry jobs. In the past, the offshore oil-and-gas industry has served as the path out of poverty for the area, but the loss of jobs and the decrease in services to jobs (such as childcare and transportation) have impacted employment in the region. Many have moved further afield to oil-and-gas jobs, including in the oil fields in Texas.
- High rates of joblessness among people of working age on disability and/or for mental health reasons in low-income communities exist. There are significant gaps between the wages employers pay and what would be considered a living wage.
- Lack of public transportation was cited as a major challenge across Vermilion and neighboring parishes, making it challenging for those who cannot afford to purchase and maintain a car to access public services, transport themselves to work, or bring their children to youth activities.

Health

- Mental health and addiction are two main health challenges in the region. Limited transportation and lack of health services have compounded challenges around access to treatment. For example, outpatient services and treatment options for children are limited.

Education

- Interviewees widely reported poor education in communities with high percentages of people of color. One interviewee noted that the schools in Vermilion Parish are very segregated, saying that the African American community is largely zoned to a “D” school. Other interviewees highlighted Erath High School in Vermilion Parish as among the top public high schools in the state. Eighty-eight percent of the Erath population is Caucasian.

10.8 References

Council on Environmental Quality (CEQ). Executive Office of the President (1997). *Environmental Justice: Guidance Under the National Environmental Policy Act.* https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/G-CEQ-EJGuidance.pdf

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Appendix K – EJScreen v2.2 Reports – CT9511 BG1 and BG2 – Retrieved 7.19.2023

ExxonMobil

Underground Injection Control – Class VI Permit Application for Pecan Island Injection Wells No. 001 and No. 002

Vermilion Parish, Louisiana

APPENDICES

July 2023

LONQUIST SEQUESTRATION LLC

APPENDIX A: PROJECT MAPS

APPENDIX A

Submitted to EPA via Alternative Means

APPENDIX B: SITE CHARACTERIZATION

APPENDIX B

Submitted to EPA via Alternative Means

APPENDIX C: AOR AND CORRECTIVE ACTION PLAN

Appendix C-1	USDW Determination AOR Map
Appendix C-2	Oil and Gas Wells AOR Map
Appendix C-3	Oil and Gas Wells AOR List
Appendix C-4	Freshwater Wells AOR Map
Appendix C-5	Freshwater Wells AOR List
Appendix C-6	Site Review AOR Map
Appendix C-7	SN: 91634 Current State Schematic
Appendix C-8	SN: 91634 Corrective Action Schematic
Appendix C-9	SN: 121614 Current State Schematic
Appendix C-10	SN: 121614 Corrective Action Schematic
Appendix C-11	SN: 133390 Current State Schematic
Appendix C-12	SN: 133390 Corrective Action Schematic
Appendix C-13	Magnetometer Survey Results
Appendix C-14	Magnetometer Anomalies Investigation

APPENDIX C

Submitted to EPA via Alternative Means

APPENDIX D: CONSTRUCTION

APPENDIX D

Submitted to EPA via Alternative Means

APPENDIX E: METALLURGY

APPENDIX E

Submitted to EPA via Alternative Means

APPENDIX E: TESTING AND MONITORING

APPENDIX F

Submitted to EPA via Alternative Means

APPENDIX G: EMERGENCY OPERATIONS

APPENDIX G

Submitted to EPA via Alternative Means

APPENDIX H: PLUGGING AND ABANDONMENT

APPENDIX H

Submitted to EPA via Alternative Means

APPENDIX I: FAULT SLIP POTENTIAL MODEL

APPENDIX I

Submitted to EPA via Alternative Means

APPENDIX J: FINANCIAL ASSURANCE

APPENDIX J

Submitted to EPA via Alternative Means

APPENDIX K: ENVIRONMENTAL JUSTICE

Appendix K-1	EJ Screen Report Block No. 22113951101
Appendix K-2	EJ Screen Report Block No. 22113951102

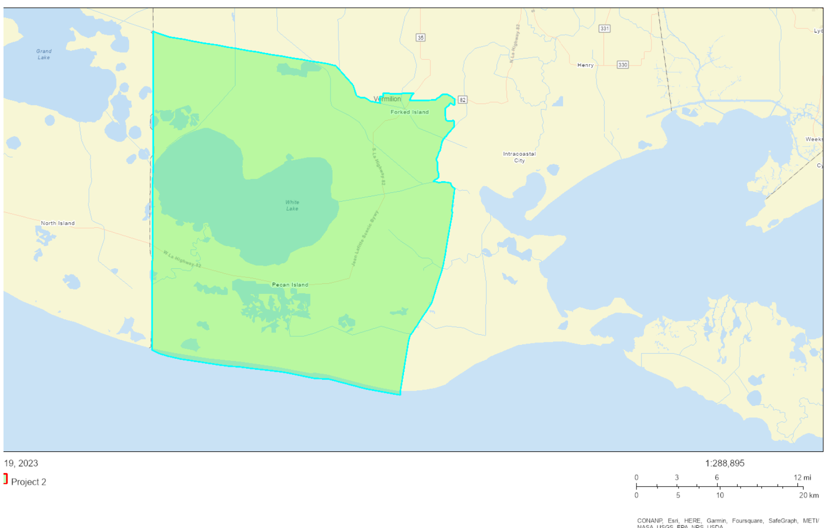
EPA

EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Vermilion Parish, LA

Blockgroup: 221139511001
Population: 518
Area in square miles: 482.70



COMMUNITY INFORMATION

- Low income: 30 percent
- People of color: 0 percent
- Less than high school education: 24 percent
- Limited English households: 3 percent
- Unemployment: 0 percent
- Persons with disabilities: 24 percent
- Male: 54 percent
- Female: 46 percent
- 78 years — Average life expectancy
- $32,270 — Per capita income
- Number of households: 245
- Owner occupied: 76 percent

BREAKDOWN BY RACE

- White: 100%
- Black: 0%
- Asian: 0%
- Hispanic: 0%
- American Indian: 0%
- Hawaiian/Pacific Islander: 0%
- Other race: 0%
- Two or more races: 0%

LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
English	83%
Spanish	6%
French, Haitian, or Cajun	11%
Total Non-English	17%

BREAKDOWN BY AGE

From Ages 1 to 4	2%
From Ages 1 to 18	14%
From Ages 18 and up	86%
From Ages 65 and up	20%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	0%
Speak Other Indo-European Languages	100%
Speak Asian-Pacific Island Languages	0%
Speak Other Languages	0%

Notes: Numbers may not sum to totals due to rounding. Hispanic popultion can be of any race.
Source: U.S. Census Bureau, American Community Survey (ACS) 2017 -2021. Life expectancy data comes from the Centers for Disease Control.

www.epa.gov/ejscreen

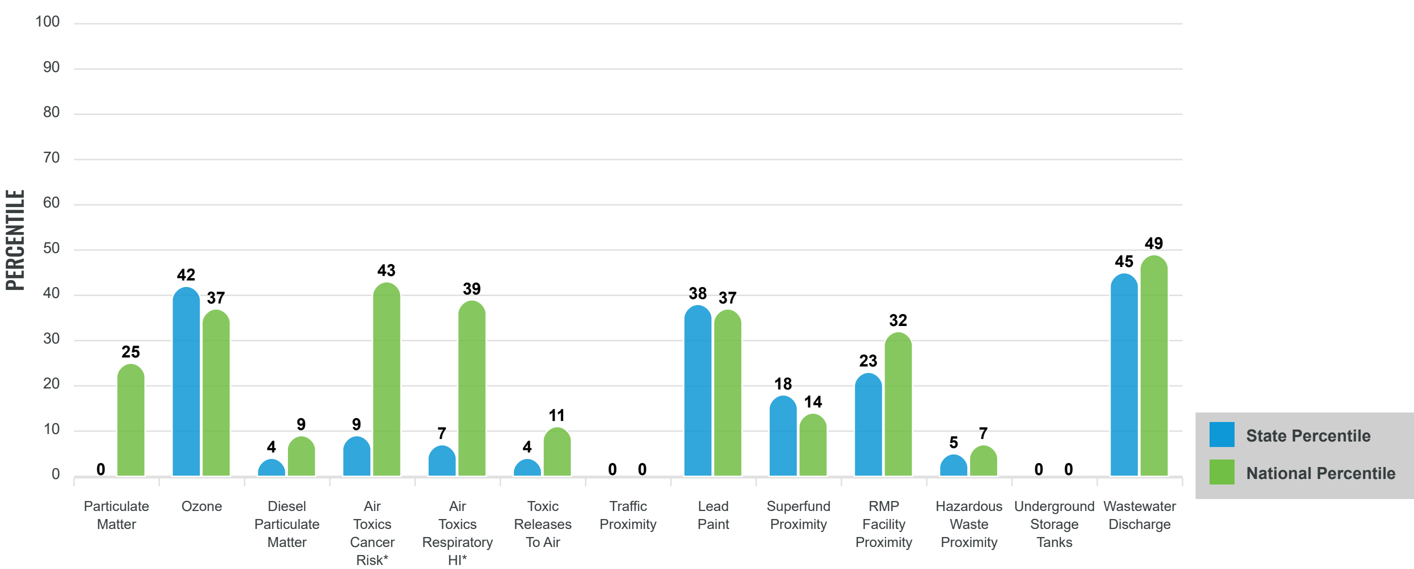
Environmental Justice & Supplemental Indexes

The environmental justice and supplemental indexes are a combination of environmental and socioeconomic information. There are thirteen EJ indexes and supplemental indexes in EJScreen reflecting the 13 environmental indicators. The indexes for a selected area are compared to those for all other locations in the state or nation. For more information and calculation details on the EJ and supplemental indexes, please visit the EJScreen website.

EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.

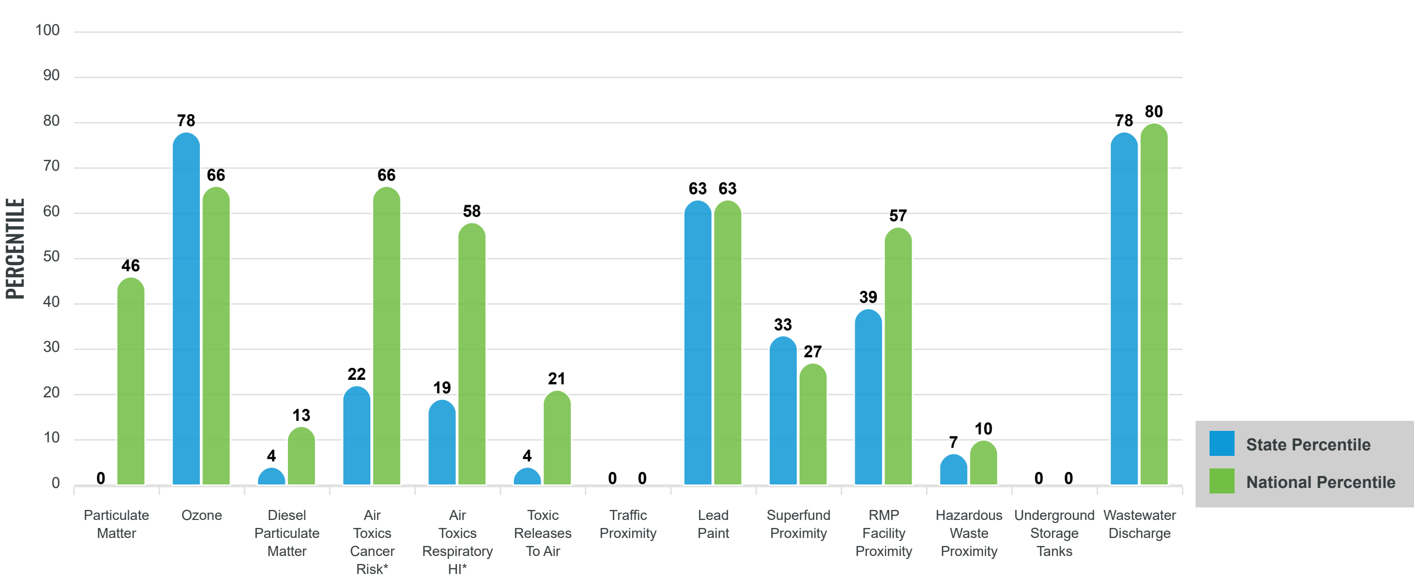
EJ INDEXES FOR THE SELECTED LOCATION



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental indicator.

SUPPLEMENTAL INDEXES FOR THE SELECTED LOCATION



These percentiles provide perspective on how the selected block group or buffer area compares to the entire state or nation.

Report for Blockgroup: 221139511001

www.epa.gov/ejscreen

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
POLLUTION AND SOURCES					
Particulate Matter (µg/m^3)	7.52	8.62	1	8.08	32
Ozone (ppb)	61.2	59.8	82	61.6	50
Diesel Particulate Matter (µg/m^3)	0.078	0.247	4	0.261	9
Air Toxics Cancer Risk* (lifetime risk per million)	30	40	2	28	35
Air Toxics Respiratory HI*	0.3	0.38	1	0.31	31
Toxic Releases to Air	31	15,000	4	4,600	14
Traffic Proximity (daily traffic count/distance to road)	0.034	86	0	210	0
Lead Paint (% Pre-1960 Housing)	0.24	0.22	67	0.3	52
Superfund Proximity (site count/km distance)	0.02	0.076	30	0.13	18
RMP Facility Proximity (facility count/km distance)	0.14	0.62	32	0.43	42
Hazardous Waste Proximity (facility count/km distance)	0.043	1.1	7	1.9	7
Underground Storage Tanks (count/km^2)	0.0023	2.2	0	3.9	0
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.05	49	85	22	78
SOCIOECONOMIC INDICATORS					
Demographic Index	15%	41%	14	35%	21
Supplemental Demographic Index	15%	17%	44	14%	63
People of Color	0%	43%	0	39%	0
Low Income	30%	40%	38	31%	55
Unemployment Rate	0%	7%	0	6%	0
Limited English Speaking Households	3%	2%	83	5%	68
Less Than High School Education	24%	15%	79	12%	85
Under Age 5	2%	6%	26	6%	20
Over Age 64	20%	17%	68	17%	66
Low Life Expectancy	20%	22%	29	20%	60

*Diesel particulate matter, air toxics cancer risk, and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

Sites reporting to EPA within defined area:

Superfund 0
Hazardous Waste, Treatment, Storage, and Disposal Facilities 0
Water Dischargers 40
Air Pollution 6
Brownfields 0
Toxic Release Inventory 1

Other community features within defined area:

Schools 2
Hospitals 0
Places of Worship 2

Other environmental data:

Air Non-attainment .... No
Impaired Waters .... Yes

Selected location contains American Indian Reservation Lands* .... No
Selected location contains a "Justice40 (CEJST)" disadvantaged community .... No
Selected location contains an EPA IRA disadvantaged community .... No

Report for Blockgroup: 221139511001

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS

INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	20%	22%	29	20%	60
Heart Disease	8	7	73	6.1	84
Asthma	9.2	9.9	35	10	30
Cancer	6.6	5.9	74	6.1	59
Persons with Disabilities	18.3%	15.9%	69	13.4%	80

CLIMATE INDICATORS

INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	93%	25%	95	12%	98
Wildfire Risk	0%	7%	0	14%	0

CRITICAL SERVICE GAPS

INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	19%	20%	54	14%	71
Lack of Health Insurance	8%	8%	51	9%	57
Housing Burden	No	N/A	N/A	N/A	N/A
Transportation Access	Yes	N/A	N/A	N/A	N/A
Food Desert	Yes	N/A	N/A	N/A	N/A

Footnotes

Report for Blockgroup: 221139511001

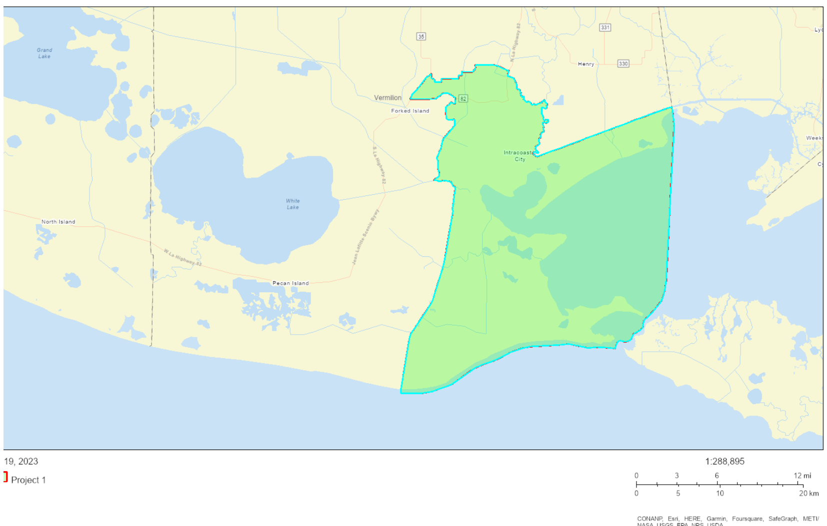
EPA

EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Vermilion Parish, LA

Blockgroup: 221139511002
Population: 976
Area in square miles: 315.79



LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
English	83%
Spanish	6%
French, Haitian, or Cajun	11%
Total Non-English	17%

COMMUNITY INFORMATION

Low income: 54 percent
People of color: 18 percent
Less than high school education: 21 percent
Limited English households: 0 percent
Unemployment: 3 percent
Persons with disabilities: 17 percent
Male: 54 percent
Female: 46 percent
78 years — Average life expectancy
$20,675 — Per capita income
Number of households: 370
Owner occupied: 88 percent

BREAKDOWN BY RACE

White: 89%
Black: 8%
Asian: 0%
Hispanic: 6%
American Indian: 0%
Hawaiian/Pacific Islander: 0%
Other race: 0%
Two or more races: 3%

BREAKDOWN BY AGE

From Ages 1 to 4	9%
From Ages 1 to 18	26%
From Ages 18 and up	74%
From Ages 65 and up	10%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	0%
Speak Other Indo-European Languages	0%
Speak Asian-Pacific Island Languages	0%
Speak Other Languages	0%

Notes: Numbers may not sum to totals due to rounding. Hispanic popultion can be of any race.
Source: U.S. Census Bureau, American Community Survey (ACS) 2017 -2021. Life expectancy data comes from the Centers for Disease Control.

www.epa.gov/ejscreen

Environmental Justice & Supplemental Indexes

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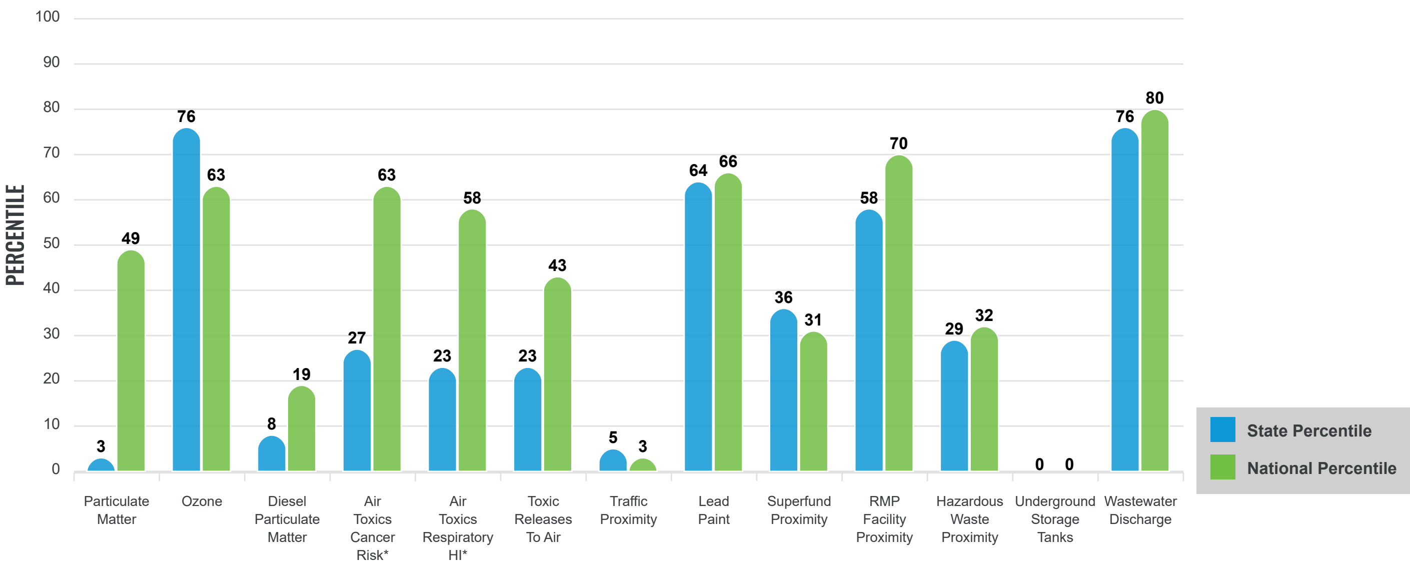
EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.

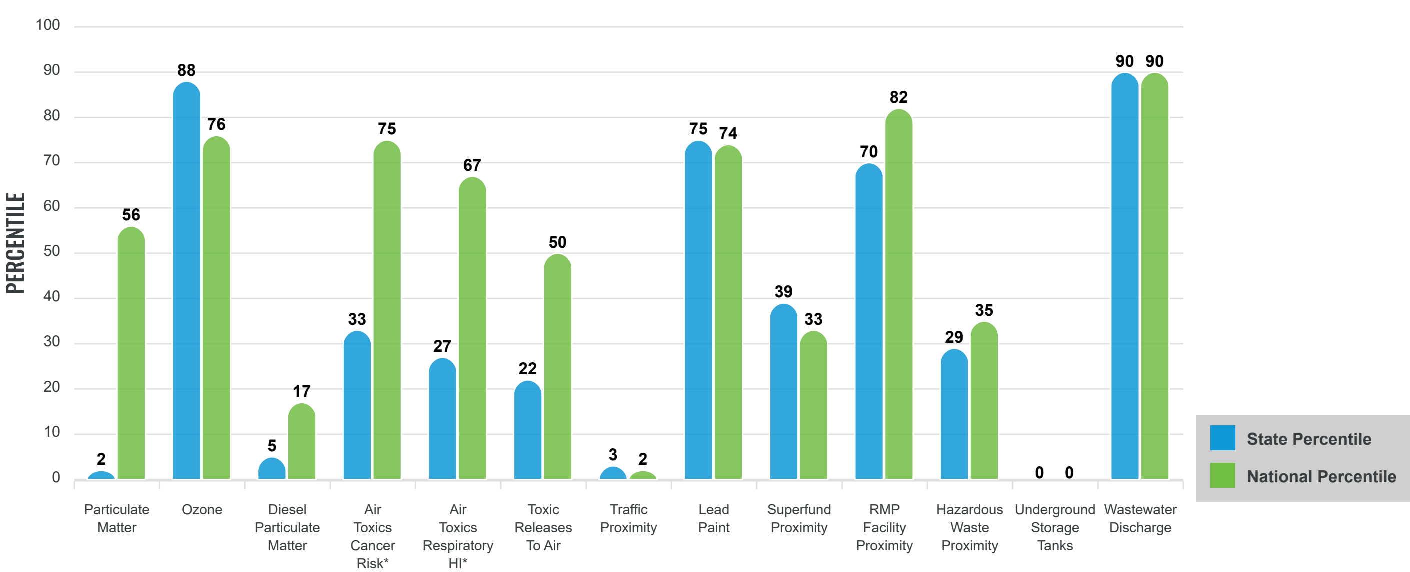
EJ INDEXES FOR THE SELECTED LOCATION



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental indicator.

SUPPLEMENTAL INDEXES FOR THE SELECTED LOCATION



These percentiles provide perspective on how the selected block group or buffer area compares to the entire state or nation.

Report for Blockgroup: 221139511002

www.epa.gov/ejscreen

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
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Ozone (ppb)	61.2	59.8	82	61.6	50
Diesel Particulate Matter ($\mu g/m^3$)	0.078	0.247	4	0.261	9
Air Toxics Cancer Risk* (lifetime risk per million)	30	40	2	28	35
Air Toxics Respiratory HI*	0.3	0.38	1	0.31	31
Toxic Releases to Air	130	15,000	15	4,600	27
Traffic Proximity (daily traffic count/distance to road)	0.41	86	2	210	1
Lead Paint (% Pre-1960 Housing)	0.24	0.22	67	0.3	53
Superfund Proximity (site count/km distance)	0.02	0.076	27	0.13	17
RMP Facility Proximity (facility count/km distance)	0.3	0.62	56	0.43	67
Hazardous Waste Proximity (facility count/km distance)	0.086	1.1	18	1.9	17
Underground Storage Tanks (count/km^2)	0.0016	2.2	0	3.9	0
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.2	49	90	22	85
SOCIOECONOMIC INDICATORS					
Demographic Index	36%	41%	48	35%	60
Supplemental Demographic Index	20%	17%	65	14%	78
People of Color	18%	43%	30	39%	35
Low Income	54%	40%	71	31%	84
Unemployment Rate	3%	7%	47	6%	46
Limited English Speaking Households	0%	2%	0	5%	0
Less Than High School Education	21%	15%	74	12%	83
Under Age 5	9%	6%	77	6%	82
Over Age 64	10%	17%	27	17%	27
Low Life Expectancy	20%	22%	29	20%	60

*Diesel particulate matter, air toxics cancer risk, and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

Sites reporting to EPA within defined area:

Superfund 0
Hazardous Waste, Treatment, Storage, and Disposal Facilities 0
Water Dischargers 88
Air Pollution 11
Brownfields 0
Toxic Release Inventory 3

Other community features within defined area:

Schools 3
Hospitals 0
Places of Worship 2

Other environmental data:

Air Non-attainment .... No
Impaired Waters .... Yes

Selected location contains American Indian Reservation Lands* .... No
Selected location contains a "Justice40 (CEJST)" disadvantaged community .... No
Selected location contains an EPA IRA disadvantaged community .... Yes

Report for Blockgroup: 221139511002

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS

INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	20%	22%	29	20%	60
Heart Disease	8	7	73	6.1	84
Asthma	9.2	9.9	35	10	30
Cancer	6.6	5.9	74	6.1	59
Persons with Disabilities	18.3%	15.9%	69	13.4%	80

CLIMATE INDICATORS

INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	96%	25%	95	12%	98
Wildfire Risk	0%	7%	0	14%	0

CRITICAL SERVICE GAPS

INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	29%	20%	74	14%	88
Lack of Health Insurance	8%	8%	50	9%	56
Housing Burden	No	N/A	N/A	N/A	N/A
Transportation Access	Yes	N/A	N/A	N/A	N/A
Food Desert	Yes	N/A	N/A	N/A	N/A

Footnotes

Report for Blockgroup: 221139511002

EJScreen Report (Version 2.11)

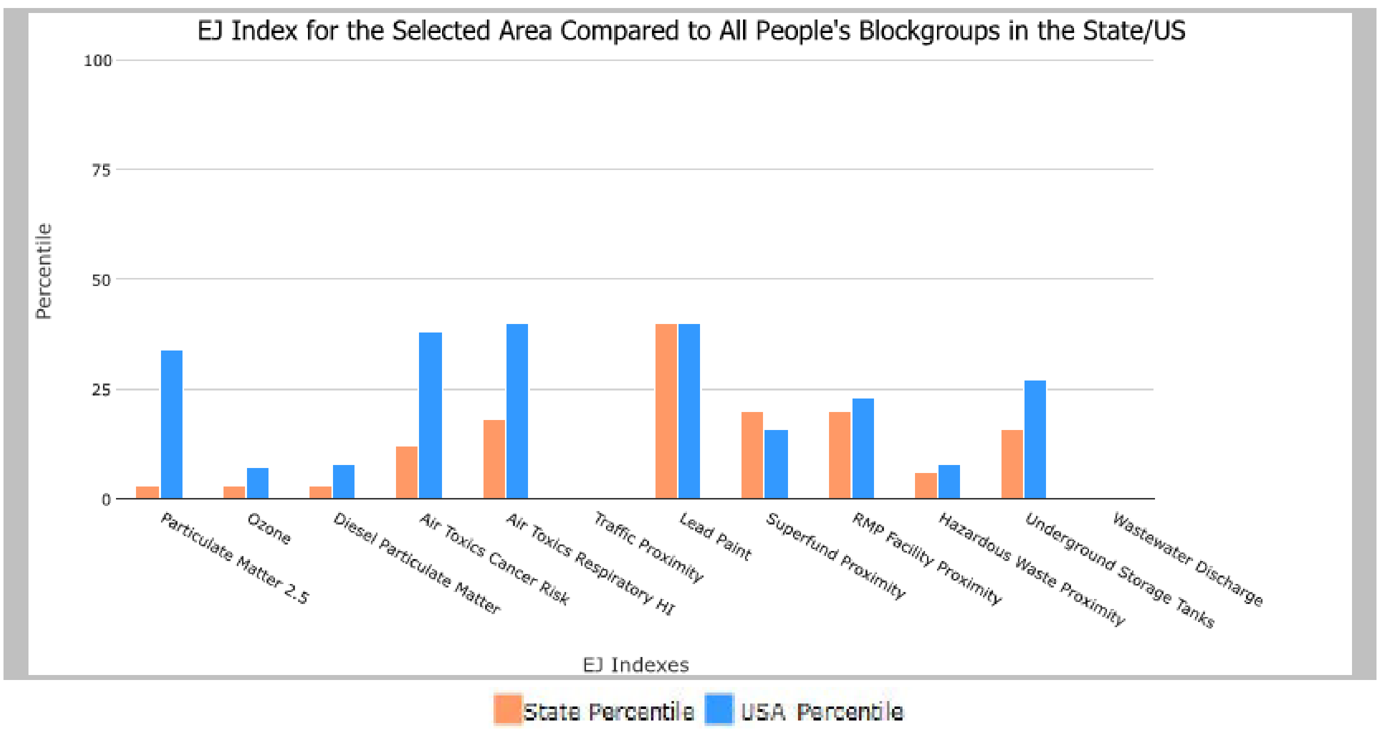
Blockgroup: 221139511001, LOUISIANA, EPA Region 6

Approximate Population: 413

Input Area (sq. miles): 482.70

Selected Variables	State Percentile	USA Percentile
Environmental Justice Indexes		
Particulate Matter 2.5 EJ index	3	34
Ozone EJ index	3	7
Diesel Particulate Matter EJ index*	3	8
Air Toxics Cancer Risk EJ index*	12	38
Air Toxics Respiratory HI EJ index*	18	40
Traffic Proximity EJ index	N/A	N/A
Lead Paint EJ index	40	40
Superfund Proximity EJ index	20	16
RMP Facility Proximity EJ index	20	23
Hazardous Waste Proximity EJ index	6	8
Underground Storage Tanks EJ index	16	27
Wastewater Discharge EJ index	N/A	N/A

EJ Indexes - The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.



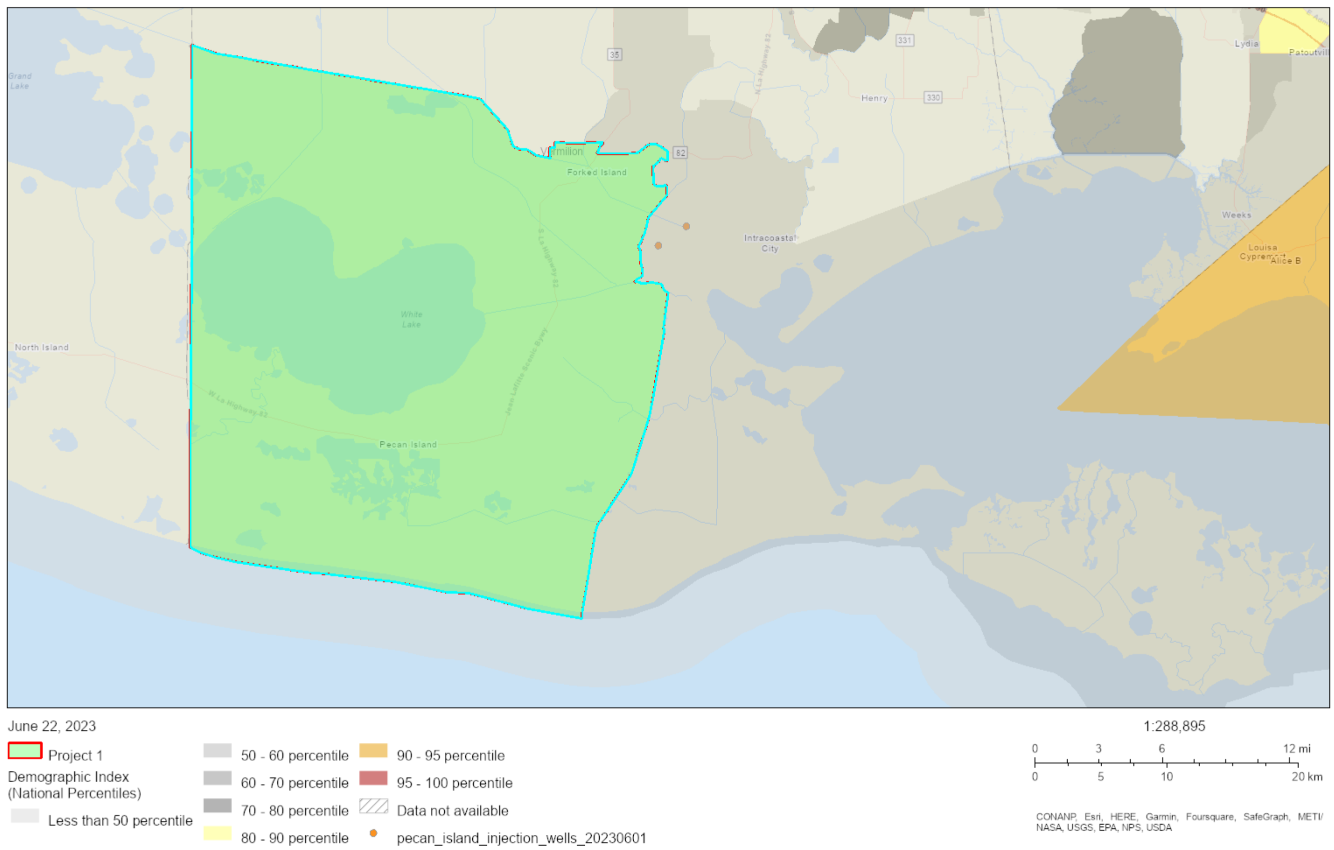
*Diesel particular matter, air toxics cancer risk, and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

EJScreen Report (Version 2.11)

Blockgroup: 221139511001, LOUISIANA, EPA Region 6

Approximate Population: 413

Input Area (sq. miles): 482.70



Sites reporting to EPA	
Superfund NPL	0
Hazardous Waste Treatment, Storage, and Disposal Facilities (TSDF)	0

EJScreen Report (Version 2.11)

Blockgroup: 221139511001, LOUISIANA, EPA Region 6

Approximate Population: 413

Input Area (sq. miles): 482.70

Selected Variables	Value	State Avg.	%ile in State	USA Avg.	%ile in USA
Pollution and Sources					
Particulate Matter 2.5 ($\mu g/m^3$)	8.38	9.2	3	8.67	44
Ozone (ppb)	34	37	3	42.5	8
Diesel Particulate Matter* ($\mu g/m^3$)	0.0791	0.297	3	0.294	<50th
Air Toxics Cancer Risk* (lifetime risk per million)	30	40	52	28	80-90th
Air Toxics Respiratory HI*	0.4	0.45	62	0.36	80-90th
Traffic Proximity (daily traffic count/distance to road)	N/A	640	N/A	760	N/A
Lead Paint (% Pre-1960 Housing)	0.27	0.2	70	0.27	55
Superfund Proximity (site count/km distance)	0.02	0.076	30	0.13	19
RMP Facility Proximity (facility count/km distance)	0.14	0.96	26	0.77	25
Hazardous Waste Proximity (facility count/km distance)	0.047	1.4	7	2.2	8
Underground Storage Tanks (count/km^2)	0.0023	2.2	0	3.9	0
Wastewater Discharge (toxicity-weighted concentration/m distance)	N/A	0.37	N/A	12	N/A
Socioeconomic Indicators					
Demographic Index	16%	41%	16	35%	23
Supplemental Demographic Index	13%	17%	32	15%	49
People of Color	13%	42%	25	40%	29
Low Income	18%	38%	21	30%	33
Unemployment Rate	0%	7%	0	5%	0
Limited English Speaking Households	4%	2%	86	5%	72
Less Than High School Education	21%	14%	72	12%	81
Under Age 5	9%	7%	74	6%	80
Over Age 64	22%	15%	76	16%	74
Low Life Expectancy	20%	22%	29	20%	60

EJScreen Report (Version 2.11)

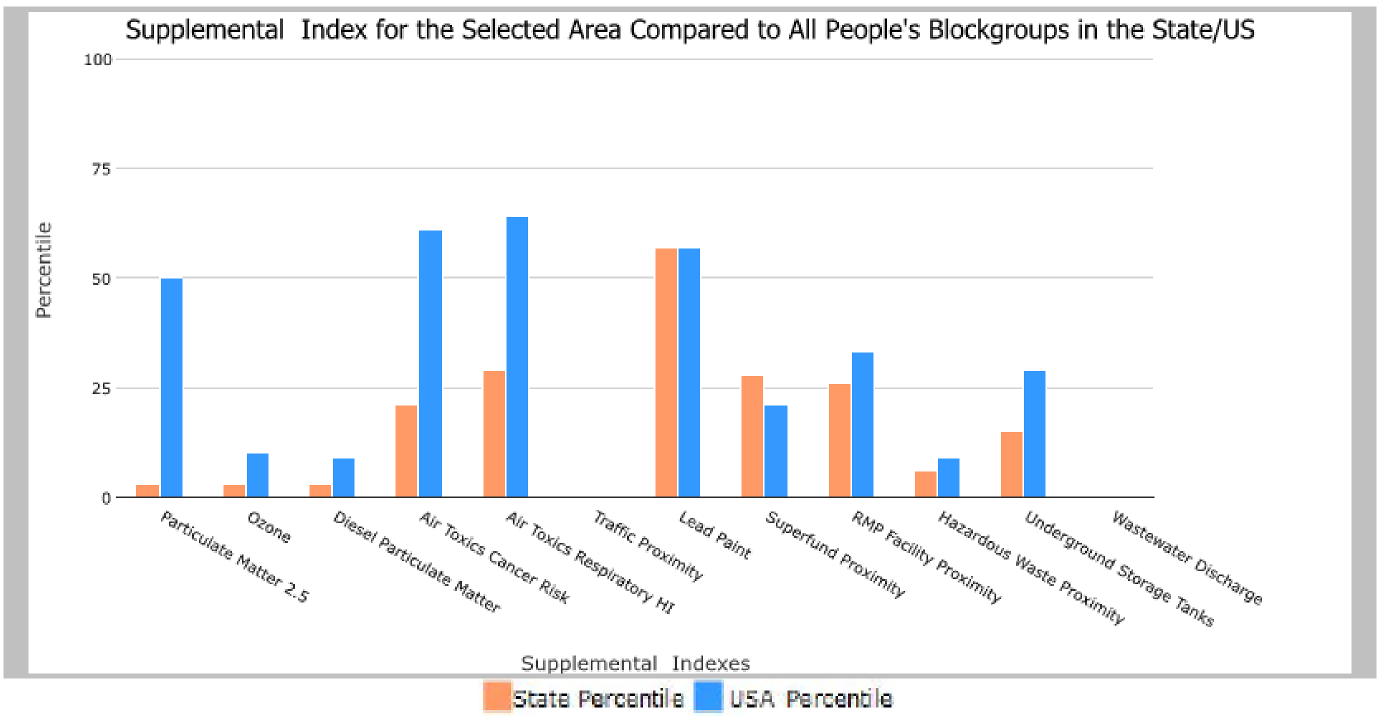
Blockgroup: 221139511001, LOUISIANA, EPA Region 6

Approximate Population: 413

Input Area (sq. miles): 482.70

Selected Variables	State Percentile	USA Percentile
Supplemental Indexes		
Particulate Matter 2.5 Supplemental Index	3	50
Ozone Supplemental Index	3	10
Diesel Particulate Matter Supplemental Index*	3	9
Air Toxics Cancer Risk Supplemental Index*	21	61
Air Toxics Respiratory HI Supplemental Index*	29	64
Traffic Proximity Supplemental Index	N/A	N/A
Lead Paint Supplemental Index	57	57
Superfund Proximity Supplemental Index	28	21
RMP Facility Proximity Supplemental Index	26	33
Hazardous Waste Proximity Supplemental Index	6	9
Underground Storage Tanks Supplemental Index	15	29
Wastewater Discharge Supplemental Index	N/A	N/A

Supplemental Indexes - The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on low-income, limited English speaking, less than high school education, unemployed, and low life expectancy populations with a single environmental indicator.



This report shows the values for environmental and demographic indicators, EJScreen indexes, and supplemental indexes. It shows environmental and demographic raw data (e.g., the estimated concentration of ozone in the air), and also shows what percentile each raw data value represents. These percentiles provide perspective on how the selected block group or buffer area compares to the entire state, EPA region, or nation. For example, if a given location is at the 95th percentile nationwide, this means that only 5 percent of the US population has a higher block group value than the average person in the location being analyzed. The years for which the data are available, and the methods used, vary across these indicators. Important caveats and uncertainties apply to this screening-level information, so it is essential to understand the limitations on appropriate interpretations and applications of these indicators. Please see EJScreen documentation for discussion of these issues before using reports. For additional information, see: www.epa.gov/environmentaljustice.

EJScreen Report (Version 2.11)

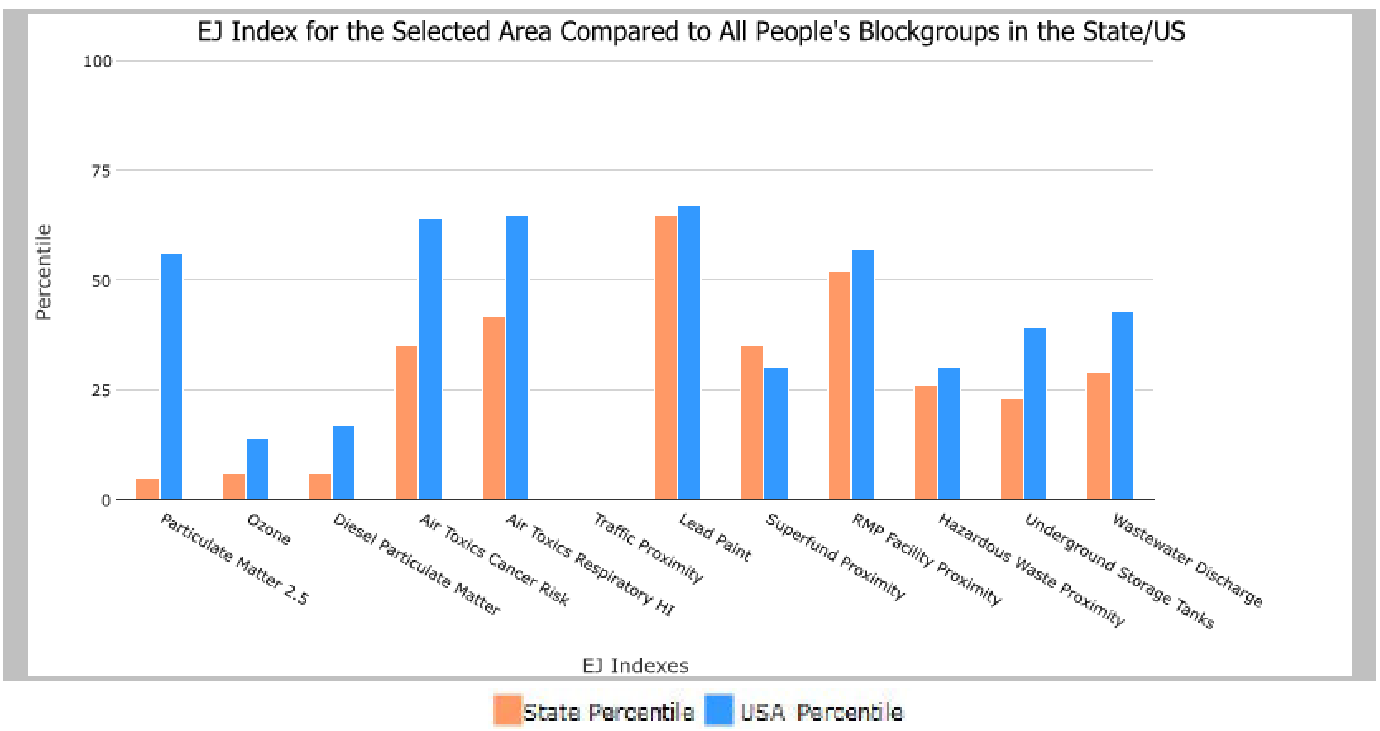
Blockgroup: 221139511002, LOUISIANA, EPA Region 6

Approximate Population: 1,017

Input Area (sq. miles): 315.79

Selected Variables	State Percentile	USA Percentile
Environmental Justice Indexes		
Particulate Matter 2.5 EJ index	5	56
Ozone EJ index	6	14
Diesel Particulate Matter EJ index*	6	17
Air Toxics Cancer Risk EJ index*	35	64
Air Toxics Respiratory HI EJ index*	42	65
Traffic Proximity EJ index	N/A	N/A
Lead Paint EJ index	65	67
Superfund Proximity EJ index	35	30
RMP Facility Proximity EJ index	52	57
Hazardous Waste Proximity EJ index	26	30
Underground Storage Tanks EJ index	23	39
Wastewater Discharge EJ index	29	43

EJ Indexes - The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.



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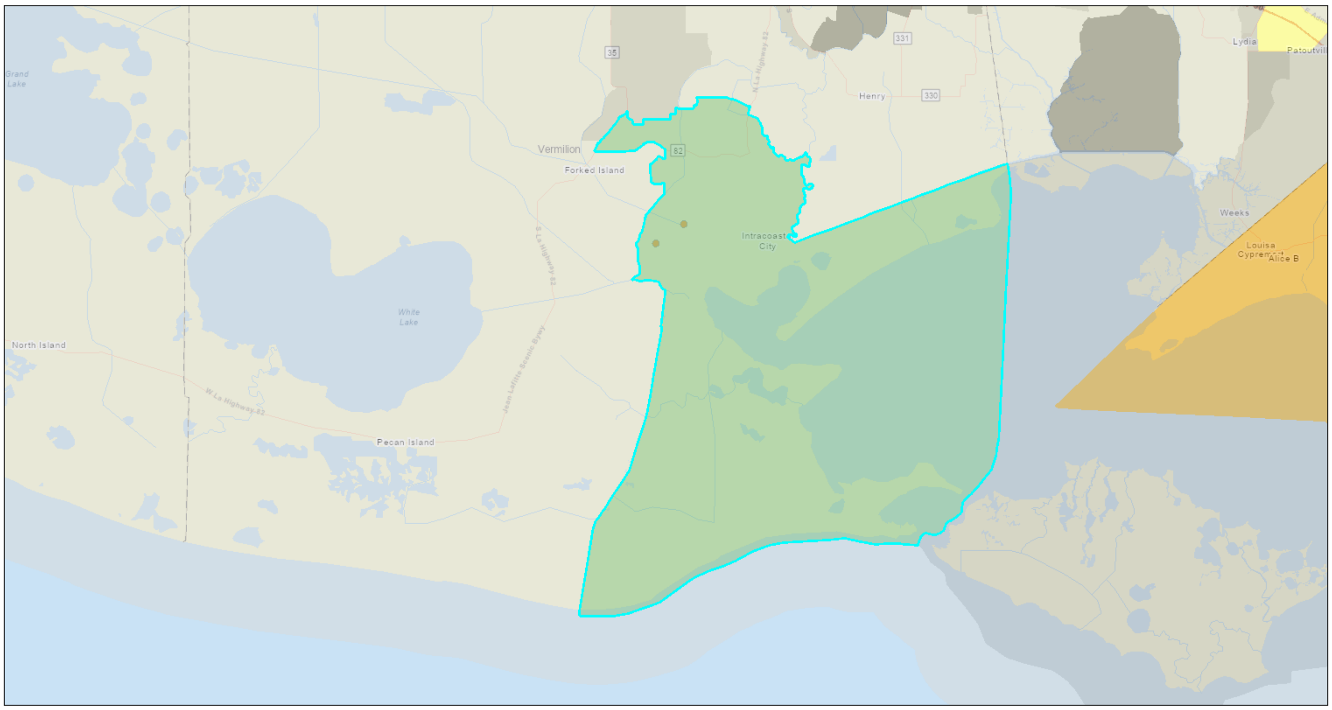
EJScreen Report (Version 2.11)

Blockgroup: 221139511002, LOUISIANA, EPA Region 6

Approximate Population: 1,017

Input Area (sq. miles): 315.79



June 22, 2023

1:288,895

Demographic Index (National Percentiles)

- Less than 50 percentile
- 50 - 60 percentile
- 60 - 70 percentile
- 70 - 80 percentile
- 80 - 90 percentile
- 90 - 95 percentile
- 95 - 100 percentile
- Data not available
- Project 1
- pecan_island_injection_wells_20230601

0 3 6 12 mi
0 5 10 20 km

CONANP, Esri, HERE, Garmin, Foursquare, SafeGraph, METI/NASA, USGS, EPA, NPS, USDA

Sites reporting to EPA	
Superfund NPL	0
Hazardous Waste Treatment, Storage, and Disposal Facilities (TSDF)	0

EJScreen Report (Version 2.11)

Blockgroup: 221139511002, LOUISIANA, EPA Region 6

Approximate Population: 1,017

Input Area (sq. miles): 315.79

Selected Variables	Value	State Avg.	%ile in State	USA Avg.	%ile in USA
Pollution and Sources					
Particulate Matter 2.5 (µg/m^3)	8.38	9.2	3	8.67	44
Ozone (ppb)	34	37	3	42.5	8
Diesel Particulate Matter* (µg/m^3)	0.0791	0.297	3	0.294	<50th
Air Toxics Cancer Risk* (lifetime risk per million)	30	40	52	28	80-90th
Air Toxics Respiratory HI*	0.4	0.45	62	0.36	80-90th
Traffic Proximity (daily traffic count/distance to road)	N/A	640	N/A	760	N/A
Lead Paint (% Pre-1960 Housing)	0.32	0.2	74	0.27	59
Superfund Proximity (site count/km distance)	0.02	0.076	28	0.13	17
RMP Facility Proximity (facility count/km distance)	0.3	0.96	46	0.77	48
Hazardous Waste Proximity (facility count/km distance)	0.087	1.4	17	2.2	16
Underground Storage Tanks (count/km^2)	0.0016	2.2	0	3.9	0
Wastewater Discharge (toxicity-weighted concentration/m distance)	7.3E-05	0.37	22	12	29
Socioeconomic Indicators					
Demographic Index	33%	41%	45	35%	56
Supplemental Demographic Index	21%	17%	70	15%	81
People of Color	16%	42%	29	40%	33
Low Income	51%	38%	67	30%	81
Unemployment Rate	5%	7%	54	5%	57
Limited English Speaking Households	0%	2%	0	5%	0
Less Than High School Education	29%	14%	86	12%	90
Under Age 5	10%	7%	80	6%	86
Over Age 64	6%	15%	17	16%	14
Low Life Expectancy	20%	22%	29	20%	60

EJScreen Report (Version 2.11)

Blockgroup: 221139511002, LOUISIANA, EPA Region 6

Approximate Population: 1,017

Input Area (sq. miles): 315.79

Selected Variables	State Percentile	USA Percentile
Supplemental Indexes		
Particulate Matter 2.5 Supplemental Index	5	71
Ozone Supplemental Index	4	16
Diesel Particulate Matter Supplemental Index*	4	16
Air Toxics Cancer Risk Supplemental Index*	53	83
Air Toxics Respiratory HI Supplemental Index*	61	85
Traffic Proximity Supplemental Index	N/A	N/A
Lead Paint Supplemental Index	81	80
Superfund Proximity Supplemental Index	41	35
RMP Facility Proximity Supplemental Index	63	72
Hazardous Waste Proximity Supplemental Index	29	35
Underground Storage Tanks Supplemental Index	22	43
Wastewater Discharge Supplemental Index	34	53

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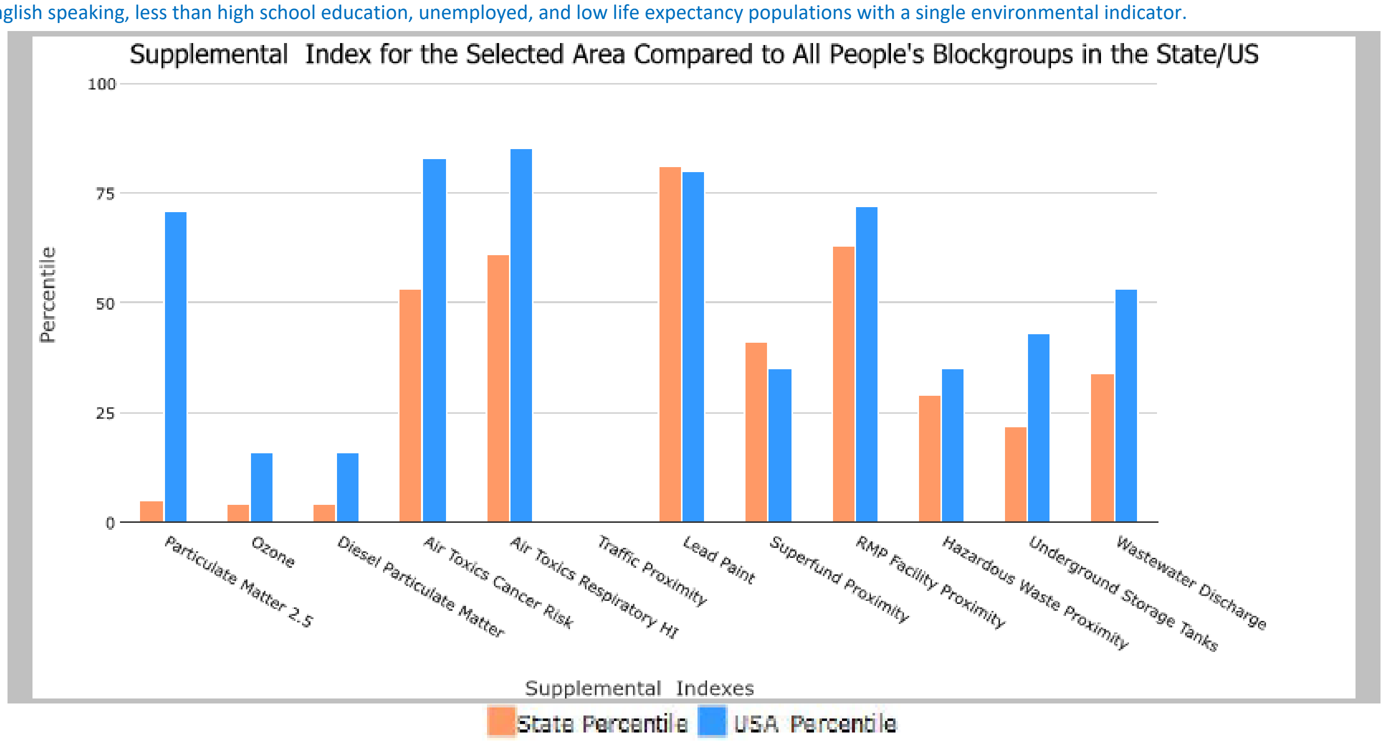

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APPENDIX L: REFERENCES