Underground Injection Control – Class VI Permit Application
for
WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

Prepared for
Harvest Bend CCS LLC
Houston, TX

By
Lonquist Sequestration, LLC
Austin, TX

Date of Original Submission: October 25, 2023

FOREWORD

Harvest Bend CCS LLC (Harvest Bend CCS) plans to develop a carbon sequestration facility in Iberville Parish, Louisiana. The White Castle CO_2 Sequestration (White Castle) Project will gather, compress, and pipe concentrated CO_2 from nearby pipelines that are gathering emissions from third-party facilities in the New Orleans/Baton Rouge industrial region. Utilizing the subject WC IW-B Wells No. 001 and No. 002 and other wells that will be part of the project, CO_2 will be permanently sequestered in the Miocene sands formation at the project site where Harvest Bend CCS has secured the pore space rights within approximately 10,000 acres.

The following application will fully characterize the geology of the proposed injection well and White Castle Project location, confirm the ability to permanently and safely store CO_2 within the Miocene sands formation, and detail the engineering design, operating strategy, and safety considerations for the subject well. The application will also discuss the proposed testing and monitoring plan that will ensure well and storage reservoir integrity, protection of freshwater aquifers, and determination of actual carbon front migration compared to reservoir modeling and simulation of the anticipated carbon front extent.

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.

Melissa Sassella

Melissa Sassella
Director Regulatory
Harvest Bend CCS LLC

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: 10/25/2023

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: 10/25/2023

ELECTRONIC VERSION CERTIFICATION

This document is an electronic version of the application titled “Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 and No. 002” dated October 24, 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
µg/L	micrograms per liter
AAPG	American Association of Petroleum Geologists
AOI	area of interest
AOR	area of review
API	American Petroleum Institute
ASCII	American Standard Code for Information Interchange
ASTM	American Society for Testing and Materials
AVO	amplitude-versus-angle
bbl	barrel(s)
bbloe/d	bbls of oil equivalent per day
BCFG	billion cubic feet of gas
BEG	Bureau of Economic Geology
BGL	below ground level
BHIP	bottomhole injection pressure
BHP	bottomhole pressure
BHT	bottomhole temperature
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and sequestration
CDP	common depth point
CEJST	Climate and Economic Justice Screening Tool
CFR	U.S. Code of Federal Regulations
CIBP	cast-iron bridge plug
CMG	Computer Modelling Group
CMT	cement mapping tool

CRC	CO_2-resistant cement
CT	computed tomography
D&A	dry and abandoned
DAS	distributed acoustic sensing
DTS	distributed temperature sensing
DV	diverter valve
EJ	environmental justice
EOR	enhanced oil recovery
EOS	equation of state
EPA	Environmental Protection Agency
ERM	Environmental Resources Management
ERRP	Emergency and Remedial Response Plan
FG	fracture gradient
FOC	fiber optic cable
FSP	fault slip potential
g/cm^3	grams per cubic centimeter
GAU	Groundwater Advisory Unit
GR	gamma ray
HDIL	high-definition induction log
HNBR	hydrogenated nitrile rubber
ICP	inductively coupled plasma
ID	inner diameter
IFT	interfacial tension
IMD	Injection and Mining Division
LAS	Log *American Standard Code for Information Interchange* (ASCII) Standard (italics here for emphasis only, to clarify the compound term)
LDNR	Louisiana Department of Natural Resources
LTI	lost-time injury
Ma	mega annum

mbbloe/mo	million bbls of oil equivalent per month
Mcf	thousand cubic feet
mD	millidarcy
MD	measured depth
mg/l	milligrams per liter
mGal	milligals
Mgal/d	million gallons per day
MIT	mechanical integrity test
MMBO	million barrels of oil
MMI	Modified Mercalli Intensity
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
MT	metric tons
MMT/yr	million metric tons per year
NAD	North American Datum
NCEI	National Centers for Environmental Information
NETL	National Energy Technology Lab
NPDES	National Pollutant Discharge Elimination System
NSHM	National Seismic Hazard Model
OBG	overburden gradient
OD	outer diameter
P&A	plugging and abandonment
PG	pore gradient
PHIE	effective porosity
PHIEST	estimated effective porosity
PHIT	total porosity
PISC	post-injection site care
PNL	pulsed neutron log
ppg	pounds per gallon

ppm	parts per million
P/S	primary and secondary
psi	pounds per square inch
psia	pounds per square inch absolute
PSTM	Pre-Stack Time Migration
P/T	pressure/temperature
QA/QC	quality assurance/quality control
SAU	storage assessment unit
SC	specific conductivity
SCADA	Supervisory Control and Data Acquisition
SHmax	maximum horizontal stress
SHPO	State Historic Preservation Office
sks	sacks
SMCL	Secondary Maximum Contaminant Level
SMU	Southern Methodist University
SONRIS	Strategic Online Natural Resources Information System
SOW	slip-on weld
SP	spontaneous potential
SPE	Society of Petroleum Engineers
SWC	sidewall core
SWO	Statewide Order
TD	total depth
TDS	total dissolved solids
Title 40	U.S. Code of Federal Regulations, Title 40
TVD	true vertical depth
TVDSS	true vertical depth subsea
UCI	upper confining interval
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

USGS	U.S. Geological Survey
VLP	Vertical Lift Performance
VSP	vertical seismic profile
WHP	wellhead pressure
XRD	X-ray diffraction
WMA	Wildlife Management Area
WOTUS	waters of the United States

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REQUIREMENTS MATRIX

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§146.82	**Required Class VI permit information**			
		§ 3605.G	Certification. Any person signing a document under §605.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 §§605, 607, 615, 617, 619, 621, 623, 625, 627, 629, 631, and §633 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 Section;			
§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)
§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 and Additional Permits)
§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 (Project Overview); Table 0-3
§144.31 (e)(2)	Name, mailing address, and location of the facility for which the application is submitted.	§ 3607.B.3-4	the operator's name, address, telephone number, and email address; ownership status, and status as federal, state, private, public, or other entity;	Introduction (Required Administrative 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 (Required Administrative 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.3-5	the name and mailing address of the applicant and the physical address of the sequestration well facility; the operator's name, address, telephone number, and email address; ownership status, and status as federal, state, private, public, or other entity;	Introduction (Required Administrative Information)
§ 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;	Introduction (Required Administrative 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.1-2	Administrative information: all required state application form(s); the nonrefundable application fee(s) as per LAC 43:XIX. Chapter 7 or successor document;	Introduction (Required Administrative Information)
§ 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, Table 0-4
§ 144.31 (e)(6)(i)	Hazardous Waste Management program under RCRA.	§ 3607.B.9.a	the Louisiana Hazardous Waste Management;	Introduction, Table 0-4
§ 144.31 (e)(6)(ii)	UIC program under SDWA.	§ 3607.B.9.b	this or any other underground injection control program;	Introduction, Table 0-4
§ 144.31 (e)(6)(iii)	NPDES program under CWA.	§ 3607.B.9.c	NPDES program under the Clean Water Act;	Introduction, Table 0-4

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HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§ 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, Table 0-4
§ 144.31 (e)(6)(v)	Nonattainment program under the Clean Air Act.	§ 3607.B.9.e	nonattainment program under the Clean Air Act;	Introduction, Table 0-4
§ 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, Table 0-4
§ 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, Table 0-4
§ 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, Table 0-4
§ 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, Table 0-4

Section 1 - Site Characterization & Appendix B

§ 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:	Sec. 1.2, 1.3, & 1.5
§ 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;	Sec. 1.2, 1.3, & 1.5
§ 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).	Sec. 1.3.5
§ 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.	
§ 146.82(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:	
§ 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;	Sec. 1.5
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s)	§3617.A.2.a.vii	lithology of injection and confining zone(s);	Sec. 1.3
§ 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;	Sec. 1.3.5
§ 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	Sec. 1.3.4, 1.3.5, 2.5 & 2.6
§ 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);	Sec. 1.4
§ 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;	Sec. 1.7
§ 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 regions seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Sec. 1.11
§ 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.	Appendix B-1 to B-14
§ 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;			Sec. 1.9, Appendix B-16 to B-20, C-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:	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§ 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:	Sec. 2 and Sec. 3
§ 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;	Sec. 1.3, 1.5, 1.12, 2.5, 2.6, 2.7 & 2.8
§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;	Sec. 1.3, 1.5, 1.12
§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	Appendix B-12; B-13; B-14

Section 2 - Carbon Front Model

§ 146.84(c)(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.	§ 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	Sec. 2.6
§ 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:	Sec. 2, Sec 2.8
§ 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;	Sec. 2.5, 2.6, 2.7, 2.8
§ 146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; an	§ 3615.B.3.a.ii	take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Sec. 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;	Sec. 2.8
§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;	Sec. 2.4
§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;	Sec. 2.4.5
§ 146.82(a)(7)(ii)	Average and maximum injection pressure;	§ 3607.C.2.f.ii	average and maximum injection pressure;	Table 2-12 to 2-13

Section 3 - AOR & Appendix C

§ 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 §615.B C;	Sec. 3.5
		§ 3607.B.12	names and addresses of all property owners within the area of review of the Class VI well or project.	Appendix A-4 and A-5

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 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.	Sec. 3.5
§ 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.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 §615.B 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-1 to C-6
		§ 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.	
		§ 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.	
		§ 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.	
		§ 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.	
		§ 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.	
§ 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 §607.C.1.a i; and	Sec. 8.7
§ 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:	Sec. 3.9 & 3.10
§ 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 §615.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;	Sec. 3.9
§ 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 (Similar language specific to USDW)	a tabulation of all wells within the area of review that penetrate the base of the USDW. Such data must include a description of each wells type, construction, date drilled, location, depth, record of plugging and/or completion, and any other information the commissioner may require;	Sec. 3.9
§ 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 commissioner, the owner or operator shall at a minimum, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that penetrate the confining and injection zone(s). (See §603.H.4) Provide a description of each wells type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the commissioner may require; and	Sec. 3.9
§ 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.	Sec. 3.9
§ 146.84(b)(2)	A description of:	§ 3615.B.2.b	A description of:	
§ 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;	Sec. 3.10

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§ 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 §615.B.2.b.i	Sec. 3.10
§ 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	Sec. 3.10
§ 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:	Sec. 3.4 & 3.5
§ 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.	Sec. 1.8, 3.4
§ 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 §615 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.	Sec. 3.9 & 3.10
§ 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.	Sec. 3.10
§ 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:	
§ 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 §615.B.3 a;	Sec. 3.10
§ 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 §615.B 3;	Sec. 3.10
§ 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 §615.C 1; and	Sec. 3.10
§ 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 Section, 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 §613, as appropriate.	Sec. 3.10
§ 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 §615.C.2 shall be retained for at least 10 years.	Sec. 3.6
§ 146.82(a)(3)(i)	Maps and cross sections of the area of review;	§ 3607.C.1.b.ii	maps and cross-sections to a scale needed to detail the local geology, geologic structure, and hydrology. The maps and cross-sections must extend at least two miles beyond the area of review;	Sec. 3.11 & Appendix C

Section 4 - Construction & Appendix D

§ 146.82(c)(5)	Final injection well construction procedures that meet the requirements of § 146.86;			Section 4, Appendix D
§146.86	**Injection well construction requirements**	§3617	**Well Construction and Completion**	

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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:	Sec. 4
§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;	Sec. 4.2
§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	Sec. 4.2, 4.2.3, 5.4
§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.	Sec. 4.2
§146.86(b)	**Casing and Cementing of Class VI Wells**	§3617.A.2	**Casing and Cementing of Class VI Wells**	.
§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);	Figure 4.1, Appendix D
§146.86(b)(1)(iii)	Hole size	§3617.A.2.a.iii	hole size;	Figure 4.1, Appendix D
§146.86(b)(1)(vi)	Down-hole temperatures	§3617.A.2.a.vi	down-hole temperatures;	Sec. 1.7
§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);	Figure 4.1
§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;	Sec. 1.7, 4.2
§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;	Sec. 4.2
§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.	Figure 4.1
§146.86(c)	Tubing and packer.	§3617.A.4	Tubing and Packer	Figure 4.1
§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.	Sec. 4.2
§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	Sec. 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.	Sec. 4.2
§146.86(b)	**Casing and Cementing of Class VI Wells**	§3617.A.2	**Casing and Cementing of Class VI Wells**	
§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;	Sec. 4.2 & 4.2.4
§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	Sec. 4.2.1
§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.	Sec. 4.2.2.2, Table 4-5 A&B
§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.	Sec. 4.2.1 & 4.2.2.5; Fig. 4-1 & 4-2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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 companys job summary or cementing tickets indicating returns to the surface shall be submitted as part of the pre-operating requirements.	Sec. 4.2.2.4
§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.	Sec. 4.2 & Table 4.15 & 4-16
§146.86(c)(3)(vi)	Size of tubing and casing; and	§3617.A.4.c.vi	size of tubing and casing; and	Sec. 4.2.1; Fig. 4-1 & 4-2
§146.86(c)(3)(vii)	Tubing tensile, burst, and collapse strengths.	§3617.A.4.c.vii	tubing tensile, burst, and collapse strengths.	Table(s) 4-3, 4-4 (A), 4-6 (A), 4-8 (A), 4-10 (A), 4-12
§ 146.82(a)(7)	Proposed operating data for the proposed geologic sequestration site:	§ 3607.C.2.f	proposed operating data:	Sec. 4.2.4
§ 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;	Sec. 4.2.2 & 4.2.4
§ 146.82(a)(7)(ii)	Average and maximum injection pressure;	§ 3607.C.2.f.ii	average and maximum injection pressure;	Sec. 4.2.4
§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:	
§146.86(c)(3)(i)	Depth of setting;	§3617.A.4.c.i	depth of setting;	Fig. 4-1
§146.86(c)(3)(iii)	Maximum proposed injection pressure	§3617.A.4.c.iii	maximum proposed injection pressure;	Sec. 4.2.4; Table 4-18 & 4-19
§146.86(c)(3)(iv)	Maximum proposed annular pressure;	§3617.A.4.c.iv	maximum proposed annular pressure;	Sec. 4.2.4
§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;	Table 4-18 & 4-19
§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 §607.C.2 h, all stimulation programs must be approved by the commissioner as part of the permit application and incorporated into the permit.	Sec. 4.2.4
§ 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 §617 B;	Sec. 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;	
§ 146.82(a)(10)	Proposed procedure to outline steps necessary to conduct injection operation	§ 3607.C.2.i	proposed injection operation procedures;	Sec. 4.2.4
§ 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;	Fig. 4-1, 4-2, 4-8, 4-9, 4-10
§ 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 §617 A;	Sec. 4.2
		§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 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-2 & D-4
		§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 stablized test pressure applied at the surface shall be aminimum of 500 pounds per square inch gauge (psig). The stabalized 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 stabalized test duration.	Appendix D-2 & D-4
		§3617.A.3.a.i	Casing test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix D-2 & D-4

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
		§3617.A.3.b	Casing seat. The casing seat and cement of any intermediate and injection casings shall be hydrostatically pressure tested after drilling ou the casing shoe. At least 10 feet of formation below the respective casing shoes shall be dreilled 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-2 & D-4
		§3617.A.3.b.i	Casing seat test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix D-2 & D-4
§146.87	**Logging, sampling, and testing prior to injection well operation.**	§3617.B	**Logging, Sampling, and Testing Prior to Injection Well Operation**	
§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 §617 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:	Sec. 4.2.3.2, 4.2.3.3 & 4.2.3.4
§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-2 & D-4
§146.87(a)(2)	Before and upon installation of the surface casing:	§3617.B.1.b	before and upon installation of the surface casing:	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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.	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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:	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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.	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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:	
§146.87(a)(4)(i)	A pressure test with liquid or gas;	§3617.B.1.d.i	a pressure test with liquid or gas;	Sec. 5.4.3
§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;	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§146.87(a)(4)(iii)	A temperature or noise log;	§3617.B.1.d.iii	a temperature or noise log;	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§146.87(a)(4)(iv)	A casing inspection log; and	§3617.B.1.d.iv	a casing inspection log.	Sec. 4.2.3.2 & 4.2.3.3; Table 4-15 & 4-16
§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.	
§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.	Sec. 4.2.3.1 & Table 4-14
§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).	Sec. 4.2.3.2
§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):	
§146.87(d)(1)	Fracture pressure;	§3617.B.4.a	fracture pressure;	Sec. 4.2.3.5
§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	Sec. 4.2.3.1
§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).	Sec. 4.2.3.4

REQUIREMENTS MATRIX

HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 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):	
§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.	Sec. 4.4.3.1
§146.88	**Injection well operating requirements**	§3621.A	**Operations**	
§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.	Sec. 4.2.2.7
§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.	Sec. 4.2.2
§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.	Sec. 4.2.2.6 & 4.2.2.7
§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.	Sec. 4.2
§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;	Sec. 4.2, Sec. 4.2.3.4 & Table 4-2

Section 5 - Testing and Monitoring & Appendix F

§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):	Sec. 4.2.3.4, 4.2.3.5, 5.4.1, 5.4.5
§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.	
§146.90	**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 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:	Sec. 5
§146.91	**Reporting requirements.** 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	**Reporting Requirements.** The owner or operator must provide, at a minimum, the following reports to the commissioner, and the USEPA as specified in §629.A 3, for each permitted Class VI well:	
§146.91(a)	Semi-annual reports containing:	§3629.A.1	semi-annual reports containing:	
§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;	Sec. 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;	Sec. 5.2
§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;	Sec. 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 §621 and the response taken;	Sec. 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;	Sec. 5.2
§146.91(a)(6)	Monthly annulus fluid volume added; and	§3629.A.1.a.vi	monthly annulus fluid volume added;	Sec. 5.2

REQUIREMENTS MATRIX

HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§146.91(a)(7)	The results of monitoring prescribed under § 146.90.	§3629.A.1.a.vii	the results of monitoring prescribed under §625; and	Sec. 5.2
§146.91(b)(2)	Any well workover; and,	§3629.A.1.b.ii	any well workover; and	Sec. 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;	Sec. 5.2
§146.91(c)	Report, within 24 hours:	§3629.A.1.c	report, within 24 hours:	Sec. 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;	Sec. 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;	Sec. 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);	Sec. 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	Sec. 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 §625.A.8 for surface air/soil gas monitoring or other monitoring technologies, if required by the commissioner;	Sec. 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 §621.A.9	Sec. 5.2
§146.91(d)(1)	Any planned well workover;			
§146.91(d)(2)	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and			
§146.91(d)(3)	Any other planned test of the injection well conducted by the permittee.			
§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:	
§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 §607 shall be retained throughout the life of the geologic sequestration project and at least 10 years following site closure.	Sec. 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 §625.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.	Sec. 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 §625.A.2 shall be retained at least 10 years after it is collected.	Sec. 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 §633.A.6 shall be retained at least 10 years following site closure.	Sec. 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.	Sec. 5.2
§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 §627.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 §627.A.4 at a frequency established in the testing and monitoring plan;	Sec. 5.4.4
§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;	Sec. 5.4.5
§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	To evaluate the absence of significant leaks, owners or operators must: continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in §621.A.6	Sec. 5.4.3 & 5.4.6
§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;	Sec. 5.4.2
§146.89(a)	A Class VI well has mechanical integrity if:	§3627.A.1	A Class VI well has mechanical integrity if:	
§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	Sec. 5.4.3
§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:	
§146.91(b)(1)	Periodic tests of mechanical integrity;	§3629.A.1.b.i	periodic tests of mechanical integrity;	Sec. 5.2
§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:	
§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	Sec. 5.4.4
§146.89(c)(2)	A temperature or noise log.	§3627.A.3.b	a temperature or noise log.	Sec. 5.4.4

REQUIREMENTS MATRIX

HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 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):	
§146.87(e)(1)	pressure fall-off test; and,	§3617.B.5.a	a pressure fall-off test; and,	Sec. 5.4.5
§146.87(e)(2)	A pump test; or	§3617.B.5.b	a pump test; or	Sec. 5.4.5
§146.87(e)(3)	Injectivity tests.	§3617.B.5.c	injectivity tests.	Sec. 5.4.5
§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 §625 to determine the presence or absence of corrosion in the long-string casing.	Sec. 5.4.7
§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.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.	
§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.	
§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.	
§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 §615.B.3 and to determine compliance with standards under §619;	
§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: surface injection or bottom-hole pressure; flow rate, volume and/or mass, and temperature of the carbon dioxide stream; tubing-casing annulus pressure and annulus fluid volume; and any other data specified by the commissioner.	Sec. 5.2, 5.4.6 & 5.5.5.2
§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 §621.A 5;	Sec. 5.4.6 & 5.5.5.2
§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 §617.A 2, by:	Sec. 5.5.1
§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;	
§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.	Sec. 5.4.4
§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:	Sec. 5.5.2

REQUIREMENTS MATRIX
HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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	Sec. 5.5.2
§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 §607.C.2.e and on any modeling results in the area of review evaluation required by §615.B.3	Sec. 5.5.2
§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:	
§146.90(g)(1)	Direct methods in the injection zone(s); and,	§3625.A.7.a	direct methods in the injection zone(s); and	Sec. 5.5.4.1
§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;	Sec. 5.5.4.2
§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 § 144.12 of this chapter;	§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 §603 D;	
§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 §625.A.8.a and b., and meets the requirements pursuant to §629.A.1 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(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 §625, operational data collected under §621, and the most recent area of review reevaluation performed under §615.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 §613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:	Sec. 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;	Sec. 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	Sec. 5.3
§146.90(j)(3)	When required by the Director.	§3625.A.10.c	when required by the commissioner.	Sec. 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.	Sec. 5.3

Section 6 - Plugging Plan & Appendix H

§146.92	**Injection well plugging**	§3631	**Plugging and Abandonment**	
§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.	Sec. 6.2.2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 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:	Sec 6.3.2 & 6.3.4
§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;	Sec. 6.2.1.2
§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 §627;	Sec. 6.2.1
§146.92(b)(3)	The type and number of plugs to be used;	§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;	Sec. 6.3.1 & Table 6-1
§146.92(b)(4)	The placement of each plug, including the elevation of the top and bottom of each plug;	§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;	Sec. 6.3.2.1, 6.2.1.2
§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.e	the type and number of plugs to be used;	Sec. 6.2.1; Table 6-2, 6-3, 6-4 & 6-5
§146.92(b)(6)	The method of placement of the plugs.	§3631.A.3.f	the placement of each plug, including the elevation of the top and bottom of each plug;	Table 6-2, 6-3, 6-4 & 6-5
§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.	6.2.1.1 and 6.3.1.1
§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:	Sec. 6.3.2 & 6.3.4
§ 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 §631;	Sec. 6.3.2 & 6.3.4

Section 7 - Post Injection Site Care and Closure Plan

§146.93	**Post-injection site care and site closure**	§3633	**Closure and Post-Closure**	
§ 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 §633.A 3;	Sec. 7.5
§ 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 commissioners discretion, a demonstration of an alternative post-injection site care timeframe required by §633.A 3;	
§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 §633.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:	
§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);	Sec. 7.2

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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 §607 and §615, 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.	
§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:	
§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 §615.B and §615 C;	
§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;	
§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;	
§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;	
§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 §633.A.3.a must meet the following criteria:	
§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;	
§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;	
§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;	
§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;	
§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;	
§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.	
§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	
§146.93(c)(2)(viii)	Any additional criteria required by the Director.	§3633.A.3.b.viii	any additional criteria required by the commissioner.	
§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 §615.B.3 a;	Sec. 7.3
§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;	Sec. 7.3.2, 5.5
§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 §629.A 3; and,	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.	Sec. 7.3.1

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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 §613, as appropriate.	Sec. 7.3.1
§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 commissioners approval within 30 days of such change.	Sec. 7.3.1
§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.	Sec. 7.3.2
§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 §633.A 3, unless the owner or operator makes a demonstration under §633.A.2.b The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under §633.A.2.b is submitted and approved by the commissioner.	Table 7-2
§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.	Sec. 7.3.2
§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.	Sec. 7.4
§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 §633.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.	
§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.	Sec. 7.5.1
§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.	Sec. 7.5.2, 6.4 & Appendix H
§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:	Sec. 7.5.4
§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 §631 and §633.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 §629.A 3;	Sec. 7.5.4

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EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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	
§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.	Sec. 7.5.4
§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:	
§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;	Sec. 7.5.4
§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	Sec. 7.5.4
§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.	Sec. 7.5.4
§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.	Sec. 7.5.4

Section 8 - Emergency and Remedial Response Plan

§ 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 §623;	Sec. 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 §623) and the demonstration of financial responsibility (as described by §609.C must account for the area of review delineated as specified in §615.B.3.a or the most recently evaluated area of review delineated under §615.C 2, regardless of whether or not corrective action in the area of review is phased.	Sec. 8.2 & 10.3
§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 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.	Sec. 8.2; Sec. 4.2.2.9
§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:	
§146.88(f)(1)	Immediately cease injection;	§3621.A.7.b.i	immediately cease injection;	Sec. 8.3
§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;	Sec. 8.3
§146.88(f)(3)	Notify the Director within 24 hours	§3621.A.7.b.iii	notify the commissioner within 24 hours;	Sec. 8.3
§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	Sec. 8.3
§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.	Sec. 8.3
§146.94	**Emergency and remedial response**	**§3623**	**Emergency Response**	
§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.	Sec. 8.3

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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:	
§146.94(b)(1)	Immediately cease injection;	§3623.A.2.a	immediately cease injection;	Sec. 8.3.2
§146.94(b)(1)	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;	Sec. 8.3.2
§146.94(b)(1)	Notify the Director within 24 hours; and	§3623.A.2.c	notify the commissioner within 24 hours; and	Sec. 8.3.2
§146.94(b)(1)	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.	Sec. 8.3.2
§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.	Sec. 8.3
§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 §623.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 §613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:	Sec. 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;	Sec. 8.8
§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;	§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	Sec. 8.8
§146.94(d)(3)	When required by the Director.	§3623.A.4.c	when required by the commissioner.	Sec. 8.8

Section 10 - Financial Assurance

	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;	§ 3607.B.11	documentation of financial responsibility or documentation of the method by which proof of financial responsibility will be provided as required in §609.C Before making a final permit decision, final (official) documentation of financial responsibility must be submitted to and approved by the Office of Conservation;	
§ 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 §609 C;	Sec. 10.2
	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	§ 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.	Sec. 10.2
	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.	§ 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.	
§ 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 §623) and the demonstration of financial responsibility (as described by §609.C must account for the area of review delineated as specified in §615.B.3.a or the most recently evaluated area of review delineated under §615.C 2, regardless of whether or not corrective action in the area of review is phased.	Sec. 10.2
§ 146.85	**Financial responsibility**			
§ 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 §609.C.4 The permittee must show evidence of financial responsibility to the commissioner by the submission of:	Sec. 10.2

REQUIREMENTS MATRIX
HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§ 146.85(a)(1)	The financial responsibility instrument(s) used must be from the following list of qualifying instruments: (i) Trust Funds, (ii) Surety Bonds, (iii) Letter of Credit, (iv) Insurance, (v) Self Insurance (i.e., Financial Test and Corporate Guarantee), (vi) Escrow Account, (vii) Any other instrument(s) satisfactory to the Director	§ 3609.C.1.a-e	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; b. a performance bond (surety bond) in sole favor of the Office of Conservation in a form prescribed by the commissioner; c. a letter-of-credit in sole favor of the Office of Conservation in a form prescribed by the commissioner; d. site-specific trust account, or e. any other instrument of financial assurance acceptable to the commissioner.	Sec. 10.2 & 10.8
§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:	
§146.85(a)(2)(i)	Corrective action (that meets the requirements of §146.84);	§3609.C.4.a.i	corrective action of §615 C;	Table 10-1 & 10-2
§146.85(a)(2)(ii)	Injection well plugging (that meets the requirements of §146.92);	§3609.C.4.a.ii	injection well plugging of §631;	Table 10-1 & 10-2
§146.85(a)(2)(iii)	Post injection site care and site closure (that meets the requirements of §146.93); and	§3609.C.4.a.iii	post-injection site care and site closure of §633; and	Table 10-1 & 10-2
§146.85(a)(2)(iv)	Emergency and remedial response (that meets the requirements of §146.94).	§3609.C.4.a.iv	emergency and remedial response of §623	Table 10-1 & 10-2
§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.	Table 10-1 & 10-2
§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.	
§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.	§3609.C.4.c	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:	
§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	§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;	Sec. 10.2
§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;	
§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.	
§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:	
§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;	

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HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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;	Sec. 10.8
§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.	
§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:	
§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.	
§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.			
§146.85(b)(1)	The owner or operator must maintain financial responsibility and resources until:	§3609.C.4.g	Class VI well owners, operators, or applicants shall comply with these additional requirements of financial responsibility.	
§146.85(b)(1)(i)	The Director receives and approves the completed post-injection site care and site closure plan; and	§3609.C.4.g.i	the owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the commissioner, including obtaining financial responsibility for the next phase of the geologic sequestration project, if required; or	Sec. 10.6.1
§146.85(b)(1)(ii)	The Director approves site closure	§3609.C.4.g.ii	the owner or operator has submitted a replacement financial instrument and received written approval from the commissioner accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	Sec. 10.6.2
§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:	Table 10-1 & 10-2; Sec. 10.8
§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;	Sec. 10.2; Table 10-1 & 10-2
§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;	Sec. 10.8

REQUIREMENTS MATRIX

HARVEST BEND CCS LLC - WC IW-B NO. 001 AND NO. 002

EPA 40 CFR	EPA 40 CFR Description	LAC 43:XVII.Chapter 6	LA 43:XVII.Chapter 6 Description	Permit Application
§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 §609.C.4.h ii. above;	Sec. 10.8
§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.	Sec. 10.8
§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:	
§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.	
§146.85(d)(2)	A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.	§3609.C.4.i.ii	An owner or operator who fulfills the financial responsibility requirements by obtaining an approved instrument of financial assurance will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the financial assurance instrument. The owner or operator must establish other financial assurance within 60 days after such an event.	
§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.	Sec. 10.8
§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.	

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

INTRODUCTION

Date of Original Submission: October 25, 2023

SECTION 0 – INTRODUCTION

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Project Overview

Harvest Bend CCS LLC (Harvest Bend CCS), a privately owned Delaware company, is a partnership between Talos Low Carbon Solutions and Storegga Limited to develop, operate, and maintain the subject injection wells, WC IW-B No. 001 and No. 002, and hub project, Harvest Bend CCS. Harvest Bend CCS is located near the New Orleans/Baton Rouge industrial region, where CO_2 emissions are estimated to be approximately 80 million metric tons per year (MMT/yr). Harvest Bend CCS plans to utilize three primary injection-site locations as part of its hub. Of the three, the White Castle CO_2 Sequestration (White Castle) Project site is the northernmost, located about 25 miles south of Baton Rouge and 65 miles west of New Orleans (Figure 0-1; *Appendix A-1*).

Talos Energy is leveraging decades of experience as an upstream operator along the U.S. Gulf Coast to build a portfolio of carbon capture and sequestration (CCS) projects focused on the decarbonization of industrial regions and specific facilities.

Storegga is an independent, UK-based, decarbonization-development business that develops early-stage CCS and hydrogen projects, both in the UK and internationally, to contribute to achieving net-zero targets. With its head office in London, the company also has established presences in the U.S. and Singapore. Storegga is a private company backed by Macquarie Group; GIC; Mitsui & Co., Ltd.; M&G Investments; and Snam.

Storegga brings a deep understanding of both the entire value chain and market-leading subsurface expertise in CO_2 storage. With more than 15 years of experience in finding and developing safe geological stores, Storegga's roots reach back to the inception of CCS in the UK.

At the White Castle Project site, the three CO_2 sequestration wells Harvest Bend CCS is proposing to develop are each capable of storing approximately 1 MMT/yr of supercritical CO_2 [redacted] The drilling of a stratigraphic test well and additional evaluation of subsurface data will allow Harvest Bend CCS to better understand the storage potential of the White Castle Project. Utilization of multiple injection wells provides redundancy to the storage project. These wells will receive carbon emissions from industrial facilities in the region and geologically sequester these greenhouse gases into subsurface reservoir formations at the project site. Ultimately, the White Castle Project will have a significant economic impact on the State of Louisiana and Iberville Parish in particular.

[redacted]

Figure 0-1 – Project Overview Map

The depositional environment along the Gulf of Mexico coastline of the southern United States offers an ideal geologic setting to sequester greenhouse gases. The targeted reservoir formations consist of very porous, unconsolidated sands with high permeabilities that are highly coveted for underground injection operations. At the White Castle Project site, these sand formations, Miocene in age, are interbedded with shales, clays, and mudstones—all of which provide excellent barriers to the upward movement of the injected gases.

The physical properties of the Miocene sands require strategic completion and operating plans to optimize the utilization of available pore space within the subsurface. To that end, the design has been engineered to ensure safe operating conditions and long-term containment of injected gases, while at the same time offering flexibility with injection operations. The subject CO_2 injection wells were designed to meet the requirements of American Petroleum Institute (API) 1171, as well as the regulatory requirements as outlined in Statewide Order (SWO) 29-N-6 **§3621.A.1** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**]. The rurally located project site was selected for its ideal subsurface geology for the sequestration of CO_2, the proximity to the regional emitters, and the availability of contiguous pore space, which result in minimal disturbance to the surrounding ecosystems and communities.

The significant magnitude of this project will generate for the State of Louisiana and Iberville Parish direct increases in local tax revenue, personal earnings, and business activity both during and after the construction of the White Castle Project. In addition to those significant, temporary direct and indirect economic benefits, there will be even greater, long-term environmental and economic benefits during the operating life of this CCS project. The environmental benefits will impact not only the state and local communities but also the global community. The sequestration of 1 MMT/yr of CO_2 per well is estimated to be equivalent to removing 445,060 total gasoline-powered passenger vehicles for one year[1].

White Castle Project Key Attributes

This project is well positioned due to several key attributes:

- It is proximally located to the New Orleans/Baton Rouge industrial region, where CO_2 emissions are estimated to be approximately 80 MMT/yr.
- It is also proximally located to existing third-party pipeline infrastructure slated for conversion to transportation of CO_2 emissions, from regional emitter locations to sites like that of the White Castle Project.
    - Converting existing pipeline infrastructure to the extent possible will minimize the environmental impact.
- It is located in an ideal reservoir for CCS, the Miocene sands formation.
    - Thick, clean sands are bedded with shale and mudstone that will provide a cap and basement to multiple injection intervals. These sands can handle the required rate and total storage requirements to support the White Castle Project.
    - Large, gross thickness of the injection reservoir will provide for a long well life and large volumes of carbon storage.
- Harvest Bend CCS has secured a large, contiguous pore-space rights position from a single landowner. This pore space is ideal for CCS storage.
    - No penetrations exist in the injection interval inside the area of review (AOR).
    - The pore space inside the AOR lacks the concerning regional and local subsurface features prevalent throughout the Gulf Coast depositional environment (i.e., faults, salt diapirs, etc.)

Agreement Discussion

A Carbon Dioxide Sequestration Agreement has been made between [redacted], that secures the pore space beneath the core White Castle Project acreage located in Iberville Parish. The lease agreement provides Harvest Bend CCS pore space rights within approximately 10,000 acres (*Appendix A-4*) and is recorded in [redacted], Clerk of Court's office for Iberville Parish.

[1] "Greenhouse Gas Equivalencies Calculator." *EPA*, Environmental Protection Agency, March 2021, www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

7).

Proposed CO_2 Sequestration System Discussion

The White Castle Project will consist of equipment to gather, compress, and pipe the CO_2 from nearby pipelines that are gathering emissions from regional industrial facilities, to the subject White Castle Injection Well (WC IW-B) No. 001, No. 002, and other wells that will be a part of the project (Figure 0-2). Harvest Bend CCS is in commercial discussions with some of these emitters and midstream providers. Additional details on the source(s) of the CO_2 will be provided once contracts are finalized. The wells and well-monitoring and metering equipment at the well site are fully owned and operated by Harvest Bend CCS.

[redacted]

Figure 0-2 – Project Infrastructure Map

Injection Strategy

The injection strategy for WC IW-B No. 001 and No. 002 is driven by the unique qualities of the Miocene sands formation that will be utilized for sequestration of the CO_2. The Miocene sands is a thick, high porosity, high permeability sand formation with interbedded shales, clays, and mudstones. The strategy will be to start at the deepest portion of the proposed injection interval and inject into discrete sections of the reservoir for a set period of time. At the end of the injection period for that interval, a plug will be set, and a new interval will be perforated. This cycle will be repeated until the top of the injection interval is reached (shown in Figure 0-3, page 7).

In general, across different acreage positions apart of the Harvest Bend CCS hub, Harvest Bend CCS plans to [redacted] Utilizing multiple wellbores [redacted] allows Harvest Bend CCS to operationally add redundancy to its storage projects, to better serve clients and mitigate potential downtime during well intervention events. If the subject well needs to be temporarily shut in, Harvest Bend CCS has the flexibility to temporarily ramp up the injection rate at other White Castle Project injection wells to maintain the same cumulative project storage rate. [redacted] *Appendices A-3* and *A-6* show the surveyed locations of the proposed WC IW-B No. 001 and No. 002, respectively.

The injection strategy across all wellbores currently planned as part of the White Castle Project is shown in Table 0-1. [redacted]

Table 0-1 – White Castle Injection Well Completion Overview

White Castle Injection Duration (years) per Completion Interval				
[redacted]	Completion Interval	WC IW-A No. 001 [redacted]	WC IW-B No. 001 [redacted]	WC IW-B No. 002 [redacted]
[redacted]				

[redacted]

Figure 0-3 – Completion Strategy Diagram

For WC IW-B No. 001, it is anticipated—based on the extensive reservoir modeling—that there will be [redacted] injection intervals, spanning a gross thickness of approximately [redacted] (Table 0-2). For WC IW-B No. 002, it is anticipated that there will be [redacted] injection intervals, spanning a gross thickness of approximately [redacted] (Table 0-3). These discrete injection intervals will have varying injection periods based on the specific geological and reservoir parameters that have been modeled. Over the life of each well, approximately 20 MMT of CO_2 will be sequestered.

Table 0-2 – Injection Interval Summary for WC IW-B No. 001 [redacted]

Well Completion Stage	Injection Duration (years)	Top Perf (TVD ft)	Bottom Perf (TVD ft)	Gross Interval (ft)
[redacted]				

*TVD= true vertical depth

Table 0-3 – Injection Interval Summary for WC IW-B No. 002 [redacted]

Well Completion Stage	Injection Duration (years)	Top Perf (TVD ft)	Bottom Perf (TVD ft)	Gross Interval (ft)
[redacted]				

Injectate Information

WC IW-B Well No. 001 and No. 002 are each designed to inject an average of 1 MMT/yr of supercritical CO_2. The chemical makeup of the injectate stream will strictly follow the composition requirements of the CO_2 pipeline system to which the White Castle Project will be connected, as shown in Table 0-4.

Table 0-4 – Injectate Composition Limits

[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]

*mol = mole
ppmv = parts per million by volume
MMscf = million standard cubic feet

The pipeline specifications (expected injectate composition) were used to drive the geochemical analysis in *Section 1 – Site Characterization*. For carbon front migration modeling purposes, the injectate stream was conservatively assumed to be 100% CO_2. As additional data is gathered on the injectate composition prior to and during injection operations, pertinent models will be updated accordingly.

Surface Facility Details

Appendix A details the locations and property boundaries applicable to the White Castle Project. The appendix consists of the following documents:

- Appendix A-1 Project Overview Map
- Appendix A-2 Project Overview (Aerial) Map
- Appendix A-3 Well Location Plat – WC IW-B No. 001
- Appendix A-4 Pore Space Ownership Map
- Appendix A-5 Pore Space Ownership/Interested Party List
- Appendix A-6 Well Location Plat – WC IW-B No. 002

Site Suitability

In the process of developing the White Castle Project and in compliance with regulations SWO 29-N-6 **§3607.C.1** [40 CFR **§146.82(a)(2)**] and SWO 29-N-6 **§3615.A** [40 CFR **§146.83**)], an evaluation of the proposed site, "Site Suitability," was generated by assessing the following factors:

- The geographic location of the proposed project site
- Site access and environmental impact considerations
- Cultural considerations, including cultural investigations, archeological sites within the corridor, National Register of Historic Places, recorded cemeteries, and recorded historic standing structures
- Tribal lands in the State's Historic Preservation Office (SHPO) online mapping database
- Consideration of the project area relative to existing structures/buildings/facilities, etc.
- Threatened and endangered species research, migratory birds, and Wildlife Management Areas (WMAs)
- Scenic streams and rivers
- Wetland classifications, waters of the United States (WOTUS), and flood zones
- Land cover analysis
- Conservation easements and mitigation banks
- 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
- Artificial penetrations in the project area
- Existing and historical oil and gas production in the project area
- Drinking water in the project area
- Any other site-related issues

Additionally, an environmental justice (EJ) survey was completed to define EJ communities within 1 mile of the White Castle Project area. The EPA's EJScreen tool, U.S. Council of Environmental Quality's Climate and Economic Justice Screening Tool (CEJST), and U.S. Census Bureau data were used to identify and evaluate risk to EJ communities. Environmental justice is covered in detail in *Section 11 – Environmental Justice*.

Injection Well Summary and Operational Overview

This permit application is for two CO_2 injection wells, WC IW-B No. 001 and No. 002. As discussed, the subject injection wells are part of the White Castle Project, which will include at least one additional CO_2 injection well. The wells will be rurally located [redacted] Iberville Parish, Louisiana, as shown in *Appendix A-2*. [redacted]

[redacted] The Miocene sands formation will be utilized, as its thick, high permeability, high porosity sands make it an ideal formation for the sequestration of CO_2. The gross injection interval is bound on top by a shale formation, [redacted]. The [redacted] is approximately [redacted] thick across the areal extent of the project area. Current plans, subject to change, are to utilize WC IW-B No. 001 to inject [redacted] WC IW-B No. 002 will be utilized to inject [redacted] The lower confining interval for the injection wells on [redacted] is defined [redacted] beneath the project area. A detailed overview of the injection reservoirs, upper confining layer, and lower confining layer can be found in *Section 1 – Site Characterization*.

The thick gross injection interval provides for multiple, discrete injection intervals that require a unique operating strategy. The injection wells will be recompleted uphole multiple times (Figure 0-2, page 5) during its injection life, to control the carbon front size. As detailed in *Section 4 – Engineering Design and Operating Strategy* and *Section 6 – Injection Well Plugging Plan*, once an injection interval has been fully developed for CO_2 storage purposes, a CO_2-resistant cement plug will be set to abandon the interval. Then the next uphole injection interval will be perforated and injection restored. This completion strategy allows for pore space utilization for the sequestration of CO_2 to be maximized.

A critical component of any CCS project is monitoring the carbon front growth over the life of the project. The White Castle Project will utilize a state-of-the-art, time-lapse seismic carbon front monitoring strategy. Throughout the project life, carbon front growth will be monitored with time-lapse seismic surveys. [redacted] This methodology allows for detailed tracking of the CO_2 over the whole project area, while minimizing the surface penetrations into the carbon front and minimizing any pathways for sequestered fluids to escape confinement. The proposed monitoring plan also includes a contingency plan if the carbon front does not conform to the expectations of the simulation model. The surveying results and downhole pressure and temperature data will be evaluated, and the reservoir model will be updated in real time to adjust for any actual variances to the modeled prediction. A detailed overview of the monitoring plan is provided in *Section 5 – Testing and Monitoring Plan.*

WC IW-B No. 001 and No. 002 will be operated as required by the Louisiana Department of Natural Resources (LDNR)/EPA in SWO 29-N-6 **§3621.A** [40 CFR **§146.88**], with complete detail of these operating plans discussed in subsequent sections of this application. It is anticipated that WC IW-B No. 001 and No. 002 will each observe an operating life of approximately 20 years, at which time they will be plugged according to SWO 29-N-6 **§3631** [40 CFR **§146.92**] requirements.

Summary

This application will provide the essential supporting details regarding the White Castle Project and will demonstrate why it is an ideal example of a world-class carbon sequestration project. The highlights of the project include:

- Favorable rock properties for carbon sequestration (thick, high porosity, high permeability, and saline-filled)
- No geological hazards within the currently predicted carbon-front boundary per 3D seismic interpretation
- Zero existing artificial penetrations inside the currently predicted AOR (Figure 0-4; *Appendix C-2*)
- Current control [redacted] of the pore space impacted by the carbon front as shown on the Pore Space Ownership Map (*Appendix A-4*)
- No economically recoverable hydrocarbon resources within the gross injection interval of the well
- Commercial scale with the ability to lower the greenhouse gas impact of many products and services provided by emitters in the New Orleans/Baton Rouge industrial region

[redacted]

Figure 0-4 – Map of Oil and Gas Wells in/near AOR (Aerial)

The proposed wells have been designed with safety and the permanent containment of the CO_2 as the top priorities. The remaining sections of the permit application will explain why this project meets or exceeds all the requirements of an LDNR/EPA Class VI CO_2 sequestration well.

Required Administrative Information

General Application Information

Injection Well Information:

Well Name and Number	WC IW-B No. 001
Parish	Iberville Parish
Location	[redacted] Louisiana
Latitude and Longitude	[redacted]
Datum	North American Datum (NAD) 1983
Well Name and Number	WC IW-B No. 002
Parish	Iberville Parish
Location	[redacted] Louisiana
Latitude and Longitude	[redacted]
Datum	NAD 1983

Applicant:

Name	Harvest Bend CCS LLC
Address	333 Clay St., Suite 3300 Houston, TX 77002
Facility Contact	[redacted]
Ownership Status	Limited Liability Company
Entity Status	Private
SIC Code	4953 – Refuse Systems – Non-Hazardous Waste Disposal Sites

This facility is located, not on federal or tribal lands, but on privately owned lands.

Additional Permits

Table 0-5 – Anticipated Permits*

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

[redacted]

[redacted]

LOCAL

[redacted]

**Dates and agency subject to change based on Class VI Primacy updates*

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 1 – SITE CHARACTERIZATION

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 1 – SITE CHARACTERIZATION

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Figures

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1.1 Overview

This site characterization for Harvest Bend CCS LLC's (Harvest Bend CCS) White Castle Injection Well (WC IW)-B Well No. 001 and No. 002 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. This site characterization incorporates analysis from multiple data types, including core, well logs, seismic (3D), academic and professional publications (e.g., regional geologic frameworks), and nearby subsurface analogs.

1.2 Regional Geology

The proposed White Castle CO_2 Sequestration (White Castle) Project site is located in southeastern Louisiana within the Gulf of Mexico basin. The onshore portion of the basin spans 148,049,000 acres and encompasses portions of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia to the state-waters boundary of the United States (Roberts-Ashby, et al., 2012). The location of the White Castle Project is displayed in Figure 1-1 relative to present coastal extents of the basin within the continental United States.

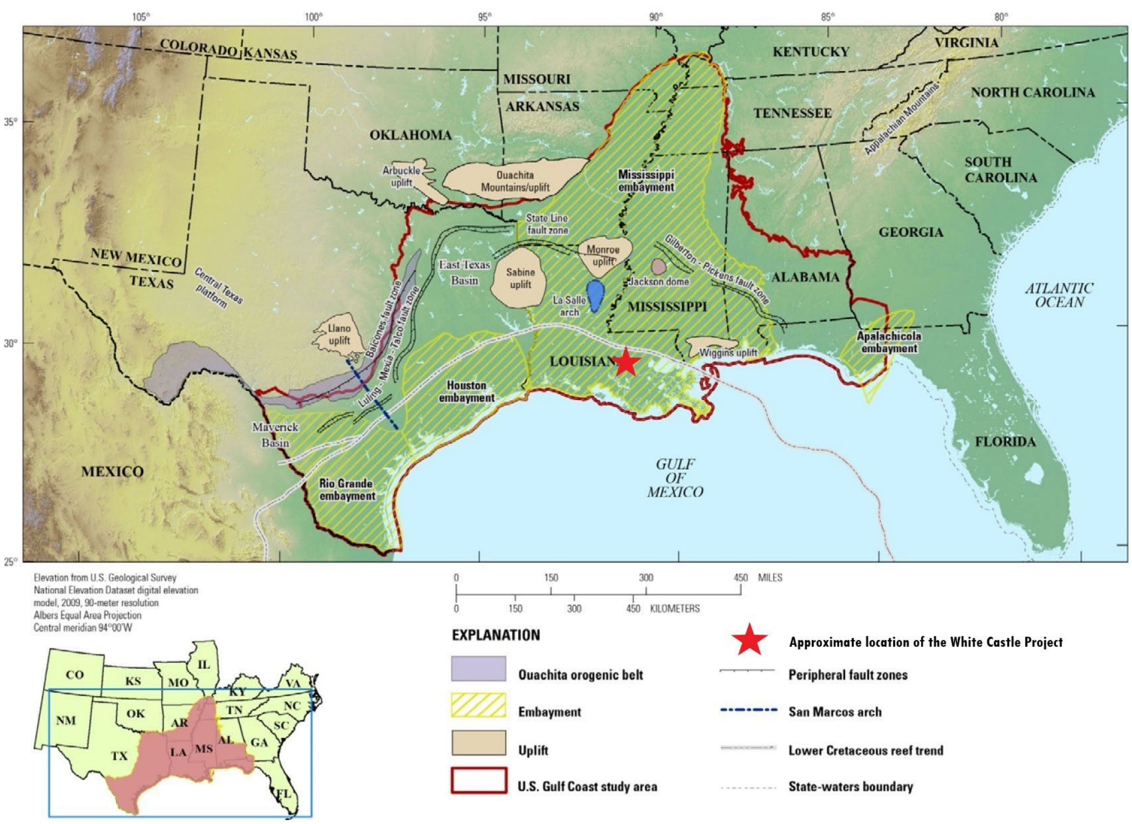


Figure 1-1 – Regional Gulf of Mexico Locator Map (Roberts-Ashby et al., 2012)

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the separation of the North American plate and Yucatan block during the Mesozoic breakup of Pangaea. Rifting initiated during the Middle Jurassic stretched and attenuated the underlying continental crust for approximately 25 million years. The deformation resulted in variable thickness of transitional crusts underlying the basin that contributed to later development of regional arches, embayments, and salt domes in the northern portion of the basin (Galloway W. E., 2008).

As the structural impression of the Gulf of Mexico formed, sediment began to accumulate in the young basin. Initial sedimentation occurred during the Late Triassic to Early Jurassic periods and was characterized by deposition of deltaic sandstones, siltstones, shales, conglomerates, and non-marine red beds of the Eagle Mills formation (Galloway W. E., 2008). During the Middle to Late Jurassic, the Yucatan block continued to drift southward away from the North American plate, resulting in a narrow connection between the Gulf of Mexico and Atlantic Ocean. The shallow hypersaline environment and communication with the Atlantic allowed for widespread deposition of a thick anhydrite and salt sequence, collectively called the Louann Salt (Galloway W. E., 2008). The Louann Salt contains up to 4 kilometers (km) of continuous salt section deposited over sediments of the Eagle Mills formation. Where that formation was absent, deposition occurred directly over pre-Cambrian igneous basement rock (Galloway W. E., 2008). Subsequent fill of the Gulf of Mexico basin resulted in a thick succession of clastics, carbonates, salts, and evaporites deposited in a highly cyclic depositional environment that was subject to sediment supply fluctuations and frequent sea level change (Galloway W. E., 2008; Roberts-Ashby, et al., 2012). These strata are Late Jurassic to Holocene in age, with total sediment accumulation reaching up to 20 km near the basin depocenter in southern Louisiana (Galloway W. E., 2008).

The structural opening of the Gulf of Mexico basin was also accompanied by northwest-to-southeast-trending transfer faults that influenced distribution of the Louann Salt and basin subsidence rates. Basement structures associated with the Ouachita range, Appalachian range, and Llano uplift contributed to Louann Salt placement and affected subsequent sediment distributions. Regional salt tectonics were also influenced by structural flexures such as the Balcones, Luling-Mexia-Talco, State Line, and Pickins-Gilberton fault zones (Galloway W. E., 2008). The current landscape of the Gulf of Mexico basin is primarily influenced by sediment loading and salt mobilization. These processes are typically expressed by structures such as growth faults, allochthonous salt bodies, salt welds, salt-based detachment faults, salt diapirs, and basin-floor compressional fold belts (Galloway W. E., 2008).

The White Castle Project is located in a tectonic salt province [redacted] further detail of the [redacted] production is discussed in *Section 1.9 – Site Evaluation of Mineral Resources*. Radial faulting associated with the offset domes has been evaluated through 3D seismic surveys incorporated into structural mapping and modeling of the White Castle Project.

Figure 1-2(A) identifies the approximate location of the proposed White Castle Project site relative to the north-south seismic line (Peel, Travis, & Hossack, 1995). The present structural setting of the Gulf of Mexico basin, displayed in Figure 1-2(B), has a regional, dip-oriented seismic line conducted near the proposed White Castle site.

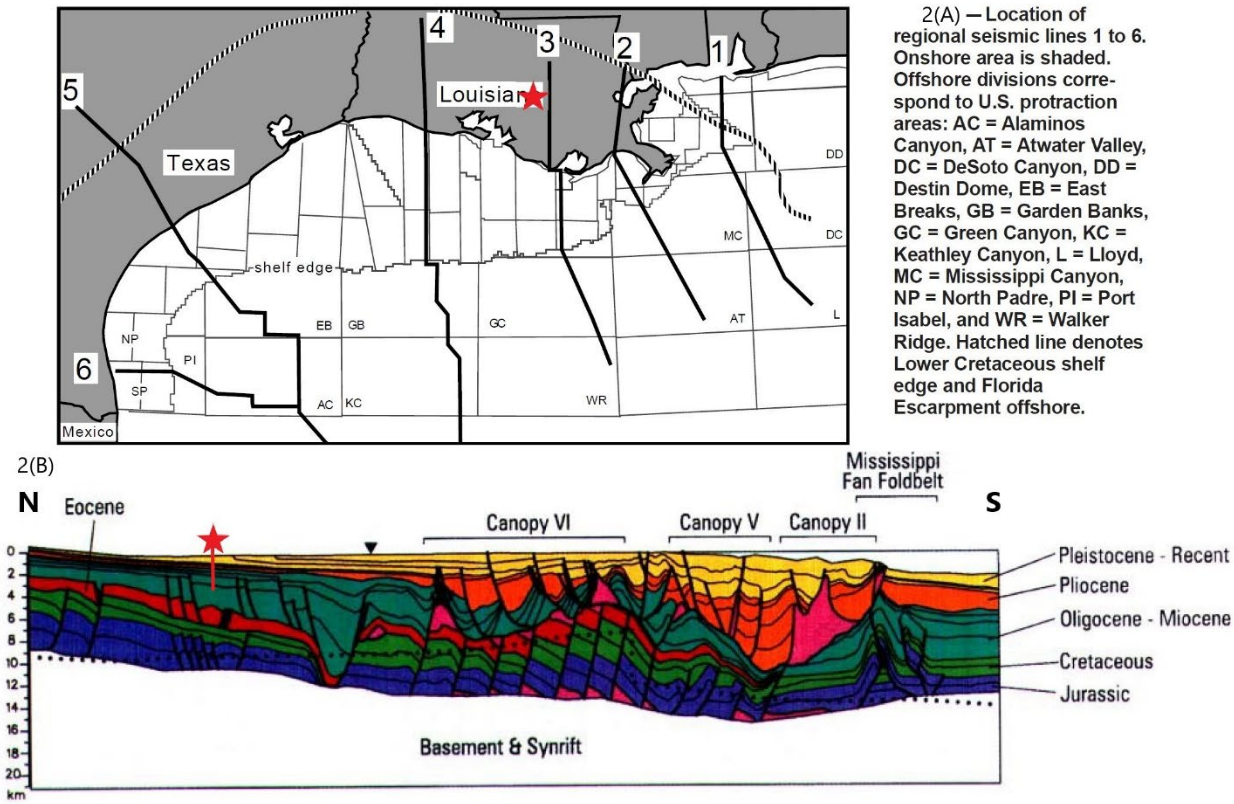


Figure 1-2 – Locator map and regional seismic line 3 (modified from Peel et al., 1995). The red star represents the approximate location of the White Castle Project.

The proposed injection interval of the White Castle sequestration site consists of Miocene sands encased within fine-grained Miocene shales that will provide regional upper and lower confinement to the injection interval (Figure 1-3). Stratigraphically, the proposed gross interval overlies the Lower Miocene depositional episode and underlies the Pliocene Citronelle Group.

Miocene strata of the Louisiana Gulf Coast represent a series of three fluvio-deltaic depositional episodes interrupted by first- and second-order marine transgressions. The section is primarily composed of terrigenous clastic sediments deposited during periods of rapid subsidence and abundant deposition. Sediments associated with regressive cycles represent Miocene reservoirs and are typically expressed in the geologic section by an increased presence of deltaic sands, silts, and clays. Periods of transgressive coastal onlaps are represented by marine transgressive shales that mark the division of Miocene strata into three stratigraphic units: the Lower, Middle, and

Upper Miocene. Index fossils associated with the Miocene section breaks, listed from oldest to youngest, include [redacted] (Hulsey, 2016; Galloway W. E., 2008). These benthic faunal markers are associated with first-order maximum flooding surfaces that correspond to global eustatic highs and are interpreted by the U.S. Geological Survey (USGS) to "serve as fine-grained sealing units" (Roberts-Ashby, et al., 2012).

Figure 1-3 illustrates the regional stratigraphic column as expected to be encountered at the proposed White Castle storage site and highlights the major stratigraphic intervals of this study. In the figure, individual Miocene units are plotted relative to key biostratigraphic markers and a coastal-onlap curve, to provide context to regional transgressive flooding surfaces. The [redacted] biomarker corresponds to the lower confining transgressive sequence, the [redacted] biomarkers correspond to the upper confining transgressive sequence, and the [redacted] biomarker corresponds to the Upper Miocene [redacted] formation. For the purposes of this permit application, the proposed injection interval includes Miocene strata from the Lentic Jeff biostratigraphic marker to the first appearance of the [redacted] biomarker. This gross geologic section contains both shale and sand intervals; however, only clean, sandy intervals with reservoir potential were modeled to sequester CO_2.

[redacted]

Figure 1-3 – Stratigraphic column of Miocene section with detailed coastal-onlap curve and key benthic foraminiferal biomarkers (Treviño & Rhatigan, 2017).

Lower Confining Zone: [redacted]

The Lower Miocene shale is a regionally extensive shale deposited conformably on top of Miocene-aged sediments during a period of second-order marine transgression. Regional mapping performed around the White Castle Project indicates that the shale correlates with the [redacted] index fossil associated with a Lower Miocene maximum flooding surface (Figure 1-3). Maximum flooding surfaces tend to be represented by periods of regional transgression associated with increased seal levels, eustatic highs, and the deposition of regionally extensive fine-grained to silt-sized clay minerals. These shales tend to be fine-grained and function as regional sealing units between episodes of regressive deposition (Roberts-Ashby, et al., 2012).

Injection Zone: *Miocene Sandstones*

Miocene sandstones near the White Castle sequestration site are generally described as fluvial-dominated deltaic deposits, dipping gently to the southeast where they thicken and increase in age basinward (Roberts-Ashby, et al., 2012). Sediments derived primarily from Appalachian and Cumberland Plateau uplands were delivered to southeastern Louisiana via the ancestral Mississippi and Tennessee Rivers. Deposition took place on the continental slope where sediments were subsequently reworked by mass-wasting and shallow marine regression (Galloway, Ganey-Curry, Li, & Buffler, 2000; Hulsey, 2016). Following Oligocene time, sediment influx began to slow along the western portion of the basin and accelerate along the eastern portion. This resulted in minimal Miocene progradation of the south Texas continental shelf, while the Louisiana continental shelf margin accumulated enough sediment to prograde basinward more than 160 km (Galloway, Ganey-Curry, Li, & Buffler, 2000; Roberts-Ashby, et al., 2012). Sandstones contained within the three Miocene stratigraphic units are lithologically similar, described as poorly consolidated to consolidated sandstones sourced from the ancestral Mississippi River. A more detailed stratigraphic review of Gulf Coast Miocene strata can be referenced in Galloway (either 2000 or 2008).

In 2012, the USGS analyzed regional Neogene reservoir porosity and permeability data measured by Nehring Associates, Inc. (2010). The data included 432 petroleum-reservoir-averaged porosity measurements and 259 petroleum-reservoir-averaged permeability measurements, which were leveraged to characterize average porosity and permeability of the Miocene storage assessment unit (SAU). The USGS reported that Miocene sands generally contain an average porosity of approximately 28% (±4%) and an average permeability of approximately 500 millidarcy (mD) (Roberts-Ashby, et al., 2012). The Miocene section is anticipated to be present between 3,000' and 12,000' below surface, near the proposed White Castle sequestration site.

Middle Miocene

Sandstones affiliated with the Middle Miocene 3 mega annum (Ma) depositional episode prograde the continental margin as much as 70 km and are bound between the underlying [redacted] shale and the overlying [redacted] shale (Galloway W. E., 2008). The USGS performed regional mapping that suggests that the gross Middle Miocene section averages 3,200' (±900') with an average net sand thickness of 480' (±140') (Roberts-Ashby, et al., 2012).

Upper Miocene

Sandstones affiliated with the Upper Miocene 6 Ma depositional episode extend across the approximately 40-90 km and are bound between the underlying [redacted] shale and the overlying [redacted] shale (Galloway W. E., 2008). The USGS regional mapping suggests the gross Upper Miocene section averages 5,400' (±1,000') with an average net sand thickness of 1,500' (±400') (Roberts-Ashby, et al., 2012).

Lower Miocene

Sandstones affiliated with the Lower Miocene 8 Ma depositional episode prograde the continental margin 65-80 km and are bound between the underlying Oligocene Anahuac shale and the overlying [redacted] shale (Galloway W. , 2008). Regional mapping performed by the USGS suggest the gross Lower Miocene section averages 3,100 ± 800 feet with an average net sand thickness of 1,150 ± 500 feet (Roberts-Ashby, et al., 2012).

Upper Confining Zone: *Upper Miocene [redacted] Shale*

The Upper Miocene depositional episode was terminated by a regional marine flooding event associated with the first occurrence of benthic foraminifer [redacted], depending on which biostratigraphic marker was present (Galloway, Ganey-Curry, Li, & Buffler, 2000). The [redacted] shale represents a retrogradational package characterized by increased sea levels, eustatic highs, and the deposition of regionally extensive, fine-grained to silt-sized clay minerals. Transgressive shales such as the [redacted] tend to be fine-grained and function as regional sealing units between episodes of regressive deposition (Roberts-Ashby, et al., 2012).

1.3 Site Geology

[redacted]

Upon issuance of the Class VI Order to Construct, data will be gathered during drilling of the proposed well to update the data obtained via research with site-specific information. Table 1-1 (page 13) lists open-hole wireline logs planned during the drilling, with top and base depths designed to provide specific data pertinent to the site characterization application. If necessary, the proposed top and base of each investigative procedure will be subject to minor depth changes during the drilling, to analyze the objective formations. During drilling, coring operations are planned to obtain mineralogic, petrophysical, mechanical, and geochemical data to further refine this site characterization. Anticipated depths to the injection and confining intervals of the proposed well are listed in Table 1-2.

General mineralogy and reservoir characteristics are described regionally first, from pooled studies. If available, offset core and cuttings data from published research will be included. Finally, analyses of offset wellbores are compiled to represent the proposed well site characteristics. Wireline logs, petrophysical analyses, and production data from wellbores adjacent to the proposed well were also studied to calculate anticipated conditions at the site.

Additionally, a stratigraphic test well is planned to be drilled prior to the issuance of the Class VI permit and used to collect the same data mentioned above, which will then be used to update previous models. This well will be strategically placed updip of the proposed injection well, [redacted].

[redacted] The stratigraphic column in Figure 1-5 corresponds to depths in this well. Table 1-3 (page 15) displays the formation tops and depths to the upper confining zone, injection zone, and lower confining zone as logged in the well.

[redacted]

Figure 1-4 – Project Overview Map

[redacted]

Figure 1-5 – Stratigraphic Column from SN [redacted]

Table 1-1 – Planned Geophysical-Wireline Logged Intervals

Geophysical Log Suite	Log Interval Top (ft)	Log Interval Bottom (ft)	Use
[redacted]			

Table 1-2 – Cored Intervals Planned Within Anticipated Formations – WC IW-B No. 002

Approximate Core Depth Intervals [redacted]	Core Type	Number of Cores	Predominate Lithology	Formation/Zone

[redacted]

*TVDSS – true vertical depth subsea
**200’ interval depths approximated in formations where 30’, 60’, or 90’ core barrels may be selected with the aid of near bit gamma ray during drilling.

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

System	Group/ Formation Name	Injection/ Confining Zone	Formation Top – Formation Bottom (ft)	Thickness (ft)
Miocene	[redacted]	Upper Confining	[redacted]	[redacted]
Miocene	[redacted]	Injection Interval	[redacted]	[redacted]
Miocene	[redacted]	Lower Confining	[redacted]	[redacted]

1.3.1 Injection Zone

The injection zone is comprised of the lower Upper Miocene, Middle Miocene, and the Lower Miocene sands, which include maximum flooding surfaces [redacted]. Figure 1-6 (page 18) depicts these maximum flooding surfaces.

Upper Miocene deposition at the White Castle location was dominated by the Mississippi–Tennessee Delta System, which was "alluvial apron, with sediments largely derived from a rejuvenated continental interior, the Nashville Dome, and southern Appalachian uplands" (Wu, 2002). The only Upper Miocene sands included in the injection interval are those in the [redacted] sand, a [redacted] equivalent. The [redacted] sand is bounded below by the maximum flooding surface of the [redacted], which marks the beginning of the Middle Miocene. This section contains blocky sands, which represent an extensive reworking of sediments in a high-energy depositional setting commonly associated with deltas or near-shore zone deposits (Nwagwu, Emujakporue, Ugwu, & Oghonya, 2019).

Middle Miocene is defined by "two widespread transgressive deposits associated with the faunal tops [redacted]" (Combellas-Bigott & Galloway, 2005). The Middle Miocene, similar to the Upper Miocene, received the bulk of the sediments from the Mississippi and Tennessee delta systems, with "salt-related structural provinces controlling the location and configuration of the depocenters" (Combellas-Bigott & Galloway, 2005). Depositional settings within the Middle Miocene are broken down into four different genetic cycles, differentiated by major maximum flooding surfaces. The details of these genetic cycles and associated maximum flooding surfaces are provided in Figure 1-7 (page 19).

Figure 1-8 (page 20) depicts the depositional environment maps for each cycle. Cycle 1 is represented by image A, cycle 2 by image B, cycle 3 by image C, and cycle 4 by image D. The primary depositional environments reflect varying deltaic style. Cycle 1 represents a progradational to aggradational delta-lobe complex; cycle 2 is characterized by minor aggradational to progradational delta-lobe complex; cycle 3 is characterized as delta-flank facies; and cycle 4 reverted back to the progradational to aggradational delta-lobe complex.

The [redacted] is characterized as a regional transgressive marine shale that is the lower bound of the Middle Miocene and upper bound of the Lower Miocene (William E. Galloway, 2000). Bureau of Economic Geology (BEG) studies identified the [redacted] as one of the most "significant" confining zones for CO_2 injection, due to the lateral extensive presence and sealant nature (Treviño & Rhatigan, 2017). Episodes of "sandstone-dominated deltaic and shore-zone progradation" were disrupted by the [redacted] transgression, which occurred towards the end of the "early Miocene and the beginning of the Middle Miocene" (Meckel & Trevino, 2014). The [redacted] intra-reservoir seal allows the total gross injection interval to be divided into upper and lower sections for targeted injection, utilizing an upper and lower injection wellbore, respectively.

During the early Miocene (Lower Miocene), deltaic progradation along the Mississippi delta was restored (William E. Galloway, 2000). The White Castle location falls on the eastern edge of the Mississippi Deltaic axis and is depicted as a fluvial-dominated delta as seen in Figure 1-9 (page 21). Similar to the environments in the Miocene sections above, similar stratigraphic sequences will be encountered throughout the injection interval.

Primary lithologies within the Miocene section are interbedded sandstones, siltstones, and shales with varying clay and calcite concentrations. Meckel and Trevino (2014) performed an analysis of the potential for carbon sequestration within the Miocene along the Gulf Coast. Core samples within the correlative injection zone were characterized as fine- to coarse-grained sandstones with interbedded mudstones and siltstones (Meckel & Trevino, 2014). Figure 1-10 (page 22) is a thin section from this study of fine-grained sandstone within the Miocene, depicting high porosity. This description corresponds with a sample log in an offset well (SN [redacted]) within the injection interval, with descriptions ranging from fine- to coarse-grained gray sandstones, with interbedded siltstones, shales, and clays (Watson, 1965).

Sand packages within the injection interval that contain optimal reservoir qualities will be targeted for injection, with the interbedded shales acting as individual seals within the interval. Further analysis was done on the lateral extents of these individual sands and shales by utilizing offset 3D seismic surveys to develop a geocellular model. The resulting model was implemented into the reservoir simulation to better illustrate sands that could potentially communicate within the injection interval. Further details of the geocellular model will be discussed in *Section 2 – Carbon Front Model*.

An open hole log from an offset well (SN [redacted]) depicting local stratigraphy is displayed in Figure 1-11 (page 23). A shale volume (Vshale) log was calculated from the spontaneous potential (SP) curve to determine the clay content within the section. The Vshale curve is found in track 1 with a shading applied to depict the varying shale content. A deep resistivity curve is plotted in track 2. The injection interval occurs at the top of the [redacted] sand and encompasses all strata down to the [redacted]. The gross thickness of the injection zone depicted in Figure 1-11 is roughly [redacted]. *Appendix B-6* illustrates the gross injection interval isopach map for the area, while *Appendix B-2* represents the top of [redacted] structure map.

[redacted]

Figure 1-6 – Stratigraphic section of Miocene with injection interval indicated (Olariu, DeAngelo, Dunlap, & Treviño, 2019).

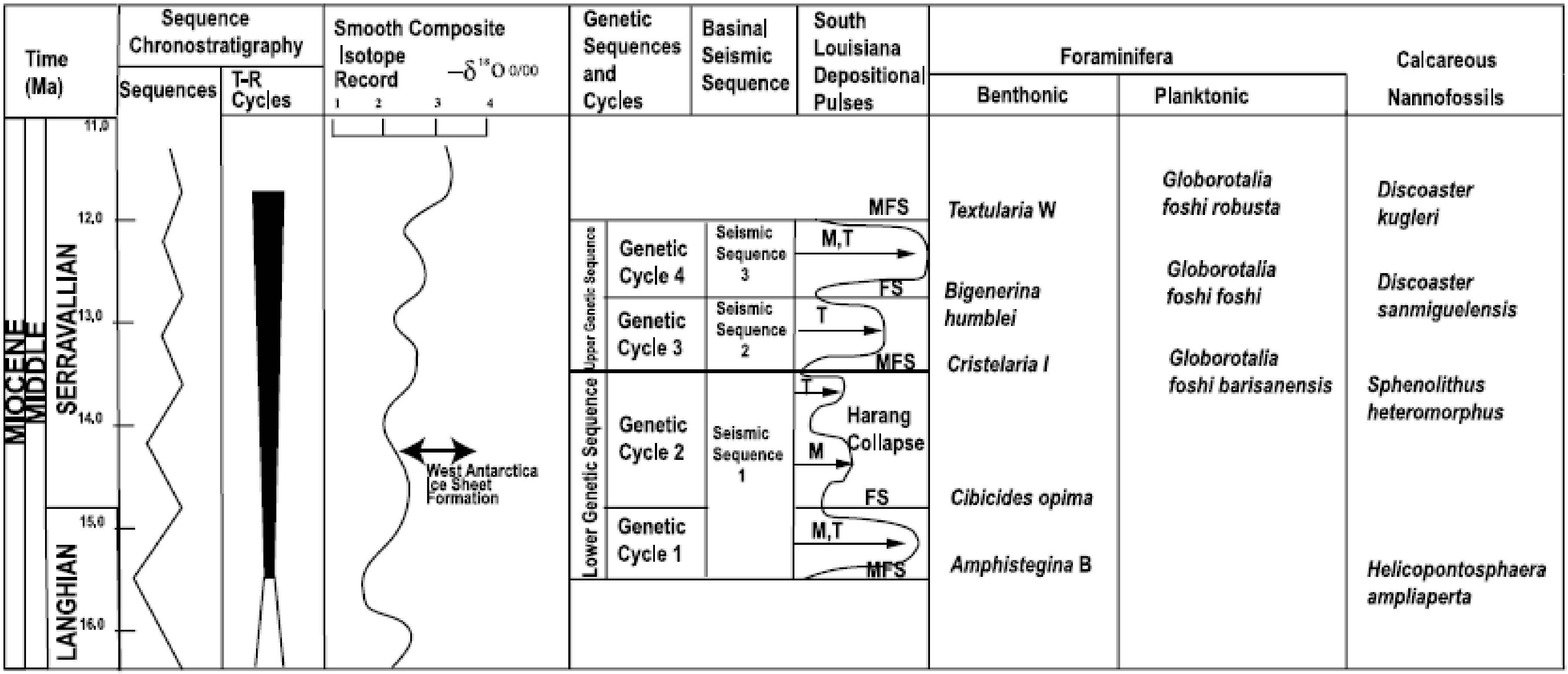


Figure 1-7 – Stratigraphic sequence with genetic cycles depicted (Combellas-Bigott & Galloway, 2005).

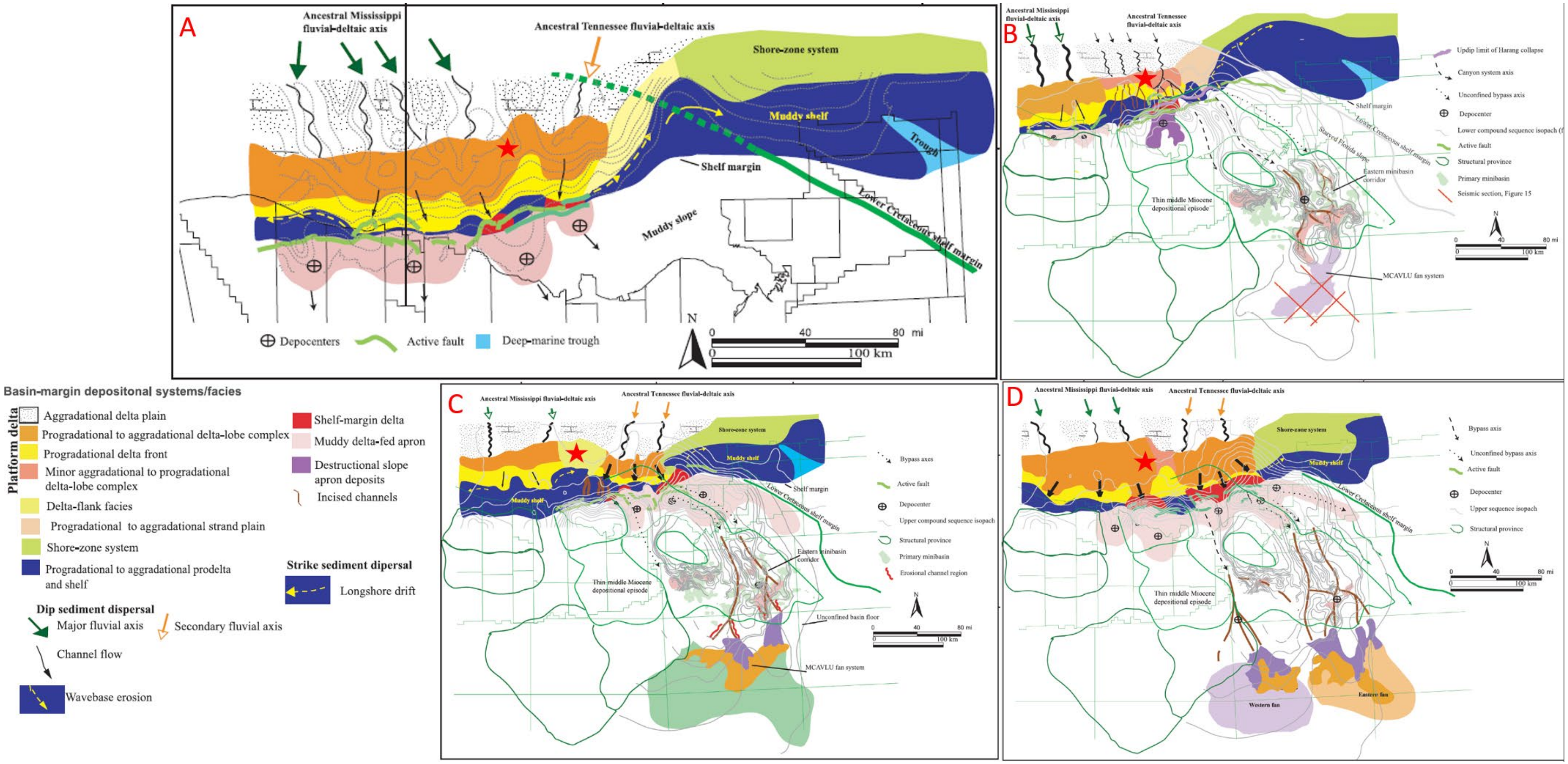


Figure 1-8 – Depositional environment maps of cycles 1–4 (A–D, respectively). The red star represents the White Castle location (Combellas-Bigott & Galloway, 2005).

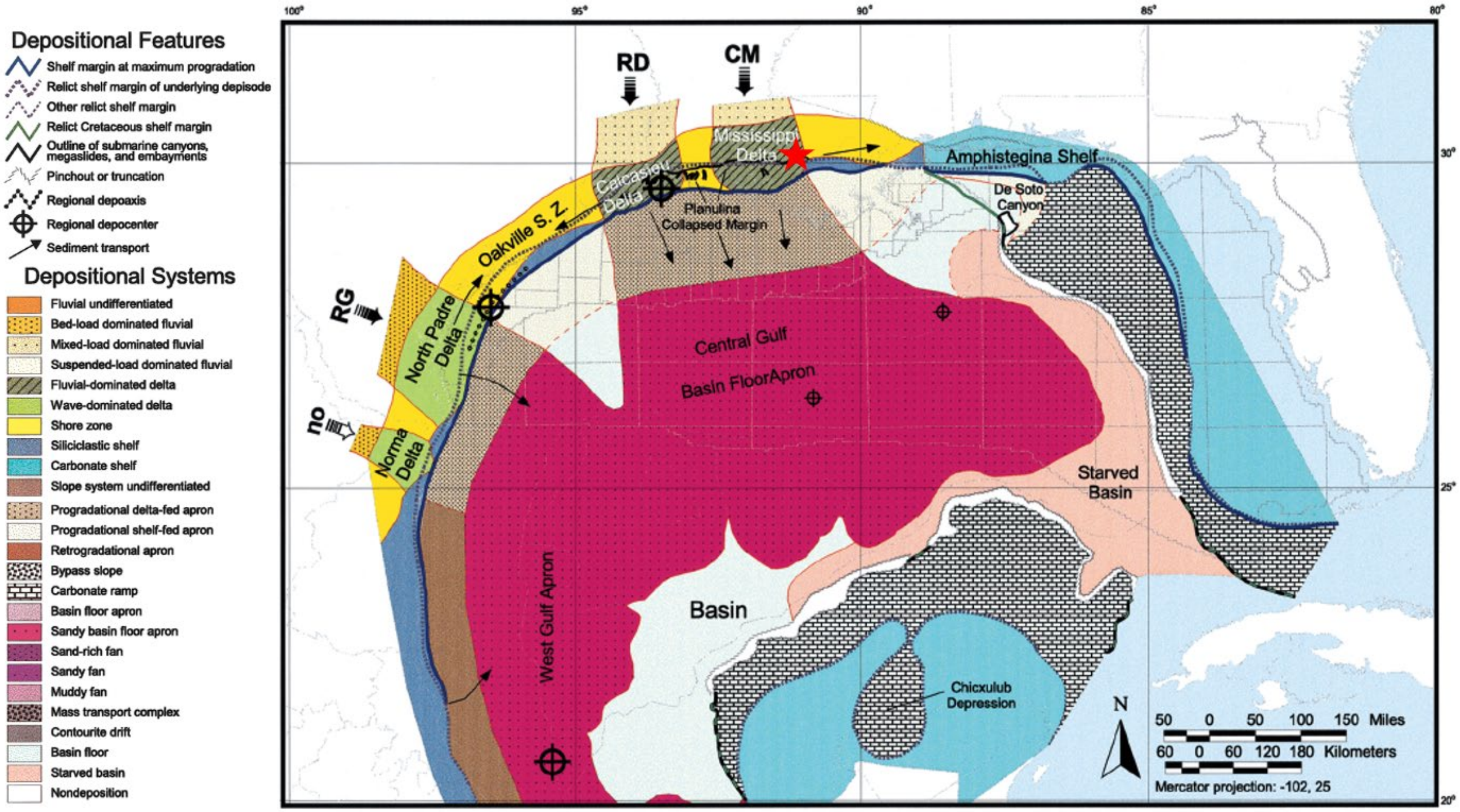


Figure 1-9 – Lower Miocene depositional systems map (Combellas-Bigott & Galloway, 2005).

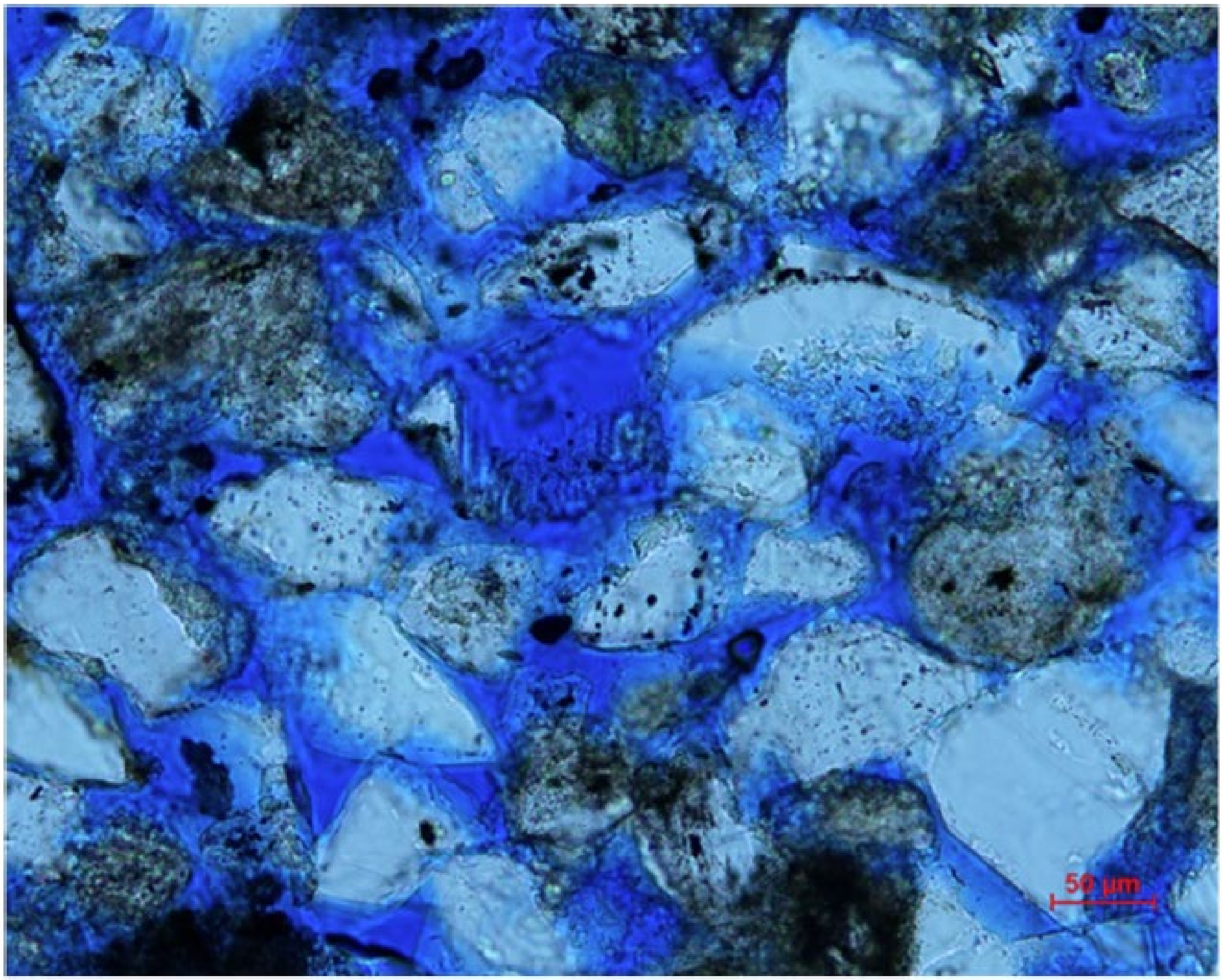


Figure 1-10 – Thin section image of fine-grained Miocene sandstone sample.
Blue is pore space and white is quartz grains with little calcite cementation present (Meckel & Trevino, 2014).

[redacted]

Figure 1-11 – Open-hole log of offset well SN [redacted] depicting the injection interval.

1.3.2 Upper Confining Zone

During the Upper Miocene period, sediment dispersal and paleogeography remained “relatively stable.” A significant deposition event occurred, mainly focused on the Mississippi dispersal axes, following the [redacted] flooding event. This depositional episode came to an end when a regional flooding event related to either the [redacted] or, in certain basin areas without the [redacted], the slightly older [redacted] (William E. Galloway, 2000). Due to the difficulty in differentiating the [redacted] from the [redacted], the latter is utilized as the upper bounding Upper Miocene maximum flooding surface.

Figure 1-12 is a map of the paleogeography of the Upper Miocene with the WC IW-B No. 001 and No. 002 well locations. The proposed well locations fall within the Mississippi Delta System, near the shore zone. There are additional maximum flooding surfaces within the Upper Miocene, between the [redacted] and the [redacted], that include [redacted], but for the sake of this permit, the primary confining zone will be referred to as the [redacted].

Figure 1-13 (page 26) is a depiction of the upper confining zone from the offset well (SN [redacted]) as used above. A Vshale curve in track 1 illustrates the sand and shale distributions within the upper confining section. The methodology of calculating the Vshale curve is later discussed within the porosity and permeability sections (*1.5.1.1* and *1.5.1.2*, respectively). Figure 1-13 shows [redacted] net feet of rock with greater than 70% shale content based on the Vshale curve, which translates to a [redacted] shale volume within the [redacted]. These same calculations were made on five additional wells within 5 miles of the proposed White Castle location. The average results of all wells were [redacted] of net shale and [redacted] shale volume within the [redacted]. The wells used for these calculations are depicted in the map shown in Figure 1-14 (page 27).

The high shale content and multiple maximum-flooding events recorded between the [redacted] and the [redacted] provide ideal sealant properties between the injection zone and Underground Source of Drinking Water (USDW). This sealing nature is evidenced by the hydrocarbon production within the [redacted] formation, [redacted]. There, one well produced out of the [redacted] sand (SN [redacted]), which correlates to the top of the proposed injection interval. This production demonstrates not only the sealing capabilities of the overlying [redacted] formation in the area but also that hydrocarbons were contained.

Structural trends and gross thickness of the [redacted] can be seen in *Appendices B-1* and *B-4*, respectively. These depict the relationship of structural and depositional features within the area.

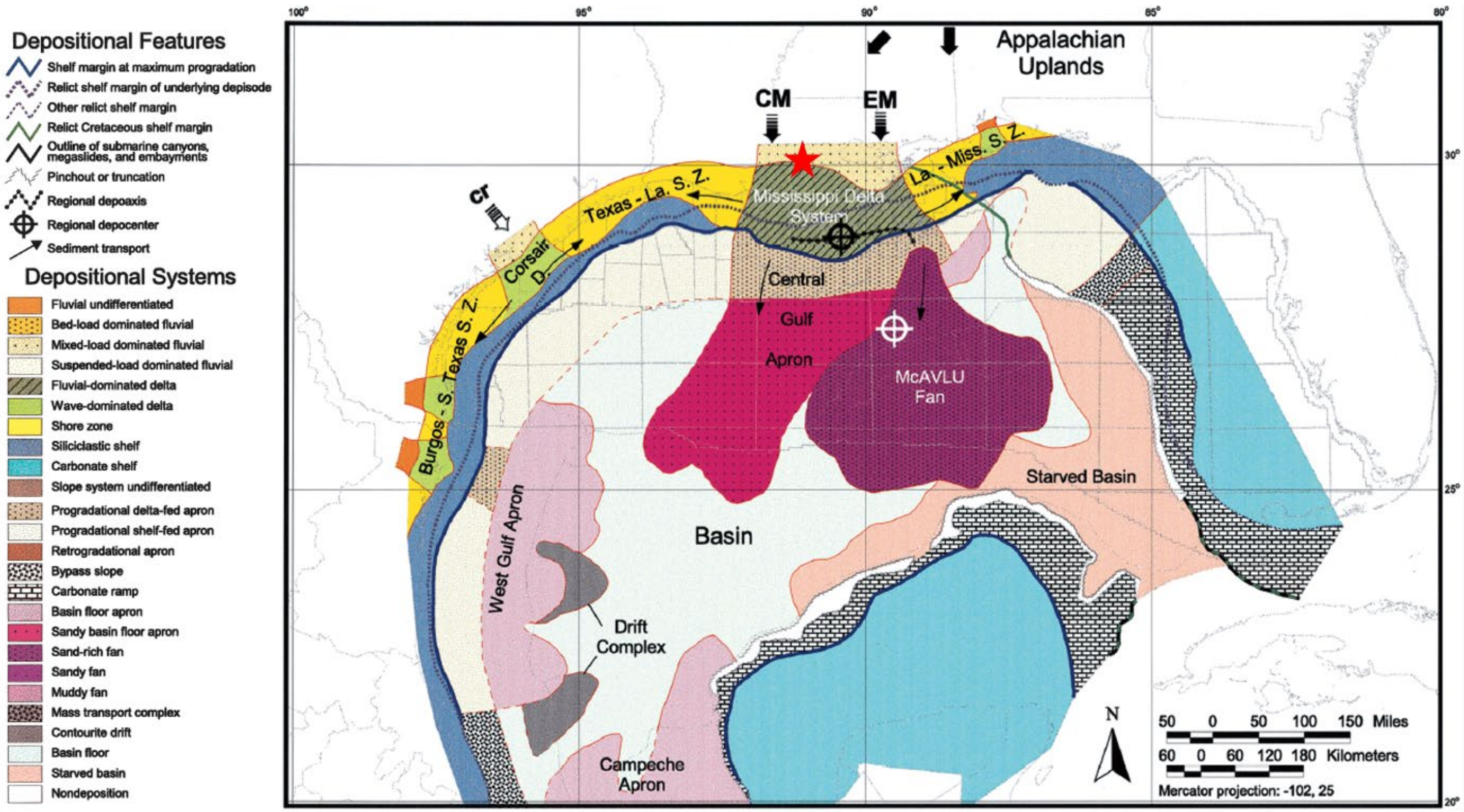


Figure 1-12 – Depositional Map of Upper Miocene (Combellas-Bigott & Galloway, 2005)

[redacted]

Figure 1-13 – Open-hole log of offset well SN[redacted] depicting the upper confining interval.

[redacted]

Figure 1-14 – Map of well control used to determine Vshale, porosity, and permeability distributions.

1.3.3 Lower Confining Zone

The early Miocene was a period of relative paleogeographic stability of the Gulf basin. Early Miocene sediment influx exhibited the first clear shift to the central Gulf fluvial axes that dominate the later Neogene. Uplift of the Edwards Plateau and adjacent inner coastal plain is reflected in the influx of reworked Cretaceous and older Cenozoic debris in the lower Miocene fluvial deposits (William E. Galloway, 2000). Figure 1-9 (*Section 1.3.1*) is a paleogeographic map of the Lower Miocene.

Within the Lower Miocene, the maximum flooding surface identified as the [redacted] will act as the lower confining unit. The [redacted] sequence was deposited during the Liebusella regression, which terminated the second-order late Oligocene Anahuac sequence. The [redacted] was deposited on a second-order relative sea level fall (Fillon & Lawless, 2000). Prior to regressive deposit of the [redacted] sand, a blanket marine shale was deposited as depicted in the regional cross sections within the area (Figure 1-17, *Section 1.3.4*).

Figure 1-15 is an open-hole log image of the lower confining interval represented in the offset well SN [redacted]. [redacted] As displayed in Figure 1-15, a thick marine shale sequence can be identified by the Vshale curve directly below the lowest most injection sand. This will act as an optimal lower confining seal for the proposed permitted injection interval. Graphs depicting the relationships between clay content and permeability/mercury injection pressure from the BEG study are displayed in Figure 1-16 (page 30). These relationships establish that higher clay contents within the interval increase the sealing capabilities of the [redacted]. This study concluded that the clay-rich Miocene mudrocks have sealing capability sufficient for potential CO_2 storage due to the clay-rich mudstone with smaller pore throats (Lu, Carr, Treviño, Rhatigan, & Fifariz, 2017).

The structural trends and overall thickness of the [redacted] are illustrated in *Appendices B-3* and *B-8*, respectively. These visuals showcase the correlation between structural characteristics and deposition patterns in the designated area.

[redacted]

Figure 1-15 – Open-hole log of offset well SN [redacted] depicting the lower confining interval.

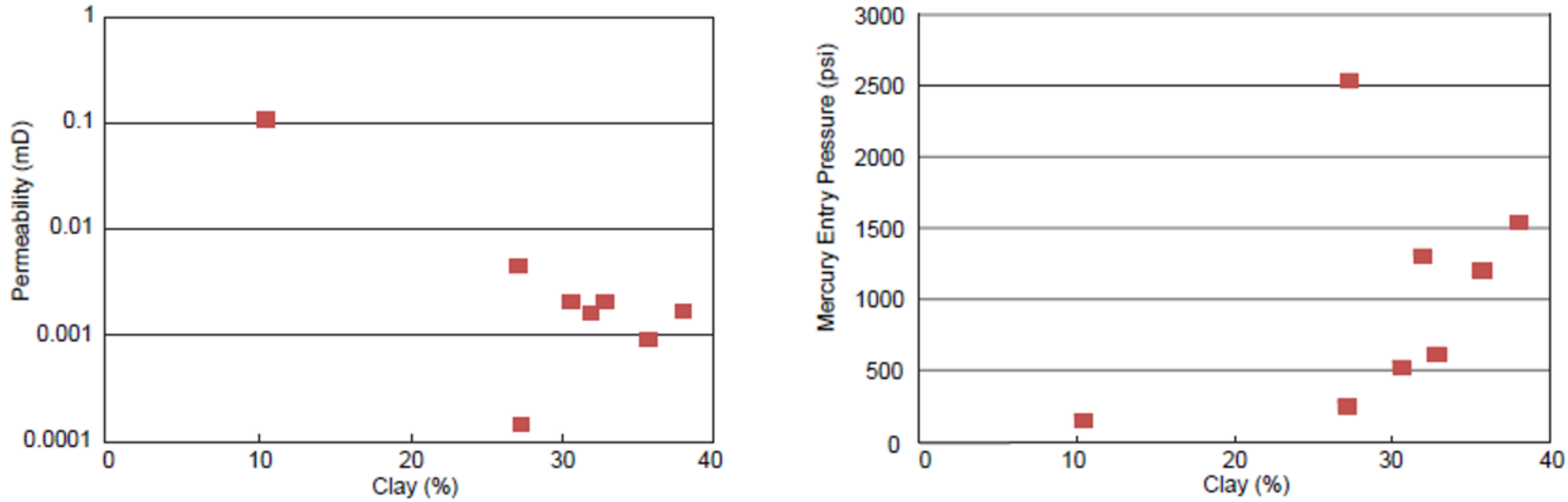


Figure 1-16 – Scatterplots showing higher clay content reflect lower perms and higher mercury entry pressure (Lu, Carr, Treviño, Rhatigan, & Fifariz, 2017).

1.3.4 Geologic Structure

Structural dip of sedimentary strata within the injection interval were mapped, utilizing well control and 3D seismic data. A full examination of well data available to the public was conducted over the AOI. To ensure data accuracy, the Louisiana Department of Natural Resources' (LDNR) SONRIS database, IHS, TGS, Enverus and GEOMAP were reviewed to locate surface and bottomhole positions for existing wells. Professional geologists and engineers double-checked by cross-referencing multiple databases and also obtained plats and scout cards for wells found only in some databases. The verified well data and locations were then imported into a geologic software with their associated well logs, if available. Sixty-nine wells and their associated logs were utilized for the subsurface control; 32 of these well logs were digitized and used to assist in tying in the seismic data. Tops were correlated across the region based on log responses and incorporated into the structural interpretation. These tops were sourced from offset field papers to assist in identifying paleo features. Figure 1-17 (*Appendix B-10*) represents a cross section displaying correlative maximum flooding surfaces used in the structural interpretation. Supplementary structural and stratigraphic cross sections, as well as a reference map, are provided in *Appendices B-9* through *B-12*.

[redacted]

Figure 1-17 – South-North Structural Cross Section

1.3.5 Reflection Seismic Profiles

Approximately 74 square miles of 3D surface seismic data ([redacted]) were licensed by Harvest Bend CCS and included in this interpretation (Figure 1-18).

[redacted]

Figure 1-18 – Overview map of licensed seismic surveys.
The blue highlight represents [redacted] and yellow highlight represents [redacted].

The [redacted] (highlighted in blue) was acquired in 1996 and reprocessed using Pre-Stack Time Migration (PSTM) in 2013. The data was acquired using dynamite as the energy source, 75' x 75' bin size, and 16,670' maximum offset, resulting in (nominal) 32-fold data. The [redacted] (highlighted in yellow) was acquired in 2002 and reprocessed using PSTM in 2008. The data was acquired using dynoseis as the energy source, 110' x 110' bin size, and a 12,320' x

39,380’ patch, resulting in (nominal) 36-fold data. The resulting 3D reflection profiles, which image the subsurface based on density and velocity contrasts, were combined with subsurface well control (geologic formation tops) to map the proposed injection and confining intervals. The resulting maps represent formation depths (Figures 1-19 and 1-20) and any discontinuities such as faulting. The 3D seismic volume was used to map a thick sequence of Miocene-aged rocks approximately 8,600’ thick. The seismic data is of good quality with sufficient offset information to image the target section (between [redacted] subsea depth). The 3D seismic data recorded and interpreted across the proposed CO_2 storage area does not indicate large-scale changes in thickness of the injection or confining zones.

The proposed WC IW-B No. 001 and No. 002 falls between the [redacted]. Major radial faulting associated with these domes occurs at depths and geographical locations outside the proposed injection area. They are all normal faults with an average dip of 45 degrees. The “radial” faults on the southeast side of [redacted] are more than [redacted] away from the edge of the currently predicted carbon front. All additional faults to the north are either well beyond the carbon front of WC IW-B No. 001 and No. 002 wells or are buried below the sealing [redacted] section and pose no threat of transmissibility.

Multiple faults to the southwest and west of the proposed locations occur at different levels of strata. These faults are normal faults that have similar orientations striking northwest-southeast with offsets ranging from 0 to 100 ft. [redacted]. Both fault offsets are well under 100 feet and pose no threat of transmissibility outside of the proposed injection interval. These faults are labeled [redacted] V and displayed in [redacted] *B-3*. [redacted]. These faults are displayed in [redacted] *B-1* as fault C and B. Although the modeled carbon front does not intersect either of these fault planes, additional fault seal analysis was performed and can be seen in *Section 1.8*.

Stratal dip within the injection interval varies with depth. The dip range within the carbon front outline at the [redacted] level is from 1 to 3 degrees, with the primary direction being updip to the northwest and downdip to the southeast. Little dip rotation occurs at the [redacted] level except for the [redacted], where it rotates to a more east-west trend. Dip ranges at the [redacted] level within the carbon front outline range from [redacted]. Primary dip direction follows the [redacted] trend, with the [redacted] dipping down to the southeast and up to the northwest. There is slight dip rotation within the northwestern portion of the carbon front, with the dip orientation rotating to a more west-northwest to east-southeast orientation. These attributes are displayed in the structure maps in *Appendix B-1, B-2*, and *B-3*.

[redacted]

Figure 1-19 – Location of a northwest-to-southeast (A-A’) 3D seismic survey line crossing the proposed CO_2 storage area.

[redacted]

Figure 1-20 – North-south 3D seismic survey intersecting the proposed injection well, which does not indicate the presence of obvious faults or large changes in thickness of the injection or confining zones at the proposed site.

1.3.6 Velocity Control and Synthetic Seismogram

Three velocity surveys were available around the 3D data used for the seismic interpretation shown in Figure 1-21. The checkshot velocity information, along with a synthetic tie from a well roughly [redacted] miles away from the proposed injection well, were used to confirm the time-to-depth relationship of the PSTM data, shown in Figure 1-22.

[redacted]

Figure 1-21 – Location of velocity surveys (indicated by magenta symbols) near 3D seismic data.

[redacted]

Figure 1-22 – Location of synthetic seismogram (blue circle) near the proposed injection well.

1.3.7 Gravity Data

Publicly accessible gravity data is available surrounding the proposed injection site. The data, though sparse (spatially), was reviewed for the project; the scale of the data is therefore insufficient to detect local features, such as *all* salt domes—and it may not augment the geological interpretation of the site. Figures 1-23 and 1-25 (pages 40 and 42, respectively) are regional overview maps by Steven Dutch, Professor Emeritus, Natural and Applied Sciences, University of Wisconsin – Green Bay ((Dutch, 2020). Figure 1-24 (page 41) displays a data set of gravity-station measurements from the USGS (Bankey & Daniels, 2008)—across the states of Louisiana and Arkansas, which cover the proposed storage site. Although these data points encompass a relatively widely spaced grid (approximately one data point every 9 miles), the grids shown in Figures 1-24 and 1-26 (page 43) are consistent with the known regional geologic setting of large thicknesses of Mesozoic sediments deposited in a wedge that thickens towards the Gulf of Mexico.

For Figures 1-24 and 1-26, the original data was extracted from the 1999 version of a gravity database maintained by the National Geophysical Data Center. Observed gravity measurements relative to the International Gravity Standardization Net 1971 (IGSN–71) datum were reduced to the Bouguer anomaly using the 1967 gravity formula (Cordell, Keller, & Hildenbrand, 1982) and a reduction density of 2.67 grams per cubic centimeter (g/cc). Terrain corrections were calculated radially outward from each station to 167 km (100 mi) using a method developed by Plouff (Plouff, 1977).

The Isostatic Residual Gravity Map (Figure 1-26) reflects variations in the earth's gravity field caused by density variations in the rocks composing the upper part of the earth's crust. The isostatic residual gravity grid was derived from the Bouguer gravity anomaly data by removing the gravitational effect of the compensating mass that supports topographic loads. The thickness of this compensating mass was calculated using averaged digital topography by assuming a crustal thickness for sea-level topography of 30 km (18 mi), a crustal density of 2.67 g/cc, and a density contrast between the crust and upper mantle of 0.40 g/cc.

Positive value trends delineate rocks denser than the Bouguer reduction density of 2.67 g/cc, whereas a negative closure such as the -25.6 milligals (mGal) contour in Figure 1-23 results from rocks of lower density (such as salt structures). In general, gravity minimums highlight subsurface salt structures. However, in this area neither the regional map nor the USGS gravity data highlight the salt dome [redacted] northeast of the proposed storage site.

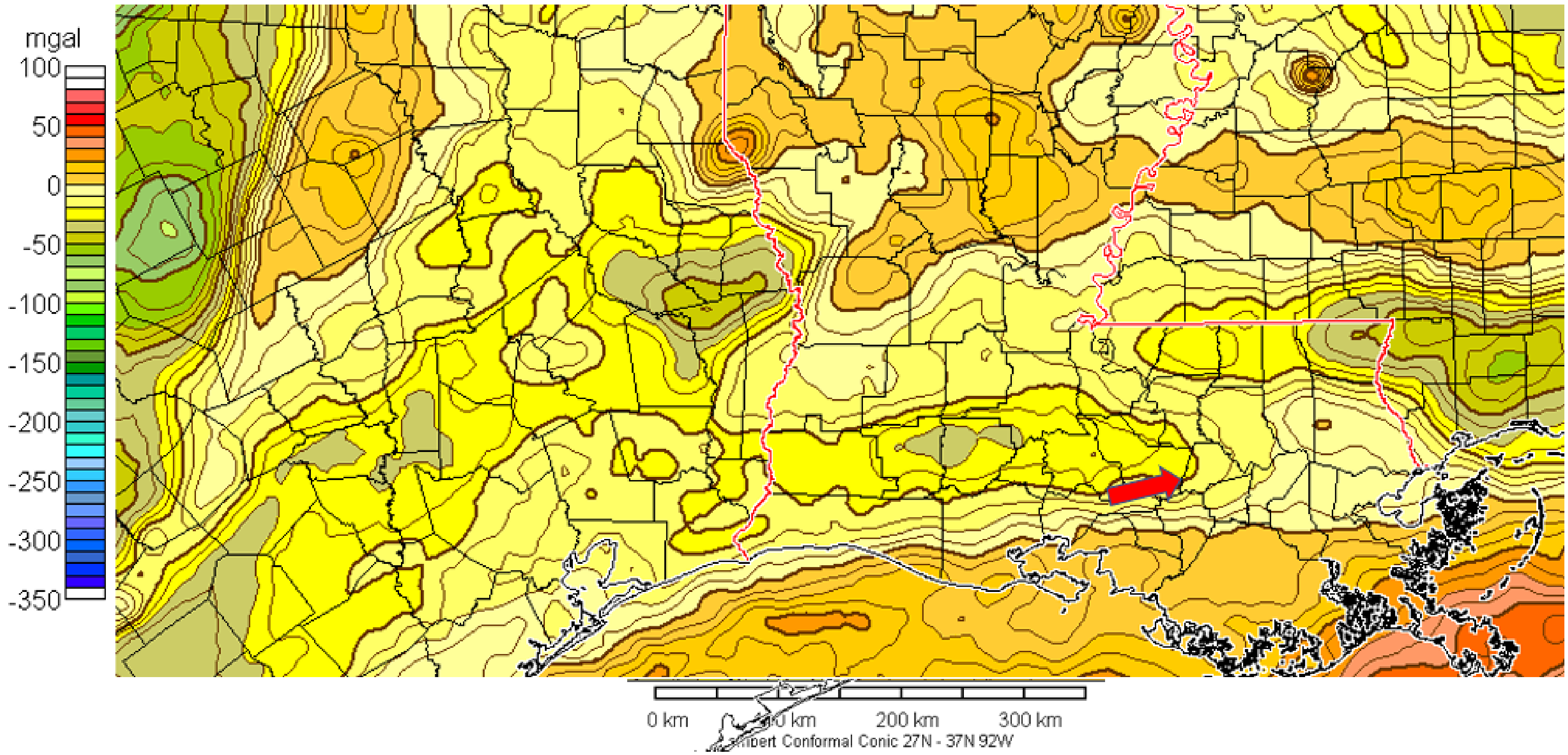


Figure 1-23 – A regional view of the Bouguer Gravity Anomaly Map for Louisiana. The red arrow indicates the proposed injection site (from https://www.stevedutch.net/stategeophmaps/lagphmap.htm).

[redacted]

Figure 1-24 – A view of the Bouguer Gravity Anomaly Map surrounding the proposed storage site (74 sq mi 3D) based on USGS data points.

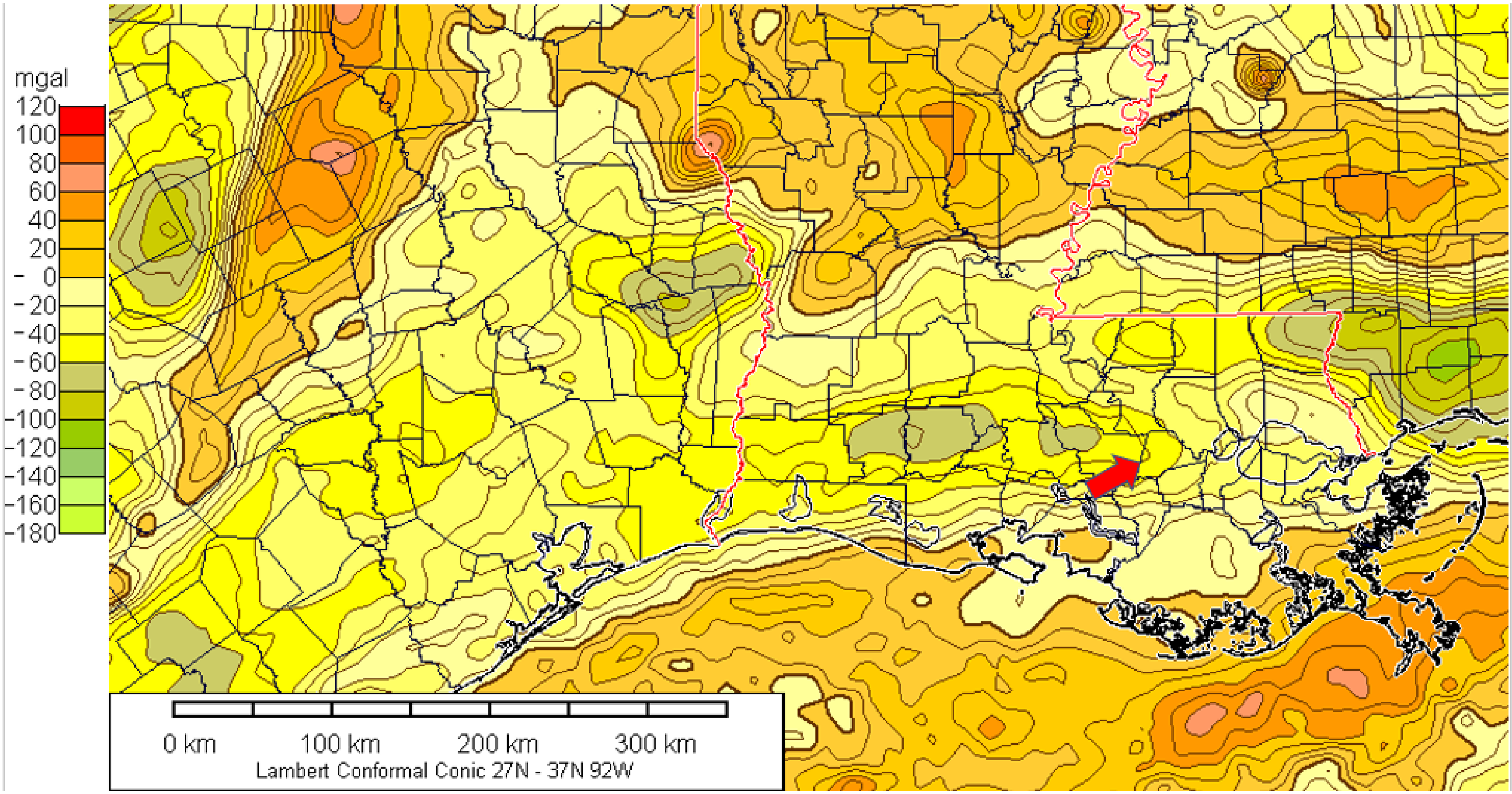


Figure 1-25 – A regional view of the Isostatic Gravity Anomaly Map for Louisiana. The red arrow indicates the proposed injection site (from https://www.stevedutch.net/stategeophmaps/lagphmap.htm).

[redacted]

Figure 1-26 – Isostatic Gravity Anomaly Map using the same USGS data points and spacing as Figure 1-24.

1.4 Geomechanics

1.4.1 Local Stress Conditions

Local stresses will be determined by running an X-dipole open-hole log in addition to performing "minifrac" tests, which are discussed in *Section 5 – Testing and Monitoring Plan*. Published maps of crustal stress orientation along the northern coast of the Gulf of Mexico basin indicate that the orientation of maximum horizontal stress (SHmax) is largely parallel to the coast, east-northeast, near the area of review (AOR) (Yassir & Zerwer, 1997).

1.4.1.1 Determination of Vertical Stress (S_v) from Density Measurements

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 bulk density for the upper and lower confining and injection zones was calculated from log data at the offset [redacted]). Values were calculated for the top depth of the injection and lower confining zones. Due to the substantial thickness of the upper confining zone, values were calculated for the depth 100' above the base of the zone. The overburden gradient and vertical stress were calculated by integrating the bulk density from the surface to the formation depth in five-foot intervals. Table 1-4 shows the overburden gradient, vertical stress, and bulk densities of the top confining, injection, and lower confining zones.

Table 1-4 – Calculated Vertical Stresses

Formation	Depth (ft)	Bulk Density (g/cm^3)	Bulk Density (lb/ft^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(a) Values calculated for the depth 100' above the base of the corresponding zone.

1.4.2 Elastic Moduli and Fracture Gradient

Elastic moduli and fracture gradients are determined from laboratory analysis of core samples. Tests are performed on two-inch diameter vertical plugs from each core. Core samples are not available at this time and will be recovered during the drilling of the stratigraphic test well. The core samples will undergo triaxial compressive strength testing to provide the geophysical properties listed in Table 1-5.

Table 1-5 – Triaxial Compressive Strength Test Results

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
N/A[a]	N/A[a]	Upper Confining	[redacted]	N/A[a]	N/A[a]	N/A[a]	N/A[a]
N/A[a]	N/A[a]	Injection	[redacted]	N/A[a]	N/A[a]	N/A[a]	N/A[a]
N/A[a]	N/A[a]	Lower Confining	[redacted]	N/A[a]	N/A[a]	N/A[a]	N/A[a]
(a) Results are pending the retrieval and lab testing of cores, which will occur when the stratigraphic test well is drilled.							

1.4.3 Fracture Gradient Calculation

The fracture pressure gradient was estimated using the uniaxial strain equation and fracture mechanics. The calculation inputs included vertical stress (S_v), pore pressure (P_p), and a value for the constant "K," which is the ratio of minimum horizontal effective stress to vertical effective stress. These variables can be changed to match the site-specific injection zone. "K" was assumed to equal 0.52 for shale and 0.48 for sand formations. To arrive at a conservative estimate, the fracture pressure was calculated as the minimum horizontal stress. This is the pressure required to open an existing fracture, which is less than the pressure required for fracture extension. The inputs as well as the resulting fracture pressure gradients are shown in Table 1-6, for the upper and lower confining zones and injection zone.

Inputs for the fracture gradient calculations were sourced from log data at the offset [redacted]. Using these values in Equation 1, a fracture gradient of [redacted] psi/ft was calculated for the upper confining zone. Due to the substantial thickness of the upper confining zone, values were calculated for the depth 100' above the base of the zone. This gradient was selected to calculate the maximum allowable bottomhole pressure, because it is slightly lower than the fracture gradients of the injection and lower confining zones. A [redacted] safety factor, as recommended in SWO 29-N-6 **§3621.A.1** [40 CFR **§146.88(a)**], was then applied to this number—resulting in a maximum allowable bottomhole pressure of [redacted] psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Equations with Variables:

(Eq. 1)
$$FG = K \times (S_v - P_p) + P_p$$
$$FG\ with\ SF = FG \times (1 - 10\%)$$

Where:
K = the ratio of minimum horizontal effective stress to vertical effective stress
S_v = vertical stress
P_p= pore pressure
FG= fracture gradient
SF= safety factor

Equations with Values for Upper Confining Zone:

$$FG = 0.52 \times (0.902 - 0.460) + 0.460 = 0.690\ psi/ft$$
$$FG\ with\ SF = 0.690 \times (1 - 10\%) = \mathbf{0.62\ psi/ft}$$

Table 1-6 – Fracture Gradient Calculation Inputs and Results

Depth (ft)	Zone	Formation	Vertical Stress (psi/ft)	Pore Pressure (psi/ft)	Fracture Gradient (psi/ft)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(a) Values calculated for the depth 100' above the base of the corresponding zone.					

Ultimately, the fracture pressure of the injection and confining zones, as required by SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**], will be determined by minifrac tests completed during the open-hole logging program on the proposed injection well. Maximum allowable injection pressures will be determined based on the results of these tests in accordance with SWO 29-N-6 **§3621.A.1** [40 CFR **§146.88(a)**]. If the minifrac tests cannot identify a fracture gradient, core analysis will be performed and the results used in conjunction with Eaton's method, to determine the fracture pressure.

1.5 Porosity and Permeability

Porosity and permeability distributions at the WC IW-B No. 001 and 002 locations are heavily driven by deposition and post-burial events. High influx of sediments from the Mississippian delta system created an environment with channelized sands with intermittent shales and silts. The injection sands contain high concentrations of quartz and have little calcite cementation at the depth of injection (Smith & Tieh, 1984). Due to the injection interval being normal in pressure and temperature, permeability destruction due to quartz overgrowth is unlikely. Therefore, injection sands within the injection interval should be unconsolidated in nature and reflect higher vertical-to-horizontal permeability ratios. These ratios are directly proportionate to effective porosity due to the shales and silts within these sands acting as baffles. The primary porosity trend seen on the Gulf Coast is *compaction*, which is the reduction of porosity with depth due to the decreasing amount of intergranular pore space—due to greater mechanical compaction. This trend can be seen in Figure 1-36 (*Section 1.5.2.2*) with porosity decreasing with depth.

Porosity and permeability estimates for the reservoir and confining intervals were made through a petrophysical analysis on offset open-hole logs and core data. The nearest well to the proposed storage site with available density/neutron porosity log data over the proposed injection interval is [redacted]). The following process was applied to that well to establish a relationship between lithology-indication logs and effective porosity. *Effective porosity* is a measure of the amount of intergranular or connected void space in a rock, which approximates available pore space for fluid movement better than *total porosity*. Total porosity includes intragranular pore space that may be detached from the pore network.

Quality assurance was performed to ensure that only valid data is used in forward calculations. A comparison of digital or Log American Standard Code for Information Interchange (ASCII) Standard (LAS) log data with a corresponding raster log was performed; digital curves were corrected as necessary, to honor the original raster log data. Washouts in the bulk density log that may artificially inflate porosity values were excluded from trend lines, as shown in Figure 1-27. A trend line to explain SP drift over depth was established to correct SP with depth. Baseline shifts in SP were identified during this analysis, shown in Figure 1-28.

[redacted]

Figure 1-27 – Log depicting example of washouts identified during the quality assurance process.

Example of SP Baseline shift

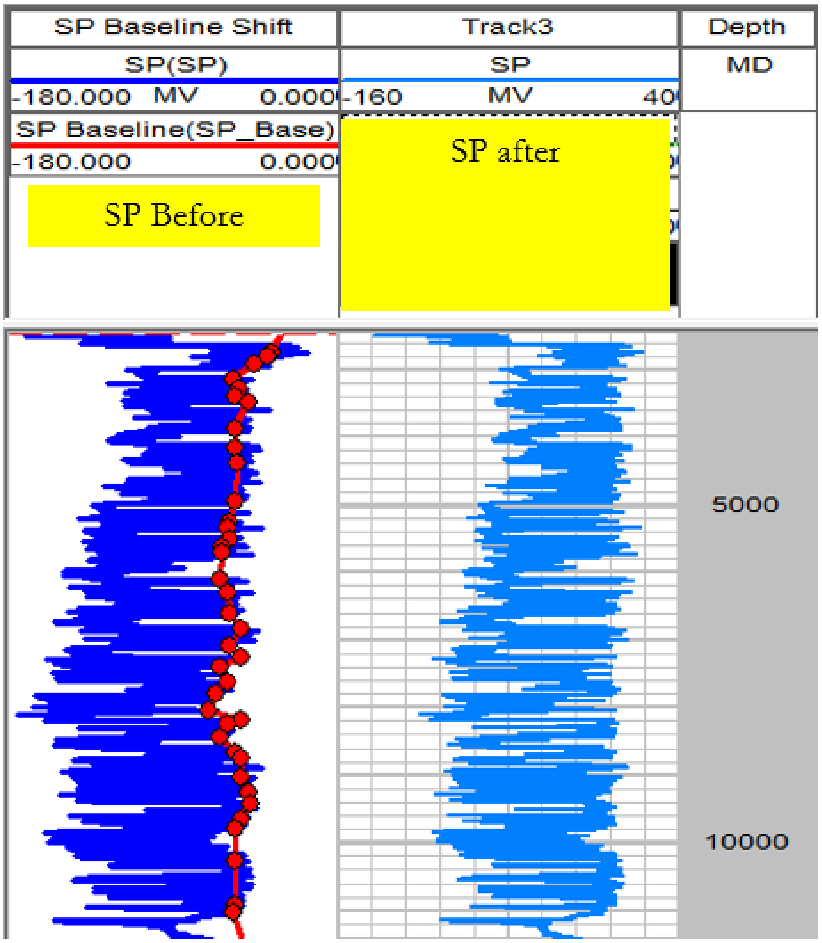


Figure 1-28 – Example of SP Baseline Shift Over Depth

After SP curves were corrected, Vshale was computed from the SP logs.

$$Vshale = \frac{(SP - SPsand)}{(SPshale - SPsand)}$$

Where:
SP = spontaneous potential
$SPsand$ *= spontaneous potential reading of a sand*
$SPshale$ *= spontaneous potential reading of a shale*

Estimated effective porosity (PHIEST, Φ_{eff}) is calculated using the Vshale log and PHIMEAN.

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

Where:
$\emptyset_{eff}$ *= effective porosity*
$\emptyset_{mean}$ *= mean porosity*

A quality check of the PHIEST curve was performed by overlaying the computed PHIEST with the PHIE curve calculated from measured density porosity logs. Figure 1-29 (page 51) demonstrates a good fit between the computed and measured curves. The PHIEST curve was applied to surrounding wells with SP log data to produce best estimates of effective porosities over the Miocene intervals.

As Φ_{eff} is a measure of interconnected pore space, a relationship with permeability can be established. Sidewall core reports were taken from an offset well, [redacted]), roughly [redacted] miles away, and analyzed. A copy of this core report is attached in *Appendix B-14*. A relationship was determined between porosity and associated permeabilities from this core data as shown in Figure 1-30 (page 52). The cores were taken from a wide range of Vshale intervals, which allowed for a robust depiction of permeability ranges that will most likely be encountered within the injection and confining intervals. This variability is shown in Figure 1-31 (page 53) through a histogram of the Vshale log readings within the cored intervals. To better represent the core vs. porosity relationship, two trend lines were determined within the same data set. The trends were separated by the [redacted] effective porosity mark, with each being applied when effective porosities were greater or less than [redacted]. The equations used to determine permeability are as follows:

[redacted]

These equations were applied to 32 wells offset from the proposed injection site and used to develop porosity and permeability distributions within the model.

[redacted]

Figure 1-29 – Comparison between calculated effective porosity (PHIE) and estimated effective porosity (PHIEST).

[redacted]

Figure 1-30 – Porosity vs. Permeability Scatterplot of Sidewall Core from SN [redacted]

[redacted]

Figure 1-31 – Histogram of the Vshale distribution over the cored intervals within SN [redacted].

1.5.1 Upper Confining Zone

The [redacted] contains high clay content due to the depositional features described in *Section 1.3.2*. The high shale net to gross ratio is reflected within the permeability and porosity distributions within the Big A. Figure 1-32 is an open-hole log image of SN [redacted], with PHIEST representing estimated effective porosity and K_Core_2500 representing permeability. Within the gross confining interval, thin channel sands are present that display higher porosity and permeabilities. Although the confining unit clearly displays a much higher proportion of low permeability/porosity shales, these sands will affect the gross average porosity and permeabilities within the upper confining zone, skewing the values to not reflect its confining nature. Therefore, permeability and porosity filters were applied to depict the confining nature of the shale facies within the upper confining zone. The filters applied to the porosity and permeability were [redacted], respectively, and are referred to as the shale facies. Distributions of the porosity and permeabilities within the model that reflect these facies are depicted in Figures 1-33 and 1-34 (pages 56 and 57, respectively).

1.5.1.1 <u>Porosity</u>

Within the shale facies in the upper confining interval, the average effective porosity is [redacted]. Figure 1-32 presents the histograms displaying these distributions. With the same filters applied within the [redacted] unit, there is a projected net value of [redacted] at the proposed WC IW-A No. 001 location. This is portrayed in Figure 1-35 (page 58), which is a net isopach map of the filters described above. With such an ample amount of net low-porosity facies within the upper confining zone, transmissibility through this confining unit is unlikely.

1.5.1.2 <u>Permeability</u>

Within the shale facies in the upper confining interval, the average permeability is [redacted] Figure 1-33 presents the histograms displaying these distributions. Similar net values of [redacted] will be seen with the [redacted] filter applied as shown in Figure 1-35 (*Appendix B-5*). Due to very low horizontal and vertical permeabilities, along with abundant net interval, transmissibility through this confining unit is unlikely.

Further evidence that the [redacted] will act as an optimal confining unit comes from a study by Bump et al. (2023), describing the pros of having a "composite confining system," which is defined by a "multi-layer stratigraphic system of sub-horizontal but potentially discontinuous flow barriers with no a priori requirement for minimum capillary entry pressure values or lateral continuity of individual elements" (Bump, et al., 2023). This study was conducted in southern Louisiana in a very similar depositional environment, in formations similar to the ones being proposed for sequestration, and concluded "permanent storage may be better served by composite confinement than by classic petroleum seals" (Bump, et al., 2023). This was concluded despite the lack of continuous seal, because the CO_2 tends to channelize underneath the capillary barriers, spreading the CO_2 laterally with significant residual trapping that attenuates and ultimately immobilizes the carbon front (Bump, et al., 2023). [redacted], located just northeast of the proposed injection site, was included in this study—furthering certainty that the proposed upper confining zone will sufficiently seal any injected CO_2.

[redacted]

Figure 1-32 – Open-hole log of offset well SN [redacted] depicting the upper confining interval. Effective porosity is displayed in green and permeability in red.

[redacted]

Figure 1-33 – Histogram of Porosity Distributions Within the Upper Confining Zone

[redacted]

Figure 1-34 – Histogram of Permeability Distributions Within the Upper Confining Zone

[redacted]

Figure 1-35 – Net Upper Confining Isopach Map of the facies reflecting a [redacted] porosity and [redacted] permeability.

1.5.2 Injection Zone

The Upper and Middle Miocene formations make up the injection zone for the proposed WC IW-B No. 001 and 002. The permeability and porosity distributions within this interval are heavily influenced by the deposition depicted in *Section 1.3.1*. Figure 1-36 is an open-hole log image of SN [redacted], with PHIEST representing estimated effective porosity and K_Core_2500 representing permeability. Within the injection interval, deltaic sands with higher effective porosities and permeabilities will be the target compartments for injection, with the interbedded shales acting as compartment seals. Figure 1-36 depicts these injection compartments where the permeability and porosity are clearly higher within the sand intervals than the shale intervals. Filters applied to the porosity and permeability were [redacted], respectively, to filter out the shalier porosity and permeabilities, to better depict the injection sands' reservoir characteristics within the injection interval.

1.5.2.1 <u>Porosity</u>

Within the sandier sections of the injection interval, the average effective porosity is 24[redacted]. Figure 1-37 (page 60) presents the histograms displaying these distributions. These porosities reflect the depositional environments and lack of diagenetic destruction of the Miocene sands on the Gulf Coast. As previously stated, porosity trends within the Miocene sands decrease with depth due to compaction, which can be seen in Figure 1-36. A net map of [redacted] porosity was created for the injection zone and can be found in *Appendix B-7*. As seen in this map, [redacted] porosity will be found at the proposed injection well location.

1.5.2.2 <u>Permeability</u>

Within the sandier sections of the injection interval, the average permeability is [redacted]. Figure 1-38 (page 61) presents the histograms displaying these distributions. Due to the fact that permeability is directly related to porosity, similar trends can be seen within the permeability distributions as the porosity described above. Vertical vs. horizontal (Kv/Kh) permeability ratios will increase with increased porosity/permeability due to the lack of diagenetic sequences within the injection interval. Therefore, porosity readings that are directly affected by the cleanliness of the sands will dictate the ratios attributed to each sand. This ratio trend will be further discussed in *Section 2 – Carbon Front Model*.

[redacted]

Figure 1-36 – Open-hole log of offset well SN [redacted] depicting the injection interval. Effective porosity is displayed in green and permeability in red

[redacted]

Figure 1-37 – Histogram of Porosity Distributions Within the Injection Interval

[redacted]

Figure 1-38 – Histogram of Permeability Distributions Within the Injection Interval

1.5.3 Lower Confining Interval

The [redacted] is a laterally extensive regional maximum flooding surface that occurred in the early portion of the Lower Miocene, depositing a regional layer of clay and silt. Further detail on the depositional environment was discussed in *Section 1.3.3*. Figure 1-39 is an open-hole log image of SN [redacted], with PHIEST representing estimated effective porosity and K_Core_2500 representing permeability. A thick and continuous bed interpreted as a maximum flooding surface occurs within the [redacted] lower confining interval, depicting impermeable shale with little to no effective porosity. The filters applied to the porosity and permeability were [redacted], respectively—even though both gross and net values display a very impermeable section.

1.5.3.1 Porosity

Within the shalier facies in the lower confining interval, the average effective porosity is [redacted]. Figure 1-40 (page 65) presents the histograms displaying these distributions.

1.5.3.2 Permeability

Within the shalier facies in the lower confining interval, the average permeability is [redacted]. Figure 1-41 (page 66) presents the histograms displaying these distributions.

These results reflect an optimal lower confining zone that will adequately act as a lower seal for the proposed injection site.

[redacted]

Figure 1-39 – Open-hole log of offset well SN [redacted] depicting the lower confining interval. Effective porosity is displayed in green and permeability in red.

[redacted]

Figure 1-40 – Histogram of Porosity Distributions Within the Lower Confining Zone

[redacted]

Figure 1-41 – Histogram of Permeability Distributions Within the Lower Confining Zone

1.6 Injection Zone Water Chemistry

A water sample from [redacted] on the eastern flank of the [redacted] field was provided to Core Lab for analysis. Figure 1-42 is a complete water analysis of sample RFS ID No. 202206840-02. (A copy of the analysis is included in *Appendix B-15*.) To ensure the analyzed samples are representative of the entire project AOR, a review of nearby produced waters from Miocene sandstones was performed.

[redacted]

Figure 1-42 – RFS ID No. 202206840-02 Complete Water Analysis Report

The USGS National Produced Waters Geochemical Database was filtered to fluid samples from Miocene sands, in a geographic window ranging from [redacted] This area was chosen to incorporate a range of depth values to examine the relationship between salinity and depth. Figure 1-43 is a plot of measured depth (ft) and total dissolved solids (TDS) (mg/l) from the filtered USGS data set and the water analysis from [redacted]. Approximate depths of the proposed injection interval are included on the scatterplot for reference. Over the depths of the injection interval, the average salinity profile is consistent at approximately [redacted] mg/l. The measured data from Core Lab's analysis, sample RFS ID No. 202206840-02, lies within the anticipated values of the regional data set and is considered representative of the entire injection interval.

[redacted]

Figure 1-43 – Plot of USGS Produced Water Samples and [redacted] Well

Water samples of the injection interval will be obtained during drilling operations of the proposed injection well, and complete water analyses will be performed to establish baseline reservoir fluid conditions.

1.7 Baseline Geochemistry

1.7.1 Mineralogy

Approximate locations within depositional environments and regional studies of provenance were considered in constructing mineralogical composition estimates of the Upper, Middle, and Lower Miocene reservoirs. Samples of the Middle and Lower Miocene sediments transported by the Mississippi and Tennessee rivers from Appalachian and Cumberland Plateau provenances are plotted on QFL diagrams (Xu, 2022). Upper Miocene mineralogy was best estimated from qualitative descriptions of Louisiana coastal Upper Miocene sandstones (Gold, 1985). Quartz is the dominant mineral in these deltaic sand deposits, followed by feldspar. Both plagioclase and potassium feldspars are present, in an approximate 3:2 ratio (Gold, 1985).

Local variations of calcite and clay were best estimated from qualitative core descriptions of the [redacted]), located north of the AOR in [redacted] field. Only smectite clay at deposition was assumed. A linear trend line applied to a plot of smectite-to-illite ratios by depth, from analyses of Late Miocene and Pliocene shales in [redacted] field, was used to estimate the percentage of each clay mineral at the depths of the Miocene intervals (Totten, 2002). Table 1-7 is an approximate mineralogical composition by volume of the formations that constitute the injection interval, normalized to 100%.

The primary mineralogy of the upper and lower confining intervals is anticipated as clay, quartz, feldspar, and calcite. The clay percentage was estimated by the average Vshale over the confining intervals to be 80%. Calcite was included, as it is one of the most reactive minerals anticipated to be present in this mineral assemblage. The remaining composition was assumed to be similar ratios of the sediment present in the adjacent Miocene injection zones. Table 1-8 displays the approximated mineralogical composition of the [redacted] shales.

Table 1-7 – Estimates of injection-interval mineralogical composition by volume (%).

Interval	Quartz	Plagioclase	Kspar	Calcite	Smectite	Illite
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 1-8 – Estimates of Confining Units' Mineralogical Composition by Volume (%)

Confining Unit	Smectite	Illite	Quartz	Plagioclase	Kspar	Calcite
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1.7.2 Brine and Rock Inputs

The brine composition used for the injection simulations comes from a produced water sample (RFS ID No. 202206840-02) as described in *Section 1.6*. The sample was analyzed for a standard set of anions and cations as well as TDS, pH, resistivity, conductivity, and specific gravity. All analyses were conducted at a temperature of 60°F. The concentrations of cations and anions inputted into PHREEQC and the calculated molality values are shown in Table 1-9.

In practice, it is presumed that formation brines are in equilibrium with the host formations due to long residence times and limited reactive surface area in the pore space. In simulation studies, analyzing the equilibrium between the produced water and non-reservoir intervals (i.e., seals) provides insight into the reactivity of the reservoir formation brine and the non-reservoir interval away from the reservoir-seal interface. This equilibrium reaction is useful in assessing extreme upper bounds of water-rock reactivity. The results are also shown in Table 1-9.

Table 1-9 – Estimate of reservoir brine composition (column 1) and the equilibration of the brine composition with the seal formations.

PHREEQC Equilibrated Zone Brines			
	Produced Water RFS ID No. 202206840-02	**Upper Confining Zone**	**Lower Confining Zone**
Temperature (°C)	[redacted]		
pH			
Water Mass (kg)			
Al			
B			
Ba			
Br			
C			
Ca			
Cl			
Fe			
I			
K			
Li			
Mg			
Mn			
Na			
S			
Si			
Sr			
Ti			

The mineralogic composition of the confining zones as well as the reservoir zones were estimated as described in *Section 1.7.1*. The upper and lower confining zones are principally composed of clay and quartz; the upper reservoir interval is principally quartz with minor amounts of calcite, feldspars, and clay; and the lower reservoir interval is principally quartz with a significant amount of feldspar and some calcite (all displayed in Table 1-10).

Table 1-10 – Mineralogic Composition of the Confining and Reservoir Intervals

Zone Compositions	
	[redacted]
Water Mass (kg)	
Plagioclase (mol) as Albite	
Anhydrite (mol)	
Feldspar (mol) as Anorthite	
Calcite (mol)	
Chlorite (mol) as Chamosite-7A	
Dolomite (mol)	
Illite (mol)	
Potassium Feldspar (mol)	
Kaolinite (mol)	
Pyrite (mol)	
Quartz (mol)	
Siderite (mol)	
Smectite (mol)	

To model the injection process, an approximate gas composition was derived from current pipeline specifications. The pipeline gas is [redacted], with accessory gases and water making up the remaining [redacted]. While it is likely that this gas composition is more heterogenous than the final CO_2 injection stream, the reaction modeling is not highly sensitive to the accessory gasses ([redacted]), thus the simulations are representative of the expected reactions.

1.7.3 Rock-Brine-Gas Interaction

The interactions between the rock mineralogy, brine, and CO_2 gas injectate were modeled using PHREEQC batch reactions. In the batch reaction, a 1 cubic meter rock-brine system is injected with 1,000 moles of injection gas. The simulation holds the formation pressure and temperature constant at values relevant for each interval, and calculates the solution and dissolution of mineral phases over ten equilibration steps. Simulations were run for the upper and lower confining formations as well as the upper and lower reservoir intervals.

The equilibrated brine compositions for the reservoir rock-brine-gas systems are shown in Table 1-11(A). The simulation for the upper reservoir layer shows that the formation brine loses mass due to the precipitation of quartz, dolomite, kaolinite, and siderite, while calcite and albite are dissolved. The simulation of the lower reservoir layer shows that the formation brine loses mass because of the precipitation of kaolinite, calcite, and dolomite, while anorthite, quartz, and illite are dissolved.

The equilibrated brine compositions for the confining layer rock-brine-gas systems are shown in Table 1-11(B). The simulation for the upper confining layer shows that the formation brine gains mass due to the dissolution of calcite and k-feldspar (kspar), while the precipitation of quartz, siderite, illite, albite, and dolomite occurs. The simulation of the lower confining layer shows that the formation brine loses mass due to the precipitation of quartz, dolomite, and kaolinite while the dissolution of illite, calcite, and anorthite occurs. The modest mass gain for the upper seal brine, coupled with precipitation of assorted minerals including clays, will have a net neutral effect on seal capacity—due to pore-occlusion and a limited amount of minerals available for dissolution. The modeled net precipitation of minerals for the lower confining layer suggests that seal capacity will increase due to pore-occlusion processes.

Table 1-11 – Upper and Lower Reservoir (A) and Confining Zone (B) Brine Outputs

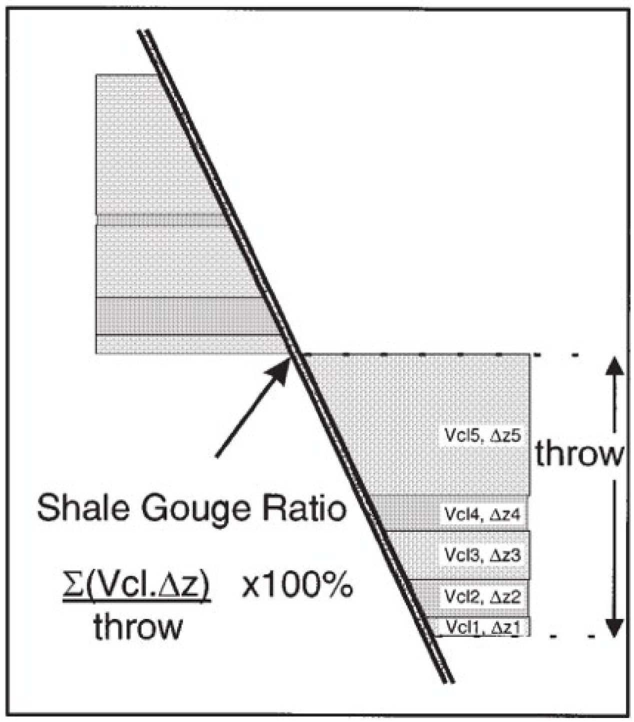
(A) Equilibrated Reservoir Rock-Brine-Gas			
	Upper Reservoir	Middle Reservoir	Lower Reservoir
	[redacted]		
Temperature (°C)	[redacted]		
pH	[redacted]		
Water Mass (kg)	[redacted]		
Al	[redacted]		
B	[redacted]		
Ba	[redacted]		
Br	[redacted]		
C	[redacted]		
Ca	[redacted]		
Cl	[redacted]		
Fe	[redacted]		
I	[redacted]		
K	[redacted]		
Li	[redacted]		
Mg	[redacted]		
Mn	[redacted]		
Na	[redacted]		
S	[redacted]		
Si	[redacted]		
Sr	[redacted]		
Ti	[redacted]		

(B) Equilibrated Seal Rock-Brine-Gas		
	Upper Seal	Lower Seal
	[redacted]	
Temperature (°C)	[redacted]	
pH	[redacted]	
Water Mass (kg)	[redacted]	
Al	[redacted]	
B	[redacted]	
Ba	[redacted]	
Br	[redacted]	
C	[redacted]	
Ca	[redacted]	
Cl	[redacted]	
Fe	[redacted]	
I	[redacted]	
K	[redacted]	
Li	[redacted]	
Mg	[redacted]	
Mn	[redacted]	
Na	[redacted]	
S	[redacted]	
Si	[redacted]	
Sr	[redacted]	
Ti	[redacted]	

1.8 Fault Seal Analysis

The Fault Seal Analysis was conducted jointly for most of the normal faults within the area. The Shale Gouge Ratio (SGR) based analysis provides useful information about fault properties and estimation of their sealing capacities in addition to a permeable-impermeable rocks juxtaposition captured in the geostatic model and typically accounted for at the dynamic modeling stage. To estimate fault sealing capacity, the SGR, fault zone entry capillary pressure (FZP), and faults' permeability were calculated.

While accounting for the lithological juxtaposition, the SGR is an important parameter used to estimate the amount of clay within the fault gouge, as the very-fine phyllosilicates result in very small pore-throats, leading to high FZP and low permeabilities within the fault zone (Yielding, 2002). The accuracy of the SGR estimations certainly depends by quality of input data, but overall, the SGR "has proven to be a robust and quantitative predictor of fault seal in mixed clastic sequences" (Yielding, 2002). The SGR and SGR equation (Yielding et al., 1997) is a widely accepted method used to estimate the amount of clay within the fault gouge (Figure 1-44).



$$SGR = \frac{\Sigma[(\text{Zone thickness}) \times (\text{Zone clay fraction})]}{\text{Fault throw}} \times 100\%$$

Figure 1-44 – Shale Gouge Ratio conceptual diagram and equation. Calculation for a sequence of reservoir zones; Δz is the thickness of each reservoir zone and Vcl is the clay volume fraction in the zone (Yielding et al., 1997).

The SGR has been shown to be an effective qualitative predictor for sealing vs. non-sealing faults in hydrocarbon systems. SGR data from the fault-bounded reservoirs of both sealing and non-sealing faults show that SGR values of approximately 15-20% are the typical cutoff for sealing vs. non-sealing faults (e.g., Bretan et al., 2003; Meckel and Trevino, 2014). [redacted].

SGR and other calculated parameters were analyzed for the injection and upper confining intervals, predicting their horizontal and vertical sealing capacities. The sealing capacity of the upper confining interval and penetrating faults are of particular importance. Figure 1-45 depicts the facies distribution within the upper confining interval, [redacted]. This significant shale presence serves as the foundation for the consistent behavior observed in both the interval and penetrating faults.

[redacted]

Figure 1-45 – Facies distribution within the upper confining interval and corresponding histogram, showing that [redacted] of this interval is presented by shales. Histogram codes represent the following facies: 1 – shale; 2 – siltstone; 3 – distal; 4 – proximal; 5 – axial sandstones.

Figure 1-46 shows the histograms of SGR distribution for the upper confining and injection intervals, accompanied by the 3D view at the fault planes with the SGR values distribution along them. [redacted]

[redacted]

Figure 1-46 – Histograms and corresponding 3D inserts of the calculated Shale Gouge Ratio (SGR) distribution along the faults within the model for (a) upper confining and (b) injection intervals. [redacted]

FZP calculations were then performed to identify if the capillary entry pressure of the fault gouge was reached from the influence of the injected CO_2. The classic SGR equation for hydrocarbon systems (Bretan et al., 2003) used to calculate the FZP using SGR and fault rock strength is

$$FZP\ or\ P_C\ (bar) = 10^{\left(\frac{SGR}{27} - C\right)}$$

Where: C is fault rock strength, which varies with depth.

The C values are as follows: C = .5 for burials depths less than 9,850'; C = .25 for burial depths between 9,850-11,500'; and C = 0 where burial depths exceed 11,500' (Bretan P. Y., 2003). However, since the wetting properties of various rock-forming minerals are different for CO_2 and hydrocarbons, this equation needs modification. The most recent work to address this difference was done by Karolyte et al. (2020). As noted by Bretan et al. (2022), proposed modifications lead to FZP reduction of about [redacted] off of the classic FZP results. Thus, the correction multiplier of [redacted] was applied to the resulting FZP value as well as a unit conversion from bar to psi. Figure 1-47 shows calculated threshold FZP values vs. SGR for the upper confining and injection intervals. The threshold lines represent the maximum capillary entry pressure that can be supported at a specific SGR value at certain ranges of the burial depth.

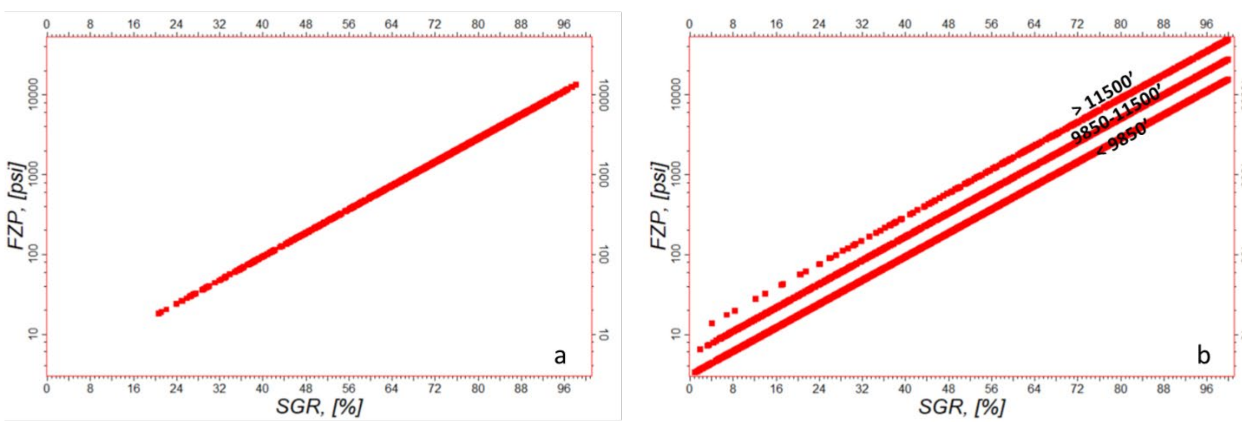


Figure 1-47 – Fault zone entry pressure (FZP) vs Shale Gouge Ratio (SGR) for (a) upper confining and (b) injection intervals. Lines are ''seal-failure envelopes'' (or thresholds) that represent the maximum capillary entry pressure that can be supported at a specific SGR value at certain ranges of the burial depth.

Another valuable application of SGR calculations lies in estimating fault permeability, particularly when capillary pressure differences are absent, and only a single fluid type (brine) is present on both sides of the fault. This assessment becomes crucial in such scenarios. Different general equations have been proposed and used for this. Permeability calculations from SGR using Jolley et al., 2007, equation have been applied here. Figure 1-48 shows fault zone permeabilities vs SGR for upper confining and injection intervals. Figure 1-49 shows the histograms of permeability distribution for the upper confining and injection intervals and accompanied by the 3D view at the fault planes with the permeability values distribution along them. [redacted]

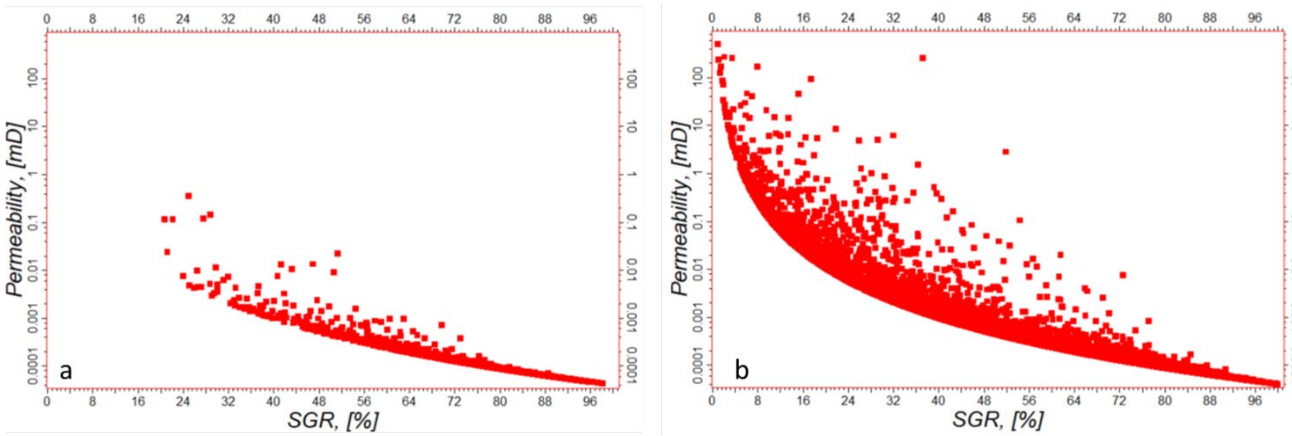


Figure 1-48 – Fault zone permeabilities vs. Shale Gouge Ratio (SGR) for (a) upper confining and (b) injection intervals.

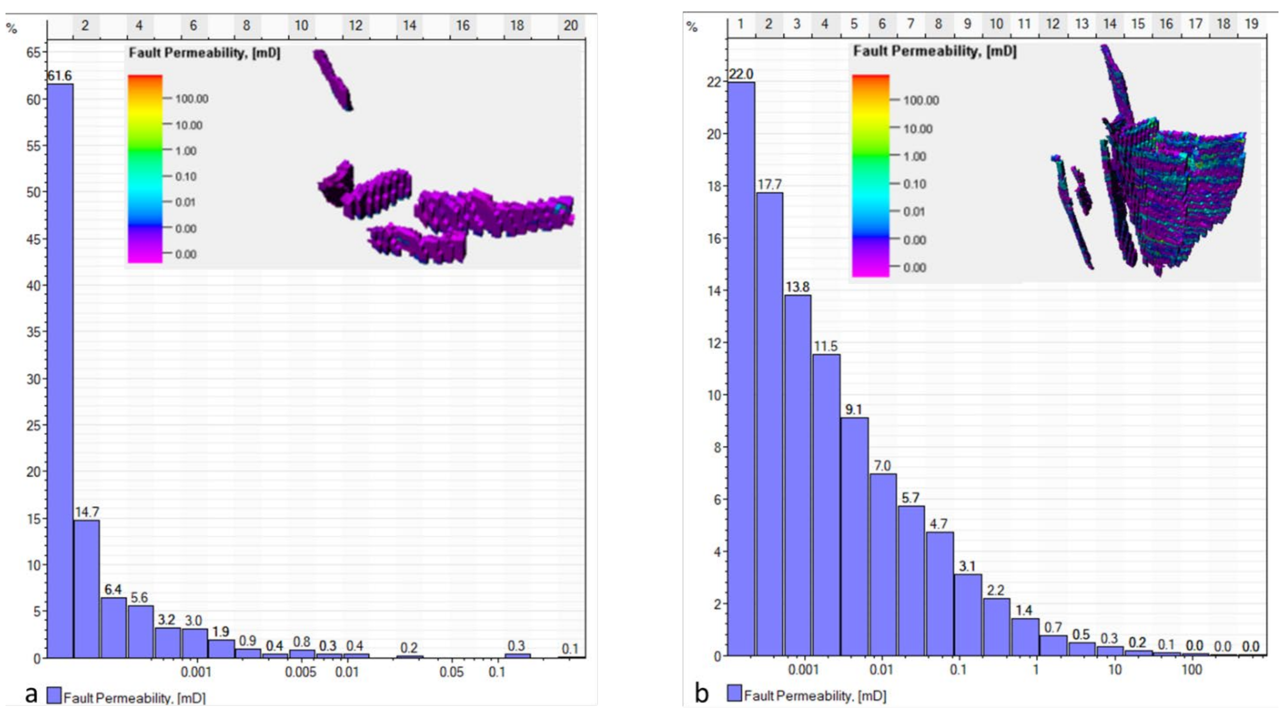


Figure 1-49 – Histograms and corresponding 3D inserts of the calculated fault permeability distribution within the model for (a) upper confining and (b) injection intervals.

The Shale Gouge Ratio based analysis provides useful information about fault properties and estimation of their sealing capacities in addition to a permeable-impermeable rocks juxtaposition captured in the geostatic model and typically accounted for at the dynamic modeling stage. Three parameters provided by the fault seal analysis are shale gouge ratio, fault zone entry capillary pressure, and fault permeability at the present/static conditions. These calculated parameters indicate that at present conditions the fault planes are characterized by a moderately high to high sealing capacity for the injection and upper confining intervals, respectively. [redacted]. Notice that in the presence of only one fluid (brine) and, therefore, lack of the capillary pressure within the fault zones, permeabilities may play a more important role to estimate fault sealing properties. [redacted]. SGR and permeability define the fault behavior under present conditions and, along with FZP, set thresholds for the fault behavior under changing dynamic conditions.

1.9 Hydrology

The hydrogeologic framework of southeastern Louisiana is generally characterized as a shallow alluvial aquifer and an interconnected series of deeper aquifers that dip and thicken toward the Gulf of Mexico. These aquifer systems are primarily recharged by precipitation, in eastern Louisiana and western Mississippi, that percolates down through the geologic section. Once in the system, freshwater continues to flow downdip toward the gulf at rates of several tens of feet to hundreds of feet per year (Lindaman & White, 2021; Griffith, 2003).

The three deep aquifer systems in Iberville Parish—the Jasper equivalent, the Evangeline equivalent, and the Chicot equivalent—are comprised of a complex sequence of interbedded clay, sand, and gravel with aquifers occurring as lenticular sand and gravel deposits. These deposits typically contain a high degree of heterogeneity, can terminate bluntly, and are hydraulically connected to overlying and underlying deposits. Each aquifer system is comprised of a series of deposits that coalesce within clay-rich confining intervals, as depicted in Figure 1-51 (page 84) (Lindaman & White, 2021; Griffith, 2003). The stratigraphic column in Figure 1-50 (page 82) clarifies individual sand nomenclatures of each aquifer system, and Figure 1-52(A) (page 85) illustrates their freshwater extents relative to the proposed White Castle Project location. The thickness of the Jasper equivalent aquifer system ranges from 780’ to 1,350’, the thickness of the Evangeline equivalent aquifer system ranges from 150’ to 2,000’, and the thickness of the Chicot equivalent aquifer system ranges from 75’ to 1,100’, with thickness increasing towards the south (Griffith, 2003).

Although freshwater production has been reported for several aquifers in Iberville Parish, Harvest Bend CCS only anticipates encountering freshwater within the Mississippi River alluvial aquifer and the Chicot equivalent aquifer system. These formations represent the anticipated freshwater column near the White Castle Project and tend to be in direct communication with each other. This agrees with published regional literature, which report that deep aquifer systems only produce freshwater in northern Iberville Parish, north of Baton Rouge and the Baton Rouge fault system, where depths are shallower and saltwater encroachment poses less of an issue to water quality. This is also supported by regional studies that verify the Baton Rouge fault corresponds with a quick shift in the depth of the lowest USDW, which is substantially deeper north of the fault (Chamberlain, 2012; Griffith, 2003).

The schematic cross section depicted in Figure 1-51 utilized wireline logs to illustrate the stratigraphic relationship of freshwater and saltwater bearing formations relative to Baton Rouge and the Baton Rouge fault. The figure suggests that a significant majority of deep aquifer systems are interpreted to contain saline water near the proposed White Castle location. Offset open hole logs from the [redacted]. One such open-hole log is included in Figure 1-53, with blue shading to highlight induction values greater than 3 ohms, following the LDNR-suggested methodology to determine the base of the USDW from open-hole logs. Cross sections were generated depicting the USDW in relation to the injection interval. These can be found in *Appendices B-16* and *B-17*. Additionally, a USDW structure map was generated through USDW picks within offset wells and is represented in *Appendix B-18*.

The Mississippi River alluvial aquifer, commonly referred to as the “Mississippi River Valley alluvial aquifer,” is a tremendous freshwater resource for southeastern Louisiana and represents the primary freshwater aquifer supplying Iberville Parish. The aquifer consists of a largely uninterrupted mass of sand deposited into an incised valley of the underlying Chicot formation (Lindaman & White, 2021; Griffith, 2003). The aquifer is overlain by 75’ to 100’ of silt and clay that functions as a surficial confining unit. The thickness of the aquifer ranges from 125’ to 300’ in southeastern Louisiana and generally thickens to the southeast. Figure 1-52(B) depicts the freshwater extents of the aquifer and illustrates alluvial fill primarily developed west of the Mississippi River (Griffith, 2003).

In 2014, Iberville Parish withdrew an average of 589.87 million gallons of water per day (Mgal/d), sourced from a combination of groundwater (30.86 Mgal/d) and surface water (559.01 Mgal/d) resources. The majority of freshwater withdrawn was provided by surface water from the Mississippi River (551.28 Mgal/d), with some contribution from the Lower Grand River (0.58 Mgal/d) and miscellaneous streams (7.15 Mgal/d). Groundwater production in Iberville Parish was restricted to shallow aquifers that range from Quaternary to Miocene in age. These formations include the Mississippi River alluvial aquifer (26.72 Mgal/d), the Chicot equivalent aquifer system (3.68 Mgal/d), the Evangeline equivalent aquifer system, and the Jasper equivalent aquifer system (0.46 Mgal/d) (Lindaman & White, 2021). Figure 1-50 displays the hydrogeologic units of Louisiana as published by Collier and Sargent (2015). Formations with freshwater potential at the White Castle location are outlined in blue, and formations anticipated to be saltwater bearing are outlined in red.

[redacted]

Figure 1-50 – Hydrogeologic units of Louisiana, with formations with freshwater potential outlined in blue (modified from Collier & Sargent, 2015).

In 2017, there were 403 active Iberville Parish water wells screened in the Mississippi River alluvial aquifer, with well depths ranging from 30’ to 733’ below surface. Water quality samples from the Mississippi River alluvial aquifer contained a medium hardness of 170 mg/L, classifying it as hard. Water samples exhibited variable iron concentrations that range from 30 to 16,000 micrograms per liter (µg/L) with a median of 1,400 µg/L. As a result, approximately 87% of samples analyzed exceeded the EPA’s Secondary Maximum Contaminant Level (SMCL) of 300 µg/L for iron.

Water analysis from aquifer samples also indicated that 7% of chloride samples exceeded the EPA’s SMCL concentration of 250 mg/L for chlorides. Water levels reported from 18 wells screened in the parish ranged from 7’ below to 25’ above sea level and indicate a general flow direction of south to southeast. This is substantiated by a potentiometric surface map generated by the USGS in 2016 (Figure 1-54, page 87; *Appendix B-20*), which shows a general flow direction to the south with contours ranging from 10’ to 20’ around the proposed White Castle location. Additional support is provided in *Appendix B-19*, the *Altitude of the Potentiometric Surface in the Mississippi River Valley Alluvial Aquifer* published by the USGS in the Spring of 2020. Historic water data indicates that the water level of the Mississippi River alluvial aquifer is also affected by the stage of the Mississippi River, with fluctuations increasing along with proximity to the river (Lindaman & White, 2021).

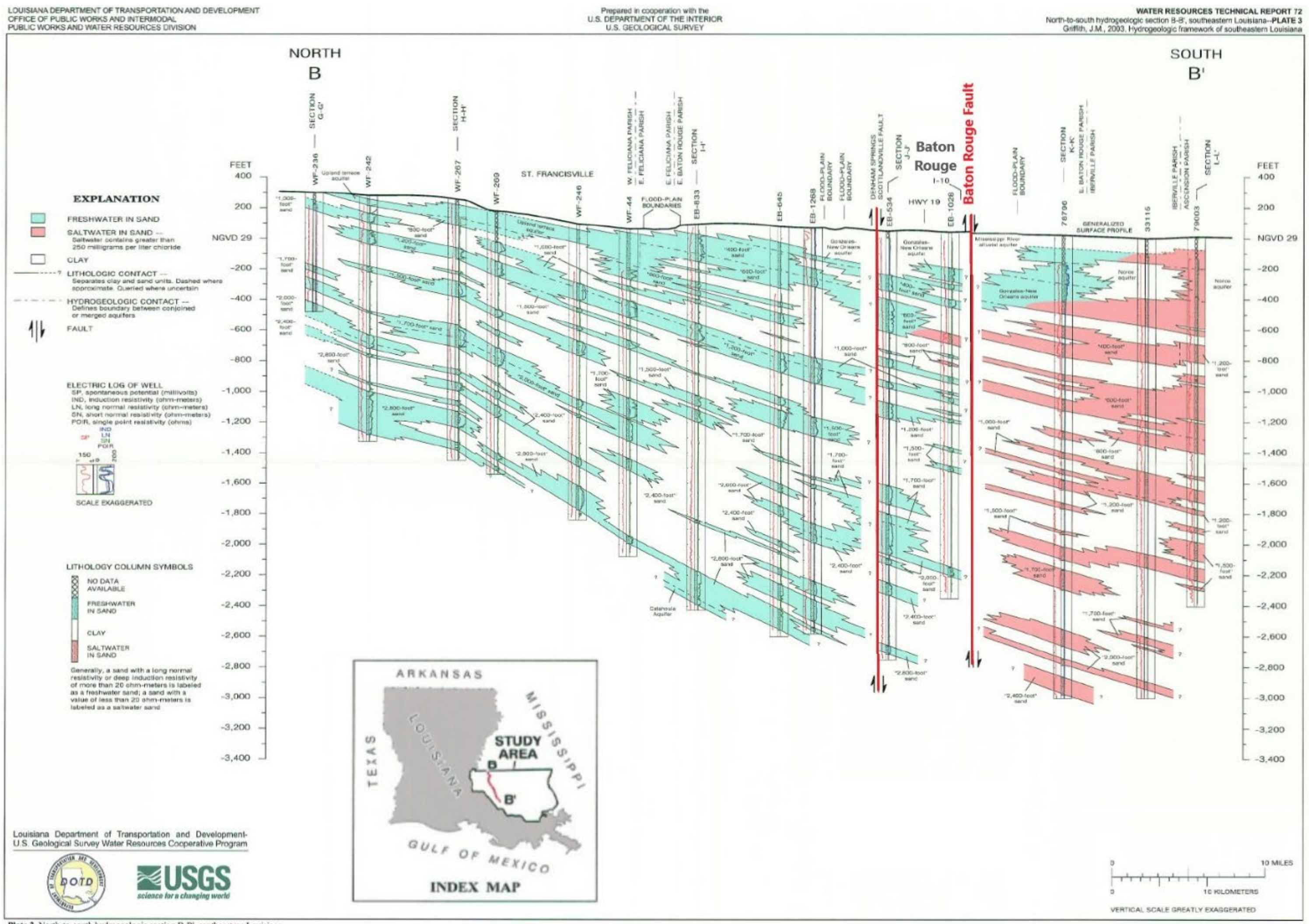


Plate 3. North-to-south hydrogeologic section B-B', southeastern Louisiana.

Figure 1-51 – North-south oriented cross section depicting USGS-identified aquifers relative to offset faulting. Freshwater aquifers are indicated in blue, brackish aquifers in red, and mudstones in white. Note: The Baton Rouge fault represents an interpretated boundary of freshwater to the north and brackish water to the south (modified from Griffith, 2003).

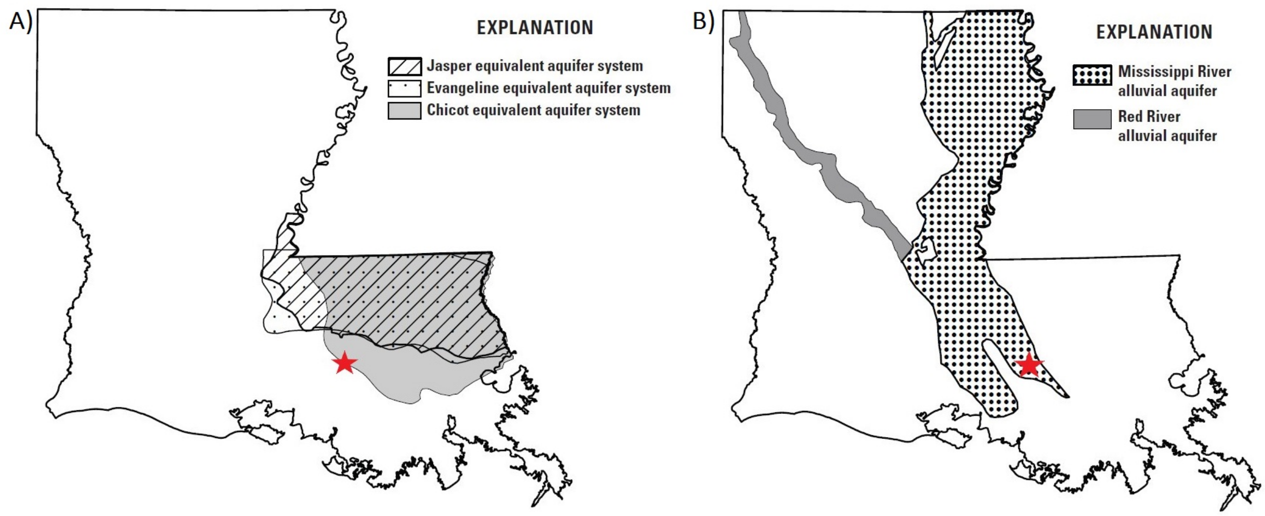


Figure 1-52 (A) – Approximate areal extent of Jasper, Evangeline, and Chicot equivalent aquifer systems. Figure 1-52 (B) – Approximate areal extent of Mississippi River and Red River alluvial aquifers. The red star represents the approximate White Castle Project location (modified from Collier & Sargent, 2015).

[redacted]

Figure 1-53 – Open-hole log and USDW determination from offset well ([redacted]). The deep induction curve is shaded blue for values >3 ohms to illustrate the state-suggested determination method.

[redacted]

Figure 1-54 – Mississippi River alluvial aquifer potentiometric-surface map for Atchafalaya, Deltaic, and Chenier Plain regions of the Mississippi alluvial plain (McGuire, Seanor, Asquith, Kress, & Strauch, 2019).

1.10 Site Evaluation of Mineral Resources

The proposed CO_2 storage site lies [redacted], a structural high centered within a depleted oil field. Given its proximity to a producing field, the likelihood of encountering hydrocarbons at the storage site was assessed. Nine wells southeast and downdip from the dome, with representative geology to the storage site, were evaluated (Table 1-12). All nine were dry holes, abandoned after drilling (Table 1-12 and Figure 1-55, page 89). Each of these dry holes did not evidence hydrocarbons as they drilled to anomalously high depths (greater than 12,500') and straight through the targeted injection intervals. Resistivity logs from these wells corroborate the saline nature of the Miocene storage aquifers beneath the injection site. Therefore, for purposes of this permit application, the dry holes indicate the lack of developable hydrocarbon resources in the Miocene sands formation within the proposed storage area.

Table 1-12 – Dry Hole Wells in the White Castle Area

Well Serial	API Number	Well Name	TD	Final Status	Distance from Injector (miles)
[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]

Figure 1-55 – Dry and Abandoned Wells and Producing Wells in the White Castle Area

In the 1920s, the [redacted] was identified using seismic refraction data. Soon thereafter, hydrocarbons were discovered upon drilling the [redacted]) well. A piercement structure and rather cylindrical, the top of the [redacted] is located approximately 2,300' below surface. Faults centered atop the dome trapped hydrocarbon accumulations in Pliocene sands, above the proposed CO_2 injection zone. Moving away from the center of the dome, hydrocarbon accumulations were found trapped in stratigraphically lower Miocene sands between faults radiating from the dome. These sands are age-equivalent to the downdip CO_2 injection intervals. Moving away from the dome, sub-injection Oligocene sand discoveries predominantly produce gas beneath salt overhangs.

[redacted] Approximately 600 wells have been drilled there, of which 96% have been plugged and abandoned. As of late 2022, 25 wells produce and most generate less than 5 bbloe/d with water cut greater than 99%. The highest active producers are withdrawing primarily gas from those Oligocene sands beneath a salt overhang along the northern flank of the dome. Production from these wells is not expected to impact planned CO_2 injection activity, or vice versa.

As mentioned, there are approximately 25 actively producing wells in the [redacted] field. Detailed analysis of log and completion data indicates that 11 of the 25 (Table 1-13) were determined to produce from the targeted injection interval—of which five were deemed to be low impact because of their location around the dome. Therefore, the six closest producing wells along the southeast side of the dome were further evaluated. These six wells produce from the proposed injection interval but are at a sufficient distance (4.65 miles) such that injection activities will likely not communicate. Additionally, facies distributions as determined from the 3D seismic indicate that sand deposition was diverted around the dome during Mid to Late Miocene halokinesis. [redacted] In fact, all six of these wells can be categorized as "stripper wells," in that maximum daily production does not exceed 15 barrels of oil (cumulative for all wells) or 90 thousand cubic feet of gas (Mcf). Additionally, each of these wells produces substantial water (>95% water cut).

Lastly, the nature of these Miocene reservoirs is indicative of stratigraphic and structural compartmentalization. Not only is the likelihood of these hydrocarbon accumulations being communicative to the downdip injection site low, but the maximum carbon front extent is [redacted] from the nearest production, which further minimizes potential impact.

Table 1-13 – Productive Wells in the White Castle Area

Well Serial	API No.	Well Name	TD	Perf Upper	Perf Lower	Current Status	Producing Formation	Distance from Injector (miles)
[redacted]								

The [redacted] is also used for its mineral resources, whereby solution-mining operations supply liquid brine for industrial and chemical operations near Baton Rouge. Salt caverns formed by this activity may be used for storage in the future. The solution mining operations do not interfere with this project's targeted injection interval as these wellbores do not penetrate the targeted CO_2 injection interval.

1.11 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 requirements in SWO 29-N-6 **§3607.C.2.c** [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, and
4. Seismic hazard.

1.11.1 Identification of Historical Seismic Events

To conduct the historical seismic data investigation, an AOR must be established, which is defined as a 5.6-km radius[1] or a 98.5-square-km area surrounding the project. 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 2.0 magnitude[2] were recorded within the 5.6-km radius of the WC IW-B No. 001 and No. 002 location (Figure 1-56). Further research was conducted on the National Centers for Environmental Information (NCEI), Texas Seismological Network Earthquake Catalog (TexNet), 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 (page 94). [redacted]

[1] The FSP seismicity review radius was established based on local geology and the model extent of the plume.
[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.

[redacted]

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

[redacted]

Figure 1-57 – All USGS-Registered Earthquakes in Inland Louisiana.
The red star is the location of the proposed well, the red circles are the 5.6 km area of interest, and the green dot is the closest earthquake.

1.11.2 Faults and Influence

The USGS has developed a database with detailed information on faults and related folds across the United States. EPA regulations require that a complete understanding of the extent and location of the resultant injection plume be determined and identified. Regionally, the USGS catalogs the faults in southwest Louisiana as “Class B” (Figure 1-58), as most of the faults are in sediments and poorly lithified rocks unable to sustain the forces necessary for the propagation of large seismic ruptures that could result in harmful ground motions. It is likely 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 – Carbon Front Model* discusses CO_2 and pressure plume results, demonstrating that multiple faults are adjacent to, WC IW-B No. 001 and No. 002 injection operations. An FSP model was conducted to comply with EPA regulations.

[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).

1.11.3 Fault-Slip Potential Model

The FSP software provides an initial approximation of the cumulative likelihood of a known fault to exceed Mohr-Coulomb slip criteria due to fluid injection. As additional reservoir data is collected, models will be updated and induced seismicity potential will be further evaluated. It is critical to account for pressure variations at the prospective site to prevent faults from reactivating or the seal from being hydraulically fractured (Meckel & Trevino, 2014). Because faults were observed near the anticipated carbon and pressure front extents, but no historical seismic activity data was found in the study area, the projected induced seismic risk is assumed

[3] The USGS defines a "significant" earthquake as one with a significance >600. This number is derived by magnitude, number of "Did You Feel It" responses, and Prompt Assessment of Global Earthquakes for Response (PAGER) alert level.

to be low. Nevertheless, an FSP model was completed. The results and data used, including assumptions—plus uncertainty—are discussed in *Appendix I*. The FSP demonstrated a low probability of injection-induced seismicity.

1.11.4 Seismic Hazard

The USGS 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 (MMI) hazard map, with a 2% probability of exceedance in 50 years for a firm rock site, predicts that southern Louisiana will most likely encounter a class V[4] earthquake. The AOI is in the Class V extent, as shown in Figure 1-59. Figure 1-60 illustrates a 100-year prediction, in which population density is considered, and shows that southern Louisiana has a 4%–19% chance of having a VI[5] earthquake. In terms of 10,000 years, Figure 1-61 (page 98) depicts fewer than two damaging earthquakes[6] to occur in southern Louisiana. Based on the NSHM and the location of the proposed project, some earthquakes could occur in the future. However, the shake will be light to strong, causing furniture to be moved, and minor[7] damage might occur to structures. In terms of natural hazards[8], Iberville Parish is considered "Low" based on the National Risk Index, as hurricanes, landslides, riverine flooding, and tornados could occur, as Figure 1-62 (page 99) also depicts (National Risk Index FEMA, 2023).

Through analysis, it is very unlikely for a class VI MMI earthquake[9] to occur at the proposed location, based on NSHM, regional geology, historical seismic events, and natural hazards.

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[4] Note: The Modified Mercalli Intensity (MMI) scale ranges from I to XII. The following descriptions, starting here with "Class V" and continuing into the next five footnotes, are from the Public Domain USGS Earthquake Hazards Program (originally abridged by Wood and Neumann, 1931). Class V. "MODERATE; felt by nearly everyone; many awakened: some dishes and windows are broken. Unstable objects are overturned. Pendulum clocks may stop."

[5] 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."

[6] Damaging earthquake shaking; meaning a level VI or higher earthquake causing some structures failure.

[7] Minor damage; structural stable building, but some fallen plaster could occur.

[8] 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.

[9] 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."

[redacted]

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

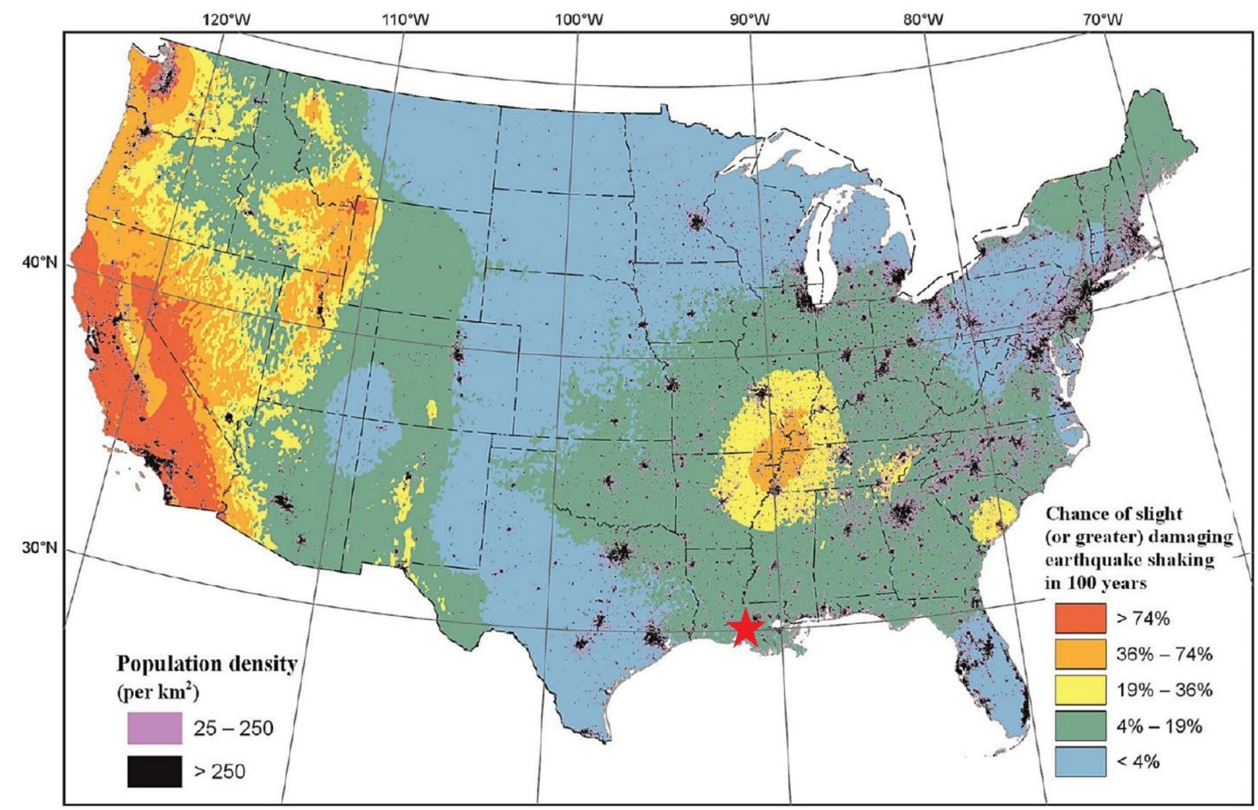

Figure 1-60 – Location of the proposed project (indicated by red star), population density, and the risk of a class VI earthquake shaking in 100 years (Petersen, et al., 2019, p. 7).

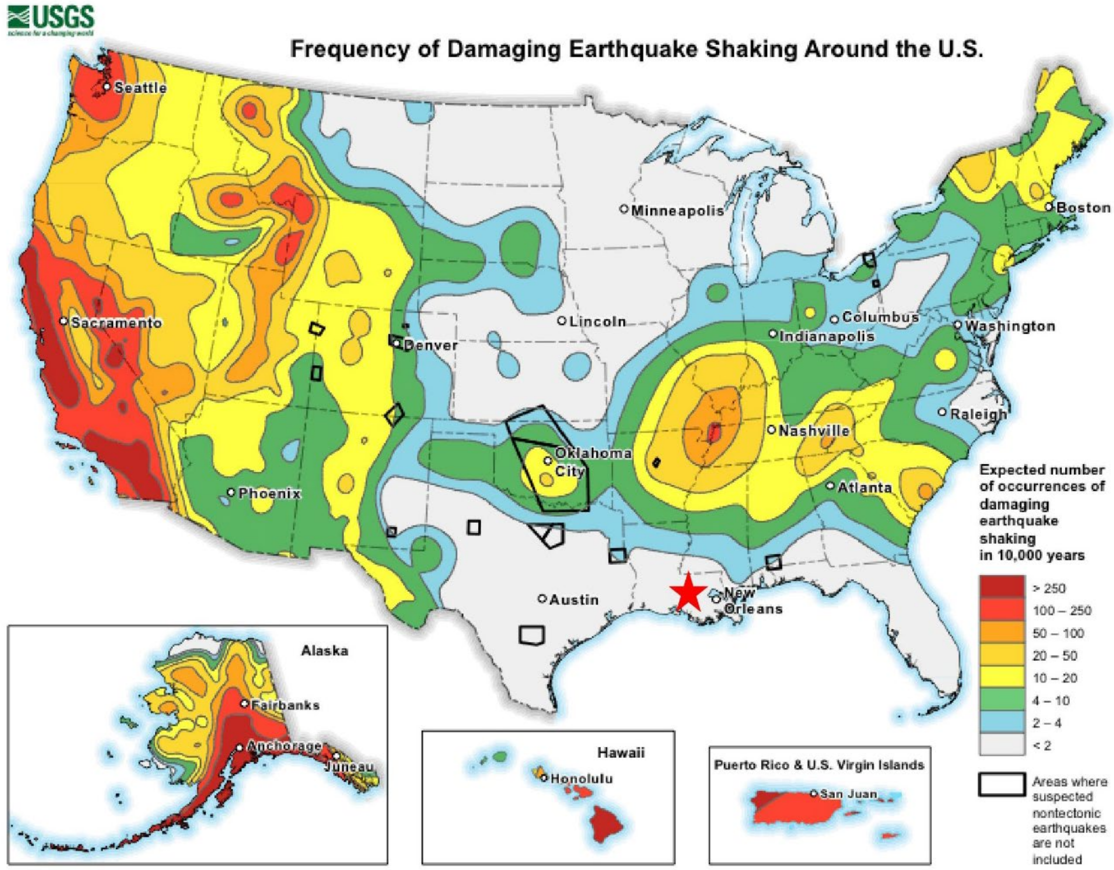

Figure 1-61 – Predicted damaging earthquake shaking around the U.S., with the red star indicating the location of the proposed project (Frequency of Damaging Earthquake Shaking Around the U.S., retrieved 2023).

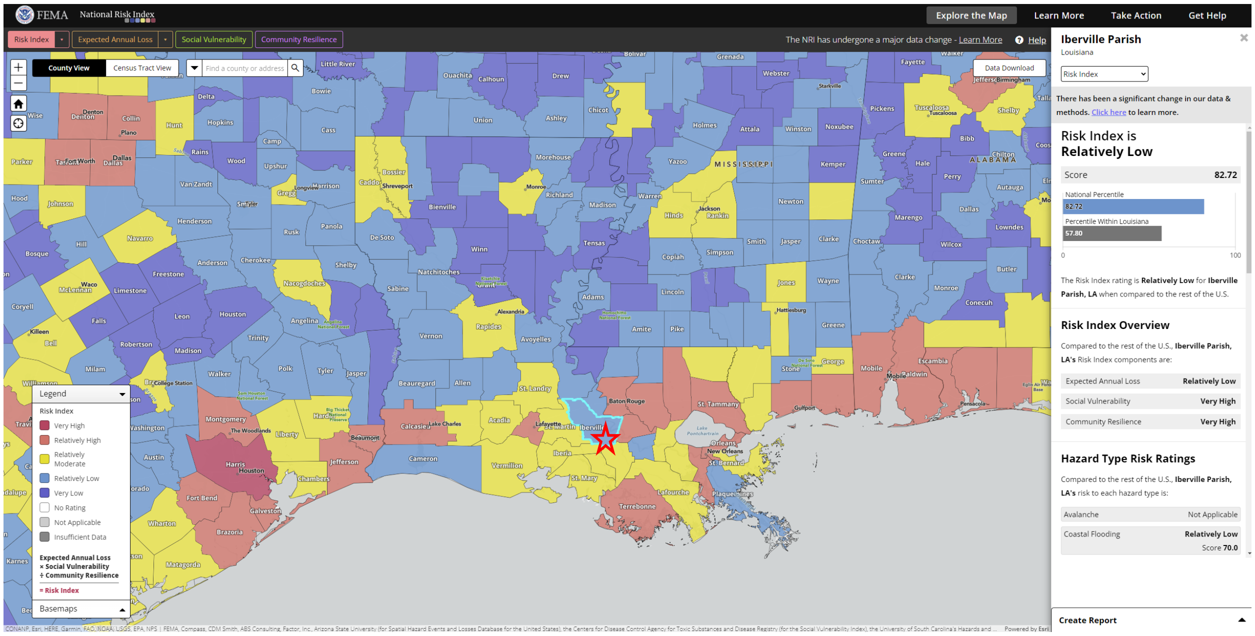

Figure 1-62 – Risk Index Map and the Location of the Proposed Project (National Risk Index FEMA, 2023)

1.12 <u>Conclusion</u>

The site characterization of the proposed White Castle Project and subject injection wells, WC IW-B No. 001 and No. 002, indicates that the Miocene sandstones have sufficient porosity, permeability, and lateral continuity, and are of sufficient depth and thickness to store the proposed amount of CO_2. The [redacted] shale at the site location has low enough permeability and sufficient thickness and lateral continuity of mudstone beds to serve as the primary upper confining zone. At the site, the [redacted] shale has low enough permeability and sufficient thickness and lateral continuity of mudstone beds to serve as the lower confining zone. Potential geologic CO_2 migration pathways in the Miocene injection zones within the AOR are identified, located, characterized, and modeled and determined to be of low risk. No wellbores are located within the AOR. Upon issuance of the Class VI Order to Construct, additional data will be collected and assessed to ensure the site remains low risk for CO_2 injection and storage.

Larger scale versions of the structure maps, cross sections, reference map, and reports are available in *Appendix B.*

Appendix B-1: [redacted] Unit, Top of Structure Map
Appendix B-2: [redacted] Unit, Top of Structure Map
Appendix B-3: [redacted] Structure Map
Appendix B-4: [redacted] Unit, Isopach Map
Appendix B-5: Net Upper Confining Isopach Map
Appendix B-6: Injection Zone, Gross Isopach Map

Appendix B-7:	Net Injection Interval Isopach Map
Appendix B-8:	Lentic Jeff Unit, Lower Confining Zone Isopach Map
Appendix B-9:	Cross Section Reference Map
Appendix B-10:	S-N Structural Cross Section
Appendix B-11:	S-N Stratigraphic Cross Section
Appendix B-12:	W-E Structural Cross Section
Appendix B-13:	W-E Stratigraphic Cross Section
Appendix B-14:	[redacted] Sidewall Core Report
Appendix B-15:	RFS ID No. 202206840-02 Complete Water Analysis Report
Appendix B-16:	NW-SE USDW Structural Cross Section
Appendix B-17:	SW-NE USDW Structural Cross Section
Appendix B-18:	USDW Structure / Cross Section Reference Map
Appendix B-19:	USGS Potentiometric Surface Report
Appendix B-20:	USGS Potentiometric Surface Map

1.13 References

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HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 2 – CARBON FRONT MODEL

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 2 – CARBON FRONT MODEL

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2.1 Introduction

The White Castle CO_2 Sequestration (White Castle) Project site, in southeastern Louisiana, is within the Iberville Parish near the New Orleans/Baton Rouge industrial region. Currently, Harvest Bend CCS LLC (Harvest Bend CCS) has sequestration rights within approximately 10,000 acres in that area and is proposing the development of three CO_2 sequestration wells—each capable of storing approximately 1 million metric tons per year (MMT/yr) of supercritical CO_2 [redacted]

[redacted] All three wells were included in an in-depth model created to simulate 20 years of supercritical CO_2 injection for the [redacted] injection sites. An overview of the well completions is provided in *Section 0 – Introduction*, Table 0-1.

In the case of WC IW-B No. 001, [redacted], the injection interval consists of Miocene sands formations, including the [redacted]. The injection zone is bounded by an upper confining interval and lower seal, the [redacted]

[redacted]. Each injection well, [redacted], plans to inject and store 1 MMT/yr for 20 years in the Miocene sandstone. Modeling a total of three injection wells [redacted] results in a total of 60 MMT of CO_2 sequestered, [redacted].

2.2 Data Sources

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

Regional and site-specific publications were used to help characterize the reservoir and provide guidance on simulation techniques for CO_2 sequestration. The literature consists of publicly available databases and published research papers. As discussed in detail in *Section 1 – Site Characterization*, sidewall core reports from an offset well were used to determine a relationship between porosity and associated permeabilities. Relative permeability curves were generated through the guidance of research papers. Fluid properties of the formation brine, such as salinity, were taken from public databases and water-analysis data on producing wells outside the storage area. These are further discussed in *Section 2.6.2*.

Analysis on offset well logs was also done to help characterize the reservoir and populate the geologic model. A petrophysical analysis on 32 critical offset wells was conducted to assess the potential injection reservoirs and confining zones in the region. The analyzed well logs were incorporated into earth modeling and used to link more than 40 wells to offset seismic lines as discussed in *Section 1*. The well logs were also used as control points in the geologic model to assign rock property values. The available open-hole log data included various analyses such as gamma ray, spontaneous potential, resistivity, porosity (sonic, neutron, density), photoelectric factor, caliper, sidewall core, and any other related analyses.

The 3D seismic data was used in conjunction with formation tops identified through log analysis to understand the geologic structure of the area. That analysis also identified any faults or structural changes that the well log analysis did not identify, thereby enhancing the accuracy of the geologic model by providing a clearer understanding of the targeted stratigraphy. A 3D cross section visual of these structural trends within the injection interval is displayed in Figure 2-1.

[redacted]

Figure 2-1 – Seismic Data (View from the West) of Major Horizons and Faults

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

2.3 Software Discussion

2.3.1 DecisionSpace Software

The static geologic model for the proposed White Castle Project site was created using Landmark's DecisionSpace® software, which is widely used to integrate log and seismic data and create a geostatistical representation of the reservoir. Geoscientists use the DecisionSpace® platform to study and characterize geologic reservoirs. The tool offers a range of features for data analysis, including the ability to (1) generate well-correlation panels and map plots, (2) perform stratigraphic interpretation and contouring, and (3) evaluate structural complexity. The model consists of the [redacted] Miocene sands (injection zone) formations. Petrel™ was used to create the acoustic impedance volume.

2.3.2 Computer Modelling Group's Software

The geologic model from DecisionSpace® was then used as an input into Computer Modelling Group's (CMG) GEM **2022.10** (GEM) simulator—a highly accurate and reliable software package for the long-term simulation of conventional, unconventional, and secondary recovery processes. GEM uses advanced computational methods and equation-of-state (EOS) algorithms to evaluate compositional, chemical, and geochemical processes and characteristics within the injection zone—to produce reliable simulation models used for CO_2 sequestration. To simulate the injection and migration of supercritical CO_2, GEM was chosen for its ability to simulate a wide range of trapping mechanisms and the resulting increase in reservoir pressure due to injection operations.

2.3.3 Prosper Software

The majority of the CO_2 injection well modeling was completed using Prosper, a NODAL analysis software developed by Petroleum Experts (Petex) as part of their Integrated Production Modeling (IPM) suite. The software has evolved into the oil-and-gas industry standard for well and pipeline modeling due to its strong technical basis and modeling capabilities. For enhanced oil recovery (EOR) and CO_2 sequestration applications, Prosper can be set up for injection well modeling and the stream composition modified to reflect the CO_2 stream along with any impurities. Prosper also has a special handling of CO_2 that takes into account both the dense and supercritical phases.

2.4 <u>Trapping Mechanisms</u>

To simulate CO_2 injection as precisely as possible, CMG models CO_2 trapping mechanisms within the injection zone. The flow of CO_2, or carbon front migration, in the reservoir from injection can be defined by five primary trapping mechanisms: (1) structural and (2) hydrodynamic; (3) residual gas (hysteresis); (4) solubility; and (5) geochemical. These mechanisms are described as follows.

2.4.1 Structural and Hydrodynamic Trapping

Structural trapping, a physical form of trapping, occurs by trapping the injected CO_2 in geologic structures within the subsurface. The most common structural trap is an anticline structure with a concave shape caused by a deformation of the formation reservoir rock and caprock. Other traps may also include sealing faults, pinchouts, or shale baffles. Supercritical CO_2 is less dense than the natural brine found in the formation and tends to rise to the top and sit below the caprock. The density of CO_2 in this model ranges from [redacted] pounds per cubic foot (lb/ft^3), while the density of brine is around [redacted] lb/ft^3.

Hydrodynamic trapping is a time-dependent hydrogeological process seen in deep, sedimentary saline aquifers with low permeability rock. As discussed above, supercritical CO_2 is much lighter than the surrounding rock. When the supercritical fluid's movement is impeded by a caprock or low permeability zone, the CO_2 begins to move laterally along the caprock. This process is very similar to structural trapping except that the CO_2 is effectively trapped by very long travel times to the surface. These travel times can be on the order of magnitude of thousands to tens of thousands of years. This mechanism is effective in laterally unconfined sedimentary basins with limited structural traps (Rosenbauer and Thomas, 2010).

To determine the phase of CO_2 at a specific location for both structural and hydrodynamic trapping, EOS calculations are used based on pressure and temperature. The oil and gas industry uses various EOS formulae for reservoir modeling, such as the Van der Waals equation, along with the Peng-Robinson and Soave-Redlich-Kwong methods, both of which can be found within the GEM simulator. The White Castle Project model uses Peng-Robinson, as it is commonly used for volumetric and phase-equilibrium calculations of gas reservoirs.

2.4.2 Residual Gas (Hysteresis) Trapping

Residual gas trapping is another physical form of trapping caused by the trapping of the injected CO_2 gas within the formation pore space. This form of trapping is regarded as one of the most important forms of trapping in high-permeability saline aquifers. This mechanism of trapping occurs when the supercritical CO_2 migrates upwards and laterally through the formation post-injection. As the carbon front migrates, brine displaces the supercritical fluid, leaving small quantities of CO_2 imbedded between the pore spaces due to the surface tension of the rock matrix. Other factors affecting the amount of CO_2 that gets trapped are capillary forces, saturation, and the phase of the CO_2.

To simulate the effect of residual gas trapping, CMG uses hysteresis modeling including both the Carlson and Land and the Larsen and Skauge models—both of which are available in the GEM simulator. For purposes of the simulation discussed here, [redacted] was chosen for the two-phase hysteresis model. The [redacted] was utilized with this model to more accurately simulate the imbibition curves. While the Carlson and Land model is known for its ability to determine two-phase systems, the default linear model is also suited for two-phase systems between water and gas.

2.4.3 Solubility Trapping

Solubility trapping is one of two forms of chemical trapping caused by the interaction between CO_2 and brine. This form occurs when the supercritical CO_2 dissolves into the surrounding brine. The amount of CO_2 dissolved in the brine depends on formation-brine salinity, pressure, and temperature. As a result of the dissolution of CO_2, a denser, CO_2-enriched brine is created—a new enriched brine that is now heavier than the connate brine and that begins to sink within the formation, trapping the CO_2-entrained brine as a result. This process of dissolution increases the storage capacity and reduces fluid migration. The process of solubility trapping is slow and can take upwards of thousands of years for the CO_2 to be completely dissolved.

For solubility modeling, GEM offers the choice of using either the Harvey (1996) or Li-Ngheim (1986) method. For the purposes here, the [redacted] was chosen as it is often preferred in situations with extremely high sodium chloride content. Keywords were included to enable an enhanced solubility model, where the Henry's constants would be based on *salinity*, *pressure*, and *temperature*.

2.4.4 Geochemical Trapping

Geochemical trapping, also referred to as *mineral trapping*, is the second form of chemical trapping. This form of trapping occurs due to chemical reactions between CO_2 and the geochemistry of the disposal formation. During the injection of supercritical CO_2 into the disposal formation, four primary chemical compounds are present: (1) CO_2 in the supercritical phase, (2) in situ hydrochemistry of the connate brine, (3) aqueous CO_2 (an ionic bond between the CO_2 gas and connate brine within the formation), and (4) the geochemistry of the formation rock. These compounds interact with one another, often resulting in CO_2 being precipitated out as a new mineral, which is typically calcium carbonate ($CaCO_3$), or limestone.

Mineral trapping of CO_2 can occur through the adsorption of the gas onto clay minerals. To accurately model this process, we must consider both hysteresis and solubility trapping—done by incorporating geochemical formulae from our database, describing the reactions involved in mineral trapping. These formulae, specifically designed for aqueous reactions, are as follows:

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

Three common ionic reactions can occur in the reservoir between water and CO_2. The following formulae describe these reactions, showing the mineral reactions included in our model. These minerals, commonly found in deep saline aquifers, can cause the precipitation of carbon oxides in a solid state:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

Although geochemical trapping can have a significant impact on CO_2 over long periods of time, thousands or millions of years, its short-term effects are relatively minor, and fluid movement is primarily controlled by hydrodynamic and solubility trapping. Currently, the model does not include geochemical-trapping mechanisms due to limitations in site-specific data on the compositions of minerals and components in the reservoir, as well as computational constraints.

2.4.5 Trapping Mechanisms Summary

The residual trapping of supercritical CO_2 has the largest effect on containing the injected fluid. By the end of the model (120 years), [redacted] of supercritical CO_2 has been residually trapped. The dissolution of CO_2 into the connate brine accounts for [redacted] of all of the trapped supercritical fluid. Figure 2-2 highlights these modelled mechanisms in million metric tons.

[redacted]

Figure 2-2 – Trapping Mechanisms

2.5 <u>Static Geologic Model</u>

2.5.1 Introduction

The 3D computational model of the geologic layers (static model) was constructed using the DecisionSpace® software, and efforts relied heavily on data gathering, data analysis, and geostatistical analysis. Data-gathering activities consisted of gathering all data sources useful in creating the geologic model. Analysis of the data was then conducted to create the structural model and provide a baseline understanding of the major structural horizons in the Lower, Middle, and Upper Miocene sands. Geostatistical analysis and acoustic impedance from seismic data were used to distribute facies, porosity, and permeability values across the model.

2.5.2 Surfaces

Surfaces from the [redacted] were created from the seismically mapped surfaces, mapped in two-way time (TWT), then following a depth conversion, the surfaces were flexed to well picks to encompass the well data within the zones (*Sections 1.3.5* and *1.3.6*). The algorithm used was [redacted], and extrapolation of depth values was restricted to the maximum and minimum of the input data. A grid increment of [redacted] was used.

2.5.3 3D Mesh

[redacted]

Additional vertical resolution was provided by use of proportional layering, with an average of 20' in height. The horizontal (I-J) grid dimensions in the static model are 350' x 350'. The total area of the model is 55.58 square miles. Table 2-1 shows the cell count and average thickness for the vertical cells in the static model within the White Castle Project area, while Figure 2-3 shows a map of the static-model grid boundary and seismic coverage.

Table 2-1 – Vertical Layering Design in the Static Model

Name	Layer Count	Average Thickness (ft)
[redacted]		

[redacted]

Figure 2-3 – Map of the Static Model Grid Boundary

2.5.4 Property Distribution

Properties (e.g., facies, porosity, permeability) were populated in all the cells of the model within the Lower, Middle, and Upper Miocene sands layers in the 3D static model.

2.5.4.1 <u>Facies</u>

[redacted] lithofacies were interpreted using log data and applying porosity cut-offs as Figure 2-4 shows. The best facies interpretation was then upscaled to the 3D grid cells. The seismic data was inverted to obtain acoustic impedance and sampled into the 3D grid as represented through a K slice in Figure 2-5. The acoustic impedance was then used as a collocated co-kriging property for characterizing the porosity and permeability distribution away from well control. The resulting property was also used for the distribution of facies, along with the use of geostatistical tools such as vertical proportions (see summary of vertical proportions in Figure 2-6, page 15) and variogram calculations indicating mostly a [redacted] orientation of the data (an example of which is displayed in Figure 2-7, page 15).

The azimuth for the major direction is [redacted] degrees and was generated with a nugget of zero and sill of [redacted], with the variogram defined for the major, minor, and vertical directions (Figure 2-7). The algorithm used for the facies distribution was [redacted]. Slices trending north-to-south and west-to-east from the facies-modeling results are shown in Figures 2-8 and 2-9 (pages 16 and 17, respectively), as well as a comparison of the raw, upscaled, and property facies distribution (Figure 2-10, page 18).

[redacted]

Figure 2-4 – Porosity cut-offs applied to lithofacies interpretation from log data to define [redacted] facies.

[redacted]

Figure 2-5 – Acoustic impedance slice draped on horizon. This property was used to better characterize facies and porosity modeling away from well control.

[redacted]

Figure 2-6 – Bar Chart of Lithotype Proportions (Facies) by Interval

[redacted]

Figure 2-7 – Variogram model defined for vertical, major, and minor ranges (at left), with variogram parameters and anisotropy direction (right).

[redacted]

Figure 2-8 – North-South Cross Section of the Facies 3D Property of the Static Mode

[redacted]

Figure 2-9 – West-East Cross Section of the Facies 3D Property of the Static Model

[redacted]

Figure 2-10 – Comparative raw (in blue), upscaled (green), and property (yellow) distribution of facies.

2.5.4.2 Porosity

Thirty-two wells in the area of the model, the locations of which Figure 2-11 shows, were used to best estimate the porosity from logs. Porosity estimates for the White Castle Project are discussed in detail in *Section 1.5*. The porosity was upscaled from well logs to grid cells (resolution approximately 20’) via arithmetic averaging. Table 2-2 shows a comparison of the well logs and upscaled porosity values for all porosity logs included in the model.

The porosity values show similar mean-porosity values before and after the upscaling. A normalized score of the porosity data using all the upscaled porosity data was completed prior to distributing porosity between well locations in the grid. Figure 2-12 (page 20) shows a histogram comparing the raw, upscaled, and porosity property values. The porosity was distributed using the upscaled data, collocated to the acoustic impedance and facies properties during the application of the [redacted] algorithm. Figures 2-13 and 2-14 (pages 21 and 22, respectively) show north-south and west-east trending cross sections, respectively, through [redacted] WC IW-B No. 001 and No. 002 in the resulting porosity model.

[redacted]

Figure 2-11 – Well locations (indicated in red) where petrophysical analysis was performed for the area of the static model.

Table 2-2 – Summary of the Log Porosity vs. Upscaled Porosity Data

Porosity Data Comparison			
Porosity Data	**Min**	**Max**	**Mean**
Log	[redacted]	[redacted]	[redacted]
Upscaled	[redacted]	[redacted]	[redacted]

[redacted]

Figure 2-12 – Histogram comparing the well logs (blue), upscaled cells (green), and property cells (yellow) from the porosity model.

[redacted]

Figure 2-13 – North-South Cross Section of the Porosity 3D Property from the Static Model

[redacted]

Figure 2-14 – West-East Cross Section of the Porosity 3D Property from the Static Model

2.5.4.3 Permeability

A two-function porosity-permeability curve was developed from the well and core data as shown in Figure 2-15. Core data was limited to percussion sidewall cores taken from one well ([redacted]) near the acreage of interest. The data quality issues commonly expected with percussion sidewall cores included fractured grains, irregular compaction, and enhanced permeability. These issues increase uncertainty especially in the case of loosely consolidated gulf coast sediments. A single porosity vs. permeability trend is very uncommon for the subsurface and the core data supports the same assessment for this area. A single trend would result in a significant overestimation of permeability for porosities over [redacted]. The addition of the dual trend honors the available data while limiting the ultimate permeability to reasonable values. These equations were used to generate permeability curves at the well level which were upscaled to the 3D grid. The permeability was distributed using the upscaled curves collocated to the acoustic impedance and facies properties during the application of the sequential-gaussian simulation algorithm. The results are shown in a porosity-permeability cross plot in Figure 2-16, while Figure 2-17 (page 24) displays the histogram and statistics showing the permeability results from the permeability property. Figures 2-18 and 2-19 (pages 25 and 26, respectively) show north-south and west-east cross sections through the permeability model, respectively.

[redacted]

Figure 2-15 – Two-function porosity-permeability curve calculated from log and core data.

[redacted]

Figure 2-16 – Porosity-Permeability Cross-Plot of Whole Model Simulation Results

[redacted]

Figure 2-17 – Histogram, Whole Model, and Statistical Results, All Data [redacted], for the Permeability Model

[redacted]

Figure 2-18 – North-South Cross Section of the Permeability 3D Property from the Static Model

[redacted]

Figure 2-19 – West-East Cross Section of the Permeability 3D Property of the Static Model

2.6 <u>Dynamic Model</u>

2.6.1 Model Orientation and Gridding Parameters

2.6.1.1 <u>Spatial Conditions</u>

To identify sand packages for supercritical CO_2 injection, 3D seismic was utilized. Multiple distinct sand packages were identified as potential injection-interval targets, separated by interbedded shale layers and shale baffles. The use of 3D seismic allows for the specific identification of these sand packages as injection targets, helping to optimize the modeling process and improve reservoir-characterization accuracy.

A completion strategy was designed for all wells to control carbon front growth. Sand packages were combined into completion intervals. A *completion interval* is a portion of the gross injection interval that is perforated, injected into, and then plugged at a later date during CO_2 injection operations, once the interval is fully developed. [redacted] The completion-strategy criteria and role of the completion intervals is further discussed in *Section 2.*7, on the Wellbore Model.

[redacted] The model is oriented to the north and has approximately [redacted] million active grid blocks. The total area modeled is approximately [redacted].

[redacted]

Figure 2-20 – Geologic Model of the White Castle CO_2 Sequestration Site

Boundary Conditions

An [redacted] reservoir was created in the model to accurately predict the reservoir's pressure response to CO_2 injection. In order to create an [redacted] reservoir, adjustments called "volume modifiers" were applied to the grid. The Miocene sands appear to be generally well-connected in the region, with few geologic structures that could impede any flow. A regional review was conducted, showing that the aquifer has greater channeling in the north-south than the east-west direction. All nearby faults were determined to be non-transmissive in the model.

Additionally, the upper and lower confinement were assumed to be impermeable to allow for the largest possible carbon front. A volume modifier of [redacted] was applied along the north and south edges of the grid (indicated by the red arrows) and [redacted] on the east and west edges of the grid (green arrows) as shown in Figure 2-21.

[redacted]

Figure 2-21 – Boundary Conditions

2.6.1.2 Model Time Frame

The model was simulated for 120 years, consisting of 20 years of active injection and an additional 100 years of density drift. This time frame was long enough to accurately determine the maximum extent of the carbon front. The model results are further discussed in *Section 2.8*.

2.6.2 Initial Conditions

A dynamic model was built using the geologic model as an input and initialized with the assumptions shown in Table 2-3. The model assumes a brine-filled reservoir of 100% water saturation. [redacted] The following subsections describe the methodology on how this information was derived.

Table 2-3 – Dynamic Modeling Assumptions

Assumptions	Values
Average Permeability (mD)	[redacted]
Average Porosity (%)	
Pore Gradient (psi/ft)	
Frac Gradient (psi/ft)	
Mean Surface Temperature (°F)	
Temperature Gradient (°F/100 ft)	
Salinity (mg/L)	
Max Trapped Gas Saturation (%)	

2.6.2.1 Porosity and Permeability Discussion

Porosity and permeability were determined through petrophysical analysis on offset open-hole logs and core data. As discussed above in the subsection on the *Static Geologic Model* (*Section 2.5*), porosity was determined through the analysis of open hole logs, and permeability was calculated using a two-function porosity-permeability curve relationship (Figure 2-15, *Section 2.5.4.3*) developed from the well and core data.

Porosity and permeability were geostatistically distributed throughout the model as described in *Section 2.5.4.2*. [redacted]. These distributions are shown in north-to-south (N-S) (Figure 2-22) and east-to-west (E-W) (Figure 2-23) cross sections. Table 2-4 also provides a breakdown of these ranges by each facies included in the model.

[redacted]

Figure 2-22 – North-South Cross Section

[redacted]

Figure 2-23 – East-West Cross Section

Table 2-4 – Porosity and Permeability Ranges in the Reservoir Model

Facies	Porosity (%)	Permeability (mD)
Shale	[redacted]	[redacted]
Siltstone	[redacted]	[redacted]
Distal	[redacted]	[redacted]
Proximal	[redacted]	[redacted]
Axial	[redacted]	[redacted]

2.6.2.2 Reservoir Pressure Discussion

A regional review of South Louisiana was first conducted to best estimate the depth of the geopressured zone. Identifying the depth of overpressure is a critical step to ensure that the injection zone is hydrostatic. This review concluded that the geopressured zone (greater than

0.7 psi/ft) is below approximately 11,500' (Burke et al.. 2012). The regional map of South Louisiana provided in Figure 2-24 highlights the depth of the geopressured zone.

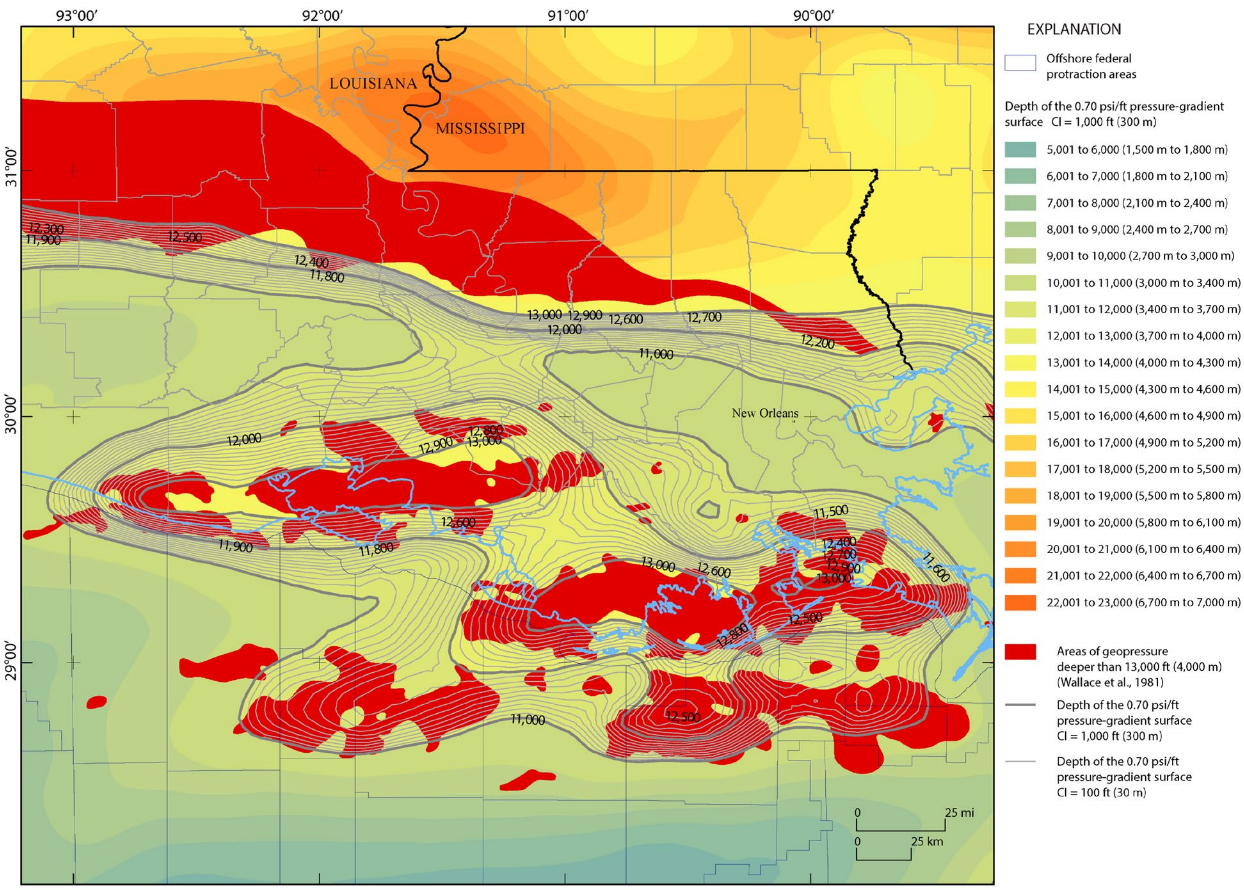

Figure 2-24 – Regional Map of 0.7 psi/ft Gradient (Burke et al., 2012)

After identifying the overpressure regions, well mud analysis was conducted on offset [redacted] to best estimate the in situ reservoir pressure. The analysis (Figure 2-25) concluded that, based on mud weight and open-hole log data, reservoir pore pressure approached approximately [redacted] (Figure 2-25) in the lower sands of the gross injection interval for the subject well. This equates to a reservoir pressure of [redacted]. Further analysis was done on the connate brine density to confirm this pressure gradient. Using McCain's Correlations, a calculated salinity of roughly [redacted] mg/L, the density of the connate brine is [redacted]. This density would equate to a [redacted] pressure gradient assuming hydrostatic conditions.

The model is initialized with the [redacted] pore pressure gradient. The simulation model then calculates reservoir pressure as the temperature varies with depth which results in a lower reservoir pressure gradient at shallower intervals and a higher pressure gradient at lower intervals in the model.

[redacted]

Figure 2-25 – Mud Log Analysis of Target Formation

2.6.2.3 Fracture Pressure Discussion

Uniaxial Strain Equation

The fracture pressure was best estimated using data from the [redacted] Well using the uniaxial strain equation and fracture mechanics. The calculation inputs include vertical stress (S_v), pore pressure (P_p), and a value for the constant "K," which is the ratio of minimum horizontal effective stress to vertical effective stress. These variables can be changed to match the site-specific injection zone. Table 2-5 provides a summary of all inputs used to calculate the fracture gradient, while *Section 1 – Site Characterization* contains a more detailed discussion.

Table 2-5 – Fracture Gradient Calculation Assumptions – Uniaxial Strain

Inputs	Values
Vertical Stress Gradient (psi/ft)	[redacted]
Pore Gradient (psi/ft)	
K	

Using these values in Equation 1, a fracture gradient of [redacted] was calculated for the upper confining zone. Due to the substantial thickness of the upper confining zone, values were calculated for the depth 100' above the base of the zone. This gradient was selected to calculate the maximum allowable bottomhole pressure, because it is slightly lower than the fracture gradients of the injection and lower confining zones. A [redacted] safety factor was then applied to this number—resulting in a maximum allowable bottomhole pressure of [redacted] This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Equations with Variables:

(Eq. 1)

$$FG = K \times \left(S_v - P_p\right) + P_p$$
$$FG\ with\ SF = FG \times (1 - 10\%)$$

Where:
K = the ratio of minimum horizontal effective stress to vertical effective stress
S_v = vertical stress
P_p = pore pressure
FG = fracture gradient
SF = safety factor

Equations with Values for Upper Confining Zone:

[redacted]

2.6.2.4 Temperature Discussion

Well data and public literature were utilized to determine reservoir temperature. Drilling-fluid analysis from five offset logs was used to calculate the bottomhole temperature (BHT). The BHTs were then corrected to time since the last circulation. The calculated geothermal gradients were compared to publicly available geothermal gradients from Southern Methodist University (SMU) as Figure 2-26 shows. The resulting temperature gradient is [redacted] and is applied throughout the reservoir model.

[redacted]

Figure 2-26 – Geothermal Gradients from Offset Wells and SMU

2.6.2.5 Reservoir Salinity Discussion

The formation brine salinity was determined through a regional review of publicly available brine samples. The U.S. Geological Survey (USGS) provides a database on fluid properties across the entire country. The National Produced Waters Geochemical Database provided by the USGS was used to best estimate the salinity of the target injection zone. Samples within a 620 square mile window were reviewed to best estimate the average salinity in the reservoir. Also, 288 samples were taken from this window and plotted to identify any trends in the injection zone (Figure 2-27). A complete water analysis was also conducted on the [redacted], where the total dissolved solids (TDS) was determined to be [redacted] mg/L (discussed in greater detail in *Section 1 – Site Characterization*). Based on the data, the TDS, best estimated to be [redacted] mg/L, was used to delineate the salinity in the model.

[redacted]

Figure 2-27 – TDS vs. Depth Chart

2.6.3 Relative Permeability Curve Generation

To predict the amount of supercritical CO_2 that is residually trapped, CMG's GEM utilizes hysteresis modeling. The hysteresis model allows for the simulation of the drainage and imbibition processes. *Drainage* is the process of a nonwetting fluid (supercritical CO_2) displacing the wetting fluid (brine) in the reservoir. *Imbibition* describes the process of the wetting fluid reentering the pore space. During imbibition, a small amount of CO_2 is effectively trapped in the pore space. The maximum amount of gas that can be trapped in the rock is known as the maximum residual gas saturation ($S_{gr,max}$).

[redacted]

Absolute permeability of a porous medium is the permeability at 100% saturation of a single fluid. When a reservoir only has one type of fluid, the *effective permeability* is the same as the absolute permeability. However, the effective permeability is reduced as a new fluid is introduced into the reservoir. This phenomenon is reflected by relative permeability curves, which describe the effective permeability of two or more fluids flowing through a porous medium.

Relative permeability curves (Figures 2-28) were generated as model inputs into the GEM. Lack of core data resulted in an extensive literature review to create relative permeability curves representative of the Miocene sands. Based on this review, relative permeability curves fitted to the datapoints from the Barea formation were used (Krevor, 2011). [redacted]

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

[redacted]

Figure 2-28 – Kr vs. Sg Relative Permeability Curve

2.7 Wellbore Model

For the White Castle Project, the wellbores were set up using the latest wellbore schematics (WBS) along with some assumptions as provided in Table 2-6. Three primary constraints were imposed in CMG to limit the pressure response and carbon front growth: (1) a maximum injection rate of 1 MMT/yr, (2) a maximum (BHP) gradient of [redacted] and (3) an injection duration of 20 years. The injection rate and duration constraints were imposed to provide the largest possible carbon front based on estimated CO_2 available for sequestration. The pressure constraint was determined through calculations discussed in the subsection on *Fracture Pressure Discussion* (*Section 2.6.1.5*). These constraints would result in a BHP response to be used as an input for Prosper to determine surface injection pressures.

Using the Vertical Lift Performance (VLP) module along with reservoir properties, it is possible to solve for the estimated surface pressure required to inject along with the maximum surface pressure (not to exceed 90% fracture gradient). While Prosper has many other functionalities, the main purpose of this exercise with Prosper is to calculate the operating range for each injection interval along with the maximum expected surface/wellhead pressure during injection.

Table 2-6 – Wellbore Model Assumptions

Inputs	WC IW-B No. 001	WC IW-B No. 002
Max Injection Rate (mt/yr)	1,000,000	1,000,000
[redacted]		

Two scenarios were run to predict the surface injection pressure. A worst-case scenario was first looked at to provide a conservative, best estimate. This case assumed a 1.5 MT/yr injection rate and a max BHP that is 90% of the fracture gradient. A second scenario provided a more realistic wellhead pressure (WHP) estimate. An injection rate of 1.0 MT/yr and an average BHP were assumed. The BHP values were determined from the model to be the averaged BHP of each completion stage.

[redacted] To minimize carbon front growth, the wells are further divided into completion stages. Each completion stage represents a portion of the reservoir that will be injected into, at a given time. [redacted] At each new stage, the pressure constraint is updated based on the upper perforation depth. This was done to ensure that the bottomhole pressure never exceeds the calculated fracture gradient. A general description of the well designs and completion strategies is detailed in Tables 2-7 and 2-8.

Table 2-7 – Completion Strategy for WC IW-B No. 001

Well Completion Stage	Injection Duration (years)	Top Perf (TVD ft)	Bottom Perf (TVD ft)	Net Pay (ft)
[redacted]				

* TVD = true vertical depth

Table 2-8 – Completion Strategy for WC IW-B No. 002

Well Completion Stage	Injection Duration (years)	Top Perf (TVD ft)	Bottom Perf (TVD ft)	Net Pay (ft)
[redacted]				

2.8 Model Results

2.8.1 Carbon Front Migration

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 carbon front or critical pressure front or both. The first review starts with the extent of the carbon front. All injection wells that are part of the White Castle Project were accounted for when determining the carbon front extent. [redacted]

The supercritical carbon front may grow in different directions due to the structure of the reservoir and presence of channels visualized in Figure 2-29. These channels can act as high-permeability pathways for the CO_2 to migrate through. In this case, significant channeling is trending in the north-south direction.

[redacted]

Figure 2-29 – GEM Carbon Front Model Results, Colored by CO_2 Saturation

Figures 2-30 and 2-31 highlight how the carbon front's shape and size vary in each sand package; the goal of the completion strategy design is to minimize this variation as much as possible. The current design allows for the injection site to use the geology of the shale baffles, to permanently sequester the CO_2 while minimizing the carbon front's footprint.

[redacted]

Figure 2-30 – East-West Cross-Sectional View, Colored by CO_2 Saturation

[redacted]

Figure 2-31 – North-South Cross-Sectional View, Colored by CO_2 Saturation

The AOR is delineated by taking the maximum extent of the CO_2 in every layer of the model [redacted] years after injection ceases. The maximum extent of the carbon front is determined using a gas saturation cutoff of [redacted]. Offset CO_2 injection is also taken into account, and the additional supercritical CO_2 is used to determine the maximum extent of the carbon front. [redacted]

[redacted]

Figure 2-32 – Maximum Extent of Carbon Front

2.8.2 Carbon Front Stabilization

Carbon front stabilization is considered to occur when the rate of growth or positional change of the carbon front is minimal, and the carbon front remains reasonably emplaced. At this point, the carbon front has become hydrodynamically trapped within the pore space. [redacted]

[redacted] Figure 2-33 shows the plume stabilizing within [redacted] years after injection operations. [redacted]

[redacted]

Figure 2-33 – Carbon Front Growth Over Time

2.8.3 Well Operations

During the active life of the well, bottomhole pressure and rate were simulated for each completion stage. [redacted] During active operations, pressure will continuously be monitored to ensure BHP remains below 90% fracture gradient. Figure 2-34 and Figure 2-35 display the injection rate and subsequent BHP response during the active life of WC IW-B No. 001 and No 002, respectively. Tables 2-9 and 2-10 also summarize the completion operations in the model for the injection wells [redacted].

[redacted]

Figure 2-34 – BHP and Injection Rate During Operations (WC IW-B No. 001)

[redacted]

Figure 2-35 – BHP and Injection Rate During Operations (WC IW-B No. 002)

Table 2-9 – WC IW-B No. 001 Well Model Outputs

Stage	Injection Duration (yrs)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)
[redacted]				

Table 2-10 – WC IW-B No. 002 Well Model Outputs

Stage	Injection Duration (yrs)	Avg Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)
[redacted]				

To predict the movement of in situ fluid, the increase in reservoir pressure due to gas injection is also simulated. This phenomenon is referred to as *pressure buildup*, which is monitored by the rise of reservoir pressure as well as its associated gradient—based on the top of the perforated interval. BHP values used to calculate pressure buildup are taken at the wellbore in the model. Figures 2-36 and 2-37 represent both the maximum pressure buildup and maximum pressure gradient seen within the reservoir at any given time for WC IW-B No. 001 and No. 002, respectively. In the model, the reservoir experiences a maximum pressure buildup of [redacted] Pressure will be continuously monitored to ensure that 90% of the fracture gradient will not be exceeded, allowing for the safe injection of supercritical CO_2.

[redacted]

Figure 2-36 – Pressure Buildup During Active Injection (WC IW-B No. 001)

[redacted]

Figure 2-37 – Pressure Buildup During Active Injection (WC IW-B No. 002)

Once injection ceases, the reservoir pressure buildup drastically decreases to near in situ conditions. Pressure buildup falls to a maximum of [redacted] once the wells are shut in. The reservoir remains approximately [redacted] above initial conditions by the end of the model. Table 2-11 provides a summary of the reservoir pressure buildup at the wellbore.

Table 2-11 – Maximum Bottomhole Pressure Buildup in the Model at [redacted]

Year	WC IW B No. 001 Max BHP Buildup (psi)	WC IW B No. 002 Max BHP Buildup (psi)
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]
5	[redacted]	[redacted]
6	[redacted]	[redacted]
7	[redacted]	[redacted]
8	[redacted]	[redacted]
9	[redacted]	[redacted]
10	[redacted]	[redacted]
11	[redacted]	[redacted]
12	[redacted]	[redacted]
13	[redacted]	[redacted]
14	[redacted]	[redacted]
15	[redacted]	[redacted]
16	[redacted]	[redacted]
17	[redacted]	[redacted]
18	[redacted]	[redacted]
19	[redacted]	[redacted]
20	[redacted]	[redacted]
21	[redacted]	[redacted]
25	[redacted]	[redacted]
30	[redacted]	[redacted]
35	[redacted]	[redacted]
40	[redacted]	[redacted]
45	[redacted]	[redacted]
50	[redacted]	[redacted]
60	[redacted]	[redacted]
70	[redacted]	[redacted]
80	[redacted]	[redacted]
90	[redacted]	[redacted]
100	[redacted]	[redacted]
110	[redacted]	[redacted]
120	[redacted]	[redacted]

Wellhead pressure was calculated to be a maximum of [redacted] at WC IW-B No. 001 and [redacted] at WC IW-B No. 002. The first scenario (Max WHP) calculated a surface injection pressure of [redacted], whereas the second scenario (Avg WHP) estimated an average of [redacted] WHP over the life of the WC IW-B No. 001. A Max WHP of [redacted] and an Avg WHP of [redacted] resulted for WC IW-B No. 002. Both cases show that the maximum wellhead pressure occurs in the first completion in each well and is expected to decrease as the completions become shallower. All equipment will be sized to handle the maximum WHP seen in the worst-case scenario. Tables 2-12 and 2-13 summarize the results from Prosper's VLP analysis.

Table 2-12 – Surface Injection Pressure Output Summary – WC IW-B No. 001

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

Table 2-13 – Surface Injection Pressure Output Summary – WC IW-B No. 002

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

2.8.4 Critical Pressure Front Delineation

In accordance with SWO 29-N-6 **§3615.A** [40 CFR **§146.84**], the AOR must be determined by the maximum extent of either the supercritical carbon front or critical pressure front or both. *Critical pressure* is the increase in reservoir pressure that may push in situ fluids out of the injection zone and into the lowermost USDW. The first step is to calculate the critical pressure for each completion stage from each injection well. Once critical pressure is determined, numerical simulation is used to predict the size and shape of the critical pressure front for each completion stage from each injection well.

The EPA has outlined three potential methodologies to calculate the critical pressure. The methodology was selected from EPA Method 2, which utilizes Nicot's method to calculate the critical pressure. Nicot assumes that the reservoir is in hydrostatic equilibrium, neither over-pressurized nor under-pressurized, and that a direct path between the two zones is also assumed to exist. This can include an incorrectly plugged and abandoned wellbore or some other subsurface feature.

[redacted]

The critical pressure was calculated for each of the completions for each of the three injection wells. [redacted] The fluid in the injection zone is assumed to be brine, with [redacted] mg/L TDS, which results in a [redacted] pressure gradient. The fluid within the USDW was assumed to be fresh water (less than 10,000 ppm) with a pressure gradient of [redacted] For an example completion interval, the shallowest interval in WC IW-A No. 001, the inputs used in the critical pressure calculation are provided in Table 2-14.

Table 2-14 – Critical Pressure Calculation Assumptions

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

The calculations for the uppermost stage in WC IW-A No. 001 are detailed below. The coefficient (ξ) is first calculated in Equation 4 using the pressure gradients and depths for the base of the USDW and top of injection zone.

(Eq. 4) $$\xi = \frac{G_i - G_u}{D_i - D_u}$$

[redacted]

[redacted]

Where:
ξ *= coefficient*
G_i *= gradient of injection zone*
G_u *= gradient of USDW*
D_i *= depth to top of injection zone*
D_u *= depth to base of USDW*

The critical pressure rise (ΔP_c) is then calculated using Equation 5. The inputs include the coefficient (ξ) calculated in Equation 4 and the depths for the base of USDW (D_u) and top of injection (D_i).

(Eq. 5) $$\Delta P_c = \frac{1}{2} * \xi * (D_i - D_u)^2$$

[redacted]

Where:
ΔP_c = critical pressure rise
ξ *= coefficient*
D_i *= depth to top of injection zone*
D_u *= depth to base of USDW*

The resulting critical pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by approximately [redacted] without risk of fluid migration to the USDW. The calculated critical-pressure rise for each of the [redacted] stages in each injection well is included in Tables 2-15 through 2-17.

Table 2-15 – Critical-Threshold Pressure at Each Stage – WC IW-A No. 001

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Table 2-16 – Critical-Threshold Pressure at Each Stage – WC IW-B No. 001

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Table 2-17 – Critical-Threshold Pressure at Each Stage – WC IW-B No. 002

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

The largest pressure front or a combination of each completion's pressure front is used to delineate the AOR. The buildup of pressure is largely affected by offset CO_2 injectors, which were considered in this model. The maximum critical pressure front of WC IW-B No. 001 communicates with the pressure front from WC IW-A No. 001 ([redacted]) to form one continuous critical-pressure front. The currently predicted composite pressure front for all three injection wells covers [redacted]) of land. The pressure front primarily extends mostly in the north-south direction with a maximum extent of [redacted]. Figure 2-38 provides the maximum extent of the critical pressure rise.

[redacted]

Figure 2-38 – Maximum Extent of the Critical Pressure Front

2.9 Area of Review

The final AOR is comprised of both the maximum carbon and critical pressure fronts from each completion stage for each injection well part of the White Castle Project. The AOR determines the necessary monitoring and potential corrective action plan for any offset wells. The two fronts that comprise the AOR may potentially require different monitoring and corrective action considerations. The AOR encompasses [redacted] by the end of the monitoring period. Figure 2-39 shows the final outline of the AOR for the White Castle Project.

[redacted]

Figure 2-39 – White Castle Project AOR

2.10 References

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HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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Tables

3.1 Introduction

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) be conducted for a Class VI carbon sequestration well application. The Environmental Protection Agency (EPA) defines the AOR as the greater of either the maximum extent of the separate-phase plume (pore occupancy carbon front), or the pressure front where the pressure buildup is of sufficient magnitude to force fluids from the injection zone into the formation matrix of an Underground Source of Drinking Water (USDW). Both parts of this definition were analyzed for the White Castle CO_2 Sequestration (White Castle) Project AOR.

3.2 Model Background

Model Name and Version: **GEM 2022.10**

Model Authors/Institution: Computer Modelling Group, Ltd.

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

3.3 Model Inputs and Assumptions

The input parameters for the GEM model are summarized in Table 3-1. These parameters are based on the values best estimated at the White Castle Project location.

Table 3-1 – Model Input Parameters and Assumptions

Input	Value
Injection Rate	1 million metric tons per year (MMT/yr) (53,300,000 million cubic feet per day (MMscf/d))
Porosity	[redacted]
Permeability	[redacted]
Bottomhole Temperature	[redacted]
Fracture Gradient	[redacted]
Maximum Allowable Injection Gradient	[redacted]
Brine Salinity	[redacted]
Injected Fluid Composition	100% CO_2

3.4 Area of Review: Pore Occupancy Carbon Front

The first component of the currently predicted AOR is delineated using computational carbon front modeling of an injected CO_2 stream. Computational modeling accounts for the physical and chemical properties of all phases of the injectate and is constructed based on available site characterization, operational, and monitoring data. (*Section 2 – Carbon Front Model* discussed the methodology and process in detail.) The pore occupancy carbon front is considered and reviewed based on three primary details: *artificial penetrations*, *subsurface features*, and *pore space rights*.

Any **artificial penetrations** located within the AOR must be evaluated for proper completions, plugging, and construction materials. These wellbores must be constructed and/or plugged using appropriate materials to support long-term storage of carbon oxides. Most legacy wells in North America, however, were not constructed with the intent of future CO_2 storage projects in the area. Thus, most wellbores located within the pore occupancy carbon front, that penetrate the gross injection zone, would require a corrective action or a contingency plan—to ensure that stored gases do not risk escaping containment by way of these penetrations. Any wells identified within this AOR that do not penetrate the gross injection zone would not pose a threat to the containment integrity and are hence excluded from any corrective action or contingency plan.

Subsurface features, such as faults, folds, mapped fractures, steeply dipping formations, and salt diapirs, etc., identified within the AOR will be assessed for their expected impact to the storage reservoir. Should any structural anomalies be discovered within the gross injection zone or upper confining interval, efforts to assess their sealing nature will be conducted. These features can act as either barriers aiding CO_2 containment or, conversely, as conduits allowing the CO_2 to move out of the storage zone. [redacted]

Pore space rights are critically important when evaluating a project's potential due to the classification of carbon injection wells as *storage* wells rather than *disposal* wells. Operating strategies and reservoir management practices were designed to maintain control of the resulting carbon front in the storage reservoir. The area determined for pore space rights was used to identify landowners within the currently predicted carbon front area. [redacted]

3.5 Area of Review: Pressure Front

A second component of the AOR delineation considers the pressure front created by the injection of fluids into a previously stable reservoir. Both calculation and computational modeling determine this component of the AOR. The 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 interval of the gross injection zone.

The worst-case scenario for moving reservoir fluids to the USDW would be through an improperly plugged and abandoned wellbore or subsurface feature that is open both at the base of the USDW and at the top of the injection interval. The methodology for finding this resultant pressure—referred to as the *critical pressure*—was sourced from EPA Method 2 guidance for calculations based on displacing fluid initially present in the borehole in the hydrostatic case.

Table 3-2 lists the details for the nearby USDW determinations used to best estimate the depth of the base of the USDW in the area. Figure 3-1 (*Appendix C-1*) maps the location of these wells relative to the White Castle Project area.

Table 3-2 – USDW Depths from Offset Well Locations

API Number	Serial Number	USDW Depth (feet)	Distance from WC IW-B No. 001 (feet)	Distance from WC IW-B No. 001 (feet)
[redacted]				

[redacted]

Figure 3-1 – USDW Determination Map

The base of the USDW in the area is estimated to range from approximately [redacted] based off numerous offset wells; [redacted]

The critical pressure was calculated for each of the completions for each of the three injection wells part of the White Castle Project. The [redacted] The fluid within the USDW was assumed to be brine water with 10,000 ppm of total dissolved solids (TDS), which results in a pressure gradient of 0.436 psi/ft. A summary of the calculation inputs for an example completion interval, the shallowest interval in WC IW-A No. 001, is included in Table 3-3.

Brine was assumed as the fluid in the injection zone with [redacted] of TDS, based on water analysis from the nearby [redacted] and data from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database, taken for wells close to the White Castle Project area.[1] The distribution of the TDS data for those wells is shown in Figure 3-2. The density of the formation brine in the injection zone was calculated to be [redacted] using correlations by McCain (1991), which results in a [redacted] pressure gradient.

[1] https://www.usgs.gov/data/us-geological-survey-national-produced-waters-geochemical-database-v23

[redacted]

Figure 3-2 – TDS Data for Offset Wells in the Miocene Formation

Table 3-3 – Inputs for Critical Pressure Calculation

Inputs for Critical Pressure Calculation	
Depth to Base of USDW (D_u)	[redacted]
Depth to Top of Injection Zone (D_i)	[redacted]
Gradient of USDW (G_u)	[redacted]
Gradient of Injection Zone (G_i)	[redacted]

The calculations for the uppermost stage in WC IW-A No. 001 are detailed as follows. 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]

Where:
ξ = coefficient
G_i = gradient of injection zone
G_u = gradient of USDW
D_i = depth to top of injection zone
D_u = depth to base of USDW

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]

Where:
ΔP_c = critical pressure rise
ξ = coefficient
D_i = depth to top of injection zone
D_u = depth to base of USDW

The resulting critical pressure rise for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by [redacted] without risk of fluid migration to the USDW. Tables 3-4 through 3-6 display the calculated critical pressure rise for each of the completion stages in each injection well. Once critical pressure is determined, numerical simulation is used to predict the size and shape of the critical pressure front for each completion stage from each injection well.

Table 3-4 – Results of Critical Pressure Calculation – WC IW-A No. 001

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Table 3-5 – Results of Critical Pressure Calculation – WC IW-B No. 001

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

Table 3-6 – Results of Critical Pressure Calculation – WC IW-B No. 002

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
[redacted]		

The complete, currently predicted AOR for the White Castle Project is the total area covered by both the carbon and critical pressure front areas for each completion stage from each of the three injection wells that are a part of the project. Any artificial penetrations or structurally anomalous subsurface features identified within the AOR were assessed for sufficient USDW protection and, if deemed insufficient, included in the corrective action or contingency plan.

The AOR was determined according to the following three purposes—the same details used to review the pore occupancy volume, as discussed in *Section 3.4*:

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 features* that may influence the ability to store sequestered gases for an indefinite length of time
3. Identification of *pore space rights* impacted by the extent of the carbon front over the modeled time period

3.6 Reevaluation of AOR

Per SWO 29-N-6 **§3615.B.2.b** [40 CFR **§146.84(b)(2)**] requirements, Harvest Bend CCS will reevaluate the AOR at each of the following intervals:

- At a minimum frequency of 5 years
- Upon detection of a significant change in the carbon front
- As otherwise warranted by routine monitoring or operational conditions

Wells identified requiring corrective action within the reevaluated AOR will be addressed in an amended AOR and corrective action plan that will be submitted to the EPA Underground Injection Control (UIC) Program Director (UIC Director) for approval. Once approved, all amendments and corrective plans will be incorporated into the permit and subjected to permit alteration requirements.

If the evaluation does not result in changes to the AOR or the corrective action plan, Harvest Bend CCS will demonstrate to the UIC Director that such changes are not needed, by providing the supporting monitoring data and model results. All model inputs and data used in AOR reevaluations will be retained for 10 years.

3.7 Operating Strategies Influencing Reservoir Modeling Results

[redacted], approximately [redacted] of usable sand packages were targeted for injection completed in the Upper and Lower Miocene sands. [redacted] The primary objective of the operating strategies was to control the resultant lateral carbon front extent to ensure it remains contained within the controlled pore space. The GEM simulator was employed to produce the following outputs—in Figures 3-3 and 3-4—associated with this reservoir management program. Both cross-sectional and oblique cross-sectional visualizations are displayed, respectively. The X and Y scales on both figures are shown in U.S. feet, and the color scales represent the specified property values in the model.

[redacted]

Figure 3-3 – GEM Carbon Front Model Results—East-West Cross-Sectional View
(Colored by CO_2 Saturation)

[redacted]

Figure 3-4 – GEM Carbon Front Model Results—North-South Cross-Sectional View
(Colored by CO_2 Saturation)

The shape and lateral extent of the stabilized carbon front for the proposed wells are illustrated in Figure 3-5. This extent was used to determine the initial project AOR.

[redacted]

Figure 3-5 – GEM Carbon Front Model Results—Plan View of Stabilized Carbon Front

These carbon front extents for each completion stage from each injection well were digitized from the GEM output and imported into ArcGIS for use as the defined area of influence from which the White Castle Project AOR was established. Harvest Bend CCS conducted a review to identify any artificial penetrations or other features that may endanger the lowermost USDW as a result of injection activity or operations per SWO 29-N-6 **§3615.B.1** [40 CFR **§146.84].** Harvest Bend CCS also generated maps showing the area of influence and any man-made structures found within the AOR for the proposed White Castle Project (displayed in Figure 3-6). No oil and gas wells were found in the AOR.

The maps and associated lists generated during this effort can be found in *Appendix C*.

[redacted]

Figure 3-6 – White Castle Project AOR

3.8 Area of Review Results

The LDNR's Strategic Online Natural Resources Information System (SONRIS) was the primary source for collecting oil and gas well data for the AOR. Supplemental well data from Enverus/DrillingInfo, TGS, and S&P Global's Enerdeq Browser were then included and assessed to prevent historical well omissions and data inaccuracies. Well information was also gleaned by searching historical microfiche, onion skin paper files, and hand-drawn maps found in archives at the LDNR in Baton Rouge, Louisiana. Review of these hard-copy files confirmed that there were no undocumented orphan wells in the project area that were missing from SONRIS. All water well data was also gathered from the SONRIS database.

As stated in *Section 0 – Introduction*, the proposed White Castle Project location is favorably suited for carbon sequestration. The evaluation of the AOR results yielded zero existing artificial penetrations within the AOR boundary (Figure 3-7; *Appendix C-2*). No faults or other subsurface features or other man-made structures, such as cleanup sites, subsurface mines, or quarries (*Appendix C-6*), were found within the AOR, within the proposed injection interval, that could affect the integrity of the disposal intervals for permanent CO_2 sequestration.

[redacted]

Figure 3-7 – Map of Oil and Gas Wells in/near AOR (Aerial)

No freshwater wells were found within the AOR, as shown in Figure 3-8 (*Appendix C-4*). [redacted] A list of all water wells found on properties within or adjacent to properties in the AOR are provided in *Appendix C-5*.

[redacted]

Figure 3-8 – Map of Active Freshwater Wells in/near AOR

3.9 Corrective Action Plan and Schedule

As discussed above, the AOR is described as the maximum area covered by the carbon and pressure front boundaries. The carbon front extent considers the pore space occupied by the CO_2 injectate as determined by the reservoir modeling results. The pressure front covers a calculated distance, where the injected CO_2 could pressure up the reservoir enough to allow brine and other formation fluids to be pushed upward into a USDW. No wells were found to be present within the bounds of the AOR.

Upon each reevaluation of the AOR, a new review of all artificial penetrations and other geological structures will be performed and the corrective action plan updated as needed.

3.10 Area of Review Reevaluation Plan and Schedule

3.10.1 Proposed Reevaluation Cycle

In accordance with SWO 29-N-6 **§3615.B.2.b.i** [40 CFR **§146.84(b)(2)(i)**], Harvest Bend CCS will reevaluate the AOR at least every 5 years or upon a triggering event. Table 3-7 lists these possible triggers. The evaluations will be used to validate the carbon front model against actual, empirical results.

Table 3-7 – Triggers for AOR Reevaluations

Reevaluation Trigger	Measure to be Taken	Schedule for Reevaluation
5-year carbon front migration survey SWO 29-N-6 **§3615.C.2** [40 CFR **§146.84(e)**] identifies a greater carbon front extent than modeled	• Re-run the reservoir carbon front model with new data. • Reevaluate the AOR.	At least once every 5 years
5-year carbon front migration survey SWO 29-N-6 **§3615.C.2** [40 CFR **§146.84(e)**] identifies the carbon front direction is different than modeled	• Re-run the reservoir carbon front model with new data. • Reevaluate the AOR.	At least once every 5 years
<u>Operational change</u>: total reservoir storage volume for a well completion stage increases to a volume greater than modeled	• Re-run the reservoir carbon front model with new data. • If carbon front increases in extents, reevaluate the AOR.	Within 1 month of detection
<u>Operational change</u>: injectate composition changes to a new mixture outside range of expected pipeline specifications	• Re-run the reservoir carbon front model with new data. • If carbon front increases in extents, reevaluate the AOR.	Within 1 month of detection
New site characterization data outside the range of modelled uncertainty	• Re-run the reservoir carbon front model with new data. • If plume increases in extents, reevaluate the AOR.	Within 1 month of detection
New injection well within the Harvest Bend acreage being brought online within or near the carbon front extent	• Re-run the reservoir carbon front model with new data. • If carbon front increases in shape or extents, reevaluate the AOR.	Within 1 month of detection
Seismic event or other emergency	• Perform a carbon front migration survey. • If carbon front increases in shape or extents, reevaluate the AOR.	Within 1 month of detection

3.11 <u>Conclusion</u>

The results of this AOR investigation validate the favorable conditions for carbon sequestration at the proposed White Castle CO_2 Sequestration Project area. The currently predicted AOR determined from model results and pressure front calculations did not identify any wells that require corrective action. Unless otherwise triggered by one of the events described above, the AOR investigation will be reevaluated at least every 5 years.

Larger scale versions of the AOR maps and associated lists are available in *Appendix C*.

Appendix C-1	USDW Determination Map
Appendix C-2	Map of Oil and Gas Wells in/near AOR
Appendix C-3	List of Oil and Gas Wells in AOR
Appendix C-4	Map of Active Freshwater Wells in/near AOR
Appendix C-5	List of Freshwater Wells in/near AOR
Appendix C-6	Map of AOR Site Review

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

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4.1 Introduction

The following section describes the engineering design details and operational strategies employed during the planning of the proposed White Castle Injection Well (WC IW)-B No. 001 and No. 002 carbon sequestration wells. Along with the proposed sequestration/injection wells, the engineering design details and operational strategies of the proposed stratigraphic, above-zone monitoring, and groundwater wells—respectively named White Castle Strat Well (WC SWMW) No. 001, White Castle Above-Zone Monitoring Well (WC AZMW)-B No. 001, and White Castle Groundwater Well (WC GW)-B No. 001—are also presented in this section. The engineering design details meet the requirements of Statewide Order (SWO) 29-N-6 **§3621.A.1** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**] Injection Well Operating Requirements and Injection Well Construction Requirements, respectively.

The design, construction, and operation of injection wells fall under the jurisdiction of the Environmental Protection Agency (EPA) Underground Injection Control (UIC) program. Since 1977, the UIC has governed the operation of injection wells, either at the federal level or through states that have been granted primacy over a certain type of well. In 2010, the EPA added an additional class of well, Class VI, which is specifically for the injection and storage of CO_2.

A significant amount of work has been conducted to evaluate various regions of the United States to assess the viability of carbon capture and sequestration (CCS) projects. Those evaluations focus on reservoir quality, proximity to emitters, and available pore space. The White Castle CO_2 Sequestration (White Castle) Project is an ideal CCS project for several reasons: (1) proximity to the New Orleans/Baton Rouge, Louisiana industrial region, where CO_2 emissions are estimated at approximately 80 million metric tons per year (MMT/yr); (2) the rural location of the large, contiguous pore space lease that is near existing third-party pipeline infrastructure slated for conversion to transportation of CO_2 emissions; and (3) optimal geological characteristics for storage and sequestration within the Miocene sands formation—including thick, high porosity, high permeability sands bedded with shale and mudstone, which will provide a cap and basement to multiple stacked injection intervals.

Class VI regulations include specific requirements for the design and operation of a CCS well. This section of the permit application addresses each of those requirements in detail.

4.2 Engineering Design

The design of WC IW-B No. 001 and No. 002 is optimized to permanently sequester CO_2 gas, prevent its movement into Underground Sources of Drinking Water (USDWs), and account for various operational factors, such as injection volume, rate, chemical composition, and physical properties of the injectate fluid, as well as the corrosive nature of the injectate fluid and its impact on wellbore components. The operation of the wells will be managed to ensure efficient use of pore space in the reservoir and contain the CO_2 within the authorized injection interval for the duration of the project.

The design of the wells took into account several key considerations, including volume and rate of injection, chemical composition and physical properties of the injectate fluid, corrosion concerns, metallurgical evaluations, and operational details necessary to maintain proper reservoir management and well integrity.

Class VI wells are designed in a similar fashion as Class I injection wells, including specialized metallurgy to handle potentially corrosive fluids. CO_2 alone is not corrosive, but when combined with water and other chemical compounds, such as hydrogen sulfide (H_2S), it can create carbonic acid with a pH as low as 3. The injection wells are designed to withstand the corrosiveness of the injectate. Special metallurgies and coatings are considered for the casing, tubing, wellhead equipment, and downhole tools.

The drilling program also considers the types of cement that will be used in the wellbores. The cement design and products used to cement the wells are designed to create good bonding between the casing and formations while withstanding the corrosive nature of the injectate. The cementing of the casings is designed with a sufficient cement sheath to protect the wellbores from developing any channeling out of the injection interval, and to maintain the CO_2 below the upper confining interval (UCI)—the approximately [redacted] formation known as the [redacted] that was discussed in detail in *Section 1.3.2*. Prior to approval to drill the proposed injection wells, a detailed cement program will be finalized and provided for review. The cement program will include the type or grade of cement, cement additives including slurry weight (lb/gal) and yield (cu ft/sack), and other design details.

The WC IW-B No. 001 and No. 002 wells will be located in the wooded wetlands in Iberville Parish, [redacted]. Existing pipelines near the Mississippi River corridor will be converted to transport emissions from regional industrial emitters to a central compression facility about [redacted] of the White Castle Project area. Compressed CO_2 will be transported from the central compression facility to WC IW-B No. 001 and No. 002, [redacted] via a newly constructed pipeline for injection into the storage reservoir. Figure 4-3 (*Appendix A-3*) and Figure 4-4 (*Appendix A-6*) show the proposed well location plats for WC IW-B No. 001 and No. 002, respectively.

The Miocene sands, to be used as the storage reservoir for this project, are composed of stacked layers of sand and shale sequences (as discussed in *Section 1 – Site Characterization*). The Miocene sands in this area are generally located from 3,000' to 12,000' true vertical depth (TVD), [redacted] WC IW-B No. 001 [redacted]) will be utilized to inject and permanently sequester CO_2 in the [redacted] WC IW-B No. 002 [redacted]) will be utilized to inject and permanently sequester CO_2 in the [redacted]. Due to their porous, permeable, and unconsolidated nature, the Miocene sands are an extremely desirable formation to be used for CO_2 injection and storage. WC IW-B No. 001 and No. 002 will each be injecting into one continuous zone of sands through multiple recompletions over the life of the wells. The design of the wells accounts for this specific type of completion strategy.

Both wellbores will be designed with [redacted] casing, with premium connections from the surface to [redacted]. There will be a [redacted] crossover at that point. The casing will be [redacted] from that crossover to total depth (TD). The [redacted] casing will be set [redacted] into the bottom-sealing formation in WC IW-B No. 001 and [redacted] into the bottom-sealing formation in WC IW-B No. 002. The production tubing will be [redacted], with premium connections and a [redacted] production packer. The packer in each well should be located approximately [redacted]. The packer location may change, provided there is at least [redacted] good cement bonding across the isolating shale directly above the top of the injection zone. The production packers will also be made of [redacted] material or a CO_2 injectate compatible material. In accordance with the metallurgical analysis provided in *Appendix E*, this design uses [redacted] material or its equivalent in all sections where the CO_2 will contact the tubulars. Final determination on the suitability of lesser chromium materials, such as [redacted], is still pending additional data gathering and testing. [redacted] Figure 4-1 (*Appendix D-1*) and Figure 4-2 (*Appendix D-3*) show the wellbore schematics for WC IW-B No. 001 and No. 002, respectively.

In each well, annular and tubing pressures will be continuously monitored via downhole pressure gauges run on a fiber optic cable sensing package [redacted]. Pressures will be continuously monitored to ensure that well integrity is maintained. The fiber optic cable sensing package will include distributed acoustic sensing (DAS) and distributed temperature sensing (DTS) technology to support carbon front size monitoring through vertical seismic profile (VSP) surveys, if needed, and continuous temperature monitoring capabilities. A Supervisory Control and Data Acquisition (SCADA) monitoring system will be in place throughout the life of each well.

Harvest Bend CCS also plans to drill a stratigraphic test ("strat") well [redacted]. Upon drilling the test well, data will be gathered on the upper-confining, injection, and lower-confining intervals to better support the White Castle Project and to refine the carbon front modeling efforts, if needed. [redacted]

As part of the monitoring plan for WC IW-B No. 001 and No. 002, Harvest Bend CCS aims to drill one above-zone monitoring well and [redacted] dedicated USDW monitoring well [redacted]. The above-zone monitoring well on [redacted], WC AZMW-B No. 001, will be completed in the [redacted] sand—the first permeable zone above the [redacted]. The USDW monitoring well on Drill Site B, WC GW-B No. 001, will be drilled to the base of the USDW at around [redacted] near the proposed injection wells.

[redacted]

Figure 4-1 – WC IW-B No. 001 Wellbore Schematic (Initial Completion)

[redacted]

Figure 4-2 – WC IW-B No. 002 Wellbore Schematic (Initial Completion)

[redacted]

Figure 4-3 – Well Location Plat – WC IW-B No. 001

[redacted]

Figure 4-4 – Well Location Plat – WC IW-B No. 002

4.2.1 General Outline of Well Design and Completion Schematic

WC IW-B No. 001 was designed with the following specifications:

- Drive Pipe
  - Size: [redacted]
  - Depth: [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - Currently estimated setting depth: [redacted]
      - Based on offset open-hole log evaluation
    - The USDW will be further confirmed via open-hole logging during the drilling of the well and adjusted as necessary.
  - Casing outside diameter (OD): [redacted]
  - Hole size: [redacted]
  - Top of cement: surface
- Intermediate Casing
  - [redacted] casing set at [redacted]
  - Composed of [redacted] grade
  - Hole size: [redacted]
  - Top of cement: surface
- Production Casing
  - [redacted] casing set at TD – [redacted]
    - [redacted] casing from surface to [redacted]
    - [redacted] casing below [redacted]
    - Crossover between [redacted]
    - [redacted] diverter valve (DV) tools set:
      - [redacted]
  - Hole size: [redacted]
  - Top of cement: surface
    - Cement to be comprised of the following:
      - [redacted]
- Injection Tubing
  - [redacted] tubing set (initially) on packer, with tail pipe at [redacted]
  - Packer will be set [redacted].
  - Per metallurgical analysis, composition to be of [redacted]
  - Annular fluid to consist of corrosion inhibitor fluid
  - [redacted] at approximately [redacted]
  - Fiber optic cable (FOC) with DTS and DAS capabilities will be run [redacted].
    - Annular and tubing pressure gauges will be run on the end of the FOC [redacted]
- Packer (Figure 4-8, *Section 4.2.2.7*)

- [redacted] production packer
- Flow-wetted steel type: [redacted] or a CO_2 –injectate-compatible material
- Elastomer options: [redacted]
- Temperature range: [redacted]

- Wellhead (Figure 4-9, *Section 4.2.2.9*)
  - [redacted]
  - Production Tree
    - [redacted]

A complete drilling procedure for WC IW-B No. 001 has been included in *Appendix D-2*.

WC IW-B No. 002 was designed with the following specifications:

- Drive Pipe
  - Size: [redacted]
  - Depth: [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - Currently estimated setting depth: [redacted]
      - Based on offset open-hole log evaluation
    - The USDW will be further confirmed via open-hole logging during the drilling of the well and adjusted as necessary.
  - Casing outside diameter (OD): [redacted]
  - Hole size: [redacted]
  - Top of cement: surface
- Intermediate Casing
  - [redacted] casing set at [redacted]
  - Composed of [redacted] grade
  - Hole size: [redacted]
  - Top of cement: surface
- Production Casing
  - [redacted] casing set at TD – [redacted]
    - [redacted] casing from surface to [redacted]
    - [redacted] casing below [redacted]
    - Crossover between [redacted]

        - [redacted] diverter valve (DV) tools set:
            - [redacted] above the base of the [redacted] intra-reservoir shale
    - Hole size: [redacted]
    - Top of cement: surface
        - Cement to be comprised of the following:
            - [redacted]
- Injection Tubing
    - [redacted] tubing set (initially) on packer, with tail pipe at [redacted]
    - Packer will be set [redacted].
    - Per metallurgical analysis, composition to be of [redacted]
    - Annular fluid to consist of corrosion inhibitor fluid
    - [redacted] at approximately [redacted]
    - Fiber optic cable with DTS and DAS capabilities will be run [redacted].
        - Annular and tubing pressure gauges will be run on the end of the FOC [redacted].
- Packer (Figure 4-8, *Section 4.2.2.7*)
    - [redacted] production packer
    - Flow-wetted steel type: [redacted] or a CO_2 –injectate-compatible material
    - Elastomer options: [redacted]
    - Temperature range: [redacted]
- Wellhead (Figure 4-9, *Section 4.2.2.9*)
    - [redacted]
    - Production Tree
        - [redacted]

A complete drilling procedure for WC IW-B No. 002 has been included in *Appendix D-4*.

4.2.2 Detailed Discussion of Injection Well Design

The design of an injection well starts with the final tubing in mind and works backward. The required injection rate defines the tubing size, which defines the casing design and completion strategy.

Harvest Bend CCS plans to inject an average flow rate of 1.0 MMT/yr of gas into each proposed well, which translates to a daily injection rate of approximately 53 MMscf/d at standard conditions. Table 4-1 shows the standard conditions of CO_2 that are used in the modeling and flow calculations.

Table 4-1 – CO_2 Standard Conditions

CO_2 Standard Conditions				
Temperature (°F)	Pressure (psia**)	Density (lbm/cuft)	Enthalpy (Btu/lbm)	Entropy (Btu/lbm-°R)
77*	14.696	0.113	214.18	0.64759

*Basis of 25°C as per EPA standard conditions reference

**pounds per square inch absolute

An analysis was conducted on the tubing design by taking into account various factors, such as pipe friction losses, (erosional) velocities, thermal considerations, compression requirements, and economic evaluations. Using the results of the dynamic reservoir model, the bottomhole injection pressure (BHIP) was determined (Figures 4-5 and 4-6). The data obtained from this analysis is used to identify the point during the project's lifespan when the maximum BHIP occurs, as well as the resulting maximum flowing pressure at the surface. This information is used to properly design the casing, tubing, and wellhead configurations.

[redacted] During active operations, pressure will continuously be monitored to ensure BHP remains below 90% fracture gradient.

[redacted]

Figure 4-5 – Injection Pressure Plot (WC IW-B No. 001)

[redacted]

Figure 4-6 – Injection Pressure Plot (WC IW-B No. 002)

The pipeline specifications for the CO_2 stream to be injected in WC IW-B No. 001 and No. 002 are provided in Table 4-2. For conservative reservoir carbon front modeling purposes, the injectate was assumed to be 100% CO_2.

Table 4-2 – Injectate Composition Limits

Composition	Composition Amount
[redacted]	

A [redacted] tubing was determined to be the appropriate size necessary to move the desired volumes of supercritical CO_2 in this well, based on the model results. The model also verified that the CO_2 would remain in supercritical state in the wellbore. The CO_2 is in the supercritical state from the point it enters the wellhead—and remains supercritical throughout the path of the wellbore as it is being injected (Figure 4-7).

[redacted]

Figure 4-7 – CO_2 Flow Conditions

Based on appropriate bit-size selection, pipe clearance considerations, and recommended annular spacing for assurance of proper cementing, it was determined that the following casing sizes are appropriate to accommodate the [redacted] injection tubing.

- [redacted] drive pipe driven to [redacted]
- [redacted] open hole with [redacted] surface casing drilled to [redacted]
- [redacted] open hole with [redacted] intermediate casing drilled to [redacted]
- [redacted] open hole with [redacted] production casing drilled to [redacted] in WC IW-B No. 001 and [redacted] in WC IW-B No. 002

4.2.2.1 Drive Pipe – Wells No. 001 and 002

Due to the loose and unconsolidated nature of the ground, a drive pipe will be required to maintain the integrity of the hole during the initial drilling of each well. A [redacted] drive pipe (Table 4-3) will be used for this purpose and will be driven using a casing hammer, either to the proposed depth or to refusal.

The selection of the drive pipe size is based on the desired bit size for drilling the surface casing borehole. With a drive pipe inner diameter (ID) of [redacted], a [redacted] bit can be used to clean out the drive pipe and drill the next section of each well to a depth of [redacted].

After the drive pipe is in place, the inside of it can be flushed so the next stage of drilling can begin.

Table 4-3 – Drive Pipe Engineering Calculations for Wells No. 001 and 002

Drive Pipe								
Description	**Casing Wt. (ppf)**	**Depth (ft)**	**Tensile (psi)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
[redacted]	[redacted]							
Safety Factor								

4.2.2.2 Surface Casing – Wells No. 001 and 002

The surface casing section of each well will be drilled using a [redacted] bit, which will create enough space to securely cement the [redacted] casing to the surface. The surface hole will be drilled with casing set at a minimum of [redacted] below the USDW, measured from ground level. This casing string, along with a proper cementing job, will provide two barriers to prevent contamination of the USDW during drilling operations. A cement-bond logging tool will be used to check the quality of the cementing job and ensure that it was successful.

Summaries of engineering calculations for the surface casing are provided in Table 4-4 (A, B, and C), including the cement calculations at Table 4-5 (A and B).

Table 4-4 – Surface Casing Engineering Calculations (A), Annular Geometry (B), and Casing (C) for Wells No. 001 and 002

(A) Surface Casing									
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(psi)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
[redacted]								
Safety Factor			[redacted]					

(B) Annular Geometry			
Section	**ID**	**MD**	**TVD**
	(in)	(ft)	(ft)
Drive Pipe	[redacted]		
Open Hole			

(C) Casing					
Section	**OD**	**ID**	**Weight**	**MD**	**TVD**
	(in)	(in)	(lb/ft)	(ft)	(ft)
Surface	[redacted]				

Table 4-5 – Surface Casing Cement Calculations (A) Including Volume (B) for Wells No. 001 and 002

(A) Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Lead	[redacted]		
Tail			

(B) Volume Calculations				
Section	Footage	capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Drive Pipe/Casing Annulus Lead	[redacted]			
Open Hole/Casing Annulus Lead				
Open Hole/Casing Annulus Tail				
Shoe Track Tail				

To ensure cement returns to surface are achieved, excess of open-hole volumes will be pumped; 100% excess is assumed above but excess could be less based on the caliper log.

4.2.2.3 Intermediate Casing – Wells No. 001 and 002

For the intermediate casing section of each well, [redacted] casing has been selected. This section will be drilled with a [redacted] bit to provide sufficient annular space to cement the casing to surface with good bond. This casing string, along with an effective cement job, will provide two barriers to the USDW during drilling operations. After the surface and intermediate casing are set, there will be four barriers between the USDW and the fluid in the wellbore.

Summaries of engineering calculations for the intermediate casing are provided in Table 4-6 (A, B, and C), including the cement calculations at Table 4-7 (A and B).

Table 4-6 – Intermediate Casing Engineering Calculations for Wells No. 001 and 002

(A) Intermediate Casing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)
[redacted]								
Safety Factor			[redacted]					

(B) Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Surface	[redacted]		
Open Hole			

(C) Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Intermediate	[redacted]				

Table 4-7 – Intermediate Casing Cement Calculations for Wells No. 001 and 002

(A) Cement			
System	**Top**	**Bottom**	**Volume of Cement**
	(ft)	**(ft)**	**(cf)**
Lead	[redacted]		
Tail			

(B) Volume Calculations				
Section	**Footage**	**capacity**	**% Excess**	**Cement Volume**
	(ft)	**(cf/ft)**	**(%)**	**(cf)**
Surface Casing/Casing Annulus Lead	[redacted]			
Open Hole/Casing Annulus Lead				
Open Hole/Casing Annulus Tail				
Shoe Track Tail				

To ensure cement returns to surface are achieved, excess of open-hole volumes will be pumped; 30% excess is assumed above but excess could be less based on the caliper log.

4.2.2.4 <u>Production Casing</u>

Production casing (long-string casing) will run from the surface to TD and be cemented to surface. After the surface, intermediate, and production casings are set, there will be six barriers between the USDW and the fluid in the wellbore. Design criteria of production casing are the [redacted] material of the casing, [redacted] cement, and tools like centralizers, and float equipment.

A comprehensive metallurgical analysis, which considered the chemical composition of the CO_2 injectate and the downhole conditions, was conducted and is included in *Appendix E*. The analysis determined that the CO_2 injectate is not corrosive on its own. However, to protect against the potential for water from the reservoir entering the wellbore, and to guard against potential surface issues or failures, it was decided to use [redacted] for the downhole tubulars that will come into contact with the injectate stream.

[redacted] cement will be used to protect the cement sheath from degradation due to exposure to an acidic environment, thereby extending the well's integrity and lifespan. As Figure 4-1 showed (in *Section 4.2*), [redacted] cement will be placed to [redacted]. The entire cement column will be brought back to the surface using a [redacted] cement job for WC IW-B No. 001 and a three-stage cement job for WC IW-B No. 002.

Summaries of engineering calculations for the production casing for WC IW-B No. 001 are provided in Table 4-8 (A, B, and C), including the cement calculations at Table 4-9 (A and B). Summaries of engineering calculations for the production casing for WC IW-B No. 002 are provided in Table 4-10 (A, B, and C), including the cement calculations at Table 4-11 (A and B).

Table 4-8 – Production Casing Engineering Calculations for Well No. 001

(A) Production Casing								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(psi)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
[redacted]								
Safety Factor			[redacted]					
[redacted]								
Safety Factor			[redacted]					

(B) Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Intermediate Casing	[redacted]		
Open Hole			

(C) Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
[redacted]					

Table 4-9 – Production Casing Cement Calculations for Well No. 001

(A) Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
[redacted]			

(B) Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
[redacted]				
Shoe Track	[redacted]			

Table 4-10 – Production Casing Engineering Calculations for Well No. 002

(A) Production Casing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)
[redacted]								
Safety Factor	[redacted]							
[redacted]								
Safety Factor	[redacted]							

(B) Annular Geometry			
Section	ID (in)	MD (ft)	TVD (ft)
Intermediate Casing	[redacted]		
Open Hole			

(C) Casing					
Section	OD (in)	ID (in)	Weight (lb/ft)	MD (ft)	TVD (ft)
[redacted]					

Table 4-11 – Production Casing Cement Calculations for Well No. 002

(A) Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
[redacted]			

(B) Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
[redacted]				
Shoe Track	[redacted]			

In each well, the production casing will be installed using premium connections. To ensure cement returns to surface are achieved, excess of open-hole volumes will be pumped; 30% excess is assumed above but excess could be less based on the caliper log.

4.2.2.5 Centralizers

Centralizer selection and installation for the referenced wells will have two separate functions. The centralizer design for the [redacted] surface casing will be planned to protect any shallow aquifer zones per state regulations. The specific placement is also to ensure a continuous, uniform column of cement is present throughout the [redacted] annulus. The recommended location will be:

[redacted]

The centralizer design for the [redacted] intermediate casing will be planned per state regulations to ensure that a continuous, uniform column of cement is present throughout the [redacted] annulus. The recommended location will be:

[redacted]

The centralizer design for the [redacted] production casing will be planned per state regulations to ensure that a continuous, uniform column of cement is present throughout the [redacted] annulus, [redacted] for Well No. 001 and [redacted] for Well No. 002. The recommended location will be:

[redacted]

Final centralizer design for all strings will be finalized at a later date when detailed cement design is also finalized and a stand-off model is completed.

4.2.2.6 Injection Tubing – Wells No. 001 and 002

As previously mentioned, the size of the injection tubing was chosen based on the injection volumes, rates, and injectate composition. It is important to consider the injectate and the potential for a corrosive environment when selecting the material of the tubing, similar to the casing string. The injectate stream is expected to be dry and non-corrosive, but the design allows for the possibility of a surface upset or the invasion of connate water from the reservoir. A comprehensive summary of the metallurgical analysis is included in *Appendix E*. Taking into account the potential for the presence of carbonic acid in a mixture of water and CO_2, tubing made of [redacted] material or better is recommended. Detailed injection tubing specifications are shown below in Tables 4-12 and 4-13.

Table 4-12 – Injection Tubing Specifications for Well No. 001

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

Table 4-13 – Injection Tubing Specifications for Well No. 002

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

The tubing will be installed using premium connections. FOC with DTS and DAS capabilities will be [redacted]. A cross-coupling cable protector will be mounted to each tubing joint coupling to protect the cable across couplings. Annular and tubing pressure gauges will be run on the end of the FOC [redacted].

4.2.2.7 Packer Discussion

The production tubing will be run into each well with a [redacted], production packer with premium connections (Figure 4-8).

[redacted]

Figure 4-8 – [redacted] Production Packer

The tubing and production casing annulus will be filled with a non-corrosive fluid as approved by the UIC Program Director (UIC Director), prior to setting the packer. Pressure will be maintained and monitored on the annulus at a pressure that exceeds the operating injection pressure of the well.

4.2.2.8 [redacted]

A [redacted] will be run at [redacted] that will enable a plug to be set via wireline in the [redacted] as a second barrier, to be able to work on any wellhead, surface leaks, or other surface problems safely. [redacted]

4.2.2.9 <u>Wellhead Discussion</u>

The wellhead proposal, similar to the production packer, should be 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, whereas Inconel lining will be located across trims, stems, gates, valves, etc. The wellhead is designed with a [redacted] working pressure rating and [redacted] for the flow-wetted components. The preliminary wellhead design is shown in Figure 4-9. Figure 4-10 shows a conceptual illustration of wellhead and injection skid valves and pressure and temperature monitoring equipment tied into a supervisory control and data acquisition (SCADA) system. Per SWO 29-N-6 **§3621.A.7.a.i** [40 CFR **§146.88(e)(2)**], automatic shut-off systems and alarms will be installed to alert the operator and shut in the well when operating parameters such as annulus pressure, injection rate, etc., diverge from permitted ranges or gradients.

[redacted]

Figure 4-9 – Harvest Bend CCS WC IW-B No. 001 and No. 002 Preliminary Wellhead Design

[redacted]

Figure 4-10 – Typical Injection Well and Injection Skid Flow Schematic

4.2.3 Testing and Logging During Drilling and Completion Operations

A comprehensive subsurface data gathering (core, logging and fluids) and evaluation of the stratigraphic test well (WC SWMW No. 001) for the White Castle Project is planned in advance of the execution of the proposed injection wells. As described in *Section 4.3*, this planned data acquisition program not only satisfies SWO 29-N-6 **§3617.A** and **§3617.B** [40 CFR **§146.86** and **§146.87**], but also satisfies Harvest Bend CCS's internal best-practice criteria. The data acquired in the strat well will likely be analogous to that of the injection wells and will be sufficient to adequately characterize the confining and injection intervals of interest. Additionally, if Harvest Bend CCS is unable to acquire any desired data sets from the strat well data gathering program, the injection well data gathering programs will provide an opportunity to supplement the required information.

Harvest Bend CCS will implement similar *advanced* open-hole logging programs while drilling both the [redacted] injection well (WC IW-B No. 002) and the strat well. Implementing the same logging programs in both the strat well and the [redacted] injection well will allow for not only comprehensive comparison and demonstration of similar geology [redacted], but also confidence in geological and carbon front models constructed from strat well data.

4.2.3.1 <u>Coring Plan – WC IW-B No. 002</u>

As discussed in the drilling procedure in *Appendix D-4*, core samples will be collected during the drilling of the [redacted] injection well in the UCI, the gross injection interval [redacted], and the lower confining interval. [redacted], no coring is planned in the [redacted] injection well (WC IW-B No. 001). [redacted]

Detailed evaluation of core and fluids can vastly improve the chances of successful CO_2 sequestration and result in overall cost savings. Uncertainty in intervals identified for CO_2 injection can be significantly reduced early on by investing in laboratory studies of confining and storage zone cores. Sections of whole core cut in [redacted] increments, with an option to lengthen core barrels to [redacted], will be collected from the [redacted] formation (upper confining interval) and the Miocene sands formation (injection interval) as listed in Table 4-14. Whole core will follow low-invasion acquisition protocol using high-performance, oil-based drilling fluid. Four-inch diameter whole cores will be obtained in the interval below the intermediate casing. Because of anticipated poor consolidation and lack of cohesion in these siliciclastic rocks, special vented-aluminum, disposable-core inner-barrels and full-closure core catchers will be utilized. Wellsite core handling, stabilization, and preservation will follow strict guidelines to ensure confining and injection interval cores remain representative of in situ rock properties.

If the sidewall coring tool for soft rock proves to be reliable, confining or injection intervals ([redacted]) will be supplemented with attempting up to [redacted] rotary sidewall cores (SWC). Wellsite core handling, stabilization, and preservation would be proportional to whole core footage and the number of sidewall cores acquired.

Given the supplemental nature of the core analysis in the [redacted] injection well compared to the strat well core analytical programs (*Section 4.3.1*), analytical programs for confining and injection interval characterization will include:

[redacted]

The core analysis program has been designed to thoroughly confirm and supplement the characterization of confining and injection intervals through the strat well subsurface data gathering and evaluation programs discussed in *Section 4.3.1*. Additionally, the *advanced logs* discussed in Section *4.2.3.2*, for the lower injection well, will eliminate the need to collect whole core throughout the entire injection zone and confining system, which is more than 5,000' thick. The advanced logs will allow Harvest Bend CCS to extrapolate the results from select intervals in the coring plan throughout the entire gross interval.

Table 4-14 – Approximate Coring Plan – WC IW-B No. 002

Approximate Core Depth Intervals (ft TVDSS*)	Core Type	Number of Cores	Predominate Lithology	Formation/Zone
[redacted]				

*TVDSS – true vertical depth subsea

**200' interval depths approximated in formations where 30', 60', or 90' core barrels may be selected with the aid of near bit gamma ray during drilling.

4.2.3.2 Logging Plan – WC IW-B No. 002

A number of logging requirements are necessary to meet EPA standards and the needs of a responsible operation. These logging requirements can be described through the use of the three subsets detailed in Table 4-15. These are the *standard logs*, *advanced logs*, and *cased-hole logs*. *Standard logs* include the gamma ray, resistivity, neutron, density, caliper, and spontaneous potential. Spontaneous potential is only used in the zones with water-based mud. This data is used for primary reservoir and fluid characterization including lithology, porosity, salinity, fracture identification, indications of permeability, and fluid saturations. The *standard* logs can answer most of the primary reservoir questions related to storage volume.

Advanced logs, which make up the second set of tools, [redacted]

[redacted]

The planned *cased-hole logs* that will be run include radial cement bond logs as well as several other tools meant to set up baselines for the interval pre-injection. These baseline logs include casing inspection logs, imaging caliper, and [redacted] Future logging of this zone with the same technology will allow the monitoring of the carbon front and the mechanical integrity of the wellbore.

Table 4-15 – Logging Plan – WC IW-B No. 002

Wireline Logging Program		
Depth Interval	**Logs**	**Purpose/Comments**
Conductor Casing Interval [redacted] feet below ground level (BGL))		
Casing (driven)	[redacted]	
Surface Casing Interval		
Open-Hole Logs	[redacted]	
Casing Logs		
Intermediate Casing Interval		
Open-Hole Logs	[redacted]	
Long-String Casing Interval		
Open-Hole Logs	[redacted]	

Depth Interval	Logs	Purpose/Comments
Long-String Casing Interval (cont.)		
Open-Hole Logs (cont.)	[redacted]	
Casing Logs		

4.2.3.3 Logging Plan – WC IW-B No. 001

While there are a number of logging requirements necessary to meet the EPA standards and to conduct a responsible operation, the proximity of the well WC IW-B No. 002 to WC IW-B No. 001

presents opportunities for efficiencies in logistics, cost, and analysis with no loss of fidelity to the understanding for both wells. [redacted] Logging plans are detailed in Table 4-16.

[redacted]

[redacted]

The *cased-hole logs* planned for WC IW-B No. 001 are the same as those planned for the nearby deep well, WC IW-B No. 002, on Drill Site B. The cement and casing inspection results will be unique to each well. The cased-hole logs will include radial cement bond logs as well as several other tools meant to set up baselines for the interval pre-injection. These baseline logs include casing inspection logs, imaging caliper, and [redacted]. Future logging of this zone with the same technology will allow the monitoring of the carbon front and the mechanical integrity of the wellbore.

Table 4-16 – Logging Plans – WC IW-B No. 001

Logging While Drilling (LWD) Logging Program		
Depth Interval	**Logs**	**Purpose/Comments**
Conductor Casing Interval [redacted] **feet below ground level (BGL))**		
Casing (driven)	[redacted]	
Surface Casing Interval		
Open-Hole Logs	[redacted]	
Casing Logs		
Intermediate Casing Interval		
Open-Hole Logs	[redacted]	
Long-String Casing Interval		
Open-Hole Logs	[redacted]	
Cased-Hole Logging Program		
Depth Interval	**Logs**	**Purpose/Comments**
Surface Casing Interval		
Casing Logs	[redacted]	

Long-String Casing Interval	
Casing Logs	[redacted]

4.2.3.4 Formation Fluid Testing

Prior to setting the production-casing string [redacted], samples of the formation fluid [redacted] will be obtained by running an open-hole fluid recovery tool. Recovery sections will be determined based on open-hole evaluations. Multiple samples will be taken per section. [redacted].

Brine chemistry by ICP spectrometry will be used to quantify major anions/cations. Formation fluid pH (including live water pH), total dissolved and suspended solids, conductivity, alkalinity, and specific gravity will be measured for basic brine characterization.

4.2.3.5 Minifrac Test

As discussed in *Section 5 – Testing and Monitoring Plan* and if required to further corroborate confining and injection interval characteristics determined through the strat well minifrac testing program discussed in *Section 4.3.1.4*, minifrac tests will be conducted during the open-hole logging program to measure the fracture gradient of the confining and [redacted] injection intervals(s) in WC IW-B No. 002. [redacted] This testing is in compliance with SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**] and

SWO 29-N-6 **§3617.5.c** [40 CFR **§146.87€(3)**]. The tests will be conducted using a formation pressure and sampling tool.

Objectives

1. Achieve zonal isolation of the confining and injection intervals [redacted].
2. Perform injection and flowback test cycles to reduce the uncertainty and capture a better measure of the far-field minimum stress.
3. Measure tensile fracturing pressure, stress direction, far-field minimum and maximum stress, and tensile strength.

Regulatory Information

The Louisiana Department of Natural Resources (LDNR) regulates the injection wells in Louisiana. A Form UIC-17 must be submitted and all activities approved prior to commencing work. The minifrac test should also be witnessed by a Conservation Enforcement Specialist. A Form UIC-WH1 will be submitted to the LDNR Injection and Mining Division (IMD) at the conclusion of all tests, along with a report that includes an in-depth analysis of the minifrac tests.

4.2.3.6 Pressure Falloff Testing

Upon completion, but before operating the proposed injection wells, Harvest Bend CCS will perform a required pressure falloff test per SWO 29-N-6 **§3617.B.5.a** [40 CFR **§146.87(e)(1)**]. The tests will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

Testing Method

A non-hazardous fluid, approved by the LDNR, will be injected into the proposed well. The injection rate and pressure will be held as constant as possible prior to the beginning of the falloff test, and continuous data will be recorded during testing. Once the well has been shut in, continuous pressure measurements will be taken via a downhole gauge. The falloff 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.

Analytical Methods

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 via analysis of observed pressure changes and/or pressure derivates on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by the comparison of pressure falloff tests prior to initial injection, with later tests. The effects of two-phase flow effects will also be considered. Such well parameters resulting from falloff 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 falloff test results will be submitted to the IMD within 30 days of test completion.

4.2.4 Injection Well Operating Strategy

Harvest Bend CCS currently plans on injecting an average of 1.0 MMT/year of CO_2 into both WC IW-B No. 001 and No. 002. The CO_2 will be injected and will remain in a supercritical state within the reservoir during active injection and through the life of the project. The operating parameters for the injection wells are summarized in Table 4-17.

Table 4-17 – Injection Well Operating Parameters

Parameter	Well No. 001	Well No. 002
Gross Injection Interval	[redacted]	
Maximum Injection Flow Rate (MMT/yr)		
Average Injection Flow Rate (MMT/yr)		
Maximum Surface Injection Pressure (psi)		
Expected Surface Injection Pressure (psi)		
Maximum Annular Pressure (psi)		

While closely monitoring pressures to ensure that bottomhole pressure does not exceed 90% of the fracture pressure of the injection reservoir or UCI (noted as Max BHP in Table 4-18), different circumstances could require an increased injection rate resulting in the accelerated development of a completion interval. For example, the White Castle Project includes multiple injection wells so that, during well intervention events for other White Castle injection wells, Harvest Bend CCS will have the ability to increase the injection rate in WC IW-B No. 001 and/or No. 002 above the daily equivalent of 1.0 MMT/year, to continue to serve clients. Additionally, commercial requirements may result in increased injection rates up to 1.5 MMT/year and accelerated development of completion intervals. If injection rates persist above the planned average of 1.0 MMT/year, it is expected that the injection durations listed in Table 4-18 will decrease so that the total storage volume of each completion interval is not exceeded. Again, despite possible increases in injection rate above 1.0 MMT/year, pressures will be closely monitored to ensure that bottomhole pressure does not exceed 90% of the fracture pressure of the injection reservoir or UCI.

During active injection operations, the average bottomhole pressure increases expected will be 295.6 and 362.8 [redacted], but these increases will drop to [redacted] psi post-injection in WC IW-B No. 001 and No. 002, respectively. The Miocene sand reservoir properties allow for the dissipation of the pressure quickly. Expected surface and bottomhole pressure considerations are detailed for each completion stage in Tables 4-18 and 4-19.

Bottomhole pressure does not exceed 90% of the fracture pressure of the injection reservoir or UCI, which will limit surface injection pressure. The anticipated BHIP, fracture gradient with 10% safety factor, and injection rate plot over time is shown in Tables 4-18 and 4-19.

Table 4-18 – Injection Pressure by Stage – WC IW-B No. 001

Completion Stage	Injection Duration (yrs)	Total Storage Volume (MMT)	Max Rate (MMT/yr)	Average Rate (MMT/yr)	Max BHP (psi)	Average BHP (psi)	Max WHP (psi)	Average WHP (psi)
[redacted]								

Table 4-19 – Injection Pressure by Stage – WC IW-B No. 002

Completion Stage	Injection Duration (yrs)	Total Storage Volume (MMT)	Max Rate (MMT/yr)	Average Rate (MMT/yr)	Max BHP (psi)	Average BHP (psi)	Max WHP (psi)	Average WHP (psi)
[redacted]								

Multiple injection intervals are used to maximize the use of available pore space. This is the optimal way to inject, because if all intervals were perforated at once, the gas would not be evenly distributed throughout the reservoir. There will be discrete injection intervals utilized for a given amount of time and then abandoned (Tables 4-20 and 4-21).

Table 4-20 – Injection Intervals – WC IW-B No. 001

Completion Stage	Injection Duration (years)	Top Perf (TVD ft)	Bottom Perf (TVD ft)	Net Pay (ft)
[redacted]				

Table 4-21 – Injection Intervals – WC IW-B No. 002

Completion Stage	Injection Duration (years)	Top Perf (TVD ft)	Bottom Perf (TVD ft)	Net Pay (ft)
[redacted]				

The density of the injectate typically ranges from [redacted] in the shallowest injection interval to [redacted] in the deepest injection interval, compared to [redacted] for the connate brine in the same formations. This density difference, coupled with the high vertical permeability in the Miocene sands, allows the CO_2 to migrate upward to the top of each discrete injection interval, and laterally under the confining layer of that interval.

This results in a significant "mushroom cap" effect seen in Figure 4-11.

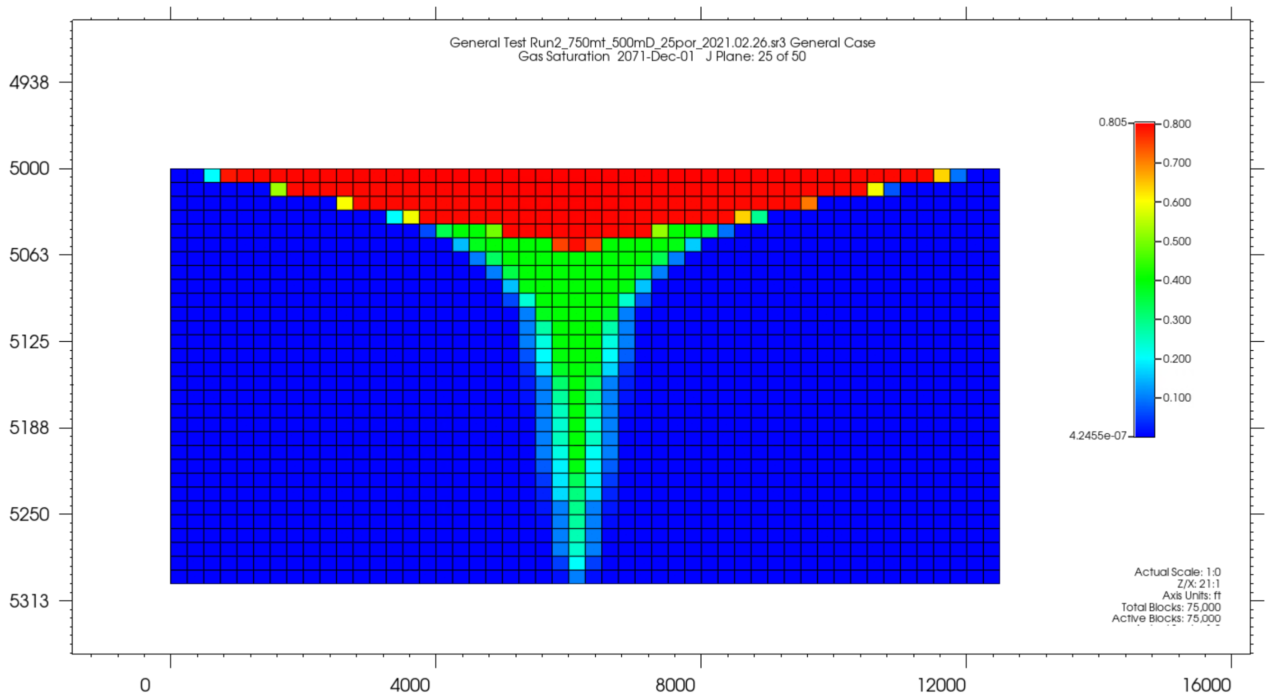

Figure 4-11 – Typical Carbon Front Profile in Loose Formations

To make the most use of the pore space, specific intervals for injecting CO_2 need to be determined. This can be done by creating a detailed geological model, modeling the injection of CO_2 in the reservoir, and building a carbon front model based on the specific well completion strategy. From this strategy, maps of the carbon and pressure fronts will be generated to show the lateral extent of the carbon front. These maps will then be used to confirm which areas of the pore space will be affected by the carbon front.

Reservoir management is extremely important for storage wells. The operating strategy for both WC IW-B No. 001 and No. 002 are as follows:

- The gross injection interval will be broken into several "discrete injection intervals" [redacted]
- These injection intervals are then divided into discrete completion intervals.
- The discrete intervals are perforated.
- The injectate fluids are injected into the discrete completions for a relatively short period of time—no less than 1 year; no more than 5 years (estimated).
- Pressure transient analysis to be conducted each year to contrast actual carbon front development with the simulated carbon front model.
- As determined by seismic surveying and dynamic modeling efforts, once a completion interval has been fully developed, the interval is isolated and a recompletion to the next interval is performed.
- The completed sub-section is then plugged with a corrosion-resistant plug.
- This process repeats until the entirety of the gross injection interval has been completed.

Figure 4-12 depicts this process in a general form.

[redacted]

Figure 4-12 – Operational Completion Strategy

The actual injection intervals, time frame, and rate can be found in Tables 4-17 through 4-20.

The sand packages to be targeted by the completion intervals identified in Tables 4-19 and 4-20 were selected by analysis of the static model at the proposed injection locations that were populated from offset well data and seismic attributes. The actual discrete intervals completed and final staging will be selected based on well-specific data.

4.2.5 Injection Well Operational Strategy Summary

WC IW-B No. 001 and No. 002 are engineered to optimize the utilization of pore space and securely store CO_2 in the most secure, least hazardous, efficient, and cost-effective manner feasible. The pressure and temperature within the wellbores will be determined, and these measurements will be incorporated into the carbon front model and the strategies for future injections will be refined, as outlined in the Testing and Monitoring Plan (*Section 5*). This will help ensure that the movement and rate of the CO_2 is accurately assessed and, if necessary, adjustments can be made to the injection and operational plans. Once injection has stopped, the wells will be sealed as per the Injection Well Plugging Plan (*Section 6*).

To confirm that the carbon front is developing as expected, a time-lapse seismic carbon front monitoring approach will be utilized as outlined in the Testing and Monitoring Plan (*Section 5*). Carbon front growth will be monitored with time-lapse seismic surveys. [redacted] Any variations observed between the surveys and the carbon front model will be used to further improve the completion strategy. This iterative process will ensure that the movement and rate of the CO_2 is accurately evaluated and, if necessary, adjustments can be made to the completion and operational plans. Once all of the available sand packages have been utilized, the wells will be sealed.

As previously mentioned, the location of this project is ideal for carbon sequestration. By combining the best engineering practices in well design with both a cutting-edge monitoring system and a comprehensive reservoir management strategy, these wells will safely and permanently store CO_2.

4.3 Stratigraphic Test Well

Harvest Bend CCS intends to drill a strat well named WC SWMW No. 001 to extensively gather and evaluate subsurface data for the confining and injection intervals. Following data gathering exercises, WC SWMW No. 001 will be cased, but not completed like the injection wells and above-zone monitoring wells. [redacted]

The location and design of the strat well have not yet been finalized. It is anticipated that the strat well will be drilled [redacted] Once location and design are finalized, the well will be permitted with LDNR as a Class V well. Design can be further reviewed and approved at that time through the Class V well application process.

4.3.1 Testing and Logging of Strat Well During Drilling and Completion Operations

A comprehensive subsurface data gathering (core, logging, and fluids) and evaluation of the strat test well is planned in advance of the execution of the injection wells. As described below, the planned data acquisition program not only satisfies SWO 29-N-6 **§3617.A** and **§3617.B** [40 CFR **§146.86** and **§146.87**], but also satisfies Harvest Bend CCS's internal best-practice criteria. Data gathered during testing and logging programs will be used to further characterize the proposed injection interval and confining layers for WC IW-B No. 001 and No. 002. The analytical results from the detailed evaluation programs will be used to validate current reservoir modeling assumptions and update the model (*Section 2 – Carbon Front Model*) and this Class VI application as needed.

4.3.1.1 Coring Plan

Detailed evaluation of core and fluids can vastly improve the chances of successful CO_2 sequestration and can result in overall cost savings and, potentially, determination of additional storage capacity. Uncertainty in intervals identified for CO_2 injection can be significantly reduced early on by investing in laboratory studies of confining seal and injection interval cores. Sections of whole core cut in [redacted] increments, with an option to lengthen core barrels to [redacted], will be collected from the [redacted] formation (upper confining interval) and the Miocene sands formation (injection interval) as listed in Table 4-22. Whole core will follow low-invasion acquisition protocol using high-performance, oil-based drilling fluid. Four-inch diameter whole cores will be obtained in the interval below the intermediate casing. Because of anticipated poor consolidation and lack of cohesion in these siliciclastic rocks, special vented-aluminum, disposable-core inner-barrels and full-closure core catchers will be utilized. Wellsite core handling, stabilization, and preservation will follow strict guidelines to ensure confining and injection interval cores remain representative of in situ rock properties. Sidewall cores will be acquired to fill gaps between whole core depths.

Detailed analytical programs will be conducted for seal and injection zone characterization to include:

[redacted]

The core analysis program has been designed to thoroughly confirm and supplement the characterization of confining and injection intervals through the strat well subsurface data gathering and evaluation programs.

Table 4-22 – Coring Program

Approximate Core Depth Intervals (ft TVDSS)	Core Type	Predominate Lithology	Petition Interval
[redacted]			

4.3.1.2 Logging Plan

Open-hole log data will be acquired reflecting in situ, structural, stratigraphic, physical, chemical, and geomechanical information for the Miocene sands formation, the [redacted] confining intervals, and other zones of interest. Wireline-conveyed open-hole logs will be acquired at the surface casing point, intermediate casing point, and over the production zone—including the injection targets. Open-hole logs will not be acquired in the conductor casing hole.

While drilling the strat well, Harvest Bend CCS will implement a similar logging program as is planned in the [redacted] injection well (WC IW-B No. 002) and discussed in detail in *Section 4.2.3*. Implementing the same robust open-hole logging programs in both the strat well and the injection well will allow for comprehensive comparison and demonstration of similar geology between the strat well and [redacted] and confidence in geological and carbon front models constructed from strat well data.

4.3.1.3 Formation Fluid Testing

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

Understanding the thermo-physical properties of super critical CO_2 ($scCO_2$) and formation brine are critical for achieving safe and long-term storage of $scCO_2$. Brine chemistry by inductively coupled plasma (ICP) spectrometry for quantifying major anions/cations along with pH (including live water pH measurement), total dissolved and suspended solids, conductivity, alkalinity, and specific gravity are essential for basic brine characterization.

Fluid chemistry controls the amount of CO_2 that can dissolve in the brine (solubility), affecting estimates of carbon dioxide trapping and storage capacity. Solubility of $scCO_2$ in brine must be high for efficient trapping and this variable will be quantified. The in situ dissolution of $scCO_2$ depends on the pressure, temperature, and salinity of the formation brine.

[redacted]. Capillary pressure in the seal that includes $scCO_2$-brine IFT must be higher than the buoyancy forces exerted by the seal to prevent upward migration and escape of CO_2. Interfacial tension effects can also influence effective permeabilities and $scCO_2$-formation brine relative permeabilities.

[redacted] The viscosity contrast between $scCO_2$ and $scCO_2$-saturated brine must be sufficiently high to prevent the displacement of stored CO_2 by brine; these viscosities will be measured with a capillary viscometer. Brine compressibility by Constant Composition Expansion will be determined for quantifying CO_2 and storage capacity, as well as the change in aquifer volume with changing pressure.

4.3.1.4 Minifrac Test

As discussed in *Section 5 – Testing and Monitoring Plan*, during the open-hole logging program, minifrac tests will be conducted to measure the fracture gradient of the confining and injection intervals(s) in WC SWMW No. 001. This testing relates to the injection well requirements in SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**] and SWO 29-N-6 **§3617.5.c** [40 CFR **§146.87€(3)**] and is meant to supplement and possibly fulfill these data gathering requirements for the storage reservoir. The tests will be conducted using a formation pressure and sampling tool.

Objectives

1. Achieve zonal isolation of the confining and injection intervals [redacted].
2. Perform several (up to four or five) injection and flowback test cycles to reduce the uncertainty and capture a better measure of the far-field minimum stress.
3. Measure tensile fracturing pressure, stress direction, far-field minimum and maximum stress, and tensile strength.

4.3.2 Overview of Stratigraphic Well Completion Program

[redacted].

4.3.3 Stratigraphic Well Operational Strategy Summary

WC SWMW No. 001 is engineered to be an available test well, if needed, for the purpose of gathering subsurface data for WC IW-B No. 001 and No. 002 prior to injection. WC SWMW No. 001 will be located [redacted] and No. 002. The primary purpose of the strat well is to gather reservoir data, such as whole cores, fluid samples, and open-hole logs, from the Miocene sands formation and confining layers. [redacted]

4.4 Above-Zone Monitoring Well

Harvest Bend CCS intends to drill and complete an above-zone monitoring well [redacted] WC AZMW-B No. 001, [redacted], will monitor the first permeable zone above the UCI—the [redacted] formation—with the same pressure and temperature sensor technology used in the injection wells. Tubing pressures will be monitored via downhole pressure gauges run on a fiber optic cable sensing package [redacted]. WC AZMW-B No. 001 will be situated in the currently predicted carbon and critical-pressure boundaries and will monitor for signs of CO_2 escaping through the UCI. This well will not be drilled through the UCI, thus it will not require acid-resistant materials for its construction.

The proposed preliminary design for WC AZMW-B No. 001 is depicted in Figure 4-13 (*Appendix D-5*).

[redacted]

Figure 4-13 – WC AZMW-B No. 001 Wellbore Schematic

4.4.1 General Outline of Well Design and Completion Schematic

WC AZMW-B No. 001 was designed with the following specifications:

- Drive Pipe
  - Size: [redacted]
  - Depth: [redacted]
- Surface Casing
  - To be set below the lowermost USDW
    - Currently estimated setting depth: [redacted]
      - Based on offset open-hole log evaluation
    - The USDW will be further confirmed via open-hole logging during the drilling of the well and adjusted as necessary.
  - Casing OD: [redacted]
  - Top of cement: surface
- Production Casing
  - [redacted] casing set at TD – [redacted]
  - Composed of [redacted] grade
  - Hole size: [redacted]
  - Top of cement: surface
- Injection Tubing
  - [redacted] tubing set on packer, with tail pipe at [redacted]
  - Per metallurgical analysis, composition to be of [redacted]
  - Annular fluid to consist of corrosion-inhibitor fluid
  - [redacted] at approximately [redacted]
  - Fiber-optic cable will be run [redacted].
    - Tubing pressure and temperature gauges will be run on the end of the FOC [redacted].
- Packer (Figure 4-14, *Section 4.4.2.6*)
  - [redacted] production packer
  - Elastomer options: [redacted]
  - Temperature rating: [redacted]
- Wellhead (Figure 4-15, *Section 4.4.2.7*)
  - [redacted]
  - Production Tree
    - [redacted]

4.4.2 Detailed Discussion of Above-Zone Well Design

Based on appropriate bit-size selection, pipe-clearance considerations, and recommended annular spacing for assurance of proper cementing, it was determined that the following casing sizes are appropriate to accommodate the [redacted] injection tubing:

- [redacted] drive pipe driven to [redacted]
- [redacted] open hole with [redacted] surface casing drilled to [redacted]
- [redacted] open hole with [redacted] production casing drilled to [redacted]

4.4.2.1 <u>Drive Pipe</u>

Due to the loose and unconsolidated nature of the sediments found below the waterline, a drive pipe will be required to maintain the integrity of the hole during the initial drilling of the well. A [redacted] drive pipe will be used for this purpose. The pipe will be driven using a casing hammer, either to the proposed depth or to refusal.

The selection of the drive pipe size (Table 4-23) is based on the desired bit size for drilling the surface casing borehole. With a drive pipe having an ID of [redacted], a [redacted] bit can be used to clean out the drive pipe and drill the next section of the well to a depth of [redacted].

After the drive pipe is in place, the inside of the pipe can be flushed, allowing the next stage of drilling to begin.

Table 4-23– Drive Pipe Engineering Calculations

Drive Pipe								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
	(ppf)	(ft)	(psi)	(psi)	(psi)	(bbl/ft)	(in.)	(in.)
[redacted]								
Safety Factor	[redacted]							

4.4.2.2 <u>Surface Casing</u>

The surface casing section of the well will be drilled using an [redacted] bit, which will create enough space to securely cement the [redacted] casing to the surface. The surface hole will be drilled with casing set at a minimum of [redacted] below the USDW, measured from ground level. This casing string, along with a proper cementing job, will provide two barriers to prevent contamination of the USDW during drilling operations. A cement-bond logging tool will be used to check the quality of the cementing job, to ensure that it was successful.

Summaries of engineering calculations for the surface casing are provided in Table 4-24 (A, B, and C), including the cement calculations at Table 4-25 (A and B).

Table 4-24 – Surface Casing Engineering Calculations

(A) Surface Casing								
Description	Casing Wt. (ppf)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]								
Safety Factor	[redacted]							

(B) Annular Geometry			
Section	ID (in)	MD (ft)	TVD (ft)
Drive Pipe	[redacted]		
Open Hole			

(C) Casing					
Section	OD (in)	ID (in)	Weight (lb/ft)	MD (ft)	TVD (ft)
Surface	[redacted]				

Table 4-25 – Surface Casing Cement Calculations

(A) Cement			
System	Top (ft)	Bottom (ft)	Volume of Cement (cf)
Lead	[redacted]		
Tail			

(B) Volume Calculations				
Section	Footage (ft)	Capacity (cf/ft)	% Excess (%)	Cement Volume (cf)
Drive Pipe/Casing Annulus Lead Cement	[redacted]			
Open Hole/Casing Annulus Lead Cement				
Open Hole/Casing Annulus Tail Cement				
Shoe Track				

4.4.2.3 Production Casing

Production casing (long-string casing) section will be drilled using a [redacted] bit, and the [redacted] casing will be run from the surface to TD and then cemented to surface. After the surface and production casing are set, four barriers will exist between the USDW and the fluid in the wellbore. This well will not be drilled through the UCI, thus the production casing will not require acid-resistant materials for its construction.

Summaries of engineering calculations for the surface casing are provided in Table 4-26 (A, B, and C), including the cement calculations at Table 4-27 (A and B).

Table 4-26 – Production Casing Engineering Calculations

(A) Production Casing								
Description	Casing Wt. (ppf)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
[redacted]								
Safety Factor	[redacted]							

(B) Annular Geometry			
Section	ID (in)	MD (ft)	TVD (ft)
Surface Casing	[redacted]		
Open Hole			

(C) Casing					
Section	OD (in)	ID (in)	Weight (lb/ft)	MD (ft)	TVD (ft)
Intermediate	[redacted]				

Table 4-27 – Production Casing Cement Calculations

(A) Cement			
System	Top	Bottom	Volume of Cement
Lead	[redacted]		
Tail			

(B) Volume Calculations				
Section	Footage (ft)	Capacity (cf/ft)	% Excess (%)	Cement Volume (cf)
Surface Casing/Intermediate Casing Annulus Lead Cement	[redacted]			
Open Hole/Casing Annulus Lead Cement				
Open Hole/Casing Annulus Tail Cement				
Shoe Track				

4.4.2.4 Centralizers

Centralizer selection and installation for the referenced well will have two separate functions. The bow-spring centralizer design for the [redacted] surface casing will be planned to protect any shallow aquifer zones per state regulations. The specific placement is also to ensure a continuous, uniform column of cement is present throughout the [redacted] annulus. The recommended location will be:

[redacted]

The bow-spring centralizer design for the [redacted] production casing will also be planned to protect any shallow aquifer zones per state regulations. The specific placement is to ensure a continuous, uniform column of cement is present throughout the [redacted] annulus. The recommended location will be:

[redacted]

Final centralizer design for all strings will be finalized at a later date when detailed cement design is also finalized and a stand-off model is completed.

4.4.2.5 Tubing

The tubing string (Table 4-28) will consist of [redacted] tubing and a permanent packer assembly. The tubing string will be used to collect fluid samples above the UCI. WC AZMW-B No. 001 will be equipped with pressure and temperature gauges run on a FOC [redacted], for continuous downhole pressure and temperature monitoring. A cross-coupling cable protector will be mounted to each tubing joint coupling to protect the cable across couplings.

Table 4-28 – Injection Tubing Specifications

Tubing								
Description	Casing Wt.	Depth	Tensile	Collapse	Burst	Capacity	ID	Drift ID
[redacted]								
Safety Factor	[redacted]							

4.4.2.6 Packer Discussion

The production tubing will be run into the well with a [redacted] production packer with premium connections (Figure 4-14).

[redacted]

Figure 4-14 – [redacted] Permanent Packer

4.4.2.7 Wellhead Discussion

The wellhead is designed to accommodate anticipated working pressure. The final pressure rating, currently specified to be [redacted], will be confirmed before beginning the manufacturing process. The wellhead will be configured as shown in Figure 4-15 (note: the manufacturer may differ from the one shown).

[redacted]

Figure 4-15 – WC AZMW-B No. 001 Preliminary Wellhead Design

4.4.3 Testing and Logging of Above-Zone Monitoring Well During Drilling and Completion Operations

4.4.3.1 <u>Logging Plan</u>

The logging plan is detailed below (Tables 4-29 and 4-30). Harvest Bend CCS will provide a schedule of all logging plans to the UIC Director at least 30 days prior to conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

Table 4-29 – Open-Hole Logging Plan

Hole Section	Logging Suite	Target Data Acquisition	Open Hole Diameter	Depths of Survey
Surface Casing	[redacted]			
Production Casing				

Table 4-30 – Cased Hole Logging Plan

Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension	Depths of Survey
Surface Casing	[redacted]			
Production Casing				

4.4.3.2 <u>Formation Fluid Testing</u>

Baseline fluid samples will be obtained and tested from the [redacted] formation upon completion of WC AZMW-B No. 001. If pressure anomalies are observed in the [redacted] during injection well operations, additional samples may be obtained and compared against baseline testing results.

4.4.4 Overview of Above-Zone Monitoring Well Completion Program

After setting and cementing the production casing, the production tubing string will be run. The completion program includes the following:

- Make bit and scraper run to TD.
- Run cased-hole logs as described in Table 4-30.
- Test the casing.
- Run tubing and packer to depth.
- Displace the hole with corrosion – resistant packer fluid.
- Set packer and test.
- Perforate the [redacted] formation around [redacted] TVD, specific depths to be determined with open-hole logs [redacted].
- Pump-in test to ensure fluid and pressure communication with the formation. [redacted].

4.4.5 Above-Zone Monitoring Well Operational Strategy

WC AZMW-B No. 001 is engineered to be an above-zone monitoring well. Constant monitoring of downhole pressure and temperature in the [redacted] will be accomplished using a fiber-run pressure and temperature gauges and SCADA systems. The [redacted] formation is the first permeable interval above the UCI, the [redacted]. Temperature and pressure anomalies within the [redacted] are an early indication of injectate from WC IW-B No. 001 and No. 002 moving out of the gross injection zone. If pressure or temperature anomalies are detected, and deemed not a result of thermal interference from normal operation of the injection well, injection will be halted, and the incident will be evaluated as detailed in the Emergency and Remedial Response Plan (*Section 8*). Following completion of post-injection monitoring requirements, the monitoring well will be sealed per the Injection Well Plugging Plan (*Section 6*).

The location of this project is ideal for carbon sequestration monitoring. By combining the best engineering practices in well design with both a cutting-edge monitoring system and a comprehensive reservoir management strategy, this monitoring well will help ensure the safe storage of CO_2 for an extended period of time.

4.5 USDW Monitoring Well

Harvest Bend CCS intends to drill and complete a USDW monitoring well [redacted] WC GW-B No. 001, [redacted], will monitor the lowermost USDW intervals near the injection wells. WC GW-B No. 001 will be situated in the currently predicted carbon and critical pressure boundaries and will monitor for signs of CO_2 escaping up into USDWs. This well will not be drilled through the UCI, thus it will not require acid-resistant materials for its construction.

The proposed preliminary design for WC GW-B No. 001 is depicted in Figure 4-16.

[redacted]

Figure 4-16 – WC GW-B No. 001 Wellbore Schematic

4.5.1 Formation Fluid Testing

Baseline aquifer water samples will be obtained and tested from the lowermost USDW interval upon completion of WC GW-B No. 001. As discussed in *Section 5.5.3* of the Testing and Monitoring Plan, WC GW-B No. 001 will be a critical part of monitoring the ongoing CO_2 storage operations.

4.5.2 USDW Monitoring Well Operational Strategy

WC GW-B No. 001 is engineered to be a USDW monitoring well. Representative aquifer water samples will be obtained quarterly and compared against baseline sampling and fluid testing results, to verify that injectate is not leaking into the USDW. If fluid sample anomalies are detected, injection will be halted, and the incident will be evaluated as detailed in the Emergency and Remedial Response Plan (*Section 8*). Following completion of post-injection monitoring requirements, the USDW monitoring well will be sealed as per the Injection Well Plugging Plan (*Section 6*).

Appendix D: Well Construction Schematics and Procedures

- Appendix D-1 WC IW-B No. 001 – Wellbore Schematic (Initial Completion)
- Appendix D-2 WC IW-B No. 001 – Detailed Drilling Procedure
- Appendix D-3 WC IW-B No. 002 – Wellbore Schematic (Initial Completion)
- Appendix D-4 WC IW-B No. 002 – Detailed Drilling Procedure
- Appendix D-5 WC AZMW-B No. 001 – Wellbore Schematic

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 5 – TESTING AND MONITORING PLAN

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 5 – TESTING AND MONITORING PLAN

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5.1 <u>Introduction</u>

This section includes the proposed testing and monitoring plans for the White Castle Injection Wells (WC IW-B) No. 001 and No. 002 carbon capture and sequestration (CCS) wells [redacted] 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 Testing and Monitoring Plan, as explained in detail below, will begin operating before CO_2 injection commences. 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 pre-determined timeline based on carbon front growth and well conditions at the time of injection cessation. Included here as well is the monitoring strategy for the injection stream, well operating conditions, downhole parameters, Underground Sources of Drinking Water (USDWs), above-zone confinement, and carbon front growth.

5.2 <u>Reporting Requirements</u>

In compliance with SWO 29-N-6 **§3629.A** [40 CFR **§146.91**] requirements, Harvest Bend CCS LLC (Harvest Bend CCS) will provide routine reports to the Underground Injection Control (UIC) Program Director (UIC Director). The contents of those reports and their submittal frequencies are described below:

- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs
    - <u>Verbal Notification</u> – Reported within 24 hours of event
    - <u>Written Notification</u> – Reported within 5 working days of the event
- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW
    - <u>Verbal Notification</u> – Reported within 24 hours of event
    - <u>Written Notification</u> – Reported within 5 working days of the event
- Any failure to maintain mechanical integrity
    - <u>Verbal Notification</u> – Reported within 24 hours of event
    - <u>Written Notification</u> – Reported within 5 working days of the event
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure, as specified in the permit
    - <u>Verbal Notification</u> – Reported within 24 hours of event
    - <u>Written Notification</u> – Reported within 5 working days of event
- Description of any event that triggers a shutoff device, either downhole or at the surface, and the response taken
    - <u>Verbal Notification</u> – Reported within 24 hours of event
    - <u>Written Notification</u> – Reported within 5 working days of event

Quarterly Reports:

- Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data or parameters
- 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 volume of total annulus fluid and any annulus fluid added
- Results of any monitoring as described in this section

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

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

Harvest Bend CCS will submit all reports, submittals, and notifications to both the Environmental Protection Agency (EPA) and the Louisiana Department of Natural Resources (LDNR), and ensure that all records are retained throughout the life of the project. Per SWO 29-N-6 **§3629.A.6** [40 CFR **§146.91(f)**], records will be retained for 10 years after site closure. Additionally, injected fluid data, including nature and composition, will also be retained for 10 years following site closure—and, after the retention period, can be delivered to the UIC Director upon request. Monitoring data will be retained for 10 years post-collection, while well-plugging reports, post-injection site care data, and the site closure report will be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

Per 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 least every 5 years to incorporate collected monitoring and operational data, and the most recent area of review (AOR) reevaluation. Plan amendments will also be submitted within 1 year of an AOR reevaluation, following significant facility changes, such as the development of offset monitoring wells or newly permitted injection wells within the AOR; or as required by the UIC Director.

5.4 Testing Strategies

5.4.1 Minifrac Test

To measure the fracture gradient of the confining and injection zones [redacted] Harvest Bend CCS proposes conducting multiple "minifrac" tests during the open-hole logging program on WC IW-B No. 002. [redacted]. Minifrac testing serves to fulfill requirements in SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**] and provides an alternative to the injectivity test requirement from SWO 29-N-6 **§3617.B.5.c** [40 CFR **§146.87(e)(3)**], which could potentially put a larger frac on the injection sands and confining interval.

5.4.1.1 <u>Testing Method</u>

The minifrac tests will be conducted using a formation pressure and sampling tool, with parameters such as tensile fracturing pressure, stress direction, far-field minimum and maximum stress, and tensile strength. Zonal isolation will be achieved [redacted]. The program will be designed so that the fracture will propagate into the formation on the order of tens of feet, but fracture height will not exceed the distance between the packers. After running filtration tests, borehole fluid will be pumped against the formation at a constant rate until a fracture is created. Once the fracture has been initiated, the pump will be stopped, and both the instantaneous shut-in pressure and subsequent pressure decline will be measured.

Several injection and flowback tests will be performed. Capturing this data in four to five test cycles will reduce the uncertainty and capture a better measure of the far-field minimum stress. The data will be paired with dual oil-based, mud-imaging tools to give information regarding the maximum and minimum stress directions.

5.4.2 Chemical Composition Confirmation Testing

Under SWO 29-N-6 **§3625.A.1** [40 CFR **§146.90(a)**] requirements, Harvest Bend CCS will acquire samples of the CO_2 injection stream and evaluate any potential interactions of carbon dioxide and other injectate components. CO_2 injection stream samples will be taken quarterly for chemical analysis of the parameters listed in Table 5-1, in addition to continuous pressure and temperature analysis.

5.4.2.1 <u>Sampling Methods</u>

Carbon dioxide stream samples will be collected from the CO_2 pipeline in a location where the injection conditions are representative. A sampling station will be connected to the pipeline at a sampling manifold, and sample cylinders will be purged with the injectate gas—to expel laboratory-added gas and confirm a quality sample collection.

5.4.2.2 <u>Parameters Measured</u>

Table 5-1 – Injectivity Test Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
pH	Quarterly
CO_2 (%)	Quarterly
Water (lb/MMscf)	Quarterly
Oxygen (%)	Quarterly
Sulfur (ppm)	Quarterly
Methane (%)	Quarterly
Ethane (%)	Quarterly
Other Hydrocarbons (%)	Quarterly
Hydrogen Sulfide (ppm)	Quarterly
Benzene (%)	Quarterly

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

5.4.3 Mechanical Integrity Testing – Annulus Pressure Test

In accordance with SWO 29-N-6 **§3627.A.2** [40 CFR **§146.89(b)**], Harvest Bend CCS will ensure mechanical integrity by performing annular pressure tests after the wells have been completed, prior to the start of injection, and after any workover operation involving the removal and replacement of the tubing and packer.

The annular pressure tests should 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) fluid pressure, then using a block valve 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 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 that 30-minute minimum duration.

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

5.4.4 External Mechanical Integrity Testing

In adherence to the requirements of SWO 29-N-6 **§3627.A.3** [40 CFR **§146.89(c)**], Harvest Bend CCS will perform an annual external mechanical integrity test (MIT) by conducting a temperature log [redacted]. A temperature log [redacted] will be run in each well before initiating injection operations, to establish a baseline against which future logs can be compared. The wells will be shut in for a duration of approximately 36 hours prior to running the temperature logs, to allow temperatures to stabilize. Satisfactory mechanical integrity is demonstrated by proper correlation between the baseline and subsequent logs.

All temperature logs [redacted] recorded during the MIT will be submitted to the Injection and Mining Division within 30 days of log-run completion.

5.4.5 Pressure Falloff Testing

Harvest Bend CCS will perform a required pressure falloff test on each well every 5 years per SWO 29-N-6 **§3625.A.6** [40 CFR **§146.90(f)**]. The tests will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

5.4.5.1 Testing Method

The injection rate and pressure will be held as constant as possible prior to the beginning of the test, and continuous data will be recorded during testing. Once the well has been shut in, continuous pressure measurements will be taken via a downhole gauge. The falloff 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.

5.4.5.2 Analytical Methods

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 via analysis of observed pressure changes and/or pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by the comparison of pressure falloff tests prior to initial injection, with later tests. The effects of two-phase flow effects will also be considered. Such well parameters resulting from falloff testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties outside the range of modelled uncertainties may dictate that an AOR reevaluation is necessary.

All pressure falloff test results will be submitted to the Injection and Mining Division within 30 days of test completion.

5.4.5.3 Quality Assurance/Control (QA/QC)

All field equipment will undergo inspection and testing prior to operation. Manufacturer calibration recommendations will be adhered to during the use of pressure gauges in the falloff test. Documentation certifying proper calibration will also be enclosed with the test results.

5.4.6 Continuous Injection Stream Monitoring

Harvest Bend CCS will ensure that continuous monitoring of the injection pressure, rate and volume, and annulus pressure comply with SWO 29-N-6 **§3625.A.2** [40 CFR **§146.90(b)**] requirements. A Supervisory Control and Data Acquisition (SCADA) system will be installed [redacted] to facilitate the operational data collection, monitoring, recording, and reporting for each injection well.

Continuous monitoring of the injected CO_2 stream pressure and temperature will be performed, using digital pressure gauges installed in the CO_2 pipeline near the pipeline-wellhead interface. An on-site SCADA system will be connected to the pipeline, and a flow meter—used to measure the injected CO_2 mass flow rate—will be installed upstream of the injection wells. The mass flow rate meter will be connected to the SCADA system at the CO_2 storage site to ensure continuous monitoring and control of the CO_2 injection rate.

Downhole annular and tubing pressures will be monitored via downhole pressure gauges run on a fiber-optic-cable sensing package [redacted]. Pressures will be continuously monitored to ensure that well integrity is maintained. The package will include distributed temperature sensing (DTS) technology to support continuous temperature monitoring capabilities. *Section 5.5.5* provides more detail on this equipment.

Figure 5-1 provides an illustration of the control and monitoring systems to be installed at [redacted] injection wells.

[redacted]

Figure 5-1 – Typical Injection Well and Injection Skid Flow Schematic

5.4.6.1 Analytical Methods

Harvest Bend CCS will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination for trends to help determine any need for equipment maintenance or calibration. Quarterly reports on the monitoring data will also be submitted.

Per SWO 29-N-6 **§3621.A.7.a.i** [40 CFR **§146.88(e)(2)]**, automatic shut-off systems and alarms will be installed to alert the operator and shut in the well when operating parameters such as annulus pressure, injection rate, etc., diverge from permitted ranges or gradients.

5.4.7 Cement Evaluation and Casing Inspection Logs

Per SWO 29-N-6 **§3617.B.1.c.ii** [40 CFR **§146.87(a)(3)(ii)**] and SWO 29-6-N **§3617.B.1.d.iv** [40 CFR **§146.87(a)(4)(iv)**], at the time of initial well completion a comprehensive cased-hole logging suite will be run on the production casing string for each well. This suite of logs will include a radial cement bond log with variable density and temperature tracks. Additional baseline logs will include [redacted] to establish the condition of the casing. This survey will characterize the original state of the wellbore materials. [redacted] This survey will serve as the baseline survey for future casing inspection efforts.

Casing inspection logs will be performed every 5 years, using a combination of conventional casing inspection logs and [redacted] surveys. The tools that will be run at that time include:

[redacted]

5.4.8 Logging and Testing Reporting

A report that includes log and test results obtained during the drilling and construction of WC IW-B No. 001 and No. 002, and interpretated by a knowledgeable log analyst, will be submitted to the UIC Director as per SWO 29-N-6 **§3617.B.1** [40 CFR **§146.87(a)**].

5.5 <u>Monitoring Programs</u>

5.5.1 Corrosion Coupon Monitoring

Monitoring corrosion of the wells' 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 Harvest Bend CCS, will be performed in addition to the examination of casing inspection logs conducted every 5 years, with permit renewal. This evaluation will ensure that the well components meet the minimum standards for material strength and performance.

5.5.1.1 Sampling Methods

Corrosion coupons, comprising the same material as the injection tubing and production casing, will be placed in the carbon dioxide injection-flow stream. They 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.

5.5.2 Groundwater Quality Monitoring

In order to meet SWO 29-N-6 **§3625.A.4** [40 CFR **§146.90(d**] requirements, groundwater quality and geomechanical monitoring will be conducted above the confining zone to detect potential changes that could result from fluid leakage from the injection zone. Due to the lack of artificial penetrations and shallow-cutting faults in the AOR, Harvest Bend CCS will utilize [redacted] groundwater monitoring well [redacted] as shown in Figure 5-2. [redacted] WC GW-A No. 001 [redacted] and WC GW-B No. 001 [redacted] perforating into the lowermost USDW sand formation. WC GW-B No. 001 will be drilled and analysis performed on baseline samples prior to injection in WC IW-B No. 001 and No. 002 [redacted]. Then, water samples will be collected and tested quarterly from this depth to monitor for signs of CO_2 leakage.

Figure 5-2 (*Appendix F-1*) displays the well locations, which are also listed in Table 5-3.

[redacted]

Figure 5-2 – Monitoring Wells Plan

The evaluation of well logs for four nearby wells has indicated the base of the USDW to be at approximately [redacted] below surface, near the proposed injection wells. Water samples will be collected at this depth to monitor for signs of CO_2 leakage. These four wells (Table 5-2; *Appendix C-2*) are located within [redacted] of the proposed WC IW-B No. 001 and No. 002.

Table 5-2 – Nearby Wells for USDW Determination
(Arranged in increasing distance from injector)

	API Number	Serial Number	Depth of USDW (ft)	Distance from WC IW-B No. 001 (ft)	Distance from WC IW-B No. 002 (ft)
1	[redacted]				
2					
3					
4					

The monitoring well locations (Table 5-3) were selected to minimize surface impact and at a location down-gradient of the regional water flow.

Table 5-3 – Groundwater Monitoring Well Locations

Monitoring Well Location Info	WC GW-A No. 001	WC GW-B No. 001
Latitude	[redacted]	
Longitude		
Datum		
Total Depth		

5.5.2.1 Parameters Measured

Table 5-4 – Groundwater Quality Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Aqueous and pure-phase CO_2	Quarterly
TDS	Quarterly
pH	Quarterly
Specific conductivity (SC)	Quarterly
Density	Quarterly
Other parameters including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds	Quarterly

5.5.2.2 Sampling Methods

Fluid samples will be acquired quarterly from the groundwater monitoring well. The sampling methodology will ensure that all samples represent current USDW fluid properties. Water samples will be collected per procedures from the Injection and Mining Division's state-approved laboratories.

5.5.2.3 Analytical Methods

Harvest Bend CCS will test water samples and maintain results for the parameters listed in Table 5-4. If results indicate the existence of impurities in the injectate, groundwater samples should also be tested to flag any concentrations exceeding the baseline. Testing results will be stored in an electronic database.

Observation of the following trends may be detection of signs that fluid may be leaking from the injection interval(s):

- Change in total dissolved solids (TDS)

- Changing signature of major cations and anions
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increasing concentration of leached constituents
- Increased reservoir-pressure and/or static-water levels

5.5.2.4 Laboratory to be Used/Chain of Custody Procedures

Water samples will be submitted to the Injection and Mining Division via a state-approved laboratory. Harvest Bend CCS will observe standard chain-of-custody procedures as well as maintain records, to allow full reconstruction of the sampling procedure and storage and transportation, including problems encountered.

5.5.2.5 Quality Assurance and Surveillance Measures

Harvest Bend CCS will collect duplicate samples and trip blanks for QA/QC purposes. These will be used to validate test results and ensure that samples have not been contaminated.

5.5.2.6 Plan for Guaranteeing Access to All Monitoring Locations

The surface-use lease agreement with the landowner authorizes the installation of groundwater monitoring wells in locations that ensure access to them for sampling and maintenance purposes. The operator will have full-time access to the USDW monitoring well location. Unauthorized access will be prevented by capping and locking out the well.

5.5.2.7 Additional Freshwater Baseline Sampling

Prior to first injection, Harvest Bend CCS will collect baseline freshwater samples from several active water wells in close proximity to the White Castle Project area. To the extent that Harvest Bend CCS can obtain approval from the well owners, the closest active freshwater wells to the currently predicted carbon front extent will be sampled. Water samples will be collected per procedures from the Injection and Mining Division's state-approved laboratories, one of which will perform baseline analysis to measure the same parameters discussed in *Section 5.5.3.1*. These baseline analyses will serve for comparison against subsequent samples collected after first injection, should the need arise. All active freshwater wells near the White Castle Project area are shown in *Appendix C-4*.

5.5.3 Upper Confining Interval Monitoring

Similar to the groundwater monitoring strategy, Harvest Bend CCS will utilize [redacted] upper confining interval (UCI) or "above-zone" monitoring well [redacted] as shown in Figure 5-2 (*Appendix F-1*). The WC AZMW-B No. 001 will be drilled near the subject injection wells, [redacted] in the White Castle Project area, for above-zone monitoring purposes. Conceptual well-construction plans are included in *Section 4*. This well will continuously monitor the pressure of the first mappable sand identified above the UCI. The well will be completed around [redacted] formation. Any deviations from baseline pressures will initiate additional investigations in the area. If necessary, fluid samples can be obtained from this well to compare against baseline samples, collected and tested when the well is completed.

5.5.4 Carbon Front and Critical Pressure Monitoring

Harvest Bend CCS proposes a two-tiered system to be used for carbon and pressure front tracking per the operational monitoring requirements of SWO 29-N-6 **§3625.A.7** [40 CFR **§146.90(g)**]. Carbon front calculations based on continuously recorded pressures and temperatures will be used as a direct monitoring approach, while a phased, time-lapse seismic-surveying approach will be used to monitor the carbon front indirectly.

- Direct method: rate transient analysis from measured parameters
- Indirect method: time-lapse seismic surveying

This two-tiered system, detailed further below, will serve two purposes: first, to verify reservoir conditions during injection; second, to track carbon front migration and validate the carbon front model. Continuous pressure and temperature monitoring of the injection reservoir will allow for continuous monitoring of reservoir conditions and calculations. To confirm that the carbon front is developing as expected, a phased carbon front-monitoring approach will be utilized. Initially, carbon front growth will be monitored with time-lapse 2D surveys. [redacted] Seismic surveys will be run, minimally, every 5 years to monitor carbon front growth.

Additionally, Harvest Bend CCS also plans to drill a stratigraphic test ("strat") well approximately [redacted]

5.5.4.1 Direct Monitoring: Rate Transient Analysis

Rate transient analysis using known reservoir characteristics will allow for the calculation of more complex parameters within each injection interval. By using proven and industry-standard flow equations to suit CO_2 injection, the extent of the carbon front can be determined. Direct monitoring, to satisfy requirements specified in SWO 29-N-6 **§3625.A.7.a** [40 CFR **§146.90(g)(1)**], will be based on continuous pressure, temperature, and injection rate data to verify and refine modeling efforts, ensure that the backflow of CO_2 does not occur, and prevent USDW contamination.

The reservoir model built during the site evaluation and permitting phase of the project may be further used to predictively monitor the reservoir conditions during injection operations. Through reservoir engineering and transient flow analyses, the model may be updated with actual temperature, pressure, and rate injection data, to evaluate the injection stream's effect on reservoir conditions and so derive accurate reservoir conditions.

Additionally, any periods of shut-in can be observed and evaluated as a drawdown test. To do this, the shut-in wellhead pressure, downhole tubing pressure, and temperature readings will be recorded and used for pressure transient analysis of the reservoir. Results of the analysis will include the radius and magnitude of pressure buildup and reservoir performance characteristics, such as permeability and transmissibility. Analysis results will then be used to confirm and adjust the previously constructed models.

Through predictive modeling and analysis of recorded pressure and temperature data, the operator can closely monitor the injection wells' effects on the subsurface and AOR—to help ensure regulatory compliance and safety while contributing to informed decision-making.

5.5.4.2 Indirect Monitoring: Time-Lapse Seismic Surveying

Harvest Bend CCS will use time-lapse seismic technology as the first method to monitor the carbon front and development in order to meet the operation monitoring requirements specified in SWO 29-N-6 **§3625.A.7.b** [40 CFR **§146.90(g)(2)**].

Reservoir monitoring using time-lapse seismic has an extensive history of use in tertiary oil and gas recovery. The methodology has undergone thorough testing in saline aquifers with the presence of CO_2. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from the contrast in compressional velocity between high CO_2 concentrations and formation fluids. As formation fluids are displaced by CO_2, the change in acoustic impedance during carbon front growth can be mapped.

Time-lapse seismic monitoring is proposed for the White Castle Project to:

- Monitor the CO_2 injection to ensure the CO_2 propagation within the storage reservoir is as intended,
- Confirm there is no leakage of CO_2 through the upper confining interval, and
- Confirm long-term carbon front stability after injection.

The work steps involved in a time-lapse seismic monitoring program include:

1. Rock Physics Model
2. Seismic Monitoring Feasibility
   a. 1D synthetic model with brine-filled reservoir
   b. 1D model with fractional CO_2-filled reservoir
3. Baseline Surveys
4. Seismic Monitoring
   a. Repeat/time-lapse 2D surface seismic survey
   b. Repeat/time-lapse 3D surface seismic survey, if needed

Rock Physics Model

The first step in seismic monitoring of CO_2 injection is to create a locally calibrated rock physics model. The model is used to predict the seismic response of the reservoir following injection of CO_2 and to design a seismic monitoring program that is optimized for the project.

Deterministic petrophysical analysis estimations, predominantly from local wireline data, are used to forecast the dry mineral rock components from the in situ (in this case, brine) response prior to saturation modeling. The model uses rock properties such as:

- Total porosity
- Effective porosity
- Water saturation
- Clay (type)
- Quartz
- Mineral content

For the White Castle Project, the initial rock physics model was evaluated with Paradigm Geophysical's wireline log evaluation tools, part of their Paradigm-19 software package. [redacted] The analog reservoir properties were taken from wireline logs from the nearby [redacted] well, for which both sonic and density logs are available (Figure 5-3). [redacted].

[redacted]

Figure 5-3 – [redacted] Log Analysis

Based on those wireline logs, the in-situ brine-filled sand is expected to have an effective porosity of [redacted] and a corresponding bulk density of [redacted] gm/cc. Sonic log response is [redacted] μsec/ft, which corresponds to compressional velocity of [redacted] ft/sec. The corresponding values for the adjacent shales were measured to be [redacted] gm/cc and [redacted] ft/sec.

For seismic elastic modeling, three elastic parameters are required, typically represented by density (ρ), compressional velocity (Vp) and shear velocity (Vs). Shear velocity is usually more difficult to determine than the other two parameters because relatively few wireline shear sonic logs are recorded. Fortunately, with respect to the White Castle Project area, there is a nearby well, [redacted] with a shear sonic log over the depth range of interest. The wireline Vp/Vs was cross-plotted against gamma-ray for that well (Figure 5-4) and observed that the clean sands (e.g., low gamma ray values around 20) have a Vp/Vs ratio of about 2.0, whereas shales (e.g., high gamma ray values around 100) have a Vp/Vs ratio of about 2.5. This linear Vp/Vs trend was applied to the observed gamma ray values and compressional velocities for the [redacted] well, to derive corresponding shear velocities for clean sand ([redacted] ft/s) and shale ([redacted] ft/s) for our rock physics model.

[redacted]

Figure 5-4 – Vp/Vs vs. Gamma Ray in the [redacted]

The trio of elastic properties for the clean sand were then used for a starting condition (brine case) for Gassmann fluid substitution. Physical properties in the reservoir at [redacted] depth are shown in Table 5-5. Reservoir temperature and pressure were derived from local gradients. Brine salinity is known from local resistivity to be approximately [redacted] ppm.

Table 5-5 – Physical Properties for [redacted] CO_2 Injection

Physical Property	Value
[redacted]	

The salinity, pressure and temperature, assumed to be [redacted], respectively, are used as inputs to determine brine compressional velocity and density using industry-standard empirical relationships (Batzle & Wang, 1992) that are encoded in a fluid property calculator in Paradigm's software (Table 5-6). From brine Vp and ρ, the brine's fluid bulk modulus (K) was calculated to be [redacted] MPa (SI units) at reservoir conditions. Similarly, the fluid properties for 100% CO_2 at reservoir conditions were calculated using the National Institute of Standards and Technology's (NIST) online web calculator. At reservoir conditions the CO_2 is a supercritical fluid with a bulk modulus of [redacted] MPa.

Table 5-6 – Fluid Acoustic Properties for [redacted] CO_2 Injection

Fluid Acoustic Properties for [redacted] CO_2 Injection		
Property	**Brine**	**CO_2**
[redacted]		

By using the known elastic properties of the brine-saturated clean sand, the so-called "dry rock" bulk modulus of the sand without any fluids can be calculated. The dry bulk-modulus is then used as an input to the Gassmann fluid substitution Equation 1 (Figure 5-5) to calculate the bulk modulus for different saturations of CO_2 in the clean sand.

$$K_{sat} = K_{frame} + \frac{\left(1 - \frac{K_{frame}}{K_{mineral}}\right)^2}{\frac{\varphi}{K_{fl}} + \frac{1-\varphi}{K_{mineral}} - \frac{K_{frame}}{K_{mineral}^2}} \quad \text{(Eq. 1)}$$

Figure 5-5 – Gassmann Fluid Substitution Equation

The results of those calculations are shown in Table 5-7 with Vp, Vs, and ρ of the CO_2-saturated sand, along with several other corresponding elastic properties.

Table 5-7 – Elastic Rock Properties from Gassmann Fluid Substitution

Clean Sand Reservoir Model												
	Sw	**DT**	**DTS**	**ρ**	**Vp**	**Vs**	**Vp/Vs**	**K**	**λρ**	**μρ**	**Pimp**	**Simp**
shale	[redacted]											
wet sand												
CO_2 sand												
CO_2 sand												

Petro-Elastic Model

The rock physics model will generate a zero-order dry rock model, which will then be used to establish a petro-elastic model (PEM) by perturbing the elastic parameters for varying degrees of saturation. Figure 5-6 illustrates the combination of the rock physics model (in red) and the PEM at [redacted] water saturation (blue). Changes in saturation result in changes primarily to the compressional wave velocity for this type of rock. The effect of gas replacement of the reservoir fluid can be estimated using both the fluid saturation and fluid replacement from the rock physics model.

[redacted]

Figure 5-6 – Application of Petro-Elastic Model to Rock Physics Model

Prediction of velocity and density as functions of injectate saturation is the final result of the PEM. The seismic response measured by seismic surveys can be determined using the acoustic impedance calculated from both of those elastic properties (Figure 5-7).

[redacted]

Figure 5-7 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation

Seismic Monitoring Feasibility

With the elastic properties determined for the CO_2 injected sand, the changes in reflectivity of the CO_2 sand versus the original brine sand can be modeled via Zoeppritz seismic modelling (Aki & Richards, 1980). This is done in two ways. The first is an idealized amplitude-versus-angle (AVO) plot for a single shale-on-sand interface. The second is a synthetic angle gather showing the expected seismic response of the sands, using a real-world, band-limited wavelet and well logs from the [redacted] well.

Results of the single-interface AVO curve analysis are shown in Figure 5-7. The response of the clean, brine-filled sand is seen to be a simple Class III AVO (Rutherford & Williams, 1989), as commonly seen for clean sands in the Gulf Coast at this depth. [redacted]

[redacted]

[redacted]

Figure 5-8 – Seismic Zoeppritz Modeling Results

A more realistic seismic model can be created using the elastic logs from the [redacted] well, convolved with a real-world wavelet extracted from the White Castle Project–area 3D seismic volume. The logs are first modeled with their original wet fluids in the [redacted] blocky sand. The model is then repeated, substituting the reservoir properties for the [redacted] CO_2-saturated sand. The model uses an [redacted], which closely matches the seismic spectrum observed in the White Castle Project–area 3D seismic volume, at the two-way time corresponding to reservoir depths. The input logs and output synthetic angle gather are shown in Figure 5-9A.

[redacted]

Figure 5-9 – [redacted] Sand AVO Model with CO_2 Fluid Substitution in the [redacted]

The results of the AVO modeling (Figure 5-9B) using CO_2 injection into the [redacted] sand in the [redacted] confirm the results seen from the simple single-interface model. There is a large increase in seismic amplitude, [redacted], from the wet reservoir case to the CO_2-saturated case. The CO_2 saturated case also has a much stronger Class III AVO, as measured from the trough associated with the top of the reservoir. For this particular sand, the bottom of the reservoir—a peak—could also be easily mapped, giving similar results but with opposite polarity.

By modifying this elastic seismic model with differing saturations of the injectate, expected amplitude of the resulting seismic stacks can be plotted against CO_2 saturation. [redacted]

[redacted]

[redacted]

Figure 5-10 – Seismic Stack Response vs. Fractional CO_2 Saturation

Baseline Surveys

The primary seismic monitoring method will be time-lapse 2D seismic surveys. To ensure that an accurate time-lapse response can be calculated, a baseline 2D survey will be acquired prior to the start of injection. The baseline 2D survey will extend beyond the limits of ultimate carbon front to ensure that the edge of the carbon front can be confirmed in all directions. [redacted] Figure 5-11 displays an example of the proposed 2D seismic baseline that will be acquired prior to injection. The final grid layout is subject to detailed surveying, permitting, and alignment with the seismic contractor. The advantage of utilizing 2D for monitoring is that the results of the monitoring will be available quickly, and along the 2D lines the resolution of the reservoir will be higher than of a standard 3D seismic survey acquired in this type of environment. Because the entire storage site is flooded timber with a high amount of vegetation and wildlife, 2D surveys will also require less clearance and impart a lower environmental impact on the area. Harvest Bend CCS does recognize that in some instances a full 3D view of the storage site may be required. Our studies have indicated that the strong time-lapse response allows us to utilize existing 3D surveys as a baseline; these surveys will be reprocessed as a 3D baseline if necessary.

[redacted]

Figure 5-11 – Proposed 2D Seismic Baseline

<u>Seismic Monitoring</u>

Seismic surveys will be run, at least, every 5 years to monitor carbon front growth.   An example of the output from time-lapse seismic monitoring is shown in Figure 5-12[1].

[1] https://csegrecorder.com/articles/view/using-a-walk-away-das-time-lapse-vsp-for-co2-sub-plume-monitoring

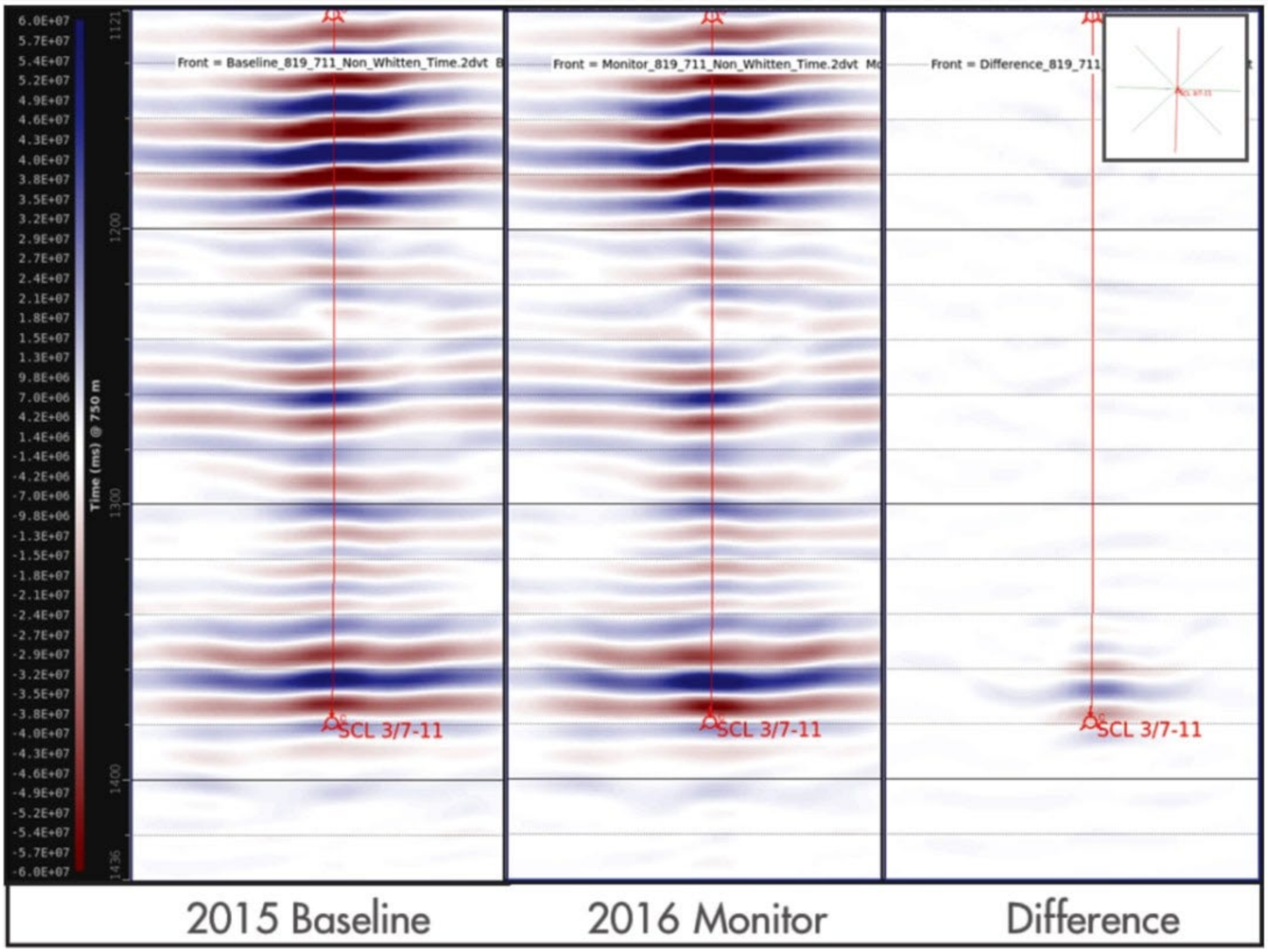

Figure 5-12 – Baseline and Subsequent VSP

The seismic monitoring will take advantage of the fact that the carbon front will expand away from the injection wells [redacted]

2D Surface Seismic

The baseline 2D survey will be repeated periodically to track the movement of CO_2 through the reservoir. These 2D lines have been designed [redacted], which gives much denser coverage closer to the injection wells, allowing for detailed analysis of the behavior and migration of CO_2 through the reservoir. The development plan of recompletion of multiple stages (creating stacked carbon fronts) means that this close-by dense coverage will continue to be useful throughout the project, as shallower injection stages are developed.

Vertical Seismic Profiles

One option under consideration is to record offset vertical seismic profiles (VSPs) via distributed acoustic sensing (DAS) fiber optic cable permanently installed in the injection well(s). VSP data can be acquired at the same time as the 2D lines; thereby "piggybacking" on the same source points as simultaneously used for the 2D surface-seismic lines. The resulting time-lapse VSP surveys would be used for additional imaging of those injection reservoir levels in which the carbon front is still relatively close to the injection well, and will be a useful calibration for the 2D time-lapse seismic response.

3D Surface Seismic

Time-lapse 3D surveys can be acquired, if necessary, [redacted]. The conformance of the dynamic reservoir model will be evaluated throughout the project, and if there are significant deviations from the model this tool may be deployed to help reduce uncertainty.

5.5.5 Monitoring Equipment and Setup

This section details proposed equipment to be utilized in periodic survey and downhole pressure and temperature monitoring operations to determine the carbon front growth over time.

5.5.5.1 Seismic Survey Acquisition

Surface seismic acquisition for carbon front monitoring will use dynamite shot holes for seismic source and independent node receivers. This is applicable to both 2D and 3D surveys. Shot holes will be drilled with a small rig mounted on either an airboat or marsh buggy. Holes are drilled to 100' in depth and typically loaded with 2 kilograms of pentolite and safety-cap detonators. Receivers will be either single-point geophones or a small array of geophones, planted in the ground. Each geophone group either has internal solid-state recording capabilities within the geophone housing or is connected by a short wire directly into a small, autonomous digital recording unit. This eliminates the need for extensive stretches of wire to connect the geophone spread to a central recording "doghouse," as was traditionally used by seismic crews. If the surface seismic recording is complemented by downhole recording in the injection well(s), the recordings will be made with DAS glass fiber installed during the completion of the well. The fiber is connected to an interrogator that pulses light down the fiber; slight delays in the returned light signal are measured to determine strain in the fiber and thereby measure the arrival of seismic waves at the borehole.

5.5.5.2 Wellbore Overview

The proposed wellbore design for WC IW-B No. 001 (Figure 5-13, page 31; *Appendix D-1*) consists of [redacted] surface casing run below the USDW, to be cemented in place per EPA Class VI standards. The wellbore will be designed with [redacted] casing, with premium connections from the surface to [redacted] above the top of the UCI ([redacted]). There will be a [redacted] crossover at that point. The casing will be [redacted] from that crossover to total depth (TD). The [redacted] casing will be set [redacted] into the bottom-sealing, intra-reservoir shale. The production tubing will be [redacted], with premium connections and a [redacted] production packer. The packer should be located approximately [redacted]. The packer location may change, provided there is at least [redacted] good cement bonding across the isolating shale directly above the top of the injection zone. The production packer will also be made of [redacted] material.

The proposed wellbore design for WC IW-B No. 002 (Figure 5-14, page 32; *Appendix D-3*) consists of [redacted] surface casing run below the USDW, to be cemented in place per EPA Class VI standards. The wellbore will be designed with [redacted] casing, with premium connections from the surface to [redacted] above the top of the UCI ([redacted]). There will be a [redacted] crossover at that point. The casing will be [redacted] from that crossover to total depth (TD). The [redacted] casing will be set [redacted] into the lower confining interval. The production tubing will be [redacted], with premium connections and a [redacted] production packer. The packer should be located approximately [redacted]. The packer location may change, provided there is at least [redacted] good cement bonding across the isolating shale directly above the top of the injection zone. The production packer will also be made of [redacted] material.

Annular and tubing pressures will be monitored in each well via downhole pressure gauges run on a fiber-optic-cable sensing package [redacted]. Pressures will be continuously monitored to ensure that well integrity is maintained. The fiber-optic-cable sensing package will include DAS and DTS technology to support carbon front-size monitoring through VSP surveys—if needed—and continuous temperature-monitoring capabilities. A SCADA monitoring system will be in place throughout the project's life.

As the first injection zone reaches capacity, those sands will be plugged and left behind. New perforations will be established in successively shallow sand packages to establish new injection horizons. This recompletion process will repeat from the deepest injection intervals to the top of the gross injection interval throughout the life of the well.

[redacted]

Figure 5-13 – WC IW-B No. 001 Wellbore Schematic (Initial Completion)

[redacted]

Figure 5-14 – WC IW-B No. 002 Wellbore Schematic (Initial Completion)

5.5.5.3 Equipment Overview

This section discusses example hardware setup and use of equipment for continuous downhole pressure and temperature monitoring that will employ fiber optic cable to communicate with a surface-located interrogator box, to record real-time or periodic data. Specific vendor-proprietary equipment will be provided when the vendor is selected nearer to the time the well is drilled. Specification sheets can be found in *Appendix F-2*.

SureVIEW with CoreBright Optic Fiber

SureVIEW downhole cable uses CoreBright optical fiber, which leads the industry in resisting hydrogen darkening—the primary cause of failure for fiber optic systems in high-temperature applications. CoreBright is constructed from pure silica, minimizing hydrogen darkening, combined with a layer of hydrogen-absorbing gel. Figure 5-15 illustrates the optical fiber, and Table 5-8 provides the specifications.

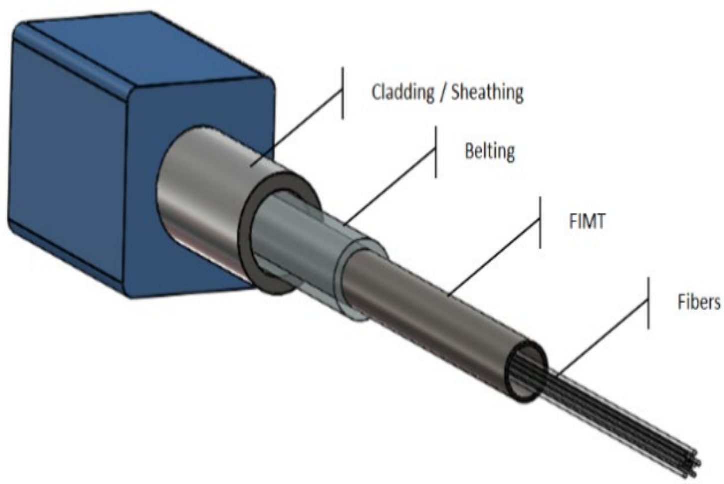

Figure 5-15 – SureVIEW with CoreBright Optic Fiber

Table 5-8 – SureVIEW Downhole Specifications

Description	Specifications
Maximum Pressure	25,000 psi
Overpressure	1.2x maximum pressure
Operating Temperature	• 150°C / 302°F for standard • 250°C / 482°F for high temperature • Higher temperature solutions available upon request
Sheath Material	A825, 316LSS
Crush	>5,000lbf
Fibers	Maximum of 12, any combination of SM and MM
Fiber Protection	• Standard Temperature: Hydrogen-scavenging gel, carbon coating, acrylate buffer • High Temperature: High-temperature stabilized gel, polyimide buffer, optional carbon coating
Dimensions	0.25 inch outside diameter (excluding encapsulation)

SureVIEW DTS Interrogator

The SureVIEW DTS interrogator provides continuous monitoring, rapidly updating temperature profiles along the length of the completions. Its specifications are listed in Table 5-9.

Table 5-9 – SureVIEW DTS Surface Interrogator Specifications

Description	Value
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 μm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW sDAS Interrogator

The SureVIEW sDAS interrogator offers all the benefits of fiber-optic acoustic monitoring, from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring, combined in a single interrogator (Table 5-10 and Figure 5-16).

Table 5-10 – SureVIEW DAS VSP Specifications

Technical Specifications	
Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110-240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC
Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 με

SureVIEW™ WIRE Cable	
Specifications	

Low Temperature Cable	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 120 Deg C Temperature Rating
	• 15,000 psi Pressure Rating

High Temperature	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 225 Deg C Temperature Rating
	• 15,000 psi 15,000 psi Pressure Rating

**may require multiple cables spliced to achieve desired length*

Figure 5-16 – SureVIEW WIRE Illustration

<u>SureVIEW PT Gauge</u>

The SureVIEW™ pressure/temperature (P/T) system is a fiber-optic-based monitoring system that provides reliable and accurate well monitoring. Each fiber-optic gauge measures both temperature and absolute pressure using established Fabry-Perot technology. With no downhole electronics, gauges can operate reliably at much higher temperatures than traditional electronic gauges, and they are immune to electromagnetic interference. Technical specifications are provided in Table 5-11 and an illustration is provided in Figure 5-17.

Table 5-11 – SureVIEW PT Gauge Specifications

SureVIEW P/T gauges	
Standard, high temperature (HT), and ultra temperature (UT)	
Operational temperature	86°F to 302°F (30°C to 150°C) standard
	86°F to 482°F (30°C to 250°C) HT
Temperature accuracy	±1.8°F (±1°C)
Temperature resolution	0.2°F (0.1°C)
Pressure resolution	0.2 psi (0.014 bar)
Pressure range	15 psi to 15,000 psi
Dynamic Pressure Response	1,000psi per second
Overpressure	150% without performance degradation
Pressure accuracy	±5 psi (±0.3 bar)
Dimensions (length x width)	4 in. x 0.75 in. (10.0 cm x 2.0 cm)
Vibration	17g RMS, 10 to 2000 Hz
Shock	100g peak, 10 ms, half-sine
Material	A718
Porting options	Manifold, Testable Autoclave, Annulus

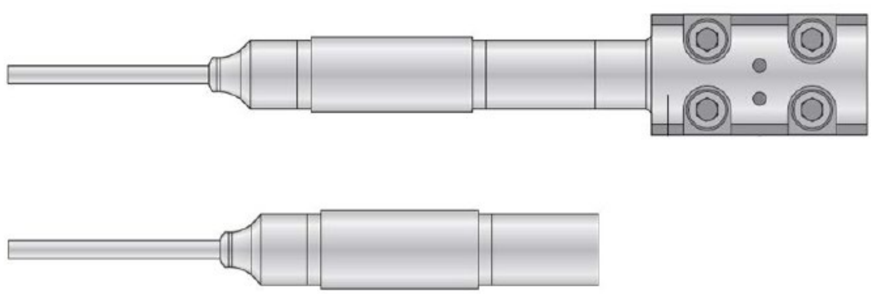

Figure 5-17 – SureVIEW Fiber PT Gauge

<u>SureVIEW PT Interrogator</u>

SureVIEW PT Interrogator is capable of interrogating up to eight SureVIEW fiber-optic P/T gauges to generate raw interferometric-signal information that it then converts into P/T values. Technical specifications are provided in Table 5-12.

Table 5-12 – SureVIEW PT Interrogator

Technical Specifications	
Description	**Specification**
Interrogator Model	Gen 3
Technology Supported	SureVIEW PT gauges
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	2U
Dimensions	19 in. x 3.47 in. x 19.8 in. (483mm x 88mm x 503mm)
Weight	20.3 lbs / 9.2 kg
Certifications	CE
Supply Voltage	24VDC
Power Consumption	Up to 35 Watts
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Humidity	5-75% RH (non-condensing)
Data Interface Connection	Ethernet or Serial RS-485
Internal Data Storage	64GB (> 1 year log capacity)
Fiber Connections	LC/APC (F3000)

Cross-Coupling Protectors

To protect the downhole cable, cross-coupling cable protectors are mounted at each tubing-joint coupling to protect the cable transitions across the coupling, as shown in Figure 5-18. There is a potential for the downhole cable to be damaged due to abrasion or crushing between the tubing and casing internal wall during the installation process, resulting in the loss of functionality of the associated downhole equipment.

Figure 5-18 – Image of Cross Coupling Protector

5.5.6 Monitoring Conclusion

The contents of this Testing and Monitoring Plan have been designed to satisfy all necessary requirements of SWO 29-N-6 **§3625.A** [40 CFR **§146.90**], specific to this project. Reporting and reevaluation requirements are explained and will be executed by Harvest Bend CCS for the life of the project. Monitoring strategies are included for injection-stream composition and conditions, bottomhole operating parameters, well integrity, above-confinement reservoir conditions, and

USDW composition. The planned well equipment to be used is included in their respective sections. The spatial distribution of monitoring wells is described and justified.

The time-lapse seismic surveying method for quantifying carbon front development over time has been well demonstrated. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from the contrast in compressional velocity between high CO_2 concentrations and formation fluids. For Harvest Bend CCS, as formation fluids are displaced by CO_2, even at relatively low concentrations, the change in acoustic impedance during carbon front growth can be mapped to generate a time-lapse seismic image of the carbon front extent.

Most importantly, the need to add artificial penetrations (and risk inadvertently forming a conduit from confinement intervals) for monitoring purposes is eliminated with time-lapse seismic surveying and downhole gauges for accurate monitoring of carbon front migration.

Appendix F: Testing and Monitoring

- Appendix F-1 Monitoring Wells Plan Map
- Appendix F-2 Monitoring Equipment Specification Sheets

5.6 References

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HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 6 – INJECTION WELL PLUGGING PLAN

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 6 – INJECTION WELL PLUGGING PLAN

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6.1 <u>Introduction</u>

This plugging plan for the WC IW-B No. 001 and 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**]. It provides the steps that will be taken to plug and abandon the planned stages of each well development including final abandonment. Any plugging activities required for the monitoring wells associated with this project are also discussed below. Complete plugging and abandonment procedures for WC IW-B No. 001 and No. 002 have been included in *Appendices H-3* and *H-6* of this application, respectively.

As described in *Section 4 – Engineering Design and Operating Strategy*, the wells will be completed with multiple injection horizons within the gross injection zone. Each injection interval will be utilized for a discrete period as identified in the carbon front model and operating plans. Once an active injection interval has been exhausted of CO_2 storage capabilities, the injection interval will be plugged to prevent crossflow conditions between new and existing injection intervals. Once the exhausted sand package has been plugged, a new injection interval uphole will be perforated and opened for injection. This process will be repeated until the entire gross injection interval has been fully developed. After approximately 20 years of injection in each well, or when available storage capacity has been fully utilized, the wells will be permanently plugged and abandoned.

The following details outline the procedures for both types of plugs to be installed in the wells. In summary, the two types of plugs are:

1. Isolation of the active injection section via recompletion operations
2. Final P&A of the wellbores

6.2 <u>Zonal Isolation of Injection Zone/Intermediate Plugback Plan</u>

When the current zone has been exhausted of available pore space or the carbon front migration monitoring indicates storage capacity has been reached, the zone will be abandoned. The general procedure for zonal isolation is described below and illustrated by the first plugback schematic in Figure 6-1 (*Appendix H-1*) and Figure 6-2 (*Appendix H-4*) for WC IW-B No. 001 and No. 002, respectively.

6.2.1 Pre-Plugging Activities

1. Harvest Bend CCS LLC (Harvest Bend CCS) will comply with reporting and notification provisions.
   a. The Underground Injection Control (UIC) Program Director (UIC Director) will be notified 60 days in advance of 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**]

   c. Plugging operations will not start until the UIC Director approves the proposed plan.
2. Tubing pressure will be measured using the downhole gauge [redacted] This measurement will provide information to calculate the well kill-weight fluid density. [SWO 29-N-6 **§3631.A.3.a**; 40 CFR **§146.92(b)(1)**]
3. External mechanical integrity will be demonstrated through approved logging methods, such as a temperature log [redacted], described in *Section 5*. [SWO 29-N-6 **§3631.A.2**; 40 CFR **§146.92(a)**]
4. Harvest Bend CCS will conduct a mechanical integrity test (MIT) to at least 500 pounds per square inch (psi) on the casing-tubing annulus.

[redacted]

Figure 6-1 – WC IW-B No. 001 – First Plugback/Zonal Isolation Wellbore Schematic

[redacted]

Figure 6-2 – WC IW-B No. 002 – First Plugback/Zonal Isolation Wellbore Schematic

6.2.2 Zonal Isolation Activities

1. After pressure testing the annulus, a CO_2 compatible thru-tubing plug and cement will be set above the injection zone to be isolated.
2. The plug will be qualified by conducting a successful pressure test.

6.3 Final Plugging and Abandonment

At the conclusion of the injection and post-injection pressure and temperature monitoring operations discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*, the injection wells will be prepared for final plugging and abandonment (P&A). Figures 6-3 and 6-4 show the status of the wellbore following injection and post-injection monitoring operations and prior to final P&A.

[redacted]

Figure 6-3 – WC IW-B No. 001 Prior to Final Plugging and Abandonment

[redacted]

Figure 6-4 – WC IW-B No. 002 Prior to Final Plugging and Abandonment

The general final P&A procedures are described below, and Figure 6-5 (*Appendix H-2*) and Figure 6-6 (*Appendix H-5*) show the final plugged injection-well schematics for WC IW-B No. 001 and No. 002, respectively.

6.3.1 Pre-Plugging Activities – WC IW-B No. 001 and No. 002

1. Harvest Bend CCS will comply with all reporting and notification provisions.
    a. The UIC Director will be notified 60 days in advance of 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**]
    c. Plugging operations will not start until the UIC Director approves the proposed plan.
2. Casing inspection and cement bond logs will be performed prior to plugging.
3. Tubing pressure will be measured using the downhole gauge installed [redacted] This measurement will provide information to calculate the well kill-fluid density. [SWO 29-N-6 **§3631.A.3.a**; 40 CFR **§146.92(b)(1)**]
4. External mechanical integrity will be demonstrated through approved logging methods, such as a temperature log [redacted], described in *Section 5*. [SWO 29-N-6 **§3631.A.2**; 40 CFR **§146.92(a)**]
5. All uncemented, non-permanent components of the well will be removed, if possible.

Table 6-1 – Description of Casing, Tubing, and Other Well Construction Materials to Be Removed

Injection Well	Well Component	Size	Amount	Notes/Comments
[redacted]				

6.3.2 Plugging Activities – WC IW-B No. 001

The summary procedure for WC IW-B No. 001 is as follows. A full plugging procedure is included in *Appendix H-3*.

1. Flush the well with buffer/kill-weight fluid [SWO 29-N-6 **§3631.A.2**; 40 CFR **§146.92(a)**] and pressure test the annulus. Remove tubing and packer.

2. The gross injection interval will be fully isolated.
    a. A balanced, CO_2-resistant cement plug will be set above the final perforated injection interval extending ~100’ above the base of the upper confining interval (UCI).
    b. The plug will be qualified by tagging the top and conducting a successful pressure test.
    c. A CO_2-resistant (CR) cast-iron bridge plug (CIBP) will be set at [redacted] and a balanced, CO_2-resistant cement plug pumped from [redacted].
    d. The plug will be qualified by tagging the top.
3. [redacted]
4. [redacted]
5. [redacted]
6. Casing will be cut 5’ below plow level and a ½” steel plate, bearing the well serial number, welded on.

Final plugging reports, certified by the operator and the person who performed the plugging operation, will be submitted to the UIC Director within 30 days after plugging. Harvest Bend CCS will retain the final plugging report at least 10 years following site closure.

6.3.3 Plug Details – WC IW-B No. 001

Table 6-2 – Plug Details for Plugs #1–#6 – WC IW-B No. 001

Plug Description	[redacted]	[redacted]				
Plug Number	**1**	**2**	**3**	**4**	**5**	**6**
Diameter of Bore in Which Plug Will Be Placed (in.)	[redacted]					
Depth to Bottom of Workstring (MD)						
Sacks of Cement to Be Used (sks)						
Slurry Volume to Be Pumped (ft^3)						
Slurry Weight (lb/gal)						
Calculated Top of Plug (MD)						
Bottom of Plug (MD)						
Depth of Thru-Tubing Plug (MD)						
Type of Cement or Other Material						
Method of Emplacement						

* [redacted]
MD = measured depth
sks = sacks

Table 6-3 – Plug Details for Plugs #7–#11 – WC IW-B No. 001

Plug Description	[redacted]	[redacted]	[redacted]	[redacted]	
Plug Number	**7**	**8**	**9**	**10**	**11**
Diameter of Bore in Which Plug Will Be Placed (in.)	[redacted]				
Depth to Bottom of Workstring (MD)					
Sacks of Cement to Be Used (each plug) (sks)					
Slurry Volume to Be Pumped (ft^3)					
Slurry Weight (lb/gal)					
Top of Plug (MD)					
Bottom of Plug (MD)					
Depth of Thru-Tubing Plug (MD)					
Type of Cement or Other Material					
Method of Emplacement					

[redacted]

Figure 6-5 – WC IW-B No. 001 – Plugged Wellbore Schematic

6.3.4 Plugging Activities – WC IW-B No. 002

The summary procedure for WC IW-B No. 002 is as follows. A full plugging procedure is included in *Appendix H-6*.

1. Flush the well with buffer/kill-weight fluid [SWO 29-N-6 **§3631.A.2**; 40 CFR **§146.92(a)**] and pressure test the annulus. Remove tubing and packer.
2. The gross injection interval will be fully isolated.
    a. A balanced, CO_2-resistant cement plug will be set across the final perforated injection interval from ~50' below to about ~50 above the perforated interval.
    b. The plug will be qualified by tagging the top and conducting a successful pressure test.
    c. A balanced, CO_2-resistant cement plug will be set from [redacted] across the base of the upper confining interval (UCI) at [redacted].
    d. The plug will be qualified by tagging the top and conducting a successful pressure test.
    e. A CO_2-resistant (CR) cast-iron bridge plug (CIBP) will be set at [redacted] and a balanced, CO_2-resistant cement plug pumped from [redacted]
    f. The plug will be qualified by tagging the top.
3. [redacted]
4. [redacted]
5. [redacted]
6. Casing will be cut 5' below plow level and a ½" steel plate, bearing the well serial number, welded on.

Final plugging reports, certified by the operator and the person who performed the plugging operation, will be submitted to the UIC Director within 30 days after plugging. Harvest Bend CCS will retain the final plugging report at least 10 years following site closure.

6.3.5 Plug Details – WC IW-B No. 002

Table 6-4 – Plug Details for Plugs #1–#6 – WC IW-B No. 002

Plug Description	[redacted]	[redacted]				
Plug Number	**1**	**2**	**3**	**4**	**5**	**6**
Diameter of Bore in Which Plug Will Be Placed (in)	[redacted]					
Depth to Bottom of Workstring (MD)						
Sacks of Cement to Be Used (sks)						
Slurry Volume to Be Pumped (ft^3)						
Slurry Weight (lb/gal)						
Calculated Top of Plug (MD)						
Bottom of Plug (MD)						
Depth of Thru-Tubing Plug (MD)						
Type of Cement or Other Material						
Method of Emplacement						

Table 6-5 – Plug Details for Plugs #7–#11 – WC IW-B No. 002

Plug Description	[redacted]				
Plug Number	**7**	**8**	**9**	**10**	**11**
Diameter of Bore in Which Plug Will Be Placed (in)	[redacted]				
Depth to Bottom of Workstring (MD)	[redacted]				
Sacks of Cement to Be Used (each plug) (sks)	[redacted]				
Slurry Volume to Be Pumped (ft^3)	[redacted]				
Slurry Weight (lb/gal)	[redacted]				
Top of Plug (MD)	[redacted]				
Bottom of Plug (MD)	[redacted]				
Depth of Thru-Tubing Plug (MD)	[redacted]				
Type of Cement or Other Material	[redacted]				
Method of Emplacement	[redacted]				

[redacted]

Figure 6-6 – WC IW-B No. 002 – Plugged Wellbore Schematic

6.4 Monitoring Wells Plugging and Abandonment

When the storage space has been fully utilized and the post-injection site care period, as discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*, has ended, monitoring the carbon front and ground water will no longer be needed. At this time, all monitoring wells will be prepared for P&A and plugged in a manner which will not allow movement of injection or formation fluids that endangers a USDW.

Both types of monitoring wells will be drilled to depths that are too shallow to intersect injection layers, confinement layers, or the corrosive injectate fluids. As such, there is no need for a plugging procedure designed for containment of, or resistance to, acidic fluids.

General plugging plans for the monitoring wells are provided below. The proposed plugging schematic for the above-zone monitoring well (WC AZMW-B No. 001) [redacted] is shown in Figure 6-7 (*Appendix H-7*).

6.4.1 Above-Zone Monitoring Well Plugging Activities

1. After pressure testing the annulus, the well will be flushed with kill-weight fluid.
2. Squeeze perforations with cement. Wait on cement (WOC), tag top of plug, then conduct a successful pressure test.
3. Remove tubing and packer.
4. Perform casing-inspection log and cement bond log.
5. A CIBP will be set at [redacted] with [redacted] of class H cement pumped on top of it to plug across the [redacted] surface casing shoe and base of the USDW.
6. A [redacted] cement plug will be spotted from [redacted]
7. Casing will be cut 5’ below plow level and a ½” steel plate, bearing the well serial number, welded on.

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.

6.4.2 Groundwater Monitoring Well Plugging Activities

1. The perforated monitoring interval will be squeezed with cement to seal off exposure to the USDW.
2. The plug will be qualified by tagging the top and conducting a successful pressure test.
3. The wellbore will be filled with grout to [redacted].
4. A [redacted] cement plug will be spotted at surface and the casing cut off to 5’ below ground level.
5. A ½” steel plate will then be welded across the top of the casing.

[redacted]

Figure 6-7 – WC AZMW-B No. 001 – Plugged Wellbore Schematic

Detailed schematics and procedures are provided in *Appendix H*, as follows:

- Appendix H-1 WC IW-B No. 001 – First Plugback/Zonal Isolation Wellbore Schematic
- Appendix H-2 WC IW-B No. 001 – Plugged Wellbore Schematic
- Appendix H-3 WC IW-B No. 001 – Detailed Plugging Procedure
- Appendix H-4 WC IW-B No. 002 – First Plugback/Zonal Isolation Wellbore Schematic
- Appendix H-5 WC IW-B No. 002 – Plugged Wellbore Schematic
- Appendix H-6 WC IW-B No. 002 – Detailed Plugging Procedure
- Appendix H-7 WC AZMW-B No. 001 – Plugged Wellbore Schematic

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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7.1 Introduction

This Post-Injection Site Care (PISC) and Site Closure Plan was prepared for the WC IW-B No. 001 and No. 002 and has been designed to meet the requirements of Statewide Order (SWO) 29-N-6, **§3633** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93(a)**]. Included are the various activities that will be executed following the end of injection, determination of the final carbon front extent, and during the process of total site closure. This plan will commence once monitoring of the carbon front has ceased and the carbon front has been declared a non-threat to the above-lying Underground Source of Drinking Water (USDW).

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 has been compiled to show the expected pressure differential between the pre- and post-injection pressures in the injection zone. This is determined by the carbon front model results described in *Section 2 – Carbon Front Model*. The pressure differential is calculated from the modeled bottom-hole pressure (BHP) results measured at the wellbore. As discussed there and in *Section 4 – Engineering Design and Operating Strategy*, the WC IW-B No. 001 and No. 002 will inject into sequentially shallower intervals over the life of the project [redacted], resulting in a separate pressure profile for each interval. [redacted]
After injection has ceased in each stage, the pressure drops back down to near in situ pressures. Table 7-1 shows the maximum pressure differential expected within each year included in the model. Figure 7-1 provides a graphical representation of these pressures over the simulated total injection time frame of 20 years.

Table 7-1 – Maximum Bottom Hole Pressure Differential by Year

Year	**WC IW-B No. 001**		**WC IW-B No. 002**	
	Maximum BHP Differential (psi)	Well Completion Stage	Maximum BHP Differential (psi)	Well Completion Stage
[redacted]				

Year	Maximum BHP Differential (psi)	Well Completion Stage	Maximum BHP Differential (psi)	Well Completion Stage
[redacted]				

Year	Maximum BHP Differential (psi)	Well Completion Stage	Maximum BHP Differential (psi)	Well Completion Stage
[redacted]				

Figures 7-1 and 7-2 depict the expected reservoir pressure differential for each injection well. The dark green solid line represents the pressure buildup from in situ pressure, and the light green solid line represents the maximum pressure gradient. The light green dashed line shows the maximum bottomhole pressure constraint.

[redacted] During active operations, pressure will continuously be monitored to ensure BHP remains below 90% fracture gradient.

[redacted]

Figure 7-1 – Maximum Pressure Differential over Time (WC IW-B No. 001)

[redacted]

Figure 7-2 – Maximum Pressure Differential over Time (WC IW-B No. 002)

7.3 Carbon and Pressure Front Positions at End of Injection and at Closure

The carbon front is delineated from the maximum extent of the CO_2 occupied pore space, combined from all carbon front layers in the model, for all injection wells (displayed in *Section 0*, Table 0-1) [redacted] collectively referred to as the White Castle CO_2 Sequestration (White Castle) Project. [redacted].

The carbon front may migrate in various directions, as the target formation is completed in stages. Figures 7-3, 7-4, and 7-5 help demonstrate the furthest migration in each direction. [redacted] This phenomenon is due to the presence of channels and shale baffles through the entire injection zone.

For all figures below, the X/Y scale is in U.S. feet, and the color scale represents the values of the specified property in the model.

[redacted]

Figure 7-3 – Aerial View (Left), E-W View (Middle) S-N View (Right) 50 Years Post-Injection, Colored by CO_2 Saturation

[redacted]

Figure 7-4 – East-West Cross-Sectional View 50 Years Post-Injection, Colored by CO_2 Saturation

[redacted]

Figure 7-5 – North-South Cross-Sectional View 50 Years Post-Injection, Colored by CO_2 Saturation

The maximum critical pressure front area for the White Castle Project is delineated from individual critical-pressure extents for each well completion stage for each well that is part of the White Castle Project. [redacted] As Figures 7-6 and 7-7 show, the maximum critical-pressure front is colored red. [redacted] A cross-sectional view, looking north–south, is shown in Figure 7-7 to visualize the combination of both pressure fronts.

[redacted]

Figure 7-6 – Aerial View of Maximum Pressure Radius of Influence

[redacted]

Figure 7-7 – North–South Cross-Sectional View of Maximum Pressure Radius of Influence, Colored by Pressure Buildup

7.3.1 Post-Injection Monitoring Plan

As required by SWO 29-N-6 **§3633.A.2** [40 CFR **§146.93(b)**], Harvest Bend CCS LLC (Harvest Bend CCS) will continue to monitor the project site until the carbon front is determined to be a non-threat to the USDW formations. [redacted], at which point the majority of free phase CO_2 will have been trapped in the rock, unable to flow naturally. Thus, Harvest Bend CCS proposes a default, 50-year PISC time frame for the White Castle Project.

Throughout the injection life of the well, the reservoir model will be further calibrated with active injection data. The duration of the PISC time frame will be reevaluated alongside area of review (AOR) reevaluations that are to occur at least once every 5 years and increased or decreased accordingly through an amended PISC and Site Closure Plan. Additionally, upon cessation of injection and at least once every 5 years, as needed, an amended PISC and Site Closure Plan will be submitted to the Underground Injection Control (UIC) Program Director (UIC Director). With these amendments to the plan, the PISC time frame will be updated based on the latest modeling and monitoring data, and an alternative PISC time frame will be proposed if demonstrable per SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(c)**].

7.3.2 Post-Injection Monitoring Activities

Post-injection monitoring will be utilized to track the movement of the carbon front and pressure front per SWO 29-N-6 **§3633.A.2** [40 CFR **§146.93(b)**]. The Testing and Monitoring Plan will be extended and used to confirm not only that the injection project is continuing to conform to the permit conditions, but also that any unexpected USDW endangerment is identified and mitigated. 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	Duration (years)
Groundwater Monitoring Wells Geochemical Analysis	Annually	Within 30 days after data collection and analysis	Until the end of the PISC time frame
Pressure and Temperature Monitoring – Above-Zone Monitoring Wells	Continuously	Annually	Until the end of the PISC time frame
Pressure and Temperature Monitoring – Injection Wells	Continuously	Annually	[redacted]
Direct Carbon Front Calculations Based on Pressure and Temperature Data	Annually	Annually	[redacted]
Indirect Carbon and Pressure Front Monitoring (Seismic Survey)	Every five years	Within 30 days after data collection and analysis	Until the end of the PISC time frame

[redacted] Sufficient pressure data will be gathered to adequately forecast the stabilization of the gross injection reservoir.

Figures 7-8 and 7-9 show the proposed wellbore configuration for [redacted] direct monitoring in WC IW-B No. 001 and No. 002, respectively. As discussed in *Section 4 – Engineering Design and Operating Strategy*, annular and tubing pressures will be monitored via downhole-pressure gauges run on a fiber optic cable sensing package [redacted]. Pressures will be continuously monitored to ensure that well integrity is maintained and that reservoir pressures are declining to near in situ pressures as expected. [redacted] data will be submitted to the UIC Director for verification prior to plugging the injection wells per *Section 6 – Injection Well Plugging Plan*.

Additionally, Table 7-2 discusses the continuation of other monitoring activities throughout the PISC time frame. It is reasonably expected that the rate of carbon front growth will decline and the rate of carbon front stabilization will increase as such that the White Castle Project will no longer pose an endangerment to USDWs. [redacted]

All testing and monitoring activities listed will be performed and analyzed as discussed in *Section 5*, including quality assurance/quality control (QA/QC) measures.

[redacted]

Figure 7-8 – Post-Injection Monitoring Wellbore Configuration – WC IW-B No. 001

[redacted]

Figure 7-9 – Post-Injection Monitoring Wellbore Configuration – WC IW-B No. 002

7.4 Demonstration of Non-Endangerment of USDW

As required by SWO 29-N-6 **§3633.A.3** [40 CFR **§146.93(c)**], Harvest Bend CCS will provide documentation that the USDW is not at risk of further endangerment from the carbon front before site-closure authorization can be approved. Harvest Bend CCS will also submit a report to the UIC Director demonstrating the non-endangerment of the USDW—including site-specific conditions, an updated carbon front model, predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model.

7.5 Site Closure Plan

To meet the requirements of SWO 29-N-6 **§3633.A.5** [40 CFR **§146.93(e)**], the following site closure activities will be performed, including removal of surface equipment, plugging of all project wells, site restoration/remediation, and submittal of final site-closure reports.

7.5.1 Pre-Closure

Notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to site-closure operations. If any changes have been made to the original PISC and Site Closure Plan, a revised plan must also be submitted. Relevant notifications and applications, such as plugging requests, must be submitted and approved by the appropriate agency prior to commencing such activities.

7.5.2 Plugging Activities

The subject injection wells, WC IW-B No. 001 and No. 002, groundwater monitoring wells, and the above-zone monitoring wells for the White Castle Project will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*. The plugging and abandonment procedures for the injection wells are designed to prevent CO_2 or formation fluids in the injection interval from migrating up and into the USDW. Prior to plugging the injection wells, the mechanical integrity of the wells will be determined by an annulus pressure test, casing inspection log, radial cement bond log, and temperature log as described in *Section 5 – Testing and Monitoring Plan*. Detailed plugging schematics (*Appendices H-2* and *H-5*) and procedures (*Appendices H-3* and *H-6*) are provided in *Appendix H*.

7.5.3 Site Restoration

Once the injection wells and monitoring wells are plugged and capped below grade, all surface equipment will be decommissioned and removed from the site.

7.5.4 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)**], to include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats
- Documentation of the well-plugging report to the Louisiana Department of Natural Resources (LDNR)
- 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:

- A complete legal description of the affected party;
- The fact the land was used to sequester CO_2;
- That the survey plat was filed with the LDNR and the EPA;
- The address of the office of the EPA, to which the operator sent a copy of the survey plat; and
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which injection occurred.

Harvest Bend CCS will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, Harvest Bend CCS will deliver to the UIC Director all records, which will thereafter be retained at a location that the UIC Director designates for that purpose.

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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Figures

None included.

Tables

8.1 Introduction

This Emergency and Remedial Response plan for the subject injection well, WC IW-A No. 001, was prepared to meet the requirements of Statewide Order (SWO) 29-N-6, **§623** [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 plan to be updated immediately.

8.2 Resources/Infrastructure in AOR

[redacted] The proposed location is approximately [redacted] miles from the nearest freshwater drinking water well. No dwellings are located within the currently predicted area of review (AOR), and no artificial penetrations lie there within. Structures within the AOR are located on the leased acreage and are used for recreational purposes, such as hunting. Additionally, as shown in *Appendix C-6*, no state or federal subsurface cleanup sites, subsurface mines, or quarries are located within the currently predicted AOR.

The wells and the currently predicted carbon front are located on and below what are primarily wooded wetlands. A portion of the carbon front extent is located in the subsurface below rural farmland. The well locations will be accessible through new roads to be constructed in the wooded wetlands. *Appendix G-3* shows roads, pipelines, and other infrastructure in the area as well as the well locations and carbon front extent.

The lowermost Underground Source of Drinking Water (USDW) in the AOR is estimated to be found at approximately [redacted].

8.3 Resources/Infrastructure – Specific Events and Response Plans

The following scenarios represent high-level concepts of potentially significant adverse events, methods of prevention and detection, and likely remedial responses.

8.3.1 Event Category – CO_2 Release to or at the Surface

8.3.1.1 Specific Event Description – Overpressurization (i.e., induced) and/or major mechanical failure of facility equipment or flowlines on the injection well pad

Risk Assessment Matrix, Section 1.1 (Appendix G-1)

This event could happen during operations of the injection facility by operating equipment outside of designed pressures or outside of compositional limits, beyond recommended preventative maintenance (PM) cycles, or, otherwise, improperly. This could also occur if the maximum allowable operating parameters change due to depreciation or corrosion of equipment and are not accounted for.

Likelihood: [redacted]

Prevention and Detection

- Proper operation and PM of all facility equipment on the injection well pad will be carried out.
- The facility will be closely monitored with system controls in place to prevent overpressure and release.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- The surface wellhead tree will be regularly maintained and tested for integrity.
- Safety systems will have automatic shut-in capabilities.
- CO_2 detectors will be utilized to continuously monitor ambient air.

Potential Response Actions

- Stop the injection and notify the Underground Injection Control (UIC) Program Director (UIC Director) within 24 hours.
- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Set plug in near-surface nipple as secondary barrier to flow.
- Close the applicable wellhead valve(s).
- 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, to initiate repairs, if feasible, prior to resuming injection operations.
- 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.

8.3.1.2 Specific Event Description – Caprock/reservoir failure (e.g., carbon front migrates along fault line/fissure to surface)

Risk Assessment Matrix, Section 1.2 (Appendix G-1)

This event could occur due to unforeseen geological complications.

Likelihood: [redacted]

Prevention and Detection

- Wells have been located to avoid faults of concern and verified via 3D seismic survey.
- Confinement has been demonstrated through dynamic geocellular modeling efforts.
- Pressure and rate monitoring, pressure falloff 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.

<u>Potential Response Actions</u>

- Stop the injection and notify the UIC Director within 24 hours.
- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Close the applicable wellhead valve(s).
- Monitor well and annulus pressures.
- Continue carbon front monitoring at a more frequent interval to determine if migration continues.
- If the carbon front continues to migrate out of the zone or beyond the expected carbon front extent, recomplete uphole into the next planned injection interval.
- 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, to initiate repairs, if feasible, prior to resuming injection operations.
- Recomplete well to a new injection interval to avoid permanent reservoir damage.
- 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.

8.3.1.3 <u>Specific Event Description – Poor cement job can allow for CO_2 to escape near wellbore</u>
Risk Assessment Matrix, Section 1.3 (Appendix G-1)

This event could occur due to an inadequate cement selection or design.

<u>Likelihood</u>: [redacted]

<u>Prevention and Detection</u>

- Proper wellbore design, including proper premium CO_2 cement, will be implemented in the well construction phase.
- A cement-bond logging tool will be used to check the quality of the cementing job, to ensure the job was successful.
- Routine temperature and casing inspection logs will be performed.

- CO_2 detectors will be utilized to continuously monitor ambient air.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Close the applicable wellhead valve(s).
- 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, to initiate repairs, if feasible, prior to resuming injection operations. 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.

8.3.1.4 Specific Event Description – Casing or wellhead failure/leak
Risk Assessment Matrix, Section 1.4 (Appendix G-1)

This event could occur due to the corrosive nature of the injection fluid.

Likelihood: [redacted]

Prevention and Detection

- Proper wellbore design, including proper metallurgy of the casing and tubing, will be implemented in the construction phase.
- Ongoing monitoring and mechanical integrity testing will confirm integrity.
- Perform routine wellhead and casing inspection.
- Perform quality assurance/quality control (QA/QC) per American Petroleum Institute (API) standards.
- Utilize CO_2 detectors to continuously monitor ambient air.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Set plug in near-surface nipple as secondary barrier to flow.
- Close the applicable wellhead valve(s).
- 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, to initiate repairs, if feasible, prior to resuming injection operations. 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.

8.3.1.5 Specific Event Description – Well seal failure of adjacent well(s) (e.g., plugging and abandonment (P&A) wells, monitor wells)
Risk Assessment Matrix, Section 1.5 (Appendix G-1)

This event could occur due to the corrosive nature of the CO_2 stream and failure of the use of proper materials in adjacent wellbores, such as cement inside and behind casing, casing and equipment metallurgy, and plugging materials.

Likelihood: [redacted]

Prevention and Detection

- Corrective action will include detailed review and design, including appropriate cement and metallurgy of the plugging materials.
- Continuous pressure monitoring at surface and downhole will highlight potential issues.
- Pressure and rate monitoring, pressure falloff tests, etc., will all be performed according to *Section 5*.
- The facility and surrounding area will be closely monitored, with competent management of operations.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Close the applicable wellhead valve(s).
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas monitoring operations.
- Determine the cause and severity of the failure, to determine if any of the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer (in adjacent well), if necessary.
- Install a chemical sealant barrier and/or attempt a cement squeeze to block leaks in the offset wellbore.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

8.3.1.6 Specific Event Description – Orphan well failure (e.g., well not identified prior to injection)
Risk Assessment Matrix, Section 1.6 (Appendix G-1)

This event could occur due to orphan wells that are not known to exist. These wells could create leak paths to the surface due to improper plugging and/or lack of proper materials, such as cement inside and behind casing, casing and equipment metallurgy, and plugging materials.

Likelihood: [redacted]

Prevention and Detection

- An exhaustive well-records search will be performed to identify all wellbores in the AOR.
- Magnetic surveying could be performed to potentially find undocumented/unknown wellbores.
- Corrective action will include detailed review and design, including appropriate cement and metallurgy of the plugging materials.
- Continuous pressure monitoring at surface and downhole will highlight potential issues.
- Pressure and rate monitoring, pressure falloff tests, etc., will all be performed according to *Section 5*.
- The facility and surrounding area will be closely monitored, with competent management of operations.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Close the applicable wellhead valve(s).
- Monitor well and annulus pressures.
- Determine the cause and severity of the failure, to determine if any of 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 – Testing and Monitoring Plan*.
- Notify the UIC Director when injection can be expected to resume.

8.3.1.7 Specific Event Description – Sabotage/terrorist attack

Risk Assessment Matrix, Section 1.7 (Appendix G-1)

This event could happen during operations of the injection facility 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 has a very low risk.

Likelihood: [redacted]

Prevention and Detection

- Stay up to date with current events in the local area and country and around the world that could potentially warrant a threat to the facility.
- Maintain proper security of the facility and surrounding area.
- Carry out proper operation and PM of all surface facility equipment.
- Maintain the surface wellhead tree regularly and test for integrity.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Set plug in near-surface nipple as secondary barrier to flow.
- Close the applicable wellhead valve(s).
- 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, to initiate repairs, if feasible, prior to resuming injection operations.
- 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.

8.3.1.8 Specific Event Description – Induced seismicity directly caused by injection, resulting in leakage

Risk Assessment Matrix, Section 1.8 (Appendix G-1)

This event could occur if the process of injection builds up reservoir pressure, to the point that it induces a seismic event that causes the carbon front to reach faults or fractures that allow CO_2 migration to the surface.

Likelihood: [redacted]

Prevention and Detection

- Pressure, rate, and carbon front monitoring, pressure falloff tests, etc., will all be performed according to *Section 5*.
- During active injection, pressure will be continuously monitored to ensure the bottomhole pressure remains below 90% fracture gradient.
- The chosen project location is a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.

- Known faults have been assessed and modeled appropriately, and with low seismic risk in the area, this event is not likely.
- Fault-slip potential analysis (refer to *Appendix I*) does not indicate induced seismicity potential.
- Geomechanical modeling to be completed as needed to optimize injection program.
- Secondary/tertiary seals are present above the primary upper confinement.
- The wells and operating strategy are designed to prevent the likelihood of this occurring.

<u>Potential Response Actions</u>

- Stop the injection and notify the UIC Director within 24 hours.
- Close the wellhead valve(s), if applicable.
- Monitor well and annulus pressures.
- Use seismic surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Continue carbon front monitoring at a more frequent interval to determine if migration continues.
- If the carbon front continues to migrate out of the zone or beyond the expected carbon front extent, recomplete uphole into the next planned injection interval.
- 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, to determine if any of the CO_2 stream or formation fluids may have been released into any unauthorized zone and to initiate repairs, if feasible.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

8.3.1.9 <u>Specific Event Description – Act of God (force majeure)</u>
Risk Assessment Matrix, Section 1.9 (Appendix G-1)

This event could occur when the surface structures are impacted by major storms or wildfire, or their equivalent.

<u>Likelihood</u>: [redacted]

<u>Prevention and Detection</u>

- Proper operation and PM of all surface facility equipment will be carried out.
- The surface wellhead tree will be regularly maintained and tested for integrity.
- Safety systems will have automatic shut-in capabilities.
- Surface equipment will be designed to withstand storms.
- Company policy ensures that operations are shut in during possible events.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Set plug in near-surface nipple as secondary barrier to flow.
- Close the applicable wellhead valve(s).
- 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 any potential failures, to initiate repairs, if feasible, prior to resuming injection operations.
- 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 Event Category – Water Quality Contamination

8.3.2.1 Specific Event Description – Leakage of CO_2 or other dissolved contaminant outside permitted area into freshwater aquifer
Risk Assessment Matrix, Sections 2.1 & 2.3 (Appendix G-1)

Water quality contamination could happen during operations of the carbon storage facility. Contamination could occur if the carbon front reaches faults, fractures, or artificial penetrations that allow CO_2 migration into another zone—including the USDW—or to the surface. Failure of the confining zone and the wellbore's integrity could also cause CO_2 or other dissolved contaminants from the injection formation to migrate and contaminate the USDW. In general, many events that are discussed in *Section 8.3.1* could lead to water quality contamination.

Likelihood: [redacted]

Prevention and Detection

- The carbon front will be closely monitored with time lapse seismic surveys as described in *Section 5*.
- The wellbore is designed with premium materials and for long-term integrity to prevent the likelihood of this event occurring.
- Wellbore integrity will be monitored, tested, and verified as described in *Section 5 – Testing and Monitoring Plan*.
- The chosen project location is a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- Fault-slip potential analysis does not indicate induced seismicity potential.
- Geomechanical modeling will be completed as needed to optimize the injection program.

- Secondary/tertiary seals are present above the primary upper confinement.
- The wells and operating strategy are designed to prevent the likelihood of this event occurring.
- Continuous monitoring of injection rate, pressure, and temperature downhole provide additional insight into wellbore integrity.
- Carbon and critical pressure front models will be periodically updated to make sure no artificial penetrations create a leakage path—and, if one is found, the wells will be corrected.

Potential Response Actions

- Reduce injection rates or cease injection and notify the UIC Director within 24 hours.
- Determine the cause and severity of the failure, to determine if any of the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Investigate downhole issues.
- Use seismic surveys to assess carbon front migration, as described in *Section 5*.
- Continue monitoring the carbon front at a more frequent survey interval to determine if migration continues.
- If groundwater/USDW is negatively impacted, then:
  - Pump CO_2-contaminated groundwater to the surface and aerate it to remove carbon dioxide to acceptable levels.
  - Apply "pump and treat" methods to remove trace elements, if necessary.
  - Drill wells that intersect the accumulations in groundwater, and extract carbon dioxide to acceptable levels.
  - Provide an alternative water supply if groundwater-based public water supplies are contaminated.
- If surface water is impacted, then:
  - Verify through water analysis that dissolved CO_2 is being quickly released back into the atmosphere.
  - Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.
- If the carbon front continues to migrate out of the zone or beyond the expected carbon front extent, recomplete uphole into the next planned injection interval.
- Demonstrate mechanical integrity per the methods discussed in *Section 5.*
- Notify the UIC Director when injection can be expected to resume.

8.3.2.2 Specific Event Description – Leakage of drilling fluid contaminates potable water aquifer

Risk Assessment Matrix, Section 2.2 (Appendix G-1)

This event could happen during the drilling of the injection well and would be a short-term event in the project life cycle. Drilling fluid may contaminate the potable water aquifer.

Likelihood: [redacted]

Prevention and Detection

- Select a proper drilling-fluids program including fresh-water-based muds while drilling the surface hole interval.
- Drilling mud will be conditioned to prevent losses to the formation.
- All USDWs will be isolated with casing and cement per regulations.
- Industry best practices will minimize the probability of this incident.
- The injection wells are designed to prevent the likelihood of this occurring.

Potential Response Actions

- Investigate downhole issues.
- Drilling mud will be conditioned to prevent losses to the formation.
- If the groundwater/USDW is negatively impacted, then:
    - 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 contaminated.

8.3.3 Event Category – Storage Rights Infringement (i.e., Mineral Rights Infringement)

8.3.3.1 Specific Event Description – Carbon front migrates into adjacent pore space
Risk Assessment Matrix, Section 3.1 (Appendix G-1)

This event could occur if the carbon front expands beyond what the reservoir model predicts—and migrates off controlled acreage, into neighboring pore space not controlled by the operator.

Likelihood: [redacted]

Prevention and Detection

- The carbon front will be monitored as described in *Section 5 – Testing and Monitoring Plan*, to reduce the likelihood that the carbon front exceeds the controlled pore-space boundary.
- Control of pore space will be obtained through outright ownership or lease agreements.

Potential Response Actions

- Notify the UIC Director within 24 hours.
- Use seismic surveys to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Possibly recomplete into a new, shallower injection interval to control maximum carbon front extent.
- Continue carbon front monitoring at a more frequent interval to determine if migration continues.
- If trespass is detected or identified to be likely, then:
    - Begin negotiations with the neighboring landowner to acquire rights to store within

adjacent pore spaces.

- If infringement is detected or identified to be likely, then:
    - Obtain control of additional pore space through outright ownership or lease agreements, to maintain total project-storage potential.
- Notify the UIC Director when injection can be expected to resume.

8.3.3.2 Specific Event description – Infringement on White Castle storage space by others/competitors

Risk Assessment Matrix, Section 3.2 (Appendix G-1)

This event could occur if the pore space controlled by the operator is infringed upon by others or competitors. The probability of this event is low, this project being the first to exist in this location; the adjoining acreage has limited project-development capabilities.

Likelihood: [redacted]

Prevention and Detection

- The carbon front 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

- Reduce injection rates or cease injection, if needed, and notify the UIC Director within 24 hours.
- Use seismic surveys to assess location and degree of CO_2 movement, as described in *Section 5 – Testing and Monitoring Plan*.
- Possibly recomplete into a new, shallower injection interval to control maximum carbon front extent.
- Continue carbon front monitoring at a more frequent interval to determine if migration continues.
- Notify the UIC Director when injection can be expected to resume.

8.3.3.3 Specific Event description – Acts of God affecting storage capacity of pore space (force majeure)

Risk Assessment Matrix, Section 3.3 (Appendix G-1)

This event could occur if a major natural event impacts the subsurface.

Likelihood: [redacted]

Prevention and Detection

- Known faults have been assessed and modeled appropriately, and with low seismic risk in the area, this event is not likely.
- Wildfire or a major storm is more likely, which would impact surface—not pore space.
- Safety systems will have automatic shut-in capabilities.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Close the applicable wellhead valve(s).
- Monitor well and annulus pressures.
- Possibly recomplete into a new, shallower injection interval to control maximum carbon front extent.
- Notify the UIC Director when injection can be expected to resume.

8.3.4 Event Category – Mineral Rights Infringement (Trespass)

8.3.4.1 Specific Event Description – Carbon front migrates into mineral zone or hydraulic front impacts recoverable mineral zone
Risk Assessment Matrix, Section 4.1 (Appendix G-1)

This event could occur if the carbon front expands beyond what the reservoir model predicts, migrates off controlled acreage into neighboring pore space not controlled by the operator—and affects economic production of mineral resources from that area.

Likelihood: [redacted]

Prevention and Detection

- Strategically locate the injection operations in an area devoid of hydrocarbon resources.
- The carbon front will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- Obtain control of pore space through outright ownership or lease agreements.

Potential Response Actions

- Reduce injection rates or cease injection and notify the UIC Director within 24 hours.
- Use seismic surveys to assess location and degree of CO_2 movement, as described in *Section 5*.
- Possibly recomplete into a new, shallower injection interval to control maximum carbon front extent.
- Continue carbon front monitoring at a more frequent interval to determine if migration continues.
- If trespass is detected or identified to be likely, then:
    - Begin negotiations with the neighboring landowner to acquire rights to store within adjacent pore spaces.

- If hydrocarbon resource infringements are detected or identified to be likely, then:
    - Begin negotiations with mineral owners to determine the impact of the infringement.

8.3.4.2 <u>Specific Event Description – Discovery of recoverable minerals below the injection interval or enabled recovery of previously uneconomically recoverable minerals</u>
Risk Assessment Matrix, Sections 4.2 & 4.3 (Appendix G-1)

This event could occur if there is a post-injection discovery of recoverable minerals below the injection interval—thereby creating a higher cost for future discovery and potential litigation—and/or if previously uneconomically recoverable minerals become economically feasible.

<u>Likelihood</u>: [redacted]

<u>Prevention and Detection</u>

- The carbon front will be monitored as described in *Section 5*.
- Control of pore space will be obtained through outright ownership or lease agreements.
- Injection operations will be strategically located in an area devoid of hydrocarbon resources.
- Multiple dry holes drilled in the area demonstrate a general lack of recoverable hydrocarbon resources in the immediate vicinity.

<u>Potential Response Actions</u>

- If hydrocarbon resource infringements are detected or identified to be likely below the injection interval, begin negotiations with mineral owners to determine the impact of the infringement.

8.3.4.3 <u>Specific Event Description – Seismic event or other Act of God occurs in project area</u>
Risk Assessment Matrix, Section 4.4 (Appendix G-1)

This event could occur if the carbon front reaches faults or fractures that allow CO_2 migration into another zone. Failure of the confining zone could also cause CO_2 to migrate and impact future mineral production. It is unlikely that productive minerals exist above the injection interval, given the lack of historical production in this area.

<u>Likelihood</u>: [redacted]

<u>Prevention and Detection</u>

- The carbon front will be monitored as described in *Section 5 – Testing and Monitoring Plan*.
- The chosen project location is a seismically quiet area and a sufficient distance from nearby shallow faults that could act as a conduit.
- Fault-slip potential analysis (refer to *Appendix H*) does not indicate induced seismicity potential.

- Geomechanical modeling to be completed as needed to optimize the injection program.
- The wells and operating strategy are designed to prevent the likelihood of this event occurring.

Potential Response Actions

- If hydrocarbon resource infringements are detected or identified to be likely, begin negotiations with mineral owners to determine the impact of the infringement.

8.3.4.4 Specific Event Description – Formation fluid interaction due to CO_2 injection
Risk Assessment Matrix, Section 4.5 (Appendix G-1)

This event is expected to happen. Chemical compatibility studies indicate that this will happen, with no adverse effects. In fact, this chemical interaction is desired.

Likelihood: [redacted]

Prevention and Detection

- No prevention necessary.

Potential Response Actions

- The saline aquifer is not usable as a freshwater source. No detrimental impacts are expected. Chemical interaction is desired to lock CO_2 in place.

8.3.5 Event Category – Entrained Contaminant (Non-CO_2) in Injection Stream

8.3.5.1 Specific Event Description – Change in CO_2 composition/properties from its source impacts the storage reservoir
Risk Assessment Matrix, Section 5.1 (Appendix G-1)

This event could occur due to unexpected changes in contamination levels in the CO_2 stream outside of what the project has been designed to receive. The sources of contaminants may impact dissolution and geochemical reactions.

Likelihood: [redacted]

Prevention and Detection

- Based on the pipeline composition specifications (see Table 4-2 in *Section 4 – Engineering Design and Operating Strategy*), geochemical considerations have been, and will continue to be, evaluated as additional data is gathered on the gas stream and storage reservoir.

- Samples of the CO_2 stream will be collected from the injection source pipeline. Representing injection conditions, the samples will be sent to a third-party laboratory for analysis, which will be used to indicate contaminant levels.

Potential Response Actions

- Reduce injection rates or cease injection and notify the UIC Director within 24 hours.
- Determine the cause of contaminants.
- Investigate downhole issues.
- Investigate potential reservoir impacts from contaminants.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce the effect of contaminants.
- Notify the UIC Director when injection can be expected to resume.

8.3.5.2 Specific Event Description – Change in CO_2 composition/properties from its source impacts metallurgical considerations
Risk Assessment Matrix, Section 5.2 (Appendix G-1)

This event could occur due to unexpected changes in contamination levels in the CO_2 stream outside of what the project has been designed to receive. The sources of contaminants may impact the wellbore integrity of all penetrations in the injection interval.

Likelihood: [redacted]

Prevention and Detection

- Based on the pipeline composition specifications (see Table 4-2 in *Section 4*), metallurgical analysis (*Appendix E*) has, and will continue to, inform engineering design as additional data is gathered on the gas stream and storage reservoir.
- Samples of the CO_2 stream will be collected from the injection source pipeline. Representing injection conditions, the samples will be sent to a third-party laboratory for analysis, which will be used to indicate contaminant levels.

Potential Response Actions

- Reduce injection rates or cease injection and 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.
- Pull and replace tubing and packer if necessary.
- Assess the risk of contaminant creating metallurgical incompatibilities.
- 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.

8.3.5.3 Specific Event Description – Microbial activity initiated by injection process or composition allowing possible production of H_2S gas in the subsurface, impacting dissolution and geochemical reactions

Risk Assessment Matrix, Section 5.3 (Appendix G-1)

This event could occur due to changes in contamination levels in the CO_2 source and allow microbial activity for possible production of H_2S gas. These sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity.

Likelihood: [redacted]

Prevention and Detection

- Samples of the CO_2 stream will be collected from the injection source pipeline. Representing injection conditions, the samples will be sent to a third-party laboratory for analysis, which will be used to indicate contaminant levels.

Potential Response Actions

- Reduce injection rates or cease injection and 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.
- Pull and replace tubing and packer if necessary.
- Assess the risk of contaminant creating metallurgical incompatibilities.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

8.3.6 Event Category – Accidents/Unplanned Events (Typical Insurable Events)

8.3.6.1 Specific Event Description – Accidental surface infrastructure damage (wellhead or flowlines)

Risk Assessment Matrix, Section 6.1 (Appendix G-1)

Unforeseen events such as surface infrastructure damage, pipeline leak, compressor failure, human accident-related or animal damage, or weather-related events, may occur while operating the White Castle Project.

Likelihood: [redacted]

Prevention and Detection

- Equipment will be maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed, and markers will be placed to alert the general 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 and well sites.
- Monitoring and safety equipment in place would minimize the likelihood and impact of such events.
- Continuous and redundant surface-equipment controls will prevent overpressure.
- Safety systems will have automatic shut-in capabilities.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.
- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Set plug in near-surface nipple as secondary barrier to flow, if necessary.
- Determine the cause and severity of the failure, 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.

8.3.6.2 Specific Event Description – Hurricane
Risk Assessment Matrix, Section 6.2 (Appendix G-1)

Unforeseen weather-related events (e.g., hurricane) are likely to occur while operating the White Castle Project.

Likelihood: [redacted]

Prevention and Detection

- Equipment will be maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed, and markers will be placed to alert the general 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 taken to limit the potential impact if one should occur.
- Surface equipment, facilities, and buildings will be designed to withstand storms.
- Company policy ensures that operations will be shut in during possible events.

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.

- Shut in the flow line (source) upon any detection of CO_2 at the surface.
- Set plug in near-surface nipple as secondary barrier to flow, if necessary.
- Determine the cause and severity of the failure, to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when injection can be expected to resume.

The following tables and figures outline the risk assessment process discussed above.

8.4 Risk Assessment Metrics

Table 8-1 – Risk Likelihood Metrics

Likelihood	Description
[redacted]	

Table 8-2 – Risk Severity Metrics

Impact / Severity	Financial Impact	Health & Safety	Natural Environment
[redacted]			

8.5 Risk Activity Matrix

Table 8-3 – Risk Assessment Summary Table

		Likelihood	Severity				
			Safety	Environmental	Financial		
			[redacted]				
Section	Risk (Feature, Event, or Process)	1 – Remote, 5 – Almost Certain	1 – Very Low, 5 – Very High				
		Assigned	Assigned	Assigned	Assigned	Estimated Costs	Total Score
1	CO_2 Release to or at the Surface	[redacted]					
2	Water Quality Contamination						
3	Storage Rights Infringement – Form of Mineral Rights Infringement						
4	Mineral Rights Infringement (Trespass)						
5	Entrained Contaminant (Non-CO_2) in Injection Stream						
6	Accidents/Unplanned Events (Typical Insurable Events)						
	Total					[redacted]	

Table 8-4 – Risk Mitigation and Threat Scores

[redacted]

Table 8-5 – Risk Assessment Scores

[redacted]

8.6 Training

Personnel will be trained on their duties and responsibilities related to these facilities during annual on-site and/or tabletop 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.

Prior to first injection, Harvest Bend CCS LLC (Harvest Bend CCS) will provide to local first responders and the UIC Director a copy of the Emergency and Remedial Response Plan that includes potential response scenarios and contact information for internal safety and emergency personnel.

8.7 Communications Plan and Emergency Notification Procedures:

Emergency response contacts:

Table 8-6 – Emergency Services – **CALL 911**

Agency	Telephone Number
White Castle Fire Department	911 or (225) 545-9214
Iberville Parish Sheriff	911 or (225) 687-5100
Iberville Parish Health Unit	(225) 687-9021
Iberville Parish Office of Emergency Preparedness	(225) 687-5140
Louisiana Emergency Preparedness Office	(225) 763-3535
Louisiana State Police	(504) 310-7000
Louisiana State Police – Hazardous Material Hotline	(877) 925-6595

Table 8-7 – Government Agency Notification

Agency	Telephone Number
Environmental Protection Agency 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
Iberville-Community Awareness Emergency Response (I-CAER) Committee	(225) 687-5140
National Response Center (NRC)	(800) 424-8802
Louisiana State Police – Hazardous Material Hotline	(877) 925-6595

8.8 Flood Hazard Risk

Though the White Castle Project falls within a wooded wetlands environment, none of the project area falls within a Federal Emergency Management Agency (FEMA) Flood Hazard Zone, thus the flood hazard risk for the White Castle Project is low. The well locations and FEMA Flood Hazard Zones are shown in *Appendix G-2*.

8.9 Emergency and Remedial Response Plan Review and Updates

This Emergency and Remedial Response Plan will be reviewed and updated at least once every 5 years. 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 the addition of injection or monitoring wells;
- due to any change in personnel; or
- as required by the UIC Director.

The following attachments are located in *Appendix G*:

- Appendix G-1 Risk Assessment Table
- Appendix G-2 FEMA Flood Zone Hazards Map
- Appendix G-3 Resources and Infrastructure Map

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 9 – IT DECISION RESPONSE

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 10 – FINANCIAL ASSURANCE

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

SECTION 10 – FINANCIAL ASSURANCE

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(None)

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10.1 Introduction

This financial assurance section for WC IW-B No. 001 and No. 002 was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3607.C.2.m** and **§3609.C.1** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(14)** and **§146.85(a)**].

10.2 Financial Assurance

Harvest Bend CCS LLC (Harvest Bend CCS) will secure a combination of insurance policies and surety bonds, which will be used to provide sufficient coverage and funding for any corrective action, injection and monitor well plugging, post-injection site care and site closure, and emergency and remedial response. The total amount of financial assurance will be [redacted] in the form of insurance policies, [redacted] in the form of surety bonds [redacted] and [redacted] in the form of surety bonds [redacted]—and will reflect the minimum amount of funding to cover the costs for which financial responsibility must be maintained.

Table 10-1 summarizes costs associated with financial assurance submitted with the first application for the White Castle CO_2 Sequestration (White Castle) Project pertaining to the proposed WC IW-A No. 001 [redacted].

Table 10-1 – Summary of Costs Associated with Financial Assurance – WC IW-A No. 001

Financial Assurance Cost Breakdown	
Cost Category	**Estimated Cost**
Corrective Action (0 wells)	[redacted]
Injection Well Plugging	
Deep, Above-Zone Monitoring Wells (x1 Well)	
Shallow, USDW Monitor Wells (x1 Wells)	
Post-Injection Site Care and Site Closure	
Emergency and Remedial Response	
TOTAL	

Certain final assurance costs in Table 10-1 apply specifically to WC IW-A No. 001. Other costs such as certain emergency and remedial response costs are project-level costs or only increase by a limited extent with the addition of injection wells to the project, such as the subject injection wells on [redacted]. Table 10-2 breaks down the estimated incremental financial assurance costs associated with the subject injection wells as prepared by a third party.

Table 10-2 – Breakdown of Costs Associated with Financial Assurance – WC IW-B No. 001 & No. 002

Financial Assurance Cost Breakdown			
Corrective Action (0 wells)			[redacted]
[redacted]			
Injection Well Plugging (x2 wells)			[redacted]
[redacted]			
Deep, Above-Zone Monitoring Wells (x1 Well)			[redacted]
[redacted]			
Shallow, USDW Monitor Wells (x1 Wells)			[redacted]
[redacted]			
Post-Injection Site Care and Site Closure			[redacted]
[redacted]			
Emergency and Remedial Response			[redacted]
[redacted]			
TOTAL			[redacted]

10.3 Corrective Action Plan

The Corrective Action Plan was discussed in detail in *Section 3 – Area of Review and Corrective Action Plan*. If applicable, the plan specifically outlines not only revised plugging plans for wells found within the currently predicted carbon and critical pressure fronts, but also the recompletion schedule whereby the wellbore modifications will have been completed.

With regard to WC IW-B No. 001 and No. 002, there exist no wells requiring plugging modifications to be completed within the currently predicted area of review (AOR). As such, there is no financial risk for existing wells requiring corrective action.

The AOR will be reevaluated every 5 years to determine if any new wellbore penetrations have occurred, or if changes to the AOR require changes to the Corrective Action Plan and associated financial assurance.

10.4 Injection Well Plugging and Abandonment

Plugging and abandonment (P&A) of WC IW-B No. 001 and No. 002 will meet the requirements of SWO 29-N-6 **§631** [40 CFR **§146.92**]. The P&A of the injection wells must be designed so that no movement of fluids will occur from the injection interval. A more detailed P&A plan was discussed in *Section 6 – Injection Well Plugging Plan*. Funds will be guaranteed, via a surety bond, to ensure that P&A operations are properly managed. These funds include costs for logs/wireline to be run in the wellbore before cementing occurs. CO_2-resistant cement will be used in the initial plugs of the wells, to ensure the cement does not react with the injected fluid—so a higher cement expense than that for a typical well of these depths is to be expected. All expenses relating to personnel and equipment have been accounted for in Table 10-2. Pressure-test costs are also included to account for proving the integrity of the wells.

10.5 Monitoring Wells Plugging and Abandonment

The P&A of the monitoring wells associated with WC IW-B No. 001 and No. 002 will also meet the requirements of SWO 29-N-6 **§631** [40 CFR **§146.92**]. The P&A of these shallow monitoring wells will be designed so that no movement of fluids will occur from the injection interval, nor will fresh, treatable water found within the Underground Source of Drinking Water (USDW) be threatened. A more detailed P&A plan is discussed in *Section 6*. Funds will be guaranteed via a surety bond to ensure that P&A operations are properly managed. Because these wells will be completed above the uppermost confining geologic interval, conventional plugging procedures will be utilized. These funds include costs for logs/wireline to be run in the wellbore before cementing occurs. All expenses relating to personnel and equipment have also been accounted for in Table 10-2. Pressure test costs are also included to account for proving the integrity of the well.

10.6 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 **§633** [40 CFR **§146.93**]. The costs associated with the plan have been highlighted as well in Table 10-2***.*** The plan is discussed in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

10.6.1 Post-Injection Monitoring

As discussed in *Section 5 – Testing and Monitoring Plan*, time-lapse seismic monitoring will be conducted every 5 years to ensure the integrity of the wells and to track the migration of the plume. [redacted]. The costs estimated in Table 10-2 cover additional post-injection monitoring activities to occur until the owner is released from post-injection site duties, including groundwater and above-zone monitoring activities.

10.6.2 Site Closure

Site closure will occur when the Underground Injection Control (UIC) Program Director (UIC Director) has released the owner from all post-injection site duties. The costs above reflect the amount expected to close the site and restore the facility to its natural state. Dismantling of surface facilities includes removing storage vessels, piping, pumps, and surface equipment, etc. Concrete and debris removal are also included in surface facilities costs. Funds will be allocated for site restoration to leave minimal environmental impact.

10.7 Emergency and Remedial Response Plan

The Emergency and Remedial Response Plan, referenced eponymously in *Section 8*, is designed to be in compliance with SWO 29-N-6 **§623.A.1** [40 CFR **§146.94**]. The total cost for all scenarios determines the final levels of insurance required, which ensures the operator will have the ability to remediate any given scenario. For the purposes of assigning value to the categories listed on the Risk Assessment Matrix, the following modifiers shown in Table 10-3 have been applied to account for the levels of likelihood and severity (i.e., Total Score) determined from the matrix:

Table 10-3 – Risk Assessment Matrix Cost Modifiers

Risk Level	**Threat Scores**	**Cost Modifier**
High	[redacted]	[redacted]
Moderate	[redacted]	[redacted]
Low	[redacted]	[redacted]

The resultant costs for the Emergency and Remedial Response Plan were shown in Table 10-2.

The following is a discussion regarding the costs associated with various scenarios that may occur at any phase during CO_2 sequestration as identified in the Risk Assessment Matrix.

10.7.1 Scenario 1: CO_2 Release to or at the Surface

CO_2 released at the surface can create a potential risk to human health as well as the local environment and ecosystems. The release could result from a variety of events such as major mechanical and integrity failures or damage to the CO_2 distribution and storage facilities, unidentified orphan wells, well integrity issues, operating equipment over designed pressures, and geological complications. The costs in Table 10-2 consider the amount needed to correct the source of the release, such as system repair and plugging or remediation costs of the problem well, as well as potential litigation fees and regulatory fines. Table 10-2 also includes costs for closure of WC IW-B No. 001 and No. 002 in the event the release cannot be repaired.

10.7.2 Scenario 2: Water Quality Contamination

If, during the drilling of the injection wells, the USDW is contaminated with drilling fluids—or during the operation of the injection wells, the injectate leaks into the USDW—the costs in Table 10-2 demonstrate the amount needed to remediate the impact of contamination of potable water. This expense amount also accounts for returning the USDW to conditions before the intrusion of CO_2; the potential local, state, and federal regulatory fines; litigation; damages; and closure of the geologic storage project.

10.7.3 Scenario 3: Storage Rights Infringement

In the event that the carbon front migrates out of the controlled or leased pore space into adjacent pore space, the costs in Table 10-2 demonstrate the amount needed to resolve any potential storage rights issues. This estimate considers the cost of addressing potential litigation and damages, as well as acquiring additional pore space.

10.7.4 Scenario 4: Mineral Rights Infringement (Trespass)

In the event that the carbon front migrates out of the controlled or leased pore space into adjacent oil and gas mineral resources, the costs in Table 10-2 demonstrate the amount needed to remediate the impact to current or future mineral resource production. As the Carbon Dioxide Sequestration agreement discussed in *Section 0 – Introduction* is in place with not only the pore space owner, but also the mineral owner, this risk has been fully mitigated.

10.7.5 Scenario 5: Entrained Contaminant (Non-CO_2) In Injection Stream

During injection operations, the composition and properties of the injectate can deviate from chemically desired conditions. The change in composition can have metallurgical effects and induce corrosion. Additionally, the contaminant-containing injectate stream can initiate microbial activity, such as H_2S gas production, thus impacting dissolution, leading to unexpected geochemical reactions and impacting wellbore and reservoir integrity. The estimate in Table 10-2 covers repair and cleanup costs.

10.7.6 Scenario 6: Accidents/Unplanned Events

Unforeseen events, such as accidental surface-infrastructure damage, pipeline leak, and weather-related events (e.g., hurricanes), may occur while operating the CO_2 storage facility. The costs identified in Table 10-2 are tied to repair and cleanup costs due to such events or accidents and supported by insurance.

10.8 Updates to Financial Assurance

During the active life of this project, Harvest Bend CCS will adjust the cost estimate for inflation within 60 days, prior to the anniversary date of the establishment of the surety bond and provide this adjustment to the UIC Director. Harvest Bend CCS will also provide 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 PISC and Site Closure Plan, and the Emergency and Remedial Response Plan. If the updated cost estimate increases to an amount greater than the face value of the surety bond in use, Harvest Bend CCS will either obtain an increase in the surety bond at an amount at least equal to the current cost estimate or obtain other financial responsibility instruments to cover the increase—and supply evidence of such to the UIC Director. If the estimated value is reduced due to changes in the operational cycle of the project, the bond will be reduced in value accordingly if approved by the UIC Director.

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

SECTION 11 – ENVIRONMENTAL JUSTICE ASSESSMENT

Date of Original Submission: October 25, 2023

SECTION 11 – ENVIRONMENTAL JUSTICE ASSESSMENT

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11.1 Introduction

The purpose of this environmental justice (EJ) evaluation is to determine if the White Castle CO_2 Sequestration (White Castle) Project, which includes the proposed WC IW-B No. 001 and No. 002 Class VI injection wells, could have a disproportionately high and adverse environmental impact on defined communities or populations. The White Castle Project will sequester CO_2 in the Louisiana area near the New Orleans/Baton Rouge industrial region.

Environmental justice is defined as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies (United States Environmental Protection Agency (USEPA) 1998). Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, was published in the Federal Register (59 FR 7629) on February 11, 1994. Executive Order 12898 requires federal agencies to identify and address the potential for disproportionately high and adverse human health or environmental effects resulting from the implementation of their programs, policies, and activities on minority and low-income populations.

11.2 Environmental Justice Assessment

Identification of the EJ populations and assessment of the EJ impacts/burdens of the White Castle Project was performed by a third-party, Environmental Resources Management (ERM). The assessment, including methodology, analysis area, findings, and conclusions, is included as *Appendix J – Environmental Justice Screening Cumulative Impact/Burden Assessment*.

ERM used USEPA (2016) guidance to identify block groups entirely or partially within a 1-mile radius of the White Castle Project area that are considered EJ communities. It was determined that [redacted], discussed in detail in *Appendix J*, to be considered EJ communities. To summarize the findings:

- [redacted] block groups (as well as Iberville Parish) meet the EJ criteria for nonwhite populations;
- [redacted] block groups meet the criteria for low-income populations;
- [redacted] block group is in the 80th percentile or higher for children under age 5 and 1 block group is in the 80th percentile or higher for residents aged 65 or older; and
- [redacted] block group (and Assumption and Iberia parishes) has limited English proficiency populations in the 80th percentile or higher.

Additionally, ERM used USEPA and U.S. Council on Environmental Quality (CEQ) data and tools to identify notable concentrations of populations with specific health risk factors that contribute to disproportionately high and adverse impacts on EJ populations, such as the prevalence of asthma, heart disease, and certain cancers. To summarize the findings:

- [redacted] block groups exceed the established threshold for heart disease;
- [redacted] block groups exceed the established threshold for asthma;
- [redacted] block groups exceed the established threshold for low life expectancy; and
- [redacted] block groups (and Assumption and Iberville parishes) exceed the established threshold for risk of cancer due to air toxics.

11.2.1 Environmental Justice Summary Data

Figure 11-1 summarizes the demographic data for each block group in the analysis area, as well as parish and state data, from ERM's EJ assessment report.

[redacted]

Figure 11-1 – EJ Demographic Summary Data

Figure 11-2 summarizes notable health risk factors for each block group in the analysis area, as well as parish and state data, from ERM's EJ assessment report.

[redacted]

Figure 11-2 – EJ Health Risk Factor Summary Data (Percentiles)

11.3 Proposed Environmental Justice Efforts

Harvest Bend CCS LLC (Harvest Bend CCS) will emphasize engaging the community for education on the proposed White Castle Project.

- Key stakeholders will be identified and included in these efforts, such as community leaders, public officials, and residents located in the parishes.
- Communication and engagement activities will be held, such as open houses, individual meetings, and/or small group meetings to gather areas of interest, to inform materials to be distributed.
- English and bilingual informational materials will be developed and distributed, including but not limited to fact sheets, project overview, website, frequently asked questions (FAQs), and maps.
- Consistent project updates will be provided to interested parties through various channels.

11.4 Evaluation of Alternative Project Sites

Multiple potential CO_2 sequestration project sites were evaluated to ensure that adverse environmental effects are minimized. Compared to the other sites evaluated, the White Castle Project site was selected as the preferred site to develop for sequestration of regional CO_2 emissions for the following reasons:

- There are fewer abandoned oil and gas wells in the area that could act as a conduit for the migration of CO_2 injectate from the storage reservoir, either to Underground Sources of Drinking Water (USDWs) or to the surface.
- The remote area is further from residential housing, which decreases potential impact to the public.
- The site has existing roads, thus lessening not only the need for newly constructed roads but also environmental impact.
- The site is located in closer proximity to regional emission sources and existing pipelines that are planned for conversion to CO_2 service. Less pipeline will need to be constructed and fewer landowners will need to be impacted.

Evaluation of alternative project sites is discussed further in *Section 9 – IT Decision Questions*.

11.5 Mitigation of Adverse Environmental Effects

The White Castle Project will have both potential and real adverse environmental effects that require mitigating measures, to ensure that effects are minimized. Mitigation of these adverse environmental effects is discussed in detail in *Section 9*.

Potential adverse environmental effects include CO_2 release to or at the surface, CO_2 escape into a productive oil and gas reservoir, and CO_2 migration into USDWs. All potential adverse environmental effects are estimated to be of remote likelihood, or extremely unlikely to occur in this asset. Risk prevention efforts, including detailed site-reservoir characterization, dynamic geocellular reservoir modeling, well construction to industry standards with premium materials, and ongoing testing and monitoring programs, are comprehensively discussed in *Section 8 – Emergency and Remedial Response Plan* (ERRP). The ERRP incorporates the risk analysis for all applicable environmental-risk scenarios as well as response action plans in the event a risk scenario should ever occur.

The real, primary adverse environmental effect associated with the White Castle Project is the impact to the wetlands where the project is to be located. To minimize said impact, the following actions have been or will be taken:

- All environmental analysis and mitigation requirements of the applicable federal, state, and local permits will be addressed, as identified in Table 0-4, Anticipated Permits, in *Section 0 – Introduction*.
- Access to the site has been thoroughly evaluated to minimize road construction requirements.
- [redacted]
- It is anticipated that mitigation banking will be utilized to replace the loss of natural resources and compensate unavoidable impacts to wetlands through restoration or creation of wetlands at a separate location.
- Harvest Bend CCS will work constructively with the U.S. Army Corps of Engineers (USACE) to ensure proper permitting and mitigative efforts.

HARVEST BEND CCS LLC

Underground Injection Control – Class VI Permit Application for WC IW-B Wells No. 001 & No. 002

Iberville Parish, Louisiana

APPENDICES

Date of Original Submission: October 25, 2023

LONQUIST SEQUESTRATION LLC

APPENDIX A: PROJECT MAPS

APPENDICES A-1 TO A-6 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX B: SITE CHARACTERIZATION

Appendix B-1	[redacted] Unit, Top of Structure Map
Appendix B-2	[redacted] Unit, Top of Structure Map
Appendix B-3	[redacted] Structure Map
Appendix B-4	[redacted] Unit, Isopach Map
Appendix B-5	Net Upper Confining Isopach Map
Appendix B-6	Injection Zone, Gross Isopach Map
Appendix B-7	Net Injection Interval Isopach Map
Appendix B-8	[redacted] Unit, Lower Confining Zone Isopach Map
Appendix B-9	Cross Section Reference Map
Appendix B-10	S-N Structural Cross Section
Appendix B-11	S-N Stratigraphic Cross Section
Appendix B-12	W-E Structural Cross Section
Appendix B-13	W-E Stratigraphic Cross Section
Appendix B-14	[redacted] Sidewall Core Report
Appendix B-15	RFS ID No. 202206840-02 Complete Water Analysis Report
Appendix B-16	NW-SE USDW Structural Cross Section
Appendix B-17	SW-NE USDW Structural Cross Section
Appendix B-18	USDW Structure / Cross Section Reference Map
Appendix B-19	USGS Potentiometric Surface Report
Appendix B-20	USGS Potentiometric Surface Map

APPENDICES B-1 TO B-18 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

science for a changing world

Water Availability and Use Science Program

Altitude of the Potentiometric Surface in the Mississippi River Valley Alluvial Aquifer, Spring 2020

Pamphlet to accompany

Scientific Investigations Map 3478

U.S. Department of the Interior
U.S. Geological Survey

Cover: Image of Mississippi delta area, August 2021, from Analytical Graphics, Inc., Systems Tool Kit, created by Shankar N. Ramaseri Chandra (Earth Resources Observation and Science [EROS], U.S. Geological Survey).

Altitude of the Potentiometric Surface in the Mississippi River Valley Alluvial Aquifer, Spring 2020

By Virginia L. McGuire, Ronald C. Seanor, William H. Asquith, Kellan R. Strauch, Anna M. Nottmeier, Judith C. Thomas, Roland W. Tollett, and Wade H. Kress

Water Availability and Use Science Program

Scientific Investigations Map 3478

U.S. Department of the Interior
U.S. Geological Survey

U.S. Geological Survey, Reston, Virginia: 2021

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• Mississippi Department of Environmental Quality: Madison Kymes; Kay Whittington, Sam Mabry, and James Hoffmann (retired); and

• Yazoo Mississippi Delta Joint Water Management District: Don Christy.

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Conversion Factors

U.S. customary units to International System of Units

Multiply	By	To obtain
	Length	
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
	Area	
section (640 acres or 1 square mile)	259.0	square hectometer (hm^2)
square mile (mi^2)	259.0	hectare (ha)
square mile (mi^2)	2.590	square kilometer (km^2)
	Flow rate	
million gallons per day (Mgal/d)	0.04381	cubic meter per second (m^3/s)

Datum

Horizontal coordinate information is referenced to the World Geodetic Survey of 1984 (WGS 84). Historical data collected and stored as North American Datum of 1927 (NAD 27) or the North American Datum of 1983 (NAD 83) have been converted to WGS 84 for use in this publication.

Vertical coordinate information is referenced to the North American Vertical Datum of 1988 (NAVD 88). Historical data collected and stored as National Geodetic Vertical Datum of 1929 (NGVD 29) have been converted to NAVD 88 for use in this publication.

Altitude, as used in this report, refers to distance above the vertical datum.

Abbreviations

GIS	geographic information system
MAP	Mississippi Alluvial Plain
MRVA	Mississippi River Valley alluvial aquifer
NAVD 88	North American Vertical Datum of 1988
NGVD 29	National Geodetic Vertical Datum of 1929
RMSE	root mean square error
USGS	U.S. Geological Survey

Altitude of the Potentiometric Surface in the Mississippi River Valley Alluvial Aquifer, Spring 2020

By Virginia L. McGuire, Ronald C. Seanor, William H. Asquith, Kellan R. Strauch, Anna M. Nottmeier, Judith C. Thomas, Roland W. Tollett, and Wade H. Kress

Introduction

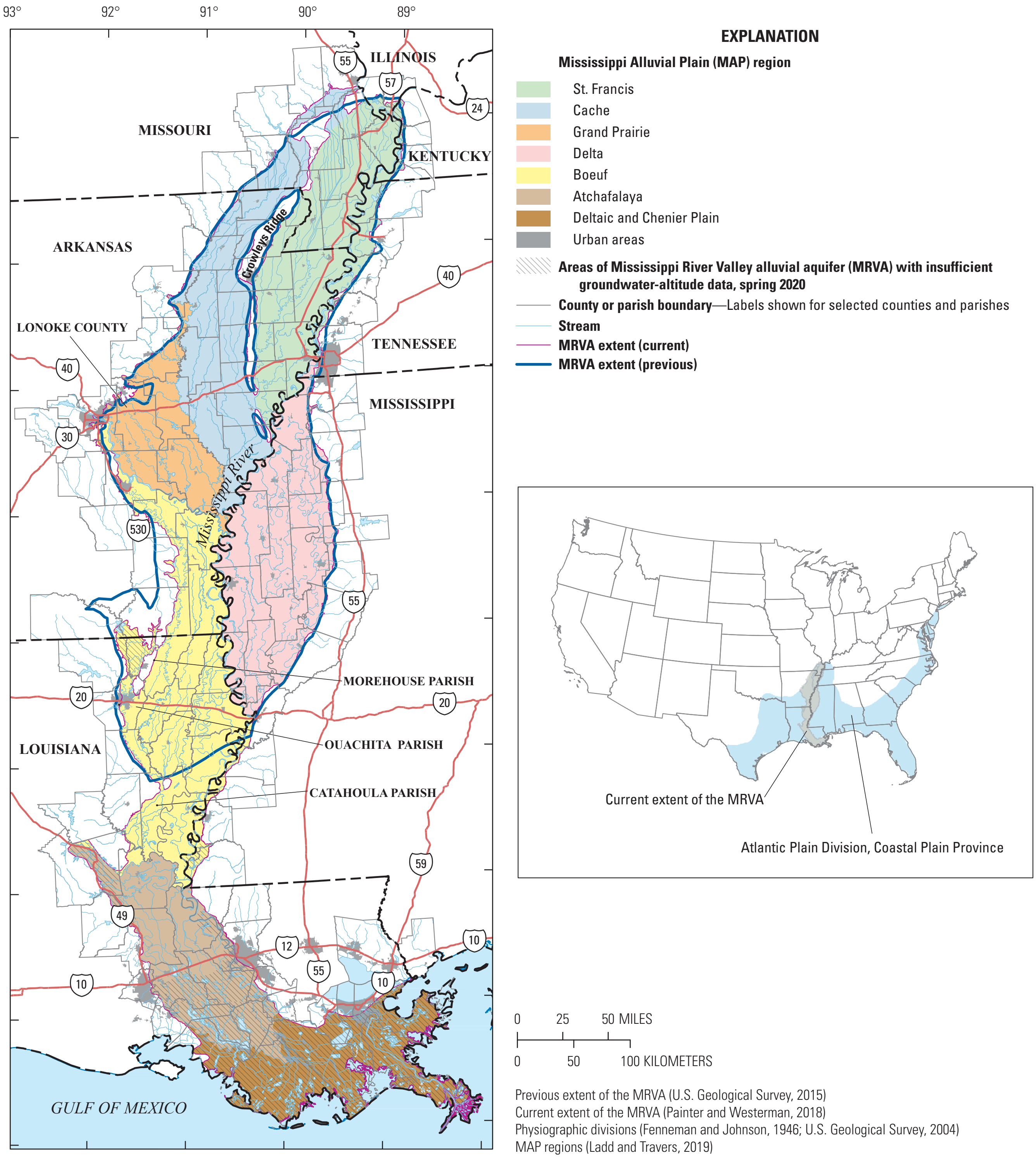
The Mississippi River Valley alluvial aquifer (MRVA) is an important surficial aquifer in the Mississippi Alluvial Plain (MAP) area (fig. 1). The aquifer is generally considered to be an unconfined aquifer (Clark and others, 2011), and withdrawals are primarily used for irrigation (Lovelace and others, 2020). These groundwater withdrawals have resulted in substantial areas of water-level decline in parts of the aquifer. Concerns about water-level declines and the sustainability of the MRVA have prompted the U.S. Geological Survey (USGS), as part of the USGS Water Availability and Use Science Program and with assistance from other Federal, State, and local agencies, to undertake a regional water-availability study to assess the characteristics of the MRVA, including creation of a map of the potentiometric surface of the MRVA for spring 2020, and to provide information to water managers to inform their decisions about resource allocations and aquifer sustainability.

The purpose of this report is to present a potentiometric-surface map for the MRVA. The source data for the map were groundwater-altitude data from wells measured manually or continuously generally in spring 2020 and from the altitude of the top of the water surface (hereinafter referred to as "surface-water altitude") measured generally on April 9, 2020, in rivers in the area.

The term "potentiometric surface" is applicable for maps of the groundwater-altitude surface in unconfined, semiconfined, and confined aquifers (Lohman, 1972). The MRVA generally exhibits characteristics of unconfined conditions, where surface-water features may or may not be hydraulically connected to the aquifer, but it also exhibits characteristics of confined or semiconfined conditions in some areas at least during part of the year. The location of these areas, where the aquifer is confined or semiconfined, have been assessed by various authors in parts of the MRVA but applicable datasets, suitable for use in this potentiometric surface map, were not found and therefore were not included in this study.

Previously published potentiometric-surface maps for a large part of the MRVA include maps from water levels measured from 1953 to 1961 (Krinitzsky and Wire, 1964), for 1964 (Boswell and others, 1968), and for 2016 and 2018 (McGuire and others, 2019, 2020). Previously published potentiometric-surface maps for parts of the MRVA include maps for the Grand Prairie region in Arkansas in 1929, 1939, and 1959 (Engler and others, 1963) and selected counties in northeast and central Arkansas in 1965 and 1966 (Albin and others, 1967; Plebuch and Hines, 1967); the entire aquifer area in Arkansas for 1972, 1980, 1983, 1984, 1985, 1986, 1987, 1989, 1992, 1994, 1996, 1998, 2000, 2002, 2004, 2006, 2008, and 2012 (Ackerman, 1989; Edds and Fitzpatrick, 1984; Joseph, 1999; Plafcan and Edds, 1986; Plafcan and Fugitt, 1987; Plafcan and Remsing, 1989; Reed, 2004; Schrader, 2001, 2006, 2008, 2010, 2015; Stanton and others, 1998; Westerfield, 1990; Westerfield and Gonthier, 1993; Westerfield and Poynter, 1994); the aquifer area in northwestern Mississippi for various years including 1976, 1980, 1981, 1982, and 1983 (Dalsin, 1978; Darden, 1981, 1982a, 1982b, 1983; James Hoffmann, Mississippi Department of Environmental Quality, written commun., 2018; Sumner, 1984, 1985; Wasson, 1980); the entire aquifer area in Missouri for 1976 (Miller and Appel, 1997); and the part of the aquifer in northeastern Louisiana for 1990 (Seanor and Smoot, 1995). The previously published potentiometric-surface maps that were used in this study were McGuire and others (2019, 2020), Miller and Appel (1997), Seanor and Smoot (1995), and Schrader (2015).

To best reflect hydrologic conditions in the MRVA, the groundwater altitudes used to create the 2020 potentiometric-surface map would be measured in a short timeframe of days or 1 or 2 week(s) and there would be available data (for example, from sets of wells, with short [5 to 10 feet (ft)] screens, installed near the top, in the middle, and near the bottom of the aquifer) to indicate vertical flow components (Fetter, 2001; Freeze and Cherry, 1979). However, the measurement timing for many wells was determined by the needs and schedules of the entities doing the measurements instead of the preferred schedule for a regional potentiometric-surface map. Many of the measured wells also have longer (greater than 10 ft) screens, so these water-level measurements tend to represent a mean hydraulic head in the aquifer for that location (Fetter, 2001). For this report, recognizing the limitations of the available data, it was decided to assess all available groundwater-altitude data from wells measured from January 21 to June 17,



Base from U.S. Geological Survey digital data, 1:1,000,000 and 1:2,000,000, variously dated
Highways from National Highway Planning Network, various scales, 2014
Urban areas from U.S. Census Bureau, 1:500,000, 2016
Albers National Hydrogeologic Grid projection
Standard parallels 45°30′ N. and 29°30′ N., central meridian 96°00′ W.
World Geodetic Survey of 1984

Figure 1. Previous and current extent of the Mississippi River Valley alluvial aquifer (MRVA) and areas with insufficient groundwater-altitude data to map the potentiometric surface for spring 2020.

2020, for use in the potentiometric-surface map for spring 2020. The resultant potentiometric-surface map would then represent the generalized central tendency for spring 2020, but it would not be useful for some purposes, such as for calibration of a groundwater-flow model for early April 2020 or for some local scale assessments.

Study Area Description

The current (2020) extent of the MRVA is defined to be the same as the boundary of the MAP physiographic division, which is a revision of the aquifer extent used in previous studies (fig. 1; Ackerman, 1996; Clark and others, 2011; Painter and Westerman, 2018; and U.S. Geological Survey, 2015). The MRVA underlies an area of approximately 43,800 square miles (mi^2) in parts of seven States—Arkansas, Illinois, Kentucky, Louisiana, Mississippi, Missouri, and Tennessee (fig. 1; Painter and Westerman, 2018).

The MRVA primarily underlies the MAP section within the Atlantic Plain Division, Coastal Plain Physiographic Province (fig. 1; Fenneman and Johnson, 1946; U.S. Geological Survey, 2004). The MRVA extends about 560 miles (mi) north to south from southeastern Missouri and Illinois and southwestern Kentucky to the southern boundary of Louisiana. The width of the MRVA ranges from about 35 mi in northeast Louisiana and southwest Mississippi to 134 mi in southern Louisiana. The Mississippi River (fig. 1) is within the MRVA boundary except in southeast Louisiana, where the river is north of the MRVA boundary and instead overlies aquifers in Pleistocene-aged deposits (Smoot, 1986). Where the Mississippi River is within the MRVA boundary, the river is along the eastern boundary of the northern and southern part of the aquifer; in the central part of the MRVA, the Mississippi River curves toward the middle of the aquifer at the northwest boundary of Mississippi before curving back toward the eastern boundary of the aquifer about 50 mi south of the northeast boundary of Louisiana (fig. 1).

The MRVA is contained in Quaternary-age sand, gravel, silt, and clay deposits overlying Tertiary-age units (Clark and others, 2011; Hosman and Weiss, 1991; Saucier, 1994). In some areas, the MRVA is overlain by a Quaternary-age confining unit of silt and clay; where present, this confining unit impedes recharge to the MRVA (Ackerman, 1989; Boswell and others, 1968; Kleiss and others, 2000). There are four areas within the MAP extent where the MRVA is not present (fig. 1; Painter and Westerman, 2018). The two northernmost areas, in northeastern Arkansas and southeastern Missouri, which are termed “Crowleys Ridge,” are erosional remnants of Tertiary-age deposits of clay, silt, sand, and lignite, overlaid by Quaternary-age sand and gravel, and capped by Quaternary-age loess (fig. 1; Guccione and others, 1986; McFarland, 2004). The combined area of the two Crowleys Ridge parts is about 1,053 mi^2; the combined length of the two parts of Crowleys Ridge is about 185 mi and the width ranges from less than a mile to about 21 mi. Crowleys Ridge forms a physical barrier to groundwater flow in the MRVA (Kresse and others, 2014; Schrader, 2008, 2010, 2015). Two other areas where the aquifer is not present are an upland area of about 128 mi^2 in northeastern Louisiana in the center of Morehouse Parish and the northeastern part of Ouachita Parish, and an upland area of about 21 mi^2 in the north-central part of Catahoula Parish (fig. 1; Saucier, 1994).

Groundwater withdrawals from the MRVA in 2015 were 12,100 million gallons per day, making it the second most heavily pumped aquifer in the Nation. Ninety-seven percent of total withdrawals in 2015 were for irrigation (Lovelace and others, 2020).

Data and Methods

The 2020 potentiometric-surface raster and associated contours were created by interpolating the groundwater-altitude data from wells and surface-water-altitude data from streamgages into a raster dataset (grid with a uniform cell size and hereinafter referred to as a “raster”), converting the resultant raster to contours, manually modifying some of the contours, conducting spatial analysis, and generating outputs using a geographic information system (GIS) software (Esri® ArcMap, version 10.7; Esri, 2018). The GIS tool, topo to raster (Esri, 2021a), was used to interpolate the water-level altitude data from selected wells and streamgages (McGuire and others, 2021), which is the same method used for the 2016 and 2018 potentiometric-surface maps (McGuire and others, 2019, 2020). The topo to raster tool is an interpolation method designed for the creation of hydrologically correct digital elevation models. The topo to raster tool (Esri, 2021b) is based on the ANUDEM program, version 5.3 (Hutchinson, 1988, 1989, 1996, and 2000; Hutchinson and others, 2011). The GIS tool, point density, was used to designate areas with estimated contours for the 2020 potentiometric-surface map (Esri, 2021a); this is not the same method used to identify estimated contours in the 2016 and 2018 potentiometric-surface maps (McGuire and others, 2019, 2020). For the 2016 and 2018 potentiometric-surface maps, the estimated contours were identified manually by qualitatively assessing the amount of available groundwater and surface-water data in the vicinity of the contour. For spring 2020, the point shapefiles of groundwater- and surface-water-altitude data, raster files of the potentiometric-surface map, and shapefile of the potentiometric-surface-altitude contours are available in a USGS data release (McGuire and others, 2021).

Water-Level Data

Groundwater-altitude data were compiled by the USGS (table 1; McGuire and others, 2021; U.S. Geological Survey, 2020a) from 1,237 wells completed in the MRVA and measured either manually in the time period from January 21 to

Table 1. Total number of wells that were completed in the Mississippi River Valley alluvial aquifer and measured manually one or more times or continually for spring 2020, and the subset of these wells whose groundwater-altitude data were used to generate the potentiometric-surface map for the Mississippi River Valley alluvial aquifer, spring 2020, by Mississippi Alluvial Plain region (Ladd and Travers, 2019; U.S. Geological Survey, 2020a).

[MAP, Mississippi Alluvial Plain; MRVA, Mississippi River Valley alluvial aquifer; --, no data]

MAP Region	Total number of wells measured manually, pre-irrigation season, 2020	Total number of wells measured continually, pre-irrigation season, 2020	Number of wells measured manually and used in the potentiometric-surface map, MRVA, spring 2020	Number of wells measured continually and used in the potentiometric-surface map, MRVA, spring 2020	Total number of wells used to generate the potentiometric-surface map, MRVA, spring 2020
St. Francis	163	7	156	7	163
Cache	249	7	244	7	251
Grand Prairie	134	2	132	2	134
Delta	455	11	455	10	465
Boeuf	205	2	202	2	204
Atchafalaya	22	--	20	--	20
Deltaic and Chenier Plain	--	--	--	--	--
MRVA	1,228	29	1,209	28	1,237

June 17, 2020, or continually during all or part of the time period from January 1 to May 31, 2020. The groundwater-altitude data in wells that were manually measured one or more times are hereinafter referred to as “manually measured.” The groundwater-altitude data in wells that were measured continually for all or part of the time period are hereinafter referred to as “continually measured.” The wells were measured as part of a regular water-level monitoring program by the Arkansas Natural Resources Commission, Missouri Department of Natural Resources, U.S. Department of Agriculture Natural Resources Conservation Service, USGS, and Yazoo Mississippi Delta Joint Water Management District. Wells measured by drillers in Missouri were included in the data used to map the potentiometric surface for the MRVA in 2016 (McGuire and others, 2019) but were not included for the 2020 potentiometric-surface map because the data from 2020 were not yet available (September 2020).

The manually and continually measured water levels for wells screened in the MRVA were stored in the USGS National Water Information System database (U.S. Geological Survey, 2020a) as depth to water below land surface. For the manually and continually measured wells, the land-surface altitude, in feet, and associated vertical datum (National Geodetic Vertical Datum of 1929 [NGVD 29] or North American Vertical Datum of 1988 [NAVD 88]) were retrieved or determined for each well. If the stored land-surface altitude datum was NGVD 29, the land-surface altitude was converted to NAVD 88 using the National Geodetic Survey’s VERTCON computer program (Miller, 1999), and the measured groundwater altitude or daily mean groundwater altitude with respect to NAVD 88 was calculated for each well. Groundwater altitudes from the well’s measuring point for manually and continually measured wells are assumed to be accurate to the hundredths of a foot.

All groundwater-altitude data from manually and continually measured wells were reviewed to identify and exclude groundwater-altitude values that appeared to be affected by current or recent pumping and that were substantially different from the groundwater altitudes in nearby wells, possibly because of local or seasonal conditions. Other considerations for rejecting a well’s groundwater altitude were apparent discrepancies between the spatial location of the well and the well’s legal description or identifier and suspected inaccuracy in the land-surface altitude value. In addition, groundwater-altitude data from wells were not used for (1) wells that were flowing and could not be measured or (2) wells that were dry.

For manually measured wells with one measurement, the only available measurement was selected as the groundwater altitude to consider for use to create the potentiometric-surface map. For the 182 manually measured wells with more than one measurement and used in the 2020 potentiometric surface map, the maximum (highest) groundwater altitude for each well was selected; the difference between the maximum and minimum groundwater-altitude values ranged from 0.02 to 27.08 ft, with a median difference of 1.34 ft (fig. 2). Only two wells, in the Boeuf region in Louisiana, had three measurements; the remaining 180 wells had two measurements. The number of wells with more than one measurement by region were Cache (90 wells), St. Francis (41 wells), Boeuf (29 wells), Grand Prairie (21 wells), and Atchafalaya (1 well); the number of wells with more than one measurements by State were Arkansas (172 wells) and Louisiana (10 wells). For the

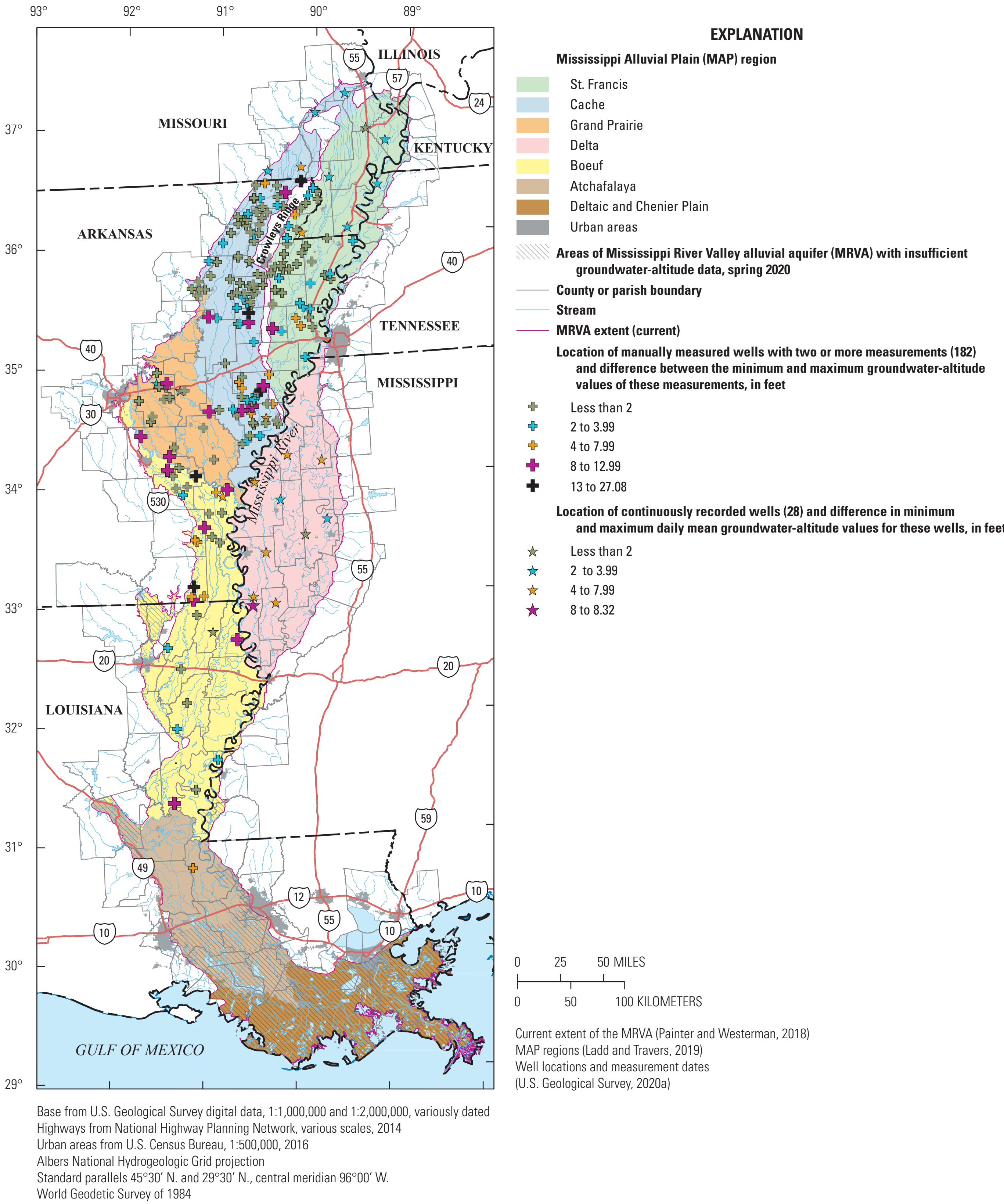


Figure 2. Location of manually and continuously measured wells screened in the Mississippi River Valley alluvial aquifer (MRVA) with two or more groundwater-altitude values for spring 2020 and the difference between the minimum and maximum groundwater-altitude values for these wells in this time period.

wells with more than one manual measurement, the minimum and maximum measurement dates and range of groundwater-altitude values are described as follows:

- The multiple measurements for 11 wells were on the same day and the differences between the minimum and maximum groundwater altitudes were from 0.02 to 4.34 ft.
- The multiple measurements for 88 wells were less than 10 days apart, but not on the same day, and the differences between the minimum and maximum groundwater altitudes were from 0.04 to 27.08 ft.
- The multiple measurements for 83 wells were 10 days to 106 days apart and the differences between the minimum and maximum groundwater altitudes were from 0.04 to 22.05 ft.

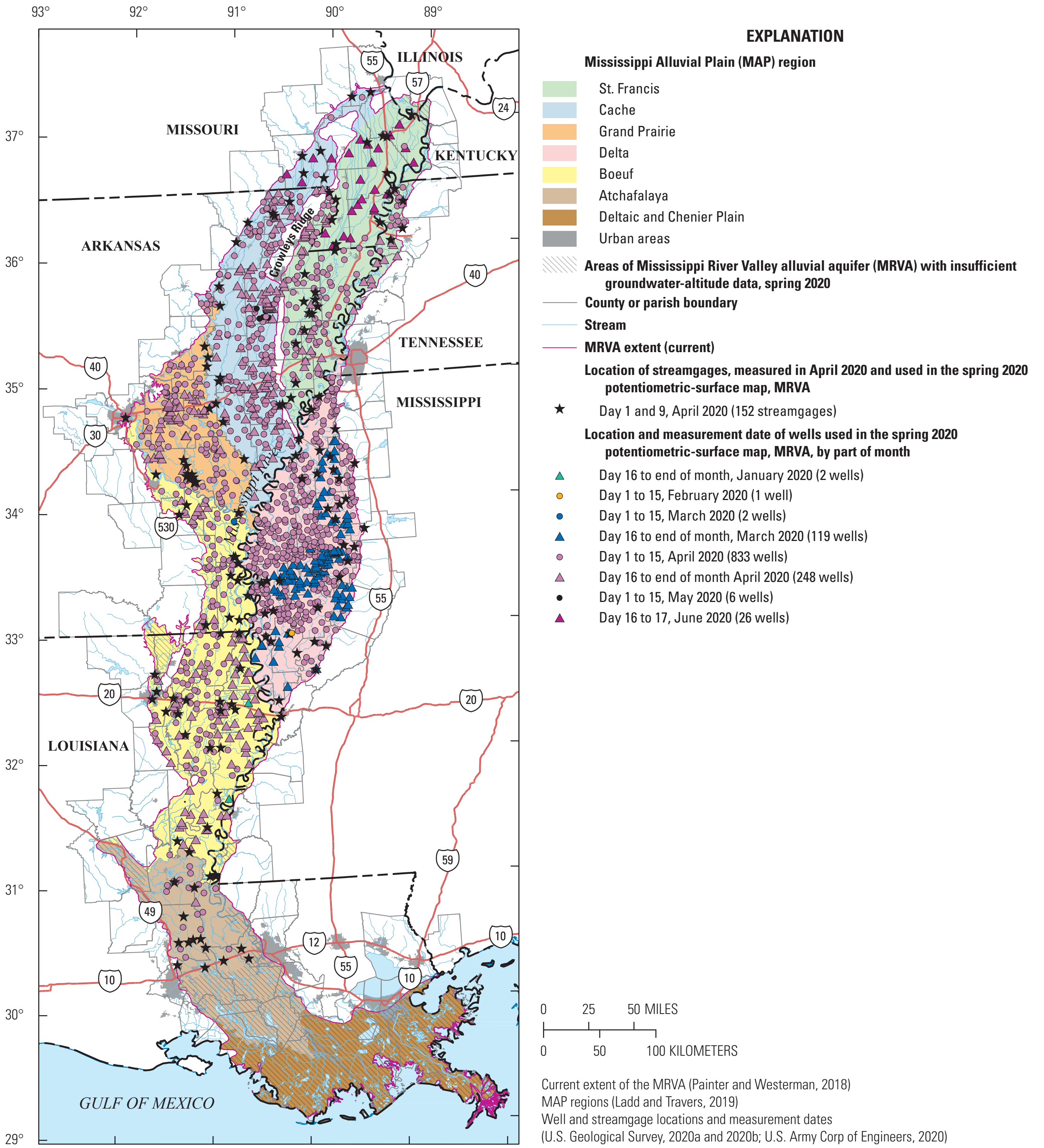
Measurement data for 29 continuously measured wells screened in the MRVA were retrieved (McGuire and others, 2021). The location and number of continuously measured wells by region were St. Francis (7 wells), Cache (7 wells), Grand Prairie (2 wells), Delta (11 wells), and Boeuf (2 wells); and by State were Arkansas (7 wells), Louisiana (1 well), Mississippi (11 wells), Missouri (9 wells), and Tennessee (1 well). One of the continuously measured wells in the Delta region in Mississippi was not used in the 2020 potentiometric surface map because the water-level altitude in this well was much higher than the water-level altitude in nearby wells. For 28 continually measured wells that were used in the 2020 potentiometric surface map, the difference between the maximum and minimum available groundwater altitude from January 1 to May 31, 2020 was from 0.90 to 8.32 ft (fig. 2; McGuire and others, 2021). The date of the minimum measurement ranged from January 1 to May 31, 2020; the date of the maximum measurement ranged from January 13 to May 31, 2020. The number of days between the minimum and maximum measurement for each well ranged from 3 to 151 days.

Groundwater-altitude data from 1,237 wells were used in the spring 2020 potentiometric-surface map (table 1; fig. 3). The minimum, maximum, mean, and median distances between the 1,237 wells were 7.2 ft, 20.5 mi, 2.5 mi, and 2.1 mi, respectively. These wells included 1,027 manually measured wells, which were measured one time; 182 manually measured wells, which were measured two or three times; and 28 continually measured wells (McGuire and others, 2021). The median measurement date for the selected manually and continually measured water levels was April 9, 2020 (table 2). When groundwater-altitude data were not available for a continually measured well on April 9, 2020, the first available daily mean groundwater altitude for that well prior to April 9, 2020, was used. For continually measured wells, the mean, and not the maximum, groundwater-altitude values were selected or calculated because that was the daily statistic that was publicly available for most continually measured wells (U.S. Geological Survey, 2020a). Following review of the data, groundwater-altitude data from 19 of 1,228 manually measured wells and 1 of 29 continually measured wells were not used in the 2020 potentiometric-surface map; in the USGS data release, these wells have the USE2020 field set to −1 and the USECMT2020 field contains the reason the groundwater-altitude data were not used (table 1; fig. 4; McGuire and others, 2021).

The distribution of measurement dates for the selected groundwater-altitude values ranged from 0 wells for the first 15 days in January 2020 to 833 wells in the first 15 days of April 2020 (fig. 3). The areas of insufficient groundwater data were assessed qualitatively using the distance between wells and by visually examining aquifer areas not included in buffers of various sizes around the wells; for this report, the area with insufficient groundwater data was defined as no wells within 12.4 mi of the center of a given cell. This distribution indicates that if only wells measured in a short timeframe, such as the first 15 days in April 2020, were used to create the 2020 potentiometric-surface map, there would be larger areas with insufficient groundwater-altitude data.

Daily mean surface-water-altitude data were assembled for 310 streamgages routinely operated by the U.S. Army Corps of Engineers and the USGS in the MRVA area (table 3; U.S. Geological Survey, 2020b; U.S. Army Corps of Engineers, 2020; McGuire and others, 2021). For this study, the streamgage altitude, in feet; the associated vertical datum (NGVD 29 or NAVD 88); and the daily mean river stage on April 9, 2020, if available or the first available value prior to April 9, 2020, were retrieved for each streamgage. If the vertical datum associated with the streamgage altitude was NGVD 29, the streamgage altitude was converted to NAVD 88 using National Geodetic Survey's VERTCON program (Miller, 1999) for possible use to create the potentiometric-surface map.

Of the 310 streamgages considered for use in the potentiometric-surface map (table 3), a total of 158 streamgages were not used for the 2020 potentiometric-surface map (fig. 4; McGuire and others, 2021). These 158 streamgages were not used because 98 were in areas with insufficient groundwater data to substantiate that the surface-water altitude was representative of the groundwater altitude in the area; 47 had surface-water altitudes that were much higher than the nearby wells screened in the MRVA, likely either because the surface-water altitude was affected by precipitation events or the MRVA is not connected to the surface water at these locations; 6 had surface-water altitude values that seemed problematic; 6 had surface-water altitudes that possibly were substantially affected by control structures, and 1 was a duplicate site. There were 152 streamgages in areas with nearby groundwater-altitude data for 2020 that were used to create the 2020 potentiometric-surface map (fig. 3; McGuire and others, 2021). The surface-water-altitude values were considered approximations of the groundwater altitude at the river location because the altitude of the connection between groundwater and surface water at this location is not known.



Base from U.S. Geological Survey digital data, 1:1,000,000 and 1:2,000,000, variously dated
Highways from National Highway Planning Network, various scales, 2014
Urban areas from U.S. Census Bureau, 1:500,000, 2016
Albers National Hydrogeologic Grid projection
Standard parallels 45°30′ N. and 29°30′ N., central meridian 96°00′ W.
World Geodetic Survey of 1984

Figure 3. Location of wells with groundwater-altitude values and streamgages with surface-water-altitude values used to create the potentiometric-surface map of the Mississippi River Valley alluvial aquifer (MRVA), spring 2020, and the part of the measurement month for the selected water-level-altitude value.

Table 2. Summary statistics for water-level measurement dates of water levels used in the spring 2020 potentiometric-surface map for wells that were completed in the Mississippi River Valley alluvial aquifer and measured manually one or more times or continually as part of groundwater monitoring networks for spring 2020, by Mississippi Alluvial Plain region (Ladd and Travers, 2019; U.S. Geological Survey, 2020a).

[Minimum, maximum, and median columns are shown in YYYYMMDD format; YYYY, year; MM, month; DD, day; MAP, Mississippi Alluvial Plain; MRVA, Mississippi River Valley alluvial aquifer; --, no data]

MAP Region	Summary statistics for water-level measurement dates of water levels used in the potentiometric-surface map, MRVA, spring 2020								
	Manually measured wells in groundwater monitoring networks			Continuously measured wells			All wells		
	Minimum	Maximum	Median	Minimum	Maximum	Median	Minimum	Maximum	Median
St. Francis	20200406	20200617	20200414	20200409	20200409	20200409	20200406	20200617	20200414
Cache	20200406	20200616	20200414	20200409	20200409	20200409	20200406	20200616	20200414
Grand Prairie	20200406	20200430	20200414	20200409	20200409	20200409	20200406	20200430	20200414
Delta	20200316	20200423	20200402	20200210	20200409	20200409	20200210	20200423	20200402
Boeuf	20200121	20200427	20200415	20200308	20200409	20200324	20200121	20200427	20200415
Atchafalaya	20200413	20200417	20200414	--	--	--	20200413	20200417	20200414
Deltaic and Chenier Plain	--	--	--	--	--	--	--	--	--
MRVA	20200121	20200617	20200409	20200210	20200409	20200409	20200121	20200617	20200409

Characterizing the 2020 Potentiometric-Surface Raster and Contours

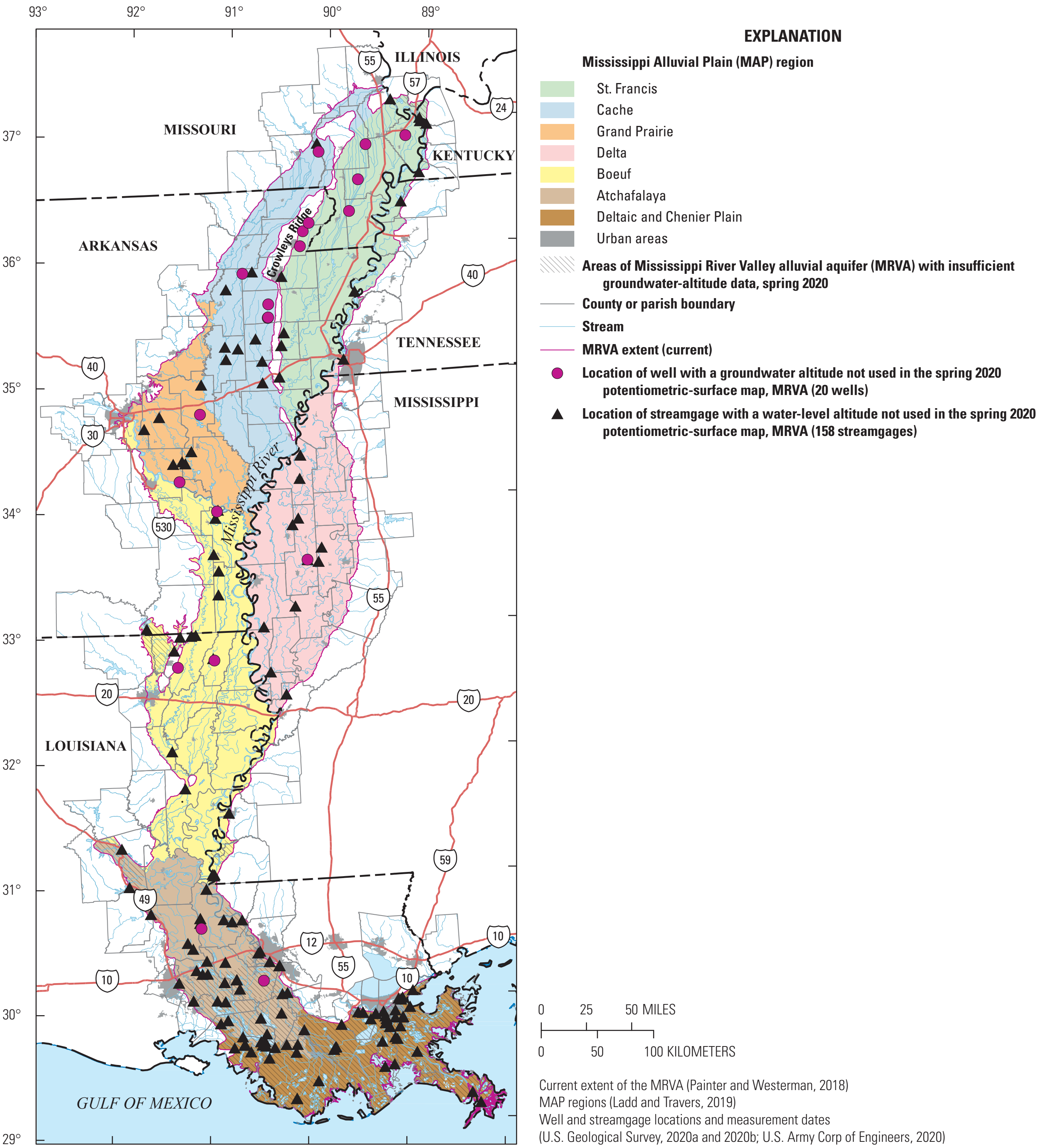
The potentiometric-surface raster and contours were generated using source files of selected groundwater- and surface-water-altitude data for spring 2020 (tables 1, 3; McGuire and others, 2021). About 81 percent of the aquifer area had sufficient groundwater data for 2020 (fig. 1) to create a potentiometric-surface map for spring 2020. The resultant spatial files are in Albers equal-area conic projection in meters using the World Geodetic Survey of 1984 and the potentiometric-surface altitude is expressed relative to the NAVD 88 datum. The rasters have a cell size of about 0.386 mi^2 and are aligned with the National Hydrologic Grid (Clark and others, 2018).

The potentiometric-surface raster was compared to a raster of the aquifer base (Torak and Painter, 2019) to identify where the potentiometric-surface raster was below the aquifer-base raster. The potentiometric-surface raster was as much as 11 ft below the aquifer base only in an approximate 19-mi^2 area in the south-central part of Lonoke County, Arkansas (fig. 1). In this area, there are five wells with water-level altitudes used to generate the potentiometric-surface raster. The well identification code for these wells (termed “site badge” in the related data file; McGuire and others, 2021) and, for each well, the depth of the water-level altitude below the aquifer base are USGS:344249091493201 (6.86 ft), USSCS:344253091483101 (7.03 ft), AR008:344405091503701 (6.15 ft), AR008:344355091451501 (3.75 ft), and USGS:344648091494601 (0.73 ft). No changes were made to the potentiometric-surface raster as a result of this comparison.

A total of five potentiometric maps were created—one for the entire MRVA, and one each for the St. Francis and Cache MAP regions in the north, Boeuf and Grand Prairie MAP regions in the west-central area, Delta MAP region in the east-central area, and Atchafalaya, Deltaic, and Chenier Plains MAP regions in the south. The maps are at a reduced, regional scale of 1:625,000 to allow for the display of control-point values.

The interpolation process, which was used to generate the rasters, can result in cell values for cells collocated with a measured well that are generally similar to, but commonly not equal to, the corresponding groundwater- and surface-water-altitude values based on measurements. This difference is partly because the cell values represent the value for the cell area, and the measured values are values at specific locations within the area represented by the cell.

To assess the uncertainty in the final raster and contours, the water-level altitude values for the 1,237 wells used in the potentiometric-surface map and the 20 wells not used to generate the potentiometric-surface raster were compared, if possible, to the final potentiometric-surface raster value in the cell where the well or streamgage is located (McGuire and others, 2021). For each well, the root mean square error (RMSE) and bias were calculated for the difference between the manually measured water-level altitude and the value extracted from the potentiometric-surface raster generated using the contours and point values (Helsel and others, 2020).



Base from U.S. Geological Survey digital data, 1:1,000,000 and 1:2,000,000, variously dated
Highways from National Highway Planning Network, various scales, 2014
Urban areas from U.S. Census Bureau, 1:500,000, 2016
Albers National Hydrogeologic Grid projection
Standard parallels 45°30′ N. and 29°30′ N., central meridian 96°00′ W.
World Geodetic Survey of 1984

Figure 4. Location of wells with groundwater-altitude values and streamgages with surface-water-altitude values for spring 2020 that were not used to create the potentiometric-surface map of the Mississippi River Valley alluvial aquifer (MRVA), spring 2020.

Table 3. Total number of streamgages in the Mississippi Alluvial Plain with surface-water-altitude values for spring 2020, and number of surface-water-altitude values, generally for April 9, 2020, used to generate the potentiometric-surface map, spring 2020, for the Mississippi River Valley alluvial aquifer by Mississippi Alluvial Plain region (Ladd and Travers, 2019; U.S. Army Corps of Engineers, 2020; U.S. Geological Survey, 2020b).

[MAP, Mississippi Alluvial Plain; MRVA, Mississippi River Valley alluvial aquifer; --, no data]

MAP Region	Number of streamgages with surface-water-altitude values, generally for April 9, 2020, in the MAP area	Number of surface-water-altitude values, generally for April 9, 2020, used to generate the potentiometric-surface map, MRVA, spring 2020
St. Francis	42	30
Cache	30	20
Grand Prairie	23	17
Delta	47	34
Boeuf	55	38
Atchafalaya	65	13
Deltaic and Chenier Plain	48	--
MRVA	310	152

Potentiometric-Surface Map, Spring 2020

The spring 2020 potentiometric-surface contours ranged from 10 to 340 ft above NAVD 88, and the regional direction of groundwater flow was to the south-southwest, except in areas of groundwater-altitude depressions (sheet 1), where groundwater flowed into the depression, and near rivers, where flow was generally parallel to the rivers. However, in some areas, flow was from the aquifer into the river or from the river into the aquifer. The lowest measured groundwater altitude was in Saint Landry Parish, Louisiana, and the highest was in Bollinger County, Missouri; the lowest measured surface-water altitude was in West Baton Rouge Parish, La., and the highest was in Cape Girardeau, Mo. (McGuire and others, 2021). Based on groundwater- and surface-water-altitude measurements for spring, 2020, the MRVA is connected to surface-water features in some areas and disconnected in other areas at least during part of the year; however, the extent of the degree of connectivity of these areas cannot be derived from these data.

The RMSE and bias for the differences between the measured water-level altitude and potentiometric-surface raster value for the 19 manually and 1 continually measured wells, which were not used in the potentiometric-surface map and were located in a raster cell with a potentiometric-surface value, were 51.42 and 15.2 ft, respectively. One of the manually measured wells not used in the 2020 potentiometric-surface map was in a raster cell where the potentiometric-surface value was not defined.

The RMSE for the difference between the measured water-level altitude for the 1,209 manually and 28 continually measured wells, which were used in the potentiometric-surface map and were located in a raster cell with a potentiometric-surface value, was 1.71 ft with a bias of 0.07 ft. Two of the manually measured wells used in the 2020 potentiometric-surface map were in raster cells where the potentiometric-surface value was not defined.

The spring 2020 potentiometric contours in the Cache region ranged from 120 to 340 ft above NAVD 88 and show a large depression in the lower one-half of the Cache region (sheet 2). The lowest measured groundwater altitude was 110.89 ft in a depression in Poinsett County, Ark., and the highest measured groundwater altitude was 340.27 ft in Bollinger County, Mo.; the lowest measured surface-water altitude was 168.67 ft in Monroe County, Ark., and the highest was 344.16 ft in Cape Girardeau County, Mo. (McGuire and others, 2021). Flow in the Cache region generally is to the south-southwest or into the depression in the southern part of the region.

The spring 2020 potentiometric contours in the St. Francis region ranged from 160 to 320 ft above NAVD 88 (sheet 2). The lowest measured groundwater altitude was 158.22 ft in St. Francis County, Ark., and the highest measured groundwater altitude was 316.51 ft in Mississippi County, Mo.; the lowest measured surface-water altitude was 178.74 ft in Lee County, Ark., and the highest was 325.13 ft in Mississippi County, Mo. (McGuire and others, 2021). Flow in the St. Francis region generally is to the south-southwest.

The spring 2020 potentiometric contours in the Boeuf region ranged from 40 to 230 ft above NAVD 88 (sheet 3). The lowest measured groundwater altitude was 33.10 ft in Concordia Parish, La., and the highest measured groundwater altitude was 218.00 ft in Pulaski County, Ark.; the lowest measured surface-water altitude was 36.64 ft in Concordia Parish, La., and the highest was 236.02 ft in Pulaski County, Ark. (McGuire and others, 2021). Flow in the Boeuf region is to the southeast, southwest, south, and into the depressions.

The spring 2020 potentiometric contours in the Grand Prairie region ranged from 90 to 230 ft above NAVD 88; there is a large depression in the potentiometric surface within the region (sheet 3). The lowest measured groundwater altitude was 82.91 ft in Lonoke County, Ark., and the highest measured groundwater altitude was 230.04 ft in Pulaski County, Ark.; the lowest measured surface-water altitude was 158.57 ft in Arkansas County, Ark., and the highest was 200.60 ft in White County, Ark. (McGuire and others, 2021). Flow in the Grand Prairie region generally is into the depression that encompasses most of the region.

The spring 2020 potentiometric contours in the Delta region ranged from 60 to 210 ft above NAVD 88; there is a large depression in the potentiometric surface within the central part of the region (sheet 4). The lowest measured groundwater altitude was 54.36 ft in Leflore County, Mississippi, and the highest measured groundwater altitude was 208.42 ft in DeSoto County, Miss.; the lowest measured surface-water altitude was 95.76 ft in Issaquena County, Miss., and the highest was 203.04 ft in Tunica County, Miss. (McGuire and others, 2021). Flow in the Delta region generally is into the large depression at the center of the region.

For most of the Atchafalaya region and all the Deltaic and Chenier Plains region, a spring 2020 potentiometric-surface map could not be created because of insufficient groundwater-altitude data (sheet 5). In the part of the Atchafalaya region included in the 2020 potentiometric-surface map, potentiometric contours ranged from 10 to 40 ft above NAVD 88 (sheet 5). The lowest measured groundwater altitude was 4.46 ft in Saint Landry Parish, La., and the highest measured groundwater altitude was 48.86 ft in Avoyelles Parish, La.; the lowest measured surface-water altitude was 3.49 ft in West Baton Rouge Pariah, La., and the highest was 39.46 ft in Avoyelles Parish, La. (McGuire and others, 2021). Groundwater flow in the mapped area is generally toward the south and southwest.

Summary

A potentiometric-surface map for spring 2020 was created for the Mississippi River Valley alluvial aquifer (MRVA) using available groundwater-altitude data from 1,237 wells completed in the MRVA and from the altitude of the top of the water surface in area rivers from 152 streamgages. Personnel from local, State, and Federal entities routinely collect groundwater-level data from wells screened in the MRVA. The U.S. Geological Survey and the U.S. Army Corps of Engineers routinely collect data on river stage and streamflow for the rivers overlying the MRVA area. The potentiometric-surface map for 2020 was created utilizing existing groundwater and surface-water altitudes to support investigations to characterize the MRVA as part of the U.S. Geological Survey Water Availability and Use Science Program.

Sufficient data were available to map the potentiometric surface of the MRVA for spring 2020 for about 81 percent of the aquifer area. The lowest measured groundwater altitude was 4.46 feet (ft) in Saint Landry Parish, Louisiana, and the highest was 340.27 ft in Bollinger County, Missouri; the lowest measured surface-water altitude was 3.49 ft in West Baton Rouge Parish, La., and the highest was 344.16 ft in Cape Girardeau County, Mo. The potentiometric contours ranged from 10 to 340 ft above the North American Vertical Datum of 1988. The regional direction of groundwater flow was generally to the south-southwest, except in areas of groundwater-altitude depressions, where groundwater flowed into the depression, and near rivers, where flow can be parallel to the river, from the aquifer to the river, or from the river into the aquifer. There are large depressions in the potentiometric-surface map in the lower one-half of the Cache region and in most of the Grand Prairie and Delta regions.

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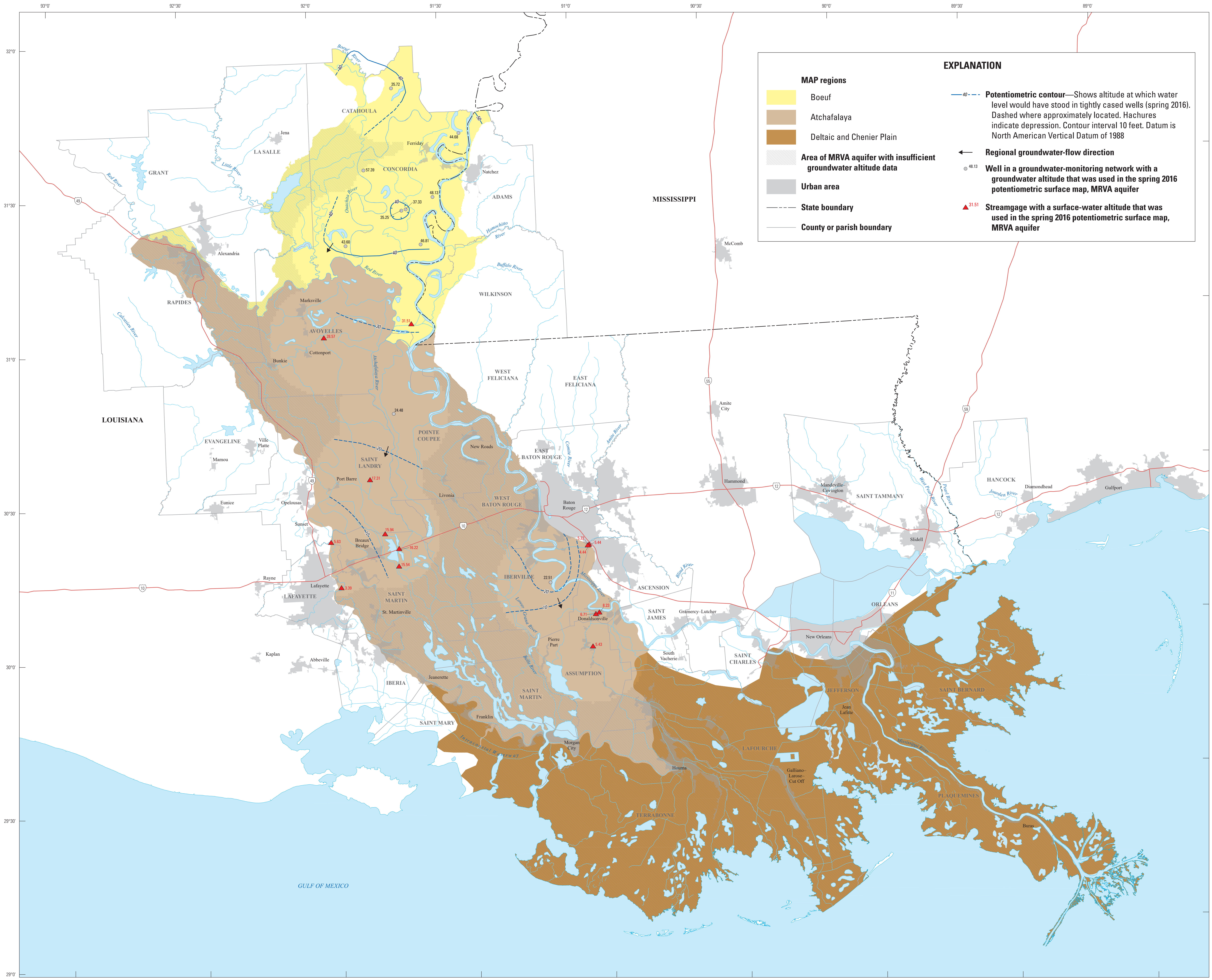

0 10 20 30 40 50 MILES

0 10 20 30 40 50 KILOMETERS

Base from U.S. Geological Survey digital data, 1:1,000,000 and 1:2,000,000, variously dated
Highways from National Highway Planning Network, various scales, 2014
Urban areas from U.S. Census Bureau, 1:500,000, 2016
Albers_NHG projection
Standard parallels 45°30′N and 29°30′N, central meridian 96°00′N
World Geodetic Survey of 1984

Current extent of MRVA aquifer from Painter and Westerman, 2018
MAP regions from Ladd and Travers, 2019

Potentiometric Surface, Mississippi River Valley Alluvial (MRVA) Aquifer, Spring 2016, and Associated Groundwater and Surface-Water Control Points for Atchafalaya and Deltaic and Chenier Plain Regions in the Mississippi Alluvial Plain (MAP)

By
V.L. McGuire, R.C. Seanor, W.H. Asquith, W.H. Kress, and K.R. Strauch
2019

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APPENDIX C: AOR AND CORRECTIVE ACTION PLAN

Appendix C-1	USDW Determination Map
Appendix C-2	Map of Oil and Gas Wells in/near AOR
Appendix C-3	List of Oil and Gas Wells in AOR
Appendix C-4	Map of Active Freshwater Wells in/near AOR
Appendix C-5	List of Freshwater Wells in/near AOR
Appendix C-6	Map of AOR Site Review

APPENDICES C-1 TO C-6 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX D: WELL CONSTRUCTION

APPENDICES D-1 TO D-5 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX E: CASING AND TUBING ALLOY SELECTION REPORT (METALLURGY ANALYSIS)

APPENDIX E IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX F: TESTING AND MONITORING

APPENDIX F-1 IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

Baker Hughes

SureVIEW™ with CoreBright™ Optical Fiber

Ensure industry-leading protection against hydrogen darkening in high-temperature applications

SureVIEW™ downhole cable by Baker Hughes uses CoreBright™ optical fiber, which leads the industry in hydrogen darkening resistance, the primary cause of failure for fiber optic systems in high- temperature applications. CoreBright fiber is constructed from pure silica that minimizes hydrogen darkening. The cable also includes a layer of hydrogen- absorbing gel. This combination provides the industry's best protection against hydrogen darkening.

Fabricating a downhole optical cable with the performance and reliability demanded by the oil and gas industry requires a sophisticated understanding of fiber design, fiber coatings, cable manufacturing processes, and cable construction. Optical, chemical, and physical disciplines are combined with extensive oilfield experience to offer a superior cable.

CoreBright fiber offers its extended lifetime through a simple principle: Rather than attempt to avoid hydrogen damage by trying to block hydrogen (a near impossibility in enhanced oil recovery operations due to high temperatures), CoreBright optical fiber avoids the hydrogen damage by preventing the reaction between SiO2 structure of the optical fiber and the hydrogen. Thus, CoreBright fiber tolerates the presence of hydrogen without suffering lifetime limiting damage.

In this way, our solution is unique: The fiber will never darken, and reliable readings over the full life of the installation are assured. Independent testing has concluded that CoreBright optical fiber is the only fiber in the industry that is suitable for oil and gas environments over a long duration; it is the only known fiber designed for, and has demonstrated, long-term immunity to first and second-order hydrogen darkening effects.[1]

Applications

- Downhole fiber optic monitoring systems

Features and Benefits

- Industry leading reliability
- Proprietary glass composition delivers industry-leading resistance to hydrogen darkening
- Extreme temperature rating
- 100% dynamically proof-tested before cabling

Multiple applications

- CoreBright fiber can be used in a variety of applications from SAGD to Leak Detection to Acid Stimulation and many more

Baker Hughes

Technical Specifications - SureVIEW Downhole	
Description	**Specifications**
Maximum Pressure	25,000 psi
Overpressure	1.2x maximum pressure
Operating Temperature	• 150°C / 302°F for standard • 250°C / 482°F for high temperature • Higher temperature solutions available upon request
Sheath Material	A825, 316LSS
Crush	>5,000lbf
Fibers	Maximum of 12, any combination of SM and MM
Fiber Protection	• Standard Temperature: Hydrogen-scavenging gel, carbon coating, acrylate buffer • High Temperature: High-temperature stabilized gel, polyimide buffer, optional carbon coating
Dimensions	0.25 inch outside diameter (excluding encapsulation)
Encapsulation Options	• 0.43 inch square encapsulation • 0.41 inch round encapsulation • Variety of encapsulation materials can be utilized

Call your local Baker Hughes representative today to learn more about how SureVIEW fiber optic monitoring solutions can reliably monitor and deliver the downhole wellbore and reservoir data you need, when you need it.

1. van Rooyen, A. (Royal Dutch Shell), "Fibre Testing at Elevated Temperatures Under Hydrogen Conditions", SEAFOM Industry Meeting (Dec. 2012)

SureVIEW P/T monitoring system

Gather accurate pressure and temperature data for enhanced production

The **SureVIEW™ pressure/temperature (P/T) system** is a fiber-optic-based monitoring system that provides reliable and accurate well monitoring to help operators enhance production from their wells.

The SureVIEW P/T system uses our industry-leading **CoreBright™ optical fiber** to ensure the best protection against hydrogen darkening of any downhole single-mode-based system on the market, and to provide reliable long-term operation at elevated temperatures.

Each fiber-optic gauge measures both temperature and absolute pressure using established Fabry-Perot technology. With no downhole electronics, gauges can operate reliably at much higher temperatures than traditional electronic gauges, and they are immune to electromagnetic interference.

The surface instrumentation unit (SIU) interrogates the gauges and then converts the raw information into pressure and temperature values. Users can access the data locally on the SUI's front panel display or remotely via telemetry and supervisory control and data acquisition (SCADA).

Rack-mount, pole-mount, CSA-approved, and hazardous location SIUs are available with two- and eight-gauge channel options. With multi-gauge support, a single SIU can typically support monitoring for multiple wells on a platform.

Field-proven accessories are available to complete the installation, including splice hardware, solid body carriers, pressure retaining wellhead outlets, and more. All downhole equipment is dual-sealed and leak-testable. Traditional deployment methods are used to install the system, requiring no special tools from the operator.

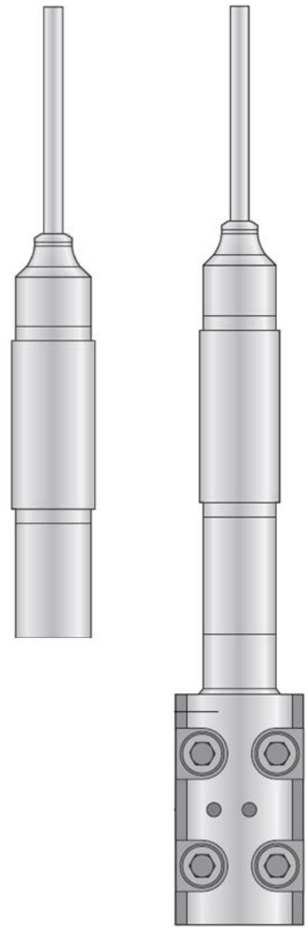
Contact Baker Hughes today to learn more about how our SureVIEW P/T systems provide reliable and accurate well monitoring and enhance production.

Applications

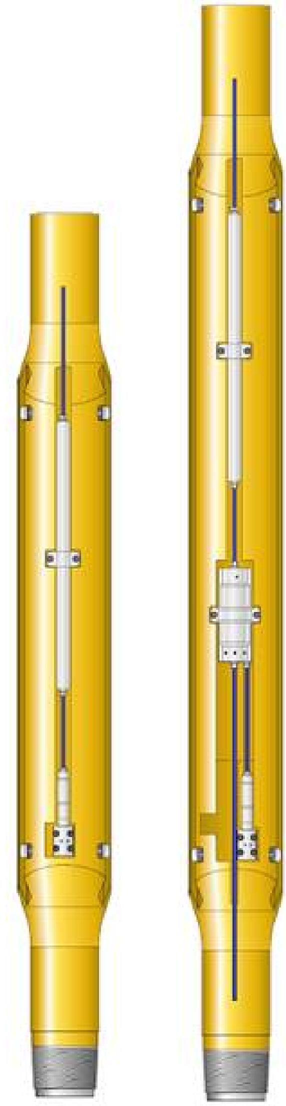
- Tubing and annulus monitoring
- Electric submersible pump monitoring
- Temperature reference for distributed temperature sensing
- Multiple drop gauges for reservoir and production monitoring

Benefits

- Provides an ideal setup for well-bay and pad configurations by accommodating multiple gauges on one cable
- Minimizes risks during deployment
- Guarantees accuracy within calibrated range
- Eases integration with the completion system because of its small size

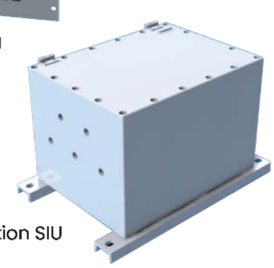


SureVIEW P/T gauges	
Standard, high temperature (HT), and ultra temperature (UT)	
Operational temperature	86°F to 302°F (30°C to 150°C) standard 86°F to 482°F (30°C to 250°C) HT
Temperature accuracy	±1.8°F (±1°C)
Temperature resolution	0.2°F (0.1°C)
Pressure resolution	0.2 psi (0.014 bar)
Pressure range	15 psi to 15,000 psi
Dynamic Pressure Response	1,000psi per second
Overpressure	150% without performance degradation
Pressure accuracy	±5 psi (±0.3 bar)
Dimensions (length x width)	4 in. x 0.75 in. (10.0 cm x 2.0 cm)
Vibration	17g RMS, 10 to 2000 Hz
Shock	100g peak, 10 ms, half-sine
Material	A718
Porting options	Manifold, Testable Autoclave, Annulus



SureVIEW surface instrumentation unit (SIU)		
Description	Rack-mounted	Hazardous location
Operational temperature	32°F to 104°F (0° to 40°C)	-40°F to 131°F (-40°C to 55°C)
Power requirements	22-28VDC, 35W max	22-28VDC, 53w @ 55°C nominal, 95W max
Gauge channels	8 channels standard	8 channels standard
Data logging	64GB onboard storage	64GB onboard storage
Interfaces	Ethernet, MODBUS over RS-485 or TCP	Ethernet, MODBUS over RS-485 or TCP
Dimensions and weight (width x height x depth)	19 in. x 3.47 in. x 19.8 in. (48.3 cm x 8.81 cm x 50.3 cm) 20.3 lb. (19.2kg)	Zone 1: 26.4 in. x 22.8 in. x 13.6 in. (67 cm x 58 cm x 34.6 cm) 211.64 lbs (96 kg) Zone 2: 25.5 in. x 25.5 in. x 9.84 in. (65 cm x 65 cm x 25 cm) 75.3 lb (34.1 kg)
Approvals	CE	Zone 1: Ex d IIB T4 Gb (ATEX) Zone 2: Ex nR op pr II C T6 Gc

Rack-mounted SIU



Hazardous location SIU

SureVIEW PT Surface Interrogator

SureVIEW PT Interrogator is capable of interrogating up to eight SureVIEW fiber optic pressure / temperature gauges to generate raw interferometric signal information that it then converts into pressure and temperature values.

Users can access the data locally on the interrogator's front panel display or remotely over telemetry and SCADA. The interrogator provides data and diagnostic logging with sufficient memory to store data for over a year. The interrogator software also includes various trending/charting features enabling simple system and well commissioning.

Technical Specifications	
Description	**Specification**
Interrogator Model	Gen 3
Technology Supported	SureVIEW PT gauges
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	2U
Dimensions	19 in. x 3.47 in. x 19.8 in. (483mm x 88mm x 503mm)
Weight	20.3 lbs / 9.2 kg
Certifications	CE
Supply Voltage	24VDC
Power Consumption	Up to 35 Watts
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Humidity	5-75% RH (non-condensing)
Data Interface Connection	Ethernet or Serial RS-485
Internal Data Storage	64GB (> 1 year log capacity)
Fiber Connections	LC/APC (F3000)

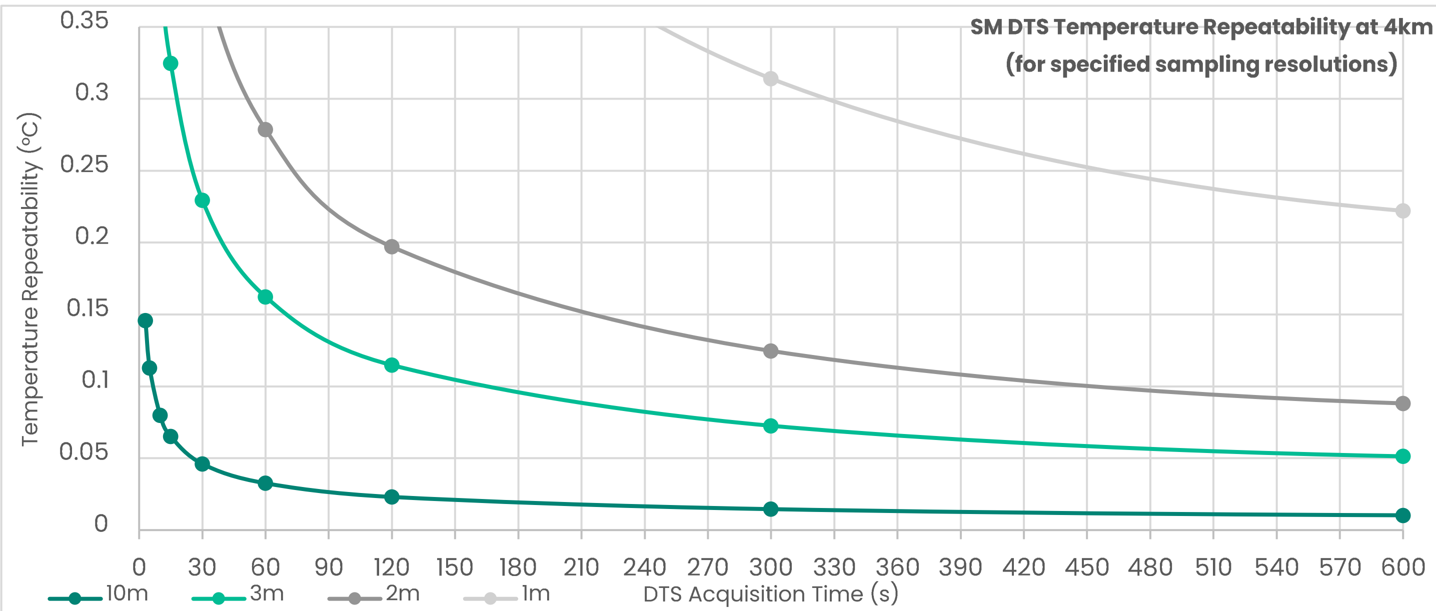
Baker Hughes

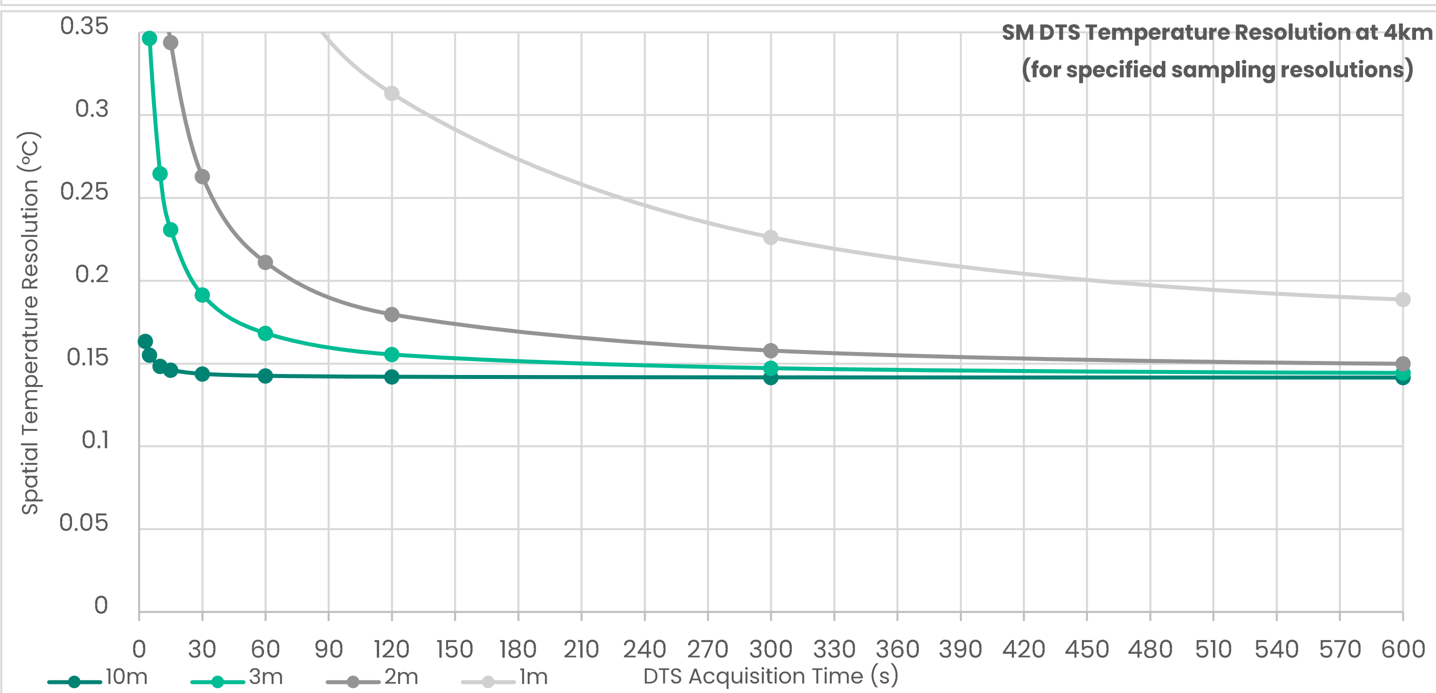
SureVIEW™ DTS Interrogator

The SureVIEW™ DTS fiber optic interrogator provides convenient multi-well performance monitoring with continuous, rapidly updating temperature profiles along the length of the completion. The interrogator is designed to provide highly accurate temperature data from a single SM fiber, which reduces cost by eliminating the need for dual-ended fibre configurations.

SureVIEW™ DTS Surface Interrogator Specifications	
Description	**Value**
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 µm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW™ DTS Surface Interrogator Specifications	
Description	**Value**
Voltage Input	22-27 VDC
Differential Attenuation Compensation	Yes
Fiber Configuration	Single-Ended or J-Type
Absolute Temperature Accuracy (°C)	±2 (worst-case, rapid cycling over full operating range)
Operating temperature (°C)	0 to 40
Storage temperature (°C)	-40 to 80
Operating relative humidity (%)	5 to 95
Sensing temperature Range (°C)	0 to 300





Call your local Baker Hughes representative today to learn more about how SureVIEW monitoring systems can reliably enhance your production operations.

bakerhughes.com

Baker Hughes

SureVIEW sDAS

Fiber optic acoustic monitoring for subsea wells

The **SureVIEW™ seismic distributed acoustic sensing (sDAS) interrogator** offers all of the benefits of fiber optic acoustic monitoring—from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring—combined in a single interrogator unit.

Unlike other DAS interrogators, SureVIEW sDAS utilizes Baker Hughes SureVIEW **CoreBright™ optical fiber**, a proprietary fiber specifically designed for durable oil and gas deployments. This allows operators to monitor high value assets through the life of the well, from well-centric to reservoir focused scales.

The combination of SureVIEW sDAS with **CoreBright™ enhanced backscatter fiber (EBF)** permits the acquisition of data in subsea wells located long distances from the data acquisition unit. Testing shows that a vertical seismic profile (VSP) can be acquired from the shore, or host facility up to 50 miles (80 km) away.

The SureVIEW sDAS interrogator can output various formats, suitable for various applications, and has the ability to break down the raw data, as well as compute attributes on-the-fly (frequency-band energy, individual spectra). It can also record data either in continuous or trigger mode, and is equipped with an independent global positioning system (GPS)–thus permitting clock synchronization and clock drift control.

SureVIEW sDAS delivers high fidelity data readily available to processing and answer solution teams. The system may also be remotely operated through a connection to the Baker Hughes cloud services, and is compliant with HDF5 data format.

From seismic processing, reservoir characterization, data visualization and advanced modelling and interpretation, we deliver answers, not just data.

Contact a Baker Hughes representative today to learn how we can help you take energy forward.

Applications

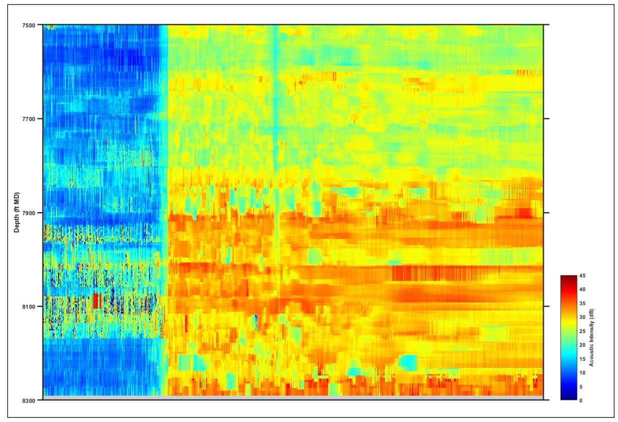
- Subsea and land wells
- Permanent reservoir monitoring
  - Flow monitoring
  - Sand detection
  - Leak detection
  - Stimulation optimization
  - Microseismic monitoring
  - Vertical seismic profiling (VSP)

Benefits

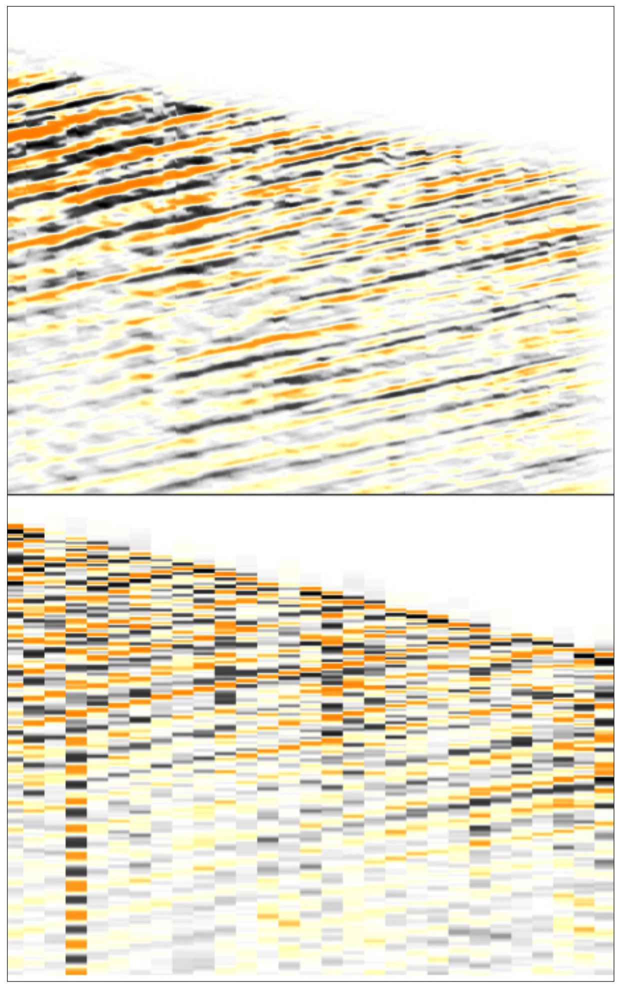
- Delivers an integrated solution from subsurface equipment to remote visualization and analytics that saves time and cost
- Simplifies handling and management of data reducing IT integration time
- Offers a better understanding of the wellbore/reservoir enabling sustained and/or incremental production of your asset
- Enables understanding of the entire completion when coupled with Baker Hughes SureCONNECT™ downhole intelligent wet-connect system
- Provides a long-term well and reservoir monitoring solution while reducing operating costs by minimizing/eliminating unnecessary interventions

Technical Specifications

Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110-240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC
Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 $\mu\varepsilon$



This Distributed Acoustic Sensing (DAS) Frequency Band Energy (FBE) shows acoustic energy acquired in a multi-zone injection well. This information was used to estimate zonal flow allocation.



This comparison shows the upgoing wavefield of a vertical seismic profile (VSP) acquired above the well with a wireline tool (bottom) versus 43 miles (69 km) away from the wellhead (top) with sDAS, and CoreBright™ as lead-in fiber, a 3dB attenuation and a subsea amplifier, and CoreBright™ EBF inside the well.

Baker Hughes

APPENDIX G: EMERGENCY OPERATIONS

Appendix G-1	Risk Assessment Table
Appendix G-2	FEMA Flood Zone Hazards Map
Appendix G-3	Resources and Infrastructure Map

APPENDICES G-1 TO G-3 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX H: PLUGGING AND ABANDONMENT

APPENDICES H-1 TO H-7 ARE

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX I: FAULT SLIP POTENTIAL ANALYSIS

Harvest Bend CCS LLC

WC IW-A No. 001

WC IW-B No. 001

WC IW-B No. 002

Fault Slip Potential Analysis

Iberville Parish, LA

July 18, 2023

LONQUIST SEQUESTRATION LLC

Table of Contents

FIGURES

TABLES

1.0 OVERVIEW

The Fault-Slip Potential (FSP) tool is a simple, coupled reservoir geomechanics model that approximates the cumulative probability of a known fault to exceed [redacted] slip criteria caused by fluid injection. [redacted]. The FSP program integrates fault location and orientation, location of injection well(s), rates, reservoir characteristics, regional stress direction and magnitude, and natural pore pressure. The FSP is considered a screening tool designed to assist operators and regulators in making educated decisions when designing injection operations [redacted]. As additional reservoir data is collected, initial screening models will be updated and induced seismicity potential will be further evaluated.

The following report prepared by Lonquist & Co., LLC discusses the FSP analysis requested on behalf of Harvest Bend CCS LLC (Harvest Bend CCS) for the White Castle CO_2 Sequestration (White Castle) Project, including the WC IW-A No. 001, WC IW-B No. 001, and WC IW-B No. 002 proposed Class VI injection wells. The analysis was performed in accordance with requirements in Statewide Order (SWO) 29-N-6 **§3607.C.2.c** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(3)(v)**]. The FSP modeling used [redacted] software.

2.0 KEY ELEMENTS

The FSP modeling's use of [redacted] software included the following elements.

a. Model area of interest (AOI) with a radius[1] 5.6 km (3.5 mi).
b. Model input includes known subsurface fault locations with faults segmented to a maximum length of 3 km.
c. One or two models were run for each well and known faults at critical depth intervals (six models in total) with injection terminating after 20 total years of injection (Figure 1).
    i. First model run includes all permitted injection well volumes (obtained from DrillingInfo) in the AOI plus the proposed injection well.
    ii. Second model run includes only the proposed injection well.

3.0 Executive Summary

The FSP integrated all the faults, some extending outside the AOI, covering an area of 135 km^2. Figure 1 highlights the location of WC IW-A No. 001, WC IW-B No. 001, WC IW-B No. 002, existing and historical injection wells, and faults in the AOI and around Iberville Parish, Louisiana. The WC IW-A No. 001 permit application targets [redacted] sands at a true vertical depth (TVD) of [redacted], with a 20-year injection duration.

1. The FSP seismicity review radius was established based on local geology and the model extent of the plume.

The WC IW-B No. 001 permit application targets [redacted] sands at a TVD of [redacted], with a 20-year duration. The WC IW-B No. 002 permit application targets [redacted] sands at a TVD of [redacted], with a 20-year duration.

The FSP models apply [redacted] level fault traces derived from 3D seismic interpretation. None of the FSP models run utilizing the fault traces, proposed injection interval reservoir properties, and nearby fluid injection data, demonstrated evidence that the faults would slip.

[redacted]

Figure 1 – FSP Analysis, Injection Wells, and Faults

The [redacted] paper and open data were used to calculate the relative stress magnitude $|A_{\Phi}|$, with a baseline value of [redacted]. The [redacted] provides a worldwide account of the current stress field in the Earth's crust. Based on the publication by [redacted] as well as publicly available data, the mean $|S_{Hmax}|$ of [redacted] was computed and used for this investigation.

[redacted]

Figure 2 – FSP A_{Φ} and S_{Hmax} Stress Parameters

4.0 FSP Analysis MODEL 1 – [redacted] Faults and WC IW-B No. 002

The [redacted] software [redacted] used for the analysis also included:

- Fluid injection history from DrillingInfo within the 5.6 km AOI (no injection wells recorded).
- Proposed rate (692,000 reservoir barrels per month, which equates to 1 million metric tons per year) for WC IW-B No. 002 well for 20 years.
- Wells WC IW-A No. 001 and WC IW-B No. 001 do not inject into [redacted] sandstones.
- Wells WC IW-B No. 001 and WC IW-B No. 002 are [redacted]
- Reservoir parameters and average depths of the proposed injection intervals.
- Local stress information and pressure gradients.
- Known fault locations within AOI, with faults segmented to a maximum length of 3 km.

Only one FSP model was run per fault with respect to WC IW-B No. 002, as no other injection wells were reported, including analysis after 20 years of injection. Model 1 analyzes the [redacted] shale and intra-reservoir [redacted] shale fault traces within the AOI. [redacted] shale is the lower confining interval for WC IW-B No. 002. [redacted].

Figure 1 showed the location of existing fluid injection wells (none) and the proposed wells in relation to the fault documented within the AOI. The lower confining shale ([redacted]) and intra-reservoir shale ([redacted]) fault traces utilized in Model 1 are shown in Figure 5. Table 1 is the general input parameters assumed and utilized the FSP Models. Table 2 and Figures 3 to 22 illustrate the fault traces used as input and the FSP results tabs for Model 1.

Table 1 – General Assumed Parameters

Data	WC IW-A No. 001	WC IW-B No. 001	WC IW-B No. 002
Proposed Rate (bbl/Month)	692,000	692,000	692,000
Total Injection Time (Years)	20	20	20
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

* AΦ = relative stress magnitude

Table 2 – Reservoir Parameters for Models 1

Data	WC IW-A No. 001	WC IW-B No. 001	WC IW-B No. 002
Proposed Rate (bbl/month)	-	-	692,000
Time (years)	-	-	20
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
Net Aquifer			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Figure 3 – FSP [redacted] Fault Input (Partial View) for Model 1

[redacted]

Figure 4 – FSP Injection Wells (3) Input for Model 1

[redacted]

Figure 5 – [redacted] Fault Segments (54) Used in FSP Analysis Model 1

The Model 1 inputs show the location of the wells and [redacted] faults segments within the FSP model (Figure 6).

[redacted]

Figure 6 – FSP Model 1 Input: 3 Injectors and 54 [redacted] Fault Segments

The graphs in the middle-left section (Figure 7) demonstrate stress and pore pressure conditions at the specified depth for each fault segment. Faults are colored by their pore pressure to slip according to the color scale. The top-right image shows a Mohr diagram, with shear stress on the vertical axis and effective compressive stress on the horizontal axis. The red line is a frictional slip line. The lower-right image represents a colored composite stereonet representing faults' normal orientation for all possible fault orientations based on the color scale. The arrows in gray indicate the azimuth of the greatest horizontal compression [redacted].

[redacted]

Figure 7 – FSP Geomechanics Tab, Models 1

[redacted]

Figure 8 – Input for Probabilistic Geomechanics Tab

The Probabilistic Geomechanics model (Figure 9) is similar to model the Deterministic GeoMechanics tab. However, a Monte Carlo Simulation is performed in the Probabilistic Geomechanics model, in which the uncertainties of each parameter, represented by a uniform distribution function, are sampled at random. Figure 8 showed the assumed uncertainty inputs used for the Probabilistic Geomechanics model.

[redacted]

Figure 9 – FSP Probabilistic Geomechanics Tab, Models 1

The Hydrology model calculates the radially symmetric pressure profile for each injection well at a given time. Figure 10 shows the initial conditions for pore pressure before the proposed well is completed.

[redacted]

Figure 10 – Model 1 FSP Hydrology Tab, Before WC IW-B No. 002 Proposed Completion

The projected pressure change is shown in Figure 11 from each injector after injections are completed.

[redacted]

Figure 11 – Model 1 FSP Hydrology Tab, Post-Injection

The projected pressure change is shown in Figure 12 from each injector 20 years post-injections.

[redacted]

Figure 12 – Model 1 FSP Hydrology Tab, 20 Years Post-Injection

Probabilistic Hydrology analysis input (Figure 13) was utilized for this internal radial flow-based model**.**

[redacted]

Figure 13 – Probabilistic Hydrology Tab Parameters, Model 1

The Probabilistic Hydrology tabs combine hydrology with the Probabilistic Geomechanical cumulative distribution function (CDF) of the pore pressure to slip. The results in Figure 14 establish the initial conditions before WC IW-B No. 002.

[redacted]

Figure 14 – Model 1 Probabilistic Hydrology Tab, Before Proposed Completion

The results shown in Figure 15 establish the conditions post-injection. This model only includes the proposed injector, held constant at the permitted rate.

[redacted]

Figure 15 – Model 1 Probabilistic Hydrology Tab, Post-Injection

The results shown in Figure 16 establish the conditions 20 years post-injection.

[redacted]

Figure 16 – Model 1 Probabilistic Hydrology Tab, 20 Years Post-Injection

The following pages show the integrated tabs with combined results of probabilistic geomechanics and hydrology models run for all 54 fault segments.

The starting conditions prior to the WC IW-B No. 002 well are depicted in Figure 17 for each fault segment's pore pressure change (psi).

[redacted]

Figure 17 – Model 1 Integrated Tab, Pore Pressure Before Proposed Completion

The starting conditions prior to the WC IW-B No. 002 well are depicted in Figure 18 for each fault segment's fault slip potential (%).

[redacted]

Figure 18 – Model 1 Integrated Tab, Fault Slip Potential Before Proposed Completion

The forecast conditions for WC IW-B No. 002 well post-injection are depicted in Figure 19 for each fault segment's pore pressure change (psi).

[redacted]

Figure 19 – Model 1 Integrated Tab, Pore Pressure Post-Injection

The forecast conditions for WC IW-B No. 002 well post-injection are depicted in Figure 20 for each fault segment's fault slip potential (%).

[redacted]

Figure 20 – Model 1 Integrated Tab, FSP Post-Injection

Figure 21 depicts the conditions 20 years post-injection for WC IW-B No. 002 well and the pore pressure change (psi) for each fault segment.

[redacted]

Figure 21 – Model 1 Integrated Tab, Pore Pressure Change (psi) After 20 Years

Figure 22 depicts the conditions 20 years post-injection for WC IW-B No. 002 well and the fault slip potential (%) for each fault segment.

[redacted]

Figure 22 – Model 1 Integrated Tab, Fault Slip Potential After 20 Years

5.0 FSP Analysis **MODEL 2** – [redacted] Faults and WC IW-B No. 002

Model 2 analyzes the [redacted] fault traces within the AOI as the [redacted] is the upper confining interval for WC IW-B No. 002 injection. The methodology and input parameters for injection wells, stress regime, reservoir parameters, and probabilistic ranges are consistent with Model 1. However, fault segments are different. Figures 23 to 39 illustrate the fault traces used as input, as well as the FSP results tabs.

[redacted]

Figure 23 – FSP [redacted] Fault Input (Partial View) for Model 2

[redacted]

Figure 24 – [redacted] Fault Segments (31) Used in FSP Analysis Model 2

The Model 2 Input Tab shows the location of the proposed well and [redacted] faults segments within the FSP model (Figure 25).

[redacted]

Figure 25 – FSP Model 2 Input: 3 Injectors and 31 [redacted] Fault Segments

Figure 26 shows the pore pressure (psi) to slip for each fault segment, with the direction of S_{Hmax}, and a Mohr diagram with frictional slip line shown in red. Faults are colored by their pore pressure to slip according to the color scale.

[redacted]

Figure 26 – FSP Geomechanics Tab, Model 2

A Monte Carlo Simulation is performed in the Probabilistic Geomechanics model, in which the uncertainties of each parameter, represented by a uniform distribution function, are sampled at random. Figure 27 shows the assumed uncertainty inputs used for the Probabilistic Geomechanics model.

[redacted]

Figure 27 – FSP Probabilistic Geomechanics Tab, Model 2

Model 2 calculates the radially symmetric pressure profile for each injection well at a given time. Figure 28 shows the initial conditions for pore pressure before WC IW-B No. 002 well is completed.

[redacted]

Figure 28 – Model 2 FSP Hydrology Tab, Before Proposed Completion

The projected pressure change is shown in Figure 29 from each injector post-injection.

[redacted]

Figure 29 – Model 2 FSP Hydrology Tab, Post-Injection

The projected pressure change is shown in Figure 30 from each injector 20 years post-injections.

[redacted]

Figure 30 – Model 2 FSP Hydrology Tab, 20 Years Post-Injection

The Probabilistic Hydrology tabs combine hydrology with the Probabilistic Geomechanical CDF of the pore pressure to slip. The results (Figure 31) establish the initial conditions before WC IW-B No. 002.

[redacted]

Figure 31 – Model 2 Probabilistic Hydrology Tab, Before Proposed Completion

The results shown in Figure 32 establish the conditions post-injection and only include the proposed injector, held constant at the permitted rate.

[redacted]

Figure 32 – Model 2 Probabilistic Hydrology Tab, Post-Injection

The results shown in Figure 33 establish the conditions 20 years post-injection.

[redacted]

Figure 33 – Model 2 Probabilistic Hydrology Tab, 20 Years Post-Injection

The integrated tabs below combined results of probabilistic geomechanics and hydrology models run for all the fault segments. The starting conditions prior to WC IW-B No. 002 are depicted in Figure 34 for each fault segment's pore pressure change (psi).

[redacted]

Figure 34 – Model 2 Integrated Tab, Pore Pressure Before Proposed Completion

Starting conditions prior to WC IW-B No. 002 fault segment's fault slip potential (%) are shown in Figure 35.

[redacted]

Figure 35 – Model 2 Integrated Tab, Fault Slip Potential Before Proposed Completion

The forecast conditions post-injections are depicted in Figure 36 for each fault segment's pore pressure change (psi).

[redacted]

Figure 36 – Model 2 Integrated Tab, Pore Pressure Post-Injection

The forecast conditions post-injections are depicted in Figure 37 for each fault segment's fault slip potential (%).

[redacted]

Figure 37 – Model 2 Integrated Tab, FSP Post-Injection

Figure 38 depicts the conditions 20 years after injection and the pore pressure change (psi) for each fault segment.

[redacted]

Figure 38 – Model 2 Integrated Tab, Pore Pressure Change (psi) After 20 Years

Figure 39 depicts the conditions 20 years after injection and the fault slip potential (%) for each fault segment.

[redacted]

Figure 39 – Model 2 Integrated Tab, Fault Slip Potential After 20 Years

6.0 FSP Analysis **MODEL 3** – [redacted] Faults, WC IW-A No. 001 and WC IW-B No. 001

The analysis includes:

- Fluid injection history within the 5.6 km AOI (no injection wells recorded).
- Proposed rate (692,000 reservoir barrels per month) for the WC IW-A No. 001 and WC IW-B No. 001 proposed Class VI injection wells for a total of 9.5 and nine years, respectively, as currently planned.
- [redacted]
- Reservoir parameters and average depths of the proposed injection interval.
- Local stress information and pressure gradients.
- Known fault locations within AOI, with faults segmented to a maximum length of 3 km.

Two FSP models were run per fault, including analysis after nine years of injection.

- First model run includes all injection well volumes for both proposed injection wells in the AOI, as no other injection wells were found in DrillingInfo.
- Second model run evaluates each proposed [redacted] injection well separately.

In summary, the proposed fluid injection does not significantly increase the risk that these faults will slip.

Models 3 and 4 analyzed the [redacted] shale (lower confining interval) faults for the WC IW-A No. 001 and WC IW-B No. 001 proposed wells. The general assumed parameters (Table 1), reservoir parameters (Table 3) and faults traces in Figure 42 were utilized for Models 3 and 4. Figures 40 to 64 illustrate the fault traces used as input and the FSP results tabs for Model 3.

Table 3 – Reservoir Parameters Model 3 and 4

Data	WC IW-A No. 001	WC IW-B No. 001	WC IW-B No. 002
Proposed Rate (bbl/month)	692,000	692,000	-
Time (years)	9.5	9	-
[redacted]	[redacted]	[redacted]	-
[redacted]	[redacted]	[redacted]	-
[redacted]	[redacted]	[redacted]	-
Net Aquifer			
[redacted]	[redacted]	[redacted]	-
[redacted]	[redacted]	[redacted]	-
[redacted]	[redacted]	[redacted]	-

[redacted]

Figure 40 – FSP Injection Wells (3) Input for Model 3

[redacted]

Figure 41 – FSP [redacted] Fault Input (Partial View) for Models 3 and 4

[redacted]

Figure 42 – [redacted] Fault Segments (20) Used in FSP Analysis Models 3 and 4

The Model 3 inputs (Figure 43) show the location of the wells and [redacted] faults segments within the FSP model.

[redacted]

Figure 43 – FSP Model 3 Input: 3 Injectors and 20 [redacted] Fault Segments

Figure 44 shows the pore pressure (psi) to slip for each fault segment, with the direction of S_{Hmax}, and a Mohr diagram with frictional slip line shown in red. Faults are colored by their pore pressure to slip according to the color scale.

[redacted]

Figure 44 – FSP Geomechanics Tab, Models 3 and 4 (WC IW-A No. 001)

[redacted]

Figure 45 – FSP Geomechanics Tab, Models 3 and 4 (WC IW-B No. 001)

[redacted]

Figure 46 – Input for Probabilistic Geomechanics Tab

A Monte Carlo Simulation is performed in the Probabilistic Geomechanics model, in which the uncertainties of each parameter (Figure 46), represented by a uniform distribution function, are sampled at random as shown in Figure 47.

[redacted]

Figure 47 – FSP Probabilistic Geomechanics Tab, Models 3 and 4

Model 3 calculates the radially symmetric pressure profile for each injection well at a given time. Figure 48 shows the initial conditions for pore pressure before the proposed wells, WC IW-A No. 001 and WC IW-B No. 001, are completed.

[redacted]

Figure 48 – Model 3 FSP Hydrology Tab, Before Proposed Completion

Figure 49 shows projected pressure changes away from each injector after the [redacted] Sand injection is completed.

[redacted]

Figure 49 – Model 3 FSP Hydrology Tab, After [redacted] Injection

The projected pressure change is shown in Figure 50 from each injector post-injection.

[redacted]

Figure 50 – Model 3 FSP Hydrology Tab, Post-Injection

The projected pressure change is shown in Figure 51 from each injector 20 years post-injections.

[redacted]

Figure 51 – Model 3 FSP Hydrology Tab, 20 Years Post-Injection

Probabilistic analysis input was utilized for this internal radial flow-based model (Figure 52).

[redacted]

Figure 52 – Probabilistic Hydrology Tab, Parameters Models 3 and 4

The Probabilistic Hydrology tabs combine hydrology with the Probabilistic Geomechanical CDF of the pore pressure to slip. The results shown in Figure 53 establish the initial conditions before the WC IW-A No. 001 and WC IW-B No. 001 wells.

[redacted]

Figure 53 – Model 3 Probabilistic Hydrology Tab, Before Proposed Completion

The results shown in Figure 54 establish the conditions after the [redacted] sands injection for WC IW-A No. 001 and WC IW-B No. 001 are completed.

[redacted]

Figure 54 – Model 3 Probabilistic Hydrology Tab, After [redacted] Sand Injection

The results shown in Figure 55 establish the conditions post injection.

[redacted]

Figure 55 – Model 3 Probabilistic Hydrology Tab, Post-Injection

The results shown in Figure 56 establish the conditions 20 years post-injection.

[redacted]

Figure 56 – Model 3 Probabilistic Hydrology Tab, 20 Years Post-Injection

The following pages show the integrated tabs with combined results of probabilistic geomechanics and hydrology models run for all 20 [redacted] fault segments.

The starting conditions prior to the WC IW-A No. 001 and WC IW-B No. 001 wells are depicted in Figure 57 for each fault segment's pore pressure change (psi).

[redacted]

Figure 57 – Model 3 Integrated Tab, Pore Pressure Before Proposed Completion

The starting conditions prior to the WC IW-A No. 001 and WC IW-B No. 001 wells are depicted in Figure 58 for each fault segment's fault slip potential (%).

[redacted]

Figure 58 – Model 3 Integrated Tab, Fault Slip Potential Before Proposed Completion

The conditions following [redacted] Sand Injection are depicted in Figure 59, along with the pore pressure change (psi) for each fault section.

[redacted]

Figure 59 – Model 3 Integrated Tab, Pore Pressure After [redacted] Sand Injection

The conditions following [redacted] Sand Injection are depicted in Figure 60, along with the fault slip potential (%) for each fault section.

[redacted]

Figure 60 – Model 3 Integrated Tab, FSP After [redacted] Sand Injection

The forecasted conditions post-injections for WC IW-A No. 001 and WC IW-B No. 001 are depicted in Figure 61 for each fault segment's pore pressure change (psi).

[redacted]

Figure 61 – Model 3 Integrated Tab, Pore Pressure Post-Injection

The forecasted conditions post-injection for the WC IW-A No. 001 and WC IW-B No. 001 wells are depicted in Figure 62 for each fault segment's fault slip potential (%).

[redacted]

Figure 62 – Model 3 Integrated Tab, FSP Post-Injection

Figure 63 depicts the conditions 20 years after injection and the pore pressure change (psi) for each fault segment.

[redacted]

Figure 63 – Model 3 Integrated Tab, Pore Pressure (psi) Change After 20 Years

Figure 64 depicts the conditions 20 years after injection and the fault slip potential (%) for each fault segment.

[redacted]

Figure 64 – Model 3 Integrated Tab, Fault Slip Potential After 20 Years

7.0 FSP Analysis **MODEL 4** – [redacted] Faults and Single Injection Well Scenarios

Model 4 evaluates each of the proposed injection wells (WC IW-A No. 001 and WC IW-B No. 001) separately, with the proposed rate (maximum injection rate of 692,000 barrels per month) and a 9.5- and 9-year injection period, respectively, as currently planned, into the [redacted] sands.

All other parameters remain identical to Model 3, such as faults, stress regime, reservoir, and probabilistic parameters. Below is the only change regarding Model 4 regarding injector data. Figures 65 to 78 illustrate the fault traces used as input, as well as the FSP results tabs.

[redacted]

Figure 65 – FSP Injection Well Input for Model 4

The Model 4 inputs show the location of the wells and [redacted] faults segments within the FSP model (Figure 66).

[redacted]

Figure 66 – FSP Model 4 Input: 1 Injector and 20 [redacted] Fault Segments

The Geomechanics and Probabilistic Geomechanics tabs are the same as Model 3 (pages 51 to 53).

Model 4 calculates the radially symmetric pressure profile for each injection well at a given time. Figure 67 shows the initial conditions for pore pressure before the proposed wells, WC IW-A No. 001 and WC IW-B No. 001, are completed.

[redacted]

Figure 67 – Model 4 Hydrology Tab, Before Proposed Injection

Figure 68 shows projected pressure changes away from each injector after the [redacted] Sand injection is completed (single injection well scenarios).

[redacted]

Figure 68 – Model 4 Hydrology Tab, After [redacted] Sand Injection

The projected pressure change shown in Figure 69 is from each injector 20 years post-injections (single injection well scenarios).

[redacted]

Figure 69 – Model 4 Hydrology Tab, 20 Years Post-Injection

The Probabilistic Hydrology tabs combine hydrology with the Probabilistic Geomechanical CDF of the pore pressure to slip. The results (Figure 70) establish the initial conditions before the WC IW-A No. 001 or WC IW-B No. 001 wells are completed.

[redacted]

Figure 70 – Model 4 Probabilistic Hydrology Tab, Before Proposed Injection

The results shown in Figure 71 establish the conditions after the [redacted] sands injection for WC IW-A No. 001 or WC IW-B No. 001 are completed.

[redacted]

Figure 71 – Model 4 Probabilistic Hydrology Tab, After [redacted] Sand Injection

The results shown in Figure 72 establish the conditions 20 years post-injection (single injection well scenarios).

[redacted]

Figure 72 – Model 4 Probabilistic Hydrology Tab, 20 Years Post-Injection

The following pages show the integrated tabs with combined results of probabilistic geomechanics and hydrology models run for all 20 [redacted] fault segments.

The starting conditions prior to the WC IW-A No. 001 or WC IW-B No. 001 wells are depicted in Figure 73 for each fault segment's pore pressure change (psi).

[redacted]

Figure 73 – Model 4 Integrated Tab, Pore Pressure Before Proposed Injection

The starting conditions prior to the WC IW-A No. 001 or WC IW-B No. 001 wells are depicted in Figure 74 for each fault segment's fault slip potential (%).

[redacted]

Figure 74 – Model 4 Integrated Tab, Fault Slip Potential Before Proposed Injection

The conditions following the [redacted] Sand Injection are depicted in Figure 75, along with the pore pressure change (psi) for each fault section (single injection well scenarios).

[redacted]

Figure 75 – Model 4 Integrated Tab, Pore Pressure After [redacted] Sand Injection

The conditions following the [redacted] Sand Injection are depicted in Figure 76, along with the fault slip potential (%) for each fault section (single injection well scenarios).

[redacted]

Figure 76 – Model 4 Integrated Tab, FSP After [redacted] Sand Injection

The forecasted conditions post-injection for WC IW-A No. 001 or WC IW-B No. 001 are depicted in Figure 77 for each fault segment's pore pressure change (psi).

[redacted]

Figure 77 – Model 4 Integrated Tab, Pore Pressure (psi) Change After 20 Years

The forecasted conditions post-injection for WC IW-A No. 001 or WC IW-B No. 001 wells are depicted in Figure 78 for each fault segment's fault slip potential (%).

[redacted]

Figure 78 – Model 4 Integrated Tab, Fault Slip Potential After 20 Years

8.0 FSP Analysis MODEL 5 – [redacted] Faults, WC IW-A No. 001 and WC IW-B No. 001

Models 5 and 6 analyze the upper confining interval [redacted] fault traces within the AOI. The methodology is the same as the previous model and input parameters for stress regime, and probabilistic ranges are consistent with Model 3. However, the fault segments, reservoir parameters, and injection interval utilized are shown in Table 4. Injections of 10.5 and 11 years were modeled into the injection interval ([redacted] sands) as currently proposed for WC IW-A No. 001 and WC IW-B No. 001, respectively. Figures 79 to 103 illustrate the fault traces used as input, as well as the FSP results tabs.

Table 4 – Reservoir Parameters Model 5 and 6

Data	WC IW-A No. 001	WC IW-B No. 001	WC IW-B No. 002
Proposed Rate (bbl/month)	692,000	692,000	-
Time (years)	10.5	11	-
Reference Depth for Calculations (ft)	[redacted]	[redacted]	-
Density Fluid (kg/m^3)	[redacted]	[redacted]	-
Dynamic Viscosity (Pa.s)	[redacted]	[redacted]	-
Net Aquifer			
Thickness (ft)	[redacted]	[redacted]	-
Porosity (%)	[redacted]	[redacted]	-
Permeability (mD)	[redacted]	[redacted]	-

[redacted]

Figure 79 – FSP Injection Wells (3) Input for Models 5

[redacted]

Figure 80 – FSP [redacted] Fault Input for Models 5 and 6

[redacted]

Figure 81 – [redacted] fault segments (31) used in FSP Analysis Models 5 and 6

The Model 5 inputs show the location of the wells, with the [redacted] faults segments within the FSP model (Figure 82).

[redacted]

Figure 82 – FSP Model 5 Input: 3 Injectors and 31 [redacted] Fault Segments

Figures 83 and 84 demonstrate pore pressure (psi) to slip for each fault segment, direction of S_{Hmax}, and a Mohr diagram with the frictional slip line shown in red. Faults are colored by their horizontal distance to slip according to the color scale.

[redacted]

Figure 83 – FSP Geomechanics Tab, Models 5 and 6 (WC IW-A No. 001)

[redacted]

Figure 84 – FSP Geomechanics Tab, Models 5 and 6 (WC IW-B No. 001)

[redacted]

Figure 85 – Input For Probabilistic Geomechanics Tab

Monte Carlo Simulation is performed in the Probabilistic Geomechanics model, in which the uncertainties of each parameter (Figure 85), represented by a uniform distribution function, are sampled at random as shown in Figure 86.

[redacted]

Figure 86 – FSP Probabilistic Geomechanics Tab, Models 5 and 6

Model 5 calculates the radially symmetric pressure profile for each injection well at a given time. Figure 87 shows the initial conditions for pressure changes away from each injector at the beginning of [redacted] injection.

[redacted]

Figure 87 – Model 5 FSP Hydrology Tab, [redacted] Injection Conditions

Figure 88 displays pressure changes away from each injector WC IW-A No. 001 and WC IW-B No. 001 at the beginning of the [redacted] injection.

[redacted]

Figure 88 – Model 5 FSP Hydrology Tab, [redacted] Injection Conditions

The anticipated pressure change is shown in Figure 89, post-injection for each injector.

[redacted]

Figure 89 – Model 5 FSP Hydrology Tab, Post-Injection

The anticipated pressure change is shown in Figure 90, 20-years post-injection for each injector.

[redacted]

Figure 90 – Model 5 FSP Hydrology Tab, 20 Years Post-Injection

Probabilistic analysis input utilized for this internal radial flow-based model is displayed in Figure 91.

[redacted]

Figure 91 – Probabilistic Hydrology Tab Parameters Models 5 and 6

The Probabilistic Hydrology tabs combine hydrology with the Probabilistic Geomechanical CDF of the pore pressure to slip. The results displayed in Figure 92 establish the [redacted] injection conditions for the WC IW-A No. 001 and WC IW-B No. 001 wells.

[redacted]

Figure 92 – Model 5 Probabilistic Hydrology Tab, [redacted] Injection Conditions

The results shown in Figure 93 establish the [redacted] injection conditions for the IW-A No. 001 and WC IW-B No. 001 wells.

[redacted]

Figure 93 – Model 3 Probabilistic Hydrology Tab, [redacted] Injection Conditions

The results shown in Figure 94 establish the conditions after [redacted] sands injection for WC IW-A No. 001 and WC IW-B No. 001 are completed.

[redacted]

Figure 94 – Model 5 Probabilistic Hydrology, Post-Injection

The results shown in Figure 95 establish the conditions 20 years post-injection.

[redacted]

Figure 95 – Model 5 Probabilistic Hydrology Tab, 20 Years Post-Injection

The following pages show the integrated tabs, which combined results of probabilistic geomechanics and hydrology models run for all 31 [redacted] fault segments.

The early conditions for WC IW-A No. 001 and WC IW-B No. 001 [redacted] injection are depicted in Figure 96 for each fault segment's pore pressure change (psi).

[redacted]

Figure 96 – Model 5 Integrated Tab, Pore Pressure [redacted] Injection Conditions

The early conditions for WC IW-A No. 001 and WC IW-B No. 001 [redacted] injection are depicted in Figure 97 for each fault segment's Fault Slip Potential (%).

[redacted]

Figure 97 – Model 5 Integrated Tab, Fault Slip Potential [redacted] Injection Conditions

The early conditions for WC IW-A No. 001 and WC IW-B No. 001 [redacted] injection are depicted in Figure 98 for each fault segment's pore pressure change (psi).

[redacted]

Figure 98 – Model 5 Integrated Tab, Pore Pressure [redacted] Injection Conditions

The early conditions for WC IW-A No. 001 and WC IW-B No. 001 [redacted] injection are depicted in Figure 99 for each fault segment's fault slip potential (%).

[redacted]

Figure 99 – Model 5 Integrated Tab, FSP [redacted] Injection Conditions

The conditions following [redacted] sand injection are depicted in Figure 100, along with the pore pressure change (psi) for each fault section.

[redacted]

Figure 100 – Model 5 Integrated Tab, Pore Pressure Post-Injection

The conditions following [redacted] Sand Injection are depicted in Figure 101, along with the fault slip potential (%) for each fault section.

[redacted]

Figure 101 – Model 5 Integrated Tab, FSP Post-Injection

Figure 102 depicts the condition 20 years after injection and the pore pressure change (psi) for each fault segment.

[redacted]

Figure 102 – Model 5 Integrated Tab, Pore Pressure (psi) Change After 20 Years

Figure 103 depicts the conditions 20 years after injection and the fault slip potential (%) for each fault segment.

[redacted]

Figure 103 – Model 5 Integrated Tab, Fault Slip Potential After 20 Years

9.0 FSP Analysis **MODEL 6** – [redacted] Fault and Single Injection Well Scenarios

Model 6 evaluates each of the proposed injection wells (WC IW-A No. 001 and WC IW-B No. 001) separately with the proposed rate (maximum injection rate of 692,000 barrels per month). Injections for 10.5 and 11 years were modeled into the injection interval ([redacted] sands) as currently proposed for WC IW-A No. 001 and WC IW-B No. 001, respectively.

All other parameters remain identical to Model 5 (i.e., faults, stress regime, reservoir, and probabilistic parameters). The following is the only change regarding Model 6, with Figures 104 through 117 illustrating the fault traces used as input, plus the FSP results tabs.

[redacted]

Figure 104 – FSP Injection Well Input for Models 6

The Model 6 inputs show the location of the wells, with the [redacted] faults segments within the FSP model (Figure 105).

[redacted]

Figure 105 – FSP Model 6 Input: 1 Injector and 31 [redacted] Fault Segments

The Geomechanics and Probabilistic Geomechanics tabs are the same as Model 5 (pages 90-93).

Model 6 calculates the radially symmetric pressure profile for each injection well at a given time. Figure 106 shows the initial conditions for pressure changes away from each injector at the beginning of [redacted] injection.

[redacted]

Figure 106 – Model 6 Hydrology Tab, Early Injection Conditions

The anticipated pressure change is shown in Figure 107, post-injection for each injector.

[redacted]

Figure 107 – Model 6 Hydrology Tab, Post-Injection

The anticipated pressure change is shown Figure 108, 20-years post-injection for each injector.

[redacted]

Figure 108 – Model 6 Hydrology Results, 20 Years Post-Injection

The Probabilistic Hydrology tabs combine hydrology with the Probabilistic Geomechanical CDF of the pore pressure to slip. The results shown in Figure 109 establish the [redacted] injection conditions for the WC IW-A No. 001 or WC IW-B No. 001 wells.

[redacted]

Figure 109 – Model 6 Probabilistic Hydrology Tab, Early Injection Conditions

The results shown in Figure 110 establish the conditions after [redacted] sands injection for WC IW-A No. 001 or WC IW-B No. 001 are completed. Each proposed injection well is modeled separately, with injection held constant at the permitted rate.

[redacted]

Figure 110 – Model 6 Probabilistic Hydrology Tab, Post-Injection

The results shown in Figure 111 establish the conditions 20 years post-injection.

[redacted]

Figure 111 – Model 6 Probabilistic Hydrology Tab, 20 Years Post-Injection

The following pages show the integrated tabs, which combined results of probabilistic geomechanics and hydrology models run for all 31 [redacted] fault segments.

The early conditions for WC IW-A No. 001 or WC IW-B No. 001 [redacted] injection are depicted in Figure 112 for each fault segment's pore pressure change (psi).

[redacted]

Figure 112 – Model 6 Integrated Tab, Pore Pressure Early Injection Conditions

The early conditions for WC IW-A No. 001 or WC IW-B No. 001 [redacted] injection are depicted in Figure 113 for each fault segment's fault slip potential (%).

[redacted]

Figure 113 – Model 6 Integrated Tab, FSP Early Injection Conditions

The conditions following the [redacted] sand injection are depicted in Figure 114, along with the pore pressure change (psi) for each fault section.

[redacted]

Figure 114 – Model 6 Integrated Tab, Pore Pressure Post-Injection

The conditions following the [redacted] sand injection are depicted in Figure 115, along with the fault slip potential (%) for each fault section.

[redacted]

Figure 115 – Model 6 Integrated Tab, FSP Post-Injection

Figure 116 depicts the conditions 20 years after injection and the pore pressure change (psi) for each fault segment.

[redacted]

Figure 116 – Model 6 Integrated Tab, Pore Pressure (psi) Change After 20 Years

Figure 117 depicts the conditions 20 years after injection and the fault slip potential (%) for each fault segment.

[redacted]

Figure 117 – Model 6 Integrated Tab, Fault Slip Potential After 20 Years

10.0 MODEL 1 FSP Analysis Results

Table 5 – Model 1 FSP Results Per Fault Segment [redacted]

Model 1 – [redacted] FAULTS
[redacted]

Table 5 – Model 1 FSP Results Per Fault Segment [redacted] (cont'd)

Model 1 – [redacted] FAULTS (cont'd)
[redacted]

11.0 MODEL 2 FSP Analysis Results

Table 6 – Model 2 FSP Results Per Fault Segment [redacted]

Model 2 – [redacted] FAULTS
[redacted]

12.0 MODEL 3 FSP Analysis Results

Table 7 – Model 3 FSP Results Per Fault Segment [redacted]

Model 3 - ALL INJECTORS AND [redacted] FAULTS
[redacted]

13.0 MODEL 4 FSP Analysis Results

Table 8 – Model 4 FSP Results Per Fault Segment [redacted]

Model 4 – INDIVIDUAL INJECTOR AND [redacted] FAULTS
[redacted]

14.0 MODEL 5 FSP Analysis Results

Table 9 – Model 5 FSP Results Per Fault Segment [redacted]

Model 5 - ALL INJECTORS AND [redacted] FAULTS
[redacted]

Table 9 – Model 5 FSP Results Per Fault Segment [redacted] (cont'd)

Model 5 - ALL INJECTORS AND [redacted] FAULTS (cont'd)
[redacted]

15.0 MODEL 6 FSP Analysis Results

Table 10 – Model 6 FSP Results Per Fault Segment [redacted]

Model 6 - INDIVIDUAL INJECTOR AND [redacted] FAULTS
[redacted]

Table 10 – Model 6 FSP Results Per Fault Segment [redacted] (cont'd)

Model 6 - INDIVIDUAL INJECTOR AND [redacted] FAULTS (cont'd)
[redacted]

16.0 Recorded Seismicity

Section 1.10.4 in the permit application (*Section 1 – Site Characterization*) details the "Seismic Hazard" with respect to the White Castle Project site. The section below highlights the research done using the USGS Earthquake Archive Search, TexNet, and Volcano Discovery.

Between 05/12/1900 and 05/19/2023, **0 earthquakes** with magnitudes 2.0 or greater were recorded by **USGS** within the proposed injection well (WC IW-A No. 001) AOI.

[redacted]

Figure 118 – USGS Earthquake Catalog within AOI

Between 1/1/2017 and 5/24/2023, **0 earthquakes** with magnitudes 2.0 or greater were recorded by **BEG TexNet** catalog within the proposed injection well AOI.

[redacted]

Figure 119 – TexNet Earthquake Catalog within AOI

Between 4/25/1900 and 5/24/2023, **0 earthquakes** with magnitudes 2.0 or greater were recorded by **Volcano Discovery** catalog within the proposed injection well AOI.

[redacted]

Figure 120 – Volcano Discovery Earthquake Catalog in Louisiana and AOI

According to the USGS Earthquake Archive Search, no seismic events greater than 2.0 magnitude were recorded within the 5.6-kilometer radius of the White Castle Project site. The closest known earthquake to have occurred around the proposed location was a magnitude 4.2 earthquake (unknown depth), ID ushis853, which occurred in 1930 in Assumption Parish, LA, more than 20.03 km away from the site.

[redacted]

Figure 121 – USGS Closest Earthquakes to White Castle Project AOI

17.0 Conclusion

Six FSP models were run within the White Castle Project AOI, in which six faults levels were analyzed in the following order.

[redacted]	One model
[redacted]	One model
[redacted]	Two models
[redacted]	Two models

For WC IW-A No. 001 and WC IW-B No. 001, the upper confining shale is [redacted], and the lower confining shale [redacted] For WC IW-B No. 002, the upper intra-reservoir shale is the [redacted] and the lower confining shale is [redacted] The models run for each set of fault traces, including all injectors within the AOI (three injectors) and only a single proposed injection well, indicate that the reservoir and stress parameters for the proposed injection interval do not increase the potential for the analyzed faults to slip.

In our opinion, the proposed injection wells do not pose a risk of increasing seismicity within the White Castle Project AOI.

References

[redacted]

[redacted]

[redacted]

APPENDIX J: ENVIRONMENTAL JUSTICE ASSESSMENT

APPENDIX J IS

PROPRIETARY BUSINESS INFORMATION

THIS DATA HAS BEEN REDACTED.

APPENDIX K: REFERENCES

PLEASE SEE SEPARATE .ZIP FOLDER