Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001

Cameron Parish, Louisiana

Prepared for *Hackberry Carbon Sequestration, LLC*
Cameron, LA

By

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Austin, TX

August 2021

FOREWORD

Hackberry Carbon Sequestration, LLC is proposing to develop a carbon sequestration facility in Cameron Parish, Louisiana near the town of Hackberry. The project is being designed to handle captured carbon oxides from the various industries in southwest Louisiana and the location for this proposed facility is ideally suited for that purpose. This site was selected for several reasons such as favorable geology, controlled pore space storage rights, numerous industrial facilities with sequestration needs, and existing pipeline right of ways by which to transport the captured gases for disposal.

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

The application has been developed to meet all of the requirements of both US Code ***40 CFR 146.82*** thru ***146.95*** as well as Louisiana Code ***LAC 43:XVII Chapter 6, Statewide Order No. 29-N-6*** ("SWO 29-N-6"), both of which detail regulations for Underground Injection Control ("UIC") Class VI wells. Once the permit has been issued, per the requirements of ***40 CFR 144.36(a)*** and SWO 29-N-6 ***§607.M.1***, the permit will be updated every five (5) years thereafter for the active injection life of the well.

Per ***§605.C.1.b***, this document is an electronic version of the application titled "*Underground Injection Control – Class VI Permit Application for Hackberry Carbon Sequestration Well No. 001*" dated June 7, 2021. This electronic version is an exact duplicate of the paper copy submitted in three (3) 3-ring binders, Volumes 1 thru 3, to the Louisiana Office of Conservation.

CERTIFICATION

CERTIFIED BY:

Lonquist & Co., LLC
Louisiana Registration No. EF5937

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.

LOUISIANA BOARD OF PROFESSIONAL GEOSCIENTISTS
STEPHEN L. PATTEE
1001
Est. 2011
08/30/2021

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

I, Ben H. Bergman, 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.

STATE OF LOUISIANA
BEN H. BERGMAN
License No. 40184
8/30/21
PROFESSIONAL ENGINEER

Ben H. Bergman P.E.

Ben H. Bergman, P.E.
Vice President / Sr. Engineer
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ACRONYMS AND ABBREVIATIONS

%	Percent(age)
§45Q	IRS Tax Code §45Q
°C	Degrees Celsius
°F	Degrees Fahrenheit
1D	One-Dimensional
2D	Two-Dimensional
3D	Three-Dimensional
4D	Four-Dimensional
AFI	Active Fracture Images
AOR	Area of Review
ARM	Ambient Reservoir Monitoring
ATSM	American Society for Testing and Materials
bbl	Barrel(s)
Bcf	Billion Cubic Feet
bpm	Barrels per Minute
CAA	Clean Air Act
CH4	Methane
CO2	Carbon Dioxide (may also refer to other Carbon Oxides)
CRA	Corrosion Resistant Alloy
CWA	Clean Water Act
DTS	Distributed Temperature Sensing
EPA	U.S. Environmental Protection Agency
ft	Foot (Feet)
g/cc	Grams per Cubic Centimeter
GR	Gamma Ray
H2O	Water
HCS	Hackberry Carbon Storage
hz	Hertz
ID	Inner Diameter

IGSN 71	International Gravity Standardization Net 1971
km	Kilometer(s)
LAC	Louisiana Administrative Code
LADNR	Louisiana Department of Natural Resources
Lat	Latitude
LNG	Liquified Natural Gas
Long	Longitude
MASIP	Maximum Allowable Surface Pressure
Mbbls	Thousand Cubic Feet
mD	Millidarcy(ies)
MEQ	Microseismic Earthquakes
mg/l	Milligrams per Liter
mGal	Milligals
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMbbls	Million Barrels
MMcf	Million Cubic Feet
mmscf	Million Standard Cubic Feet
mmscf/d	Million Standard Cubic Feet per Day
MT/yr	Metric Tons
MT/yr	Metric Tons per Year
NPDES	National Pollutant Discharge Ellimination System
OD	Outer Diameter
pH	Scale of Acidity
PHIX_EFF	Effective Porosity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge

QA/QC	Quality Assurance / Quality Control
QPT	Quartz Pressure Temperature
RCRA	Resource Conservation and Recovery Act
SC	Specific Conductivity
SCADA	Supervisory Control and Data Acquisition
scf	Standard Cubic Feet
sDAS	Seismic Distributed Acoustic Sensing
SDI	Stream Depth Imaging
SDWA	Safe Water Drinking Act
S_{Hmax}	Maximum Horizontal Stress
SP	Spontaneous Potential
S_v	Vertical Stress
SWO	State-wide Order
TD	Total Depth
TDS	Total Dissolved Solids
TEC	Tubing Encapsulated Conductor
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
Vshale	Volume Shale
VSP	Vertical Seismic Profile
XRD	X-Ray Diffraction
$\emptyset_{eff}$	Effective Porosity
$\emptyset$	Porosity

TABLE OF CONTENTS

FOREWARD

CERTIFICATIONS

ACRONYMS AND ABBREVIATIONS

TABLE OF CONTENTS

REQUIREMENTS MATRIX

INTRODUCTION

SECTION 1 – SITE CHARACTERIZATION

SECTION 2 – PLUME MODEL

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

SECTION 5 – TESTING AND MONITORING PLAN

SECTION 6 – WELL PLUGGING PLAN

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

SECTION 9 – "IT DECISION"

SECTION 10 – FINANCIAL RESPONSIBILITY

SECTION 11 – ENVIRONMENTAL JUSTICE

APPENDICES:

- APPENDIX A: PLATS
- APPENDIX B: SITE CARACTERIZATION MAPS
- APPENDIX C: HYDROGEOLOGY
- APPENDIX D: PLUME MODEL OUTPUTS
- APPENDIX E: AREA OF REVIEW MAPS, TABLES
- APPENDIX F: WELL CONSTRUCTION SCHEMATICS AND PROCEDURES
- APPENDIX G: METALLURGY SUMMARY
- APPENDIX H: TESTING AND MONITORING
- APPENDIX I: EMERGENCY OPERATIONS PLAN
- APPENDIX J: PLUGGING SCHEMATICS AND PROCEDURES

REQUIREMENTS MATRIX

Table 1 : 40 CFR - Subpart H - Criteria and Standards Applicable to Class VI Wells			
EPA 40 CFR	**LAC 43:XVII.Chapter 6**	**Description**	**Permit Application**
§146.82		**Required Class VI permit information**	
§146.82(a)	§603.A.3	(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to §146.91(e), and the Director shall consider the following:	
	§605.C.1	Permit Application. New applicants, permittees, and any person required to have a permit shall complete, sign, and submit an appplication to the commissioner as described in this section.	
	§605.C.1.a	the applicant shall submit one signed paper version of the application and an exact duplicate of the application in an electronic format approved by the commissioner. The commissioner may request additional paper copies of the application - either in its entirety or in part - as needed.	
	§605.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 doc title) dated (insert date). This electronic version is an exact duplicate of the paper copy submitted in (insert number of volumes comprising the full application) to the Louisiana Office of Conservation."***	Electronic Document Certification
	§605.C.1.c	the applicant shall submit the application identified in §605.C.1 above to the USEPA in an electronic format approved by the USEPA.	
	§605.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	Master Documents
§146.82(a)(1)		Information required in §144.31 (e)(1) through (6) of this Section;	
§144.31 (e)(1)	§607.B	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.	Intro - Required Administrative Info
§144.31 (e)(2)	§607.B.3-4	Name, mailing address, and location of the facility for which the application is submitted.	Intro - Required Administrative Info
§144.31 (e)(3)	§607.B.8	Up to four SIC codes which best reflect the principal products or services provided by the facility.	Intro - Required Administrative Info
§144.31 (e)(4)	§607.B.3-5	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	Intro - Required Administrative Info
	§607.B.6	a brief description of the nature of the business associated with the activity;	Intro - Required Administrative Info
	§607.B.7	the activity or activities conducted by the applicant which require the applicant to obtain a permit under these regulations;	Introduction
	§607.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;	Introduction
	§607.B.12	names and addresses of all property owners within the area of review of the Class VI well or project.	N/A - Sec. 3 - AOR Results
§144.31 (e)(5)	§607.B.10	Whether the facility is located on Indian lands.	Intro - Required Administrative Info
§144.31 (e)(6)	§607.B.9	A listing of all permits or construction approvals received or applied for under any of the following programs:	Intro - Required Administrative Info
§144.31 (e)(6)(i)	§607.B.9.a	Hazardous Waste Management program under RCRA.	Intro - Required Administrative Info
§144.31 (e)(6)(ii)	§607.B.9.b	UIC program under SDWA.	Intro - Required Administrative Info
§144.31 (e)(6)(iii)	§607.B.9.c	NPDES program under CWA.	Intro - Required Administrative Info
§144.31 (e)(6)(iv)	§607.B.9.d	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(6)(ix)	§607.B.9.i	Other relevant environmental permits, including State permits.	Intro - Required Administrative Info
§144.31 (e)(6)(v)	§607.B.9.e	Nonattainment program under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(6)(vi)	§607.B.9.f	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.	Intro - Required Administrative Info
§144.31 (e)(6)(vii)	§607.B.9.g	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.	Intro - Required Administrative Info
§144.31 (e)(6)(viii)	§607.B.9.h	Dredge and fill permits under section 404 of CWA	Intro - Required Administrative Info

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.82(a)(2)	§607.C.1	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;	Sect. 3 - Figure 3.3, Appendix E-1, E-3, E-5, E-6
§146.82(a)(3)	§607.C.1.b	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	Section 1 - Site Characterization
§146.82(a)(3)(i)	§607.C.1.b.ii	Maps and cross sections of the area of review;	Appendix E
§146.82(a)(3)(ii)	§607.C.1.b.iii	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Section 1, Geologic Structure
§146.82(a)(3)(iii)	§607.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;	Section 1 - Site Characterization
§146.82(a)(3)(iv)	§607.C.2.b	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Section 1, Geomechanics
§146.82(a)(3)(v)	§607.C.2.c	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	Section 1, Seismic History
§146.82(a)(3)(vi)	§607.C.1.b.i	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Appendix B, C
§146.82(a)(4)	§607.C.2.d (Similar language specific to USDW)	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;	N/A: Water bottom
§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;	Appendix B
§146.82(a)(6)	§607.C.2.e	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Section 1, Geochemistry
§146.82(a)(7)	§607.C.2.f	Proposed operating data for the proposed geologic sequestration site:	Section 4
§146.82(a)(7)(i)	§607.C.2.f.i	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4, Detailed Discussion of Well Design
§146.82(a)(7)(ii)	§607.C.2.f.ii	Average and maximum injection pressure;	Section 2/Section 4
§146.82(a)(7)(iii)	§607.C.2.f.iii	The source(s) of the carbon dioxide stream; and	Intro - Injectate Information
§146.82(a)(7)(iv)	§607.C.2.f.iv	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Intro - Injectate Information
§146.82(a)(8)	§607.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 §146.87	Appendix F
§146.82(a)(9)	§607.C.2.h	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment	N/A
§146.82(a)(10)	§607.C.2.i	Proposed procedure to outline steps necessary to conduct injection operation	Appendix F
§146.82(a)(11)	§607.C.2.j	Schematics or other appropriate drawings of the surface and subsurface construction details of the well	Section 4, App F
§146.82(a)(12)	§607.C.2.k	Injection well construction procedures that meet the requirements of §146.86	Section 4, App F
§146.82(a)(13)	§607.C.2.l	Proposed area of review and corrective action plan that meets the requirements under §146.84	Section 3
§146.82(a)(14)	§607.C.2.m	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under §146.85	Section 10
§146.82(a)(15)	§607.C.2.n	Proposed testing and monitoring plan required by §146.90	Section 5
§146.82(a)(16)	§607.C.2.o	Proposed injection well plugging plan required by §146.92(b);	Section 6, Appendix G
§146.82(a)(17)	§607.C.2.p	Proposed post-injection site care and site closure plan required by §146.93(a);	Section 7
§146.82(a)(18)	§607.C.2.q	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by §146.93(c);	N/A
§146.82(a)(19)	§607.C.2.r	Proposed emergency and remedial response plan required by §146.94(a);	Section 8, Appendix I
§146.82(a)(20)	§607.C.2.s	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	N/A
§146.82(a)(21)	§607.C.2.t	Any other information requested by the Director.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.82(b)		The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.	
§146.82(c)		Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:	
§146.82(c)(1)		The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;	Post drilling
§146.82(c)(10)		Any other information requested by the Director.	Post drilling
§146.82(c)(2)		Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;	Post drilling
§146.82(c)(3)		Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	Post drilling
§146.82(c)(4)		The results of the formation testing program required at paragraph (a)(8) of this section;	Post drilling
§146.82(c)(5)		Final injection well construction procedures that meet the requirements of § 146.86;	N/A
§146.82(c)(6)		The status of corrective action on wells in the area of review;	Post drilling
§146.82(c)(7)		All available logging and testing program data on the well required by § 146.87;	Post drilling
§146.82(c)(8)		A demonstration of mechanical integrity pursuant to § 146.89;	Post drilling
§146.82(c)(9)		Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and	Post drilling
§146.82(d)		Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.	N/A
§146.83(a)	§615.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:	Section 1, App B
§146.83(a)(1)	§615.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;	Section 1, App B
§146.83(a)(2)	§615.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).	Section 1, App B
§146.83(b)	§615.A.2.a	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.	
§146.84	§615.B	**Area of Review and Corrective Action**	
§146.84(a)	§615.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.	Section 3, Section 2
§146.84(b)	§615.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 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:	Section 3

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.84(b)(1)	§615.B.2.a	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;	Section 3
§146.84(b)(2)		A description of:	
§146.84(b)(2)(i)	§615.B.2.b.i	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	Section 3, Proposed Reevaluation Cycle
§146.84(b)(2)(ii)	§615.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 paragraph (b)(2)(i) of this section.	Section 3, Table 2 - Reevaluation Triggers
§146.84(b)(2)(iii)	§615.B.2.b.iii	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	Section 3, Table 2 - Reevaluation Triggers
§146.84(b)(2)(iv)	§615.B.2.b.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.	N/A
§146.84(c)	§615.B.3	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)	§615.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 Director. The model must:	Section 1, Section 2, Section 3
§146.84(c)(1)(i)	§615.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;	Section 1, Section 2
§146.84(c)(1)(ii)	§615.B.3.a.ii	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Section 1, Section 2
§146.84(c)(1)(iii)	§615.B.3.a.iii	Consider potential migration through faults, fractures, and artificial penetrations.	None
§146.84(c)(2)	§615.B.3.b	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	None
§146.84(c)(3)	§615.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.	None
§146.84(d)	§615.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.	N/A
§146.84(e)	§615.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:	N/A
§146.84(e)(1)	§615.C.2.a	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section	N/A
§146.84(e)(2)	§615.C.2.b	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	N/A
§146.84(e)(3)	§615.C.2.c	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	N/A
§146.84(e)(4)	§615.C.2.d	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.	N/A

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.84(f)	§615.C.3	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.	Section 8, 10
§146.84(g)	§615.C.4	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Section 3
	§609.C.2	The amount of funds available in the financial instrument shall be no less than the amount identified in the cost estimate of the closure plan and any required post-injection site care and site closure, and must be approved by the commissioner	Section 10
	§609.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.	Section 10
§146.85		**Financial responsibility**	
§146.85(a)	§609.C.1	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	Section 10
§146.85(a)(1)	§609.C.1.a-e	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	Section 10
§146.85(a)(2)	§609.C.4.a	The qualifying instrument(s) must be sufficient to cover the cost of"	Section 10
§146.85(a)(2)(i)	§609.C.4.a.i	Corrective action (that meets the requirements of §146.84);	Section 10
§146.85(a)(2)(ii)	§609.C.4.a.ii	Injection well plugging (that meets the requirements of §146.92);	Section 10
§146.85(a)(2)(iii)	§609.C.4.a.iii	Post injection site care and site closure (that meets the requirements of §146.93); and	Section 10
§146.85(a)(2)(iv)	§609.C.4.a.iv	Emergency and remedial response (that meets the requirements of §146.94).	Section 10
§146.85(a)(3)	§609.C.4.b	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	Section 10
§146.85(a)(4)	§609.C.4.c	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	Section 10
§146.85(a)(4)(i)	§609.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.	Section 10
§146.85(a)(4)(i)(A)	§609.C.4.c.i	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	Section 10
§146.85(a)(4)(i)(B)	§609.C.4.c.ii	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.	
§146.85(a)(4)(i)(C)	§609.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 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.	
§146.85(a)(5)	§609.C.4.d	The qualifying financial responsibility instrument(s) must be approved by the Director.	
§146.85(a)(5)(i)	§609.C.4.d.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).	
§146.85(a)(5)(ii)	§609.C.4.d.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.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.85(a)(5)(iii)	§609.C.4.d.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.	
§146.85(a)(6)	§609.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)	§609.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 (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.	
§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(a)(6)(iii)		An owner or operator using certain types of third party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed	
§146.85(a)(6)(iv)		An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.	
§146.85(a)(6)(v)		An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: a ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; a ratio of current assets minus current liabilities to total assets greater than -0.1; and a net profit (revenues minus expenses) greater than 0.	
§146.85(a)(6)(vi)		An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.	
§146.85(a)(6)(vii)		An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.	
§146.85(b)		The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.	
§146.85(b)(1)	§609.C.4.g	The owner or operator must maintain financial responsibility and resources until:	
§146.85(b)(1)(i)	§609.C.4.g.i	The Director receives and approves the completed post-injection site care and site closure plan; and	
§146.85(b)(1)(ii)	§609.C.4.g.ii	The Director approves site closure	
§146.85(b)(2)		The owner or operator may be released from a financial instrument in the following circumstances:	
§146.85(b)(2)(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 Director, including obtaining financial responsibility for the next phase of the GS project, if required; or	
§146.85(b)(2)(ii)		The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	
§146.85(c)	§609.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.	Section 10

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.85(c)(1)	§609.C.4.h.i	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.	Section 10
§146.85(c)(2)	§609.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 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).	Section 10
§146.85(c)(3)	§609.C.4.h.iii	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.	Section 10
§146.85(c)(4)	§609.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 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.	Section 10
§146.85(d)	§609.C.4.i	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.	
§146.85(d)(1)	§609.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 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.	
§146.85(d)(2)	§609.C.4.i.ii	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.	
§146.85(d)(3)		An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.	
§146.85(e)	§609.C.4.j	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)	
§146.85(f)	§609.C.4.k	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	
§146.86	§617	**Injection well construction requirements**	Section 4
§146.86(a)	§617.A.1	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	Section 4
§146.86(a)(1)	§617.A.1.a	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Section 4, General Outline
§146.86(a)(2)	§617.A.1.b	Permit the use of appropriate testing devices and workover tools; and	Section 4
§146.86(a)(3)	§617.A.1.c	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Section 4
§146.86(b)	§617.A.2	Casing and Cementing of Class VI Wells	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.86(b)(1)	§617.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 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:	Section 4, Detailed Well Design; Appendix F; Appendix G
§146.86(b)(1)(i)	§617.A.2.a.i	Depth to the injection zone(s);	Section 4, Detailed Well Design (need to list in addition to schematic)
§146.86(b)(1)(ii)	§617.A.2.a.ii	Injection pressure, external pressure, internal pressure, and axial loading	Section 4
§146.86(b)(1)(iii)	§617.A.2.a.iii	Hole size	Section 4- Schematic
§146.86(b)(1)(iv)	§617.A.2.a.iv	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Section 4, Schematic
§146.86(b)(1)(ix)	§617.A.2.a.ix	Quantity, chemical composition, and temperature of the carbon dioxide stream.	Appendix G
§146.86(b)(1)(v)	§617.A.2.a.v	Corrosiveness of the carbon dioxide stream and formation fluids	Appendix G
§146.86(b)(1)(vi)	§617.A.2.a.vi	Down-hole temperatures	Section 4, Detailed Well Design (need to list in addition to schematic)
§146.86(b)(1)(vii)	§617.A.2.a.vii	Lithology of injection and confining zone(s)	Section 1
§146.86(b)(1)(viii)	§617.A.2.a.viii	Type or grade of cement and cement additives; and	Section 4, Appendix F
§146.86(b)(2)	§617.A.2.b	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.	Section 4
§146.86(b)(3)	§617.A.2.c	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	Section 4
§146.86(b)(4)	§617.A.2.d	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.	Section 4
§146.86(b)(5)	§617.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.	Section 4
	§617.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 F
	§617.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 F
	§617.A.3.a.i	Casing test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix F
	§617.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 F
	§617.A.3.b.i	Casing seat test pressures shall never exceed the rated burst or collapse pressures of the respective casings.	Appendix F
§146.86(c)	§617.A.4	Tubing and packer.	Section 4
§146.86(c)(1)	§617.A.4.a	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.	Appendix G

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.86(c)(2)	§617.A.4.b	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.	
§146.86(c)(3)	§617.A.4.c	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	
§146.86(c)(3)(i)	§617.A.4.c.i	Depth of setting;	Section 4
§146.86(c)(3)(ii)	§617.A.4.c.ii	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Appendix G
§146.86(c)(3)(iii)	§617.A.4.c.iii	Maximum proposed injection pressure	Section 4
§146.86(c)(3)(iv)	§617.A.4.c.iv	Maximum proposed annular pressure;	Section 4
§146.86(c)(3)(v)	§617.A.4.c.v	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream	Section 4
§146.86(c)(3)(vi)	§617.A.4.c.vi	Size of tubing and casing; and	Section 4
§146.86(c)(3)(vii)	§617.A.4.c.vii	Tubing tensile, burst, and collapse strengths.	Section 4
§146.87	§617.B	**Logging, sampling, and testing prior to injection well operation.**	
§146.87(a)	§617.B.1	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:	Appendix F
§146.87(a)(1)	§617.B.1.a	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	Appendix F
§146.87(a)(2)	§617.B.1.b	Before and upon installation of the surface casing:	Appendix F
§146.87(a)(2)(i)	§617.B.1.b.i	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Appendix F
§146.87(a)(2)(ii)	§617.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.	Appendix F
§146.87(a)(3)	§617.B.1.c	Before and upon installation of the long string casing:	Appendix F
§146.87(a)(3)(i)	§617.B.1.c.i	(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	Appendix F
§146.87(a)(3)(ii)	§617.B.1.c.ii	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	Appendix F
§146.87(a)(4)	§617.B.1.d	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	Appendix F
§146.87(a)(4)(i)	§617.B.1.d.i	A pressure test with liquid or gas;	Appendix F
§146.87(a)(4)(ii)	§617.B.1.d.ii	A tracer survey such as oxygen-activation logging;	N/A
§146.87(a)(4)(iii)	§617.B.1.d.iii	A temperature or noise log;	Appendix F
§146.87(a)(4)(iv)	§617.B.1.d.iv	A casing inspection log; and	Appendix F
§146.87(a)(5)	§617.B.1.e	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	N/A
§146.87(b)	§617.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 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.	Appendix F
§146.87(c)	§617.B.3	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Appendix F
§146.87(d)	§617.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)	§617.B.4.a	Fracture pressure;	Appendix F
§146.87(d)(2)	§617.B.4.b	Other physical and chemical characteristics of the injection and confining zone(s); and	Appendix F
§146.87(d)(3)	§617.B.4.c	Physical and chemical characteristics of the formation fluids in the injection zone(s).	Appendix F

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.87(e)	§617.B.5	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	Appendix F
§146.87(e)(1)	§617.B.5.a	pressure fall-off test; and,	Appendix F, Section 5
§146.87(e)(2)	§617.B.5.b	A pump test; or	Appendix F, Section 5
§146.87(e)(3)	§617.B.5.c	Injectivity tests.	Appendix F, Section 5
§146.87(f)	§617.B.6	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.	Appendix F
§146.88	§621.A	**Injection well operating requirements**	
§146.88(a)	§621.A.1	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.	Section 4
§146.88(b)	§621.A.2	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Section 4
§146.88(c)	§621.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 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.	Section 4, Appendix F
§146.88(d)	§621.A.4	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.	Section 4, Section 5
§146.88(e)		The owner or operator must install and use:	
§146.88(e)(1)	§621.A.6.a	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	Section 5
§146.88(e)(2)	§621.A.7.a.i	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	Section 5, Plume Monitoring Equipment Review [redacted]
§146.88(e)(3)	§621.A.7.a.ii	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	N/A
§146.88(f)	§621.A.6.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 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	Section 8
§146.88(f)(1)	§621.A.6.b.i	Immediately cease injection;	Section 8
§146.88(f)(2)	§621.A.6.b.ii	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone	Section 8
§146.88(f)(3)	§621.A.6.b.iii	Notify the Director within 24 hours	Section 8
§146.88(f)(4)	§621.A.6.b.iv	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	Section 8
§146.88(f)(5)	§621.A.6.b.v	Notify the Director when injection can be expected to resume	Section 8
§146.89	**§627**	**Mechanical Integrity**	
§146.89(a)	§627.A.1	A Class VI well has mechanical integrity if:	
§146.89(a)(1)	§627.A.1.a	There is no significant leak in the casing, tubing, or packer; and	Section 5
§146.89(a)(1)	§627.A.1.b	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	Section 5
§146.89(b)	§627.A.2	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);	Section 5

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.89(c)	§627.A.3	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:	Section 5
§146.89(c)(1)	§627.A.3.a	An approved tracer survey such as an oxygen-activation log; or	
§146.89(c)(2)	§627.A.3.b	A temperature or noise log.	Section 5
§146.89(d)	§627.A.4	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.	Section 5
§146.89(e)	§627.A.5.a	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.	N/A
§146.89(f)	§627.A.6	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.	N/A
§146.89(g)	§627.A.7	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.	N/A
§146.90	§625.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 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:	Section 5
§146.90(a)	§625.A.1	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 5
§146.90(b)	§625.A.2	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;	Section 5
§146.90(c)	§625.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 §146.86(b), by:	Section 5
§146.90(c)(1)	§625.A.3.a	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Section 5
§146.90(c)(2)	§625.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	Section 5
§146.90(c)(3)	§625.A.3.c	Using an alternative method approved by the Director	Section 5
§146.90(d)	§625.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:	Section 5
§146.90(d)(1)	§625.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	Section 5
§146.90(d)(2)	§625.A.4.b	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).	Section 5

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.90(e)	§625.A.5	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;	
§146.90(f)	§625.A.6	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	
§146.90(g)	§625.A.7	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Section 5
§146.90(g)(1)	§625.A.7.a	Direct methods in the injection zone(s); and,	Section 5
§146.90(g)(2)	§625.A.7.b	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;	Section 5
§146.90(h)	§625.A.8	The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	N/A: Water bottom
§146.90(h)(1)	§625.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;	N/A: Water bottom
§146.90(h)(2)	§625.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 § 144.12 of this chapter;	N/A: Water bottom
§146.90(h)(3)	§625.A.8.c	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;	N/A: Water bottom
§146.90(i)	§625.A.9	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;	Section 5
§146.90(j)	§625.A.10	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:	N/A
§146.90(j)(1)	§625.A.10.a	Within one year of an area of review reevaluation;	N/A
§146.90(j)(2)	§625.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 Director; or	N/A
§146.90(j)(3)	§625.A.10.c	When required by the Director.	N/A
§146.90(k)	§625.A.11	A quality assurance and surveillance plan for all testing and monitoring requirements.	
§146.91	§629.A	**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:	
§146.91(a)	§629.A.1	Semi-annual reports containing:	Section 5
§146.91(a)(1)	§629.A.1.a	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	Section 5
§146.91(a)(2)	§629.A.1.b	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	Section 5
§146.91(a)(3)	§629.A.1.c	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	Section 5
§146.91(a)(4)	§629.A.1.d	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	Section 5
§146.91(a)(5)	§629.A.1.e	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	Section 5

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.91(a)(6)	§629.A.1.f	Monthly annulus fluid volume added; and	Section 5
§146.91(a)(7)	§629.A.1.g	The results of monitoring prescribed under § 146.90.	Section 5
§146.91(b)	§629.A.2	Report, within 30 days, the results of:	Section 5
§146.91(b)(1)	§629.A.2.a	Periodic tests of mechanical integrity;	Section 5
§146.91(b)(2)	§629.A.2.b	Any well workover; and,	Section 5
§146.91(b)(3)	§629.A.2.c	Any other test of the injection well conducted by the permittee if required by the Director.	Section 5
§146.91(c)	§629.A.3	Report, within 24 hours:	Section 5
§146.91(c)(1)	§629.A.3.a	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW	Section 5
§146.91(c)(2)	§629.A.3.b	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Section 5
§146.91(c)(3)	§629.A.3.c	Any triggering of a shut-off system (*i.e.,* down-hole or at the surface);	Section 5
§146.91(c)(4)	§629.A.3.d	Any failure to maintain mechanical integrity; or.	Section 5
§146.91(c)(5)	§629.A.3.e	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.	Section 5
§146.91(d)	§629.A.4	Owners or operators must notify the Director in writing 30 days in advance of:	Section 5
§146.91(d)(1)	§629.A.4	Any planned well workover;	Section 5
§146.91(d)(2)	§629.A.4	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and	Section 5
§146.91(d)(3)	§629.A.4	Any other planned test of the injection well conducted by the permittee.	Section 5
§146.91(e)	§629.A.5	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.	Section 5
§146.91(f)	§629.A.6	Records shall be retained by the owner or operator as follows:	Section 5
§146.91(f)(1)	§629.A.6.a	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.	Section 5
§146.91(f)(2)	§629.A.6.b	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.	Section 5
§146.91(f)(3)	§629.A.6.c	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	Section 5
§146.91(f)(4)	§629.A.6.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 §§ 146.93(f) and (h) shall be retained for 10 years following site closure.	Section 5
§146.91(f)(5)	§629.A.6.e	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.	
§146.92	**§631**	**Injection well plugging**	
§146.92(a)	§631.A.2	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.	Section 6, Appendix H
§146.92(b)	§631.A.3	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:	Section 6, Appendix H
§146.92(b)(1)	§631.A.3.a	Appropriate tests or measures for determining bottomhole reservoir pressure;	Section 6, Appendix H
§146.92(b)(2)	§631.A.3.b	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	Section 6, Appendix H
§146.92(b)(3)	§631.A.3.c	The type and number of plugs to be used;	Section 6, Appendix H
§146.92(b)(4)	§631.A.3.d	The placement of each plug, including the elevation of the top and bottom of each plug;	Section 6, Appendix H
§146.92(b)(5)	§631.A.3.e	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	Section 6, Appendix H
§146.92(b)(6)	§631.A.3.f	The method of placement of the plugs.	Section 6, Appendix H

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.92(c)	§631.A.4	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.	Section 6, Appendix H
§146.92(d)	§631.A.5	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.	Section 6, Appendix H
§146.93	**§633**	**Post-injection site care and site closure**	
§146.93(a)	§633.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 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.	Section 7
§146.93(a)(1)	§633.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 to be approved by the Director.	Section 7
§146.93(a)(2)	§633.A.1.b	The post-injection site care and site closure plan must include the following information:	Section 7
§146.93(a)(2)(i)	§633.A.1.b.i	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Section 7
§146.93(a)(2)(ii)	§633.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 § 146.84(c)(1);	Section 7
§146.93(a)(2)(iii)	§633.A.1.b.iii	A description of post-injection monitoring location, methods, and proposed frequency;	Section 7
§146.93(a)(2)(iv)	§633.A.1.b.iv	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	Section 7
§146.93(a)(2)(v)	§633.A.1.b.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.	Section 7
§146.93(a)(3)	§633.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 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.	Section 7
§146.93(a)(4)	§633.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 Director's approval within 30 days of such change.	
§146.93(b)	§633.A.2	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	Section 7
§146.93(b)(1)	§633.A.2.a	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.	Section 7
§146.93(b)(2)	§633.A.2.b	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.	Section 7
§146.93(b)(3)	§633.A.2.c	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.	Section 7

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.93(b)(4)	§633.A.2.d	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.	
§146.93(c)	§633.A.3	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.	Section 7
§146.93(c)(1)	§633.A.3.a	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	
§146.93(c)(1)(i)	§633.A.3.a.i	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	Section 7
§146.93(c)(1)(ii)	§633.A.3.a.ii	The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	Section 7
§146.93(c)(1)(iii)	§633.A.3.a.iii	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	Section 2
§146.93(c)(1)(iv)	§633.A.3.a.iv	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	Section 2
§146.93(c)(1)(ix)	§633.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;	None
§146.93(c)(1)(v)	§633.A.3.a.v	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	Section 2
§146.93(c)(1)(vi)	§633.A.3.a.vi	The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;	Post drilling
§146.93(c)(1)(vii)	§633.A.3.a.vii	A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	Section 1
§146.93(c)(1)(viii)	§633.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;	N/A
§146.93(c)(1)(x)	§633.A.3.a.x	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	Section 1, App B
§146.93(c)(1)(xi)	§633.A.3.a.xi	Any additional site-specific factors required by the Director.	
§146.93(c)(2)	§633.A.3.b	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	
§146.93(c)(2)(i)	§633.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)	§633.A.3.b.ii	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	
§146.93(c)(2)(iii)	§633.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)	§633.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)	§633.A.3.b.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;	
§146.93(c)(2)(vi)	§633.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)	§633.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)	§633.A.3.b.viii	Any additional criteria required by the Director.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.93(d)	§633.A.4	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.	Section 7
§146.93(e)	§633.A.5	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.	Section 7
§146.93(f)	§633.A.6	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:	Section 7
§146.93(f)(1)	§633.A.6.a	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;	Section 7
§146.93(f)(2)	§633.A.6.b	Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	Section 7
§146.93(f)(3)	§633.A.6.c	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	Section 7
§146.93(g)	§633.A.7	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	Section 7
§146.93(g)(1)	§633.A.7.a	The fact that land has been used to sequester carbon dioxide;	Section 7
§146.93(g)(2)	§633.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 Environmental Protection Agency Regional Office to which it was submitted; and	Section 7
§146.93(g)(3)	§633.A.7.c	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	Section 7
§146.93(h)	§633.A.8	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.	Section 7
§146.94	**§623**	**Emergency and remedial response**	
§146.94(a)	§623.A.1	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.	Section 8
§146.94(b)	§623.A.2	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	Section 8
§146.94(b)(1)	§623.A.2.a	Immediately cease injection;	Section 8
§146.94(b)(1)	§623.A.2.b	Take all steps reasonably necessary to identify and characterize any release;	Section 8
§146.94(b)(1)	§623.A.2.c	Notify the Director within 24 hours; and	Section 8
§146.94(b)(1)	§623.A.2.d	Implement the emergency and remedial response plan approved by the Director.	Section 8
§146.94(c)	§623.A.3	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.	Section 8
§146.94(d)	§623.A.4	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:	Section 8
§146.94(d)(1)	§623.A.4.a	Within one year of an area of review reevaluation;	Section 8
§146.94(d)(2)	§623.A.4.b	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	Section 8
§146.94(d)(3)	§623.A.4.c	When required by the Director.	

EPA 40 CFR	LAC 43:XVII.Chapter 6	Description	Permit Application
§146.95		**Class VI injection depth waiver requirements**. This section sets forth information which an owner or operator seeking a waiver of the Class VI injection depth requirements must submit to the Director; information the Director must consider in consultation with all affected Public Water System Supervision Directors; the procedure for Director—Regional Administrator communication and waiver issuance; and the additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements.	No Waiver Requested

SECTION 0 – INTRODUCTION

TABLE OF CONTENTS

Project Overview 2
Hackberry Carbon Sequestration, LLC ("HCS") 3
Hackberry Sequestration Project Overview 3
Agreement Discussion 4
Proposed CO_2 Sequestration System Discussion 4
Injection Strategy 6
Stratigraphic Test Well Discussion 7
Injectate Information 9
Surface Facilities and Details 9
Site Suitability 9
Injection Wells Summary and Operational Overview 10
Summary 12
Required Administrative Information 13
General Application Information 13
Additional Permits 14

Figures

[redacted]

Tables

Table Intro- 1: Permits Required 14

Project Overview

Large scale capture of anthropogenic carbon dioxide ("CO_2") is increasingly viewed as critical for the United States and global community to meet ambitious goals for greenhouse gas reductions by companies, states, and national governments. For example, the International Energy Agency ("IEA") has highlighted a potential need for CO_2 storage to increase from around 40 million tonnes per year today to more than 5,000 million tonnes per year by mid-century. Today, the United States is the global leader in Carbon Capture, Use, and Sequestration ("CCUS"), holding more than 60% of current CCUS capacity and half of all global CCUS capacity under development. [1]

To have an impact on global greenhouse gas levels, once carbon, generally in the form of CO_2, is captured from a source, that CO_2 must safely be disposed of in some manner. One of the more common methods of dealing with the captured CO_2 is injection into porous formations below the earth's surface. The United States Gulf Coast has long been viewed as suitable for long-term sequestration of CO_2.[2]

The costs associated with CCUS technologies have historically made carbon injection and sequestration projects uneconomical without substantial governmental assistance or revenue from utilizing the CO_2 in an enhanced oil recovery application. However, expansion of the 26 U.S Code **§45Q** tax credit through the Bipartisan Budget Act of 2018 and implementation of the associated guidance and regulations by the U.S. Department of Treasury has now created a framework where more carbon capture and sequestration projects can be economically feasible.

Hackberry Carbon Sequestration, LLC ("HCS") proposes drilling and completing a carbon sequestration well in Cameron Parish, Louisiana. As such, HCS is applying for a Class VI permit to construct and operate the well, which will be located on surface acreage, with CO_2 injected and sequestered into subsurface pore space controlled pursuant to an exclusive option to purchase by HCS. The information contained within this permit application is being submitted in support of this proposed Class VI well.

The application will (i) fully detail and characterize the geology of the proposed well location, evaluate the formation for properties necessary to safely and permanently sequester CO_2, (ii) describe the engineering design and safety considerations for the well, and (iii) discuss the proposed monitoring system which will be utilized to compare and contrast actual injectate plume migration to reservoir modeling and simulation of the anticipated plume. In accordance with all federal and local regulations for Class VI wells, the permit will be updated every five (5) years thereafter of the active injection life of the well.

---

[1] The world has vast capacity to store CO_2: Net zero means we'll need it – Analysis - IEA

[2] 2010 Carbon Atlas of the United States and Canada, National Energy Technology Laboratory, US Department of Energy

Hackberry Carbon Sequestration, LLC ("HCS")

HCS is an entity formed to support the capture and permanent sequestration of CO_2 emitted from liquefied natural gas ("LNG") export terminals as well as other industrial facilities located in the Gulf Coast region. LNG terminals operating and under construction in southwest Louisiana and southeast Texas have enabled the United States to become a global leader in exporting natural gas to foreign customers. Increasingly, these customers are seeking natural gas sourced through lower-carbon processes to meet their energy needs and are looking to US suppliers to supply this cleaner product. Likewise, industrial operators and their customers are seeking to decarbonize their facilities and their products. HCS's commitment to facilitate lower carbon energy and industrial production will help these crucial manufacturers evolve as leaders in the global energy transition.

Hackberry Sequestration Project Overview

The project described in this application ("Hackberry Sequestration Project") is located in Cameron Parish in southwest Louisiana; the location of the Hackberry Sequestration Project is ideal given several essential factors.

These factors include:

A) Project location near operational LNG export facilities and additional Lake Charles area industrial facilities nearby for point-source collection of CO_2 gases

B) Ideal subsurface geologic conditions for the injection and storage of the captured CO_2 gases
   a. [redacted]
   b. [redacted]

C) Single tract surface and pore space interests controlled by HCS for the entirety of the CO2 plume

D) With regards to any pressure sources, sinks or other critical activities in the confining or injection zones of the region, there are none found within an influential distance of this injection operation. The nearest production is several miles away and found primarily in formations other than those being utilized for this project.

Hackberry Carbon Sequestration Project Positive Attributes

The development of the Hackberry Carbon Sequestration Project will have significant economic and social benefits to the State of Louisiana, specifically to Cameron Parish. The development of the Hackberry Carbon Sequestration Project will employ approximately 310 workers during construction, of which fifteen percent (15%) would be local residents, seventy-five percent (75%) commuters, and ten percent (10%) of whom will temporarily relocate to the area. In addition, once fully operational, the Hackberry Carbon Sequestration Project will require approximately two (2) full-time employees.

As measured by sales and personal earnings, business activity is expected to increase during the construction of the Hackberry Carbon Sequestration Project. Additionally, there will be an increase in tax revenue to local parishes, positively growing the local tax revenue based on tax revenue projections.

In short, the Hackberry Carbon Sequestration Project will provide significant temporary direct and indirect economic benefits to the state of Louisiana and the local communities of southwest Louisiana during construction of the project and even greater long-term economic benefits during the full operating life of the project.

The environmental benefits of the Hackberry Carbon Sequestration Project impact not just the state and local communities, but the global community as well. The sequestration of up to 4.5 MM Mt/yr of CO_2 is equivalent to removing approximately 980,000 passenger cars off the road each year[3]. Further, no permanent wetland impacts are expected to result from the project nor any long-term adverse impacts to environmentally sensitive habitats. In fact, the Hackberry Sequestration Project is expected to create approximately thirty-seven (37) acres of wetland marsh, through the beneficial use of dredge material.

[redacted]

Proposed CO_2 Sequestration System Discussion

HCS proposes to construct and operate the Hackberry Sequestration Project facilities to sequester up to 4.5 MM Metric Tons per year ("MT/yr") of captured carbon via injection into up to three (3) storage wells. This application is for the first of those three (3) wells. The proposed well discussed in this application will be named ***"Hackberry Carbon Sequestration Well No. 001"*** and will be designed to sequester 2 MM MT/yr. [redacted]

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

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- [redacted]

[redacted]

[redacted]

[redacted]

Required Administrative Information

General Application Information

Injection Well Information:

Well Name and Number	Hackberry Carbon Sequestration Well No. 001
Parish	Cameron Parish, Louisiana
[redacted]	[redacted]

Applicant:

Name	Hackberry Carbon Sequestration, LLC
Address	1500 Post Oak Blvd, Suite 1000 Houston, TX 77056
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	

Additional Permits

Agency	Permit & Authorization	Anticipated Filing Date	Anticipated Receipt Date	Status
FEDERAL				
Federal Energy Regulatory Commission (FERC)	Amendment of CLNG FERC Order	(January 2022)	(September 2022)	
Environmental Protection Agency (EPA)	Class VI Injection Well Permit – 40 CFR146	(August 2021)		Permit Submitted to EPA Region 6 and LADNR
Environmental Protection Agency (EPA)	RCRA Hazardous Waste Management Exemption			
U. S. Army Corps of Engineers (USACE)	Section 404/10 Permit	(August 2021)	(March 2023)	To be Submitted
U.S. Fish and Wildlife Service (USFWS)	Section 7 Consultation	(August 2021)	(November 2021)	
NOAA National Marine Fisheries Service (NMFS)	Section 7 Consultation	(August 2021)	(November 2021)	
LOUISIANA				
Louisiana Department of Environmental Quality (LDEQ)	Louisiana Pollutant Discharge Elimination System (LPDES) Permit – Sanitary Wastewater	(January 2023)	(June 2023)	
Louisiana Department of Environmental Quality (LDEQ)	401 Water Quality Certification	(August 2021)	(November 2021)	
Louisiana Department of Environmental Quality (LDEQ)	Hydrostatic Test Water Discharge General Permit	(November 2022)	(March 2023)	
Louisiana Office of Cultural Development	Section 106 Consultation	(August 2021)	(December 2021)	
Louisiana Department of Natural Resources (LDNR)	Coastal Use Permit – Office of Coastal Management	(August 2021)	(March 2023)	To be Submitted

Table Intro- 1: Permits Required

Louisiana Department of Natural Resources (LDNR)	Class VI Injection Well Permit	(August 2021)		
Louisiana Department of Natural Resources (LDNR)	Stratigraphic Test Well Drilling Permit			Serial No. 975774, Approval 12/14/2020
Louisiana Department of Natural Resources (LDNR)	Hackberry Carbon Sequestration Well No. 001 Drilling Permit			To be Submitted
LDNR – Office of Conservation	Pipeline Construction & Operating Permit	(January 2023)	(March 2023)	To be Submitted
Louisiana Department of Wildlife and Fisheries	Letter of Comment for state listed Threatened and Endangered Species and Fish and Wildlife concerns	(August 2021)	(November 2021)	
LOCAL				
Local permits will be determined upon further facilities design.				

Table Intro-1: Permits Required

SECTION 1 – SITE CHARACTERIZATION

This Site Characterization for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6 **§607.C.1.b** [40 CFR **§146.82(a)(3)**]. This section describes the regional and site geology for the proposed location.

TABLE OF CONTENTS

Regional Geology, Hydrogeology and Local Structural Geology 1
Regional Geology 1
Major Stratigraphic Units 2
Site Geology 5
Injection Zone 10
Upper Confining Zone 12
Lower Confining Zone 14
Injection Zone Water Chemistry 16
Geologic Structure 17
Site Geologic Structure 17
Geomechanics 23
Local Stress Conditions 23
Elastic Moduli and Fracture Gradient 24
Injection Zone Fracture Gradient 24
Confining Zone Fracture Gradient 26
Porosity and Permeability 26
Upper Confining Zone 27
Injection Zone 32
Lower Confining Zone 36
Geochemical Characterization 38
Baseline Geochemistry 38
Simulated Reservoir Brine and Gas Interaction 40
Simulated Seal Brine and Gas Solution 42
Hydrology 43
"200-Foot Sand" 43
"500-Foot Sand" 44
"700-Foot Sand" 44
Site Evaluation of Mineral Resources 45
Seismic History 46
Conclusion 48
References 49

Figures

[redacted]

[redacted]

Tables

[redacted]

Regional Geology, Hydrogeology and Local Structural Geology

Exploratory wells and borings for hydrocarbons, geothermal, storage and groundwater development provide regional geological information across southwest Louisiana. The State of Louisiana Department of Natural Resources (LADNR) provides publicly available documents, well and groundwater information. The United States Geological Survey (USGS) performed a National Assessment of Carbon Dioxide Storage Resources, including a study detailing the U.S. Gulf Coast geologic framework to evaluate possible targets for geologic storage of CO_2. In addition, literature from peer-reviewed journals, dissertations and theses are included in the study of southern Louisiana regional geology.

Regional Geology

The portion of the Gulf of Mexico Basin within the state-waters boundary of the United States covers an area of 148,049,000 acres and spans West to East from the southern coast of Texas to western Florida and reaches as far North as the Mississippi River in southern Missouri, Illinois and Kentucky (Roberts-Ashby et al., 2012). Crustal extension and expansion of the seafloor during the Mesozoic formed the Gulf of Mexico Basin, upon which the thick Jurassic Louann Salt was deposited (Salvador, 1991). Jurassic through Holocene sediment accumulated to as much as 20 kilometers thick in the depocenter located beneath southern Louisiana (Galloway, 2008).

Seafloor spreading during the opening of the Gulf of Mexico Basin was accommodated by NW-SE trending transfer faults which influenced rates of subsidence and salt distribution (Galloway, 2008). Basement structures associated with the Ouachita and Appalachian Mountain ranges and the Llano uplift influenced Louann Salt and subsequent strata deposition. The Balcones, Luling-Mexia-Talco, State Line, and Pickins-Gilberton fault zones are regional structural influences on salt tectonics. The Gulf of Mexico Basin is influenced by sediment loading and salt mobilization expressed as growth-fault related structures, allochthonous salt bodies, salt welds, salt-based detachment faults, salt diapirs, and basin-floor compressional fold belts (Galloway, 2008).

A dip-oriented basin-scale cross-section across the general area of the proposed CO_2 storage site illustrates basin structure in Figure 1-1. Figure 1-1(A) plots the path of the cross-section from a general North to South direction; the red star approximates the proposed facility location. Figure 1-1(B), modified from Galloway (2008), is a North-South illustrated cross-section with generalized stratigraphy, structure, crustal and salt features.

[redacted]

Major Stratigraphic Units

Miocene depositional episodes are characteristically deltaic systems separated by regionally extensive fine-grained sealing units. Miocene strata are divided into three stratigraphic units: the Lower, Middle and Upper Miocene. The Lower Miocene is the stratigraphic interval of this study. [redacted]

The Lower Miocene is a high sediment supply rate depositional episode following the end of the Oligocene-age Anahuac transgression (Galloway, 2008). The Lower Miocene is further subdivided into the Lower Miocene I and Lower Miocene II. The Lower Miocene I is the basal stratigraphic unit, from the Oligocene-age Anahuac Shale to the *Marginulina A*. The Lower Miocene II unit basal boundary is the *Marginulina A*, while the *Amphistegina B* forms the upper boundary

(Galloway et al, 2000). The shale-prone *Amphistegina B* and the Anahuac Shale should act as robust regional seals and both the Lower Miocene I and Lower Miocene II reservoirs are noted in the USGS storage assessment as "self-sealed" (Roberts-Ashby et al., 2012). The Lower Miocene I Storage Assessment Unit (SAU), defined by the *Marginulina A* top-seal limit and the State-water boundary, covers an area of 8,432,000 acres. The Lower Miocene II SAU, defined by the *Amphistegina B* top-seal limit and State-water boundary, covers an area of 9,924,000 acres (Roberts-Ashby et al., 2012).

Hydrocarbon production in this region from Miocene and Oligocene formations beneath the upper and middle Miocene demonstrate the capability of Miocene and Oligocene clay-rich shales as vertical and laterally sealing units to contain buoyant fluids (oil and natural gas) and prevent vertical migration. Black Bayou Field, west of the proposed storage site, has produced over 12 million BBLS of oil and 10 million mcf of gas from Miocene and Oligocene sands, trapped beneath Miocene and Oligocene shales.

Anahuac Shale

The Anahuac is a regionally thick transgressive shale deposited conformably on top of the blanket sands of the Oligocene-age Frio Formation. Regional lithology of the Anahuac Shale is calcareous marine shale with localized, lenticular, micritic limestone typical of open-shelf environments (BEG study). Marine shales are fine-grained sedimentary rock formed from mud deposited in a marine environment. The mud is composed of clay minerals and silt-sized particles; the large percentage of calcite categorizes this shale as calcareous.

The Anahuac Shale was deposited across the extent of the Gulf margin, 75 miles inland from the current coastline at the Texas-Louisiana border (Galloway, 2008). From this inland depositional limit, the Anahuac Shale thickens basinward to nearly 2,000 ft.

Lower Miocene Sandstones

Lower Miocene sandstones in southwest Louisiana are fluvial-dominated deltaic deposits which prograded the continental margin 65-80 km basinward (Galloway, 2008). Gross sandstone thickness averages 3,100 ± 800 ft, with an average net sandstone thickness of 1,150 ± 500 ft (Robert-Ashby et al., 2012). Regional reservoir porosity gathered from a production database of 432 petroleum-reservoir-averaged porosity measurements by Nehring Associates, Inc. (2010) was analyzed by the Texas Bureau of Economic Geology and found to be 28 ± 4 percent (Roberts-Ashby et al., 2012). Regional permeability measurements in the production database averaged 500 mD (Nehring Associates, Inc., 2010).

Amphistegina B

The Lower Miocene depositional episode terminates with the maximum flooding surface within the widespread *Amphistegina B* (Amph B) calcareous marine shale (Galloway, 2008). This regional, transgressive shale can reach thicknesses of 820 ft and is chosen as the primary sealing interval in the Offshore CO_2 Storage Resource Assessment by the U.S. Department of Energy National Energy Technology Laboratory (Trevino and Meckel, 2019).

[redacted]

Site Geology

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The Lower Miocene is primarily composed of deltaic sands with interbedded shale and siltstone. [redacted]

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[redacted] Smectites are “swelling clays” which indicate these clay minerals readily swell in the presence of water. This property of smectite clays is relevant to many environmental and industrial processes including limiting hazardous contaminant transport in the subsurface and in engineered barriers in nuclear waste repositories (Teich-McGoldrick et al., 2015). In smectite and kaolinite clays, vertical permeability decreases logarithmically as vertical effective stress increases. [redacted]

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[redacted]

Geologic Structure

[redacted] Near surface, the site is overlain by the Chenier Plain, “a low profile, storm-dominated, microtidal coast, downdrift, and west of the Mississippi River deltaic plain” (O’Leary and Gottardi, 2020).

Site Geologic Structure

[redacted] Conditions were favorable during Middle Jurassic for the deposition of the thick Louann Salt in the Gulf of Mexico. Deposition of large quantities of sediment on top of this layer-initiated salt flow, forming salt structures including the southeast-plunging West Hackberry salt ridge (O’Leary and Gottardi, 2020). [redacted]

Reflection Seismic Profiles

[redacted]

[redacted]

[redacted]

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Gravity Data

A publicly available data set of gravity station measurements from USGS across the states of Louisiana and Arkansas covers the proposed storage site (Figure 1-11 and Figure 1-12). Although this survey is based on a relatively wide-spaced grid (approximately one data point every 9 miles) the two captioned grids below confirm the regional geologic setting of large quantities of sediment on top of the less dense salt structures.

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 IGSN–71 datum was reduced to the Bouguer anomaly using the 1967 gravity formula (Cordell and others, 1982) and a reduction density of 2.67 g/cc. Terrain corrections were calculated radially outward from each station to a distance of 167 km (100 mi) using a method developed by Plouff (1977).

[redacted]

[redacted]

Figure 1-12 represents an isostatic gravity anomaly map utilizing the same data point spacing as the previous figure. The isostatic residual gravity map 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.

[redacted]

[redacted]

Geomechanics

Local Stress Conditions

[redacted]

Technical publications on the regional stress conditions in the Gulf of Mexico Basin indicate the orientation of maximum horizontal stress (S_{Hmax}) is largely parallel to the strike of the progradational clastic sedimentary wedge, in a general northeast-southwest direction (Zerwer, 1997). [redacted]

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). [redacted]

[redacted]

Elastic Moduli and Fracture Gradient

Elastic moduli and fracture gradients were determined from laboratory analysis of core samples where available. [redacted]

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Porosity and Permeability

In the sections below, porosity described is effective porosity. Due to the irreducible bound water in the clay matrix, total porosity is not representative of the pore space that can be occupied by mobile fluids. As addressed in the site geology section, measured total porosity in the smectite clay is higher than kaolinite clay though the permeability in smectite clay is much lower than permeability measured in higher kaolinite clay shales. Due to this, effective porosity is a better estimate of void space that mobile fluid can occupy and a closer approximation to fluid migration conditions in the reservoir.

Effective porosity is described as the porosity of a rock or sediment available to contribute to fluid flow through the rock. The effective porosity is calculated by determining the Vshale of the interval:

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

The Vshale is incorporated into the effective porosity (ϕ_{eff}) equation:

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

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted] Pliocene and Miocene shales that are 100% clay have 0% effective porosity thus 0 mD permeability, as evidence in the Coates Permeability Equation below:

$$Coates\ K = (70 * PHIE^2 * \left(1 - \frac{Swlrr}{Swlrr}\right)^2$$

Where:

Coates K = Permeability in mD
PHIE = Effective porosity v/v
SwIrr = Irreducible water saturation v/v

[redacted] In consideration, the vertical permeability is assumed to be 1/10th of the horizontal permeability (Fanchi, 2010).

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Geochemical Characterization

[redacted] The lower-density injected CO_2 will mix with the reservoir brine, rise buoyantly to the top of the aquifer formation and accumulate underneath the seal rock (Lindeberg and Wessel-Berg, 1997). The CO_2 brine will partially dissolve into the seal rock formation water and may diffuse upward into the seal rock, an extremely slow process in low-permeability seal rocks. Any CO2 that may diffuse upward will likely react with minerals present in the seal rock (Hildenbrand et al., 2002). To simulate the potential slow diffusion, geochemical interactions at the interface between the surface of the seal rock minerals, seal rock fluid and injected CO_2-rich gas solution are modeled.

Baseline Geochemistry

[redacted]

PHREEQC Interactive software, available from the USGS, is a geochemical simulator of single-phase one-dimensional reactive transport, batch-reaction equilibrium or kinetic problems.

A baseline sample of the USDWs will be taken during the drilling and installation of the groundwater monitoring well as discussed in Section 5.

[redacted]

Simulated Reservoir Brine and Gas Interaction

The interaction between the gas injectate and reservoir rock/brine is modeled through PHREEQC batch reaction. [redacted] The model assumes a 1 cubic meter rock and brine sample injected with 100 L of gas. [redacted] The pH scale is logarithmic and inversely indicates the concentration of hydrogen ions in solution. [redacted] The modeled reservoir brine and gas solution is referred to as “gas solution” in the following section.

[redacted]

Simulated Seal Brine and Gas Solution

The interaction of gas solution, seal rock and seal brine is modeled through PHREEQC batch reaction. We build off the previous model to simulate a 1:1 mixture of gas solution and modeled in-situ brine. The model assumes a 1 cubic meter rock and brine sample flushed with 50% gas solution. [redacted]

[redacted]

[redacted]

[redacted]

Hydrology

Beneath the Prairie Formation is a sequence of Pleistocene deposits that collectively form what is known as the Chicot aquifer. Based on the depths of similar deposits in the Lake Charles area, the aquifer is comprised of three sand units referred to as the "200-Foot Sand", "500-Foot Sand" and "700-Foot Sand". [redacted] The nomenclature of "200-Foot Sand", etc. refers to the analogous sand body and not the actual depth and is used herein for consistency. [redacted] The sand and gravel deposits that comprise the Chicot aquifer thicken along their southern dip and are coarser at their base. [redacted] The confining clays were deposited in lagoonal and flood plain environments and vary in thickness and extent. For a general depiction of subsurface groundwater flow direction within the Chicot aquifer, please refer to Appendix C-8. As illustrated in the attached appendix, groundwater flow trends South to North at the proposed HCS project area.

"200-Foot Sand"

The "200-Foot Sand" generally consists of fine to medium sand with coarse-grained sand and occasionally gravel at its base in areas where the zone is thickest. This layer dips generally

southward at a gradient of approximately 10 vertical feet per mile. [redacted]

“500-Foot Sand”

[redacted] The 500-Foot Sand is composed of fine to coarse grain sand fining upward and grades to deltaic deposits (Whiting, 1980).

[redacted]

“700-Foot Sand”

The “700-Foot Sand” is the deepest of the groundwater bearing sands in the Chicot aquifer. [redacted]

[redacted]

Site Evaluation of Mineral Resources

Other subsurface geochemical considerations include the potential for mineral or hydrocarbon resources beneath the proposed CO_2 storage site. [redacted] West Hackberry Dome was discovered in 1902 followed by the discovery of the bordering Oil Field in 1928.

West Hackberry Dome is currently used for emergency crude oil storage by the U.S. Strategic Petroleum Reserve. West Hackberry Dome currently has 21 storage caverns, an authorized storage capacity of 220.4 million barrels and a cavern inventory of 192.3 million barrels.

West Hackberry Oil Field is primarily productive out of the Pliocene, Fleming and Anahuac formations. More than 800 wells have been drilled though only 18 of those wells are still active today. To date, the field has produced about 152 MMbbls of oil and 19 Bcf of gas. In February 2021, the field produced 5.3 Mbbls of oil and 1.9 MMcf of gas.

[redacted]

[redacted]

[redacted]

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 effort is comprised of a three-step approach. These three steps include:

1. Identification of historical seismic events within proximity to the project
2. Determination of operational influences on nearby faults
3. Performance of a fault-slip potential (FSP) simulation model

Identification of Historical Seismic Events

For the first step, an area of review surrounding the project location is conducted. This area of review is defined as a 9.08-kilometer radius or a 100 square kilometer area surrounding the project. If any recorded events are discovered, an FSP model may be run.

[redacted] The search included all seismic events greater than a 2.0 magnitude. See Figure 1-23 and 1-24.

Influencing of Nearby Faults

EPA regulations require that a complete understanding of the extent and location of the resultant injection plume be determined and identified. Should the final plume extent encounter a nearby fault, an FSP model would be run. The results discussed in Section 2 of this application (see subsequent section), indicate that no faults are encountered during the injection operations for HCS Well No. 001.

Fault-Slip Potential Model

[redacted] no seismic risk has been associated with this project. Hence, no FSP model was performed.

[redacted]

[redacted]

[redacted]

Conclusion

[redacted] No faults or fractures are identified based on seismic analysis or geophysical well log characterization. [redacted]

[redacted]

[redacted]

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SECTION 2 – PLUME MODEL

This discussion of the Plume Model used for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§615.31** [40 CFR **§146.84**]. This section describes the key details of the plume model. The plume defines the pore space rights, area of review (AOR) for the well, corrective action plan if necessary, and overall viability of the project. The Hackberry Carbon Sequestration project will be comprised of three (3) wells for a total project injection capacity of 4.5 million metric tons of carbon dioxide being injected and sequestered per year.

[redacted]

This modeling software used to evaluate this project was Computer Modelling Group's GEM 2020.11 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon sequestration.

[redacted] GEM utilizes the compositional methods described above along with equations specific to CO_2 to effectively model and simulate plume behavior within the injection intervals.

TABLE OF CONTENTS

Model Inputs 1
Trapping Mechanisms 1
Stratigraphy of Location 3
Hydrogeology 3
Relative Permeability and Capillary Pressure 5
Initial Conditions 8
Injection Rate 9
Injected Composition 9
Completion Plan 10
Model Orientation and Gridding Parameters 14
Spatial Conditions 14
Boundary Conditions 15
Model Timeframe 15
Model Results 15

Figures

[redacted]

Tables

[redacted]

Model Inputs

Trapping Mechanisms

The flow of CO_2, or plume migration, can be defined by five primary trapping functions: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. Each of these functions is explained in further detail below.

Structural Trapping

Structural trapping is a physical form of trapping caused by geological structures. CO_2 is much lighter than the connate brine and therefore tends to float to the top of the injected formation and is stored beneath the cap rock. For this model, CO_2 mass density ranges from between 38 lb/ft^3 in the shallow injection intervals and up to 53 lb/ft^3 in the deep injection intervals, whereas brine density is approximately 68 lb/ft^3. Common examples of structural trapping include cap rock geology such as shales which prevent upward migration of the injected gases and faults or pinchouts which can limit the lateral extent of the plume migration within the reservoir.

Hydrodynamic Trapping

Hydrodynamic trapping is another physical form of trapping caused by the physical interaction of CO_2 and brine. The carbon dioxide will push against and/or mix with the brine differently depending on pressure deltas and phase of the CO_2. This mechanism is particularly effective in laterally unconfined sedimentary basins with limited structural traps, but with large-scale flow systems and low groundwater and fluid flow rates as is seen in the Hackberry location.

For both structural and hydrodynamic trapping, equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong method. The EOS implemented within the Hackberry Carbon Sequestration Well No. 001 model was the Peng-Robinson (1978) due to its widely accepted use for volumetric and phase equilibria.

Residual Gas Trapping

Residual gas trapping is the physical trapping of CO_2 within pore space. As water is displaced in the rock, the CO_2 fills in the space. However, depending on the movement of CO_2 and the aqueous phase through saturation and capillary forces, CO_2 will remain imbibed within the pore space and become trapped. As with the structural and hydrodynamic trapping discussed above, several methods are used in the petroleum industry for determining residual gas trapping such as the Carlson and Land model and the Larsen and Skauge model, both of which are available in GEM. For the purposes of the simulation discussed herein, the Larsen and Skauge model was used for its ability to determine 3-phase relative permeabilities which includes water phase hysteresis. Whereas the Carlson and Land model is somewhat limited in that it is primarily used for 2-phase hysteresis between oil and gas only.

Solubility Trapping

Solubility trapping is a form of chemical trapping between CO_2 and brine. CO_2 is highly soluble in brine with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher density brine to sink within the formation thereby trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration.

For solubility modeling, GEM offers the options of the Harvey (1996) and Li-Ngheim's (1986) methods. While the Harvey method is often preferred in situations with extremely high sodium chloride content, the Li-Ngheim's method was chosen due to its ability to include solubility parameters specific to CO_2, which were defined using Henry's Law Constant Correlations.

Geochemical Trapping

Geochemical trapping, or mineral trapping, is another form of chemical trapping that occurs due to reactions between CO_2 and the geochemistry of the disposal formation. During injection of CO_2 into the disposal reservoir, four (4) primary chemical compounds are found: CO_2 in supercritical phase, insitu hydrochemistry of the connate brine, aqueous CO_2, and the geochemistry of the formation rock. The aqueous CO_2 is an ionic bond between the CO_2 gas and connate brine within the formation. These compounds will all interact with each other often resulting in CO_2 being precipitated out as a new mineral. This new mineral is typically Ca CO_3, or calcium carbonate (limestone).

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

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

These three (3) reactions are all common ionic reactions that can occur in the reservoir between water and/or CO_2. The following formulae show the mineral reactions used within the model. Each of these is a common mineral found within sandstone in an underground aquifer and cause the precipitation of carbon oxides in a solid state:

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

While geochemical trapping can have a greater impact on carbon dioxide over hundreds or thousands of years, the short term effects of these trapping mechanisms are relatively small, and fluid movement is predominated by hydrodynamic and solubility trapping. Due to both the current limitations in data for the compositions of these minerals and components in the reservoir

and the computational stress added to the software, the geochemical trapping mechanisms have not been assumed in the current model. As more data is received on the geochemical properties of the reservoir, sensitivities could be run to determine the applicability of these traps.

Stratigraphy of Location

[redacted]

Hydrogeology

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Relative Permeability and Capillary Pressure

[redacted]

[redacted]

A study was presented at the SPE Annual Technical Conference and Exhibition in October 2003 that focused on correlations used to determine maximum residual gas saturation in various sandstone reservoirs. From this study, it was found that for sandstone with large porosity, and specifically sandstone with large pore sizes, had the ability to trap more residual gas (Suzanne et al., 2003). [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Initial Conditions

The model is assumed to initially be completely brine filled. [redacted]

[redacted]

[redacted]

Injection Rate

The injection rate can be limited by either a set maximum injection rate or maximum pressure in the wellbore. [redacted] The calculations for fracture pressure are shown in Eaton's Equation below, where FG is the fracture gradient, ν is Poisson's Ratio, OBG is overburden gradient, and P_p is the pore pressure gradient:

$$FG = \frac{\nu}{1-\nu}\left(OBG - P_p\right) + P_p$$

[redacted]

Injected Composition

The composition of the injected fluid in the model is based on the actual expected components to be injected. [redacted]

[redacted]

[redacted]

Completion Plan

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Model Orientation and Gridding Parameters

Spatial Conditions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Boundary Conditions

[redacted]

Model Timeframe

[redacted]

Model Results

After variable inputs for all of the above parameters, the model was run. The primary objective of the model is to optimize injection patterns to reduce the horizontal extent of the plume while

keeping below the fracture pressure for the targeted injection rate. [redacted]

[redacted]

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SECTION 3 - AREA OF REVIEW AND CORRECTIVE ACTION PLAN

TABLE OF CONTENTS

Facility Information 1
Computational Modeling 1
Area of Review Discussion 2
Area of Review Results 6
Corrective Action Plan and Schedule 6
Area of Review Reevaluation Plan and Schedule 7
Proposed Reevaluation Cycle 7

Figures

[redacted]

Tables

[redacted]

Table 3- 2: Corrective Action Plan 6
Table 3- 3: Triggers for AOR Reevaluations 7

Facility Information

Facility name: **Hackberry Carbon Sequestration, LLC**

[redacted]

Location: 1500 Post Oak Blvd, Suite 1000
Houston, TX 77056

Computational Modeling

Model Name: **GEM**

Model Authors/Institution: Computer Modeling Group, Ltd.

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

[redacted]

[redacted]

Area of Review Discussion

Statewide Order 29-N-6, ***§615.B*** [EPA ***40 CFR §146.84***] requires that an area of review (AOR) be conducted for a Class VI carbon sequestration well application. This AOR is defined as 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.

The AOR is conducted with three (3) primary purposes in mind. These are: CO_2

1. Identification of any subsurface geological features which may influence the ability to store sequestered gases for an indefinite length of time
2. Identification of any artificial penetrations or manmade structures which 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 injection plume over the modeled time period

In accordance with Statewide Order and Federal EPA requirements, Hackberry Carbon Sequestration will reevaluate the AOR at each of the following intervals:

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

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

Alternatively, wells that do not require AOR amendments or corrective action will demonstrate to the EPA UIC Program Director that no changes are needed through monitoring data support and modeling results. All modeling inputs and data used to support AOR reevaluations will be retained for 10 years.

An unfortunate impact to carbon sequestration projects, resulting from qualifying carbon injection wells as storage wells instead of disposal wells, is that pore space rights now become of paramount importance in the evaluation of a project's potential. This impact could end up being so adverse that it could possibly prevent a project from being economically viable. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

This plume extent was digitized from the GEM output and imported into ArcGIS to be utilized as the defined area of influence from which the AOR for the Hackberry Carbon Sequestration Well No. 001 was performed. Per the requirements of ***§615.B.1 [§146.84]***, a review was conducted to determine if there were any artificial penetrations or other features which may endanger the lowermost underground sources of drinking water (USDW) as a result of injection activity or operations. This review consisted of creating maps depicting the area of influence and identifying any manmade structures found within that area of review. Any artificial penetrations or other artifacts were then evaluated for depth of completion, construction details, and/or plugging and abandonment practices utilized to determine if said penetrations could possibly affect the containment integrity of the storage formation(s).

[redacted]

[redacted]

[redacted]

Area of Review Results

[redacted]

Corrective Action Plan and Schedule

Well Name / Location	Planned Corrective Action Method	Planned Date of Corrective Action	Notes / Comments
NONE	NONE	NONE	NONE

Table 3- 2: Corrective Action Plan

Area of Review Reevaluation Plan and Schedule

Proposed Reevaluation Cycle

Hackberry Carbon Sequestration, LLC will reevaluate the area of review at a minimum of every five years, per SWO 29-N-6 ***§615.B.2.b.i*** [EPA *40 CFR* ***§146.84(b)(2)(i)***]. The plume migration however, will be evaluated annually for the first five (5) years after commencing injection operations and then, operations-permitting, every five (5) years thereafter. The purpose of the annual survey is to confirm the validity of the plume model as compared to actual, empirical results.

As previously stated, due to the classification of carbon sequestration wells as storage wells, it will be important, operationally, to maintain a firm understanding of the movement of the injectate plume within the reservoir. [redacted] Notwithstanding this relationship and at a minimum, the survey will be performed at least once every five (5) years from the commencement of injection operations.

[redacted]

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

Reevaluation Trigger	Measure to be Taken	Schedule for Reevaluation
SWO 29-N-6 §615.B.2.b.i ***40 CFR 146.84(b)(2)(i)***	Reevaluate the AOR as required by statute	At least once every five (5) years
Annual plume migration survey identifies a greater extent than modeled	Re-run the reservoir plume model with new data Reevaluate the AOR	Within one (1) month of detection

Table 3- 3: Triggers for AOR Reevaluations

Annual plume migration survey identifies the plume direction is different than modeled	Re-run the reservoir plume model with new data Reevaluate the AOR	Within one (1) month of detection
Operational Change: Injection rate increases to a rate greater than that modeled	Re-run the reservoir plume model with new data If plume increases in extents, reevaluate the AOR	Within one (1) month of detection
Operational Change: Injectate composition changes to a new mixture	Re-run the reservoir plume model with new data If plume increases in extents, reevaluate the AOR	Within one (1) month of detection
New site characterization data	Re-run the reservoir plume model with new data If plume increases in extents, reevaluate the AOR	Within one (1) month of detection
New operations being brought online within or near the plume extents	Re-run the reservoir plume model with new data If plume increases in shape or extents, reevaluate the AOR	Within one (1) month of detection
Seismic event or other emergency	Perform a plume migration survey If plume increases in shape or extents, reevaluate the AOR	Within one (1) month of detection

Table 3- 3: Triggers for AOR Reevaluations, Continued

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

The following section describes the engineering design details and operational strategies employed during the planning of the proposed Hackberry Carbon Sequestration Well No. 001. The engineering design details meet the requirements of SWO 29-N-6 **§621.A.1** [40 CFR **§146.86**].

TABLE OF CONTENTS:

Engineering Design 2
General Outline of Well Design and Completion Schematic 2
Detailed Discussion of Injection Well Design 4
Testing and Logging During Drilling and Completion Operations 14
Logging Plan 14
Formation Fluid Testing 14
Step-Rate Test 14
Injection Well Operating Strategy 14
Injection Well Operational Strategy Summary 20

Figures

[redacted]

Tables

[redacted]

The design, construction, and operation of injection wells falls under the jurisdiction of the US EPA Underground Injection Control (UIC) program. Injection wells governed by the UIC program have operated since its inception in 1977. With the advent of Class VI regulations in 2010, and in no small part to the Bipartisan Budget Act of 2018 and subsequent IRS tax code 45Q in 2019, the industry has seen a recent flurry of activity in captured carbon injection wells.

All regions of the United States are being evaluated for the suitability for carbon sequestration from a geologic perspective. In all instances, due to the classification of Class VI wells as storage wells, reservoir management will be imperative for the purposes of plume migration control. Some depositional environments offer more options for reservoir management strategies than others. The Gulf Coast Basin, the basin which the proposed Hackberry Carbon Sequestration Well No. 001 is located, is one such location.

[redacted]

Engineering Design

The design of the Hackberry Carbon Sequestration Well No. 001 was developed with several considerations in mind. These considerations included volume and rate of injection, chemical composition and physical properties of the injectate fluid, corrosion concerns and metallurgical evaluations, and operational details necessary to maintain reservoir management for the well.

Carbon sequestration wells are designed along similar parameters and considerations as acid gas injection well, including special metallurgies. While carbon dioxide is not inherently hazardous, when mixed with water under the right conditions, carbonic acid can form with a pH as low as 3. As with all classes of injection wells, the protection of underground sources of drinking water is of paramount importance. Of secondary importance, the protection of other subsurface natural resources, if present, must also be protected. This is accomplished through the casing design for the injection well which is engineered to prevent injected fluids from escaping the confinement intervals into which they have been disposed.

[redacted]

General Outline of Well Design and Completion Schematic

[redacted]

[redacted]

Detailed Discussion of Injection Well Design

The typical procedure followed in the design of injection wells is to determine the minimum requirements for the injection tubing and then work back up through the production casing string, any intermediate casing strings (if necessary), and finishing with surface casing requirements. This was the procedure employed for the design of the Hackberry Carbon Sequestration Well No. 001.

To properly size the injection tubing, desired injection parameters were necessary. [redacted]

[redacted]

From these defined criteria, calculations were made to optimize the size of the tubing considering calculated pipe friction losses, exit velocities, compression requirements, and economic evaluations. [redacted]

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Figure 4- 3: Premier Removable 9-5/8" Production Packer Illustration

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SECTION 5 – TESTING AND MONITORING PLAN

The operating plans for the proposed Hackberry Carbon Sequestration Well No. 001 will include a robust testing and monitoring program, which are designed to satisfy the requirements of SWO 29-N-6 ***§625.A*** [40 CFR ***§146.90***]. This section discusses the key details of this program.

TABLE OF CONTENTS

Reporting Requirements 1
Testing Plan Review and Updates 2
Testing Strategies 2
Initial Step Rate Injectivity Test 2
Mechanical Integrity Testing – Annulus Pressure Test 4
External Mechanical Integrity Testing – Temperature Log 4
Pressure Fall-Off Testing 4
Cement Evaluation and Casing Inspection Logs 5
Monitoring Programs 5
Continuous Injection Stream Monitoring 5
Corrosion Coupon Monitoring 6
Ground Water Quality Monitoring 6
Injectate Plume and Pressure Front Tracking 9
Monitoring Conclusion 31
Contingency Secondary Monitoring System: Indirect Carbon Dioxide Plume and Pressure Front Tracking 32
References and Publications 47

[redacted]

Figure 5- 7: Illustration of Seismic Surveys (example is on land – the truck would be replaced by shallow-bottom boat) 14
Figure 5- 8: Illustration of a Checkshot Survey 15

[redacted]

Figure 5- 10: Geological Model Used for 2D Modeling for a VSP survey 17
Figure 5- 11: One Shot Geometry for VSP Geometry (Top: on the Water Zone, Bottom: on the CO_2 Zone) .17
Figure 5- 12: 4D Processing Workflow Diagram 18
Figure 5- 13: Example of 4D Model (shows time-lapsed gas-replacement of connate fluids) 19
Figure 5- 14: Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection as measured from the injector well Itself. Estimation of plume growth over time in plot on the right. 19
Figure 5- 15: Example of a 4D Output 20

Figure 5- 25: ARM images the acoustic energy caused by fluid flow in fractures (green surfaces). In this example, we monitored the path of the proppant from the Well 2 to 3 going below Well 1. Yellow bars show amount of proppant detected in wellbores using radioactive tracers. 33
Figure 5- 26: (Left) Depth slice through the ARM images at 1421 meters depth below the processing datum of 650 meters. Colored lines are injector wells. (Right) The same ARM image depth slice superimposed on the stacked 1 hr. of semblance 34
Figure 5- 27: The Stimulated Rock Volume (SRV) and two Active Production Volumes (APV) generated after two and three years of production. (Left) Map-view slices through the volumes at the wellbore depth. (Right) Profile views of the same three volumes sliced along the wellbore. Warm colors show high levels of activity and cool colors show lower activity levels.....34
Figure 5- 28: Frac energy was kept below the Maxton formation and thus did not enter the aquifer 35
Figure 5- 37: Workflow for one-way travel time depth migration. After trace processing and velocity model building and calibration, the traces are depth migrated for each time window and each depth voxel for the time interval that will be summed; f_{ij} is the trace amplitude.....44

Tables

Table 5- 1: Injectivity Test Parameters Measured and Measurement Frequency 3
Table 5- 3: Ground Water Quality Parameters Measured and Measurement Frequency.....8

Reporting Requirements

As per the requirement of 29-N-6 ***§629A*** [***40 CFR §146.91***], HCS will provide semi-annual reports to the UIC Director containing the following:

- Any changes to the physical, chemical and other relevant characteristics of the CO2 stream from what has been described in the proposed operating data.
- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure;
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
- Description of any event which triggers a shut-off device and the response taken
- Monthly volume and/or mass of the CO2 stream injected over the reporting period and the volume injected cumulatively over the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring as described in this Section

In addition, reports will be submitted within thirty (30) days after the following events:

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

Reports will be submitted to the Director, within 24 hours of the following:

- Any evidence that the injected VO2 stream or associated pressure front may cause an endangerment to a USDW
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs
- Any triggering of a shut-off system, either down-hole or at the surface
- Any failure to maintain mechanical integrity

Notification must be made to the UIC, in writing, 30 days of advance of:

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

All reports, submittals and notifications will be submitted to both the EPA and the LADNR. All records will be retained by HCS throughout the life of the project and for ten (10) years following site closure. Data on the nature and composition of all injected fluids collected will be retained as well for ten (10) years after site closure. The records will be delivered to the Director after the retention period if required by the director. Monitoring data as described in Section 5 will be retained for 10 years after it is collected. Well plugging reports, post-injection site care data and the site closure report itself will be retained for ten (10) years following site closure.

Testing Plan Review and Updates

This testing and monitoring plan will be reviewed and updated to incorporate monitoring data collected as described at least every five (5) years. An amended testing and monitoring plan will also be submitted within one year of an area of review reevaluation, following any significant changes to the facility such as the addition of monitoring wells or newly permitted injection wells within the area of review; or as required by the Director.

Testing Strategies

Initial Step Rate Injectivity Test

In order to determine the fracture gradient of the Hackberry Carbon Sequestration Well No. 001, per SWO 29-N-6 ***§617.B.4.a*** [***40 CFR §146.87(d)(1)***] and SWO 29-N-6 ***§617.5.c*** [*40 CFR* ***§146.87(e)(3)***], a step-rate injectivity test will be performed before CO_2 injection begins. A bottom hole pressure gauge and temperature gauge will be run to the bottom of the wellbore. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottom hole pressure and temperature readings must be taken prior to beginning injection.

[redacted]

Testing Method

HCS will collect samples of the CO_2 injection stream and perform analysis to meet the requirements of SWO 29-N-6 ***§625.A.1*** [40 CFR ***§146.90(a)***]. Samples of the CO_2 stream will be collected quarterly for the chemical analysis parameters provided below and continuously for pressure and temperature. The purpose of analyzing the carbon dioxide stream is to evaluate potential interactions of carbon dioxide and other components of the injectate.

Parameters Measured

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

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

Sampling Methods

Samples of the carbon dioxide stream will be collected from the CO_2 pipeline at a location which represents the injection conditions, with a sampling station connected to the pipeline via a sampling manifold. Sample cylinders will be purged with injectate gas to remove any laboratory-added gas and ensure a quality sample collection.

Mechanical Integrity Testing – Annulus Pressure Test

HCS will perform internal mechanical integrity tests (MIT) prior to initial injection and after any subsequent workovers to meet the requirements of SWO 29-N-6 ***§627.A.2*** [*40 CFR* ***§146.89(b)***].

[redacted]

The results of the Annulus Pressure Test will be reported to the UIC Division on Form UIC-5 within 30 days of the test.

External Mechanical Integrity Testing – Temperature Log

HCS will perform external mechanical integrity tests (MIT) annually to meet the requirements of SWO 29-N-6 ***§627.A.3*** [40 CFR ***§146.89(c)***] by running a temperature log, through tubing. Temperature logs will be run prior to beginning injection operations and will establish the baseline to compare against future logs. Prior to running the temperature logs, the well will be shut in long enough to stabilize temperatures, approximately 36 hours. Correlation between the baseline and subsequent logs will demonstrate mechanical integrity. Temperature logs will be reported to the UIC Division within 30 days of the log run.

Pressure Fall-Off Testing

To meet the operational testing requirements in SWO 29-N-6 ***§625.A.6*** [40 CFR ***§146.90(f)***], HCS will conduct a pressure fall-off test every five years. These fall-off tests will be used to measure formation properties near the injection well and to monitor for any changes in the near-well bore environment that may impact injectivity and increase pressures.

Testing Method

Prior to beginning the pressure fall-off test, injection rate and pressure will be maintained as constant as possible, while continuously recorded. Upon shutting in the well, pressure measurements will be taken continuously through the use of two bottomhole pressure gauges, with one serving as a backup and for verification in cases of questionable data quality. The fall-off period will continue until radial flow conditions are observed, as indicated by a straight line of pressure decay on a semi-log plot.

Analytical Methods

Standard diagnostic log-log and semi-log plots will be generated with observed pressure changes and/or pressure derivative plots. The purpose of these tests is to determine specific near-well bore conditions, such as well skin, the prevailing flow-regimes and hydraulic property and boundary conditions. Comparison of pressure fall-off tests prior to beginning injection operations with those performed subsequently can indicate whether significant changes in the well or reservoir conditions have occurred. Analysis will consider the effects of two-phase flow effects, and parameters determined from the fall-off test will be compared to those used in the site computational modeling and AOR determination. Any significant changes in reservoir properties may result in a reevaluation of the AOR. Results of the pressure fall of test will be reported to the UIC Division within 30 days of the test.

Quality Assurance/Control

All field equipment will be inspected and tested prior to use. Pressure gauges used in the fall-off test much be calibrated in accordance with manufacturers' recommendations and calibration certificates will be provided with the test results. The use of the second bottomhole pressure gauge will further provide validation of the test results.

Cement Evaluation and Casing Inspection Logs

Casing inspection logs will be run annually, through tubing on wireline and whenever tubing is removed for workover operations. The following tools will be run at that time:

- Multiple-armed calipers to measure the inner diameter of the casing as the tool is raised or lowered into the well
- Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
- Electromagnetic tools that measure magnetic flux of the tubular and can provided mapped circumferential images to indicate potential pitting.

Monitoring Programs

Continuous Injection Stream Monitoring

HCS will continuously monitor the injection pressure, rate and volume, plus the annulus pressure to meet the requirements of SWO 29-N-6 ***§625.A.2*** [40 CFR ***§146.90(b)***]. To facilitate the collection, monitoring and reporting of operational data, a Supervisory Control and Data Acquisition system (SCADA) will be installed on the site of the injection well.

The pressure and temperature of the injected carbon dioxide stream will be continuously monitored by the use of digital pressure gauges installed in the carbon dioxide pipeline near the pipeline interface with the wellhead and will be connected to the SCADA system on site. A Coriolis mass flow transmitter will be installed on the injection well to measure the mass flow rate of carbon dioxide injected. The flow transmitter will be connected to the CO_2 storage site's SCADA system to

continuously monitor and control the rate of CO_2 injection.

Reservoir temperatures and pressures will be measured through a fiber-optic, sDAS (Seismic Distributed Acoustic Sensing), embedded in the cemented annulus behind the long string casing. The gauges are described in detail in the Vertical Seismic Profile technology discussion in the plume monitoring section of this plan.

Analytical Methods

Continuously monitored parameters will be reviewed and interpretated regularly, to ensure the parameters are within permitted limits. The data will also be reviewed for trends to help identify need for equipment maintenance or calibration. Monitoring results will be included in the semi-annual reports.

Corrosion Coupon Monitoring

HCS will conduct corrosion monitoring of the tubing and casing materials of the well to meet the requirements of SWO 29-N-6 ***§625.A.3*** [40 CFR ***§146.90(c)***]. HCS will implement a corrosion coupon monitoring system, to be evaluated quarterly, as well as casing inspection logs performed every 5 years at the time of permit renewal. If plume surveys indicate it is time to recomplete uphole to a shallower sub-section, then the tubing and packer will be removed and inspected, and a casing inspection logging suite will be run. If abandonment of a sub-section is not warranted at the time of permit renewal, then a thru-tubing inspection will be performed.

Sampling Methods

Corrosion coupons, made of the same material as the production casing and the injection tubing, will be placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ATSM) standards for evaluating corrosion tests. When the coupons are removed, they will be inspected visually for any signs of corrosion, including pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

Ground Water Quality Monitoring

Hackberry Carbon Sequestration, LLC will conduct ground-water quality and geochemical monitoring above the confining zone to meet the requirements of SWO 29-N-6 ***§625.A.3*** [*40 CFR* ***§146.90(c)***]. The purpose of the ground water monitoring is to detect potential changes that may result from fluid leakage out of the injection zone. [redacted]

[redacted]

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Parameters Measured

Parameter/Analyte	Frequency
Aqueous and pure phase carbon dioxide	Every five years
Total dissolved solids	Every five years
pH	Every five years
Specific conductivity (SC)	Every five years
Temperature	Every five years
Density	Every five years
Other parameters including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds)	Every five years

Table 5- 3: Ground Water Quality Parameters Measured and Measurement Frequency

Sampling Methods

Fluid samples in the groundwater monitoring well will be collected at the monitored formation temps and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the well bore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

Analytical Methods

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested for in the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database.

Trends that may indicate fluid leakage include:

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

Laboratory to be Used/Chain of Custody Procedures

Water samples will be sent to an EPA approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

Quality Assurance and Surveillance Measures

Duplicate samples and trip blanks for QA/QC purposed will be collected and used to validate test results and ensure samples are free of contamination.

[redacted]

Injectate Plume and Pressure Front Tracking

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1D and 2D Models

To determine the magnitude of changes in the CO_2 plume, 1D and 2D models are generated to measure the effect on different scenarios. In this section we will explain the methodology behind each one of these models.

Seismic surveys create a seismic wave that travels through the earth and are subsequently reflected back to geophones that listen for these waves. The seismic waves can be created by a "shot" which is a term that refers to explosives or other mechanical sources. A vibrator is the most common mechanical source and is a device that uses a steel plate to pound into the earth and generate seismic waves. Geophones are recorders that listen for the sound waves that are reflected back to surface as seen in Figure 5-7. Specifically, they allow engineers to determine the time it takes for seismic waves to bounce off each transition zone between formations. The differences in time between each reflection allow for the calculation of a velocity in each formation. The variation in sonic velocities allow for geologists to understand the lithology of the subsurface. Seismographs are then used to store the data sent by the geophones.

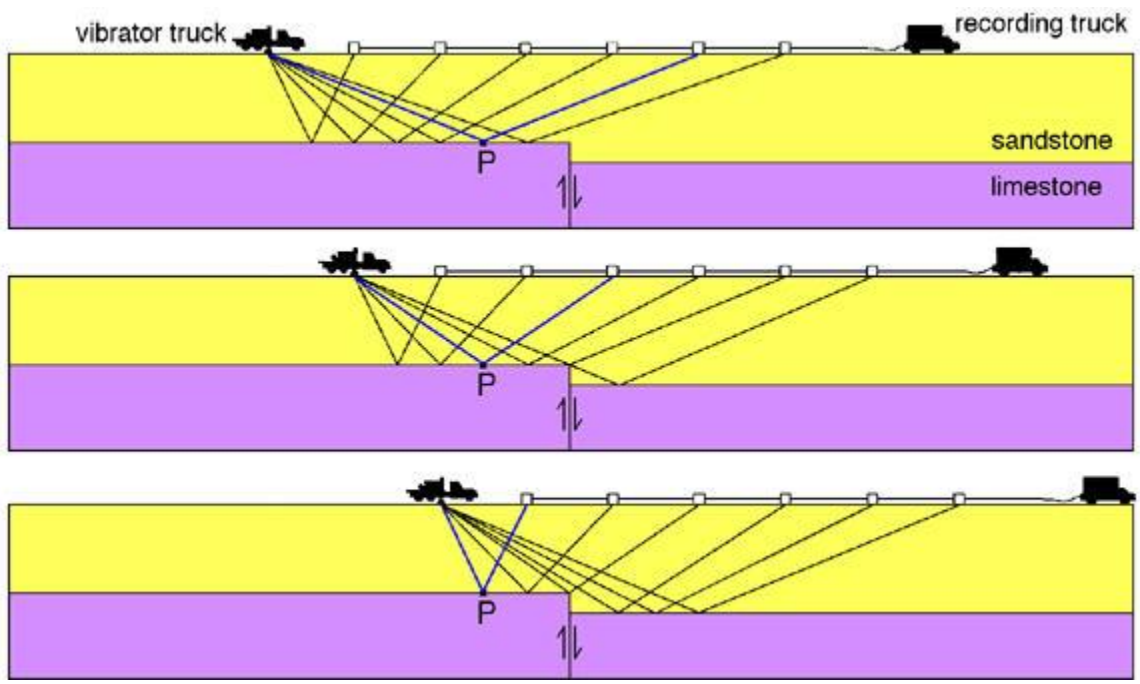

Figure 5- 7: Illustration of Seismic Surveys (example is on land – the truck would be replaced by shallow-bottom boat)

1D Model

One-dimensional (1D) seismic surveys operate on the same principles as previously discussed. Figure 5-8 shows an example of a checkshot survey which is a common method of obtaining 1D seismic data. However, the geophones are placed vertically, along the wellbore. As the shots are fired from surface, the geophones are able to record the seismic waves at various depths. They provide the most accurate measures of sonic velocities of the geologic layers effected by the construction of the wellbore. These are generally used to create more accurate two-dimensional (2D), three-dimensional (3D), and four-dimensional (4D) surveys. 1D surveys make the assumption

that each formation is horizontally homogeneous so they can only provide average sonic velocities. The data from 1D surveys can also be used to correct sonic logs and generate synthetic seismograms. Synthetic seismograms are used to predict the seismic responses of the subsurface. Acoustic logs are a special variation of 1D seismic surveys. They use wireline sonic tools to generate acoustic data along the wellbore. These are used for different purposes than seismic surveys, but they can lead to a 1D understanding of the variation in velocities.

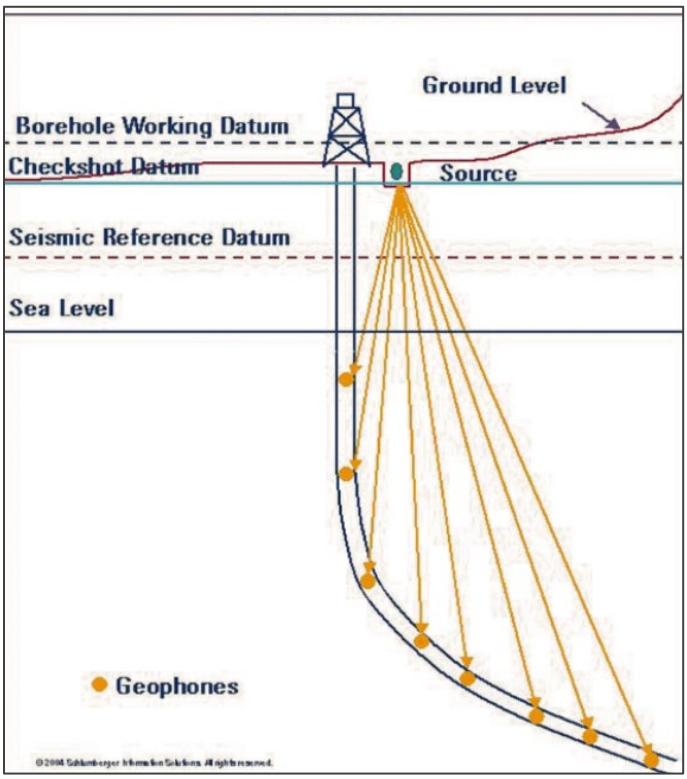

Figure 5- 8: Illustration of a Checkshot Survey

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2D Model

Following the results of the interpretation of a 1D model, a subsequent geological model is built to reflect the two saturation cases, connate formation fluids as one case and CO_2 replaced fluid as the second case.

2D seismic surveys work off the same principles as previously discussed, but they provide a picture of a thin slice of the Earth's crust. The geophones are instead placed in a line along the surface and record the seismic waves as they reflect off each formation. 2D surveys require multiple lines to be set in order to achieve the best results. They ideally set each line to be orthogonal to the strike of a geologic structure and parallel to the dip of said structure. They provide information of various formations, faults, and other subsurface characteristics. The intersection of multiple 2D surveys allows for the geologist to interpret contour lines and generate geologic maps. These surveys are cheaper and have less environmental impact than 3D surveys. 2D surveys are commonly used for initial exploration of unexplored areas to give geologists an understanding of what formations lie beneath the surface.

In the following example, Figure 5-10, a 2D geologic model is built to reflect the two (2) saturation cases and VSP geometry is used as indicated. This shows how VSP technology monitors the CO_2 front. In-situ log results, or open hole sonic or density logs, are inserted in the left and formation log on the right. A weighted distance linear interpolation is used to generate the 2D P-wave model.

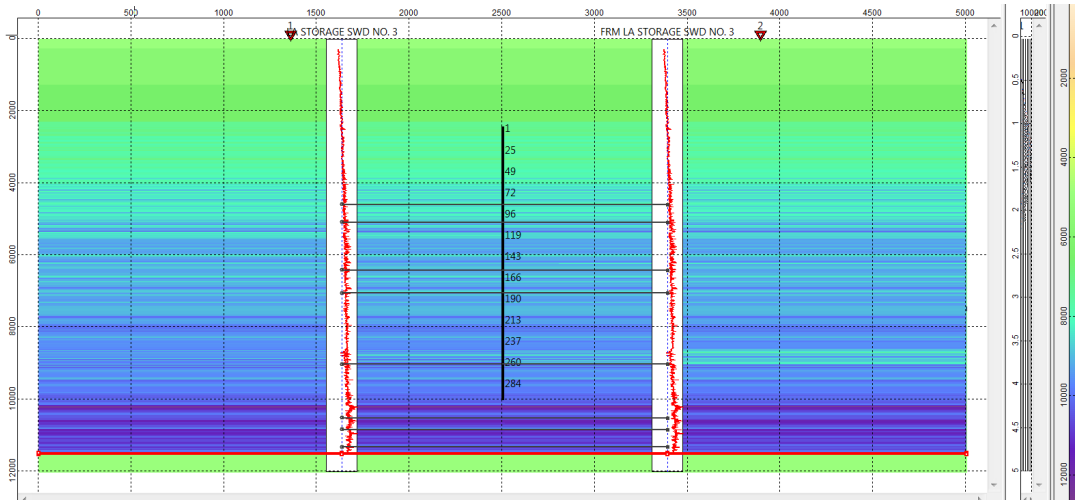

Figure 5- 10: Geological Model Used for 2D Modeling for a VSP survey

An expected response using 100% water and a modeled response using CO_2 indicates a change of amplitude and is interpreted that it is feasible to use VSP to monitor fluid changes with the rock for this project as seen in Figure 5-11.

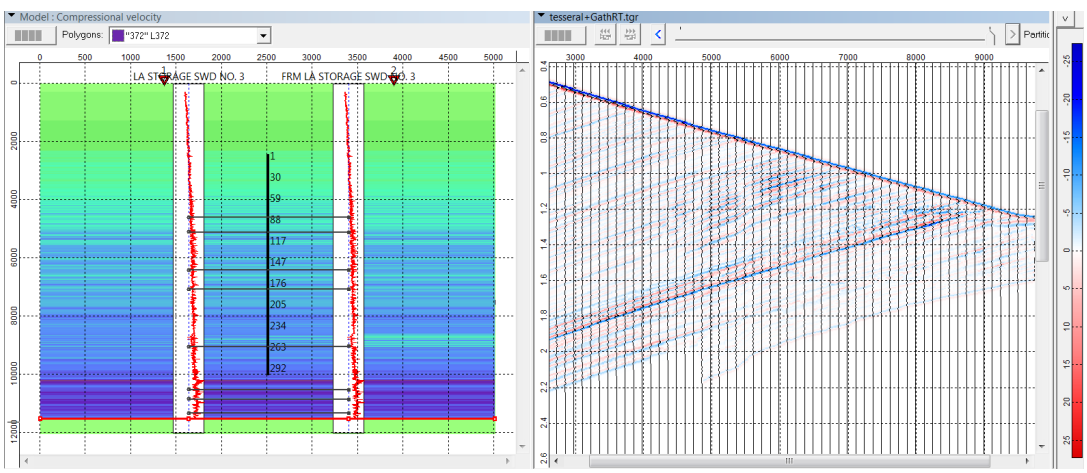

Figure 5- 11: One Shot Geometry for VSP Geometry (Top: on the Water Zone, Bottom: on the CO_2 Zone)

<u>Processing Workflow and 4D Seismic Volume Determinations</u>

The final interpretation from consecutive surveys will be made by observing gas volume build-ups over time. When 1D, 2D, and 3D seismic surveys are combined with a time component, i.e. surveys conducted at various time periods from one another (year 1, year 5, year 10, etc.), a 4D model is produced. The 4D interpretation of a seismic survey will identify changing volumes of gas build-up which are represented by log shifts on 1D and 2D responses or heat blooms on 3D models.

A basic example of the workflow is illustrated in Figure 5-12.

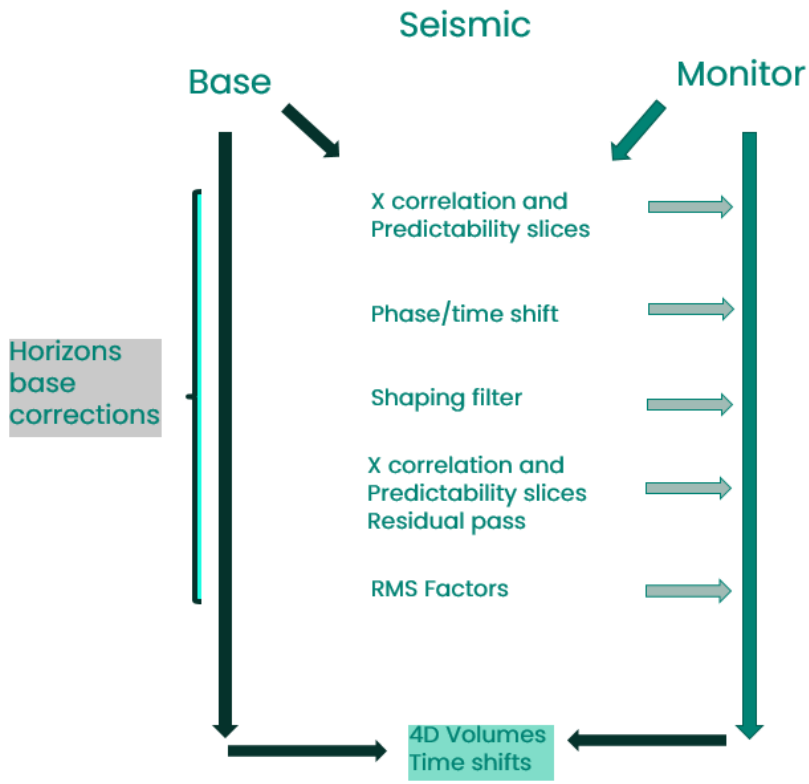

Figure 5- 12: 4D Processing Workflow Diagram

The 3D model of the horizon is generated from the base survey and every subsequent survey conducted generates a reflection differential which is mapped on the 3D model to determine plume geometry. This process is repeated to show time-lapsed growth or development of the injectate plume.

All the seismic volumes will be processed with same software and for each of the workflow steps below and will be used for consistency. The following figure, is an example of output from the 4D processing workflow.

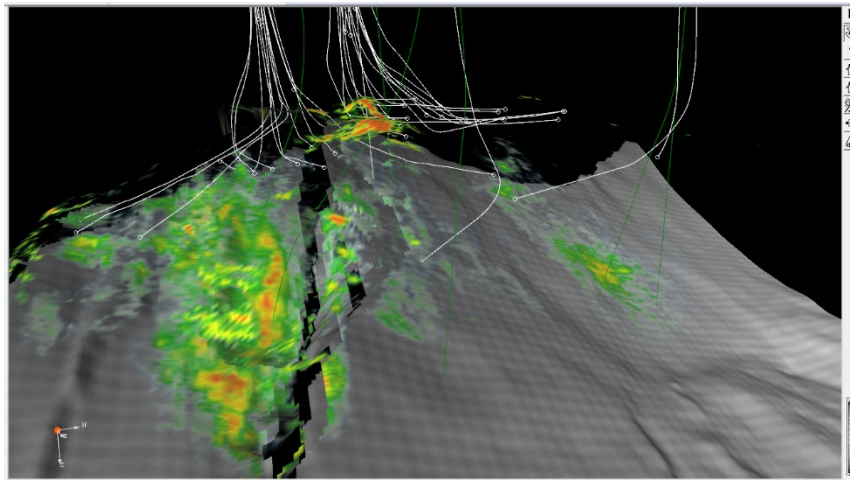

Figure 5- 13: Example of 4D Model (shows time-lapsed gas-replacement of connate fluids)

Inversion Workflow

Baseline surveys will be inverted using post-stack seismic volumes, well log data and a structural model to generate the basic low component model. Subsequent monitor surveys will use the same low component and residual corrections for consistency and the detection of changes over time. These changes over time will be assumed to be due to the injection activities.

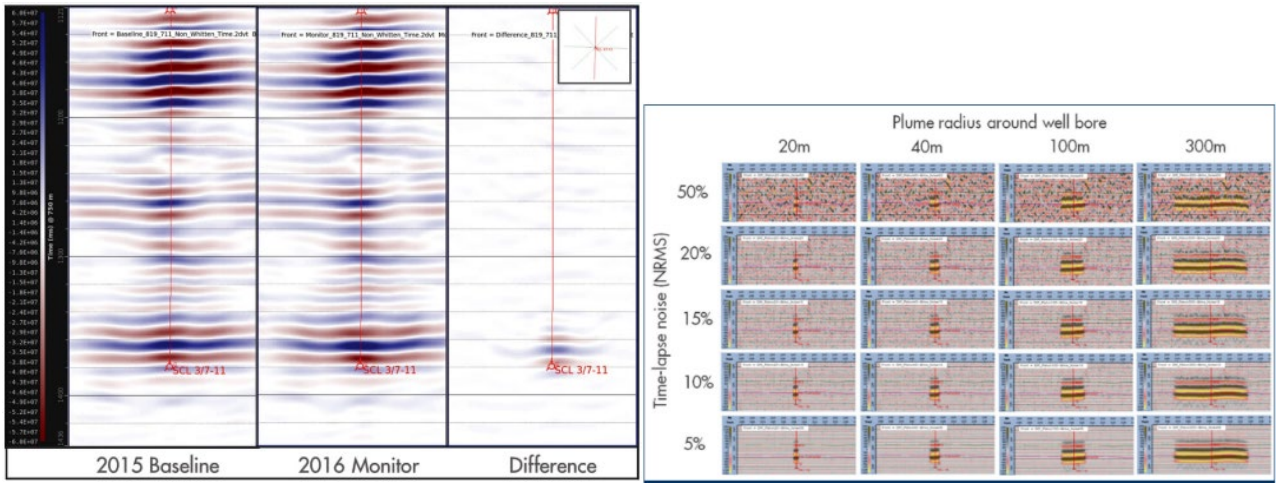

Figure 5- 14: Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection as measured from the injector well Itself. Estimation of plume growth over time in plot on the right.

Baseline Survey

The importance of a quality baseline survey cannot be stressed. This represents the only opportunity to capture an image of the reservoir before any perturbation of the reservoir occurs due to injection or offset activity (man-made or natural). Without the baseline survey no interpretation of formation changes can be made. Any errors made in the construction of the baseline image will impair sensitivity and interfere with the sensitivity to which formation changes can be made. Further, the size of the baseline survey determines the extent to which plume can be measured. Given uncertainty in our reservoir models, it is important to acquire a baseline survey with sufficient extent to provide utilization in the event the initial reservoir models are not accurately predicting the plume migration.

An example of a 4D time-lapse model is shown below visualized in 3Dimensional space with analysis software. Each horizon can be displayed along with a color code for differences in amplitude over time.

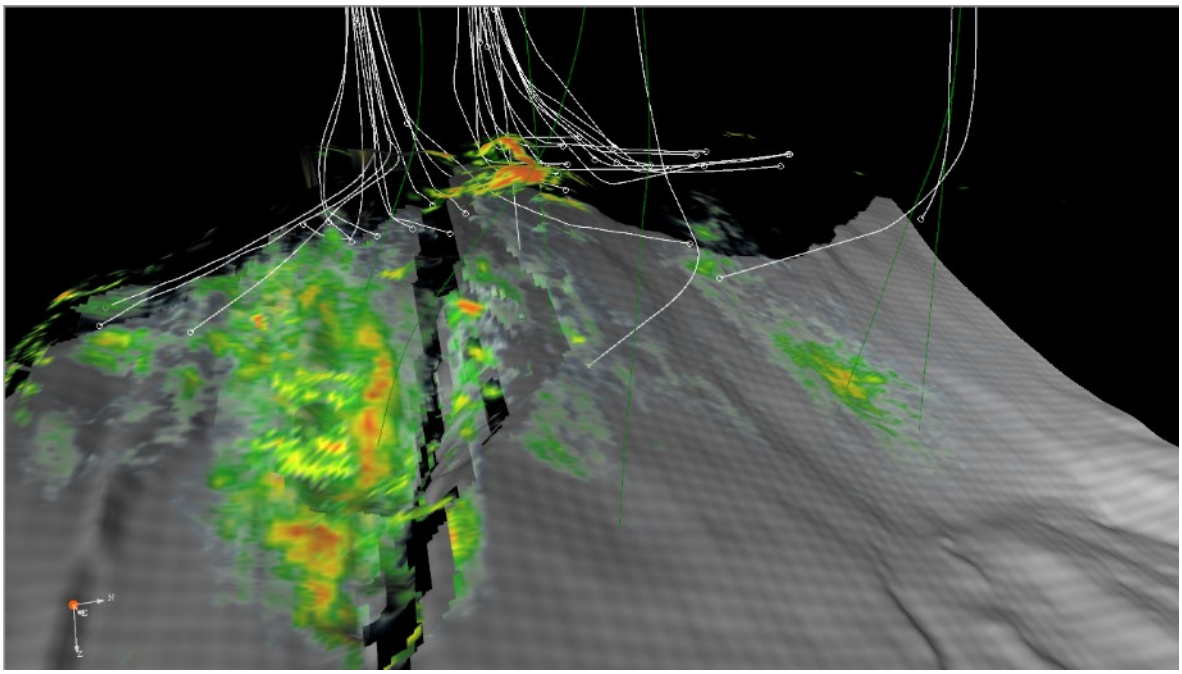

Figure 5- 15: Example of a 4D Output

Equipment Design and Setup

The equipment proposed in this section will be used in the periodic surveys to determine CO_2 plume growth over time. [redacted]

Wellbore Overview

[redacted]

[redacted]

[redacted]

Equipment Overview

[redacted]

[redacted] type seal assembly from the upper sealbore of the packer while leaving the packer down hole.

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Ambient Reservoir Monitoring Technology Overview

Ambient Reservoir Monitoring (ARM) uses a proprietary, patented process based on a signal process known as Streaming Depth Imaging (SDI) to image the intensity and distribution of weak acoustic emissions from reservoir depths. This process starts with a recording of passive seismic data from an array of geophones at the surface or near-surface and uses a modified Kirchhoff migration processing algorithm and a semblance computation to detect the presence of long duration low amplitude seismic emissions coming from depth. This technology was originally developed to monitor the large signals associated with hydraulic fracturing in unconventional oil and gas resource plays but was later shown to be effective at imaging lower amplitude signals from water flood and gas injections, hydrocarbon production, and even signals associated with water intrusions into mines.

In a 2017 article in the SEG Leading Edge magazine, Whiting Oil and Gas, in conjunction with ARM's predecessor company Global Geophysical Services, published a particularly insightful example showing the use of SDI to image the propagation path of fluid and proppant from the horizontal well being treated (Well 2 in Figure 5-25 below) into a second horizontal well (Well 1) while dipping under another over pressured horizontal well positioned between them. Because the proppant contained

a radioactive tracer this provide a rare opportunity to confirm via direct downhole measurement that we had imaged this fluid flow pathway precisely.

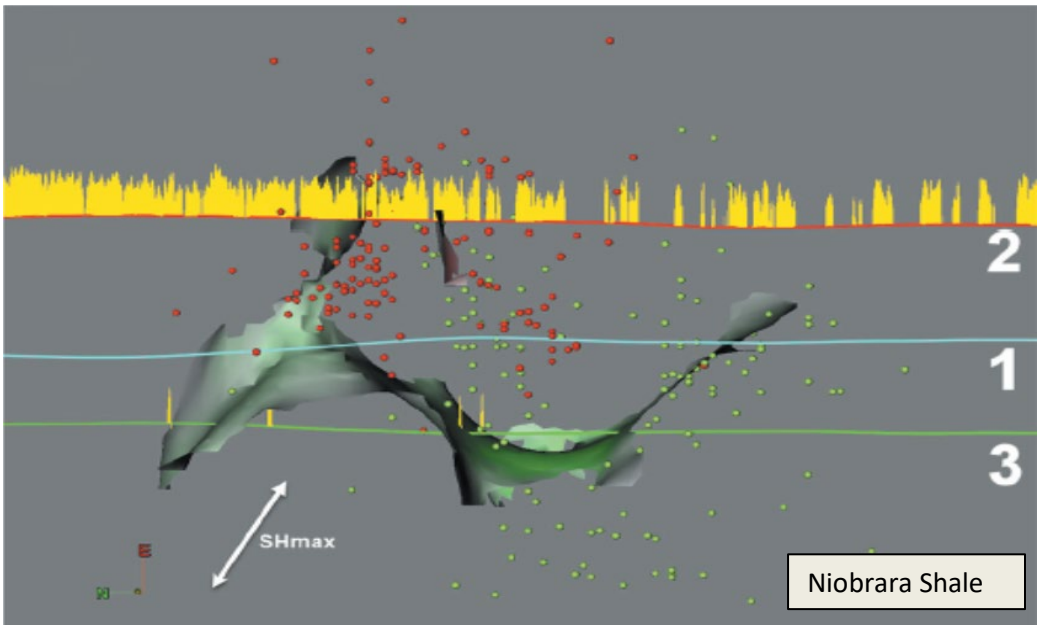

Figure 5- 25: ARM images the acoustic energy caused by fluid flow in fractures (green surfaces). In this example, we monitored the path of the proppant from the Well 2 to 3 going below Well 1. Yellow bars show amount of proppant detected in wellbores using radioactive tracers.

Another important distinction from this example can be made by comparing the microseismic earthquakes (MEQ) from two frac stages recorded using a reservoir level downhole instrument (as shown as green and red on Figure 5-25) versus the SDI results. The MEQ's show some general relationship to the zone being stimulated but do not provide a clear delineation of the permeable pathway.

Other examples from ARM's archive show that the high pressures associated with hydraulic fracturing are not required to create an acoustic signal that can be mapped from the surface. Figure 5-26 is an example of a water flood in Saskatchewan, Canada. The goal of the project was to illuminate facture networks and permeable pathways in an area of tertiary oil recovery. The method can image weak pressure changes far from a well because even very small fluid pressure changes can induce acoustic activity (Ziv and Rubin, 2000) and the ARM method is highly sensitive. In this study there was a large increase in acoustic emissions observed as the water injecting wells and producing wells were activated as compared to the "quiet" state where neither injection nor production was occurring.

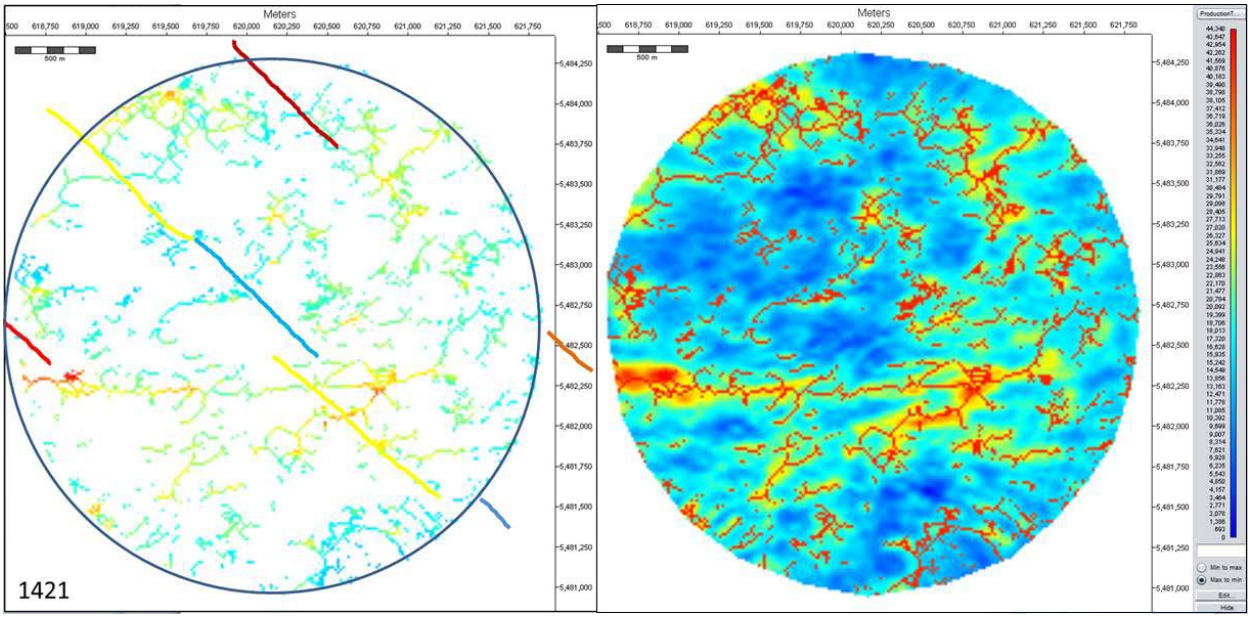

Figure 5- 26: (Left) Depth slice through the ARM images at 1421 meters depth below the processing datum of 650 meters. Colored lines are injector wells. (Right) The same ARM image depth slice superimposed on the stacked 1 hr. of semblance

Monitoring CO_2 sequestration will certainly involve time lapse sequencing where the current image can be compared to previous images recorded in the same location. The example in Figure 5-27 shows the changes in oil and production along the same horizontal well in the Eagle Ford at three different times over a period of 3 years. In this case study the time lapse imaging shows the number of locations and lateral extent of the fluids feeding into the wellbore decreasing over time as the well depletes and/or the induced fractures gradually close or silt up. This example was recorded using a shallow buried grid as we would propose for HCS CO_2 sequestration monitoring.

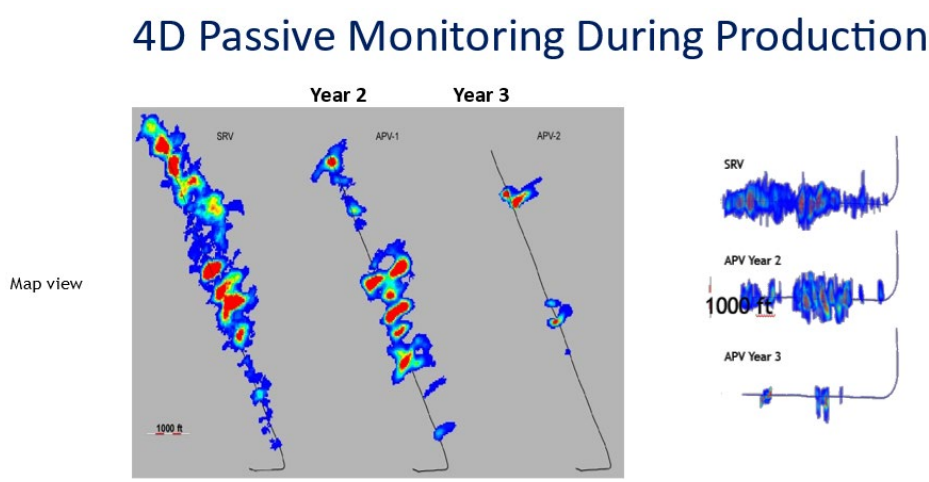

Figure 5- 27: The Stimulated Rock Volume (SRV) and two Active Production Volumes (APV) generated after two and three years of production. (Left) Map-view slices through the volumes at the wellbore depth. (Right) Profile views of the same three volumes sliced along the wellbore. Warm colors show high levels of activity and cool colors show lower activity levels.

[redacted]

The previous two examples discussed have highlighted the use of SDI to monitor the movement of fluids laterally, i.e., in the X or Y direction in our 3D image volumes. In the next example we specifically show how our images have been used to monitor vertical containment for injected fluids. In a case study conducted in the Appalachian Basin in West Virginia our technology was used to measure the vertical upward extent of the fluids injected during a nitrogen frac into four stacked laterals. In this area the regulators were worried about the potential for the frac fluid to move into shallow aquafers or even to the surface. However, our image illustrates a clear containment of acoustic energy below the Maxton Sandstone cap rock and no "break-throughs" in containment.

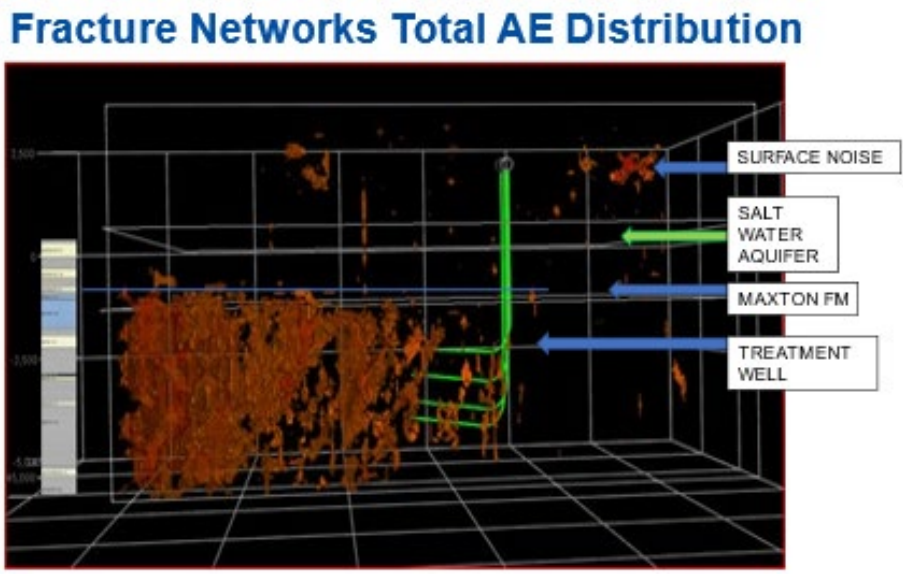

Figure 5- 28: Frac energy was kept below the Maxton formation and thus did not enter the aquifer

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Ambient Reservoir Monitoring Processing Methodology

ARM utilizes patented streaming depth imaging (SDI), based on a modified version of Kirchhoff migration, to image the intensity and distribution of weak seismic signals emitted from reservoir depths. SDI captures low-amplitude signals that are continuous for longer time durations (Sicking et al., 2014, 2015). Imaging these very weak signals requires the use of high-quality trace filtering to suppress noise (Sicking et al., 2016). The objective of the processing is to suppress reflectivity noise and surface-wave noise without modifying the phase of the signal waveforms that are emitted at depth and travel to the receivers at the surface. The most important processing steps include cepstral filtering, median filtering, and low-cut frequency bandpass. The processing is designed to

preserve signal in the 15 to 50 Hz frequency domain, important for transmission of seismic waves in the earth (Woodburn et al., 2012), and this frequency band has the highest signal transmission. The trace-processing workflow preserves this frequency band without phase distortion in the waveforms. Preserving waveform phase is important for SDI performance because the seismic waves generated from the same location at different times will have different waveforms. Summing the images over longtime intervals requires that the signals from the same location stack up to build the signal-to-noise ratio. Knowing the bandwidth of the signals generated at depth is not as important as knowing the bandwidth of the signal that arrives at the receiver grid.

[redacted]

Traditional seismic methods first identify that a seismic event occurred and then locate and measure that event. SDI assumes that each point in time and space in the model is a potential seismic source. To image the signal, it is streamed through the SDI algorithm using one-way travel times to sequentially move out the trace data as if there were a seismic source at each voxel. For each time step, the coherence (semblance) of the moved-out traces is calculated.

Coherence is a measure of the similarity between traces. The higher the coherence, the more likely that there was seismic activity in that voxel during that time window. A genuine seismic emission will result in the same waveform being received at many receivers, while noise will be less coherent across receivers if surface and reflectivity noise have been removed properly. After filtering, the coherent arrival is visible in both the trace data and in the coherence volume. Further detailed discussion of how the trace processing affects the image is available in Sicking et al. (2016).

The sources at each voxel emit energy multiple times over the time window of recording. These emissions tend to be of a very low amplitude, but the energy accumulates over time, revealing the locations of the active fractures. The images from each of the time steps are summed into a three-dimensional image of the subsurface. This coherence volume is processed further to generate detailed fracture image volumes.

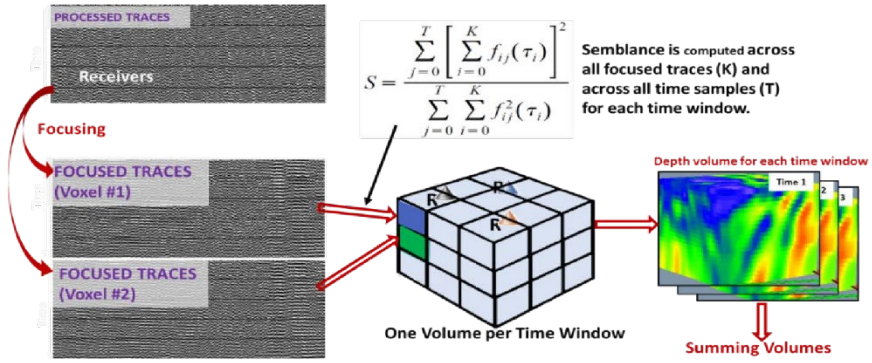

Figure 5- 37: Workflow for one-way travel time depth migration. After trace processing and velocity model building and calibration, the traces are depth migrated for each time window and each depth voxel for the time interval that will be summed; f_{ij} is the trace amplitude.

Fracture networks are extracted from the coherence volume based on a physical model of fracture damage zones. Seismic energy is not evenly distributed in the earth's crust but is preferentially released on fracture/fault surfaces and in damage zones surrounding these surfaces. Fracture mechanics predict that stress concentrations are associated with fractures.

In work related to our ARM seismic method, Tary et al. (2012) [10] compute continuous time-frequency transforms that highlight signals that have time-varying resonance frequencies. They conclude that these signals are the result of resonance in fluid-filled fractures or, alternatively, successions of very small repetitive seismic events along the fractures. They note that there is a direct correspondence between variations in the injection rate and the combined energy emitted. If a fluid-filled fracture is growing, the opening and shearing can initiate the Krauklis waves on the fracture surfaces and they are influenced by the fracture fluid and the surrounding rock. The waves travel along the fracture surfaces, quickly interfering to produce a modal/harmonic resonance of the whole fluid, fracture surface, and surrounding rock system. Recent research on the source of fracture seismic signals has put the fracture seismic method on a solid theoretical and practical base (e.g., Tary et al., 2014 [3]; Liang et al., 2017) [22]. It has now been applied to dozens of field projects.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ARM, Inc. U.S. Patents

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2) **U.S. Patent 7,127,353**, "Method and Apparatus for Imaging Permeability Pathways of Geologic Fluid Reservoirs Using Seismic Emission Tomography", by Peter Anderson Geiser – 2006
3) **U.S. Patent 9,001,619**, "Method for Imaging Microseismic Events Using an Azimuthally-Dependent Focal Mechanism", by David Diller, Barry Fish, Ran Xuan and Charles John Sicking – 2015
4) **U.S. Patent 9,045,970**, "Methods, Device and Components for Securing or Coupling Geophysical Sensors to a Borehole", by Duncan W. Riley, Jr. and Russell Roundtree – 2015
5) **U.S. Patent 9,075,158**, "Using a Drill Bit as a Seismic Source for SET Velocity Analysis", by Peter Anderson Geiser – 2015
6) **U.S. Patent 9,194,967**, "Tomographic Imaging of Fracture-Fault Permeability Zones During Drilling Operations", by Alfred Lacazette and Peter Anderson Geiser – 2015
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8) **U.S. Patent 9,389,326**, "Methods, Systems and Devices for Near-Well Fracture Monitoring Using Tomographic Fracture Imaging Techniques", by Jan Meredith Vermilye and Peter Anderson Geiser – 2016
9) **U.S. Patent 9,442,205**, "Method for Assessing the Effectiveness of Modifying Transmissive Networks of Natural Reservoirs", by Peter Anderson Geiser, Jan Meredith Vermilye and Charles John Sicking – 2016
10) **U.S. Patent 9,557,433**, "Fracture Imaging Methods Employing Skeletonization of Seismic Emission Tomography Data", by Peter Anderson Geiser and Jan Meredith Vermilye – 2017
11) **U.S. Patent 9,810,803**, "Method for Subsurface Mapping Using Seismic Emissions", by Jan Meredith Vermilye, Charles John Sicking, Ross G. Peebles, Laird Berry Thompson, Amanda Jean Klaus and Peter Anderson Geiser – 2017

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1) 2018. Suggested Best Practice for Seismic Monitoring and Characterization of Non-conventional Reservoirs, Bohnhoff, Malin, Heege, Deflandre & Sicking, First Break, February, pp. 59-64.
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3) 2017. Tomographic Fracture Imaging: Examples of Induced Fracture and Reservoir-scale Observations during Wellbore Stimulations, Niobrara and Bakken Plays, USA, Ross, Parrott, Vermilye, & Klaus, The Leading Edge, May, pp.437-444.
4) 2016. Predicting Performance, Vermilye & Sicking, Oilfield Technology, February, 4pgs.
5) 2016. Pre-drill Reservoir Evaluation using Passive Seismic Imaging, Sicking, Vermilye & Yaner, URTEC 2460524, 17pgs.
6) 2016. Microseismic Maps Production Volume, Vermilye & Sicking, The American Oil & Gas Reporter, January, pp. 81-85.
7) 2015. Predicting Frac Performance and Active Producing Volumes Using Microseismic Data, Sicking, Vermilye & Lacazette, URTEC 2154977, 9pgs.
8) 2015. Ambient Seismic Imaging throughout the Unconventional Field's Life Cycle, Lacazette & Laudon, Journal of Petroleum Technology, October, pp. 32-35.
9) 2013. Ambient Fracture Imaging: A New Passive Seismic Method, Lacazette, Vermilye, Fereja, & Sicking, URTEC 1582380 / SPE 168849, 10pgs.
10) 2013. The Value of Monitoring Fractures, Sicking, GeoExPro, vol. 10, no. 4, pp 79-82.

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2) Using Walk-away DAS Time-lapse VSP for CO_2 Plume Monitoring at the Quest CCS Project. Vicente Oropeza Bacci, Simon O'Brien, Jordan Frank & Mark Anderson, Shell Canada, Calgary AB, Canada. NADA.
3) Time-Lapse Seismic Monitoring and Performance Assessment of CO_2 Sequestration in Hydrocarbon Reservoirs. Texas A&M Engineering Experiment Station, 400 Harvey Mitchell Parkway South, Suite 300, College Station, TX 77845-4375.
4) Fluid Mechanics of Carbon Dioxide Sequestration. Herbert E. Huppert1-3 and Jerome A. Neufeld, Institute of Theoretical Geophysics and Department of Applied Mathematics and Theoretical Physics, University of Cambridge, Cambridge CB3 0WA, United Kingdom.
5) Borehole Seismic Monitoring of Injected CO_2 at the Frio Site. Thomas M. Daley, Larry R. Myer, G.M. Hoversten, John E. Peterson, Valeri A. Korneev. Lawrence Berkeley National Laboratory, Berkeley CA, USA.

SECTION 6 – INJECTION WELL PLUGGING PLAN

This Injection Well Plugging plan for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§631** [40 CFR **§146.92**]. Section 6 only provides a general description of the steps that will be taken to plug and abandon the planned stages of well development through final abandonment. Complete plugging and abandonment prognoses have been included in Appendix J of this application.

TABLE OF CONTENTS:

Sub-Completion Intervals 1
- Pre-Plugging Activities 1
- Plugging Activities 2

Final Plugging and Abandonment 4
- Pre-Plugging Activities 4
- Plugging Activities 4
- Plug Details 5

Figures

[redacted]

Tables

[redacted]

[redacted]

Sub-Completion Intervals

Pre-Plugging Activities

1. Hackberry Carbon Sequestration, LLC will comply with all reporting and notification provisions.
    a. EPA UIC Program 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 DNR by submitting Form UIC-17 with detailed plans. [SWO 29-N-6 ***§*631.A.4**]
2. [redacted] [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
3. External mechanical integrity will be demonstrated through approved temperature logging methods described in Section 5 – Testing & Monitoring Plan. [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
4. The injection well will be flushed with a buffer fluid prior to pulling injection tubing and packer. [SWO 29-N-6 ***§*631.A.2**; 40 CFR **§146.92(a)**]
5. All uncemented, non-permanent components of the well will be removed.
6. Casing inspection and cement bond logs will be performed prior to plugging.

[redacted]

Plugging Activities

[redacted]

The injection tubing and packer will be removed with the tubing string and packer being inspected for any signs of damage, corrosion, or premature wearing caused by the corrosive nature of the injection operations. If necessary, retooling will be performed on these components.

[redacted]

[redacted]

Final Plugging and Abandonment

Pre-Plugging Activities

1. Hackberry Carbon Sequestration, LLC will comply with all reporting and notification provisions.
    a. EPA UIC Program 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 DNR by submitting Form UIC-17 with detailed plans. [SWO 29-N-6 ***§*631.A.4**]
2. [redacted] [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
3. External mechanical integrity will be demonstrated through approved temperature logging methods described in Section 5 – Testing & Monitoring Plan. [SWO 29-N-6 ***§*631.A.2**; 40 CFR ***§*146.92(a)**]
4. The injection well will be flushed with a buffer fluid prior to pulling injection tubing and packer. [SWO 29-N-6 ***§*631.A.2**; 40 CFR **§146.92(a)**]
5. All uncemented, non-permanent components of the well will be removed.
6. Casing inspection and cement bond logs will be performed prior to plugging.

[redacted]

Plugging Activities

[redacted]

Plug Details

[redacted]

[redacted]

[redacted]

[redacted]

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

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

This Post-Injection Site Care and Site Closure Plan ("PISC") for the Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SWO 29-N-6, **§633** [40 CFR **§146.93**]. The plan describes various activities that will occur once injection has ceased and during the site closure once it is demonstrated that no additional monitoring is needed to ensure that this project does not pose a further endangerment to the USDW.

TABLE OF CONTENTS:

Post-Injection Pressure Differentials 1
CO2 Plume Position and Pressure Front at End of Injection and at Closure 3
Post-Injection Monitoring Plan 5
  Post-Injection Monitoring Activities 5
Demonstration of Non-Endangerment of USDW 6
Site Closure Plan 6
  Pre-Closure 6
  Plugging Activities 6
  Site Restoration 7

Figures

[redacted]

Tables

[redacted]

Table 7- 2: Post-Injection Monitoring and Reporting Frequency 6

Post-Injection Pressure Differentials

To meet the requirements of SWO 29-N-6 **§633.A.1.b** [40 CFR **§146.93(a)(2)**], the following table shows the expected pressure differential between pre-injection and post-injection pressures in the injection zone, as determined by the plume model described in Section 2. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Post-Injection Monitoring Plan

As required by SWO 29-N-6 **§633.A.2** [40 CFR **§146.93(b)**], HCS will continue to monitor the site until the project no longer poses an endangerment to USDWs. [redacted]

Post-Injection Monitoring Activities

During the monitoring period, the testing and monitoring activities as described in Section 5 will be performed and reported at the frequency shown in Table 2.

Testing/Monitoring Activity	Frequency	Reporting Schedule
Groundwater Monitoring Well Geochemical Analysis	Every five years	Within 30 days after data collection and analysis
Injection Well Pressure and Temperature monitoring	Continuously	Annually
Direct Plume and Pressure Front Monitoring (VSP)	Annually	Within 30 days after data collection and analysis
Indirect Plume Calculations based on Pressure and Temperature data	Annually	Annually

Table 7- 2: Post-Injection Monitoring and Reporting Frequency

All testing and monitoring activities listed will be performed and analyzed as discussed in Section 5, including QA/QC measures.

Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization, HCS will provide documentation that the USDW will not risk further endangerment from the CO2 plume, as required by SWO 29-N-6 **§633.A.3** [40 CFR **§146.93(c)**]. HCS will submit a report to the UIC Director demonstrating the non-endangerment of the USDW including site-specific conditions, updated plume model, predicted pressure decline within the injection zone and any updates to the underlying geological assumptions used in the original model.

Site Closure Plan

To meet the requirements of SWO 29-N-6 **§633.A.3** [40 CFR **§146.93(e)**], the following site closure activities will be performed. These activities include removal of surface equipment, plugging of all wells, site restoration and submittal of final site closure reports.

Pre-Closure

Notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to closure operations. If any changes have been made to the original Post-Injection Site Care 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.

Plugging Activities

The Hackberry Carbon Sequestration Well No. 001 and the ground water monitoring well, HCS Monitor Well No. 001, will be plugged as discussed in Section 6. The Plug and Abandonment procedures are

designed to prevent migration of CO2 or formation fluids in the injection interval from migrating to the USDW. Prior to plugging the wells, the mechanical integrity of these wells will be determined by an Annulus Pressure Test, casing inspection log, temperature log as well as a pressure fall-off test as described in Section 5. Plugging schematics and procedures are provided in Appendix J.

Site Restoration

Once the injection well and monitoring well are plugged and capped below grade, all surface equipment will be decommissioned and removed from the site.

Documentation of Site Closure

Within ninety (90) days of site closure, a final report must be submitted to the UIC Director, per requirements SWO 29-N-6 **§633.A.6** [40 CFR **§146.93(f)**], and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including copy of the survey plats
- Documentation of well-plugging report to LADNR
- Records of the nature, composition and volume of the CO2 stream over the injection period

A record of notation in the facility property deed will be added to provide, in perpetuity, any potential purchaser of the property the following information:

- The fact the land was used to sequester carbon dioxide
- The name of the State agency (LADNR) with which the survey plat was filed and the EPA and or State Agency to which it was submitted
- The total volume of fluid injected, the injection zones into which it was injected and the period over which injection occurred

HCS will retain all records collected during the post-injection site care period for 10 years following site closure. At the end of the retention period, HCS will deliver all records to the UIC Director, which will thereafter be retained at a location designation by the Director for that purpose.

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

This Emergency and Remedial Response plan for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements of SO 29-N-6, **§623** [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.

TABLE OF CONTENTS

Resources/Infrastructure in AOR....1
Infrastructure/Resource-Specific Events and Response Plans....1
Event Description – Well blowout....1
Event Description – Spill....2
Event Description – CO_2 Migration....2
Event Description – Loss of Mechanical Integrity....3
Training:....3
Communications Plan and Emergency Notification Procedures:....4
Flood risk....5
Emergency Response Plan Review and Updates....5

Figures

(None)

Tables

Table 8- 1: Emergency Services – **CALL 911**....4
Table 8- 2: Government Agency Notification....5

Resources/Infrastructure in AOR

[redacted].

Infrastructure/Resource-Specific Events and Response Plans

The following scenarios represent a high-level concept of potentially significant adverse events, methods of prevention and detection and likely remedial responses. The likely responses are not intended to be exhaustive in nature. Each situation will be evaluated based on the specific event, using best engineering practices.

Event Description – Well blowout

This event could occur during wellbore drilling if unexpected changes in reservoir pressures cause a sudden release of hydrocarbons.

Risk Level: Low

Prevention and Detection:

- Maintain appropriate mud weights as expected for the area based on offset well data
- Monitor rate of drilling fluid returns versus rates pumped, penetration rates, pump pressures, etc.

Potential Response Actions:

- Stop drilling
- Close the blowout preventer; insert rams into the well.
- Read and record stabilized shut-in pressures
- Stop injection and notify the UIC Program Director within 24 hours.
- Kill the well by pumping fluid down the wellbore that is heavier than the current fluid until the well stops flowing.

Response Personnel: Onsite drilling personnel and supervisors.

Equipment: Drilling rig, mud logging equipment, blowout preventers with annular rams, drilling fluid materials to increase mud weight adequately.

Event Description – Spill

This event could occur during the drilling of the wellbore due to an accidental release of drilling fluids, hydrocarbons, chemicals, etc. during drilling and completion or workover operations.

Risk Level: Medium

Prevention and Detection:

- Properly maintained blowout preventers to prevent accidental release of drilling fluids or hydrocarbons
- Spill prevention equipment on drilling or workover rig

Potential Response Actions:

- Contain spill using available equipment such as absorbents, booms, etc.
- Notify appropriate regulatory authority and supervisory personnel
- Immediately take samples around the point of entry
- Initiate Spill Prevention, Control and Countermeasures Plan for facility

Response Personnel: Drilling/workover crews or operations personnel.

Equipment: Absorbents, containment equipment

Event Description – CO_2 Migration

This event could occur if the plume reaches faults or fractures that allow CO_2 migration into another zone, including the USDW, or to the surface. Failure of the confining zone could also cause CO_2 to migrate.

Risk Level: Medium

Prevention and Detection: The CO_2 plume will be monitored as described in the Testing and Monitoring Section.

Potential Response Actions:

- Lower injection rates or stop the injection and notify the UIC Program Director within 24 hours.
- Use Ambient Reservoir Monitoring system and/or Vertical Seismic Profile system to assess location and degree of CO_2 movement, as described in the Testing and Monitoring Plan.
- Resume injection, if able, at a reduced rate.
- Continue monitoring of plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted:
    - Pump carbon dioxide-contaminated groundwater to the surface and aerate it to

remove carbon dioxide.
  - Apply "pump and treat" methods to remove trace elements.
  - Drill wells that intersect the accumulations in groundwater and extract carbon dioxide.
  - Provide an alternative water supply if ground water-based public water supplies are contaminated.
- If surface water is impacted:
  - Shallow lakes will quickly release dissolved carbon dioxide back into the atmosphere.
  - Create a hydraulic barrier by increasing reservoir pressure upstream of the leak.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete up hole into the next planned injection interval.

Event Description – Loss of Mechanical Integrity

This event could occur due to failure of cement behind the casing, improperly seated packer or tubing leak.

Risk Level: Medium

Prevention and Detection: Proper wellbore design, including proper cement and metallurgy of the casing and tubing will be implemented in the construction phase. Pressure and rate monitoring, pressure fall-off tests, annulus pressure tests, etc., will all be performed per the Testing and Monitoring Plan.

Potential Response Actions:
- Stop injection and notify the UIC Program Director within 24 hours.
- Close wellhead valve.
- Monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer.
- Install chemical sealant barrier and or attempt cement squeeze to block leaks.
- Demonstrate Mechanical Integrity per the methods discussed in Section 5.
- Notify the Director when injection can be expected to resume.

Training:

Personnel responsible for implementing this plan shall be trained on their duties and responsibilities related to these facilities during annual on-site and/or table-top training exercises. All plant personnel, visitors, and contractors must attend a Plant overview orientation before obtaining permission to enter any of the Facilities. A refresher course on this training is required annually.

Before starting CO_2 injection operations, Hackberry Carbon Sequestration, LLC will provide a copy of the Emergency Response plan to local first responders and discuss potential response scenarios.

Communications Plan and Emergency Notification Procedures:

Emergency response contacts:

Agency	Telephone Number
Cameron Parish Fire Department	911 or (337) 775-7511
Cameron Parish Sheriff	911 or (337) 775-5111
Cameron Parish Health Unit	(337) 775-5368
Cameron Parish Office of Emergency Preparedness	(337) 775-7048
Louisiana Emergency Preparedness Office	(225) 925-7500
Louisiana State Police	(337) 491-2511
Louisiana State Police – Hazardous Material Hotline	(225) 925-6595

*Table 8- 1: Emergency Services – **CALL 911***

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
Cameron Parish Local Emergency Planning Committee (LEPC)	(337)-775-7048
National Response Center (NRC)	(800) 424-8802
Louisiana State Police – Hazardous Material Hotline	(225) 925-6595

Table 8- 2: Government Agency Notification

[redacted]

As appropriate, Hackberry Carbon Sequestration, LLC will communicate with the public regarding events that require an emergency response, including the impact of the event on drinking or the severity of the event, actions taken or planned, etc.

Flood risk

[redacted]

Floodplain management standards apply.

Emergency Response Plan Review and Updates

This Emergency Response Plan will be reviewed and updated annually. Any amendments to the plan must be approved by the Director and will be incorporated into the permit. This plan will also be reviewed and submitted to the Director within one year of an area of review evaluation; following any significant changes to the facility, such as addition of injection or monitoring wells; change in personnel; or when required by the Director.

[redacted]

- [redacted]
- [redacted]
- [redacted]

SECTION 9 – IT DECISION

TABLE OF CONTENTS

Executive Summary 1
Hackberry Pump Station 2
Injection Site 3
Summary of Environmental Impacts of the Project 4
IT Questions 4
I. Have the potential and real adverse environmental effects of the proposed facilitybeen avoided to the maximum extent possible? 4
II. Does a cost-benefit analysis of the environmental impact costs balanced against the social and economic benefits of the proposed facility demonstrate that the latter outweighs the former? 8
III. Are there alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits? 9
IV. Are there alternative sites which would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits? 9
V. Are there mitigating measures which would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits? 10

Figures

Executive Summary

Large-scale capture of anthropogenic carbon dioxide ("CO_2") is increasingly viewed as critical for the United States (U.S.) and global community to meet ambitious goals for greenhouse gas reductions by companies, states, and national governments. For example, the International Energy Agency ("IEA") has highlighted a potential need for CO_2 storage to increase from around 40 million tonnes per year today to more than 5,000 million tonnes per year by mid-century. Today, the United States is the global leader in carbon capture, use, and sequestration ("CCUS"), holding more than 60% of current CCUS capacity and half of all global CCUS capacity under development.[1] To impact global greenhouse gas levels, once carbon, generally in the form of CO_2, is captured from a source, that CO_2 must be safely disposed of in some manner. One of the more common methods of dealing with the captured CO_2 is injecting it into porous formations below the earth's surface.

The U.S. Gulf Coast has long been viewed as suitable for long-term sequestration of CO_2.[2] Hackberry Carbon Sequestration, LLC ("HCS") is proposing to develop a carbon sequestration facility in Cameron Parish, Louisiana. HCS was formed to primarily support the capture and permanent sequestration of CO_2 emitted from liquefied natural gas ("LNG") export terminals located in the Gulf Coast region. LNG terminals operating and under construction in southwest Louisiana and southeast Texas have enabled the United States to become a global leader in exporting natural gas to foreign customers. Increasingly, these customers seek natural gas sourced through lower-carbon processes to meet their energy needs and are looking to US suppliers to supply this cleaner product.

HCS plans to build a premier carbon sequestration operation in the Gulf Coast region of the US. Through disciplined and innovative processes and engineering designs, HCS will facilitate the sequestration of captured carbon from nearby LNG facilities and other industrial facilities located in the Gulf Coast Region, thereby locking the greenhouse gas away in subsurface geologic structures for all time. In addition, HCS's commitment to facilitate lower-carbon energy and industrial production will help these crucial manufacturers evolve as leaders in the global energy transition.

The Project is being designed to handle captured from the various industries in southwest Louisiana, and the location for this proposed facility is ideally suited for that purpose. This site was selected for several reasons: favorable geology, controlled pore space storage rights, numerous industrial facilities with sequestration needs, and existing pipeline rights-of-ways to transport the captured gases for disposal. HCS is proposing to drill and complete carbon sequestration well in Cameron Parish, Louisiana. As such, HCS is applying for a Class VI permit to construct and operate the well. The well will be located on surface acreage, with CO_2 injected into and sequestered in subsurface pore space wholly owned by HCS.

HCS is developing the Hackberry Carbon Storage Project (Project) to capture carbon from nearby LNG and industrial facilities and sequester the carbon by injecting it into porous formations. The Project will capture and compress low-pressure CO_2 and transport it by pipeline to the new

[1] The world has vast capacity to store CO2: Net zero means we'll need it – Analysis - IEA

[2] 2010 Carbon Atlas of the United States and Canada, National Energy Technology Laboratory, US Department of Energy

Hackberry processing facility. The Hackberry Pump Station will be constructed for this project on land owned by LA Storage, a subsidiary of Sempra Infrastructure. At the Hackberry Pump Station, CO_2 will be compressed and transported to the injection well via the proposed high-pressure pipeline. The injection well will be drilled on land controlled by HCS. [redacted] The Project will be sized to permanently store up to 2 million tons per year of CO_2. Initially, Hackberry Carbon Sequestration, LLC will be working with its affiliate Cameron LNG, LLC ("Cameron LNG") to handle and dispose of captured CO_2 from their Cameron, LA export facility. Cameron LNG receives natural gas from various pipelines and compresses the gas into LNG products for export. The process of preparing the natural gas for export generates significant quantities of CO_2. Cameron LNG will be capturing a portion of these resultant emissions and delivering them to HCS for disposal into the carbon sequestration well.

The Project facilities, except the pipelines, will be constructed and operated on the property entirely under the control of HCS.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

[redacted]

[redacted]

Summary of Environmental Impacts of the Project

The Project will provide significant support to reduce global emissions of greenhouse gases by taking CO_2 from LNG and other industrial facilities in the region and sequestering (i.e., permanently storing) it thousands of feet underground. Burning natural gas already emits less CO_2 than coal or fuel oil, and the Project will further reduce the CO_2 associated with natural gas making it an even greener energy source.

The Project includes electric-powered compressors and dehydration facilities to eliminate permitted air emissions. In addition, because of the electric-powered equipment, the Project will not generate emissions of carbon monoxide, volatile organic compounds, formaldehyde, or nitrogen oxides.

The Project will not treat or dispose of any hazardous waste or solid waste. There will be a small quantity of sanitary sewage generated by operations of the Project, but that stream will be treated in accordance with state water quality regulations tying into LA Storage's existing utilities. The discharge will have no impact on water quality.

Due to the size of the Project, transportation is not anticipated to be a concern. C[redacted] Construction materials and process equipment will be delivered to the pump and compressor stations via trucks on existing roads. Deliveries of any large equipment that could interfere with local traffic will be scheduled during off-peak traffic hours when possible.

The site location has been assessed for impacts to environmental resources. A response to each of the "IT Decision" questions follows.

IT Questions

I. Have the potential and real adverse environmental effects of the proposed facility been avoided to the maximum extent possible?

Yes. HCS designed the Project to avoid the potential and real adverse environmental effects to the maximum extent possible by placing CO_2 processing facilities on existing developed property and placing the well on property controlled by HCS. The Project will meet all applicable State and Federal environmental statutes, rules, and regulations. The primary purpose of this facility is for geologic sequestration (permanent storage) of CO_2. Once in operation, safe operating procedures, safety measures, and required monitoring and maintenance practices will be followed to continue to avoid the potential and real adverse environmental effects to the maximum extent possible. No hazardous wastes will be accepted at the site.

Air Quality

The potential air emissions from the Project construction and operation are minimal and will not cause any adverse impacts to air quality.

Air quality impacts associated with the construction of the Project can be generally classified as temporary impacts from the operation of equipment during construction activities and impacts from dust generation. Impacts associated with equipment operation during construction activities, including well drilling, pipeline construction, and dredging, may result in a minor, temporary increase in emissions. Equipment and movement of material for land clearing, grading, excavation, drilling, and concrete work, along with vehicular traffic on paved and unpaved roads, could cause dust. The amount of dust will be based on the area of construction, silt and moisture contents of the soil, wind speed, frequency of precipitation, amount of vehicle traffic, vehicle types, and paved or unpaved roads. Fugitive dust may occur during all phases of construction. Dust will be greater during the drier winter months and in areas of fine-textured soils. During these periods, dust suppression techniques, such as watering, will minimize the impacts of fugitive dust.

The Project does not include any regulated processes by National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 61. The Project will not be a source of federal Hazardous Air Pollutants (HAP). The emergency generator on the well platform will be subject to 40 CFR 63 Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines.

Water Quality

During normal operation of the Project facilities, surface water discharge will include stormwater runoff. All stormwater from Hackberry Pump Station will be managed in accordance with HCS's Environmental Plan. In addition, HCS will install all necessary erosion and sedimentation control structures required by the state to minimize potential impacts from stormwater runoff.

Temporary soil erosion and sediment control measures will be installed along the proposed pipeline construction right-of-way (ROW) and other work areas, as applicable, in accordance with HCS's Environmental Plan. The Environmental Plan details the Best Management Practices (BMPs) that will be implemented during and after construction to minimize potential impacts to the surrounding environment. The BMPs will be used to minimize erosion of disturbed soils and prevent the transportation of sediment outside of the construction boundary into environmentally sensitive areas such as wetlands and waterbodies. HCS's Environmental Plan provides specifications for the installation, implementation, and maintenance of the BMPs while allowing for flexibility in selecting specific BMPs based on site-specific conditions. This document will be included as part of the construction contract and will provide contractors and environmental inspectors a reference to specific environmental conditions and associated BMP plans and procedures.

Sensitive Soils and Vegetation

Construction of the Project facilities will not generate waste that could leach into soils and affect shallow groundwater. Project operations will not cause the destruction of important vegetation or have any impacts on forested lands.

The areas where the Project facilities are to be located consist of open water, existing industrial facilities, or undeveloped marshland. The total disturbance to accommodate these facility components is estimated to be no greater than 10 acres. No permanent wetland impacts are being proposed for the Project. There are no long-term adverse impacts anticipated on environmentally sensitive areas. In fact, the Project, through the beneficial use of dredge material, will create approximately 37 acres of wetland marsh.

Sensitive Wildlife and/or Habitat

HCS consulted with the U.S. Fish & Wildlife Service and the National Marine Fisheries Service to determine the potential for the occurrence of federally listed species and their critical habitat that are known or expected to be in the vicinity of the Project. HCS conducted habitat and wetland surveys of the entire proposed Project area, and no endangered or threatened species or critical habitat were observed during the field surveys.

Archaeological and Historic Resources

HCS performed a Phase I Archaeological Survey of the entire proposed Project area to identify archaeological and historic resources. No archaeological or historic resources were identified within the proposed Project survey areas.

Accidental Releases

The Project facilities are designed to meet or exceed all existing environmental regulations in a manner that minimizes the potential for accidental releases using the best available technology, best equipment, and best management practices.

The potential for a release of CO_2 to the surface or into an Underground Source of Drinking Water (USDW) will be monitored continuously, and the possibility of any impact from such release will be kept to a minimum by operating the well in accordance with Statewide Order 29-N-6 and EPA's regulations for Class VI CO_2 geologic sequestration injection wells found in 40 CFR Part 146, Subpart H. Well design, construction, and continuous monitoring requirements in federal and state regulations are written to protect USDWs. However, in the event of a suspected release to a USDW, HCS will shut in the system, begin an assessment of the area possibly affected, and begin evaluation of the possible source of the release. Notification to those listed in the facility Emergency Action Plan, including the Office of Conservation, will be initiated, and additional actions will be planned based on the results of the assessment. In the event of any leak or spill of drilling fluid or fuel during construction, the system will be shut-in, and HCS will implement the directives set forth in its Emergency Action and Spill Prevention Plans.

The risk of mechanical failure of the well will be minimized by routine visual inspections, preventive maintenance, and monitoring. Periodic demonstration of mechanical integrity of all wells is required by the Office of Conservation and as set forth in Statewide Order 29-N-6. HCS

will establish mechanical integrity prior to commencing injection and on a schedule as set forth in the Order. In addition, HCS will maintain mechanical integrity as defined in §3627 of the Louisiana Administrative Code, Title 43, Part XVII (January 2021). These measures will include:

- Perform an annulus pressure test after initial well construction as part of the pre-operating requirements; and at least once every 12 months witnessed by an agent of the Office of Conservation; and after performing any well remedial work that involves unseating the tubing or packer.

- Continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in **§3621.A.6.**

In addition, as described in Statewide Order 29-N-6, HCS will monitor the predicted extent of the injected CO_2 plume and any mobilized fluids that may result in degradation of water quality over the lifetime of the project, as informed by computational modeling, in order to ensure that the proposed injection operation will not at any time endanger USDWs including non-exempted portions of the injection formation. At least once every 12 months, HCS will determine the absence of significant fluid movement by using an approved tracer-type survey such as a radioactive tracer, oxygen-activation log, or similar tool; or a temperature or noise log. [redacted]

In the event that a well fails a mechanical integrity test, HCS will immediately take the well out of service and notify the Office of Conservation. Written procedures for correcting the well failure will be submitted within 60 days, and the well will be rehabilitated upon approval by the Office of Conservation. In addition to adhering to the measures specified in §3627, HCS will also adhere to the reporting and recordkeeping measures defined in §3629.

No land-based treatment or disposal of solid or liquid waste is planned for the Project. HCS will design, construct, and operate the Project, including the well, pipelines, pump station, and other facilities in accordance with good engineering practices. These practices ensure systems provide maximum safeguards for the protection of the groundwater and surrounding environment. No adverse effects on groundwater resources are anticipated from the placement of foundations for the well pad, pipelines, or Project facilities.

BMPs will be followed to prevent and control the discharge of pollutants from accidental release incidents. HCS will develop contingency plans, operating procedures, and BMPs to prevent the discharge of pollutants resulting from accidental release events.

The Project facilities will have highly trained and dedicated staff to operate the facility, and HCS will utilize experienced personnel to form the core of its operating staff. Operations, maintenance, and support personnel will be thoroughly trained and periodically tested in the proper use and operation of appropriate equipment and will be familiar with the potential hazards of operating the Project facilities. Combining properly designed facilities and

thoroughly trained personnel accomplishes the goal of minimizing the potential for accidental releases.

II. Does a cost-benefit analysis of the environmental impact costs balanced against the social and economic benefits of the proposed facility demonstrate that the latter outweighs the former?

Yes. The purpose of the Project is to provide beneficial environmental impacts by sequestering CO_2 emissions that would otherwise be released to the environment. This environmental benefit, along with the social and economic benefits, more than balances the minor adverse impacts associated with the construction and operation of the Project.

The Project will provide important economic and social benefits to Cameron Parish and the State of Louisiana. Construction of the Project will create jobs, additional earnings for households, and rising business activity throughout the Louisiana economy. An increase in employment will be realized as a result of the Project. The Project estimates an average of approximately 310 workers will be needed during construction. HCS anticipates that the workforce will be composed of 15 percent local residents, 75 percent commuters, and 10 percent who will temporarily relocate to the area. The operations phase of the Project is expected to create approximately two (2) full-time employment positions. The Project will result in increased business activity associated with the construction, as measured by sales and personal earnings. Additionally, during construction, there will be an increase in tax revenue to local Parishes. The operation of the Project facilities will positively affect local tax revenue based on tax revenue projections.

The economic benefits and spillovers from the construction of the Project are substantial but temporary. The economic benefits and spillovers from the ongoing operation of the Project facilities are both substantial and permanent. These economic benefits will accrue to the State of Louisiana and the Cameron Parish region for the duration of facility operations. HCS intends to be a good corporate citizen involved in employee/community partnerships in Cameron Parish and surrounding communities. HCS will make an effort to buy goods and services locally and hire locally for the construction and implementation of the Project. Employment opportunities are provided to all aspects of the Louisiana workforce. As a result, the Project will result in a net social benefit to the community in the vicinity of the proposed Project.

Geologic carbon sequestration is the process of capturing CO_2, the most commonly produced greenhouse gas, and storing it underground in deep geologic formations. Carbon sequestration is one method of reducing the amount of CO_2 in the atmosphere with the goal of reducing global climate change.

In conclusion, because HCS anticipates no potential negative economic effects on the community and no additional costs to the community for police, fire, school, or medical services, HCS believes that the benefits of the Project, coupled with the economic benefits that the Project will bring to the area, outweigh the minimal adverse environmental impacts as described in the response to Question 1.

III. Are there alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits?

No. There are no alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits. The primary goal of this Project is to sequester CO_2 captured from nearby LNG facilities by permanently storing it in subsurface geologic formations. The Project will support the delivery of green LNG products to foreign customers for their energy needs and provide the environmental benefit of reducing greenhouse gas emissions. Carbon sequestration has only recently become economically feasible. Based on publicly available information, no other such projects planned would serve the same purpose in this area. The project is designed to maximize co-location with other facilities, minimize the footprint of surface facilities, and minimize environmental impacts within the Louisiana coastal zone. As explained in the response to Question 1, the Project will have minimal adverse environmental impacts, which will be outweighed by its environmental benefit.

IV. Are there alternative sites which would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits?

No. There are no alternative sites that would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits or the environmental benefits that are the Project's primary purpose. [redacted]

In conclusion, HCS has not identified an alternative that would result in a significant environmental advantage compared to the proposed Project.

V. Are there mitigating measures which would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits?

No. There are no mitigating measures that would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits or the environmental benefits that are the Project's primary purpose.

[redacted]

- [redacted]

- [redacted]

- [redacted]

- There is no treatment or disposal of solid or hazardous waste associated with the Project.

- There will be no significant adverse impacts on historical, archaeological, wetland, estuarine, wildlife habitat, or prime agricultural areas as a result of the Project.

- There will not be any permanent filling of wetlands.

- The Project will create approximately 37 acres of wetland marsh through the beneficial use of dredge material.

- The Project provides increased economic and social benefits to the local and regional areas.

- Groundwater resources are protected to the maximum extent possible.

- Wastewater and stormwater discharges from the Project will have minimal impacts to receiving waters. Only stormwater runoff will be discharged to local drainage.

- The injection well will be operated in such a fashion as to meet the state requirements of Statewide Order 29-N-6 and federal requirements of 40 CFR 146.88. These requirements include limiting injection pressures, maintaining mechanical integrity, and monitoring.

- The compressors/pumps and dehydration equipment will be powered by electricity. Solar energy will be the primary source to power communication systems at the injection wellhead with battery storage.

SECTION 10 – FINANCIAL ASSURANCE

This financial assurance section for Hackberry Carbon Sequestration Well No. 001 was prepared to meet the requirements SWO 29-N-6 **§607.C.2.m** and **§609.C.1** [40 CFR **§146.82(a)(14)** and **§146.85(a)**]. This section outlines the instruments and associated costs for the well.

TABLE OF CONTENTS

Financial Assurance 1
Corrective Action Plan 2
Injection Well Plug & Abandonment 2
Post-Injection Site Care & Site Closure 2
  Post-Injection Monitoring 2
  Site Closure 2
Emergency & Remedial Plan 2
  Scenario 1: Injected Fluid Release into Outside Zone 3
  Scenario 2: Injected Fluid Release into USDW 3
  Scenario 3: Injected Fluid Release into Surface 3

Figures

(None)

Tables

[redacted]

Financial Assurance

A surety bond will be secured and used to provide sufficient funding for any corrective action, injection well plugging, post injection site care & site closure, and emergency & remedial response. In compliance with SWO 29-N-6 **§609.C.4.c** [40 CFR **§146.85(a)(4)]**, this instrument may not be terminated except due to failure to make payment and may not be final until 120 days after receipt. [redacted]

[redacted]

Corrective Action Plan

[redacted] The AOR will be reevaluated every five years to determine if any new penetrations have occurred.

Injection Well Plug & Abandonment

Plug and abandonment (P&A) of Hackberry Carbon Sequestration Well No. 001 will meet the requirements of SWO 29-N-6 **§631** [40 CFR **§146.92**]. The plug and abandonment of the injection well must be designed such that no movement of fluids will occur from the injection interval. [redacted]

Post-Injection Site Care & Site Closure

The post injection site care and site closure plan will be designed to meet the requirements of SWO 29-N-6 **§633** [40 CFR **§146.93**]. [redacted]

Post-Injection Monitoring

[redacted]

Site Closure

When the director has released the owner from all post-injection site duties, site closure will occur. [redacted]

Emergency & Remedial Plan

The emergency and remedial plan is referenced in Section 8 and is designed to be in compliance with SWO 29-N-6 **§623.A.1** [40 CFR **§146.94**]. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Updates to Financial Assurance

During the active life of this project, HCS 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 Director. HCS 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 post-injection site care 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, HCS will 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 Director.

SECTION 11 – ENVIRONMENTAL JUSTICE

According to the CEQ environmental justice guidance under NEPA and EPA's *Promising Practices for EJ Methodologies in NEPA Reviews*, minorities are those groups that include American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. Minority populations are defined where either; (a) the minority population of the affected area exceeds 50 percent or (b) the minority population of the affected area is meaningfully greater (10 percent greater) than the minority population percentage in the general population or other appropriate unit of geographic analysis. The CEQ guidance further recommends that low-income populations in an affected area should be identified using data on income and poverty from the U.S. Census Bureau and considered in the analyses. According to the U.S. Census Bureau, low-income populations are populations where households have an annual household income below the poverty threshold, which is $26,500 for a family of four in 2021.

Rates of households below the poverty level and percentages of minority residents are significantly lower in Cameron Parish than for Louisiana as a whole. U.S. Census data shows that in the State of Louisiana in 2020, 42.8 percent of the population was minority, while in Cameron Parish, 12.8 percent of the population was minority. Similarly, 19.4 percent of Louisiana households were below the poverty threshold. Poverty rates were lower in Cameron Parish, where only 10.3 percent of households fell below the poverty threshold.

Potentially adverse environmental effects associated with the Project will be minimized and/or mitigated, as applicable, and are not characterized as high and adverse. Beneficial environmental effects of the Project will extend beyond Cameron Parish and the State of Louisiana. The Project will not cause a disproportionate share of high and adverse environmental or socioeconomic impacts on any racial, ethnic, or socioeconomic group.

APPENDIX A: SURVEY PLATS

[redacted]

APPENDIX B: SITE CHARACTERIZATION MAPS

[redacted]

APPENDIX C: HYDROGEOLOGY

[redacted]

APPENDIX D: PLUME MODEL

[redacted]

[redacted]

[redacted]

APPENDIX E: AREA OF REVIEW MAPS, TABLES

[redacted]

APPENDIX F: WELL CONSTRUCTION SCHEMATICS AND PROCEDURES

[redacted]

APPENDIX G: METALLURGY SUMMARY

[redacted] [redacted]

APPENDIX H: TESTING AND MONITORING

[redacted] [redacted]

APPENDIX I: EMERGENCY OPERATIONS PLAN

[redacted]

APPENDIX J: PLUGGING SCHEMATICS AND PROCEDURES

[redacted]