Underground Injection Control – Class VI Permit Application

Tea Olive No. 1 and Flowering Crab Apple No. 1

Sabine and San Augustine Counties, Texas

Prepared for
Aethon Energy Operating LLC

By
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FOREWORD

Aethon Energy Operating LLC (Aethon) is developing a CO_2 sequestration facility in Sabine and San Austine Counties. The TXCCS#1 Project is designed to sequester significant amounts of CO_2 from industrial sources, primarily existing gas treating plants, in a sparsely populated area on the Texas Gulf Coast. As a leading natural gas producer in the area, Aethon is committed to building strong community relations specific to this sequestration project.

This site is ideally suited for the sequestration of CO_2 within an injection zone exhibiting quality storage capacity. Additionally, no artificial penetrations exist within the CO_2 plume and no future oil and gas drilling opportunities exist in the area.

The following application will detail and characterize the geology of the proposed well locations, evaluate the formations for properties necessary to contain the sequestered CO_2 permanently, and outline the high standard of engineering safety to be incorporated into the well construction. The application will also discuss the proposed monitoring systems that will be used to compare actual plume migration to those generated by reservoir modeling and simulation.

The application has been developed to exceed the requirements of both Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82** through **§146.95** and the Texas Administrative Code (TAC), Part 1, Title 16, Chapter 5 (16 TAC **§5**). Both codes detail the regulations for Underground Injection Control Class VI wells. Once the permit has been issued, per the requirements of 40 CFR **§144.36(a)** and 16 TAC **§5.203(d)(1)(A)**, the permit will be updated every five years thereafter for the active injection life of the well.

ACRONYMS AND ABBREVIATIONS

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

AAPG	American Association of Petroleum Engineers
AOR	area of review
API	American Petroleum Institute
ASCII	American Standard Code for Information Interchange
ASTM	American Society for Testing and Materials
AZM	above-zone monitoring
bbl	barrel(s)
Bcf/D	billion cubic feet per day
BEG	Bureau of Economic Geology
BHP	bottomhole pressure
bpd	barrels per day
bpm	barrels per minute
BTC	buttress-thread and coupled
BUQW	base of usable quality water
CCS	carbon capture and sequestration
cf	cubic feet
CF-IRMS	continuous-flow isotope ratio mass spectrometry
CFR	U.S. Code of Federal Regulations
CIBP	cast-iron bridge plug
CRA	corrosion-resistant alloy
CRDS	cavity ring-down spectroscopy
CSEM	controlled-source electromagnetic
CT	computed tomography
DAS	distributed acoustic sensing
DIC	dissolved inorganic carbon
DPDP	dual porosity, dual permeability
DTS	distributed temperature sensing

EMS	emergency medical services
EOR	enhanced oil recovery
EOS	equation of state
ERRP	Emergency and Remedial Response Plan
ft^3	cubic feet
FG	fracture gradient
FOC	fiber optic cable
FSA	fault seal analysis
FSP	fault slip potential
g/cm^3	grams per cubic centimeter
GAU	Groundwater Advisory Unit
GC	gas chromatography
GC/HID	gas chromatography with helium ionization detector
GME	geomodel extent
GR	gamma ray
ID	inner diameter
ILD	deep induction log
IRMS	isotope ratio mass spectrometry
IZM	injection zone monitoring
ksi	kilopounds per square inch
LAS	Log ASCII Standard
lb/ft^3	pounds per cubic foot
lbm	pound mass
LCZ	lower confining zone
LDENR	Louisiana Department of Energy and Natural Resources
LGR	local grid refinement
LNG	liquid natural gas
mBq/L	megabecquerel per liter
Mcf	thousand cubic feet
mD	millidarcy

MD	measured depth
mg/L	milligrams per liter
MIT	mechanical integrity test
MMcf	million cubic feet
MMI	Modified Mercalli Intensity
MMscf	million standard cubic feet (per day: MMscf/D)
MMT	million metric tons
ms	milliseconds
MS	mass spectrometry
NAD	North American Datum (e.g., "of 1927"—NAD 27)
NIST	National Institute of Standards and Technology
NOM	nominal
NSHM	National Seismic Hazard Model
OBG	overburden gradient
OD	outer diameter
OSHA	Occupational Safety and Health Administration
P&A	plugging and abandonment
PBTD	plugback total depth
PERM	permeability
PG	pore gradient
PHIA	total porosity
PHIE	effective porosity
PISC	post-injection site care
PM	preventive maintenance
PNL	pulsed neutron log
ppf	pounds per foot
ppg	pounds per gallon
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute

psig	pounds per square inch gauge
PSTM	Pre-Stack Time Migration
P/T	pressure and temperature
QA/QC	quality assurance/quality control
REFPROP	Reference Fluid Thermodynamic and Transport Properties
RSC	residual sodium carbonate
Rwa	water resistivity
SAR	sodium adsorption ratio
SAU	Storage Assessment Unit
SCADA	Supervisory Control and Data Acquisition
SCAL	Special Core Analysis
SIC	Standard Industrial Classification
SONRIS	Strategic Online Natural Resources Information System
SOW	slip-on weld
SP	spontaneous potential
SPBL	SP with a corrected shale *base line* of zero
SPE	Society of Petroleum Engineers
SRK	Soave-Redlich-Kwong
SWD	saltwater disposal (well)
TAC	Texas Administrative Code
TCD	thermal conductive detector
TCEQ	Texas Commission on Environmental Quality
TD	total depth
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TexNet	Texas Seismological Network and Seismology Research
TID	thermal ionization detector
TOC	total organic carbon
TRRC	Railroad Commission of Texas
TVD	true vertical depth

TVDSS	true vertical depth subsea
TWDB	Texas Water Development Board
UCZ	upper confining zone
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
μg/L	micrograms per liter
UQW	usable quality water
Vshale	shale volume
VPC	vertical proportion curve
VSP	vertical seismic profile
WAG	water-alternating-gas
WBS	wellbore schematics
WHP	wellhead pressure
WHT	wellhead temperature
WS-CRDS	wave-scanned cavity ring-down spectroscopy
wt%	weight percent
XRD	X-ray diffraction

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REQUIREMENTS MATRIX

40 CFR - Subpart H - Criteria and Standards Applicable to Class VI Wells

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
§146.82 - Required Class VI permit information					
§146.82	Required class VI permit Information	This section sets forth the information which must be considered by the Director in authorizing Class VI wells. For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the Director, and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Regional Administrator.			
§146.82(a)	Required class VI permit Information	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:			
§146.82(a)(1)	**Required class VI permit Information**	**Information required in § 144.31(e)(1) through (6) of this chapter;**	§5.203 (a)(2)	General	
§146.82(a)(2)	Required class VI permit Information	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;	§5.203 (b)	Surface map and information. Only information of public record is required to be included on this map.	
			§5.203 (b)(1)	The applicant must file with the director a surface map delineating the proposed location of any injection wells and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR.	Introduction
			§5.203 (b)(2)	The applicant must show within the AOR on the map the number or name and the location of:	
			§5.203 (b)(2)(A)	all known artificial penetrations through the confining zone, including injection wells, producing wells, inactive wells, plugged wells, or dry holes;	3.3.4, Appendix C

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			§5.203 (b)(2)(B)	the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and	3.3.4, Appendix A
			§5.203 (b)(2)(C)	other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.	Appendix A
			§5.203 (b)(3)	The applicant must identify on the map any known or suspected faults expressed at the surface.	1.10.2
§146.82(a)(3)	Required class VI permit Information	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	§5.203 (c)(2)	The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:	
§146.82(a)(3)(i)	Required class VI permit Information	Maps and cross sections of the area of review;			Appendix B
§146.82(a)(3)(ii)	Required class VI permit Information	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;	§5.203 (c)(2)(C)	the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;	1.10.2
§146.82(a)(3)(iii)	Required class VI permit Information	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;	§5.203 (c)(2)(B)	The depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	1.3, 1.4, 1.5, 1.7, 2.3
§146.82(a)(3)(iv)	Required class VI permit Information	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	§5.203 (c)(2)(E)	geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;	1.4
§146.82(a)(3)(v)	Required class VI permit Information	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	§5.203 (c)(2)(D)	the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;	1.10
§146.82(a)(3)(vi)	Required class VI permit Information	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.			1.2, 1.3.4, 1.8, Appendix A, B

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§146.82(a)(4)	Required class VI permit Information	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;	§5.203 (d)(1)(B)	Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR [area of review] that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled, location, depth, record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	3.3.4, Appendix C
§146.82(a)(5)	Required class VI permit Information	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;	§5.203 (c)(2)(A)	geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	1.8
§146.82(a)(6)	Required class VI permit Information	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	§5.203 (c)(2)(G)	Baseline geochemical data on subsurface formations, including all formations containing USDWs in the AOR;	1.7
§146.82(a)(7)	Required class VI permit Information	Proposed operating data for the proposed geologic sequestration site:	§5.203 (i)(1)	Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) [§5.206(c)] of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	4.4
§146.82(a)(7)(i)	Required class VI permit Information	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	§5.203 (i)(1)(A)	The average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	2.7.1, 4.4
§146.82(a)(7)(ii)	Required class VI permit Information	Average and maximum injection pressure;	§5.203 (i)(1)(B)	The average and maximum surface injection pressure;	4.4
§146.82(a)(7)(iii)	Required class VI permit Information	The source(s) of the carbon dioxide stream; and	§5.203 (i)(1)(C)	The sources of the carbon dioxide stream and the volume of carbon dioxide from each source; and	Introduction (Project Overview)
§146.82(a)(7)(iv)	Required class VI permit Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	§5.203 (i)(1)(D)	An analysis of the chemical and physical characteristics of the carbon dioxide stream prior to injection.	2.5.2, 4.4
§146.82(a)(8)	Required class VI permit Information	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;	§5.203 (c)(2)(F)	a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and	N/A

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§146.82(a)(9)	Required class VI permit Information	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	§5.203 (e)(4)	Well stimulation plan. The applicant must submit, as applicable, a description of the proposed well stimulation program and a determination that stimulation will not compromise containment	N/A
§146.82(a)(10)	Required class VI permit Information	Proposed procedure to outline steps necessary to conduct injection operation;	§5.203 (i)(1)	Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) of this title, and that outlines the steps necessary to conduct injection operation The applicant must include the following proposed operating data in the plan:	4.4
§146.82(a)(11)	Required class VI permit Information	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	§5.203 (e)(2)(K)	Schematic drawings of the surface and subsurface construction details.	4.2, Appendix D
§146.82(a)(12)	Required class VI permit Information	Injection well construction procedures that meet the requirements of § 146.86;	§5.203 (e)(3)	Well construction plan. The applicant must submit an injection well construction plan that meets the criteria in paragraph (1) of this subsection.	4.2, Appendix D
§146.82(a)(13)	Required class VI permit Information	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	§5.203 (d)(2)	Area of review and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information:	3.3.4, 3.4
§146.82(a)(14)	Required class VI permit Information	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§5.202 (c)(2)	Evidence of financial responsibility. The operator acquiring the permit must provide the director with evidence of financial responsibility satisfactory to the director in accordance with §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9
			§5.203 (n)	Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9
§146.82(a)(15)	Required class VI permit Information	Proposed testing and monitoring plan required by § 146.90;			Section 5
§146.82(a)(16)	Required class VI permit Information	Proposed injection well plugging plan required by § 146.92(b);	§5.206 (j)	Well plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by §5.203(k) of this title.	Section 6
§146.82(a)(17)	Required class VI permit Information	Proposed post-injection site care and site closure plan required by § 146.93(a);	§5.206 (k)(1)	Post-injection storage facility care and closure plan.	Section 7
§146.82(a)(18)	Required class VI permit Information	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);			
§146.82(a)(19)	Required class VI permit Information	Proposed emergency and remedial response plan required by § 146.94(a);	§5.206 (h)(1)	The operator must maintain and comply with the approved emergency and remedial response plan required by §5.203(l) of this title. The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title (relating to Reporting and Record-Keeping). The operator must make copies of the plan available at the storage facility and at the company headquarters.	Section 8
§146.82(a)(20)	Required class VI permit Information	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			8.6

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
§146.82(a)(21)	Required class VI permit Information	Any other information requested by the Director.			
§146.82(b)	Required class VI permit Information	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)	Required class VI permit Information	**Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:**			
§146.82(c)(1)	Required class VI permit Information	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;			
§146.82(c)(2)	Required class VI permit Information	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;			
§146.82(c)(3)	Required class VI permit Information	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;	§5.203 (g)	Compatibility determination. Based on the results of the formation testing program required by subsection (f) of this section, the applicant must submit a determination of the compatibility of the CO2 stream with:	
			§5.203 (g)(1)	the materials to be used to construct the well;	4.2
			§5.203 (g)(2)	fluids in the injection zone; and	1.7
			§5.203 (g)(3)	minerals in both the injection and the confining zone.	1.7
§146.82(c)(4)	Required class VI permit Information	The results of the formation testing program required at paragraph (a)(8) of this section;			
§146.82(c)(5)	Required class VI permit Information	Final injection well construction procedures that meet the requirements of § 146.86;			
§146.82(c)(6)	Required class VI permit Information	The status of corrective action on wells in the area of review;			
§146.82(c)(7)	Required class VI permit Information	All available logging and testing program data on the well required by § 146.87;			
§146.82(c)(8)	Required class VI permit Information	A demonstration of mechanical integrity pursuant to § 146.89;			

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
§146.82(c)(9)	Required class VI permit Information	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			
§146.82(c)(10)	Required class VI permit Information	Any other information requested by the Director.			
§146.82(d)	Required class VI permit Information	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.	§5.201 (f)	Injection depth waiver. An operator may seek a waiver from the Class VI injection depth requirements for geologic storage to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment. An operator seeking a waiver of the requirement to inject below the lowermost USDW shall submit, concurrent with the permit application, a supplemental report that complies with 40 21 CFR §146.95. The Commission adopts 40 CFR §146.95 by reference, effective July 1, 2022.	N/A
§144.31(e)(1)	Required class VI permit Information	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.			
§144.31 (e)(2)	Required class VI permit Information	Name, mailing address, and location of the facility for which the application is submitted.			Not available at this time
§144.31 (e)(3)	Required class VI permit Information	Up to four SIC codes which best reflect the principal products or services provided by the facility.			Introduction (General Application Information)
§144.31 (e)(4)	Required class VI permit Information	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.			Introduction (General Application Information)
§ 144.31 (e)(5)	Required class VI permit Information	Whether the facility is located on Indian lands.			Introduction (General Application Information)
§ 144.31 (e)(6)	Required class VI permit Information	A listing of all permits or construction approvals received or applied for under any of the following programs:			Introduction (Additional Permits)
§ 144.31 (e)(6)(i)	Required class VI permit Information	Hazardous Waste Management program under RCRA.			
§ 144.31 (e)(6)(ii)	Required class VI permit Information	UIC program under SDWA.			
§ 144.31 (e)(6)(iii)	Required class VI permit Information	NPDES program under CWA.			
§ 144.31 (e)(6)(iv)	Required class VI permit Information	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.			
§ 144.31 (e)(6)(v)	Required class VI permit Information	Nonattainment program under the Clean Air Act.			
§ 144.31 (e)(6)(vi)	Required class VI permit Information	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.			

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
§ 144.31 (e)(6)(vii)	Required class VI permit Information	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.			
§ 144.31 (e)(6)(viii)	Required class VI permit Information	Dredge and fill permits under section 404 of CWA			
§ 144.31 (e)(6)(ix)	Required class VI permit Information	Other relevant environmental permits, including State permits.			Introduction (Additional Permits)
			§5.203 (o)	Letter from the Groundwater Advisory Unit of the Oil and Gas Division. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with Texas Water Code, §27.046.	Appendix A
§146.83					
§146.83(a)	Minimum Criteria for siting	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:	§5.206 (b)(6)	the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include:	
§146.83(a)(1)	Minimum Criteria for siting	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	§5.206 (b)(6)(A)	an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO2 stream; and	1.3.1, 1.11
§146.83(a)(2)	Minimum Criteria for siting	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).	§5.206 (b)(6)(B)	a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs;	1.3.2, 1.3.3. 1.11
§146.83(b)	Minimum Criteria for siting	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	**Area of review and corrective action**		**§5.203 (d)**	**Area of Review and Corrective Action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application.**	
§146.84(a)	Area of review and corrective action	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.	§5.203 (d)(1)(A)(ii)(IV)	considers the physical and chemical properties of injected and formation fluids; and	2.5.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
§146.84(b)	Area of review and corrective action	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:	§5.203 (d)(1)	Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3
§146.84(b)(1)	Area of review and corrective action	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;	§5.203 (d)(2)(A)	The method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	2.2.1, 2.4, 2.5
§146.84(b)(2)	Area of review and corrective action	A description of:	§5.203 (d)(2)(B)	For AOR, a description of:	
§146.84(b)(2)(i)	Area of review and corrective action	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	§5.203 (d)(2)(B)(i)	the minimum frequency subject to the annual certification pursuant to §5.206(f) of this title (relating to Permit Standards) at which the applicant proposes to re-evaluate the AOR during the life of the geologic storage facility;	3.5
§146.84(b)(2)(ii)	Area of review and corrective action	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.	§5.203 (d)(2)(B)(iii)	the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and	3.5.1
§146.84(b)(2)(iii)	Area of review and corrective action	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	§5.203 (d)(2)(B)(ii)	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	3.5.1
§146.84(b)(2)(iv)	Area of review and corrective action	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be	§5.203 (d)(2)(C)	a corrective action plan that describes:	
			§5.203 (d)(2)(C)(i)	how the corrective action will be conducted;	3.4
			§5.203 (d)(2)(C)(ii)	how corrective action will be adjusted if there are changes in the AOR;	3.4
			§5.203 (d)(2)(C)(iii)	if a phased corrective action is planned, how the phasing will be determined; and	3.4
			§5.203 (d)(2)(C)(iv)	how site access will be secured for future corrective action.	3.4

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§146.84(c)	Area of review and corrective action	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)	Area of review and corrective action	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:	§5.203 (d)(1)(A)(i)	Using computational modeling that considers the volumes and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods:	2.2, 2.4, 2.5, 2.6, 2.8, 7.2
			§5.203 (d)(1)(A)(i)(I)	five years after initiation of injection;	3.3.4, 5.5.5, Appendices C-5, E-1
			§5.203 (d)(1)(A)(i)(II)	from initiation of injection to the end of the injection period proposed by the applicant; and	7.3
			§5.203 (d)(1)(A)(i)(III)	from initiation of injection until the plume movement ceases, for a minimum of [to] 10 years after the end of the injection period proposed by the applicant.	2.8, 7.3
			§5.203 (d)(1)(A)(ii)	The applicant must use a computational model that:	
§146.84(c)(1)(i)	Area of review and corrective action	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;	§5.203 (d)(1)(A)(ii)(I)	Is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone	2.4.2, 2.4.3, 2.5.2
			§5.203 (d)(1)(A)(ii)(II)	is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	2.6
§146.84(c)(1)(ii)	Area of review and corrective action	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§5.203 (d)(1)(A)(ii)(III)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	2.2, 2.7
§146.84(c)(1)(iii)	Area of review and corrective action	Consider potential migration through faults, fractures, and artificial penetrations.	§5.203 (d)(1)(A)(ii)(V)	Considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.	2.2.2
			§5.203 (d)(1)(A)(iii)	The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.	2.2.1, 2.4, 2.5, 2.6

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§146.84(c)(2)	Required class VI permit Information	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	§5.203 (d)(1)(B)	Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR [area of review] that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	3.3.4, Appendix C
§146.84(c)(3)	Area of review and corrective action	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.	§5.203 (d)(1)(C)	Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased.	3.3.4
§146.84(d)	Area of review and corrective action	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.			3.4.2
§146.84(e)	Area of review and corrective action	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:	§5.206 (g)	Permit conditions for AOR and corrective action. At the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:	3.5
§146.84(e)(1)	Area of review and corrective action	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	§5.206 (g)(1)	perform a re-evaluation of the AOR by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate the AOR;	3.5.1
§146.84(e)(2)	Area of review and corrective action	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	§5.206 (g)(2)	Identify all wells in the reevaluated area of review that require corrective action;	3.5

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§146.84(e)(3)	Area of review and corrective action	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	§5.206 (g)(3)	perform corrective action on wells requiring corrective action in the re-evaluated AOR in the same manner specified in §5.203(d)(1)(C) of this title;	3.5
§146.84(e)(4)	Area of review and corrective action	Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.206 (g)(4)	submit an amended AOR and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR and corrective action plan is needed. Any amendments to the AOR 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 §5.202 of this title (relating to Permit Required, and Draft Permit and Fact Sheet), as applicable; and	
§146.84(f)	Area of review and corrective action	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.	§5.205 (b)(3)	The applicant's demonstration of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	8.2, 9.4
§146.84(g)	Area of review and corrective action	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	§5.206 (g)(5)	retain all modeling inputs and data used to support AOR reevaluations for at least 10 years.	3.5
			§5.205 (b)(1)	A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The operator must demonstrate and maintain financial responsibility and resources for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9
			§5.205 (b)(2)	In determining whether the person is financially responsible, the director must rely on:	
			§5.205 (b)(2)(A)	the person's most recent audited annual report 1 filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); and	
			§5.205 (b)(2)(B)	the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or	
			§5.205 (b)(2)(C)	if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the director.	

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			§5.205 (b)(3)	The applicant's demonstratio of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.4
			§5.205 (c)	Financial assurance.	
			§5.205 (c)(1)	Injection and monitoring wells. The operator must comply with the requirements of §3.78 of this title for all monitoring wells that penetrate the base of usable quality water and this subsection for all injection wells.	4.6
			§5.205 (c)(2)	Geologic storage facility.	
			§5.205 (c)(2)(A)	The applicant must include in an application for a geologic storage facility permit:	
			§5.205 (c)(2)(A)(iii)	information concerning the issuer of the bond or letter of credit including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.	
			§5.205 (c)(2)(B)	A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	
			§5.205 (c)(2)(C)	The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:	
			§5.205 (c)(2)(C)(ii)	A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act; and	
			§5.205 (c)(2)(C)(iii)	The Commission may use the proceeds of financial assurance filed under this subsection to pay the costs of plugging any well or wells at the facility if the financial assurance for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.	
			§5.205 (c)(2)(D)	Bonds and letters of credit filed in satisfaction of the financial assurance requirements for a geologic storage facility must comply with the following standards as to issuer and form.	
			§5.205 (c)(2)(D)(i)	The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.	

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			§5.205 (c)(2)(D)(ii)	Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101 - 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.	
			§5.205 (c)(2)(D)(iii)	The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	9.3
			§5.205 (c)(2)(D)(iii)(I)	Cancellation. An owner or operator must provide that its financial instrument 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 until at least 120 days after the Commission receives the cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.	
			§5.205 (c)(2)(D)(iii)(II)	Renewal. If a financial instrument expires, the owner or operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the 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.	
			§5.205 (c)(2)(D)(iii)(III)	Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration:	
			§5.205 (c)(2)(D)(iii)(III)(-a-)	the director deems the facility abandoned;	
			§5.205 (c)(2)(D)(iii)(III)(-b-)	the permit is terminated or revoked or a new permit is denied;	
			§5.205 (c)(2)(D)(iii)(III)(-c-)	closure is ordered by the director or a United States district court or other court of competent jurisdiction;	
			§5.205 (c)(2)(D)(iii)(III)(-d-)	the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or	
			§5.205 (c)(2)(D)(iii)(III)(-e-)	the amount due is paid.	

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			§5.205 (c)(2)(A)(ii)	a copy of the form of the bond or letter of credit that will be filed with the Commission; and	
			§5.205 (c)(2)(C)(i)	The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit;	
			§5.205 (c)(2)(A)(i)	a written estimate of the highest likely dollar amount necessary to perform post-injection monitoring and closure of the facility that shows all assumptions and calculations used to develop the estimate;	9.6.1
			§5.205 (c)(2)(E)	The operator of a geologic storage facility must provide to the director annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The operator must provide to the director upon request an adjustment of the cost estimate if the director has reason to believe that the original demonstration is no longer adequate to cover the cost of injection well plugging and post-injection storage facility care and closure.	9.3

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			§5.205 (c)(2)(F)	The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage 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 AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
			§5.205 (c)(2)(G)	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 operator has received written approval from the director.	
			§5.205 (c)(2)(H)	The requirement to maintain adequate financial responsibility is directly enforceable regardless of whether the requirement is a condition of the permit.	
			§5.205 (c)(2)(H)(i)	The owner or operator must maintain financial responsibility until:	
			§5.205 (c)(2)(H)(i)(I)	the director receives and approves the completed post-injection storage facility care and closure plan; and	
			§5.205 (c)(2)(H)(i)(II)	the director issues the certificate of closure.	
			§5.205 (c)(2)(H)(ii)	The owner or operator may be released from a financial instrument in the following circumstances:	

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			§5.205 (c)(2)(H)(ii)(I)	The owner or operator has completed the phase of the geologic storage 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 geologic storage project, if required; or	
			§5.205 (c)(2)(H)(ii)(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.	
			§5.205 (c)(3)	The director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors.	
			§5.205 (c)(4)	The director may approve a reduction in the amount of financial assurance required for post-injection monitoring and/or corrective action based on project-specific monitoring results.	
			§5.205 (c)(5)	The owner or operator must maintain the required financial responsibility regardless of the status of the director's review of the financial responsibility demonstration.	
			§5.205 (D)	Notice of adverse financial conditions	
			§5.205 (D)(1)	The operator must notify the Commission of adverse financial conditions that may affect the operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The operator must give such notice by certified mail.	
			§5.205 (D)(2)	The operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business.	
			§5.205 (D)(3)	Upon the incapacity of a bank or surety company by reason of bankruptcy, insolvency or suspension, or revocation of its charter or license, the Commission must deem the operator to be without bond coverage. The Commission must issue a notice to any operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.	
§146.85	**Financial Responsibility**				
§146.85(a)	Financial Responsibility	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:			
§146.85(a)(1)	Financial Responsibility	The financial responsibility instrument(s) used must be from the following list of qualifying instruments:			
§146.85(a)(1)(i)	Financial Responsibility	Trust Funds.			9.3
§146.85(a)(1)(ii)	Financial Responsibility	Surety Bonds.			9.3

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§146.85(a)(1)(iii)	Financial Responsibility	Letter of Credit.			
§146.85(a)(1)(iv)	Financial Responsibility	Insurance			9.3
§146.85(a)(1)(v)	Financial Responsibility	Self Insurance (i.e., Financial Test and Corporate Guarantee).			
§146.85(a)(1)(vi)	Financial Responsibility	Escrow Account			
§146.85(a)(1)(vii)	Financial Responsibility	Any other instrument(s) satisfactory to the Director.			
§146.85(a)(2)	Financial Responsibility	The qualifying instrument(s) must be sufficient to cover the cost of:	§5.203 (n)(1)	The applicant must demonstrate financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided to	9.3
§146.85(a)(2)(i)	Financial Responsibility	Corrective action (that meets the requirements of § 146.84);			
§146.85(a)(2)(ii)	Financial Responsibility	Injection well plugging (that meets the requirements of § 146.92);			
§146.85(a)(2)(iii)	Financial Responsibility	Post injection site care and site closure (that meets the requirements of § 146.93); and			
§146.85(a)(2)(iv)	Financial Responsibility	Emergency and remedial response (that meets the requirements of § 146.94).			
§146.85(a)(3)	Financial Responsibility	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.			9.3
§146.85(a)(4)	Financial Responsibility	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.			9.3
§146.85(a)(4)(i)	Financial Responsibility	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.			9.3

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§146.85(a)(4)(i)(A)	Financial Responsibility	Cancellation - for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.			
§146.85(a)(4)(i)(B)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	The qualifying financial responsibility instrument(s) must be approved by the Director.			
§146.85(a)(5)(i)	Financial Responsibility	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)	Financial Responsibility	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.			9.3

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§146.85(a)(5)(iii)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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.			

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§146.85(a)(6)(v)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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.			9.3
§146.85(b)	Financial Responsibility	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)	Financial Responsibility	The owner or operator must maintain financial responsibility and resources until:			
§146.85(b)(1)(i)	Financial Responsibility	The Director receives and approves the completed post-injection site care and site closure plan; and			9.3
§146.85(b)(1)(ii)	Financial Responsibility	The Director approves site closure.			9.3

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§146.85(b)(2)	Financial Responsibility	The owner or operator may be released from a financial instrument in the following circumstances:			
§146.85(b)(2)(i)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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.			9.4, 9.5, 9.6
§146.85(c)(1)	Financial Responsibility	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.			9.3
§146.85(c)(2)	Financial Responsibility	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).			9.3

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§146.85(c)(3)	Financial Responsibility	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.			
§146.85(c)(4)	Financial Responsibility	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.			
§146.85(d)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	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.			

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§146.85(d)(3)	Financial Responsibility	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)	Financial Responsibility	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)	Financial Responsibility	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.			
§146.86	**Injection well construction requirements**		**§5.203 (e)**	**Injection well construction**	
§146.86(a)	Injection well construction requirements	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§5.203 (e)(1)	Criteria for construction of anthropogenic CO2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO2 injection wells that an applicant must include in an application.	
			§5.203 (e)(1)(A)	General. The operator of a geologic storage facility must ensure that all anthropogenic CO2 injection wells are constructed and completed in a manner that will:	
§146.86(a)(1)	Injection well construction requirements	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	§5.203 (e)(1)(A)(i)	Prevent the movement of injected CO2 or displaced fromation fluids into any unauthorized zones or into any areas where they could endanger USDWs;	4.2
§146.86(a)(2)	Injection well construction requirements	Permit the use of appropriate testing devices and workover tools; and	§5.203 (e)(1)(A)(ii)	Allow the use of appropriate testing devices and workover tools; and	4.2
§146.86(a)(3)	Injection well construction requirements	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	§5.203 (e)(1)(A)(iii)	Allow continuous monitoring of the annulus space between the injection tubing and long string casing.	4.2
§146.86(b)	Injection well construction requirements	Casing and cementing of Class VI wells.	§5.203 (e)(1)(B)	Casing and Cementing of anthropogenic CO2 injection wells	

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§146.86(b)(1)	Injection well construction requirements	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:	§5.203 (e)(1)(B)(ii)	Casing and cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well 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 approved by the Director.	4.2; Appendix D
			§5.203 (e)(2)	Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	
§146.86(b)(1)(i)	Injection well construction requirements	Depth to the injection zone(s);	§5.203 (e)(2)(A)	Depth to the injection zone(s);	4.2, Appendix D
§146.86(b)(1)(ii)	Injection well construction requirements	Injection pressure, external pressure, internal pressure, and axial loading;			4.2.1
§146.86(b)(1)(iii)	Injection well construction requirements	Hole size;	§5.203 (e)(2)(B)	Hole size	4.2.1
§146.86(b)(1)(iv)	Injection well construction requirements	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	§5.203 (e)(2)(C)	size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);	4.2.1
§146.86(b)(1)(v)	Injection well construction requirements	Corrosiveness of the carbon dioxide stream and formation fluids;	§5.203 (e)(2)(F)	a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids;	4.2
§146.86(b)(1)(vi)	Injection well construction requirements	Down-hole temperatures;	§5.203 (e)(2)(G)	Down-hole temperatures and pressures	2.5.2.4, 4.2.1
§146.86(b)(1)(vii)	Injection well construction requirements	Lithology of injection and confining zone(s);	§5.203 (e)(2)(H)	Lithology of injection and confining zone(s)	4.2
§146.86(b)(1)(viii)	Injection well construction requirements	Type or grade of cement and cement additives; and	§5.203 (e)(2)(I)	Type or grade of cement and cement additives; and	4.2.1, Appendix D
§146.86(b)(1)(ix)	Injection well construction requirements	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§5.203 (e)(2)(J)	Quantity, chemical composition, and temperature of the carbon dioxide stream.	2.2, 2.5.2, 4.2.1
			§5.203 (e)(1)(B)(i)	The operator must ensure that injection wells are cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section.	4.2
§146.86(b)(2)	Injection well construction requirements	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.	§5.203 (e)(1)(B)(iii)	Surface casing must extend through the base of the lowermost USDW above the injection zone and be cemented to the surface	4.2, Appendix D

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§146.86(b)(3)	Injection well construction requirements	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.	§5.203 (e)(1)(B)(v)	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. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).	4.2
§146.86(b)(4)	Injection well construction requirements	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.	§5.203 (e)(1)(B)(iv)	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.	
§146.86(b)(5)	Injection well construction requirements	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.	§5.203 (e)(1)(B)(vi)	The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.	4.3.2
§146.86(c)		Tubing and packer.	§5.203 (e)(1)(C)	Special equipment.	4.2, Appendix D
§146.86(c)(1)	Injection well construction requirements	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.			4.2
§146.86(c)(2)	Injection well construction requirements	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.	§5.203 (e)(1)(C)(i)	Tubing and packer. All injection wells must inject fluids through tubing set on a mechanical packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.	4.2, Appendix D
			§5.203 (e)(1)(C)(ii)	Pressure observation valve. The wellhead of each injection well must be equipped with a pressure observation valve on the tubing and each annulus of the well.	4.2.1.8
§146.86(c)(3)	Injection well construction requirements	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)	Injection well construction requirements	Depth of setting;			4.2; Appendix D

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§146.86(c)(3)(ii)	Injection well construction requirements	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;			2.5.2, 4.2.1, 4.4
§146.86(c)(3)(iii)	Injection well construction requirements	Maximum proposed injection pressure;			2.7.1, 4.2.1, 4.4
§146.86(c)(3)(iv)	Injection well construction requirements	Maximum proposed annular pressure;			4.4
§146.86(c)(3)(v)	Injection well construction requirements	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	§5.203 (e)(2)(D)	proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, and maximum proposed volume and/or mass of the CO2 stream to be injected;	2.7.1, 4.2.1, 4.4
			§5.203 (e)(2)(E)	type of packer and packer setting depth	4.2, Appendix D
§146.86(c)(3)(vi)	Injection well construction requirements	Size of tubing and casing; and			4.2
§146.86(c)(3)(vii)	Injection well construction requirements	Tubing tensile, burst, and collapse strengths.			4.2.1
§146.87		**Logging, sampling, and testing prior to injection well operation**			
§146.87(a)	Logging, sampling, and testing prior to injection well operation	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:	§5.203 (c)(1)	The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations.	

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			§5.203 (f)	The applicant must submit a plan for logging, sampling, and testing of each injection well after permitting but prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.	4.3.2
			§5.203 (f)(1)	Logs and surveys of newly drilled and completed injection wells.	4.3.2
§146.87(a)(1)	Logging, sampling, and testing prior to injection well operation	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	§5.203 (f)(1)(A)	During the drilling of any hole that is constructed by drilling a pilot hole which is enlarged by reaming or another method, the operator must perform deviation checks 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.	
§146.87(a)(2)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the surface casing:			
§146.87(a)(2)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§5.203 (f)(1)(B)	Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	4.3.2
§146.87(a)(2)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	§5.203 (f)(1)(C)	After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.	4.3.2
§146.87(a)(3)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the long string casing:	§5.203 (f)(1)(D)	Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	
§146.87(a)(3)(i)	Logging, sampling, and testing prior to injection well operation	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			4.3.2

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§146.87(a)(3)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	§5.203 (f)(1)(C)	After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.	4.3.2
			§5.203 (h)(1)(E)	The operator must test injection wells after any workover that disturbs the seal between the tubing, packer, and casing in a manner that verifies internal mechanical integrity of the tubing and long string casing.	
			§5.203 (h)(1)(F)	An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
§146.87(a)(4)	Logging, sampling, and testing prior to injection well operation	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	§5.203 (h)(2)	Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. [The plan must include a schedule for the performance of a series of tests at a minimum frequency of five years.] The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:	5.4.2, 5.4.3
§146.87(a)(4)(i)	Logging, sampling, and testing prior to injection well operation	A pressure test with liquid or gas;	§5.203 (h)(2)(A)	A pressure test with liquid or gas;	5.4.2
§146.87(a)(4)(ii)	Logging, sampling, and testing prior to injection well operation	A tracer survey such as oxygen-activation logging;	§5.203 (h)(2)(B)	A tracer survey such as oxygen-activation logging;	5.4.3
§146.87(a)(4)(iii)	Logging, sampling, and testing prior to injection well operation	A temperature or noise log;	§5.203 (h)(2)(C)	A temperature or noise log;	5.4.3
§146.87(a)(4)(iv)	Logging, sampling, and testing prior to injection well operation	A casing inspection log; and	§5.203 (h)(2)(D)	A casing inspection log; and	4.3.2
§146.87(a)(5)	Logging, sampling, and testing prior to injection well operation	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	§5.203 (h)(2)(E)	Any alternative methods approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.	
§146.87(b)	Logging, sampling, and testing prior to injection well operation	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.	§5.203 (f)(3)(B)	The operator must submit analyses of whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well.	4.3.1
§146.87(c)	Logging, sampling, and testing prior to injection well operation	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§5.203 (f)(3)(A)	The operator must record the formation fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.	4.3.2

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§146.87(d)	Logging, sampling, and testing prior to injection well operation	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	§5.203 (f)(2)	Testing and determination of hydrogeologic characteristics of injection and confining zone.	
§146.87(d)(1)	Logging, sampling, and testing prior to injection well operation	Fracture pressure;	§5.203 (f)(2)(C)	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.4.2, 2.5.2.3, 4.3.4
§146.87(d)(2)	Logging, sampling, and testing prior to injection well operation	Other physical and chemical characteristics of the injection and confining zone(s); and			1.3, 1.4, 1.7, 4.3
§146.87(d)(3)	Logging, sampling, and testing prior to injection well operation	Physical and chemical characteristics of the formation fluids in the injection zone(s).			1.7, 4.3.2
§146.87(e)	Logging, sampling, and testing prior to injection well operation	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):			
§146.87(e)(1)	Logging, sampling, and testing prior to injection well operation	A pressure fall-off test; and,	§5.203 (f)(2)(B)	The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO2.	4.3.4
§146.87(e)(2)		A pump test; or			
		Injectivity tests.			4.3.4
§146.87(f)	Logging, sampling, and testing prior to injection well operations	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.	§5.206 (i)	Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	4.3
§146.88		**Injection well operating requirements**			
			§5.203 (i)(2)	Maximum injection pressure. The director will approve a maximum injection pressure limit that:	
			§5.203 (i)(2)(A)	Considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;	
			§5.203 (i)(2)(B)	With a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive; and	

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§146.88(a)	Injection well operating requirements	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.	§5.203 (i)(2)(C)	in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.	4.4
			§5.203 (f)(2)(C)	The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone	1.4.2, 2.5.2.3, 4.4
§146.88(b)	Injection well operating requirements	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	§5.206 (d)(2)(A)	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	
§146.88(c)	Injection well operating requirements	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.	§5.206 (d)(2)(D)	The owner or operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting 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.	4.2, 4.4
§146.88(d)	Injection well operating requirements	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.	§5.203 (h)(1)(A)	Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.	4.2
§146.88(d)	Injection well operating requirements	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.	§5.206 (f)(2)	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.	4.2
§146.88(e)	Injection well operating requirements	The owner or operator must install and use:	§5.206 (d)(2)(F)	The operator must comply with the following requirements for alarms and automatic shut-off systems.	
§146.88(e)(1)	Injection well operating requirements	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	§5.206 (d)(2)(F)(i)	The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	4.2, 5.5.1

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§146.88(e)(2)	Injection well operating requirements	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			5.5.2, 8.3.2
§146.88(e)(3)	Injection well operating requirements	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.			
§146.88(f)	Injection well operating requirements	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:	§5.206 (d)(2)(F)(ii)	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. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must	8.3
§146.88(f)(1)	Injection well operating requirements	Immediately cease injection;	§5.206 (d)(2)(F)(ii)(I)	Immediately cease injection;	8.3
§146.88(f)(2)	Injection well operating requirements	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;	§5.206 (d)(2)(F)(ii)(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	8.3
§146.88(f)(3)	Injection well operating requirements	Notify the Director within 24 hours;	§5.206 (d)(2)(F)(ii)(III)	Notify the Director within 24 hours	8.3
§146.88(f)(4)	Injection well operating requirements	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	§5.206 (d)(2)(F)(ii)(IV)	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	8.3
§146.88(f)(5)	Injection well operating requirements	Notify the Director when injection can be expected to resume.	§5.206 (d)(2)(F)(ii)(V)	Notify the Director when injection can be expected to resume	
§146.89	**Mechanical Integrity**	Mechanical Integrity	§5.203 (h)	Mechanical integrity testing.	
			§5.203 (h)(1)	Criteria. This paragraph establishes the criteria for the mechanical integrity testing plan for anthropogenic CO2 injection wells that an applicant must include in an application.	
			§5.206 (f)	**Mechanical Integrity**	
§146.89(a)	Mechanical Integrity	A Class VI well has mechanical integrity if:			
§146.89(a)(1)	Mechanical Integrity	There is no significant leak in the casing, tubing, or packer; and			
§146.89(a)(2)	Mechanical Integrity	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.			
			§5.203 (h)(1)(B)	Before beginning injection operations and at least once every five years thereafter, the operator must demonstrate internal mechanical integrity for each injection well by pressure testing the tubing-casing annulus.	5.4.2

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§146.89(b)	Mechanical Integrity	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);	§5.203 (h)(1)(C)	Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, injected volumes and pressure on the annulus between tubing and long-string casing to confrim that the injected fluids are confined to the injection zone.	5.5.1
§146.89(c)	Mechanical Integrity	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:	§5.203 (h)(1)(D)	At least once per year until the injection well is plugged the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).	5.4.3
§146.89(c)(1)	Mechanical Integrity	An approved tracer survey such as an oxygen-activation log; or			
§146.89(c)(2)	Mechanical Integrity	A temperature or noise log.			
§146.89(d)	Mechanical Integrity	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.			
§146.89(e)	Mechanical Integrity	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.			

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§146.89(f)	Mechanical Integrity	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.			
§146.89(g)	Mechanical Integrity	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.	§5.206 (f)(4)	The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	
§146.90	**Testing and monitoring requirements**	The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	**§5.203 (j)**	**Plan for monitoring, sampling, and testing after initiation of operation.**	Section 5
			§5.203 (j)(1)	The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	Section 5
			§5.203 (j)(2)	The plan must include the following:	
§146.90(a)	Testing and monitoring requirements	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	§5.203 (j)(2)(A)	The analysis of the carbon dioxide stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;	5.5.3

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§146.90(b)	Testing and monitoring requirements	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;	§5.203 (j)(2)(B)	The installation and use of continuous recording devices to monitor injection pressure, rate, and volume and the pressure on the annulus between the tubing and the long string casing, except during workovers	4.2, 5.5.2
§146.90(c)	Testing and monitoring requirements	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:	§5.203 (j)(2)(C)	After initiation of injection, the performance on a semi-annual basis of 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 subsection (e)(1)(A) of this section. The operator must report the results of such monitoring annually. Corrosion monitoring may be accomplished by:	5.5.4
§146.90(c)(1)	Testing and monitoring requirements	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	§5.203 (j)(2)(C)(i)	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	
§146.90(c)(2)	Testing and monitoring requirements	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	§5.203 (j)(2)(C)(ii)	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	5.5.4.1
§146.90(c)(3)	Testing and monitoring requirements	Using an alternative method approved by the Director;	§5.203 (j)(2)(C)(iii)	using an alternative method, materials, or time period approved by the director;	
§146.90(d)	Testing and monitoring requirements	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:	§5.203 (j)(2)(D)	Monitoring of geochemical and geophysical changes, including:	
			§5.203 (j)(2)(D)(i)	Periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone;	N/A
			§5.203 (j)(2)(D)(ii)	periodic monitoring of the quality and geochemistry of a USDW within the AOR and the formation fluid in a permeable and porous formation near to and above the top confining zone to detect any movement of the injected CO_2 through the confining zone into that monitored formation;	5.5.5
§146.90(d)(1)	Testing and monitoring requirements	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	§5.203 (j)(2)(D)(iii)	The location and number of monitoring wells justified on the basis of AOR, injection rate and volume, geology, the presence of artificial penetrations and other factors specific to the geologic storage facility; and	5.5.5
§146.90(d)(1)	Testing and monitoring requirements	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			5.5.5

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§146.90(d)(2)	Testing and monitoring requirements	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).	§5.203 (j)(2)(D)(iv)	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;	5.5.5
§146.90(e)		A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	§5.203 (j)(2)(F)	a demonstration of external mechanical integrity pursuant to subsection (h)(2) of this section at least once per year until the injection well is plugged, and, if required by the director, a casing inspection log pursuant to requirements in subsection (h)(2) of this section at a frequency established in the testing and monitoring plan;	5.4.3
§146.90(f)	Testing and monitoring requirements	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;	§5.203 (j)(2)(G)	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; and	5.4.4
§146.90(g)	Testing and monitoring requirements	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:	§5.203 (j)(2)(E)	tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	
§146.90(g)(1)		Direct methods in the injection zone(s); and,			5.5.7
§146.90(g)(2)	Testing and monitoring requirements	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;	§5.203 (j)(2)(E)	tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	5.5.7
§146.90(h)		The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.			5.5.9
§146.90(h)(1)		Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;			5.5.9
§146.90(h)(2)		The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;			5.5.9

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§146.90(h)(3)		If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;			
§146.90(i)	Testing and monitoring requirements	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;	§5.203 (j)(2)(H)	Additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.	
			§5.206 (e)(3)	The director may require additional monitoring as necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirement that the injection activity not allow movement of fluid that would endanger USDWs	
§146.90(j)	Testing and monitoring requirements	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:			5.3
§146.90(j)(1)		Within one year of an area of review reevaluation;			5.3
§146.90(j)(2)		Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	§5.207 (a)(3)	The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	5.3
§146.90(j)(3)		When required by the Director.			

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§146.90(k)	Testing and monitoring requirements	A quality assurance and surveillance plan for all testing and monitoring requirements.	§5.203 (a)(4)	Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	Appendix I
§146.91	**Reporting requirements**	The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	**§5.207 (a)**	Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information:	
			§5.207 (a)(1)	Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.	
			§5.207 (a)(2)(D)	Annual reports. The operator must submit an annual report detailing:	
			§5.207 (a)(2)(D)(i)	corrective action performed;	
			§5.207 (a)(2)(D)(ii)	new wells installed and the type, location, number, and information required in §5.203(e) of this title (relating to Application Requirements);	
			§5.207 (a)(2)(D)(iii)	re-calculated AOR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR on file with the Commission;	
			§5.207 (a)(2)(D)(iv)	the updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;	
			§5.207 (a)(2)(D)(v)	tons of CO_2 injected; and	
			§5.207 (a)(2)(D)(vi)	other information as required by the permit.	
			§5.207 (a)(2)(E)	Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter.	
			§5.207 (a)(2)(E)(i)	Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:	
			§5.207 (a)(2)(E)(i)(I)	reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and	

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			§5.207 (a)(2)(E)(i)(II)	determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator.	
			§5.207 (a)(2)(E)(ii)	Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.	
§146.91(a)	Reporting requirements	**Semi-annual reports containing:**	§5.207 (a)(2)(C)	**Semi-annual reports containing:**	5.2
§146.91(a)(1)	Reporting requirements	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	§5.207 (a)(2)(C)(ii)	Any changes to the source as well as the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	5.2
§146.91(a)(2)	Reporting requirements	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	§5.207 (a)(2)(C)(i)	a summary of well head pressure monitoring;	5.2
			§5.207 (a)(2)(C)(iii)	monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;	5.2
§146.91(a)(3)	Reporting requirements	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	§5.207 (a)(2)(C)(v)	description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;	5.2
§146.91(a)(4)	Reporting requirements	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	§5.207 (a)(2)(C)(vi)	a description of any event that triggers a shutdown device and the response taken; and	5.2
§146.91(a)(5)	Reporting requirements	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;	§5.207 (a)(2)(C)(iii)	monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure;	5.2
§146.91(a)(6)	Reporting requirements	Monthly annulus fluid volume added; and	§5.207 (a)(2)(C)(iv)	monthly annulus fluid volume added;	5.2
§146.91(a)(7)	Reporting requirements	The results of monitoring prescribed under § 146.90.	§5.207 (a)(2)(C)(vii)	the results of monitoring prescribed under §5.206€ [§5.206(d)] of this title (relating to Permit Standards).	5.2
§146.91(b)	Reporting requirements	**Report, within 30 days, the results of:**	§5.207 (a)(2)(B)	**Report, within 30 days, the results of:**	5.2
§146.91(b)(1)	Reporting requirements	Periodic tests of mechanical integrity;	§5.207 (a)(2)(B)(i)	the results of periodic tests for mechanical integrity;	5.2
§146.91(b)(2)	Reporting requirements	Any well workover; and,	§5.207 (a)(2)(B)(iii)	a description of any well workover.	5.2
§146.91(b)(3)	Reporting requirements	Any other test of the injection well conducted by the permittee if required by the Director.	§5.207 (a)(2)(B)(ii)	the results of any other test of the injection well conducted by the operator if required by the director; and	5.2
§146.91(c)	Reporting requirements	**Report, within 24 hours:**	§5.207 (a)(2)	Operating reports. The operator also must include summary cumulative tables of the information required by the reports listed in this paragraph.	

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			§5.207 (a)(2)(A)	Report within 24 hours. The operator must report to the appropriate district office the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir. Such report must be made orally as soon as practicable, but within 24 hours, following the discovery of the leak, and must be confirmed in writing within five working days.	5.2
			§5.207 (a)(2)(A)(i)	the discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir;	5.2
§146.91(c)(1)	Reporting requirements	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	§5.207 (a)(2)(A)(ii)	any evidence that the injected CO2 stream or associated pressure front may cause an endangerment to a USDW;	5.2
§146.91(c)(2)	Reporting requirements	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	§5.207 (a)(2)(A)(iii)	any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	5.2
§146.91(c)(3)	Reporting requirements	Any triggering of a shut-off system (i.e., down-hole or at the surface);	§5.207 (a)(2)(A)(iv)	any triggering of a shut-off system (i.e., down-hole or at the surface); and	5.2
§146.91(c)(4)	Reporting requirements	Any failure to maintain mechanical integrity; or.	§5.207 (a)(2)(A)(v)	any failure to maintain mechanical integrity.	5.2
§146.91(c)(5)	Reporting requirements	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.			5.2
§146.91(d)	Reporting requirements	Owners or operators must notify the Director in writing 30 days in advance of	§5.206 (i)	Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	5.2
§146.91(d)(1)	Reporting requirements	Any planned well workover;			5.2
§146.91(d)(2)	Reporting requirements	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and			5.2
§146.91(d)(3)	Reporting requirements	Any other planned test of the injection well conducted by the permittee.			5.2

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			§5.207 (b)(1)	The operator must report the results of injection pressure and injection rate monitoring of each injection well on Form H-10, Annual Disposal/Injection Well Monitoring Report, and the results of internal mechanical integrity testing on Form H-5, Disposal/Injection Well Pressure Test Report. Operators must submit other reports in a format acceptable to the Commission. At the discretion of the director, other formats may be accepted.	5.2, 5.4.2
§146.91(e)	Reporting requirements	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.	§5.207 (b)(2)	The operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by director.	
			§5.207 (c)	Signatories to reports.	
			§5.207 (c)(1)	Reports. All reports required by permits and other information requested by the director, shall be signed by a person described in §5.203(a)(1)(B) of this title, or by a duly authorized representative of that person. A person is a duly authorized representative only if:	
			§5.207 (c)(1)(A)	the authorization is made in writing by a person described in §5.203(a)(1)(B) of this title;	
			§5.207 (c)(1)(B)	the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility; and	
			§5.207 (c)(1)(C)	the written authorization is submitted to the director.	
			§5.207 (c)(2)	Changes to authorization. If an authorization under paragraph (1) of this subsection is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (1) of this subsection must be submitted to the director prior to or together with any reports, information, or applications to be signed by an authorized representative.	

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			§5.207 (d)	Certification. All reports required by permits and other information requested by the director under this subchapter, shall be certified as follows: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."	
§146.91(f)	Reporting requirements		§5.207 (e)	Record retention.	
§146.91(f)(1)	Reporting requirements	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.	§5.207 (e)(1)	The operator must retain all data collected under §5.203 of this title for Class VI permit applications throughout the life of the geologic sequestration project and for 10 years following storage facility closure.	5.2
§146.91(f)(2)	Reporting requirements	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.	§5.207 (e)(2)	The operator must retain data on the nature and composition of all injected fluids collected pursuant to §5.203(j)(2)(A) of this title until 10 years after storage facility closure. The operator shall submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	5.2
			§5.207 (e)(7)	The director may require the operator to submit the records to the director at the conclusion of the retention period.	
§146.91(f)(3)	Reporting requirements	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	§5.207 (e)(3)	The operator must retain all testing and monitoring data collected pursuant to the plans required under §5.203(j) of this title, including wellhead pressure records, metering records, and integrity test results, and modeling inputs and data used to support AOR calculations for at least 10 years after the data is collected.	5.2
§146.91(f)(4)	Reporting requirements	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.	§5.207 (e)(4)	The operator must retain well plugging reports, post-injection storage facility care data, including data and information used to develop the demonstration of the alternative post-injection storage facility care timeframe, and the closure report collected pursuant to the requirements of §5.206(k)(6) and (m) of this title for 10 years following storage facility closure.	5.2
			§5.207 (e)(5)	The operator must retain all documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility until the director issues the final certificate of closure in accordance with §5.206(k)(7) of this title.	

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§146.91(f)(5)	Reporting requirements	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.	§5.207 (e)(6)	The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years after storage facility closure.	
§146.92	**Injection Well Plugging**	**Injection well plugging**	**§5.203 (k)**	**Injection well plugging**	
§146.92(a)	Injection Well Plugging	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure,	§5.203 (k)(2)(A)	flush each injection well with a buffer fluid;	6.2.2
			§5.203 (k)(2)(B)	performing tests or measures to determine bottomhole reservoir pressure;	6.2.2
			§5.203 (k)(2)(C)	performing final tests to assess mechanical integrity; and	6.2.2
§146.92(b)	Injection Well Plugging	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	§5.203 (k)	Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that penetrate the base of usable quality water that includes the following:	Section 6
			§5.203 (k)(1)	A proposal for plugging all monitoring wells that penetrate the base of usable quality water and all injection wells upon abandonment in accordance with §3.14 of this title (relating to Plugging), in addition to the requirements of this section. The proposal must include:	Section 6
§146.92(b)(1)	Injection Well Plugging	Appropriate tests or measures for determining bottomhole reservoir pressure;	§5.203 (k)(2)(B)	performing tests or measures to determine bottomhole reservoir pressure;	6.2.2
§146.92(b)(2)	Injection Well Plugging	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	§5.203 (k)(2)(C)	performing final tests to assess mechanical integrity; and	6.2.2
§146.92(b)(3)	Injection Well Plugging	The type and number of plugs to be used;	§5.203 (k)(1)(A)	The type and number of plugs to be used;	6.2.2
§146.92(b)(4)	Injection Well Plugging	The placement of each plug, including the elevation of the top and bottom of each plug;	§5.203 (k)(1)(B)	The placement of each plug, including the elevation of the top and bottom of each plug;	6.2.2
§146.92(b)(5)	Injection Well Plugging	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	§5.203 (k)(1)(C)	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	6.2.2
			§5.203 (k)(2)(D)	ensuring that the material to be used in plugging must be compatible with the CO2 stream and the formation fluids;	6.2.2
§146.92(b)(6)	Injection Well Plugging	The method of placement of the plugs.	§5.203 (k)(1)(D)	The method of placement of the plugs.	6.2.2
§146.92(c)	Injection Well Plugging	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	§5.203 (k)(3)(A)	the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and	6.2.2
			§5.203 (k)(3)(B)	the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;	6.2.2

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§146.92(d)	Injection Well Plugging	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.	§5.203 (k)(4)	plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;	6.2.2
§146.93	**Post-injection and site closure**	**Post-injection site care and site closure**	§5.203 (m)	The applicant must submit a post-injection storage facility care and closure plan.	
§146.93(a)	Post-injection and site closure	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)	Post-injection and site closure	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.			
§146.93(a)(2)	Post-injection and site closure	The post-injection site care and site closure plan must include the following information:			
§146.93(a)(2)(i)	Post-injection and site closure	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	§5.203 (m)(2)	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	7.2
§146.93(a)(2)(ii)	Post-injection and site closure	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);	§5.203 (m)(3)	the predicted position of the CO2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;	7.3
§146.93(a)(2)(iii)	Post-injection and site closure	A description of post-injection monitoring location, methods, and proposed frequency;	§5.203 (m)(4)	A description of post-injection monitoring location, methods, and proposed frequency;	7.4
§146.93(a)(2)(iv)	Post-injection and site closure	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	§5.203 (m)(5)	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	7.4
§146.93(a)(2)(v)	Post-injection and site closure	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.	§5.203 (m)(1)	a demonstration containing substantial evidence that the geologic storage project will no longer pose a risk of endangerment to USDWs at the end of the post-injection storage facility care timeframe. The demonstration must be based on significant, site-specific data and information, including all data and information collected pursuant subsections (b)-(d) of this section and §5.206(b)(5) of this title;	7.5

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§146.93(a)(3)	Post-injection and site closure	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.			7.5
§146.93(a)(4)	Post-injection and site closure	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.	§5.206 (k)(1)(B)	The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the 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. 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 in §5.202 of this title (relating to Permit Required), as appropriate.	7.4
§146.93(b)	Post-injection and site closure	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.	§5.206 (k)(2)	Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	7.1
§146.93(b)(1)		Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.			7.4

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§146.93(b)(2)		If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.			7.5
§146.93(b)(3)	Post-injection and site closure	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.	§5.206 (k)(3)	Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the Director 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. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following:	7.5
§146.93(b)(4)	Post-injection and site closure	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)	Post-injection and site closure	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.			
			§5.203 (m)(6)	the estimated cost of proposed post-injection storage facility care and closure; and	9.3

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§146.93(c)(1)	Post-injection and site closure	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	§5.203 (m)(7)	consideration and documentation of:	
§146.93(c)(1)(i)	Post-injection and site closure	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	§5.203 (m)(7)(A)	the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;	
§146.93(c)(1)(ii)	Post-injection and site closure	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;	§5.203 (m)(7)(B)	the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-injection pressures;	
§146.93(c)(1)(iii)	Post-injection and site closure	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	§5.203 (m)(7)(C)	the predicted rate of CO2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO2 plume and associated pressure front;	
§146.93(c)(1)(iv)	Post-injection and site closure	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;	§5.203 (m)(7)(D)	a description of the site-specific processes that will result in CO2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	
§146.93(c)(1)(v)	Post-injection and site closure	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	§5.203 (m)(7)(E)	the predicted rate of CO2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	
§146.93(c)(1)(vi)	Post-injection and site closure	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;	§5.203 (m)(7)(F)	the results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in subparagraphs (D) and (E) of this paragraph;	
§146.93(c)(1)(vii)	Post-injection and site closure	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;	§5.203 (m)(7)(G)	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., CO2, formation fluids) movement;	
§146.93(c)(1)(viii)	Post-injection and site closure	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;	§5.203 (m)(7)(H)	the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO2 plume and area of elevated pressure;	
§146.93(c)(1)(ix)	Post-injection and site closure	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	§5.203 (m)(7)(I)	a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;	
§146.93(c)(1)(x)	Post-injection and site closure	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	§5.203 (m)(7)(J)	the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	
§146.93(c)(1)(xi)	Post-injection and site closure	Any additional site-specific factors required by the Director.	§5.203 (m)(7)(K)	any additional site-specific factors required by the director; and	
§146.93(c)(2)	Post-injection and site closure	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	§5.203 (m)(8)	information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:	

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§146.93(c)(2)(i)	Post-injection and site closure	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	§5.203 (m)(8)(A)	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)	Post-injection and site closure	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	§5.203 (m)(8)(B)	estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	
§146.93(c)(2)(iii)	Post-injection and site closure	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;	§5.203 (m)(8)(C)	predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project;	
§146.93(c)(2)(iv)	Post-injection and site closure	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;	§5.203 (m)(8)(D)	predictive models must be calibrated using existing information where sufficient data are available;	
§146.93(c)(2)(v)	Post-injection and site closure	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;	§5.203 (m)(8)(E)	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)	Post-injection and site closure	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.	§5.203 (m)(8)(F)	an analysis must be performed to identify and assess aspects of the alternative PISC timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	
§146.93(c)(2)(vii)	Post-injection and site closure	An approved quality assurance and quality control plan must address all aspects of the demonstration; and	§5.203 (m)(8)(G)	an approved quality assurance and quality control plan must address all aspects of the demonstration; and	
§146.93(c)(2)(viii)	Post-injection and site closure	Any additional criteria required by the Director.	§5.203 (m)(8)(H)	any additional criteria required by the director.	
§146.93(d)	Post-injection and site closure	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.	§5.206 (k)(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.	7.6.1
§146.93(e)	Post-injection and site closure	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.	§5.206 (k)(5)	Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the Director has authorized site closure, the operator must plug all monitoring wells in accordance with the approved plan required by §5.203(k) of this title.	7.6.2
§146.93(f)	Post-injection and site closure	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:	§5.206 (k)(6)	Storage facility closure report. Once the director has authorized storage facility closure, The 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:	7.6.4

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§146.93(f)(1)	Post-injection and site closure	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;	§5.206 (k)(6)(A)	Documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat which has been submitted to the Regional Administrator of Region 6 of the United States Environmental Protection Agency. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks.	7.6.4
§146.93(f)(2)	Post-injection and site closure	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	§5.206 (k)(6)(B)	Documentation of appropriate notification and information to such State and local authorities that have authority over drilling activities to enable such State and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	
§146.93(f)(3)	Post-injection and site closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	§5.206 (k)(6)(C)	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	7.6.4
			§5.206 (k)(7)	Certificate of closure. Upon completion of the requirements in paragraphs (3) - (6) of this subsection, the director will issue a certificate of closure. At that time, the operator is released from the requirement in §5.205(c) of this title to maintain financial assurance.	
§146.93(g)	Post-injection and site closure	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:	§5.206 (l)	Deed notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:	7.6.4
			§5.206 (l)(1)	a complete legal description of the affected property;	7.6.4
§146.93(g)(1)	Post-injection and site closure	The fact that land has been used to sequester carbon dioxide;	§5.206 (l)(2)	The fact that land has been used to sequester carbon dioxide;	7.6.4
§146.93(g)(2)	Post-injection and site closure	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	§5.206 (l)(3)	that the survey plat has been filed with the Commission;	7.6.4
			§5.206 (l)(4)	the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and	7.6.4
§146.93(g)(3)	Post-injection and site closure	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	§5.206 (l)(5)	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	7.6.4
			§5.206 (m)	Permit conditions for retention of records. The permittee shall retain records as follows.	
			§5.206 (m)(1)	All modeling inputs and data used to support area of review reevaluations under subsection (e) of this section shall be retained for 10 years.	3.5
			§5.206 (m)(2)	The permittee shall retain records as follows:	

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			§5.206 (m)(2)(A)	All data collected under §5.203 of this title for Class VI permit applications shall be retained throughout the life of the geologic storage project and for 10 years following site closure.	7.6.4
			§5.206 (m)(2)(B)	Data on the nature and composition of all injected fluids collected pursuant to §5.203(i)(1)(D) of this title shall be retained until 10 years following site closure. The director may require the operator to submit the records to the director at the conclusion of the retention period.	7.6.4
			§5.206 (m)(2)(C)	Monitoring data collected pursuant to §5.203(j)(2) of this title shall be retained for 10 years after it is collected.	5.2
			§5.206 (m)(2)(D)	Well plugging reports, post-injection site care data, including 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 of subsection (k)(6) of this section and paragraph (4) of this subsection shall be retained for 10 years following site closure.	7.6.4
			§5.206 (m)(2)(E)	The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years following site closure.	
			§5.206 (m)(3)	Within 60 days after plugging, the operator must submit, pursuant to §5.207(b)(2) of this title, a plugging report to the director. The report must be certified as accurate by the operator and by the person who performed the plugging operation (if other than the operator.) The operator shall retain the well plugging report for 10 years following site closure.	
			§5.206 (m)(4)	The 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 following site closure. The report must include:	7.6.4
			§5.206 (m)(4)(A)	documentation of appropriate injection and monitoring well plugging as specified in §5.203(k) of this title. The 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 operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office; and	7.6.4
			§5.206 (m)(4)(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	7.6.4
			§5.206 (m)(5)	Records reflecting the nature, composition, and volume of the CO2 plume shall be retained for 10 years following site closure.	7.6.4

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§146.93(h)	Post-injection and site closure	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.	§5.206 (m)(6)	The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	7.6.4
§146.94	**Emergency and remedial response**	**Emergency and remedial response**	**§5.206 (h)**	**Emergency mitigation, and remedial response**	
§146.94(a)	Emergency and remedial response	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	§5.203 (l)	Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:	Section 8
			§5.203 (l)(1)	accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	8.2
			§5.203 (l)(2)	describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods;	8.3
			§5.203 (l)(3)	Includes a safety plan that includes:	8.3
			§5.203 (l)(3)(A)	emergency response procedures;	8.3
			§5.203 (l)(3)(B)	provisions to provide security against unauthorized activity;	8.3
			§5.203 (l)(3)(C)	CO2 release detection and prevention measures;	8.3
			§5.203 (l)(3)(D)	instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency;	8.6
			§5.203 (l)(3)(E)	procedures for requesting assistance and for follow-up action to remove the public from an area of exposure;	8.6
			§5.203 (l)(3)(F)	provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO2,	8.6
			§5.203 (l)(3)(G)	the manner in which the public will be notified of an emergency and steps to be taken in case of an emergency; and	8.6
			§5.203 (l)(3)(H)	if necessary, proposed actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring; and	8.3
§146.94(b)	Emergency and remedial response	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:	§5.206 (h)(3)(A)	If an operator obtains evidence that the injected CO2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:	8.3
§146.94(b)(1)	Emergency and remedial response	Immediately cease injection;	§5.206 (h)(3)(A)(i)	immediately cease injection;	8.3
§146.94(b)(2)	Emergency and remedial response	Take all steps reasonably necessary to identify and characterize any release;	§5.206 (h)(3)(A)(ii)	take all steps reasonably necessary to identify and characterize any release;	8.3

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§146.94(b)(3)	Emergency and remedial response	Notify the Director within 24 hours; and	§5.206 (h)(3)(A)(iii)	notify the director as soon as practicable but within at least 24 hours; and	8.3
§146.94(b)(4)	Emergency and remedial response	Implement the emergency and remedial response plan approved by the Director.	§5.206 (h)(3)(A)(iv)	implement the approved emergency and remedial response plan.	8.3
			§5.206 (h)(3)(B)	If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized by an aquifer exemption, the director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting, including plugging of the injection well, as are necessary to prevent such movement.	
§146.94(c)	Emergency and remedial response	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.	§5.206 (h)(4)	Resumption of injection. The Director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.	
§146.94(d)	Emergency and remedial response	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:			8.8
§146.94(d)(1)	Emergency and remedial response	Within one year of an area of review reevaluation;			8.8
§146.94(d)(2)	Emergency and remedial response	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	§5.207 (a)(3)	The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	8.8
§146.94(d)(3)	Emergency and remedial response	When required by the Director.			
			§5.203 (a)(1)(A)	Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality.	

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			§5.203 (a)(1)(B)	Signatories to permit applications. An applicant must ensure that the application is executed by a party having knowledge of the facts entered on the form and included in the required attachments. All permit applications shall be signed as specified in this subparagraph:	Cover sheets
			§5.203 (a)(1)(B)(i)	For a corporation, the permit application shall be signed by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision making functions for the corporation, or the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.	Cover sheets
			§5.203 (a)(1)(B)(ii)	For a partnership or sole proprietorship, the permit application shall be signed by a general partner or the proprietor, respectively.	
			§5.203 (a)(1)(B)(iii)	For a municipality, State, Federal, or other public agency, the permit application shall be signed by either a principal executive officer or ranking elected official.	
			§5.203 (a)(1)(C)	Certification. Any person signing a permit application or permit amendment application shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."	Cover sheets
			§5.203 (a)(2)(A)	On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	N/A
			§5.203 (a)(2)(B)	When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.	
			§5.203 (a)(2)(C)	The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	

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			§5.203 (a)(2)(D)	A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.	
			§5.203 (a)(3)	Application completeness. The Commission shall [may] not issue a permit before receiving a complete application. A permit application is complete when the director determines that the application contains information addressing each application requirement of the regulatory program and all information necessary to initiate the final review by the director.	
			§5.203 (a)(5)	If otherwise required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist must conduct the geologic and hydrologic evaluations required under this subchapter and must affix the appropriate seal on the resulting reports of such evaluations.	
			§5.203 (f)(2)(A)	Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	4.3.2
			§5.203 (k)(6)	A plan for certifying that all monitoring wells that do not penetrate the base of usable quality water will be plugged in accordance with 16 TAC Chapter 76.	
			§5.203 (l)(4)	includes a description of the training and testing that will be provided to each employee at the storage facility on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility. The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. Emergency measures specific to the contractor's work must be explained in the contractor safety meeting. Training schedules, training dates, and course outlines must be provided to Commission personnel upon request for the purpose of Commission review to determine compliance with this paragraph.	8.5

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (a)	Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	
			§5.206 (a)(1)	Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	
			§5.206 (a)(2)	The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.	
			§5.206 (b)	General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that:	
			§5.206 (b)(1)	the injection and geologic storage of anthropogenic CO2 will not endanger or injure any existing or prospective oil, gas, geothermal, or other mineral resource, or cause waste as defined by Texas Natural Resources Code, §85.046(11);	
			§5.206 (b)(2)	with proper safeguards, both USDWs and surface water can be adequately protected from CO2 migration or displaced formation fluids;	
			§5.206 (b)(3)	the injection of anthropogenic CO2 will not endanger or injure human health and safety;	
			§5.206 (b)(4)	the construction, operation, maintenance, conversion, plugging, abandonment, or any other injection activity does not allow the movement of fluid containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons;	
			§5.206 (b)(5)	the reservoir into which the anthropogenic CO2 is injected is suitable for or capable of being made suitable for protecting against the escape or migration of anthropogenic CO2 from the storage reservoir;	
			§5.206 (b)(7)	the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit;	
			§5.206 (b)(8)	the applicant has provided a letter from the Groundwater Advisory Unit of the Oil and Gas Division in accordance with §5.203(o) of this title (relating to Application Requirements);	Appendix A

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			§5.206 (b)(9)	the applicant has provided a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ;	
			§5.206 (b)(10)	the applicant has provided a signed statement that the applicant has a good faith claim to the necessary and sufficient property rights for construction and operation of the geologic storage facility for at least the first five years after initiation of injection in accordance with §5.203(d)(1)(A) of this title;	Cover sheets
			§5.206 (b)(11)	the applicant has paid the fees required in §5.205(a) of this title (relating to Fees, Financial Responsibility, and Financial Assurance);	
			§5.206 (b)(12)	the director has determined that the applicant has sufficiently demonstrated financial responsibility as required in §5.205(b) of this title; and	
			§5.206 (b)(13)	the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.	Section 8
			§5.206 (c)(1)	Construction of anthropogenic CO 2 injection wells must meet the criteria in §5.203(e) of this title.	Section 4
			§5.206 (c)(2)	Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on the appropriate form showing the current completion.	
			§5.206 (c)(3)	Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical.	5.2
			§5.206 (d)	Operating a geologic storage facility.	
			§5.206 (d)(1)(A)	Operating plan. The operator must maintain and comply with the approved operating plan.	4.4
			§5.206 (d)(1)(B)	Prior to approval for the operation of a Class VI injection well, the operator shall submit, and the director shall consider, the following information:	
			§5.206 (d)(1)(B)(i)	the final AOR based on modeling, using data obtained during logging and testing of the well and the formation as required by clauses (ii), (iii), (iv), (vi), (vii), and (x) of this subparagraph;	3.3.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (d)(1)(B)(ii)	any relevant updates, based on data obtained during logging and testing of the well and the formation as required by clauses (iii), (iv), (vi), (vii), and (x) of this subparagraph to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of §5.203(c)(2) and (3) of this title;	
			§5.206 (d)(1)(B)(iii)	information on the compatibility of the CO_2 stream with fluids in the injection zones and minerals in both the injection and the confining zones, based on the results of the formation testing program, and with the materials used to construct the well;	
			§5.206 (d)(1)(B)(iv)	the results of the formation testing program required by §5.203(f) of this title;	
			§5.206 (d)(1)(B)(v)	final injection well construction procedures that meet the requirements of §5.203(e) of this title;	
			§5.206 (d)(1)(B)(vi)	the status of corrective action on wells in the AOR;	
			§5.206 (d)(1)(B)(vii)	all available logging and testing program data on the well required by §5.203(f) of this title;	
			§5.206 (d)(1)(B)(viii)	a demonstration of mechanical integrity pursuant to §5.203(h) of this title;	
			§5.206 (d)(1)(B)(ix)	any updates to the proposed AOR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection storage facility care and closure plan, or the emergency and remedial response plan submitted under §5.203(m) of this subchapter, which are necessary to address new information collected during logging and testing of the well and the formation as required by this section, and any updates to the alternative post-injection storage facility care timeframe demonstration submitted under §5.203(m) of this title, which are necessary to address new information collected during the logging and testing of the well and the formation as required by this section; and	
			§5.206 (d)(1)(B)(x)	any other information requested by the director.	
			§5.206 (d)(2)	Operating criteria.	
			§5.206 (d)(2)(B)	The total volume of CO_2 injected into the storage facility must be metered through a master meter or a series of master meters. The volume and/or mass of CO_2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.	5.5.2

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			§5.206 (d)(2)(C)	The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the permit. In approving a maximum surface injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure 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. The director may approve a plan for controlled artificial fracturing of the injection zone.	
			§5.206 (d)(2)(E)	The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO_2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.	5.5.2
			§5.206 (e)	Monitoring, sampling, and testing requirements.	
			§5.206 (e)(1)	The operator of an anthropogenic CO_2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.	Section 5
			§5.206 (e)(2)	All permits shall include the following requirements:	
			§5.206 (e)(2)(A)	the proper use, maintenance, and installation of monitoring equipment or methods;	
			§5.206 (e)(2)(B)	monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including, when required, continuous monitoring;	5.5.1
			§5.206 (e)(2)(C)	reporting no less frequently than as specified in §5.207 of this title (relating to Reporting and Record-Keeping).	5.2
			§5.206 (e)(4)	The director may require measures and actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring.	
			§5.206 (e)(5)	The operator shall comply with the following monitoring and record retention requirements.	

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			§5.206 (e)(5)(A)	Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.	
			§5.206 (e)(5)(B)	The permittee shall retain records of all monitoring information, including the following:	
			§5.206 (e)(5)(B)(i)	calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for a period of at least ten years from the date of the sample, measurement, report, or application. This period may be extended by the director at any time; and	
			§5.206 (e)(5)(B)(ii)	the nature and composition of all injected fluids until ten years after the completion of any plugging and abandonment procedures specified in §5.203(k)(2) of this title for the injection wells. The director may require the operator to submit the records to the director at the conclusion of the retention period. This period may be extended by the director at any time.	
			§5.206 (e)(5)(C)	Records of monitoring information shall include:	
			§5.206 (e)(5)(C)(i)	the date, exact place, and time of sampling or measurements;	
			§5.206 (e)(5)(C)(ii)	the individuals who performed the sampling or measurements;	
			§5.206 (e)(5)(C)(iii)	the dates analyses were performed;	
			§5.206 (e)(5)(C)(iv)	the individuals who performed the analyses;	
			§5.206 (e)(5)(C)(v)	the analytical techniques or methods used; and	
			§5.206 (e)(5)(C)(vi)	the results of such analyses.	
			§5.206 (e)(5)(D)	Operators of Class VI wells shall retain records as specified in this subchapter.	
			§5.206 (f)(1)	The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(j) of this title.	5.4.2, 5.4.3
			§5.206 (f)(3)	The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
			§5.206 (f)(5)	The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	
			§5.206 (h)(2)(A)	The operator must prepare and implement a plan to train and test each employee at the storage facility on occupational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The operator must make copies of the plan available at the geological storage facility. The operator must train all employees before commencing injection and storage operations at the facility. The operator must train each subsequently hired employee before that employee commences work at the storage facility.	8.5

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (h)(2)(B)	The operator must hold a safety meeting with each contractor prior to the commencement of any new contract work at a storage facility. The operator must explain emergency measures specific to the contractor's work in the contractor safety meeting.	8.5
			§5.206 (h)(2)(C)	The operator must provide training schedules, training dates, and course outlines to Commission personnel annually and upon request for the purpose of Commission review to determine compliance with this paragraph.	
			§5.206 (k)(1)(A)	The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.	Section 7
			§5.206 (k)(1)(C)	Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.	7.5
			§5.206 (k)(3)(A)	the estimated magnitude and extent of the facility footprint (the CO2 plume and the area of elevated pressure);	7.2, 7.3
			§5.206 (k)(3)(B)	that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs;	7.5
			§5.206 (k)(3)(C)	that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs;	7.5
			§5.206 (k)(3)(D)	that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and	6.2, 7.6.2
			§5.206 (k)(3)(E)	any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.	6.3, 7.6.2
			§5.206 (n)	Signs. The operator must identify each location at which geologic storage activities take place, including each injection well, by a sign that meets the requirements specified in §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached 24 hours a day, seven days a week in the event of an emergency.	
			§5.206 (o)	Other permit terms and conditions.	
			§5.206 (o)(1)	Protection of USDWs. In any permit for a geologic storage facility, the director must impose terms and conditions reasonably necessary to protect USDWs. Permits issued under this subchapter continue in effect until revoked, modified, or terminated by the Commission. The operator must comply with each requirement set forth in this subchapter as a condition of the permit unless modified by the terms of the permit.	
			§5.206 (o)(2)	Other conditions. The following conditions shall also be included in any permit issued under this subchapter.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (o)(2)(A)	Duty to comply. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. However, the permittee need not comply with the provisions of the permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR §144.34.	
			§5.206 (o)(2)(B)	Need to halt or reduce activity not a defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.	
			§5.206 (o)(2)(C)	Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.	
			§5.206 (o)(2)(D)	Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.	
			§5.206 (o)(2)(E)	Property rights not conveyed. The issuance of a permit does not convey property rights of any sort, or any exclusive privilege.	
			§5.206 (o)(2)(F)	Activities not authorized. The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.	
			§5.206 (o)(2)(G)	Coordination with exploration. The permittee of a geologic storage well shall coordinate with any operator planning to drill through the AOR to explore for oil and gas or geothermal resources and take all reasonable steps necessary to minimize any adverse impact on the operator's ability to drill for and produce oil and gas or geothermal resources from above or below the geologic storage facility.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (o)(2)(H)	Duty to provide information. The operator shall furnish to the Commission, within a time specified by the Commission, any information that the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The operator shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.	
			§5.206 (o)(2)(I)	Inspection and entry. The operator shall allow any member or employee of the Commission, on proper identification, to:	
			§5.206 (o)(2)(I)(i)	enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;	
			§5.206 (o)(2)(I)(ii)	have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;	
			§5.206 (o)(2)(I)(iii)	inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and	
			§5.206 (o)(2)(I)(iv)	sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.	
			§5.203 (e)(1)(B)(vii)	The director may exempt existing Class II wells that have been associated with injection of CO2 for the purpose of enhanced recovery, Class V experimental technology wells, and stratigraphic test wells from provisions of these casing and cementing requirements if the applicant demonstrates that the well construction meets the general performance criteria in subparagraph (A) of this paragraph. A converted well must meet all other requirements under this section. The demonstration must include the following:	
			§5.203 (e)(1)(B)(vii)(I)	as-built schematics and construction procedures to demonstrate that repermitting is appropriate;	
			§5.203 (e)(1)(B)(vii)(II)	recent or newly conducted well-log information and mechanical integrity test results;	
			§5.203 (e)(1)(B)(vii)(III)	a demonstration that any needed remedial actions have been performed;	
			§5.203 (e)(1)(B)(vii)(IV)	a demonstration that the well was engineered and constructed to meet the requirements of subparagraph (A) of this paragraph and ensure protection of USDWs;	
			§5.203 (e)(1)(B)(vii)(V)	a demonstration that cement placement and materials are appropriate for CO2 injection for geologic storage;	
			§5.203 (e)(1)(B)(vii)(VI)	a demonstration that the well has, and is able to maintain, internal and external mechanical integrity over the life of the project; and	
			§5.203 (e)(1)(B)(vii)(VII)	the results of any additional testing of the well to support a demonstration of suitability for geologic storage.	
			§5.203 (n)(2)	In determining whether the applicant is financially responsible, the director must rely on the following:	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.203 (n)(2)(A)	the person's most recent audited annual report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)). The date of the audit may not be more than one year before the date of submission of the application to the division; and	
			§5.203 (n)(2)(B)	the person's most recent quarterly report filed with the U. S. Securities and Exchange Commission under Section 13 or 15(d), Securities Exchange Act of 1934 (15 U.S.C. Section 78m or 78o(d)); or	
			§5.203 (n)(2)(C)	if the person is not required to file such a report, the person's most recent audited financial statement. The date of the audit must not be more than one year before the date of submission of the application to the division.	
			§5.203 (p)	Other information. The applicant must submit any other information requested by the director as necessary to discharge the Commission's duties under Texas Water Code, Chapter 27, Subchapter B-1, or deemed necessary by the director to clarify, explain, and support the required attachments.	
			§5.206 (o)(2)(J)	Schedule of compliance: The permit shall, when appropriate, specify a schedule of compliance leading to compliance with all provisions of this subchapter and Chapter 3 of this title. If the time necessary for completion of any interim requirement is more than one year and is not readily divisible into stages for completion, the permit shall specify interim dates for the submission of reports of progress toward completion of the interim requirements and indicate a projected completion date.	
			§5.206 (o)(2)(J)(i)	Any schedule of compliance shall require compliance as soon as possible, and in no case later than three years after the effective date of the permit.	
			§5.206 (o)(2)(J)(ii)	If the schedule of compliance is for a duration of more than one year from the date of permit issuance, then interim requirements and completion dates (not to exceed one year) must be incorporated into the compliance schedule and permit.	
			§5.206 (o)(2)(J)(iii)	Progress reports must be submitted no later than 30 days following each interim date and the final date of compliance.	
			§5.206 (o)(2)(K)	Modification, revocation and reissuance, or termination. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.	
			§5.206 (o)(2)(L)	Signatory requirement. All applications, reports, or information shall be signed and certified.	
			§5.206 (o)(2)(M)	Reporting requirements.	
			§5.206 (o)(2)(M)(i)	Planned changes. The permittee shall give notice to the director as soon as possible of any planned physical alterations or additions to the permitted facility.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (o)(2)(M)(ii)	Anticipated noncompliance. The permittee shall give advance notice to the director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.	
			§5.206 (o)(2)(M)(iii)	Transfers. This permit is not transferable to any person except after notice to and approval by the director. The director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.	
			§5.206 (o)(2)(M)(iv)	Monitoring reports. Monitoring results shall be reported at the intervals specified elsewhere in this permit.	
			§5.206 (o)(2)(M)(v)	Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 30 days following each schedule date.	
			§5.206 (o)(2)(M)(vi)	Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The permittee shall report any noncompliance which may endanger health or the environment including:	5.2
			§5.206 (o)(2)(M)(vi)(I)	any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and	5.2
			§5.206 (o)(2)(M)(vi)(II)	any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.	5.2
			§5.206 (o)(2)(N)	Other information. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the director, it shall promptly submit such facts or information.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	Description	Permit Application
			§5.206 (o)(2)(O)	Other noncompliance. The permittee shall report all instances of noncompliance not reported under subsection (e) of this section, subparagraphs (J) and (M) of this paragraph, and §5.207(a)(2)(A) of this title at the time monitoring reports are submitted. Any information shall be provided orally to the director within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided to the director within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The reports required by this subparagraph shall contain the following information:	
			§5.206 (o)(2)(O)(i)	any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; and	
			§5.206 (o)(2)(O)(ii)	any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.	
			§5.206 (o)(2)(P)	Incorporation of requirements in permits. New permits, and to the extent allowed under §5.202 of this title modified or revoked and reissued permits, shall incorporate each of the applicable requirements referenced in this section. An applicable requirement is a State statutory or regulatory requirement that takes effect prior to final administrative disposition of the permit. An applicable requirement is also any requirement that takes effect prior to the modification or revocation and reissuance of a permit, to the extent allowed in §5.202 of this title.	
			§5.206 (o)(2)(Q)	Compliance with SWDA and related regulations. In addition to conditions required in all permits, the director shall establish conditions in permits as required on a case-by-case basis to provide for and assure compliance with all applicable requirements of the SWDA and 40 CFR Parts 144, 145, 146 and 124.	

TAC Regs - additional code and/or no EPA code equivalent
EPA Regs - additional code and/or no TAC equivalent
Reg code applicable to CFR Text or TAC Description in more than one instance.
Gray shade - Section header or reg not applicable

Underground Injection Control – Class VI Permit Application for

Tea Olive No.1 and Flowering Crab Apple No.1

Sabine and San Augustine Counties, Texas

INTRODUCTION

July 2025

SECTION 0 – INTRODUCTION

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Project Overview

Headquartered in Dallas, Texas, Aethon Energy Operating LLC (Aethon) is a private investment firm focused on acquiring, operating, and developing onshore, vertically integrated energy resources across North America. Aethon is a leading, low-emission operator and one of the largest private natural gas producers and suppliers to liquid natural gas (LNG) facilities in the United States.

Aethon's assets include approximately 380,000 net acres across Louisiana and Texas as well as more than 1,200 miles of pipeline infrastructure in the region, with more than 70% of operated volumes flowing through the company's own gathering systems. Aethon has drilled more than 500 operated horizontal wells in the Haynesville and Bossier shales since 2018 and averages approximately 3.0 billion cubic feet per day (Bcf/d) in gross natural gas production as of February 2025.

Aethon is proposing to permit two Class VI injection wells in the proposed TXCCS#1 Project on the Texas Gulf Coast, with the currently defined area of review (AOR) located in Sabine and San Augustine Counties. The project goal is to sequester [redacted] million metric tons (MMT) of CO_2 over [redacted] years. The CO_2 will be sourced from industrial sources, primarily from existing gas treating plants.

The selection process undertaken for the project resulted in a location that meets Underground Injection Control (UIC) requirements, with an injection zone with quality storage capacity, substantial sealing zones, no artificial penetrations in the CO_2 plume, and minimal environmental impact.

The two Class VI injection wells proposed in this permit application—Tea Olive No. 1 and Flowering Crab Apple No. 1, located in Sabine and San Augustine Counties, respectively—are designed to meet the requirements of Title 16, Texas Administrative Code (16 TAC), Title 40, U.S. Code of Federal Regulations (40 CFR) Subpart H. Maps of the proposed injection wells' location and project overview are shown in Figures 0-1 and 0-2, respectively.

[redacted]

Figure 0-1 – Map of the Location of the Proposed Injection Wells

[redacted]

Figure 0-2 – Project Overview Aerial Map

The injection wells will be used to sequester CO_2 in the [redacted] Formation as the injection zone. Modeled lithologic and petrophysical properties of the formation at the project location agree with the findings of regionally published literature and suggest that the injection reservoir provides the sufficient pore space required to store the modeled and proposed CO_2 volumes.

The [redacted] Formation is anticipated to exhibit low permeability throughout the gross overlying section, with sufficient thickness and lateral continuity to serve as the upper confining zone. The low permeability, low porosity facies of the [redacted] Formation that immediately underlie porous [redacted] development are unsuitable for fluid migration and therefore can serve as the lower confining zone.

Project Key Attributes

- Tea Olive No. 1 and Flowering Crab Apple No. 1 are designed to inject up to [redacted] MMT/yr of CO_2 each, with the goal of permanently sequestering [redacted] MMT of CO_2 over the life of the TXCCS#1 Project. The [redacted] Formation comprising the injection zone is a [redacted] with a gross thickness of approximately [redacted] feet (ft) within the project area. Bound to the [redacted] with significant reservoir quality [redacted], the formation is anticipated to be relatively homogeneous moving along the east-west reef trend.

- As the upper confining zone, the [redacted] Formation is anticipated to be represented by the deposition of [redacted], providing an upper seal to any CO_2 movement out of the intended injection zone. The [redacted] is expected to be approximately [redacted] ft thick near the injection sites and is regionally extensive beyond the project area.

- [redacted] well lacking documentation will require corrective action to ensure containment of the increased pressure.

- The project site is located in a sparsely populated, agricultural grassland area.

Pore Space Discussion

Future reservoir modeling simulations will be used to assess and acquire the required pore space acreage for the project. A map and list of adjacent landowners are located in *Appendices A-3* and *A-4*, respectively.

Proposed CO_2 Sequestration System Discussion

The CO_2 will be captured and piped via buried pipelines from Aethon-operated natural gas processing plants. The project infrastructure will consist of gathering facilities, transport compression, pipelines, and booster pumps for injection.

Site Suitability

In compliance with regulations, an evaluation of the proposed site ("Site Suitability") assessed factors including the following:

- Location of the proposed project site
- Consideration of the project area relative to federal sites/buildings/facilities, etc.
- Flood zone
- Existing infrastructure, surface, and subsurface mines or quarries
- Any existing faults or fractures in the project area based on seismic analysis or geophysical well-log characterization
- State or federal subsurface cleanup sites within the project area
- Artificial penetrations in the project area
- Drinking water in the project area
- Any other site-related issues

The results of this site assessment make up the content of this permit application.

Summary

The proposed TXCCS#1 Project is designed with two Class VI injection wells, each constructed to sequester up to [redacted] MMT/yr of CO_2 in the [redacted] Formation in west-central Sabine County and eastern San Augustine County, Texas. Over the life of the project, [redacted] MMT of CO_2 will be permanently and safely stored.

This permit application includes a detailed assessment of the overall geologic environment outlined in ***Section 1 – Site Characterization*** and the resulting plume model and simulation results in ***Section 2 – Plume Model*** used to determine the aerial extent of the plume and the resulting AOR. As detailed in ***Section 3 – Area of Review and Corrective Action Plan***, the AOR for the project has [redacted] existing artificial penetration that will require corrective action. Well design and construction plans that take into consideration the needs of the project, modeling results, and requirements to ensure the protection of the USDWs are detailed in ***Section 4 – Well Construction and Design.***

To ensure that the CO_2 plume is being monitored during the life of the project, a detailed Testing and Monitoring Plan is provided in ***Section 5 – Testing and Monitoring Plan***. The plan consists of (1) two USDW monitoring wells, (2) the use of the injection wells to directly monitor the reservoir pressure over the life of the project, (3) the use of the injection wells to also serve as above-zone monitoring wells, (4) and the use of fiber optics to provide distributed temperature sensing (DTS) and distributed acoustic sensing (DAS). The fiber optics will also allow for geophysical survey technologies, such as controlled-source electromagnetic (CSEM), vertical seismic profile (VSP), or time-lapse 2D seismic, to monitor the growth of the CO_2 plume during the life of the project.

The proposed TXCCS#1 Project addresses the requirements for Class VI sequestration wells. This project is ideally located near emitters and natural gas plants to sequester significant amounts of CO_2 with minimal impact to the surrounding environment and community.

The following maps, lists, and permits are included in *Appendix A:*

- Appendix A-1 Proposed Injection Wells Location Map
- Appendix A-2 Project Overview Aerial Map
- Appendix A-3 Adjacent Landowners Map
- Appendix A-4 Adjacent Landowners List
- Appendix A-5 Well Location Plat – Tea Olive No. 1
- Appendix A-6 Topographic Map
- Appendix A-7 Drilling Permit (W-1) – Tea Olive No. 1
- Appendix A-8 Groundwater Advisory Unit Permit to Dispose (W-14) – Tea Olive No. 1
- Appendix A-9 Groundwater Determination Letter – Tea Olive No. 1
- Appendix A-10 Groundwater Determination Letter – Flowering Crab Apple No. 1
- Appendix A-11 Statewide Rule 36 Compliance (H-9) – Tea Olive No. 1

Required Administrative Information

General Application Information

Injection Well Information:

Well Name and Number	Tea Olive No. 1
County, State	Sabine County, Texas
Latitude and Longitude	[redacted]

Well Name and Number	Flowering Crab Apple No. 1
County, State	San Augustine County, Texas
Latitude and Longitude	[redacted]

*NAD 27 – North American Datum of 1927

Applicant:

Name	Aethon Energy Operating LLC
Address	12377 Merit Drive, Suite 1200 Dallas, TX 75251
Facility Contact	Aaron Wimberly

	214-750-3820 regulatory@aethonenergy.com
Ownership Status	Limited Liability Company
Entity Status	Private
Standard Industrial Classification (SIC) Codes	4925 – Mixed, Manufactured, or Liquified Petroleum Gas Production and/or Distribution 4953 – Refuse Systems (Nonhazardous Waste – Disposal Sites)

This facility is not located on federal or tribal lands.

Additional Permits

Table 0-1 – Additional Required Permits

Agency	Permit and Authorization	Filing Date	Receipt Date	Status
TRRC	Permit to Drill (W-1): Tea Olive No. 1	10/2/2023	10/3/2023	Approved
TRRC	Dispose of Oil & Gas Waste (W-14): Tea Olive No. 1	4/15/2024	4/2/2025	Approved – awaiting revision
TRRC	Groundwater Determination: Tea Olive No. 1	1/8/2024	1/16/2024	Received
TRRC	Groundwater Determination: Flowering Crab Apple No. 1	12/30/2024	2/13/2025	Received
TRRC	Statewide Rule 36 Compliance (H-9): Tea Olive No. 1	5/3/2024	6/10/24	Approved

Underground Injection Control – Class VI Permit Application for

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Sabine and San Augustine Counties, Texas

SECTION 1 – SITE CHARACTERIZATION

July 2025

SECTION 1 – SITE CHARACTERIZATION

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1.1 Overview

This site characterization for Aethon Energy Operating, LLC's (Aethon) TXCCS#1 Project was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(c)(2)** (Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(3)**). This section describes the regional and site geology for the proposed location. The site characterization incorporates analysis of multiple data types from public, proprietary, and licensed data sets, including well logs, 2D and 3D seismic, academic and professional publications, and existing and acquired core-sample analyses.

1.2 Regional Geology

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

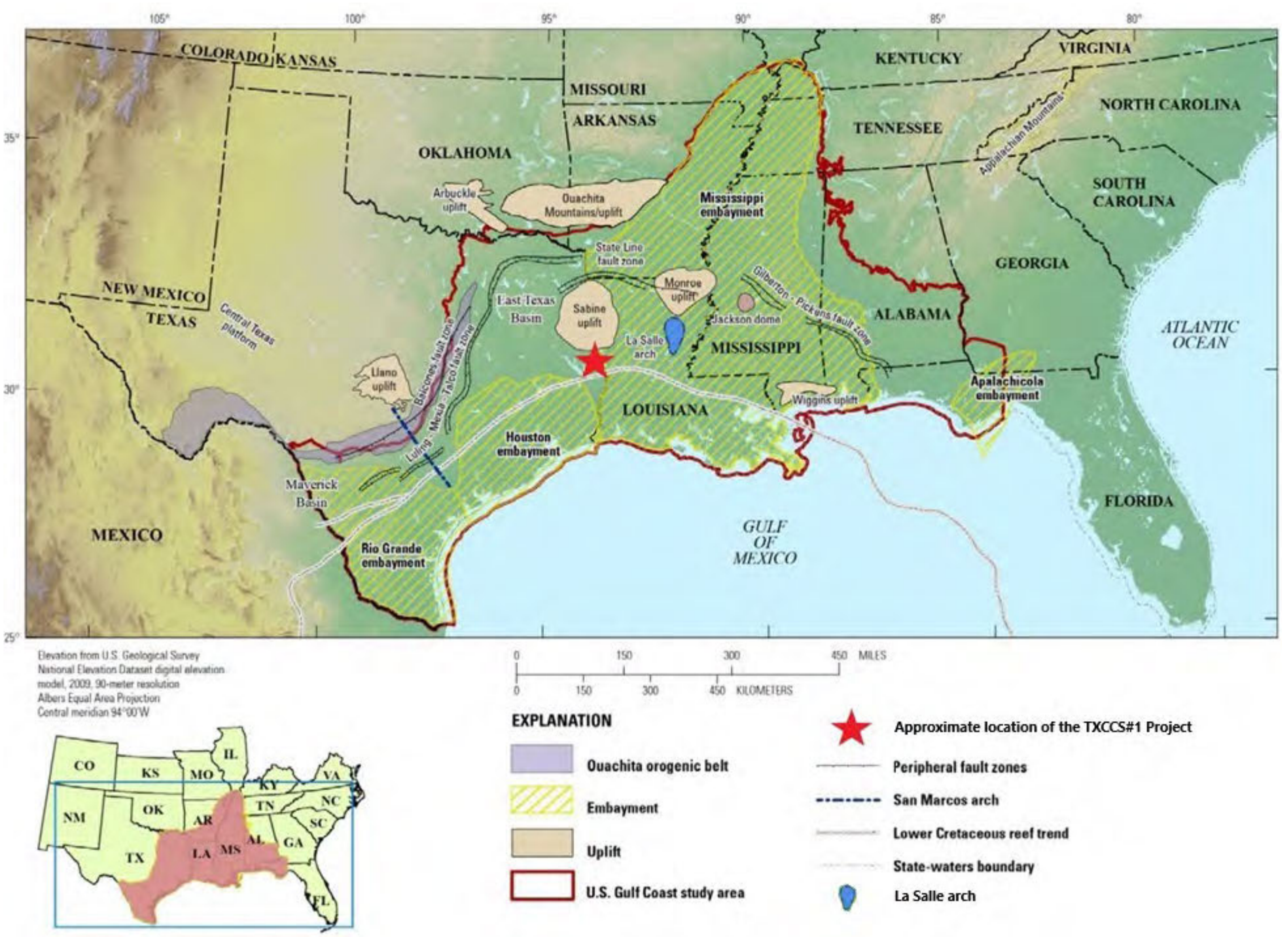

Figure 1-1 – Regional Gulf of Mexico Locator Map (modified from Roberts-Ashby et al., 2012)

Figure 1-2 depicts the regional stratigraphic column as found at the proposed project location, with red shading referencing the injection formation, blue shading signifying potential freshwater aquifers, and green shading indicating productive intervals in the area of review (AOR).

[redacted]

Figure 1-2 – Regional stratigraphic column of the Gulf Coast Region (adapted from Bruun et al., 2016; Roberts-Ashby et al., 2012; and [redacted]

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the Mesozoic breakup of Pangea. Rifting of northwest-to-southeast-trending transfer faults during the Middle Jurassic lasted approximately 25 million years and resulted in variable thickness of transcontinental crust underlying the region. By [redacted] time, the general outline and morphology of the gulf were similar to that of present day (Galloway, 2008; [redacted]). [redacted] tectonic activity was limited to regional subsidence associated with areas of variable crustal thickness and local structuring caused by movement of the Louann Salt [redacted]). The combination of these processes resulted in the structural development of regional arches, grabens, uplifts, embayments, salt domes, and salt basins around the northern edge of the basin [redacted] Galloway, 2008).

Initial sedimentation into the Gulf of Mexico basin occurred during the Late Triassic to Early Jurassic periods, when siltstone, shale, deltaic sandstone, conglomerates, and non-marine red beds of the Eagle Mills Formation began filling accommodation space found within basement graben structures. During the Middle Jurassic, large-scale evaporite deposition began to take place in the young basin due to the presence of a hypersaline environment with communication to the Atlantic Ocean. Influx of sea water from the Atlantic allowed for continual precipitation of evaporites and resulted in the deposition of the Louann Salt, a defining characteristic to later structural evolution of the basin. Louann Salt deposition ceased toward the end of the Jurassic with continuous deposits reaching up to 4 kilometers (km) thick (Galloway, 2008). Subsequent basin fill consisted of a thick succession of carbonate, clastic, and evaporite material deposited in a highly cyclic environment, subject to frequent sea-level change and sediment-supply fluctuations (Galloway, 2008; Roberts-Ashby et al., 2012). These strata are Late Jurassic to Holocene in age and reach up to 20 km thick near the basin depocenter in southern Louisiana (Galloway, 2008).

Figure 1-3 depicts the location of structural features within the Gulf of Mexico basin relative to the project location. The proposed TXCCS#1 Project is situated [redacted]

The schematic cross section provided in Figure 1-4 displays the present structural setting of the Gulf of Mexico basin and illustrates the stratigraphic relationship of [redacted] The map in the upper left corner of Figure 1-4 identifies the approximate location of the proposed storage site relative to the north-south schematic cross section and nearby structural features [redacted]). The structural interpretation presented in Figure 1-4 is consistent with Aethon's regional seismic investigation, which did not identify within the targeted formations any faulting in the region.

[redacted]

Figure 1-3 – Regional map of the Gulf of Mexico basin showing basins, uplifts, and other structural features in the Gulf Coast region that influenced deposition ([redacted] The red star is the approximate location of the TXCCS#1 Project.

[redacted]

Figure 1-4 – North to south schematic cross section through the Gulf Coast region [redacted]
The red stars represent the approximate location of the TXCCS#1 Project.

1.2.1 Major Stratigraphic Units

The targeted formations of this study are [redacted] period deposits, specifically [redacted] in age, as depicted in Figure 1-5. The injection zone is found within the Mooringsport Formation and contained by the overlying [redacted] and underlying [redacted] formations. The confining zones and injection zone are located entirely within the [redacted] Group. For the purposes of this permit application, the nomenclature of targeted formations will simply be referred to as the [redacted] formations (Figure 1-5). [redacted] that dominate the geologic section from the top of the [redacted] to the base of the [redacted] will be referred to as the [redacted] complex.

The approximate time of deposition of upper to lower [redacted] million years ago. During this time, the area of interest was located along a broad, [redacted] that extended along the northern rim of the ancestral Gulf of Mexico, as illustrated in Figure 1-6. The [redacted] platform spanned approximately [redacted] miles from western Florida to northeastern Mexico with a shoreline-to-basin margin that ranged between [redacted] miles wide [redacted] The depositional environment during the [redacted] generally consisted of a well-defined [redacted] oward the basin center.

The [redacted] but experienced [redacted] that resulted in [redacted] that vary both spatially and within the geologic section. [redacted] Galloway, 2008).

In general, long stands of [redacted] and represent reservoir-quality rock found within the [redacted]. Deeper, basinward deposits resulted in tighter petrophysical properties due to an increased presence of [redacted] associated with the heightening of the [redacted] ([redacted]

Within the [redacted] stage, units are generally anticipated to prograde basinward, with each progressive cycle moving further up-section. For the [redacted] and its effect on deposition and facies distributions ([redacted]

Figure 1-6 displays the paleogeography during deposition of the slightly younger [redacted] Group, to visually demonstrate the position of the TXCCS#1 Project relative to the [redacted] The schematic cross section and map that were provided in Figure 1-4 clarify the location of the project relative to primary [redacted] development. A detailed stratigraphic review of [redacted] formations and related deposition in the Gulf of Mexico basin are presented in material published by Galloway (2008) and [redacted]

[redacted]

Figure 1-5 – Simplified stratigraphic column of the targeted, underlying, and overlying formations. The red shade indicates the injection zone; the gray, the confining zones.

[redacted]

Figure 1-6 – Paleogeographic reconstruction of the [redacted] Group, Gulf of Mexico. The red star is the approximate location of the TXCCS#1 Project (modified from [redacted]

1.3 Site Geology

According to the modeled extents of the injection plume and critical pressure front, the AOR of the proposed TXCCS#1 Project is situated in Sabine County and eastern San Augustine County, Texas—[redacted], as indicated by the critical pressure front extent in Figure 1-7.

[redacted]

Figure 1-7 – Overview Map of the TXCCS#1 Project

Aethon intends to drill the proposed Tea Olive No. 1 as a stratigraphic test well to collect additional data and enhance initial site-characteristic assessments based on prior research in the region. The well is situated approximately [redacted] to the [redacted] of the proposed Flowering Crab Apple No. 1 injection well. Drilling of the Tea Olive No. 1 will provide site-specific subsurface information to enhance the initial data set built upon regional geologic investigations. The collection of data will include extensive openhole logging and the acquisition of up to [redacted] feet (ft) of whole core, the analysis of which will help improve understanding of rock properties and calibrate logs for future wells.

Table 1-1 provides a comprehensive list of openhole wireline logs planned to be acquired during the drilling of Tea Olive No. 1 and Flowering Crab Apple No. 1. Additional information regarding the openhole and cased-hole logging programs of the wells are provided in ***Section 4 – Well Construction and Design***. Table 1-1 includes the projected top and base of proposed log intervals to provide precise data-acquisition estimates relative to the site characterization objectives. The top and base depths of investigation were approximated from regional mapping of offset well data and may be adjusted during drilling to ensure coverage over the intended target formations.

Table 1-2 lists the planned intervals to be cored during the drilling of Tea Olive No. 1. The collected core and resulting analysis will gather additional mineralogical, fluid composition, petrophysical, mechanical, and geochemical data, which will be utilized to improve site-specific characterization efforts. Aethon anticipates to collect various sidewall cores within the targeted injection and confining zones of Flowering Crab Apple No. 1, on an as-needed basis. Specific coring procedures for that injection well will be determined after the drilling of Tea Olive No. 1.

Table 1-1 – Openhole Logging Plan for Tea Olive No. 1 and Flowering Crab Apple No. 1

Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Tea Olive No. 1 Depths	Flowering Crab Apple No. 1 Depths
Surface Section	Gyro Survey	Directional Survey	[redacted]	[redacted]	[redacted]
	Total Gamma Ray Array Induction Spontaneous Potential Bulk Density Neutron Porosity Monopole Sonic Caliper Formation Fluid Sampling Tool	Identification of USDW	[redacted]	[redacted]	[redacted]
Production Section	Gyro Survey (Directionally Drilled)	Directional Survey	[redacted]	[redacted]	[redacted]
	Deep Shear-Wave Sonic/Acoustic Multi-Arm Caliper Induction Micro-Imager	Synthetic Ties Deep Shear-Wave Imaging Maximum and Minimum Stress Regimes Aid in Cement Calculations, Structural Dip Determination, and Fracture Characterization	[redacted]	[redacted]	[redacted]
	Spectral Gamma Ray Array Induction Spontaneous Potential Bulk Density Neutron Porosity Magnetic Resonance Elemental Capture Formation Fluid Sampling Formation Pressure Testing	Identification of Rock and Fluid Properties	[redacted]	[redacted]	[redacted]

Table 1-2 – Planned Whole Core Intervals, Tea Olive No. 1

Stratigraphic Unit	Zone
[redacted]	

Information regarding geologic properties and reservoir characteristics of the injection and confining zones was sourced from various data repositories, including publicly available, subscribed, licensed, and proprietary data sets. These sources include the Louisiana Department of Energy and Natural Resources (LDENR) Strategic Online Natural Resources Information System (SONRIS), Railroad Commission of Texas (TRRC) online database, Texas Bureau of Economic Geology (BEG), Enverus, IHS LogNet, TGS R360, and published research—from which a comprehensive understanding of the regional geologic setting and lithological properties was established. Additionally, this understanding was further corroborated by offset wellbore and core data, where available.

The anticipated geologic conditions of the modeled sequestration site were projected through [redacted] wells with formation picks from analysis of openhole wireline logs, as shown in Figure 1-8. The data set included [redacted] wells with petrophysical analysis of digitized log curves (Log American Standard Code for Information Interchange (ASCII) Standard (LAS)), as well as production data from wellbores proximal to the modeled project area.

[redacted]

Figure 1-8 – Well Log Data

The offset wellbore with core closest to the proposed TXCCS#1 Project site is the [redacted], located within the [redacted] trend approximately [redacted] miles [redacted] of Tea Olive No. 1 and approximately [redacted] miles [redacted] of Flowering Crab Apple No. 1. [redacted] was spudded on [redacted]; coring operations were performed between [redacted], and [redacted] and openhole logging operations were conducted on [redacted]. Openhole logging of the targeted formations consisted of the collection of electrical induction and spontaneous potential (SP) logs between [redacted] ft. A total of [redacted] whole cores were collected between [redacted] ft.

The cored intervals were analyzed by [redacted] in [redacted] to measure the porosity, permeability, oil saturation, and water saturation of the targeted intervals. Several core fragments from the [redacted] were identified as being stored by the [redacted] at their [redacted] Additional analysis was performed on the [redacted] core samples in [redacted] The analysis included porosity, permeability, and grain density measurements conducted by [redacted] and X-ray diffraction (XRD) analysis conducted by [redacted]. A series of core plug photos and computed tomography (CT) images of the identified core plugs were also taken by [redacted]

One other regional core was located within the [redacted] reef trend from the [redacted]), located approximately [redacted] miles [redacted] of Tea Olive No. 1. [redacted] was spudded on [redacted], and openhole logging operations were conducted on [redacted]. Openhole logging consisted of the collection of electrical induction and SP logs between the depths of [redacted] ft.

The location of identified core data relative to the proposed injection wells is provided in Figure 1-9. Table 1-3 clarifies the age, depths, and respective thicknesses of the upper confining, injection, and lower confining zones, as encountered in [redacted] Additionally, Figure 1-10 provides a stratigraphic column illustrating formations encountered within the [redacted] with their corresponding lithology and depth profile.

[redacted]

Figure 1-9 – Map of Identified Core Data Relative to the Proposed Injection Wells

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

System	Group/Formation	Zone	Formation Top–Bottom (ft)	Thickness (ft)
[redacted]				

[redacted]

Figure 1-10 – Stratigraphic Column from [redacted]

1.3.1 Injection Zone

The proposed injection zone for the TXCCS#1 Project is the [redacted] Formation, also known as the [redacted]. The [redacted] consists of [redacted], as discussed in *Section* [redacted]

In general, [redacted] Formation.

For the purposes of this permit application, facies nomenclatures have been generalized to account for the limited distribution of modern openhole logs and core data available for modeling within the geomodel extent (GME). Modeled facies within [redacted]

Figure 1-12 displays a highstand facies map of the [redacted] to visually demonstrate the position of the project relative to the [redacted] and published facies distributions. The north-south schematic cross section provided in Figure 1-13 illustrates the location of primary [redacted] development and clarifies stratigraphic changes encountered while moving away from the [redacted]

[redacted]

Figure 1-11 – Classification of [redacted] According to Depositional Texture [redacted]

[redacted]

Figure 1-12 – [redacted] highstand facies map (modified from [redacted] The red star denotes the project location, and the red line approximates the line of section presented in Figure 1-13.

[redacted]

Figure 1-13 – North to south stratigraphic cross section through the [redacted] section, flattened on the base of the [redacted] (modified from [redacted] The hatched red box denotes [redacted] development; the purple star, the project location.

Primary [redacted]

[redacted]

[redacted] Additional material regarding facies determinations, their respective distributions, and associated porosity and permeability relationships are provided in *Section 1.2.1*.

An openhole log of the [redacted] injection zone is provided in Figure 1-15 to illustrate the local stratigraphy of [redacted] The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in measured depth (MD), and a deep induction log (ILD). The figure also clarifies the location of cored intervals within the [redacted] signified with hatched shading along the depth track. The injection zone starts at the top of the [redacted] Formation and extends to the top of the [redacted] Formation, with a gross thickness of [redacted] ft and net [redacted] thickness of approximately [redacted]

[redacted]

Figure 1-14 – Net [redacted] Isochore Map of the Injection Zone

[redacted]

Figure 1-15 – Openhole log of the offset [redacted] depicting the injection zone.

Analogous [redacted] were evaluated to improve understanding of potential porosity and permeability distributions within the [redacted] due to a general lack of modern, openhole density data in the region—particularly within the [redacted]. Figure 1-16 displays the depositional model of the [redacted] to visually conceptualize depositional environments and anticipated petrophysical properties of anticipated facies [redacted]). The porosity and permeability ranges are in general agreement with regional data, analyzed by Nehring Associates, Inc., in 2009, and published by the U.S. Geological Survey (USGS) in 2016. The 2009 study reviewed data from [redacted] equivalent reservoirs, which indicated an average porosity of [redacted] and an average permeability of [redacted] millidarcy (mD) (Merrill, 2016).

Offset core data was reviewed from two wells in the region [redacted] As noted earlier, the closest well with core to the proposed TXCCS#1 Project site is [redacted] A total of [redacted] ft of conventional core was collected from two intervals within the Mooringsport Formation and included coverage of both [redacted] facies. Table 1-4 provides the results of porosity and permeability analysis conducted on [redacted] core samples from [redacted] The table includes facies identified from openhole logs to illustrate changes in reservoir properties observed between facies of the injection zone.

Analysis of samples within facies identified as [redacted]

Additional analysis was completed in 2024 on [redacted] core samples stored by [redacted] to improve understanding of the [redacted] However, modern analysis was limited to packstone facies of the formation due to the limited availability of core samples stored at [redacted]. Table 1-5 provides the results of XRD analysis conducted by [redacted] The [redacted] Figure 1-17 presents a core plug photo by [redacted] of a [redacted] sample taken from [redacted] and Figure 1-18 shows a CT image by [redacted] of the same core plug.

The figures demonstrate the potential for development of [redacted] porosity within the [redacted] The current interpretation is constrained to [redacted] porosity due to limited core availability and minimal coverage required to understand distributions of vugular [redacted]. The interpretation is modeled from petrophysical analysis and therefore does not take into account [redacted] by openhole porosity logs. The current petrophysical interpretation will be updated to include [redacted] once the stratigraphic test well has been drilled, cored, and analyzed.

[redacted]

Figure 1-16 – Depositional model for the [redacted] with estimated porosity and permeability values of typical facies. The red star represents the approximate location of the TXCCS#1 Project (modified from [redacted]

Table 1-4 – Porosity and permeability analysis of core from [redacted] within the [redacted] Formation

Formation	Depth (ft)	Facies from Logs	Porosity (%)	Permeability (mD)
[redacted]				

*Italicized sample is from 2024 analysis o [redacted] stored core sample; all other samples are from the original [redacted] analysis.

Table 1-5 – 2024 XRD analysis of whole core from [redacted] within the [redacted] Formation.

Depth (ft)	Quartz (wt%)	Plagioclase (wt%)	Calcite (wt%)	Pyrite (wt%)	Total Minerals (wt%)
[redacted]					

*wt% - weight percent

[redacted]

Figure 1-17 – Core plug photo of [redacted] sample fro [redacted] Formation.

[redacted]

Figure 1-18 – CT scan of [redacted]-ft sample from [redacted] Formation.

1.3.2 Upper Confining Zone

Upper confinement of the [redacted] will be provided by the tight overlying [redacted] Formation, which consists of [redacted] injection zone.

The [redacted]

Figure 1-19 displays a facies map of the [redacted] interval to illustrate the positioning of the [redacted] relative to the project site and associated facies [redacted] The map indicates that [redacted] deposition occurred within an [redacted] at the project location and should be represented by deposition of [redacted] This deposition is beneficial for the sealing capability of the [redacted]. Figure 1-19 also illustrates the movement of [redacted] when compared to the [redacted] map provided in Figure 1-12 for the [redacted] Formation.

The published literature is in agreement with petrophysical analysis and modeling conducted within the GME. However, facies nomenclatures were simplified to account for the limited distribution of modern openhole logs and core data available within the GME. Petrophysical analysis conducted within the GME indicates that the lowstand wedge is approximately [redacted] ft thick and generally consists of [redacted] The overlying highstand wedge is approximately [redacted] ft thick and primarily consists of [redacted].

An openhole log from [redacted] is provided in Figure 1-20 to illustrate the stratigraphy of the [redacted] confining zone near the proposed injection sites. The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in MD, and ILD. The figure also clarifies the location of cored intervals within the [redacted] Formation, signified with hatched shading along the depth track. The upper confining zone (UCZ) starts at the top of the [redacted] Formation and extends to the top of the [redacted] Formation, with a gross thickness of [redacted] ft in [redacted]

Offset core data from the [redacted] Formation was also identified and reviewed from [redacted]. A total of [redacted] ft of conventional core was collected from [redacted] intervals within the [redacted] Formation, including coverage of both [redacted] facies. Analysis of the samples was limited to conventional porosity and permeability measurements conducted in [redacted] as no [redacted] samples from the well were available at the [redacted]. Table 1-6 provides the results of porosity and permeability analysis conducted on [redacted] core samples. The data set suggests an average porosity of [redacted] and an average permeability of [redacted] mD within the Glen Rose confining zone, indicating a significant reduction in the porosity-permeability relationship relative to the relationship observed in the Mooringsport injection zone [redacted] The XRD analysis was not available for the [redacted] Formation but will be conducted on core samples collected during the drilling of the proposed stratigraphic test well. Lithology and petrophysical properties will be incorporated with site-specific data, once the planned core has been collected and analyzed.

Mapping of offset openhole logs suggests that the gross thickness of the [redacted] Formation ranges from approximately [redacted] ft within the GME and, as noted earlier, is roughly [redacted] ft thick near the proposed injection sites. The [redacted] is regionally extensive beyond the GME, and core data proximal to the injection sites suggest that the formation contains sufficient petrophysical properties to prevent the migration of CO_2 from the underlying [redacted] injection zone.

[redacted]

Figure 1-19 – [redacted] facies map ([redacted]
The red star is the approximate location of the TXCCS#1 Project.

[redacted]

Figure 1-20 – Openhole log of the offset [redacted] the UCZ and regional overlying shale beds.

Table 1-6 – Porosity and permeability analysis of core from [redacted] within the [redacted] Formation.

Formation	Depth (ft)	Porosity (%)	Permeability (mD)
[redacted]			

1.3.2.1 Regional Overlying Shale Beds

Modeling conducted through the TXCCS#1 Project concluded that reservoir facies of the [redacted] Formation contain the petrophysical properties required to accept the CO_2 volumes discussed in this permit application, with sufficient upper confinement provided by the [redacted] Formation. The petrophysical model was distributed through the entirety of the [redacted] reef complex, from the top of the [redacted] Formation to geostatistically confirm the sealing capability of the [redacted] Additional shale beds identified above the [redacted] Formation are discussed herein, should core results of the stratigraphic test well reduce any confidence in the [redacted] as upper confinement. The openhole log presented in Figure 1-20 referenced the location of regional overlying shales.

[redacted] *Formation*

The [redacted] UCZ is immediately overlain by deposition of [redacted] ft of the [redacted] Formation. Regionally, the formation tends to consist of [redacted] with occasional [redacted]. However, interpretations published by Kreitler et al. (1983) suggest that [redacted] primarily occurred to the [redacted] within the east Texas basin, with [redacted] Offset openhole logs correlated through the [redacted]

Formation [redacted] as illustrated in Figure 1-20. The [redacted] is anticipated to have a gross thickness of approximately [redacted] ft near the proposed injection sites. Lithology is anticipated to consist primarily of [redacted]. Lithology and petrophysical assumptions of the [redacted] Formation will be incorporated with site-specific data, once the planned core has been collected from the stratigraphic test well and analyzed.

Kiamichi Formation

Additional overlying confinement will be provided by the [redacted] Formation, a [redacted] ft thick within the GME. Regionally, the formation is situated between the [redacted], as depicted in the stratigraphic column provided in Figure 1-2. However, [redacted] Offset openhole correlations conducted by Aethon indicate that [redacted] within the GME. [redacted] in the current data set due to shared petrophysical properties and log response.

According to the 2012 USGS CO_2 Storage Assessment Unit (SAU), the [redacted] Formation contains the physical properties required to act as a regional seal and was designated as the upward confining interval for their [redacted] of the east Texas basin. The study noted that the [redacted] Formation must be of sufficient thickness to provide adequate confinement and is approximately [redacted] ft thick in the subsurface where considered a regional seal by the USGS (Roberts-Ashby, 2012). The formation is anticipated to have a gross thickness of approximately [redacted] ft proximal to the proposed injection sites. Lithology and petrophysical assumptions of the [redacted] Formation will be incorporated with site-specific data, once the planned core has been collected from the stratigraphic test well and analyzed.

1.3.3 Lower Confining Zone

Lower confinement of the [redacted] will be provided by the [redacted]

The published regional literature is in general agreement with petrophysical analysis and modeling conducted within the GME. [redacted] Figure 1-21 presents a true vertical depth subsea (TVDSS) structure map on the top of Ferry Lake and clarifies the southern extent of [redacted]

An offset openhole log of the LCZ is provided in Figure 1-22 from [redacted] to illustrate the stratigraphy of the zone near the proposed injection sites. The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in MD, and ILD. The figure also clarifies the location of cored intervals within the [redacted] Formation, signified with hatched shading along the depth track. The LCZ starts at the top of the formation and extends to the top of the [redacted] Formation, with a gross thickness of [redacted]

Offset core data from the [redacted] Formation was also identified and reviewed from [redacted], representing the only regional core identified within the [redacted]. A total of [redacted] ft of conventional core was collected from [redacted] ft intervals within the formation and includes coverage of both [redacted] facies. Table 1-7 provides the results of porosity and permeability analysis conducted on [redacted] core samples from the [redacted] Porosity within the upper [redacted] ft of the [redacted] confining zone ranges from [redacted] in [redacted] with an average porosity of [redacted]. Permeability within the same interval ranges from [redacted] mD with an average permeability of [redacted] mD.

A stark contrast is observed between porosity-permeability relationships of this portion of the [redacted] confining zone and the overlying [redacted] injection zone (average of [redacted]% and [redacted] mD). The permeability contrast is beneficial to confinement, particularly lower confinement, because injected CO_2 is buoyant and has a tendency to migrate upward (Metz et al., 2005).

A few samples from the XRD data set exhibit relatively [redacted] within the [redacted] Formation, likely attributed to [redacted] deposition. The samples are located at depths of [redacted] ft and [redacted] ft in [redacted], underlying [redacted] development at the top of the [redacted]. These deposits are represented by only [redacted] samples analyzed, suggesting limited occurrences within the gross [redacted] section. Modeling within the GME indicates that the [redacted] facies [redacted] of the [redacted] will not have an effect on lower confinement due to the [redacted] facies present above and below ([redacted] mD).

Additional analysis was completed in 2024 on [redacted] core samples stored by [redacted] to improve understanding of the [redacted] Formation. The recent investigation consisted of porosity, permeability, and grain density measurements, along with a series of core plug photos and CT images, taken by [redacted] Results from the 2024 conventional porosity and permeability analysis are included in Table 1-7, signified with italics. Table 1-8 provides the results of XRD analysis conducted by [redacted] in 2024. Samples analyzed from the [redacted] Formation are predominantly [redacted] Lithology and petrophysical properties of the LCZ will be incorporated with site-specific data, once the planned core has been collected and analyzed. [redacted], further enhancing the sealing capability of the [redacted]

The [redacted] Formation is anticipated to have a gross thickness of approximately [redacted] ft within the GME and roughly [redacted] ft thick near the proposed injection sites. Petrophysical characteristics modeled through the upper portion of the [redacted] suggest that the formation will provide sealing properties sufficient to prevent the migration of injectables out of the designated injection zone within the GME. The [redacted] was also chosen as the upward confining interval for the USGS's 2012 CO_2 [redacted] (Roberts-Ashby, 2012). [redacted] lithologies, thickness, and confining properties will be updated to confirm sealing capability once a stratigraphic test well has been approved and drilled, and analysis completed.

[redacted]

Figure 1-21 – TVDSS structure map of the [redacted] base (modified from [redacted]). The blue dashed line represents the southern extent of [redacted] development. The red star is the approximate location of the proposed TXCCS#1 Project.

[redacted]

Figure 1-22 – Openhole log of the offset [redacted] depicting the LCZ.

Table 1-7 – Porosity and permeability analysis of core from [redacted] within the [redacted] Formation.

Formation	Depth (ft)	Porosity (%)	Permeability (mD)
[redacted]			

*Italic samples are from 2024 analysis of [redacted] core samples; all other samples are from the original [redacted] analysis.

Table 1-8 – 2024 XRD analysis of whole core from [redacted] within the [redacted] Formation.

Depth (ft)	Quartz (wt%)	Plagioclase (wt%)	Calcite (wt%)	Dolomite (wt%)	Barite (wt%)	Total Minerals (wt%)
[redacted]						

1.3.4 Geologic Structure

The proposed TXCCS#1 Project CO_2 storage site is located in east Texas within the Gulf of Mexico basin. Structural dips of targeted intervals within the [redacted] were mapped using offset well control and 2D and 3D seismic data. Information regarding the 3D structural model and interpretation is discussed herein, and the resulting structure maps, isochore maps, and cross sections are provided in *Appendix B*.

1.3.4.1 <u>Seismic Data</u>

Approximately [redacted] square miles of 3D surface seismic data and [redacted] linear miles of 2D were licensed by Aethon and included in this interpretation (Figure 1-23). The [redacted] 3D survey overlies the proposed Tea Olive No. 1 location and covers approximately [redacted] square miles. The eastern edge of the [redacted] survey overlies the proposed Flowering Crab Apple No. 1 location and covers a roughly [redacted] square mile subset of a larger shoot. These two 3D surveys were merged to provide continuity of the interpretation within the 3D model extent. Figure 1-23 clarifies the boundary of the 3D model relative to the proposed locations and incorporated data sets. Table 1-9 and Figure 1-24 provide vintage and acquisition parameters for the 3D surveys. The seismic data is of sufficient quality regarding offset information and frequency content to image the target section between [redacted] ft subsea depths.

[redacted]

Figure 1-23 – TXCCS#1 Project 3D model extent with incorporated well data, 2D lines, and 3D surveys—including the merged [redacted] and [redacted] 3D seismic surveys. Seismic cross sections presented in Figures 1-25 and 1-26 are displayed with dashed pink lines.

Table 1-9 – Parameters of 3D Seismic Surveys

Survey	[redacted]
Type	[redacted]
Year Acquired	[redacted]
Processed Version/Date	[redacted]
Source Type	[redacted]
Sample Rate (ms)	[redacted]
Record Length (sec)	[redacted]
Source Line Interval (ft)	[redacted]
Source Line Spacing (ft)	[redacted]
Receiver Line Interval (ft)	[redacted]
Receiver Line Spacing (ft)	[redacted]
Maximum Offset (ft)	[redacted]
Bin Size	[redacted]
Fold	[redacted]
Area	[redacted]

*PSTM – Pre-Stack Time Migration; ms – milliseconds

[redacted]

Figure 1-24 – 3D [redacted] seismic data frequency content centered around zones of interest: the top of the [redacted] (UCZ) to the base of the [redacted] (LCZ). Velocity: approximately [redacted] ft/s; dominant frequency: approximately [redacted] Hz; vertical resolution: [redacted] ft.

1.3.4.2 Reflection Seismic Profiles

Seismic surveys image the subsurface based on density and velocity contrasts. To define the structure of the confining and injection zones (Figure 1-5), four seismic time horizons were interpreted within the merged 3D seismic survey and on seven 2D seismic lines: the top of the [redacted] (UCZ), the top of the [redacted] (injection zone), the top of the [redacted] (LCZ), and the top of the [redacted] Formation (LCZ base). Figure 1-23 showed the location of two seismic cross sections: (1) north-south, [redacted] and going through the proposed Flowering Crab Apple No. 1 (Figure 1-25); and (2) southwest-northeast, oriented [redacted] and going through both Flowering Crab Apple No. 1 and Tea Olive No. 1 (Figure 1-26).

[redacted]

Figure 1-25 – North-south two-way travel time (microseconds) seismic cross section: (a) without interpretation; and (b) with interpreted horizons. The location of the cross section was displayed in Figure 1-23.

[redacted]

Figure 1-26 – Southwest-northeast two-way travel time (microseconds) seismic cross section: (a) without interpretation; and (b) with interpreted horizons. The location of the cross section was displayed in Figure 1-23.

1.3.4.3 Velocity Control and Synthetic Seismogram

A synthetic well-tie within [redacted] miles of both proposed injection wells was used to confirm the time-to-depth relationship between geologic formation tops and the 3D seismic data. The synthetic seismogram generated for [redacted] is presented in Figure 1-27 for reference. The well is located within the 3D [redacted] seismic survey and was signified by the yellow triangle displayed in Figure 1-23. No checkshot velocity information or surveys were licensed or utilized in the 3D structural model for the project.

[redacted]

Figure 1-27 – Synthetic Seismogram for [redacted]

1.3.4.4 Time-to-Depth Conversion and Structural Framework

A multi-well velocity model was built by integrating the mapped seismic horizons with high-confidence geologic formation picks from wells within the modeled area. The model was used to convert seismic time horizons to depth. Depth-converted seismic horizons were combined with the formation tops of up to [redacted] wells to create structural surfaces for the entire model extent. Directional surveys were utilized where available to correctly position deviated and horizontal wellbores. Well information and log data were gathered from several sources and compared among each other to ensure an accurate and complete data set. These sources included the LDENR SONRIS, TRRC online database, BEG, Enverus, IHS, and TGS.

Table 1-10 summarizes the model horizons and sources used to generate them. Figures 1-28 through 1-30 show the seismic/formation-top integrated surfaces for the top of the [redacted] (top of the UCZ), top of the [redacted] (top of the injection zone), and the top of the [redacted] (top of the LCZ), respectively. These surfaces were incorporated into the 3D structural model along with the top of the [redacted] (base of the LCZ) and are illustrated together on the 3D rendering provided in Figure 1-31. The resulting structure maps, isochore maps, and cross sections from 3D structural modeling are provided in *Appendix B*.

The overall structure across the modeled area [redacted]. The subsurface interpretation does not indicate any large-scale changes in the thickness of the injection or confining zones. The injection wells are located away from any published fault locations. No seismically detected faults are mappable within the 3D seismic data or on 2D lines within the expected extent of the CO_2 plumes or critical pressure front. The fault interpretation being at or greater than the seismic resolution is the only caveat; therefore, any potential faults with throws less than the seismic resolution would not be visible. Vertical resolution varies among the 2D and 3D data sets due to vintage and associated data quality, but generally ranges between [redacted]

Table 1-10 – Model horizons and number of wells with formation tops used to generate them along with 3D and 2D seismic horizons.

Horizon	Well Tops Used	Seismic Horizon Used
[redacted]		

[redacted]

Figure 1-28 – Structure Map: Top of the [redacted] Formation (Top of the UCZ)

[redacted]

Figure 1-29 – Structure Map: Top of the [redacted] Formation (Top of the Injection Zone)

[redacted]

Figure 1-30 – Structure Map: Top of the [redacted] Formation (Top of the LCZ)

[redacted]

Figure 1-31 – 3D View of the TXCCS#1 Project Structural Model

1.3.4.5 Project GME Structure and Cross Sections

A TVDSS structure map of the top of the [redacted] Formation is provided in Figure 1-32. The map illustrates the gentle [redacted] f the formation within the modeled area and identifies the location of Tea Olive No. 1 and Flowering Crab Apple No. 1 relative to the modeled plume extents, the modeled pressure front extent, the [redacted] and the [redacted] The edge of the modeled pressure front tends to follow the edge of the [redacted] margin due to facies changes observed and modeled within the GME.

Primary reservoir development occurred along the [redacted] with [redacted], as illustrated in the structural cross sections presented in Figures 1-33 and 1-34. As a result, modeled injection is anticipated to experience a [redacted] that will restrict the migration of CO_2 outside of the primary reservoir facies. Larger versions of Figures 1-32 through 1-34 are provided in *Appendix B*.

[redacted]

Figure 1-32 – [redacted] structure map (TVDSS): the black outline around the proposed injection wells represents the modeled plume extents; the pink outline identifies the extent of the pressure front.

[redacted]

Figure 1-33 – Structural West-East Cross Section

[redacted]

Figure 1-34 – Structural North-South Cross Section

1.4 <u>Geomechanics</u>

1.4.1 Local Stress Conditions

Local formation stresses will be calculated by integrating mechanical rock properties from a dipole openhole log, calibrated with geomechanical core tests. According to published maps of crustal-stress orientation along the northern coast of the Gulf of Mexico basin, the maximum horizontal stress orientation is [redacted] n near the TXCCS#1 Project (Yassir and Zerwer, 1997; Heidbach et al., 2016).

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

Vertical stress can be determined by evaluating the pressure exerted on a formation at a particular depth based on the total weight of the overlying rocks and fluids (Aird, 2019). The vertical stress and overburden gradient at the top of the upper confining, injection, and lower confining zones were estimated from log data at the offset [redacted]. These were calculated by integrating bulk density from surface to the formation depth in half-foot intervals. The average bulk density of the upper confining and injection zones was estimated from the same log. Tables 1-11 and 1-12 show the overburden gradient and vertical stress (both in pounds per square inch (psi)) and average bulk densities (in grams per cubic centimeter (g/cm^3)) of the upper confining, injection, and lower confining zones for the Tea Olive No. 1 and Flowering Crab Apple No. 1 locations. Figure 1-35 depicts the vertical stress gradient log used to calculate the vertical stress from [redacted]

Table 1-11 – Calculated Vertical Stresses for Tea Olive No. 1

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

Table 1-12 – Calculated Vertical Stresses for Flowering Crab Apple No. 1

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

[redacted]

Figure 1-35 – Vertical stress gradient log used to calculate vertical stress gradient for [redacted]

1.4.2 Elastic Moduli and Fracture Gradient

Elastic moduli will be established by integrating analysis of core samples and log data where applicable. Core samples and log data required for calculations are not currently available near the project site but will be recovered during the drilling of the Tea Olive No. 1 stratigraphic test well. The results of mechanical testing will be provided in future permit updates. The core samples will undergo triaxial compressive strength testing to populate the geomechanical properties listed in Tables 1-13 and 1-14.

Table 1-13 – Triaxial Compressive Strength Test Results from Tea Olive No. 1

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
N/A[(a)]	N/A[(a)]	Upper Confining	[redacted]	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Injection		N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Lower Confining		N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
(a) Results will be updated once this stratigraphic test well has been drilled, cored, and analyzed.							

Table 1-14 – Triaxial Compressive Strength Test Results from Flowering Crab Apple No. 1

Sample Number	Depth (ft)	Zone	Formation	Confining Pressure (psi)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
N/A[(a)]	N/A[(a)]	Upper Confining	[redacted]	N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Injection		N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
N/A[(a)]	N/A[(a)]	Lower Confining		N/A[(a)]	N/A[(a)]	N/A[(a)]	N/A[(a)]
(a) Results will be updated once this well has been drilled, cored, and analyzed.							

1.4.2.1 Fracture Gradient Calculations

Eaton's method (Eaton, 1969), widely acknowledged as the standard practice for the determination of fracture gradients, was used to calculate the pressure required to fracture the injectable rock. The method requires Poisson's ratio, overburden gradient, and pore gradient to determine the fracture gradient. Table 1-15 provides the values utilized for the calculation.

Table 1-15 – Fracture Gradient Calculation Assumptions – Eaton's Method

Zone	Poisson's Ratio	Overburden Gradient (psi/ft)	Pore Gradient (psi/ft)	Fracture Gradient (psi/ft)
[redacted]				

Poisson's ratio was determined through petrophysical analysis of compressional and sheer sonic log data from four wells [redacted] for the UCZ, injection zone, and LCZ. Literature published by Molina, Vilarras, and Zeidouni (2017) suggests Poisson's ratio of [redacted] typically ranges between [redacted], in agreement with the petrophysical values provided in Table 1-15. A value of [redacted] was chosen for the injection zone Poisson's ratio based on the petrophysical work performed on nearby wells and confirmed from literature. A value of [redacted] psi/ft was determined for the vertical stress gradient of the injection zone using an offset bulk density log [redacted]), as was shown in Figure 1-35. Lastly, a pore pressure gradient of [redacted] psi/ft was estimated based on nearby drilling muds used at similar depths to the injection zone and observed regional trends, as discussed below.

1.4.3 Geopressure

Anticipated pressures of the injection interval at the project site were acquired from regional trends observed in offset scout tickets, mudlogs, and well headers. Data was located from four offset wells within 5 miles of the proposed locations to investigate local pore pressure gradients and the potential for geopressured intervals in the region [redacted]. The data set reported mud weights within the [redacted] section of [redacted] pounds per gallon (ppg) at depths of approximately [redacted] ft, indicating that the proposed injection zone is [redacted] However, a scout ticket from the [redacted] indicates that the [redacted]

A mudlog from the [redacted] reported relatively consistent mud weights of [redacted] ppg within and below the [redacted] section, which gradually increased to [redacted] ppg at a depth of [redacted] ft, [redacted]. Once back in the hole, mud weights were immediately [redacted] ppg, where they stayed until reaching a total depth of 14,370 ft. The relatively quick increase in mud weight suggests the possibility of a geopressured zone deeper in the geologic section, which aligns with regional interpretations. If present, [redacted]

[redacted]

1.5 Porosity and Permeability

Porosity and permeability distributions within the [redacted] at the TXCCS#1 Project location are [redacted] and significantly impacted by positioning relative to the platform margin, the height of the water column at any given time, and the degree of energy or wave action within the system [redacted] Galloway, 2008).

Facies within the [redacted] generally consist of [redacted]

[redacted]

A series of studies conducted by [redacted] investigated the [redacted]

The generalized porosity-permeability crossplot depicted in Figure 1-37 clarifies the need for a variable, facies-dependent porosity-permeability transform to properly estimate permeability from interparticle porosity. [redacted] acknowledges that these transforms should be limited to interparticle porosity, which can be reliably measured with openhole porosity logs. The interpretation and resulting transforms do not take into account [redacted] missed by openhole porosity logs. The current petrophysical interpretation will be updated to include [redacted], once the stratigraphic test well has been drilled, cored, and analyzed.

[redacted]

Figure 1-36 – Geological and petrophysical classification of [redacted] based on size and sorting of grains and crystals (modified from [redacted]

[redacted]

Figure 1-37 – Generalized porosity-permeability trends of [redacted]

1.5.1 Petrophysical Evaluation

Petrophysical analysis was conducted on [redacted] offset wells within the GME to identify facies distributions and their respective petrophysical properties. The data set incorporated openhole porosity data from [redacted] of the wells, which were used to generate total porosity curves. A synthetic porosity curve was calculated from deep resistivity for the remaining [redacted] wells due to sparse openhole porosity coverage within the GME. Core analysis from [redacted] wells was also integrated into the petrophysical model and utilized to improve understanding of porosity-permeability relationships within the [redacted] [redacted] cored wells were taken from within the [redacted] one of which is located within the GME. The other cored well is located in [redacted] of the GME. Figure 1-38 depicts the data set utilized for petrophysical analysis and clarifies the location of wells with openhole porosity data, synthetic porosity data, and core data.

[redacted]

Figure 1-38 – Petrophysical Overview Map

1.5.1.1 Data Quality Assurance

Quality assurance (QA) was performed on the wells to verify the quality and accuracy of the LAS log data collected for petrophysical analysis. The digital log curves were compared to their corresponding raster image to ensure agreement between the image and digital files. Adjustments to the digitized curves were made on an as-needed basis to ensure proper reflection of the original raster image. The SP log data was also normalized on an as-needed basis to ensure that the data represented a shale baseline of zero (SPBL curve). An example of the data QA procedure is provided in Figure 1-39.

[redacted]

Figure 1-39 – Log depicting example QA process to ensure digital data resembles raster data.

1.5.1.2 Shale Volume

After the QA procedure was conducted, shale volume (Vshale) was computed from the gamma ray (GR) log, using Equation 1. If GR logs were not available, Vshale was calculated using the same equation, but with values from SP logs in the place of GR.

(Eq. 1) $$Vshale = \frac{(GR - GRcarb)}{(GRshale - GRcarb)}$$

Where:
Vshale = shale volume, in percentage
GR = gamma ray
$GRcarb$ = gamma ray reading of a carbonate
$GRshale$ = gamma ray reading of a shale

1.5.1.3 Total Porosity

Total porosity (PHIA) was determined for 42 wells that contained openhole porosity coverage of the [redacted]. The PHIA was established from a crossplot of density porosity and neutron porosity curves where available. In the absence of quality density-neutron crossplot data, density porosity or sonic porosity was utilized, with a preference on density porosity data. If no raw porosity data was identified or the section contained significant washout, then a synthetic porosity curve was calculated from deep resistivity, using Equation 2.

(Eq. 2)

$$PHIRES = min(.22, max(0, ((0.175341*ResD^{-0.511788})+(0.210897*ResD^{-0.726535}))/2))$$

Where:
$PHIRES$ = synthetic porosity from ResD, in decimal format
$ResD$ = deep resistivity

This step was critical to understand porosity trends within the [redacted] due to the low concentration of openhole porosity data identified within the GME, particularly to the [redacted] and [redacted] of the proposed Tea Olive No. 1 and Flowering Crab Apple No. 1 locations. Many of the offset wells predate modern logging capabilities and only gathered basic SP and induction data. An example of the resistivity-porosity relationship used for the transform is provided in Figure 1-40, showing the correlation between the two curves.

Petrophysical analysis conducted on [redacted] is presented in Figure 1-41, illustrating the strong correlation observed between the calculated synthetic porosity from deep resistivity and measured density porosity within the data set. Synthetic porosity curves were utilized for [redacted] wells within the model.

[redacted]

Figure 1-40 – Synthetic Porosity from Deep Resistivity

[redacted]

Figure 1-41 – Comparison of synthetic porosity from deep resistivity curve (in yellow) to measured density porosity (in red) for [redacted]

1.5.1.4 Facies Determination

[redacted] from openhole log response and to distribute their petrophysical properties accordingly. The petrophysical cutoffs used for facies determination are as follows:

[redacted]

Where:
$SPBL$ = normalized spontaneous potential
$PHIA$ = total porosity, in decimal format
$Vshale$ = shale volume, in decimal percent

The SP logs were utilized on an as-needed basis to manually refine the identification of [redacted] The SP data was particularly helpful to identify m[redacted] that had a clean GR but no SP response, indicating a lack of reservoir development.

1.5.1.5 Effective Porosity

Vshale was utilized along with PHIA to generate an estimated effective porosity (PHIE) curve in Equation 3.

(Eq. 3) $$PHIE = PHIA * (1 - Vshale)$$

Where:
$PHIE$ = effective porosity, in decimal format
$PHIA$ = total porosity, in decimal format
$Vshale$ = shale volume, in decimal percent

Effective porosity represents the percent volume of interconnected pore space. Therefore, the resulting PHIE curves were used for all subsequent mapping and modeling to properly distribute petrophysical properties within the GME.

1.5.1.6 Permeability

An initial porosity-permeability relationship was established by plotting core porosity and permeability values from the [redacted] offset wells. Their locations were identified in Figure 1-38, and the resulting porosity-permeability relationship is presented in Figure 1-42—relative to facies-dependent porosity-permeability transforms published by [redacted] The data spread is typical for [redacted] and aligns well with the porosity-permeability transforms developed by [redacted] for [redacted]

[redacted] (Figures 1-42 and 1-43). These transforms were tied to petrophysical analysis to toggle between transforms, depending on facies determination.

Equations 4 through 7 were applied to all 68 wells containing PHIE data within the GME, whether derived from measured or calculated data.

(Eq. 4)

(Eq. 5)

(Eq. 6)

(Eq. 7)

[redacted]

Where:

[redacted]

The resulting permeabilities were utilized to establish permeability distributions throughout the model. The locations of wells with modeled effective porosity and permeability data are depicted in Figure 1-44. Figure 1-38 depicted the data set utilized for petrophysical analysis and clarified the location of wells with openhole porosity data, synthetic porosity data, and core data.

An example export of petrophysical analysis conducted for the TXCCS#1 Project is provided in Figure 1-45 for [redacted]—chosen as the primary type-log for the project because it is the only well identified to collect core within primary reservoir development of the GME. The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in measured depth with core points, calculated PHIE, and calculated permeability (PERM). Effective porosity data for [redacted] was determined from deep resistivity due to the log vintage and is scaled from 30–0%, in decimal form. The permeability was calculated from PHIE utilizing Equations 4 through 7—dependent upon facies—and is scaled from 1,000–0 mD.

[redacted]

Figure 1-42 – Log-log crossplot of core porosity and permeability values from [redacted] relative to facies-dependent porosity-permeability transforms [redacted]

[redacted]

Figure 1-43 – Porosity vs. permeability histogram of whole core data from [redacted] by [redacted] Core samples were restricted to [redacted] for an accurate comparison.

[redacted]

Figure 1-44 – Porosity Modeling Wells

[redacted]

Figure 1-45 – Petrophysical analysis of [redacted] Calculated total porosity (PHIA) is displayed in black, calculated effective porosity (PHIE) in green, and calculated permeability (PERM) in blue.

1.5.2 Upper Confining Zone

An openhole log of the [redacted] UCZ is provided in Figure 1-46 from [redacted] The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in MD, ILD, calculated PHIE, and calculated PERM. Effective porosity data for [redacted] was determined from deep resistivity due to the log vintage and is scaled from 30–0%, in decimal form; permeability is scaled from 1,000–0 mD. A histogram displaying average modeled facies volumes within the [redacted] is displayed in Figure 1-47. The UCZ is anticipated to be comprised of approximately [redacted] within the GME.

[redacted]

Figure 1-46 – Openhole log of offset [redacted] depicting the UCZ. Calculated PHIE is displayed in green and calculated PERM in blue.

[redacted]

Figure 1-47 – Histogram of Volume of facies (%) Within the [redacted] UCZ

1.5.2.1 Upper Confining Zone Porosity

A histogram of effective porosity modeled for the [redacted] UCZ is presented in Figure 1-48, from 0–25% PHIE. The porosity distribution is further delineated in Figure 1-49 to illustrate the distribution of effective porosity values within each modeled facies of the UCZ. The majority of the UCZ ([redacted]%) is comprised of [redacted] facies within the geocellular model. These facies contain an average effective porosity of [redacted] within [redacted] modeling and are anticipated to behave as hydraulic barriers. Only [redacted]% of the UCZ is comprised of [redacted] facies, where reservoir development tends to occur. [redacted] facies have an average effective porosity of [redacted]% within the modeled [redacted] with very few occurrences.

[redacted]

Figure 1-48 – Histogram of Modeled Porosity Distributions Within the UCZ

[redacted]

Figure 1-49 – Histograms of Modeled Effective Porosity Distributions by Facies Within the UCZ

1.5.2.2 Upper Confining Zone Permeability

A histogram of modeled permeability of the [redacted] UCZ is presented in Figure 1-50, from 0–1,000 mD. The data set is further delineated in Figure 1-51 to illustrate the distribution of permeability values within each modeled facies of the UCZ. Permeabilities are facies dependent and were determined from Equations 4 through 7 (*Section 1.5.1.6*) to properly reflect the porosity-permeability transforms developed by [redacted].

The non-reservoir facies ([redacted]) that comprise the majority of the UCZ ([redacted]%) contain an average permeability of [redacted] within the [redacted] model. Only [redacted] of the zone is comprised of [redacted] where reservoir development tends to occur. The presence of a thick, low permeability section immediately overlying the injection interval creates an ideal UCZ with high confidence in its sealing capability. Core will be collected during the drilling of the stratigraphic test well and analyzed to validate the porosity and permeability modeling of the UCZ. Once complete, the model and permit application will be updated.

[redacted]

Figure 1-50 – Histogram of Modeled Permeability Distributions Within the UCZ

[redacted]

Figure 1-51 – Histograms of Modeled Permeability Distributions by Facies Within the UCZ

1.5.3 Injection Zone

An openhole log of the Mooringsport injection zone is provided in Figure 1-52 from [redacted] The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in MD, ILD, calculated PHIE, and calculated PERM. Effective porosity data for [redacted] was determined from deep resistivity due to the log vintage and is scaled from 30–0%, in decimal form; permeability is scaled from 1,000–0 mD. A histogram displaying average modeled facies volumes within the [redacted] is displayed in Figure 1-53.

The injection zone is anticipated to be comprised of approximately [redacted] within the GME. [redacted] are primarily focused within the [redacted], as demonstrated in the [redacted] isochore provided in Figure 1-14. [redacted] of the [redacted] formation are primarily distributed [redacted] identified on the map.

[redacted]

Figure 1-52 – Openhole log of the offset [redacted] depicting the injection zone. Calculated PHIE is displayed in green and calculated PERM in blue.

[redacted]

Figure 1-53 – Histogram of the volume of Facies (%) Within the Injection Zone

1.5.3.1 Injection Zone Porosity

A histogram of effective porosity distributions modeled for the [redacted] injection zone is presented in Figure 1-54, from 0–25% PHIE. The distributions are delineated by facies to illustrate effective porosity distributions within each modeled facies of the injection zone. Primary reservoir development occurred within [redacted] Formation, which contain an average porosity of [redacted] and represent the targeted facies for injection. [redacted] and [redacted] but tend to exhibit [redacted] Galloway, 2008). [redacted] contain the lowest reservoir potential within the targeted section, with an average porosity of [redacted]. Facies [redacted]

[redacted]

Figure 1-54 – Histograms of Modeled Effective Porosity Distributions by Facies Within the Injection Zone

1.5.3.2 Injection Zone Permeability

A histogram of permeability distributions modeled for the injection zone is presented in Figure 1-55, from 0–1,000 mD. The distributions are delineated by facies to illustrate permeability distributions within each modeled facies of the injection zone. The modeled permeabilities are facies dependent and were determined from Equations 4 through 7 (*Section 1.5.1.6*) to properly reflect the porosity-permeability transforms developed by [redacted]

The majority of high permeability values are located within [redacted] Formation, which contain an average permeability of [redacted] mD. [redacted] averaged [redacted] mD within the modeled injection zone, while [redacted] and [redacted] averaged [redacted] mD. Core will be collected during the drilling of the stratigraphic test well and analyzed to validate porosity and permeability assumptions modeled for the injection zone. Once complete, the model and permit application will be updated.

[redacted]

Figure 1-55 – Histograms of Modeled Permeability Distributions by Facies Within the Injection Zone

1.5.4 Lower Confining Zone

An openhole log of the [redacted] LCZ is provided in Figure 1-56, from [redacted] The log curves presented in the figure consist of the following, from left to right: facies determined from petrophysical analysis, SP, depth track in MD, ILD, calculated PHIE, and calculated PERM. Effective porosity data for [redacted] was determined from deep resistivity due to the log vintage and is scaled from 30–0%, in decimal form; permeability is scaled from 1,000–0 mD. A histogram displaying average modeled facies volumes within the [redacted] Formation is displayed in Figure 1-57. The confining zone is anticipated to be comprised of approximately [redacted] within the GME.

[redacted]

Figure 1-56 – Openhole log of the offset [redacted] depicting the LCZ. Calculated PHIE is displayed in green and calculated PERM in blue.

[redacted]

Figure 1-57 – Histogram of the volume of Facies (%) Within the [redacted] Across the GME

1.5.4.1 Lower Confining Zone Porosity

A histogram of effective porosity distributions modeled for the LCZ is presented in Figure 1-58, from 0–25% PHIE. The distributions are delineated by facies to illustrate the porosity distributions within each modeled facies of the LCZ.

The majority of the LCZ ([redacted] is comprised of [redacted]. These facies contain an average effective porosity of [redacted] within [redacted] modeling and are anticipated to behave as hydraulic barriers within the zone.

The remaining [redacted] of the LCZ is comprised of grainstone facies that contain an average effective porosity of [redacted]. [redacted] within the [redacted] are anticipated to represent reservoir development, even within the zone. However, the highest [redacted] bed within the [redacted] occurs well below the base of [redacted], separated by approximately [redacted] ft of [redacted] Injection modeling into Tea Olive No. 1 and Flowering Crab Apple No. 1 indicate that the [redacted] will effectively restrict the migration of CO_2 below the injection zone and is sufficient to act as the LCZ across the GME.

[redacted]

Figure 1-58 – Histograms of Modeled Effective Porosity Distributions by Facies Within the LCZ

1.5.4.2 Lower Confining Zone Permeability

A histogram of permeability distributions modeled for the LCZ is presented in Figure 1-59, from 0–1,000 mD. The distributions are delineated by facies to illustrate permeability distributions within each modeled facies of the zone. The modeled permeabilities are facies dependent and were determined from Equations 4 through 7 (*Section 1.5.1.6*) to properly reflect the porosity-permeability transforms developed by [redacted]

The shale, muddy packstone, and packstone facies that comprise the majority of the LCZ [redacted]) contain an average permeability of [redacted] within [redacted] modeling, and are anticipated to behave as hydraulic barriers within the zone. Grainstone facies are present approximately [redacted] below the top of [redacted] and contain an average permeability of [redacted] mD within the GME.

Injection modeling into Tea Olive No. 1 and Flowering Crab Apple No. 1 indicate that the [redacted] will effectively restrict the migration of CO_2 below the injection zone and is sufficient to act as the LCZ across the GME. Core will be collected during the drilling of the stratigraphic test well and analyzed to validate porosity and permeability assumptions modeled for the LCZ. Once complete, the model and permit application will be updated.

[redacted]

Figure 1-59 – Histograms of Modeled Permeability Distributions by Facies Within the LCZ

1.6 Injection Zone Brine Chemistry

A review of chemical analyses of oil-field brines from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database Version 2.3 (Blondes et al., 2018) identified 12 wells with fluid analysis from the [redacted] within the Gulf Coast region. No data was reported for the [redacted] in Texas, therefore water chemistry analyses had to be gathered from oil-field brines collected in [redacted]. The location of these wells is shown in Figure 1-60.

The sampled locations contain a wide range of depths and ion concentrations that were used to generate a scatterplot graph, displayed in Figure 1-61. An apparent quantitative relationship was identified in the data set and used to predict total dissolved solids (TDS) concentrations for depths between [redacted] ft. Results from the water quality investigation are provided in Figure 1-61 and Table 1-16. The data spread suggests that [redacted] fluid should contain TDS concentrations between [redacted] parts per million (ppm) at a depth of [redacted] ft, as indicated by the dashed red line depicted in Figure 1-61. The average salinity from the [redacted] identified Mooringsport samples contained an average TDS of [redacted] ppm, as presented in Table 1-16.

Additionally, petrophysical analysis was conducted on [redacted] wells proximal to the proposed injection site to refine regional data gathered from the USGS and to improve understanding of water salinities within the GME. The apparent resistivity of the water was determined from resistivity and porosity data and utilized to generate TDS estimations for each well. The resulting data set is presented in Table 1-17 and suggests an average salinity of [redacted] ppm for the seven wells. This is in agreement with the results of the regional USGS investigation of [redacted] Formation fluid but with improved resolution relative to the GME. Therefore, a value of [redacted] ppm was established for modeling.

The analysis indicates that the in situ reservoir fluid of the [redacted] is compatible with the proposed injection fluids. Fluid analysis will be conducted on [redacted] fluid samples once the stratigraphic test well has been approved and drilled. The resulting data will improve Aethon's chemical understanding of the formation's water and provide further insight to model potential geochemical interactions following injection.

[redacted]

Figure 1-60 – Produced Water Samples for [redacted] Formation Fluid Characterization

[redacted]

Figure 1-61 – [redacted] Gulf Coast salinity data relative to depth. Data sourced from the USGS National Produced Waters Geochemical Database (Blondes et al., 2018). The red dashed line represents the approximate top of the injection zone.

Table 1-16 – Brine composition of the [redacted] Formation; data sourced from the USGS National Produced Waters Geochemical Database (Blondes et al., 2018).

Species	Concentration	Units
TDS	[redacted]	ppm
Ba	[redacted]	ppm
HCO_3	[redacted]	ppm
Ca	[redacted]	ppm
Cl	[redacted]	ppm
FeTot	[redacted]	ppm
Na	[redacted]	ppm
Mg	[redacted]	ppm
SO_4	[redacted]	ppm
Si	[redacted]	ppm

Table 1-17 – Average [redacted] TDS from Well Log Water-Resistivity Curves

API No.	Rwa	Rwa Temperature	Rwa at 75°F	TDS (ppm)
[redacted]				

*Rwa – water resistivity

1.7 Geochemistry

The mineral-brine-CO_2 interactions that occur during CO_2 sequestration lead to the alteration of the host rock, and eventual equilibrium in the mineral-brine-CO_2 system. Chemical modeling and laboratory experiments show that these reactions and eventual equilibria are driven by the specific mineralogy of the target formation, composition of the brine, acidity of the brine-CO_2 mixture, and pressure and temperature in the subsurface. This section covers the modeling of the mineral-brine-CO_2 system across the mineralogical facies associations present for the proposed TXCCS#1 Project site.

1.7.1 Methods

Simplified, batch kinetic simulations (i.e., models) were created for each facies present at the project site. The models are built to simulate the reactions that occur in the mineral-brine-CO_2 system, contained inside a laboratory reactor vessel as a proxy for the subsurface system. The models use phase thermodynamic data in the PHREEQC Lawrence Livermore National Laboratory Database and reaction kinetics from Palandri and Kharaka (2004) to model the mineral-brine-CO_2 interactions.

Each experiment is isothermal, with the temperature set to match the subject location and depth. The pressure for each simulation is also static and set to match the subject location and depth. The thermodynamic model is based on local equilibrium for the minerals and ions in an aqueous phase. The kinetic calculations assume that abundant CO_2 is supplied to the system during the simulation and that any consumed molecule of CO_2 is replaced. These simplifying assumptions align with the reality of the physical system, in that continuous injection allows for an abundant gas supply to the system.

1.7.2 Brine Geochemistry

The brine composition used for the simulations is derived from the USGS National Produced Waters Geochemical Database, discussed in *Section 1.6*. The database contained [redacted] samples of produced water from [redacted] The available analytical values were averaged to create a composite brine composition used in the mineral kinetics batch models for the injection and confining zones. The composition of the composite brine was shown in Table 1-16.

1.7.3 Mineral Geochemistry

Despite the well-understood nature of the stratigraphy in the vicinity of the subject site, published XRD data across the target formations are relatively scarce. The mineral compositions used in the simulations for the [redacted] were calculated from XRD analysis of [redacted] located in Sabine County, Texas. The mineral composition for the [redacted] Formation was estimated from lithologic descriptions and two core chip samples from [redacted] in Greene [redacted] The smectite-illite ratios in the confining intervals were estimated using the depth and transformation relationship published in Freed (1969). The values used in the simulation experiments are shown in Table 1-18.

Table 1-18 – Simulated Mineral Compositions for Modeling the Injection and Confining Zones

Constituent	Upper Confining Zone	Injection Zone	Lower Confining Zone
Modeled Depth (ft)	[redacted]		
Stratigraphic Unit			
Quartz			
Calcite			
Plagioclase (albite)			
Feldspar (anorthite)			
K-Feldspar			
Smectite			
Illite			
Kaolinite			
Chlorite			
Anhydrite			

1.7.4 Models

Three geochemical models were created—one for each of the injection and confining zones. The injection zone model used the temperature, depth, and pressure at the midpoint of the injection interval. The model for the UCZ used depth, pressure, and temperature estimates from the base of the [redacted] while the LCZ model used estimates from the top of the [redacted].

The reaction processes expected were modeled as a product of thermodynamic equilibrium and kinetic reactions using PHREEQC. The models were created as simplified, 1D batch models that occur at pressure and temperatures dictated by their stratigraphic position. The models assumed a pressure gradient of [redacted] psi/ft and a thermal gradient of [redacted] with a mean annual surface temperature of [redacted] F. The injected volume of CO_2 was assumed to fill the pore spaces.

1.7.5 Results

Across all of the models, the results show mild to moderate reactivity within the mineral-brine-CO_2 system. Reactions begin to occur after a few seconds of contact and accelerate through the first several hundred years of simulation time. From 1,000–10,000 years, the reactions approach equilibrium. The precipitation and dissolution of all mineral constituents of the simulation experiments are shown in Figure 1-62, while the precipitation and dissolution of the minor mineral constituents are shown in Figure 1-63.

In general, the confining zones show precipitation of [redacted] with dissolution and then re-precipitation of [redacted] The [redacted] UCZ shows minor dissolution of calcite along with precipitation of [redacted]. The injection zone shows minor dissolution of [redacted] along with minor precipitation of [redacted]

Overall, the volume of dissolved and precipitated species in the injection zone are minor compared to the overall existing pore volume, which suggests that alteration, dissolution, and precipitation of the mineral species will have limited impact on injection operations. In the confining zones, precipitation of clay minerals is likely to support seal capacity through pore occlusion.

A number of necessary assumptions were used in this modeling work that led to the models overrepresenting the speed and amount of alteration compared to what will occur in the natural system. The equilibrium rates in the subsurface are expected to be much slower than those predicted. This slower rate is primarily due to the reactions taking place within the pore system of a rock volume as opposed to the simulated batch reactor. The pore system influences concentration gradients and decreases the surface area of each mineral available for reaction, leading to slower reaction rates. Furthermore, geologic and hydrologic factors such as fluid flow paths may alter ion availability and system reactivity. Therefore, the modeling work in this section is an analysis of the upper bound of reactivity.

[redacted]

Figure 1-62 – Results of the batch simulations for all mineral constituents, shown by unit. The x-axis is “log10” time in years. The reaction time spans from 0.001 seconds to 10,000 years.

[redacted]

Figure 1-63 – Results for minor mineral phases of the batch, shown by unit. The x-axis is log10 time in years. The reaction time spans from 0.001 seconds to 10,000 years.

1.8 Hydrology

The TXCCS#1 Project is predominantly located within central Sabine County in east Texas and extends to the west, into eastern San Augustine County. Sabine County encompasses approximately 577 square miles, nearly 85 square miles (approximately 15%) of which is covered with water. The cities of Hemphill and Pineland represent the two primary population centers of Sabine County with populations of 1,029 and 888, respectively, as of 2020. San Augustine County comprises an area of approximately 592 square miles, 62 (approximately 10%) of which is covered with water. The cities of Center and San Augustine represent the two primary population centers in the county, with populations of 5,221 and 1,920, respectively, as of 2020.

This section discusses the water resources and hydrology within Sabine and San Augustine Counties. Detailed reports, dissertations, and literature from the Texas Water Development Board (TWDB), USGS, and other peer-reviewed journals conducted in the study area were utilized to build a hydrologic understanding of the region.

1.8.1 Area of Study

The hydrologic review of Sabine and San Augustine Counties identified groundwater potential within one major aquifer, the [redacted], and two minor aquifers, the [redacted] (Bruun et al., 2016). The stratigraphic column presented in Figure 1-64 clarifies the aquifers' relative position in geologic time and regionally associated geologic formations. The maps in Figures 1-65 and 1-66 illustrate the regional extents of major and minor aquifers relative to the TXCCS#1 Project. The schematic cross section provided in Figure 1-67 runs northwest of the project area, illustrating the structure and stratigraphy of the aquifer system over the [redacted] (Bruun et al., 2016).

The interpreted stratigraphic cross section provided in Figure 1-68 illustrates regional correlations of specific [redacted] intervals into Sabine County, just south of the project area (Bruun et al., 2016). The black shading in the figure represents intervals with less than 3,000 ppm TDS and suggests that freshwater potential exists within the [redacted] Formation south of the project.

Historical groundwater quality data from producing aquifers within Sabine and San Augustine Counties is provided in Figure 1-69. According to the TWDB, Sabine County does not fall within any current underground water conservation districts.

[redacted]

Figure 1-64 – Stratigraphic and hydrogeologic units underlying the TXCCS#1 Project (modified from Bruun et al., 2016). Stratigraphic intervals highlighted in blue have freshwater potential in the project vicinity.

[redacted]

Figure 1-65 – The major aquifers of Texas, illustrating the regional extent of the [redacted] aquifer. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

[redacted]

Figure 1-66 – The minor aquifers of Texas, illustrating the [redacted] aquifers' regional extent. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

[redacted]

Figure 1-67 – Schematic cross section over the [redacted]. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

[redacted]

Figure 1-68 – Interpreted well log cross section of shallow geology proximal to the TXCCS#1 Project. The red star and red box approximate the project location (modified from Baker, 1995).

[redacted]

Figure 1-69 – Comparison of groundwater quality in Sabine and San Augustine Counties with U.S. Public Health Service recommended standards. Chemical constituents are in ppm except specific conductance, sodium-adsorption ratio (SAR), and residual sodium carbonate (RSC) (Andres, 1967).

1.8.2 Groundwater Resources

1.8.2.1 [redacted]

The [redacted] aquifer is [redacted] in age and generally composed of [redacted] aquifer and represents the base of the hydrogeologic column at the TXCCS#1 Project site.

According to Bruun (2016), the [redacted] Formations are relatively thick and continuous, and contain increased permeabilities when compared to the [redacted] Formations—which, although they contain [redacted] tend to be [redacted] (Bruun et al., 2016). Therefore, the [redacted] Formations are anticipated to represent the bulk of aquifer potential within the [redacted] aquifer. The [redacted] Formations are anticipated to behave more like leaky aquitards that restrict groundwater movement between high permeability [redacted] deposits.

The [redacted] aquifer [redacted] (Figure 1-65). The aquifer is [redacted] (Figure 1-70). The figure suggests that the top of the [redacted] aquifer occurs at a depth of approximately [redacted] at the Tea Olive No. 1 location and a depth of approximately [redacted] at the Flowering Crab Apple No. 1 location.

The water quality of the aquifer varies with depth and locality but tends to be [redacted] in downdip regions of the aquifer and within deeper stratigraphic intervals. According to a published TDS map of the [redacted]quifer (Figure 1-71), the TDS are generally less than [redacted] milligrams per liter (mg/L) near the TXCCS#1 Project but can reach concentrations up to [redacted] mg/L in [redacted]. [redacted]x groundwater tends to be hard in unconfined areas and is generally softer where confined by the overlying [redacted] Formation.

The primary recharge mechanism is surface recharge from precipitation, but groundwater also interacts with local creeks, streams, and rivers that flow through unconfined portions of the aquifer. This interaction can result in discharge or recharge of groundwater, depending on the water level of the aquifer relative to the stage of the river. According to the 2016 Texas Aquifer Study, the Sabine River along eastern Sabine County has hydraulic communication with the [redacted] aquifer (Bruun et al., 2016).

[redacted]

Figure 1-70 – Subsea structure map of the top of the [redacted]. The red star approximates the Tea Olive No. 1 location; the purple star, the Flowering Crab Apple No. 1 location (modified from Andres, 1967).

[redacted]

Figure 1-71 – Total dissolved solids in the [redacted] aquifer. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

1.8.2.2 [redacted] Aquifer

The [redacted] aquifer has a similar orientation to the deeper [redacted] aquifer and extends from [redacted], approximately 100 miles inland from the Gulf of Mexico. The aquifer is [redacted], as illustrated by the structure map provided in Figure 1-72. According to the map, the top of the [redacted] aquifer occurs at a depth of approximately [redacted] at the Tea Olive No. 1 location and [redacted] at the Flowering Crab Apple No. 1 location. The Sparta Formation consists of massive sand bodies interbedded with silt and clay. The gross thickness of the formation gradually increases from approximately [redacted]. According to the total [redacted] map provided in Figure 1-73, the net [redacted] thickness of the [redacted] Formation is approximately [redacted] within the GME.

[redacted] groundwater is fresh in shallow, unconfined areas and contains an average TDS concentration of [redacted] mg/L; however, water quality tends to deteriorate with depth, and the Sparta aquifer has an average TDS concentration of [redacted] mg/L for saturated depths greater than [redacted] According to the Sparta TDS map provided in Figure 1-74, concentrations in the [redacted] aquifer are generally less than [redacted] mg/L near the project location. The average saturated freshwater thickness of the Sparta aquifer is [redacted] ft (Bruun et al., 2016).

[redacted]

Figure 1-72 – Subsea structure map of the top of the [redacted] (modified from Andres, 1967). The red star approximates the Tea Olive No. 1 location; the purple star, the Flowering Crab Apple No. 1 location.

[redacted]

Figure 1-73 – Total sand thickness in the [redacted] aquifer (modified from Bruun et al., 2016). The red star is the approximate location of the TXCCS#1 Project.

[redacted]

Figure 1-74 – Total dissolved solids in the [redacted] aquifer. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

1.8.2.3 [redacted] Aquifer

The [redacted] unconfined aquifer is [redacted] e and represents the [redacted] water source near the TXCCS#1 Project. [redacted] environments. Freshwater-bearing intervals are associated with [redacted] deposits of the [redacted] that tend to occur in [redacted] areas of the aquifer, shaded tan in Figure 1-75. [redacted] (Bruun et al., 2016).

The saturated freshwater thickness of the [redacted] varies across the extent of the aquifer but averages [redacted] t. The water quality of the aquifer is variable due to changes in composition of aquifer formations but [redacted] This is evidenced by the regional changes seen within the Yegua-Jackson TDS map provided in Figure 1-76. According to the map, the TXCCS#1 Project is located [redacted], where TDS concentrations are generally less than [redacted] mg/L (Bruun et al., 2016).

[redacted]

Figure 1-75 – Extents of the unconfined [redacted] aquifer. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

[redacted]

Figure 1-76 – Total dissolved solids in the [redacted] aquifer. The red star is the approximate location of the TXCCS#1 Project (modified from Bruun et al., 2016).

1.8.3 Surface Water Resources

In 2016, the Texas Commission on Environmental Quality (TCEQ) mapped major river basins and coastal plains of Texas to support the management of surface water resources. The resulting map is presented in Figure 1-77 and clarifies the TXCCS#1 Project location relative to identified surface water resources. San Augustine and Sabine Counties are located within the Sabine River and Neches River basins, signified by reference numbers #5 and #6 in Figure 1-77 (Andres, 1967; TCEQ, 2016). Approximately 80% of Sabine County and 10% of San Augustine County are drained by the Sabine River and its principal tributaries, which include Big Sandy Creek, Sixmile Creek, the Palo Gaucho Bayou, Patroon Bayou, and Housen Bayou (Andres, 1967). The majority of San Augustine County is drained by the Neches River and its principal tributaries, which include the Angelina River, Ayish Bayou, and Attoyac Bayou (Andres, 1967). Surface water accumulations within the Sabine River basin eventually find their way to the man-made Toledo Bend Reservoir, where they are managed for conservation and hydroelectric generation. Most of the surface water that collects within the Neches River basin is captured by the Toledo Bend Dam and Reservoir for a multitude of purposes.

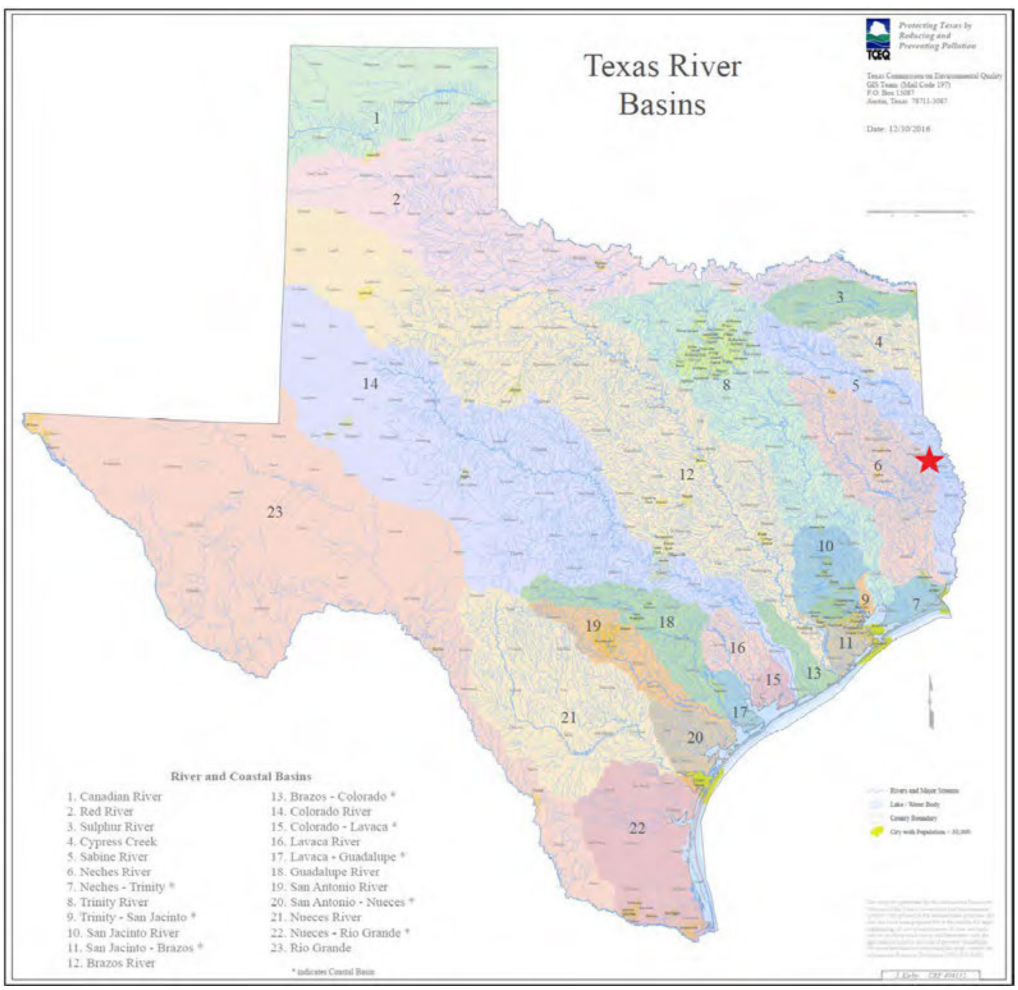

Figure 1-77 – Map of major rivers and coastal basins of Texas (TCEQ, 2016). The red star is the approximate location of the TXCCS#1 Project.

1.8.3.1 Sabine River Basin

The Sabine River basin extends from east Texas into western Louisiana across 9,756 square miles, approximately 7,570 of which is situated in Texas. The river is approximately 360 miles long and represents the Texas-Louisiana border from its headwaters in Hunt County to its eventual departure into the Gulf of Mexico. According to the TWDB, the Sabine River basin produces the second largest watershed yield of all major river basins in the state of Texas, and the Sabine River has the second highest flow volume of any Texas river (5,864,000 acre-ft/year). This is attributed to high rates of precipitation and low rates of evaporation experienced within the region. The use of surface water within the basin is subject to the "Sabine River Compact" between Louisiana and Texas (TWDB).

1.8.3.2 Toledo Bend Reservoir

The Toledo Bend Reservoir is a man-made reservoir formed by the Toledo Bend Dam, located along the Sabine River approximately 80 miles north of Beaumont, Texas. The reservoir is the largest in Texas and encompasses portions of Sabine, Panola, Newton, and Shelby Counties, as well as portions of Sabine and De Soto Parishes in Louisiana. The Toledo Bend Dam was completed in 1969 and is owned by the Sabine River authorities of Texas and Louisiana. The reservoir controls a drainage area of 7,178 square miles used for water conservation and two hydroelectric units capable of generating 80,750 kilowatt hours at total capacity, shared by the neighboring states. According to the TWDB, the Toledo Bend Reservoir stretches more than 100 river miles, has a total storage capacity of 4,661,000 acre-ft, and conserves surface water resources for industrial, agricultural, municipal, and recreational uses.

1.8.3.3 Neches River Basin

The Neches River flows approximately 416 miles from its headwaters in Van Zandt County to its eventual departure into the Gulf of Mexico. The Neches River Basin spans 9,937 square miles of east Texas and has the fourth largest flow volume in the state, with an average flow rate of 4,323,000 acre-ft/year. The basin is an important surface water resource for growing populations situated around its boundaries, therefore environmental needs should be considered during continued or future development of surface water resources within the basin (TWDB).

1.8.3.4 Sam Rayburn Reservoir

The Sam Rayburn Reservoir is a man-made reservoir formed by the Sam Rayburn Dam, located along the Angelina River approximately 10 miles northwest of Jasper, Texas. Congress authorized the dam's construction in 1955 for water conservation, flood control, and hydroelectric power as well as industrial, agricultural, and recreational uses. The dam was completed and the conservation pool achieved in 1966. The dam controls a drainage area of 3,449 square miles and the reservoir is the fourth largest in Texas, with a total storage capacity of 4,442,400 acre-ft.

1.8.4 Hydrology Conclusion

The TRRC's Groundwater Advisory Unit (GAU) identified the base of usable quality water (BUQW) at a depth of [redacted] ft and the base of the underground source of drinking water (USDW) at a depth of [redacted] ft at the Tea Olive No. 1 location—to protect potential freshwater resources identified within the [redacted] aquifers. Structure maps of these aquifer systems, published by Andres in his 1967 report *Ground-water Resources of Sabine and San Augustine Counties, Texas*, indicate that the base of USDW occurs within the [redacted] aquifer near the Tea Olive No. 1 and Flowering Crab Apple No. 1 locations.

According to structural mapping of offset openhole well logs, the top of the [redacted] is anticipated to occur at a depth of [redacted] ft. Therefore, approximately [redacted] gross ft separates the base of the USDW from the top of the injection zone at Tea Olive No. 1. The GAU identified the BUQW at a depth of [redacted] ft and the base of the USDW at a depth of [redacted] ft at Flowering Crab Apple No. 1. The top of the [redacted] is anticipated to occur at a depth of approximately [redacted] ft at Flowering Crab Apple No. 1, with roughly [redacted] ft of gross separation between the top of the injection zone and the base of the USDW. Copies of the GAU's Groundwater Protection Determination and No Harm letters issued by the TRRC as part of the Class II permitting process for Tea Olive No. 1 and Flowering Crab Apple No. 1 are provided in [redacted] A comparison of groundwater quality from producing aquifers within Sabine and San Augustine Counties was provided in Figure 1-69.

Primary upper confinement of the injection zone is provided by low permeability [redacted] facies of the overlying [redacted] Formation, with additional confinement provided by overlying [redacted] Formation and regionally extensive [redacted] Formation. The [redacted] is present below the [redacted]x aquifer, with a gross thickness of approximately [redacted] ft, and represents the base of the hydrogeologic column in Sabine County (Bruun et al., 2016).

1.9 <u>Evaluation of Mineral Resources</u>

1.9.1 Active Mines Near the Proposed Injection Location

A public data search determined that no active or inactive surface mines are located near the proposed site of the TXCCS#1 Project; therefore, no surface mineral impacts will occur from project activities.

1.9.2 Oil and Gas Resources

Oil and gas resources of the TXCCS#1 Project were reviewed by analyzing historic oil and gas exploration within a 2-mile radius of the modeled maximum critical pressure front, as presented in Figure 1-78. The investigation identified a total of [redacted] wells confirmed to be located within the area, of which [redacted] were productive (Table 1-19) and 3 were completed as saltwater disposal wells (SWDs) (Figure 1-78); the remaining wells in the 2-mile radius were dry holes. An additional 3[redacted] well locations were identified within the 2-mile radius that were absent from the TRRC online database, but given placeholder APIs as possible well locations in the Enverus online database—these wells contain little to no data to confirm or deny their existence.

Production within the 2-mile radius was reported from the [redacted] Formations; however, the majority of these producers are located outside the modeled critical pressure front, which represents the boundary of the AOR.

[redacted]

[redacted] horizontal well [redacted] tested the [redacted] interval of the [redacted] within the critical pressure front, approximately [redacted] of the proposed Tea Olive No. 1 and [redacted] of the proposed Flowering Crab Apple No. 1. Records indicate that the well was completed in [redacted], temporarily abandoned in [redacted] and plugged in [redacted] as a dry hole. The horizontal test well landed at a depth of approximately [redacted] ft TVD, roughly [redacted] ft above the proposed injection zone, and did not penetrate any proposed confining intervals of the project. Therefore, the horizontal test well is isolated from the proposed injection zone by the [redacted] (UCZ), [redacted] Formations. The [redacted] produced oil and gas from [redacted] vertical wells within the 2-mile radius [redacted]). These wells are located approximately [redacted] miles [redacted] the modeled critical pressure front and are all currently inactive.

Historic production was also identified within the 2-mile radius from [redacted] horizontal wells landed and completed in the [redacted] member of [redacted] Formation ([redacted]). Production from the [redacted] occurred at a depth of approximately [redacted] ft TVD and is isolated from the proposed injection zone by the [redacted] Formation (LCZ), the regionally extensive [redacted], and a significant reduction in [redacted] reservoir quality present beyond its primary reef extent (Figure 1-78).

Active production was identified from [redacted] horizontal wells landed and completed in the [redacted] located within the 2-mile radius, just [redacted] of the modeled critical pressure front. Production from the [redacted] Formation occurs at a depth of approximately [redacted] TVD, with additional lower confinement provided by thick, regionally extensive shales present within the [redacted].

Lastly, records identified [redacted] wells (Table 1-19) that were completed and commingled production from sands present within the [redacted] Formations. These wells are located approximately [redacted] of the critical pressure front and produce from depths of approximately [redacted] ft TVD. This section is confined from the proposed injection zone by the [redacted].

A significant number of dry holes were drilled within the 2-mile radius of the modeled maximum critical pressure front with only a minimal amount of economic oil and gas development. Productive wells are generally located outside the critical pressure front and occur from intervals much shallower or deeper than the proposed injection zone. Therefore, an analysis of offset production suggests limited oil-and-gas potential in the region and modeling indicates these formations are confined from proposed injection by the following: regionally extensive shales of the [redacted], the LCZ, facies changes present beyond primary [redacted] development, the UCZ, the [redacted] Formations, and the [redacted] Therefore, the general lack of economically viable hydrocarbons identified in the 2-mile radius suggest that the proposed injection and sequestration of CO_2 will not affect future development of oil and gas resources.

[redacted]

Figure 1-78 – Oil and Gas Wells Within 2 Miles of the TXCCS#1 Project Critical Pressure Front

Table 1-19 – Productive Oil and Gas Wells Within 2 Miles of the Modeled TXCCS#1 Project Pressure Front

API No.	Well Name	Well No.	Field	County/Parish	Well Status	Reservoir(s)	Spud Date	First Prod Date	Last Prod Date	Upper Perforation	Lower Perforation
[redacted]											

API No.	Well Name	Well No.	Field	County/Parish	Well Status	Reservoir(s)	Spud Date	First Prod Date	Last Prod Date	Upper Perforation	Lower Perforation
[redacted]											

*P&A – plugged and abandoned

1.10 Seismic History

A crucial factor in designing and developing new injection-well projects is assessing the potential for injection activities to induce seismic events. The proposed TXCCS#1 Project location of central Sabine County and eastern San Augustine County, within the Gulf of Mexico basin, is a tectonically and seismically inactive region. A three-step approach was conducted to assess the potential of induced seismicity within the GME, as follows:

1. Identification of historical seismic events proximal to the project
2. Faulting and determination of operational influences of nearby faults
3. Seismic hazard review

1.10.1 Identification of Historical Seismic Events

Texas tends to experience seismic activity within six primary regions: the Delaware and Midland basins in west Texas; the Fort Worth basin in north Texas; east Texas; the Panhandle; and the Eagle Ford trend in south Texas (Savvaidis, 2022). Figure 1-79 clarifies the location of these seismically active regions relative to the TXCCS#1 Project site. The project's seismically inactive area is located several miles southeast of seismic activity recorded within the east Texas region.

Seismographic recordings from the Texas Seismological Network and Seismology Research (TexNet) database and the USGS's Advanced National Seismic System database were reviewed to identify any seismic events greater than 2.0 magnitude[1] that have historically occurred within a 9.08-km (5.6 mile) radius[2] of the project wells. The nearest recorded seismic event in the USGS database occurred on [redacted], approximately [redacted] (Figure 1-81).

The TexNet and USGS databases did not identify any natural or induced seismic events within a 9.08-km radius of the proposed injection wells, regardless of magnitude (Figure 1-82). The TexNet and USGS seismographic databases are in agreement with the USGS interpretations presented in Figure 1-79, with the closest recorded seismic events having occurred approximately [redacted] of Tea Olive No. 1.

[1] The magnitude of an earthquake is reported using the Richter scale, which measures the amount of energy (i.e., amplitude) generated at the source of an earthquake.
[2] Texas Railroad Commission Fault Slip Potential Area of Interest Standard under the Seismicity Review.

[redacted]

Figure 1-79 – Seismically active areas in Texas. The red star is the approximate location of the TXCCS#1 Project (Savvaidis, 2022).

[redacted]

Figure 1-80 – Regional Seismicity Review (USGS – 11/3/2024). The red star approximates the Tea Olive No. 1 location; the purple star, the Flowering Crab Apple No. 1 location; and the gray circle represents the nearest USGS-recorded event.

[redacted]

Figure 1-81 – Regional Seismicity Review (TexNet – 11/3/2024). The red circle represents the 9.08-km radius from Tea Olive No. 1; the purple circle, the same radius from Flowering Crab Apple No. 1.

[redacted]

Figure 1-82 – Local Seismicity Review Map with Nearby Seismic Monitoring Stations

1.10.2 Faults and Influence

Regional Gulf Coast faulting in Texas is dominated by [redacted]-trending normal faults resulting from subsidence associated with the formation of the Gulf of Mexico basin (Galloway, 2008). Figure 1-83 identifies the TXCCS#1 Project GME relative to the modeled plume extents, critical pressure front, Gulf Coast fault data published by the USGS (2004), and published extent of the [redacted] The map clarifies the low degree of faulting near the GME relative to regional Gulf Coast faults mapped by the USGS.

The GME is situated along the [redacted], approximately [redacted] of the [redacted] [redacted], as depicted in Figure 1-84 [redacted] These structural features represent the only potential faulting identified in published literature near the GME, and 3D structural modeling did not detect any faulting or large-scale thickness changes within the extent of the modeled plumes or pressure front.

The edge of the modeled pressure front tends to follow the edge of the [redacted] due t[redacted] observed and modeled within the GME. Primary reservoir development occurred along the p[redacted] as illustrated in the cross section in Figure 1-85. As a result, modeled injection is anticipated to experience a [redacted] beyond the [redacted]f that will restrict the migration of CO_2 outside of primary reservoir facies. The edge of the pressure front and platform margin are located approximately [redacted] miles from the published location of the [redacted], and the maximum pressure up against the [redacted] Therefore, the forecasted seismic risk is considered relatively low and neither fault slip potential (FSP) nor fault seal analysis (FSA) modeling were conducted for the TXCCS#1 Project.

[redacted]

Figure 1-83 – Regional map depicting the Gulf Coast faulting (USGS, 2004) [redacted] relative to the [redacted] (the dashed line; [redacted] 1993), TXCCS#1 Project GME (in purple), modeled plume extents (black), and modeled critical pressure front (pink).

[redacted]

Figure 1-84 – Gulf Coast fault map illustrating the [redacted] (USGS, 2004) and [redacted] relative to the [redacted] (the dashed line; [redacted] modeled extents of the TXCCS#1 Project (in purple), modeled plume extents (black), and modeled critical pressure front (pink).

[redacted]

Figure 1-85 – North-to-south schematic cross section through the Gulf Coast region [redacted]
The red stars represent the approximate location of the TXCCS#1 Project.

1.10.3 Seismic Hazard

A seismic hazard analysis was conducted for the TXCCS#1 Project using the EPA-recommended tools and maps provided in the 2023 U.S. National Seismic Hazard Model (NSHM)—which integrated and updated models previously published in the 2018 NSHM, including the following: population density estimates, seismic catalogs, soil-amplification factors, amplified-shaking estimates, fault and ground-motion modeling, and the resulting seismic hazard calculations. According to the 2023 Modified Mercalli Intensity[3] (MMI) earthquake hazard map provided in Figure 1-86, there is a 2% chance that peak ground accelerations will be surpassed in 50 years. Furthermore, in that same time span, a Class V[4] earthquake is most likely to impact east Texas per the 2023 model (Figure 1-86). Figure 1-87 illustrates the likelihood of a minor damaging earthquake to occur within the United States in 100 years. The map indicates east Texas has a 5–25% chance of experiencing a Class VI[5] earthquake within the next 100 years. In terms of 10,000 years, Figure 1-88 suggests that fewer than two damaging earthquakes[6] will occur in east Texas. Therefore, the 2023 NSHM and referenced maps suggest that the TXCCS#1 Project is located within the second lowest seismic hazard area in United States.

<u>Natural Hazards</u>

In terms of natural hazards, Sabine and San Augustine Counties are considered "Very Low" based on the National Risk Index (Figures 1-89 through 1-92), which considers expected annual loss due to 18 different hazard types: Avalanche, Coastal Flooding, Cold Wave, Drought, Earthquake, Hail, Heat Wave, Hurricane, Ice Storm, Landslide, Lightning, Riverine Flooding, Strong Wind, Tornado, Tsunami, Volcanic Activity, Wildfire, and Winter Weather.

[3] The MMI scale ranges from I to XII. The following summaries were gathered from the USGS Earthquake Hazards Program:

[4] Class V: "…moderate; felt by nearly everyone; many awakened: Some dishes and windows are broken. Unstable objects are overturned. Pendulum clocks may stop."

[5] Class VI: "…strong; felt by all, and many are frightened. Some heavy furniture is moved; a few instances of fallen plaster occur. Damage is slight."

[6] *Damaging earthquake*: shaking; a level VI or higher that results in structural failure.

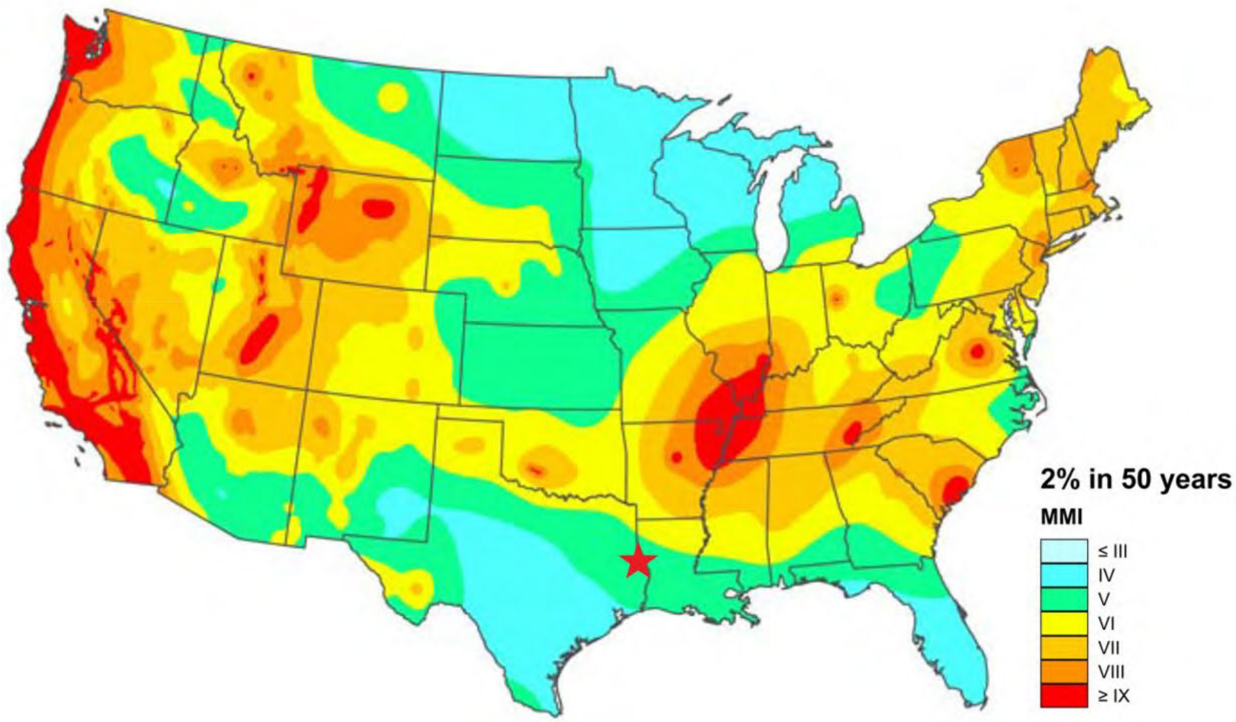

Figure 1-86 – Total mean hazard map for 2% probability of exceedance in 50 years. The red star approximates the location of the TXCCS#1 Project (modified from Petersen et al., 2024).

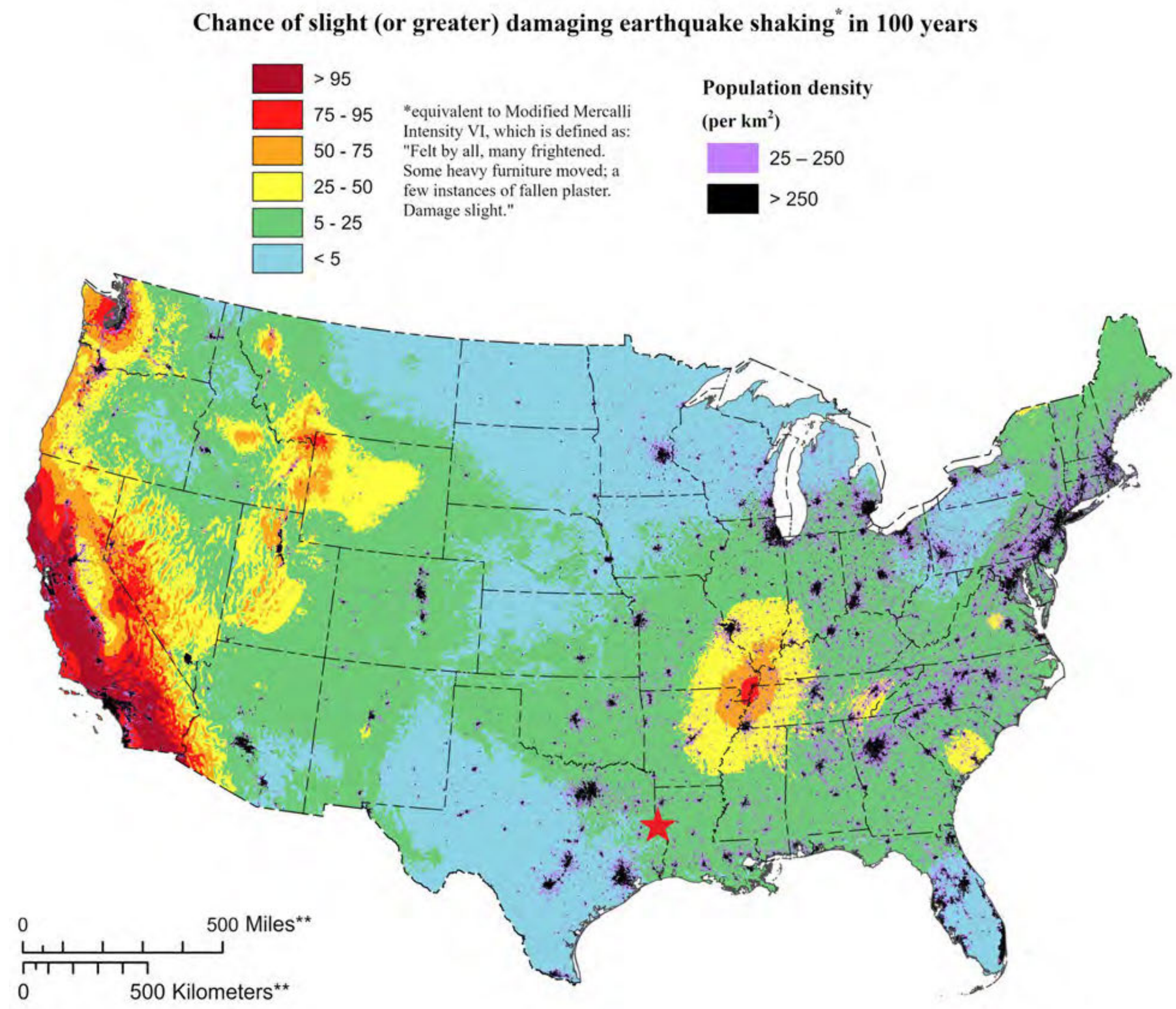

Figure 1-87 – Chance of slight (or greater) damaging earthquake shaking in 100 years–based on MMI of Class VI or greater. The red star approximates the TXCCS#1 Project location (modified from Petersen et al., 2024).

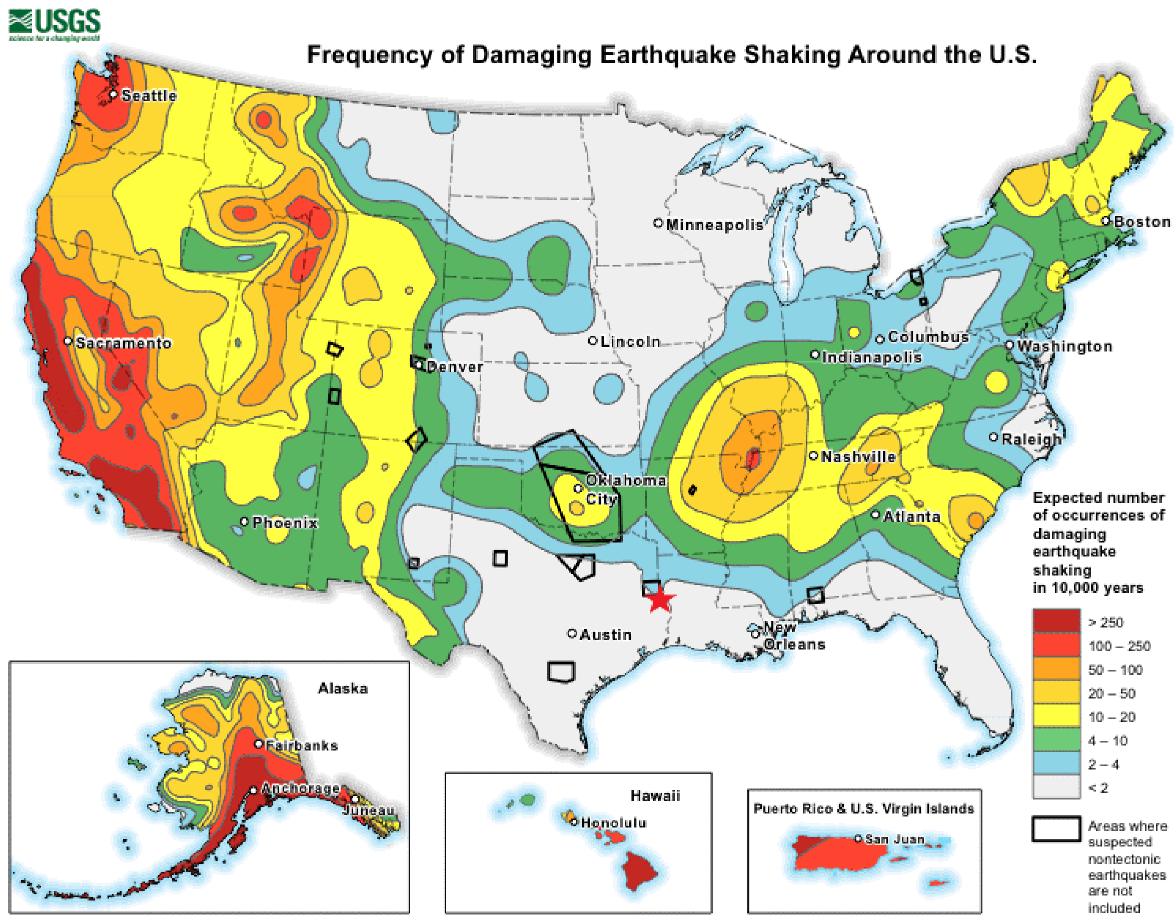

Figure 1-88 – Frequency of damaging earthquake shaking around the United States. The red star approximates the TXCCS#1 Project location (USGS, "Frequency of Damaging Earthquake Shaking Around the U.S.").

[redacted]

Figure 1-89 –National Risk Index Map of Sabine County. The red star approximates the TXCCS#1 Project location (FEMA, 2024).

[redacted]

Figure 1-90 – National Risk Index Map of San Augustine County. The red star represents the approximate location of the Aethon TXCCS#1 Project (FEMA, 2024).

Hazard Type	Risk Index Rating	Risk Index Score	National Percentile
Avalanche	Not Applicable	--	
Coastal Flooding	Not Applicable	--	
Cold Wave	Very Low	27.7	0 100
Drought	No Rating	0	0 100
Earthquake	Very Low	27.5	0 100
Hail	Very Low	32.4	0 100
Heat Wave	Relatively Low	62.3	0 100
Hurricane	Relatively Low	67.4	0 100
Ice Storm	Relatively Moderate	66.3	0 100
Landslide	Relatively Low	55.4	0 100
Lightning	Relatively Low	28	0 100
Riverine Flooding	Very Low	6.5	0 100
Strong Wind	Relatively Moderate	76	0 100
Tornado	Relatively Low	40.6	0 100
Tsunami	Not Applicable	--	
Volcanic Activity	Not Applicable	--	
Wildfire	Relatively Low	64.5	0 100
Winter Weather	Very Low	3.3	0 100

Figure 1-91 – National Risk Index Scores for Sabine County (FEMA, 2024).

Hazard Type	Risk Index Rating	Risk Index Score	National Percentile
Avalanche	Not Applicable	--	
Coastal Flooding	Not Applicable	--	
Cold Wave	No Rating	0	0 100
Drought	No Rating	0	0 100
Earthquake	Very Low	24.7	0 100
Hail	Very Low	27.3	0 100
Heat Wave	Relatively Low	57.2	0 100
Hurricane	Relatively Low	64.3	0 100
Ice Storm	Very Low	22.5	0 100
Landslide	Relatively Low	61.6	0 100
Lightning	Relatively Low	29.9	0 100
Riverine Flooding	Relatively Low	39	0 100
Strong Wind	Relatively Moderate	70.4	0 100
Tornado	Relatively Low	39.5	0 100
Tsunami	Not Applicable	--	
Volcanic Activity	Not Applicable	--	
Wildfire	Very Low	58.9	0 100
Winter Weather	Very Low	3.7	0 100

Figure 1-92 – National Risk Index Scores for San Augustine County (FEMA, 2024).

1.11 Conclusion

Nearby core data was integrated with openhole log data to approximate the petrophysical properties of the injection and confining zones within the GME for the proposed TXCCS#1 Project. Modeled lithologic and petrophysical properties of the [redacted] Formation at the project location agree with the findings of regionally published literature and suggest that the injection reservoir provides sufficient pore space required to store the modeled and proposed CO_2 volumes. The [redacted] Formation is anticipated to exhibit low permeability throughout the gross overlying section, with sufficient thickness and lateral continuity to serve as the upper confining zone. The low permeability, low porosity [redacted] facies of the [redacted] Formation that immediately underly [redacted] development are unsuitable for fluid migration and serve as the lower confining zone.

A thorough evaluation of faulting in the area did not identify any within the target intervals of the GME or modeled [redacted] Upon the drilling of the stratigraphic test well, additional data will be gathered and analyzed to ensure that the project site maintains a low-risk status for CO_2 injection and storage.

The following attachments are in *Appendix B:*

Appendix B-1	Top Upper Confining Zone Structure
Appendix B-2	Top Injection Zone Structure
Appendix B-3	Top Lower Confining Zone Structure
Appendix B-4	Upper Confining Zone Isochore
Appendix B-5	Injection Zone Isochore
Appendix B-6	Lower Confining Zone Isochore
Appendix B-7	W-E Structural Cross Section
Appendix B-8	N-S Structural Cross Section
Appendix B-9	W-E Stratigraphic Cross Section
Appendix B-10	N-S Stratigraphic Cross Section
Appendix B-11	Cross Section Reference Map

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Underground Injection Control – Class VI Permit Application for

Tea Olive No.1 and Flowering Crab Apple No.1

Sabine and San Augustine Counties, Texas

SECTION 2 – PLUME MODEL

July 2025

SECTION 2 – PLUME MODEL

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2.1 Introduction

The following discussion of the plume model used for Tea Olive No. 1 and Flowering Crab Apple No. 1, the proposed injection wells of the Aethon Energy Operating LLC (Aethon) TXCCS#1 Carbon Sequestration Project (TXCCS#1 Project), was prepared to meet the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(d)** (Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84**). This section describes the key details of the reservoir model. The plume defines the pore space rights, area of review (AOR) for the well, monitoring plans, Corrective Action Plan as necessary, and overall viability of the project. Both ***Section 3 – Area of Review and Corrective Action Plan*** and ***Section 5 – Testing and Monitoring Plan*** use the forecasted plume to help determine the best strategies and plans to minimize the impact of carbon sequestration.

The primary objectives of the plume model are as follows:

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

2.2 Project Summary

The TXCCS#1 Project, located in Sabine and San Augustine counties, Texas, will be developed by Aethon through underground storage easements. The easements encompass approximately [redacted] acres, [redacted] of which are intended to be used for carbon capture and sequestration (CCS) operations related to this Class VI permit application—for Tea Olive No. 1 and Flowering Crab Apple No. 1. The plume modeling is specific to these proposed injection wells, which were included in the reservoir model to capture their interaction with each other. Each well will be constructed to inject at a maximum rate of [redacted] million metric tons per year (MMT/yr), but are only expected to take approximately [redacted] MMT/yr. Tea Olive No. 1 and Flowering Crab Apple No. 1 are planned to inject for [redacted] years concurrently, resulting in a maximum of [redacted] MMT of supercritical CO_2 being safely sequestered.

2.2.1 Software

The static geocellular model was built in SLB's Petrel™ software using 3D seismic data, offset well logs, core data, and publicly available literature. These data sources were incorporated into the Petrel model to build the structure and enhance the heterogeneity of the reservoir. Once built, the static model was input into Rock Flow Dynamic's tNavigator Version 24.2 (tNav) simulator for dynamic simulation. *Section 2.4* describes in detail how the static geocellular model was built, while *Section 2.5* explains what inputs were used to build the dynamic model.

2.2.1.1 SLB's Software Suite – Petrel

The Petrel E&P software (ver. 2023.4.0) was chosen to create a detailed geocellular model for the CCS site. This state-of-the-art software is used worldwide and combines information from logs and seismic data to build an accurate representation of an underground reservoir. The resulting Petrel-developed geocellular model shows the different layers of the project site, including the [redacted] Formation (upper seal), [redacted] Formation (injection zone), [redacted] Formation (lower seal), and [redacted] Formation (secondary lower seal). The facies, permeability, and porosity properties of the injection zone were distributed, considering well-log analysis and established methods. These methodologies ensure a representative depiction of the reservoir in the model.

2.2.1.2 Rock Flow Dynamics' Software Suite – tNavigator

The geocellular model was developed in Petrel and then input into tNav—a leading reservoir management platform integrating all necessary tools for dynamic simulation, data analysis, and reservoir optimization within a unified environment. The simulator is a widely recognized tool for modeling compositional fluid flow in conventional and unconventional reservoirs. Its compositional fluid flow simulator efficiently models complex chemical and physical processes, supporting applications such as CCS.

The simulator's robust capabilities include dual porosity and dual permeability (DPDP) modeling, geomechanics, and advanced fluid property management. Furthermore, tNav simplifies reservoir management with built-in tools for relative permeability modeling, Special Core Analysis (SCAL) data integration, and real-time visualization, making it an ideal solution for both conventional and unconventional reservoir applications. The software can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

2.2.2 Data Sources

Constructing the geocellular and dynamic model involved the use of 3D seismic data, offset well logs, core data, and publicly available literature, such as peer-reviewed papers of the Society of Petroleum Engineers (SPE), Bureau of Economic Geology (BEG), and American Association of Petroleum Geologists (AAPG).

The comprehensive review of public databases and literature was carried out at both regional and site-specific levels. At the regional level, major trends within the project area and its surroundings were identified. These trends were then compared to more site-specific data to increase confidence in the reservoir properties. Using nearby offset well data, trends in reservoir salinity and temperature were estimated. Additionally, regional data pointed toward analogous reservoirs to incorporate into the model. Key properties like rock compressibility and relative permeability were gathered from the publicly available literature. These assumptions are further discussed in *Section 2.5.2*.

Offset log analyses were conducted to further characterize the reservoir and populate the geocellular model. Open hole log data included various analyses such as gamma ray (GR), spontaneous potential (SP), resistivity, porosity (sonic, neutron, density), photoelectric factor, caliper, and other related analyses. These well logs helped determine formation tops, rock properties, and temperature gradients. Petrophysical analyses were performed on [redacted] wells in the TXCCS#1 Project vicinity to assess the target injection zone and confining zones.

To enhance the characterization of the reservoir, 3D seismic data was used in conjunction with formation tops identified through log analysis—to identify major structural horizons as shown in Figure 2-1. The 3D seismic data also offered improved clarity of the subsurface, aiding in the identification of major structural horizons, as well as any structural alterations like faults, salt domes, or other subsurface changes, none of which were found. This data enhanced the accuracy of the geocellular model by providing a clearer understanding of the targeted stratigraphy.

[redacted]

Figure 2-1 – Major stratigraphic units in the geologic model displayed in a southwest-northeast section.

Analogous core data was used to determine the porosity-permeability relationship in the [redacted] Formation. Core data from two wells, the [redacted], located within the geocellular model extent, and the [redacted], located roughly [redacted] miles from the model's [redacted] boundary, were used to calculate the porosity-permeability relationship. The relationship was also guided by literature from analogous formations [redacted] Site-specific data will be collected after this permit application is submitted. Tea Olive No. 1 will be drilled as a stratigraphic test well to gather core, fluid samples, and a full suite of geophysical logs as outlined in ***Section 4 – Well Construction and***

Design. The inclusion of the additional data will further increase the accuracy of the model and simulation results.

2.3 <u>Trapping Mechanisms</u>

In the context of a CCS project, four mechanisms are key for trapping and storing supercritical CO_2, as illustrated in Figure 2-2. The following sections will cover structural and stratigraphic trapping, residual trapping, solubility trapping, and mineral trapping mechanisms. All of the mechanisms except for mineral trapping are present in the current model.

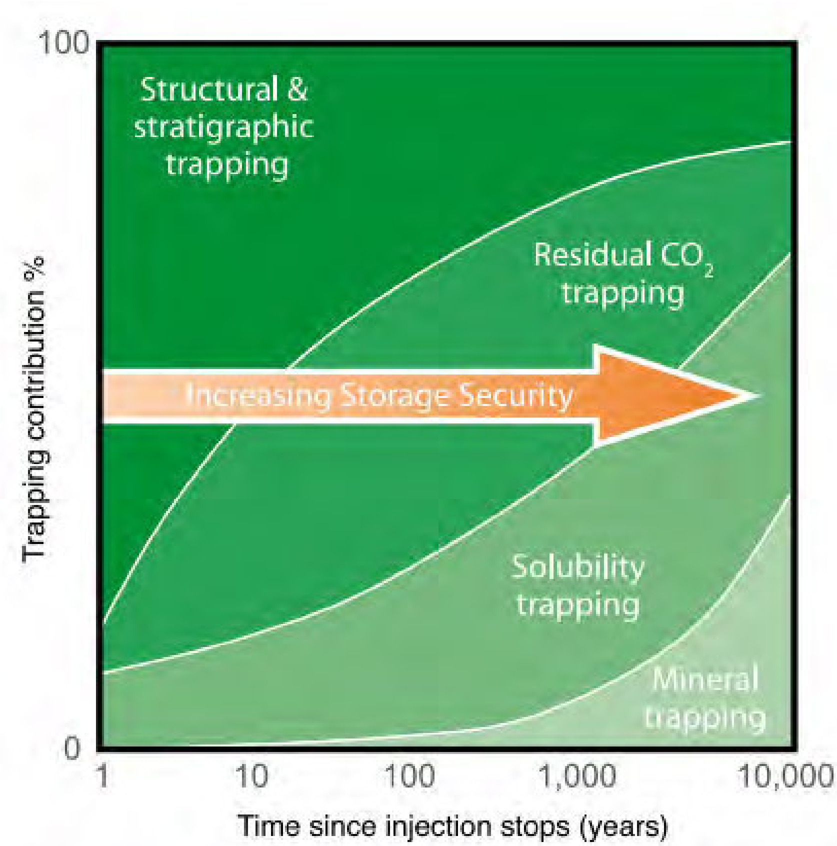

Figure 2-2 – CO_2 Storage Mechanisms (Metz et al., 2005)

2.3.1 Structural and Stratigraphic Trapping

Structural and stratigraphic trapping mechanisms play a crucial role in the initial containment of supercritical CO_2 during and after injection in CCS projects. These mechanisms rely on geological features such as sealing faults, pinchouts, and other geologic traps that physically immobilize the injected CO_2, much like the process in natural hydrocarbon reservoirs where fluids accumulate in anticlinal folds. In the early phases of injection, structural and stratigraphic trapping prevents the vertical migration of CO_2, ensuring its containment within specific geological formations. For this project, the CO_2 is confined by [redacted] facies such as [redacted], which serve as an effective barrier, halting any further upward and lateral movement.

Supercritical CO_2, which is less dense and more mobile than the surrounding brine, will naturally rise within the reservoir until the buoyant forces are countered by the capillary entry pressure of the confining zone. The density of the CO_2 in this model varies, ranging from [redacted] pounds per cubic foot (lb/ft^3) in shallower injection stages to [redacted] lb/ft^3 in deeper stages, while the surrounding brine has a higher density of [redacted] lb/ft^3. Over time, structural trapping may give way to more permanent trapping mechanisms, such as solubility and mineral trapping, as CO_2 becomes more chemically stable within the subsurface environment.

To accurately predict the phase behavior and properties of the injected CO_2, an equation of state (EOS) is used. In this case, the [redacted] EOS was selected for its effectiveness in modeling volumetric and phase equilibria, though other well-established methods like Soave-Redlich-Kwong (SRK) are also commonly applied. This EOS allows for precise calculations of CO_2 density at various pressures and temperatures throughout the injection process.

2.3.2 Residual Trapping

Residual trapping is a critical mechanism in CCS that immobilizes CO_2 within the pore spaces of rock formations. As CO_2 is injected into the reservoir, it displaces the formation brine during a process known as drainage, where the non-wetting CO_2 fills the pore space. However, as the CO_2 migrates, capillary forces prevent the complete displacement of brine, leaving small pockets of CO_2 behind. Once the injection process stops, imbibition occurs, where brine reenters the pore spaces, trapping the disconnected CO_2. This residual CO_2 becomes immobilized and cannot flow or migrate.

The hysteresis effect plays a crucial role in residual trapping by influencing the capillary pressure-saturation relationship during drainage and imbibition. In drainage, a higher capillary pressure is required to displace brine with CO_2, whereas during imbibition, less pressure is needed for brine to reenter the rock and trap the CO_2. Due to hysteresis, not all of the injected CO_2 can be displaced when brine returns, leaving behind disconnected “pockets” of CO_2 that become residually trapped. This difference between drainage and imbibition, as represented by the hysteresis loop, ensures that a significant portion of CO_2 remains trapped in the pore spaces, contributing to the long-term stability and effectiveness of the CCS strategy.

To accurately predict the amount of supercritical CO_2 that remains residually trapped, hysteresis is implemented into the simulation model. The tNav software offers several methods to determine residual trapping, such as the Carlson, Analytical Carlson, Killough, and Jargon models. The [redacted] was implemented for this simulation due to (1) its use being validated for water-alternating-gas (WAG) injection and (2) its ability to model a two-phase system (Carlson, 1981). The critical parameter—residual (trapped) gas saturation—will be discussed in *Section 2.5.3*.

2.3.3 Solubility Trapping

Solubility trapping is a chemical form of trapping where injected supercritical CO_2 dissolves into the surrounding formation brine. When CO_2 dissolves in brine, it forms a denser solution than the in situ connate brine, causing the CO_2-rich brine to sink within the formation. This sinking action helps stabilize the dissolved CO_2 and reduces the likelihood of upward fluid migration, effectively trapping the CO_2 within the subsurface.

The efficiency of solubility trapping depends on several factors, including the salinity, pressure, and temperature of the surrounding brine, which influence both the solubility of CO_2 and the rate of dissolution. Although solubility trapping occurs alongside other mechanisms like structural and residual trapping, it is typically a slower process—able to take hundreds to thousands of years to surpass residual trapping as the dominant mechanism for immobilizing CO_2 in a reservoir (Figure 2-2). During the project's proposed monitoring period, solubility trapping is third after residual trapping and—the primary trapping mechanism—structural trapping, based on the dynamic plume model (Figure 2-42).

For solubility modeling, tNav offers up to seven options for CO_2 injection tasks. Each task has a different application determined by the type of formation, the injectate composition, and the phases present during the simulation. For this model, the [redacted] was chosen due to its ability to model injection into saline aquifers, a multiple-component injection (CO_2, CH_4 (methane), etc.), and the effect of temperature and salinity on the solubility.

2.3.4 Mineral Trapping

Mineral or geochemical trapping is another form of chemical trapping that occurs due to reactions between CO_2 and the geochemistry of the formation. During injection of CO_2 into the reservoir, four primary drivers interact with each other: (1) CO_2 in supercritical phase, (2) in situ hydrochemistry of the connate brine, (3) aqueous CO_2, and (4) the geochemistry of the formation rock. The interaction of these components results in CO_2 often being precipitated out as a newly formed mineral—typically calcium carbonate ($CaCO_3$), also referred to as limestone.

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

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

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

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

While geochemical trapping, or mineral trapping, plays a significant role in securely storing CO_2 over hundreds to thousands of years, its short-term impact is minimal. In the early stages, fluid movement within the reservoir is dominated by hydrodynamic and solubility trapping mechanisms. Incorporating geochemical trapping into the current model was not feasible due to limited data on the mineral compositions and reservoir components, as well as the computational burden that such modeling imposes. As more detailed geochemical data become available, sensitivity analyses can be performed to assess the long-term significance of mineral trapping and its contribution to CO_2 storage stability.

2.4 Static (Geocellular) Model

2.4.1 Geologic Model Development

The geocellular model was designed to include the 3D seismic survey and expanded to include the area where seven 2D seismic lines and log data are available to provide the comprehensive data set. The model area was sufficiently expanded beyond the expected plume and pressure front to minimize the use of grid-edge multipliers or external analytical aquifers during the plume modeling. The model covers approximately [redacted] acres ([redacted] square miles), and ranges from [redacted] ft in depth.

Figure 2-3 summarizes the distribution of well log and seismic data as well as the extent of the 3D geocellular model, shown on the map as the area of interest (AOI). There are [redacted] wells within the model boundary. Up to [redacted] wells with formation tops (Table 2-1) were used jointly with 2D and 3D seismic data to construct the structural framework of the model (Table 2-2). Up to [redacted] wells with logs were used for property modeling (Table 2-3), [redacted] of which are within the 3D seismic survey.

[redacted]

Figure 2-3 – Project area map, showing seismic and well data coverage, and the geomodel boundary. The orange line shows the well cross section for Figure 2-7.

Geocellular model construction includes the following major steps:

- Building the structural framework and creating the 3D grid
- Distributing facies and properties through the model

The Petrel E&P software was used to generate the geocellular model for the project. Chosen for its seamless integration from seismic and well log interpretation to geocellular modeling to reservoir simulation, this software enables accurate modeling of the reservoir and confining systems.

2.4.2 Structural Framework

The structural model was based on the interpretation of 2D and 3D seismic and formation tops. [redacted] Table 2-1 summarizes the model horizons and sources used to generate them. The structural model is shown in Figure 2-4.

Table 2-1 – Model horizons and number of wells with formation tops used, along with 2D and 3D seismic horizons.

Horizon Name	Well Tops Used	Seismic Horizon Used?
[redacted]		

[redacted]

Figure 2-4 – 3D View of the Structural Model

Using this structural model, the 3D grid was created with horizontal cell dimensions of [redacted]. Vertically, a proportional layering method was applied, leading to the vertical cell dimensions with an average of [redacted] ft. Table 2-2 provides a summary of the model zones and their gridding parameters. The number of grid cells in the constructed model totaled [redacted]. The structure contour tops for the upper and lower confining zones are shown in Figures 2-5 and 2-6, respectively. The contours are shown within the geocellular model boundary, indicated by the red box.

Table 2-2 – Model Zones and Their Gridding Parameters

Model Zone	Top	Base	No. of Layers	Mean Thickness (ft)	No. of Cells
Upper Confining	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lower Confining	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Figure 2-5 – Structural Map for the Top of the [redacted] – Top of the UCZ

[redacted]

Figure 2-6 – Structural Map for the Top of the [redacted] – Top of the LCZ

2.4.3 Rock Property Distribution

Property modeling is a process of filling the cells of the grid with discrete or continuous properties. The target is to use all available geological information to build a realistic property model. [redacted] wells were used for regional-scale facies trend maps (Table 2-3), and four facies types were interpreted in the model AOI. Facies and porosity-permeability relationships were developed during the petrophysical study and guided by [redacted] estimating permeability in [redacted] using the rock-fabric methods published by the BEG.

The following facies were interpreted:

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

Porosity logs were derived during the petrophysical analysis. The number of wells with porosity depends on available logs and varies per zone (Table 2-3). Preference was put on the density porosity and then sonic logs, where available. In the absence of the open hole porosity data, a resistivity to porosity transform was also developed and utilized to predict porosity.

Figure 2-7 uses a cross section of five offset wells (Figure 2-3 containing the location) to show an example of a facies log interpretation. The interpreted logs were then upscaled for use in the property model and the information obtained from the seismic-and-log-data facies distribution analysis. Figure 2-7 also shows also the calculated, upscaled porosity and permeability.

Table 2-3 – Model zones and number of wells with interpreted facies and porosities for property modeling.

Model Zone	Wells with Facies Interpretation	Wells with Porosity Interpretation
Upper Confining	[redacted]	
Injection		
Lower Confining		

[redacted]

Figure 2-7 – Well cross section example, showing facies, porosity, and permeability interpretation (location shown in Figure 2-3).

The regional facies (Figure 2-8) and maximum porosity (Figure 2-9) distribution trends based on the well logs were used in conjunction with variogram trends for each zone, to distribute facies and properties within the model layers. Vertical variograms (Figure 2-10) were calculated for facies and porosities based on well logs. Horizontal variograms were estimated using geologic concepts, well logs, and available 3D seismic data. Tables 2-4 and 2-5 present the variogram parameters for the injection and confining zones for facies and porosity distribution, respectively.

[redacted]

Figure 2-8 — Regional probability distribution trends for [redacted] facies in the injection zone ([redacted] Formation).

[redacted]

Figure 2-9 — Maximum porosity distribution trend for [redacted] facies in the injection zone ([redacted] Formation).

[redacted]

Figure 2-10 – Example of vertical variogram estimated from well log data for [redacted] of the injection zone.

Table 2-4 – Facies Distribution: Variogram Parameters for the Model Zones

Zone	Variogram Parameters	[redacted]
Upper Confining	Azimuth (degrees)	
	Major Direction (ft)	
	Minor Direction (ft)	
	Vertical Direction (ft)	
Injection	Azimuth (degrees)	
	Major Direction (ft)	
	Minor Direction (ft)	
	Vertical Direction (ft)	
Lower Confining	Azimuth (degrees)	
	Major Direction (ft)	
	Minor Direction (ft)	
	Vertical Direction (ft)	

Table 2-5 – Porosity Distribution: Variogram Parameters for the Model Zones

Zone	Variogram Parameters	[redacted]
Upper Confining	Azimuth (degrees)	
	Major Direction (ft)	
	Minor Direction (ft)	
	Vertical Direction (ft)	
Injection	Azimuth (degrees)	
	Major Direction (ft)	
	Minor Direction (ft)	
	Vertical Direction (ft)	
Lower Confining	Azimuth (degrees)	
	Major Direction (ft)	
	Minor Direction (ft)	
	Vertical Direction (ft)	

The facies analysis also included an estimation of the facies' vertical proportion curves (VPCs) within the injection and confining zones based on the upscaled logs (Figure 2-11). The VPCs were used as an additional constraint in the property modeling, and the facies were distributed throughout the model using the sequential indicator simulation algorithm. The results of the output are presented in Figures 2-12 (the 3D model) and 2-13 (cross-sectional view from the 3D model). Figure 2-14 shows a facies distribution histogram indicating that log values were accurately preserved during the upscaling and model construction.

[redacted]

Figure 2-11 – Facies and vertical proportion curves for (a) upper confining, (b) injection, and (c) lower confining zones.

[redacted]

Figure 2-12 – 3D Model: Facies Distribution

[redacted]

Figure 2-13 – 3D Model: Facies Distribution – Cross-Sectional View

[redacted]

Figure 2-14 – Histogram comparing injection zone facies from raw logs, upscaled logs, and 3D property model ([redacted]).

The facies-dependent porosity-permeability relationships were derived using available core data from the [redacted] and [redacted] wells. The aforementioned BEG study [redacted] was also utilized. Figure 2-15 shows the porosity-permeability transform implemented in the model.

[redacted]

Figure 2-15 – Porosity-permeability transform used in the model, based on the [redacted] and [redacted] wells and a[redacted]

The derived relationships for permeability (in millidarcy (mD)) as a function of fractional porosity in each of the four facies are presented in Equations 1 through 4:

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

Minimum permeability was set to [redacted] and maximum permeability capped at [redacted].

Porosities were conditioned to facies and distributed using the Gaussian random function simulation algorithm. The results of the output are shown in Figures 2-16 (3D model, porosity and permeability distributions), 2-17 (cross-sectional, porosity distribution), and 2-18 (cross-sectional, permeability distribution). Figure 2-19 shows a porosity-distribution histogram indicating that log values were accurately preserved during the upscaling and model construction.

[redacted]

Figure 2-16 – 3D Model: (a) Porosity and (b) Permeability Distributions

[redacted]

Figure 2-17 – 3D Model: Porosity Distribution, Cross-Sectional View

[redacted]

Figure 2-18 – 3D Model: Permeability Distribution, Cross-Sectional View

[redacted]

Figure 2-19 – Histogram comparing injection zone porosity from raw logs, upscaled logs, and 3D property model.

2.5 Dynamic Plume Model

2.5.1 Model Orientation and Gridding Parameters

Spatial Conditions

As discussed in *Section 2.2.1.2*, tNav uses as an input the Petrel geocellular model, which encompasses approximately [redacted] acres (approximately [redacted] square miles)—capturing available well control and seismic data in and around the TXCCS#1 Project boundary. By incorporating information from well logs and seismic data encompassing an area larger than the project boundary, the geologic characterization of the reservoir is enhanced.

Once the geocellular model is imported into tNav for dynamic modeling purposes, the large grid size allows for the pressure and plume extents to be fully captured and not constrained by the lateral extent of the grid. At its greatest extent, the grid extends [redacted] grid cells in the x-direction, [redacted] grid cells in the y-direction, and [redacted] grid cells in the z-direction. Roughly [redacted] grid cells are modeled at [redacted] in the x and y-directions, and varying thicknesses with an average vertical resolution of [redacted] ft.

To improve computational efficiency, a pore volume cutoff of [redacted] reservoir barrels ([redacted] cubic feet (ft^3) of pore space) per grid block was implemented, and the grid was reduced by [redacted] blocks, bringing the total grid cells to [redacted] cells. Any grid cell with less pore space than the cutoff would be nulled from the model simulation. After this cutoff was applied, the resulting pore volume within the model was more than 99.99% of the original pre-cutoff values. Figures 2-20 to 2-22 show the facies, porosity, and permeability, respectively, in the west-east cross-sectional view at Tea Olive No. 1, as imported from Petrel.

[redacted]

Figure 2-20 – Model at Tea Olive No. 1, West-East Cross-Sectional: Facies ([redacted])

[redacted]

Figure 2-21 – Model at Tea Olive No. 1, West-East Cross-Sectional: Porosity

[redacted]

Figure 2-22 – Model at Tea Olive No. 1, West-East Cross-Sectional: Permeability

The model was then refined laterally around the perforations of the two injection wells to [redacted]-ft x [redacted]-ft grid cells. The refinement extended [redacted] ft in diameter around each wellbore location. To refine the cells, a cartesian subgrid, or local grid refinement (LGR), was created within the model as displayed in Figure 2-23. This process added [redacted] grid cells to the model after pore volume cutoffs were implemented into the refined cells. This refinement brought the total number of grid cells to [redacted] cells after the cutoffs and refinement around the wellbores were applied.

Implementing the subgrid greatly reduced numerical convergence errors and resulted in a more accurate simulation prediction.

[redacted]

Figure 2-23 – Local Grid Refinement Around Tea Olive No. 1 and Flowering Crab Apple No. 1

Multiple distinct, [redacted] packages were identified as potential targets for supercritical CO_2 injection. Each injectable rock package is separated by [redacted] facies, such as [redacted], that may act as barriers that impede CO_2 movement. [redacted]

To represent the targeted injection zones more accurately between large gaps of well data and further validate the geocellular model, 3D seismic was used.

Boundary Conditions

The dynamic model utilizes "volume modifiers" along the model boundaries. These modifiers alter the gross volume of each grid block by applying a multiplier to the original volume. A value of [redacted] is applied uniformly along the edge of the grid. Figure 2-24 shows this volume modifier applied to a permeability thickness map illustrating the [redacted] outline. The volume modifier along a boundary of a reservoir simulation model is used to accurately represent flow behavior near the model's edges and prevent unrealistic boundary effects. Without adjusting the volume modifier, the boundary cells can act as artificial barriers, restricting flow or causing unphysical pressure buildup. Adjusting the volume modifier also allows the CO_2 plume and critical pressure front to not be constrained by the model.

[redacted] of the model, the [redacted] structure is bounded by nonporous rock, which acts as a no-flow boundary within the model. Volume modifiers along the model boundary where there is low permeability have little to no effect on the resulting flow of fluid and pressure. Additionally, the [redacted] confines are impermeable, allowing for the largest possible AOR.

[redacted]

Figure 2-24 – Volume modifiers (indicated by the red outline) overlaid onto permeability thickness.

Model Time Frame

The model encompasses a [redacted]-year period, with [redacted] years allocated to active injection and [redacted] years for post-injection density drift. This duration allows for a comprehensive demonstration of plume stabilization. Details of the model's results are discussed in *Section 2.7.*

2.5.2 Initial Conditions

The geocellular model served as an input for constructing the dynamic plume model. The assumptions in Table 2-6 were also used to initialize the model. Porosity was geostatistically distributed and exported from Petrel, with values ranging from less than [redacted] in the injection zone. By applying the porosity-permeability relationship derived not only from petrophysical analysis of offset core but also from literature [redacted] the permeability ranged from [redacted] mD. The pore and fracture pressure gradients were calculated to be [redacted] pounds per square inch per foot (psi/ft) and [redacted] psi/ft, respectively. A regional and well log review estimated the temperature gradient to be [redacted] °F per 100 ft. Salinity within the injection zone was determined to be approximately [redacted] parts per million (ppm), as discussed in *Section 2.5.2.4*.

Table 2-6 – Initial-Conditions Inputs Summary

Inputs	Values
Average Porosity (%)	[redacted]
Average Permeability (mD)	
Vertical Permeability (Kv/Kh) Ratio	
Pore Pressure Gradient (psi/ft)	
Frac Pressure Gradient (psi/ft)	
Mean Surface Temperature (°F)	
Temperature Gradient (°F/100 ft)	
Salinity (ppm)	

2.5.2.1 <u>Porosity/Permeability</u>

As discussed in *Section 2.4*, porosity is determined through the analysis of open hole logs, and permeability is calculated using a porosity-permeability relationship (Figure 2-16, *Section 2.4.3*), derived from core data taken from two nearby offset wells within the [redacted] Formation as well as from literature [redacted] The permeability relationship implemented in the dynamic model was depicted in Equations 1 through 4 in *Section 2.4.3*.

Porosity was geostatistically distributed throughout the model. The porosity-permeability equation was then applied to the given facies grid cells to determine permeability. This process resulted in a porosity range from less than [redacted], and a permeability range of [redacted] mD for all modeled grid cells. The injectable [redacted] rock has a porosity range of [redacted]% and a permeability range of [redacted] mD, with averages of [redacted]% and [redacted] mD, respectively.

Facies that exhibit high shale volumes are expected to be clay-rich in this depositional environment. Clay-rich facies show permeability values in the range of 0.1–100 nanodarcy (Backeberg et al., 2017). In the dynamic model, a permeability value of [redacted] mD is assumed for the shale facies. For the other facies present in the model, [redacted] mD is the lower limit of permeability. This ensures that grid cells with low corresponding porosity values are considered "impermeable" while not causing strain on the model computation, as low permeability grid blocks cause convergence issues within dynamic models by not allowing fluid to flow through them. These distributions were shown west to east in Figures 2-20 through 2-22 (*Section 2.5.1*).

The vertical permeability was set to be [redacted] times that of the horizontal permeability within the dynamic model. In [redacted] reservoirs, a vertical permeability ratio of [redacted] can be assumed by accounting for the natural anisotropy of the formation. [redacted] While horizontal permeability can be relatively high due to interconnected pore spaces along bedding planes, vertical permeability is often much lower because vertical fractures are either less developed, filled with minerals, or blocked by diagenetic processes like cementation.

Using a vertical permeability ratio of [redacted] reflects this, ensuring the model captures the restricted vertical flow, which is critical for accurately predicting fluid migration, pressure changes, and recovery performance. However, this ratio can be refined if reservoir-specific core or well log data indicates different permeability distributions.

2.5.2.2 Pressure Gradient

Pressure within the tNav dynamic model is defined by a single reference pressure at a defined datum depth. The depth is chosen to represent an approximate "midpoint" depth of the injection zone. The datum depth and pressure were defined to be [redacted] ft subsea and [redacted] psi within the model, which represent a pore pressure gradient of [redacted] psi/ft, assuming a 300-ft ground-level elevation. This normal pore pressure gradient is in line with regional trends, above any abnormally geopressured formations (Burke et al., 2013) and based on drilling mud weights within the injection interval of the [redacted] offset wells near the proposed injectors ([redacted]).

For the tNav simulator to calculate the pressure at each grid block, the density of the fluid within each grid block must be determined. The fluid density is affected by the temperature gradient, salinity, and composition of the fluid. The simulator internally calculates and distributes the pressure throughout the model based on the fluid density.

2.5.2.3 Fracture Gradient

Eaton's method (Eaton, 1969), widely acknowledged as the standard practice for the determination of fracture gradients (FG), was used to calculate the pressure required to fracture the injectable rock. The method requires Poisson's ratio, overburden gradient (OBG), and pore gradient (PG) to be [redacted] psi/ft, to determine the fracture gradient. Table 2-7 provides the values of each input.

Table 2-7 – Fracture Gradient Calculation Assumptions – Eaton's Method

Zone/Formation	Poisson's Ratio	Overburden Gradient (psi/ft)	Pore Gradient (psi/ft)	Fracture Gradient (psi/ft)
[redacted]				

Poisson's ratio was determined through petrophysical analysis of compressional and sheer sonic log data from [redacted] offset wells ([redacted]) for the injection and confining zones. Literature suggests that [redacted] can have a range of potential Poisson's ratios (0.30–0.35) within the suggested values from petrophysical analysis (Molina, Vilarras, and Zeidouni, 2017). A value of [redacted] was chosen for the Poisson's ratio for the injection zone based on the petrophysical work done on nearby wells and confirmed from literature (Molina, Vilarras, and Zeidouni, 2017). A value of [redacted] psi/ft was determined for the vertical stress gradient using a bulk density log from an offset well near the AOR ([redacted]) within the same formations, as shown in Figure 2-25. Lastly, a pore pressure gradient of [redacted] psi/ft was estimated based on regional trends and nearby drilling muds used at depths similar to those of the injection zone.

[redacted]

Figure 2-25 – Vertical stress gradient log [redacted]) used to calculate vertical stress gradient for Eaton's method.

With the inputs, it is possible to calculate an FG, the necessary steps for which are shown in Equation 5. Per TAC **§5.203(f)(2)(C)** (40 CFR **§146.88(a)**), the well may not exceed 90% of the FG during injection operations. Therefore, the model applied a pressure constraint of [redacted] psi/ft to both injection wells.

(Eq. 5)

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

$FG =$ [redacted]

$FG =$ [redacted] psi/ft

$FG_{(90\%)} =$ [redacted] x 0.9

$FG_{(90\%)} =$ [redacted] psi/ft

2.5.2.4 <u>Reservoir Fluid Properties</u>

Reservoir Temperature

An evaluation of well logs near the TXCCS#1 Project was conducted to estimate the reservoir temperature. From this evaluation, [redacted] wells were used to estimate the temperature gradient ([redacted]). [redacted] data points are shown in Figure 2-26 because some wells have multiple bottomhole temperature readings at various depths. The reservoir temperature gradient was averaged from these seven wells and estimated to be [redacted]°F/100 ft. This gradient is added to a surface temperature of [redacted]°F, the mean annual surface temperature.

[redacted]

Figure 2-26 – Temperature Gradient from Bottomhole Temperature Logs

Brine Salinity

A constant salinity value of [redacted] ppm total dissolved solids (TDS) was input into the model. This value is based on the average salinity estimates of the injection zone taken from well log analysis of seven wells ([redacted]) near the proposed injection well locations. This method of estimating salinity entails determining an apparent water resistivity by applying Archie's equation to the porosity and resistivity data. Subsequently, the water resistivity value is transformed into salinity using conventional petrophysical charts, provided by service companies such as SLB. The chart used for the purposes here is displayed in Figure 2-27.

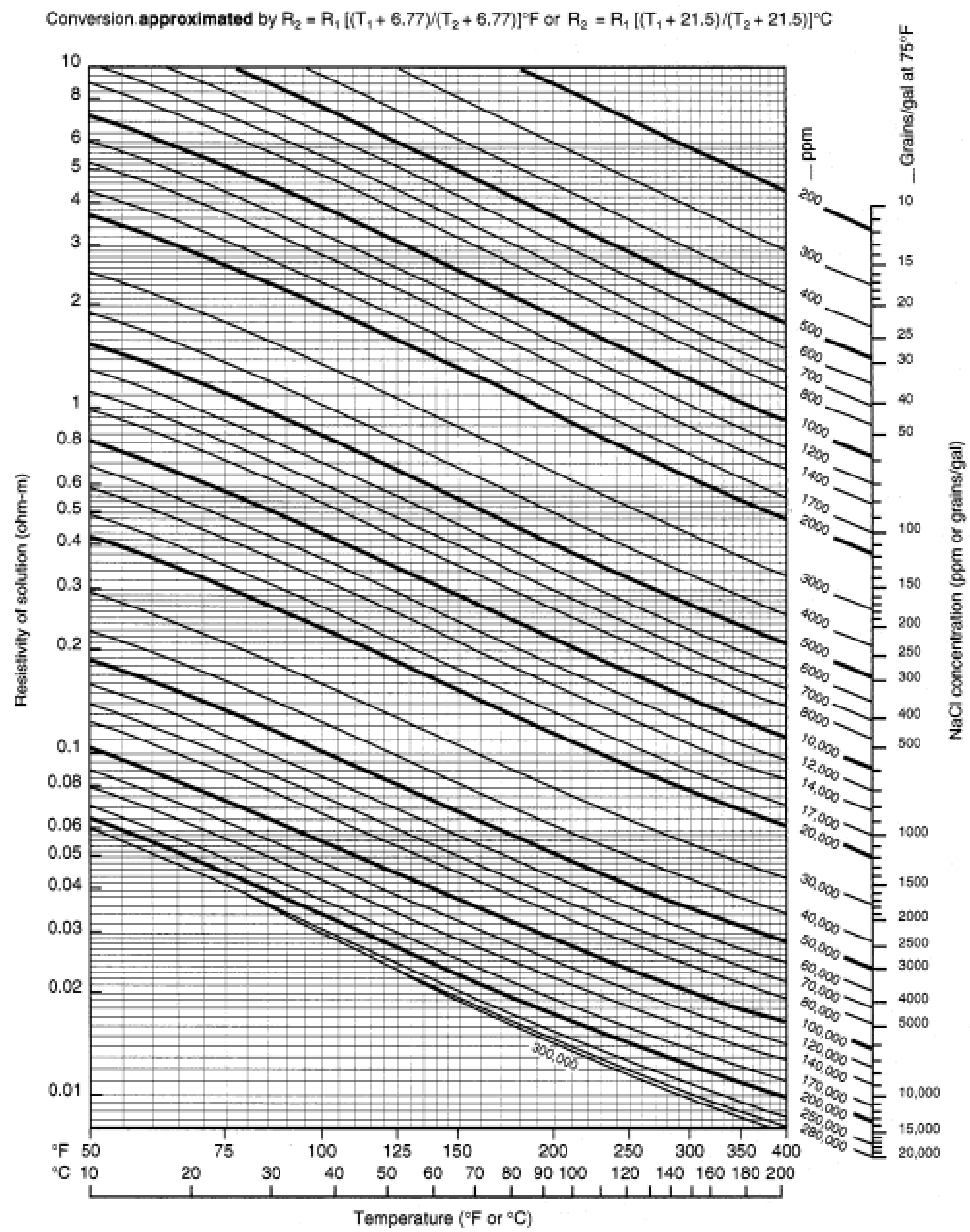

Figure 2-27 – Resistivity of Sodium Chloride (NaCl) Solutions (SLB, 2009)

2.5.2.5 Injectate Composition

The anticipated composition of the injectate (Table 2-8) is primarily CO_2. Trace components such as CH_4, ethane (C_2H_6), hydrogen sulfide (H_2S), nitrogen (N_2), and water (H_2O) are also expected, but at much lower concentrations. Because of the low anticipated composition of the trace components, CH_4 was modeled to represent all the other components in the gas stream. This is done for multiple reasons. First, the more components introduced to the model, the more computational strain is added to the model. This leads to the second reason, which is that, at such low concentrations, the trace components have minimal impact on the pressure and plume. Due to these reasons, CH_4 is modeled as the only non-CO_2 component.

Table 2-8 – Anticipated Composition of the Injectate

Component	Anticipated Area Composition (mol %)	tNav Modeled Composition (mol %)
Carbon Dioxide	[redacted]	99.6%
Methane		0.4%
Ethane		0.0%
Hydrogen Sulfide		0.0%
Nitrogen		0.0%
Water		0.0%

*MMcf – million cubic feet

2.5.3 Rock Properties Hysteresis Modeling

Rock (Pore Space Volume) Compressibility

A literature review was conducted to determine the rock compressibility of the [redacted] Formation. Due to the lack of regional rock compressibility data, an expanded search for data into [redacted] formations was undertaken. The literature review analysis indicated that this type of formation can have compressibility values within a range of [redacted] microsips, as highlighted in Figure 2-28. For the purposes of this simulation, a value of [redacted] microsips was chosen. This assumption is subject to revision as additional data from the stratigraphic test well(s) become available.

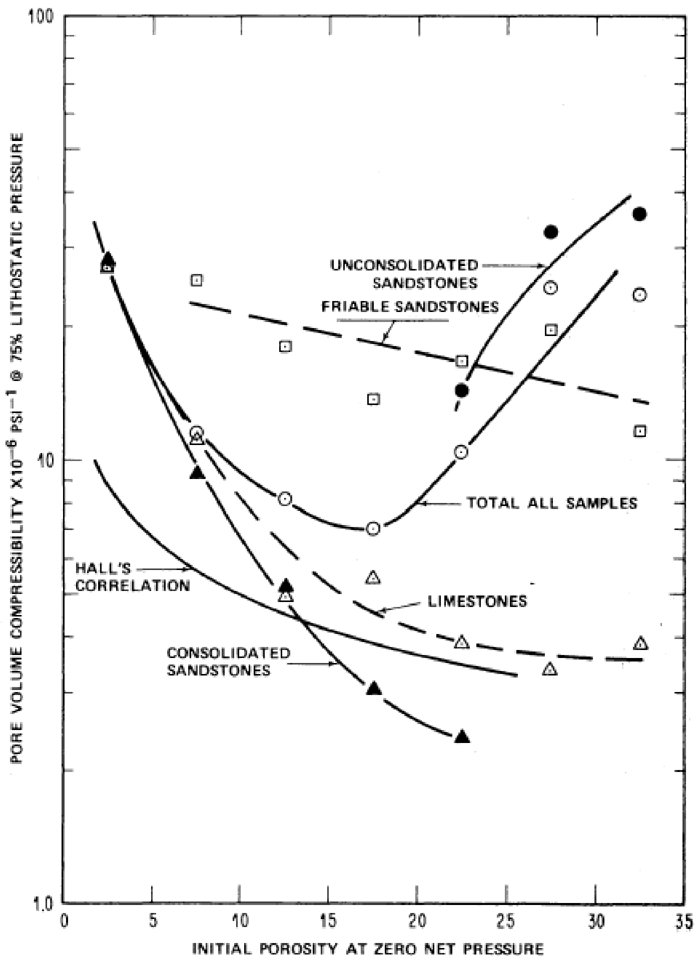

Figure 2-28 – Pore Volume Compressibility vs. Initial Sample Porosity (Newman, 1973)

<u>Residual Gas (Nonwetting Phase) Saturation</u>

A comprehensive literature review was conducted to determine the maximum residual-gas saturation of the [redacted] Formation. Numerous studies were reviewed to find a value that most accurately represents the target formation ([redacted] Holtz, 2002). One report [redacted] ran core analysis on 13 core samples analogous to the [redacted]. This study found that the maximum residual-gas saturation of a [redacted] formation can range from 5–42%. Factors affecting the saturation include porosity, pore throat size, permeability, and threshold capillary pressure. Samples from the paper [redacted] that are similar to the [redacted] Formation were considered. An average of [redacted]% maximum residual-gas saturation was implemented into the dynamic model.

<u>Relative Permeability Curves</u>

The absolute permeability of a porous medium is the permeability when only a single fluid is present within the pore space—effective permeability therefore being equal to absolute permeability. However, effective permeability decreases as new fluids are introduced into the reservoir. This phenomenon is depicted by relative permeability curves, which illustrate the effective permeability of two or more fluids as they flow through a porous medium.

The tNav simulator utilizes hysteresis modeling to establish the amount of supercritical CO_2 that is residually trapped. The hysteresis model enables the simulation of both drainage and imbibition processes. *Drainage* is the process of a nonwetting fluid (supercritical CO_2) displacing the wetting fluid (brine) as it is injected into and migrates through the reservoir. *Imbibition* refers to the reentry of the brine into the pore space, during which a certain amount of CO_2 becomes effectively trapped within the pore space.

In the absence of site-specific core data, relative permeability curves were constructed based on a literature review of similar depositional environments [redacted] Benson 2013). The Brooks-Corey equation was used to generate the relative permeability curves used in the model. Based on this research, the irreducible water saturation was assumed to be [redacted]% and the endpoints were assumed to be [redacted] and [redacted] for the brine and CO_2 curves, respectively. Fitting the endpoints to the experimental data resulted in Corey exponents for brine and CO_2 of [redacted] and [redacted], respectively. Subsequently, the imbibition curves were internally computed in tNav using the Analytical Carlson method. Figure 2-29 shows the drainage and imbibition relative-permeability curves used in the model.

[redacted]

Figure 2-29 – Two-phase relative permeability curves implemented in the model.

Site-specific core is planned to be obtained with stratigraphic test well(s) and upon completion of the proposed injection wells. The model and subsequent curves will be updated after the cores have been tested and analyzed.

2.6 Well Operations Setup

For the TXCCS#1 Project, the wellbore models for both proposed injection wells were set up using the wellbore schematics (WBS) along with assumptions provided in Table 2-9. Three primary constraints were imposed in tNav to limit the pressure response and CO_2 plume growth: (1) a maximum injection rate of [redacted] MMT/yr, (2) a maximum bottomhole pressure (BHP) gradient of [redacted] psi/ft, and (3) an injection period of [redacted] years for both Tea Olive No. 1 and Flowering Crab Apple No. 1. Based on the proposed WBS, TXCCS#1 plans to implement a [redacted] inch (in.) tubing string. This tubing size was considered when calculating the wellhead pressure (WHP) in tNav.

Table 2-9 – Well Hydraulics Input Summary

Inputs	Tea Olive No. 1 Values	Flowering Crab Apple No. 1 Values
Maximum Injection Rate (MMT/yr)	[redacted]	
Pressure Constraint Gradient (psi/ft)		
Injection Duration (yrs)		
Tubing Inner Diameter (in.)		
Tubing Setting Depth (ft, MD)		
Roughness Factor (in.)		

Each injection well will penetrate multiple high-porosity [redacted] developments. These trends of high porosity will be used as intervals that are perforated and injected into simultaneously. The top perforation of the uppermost zone will be used as the fracture pressure constraint, to ensure the BHP never exceeds the calculated fracture gradient. Using this completion strategy, each well only needs to be completed once at the beginning of injection. Once the injection period ends, the wells will be plugged and no longer used for injection. A general description of the completion strategy for each injection well is presented in Tables 2-10 and 2-11, respectively.

Table 2-10 – Summary of the Completion Stage for Tea Olive No. 1

Stage	Top Perf (ft, MD)	Bottom Perf (ft, MD)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
1	[redacted]				

Table 2-11 – Summary of the Completion Stage for Flowering Crab Apple No. 1

Stage	Top Perf (ft, MD)	Bottom Perf (ft, MD)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
1	[redacted]				

2.7 Model Results

2.7.1 Active Injection Operations

The BHP, WHP, and injection rate were simulated for both proposed injection wells—Figures 2-30 and 2-31, respectively—depicting their responses during operational activities, for the life of the wells. The Tea Olive No. 1 injection rate is held constant at [redacted] MMT/yr for the entire injection period, and the BHP never exceeds 90% of the fracture gradient. The Flowering Crab Apple No. 1 is also held at the BHP constraint of 90% of the fracture gradient—keeping the well's injection rate at less than the maximum of [redacted] MMT/yr. The CO_2 delivery condition sensitivities were run assuming a range in CO_2 delivery temperature to the injection site. A wellhead temperature (WHT) sensitivity was run assuming a range of [redacted]°F. The resulting WHP ranges are shown for both wells in Figures 2-30 and 2-31, respectively, based on the temperature range.

[redacted]

Figure 2-30 – Modeled BHP, WHP, and Injection Rate for Tea Olive No. 1

[redacted]

Figure 2-31 – Modeled BHP, WHP, and Injection Rate for Flowering Crab Apple No. 1

The WHP was calculated using tNav. Values such as tubing inner diameter, tubing setting depth, roughness factor, and compressor outlet pressure and temperature, presented in Table 2-9, were used as inputs for the wellbore model.

Based on the model simulation, the maximum expected BHP of Tea Olive No. 1 is [redacted] psi during the life of the project, evaluated at [redacted] ft. On average, the BHP of the well will be [redacted] psi. The maximum WHP is calculated to be [redacted] psi with an average of [redacted] psi. Table 2-12 highlights the outputs for this injection well as modeled in tNav.

Table 2-12 – Tea Olive No. 1 Model Outputs

[redacted]

Based on model simulation, the maximum expected BHP of Flowering Crab Apple No. 1 is [redacted] psi during the life of the TXCCS#1 Project, evaluated at [redacted] ft. On average, the BHP of the well will be [redacted] psi. The maximum WHP is calculated to be [redacted] psi with an average of [redacted] psi. Table 2-13 provides the outputs for this injection well as modeled in tNav.

Table 2-13 – Flowering Crab Apple No. 1 Model Outputs

[redacted]

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

Figures 2-32 and 2-33 represent the maximum pressure buildup at the two injection wells, respectively—the BHP result seen within the reservoir at any given time during injection. In addition, since these pressure values are retrieved at different depths, the pressure gradient is also calculated as pressure divided by depth (i.e., the calculated pressure gradient). The greatest buildup of Tea Olive No. 1 (Figure 2-32) occurs at the end of injection with a value of [redacted] psi. Flowering Crab Apple No. 1 (Figure 2-33) has a pressure buildup of [redacted] psi. As shown in these figures, the pressure gradient never exceeds the constraint (90% of the FG) imposed on the wells, to allow for the safe injection of supercritical CO_2.

[redacted]

Figure 2-32 – Pressure Buildup for Tea Olive No. 1 During Active Injection Operations

[redacted]

Figure 2-33 – Pressure Buildup for Flowering Crab Apple No. 1 During Active Injection Operations

The elevated pressure in the saline aquifer quickly dissipates once active injection operations cease. Fifty years after both wells are shut in, the reservoir pressure stabilizes to [redacted] psi above the in situ conditions at Tea Olive No. 1, and [redacted] psi above the in situ conditions at Flowering Crab Apple No. 1. Figures 2-34 and 2-35 show the pressure buildup for the two injection wells, respectively, throughout the life of the project.

[redacted]

Figure 2-34 – Pressure Buildup for the Life of Tea Olive No. 1

[redacted]

Figure 2-35 – Pressure Buildup for the Life of Flowering Crab Apple No. 1

Based on dynamic model simulation, Flowering Crab Apple No. 1 does not achieve the desired rate and is held to the 90% fracture gradient constraint throughout the entirety of injection. [redacted]

Because of this lack of [redacted], as well as the lack of well control around the proposed Flowering Crab Apple No. 1 location, these results will change once the wells are drilled to gather core, fluid samples, and geophysical logs. The inclusion of the additional data will further increase the accuracy of the model and simulation results.

2.8 CO_2 Plume Migration for AOR Delineation

According to TAC **§5.203(d)** (40 CFR **§146.84**), the AOR must be determined by the maximum extent of either the supercritical CO_2 plume or critical pressure front—or both. The first review starts with the extent of the CO_2 plume. The Occupational Safety and Health Administration (OSHA) has set an acceptable exposure limit of CO_2, indicating that up to 30,000 ppm over a 10-minute period is within safe guidelines. Based on these guidelines, a CO_2 saturation cutoff of [redacted] was used to determine the final extent of the plume. Both of the TXCCS#1 injection wells were used to determine the plume extents. Injection of CO_2 into the two wells resulted in multiple disconnected CO_2 plumes.

Due to the geologic structure of the [redacted] reservoir and the presence of fractures and vugs, the CO_2 plume may migrate in multiple directions from the injection wells. Fractures can act as high-permeability conduits, allowing the CO_2 to travel further through the formation. Structural dip also influences the migration of the CO_2 plume. The less dense CO_2 rises due to buoyancy effects until it encounters an impermeable layer, such as an [redacted]. The upward dip of the [redacted] formation facilitates further migration. In this model, the plume primarily migrates [redacted], along the [redacted] trend, although it also migrates [redacted] with the dip until structural trapping mechanisms, such as dense [redacted] or [redacted], limit lateral movement. Figure 2-36 provides a 3D view of the stabilized plume in the year [redacted] ([redacted] years after injection ceases), showing the various migration pathways and illustrating the role of structural and stratigraphic trapping. [redacted] zones act as barriers that trap the supercritical CO_2, preventing further upward and lateral migration. The largest extent of the plume is determined by the maximum saturation experienced in all of the modeled layers at a specified point in time.

[redacted]

Figure 2-36 – A vertical 3D representation (left) and aerial view (right) of supercritical CO_2 plume in [redacted], colored by CO_2 saturation.

The resulting CO_2 plume of Tea Olive No. 1 migrates primarily to the [redacted], while the resulting Flowering Crab Apple No. 1 plume primarily migrates [redacted]. Figures 2-37 through 2-40 show the cross-sectional view of the plumes and highlight how the shape and size of the plumes vary in each high-porosity interval package. Between each interval, interbedded clay-rich facies such as [redacted] exist to help structurally trap CO_2 and inhibit vertical migration. The blue regions represent the formation with zero gas saturation. The black voids within the formation correspond to nulled grid cells, which are excluded from the dynamic simulation. A detailed explanation of the grid nulling process based on pore volume cutoffs was presented in *Section 2.5.1.*

[redacted]

Figure 2-37 – West-east cross-sectional view at Tea Olive No. 1 in [redacted], colored by CO_2 saturation.

[redacted]

Figure 2-38 – West-east cross-sectional view at Flowering Crab Apple No. 1 in [redacted], colored by CO_2 saturation.

[redacted]

Figure 2-39 – South-north cross-sectional view at Tea Olive No. 1 in [redacted], colored by CO_2 saturation.

[redacted]

Figure 2-40 – South-north cross-sectional view at Flowering Crab Apple No. 1 in [redacted], colored by CO_2 saturation.

The CO_2 plume in Figure 2-41 is delineated from the maximum CO_2 saturation seen in each layer of the model. The plume extent is taken in [redacted] ([redacted] years after injection ceases), a total of [redacted] years after the start of injection. The supercritical CO_2 plume of Tea Olive No. 1 covers approximately [redacted] acres ([redacted] square miles), and the resulting Flowering Crab Apple No. 1 plume covers approximately [redacted] acres ([redacted] square miles) of land secured by underground storage easements by TXCCS#1. From Tea Olive No. 1, the plume's greatest extent is approximately [redacted] miles to the [redacted]. The carbon front also migrates about [redacted] miles to the [redacted] from Flowering Crab Apple No. 1.

[redacted]

Figure 2-41 – Aerial View of Supercritical CO_2 Front in [redacted] (outlined in black)

2.8.1 Trapping Summary

Figure 2-42 shows the breakdown of the trapping mechanism. Once injection stops (Year [redacted]), the mobile CO_2 quickly decreases as supercritical phase CO_2 migrates through pore space and is trapped. Over the life of the project, residual trapping of supercritical CO_2 has the greatest effect among the trapping mechanisms. Approximately [redacted]% of the injected CO_2 is safely sequestered by residual trapping within the pore space. The solubility of CO_2 into the connate brine will safely store approximately [redacted]% of the CO_2. The remaining [redacted]% is the free CO_2 within the system and can be considered structurally and hydrodynamically trapped. These percentages of trapped CO_2 agree with data from literature based on the maximum residual gas saturation value implemented in the model (Metz et al., 2005; Holtz, 2002).

[redacted]

Figure 2-42 – Modeled Trapping Mechanisms (the red line designating the end of injection)

2.8.1.1 Stabilized Plume

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

The reservoir model determines that plume stabilization occurs by the year [redacted] years after the wells cease injection. By [redacted], the plume growth rate is reduced to approximately [redacted]% per year while continuing to decline. The two disconnected plumes continue to migrate slowly, approximately [redacted] acres per year combined on average, and may be considered hydrodynamically trapped. To be conservative and in accordance with 40 CFR **§146.93(b)(1)**, the plume is monitored for [redacted] years after injection ceases, even though stabilization has occurred. The plume growth therefore considers the combined plume. While incidental plume movement may occur after this period, the reservoir model indicates that the plume will continue to remain on the TXCCS#1 acreage. Figure 2-43 demonstrates that the rate of plume movement decreases to less than [redacted]% within [redacted] years post-injection.

[redacted]

Figure 2-43 – Plume Growth Over Time

2.9 Critical Pressure Front for AOR Delineation

In accordance with TAC **§5.203(d)** (40 CFR **§146.84**), the AOR was delineated by the critical pressure front created by the injection of supercritical CO_2 into a saline aquifer. Critical pressure is the increase in reservoir pressure that may push in situ fluids out of the injection zone and into the lowermost USDW, in the presence of a bridging conduit, such as an unplugged borehole. The first step to predicting the critical pressure front is to calculate the critical pressure for each completion stage. Once critical pressure is determined, a numerical simulation is used to predict the size and shape of the critical pressure front.

The worst-case scenario regarding the transfer of reservoir fluids to the USDW would involve the flow of in situ fluids through an improperly sealed and abandoned wellbore that remains open at both the upper boundary of the injection zone and the lower boundary of the USDW. In this scenario, it is conservatively assumed that the wellbore is filled with mud, and the density of this mud is equivalent to a pressure gradient of [redacted] psi/ft (approximately [redacted] pounds per gallon (ppg)). This assumption is based on research of plugged and abandoned mud weights in and around the AOR. Two wells were found to have mud weights of [redacted] ppg ([redacted]). All other wells in and around the AOR that penetrate the injection zone have mud weights higher than the value chosen for this exercise.

The equations presented in Table 2-14 were developed based on methodologies recommended by the EPA and adjusted to accommodate the presence of mud within the wellbores. The critical threshold pressure was computed for each well where the injection begins at depths ranging from [redacted] ft. The corresponding stage depths and critical pressure values are shown in Tables 2-15 and 2-16 for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

For the calculation—the most conservative estimate, it should be noted—the base of the USDW was determined to be [redacted] ft at Tea Olive No. 1 and [redacted] ft at Flowering Crab Apple No. 1. These values are based on an internal determination of the base of the USDW. The value of 1,700 ft was determined by the Railroad Commission of Texas (TRRC) Groundwater Advisory Unit (GAU), dated January 16, 2024 (GAU No. 376910) for Tea Olive No. 1, matching the internal determination. A value of 1,275 ft was determined by the TRRC GAU, dated February 13, 2025 (GAU No. 389486) for Flowering Crab Apple No. 1. Because the GAU-determined value of the USDW base is less than that determined internally at Flowering Crab Apple No. 1, the deeper internal determination of [redacted] ft was used in the critical pressure front calculation for both wells—in an effort to be conservative regarding the GAU for Flowering Crab Apple No. 1, but consistent with the GAU for Tea Olive No. 1. Once the wells are drilled, the actual depth of the USDW will be precisely determined and used for future models.

The assumed characteristics of the USDW include a water density of freshwater (less than 10,000 ppm) with a corresponding pressure gradient of [redacted] psi/ft. Additionally, the injection zone gradient is determined to be [redacted] psi/ft, as outlined in *Section 2.5.2*.

Table 2-14 – Critical Pressure Calculation Parameters and Process for Calculating

[redacted]

Table 2-15 – Critical Threshold Pressure for the Tea Olive No. 1 Completion Stage

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

Table 2-16 – Critical Threshold Pressure for the Flowering Crab Apple No. 1 Completion Stage

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

The calculation in Tables 2-15 and 2-16 show what the critical pressure value is calculated to be at the top of the injection zone. Because of the heterogeneous nature of the reservoir, the critical pressure front may extend in different directions. The critical pressure front changes with depth as the pressure front exerted from injection migrates out into the formation. The critical pressure value increases deeper into the formation, as it takes more pressure to move in situ brine from a deeper point of the formation. This is taken into account in the simulation model and the resulting critical pressure front plume. Each of the two injection wells considers the pressure front of the offset well when determining the maximum extent of their respective critical pressure front.

The critical pressure front covers an area of approximately [redacted] acres ([redacted] square miles). Extending primarily to the [redacted], the front reaches a maximum extent of [redacted] miles to the [redacted] and [redacted] miles [redacted] from Tea Olive No. 1, and [redacted] miles to the [redacted] and [redacted] miles [redacted] of Flowering Crab Apple No. 1. Figure 2-44 provides a snapshot of the largest extent of the critical pressure front experienced in the model.

[redacted]

Figure 2-44 – Greatest Extent of the Critical Pressure Front (outlined in pink)

2.10 Final AOR

The maximum CO_2 plume and critical pressure front delineate the AOR, which determines the necessary evaluation of, and potential corrective action needed for, any offset wells. The CO_2 saturation front is determined by the greatest extent of the fluid in any direction throughout the injection zone. The acceptable exposure limit of CO_2 set by OSHA indicates that up to 30,000 ppm over a 10-minute period is within safe guidelines; [redacted]. The critical pressure front was determined from the greatest areal extent of all completion stages for both injection wells. Figure 2-45 provides the final AOR outlines for the project.

[redacted]

Figure 2-45 – Tea Olive No. 1 and Flowering Crab Apple No. 1 (TXCCS#1 Project) Final AOR

2.11 References

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Underground Injection Control – Class VI Permit Application for

Tea Olive No.1 and Flowering Crab Apple No.1

Sabine and San Augustine Counties, Texas

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

July 2025

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.1 Facility Information

Facility Name: Aethon TXCCS#1 Project

Injection Well Information:

Well Name and Number	Tea Olive No. 1
County	Sabine County, TX
Latitude and Longitude	[redacted]
Well Name and Number	Flowering Crab Apple No. 1
County	San Augustine County, TX
Latitude and Longitude	[redacted]

*NAD 27 – North American Datum of 1927

3.2 Computational Modeling

Model Name: tNavigator (tNav) Version 24.2

Model Author/Institution: Rock Flow Dynamics

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

Model Inputs and Assumptions: The parameters for tNav are summarized in Table 3-1.

Table 3-1 – Model Input Parameters and Assumptions Per Well

Input	Value
Maximum Injection Rate (MMT/yr)	[redacted]
Average Porosity (%)	
Average Permeability (mD)	
Average Kv/Kh Ratio	
Pore Pressure Gradient (psi/ft)	
Fracture Pressure Gradient (psi/ft)	
Mean Surface Temperature (°F)	
Temperature Gradient (°F/100 ft)	
Salinity (parts per million)	

*MMT/yr – million metric tons per year
mD – millidarcy

psi/ft – pounds per square inch per foot

3.3 Area of Review Discussion

Title 16, Texas Administrative Code (16 TAC) **§5.203(d)** (Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**) requires that an area of review (AOR) investigation be conducted for a Class VI permit application for carbon sequestration wells. The EPA defines the AOR as the greater of either (1) the maximum extent of the separate-phase plume (CO_2 plume) or (2) the critical pressure front—where the pressure buildup is of sufficient magnitude (i.e., pressure front plume) to force fluids from the injection zone into the formation matrix of the shallowest underground source of drinking water (USDW). The AOR for Aethon Energy Operating LLC's (Aethon) proposed TXCCS#1 Project was determined by combining the CO_2 plume and critical pressure front, resulting in the pressure front having the greater extent.

3.3.1 Area of Review: CO_2 Plume

Computational modeling was utilized in the determination of the CO_2 plume boundaries. The model takes into consideration both the physical and chemical properties of the injection stream, as well as operational data and data obtained during the site characterization. The model will be updated throughout the life of the project, utilizing operational and monitoring data. A detailed discussion of the modeling efforts employed to determine the CO_2 plume confines is presented in ***Section 2 – Plume Model*.**

The AOR investigation aimed to identify and assess three elements: (1) artificial penetrations, (2) subsurface characteristics, and (3) pore space rights.

3.3.1.1 Artificial Penetrations

Artificial penetrations identified within the AOR must be evaluated for proper completion, construction material, and plugging operations. To comply with Class VI regulations, all artificial penetrations within the CO_2 plume must be constructed and/or plugged with materials suitable for storing carbon oxides. Any artificial structure identified within this AOR that penetrates the upper confining zone (UCZ) and that was not constructed or plugged properly, requires corrective action. The purpose of the Corrective Action Plan is to ensure that no artificial penetration may serve as a conduit to move fluid out of the injection zone. Any artificial structure that does not penetrate the UCZ has no impact on the containment of fluid—and as such will not be considered in any plan for corrective action.

3.3.1.2 Subsurface Characteristics

Subsurface features identified within the AOR must be reviewed to determine their influence on the injection zone and the targeted formations' ability to support the long-term storage of CO_2. The features to be evaluated include faults, mapped fractures, folds, steeply dipping formations, and salt diapirs. These features may either serve as a conduit for fluid migration or as a barrier that enhances the containment of the stored CO_2. Aethon will endeavor to ensure that any identified structure will not be permitted to allow the movement of fluid from the primary injection zone to the USDW or to the surface.

3.3.1.3 Pore Space Rights

Reservoir modeling simulations indicating CO_2 plume growth will be used to assess and acquire the required pore space acreage for the project.

3.3.2 Area of Review: Critical Pressure Front

The critical pressure front AOR was determined using the same computational model iteration and data as the CO_2 plume. This AOR was also assessed to identify any inadequately plugged-and-abandoned artificial penetrations, as well as any subsurface features that penetrate the UCZ, as these features are potential conduits to move fluid out of the injection zone.

In accordance with 16 TAC **§5.203(d)** (40 CFR **§146.84**), the AOR was delineated by the critical pressure front created by the injection of supercritical CO_2 into a saline aquifer. Critical pressure is the increase in reservoir pressure that may push in situ fluids out of the injection zone and into the lowermost USDW, in the presence of a bridging conduit, such as an unplugged borehole. The first step to predicting the critical pressure front is to calculate the critical pressure for each completion stage. Once critical pressure is determined, a numerical simulation is used to predict the size and shape of the critical pressure front.

The worst-case scenario regarding the transfer of reservoir fluids to the USDW would involve the flow of in situ fluids through an improperly sealed and abandoned wellbore that remains open at both the upper boundary of the injection zone and the lower boundary of the USDW. In this scenario, it is conservatively assumed that the wellbore is filled with mud, and the density of this mud is equivalent to a pressure gradient of [redacted] psi/ft (approximately [redacted] pounds per gallon (ppg)). This assumption is based on research of plugged and abandoned mud weights in and around the AOR. Two wells were found to have mud weights of [redacted] ppg ([redacted]). All other wells in and around the AOR that penetrate the injection zone have mud weights higher than the value chosen for this exercise.

The equations presented in Table 3-2 were developed based on methodologies recommended by the EPA and adjusted to accommodate the presence of mud within the wellbores. The critical threshold pressure was computed for each well where the injection begins at depths ranging from [redacted] feet (ft) to [redacted] ft. The corresponding stage depths and critical pressure values are shown in Tables 3-3 and 3-4 for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

For the calculation, the base of the USDW was determined to be [redacted] ft at Tea Olive No. 1 and [redacted] ft at Flowering Crab Apple No. 1. These values are based on an internal determination of the base of the USDW. The value of 1,700 ft was determined by the Railroad Commission of Texas (TRRC) Groundwater Advisory Unit (GAU) of January 16, 2024 (GAU No. 376910) for Tea Olive No. 1, matching the internal determination. A value of 1,275 ft was determined by the TRRC GAU dated February 13, 2025 (GAU No. 389486) for Flowering Crab Apple No. 1. Because the GAU-determined value of the USDW base is less than that determined internally at Flowering Crab Apple No. 1, the deeper internal determination of [redacted] ft was used in the critical pressure front calculation for both wells—in an effort to be conservative regarding the GAU for Flowering Crab Apple No. 1, but consistent with the GAU for Tea Oliver No. 1. Once the wells are drilled, the actual depth of the USDW will be precisely determined and used for future models.

The assumed characteristics of the USDW include a water density of freshwater (less than 10,000 parts per million) with a corresponding pressure gradient of [redacted] psi/ft. Additionally, the injection zone gradient is determined to be [redacted] psi/ft, as outlined in ***Section 2.5.2***.

Table 3-2 – Critical Pressure Calculation Parameters and Process for Calculating

[redacted]

Table 3-3 – Critical Threshold Pressure for the Tea Olive No. 1 Completion Stage

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

Table 3-4 – Critical Threshold Pressure for the Flowering Crab Apple No. 1 Completion Stage

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

The calculations in Table 3-2 show what the critical pressure value is calculated to be at the top of the injection zone. Because of the heterogeneous nature of the reservoir, the critical pressure front may extend in different directions. The critical pressure front changes with depth as the pressure front exerted from injection migrates out into the formation. The critical pressure value increases deeper into the formation, as it takes more pressure to move in situ brine from a deeper point of the formation. This is taken into account in the simulation model and the resulting critical pressure front plume. Each of the two injection wells considers the pressure front of the offset well when determining the maximum extent of their respective critical pressure front. The critical pressure front covers an area of approximately [redacted] acres (approximately [redacted] square miles). Extending primarily to the [redacted], the front reaches a maximum extent of [redacted] miles to the [redacted] and [redacted] miles [redacted] from Tea Olive No. 1, and [redacted] miles to the [redacted] and [redacted] miles [redacted] of Flowering Crab Apple No. 1. Figure 3-1 provides a snapshot of the largest extent of the critical pressure front experienced in the model.

The comprehensive AOR for the TXCCS#1 Project encompasses the combined region of both the pore space and pressure front areas. Any feature detected within either of these zones has been assessed for its ability to adequately safeguard the USDW.

[redacted]

Figure 3-1 – Greatest Extent of the Critical Pressure Front (outlined in pink)

3.3.3 Operating Strategies Influencing Reservoir Modeling Results

The TXCCS#1 Project as modeled is projected to inject [redacted] million metric tons (MMT) over a period of [redacted] years. The proposed Tea Olive No. 1 and Flowering Crab Apple No. 1 are both designed to inject at a maximum rate of [redacted] MMT/yr. However, Tea Olive No. 1 averages [redacted] MMT/yr; Flowering Crab Apple No. 1 averages [redacted] MMT/yr, per modeling results. Both injection wells are expected to penetrate multiple [redacted] developments. These [redacted] trends have been used to define the intervals to be perforated.

The project targets approximately [redacted] net feet of usable [redacted] formation for injection into Tea Olive No. 1 and [redacted] net feet for Flowering Crab Apple No. 1. As stated in ***Section 2 – Plume Model***, these [redacted] intervals will be injected into simultaneously, allowing for a [redacted] for both wells.

The tNav model provided the following outputs for this injection program. Figures 3-2 and 3-3 show a west-east cross section for each well, respectively, and Figure 3-4 shows the oblique cross section of maximum saturation experience in all modeled layers for each well.

[redacted]

Figure 3-2 – West-east cross-sectional view at Tea Olive No. 1 in [redacted], colored by CO_2 saturation.

[redacted]

Figure 3-3 – West-east cross-sectional view at Flowering Crab Apple No. 1 in [redacted], colored by CO_2 saturation.

[redacted]

Figure 3-4 – A vertical 3D representation and, at upper right, an aerial view of the supercritical CO_2 plume in [redacted], colored by CO_2 saturation.

Figure 3-5 depicts the shape and lateral extent of the plume occupancy AOR, delineated from the maximum CO_2 saturation seen in each layer of the model. This extent was used to define the initial AOR for both proposed wells. The plume extent was exported from tNav and imported into mapping software to delineate the AOR for the corrective action assessment for the TXCCS#1 Project.

In accordance with 16 TAC **§5.203(d)(V)** (40 CFR **§146.84(c)(iii)**), a comprehensive examination was conducted to identify any artificial penetrations or potential hazards to the lowermost USDW arising from injection activities or operations. This assessment included mapping the AOR and any man-made structures located within it. All artificial penetrations or other artifacts were then subjected to evaluation—considering the completion depth, construction specifications, and plugging and abandonment procedures—to ascertain their potential impact on the containment integrity of the injection zone. Figure 3-6 depicts the TXCCS#1 Project AOR.

The maps and associated lists generated during this effort are contained in *Appendix C*.

[redacted]

Figure 3-5 – Aerial View of Supercritical CO_2 Front in [redacted] (outlined in black)

[redacted]

Figure 3-6 – Final AOR Map

3.3.4 Area of Review Results

An exhaustive multi-database search was conducted to identify artificial penetrations located inside of the AOR. Data on artificial penetration sites was gathered from the TRRC and supplemented with additional data from IHS Markit, Enverus, the Texas Commission on Environmental Quality (TCEQ), and EPA websites. Well water data was gathered directly from the Texas Water Development Board's website.

The results of the AOR evaluation yielded one well within the CO_2 plume boundary that does not penetrate the UCZ. The pressure front AOR evaluation yielded [redacted] artificial penetrations, all of which have been evaluated for proper construction or plugging. [redacted] of the wells are saltwater disposal wells (SWDs), [redacted] and do not inject into the [redacted] Formation. [redacted] of the wells identified were determined to have been constructed and plugged in a manner sufficient to, per TRRC regulations, prevent the movement of fluids out of the injection zone and into the lowermost USDW at the time of abandonment.

[redacted], does not have enough information available to evaluate and so will require corrective action. The well is [redacted] miles from the closest injection well, Tea Olive No. 1, and is not expected to see a pressure increase until [redacted] years after the start of injection or [redacted] MMT injected. A map of the AOR showing artificial penetrations is displayed in Figure 3-7, and Table 3-5 lists the wells. A list of all oil and gas wells within the AOR is located in *Appendix C-2*.

To confirm that all artificial penetrations in the AOR have been identified and assessed, Aethon will contract with a third party to perform an aerial magnetometer survey across the TXCCS#1 Project area. An aerial vehicle will conduct the survey to identify the potential presence of any abandoned wells across the project area. The data will be processed and contour maps of the magnetic field intensity will be provided in a report summarizing the survey methodology, results, and anomaly locations representing potential artificial penetrations.

All known faults, folds, mapped fractures, steeply dipping formations, diapirs, and other subsurface geologic features within the project area were studied. No faults or other features were identified that could be a detriment to USDWs. This subsurface evaluation was discussed further in ***Section 1 – Site Characterization***.

[redacted] existing water wells were found within the AOR. A map showing the nearest offset water wells is featured in Figure 3-8, and Table 3-6 lists the wells—which are at least [redacted] ft shallower than the base of the USDW. The TCEQ records were reviewed to identify Class I wells and any other artificial penetrations within the AOR; the search yielded no results.

Severa [redacted] are located inside of the pressure front AOR—but outside of the pore occupancy plume AOR. These [redacted] will not be affected by injection activities for the TXCCS#1 Project. [redacted] existing active or inactive hazardous waste sites have been identified within the AOR. Aethon will ensure that operations are designed to protect all surface water resources. A site review map showing the surface water bodies and nearest hazardous waste sites, mines, and quarries is shown in Figure 3-9.

[redacted]

Figure 3-7 – Map of Oil and Gas Wells Within the AOR

Table 3-5 – AOR: Oil and Gas Wells Penetrating the UCZ and Injection Zone

API	Well Name	Well No.	Current Operator	Abstract	Latitude (NAD 83)	Longitude (NAD 83)	Well Status	Total Depth (ft, TVD)
[redacted]								

*NAD 83 – North American Datum of 1983; P&A – plugged and abandoned; TA – temporarily abandoned

[redacted]

Figure 3-8 – Map of Nearest Offset Water Wells

Table 3-6 – AOR: List of Freshwater Wells

Well Report No.	Owner's Name	Latitude (NAD 83)	Longitude (NAD 83)	Well Use	Water Level (ft)	Total Depth (ft)	Date Drilled
[redacted]							

[redacted]

Figure 3-9 – Site Review Map

3.4 Corrective Action Plan and Schedule

[redacted] was unable to be evaluated for assurance against harm to USDWs due to a lack of available documentation. Therefore, Aethon will locate and reenter the well to determine its current condition before plugging the well using approved plugging methods—or converting it for use as a monitoring well. Corrective activity will commence [redacted] prior to the critical pressure front reaching the well, based on updated modeling (Table 3-7).

The [redacted] wells with "dry and plugged" status listed in Table 3-5 were determined to have been plugged sufficiently to, per TRRC regulations, prevent the migration of fluids out of the injection zone and into the USDW at the time of abandonment of those wells.

Table 3-7 – Corrective Action List

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

Aethon will ensure that site access is secured for any future corrective action work that may be required.

The growth and extent of the CO_2 plume will be continuously monitored throughout the life of the TXCCS#1 Project. A reevaluation of the AOR will be conducted every 5 years and, if deemed necessary, adjustments will be made to the Corrective Action Plan.

3.4.1 General Reentry Process

Using available survey data collected and/or the aerial magnetometer survey, Aethon will locate and reenter the [redacted] to determine the current condition of the well.

3.4.2 In-Depth Review of Wells Requiring Corrective Action

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

[redacted] was spudded on [redacted]. The well was drilled to a total depth of [redacted] ft per IHS Market scout card and well log. The well status is listed as plugged and abandoned. No records of plugging specifics have been found. A current wellbore schematic with known information is shown in Figure 3-10.

[redacted]

Figure 3-10 – [redacted] Schematic Based on Available Information

After reentry, a current-state schematic will be generated as well as a proposed corrective action schematic.

3.5 Area of Review Reevaluation Plan and Schedule

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

- At a minimum of every 5 years
- At detection of a significant change in the plume
- As otherwise warranted by routine monitoring or operational conditions

During reevaluation, if additional wells are identified within the AOR requiring corrective action, they will be addressed with an amended AOR and Corrective Action Plan that will be submitted to the Underground Injection Control (UIC) Program director (UIC Director) for approval. All amendments and corrective action plans will be approved and incorporated into the permit, and subject to permit modification requirements per 40 CFR **§144.39.**

If no additional wells are identified during reevaluation, Aethon will demonstrate to the UIC director that no modification to the Corrective Action Plan is needed. This will be supported by monitoring data and modeling outcomes. All modeling inputs and data utilized for the purposes of AOR reevaluations will be retained for a period of 10 years.

3.5.1 Proposed Reevaluation Cycle

Aethon will reevaluate the AOR at least every 5 years, per 16 TAC **§5.203(d)(2)(B)(i)** (40 CFR **§146.84(b)(2)(i)**). Monitoring of plume growth will be utilized to determine if reevaluation is needed more frequently than the scheduled 5-year intervals.

Plume monitoring surveys will determine the actual growth and migration of the plume and be used to update the model and AOR. The results of these surveys and the model predictions are expected to converge over time and decrease in frequency.

If at any point the surveyed plume growth or migration exceeds that which was previously modeled, a reevaluation of the AOR will be conducted.

Table 3-8 lists some of the possible triggers for an AOR reevaluation.

Table 3-8 – Triggers for AOR Reevaluation

Reevaluation Trigger	Measure to Be Taken	Schedule for Commencing Reevaluation
16 TAC **§5.203(d)(2)(B)(i)** (40 CFR **§146.84(b)(2)(i)**)	Reevaluate the AOR as required by statute.	At least once every 5 years
Operational Change: Injection rate or pressure increases or decreases by more than 50% of modeled expectations for a period greater than 3 months.	Rerun the reservoir plume model with new data. If plume extents increase, reevaluate the AOR.	Within 1 month of operational change
Compositional Change: Injectate composition is altered due to an addition of a new type of capture source.		Within 1 month of compositional change
New penetrations into the UCZ within the AOR are being proposed.		Within 1 month of commencement of new operations
Major seismic event or other emergency occurs.	Perform a plume migration survey. If plume increases in shape or extents, reevaluate the AOR.	Within 1 month of the event

Appendix C contains the following AOR maps and resultant tables in large-scale format for ease of detailed review:

- Appendix C-1 Oil and Gas Wells AOR Map
- Appendix C-2 Oil and Gas Wells AOR List
- Appendix C-3 Freshwater Wells AOR Map
- Appendix C-4 Freshwater Wells AOR List
- Appendix C-5 Site Review AOR Map
- Appendix C-6 AOR Well Data and Schematic Files

Underground Injection Control – Class VI Permit Application for

Tea Olive No.1 and Flowering Crab Apple No.1

Sabine and San Augustine Counties, Texas

SECTION 4 – WELL CONSTRUCTION AND DESIGN

July 2025

SECTION 4 – WELL CONSTRUCTION AND DESIGN

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Tables

4.1 Introduction

The following section provides the details, including the engineering design and operational strategy, for the planning and construction of Aethon Energy Operating LLC's (Aethon) proposed TXCCS#1 Project injection wells, Tea Olive No. 1 and Flowering Crab Apple No. 1. The details of the engineering design meet the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(e)** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**.

The Class VI injection well design, construction, and operation is governed by the EPA, under the jurisdiction of the Underground Injection Control (UIC) Program. This project has been developed to provide a safe method of injecting and disposing of CO_2 within the permitted injection zone and ensuring containment of the injectate within that zone—thereby protecting underground sources of drinking water (USDWs).

The TXCCS #1 Project is planned to inject and sequester CO_2 within the [redacted] Formation. Described in detail in ***Section 1 – Site Characterization*** (*Section 1.3*, on the site geology), the [redacted] consists of [redacted] that offer good transmissibility and storage capacity for sequestering CO_2 for the life of the project. The reservoir characteristics of the [redacted] include good porosity and reasonable permeability, and the formation consists of approximately [redacted] feet (ft) of gross vertical thickness of carbonate [redacted], which will aid in the isolation of the injected fluid.

The specific requirements implemented for the design and operation of Tea Olive No. 1 and Flowering Crab Apple No. 1 are described in the following sections.

4.2 Engineering Design

The proposed Tea Olive No. 1 and Flowering Crab Apple No. 1 were designed with the intent of sequestering CO_2 and protecting the USDW by ensuring confinement within the injection zone. The injection wells were engineered with consideration of the injectate parameters, such as injection rates, injection volumes, pressure, temperature, fluid properties, and chemical compatibilities.

The conditions that result from the combination of CO_2 mixed with formation fluids are known to create a corrosive environment downhole. The injection well construction materials were therefore selected to withstand exposure to a corrosive environment. Well components selected to have higher-grade corrosion-resistant materials include well casing, wellhead equipment, and downhole tools. Additional consideration was given to the cement design, with acid-resistant cement incorporated to create a permanent bond between the casing and formation in the presence of corrosive fluids. Acid-resistant cement is planned to be set across the injection zone and upper confining zone (UCZ).

The CO_2 injectate will be disposed of in the [redacted] and bound by the upper and lower confining zones, as discussed in ***Section 1***. The UCZ—comprised of the [redacted] and [redacted] formations—is anticipated to consist of [redacted] that will provide a barrier seal for the injectate. For Tea Olive No. 1 and Flowering Crab Apple No. 1, the top of the [redacted] is located at approximately [redacted] true vertical depth (TVD), respectively, and is approximately [redacted] ft thick, respectively. The formation's [redacted] are characterized as porous and permeable, which make them ideal for CO_2 injection and storage.

Tea Olive No. 1 and Flowering Crab Apple No. 1 will be constructed with surface and long string (i.e., production) casing. The [redacted] inch (in.) long string casing will be installed from the surface to the plugback total depth (PBTD) and include [redacted] casing from the PBTD to the top of the UCZ, and [redacted] from the top of the UCZ to the surface. The wells' completion will incorporate a corrosion-resistant alloy (CRA) injection packer, set at the base of the UCZ, and [redacted]-in. tubing set in the injection packer. Additionally, ported [redacted] will be installed and connected to the surface by a [redacted]) line, which will be [redacted]

The two injection wells will be completed with perforations at selected intervals across the [redacted] Tables 4-1 and 4-2, respectively). A control system will be in place that will shut in either well (or both) in the event of an unexpected pressure change. If necessary, the wells can be recompleted or reworked by removing the tubing and packer. Mechanical integrity will be monitored and maintained at all times during injection operations. Upon completion of the wells, injection will commence across the [redacted]-perforated intervals per the current model. The CO_2 injectate plume will be monitored over the life of the project to ensure that the plume growth follows the modeled projection. The extensive monitoring program is detailed in ***Section 5 – Testing and Monitoring Plan***.

Table 4-1 – Tea Olive No. 1 Operational Strategy

Stage	Top Perforation (ft, MD)	Bottom Perforation (ft, MD)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]					

*MD – measured depth

Table 4-2 – Flowering Crab Apple No. 1 Operational Strategy

Stage	Top Perforation (ft, MD)	Bottom Perforation (ft, MD)	Gross Thickness (ft)	Net Pay (ft)	Duration (yrs)
[redacted]					

Details for the production casing include a [redacted] casing from the surface to the top of the UCZ, a [redacted] casing across the injection zone to the total depth (TD) of the wells. Corrosion-resistant cement will be utilized from [redacted] in Tea Olive No. 1 and from [redacted] in Flowering Crab Apple No. 1.

Monitoring equipment will be installed in the wells, including a [redacted]

The completion assembly will incorporate a [redacted] kilopounds per square inch (ksi) [redacted] tubing string from the surface to the injection packer, a [redacted] CRA injection packer set in the UCZ, and a [redacted] tail pipe set with a profile nipple and wireline reentry guide. Materials for all permanently installed flow-wetted equipment will be [redacted] across the UCZ and injection zone.

Figures 4-1 and 4-2 present the proposed wellbore designs for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

[redacted]

Figure 4-1 – Tea Olive No. 1 Wellbore Schematic

[redacted]

Figure 4-2 – Flowering Crab Apple No. 1 Wellbore Schematic

The drilling and completion design for Tea Olive No. 1 is as follows:

- Drive Pipe
    - [redacted]. to +/- 200 ft (or 200 blows/ft)
- Surface Casing
    - To be set below the lowermost USDW
        - The USDW was determined to be at 1,700 ft per a Groundwater Determination Letter issued by the Groundwater Advisory Unit (GAU) of the Railroad Commission of Texas (TRRC).
        - The USDW will be confirmed by means of openhole logging during drilling of the well. If necessary, the final setting depth will be adjusted.
            - The current estimated setting depth is 2,000 ft TVD.
    - [redacted]
    - Cemented to surface
- Production Casing
    - [redacted]
    - Cemented to surface
        - Cement to be comprised of:
            - Corrosion-resistant cement across the UCZ and injection zone, designed to be from [redacted] ft PBTD
            - Blended Portland cement from surface to [redacted] ft
- Completion Assembly
    - [redacted] tubing from surface to [redacted]
    - [redacted]-in. injection packer at [redacted]
        - [redacted]
    - [redacted] tail pipe from [redacted] ft
        - Tail pipe will be installed with a profile nipple and wireline reentry guide.
    - Tubing annulus will be filled with a noncorrosive fluid.
- Wellhead
    - Casing head assembly
        [redacted]
    - Tubing spool assembly
        - [redacted] tubing spool
        - 2 [redacted] manual gate side-outlet valves

- Production tree assembly
  - [redacted] mandrel hanger
  - [redacted] x 4 1/16-in. 5M adapter flange
  - [redacted] manual gate lower-master valve
  - [redacted] hydraulic upper-master valve
  - [redacted] flow cross
  - [redacted] manual gate wing valves
  - [redacted] hydraulic actuated wing valve
  - [redacted] manual gate crown valve with cap flange

The drilling and completion design for Flowering Crab Apple No. 1 is as follows:

- Drive Pipe
  - [redacted]. to +/- 200 ft (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW was determined to be at 1,275 ft per a Groundwater Determination Letter issued by the GAU of the TRRC.
    - The USDW will be confirmed by means of openhole logging during drilling of the well. If necessary, the final setting depth will be adjusted.
      - The current estimated setting depth is 2,000 ft TVD.
  - 17 ½-in. hole size
  - 13 3/8-in. OD casing
  - Cemented to surface
- Production Casing
  - [redacted] in. hole size
  - 7[redacted] casing set to TD of the well
    [redacted]
  - Cemented to surface
    - Cement to be comprised of:
      - Corrosion-resistant cement across the UCZ and injection zone, designed to be from [redacted]
      - Blended Portland cement from surface to [redacted]
- Completion Assembly
  - [redacted] tubing from surface to [redacted] will be [redacted].
  - [redacted] injection packer at [redacted]
    - [redacted]
  - [redacted] tail pipe from [redacted]
    - Tail pipe will be installed with a profile nipple and wireline reentry guide.

- Tubing annulus will be filled with a noncorrosive fluid.
- Wellhead
  - Casing head assembly
    [redacted]
  - Tubing spool assembly
    - [redacted] tubing spool
      - [redacted] manual gate side-outlet valves
  - Production tree assembly
    [redacted] mandrel hanger
    [redacted] adapter flange
    [redacted]anual gate lower-master valve
    ydraulic upper-master valve
    low cross
    anual gate wing valves
    ydraulic actuated wing valve
    anual gate crown valve with cap flange

4.2.1 Detailed Discussion of Injection Well Design

The TXCCS#1 project is planned to inject CO_2 at a maximum rate of [redacted] million metric tons per year (MMT/yr) or [redacted] million standard cubic feet per day (MMscf/D) per well at standard conditions, into the [redacted]t Formation. The parameters considered in the engineering of the injection wells were derived from the reservoir model and include injectate composition, rate of injection, and injection pressures. Therefore, the production string and tubing size, weights, and grades were selected to accommodate the proposed composition and injection rates for the project.

Tables 4-3 and 4-4 show the injection conditions of CO_2 used in the modeling and flow calculations for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

Table 4-3 – Tea Olive No. 1 Average Estimated CO_2 Injection Conditions

Temperature (°F)	Pressure (psia)	Density (lbm/ft³)	Enthalpy (Btu/lbm)	Entropy (Btu/lbm-°R)
[redacted]				

*psia – pounds per square inch absolute; lbm – pound mass; ft³ – cubic feet

Table 4-4 – Flowering Crab Apple No. 1 Average Estimated CO_2 Injection Conditions

Temperature (°F)	Pressure (psia)	Density (lbm/ft³)	Enthalpy (Btu/lbm)	Entropy (Btu/lbm-°R)
[redacted]				

A sensitivity analysis was run for the tubing design that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. The reservoir-engineering model runs were used to calculate the bottomhole pressures (BHPs), as shown in Figures 4-3 and 4-4 for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively. The model outputs identified when the maximum BHP will occur during the life of the project and the resulting maximum flowing pressure at the surface—allowing for proper design of the casing, tubing, and wellhead configurations.

[redacted]

Figure 4-3 – Injection Pressure Plot for Tea Olive No. 1

[redacted]

Figure 4-4 – Injection Pressure Plot for Flowering Crab Apple No. 1

For the reservoir model, a [redacted]) injectate stream was applied at a maximum allowable injection rate of [redacted] MMT/yr.

The input injection parameters from the model for both injection wells are shown in Table 4-5. The calculated injection parameters are then shown in Tables 4-6 and 4-7 for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

Table 4-5 – Input Injection Parameters for the Injection Wells

Inputs	Tea Olive No. 1	Flowering Crab Apple No. 1
Maximum Injection Rate (MMT/yr)	[redacted]	[redacted]
Pressure Constraint Gradient (psi/ft)	[redacted]	[redacted]
Injection Duration (yrs)	[redacted]	[redacted]
[redacted] Tubing Inner Diameter (in.)	[redacted]	[redacted]
Absolute Roughness Factor (in.)	[redacted]	[redacted]
Wellhead Temperature (°F)	[redacted]	[redacted]

*psi/ft – pounds per square inch per foot

Table 4-6 – Calculated Injection Parameters for Tea Olive No. 1

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

*WHP – wellhead pressure

Table 4-7 – Calculated Injection Parameters for Flowering Crab Apple No. 1

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

Based on the inputs and results from the model, a [redacted] injection tubing for both Tea Olive No. 1 and Flowering Crab Apple No. 1 is the appropriate size to move the desired volumes of the supercritical CO_2 into the formation. The model also verified that the CO_2 would remain in the supercritical state within the formation.

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

- [redacted]. drive pipe
- [redacted] in. surface casing
- [redacted]. production casing
- [redacted]-in. tubing

4.2.1.1 Conductor Pipe

Tea Olive No. 1 and Flowering Crab Apple No. 1 will be constructed with a [redacted]. conductor pipe set at 200 ft. The purpose of the conductor is to maintain the integrity of the hole during the initial drilling phase due to the loose, unconsolidated nature of sediment near the surface.

The conductor pipe was selected for the required clearance of the surface casing borehole, and will include a [redacted]-in. inner diameter (ID) such that the [redacted] in. surface hole bit can be used to clean out the conductor pipe and drill the surface hole section of the wells to a depth of [redacted] ft each for Tea Olive No. 1 and Flowering Crab Apple No. 1.

The engineering and design parameters for the selected conductor pipe for both injection wells are summarized in Table 4-8.

Table 4-8 – Parameters for the Selected Conductor Pipe – Tea Olive No. 1 and Flowering Crab Apple No. 1

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

*ppf – pounds per foot; bbl/ft – barrels per foot; ppg – pounds per gallon

4.2.1.2 Surface Casing

The surface hole for Tea Olive No. 1 and for Flowering Crab Apple No. 1 will be drilled to below the USDW and set at approximately 2,000 ft for each well. The holes will be drilled with a [redacted]-in bit, and [redacted]-in. casing installed to allow adequate annular space for a quality cement bond between the casing and the formation. Additionally, centralizers will be installed on the surface casing to ensure that the cement will be circulated to the surface and, if necessary, a top job will be performed should the top-of-cement level fall after the cement is circulated. This will guarantee a uniform cement barrier around the casing from the shoe to the surface to protect the USDW. Upon completion of the cementing operations, a cement bond log will be run to verify bonding throughout the surface strings.

The engineering and design parameters for the surface casing of Tea Olive No. 1 and Flowering Crab Apple No. 1 are summarized in Tables 4-9 through 4-14.

Table 4-9 – Surface Casing Engineering Calculations – Tea Olive No. 1 and Flowering Crab Apple No. 1

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

*BTC – buttress-thread and coupled

Table 4-10 – Surface Casing Annular Geometry – Tea Olive No. 1

Annular Geometry			
Section	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-11 – Surface Casing Annular Geometry – Flowering Crab Apple No. 1

Annular Geometry			
Section	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-12 – Surface Casing Specifications – Tea Olive No. 1 and Flowering Crab Apple No. 1

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

Table 4-13 – Surface Casing Cement – Tea Olive No. 1 and Flowering Crab Apple No. 1

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

*cf – cubic feet

Table 4-14 – Surface Casing Cement Detail – Tea Olive No. 1 and Flowering Crab Apple No. 1

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

To ensure that cement is circulated to the surface, 30% excess for the lead cement and 40% excess for the tail cement relative to the gauge hole were used in the openhole cement volume calculations. Excess cement volumes may be adjusted based on the openhole caliper log.

4.2.1.3 Production Casing

The production casing, which will be the final long string casing installed, will be set and cemented from the TD of the well to the surface. The key design criteria for the production casing string include the following:

- The use of [redacted] material and acid-resistant cement across the lower confining zone (LCZ), UCZ, and injection zone
- The use of [redacted] material from the top of the UCZ to the surface
- The use of downhole tools, including centralizers, float equipment, and galvanic crossovers
- The use of [redacted] from the surface to the UCZ
- The use of [redacted] from the surface to the UCZ

The long string casing will be installed with corrosion-resistant cement and provide an additional barrier to prevent the migration of CO_2 above the injection zone. The corrosion-resistant cement will be installed and set from the TD of the well to above the UCZ and will provide the necessary materials to resist the corrosive effects of carbonic acid within the injection zone. Figures 4-1 and 4-2 (*Section 4.2*) illustrated the production casing design for the two injection wells.

A continuous monitoring system will be installed on the [redacted] monitor for breaches of the CO_2. Moreover, the [redacted] will be used for [redacted] to monitor the CO_2 plume. The monitoring equipment will provide real-time, continuous data from the time of well construction, through the injection and monitoring phases, and until the completion of the project. Further details are provided in ***Section 5 – Testing and Monitoring Plan***.

The engineering and design parameters for the production casing for both injection wells are summarized in Tables 4-15 through 4-24.

Table 4-15 – Production Casing Engineering Calculations – Tea Olive No. 1

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

Table 4-16 – Production Casing Engineering Calculations – Flowering Crab Apple No. 1

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

Table 4-17 – Production Casing Annular Geometry – Tea Olive No. 1

Annular Geometry			
Section	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-18 – Production Casing Annular Geometry – Flowering Crab Apple No. 1

Annular Geometry			
Section	ID (in.)	MD (ft)	TVD (ft)
[redacted]			

Table 4-19 – Production Casing Specifications – Tea Olive No. 1

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

Table 4-20 – Production Casing Specifications – Flowering Crab Apple No. 1

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

Table 4-21 – Production Casing Cement – Tea Olive No. 1

Cement			
System	Top (ft)	Bottom (ft)	Volume (cf)
Lead Portland Cement	[redacted]		
Tail Corrosion-Resistant Cement			

Table 4-22 – Production Casing Cement – Flowering Crab Apple No. 1

Cement			
System	Top (ft)	Bottom (ft)	Volume (cf)
Lead Portland Cement	[redacted]		
Tail Corrosion-Resistant Cement			

Table 4-23 – Production Casing Cement Detail – Tea Olive No. 1

Volume Calculations							
Section	Footage (ft)	Capacity (cf/ft)	Excess (%)	Cement Volume (cf)	Sacks	Yield (cf/sack)	Cement Class
Production Casing / Surface Casing Annulus Lead Cement	[redacted]						
Production Casing / [redacted] Openhole Lead Cement							
Production Casing / [redacted] Openhole Tail Cement							
Shoe Track							

Table 4-24 – Production Casing Cement Detail – Flowering Crab Apple No. 1

Volume Calculations							
Section	Footage	Capacity	Excess	Cement Volume	Sacks	Yield	Cement Class
	(ft)	(cf/ft)	(%)	(cf)		(cf/sack)	
Production Casing / Surface Casing Annulus Lead Cement	[redacted]						
Production Casing / [redacted]-in. Openhole Lead Cement	[redacted]						
Production Casing /[redacted] in. Openhole Tail Cement	[redacted]						
Shoe Track	[redacted]						

To ensure that cement is circulated to the surface, 30% excess for the lead cement and 40% excess for the tail cement relative to the gauge hole were used in the openhole cement volume calculations. Excess cement volumes may be adjusted based on the openhole caliper log.

4.2.1.4 Centralizers

Centralizers will be installed in the injection-well surface casings, which include [redacted]. casing set in the [redacted] openhole sections. The purpose of the bow-spring centralizers is to provide a continuous, uniform cement column throughout the surface casing annulus and to properly circulate cement to the surface. The recommended centralizer placement is as follows:

(1) – Above shoe joint
(1) – Above float collar
(1) – Subsequent five joints of casing
(1) – Every fourth joint (160 ft) to surface

Centralizers will be installed on the [redacted] production casing, which will be installed in a [redacted] open hole for Tea Olive No. 1 and a [redacted]. open hole for Flowering Crab Apple No. 1. The centralizers will be equipped to accommodate the installation of the [redacted]—and provide continuous, uniform cement throughout the production hole to the surface, to ensure the proper placement of the monitoring system and adequate annular space for the cement bond. The recommended centralizer placement for the production holes is as follows:

(1) – Above shoe joint
(1) – Above float collar
(1) – Subsequent five joints of casing
(1) – Every third joint (120 ft) to the end [redacted]
(1) – Every joint (40 ft) to surface

4.2.1.5 Injection Tubing

The [redacted] injection tubing was selected for the size and material to accommodate the proposed injection volumes, injection rates, and injectate fluid composition. Therefore, the [redacted] tubing will be installed with [redacted] material from the surface to the injection packer. A [redacted] ft long section of [redacted] tail pipe will be installed below the packer, which will incorporate a [redacted] profile nipple and wireline reentry guide at the base. The tubing engineering calculations incorporate the maximum anticipated wellhead pressure for the tubing collapse and burst calculations. The tubing casing annulus will be monitored, with a backside pressure applied at a minimum of 100 psi over the surface tubing-head injection pressure.

Tables 4-25 and 4-26 provide the tubing design and calculations for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

Table 4-25 – Tubing Engineering Design Calculations – Tea Olive No. 1

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

Table 4-26 – Tubing Engineering Design Calculations – Flowering Crab Apple No. 1

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

4.2.1.6 Packer Assembly

The proposed packer for Tea Olive No. 1 and Flowering Crab Apple No. 1 will be installed in the [redacted] casing. The [redacted] packer will be installed as a permanent packer and include appropriate materials, [redacted], for all flow-wetted components—to ensure that the material is compatible with the expected CO_2 injection stream and formation fluids at downhole conditions.

4.2.1.7 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Additional details on the monitoring system are described in ***Section 5 – Testing and Monitoring Plan***.

4.2.1.8 Wellhead Design

[redacted]

Figure 4-5 – Preliminary Wellhead Design – Tea Olive No. 1 and Flowering Crab Apple No. 1

4.3 Testing and Logging During Drilling and Completion Operations

A schedule of all testing and logging will be submitted to the UIC Director and TRRC at least 30 days prior to conducting any activity. The TRRC will be given at least a 48-hour notice in advance of any actual activity.

4.3.1 Coring Plan

In drilling the Tea Olive No. 1 stratigraphic test well, whole core will be collected from the UCZ, injection zone, and LCZ. During the drilling of Flowering Crab Apple No. 1, supplementary sidewall cores may be collected throughout the injection and confining zones.

4.3.2 Logging Plan

An extensive suite of electric logs will be run in the openhole sections and in each string of casing. The openhole logging plan is detailed in Tables 4-27 and 4-29 for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively. The cased-hole logging plan for both injection wells is detailed in Tables 4-28 and 4-30, respectively.

Table 4-27 – Openhole Logging Plan – Tea Olive No. 1

Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Depths
[redacted]				

[redacted]

Table 4-28 – Cased-Hole Logging Plan – Tea Olive No. 1

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

Table 4-29 – Openhole Logging Plan – Flowering Crab Apple No. 1

Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Depths
[redacted]				

[redacted]

Table 4-30 – Cased-Hole Logging Plan – Flowering Crab Apple No. 1

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

4.3.3 Formation Fluid Testing

Prior to setting the production casing, formation fluid samples will be collected from the injection zone. The fluid will be obtained through an openhole fluid recovery tool, and the sample intervals will be determined based on the openhole log evaluation. Further sampling will be conducted after completion, by swabbing the tubing clean and recovering relative samples.

4.3.4 Step-Rate Injection and Falloff Test

The proposed step-rate injection test (Table 4-31) is designed to test the formation and verify its ability to receive and sequester CO_2 at the proposed injection rate, as follows:

- The test will be conducted once the wells are cased, cemented, and perforated. The test will be performed with water prior to injection.
- A successful test will either identify the formation fracture pressure or verify that the proposed injection plan will not fracture the formation. Due to the high permeability of the intervals within the [redacted] Formation, the step-rate test may require rates significantly higher than the proposed test rate, to determine the fracture pressure.
- The test will be performed with at least three steps below and three steps above the identified fracture pressure for Tea Olive No. 1 and Flowering Crab Apple No. 1.
- The test is planned with a minimum step duration of 5 minutes and a maximum step duration of 30 minutes.
- The step duration will be determined by the time required for pressure stabilization during the initial step, and this duration will be maintained for each additional step.

Table 4-31 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (bpd)	Rate (bpm)	Stage Volume (bbl)
[redacted]				

*1 metric ton of CO_2/year = .053 thousand cubic feet (Mcf) of CO_2 per day = .022 reservoir bbl per day (bpd) of CO_2; bpm – barrels per minute

Step-Rate Injection and Falloff Test Procedure

1. Prior to testing, each well should be shut in long enough to ensure that the BHP is at or near the shut-in formation pressure.
2. Set the number of 500-bbl fracture tanks required to perform the planned step-rate test operation, and fill with clean brine water. Measure the fluid density, and ensure a consistent density throughout the job.
3. Rig up the pumps and iron equipment.
4. Move in and rig up the wireline unit and perform a gauge ring run.
5. Ensure that all gauges and pressure monitoring equipment are suited for expected pressures and calibrated.
6. Ensure that the pressure gauges and monitoring equipment are installed and active. If necessary, trip in hole with a BHP gauge to the bottom of the perforation depth.
7. Fill the well with brine.
8. Begin the test once the well is full and the surface pressure has stabilized.
    a. Initialize the test with the predetermined initial injection rate.
9. Determine the time for pressure stabilization at the initial injection rate.
    a. Continue with the step duration for all subsequent injection steps.
10. Follow the predetermined injection rate schedule and proceed with injection Steps 2 through 9.
    a. Plot the BHP vs. rate in real time.
    b. Ensure the rates are consistent with the constant flow regulator.
    c. Monitor the plot to ensure pressure stabilization for each injection step.
11. Upon completion of Step 10, shut in the well and record pressures at the highest frequency of the gauge for a minimum of 1 hour or until the radial flow is established.
12. Conclude the test, and rig down and move out the pumps.
13. Rig down and move out the wireline unit.

4.4 Injection Well Operating Strategy

The proposed TXCCS#1 Project plans to inject CO_2 at a rate of [redacted] per well, in Tea Olive No. 1 and Flowering Crab Apple No. 1. [redacted]

The injection process is designed to inject the CO_2 within the supercritical state within the injection zone. The reservoir characteristics of the [redacted] Formation will allow the pressure induced by the injection stream to be absorbed and dissipated within the reservoir.

Details on the modeled surface and bottomhole injection pressures are provided in Table 4-32.

Table 4-32 – Injection Parameters

Parameter	Tea Olive No. 1	Flowering Crab Apple No. 1
Gross Injection Zone	[redacted]	
Maximum Injection Volume		
Average Injection Volume		
Maximum Increase in BHP		
Maximum Surface Injection Pressure		
Expected Surface Pressure Injection		
Maximum Annular Pressure		

The surface injection pressures will be limited by the BHP, ensuring that injection operations do not exceed 90% of the fracture pressure at the injection formation. The surface and bottomhole injection pressures were modeled, along with the maximum required BHP. This is shown in Tables 4-33 and 4-34 for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively. Annulus pressure that exceeds operating injection pressure will be maintained unless that would harm the integrity of the well or endanger USDWs.

Table 4-33 – Initial Modeled Injection Pressures and Volumes – Tea Olive No. 1

Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowed BHP (psi)	Maximum Modeled BHP (psi)	Maximum Modeled WHP (psi)	Minimum Modeled WHP (psi)
[redacted]					

Table 4-34 – Initial Modeled Injection Pressures and Volumes – Flowering Crab Apple No. 1

Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowed BHP (psi)	Maximum Modeled BHP (psi)	Maximum Modeled WHP (psi)	Minimum Modeled WHP (psi)
[redacted]					

The densities of the injectate planned for Tea Olive No. 1 and Flowering Crab Apple No. 1 are approximately [redacted]/ft^3 into the top of the [redacted] The density of the formation fluid is estimated to be [redacted] lb/ft^3. The resulting density difference, combined with some vertical permeability of the formation, will allow some of the CO_2 to migrate vertically to the top of each vertical barrier within the formation—including up to and laterally beneath the UCZ.

Further details on the plume model are presented in ***Section 2 – Plume Model***.

4.5 Injection Well Construction and Operation Summary

Tea Olive No. 1 and Flowering Crab Apple No. 1 were engineered to adhere to UIC standards and to provide an effective method of injecting and storing CO_2 while protecting USDWs and mitigating any other risks associated with Class VI wells. The well design, casing set points, construction metallurgies, and cement meet the requirements for this classification of injection well. The proposed operating strategies to be employed during injection operations were developed to offer efficient use of the reservoir pore space and mitigate pressure influences within the injection formation.

The proximity of CO_2 emission sources to the project area, the available reservoir storage, and the plume orientation in relation to the project boundary make Tea Olive No. 1 and Flowering Crab Apple No. 1 ideal for safe carbon sequestration. Combining the best engineering practices in the design of the wells with state-of-the-art monitoring systems and extensive reservoir management strategies means these wells will safely serve the state of Texas for years to come.

4.6 USDW Monitoring Wells

To comply with (16 TAC) **§5.203(j)(2)** (40 CFR **§146.90(d)**), two USDW monitoring wells will be drilled into the deepest USDW sand to support the proposed TXCCS#1 Project. The deepest USDW formation is defined by salinity and is currently estimated to occur at a depth of 1,700 ft at the Tea Olive No. 1 location and 1,275 ft at the Flowering Crab Apple No. 1 location. When the injection and USDW monitoring wells are drilled, the USDW depth will be confirmed at each location through the collection of openhole wireline resistivity logs.

Water samples will be collected from the USDW monitoring wells to monitor not only for signs of CO_2 migration into the USDW, but also for any form of brine leakage.

4.6.1 Fluid Sampling Methods

Water samples will be collected at the surface from the USDW monitoring wells. Two well volumes will be purged prior to collection to ensure that the formation fluid sampled is representative of the USDW formation fluid. These water samples will be analyzed in the field for a variety of physical parameters, which may include cations, trace metals, anions, total dissolved solids, alkalinity, dissolved inorganic carbon, total organic carbon, carbon isotopes, water isotopes, radon, and carbon 14/12 isotopes. The initial sampling efforts will serve as a baseline for the continued monitoring operations and will be conducted annually for the first 5 years. The fluid sampling parameters and frequencies for the groundwater monitoring wells are outlined in ***Section 5*** – ***Testing and Monitoring Plan*** (*Section 5.5.5*). Details regarding sampling techniques and processes are explained in *Section 5.5.5.1.*

The proposed preliminary designs for TOMW No. 1 and FCAMW No. 1 are depicted in Figures 4-6 and 4-7, respectively.

[redacted]

Figure 4-6 – TOMW No. 1 Wellbore Schematic

[redacted]

Figure 4-7 – FCAMW No. 1 Wellbore Schematic

Appendix D – Well Construction Schematics and Cement Program:

- Appendix D-1 Drilling and Completions Wellbore Schematic – Tea Olive No. 1
- Appendix D-2 Drilling and Completion Wellbore Schematic – Flowering Crab Apple No. 1

Underground Injection Control – Class VI Permit Application for

Tea Olive No.1 and Flowering Crab Apple No.1

Sabine and San Augustine Counties, Texas

SECTION 5 – TESTING AND MONITORING PLAN

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SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

The operating plans for the proposed Aethon Energy Operating LLC (Aethon) TXCCS#1 Project include sound testing and monitoring programs in accordance with promulgated regulations. The operating plans are designed to satisfy the requirements of 16 Texas Administrative Code (16 TAC) **§5.203(j)** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90** and will begin before CO_2 injection commences. Monitoring strategies are intended to ensure and verify protection of the underground sources of drinking water (USDWs). These strategies consider, but are not limited to, the injection-stream composition, wellhead conditions, bottomhole operating parameters, seismic imaging for plume evolution, well integrity, and above-zone confinement conditions. The location and information for all monitoring wells are presented, as are the parameters to be measured at each location. An in-depth summary of plume-growth monitoring, using time-lapse seismic imaging technology, is also conveyed.

The monitoring activities described in this plan will be carried out for the entirety of the life of the injection wells, including the post-injection site care (PISC) phase. The monitoring activities will follow a predetermined timeline tailored toward verifying that the observed plume development is according to modeling expectations, as well as demonstrating that the injected CO_2 is not endangering the USDWs. This section discusses the key details of this plan.

5.2 Recordkeeping and Reporting Requirements

In compliance with 16 TAC **§5.207** (40 CFR **§146.91**), Aethon will provide routine reports to the Underground Injection Control (UIC) Program director (UIC Director). The report contents and submittal frequencies are as follows.

Per-Occurrence Reporting:

- Any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between USDWs
  - Verbal Notification – Reported within 24 hours of the event
- Any evidence that the injected CO_2 stream or associated pressure front may endanger a USDW
  - Verbal Notification – Reported within 24 hours of the event
  - Written Notification – Reported within 5 working days of the event
- Any failure to maintain mechanical integrity
  - Verbal Notification – Reported within 24 hours of the event
- Any significant data that indicate the presence of leaks in the well or lack of confinement to the injection zone
  - Verbal Notification – Reported within 24 hours of the event
  - Written Notification – Reported within 5 working days of the event
- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data

    - Written Notification – Reported within 72 hours of composition change
- Any new wells installed at the facility and the type, location, number and information required by 16 TAC **§5.203(e)**
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure, as specified in the permit
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 72 hours of the event
- Description of any event that triggers a shutoff device either downhole or at the surface and the response taken
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 72 hours of the event
- Any significant injection-rate variance from normal operating conditions (greater than 50% instantaneous increase)
    - Verbal Notification – Reported within 24 hours of the event
- Results of injection pressure and rate monitoring of each injection well, on Railroad Commission of Texas (TRRC) Form H-10, Annual Disposal/Injection Well Monitoring Report
- Any release of CO_2 to the atmosphere or biosphere
    - Verbal Notification – Reported within 24 hours of the event

Semiannual Reports:

- Summary of wellhead pressure monitoring
- Any changes to the source of the CO_2 stream
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
- Monthly average, maximum and minimum values of injection pressure, flow rate, temperature, 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 that triggers a shutdown device and the response taken
- Monthly volume of the CO_2 stream injected during the reporting period, and the volume injected cumulatively during the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring, as described in this section

Annual Reports:

- Any corrective action performed
- Recalculated area of review (AOR) or statement confirming that monitoring and operational data support the current delineation of the AOR on file with the regulatory authority
- Proof of good faith claim to sufficient property rights for the storage facility operation

- Metric tons of CO_2 injected

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

- Any well workover
- Any test of the injection wells, if required by the UIC Director
- Any periodic mechanical integrity tests

Notification to the UIC authority (16 TAC **§5.206(c)**), in writing, 30 days in advance of the following:

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

Aethon will submit the above reports, submittals, and notifications to the EPA and TRRC and ensure that such records are retained throughout the life of the project. In accordance with 16 TAC **§5.207(e)** (40 CFR **§146.91(f)**), these records will be maintained for 10 years after site closure. The records will be delivered to the UIC Director upon request after the retention period. Monitoring data will be retained for 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

In accordance with 16 TAC **§5.207(a)(3)** (40 CFR **§146.90(j)**), the Testing and Monitoring Plan will be reviewed and revised at least every 5 years or as otherwise required to incorporate collected monitoring data. Plan amendments will also be submitted within 1 year of an AOR reevaluation, following significant facility changes—such as the development of offset monitoring wells or newly permitted injection wells within the AOR—or as the UIC Director requires.

5.4 Testing Strategies

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO_2 injection, Aethon will conduct a step-rate injectivity test to measure the fracture gradient of the proposed injection wells, Tea Olive No. 1 and Flowering Crab Apple No. 1, in compliance with 16 TAC **§5.203(f)(2)(A)** (40 CFR **§146.87(d)(1)**) and **§5.203(f)(2)(C)** (40 CFR **§146.87(e)(3)**). Pressure and temperature gauges will be run on tubing to measure bottomhole injection and casing annulus pressures and temperatures. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottomhole pressure and temperature readings will be taken prior to beginning injection.

5.4.1.1 Step-Rate Testing Method

Specific wellbore and injection zone properties will define the final test parameters. The following test method outlines the expected test injection rates and times. The test schedule below was developed using preliminary estimates for reservoir conditions. The test procedure will be updated after log and core data are available from the injection wells.

Brine injection will begin at less than 1 barrel per minute (bpm) and be held for a minimum of 5 minutes, not to exceed a maximum of 30 minutes. The injection rates will be stepped up in increments until at least three measurements are taken, both below and above the estimated formation fracture-initiation pressure. Each stage duration will be based on the time required for the bottomhole pressure for the initial step to stabilize. Table 5-1 lists the proposed rates and total volumes planned for the step-rate test.

Table 5-1 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (bpd)	Rate (bpm)	Stage Volume (bbl)
1	30	720	0.5	15
2	30	1,440	1	30
3	30	2,880	2	60
4	30	4,320	3	90
5	30	5,760	4	120
6	30	7,200	5	150
7	30	10,080	7	210
8	30	12,960	9	270
9	30	15,840	11	330
10	30	18,720	13	390
11	30	21,600	15	450
12	60	0	0	0
Total	**420**			**2,115**

*bpd – barrels (bbl) per day

A plot of stabilized injection pressure vs. injection rate at each step should graphically represent a linearly sloped line, until the fracture initiation pressure is exceeded. Figure 5-1 is a graphical representation of an example step-rate test.

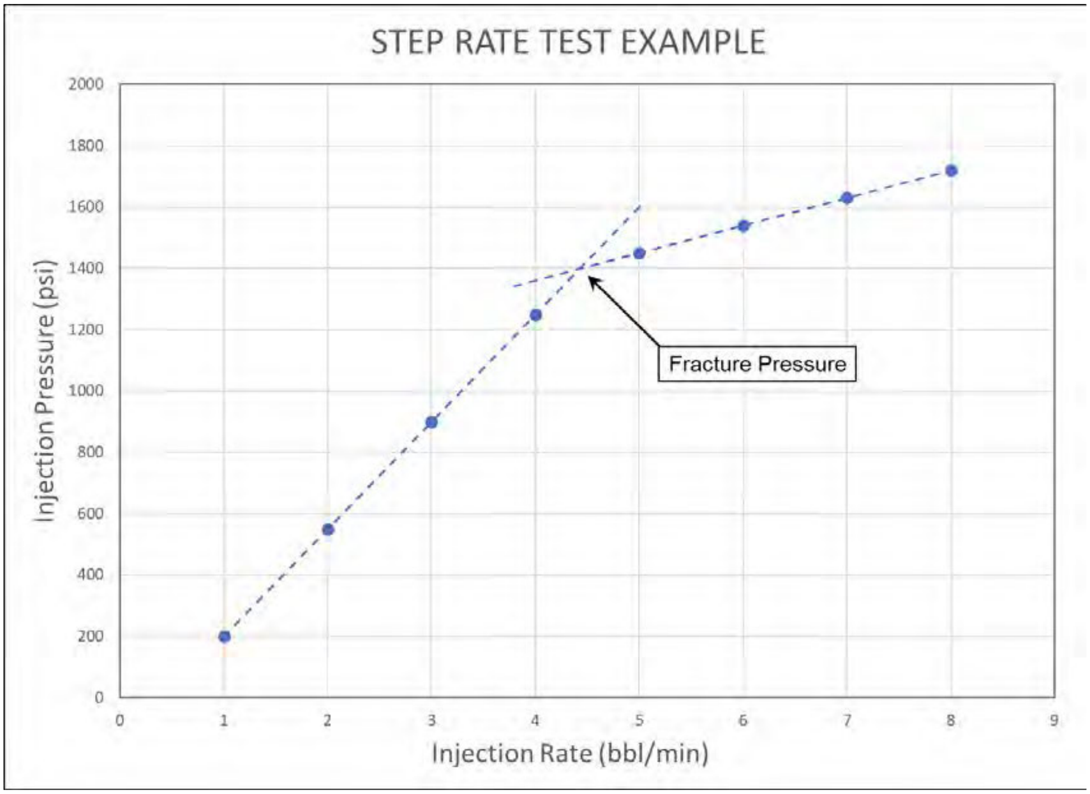

Figure 5-1 – Example Step-Rate Injectivity Test[1]

Upon completion of the final step, the wells will be shut in immediately, and pressures will be recorded at the highest frequency of the gauge for 1 hour to observe the pressure falloff.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 16 TAC **§5.203(h)(1)(B)** and **§5.203(h)(1)(C)** (40 CFR **§146.89(b)**), Aethon will ensure the mechanical integrity of both injection wells by performing annulus pressure tests (1) after the wells have been completed, (2) prior to injection, and (3) every 5 years until the wells are plugged. Annulus pressure tests specifically verify the integrity of the annulus between casing and tubing above the packer. During well construction, prior to completion, the casing will also be pressure-tested to the maximum anticipated annulus-surface pressure to verify its integrity.

After the wells are completed, an annulus pressure test will be performed prior to the start of injection, to demonstrate the mechanical integrity of the casing, tubing, and packer. An annulus pressure test will also be performed after any workover operation involving the removal and replacement of the tubing and packer. The annulus will be pressured to a minimum of 500 pounds per square inch (psi) fluid pressure, which is the TRRC H-5 test pressure if the maximum permitted injection pressure is 500 pounds per square inch gauge (psig) or more. A block valve

[1] https://www.epa.gov/sites/default/files/documents/INFO-StepRateTest.pdf

will be used to isolate the test pressure source from the test pressure gauge once the test has begun. All ports into the casing annulus—other than the one monitored by the test pressure gauge—will be closed. The test pressure will be monitored and recorded for a minimum of 30 minutes. The test pressure gauge will be of sufficient sensitivity to indicate a loss of 5%. Any loss of test pressure more than 5% during the minimum 30 minutes will indicate a lack of mechanical integrity.

All annulus pressure test results will be submitted on Form H-5 to the TRRC/EPA within 30 days of completion.

5.4.3 External Mechanical Integrity Testing

Aethon will perform external mechanical integrity tests (MITs) annually, to meet the requirements of 16 TAC **§5.203(h)(1)(D)** (40 CFR **§146.89(c)**), by running either (1) an approved tracer-type survey such as a radioactive tracer, pulsed neutron log (PNL), or similar tool; or (2) a temperature or noise log. A continuous temperature profile for monitoring mechanical integrity is done by using the distributed temperature sensing (DTS) system installed on the fiber optic system installed on the outside of the 7-inch casing, as described in ***Section 4 – Well Construction and Design***. A PNL and temperature log will be run after the casing is installed and cemented, to establish the baseline to compare against future logs. Satisfactory mechanical integrity is demonstrated by monitoring the continuous wellbore temperature profile and supplementing as needed with the PNL or temperature log—with proper correlation between the baseline and subsequent logs. All logs will be reported to the UIC Director within 30 days of the log run.

5.4.4 Pressure Falloff Testing

Aethon will perform a required pressure falloff test at least every 5 years to meet the requirements of 16 TAC **§5.203(j)(2)(G)** (40 CFR **§146.90(f)**). This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases. Parameters obtained from the falloff tests will be compared to those determined from the computational modeling and previous tests, for indications of fluid leakage during the test.

5.4.4.1 <u>Testing Method</u>

The CO_2 injection rate and pressure will be held as constant as possible prior to the beginning of the falloff test, and data will be continuously recorded during testing. After the wells are shut in, continuous pressure measurements will be recorded using the ported downhole pressure gauge installed at the end of the tubing, as described in ***Section 4***.

Pressure Falloff Test Procedure:

1. Prior to testing, keep the injection rate and pressure as constant as practical and continuously recorded.

   a. The injection rate should be high enough and maintained for a duration sufficient to produce a measurable pressure transient that will result in a valid falloff test.
   b. Offset wells should be maintained and recorded at a constant injection rate during the test and then accounted for in the analysis.
2. Stop injection and shut in the well completely.
   a. This shut-in should occur over the shortest time possible.
   b. During the shut-in period, continue to record temperatures and pressures at the highest obtainable frequency.
   c. The shut-in period should be long enough to allow for pressure transient analysis.
3. Formal pressure falloff test procedures will be submitted to the TRRC for approval before beginning the test.

5.4.4.2 Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, and hydraulic property and boundary conditions, will be determined through standard diagnostic plotting. This determination is accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by comparing pressure falloff tests performed prior to initial injection, with later tests and rate transient analysis. The effects of two-phase flow will also be considered.

The well parameters resulting from falloff testing will be compared against those used in the AOR determinations and site computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary. Results of the pressure falloff test will be reported to the UIC Director within 30 days of the test.

5.4.4.3 Quality Assurance/Quality Control

All surface field equipment will undergo inspection and testing prior to operation. The pressure gauges used in the falloff test will be calibrated according to manufacturers' instructions and field checked for proper function. Documentation of field tests will also be enclosed with the test results.

5.4.5 Cement Evaluation and Casing Inspection Logs

In accordance with 16 TAC **§5.203(h)(2)** (40 CFR **§146.87(a)(4)(iv)**), a comprehensive cased-hole logging suite will be run on the long string casing at the time of initial injection-well completions. This suite of logs will include cement bond, variable density, ultrasonic, and temperature logs, to establish the condition of the casing metal and the cement bond between the casing and the formation. This survey will characterize the original state of the wellbore materials.

A through-tubing ultrasonic casing inspection log will be run every 5 years, if another log has not been obtained in the interim. If investigation is warranted, conventional casing inspection logs, which require pulling the tubing and packer, will be run prior to abandonment. Casing inspection logs currently planned for using current technology consist of the following:

- Multiple-armed calipers to measure the inner diameter (ID) 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 the cement bonding
- Electromagnetic tools that measure the magnetic flux of the tubular and can provide mapped circumferential images to indicate potential pitting

Aethon will provide logging plans to the UIC Director as outlined in the drilling plans in ***Section 4 – Well Construction and Design***. Verbal notice will be provided at least 48 hours in advance of such activity.

5.4.5.1 <u>Logging and Testing Reporting</u>

A report that includes logging and testing results obtained during the drilling and construction of the proposed injection wells—and interpreted by a knowledgeable log analyst—will be submitted to the UIC Director in accordance with 16 TAC **§5.203(h)(2)** (40 CFR **§146.87(a)**).

5.5 <u>Monitoring Programs</u>

5.5.1 Monitoring Overview

Pressure and temperature gauges, plus fiber optic temperature and acoustic sensing, will be run and cemented behind the 7-inch casing from the surface to the total depth of the wellbore. Pressure and temperature gauges will also be run on tubing to measure bottomhole injection and casing annulus pressures and temperatures. A surface gauge with continuous readout will also be installed. Specific vendor-proprietary equipment details will be provided when the vendor is selected nearer to the time the proposed wells are drilled.

Table 5-2 summarizes the various measurements discussed in the Testing and Monitoring Plan.

Table 5-2 – Testing and Monitoring Plan Measurements

Monitoring Type	Monitoring Program	Location	Frequency
CO_2 Injection Stream Composition	• Gas chromatography (GC), thermal conductive detector (TCD), and thermal ionization detector (TID)	CO_2 meter run to injection wells	Continuous—validated with sufficient frequency to yield data representative of its chemical and physical characteristics
Corrosion Monitoring	• Corrosion coupon system	Facility flowline	Quarterly
Continuous Recording of Injection Pressure, Rate, and Volume	• Surface pressure and temperature gauges • Volumetric flowmeter	Wellhead	Continuously

Monitoring Type	Monitoring Program	Location	Frequency
Well Annulus Pressure Between Tubing and Casing	• Annular pressure gauge and casing fluid volume monitoring	Wellhead	Continuously
Groundwater Monitoring	• TOMW No. 1 and FCAMW No. 1 – USDW monitoring wells • Groundwater monitoring wells	Facility	Annually first 5 years, then every 5 years until the plume stabilizes
In-Zone Monitoring (IZM) / Direct Reservoir Monitoring	• Pressure/temperature gauges on two tubing encapsulated conductor (TEC) cables with one fiber optic cable	Tea Olive No. 1 and Flowering Crab Apple No. 1	Continuously
Above-Zone Monitoring (AZM)	• Pressures • Fluid samples	Tea Olive No. 1 and Flowering Crab Apple No. 1	• Pressure—continuously • Fluid samples—initially as a baseline
Indirect Reservoir Monitoring	• Geophysical methods	Facility	Initially and 4 years after injection begins, then will reevaluate the use of alternative technologies after 4 years of injection
Internal and External Mechanical Integrity	• Tubing-casing annulus pressure test • Pulsed neutron logs • Tubing-casing annulus pressure monitoring • External casing pressure-and-temperature monitoring • Pressure falloff test • Ultrasonic logs	Tea Olive No. 1 and Flowering Crab Apple No. 1	• 5 years • Annually • Continuously • Continuously • 5 years • 5 years

5.5.2 Continuous Injection Stream Physical Monitoring

Aethon will ensure continuous monitoring of the injection pressure, temperature, volumetric flow rate, and injection annulus pressure in compliance with 16 TAC **§5.203(j)(2)(B)** (40 CFR **§146.90(b)**). A Supervisory Control and Data Acquisition (SCADA) system will facilitate the operational data collection and monitoring for the full sequestration site—consisting of the pipeline, injection wells, and USDW wells.

The pressure and temperature of the injected CO_2 stream will be continuously monitored—using digital pressure gauges installed in the CO_2 pipeline, near its interface with the wellhead—and connected to the SCADA system on-site. A volumetric flowmeter will be installed on the injection wells to measure the volumetric flow rate of CO_2 injected. The flowmeter will be connected to the CO_2 storage site's SCADA system to continuously monitor and control the rate of CO_2 injection.

Volumetric flow rates measured during CO_2 injection can be converted to a mass flow rate using the equations below. This conversion can be performed by considering the density of the fluid. The pressure, temperature, and fluid composition are required to calculate density at specific conditions. The National Institute of Standards and Technology (NIST) Reference Fluid Thermodynamic and Transport Properties (REFPROP) database or similar fluid-property calculation software may be used to determine density.

$$\rho = f(T, P, Fluid\ Composition) \leftarrow\ REFPROP\ software$$

$$Q_m =\ Q_v * \rho$$

Where:
Q_m = mass flow rate (pounds (lb)/day)
T = temperature (°F)
P = pressure (psi)
P = CO_2 density (lb/cubic feet (ft^3))
Q_v = volumetric flow rate (ft^3/day)

<u>Example Calculation</u>

Q_v = 20,000 ft^3/day
T = 135°F
P = 3,583 psi
Fluid composition = 99.6% CO_2, 0.4% CH_4

(Eq. 1) $\rho = f(135\ °\mathrm{F}, 3583\ psi, 99.6\%\ CO2, 0.4\%\ CH4)$
$\rho = 49.475\ lb/ft3$

(Eq. 2) $Q_v = 20{,}000\ ft3/day\ *\ 49.475\ lb/ft3$
$Q_m = 989{,}500\ \mathrm{lb/day}$

Reservoir temperatures and pressures will be measured through gauges installed on a TEC and a fiber optic system embedded in the cemented annulus behind the long string casing. The gauges are described in detail in *Section 5.5.9*. These reservoir conditions will be used to calculate pressure influences throughout the reservoir as a result of injection operations, using pressure and rate transient analysis and diffusivity equations.

To meet the requirements of 16 TAC **§5.206(d)(2)(F)(i)** (40 CFR **§146.88(e)(2)**), alarms and automatic shutoff systems will be installed to alert the operator and/or shut in the well when operating parameters, such as injection pressure, injection rate, annulus pressure or other parameters, diverge from permitted ranges or gradients. The maximum injection pressure is [redacted] psi for Tea Olive No. 1 and [redacted] psi for Flowering Crab Apple No. 1. Exceeding the injection pressure outside of standard operating conditions during injection operations will result in a shutdown event.

To meet the requirements of 16 TAC **§5.206(d)(2)(D)** (40 CFR **§146.88(c)**), the annulus pressure will be maintained at a pressure above the injection pressure, using a fluid management system that allows the operator to increase or decrease the annulus pressure by adding or removing fluid. The fluid that is added or removed will be measured and recorded to identify fluid volume changes. As part of ongoing operations, changes in rate and temperatures of the injected CO_2 will expand or contract the volume of fluid in the annulus to maintain constant pressure. Excessive changes beyond expansion or contraction of the annulus fluid will indicate a possible mechanical integrity issue and result in the well(s) being shut in for further evaluation.

5.5.2.1 <u>Analytical Methods</u>

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

5.5.2.2 <u>Deviation Response</u>

In any event where the sampling or analysis indicates a variance from the normal baseline, the UIC Director will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the director for approval and implementation.

5.5.3 Injection-Stream Composition Monitoring

In accordance with 16 TAC **§5.203(j)(2)(A)** (40 CFR **§146.90(a)**) requirements, Aethon will determine the chemical composition of the injection stream, with the objective of understanding potential interactions between CO_2 and other injectate components, as well as with the wellbore construction materials. Injection stream composition is achieved by periodic measurements of the CO_2 at the metering station using GC, TCD, and TID analysis of the parameters listed in Table 5-3, plus continuous pressure and temperature analysis.

5.5.3.1 <u>Sampling Methods</u>

In a location representative of injection conditions, CO_2 stream samples will be collected from the CO_2 pipeline. A sampling station will be connected to the pipeline inlet meter at a sampling manifold. Sampling cylinders will be purged with the injectate gas to expel laboratory-added gas, or vacuum cylinders will be used to obtain the samples. The samples will tested on-site using portable analyzers.

5.5.3.2 Parameters Measured

Table 5-3 – Injection Stream Measurements and Frequency

Parameter/Analyte	Frequency	Method
Pressure	Continuous	Pressure gauges at the meter, wellhead (downstream of choke) and downhole
Temperature	Continuous	Temperature gauges at the meter, wellhead, and downhole
CO_2 (%)	Quarterly	GC/TCD
Water (lb/MMscf)	Quarterly	GC/HID
Methane (%)	Quarterly	GC/TCD
Ethane (%)	Quarterly	GC/TCD
Hydrogen Sulfide (ppm)	Quarterly	GC/TCD

*GC/HID – gas chromatography with helium ionization detector; MMscf – million standard cubic feet; ppm – parts per million

5.5.3.3 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the UIC Director will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the director for approval and implementation.

5.5.4 Corrosion Coupon Monitoring

Aethon will implement a corrosion coupon monitoring program to monitor corrosion of the tubing and casing materials in the injection wells. The program will be carried out quarterly to meet 16 TAC **§5.203(j)(2)(C)** (40 CFR **§146.90(c)**) requirements. Aethon will also use nondestructive testing per American Petroleum Institute (API) code on pipe inspections—API-570, Piping Inspection Code: In-Service Inspection, Repair, and Alteration of Piping Systems—on locations within the system that are subject to higher potential metal loss. It is well understood that coupon analyses are insufficient methods for assessment of piping corrosion and erosion, and API-570 provides an improved methodology for assurance to pipe integrity.

5.5.4.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection wells' tubing and production casing, will be exposed to the conditions of the CO_2 flow in the pipeline, in a flow loop installed off of the pipeline. The coupons will be removed and examined per the American Society for Testing and Materials (ASTM) standards. The coupons, once removed, will be visually inspected for signs of corrosion, including pitting and cracking. The loss of mass rate will be calculated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration. Aethon will further perform nondestructive inspection methods of critical spots in the piping.

Corrosion monitoring will be conducted and recorded quarterly. If a change of injectate composition is detected during gas sampling and/or continuous recording of operational parameters that indicates a potential for corrosion, Aethon will implement a risk-based schedule for inspecting coupons based on the calculated corrosion rate.

5.5.4.2 <u>Deviation Response</u>

In any event where the sampling or analysis indicates a variance from the normal baseline, the UIC Director will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the director for approval and implementation.

5.5.5 Groundwater Quality Monitoring

To meet 16 TAC **§5.203(j)(2)(D)(i)** (40 CFR **§146.90(d)**) requirements, groundwater quality and geochemical monitoring above the upper confining zone (UCZ) will be conducted in order to detect potential changes that may result from fluid leakage out of the injection zone. As discussed in *Section 1.8.2* (***Section 1 – Site Characterization***), the groundwater at the TXCCS#1 Project site generally moves from [redacted].

The TRRC's Groundwater Advisory Unit (GAU) identified the base of usable quality water (BUQW) at a depth of 1,250 feet (ft) and the base of the USDW at a depth of 1,700 ft at the Tea Olive No. 1 location. The BUQW and the base of the USDW for Flowering Crab Apple No. 1 are at 1,000 ft and 1,275 ft, respectively—to protect potential freshwater resources identified within the [redacted] aquifers. Aethon therefore plans to drill two USDW-base groundwater monitoring wells on the property, to measure any change from baseline parameters that would indicate the migration of CO_2 into the USDW.

The locations of the USDW-base monitoring wells are shown in Figure 5-2, listed in Table 5-4, and included in *Appendix E*. During the final planning of the well pads, the locations of those wells could change slightly. Well construction and drilling details, along with schematics, are included in *Appendix D* (from ***Section 4 – Well Construction and Design***).

Aethon will seek access to sample water from other existing groundwater wells for monitoring purposes, including any water wells drilled by Aethon for drilling purposes. A map of existing water wells surrounding the project is located in *Appendix C-3* (from ***Section 3 – Area of Review and Corrective Action Plan***). Access to these wells is subject to the agreements and rights of the existing owners.

[redacted]

Figure 5-2 – Proposed Locations of the Monitoring Wells

Table 5-4 – USDW Monitoring Well Details

Location Info	TOMW No. 1	FCAMW No. 1
NAD 83 (2011) Latitude	[redacted]	
NAD 83 (2011) Longitude		
Total Depth (ft)		
Depth to Base of USDW (ft) per GAU Determination	1,700	1275
Type	Vertical	Vertical

*NAD 83 – North American Datum of 1983

Detailed wellbore schematics for TOMW No. 1 and FCAMW No. 1 are displayed in Figures 5-3 and 5-4, respectively. The schematics are also included, along with drilling and completion procedures, in *Appendix D*.

[redacted]

Figure 5-3 – TOMW No. 1 Wellbore Schematic

[redacted]

Figure 5-4 – FCAMW No. 1 Wellbore Schematic

5.5.5.1 Parameters

Samples will be taken annually for the first 5 years, then every 5 years subsequently, with parameters to be measured as shown in Table 5-5.

Table 5-5 – USDW Monitoring-Well Sampling Parameters Measured

Parameter	Analysis Method	Detection Limit or (Range)	Typical Precision/Accuracy
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si	EPA Method 6010D and 7470A	0.1 to 1 mg/L (analyte dependent)	±10%
Trace Metals: Sb, As, Ba, Cd, Cr, Cu, Pb, Hg, Se, Tl	EPA Method 6010B	1 µg/L for trace elements	±10%
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-, CO_3^{2-}	EPA Method 9056A	N/A	±15%
TDS	Gravimetric Method and Standard Methods 2540C	12 mg/L	± 5%
Alkalinity	Standard Methods 2320B	4 mg/L	±3 mg/L
Dissolved Inorganic Carbon (DIC)	EPA Method 9060A	0.002%	±10%
Total Organic Carbon (TOC)	EPA Method 9060A	0.002%	±10%
Carbon Isotopes ($^{13/12}C$)	Acidified and analyzed via a gas bench and CF-IRMS	10^{-15}	±0.2‰
Water Isotopes ($^{2}H/^{1}H$, $^{18/16}O$)	Cavity ring-down spectroscopy (CRDS)	10^{-9}	IRMS: ±1.0‰ for ^{2}H; ±0.15‰ for ^{18}O; WS-CRDS: ±0.10‰ for ^{2}H; ±0.025‰ for ^{18}O
Radon (^{222}Rn)	Standard Methods 7500-Rn B	5 mBq/L	±10%
Isotopes ($^{14/12}C$)	Accelerator MS	10^{-15}	±4‰

*mg/L – milligrams per liter; µg/L – micrograms per liter; CF-IRMS – continuous-flow isotope ratio mass spectrometry ; mBq/L – megabecquerel/liter; WS – wavelength scanned; MS – mass spectrometry

5.5.5.2 Sampling Methods

Prior to sampling, each USDW monitoring well will be purged of any fluid stored in the wellbore. Static fluid levels will be measured prior to purging the wells. A U-tube sampling system or submersible pump will be lowered to the USDW-monitored zone. Samples will be obtained in laboratory-provided containers and sent to the laboratory for water analysis (Table 5-5).

5.5.5.3 Analytical Methods

Water sample test results will be maintained for the parameters listed in Table 5-5. If any impurities exist in the injectate, testing of those components will be included in the analysis 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 the following:

- Change in TDS
- Changing signature of major anions and cations
- Increasing CO_2 concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increase concentration of leached constituents
- Increased reservoir pressure and/or static water levels

5.5.5.4 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.5.5 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—and details of any problems encountered will be will included.

5.5.5.6 Quality Assurance and Surveillance Measures

Duplicate samples and trip blanks for quality assurance/quality control (QA/QC) purposes will be collected and used to validate test results and ensure that samples are free of contamination.

5.5.5.7 Plan for Guaranteeing Access to All Monitoring Locations

Aethon has access permission to the two planned USDW-base monitoring wells, TOMW No. 1 and FCAMW No. 1, and so does not anticipate issues for accessibility.

5.5.6 Above-Zone/In-Zone Monitoring Wells

No above-zone/in-zone monitoring wells will be drilled. The injection wells, Tea Olive No. 1 and Flowering Crab Apple No. 1, will be designed for both AZM and IZM.

Where applicable, any existing wells in need of corrective action may be considered for in-zone or above-zone monitoring—but will only be able to monitor for pressure, as no existing wellbores are expected to be in the CO_2 plume.

5.5.7 Injection Plume and Pressure Front Tracking

Aethon proposes a two-tiered system for plume and critical pressure front tracking per the operational monitoring requirements of 16 TAC **§5.203(j)(2)(E)** (40 CFR **§146.90(g)**). Direct and indirect monitoring methods will be used to (1) confirm reservoir conditions during injection, (2) track plume and critical pressure front migration, and (3) validate the reservoir model.

The critical pressure front will be directly monitored in the injection wells by continuously recording pressures and temperatures in the injection zone as well as using the pressure falloff tests described in *Section 5.4.4* to calculate the extent of the pressure increase. Additional use of monitoring wells, either drilled as needed or by converting existing penetration wells—as described in ***Section 3 – Area of Review and Corrective Action Plan***—could be implemented to verify variabilities in the analysis.

The CO_2 plume will be indirectly monitored using various geophysical survey technologies, such as controlled-source electromagnetic (CSEM) (Barajas-Olalde et al., 2023), vertical seismic profile (VSP), or time-lapse 2D seismic surveys, which will determine the actual CO_2 plume migration. The surveys will be run before injection initiation—to establish a baseline—then run periodically as needed, at least every 5 years. Additionally, after injection has ended, surveys will be run every 5 years, or until plume stabilization has been verified.

5.5.7.1 Direct Monitoring: Pressure and Rate Transient Analysis, and Well Logs

Continuous pressure monitoring of the reservoir in the injection zone will allow for monitoring of reservoir conditions and inform calculations. The diffusivity equation can solve reservoir pressure as a function of time and distance from the wellbore. Therefore, at a given distance away from the wellbore, the diffusivity equation can predict the pressure as a function of time and how far the critical pressure travels in the formation.

Pressure and rate transient analysis, using known reservoir characteristics, enables more complex parameters to be calculated within the injection zone. Direct monitoring can help acquire pressure, temperature, and injection-rate data during injection. Pressure and temperature gauges will be run on TEC cable on the injection wells.

Any shut-in periods can be observed and treated as a pressure falloff test. During a shut-in period, the wellhead pressure, bottomhole pressure, and temperature readings will be recorded and used for pressure and rate transient analysis of the reservoir. The analysis results will include the radius and magnitude of pressure falloff and reservoir performance characteristics, such as permeability and transmissibility. Analysis results will then confirm, and adjust as necessary, the previous model realizations.

The reservoir model built during the site-evaluation phase forecasts the reservoir conditions during the injection period. Through flow simulation and transient flow analyses, the reservoir model will be regularly updated with injection data, to evaluate the injection stream's effect on reservoir conditions. This analysis will monitor the magnitude and extent of pressure and temperature changes within the injection zone. Continual monitoring of bottomhole pressures and temperatures combined with known reservoir parameters will be used to calculate reservoir conditions throughout the injection intervals.

Through predictive modeling and analysis of recorded pressure and temperature data, Aethon can closely monitor the effect of the injection wells on the subsurface, to help ensure regulatory compliance and safety while contributing to informed decision-making.

In addition to direct injection and temperature measurements, Aethon will utilize wireline logs to determine the subsurface location at which CO_2 enters the formation. Pulsed neutron and temperature logs will be performed, and the collected data will be used to confirm or refine the reservoir simulation and verify that the injected fluid is reaching the intended zone.

5.5.7.2 Indirect Monitoring: Geophysical Surveys

Aethon will use CSEM, VSP, and/or time-lapse 2D seismic surveys to indirectly monitor the CO_2 plume extent and development in accordance with 16 TAC **§5.203(j)(2)(E)** (40 CFR **§146.90(g)(2)**) requirements.

To perform VSP surveys, a fiber optic cable with distributed acoustic sensing (DAS) will be installed and cemented in the annulus behind the long string casing in both injection wells. This system will enable real-time reservoir monitoring using pressure and temperature gauges and periodic VSP. The DAS fiber optic cable will be used to generate a VSP at the highest possible resolution compared to cemented-in-place geophones. Maps of the CO_2 plume will be created from images generated using a walk-away seismic source. The data will be collected by acoustic monitoring in the injection wells and by repositioning the acoustic source at the surface. The source locations will be determined based on well location and conditions.

The CSEM is a geophysical technique used to monitor the movement and location of injected CO_2 by detecting changes in electrical resistivity caused by the presence of CO_2, which is more resistive than the surrounding brine in the reservoir—essentially acting as a "tracer" to track the CO_2 plume within the subsurface. The technique provides crucial information about reservoir fluids and their spatial distribution. CO_2 storage, enhanced oil recovery (EOR), geothermal exploration, and lithium exploration are ideal applications for the CSEM method. The versatility of CSEM permits its customization to specific reservoir objectives by selecting the appropriate components of a multi-component system. Further, CSEM offers the ability to identify potential leaks from the storage reservoir by detecting localized changes in resistivity.

Time-lapse 2D seismic is a method of utilizing seismic shoots with reduced source and receiver arrays compared to 3D seismic, in a pattern that measures slices of the geophysical sonic reflections radially from the well(s). The CO_2 saturations, in a manner similar to VSP, reflect any variation from previous surveys to identify the movement of CO_2 in the reservoir.

As an example of where this technology has proven successful, Shell Canada used it to monitor plume movement at its Quest Project (Bacci et al., 2017). Figure 5-5 illustrates the acquired pattern strategy employed for plume development surveys from two separate wells.

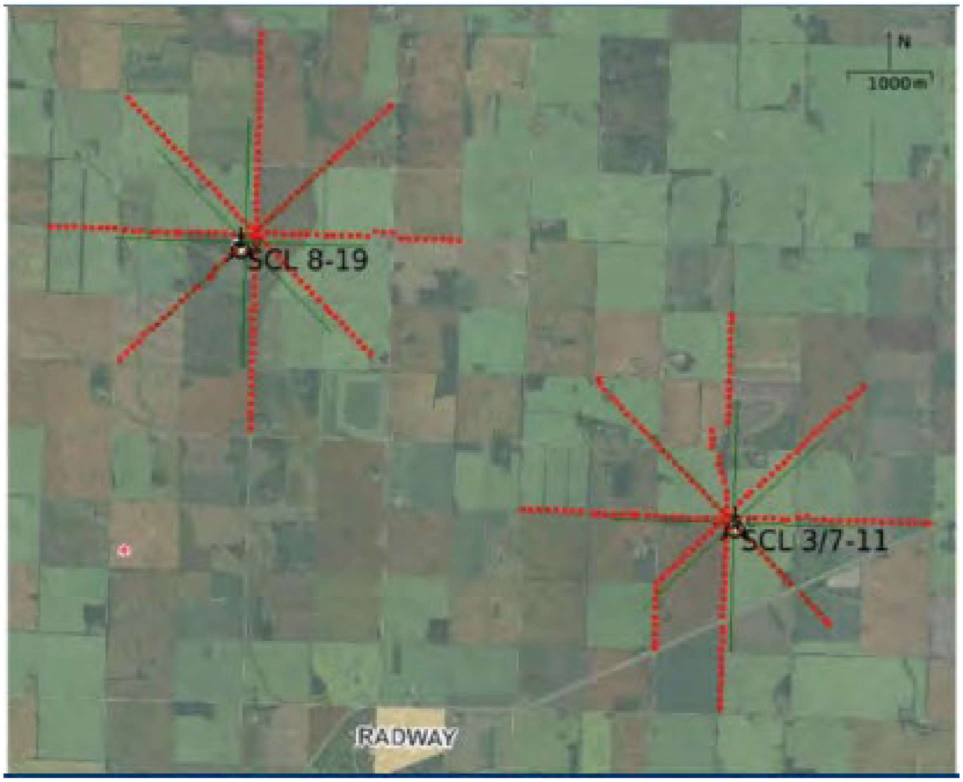

Figure 5-5 – Shell Canada Quest Project VSP Acquisition Patterns (Bacci et al., 2017)

Reservoir monitoring using time-lapse seismic surveys has an extensive history of use in tertiary oil-and-gas recovery. The methodology has undergone thorough testing in saline aquifers with the presence of CO_2. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from compressional changes in velocity between high CO_2 concentrations and formation gases and fluids. As CO_2 displaces formation fluids, the difference in acoustic impedance with time is an effective proxy for plume shape and can be visualized.

The work steps involved in a time-lapse VSP survey primarily include the following:

1. Rock Physics Model
2. Petroelastic Model
3. Feasibility
4. Baseline Survey (Data Acquisition)
5. Repeat/Time-Lapse Survey (Data Acquisition)

6. Interpretation

The following subsections discuss key portions of these work steps.

5.5.7.3 Rock Physics Model

A rock physics model is critical to time-lapse interpretation. This model establishes a relationship between fluid substitution and the change in acoustic impedance. It can be produced with high confidence, provided that the reservoir characterization data is accurate. Changes in seismic response can be projected with a synthetic survey design and reservoir model, relying on the rock physics model to calculate formation fluid impact on acoustic impedance. This model determines if the monitoring program can facilitate the detection of expected formation-fluid substitutions.

Deterministic petrophysical analysis estimations can be used to forecast the dry mineral rock components before any saturation modeling. The model accounts for the following rock properties:

- Total porosity
- Effective porosity
- Water saturation
- Clay (type)
- Quartz
- Mineral content
- Oil/gas residual (if any)

5.5.7.4 Petroelastic Model

The rock physics model will generate a zero-order dry rock model, which is then used to establish a petroelastic model by perturbing the elastic parameters for varying degrees of saturation.

Predicting velocity and density as functions of injectate saturation is the result of a petroelastic model. The seismic response measured during VSP surveys can be determined using the acoustic impedance calculated from both elastic properties.

A feasibility study will be designed to determine if connate fluids replaced with CO_2 could be detected by the petroelastic model. This study will be conducted after recovering core material from the stratigraphic test well. The CO_2 properties will be input into the model as replacement variables for openhole log readings that will be taken while drilling the stratigraphic test well for this project.

5.5.7.5 1D and 2D Models

Changes in the magnitude of the CO_2 plume are measured for different scenarios using 1D and 2D models. This section will detail the methodology used to generate these models.

Seismic waves that travel through the Earth are created with seismic surveys, and geophones listen for the waves that are subsequently reflected. The seismic waves can be made with a “shot,” referring to explosives or other mechanical sources—most commonly a vibrator, which generates seismic waves by pounding a steel plate against the Earth. Geophones are recorders that detect sound waves reflected to the surface, and the data sent by geophones is then stored using seismographs. The geophones enable geophysicists to calculate the time it takes for seismic waves to reflect off of transition zones between formations. Geoscientists can use the variation in sonar velocities to understand subsurface lithology.

Figure 5-6 depicts a standard VSP survey with a geophone configuration.

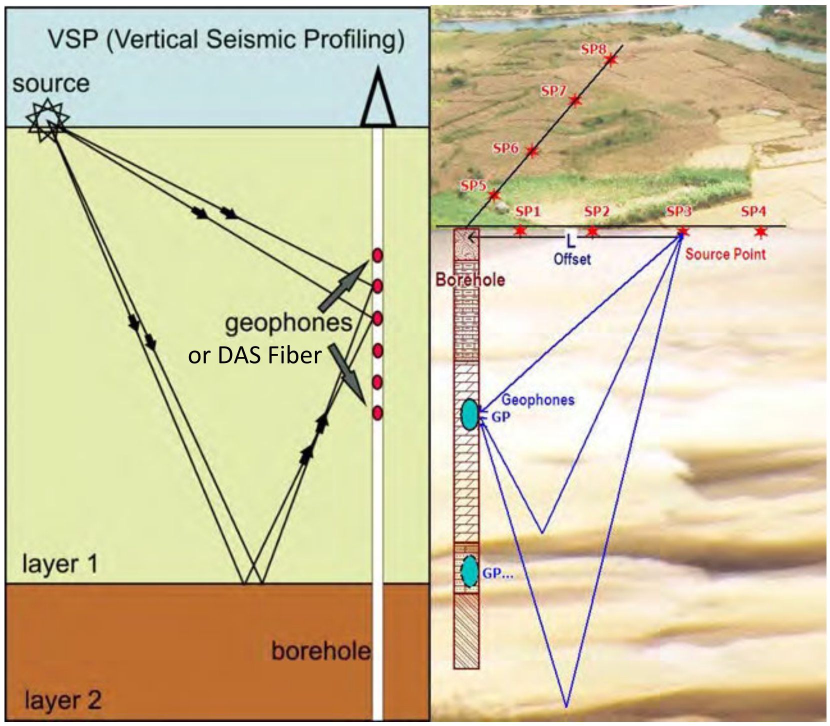

Figure 5-6 – Illustration of a Vertical Seismic Profile Survey

5.5.7.6 1D Model

The previously discussed principles apply to 1D seismic surveys. A standard method of obtaining 1D seismic data is with a checkshot survey, as illustrated in Figure 5-7. Geophones are situated vertically along the wellbore while all shots are fired from the surface. This placement allows the geophones to record seismic waves at different depths and provide measurements—at the highest levels of accuracy—of sonic velocities of the geologic layers affected by wellbore construction. A 1D offset model will be constructed for multiple cases, and differences in reflection amplitudes will be measured, a system commonly used to generate more accurate VSP, 2D, 3D, and 4D surveys.

Another variation of 1D seismic survey data is an acoustic log, which generates acoustic data along the wellbore using wireline sonic tools. Although the purposes of these logs differ from those of seismic surveys, the logs can facilitate a 1D understanding of variation in velocities. The 1D survey data can also be used to correct the sonic logs and create synthetic seismograms, which are used to forecast seismic responses of the subsurface. One caveat of the 1D survey methodology is it assumes that each formation is homogeneous in the horizontal direction; therefore, the surveys can only provide average sonic velocities.

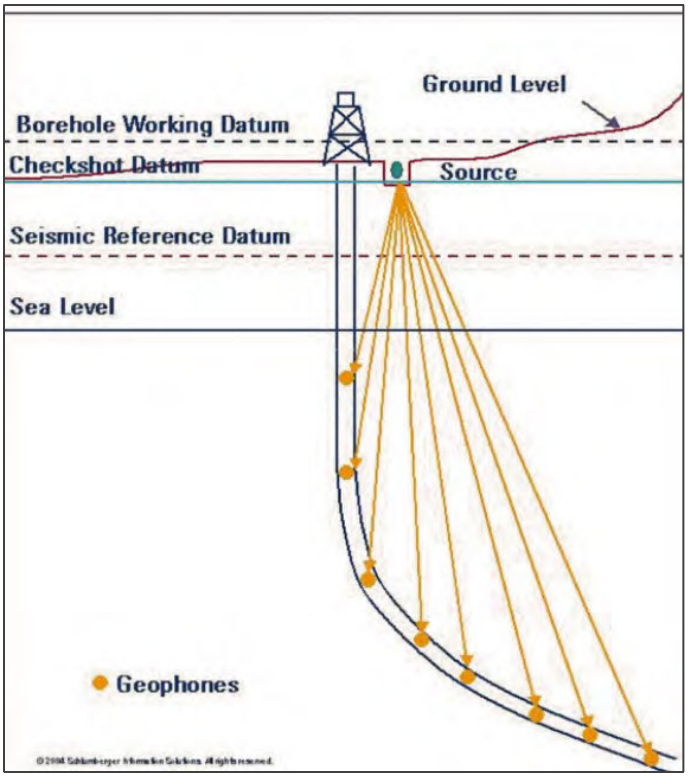

Figure 5-7 – Illustration of a Checkshot Survey

5.5.7.7 2D Model

A geologic model can be built once the results of a 1D model have been interpreted. The model reflects two saturation scenarios: one with connate formation fluid and the other with CO_2-replaced fluid.

Applying the same principles discussed in the previous section, 2D seismic surveys can provide a snapshot of a thin layer of the Earth's crust. The geophones for this survey are placed in a line along the surface and record reflected seismic waves from each formation. For best results, 2D surveys require setting multiple lines, ideally parallel to the structure dip and orthogonal to the geologic strike. The surveys provide subsurface information on various formations, faults, and other characteristics.

Geologists can interpret contour lines and produce geologic maps using the intersection of numerous 2D surveys, which cost less and have less environmental impact than 3D surveys. The 2D surveys are commonly used to explore new areas and allow geologists to visualize the formations lying beneath the surface.

5.5.7.8 Processing Workflow and 4D Seismic Volume Determinations

To produce the final interpretation, CO_2 volume buildups from consecutive surveys will be observed over time. A time-lapse or 4D model is created when VSP, 1D-, 2D-, or 3D-dedicated seismic surveys are combined with a time element (i.e., surveys recorded at various time intervals—Year 1, Year 5, Year 10, etc.). The wheel-spoke pattern of 2D survey lines, with the injection well(s) and VSP receiving fiber optic at its center, will provide coverage in all directions away from the well(s). Changing volumes of gas buildup—represented by either log shifts on the VSP, 1D, or 2D responses, or heat blooms (i.e., change in fluid density) on the 3D model—are identified in the time-lapse/4D interpretation of a seismic survey.

Figure 5-8 illustrates a basic workflow example.

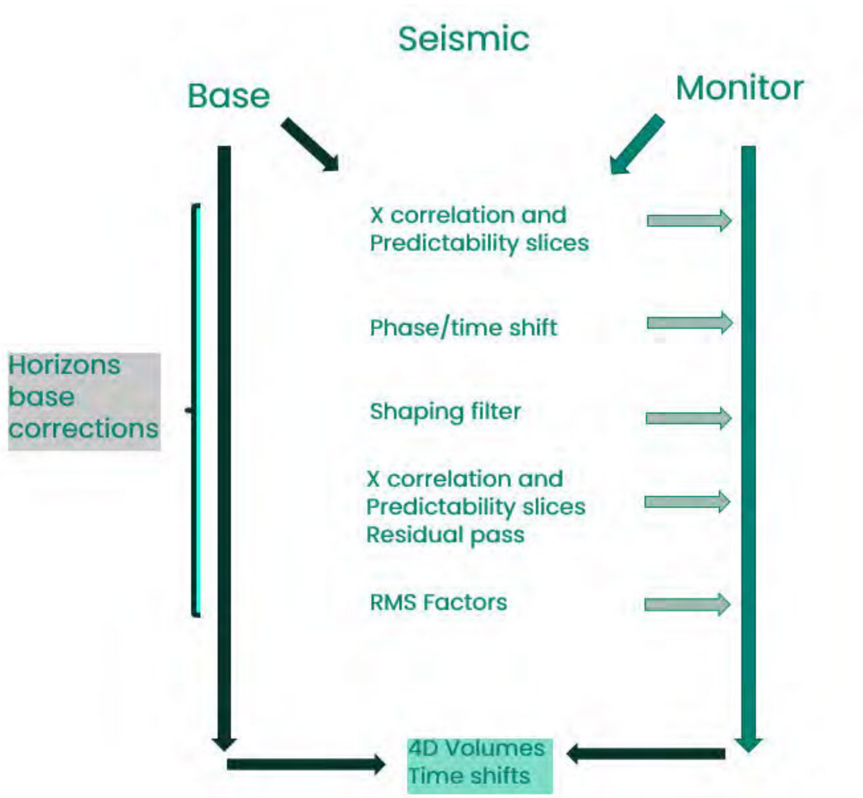

Figure 5-8 – A 4D Processing Workflow Diagram

The 3D horizon model is established from the base survey, and each successive survey creates a reflection differential mapped on the 3D model. The map is used to determine plume geometry, and the process is repeated in time increments to illustrate the time-lapse development of the injectate plume.

To ensure consistency, all seismic volumes will be processed using the same software and for each workflow step outlined.

5.5.7.9 Inversion Workflow

Log data, post-stack seismic volumes, and a structural model will be used to invert baseline surveys, as Figure 5-9 shows. Later, monitor surveys will employ the same low component and residual corrections for consistency and the detection of changes over time—changes assumed to result from the injection operations.

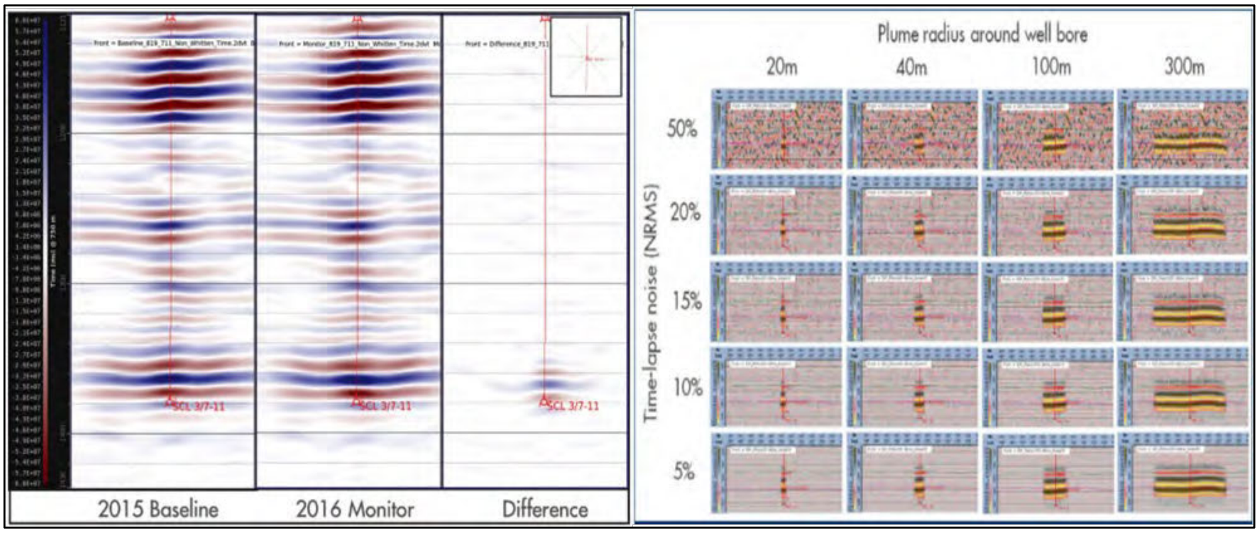

Figure 5-9 – Baseline and subsequent VSP used to determine the difference in amplitude attributed to CO_2 injection measured from the injection well itself. At right, estimation of the plume growth over time (Bacci et al. 2017).

5.5.7.10 Baseline Survey

Conducting a quality VSP baseline survey is critical, because it is the only opportunity to capture an image of the reservoir before injection operations or offset activity—either natural or man-made—impact it. Without this survey, the future interpretation of formation changes cannot be assessed. Also, the size of the baseline survey constrains the extent of plume measurement ability. It is essential to acquire a baseline survey with sufficient coverage if the initial reservoir models are not accurately forecasting plume migration. Aethon will be obtaining this baseline survey prior to the commencement of injection.

5.5.7.11 Equipment Design and Setup

The proposed equipment for periodic survey operations to determine the CO_2 plume growth over time includes the time-lapse VSP, which uses a DAS fiber optic cable—to be connected to an interrogator box at the surface. The DAS system is synchronized to the seismic acquisition system controlling both the receiver (the DAS fiber optic array cemented in the injection wells) and the source.

5.5.8 Plume Extent Monitoring Schedule

The plume extents for the proposed Tea Olive No. 1 and Flowering Crab Apple No. 1 injection wells will be monitored using the direct and indirect methods on the following schedule:

- The initial geophysical surveys and well logs will be conducted prior to the injection phase to capture the starting conditions for the formation brine.
- An additional monitoring survey will be performed approximately 1 year after injection begins. The timing for this survey, based on simulations that predict when the plume extent will remain within the imaging cone, allows early insights into the actual plume migration relative to the predicted model.
- Monitoring surveys will again be conducted at Year 5 after the start of injection; then subsequently, at least every 5 years.
- During the PISC phase of the project, surveys will be run immediately after injection ceases, and within 5 years after injection ceases. At that time, the evaluation of future surveys will be proposed, and if the plume can be shown to have stabilized, additional surveys will not be required. Pressures and temperatures will continue to be measured from the wells until site closure.
- Pulsed neutron and temperature logs will be run annually across the injection zone during injection.

5.5.9 Soil Sampling and Air Monitoring

Aethon will conduct soil gas and atmospheric monitoring pursuant to 40 CFR **§146.90(h)**. Soil gas monitoring will be conducted quarterly for 1 year of soil vapor points to establish baseline conditions and natural variation during the pre-injection phase. That monitoring will change to annual sampling for the operational and post-injection phases.

Two soil vapor points will be installed, one at each injection well. During the pre-injection period, atmospheric monitoring will include a network of continuous monitoring stations near each of the injection wells to assess baseline ambient-air conditions and hydrogen sulfide concentrations. Such atmospheric monitoring will continue throughout the operational and post-injection phases. A deviating trend from baseline and natural variation conditions will prompt an investigation for leakage.

5.6 Conclusion

Monitoring the injection wells and tracking the CO_2 plume and pressure front are key components to the successful sequestration of CO_2 for the proposed TXCCS#1 Project. Aethon is committed to ensuring that best testing and monitoring practices are employed throughout the life cycle of this project.

Appendix E – Testing and Monitoring:

- Appendix E-1 Monitoring Wells Map

5.7 References

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Underground Injection Control – Class VI Permit Application for

Tea Olive No.1 and Flowering Crab Apple No.1

Sabine and San Augustine Counties, Texas

SECTION 6 – WELL PLUGGING PLAN

July 2025

LONQUIST

SECTION 6 – INJECTION WELL PLUGGING PLAN

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Figures

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6.1 Introduction

The plans for the plugging and abandonment (P&A) of Aethon Energy Operating LLC's (Aethon) proposed TXCCS#1 Project injection wells were drafted to satisfy the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(k)**, and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**. This section details the P&A process by providing procedures as well as final well configurations for each of the injection wells—Tea Olive No. 1 and Flowering Crab Apple No. 1—and the underground source of drinking water (USDW) monitoring wells—TOWM No. 1 and FCAMW No. 1.

6.2 Final Plugging and Abandonment

As discussed in ***Section 4 – Well Construction and Design***, the proposed injection wells are designed to inject into the [redacted] Formation for [redacted] years, a span defined by the plume model or plume boundary extent. Once the injection period for the TXCCS#1 Project is complete, the wells will continue to be monitored as part of the post-injection monitoring phase.

Upon approval of the project cessation, all wells will be permanently plugged and abandoned. The plugging-operation plans will be executed to ensure that the plugs isolate the perforated injection interval and prevent the migration of injectate and formation fluids from the injection zone into the USDW. Additionally, the proposed plugging design satisfies 16 TAC **§3.14**. All plugging plans will be approved by the regulator prior to plugging operations.

The following details outline the plugging procedures for the injection and monitoring wells. Two types of plugs will be used:

- Wireline-set bridge plugs will isolate the injection interval.
- Cement plugs will be set at various depths within the wellbore to provide a barrier seal of the injection zone and shallower formations.

6.2.1 Post-Injection Monitoring Plan

Upon completion of the injection period for the project, the completion assembly and monitoring equipment will remain in Tea Olive No. 1 and Flowering Crab Apple No. 1 as part of the post-injection monitoring phase.

The injection zone will be actively monitored through the tubing encapsulated conductor (TEC) line connected to the internally and externally mounted pressure-and-temperature gauges at the base of the tubing. The tubing and packer will remain in place and the perforated interval will not be isolated such that the reservoir pressure of the injection zone will be actively monitored. The fiber, installed and cemented in place on the annulus of the long string casing, offers the ability to perform distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) along the wellbore annulus. Additionally, the plume migration will be monitored through seismic acquisition, which will utilize the fiber DAS capabilities in the event that a vertical seismic profile is conducted to determine the plume extents and stabilization of the pressure front.

Figures 6-1 and 6-2 present schematics of the final wellbore configuration of Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively, prior to P&A.

[redacted]

Figure 6-1 – Final Wellbore Configuration for Tea Olive No. 1

[redacted]

Figure 6-2 – Final Wellbore Configuration for Flowering Crab Apple No. 1

6.2.2 Final Plugging and Abandonment

Once the monitoring phase is completed and the Underground Injection Control (UIC) Program director (UIC Director) has approved the cessation of injection, the injection wells will be permanently plugged and abandoned—the general procedure for which includes the following.

6.2.2.1 Pre-Plugging Activities for Tea Olive No. 1 and Flowering Crab Apple No. 1

1. Notice of Intent to Plug will be communicated to the UIC Director 60 days before planned plugging efforts. If any changes are proposed to the original well plugging plan, a revised plan will be submitted (16 TAC **§5.203(k)(3)(A)** [40 CFR **§146.92(c)**]).
2. Notice of Intent to Plug will also be communicated to the Railroad Commission of Texas (TRRC) by submitting Form W-3A with detailed plans at least 5 days prior to the beginning of plugging operations (16 TAC **§5.203(k)(3)(B)**).
3. Bottomhole reservoir pressure will be measured using the pressure-sensing gauges installed on the tubing as discussed in ***Section 5 – Testing and Monitoring Plan*** (16 TAC **§5.203(k)(2)(B)** [40 CFR **§146.92(a)**]).
4. The injection wells will be flushed with a buffer fluid prior to pulling the injection tubing and packer (16 TAC **§5.203(k)(2)(A)** [40 CFR **§146.92(a)**]).
5. All uncemented, nonpermanent components of the wells will be removed, as described in Table 6-1.
6. Mechanical integrity of the casing annulus will be demonstrated by pressure testing, as described in ***Section 5*** (16 TAC **§5.203(k)(2)(C)** [40 CFR **§146.92(a)**]).
7. Casing inspection and cement bond logs will be performed prior to final plugging. Log evaluation will determine if the plugging procedure needs to be revised.

Table 6-1 – Injection Well Construction Materials to Be Removed

Well Component	Size	Tea Olive No. 1 Quantity	Flowering Crab Apple No. 1 Quantity	Notes / Comments
[redacted]				Tubing and packer will be pulled prior to P&A operations.

6.2.2.2 Plugging Activities for Tea Olive No. 1

[redacted]

[redacted]

25. Perform site closure requirements, and submit a site closure report within 30 days.
26. File a plugging report within 60 days to the UIC Director and Form W-3 within 30 days to the TRRC in accordance with 16 TAC **§5.203(k)(5)** (40 CFR **§146.92(d)**).

6.2.2.3 Plugging Activities for Flowering Crab Apple No. 1

[redacted]

[redacted]

23. Perform site closure requirements, and submit a site closure report within 30 days.
24. File a plugging report within 60 days to the UIC Director and Form W-3 within 30 days to the TRRC in accordance with 16 TAC **§5.203(k)(5)** (40 CFR **§146.92(d)**).

Tables 6-2 and 6-3 provide the details for cement plugs to be set in Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

Table 6-2 – Plugging Details for Cement Plugs, Tea Olive No. 1

Plug Description	UCZ Plug	Surface Casing Shoe	USDW Plug	UQW Plug 1	UQW Plug 2	Surface Plug
Plug Number	**1**	**2**	**3**	**4**	**5**	**6**
Diameter of Boring in Which Plug Will Be Placed (in.)	[redacted]					
Depth to Bottom of Tubing or Drill Pipe (ft, MD)						
Sacks of Cement to Be Used (each plug)						
Slurry Volume to Be Pumped (cf)						
Slurry Weight (lb/gal)						
Top of Plug (ft, MD)						
Bottom of Plug (ft, MD)						
Type of Cement or Other Material						

Method of Emplacement	[redacted]
New Plug?	

*UCZ – upper confining zone; UQW – usable quality water; cf – cubic feet; MD – measured depth

Table 6-3 – Plugging Details for Cement Plugs, Flowering Crab Apple No. 1

Plug Description	UCZ Plug	Surface Casing Shoe	USDW Plug	UQW Plug 1	UQW Plug 2 / Surface Plug
Plug Number	1	2	3	4	5
Diameter of Boring in Which Plug Will Be Placed (in.)	[redacted]				
Depth to Bottom of Tubing or Drill Pipe (ft, MD)					
Sacks of Cement to Be Used (each plug)					
Slurry Volume to Be Pumped (cf)					
Slurry Weight (lb/gal)					
Top of Plug (ft, MD)					
Bottom of Plug (ft, MD)					
Type of Cement or Other Material					
Method of Emplacement					
New Plug?					

Figures 6-3 and 6-4 show the final plugging schematics for Tea Olive No. 1 and Flowering Crab Apple No. 1, respectively.

[redacted]

Figure 6-3 – Final Plugging Schematic for Tea Olive No. 1

[redacted]

Figure 6-4 – Final Plugging Schematic for Flowering Crab Apple No. 1

6.3 <u>Monitoring Well Plugging and Abandonment Plans</u>

The following sections detail the P&A of the USDW monitoring wells for the proposed TXCCS#1 Project.

6.3.1 Pre-Plugging Activities for All Wells

Aethon will comply with all reporting and notification provisions.

1. The UIC Director will be notified 60 days before planned plugging efforts. If any changes are proposed to the original well plugging plan, a revised plan will be submitted (16 TAC **§5.203(k)(3)(A)** [40 CFR ***§*146.92(c)**]).
2. Notice of Intent to Plug will be communicated to the TRRC by submitting Form W-3A with detailed plans at least 5 days prior to the beginning of plugging operations (16 TAC **§5.203(k)(3)(B)**).

6.3.2 Plugging Procedure for TOMW No. 1

[redacted]

14. File a plugging report within 60 days to the UIC Director and Form W-3 within 30 days to the TRRC in accordance with 16 TAC **§5.203(k)(5)** (40 CFR **§146.92(d)**).

6.3.2.1 Final P&A Wellbore Schematic – TOMW No. 1

[redacted]

Figure 6-5 – Final Plugging Schematic for TOMW No. 1

6.3.3 Plugging Procedure for FCAMW No. 1

[redacted]

13. File a plugging report within 60 days to the UIC Director and Form W-3 within 30 days to the TRRC in accordance to with 16 TAC **§5.203(k)(5**) (40 CFR **§146.92(d)**).

6.3.3.1 Final P&A Wellbore Schematic – FCAMW No. 1

[redacted]

Figure 6-6 – Final Plugging Schematic for FCAMW No. 1

Appendix G – Well Plugging Schematics and Procedures:

- Appendix G-1 Tea Olive No. 1 Final P&A Schematic
- Appendix G-2 Flowering Crab Apple No. 1 Final P&A Schematic
- Appendix G-3 TOMW No. 1 Final P&A Schematic
- Appendix G-4 FCAMW No. 1 Final P&A Schematic

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

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

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7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the Aethon TXCCS#1 Project injection wells, Tea Olive No. 1 and Flowering Crab Apple No. 1, was prepared in accordance with the requirements of Title 16, Texas Administrative Code (16 TAC) **§5.203(m)** (Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93**). This plan describes the various activities that will occur once injection has ceased and during the site closure—and until this project poses no further endangerment to underground sources of drinking water (USDWs).

7.2 Pre- and Post-Injection Pressure Differentials

To meet the requirements of 16 TAC **§5.203(m)(2)** (40 CFR **§146.93(a)(2)(i)**), the following table shows the expected pressure differential between pre- and post-injection pressures in the injection zone, as determined by the plume modeling described in ***Section 2 – Plume Model.*** The highest pressure differential for Tea Olive No. 1 occurs in Year [redacted] and is predicted to reach [redacted] pounds per square inch (psi). The highest pressure differential for Flowering Crab Apple No. 1 occurs in Year [redacted] and is predicted to reach [redacted] psi. Table 7-1 shows the maximum pressure differential at the wellbore predicted in each year modeled.

Table 7-1 – Maximum Pressure Differential by Year

Year	Maximum Pressure Differential (psi) Tea Olive No. 1	Maximum Pressure Differential (psi) Flowering Crab Apple No. 1
[redacted]		

Year	Maximum Pressure Differential (psi)	Maximum Pressure Differential (psi)
	Tea Olive No. 1	Flowering Crab Apple No. 1
[redacted]		

Figures 7-1 and 7-2 present, respectively for each injection well, graphical representations of the data in Table 7-1, showing the pressure differential over the life of both wells. The solid dark-green line represents the buildup from in situ pressure due to injection, and the solid light-green line represents the maximum pressure gradient exhibited in each stage of injection. The dashed light-green line shows the 90% fracture-pressure gradient constraint. The light green line does not exceed the dashed light-green line, indicating that the model does not surpass the 90% fracture-pressure gradient constraint.

[redacted]

Figure 7-1 – Maximum Pressure Differential Over Time for Tea Olive No. 1

[redacted]

Figure 7-2 – Maximum Pressure Differential Over Time for Flowering Crab Apple No. 1

7.3 CO_2 Plume and Pressure Front Positions – Time Series

The area of review (AOR), as explained in ***Section 3 – Area of Review and Corrective Action Plan***, consists of both the CO_2 plumes and critical pressure maximum extents. Figure 7-3 shows the AOR and its subcomponents. The CO_2 plume is indicated by the black polygons, based on the maximum extent of all of the differing plume layers in the model, extracted at [redacted] years post-injection. The critical pressure front, at its maximum extent at the end of injection in Year [redacted], is denoted by the pink outline. The AOR considers both Tea Olive No. 1 and Flowering Crab Apple No. 1 and will be reevaluated at a minimum of every 5 years throughout the injection period. Once injection has ceased, the pressure in the injection zone will quickly dissipate to a value less than the critical pressure and eventually revert to near reservoir pressure, as was shown in Table 7-1. Pressure dissipation over time is displayed in Figures 7-4 to 7-7, which show the CO_2 plumes and critical pressure front in years [redacted], respectively.

[redacted]

Figure 7-3 – CO_2 Plumes and Critical Pressure Front – Maximum Extents

[redacted]

Figure 7-4 – CO_2 Plumes and Critical Pressure Front, Year [redacted]

[redacted]

Figure 7-5 – CO_2 Plumes and Critical Pressure Front, Year [redacted]

[redacted]

Figure 7-6 – CO_2 Plumes and Critical Pressure Front, Yea[redacted]

[redacted]

Figure 7-7 – CO_2 Plumes and Critical Pressure Front, Year [redacted]

7.4 Post-Injection Monitoring Plan

As required by 16 TAC **§5.206(k)(2)** (40 CFR **§146.93(b)**), Aethon will continue to monitor the proposed TXCCS#1 Project site for 50 years after injection ceases or until the Underground Injection Control (UIC) Program director (UIC Director) determines that the project no longer poses an endangerment to the USDW, as described in *Section 7.5*. The reservoir model will be updated, using monitoring observations, throughout the life of the project. At any time during the life of the project, Aethon may modify and resubmit the PISC and Site Closure Plan, within 30 days of such changes, for approval by the UIC Director. Upon cessation of injection, an amended PISC and Site Closure Plan—if needed per the updated model—will be submitted to the UIC Director.

Tea Olive No. 1 and Flowering Crab Apple No. 1 will also serve as in-zone and above-zone monitoring wells as discussed in ***Section 4 – Well Construction and Design****.* Two USDW monitoring wells are proposed, as discussed in ***Section 5 – Testing and Monitoring Plan***. Figure 7-8 displays the locations of TOMW No. 1 and FCAMW No. 1 (indicated in blue).

[redacted]

Figure 7-8 – Proposed Locations of the USDW Monitoring Wells

During the monitoring period, the testing and monitoring activities, as described in ***Section 5 – Testing and Monitoring Plan,*** will be performed and reported at the frequency shown in Table 7-2.

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

Monitoring Type	Monitoring Program	Location	Frequency
Groundwater Monitoring	• TOMW No. 1 and FCAMW No. 1 – USDW monitoring wells • Groundwater monitoring wells	Facility	Annually first 5 years, then every 5 years until the plume stabilizes
In-Zone Monitoring (IZM) / Direct Reservoir Monitoring	• Pressure/temperature gauges on tubing encapsulated conductor (TEC) cable with fiber optic cable installed on outside of casing	Tea Olive No. 1 and Flowering Crab Apple No. 1	Continuously
Above-Zone Monitoring (AZM)	• Pressures • Fluid samples	Tea Olive No. 1 and Flowering Crab Apple No. 1	Pressure – continuously
Indirect Reservoir Monitoring	• Geophysical methods	Facility	Initially and 4 years after injection begins, then will reevaluate the use of alternative technologies after 4 years of injection
Internal and External Mechanical Integrity	• Tubing-casing annulus pressure test • Pulsed neutron logs • Tubing-casing annulus pressure monitoring • Ultrasonic logs	Tea Olive No. 1 and Flowering Crab Apple No. 1	In the order listed: • 5 years annually • Continuously • 5 years

All testing and monitoring activities listed will be performed and analyzed as discussed in ***Section 5***, including quality assurance/quality control (QA/QC) measures.

7.5 Demonstration of Non-Endangerment of the USDW

The primary mechanism through which the USDWs are protected is the upper confining zone (UCZ)—comprised of the [redacted] Formation, measured to be about [redacted] feet (ft) thick, and the [redacted] Formation, which is about [redacted] ft thick. Monitoring data to be collected after injection ceases will confirm that the UCZ is functioning as expected and that the USDW is not endangered.

The monitoring data will also be used to calibrate the simulation model and further improve its ability to accurately predict the movement of CO_2. These calibrated predictions from the simulation model, presented in ***Section 2 – Plume Model***, are used to identify any UCZ-penetrating features—which may differ from initial forecasting—with which the CO_2 plume or critical pressure front may interact prior to final stabilization. The models presented herein do not limit the maximum volume or the injection period. These model outputs represent one snapshot of the reservoir's potential capabilities.

Ultimately, the maximum allowable injection pressure and the protection of the USDW will determine the project's maximum rates, volumes, and longevity. This model will be continuously updated and reviewed. The presented results of the model do not indicate or represent either a limit in time or the maximum volume of the reservoir capabilities.

Prior to site-closure approval, as required by 16 TAC **§5.203(m)(1)** (40 CFR **§146.93(c)**), Aethon will provide documentation that the USDW is not at risk of endangerment from the CO_2 plume. While the PISC duration is at least 50 years per regulations, it may be possible to demonstrate USDW non-endangerment earlier due to a stabilized plume. The plume will be considered stabilized if the plume growth rates have reduced to less than 0.25% per year and continue to decline in the extended simulations. In this case, the plume may be considered to be hydrodynamically trapped.

The current and historical seismic survey data, along with required monitoring data and projected plume simulations, will be used to demonstrate the containment of the plume.

Aethon will submit a report to the UIC Director demonstrating the non-endangerment of the USDW, including site-specific conditions, the updated plume model, the predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model. The UIC Director will ultimately determine and approve an alternative timeline for closure.

7.6 Site Closure Plan

To meet the requirements of 16 TAC **§5.206(k)(5)** (40 CFR **§146.93(e)**), the following site-closure activities will be performed: plugging of all wells, site closure, and submittal of final site-closure reports.

7.6.1 Pre-Closure

To meet the requirements of 16 TAC **§5.206(k)(4)** (40 CFR **§146.93(d)**), notice of the intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

7.6.2 Plugging Activities

The proposed injection and USDW monitoring wells will be plugged as discussed in ***Section 6 – Injection Well Plugging Plan***. The plugging and abandonment procedures for the injection and monitoring wells are composed to prevent CO_2 or formation fluids in the injection zone from migrating to the USDW. Prior to plugging the wells, their mechanical integrity and bottomhole pressure will be verified. Plugging schematics and procedures are provided in *Appendix G*.

7.6.3 Site Restoration

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

7.6.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Director, per the requirements of 16 TAC **§5.206(k)(6)** (40 CFR **§146.93(f)**), and include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats
- Documentation of well-plugging report to the Railroad Commission of Texas (TRRC)
- Records of the nature, composition, and volume of the CO_2 stream over the injection period

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

- The fact that the land was used to sequester CO_2
- The name of the state agency (TRRC) with which the survey plat was filed, the address of the office of the EPA (Region 6), and the state agency to which it was submitted
- The total volume of fluid injected, the injection zone into which it was injected, and the period over which injection occurred

Aethon will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, Aethon will deliver all records to the UIC Director for retention at a location designated by the UIC Director for that purpose.

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SECTION 8 – EMERGENCY RESPONSE AND REMEDIATION PLAN

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SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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8.1 Introduction

This Emergency and Remedial Response Plan (ERRP) for the proposed Aethon Energy Operating LLC (Aethon) TXCCS#1 Project was prepared to meet the requirements of Texas Water Code **§27** and Title 16, Texas Administrative Code (16 TAC) **§5.203 (l)** (Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.94**). The plan describes potential adverse events that could occur in the development, operation, and post-closure phases of the project and the actions to be taken in the event of such an emergency. This plan will be reviewed and updated annually. Any change in key personnel will also cause the ERRP to be updated immediately.

8.2 Resources/Infrastructure in the Area of Review

The proposed TXCCS#1 Project is located in west-central Sabine County and eastern San Augustine County, Texas. The two proposed injection wells, Tea Olive No. 1 and Flowering Crab Apple No. 1, are located approximately [redacted] feet (ft) and [redacted] ft, respectively, from the nearest freshwater wells (*Appendix C-3*, from ***Section 3 – Area of Review and Corrective Action Plan***). Several gravel pits, shown in the project site review map at Figure 8-1 (and in *Appendix C-5*), are located within the critical pressure front but will not be affected by injection activity. No artificial penetrations that reach the proposed upper confining zone (UCZ) have been found in the predicted CO_2 plume.

Twelve known artificial penetrations reach the UCZ within the pressure front—all of which have been evaluated for proper construction and plugging. If an undocumented artificial penetration is later found, the well will be remediated to ensure protection against any possible migration of CO_2.

Additionally, two monitoring wells will be placed at the base of the underground source of drinking water (USDW) and within the CO_2 plume—and constructed in a manner to monitor for the prevention of CO_2 migrating into the USDW and the surface atmosphere.

The Groundwater Advisory Unit (GAU) of the Railroad Commission of Texas (TRRC) identified the base of usable quality water (BUQW) at a depth of 1,250 ft and the base of the USDW at 1,700 ft at the Tea Olive No. 1 location. At the Flowering Crab Apple No. 1 location, the BUQW and the base of the USDW were identified at 1,000 ft and 1,275 ft, respectively. Copies of the GAU's Groundwater Protection Determination and No Harm letters for the two injection wells are provided in *Appendices A-9 and A-10*, respectively.

[redacted]

Figure 8-1 –TXCCS#1 Project Site Review Map

8.3 Resources/Infrastructure – Specific Events and Response Plans

The proposed TXCCS#1 Project has been assessed to have low risk when compared to alternative projects, and leakage of CO_2 outside of the permitted area has a remote likelihood of occurring during project operations. However, Aethon cannot assert that the risk of CO_2 leakage is nonexistent. Detailed geologic and engineering analysis supported by advanced computational modeling will support efforts to ensure that monitoring detection and prepared emergency response plans are put in place to protect the community and the environment.

If evidence of endangerment to USDWs is obtained, Aethon will take the following actions:

1. Immediately cease injection.
2. Take all steps necessary to identify and characterize any release.
3. Notify the UIC Director within 24 hours.
4. Implement the approved ERRP.

The following scenarios represent potential adverse events that could occur throughout the life of the project. Carefully thought-out methods of prevention and detection along with likely remedial responses are presented for each event.

8.3.1 Event Category – Water Quality Impact

8.3.1.1 Specific Event Description – Leakage of CO_2 outside the permitted area into a freshwater aquifer through fractures, faults, or artificial penetrations

Risk Assessment Matrix, Section 1.1 (Appendix F-1)

Existing wellbores and 2D and 3D seismic, combined with years of documented regional geological studies, present the reasoning that an instance where the plume would reach faults or fractures and allow CO_2 migration either into the USDW or to the surface, is extremely low. No faults or fractures were found in the area and, if there are any, the displacements would be small and sufficiently covered by the confining zone.

An instance where CO_2 would migrate up through an existing wellbore is also extremely low as indicated in ***Section 3 – Area of Review and Corrective Action Plan***. By design, no existing wells were identified within the modeled CO_2 plume. In the event that a leakage event occurs, Aethon has prepared this ERRP to stop the leak and mitigate damages.

Likelihood: Remote

Prevention and Detection

- Plume monitoring surveys as outlined in ***Section 5 – Testing and Monitoring Plan*** will detect CO_2 that migrates out of the UCZ.
- The CO_2 plume and pressure front models will be updated every 5 years—or when there

is an event that triggers reevaluation—to ensure that no artificial well penetrations have created a path for leakage.

- The injection wells will be specifically designed, constructed, and operated with components such as CO_2-resistant cement, a corrosion-resistant packer, and alloy casing strings to reduce the likelihood of a CO_2 leak.
- Continuous monitoring of the injection rates, pressures, and temperatures will provide insight into the integrity of the injection wellbores.
- An aerial electromagnetic survey will be performed to detect the potential for undocumented wellbores.
- Microseismic monitoring may detect tiny stress changes in the formations that could lead to early detection of fractures or faults.

Potential Response Actions

- Cease injection and notify the Underground Injection Control (UIC) Program director (UIC Director) and other pertinent agencies within 24 hours.
- Plume monitoring surveys as outlined in ***Section 5 – Testing and Monitoring Pla****n* will detect CO_2 that migrates out of the UCZ.
- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted (Esposito, 2010[1]):
    - Pump CO_2-impacted groundwater to the surface and aerate it to remove the CO_2.
    - Apply "pump and treat" methods to remove trace elements.
    - Drill wells that intersect the accumulations in groundwater and extract the CO_2.
    - Provide an alternative water supply if groundwater-based public-water supplies are impacted.

8.3.1.2 Specific Event Description – Leakage of drilling fluid into (i.e., contamination of) a potable water aquifer

Risk Assessment Matrix, Section 1.2 (Appendix F-1)

The [redacted] aquifers could be jeopardized during the drilling of the injection or monitoring wells, due to a drilling fluid leak. While the risk of such a leak is remote, Aethon acknowledges that it could occur.

Likelihood: Remote

Prevention and Detection

- Use freshwater-based drilling fluids while drilling through all USDW intervals.
- Follow outlined drilling procedures, which include the use of drilling-fluid monitoring

[1] Esposito, A.M.M. 2010. Remediation of Possible Leakage from Geologic CO_2 Storage Reservoirs into Groundwater Aquifers.

equipment.

- Surface casing installed to protect the USDW during drilling and injection operations.

Potential Response Actions

- Stop drilling operations and notify the appropriate agencies within 24 hours.
- If groundwater/USDW is impacted (Esposito, 2010):
    - Apply pump-and-treat methods to remove trace elements.
    - Extract and treat affected water at an above-ground treatment facility.
    - Provide an alternative water supply if groundwater-based public water supplies are impacted.

8.3.1.3 Specific Event Description – Seismic event occurs in the project area resulting in CO_2 plume leakage into the USDW

Risk Assessment Matrix, Section 1.3 (Appendix F-1)

A natural seismic event in the project area could create or open faults or fractures. Such an event could provide a pathway for CO_2 migration through multiple zones, including the UCZ, to the USDW or to the surface.

Likelihood: Remote

Prevention and Detection

- The CO_2 plume and pressure front models will be updated every 5 years—or if there is an event that triggers reevaluation.
- The project is located in a seismically quiet area with sufficient distance from any offset faulting that could act as a potential conduit for migration. Texas Seismological Network and Seismology Research (TexNet) and the U.S. Geological Society (USGS) databases did not identify any natural or induced seismic events within a 9.08 kilometer (5.6 mile) radius of the proposed injection wells, regardless of magnitude.
- Continuous monitoring of the injection rates, pressures, and temperatures will provide insight into the integrity of the injection wellbores.
- Plume monitoring surveys as outlined in ***Section 5 – Testing and Monitoring*** **Plan** will detect CO_2 that migrates out of the UCZ.
- Microseismic monitoring may detect tiny stress changes in the formations that could lead to early detection of fractures or faults.

Potential Response Actions

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Plume monitoring surveys as outlined in ***Section 5*** will detect CO_2 that migrates out of the UCZ.

- Continue monitoring the plume at a more frequent interval to determine if migration continues.
- If groundwater/USDW is impacted (Esposito, 2010):
  - Pump CO_2-impacted groundwater to the surface and aerate it to remove the CO_2.
  - Apply pump-and-treat methods to remove trace elements.
  - Drill wells that intersect the accumulations in groundwater and extract the CO_2.
  - Provide an alternative water supply if groundwater-based public-water supplies are impacted.
- If surface water is impacted:
  - Shallow ponds or lakes will quickly release dissolved CO_2 back into the atmosphere.
  - Drill a relief well and create a hydraulic barrier by increasing the reservoir pressure upstream of the leak.

8.3.2 Event Category – CO_2 Release to or at the Surface

8.3.2.1 Specific Event Description – Overpressurization (i.e., induced)

Risk Assessment Matrix, Section 2.1 (Appendix F-2)

The loss of injection-well mechanical integrity may be experienced due to overpressurization and/or an unexpected failure of pressure control equipment.

Likelihood: Remote

Prevention and Detection

- Construct wells based on industry-required standards and engineering practices.
- The pressure, rate, and temperature of the injection wells will be continuously monitored.
- Pressure falloff tests every 5 years and annual annulus-pressure tests will be performed.
- Tubing and annular pressures will be continuously monitored and maintained below the maximum allowed value—limiting injection rates to remain below the maximum allowable injection pressure, with alarms in place to notify of unplanned deviations.
- Maintain the integrity of the surface wellhead tree.
- Surface hydrogen sulfide (H_2S)/CO_2 detection equipment will be installed throughout the facilities.
- Plume monitoring surveys as outlined in ***Section 5 – Testing and Monitoring Plan*** will detect CO_2 that migrates out of the UCZ.

Potential Response Actions

- Activate emergency shutdown valve upon alarm activation.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring

operations.

- Monitor well and annulus pressures.
- Determine the cause and severity of the failure to determine if CO_2 may have been released to surface.
- Perform appropriate workover on the well(s) to restore well integrity.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5 – Testing and Monitoring Plan***.

8.3.2.2 <u>Specific Event Description – Caprock (i.e., confining zone)/reservoir failure: plume migrates along fault line/fissure to surface</u>
Risk Assessment Matrix, Section 2.2 (Appendix F-1)

As discussed in ***Section 1 – Site Characterization***, the edge of the pressure front and platform margin are located approximately [redacted] miles from the published location of the [redacted]-[redacted], and the maximum pressure against the fault is calculated to only be [redacted] pounds per square inch (psi). Therefore, the forecasted seismic risk is considered relatively low, and neither fault slip potential (FSP) nor fault seal analysis (FSA) modeling were needed for this project.

<u>Likelihood</u>: Remote

<u>Prevention and Detection</u>

- Plume monitoring surveys as outlined in ***Section 5*** will detect CO_2 that migrates out of the UCZ.
- The CO_2 plume and pressure front models will be updated every 5 years—or when there is an event that triggers reevaluation—to ensure that no artificial well penetrations have created a path for leakage.
- The injection wells will be specifically designed, constructed, and operated with components such as CO_2-resistant cement, a corrosion-resistant packer, and alloy casing strings to reduce the likelihood of a CO_2 leak.
- Continuous monitoring of the injection rates, pressures, and temperatures will provide insight into the integrity of the injection wellbores.
- An aeromagnetic survey will be conducted to ensure that no undocumented or unknown wellbores are present.
- Microseismic monitoring may detect tiny stress changes in the formations that could lead to early detection of fractures or faults.
- Tubing and annular pressures will be continuously monitored and maintained below the maximum allowed values.
- Surface H2S/CO_2 detection equipment will be installed throughout the facilities.

<u>Potential Response Actions</u>

- Shut in the flow line upon any detection of CO_2 at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5 – Testing and Monitoring Plan***.

8.3.2.3 Specific Event Description – Well blowout during drilling operations or loss of mechanical integrity of the well pressure equipment

Risk Assessment Matrix, Section 2.3 (Appendix F-1)

Although remotely possible, a well blowout could occur during wellbore drilling if unexpected changes in reservoir pressures cause a sudden release of hydrocarbons, water, and/or pressure from the subsurface formations. The integrity of the well(s) may be lost during drilling or injection if there is an unexpected failure in well pressure equipment.

Likelihood: Remote

Prevention and Detection

- Maintain appropriate mud weights as required based on offset well data.
- Monitor the rate of drilling-fluid returns vs. rates pumped, penetration rates, pump pressures, etc.
- Tubing and annular pressures will be continuously monitored and maintained below the maximum allowed values—with low and high alarms set to detect leaks.
- Proper wellbore design, including proper cement and metallurgy of the casing and tubing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to ***Section 5***.
- Surface H_2S/CO_2 detection equipment will be installed.

Potential Response Actions

- Stop drilling operations and activate blowout prevention equipment.
- Kill the well by pumping fluid that is heavier than the current fluid down the wellbore until the well stops flowing.
- Read and record stabilized shut-in pressures.
- Notify the UIC Director and other pertinent agencies within 24 hours.

- Pump a sweep to circulate out the high-pressure kick.

8.3.2.4 Specific Event Description – Well seal/casing failure of an injection well

Risk Assessment Matrix, Section 2.4 (Appendix F-1)

A well-seal failure of an injection well could occur due to an inadequate cement job, resulting in micro-annular channeling of the corrosive CO_2 stream behind the casing. A casing break is possible due to either a failure during installation or the corrosive nature of the CO_2 stream. Additionally, an improperly seated packer or a tubing leak could allow for a path to the surface.

Likelihood: Remote

Prevention and Detection

- The injection wells will be specifically designed, constructed, and operated with components such as CO_2-resistant cement, a corrosion-resistant packer, and alloy casing strings to reduce the likelihood of a CO_2 leak.
- Casing inspection logs will be run and analyzed pre-injection then annually thereafter.
- The pressure, rate, and temperature of the injection wells will be continuously monitored. Pressure falloff tests every 5 years and annual annulus-pressure tests will be performed.
- Surface H_2S/CO_2 detection equipment will be installed.

Potential Response Actions

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Determine the cause and severity of failure to determine if the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Perform appropriate workover on the well(s) to restore well integrity.
- Install a chemical-sealant barrier and or attempt a cement squeeze to block leaks, if warranted.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5 – Testing and Monitoring Plan***.

8.3.2.5 Specific Event Description – Major mechanical failure of flowlines or distribution system

Risk Assessment Matrix, Section 2.5 (Appendix F-1)

A major mechanical failure of the CO_2 flowlines or distribution system is possible during injection-facility operations by utilizing equipment (1) outside designed operating parameters, (2) beyond recommended preventive maintenance (PM) cycles, or (3) otherwise improperly. Further failures include vandalism and acts of God.

Likelihood: Rare

Prevention and Detection

- Closely monitor and operate the facility with 24/7 surveillance.
- Flow rate meters and differential pressure monitoring will be used along lines, combined with machine learning, for early leak detection.
- Ensure that automatic shutdown and pressure relief devices are strategically placed throughout the distribution system, to prevent overpressure and to minimize release.
- Proper operation and PM of all surface-facility equipment will be carried out.
- Monitor the CO_2 injectate stream for corrosion.
- Surface H_2S/CO_2 detection equipment will be installed.

Potential Response Actions

- Shut in the flow line upon any detection of CO_2 at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead and pipeline valves.
- Determine if personnel need to be evacuated from the area and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5 – Testing and Monitoring Plan***.

8.3.2.6 Specific Event Description – Well-seal failure of adjacent well(s) (i.e., plugged and abandoned wells, monitoring wells, or orphan wells)
Risk Assessment Matrix, Section 2.6 (Appendix F-1)

It is possible that well seals in adjacent wellbores could fail due to improper materials, such as cement inside and behind casing, casing and equipment metallurgy, and plugging materials. This event could also occur due to undiscovered orphan wells that create leak paths to the surface due to improper plugging.

Likelihood: Remote

Prevention and Detection

- The project location was selected to avoid existing artificial penetrations.
- Perform a diligent search for information on adjacent wells located within the area of

review (AOR).

- Perform proper corrective action review and design, including appropriate cement and metallurgy of the plugging materials.
- An aeromagnetic survey will be conducted to ensure that no undocumented or unknown wellbores are present.
- Plugging and abandonment operations for applicable artificial penetrations will be designed and executed with CO_2-resistant cement and monitored as described in ***Section 5 – Testing and Monitoring Plan***.
- On active wells, continuous pressure monitoring at surface and downhole will highlight potential issues.
- On active wells, pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to ***Section 5***.
- Operate a closely monitored facility and surrounding area.
- Surface CO_2 detection equipment will be installed.

Potential Response Actions

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve, if one exists.
- For active wells, monitor well and annulus pressures.
- Determine the cause and severity of failure to determine if the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Perform any well reentry and corrective action as necessary to regain isolation of injectate/formation fluids.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5*****.**

8.3.2.7 Specific Event Description – Sabotage/terrorist attack

Risk Assessment Matrix, Section 2.7 (Appendix F-1)

Any person or organization wishing to cause harm to life, property, or the environment could attack the injection-facility operations. This facility is not of strategic or cultural importance; therefore, an event such as this has very low risk.

Likelihood: Remote

Prevention and Detection

- Stay current with events locally, within the state and country, and globally that could potentially warrant a threat to the facility. Establish relationships with local emergency agencies and authorities.
- Secure the facility and surrounding area.
- Perform regular site visits and security inspections.
- Proper operation and PM of all surface-facility equipment will be carried out.
- Maintain the integrity of the surface wellhead tree.
- Surface H_2S/CO_2 detection equipment will be installed throughout the facility.

Potential Response Actions

- Shut in the flow line at the surface.
- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Close the wellhead valve.
- Monitor well and annulus pressures.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of any damage in order to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5 – Testing and Monitoring Plan***.

8.3.2.8 Specific Event Description – Induced seismicity directly caused by injection, leading to leakage

Risk Assessment Matrix, Section 2.8 (Appendix F-1)

Injection operations could induce a seismic event that would cause the plume to reach faults or fractures and allow CO_2 migration to the surface.

Likelihood: Remote

Prevention and Detection

- The injection pressures will remain below 90% of the formation fracture gradient.
- Microseismic monitoring may detect tiny stress changes in the formations that could lead to early detection of larger seismic events.
- The CO_2 plume and pressure front models will be updated every 5 years—or if there is an event that triggers reevaluation.
- The chosen project location is a sufficient distance from nearby faults that could act as a conduit.
- Continuous monitoring of the injection rates, pressures, and temperatures will provide insight into the stability of the formations.

- Surface H_2S/CO_2 detection equipment will be installed throughout the facilities.

Potential Response Actions

- Cease injection and notify the UIC Director and other pertinent agencies within 24 hours.
- Determine if personnel need to be evacuated from the facility and begin gas-monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas levels to return to normal.
- Determine the cause and severity of the failure in order to initiate repairs.
- Use plume monitoring surveys to assess the location and degree of CO_2 movement, as described in ***Section 5 – Testing and Monitoring Plan***.
- Increase plume monitoring to a more frequent interval to determine if migration continues.

8.3.3 Event Category – Entrained Contaminant (Non-CO_2) in the Injection Stream

8.3.3.1 Specific Event Description – Change in CO_2 composition/properties from its source impacts the reservoir
Risk Assessment Matrix, Section 3.1 (Appendix F-1)

This event could occur due to changes in the composition of the CO_2 sources. Contaminants may impact the injection zone dissolution and geochemical reactions.

Likelihood: Remote

Prevention and Detection

- Perform baseline analysis of the CO_2 injection stream.
- Continuous gas stream measurement and routine samples characterizing the CO_2 injection stream will be collected from the delivery pipeline and analyzed by a third-party laboratory. Chemical analysis will denote contaminant levels.

Potential Response Actions

- Report to the UIC Director any change in composition.
- Determine the cause of the contaminants.
- Investigate potential downhole issues by revising the subsurface compatibility simulation.
- If necessary, remediate the source of the contaminants.
- If necessary, treat the injection stream to reduce the effect of the contaminants.
- If well injectivity has been compromised, perform an appropriate workover to restore desired operational conditions.

8.3.3.2 Specific Event Description – Change in CO_2 composition/properties from its source impacts the metallurgical considerations

Risk Assessment Matrix, Section 3.2 (Appendix F-1)

This event could occur due to changes in contamination levels in the CO_2 source. The sources of the contaminants may cause metallurgical incompatibilities between injectate and/or connate reservoir fluids, affecting the wellbore integrity of all penetrations in the injection zone.

Prevention and Detection

- Perform baseline analysis of the CO_2 injection stream.
- Continuous gas stream measurement and routine samples characterizing the CO_2 injection stream will be collected from the delivery pipeline and analyzed by a third-party laboratory. Chemical analysis will denote contaminant levels.
- The injection wells will be specifically designed, constructed, and operated with components such as CO_2-resistant cement, a corrosion-resistant packer, and alloy tubulars.
- Perform a proper corrective-action review and design, including the appropriate cement and metallurgy of the plugging materials.
- Conduct a routine inspection of pipelines and injection wellheads.
- Perform quarterly coupon analysis and nondestructive testing on the pipelines.

Potential Response Actions

- Lower the injection rates or stop the injection.
- Notify the UIC Director within 24 hours.
- Determine the cause of the contaminants.
- Investigate potential interactions between the contaminants and wellbore materials within the injection zone.
- If necessary, remediate the source of the contaminants.
- If necessary, treat the stream to reduce the effect of the contaminants.
- If well integrity is compromised, perform an appropriate workover to restore integrity.
- Demonstrate mechanical integrity per the methods discussed in ***Section 5 – Testing and Monitoring Plan***.

Tables 8-1 through 8-3 outline the risk assessment process discussed above.

8.4 Risk Activity Matrix

Table 8-1 – Risk Activity Matrix

Risk Activity Summary

		Likelihood	**Severity**				
			Safety	**Environmental**	**Financial**		
			40%	40%	20%		
Section	**Risk (Feature, Event, or Process)**	1-Remote, 5-Almost Certain	1-Very Low, 5-Very High				
		Assigned	Assigned	Assigned	Assigned	Estimated Risked Costs	Total Score
1	**Water Quality Contamination**	[redacted]					2.33
2	**CO2 Release to or at the Surface**	[redacted]					1.64
3	**Storage Rights Infringement - Form of Mineral Rights Infringement**	[redacted]					0.60
5	**Entrained Contaminant (Non-CO2) Releases**	[redacted]					1.20
6	**Accidents/Unplanned Events (Typical Insurable Events)**	[redacted]					2.40
	Total	[redacted]					

Table 8-2 – Risk Mitigation and Threat Scores

Threat Scores	Risk Mitigation
≥15	Avoid. Mitigate through immediate responsive action to reduce likelihood to an acceptable level.
10.0–14.9	Preventive and mitigative (P&M) measures required.
3.5–9.9	P&M measures are optional. Monitoring required.
0–3.4	No P&M measures are required. Monitor the situation.

Table 8-3 – Risk Assessment Scores

Risk Assessment Scores							
Likelihood	5	Imminent	5	10	15	20	25
	4	Likely	4	8	12	16	20
	3	Occasional	3	6	9	12	15
	2	Rare	2	4	6	8	10
	1	Remote	1	2	3	4	5
			Very Low 1	Low 2	Moderate 3	High 4	Very High 5
			Severity				

8.5 Training

Local response personnel and Aethon's operators will be trained in their duties and responsibilities related to these facilities during annual on-site or tabletop training exercises. All plant personnel, visitors, and contractors must attend a plant safety orientation before entering any of the facilities.

Aethon will provide to local first responders a copy of the ERRP that includes potential response scenarios, 24-hour facility contacts, the location of the wells, and schematics/diagrams of the facilities and wells. Aethon will also perform an internal screening of all site personnel, including third-party contractors, to ensure safety performance and that insurance requirements are met.

8.6 Communications Plan and Emergency Notification Procedures

A site-specific emergency response plan will be developed and implemented prior to commencing injection operations. This plan will specify the Incident Command center, muster points, and person-in-charge for any events that might occur. Emergency response numbers are provided in Tables 8-4 through 8-6.

Table 8-4 – Emergency Services – CALL 911

Agency	Telephone Number
Emergency – Fire, Police, Emergency Medical Services (EMS), etc.	911
Sabine Emergency Management Operations Center	409-787-5241
Sabine County Sheriff	409-787-2266
Hemphill Police Department	409-787-2251
San Augustine County Sheriff	936-275-2424

Table 8-5 – Government Agencies

Agency	Telephone Number
Texas Commission on Environmental Quality	512-239-1000
TRRC Emergency	512-463-6788
EPA National Response Center (24 hours)	800-424-8802
EPA Region 6	214-665-7150

Table 8-6 – Internal Call List

Name	Title	Telephone Number
Aethon Energy	24/7 Operations Command Center	800-274-0033

As appropriate, Aethon will communicate with the public and affected surface owners regarding events that require an emergency response—including the impact of the event on drinking water or the severity of the event, actions taken or planned to address the event, and other information needed to protect the public during the event.

8.7 Flood Hazard Risk

Flowering Crab Apple No. 1 is located in San Augustine County, in an area covered by FEMA FIRM panel 4811830150A (effective February 26, 1982). The only zone defined on this panel is Zone A, which does not cover the proposed injection location of Flowering Crab Apple No. 1. Tea Olive No. 1 is located in Sabine County, which does not have available FEMA FIRM panel flood mapping. FEMA published a Flood Risk Map for the Toledo Bend Reservoir Watershed (March 9, 2023) that covers the proposed injection location of Tea Olive No. 1. The well falls within the area of the map defined as "very low risk." The FEMA Flood Zone Hazard Map is located in *Appendix F-2*.

8.8 Emergency and Remedial Response Plan Review and Updates

This ERRP will be reviewed no less than once every 5 years. Any amendments to the plan must be approved by the UIC Director and will be incorporated into the permit as follows:

- Within 1 year of an AOR evaluation
- Following any significant changes to the facility, such as the addition of injection or monitoring wells
- After a change in key personnel
- As required by the UIC Director

The following attachments are in *Appendix F*:

- Appendix F-1 Complete Risk Assessment Matrix
- Appendix F-2 FEMA Flood Zone Hazard Map
- Appendix F-3 Resources and Infrastructure Map

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SECTION 9 – FINANCIAL ASSURANCE

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SECTION 9 – FINANCIAL ASSURANCE

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Figures

None are included in this section.

Tables

9.1 Facility Information

Facility Name: TXCCS#1

Facility Contact: Aaron Wimberly
Chief Health, Safety and Environmental Officer

Email: regulatory@aethonenergy.com

Project Site Name: TXCCS#1 Project

Project Location: Sabine County, Texas

Tea Olive No. 1
[redacted]

Flowering Crab Apple No. 1
[redacted]

*NAD 27 – North American Datum of 1927

9.2 Introduction

Under Title 16, Texas Administrative Code (16 TAC) **§5.205** (Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.85**), owners or operators of carbon sequestration wells are required to demonstrate financial responsibility for associated activities. Aethon Energy Operating LLC (Aethon) plans to construct two Class VI injection wells, Tea Olive No. 1 and Flowering Crab Apple No. 1, for the purpose of sequestering up to a total of 1 or 2 million metric tons per year (MMT/yr) of CO_2. Consistent with these regulatory requirements, Aethon has prepared this section to demonstrate financial responsibility for the injection wells that comprise the proposed TXCCS#1 Project site.

The sections that follow summarize the project's sequestration activities, as well as the qualifying financial instruments that Aethon proposes to use, to demonstrate financial responsibility for the following carbon capture and sequestration (CCS) project phases: (1) Corrective Action; (2) Well Plugging; (3) Post-Injection Site Care (PISC) and Site Closure; and (4) Emergency and Remedial Response.

9.3 Financial Assurance Demonstration

Per 40 CFR **§146.85(a)**, Aethon will secure the financial instruments outlined in Table 9-1 for coverage of corrective action, injection and monitoring well plugging, PISC and site closure, and emergency and remedial response. The instruments will include protective conditions, which at a minimum include cancellation, renewal, and continuation provisions—and 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. This insurance policy will be in force prior to the authority to inject.

Aethon will provide any updated information related to their financial responsibility instruments on an annual basis.

Aethon will also maintain financial responsibility and resources until the Underground Injection Control (UIC) Program director (UIC Director) receives and approves the completed PISC and Site Closure Plan—and approves site closure.

In accordance with 16 TAC **§5.205(c)(2)** (40 CFR **§146.85(c)**), Aethon will adjust the value of its financial assurance instruments either for inflation or in response to any changes in cost estimates. Aethon will then resubmit its demonstration of financial responsibility to the UIC Director or their designee for review and approval within 60 days prior to the anniversary date of the establishment of the financial instruments. Aethon will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Director or their designee.

Table 9-1 – Summary of CO_2 Sequestration Activity Project Costs

Phase	Cost (2025 Dollars)	Instrument
Corrective Action	[redacted]	
Well Plugging		
PISC and Site Closure		
Emergency and Remedial Response		
TOTAL		

9.3.1 Estimated Coverage Amounts

The total current cost estimate (in 2025 dollars) for all CO_2 sequestration activities requiring financial assurance at the TXCCS#1 Project site is [redacted] in 2025 dollars. The total cost estimate is the sum of the aforementioned project phases, as follows:

1. <u>Corrective Action</u>: phased in as dictated by the monitoring of the critical pressure front.
2. <u>Well Plugging</u>: after injection ceases and the wells are no longer in use for PISC monitoring.
3. <u>Post-Injection Site Care</u>: beginning when injection ceases and continuing for 50 years until site closure.

4. Emergency and Remedial Response: beginning with initial development operations and continuing for 50 years until site closure.

Table 9-1 summarized the total estimated project costs by activity. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the permit application process. The estimated costs assume the hiring of third-party contractors to perform the services or to procure the goods associated with the performance of each type of activity.

These values are subject to change during the project to account for inflation of costs as well as changes to the project that may affect the cost of covered activities.

9.4 Corrective Action

One orphan well, the [redacted] lacks sufficient documentation for the evaluation of potential harm to underground sources of drinking water (USDWs). Aethon will locate and reenter the well to determine its current condition [redacted] prior to encroachment of the critical pressure front based on modeling. The well will either be plugged in accordance with regulations or converted to a monitoring well. The Corrective Action Plan is discussed in detail in ***Section 3 – Area of Review and Corrective Action*** **Plan**.

The area of review (AOR) for the proposed TXCCS#1 Project will be reevaluated every 5 years to determine if any additional penetrations will be impacted. The estimated costs for corrective action are detailed in Table 9-2.

Table 9-2 – Estimated Costs for Corrective Action

Activity	Cost
Workover Rig	[redacted]
Rental Tools	
Mud/Brine	
Fracture Tanks	
Wireline	
Cement	
Bridge Plugs/Packers	
Casing Crew	
Locating (Magnetometric Survey) and Reentering	
Vacuum Trucks, Transportation	
Miscellaneous	
TOTAL	

9.5 Well Plugging

9.5.1 Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the proposed TXCCS#1 Project site will meet the requirements of 16 TAC **§5.203(k)** (40 CFR **§146.92**). The P&A of the injection wells will be designed so that no movement of fluids will occur from the injection interval. Detailed P&A plans are discussed in ***Section 6 – Plugging Plan***. The funds for plugging include costs for logs/wireline to be run in the wellbores before cementing occurs. Acid-resistant cement will be used for the plug across the injection zone to ensure that the cement does not react with the injected fluid.

All expenses relating to personnel and equipment have been accounted for in Table 9-3, including pressure test costs for the final assessment of well integrity.

9.5.2 Monitoring Well Plugging

The P&A of the monitoring wells associated with the TXCCS#1 Project site will also meet the requirements of 16 TAC **§5.203(k)** (40 CFR **§146.92**). The P&A of these shallow monitoring wells will be designed so that no movement of fluids will occur from the injection interval, nor will fresh, treatable water within the USDW be threatened. Detailed P&A plans are discussed in ***Section 6 – Plugging Plan***. Because these wells will be completed above the uppermost confining geologic interval, conventional plugging procedures will be utilized. These funds include costs for logs and wireline to be run in the wellbores before plugs are set.

All expenses relating to personnel and equipment have been accounted for in Tables 9-3 (injection wells) and 9-4 (monitoring wells), including pressure test costs for the final assessment of well integrity.

Table 9-3 – Injection Well Plugging Costs Associated with Financial Security

Activity	Cost	Total
Injection Well Plugging (two wells)		
Workover Rig	[redacted]	
Kill/Buffer Fluid		
Personnel		
Wireline		
Equipment Rentals		
Other Services		
Cement and Pumping Services		
Site Construction		
Contingency		
TOTAL		

Table 9-4 – Monitoring Well Plugging Costs Associated with Financial Security

Activity	Cost Per Well	Total
USDW Monitoring Well Plugging		
Workover Rig	[redacted]	[redacted]
Personnel	[redacted]	[redacted]
Cement and Pumping Services	[redacted]	[redacted]
Other Services	[redacted]	[redacted]
Rentals	[redacted]	[redacted]
Site Restoration	[redacted]	[redacted]
Contingency	[redacted]	[redacted]
TOTAL *(two wells)*	[redacted]	[redacted]

9.6 Post-Injection Site Care and Site Closure

The PISC and Site Closure Plan will be designed to meet the requirements of 16 TAC **§5.206(k)** (40 CFR **§146.93**). Aethon will continue to monitor the site for 50 years after the cessation of injection or until the UIC Director determines that there is no longer a threat of endangerment to USDWs. Post-injection monitoring will entail the proposed Tea Olive No. 1 and Flowering Crab Apple No. 1 providing in-zone and above-zone monitoring via continuous pressure and temperature readings. TOMW No. 1 and FCAMW No. 1 will be employed for groundwater monitoring, annually for the first 5 years, then every 5 years until plume stabilization.

Geophysical surveys will be carried out initially and 4 years after injection begins, at which time alternative technologies for indirect reservoir monitoring will be researched. For cost estimate purposes, Aethon proposes a survey every 10 years for each well post-injection. Mechanical integrity testing (MIT) of the injection wells will also be included in the PISC and Site Closure Plan.

Prior to final site closure, the injection and monitoring wells will be plugged in a manner to protect USDWs per ***Section 6 – Plugging Plan***, and surface equipment will be decommissioned and removed.

The estimated costs associated with the PISC and Site Closure Plan are presented in Table 9-5.

9.6.1 Site Closure

Site closure will occur when the UIC Director has released the owner from all PISC duties. The costs estimated in Table 9-5 reflect the amount expected to decommission and close the site.

Table 9-5 – PISC and Site Closure Costs Associated with Financial Security

Activity	Cost	Total
Post-Injection Monitoring	[redacted]	
Indirect Plume Monitoring		
Other Monitoring (e.g., fluid sampling and analysis, pressure/temperature monitoring, MITs)		
Site Closure		
Removal/Disposal of Waste		
Dismantling/Removal of Facility		
Piping		
Pumps		
Concrete		
Surface Equipment		
Debris		
TOTAL		

Indirect plume monitoring surveys will be run every 10 years throughout the PISC period, or as agreed to with the UIC Director—based on actual plume measurements or until the plume has been determined to have stabilized. Plume monitoring costs are estimated to be $100,000 per well during the PISC period. Other monitoring costs, such as pressure/temperature monitoring, fluid sampling, MITs, etc., are estimated to be $75,000 total per year for 50 years.

9.7 Emergency and Remedial Response Plan

The Emergency and Remedial Response Plan (ERRP) is discussed in ***Section 8 – Emergency and Remedial Response Plan*** and designed to meet 16 TAC **§5.203(l)** (40 CFR **§146.94**) requirements.

The calculated cost for the ERRP is [redacted] in 2025 dollars. This cost assumes coverage for the proposed TXCCS#1 Project site, which includes the following risks: water-quality impact, CO_2 release, and entrained contaminant (non-CO_2) in the injection stream. Details regarding these cost estimates are explained in ***Section 8***.

9.8 Conclusion

State and federal regulations require that the owner and operator of the two proposed Class VI wells of the TXCCS#1 Project demonstrate financial responsibility. The information provided in this section detailed the instruments that Aethon will use to fulfill financial assurance, properly execute operations, and uphold regulations throughout the life of the project. Aethon will secure these financial assurance instruments prior to beginning construction of the project.

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APPENDICES

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APPENDIX A: PROJECT MAPS

APPENDIX B: SITE CHARACTERIZATION

APPENDIX C: AOR AND CORRECTIVE ACTION PLAN

APPENDIX D: CONSTRUCTION

Appendix D-1	Tea Olive No.1 Wellbore Schematic
Appendix D-2	Flowering Crab Apple No.1 Wellbore Schematic

APPENDIX E: TESTING AND MONITORING

Appendix E-1	Monitoring Wells Map

APPENDIX F: EMERGENCY AND REMEDIAL RESPONSE PLAN

APPENDIX G: INJECTION WELL PLUGGING PLAN

Appendix G-1	Tea Olive No.1 Final P&A Schematic
Appendix G-2	Flowering Crab Apple No.1 Final P&A Schematic
Appendix G-3	TOMW No.1 Final P&A Schematic
Appendix G-4	FCAMW No.1 Final P&A Schematic

APPENDIX H: REFERENCES

(Submitted as separate files)

APPENDIX I: QUALITY ASSURANCE SURVEILLANCE PLAN