Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

FOREWORD

Orchard Storage Company LLC is proposing to develop a carbon sequestration facility in Gaines County, Texas, near the town of Loop. The Orchard Project is being designed to handle captured carbon dioxide (CO_2) from various emitters through multiple sequestration wells. This site is ideally suited for the sequestration of CO_2 with minimal existing wellbores in the area, an injection interval with requisite and appropriate reservoir properties, and substantial sealing intervals. The storage site is also relatively near existing CO_2 pipeline infrastructure to accommodate the economic delivery of sourced CO_2 volumes to the Orchard Project.

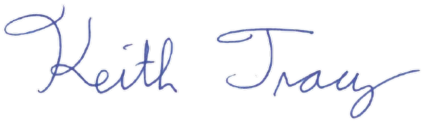
The following application will fully detail and characterize the geology of the proposed well locations, evaluate the formation for properties necessary to contain the sequestered CO_2 permanently, and describe the engineering design and safety considerations for the well. The application will also discuss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

The application has been developed to meet all of the requirements of both 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 of these 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.

CERTIFICATION

CERTIFIED BY:

I, Keith Tracy, 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.



Keith Tracy
Chief Commercial Officer

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

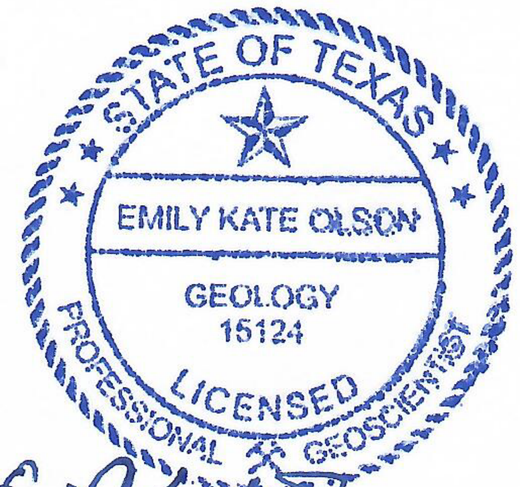


Certified By:
Lonquist Sequestration, LLC
Texas Registration No. 22610

Ben H. Bergman, P.E.
Senior Engineer
Texas License No. 95591

Date Signed: June 18, 2025

I, Emily Olson, certify that the geologic and hydrologic evaluations in this application were prepared by me or under my direct supervision and that the information and analyses presented herein are true and accurate to the best of my knowledge.



Emily Olson, P.G.
Sr. Geologist
Texas License No. 15124
Date Signed: 6.1.2025

ACRONYMS AND ABBREVIATIONS

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

§45Q	IRS Tax Code §45Q
AFI	active fracture images
AOR	area of review
API	American Petroleum Institute
ARM	ambient reservoir monitoring
ATSM	American Society for Testing and Materials
bbl	barrel(s)
bcf	billion cubic feet
BHIP	bottomhole injection pressure
BHP	bottomhole pressure
bpm	barrels per minute
CAA	Clean Air Act
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and storage
CDP	common depth point
CH_4	methane
CFR	U.S. Code of Federal Regulations
CMG	Computer Modelling Group
CMT	cement mapping tool
CO_2	carbon dioxide (may also refer to other Carbon Oxides)
CRA	corrosion resistant alloy
CWA	Clean Water Act
DTS	distributed temperature sensing
ECP	external casing packer
EOR	enhanced oil recovery
EOS	equation of state

EPA	Environmental Protection Agency
ESG	environmental, safety, and governance
FERC	Federal Energy Regulatory Commission
FMI	Fullbore Formation Microimager
g/cm^3	grams per cubic centimeter
GAPI	API gamma ray unit
GAU	Groundwater Advisory Unit
GR	gamma ray
HRVRT	high-resolution vertilog
Hz	hertz
IARF	infinite acting flow regime
ICS	Incident Command System
ID	inner diameter
IEA	International Energy Agency
kg/m^3	kilograms per cubic meter
km	kilometer(s)
KM	Kinder Morgan
lb/ft^3	pounds per cubic foot
Mbbls	thousand cubic feet
mD	Millidarcy(ies)
MD	measured depth
MDT	Modular Formation Dynamics Tester
MEQ	microseismic earthquakes
MPa	MegaPascal
mg/l	milligrams per liter
mGal	milligals
MIT	mechanical integrity test
MM	million
MMbbls	million barrels

MMcf	million cubic feet
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
MT	metric tons
MT/yr	metric tons per Year
MMT/yr	million metric tons per year
NETL	National Energy Technology Laboratory
OD	outer diameter
OIP	oil in place
P&A	plugging and abandonment
PE	photoelectric
PEC	Pulsed Eddy Current
PHIX_EFF	effective porosity
PISC	post-injection site care
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
QA/QC	quality assurance/quality control
QPT	Quartz Pressure Temperature
RCRA	Resource Conservation and Recovery Act
RFT	repeat formation tester
ROZ	Residual Oil Zone
rfn	rock fabric number(s)
SC	specific conductivity
SCADA	Supervisory Control and Data Acquisition
sDAS	seismic distributed acoustic sensing
SIC	Standard Industrial Classification

SOW	slip-on weld
SP	spontaneous potential
SS	subsea
TAC	Texas Administrative Code
TD	total depth
TDS	total dissolved solids
TEC	tubing encapsulated conductor
TRRC	Texas Railroad Commission
TVD	total vertical depth
UCL	upper confinement layer
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
VSP	vertical seismic profile
WIRE	Well Integrity Real-time Evaluation
XPHI	cross-plot porosity
XRD	X-Ray Diffraction

TABLE OF CONTENTS

FOREWORD

CERTIFICATIONS
ACRONYMS AND ABBREVIATIONS
TABLE OF CONTENTS
REQUIREMENTS MATRIX
INTRODUCTION
SECTION 1 – SITE CHARACTERIZATION
SECTION 2 – PLUME MODEL
SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN
SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY
SECTION 5 – TESTING AND MONITORING PLAN
SECTION 6 – PLUGGING AND ABANDONMENT PLAN
SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN
SECTION 9 – FINANCIAL ASSURANCE PLAN

APPENDICES:

- APPENDIX A: PROJECT OVERVIEW MAPS
- APPENDIX B: AREA OF REVIEW MAPS, TABLES/CORRECTIVE ACTION
- APPENDIX C: WELL CONSTRUCTION SCHEMATICS AND PROCEDURES
- APPENDIX D: METALLURGY SUMMARY
- APPENDIX E: TESTING AND MONITORING
- APPENDIX F: EMERGENCY RESPONSE PLAN SUPPORT
- APPENDIX G: PLUGGING SCHEMATICS AND PROCEDURES
- APPENDIX H: FINANCIAL ASSURANCE
- APPENDIX I: REFERENCES
- APPENDIX J: GEOLOGY SUPPORT
- APPENDIX K: WELL LOGS
- APPENDIX L: PLUME MODEL
- APPENDIX M: POST-INJECTION SITE CARE
- APPENDIX N: (NOT USED)
- APPENDIX O: WELL FILES FROM OFFSET WELLS AQUIRED BY ORCHARD
- APPENDIX P: ENVIRONMENTAL STUDIES

REQUIREMENTS MATRIX

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)	Applicability and compliance	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.	
§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)	Applicability and compliance	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).	9.1, 9.2
			§5.203 (a)(1)(A)	General	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.**	cover Pages
			§5.203 (a)(1)(B)	General	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 Pages
			§5.203 (a)(1)(B)(i)	General	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 Pages
			§5.203 (a)(1)(B)(ii)	General	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)	General	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)	General	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 Pages
§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	General information.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.203 (a)(2)(D)	General	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.	In progress
			§5.203 (a)(3)	General	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.	
§146.90(k)	Testing and monitoring requirements	A quality assurance and surveillance plan for all testing and monitoring requirements.	§5.203 (a)(4)	General	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.	Section 5 , QASP
			§5.203 (a)(5)	General	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.	Intro
§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 Information	Surface map and information. Only information of public record is required to be included on this map.	Appendix A-3
§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)(1)	Surface Map Information	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.	Appendix A-3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(2)	Surface Map Information	The applicant must show within the AOR on the map the number or name and the location of:	
§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)(2)(A)	Surface Map Information	all known artificial penetrations through the confining zone, including injection wells, producing wells, inactive wells, plugged wells, or dry holes;	Appendix A-3, Appendix B
§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)(2)(B)	Surface Map Information	the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and	Appendix A-3, Appendix B
§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)(2)(C)	Surface Map Information	other pertinent surface features, including pipelines, roads, and structures intended for human occupancy.	Appedix A-3, Appendix B

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(3)	Surface Map Information	The applicant must identify on the map any known or suspected faults expressed at the surface.	3.7,N/A
§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)	Geologic, geochemical, and hydrologic information	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.	1.3,,5.4.9
§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)	Geologic, geochemical, and hydrologic information	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)(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, geochemical, and hydrologic information	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;	1.2.1, 1.2.2, 1.9.3
§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, geochemical, and hydrologic information	Geologic and topographic maps and cross sections that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the injection zone(s), and the direction of water movement, where known;	1.2.1, 1.2.2, 1.9.3
§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)	Geologic, geochemical, and hydrologic information	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;	Section 1
§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)	Geologic, geochemical, and hydrologic information	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	4.3.9
§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)	Geologic, geochemical, and hydrologic information	Baseline geochemical data on subsurface formations, including all formations containing USDWs in the AOR;	4.3.9.4, 5.5.54, QASP - 6.2
§146.84	Area of review and corrective action		§5.203 (d)	AOR and corrective action	Area of Review and Corrective Action	Section 3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit 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)	AOR 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.	Section 3
§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)	AOR and corrective action	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(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)	AOR and corrective action	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:	
§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)(II)	AOR and corrective action	five years after initiation of injection;	3.7
§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)(III)	AOR and corrective action	from initiation of injection to the end of the injection period proposed by the applicant; and	3.7
§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)(III)	AOR and corrective action	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.	3.7

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(ii)	AOR and corrective action	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)	AOR and corrective action	Is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone	2.2,
§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)(II)	AOR and corrective action	is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	2.4
§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)	AOR and corrective action	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	2.2
§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)	AOR and corrective action	considers the physical and chemical properties of injected and formation fluids; and	2.4
§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)	AOR and corrective action	Considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.	1.4.2
			§5.203 (d)(1)(A)(iii)	AOR and corrective action	The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.	2.1.1, 3.2
§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)	AOR and corrective action	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.	3.7, 3.8, Appendix B

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)	AOR and corrective action	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.	3.7, 3.8, Appendix B
§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)	AOR and corrective action	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.	3.7, 3.8, Appendix B
§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.	§5.203 (d)(1)(C)	AOR and corrective action	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.	3.7, 3.8, Appendix B
§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)	AOR and corrective action	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:	3.8
§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)	AOR and corrective action	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;	Section 2, 3.2, 3.3
§146.84(b)(2)	Area of review and corrective action	A description of:	§5.203 (d)(2)(B)	AOR and corrective action	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)	AOR and corrective action	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;	3.9.1
§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)	AOR 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	3.9.1
§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)	AOR and corrective action	the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and	3.9.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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 performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§5.203 (d)(2)(C)	AOR and corrective action	a corrective action plan that describes:	
§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 performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§5.203 (d)(2)(C)(i)	AOR and corrective action	how the corrective action will be conducted;	3.8
§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 performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§5.203 (d)(2)(C)(ii)	AOR and corrective action	how corrective action will be adjusted if there are changes in the AOR;	3.9.1
§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 performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§5.203 (d)(2)(C)(iii)	AOR and corrective action	if a phased corrective action is planned, how the phasing will be determined; and	N/A
§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 performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§5.203 (d)(2)(C)(iv)	AOR and corrective action	how site access will be secured for future corrective action.	3.8
§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)(A)	Injection well construction	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)	Injection well construction	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, 4.3
§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)	Injection well construction	Allow the use of appropriate testing devices and workover tools; and	4.3
§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)	Injection well construction	Allow continuous monitoring of the annulus space between the injection tubing and long string casing.	4.2, 4.3
§146.86(b)	Injection well construction requirements	Casing and cementing of Class VI wells.	§5.203 (e)(1)(B)	Injection well construction	Casing and Cementing of anthropogenic CO2 injection wells	
			§5.203 (e)(1)(B)(i)	Injection well construction	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, 4.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(b)	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)	Injection well construction	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, 4.3, App C-5
§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)	Injection well construction	Surface casing must extend through the base of the lowermost USDW above the injection zone and be cemented to the surface	4.2.2
§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)	Injection well construction	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)(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)	Injection well construction	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).	4.2.2, 4.3
§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)	Injection well construction	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.	4.3.9.3, 5.4
§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)	Injection well construction	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.	4.2.1
§146.86	Injection well construction requirements		§5.203 (e)(2)	Injection well construction	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)	Injection well construction	Depth to the injection zone(s);	4.2.1
§146.86(b)(1)(iii)	Injection well construction requirements	Hole size;	§5.203 (e)(2)(B)	Injection well construction	Hole size	4.2.3
§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)	Injection well construction	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);	4.3
§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)	Injection well construction	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;	4.2.3
			§5.203 (e)(2)(E)	Injection well construction	type of packer and packer setting depth	4.2.1, 4.3
§146.86(b)(1)(v)	Injection well construction requirements	Corrosiveness of the carbon dioxide stream and formation fluids;	§5.203 (e)(2)(F)	Injection well construction	a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids;	Appendix D

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.86(b)(1)(vi)	Injection well construction requirements	Down-hole temperatures;	§5.203 (e)(2)(G)	Injection well construction	Down-hole temperatures and pressures	4.2.3
§146.86(b)(1)(vii)	Injection well construction requirements	Lithology of injection and confining zone(s);	§5.203 (e)(2)(H)	Injection well construction	Lithology of injection and confining zone(s)	1.2.4
§146.86(b)(1)(viii)	Injection well construction requirements	Type or grade of cement and cement additives; and	§5.203 (e)(2)(I)	Injection well construction	Type or grade of cement and cement additives; and	4.3, Appendix C
§146.86(b)(1)(ix)	Injection well construction requirements	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§5.203 (e)(2)(J)	Injection well construction	Quantity, chemical composition, and temperature of the carbon dioxide stream.	4.2.3
§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)	Injection well construction	Schematic drawings of the surface and subsurface construction details.	4.3
§146.82(a)(12)	Required class VI permit Information	Injection well construction procedures that meet the requirements of § 146.86;	§5.203 (e)(3)	Injection well construction	Well construction plan. The applicant must submit an injection well construction plan that meets the criteria in paragraph (1) of this subsection.	4.3, Appendix C
§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)	Injection well construction	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	4.3.1
§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 (f)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9, 1.3.1.1, 5.4
§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 (f)(1)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Logs and surveys of newly drilled and completed injection wells.	4.3.9, 1.3.1.1, 5.4
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9.1
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	4.3.9, 1.3.1.1, 5.4
			§5.203 (f)(1)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9, 1.3.1.1, 5.4
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9, 1.3.1.1, 5.4
			§5.203 (f)(1)(C)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9, 1.3.1.1, 5.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9, 1.3.1.1, 5.4
§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	§5.203 (f)(1)(D)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9, 1.3.1.1, 5.4
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Testing and determination of hydrogeologic characteristics of injection and confining zone.	
			§5.203 (f)(2)(A)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	4.3.9, 1.3.1.1, 5.4
§146.87(e)(1)	Logging, sampling, and testing prior to injection well operation	A pressure fall-off test; and,	§5.203 (f)(2)(B)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	5.4.2, 5.4.6
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	The operator must record the formation fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone.	4.3.9, 1.3.1.1, 5.4
§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)	Plan for logging, sampling, and testing of each injection well after permitting but prior to injection operation	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.	4.3.9.2
§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	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:	
§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)(1)	Compatibility determination	the materials to be used to construct the well;	4.2.1, Appendix D
§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)(2)	Compatibility determination	fluids in the injection zone; and	1.6.3
§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)(3)	Compatibility determination	minerals in both the injection and the confining zone.	1.6.3
§146.89	Mechanical Integrity	Mechanical Integrity	§5.203 (h)	Mechanical integrity testing	Mechanical integrity testing.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.89	Mechanical Integrity	Mechanical Integrity	§5.203 (h)(1)	Mechanical integrity testing	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.	5.4.4
§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)	Mechanical integrity testing	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.	
§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)	Mechanical integrity testing	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)	Mechanical integrity testing	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).	5.4.5
§146.89(c)(1)	Mechanical Integrity	An approved tracer survey such as an oxygen-activation log; or	§5.203 (h)(1)(D)	Mechanical integrity testing	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).	5.4.5
§146.89(c)(2)	Mechanical Integrity	A temperature or noise log.	§5.203 (h)(1)(D)	Mechanical integrity testing	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).	5.4.5
			§5.203 (h)(1)(E)	Mechanical integrity testing	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.	5.4.4
			§5.203 (h)(1)(F)	Mechanical integrity testing	An operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
§146.82(a)(15)	Required class VI permit Information	Proposed testing and monitoring plan required by § 146.90;	§5.203 (h)(2)	Mechanical integrity testing	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:	5.4.4, 5.4.5
§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	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:	
§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)	Mechanical integrity testing	A pressure test with liquid or gas;	5.4.4
§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)	Mechanical integrity testing	A tracer survey such as oxygen-activation logging;	5.4.5
§146.87(a)(4)(iii)	Logging, sampling, and testing prior to injection well operation	A temperature or noise log;	§5.203 (h)(2)(C)	Mechanical integrity testing	A temperature or noise log;	5.4.5
§146.87(a)(4)(iv)	Logging, sampling, and testing prior to injection well operation	A casing inspection log; and	§5.203 (h)(2)(D)	Mechanical integrity testing	A casing inspection log; and	5.4.8
§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)	Mechanical integrity testing	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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.82(a)(10)	Required class VI permit Information	Proposed procedure to outline steps necessary to conduct injection operation;	§5.203 (i)(1)	Operating Information	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:	
§146.82(a)(7)	Required class VI permit Information	Proposed operating data for the proposed geologic sequestration site:	§5.203 (i)(1)	Operating Information	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:	4.3.11
§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)	Operating Information	The average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	4.3.11
§146.82(a)(7)(ii)	Required class VI permit Information	Average and maximum injection pressure;	§5.203 (i)(1)(B)	Operating Information	The average and maximum surface injection pressure;	4.3.11
§146.82(a)(7)(iii)	Required class VI permit Information	The source(s) of the carbon dioxide stream; and	§5.203 (i)(1)(C)	Operating Information	The sources of the carbon dioxide stream and the volume of carbon dioxide from each source; and	Intro
§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)	Operating Information	An analysis of the chemical and physical characteristics of the carbon dioxide stream prior to injection.	5.4.3
			§5.203 (i)(2)	Operating Information	Maximum injection pressure. The director will approve a maximum injection pressure limit that:	4.3.11
			§5.203 (i)(2)(A)	Operating Information	Considers the risks of tensile failure and, where appropriate, geomechanical or other studies that assess the risk of tensile failure and shear failure;	4.3.11
			§5.203 (i)(2)(B)	Operating Information	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	4.3.11
§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)	Operating Information	in no case may cause the movement of injection fluids or formation fluids in a manner that endangers USDWs.	4.3.11
§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	Plan for monitoring, sampling, and testing after initiation of operation.	Section 5, Appendix E-2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(1)	Plan for monitoring, sampling, and testing after initiation of operation	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, Appendix E-2
§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)(2)	Plan for monitoring, sampling, and testing after initiation of operation	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)	Plan for monitoring, sampling, and testing after initiation of operation	The analysis of the carbon dioxide stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;	5.5.1, QASP 4
§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)	Plan for monitoring, sampling, and testing after initiation of operation	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	5.5.1, QASP 4
§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)	Plan for monitoring, sampling, and testing after initiation of operation	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:	5.5.2, QASP 5
§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)	Plan for monitoring, sampling, and testing after initiation of operation	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	5.5.2, QASP 5
§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)	Plan for monitoring, sampling, and testing after initiation of operation	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	
§146.90(c)(3)	Testing and monitoring requirements	Using an alternative method approved by the Director;	§5.203 (j)(2)(C)(iii)	Plan for monitoring, sampling, and testing after initiation of operation	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)	Plan for monitoring, sampling, and testing after initiation of operation	Monitoring of geochemical and geophysical changes, including:	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.203 (j)(2)(D)(i)	Plan for monitoring, sampling, and testing after initiation of operation	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;	5.5.5, QASP 6.2.1
§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)(ii)	Plan for monitoring, sampling, and testing after initiation of operation	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 CO2 through the confining zone into that monitored formation;	5.5.4, QASP 6.2.10
			§5.203 (j)(2)(D)(ii)	Plan for monitoring, sampling, and testing after initiation of operation	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 CO2 through the confining zone into that monitored formation;	5.5.4, QASP 6.2.10
§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)	Plan for monitoring, sampling, and testing after initiation of operation	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)(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)	Plan for monitoring, sampling, and testing after initiation of operation	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(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)	Plan for monitoring, sampling, and testing after initiation of operation	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)(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)	Plan for monitoring, sampling, and testing after initiation of operation	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(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)(F)	Plan for monitoring, sampling, and testing after initiation of operation	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	5.4.6
§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)(G)	Plan for monitoring, sampling, and testing after initiation of operation	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.	
§146.92	Injection Well Plugging	Injection well plugging	§5.203 (k)	Well Plugging Plan	Injection well plugging	
§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 permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§5.203 (k)	Well Plugging Plan	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:	
§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 permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§5.203 (k)(1)	Well Plugging Plan	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, Appendix G
§146.92(b)(3)	Injection Well Plugging	The type and number of plugs to be used;	§5.203 (k)(1)(A)	Well Plugging Plan	The type and number of plugs to be used;	6.1.4, 6.2.4
§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)	Well Plugging Plan	The placement of each plug, including the elevation of the top and bottom of each plug;	6.1.4, 6.2.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)	Well Plugging Plan	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	6.1.4, 6.2.4
§146.92(b)(6)	Injection Well Plugging	The method of placement of the plugs.	§5.203 (k)(1)(D)	Well Plugging Plan	The method of placement of the plugs.	6.1.4, 6.2.4
§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, and perform a final external mechanical integrity test.	§5.203 (k)(2)(A)	Well Plugging Plan	flush each injection well with a buffer fluid;	6.1.2
§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, and perform a final external mechanical integrity test.	§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.1.2
§146.92(b)(1)	Injection Well Plugging	Appropriate tests or measures for determining bottomhole reservoir pressure;	§5.203 (k)(2)(B)	Well Plugging Plan	performing tests or measures to determine bottomhole reservoir pressure;	6.1.2, 6.2.2
§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, and perform a final external mechanical integrity test.	§5.203 (k)(2)(C)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.1.2
§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)	Well Plugging Plan	performing final tests to assess mechanical integrity; and	6.1.2, 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 be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.203 (k)(3)(A)	Well Plugging Plan	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	6.1.2, 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 be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.203 (k)(3)(B)	Well Plugging Plan	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;	6.1.2, 6.2.2
§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)	Well Plugging Plan	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;	6.1.3, 6.2.3
			§5.203 (k)(5)	Well Plugging Plan	A plan for plugging all monitoring wells that do not penetrate the base of usable quality water in accordance with 16 TAC Chapter 76 (relating to Water Well Drillers and Water Well Pump Installers); and	
			§5.203 (k)(5)	Well Plugging Plan	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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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 during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§5.203 (l)	Emergency and remedial response plan	Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:	Section 8
			§5.203 (l)(1)	Emergency and remedial response plan	accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	8.2
§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 during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§5.203 (l)(2)	Emergency and remedial response plan	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;	8.5
			§5.203 (l)(3)	Emergency and remedial response plan	Includes a safety plan that includes:	
			§5.203 (l)(4)	Emergency and remedial response plan	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
			§5.203 (l)(A)	Emergency and remedial response plan	emergency response procedures;	8.4
			§5.203 (l)(B)	Emergency and remedial response plan	provisions to provide security against unauthorized activity;	8.5.10
			§5.203 (l)(C)	Emergency and remedial response plan	CO2 release detection and prevention measures;	8.7
			§5.203 (l)(D)	Emergency and remedial response plan	instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency;	8.7
			§5.203 (l)(E)	Emergency and remedial response plan	procedures for requesting assistance and for follow-up action to remove the public from an area of exposure;	8.7
			§5.203 (l)(F)	Emergency and remedial response plan	provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO2,	8.7
			§5.203 (l)(G)	Emergency and remedial response plan	the manner in which the public will be notified of an emergency and steps to be taken in case of an emergency; and	8.7
			§5.203 (l)(H)	Emergency and remedial response plan	if necessary, proposed actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring; and	8.7

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.	§5.203 (m)	Post-injection storage facility care and closure plan	The applicant must submit a post-injection storage facility care and closure plan.	7.4, 7.5
§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)	Post-injection storage facility care and closure plan	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;	7.4.2
§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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	A description of post-injection monitoring location, methods, and proposed frequency;	7.4.1
§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)	Post-injection storage facility care and closure plan	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	7.4.1
			§5.203 (m)(6)	Post-injection storage facility care and closure plan	the estimated cost of proposed post-injection storage facility care and closure; and	9.2
§146.93	Post-injection and site closure	Post-injection site care and site closure	§5.203 (m)(7)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;	Section 2
§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)	Post-injection storage facility care and closure plan	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;	7.2
§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)	Post-injection storage facility care and closure plan	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;	7.3
§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)	Post-injection storage facility care and closure plan	a description of the site-specific processes that will result in CO2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	2.3
§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)	Post-injection storage facility care and closure plan	the predicted rate of CO2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	2.3
§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)	Post-injection storage facility care and closure plan	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;	2.3
§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)	Post-injection storage facility care and closure plan	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;	1.2, 1.3, 1.4, 1.5
§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)	Post-injection storage facility care and closure plan	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;	2.2
§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)	Post-injection storage facility care and closure plan	a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;	3.7, 3.8
§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)	Post-injection storage facility care and closure plan	the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	1.9

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.93(c)(1)(xi)	Post-injection and site closure	Any additional site-specific factors required by the Director.	§5.203 (m)(7)(K)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:	
§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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	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)	Post-injection storage facility care and closure plan	any additional criteria required by the director.	
§146.82(a)(14)	Financial Responsibility	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§5.203 (n)	Fees, financial responsibility, and financial assurance	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).	9.1, 9.2
§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);	§5.203(m)(8)(F)	Post-Injection storage facility carea and closure plan	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;	
§146.85	Financial Responsibility		§5.205 (b)(1)	Fees, financial responsibility, and financial assurance	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.	9.1
§146.85	Financial Responsibility		§5.205 (b)(2)	Fees, financial responsibility, and financial assurance	In determining whether the person is financially responsible, the director must rely on:	
§146.85	Financial Responsibility		§5.205 (b)(2)(A)	Fees, financial responsibility, and financial assurance	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	9.1
§146.85	Financial Responsibility		§5.205 (b)(2)(B)	Fees, financial responsibility, and financial assurance	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	9.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85	Financial Responsibility		§5.205 (b)(2)(C)	Fees, financial responsibility, and financial assurance	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.	9.1
§146.84(f)	Financial Responsibility	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)	Fees, financial responsibility, and financial assurance	The applicant's demonstration of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.2
§146.85	Financial Responsibility		§5.205 (b)(3)	Fees, financial responsibility, and financial assurance	The applicant's demonstratio of financial responsibiltiy must account for the entire AOR, regardless of whether corrective action in the AOR is phased.	9.1
§146.85			§5.205 (c)	Financial assurance	Financial assurance.	
§146.85	Financial Responsibility		§5.205 (c)	Fees, financial responsibility, and financial assurance	Financial assurance.	9.1
§146.85	Financial Responsibility		§5.205 (c)(1)	Fees, financial responsibility, and financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)	Fees, financial responsibility, and financial assurance	Geologic storage facility.	
§146.85	Financial Responsibility		§5.205 (c)(2)(A)	Fees, financial responsibility, and financial assurance	The applicant must include in an application for a geologic storage facility permit:	
§146.85(a)(2)(i)	Financial Responsibility		§5.205 (c)(2)(A)(i)	Fees, financial responsibility, and financial assurance	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;	???
§146.85(c)	Financial Responsibility		§5.205 (c)(2)(A)(i)	Financial assurance	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
§146.85	Financial Responsibility		§5.205 (c)(2)(A)(ii)	Fees, financial responsibility, and financial assurance	a copy of the form of the bond or letter of credit that will be filed with the Commission; and	???
§146.85	Financial Responsibility		§5.205 (c)(2)(A)(iii)	Fees, financial responsibility, and financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)(B)	Fees, financial responsibility, and financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)(C)	Fees, financial responsibility, and financial assurance	The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:	
§146.85(a)(2)	Financial Responsibility		§5.205 (c)(2)(C)(i)	Fees, financial responsibility, and financial assurance	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;	9.2, 9.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(c)	Financial Responsibility		§5.205 (c)(2)(C)(i)	Financial assurance	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;	9.2, 9.3
§146.85	Financial Responsibility		§5.205 (c)(2)(C)(ii)	Fees, financial responsibility, and financial assurance	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	Section 9
§146.85	Financial Responsibility		§5.205 (c)(2)(C)(iii)	Fees, financial responsibility, and financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)(D)	Financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)(D)	Fees, financial responsibility, and financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)(D)(i)	Financial assurance	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.	
§146.85	Financial Responsibility		§5.205 (c)(2)(D)(ii)	Financial assurance	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.	
§146.85(c)	Financial Responsibility		§5.205 (c)(2)(E)	Fees, financial responsibility, and financial assurance	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.	9.1, 9.8

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(c)(2)	Financial Responsibility		§5.205 (c)(2)(E)	Financial assurance	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.	9.1, 9.8
§146.85(c)	Financial Responsibility		§5.205 (c)(3)	Fees, financial responsibility, and financial assurance	The director may consider allowing the phasing in of financial assurance for only corrective action based on project-specific factors.	
§146.85(c)(3)	Financial Responsibility		§5.205 (c)(4)	Fees, financial responsibility, and financial assurance	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.	
§146.85(d)	Financial Responsibility		§5.205 (D)	Fees, financial responsibility, and financial assurance	Notice of adverse financial conditions	
§146.85(d)	Financial Responsibility		§5.205 (D)(1)	Fees, financial responsibility, and financial assurance	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.	9.2
§146.85(d)	Financial Responsibility		§5.205 (D)(2)	Fees, financial responsibility, and financial assurance	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.	
§146.85(a)(4)(i)(A)			§5.205 (d)(3)	Nodtice of adverse financial conditions	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(d)	Financial Responsibility		§5.205 (D)(3)	Fees, financial responsibility, and financial assurance	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.	
			§5.206 (a)	Permit Standards	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 (b)	Permit Standards	General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that:	
			§5.206 (b)(1)	Permit Standards	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)(10)	Permit Standards	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)(11)	Permit Standards	the director has determined that the applicant has sufficiently demonstrated financial responsibility as required in §5.205(b) of this title; and	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (b)(12)	Permit Standards	the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.	
			§5.206 (b)(2)	Permit Standards	with proper safeguards, both USDWs and surface water can be adequately protected from CO2 migration or displaced formation fluids;	
			§5.206 (b)(3)	Permit Standards	the injection of anthropogenic CO2 will not endanger or injure human health and safety;	
			§5.206 (b)(4)	Permit Standards	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;	
§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)(5)	General Criteria	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)(5)(A)	General Criteria	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	1.3, 1.4, 1.5,
§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)(5)(B)	General Criteria	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).	1.4.2
			§5.206 (b)(5)(B)	Permit Standards	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;	1.3.3, 1.4.2, 1.5.3, 4.2.6
			§5.206 (b)(6)	Permit Standards	the applicant for the permit meets all of the other statutory and regulatory requirements for the issuance of the permit;	
			§5.206 (b)(7)	Permit Standards	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 C-7
			§5.206 (b)(8)	Permit Standards	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;	In progress
			§5.206 (b)(9)	Permit Standards	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;	
			§5.206 (c)(1)	Permit Standards	Construction of anthropogenic CO 2 injection wells must meet the criteria in §5.203(e) of this title.	4.1
			§5.206 (c)(2)	Permit Standards	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.	4.2.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (c)(3)	Permit Standards	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)	Permit Standards	Operating a geologic storage facility.	
			§5.206 (d)(1)	Permit Standards	Operating plan. The operator must maintain and comply with the approved operating plan.	
			§5.206 (d)(2)	Permit Standards	Operating criteria.	
§146.88(b)	Injection well construction requirements	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	§5.206 (d)(2)(A)	Operating a geologic storage facility	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	
			§5.206 (d)(2)(B)	Permit Standards	The total volume of CO2 injected into the storage facility must be metered through a master meter or a series of master meters. The volume and/or mass of CO2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.	5.5.1
			§5.206 (d)(2)(C)	Permit Standards	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.	4.3.11
§146.88(c)	Injection well construction 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)	Operating a geologic storage facility	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.	4.2.2
			§5.206 (d)(2)(E)	Permit Standards	The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO2 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.	5.5.1
§146.88(e)	Injection well operating requirements	The owner or operator must install and use:	§5.206 (d)(2)(F)	Operating a geologic storage facility	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)	Operating a geologic storage facility	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.	5.5.1

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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	§5.206 (d)(2)(F)(i)	Operating a geologic storage facility	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.	5.4.7
§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.	§5.206 (d)(2)(F)(i)	Operating a geologic storage facility	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.	
§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)	Operating a geologic storage facility	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	8.5.8
§146.88(f)(1)	Injection well operating requirements	Immediately cease injection;	§5.206 (d)(2)(F)(ii)(I)	Operating a geologic storage facility	Immediately cease injection;	8.5.8
§146.94(b)(1)	Emergency and remedial response	Immediately cease injection;	§5.206 (d)(2)(F)(ii)(I)			8.5.8
§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)	Operating a geologic storage facility	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	8.5.8
§146.94(b)(2)	Emergency and remedial response	Take all steps reasonably necessary to identify and characterize any release;	§5.206 (d)(2)(F)(ii)(II)			8.5
§146.88(f)(3)	Injection well operating requirements	Notify the Director within 24 hours;	§5.206 (d)(2)(F)(ii)(III)	Operating a geologic storage facility	Notify the Director within 24 hours	8.5.8
§146.94(b)(3)	Emergency and remedial response	Notify the Director within 24 hours; and	§5.206 (d)(2)(F)(ii)(III)			
§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)	Operating a geologic storage facility	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	8.5.8
§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)	Operating a geologic storage facility	Notify the Director when injection can be expected to resume	8.5.8
			§5.206 (e)	Permit Standards	Monitoring, sampling, and testing requirements.	
			§5.206 (e)(1)	Permit Standards	The operator of an anthropogenic CO2 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.	
			§5.206 (e)(2)	Permit Standards	All permits shall include the following requirements:	
			§5.206 (e)(2)(A)	Permit Standards	the proper use, maintenance, and installation of monitoring equipment or methods;	
			§5.206 (e)(2)(B)	Permit Standards	monitoring including type, intervals, and frequency sufficient to yield data that are representative of the monitored activity including, when required, continuous monitoring;	5.2
			§5.206 (e)(2)(C)	Permit Standards	reporting no less frequently than as specified in §5.207 of this title (relating to Reporting and Record-Keeping).	5.2
§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;	§5.206 (e)(3)	Monitoring, sampling, and testing requirements	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	
			§5.206 (e)(3)	Permit Standards	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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (e)(4)	Permit Standards	The director may require measures and actions designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring.	
§146.89	Mechanical Integrity	Mechanical Integrity	§5.206 (f)	Mechanical integrity	Mechanical Integrity	
			§5.206 (f)(1)	Permit Standards	The operator must maintain and comply with the approved mechanical integrity testing plan submitted in accordance with §5.203(j) of this title.	5.4.4
§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.	§5.206 (f)(2)	Mechanical integrity	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)(3)	Permit Standards	The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
§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)	Mechanical integrity	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.	
§146.84(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)	AOR and corrective action	Area of review and corrective action. Notwithstanding the requirement in §5.203(d)(2)(B)(i) of 30 this title to perform a re-evaluation of the AOR, at the fixed frequency specified in the area of review and corrective action plan or permit, the operator of a geologic storage facility also must conduct the following 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:	3.9
§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)	AOR and corrective action	a re-evaluation of the AOR [area of review] by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate the AOR [area of review] and identify all wells that require corrective action;	
§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)	AOR and corrective action	Identify all wells in the reevaluated area of review that require corrective action; and	3.9
§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)	AOR and corrective action	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in §5.203(d)(1)(C) of this title; and	
§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)	AOR 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.	
§146.94	Emergency and remedial response	Emergency and remedial response	§5.206 (h)	Emergency, mitigation, and remedial response	Emergency mitigation, and remedial response	
§146.82(a)(19)	Required class VI permit Information	Proposed emergency and remedial response plan required by § 146.94(a);	§5.206 (h)(1)	Permit Standards	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.	8.8

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (h)(2)(A)	Permit Standards	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.	8.6
			§5.206 (h)(2)(B)	Permit Standards	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.	8.6
			§5.206 (h)(2)(C)	Permit Standards	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.	8.6
§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)	Permit Standards	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.	
§146.87(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)	Permit Standards	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.	4.3.9.3, 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.	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.	
§146.91(d)(1)	Reporting requirements	Any planned well workover;	§5.206 (i)	Commission witnessing of testing and logging.	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)(2)	Reporting requirements	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and	§5.206 (i)	Commission witnessing of testing and logging.	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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(d)(3)	Reporting requirements	Any other planned test of the injection well conducted by the permittee.	§5.206 (i)	Commission witnessing of testing and logging.	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
§146.82(a)(16)	Required class VI permit Information	Proposed injection well plugging plan required by § 146.92(b);	§5.206 (j)	Permit Standards	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.	6.1, 6.2
			§5.206 (j)	Permit Standards	Schedule of compliance: The permit may, when appropriate, specify a schedule of compliance leading to compliance with all provisions of this subchapter and Chapter 3 of this title.	
			§5.206 (j)(i)	Permit Standards	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 (j)(ii)	Permit Standards	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 (j)(iii)	Permit Standards	Progress reports must be submitted no later than 30 days following each interim date and the final date of compliance.	
§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)	Permit Standards	Post-injection storage facility care and closure plan.	7.4, 7.5
			§5.206 (k)(1)(A)	Permit Standards	The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan.	7.4, 7.5
§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.	§5.206 (k)(1)(B)	Post-injection storage facility care and closure	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.	7.1, 7.4.2
§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)	Post-injection storage facility care and closure	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.	7.1, 7.4.2
			§5.206 (k)(1)(C)	Permit Standards	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.	7.1, 7.4.2
§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)	Post-injection storage facility care and closure	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:	7.4.2
			§5.206 (k)(3)(A)	Permit Standards	the estimated magnitude and extent of the facility footprint (the CO2 plume and the area of elevated pressure);	7.3

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.206 (k)(3)(B)	Permit Standards	that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs;	7.4.2
			§5.206 (k)(3)(C)	Permit Standards	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;	7.4.1
			§5.206 (k)(3)(D)	Permit Standards	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	7.5.2
			§5.206 (k)(3)(E)	Permit Standards	any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.	7.5.2
§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)	Post-injection storage facility care and 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.	7.5.1
§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)	Post-injection storage facility care and closure	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.	7.5.1, 7.5.2
§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)	Post-injection storage facility care and closure	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:	7.5.4
§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)	Post-injection storage facility care and closure	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.	7.5.4
§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)	Post-injection storage facility care and closure	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)	Post-injection storage facility care and closure	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	7.5.4
§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	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:	7.5.4
§146.93(g)	Required class VI permit Information	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)(1)	Permit Standards	a complete legal description of the affected property;	7.5.4
§146.93(g)(1)	Post-injection and site closure	The fact that land has been used to sequester carbon dioxide;	§5.206 (l)(2)	Deed notation	The fact that land has been used to sequester carbon dioxide;	7.5.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(4)	Deed notation	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	7.5.4
§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)	Deed notation	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	7.5.4
§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)	Retention of Records	The operator must retain for 10 years following facility closure records collected during the post-injection facility care period. The operator must deliver 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.	7.5.4
			§5.206 (n)	Permit Standards	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)	Permit Standards	Other permit terms and conditions.	
			§5.206 (o)(1)	Permit Standards	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)	Permit Standards	Other conditions. The following conditions shall also be included in any permit issued under this subchapter.	
			§5.206 (o)(2)(A)	Permit Standards	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)	Permit Standards	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)	Permit Standards	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)	Permit Standards	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)	Permit Standards	Property rights not conveyed. The issuance of a permit does not convey property rights of any sort, or any exclusive privilege.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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)	Permit Standards	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.	
			§5.206 (o)(2)(H)	Permit Standards	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)	Permit Standards	Inspection and entry. The operator shall allow any member or employee of the Commission, on proper identification, to:	
			§5.206 (o)(2)(I)(i)	Permit Standards	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)	Permit Standards	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)	Permit Standards	inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and	
			§5.206 (o)(2)(iv)	Permit Standards	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.	
§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	Reporting and Record-Keeping	Reporting and Record-Keeping. The operator must provide, at a minimum, the following reports to the Director and retain the following information	
§146.91(c)	Reporting requirements	Report, within 24 hours:	§5.207 (a)(2)(A)	Reporting and Record-Keeping	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.	
§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)	Reporting and Record-Keeping	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
§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)	Reporting and Record-Keeping	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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)	Reporting and Record-Keeping	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
§146.91(c)(4)	Reporting requirements	Any failure to maintain mechanical integrity; or.	§5.207 (a)(2)(A)	Reporting and Record-Keeping	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
§146.91(b)	Reporting requirements	Report, within 30 days, the results of:	§5.207 (a)(2)(B)	Reporting and Record-Keeping	Report, within 30 days, the results of:	
§146.91(b)(1)	Reporting requirements	Periodic tests of mechanical integrity;	§5.207 (a)(2)(B)(i)	Reporting and Record-Keeping	Periodic tests of mechanical integrity;	5.2
§146.91(b)(2)	Reporting requirements	Any well workover; and,	§5.207 (a)(2)(B)(ii)	Reporting and Record-Keeping	Any well workover; and,	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)(iii)	Reporting and Record-Keeping	Any other test of the injection well conducted by the permittee if required by the Director.	5.2
§146.91(a)	Reporting requirements	Semi-annual reports containing:	§5.207 (a)(2)(C)	Reporting and Record-Keeping	Semi-annual reports containing:	
§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)	Reporting and Record-Keeping	a summary of well head pressure monitoring;	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)	Reporting and Record-Keeping	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)(iii)	Reporting and Record-Keeping	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)	Reporting and Record-Keeping	monthly annulus fluid volume added;	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)	Reporting and Record-Keeping	description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;	5.2
			§5.207 (a)(2)(C)(v)	Reporting and Record-Keeping	A description of any event that exceeds operating parameters for annulus pressure or injection pressure 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)	Reporting and Record-Keeping	a description of any event that triggers a shutdown device and the response taken; and	5.2
			§5.207 (a)(2)(D)(i)	Reporting and Record-Keeping	corrective action performed;	
§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)(D)(v)	Reporting and Record-Keeping	tons of CO2 injected; and	5.2
§146.91(a)(7)	Reporting requirements	The results of monitoring prescribed under § 146.90.	§5.207 (a)(C)(vii)	Reporting and Record-Keeping	the results of monitoring prescribed under §5.206€ [§5.206(d)] of this title (relating to Permit Standards).	5.2
			§5.207 (a)(D)	Reporting and Record-Keeping	Annual reports. The operator must submit an annual report detailing:	5.2
			§5.207 (b)(1)	Reporting and Record-Keeping	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.	
§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)	Reporting and Record-Keeping	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)	Reporting and Record-Keeping	Signatories to reports.	
			§5.207 (c)(1)	Reporting and Record-Keeping	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:	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§5.207 (c)(1)(A)	Reporting and Record-Keeping	the authorization is made in writing by a person described in §5.203(a)(1)(B) of this title;	
			§5.207 (c)(1)(B)	Reporting and Record-Keeping	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)	Reporting and Record-Keeping	the written authorization is submitted to the director.	
			§5.207 (c)(2)	Reporting and Record-Keeping	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.	
			§5.207 (d)	Reporting and Record-Keeping	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."	Cover Pages
§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)	Reporting and Record-Keeping	Record retention. The operator must retain all wellhead pressure records, metering records, and integrity test results for at least 10 [ten] years. 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) [§5.206(j)(7)] of this title.	5.2
§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)(1)	Reporting and Record-Keeping	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 [the test(s) and the method(s)] used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.	5.2
§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				Intro
§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:				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(10)	Required class VI permit Information	Any other information requested by the Director.				
§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)(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;				
§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				
§146.83(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(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(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.				5.2
§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)		The financial responsibility instrument(s) used must be from the following list of qualifying instruments:				
§146.85(a)(1)(i)		Trust Funds.				
§146.85(a)(1)(ii)		Surety Bonds.				9.2
§146.85(a)(1)(iii)		Letter of Credit.				
§146.85(a)(1)(iv)		Insurance				
§146.85(a)(1)(v)		Self Insurance (i.e., Financial Test and Corporate Guarantee).				
§146.85(a)(1)(vi)		Escrow Account				
§146.85(a)(1)(vii)		Any other instrument(s) satisfactory to the Director.				
§146.85(a)(2)		The qualifying instrument(s) must be sufficient to cover the cost of:				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(2)(i)		Corrective action (that meets the requirements of § 146.84);				9.3
§146.85(a)(2)(ii)		Injection well plugging (that meets the requirements of § 146.92);				9.4
§146.85(a)(2)(iii)		Post injection site care and site closure (that meets the requirements of § 146.93); and				9.6
§146.85(a)(2)(iv)		Emergency and remedial response (that meets the requirements of § 146.94).				9.7
§146.85(a)(3)		The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.				9.7.2
§146.85(a)(4)		The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.				
§146.85(a)(4)(i)		Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.				9.2
§146.85(a)(4)(i)(A)		Cancellation - for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.				
§146.85(a)(4)(i)(B)		Renewal - for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.				
§146.85(a)(4)(i)(C)		Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.				
§146.85(a)(5)		The qualifying financial responsibility instrument(s) must be approved by the Director.				
§146.85(a)(5)(i)		The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(5)(ii)		The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.				9.2
§146.85(a)(5)(iii)		The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.				
§146.85(a)(6)		The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.				
§146.85(a)(6)(i)		In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.				
§146.85(a)(6)(ii)		When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.				
§146.85(a)(6)(iii)		An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.				
§146.85(a)(6)(iv)		An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(a)(6)(v)		An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than −0.1; and a net profit (revenues minus expenses) greater than 0.				
§146.85(a)(6)(vi)		An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.				
§146.85(a)(6)(vii)		An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.				9.2
§146.85(b)		The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.				
§146.85(b)(1)		The owner or operator must maintain financial responsibility and resources until:				
§146.85(b)(1)(i)		The Director receives and approves the completed post-injection site care and site closure plan; and				9.1
§146.85(b)(1)(ii)		The Director approves site closure.				9.1
§146.85(c)		The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.				9.2,9.3, 9.4, 9.5,9.6
§146.85(c)(1)		The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(c)(2)		During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).				9.8
§146.85(c)(3)		The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.				
§146.85(c)(4)		Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.				9.8
§146.85(c)(d)		The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.				9.2
§146.85(c)(d)(1)		In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.				
§146.85(c)(d)(2)		A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.85(c)(d)(3)		An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.				
§146.85(e)	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(b)(1)(ii)	Injection well construction requirements	Injection pressure, external pressure, internal pressure, and axial loading;				4.3
§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.				4.2.3, Appendix D
§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;				4.2.1
§146.86(c)(3)(ii)	Injection well construction requirements	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;				4.2.3
§146.86(c)(3)(iii)	Injection well construction requirements	Maximum proposed injection pressure;				4.3.11
§146.86(c)(3)(iv)	Injection well construction requirements	Maximum proposed annular pressure;				4.3.11
§146.86(c)(3)(vi)	Injection well construction requirements	Size of tubing and casing; and				4.3
§146.86(c)(3)(vii)	Injection well construction requirements	Tubing tensile, burst, and collapse strengths.				4.3
§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)(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.				4.3.9
§146.87(d)(1)	Logging, sampling, and testing prior to injection well operation	Fracture pressure;				4.3.9
§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				4.3.9.4
§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).				4.3.9.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(2)		A pump test; or				
§146.87(e)(3)		Injectivity tests.				4.3.9.5
§146.88(a)		Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.				
§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.				
§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.				
§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.				
§146.90(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;				5.4.5
§146.90(g)(1)		Direct methods in the injection zone(s); and,				5.5.7.1
§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.				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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;				5.5.3
§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;				5.5.3
§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(j)		The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:				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				5.3
§146.90(j)(3)		When required by the Director.				5.3
§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)(2)	Reporting requirements	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and				
§146.91(f)	Reporting requirements					
§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.				5.2
§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.				5.2
§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.				5.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.				
§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.				7.4, 7.5
§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(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.				7.4.1
§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.				
§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.				
§146.93(b)(4)						
§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.				
§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:				
§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:				
§146.94(b)(4)	Emergency and remedial response	Implement the emergency and remedial response plan approved by the Director.				8.4

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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:				8.7
§146.94(d)(1)	Emergency and remedial response	Within one year of an area of review reevaluation;				8.7
§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				8.7
§146.94(d)(3)	Emergency and remedial response	When required by the Director.				8.7

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Introduction

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 0 – INTRODUCTION

TABLE OF CONTENTS

Project Overview 2
Project Key Attributes 5
Pore Space Agreement Discussion 6
Proposed CO_2 Sequestration System Discussion 6
Injectate Information 6
Surface Facility Details 7
Site Suitability 7
Summary 10
Required Administrative Information 12
General Application Information 12
Additional Permits 13
APPENDIX A 13

Figures

Figure 0-1 – Emission Sources 2
Figure 0-2 – Project Overview Map. 4
Figure 0-3 – Permian Basin West-East Cross Section 5
Figure 0-4 – Distance from Valve Station to Orchard No. 1 8
Figure 0-5 – Aerial Map of Orchard Project. 9

Tables

Table 0-1 – Injectate Major Components 7
Table 0-2 – Planned Injection Rates by Well 10
Table 0-3 – Injection Well Location Details 12
Table 0-4 – State, Tribe, and Territory Contacts 13
Table 0-5 – Additional Required Permits 13

Project Overview

The International Energy Agency (IEA) states that in 2021 just over 40 million metric tons per year (MMT/yr) of CO_2 were captured worldwide.[1] By 2070, the world will need to capture and store more than 10,000 MMT/yr of CO_2 to meet the Sustainable Development Scenario plan outlined by the IEA.[2] To meet these climate goals, real projects and investment are paramount—such as carbon capture, which is becoming an essential addition to industrial processes emitting carbon dioxide into the atmosphere.[3]

Elysian Carbon Management LLC provides integrated, end-to-end carbon capture and storage (CCS) solutions to owners of industrial and power facilities seeking to transition to low carbon products and address environmental, safety, and governance (ESG) goals. Elysian is a CCS project management company that develops, designs, builds, owns, and operates carbon capture, transport, and storage projects throughout the United States. Orchard Storage Company LLC (Orchard Storage), a wholly owned subsidiary of Elysian, was established to develop and operate the Class VI CO_2 storage site discussed in this application. Orchard Storage team members have extensive expertise in the capture, transport, and geologic storage of CO_2. Carbon capture and storage represent meaningful, physical reductions in CO_2 emission—to dramatically decrease Scope 1, 2, and 3 emissions, as described in Figure 0-1.

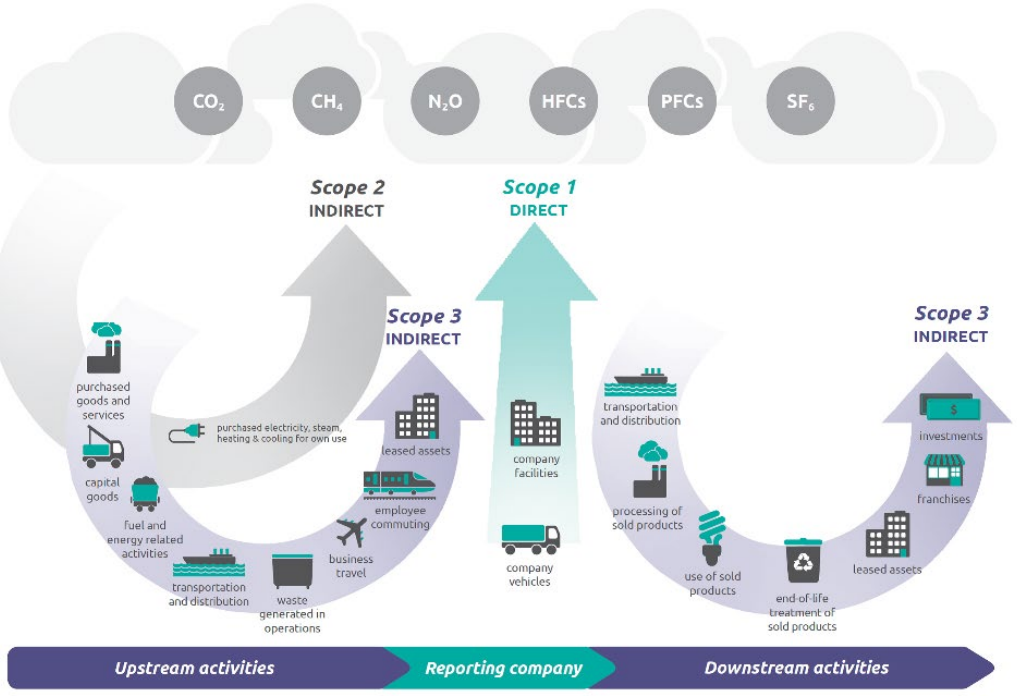


Figure 0-1 – Emission Sources[4]

[1] https://www.iea.org/reports/about-ccus
[2] https://www.iea.org/reports/about-ccus
[3] https://elysian.cc/about-us
[4] https://ghgprotocol.org/sites/default/files/standards/Corporate-Value-Chain-Accounting-Reporing-Standard_041613_2.pdf, page 5

The Orchard Project is being developed to accommodate and sequester, in secure geologic storage, anthropogenic CO_2 sourced regionally from various emitters. The Orchard Project plans to use multiple wells at the storage site to accommodate the captured CO_2 volumes. The extensive screening process for Orchard's site selection resulted in a site that meets Underground Injection Control (UIC) requirements with minimal existing wellbores, an injection interval with requisite and appropriate reservoir properties, and substantial sealing intervals. The storage site is also relatively near existing CO_2 pipeline infrastructure to accommodate the economic delivery of sourced CO_2 volumes to the Orchard Project.

This permit application is for drilling, completing, operating, and monitoring seven Class VI CCS injection wells, Orchard No. 1 through No. 7, located in Gaines County, Texas (Figure 0-2). The CO_2 injection wells are designed to meet the requirements of American Petroleum Institute (API) 1171, along with the regulatory requirements outlined in 16 Texas Administrative Code (TAC) **§5.206(c)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**].

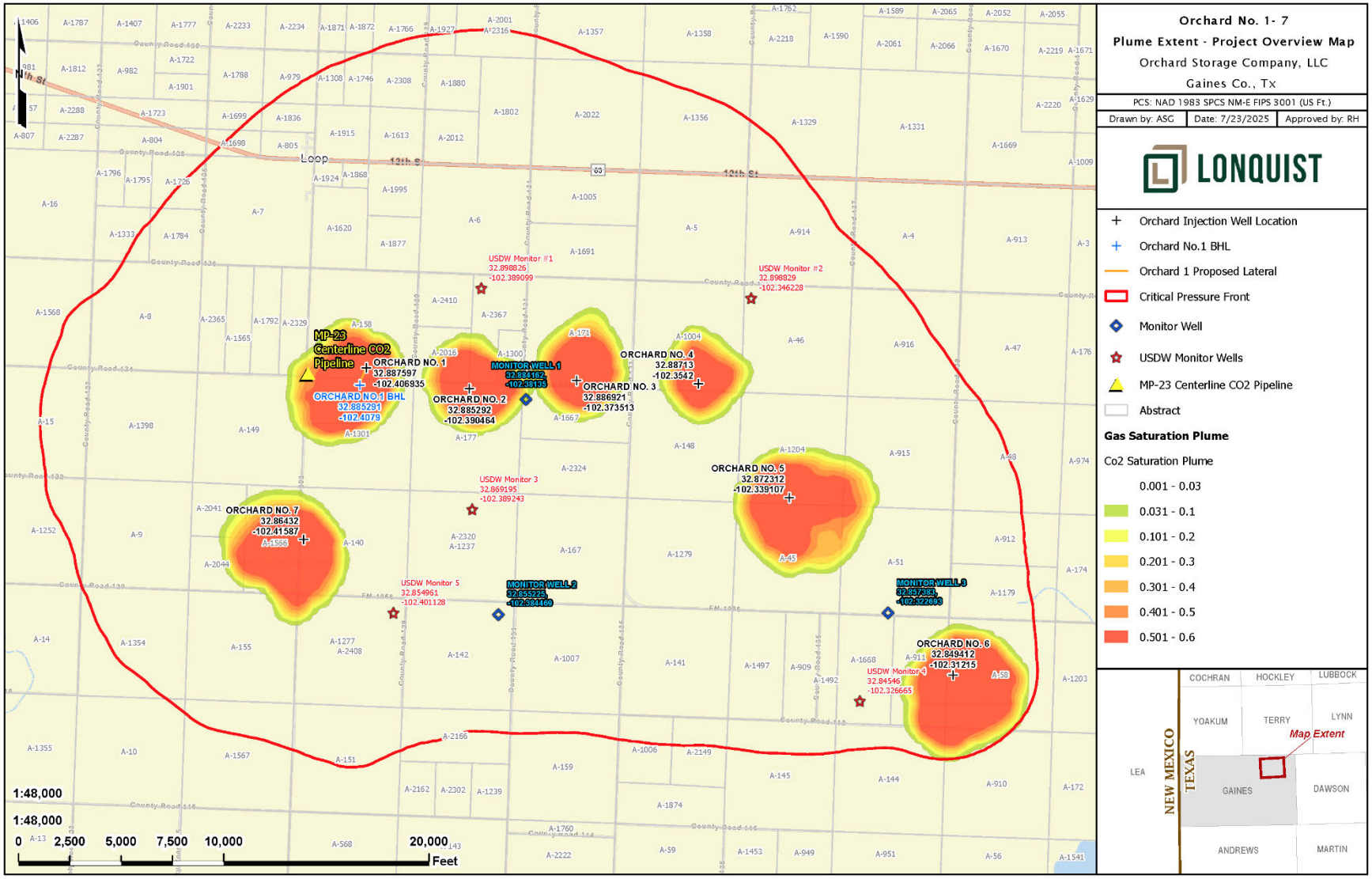


Figure 0-2 – Project Overview Map

Each of the Orchard wells will target the San Andres formation for injection. The San Andres is a Guadalupian-aged rock found in both the Central and Midland Basins in West Texas. The well sites were selected, in part, due to the favorable location of the San Andres formation on the edge of the Central Basin Platform and the Midland Basin (Figure 0-3). At this location the San Andres has a gross thickness of 1,200 ft on average with a porous interval ranging between approximately 500 ft and 1,250 ft. Porosities are in the range of 15%-20% and permeability upwards of 35 millidarcys (mD), making it a suitable reservoir for the storage of CO_2. *Section 1 – Site Characterization* of this permit application will detail the geology and reservoir characterization of this project.

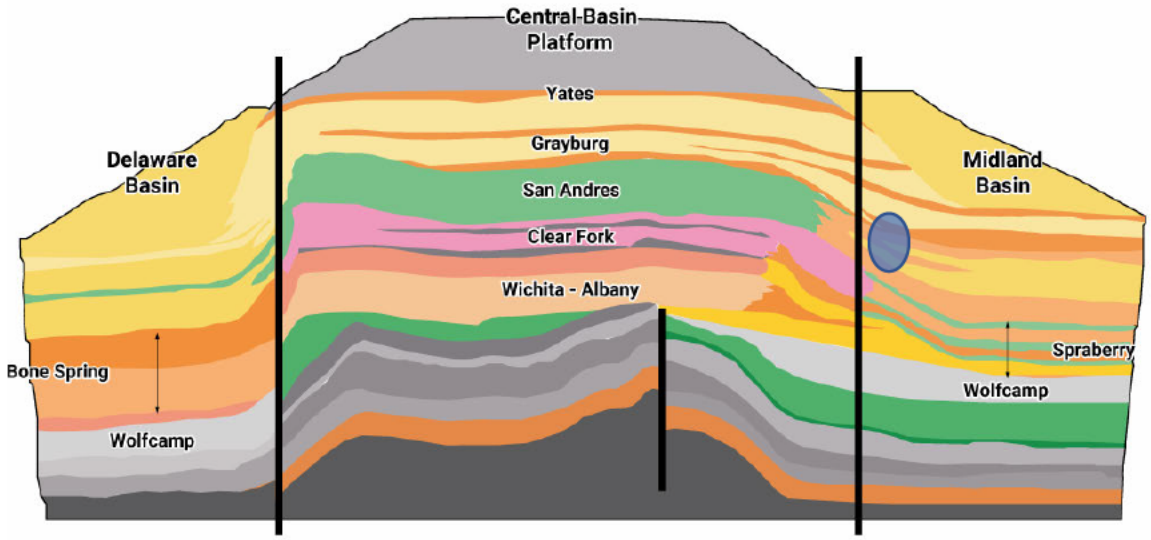


Figure 0-3 – Permian Basin West-East Cross Section[5]

By injecting 2 MMT/yr of CO_2, Elysian is supporting the world's carbon reduction efforts by removing the equivalent of 60,331 gasoline-powered passenger vehicles each year.[6]

Project Key Attributes

- The Orchard Project consists of seven wells with a goal of more than 2 MMT/yr of CO_2 injection for the overall project.
- The wells will be located near various CO_2 and natural gas pipelines, many of which transport CO_2 in a supercritical (or dense phase) state.
- The well locations have been placed outside the existing pivot irrigation to minimize the impact on the agricultural business in the area.
- The San Andres formation, the injection interval, is a thick, well-known carbonate formation prevalent across the Central Basin Platform with sufficient porosity and permeability to sequester CO_2.

[5] https://www.enverus.com/permian-basin/central-basin
[6] https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

- The upper confining zone (Upper San Andres/Grayburg) is 400 to 500 ft thick and the lower confining zone (Glorieta/Leonard Upper) is 300 to 400 ft thick.
- No major shallow faults, which may cause CO_2 to breach containment and contaminate Underground Sources of Drinking Water (USDWs), were observed.

Pore Space Agreement Discussion

The Orchard Project CO_2 plume AORs contain multiple landowners, all of whom have been contacted. Pore space options and lease agreements are in advanced negotiation at the time of this writing. Orchard Storage expects to secure pore space rights well in advance of construction. A map and list of the landowners associated with the AORs are provided in *Appendix A-1*.

Proposed CO_2 Sequestration System Discussion

The Orchard Project will be accessing supercritical CO_2 from a pipeline located near the project. Due to this proximity to the high-pressure pipelines, the surface facility for this project will be minimal. Flowline distribution infrastructure to the wells will be installed, and it is currently anticipated that no compression or treating equipment will be required, resulting in a small surface impact.

Injectate Information

All seven of the Orchard Project sequestration wells are designed to inject for 12 years, with a perforated interval in the San Andres formation, ranging from 827 to 1,227 ft in thickness, acting as the injection and storage reservoir.

The injectate stream, from an existing Kinder Morgan (KM) pipeline, will conform to the KM pipeline specification. The injectate will consist of a minimum of 95% CO_2 and meet the specifications shown in Table 0-1 and Appendix A-2

Table 0-1 – Injectate Major Components

Component	Value
CO_2	No less than 95%
Water	No free water and no more than 30 lb/million standard cubic feet (MMscf) (vapor phase)
Temperature	No more than 120°F or less than 65°F
H_2S	No more than 20 parts per million (ppm) by volume
Nitrogen	No more than 4% by mole fraction
Sulphur	No more than 35 ppm by weight
Oxygen	No more than 10 ppm by weight
Hydrocarbons	No more than 5% by mole fraction
Glycol	No more than 0.3 gallon per MMscf
Carbon Monoxide	No more than 4,250 ppm by weight
NO_x	No more than 1 ppm by weight
SO_x	No more than 1 ppm by weight
Particulates	No more than 1 ppm by weight
Amines	No more than 1 ppm by weight
Hydrogen	No more than 1% by mole fraction
Mercury	No more than 5 nanograms per liter
Ammonia	No more than 50 ppm by weight
Argon	No more than 1% by volume
Liquids	Free of liquids at delivery conditions and no condensed liquids downstream
Lube Oil	No more than 50 ppm by weight

Surface Facility Details

Minimal surface equipment will be required due to the proximity of the valve station on the KM CO_2 pipeline, as shown in Figure 0-4. The valve station is located 2,556 ft west-northwest of Orchard No. 1.

Site Suitability

The chosen surface location was selected largely to avoid disturbing the existing agricultural operations in the project area. Figure 0-5 shows the planned surface sites for the seven Orchard injection wells and the associated irrigation patterns.

Higher resolution versions of the figures and maps in this Section are provided in *Appendix A.*

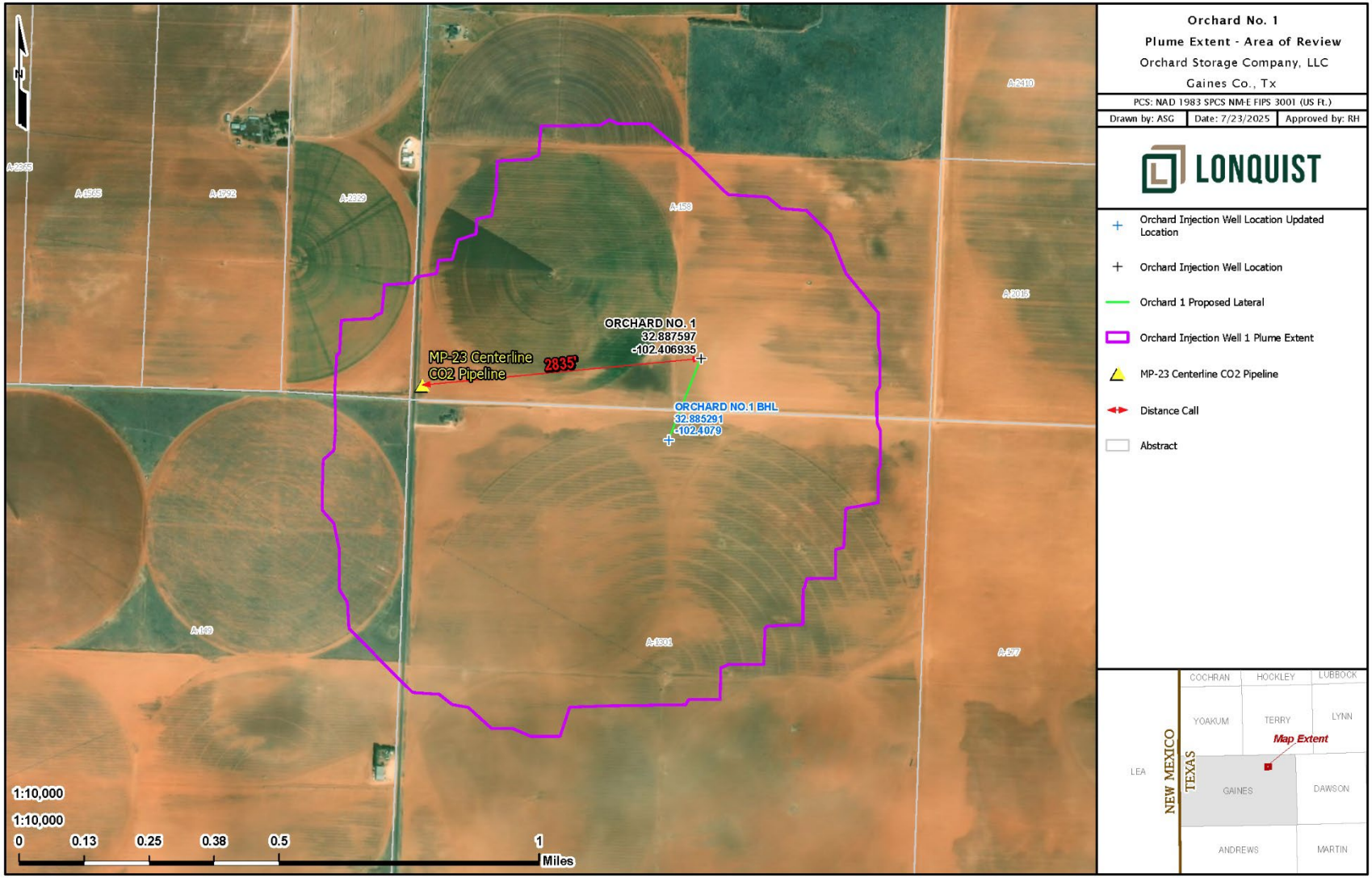


Figure 0-4 – Distance from Valve Station to Orchard No. 1



Figure 0-5 – Aerial Map of Orchard Project.

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

- Location of the proposed project site
- Consideration of the project area relative to federal sites/buildings/facilities, etc.
- Endangered species research
- Flood zone
- Existing infrastructure, surface, and subsurface mines or quarries
- Faults or fractures in the project area based on seismic analysis or geophysical well log characterization
- State or federal subsurface cleanup sites within the project area
- 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

Orchard No. 1 through No. 7 are the seven planned injection wells in the Orchard Project area. Individual wells are designed to accommodate injection rates ranging from approximately 0.25 MMT/yr to 0.66 MMT/yr for 12 years. The planned injection rates are provided in Table 0-2.

Table 0-2 – Planned Injection Rates by Well

Well Name	County	Location	Predicted Injection Rate (MMT/yr)
Orchard No. 1	Gaines	A-1301, Block H, Section 88	0.303
Orchard No. 2	Gaines	A-177, Block H, Section 85	0.283
Orchard No. 3	Gaines	A-1667, Block H, Section 60	0.278
Orchard No. 4	Gaines	A-1004, Block H, Section 50	0.211
Orchard No. 5	Gaines	A-1204, Block H, Section 40	0.458
Orchard No. 6	Gaines	A-58, Block H, Section 31	0.483
Orchard No. 7	Gaines	A-140, Block H, Section 89	0.303

This permit application includes a detailed assessment of the overall geologic environment (*Section 1 – Site Characterization*) and the resulting plume model and results (*Section 2 – Plume Model*) used to determine the arial extent of the plumes and the resulting AOR. As detailed in *Section 3 – Area of Review and Corrective Action Plan*, the AOR for the proposed Orchard Project has ten existing artificial penetrations that will require corrective action. Well design and construction plans that take into consideration the needs of the project, the modeling results,

and the requirements to ensure the protection of the USDWs are detailed in *Section 4 – Engineering Design and Operating Strategy*.

To ensure that the CO_2 plumes are being monitored over the life of the project, a detailed Testing and Monitoring Plan has been assembled in *Section 5 – Testing and Monitoring Plan*. The plan consists of (1) two above-confining-zone monitoring wells, (2) an in-zone San Andres monitoring well, (3) USDW monitoring wells, (4) soil-gas monitoring stations, and (5) the use of fiber optics in conjunction with vertical seismic profile (VSP) technology to monitor the growth of the CO_2 plume over the life of the project.

The proposed Orchard Project addresses all the requirements for Class VI sequestration wells. These wells are ideally located to sequester significant amounts of CO_2 with minimal impact to the surface and surrounding communities.

Required Administrative Information

General Application Information

Location details for Orchard No. 1 through No. 7 are provided in Table 0-3.

Table 0-3 – Injection Well Location Details

Well Name	County	Location	Latitude (NAD83)	Longitude (NAD83)
Orchard No. 1 (BHL)	Gaines	A-1301, Block H, Section 88	32.885291	-102.407902
Orchard No. 1 (SHL)	Gaines	A-1301, Block H,	32.887603	-102.406944
Orchard No. 2	Gaines	A-177, Block H, Section 85	32.885292	-102.390464
Orchard No. 3	Gaines	A-1667, Block H, Section 60	32.886921	-102.373513
Orchard No. 4	Gaines	A-1004, Block H, Section 58	32.88713	-102.3542
Orchard No. 5	Gaines	A-1204, Block H, Section 40	32.872312	-102.339107
Orchard No. 6	Gaines	A-58, Block H, Section 31	32.849412	-102.31215
Orchard No. 7	Gaines	A-140, Block H, Section 89	32.86432	-102.41587

Applicant:

Name	Orchard Storage Company LLC
Address	4200 Westheimer Road Suite 975 Houston, Texas 77027
Facility contacts	Keith Tracy Chief Commercial Officer Claimed as PBI ktracy@elysian.cc Bret Logue Chief Executive Officer Claimed as PBI blogue@elysian.cc
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)

Table 0-4 provides a list of contacts for those States, Tribes, and Territories identified to be within the area of review of the Orchard Project. This facility and its AOR are not located on federal or tribal lands.

Table 0-4 – State, Tribe, and Territory Contacts

Agency	Mailing Address	Phone
Texas Railroad Commission – Underground Injection/Storage	P.O. Box 12967 Austin, Texas 78711-2967	(512) 463-6792

Additional Permits

Table 0-5 – Additional Required Permits

Agency	Permit and Authorization	Anticipated Filing Date	Anticipated Receipt Date	Status
Texas Railroad Commission	Drilling Permit	TBD*	TBD	To be filed*
EPA	Class VI Injection Well Permit – 40 CFR 146			

*Orchard Storage has received its P-5 Operator designation from the Texas Railroad Commission. The drilling permit requests will be filed well in advance of the drilling efforts.

APPENDIX A

High-resolution files are provided in Appendix A:

- Appendix A-1 Pore Space Ownership Map and List
- Appendix A-2 Kinder Morgan Pipeline Specification
- Appendix A-3 Combined Project Map

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 1 – Site Characterization

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 1 – SITE CHARACTERIZATION

TABLE OF CONTENTS

1.1 Overview 5

1.2 Regional Geology 5

1.2.1 Regional Geologic Setting 5
1.2.2 Regional Stratigraphic Model 7
1.2.3 Regional Depositional Model 11
1.2.4 Major Stratigraphic Units 13

1.3 Site Geology 27

1.3.1 Subsurface Data and Methods 31
1.3.2 Injection Zone 34
1.3.3 Primary Upper Confining Zone 54
1.3.4 Primary Lower Confining Zone 85

1.4 Site Structure, Stratigraphy, and Deposition: 2D Seismic Integration 91

1.4.1 Horizon Interpretation 95
1.4.2 Fault Interpretation 100

1.5 Geomechanics 103

1.5.1 Local Stress Conditions 103
1.5.2 Injection Zone Fracture Gradient 105

1.6 Geochemistry 106

1.6.1 Fluid Chemistry (Injection Zone) 106
1.6.2 Rock Chemistry (Injection Zone and Upper Confining Zone) 109
1.6.3 Simulated Interactions (Injection Zone and Confining Zones) 111

1.7 Site Evaluation of Mineral Resources 117

1.8 Seismic History 117

1.9 Site Suitability 119

1.9.1 Lithofacies 119
1.9.2 Leakage Pathways 119
1.9.3 Hydrology and Hydrogeology 119
1.9.4 Total Storage Capacity 122
1.9.5 Injection Capacity 122
1.9.6 Secondary Confinement 122

1.10 Further Site Characterization 123

1.10.1 Core 123
1.10.2 Sequence Stratigraphy 123
1.10.3 Facies 123

1.11 References 125

Figures

Figure 1-1 – Permian Basin sub-basins 6
Figure 1-2 – Generalized stratigraphic column of geologic units in the Paleozoic strata of the Permian Basin 7
Figure 1-3 – A schematic cross section through the central part of the Permian Basin, showing dominant lithology from surface to basement. 9
Figure 1-4 – Regional county map showing the location of the cross section in Figure 1-3 through the central part of the Permian Basin 10
Figure 1-5 – Upper Permian stratigraphy of the Northwest Shelf of the Delaware Basin 12
Figure 1-6 – Reference map showing the location of cross section B-B' 14
Figure 1-7 – A west-to-east cross section illustrating the change of lithofacies and stratigraphy in the Central Basin Platform 15
Figure 1-8 – Base map showing the location of the Orchard Project (black star) and the Horseshoe Atoll feature 16
Figure 1-9 – A simplified depositional facies model relative to the position on the San Andres carbonate ramp 18
Figure 1-10 – San Andres sequences across several Permian Basin sub-basins and hydrocarbon-producing play areas 19
Figure 1-11 – Schematic cross section showing the hierarchy of composite/high-frequency sequences for the late Leonardian and Guadalupian succession 20
Figure 1-12 – A schematic cross section of the dominant lithofacies across the high-frequency cycles 21
Figure 1-13 – Map of hydrocarbon-producing play areas associated with the San Andres formation relative to the Orchard No. 1 to No. 7 locations 23
Figure 1-14 – Simplified map highlighting the regional patterns of dominant lithologies in the confining zone part of the San Andres and Grayburg formations 25
Figure 1-15 – Map of the Orchard No. 1 to No. 7 locations (indicated by the blue diamonds) relative to existing wells within the wider area (black, dashed outline) and associated with hydrocarbon-producing play areas. 28
Figure 1-16 – Map of the Orchard No. 1–No. 7 locations (indicated by the blue diamonds), available subsurface data used for the site characterization, and nearby well-known hydrocarbon-producing play areas 30
Figure 1-17 – Depth structure map (TVD SS) for the top of the injection zone in the San Andres formation. 35
Figure 1-18 – Depth structure map (TVD SS) for the base of the injection zone in the San Andres formation 36
Figure 1-19 – Thickness map (ft) of the injection zone within the San Andres formation. 38
Figure 1-20 – Well log data and petrophysical analysis for the confining zones and injection zone from the type well for the Orchard Project area (API No. 42-165-38804). 39
Figure 1-21 – A north-south cross section of well log data from five wells 40
Figure 1-22 – A west-east cross section of well log data from six wells 41
Figure 1-23 – Reference map 42
Figure 1-24 – Average porosity map of the Upper San Andres part of the injection zone. 45
Figure 1-25 – The continuum of rock fabrics and associated porosity-permeability transforms 50
Figure 1-26 – Permeability versus porosity for Valiant 1D (API No. 42-165-38785), compared to permeabilities calculated using the Lucia Transform. 52
Figure 1-27 Permeability versus porosity for the Valiant 1D and ARCO Fee 198-1 wells 53

Figure 1-28 – Depth structure map (TVD SS) for the top of the San Andres formation (middle of upper confining zone)..... 55
Figure 1-29 – Thickness Map of the Upper Confining Zone..... 56
Figure 1-30 – Depth structure map (TVD SS) for the top of the Grayburg formation (top of confining zone). 57
Figure 1-31 – Thickness Map of the Grayburg..... 58
Figure 1-32 – Isopach Map of Combined Upper San Andres and Grayburg formations (gross UCZ thickness). 59
Figure 1-33 – A cross section of wells API No. 42-165-34836, 42-165-31473 and 42-165-33680, from left to right. 61
Figure 1-34 – Map showing the location of the cross section shown in Figure 1-33 (black dashed line) and the north-south 2D Seismic Line (A-A' in red color) shown on Figures 1-53, 1-54 and 1-55. 62
Figure 1-35 – Thin section from well API No. 42-165-31473 at a depth of 4,946.5 ft MD. 64
Figure 1-36 – Photograph of slabbed core for well API No. 42-165-31473..... 65
Figure 1-37 – Thin section from well API No. 42-165-31473 at a depth of 4,966.5 ft MD. 67
Figure 1-38 – Photograph of slabbed core for well API No. 42-165-31473..... 68
Figure 1-39 – Thin section from well API No. 42-165-31473 at a depth of 4,986.6 ft MD. 70
Figure 1-40 – Photograph of slabbed core for well API No. 42-165-31473..... 71
Figure 1-41 – Thin section from well API No. 42-165-31473 at a depth of 5,006.5 ft MD. 73
Figure 1-42 – Photograph of slabbed core for well API No. 42-165-31473..... 74
Figure 1-43 – Thin section from well API No. 42-165-31473 at a depth of 5,026.5 ft MD. 76
Figure 1-44 – Photograph of slabbed core for well API No. 42-165-31473..... 77
Figure 1-45 – Thin section from well API No. 42-165-31473 at a depth of 5,046.5 ft MD. 79
Figure 1-46 – Photograph of slabbed core for well API No. 42-165-31473..... 80
Figure 1-47 – Mercury saturation versus injection pressure results from high-pressure mercury injection testing 83
Figure 1-48 – Pore-throat size and distribution results from high-pressure mercury injection testing..... 84
Figure 1-49 – Depth structure map (TVD SS) of the base of the Glorieta/Leonard Upper formation..... 86
Figure 1-50 – Thickness map of the Glorieta/Leonard Upper formation 87
Figure 1-51 – Simplified depiction of a cross section oriented north-south to the east of the Orchard Project vicinity..... 89
Figure 1-52 – A snapshot of the mud-log sample lithologic interpretation (Track 2) for the Glorieta/Leonard Upper formation 90
Figure 1-53 – A 7.2-mile long 2D seismic line running north (left) to south (right) through the Orchard Project area. 92
Figure 1-54 – The same 7.2-mile long 2D seismic line from Figure 1-53, but with interpreted horizons and faults shown. 94
Figure 1-55 – The same 2D seismic line from Figures 1-53 and 1-54, showing the API No. 42-165-33270 pseudo-well tie, ... 97
Figure 1-56 – The time-to-depth profile, or relationship, used for the API No. 42-165-33270 pseudo-well tie. 98
Figure 1-57 – Diagram showing tectonic events by geologic age for the Delaware Basin and Central Basin Platform 101
Figure 1-58 – Regional fault map..... 102
Figure 1-59 – Regional map showing the maximum horizontal stress orientation across the Permian Basin 104
Figure 1-60 – Probability Distribution of Minimum Horizontal Stress from Valiant No. 1D..... 106
Figure 1-61 – Tabulated records of water quality 107

Figure 1-62 – Tabulated records of water quality (continued)..... 108
Figure 1-63 – The results of the batch simulations for all mineral constituents shown by unit. 115
Figure 1-64 – The results for minor mineral phases of the batch shown by unit. 116
Figure 1-65 – Two maps of historical seismic events in the Permian Basin area 118
Figure 1-66 – Simplified cross section of the major and minor aquifers across the region 120
Figure 1-67 – Map showing the distribution of TDS in groundwater from the Dockum aquifer 121

Tables

Table 1-1 – Select well log data described by log curve type and logged depth intervals, used for this site characterization. 31
Table 1-2 – Cored Intervals and Testing Program..... 34
Table 1-3 – Results of routine sidewall core analysis for well API No. 42-165-38785. 47
Table 1-4 – Results of X-ray diffraction (XRD) analysis for well API No. 42-165-38785. 48
Table 1-5 – Mineralogy determined by XRD for API No. 42-165-38785 and 42-165-31473. 110
Table 1-6 – Brine Composition Used in Geochem Model..... 112
Table 1-7 – Estimated Mineral Compositions Used in Model 113

1.1 Overview

This site characterization for Orchard Storage Company LLC's (Orchard Storage) Orchard Project, for injection wells No. 1 through No. 7 was prepared to meet the requirements of 16 Texas Administrative Code (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. This site characterization incorporates analysis from multiple data types, including core, well logs, seismic (2D), academic and professional publications (e.g., regional geologic frameworks), and nearby subsurface analogs.

1.2 Regional Geology

1.2.1 Regional Geologic Setting

The Permian Basin is a large sedimentary basin covering more than 75,000 square miles of west Texas and southeastern New Mexico. The basin developed in an open marine environment in the middle of the Carboniferous period, approximately 320 to 325 million years ago (Galley, 1958). It is an asymmetrical, northwest-southeast trending system bound by the Marathon-Ouachita orogenic belt to the south, the Northwest Shelf and Matador Arch to the north, the Diablo Platform to the west, and the Eastern Shelf to the east (Beaumont, 1981). Figure 1-1 shows a map of the Permian Basin sub-basins and the Orchard location (from Merrill et al., 2015).

Researchers commonly subdivide the Permian Basin into two sub-basins and one platform—the Delaware Basin to the west, the Central Basin Platform in the center, and the Midland Basin to the east (Popova, 2022). The tectonic history of the Permian Basin is mainly affected by the uplift of the Central Basin Platform, and partly by the thrusting of the Marathon-Ouachita orogenic belt, with the main phase of basin differentiation occurring during the Pennsylvanian and Wolfcampian periods due to rapid subsidence in the Delaware and Midland basins (Popova, 2020).

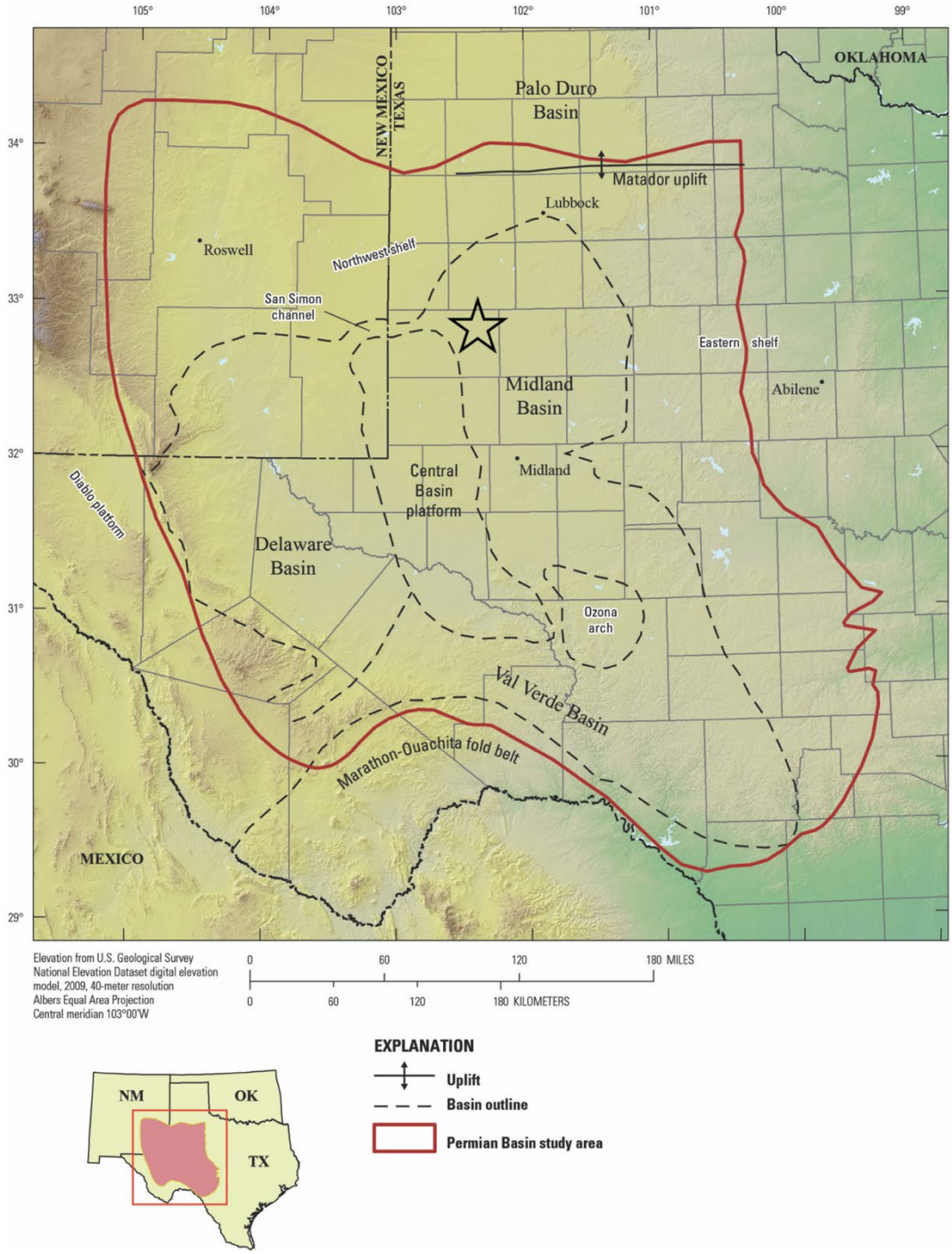


Figure 1-1 – Permian Basin sub-basins with the Orchard location indicated by the black star (from Merrill et al., 2015).

1.2.2 Regional Stratigraphic Model

The Permian Basin Paleozoic succession is comprised of carbonate, clastic, and evaporite rocks. Figure 1-2 shows a generalized stratigraphic column of geologic units in the Paleozoic strata of the Permian Basin (Merrill et al., 2015). This Permian System stratigraphy, per the U.S. Geological Survey (USGS) assessment of CO_2 storage opportunities, reflects a composite of several stratigraphic schemes attributed to several decades of hydrocarbon development in the area.

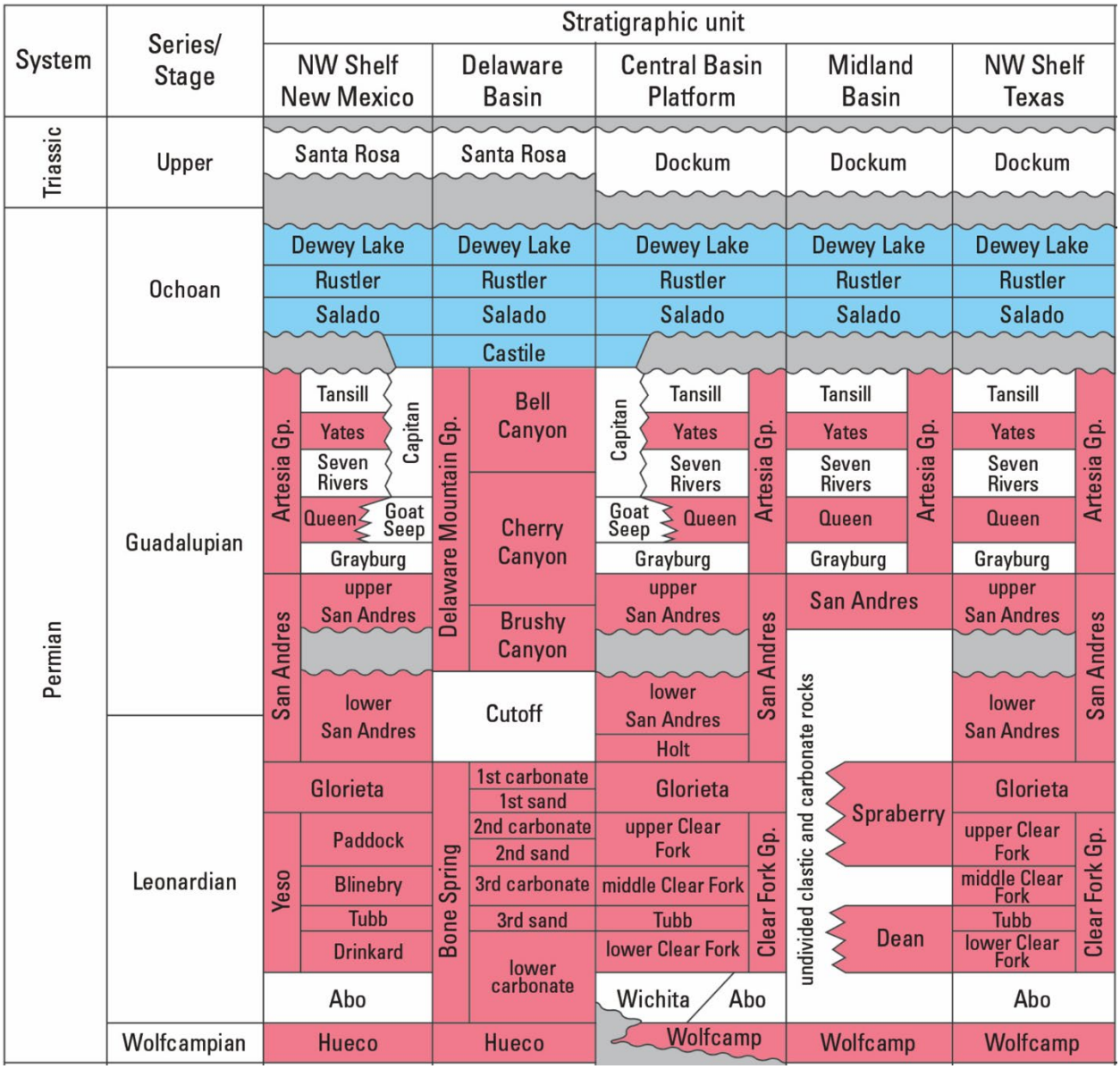


Figure 1-2 – Generalized stratigraphic column of geologic units in the Paleozoic strata of the Permian Basin (Merrill et al., 2015).

Each stratigraphic succession reflects a composite of high-frequency cyclicity incorporating lowstand, transgressive, and highstand system tracts across the region. These successions are reflective of paleo-topographic changes across the area caused by sea-level fluctuation, subsidence, water depth, and compaction forces. These successions also demonstrate common carbonate production in the Central Basin Platform and Northwest Shelf and clastic sedimentation in the Midland Basin.

Figure 1-3, a cross section through the central part of the Permian Basin, shows dominant lithology from surface to basement. Figure 1-4 shows the location of this cross section. The Orchard location is approximately between and representative of the location 55-60 on the cross section (from Matchus and Jones, 1984).

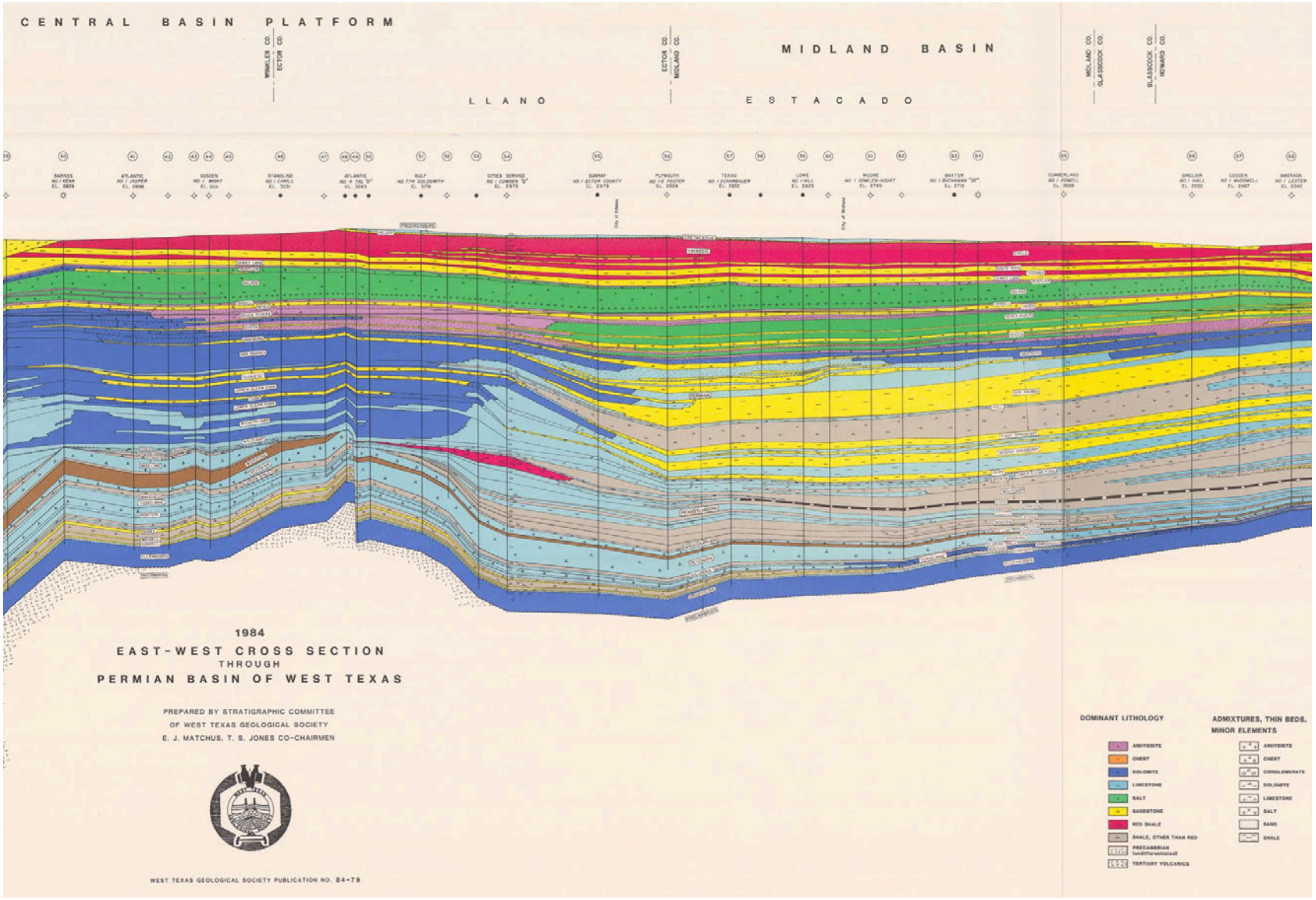


Figure 1-3 – A schematic cross section through the central part of the Permian Basin, showing dominant lithology from surface to basement. The Orchard location is approximately between and representative of the location 55-60 on the cross section (Matchus and Jones, 1984).

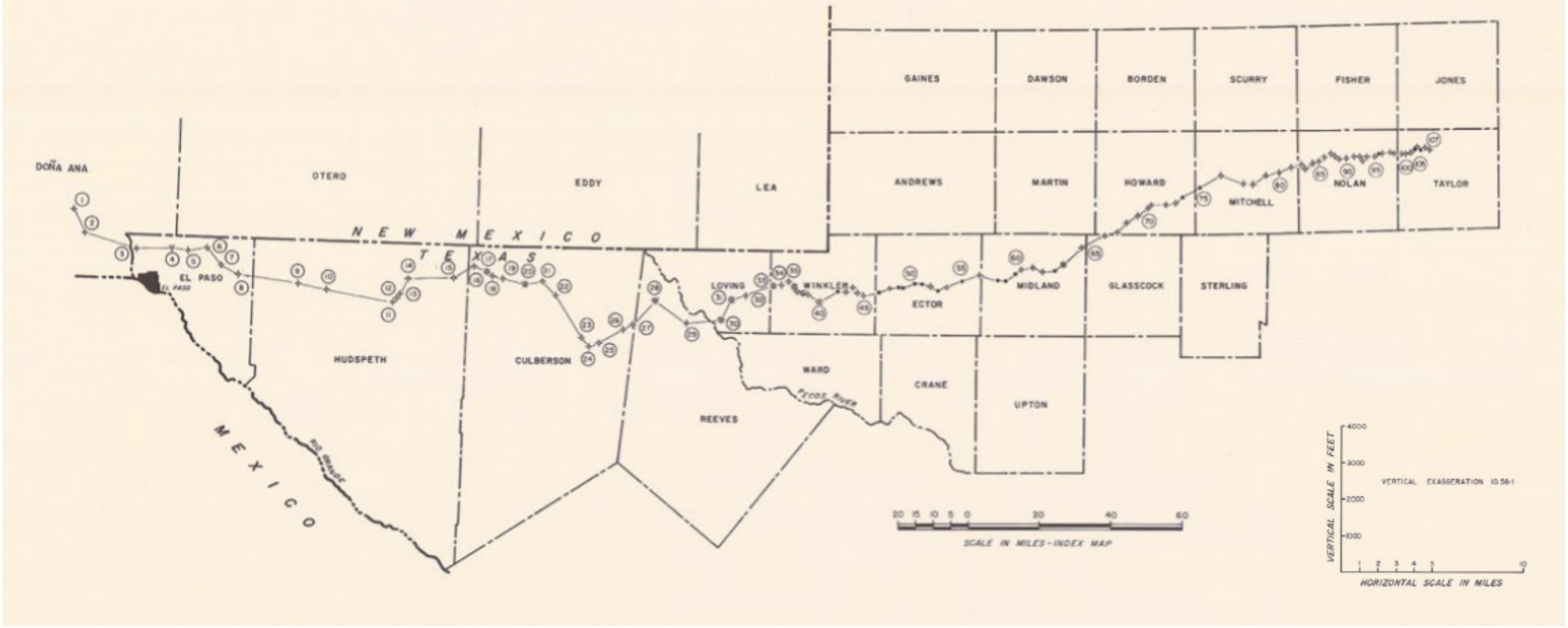


Figure 1-4 – Regional county map showing the location of the cross section in Figure 1-3 through the central part of the Permian Basin (from Matchus and Jones, 1984).

1.2.3 Regional Depositional Model

Facies are associated with shelf-to-basin changes across the region. The proposed Orchard No. 1 to No. 7 injection wells are in an area that reflects evolution from slope- to supratidal-dominated regimes, from the Leonardian through the Guadalupian successions. Iterations of the regional depositional model have been developed through several decades of academic and professional research. These models incorporate the research of time-equivalent outcrops in western Texas and eastern New Mexico, showing shelf-to-basin changes from the Northwest Shelf into the Delaware Basin portion of the Permian Basin. These models correlate to the Leonardian and Guadalupian successions in the Central Basin Platform, Northwest Shelf, Midland Basin, and Eastern Shelf, as Figure 1-5 shows.

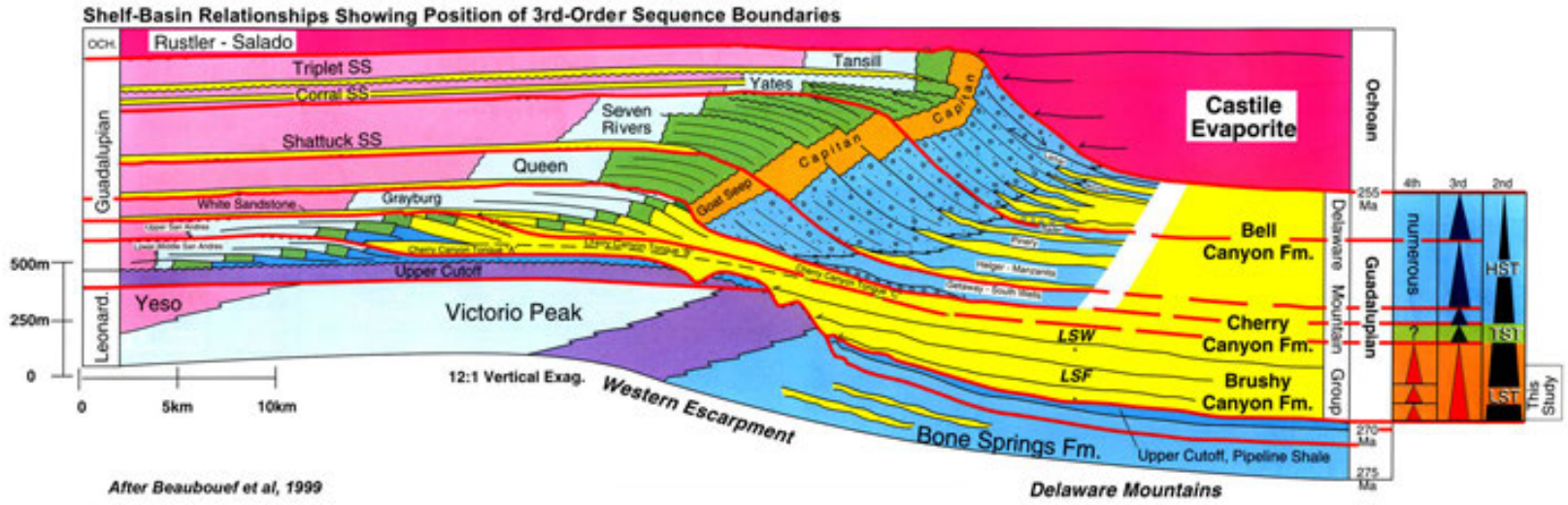


Figure 1-5 – Upper Permian stratigraphy of the Northwest Shelf of the Delaware Basin (after Beaubouef et al., 1999).

1.2.4 Major Stratigraphic Units

The injection zone is a portion of the San Andres formation. The upper confining zone is the top portion of the San Andres formation, including the overlying Grayburg formation. The lower confining zone is the underlying Glorieta/Leonard Upper formation. A secondary upper confining zone is a portion of the Queen formation.

1.2.4.1 Lower Confinement: Glorieta/Leonard Upper Formation

The lower confining zone is approximately 300 to 400 ft thick and is low porosity with a dominant limestone lithology. This interval reflects the onset of undivided clastic and carbonate rocks in the Midland Basin associated with the change from the shelf to the basin, as noted by the USGS in Figure 1-2. The reason for using two names to describe the lower confining zone can be attributed to the deposition style of these and deeper strata—that is, they are shelf-to-basin time equivalent sequences between the Northwest Shelf, Central Basin Platform, and Midland Basin.

The Glorieta formation represents a period and broad area of highstand deposition of a mud-rich limestone with consistent thickness. This period occurs before the onset of change to clastic lithology in the Midland Basin associated with the Leonard Upper and Spraberry nomenclature. The Spraberry formation below this confining zone is coeval with the Clear Fork and Dean formations and is the basin equivalent of the Clear Fork Lower and Tubb formations (Handford, 1981).

Figure 1-6 shows a map of the location of cross section B-B’ from west to east through the Orchard site. Figure 1-7 shows a cross section (B-B') of the change of lithofacies and stratigraphy in the Central Basin Platform margin (west), slope/transition, and Midland Basin (east).

The Spraberry (and underlying Dean and Wolfcamp) sequences represent interbedded terrigenous mud, carbonate mud, and lesser deep-water silts and sands associated with sedimentary fill into the Midland Basin, sourced principally from the northwest, north, and northeast (Tyler et al., 1987). Coarse clastic sediments are likely attributed to the Pennsylvanian Horseshoe Atoll. Figure 1-8 shows the Horseshoe Atoll feature, which is an “isolated carbonate platform including an arcuate chain of reef-shoal complexes of Pennsylvanian and early Permian age, located within the northern portion of the Midland Basin, west Texas” (Waite, 2021).

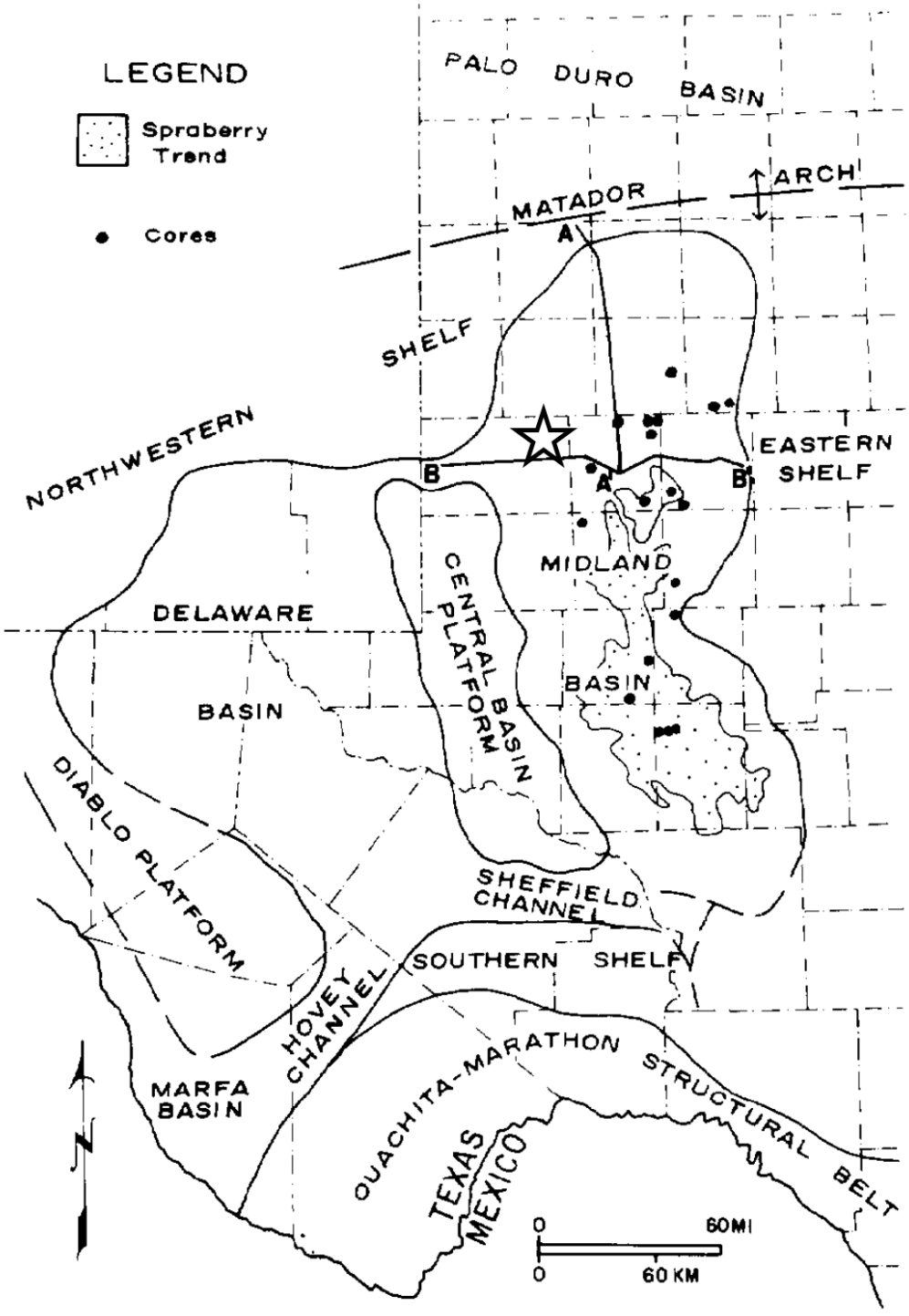


Figure 1-6 – Reference map showing the location of cross section B-B' (Figure 1-7) from west to east through the Orchard location (indicated by the black star).

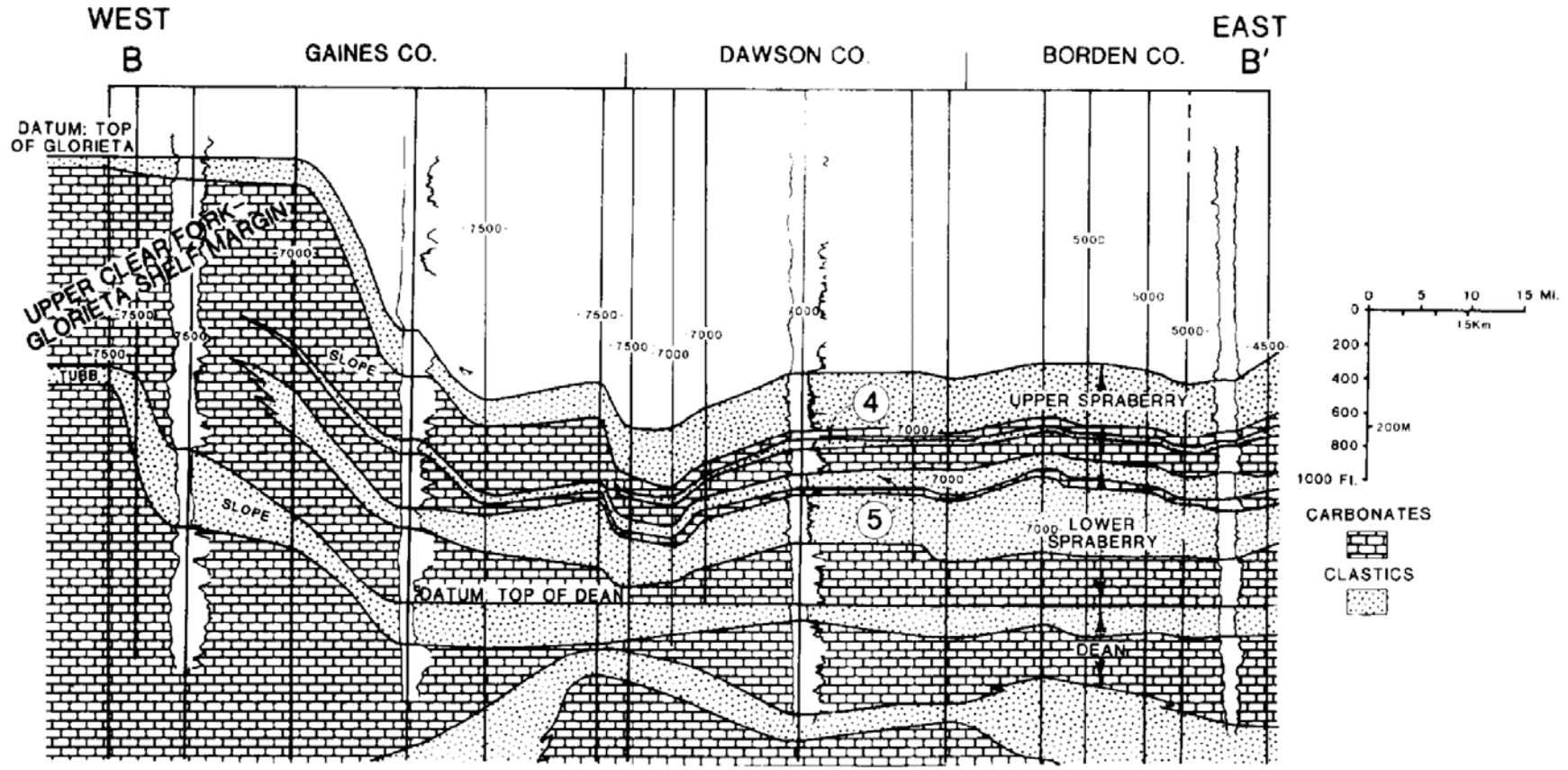


Figure 1-7 – A west-to-east cross section illustrating the change of lithofacies and stratigraphy in the Central Basin Platform margin (west), slope/transition, and Midland Basin (east).

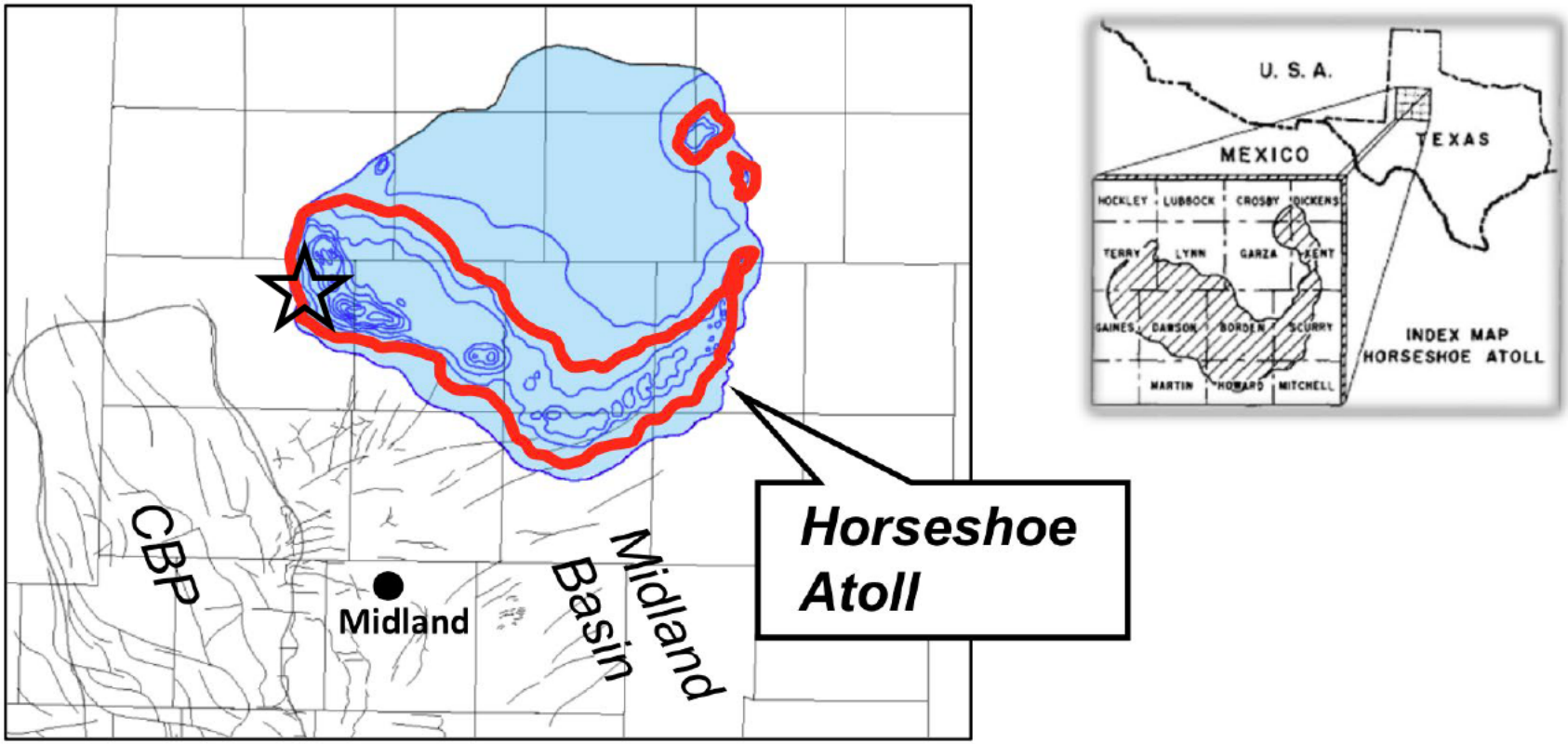


Figure 1-8 – Base map showing the location of the Orchard Project (black star) and the Horseshoe Atoll feature (Waite, 2021).

The Leonard Upper and Spraberry depositional model is a network of submarine fan complexes comprising large-scale cyclical sequences deposited by turbidity currents and saline density underflows (Handford, 1981). These sequences can be either carbonate- or clastic-dominated. Carbonate debris flows interbedded with carbonate turbidites, and organic-rich calcareous mudstones can provide adequate confinement above and below this zone.

1.2.4.2 San Andres Formation

The San Andres Formation within the region around the Orchard Project is the injection interval and is also the upper seal interval. Orchard refers to the subdivisions (from top to bottom) as the Upper Confining Interval, the Upper Injection Zone and the Lower Injection Zone. The Upper Confining Interval of the San Andres is broadly characterized by low porosity and permeability typical of confining zones. The San Andres Injection Zone, both upper and lower, have higher porosity and permeability suitable for CO_2 storage injection. Each of these divisions are described in detail in the following sections.

1.2.4.3 Injection Zone: San Andres Formation

The injection zone comprises an approximately 1,200 ft thick, mixed dolomitic-calcitic carbonate interval of the San Andres formation. The San Andres has proven injection capacity for different fluid types based on multiple active CO_2 and water enhanced oil recovery (EOR) projects in the region.

The San Andres formation is part of a larger genetic grouping of shallow shelf-carbonate and mixed siliciclastic-carbonate sequences in the Permian Basin (Ward et al., 1986; Ruppel & Cander, 1988; Kerans et al., 1992). A summary of lithofacies found along the San Andres carbonate depositional ramp model helps to understand that Orchard's location encompasses "ramp slope" (i.e., outer ramp fusulinid-dominated) and open-marine limestone and dolomite lithofacies.

Figure 1-9 shows a summarization of facies associations relative to the position on the San Andres carbonate ramp (after Beserra and Dorobek, 1995).

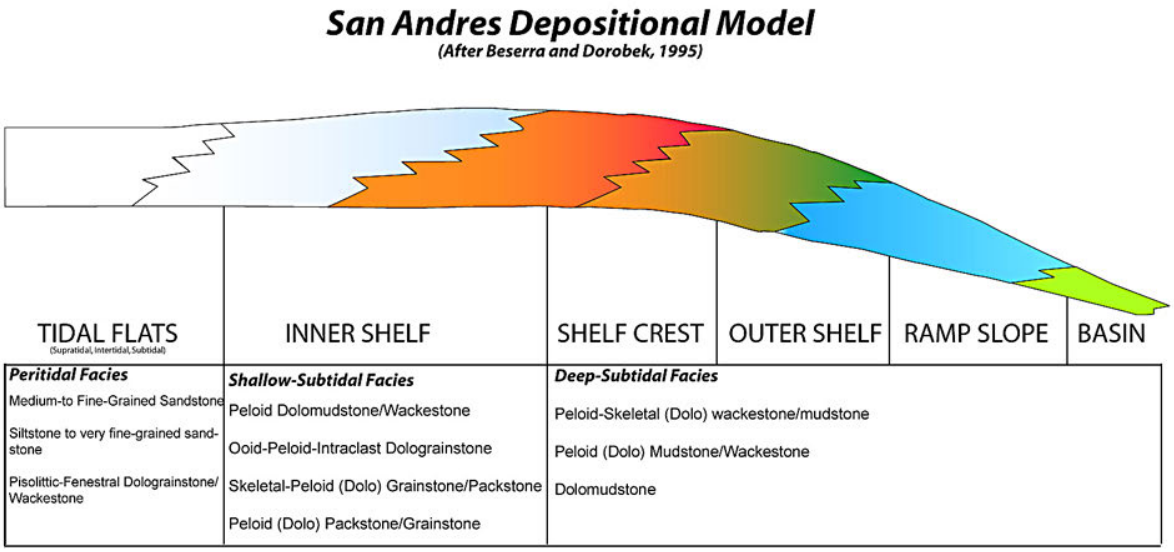


Figure 1-9 – A simplified depositional facies model relative to the position on the San Andres carbonate ramp (after Beserra and Dorobek, 1995) (from SEPM Strata, 2022).

The position of the Orchard Project site within the region means this relatively open-marine depositional setting can be tied to depositional models developed from well-known and well-studied nearby hydrocarbon-producing play areas, which serve as analogs. The Orchard Project's location is related to regional depositional models of the San Andres formation located to the southwest (Central Basin Platform, e.g., Seminole), the northwest (Northwest Shelf, e.g., Wasson, Reeves), and the east (lowstand carbonate buildups, e.g., Adair, Cedar Lake, Welch).

Figure 1-10 shows the high-frequency sequences of the San Andres across several Permian Basin sub-basins and hydrocarbon-producing play areas (modified after Kerans, 2000, and Trentham & Smith, 2002) (taken from Kerans, 2006).

The San Andres formation is commonly separated into upper and lower sequences dependent on the location in the Permian Basin. Kerans and Kempter (2002) subdivided the San Andres Lower composite sequence into six high-frequency sequences (Leonardian 7-8, Guadalupian 1-4) and the Upper San Andres into two high-frequency cycles (Guadalupian 8-9).

	Guad Mts.	Downdip Northwest Shelf	Updip Northwest Shelf NM	Updip Northwest Shelf TX	Delaware Basin	Central Basin Platform	Eastern Shelf, NE Midland Basin
	Guad. 10	Grayburg 1 Premier Sand	Evaporites		U. Cherry Cnyn	L. Grayburg	L. Grayburg
Upper San Andres Composite Seq. CS10	Guad. 9	Upper S A Lovington Sand	Evaporites		L. Cherry Cnyn	U. San Andres Lovington Sand	
	Guad. 8	Upper S A	P1-3	Slaughter 1-3		U. San Andres	U. San Andres Cedar Lake, Welch
	Guad. 7				Brushy Canyon		
	Guad. 6						
	Guad. 5						
Lower San Andres Composite Seq. CS9	Guad. 4	Upper S A2	P4	Slaughter 4	U. Bone Spring or Cut Off	San Andres	San Andres
	Guad. 3	Upper S A 1	P5	Slaughter 5		San Andres	
	Guad. 2	Middle S A2	P6			McKnight Shale	
	Guad. 1	Middle S A 1	P7				
	Leonardian 8	Lower S A 2	P8			Holt	Lower San Andres Howard Glasscock, Iatan, Ddiamond M
	Leonardian 7	Lower S A 1	P8		Pipeline Sh		
	Leonardian 6	Glorieta	Glorieta		Bone Spring	Glorieta	San Angelo

Figure 1-10 – San Andres sequences across several Permian Basin sub-basins and hydrocarbon-producing play areas (modified after Kerans, 2000, and Trentham & Smith, 2002) (taken from Kerans, 2006).

Figure 1-11 shows a schematic of the hierarchy of composite/high-frequency sequences for the late Leonardian and Guadalupian succession (Kerans, 2006). Figure 1-12 shows a schematic of the dominant lithofacies across the high-frequency cycles shown previously and are based on observations from several regional workers (Kerans, 2006) studying outcrops of the Leonardian and Guadalupian successions.

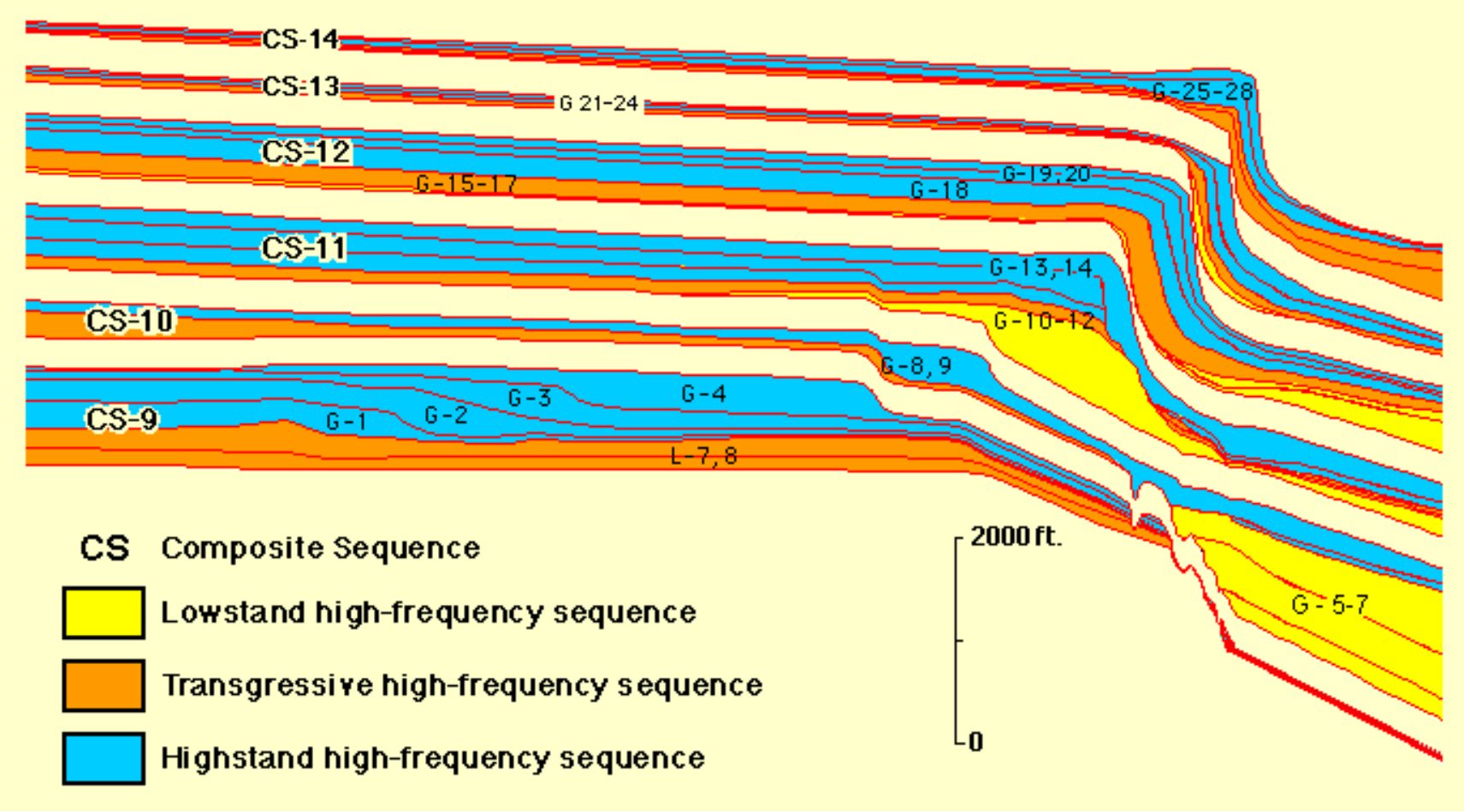


Figure 1-11 – Schematic cross section showing the hierarchy of composite/high-frequency sequences for the late Leonardian and Guadalupian succession (Kerans, 2006).

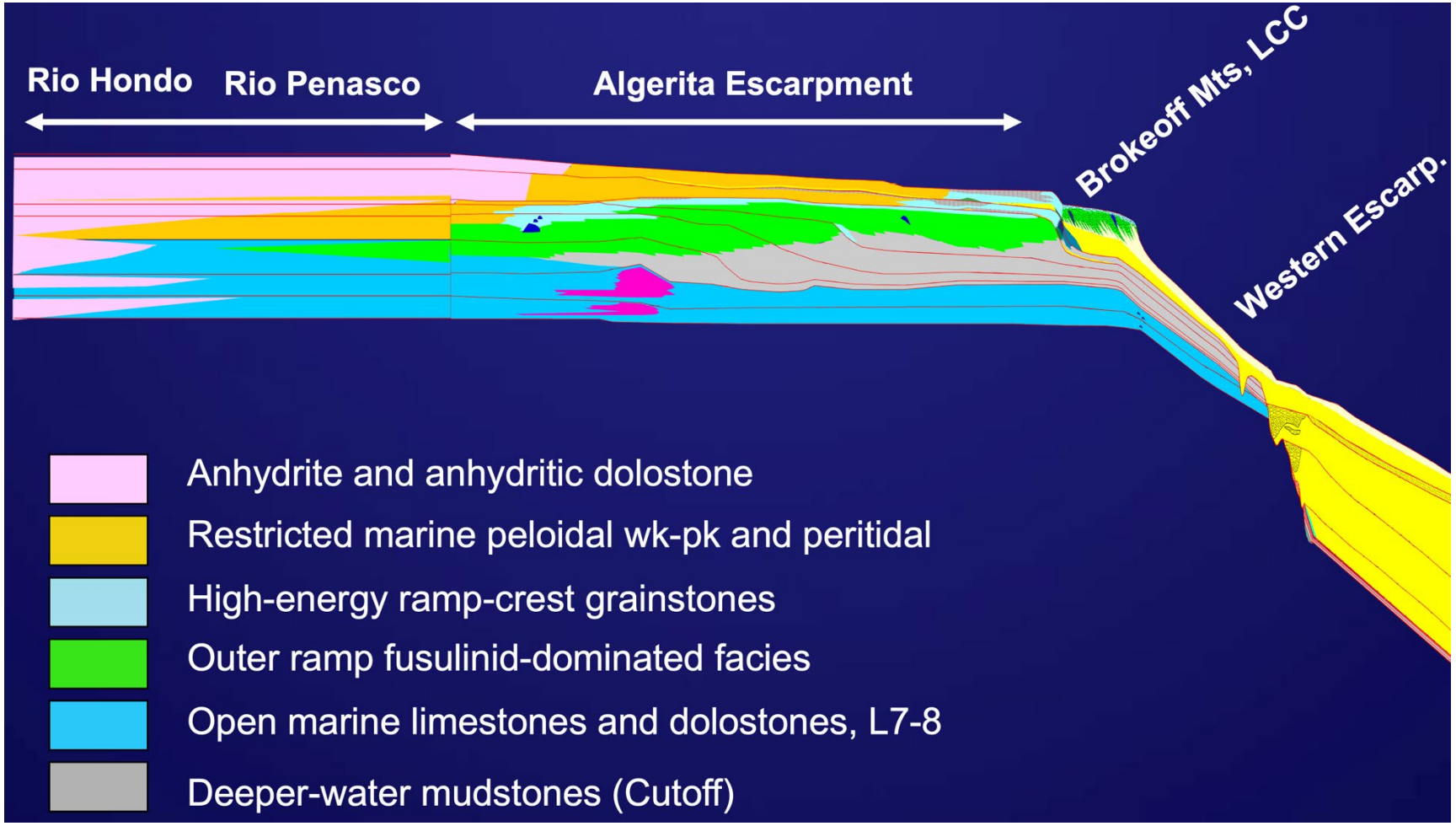


Figure 1-12 – A schematic cross section of the dominant lithofacies across the high-frequency cycles shown previously, based on observations from several regional workers (Kerans, 2006) studying outcrops of the Leonardian and Guadalupian succession.

The San Andres typically exhibits carbonate third- and fourth-order sequences across the Permian Basin. These high-frequency cycles cause variations of lithofacies vertically and laterally across the region. Inner-ramp and ramp-crest lithofacies are common in the Central Basin Platform and Northwest Shelf areas. Outer-ramp and deeper water lithofacies are common in the Midland Basin margin areas. These lithofacies usually include anhydritic dolostone, restricted marine peloidal wackestones and packstones, high-energy ramp-crest grainstones, outer-ramp fusulinid-dominated wackestones and packstones, open-marine lime and dolostones, and, finally, deep-water mudstones (Kerans, 2006).

The San Andres depositional setting of the wider area encompassing the Orchard Project's location contains well-known hydrocarbon fields producing oil from the San Andres. These fields are associated with high-frequency sequences that comprise composite sequences from the base to the top of the San Andres. These sequences are structurally controlled and can drape across tens of miles. Composite sequences 9, 10, and 11 form the regional sequence stratigraphic model. Figure 1-13 shows a map of hydrocarbon-producing play areas associated with the San Andres formation relative to the location of Orchard No. 1 through No. 7 and the wider area around them.

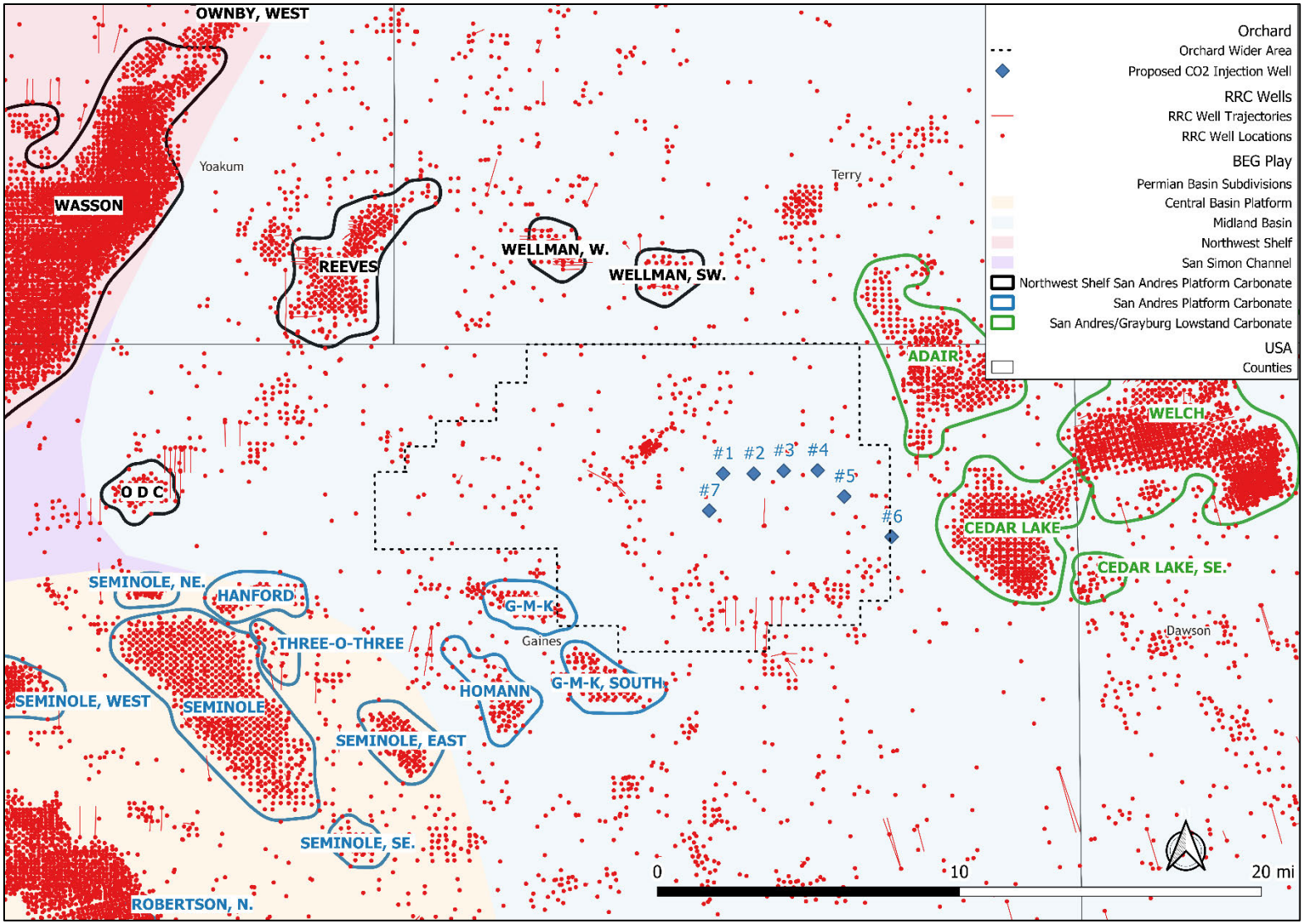


Figure 1-13 – Map of hydrocarbon-producing play areas associated with the San Andres formation relative to the Orchard No. 1 to No. 7 locations (indicated by the blue diamonds) and the wider area around them (black dashed polygon).

Fields to the east of the Orchard Project area are commonly associated with the younger composite sequence 10, compared to fields to the west—associated with composite sequence 9. The Orchard Project injection zone is associated with both composite sequences 9 and 10. Nearby San Andres oil production comes from the Northwest Shelf (Wasson Field), the Central Basin Platform (Seminole Field) and several fields at the margin between the Midland Basin and the Central Basin Platform (Homann, GMK). The Reeves Field is situated northwest of the injection site at the margin between the Northwest Shelf and the Midland Basin. Wellman field (to the north); Adair, Cedar Lake and Welch fields (to the east) of the Orchard site are considered part of the Midland Basin.

Younger sequences interpreted as composite sequences 10 and 11 are attributed to lowstand deposition. The Welch field is located to the east of the Orchard Project area. The San Andres in the Welch field has been interpreted to have been deposited in an arid, nearshore, shallow-water sabkha environment (Hinterlong and Taylor, 1996). This pronounced change across tens of miles was noted during the site assessment in the project area.

In the northeast part of Gaines County, within the Midland Basin margin, the dip azimuth is to the southwest and is locally associated with geologic features (e.g., Horseshoe Atoll) and regionally associated with Midland Basin subsidence through time.

Diagenesis is commonly observed across the San Andres formation in the Permian Basin to varying degrees and intensity. Porosity-reducing diagenetic features include cementation, mineralogic changes, and compaction, whereas porosity-enhancing diagenetic features include dissolution and fractures (Lucia, 2007).

1.2.4.4 Upper Confinement: San Andres and Grayburg Formations

The top 400 to 500 ft part of the Upper San Andres is a widespread anhydritic and dolomitic interval serving as a high-quality confining zone for the injection zone below. This interval is commonly cited as a confinement zone in similar long-term CO_2 storage projects (e.g., Occidental's CO_2 injection and storage at West Seminole field – Occidental Monitoring, Reporting, and Verification (MRV) Plan, 2020). The confining zone encompasses the relatively thinner overlying Grayburg formation, a mixed carbonate-siliciclastic sequence (Lindsay, 2017).

This low porosity and permeability interval commonly forms stratigraphic traps in adjacent producing San Andres fields, including Cedar Lake. Figure 1-14 shows a simplified map highlighting the regional patterns of dominant lithologies in the confining zone part of the San Andres and Grayburg formations (Ward et al., 1986). These rocks are associated with thinning subtidal facies and are capped by supratidal facies (Dutton et al., 2005).

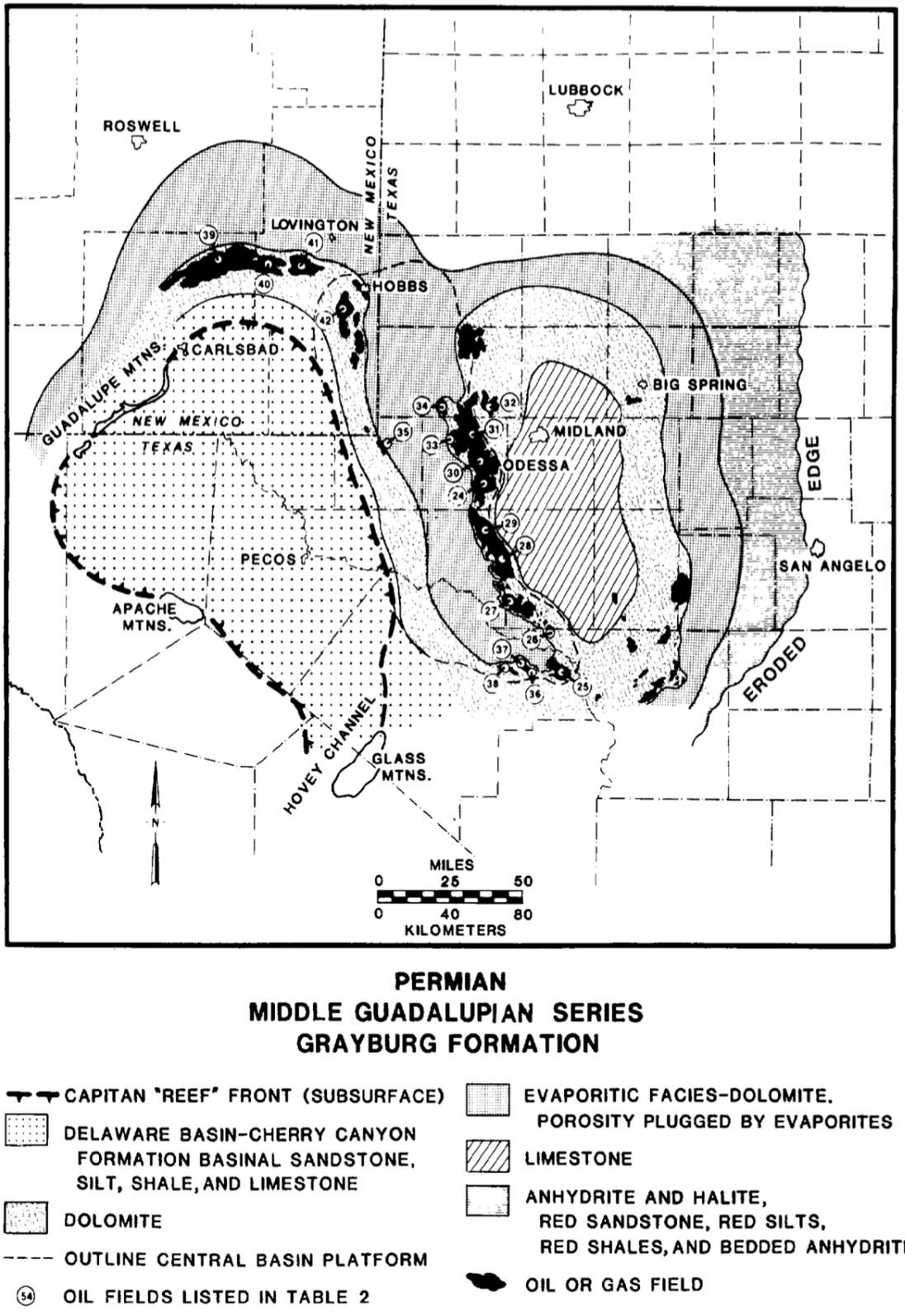


Figure 1-14 – Simplified map highlighting the regional patterns of dominant lithologies in the confining zone part of the San Andres and Grayburg formations (Ward et al., 1986).

In the Orchard Project area, the total thickness of the San Andres formation, including both the injection and confining zones, is approximately 1,600 ft.

1.2.4.5 Secondary Upper Confinement: Queen Formation

The Queen formation provides a secondary upper confinement zone. This approximately 700 ft thick interval represents a change to evaporitic lithofacies. Halite, possibly gypsum, anhydrite, dolomite, and sandstone lithologies are relatively thinly interbedded and demonstrate high vertical heterogeneity. These lithologies are laterally consistent across the region and through the Orchard Project area. The deepest portion (approximately 300 ft thick) of the Queen is considered the secondary upper confining zone.

The Queen features regular alternating evaporitic, carbonate, and siliciclastic sedimentation associated with shelf deposition and is part of a wider, gently sloping surface from nonmarine to subtidal environments. Low-amplitude, high-frequency eustatic changes are responsible for the Queen lithofacies (Tucker, 1991).

Mazzullo's study of the Queen in the Northwest Shelf describes the sandstones as being of nonmarine origin and interbedded with evaporitic and dolomudstones that are playa and sabkha deposits located behind the shelf margin (Tucker, 1991).

1.2.4.6 Shallower Formations

The Seven Rivers formation was deposited on a broad, shallow shelf in a back-reef lagoonal setting located updip of the shelf-margin reef carbonates that rimmed the Delaware Basin (Silver and Todd, 1969; Ward et al., 1986). The Seven Rivers is composed mainly of evaporites and dolostones, with only minor siliciclastics (Sarg, 1981; Borer and Harris, 1991; Andreason, 1992).

The Yates formation represents a period of major siliciclastic shelf deposition (Andreason, 1992) with an overall upward-shallowing sequence of cyclically interbedded siliciclastics associated with sabkha carbonates and evaporites (Ward et al., 1986; Borer and Harris, 1991; Andreason, 1992). The Yates is interpreted as having been deposited in a complex of coastal and lagoonal environments upslope of the shelf-margin reef (Andreason, 1992).

The Tansill formation is dominated by anhydrite with or without dolomite and siliciclastic interbeds. In depositional environments toward the northern margins of the Midland Basin, the Tansill is composed of halite with abundant siliciclastic interbeds (Hovorka and Nava, 2000). The overlying Salado formation is distinctive because the Tansill contains thinner cycles and abundant thin siliciclastic beds (Hovorka and Nava, 2000).

The Salado formation is mostly salt-bearing and contains the thickest salt beds in the west Texas Permian section (SEPM Strata, 2022).

Underground Sources of Drinking Water (USDWs), discussed in *Section 1.9.3*, are shallower than the Salado formation. These shallow formations and confining zones below comprise sediments

more than 2,000 ft thick between the injection zone and the transition into water-bearing strata classified as a USDW.

1.3 Site Geology

The proposed Orchard No. 1 to No. 7 site is located approximately 2.5 miles southeast of Loop, Texas, within the northeast part of Gaines County, Texas. The wider area around the proposed site provides multiple data types that increased the accuracy of this site characterization. Figure 1-15 shows a map of the individual locations of Orchard No. 1 through No. 7 relative to existing wells within the wider area and associated with hydrocarbon-producing play areas.

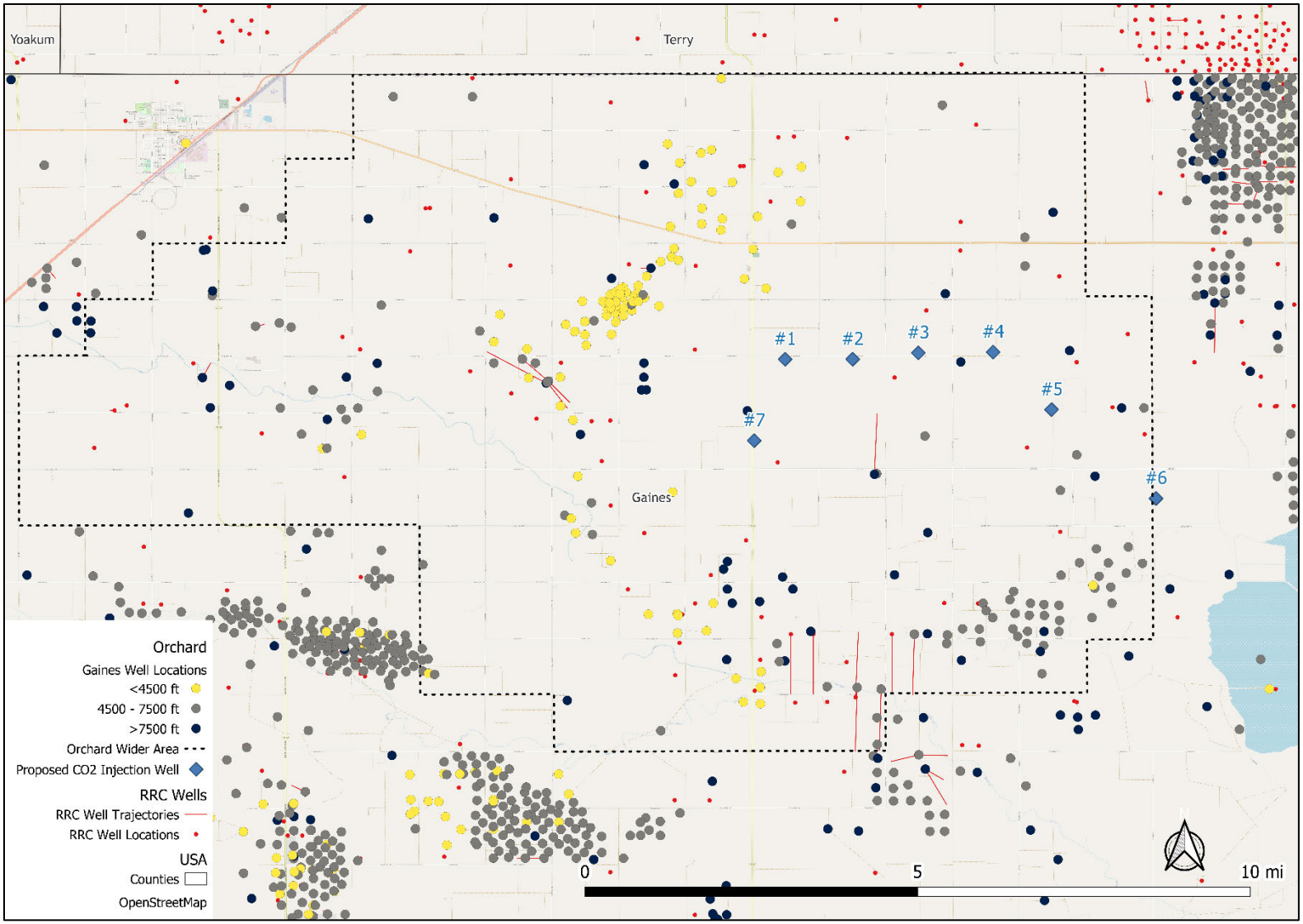


Figure 1-15 – Map of the Orchard No. 1 to No. 7 locations (indicated by the blue diamonds) relative to existing wells within the wider area (black, dashed outline) and associated with hydrocarbon-producing play areas.

Subsurface data and analysis from several wells drilled in the area were incorporated into this site evaluation for the major stratigraphic units. These wells—all dry holes—provide sources of core, wireline logs, and mud logs, plus injectivity and productivity data over several decades.

Furthermore, 2D seismic data is available in the Orchard Project area and has been integrated into the subsurface analysis. The seismic data and offset well data have helped to reduce subsurface uncertainty and risk for the project. The resulting interpretations of the project site and broader area, together with the regional geologic model, were used to create a 3D model discussed in *Section 2 – Plume Model.*

Figure 1-16 shows a map of the Orchard No. 1 to No. 7 locations, available subsurface data used for this site characterization, and nearby well-known hydrocarbon-producing play areas.

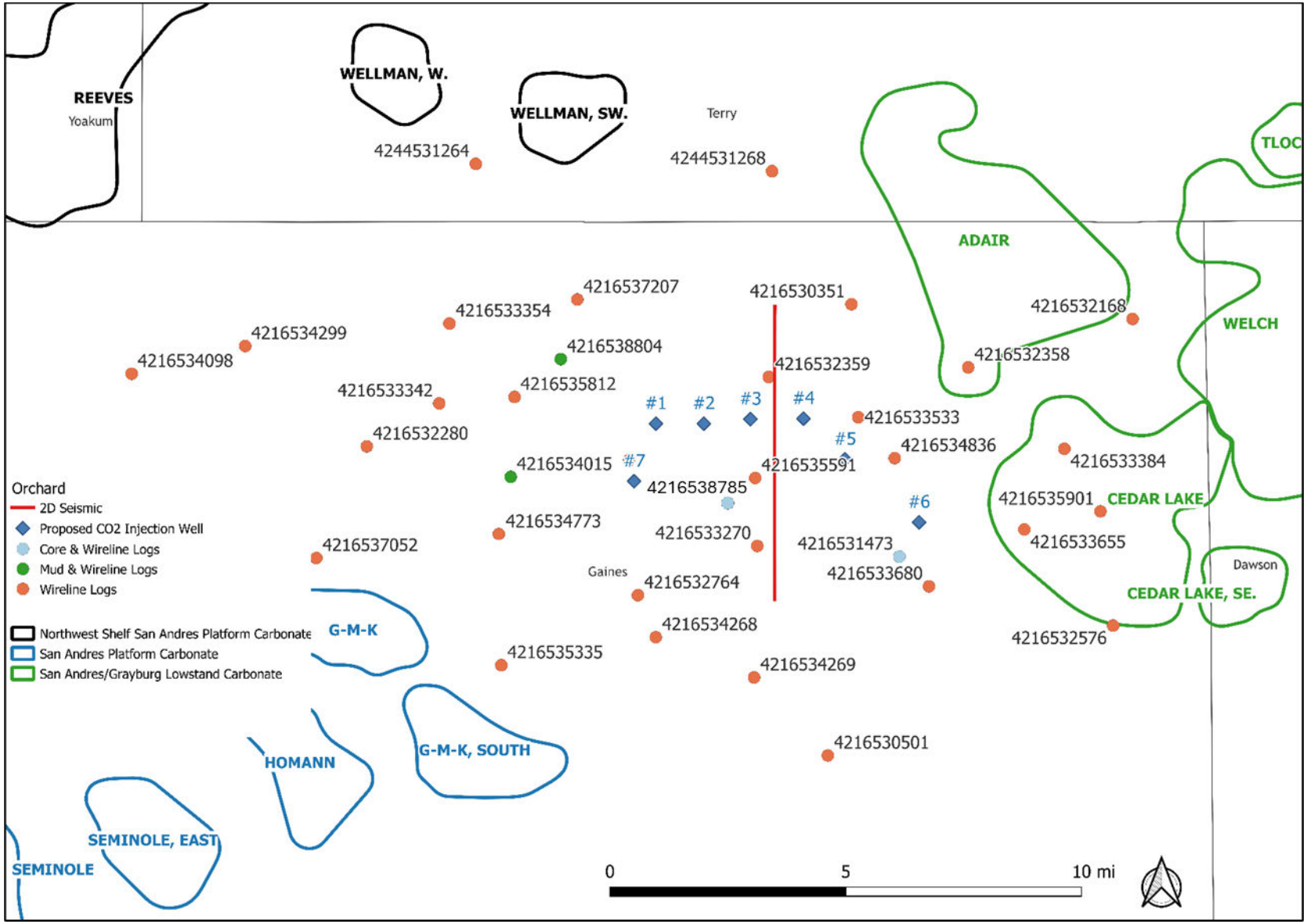


Figure 1-16 – Map of the Orchard No. 1–No. 7 locations (indicated by the blue diamonds), available subsurface data used for the site characterization, and nearby well-known hydrocarbon-producing play areas. The red line indicates the 2D seismic line evaluated.

1.3.1 Subsurface Data and Methods

1.3.1.1 Well Logs

Digital well log files (.las file format) were used for several site characterization tasks, including stratigraphic top determinations, petrophysical calculations, integration to the core and seismic data, and creation of a 3D conceptual and numerical model ("geomodel"). These well logs were the primary source for understanding vertical and lateral rock quality changes in the injection and confining zones. Several wells drilled after 1980 have high-quality electric wireline logs suitable for quantitative lithology, porosity, permeability, and fluid-type derivations via petrophysical analysis. It is important to note that some of those wells do not penetrate the entire San Andres injection zone.

Thirty-four wells within the Orchard Project area were identified as having a complete suite of well logs for petrophysical analysis. Neutron and density logs were critical to quantitatively deriving porosity and lithologic information for the injection and confining zones. These wells were selected based on their relatively consistent spacing throughout the project area and to provide a picture of the subsurface without heavily biasing one location. Table 1-1 shows select well-log data used for this site characterization. The digital .las and .pdf files are included in Appendix K.

Table 1-1 – Select well log data described by log curve type and logged depth intervals, used for this site characterization.

Well API Number	Log Curves	Logged Interval (ft)	KB (ft)	Run Date
42-165-30351	CALD, CALS, DPHI_LS, DRHO, DT, GRD, GRS, ILD, ILM, LL8, NPHI_LS, RHOB, SPR	4,593-9,792	3,225	1974
42-165-30501	CALD, CALN, CALS, CORR, DPHI_LS, GRD, GRN, GRS, ILD, ILM, NPHI_LS, RHOB, SFL, SNP_LS, SPR, TEND, TENN, TENR, TENS	4,967-13,285	3,149	1975
42-165-31473	GRN, NEUT	1,700-5,057	3,174	1978
42-165-32168	NPHI_LS, CALD, DPHI_LS, DRHO, RHOB, LLD, LLS, MSFL, DT, CALR, CALS, GRD, GRR, GRS, TEND, TENR, TENS	4,800-12,397	3,185	1981
42-165-32280	AC, CALD, CALS, CORR, DPHI, GRD, GRR, GRS, ILD, ILM, NPOR_LS, RHOB, SFL, SPR, TEND, TENR, TENS	5,197-13,566	3,340	1982
42-165-32358	GR, SP, ILS, ILD	4,492-10,018	3,187	1982
42-165-32359	GRR, LLS, LLD, MSFL, CALR, ILD, ILM, SFLU, SPR, GR, SNP, DT	424-5,519	3,226	1982
42-165-32576	ILD, ILS, GR, CAL	5,073-12,490	3,099	1983
42-165-32764	CORR, GRD, NPHI, RHOB, CALD, DPHI, FORX, GURD	4,955-13,211	3,206	1984
42-165-33270	CALD, CALR, CALS, DPHI_LS, DRHO, DT, GR, GRR, GRS, ILD, ILM, NPHI, PEF, RHOB, ILS, SPR, SPS, TEND, TENR, TENS	4,940-13,165	3,170	1985

Well API Number	Log Curves	Logged Interval (ft)	KB (ft)	Run Date
42-165-33342	GRD, RHOB, NPHI, CALD, DRHO, PEF, DPHI, LLD, LLS, MSFL, DT	2,209-5,739	3,301	1985
42-165-33354	CAL, ILS, NPHI, ILD, GR, DT, DPHI, RHOB	5,052-13,430	3,325	1985
42-165-33384	CALD, CALS, DPHI_LS, DRHO, DT, GRD, GRR, GRS, ILD, ILM, NPHI_LS, PEF, RHOB, SFLU, SPR, TEND, TENR, TENS	5,501-11,454	3,156	1985
42-165-33533	CALD, DCOR, DPOR_LS, DT, GRD, GRR, GUARD, ILD, ILM, NPOR_LS, PEL, PES, RHOB, SPR, TEND, TENR, TENS	4,624-12,887	3,199	1986
42-165-33655	CAL, DPHI, GR, ILD, LLS, NPHI, PE, RHOB, SP	5,197-12,704	3,115	
42-165-33680	DPHI, CAL, GR, RHOB, ILS, NPHI, ILD	463-13,686	3,201	1987
42-165-34015	GRR, GRS, RHOB, SPHI_LS, GRD, NPHI_LS, DPHI_LS, DRHO, PEF, TEND, CALD, SPR, ILD, ILM, SFLU, TENS, DT	4,924-13,198	3,301	1986
42-165-34098	CAL, DPHI, DT, GR, ILD, LLS, NPHI, PE, RHOB, SP	5,270-13,940	3,376	
42-165-34268	ILS, NPHI, RHOB, ILD, GR, SP, CAL, DPHI	4,941-13,224	3,190	1990
42-165-34269	ILD, ILS, SP, CAL, DT, GR	5,286-11,625	3,164	1990
42-165-34299	GR, CALR, GRR, SPR, LLD, LLS, MSFL, ILD, ILM, SFLU, RHOB, CALD, DRHO, PEF, DPHI, NPHI, CALS, DT	5,251-13,702	3,362	1991
42-165-34773	LLD, LLS, MSFL, SGR, CALD, DPHI, NPHI, DRHO, PEF, RHOB	2,266-5,548	3,261	1994
42-165-34836	AO90, AO30, AO20, CALD, GRD, PEF, DRHO, DPHI, NPHI, RHOB	4,691-10,597	3,187	1995
42-165-35335	DPHZ_LS, RHOZ, AHF10, AHF20, AHF30, AHF60, AHF90, CALS, PORZ_DM, DT, GRD, GRR, GRS, HCALD, HCALR, HDRA, PEFZ, SPHI_LS, SPR, TEND, TENR, TENS, TNPH_DM, TNPH_LS	4,926-13,415	3,228	1994
42-165-35591	GRD, CNC, PE, PORZ, ZCOR, CALD, ZDEN, RD, RS, RMLL	3,200-5,216	3,191	2000
42-165-35812	ILM, LL, SPR, ILD, DT, CALD, DCOR, DPOR, GRD, NPOR, PE, RHOB	195-3,219	3,296	2002
42-165-35901	GRD, NPOR_LS, PE, CALD, DCOR, DPOR_LS, RHOB	2,984-4,993	3,085	2003
42-165-37052	CALXD, DCOR, DPOR_DM, DPOR_LS, DT, GRD, LLD, LLS, MLL, NPOR_DM, NPOR_LS, PE, RHOB, SPHI_DM, SPHI_LS, TEND, TENR, TENS	4,800-13,425	3,314	2010
42-165-37205	GRR, HCALR, AF30, AF90, SPR, RXOZ	4,962-13,188	3,239	2010
42-165-37207	NPHI, GR, DT, CAL, RHOB, DPHI	4,933-13,166	3,287	2010
42-165-38785	GR, HCAL, HCGR, HSGR, TENS, RXOZ, RM_HRLT, TNPH, DPHZ, PXND, HDRA, PEFZ, DSOZ, RSOZ, BFV, CBP, CDF, CFTC, CMFF, CMR, DI_HRLT, DNPH, DSOZ, ECGR, HCGR, HDRA, HDRB, HMIN, HMNO, HPRA, HTHO,	2,200-7,210	3,188	2019

Well API Number	Log Curves	Logged Interval (ft)	KB (ft)	Run Date
	HTNP, HURA, KSDR, KTIM, NPOR, RHOZ, RLA0 – RLA5, RM_HLT, TCMR, HTNP_SAN, HDPH_SAN			
42-165-38804	CALX, CNC, CPPZC, DAZODQI, DEVODQI, DT24QI, DTCQI, DTSQI, GR, K, KTH, MLR1C, MLR2C, MLR3C, MLR4C, PE, PORAQI, PORZC, RMLL, TEN, TH, TTQI, U, WRM, WTBH, ZCOR, ZDNC	4,880-12,092	3,282	2020
42-445-31264	CALD, CALS, CGRD, DPHI_LS, DRHO, DT, GRR, GRS, ILD, ILM, NPHI_LS, PEF, RHOB, SFLU, SGRDD, SPR, SPS, TEND, TENR, TENS, GRT, SIGMA, TRAT, THOR, POTA, URAN	5,024-13,489	3,345	1985
42-445-31268	CALD, CALR, CALS, CGRD, DPHI_LS, DRHO, DT, GRR, GRS, ILD, ILM, NPHI_LS, PEF, RHOB, SFLU, SGRDD, SPR, TEND, TENR, TENS, THOR, POTA, URAN	4,892-13,079	3,292	1985

A few of these wells did not have a sufficiently complete suite of well logs for petrophysical analysis but provided qualitative understanding of the injection and confining zones. Two mud logs containing gas readings, and one with a detailed lithological description of all major stratigraphic units, were available. The mud log for the R.W. McIlvain No. 1 (API No. 42-165-34015) is included in Appendix K.

The current well tops incorporate elements of lithostratigraphy and regional sequence stratigraphy. The major sequence boundaries were identified and used to create the 3D conceptual and numerical model.

1.3.1.2 Core

Two wells within the vicinity of the proposed Orchard No. 1 to No. 7 wells are sources of site-specific core—from the top of the injection zone and base of the upper confining zone, respectively. Sidewall cores from the injection zone were obtained and analyzed during the drilling of the nearby Valiant 1D (API No. 42-165-38785). Orchard recently acquired this well and intends to convert to a monitoring well. Analysis was performed by Special Core Analysis Laboratories, Inc. (SCAL) in 2019. Core of the confining zone from Sanderson No. 1 (API NO. 42-165-31473) was obtained from the Texas Bureau of Economic Geology and tested by Core Lab Houston. Table 1-2 provides a list of the cored intervals and testing program completed by Core Lab Houston. The core reports for each well are included in Appendix J-1 and J-2.

Table 1-2 – Cored Intervals and Testing Program

Well API Number	Cored Interval (ft)	Testing Program
42-165-31473	4,946 to 5,053	- 6 vertical plugs - Triaxial - Mercury injection - X-ray diffraction - Thin section description - White-light photography - Spectral gamma ray - Plug CT scan
42-165-38785	5,176 to 6,924	- 74 sidewall cores (SWC) – routine & special analysis - Extended gas analysis - White light photography - Ultraviolet light photography - X-ray diffraction (XRD)

1.3.1.3 Seismic

Two-dimensional seismic data (post-stack time migrated) provided an additional data source to help understand the stratigraphic and structural variations across the Orchard Project area and tie into the regional and local geologic framework. The 2D seismic line, shown in Figure 1-16, was licensed from a third-party data provider, from a 1982 survey shot that was reprocessed in 2016. The seismic line is 7.2 miles long and oriented north-south through the project area.

1.3.2 Injection Zone

The San Andres formation is the proposed injection zone. As discussed in Section 1.2.4, the San Andres is segregated into the upper confining interval and deeper injection zone. The injection zone is divided into an upper injection zone (the lower part of the Upper San Andres) and a lower injection zone (the upper part of the Lower San Andres). Of the two injection zones, the upper portion has higher porosity and permeability than the Lower San Andres injection zone. The average depths for the injection zone top and base are approximately -2,050 ft true vertical depth (TVD) subsea (SS) and -3,250 ft TVD SS, respectively. Surface elevations are approximately 3,100 ft in the Orchard Project area. Therefore, the injection zone top is typically greater than 5,000 ft TVD below the surface.

Figure 1-17 shows a structure map for the top of the injection zone in the San Andres formation. Figure 1-18 is a structure map for the base of the injection zone in the San Andres (i.e., top of the Glorieta/Leonard Upper).

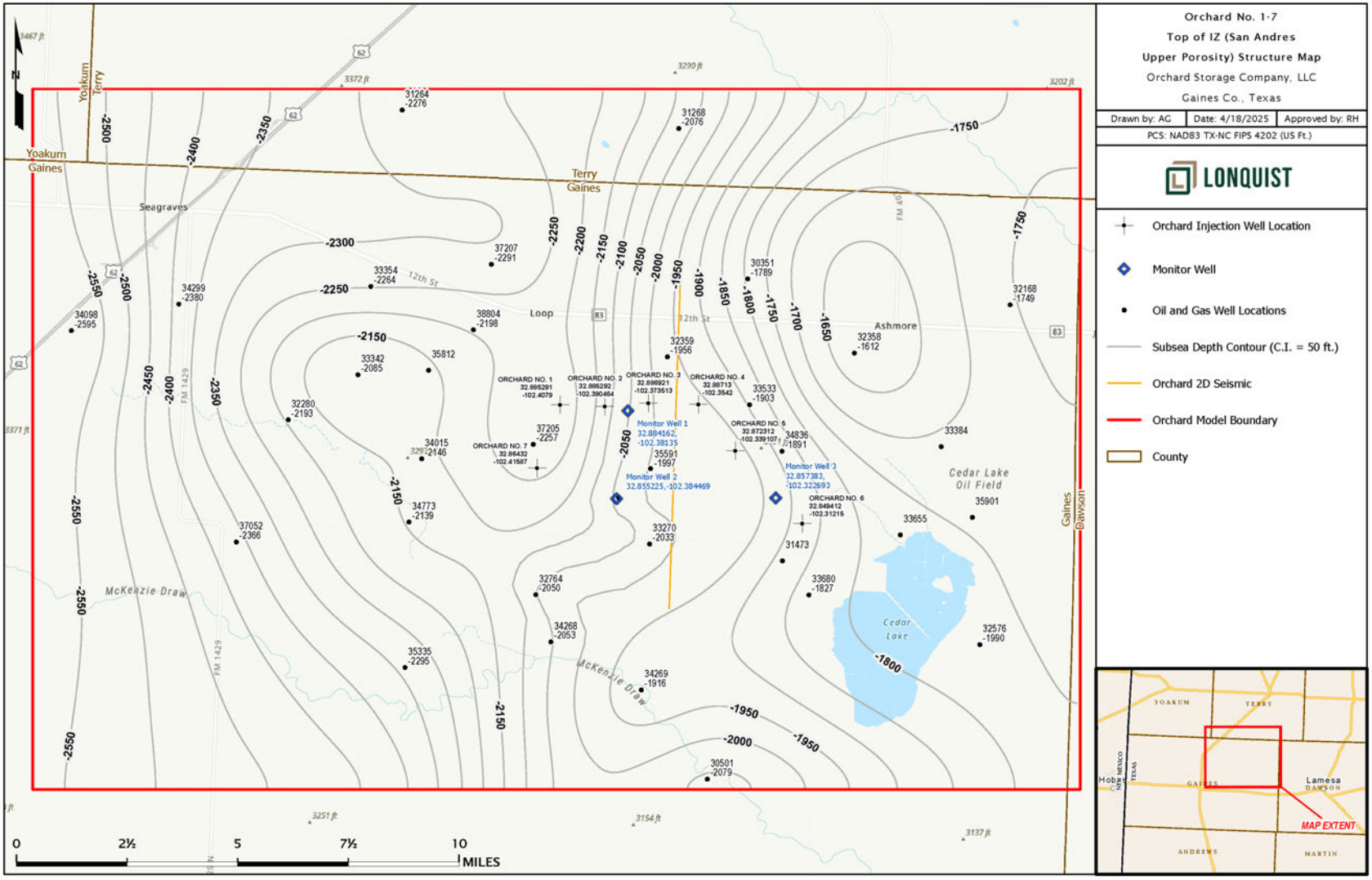


Figure 1-17 – Depth structure map (TVD SS) for the top of the injection zone in the San Andres formation.

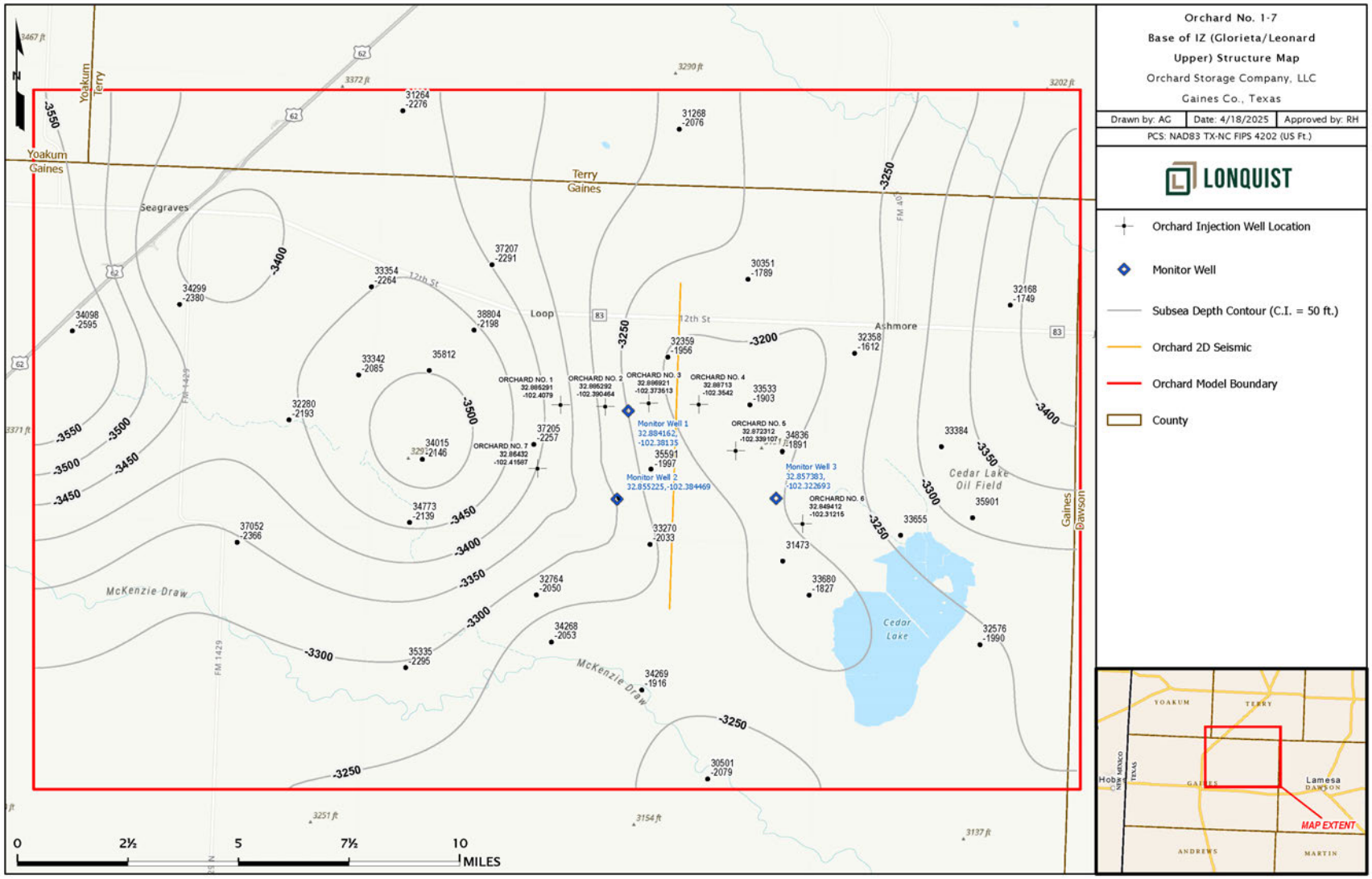


Figure 1-18 – Depth structure map (TVD SS) for the base of the injection zone in the San Andres formation (i.e., top of the Glorieta/Leonard Upper).

The thickness of the San Andres injection zone is approximately 1,200 ft at the Orchard Project site. The injection zone thickness of the Upper San Andres is approximately 500 ft, and the thickness of the Lower San Andres is approximately 700 ft. Figure 1-19 shows a thickness map of the injection zone within the San Andres formation.

Figure 1-20 shows well log data and petrophysical analysis for the confining zones and injection zone from well API No. 42-165-38804, which is the type well for the Orchard Project area and approximately 3.3 miles northwest of Orchard No. 1 through No. 7.

Figure 1-21 shows a north-south cross section of well log data from five existing wells, while Figure 1-22 shows a west-east cross section of well log data from another six wells. Figure 1-23 shows the two cross sections in Figures 1-21 and 1-22.

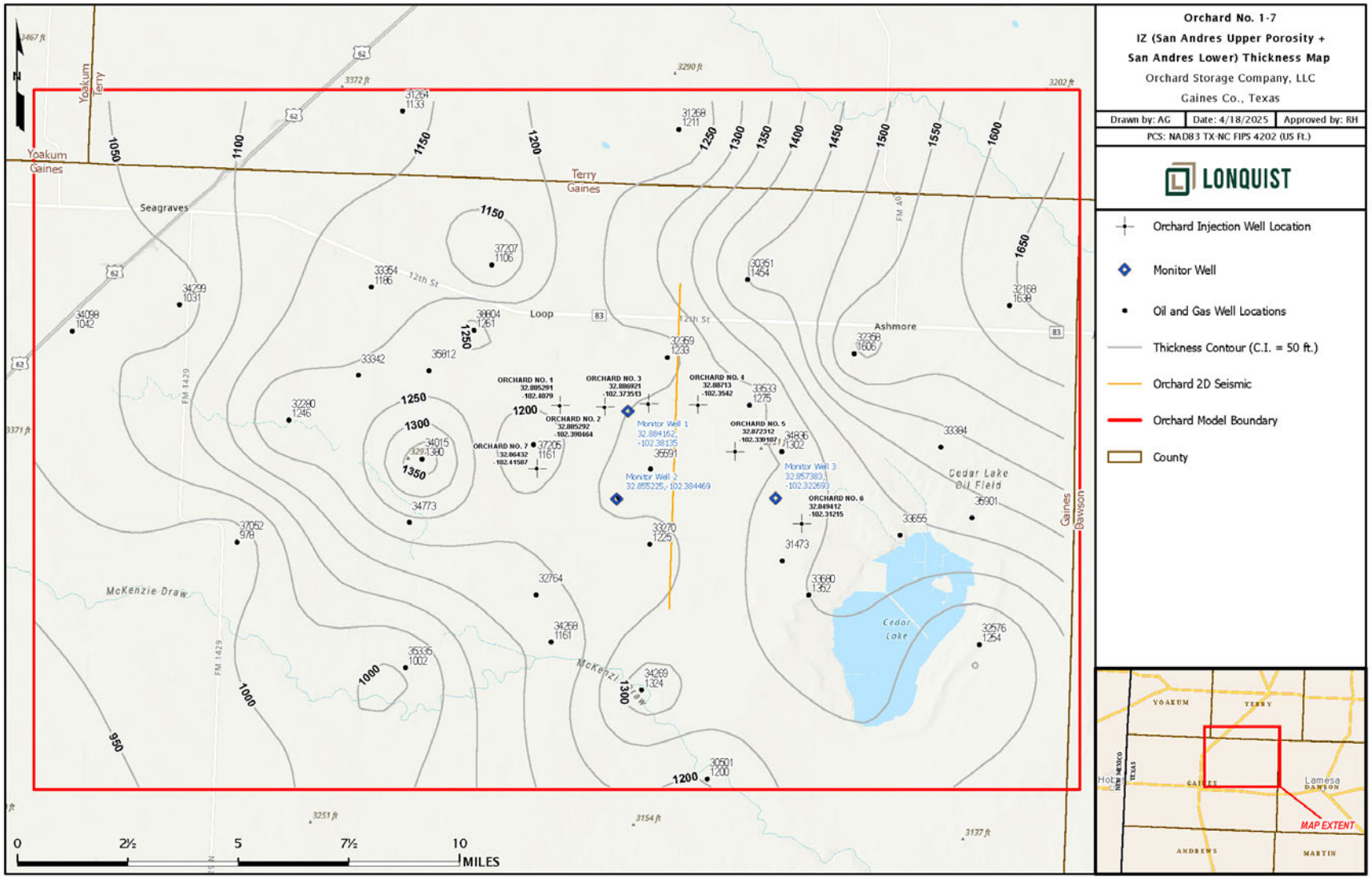


Figure 1-19 – Thickness map (ft) of the injection zone within the San Andres formation.



Figure 1-20 – Well log data and petrophysical analysis for the confining zones and injection zone from the type well for the Orchard Project area (API No. 42-165-38804). This well is northwest of Orchard No. 1–No. 7 by approximately 3.3 mi. Track 1: @IGR is potassium-thorium (GAPI), and Track 8: v is Poisson's ratio, G is Shear modulus, E is Young's modulus, Sh is horizontal stress, Kb is Bulk modulus, and Biot is Biot's coefficient.

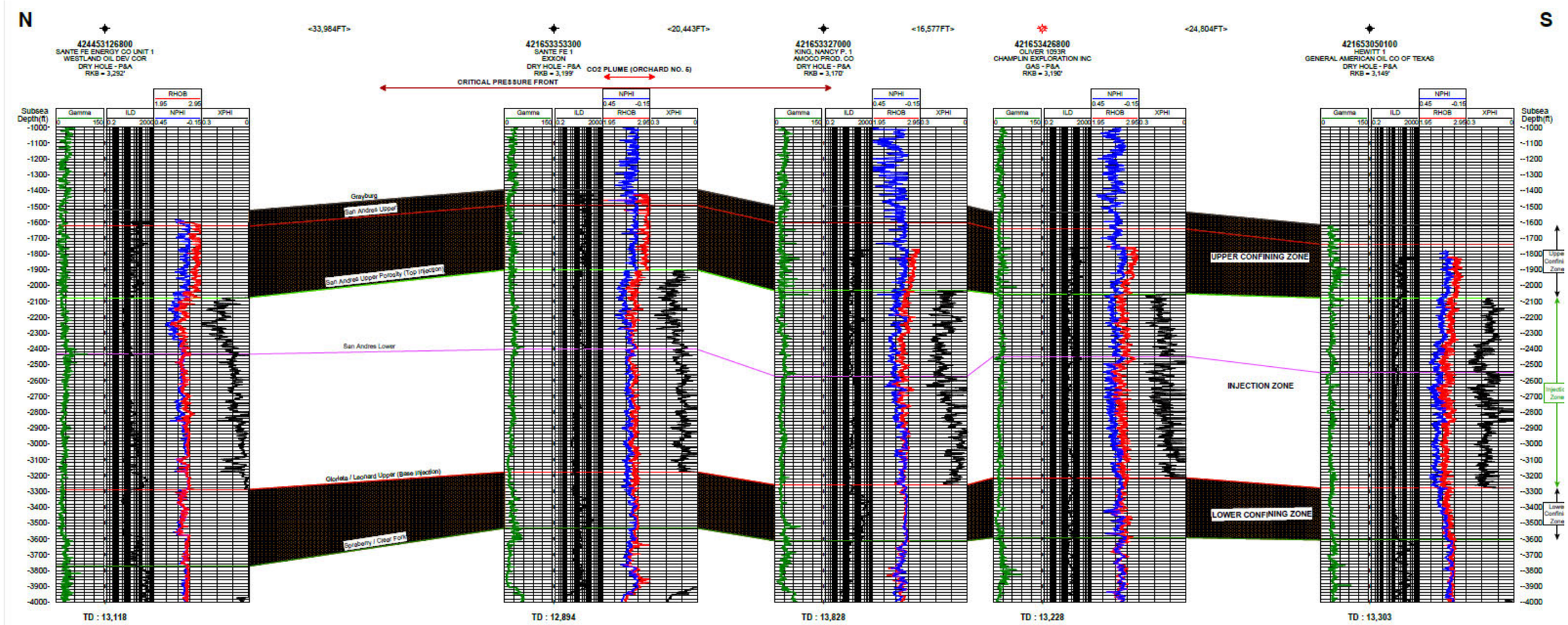


Figure 1-21 – A north-south cross section of well log data from five wells (Figure 1-23 shows the well locations).

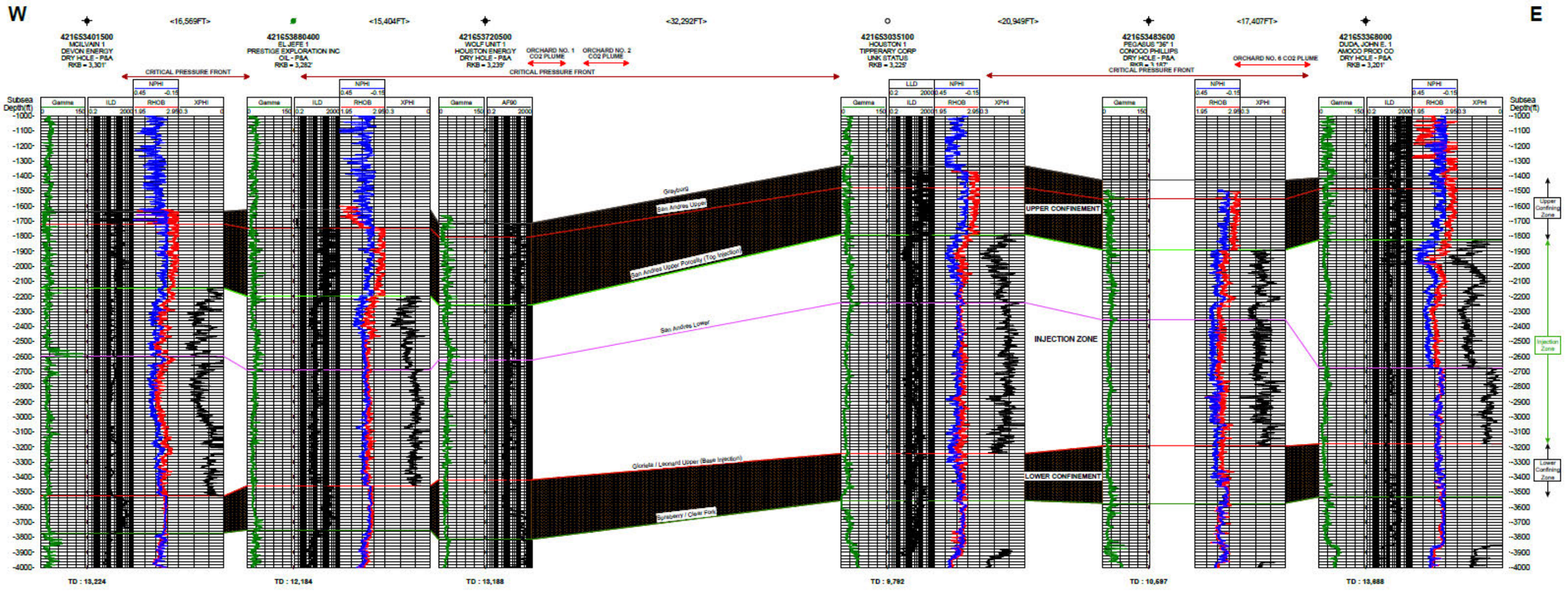


Figure 1-22 – A west-east cross section of well log data from six wells (Figure 1-23 shows the well locations).

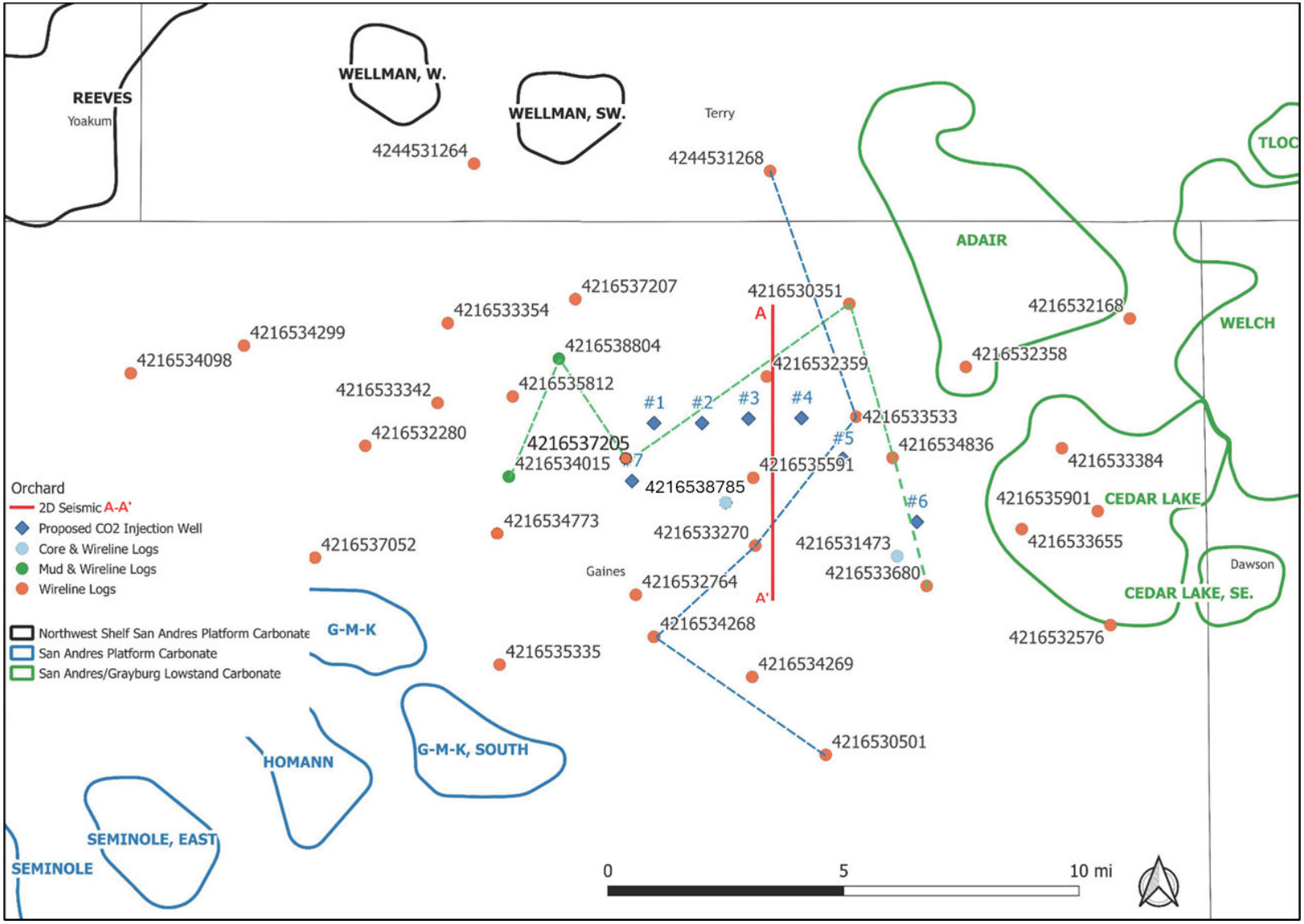


Figure 1-23 – Reference map showing the two cross sections in Figure 1-21 (indicated by the blue dashed line) and Figure 1-22 (green dashed line). The red vertical line indicates the location of the 2D seismic line.

Well tops were selected for the top of the injection zone, primarily where a pronounced inflection of the neutron-density log curves occurred and could be correlated to a neighboring well. This inflection marks the point of significant increase of porosity through to the base of the injection zone compared to the confining zone above. Well tops between the Upper and Lower San Andres were commonly selected where the gamma ray increased. A small inflection on the neutron-density log curves indicated a probable sequence boundary. The base of the injection zone was identified by a pronounced decrease of rock quality based on neutron-density changes, increase of (and lack of separation between) resistivity curves, and increasing gamma ray.

1.3.2.1 Lithology

The San Andres is predominantly dolomitic, with the Upper San Andres more so than the Lower San Andres. High-frequency cycles of the San Andres provide a range of depositional textures and rock types according to lithologic descriptions from core samples taken from API No. 42-165-38785.

General rock types, based on depositional texture and mineralogy observed in the nearby core and fitting into the regional geologic framework, are as follows:

- Dolostone
- Limestone
- Anhydrite
- Pyrite
- Styolite
- Chert (towards base of zone)

Depositional textures are representative of a mix of ramp-crest, outer-ramp, and open-marine depositional environments and include the following:

- Fusulinid-oolitic wackestone/packstone
- Fusulinid-oolitic packstone/grainstone
- Intertidal/subtidal mudstone

Additionally, well log data shown in the type well (API No. 42-165-38804) was quantitatively used to understand the dominant lithology in the San Andres. Other well data was used to qualitatively understand whether the dominant lithology in the injection zone is dolomitic or calcitic. These learnings came from observing the neutron-density separation and overlap and the photoelectric factor log curve (where available).

Further refinement of the petrophysical model to derive dominant lithology or facies is discussed in *Section 1.10.*

1.3.2.2 Porosity – Petrophysics

Density porosity was derived using the bulk density log and an estimated matrix density for the Upper and Lower San Andres. The matrix density assumed a dominant mineralogy of dolomite (2.87 grams per cubic centimeter (g/cm^3)) for the Upper San Andres. The matrix density also assumed the dominant mineralogy of calcite (2.71 g/cm^3) for the Lower San Andres. The fluid density used was 1.1 g/cm^3. The density porosity was averaged with the limestone neutron-porosity log to derive cross-plot porosity (XPHI).

Minimal correction was needed for shale (i.e., clay and silt) effects based on the very low potassium-thorium gamma ray log values. Uranium is the main driver for relatively higher (10-30 GAPI) gamma ray values (i.e., total and effective porosity are treated similarly). Uranium is often diagenetic and unrelated to depositional facies or rock fabric (Lucia, 2007).

The average porosity derived from well logs using this approach is approximately 15% in the Upper San Andres and about 10% in the Lower San Andres within the Orchard Project area. For comparison purposes only, the mineralogy log curves generated for the type well were used to calculate an effective porosity (PHIE). Shale proportions based on gamma ray and generic corrections were applied to PHIE before calculating XPHI. The resulting average well-log porosity for the type well is reduced to approximately 9% for the whole injection interval.

Figure 1-24 shows an average porosity map for the Upper San Andres part of the injection zone. This interval (as shown in *Section 1.2.4*) is the main target for CO_2 injection, based on having a higher pore volume than the Lower San Andres. The spatial distribution of porosity was mapped using the XPHI well log. The porosity within the Orchard Project area is expected to be relatively consistent based on observations between wells surrounding the project area (e.g., API No. 42-165-38804, 42-165-33533, 42-165-33270, 42-165-34015). This average porosity map was extracted from the 3D numerical model, created via kriging methodology to distribute porosity between upscaled well log data, as discussed in *Section 3 – Area of Review and Corrective Action Plan*.

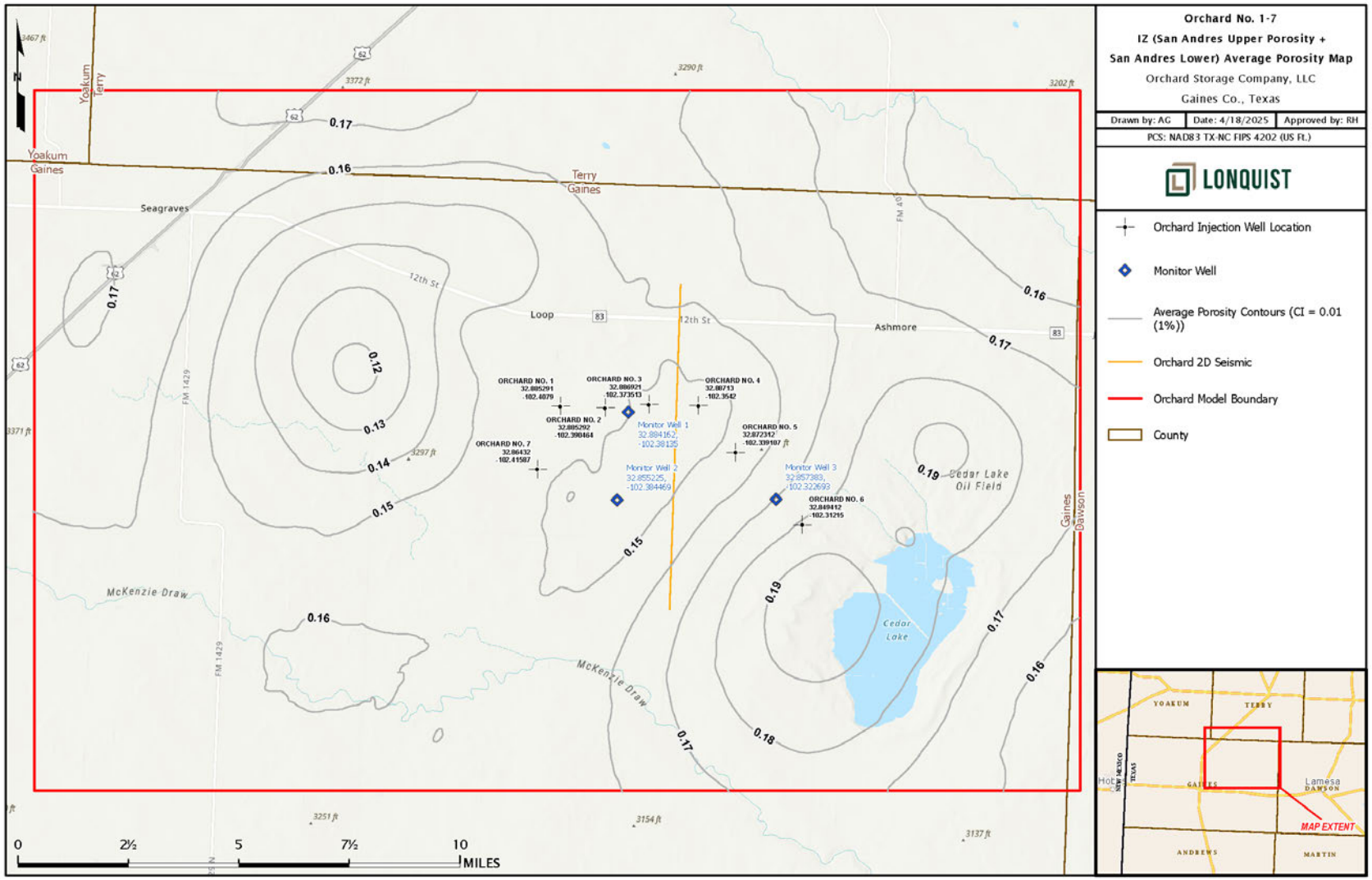


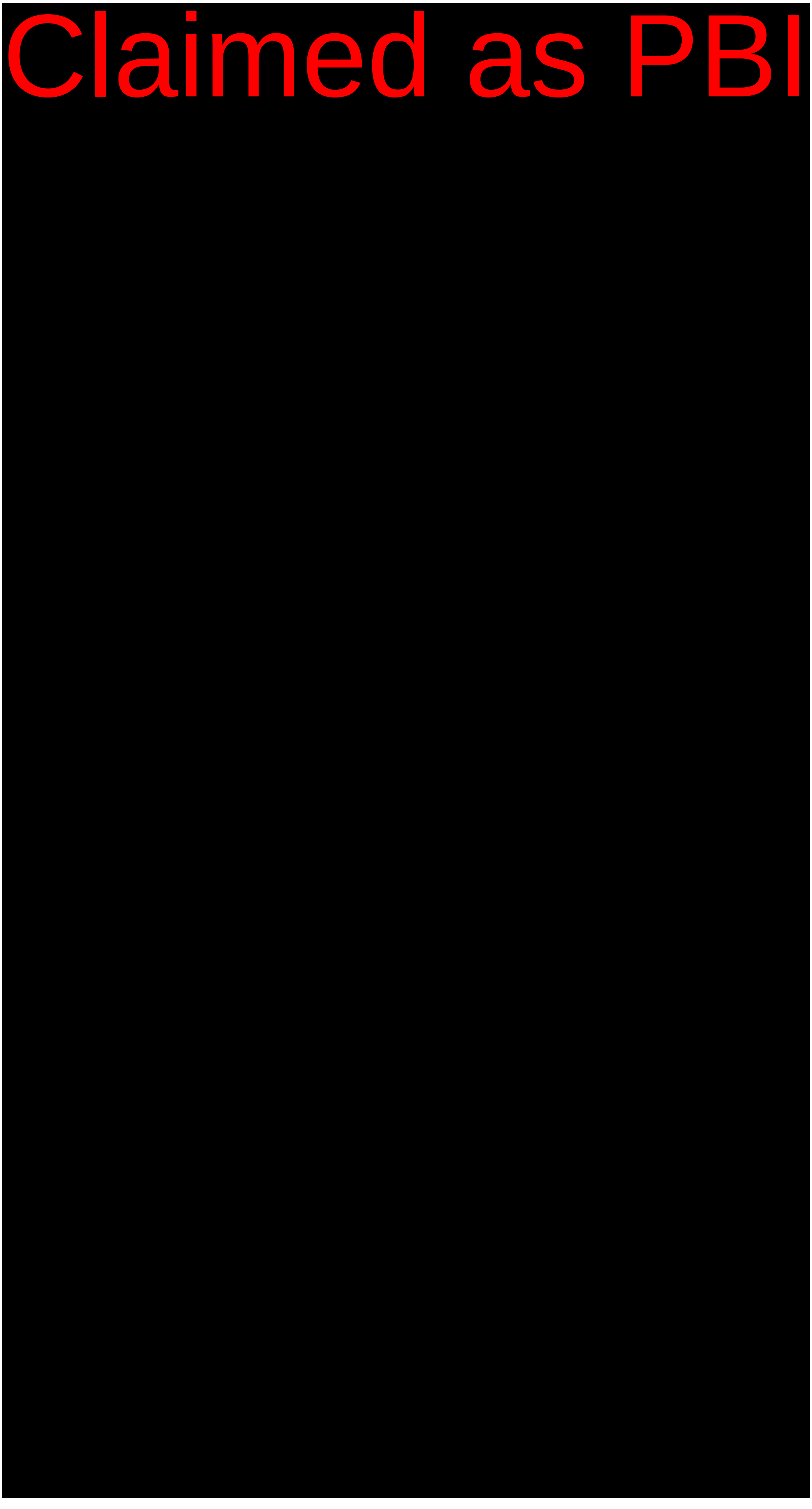
Figure 1-24 – Average porosity map of the Upper San Andres part of the injection zone.

The average porosity map indicates several changes outside of the Orchard Project area. The higher porosity observed east of the project area is attributed to lithofacies changes related to a higher-energy depositional setting (likely within a younger sequence of the Upper San Andres). This area is the location of several prolific oil-producing fields, including Adair, Cedar Lake, and Welch. The lower porosity observed northwest of the project area is likely a consequence of the mapping algorithm and constraining statistics.

1.3.2.3 Porosity – Core Data

Seventy-four sidewall core (SWC) samples were collected in well API 42-165-38785 upon which multiple different types of analyses were performed. These analyses yield detailed insights into the mineralogy, fluid saturation, porosity, and permeability of the San Andres injection zone. Table 1-3 shows the results of the routine SWC analysis performed by Special Core Analysis Laboratories (SCAL). The average porosity of the injection zone is 10.6%, which is consistent with well log-derived porosity distributions in the Orchard Project area. The complete core analysis report for this well is provided in Appendix J-2.

Claimed as PBI



Additionally, SCAL performed X-ray diffraction on well API 42-165-38785 with mineral composition calculated using Bragg's Law. The results, which are shown in Table 1-4, showed minimal clay content (average of 2% by weight) but higher-than-expected anhydrite content (average of 7.5% by weight) in the upper portion of the injection zone. This content may correlate to the low total gamma ray well-log expression observed in the cored well and other nearby wells. The discussion of rock mineralogy continues in *Section 1.6*.



Primary porosity (or interparticle porosity) is the dominant porosity type expected in the Orchard Project area, confirmed by observations in core analyses. No secondary porosity that may act as a "thief zone" to injected CO_2 was observed in the core, nor is it expected to be featured in the project area based on the depositional setting. No major dissolution porosity, connected vuggy pore types, or preexisting large-scale fracture porosity is predicted to interfere with CO_2 injection in the project area.

1.3.2.4 Permeability

The average calculated matrix permeability for the Upper San Andres is approximately 35.7millidarcys (mD) and approximately 7.1 mD for the Lower San Andres. Permeability was derived using Lucia's carbonate permeability estimation method. A continuum of rock-fabric numbers, or petrophysical classes, can relate interparticle porosity and permeability using a global transform representative of grain size and sorting for limestone and dolostone rock types (Lucia, 2007). This permeability estimate will be confirmed once the wells are drilled.

Figure 1-25 shows the continuum of rock fabrics and associated porosity-permeability transforms: (a) fabric continuum in nonvuggy limestone; (b) fabric continuum in nonvuggy dolostone; and (c) rock-fabric numbers (rfn) ranging from 0.5 to 4, defined by class-average and class-boundary porosity-permeability transforms (Lucia, 2007).

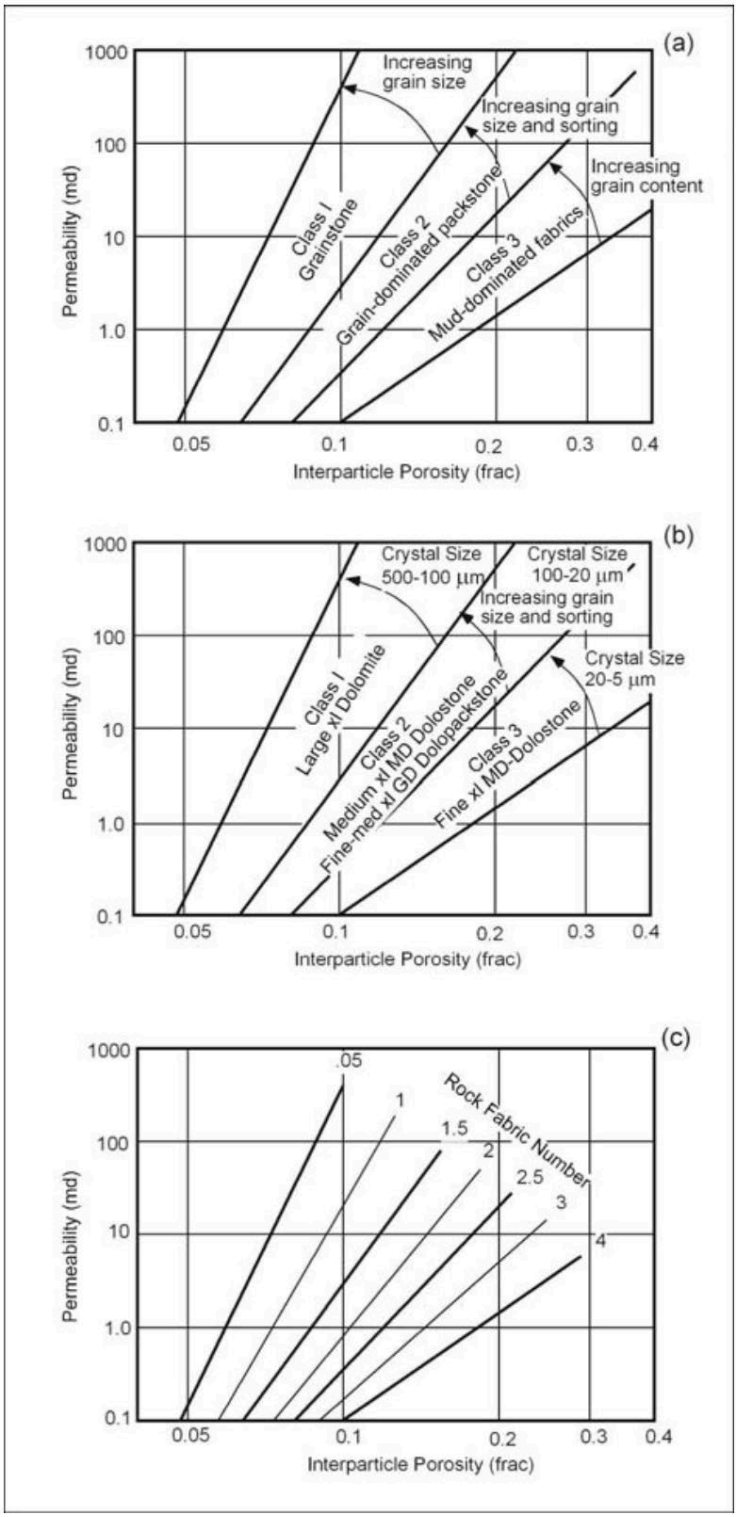


Figure 1-25 – The continuum of rock fabrics and associated porosity-permeability transforms: (a) fabric continuum in nonvuggy limestone; (b) fabric continuum in nonvuggy dolostone; and (c) rfn ranging from 0.5 to 4 defined by class-average and class-boundary porosity-permeability transforms (Lucia, 2007).


Claimed as PBI


Claimed as PBI



1.3.2.5 Water Saturation

The presence of a residual oil zone (ROZ) over much of the San Andres is well documented (Kuuskraa, Petrusac, & Wallace, 2020). That report, along with its associated supporting data (Kuuskraa, Petrusak, & Wallace, ROZ Database, 2020), includes a section ("2.10 Partition #5.") describing ROZ properties in eastern Gaines County, where the Orchard project is located.

The sidewall core samples for API No. 42-165-38785 show oil saturations throughout the injection zone. The range in values of oil saturations is 2 to 19% with a median value of 15.5%. Correcting for bottomhole conditions with a FVF of 1.2 to account for dissolved gas results in an in-situ median oil saturation value of 18.6%. This corresponds well to the characteristics of the "low-quality ROZ" from the report referenced above, which described the low-quality ROZ as having oil saturations of 17% and 16% respectively for eastern Gaines County.

The dynamic model was initialized with an immobile oil saturation of 19% throughout the injection zone.

1.3.3 Primary Upper Confining Zone

The top portion of the Upper San Andres formation, along with the Grayburg formation, comprise the primary confining zone overlying the injection zone. The combined thickness of the Upper San Andres and Grayburg confining zone is approximately 440 to 575 ft in the Orchard Project area. The top depths range from -1,425 to -1,760 ft TVD SS and bottom depths are approximately at -1,880 to – 2,235 ft TVD SS.

Figure 1-28 shows a depth structure map for the top of the San Andres formation (mid-upper confining zone). (For reference, Figure 1-17 in *Section 1.3.2* showed a depth map of the base of the confining zone (top of the injection zone)). Figure 1-29 shows a thickness map of the upper San Andres portion of the upper confining zone. Figure 1-30 is a structure map of the top of the Grayburg formation (top of upper confining zone). Figure 1-31 shows a thickness map for the Grayburg formation and Figure 1-32 is an isopach of the aggregate Grayburg and Upper San Andres primary upper confining zone.

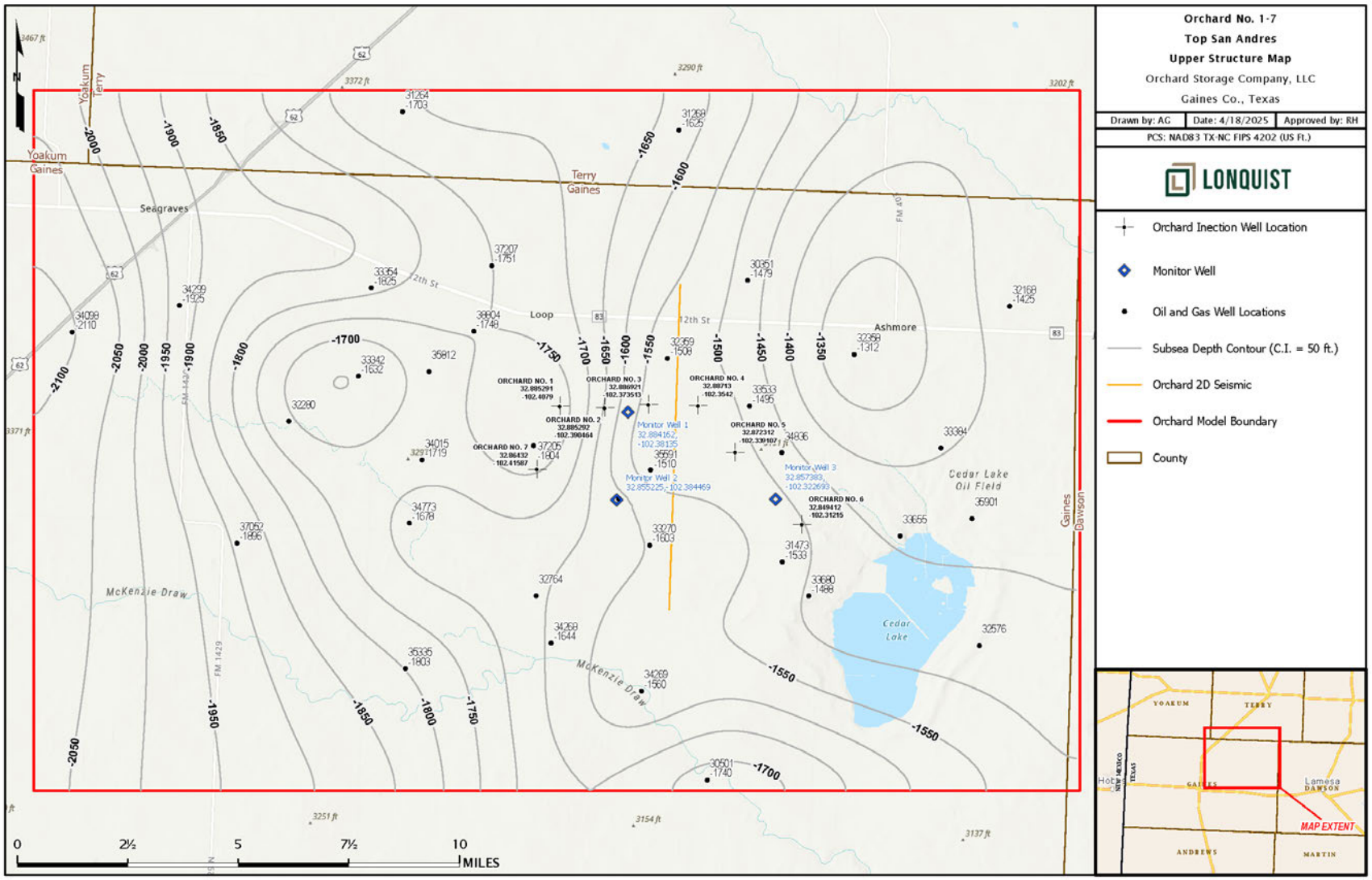


Figure 1-28 – Depth structure map (TVD SS) for the top of the San Andres formation (middle of upper confining zone).

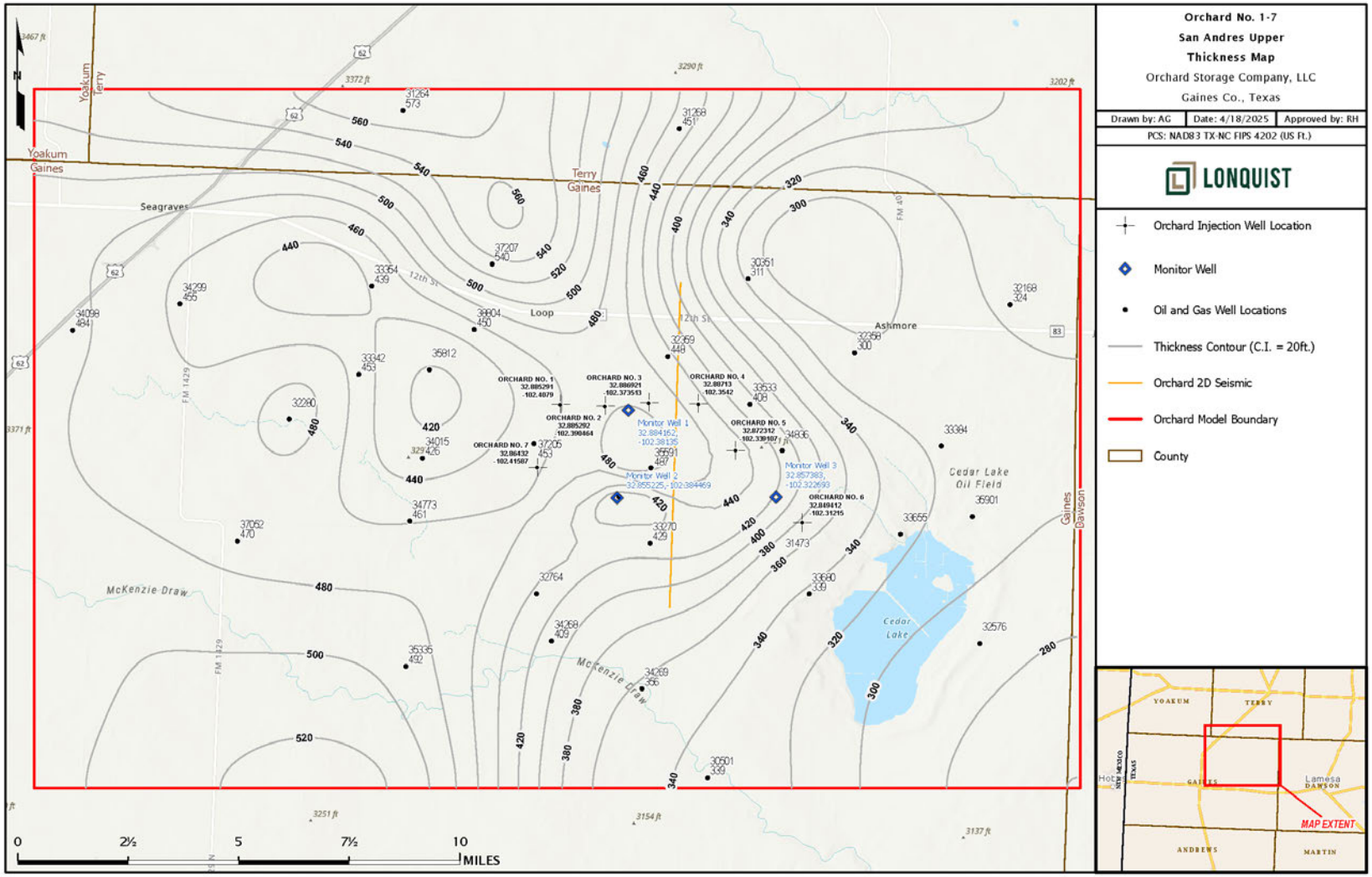


Figure 1-29 – Thickness Map of the Upper Confining Zone

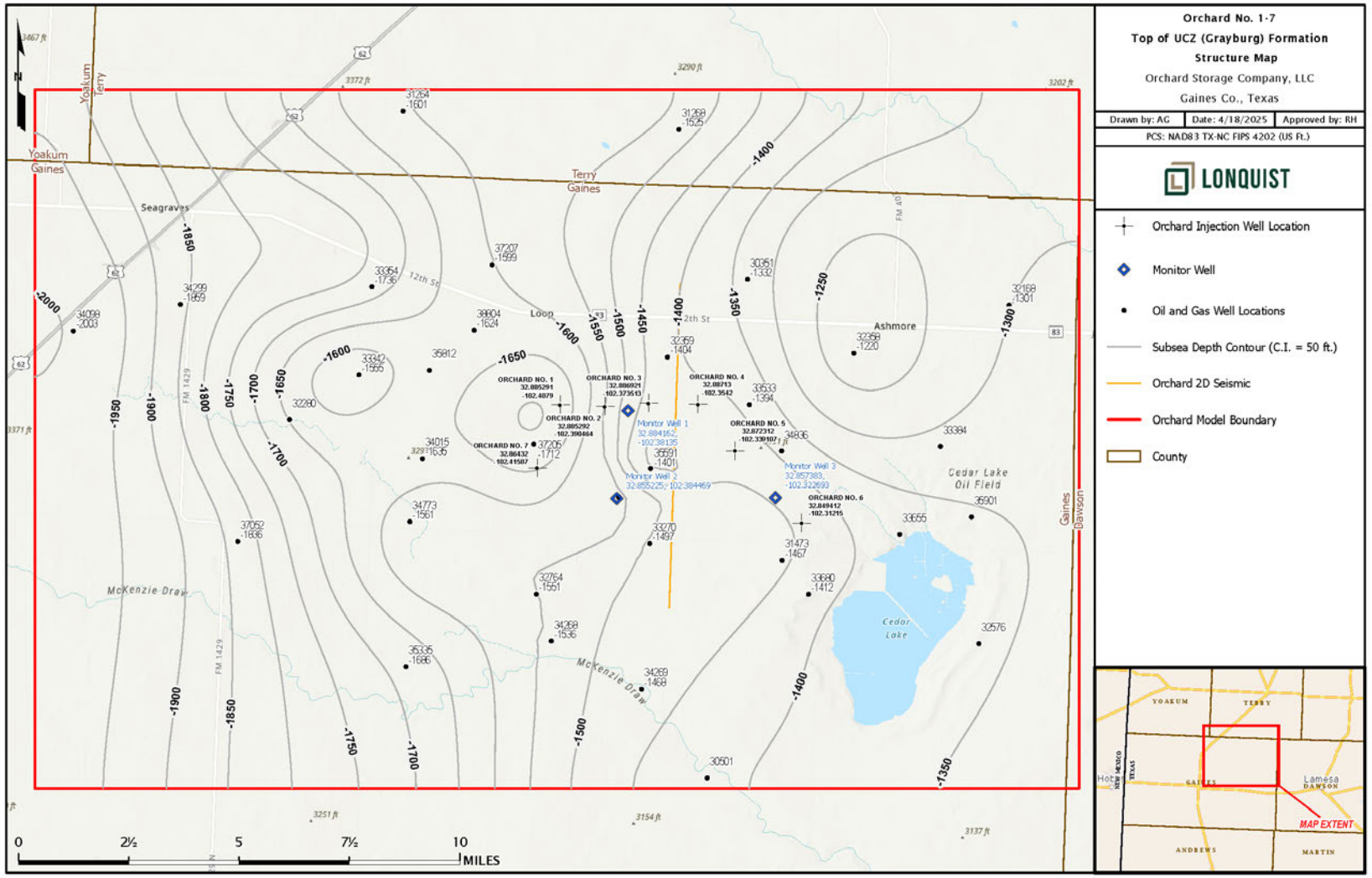


Figure 1-30 – Depth structure map (TVD SS) for the top of the Grayburg formation (top of confining zone).

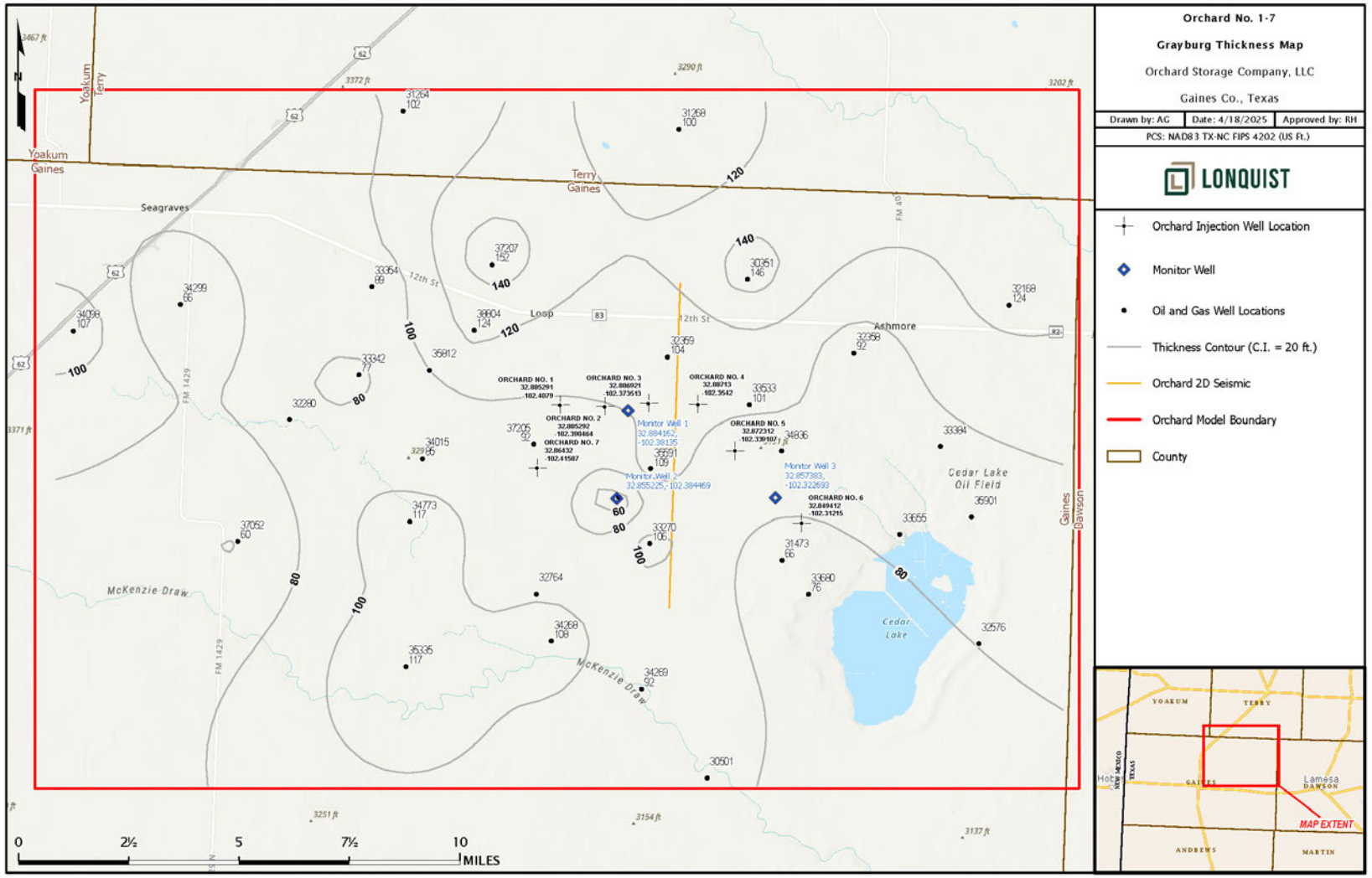


Figure 1-31 – Thickness Map of the Grayburg

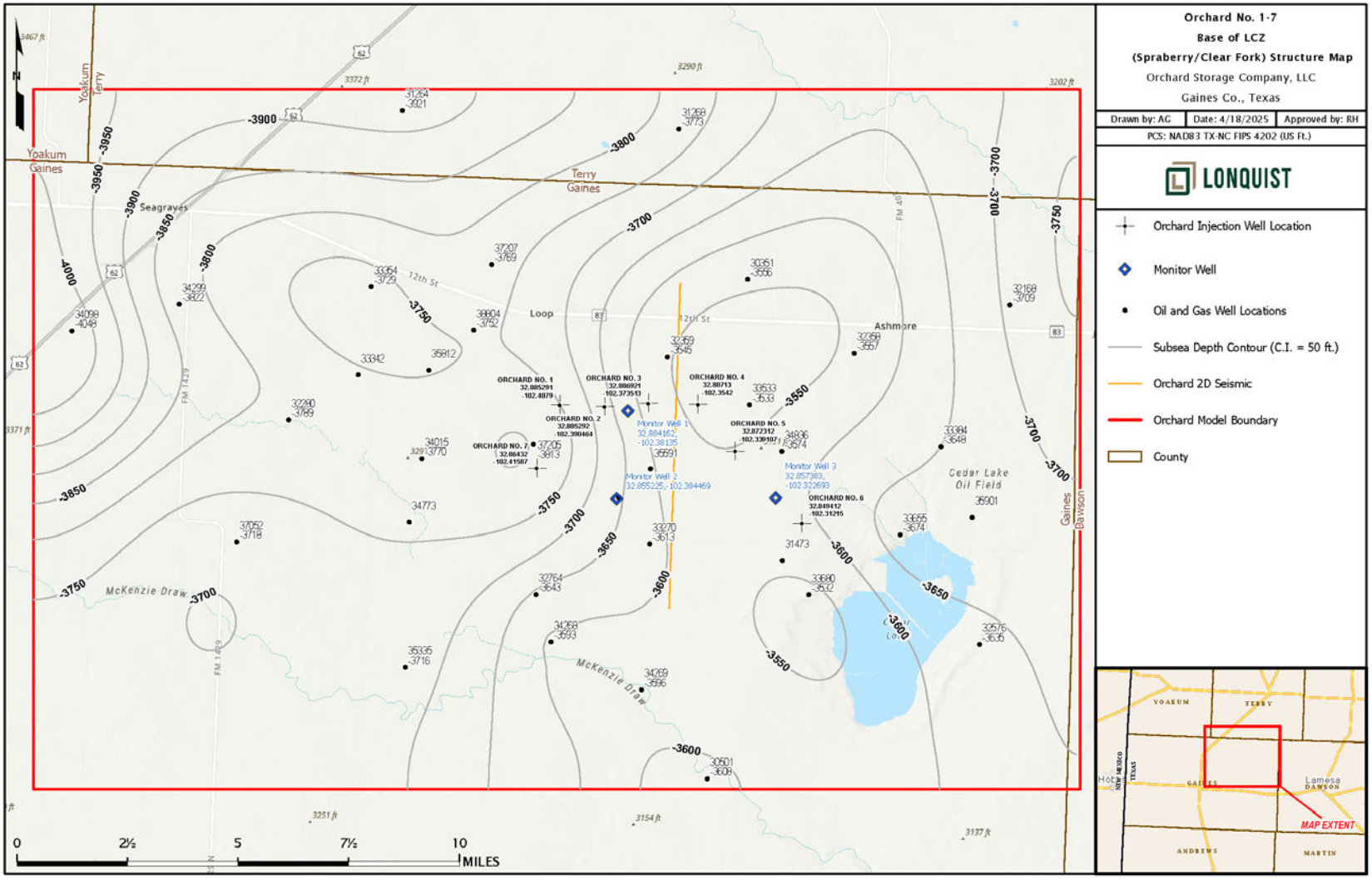


Figure 1-32 – Isopach Map of Combined Upper San Andres and Grayburg formations (gross UCZ thickness).

1.3.3.1 Lithology

The primary upper confining zone in the Orchard Project area will prevent the migration of injected CO_2 from the injection zone to shallower geologic intervals and USDWs. The sealing integrity is high due to the dominant lithological characteristics based on core, well log, and subsurface analog data.

The San Andres and Grayburg formations combine predominantly dolomitic beds with anhydritic alteration, both caused by diagenesis. High-frequency cycles of this interval exhibit depositional textures and rock types associated with inner ramp settings, commonly lagoonal, intertidal, and supratidal. This interval is laterally homogenous and vertically heterogeneous over the region, indicating effective confinement wider than the scope of the project area.

Figure 1-33 shows a cross section of wells API No. 42-165-34836, 42-165-31473 and 42-165-33680. The middle well (42-165-31473) has 107 ft of slabbed core in the lower part of the confining zone. The core in the lower part of the confining zone demonstrates the transition of lithofacies from the injection zone up into the beginnings of a confining zone. Figure 1-34 shows a map of the location of the cross section in Figure 1-33.

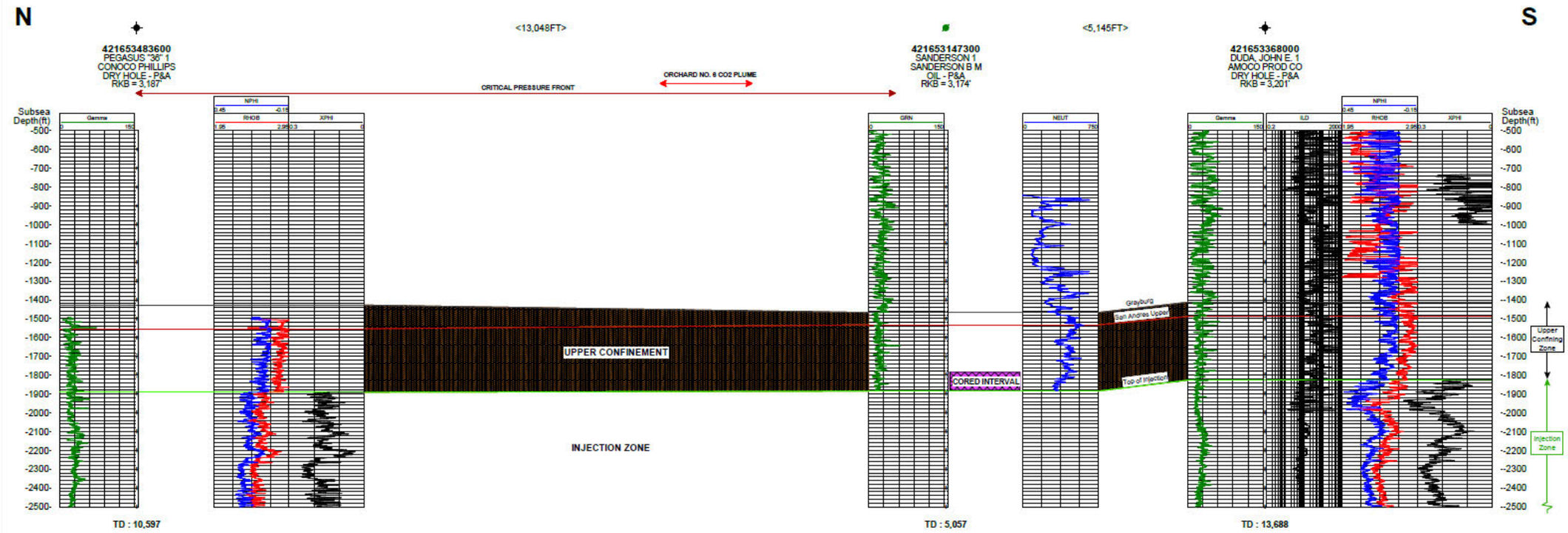


Figure 1-33 – A cross section of wells API No. 42-165-34836, 42-165-31473 and 42-165-33680, from left to right. The middle well has 107 ft of slabbed core in the lower part of the upper confining zone.

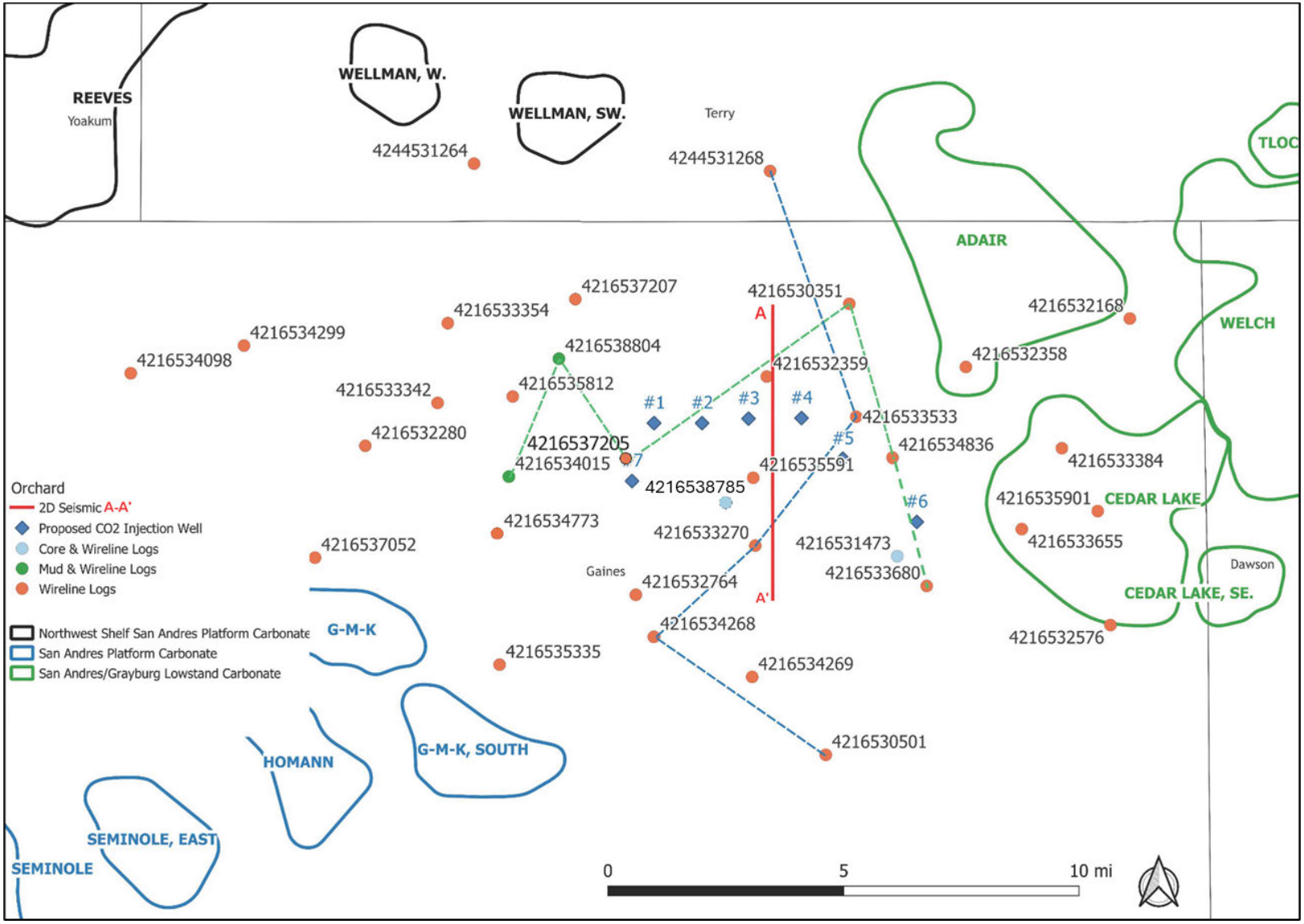


Figure 1-34 – Map showing the location of the cross section shown in Figure 1-33 (black dashed line) and the north-south 2D Seismic Line (A-A' in red color) shown on Figures 1-53, 1-54 and 1-55.

The site-specific slabbed core from API No. 42-165-31473 was photographed, and six core plugs were acquired every 20 ft for Core Lab Houston to further analyze. No petrophysical analysis was performed. Although the neutron log was relatively old, it showed a transition between two wells to the north and south of the cored well. Higher neutron-count readings indicate lower porosity.

The location of the core on the southeastern side of the Orchard Project area (and within the Cedar Lake field vicinity) demonstrates the beginnings of a transition of the basal part of the confining zone's lithofacies. This transition shows gradual improvement in reservoir quality toward the southeastern side of the project area and beyond. For example, well logs for API No. 42-165-33680 show improvements at approximate depths of 4,925 ft and 5,000 ft, compared to API No. 42-165-34836 on the eastern side of the project area.

The hydrocarbon-producing fields several miles east of the Orchard Project (e.g., Adair, Cedar Lake) typically target production from these younger sequences, which contain lithofacies tied to higher-energy ramp-crest settings (e.g., grainstones, as previously shown in schematics of the San Andres carbonate ramp model based on outcrop). In the project area, however, the well logs exhibit a laterally consistent, low-porosity lithofacies in the basal part of the confining zone representative of a lower-energy setting, reflected in Figures 1-20 and 1-21 (in *Section 1.3.2*).

The six thin sections from the core were described, and the slabbed core was observed and photographed (shown in Figures 1-35 through 1-46). These vertical core plug samples demonstrate how the basal part of the confining zone to the east of the Orchard Project area is highly heterogeneous and predominantly very low porosity.

Figure 1-35 shows a thin section from [redacted] Claimed as PBI [redacted].


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

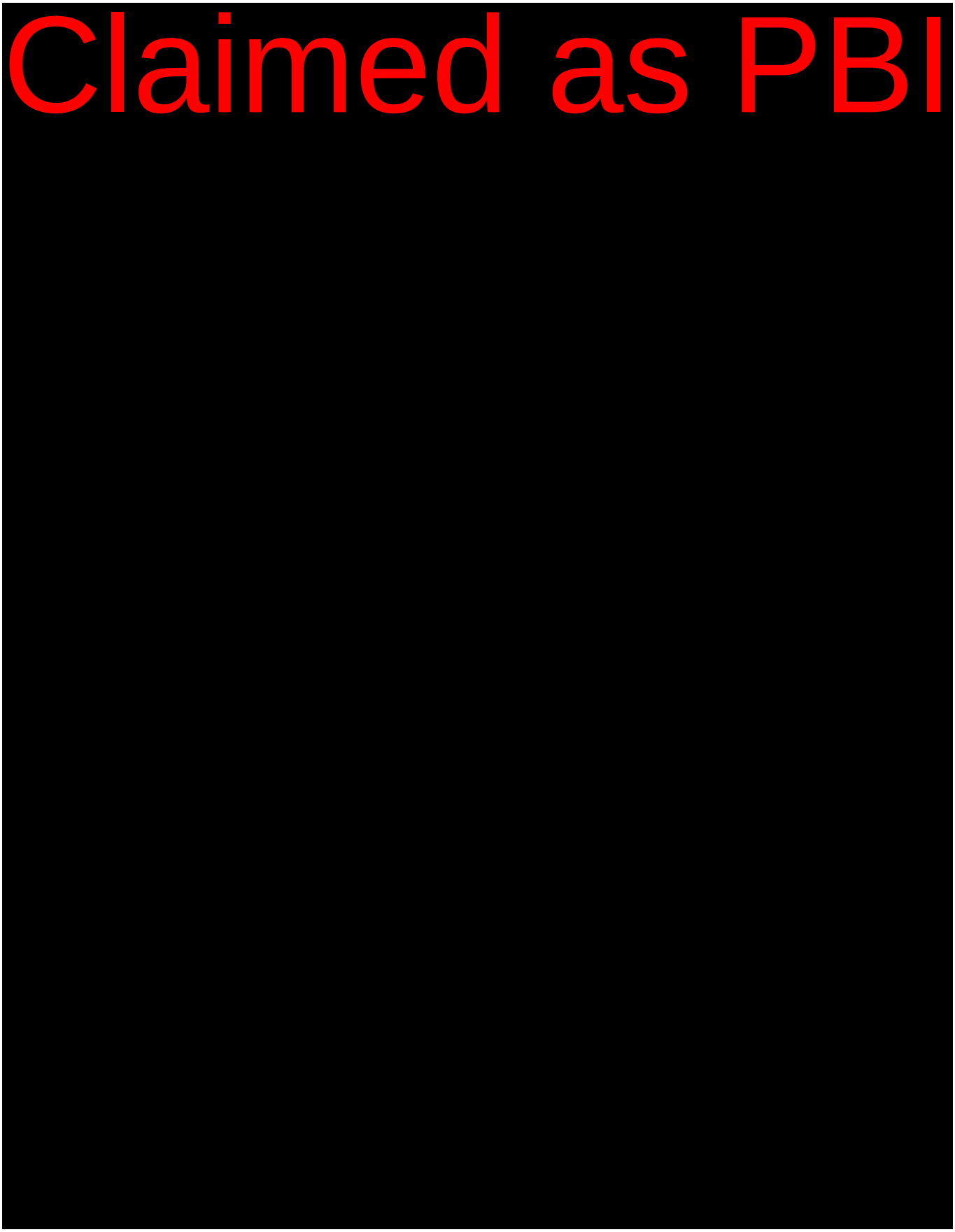

Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

Claimed as PBI




Claimed as PBI


Claimed as PBI


Claimed as PBI


Claimed as PBI

The shallowest plug acquired from this core (as was shown in Figure 1-37) is helpful as representing the dominant lithofacies to expect within the Orchard area (from the base to the top of this confining zone). Thin sections showing higher-porosity and higher-energy lithofacies are related to the transition of the basal part of this sequence, as discussed above.

Furthermore, field-specific and regional-scale publications have featured this confining zone as a relatively thick interval with high sealing integrity, to prevent injected CO_2 (or in situ hydrocarbons) from migrating vertically into shallower formations.

1.3.3.2 Porosity

Density porosity was derived using the bulk density log and an estimated matrix density for the upper confining zone. The matrix density assumed a dominant mineralogy of dolomite (2.87 g/cm^3) for the top of the Upper San Andres. The fluid density used was 1.1 g/cm^3. The density porosity was averaged with the limestone neutron-porosity log to derive XPHI.

Minimal correction was needed for shale (i.e., clay and silt) effects. This was based on the very low potassium-thorium gamma ray log values. Uranium is the main driver for relatively higher (10-30 GAPI) gamma-ray values (i.e., total and effective porosity are treated similarly). Uranium is usually diagenetic and unrelated to depositional facies or rock fabric (Lucia, 2007).

The average porosity derived from well logs using this approach is approximately 3% in the confining zone. The lowest porosity is in the upper half of the confining zone. No average map of porosity in this confining zone was created; however, low porosity was observed in wells surrounding the proposed Orchard No. 1–No. 7 locations (e.g., API No. 42-165-38804, 42-165-33533, 42-165-33270, 42-165-34015, and 42-165-35591). Furthermore, the nearest well (API No. 42-165-37205) provides a qualitative data point. Although no petrophysical analysis was completed due to a lack of neutron-density logs, the high resistivity values (and lack of separation between deep and shallow curves) look similar to adjacent wells and indicate low porosity rock.

Porosity was not visible within the slabbed core sample of well API No. 42-165-31473. No secondary porosity features that would breach the containment of CO_2 in the injection zone, such as major dissolution porosity or fractures (indicating shear fractures or fracture networks in the vicinity), were observed in the core.

1.3.3.3 Permeability

The average calculated matrix permeability for the confining zone is null, based on the average calculated porosity. A review of Lucia's porosity permeability transform for the various rock fabrics indicates that permeability cannot be determined for porosity less than 5%. The confining interval core analysis indicates a very low permeability, typical of suitable confining intervals. This confining zone permeability will be revisited once wells are drilled and new core is obtained in the confining interval.

A closer examination of the confining zone shows vertical heterogeneity causing well log porosity to vary significantly. Further work to characterize these beds via conceptual and numerical modeling is discussed in *Section 1.10*.

Claimed as PBI


Claimed as PBI

Claimed as PBI

1.3.3.4 Water Saturation

The upper confining zone is assigned 100% water saturation with the same salinity as the injection zone.

1.3.4 Primary Lower Confining Zone

The Glorieta/Leonard Upper formation is the primary lower confining zone beneath the injection zone. The thickness of this lower confining zone is approximately 350-390 ft in the Orchard Project area. The top of the lower confining zone ranges from -3,175 to -3,400 TVD SS and the base ranges from -3,585 ft to -3,790 ft TVD SS in the Orchard Project area. No core or equivalent was available for integration into this site characterization.

Figure 1-49 shows a depth map of the base of the Glorieta/Leonard Upper formation (lower confining zone). (For reference, Figure 1-18 in *Section 1.3.2* provided the depth map to the base of the injection zone, which is the top of the lower confining zone.) Figure 1-50 shows a thickness map of the Glorieta/Leonard Upper formation.

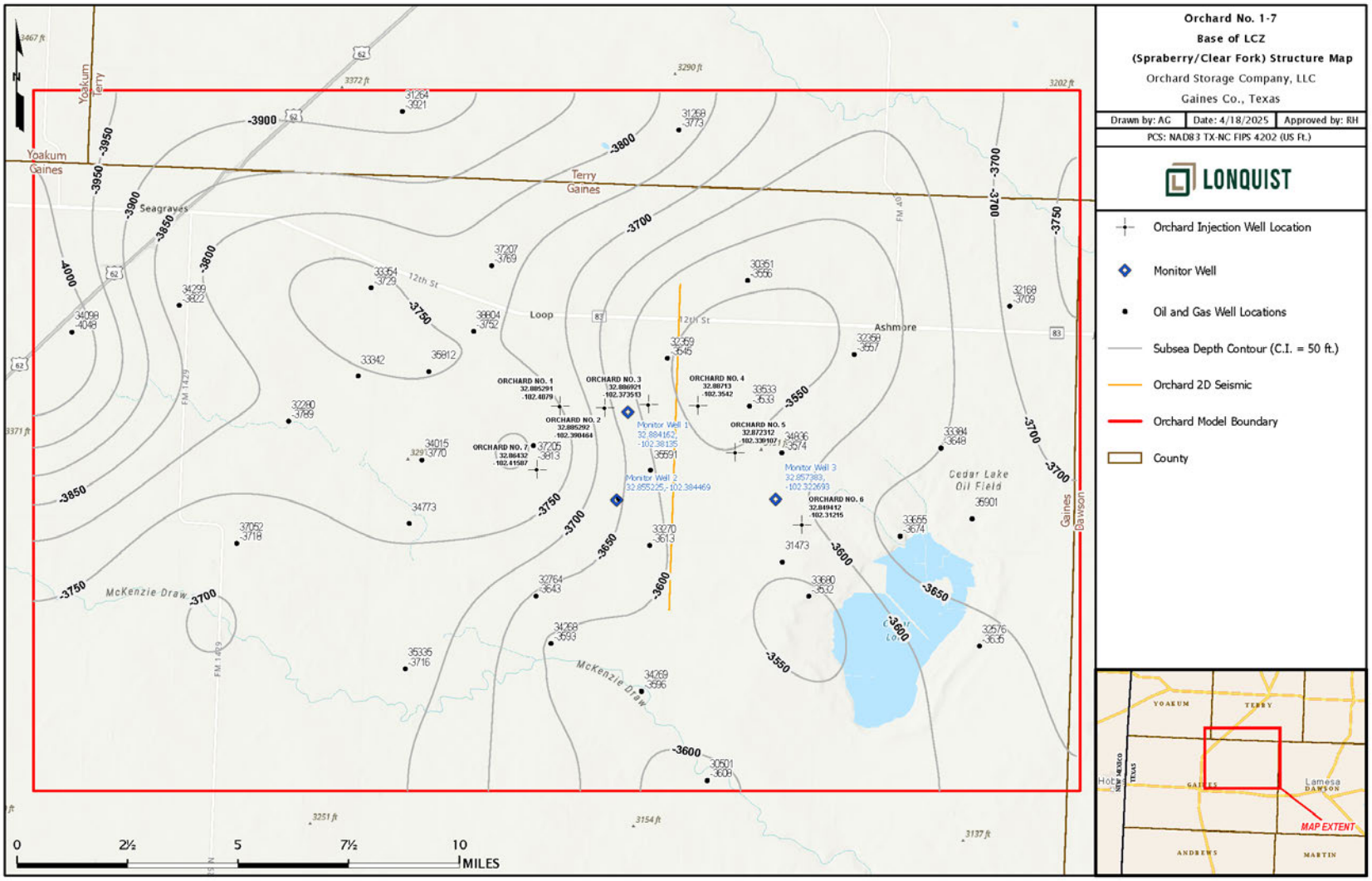


Figure 1-49 – Depth structure map (TVD SS) of the base of the Glorieta/Leonard Upper formation (lower confining zone).

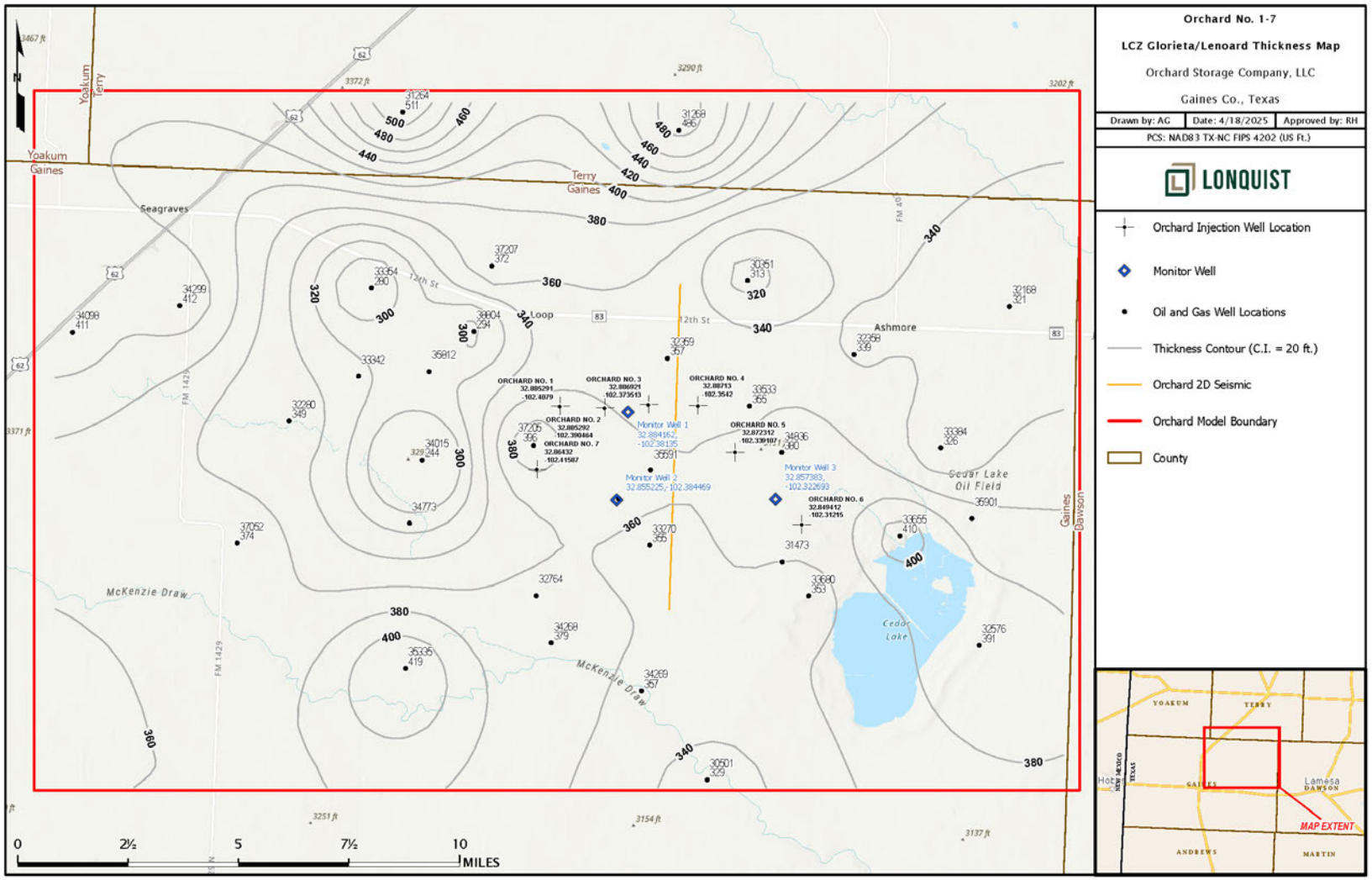


Figure 1-50 – Thickness map of the Glorieta/Leonard Upper formation (lower confining zone).

1.3.4.1 Lithology

The Glorieta/Leonard Upper formation is predominantly calcitic, with interbedded dolomitic and clastic beds, based on wireline and mud log data across the Orchard Project area. As Figures 1-21 and 1-22 showed (in *Section 1.3.2*), the confining zone quality is good within the project area. Heterogeneity begins to appear outside that area, likely due to regional depositional changes from shelf to basin.

Figure 1-51 shows a simplistic depiction of a cross section north-south to the east of the Orchard Project vicinity, illustrating the dominant lithology changes across the Midland Basin, from the Pennsylvanian unconformity to the Glorieta/Leonard Upper formation.

Figure 1-52 provides a snapshot of the mud-log sample lithologic interpretation for the Glorieta/Leonard Upper formation (lower confining zone) between approximately 6,825-7,070 ft MD from API No. 42-165-34015. This interval is dominantly limestone but interbedded with clastic, dolomitic, and anhydritic beds. The complete mud log is included in Appendix K.

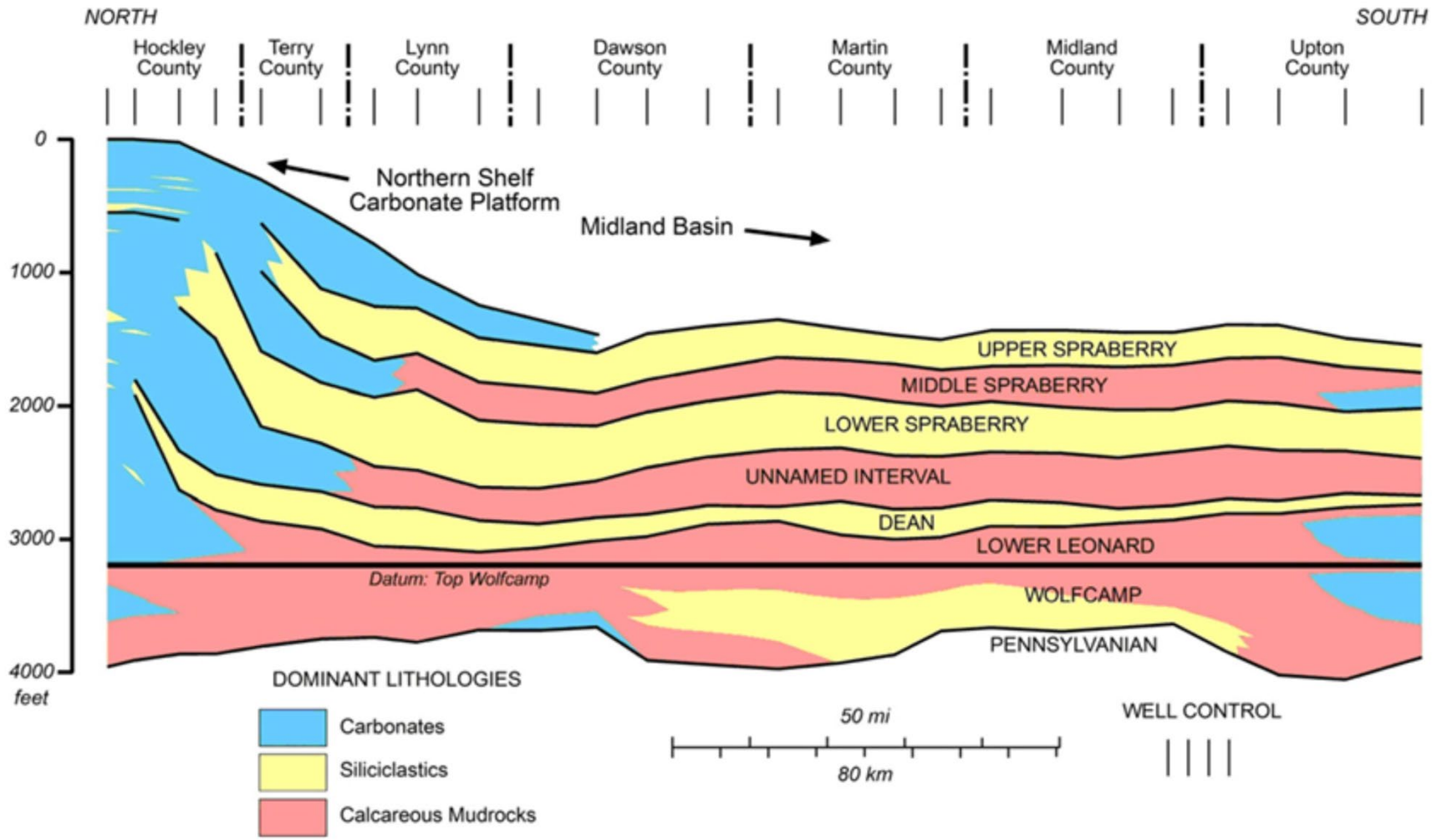


Figure 1-51 – Simplified depiction of a cross section oriented north-south to the east of the Orchard Project vicinity. It shows the dominant lithology changes across the Midland Basin, from the Pennsylvanian unconformity to the Glorieta/Leonard Upper formation.

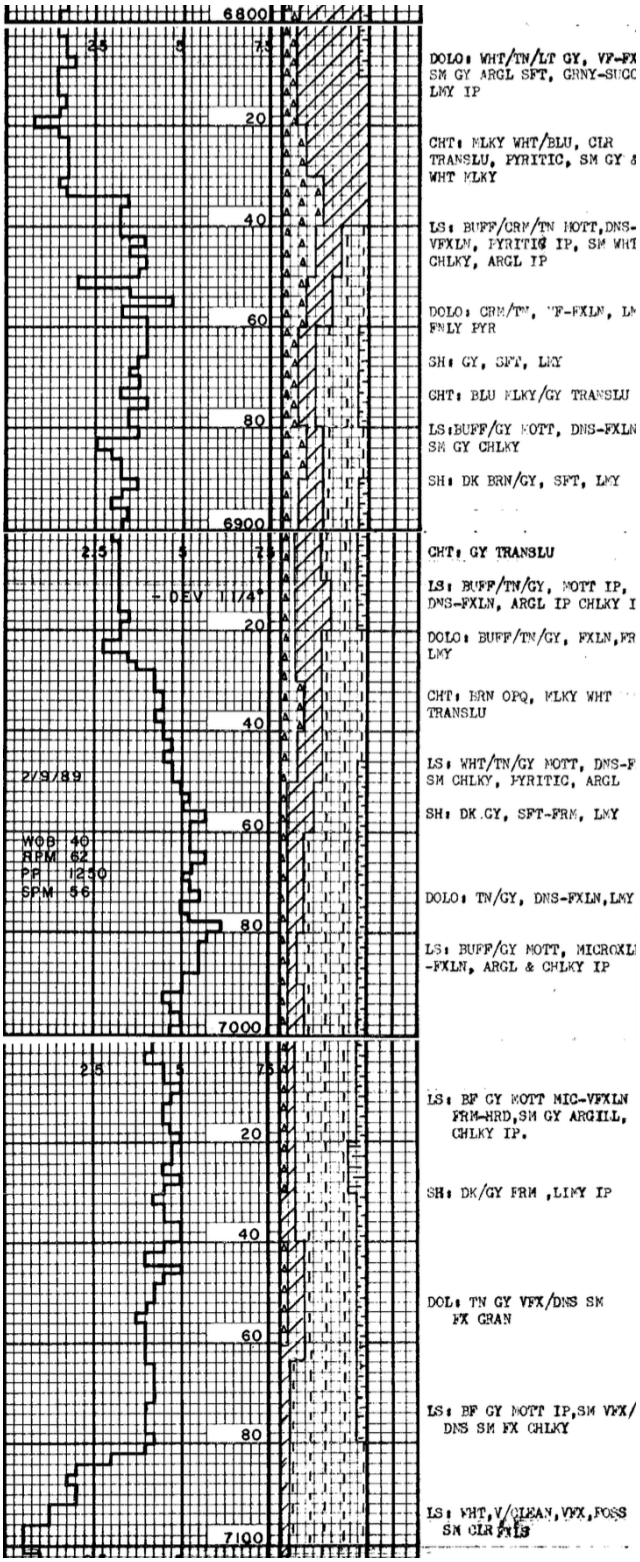


Figure 1-52 – A snapshot of the mud-log sample lithologic interpretation (Track 2) for the Glorieta/Leonard Upper formation (lower confining zone) between approximately 6,825-7,070 ft MD from well API No. 42-165-34015.

1.3.4.2 Porosity

Density porosity was derived using the bulk density log and an estimated matrix density for this confining zone. The matrix density assumed the dominant mineralogy of limestone (2.71 g/cm^3). The fluid density used was 1.1 g/cm^3. The density porosity was averaged with the limestone neutron-porosity log to derive XPHI.

Minimal correction was needed for shale (i.e., clay and silt) effects. This was based on the very low potassium-thorium gamma ray log values. Uranium is the main driver for relatively higher (10-30 GAPI) gamma-ray values (i.e., total and effective porosity are treated similarly). Uranium is often diagenetic and unrelated to depositional facies or rock fabric (Lucia, 2007).

The average porosity derived from well logs using this approach is approximately 4% in the confining zone. The porosity is consistent vertically, based on API No. 42-165-38804. However, the closest well (API No. 42-165-37205) shows separation between resistivity log curves (deep and shallower) in the upper portion, indicating some beds possible with high porosity or an incorrect well top pick (i.e., could be deepened by approximately 90 ft). Furthermore, increased porosity and vertical heterogeneity are evident in wells located in multiple directions outside the Orchard Project area.

1.3.4.3 Permeability

The average calculated matrix permeability for the confining zone is null, based on the average calculated porosity. A review of Lucia's porosity permeability transform for the various rock fabrics indicates that permeability cannot be determined for porosity less than 5%.

1.3.4.4 Water Saturation

The lower confining zone is assigned 100% water saturation with the same salinity as the injection zone.

1.4 Site Structure, Stratigraphy, and Deposition: 2D Seismic Integration

Two-dimensional seismic data was integrated with well log data to create the 3D geologic framework within the Orchard Project area. Seismic data was also used to tie in to the regional geologic structural and stratigraphic models. The data also offered additional quality control of the stratigraphic interpretation.

Figure 1-53 shows a 7.2-mile long 2D seismic line running north-south (A-A') through the Orchard Project area. The location of the 2D seismic line is shown on Figure 1-34. The nearby well API No. 42-165-33270, located approximately 0.4 miles to the west of the line, was used as a pseudo-well to perform a seismic-to-well tie ("pseudo-well tie"). This pseudo-well related well-log data to seismic data, in two-way travel time, to develop a synthetic seismic model to assist with interpreting seismic horizons. The location of the pseudo-well is approximately common depth point (CDP) 493.



Figure 1-53 – [redacted] 2D seismic line running north (left) to south (right) through the Orchard Project area. The Y-axis is two-way travel time (milliseconds) and the X-axis is CDP traces.

Tying well log data to seismic surveys involved forward modeling of a synthetic seismogram, derived from sonic and density well-log data. The seismogram was used to generate "normal reflectivity," reflection coefficients, and acoustic-impedance log curves. There is an absence of density and acoustic impedance in nearby wells for intervals shallower than the San Andres formation. Nevertheless, the synthetic seismogram was visually matched to the seismic-reflection wavelets data. This match resulted in a time-to-depth relationship while considering the following:

- Well-log data quality
- Seismic data quality
- Handling of seismic data at shallow depths
- Handling of seismic wavelet data

The seismic-to-well tie allowed for selection of seismic horizons that either matched well log data and well tops or were not observable on well log data or current well tops—but were visible on the seismic data. The interplay of basement-rooted major faults with carbonate and clastic depositional trends controls major geologic structures across the Permian Basin subdivisions. The proposed Orchard Project area is in the northwest portion of the Midland Basin, in an area representing the shelf-to-basin transition away from the Northwest Shelf and Central Basin Platform. Regional dip through the project site is reflective of local and regional controls.

The following discussion on structure, stratigraphy, and deposition is related to the 2D seismic evaluation and its integration with well log data and the regional geologic framework.

Figure 1-54 shows the same 7.2-mile long 2D seismic line (A-A') from Figure 1-53—with API No. 42-165-33270 used to complete a pseudo-well tie—but with interpreted horizons and faults. The bold-line seismic horizons are high confidence and/or correlate to well tops, whereas the dashed-line seismic horizons have lower confidence and/or do not match a well top. The well log from API No. 42-165-33270 shows gamma ray (at left) and acoustic impedance (calculated from sonic, at right). The acoustic impedance well log is colored in discrete scale by photoelectric factor log values. All large-scale (i.e., observable on seismic data) fault tips are deeper than the lower confining zone. The fault interpretation correlates to the regional fault model where most tectonic deformation ends in the Guadalupian time.



Figure 1-54 – The [redacted] 2D seismic line from Figure 1-53, but with interpreted horizons and faults shown.

This 2D seismic line trajectory (north to south) is roughly perpendicular to the dominant regional depositional trend (of shelf-to-basin from northwest to southwest). The seismic interpretation objective was to identify low- and high-frequency depositional sequences in the north-south direction through the Orchard Project site and wider area. The aim was to understand and explain these sequences' lateral or vertical changes that may affect efficient CO_2 injection and storage in the San Andres injection zone and possible secondary injection targets, as described in *Section 1.3*.

1.4.1 Horizon Interpretation

Several seismic horizons were interpreted from the Yates to the Pennsylvanian on the 2D seismic line (A-A'). Most seismic horizons matched the well tops in well API No. 42-165-33270. The tops of the Upper and Lower San Andres were interpreted as high-confidence seismic horizons for the upper confining and injection zones. The top of the injection zone and the top and base of the lower confining zone were interpreted as lower-confidence seismic horizons. Deeper and shallower seismic horizons than the injection and confining zones were mostly interpreted as high-confidence picks.

As was displayed in bold lines in Figure 1-54, the injection and confining zones show continuous seismic horizons. The dashed lines illustrate the effect of high-frequency cycles and lateral variations of lithofacies within the injection and lower confining zones (and below). Several dashed lines likely represent and correlate to higher frequency surfaces (associated with either transgression or highstand or lowstand periods) within the San Andres and Glorieta/Leonard Upper formations, rather than the current well-top stratigraphic framework. At least four seismic horizons were observed between the Upper and Lower San Andres tops.

Claimed as PBI

As mentioned above, the San Andres top is a high-confidence seismic horizon matching well log data and well top picks. The upper confining zone is represented between the "SanU" and "SAN_mid" (nomenclature used by the seismic interpreter) on the 2D seismic line. This low porosity interval's continuity and consistent thickness across the whole seismic line are suitable.

The interpreted well top of the Glorieta and Leonard Upper does not correlate definitively to one seismic "event" pickable across the entire seismic line with high confidence. The blue dashed seismic horizons that were displayed in Figure 1-54, near the well top pick in the pseudo-well, have a few minor gaps in interpretation across the seismic line. The seismic expression is likely due to the Orchard Project area representing a *microcosm* of shelf-to-basin sedimentation and cyclical variations between clastic and carbonate deposition. This vertical heterogeneity observed on the seismic data continues down to the Spraberry and Clear Fork formations.

Figure 1-55 shows the API No. 42-165-33270 pseudo-well tie with well log data, a synthetic seismogram, and seismic data for comparison. Figure 1-56 shows the time-to-depth relationship for the pseudo-well tie.



Figure 1-55 – The same 2D seismic line from Figures 1-53 and 1-54, showing the [redacted] pseudo-well tie, with well log data, a synthetic seismogram overlayed, and seismic data for comparison.



Figure 1-56 – The time-to-depth profile, or relationship, used for the [redacted] pseudo-well tie.

The velocity model was derived from the sonic log and adjusted using replacement velocities above the top of the shallowest sonic depth (near the San Andres top). The time-to-depth relationship for the API No. 42-165-33270 pseudo-well tie is essentially a 1D velocity model. This model was derived from integrating (i.e., summing up) the sonic log slowness and manual adjustment, using the synthetic seismic correlation with the nearby actual seismic traces.

Analogous shallow velocities above the San Andres formation were obtained from well API No. 42-165-34098, located west of the Orchard Project area. The sonic log curve for this well has a shallower start depth. The velocities were lightly adjusted via stretching and squeezing—an adjustment that is smoother than inserting a single constant replacement velocity in the depths shallower than the San Andres formation, but not necessarily more accurate below the San Andres formation. The velocities are almost constant through the Queen formation to the Dean well tops. There are minor perturbations, but the major velocity variations are above the Yates and below the Dean formations.

Across the Orchard Project area, from north to south, there is relatively little change to the dip of all the seismic horizons. The dip angle of the injection zone top through the project area is approximately 1.5 degrees, with a dip azimuth directed to the west. The dip angle of the upper confining zone top through the project area is approximately 1.5 degrees, with a dip azimuth directed to the west. The dip angle of the lower confining zone top through the area is approximately 1 degree, also with a dip azimuth to the west.

Other seismic horizons mentioned in *Section 1.2* were identified to provide quality control of the seismic data and ensure valid injection and confining zone observations. The Pennsylvanian well top is a major unconformity across the Permian Basin area. No significant dip at the Pennsylvanian horizon was noticeable due to the 2D line (A-A') being perpendicular to the prevailing dip azimuth (to the southwest). The Horseshoe Atoll feature likely controls the dip angle and dip azimuth of deeper geologic formations (from Wolfcampian to Spraberry Upper) in that part of Gaines County.

Claimed as PBI

1.4.2 Fault Interpretation

No publicly available maps or other published sources of information were identified during this site characterization that indicated the existence of faults and fracture networks within the vicinity of the Orchard Project area. A thorough fault interpretation on the seismic 2D line was completed and tied to the regional structural model.

Fault tips are deeper than the lower confining zones. No faults were interpreted shallower than the Spraberry Lower. The fault interpretation correlates to the regional fault model, where most tectonic deformation ends in the Guadalupian time. Six possible faults have been identified, but fault displacement or throw appears relatively minor. The faults do not show a significant juxtaposition of different strata that would affect the confining or injection zones. No faults were observed between the wells used for well top picking (e.g., no major vertical offset between wells, and no missing or repeated intervals on the well logs).

The Permian Basin has been shaped by several extensional and contractional deformation events through geologic time (Horne et al., 2021). After several phases of contractional deformation across the Permian Basin due to continental tectonics (e.g., ancestral Rocky Mountain orogeny) up to the start of the Leonardian period, a subsidence regime from sediment accumulation dominates. Within the Orchard Project area, the faults are likely basement-rooted and truncated by the major unconformities of the Pennsylvanian and Wolfcampian. Basin-wide subsidence began in the Pennsylvanian period and persisted through tectonic deformation past the late Permian era (Ewing, 2019).

Figure 1-57 shows the tectonic events by geologic age for the Delaware Basin and Central Basin Platform (taken from Horne et al., 2021). Although the stratigraphy and sequences of the Guadalupian and Leonardian are not the same names as the Midland Basin, they are time equivalent to the Orchard Project area strata (e.g., Brushy Canyon is equivalent to San Andres and Glorieta).

Figure 1-58 shows a regional fault map. Researchers at the TexNet Seismic Monitoring and Center for Integrated Seismicity research group have made a concerted effort to better understand the causative hazards associated with induced seismicity across the state of Texas.

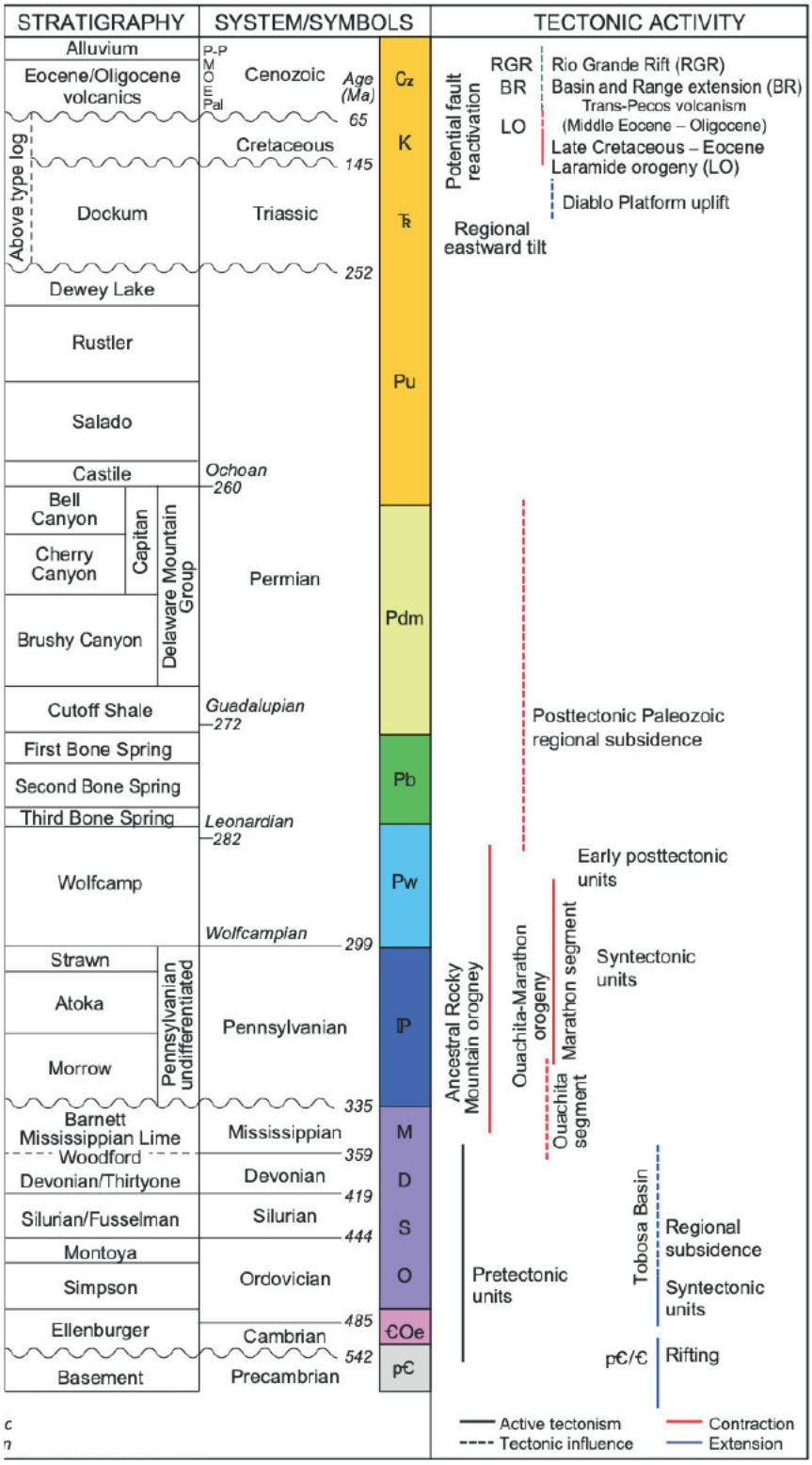
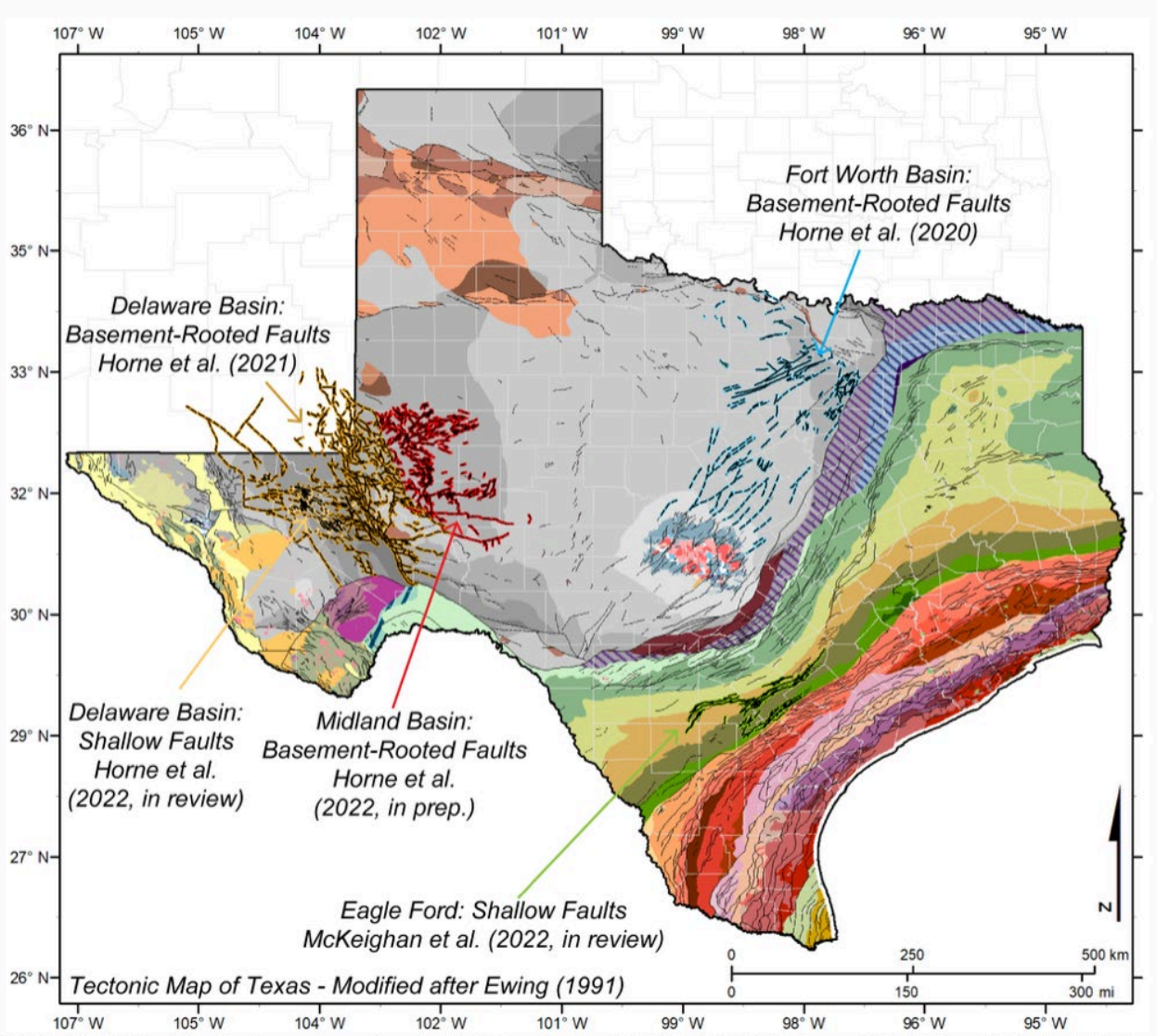


Figure 1-57 – Diagram showing tectonic events by geologic age for the Delaware Basin and Central Basin Platform (taken from Horne et al., 2021).



R1: TexNet-CISR principal fault mapping regions. Add links to sub-pages (Fort Worth Basin, Delaware Basin, Midland Basin, Eagle Ford, and supplemental materials).

Figure 1-58 – Regional fault map generated by researchers at the TexNet Seismic Monitoring and Center for Integrated Seismicity research group (https://www.beg.utexas.edu/texnet-cisr/fault-maps).

The 2D seismic-line trajectory (north-south) is roughly perpendicular to the dominant regional fault strike and the present-day stress (S_H maximum) direction. The present-day slip potential of this faulting regime (from Snee and Zoback, 2018) in this part of the Permian Basin is associated with the normal-type state of stress.

1.5 Geomechanics

Data from site-specific and publicly available publications were used to estimate the local stress conditions and fracture gradient for the project area. It should be noted that while these have been estimated for this application, actual in-situ stress conditions and fracture gradient will be determined from physical measurements as wells are drilled during the project execution phase.

1.5.1 Local Stress Conditions

The lithostatic, or overburden, stress (S_v) gradient used in the geomechanical model is 1.0 pounds per square inch (psi)/ft. The pore pressure gradient is estimated at 0.4 psi/ft. Additional discussion of the pore pressures anticipated for the project area can be found in Section 2.4.4 of the Section 2 – Plume Model portion of this application.

The azimuth of maximum horizontal stress (S_H maximum) in the Orchard Project area is approximately N105^{o}E (Snee & Zoback, 2018) as shown in Figure 1-61. This study also demonstrated that the principal stress regime is normal in the project area. The azimuth of minimum horizontal stress (S_h minimum) in the project area is predicted to be perpendicular to the S_H maximum.

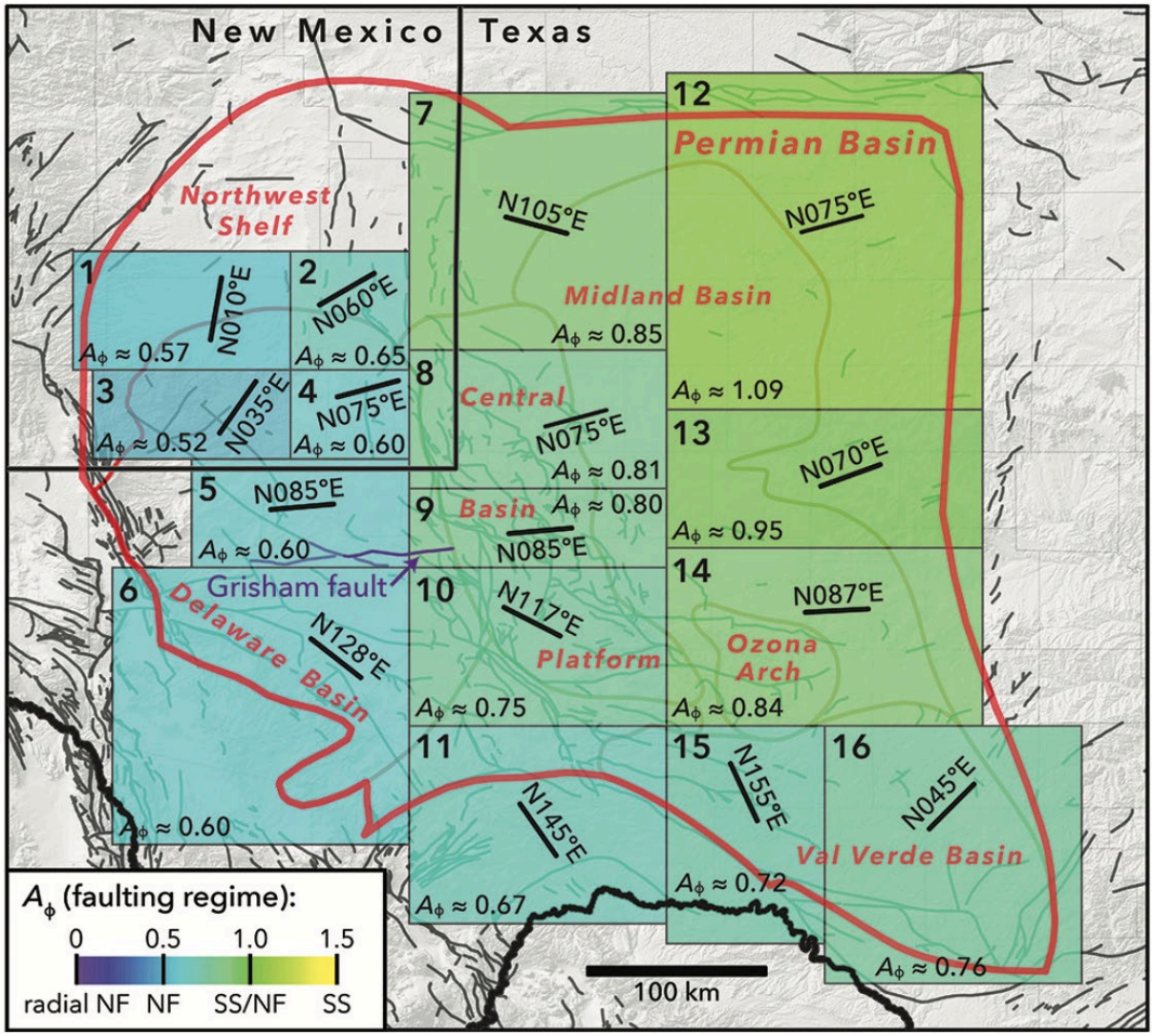


Figure 1-59 – Regional map showing the maximum horizontal stress orientation across the Permian Basin derived from a combination of well data and seismicity (Snee & Zoback, 2018).

1.5.2 Injection Zone Fracture Gradient

The fracture gradient for the injection zone has been estimated based on sonic log data (shear and compression) obtained in the Valiant No. 1D well (API No. 42-165-38785), located in the central part of the project area. In that well, data from the sonic logs were used to calculate Poisson's ratio which is used in the Eaton equation for calculation of minimum horizontal stress, corresponding to the pressure below which a fracture cannot propagate. This relationship is presented in the equation below:

$$S_{hmin} = \left(\frac{\nu}{1-\nu}\right) \times \left(S_v - p_p\right) + p_p$$

Where,

S_{hmin}	=	Minimum horizontal stress gradient (psi/foot)
ν	=	Poisson's ratio (dimensionless)
S_v	=	Overburden stress gradient (psi/foot)
P_p	=	Pore pressure gradient (psi/foot)

Applying this relationship to Poisson's ration data calculated from the shear-wave sonic log in the Valiant No 1D allows the calculation of the fracture pressure (or S_{hmin}) for every increment on which the well log data were recorded (in this case 0.5 feet). Figure 1-60 presents a probability distribution of the calculated fracture pressure (or minimum horizontal stress) gradients across the entire injection interval of the Valiant No. 1D. This plot is created where the vertical axis is the normal distribution function on the data, and the horizontal axis represents the data value. With this type of plot, a normal probability distribution will plot as a straight line. Reference lines for percentile values are shown with labels on the vertical axis.

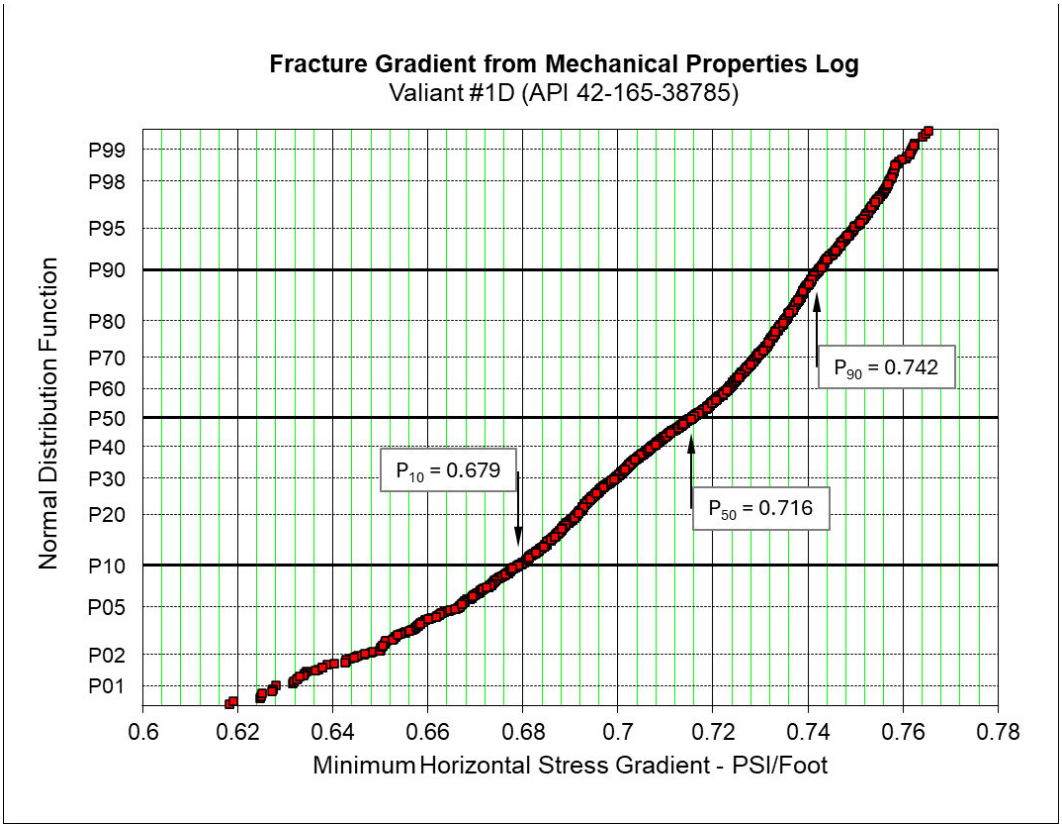


Figure 1-60 – Probability Distribution of Minimum Horizontal Stress from Valiant No. 1D

From these data it is seen that the fracture pressure gradient at the P_{10} , P_{50} , and P_{90} values on the distribution are 0.68, 0.72, and 0.74 psi/foot, respectively. The dynamic model was run with a maximum injection pressure limit set to 0.60 psi per foot, corresponding to 90% of a 0.67 psi/foot fracture gradient. It should be noted that the dynamic model results (discussed in Section 2) show the maximum injection pressures stay well below the set 0.60 psi/foot limit. The maximum gradient seen on any of the wells during the simulation run is 0.53 psi/foot.

1.6 Geochemistry

This section discusses the fluid and solid-phase geochemistry in the Orchard Project site and wider area.

1.6.1 Fluid Chemistry (Injection Zone)

Laboratory analyses of produced water from the San Andres formation in adjacent hydrocarbon fields have been used to understand the range and likely salinity of the injection zone water in the Orchard Project area. Figures 1-61 and 1-62 show examples of historical results from several laboratory analyses within the Gaines and neighboring Dawson counties. Further details are provided in *Section 3 – Area of Review and Corrective Action Plan*. The selected total dissolved solids (TDS, or equivalent), representative of the San Andres formation in the project area, is 59,000 parts per million.

TEXAS WATER DEVELOPMENT BOARD - SALINE WATER RESOURCES SURVEY OF THE STATE OF TEXAS

GAINES COUNTY

AVERAGE DEPTH FEET	TOTAL SOLIDS PPM	SODIUM (NA) PPM	CALCIUM (CA) PPM	MAGNESIUM (MG) PPM	CHLORIDE (CL) PPM	SULFATE (SO_4) PPM	BICARBONATE (HCO_3) PPM	IRON (FE) PPM	HYDROGEN SULFIDE (H_2S)	PH	SPECIFIC GRAVITY	GEOLOGICAL FORMATION	REF. NO.
					***** DEPTH RANGE 5001 - 6000 *****								
5032	61,953	11,132	7,360	4,880	36,900	1,450	231			3.0	1.057	SAN ANGELO	309J
5032	41,383	13,284	1,579	433	21,231	3,403	1,386			7.8	1.029	SAN ANDRES	315J
5032	82,016		8,770	4,690	55,065	4,008		540		4.3		SAN ANDRES	316J
5032	49,383	12,650	3,560	1,550	27,300	3,500	793		YES	7.2	1.049	SAN ANDRES	307J
5037	39,310	8,000	1,350	3,450	26,100	304	106			8.7	1.034	SAN ANDRES	298J
5060	41,214	13,386	1,514	408	21,200	3,843	831			7.4		SAN ANDRES	313J
5100	44,309	13,480	2,142	654	23,040	3,150	1,843			7.3	1.041	SAN ANDRES	249G
5100	103,140	22,800	3,050	9,200	65,600	1,650	840			7.4	1.082	SAN ANDRES	295J
5100	27,354	8,100	1,365	484	14,000	1,875	1,530			7.5	1.024	SAN ANDRES	303J
5100	44,330	14,700	1,750	505	25,100	1,485	790			7.7	1.036	SAN ANDRES	305J
5175	41,072	13,250	1,436	539	21,090	4,380	377			7.7	1.033	CLEARFORK	250G
5175	30,240	9,380	1,320	400	13,690	3,850	1,360			7.7	1.022	SAN ANDRES	322J
5200	29,635	6,580	2,310	1,410	15,650	1,945	1,740			6.7	1.022	SAN ANDRES	292J
5200	31,760	6,930	2,980	1,320	18,500	765	1,265			7.4	1.028	SAN ANDRES	293J
5200	251,553	79,500	2,100	11,000	158,200	495	258			7.4	1.208	SAN ANDRES	294J
5200	29,635	6,580	2,310	1,410	15,650	1,945	1,740			6.7	1.022	SAN ANDRES	297J
5200	64,280	15,220	5,530	2,430	38,300	2,800				5.0	1.050	SAN ANDRES	306J
5200	64,280	15,220	5,530	2,430	38,300	2,800				5.0	1.050	SAN ANDRES	308J
5225	48,317	15,430	1,321	940	24,400	4,850	1,376			7.7	1.032	SAN ANDRES	251G
5281	45,294				CALCULATED FROM RW = 0.149 AT 75 DEG (F)							SAN ANDRES	160C
5300	55,553	14,800	2,370	2,800	34,400	493	690			7.1	1.050	SAN ANDRES	302J
5375	39,742	12,010	1,984	718	21,730	3,121	179			7.3	1.031	SAN ANDRES	252G
5448	4,360				CALCULATED FROM RW = 1.290 AT 75 DEG (F)							MISSISSIPPIAN	768C
5475	9,500				CALCULATED FROM RW = 0.590 AT 75 DEG (F)							DEVONIAN	799C
5795	114,495	42,365	1,169	506	63,700	6,728	395	5		6.5		DEVONIAN	273J
5950	55,909				CALCULATED FROM RW = 0.122 AT 75 DEG (F)							GLORIETA	231C
5957	46,498	14,637	1,980	541	23,900	3,920	1,520	12		8.1	1.032	SAN ANGELO	361J
5984	76,154				CALCULATED FROM RW = 0.092 AT 75 DEG (F)							GLORIETA	230C
5994	23,208	2,769	4,081	418	7,180	2,920	5,840	5		7.9	1.020	DOLOMITE	362J
					***** DEPTH RANGE 6001 - 7000 *****								
6050	136,667				CALCULATED FROM RW = 0.058 AT 75 DEG (F)							GLORIETA	232C
6060	103,785	31,600	6,850	945	62,060	1,875	515			6.4	1.082	CLEARFORK	253G
6100	183,058	66,574	4,906	1,823	114,040	2,963	797	2		6.6	1.119	GLORIETA	274J
6100	170,540	42,150	13,200	6,800	107,500	680	210			5.6	1.136	GLORIETA	275J
6103	136,667				CALCULATED FROM RW = 0.058 AT 75 DEG (F)							CLEARFORK	314C
6103	120,455	35,300	9,960	1,018	71,800	1,710	667			6.7	1.100	CLEARFORK	254G
6115	98,735	30,950	4,480	930	59,100	2,800	475			7.0	1.075	GLORIETA	257J
6123	91,699	26,400	7,070	1,200	55,050	1,660	319			5.4	1.073	CLEARFORK	255G
6165	105,752	29,900	6,710	2,600	63,600	2,065	877			7.1	1.084	CLEARFORK	256G
6181	47,941				CALCULATED FROM RW = 0.140 AT 75 DEG (F)							GLORIETA	233C
6343	40,747	12,457	1,790	657	20,900	3,470	1,473	1	YES	6.6	1.030	CLEARFORK	249J
6370	25,614	7,454	1,380	434	11,460	3,200	1,440			7.7	1.017	SAN ANGELO	323J
6380	170,000				CALCULATED FROM RW = 0.050 AT 75 DEG (F)							UPPER CLEARFORK	366C
6420	168,678	41,050	2,424	14,490	107,500	2,912	302			7.0	1.147	CLEARFORK	257G
6455	213,606	66,350	1,933	9,810	130,700	4,241	572			7.2	1.170	CLEARFORK	258G
6536	60,794	9,022	7,270	4,370	38,400	1,500	232			3.2	1.058	SAN ANGELO	310J
6600	152,749	47,956	7,580	2,480	94,100	358	275			6.4	1.128	UPPER CLEARFORK	279J
6630		41,241	10,760	3,305	83,600	1,400	793			5.9	1.100	WASSON 6600	289J

Figure 1-61 – Tabulated records of water quality from the Texas Water Development Board's Saline Water Resources Survey of the State of Texas for Gaines County (1971).

TEXAS WATER DEVELOPMENT BOARD JUL 1971

SALINE WATER RESOURCES SURVEY

OF THE

STATE OF TEXAS

CHEMICAL ANALYSIS OF SALINE WATER

DAWSON COUNTY

AVERAGE DEPTH FEET	TOTAL SOLIDS PPM	SODIUM (NA) PPM	CALCIUM (CA) PPM	MAGNESIUM (MG) PPM	CHLORIDE (CL) PPM	SULFATE (SO4) PPM	BICARBONATE (HCO3) PPM	IRON (FE) PPM	HYDROGEN SULFIDE (H_2S)	PH	SPECIFIC GRAVITY	GEOLOGICAL FORMATION	REF. NO.
					***** DEPTH RANGE 1 - 1000 *****								
70	1,410	176	142	116	472	254	316			8.2		OGALLALA FORM	361A
488	7,434	302,472	90,252	85	104,200	384	403			7.0	1.055	SAN ANDRES	785J
					***** DEPTH RANGE 3001 - 4000 *****								
3930	133,036		4,760	1,652	79,200	2,624	525		YES	7.7	1.095	SAN ANDRES	230J
3930	120,155		4,240	2,017	71,000	2,857	1,000	29	YES	7.7	1.075	SAN ANDRES	2291
					***** DEPTH RANGE 4001 - 5000 *****								
4200	82,857				CALCULATED FROM RW = 0.085 AT 75 DEG (F)							SAN ANDRES	149C
4800			4,544	2,661	46,081	3,357				6.8	1.041	SAN ANDRES	239J
4835	83,077				CALCULATED FROM RW = 0.109 AT 75 DEG (F)							SAN ANDRES	148C
4916	81,429				CALCULATED FROM RW = 0.086 AT 75 DEG (F)							SAN ANDRES	150C
5000			5,900		63,000	5,400		5		7.0	1.048	SAN ANDRES	238J
5000	71,373	23,391	2,680	802	40,000	3,500	1,000			6.7	1.053	SAN ANDRES	991J
					***** DEPTH RANGE 5001 - 6000 *****								
5015			111	96	1,839	3,213				7.7	1.005	SAN ANDRES	824J
5708	112,000				CALCULATED FROM RW = 0.069 AT 75 DEG (F)							SAN ANDRES	151C
					***** DEPTH RANGE 6001 - 7000 *****								
6420			4,650		88,000	68	470			7.1	1.103	SPRABERRY	231J
6700	128,125				CALCULATED FROM RW = 0.061 AT 75 DEG (F)							SPRABERRY	455C
					***** DEPTH RANGE 7001 - 8000 *****								
7010	157,349	56,971	2,520	1,320	96,000	40	498	5		5.0	1.110	SPRABERRY (UPPER)	220J
7010	153,032	55,844	2,600	984	93,000	160	444			7.2	1.105	SPRABERRY (UPPER)	221J
7108	83,412	28,101	6,200	3,993	78,037	3,687			YES	6.7	1.065	SPRABERRY	826J
7323	180,000				CALCULATED FROM RW = 0.048 AT 75 DEG (F)							SPRABERRY	454C
7396	20,898	7,080	560	292	11,600	1,220	146			6.5	1.020	SPRABERRY	823J
7592	140,330	51,300	2,600	608	85,500	90	232			7.1	1.101	LOWER SPRABERRY	228J
7794	153,114	54,257	3,560	1,272	93,500	120	405			5.0	1.110	SPRABERRY	829J
7824	170,000				CALCULATED FROM RW = 0.050 AT 75 DEG (F)							SPRABERRY	453C
7900	263,007	75,164	20,691	3,675	163,116	83	207	67		5.3	1.179	SPRABERRY	240J
7900	225,000				CALCULATED FROM RW = 0.039 AT 75 DEG (F)							SPRABERRY	957J
					***** DEPTH RANGE 8001 - 9000 *****								
8068	152,885	55,900	2,000	600	94,200		185			6.0	1.108	SPRABERRY	825J
8172			2,302	314	89,000	353	245			6.6		DEAN SAND	817J
8172	154,367	57,818	2,145	312	93,450	401	241			6.7		DEAN SAND	818J
8172	144,099	53,845	2,038	260	87,402	342	212			6.3		DEAN SAND	819J
8172	144,136	53,809	2,132	310	87,220	420	245			6.1		DEAN SAND	820J

Figure 1-62 – Tabulated records of water quality (continued) from the Texas Water Development Board's Saline Water Resources Survey of the State of Texas for Dawson County (1971).

Results of the proportions of water versus hydrocarbons within the injection zone area are included in *Section 1.3.2*. A description of the hydrocarbon composition and chemistry is included in *Section 2 – Plume Model.*

1.6.2 Rock Chemistry (Injection Zone and Upper Confining Zone)

Twenty-one x-ray diffraction (XRD) samples (twenty in the injection zone and one in the confining zone) were acquired from existing core. Table 1-5 shows the mineralogy determined by XRD for both cored wells.

The samples from API No. 42-165-38785 show relatively low clay content but relatively high anhydrite content. The sample from API No. 42-165-31473 has relatively low clay content and relatively high dolomite content.


Claimed as PBI

1.6.3 Simulated Interactions (Injection Zone and Confining Zones)

The mineral-brine-CO_2 interactions that occur during CO_2 sequestration lead to the alteration of 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, the composition of the brine, the acidity of the CO_2-brine mixture, and the pressure and temperature in the subsurface. This chapter covers the modeling of the mineral-brine-CO_2 system across the mineralogical facies associations present for the subject site.

1.6.3.1 Methods

Simplified, batch kinetic simulation experiments (models) were created for each facies present at the subject location. 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 CO_2-brine-rock interactions. Each simulation experiment is isothermal, with the temperature set to match the subject location and depth. The pressure for each simulation experiment 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.

1.6.3.2 Brine Geochemistry

The brine composition used for the simulations is derived from the USGS Produced Waters Database. The database contained 28 samples of produced water from the San Andres reservoirs and one sample from the Glorietta Formation in the northeast quadrant of Gaines County, the south half of Terry County and the eastern half of Dawson County. The available analytical values were interpreted to create a composite brine composition used in the mineral kinetics batch models for the confining and injection zones. The composition of the composite brine is shown in Table 1-6. The model will be updated when actual fluid samples are collected during the drilling and testing of the injection wells, if the fluid composition is materially different than the values derived from the USGS database.

Table 1-6 – Brine Composition Used in Geochem Model

Species	Concentration	Units
TDS	61,431	mg/l
Ba	N/A	mg/l
HCO_3	848	mg/l
Ca	2,649	mg/l
Cl	34,540	mg/l
FeTot	21	mg/l
Na	19,876	mg/l
Mg	1,071	mg/l
SO_4	3,456	mg/l
Si	N/A	mg/l

1.6.3.3 Injectate Specifications

The composition of the injectate in the model is based on the pipeline specifications as discussed in Section 0 – Introduction (minimum 95% CO_2).

1.6.3.4 Mineral Geochemistry

Despite the well-understood nature of the stratigraphy in the vicinity of the subject site, published X-Ray Diffraction (XRD) data across the confining formations are scarce. The mineral composition used for the lower confining interval was estimated from well logs, regional geology and the work of Dutton and others (2004), Flemings and Mohrig (2012), DiMichele and Chaney (2000) and Milner (1978). The mineral composition for the simulation of the upper confining interval was informed by one XRD analysis point from the Reliance Valiant SWD No. 1 (API No. 42-165-38785) well in Gaines County, Texas, along with data from Dutton and others (2004), Flemings and Mohrig (2012), DiMichele and Chaney (2000) and Milner (1978). The Smectite-illite ratios in both confining intervals were estimated using the depth and transformation relationship published in Freed (1979). The mineral composition for the injection interval was created by using the average of available XRD data in the Reliance Valiant SWD No. 1 well (n=20). The values used in the simulation experiments are shown in Table 1-7.

1.6.3.5 Models

A total of three geochemical models were created, one for each of the upper and lower confining zones and one for the injection zone. Each model uses pressures and temperatures calculated using a generalized depth for the interval.

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 assume a pressure gradient of 0.465 psi/ft and a thermal gradient of 0.7°F/100 ft with a mean annual surface temperature of 65°F. The injected volume of CO_2 was assumed to fill the head space.

Table 1-7 – Estimated Mineral Compositions Used in Model

Facies Name	Upper Confining Zone	Injection Zone	Lower Confining Zone
Modeled Depth (ft)	5,251	6,015	43
Stratigraphic Unit	Grayburg	San Andres	Glorietta
Quartz	1.8	2.0	40.0
Calcite	0.0	2.0	10.0
Dolomite	90.0	76.0	10.0
Anhydrite	4.5	10.0	20.0
Plagioclase (albite)	0.0	3.0	0.0
Feldspar (anorthite)	0.0	0.0	0.0
K-Feldspar	0.0	4.0	8.0
Smectite	1.2	1.0	2.0
Illite	1.2	1.0	2.0
Kaolinite	0.0	0.0	8.0
Chlorite	0.0	0.0	0.0
Pyrite	1.3	1.0	0.0

1.6.3.6 Results

Across all of the models, the results show mild to moderate reactivity within the rock-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 to 10,000 years the reactions approach equilibrium. The precipitation and dissolution of all mineral constituents of the simulation experiments is shown in Figure X-1. The precipitation and dissolution of the minor mineral constituents is shown in Figure X-2.

In general, the upper confining interval shows precipitation of quartz and smectite with dissolution of anhydrite. The alteration of accessory minerals in the confining zones is most active after several days of reaction time and approaches equilibrium in 10 years. Overall, the model indicates that the reactivity of this rock-brine-CO_2 system is low.

The model for the injection interval shows precipitation of anhydrite and feldspar along with dissolution of calcite and illite during the injection period. After the injection timeframe, quartz and smectite precipitate and calcite and quartz precipitate while calcite re-precipitates. The modeled reactivity is mild to moderate for the accessory minerals.

In the lower confining interval, the model shows that overall reactivity is low. The quartz and anhydrite fractions are mildly reactive. During injection a small fraction of calcite is dissolved and re-precipitates approaching the end of the modeled period. Dolomite is precipitated during the injection period and continues to precipitate through the end of the model period. Illite is dissolved and smectite precipitates over the model period.

There are several necessary assumptions used in this modeling work that lead to the models over-representing 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. Thus, the modeling work in this chapter is an analysis of the upper bound of reactivity.



Figure 1-63 – The results of the batch simulations for all mineral constituents shown by unit. The x axis is log 10 time in years. The reaction time spans from 0.001 seconds to 10,000 years.



Figure 1-64 – The results for minor mineral phases of the batch shown by unit. The x axis is log 10 time in years. The reaction time spans from 0.001 seconds to 10,000 years.

1.7 Site Evaluation of Mineral Resources

While regional economic oil-and-gas production is prolific in the Permian basin in West Texas and Southeastern New Mexico, the Orchard Project is located near the northwest limit of the Midland Basin, where it adjoins the Central Basin Platform in Gaines County, Texas. This portion of the Midland Basin is far less suitable for recovering oil and gas in economic quantities.

A thorough review of oil-and-gas plays was conducted to avoid any potential conflicts with economic oil-and-gas production in the Orchard Project area. Within the project area of review (AOR), as defined in Section 3.5 and 3.6, 41 oil and gas wells were drilled. Of the 41 wells drilled, 35 were classified as dry holes, one was drilled as a disposal well, and five were completed as producing wells. Only two wells, API Nos. 42-165-33522 and 42-165-33988, produced at economic quantities (cumulative production greater than 100,000 barrels of oil equivalent). Both wells produced from the deeper Silurian formation and are located east of the well field.

The nearest San Andres producer to Orchard No. 1, No. 2, and No. 3 is well API No. 42-165-34832, located 2.4, 3.5, and 4.5 miles, respectively, west-northwest. That well is also nearest to Orchard No. 6, located 1 mile southeast, and to Orchard No. 7, at 3 miles northwest. This well produced only 8,679 barrels of oil before it was abandoned in 2010. The nearest San Andres producer to Orchard No. 4, well API No. 42-165-31473, is located 3.3 miles southeast. This well produced only 1,733 barrels of oil before it was abandoned in 1982. The nearest San Andres producer to Orchard No. 5, well API No. 42-165-31473, is located 2.7 miles southwest. This well produced only 1,733 barrels of oil before it was abandoned in 1982. The abandonment of those three wells provides further evidence of the lack of recoverable commercial quantities of hydrocarbons from the proposed injection zone in the greater Orchard Project area.

API No. 42-165-38794, located 2-4 miles from each injection well was drilled in 2019 as a horizontal San Andres well, but was a dry hole.

Other oil and gas activity in the immediate Orchard Project area is minimal. A shallow Yates storage field is located to the northeast of the project area, San Andres hydrocarbon production fields are shown on Figure 1-13. With the Permian Basin having been the most actively developed basin in North America during the last two decades, one would expect both historical and present activities in the greater Orchard Project area to be much higher—if it were considered attractive to mineral or working interest owners as an opportunity for economic oil or gas production.

1.8 Seismic History

Figure 1-65 shows two maps of historical seismic events in the Permian Basin area. The top map is USGS data of seismic events of more than 2.5 magnitude from 1900 to the present. The bottom map is from TexNet data for seismic events of more than 1.5 magnitude from 2017 to the present. Neither data source shows seismicity occurrences in the Orchard Project vicinity.

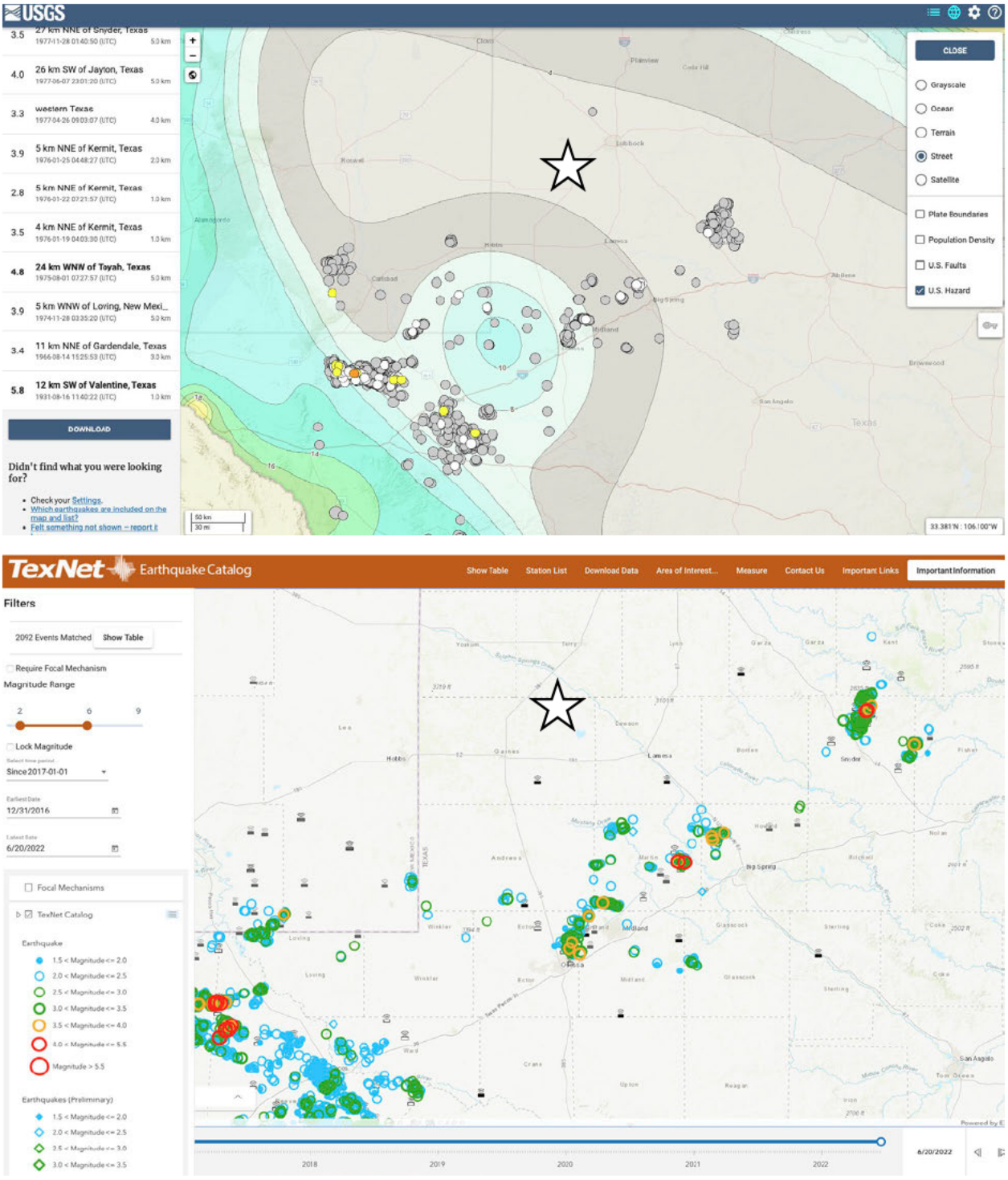


Figure 1-65 – Two maps of historical seismic events in the Permian Basin area; the upper map is from USGS, the lower from TexNet. Neither data source shows seismicity occurrences in the Orchard Project vicinity (indicated by the black star).

The Bureau of Economic Geology's TexNet site identifies a permanent active monitoring station 18 miles southwest of the Orchard Project area, adding confidence that if a seismic event had occurred in or near the project area, it would have been detected.

As discussed previously, there is a low probability of faults or fracture zones within the vicinity of the Orchard Project area injection zone that would pose an induced seismicity risk caused by CO_2 injection. Furthermore, there is an absence of active disposal wells within the project site. Areas with active disposal wells may have an increased induced-seismicity risk by injecting into deeper intervals where seismic data has revealed faults.

1.9 Site Suitability

The following is based on synthesis of the above site characterization work completed for this application. As shown in *Section 2 – Plume Model*, the injection zone has pore volume available for sequestration of injected CO_2, and the confining zone has sufficient integrity to contain the fluid—to prevent leakage into a USDW.

1.9.1 Lithofacies

The distribution of lithofacies in the San Andres carbonate is critical to consider, as spatial variations may hinder efficient CO_2 storage. The Orchard Project is located in an area where the dominant lithofacies are relatively consistent in an area larger than that of the project.

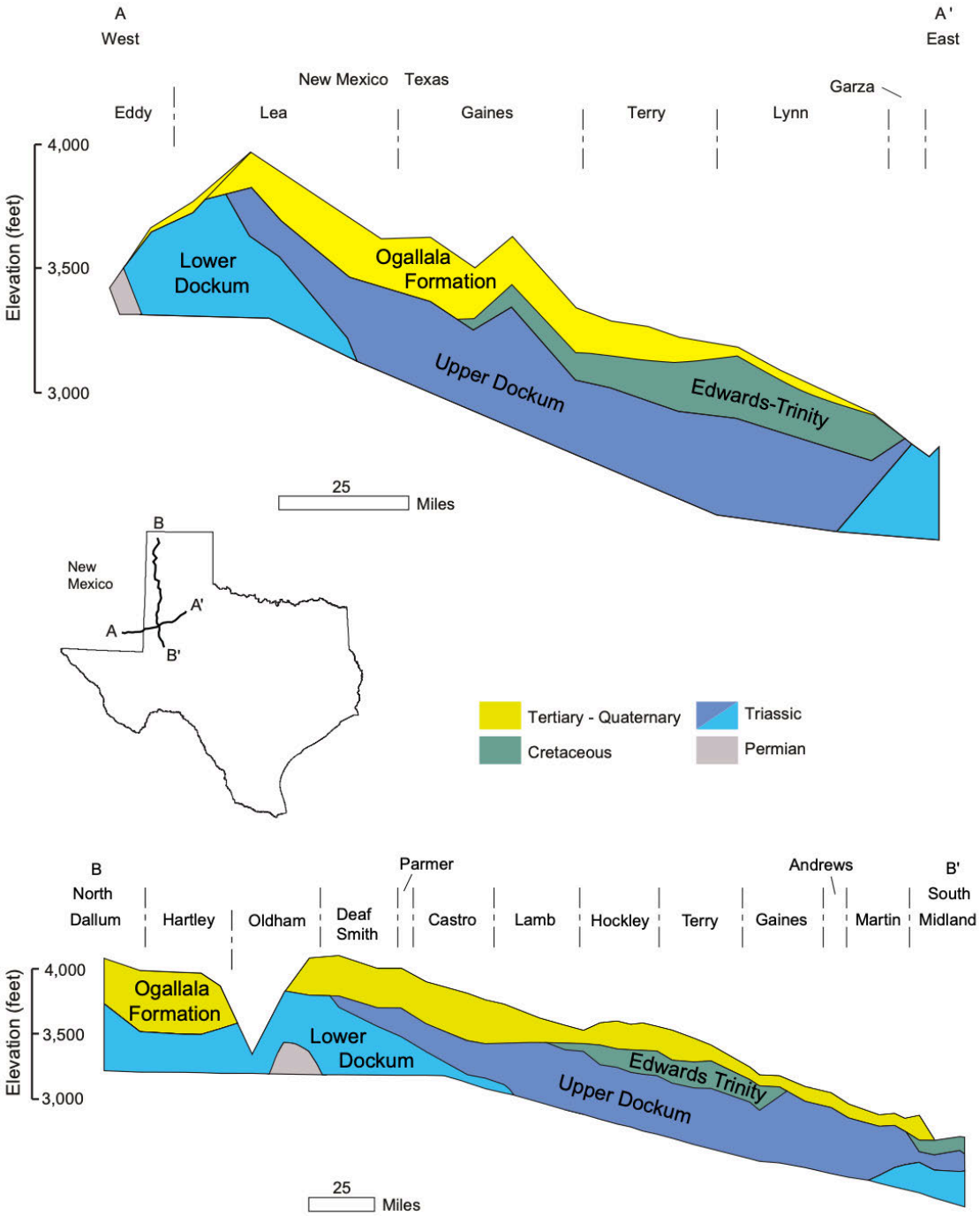
1.9.2 Leakage Pathways

Site-specific data and regional understanding show a low probability of the occurrence of faults or fractures causing leakage of injected CO_2. The confining zone above the injection zone has good continuity and sufficient low porosity to provide a high probability of containment.

1.9.3 Hydrology and Hydrogeology

A regional hydrogeologic picture published by the Texas Water Development Board establishes one major aquifer (Ogallala) and two minor aquifers (Edwards-Trinity and Dockum) throughout the Orchard Project area. Groundwater flow direction is generally the same for the three aquifers, from northwest to southeast (Teeple et al., 2021).

Figure 1-66 shows a simplistic cross section of the major and minor aquifers across the region and through the Orchard Project area in Gaines County (George et al., 2011).



Geologic cross sections showing the relationship of the Ogallala Formation to underlying strata (modified from McGowen and others, 1977).

Figure 1-66 – Simplified cross section of the major and minor aquifers across the region and through the Orchard Project area in Gaines County, Texas (George et al., 2011).

The Dockum aquifer, the oldest of the three discussed aquifers, was formed in the Triassic and underlies the Cretaceous Trinity and Fredericksburg Groups (Teeple et al., 2021). The TDS meet or exceed 5,000 mg/l; therefore, the aquifer is considered brackish. The Edwards-Trinity aquifer is of Cretaceous age, with the Trinity Group Antlers formation and Fredericksburg Group limestones being the primary sedimentary constituents of the aquifer. The infiltration of freshwater into the Edwards-Trinity system is primarily from the overlying Ogallala aquifer (George et al., 2011). The Ogallala aquifer is Tertiary in age and produces the majority of freshwater for Gaines and surrounding counties.

Figure 1-67 features a map showing the distribution of TDS in groundwater from the Dockum aquifer (Ewing et al., 2008).

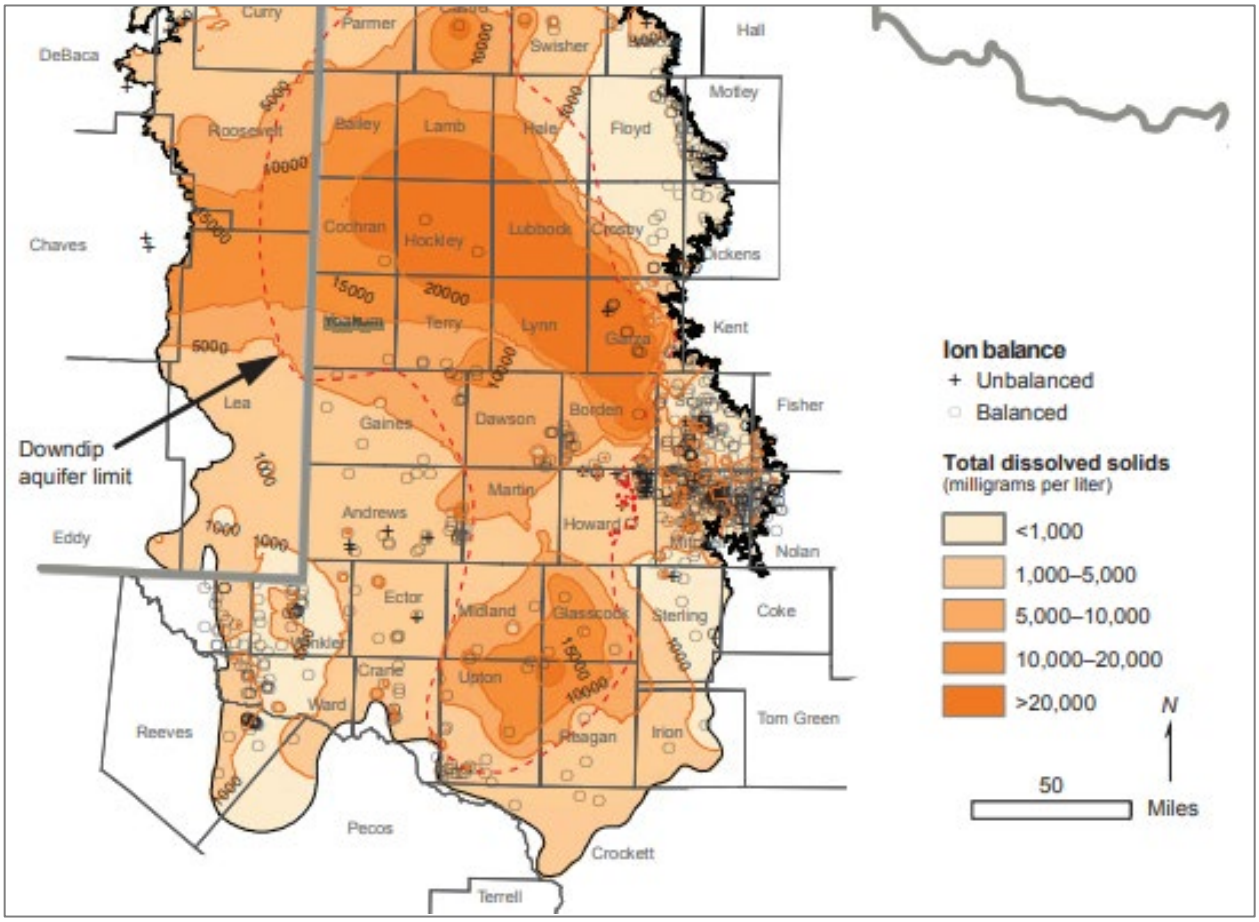


Figure 1-67 – Map showing the distribution of TDS in groundwater from the Dockum aquifer (Ewing et al., 2008).

The Texas Railroad Commission (TRRC) Groundwater Advisory Unit (GAU) identified the base of a USDW at a depth of 300 ft TVD, at the location of the Welborn No. 1WD injection well (API No. 42-165-10310). The TRRC approved the injection/disposal Permit No. 10004 for the Welborn No. 1WD on September 3, 1993 (amended to include produced saltwater as disposal fluid on

September 13, 1999). This well is 3.1 miles west of the proposed Orchard No. 2 well and was used to estimate the base of the USDW at this location. Major stratigraphic markers were logged by the Welborn No. 1WD as follows:

- Base of USDW per TRRC at 300 ft TVD
- Yates at 3,370 ft TVD
- San Andres at 4,890 ft TVD
- Spraberry Upper at 7,450 ft TVD

1.9.4 Total Storage Capacity

A simple experiment using the 3D numerical model demonstrates the total pore volume within a 1-kilometer radius surrounding the injection wells. The Upper San Andres, the likely target for most of the injected CO_2, contains approximately 57 million cubic meters of pore volume. Assuming 700 kilograms per cubic meter density of supercritical CO_2, 50^{o}C temperature and 16 megapascal pressure within the Upper San Andres, the estimated total storage capacity with all other parameters being ignored (e.g., injection capacity) is approximately 40 million metric tons (MMT). Assuming a 5% efficiency factor, the resulting total storage capacity is 2 MMT.

Similar results were produced when using the CO2-SCREEN[1] tool. Using the saline model parameters, the range of total storage capacity in the Upper San Andres is estimated to be 2 to 4 MMT per square kilometers.

1.9.5 Injection Capacity

Several iterations of the porosity and permeability model have incorporated site-specific data, regional geologic frameworks, and subsurface analog information to reduce uncertainty around the quality of the injection zone in the Orchard Project area. Nonetheless, two permeability models were created to capture both the relatively poor and good scenarios for injection performance.

1.9.6 Secondary Confinement

Based on the site-specific data and regional perspective of the upper confining zone, a secondary upper confining zone is not necessary to ensure USDW protection. The site characterization for the Orchard Project identified the secondary upper confining zone directly above the primary upper confining zone as one with sufficient integrity to prevent migrating fluid from reaching the USDW. Both confining zones are vertically heterogeneous and relatively thinly bedded.

[1]DOE's NETL developed CO2-SCREEN (CO_2 Storage prospeCtive Resource Estimation Excel aNalysis) to screen saline formations for prospective CO_2 storage resources.

1.10 Further Site Characterization

Several topics below are opportunities for future work to increase the accuracy and reduce the uncertainty of the Orchard Project site characterization. Much of this information will be acquired during the drilling of the initial well and incorporated into the site characterization and plume modeling and the application updated as needed.

1.10.1 Core

Further core analysis will be performed when confining and injection zone cores are obtained. Testing may include thin-section description, mercury injection, core description (confining zone), XRD, scanning electron microscopy, relative permeability (CO_2, brine), etc.

1.10.2 Sequence Stratigraphy

Depending on additional core analyses and seismic data, the current stratigraphy may be refined to represent a stratigraphic-sequence framework closely aligned to the higher-frequency cycles within the regional geologic framework (shown in *Section 1.2*). The current stratigraphic framework in the conceptual model, which was used to create the numerical simulation model, includes the major stratigraphic boundaries only (i.e., San Andres Upper and Lower).

1.10.3 Facies

Similar to increasing the resolution of the stratigraphic-sequence framework in the Orchard Project site and wider area, testing the effect on the porosity and permeability model by lithological and facies changes spatially may help reduce uncertainty. The purpose would be to create facies logs in multiple wells. The facies log may be related to core-described facies and expectations based on the regional depositional model.

1.11 Appendices

Higher resolution maps and cross sections are provided in Appendix J and include:

- Appendix J-1 Sanderson Core Report
- Appendix J-2 Arco Fee 198-1 Core Report
- Appendix J-3 Valiant No. 1 Core Report
- Appendix J-4 Structure Map, Base of Injection Zone
- Appendix J-5 Thickness Map, Injection Zone
- Appendix J-6 North-South Structural Cross Section
- Appendix J-7 West-East Structural Cross Section
- Appendix J-8 Average Porosity Map, Injection Zone
- Appendix J-9 Structure Map, Top of Upper San Andres

- Appendix J-10 Thickness Map, Upper San Andres
- Appendix J-11 Structure Map, Grayburg
- Appendix J-12 Thickness Map, Grayburg
- Appendix J-13 Thickness Map, Combined Upper Confining Zone
- Appendix J-14 Cross section Showing Upper Confining Zone Cored Interval
- Appendix J-15 Structure Map, Base of Lower Confining Zone
- Appendix J-16 Thickness Map, Lower Confining Zone

1.12 References

Alimahomed, F., Haddad, E., Velez, E., Foster, R., Downing, T., Seth, C., Melzer, S., Downing, W. (2018). The San Andres Play: Observations and Challenges in Horizontal Wells on the Central Basin Platform, Permian Basin. *Society of Petroleum Engineers*.

Andreason, M.W. (1992). Coastal siliciclastic sabkhas and related evaporative environments of the Permian Yates Formation, North Ward-Estes Field, Ward County, Texas. *American Association of Petroleum Geologists Bulletin, Vol. 76, No. 11, P. 1735-1759.*

Atchley, S.C., Kozar, M.G., Yose, L.A. (1999). A Predictive Model for Reservoir Distribution in the Permian (Leonardian) Clear Fork and Glorieta Formations, Robertson Field Area, West Texas. *AAPG Bulletin, Vol. 83, No. 7, P. 1031-1056*.

Barree, R.D. (2009). Input Data for Frac Design Models. *Barree & Associates LLC, 2009 Seminar*.

Beaumont, Christopher (1981). Foreland basins. *Geophys. J. R. Astr. Soc., V. 65, P. 291-329*.

Beaver, James L. (1982). Deposition and Diagenesis of Abo and Wichita Carbonates, Northern Midland Basin, Texas. *Texas Tech University Libraries*. Retrieved from http://hdl.handle.net/2346/9495

Bhatnagar, P., Scipione, M., Verma, S., Bianco, R. (2018). Characterization of mass transport deposit using seismic attributes: Spraberry formation, Midland Basin, West Texas. *SEG International Exposition and 88th Annual Meeting*.

Bhatnagar, P., Verma, S., Bianco, R. (2019). Characterization of mass transport deposits using seismic attributes: Upper Leonard Formation, Permian Basin. *Society of Exploration Geophysicists and American Association of Petroleum Geologists, Interpretation, Vol. 7, No. 4, P. 1-14*.

Bhatnagar, P., Verma, S., Trentham, R., Zobaa, M., Bianco, R., Watson, S. (2018). Geomorphologic Character of an Upper Leonardian Mass Transport Deposit, Midland Basin: Insights from 3D Seismic Data. *The University of Texas of the Permian Basin*. Retrieved from https://www.researchgate.net/publication/335150144

Borer, J.M., Harris, P.M. (2009). Computer Simulation of the Yates Formation (Permian, Delaware Basin) – Sequence Stratigraphy and Shelf-to-Basin Correlation Implications. *AAPG Search and Discovery Article No. 60044*.

Borer, J.M., Harris, P.M. (1991). Lithofacies and cyclicity of the Yates Formation, Permian Basin: implications for reservoir heterogeneity. *American Association of Petroleum Geologists Bulletin, Vol. 75, No. 4, P. 726-779.*

Brown, A.A., Loucks, R.G. (2016). Geological Controls on Evaporite – Carbonate Facies Transition in Permian Seven Rivers Formation, SE New Mexico. *AAPG Search and Discovery Article No. 51317*.

Browning, J., Gorrell, S.B., Asquith, G.B., Henderson, S.K., Watson, M.C., Sheridan, M. (2021). Evaluating the San Andres Horizontal Play in the Northwest Shelf of the Permian Basin, Developing Best Practices for Exploration. *Texas Tech University Libraries*. Retrieved from https://hdl.handle.net/2346/87838

Burnside, N.M., Naylor, M. (2014). Review and implications of relative permeability of CO_2/brine systems and residual trapping of CO_2. *International Journal of Greenhouse Gas Control, Vol. 23, P. 1-11*. Retrieved from http://dx.doi.org/10.1016/j.ijggc.2014.01.013

Caf, A.B., Pigott, J.D. (2021). Dolomitization geometry and reservoir quality from supervised Bayesian classification and probabilistic neural networks: Midland Basin Leonardian Wichita and Clear Fork Formations. *Society of Exploration Geophysicists and American Association of Petroleum Geologists, Interpretation, Vol. 9, No. 2, P. T585-T598*. Retrieved from http://dx.doi.org/10.1190/INT-2020-0204

Davis, Ken E. & Associates (1988). Survey of Methods to Determine Total Dissolved Solids Concentrations. *U.S. Environmental Protection Agency, Underground Injection Control Program, EPA LOE Contract No. 68-03-3416*.

Detournay, E., Cheng, A.H.D. (1993). Fundamentals of Poroelasticity. *Comprehensive Rock Engineering: Principles, Practice and Projects, Vol. 2, P. 113-171.*

DiMichele, W.A., Chaney, D.S., Dixon, W.H., Nelson, W.J., Hook, R.W. (2000). An Early Permian Coatal Flora from the Central Basin Platform of Gaines County, West Texas. Palaios, V15, p. 524-534. Society for Sedimentary Geology.

Draper, C.H., Kerans, C., Wahlman, G.P., Janson, X. (2019). Wolfcampian Shelf-to-Basin Stratigraphic Framework of the Central Basin Platform and Midland Basin, Andrews County, Texas. *The University of Texas at Austin, Jackson School of Geosciences*.

Dutton, A.R. (1987). Origin of brine in the San Andres Formation, evaporite confining system, Texas Panhandle and eastern New Mexico. *Geological Society of America Bulletin, Vol. 99, P. 103-112.*

Dutton, S.P., Kim, E.M., Broadhead, R.F., Breton, C.L., Raatz, W.D., Ruppel, S.C., Kerans, C. (2004). Play Analysis and Digital Portfolio of Major Oil Reservoirs in the Permian Basin: Application and Transfer of Advanced Geological and Engineering Technologies for Incremental Production Opportunities. *The University of Texas at Austin, Bureau of Economic Geology, and New Mexico Bureau of Geology and Mineral Resources*.

Eaton, B.A. (1969). Fracture Gradient Prediction and its application in Oilfield Operations. *Journal of Petroleum Technology, SPE-2163-PA*. Retrieved from https://doi.org/10.2118/2163-PA

Engle, M.A., Reyes, F.R., Varonka, M.S., Orem, W.H., Ma, L., Ianno, A.J., Schell, T.M., Xu, P., Carroll, K.C. (2016). Geochemistry of formation waters from the Wolfcamp and "Cline" shales: Insights into brine origin, reservoir connectivity, and fluid flow in the Permian Basin, USA. *USGS, Chemical Geology Vol. 425, P. 76-92*.

Ewing, J.E., Jones, T.L., Yan, T., Vreugdenhill, A.M. (2008). Groundwater Availability Model for the Dockum Aquifer – Final Report. *Prepared by INTERA Inc. for Texas Water Development Board, Austin, Texas.*

Ewing, T.E. (2019). Tectonics and Subsidence in the West Texas (Permian) Basin: A Model for Complex Intracratonic Basin Development. *AAPG Search and Discovery Article No. 30606.*

Fairhurst, B., Ikonnikova, S., Dommisse, R., Hamlin, S., Carr, D., Gherabati, A., Male, F., Yurchenko, I. (2019). Reconstructing the Permian Basin for Wolfberry and Wolfbone Unconventional Assessment. *The University of Texas at Austin, Bureau of Economic Geology*.

Galley, J.D. (1958). Oil and gas geology in the Permian Basin in Texas and New Mexico. *Weeks, L.G., ed., Habitat of oil—a symposium: Tulsa, Oklahoma, American Association of Petroleum Geologists, P. 395-446.*

Galloway, W.E., Tyler, N., Garrett Jr., C.M., Bebout, D.G., Cheng, E.S., Fisher, W.L., Ewing, T.E., Posey, J.S., Dutton, S.P. (1983). Geological Characterization of Texas Oil Reservoirs. *The University of Texas at Austin, Bureau of Economic Geology*.

Garber, R.A., Harris, P.M. (2009). Depositional Facies of Grayburg/San Andres Dolomite Reservoirs, Central Basin Platform, Permian Basin. *AAPG Search and Discovery Article No. 60031.*

Garcia-Fresca, B., Lucia, F.J., Sharp Jr., J.M., Kerans, C. (2012). Outcrop-constrained hydrogeological simulations of brine reflux and early dolomitization of the Permian San Andres Formation. *AAPG Bulletin, Vol. 96, No. 9, P. 1757-1781*.

George, P.G., Mace, R.E., Petrossian, R. (2011). Aquifers of Texas. *Texas Water Development Board, Report 380*.

Grigg, R.B., Svec, R.K., Ferguson, D.J. (2002). Improving CO_2 Efficiency for Recovering Oil in Heterogeneous Reservoirs. *New Mexico Petroleum Recovery Research Center, DOE Contract No. DE-FG26-01BC15364*.

Handford, C.R. (1981). Sedimentology and Genetic Stratigraphy of Dean and Spraberry Formations (Permian), Midland Basin, Texas. *The American Association of Petroleum Geologists.*

Helbert, D.K., Ruppel, S.C., Kerans, C., Fisher, W.L. (2010). Reservoir Characterization and Sequence Stratigraphy of Permian San Andres Platform Carbonates, Fullerton Field, Permian Basin, West Texas. *The University of Texas at Austin, Jackson School of Geosciences*.

Hinterlong, G.D., Taylor, A.R. (1996). Characterization of Rock Types with Mixed Wettability Using Log and Core Data – DOE Project Welch Field, Dawson County, Texas. *SPE-35160-MS.*

Hiss, K.A., Williamson, D.B. (2020). Facies and Stratigraphy of the San Andres Formation (Mid-Permian) Petroleum Province, Northwest Shelf of the Permian Basin, West Texas: A Resurgent Play. *The University of Texas at Dallas, GSA South-Central Section*.

Hoak, T., Sundberg, K., Ortoleva, P. (1998). Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico. *U.S. Department of Energy, Report No. DOE/PC/91008-23-Pt.8*.

Holtz, M.H., Garrett Jr., C.M., Tremblay, T.A., Finley, R.J., Tyler, N. (1993). Update of Atlas of Major Texas Oil Reservoirs Data Base and Atlas of Major Texas Gas Reservoirs Data Base. *The University of Texas at Austin, Bureau of Economic Geology*.

Honarpour, M.M., Nagarajan, N.R., Grijalba, A.C., Valle, M., Adesoye, K. (2010). Rock-Fluid Characterization for Miscible CO_2 Injection: Residual Oil Zone, Seminole Field, Permian Basin. *Society of Petroleum Engineers, No. 133089*.

Horne, E.A., Hennings, P.H., Zahm, C.K. (2021). Basement-Rooted Faults of the Delaware Basin and Central Basin Platform, Permian Basin, West Texas and Southeastern New Mexico. *The University of Texas at Austin, Bureau of Economic Geology*.

Hoteit, H., Fahs, M., Soltanian, M.R. (2019). Assessment of CO_2 Injectivity During Sequestration in Depleted Gas Reservoirs. *MDPI Geosciences 2019, Vol. 9, No. 199*.

Hovorka, S.D. (1997). Salt Cavern Studies – Regional Map of Salt Thickness in the Midland Basin. *The University of Texas at Austin, Bureau of Economic Geology*.

Hovorka, S.D., Nava, R. (2000). Characterization of Bedded Salt for Storage Salt Caverns – A Case Study from the Midland Basin, Texas. *The University of Texas at Austin, Bureau of Economic Geology*.

Johnson, K.S. (1993). Dissolution of Permian Salado salt during Salado time in the Wink area, Winkler County, Texas. *New Mexico Geological Society, 44th Annual Fall Field Conference Guidebook, P. 211-218*.

Johnson, R.D., Mazzullo, J., Dorobek, S., Wu, C., Rabinowitz, P. (1997). The Facies, Environments of Deposition and Cyclicity of the Yates Formation, North Ward-Estes Field, Ward County, Texas. *Texas A&M University*.

Kerans, C. (2006). San Andres Formation: Outcrop to Subsurface Stratigraphic Framework. *The University of Texas at Austin, Jackson School of Geosciences.*

Kerans, C., Kempter, K. (2002). Hierarchical stratigraphic analysis of a carbonate platform, Permian of the Guadalupe Mountains. *The University of Texas at Austin, Bureau of Economic Geology, American Association of Petroleum Geologists – Datapages Discovery Series No. 5.*

Kerans, C., Lucia, F.J., Senger, R.K. (1994). Integrated Characterization of Carbonate Ramp Reservoirs Using Permian San Andres Formation Outcrop Analogs. *AAPG Bulletin, Vol. 78, No. 2, P. 181-216*.

Kerans, C., Lucia, F.J., Senger, R.K., Fogg, G.E., Nance, H.S., Hovorka, S.D. (1992). Characterization of Facies and Permeability Patterns in Carbonate Reservoirs based on Outcrop Analogs. *The University of Texas at Austin, Bureau of Economic Geology*.

Koperna, G.J. (2020). CarbonSAFE Phase II: 8.1.a Project ECO_2S Numerical Modeling Report. *U.S. Department of Energy, DOE Project DE-FE0029465*.

Kuuskraa, V.A., Petrusak, R., Wallace, M. (2020). A Four-County Appraisal of the San Andres Residual Oil Zone (ROZ) "Fairway" of the Permian Basin. *U.S. Department of Energy, National Energy Technology Laboratory, DOE/NETL-2020/2627*.

Lee, B., Khoudaiberdiev, R., Lujan, B., Verma, S. (2019). Depositional Environment and Sedimentary Structures of the Grayburg Formation, Midland Basin. *AAPG Search and Discovery Article No. 51550.*

Leibrock, R.M., Hiltz, R.G., Huzarevich, J.E. (1951). Results of Gas Injection in the Cedar Lake Field. *Petroleum Transactions, AIME, Vol. 192, P. 357-366*.

Li, S., Yu, X., Li, S., Giles, K.A. (2015). Role of sea-level change in deep water deposition along a carbonate shelf margin, Early and Middle Permian, Delaware Basin: implications for reservoir characterization. *Geologica Carpathica, Vol. 66, No. 2, P. 99-116*.

Lindsay, R. (2017). Grayburg Formation Reservoir-Scale Architecture and Sequence Stratigraphy, Permian Basin. *AAPG Search and Discovery Article No. 51388.*

Lucia, F.J. (2007). Carbonate Reservoir Characterization, an Integrated Approach. *The University of Texas at Austin, Bureau of Economic Geology*.

Matchus, E.J., Jones, T.S. (1984). East-west cross section through Permian Basin of West Texas. *West Texas Geological Society.*

Mazullo, J., Malicse, A., Siegel, J. (1991). Facies and Depositional Environments of the Shattuck Sandstone on the Northwest Shelf of the Permian Basin. *Journal of Sedimentary Petrology, Vol. 61, No. 6, P. 940-958.*

Mazzullo, S.J., Reid, A.M. (1989). Depositional-sequence analysis of Lower Permian progradational systems, Midland Basin, Texas. *Kansas Geological Survey, Subsurface Geology Vol. 12, P. 47-50*.

Mazzullo, S.J., Reid, A.M. (1989). Lower Permian Platform and Basin Depositional Systems, Northern Midland Basin, Texas. *Society of Economic Paleontologists and Mineralogists Special Publication No. 44*.

McKee, E.D., Oriel, S.S. (1967). Paleotectonic Investigations of the Permian System in the United States. *U.S. Department of the Interior (DOI), Geological Survey Professional Paper 515*.

Melzer, S. (2006). Stranded Oil in the Residual Oil Zone. *Prepared for Advanced Resources International and U.S. Department of Energy Office of Fossil Energy—Office of Oil and Natural Gas*. Retrieved from https://doi.org/10.13140/RG.2.2.16299.95528

Merrill, M.D., Slucher, E.R., Roberts-Ashby, T.L., Warwick, P.D., Blondes, M.S., Freeman, P.A., Cahan, S.M., DeVera, C.A., Lohr, C.D. (2015). Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources – Permian, Palo Duro Basins, and Bend Arch-Fort Worth Basin. *USGS, Chapter K*.

Milner, Sam (1978). Genesis, provenance, and petrography of the glorieta Sandstone of eastern New Mexico. Circular 165, New Mexico Bureau of Mines & Mineral Resources.

Nance, H.S. (2006). Geology and Reservoir Development in the Upper Guadalupian Series Permian Basin. *The University of Texas at Austin, Jackson School of Geosciences.*

Nance, H.S. (2020). Guadalupian (Artesia Group) and Ochoan Shelf Succession of the Permian Basin: Effects of Deposition, Diagenesis, and Structure on Reservoir Development. *The University of Texas at Austin, Bureau of Economic Geology*.

Occidental Petroleum Ltd. (2015). Oxy Denver Unit CO_2 Subpart RR – Monitoring, Reporting and Verification (MRV) Plan. *Environmental Protection Agency*.

Occidental Petroleum Ltd. (2017). Oxy Hobbs Field CO_2 Subpart RR – Monitoring, Reporting and Verification (MRV) Plan. *Environmental Protection Agency*.

Occidental Petroleum Ltd. (2020). Oxy West Seminole San Andres Unit CO_2 Subpart RR – Monitoring, Reporting and Verification (MRV) Plan. *Environmental Protection Agency*.

Onishi, T., Nguyen, M.C., Carey, J.W., Will, B., Zaluski, W., Bowen, D.W., Devault, B.C., Duguid, A., Zhou, Q., Fairweather, S.H., Spangler, L.H., Stauffer, P.H. (2019). Potential CO_2 and brine leakage through wellbore pathways for geologic CO_2 sequestration using the National Risk Assessment Partnership tools: Application to the Big Sky Regional Partnership. *International Journal of Greenhouse Gas Control, Vol. 81, P. 44-65*.

Perlman, Z.S. (2017). Stratigraphic, Geochemical, and Geochronological Analysis of the Wolfcamp-D Interval, Midland Basin, Texas. *The University of Kentucky, Earth and Environmental Sciences*.

Playton, T., Kerans, C. (2006). Early Permian Carbonate Slope & Basin Channel-Fan Complexes, West Texas: Implications for Early Permian Deep Water Reservoir Development in the Permian Basin. *The University of Texas at Austin, Bureau of Economic Geology, PGGSP Annual Meeting*.

Popova, O. (2020). Permian Basin, Part 1: Wolfcamp, Bone Spring, Delaware Shale Plays of the Delaware Basin. *U.S. Energy Information Administration*. Retrieved from https://www.eia.gov/maps/pdf/Permian-pI_Wolfcamp-Bonespring-Delaware.pdf

Popova, O. (2022). Permian Basin, Part 2: Wolfcamp and Spraberry Shale Plays of the Midland Sub-Basin. *U.S. Energy Information Administration*. Retrieved from https://www.eia.gov/maps/pdf/Permian-p2_Spraberry_Midland.pdf

Pranter, M.J., Hurley, N.F., Davis, T.L. (2004). Anhydrite distribution within a shelf-margin carbonate reservoir: San Andres Formation, Vacuum Field, New Mexico, USA. *Geological Society of London, Petroleum Geoscience, Vol. 10, P. 43-52*.

Raza, A., Gholami, R., Rezaee, R., Bing, C.H., Nagarajan, R., Hamid, M.A. (2018). CO_2 storage in depleted gas reservoirs: A study on the effect of residual gas saturation. *Petroleum, Vol. 4, No. 1, P. 95-107*. Retrieved from https://doi.org/10.1016/j.petlm.2017.05.005

Raziperchikolaee, S., Singh, V., Kelley, M. (2020). The effect of Biot coefficient and elastic moduli stress–pore pressure dependency on poroelastic response to fluid injection: laboratory experiments and geomechanical modeling. *Greenhouse Gases: Science and Technology*. Retrieved from https://doi.org/10.1002/ghg.2019

Ren, B., Duncan, I.J. (2021). Maximizing Oil Production from Water Alternating Gas (CO_2) Injection into Residual Oil Zones: The Impact of Oil Saturation and Heterogeneity. *The University of Texas at Austin, Bureau of Economic Geology.* Retrieved from https://www.sciencedirect.com/science/article/pii/S036054422100164X

Ren, B., Duncan, I.J. (2019). Modeling Oil Saturation Evolution in Residual Oil Zones: Implications for CO_2 EOR and Sequestration. *The University of Texas at Austin, Bureau of Economic Geology.* Retrieved from https://www.sciencedirect.com/science/article/pii/S0920410519302098

Ren, B., Duncan, I.J. (2018). Reservoir Simulation of Carbon Storage Associated with CO_2 EOR in Residual Oil Zones, San Andres Formation of West Texas, Permian Basin, USA. *The University of Texas at Austin, Bureau of Economic Geology.* Retrieved from https://www.sciencedirect.com/science/article/pii/S0360544218322114

Rogers, B.F., Hu, Q. (2017). Petrophysical Characterization of the Jo Mill Submarine Fan Complex, Spraberry Trend, Midland Basin, Texas. *The University of Texas at Arlington*.

Rose, M.W. (2005). Application of Water-Jet Horizontal Drilling Technology to Drill and Acidize Horizontal Drain Holes, Tedbit (San Andres) Field, Gaines County, Texas. *U.S. Department of Energy, NETL/NPTO No. 288, P. 2-11*.

Ruppel, S.C. (2006). Key to Reservoir Development and Characterization: Clear Fork, Wichita, Abo. *The University of Texas at Austin, Jackson School of Geosciences.*

Ruppel, S.C. (2001). Opportunities for Recovery of Remaining Oil in San Andres Reservoirs: Example from Fuhrman-Mascho Field, University Lands Block 10, Andrews County, Texas. *The University of Texas at Austin, Jackson School of Geosciences.*

Ruppel, S.C., Cander, H.S. (1988). Dolomitization of shallow-water platform carbonates by sea water and seawater-derived brines: San Andres Formation (Guadalupian), West Texas. *SEPM Special Publications No. 43.*

Saller, A., Bierly, L., Shafer, D., Owens, L. (2012). Contrasting Styles of San Andres Reservoirs: Vacuum Versus Slaughter Fields, Middle Permian, West Texas and Southeast New Mexico. *AAPG Search and Discovery Article No. 20168.*

Sarg, J.F. (1981). Petrology of the carbonate-evaporite facies transition of the Seven Rivers Formation (Guadalupian, Permian), southeast New Mexico. *Journal of Sedimentary Petrology, Vol. 51, No. 1, P. 73-96.*

SEPM Strata (2022). The Geology of the Upper Permian – Permian Basin. *SEPM Strata – Society for Sedimentary Geology.* Retrieved from www.sepmstrata.org

Shelton, J.L., McIntosh, J.C., Hunt, A.G., Beebe, T.L., Parker, A.D., Warwick, P.D., Drake II, R.M., McCray, J.E. (2016). Determining CO_2 storage potential during miscible CO_2 enhanced oil recovery: Noble gas and stable isotope tracers. *International Journal of Greenhouse Gas Control, Vol. 51, P. 239-253*.

Silver, B.A., Todd, R.G. (1969). Permian cyclic strata, northern Midland and Delaware Basins, West Texas and Southeastern New Mexico. *American Association of Petroleum Geologists Bulletin, Vol. 53, P. 2223-2251.*

Snee, J.L., Zoback, M.D. (2018). State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity. *Stanford University, Department of Geophysics, The Leading Edge*.

Spitz, T., Chalmers, H., Ascui, F., Lucquiaud, L. (2017). Operating flexibility of CO_2 injection wells in future low carbon energy system. *Energy Procedia, Vol. 114, P. 4797-4810*.

Tait, D.B., Ahlen, J.L., Gordon, A., Scott, G.L., Motts, W.S., Spitler, M.E. (1962). Artesia Group of New Mexico and West Texas. *Bulletin of the American Association of Petroleum Geologists, Vol. 46, No. 4, P. 504-517.*

Teeple, A.P., Ging, P.B., Thomas, J.V., Wallace, D.S., Payne, J.D. (2021). Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers in and near Gaines, Terry, and Yoakum Counties, Texas. *USGS Scientific Investigations Report 2021-5009.*

Tinsley, W.E., Shurbet, M., Gilmore, R.B., McCoy, J.H., Potts, M.T., Illig, C. (1972). A Survey of the Subsurface Saline Water of Texas. *Texas Water Development Board, Vol. 2, Report No. 157*.

Trentham, R.C. (2014). Goldsmith Landreth San Andres Unit (GLSAU) No. 203R-A CO_2 Oil Bank Caught in the Act. *AAPG Search and Discovery Article No. 10648.*

Trentham, R.C., Melzer, L.S., Kuuskraa, V., Koperna, G. (2015). Case Studies of the ROZ CO_2 Flood and the Combined ROZ/MPZ CO_2 Flood at the Goldsmith Landreth Unit, Ector County, Texas. Using "Next Generation" CO_2 EOR Technologies to Optimize the Residual Oil Zone CO_2 Flood. *U.S. Department of Energy, DE-FE0005889.*

Trentham, R.C., Melzer, L.S., Vance, D.B., Kuuskraa, V., Petrusak, R. (2015). Identifying and developing technology for enabling small producers to pursue the residual oil zone (ROZ) fairways in the Permian Basin San Andres. University of Texas of the Permian Basin, RPSEA. Retrieved from https://www.researchgate.net/publication/341357679

Tucker, K.E., Chalcraft, R.G. (1991). Cyclicity in the Permian Queen Formation – U.S.M. Queen Field, Pecos County, Texas. *SEPM Society for Sedimentary Geology, Vol. 15, P. 385-428*. Retrieved from https://doi.org/10.2110/cor.91.15

Tutolo, B.M., Luhmann, A.J., Kong, X.Z., Saar, M.O., Seyfried Jr., W.E. (2019). CO_2 sequestration in feldspar-rich sandstone: Coupled evolution of fluid chemistry, mineral reaction rates, and hydrogeochemical properties. *University of Minnesota, Department of Earth Sciences*. Retrieved from https://www.sciencedirect.com/science/article/pii/S0016703715001957

Tyler, N., Guevara, E.H., Coates, G.R., Wolff, M., Mukhopadhyay, P.K., Roberts, M.P., Gholston, J.C., Farrely, J.J., Graham, R.L., Walter, T., Reistroffer, J.R. (1987). Geological Characterization and Reserve Growth Potential of Spraberry Reservoirs in the Midland Basin, West Texas. *The University of Texas at Austin, Bureau of Economic Geology.*

Wahlman, G.P., Tasker, D.R. (2013). Lower Permian (Wolfcampian) Carbonate Shelf-Margin and Slope Facies, Central Basin Platform and Hueco Mountains, Permian Basin, West Texas, USA. *SEPM Society for Sedimentary Geology, Special Publication No. 105, P. 305-333*.

Waite, L. (2021). Stratigraphic Framework of the Wolfcamp-Spraberry of the Midland Basin. *University of Texas at Dallas, Abilene Geologic Society*.

Waite, L. (2019). Stratigraphic Framework of the Wolfcamp-Spraberry of the Midland Basin. *University of Texas at Dallas, Roswell Geologic Society*.

Waite, L., Stern, R.J. (2021). Reefs of the Permo-Penn Caribbean: The Horseshoe Atoll of the Midland Basin. *University of Texas at Dallas.*

Wang, J., Zhao, Y., An, Z., Shabani, A. (2022). CO_2 storage in carbonate rocks: An experimental and geochemical modeling study. *Journal of Geochemical Exploration, Vol. 234, P. 1-14*. Retrieved from https://doi.org/10.1016/j.gexplo.2021.106942

Ward, R.F., Kendall, C.G., Harris, P.M. (1986). Upper Permian (Guadalupian) facies and their association with hydrocarbons – Permian Basin, west Texas and New Mexico. *AAPG Bulletin, Vol. 70, No. 3, P. 239-262*.

Ward, Z.D., Pashin, J.C., Puckette, J., Hileman, M. (2013). Depositional Processes and Environments in Wolfcampian-Leonardian Strata, Southern Midland Basin, Texas. *Oklahoma State University*.

Warn, G.F., Sidwell, R. (1953). Petrology of the Spraberry Sands of West Texas. *Journal of Sedimentary Petrology, Vol. 23, No. 2, P. 67-74*.

Wells, J.A., Evans, L.J. (1992). Engineering Evaluation and Performance Analysis of the Loop Gas Storage Field. *Society of Petroleum Engineers, SPE No. 24922*.

Zapata, Y., Kristensen, M.R., Huerta, N., Brown, C., Kabir, C.S., Reza, Z. (2020). CO_2 geological storage: Critical insights on plume dynamics and storage efficiency during long-term and post-injection period. *Journal of Natural Gas Science and Engineering, Vol. 83, P. 1-29*. Retrieved from https://doi.org/10.1016/j.jngse.2020.103542

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 2 – Plume Model

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 2 – PLUME MODEL

TABLE OF CONTENTS

SECTION 2 – PLUME MODEL 2

2.1 Introduction 7

2.1.1 Software 7

2.2 Static (Geocellular) Model Development 7

2.2.1 Structural Framework 8

2.2.2 Rock Property Distribution 11

2.3 Trapping Mechanisms 16

2.3.1 Structural Trapping 32

2.3.2 Residual Gas Trapping 32

2.3.3 Solubility Trapping 34

2.3.4 Geochemical Trapping 43

2.3.5 Trapping Summary 43

2.4 Dynamic Model 44

2.4.1 Structural and Stratigraphic Elements 44

2.4.2 Relative Permeability and Capillary Pressure 53

2.4.3 Capillary Pressure Relations 59

2.4.4 Initial Conditions 59

2.4.5 Injection Rate 63

2.4.6 Injected Fluids Composition 65

2.4.7 Completion Plan 65

2.4.8 Characterization of Stimulations in Plume Model 66

2.5 Model Orientation and Gridding Parameters 69

2.5.1 Spatial Conditions 69

2.5.2 Boundary Conditions 75

2.5.3 Model Time Frame 77

2.6 CO_2 Plume Model Results 78

2.7 Dynamic Model Sensitivity Analysis 95

2.7.1 Sensitivity Parameter Discussion 97

2.7.2 Results of Sensitivity Cases 102

2.8 Critical Pressure Front 112

2.9 Area of Review Delineation 125

REFERENCES 134

Appendix 2-1 Water Property Correlations 137

Appendix 2-2 Hydrocarbon EOS Parameters in Plume Model 138

Figures

Figure 2-1 – Project area map, showing geomodel boundary and well data coverage. The well cross-section for Figure 2-5 is shown as a red line. 8
Figure 2-2 – 3D view of the structural model. 9
Figure 2-3 – West-east cross-sectional view of the structural model. The cross section slice is shown on Figure 2-2. 9
Figure 2-4 – Structural map for the Top of Upper San Andres (Upper Confining Zone) 10
Figure 2-5 – Structural map for the Top of Glorieta (Lower Confining Zone) 11
Figure 2-6 – Well cross section example, showing upscaled generalized porosity (5% cut-off), porosity and permeability (location is shown on Figure 2-1). The cross section is flattened at the Top of Upper San Andres. 12
Figure 2-7 – Example of vertical variogram estimated from porosity log data within the injection zone. 13
Figure 2-8 – 3D view of the porosity distribution model. 14
Figure 2-9 – West-east cross-sectional view of the porosity distribution model. The cross section location is shown on Figure 2-8. 15
Figure 2-10 – Histogram comparing injection zone porosity from raw logs, upscaled logs, and 3D property model. 15
Figure 2-11 – Porosity-permeability transform used in the model, based on the Reliance Valiant SWD No. 1. 16
Figure 2-12 – Orchard No. 1 east-west cross-sectional view depicting movement of CO_2 phase during injection. 18
Figure 2-13 – Orchard No. 1 east-west cross-sectional view depicting movement of CO_2 phase post-injection. 19
Figure 2-14- Orchard No. 2 east-west cross-sectional view depicting movement of CO_2 phase during injection 20
Figure 2-15– Orchard No. 2 east-west cross-sectional view depicting movement of CO_2 phase post-injection. 21
Figure 2-16– Orchard No. 3 east-west cross-sectional view depicting movement of CO_2 phase during injection. 22
Figure 2-17– Orchard No. 3 east-west cross-sectional view depicting movement of CO_2 phase post-injection. 23
Figure 2-18– Orchard No. 4 east-west cross-sectional view depicting movement of CO_2 phase during injection. 24
Figure 2-19– Orchard No. 4 east-west cross-sectional view depicting movement of CO_2 phase post-injection. 25
Figure 2-20 – Orchard No. 5 east-west cross-sectional view depicting movement of CO_2 phase during injection. 26
Figure 2-21– Orchard No. 5 east-west cross-sectional view depicting movement of CO_2 phase post-injection. 27
Figure 2-22– Orchard No. 6 east-west cross-sectional view depicting movement of CO_2 phase during injection. 28
Figure 2-23– Orchard No. 6 east-west cross-sectional view depicting movement of CO_2 phase post-injection 29

Figure 2-24 – Orchard No. 7 east-west cross-sectional view depicting movement of CO_2 phase during injection 30
Figure 2-25 – Orchard No. 7 east-west cross-sectional view depicting movement of CO_2 phase post-injection 31
Figure 2-26 – Trapped Gas Saturation Experimental Data ((Keelan, 1975)..... 33
Figure 2-27 – Orchard No. 1 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 36
Figure 2-28 – Orchard No. 2 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 37
Figure 2-29 – Orchard No. 3 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 38
Figure 2-30 – Orchard No. 4 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 39
Figure 2-31 – Orchard No. 5 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 40
Figure 2-32 – Orchard No. 6 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 41
Figure 2-33 – Orchard No. 7 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2. 42
Figure 2-34 – Balance of Injected CO_2 44
Figure 2-35 – Permeability versus porosity for Valiant 1D (API No. 42-165-38785), compared to permeabilities calculated using the Lucia Transform. 46
Figure 2-36 - Permeability versus porosity for Valiant 1D (API No. 42-165-38785) plus Arco Fee 198-1 (API No. 42-165-34473) 47
Figure 2-37 – Horizontal Permeability at Orchard No. 1 through 4 Injectors (East-West Section) .. 48
Figure 2-38 – Horizontal Permeability at Orchard No. 5 Injector (East-West Section) 49
Figure 2-39 – Horizontal Permeability at Orchard No. 6 Injector (East-West Section) 50
Figure 2-40 – Horizontal Permeability at Orchard No. 7 Injector (East-West Section) 51
Figure 2-41 – Gas-Liquid Relative Permeability Relationship..... 55
Figure 2-42 – Probability Distribution of CO_2 Endpoint Relative Permeability 56
Figure 2-43 – CO_2 Fractional Flow Curve 57
Figure 2-44 – Water-Oil Relative Permeability 58
Figure 2-45 – Orchard Area Temperature Gradients 62
Figure 2-46 – Normal Probability Plot of Gaines County TDS Data in the San Andres Formation.... 63
Figure 2-47 – Transient Flow Regimes Around an Injector 67
Figure 2-48 – Active model grid overlain with injection wells, plume outlines, and pressure front outline 70
Figure 2-49 – Detail of local grid refinement 71
Figure 2-50 – Cedar Lake Material Balance 77
Figure 2-51 – Aggregate Plume Growth Vs. Time for Orchard Project Injection Wells 78
Figure 2-52 – Stabilized CO_2 Plumes, 50 Years Post-Injection..... 79
Figure 2-53 – Orchard No. 1 West-East Cross-Sectional Views of Effective CO_2 Saturation 80
Figure 2-54 – Orchard No. 1 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 81
Figure 2-55 – Orchard No. 2 East-West Cross-Sectional Views of Effective CO_2 Saturation 82
Figure 2-56 – Orchard No. 2 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 83

Figure 2-57 – Orchard No. 3 East-West Cross-Sectional Views of Effective CO_2 Saturation 84
Figure 2-58 – Orchard No. 3 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 85
Figure 2-59 – Orchard No. 4 East-West Cross-Sectional Views of Effective CO_2 Saturation 86
Figure 2-60 – Orchard No. 4 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 87
Figure 2-61 – Orchard No. 5 East-West Cross-Sectional Views of Effective CO_2 Saturation 88
Figure 2-62 – Orchard No. 5 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 89
Figure 2-63 – Orchard No. 6 East-West Cross-Sectional Views of Effective CO_2 Saturation 90
Figure 2-64 – Orchard No. 6 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 91
Figure 2-65 – Orchard No. 7 East-West Cross-Sectional Views of Effective CO_2 Saturation 92
Figure 2-66 – Orchard No. 7 North-South Cross-Sectional Views of Effective CO_2 Saturation..... 93
Figure 2-67 – Total Metric Tons of CO_2 and Trapping Mechanisms Over Time 94
Figure 2-68 – Percent of CO_2 in Each State Over Time..... 95
Figure 2-69 – Statistical Distribution for CO_2 Endpoint Relative Permeability..... 97
Figure 2-70 – Experimental Data for Maximum Trapped Gas Saturation..... 99
Figure 2-71 – Residual Oil Saturation from Sidewall Cores..... 100
Figure 2-72 – Temperature Gradient - °F per 100 Feet..... 101
Figure 2-73 – Sensitivities for Plume Size versus Time 103
Figure 2-74 – Sensitivities for Percent of Mobile CO_2 versus Time..... 104
Figure 2-75 – Sensitivities for Percent of Trapped CO_2 versus Time..... 104
Figure 2-76 – Sensitivities for Percent of CO_2 in Gas Phase versus Time 105
Figure 2-77 – Sensitivities for Percent of CO_2 Dissolved in Oil and Water versus Time 105
Figure 2-78 – Plume Size Sensitivities Tornado Chart..... 107
Figure 2-79 – Mobile CO_2 Phase Sensitivities Tornado Chart 108
Figure 2-80 – Trapped CO_2 Phase Sensitivities Tornado Chart 109
Figure 2-81 – Supercritical Gas Phase Sensitivities Tornado Chart..... 110
Figure 2-82 – Total Dissolved CO_2 Sensitivities Tornado Chart..... 111
Figure 2-83 Variation of Threshold and Injection Interval Pressures versus Depth 118
Figure 2-84 – Orchard No. 1 Pressure Buildup from Initial Value 119
Figure 2-85 – Orchard No. 2 Pressure Buildup from Initial Value 120
Figure 2-86 – Orchard No. 3 Pressure Buildup from Initial Value 121
Figure 2-87– Orchard No. 4 Pressure Buildup from Initial Value 122
Figure 2-88– Orchard No. 5 Pressure Buildup from Initial Value 123
Figure 2-89– Orchard No. 6 Pressure Buildup from Initial Value 124
Figure 2-90 – Orchard No. 7 Pressure Buildup from Initial Value 125
Figure 2-91 – Stabilized CO_2 Plumes and Critical Pressure Front at the Orchard Project..... 126
Figure 2-92 – Injection Rate and BHP Data for Orchard No. 1 127
Figure 2-93 – Injection Rate and BHP Data for Orchard No. 2 128
Figure 2-94 – Injection Rate and BHP Data for Orchard No. 3 129
Figure 2-95 – Injection Rate and BHP Data for Orchard No. 4 130
Figure 2-96 – Injection Rate and BHP Data for Orchard No. 5 131
Figure 2-97 – Injection Rate and BHP Data for Orchard No. 6 132
Figure 2-98 - Injection Rate and BHP Data for Orchard No. 7..... 133

Tables

Table 2-1 – Model horizons. 8
Table 2-2 – Model zones and their gridding parameters. Confining zones are highlighted in gray, injection zone – in blue. 10
Table 2-3– Model zones and number of wells with interpreted porosities. 13
Table 2-4 – Porosity and permeability distribution: variogram parameters for the model zones. .. 14
Table 2-5 – Gross Injection Interval and Modeled ROZ Parameters 34
Table 2-6 – Orchard No. 1 Model Porosity and Permeability Summary 51
Table 2-7 – Orchard No. 2 Model Porosity and Permeability Summary 52
Table 2-8 – Orchard Well No. 3 Model Porosity and Permeability Summary 52
Table 2-9 – Orchard No. 4 Model Porosity and Permeability Summary 52
Table 2-10 – Orchard No. 5 Model Porosity and Permeability Summary 52
Table 2-11 – Orchard No. 6 Model Porosity and Permeability Summary 53
Table 2-12 – Orchard No. 7 Model Porosity and Permeability Summary 53
Table 2-13 – Reservoir Pressure Gradient Data for Nearby San Andres Fields 60
Table 2-14 – Formation Temperature for Orchard Area Wells 61
Table 2-15 – Orchard No. 1 to No. 7 Model Completion Timing 66
Table 2-16 – Model Layer Parameters 72
Table 2-17 – Simulator Permeability Values in Area of Orchard No. 1 Well 72
Table 2-18 – Simulator Permeability Values in Area of Orchard No. 2 Well 73
Table 2-19 – Simulator Permeability Values in Area of Orchard No. 3 Well 74
Table 2-20 – Simulator Permeability Values in Area of Orchard No. 4 Well 74
Table 2-21 – Simulator Permeability Values in Area of Orchard No. 5 Well 74
Table 2-22 – Simulator Permeability Values in Area of Orchard No. 6 Well 74
Table 2-23 – Simulator Permeability Values in Area of Orchard No. 7 Well 75
Table 2-24 – Cedar Lake Reservoir Parameters 76
Table 2-25 – Parameters Used in Dynamic Modeling Sensitivity Analysis 96
Table 2-26 – Sensitivity Result Measures with Base Case Reference Values 102
Table 2-27 – Plume Area Sensitivity Results 107
Table 2-28 – Mobile CO_2 Phase Sensitivity Results 108
Table 2-29 – Trapped CO_2 Phase Sensitivity Results 109
Table 2-30 – Total Supercritical Gas Phase Sensitivity Results 110
Table 2-31 – Total Dissolved CO_2 Sensitivity Results 111
Table 2-32 – Base USDW Depth and Elevation from GAU 113
Table 2-33 – Ogallala Aquifer GCD Observation Well Data 113
Table 2-34 – Calculations of USDW initial fluid pressure 114
Table 2-35 – Critical Pressure Calculations 116

2.1 Introduction

This section discusses key details of the plume model. The model characterizes the performance of CO_2 injection wells, the 3D spatial distribution of the CO_2 plume, and the associated pressure front over time. It incorporates hydrogeologic data with subsurface flow physics to model the significant physical processes that affect the plume and pressure front evolution. The distribution of the plume and pressure front defines the area of review (AOR) for the well, a corrective action plan if necessary, and the overall viability of the project.

The proposed Orchard No. 1 through No. 7 injection wells were modeled simultaneously to consider the relationship between the wells during injection operations—and to ensure that the plumes of the respective wells do not significantly impact each other within the storage reservoir. This also helps to verify that the pressure of the reservoir remains below the fracture pressure gradient limits of the formation during combined injection operations.

The Orchard Project will target the San Andres formation for injection of CO_2. This formation has commonly been divided into two main units, the Upper and Lower San Andres intervals. The top portion of the Upper San Andres plus the Grayburg formation form the confining interval overlying the injection interval. The dynamic flow model incorporates all the San Andres formation below the impermeable upper confining zone. For purposes of model construction and discussion of the simulation results, the term "Upper San Andres" in this section *excludes* the upper confining zone.

2.1.1 Software

2.1.1.1 Petrel™ Software Suite

SLB's (previously known as Schlumberger) was used to build the detailed geocellular model for this application. This globally recognized software integrates data from well logs and seismic to generate subsurface reservoir models. The geocellular model spatially distributes the permeability and porosity properties across the injection area.

2.1.1.2 Rock Flow Dynamic's Software Suite – tNavigator™

The tNavigator software suite allows for advanced reservoir modeling and simulation using a high-performance computing architecture. This architecture uses sophisticated Equation of State (EOS), which is critical to predict movement of supercritical fluids. This software allows for advanced visualization capabilities and provides detailed insights to the modeling results. The software also enables sensitivity analysis for risk assessments and field development optimization.

2.2 Static (Geocellular) Model Development

The geocellular model was designed to include available log data to provide a comprehensive dataset. The model area was sufficiently expanded beyond the expected plume and pressure front to minimize use of grid-edge multipliers or external analytical aquifers during the plume modeling. The model covers approximately 370 square miles (236,800 acres) and ranges from 1,300 to 3,500 ft subsea in depth.

Figure 2-1 summarizes the distribution of well log data as well as the extent of the 3D geocellular model, shown on the map as the AOI.

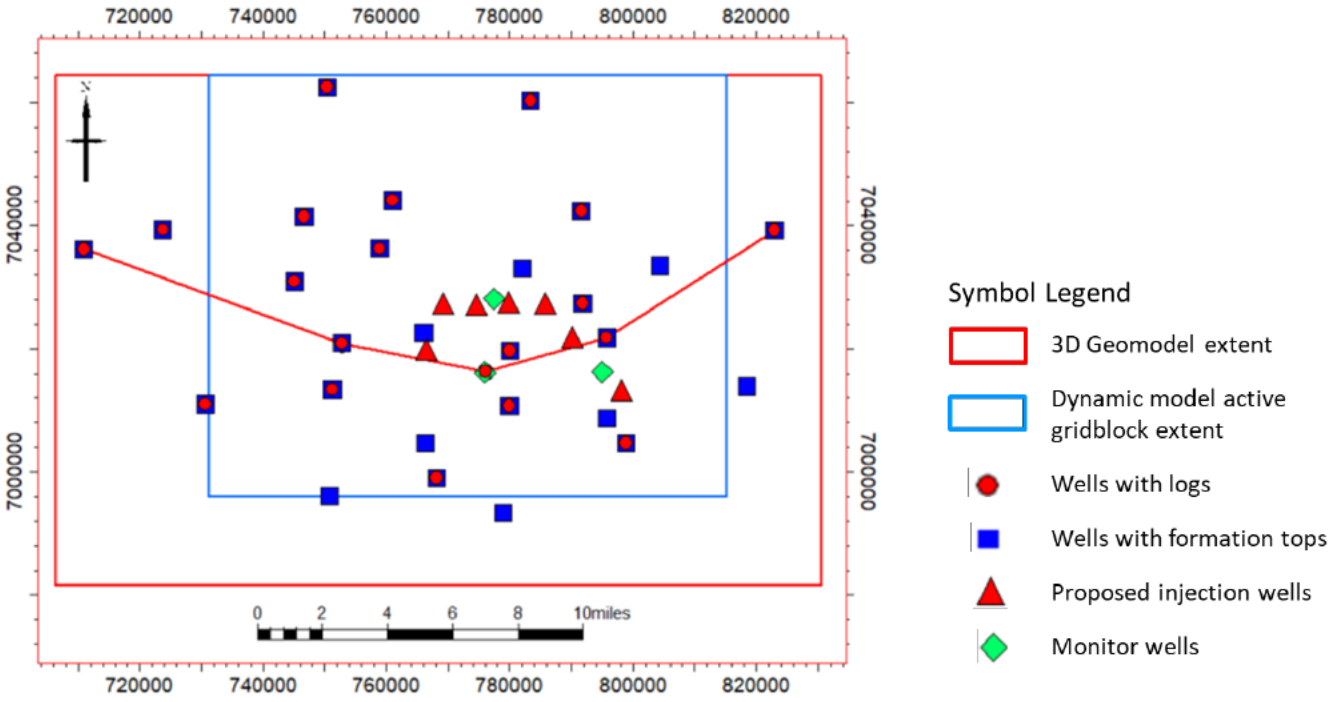


Figure 2-1 – Project area map, showing geomodel boundary and well data coverage. The well cross-section for Figure 2-3 is shown as a red line.

Geocellular model construction includes the following major steps:

- Building the structural framework and creating the 3D grid
- Distributing petrophysical properties (porosity and permeability) through the model

2.2.1 Structural Framework

The structural model was built using 27 wells with formation tops. Table 2-1 summarizes the model horizons. The 3D view of the structural model is shown in Figure 2-2, and the cross-sectional view in Figure 2-3.

Table 2-1 – Model horizons.

Horizon Name
Top Upper San Andres
Top Upper San Andres Injection
Top Lower San Andres Injection
Top Glorieta
Base Glorieta

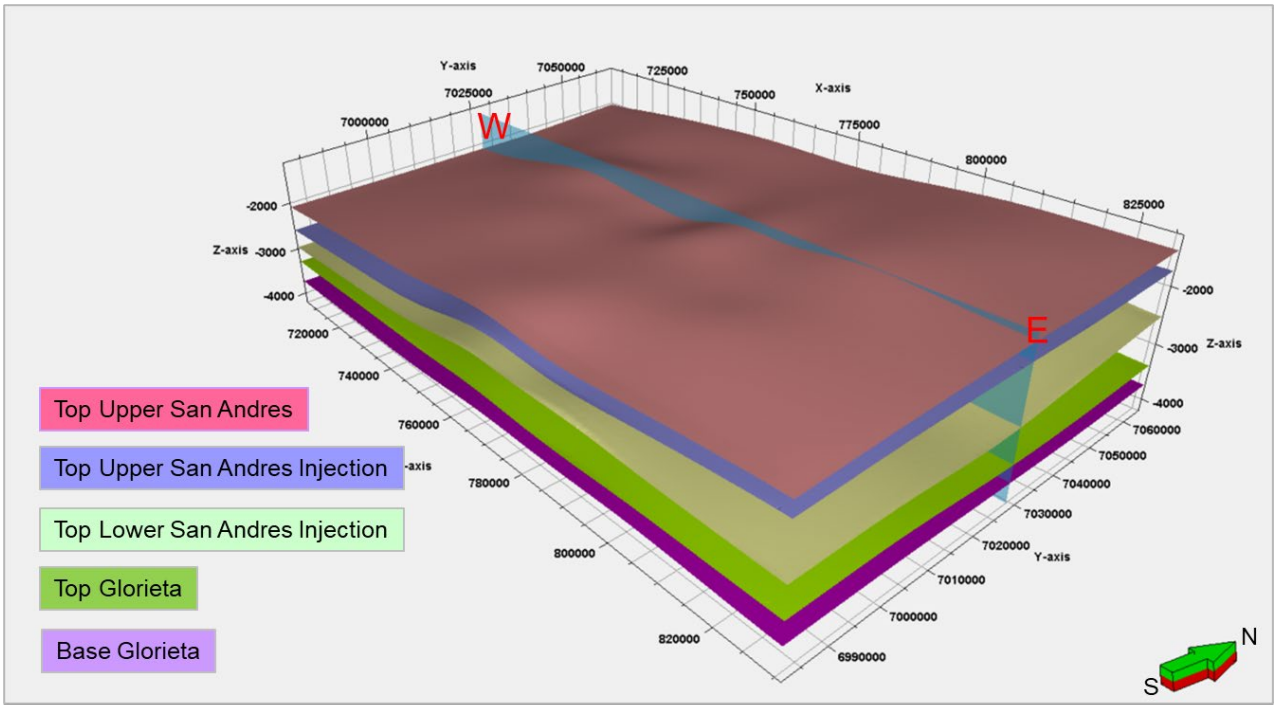


Figure 2-2 – 3D view of the structural model.

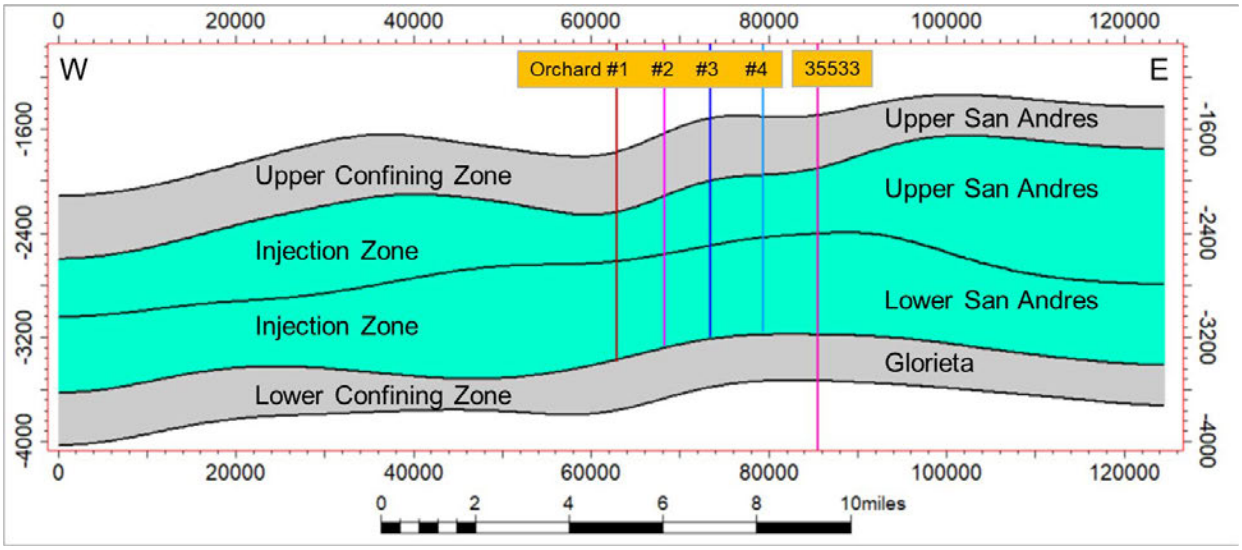


Figure 2-3 – West-east cross-sectional view of the structural model. The cross section slice is shown on Figure 2-1.

Using this structural model, the 3D grid was created with horizontal cell dimensions of 400 ft x 400 ft. Vertically, a proportional layering method was applied leading to the vertical cell dimensions with an average of 8 ft for the injection zone. Table 2-2 provides a summary of the model zones and their gridding parameters. The number of grid cells in the constructed model totaled 10,879,713, with 9,334,665 cells within the injection zones. The structure contour tops for the upper and basal confining units are shown in Figures 2-4 and 2-5, respectively.

Table 2-2 – Model zones and their gridding parameters. Confining zones are highlighted in gray, injection zone – in blue.

Model Zone	Top	Base	No. of Layers	Mean Thickness, ft	No. of Cells
Upper Confining Zone	Top Upper San Andres	Top Upper San Andres Injection	13	32.37	836,901
Injection Zone	Top Upper San Andres Injection	Top Lower San Andres Injection	76	7.45	4,892,652
Injection Zone	Top Lower San Andres Injection	Top Glorieta	69	9.59	4,442,013
Lower Confining Zone	Top Glorieta	Base Glorieta	11	34.63	708,147

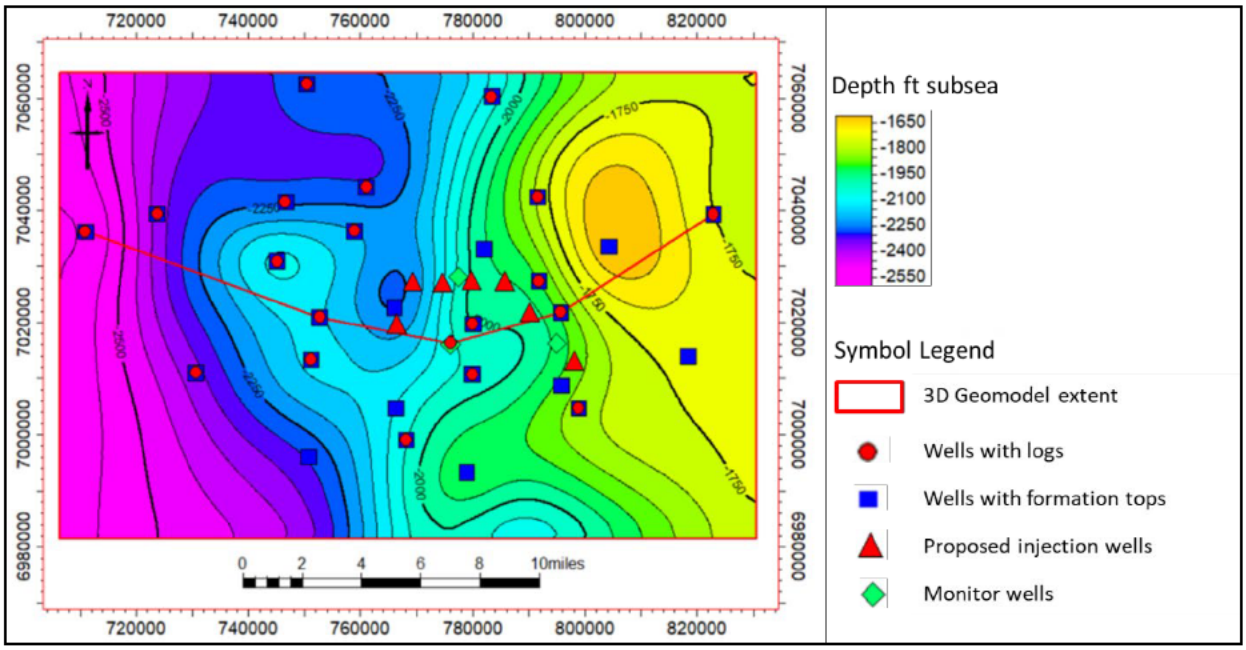


Figure 2-4 – Structural map for the Top of Upper San Andres (Upper Confining Zone)

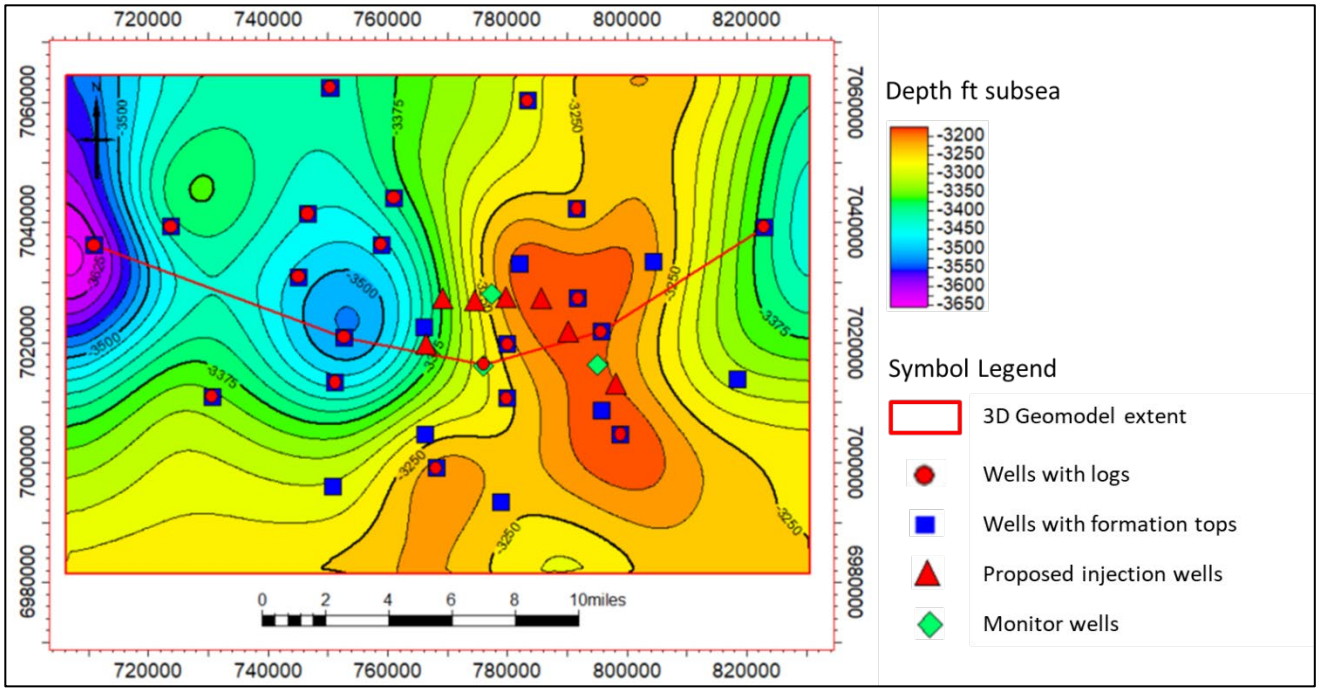


Figure 2-5 – Structural map for the Top of Glorieta (Lower Confining Zone)

2.2.2 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. Porosity logs for 20 wells (Table 2-3), containing sufficient data and porosity-permeability relationships, were developed during the petrophysical study and guided by J. Lucia's Estimating permeability in carbonates using the rock-fabric methods published by BEG (Lucia, 2007).

The porosity logs were upscaled for use in the property model. Figure 2-6 shows calculated and upscaled porosity and permeability.



Figure 2-6 – Well cross section example, showing upscaled generalized porosity (5% cut-off), porosity and permeability (location is shown on Figure 2-1). The cross section is flattened at the Top of Upper San Andres.

Table 2-3– Model zones and number of wells with interpreted porosities.

Model Zone	Wells with Porosity Interpretation
Upper Confining Zone	20
Upper San Andres Injection Zone	20
Lower San Andres Injection Zone	17
Lower Confining Zone	17

Vertical variograms (Figure 2-7) were estimated for porosity and permeability based on well logs. Horizontal variograms were estimated using geologic concepts, well logs and derived from them regional porosity trends, and spatial extent of the produced fields in the area. Tables 2-4 summarizes porosity and permeability variogram parameters for each of the model zones.

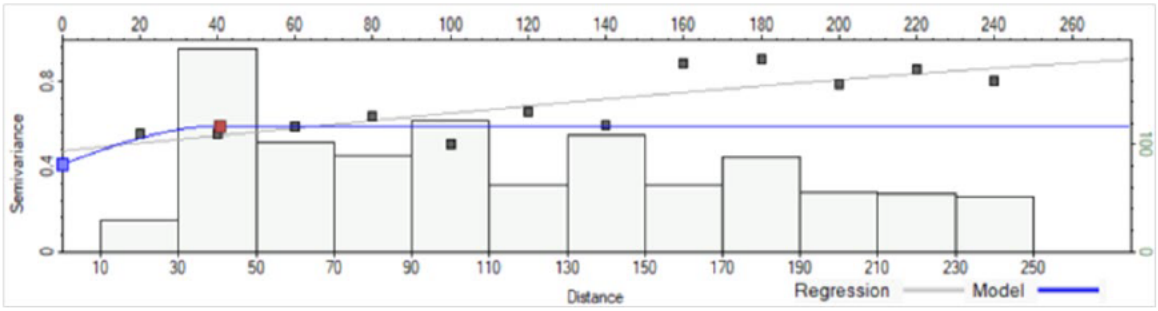


Figure 2-7 – Example of vertical variogram estimated from porosity log data within the injection zone.

Table 2-4 – Porosity and permeability distribution: variogram parameters for the model zones.

Zones	Variogram Parameters	Shale
Upper Confining Zone	Azimuth (degrees)	30
	Major Direction (ft)	15,000
	Minor Direction (ft)	12,000
	Vertical Direction (ft)	40
Injection Zone	Azimuth (degrees)	30
	Major Direction (ft)	15,000
	Minor Direction (ft)	12,000
	Vertical Direction (ft)	40
Injection Zone	Azimuth (degrees)	30
	Major Direction (ft)	15,000
	Minor Direction (ft)	12,000
	Vertical Direction (ft)	40
Upper Confining Zone	Azimuth (degrees)	30
	Major Direction (ft)	15,000
	Minor Direction (ft)	12,000
	Vertical Direction (ft)	40

Upscaled porosities were distributed using Sequential Gaussian Simulation algorithm. The 3D view of the porosity distribution model is shown in Figure 2-8 and cross-sectional view in Figure 2-9. Figure 2-10 shows a porosity distribution histogram indicating that log values were accurately preserved during the upscaling and model construction.

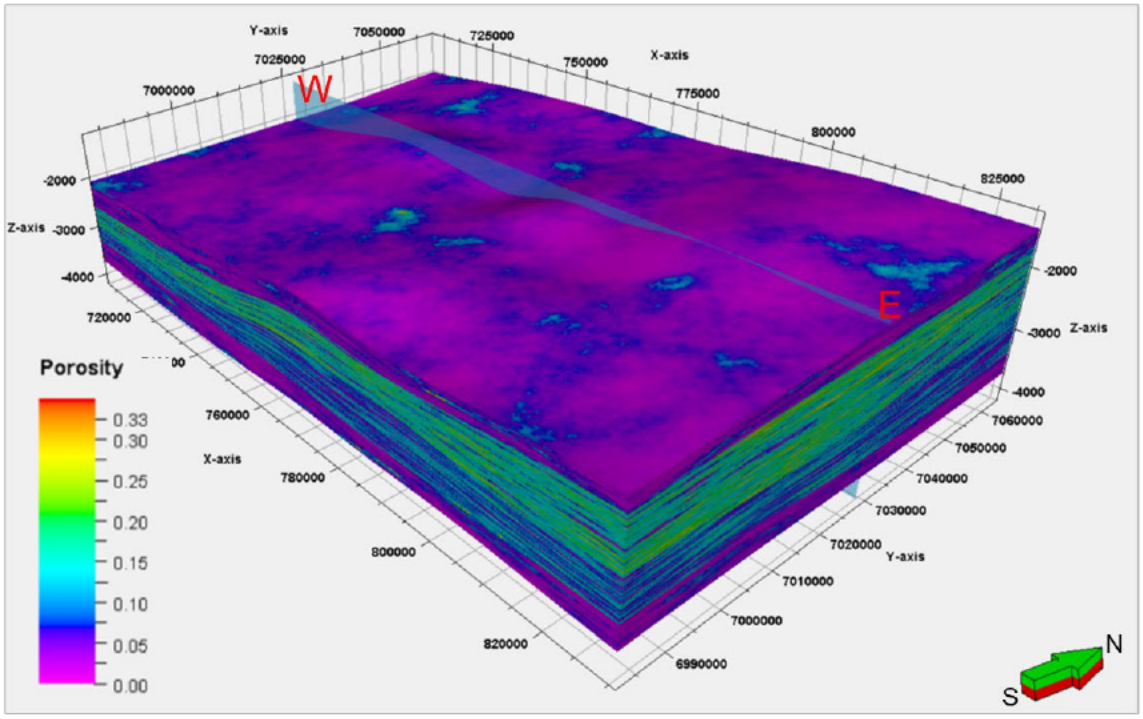


Figure 2-8 – 3D view of the porosity distribution model.

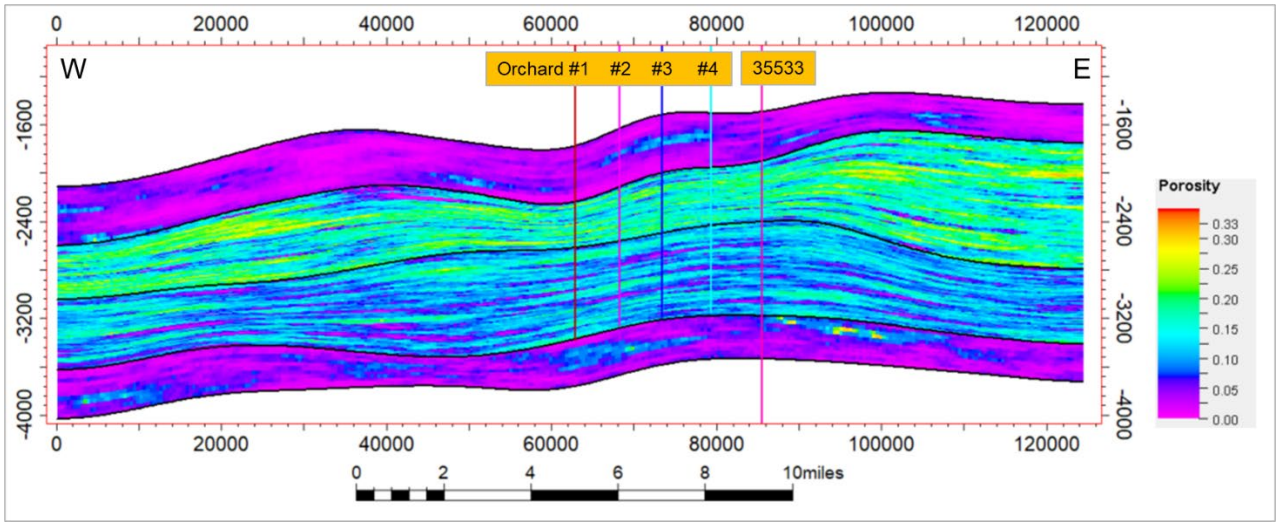


Figure 2-9 – West-east cross-sectional view of the porosity distribution model. The cross section location is shown on Figure 2-8.

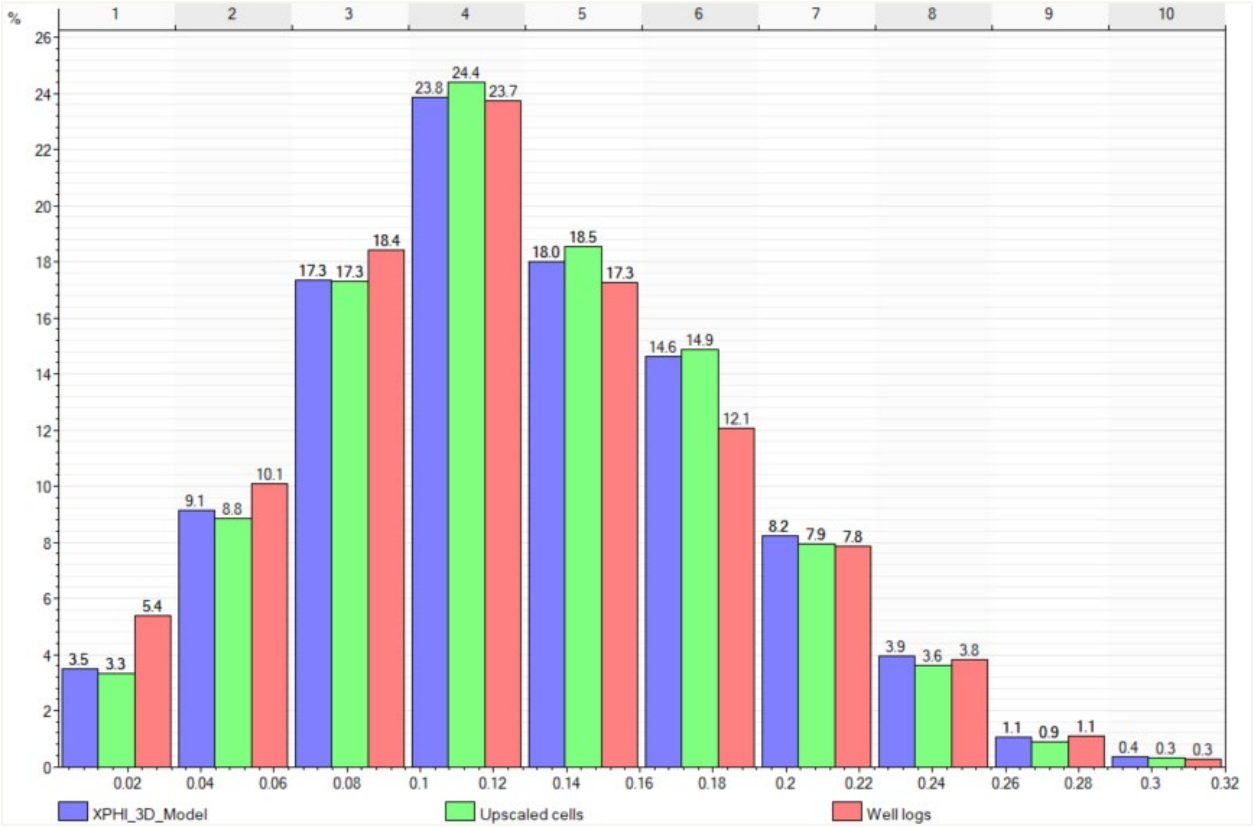


Figure 2-10 – Histogram comparing injection zone porosity from raw logs, upscaled logs, and 3D property model.

The porosity-permeability relationship (Figure 2-11) was tuned by matching injection performance data from the Reliance Valiant SWD No. 1 well (API No. 42-165-38785), located in the central part of the model. The tuned relationship Claimed as PBI is shown in comparison to sidewall core plug porosity and permeability from the same well.

Claimed as PBI



Figure 2-11 – Porosity-permeability transform used in the model, based on the Reliance Valiant SWD No. 1.

The performance-based relationship was used in the dynamic model to calculate permeability based on distributed porosity values. This relationship is discussed further in Section 2.4.

2.3 Trapping Mechanisms

The CO_2 injected into the reservoir will take the form of a mobile, CO_2-rich supercritical phase. In this phase, the CO_2 will displace reservoir fluids as it moves laterally and vertically into the reservoir. Viscous forces created by pressure gradients between the higher-pressure wellbore and

surrounding reservoir will dominate the initial movement of this CO_2 phase. The most significant flow direction will be radially outward from the higher-pressure wellbore into the surrounding lower-pressure reservoir. Vertical movement of CO_2 and displaced fluids may occur within the reservoir due to the heterogeneity between layers in the reservoir.

Figure 2-12 illustrates the lateral movement of CO_2 away from Orchard No. 1 at three-year intervals over the 12-year injection period. These panels show that the dominant direction of movement is horizontally away from the wellbore.

After injection ceases, induced pressure gradients away from the wellbore will dissipate. The movement of CO_2 within the reservoir becomes dominantly vertical, driven by gravity and the density contrast between the CO_2 and formation brine (i.e., buoyancy effects). Figure 2-13 shows snapshots of the CO_2 plume over the 50-year interval post-injection. The first panel (image a) illustrates that, at a depth just below 2,500 ft subsea (see depth scale at left), the layers with the largest plume extent at the end of injection are found. With subsequent time intervals (images b through d), the plume extent in those layers does not expand, but instead moves vertically.

Figures 2-14 through 2-25 then illustrate the same for Orchard No. 2 through No. 7, respectively.

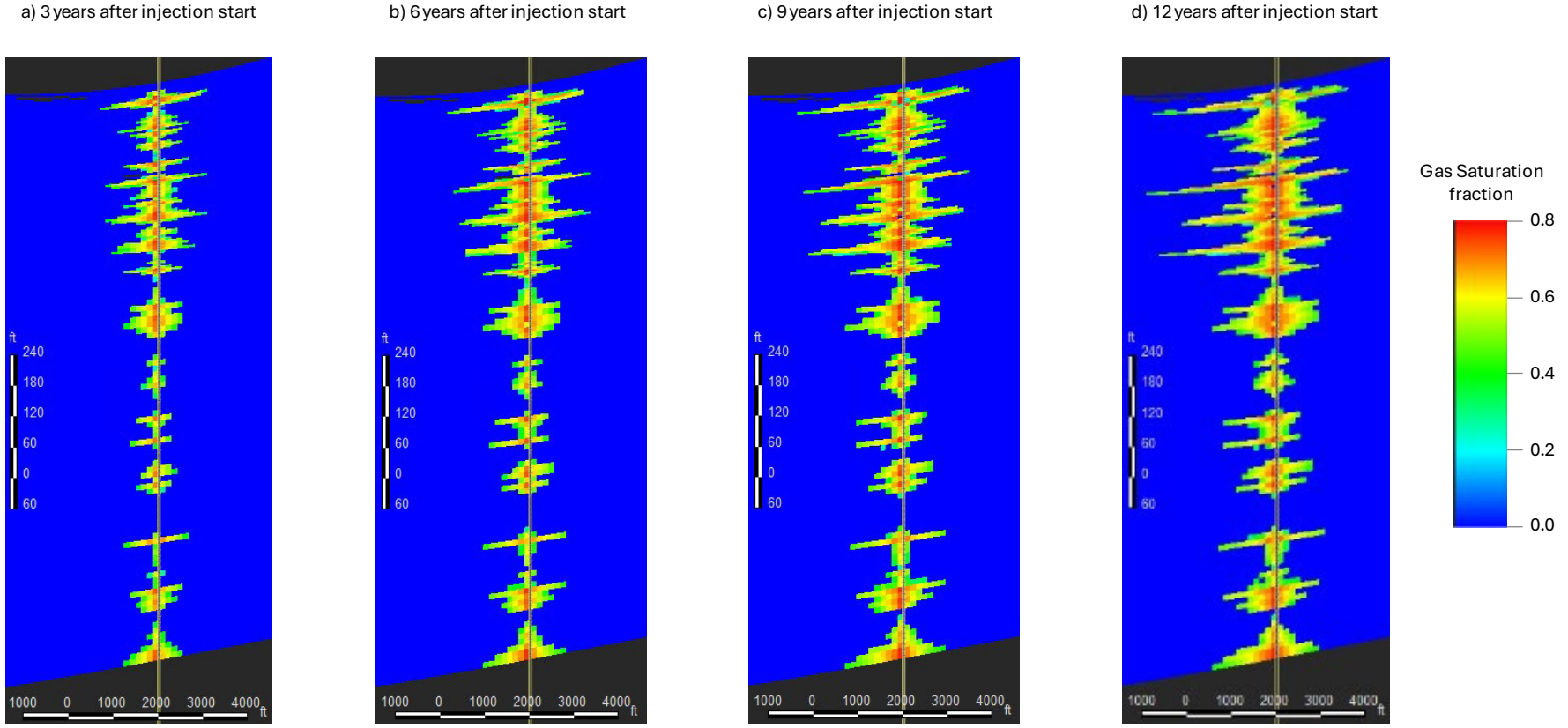


Figure 2-12 – Orchard No. 1 east-west cross-sectional view depicting movement of CO_2 phase during injection.

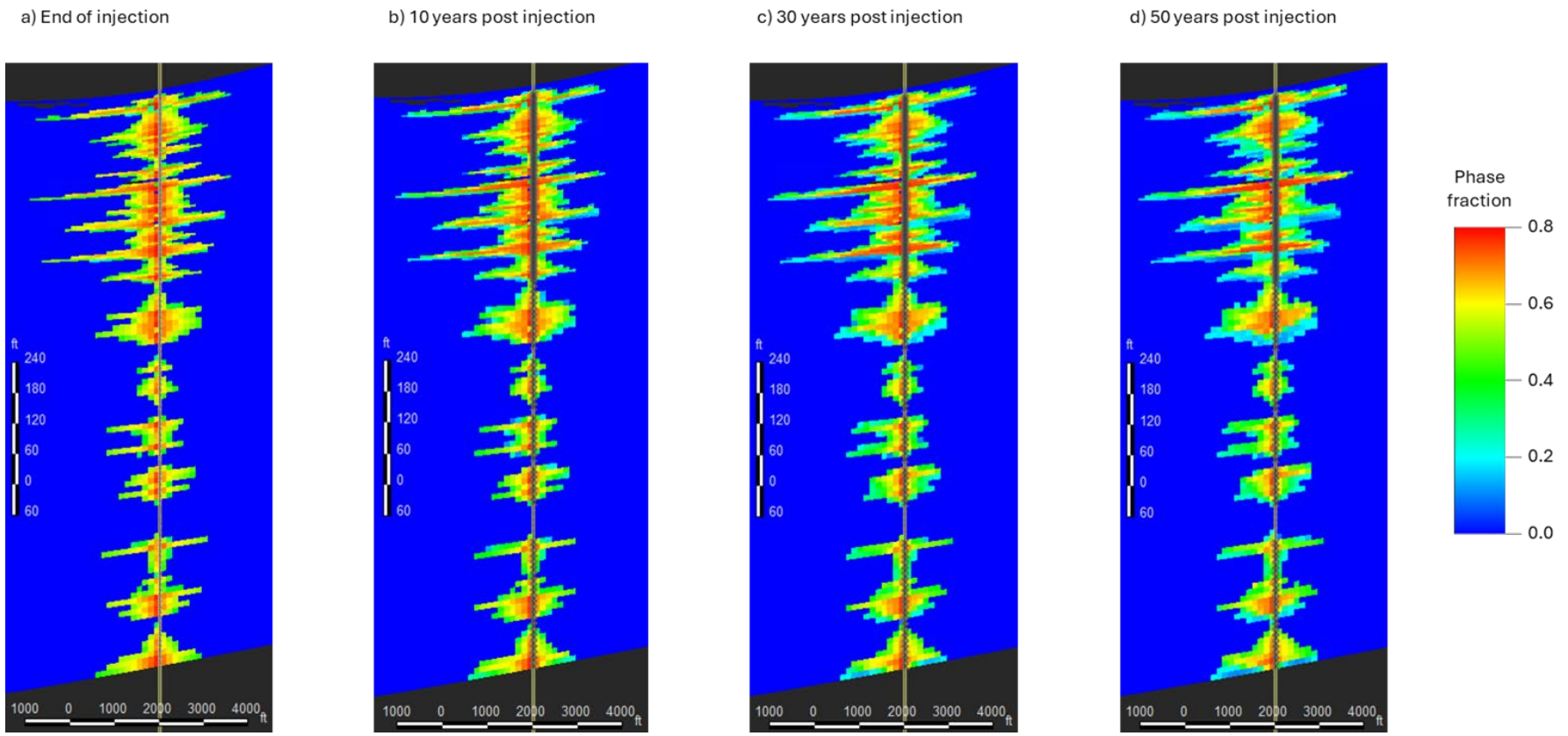


Figure 2-13 – Orchard No. 1 east-west cross-sectional view depicting movement of CO_2 phase post-injection.

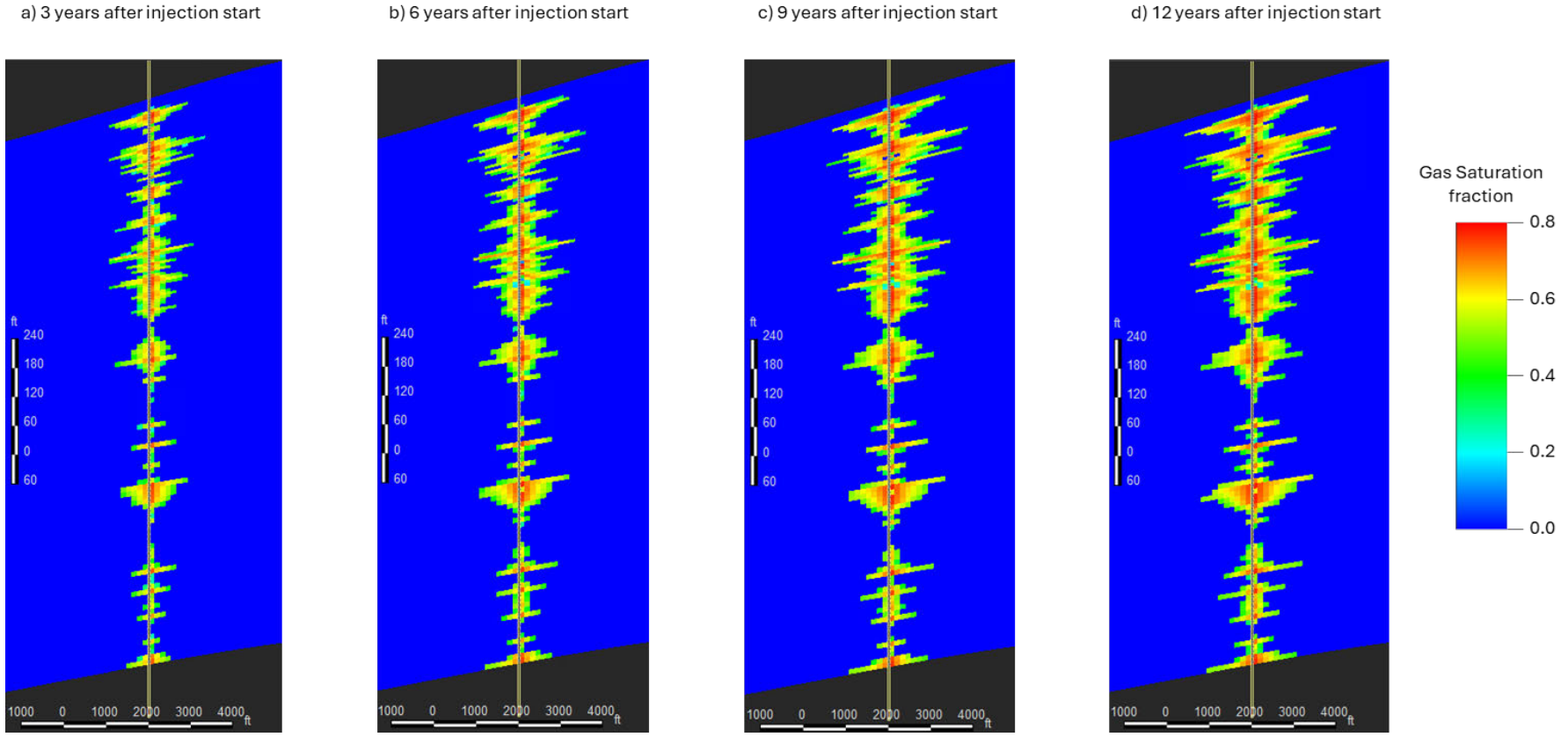


Figure 2-14- Orchard No. 2 east-west cross-sectional view depicting movement of CO_2 phase during injection

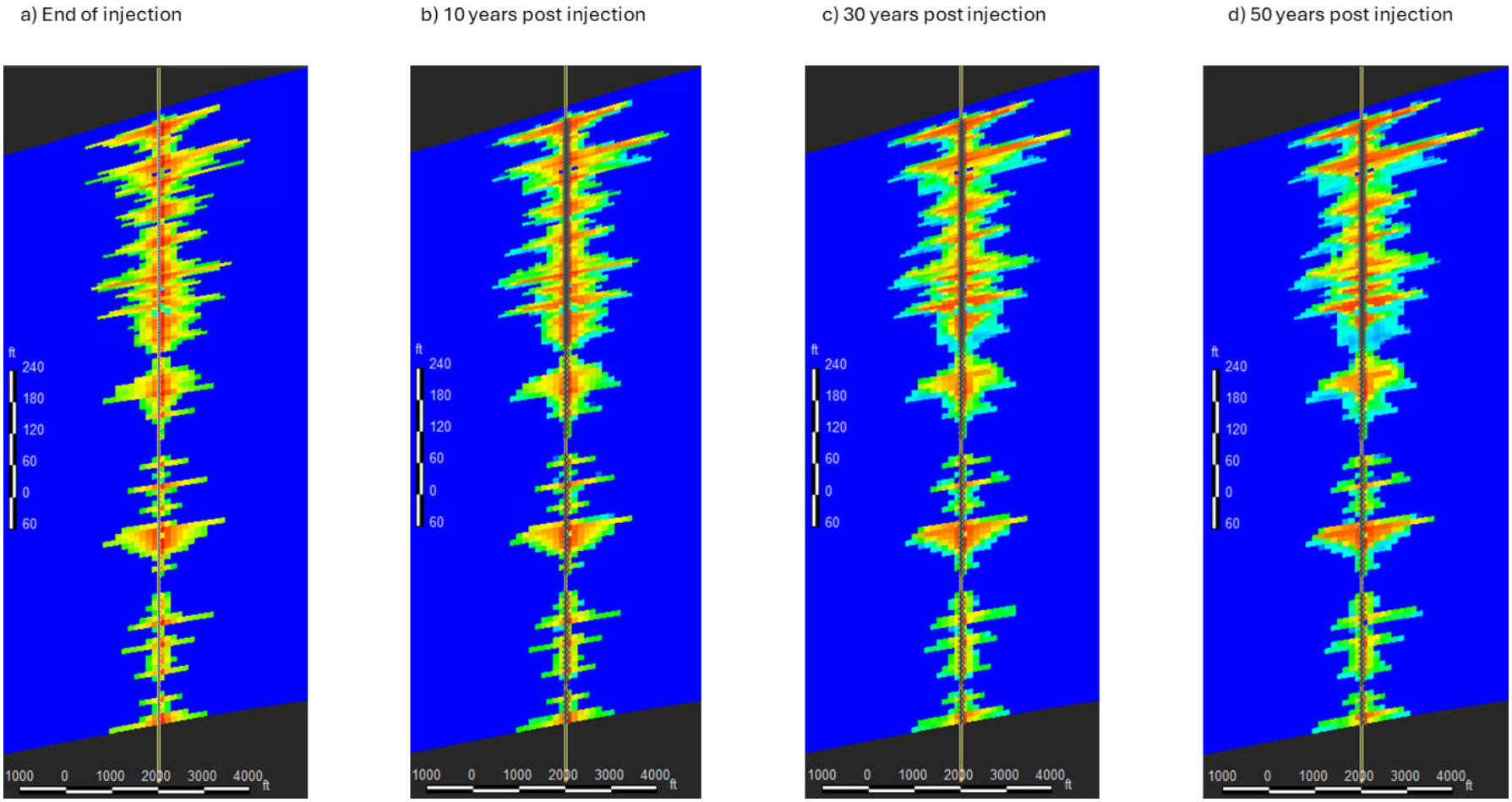


Figure 2-15– Orchard No. 2 east-west cross-sectional view depicting movement of CO_2 phase post-injection.

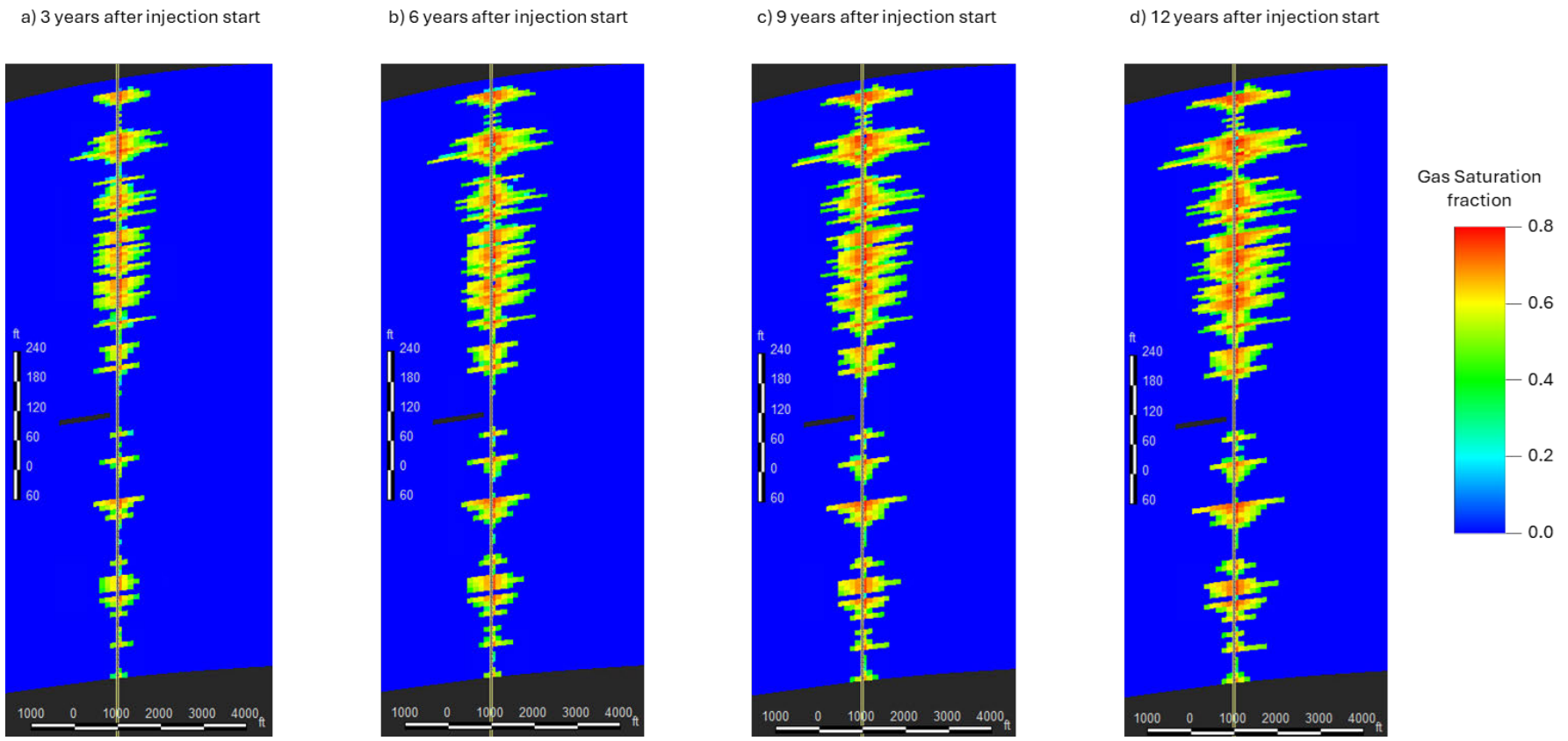


Figure 2-16– Orchard No. 3 east-west cross-sectional view depicting movement of CO_2 phase during injection.

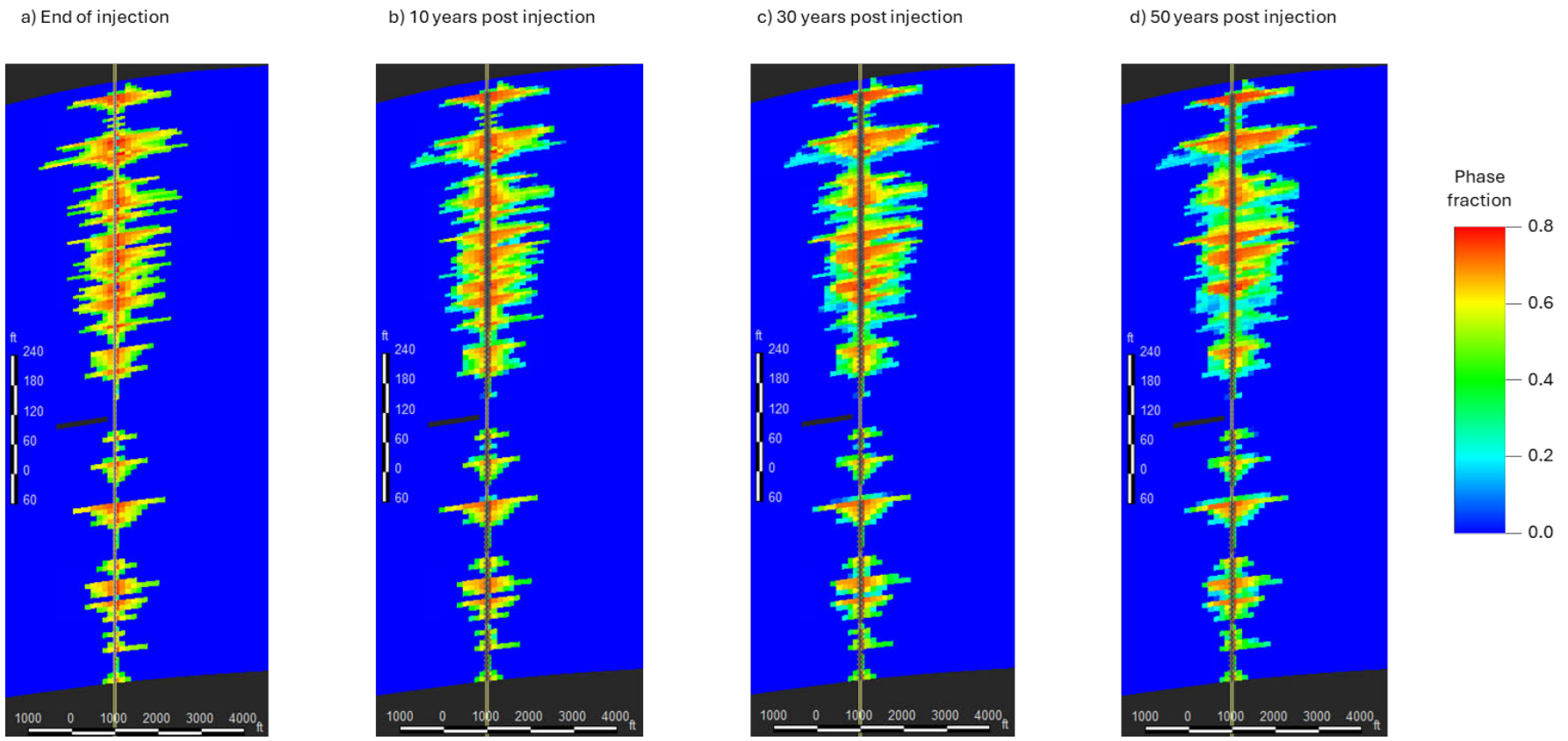


Figure 2-17– Orchard No. 3 east-west cross-sectional view depicting movement of CO_2 phase post-injection.

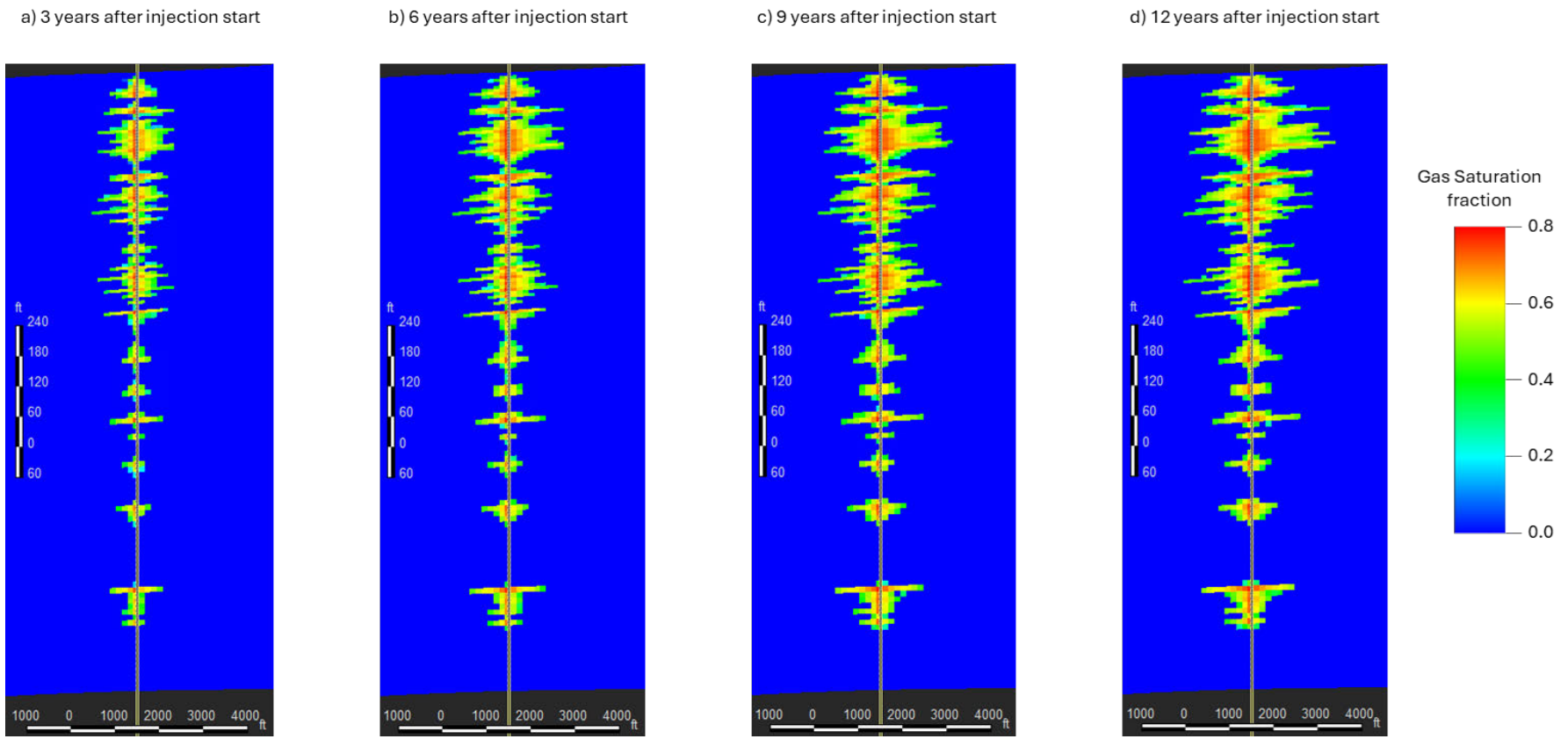


Figure 2-18– Orchard No. 4 east-west cross-sectional view depicting movement of CO_2 phase during injection.

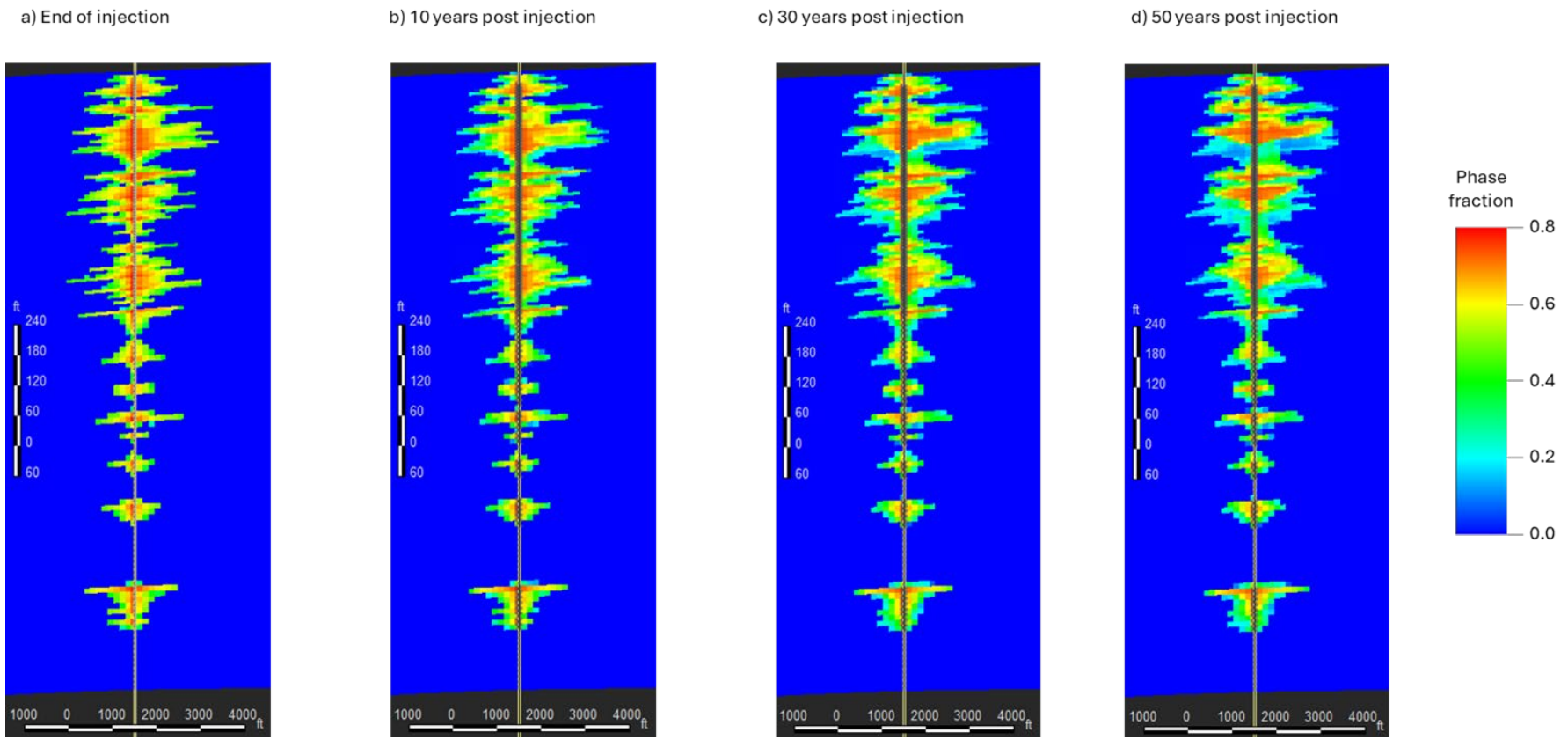


Figure 2-19– Orchard No. 4 east-west cross-sectional view depicting movement of CO_2 phase post-injection.

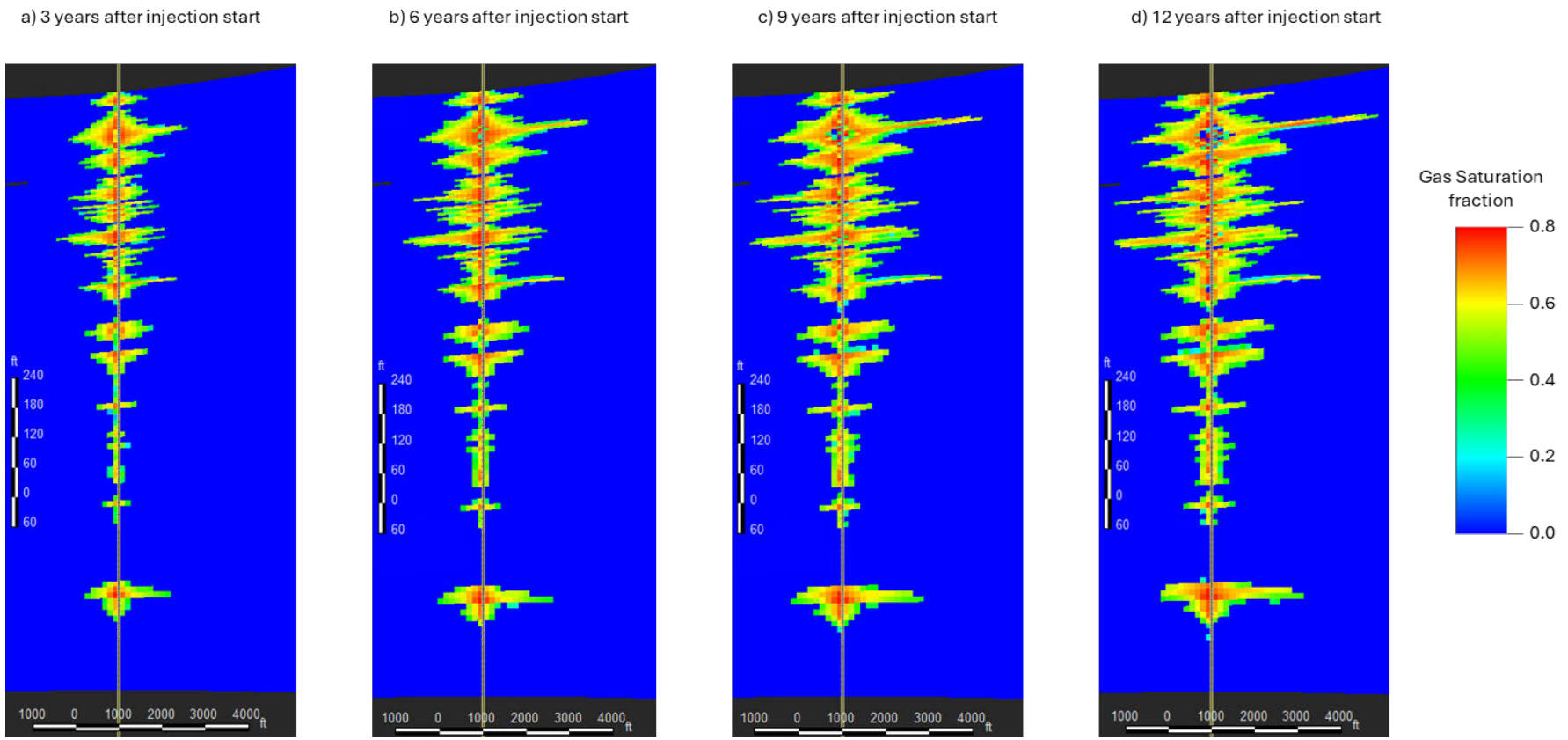


Figure 2-20 – Orchard No. 5 east-west cross-sectional view depicting movement of CO_2 phase during injection.

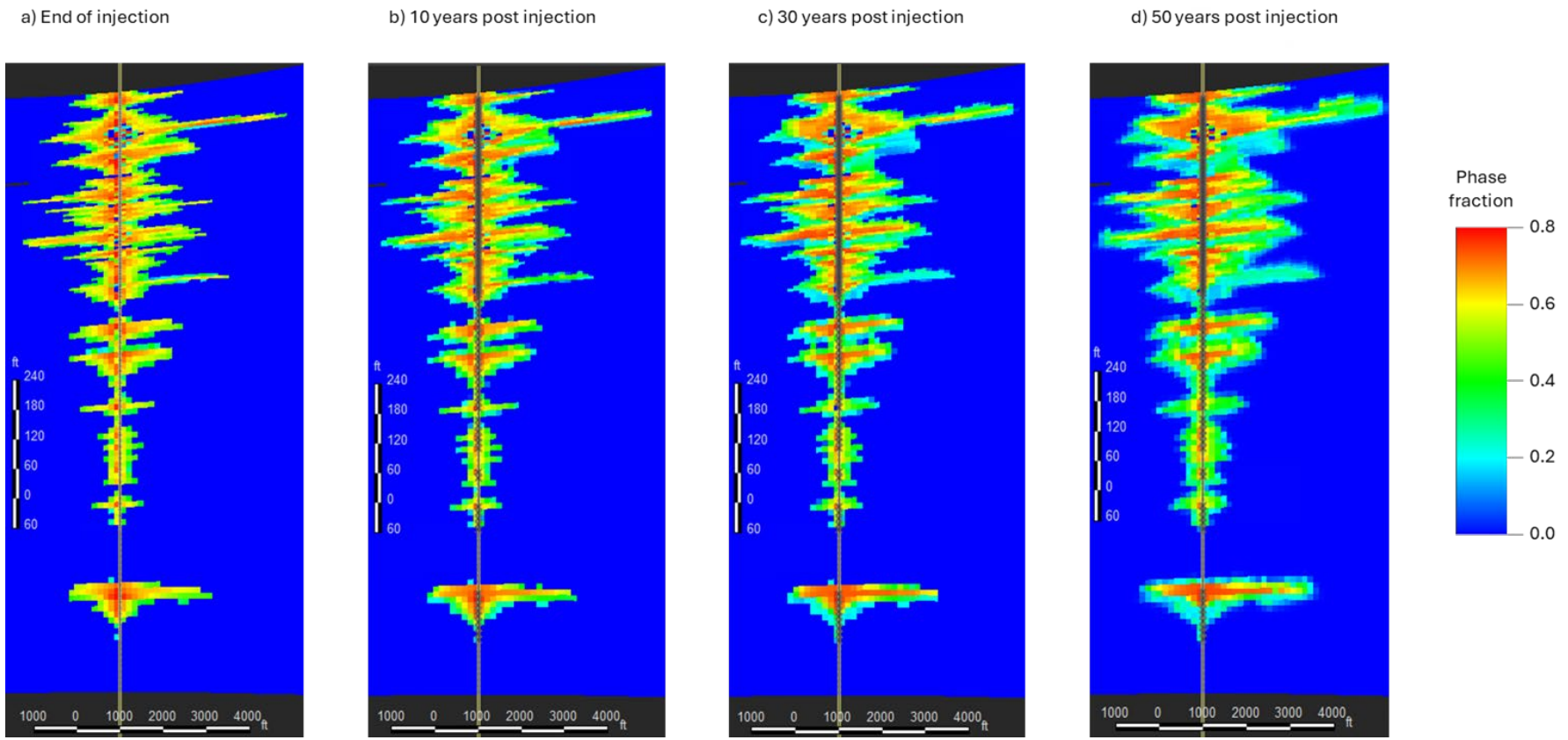


Figure 2-21– Orchard No. 5 east-west cross-sectional view depicting movement of CO_2 phase post-injection.

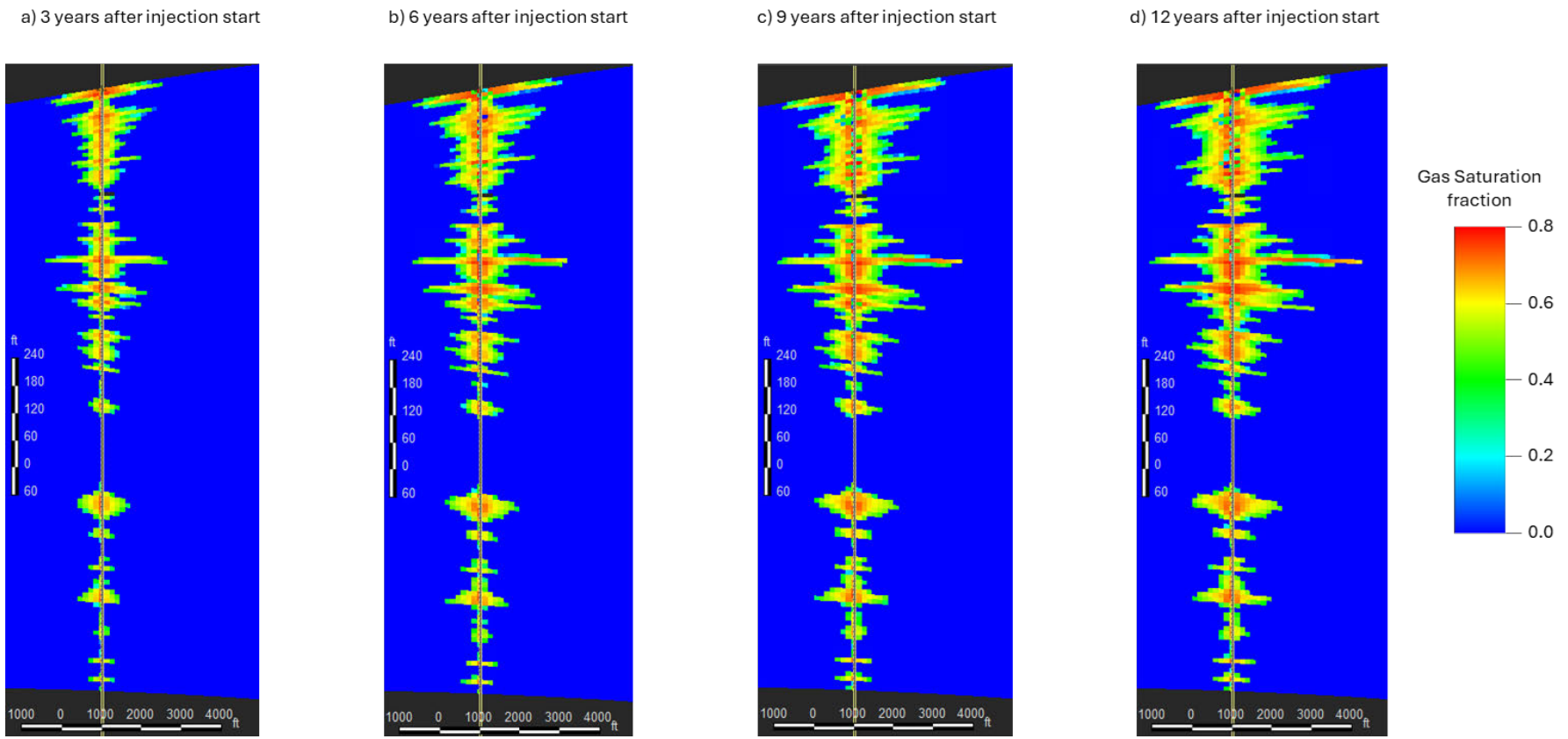


Figure 2-22– Orchard No. 6 east-west cross-sectional view depicting movement of CO_2 phase during injection.

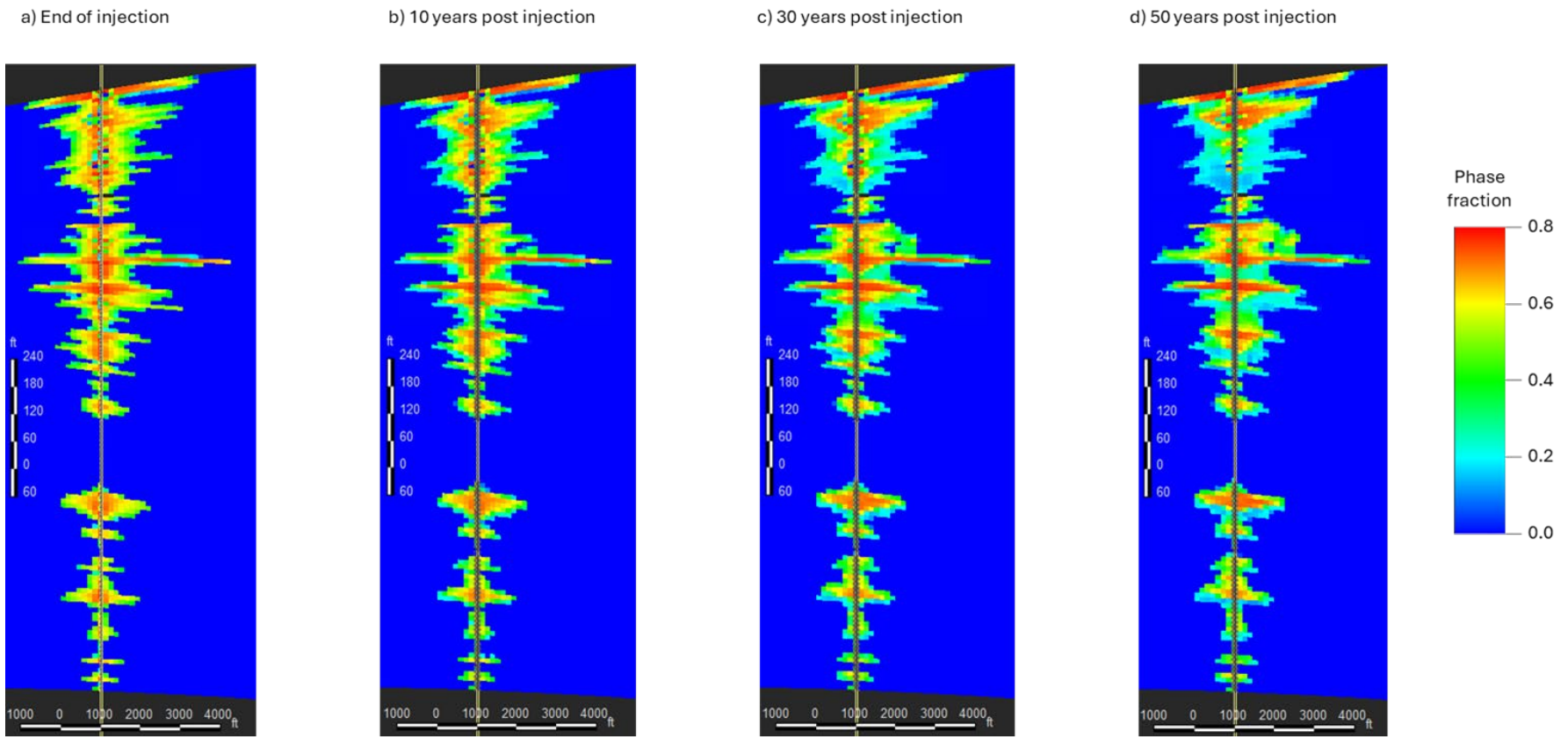


Figure 2-23– Orchard No. 6 east-west cross-sectional view depicting movement of CO_2 phase post-injection

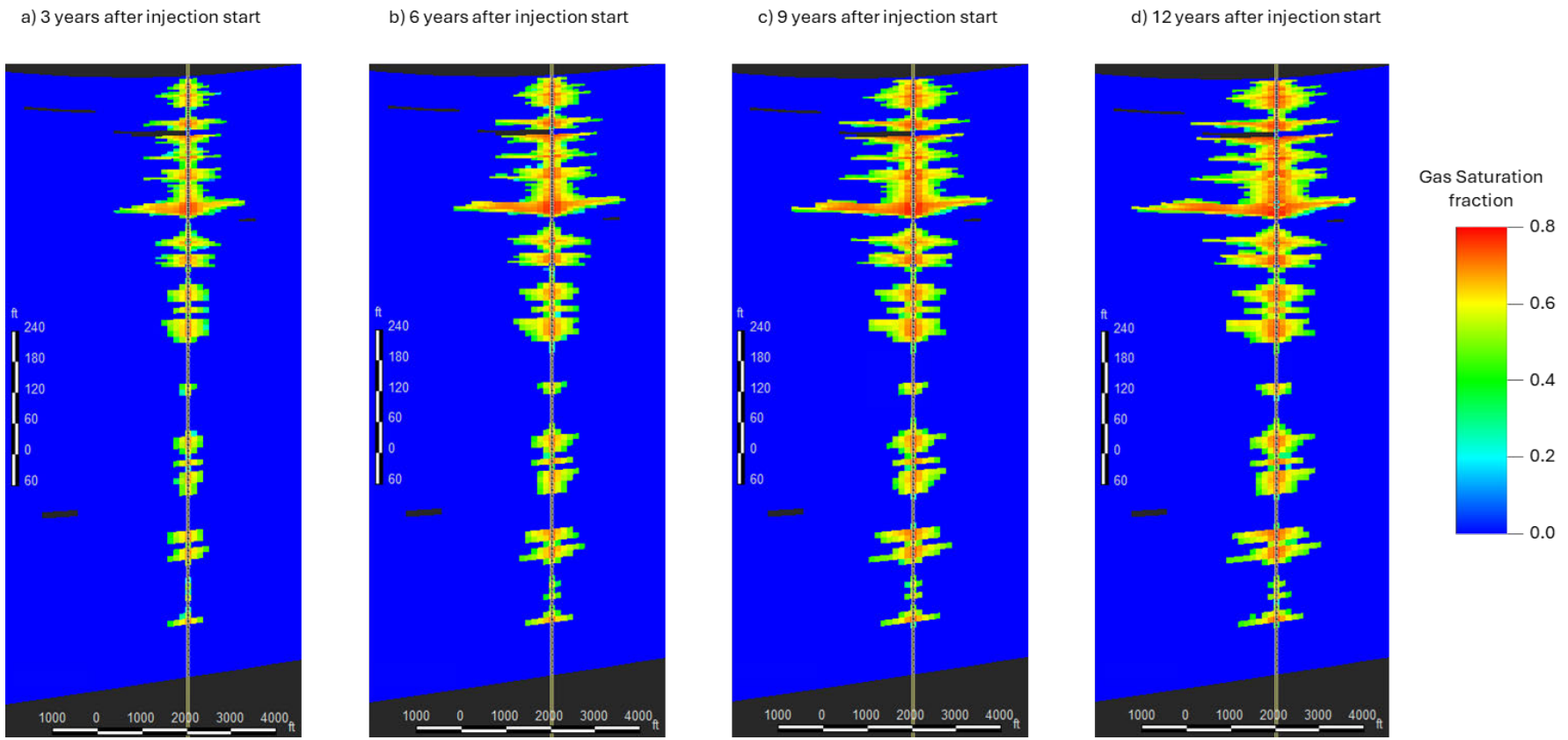


Figure 2-24 – Orchard No. 7 east-west cross-sectional view depicting movement of CO_2 phase during injection

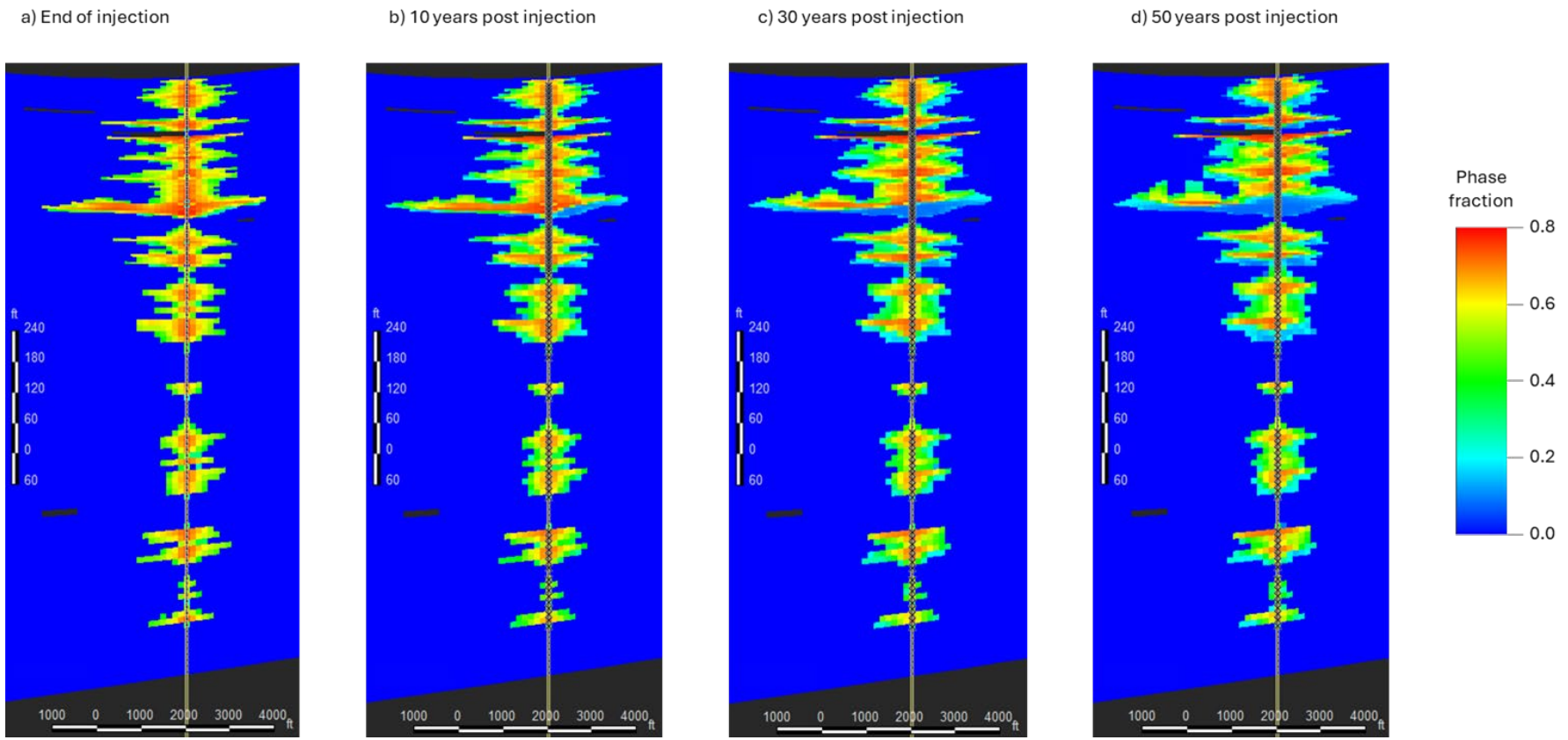


Figure 2-25 – Orchard No. 7 east-west cross-sectional view depicting movement of CO_2 phase post-injection

Movement of the CO_2 phase does not continue indefinitely. As the CO_2 moves both vertically and horizontally, various trapping mechanisms immobilize the CO_2 within the reservoir. The most significant trapping mechanism is the presence of the upper confining zone, which stops vertical movement of the CO_2. The other important mechanisms for trapping are residual gas (relative permeability) trapping, dissolution of the CO_2 into formation brines, and condensing of CO_2 into immobile residual oil. Furthermore, trapping can occur from geochemical and structural effects.

2.3.1 Structural Trapping

Within our area of interest, the primary structural trapping mechanism in the upper confining zone. Vertical movement of CO_2 will be contained by the low permeability Upper San Andres and Grayburg confining intervals above the injected interval. The thick intervals (approximately 300 ft) of predominantly dolomitic beds with anhydritic alteration will act as a barrier to vertical movement of the relatively buoyant CO_2 through capillary pressure and relative permeability effects.

The dip angle through the Orchard Project area is approximately 1.5 degrees, down to the west. (Formation dips were discussed further in *Section 1.4.1*.) The localized near-wellbore dips may affect some slow updip migration of CO_2 plumes; however, because of the gas trapping mechanism, the overall impact of these local dips is small.

2.3.2 Residual Gas Trapping

While the CO_2 will remain in the supercritical phase within the storage interval ("reservoir"), the gas-liquid relative-permeability relationships will govern fluid flow between the CO_2 and liquid phases present. "CO_2 phase," "supercritical," and "gas" may therefore be used interchangeably in this discussion.

Relative permeability effects on fluid flow depend on the direction of saturation changes. The displacement of brine by injected CO_2 (the *drainage* process) behaves differently than the reverse (the *imbibition* process). During the CO_2 injection, the drainage process controls the relative permeability behavior, as injected CO_2 displaces the brine found in the reservoir. In this process, the non-wetting phase occupies the most favorable flow channels, allowing the CO_2 to be mobile at very low initial saturations. When water is displacing CO_2 under the imbibition process, the increasing saturations of the brine will bypass volumes of CO_2, leaving a portion of the CO_2 phase in an immobile condition (Land C. S., 1971) (Land C. , 1968).

The imbibition process becomes important after injection ceases and gravity forces begin to drive CO_2 movement. As CO_2 moves out of a rock volume, brine will flow to fill what the CO_2 "vacated." The residual (i.e., trapped) CO_2 saturation in a simulator grid block will be a function of the maximum trapped gas parameter and the CO_2 saturation at the beginning of the imbibition process (Land C. , 1968). The trapped CO_2 saturation will be at the maximum value for rock volumes in which the liquid saturation was displaced down to its residual value by the CO_2 phase prior to the imbibition.

Typical maximum trapped-gas-saturation parameters range from around 30% to more than 40%. Experimental data in carbonates have shown this parameter to vary between 23% and 69% (Keelan, 1975). A statistical representation of the trapped gas data from Keelan is shown in Figure 2-26. The trapped gas saturation parameter is plotted versus a normal probability function, with horizontal

grid lines scaled to represent percentile probability values. In this plot, "P_{90}" represents a value for which 90% of the data will fall below this value. In the scaling of the plot, a straight line represents a normal probability distribution.

In the tNavigator simulator used to characterize the CO_2 plume movement, the maximum trapped gas saturation parameter was set to 30% of the pore volume. This assumption represents a conservative value (i.e., more favorable to the spread of a CO_2 plume) as compared to a median value of 37%.

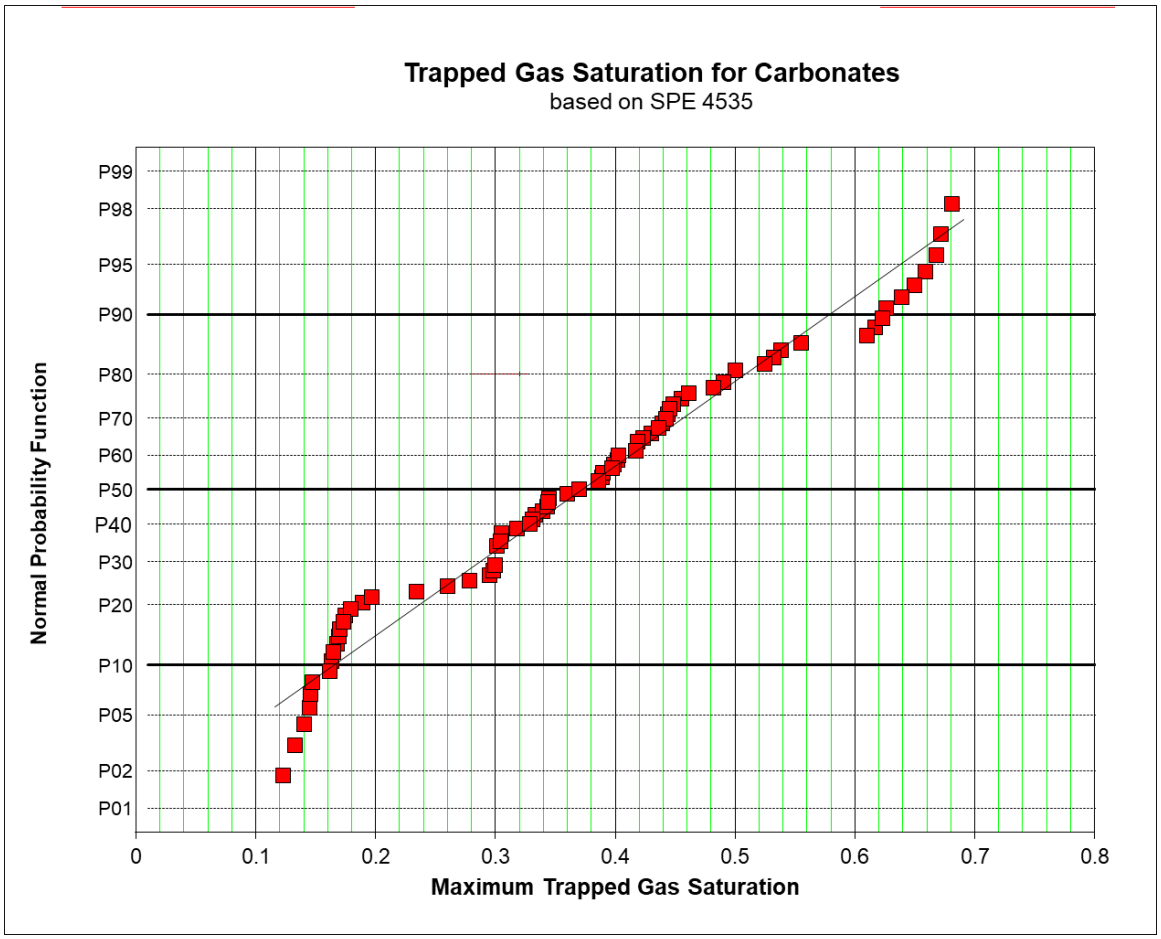


Figure 2-26 – Trapped Gas Saturation Experimental Data ((Keelan, 1975)

The effect of trapped gas was illustrated in Figure 2-13 for Orchard No. 1 (then in Figures 2-15, 2-17, 2-19, 2-21, 2-23, and 2-25 for Orchard No. 2 through No. 7, respectively), where the four panels show how the mobile CO_2 saturations migrate vertically over time. The areas with higher (mobile) saturations of the CO_2 phase are represented by the warmer shades (yellow to red) on the color scale. As the mobile CO_2 moves away from grid blocks, cells are shaded a uniform green, representing saturations at or near the trapped (immobile) saturation of CO_2.

2.3.3 Solubility Trapping

2.3.3.1 Solubility Trapping in Brines

The solubility of CO_2, nitrogen gas (N_2), and hydrocarbon components in the water phase is incorporated into the simulation model. The fluid model used Harvey's correlations (Harvey, 1996) for Henry's Law coefficients for the CO_2, nitrogen, and methane components. With the modeled reservoir conditions, brine contacted by the CO_2 phase may have up to 1.9 mole percent of CO_2. This value contrasts with the trace initial CO_2 saturations (0.008 mole percent) before CO_2 contact. As mobile CO_2 moves within the reservoir, it will contact "new" brine, which will solubilize additional volumes of CO_2. Additionally, the CO_2-rich water phase has a slightly higher density than the initial water in place, differing by approximately 1%. Over centuries, there may be convective mixing of the water phases, resulting in the solubility trapping of additional moles of CO_2 within the water phase.

2.3.3.2 Solubility Trapping in Residual Oil

The presence of a residual oil zone (ROZ) over much of the San Andres is well documented (Kuuskraa, Petrusac, & Wallace, A Four-County Appraisal of the San Andres Residual Oil Zone (ROZ) "Fairway" of the Permian Basin, 2020). That report, along with its associated supporting data (Kuuskraa, Petrusak, & Wallace, ROZ Database, 2020), includes a section ("2.10 Partition #5.") describing ROZ properties in eastern Gaines County, where the Orchard project is located.

Sidewall core (SWC) plugs taken from the Valiant No. 1D well (API No. 42-165-38785), located in the central part of the project area, encountered residual oil though the San Andres section. Table 2-5 describes the distribution of oil saturations from the SWC plugs. In situ saturations were calculated to correct for shrinkage due to evolution of dissolved gas as the core plugs are brought to the surface. That correction was made using an oil formation volume factor of 1.2.

Table 2-5 – Gross Injection Interval and Modeled ROZ Parameters

Statistical Measure	Measured Oil Saturation (percent)	In Situ Oil Saturation (percent)
Average	14.6	17.5
Minimum	1.5	1.8
Maximum	18.9	22.7
P_{10}	10.1	12.1
P_{50} (median)	15.6	18.7
P_{90}	18.1	21.7

Based on these data, the reservoir simulation model was initialized with a constant residual oil saturation of 19% based on the median value encountered in the core. The NETL report presents average residual oil saturation for the "low quality" zones in the Upper- and Lower-San Andres of 17% and 16%, respectively: The values in Table 2-5 corresponds to those from the report.

Under the right conditions of pressure, temperature, and reservoir oil composition, CO_2 can be highly miscible with in situ oil. While not "first contact" miscible, as observed in the mixing of kerosene and gasoline, the CO_2 can achieve complete miscibility through a multi-contact process. This process entails simultaneous evaporation of lighter oil components into the CO_2-rich gas phase along with condensation of CO_2 into the hydrocarbon phase. This process forms a transition phase that is miscible with both the injected CO_2 and in-place oil phases (Stalkup, 1983)

The key feature of the miscible behavior between CO_2 and reservoir oil regarding the Orchard Project is the significant solubility of CO_2 in the oil phase. Within the ROZ, oil-bearing grid blocks adjacent to the CO_2 plume can contain oil with a mole fraction of CO_2 greater than 60%. In the seven ROZ layers of the simulation model, the amount of CO_2 contained in the oil phase at the end of injection is more than three times the amount of CO_2 dissolved in brine.

Because of the significant amount of CO_2 contained within oil adjacent to the CO_2 phase, the CO_2 plume is tracked as the total effective saturation of CO_2—that is, the mole fraction of CO_2 in each of the phases present multiplied by the saturation of the respective phase:

(Eq. 2) $$S_{CO_2\,e} = S_o \cdot x_{CO_2} + S_g \cdot y_{CO_2} + S_w \cdot w_{CO_2}$$

Where S_o, S_g, and S_w are the respective saturations of the oil, gas (supercritical), and water phases, and x_{CO_2}, y_{CO_2}, and w_{CO_2} are the respective mole fractions of CO_2 within each of those phases, $S_{CO_2\,e}$ is the effective total CO_2 saturation.

Figure 2-27 illustrates the comparison of CO_2 phase saturation and the effective total CO_2 saturation at the end of injection and 50 years post-injection for Orchard No. 1. This shows how the effective CO_2 front extends further than does the CO_2-only phase. The difference between the pairs of panels (image a versus b, and c versus d, respectively) is most prominent in the layers where the colors representing CO_2 presence have a larger lateral extent. The primary source of this difference is the CO_2-rich oil phase ahead of the supercritical phase front.

Figures 2-28 through 2-33 then show the same for Orchard No. 2 through No. 7, respectively.

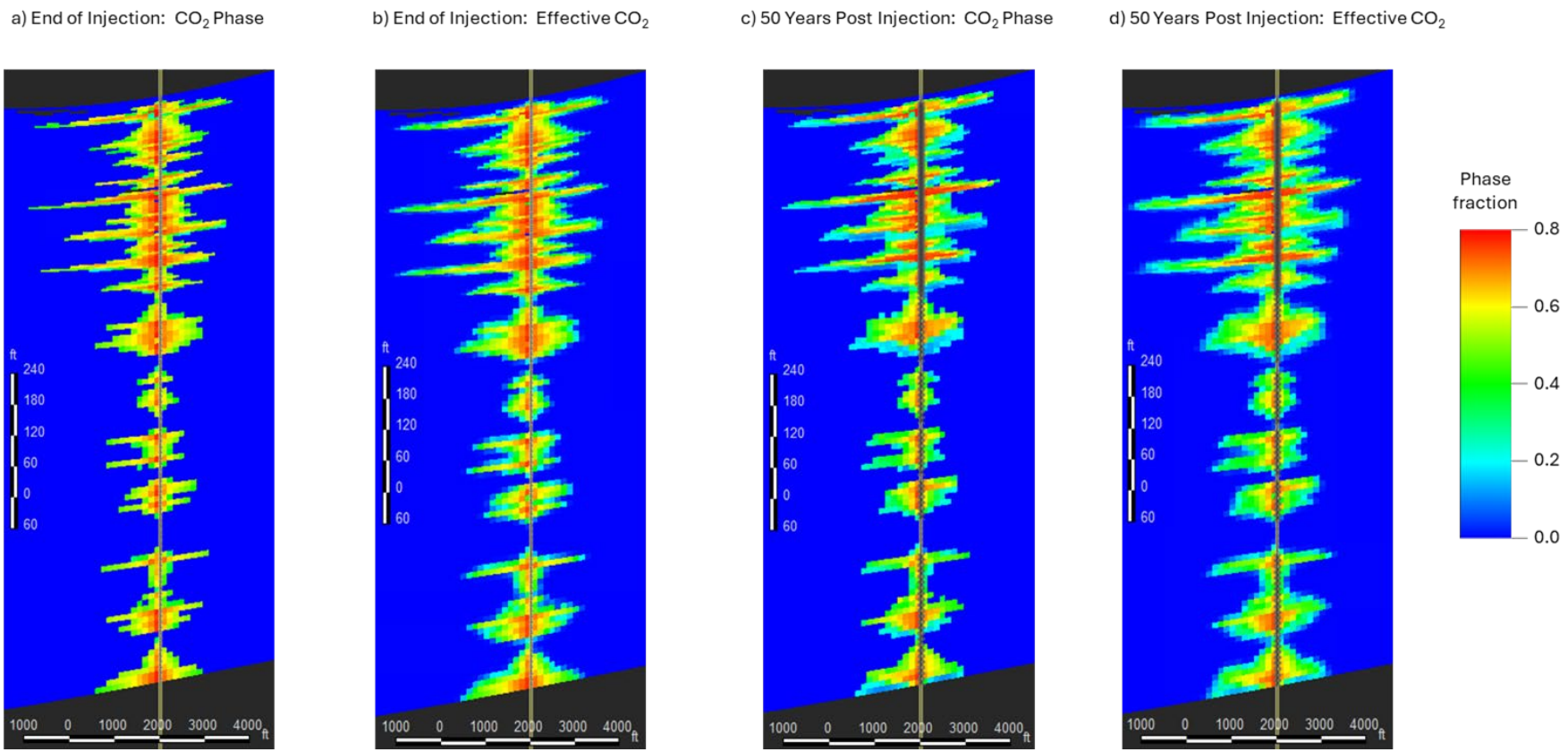


Figure 2-27 – Orchard No. 1 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

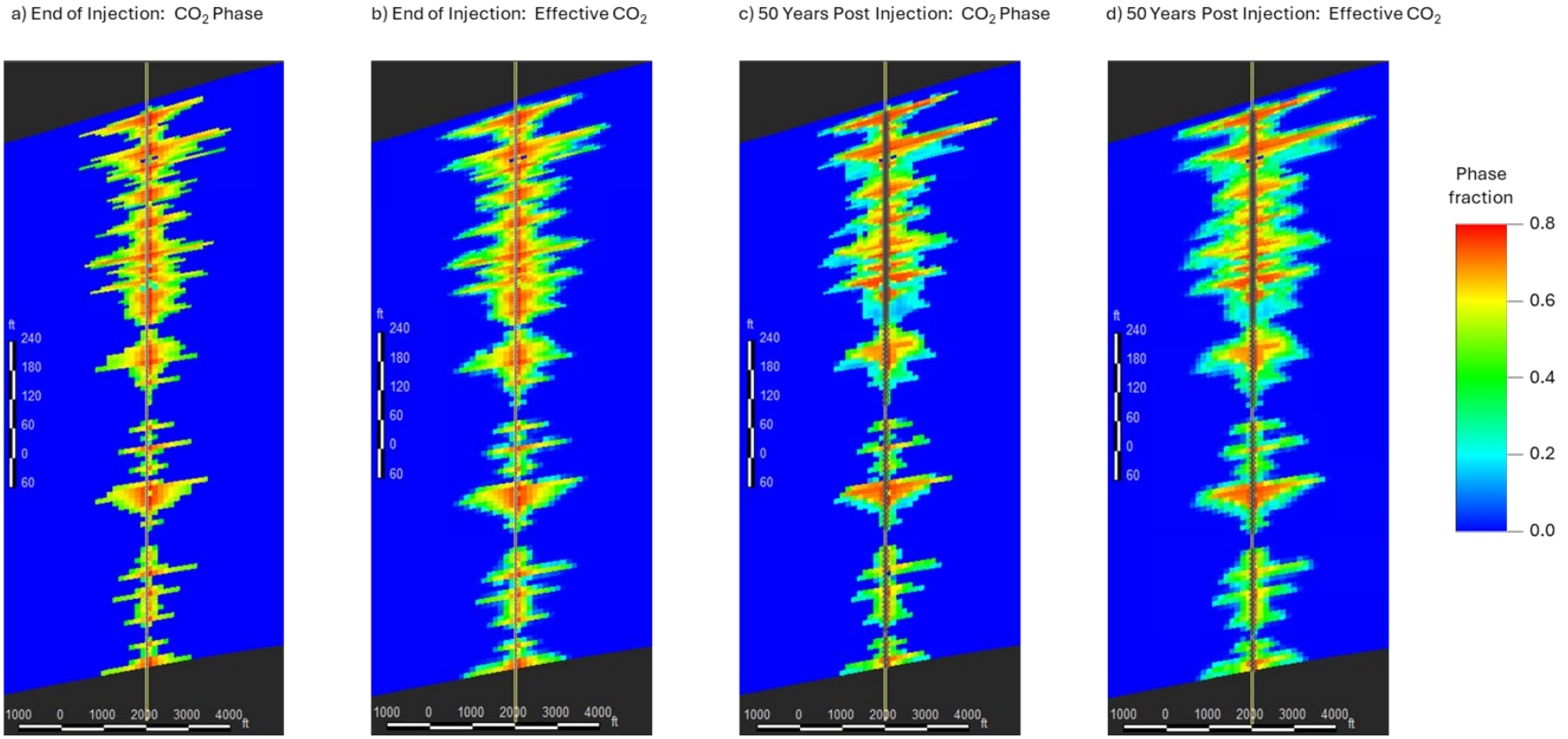


Figure 2-28 – Orchard No. 2 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

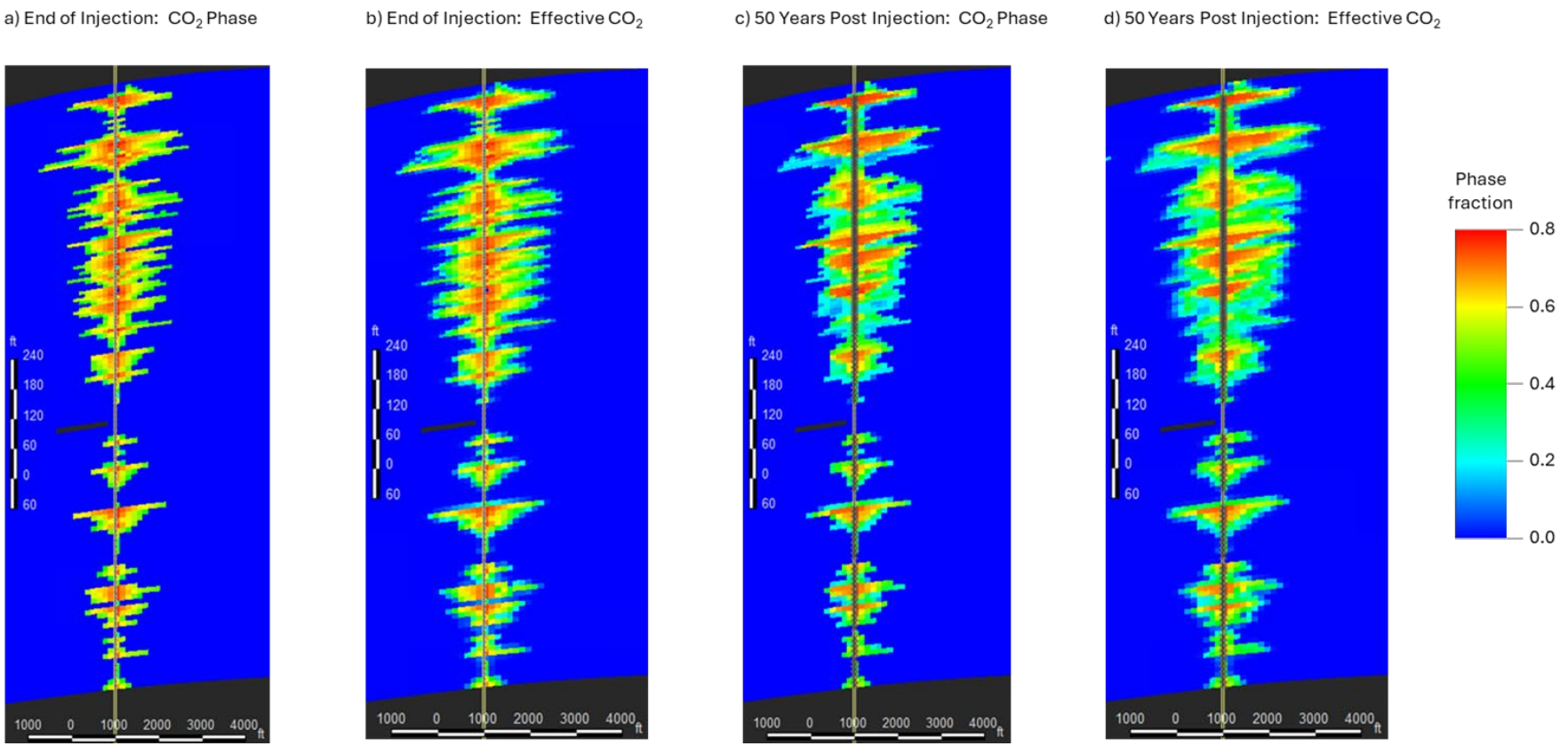


Figure 2-29 – Orchard No. 3 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

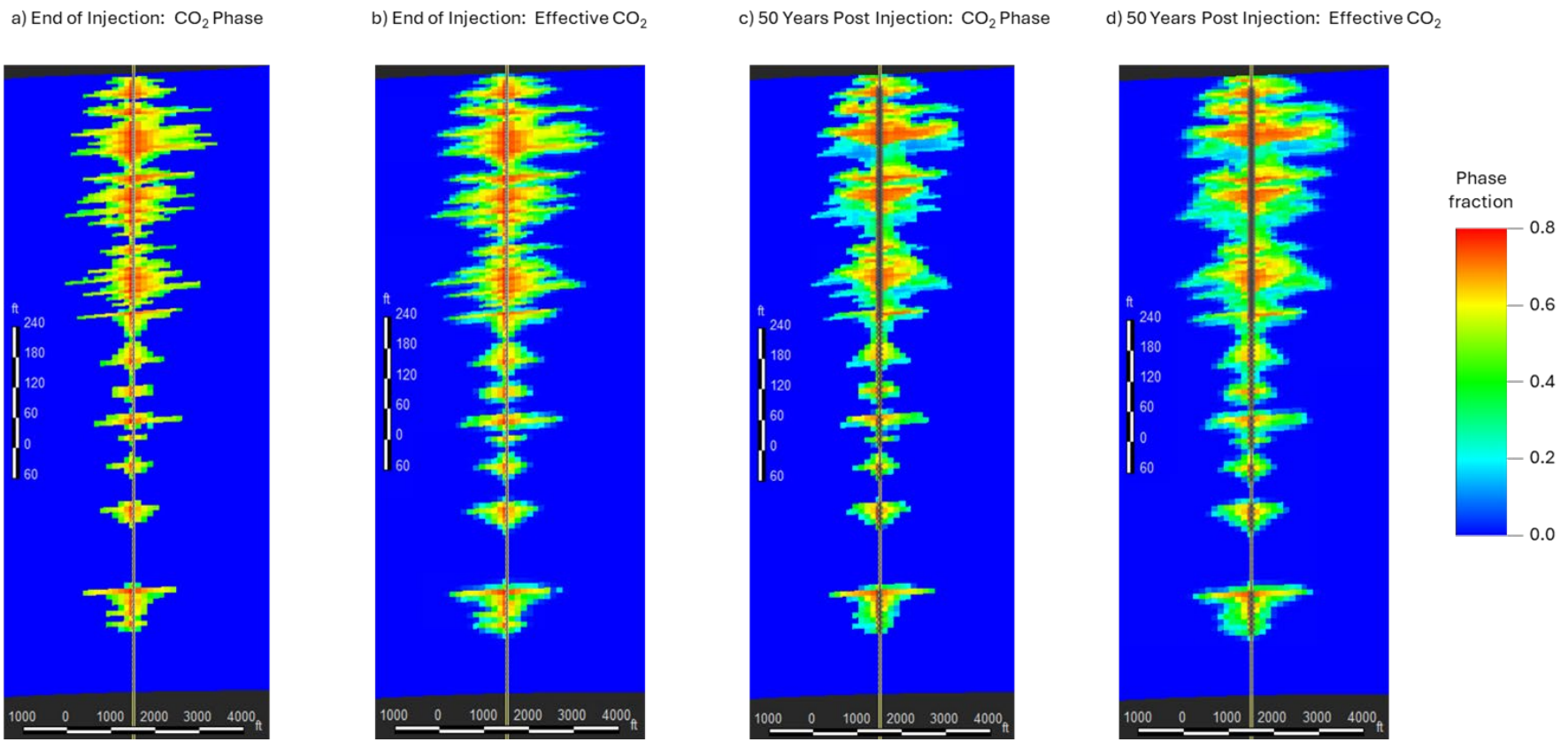


Figure 2-30 – Orchard No. 4 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

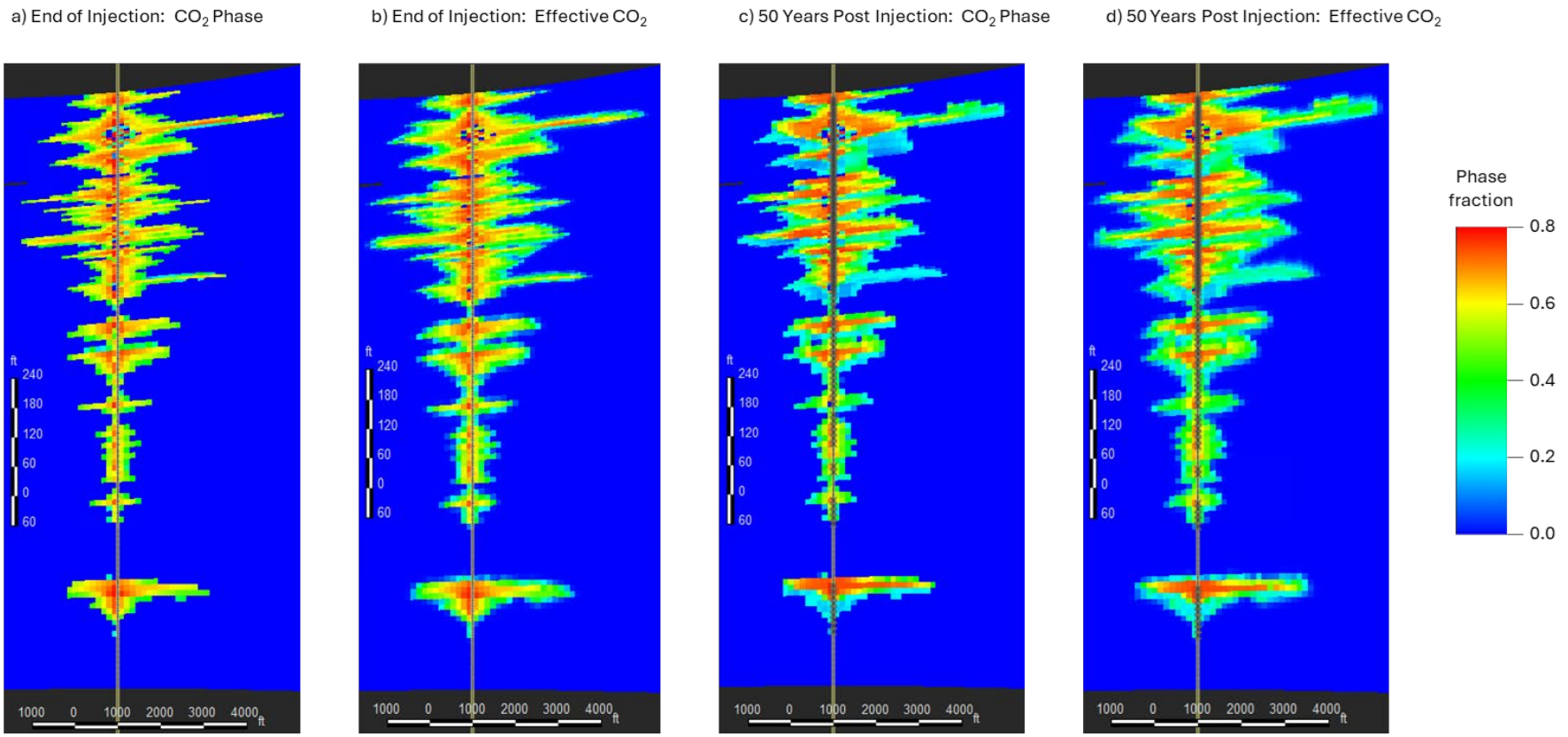


Figure 2-31 – Orchard No. 5 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

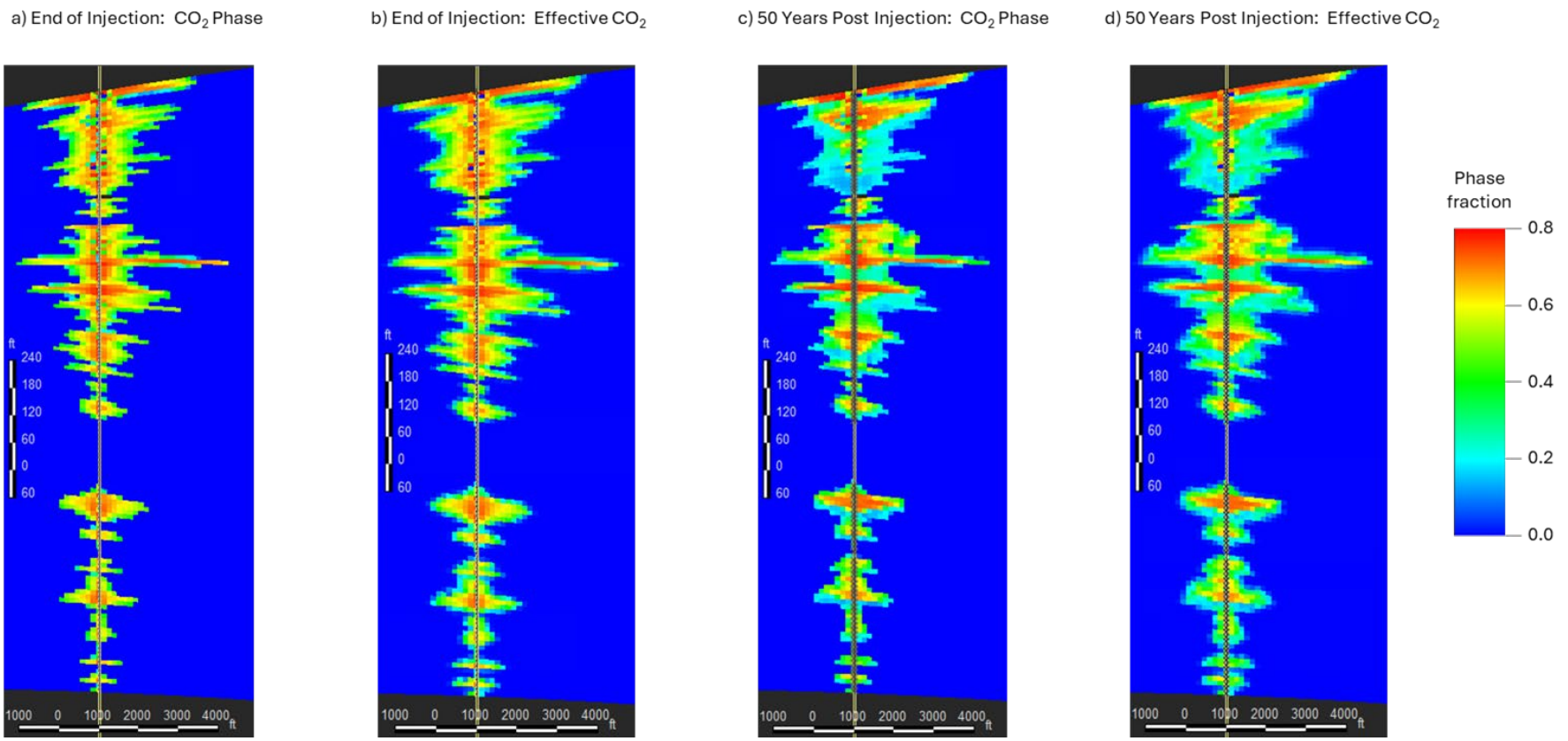


Figure 2-32 – Orchard No. 6 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

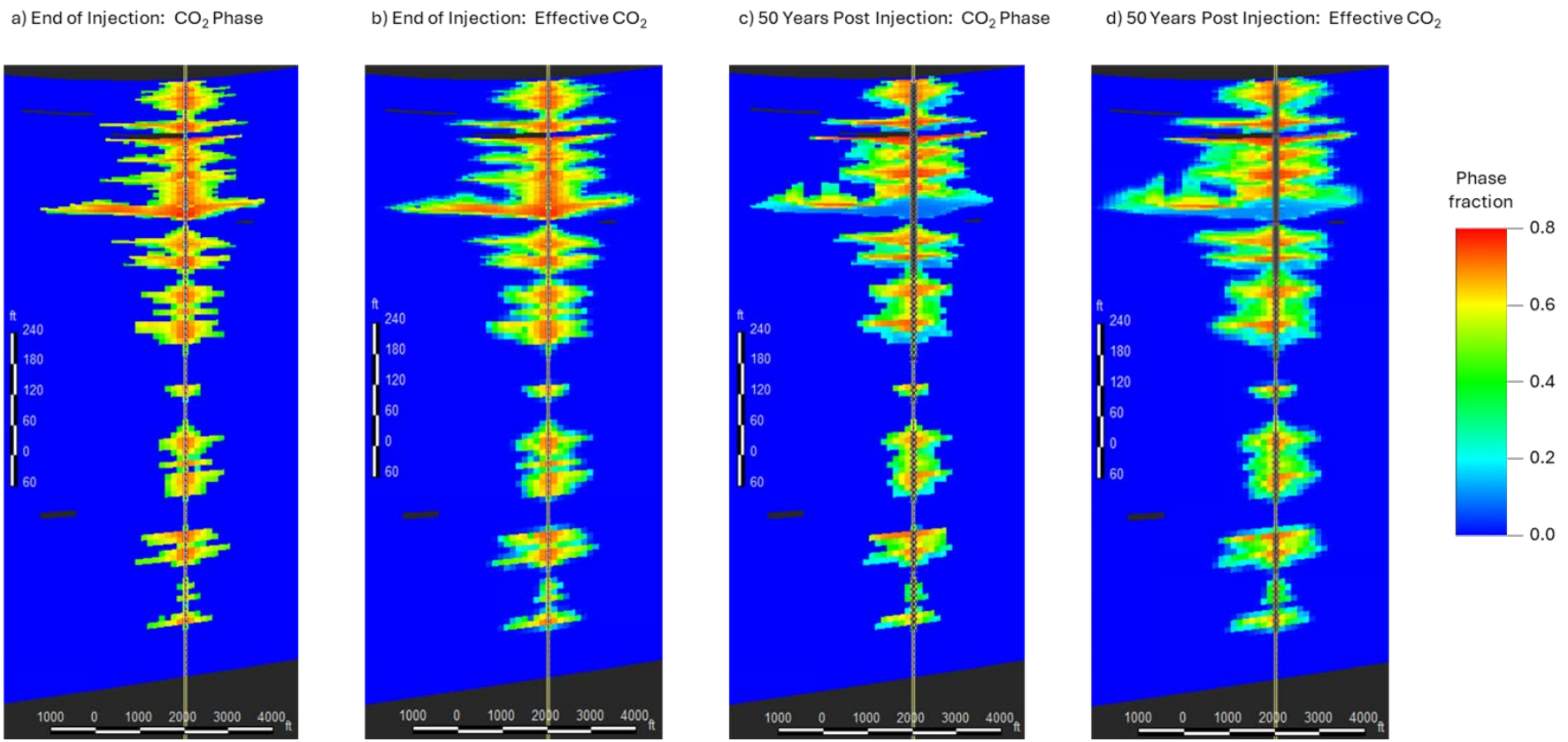


Figure 2-33 – Orchard No. 7 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

2.3.4 Geochemical Trapping

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

While geochemical trapping can have a greater impact on carbon dioxide over hundreds or thousands of years, the short-term effects of these trapping mechanisms are relatively small (i.e., not significant), and fluid movement is predominated by hydrodynamic and solubility trapping. Given that, plus the significant computational burden on the model runs created by including geochemical reactions and trapping mechanisms in the simulation model, the geochemical processes have not been included in the simulation cases. A geochemical model was performed to understand the geochemical interactions, as described in Section 1.6.

2.3.5 Trapping Summary

After the containment zone overlying the reservoir, the significant mechanisms by which CO_2 is trapped in the storage interval are illustrated in Figure 2-34, which also shows the metric tons of injected CO_2 in the mobile phase and in each of the trapped phases. In this and the figures following, "rel perm" refers to relative permeability.

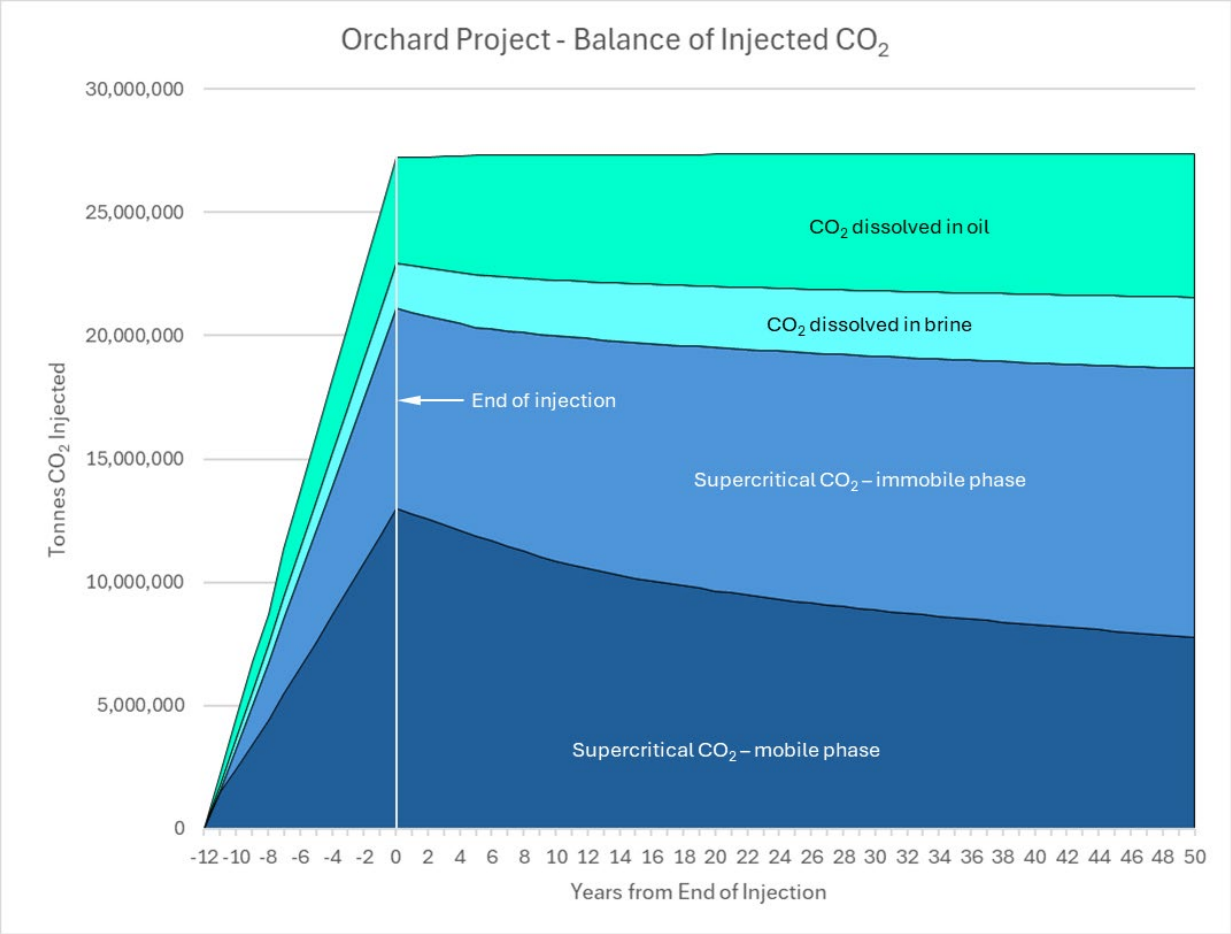


Figure 2-34 – Balance of Injected CO_2

2.4 Dynamic Model

2.4.1 Structural and Stratigraphic Elements

The model was built using the geologic data described in Section 2.1, and in *Section 1 – Site Characterization*, on how the analysis of well logs, core data, and seismic data were used to generate structure maps and hydrogeology, and to define other rock properties. The simulation model was built for the approximately 1,200 ft thick, heterogeneous mixed carbonates that comprise the permeable portions of the San Andres formation. The uppermost several hundred feet of the San Andres and Grayburg formations form the upper confinement (seal) zone and are not incorporated into the plume model discussed here.

The San Andres has been divided stratigraphically into Upper and Lower San Andres intervals, as also described in *Section 1*. Generally, the more porous and permeable portions of the injection zone are found in the Upper San Andres.

Horizontal permeability was calculated using a single transform (discussed in *Section 1.3.2*). Permeability in the horizontal plane is isotropic: there is no contrast between permeability in the "I"

and "J" (horizontal plane) model directions. Permeability correlations developed for carbonates by Lucia (Lucia, 2007) were used to calculate permeability as a function of porosity.

Claimed as PBI

(Eq. 3) Claimed as PBI

Permeability in the simulation model was calculated using this relationship with an input Claimed as PBI Claimed was derived to match derived permeabilities from well logs to in situ permeabilities calculated from transient injection response during completion operations of the Valiant No. 1D well, API No. 42-165-38785. After matching the San Andres permeability-thickness calculated from well logs to the performance-based permeability, the permeability was distributed through the simulation model by applying this relationship to the upscaled and distributed porosity in each grid block.

Figure 2-35 shows permeability versus porosity data for side wall core samples taken from the well API No. 42-165-38785. There appears to be a good permeability trend close to that calculated using the Lucia transform with Claimed as PBI shown as the dashed line on the plot. Injectivity data from this well indicates that the in situ permeability in the formation is much higher. Rate and pressure data obtained from injection during completion operations were used to estimate the formation permeability-thickness (k_h) for the individual completion stages. Those k_h values were matched against calculated permeability from well log-derived porosity using the Lucia Transform with an Claimed as PBI shown for comparison on Figure 2-35 as the solid red line.



Figure 2-35 – Permeability versus porosity for Valiant 1D (API No. 42-165-38785), compared to permeabilities calculated Claimed as PBI .

Considering that the performance-based in situ permeability and k_h for Valiant 1D are much higher, additional porosity-permeability data from a well in Gaines County was reviewed and compared. Figure 2-36 presents the data from Figure 2-35, with the comparative data from the ARCO Fee 198-1 (API No. 42-165-34473), and those calculated using a RFN of 1.5.



Figure 2-36 - Permeability versus porosity for Valiant 1D (API No. 42-165-38785) plus Arco Fee 198-1 (API No. 42-165-34473)

The horizontal permeability on a line though the Orchard No. 1, 2, 3, and 4 injection wells is shown as an east-west cross section in Figure 2-37 and summarized in Tables 2-6 through 2-9. Figures 2-38 through 2-40 and Tables 2-10 through 2-12 then show the same for Orchard No. 5 through No. 7, respectively.

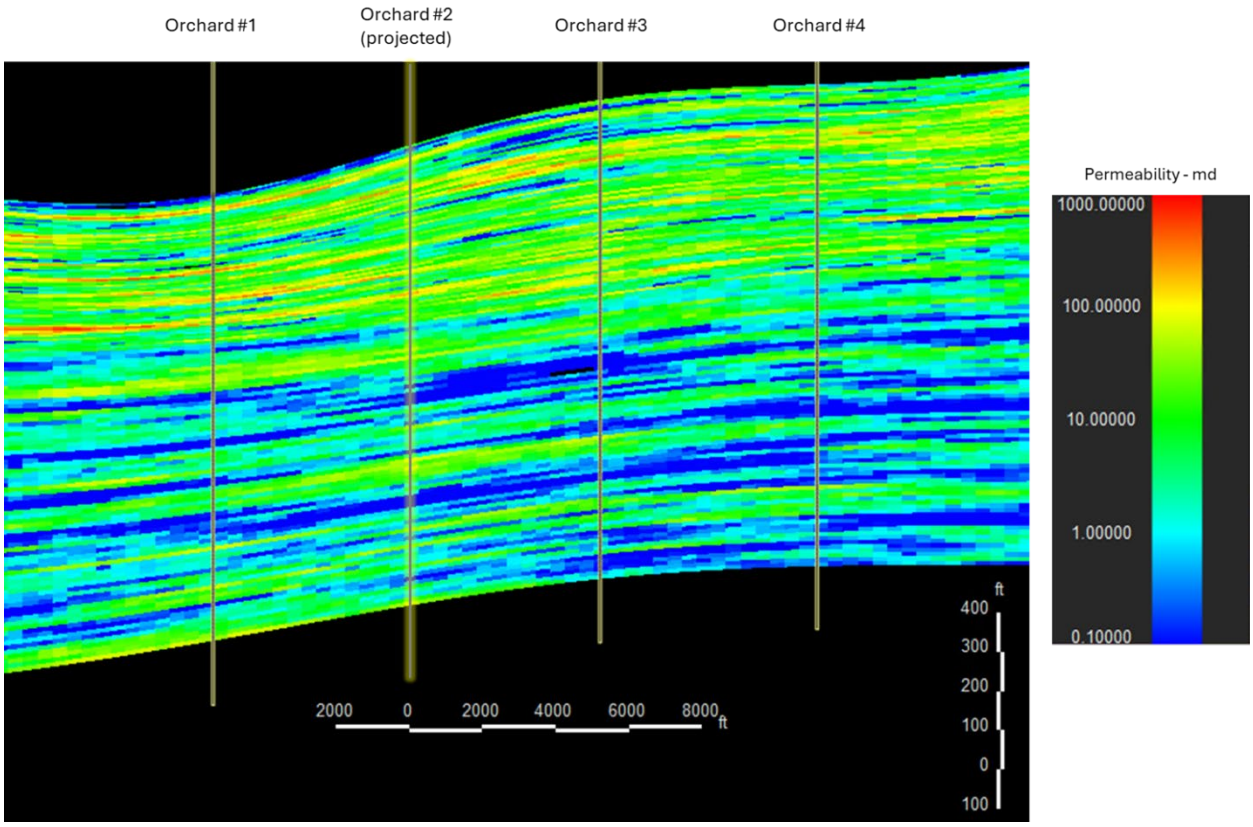


Figure 2-37 – Horizontal Permeability at Orchard No. 1 through 4 Injectors (East-West Section)

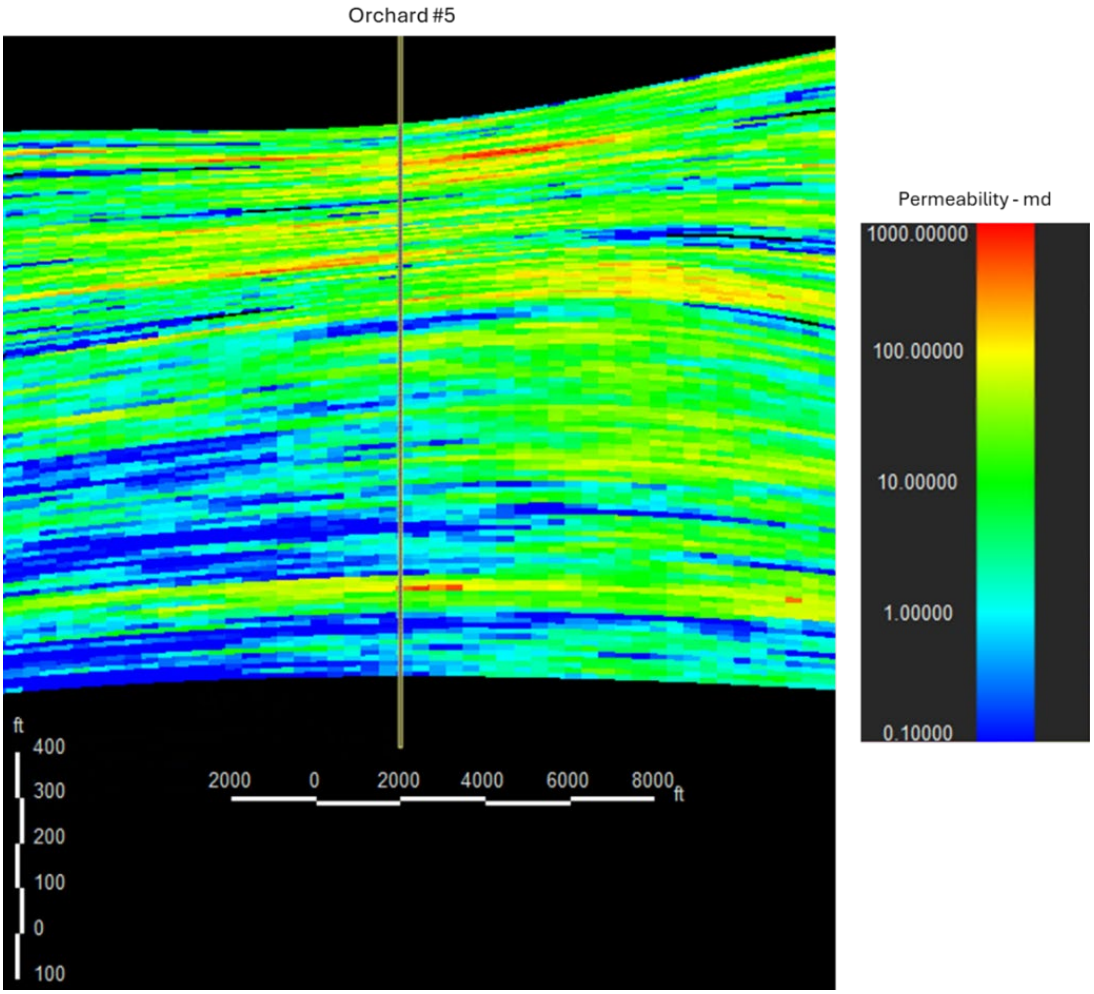


Figure 2-38 – Horizontal Permeability at Orchard No. 5 Injector (East-West Section)

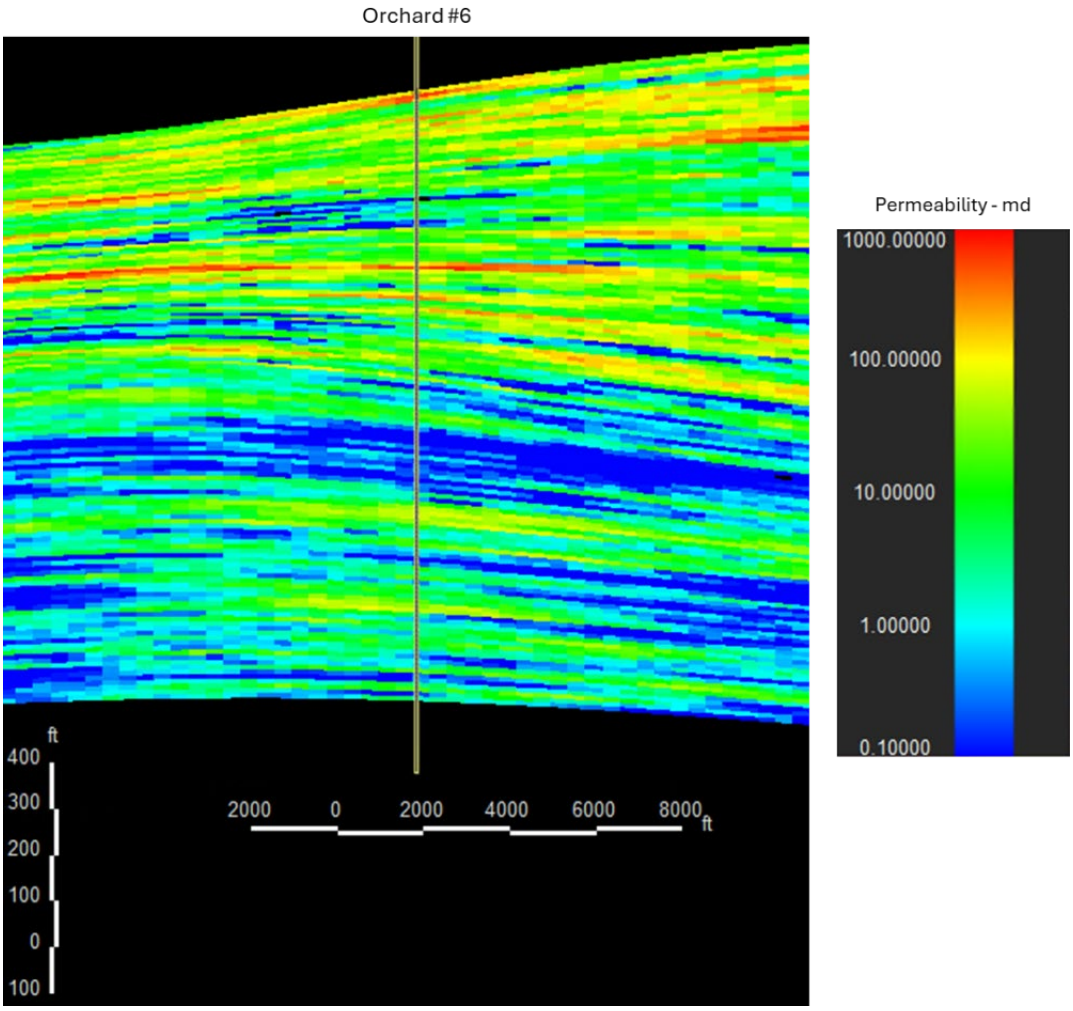


Figure 2-39 – Horizontal Permeability at Orchard No. 6 Injector (East-West Section)

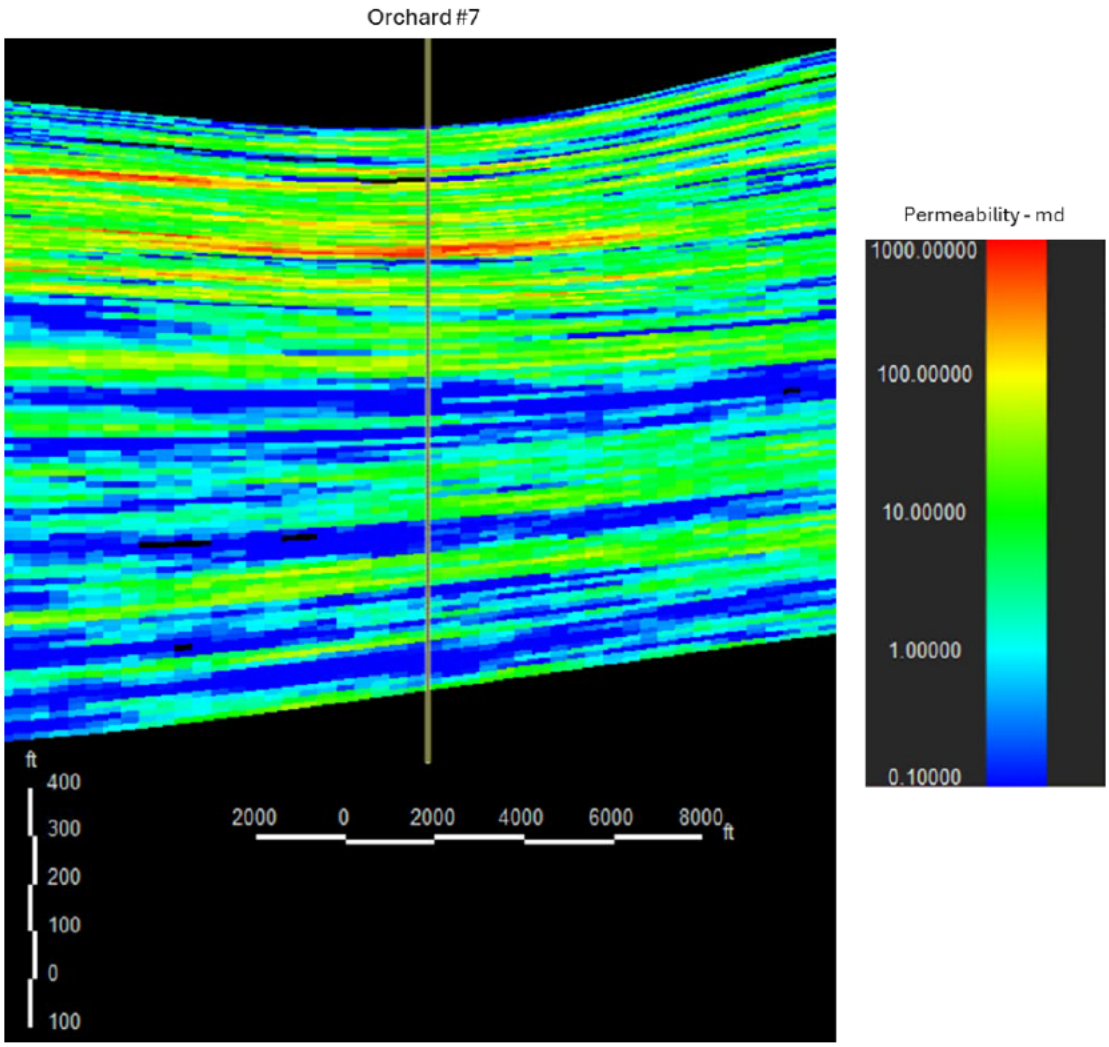


Figure 2-40 – Horizontal Permeability at Orchard No. 7 Injector (East-West Section)

Tables 2-6 through 2-12 summarize the values for porosity and permeability for injection zone model layers at intersection of the wellbore and the injection layers at each of the Orchard No. 1 through No. 7 locations.

Table 2-6 – Orchard No. 1 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	15.4%	30.9
	Min	1.8%	0
	Max	25.7%	250.1
Lower San Andres	Average	11.9%	8.3
	Min	0.6%	0
	Max	19.6%	48.3

Table 2-7 – Orchard No. 2 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	15.2%	21.5
	Min	5.9%	0.034
	Max	22.5%	112.3
Lower San Andres	Average	11.7%	7.9
	Min	2.4%	0
	Max	20.8%	69.1

Table 2-8 – Orchard Well No. 3 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	15.5%	27.9
	Min	5.3%	0.019
	Max	25.6%	242.0
Lower San Andres	Average	10.5%	4.8
	Min	0.6%	0
	Max	20.2%	58.4

Table 2-9 – Orchard No. 4 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	15.0%	19.9
	Min	6.1%	0.042
	Max	22.9%	125.4
Lower San Andres	Average	10.3%	2.9
	Min	4.5%	0.007
	Max	18.7%	36.2

Table 2-10 – Orchard No. 5 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	17.2%	44.0
	Min	3.4%	0.001
	Max	26.6%	303.3
Lower San Andres	Average	11.7%	11.9
	Min	1.1%	0
	Max	27.2%	350.0

Table 2-11 – Orchard No. 6 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	16.9%	52.0
	Min	0.3%	0
	Max	30.0%	636.9
Lower San Andres	Average	11.5%	8.0
	Min	0.6%	0
	Max	20.5%	63.9

Table 2-12 – Orchard No. 7 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
Upper San Andres	Average	16.5%	54.7
	Min	1.1%	0
	Max	28.7%	480.0
Lower San Andres	Average	10.9%	6.0
	Min	3.7%	0.002
	Max	18.4%	33.6

2.4.1.1 Vertical Permeability

Permeability normal to the bedding plane is usually lower than the permeability in the parallel direction. In most cases, "normal to the bedding plane" equates to *vertical* permeability, while the parallel-direction permeability corresponds to *horizontal* permeability. This contrast is caused by vertical heterogeneity over multiple scales, from very small (fractional inch) through many feet in range. By comparison, the scales of heterogeneity in the horizontal orientation will be significantly larger.

When permeabilities are averaged for upscaling into the simulator grid cell scale, flow in the direction normal to the heterogeneity will be significantly affected by the lowest permeability layers. For this reason, vertical permeability is typically characterized by the harmonic mean of layer permeabilities. In contrast, the horizontal flow (within the model) is typically characterized by the higher arithmetic mean value for permeability. Ratios of vertical to horizontal permeability (k_v/k_h) in the range of 0.01 to 0.05 are very common in history-matched simulations of similar carbonate hydrocarbon fields. In the Orchard simulator model, a value of 0.03 was chosen. This can be considered as a moderate vertical permeability ratio.

2.4.2 Relative Permeability and Capillary Pressure

Relative permeability curves were generated using the industry-standard power law model based on the approach developed by Corey (Corey, 1954). In this model, the relative permeability for the respective water and supercritical gas phases are based on the normalized saturation, scaled between the end points of mobility for a respective phase, and raised to an exponent value (termed

the "Corey exponent"). Relationships for water and gas relative permeabilities can be expressed with Equations 4 and 5. The gas relative permeability applies to the supercritical CO_2 phase.

(Eq. 4) $$k_{rw} = k_{rwcg}\left[\frac{(S_w - S_{wc})}{(1 - S_{wc} - S_{gc})}\right]^{nw}$$

and

(Eq. 5) $$k_{rg} = k_{rgrl}\left[\frac{(S_g - S_{gc})}{(1 - S_{wc} - S_{gc})}\right]^{ng}$$

Where:

k_{rw}, k_{rg} = Relative permeability to water and gas phases, respectively

k_{rwcg} = Water relative permeability endpoint, k_{rw} at critical gas saturation

k_{rgrl} = Gas relative permeability endpoint, k_{rc} at irreducible water saturation

S_w, S_g = Water and gas saturations, respectively

S_{wc} = Irreducible saturation of water

S_{gc} = Critical saturation of gas

nw, ng = Corey exponents for water and gas curves, respectively.

Figure 2-41 shows the gas-liquid relative permeability curves for the drainage process (CO_2 displacing water) used in the reservoir simulation model. These curves were generated using "generic" Corey exponents of 2.0 for both the liquid and supercritical gas phases.



The red curve shows the relative permeability to the supercritical CO_2 phase, starting at a maximum value of 0.10 and decreasing with increasing liquid saturations. The liquid-phase relative permeability is shown as the blue curve, starting at zero at the irreducible liquid saturation value of 0.4 and increasing together with the liquid saturation.

The value of 0.10 for the CO_2 phase relative-permeability endpoint may be considered low relative to "conventional" relative-permeability data used in the energy industry. The use of this value is supported by published CO_2 brine relative-permeability data from several references (Benson, et al., 2015) (Bennion & Bachu, 2005) (Bennion & Bachu, 2008). Figure 2-42 shows a statistical distribution of the CO_2 endpoint relative-permeability data for carbonates, taken from the Bennion and Bachu papers as well as the National Energy Technology Laboratory's CO_2 Brine Relative Permeability Database (NETL-CO2BRA) (Crandall, Moore, Brown, & King, 2019). On this plot, data values are plotted on the horizontal axis against the standard deviation for that data vs. the entire distribution. Horizontal lines are the probability (analogous to "percentile") for the data within the distribution. Data that lie in a straight line when plotted on a logarithmic scale for the horizontal axis, as Figure 2-42 indicates, denote a log-normal distribution.

Claimed as PBI



2

When considering a relative permeability relationship, it is important to look at the data in the context of reservoir conditions, using in situ fluid properties by the generation of a fractional flow curve. Absent gravity effects, the fractional flow of CO_2 vs. saturation is calculated using the relationship:

(Eq. 6) $$f_g = \frac{1}{1+\frac{\mu_g k_{rw}}{\mu_w k_{rg}}}$$

Where f_g represents the volume fraction of the gas (supercritical CO_2), μ_g and μ_w represent the in situ viscosity for the CO_2 and brine, and k_{rw} and k_{rg} represent the relative permeability for the brine and CO_2 at the saturations evaluated. Figure 2-43 shows the fractional flow curve for CO_2 arising from the relative permeability curve, together with in situ fluid viscosities.

This plot includes a tangent line according to Welge's method for analysis of Buckley-Leverett displacement theory (Buckley & Leverett, 1942) (Welge, 1952). Taken together, the fractional flow curve and its "Welge Tangent" will indicate that the displacement of water by CO_2 will be relatively efficient, having a nearly "piston-like" behavior. In a volume of rock with 1D flow (e.g., a core plug), the brine will be displaced by the CO_2 phase ahead of a fluid front, often termed a "shock front."

Phase saturations are not continuous. Ahead of the displacing fluid front, the rock volume will be at 100% brine saturation. According to Welge, the tangent point saturation (0.42) defines the CO_2 phase saturation at the front, while the extrapolation of the tangent line to 1 will indicate the average CO_2 saturation (0.49) behind the shock front. These 1D-displacement analysis results predict that the displacement of water by CO_2 will be efficient, leading to compact CO_2 plumes having relatively high CO_2 saturations behind the plume front. This behavior can be confirmed from the simulation results displayed in the leftmost panel of Figure 2-27, depicting the CO_2 phase saturations at the end of injection for Orchard No. 1. Figures 2-28 through 2-33 show similar results for the Orchard No. 2 through Orchard No. 7 wells, respectively.



Figure 2-43 – CO_2 Fractional Flow Curve

The displacement and relative permeability curves represent the displacement of water by injected CO_2. In the reverse process, discussed in Section 2.2.1.2, formation brine replaces CO_2 that flows out of the rock volume; the CO_2 will not return to its initial saturation, but rather leave behind a trapped gas saturation. This hysteresis in the relative permeability is implemented in the dynamic model using Carlson's modification of Land's methodology (Carlson, 1981) (Land C. , 1968) (Land C. S., 1971). With the methodology of Carlson and Land, the imbibition relative permeability is a

function of the historical maximum saturation of the nonwetting CO_2 phase as well as the trapped gas saturation at the endpoint of the CO_2 relative permeability

As discussed under trapping mechanisms in subsection 2.3.3.2, the model was initialized with an immobile Claimed as PBI the pore volume. Figure 2-44 shows Claimed as PBI relative permeability curves incorporated for the



Figure 2-44 – Water-Oil Relative Permeability

At initial conditions, Claimed as PBI immobile. As noted in the discussion on trapping mechanism, the oil phase near the supercritical CO_2 front can contain significant fractions of dissolved CO_2. The addition of the CO_2 component to the residual oil will affect an increase in volumes, potentially to values where the oil may be mobilized and displaced by the injected CO_2. When there are three mobile phases present in a grid block, the tNavigator simulator calculates



2.4.3 Capillary Pressure Relations

Capillary pressure relations were not incorporated into the simulation model. The effects of capillary pressure are implicit in the no-flow nature of the upper and lower confining beds. Low permeabilities, together with associated high capillary-entry pressures, will combine to prevent flow through the confining interval. Within the San Andres reservoir itself, the incorporation of capillary pressure into the model is not expected to be significant and certainly would not increase rates of plume growth. Capillary entry pressures at lower permeability "baffles" would likely slow migration of CO_2 into those cells.

2.4.4 Initial Conditions

Initial pressure in the model was set to 2,260 pounds per square inch (psi) at a datum depth of 2,450 ft below sea level. The datum depth represents an approximate midpoint for the Upper San Andres injection interval in the Orchard No. 1 to No. 7 injection wells. The pressure value of 2,260 psi

represents the typical formation pressure gradient of 0.40 psi/ft based on published data for several nearby fields, as shown in Table 2-13.

Table 2-13 – Reservoir Pressure Gradient Data for Nearby San Andres Fields

Field	San Andres Reservoir Pressure Gradient (psi/ft)
Cedar Lake Field (Beebe, 2004)	0.400
West Seminole San Andres (Barrett & Harpole, 1977)	0.395
Hobbs East Field (Society, 1956)	0.365
Wasson San Andres Denver Unit (Ghauri, 1980)	0.347

The formation temperature in the simulation model was initialized with a linear gradient of 0.7°F per 100 feet. Input temperature at model datum depth of 2,450 feet subsea is 105°F. The temperature gradient used is based on bottomhole temperature data reported on well-log headers for several nearby wells and provided in Table 2-14. Temperature gradients were calculated from a surface soil temperature of 65°F. This surface temperature of 65°F is consistent with reported temperatures on groundwater samples in the project area. These reports are available from the Texas Water Development Board's (TWDB) database of groundwater source wells in Texas (TWDB, 2025).

Table 2-14 – Formation Temperature for Orchard Area Wells

API No.	Maximum Temperature (°F)	Depth (ft)	Calculated Gradient (°F/100 ft)
42-165-30460	124	10,479	0.563
42-165-31367	106	5,414	0.757
42-165-35686	117	9,260	0.562
42-165-32106	110	5,525	0.814
42-165-36581	104	5,575	0.700
42-165-38059	126	8,776	0.694
42-165-35526	137	10,133	0.711
42-165-35792	110	6,968	0.646
42-165-36234	105	6,801	0.588
42-165-36433	113	7,071	0.679
42-165-36570	104	5,849	0.667
42-165-36809	103	5,937	0.640
42-165-36863	137	10,162	0.709
42-165-37161	145	11,199	0.714
42-165-31762	125	6,812	0.881
42-165-37207	160	13,155	0.722
42-165-37396	135	10,719	0.653
42-165-37417	114	6,068	0.808
42-165-38059	126	8,777	0.694

The temperature gradient data are used with the surface temperature from which they were derived (65°F) to determine a formation temperature at depth.

The gradient data are then presented in Figure 2-45, which yields a median temperature gradient for the Orchard Project area of 0.69°F per 100 ft. This was rounded to 0.7°F per 100 ft for model initialization.

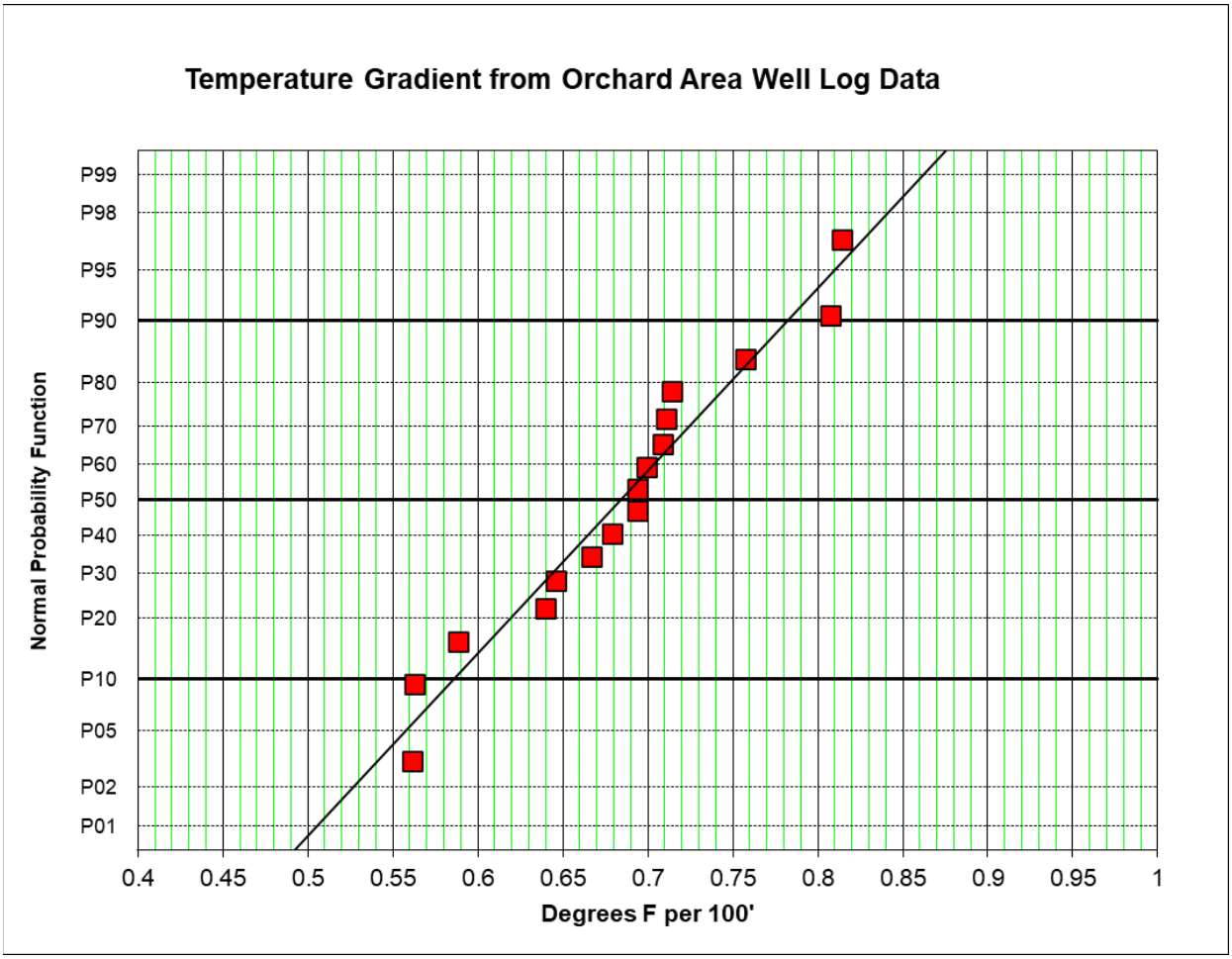


Figure 2-45 – Orchard Area Temperature Gradients

The dynamic simulation model was initialized with oil saturations set to 19% for all layers in the injection interval, based on data from side wall cores taken in the Valiant No. 1D (API No. 42-165-38785). This residual oil zone is discussed in further detail in Section 2.3.3.2. The EOS fluid property model used in this simulation model is summarized in *Appendix 2-2*. This property is modeled as a slightly undersaturated reservoir fluid, in between Cedar Lake and Seminole (Beebe, 2004) (Barrett & Harpole, 1977).

Dissolved solids content for the formation brine was set to 59,000 parts per million (ppm). This value was chosen as the median dissolved solids for water samples in and around the Orchard Project area, as plotted in Figure 2-46. The principal impact of total dissolved solids (TDS) present will affect the density of the formation brine and its ability to dissolve CO_2. Density of the formation brine has been calculated using correlations of McCain (see *Appendix 2-1*) to be 64.52 pounds per cubic foot (lb/ft^3), yielding a gradient of 0.448 psi/ft at downhole conditions.

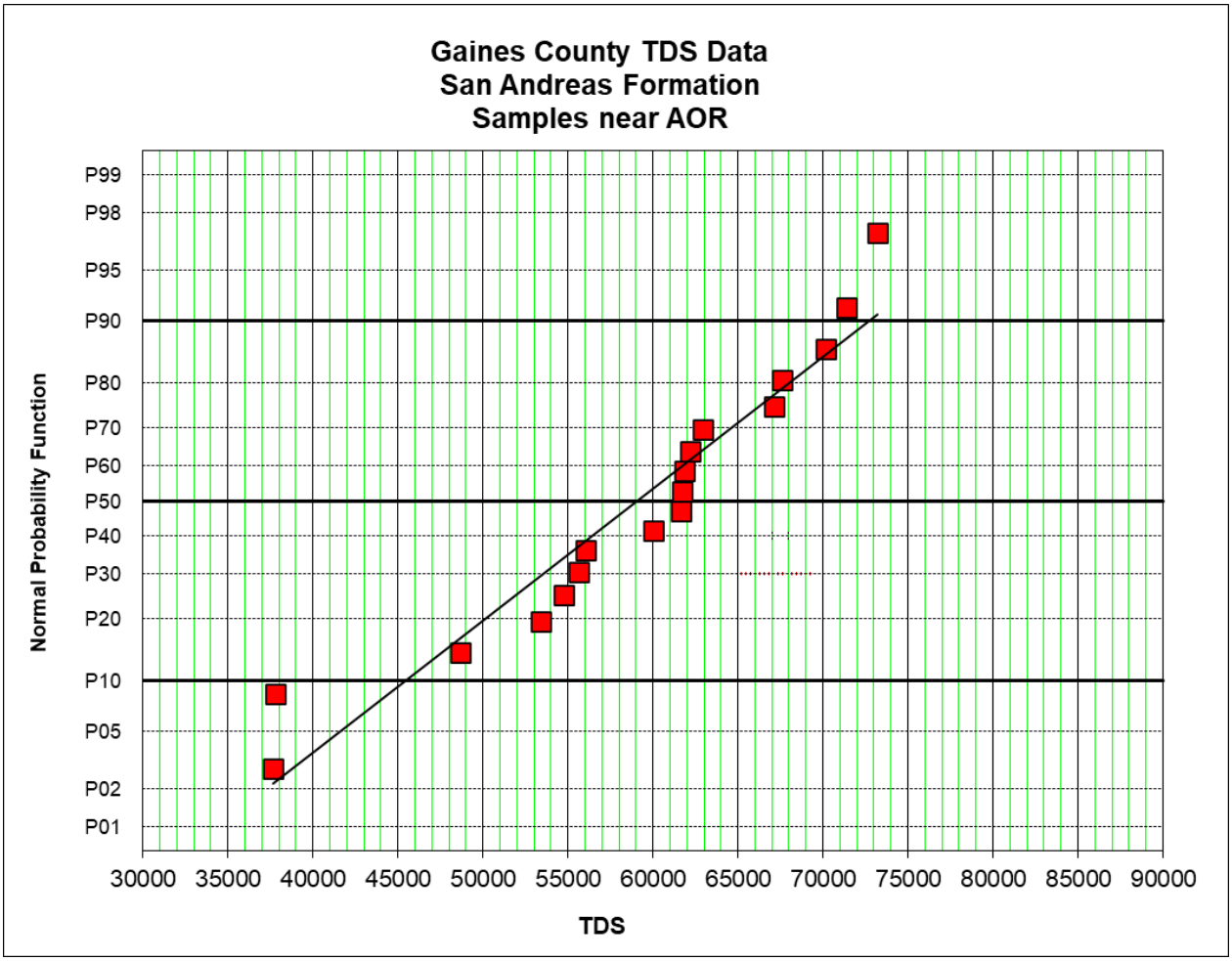


Figure 2-46 – Normal Probability Plot of Gaines County TDS Data in the San Andres Formation

2.4.5 Injection Rate

2.4.5.1 Injection Rate Controls

Injection rates are controlled in the simulator by the overall injection target rate and individual well injectivity. Each well will inject at its allocated rate, subject to a maximum bottomhole injection pressure limit. The maximum injection pressure is calculated based on the measured depth of the shallowest open layer into which each well is injecting, using a gradient of 0.6 psi/ft. The 0.6 psi/ft limiting pressure gradient corresponds to 90% of the anticipated fracture gradient of 0.67 psi/ft. This pressure limit will be updated to 90% of the fracture gradient, as determined from a step-rate test on an injection well.

The overall project injection target was set to 121.5 million standard cubic feet per day (MMscf/d), which corresponds to the project target rate of 2.3 million metric tons per year (MMT/yr) of CO_2 for an inlet stream with 98% purity, converted at standard conditions of 14.7 pounds per square inch absolute (psia) and 60°F. The range of proposed injection for the seven Orchard Project wells, detailed in *Section 3.3 (Table 3-1)*, is from approximately 13 MMscf/d (Orchard No. 3 and No. 4) up to approximately 35 MMscf/d (Orchard No. 6) for the 12-year life of the project, which equates to a

range of 250,000 to 660,000 metric tons per year (MT/yr), respectively. While there are injection pressure limits set for each well, sufficient spare capacity exists for all wells to operate at bottomhole pressures below their limits. In this case, where there is spare capacity available to the model, the simulator internally allocates injection rates based on the calculated injectivity for each of the injection wells.

2.4.5.2 Well Injectivity and Pressure Calculations in Simulation Model

Injection pressures and rates are calculated using standard relationships for well injectivity/productivity applied across multiple simulation platforms. These relationships account for gridblock geometry and size, well completion effects, and intrinsic gridblock properties (e.g. effective permeability, porosity, pressure). The relationships used are described in Section 2.15 of RFD's tNavigator user manual and outlined here. This well model is based on the approach developed by Peaceman (Peaceman D. , 1978) (Peaceman D. W., 1983).

The reservoir flow rate of a phase j ("Qj") is correlated to wellbore and gridblock pressures according to the relationships

(Eq. 8) $$Q_j = \sum_l WI_l \, \lambda_{T,l} \, (p_{bh} - p_{o,i})$$

(Eq. 9) $$WI = 2\pi \;\; ff \;\; kh \, \frac{wfrac}{ln(r_e/r_w)+S}$$

(Eq. 10) $$r_e = CC\sqrt{A_i/wfrac}$$

where

Q_j = flow rate of phase *j* at reservoir conditions

p_{bh} = bottomhole pressure

$p_{o,i}$ = pressure of the i-th grid block containing the well

$WI_{j,l}$ = well injectivity index for phase *j* to layer l

$wfrac$ = well fraction areal geometry term (set to 1 for well blocks not on edge of model)

k = effective permeability in the plane perpendicular to the well direction

h = gridblock thickness in well direction

$\lambda_{T,l}$ = total mobility of the fluid in the well block (for layer *"l"*)

r_w = wellbore radius

r_e = effective radius from Peaceman (Peaceman D. , 1978)

A_i = area of i-th gridblock perpendicular to well direction

CC = geometric factor (0.37 for well in square grid block not on model edge)

S = skin factor

ff = fraction of completion of the well in the gridblock

$\sum_l$ = summation over all layers

2.4.6 Injected Fluids Composition

While the simulation model was constructed with a nine-component EOS to describe the fluids found in the San Andres formation, the injected fluid composition was simplified to include two components, CO_2 and N_2. This composition was set to be 98% CO_2 and 2% N_2 for model simulations prior to collection of actual compositional data. The nitrogen impurity was chosen to create a characterization for an injected fluid with a relatively soluble element (CO_2) combined with a relatively insoluble impurity (N_2). These solubility characteristics apply to dissolution in both water- and hydrocarbon-phase liquids.

The exact injected-fluid composition will depend on the average compositions over time within the Kinder Morgan CO_2 pipeline. Pipeline specifications call for a minimum CO_2 content of 95%, with minor impurities consisting of predominantly nitrogen and light hydrocarbons (e.g., methane). The value of 98% CO_2 was chosen as a mid-range placeholder between the minimum specification and pure CO_2. This composition will be adjusted as pipeline compositional data becomes available.

2.4.7 Completion Plan

The proposed Orchard injection wells will be perforated in all permeable layers through the lower portion of the Upper and Lower San Andres formations (i.e., injection interval). This perforation strategy is simulated in the model by opening layers with permeabilities greater than 0.5 millidarcys (mD) based on the petrophysical evaluation. This completion strategy will be implemented for all the injectors planned in the Orchard Project. The interval and timing inputs to the model for the injection wells are shown in Table 2-15. The thickness column represents the interval between the top of the shallowest to the base of the deepest perforation interval.

Table 2-15 – Orchard No. 1 to No. 7 Model Completion Timing

Injection Well	Year	Duration (yrs)	Top perforation (ft)	Thickness (ft)	Net Perforated (ft)	Geologic Layer
Orchard No. 1	2025	12	5,473	1,124	957	Upper and Lower San Andres
Orchard No. 2	2025	12	5,345	1,145	1,119	Upper and Lower San Andres
Orchard No. 3	2025	12	5,230	1,333	1,165	Upper and Lower San Andres
Orchard No. 4	2025	12	5,183	1,074	831	Upper and Lower San Andres
Orchard No. 5	2025	12	5,168	1,096	851	Upper and Lower San Andres
Orchard No. 6	2025	12	5,051	1,314	1,227	Upper and Lower San Andres
Orchard No. 7	2025	12	5,453	1,061	827	Upper and Lower San Andres

The stimulation aspect of the completion strategy was modeled by assigning a skin value of -3.5 to all wells upon initial completion, with the exception that high permeability intervals (generally greater than 50 millidarcies) are not stimulated, reflecting a completion strategy to focus on opening lower permeability layers to improve injector conformance. This skin value corresponds to a small fracture stimulation with a half-length of 27 ft. In addition to improving injectivity in each well, the strategy of stimulating the formations ensures that all perforated intervals are open, to better manage vertical injection conformance.

2.4.8 Characterization of Stimulations in Plume Model

As discussed in Section 2.4.7, well completions were specified in the simulation model with a skin set to -3.5, reflecting a modest stimulation of each wellbore. This skin factor can be related to a half-length for an infinite-conductivity fracture using the relationship (Matthews & Russell, 1967) (Russell & Truitt, 1964):

(Eq. 11) $$\left(x_f\right)_{calc} = 2r_w e^{-s}$$

Where

x_f = fracture half length
r_w = wellbore radius
s = skin factor

The input skin values of -3.5 and r_w of 0.411 ft in Equation 11 yields a calculated half-length of 27 ft.

The standard practice in well test and well performance analysis is to characterize a fractured well using radial flow equations together with a negative skin. This methodology is applicable for cases where the flow conditions around the well are in the proper flow regime. Cinco-Ley (Cinco-Ley & Samaniego-V, 1981) describes the different transient flow regimes that occur in and around a vertically fractured well, illustrated in Figure 2-47. The four panels represent different flow regimes (or flow geometries) around an injector, at different times relative to the start of a flow (or injection) period.

The first period (a) in the upper left represents very early time. The flow regime is termed fracture linear flow, where pressure transients are propagating down the length of the fracture without any significant influence from the surrounding formation. The second period (b), found in the upper right quarter, represents the bilinear flow regime. In this flow regime, pressures at the wellbore are affected by the propagation of transients both down the fracture and linearly out into the surrounding formation.

With increasing time, the effect of transient pressure propagation down the fracture becomes insignificant compared to the linear propagation of pressures in the formation, normal to the orientation of the fracture plane. This flow regime is termed formation linear flow, illustrated as (c) in the lower left quarter of Figure 2-47. Finally, after sufficient time has passed, pressures at the wellbore will be dominated by the radial flow properties of the surrounding formation, illustrated by the pseudo-radial flow period shown as (d) in the lower right quarter of Figure 2-47.

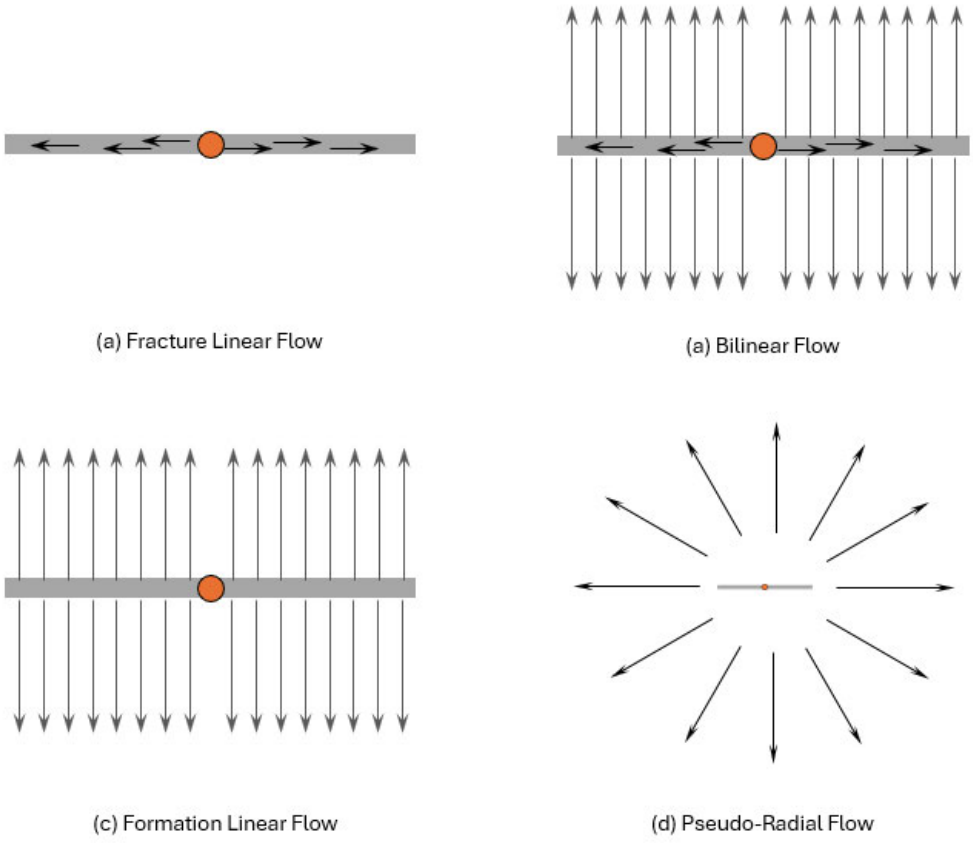


Figure 2-47 – Transient Flow Regimes Around an Injector

The application of radial flow equations with an equivalent skin factor to characterize pressure behavior of a well becomes valid when the well is operating in the radial or pseudo-radial flow regime. For cases where the well is not yet operating in this flow regime (typically very low permeability formations with large fractures, as may be seen in unconventional reservoirs), it is necessary to model well behavior by explicitly describing the fracture. The test for the suitability of radial flow equations will be whether the well has reached the appropriate flow regime.

Analysis of pressure transient response over wide ranges of reservoir conditions, geometries, and time scales is done through the use of dimensionless pressure and time functions, which allow scaling of a "type-well" response to specific formation and well parameters (e.g. fracture half length, permeability, porosity) (Erlougher, 1977). The dimensionless time function for a well with a vertical fracture can be used to establish the onset of fully developed pseudo-radial flow, after which radial flow equations are applicable for the characterization of the well's pressure response.

The onset of fully developed pseudo-radial flow occurs when the dimensionless fracture time (t_{Dxf}) reaches a value of approximately 3 (Economides & Poe, 2000). This dimensionless time function is defined by Equation 12:

(Eq. 12) $$t_{Dxf} = \frac{0.000264kt}{\varphi\mu c_t x_f^2}$$

Rearranging Equation 12 and substituting 3.0 for the t_{Dxf} term yields the following equation for the number of hours to reach pseudo-radial flow:

(Eq. 13) $$t = \frac{\varphi\mu c_t x_f^2\,(3.0)}{0.000264\,k}$$

Where

k = permeability (mD)

t = time (hours)

φ = porosity (fraction)

μ = viscosity (centipoise)

c_t = total system compressibility (psi^{-1})

x_f = fracture half length (ft)

Using properties evaluated at typical reservoir conditions during injection, values of 0.059 centipoise and 1.2 x 10-4 psi^{-1} were assumed for the CO_2 viscosity and system compressibility, respectively. To calculate the time to reach pseudo-radial flow for a well with x_f = 27 ft, two cases are considered:

Case 1: Upper San Andres average porosity and permeability for Orchard No. 4, taken from Table 2.5:

φ = 0.150 and k = 19.9 mD

$$t = \frac{(0.150)(0.059)(1.2 \times 10^{-4})\,(27)^2(3.0)}{0.000264\,(19.9)} = 0.44 \text{ hours}$$

Case 2: Lower San Andres average porosity and permeability for Orchard No. 5, taken from Table 2.5:

φ = 0.085 and k = 0.83 md

$$t = \frac{(0.103)(0.059)(1.2 \text{ x } 10^{-4})\ (27)^2(3.0)}{0.000264\ (2.9)} \quad = \text{ 2.1 hours}$$

The majority of injected CO_2 will enter rock that may be characterized by Case 1, based on typical average properties for the Upper San Andres. Case 2 describes rock which may be at the low end of the formation properties for the injection interval. Even in that low case, fully developed pseudo-radial flow will be established within a few hours after the commencement of injection. Considering that the purpose of the plume model is to characterize the pressure and saturation impacts of CO_2 injection over a timespan of many years, use of radial flow relationships together with equivalent skin is appropriate to characterize the pressure response at the injectors.

Only in the case of low permeability formations, together with large fracture stimulations, would it become important to characterize a fracture stimulation explicitly. For example, in a hypothetical low permeability conventional reservoir (0.1 mD) with 6% porosity and a 300-ft fracture, the above equations would yield a time to pseudo-radial flow of 4,370 hours, corresponding to half a year from the start of the injection period. In that hypothetical case the simulation model should include a characterization of the fracture stimulation, typically implemented through custom grid refinement around the injectors.

2.5 Model Orientation and Gridding Parameters

2.5.1 Spatial Conditions

The simulation of the CO_2 injection and migration was performed for the entire San Andres interval underlying the impermeable sediments at the top of the San Andres/Grayburg formation. The simulated interval consists of heterogeneous dolomite/limestone carbonates. Figure 2-38 through Figure 2-41 (Section 2.4.1) showed a representation of permeability near the planned injection wells.

The reservoir simulator covers two zones, termed the Upper and Lower San Andres injection intervals, respectively. The Upper San Andres injection interval is divided into 25 model layers; the Lower San Andres, into 36. The model gridding is proportional (i.e., layers in each of the respective zones are of equal thickness).

The overall active model area consists of 210 x 171 x 145 grid blocks in the x, y, and z dimensions, respectively. Block x- and y- dimensions are a constant 400 feet with the exception that the grid is refined in the x and y directions to 3 x 3 refined grid blocks in an area 9,200' square surrounding each well. The local grid refinement was done to more accurately place each injection model and to provide better definition of the plume extents. Figures 2-48 shows the active model grid together with the injection wells, CO_2 plume extent, and pressure front outline. Shaded areas around the wells and plume outlines represent the portion of the grid which has been refined. Details of the refined grid are shown as Figure 2-49.

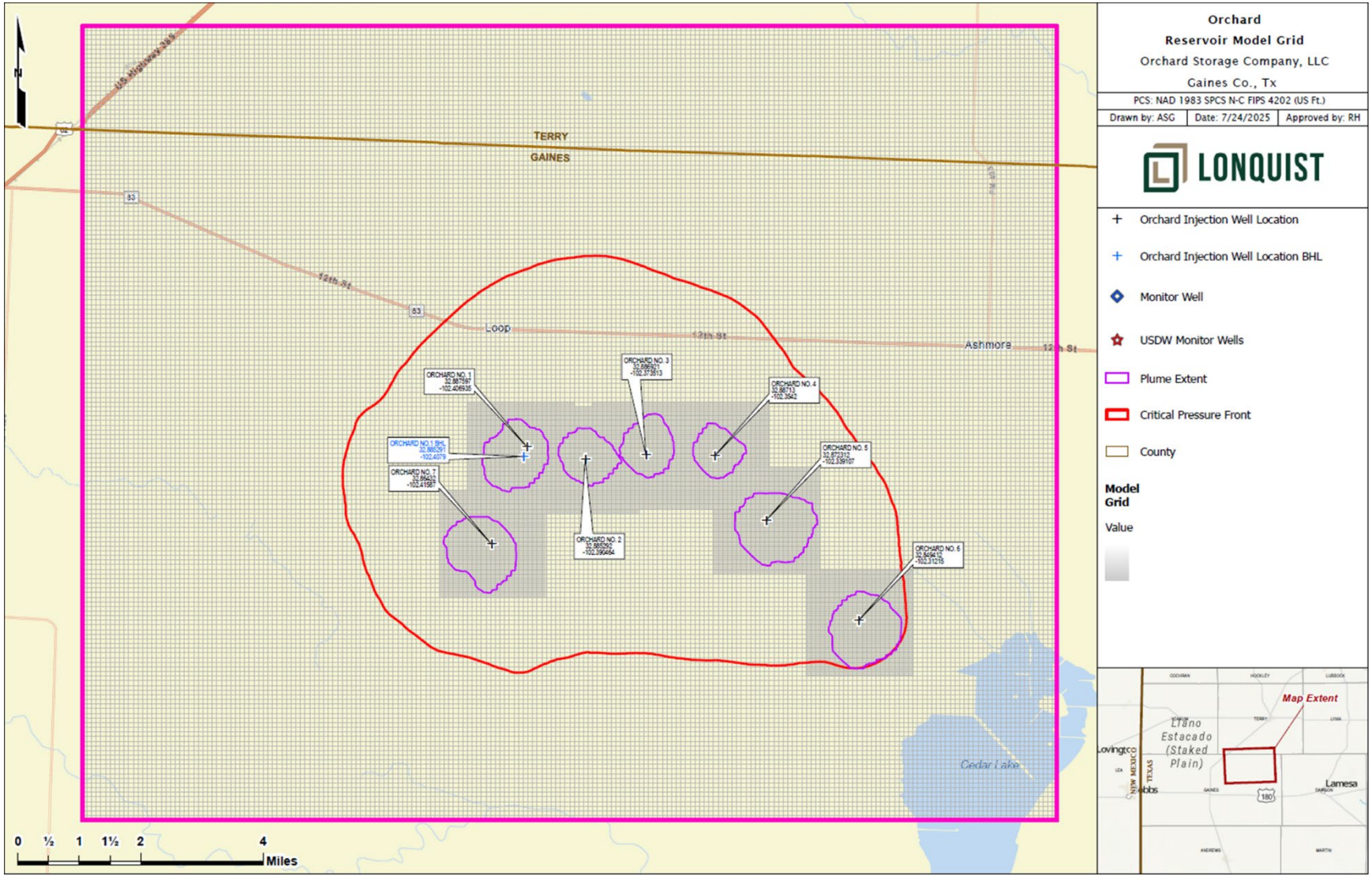


Figure 2-48 – Active model grid overlain with injection wells, plume outlines, and pressure front outline

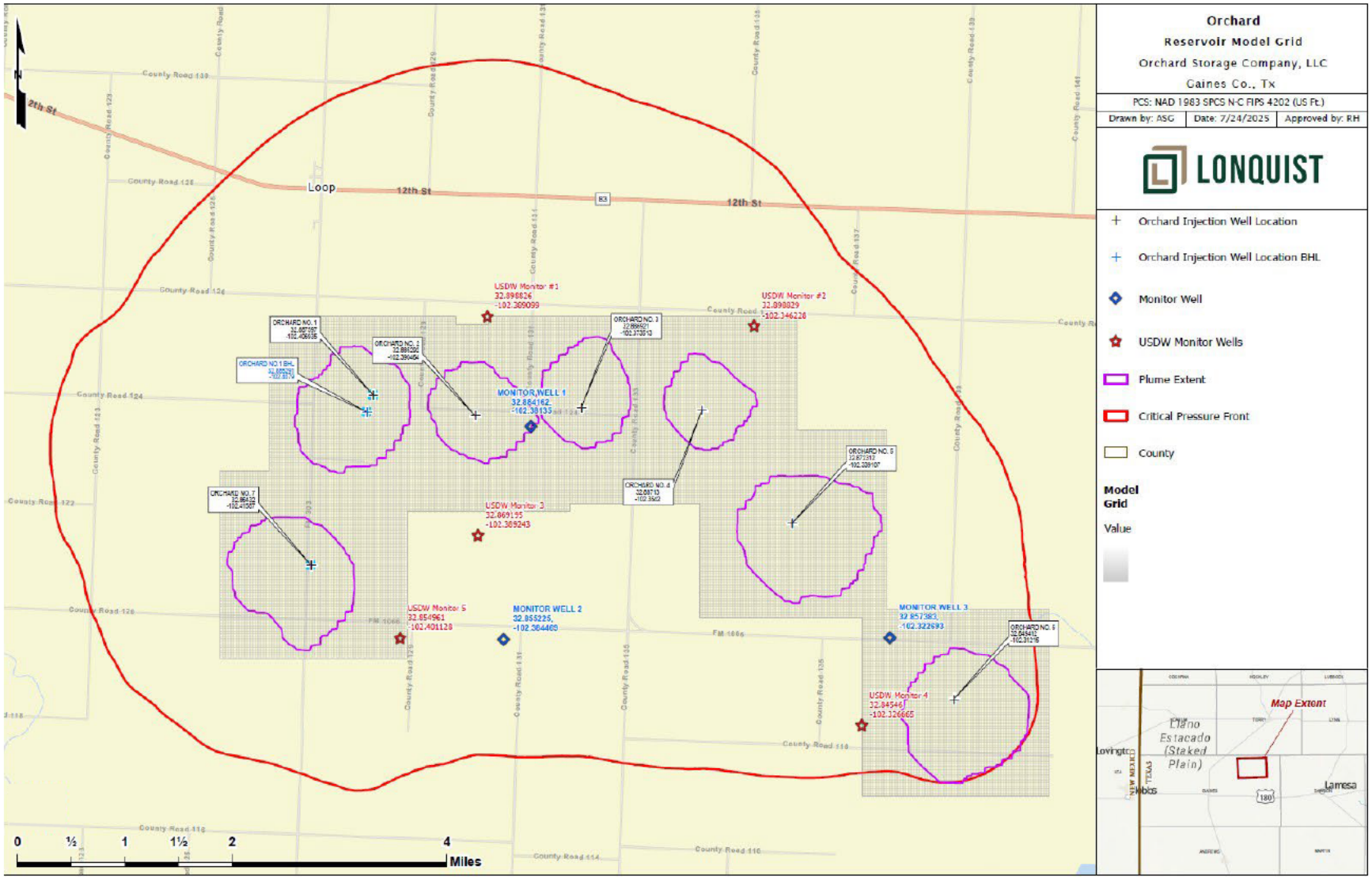


Figure 2-49 – Detail of local grid refinement

Higher resolution versions of Figures 2-48 and 2-49 are provided in Appendix L.

The model covers an area of 15.9 x 13.0 miles (east-west and north-south, respectively), with a total area of 206 square miles. Including refined grid blocks, there are 8.59 million active blocks in the dynamic simulation model. Absent local grid refinement, there would have been 5.21 million active blocks in the model. Grid block thicknesses vary throughout the model, as shown in Table 2-16. Boundary conditions are described in Section 2.5.2.

Table 2-16 – Model Layer Parameters

Well Name	Upper San Andres Gross Thickness (ft)	Upper San Andres Grid Thickness (ft)	Lower San Andres Gross Thickness (ft)	Lower San Andres Grid Thickness (ft)
Orchard No. 1	374	5.0	756	11.0
Orchard No. 2	453	6.0	718	10.4
Orchard No. 3	503	6.6	718	10.4
Orchard No. 4	478	6.3	747	10.9
Orchard No. 5	400	6.3	813	10.9
Orchard No. 6	612	8.2	706	10.1
Orchard No. 7	382	5.1	790	11.5

The vertical variation in permeability throughout the simulator area is considerable, with values ranging from a minimum of 0.001 mD up to a maximum of more than 400 mD. Tables 2-17 through 2-23 illustrate the ranges of permeabilities in the injection interval around each of the Orchard No. 1 to No. 7 injection wells (11 x 11 grid cells x-y, approximately 1 square mile). These values differ from the permeabilities shown in Tables 2-2 through 2-8 in that they reflect the calculated permeability of the greater area (11 X 11 grid cells), influenced by the porosity contours established by well control in the geologic model.

Table 2-17 – Simulator Permeability Values in Area of Orchard No. 1 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	37.6	0.0001	802
Lower San Andres	7.6	0.0001	264
All San Andres	23.3	0.0001	63.1

Table 2-18 – Simulator Permeability Values in Area of Orchard No. 2 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	33.7	0.0001	476
Lower San Andres	9.4	0.0001	87.8
All San Andres	17.9	0.0001	476

Table 2-19 – Simulator Permeability Values in Area of Orchard No. 3 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	33.5	0.0001	510
Lower San Andres	9.5	0.0001	86.2
All San Andres	17.3	0.0001	510

Table 2-20 – Simulator Permeability Values in Area of Orchard No. 4 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	33.4	0.0001	325
Lower San Andres	8.7	0.0001	72.2
All San Andres	13.8	0.0001	92

Table 2-21 – Simulator Permeability Values in Area of Orchard No. 5 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	33.9	0.0001	789
Lower San Andres	11.5	0.0001	646
All San Andres	26.9	0.0001	789

Table 2-22 – Simulator Permeability Values in Area of Orchard No. 6 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	33.8	0.0001	729
Lower San Andres	12.0	0.0001	460
All San Andres	28.0	0.0001	729

Table 2-23 – Simulator Permeability Values in Area of Orchard No. 7 Well

Model Layer	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
Upper San Andres	33.7	0.0001	802
Lower San Andres	12.7	0.0001	242
All San Andres	30.8	0.0001	137

The distribution of cumulative injection between the Upper and Lower San Andres intervals reflects their contrasting permeability. Eighty-one percent of the injected CO_2 enters the Upper San Andres injection interval

2.5.2 Boundary Conditions

2.5.2.1 Boundary Definition

The top and base of the model were set up as no-flow boundaries to vertical flow, these being the upper and lower confining zones, respectively. Connectivity between the lateral model boundaries and larger regional pore volumes has been simulated by applying pore volume multipliers to the simulator grid blocks on the model boundaries. Pore volume multipliers were specified to allow the representation of finite, but very large, pore volumes connected to the simulator edges.

Boundary grid blocks on the north, south, and west model edges were adjusted with a pore volume multiplier of 250 applied to each block. The resulting pore volume for those three model boundaries is 4.0 times the pore volume for the non-boundary portion of the simulator. The boundary grid blocks on the eastern model edge had a pore volume multiplier of 50 applied, with the result that the boundary pore volume on the model's eastern edge is 0.22 times that of the active non-boundary simulator volumes.

The x- and y-direction transmissibility was reduced for the connection to those large pore volumes and the pore volumes increased at the simulator boundaries. This reduction in transmissibility was applied in recognition that the larger pore volumes applied to the simulator boundaries represent connectivity to reservoir volumes which extend over much larger areas than that in the respective boundary grid blocks. The applied transmissibility multipliers were 0.05 for the north, south, and west boundaries; while a multiplier for the transmissibility to the more limited east boundary was set at 0.10.

The more limited pore volumes to the east of the simulation area were defined based on performance data from the nearby Cedar Lake field to the east. Reservoir performance data from that field provides strong evidence of limited hydrodynamic connectivity between that field and the surrounding regions. Analysis of the early performance data is discussed in Section 2.5.2.1. The limited connectivity is likely affected by stratigraphic changes such as sequence boundaries towards the east into the Midland Basin.

2.5.2.2 East Boundary – Cedar Lake

Early performance for the Cedar Lake field has been well documented (Leibrock, Hiltz, & and Huzarevich, 1951). This study includes a description of the initial reservoir oil in place ("PVT data"), as well as a plot of reservoir pressure vs. time during early production. The PVT data shows that the reservoir oil was initially very undersaturated, having a bubble point pressure of 326 psia. The pressure data plot indicates that the Cedar Lake reservoir pressures stayed above the bubble point during early production, between 1939 and 1946. The combination of good reservoir pressure data with depletion above the bubble point indicates that simple material balance calculations are appropriate and effective. These calculations are used to estimate connected in-place volumes of reservoir fluids and the potential for aquifer pressure support.

Given the pressure decline above the bubble point for Cedar Lake field, the early production mechanism lends itself to the simplest form of material balance. Absent external water influx, fluid withdrawals from such a reservoir will affect a decline in pressure, controlled by three terms. These terms, affected by changes in reservoir pressure, will be (1) the reduction in pore volume, (2) expansion of connate water, and (3) expansion of reservoir oil. A description of the case for fluid expansion above the bubble point is described in the referenced text (Craft & Hawkins, 1959).

Using the parameters for the Cedar Lake field tabulated in Table 2-24, a match to the pressure decline vs. cumulative production (Figure 2-50) was obtained for an oil-in-place (OIP) estimate of 190 million stock tank barrels and a pore volume of 284 million reservoir barrels. The OIP and pore volume estimates are less than Oxy Permian subsequently reported (Beebe, 2004). Considering that field developments will expand over time, it is not unexpected for the original OIP numbers to increase as a field is developed over decades.

Table 2-24 – Cedar Lake Reservoir Parameters

Parameter	Value
Initial Reservoir Pressure (psi)	1,950
Initial Water Saturation (%)	0.28
Initial Oil Formation Volume Factor (RB/STB*)	1.077
Oil Compressibility (psi^{-1})	6.6×10^{-6}
Water Compressibility (psi^{-1})	3.0×10^{-6}
Formation Compressibility (psi^{-1})	4.0×10^{-6}

*Reservoir barrel per stock-tank barrel.

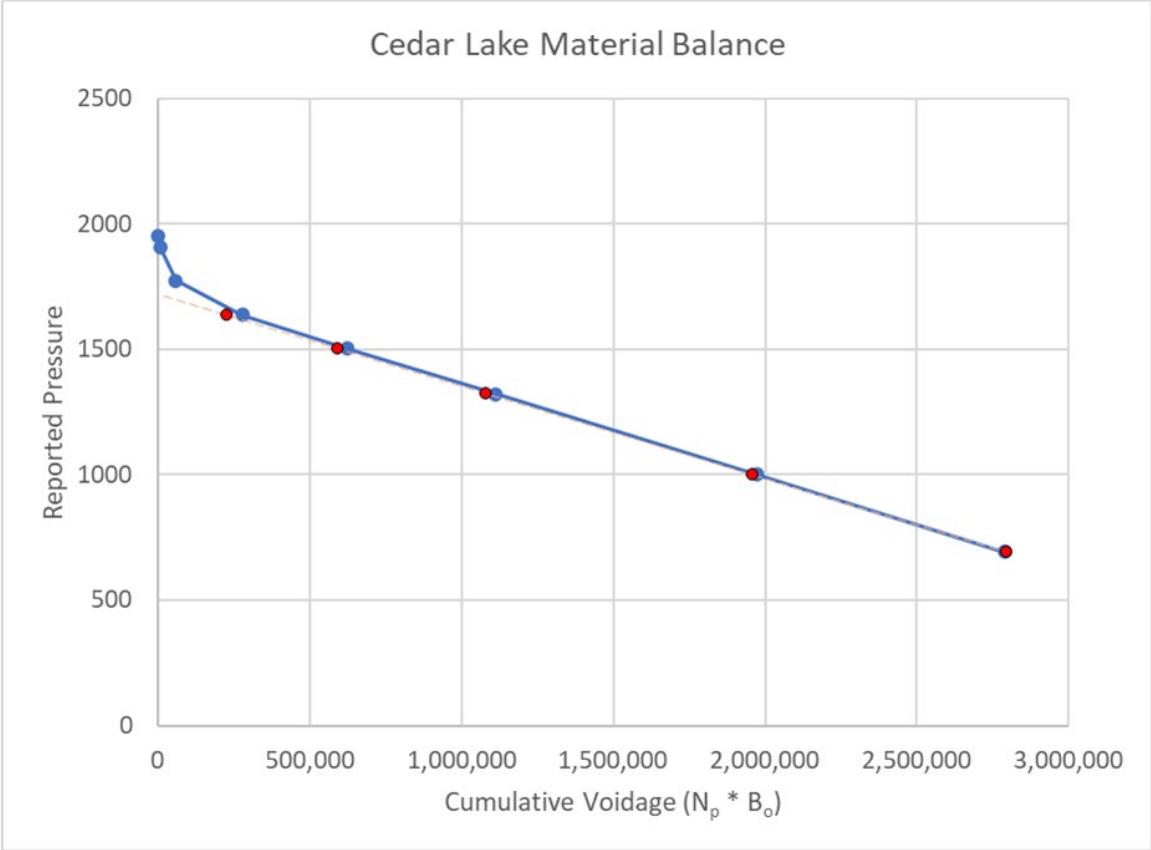


Figure 2-50 – Cedar Lake Material Balance

The results of the material-balance match are significant when considering the regional connectivity of the Cedar Lake field. If the field was connected to a much larger pore volume (i.e., a regional aquifer), the material balance should reflect very large pore volumes. This evaluation, however, indicates that Cedar Lake field is likely not in communication with the surrounding area, particularly the Orchard Project area. The data acquired during the drilling of the well will confirm this analysis. The Cedar Lake field currently operates at higher than initial pressures, approximately 2,500 psi at 4,900 ft below the surface (-1,700 ft subsea). If Cedar Lake is in communication with the Orchard Project area, relatively high pressures should be seen, which is contrary to the performance-based evidence.

2.5.3 Model Time Frame

The reservoir simulation model was run for a period of 62 years, incorporating 12 years of active injection followed by 50 years of post-injection monitoring. During the latter (i.e., non-injecting) phase, the movement of the CO_2 phase is a largely gravity-driven vertical migration as discussed in Section 2.3. Figure 2-51 shows a graph of the aggregate plume size for the seven injectors over time. The plume size is calculated based on the maximum value of effective CO_2 saturation through all layers at any x, y (or model "I, J") map location, with saturations above a 3% minimum value as a cutoff. The calculation of effective CO_2 content was described in Section 2.3.3.2.

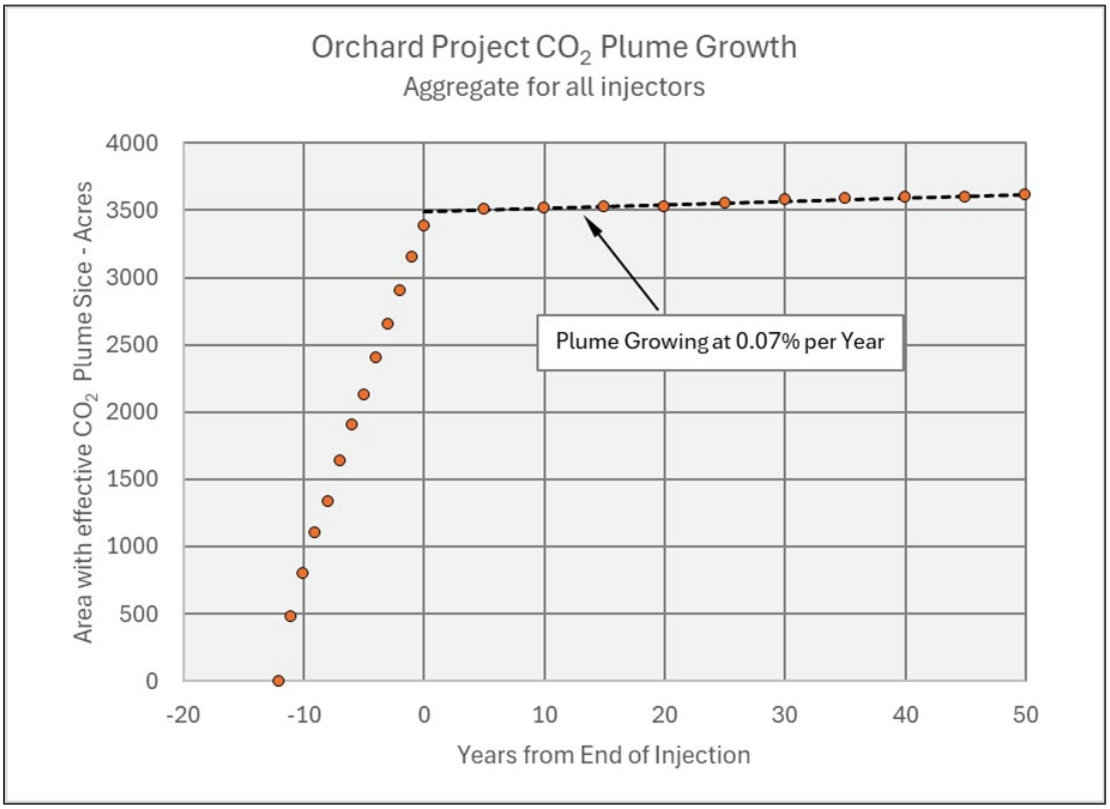


Figure 2-51 – Aggregate Plume Growth Vs. Time for Orchard Project Injection Wells

The horizontal axis on this plot is *years*, referenced to the end of the injection period. Figure 2-51 shows how the plume stabilizes to a very slow growth rate within the first few years post-injection.

2.6 CO_2 Plume Model Results

Model cases were run that included all wells, to ensure overall injectivity while honoring injection pressure limits. Figure 2-52 shows the stabilized CO_2 plumes for all seven injection wells at 50 years post-injection as color contours. The solid contour line depicts the CO_2 plume outline at 5 years post injection for reference. Figures 2-53 through 2-66 display cross sections of the CO_2 plumes for Orchard No. 1 to No. 7, respectively, taken at the end of injection and 50 years post-injection.



Figure 2-52 – Stabilized CO_2 Plumes, 50 Years Post-Injection

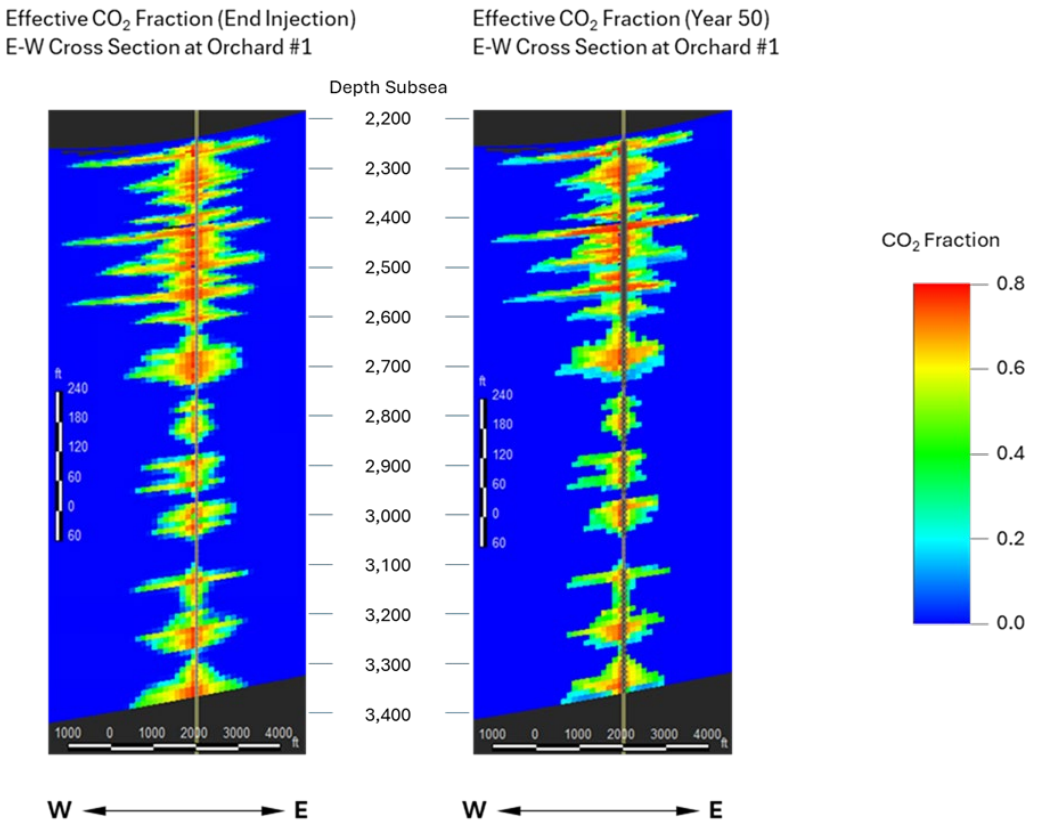


Figure 2-53 – Orchard No. 1 West-East Cross-Sectional Views of Effective CO_2 Saturation

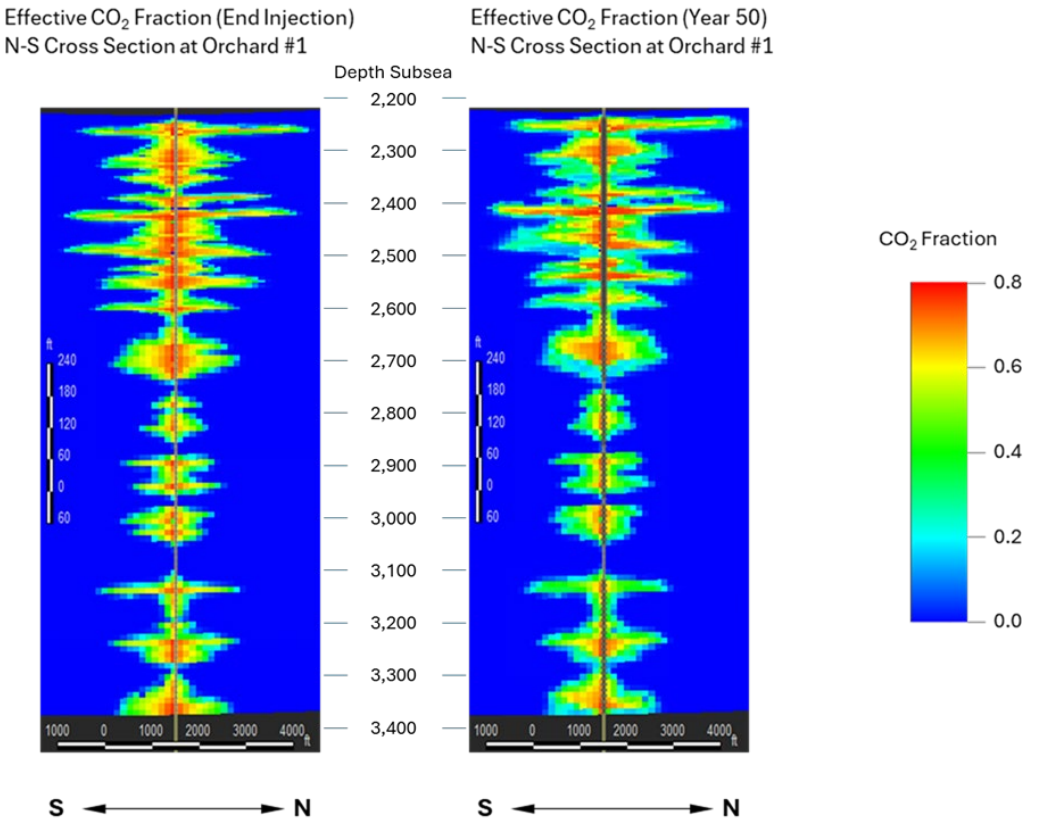


Figure 2-54 – Orchard No. 1 North-South Cross-Sectional Views of Effective CO_2 Saturation

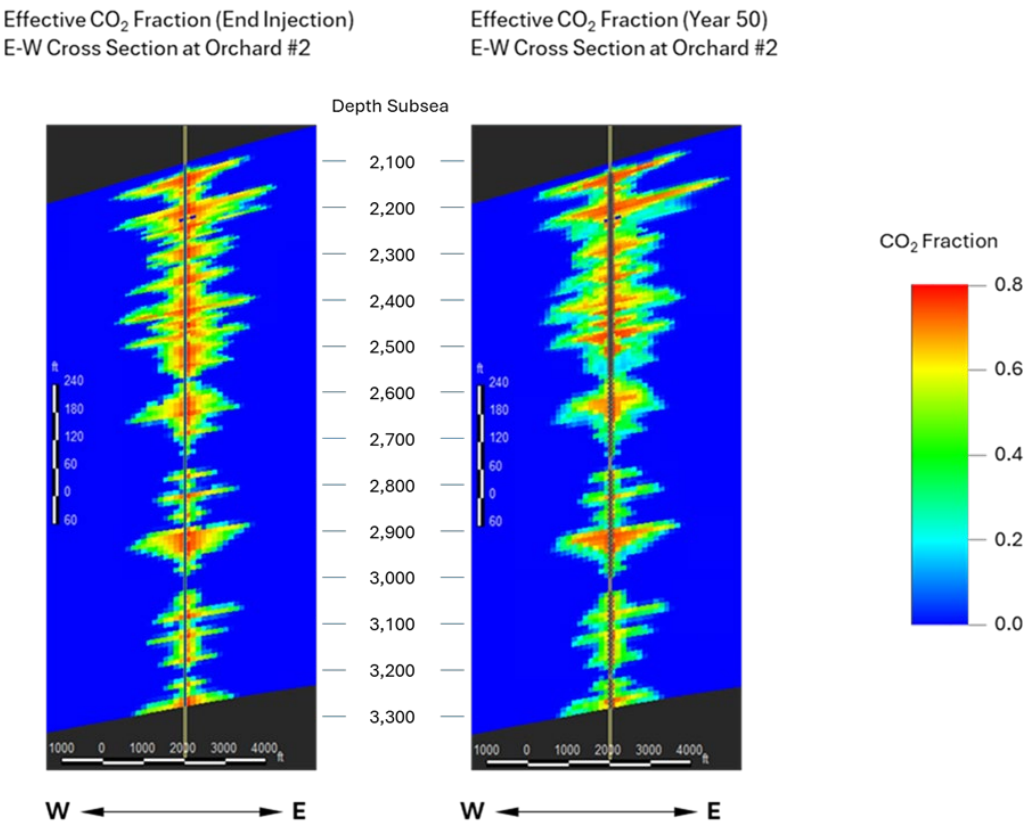


Figure 2-55 – Orchard No. 2 East-West Cross-Sectional Views of Effective CO_2 Saturation

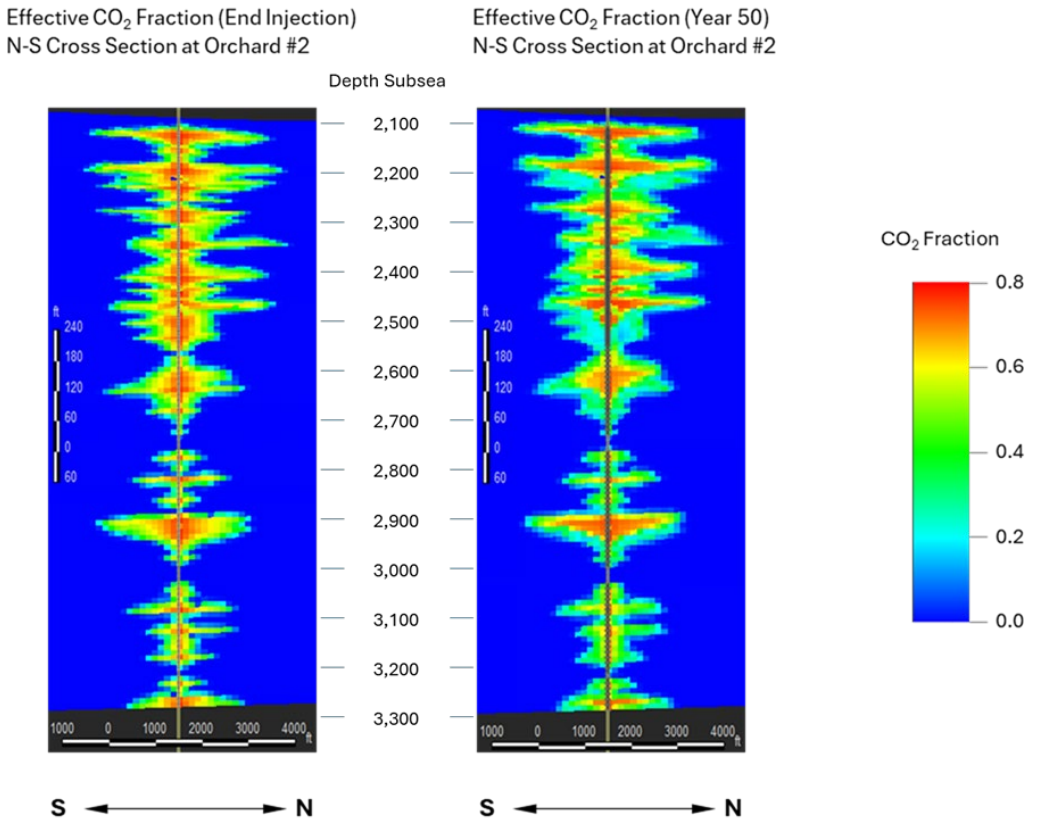


Figure 2-56 – Orchard No. 2 North-South Cross-Sectional Views of Effective CO_2 Saturation

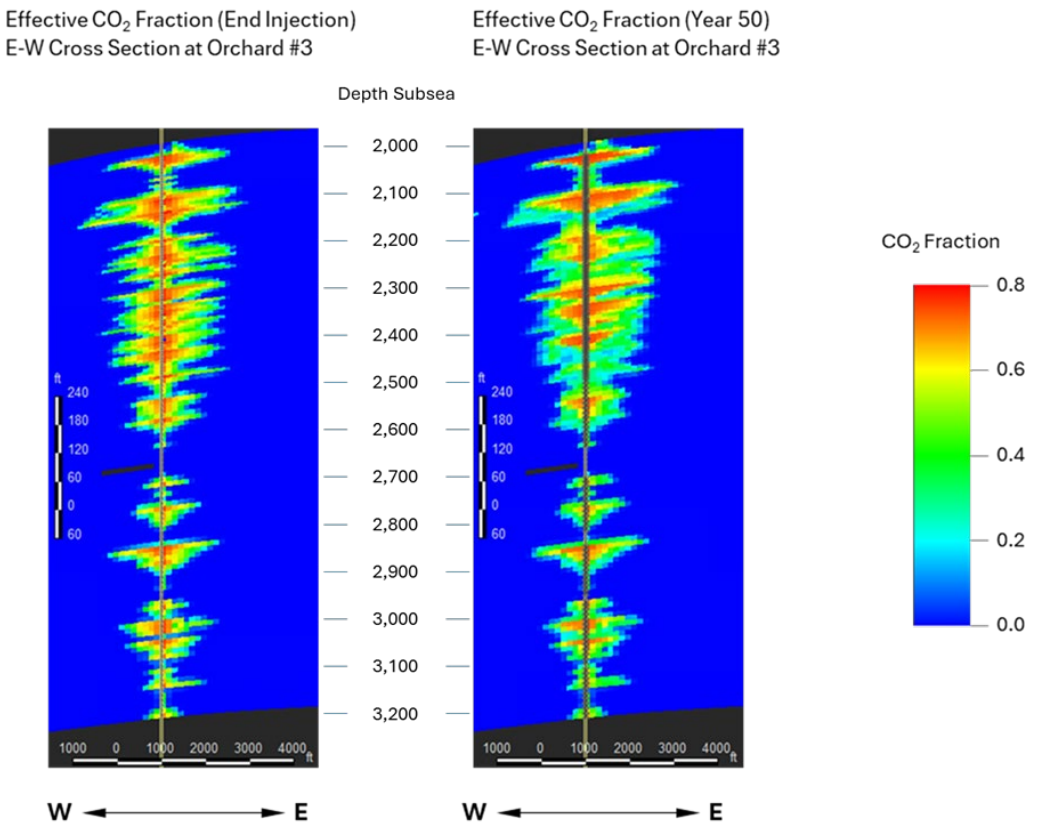


Figure 2-57 – Orchard No. 3 East-West Cross-Sectional Views of Effective CO_2 Saturation

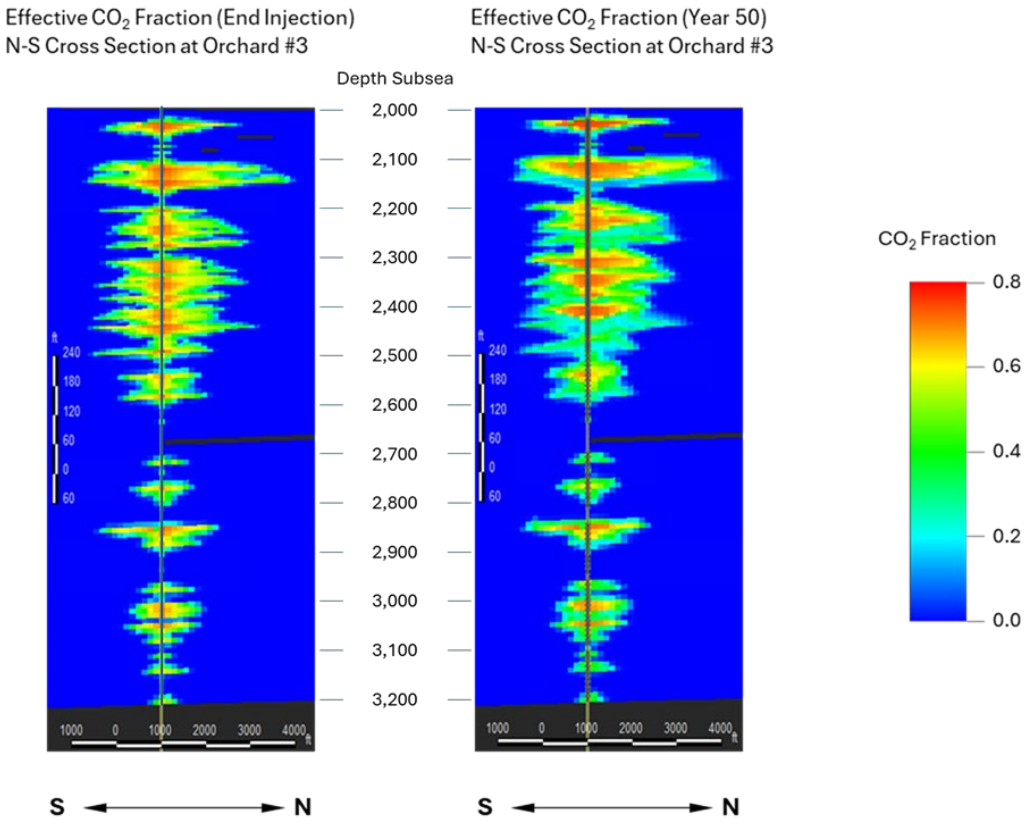


Figure 2-58 – Orchard No. 3 North-South Cross-Sectional Views of Effective CO_2 Saturation

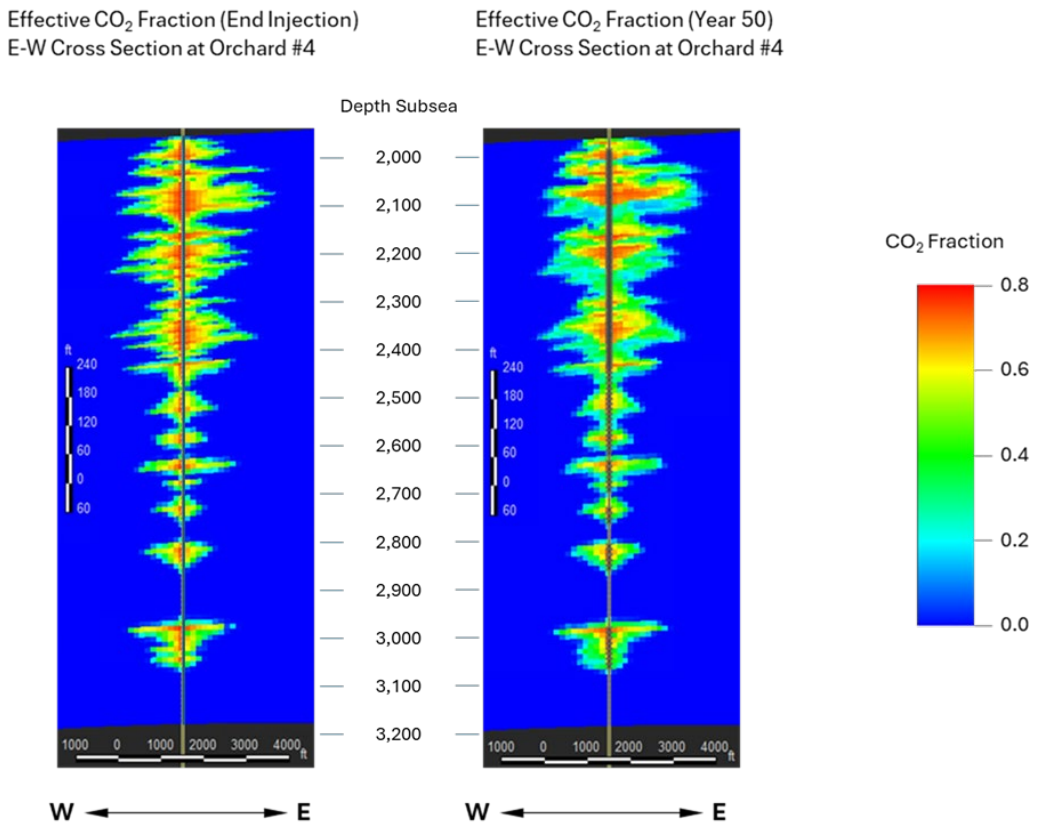


Figure 2-59 – Orchard No. 4 East-West Cross-Sectional Views of Effective CO_2 Saturation

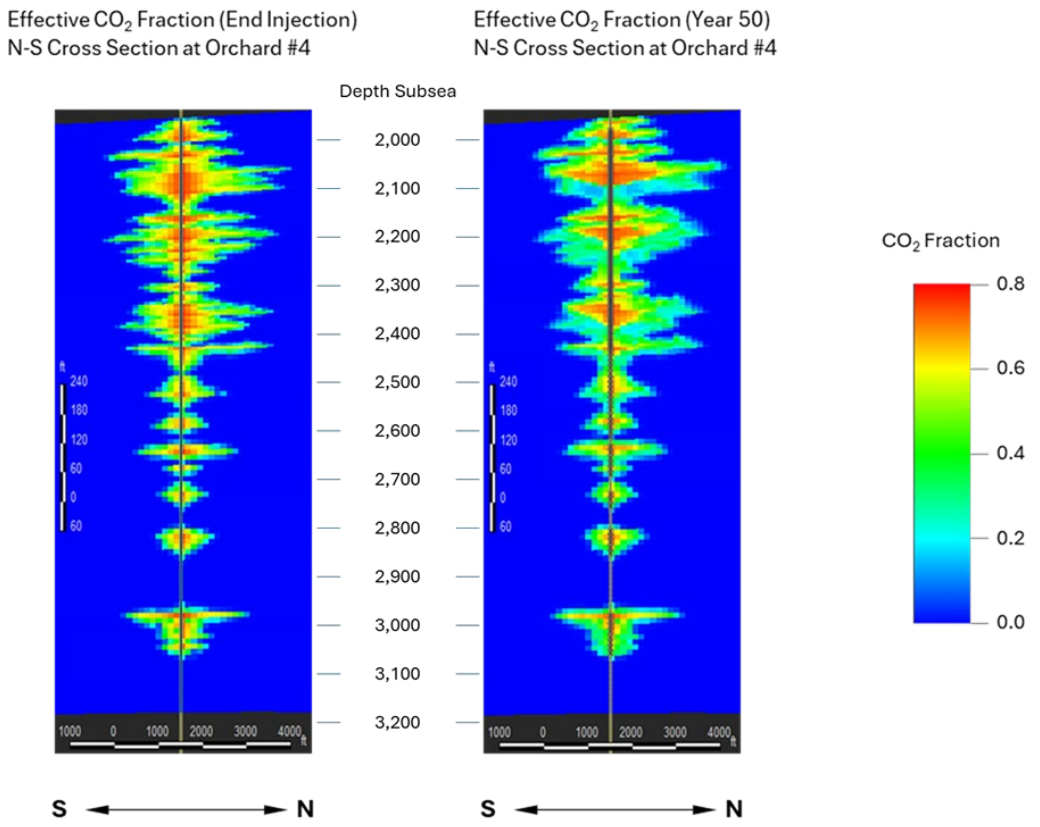


Figure 2-60 – Orchard No. 4 North-South Cross-Sectional Views of Effective CO_2 Saturation

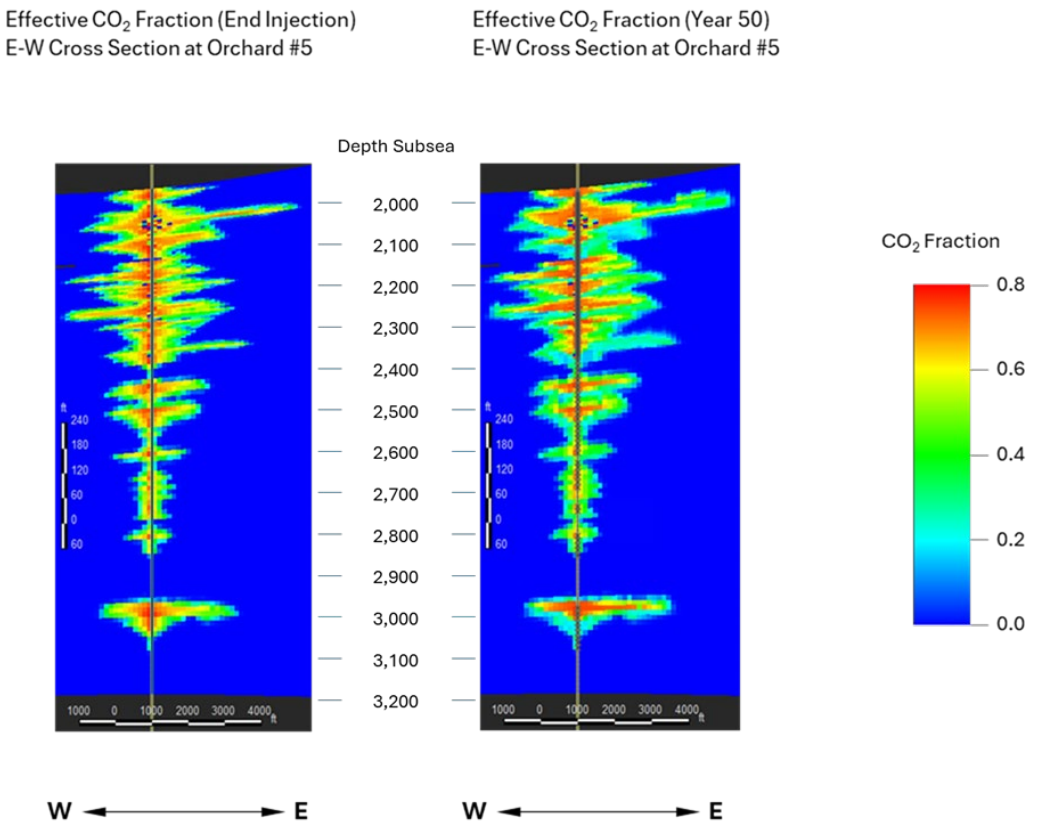


Figure 2-61 – Orchard No. 5 East-West Cross-Sectional Views of Effective CO_2 Saturation

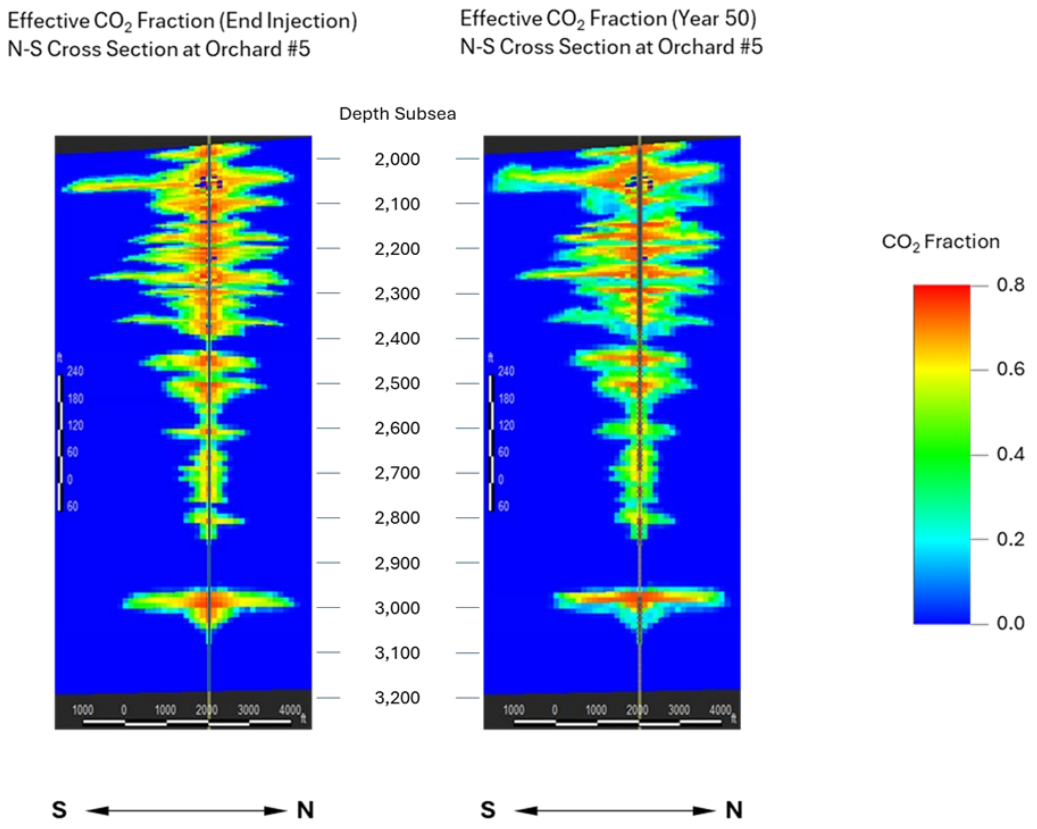


Figure 2-62 – Orchard No. 5 North-South Cross-Sectional Views of Effective CO_2 Saturation

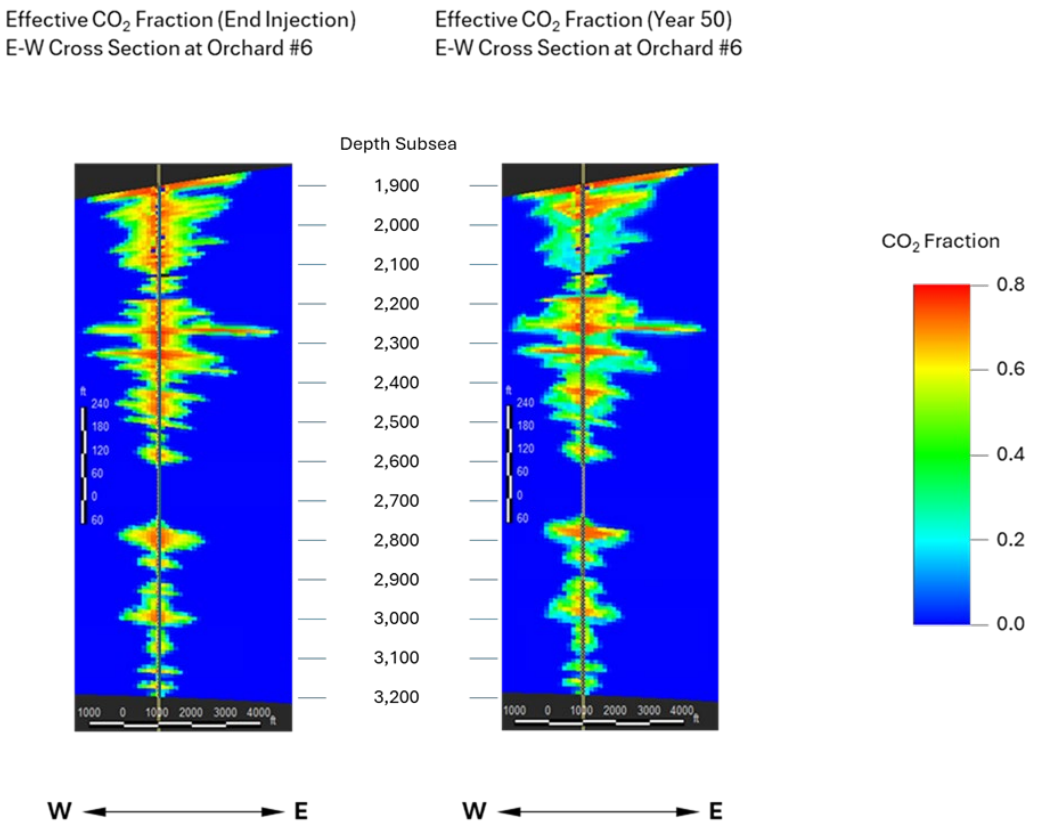


Figure 2-63 – Orchard No. 6 East-West Cross-Sectional Views of Effective CO_2 Saturation

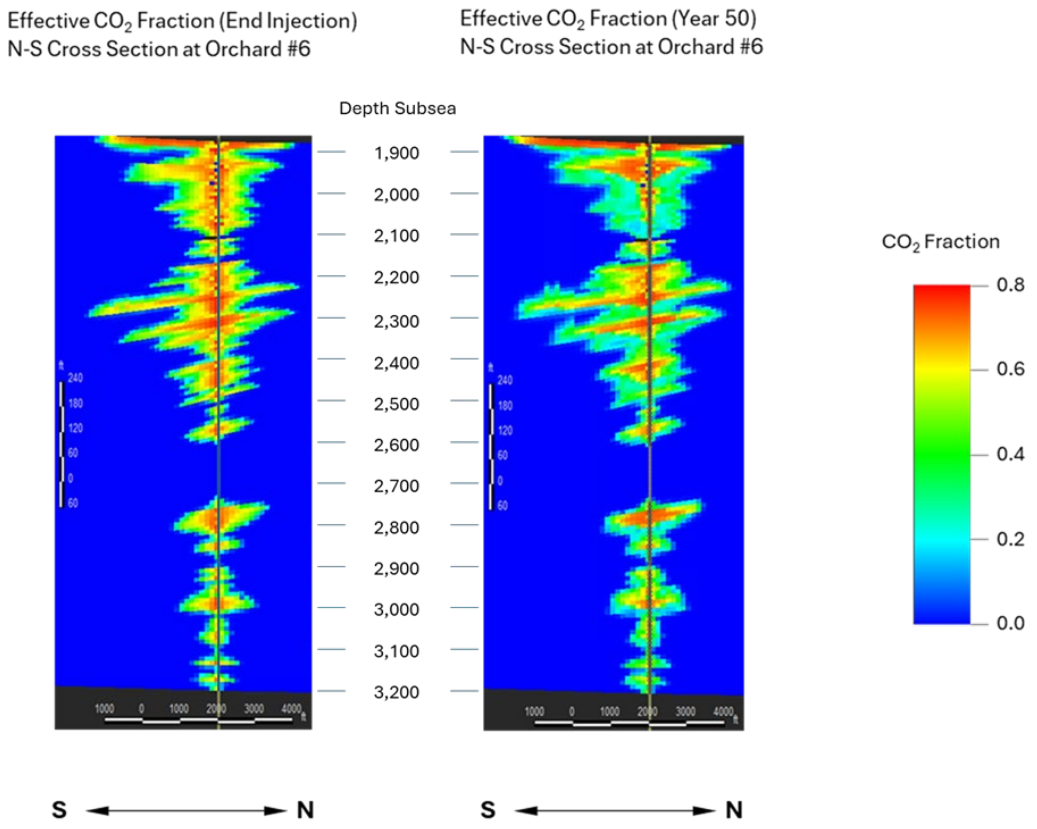


Figure 2-64 – Orchard No. 6 North-South Cross-Sectional Views of Effective CO_2 Saturation

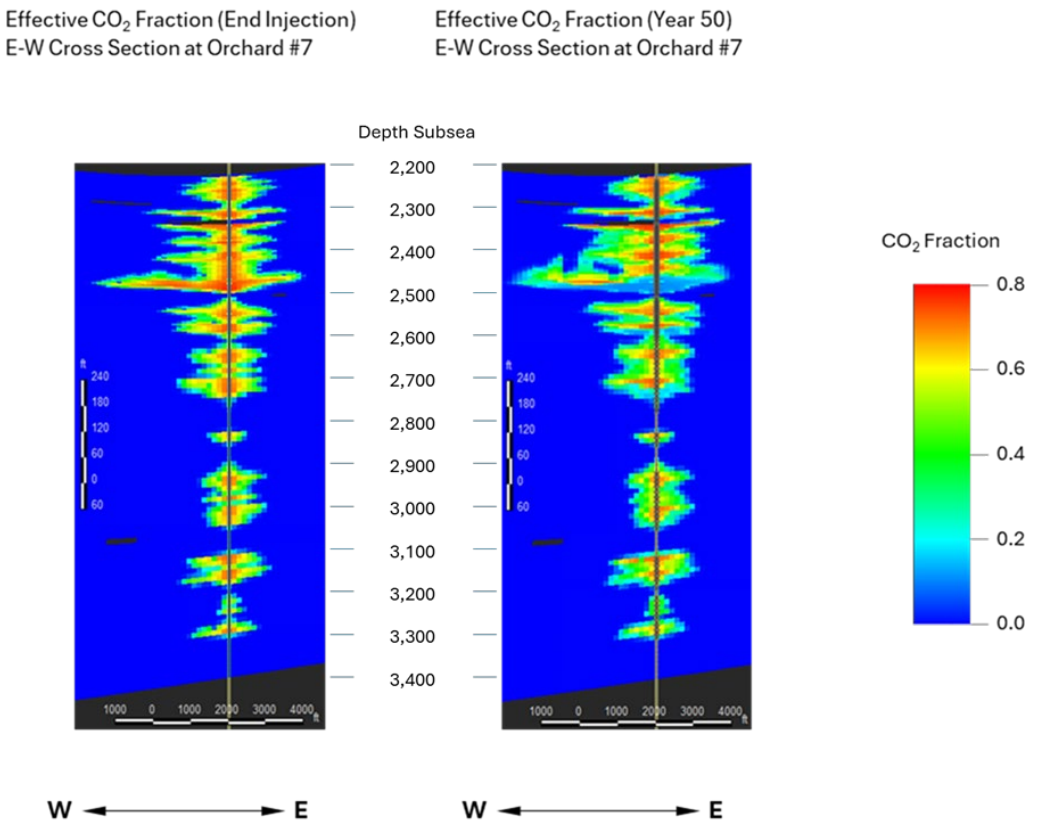


Figure 2-65 – Orchard No. 7 East-West Cross-Sectional Views of Effective CO_2 Saturation

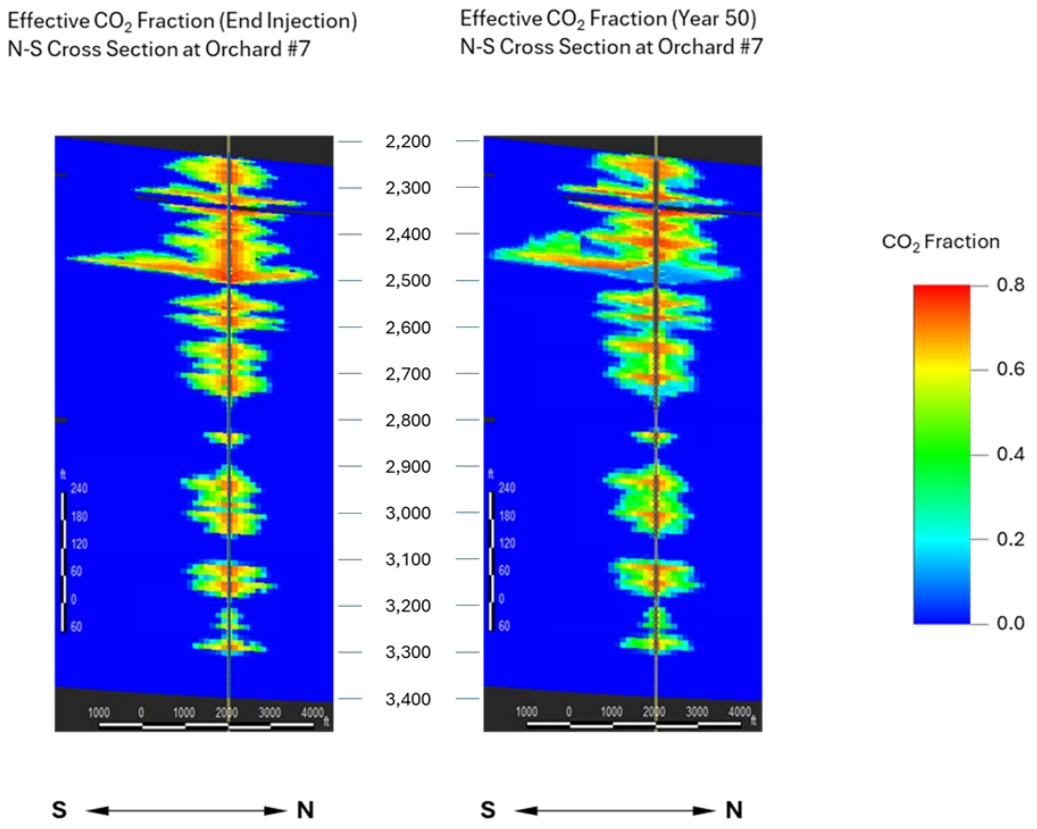


Figure 2-66 – Orchard No. 7 North-South Cross-Sectional Views of Effective CO_2 Saturation

Figure 2-51 demonstrated how the plume areal extent stabilizes during the first few years after injection. While the plume areas quickly stabilize, the trapping of the CO_2 phase progresses over many years (discussed in *Section 2.3.5*). Figures 2-67 and 2-68 show how the trapped CO_2 volumes will change over time for the Orchard Project.

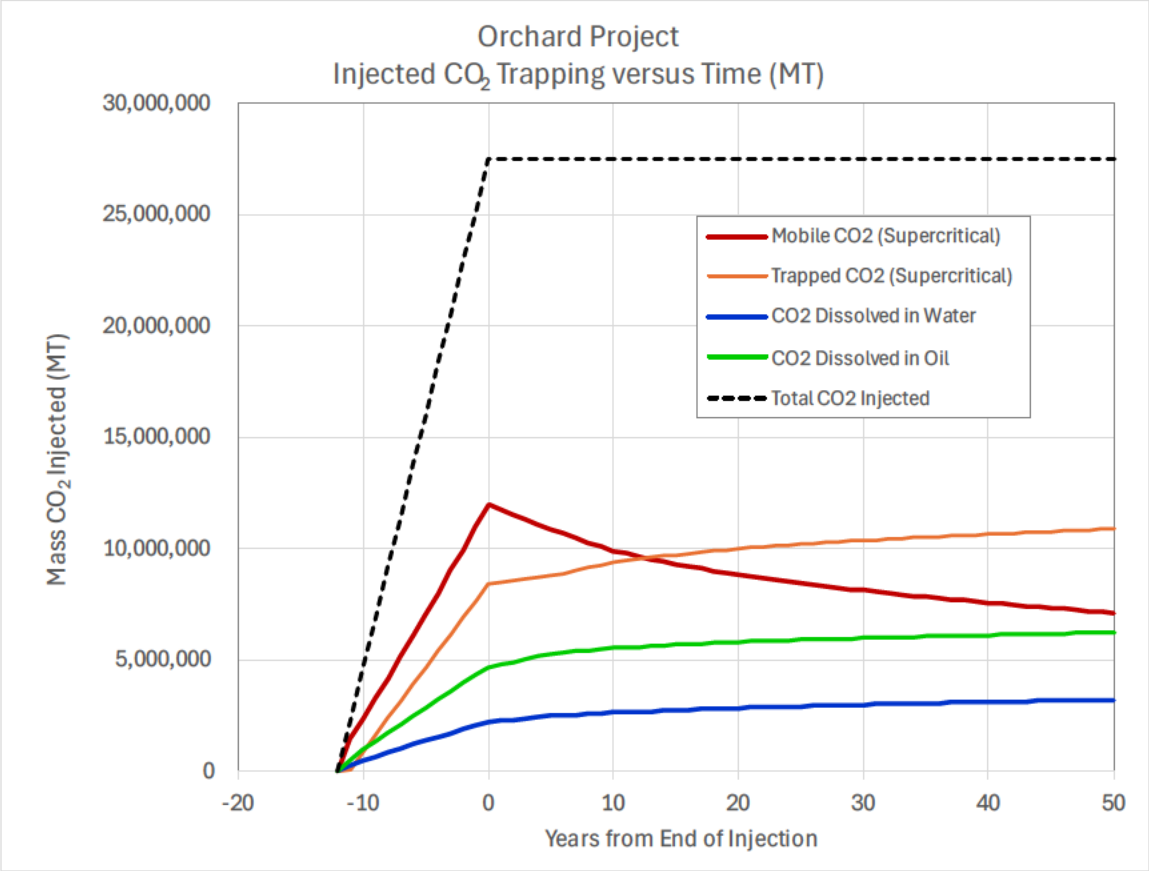


Figure 2-67 – Total Metric Tons of CO_2 and Trapping Mechanisms Over Time

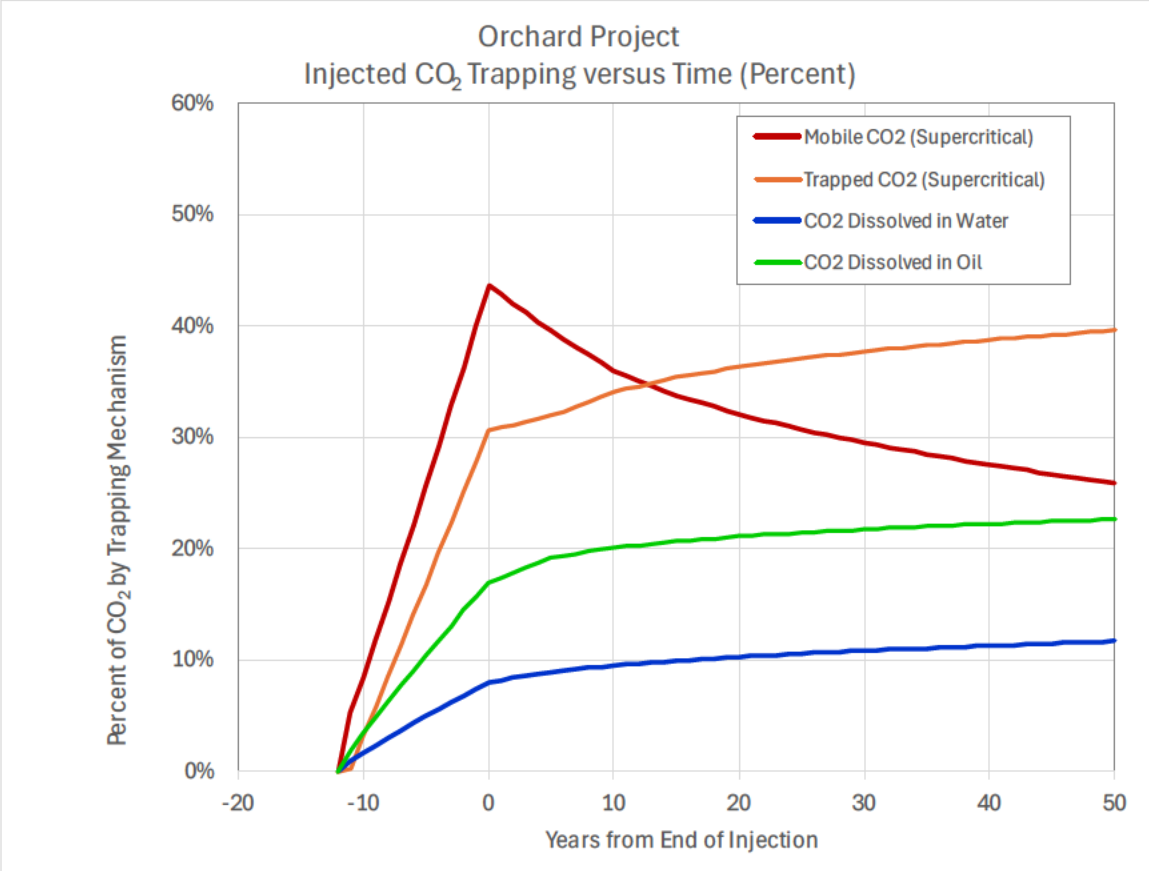


Figure 2-68 – Percent of CO_2 in Each State Over Time

2.7 Dynamic Model Sensitivity Analysis

A sensitivity analysis was performed to determine the most significant parameters as they impact CO_2 plume stability and trapping mechanism effectiveness. Each of the parameters was varied individually for comparison of its impact on key model results. Table 2-25 summarizes the parameters and the values chosen for this analysis.

Table 2-25 – Parameters Used in Dynamic Modeling Sensitivity Analysis

Parameter	Parameter Value			Comments
	Low	Base	High	
Gas relative permeability endpoint value (k_{rgrl})	0.045	0.10	0.20	Gas relative permeability at irreducible liquid saturation.
Maximum trapped gas saturation (S_{gt})	0.27	0.30	0.48	Hysteresis parameter for gas relative permeability function under imbibition (water displacing gas) conditions.
Residual oil saturation (S_{or})	0.14	0.19	0.30	Initial oil saturation in ROZ.
Permeability Multiplier	0.5	1	2	Multiplier applied to base-case model permeabilities for each grid block in simulation model.
Vertical Permeability Ratio (k_v/k_h)	0.01	0.03	0.10	Ratio of vertical permeability to horizontal permeability. Applied throughout model.
Temperature Gradient (°F per 100 ft)	0.59	0.7	0.78	Model temperatures distributed based on temperature gradient and depth, relative to surface temperature of 65.5°F at 3,200 ft above sea level.

2.7.1 Sensitivity Parameter Discussion

2.7.1.1 Gas relative permeability endpoint value (k_{rgrl})

As discussed in Section 2.4.2, this parameter represents the relative permeability value for the supercritical CO_2 when the CO_2 is at its maximum saturation (i.e. liquid saturation at irreducible value). The relative permeability curves used in the dynamic model have been created using "Corey" analytical functions (Corey, 1954) shown as Equations 4 and 5. The respective endpoint value for the water and CO_2 relative permeability functions (k_{rwcg} and k_{rgrl}) scale the calculated relative permeability values for water and CO_2 phases. Accordingly, changing the gas (or CO_2) relative permeability endpoint value will proportionally change the relative permeability to CO_2 throughout the entire saturation range (e.g., doubling the k_{rgrl} parameter will double the gas relative permeability (relative to the base) throughout the saturation range). Changes in the gas relative permeability will likewise affect the mobility of the gas phase in the gas-liquid system.

The base case value for this parameter was chosen based on data from several references (Benson, et al., 2015) (Bennion & Bachu, 2005) (Bennion & Bachu, 2008) (Crandall, Moore, Brown, & King, 2019). The base-case value was chosen at the P_{50} value of the distribution of the k_{rgrl} parameter data from these sources, as found in Figure 2-42 and presented, with annotations for base- and respective low- and high-case sensitivity values, as Figure 2-69.

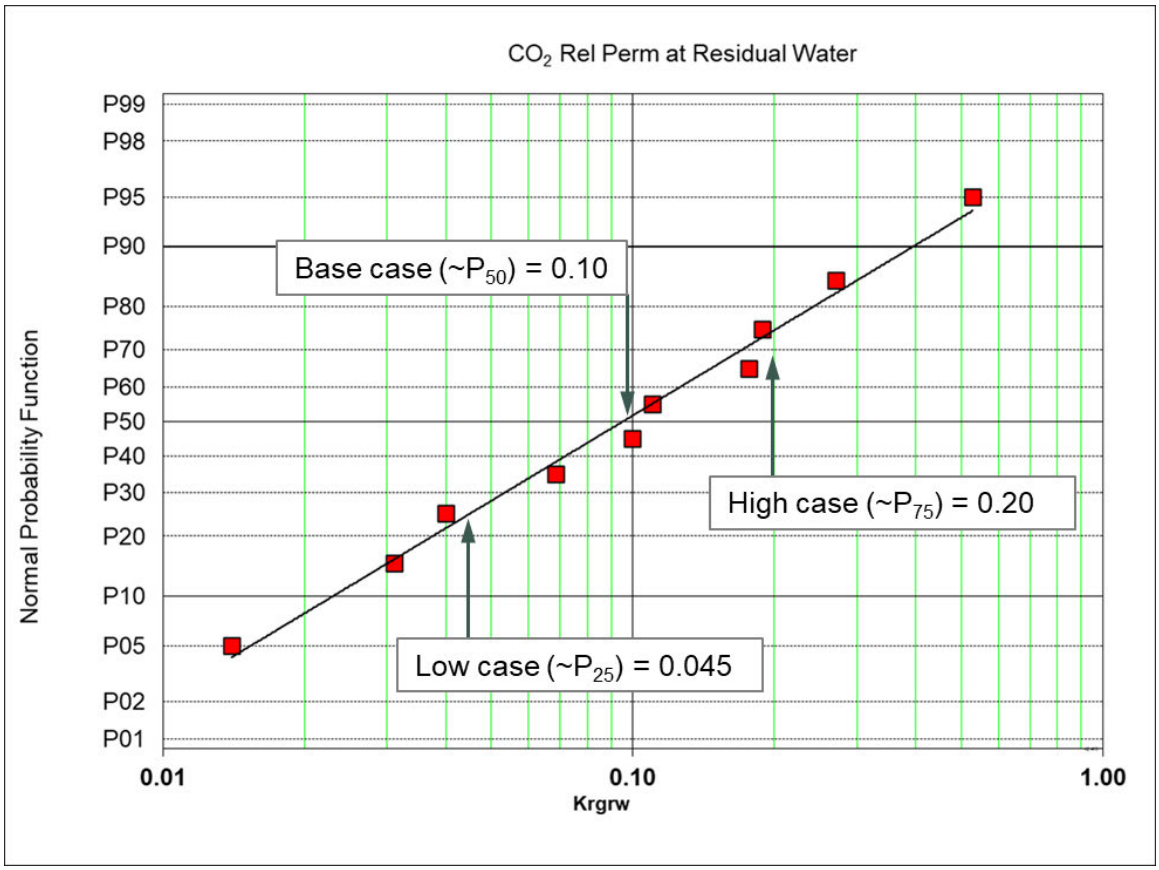


Figure 2-69 – Statistical Distribution for CO_2 Endpoint Relative Permeability

2.7.1.2 Maximum Trapped Gas Saturation (S_{gt})

As discussed in section 2.3.2, the relative permeability behavior of a gas (or supercritical gas) water system is dependent on the direction of the saturation changes. Under injection conditions or at the front of a migrating CO_2 plume, CO_2 can be mobile at very low saturations, as it will initially occupy the most favorable flow channels. As saturation of the CO_2 phase increases, it will occupy progressively smaller pore spaces in which it may become trapped by capillary forces (Land C. , 1968). After injection, at the following edge of a moving CO_2 plume, water is displacing the CO_2 in an imbibition process (opposed to the "drainage" process in which CO_2 is displacing water). Under the imbibition process, some part of the CO_2 occupying the pore volume is bypassed by the displacing fluid (water) and consequently remains immobile as trapped gas. The relative permeability for the nonwetting CO_2 phase for a grid block is dependent on both the saturation history and the specified maximum trapped gas saturation (maximum S_{gt}) parameter.

The maximum S_{gt} value represents the trapped gas (CO_2) saturation when the drainage process has displaced liquids down to irreducible value. The irreducible CO_2 saturation at any point (and time) will be a function of the previous maximum CO_2 saturation and the specified maximum S_{gt} parameter according to functions developed by Land and Carlson (Land C. , 1968) (Land C. S., 1971) (Carlson, 1981).

The base-case value for the maximum S_{gt} parameter was chosen at a conservative value of 0.30, as discussed in Section 2.3.2 and shown on Figure 2-26 and Figure 2-70. Figure 2-70 is based experimental data for carbonate rocks by Keelan (Keelan, 1975), and is annotated with the selected base-case and sensitivity values.

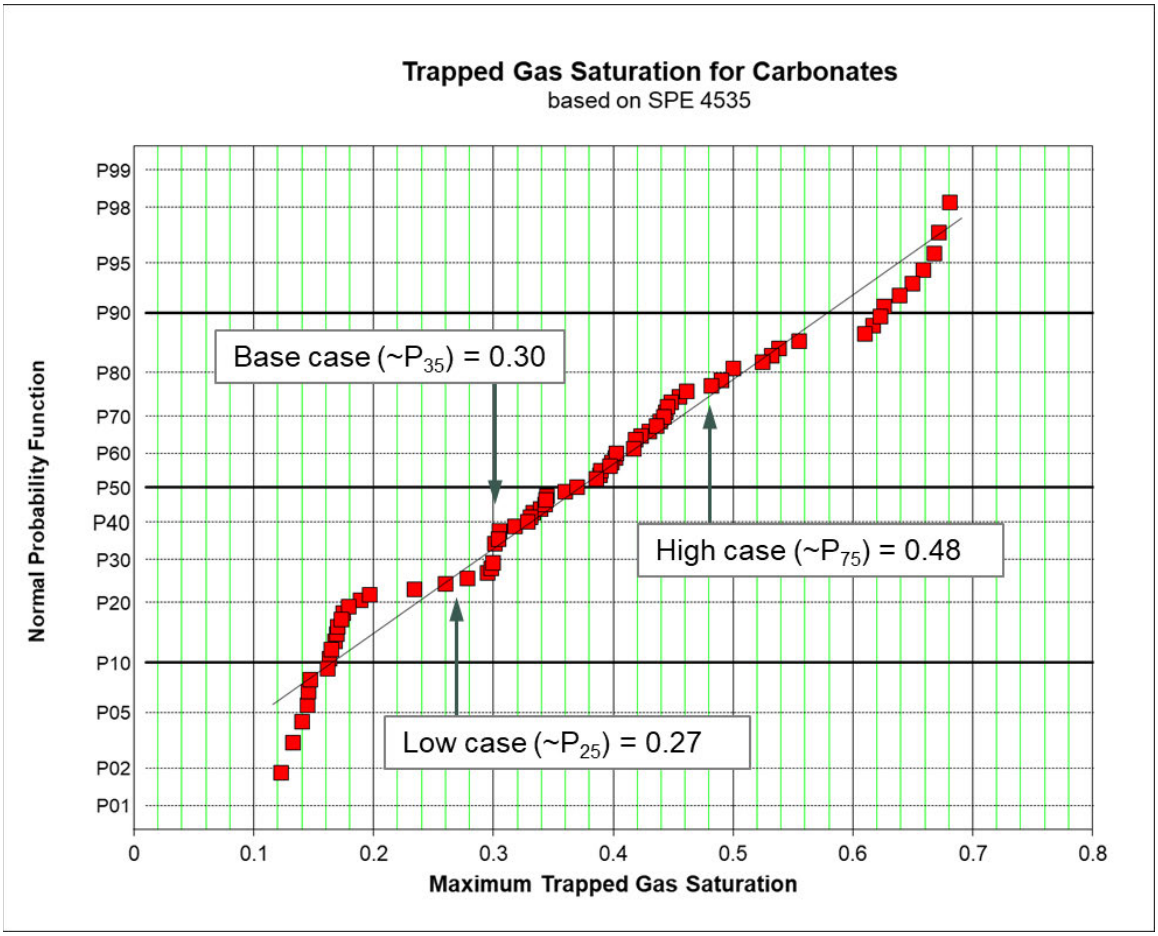


Figure 2-70 – Experimental Data for Maximum Trapped Gas Saturation

2.7.1.3 Residual Oil Saturation

The presence of residual oil saturation zones (ROZ) in the region is well documented (Kuuskraa, Petrusac, & Wallace, 2020), and is supported by the presence of residual oil saturations throughout the storage interval in sidewall cores recovered from the Valiant No. 1D well (API No. 42-165-38785). Using these core data, the model was initialized with a residual oil saturation of 19% throughout the storage interval. Further discussion of the ROZ can be found in section 2.3.3.2 under trapping mechanisms.

The oil saturation value of 19% is based on measurements from core data taken within the project area. The Kuuskraa et. al. paper categorizes ROZ accumulations as "Higher Quality" and "Lower Quality" ROZ Fairway Resources. Data from the sidewall cores suggest that the residual oil saturations found in the storage interval are close to the "Lower Quality" resources identified by these authors. The upper value for the residual oil saturation sensitivity was chosen at 30%, matching residual oil saturation in the higher quality ROZ accumulations for project area (Eastern Gaines County) in the referenced report. Low case sensitivity value for the residual oil saturation was chosen at 14%. This corresponds to approximately a P_{20} value on the distribution of S_{or} values at reservoir conditions, based on sidewall cores, as shown in Figure 2-71.

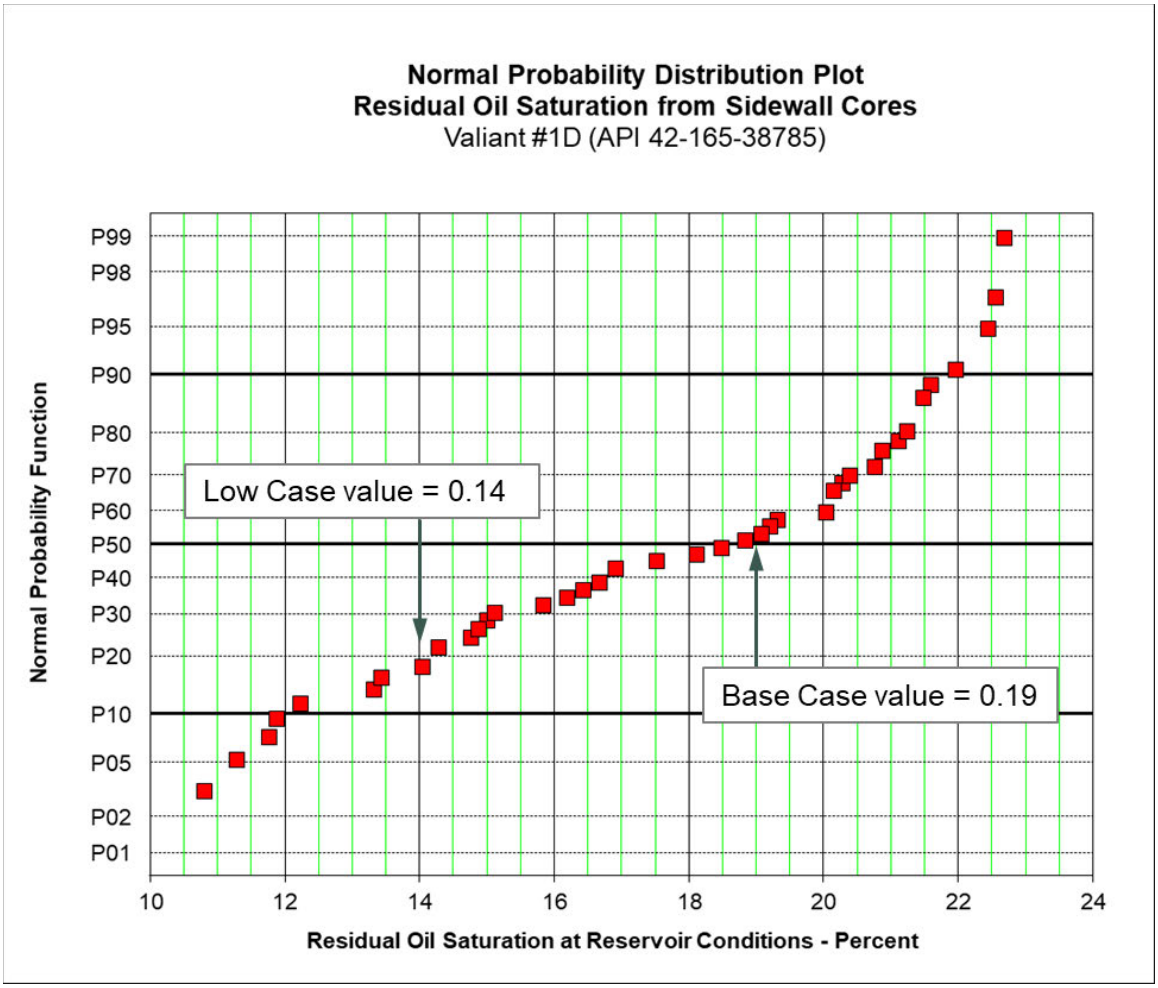


Figure 2-71 – Residual Oil Saturation from Sidewall Cores

2.7.1.4 Permeability Multiplier

Sensitivity cases on formation permeability were generated by applying a global multiplier to permeability values throughout the model. In the low case model, permeabilities were multiplied by 0.5; in the high case sensitivity, permeabilities were multiplied by 2.

2.7.1.5 Vertical to Horizontal Permeability Ratio

The vertical to horizontal permeability ratio (k_v/k_h) is discussed in section 2.4.1.1. A base-case value of 0.03 was chosen as "typical" as used in history-matched simulations of carbonate reservoirs. It should be noted that core plug k_v/k_h ratios will likely be significantly higher than those used in a simulation model as the effective k_v/k_h ratio is scale dependent. While the core plug measurements may be made over a scale of a few centimeters, the simulator values are characterizing flow over many feet. Heterogeneity not seen on the core plug scale will affect the inter-block flows on a simulation model scale.

Sensitivity values of 0.01 and 0.10 were chosen for the low- and high-end sensitivity cases. These values represent typical ranges used in history-matched simulation models of hydrocarbon fields.

2.7.1.6 Temperature Gradient

The base-case temperature gradient was chosen to be 0.7°F per 100 ft based on temperature data recorded from well logging runs for nearby wells, as discussed in Section 2.4.4 and presented as Table 2-14. A statistical representation of these data is shown as Figure 2-45, and Figure 2-72 (with annotations for sensitivity values). Low and high case sensitivities were chosen at 0.59 and 0.78°F/100 ft, representing approximately P_{10} and P_{90} values on the distribution, respectively. That distribution is shown in Figure 2-72.

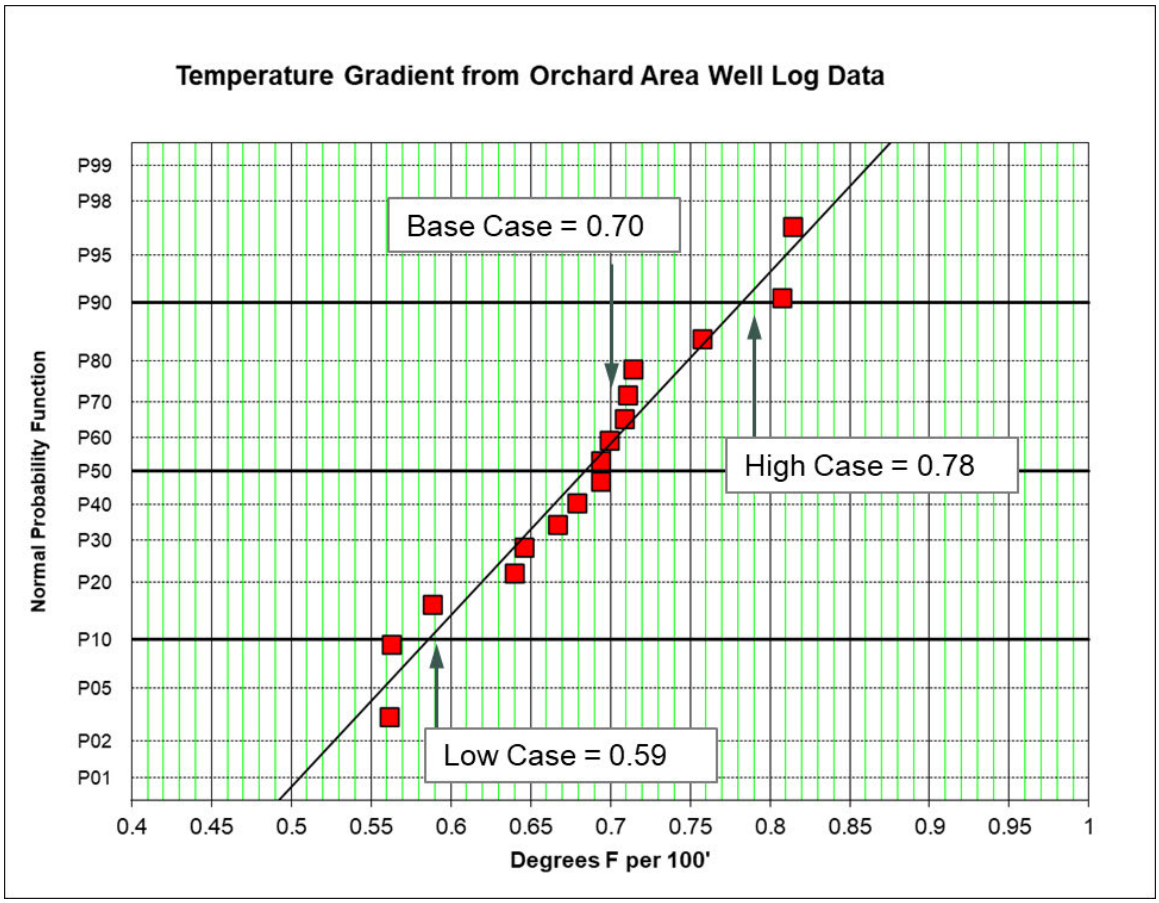


Figure 2-72 – Temperature Gradient - °F per 100 Feet

Temperature gradients were implemented by using a datum temperature of 65.5°F at an elevation of 3,200 ft above sea level, corresponding to a 0.70°F/100 ft temperature gradient and a base-case temperature of 105 °F at the simulator datum elevation of 2,450 ft below sea level. In each of the sensitivities, the model temperatures were derived from the surface temperature through the application of the respective temperature gradient.

2.7.2 Results of Sensitivity Cases

The dynamic simulation model was run for each of the six pairs (low- and high-case) of sensitivity values discussed in Section 2.7.1. The sensitivity cases were run by varying only a single parameter at a time. Results for each of the sensitivity runs were compared to the base case for a set of five output measures which characterize plume stability and CO_2 trapping. These base case values are tabulated in Table 2-26, with the output measures listed with the values from the base case simulation output.

Table 2-26 – Sensitivity Result Measures with Base Case Reference Values

Model Output Variable	Units	Base Case Value (50 years after injection end)
Plume Size	Acres	3,611
Fraction of Injected CO_2 in Mobile Gas Phase	%	26.4
Fraction of Injected CO_2 in Trapped Gas Phase	%	39.5
Fraction of Injected CO_2 in Gas Phase (total)	%	65.9
Fraction of Injected CO_2 Total Dissolved (water + oil)	%	34.1

Plots of these measures versus time relative to end of injection are presented in Figures 2-73 through 2-77. Sensitivity results at the end of the model run are presented compared to the base case values in Tables 2-27 through 2-31.

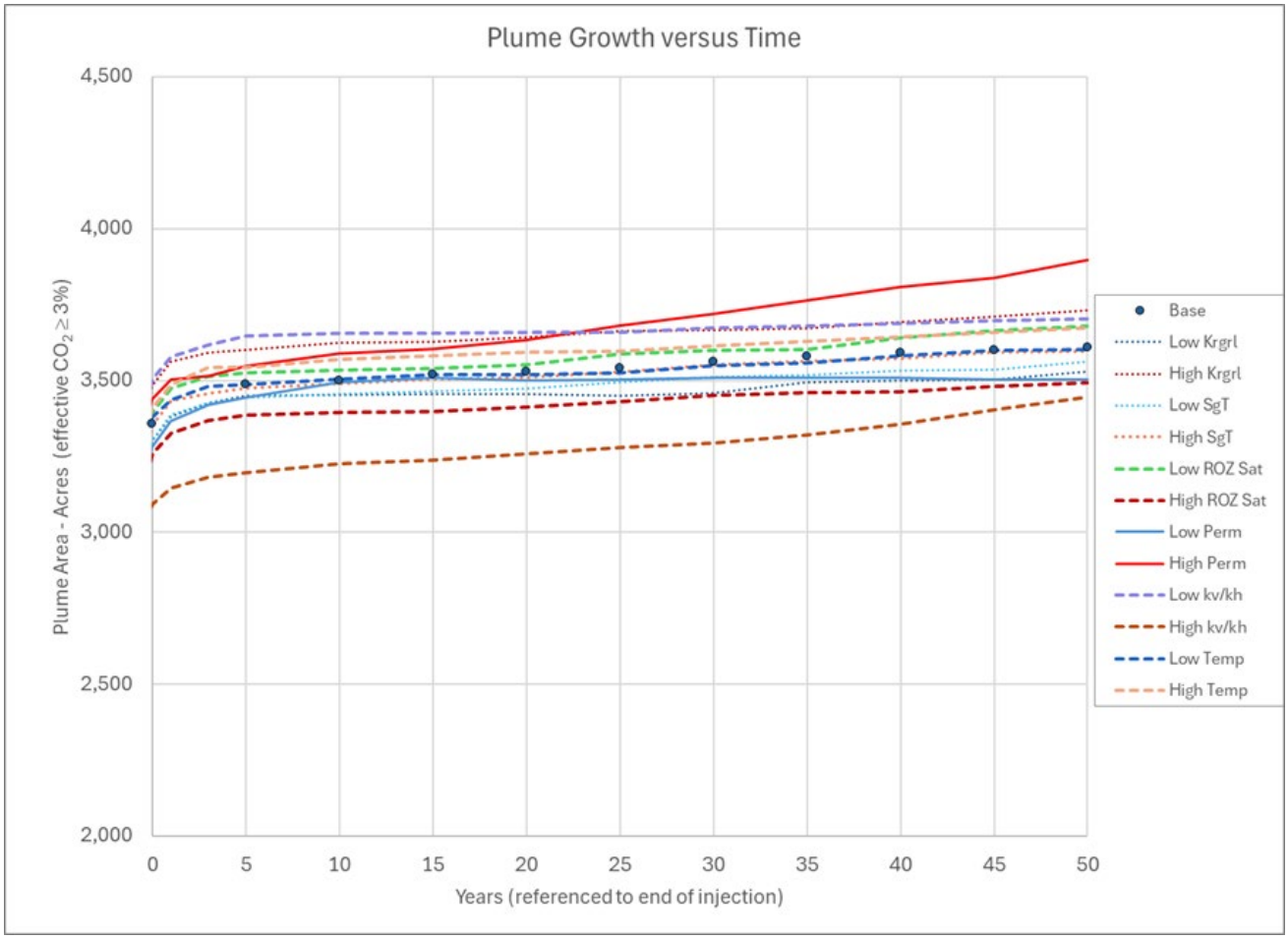


Figure 2-73 – Sensitivities for Plume Size versus Time

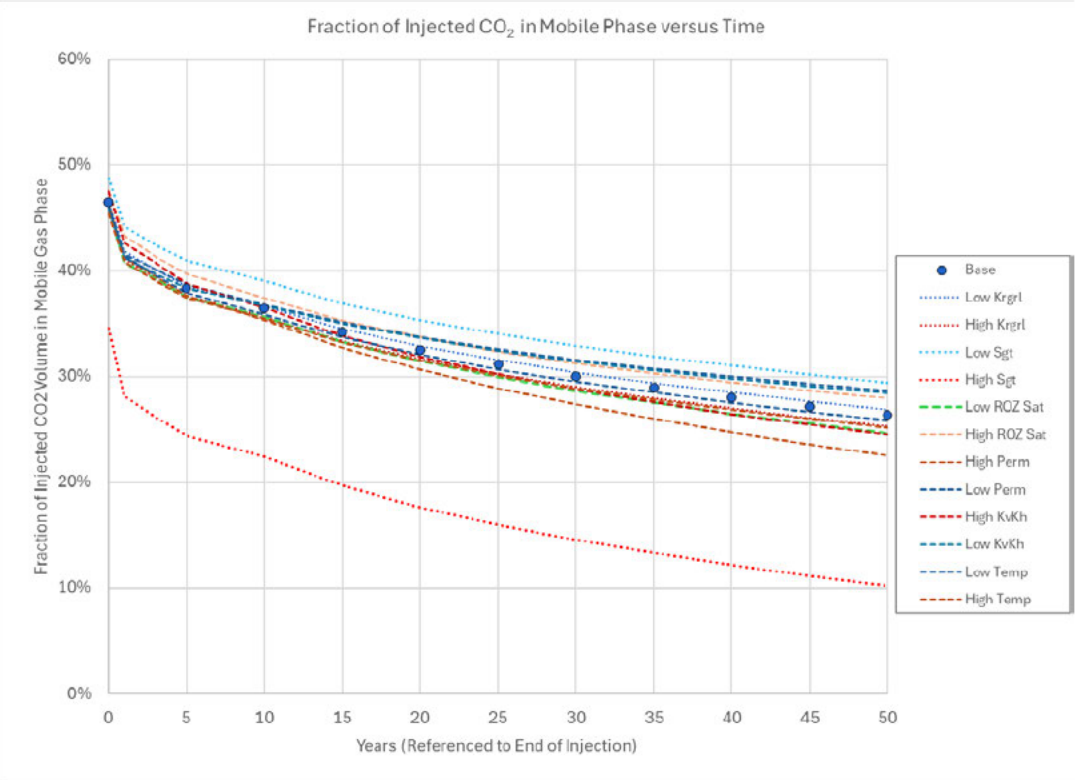


Figure 2-74 – Sensitivities for Percent of Mobile CO_2 versus Time

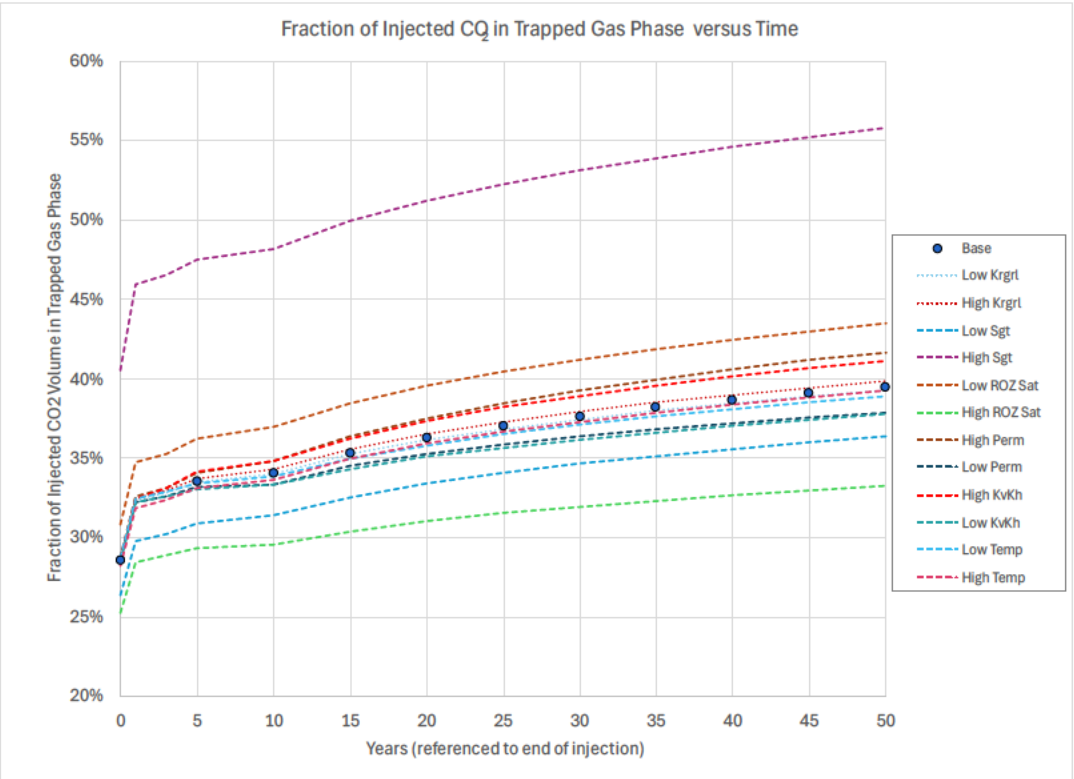


Figure 2-75 – Sensitivities for Percent of Trapped CO_2 versus Time

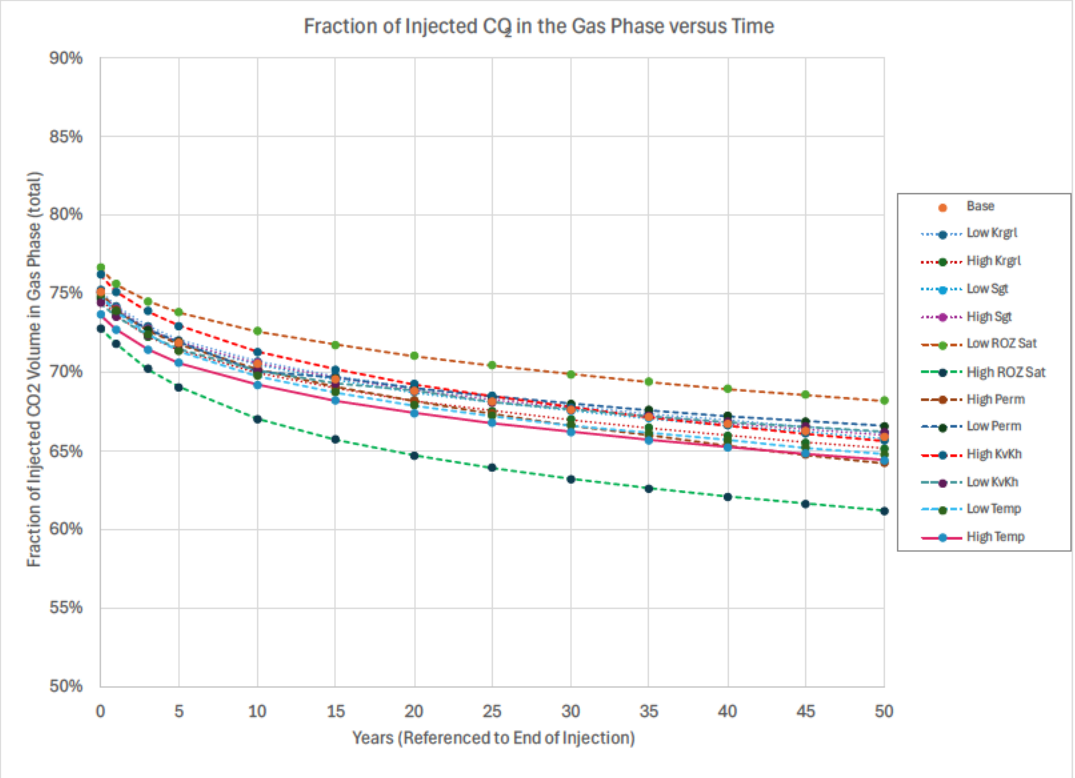


Figure 2-76 – Sensitivities for Percent of CO_2 in Gas Phase versus Time

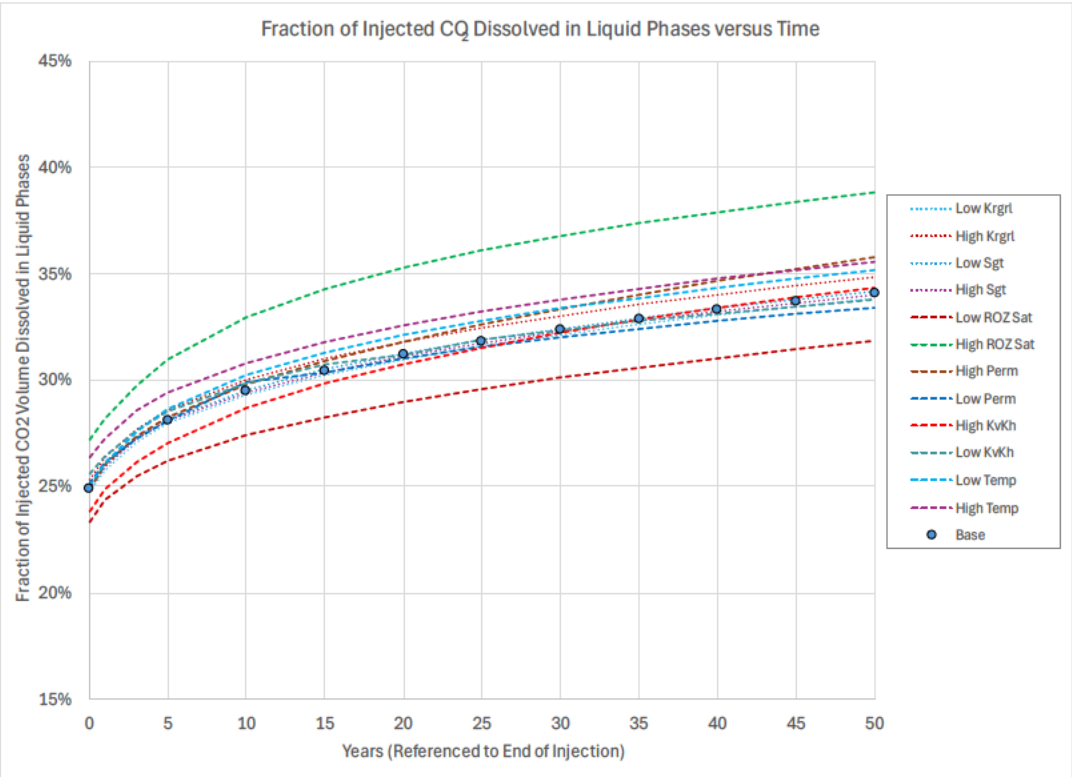


Figure 2-77 – Sensitivities for Percent of CO_2 Dissolved in Oil and Water versus Time

Comparison of the relative impact of the sensitivity parameters on simulator output measures is done by looking at the respective output measures (e.g., plume area) at the end of the simulation run, 50 years after injection ends. Results for these sensitivity "snapshots" are shown in Tables 2-27 through 2-31. Each table is followed by a tornado plot (Figures 2-78 through 2-82) showing the relative change for the output measure summarized on the respective table. The relative change represents the difference in output measure between sensitivity and base-case, divided by the base-case value. Note that the mobile gas and trapped gas phases refer to supercritical phase CO_2.

In Tables 2-27 through 2-31, the "Output Result" columns represent the respective values for the low- and high-case sensitivities on the output measure, 50 years post injection. The "Change from Base" columns represent the respective difference between the sensitivity results and the base case values; and the "Percent Change" columns represent the amount of change relative to the base case value. An example calculation of the Percent Change column for the Plume Area measure is shown in Equation 14.

(Eq. 14) $$Percent\ Change = \frac{\Delta A_{sens}}{A_{base}}$$

Where,

A	=	Plume area
A_{base}	=	Base case
A_{sens}	=	Sensitivity case
ΔA_{sens}	=	$A_{sens} - A_{base}$

Table 2-27 – Plume Area Sensitivity Results

Model Output Measure	**Plume Area - Acres (50 years post injection)**					
Base Case Value	3,611 Acres					
Parameter	**Output Result**		**Change from Base**		**Percent Change Relative to Base**	
	Low Case	High Case	Low Case	High Case	Low Case	High Case
Permeability	3,504	3,897	-106.5	+286.5	-3.0%	+7.9%
kv/kh	3,702	3,445	+91.8	-165.3	+2.5%	-4.6%
Krg Endpoint	3,530	3,732	-80.8	+121.2	-2.2%	+3.4%
Residual oil saturation	3,680	3,493	+69.8	-117.5	+1.9%	-3.3%
Temperature gradient	3,603	3,673	-7.3	+62.4	-0.2%	+1.7%
Trapped gas saturation	3,563	3,596	-47.8	-14.7	-1.3%	-0.4%

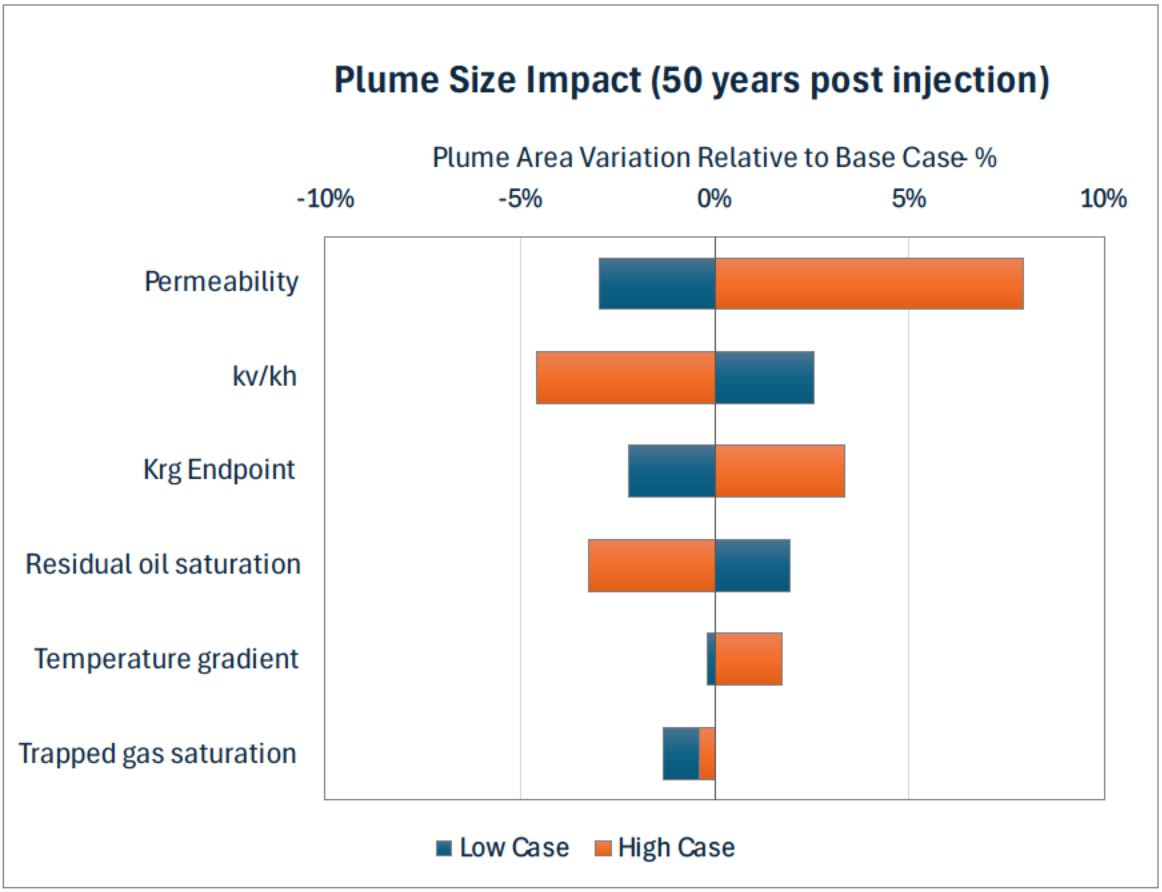


Figure 2-78 – Plume Size Sensitivities Tornado Chart

Table 2-28 – Mobile CO_2 Phase Sensitivity Results

Model Output Measure	**Percent of Injected CO_2 in Mobile Phase (50 years post injection)**					
Base Case Value	26.4% of Injected Volumes					
Parameter	**Output Result**		**Change from Base**		**Percent Change Relative to Base**	
	Low Case	High Case	Low Case	High Case	Low Case	High Case
Trapped gas saturation	29.4%	10.2%	+3.0%	-16.2%	+11.5%	-61.3%
Permeability	28.7%	22.5%	+2.3%	-3.9%	+8.7%	-14.7%
kv/kh	28.5%	24.5%	+2.1%	-1.9%	+7.8%	-7.1%
Residual oil saturation	24.7%	27.9%	-1.7%	+1.5%	-6.6%	+5.8%
Krg Endpoint	26.9%	25.3%	+0.5%	-1.1%	+1.8%	-4.2%
Temperature gradient	25.9%	25.2%	-0.5%	-1.2%	-1.9%	-4.6%

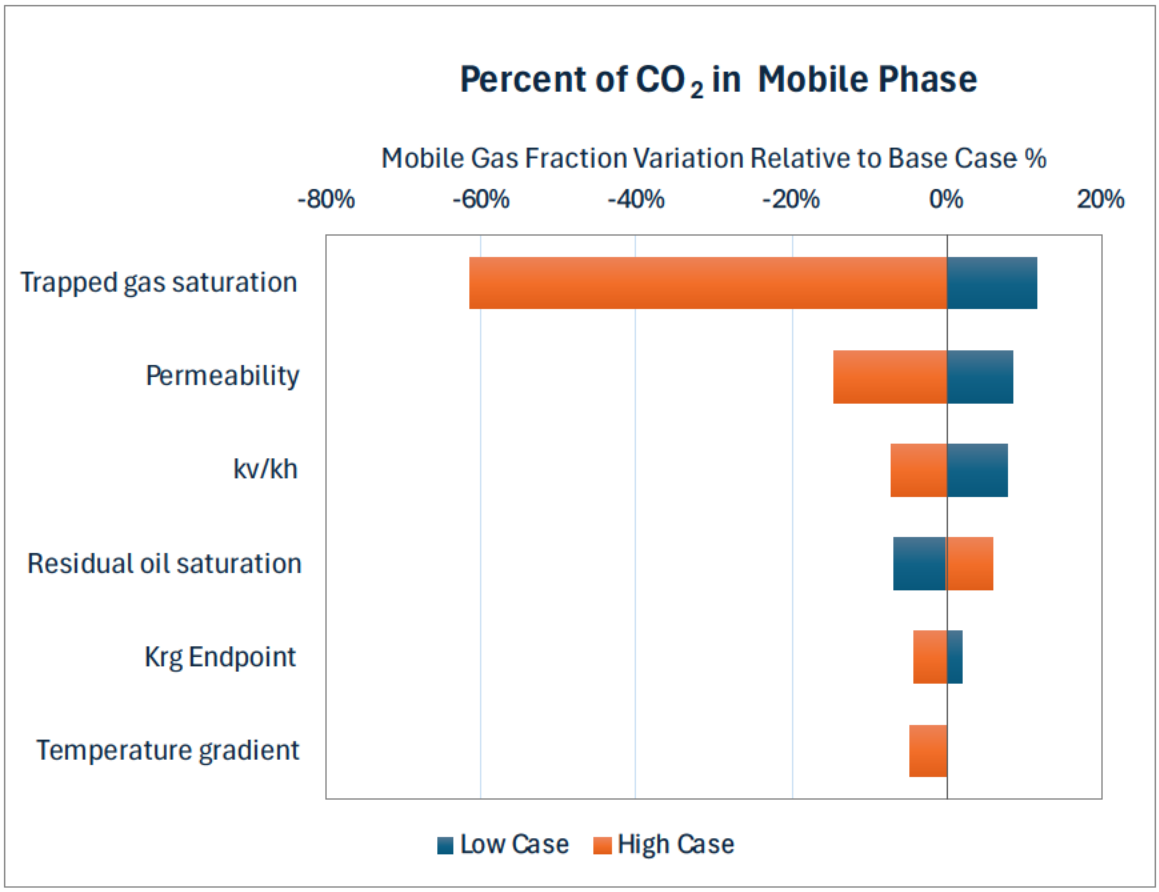


Figure 2-79 – Mobile CO_2 Phase Sensitivities Tornado Chart

Table 2-29 – Trapped CO_2 Phase Sensitivity Results

Model Output Measure	**Percent of Injected CO_2 in Trapped Phase (50 years post injection)**					
Base Case Value	39.5% of Injected Volumes					
Parameter	**Output Result**		**Change from Base**		**Percent Change Relative to Base**	
	Low Case	High Case	Low Case	High Case	Low Case	High Case
Trapped gas saturation	36.4%	55.8%	-3.1%	+16.3%	-7.9%	+41.2%
Residual oil saturation	43.5%	33.3%	+4.0%	-6.2%	+10.2%	-15.8%
Permeability	37.9%	41.7%	-1.6%	+2.2%	-4.1%	+5.5%
kv/kh	37.8%	41.1%	-1.7%	+1.6%	-4.4%	+4.1%
Temperature gradient	38.9%	39.2%	-0.6%	-0.2%	-1.5%	-0.6%
Krg Endpoint	39.3%	39.9%	-0.2%	+0.4%	-0.6%	+0.9%

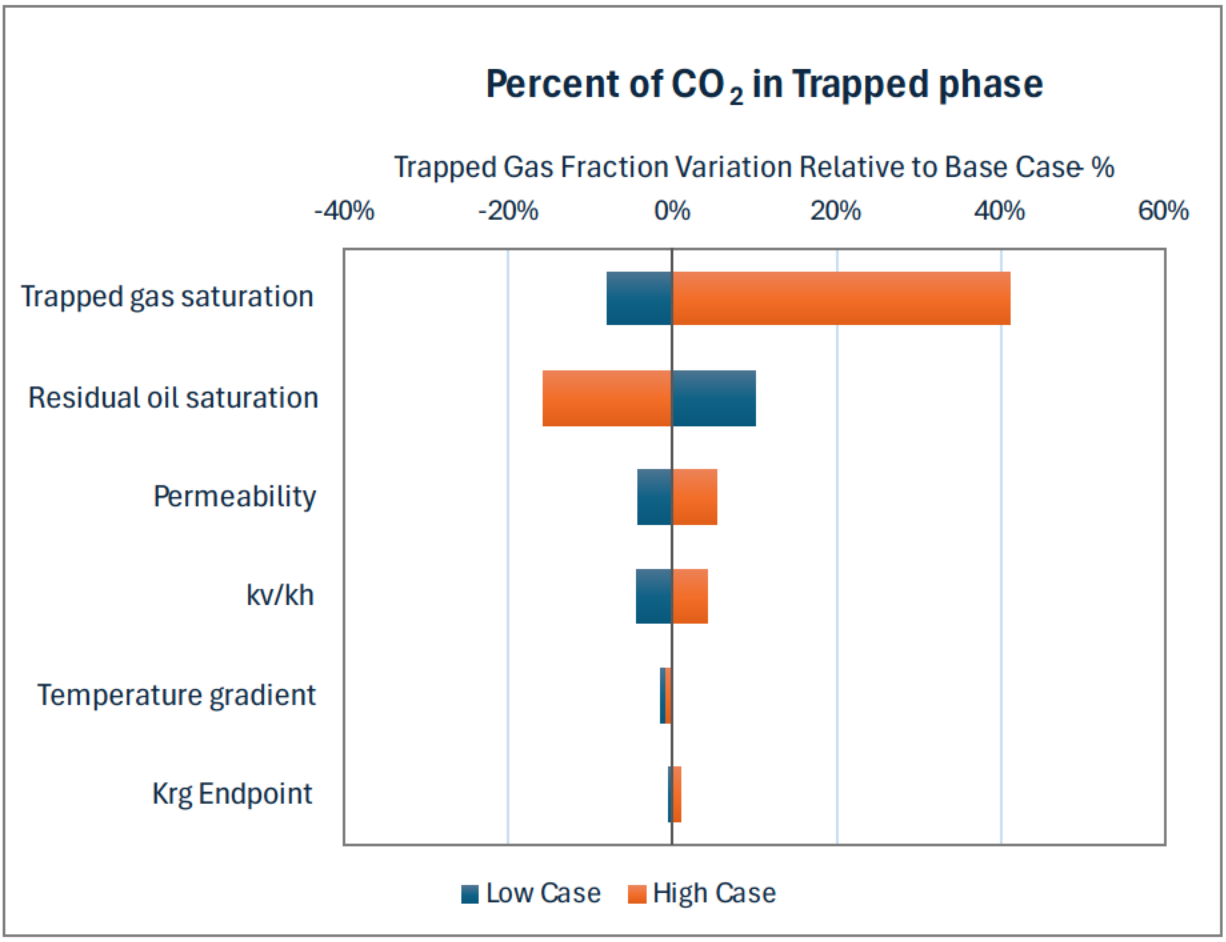


Figure 2-80 – Trapped CO_2 Phase Sensitivities Tornado Chart

Table 2-30 – Total Supercritical Gas Phase Sensitivity Results

Model Output Measure	**Percent of Injected CO_2 in Supercritical Gas Phase (50 years post injection)**					
Base Case Value	65.9% of Injected Volumes					
Parameter	**Output Result**		**Change from Base**		**Percent Change Relative to Base**	
	Low Case	High Case	Low Case	High Case	Low Case	High Case
Residual oil saturation	68.2%	61.2%	+2.3%	-4.7%	+3.5%	-7.1%
Permeability	66.6%	64.2%	+0.7%	-1.7%	+1.0%	-2.5%
Temperature gradient	64.8%	64.4%	-1.1%	-1.5%	-1.7%	-2.2%
Krg Endpoint	66.1%	65.1%	+0.3%	-0.7%	+0.4%	-1.1%
Trapped gas saturation	65.8%	66.0%	-0.1%	+0.1%	-0.1%	+0.2%
Trapped gas saturation	65.8%	66.0%	-0.1%	+0.1%	-0.1%	+0.2%

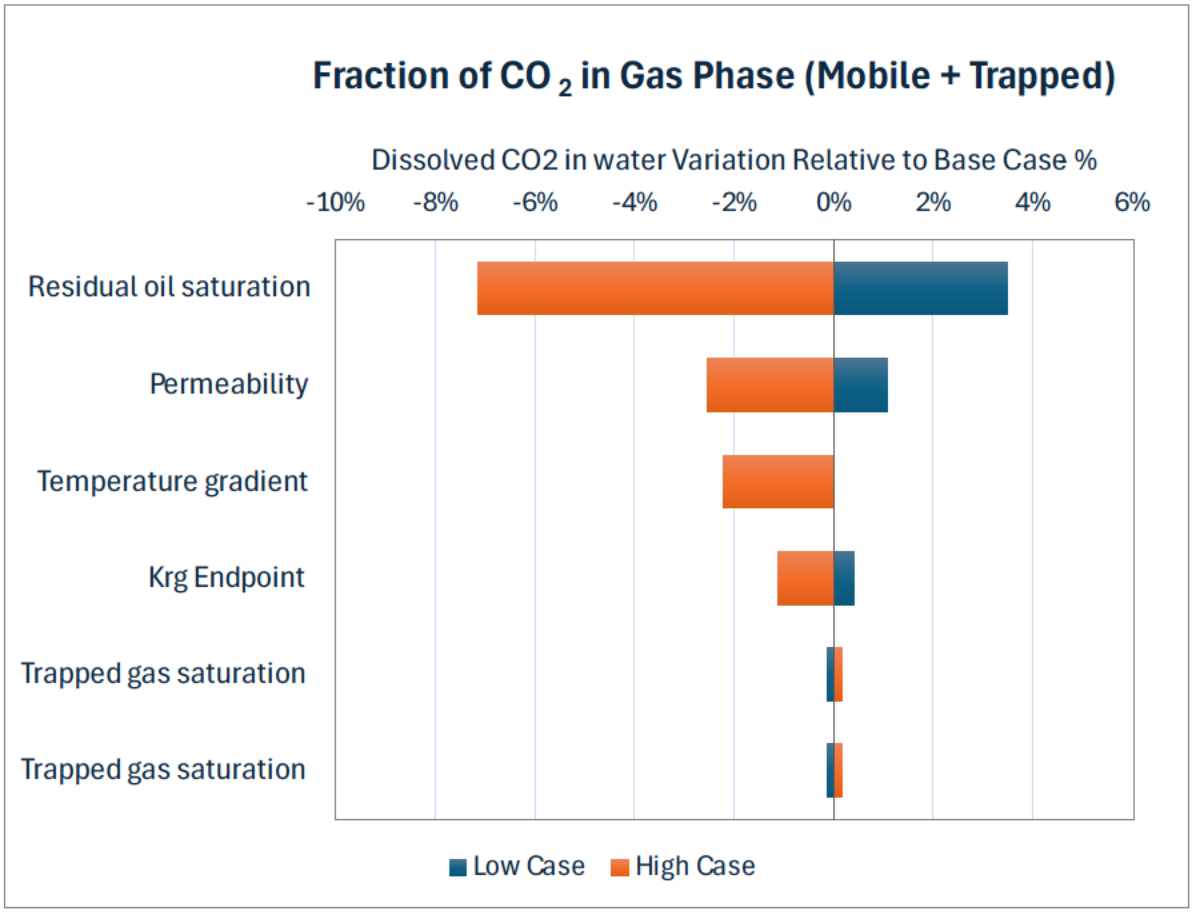


Figure 2-81 – Supercritical Gas Phase Sensitivities Tornado Chart

Table 2-31 – Total Dissolved CO_2 Sensitivity Results

Model Output Measure	**Percent of Injected CO_2 Dissolved in liquid phases (50 years post injection)**					
Base Case Value	34.1% of Injected Volumes					
Parameter	**Output Result**		**Change from Base**		**Percent Change Relative to Base**	
	Low Case	High Case	Low Case	High Case	Low Case	High Case
Residual oil saturation	31.8%	38.8%	-2.3%	+4.7%	-6.7%	+13.8%
Permeability	33.4%	35.8%	-0.7%	+1.7%	-2.0%	+4.9%
Temperature gradient	35.2%	35.6%	+1.1%	+1.5%	+3.2%	+4.3%
Krg Endpoint	33.9%	34.9%	-0.3%	+0.7%	-0.8%	+2.2%
kv/kh	33.8%	34.4%	-0.3%	+0.3%	-1.0%	+0.7%
Trapped gas saturation	34.2%	34.0%	+0.1%	-0.1%	+0.2%	-0.3%

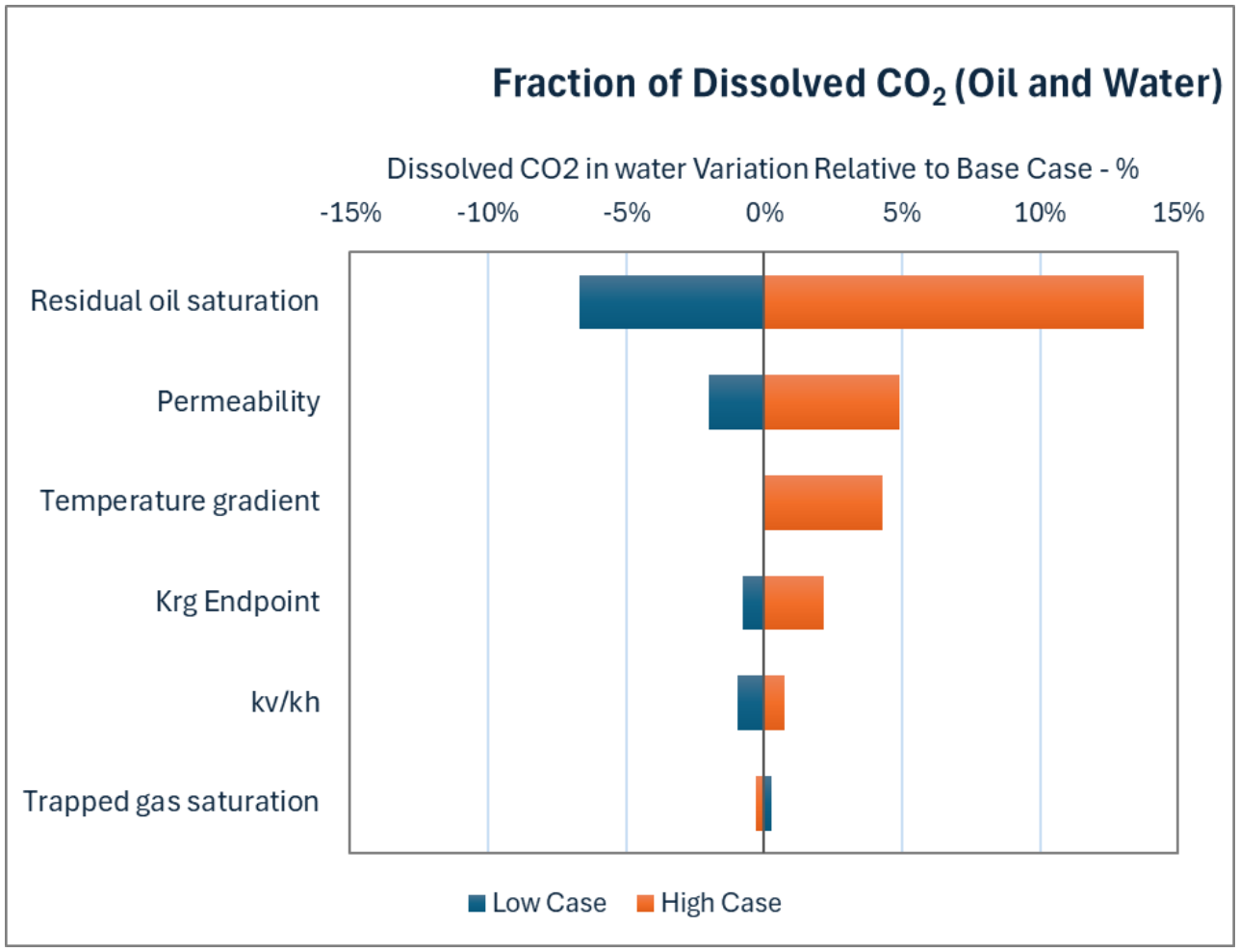


Figure 2-82 – Total Dissolved CO_2 Sensitivities Tornado Chart

2.8 Critical Pressure Front

The second component to defining the AOR is determining the extent of the critical pressure front. The pressure front is defined as the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the USDW through a hypothetical open conduit. In a worst-case scenario, an open conduit might be through an improperly plugged and abandoned wellbore or a subsurface feature which is open to both the USDW and the injection interval. This pressure front value is called the *critical pressure*. The methodology for finding critical pressure was sourced from Environmental Protection Agency (EPA) Method 1 guidance, for calculations based on displacing fluid initially present in the borehole in the under-pressured case.

Method 1 guidance applies the following equations for calculation of the critical pressure value ($P_{i,f}$) and critical pressure increase ($\Delta P_{i,f}$) terms which are used to define the AOR:

(Eq. 15) $$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i)$$

(Eq. 16) $$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i$$

Where:

P_u	is the initial fluid pressure at the base of the USDW,
$\rho_i g$	is the injection-zone fluid density times acceleration due to gravity
z_u and z_i	are the elevations of the USDW and the injection zone, respectively
and P_i	is the initial pressure in the injection interval.

The pressure at the base of the USDW (P_u) is calculated based on the height of the fluid column and its respective density within the USDW. The height of the fluid column will be the elevation difference between the base USDW and the top of the water column (aquifer hydraulic head) within the USDW. Note that in this area, the water column in the USDW does not reach the surface: Calculations of P_u will therefore consider measured (sub-surface) water column elevations from representative observation wells.

The base of the USDW has been determined by the Groundwater Advisory Unit (GAU) of the Railroad Commission of Texas for each of the seven Orchard injection wells. Depths and elevations for base USDW as determined by the GAU are tabulated in Table 2-32.

Table 2-32 – Base USDW Depth and Elevation from GAU

Injection Well	Ground Elevation (Ft Above Sea Level)	Base USDW Depth (Ft)	Base USDW Elevation (Ft Above Sea Level)
Orchard No. 1	3,219	2,000	1,219
Orchard No. 2	3,211	2,000	1,211
Orchard No. 3	3,208	2,000	1,208
Orchard No. 4	3,202	1,950	1,252
Orchard No. 5	3,187	1,925	1,262
Orchard No. 6	3,169	1,850	1,319
Orchard No. 7	3,212	2,000	1,212

Fluid gradient for the USDW / aquifer zones has been calculated to range from 0.433 to 0.434 psi/ft based on average TDS values of 1,130 and 6,000 ppm for the Ogallala and Dockum aquifers, respectively. To calculate the critical pressure rise, the more conservative 0.433 psi/ft has been used to characterize the USDW fluid gradient.

The aquifer hydraulic head (i.e., the height of the water column in the aquifer) is obtained from the Texas Water Development Board's (TWDB) database of groundwater source wells in Texas. This database contains information for wells in which liquid levels are routinely measured. Currently designated as Groundwater Conservation District (GCD) observation wells by the TWDB, six of such wells were found within the Orchard AOR, all having good quality data between late 2022 and early 2024. Table 2-33 presents the most recent data for measured aquifer water level in those wells.

Table 2-33 – Ogallala Aquifer GCD Observation Well Data

Water Well No.	Water Level (Ft Above Sea Level)	Measurement Date
27-05-620	3,150.9	1/18/2024
27-05-922	3,141.7	12/5/2023
27-13-221	3,102.3	12/5/2023
27-14-114	3,126.1	12/5/2023
27-14-115	3,096.9	12/5/2023
27-14-202	3,097.0	12/20/2022

In the calculation of P_u for each of the Orchard injection wells, the representative aquifer water level was selected from the closest of the water observation wells to the injection well location. Parameters used and resulting USDW pressure (at representative base USDW elevation "z_u") for each of the Orchard injection wells is included as Table 2-34.

Table 2-34 – Calculations of USDW initial fluid pressure

	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
Closest GCD Observation Well	27-05-922	27-05-922	27-05-922	27-14-114	27-14-114	27-14-202	27-13-221
Distance / Direction from Injection Well to GCD well	1.0 mile NE	1.0 mile NW	1.7 mile NW	2.1 mile SW	1.8 mile SW	0.8 mile SW	0.9 mile S
Observed USDW Fluid Level (ft above sea level)	3,141.7	3,141.7	3,141.7	3,126.1	3,126.1	3,097.0	3,102.3
Representative elevation of USDW base (z_u, ft above sea level)	1,219	1,211	1,208	1,252	1,262	1,319	1,212
USDW Fluid Column height (ft)	1,922.7	1,930.7	1,933.7	1,874.1	1,864.1	1,778.0	1,890.3
Fluid Gradient in USDW (psi/ft)	0.433	0.433	0.433	0.433	0.433	0.433	0.433
Hydrostatic pressure differential in USDW (psi)	832.5	836.0	837.3	811.5	807.2	769.9	818.5
Initial fluid pressure in the USDW (P_u, corrected to psia)	847.2	850.7	852.0	826.2	821.9	784.6	833.2

An example calculation of the representative USDW pressure, based on inputs for Orchard No. 1, is shown in Equation 17.

(Eq. 17)
$$\Delta P_u = \rho g \cdot (z_h - z_u)$$
$$\Delta P_u = 0.433 \cdot (3{,}141.7 - 1{,}219)$$
$$\Delta P_u = 832.5$$
$$P_u = 832.5 + 14.7 \text{ (absolute pressure conversion)}$$
$$P_u = 847.2 \text{ psia}$$

Where ΔP_u is the hydrostatic pressure differential in the USDW, and z_h and z_u are the respective elevations for the top of the water column and the base of the USDW.

The USDW pressure (P_u) is used together with the elevation difference between USDW and injection zone and the injection zone fluid density using Equation 14. The fluid in the injection zone is assumed to be brine with 59,000 ppm TDS. This assumption is based on data from the U.S. Geological Survey's National Produced Waters Geochemical Database for wells close to the Orchard Project area (and distributed as displayed in Figure 2-47, in Section 2.2.4). The density of the formation brine in the injection zone was calculated to be 64.52 lb/ft^3, using correlations by McCain (McCain, 1991). The fluid gradient within the storage interval will therefore be 0.448 psi/ft.

Table 2-35 details the calculation of critical pressure and critical pressure increase for each of the seven Orchard injection wells. It should be noted that the representative elevations for the USDW and the injection zone are taken at the base of the USDW and top of perforated interval, respectively. Perforation elevations are below sea level and will therefore be negative. The values used in the calculations and final results (shown in bold) are provided in Table 2-28.

Table 2-35 – Critical Pressure Calculations

Input Variable	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
Representative pressure at base USDW (Pu , psia)	847	851	852	826	822	785	833
Elevation of USDW(z_u , ft above sea level)	1,219	1,211	1,208	1,252	1,262	1,319	1,212
Elevation of injection zone (z_i, ft above sea level)	-2,304	-2,129	-2,029	-1,973	1,972	-1,881	-2,243
Elevation difference from USDW to injection zone (ft)	3,523	3,340	3,237	3,225	3,234	3,200	3,455
Injection zone fluid density gradient (ri g, psi/ft)	0.448	0.448	0.448	0.448	0.448	0.448	0.448
Injection zone datum pressure (psia)	2,260	2,260	2,260	2,260	2,260	2,260	2,260
Injection zone datum elevation (ft above sea level)	-2,450	-2,450	-2,450	-2,450	-2,450	-2,450	-2,450
Elevation difference from injection zone datum to zi (ft)	-146	-321	-421	-477	-478	-569	-207
Pressure correction from datum to top perforation (psi)	-66	-144	-189	-214	-214	-255	-93
Pressure at top of injection zone (Pi , psia)	2,194	2,116	2,071	2,046	2,046	2,005	2,167
Critical pressure at top of injection zone (Pi,f , psia)	**2,425**	**2,347**	**2,302**	**2,271**	**2,271**	**2,218**	**2,381**
Critical Pressure increase (DPi,f , psia)	**231**	**231**	**231**	**225**	**225**	**213**	**214**

Example calculation steps for variables in Table 2-28 are shown in Equations 18 and 19:

(Eq. 18)

$$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i)$$

$$(z_u - z_i) = 1219 - (-2303.6)$$

$$(z_u - z_i) = 3522.6$$

$$P_{i,f} = 847.2 + 0.448 \cdot (3522.6)$$

$$P_{i,f} = 2425.3$$

(Eq. 19)

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i$$

$$\Delta P_{i,f} = P_{i,f} - P_i$$

$$P_i = P_{datum} - \rho_i g \cdot (z_{datum} - z_i)$$

$$P_i = 2260 - .448 \cdot (-146.4)$$

$$P_i = 2194.4$$

$$\Delta P_{i,f} = 2425.3 - 2194.4$$

$$\Delta P_{i,f} = 230.9$$

Figure 2-83 illustrates how $\Delta P_{i,f}$ remains constant over ranges in depth for a single injector. The threshold pressure ($P_{i,f}$) does vary with depth for the injection interval, however as $P_{i,f}$ value changes with depth, so does the pressure within the storage interval. The figure shows a plot of pressure versus elevation, with USDW pressure and elevation based on Orchard No. 1. The solid blue line represents the calculated threshold pressure value at any depth, starting from the pressure at the base of the USDW (shown as a blue triangle). The slope of that line is defined by the pressure gradient ($\rho_I g$) for the native fluid in the injection interval. The dashed red line on this graph represents the pressure within the injection interval, starting from the defined model datum pressure and depth, shown as the red diamond. The slope of that line is also defined by the pressure gradient for the fluid in the injection interval.

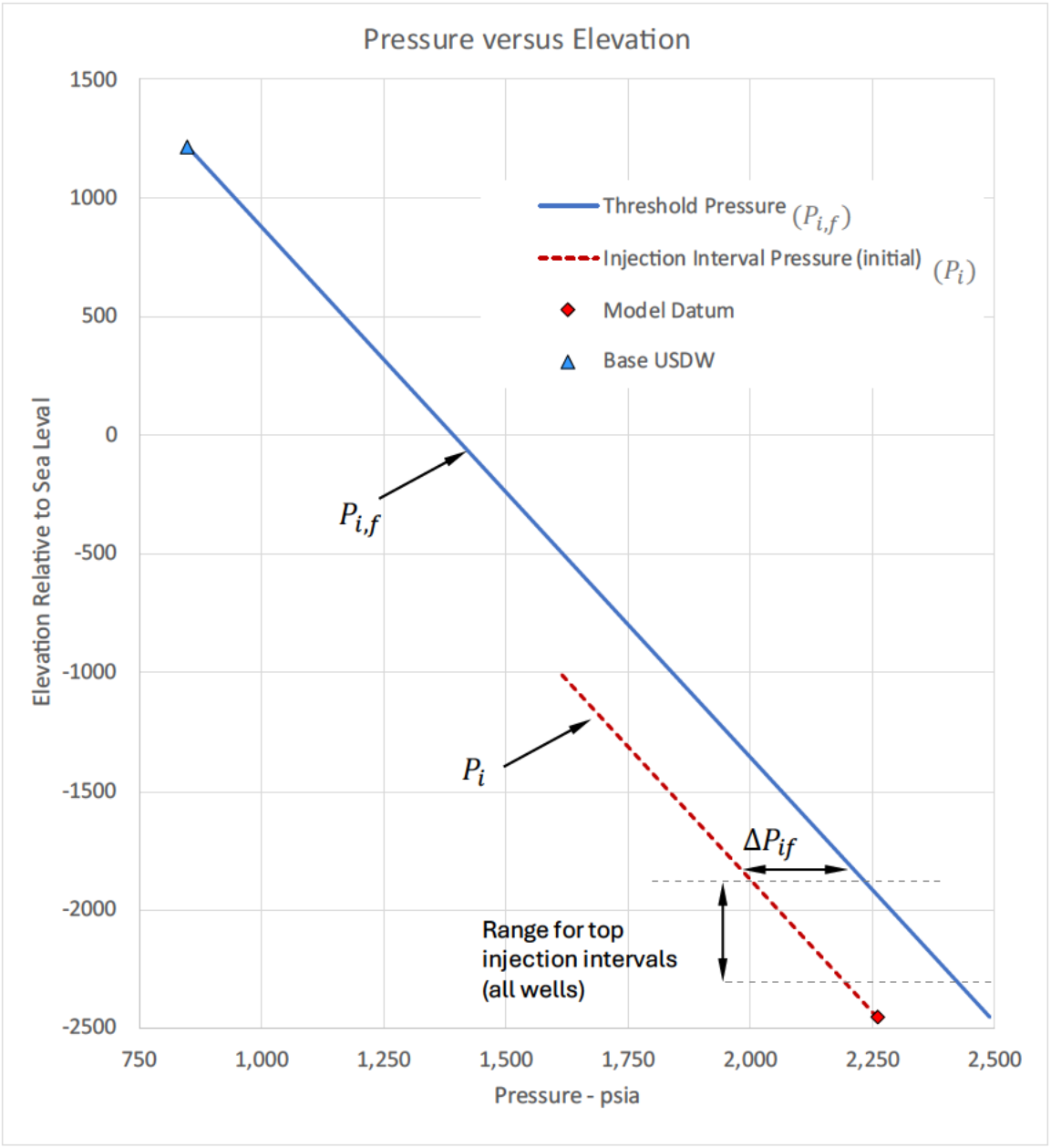


Figure 2-83 Variation of Threshold and Injection Interval Pressures versus Depth

The critical pressure increase at any depth will be the difference in pressure between the initial pressure in the respective injection interval and allowable threshold pressures at that depth. Both of those lines have the same slope, being based on the gradient of the fluid in the injection interval. Because these lines are parallel, the pressure difference (at any depth) between the two lines is constant. Variations of $\Delta P_{i,f}$ between one injector to another will be driven by the base USDW elevation z_u and the calculated the base of USDW pressure P_u.

The expected pressure differential relative to pre-injection pressures for each of the Orchard injection wells is presented in Figures 2-84 through 2-90, respectively. These plots present the difference between the bottom hole pressure at the well and the initial pre-injection pressure. The

dashed horizontal line shows the value of the critical pressure differential calculated for each respective injector, and a vertical dashed line flags the time at which injection ceases for this project.

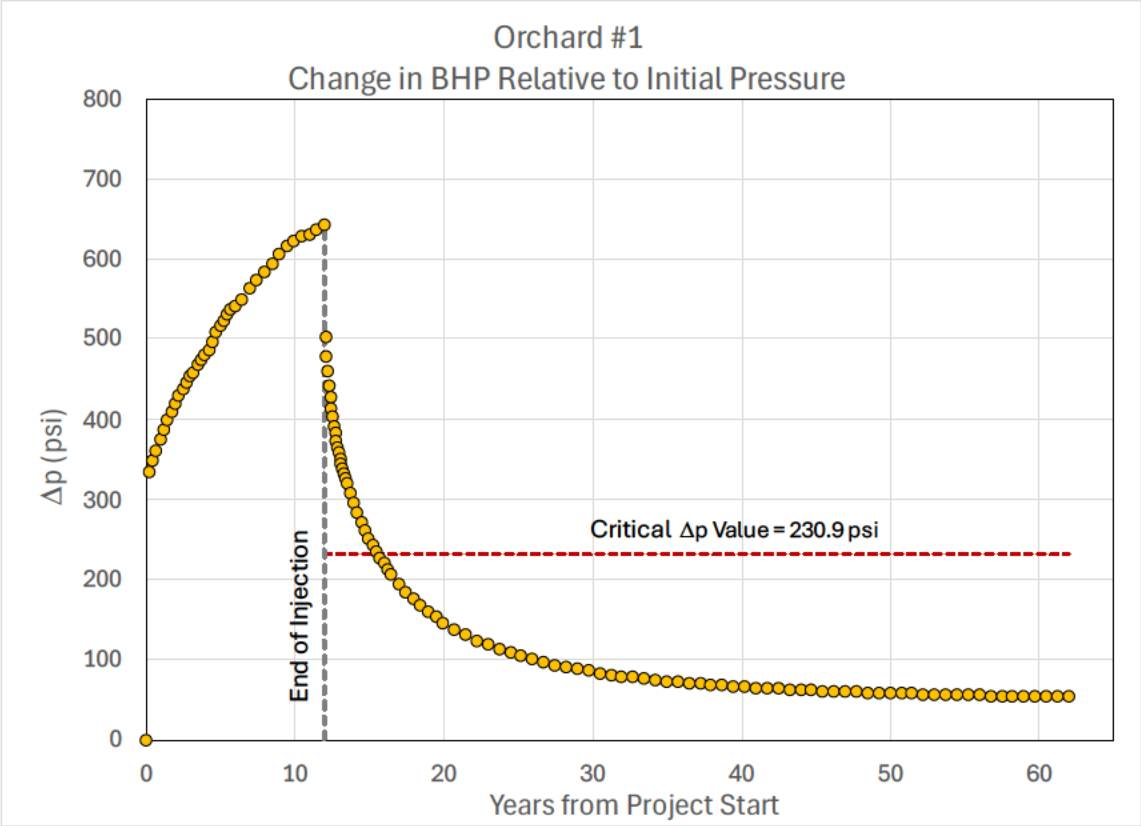


Figure 2-84 – Orchard No. 1 Pressure Buildup from Initial Value

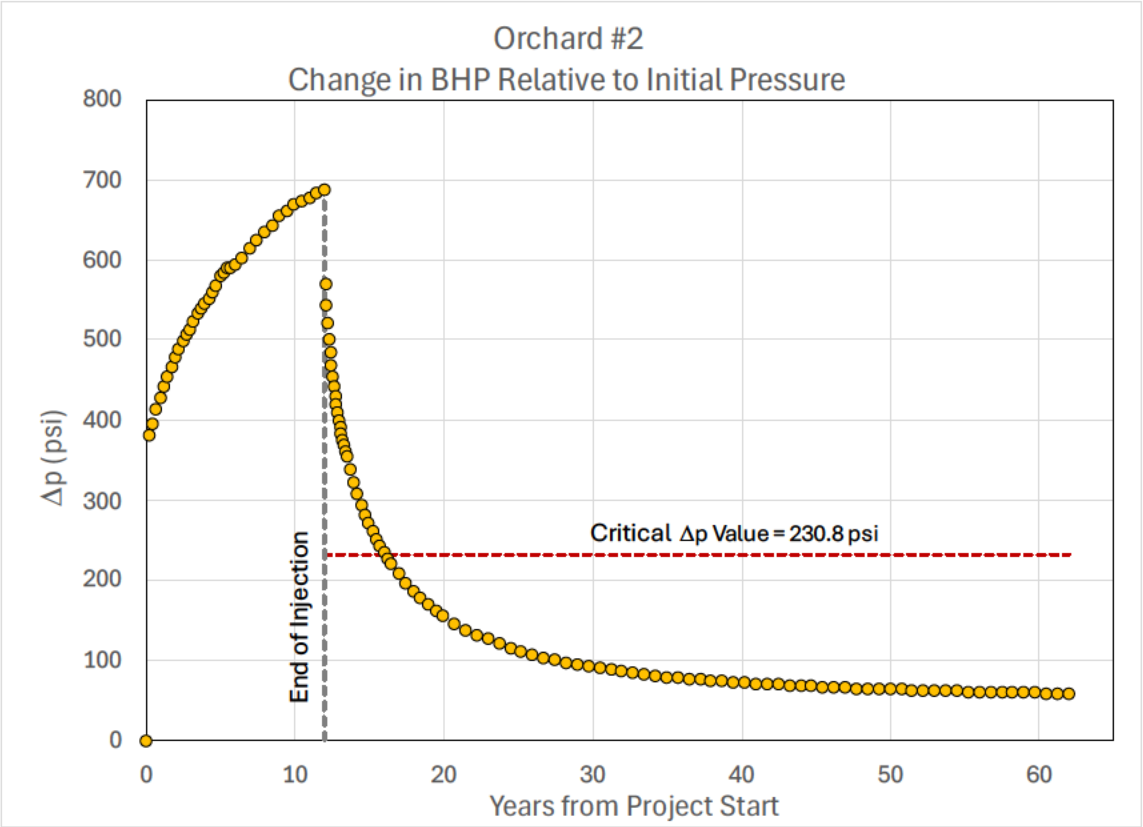


Figure 2-85 – Orchard No. 2 Pressure Buildup from Initial Value

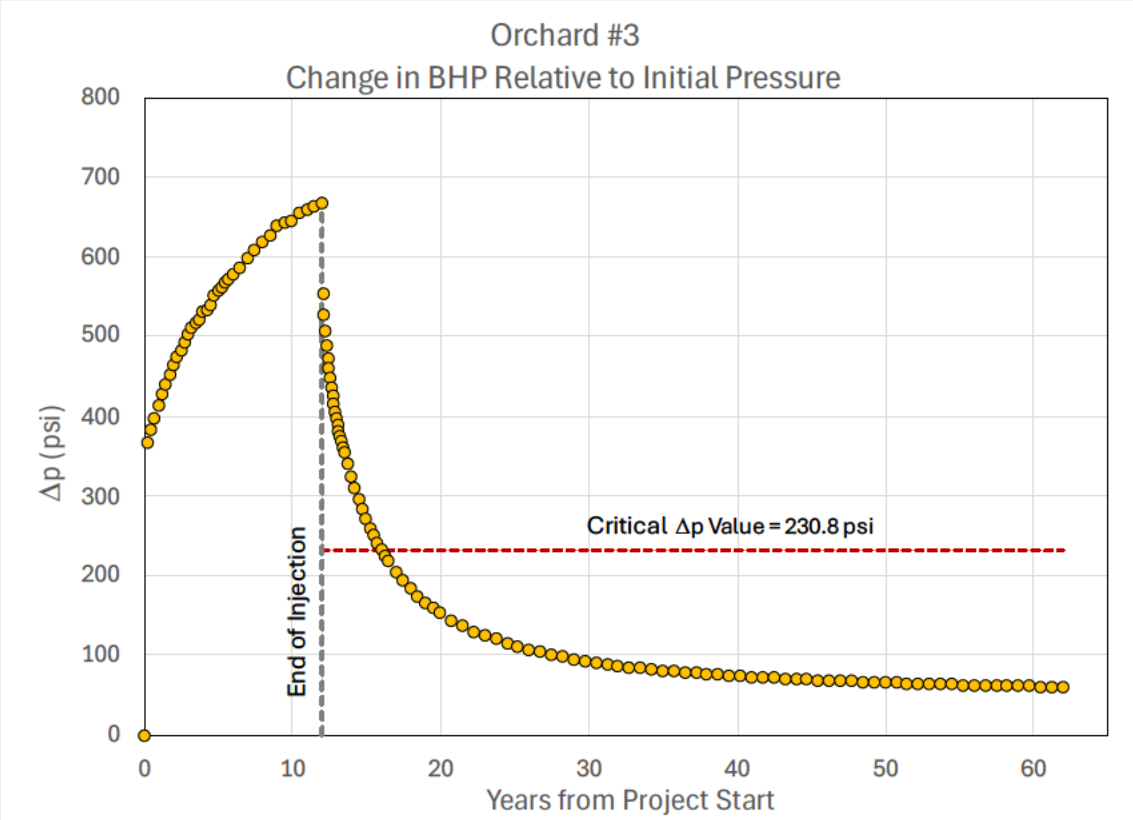


Figure 2-86 – Orchard No. 3 Pressure Buildup from Initial Value

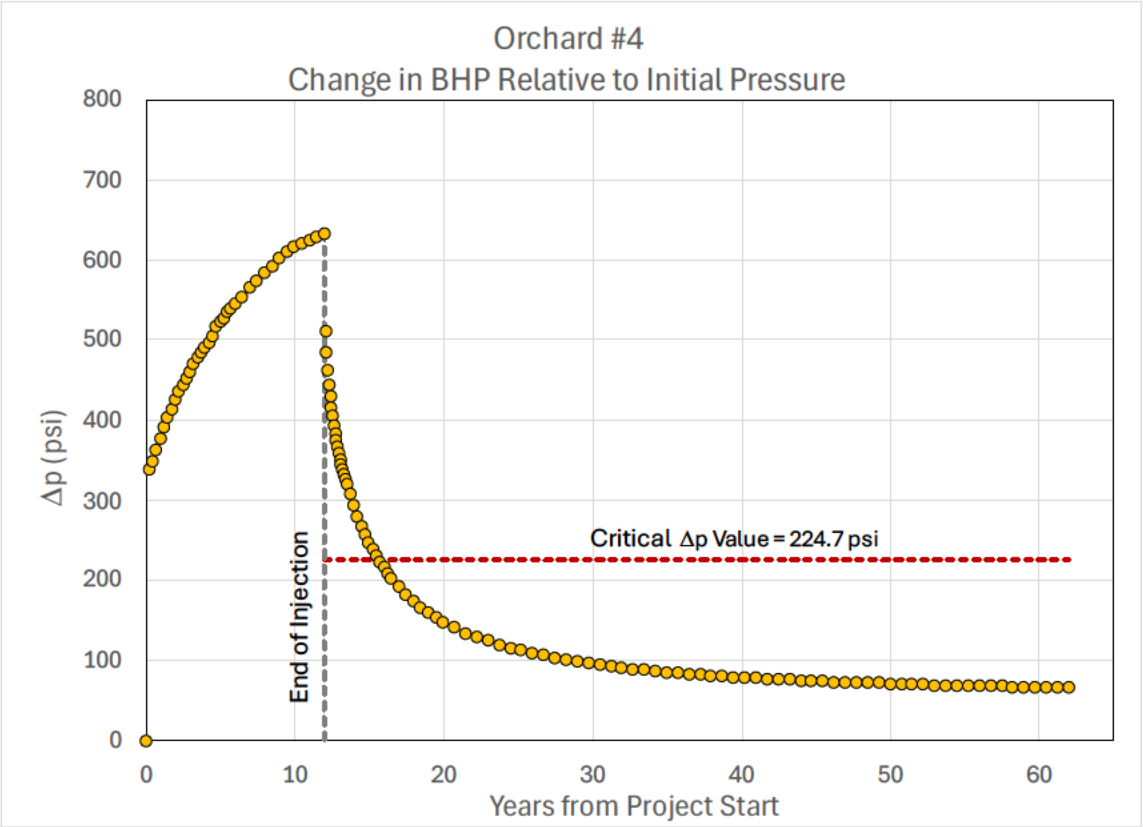


Figure 2-87– Orchard No. 4 Pressure Buildup from Initial Value

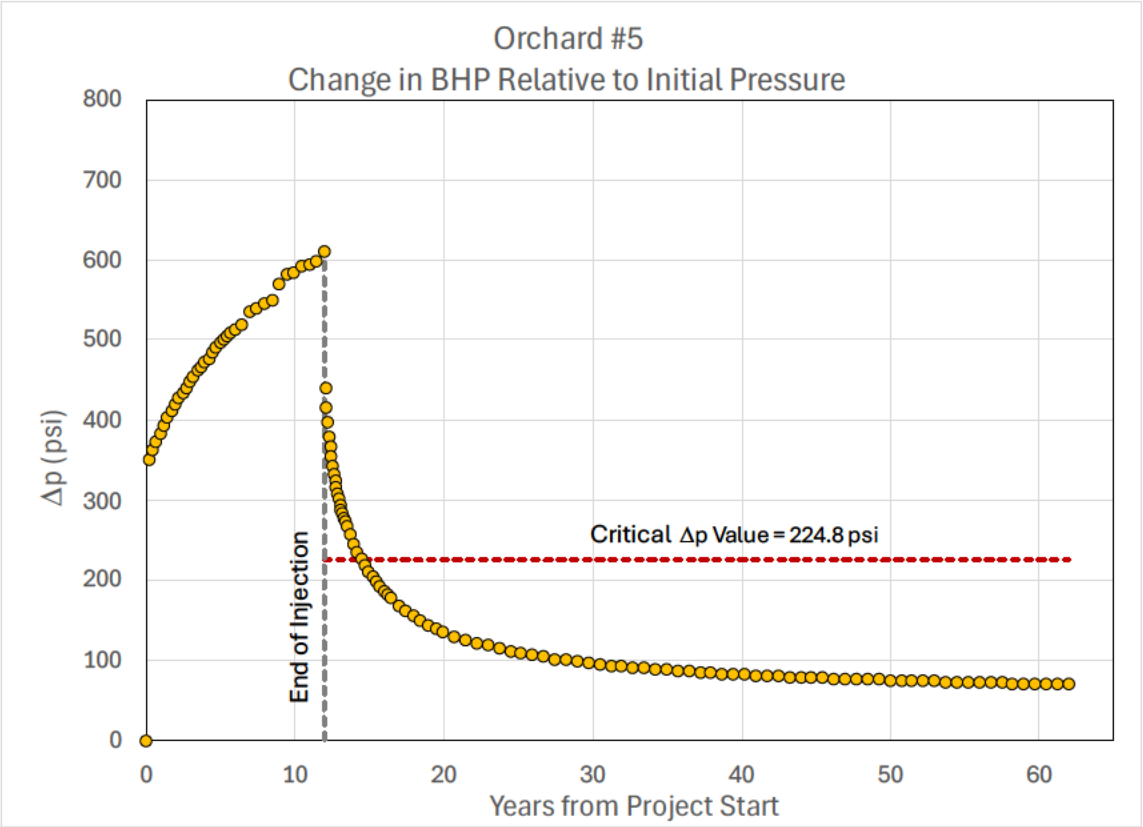


Figure 2-88– Orchard No. 5 Pressure Buildup from Initial Value

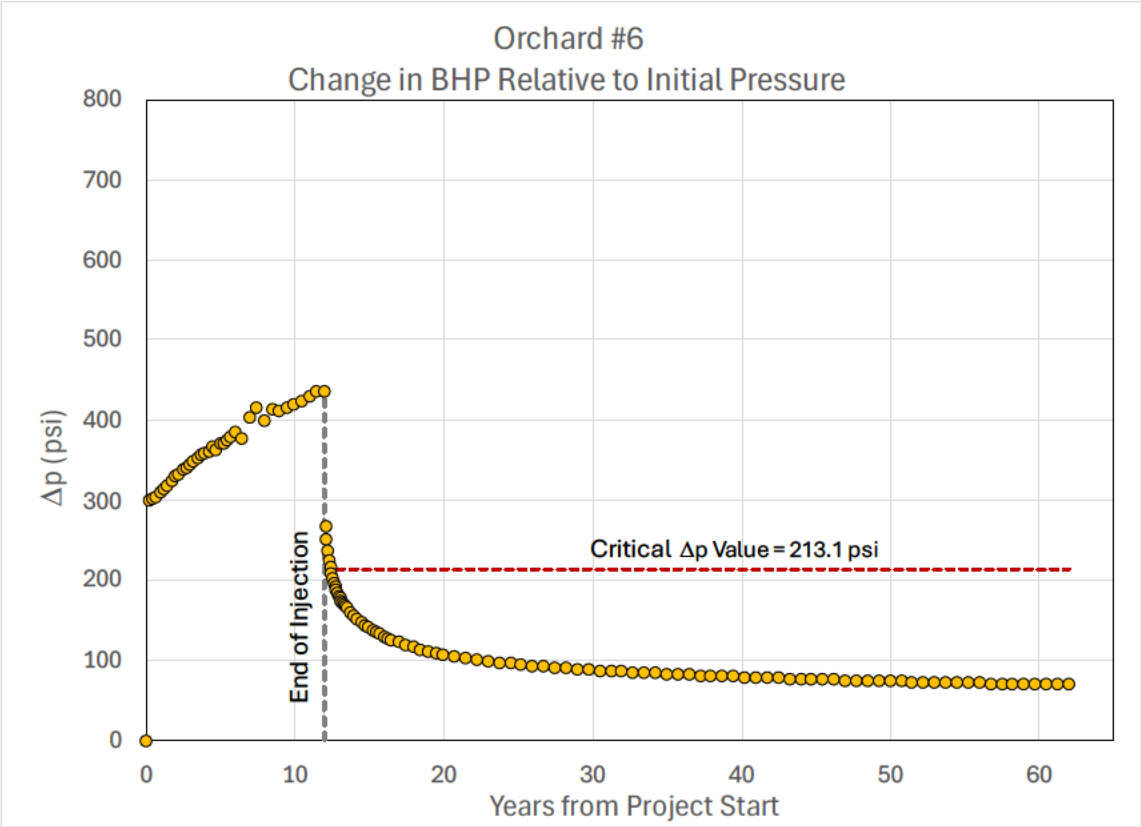


Figure 2-89– Orchard No. 6 Pressure Buildup from Initial Value

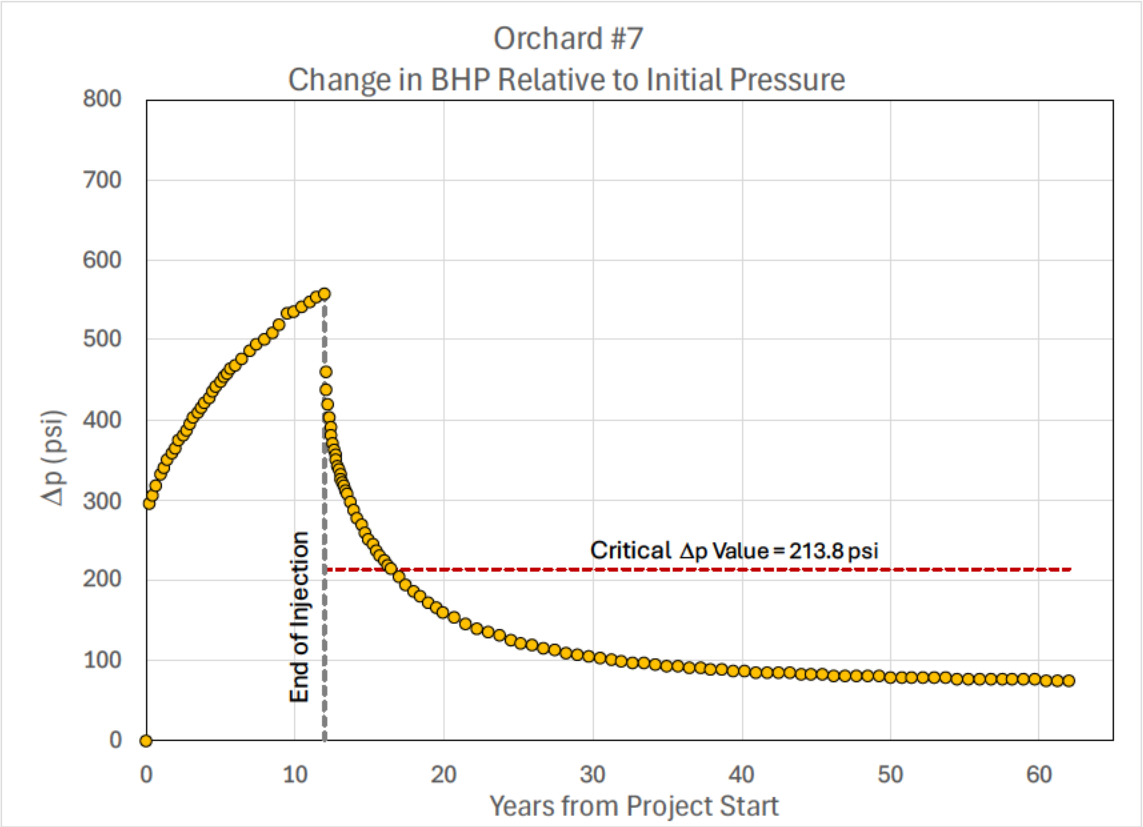


Figure 2-90 – Orchard No. 7 Pressure Buildup from Initial Value

2.9 Area of Review Delineation

Title 16 of the Texas Administrative Code (TAC) **§5.203(d)(1)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] requires that an AOR be delineated for a Class VI carbon sequestration well application. The EPA defines the AOR as the greater of either the maximum extent of the separate-phase plume (pore occupancy plume), or the pressure front where the pressure buildup is of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW. Both parts of this definition were analyzed to define the Orchard Project AOR.

Figure 2-91 shows a reference line (in red) for the critical pressure differential with a value of 213 psi, based on the lowest critical pressure increase calculated for all of the Orchard injection wells. The extent of the pressure front defined by the value of the critical pressure differential is used with the pore occupancy plume to define the AOR for the Orchard injection wells.

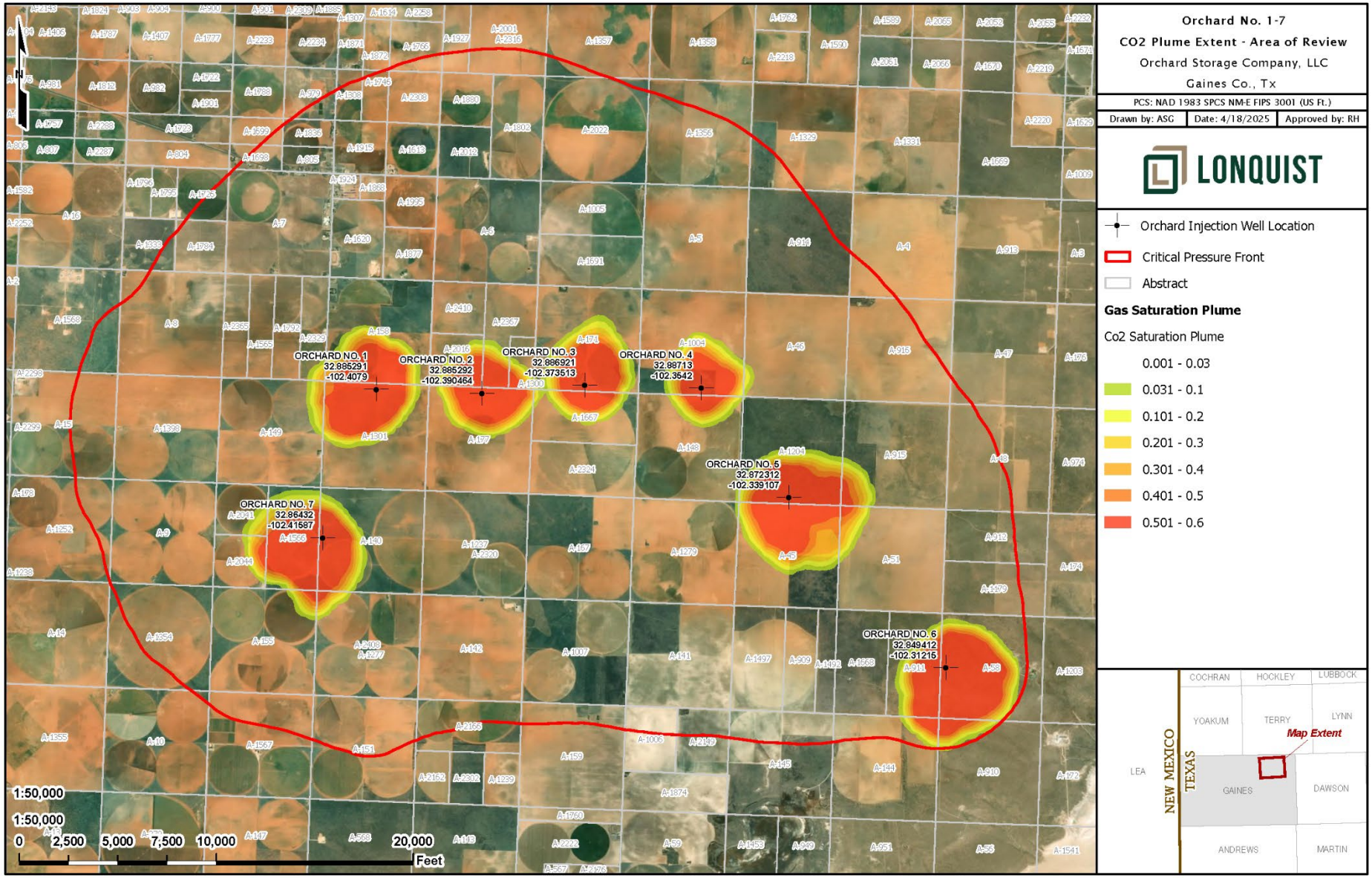


Figure 2-91 – Stabilized CO_2 Plumes and Critical Pressure Front at the Orchard Project

Figures 2-92 through 2-98 show the injection rates and bottomhole pressures over time for the Orchard injection wells, respectively. The horizontal axis in each is scaled in years, referencing the CO_2 injection startup. Bottomhole pressure (BHP) builds over the 12-year injection period, influenced by overall project-area pressure buildup within the pressure front—pressure that starts to fall off after the injection well is shut in. Around year 17, the pressure at each Orchard injector falls below the calculated critical pressure that is required to affect the flow of formation fluids vertically from the injection interval to the deepest known USDW zone.

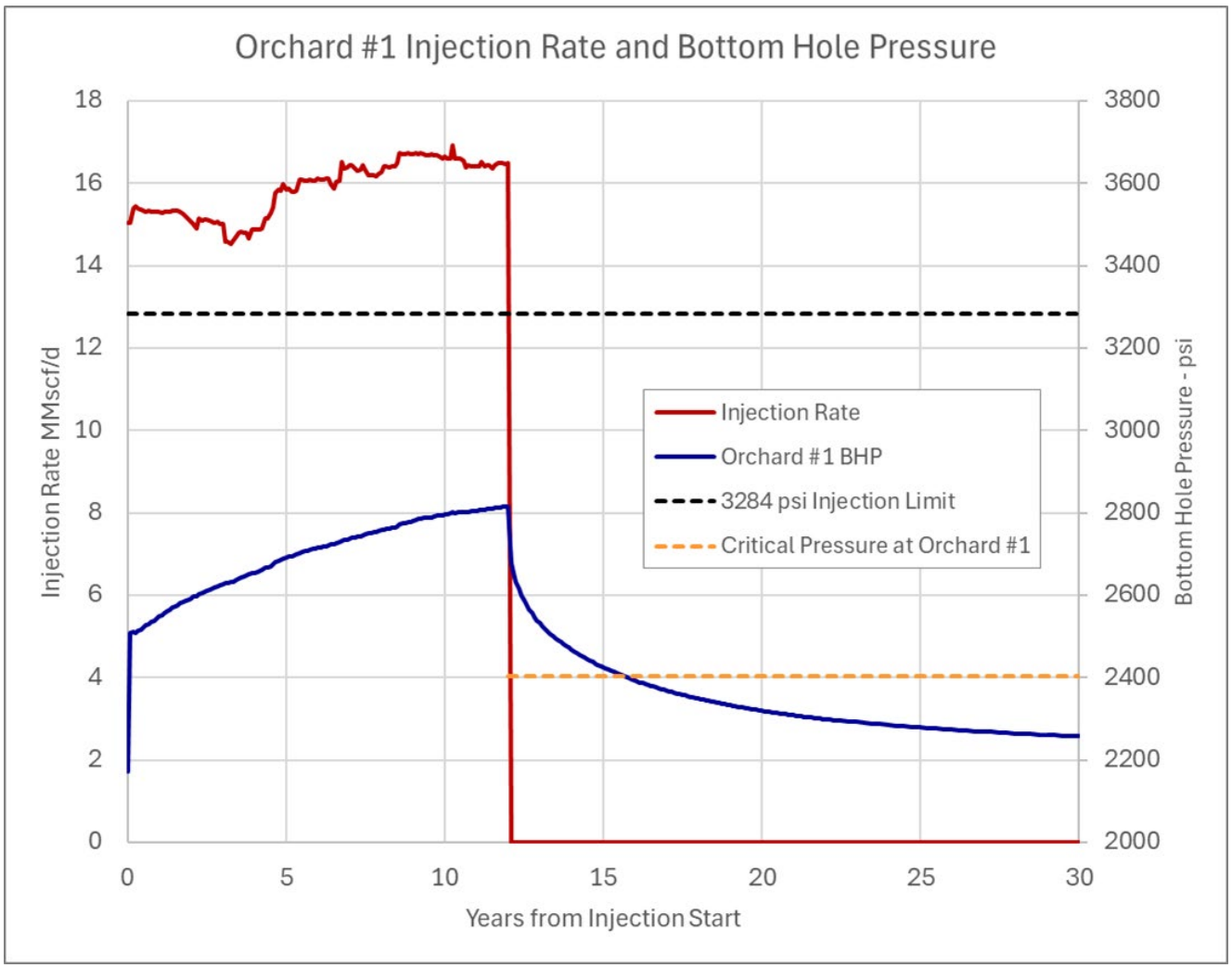


Figure 2-92 – Injection Rate and BHP Data for Orchard No. 1

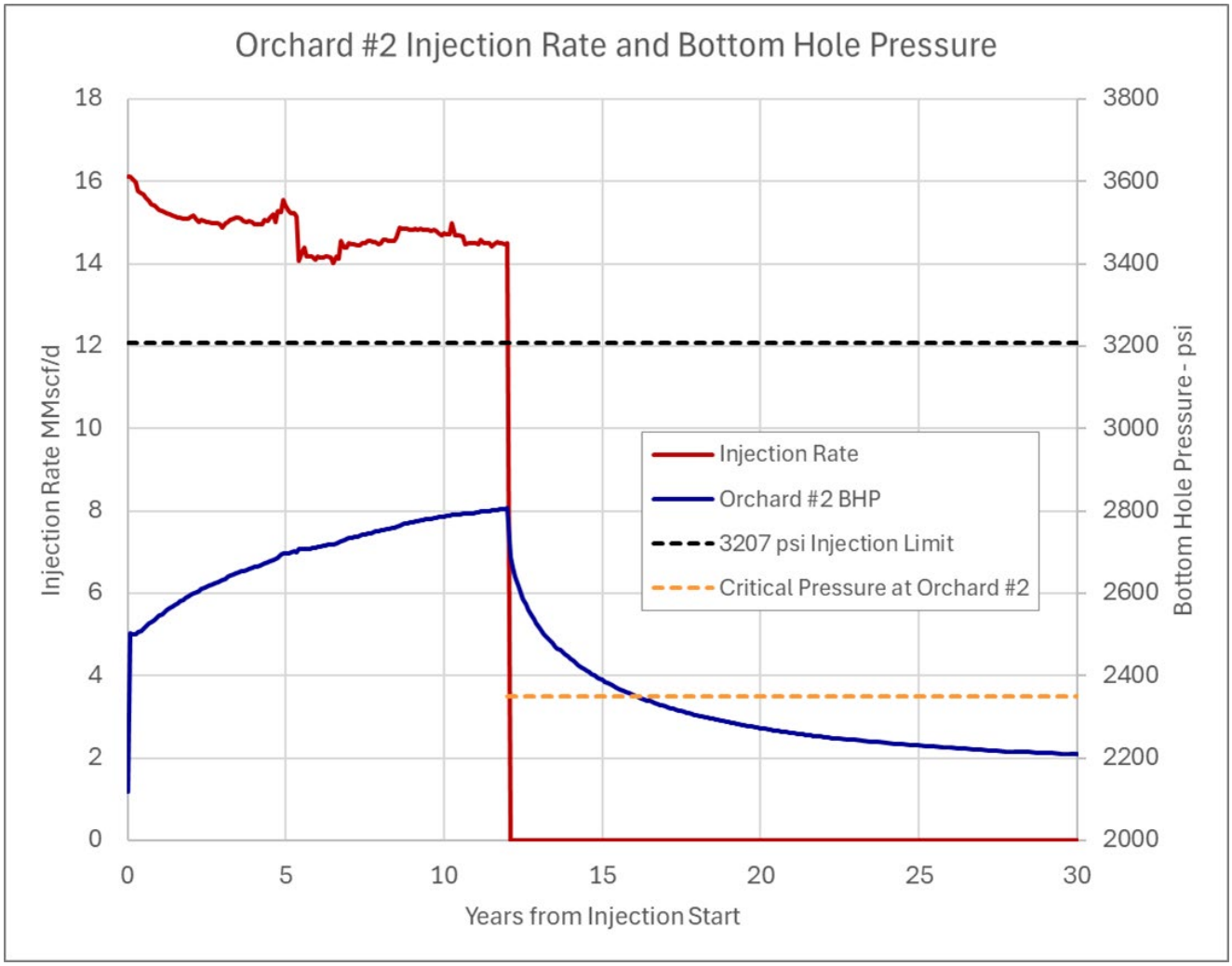


Figure 2-93 – Injection Rate and BHP Data for Orchard No. 2

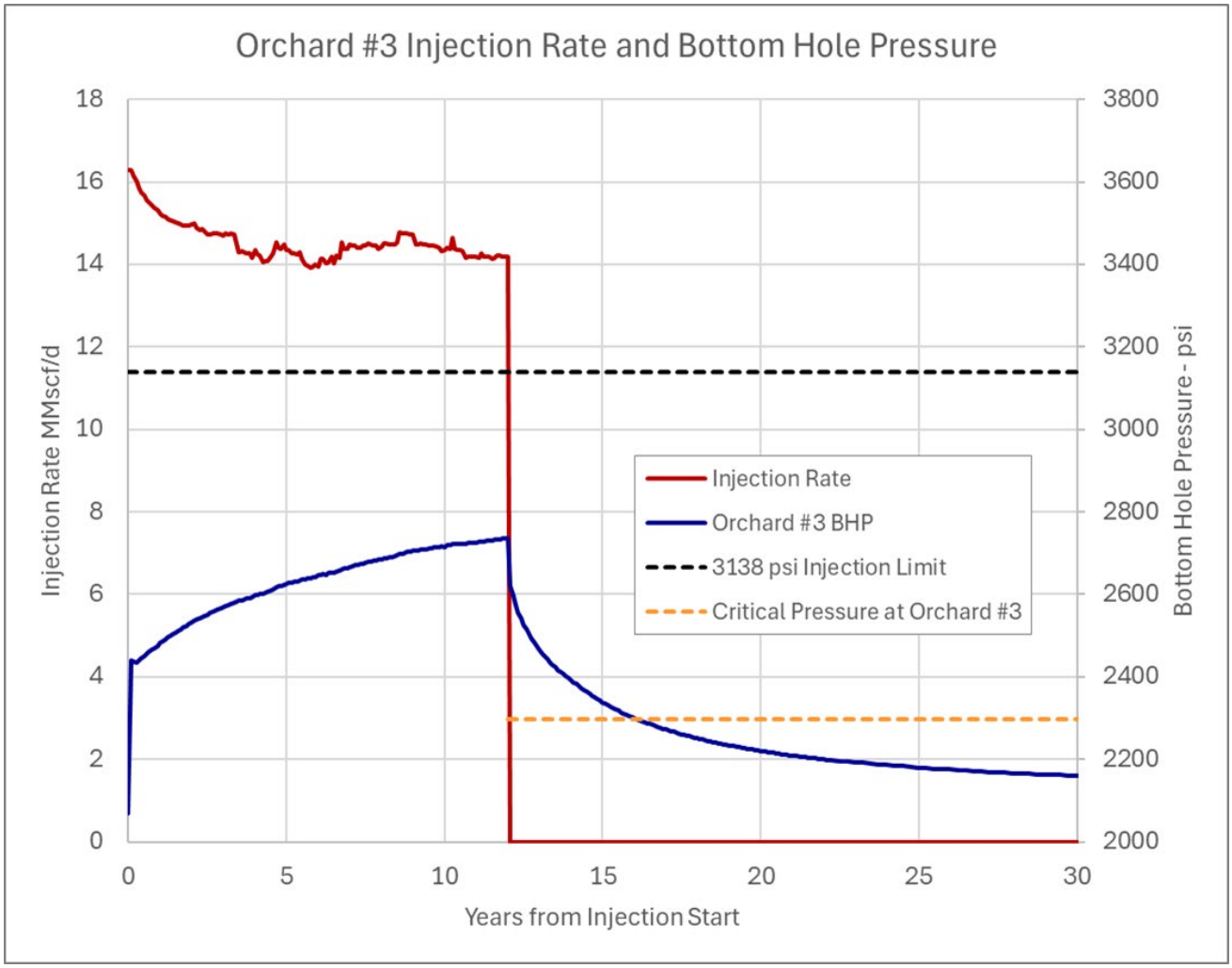


Figure 2-94 – Injection Rate and BHP Data for Orchard No. 3

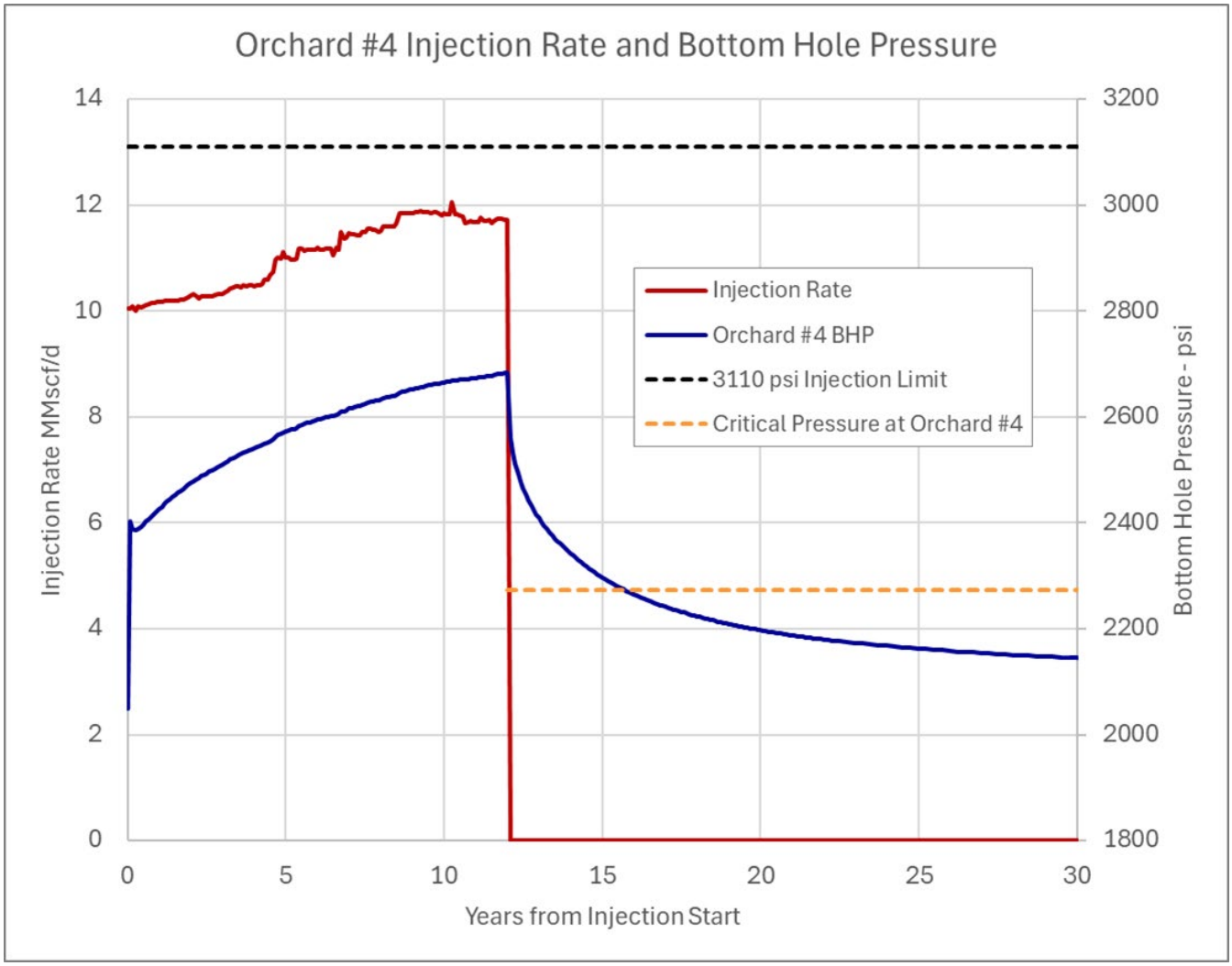


Figure 2-95 – Injection Rate and BHP Data for Orchard No. 4

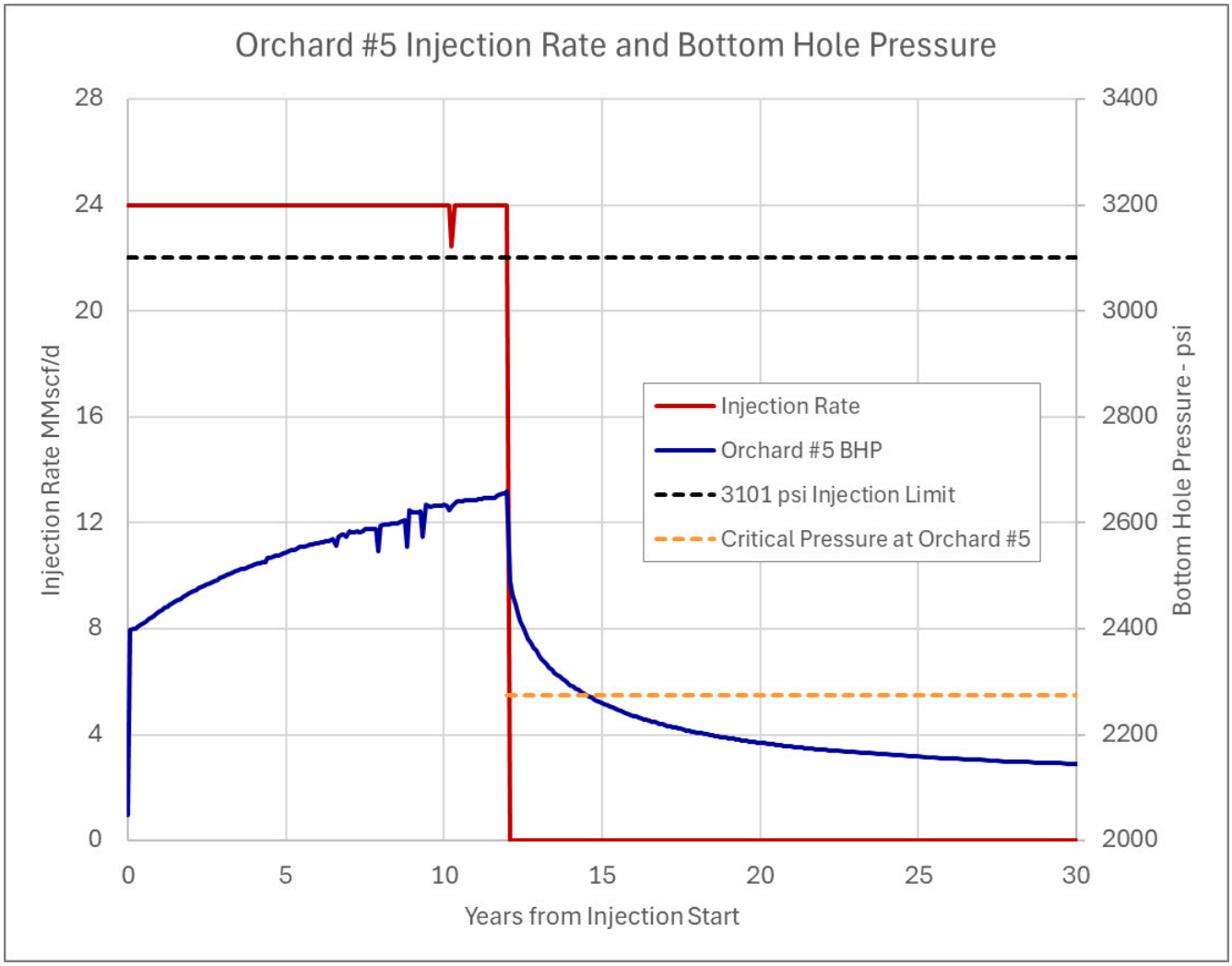


Figure 2-96 – Injection Rate and BHP Data for Orchard No. 5

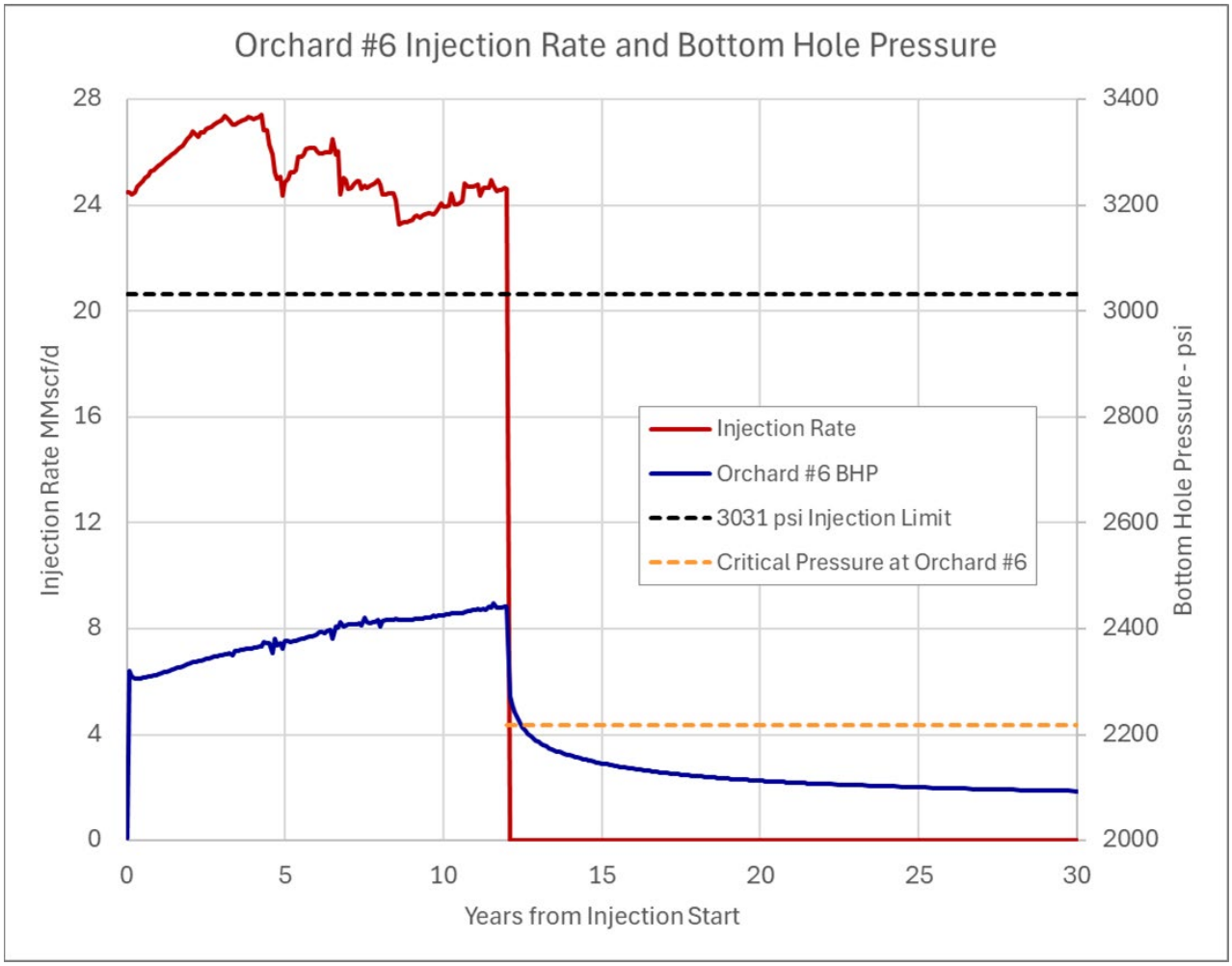


Figure 2-97 – Injection Rate and BHP Data for Orchard No. 6

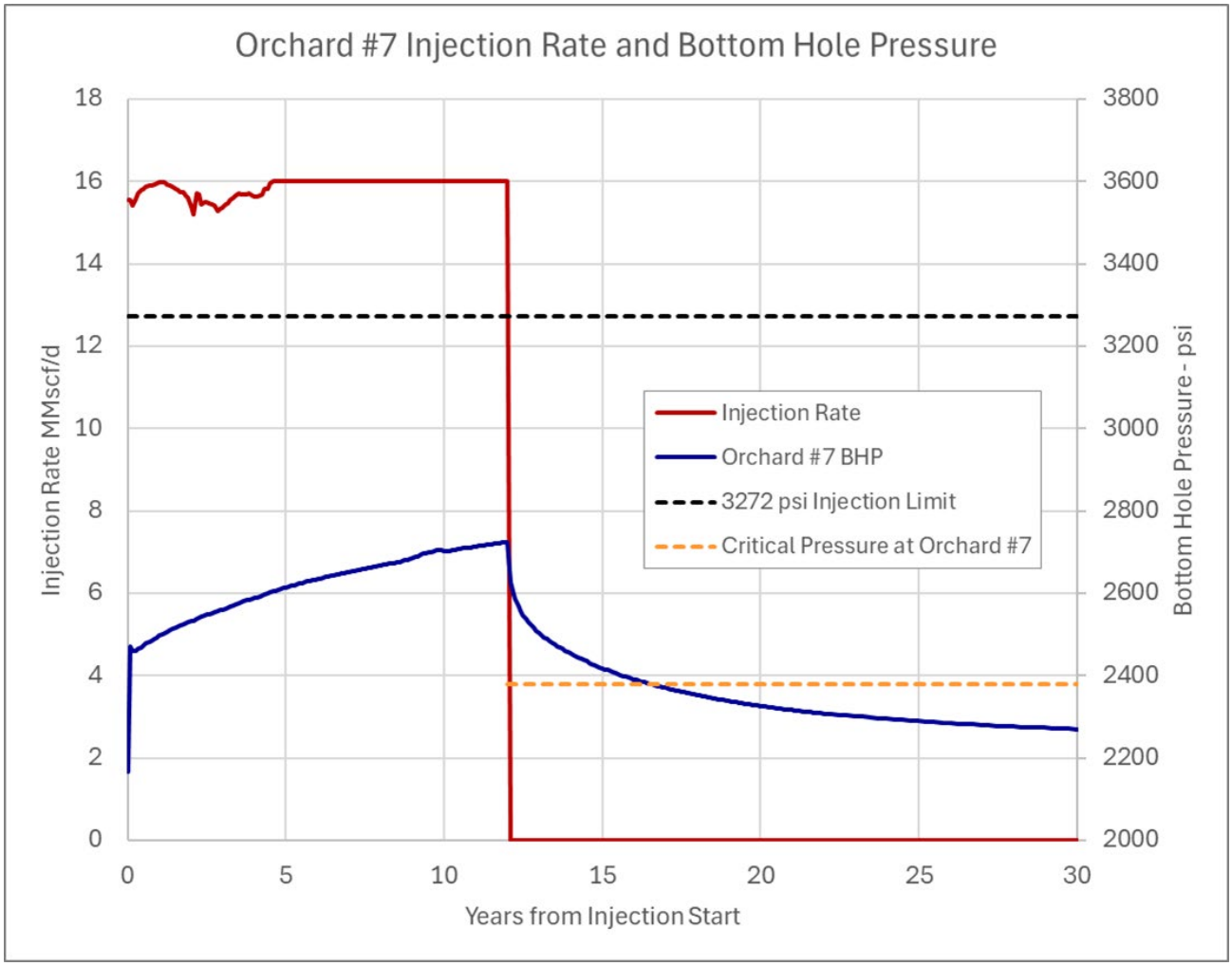


Figure 2-98 - Injection Rate and BHP Data for Orchard No. 7

Changes in the CO_2 plume over time were illustrated for all seven wells in Figures 2-53 through 2-66 (in Section 2.4), with cross-sectional views—east-west and north-south, respectively—of effective CO_2 saturation, comprised of CO_2 in all phases (discussed in Section 2.3). Those figures presented snapshots of the predicted distribution of the CO_2, taken at the end of injection and 50 years thereafter.

REFERENCES

Barrett, D., & Harpole, K. (1977). Reservoir Data Pays Off: West Seminole San Andres Unit, Gaines County, TX. *52nd Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers.* Denver: Society of Petroleum Engineers .

Beebe, T. (2004, December). Cedar Lake Unit - Tertiary Results, Performance Anomalies and Challenges in a San Andres CO2 Flood. Midland, TX: Society of Petroleum Engineers.

Bennion, B., & Bachu, S. (2005). Relative Permeability Characteristics for Supercritical CO2 Displacing Water in a Variety of Potential Sequestration Zones in the Western Canada Sedimentary Basin. *Paper Number SPE 95547, Presented at the SPE Annual Technical Conference and Exhibition.* Dallas: Society of Petroleum Engineers.

Bennion, D., & Bachu, S. (2008). Drainage and Imbibition Relative Permeability Relationships for Supercritical CO2/Brine and H2S/Brine Systems in Intergranular Sandstone, Carbonate, Shale, and Anhydrite Rocks. *SPE Reservoir Evaluation and Engineering*, 487-496.

Benson, S., Hingerl, F., Zuo, L., Krevor, S., Niu, B., Calvo, R., & Niemi, A. (2015). *Relative Permeability for Multi-phase Flow in CO2 Storage Reservoirs; Part II: Resolving Fundamental Issues and Filling Data Gaps.* Stanford, CA: Stanford University.

Bradley, R., & Kalaswad, S. (2003). *The Groundwater Resources of the Dockum Aquifer in Texas.* Austin: Texas Water Development Board.

Buckley, S., & Leverett, M. (1942). Mechanism of FLuid Displacement in Sands. *Transactions of the AIME*, 107-116.

Carlson, F. M. (1981). Simulation of Relative Permeability Hysteresis to the Nonwetting Phase. *56th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME* (pp. 1-9). Dallas: Society of Petroleum Engineers of AIME.

Cinco L., H., Samaniego V., F., & Dominguez A., N. (1978). Transient Pressure Behavior for a Well With a Finite-Conductivity Vertical Fracture. *Society of Petroleum Engineers Journal*, 253-264.

Cinco-Ley, H., & Samaniego-V, F. (1981). Transient Pressure Analysis for Fractured Wells. *Journal of Petroleum Technology*, 1749-1766.

Corey, A. (1954). The Interrelation Between Gas and Oil Relative Permeabilities. *Producers Monthly*, 38-41.

Craft, B., & Hawkins, M. (1959). Undersaturated Oil Reservoirs. In B. Craft, & M. Hawkins, *Applied Petroleum Reservoir Engineering* (pp. 135-136). Englewood Cliffs, NJ: Prentice-Hall Inc.

Crandall, D., Moore, J., Brown, S., & King, S. (2019). *NETL-CO2BRA Relative Permeability Database.* Retrieved from NETL-CO2BRA Relative Permeability Database.

Dykstra, H., & Parsons, R. (1950). The Prediction of Oil Recovery by Waterflooding. In A. P. Production, *Secondary Recovery of Oil in the United States* (pp. 160-174). Washington DC: American Petroleum Institute.

Economides, M. J., & Poe, B. (2000). Post Treatment Evaluation and Fractured Well Performance. In M. J. Economides, & K. G. Nolte (Eds.), *Reservoir Stimulation, Third Edition* (pp. 12-6 to 12-16). Chichester, United Kingdom: John Wiley & Sons, LTD.

Edwardson, M., Girner, H., Parkison, H., Williamson, C., & Matthew, C. (1962). Calculation of Formation Temperature Distyrbances Caused by Mud Circulation. *Journal of Petroleum Engineering*, 416-426.

Erlougher, R. C. (1977). *Advances in Well Test Analysis.* Dallas: Society of Petroleum Engineers of AIME.

Ertekin, T., Abou-Kassem, J. H., & King, G. R. (2001). *Basic Applied Reservoir Simulation.* Richardson: Society of Petroleum Engineers.

Fetkovich, M. (1971). A Simplified Approach to Water Influx Calculations - Finite Aquifer Systems. *Journal of Petroleum Technology*, 814-828.

Ghauri, W. (1980). Production Technology Experience in a Large Carbonate Waterflood, Denver Unit, Wasson San Andres Field. *Journal of Petroleum Technology*, 1493 - 1502.

Harvey, A. (1996). Semiempirical Correlation for Henry's Constants over Large Temperature Ranges. *AIChE Journal*, 1491-1494.

Keelan, D. a. (1975). Trapped-Gas Saturations in Carbonate Formations. *Society of Petroleum Engineers Journal*, 149-160.

Kuuskraa, V. A., Petrusac, R., & Wallace, M. (2020). *A Four-County Appraisal of the San Andres Residual Oil Zone (ROZ) "Fairway" of the Permian Basin.* US Department of Energy National Energy Technology Laboratory .

Kuuskraa, V. A., Petrusak, R. L., & Wallace, M. (2020, 9 1). *ROZ Database.* Retrieved from ROZ Database for San Andres Formation in Four Counties in Permian Basin in Energy Analysis Details Page: https://www.netl.doe.gov/projects/VueConnection/energy-analysis-details.aspx?id=9f7a7257-7bac-4f8e-9ebc-4074be8756fe

Land, C. (1968). Calculation of Imbibition Relative Permeability for tow- and Three-Phase Flow from Rock Properties. *Society of Petroleum Engineers Journal*, 149-156.

Land, C. S. (1971). Comparison of Calculated with Experimental Imbibition Relative Permeability. *Society Of Petroleum Engineers Journal*, 419-425.

Leibrock, R., Hiltz, R., & and Huzarevich, J. (1951). Results of Gas Injection in the Cedar Lake FIeld. *Petroleum Transactions, AIME*, 357-366.

Lucia, F. (2007). *Carbonate Reservoir Characterization, and Integrated Approach.* Austin: The University of Texas at Austin, Bureau of Economic Geology.

Matthews, C., & Russell, D. (1967). *Pressure Buildup and Flow Tests in Wells* (Vol. SPE Monograph Volume 1). Dallas: Society of Petroleum Engineers of AIME.

McCain, W. (1991). *The Properties of Petroleum Fluids, Second Edition.* Tulsa: PenWell Books.

Peaceman, D. (1978). Interpretation of Well Block Pressures in Numerical Reservoir Simulation. *Society of Petroleum Engineers Journal*, 183-194.

Peaceman, D. W. (1983). Interpretation of Well-Block Pressures in Numerical Reservoir Simulation with Nonsquare Grid Blocks and Anisotripic Permeability. *Society of Petroleum Engineers Journal*, 531-543.

Rettman, P., & Leggat, E. (1966). *Ground Water Resources of Gaines County, Texas.* Austin: United States Geological Survey.

Russell, D., & Truitt, N. (1964). Transient Pressure Behavior in Vertically Fractured Reservoirs. *Journal of Petroleum Technology*, 1159-1170.

Society, R. G. (1956). *Symposium on Oil and Gas FIelds of Southeastern New Mexico.* Roswell, NM: Roswell Geological Society.

Stalkup, F. I. (1983). Principles of Phase Behavior and Miscibility. In F. I. Stalkup, *Miscible Displacement* (pp. 17-22). New York, Dallas: Society of Petroleum Engineers of AIME.

Stone, H. (1970). Probability Model for Estimating Three-Phase Relative Permeability. *Journal of Petroleum Technology*, 214-218.

TWDB, T. W. (2025). *Water Data Interactive*. Retrieved from Groundwater Data Viewer (Interactive Map): https://www3.twdb.texas.gov/apps/waterdatainteractive/groundwaterdataviewer

Welge, H. (1952). A Simplified Method for Computing Oil Recovery by Gas or Water Drive. *Petroleum Transactions, AIME*, 91-98.

Appendix 2-1 Water Property Correlations

Density of formation water at standard conditions:

$$\rho_w = 62.368 + 0.438603 \times S + 1.60074 \times 10^{-3} \times S^2$$

This correlation has been found to be as accurate as a laboratory measurement, throughout the full range of solids contents. (McCain, 1991)

Correction of formation water density to reservoir conditions $f(p, T)$:

$$\rho_{w(p,T)} = \rho_w / B_w$$

Formation volume factor of water, B_w, a function of pressure and temperature:

$$B_w = (1 + \Delta V_{wp})(1 + \Delta V_{wp})$$

These correlations are valid for the full range of potential dissolved solids content at temperatures less than 260°F and pressures less than 5,000 psia. (McCain, 1991)

Change in water volume vs. temperature (ΔV_{wT}):

$$\Delta V_{wT} = -1.0001 \times 10^{-2} + 1.33391 \times 10^{-4} \times T + 5.50654 \times 10^{-7} \times T^2$$

Change in water volume vs. pressure (ΔV_{wp}):

$$\Delta V_{wp} = -1.95301 \times 10^{-9} \times (pT) - 1.72834 \times 10^{-13} \times (p^2T) - 3.58922 \times 10^{-7} \times p - 2.25341 \times 10^{-10} \times p^2$$

Nomenclature:

- B_w = *Water formation volume factor vol/vol*
- ρ = *density, lb/ft^3*
- S = *weight percent dissolved solids (equivalent to milligrams per liter* $\times 10^{-4}$)
- T = *Temperature, °F*
- p = *Pressure, psia*

Reference:

McCain, W. (1991). Reservoir-Fluid Property Correlations - State of the Art. *SPE Reservoir Engineering*, 266-272.

Appendix 2-2 Hydrocarbon EOS Parameters in Plume Model

Simulator Fluid Properties

Fluid Properties of Hydrocarbon Components (Used in Peng Robinson EOS):

	CO_2	N_2	CH_4	C_2-C_3	C_4-C_5	C_6-C_8	C_9-C_{14}	C_{15}-C_{29}	C_{30+}
LHC	0.000000	0.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
Vc, l/mol	0.094000	0.089500	0.099000	0.182260	0.288090	0.391550	0.590470	0.995230	1.554890
Acentric f	0.225000	0.040000	0.008000	0.134320	0.225830	0.275570	0.426880	0.737240	1.412020
MW, g/mol	44.010000	28.013000	16.043000	39.412000	66.486000	99.306000	153.481000	305.000000	640.000000
Parachor	78.000000	41.000000	77.000000	112.483000	193.625000	287.663000	432.520000	769.095000	1154.680000
VCMU l/mol	0.094000	0.089500	0.099000	0.182260	0.288090	0.391550	0.590470	0.995230	1.554890
OMEG-A	0.457240	0.457240	0.457240	0.457240	0.457240	0.457240	0.457240	0.457240	0.457240
OMEG-B	0.077796	0.077796	0.077796	0.077796	0.077796	0.077796	0.077796	0.077796	0.077796
EOS-Bc	0.000942	0.000849	0.000946	0.001794	0.002917	0.004028	0.006381	0.012001	0.025058
Pc, atm	72.800000	33.500000	45.400000	43.891000	34.702000	30.974000	23.153000	15.310000	8.737000
tc, K	304.200000	126.200000	190.600000	349.311000	449.039000	553.372000	655.339000	815.000000	971.111000
Zc	0.274140	0.289520	0.287370	0.279080	0.271300	0.267080	0.254220	0.227830	0.170480
SHV/Bc	-0.094347	-0.128390	-0.153860	-0.104130	-0.046518	-0.024895	0.056739	0.073590	0.073804

Binary Interaction Coefficients

CO_2	0								
N_2	0	0							
CH_4	0.105	0.025	0						
C_2-C_3	0.1257	0.06877	0.006179	0					
C_4-C_5	0.11538	0.10261	0.018738	0.003484	0				
C_6-C_8	0.0967	0.11	0.030755	0.009672	0.001567	0			
C_9-C_{14}	0.0874	0.11	0.051036	0.022623	0.008527	0.002807	0		
C_{15}-C_{29}	0.08283	0.11	0.083014	0.046293	0.025114	0.014342	0.004526	0	
C_{30+}	0.11295	0.11	0.115036	0.072271	0.045684	0.030933	0.015437	0.00331	0

Reservoir Hydrocarbon Composition

Component	Mole Fraction
CO_2	0.0027881
N_2	0.0063427
CH_4	0.31149
C_2-C_3	0.0471229
C_4-C_5	0.0950562
C_6-C_8	0.175346
C_9-C_{14}	0.190389
C_{15}-C_{29}	0.148904
C_{30+}	0.0225611

Properties of Reservoir Hydrocarbons

Parameter	Value
Bubble Point – psia	1,656
Reservoir Oil Density – lbm/ft^3	47.9
Reservoir Oil Molecular Weight	185.3
Stock Tank GOR* SCF/STB	415
Stock Tank Oil API Gravity*	36
Stock Tank Gas-Specific Gravity*	0.87

*Stock tank properties based on a single stage flash to standard conditions (60°F, 14.7 psia).

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 3 – Area of Review and Corrective Action

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

TABLE OF CONTENTS

3.1 Introduction 3
3.2 Model Background 3
3.3 Model Inputs and Assumptions 3
3.4 Area of Review: Pore Occupancy Plume 5
3.5 Area of Review: Pressure Front 6
3.6 Operating Strategies Influencing Reservoir Modeling Results 13
3.7 Area of Review Results 30
3.8 Corrective Action Plan and Schedule 37
3.8.1 Corrective Action Plan 37
3.8.2 Review of Wells Needing Corrective Action 39
3.9 Area of Review Revaluation Plan and Schedule 64
3.9.1 Proposed Reevaluation Cycle 64
3.10 Conclusion 65
3.11 References 66

Figures

Figure 3-1 Variation of Threshold and Injection Interval Pressures versus Depth 12
Figure 3-2 – Orchard No. 1 Plume Model Results – Cross-Sectional View 13
Figure 3-3 – Orchard No. 1 Plume Model Results – Oblique Cross-Sectional View 14
Figure 3-4 – Orchard No. 2 Plume Model Results – Cross-Sectional View 15
Figure 3-5 – Orchard No. 2 Plume Model Results – Oblique Cross-Sectional View 16
Figure 3-6 – Orchard No. 3 Plume Model Results – Cross-Sectional View 17
Figure 3-7 – Orchard No. 3 Plume Model Results – Oblique Cross-Sectional View 18
Figure 3-8 – Orchard No. 4 Plume Model Results – Cross-Sectional View 19
Figure 3-9 – Orchard No. 4 Plume Model Results – Oblique Cross-Sectional View 20
Figure 3-10 – Orchard No. 5 Plume Model Results – Cross-Sectional View 21
Figure 3-11 – Orchard No. 5 Plume Model Results – Oblique Cross-Sectional View 22
Figure 3-12 – Orchard No. 6 Plume Model Results – Cross-Sectional View 23
Figure 3-13 – Orchard No. 6 Plume Model Results – Oblique Cross-Sectional View 24
Figure 3-14 – Orchard No. 7 Plume Model Results – Cross-Sectional View 25
Figure 3-15 – Orchard No. 7 Plume Model Results – Oblique Cross-Sectional View 26
Figure 3-16 –Plume Model Results – Plan View of Stabilized Plume 27
Figure 3-17 – CO_2 Occupancy Plume and Critical Pressure AOR Map 29
Figure 3-18 – CO_2 Plume AOR 31
Figure 3-19 – Map of Oil and Gas Wells Within Orchard No. 1–No. 7 AOR 32
Figure 3-20 – Map of Penetrating Oil and Gas Wells Within Orchard No. 1 to No. 7 AOR 33
Figure 3-21 – Map of Freshwater Wells Within Orchard No. 1 to No. 7 AOR 34
Figure 3-22 – Map of Known Cleanup Sites, Mines, and Springs in AOR 36

Figure 3-23 – Well API No. 42-165-00128 Current Schematic 40
Figure 3-24 – Well API No. 42-165-00128 Proposed Plugged Schematic..... 41
Figure 3-25 – Well API No. 42-165-00908 Current Schematic 42
Figure 3-26 – Well API No. 42-165-00908 Proposed Plugged Schematic..... 43
Figure 3-27 – Well API No. 42-165-01063 Current Schematic 44
Figure 3-28 – Well API No. 42-165-01063 Proposed Plugged Schematic..... 45
Figure 3-29 – Well API No. 42-165-02139 Current Schematic 46
Figure 3-30 – Well API No. 42-165-02139 Proposed Plugged Schematic..... 47
Figure 3-31 – Well API No. 42-165-02216 Current Schematic 48
Figure 3-32 – Well API No. 42-165-02216 Proposed Plugged Schematic..... 49
Figure 3-33 – Well API No. 42-165-02526 Current Schematic 50
Figure 3-34 – Well API No. 42-165-02526 Proposed Plugged Schematic..... 51
Figure 3-35 – Well API No. 42-165-02580 Current Schematic 52
Figure 3-36 – Well API No. 42-165-02580 Proposed Plugged Schematic..... 53
Figure 3-37 – Well API No. 42-165-03242 Current Schematic 54
Figure 3-38 – Well API No. 42-165-03242 Proposed Plugged Schematic..... 55
Figure 3-39 – Well API No. 42-165-10051 Current Schematic 56
Figure 3-40 – Well API No. 42-165-10051 Proposed Plugged Schematic..... 57
Figure 3-41 – Well API No. 42-165-33522 Current Schematic 58
Figure 3-42 – Well API No. 42-165-33522 Proposed Plugged Schematic..... 59
Figure 3-43 – Well API No. 42-165-38785 Current Schematic 60
Figure 3-44 – Well API No. 42-165-38785 Proposed Monitoring Well Schematic..... 61
Figure 3-45 – Well API No. 42-165-38794 Current Schematic 62
Figure 3-46 – Well API No. 42-165-38794 Proposed P&A Schematic 63

Tables

Table 3-1 – Model Input Parameters and Assumptions for Orchard No. 1 to No. 7..... 4
Table 3-2 – Base USDW Depth and Elevation from GAU 6
Table 3-3 – Ogallala Aquifer GCD Observation Well Data..... 7
Table 3-4 – Calculations of USDW initial fluid pressure 8
Table 3-5 – Critical Pressure Calculations..... 10
Table 3-6 – Wells in the Pressure Front AOR Requiring Corrective Action 38
Table 3-7 – Triggers for AOR Reevaluations..... 64

3.1 Introduction

Title 16 of the Texas Administrative Code (TAC) **§5.203(d)(1)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] requires that an area of review (AOR) be conducted for a Class VI carbon sequestration well application. The Environmental Protection Agency (EPA) defines the AOR as the greater of either the maximum extent of the separate-phase plume (pore occupancy plume), or the pressure front where the pressure buildup is of sufficient magnitude to force fluids from the injection zone into the formation matrix of an Underground Source of Drinking Water (USDW). Both parts of this definition were analyzed for the Orchard Project AORs.

3.2 Model Background

Model Name and Version: **tNavigator (Version No. 24.2)**

Model Authors/Institution: Rock Flow Dynamics

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

3.3 Model Inputs and Assumptions

The input parameters for the tNavigator model are summarized in Table 3-1. These parameters are based on the values estimated at each injection well location.

Table 3-1 – Model Input Parameters and Assumptions for Orchard No. 1 to No. 7

Well	Injection Rate (MT/yr*)	Injection rate (MMscf/d**)	Upper San Andres		Lower San Andres		Bottomhole Temperature*** (°F)	Fracture Gradient (psi/ft***)	Maximum Allowable Injection Gradient (psi/ft)	Brine Salinity (ppm^)	Injectate Composition
			Porosity (%)	Permeability (mD)	Porosity (%)	Permeability (mD)					
Orchard No. 1	303,000	15.9	1.8-25.7	10^{-3} - 250	0.6-19.6	0.0 - 48	105-111	0.67	0.6	59,000	98% CO_2, 2% N_2
Orchard No. 2	283,000	14.8	5.9-22.5	0.03-112	2.4-20.8	0.0 - 69	105-111				
Orchard No. 3	278,000	14.6	5.3-25.6	0.02-242	0.6-20.8	0.0 - 70	105-111				
Orchard No. 4	211,000	11.1	6.1-22.9	0.04-125	4.5-20.3	0.01 - 60	105-109				
Orchard No. 5	458,000	24.0	3.4-26.6	0.04-125	1.1-27.2	0.01 - 60	105-109				
Orchard No. 6	483,000	25.3	5.4-30.0	0.02-637	0.06-20.5	0.0 - 64	105-110				
Orchard No. 7	303,000	15.9	1.1-28.7	10^{-3} - 480	3.7-18.4	0.0 - 34	105-111				

*MT/yr – metric tons per year
**MMscf/d – million standard cubic foot per day
***Temperature at top and base of perforations
****psi/ft – pounds per square inch per foot
^ppm – parts per million

3.4 Area of Review: Pore Occupancy Plume

The first AOR is related to the CO_2 pore space occupancy plume and is delineated using computational plume modeling of an injected CO_2 stream. Such modeling accounts for the physical and chemical properties of all phases of the injectate and is constructed based on available site characterization, operational, and monitoring data. (*Section 2 – Plume Model* discusses the methodology and process in detail.) The pore occupancy plume is considered and reviewed based on three primary details: *artificial penetrations*, *subsurface features*, and *pore space rights*.

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

Subsurface features identified within the AOR will be assessed for their expected impact to the gross injection zone. Such features could include faults, folds, mapped fractures, steeply dipping formations, and salt diapirs. Should any structural anomalies be discovered, efforts to assess their sealing nature will be conducted. These features can act as either barriers aiding in containing the stored CO_2 or, conversely, as conduits moving the CO_2 out of the containment zone. No such features have been identified in the Orchard Project area.

Pore space rights are critically important when evaluating a project's potential due to the classification of carbon injection wells as *storage* wells rather than *disposal* wells. To mitigate the risk of an uneconomically viable project, operating strategies and reservoir management practices were designed with the utmost care, to maintain control of the resulting subsurface injectate plume extent.

The area determined for pore space rights was used to identify landowners within the CO_2 plume area. Multiple landowners own the surface and pore space at the sites for the Orchard No. 1 through No. 7 wells. Orchard Storage Company LLC (Orchard Storage) has been in contact with them and is currently in advanced negotiation for pore space options and related lease agreements.

Results from reservoir modeling simulations indicate that the carbon dioxide plume growth and extents will remain within this leased area.

3.5 Area of Review: Pressure Front

A second AOR considers the pressure front created by the injection of fluids into a previously stable reservoir. Both calculation and computational modeling determine this AOR. The pressure buildup that could cause potential fluid migration is determined for either insufficiently plugged and abandoned artificial penetrations, or subsurface features that are found to penetrate the upper confining interval of the gross injection zone.

The worst-case scenario for moving reservoir fluids to the USDW would be through an improperly plugged and abandoned wellbore or subsurface feature that is open both at the base of the USDW and at the top of the injection interval. This resultant pressure is referred to as the *critical pressure*, and the methodology for finding it came from EPA Method 1 guidance for calculations based on displacing fluid initially present in the borehole in the hydrostatic case.

The base of the USDW has been determined by the Groundwater Advisory Unit (GAU) of the Railroad Commission of Texas for each of the seven Orchard injection wells. Depths and elevations for base USDW as determined by the GAU are tabulated in Table 3-2.

Table 3-2 – Base USDW Depth and Elevation from GAU

Injection Well	Ground Elevation (Ft Above Sea Level)	Base USDW Depth (Ft)	Base USDW Elevation (Ft Above Sea Level)
Orchard No. 1	3,219	2,000	1,219
Orchard No. 2	3,211	2,000	1,211
Orchard No. 3	3,208	2,000	1,208
Orchard No. 4	3,202	1,950	1,252
Orchard No. 5	3,187	1,925	1,262
Orchard No. 6	3,169	1,850	1,319
Orchard No. 7	3,212	2,000	1,212

Fluid gradient for the USDW / aquifer zones has been calculated to range from 0.433 to 0.434 psi/ft based on average TDS values of 1,130 and 6,000 ppm for the Ogallala and Dockum aquifers, respectively. For the purpose of calculating the critical pressure rise, the more conservative 0.433 psi/ft has been used to characterize the USDW fluid gradient.

The aquifer hydraulic head (i.e., the height of the water column in the aquifer) is obtained from the Texas Water Development Board's (TWDB) database of groundwater source wells in Texas. This database contains information for wells in which liquid levels are routinely measured. Currently designated as Groundwater Conservation District (GCD) observation wells by the TWDB, six of such wells were found within the Orchard AOR, all having good quality data between late 2022 and early 2024. Table 3-3 presents the most recent data for measured aquifer water level in those wells.

Table 3-3 – Ogallala Aquifer GCD Observation Well Data

Water Well No.	Water Level (Ft Above Sea Level)	Measurement Date
27-05-620	3,150.9	1/18/2024
27-05-922	3,141.7	12/5/2023
27-13-221	3,102.3	12/5/2023
27-14-114	3,126.1	12/5/2023
27-14-115	3,096.9	12/5/2023
27-14-202	3,097.0	12/20/2022

In the calculation of P_u for each of the Orchard injection wells, the representative aquifer water level was selected from the closest of the water observation wells to the injection well location. Parameters used and resulting USDW pressure (at representative base USDW elevation "z_u") for each of the Orchard injection wells is included as Table 3-4.

Table 3-4 – Calculations of USDW initial fluid pressure

	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
Closest GCD Observation Well	27-05-922	27-05-922	27-05-922	27-14-114	27-14-114	27-14-202	27-13-221
Distance / Direction from Injection Well to GCD well	1.0 mile NE	1.0 mile NW	1.7 mile NW	2.1 mile SW	1.8 mile SW	0.8 mile SW	0.9 mile S
Observed USDW Fluid Level (ft above sea level)	3,141.7	3,141.7	3,141.7	3,126.1	3,126.1	3,097.0	3,102.3
Representative elevation of USDW base (z_u, feet above sea level)	1,219	1,211	1,208	1,252	1,262	1,319	1,212
USDW Fluid Column height (ft)	1,922.7	1,930.7	1,933.7	1,874.1	1,864.1	1,778.0	1,890.3
Fluid Gradient in USDW (psi/ft)	0.433	0.433	0.433	0.433	0.433	0.433	0.433
Hydrostatic pressure differential in USDW (psi)	832.5	836.0	837.3	811.5	807.2	769.9	818.5
Initial fluid pressure in the USDW (P_u, corrected to psia)	847.2	850.7	852.0	826.2	821.9	784.6	833.2

An example calculation of the representative USDW pressure, based on inputs for Orchard No. 1, is shown in Equation 1.

(Eq. 1)

$$\Delta P_u = \rho g \cdot (z_h - z_u)$$

$$\Delta P_u = 0.433 \cdot (3{,}141.7 - 1{,}219)$$

$$\Delta P_u = 832.5$$

$$P_u = 832.5 + 14.7 \text{ (absolute pressure conversion)}$$

$$P_u = 847.2 \text{ psia}$$

Where ΔP_u is the hydrostatic pressure differential in the USDW, and z_h and z_u are the respective elevations for the top of the water column and the base of the USDW.

The USDW pressure (P_u) is used together with the elevation difference between USDW and injection zone and the injection zone fluid density using Equation 6. The fluid in the injection zone is assumed to be brine with 59,000 ppm TDS. This assumption is based on data from the U.S. Geological Survey's National Produced Waters Geochemical Database for wells close to the Orchard Project area. The density of the formation brine in the injection zone was calculated to be 64.52 lb/ft^3, using correlations by McCain (McCain, 1991). The fluid gradient within the storage interval will therefore be 0.448 psi/ft.

Table 3-5 details the calculation of critical pressure and critical pressure increase for each of the seven Orchard injection wells. It should be noted that the representative elevations for the USDW and the injection zone are taken at the base of the USDW and top of perforated interval, respectively. Perforation elevations are below sea level and will therefore be negative. The values used in the calculations and final results (shown in bold) are provided in Table 3-5.

Table 3-5 – Critical Pressure Calculations

Input Variable	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
Representative pressure at base USDW (Pu , psia)	847	851	852	826	822	785	833
Elevation of USDW(z_u , ft above sea level)	1,219	1,211	1,208	1,252	1,262	1,319	1,212
Elevation of injection zone (z_i, ft above sea level)	-2,304	-2,129	-2,029	-1,973	1,972	-1,881	-2,243
Elevation difference from USDW to injection zone (ft)	3,523	3,340	3,237	3,225	3,234	3,200	3,455
Injection zone fluid density gradient (ri g, psi/ft)	0.448	0.448	0.448	0.448	0.448	0.448	0.448
Injection zone datum pressure (psia)	2,260	2,260	2,260	2,260	2,260	2,260	2,260
Injection zone datum elevation (ft above sea level)	-2,450	-2,450	-2,450	-2,450	-2,450	-2,450	-2,450
Elevation difference from injection zone datum to zi (ft)	-146	-321	-421	-477	-478	-569	-207
Pressure correction from datum to top perforation (psi)	-66	-144	-189	-214	-214	-255	-93
Pressure at top of injection zone (Pi , psia)	2,194	2,116	2,071	2,046	2,046	2,005	2,167
Critical pressure at top of injection zone (Pi,f , psia)	**2,425**	**2,347**	**2,302**	**2,271**	**2,271**	**2,218**	**2,381**
Critical Pressure increase (DPi,f , psia)	**231**	**231**	**231**	**225**	**225**	**213**	**214**

Example calculation steps for variables in Table 3-25 are shown in Equations 2 and 3:

(Eq. 2)
$$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i)$$
$$(z_u - z_i) = 1219 - (-2303.6)$$
$$(z_u - z_i) = 3522.6$$
$$P_{i,f} = 847.2 + 0.448 \cdot (3522.6)$$
$$P_{i,f} = 2425.3$$

(Eq. 3)
$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i$$
$$\Delta P_{i,f} = P_{i,f} - P_i$$
$$P_i = P_{datum} - \rho_i g \cdot (z_{datum} - z_i)$$
$$P_i = 2260 - .448 \cdot (-146.4)$$
$$P_i = 2194.4$$
$$\Delta P_{i,f} = 2425.3 - 2194.4$$
$$\Delta P_{i,f} = 230.9$$

Figure 3-1 illustrates how $\Delta P_{i,f}$ remains constant over ranges in depth for a single injector. The threshold pressure ($P_{i,f}$) does vary with depth for the injection interval, however as $P_{i,f}$ value changes with depth, so does the pressure within the storage interval. The figure shows a plot of pressure versus elevation, with USDW pressure and elevation based on Orchard No. 1. The solid blue line represents the calculated threshold pressure value at any depth, starting from the pressure at the base of the USDW (shown as a blue triangle). The slope of that line is defined by the pressure gradient ($\rho_l g$) for the native fluid in the injection interval. The dashed red line on this graph represents the pressure within the injection interval, starting from the defined model datum pressure and depth, shown as the red diamond. The slope of that line is also defined by the pressure gradient for the fluid in the injection interval.

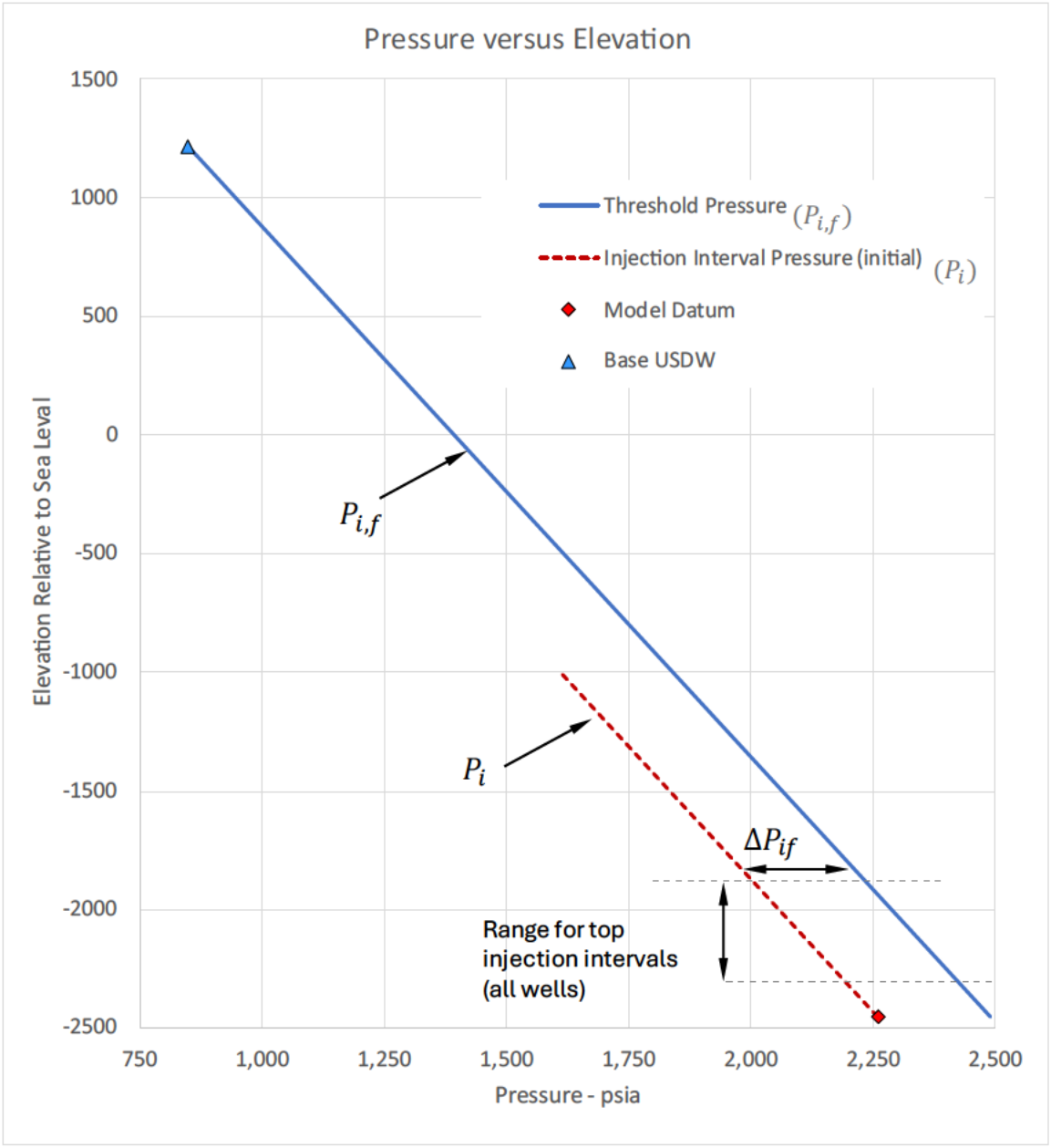


Figure 3-1 Variation of Threshold and Injection Interval Pressures versus Depth

The critical pressure increase at any depth will be the difference in pressure between the initial pressure in the respective injection interval and allowable threshold pressures at that depth. Both of those lines have the same slope, being based on the gradient of the fluid in the injection interval. Because these lines are parallel, the pressure difference (at any depth) between the two lines is constant. Variations of $\Delta P_{i,f}$ between one injector to another will be driven by the base USDW elevation z_u and the calculated the base of USDW pressure P_u.

The pressure front created by all seven wells results in an AOR that extends beyond the individual CO_2 plumes. Therefore, to ensure adequate protection of the USDW, the pressure front extent was used to define the AOR. Any subsurface features identified within it were assessed for

appropriate USDW protection and, if deemed insufficient, included in the corrective action or contingency plan.

3.6 Operating Strategies Influencing Reservoir Modeling Results

The seven injection wells target an average of 780 ft of permeable carbonate in the Upper and Lower San Andres. Carbon dioxide injection will occur for 12 years. The primary objective of the operating strategies was to control the resultant lateral plume extent, to ensure it remains contained within the controlled pore space. The tNavigatotor simulator was employed to produce the outputs—shown in Figures 3-2 through 3-15 for Orchard No. 1 through No. 7—associated with this reservoir management program. Both cross-sectional and oblique cross-sectional visualizations are displayed for each of the seven injection wells.

The X and Y scales on the following figures are shown in U.S. feet, and the color scales represent the specified property values in the model.

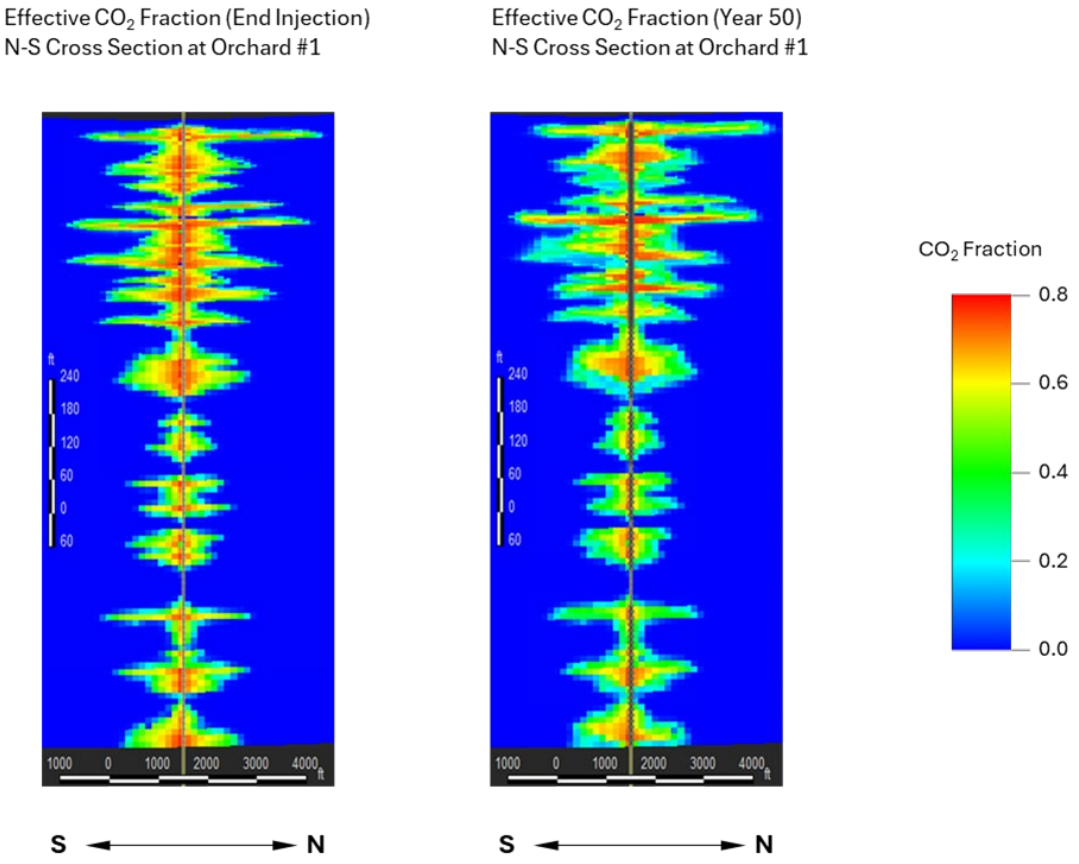


Figure 3-2 – Orchard No. 1 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

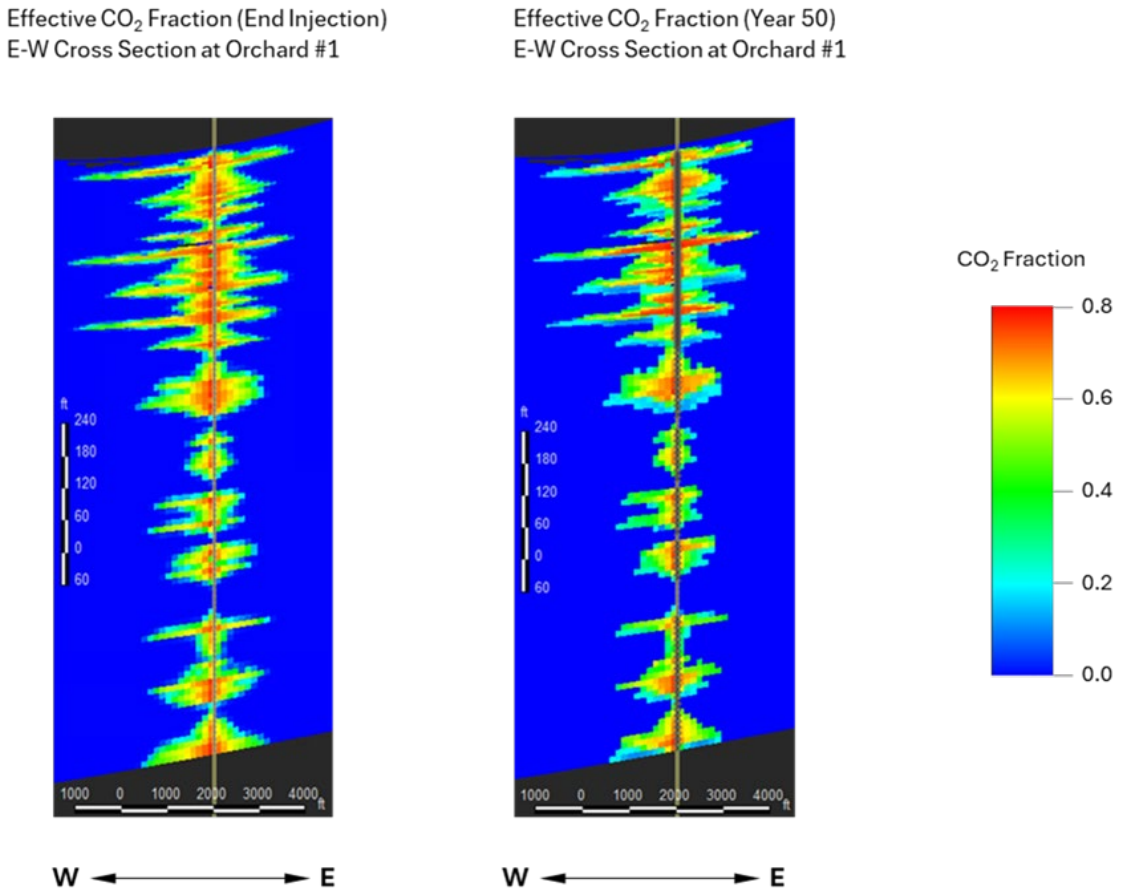


Figure 3-3 – Orchard No. 1 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

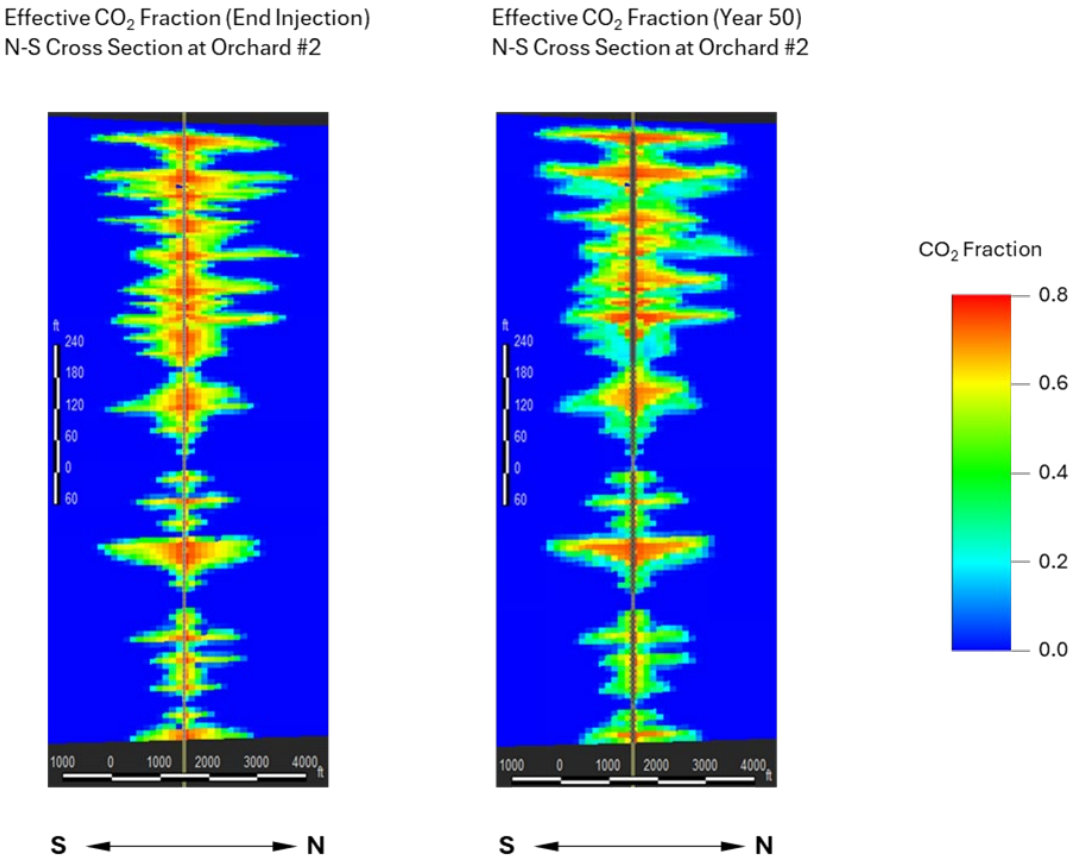


Figure 3-4 – Orchard No. 2 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

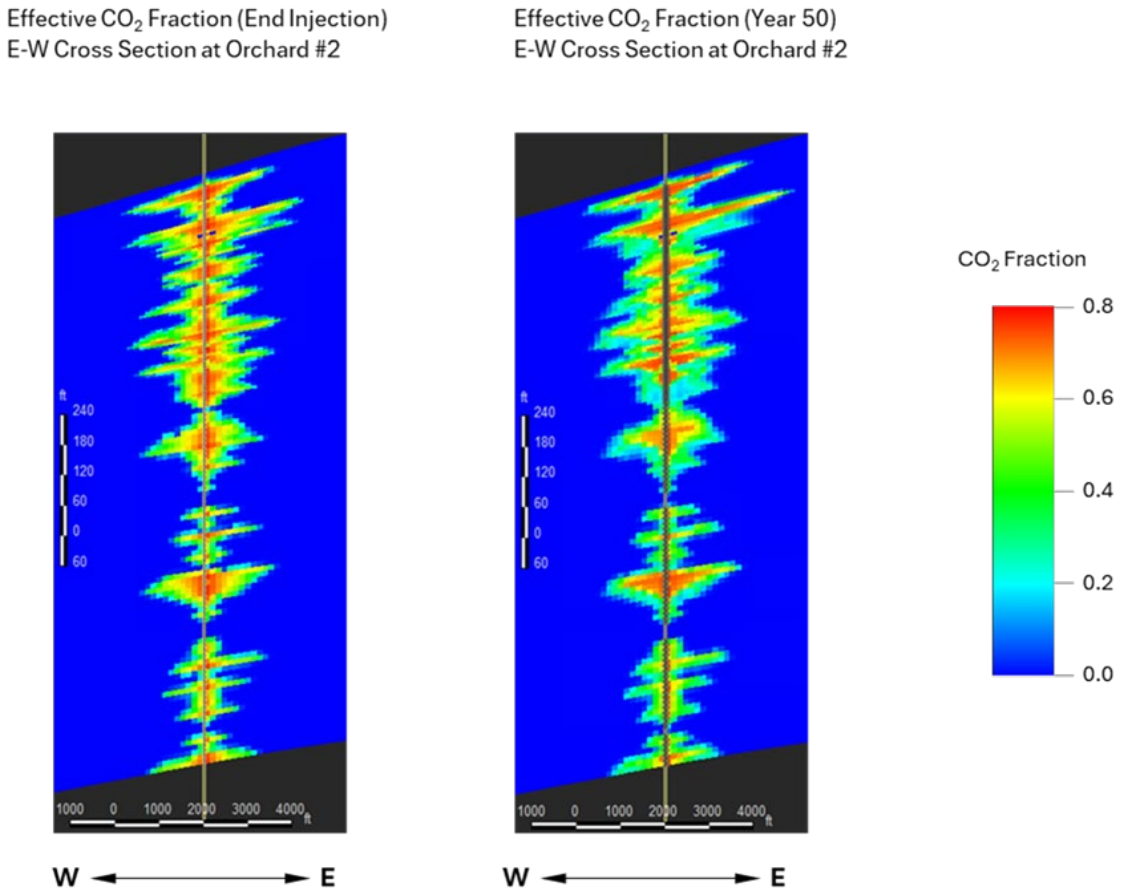


Figure 3-5 – Orchard No. 2 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

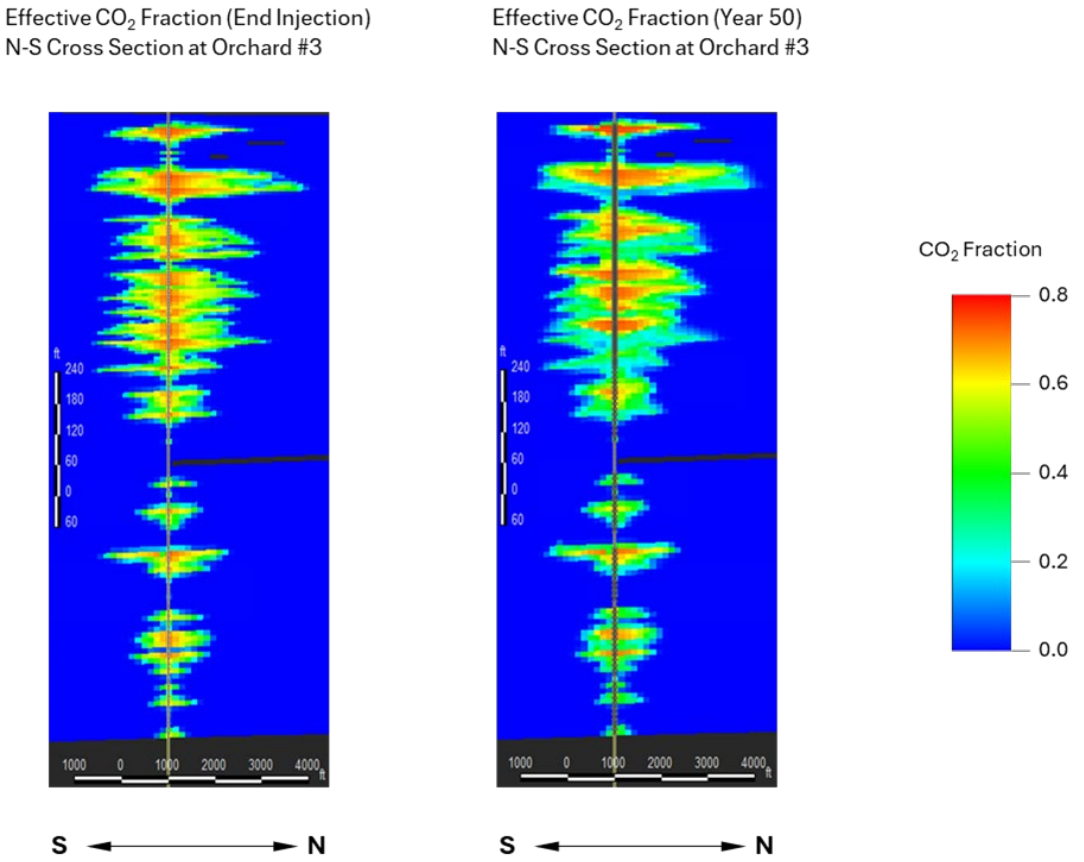


Figure 3-6 – Orchard No. 3 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

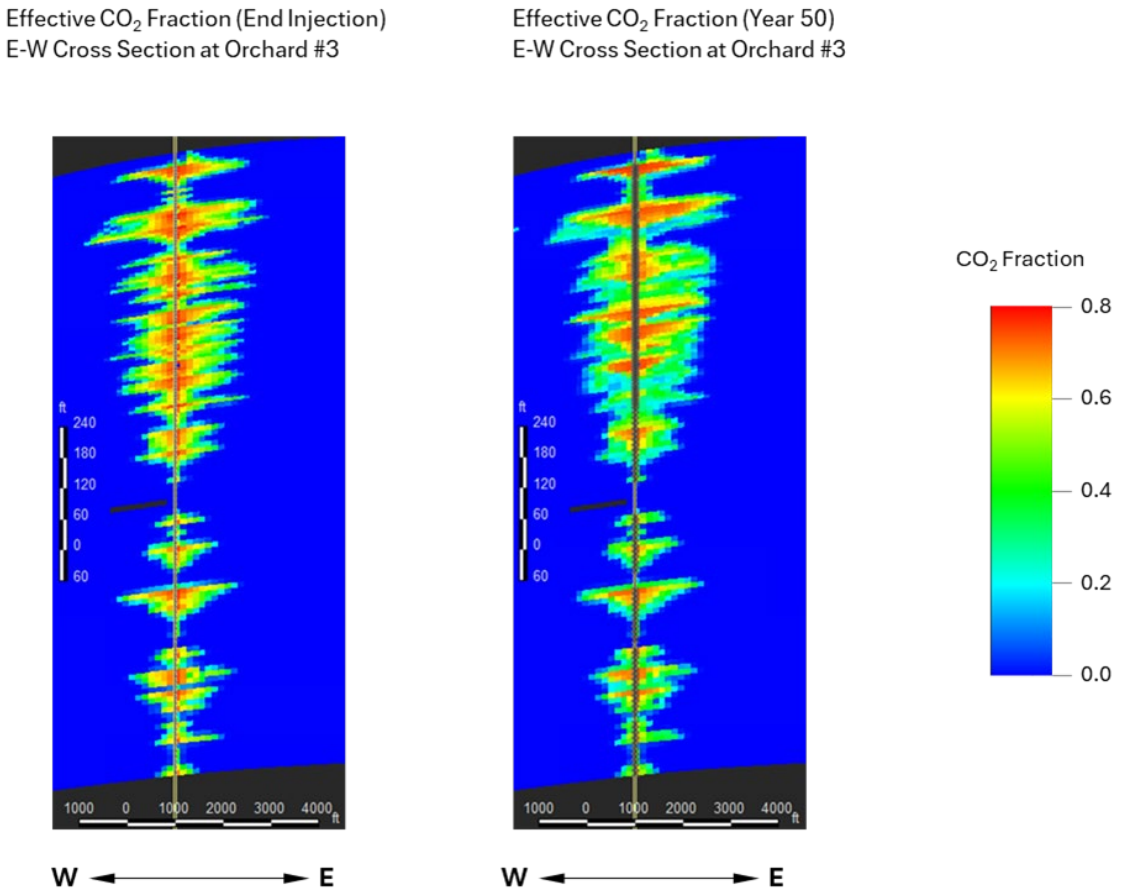


Figure 3-7 – Orchard No. 3 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

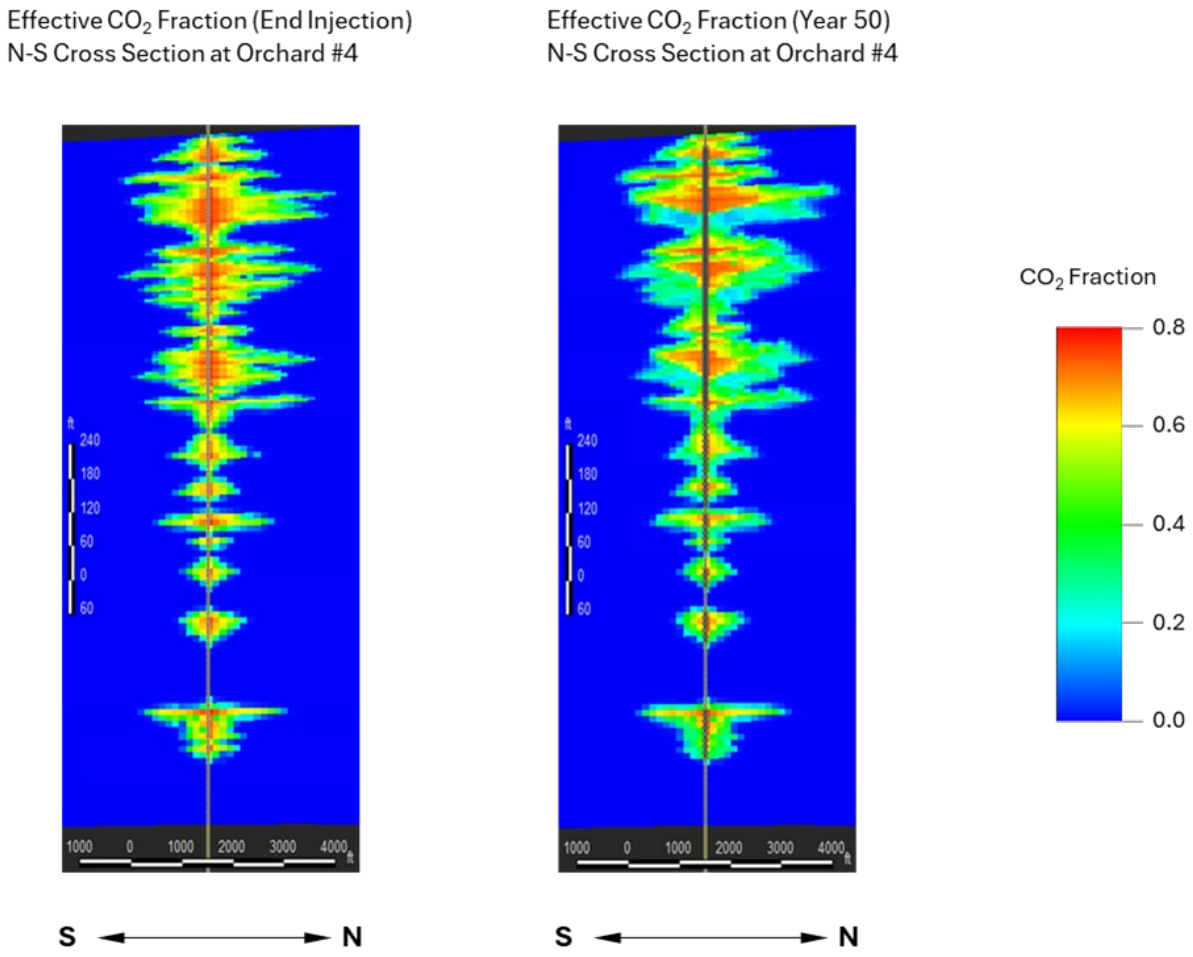


Figure 3-8 – Orchard No. 4 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

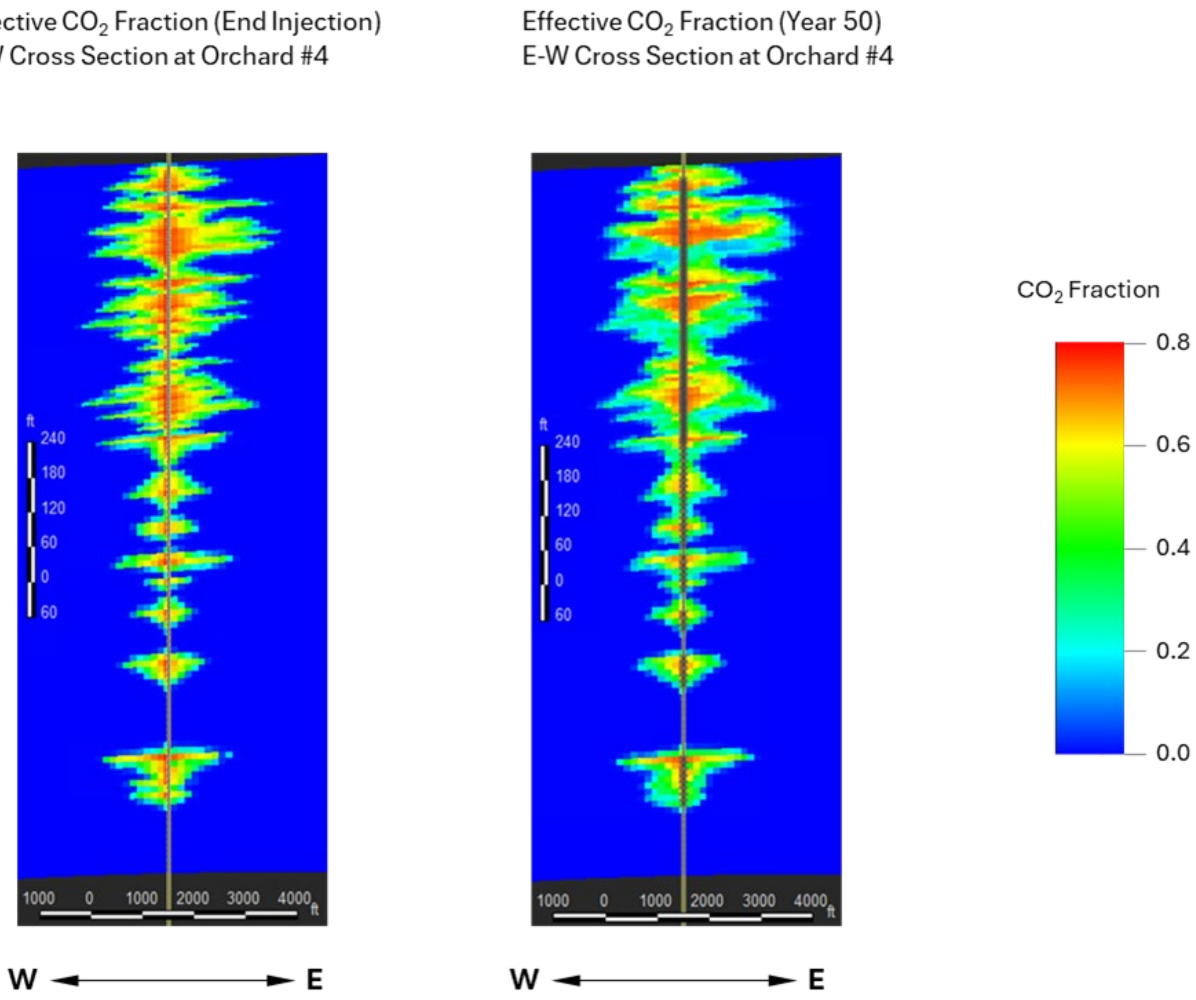


Figure 3-9 – Orchard No. 4 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

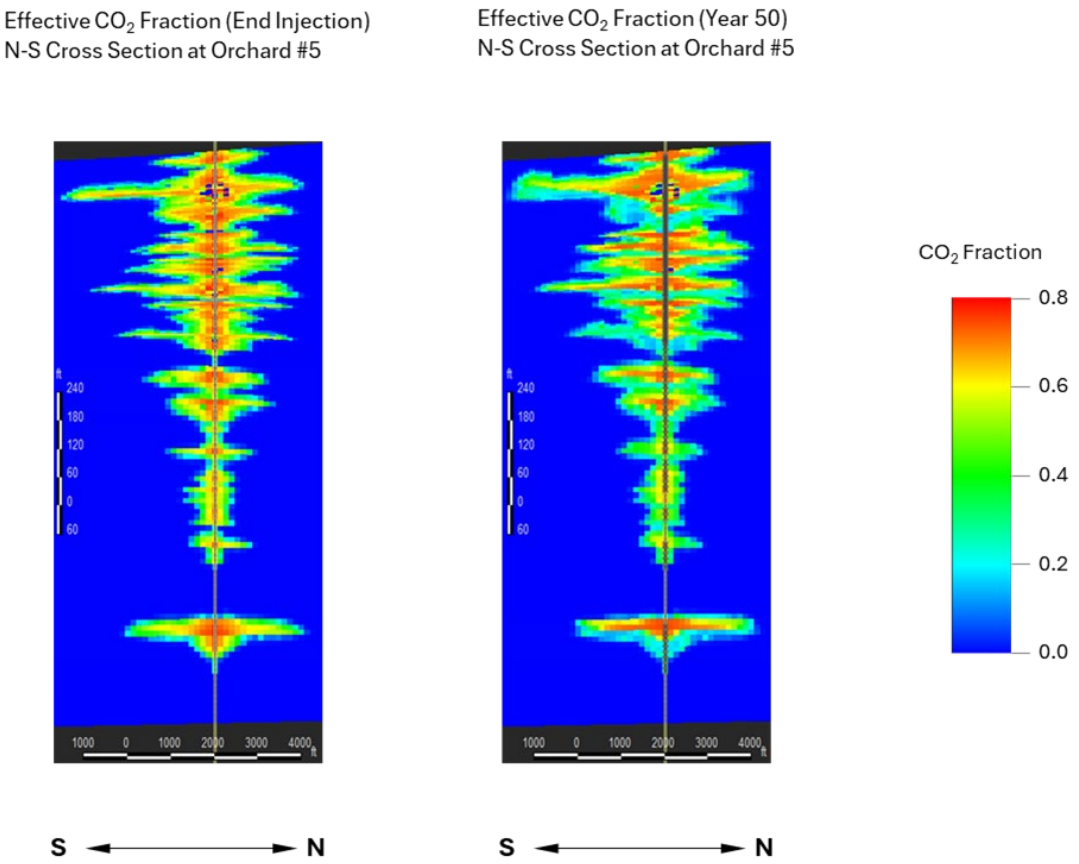


Figure 3-10 – Orchard No. 5 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

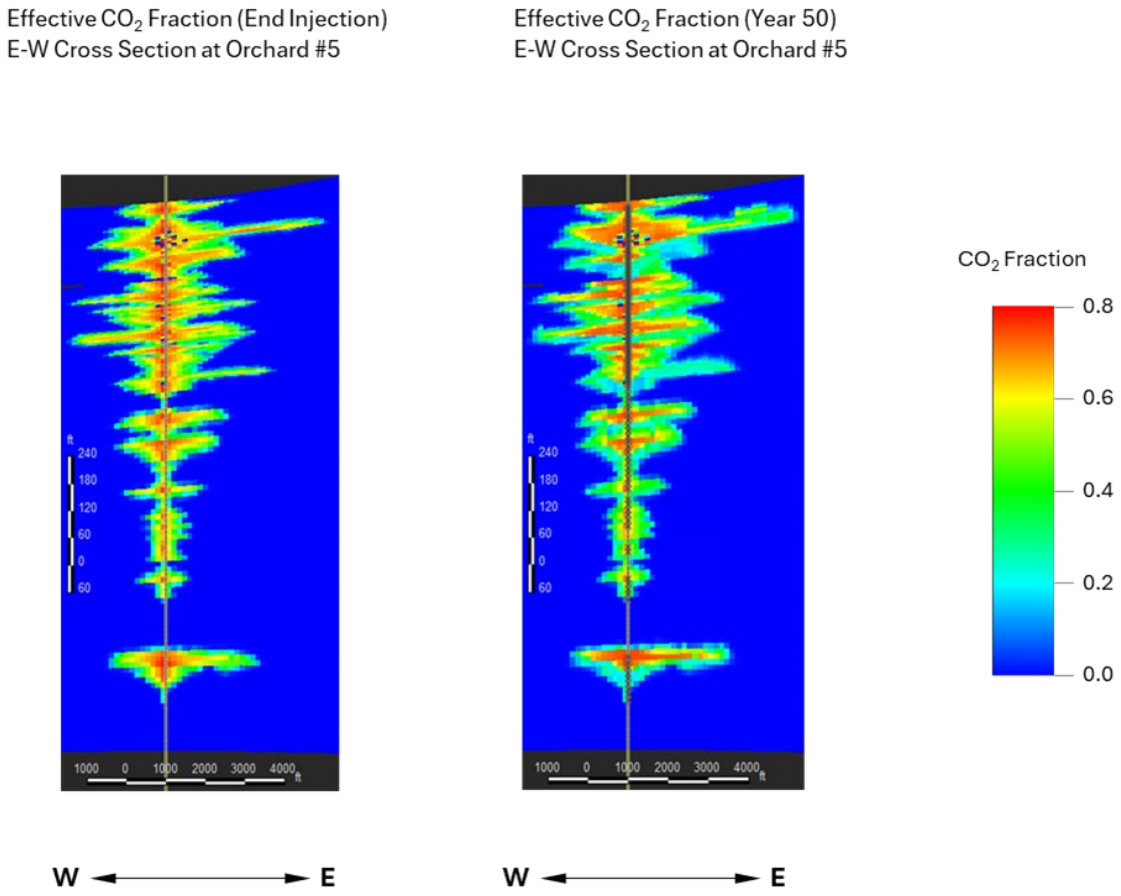


Figure 3-11 – Orchard No. 5 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

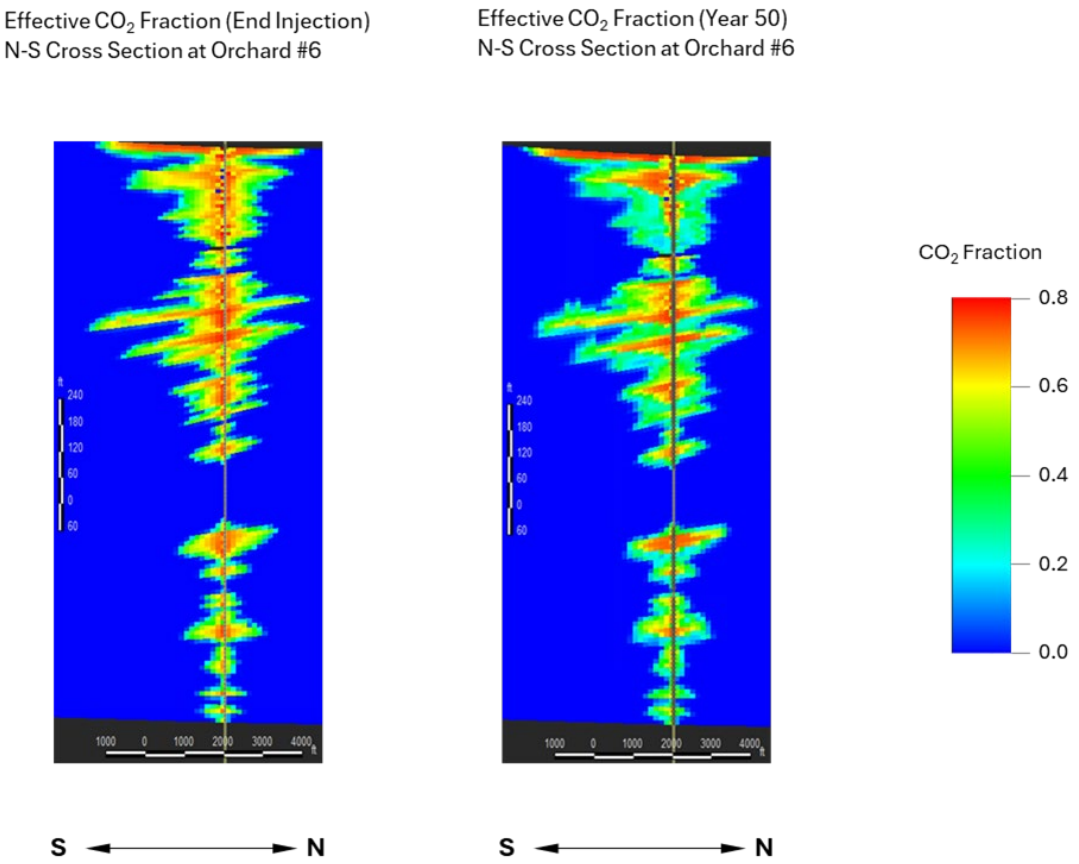


Figure 3-12 – Orchard No. 6 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

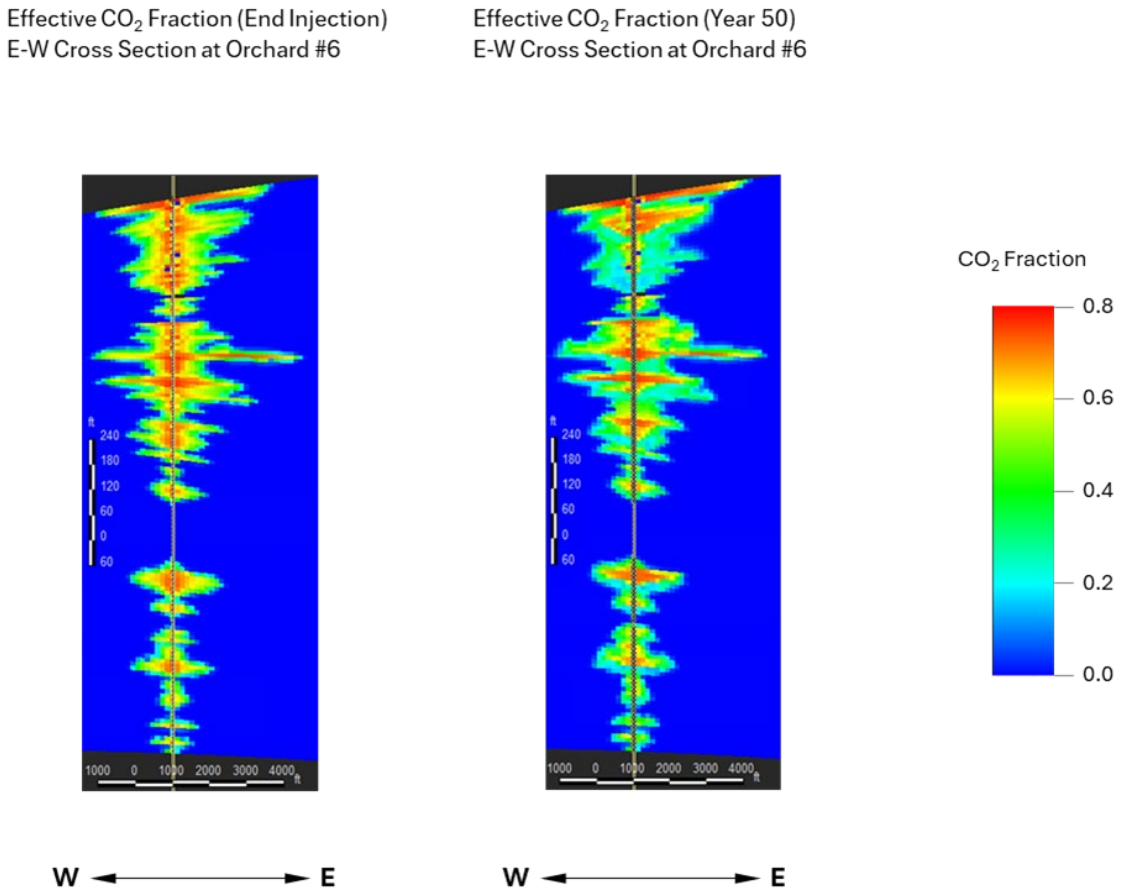


Figure 3-13 – Orchard No. 6 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

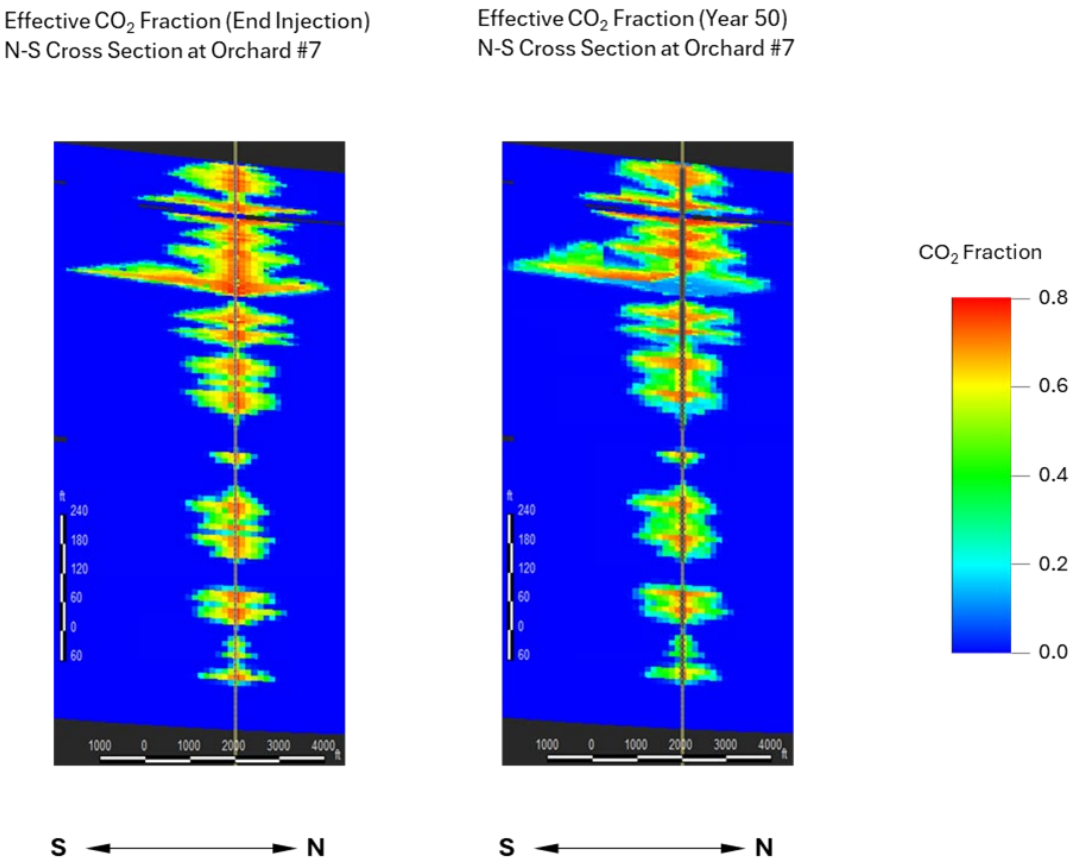


Figure 3-14 – Orchard No. 7 Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation

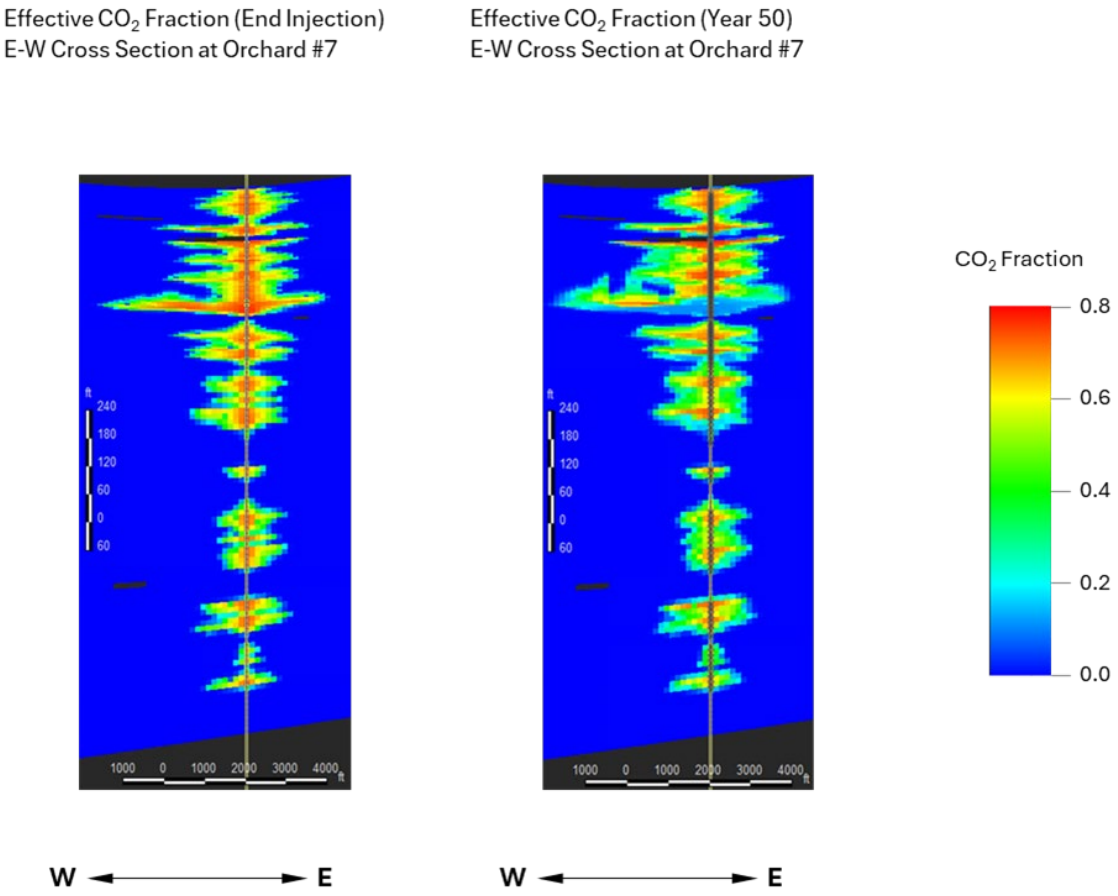


Figure 3-15 – Orchard No. 7 Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation

The shape and lateral extent of the stabilized pore occupancy plumes for the proposed seven wells is illustrated in Figure 3-16. These extents were used to determine the initial project AOR for pore space occupancy and corrective action.

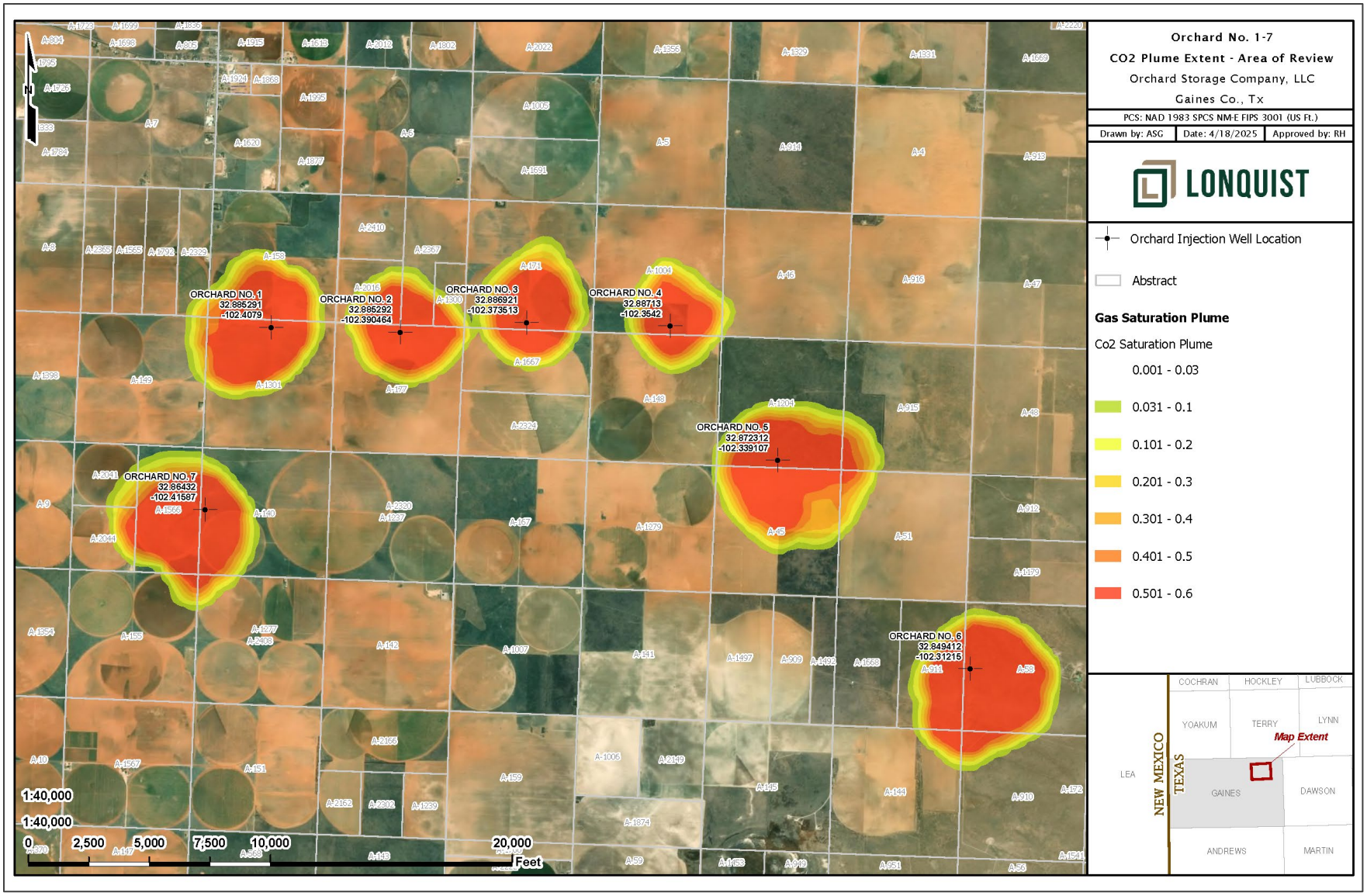


Figure 3-16 –Plume Model Results – Plan View of Stabilized Plume (Colored by CO_2 Saturation)

These plume extents were digitized from the tNavigator output and imported into ArcGIS for use as the defined area of influence for establishing the Orchard No. 1 to No. 7 AORs. As discussed in *Section 3.7*, Orchard Storage conducted a review to identify any artificial penetrations or other features that may endanger the lowermost USDW as a result of injection activity or operations per 16 TAC **§5.203(d)(1)(C)** [40 CFR **§146.84(c)(3)**]**.** Orchard Storage also generated maps showing the area of influence and any man-made structures found within the AOR. The maps and associated lists generated during this effort can be found in *Appendix B*. No wells in the AOR were found to penetrate the confining zone. The wells that penetrate the confining zone, and are in the critical pressure front, are discussed in Section 3.8.2.

The AORs were determined according to the following three purposes—to reiterate the three primary details used to review the pore occupancy plume, as discussed in *Section 3.4*:

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

Figure 3-17 displays the CO_2 occupancy plume and critical pressure front AORs for the project.



Figure 3-17 – CO_2 Occupancy Plume and Critical Pressure AOR Map

3.7 Area of Review Results

The TRRC information system was the primary source for collecting oil-and-gas well data for the AOR. Supplemental well data from Enverus/DrillingInfo, IHS, and TGS were then included and assessed to prevent historical-well omissions and data inaccuracies. All water well data was gathered from the TWDB's database and the local water conservation district (Llano Estacado).

The proposed location of the Orchard No. 1 to No. 7 injection wells is favorably suited for carbon sequestration. Evaluation of the AOR results yielded zero existing artificial penetrations within the CO_2 pore-occupancy-plume AOR boundary (Figure 3-18). No faults or other geologic features or man-made structures were found within the AOR that could affect the integrity of the disposal intervals for permanent CO_2 sequestration.

Within the pressure front AOR, 55 oil and gas well permits were identified as shown in Figure 3-19. Of these, two were cancelled locations and two expired prior to drilling. Of the 51 wells drilled, 33 were drilled through the upper confining layer (Figure 3-20). The current schematics and historical well files for all these wells are included in *Appendix B-8.* A spreadsheet listing of these wells is included as Appendix B-4.

Additionally, 277 freshwater wells were identified (Figure 3-21), details for which are provided in *Appendix B-3*.

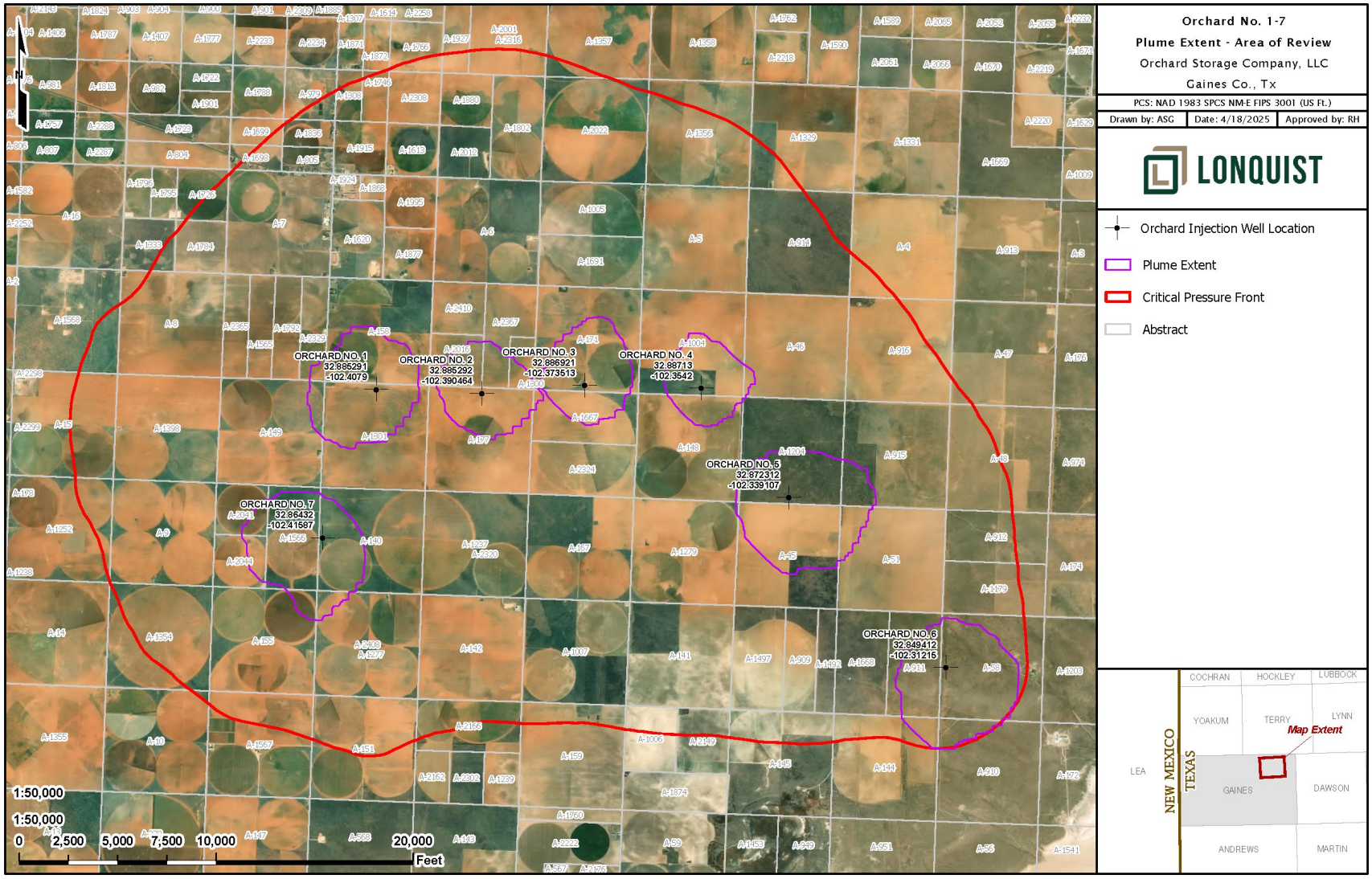


Figure 3-18 – CO_2 Plume AOR

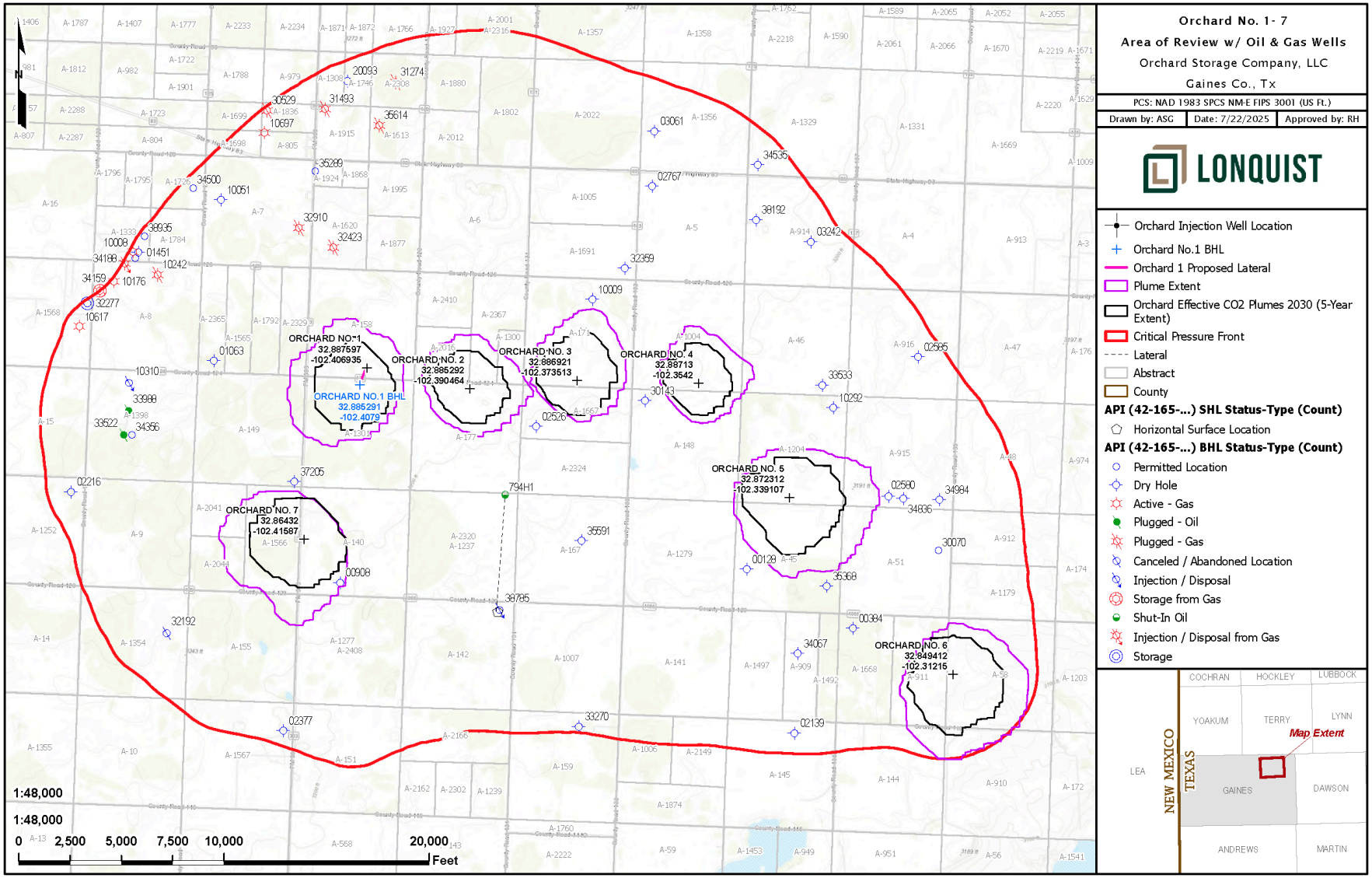


Figure 3-19 – Map of Oil and Gas Wells Within Orchard No. 1–No. 7 AOR

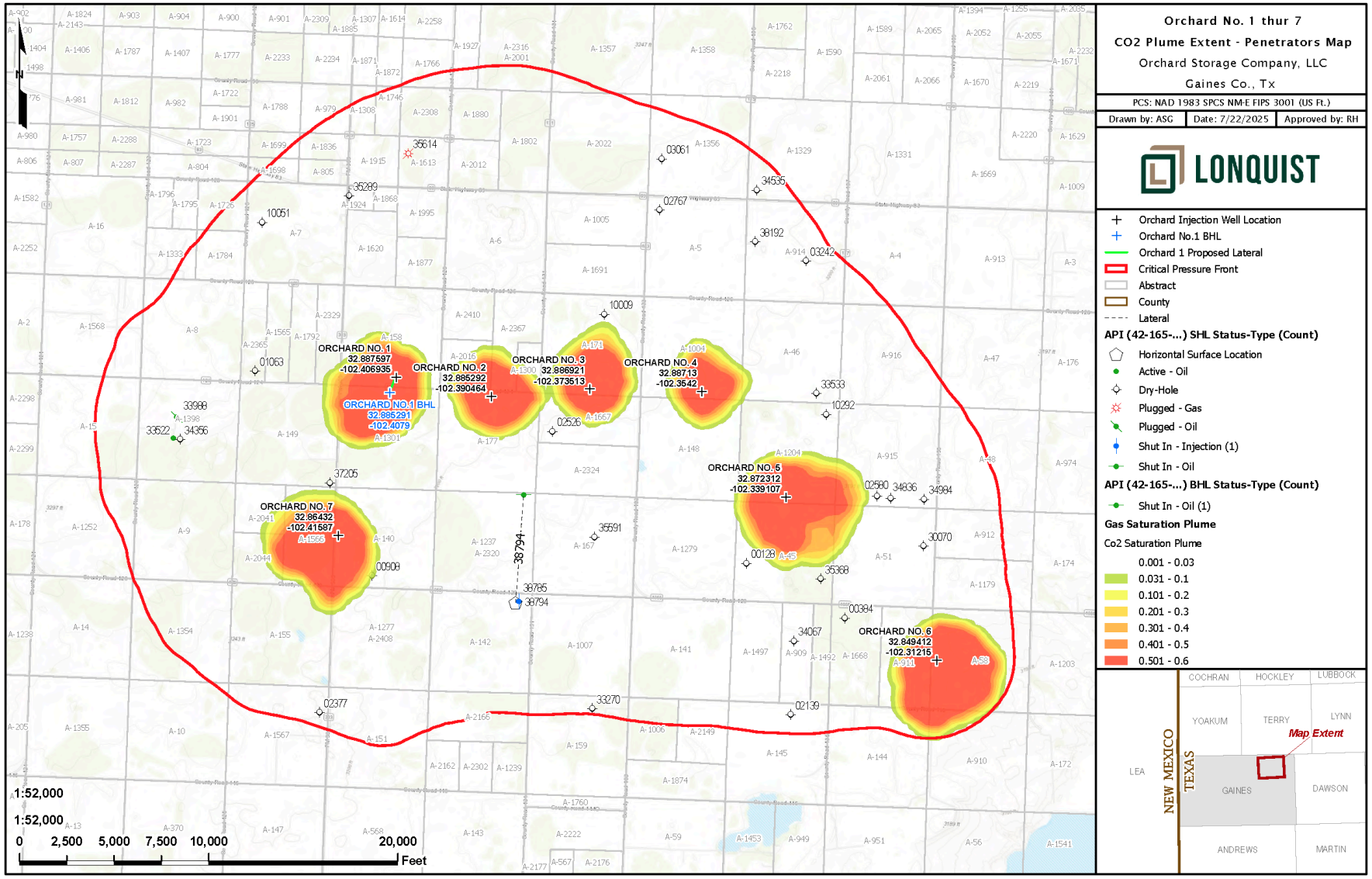


Figure 3-20 – Map of Penetrating Oil and Gas Wells Within Orchard No. 1 to No. 7 AOR

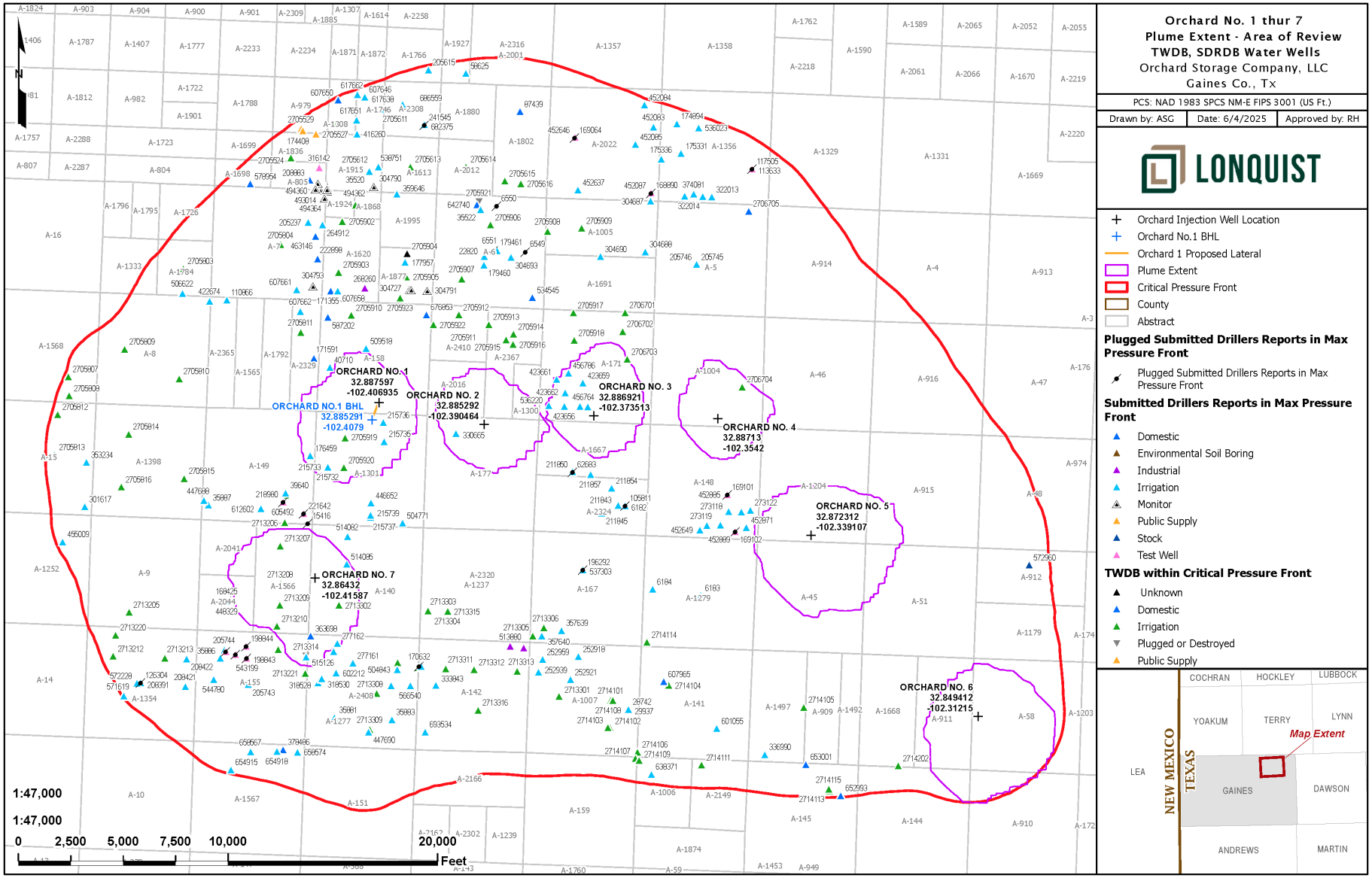


Figure 3-21 – Map of Freshwater Wells Within Orchard No. 1 to No. 7 AOR

A search of the EPA's "Cleanups in My Community Map"[1] found one RCRA one leaking underground storage tank. A search of the Bureau of Economic Geology's Texas Mineral Resources Map did not identify any known mines in the AOR.[2] A review of known springs in Texas did not find any in the AOR (Heimuller and Reece 2003). The result of these searches is shown in Figure 3-22.

[1] https://cimc.epa.gov/ords/cimc/f?p=cimc:map::::71
[2] https://coastal.beg.utexas.edu/txmineralresources/No. !/

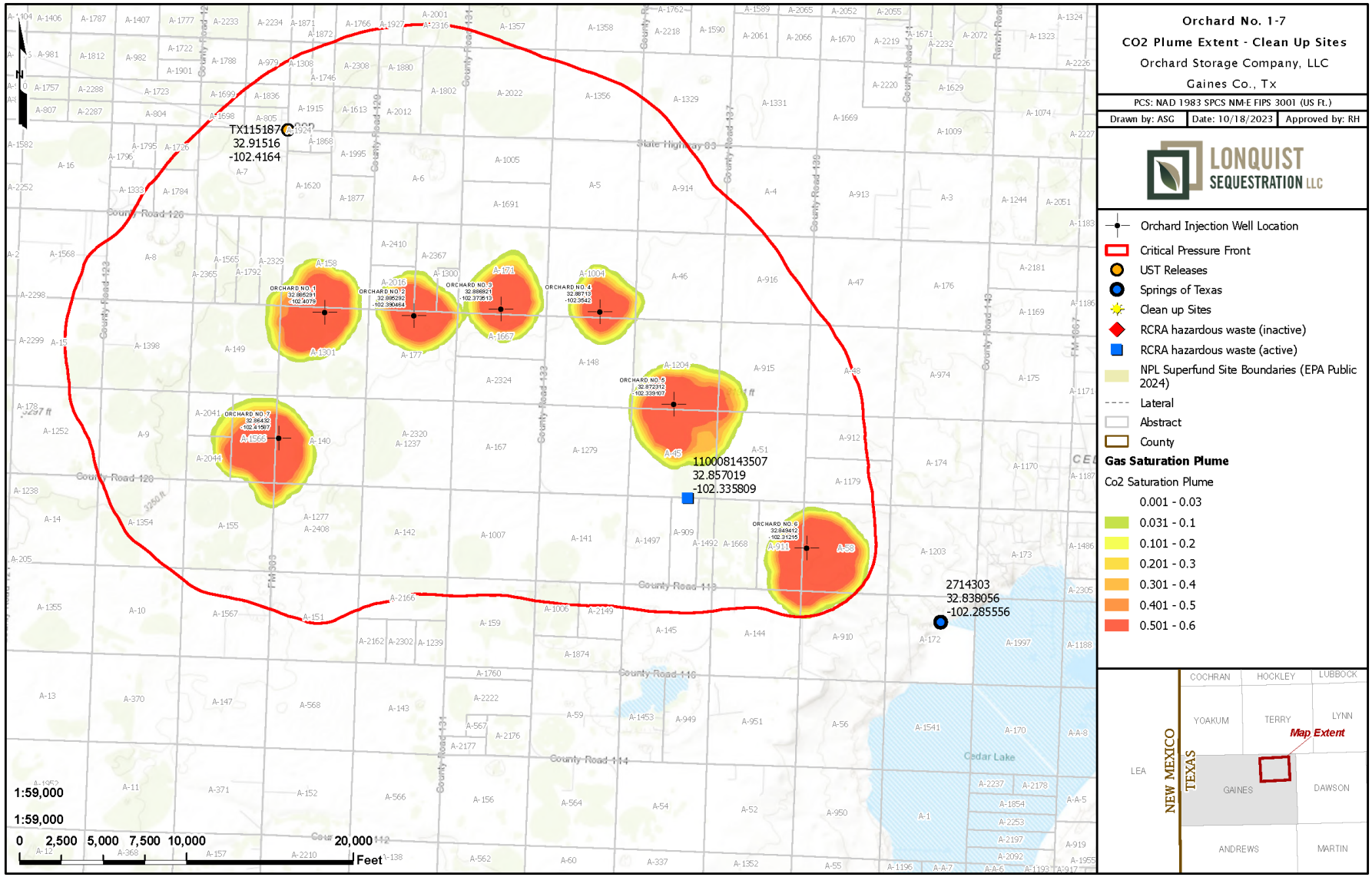


Figure 3-22 – Map of Known Cleanup Sites, Mines, and Springs in AOR

3.8 Corrective Action Plan and Schedule

As explained in *Section 3.4*, the plume extent AOR considers the pore space occupied by the CO_2 plume as determined by the reservoir modeling results. One well (42-165-00908) is predicted to intersect the CO_2 plume extent from Orchard No. 7 during the density drift period after injection ceases. This well likely will require corrective action as it was a dry hole that penetrates the upper confining zone within the projected CO_2 plume from the Orchard No. 7 well. However, this well has conflicting records regarding whether the well was drilled or not and there are no plugging records available. Orchard will attempt to locate the well and determine if the well can be reentered.

The pressure front AOR covers a calculated distance, where the injected CO_2 could pressure up the reservoir enough to allow brine and other formation fluids to be pushed upward into a USDW interval. The calculations for determining this area were included in *Section 3.5.* Fifty-one wells were identified in the pressure front AOR, 33 of which were found to penetrate the confining layer. The penetrating wells in the critical pressure front were reviewed to determine if they were constructed adequately to protect brine from entering the USDW. As shown in the schematics and files provided in Appendix B-1, 23 of the wells were constructed and plugged in a manner that will withstand the movement of brine from the pressure front and protect the USDW. Nine of the wells were plugged correctly to TRRC standards with adequate surface casing and cement to protect the base of usable quality water, which occurs at approximately 300 ft. Historically, many wells in Texas were not plugged explicitly to protect the base of the USDW (i.e., Rustler formation). Accordingly, these nine wells will be reentered and plugged to protect the Rustler from possible movement of brine. If the well identified as being in the CO_2 plume extent does exist, it will also need to be plugged to protect the USDW. Additionally, two wells in the pressure front were recently acquired by Orchard. While these wells were constructed correctly to prevent movement of brine to the USDW, Orchard plans to re-enter and workover these wells. One of these wells (API No. 42-165-38794) will be plugged and abandoned and the other (API No. 42-165-38785) will be converted to an in-zone monitoring well. A summary table listing key well data of oil and gas wells within the critical pressure front and CO_2 plume is included as Appendix B-4_AORwelllists.pdf.

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

3.8.1 Corrective Action Plan

Table 3-6 lists the ten penetrating wells that require corrective action plus the two that have been acquired and will be worked over/plugged, and the description of said actions. Schematics for all wells in the pressure front AOR are included in *Appendix B-1*. *Appendix B-2* contains the schematics for the post-corrective actions for the 11 wells.

Table 3-6 – Wells in the Area of Review Requiring Corrective Action

API No.	Status	Spud Date	Initial Plug Date	Elevation (ft)	TVD (ft)	Action Type
42-165-00128	Dry Hole	12/15/1948	1/4/1949	3,170	5,200	Plug Rustler and surface casing shoe
42-165-00908	Dry Hole	5/29/1959	6/18/1959	3,217	5,515	Plug Rustler and surface casing shoe Plug 150 ft across the upper confining zone
42-165-01063	Dry Hole	4/15/1958	5/10/1958	3,272	5,552	Plug Rustler and surface casing shoe
42-165-02139	Dry Hole	6/8/1938	7/19/1938	UNK	5,128	Plug Rustler and surface casing shoe
42-165-02216	Dry Hole	6/14/1938	7/23/1938	UNK	5,315	Plug Rustler and surface casing shoe
42-165-02526	Dry Hole	12/21/1953	1/14/1954	UNK	5,315	Plug Rustler and surface casing shoe
42-165-02580	Dry Hole	10/16/1944	11/25/1944	3,175	5,250	Plug inside casing, plug across Rustler and shoe
42-165-03242	Dry Hole	3/13/1959	5/18/1959	3,205	11,465	Plug inside casing, plug across Rustler and shoe
42-165-10051	Dry Hole	12/21/1962	1/21/1963	3,256	5,535	Plug Rustler and surface casing shoe
42-165-33522	Plugged-Oil	10/17/1968	4/4/2024	3,260	13,083	Plug inside casing, plug across Rustler and shoe
42-165-38785*	Temporarily Abandoned – Injection Well	7/26/2019	N/A	3,171	7,210	Convert to in-zone monitoring well (Orchard MW No. 2)
42-165-38794*	Shut-In	12/03/2019	N/A	3,174	5,287 (MD 10,728)	Plug and Abandon

*Additional wells that will be reworked

Each plugged and abandoned well will be located using the coordinate locations as found in the TRRC documents, using metal detection and other processes to confirm the locations. If surface casing is not found at a given location, magnetic surveys may be employed to find the well location. Once the locations are found, Orchard Storage will work with the UIC Director to prepare the appropriate plan to reenter and correctly plug each well to protect the USDW.

In general, the following steps will be taken:

- Move in and rig up the workover unit.
- Install the wellhead or other pressure-control equipment.
- Drill out the existing plug to below the surface casing shoe.
- If a plug is required across the San Andres, drill to the base there.
- If needed, set a cement plug inside the casing, across and above the San Andres.
- Set a cement plug across the Rustler formation.
- Set a cement plug across the surface casing shoe.
- Set a cement plug at surface.
- Rig down and move off the location.

3.8.2 Review of Wells Needing Corrective Action

This section provides a summary of the ten wells requiring corrective action and the two additional wells to be acquired. Figures 3-23 to 3-42 provide both the current and the proposed wellbore schematics for each well.

Well Name: G. D. Boldin No. 1
API Number: 42-165-00128

Vertical dry hole well drilled in 1948. No cement plugs were placed across the Rustler or the surface casing shoe. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

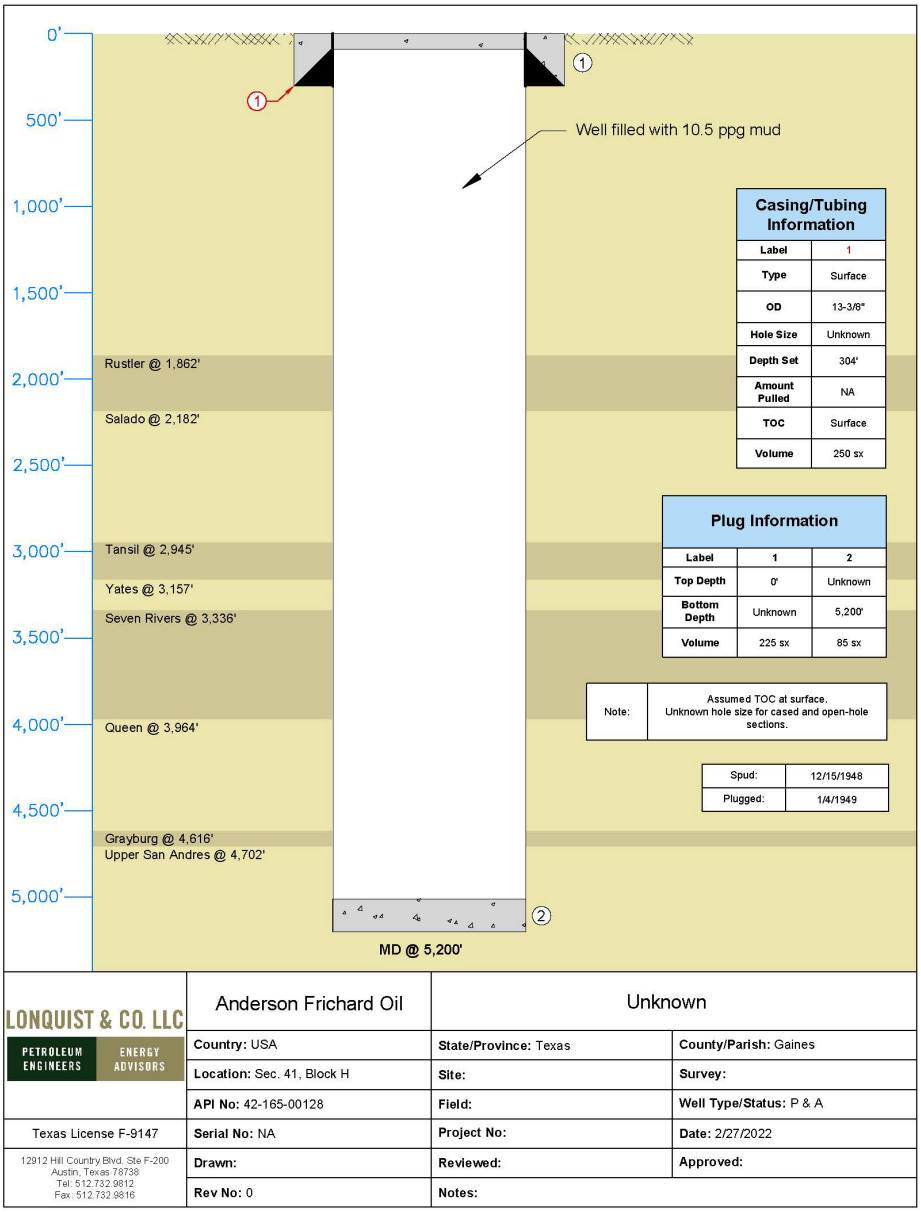


Figure 3-23 – Well API No. 42-165-00128 Current Schematic

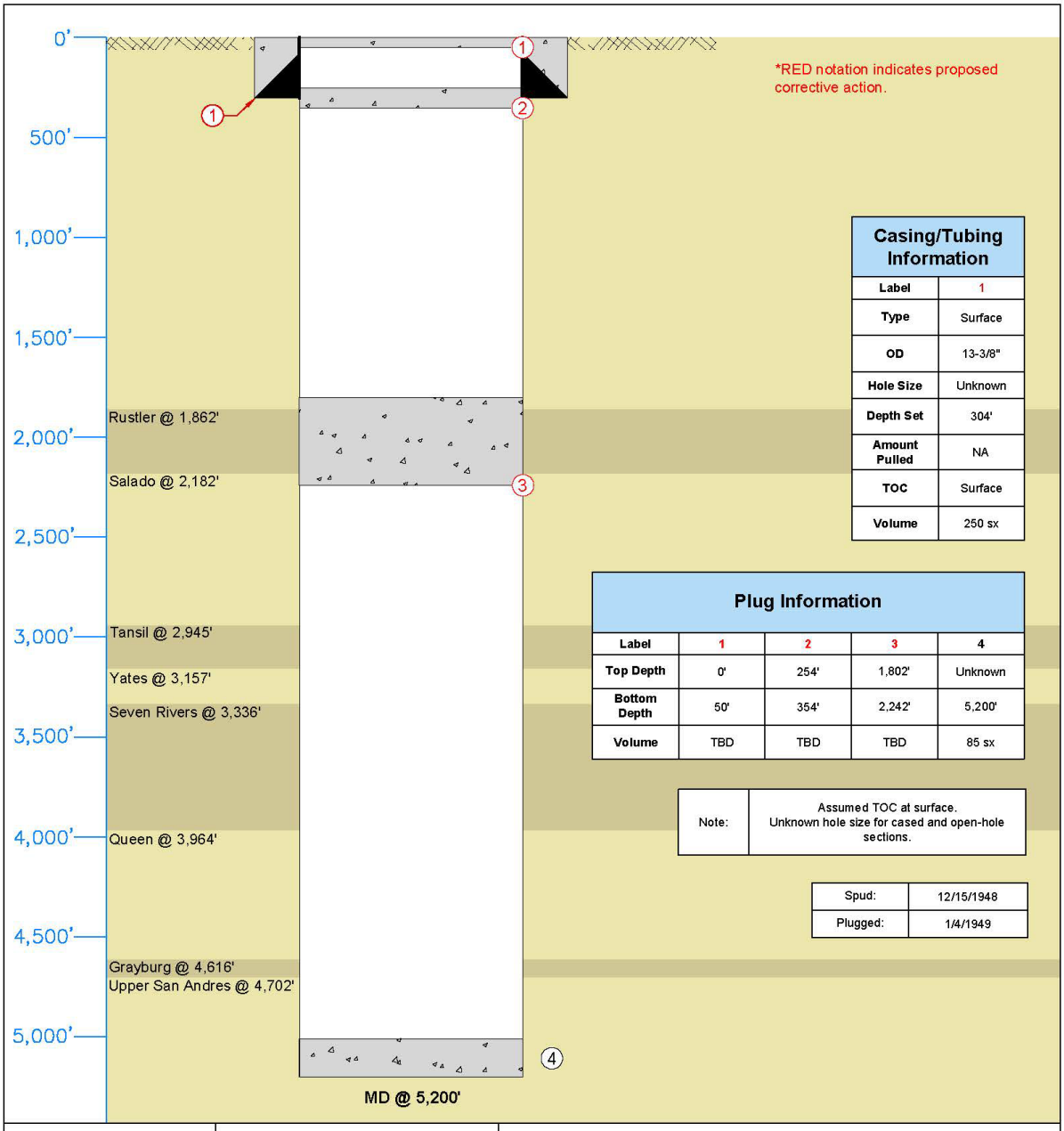


Figure 3-24 – Well API No. 42-165-00128 Proposed Plugged Schematic

Well Name: J.D. Mills No. 1
API Number: 42-165-00908

The TRRC records for this well indicate that its drilling permit was cancelled in 1959. However, SPGlobal (formally IHS and PI) have scout tickets that show the well was drilled and surface casing set at 355 ft. No plugging records were found, but it was unlikely to have been plugged across the Rustler. If the well can be located, Orchard will attempt to reenter the well to place a 150 ft corrosion-resistant cement or equivalent plug from 4,800 to 4,950 ft, a cement plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

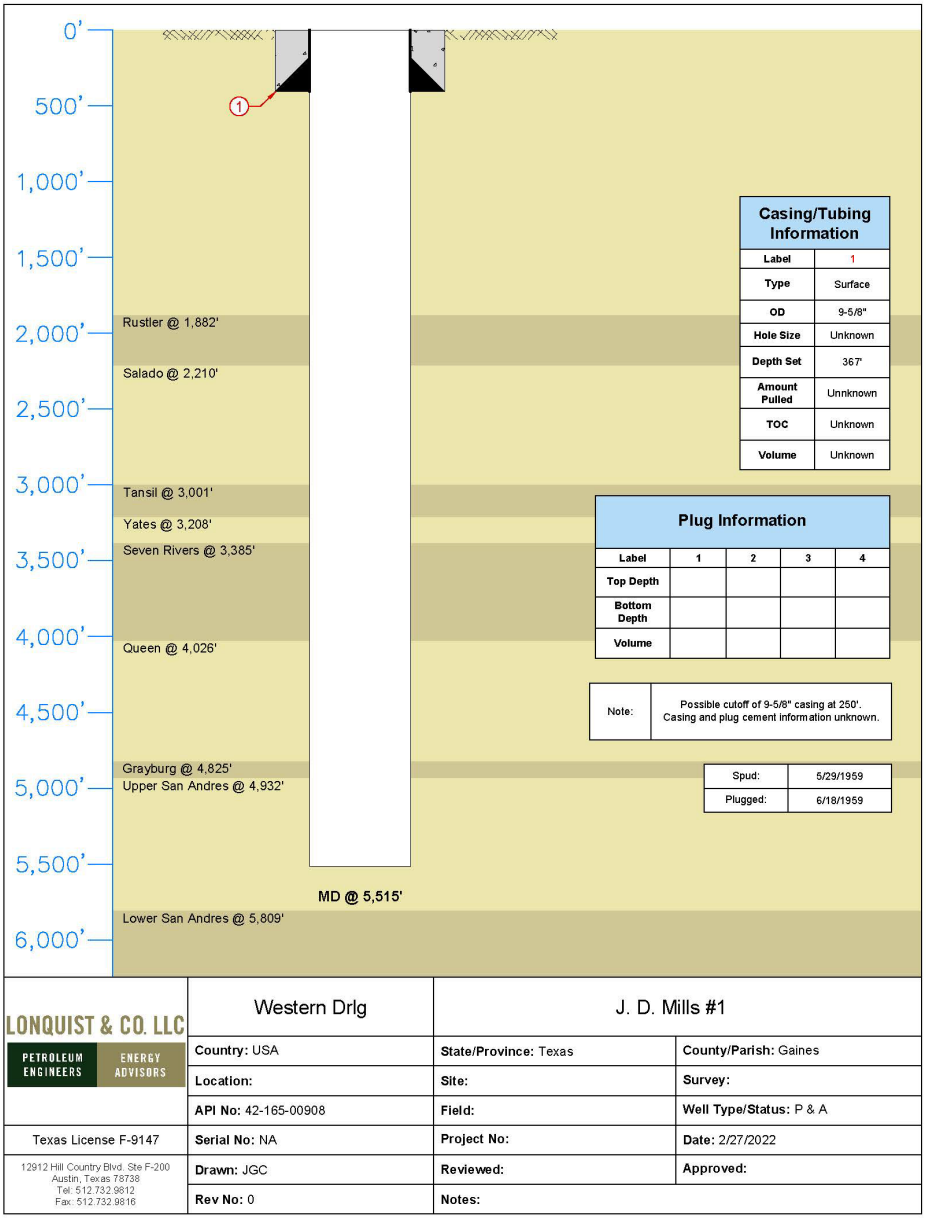


Figure 3-25 – Well API No. 42-165-00908 Current Schematic

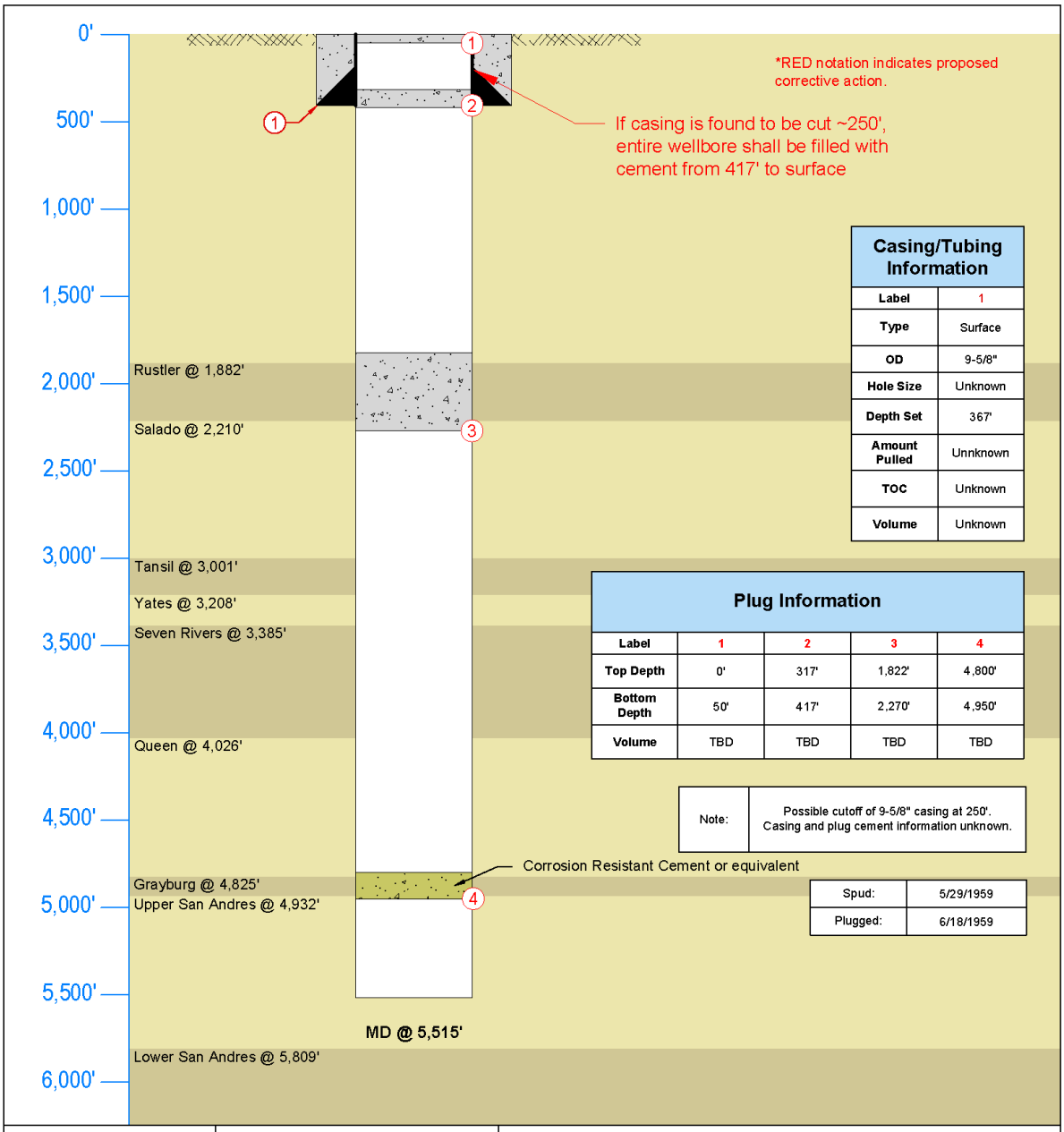


Figure 3-26 – Well API No. 42-165-00908 Proposed Plugged Schematic

Well Name: Reid No. 1
API Number: 42-165-01063

Vertical dry hole well drilled in 1958. No cement plugs were placed across the Rustler. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

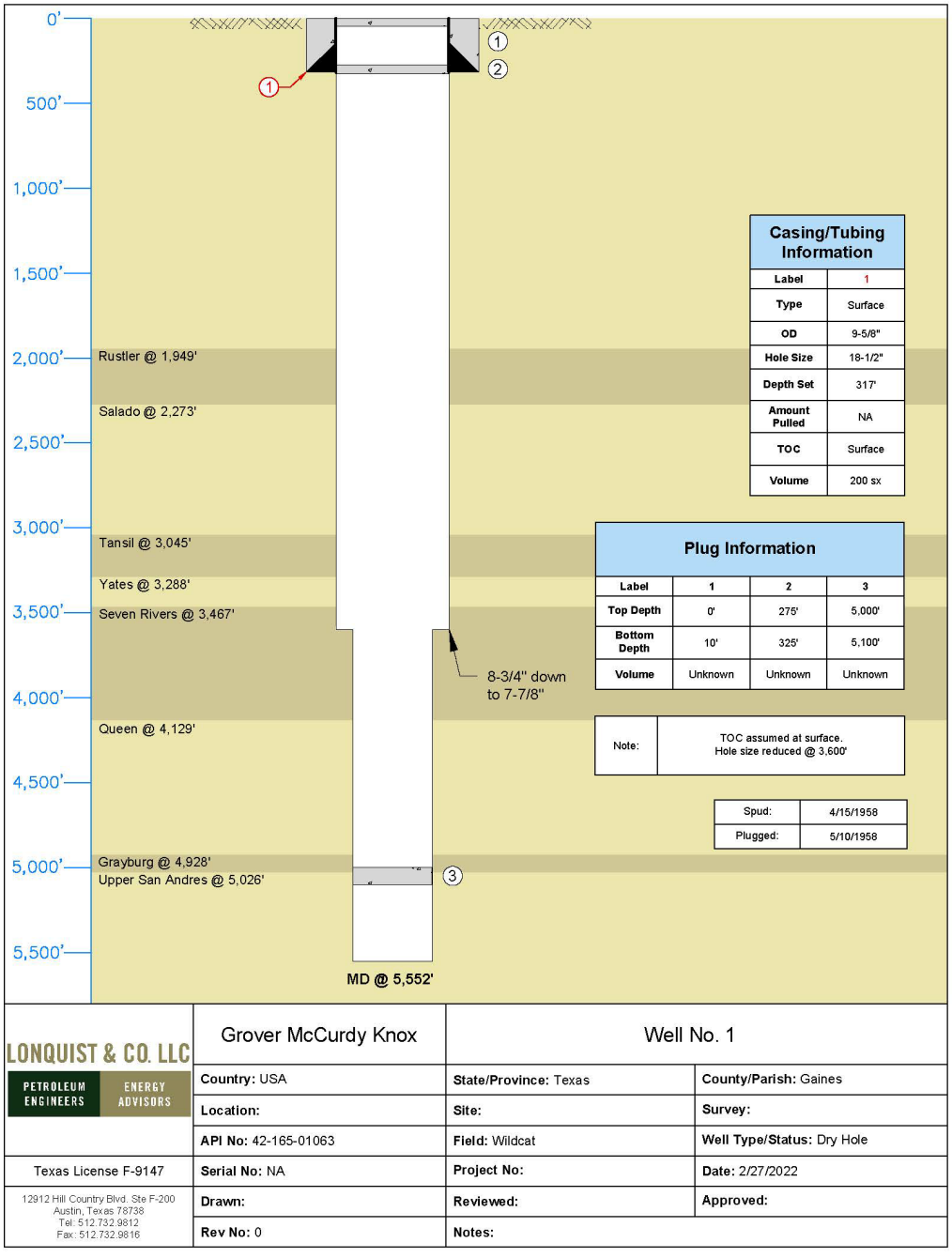


Figure 3-27 – Well API No. 42-165-01063 Current Schematic

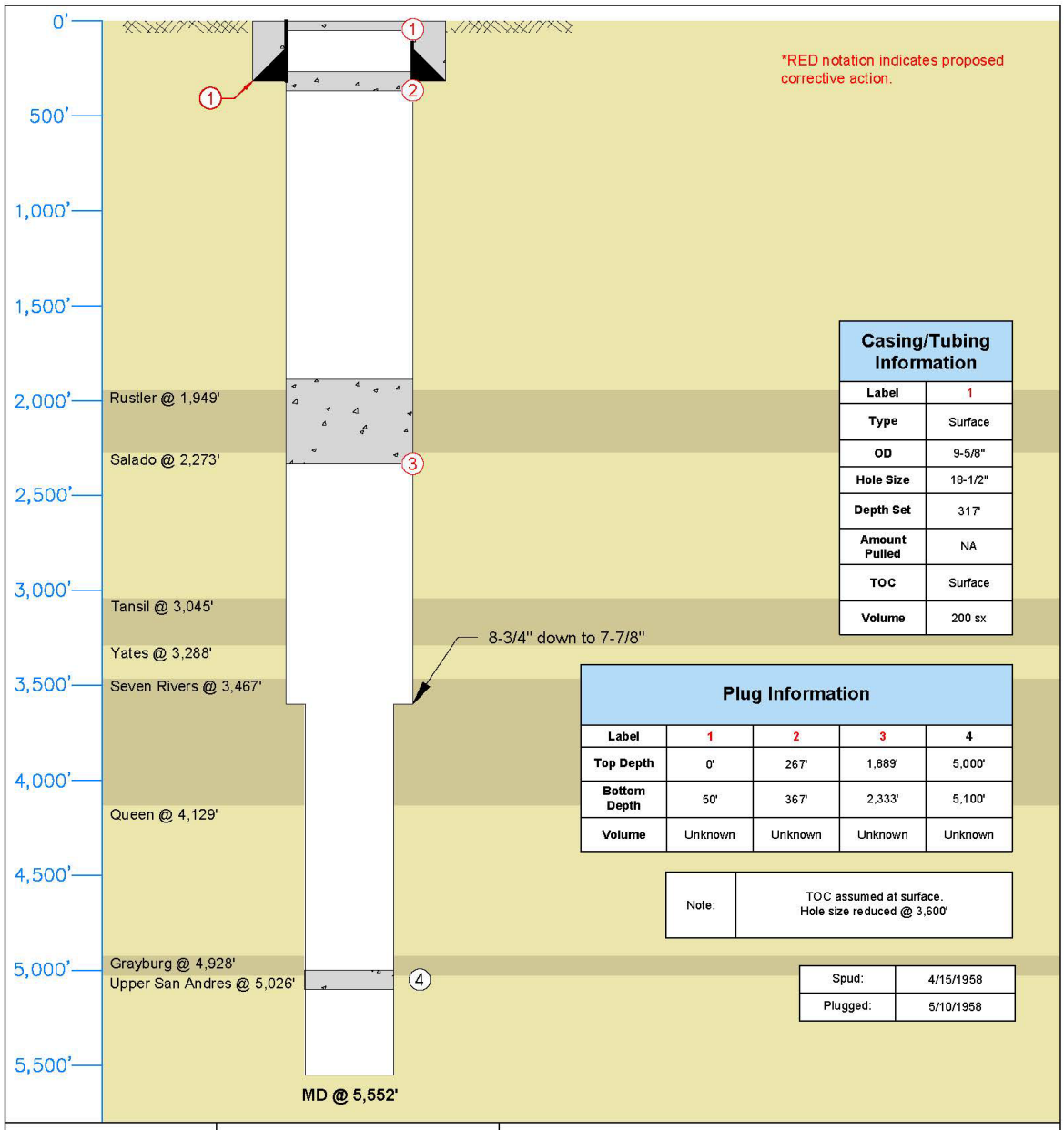


Figure 3-28 – Well API No. 42-165-01063 Proposed Plugged Schematic

Well Name: C. H. Doak No. 1
API Number: 42-165-02139

Vertical dry hole well drilled in 1938. No cement plugs were placed across the Rustler or the surface casing shoe. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

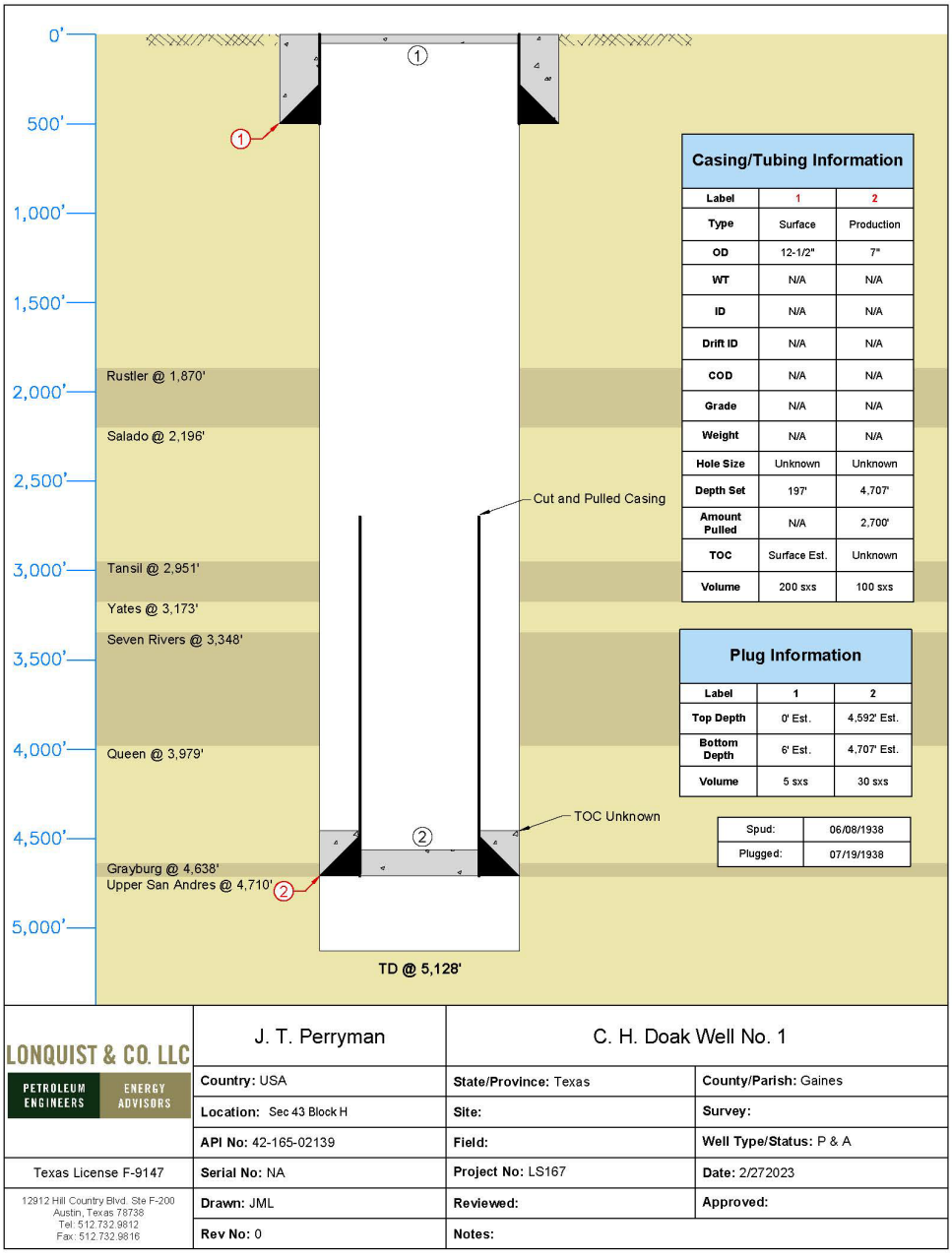


Figure 3-29 – Well API No. 42-165-02139 Current Schematic

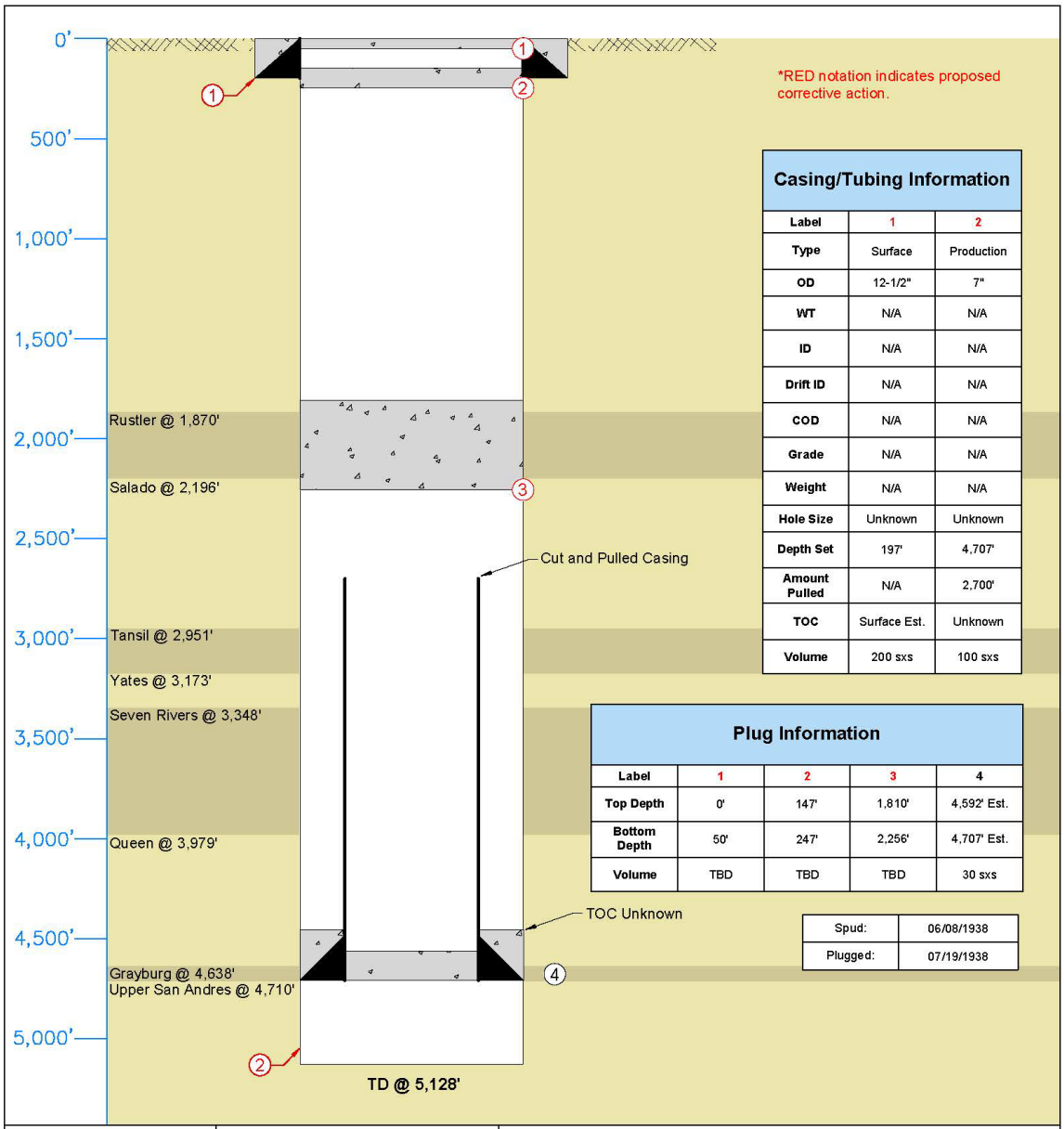


Figure 3-30 – Well API No. 42-165-02139 Proposed Plugged Schematic

Well Name: J. H. Brown No. 1
API Number: 42-165-02216

Vertical dry hole well drilled in 1938. No cement plugs were placed across the Rustler or the surface casing shoe. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

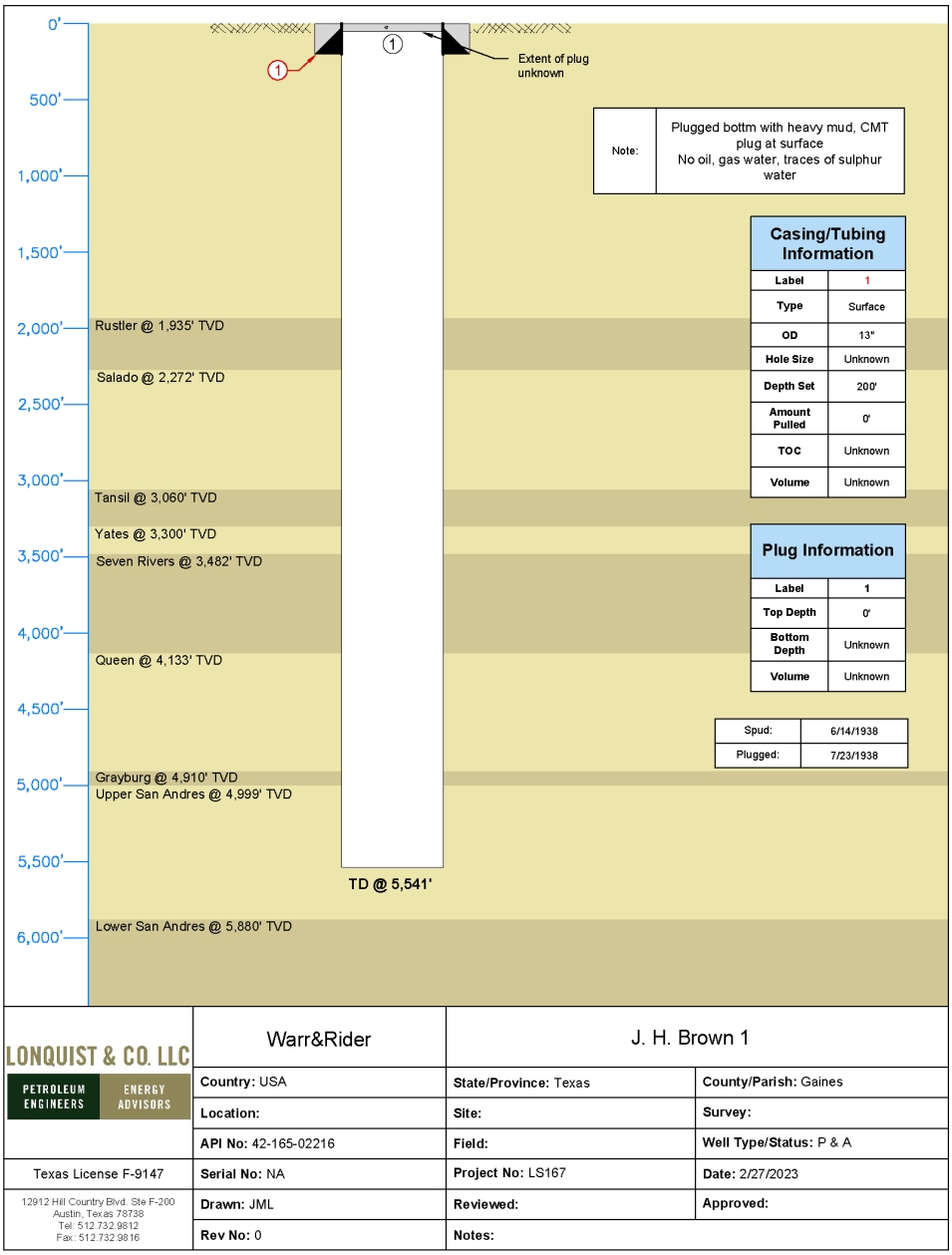
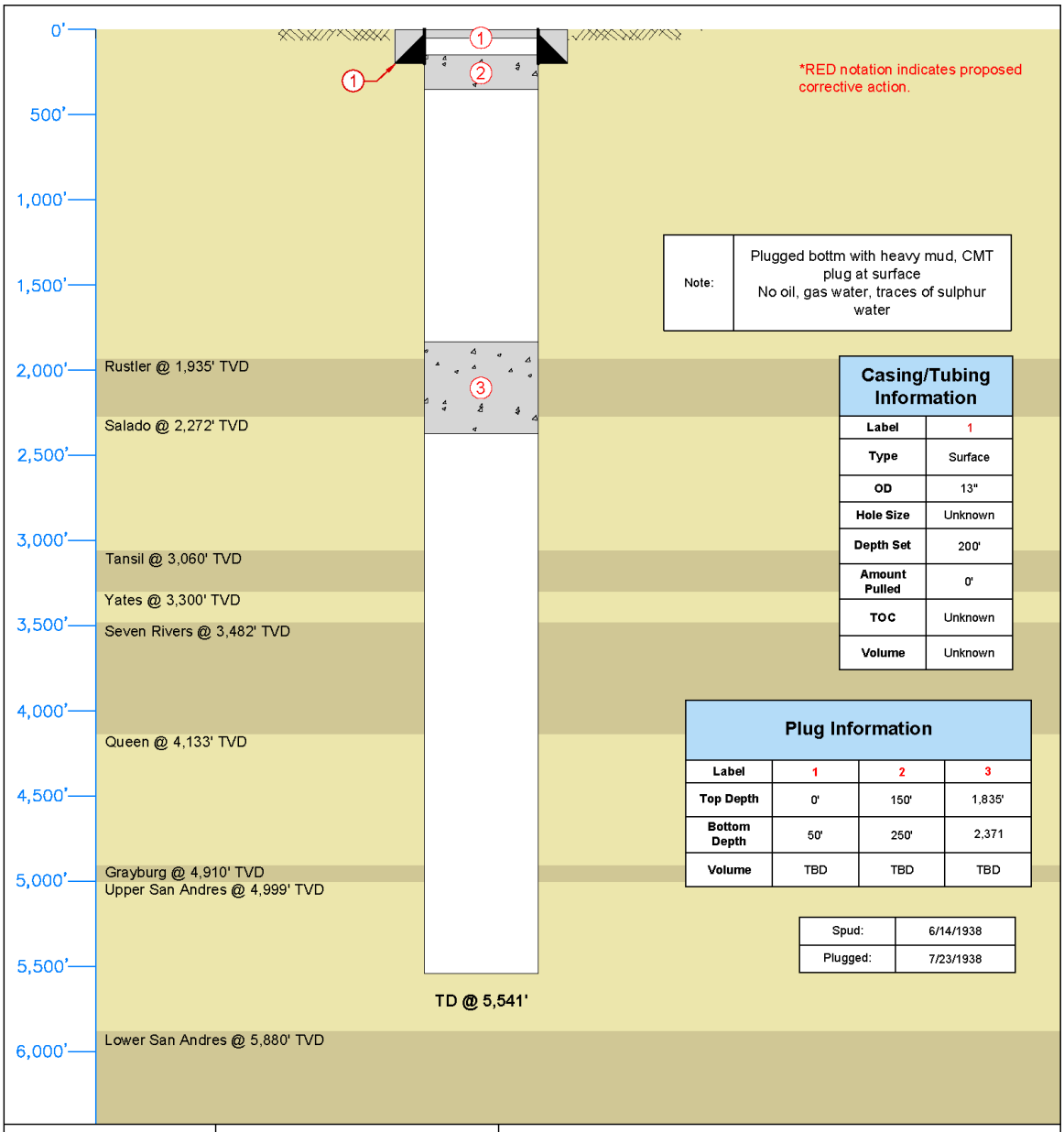


Figure 3-31 – Well API No. 42-165-02216 Current Schematic

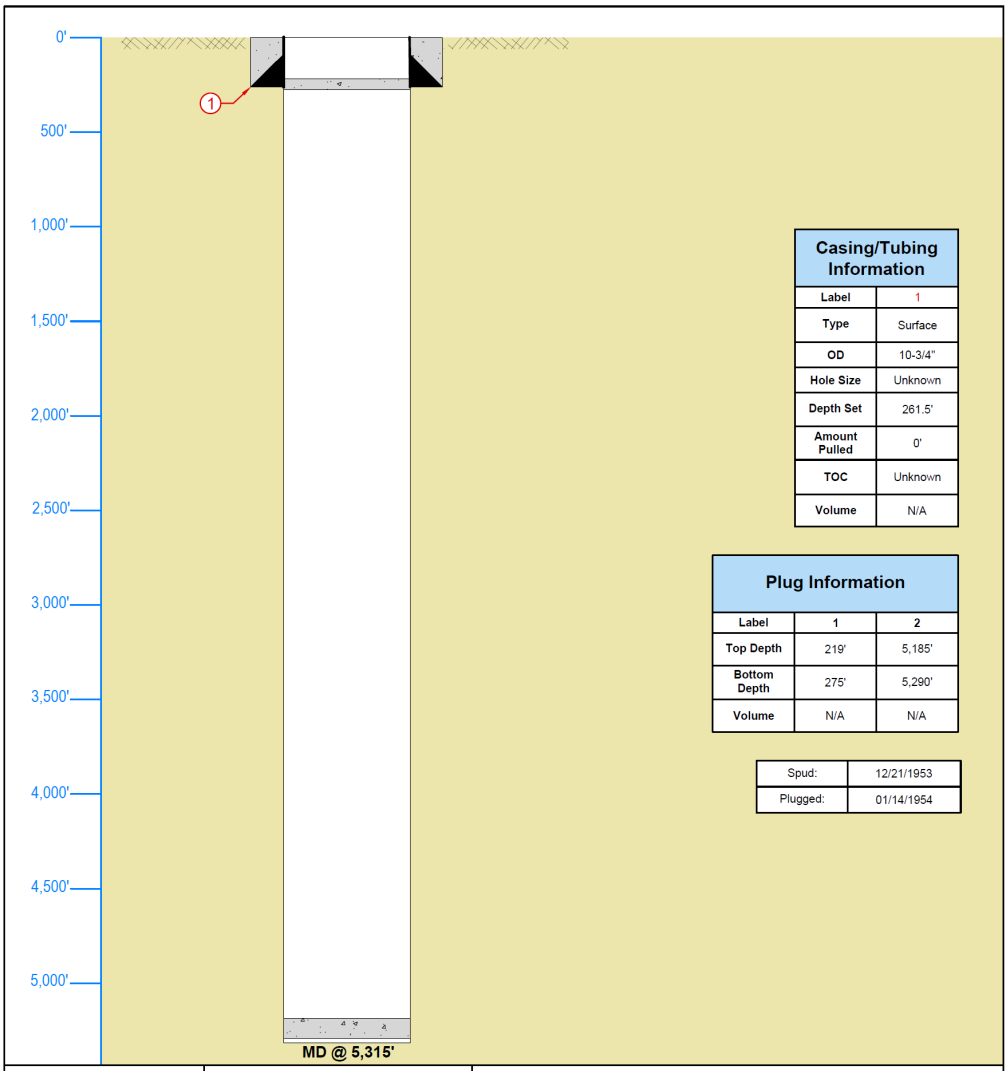


LONQUIST & CO. LLC PETROLEUM ENGINEERS | ENERGY ADVISORS	Warr&Rider	J. H. Brown 1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location:	**Site:**	**Survey:**
	API No: 42-165-02216	**Field:**	**Well Type/Status:** Corrective Action
Texas License F-9147	**Serial No:** NA	**Project No:** LS167	**Date:** 2/27/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JML	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 3-32 – Well API No. 42-165-02216 Proposed Plugged Schematic

Well Name: W.M. Richards NO. 1
API Number: 42-165-02526

Vertical dry hole well drilled in 1953. No cement plugs were placed across the Rustler. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.



LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Fred W. Shield	W. M. Richards No. 1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: Sec 60 Block H	**Site:**	**Survey:**
	API No: 42-165-02526	**Field:**	**Well Type/Status:** P & A
Texas License F-9147	**Serial No:** NA	**Project No:** LS167	**Date:** 1/10/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JML	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 3-33 – Well API No. 42-165-02526 Current Schematic

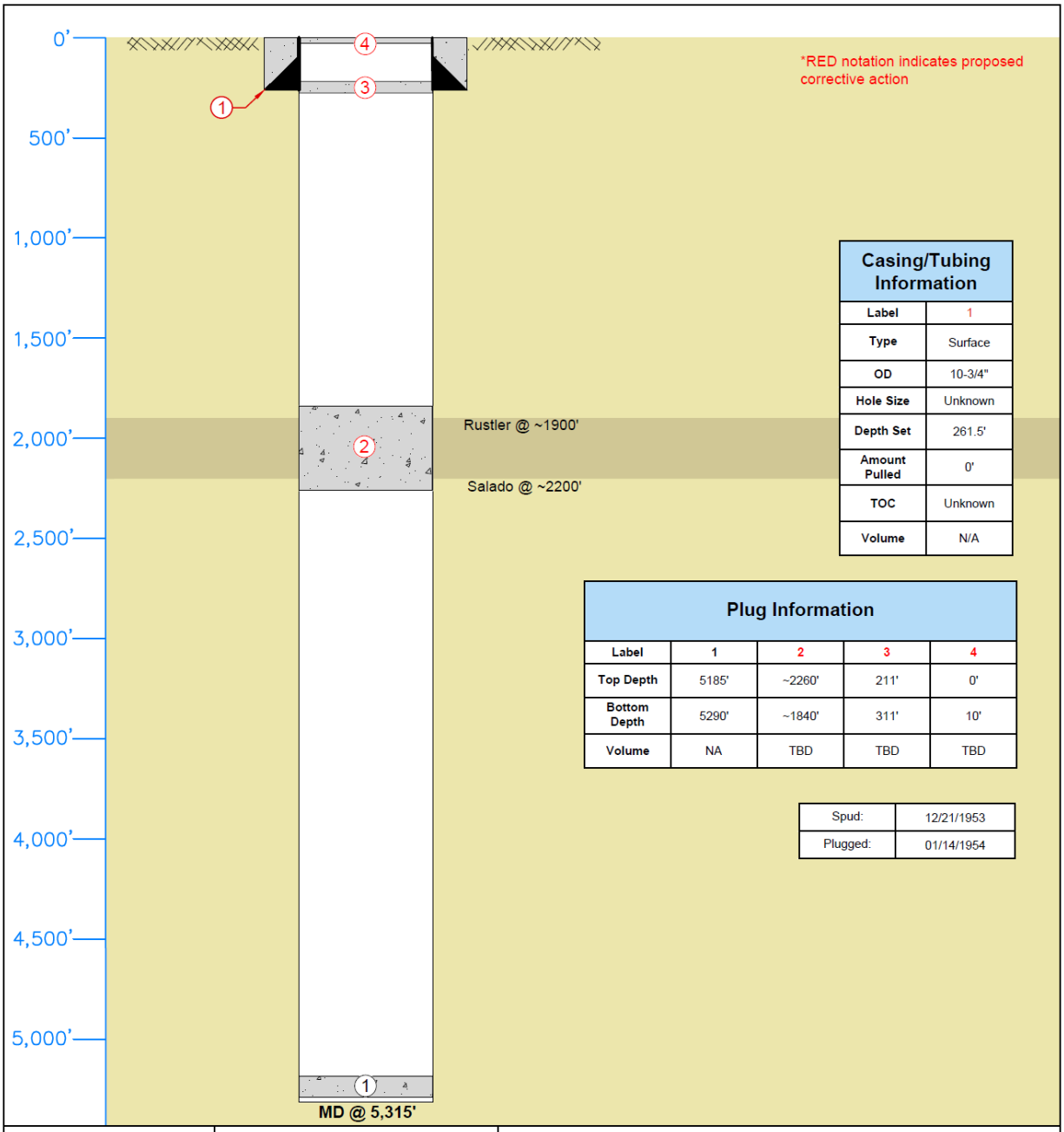


Figure 3-34 – Well API No. 42-165-02526 Proposed Plugged Schematic

Well Name: Ruth McGill Dodge No. 2
API Number: 42-165-02580

Vertical dry hole well drilled in 1944. No plugging records were found for this well, but it was unlikely plugged across the Rustler. This well does have casing across the Rustler, but the top of the cement is unknown. Orchard proposes reentry to perforate and squeeze cement at 60 ft below the base of the Rustler formation, place 100 ft of cement across the surface casing shoe, and place a surface plug from 0-50 ft.

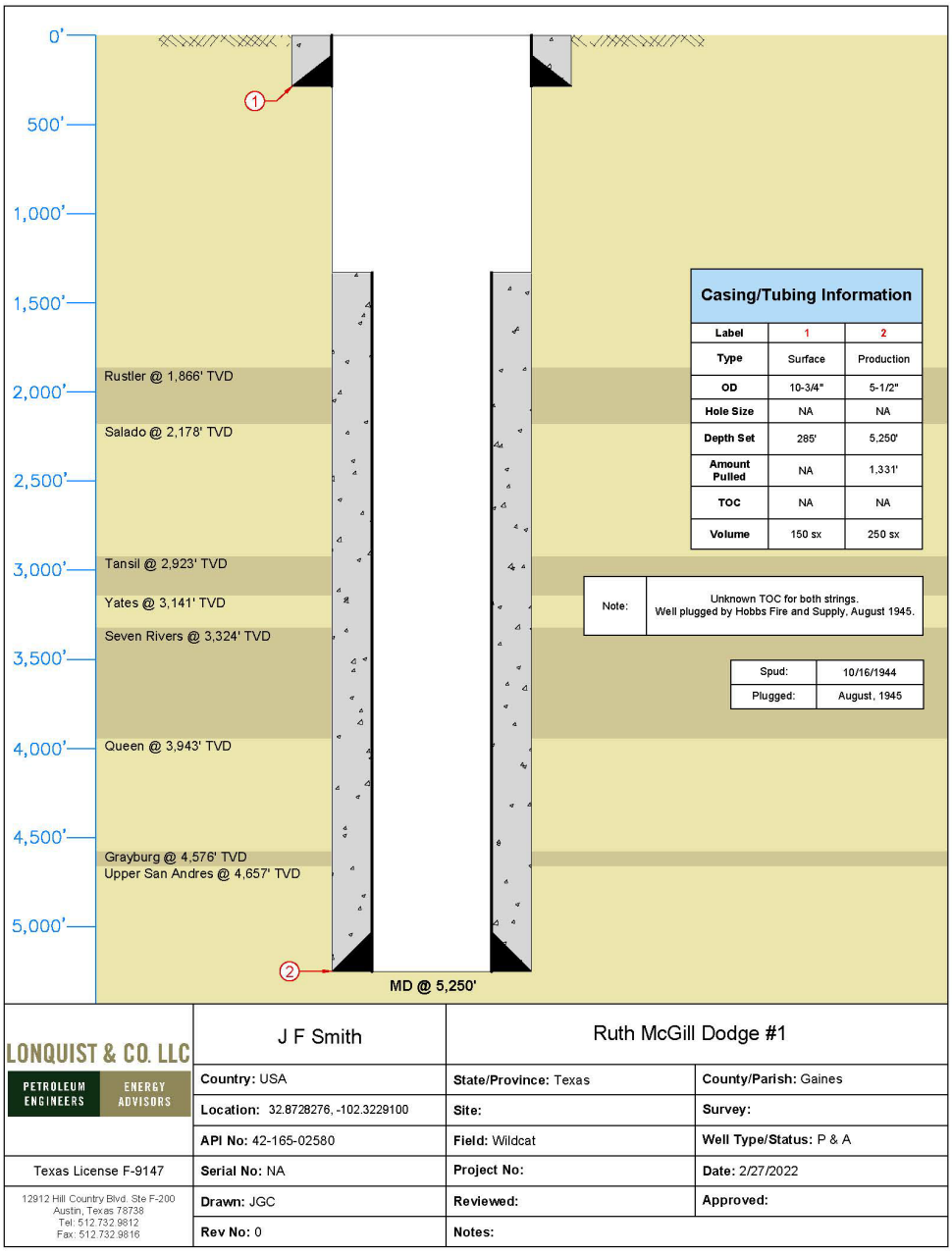
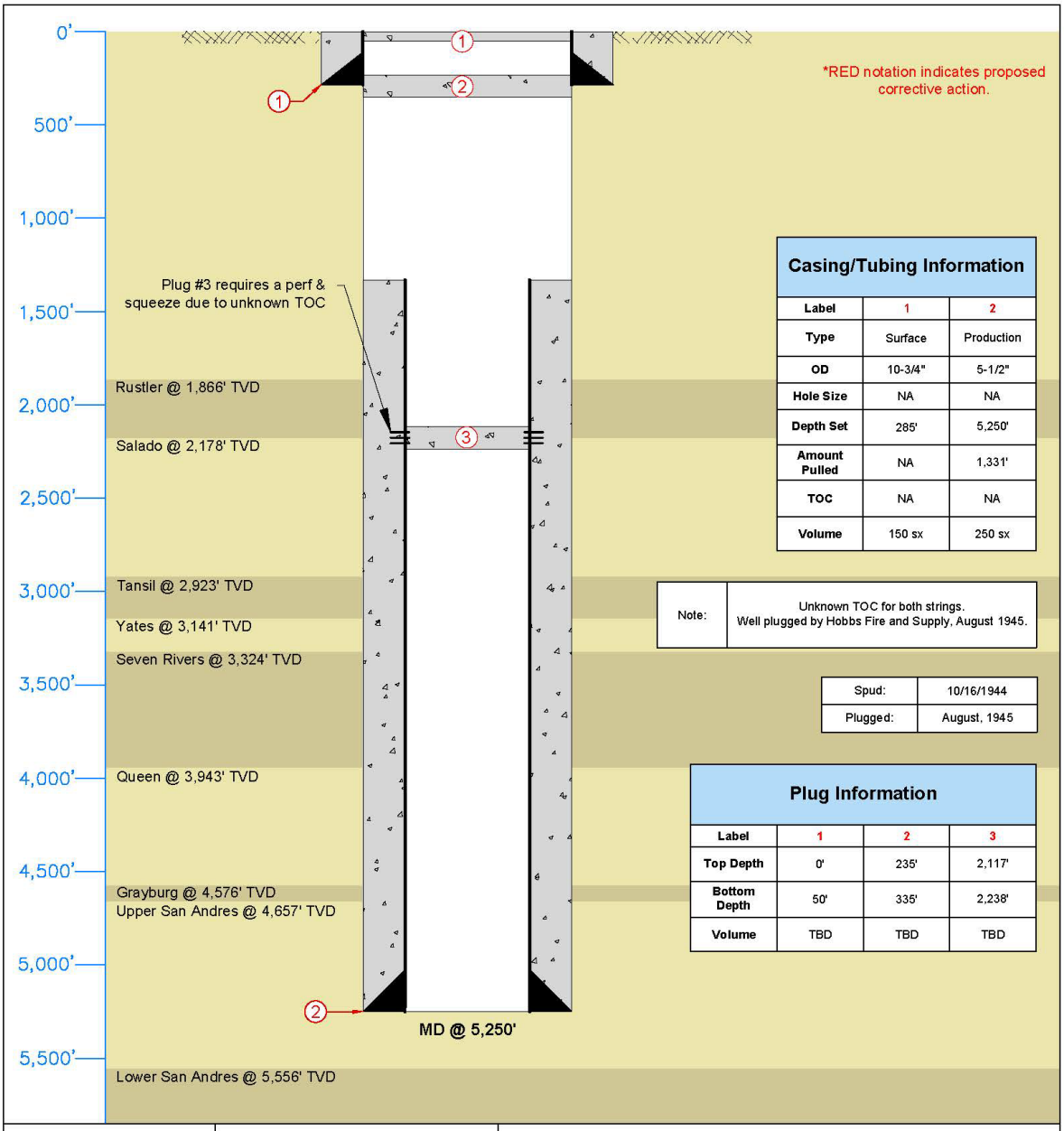


Figure 3-35 – Well API No. 42-165-02580 Current Schematic



LONQUIST & CO. LLC PETROLEUM ENGINEERS | ENERGY ADVISORS	J F Smith	Ruth McGill Dodge #1	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: 32.8728276, -102.3229100	**Site:**	**Survey:**
	API No: 42-165-02580	**Field:** Wildcat	**Well Type/Status:** Corrective Action
Texas License F-9147	**Serial No:** NA	**Project No:**	**Date:** 2/27/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 3-36 – Well API No. 42-165-02580 Proposed Plugged Schematic

Well Name: Ida Huckabee No. 1
API Number: 42-165-03242

Vertical dry hole well drilled in 1959. No plugging records were found for this well, but it was unlikely plugged across the Rustler. However, the well was cased and cemented across the Rustler. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

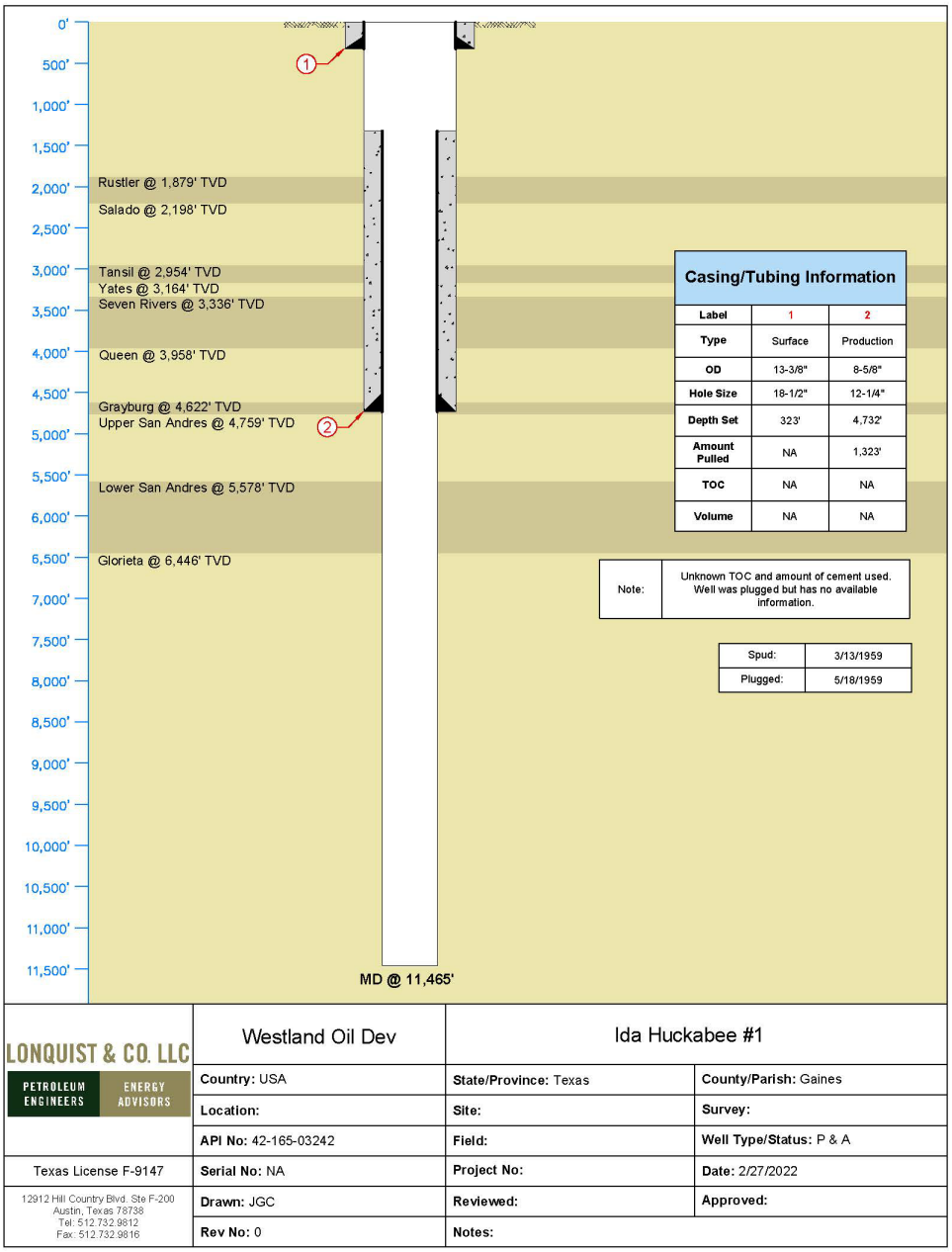


Figure 3-37 – Well API No. 42-165-03242 Current Schematic

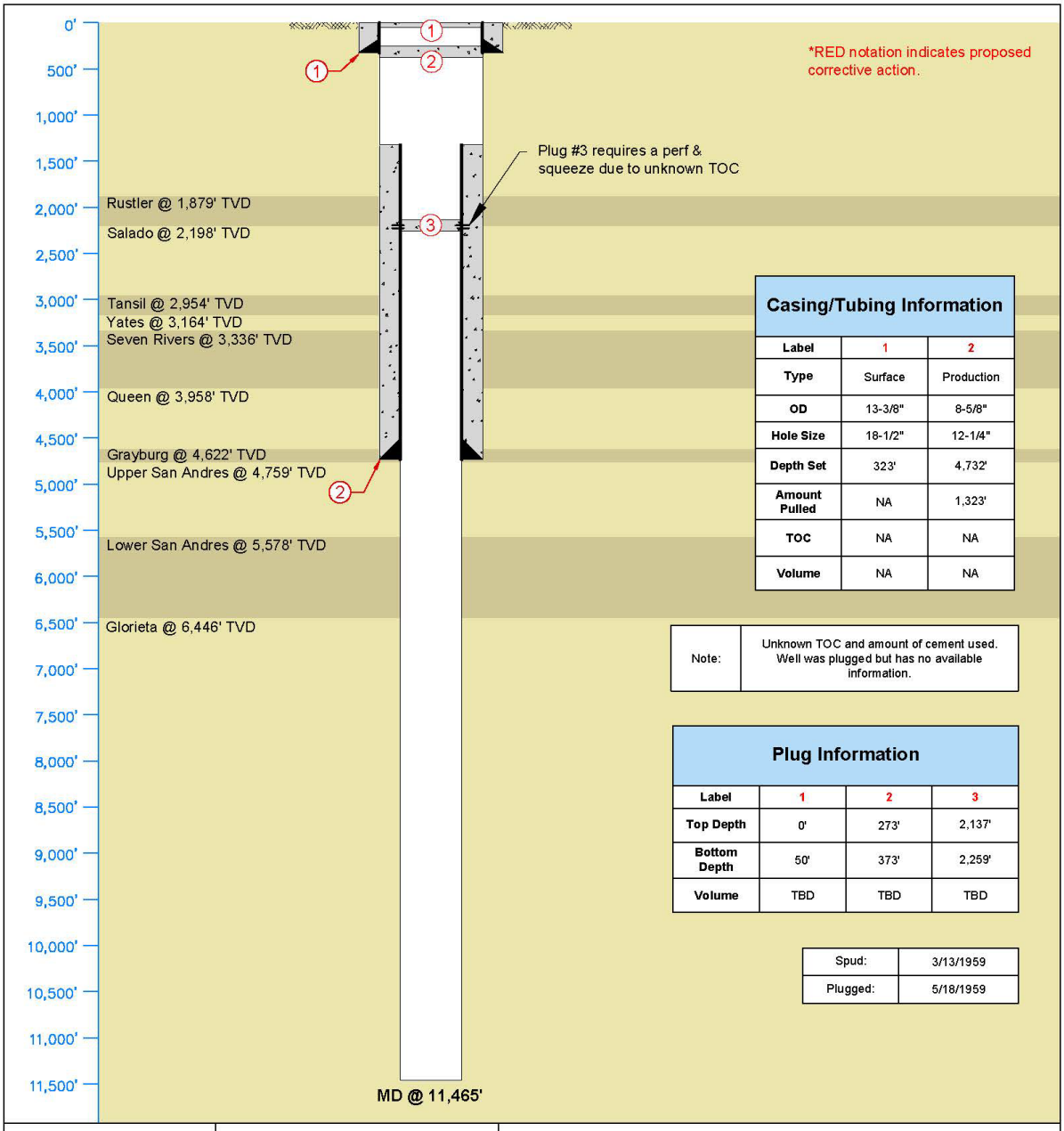


Figure 3-38 – Well API No. 42-165-03242 Proposed Plugged Schematic

Well Name: Winnie Lee Edmonson No. 1
API Number: 42-165-10051

Vertical dry hole well drilled in 1962. No cement plugs were placed across the Rustler or the surface casing shoe. Orchard proposes reentry to place a plug from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and a surface plug from 0-50 ft.

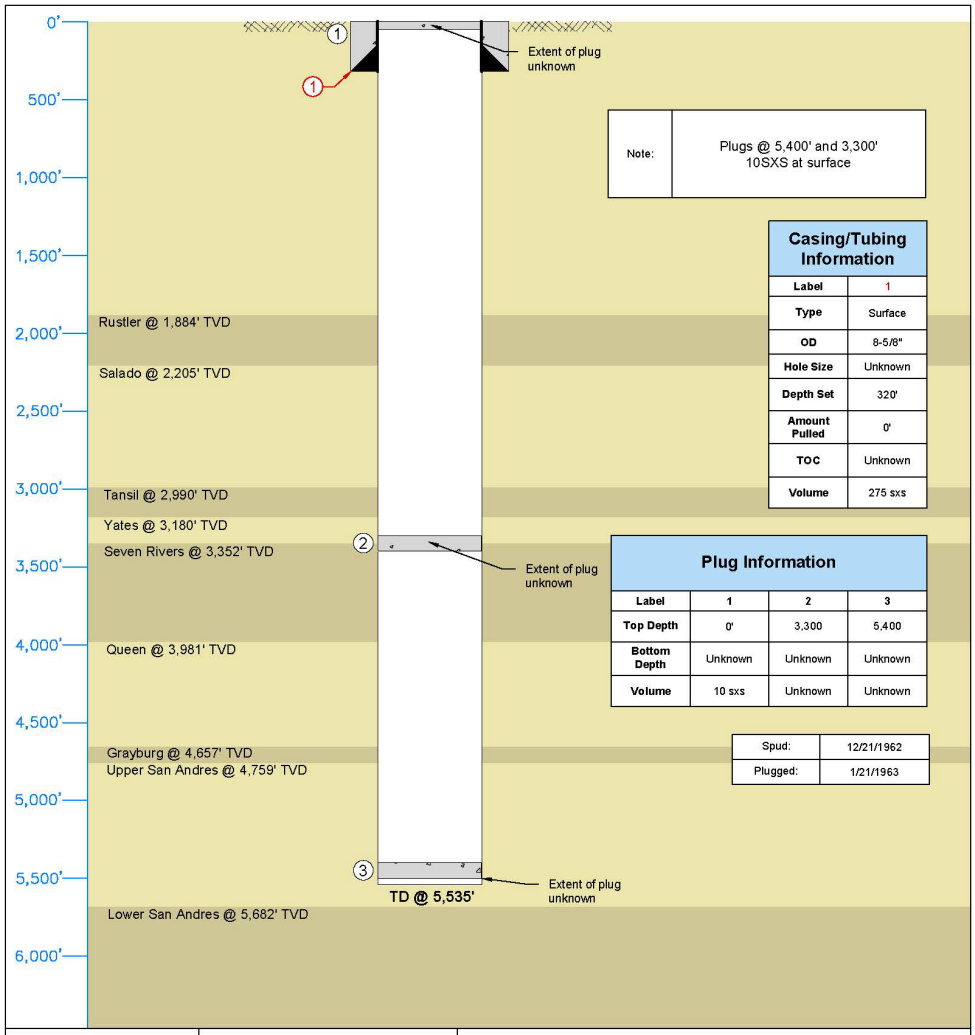


Figure 3-39 – Well API No. 42-165-10051 Current Schematic

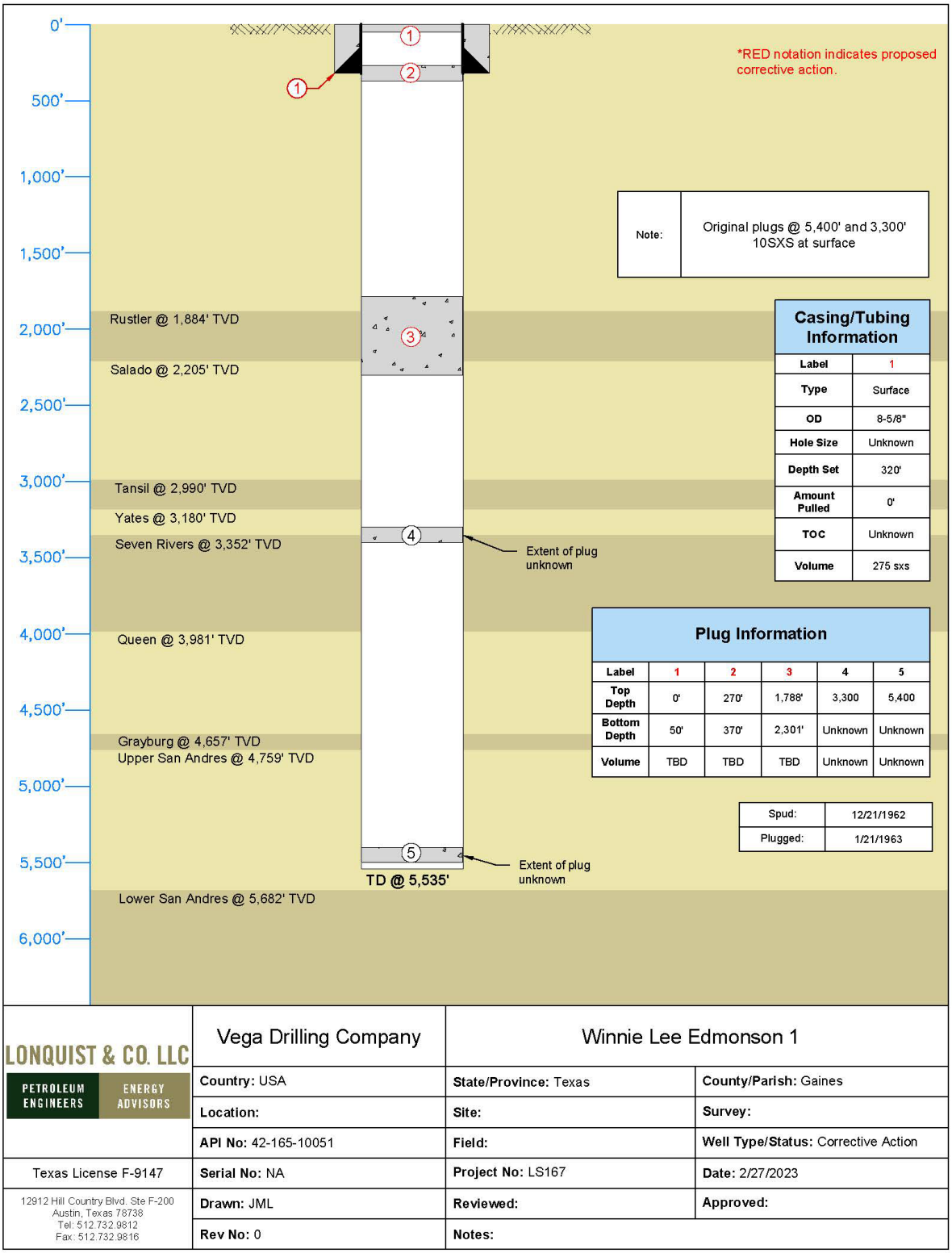


Figure 3-40 – Well API No. 42-165-10051 Proposed Plugged Schematic

Well Name: C. D. Butchee “14” No. 1
API Number: 42-165-33522

Vertical oil well drilled and completed in 1968. This well was plugged in 2024 and met the TRRC standards. However, no cement was placed across the San Andres or the Rustler. Orchard proposes reentry to place a plug across the upper San Andres. The plugs will be placed from 60 ft below the base of the Rustler formation to 60 ft above the top of the Rustler, 100 ft across the surface casing shoe, and at the surface from 0-50 ft.

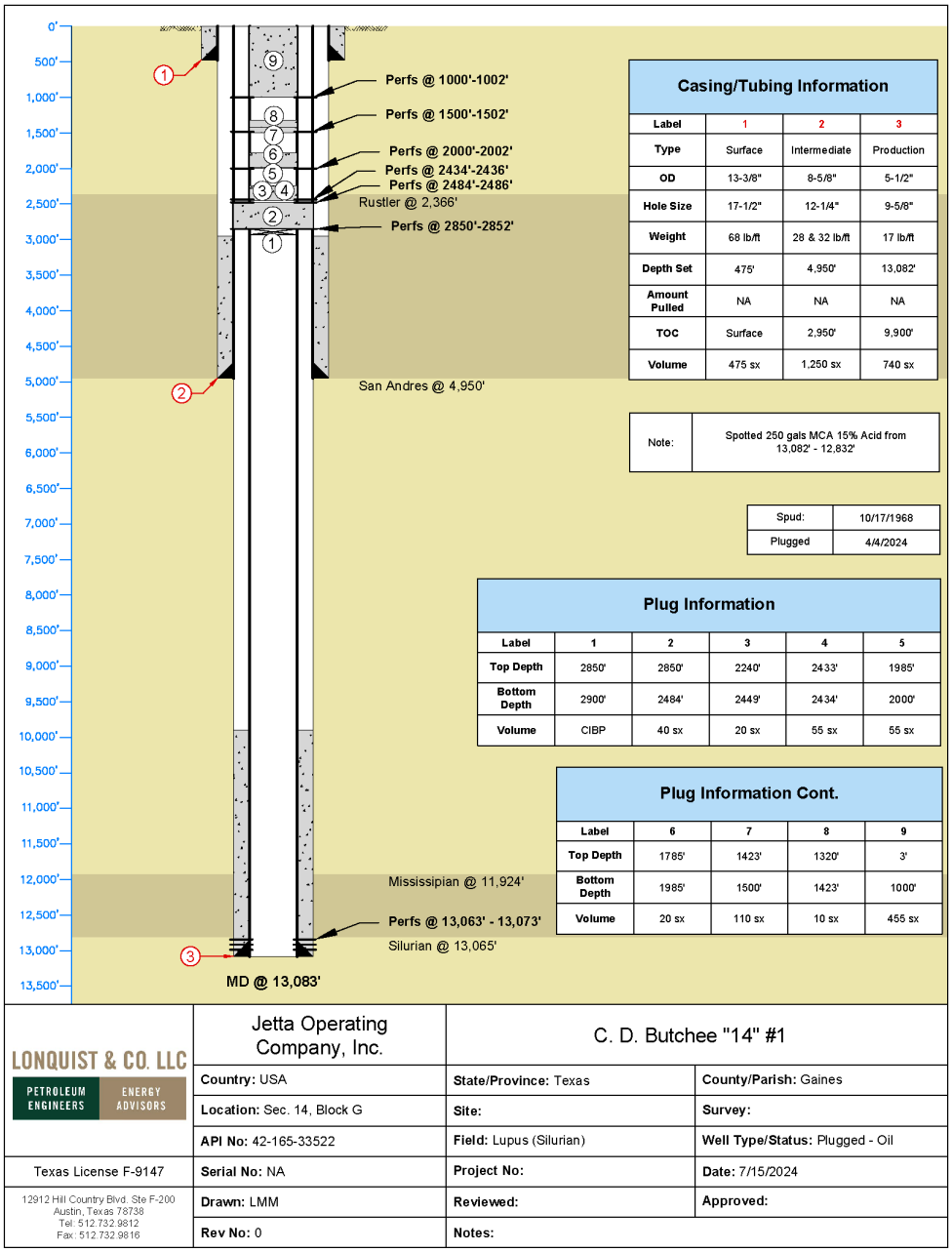


Figure 3-41 – Well API No. 42-165-33522 Current Schematic

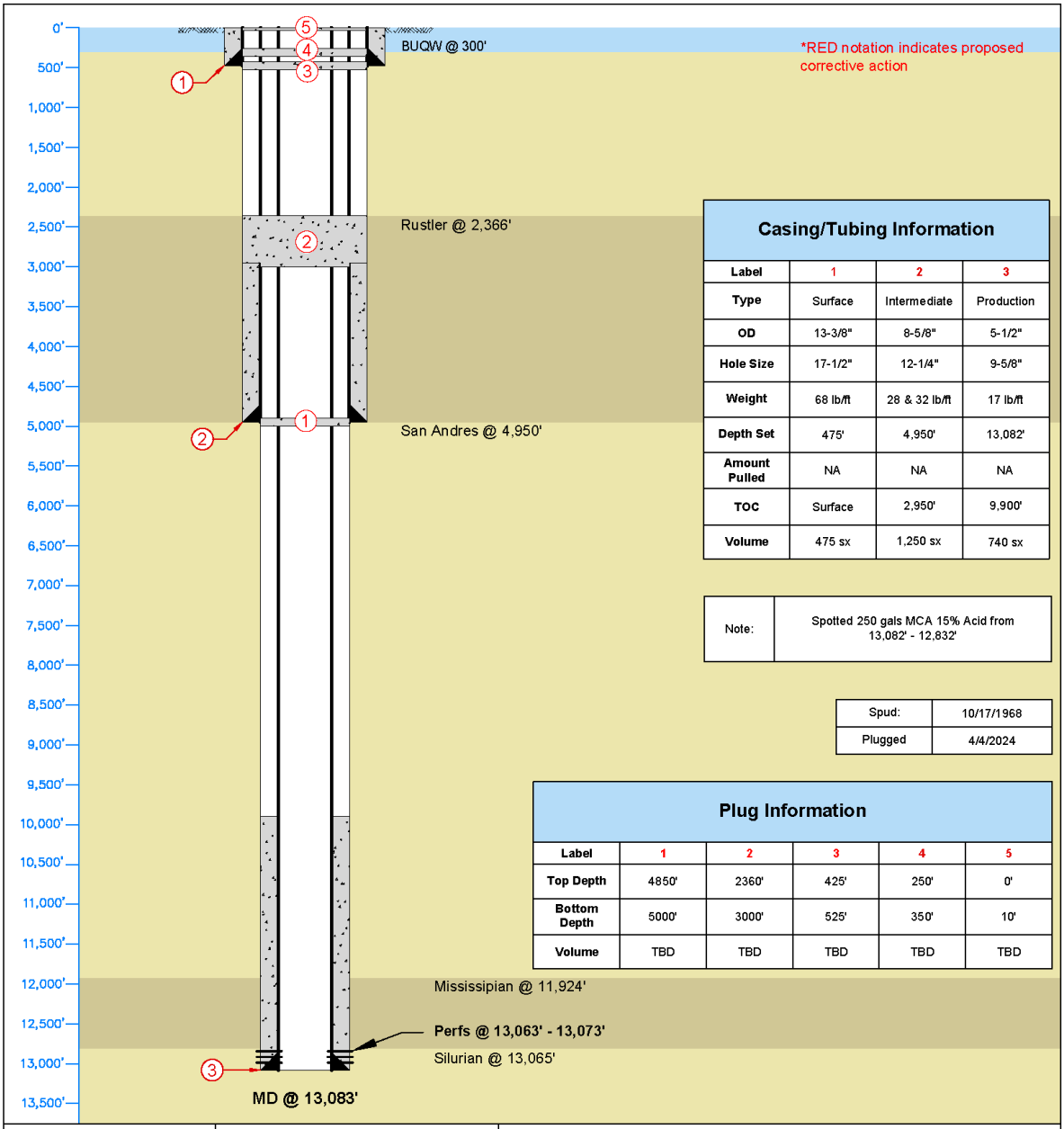
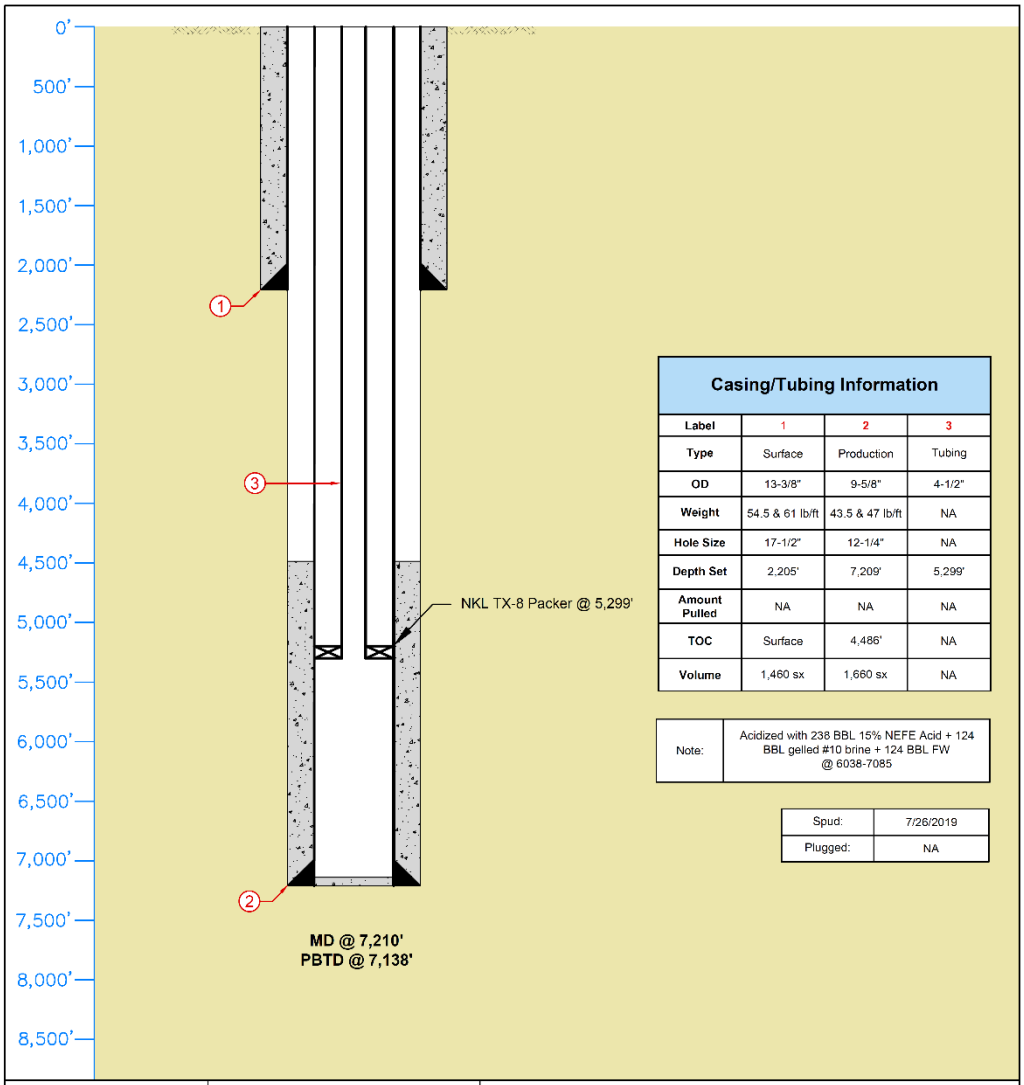


Figure 3-42 – Well API No. 42-165-33522 Proposed Plugged Schematic

Well Name: Valiant No. 1D
API Number: 42-165-38785

Vertical well drilled and completed as an injection well in 2019. The surface casing was appropriately set and cemented to protect the USDW. The injection interval included the San Andres, Glorieta and Clearfork formations. Injection only occurred between January and April 2020. The well is currently listed as temporarily abandoned by the TRRC. Orchard has acquired this well and plans to convert it to an in-zone monitoring well as shown in Figure 3-51.



Casing/Tubing Information

Label	1	2	3
Type	Surface	Production	Tubing
OD	13-3/8"	9-5/8"	4-1/2"
Weight	54.5 & 61 lb/ft	43.5 & 47 lb/ft	NA
Hole Size	17-1/2"	12-1/4"	NA
Depth Set	2,205'	7,209'	5,299'
Amount Pulled	NA	NA	NA
TOC	Surface	4,486'	NA
Volume	1,460 sx	1,660 sx	NA

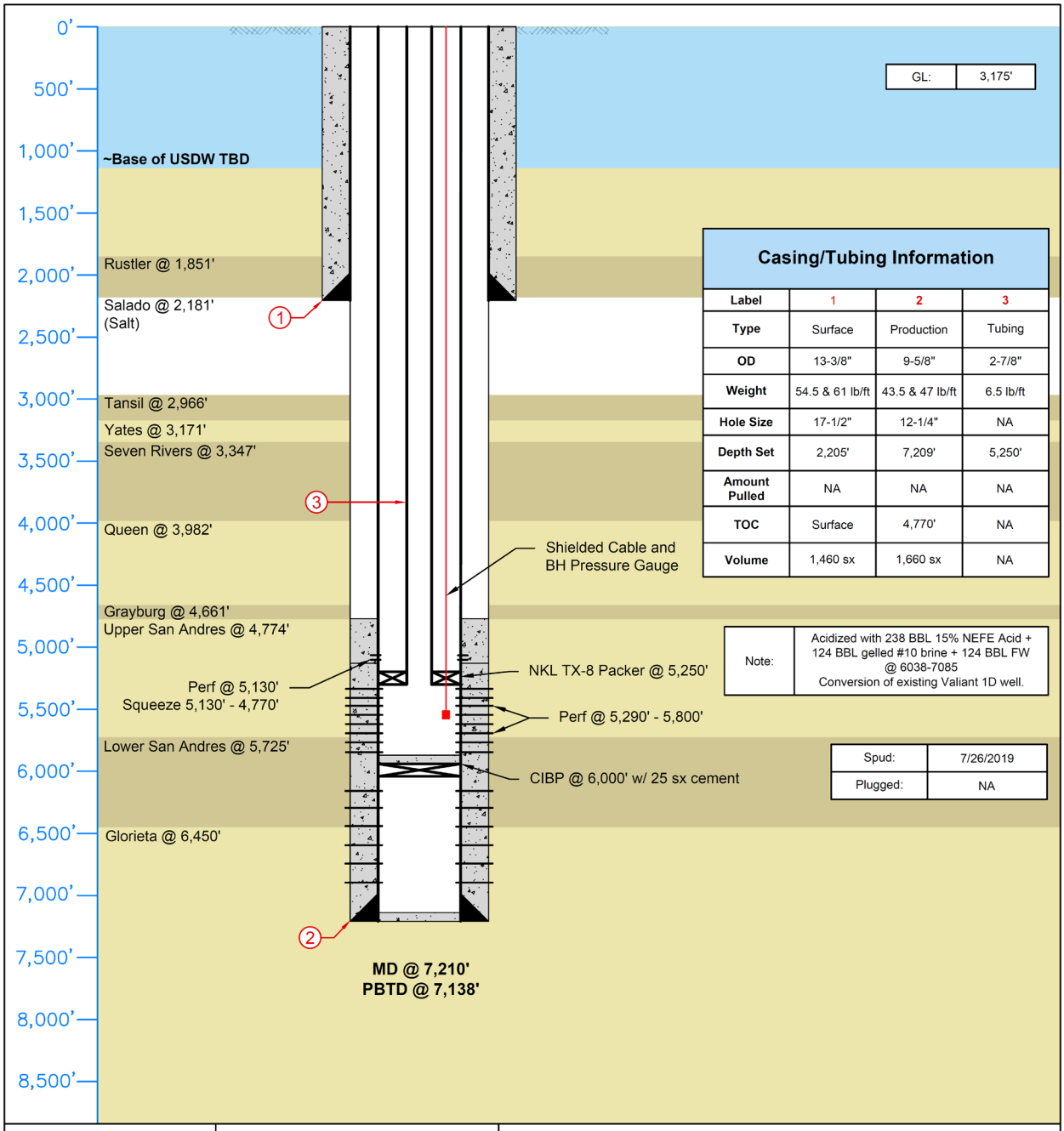
Note:	Acidized with 238 BBL 15% NEFE Acid + 124 BBL gelled #10 brine + 124 BBL FW @ 6038-7085

Spud:	7/26/2019
Plugged:	NA

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
Texas License F-9147
12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Reliance Energy, Inc.	Valiant 1D	
Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
Location: 32.855656, -102.383807	**Site:**	**Survey:**
API No: 42-165-38785	**Field:**	**Well Type/Status:** Injection (Shut-in)
Serial No: NA	**Project No:**	**Date:** 1/10/2023
Drawn: JGC	**Reviewed:**	**Approved:**
Rev No: 0	**Notes:**	

Figure 3-43 – Well API No. 42-165-38785 Current Schematic



LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #2 Monitoring Well	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: 32.855656, -102.383807	**Site:**	**Survey:**
	API No: 42-165-38785	**Field:**	**Well Type/Status:** Monitor
Texas License F-9147	**Serial No:** NA	**Project No:**	**Date:** 4/11/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 3-44 – Well API No. 42-165-38785 Proposed Monitoring Well Schematic

Well Name: Garver-Alexander 84 1H
API Number: 42-165-38794

Horizontal well drilled and completed in late 2019/early 2020. The well was not productive and is listed as shut-in by the TRRC. The surface casing was appropriately set and cemented to protect the USDW. Orchard has acquired this well and will P&A it, as shown in Figure 3-53.

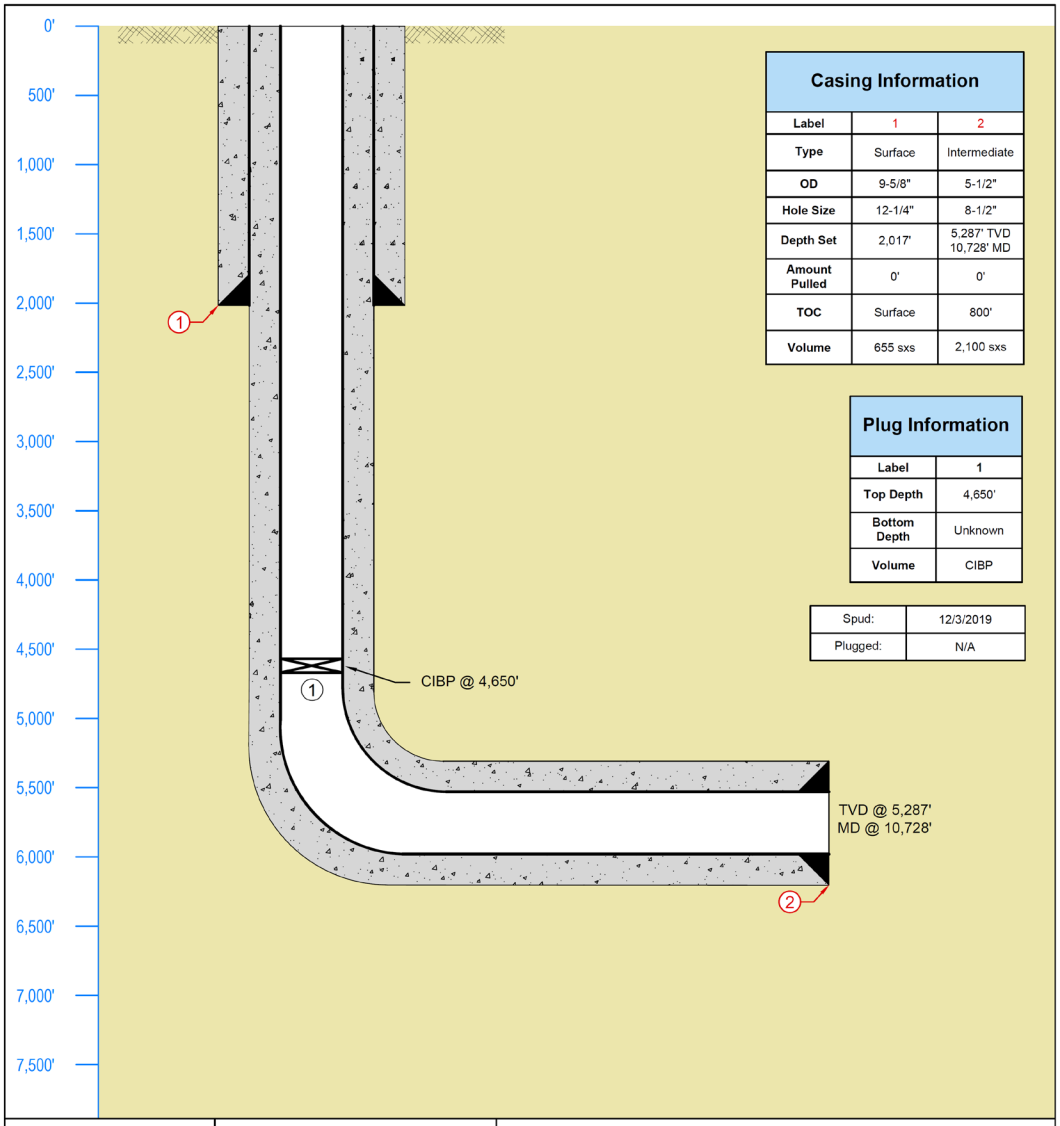
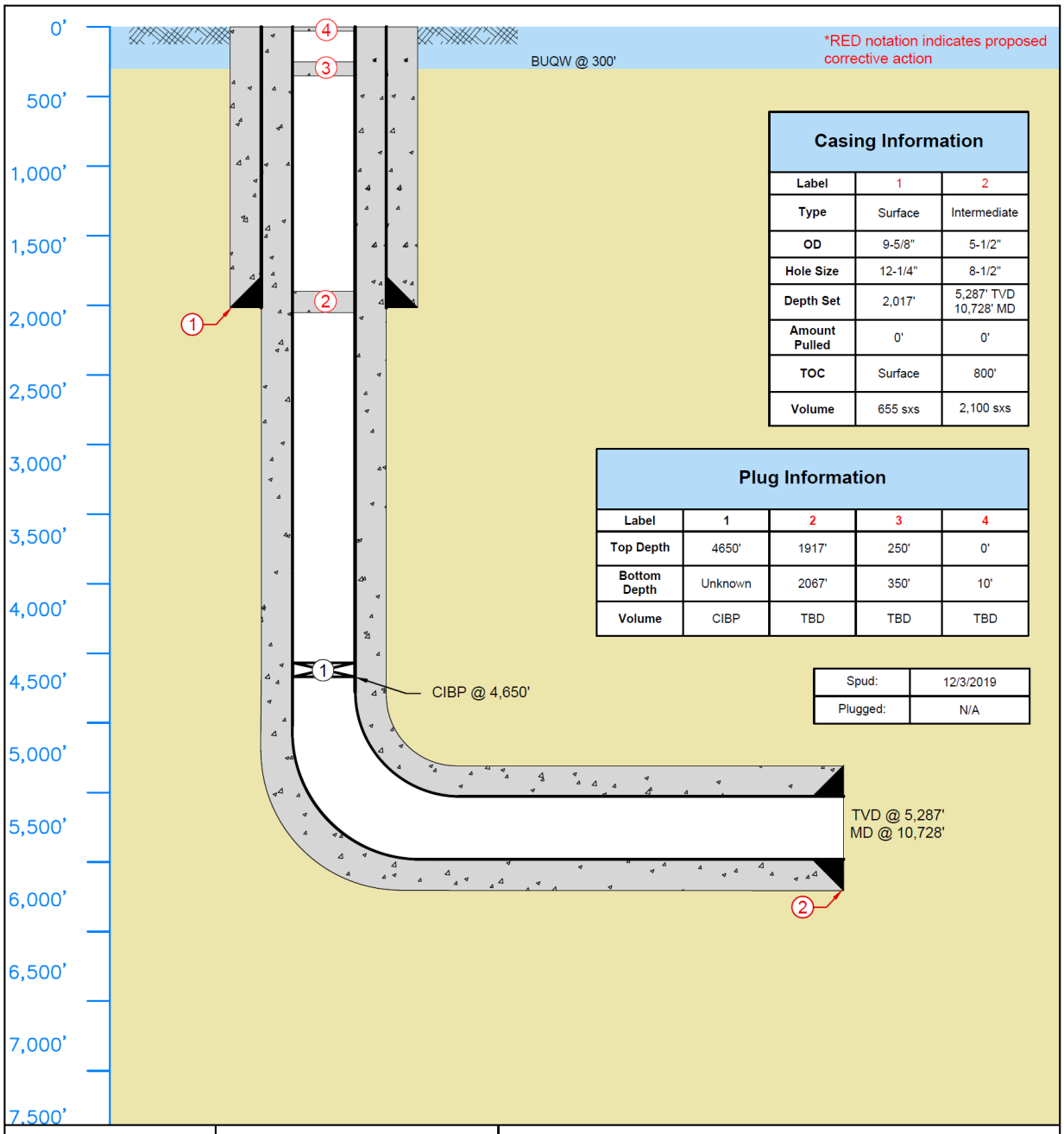


Figure 3-45 – Well API No. 42-165-38794 Current Schematic



LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Reliance Energy, Inc.	Garver-Alexander 84 1H	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: Sec 83 Block H	**Site:**	**Survey:**
	API No: 42-165-38794	**Field:**	**Well Type/Status:** Corrective Action
Texas License F-9147	**Serial No:** NA	**Project No:** LS167	**Date:** 7/16/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** LMM	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 3-46 – Well API No. 42-165-38794 Proposed P&A Schematic

3.9 Area of Review Revaluation Plan and Schedule

3.9.1 Proposed Reevaluation Cycle

Per 16 TAC **§5.203(d)(2)(B)** [40 CFR **§146.84(b)(2)**] requirements, Orchard Storage will reevaluate the AORs at each of the following intervals:

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

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

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

Table 3-7 provides a list of the possible triggers and, should one occur, the measures to be taken. The evaluations will be used to validate the plume model against actual, empirical results.

Table 3-7 – Triggers for AOR Reevaluations

Reevaluation Trigger	Measures to Be Taken	Schedule for Reevaluation
5-year plume migration survey per 16 TAC **§4.206(g)** [40 CFR **§146.84(e)**] identifies a greater extent than modeled	• Re-run the reservoir plume model with new data. • Reevaluate the AORs.	At least once every 5 years
5-year plume migration survey per 16 TAC **§4.206(g)** [40 CFR **§146.84(e)**] identifies the plume direction is different than modeled	• Re-run the reservoir plume model with new data. • Reevaluate the AORs.	At least once every 5 years
Operational change: injection rate increases to a rate greater than that modeled	• Re-run the reservoir plume model with new data. • If plume increases in extents, reevaluate the AORs.	Within 1 month of detection
Operational change: significant injectate composition changes to a new mixture	• Re-run the reservoir plume model with new data.	Within 1 month of detection

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

3.10 Conclusion

The results of this AOR investigation validate the favorable conditions for carbon sequestration at the proposed area for Orchard No. 1 through No. 7. The CO_2 pore-occupancy-plume AOR determined from model results did not identify any penetrating wells ("penetrators") of the upper confining layer. The pressure front AOR identified eight penetrators that will require corrective action to ensure formation fluids do not enter the USDW through one of those wells. Unless otherwise triggered by one of the cases above, the AOR investigation will be reevaluated at least every five years.

Higher resolution versions of the AOR maps and associated lists are available in *Appendix B*.

Appendix B-1	Map of Oil and Gas Wells in AOR
Appendix B-2	List of Oil and Gas Wells in AOR
Appendix B-3	Map of Penetrating Oil and Gas Wells in AOR
Appendix B-4	List of Penetrating Wells in AOR
Appendix B-5	Freshwater Wells in AOR
Appendix B-6	List of Freshwater Wells in AOR
Appendix B-7	Map of Cleanup Sites, Mines and Springs in AOR
Appendix B-8	Review of Oil and Gas Wells in AOR

Historical well files for all oil and gas wells and groundwater wells are provided in Supplemental Appendix B.

3.11 References

Bradley, R., & Kalaswad, S. (2003). The Groundwater Resources of the Dockum Aquifer in Texas. Austin: Texas Water Development Board.

Bureau of Economic Geology. Texas Mineral Resources Map, https://coastal.beg.utexas.edu/txmineralresources/No. !/ (accessed March 6, 2023)

EPA (2023). Cleanups in My Community Map, https://cimc.epa.gov/ords/cimc/f?p=cimc:map:::71 (accessed March 6, 2023)

Heitmuller, F.T., and Reece, B.D. (2003). Data base of historically documented springs and spring flow measurements in Texas: U.S. Geological Survey Open-File Report 03-315, https://databasin.org/maps/new/No. datasets=2400de0b78284e0fa44083e78824ff24 (accessed March 6, 2023)

Rettman, P., & Leggat, E. (1966). Ground Water Resources of Gaines County, Texas. Austin: United States Geological Survey.

United States Geological Survey (2019). U.S. Geological Survey National Produced Waters Geochemical Database v2.3. U.S. Geological Survey National Produced Waters Geochemical Database v2.3 | U.S. Geological Survey (usgs.gov) (accessed December 2022)

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 4 – Engineering Design and Operating Strategy

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

TABLE OF CONTENTS

4.1 Introduction 6

4.2 Injection Well Design Strategy 6

4.2.1 Engineering Design 6
4.2.2 General Outline of Well Design 7
4.2.3 Orchard Project Design Specifics 9
4.3 Detailed Discussions of Individual Orchard Well Designs 17

4.3.1 Orchard Well No. 1 Design 18
4.3.2 Orchard Well No. 2 Design 24
4.3.3 Orchard Well No. 3 Design 28
4.3.4 Orchard Well No. 4 Design 32
4.3.5 Orchard Well No. 5 Design 36
4.3.6 Orchard Well No. 6 Design 40
4.3.7 Orchard Well No.7 Design 44
4.3.8 Wellhead Discussion 48
4.3.9 Testing and Logging During Drilling and Completion Operations 51
4.3.10 Completion/Stimulation Plans 55
4.3.11 Orchard Injection Well Operating Strategy 56
4.3.12 Orchard Injection Wells Operational Summary 65
4.4 Above Confining Zone Monitoring Wells 66

4.4.1 General Outline of Monitoring Well Design, Orchard MW No. 1 and MW No. 3 66
4.4.2 Testing and Logging of Orchard MW No. 1 and MW No. 3 75
4.4.3 Overview of Well Completion Program 75
4.5 In-Zone Monitoring Well 76

4.5.1 Orchard MW No. 2 Conversion 76
4.5.2 Monitoring Well Operational Strategy Summary 79
4.6 References 80

Figures

Figure 4-1 – 7 in. Seal Assembly and Permanent Packer 8
Figure 4-2 – Example Injected Fluid Temperature Profile versus Depth 16
Figure 4-3 – CO_2 Flow Conditions 17
Figure 4-4 – Orchard No. 1 Wellbore Schematic 18
Figure 4-5 – Orchard No. 2 Wellbore Schematic 24
Figure 4-6 – Orchard No. 3 Wellbore Schematic 28
Figure 4-7 – Orchard No. 4 Wellbore Schematic 32
Figure 4-8 – Orchard No. 5 Wellbore Schematic 36
Figure 4-9 – Orchard No. 6 Wellbore Schematic 40
Figure 4-10 – Orchard No. 7 Wellbore Schematic 44

Figure 4-11 –Preliminary Wellhead Design, Orchard No. 1 to No. 7 49
Figure 4-12 – Typical Injection Well and Injection Skid Flow Schematic 50
Figure 4-13 – Injection Pressure Plot, Orchard No. 1 59
Figure 4-14 – Injection Pressure Plot, Orchard No. 2 60
Figure 4-15 – Injection Pressure Plot, Orchard No. 3 61
Figure 4-16 – Injection Pressure Plot, Orchard No. 4 62
Figure 4-17 – Injection Pressure Plot, Orchard No. 5 63
Figure 4-18 – Injection Pressure Plot, Orchard No. 6 64
Figure 4-19 – Injection Pressure Plot, Orchard No. 7 65
Figure 4-20 – Orchard MW No. 1 Monitoring Wellbore Schematic 67
Figure 4-21 – Orchard MW No. 3 Monitoring Wellbore Schematic 68
Figure 4-22 – 5-1/2 in. Seal Assembly & Permanent Packer 73
Figure 4-23 – Orchard Monitoring Wells Preliminary Wellhead Design 74
Figure 4-24 – Valiant 1D Current Wellbore Schematic 77
Figure 4-25 – Orchard MW No. 2 Proposed Wellbore Schematic 78

Tables

Table 4-1 – CO_2 Standard Conditions 9
Table 4-2 – Kinder Morgan Pipeline Specification 10
Table 4-3 – CO_2 Injection Composition 10
Table 4-4 – Calculated Injection Parameters, Orchard No. 1 to No. 7 12
Table 4-5 – Input Parameters for Wellbore Calculations, Orchard No. 1 to No. 7 13
Table 4-6 – Injection Depth References (ft) by Well 14
Table 4-7 – Injection Well Surface Casing Engineering Calculations, Orchard No. 1 20
Table 4-8 – Injection Well Surface Casing Annular Geometries, Orchard No. 1 20
Table 4-9 – Injection Well Surface Casing Cement Calculations, Orchard No. 1 20
Table 4-10 – Injection Well Production Casing Engineering Calculations, Orchard No. 1 21
Table 4-11 – Injection Well Production Casing Annular Geometries, Orchard No. 1 22
Table 4-12 – Injection Well Production Casing Cement Calculations, Orchard No. 1 22
Table 4-13 – Injection Tubing Specifications, Orchard No. 1 23
Table 4-14 – Injection Well Surface Casing Engineering Calculations, Orchard No. 2 25
Table 4-15 – Injection Well Surface Casing Annular Geometries, Orchard No. 2 25
Table 4-16 – Injection Well Surface Casing Cement Calculations, Orchard No. 2 25
Table 4-17 – Injection Well Production Casing Engineering Calculations, Orchard No. 2 26
Table 4-18 – Injection Well Production Casing Annular Geometries, Orchard No. 2 26
Table 4-19 – Injection Well Production Casing Cement Calculations, Orchard No. 2 26
Table 4-20 – Injection Tubing Specifications, Orchard No. 2 27
Table 4-21 – Injection Well Surface Casing Engineering Calculations, Orchard No. 3 29
Table 4-22 – Injection Well Surface Casing Annular Geometries, Orchard No. 3 29
Table 4-23 – Injection Well Surface Casing Cement Calculations, Orchard No. 3 29
Table 4-24 – Injection Well Production Casing Engineering Calculations, Orchard No. 3 30
Table 4-25 – Injection Well Production Casing Annular Geometries, Orchard No. 3 30

Table 4-26 – Injection Well Production Casing Cement Calculations, Orchard No. 3 30
Table 4-27 – Injection Tubing Specifications, Orchard No. 3 31
Table 4-28 – Injection Well Surface Casing Engineering Calculations, Orchard No. 4 33
Table 4-29 – Injection Well Surface Casing Annular Geometries, Orchard No. 4 33
Table 4-30 – Injection Well Surface Casing Cement Calculations, Orchard No. 4 33
Table 4-31 – Injection Well Production Casing Engineering Calculations, Orchard No. 4 34
Table 4-32 – Injection Well Production Casing Annular Geometries, Orchard No. 4 34
Table 4-33 – Injection Well Production Casing Cement Calculations, Orchard No. 4 34
Table 4-34 – Injection Tubing Specifications, Orchard No. 4 35
Table 4-35 – Injection Well Surface Casing Engineering Calculations, Orchard No. 5 37
Table 4-36 – Injection Well Surface Casing Annular Geometries, Orchard No. 5 37
Table 4-37 – Injection Well Surface Casing Cement Calculations, Orchard No. 5 37
Table 4-38 – Injection Well Production Casing Engineering Calculations, Orchard No. 5 38
Table 4-39 – Injection Well Production Casing Annular Geometries, Orchard No. 5 38
Table 4-40 – Injection Well Production Casing Cement Calculations, Orchard No. 5 38
Table 4-41 – Injection Tubing Specifications, Orchard No. 5 39
Table 4-42 – Injection Well Surface Casing Engineering Calculations, Orchard No. 6 41
Table 4-43 – Injection Well Surface Casing Annular Geometries, Orchard No. 6 41
Table 4-44 – Injection Well Surface Casing Cement Calculations, Orchard No. 6 41
Table 4-45 – Injection Well Production Casing Engineering Calculations, Orchard No. 6 42
Table 4-46 – Injection Well Production Casing Annular Geometries, Orchard No. 6 42
Table 4-47 – Injection Well Production Casing Cement Calculations, Orchard No. 6 42
Table 4-48 – Injection Tubing Specifications, Orchard No. 6 43
Table 4-49 – Injection Well Surface Casing Engineering Calculations, Orchard No. 7 45
Table 4-50 – Injection Well Surface Casing Annular Geometries, Orchard No. 7 45
Table 4-51 – Injection Well Surface Casing Cement Calculations, Orchard No. 7 45
Table 4-52 – Injection Well Production Casing Engineering Calculations, Orchard No. 7 46
Table 4-53 – Injection Well Production Casing Annular Geometries, Orchard No. 7 46
Table 4-54 – Injection Well Production Casing Cement Calculations, Orchard No. 7 46
Table 4-55 – Injection Tubing Specifications, Orchard No. 7 47
Table 4-56 – Core Plan Summary Table 52
Table 4-57 – Proposed Core Analysis 53
Table 4-58 – Injection Well Openhole Logging Plan 54
Table 4-59 – Injection Well Casedhole Logging Plan 55
Table 4-60 – Orchard Injection Well Operating Parameters 57
Table 4-61 – Monitoring Well Surface Casing Engineering Calculations, Orchard MW No. 1 and MW No. 3 .69
Table 4-62 – Monitoring Well Surface Casing Annular Geometries, Orchard MW No. 1 and MW No. 3 69
Table 4-63 – Monitoring Well Surface Casing Cement Calculations, Orchard MW No. 1 and MW No. 3 70
Table 4-64 – Monitoring Well Production Casing Engineering Calculations, Orchard MW No. 1 70
Table 4-65 – Monitoring Well Production Casing Annular Geometries, Orchard MW No. 1 70
Table 4-66 – Monitoring Well Production Casing Cement Calculations, Orchard MW No. 1 70
Table 4-67 – Monitoring Well Production Casing Engineering Calculations, Orchard MW No. 3 71
Table 4-68 – Monitoring Well Production Casing Annular Geometries, Orchard MW No. 3 71

Table 4-69 – Monitoring Well Production Casing Cement Calculations, Orchard MW No. 3 67
Table 4-70 – Monitoring Well Tubing Engineering Calculations- Orchard MW No. 1.....68
Table 4-71 – Monitoring Well Tubing Engineering Calculations- Orchard MW No. 3.....68
Table 4-72 – Openhole Logging Plan 71
Table 4-73 – Casedhole Logging Plan 71
Table 4-74 – Monitoring Well Tubing Engineering Calculations – Orchard MW No. 2 75



Certified By:
Lonquist Field Service, LLC
Texas Registration No. 22610

Ben H. Bergman, P.E.
Senior Engineer
Texas License No. 95591

Date Signed: July 28th, 2025
Houston, Texas

4.1 Introduction

This section describes the engineering design details and operational strategies employed during the planning of the seven proposed Orchard Project injection wells and associated monitoring wells. The details meet the requirements of Title 16, Texas Administrative Code (TAC) **§5.203(e)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**]. Class VI regulations include specific requirements for the design and operation of a carbon capture and storage (CCS) well. This section of the permit application addresses each of those requirements in detail.

4.2 Injection Well Design Strategy

4.2.1 Engineering Design

A Class VI CO_2 sequestration well must be designed to protect any Underground Source of Drinking Water (USDW) from any CO_2 injectate contamination. CO_2 mixed with formation fluids and other injectate components—a combination producing carbonic acid with a pH as low as 3—is highly corrosive to the metallurgy of many of the well components.

The design parameters for Orchard No. 1 through No. 7 and associated monitoring wells will therefore consider injection rates, volumes, pressures plus fluid properties, chemical properties of the injectate fluid, and estimated total storage volumes in the formation, to ensure the wells are designed to withstand the corrosiveness of the injectate. Special metallurgies are considered for the casing, tubing, wellhead equipment, and downhole tools.

The drilling program also includes the types of cement used in the wellbore. The cement design and products used to cement the well will create good bonding between the casing and formations while withstanding the injectate corrosive nature. The cementing of the casings is designed with a sheath sufficient to (1) protect the wellbore from developing any channeling out of the injection interval, and (2) maintain the CO_2 below the upper confining zone (UCZ)—that is, the Grayburg formation and Upper San Andres confining zone, as described in *Section 1.3.3*. The annulus from total depth (TD) to 500 ft above the UCZ will be cemented with an acid-resistant cement.

The wellbore will be designed with 7 in. CR22/CR25 production casing from +/- 245 ft above the upper containment zone with premium connections to TD. The 7 in. casing will be set +/- 150 ft into the bottom-sealing formation. Above that will go a galvanic 7 in. x 7 in. crossover. The production tubing will be 4-½ in. CR22/CR25 with premium connections and a 7 in. x 4-½ in. permanent production packer—also made of CR22/CR25 material with acid-resistant sealing elements—will be located approximately 70 ft above the top of the injection zone. *Sections 4.2.3* through *4.2.9* show the wellbore schematics for Orchard No. 1–No.7, respectively.

The tubing and casing annulus pressures will be continuously monitored to ensure that well integrity is maintained. A Supervisory Control and Data Acquisition (SCADA) monitoring system will be in place throughout the life of the wells, able to measure and record downhole temperatures and pressures in the injection interval and monitor the size of the plume.

The monitoring systems include running a fiber optic and electric cable sensor package as the production casing string is run in the hole. The cable and sensors will then be cemented into place.

4.2.2 General Outline of Well Design

Orchard No. 1 through No.7 injection wells were designed with the following specifications:

- Conductor
  - 16 in. to +/- 120 ft
- Surface Casing
  - To be set below the lowermost USDW, per the Texas Railroad Commission (TRRC) Groundwater Advisory Unit (GAU) determination, for each well
    - Estimated setting depth is approximately 100 ft below the base of the USDW. The GAU determination letters are provided in Appendix C-6.
  - 10-¾ in. outer diameter (OD) casing
  - 14-¾ in. hole size
  - Cemented back to surface
- Production Casing
  - 7 in. casing set to TD of wells
    - Casing across the upper confining interval and the injection zone will be 22CR/25CR material.
      - Galvanic crossover between L-80 and 22CR/25CR chrome casing
      - DV Tool just below the injection level – 22CR/25CR/Inconel CO_2 resistant material
      - ECP (external casing packer) just below DV Tool – 22CR/25CR/Inconel acid-resistant material
  - 9-⅞ in. hole size
  - Cemented back to surface
    - Cement to be comprised of the following:
      - +/- 500 ft above the top of the UCZ to surface – Salt blend cement
      - TD to 500 ft above the UCZ – acid-resistant cement, as described in Appendix C-1.[1]
- Injection Tubing
  - 4-½ in. tubing with 7 in. x 4-½ in. packer
  - Packer will be set approximately 40 ft above the injection interval.
  - Per metallurgical analysis, composition to be of [22CR/25CR] duplex stainless steel or greater
  - Annular fluid to consist of corrosion-inhibitor fluid
    - Annular fluid to be designed prior to installation, based on well conditions, and may include corrosion inhibitors, surfactants, buffering agents, solvents
- Permanent Packer (displayed in Figure 4-1)
  - 7 in. x 4-½ in. permanent production packer – 22CR/25CR material
  - Elastomer options – Nitrile, HNBR, Aflas (CO_2 resistant)

[1] Final vendor to be selected prior to const

    - Temperature limitation 100 to 300°F
    - Inconel-lined (flow-wetted) anchor, mandrel, and cylinder for corrosion resistance
    - Sealing elements will be acid-resistant
- Wellhead (displayed in Figure 4-30, in *Section 4.2.10*)
    - 10-¾ in. slip-on weld (SOW) x 10-¾ in. 5M – casing head
    - 10-¾ in. x 7 in. – casing hanger
    - 10-¾ in. x in. 5M x 11 in. 5M casing spool
    - 11 in. 5M x 7-1/16 in. FF trim tubing head
        - Production tree 7-1/16 in. 5M, gate valve, manual
        - 4-1/16 in. 5M, gate valve, pneumatic
        - 4-1/16 in. x 5-⅛ in. 5M flow cross with 5-⅛ in. 5M wing valves
        - 4-1/16 in. 5M, gate valve, manual for the crown with cap
    - Stainless and Inconel-lined wetted sections for corrosion resistance

Figure 4-1 illustrates how the production tubing will be run into the well with a 7 in. x 4-½ in. 22CR/25CR permanent packer with premium connections and corrosion resistant sealing elements.

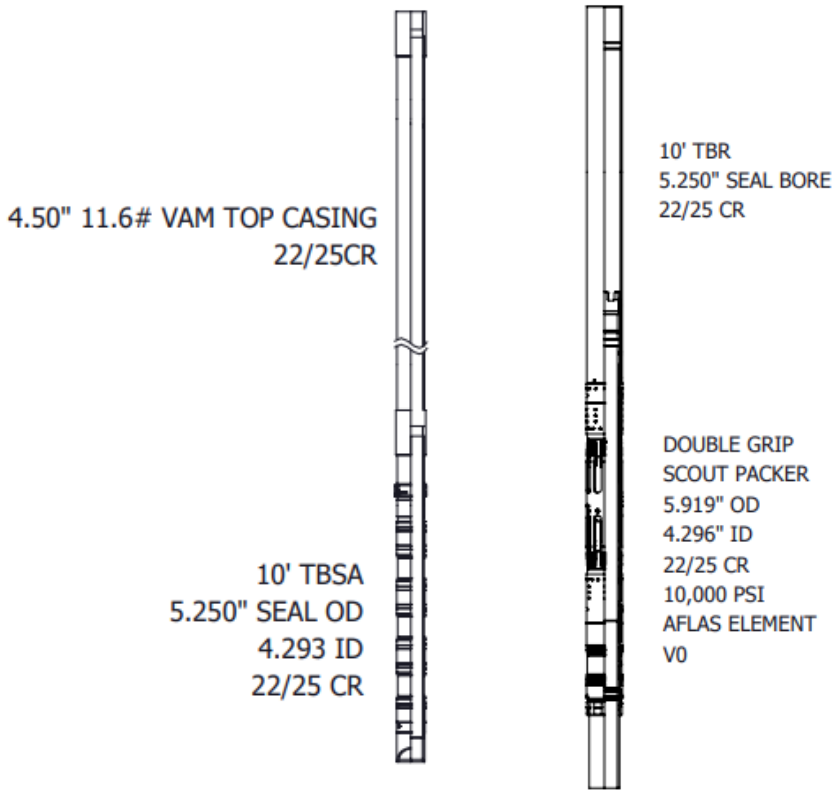


Figure 4-1 – 7 in. Seal Assembly and Permanent Packer

Before setting the packer, the tubing/production casing annulus will be filled with a noncorrosive fluid as approved by the UIC Director. Orchard anticipates that the annular fluid will be comprised of a treated freshwater with additional additive such as corrosion inhibitors, surfactants, buffering agents, or solvents. The final design will be based on wellbore conditions encountered. Pressure

will be maintained and monitored on the annulus at a pressure that exceeds the operating injection pressure of the well.

Within 30 days after the completion of Orchard No. 1 to No.7, Orchard Storage Company LLC (Orchard Storage) will file a complete record of the wells with the Underground Injection Control (UIC) Division showing the current completion details, per 16 TAC **§5.206 (c)(2).** A complete drilling and completion prognosis has been included in *Appendix C-1*. The mud and cement programs included in the prognosis are representative and may be modified before starting construction.

4.2.3 Orchard Project Design Specifics

Orchard Storage plans to inject between 211 and 483 thousand metric tons per year, on average, of captured carbon gas into the Orchard injection wells. These masses translate to rates of approximately 11.1 to 25.3 million standard cubic feet per day (MMscf/d) at standard conditions. These rates are the determining factor in selecting the size of the production tubing. Detailed modeling programs were run based on the size of the production string, properties and temperatures of the injectate, and the rate of injection, to determine the production-tubing grade and weight. The casing was then designed to accommodate the 4-½ in. tubing.

Table 4-1 shows the standard conditions of CO_2 used in the modeling and flow calculations.

Table 4-1 – CO_2 Standard Conditions

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

*psia – pounds per square inch absolute
lbm – pound mass

Tubing design sensitivity was run, considering calculated pipe-friction losses, exit velocities, and economic considerations. Detailed reservoir-engineering model runs estimated the bottomhole injection pressures (BHIPs) over time (Figure 4-3). The data in Figure 4-3 not only identifies when the maximum BHIP occurs during project life and the resulting maximum injection pressure at the surface but also allows for the proper design of the casing, tubing, and wellhead configurations.

Table 4-2 provides the pipeline specifications for the CO_2 stream to be injected into the Orchard injection wells.

Table 4-2 – CO_2 Stream Specification

Component	Value
CO_2	No less than 95%
Water	No free water and no more than 30 lb/MMscf (vapor phase)
Temperature	No more than 120°F or less than 65°F
H_2S	No more than 20 parts per million (ppm) by volume
Nitrogen	No more than 4% by mole fraction
Sulphur	No more than 35 ppm by weight
Oxygen	No more than 10 ppm by weight
Hydrocarbons	No more than 5% by mole fraction
Glycol	No more than 0.3 gallon per MMscf
Carbon Monoxide	No more than 4,250 ppm by weight
NO_x	No more than 1 ppm by weight
SO_x	No more than 1 ppm by weight
Particulates	No more than 1 ppm by weight
Amines	No more than 1 ppm by weight
Hydrogen	No more than 1% by mole fraction
Mercury	No more than 5 nanograms per liter
Ammonia	No more than 50 ppm by weight
Argon	No more than 1% by volume
Liquids	Free of liquids at delivery conditions and no condensed liquids downstream
Lube Oil	No more than 50 ppm by weight

Parameters for the injectate composition were derived from the pipeline CO_2 line specification, for input into the reservoir model. The chemical composition modeled is outlined in Table 4-3.

Table 4-3 – CO_2 Injection Composition

Composition	% mole
Nitrogen	2
CO_2	98

Injection tubing size of 4-½ in. has been selected for the Orchard wells based on anticipated injection rates and bottomhole pressures output from the simulation model.

Tables 4-4 and 4-5 provide the input parameters from the plume model and assumptions used in the determination of the tubing hydraulics. Parameters tabulated in Table 4-4 were calculated using

input parameters listed in Table 4-5. Wellhead pressures were calculated by incorporating wellbore hydraulics vertical flow pressure tables (termed “VFP” tables) into the dynamic simulator. These tables were generated using a wellbore hydraulics package which is part of RFD’s tNavigator software suite.

Input temperature profiles for the tNavigator Wellbore Hydraulics software were calculated using a transient wellbore heat transfer model based on the approach of Ramey (Ramey, 1962), in combination with incorporation of temperature changes due to Joule-Thomson effects. Thermodynamic and heat-transfer properties used in the temperature modeling were sourced from National Institute of Standards and Technology’s Thermophysical Properties of Fluid Systems web page (Linstrom & Mallard, 2025). Typical bottom hole and well head pressures are taken at mid project life, 6 years after the start of injection.

Table 4-6 lists the top and base of the injection zone, and the upper and lower perforations, for each well in both subsurface depths and measured depths (from ground level elevation).

Table 4-4 – Calculated Injection Parameters, Orchard No. 1 to No. 7

Parameter	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
Formation Temperature (at Top Perforation) (°F)	105						
Formation Pressure (Top Perforation) - (psi)	2,174	2,118	2,068	2,049	2,049	2,005	2,167
Formation Density at Reservoir Conditions (lb/ft^3)	64.5						
Injectate Density in Formation (lb/ ft^3)	46.2	46.3	46.1	45.8	45.2	43.6	46.1
Wellhead Injection Pressure (typical) - (psi)	865	884	872	850	870	832	829
Wellhead Injection Temperature (typical) - (°F)	64	64	64	64	64	64	64
Bottomhole Injection Pressure (typical)	2,715	2,712	2,647	2,594	2,561	2,390	2,635
Bottomhole Injection Temperature (typical) - (°F)	88	88	88	89	84	83	88
Average Wellbore Density (lb/ ft^3)	49.7	50.0	49.6	48.9	49.6	46.9	48.7
Pipe Friction Pressure Loss (typical) - (psi)	39	27	27	17	90	88	39
Fluid Column Head Pressure (psi)	1,889	1,855	1,802	1,761	1,781	1,646	1,845

*lb/ft^3 – pounds per cubic foot

Table 4-5 – Input Parameters for Wellbore Calculations, Orchard No. 1 to No. 7

Parameter	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No.7	Source
Bottomhole Injection Pressure (typical) - (psi)	2,715	2,712	2,647	2,594	2,561	2,390	2,635	Simulation model, 6 years after injection start (mid-project)
Pipeline Delivery Pressure (psi)	2,170							Assumed value, higher than minimum pipeline delivery pressure of 2,070 psi
Pipeline Delivery Temperature (°F)	70							Slightly higher than ambient average soil temperature
Depth for BHP value (ft)	5,473	5,345	5,230	5,183	5,168	5,051	5,453	Simulation model BHP reference depth for each well
Injection Rate (Typical) - (MMscf/d)	15.9	14.8	14.6	11.1	24.0	25.3	15.9	Average injection rate
Tubing Inner Diameter (in.)	3.958							4 ½ in. 12.6 lb/ft tubing

*BHP – bottomhole pressure

Table 4-6 – Injection Depth References (ft) by Well

Reference Point	Depth Reference	Well Number						
		1	2	3	4	5	6	7
Surface elevation		3,218	3,211	3,208	3,202	3,187	3,169	3,212
Top of injection zone	Subsea	-2,254	-2,134	-2,022	-1,981	-1,981	-1,882	-2,241
Base of injection zone		-3,378	-3,279	-3,355	-3,055	-3,077	-3,196	-3,302
Top of injection zone	Measured	5,473	5,345	5,230	5,183	5,168	5,051	5,453
Base of injection zone		6,597	6,490	6,563	6,257	6,264	6,365	6,514
Total well depth	Measured	6,800	6,600	6,580	6,540	6,525	6,520	6,760

Friction and hydrostatic pressure drops were calculated using conventional using the correlations of Hagedorn and Brown (Hagedorn & Brown, 1965) using the Rock Flow Dynamics ("RFD") tNavigator wellbore hydraulics module. Additional wellbore flow modeling for the purpose of integrating wellbore hydraulics calculations with heat transfer modeling was done using the wellbore hydraulics package "SNAP" from Nations Consulting LLC (www.nationsconsultingllc.com) using the same correlation. While the Hagedorn and Brown correlation was developed for the purpose of correcting hydraulic friction factors for multi-phase flow slippage effects, under single phase flow this model reverts to conventional single-phase flow equations as described by Craft et al. (Craft, Holden, & Graves, 1962).

The injected fluid temperatures at wellhead and bottomhole conditions are affected initially by the temperature and pressure of the fluid in the pipeline. When the pressure is reduced from pipeline to wellhead pressure, the injected fluid will cool due to Joule-Thompson (JT) effects. As the fluid moves down the wellbore, it will be subject to warming from the surrounding rock as well as temperature changes induced by JT effects as the pressure increases. The temperature of the CO_2 in the wellbore can have a significant on the fluid density and consequently the wellhead pressure calculated based on a pressure traverse from the BHP. Accordingly, wellbore temperature was modeled by integrating detailed wellbore hydraulics output from the SNAP package into calculations using the correlations of Ramey (Ramey, 1962). An example temperature profile calculated for an Orchard injector is presented below as Figure 4-2.

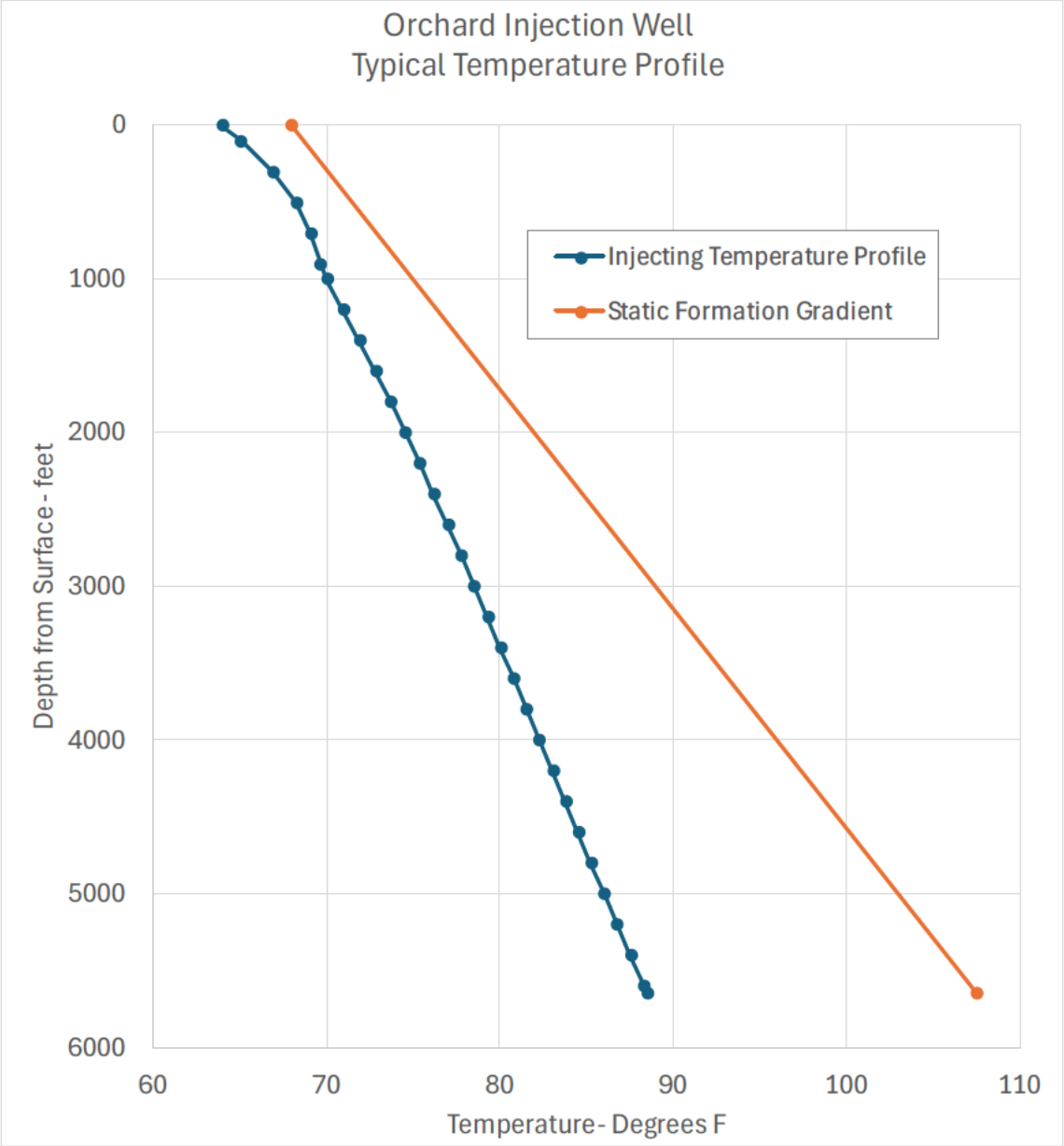


Figure 4-2 – Example Injected Fluid Temperature Profile versus Depth

Given the pressures and temperatures calculated for the Orchard Project wells, the injected fluid will remain in the dense phase (liquid or supercritical) from the time it enters the Orchard Storage site through its path into the subsurface storage interval. At the surface, fluid temperature is below the critical temperature (above which supercritical fluid is found). Temperature and pressure will increase as the fluid moves down the tubing and into the storage reservoir, by which time the injected fluid has transitioned (without actual phase change) into the supercritical phase. Figure 4-3 shows a phase diagram for CO_2 for Orchard No. 1, as an example, highlighting its supercritical state within the formation.

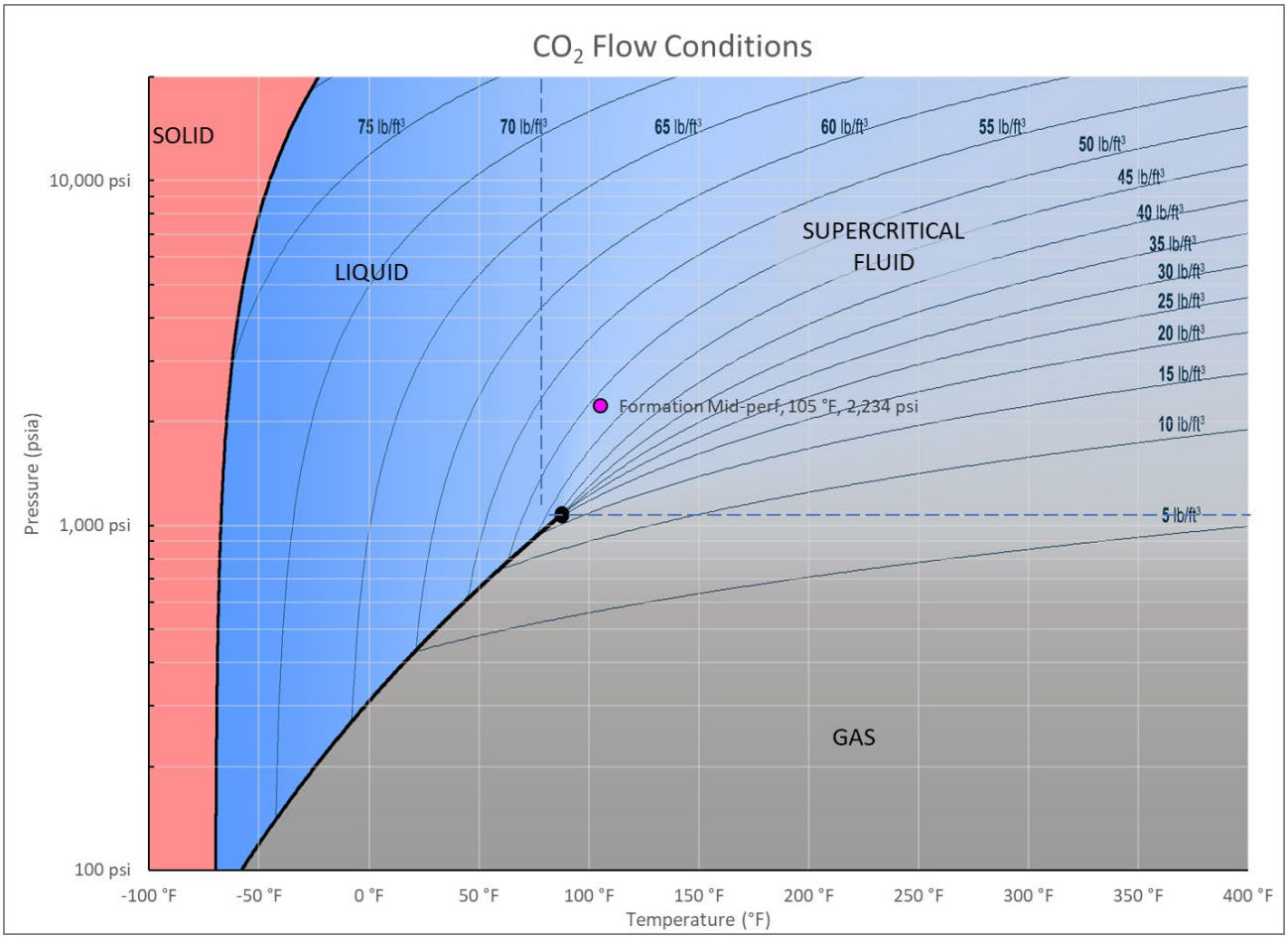


Figure 4-3 – CO_2 Flow Conditions

In support of the tubing size, the following casing and hole sizes were chosen to provide sufficient annular spacing, to allow for a good cement sheath that will promote good cement bonding and provide sufficient protection for the casing.

- 16 in. conductor to be drilled to 120 ft
- 14-¾ in. openhole with 10-¾ in. surface casing
- 9-⅞ in. openhole with 7 in. production casing

4.3 Detailed Discussions of Individual Orchard Well Designs

Based on the general well design requirements as discussed in Section 4.2, the specifics of each well design and their associated engineering calculations are included in Section 4.3.1 to 4.3.7. Additionally, the drilling and completion prognosis for each injection well is included in *Appendix C-1 Injection Well Prognoses.*

4.3.1 Orchard Well No. 1 Design

Figure 4-4 provides the design schematic for Orchard No. 1.

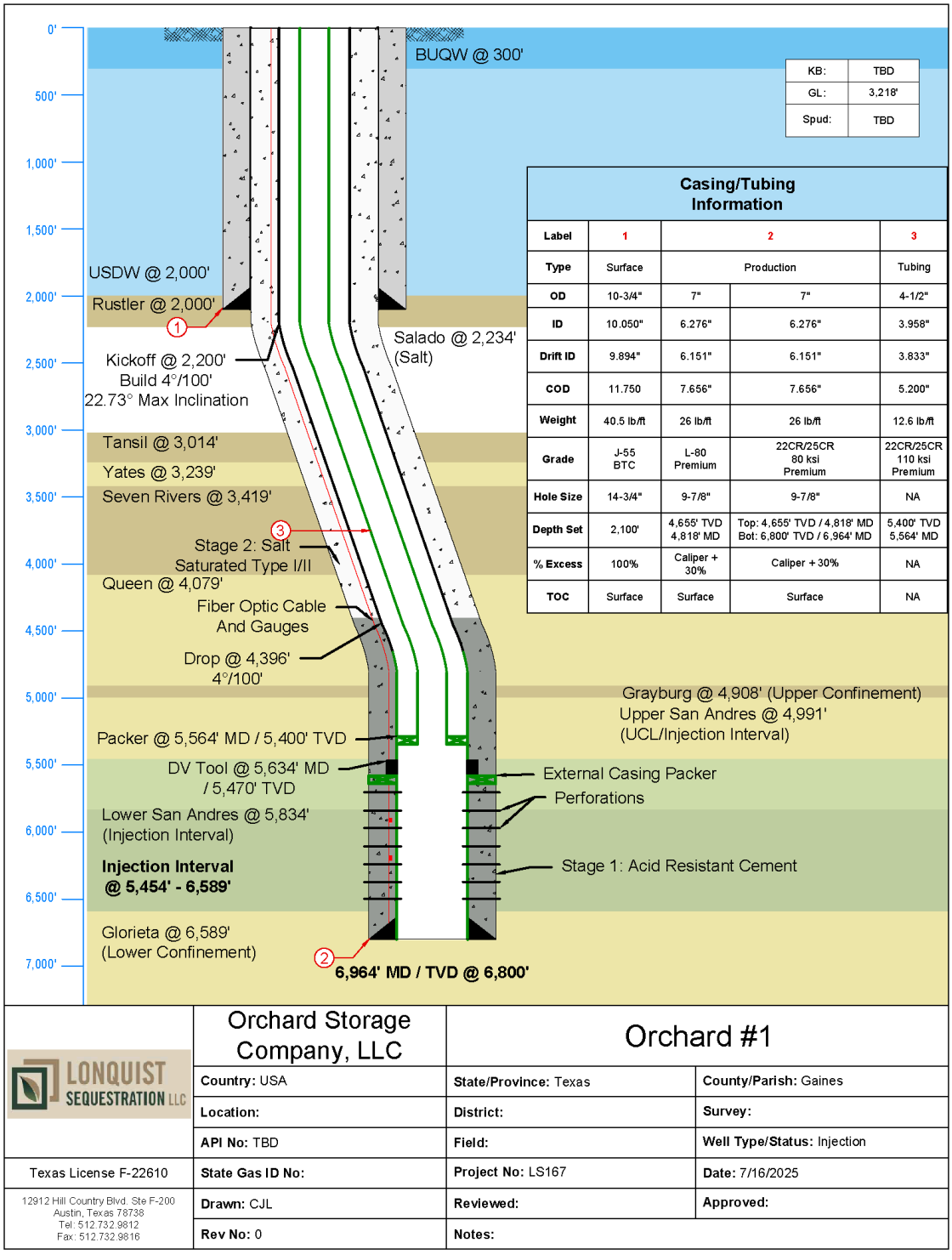


Figure 4-4 – Orchard No. 1 Wellbore Schematic

4.3.1.1 Conductor Casing

Sixteen-inch conductor casing will be used to ensure that hole integrity can be maintained during the initial drilling of the well. The 16 in., 84 lb/ft conductor casing will be set at approximately 120 ft. The 15.010 in. inner diameter (ID) of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.1.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 2,100 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers. Being centralized, the size of the annulus chosen will provide a consistent cement thickness between the casing and the open hole. This will help to ensure a quality cement bond and create two barriers between the USDW formation and wellbore during the remaining drilling operations. Cement will be circulated to the surface, and a top job will be provided, if needed, should the cement level fall after the cement has been circulated to the surface. After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole. Once the production casing has been run and cemented to the surface, there will be four barriers between the USDW formation and the wellbore.

The calculations used for the design criteria of the surface casing are as follows:

Tensile stress = casing weight x length = 40.5 lb/ft x 2,100 ft = **85,050 lbs**

Collapse pressure = length x max mud weight x 0.052 ft^3/ppg = 2,100 ft x 12.5 ppg x 0.052 ft^3/ppg = **1,365 psi**

Burst Pressure = length x max mud weight x 0.052 ft^3/ppg= 2,100 ft x 12.5 ppg x 0.052 ft^3/ppg = **1,365 psi**

These equations are used to calculate all subsequent design criteria.

Based on the current stimulation case, a maximum injection bottomhole gradient was set to 0.6 psi/ft, which is 90% of the estimated frac gradient of 0.67 psi/ft. Therefore, a conservative mud weight of 12.5 was applied to all casing collapse/burst calculations and corresponds to a gradient of 0.65 psi/ft. This gradient exceeds the maximum bottomhole gradient expected and does not exceed fracture pressure.

Summaries of engineering calculations for the surface casing for Orchard No. 1 are provided in Tables 4-7 through 4-9.

Table 4-7 – Injection Well Surface Casing Engineering Calculations, Orchard No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 ft – 2,100 ft ft TD)	40.5	2,100	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			85,050	1,365	1,365			
Safety Factor			7.40	1.16	2.29			

*lb/ft – pound per foot; bbl/ft – barrels per foot

Table 4-8 – Injection Well Surface Casing Annular Geometries, Orchard No. 1

Section	ID (in)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	2,100	2,100

*MD – measured depth
TVD – true vertical depth

Table 4-9 – Injection Well Surface Casing Cement Calculations, Orchard No. 1

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,980	0.5563	100	2,203
Shoe Track	45	0.5509	0	25

* ft^3/ft – cubic feet per foot

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.1.3 Production Casing

The production (i.e., long-string) casing is the final, permanently cemented string of casing installed in the well, to be run from the surface to TD then cemented back to the surface. There are several critical design criteria for the long string:

- 22CR/25CR material from above the upper confining zone through the injection interval to TD
- Fiber optic/electric cable along the exterior of the casing
- Integration of tools such as a galvanic crossover, float equipment, and centralizers
- Acid-resistant cement systems from 500 ft above the UCZ through the injection interval to TD

A detailed metallurgical analysis was performed that considered the chemical composition of the injectate and downhole conditions (Table 4-2) and is included in *Appendix D*. When dry, CO_2 is not considered corrosive. The production casing and related accessories will be a 22CR/25CR duplex stainless-steel design to prevent corrosion and downhole or surface failures, should fluids enter the wellbore and contact the injectate stream. The production casing will be installed using premium connections.

The production casing will be cemented with acid-resistant tail cement from TD to 500 ft above the UCZ. These additives will protect the cement in the annulus from carbonic acid damage and prevent channeling. The cement is intended to maintain good bonding between formation and casing to preserve integrity and maximize the life of the well. The annular section from the top of the UCZ to surface will be cemented with a salt blend cement (Figure 4-2, page 8). A detailed proposal for the cement is provided in the prognoses provided in Appendix C-1. This proposal is representative of the materials to be used. Final vendor and product selection will be made prior to beginning construction and will meet or exceed what is included in this proposal. The cement system proposed here is applicable to all seven injection wells.

The engineering and design parameters for the production casing are summarized in Tables 4-10 through 4-12.

Table 4-10 – Injection Well Production Casing Engineering Calculations, Orchard No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 to 4,655 ft TVD / 4,818 ft MD)	26	4,655 TVD 4,818 MD	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			176,800	3,026	3,026			
Safety Factor			3.42	1.79	2.39			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,655 TVD / 4,818 ft MD to 6,800 ft TVD / 6,964 ft MD)	26	6,800 TVD 6,964 MD	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			55,770	4,420	4,420			
Safety Factor			10.83	1.22	1.64			

Table 4-11 – Injection Well Production Casing Annular Geometries, Orchard No. 1

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	10.050	2,100	2,100
Openhole	9.875	6,964	6,800

Table 4-12 – Injection Well Production Casing Cement Calculations, Orchard No. 1

Section	Footage (ft, MD)	Capacity (ft^3/ft)	% Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	2,100	0.2836	0	596
Stage 2 Openhole/7 in. Casing Annulus Lead	2,459	0.2646	30	845
Stage 2 Openhole/7 in. Casing Annulus Tail	1,075	0.2646	30	370
Stage 1 Openhole/7 in. Casing Annulus	1,330	0.2646	30	458
Shoe Track	90	0.2148	0	19

4.3.1.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place. Surface monitoring of the injection stream is further described in Section 4.3.8.

4.3.1.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,100 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 19 centralizers will be run on the surface casing.

Centralizer placement for the 7 in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.

- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.1.6 Injection Tubing

The injection tubing size was selected based on the injection volumes, rates, and injectate composition, as discussed in Section 4.2. The injectate composition and the potential for a corrosive environment were considered when determining the metallurgy of the tubing as it was for the casing string. Although the injectate stream is anticipated to be dry and noncorrosive, the planned design allows for a surface upset or invasion of connate water from the reservoir. (A complete summary of the metallurgical analysis is included in *Appendix D* of this application.) Considering the potential for the presence of carbonic acid, 22CR/25CR material or better is recommended for the tubing string. The tubing will be installed using premium connections and set in the 22CR/25CR packer, which will include corrosion resistant sealing elements.

Table 4-13 lists the tubing specifications, design criteria, and calculated safety factors for Orchard No. 1. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-13 – Injection Tubing Specifications, Orchard No. 1

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Drift ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,400 ft TVD)	12.6	5,400	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			68,040	6,908	7,470			
Safety Factor			5.82	1.73	1.23			

4.3.2 Orchard Well No. 2 Design

Figure 4-5 provides the design schematic for Orchard No. 2.

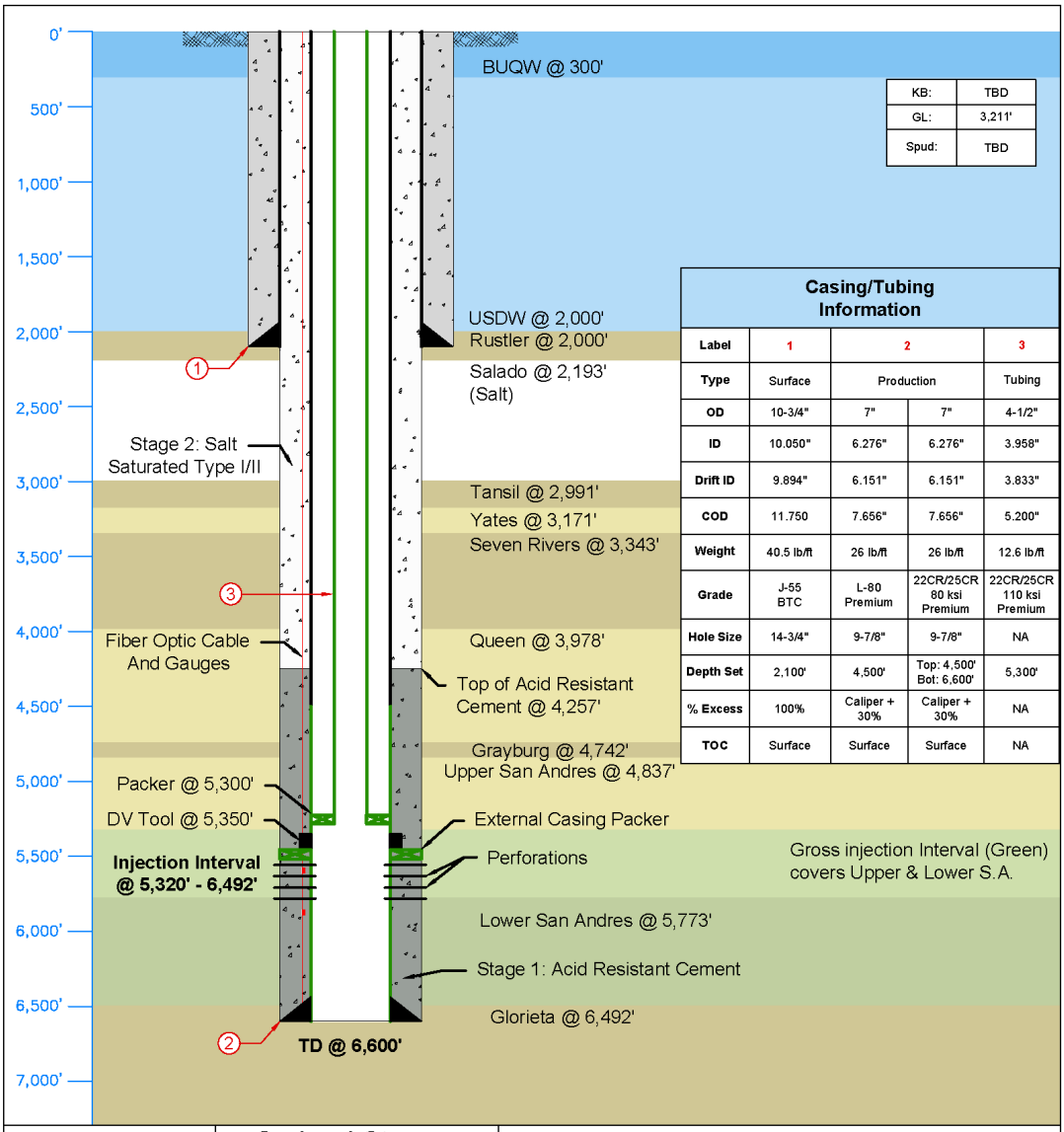


Figure 4-5 – Orchard No. 2 Wellbore Schematic

4.3.2.1 Conductor Casing

The 16 in., 84 lb/ft conductor casing will be set at approximately 120 ft. The 15.010 in. ID of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.2.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 2,100 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers.

Summaries of engineering calculations for the surface casing are provided in Tables 4-14 through 4-16.

Table 4-14 – Injection Well Surface Casing Engineering Calculations, Orchard No. 2

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 to 2,100 ft)	40.5	2,100	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			85,050	1,365	1,365			
Safety Factor			7.40	1.16	2.29			

Table 4-15 – Injection Well Surface Casing Annular Geometries, Orchard No. 2

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	2,100	2,100

Table 4-16 – Injection Well Surface Casing Cement Calculations, Orchard No. 2

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,980	0.5563	100	2,203
Shoe Track	45	0.5509	0	25

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.2.3 Production Casing

The engineering and design parameters for the production casing are summarized in the Tables 4-17 through 4-19.

Table 4-17 – Injection Well Production Casing Engineering Calculations, Orchard No. 2

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 to 4,500 ft)	26	4,500	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			171,600	2,925	2,925			
Safety Factor			3.52	1.85	2.48			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,500 to 6,600 ft)	26	6,600	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			54,600	4,290	4,290			
Safety Factor			11.06	1.26	1.69			

Table 4-18 – Injection Well Production Casing Annular Geometries, Orchard No. 2

Section	ID (in)	MD (ft)	TVD (ft)
Surface Casing	10.050	2,100	2,100
Openhole	9.875	6,600	6,600

Table 4-19 – Injection Well Production Casing Cement Calculations, Orchard No. 2

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	2,100	0.2836	0	596
Stage 2 Openhole/7 in. Casing Annulus Lead	2,140	0.2646	30	736
Stage 2 Openhole/7 in. Casing Annulus Tail	1,110	0.2646	30	382
Stage 1 Openhole/7 in. Casing Annulus	1,250	0.2646	30	430
Shoe Track	90	0.2148	0	19

4.3.2.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place.

4.3.2.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,100 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 19 centralizers will be run on the surface casing.

Centralizer placement for the 7 in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.
- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.2.6 Injection Tubing

Table 4-20 lists the tubing specifications, design criteria, and calculated safety factors. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-20 – Injection Tubing Specifications, Orchard No. 2

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Drift ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,300 ft)	12.6	5,300	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			66,780	6,856	7,407			
Safety Factor			5.93	1.74	1.24			

4.3.3 Orchard Well No. 3 Design

Figure 4-6 provides the design schematic for Orchard No. 3.

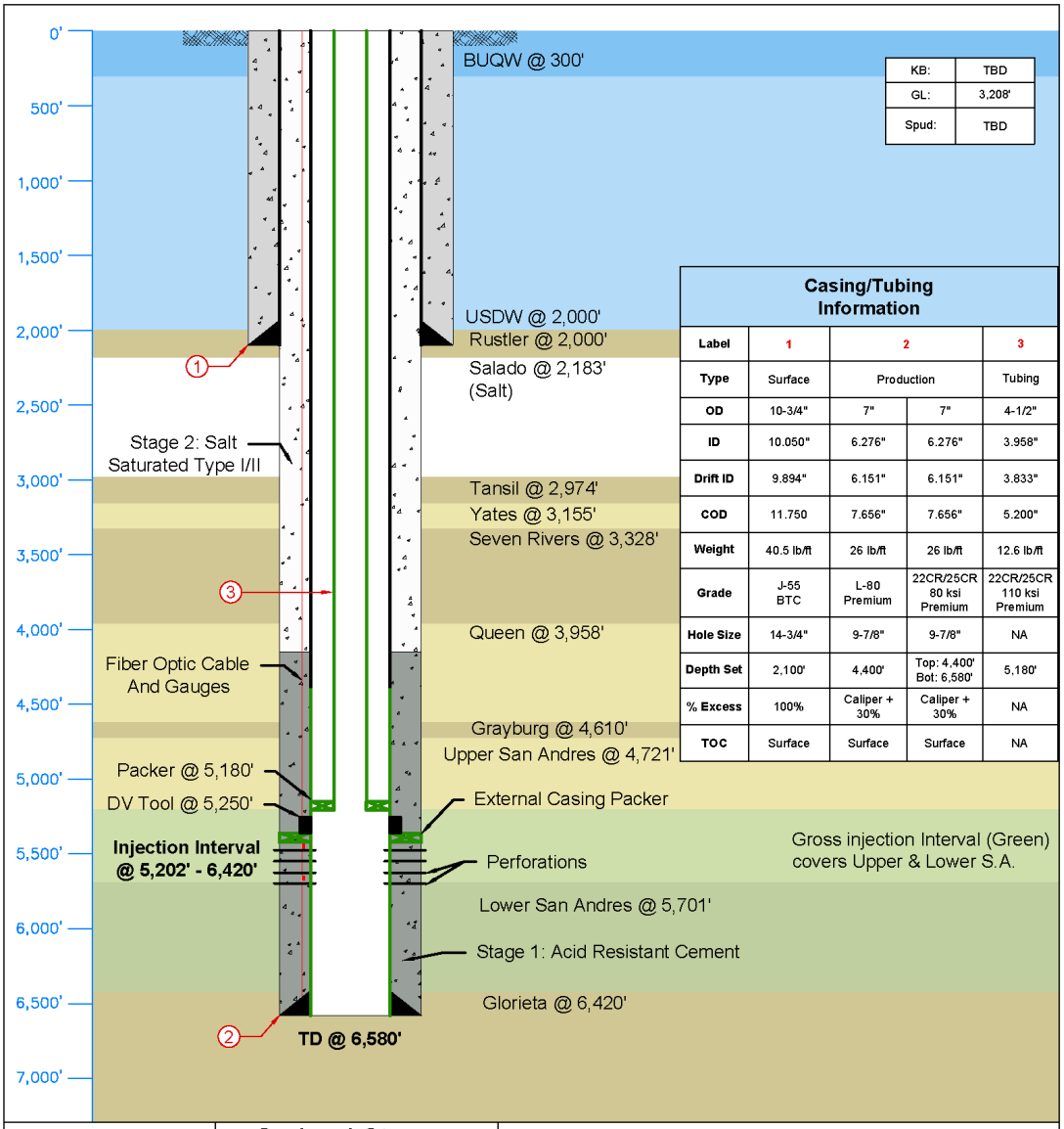


Figure 4-6 – Orchard No. 3 Wellbore Schematic

4.3.3.1 Conductor Casing

The 16 in., 84 lb/ft conductor casing will be set at approximately 120 ft. The 15.010 in. ID of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.3.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 2,100 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers.

Summaries of engineering calculations for the surface casing are provided in Tables 4-21 through 4-23.

Table 4-21 – Injection Well Surface Casing Engineering Calculations, Orchard No. 3

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 – 2,100 ft)	40.5	2,100	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			85,050	1,365	1,365			
Safety Factor			7.40	1.16	2.29			

Table 4-22 – Injection Well Surface Casing Annular Geometries, Orchard No. 3

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	2,100	2,100

Table 4-23 – Injection Well Surface Casing Cement Calculations, Orchard No. 3

Section	Footage (ft)	Capacity (ft^3/ ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,980	0.5563	100	2,203
Shoe Track	45	0.5509	0	25

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.3.3 Production Casing

The engineering and design parameters for the production casing are summarized in Tables 4-24 through 4-26:

Table 4-24 – Injection Well Production Casing Engineering Calculations, Orchard No. 3

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 to 4,400 ft)	26	4,400	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			171,080	2,860	2,860			
Safety Factor			3.53	1.89	2.53			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,400 to 6,580 ft)	26	6,580	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			56,680	4,277	4,277			
Safety Factor			10.66	1.26	1.69			

Table 4-25 – Injection Well Production Casing Annular Geometries, Orchard No. 3

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	10.050	2,100	2,100
Openhole	9.875	6,580	6,580

Table 4-26 – Injection Well Production Casing Cement Calculations, Orchard No. 3

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	2,100	0.2836	0	596
Stage 2 Openhole/7 in. Casing Annulus Lead	2,010	0.2646	30	691
Stage 2 Openhole/7 in. Casing Annulus Tail	1,140	0.2646	30	392
Stage 1 Openhole/7 in. Casing Annulus	1,330	0.2646	30	458
Shoe Track	90	0.2148	0	19

4.3.3.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place.

4.3.3.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,100 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 19 centralizers will be run on the surface casing.

Centralizer placement for the 7 in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.
- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.3.6 Injection Tubing

Table 4-27 lists the tubing specifications, design criteria, and calculated safety factors. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-27 – Injection Tubing Specifications, Orchard No. 3

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Dri ft ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,180 ft)	12.6	5,180	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			65,268	6,794	7,332			
Safety Factor			6.07	1.75	1.26			

4.3.4 Orchard Well No. 4 Design

Figure 4-7 provides the design schematic for Orchard No. 4.

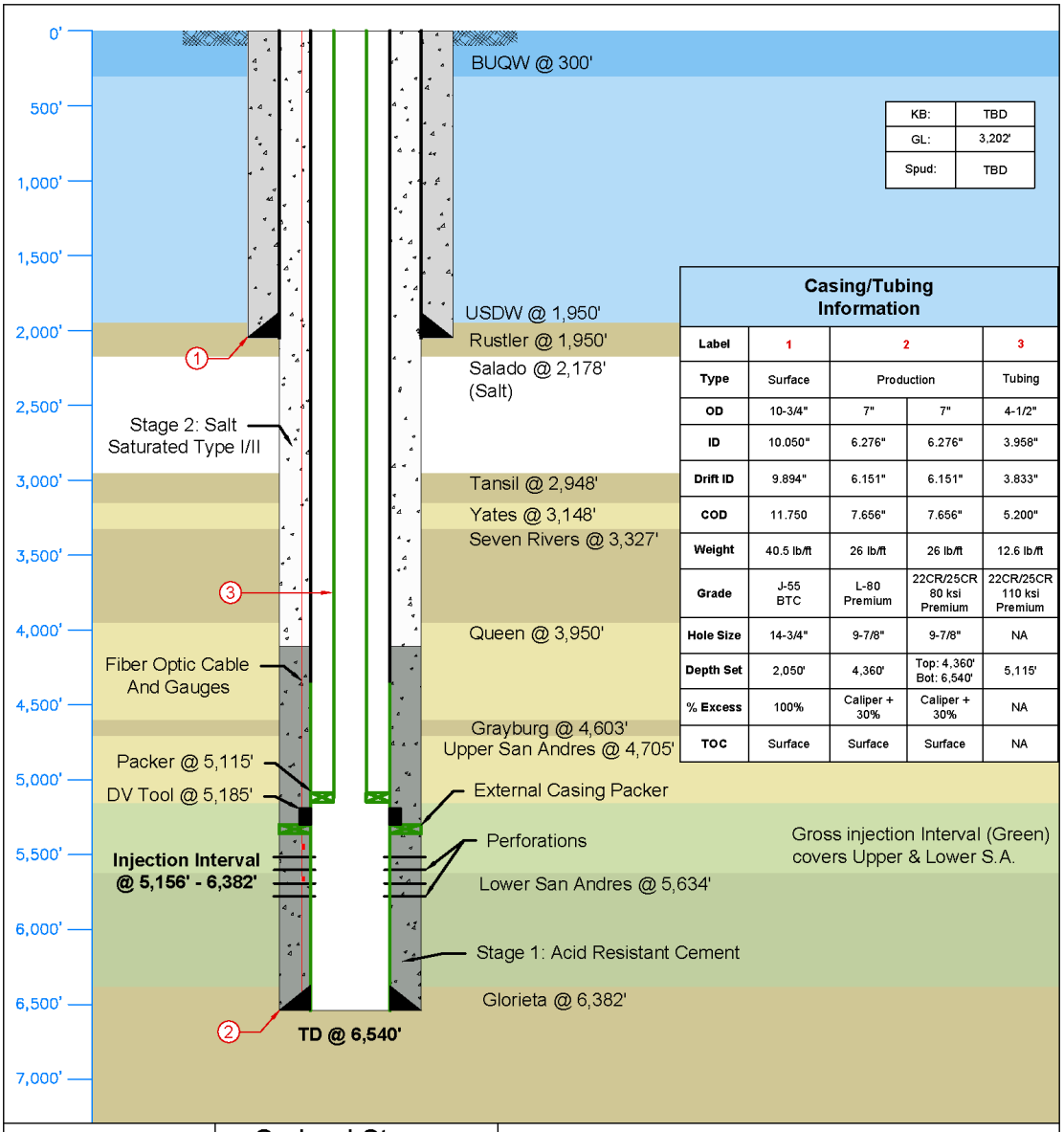


Figure 4-7 – Orchard No. 4 Wellbore Schematic

4.3.4.1 Conductor Casing

The 16 in., 84 lb/ft conductor casing will be set at approximately 120 ft. The 15.010 in. ID of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.4.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 2,050 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers.

Summaries of engineering calculations for the surface casing are provided in Tables 4-28 through 4-30.

Table 4-28 – Injection Well Surface Casing Engineering Calculations, Orchard No. 4

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 to 2,050 ft TD)	40.5	2,050	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			83,025	1,333	1,333			
Safety Factor			7.58	1.19	2.35			

Table 4-29 – Injection Well Surface Casing Annular Geometries, Orchard No. 4

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	2,050	2,050

Table 4-30 – Injection Well Surface Casing Cement Calculations, Orchard No. 4

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,930	0.5563	100	2,147
Shoe Track	45	0.5509	0	25

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.4.3 Production Casing

The engineering and design parameters for the production casing are summarized in Tables 4-31 through 4-33.

Table 4-31 – Injection Well Production Casing Engineering Calculations, Orchard No. 4

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 to 4,360 ft)	26	4,360	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			170,040	2,834	2,834			
Safety Factor			3.55	1.91	2.55			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,360 to 6,540 ft)	26	6,540	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			56,680	4,251	4,251			
Safety Factor			10.66	1.27	1.70			

Table 4-32 – Injection Well Production Casing Annular Geometries, Orchard No. 4

Section	ID (in)	MD (ft)	TVD (ft)
Surface Casing	10.050	2,050	2,050
Openhole	9.875	6,540	6,540

Table 4-33 – Injection Well Production Casing Cement Calculations, Orchard No. 4

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	2,050	0.2836	0	581
Stage 2 Openhole/7 in. Casing Annulus Lead	2,050	0.2646	30	705
Stage 2 Openhole/7 in. Casing Annulus Tail	1,085	0.2646	30	373
Stage 1 Openhole/7 in. Casing Annulus	1,355	0.2646	30	466
Shoe Track	90	0.2148	0	19

4.3.4.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place.

4.3.4.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,050 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 19 centralizers will be run on the surface casing.

Centralizer placement for the 7-in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.
- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.4.6 Injection Tubing

Table 4-34 lists the tubing specifications, design criteria, and calculated safety factors. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-34 – Injection Tubing Specifications, Orchard No. 4

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Drift ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,115 ft)	12.6	5,115	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			64,449	6,760	7,292			
Safety Factor			6.14	1.76	1.26			

4.3.5 Orchard Well No. 5 Design

Figure 4-8 provides the design schematic for Orchard No. 5.

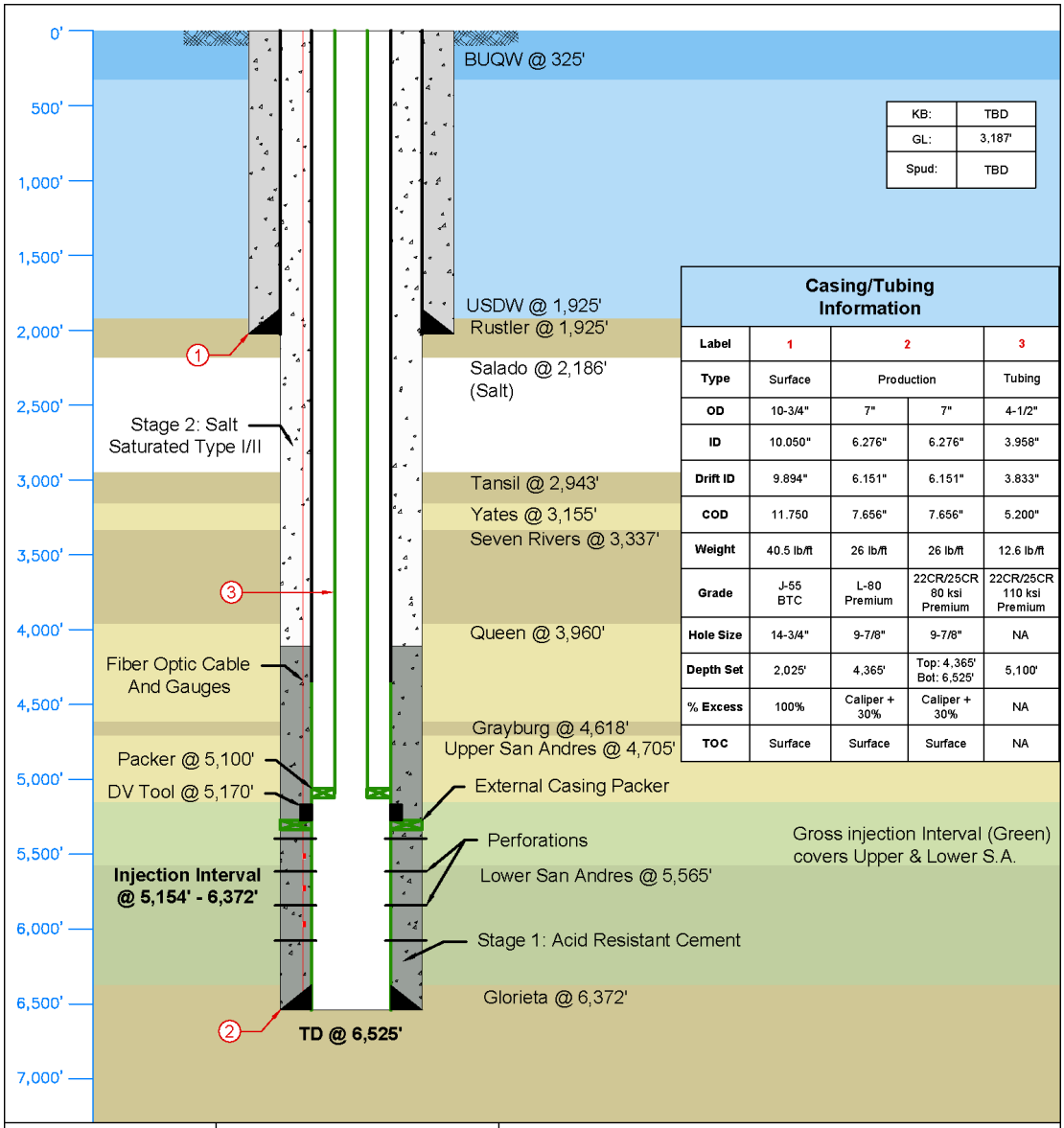


Figure 4-8 – Orchard No. 5 Wellbore Schematic

4.3.5.1 Conductor Casing

The 16 in., 84 lb/ft conductor casing will be set at approximately 120 ft. The 15.010-in. ID of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.5.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 2,025 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers.

Summaries of engineering calculations for the surface casing are provided in the following tables (4-35 through 4-37):

Table 4-35 – Injection Well Surface Casing Engineering Calculations, Orchard No. 5

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 to 2,025 ft TD)	40.5	2,025	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			82,013	1,316	1,316			
Safety Factor			7.67	1.20	2.38			

Table 4-36 – Injection Well Surface Casing Annular Geometries, Orchard No. 5

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	2,025	2,025

Table 4-37 – Injection Well Surface Casing Cement Calculations, Orchard No. 5

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,905	0.5563	100	2,120
Shoe Track	45	0.5509	0	25

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.5.3 Production Casing

The engineering and design parameters for the production casing are summarized in Tables 4-38 through 4-40.

Table 4-38 – Injection Well Production Casing Engineering Calculations, Orchard No. 5

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 ft to 4,365 ft)	26	4,365	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			169,650	2,837	2,837			
Safety Factor			3.56	1.91	2.41			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,365 to 6,525 ft)	26	6,525	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			56,160	4,241	4,241			
Safety Factor			10.75	1.28	1.71			

Table 4-39 – Injection Well Production Casing Annular Geometries, Orchard No. 5

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	10.050	2,025	2,025
Openhole	9.875	6,525	6,525

Table 4-40 – Injection Well Production Casing Cement Calculations, Orchard No. 5

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	2,025	0.2836	0	574
Stage 2 Openhole/7 in. Casing Annulus Lead	2,085	0.2646	30	717
Stage 2 Openhole/7 in. Casing Annulus Tail	1,060	0.2646	30	365
Stage 1 Openhole/7 in. Casing Annulus	1,355	0.2646	30	466
Shoe Track	90	0.2148	0	19

4.3.5.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place.

4.3.5.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,025 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 18 centralizers will be run on the surface casing.

Centralizer placement for the 7 in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.
- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.5.6 Injection Tubing

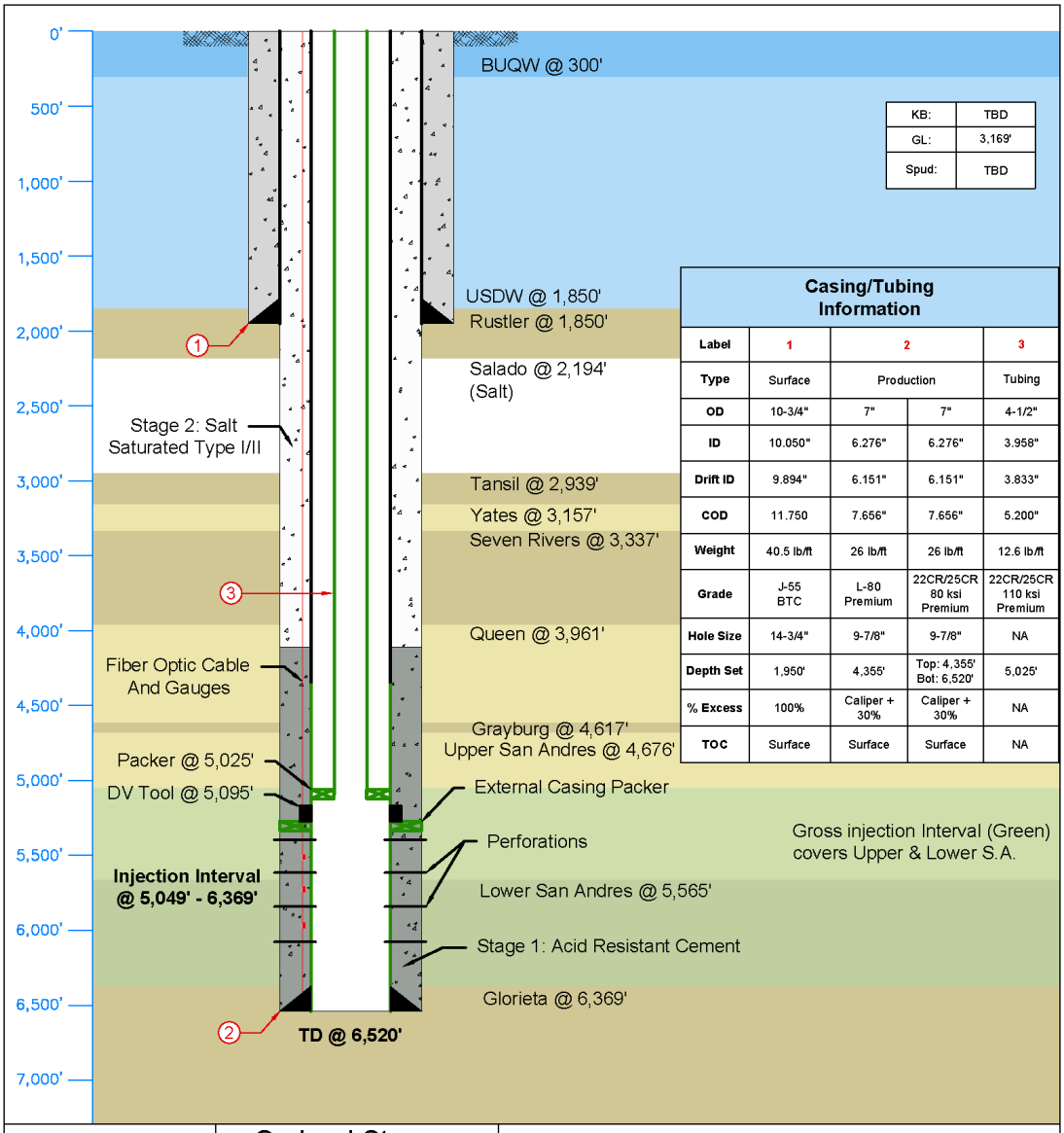
Table 4-41 lists the tubing specifications, design criteria, and calculated safety factors. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-41 – Injection Tubing Specifications, Orchard No. 5

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Drift ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,100 ft)	12.6	5,100	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			64,260	6,752	7,282			
Safety Factor			6.16	1.77	1.26			

4.3.6 Orchard Well No. 6 Design

Figure 4-9 provides the design schematic for Orchard No. 6.



KB:	TBD
GL:	3,169'
Spud:	TBD

Casing/Tubing Information

Label	1	2		3
Type	Surface	Production		Tubing
OD	10-3/4"	7"	7"	4-1/2"
ID	10.050"	6.276"	6.276"	3.958"
Drift ID	9.894"	6.151"	6.151"	3.833"
COD	11.750	7.656"	7.656"	5.200"
Weight	40.5 lb/ft	26 lb/ft	26 lb/ft	12.6 lb/ft
Grade	J-55 BTC	L-80 Premium	22CR/25CR 80 ksi Premium	22CR/25CR 110 ksi Premium
Hole Size	14-3/4"	9-7/8"	9-7/8"	NA
Depth Set	1,950'	4,355'	Top: 4,355' Bot: 6,520'	5,025'
% Excess	100%	Caliper + 30%	Caliper + 30%	NA
TOC	Surface	Surface	Surface	NA

LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #6	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: TBD	**District:** 8A	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** Injection
Texas License F-22610	**State Gas ID No:**	**Project No:** LS175	**Date:** 1/31/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 4-9 – Orchard No. 6 Wellbore Schematic

4.3.6.1 Conductor Casing

Sixteen-inch conductor casing will be used to ensure that hole integrity can be maintained during the initial drilling of the well. The 16 in., 84 lb/ ft conductor casing will be set at approximately 120 ft. The 15.010 in. ID of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.6.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 1,950 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers.

Summaries of engineering calculations for the surface casing are provided in Table 4-42 through 4-44.

Table 4-42 – Injection Well Surface Casing Engineering Calculations, Orchard No. 6

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 to 1,950 ft)	40.5	1,950	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			78,975	1,268	1,268			
Safety Factor			7.96	1.25	2.47			

Table 4-43 – Injection Well Surface Casing Annular Geometries, Orchard No. 6

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	1,950	1,950

Table 4-44 – Injection Well Surface Casing Cement Calculations, Orchard No. 6

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,830	0.5563	100	2,036
Shoe Track	45	0.5509	0	25

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.6.3 Production Casing

The engineering and design parameters for the production casing are summarized in Tables 4-45 through 4-47.

Table 4-45 – Injection Well Production Casing Engineering Calculations, Orchard No. 6

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 to 4,355 ft)	26	4,355	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			169,520	2,831	2,831			
Safety Factor			3.56	1.91	2.56			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,355 to 6,520 ft)	26	6,520	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			56,290	4,238	4,238			
Safety Factor			10.73	1.28	1.71			

Table 4-46 – Injection Well Production Casing Annular Geometries, Orchard No. 6

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	10.050	1,950	1,950
Openhole	9.875	6,520	6,520

Table 4-47 – Injection Well Production Casing Cement Calculations, Orchard No. 6

Section	Footage (ft)	Capacity (ft^3/ ft)	Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	1,950	0.2836	0	553
Stage 2 Openhole/7 in. Casing Annulus Lead	2,160	0.2646	30	743
Stage 2 Openhole/7 in. Casing Annulus Tail	985	0.2646	30	339
Stage 1 Openhole/7 in. Casing Annulus	1,425	0.2646	30	490
Shoe Track	90	0.2148	0	19

4.3.6.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place.

4.3.6.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 1,950 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 18 centralizers will be run on the surface casing.

Centralizer placement for the 7 in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.
- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.6.6 Injection Tubing

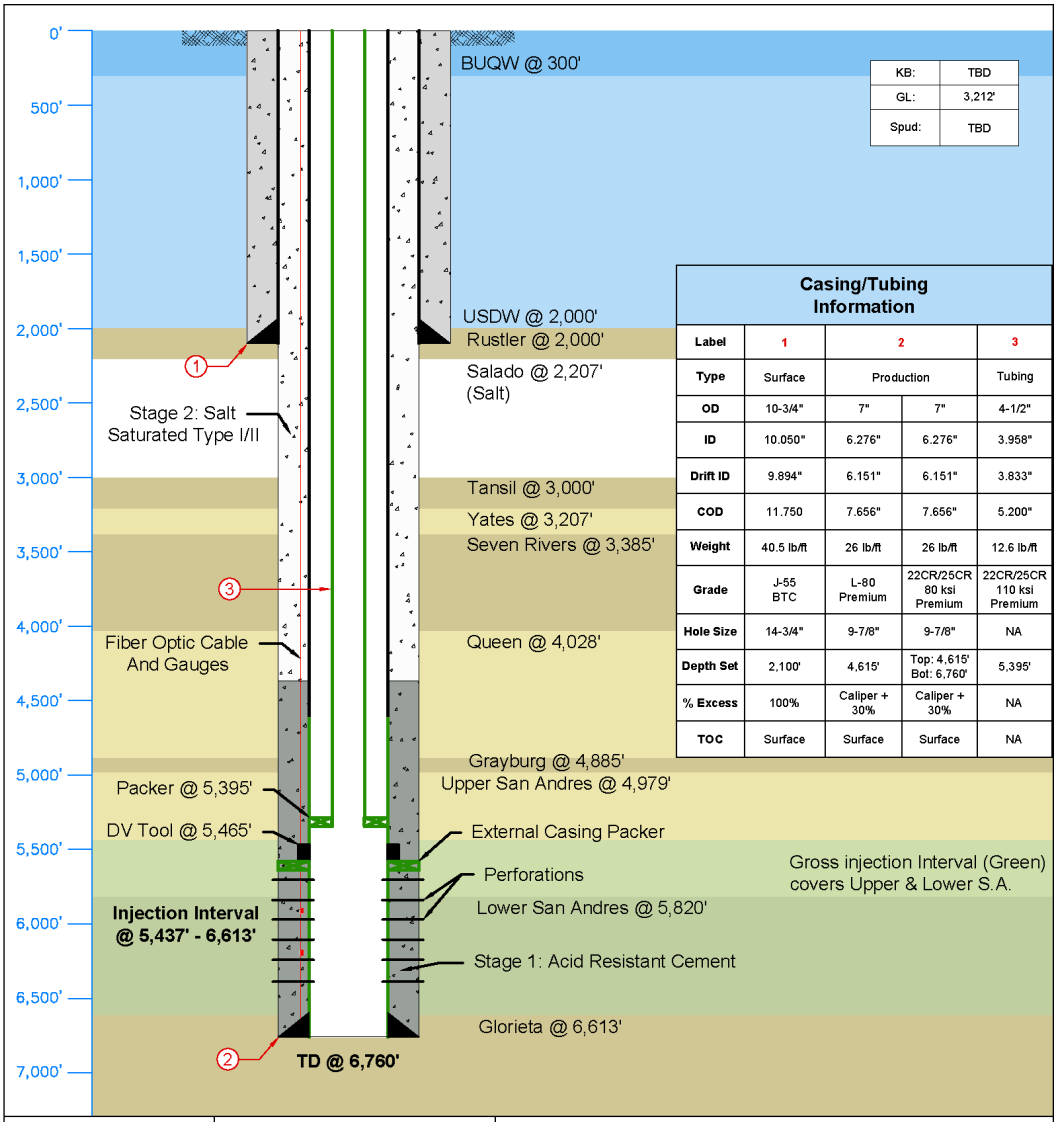
Table 4-48 lists the tubing specifications, design criteria, and calculated safety factors. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-48 – Injection Tubing Specifications, Orchard No. 6

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Drift ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,025 ft)	12.6	5,025	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			63,315	6,713	7,236			
Safety Factor			6.25	1.78	1.27			

4.3.7 Orchard Well No.7 Design

Figure 4-10 provides the design schematic for Orchard No. 7



KB:	TBD
GL:	3,212'
Spud:	TBD

Casing/Tubing Information

Label	1	2		3
Type	Surface	Production		Tubing
OD	10-3/4"	7"	7"	4-1/2"
ID	10.050"	6.276"	6.276"	3.958"
Drift ID	9.894"	6.151"	6.151"	3.833"
COD	11.750	7.656"	7.656"	5.200"
Weight	40.5 lb/ft	26 lb/ft	26 lb/ft	12.6 lb/ft
Grade	J-55 BTC	L-80 Premium	22CR/25CR 80 ksi Premium	22CR/25CR 110 ksi Premium
Hole Size	14-3/4"	9-7/8"	9-7/8"	NA
Depth Set	2,100'	4,615'	Top: 4,615' Bot: 6,760'	5,395'
% Excess	100%	Caliper + 30%	Caliper + 30%	NA
TOC	Surface	Surface	Surface	NA

LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #7	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: TBD	**District:** 8A	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** Injection
Texas License F-22610	**State Gas ID No:**	**Project No:** LS175	**Date:** 1/31/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 4-10 – Orchard No. 7 Wellbore Schematic

4.3.7.1 Conductor Casing

Sixteen-inch conductor casing will be used to ensure that hole integrity can be maintained during the initial drilling of the well. The 16 in., 84 lb/ ft conductor casing will be set at approximately 120 ft. The 15.010 in. ID of conductor casing was selected to facilitate the drilling of the surface casing borehole with a 14-¾ in. bit.

4.3.7.2 Surface Casing

The surface hole will be drilled with a 14-¾ in. bit with casing set approximately 2,100 ft, which is below the lowermost USDW. A string of 10-¾ in. casing will be run and cemented with the casing centered in the open hole using centralizers.

Summaries of engineering calculations for the surface casing are provided in Tables 4-49 through 4-51.

Table 4-49 – Injection Well Surface Casing Engineering Calculations, Orchard No. 7

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-3/4 in., 40.5 lb/ft, J-55, BTC (0 to 2,100 ft)	40.5	2,100	629,000	1,580	3,130	0.0981	10.050	9.894
Design Criteria			85,050	1,365	1,365			
Safety Factor			7.40	1.16	2.29			

Table 4-50 – Injection Well Surface Casing Annular Geometries, Orchard No. 7

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	15.010	120	120
Openhole	14.75	2,100	2,100

Table 4-51 – Injection Well Surface Casing Cement Calculations, Orchard No. 7

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Conductor Pipe/Casing Annulus	120	0.5985	0	72
Openhole/Casing Annulus	1,980	0.5563	100	2,203
Shoe Track	45	0.5509	0	25

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes will be used. The equipment and cement will be on location to perform a top job if needed.

4.3.7.3 Production Casing

The engineering and design parameters for the production casing are summarized in Tables 4-52 through 4-54.

Table 4-52 – Injection Well Production Casing Engineering Calculations, Orchard No. 7

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7 in., 26 lb/ft, L-80, Premium Connection (0 to 4,615 ft)	26	4,615	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			175,760	3,000	3,000			
Safety Factor			3.44	1.80	2.41			
7 in., 26 lb/ft, 22CR/25CR, 80ksi Premium Connection (4,615 to 6,760 ft)	26	6,760	604,000	5,410	7,240	0.0383	6.276	6.151
Design Criteria			55,770	4,394	4,394			
Safety Factor			10.83	1.23	1.65			

Table 4-53 – Injection Well Production Casing Annular Geometries, Orchard No. 7

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	10.050	2,100	2,100
Openhole	9.875	6,760	6,760

Table 4-54 – Injection Well Production Casing Cement Calculations, Orchard No. 7

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Stage 2 Surface Casing/Casing Annulus Lead	2,100	0.2836	0	596
Stage 2 Openhole/7 in. Casing Annulus Lead	2,285	0.2646	30	786
Stage 2 Openhole/7 in. Casing Annulus Tail	1,080	0.2646	30	372
Stage 1 Openhole/7 in. Casing Annulus	1,295	0.2646	30	445
Shoe Track	90	0.2148	0%	19

4.3.7.4 Downhole Monitoring System

The Orchard injection wells will have a continuous downhole monitoring system in place throughout the life of the well. The system will be able to measure and record downhole temperatures and pressures in the injection interval and allow for vertical seismic profile (VSP) surveys of the CO_2 plume. The system will include fiber optic cable with an electric cable sensor package run along the backside of the production casing and cemented in place.

4.3.7.5 Centralizers

The bow-spring centralizer placement for the 10-¾ in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,100 ft of 10-¾ in. x 14-¾ in. annular void. The recommended locations will be as follows:

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

A total of 19 centralizers will be run on the surface casing.

Centralizer placement for the 7 in. production casing will be designed to install the fiber optic cable. Clamp and eccentric centralizers of the same alloy as the production casing will be utilized to ensure the fiber optic cable is not damaged.

- Two slide-on, eccentric centralizers will be placed across a two-joint shoe track. A cable clamp will be installed above the top eccentric centralizer for security.
- Clamp centralizers will be run every four joints (160 ft) to the surface, and cable detection clamps will be run every three to four joints.
- Fiber module protectors will be installed every five to six joints.

4.3.7.6 Injection Tubing

Table 4-55 lists the tubing specifications, design criteria, and calculated safety factors. The collapse design assumes evacuated tubing with brine on the backside, and 4,100 psi applied. The burst assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,100 psi applied.

Table 4-55 – Injection Tubing Specifications, Orchard No. 7

Description	Tubing Wt. (lb/ft)	Depth (ft)	Tensile (lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	Casing ID (in.)	Drift ID (in.)
4-1/2 in., 12.6 lb/ft, 22CR/25CR, 110ksi Premium Connections (0 to 5,395 ft)	12.6	5,395	396,000	11,920	9,210	0.0152	3.958	3.833
Design Criteria			67,977	6,905	7,466			
Safety Factor			5.83	1.73	1.23			

4.3.8 Wellhead Discussion

The wellheads are designed to accommodate anticipated working pressures and eliminate corrosion complications. The wellhead equipment will be manufactured from a combination of stainless-steel components across the hanger and casing spool. Inconel lining will be placed across trims, stems, gates, valves, etc. The final pressure rating will be confirmed before beginning the manufacturing process. The wellheads for each of the Orchard No. 1 to No.7 injection wells will be configured as shown in Figure 4-11 (note: the manufacturer of the wellhead may differ).

Figure 4-12 illustrates the control valves and monitoring equipment that will be installed at Orchard No. 1 to No. 7. As described in Section 5.5.1, the injection stream will be continuously monitored to meet 16 TAC ***§*5.203 (j)(2)(B)** [40 CFR ***§*146.90(b)]** requirements. A Supervisory Control and Data Acquisition (SCADA) system will be installed at the Project Orchard site to facilitate the operational data collection, monitoring, and reporting. In accordance with 16 TAC ***§*5.206 (d)(2)(B)**, the total volume of CO_2 injected into the Orchard Project facility will be metered through either a master meter or a series of master meters. The volume or mass of CO_2 injected into Orchard wells No. 1 through No. 7 will be metered through individual well meters.

Continuous monitoring of the injected CO_2 stream pressure and temperature will be performed using digital pressure and temperature gauges installed at individual well sites. A flowmeter will also be installed on each of the injection wells and connected to the SCADA system at the CO_2 storage site, to ensure continuous monitoring and control of the CO_2 injection rate.

The wellhead (wellhead and tree assembly) will accommodate continuous annular pressure measurement and injection pressure (tubing pressure) measurement. As described in Section 5.4.7, injection wells, the tree and well injection skid will be continuously monitored via the SCADA system and will be equipped with automated shutdown systems. These systems include, at a minimum, an actuated master valve and an actuated wing valve to automatically shut down flow in the event of an emergency.

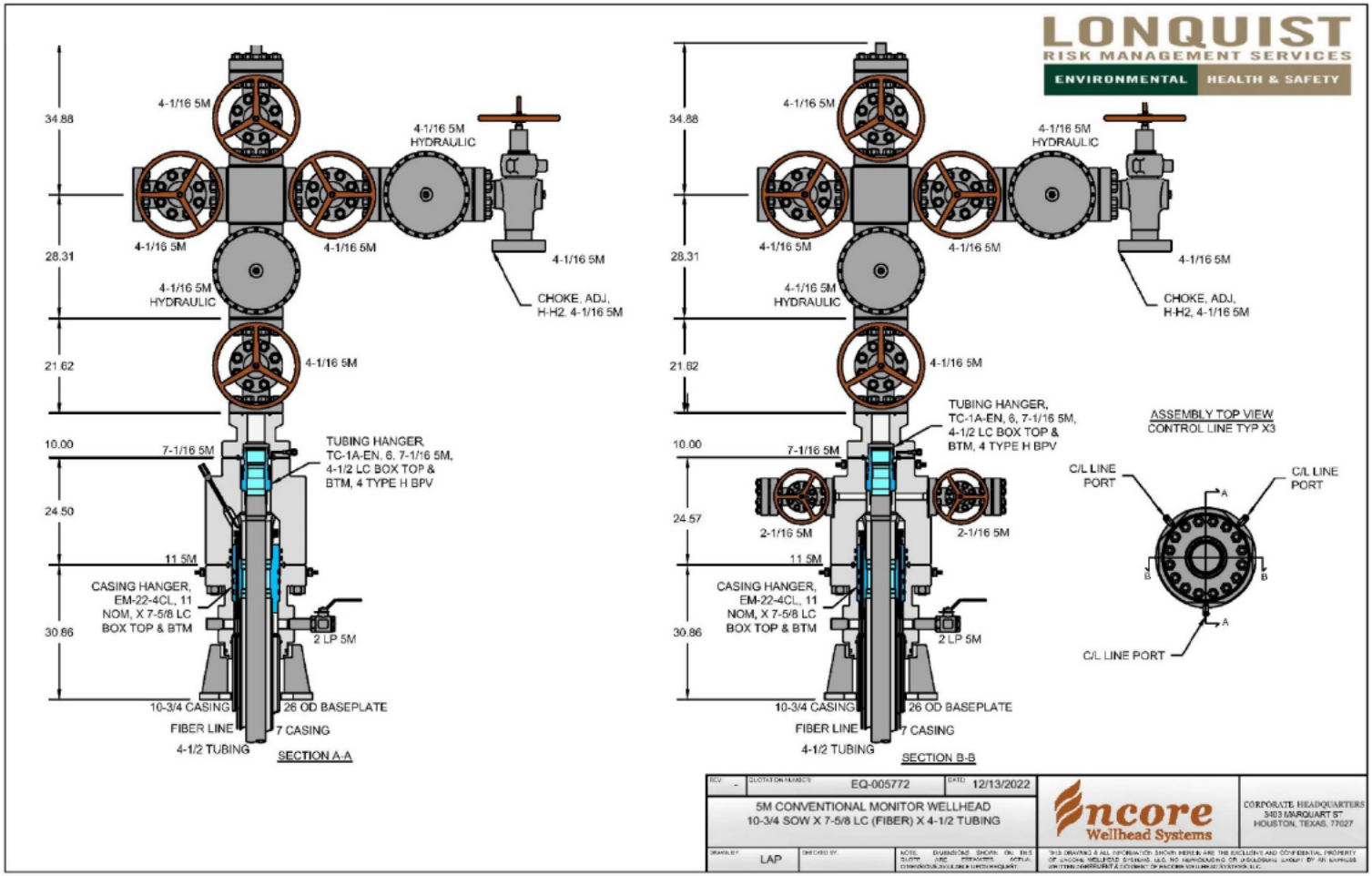
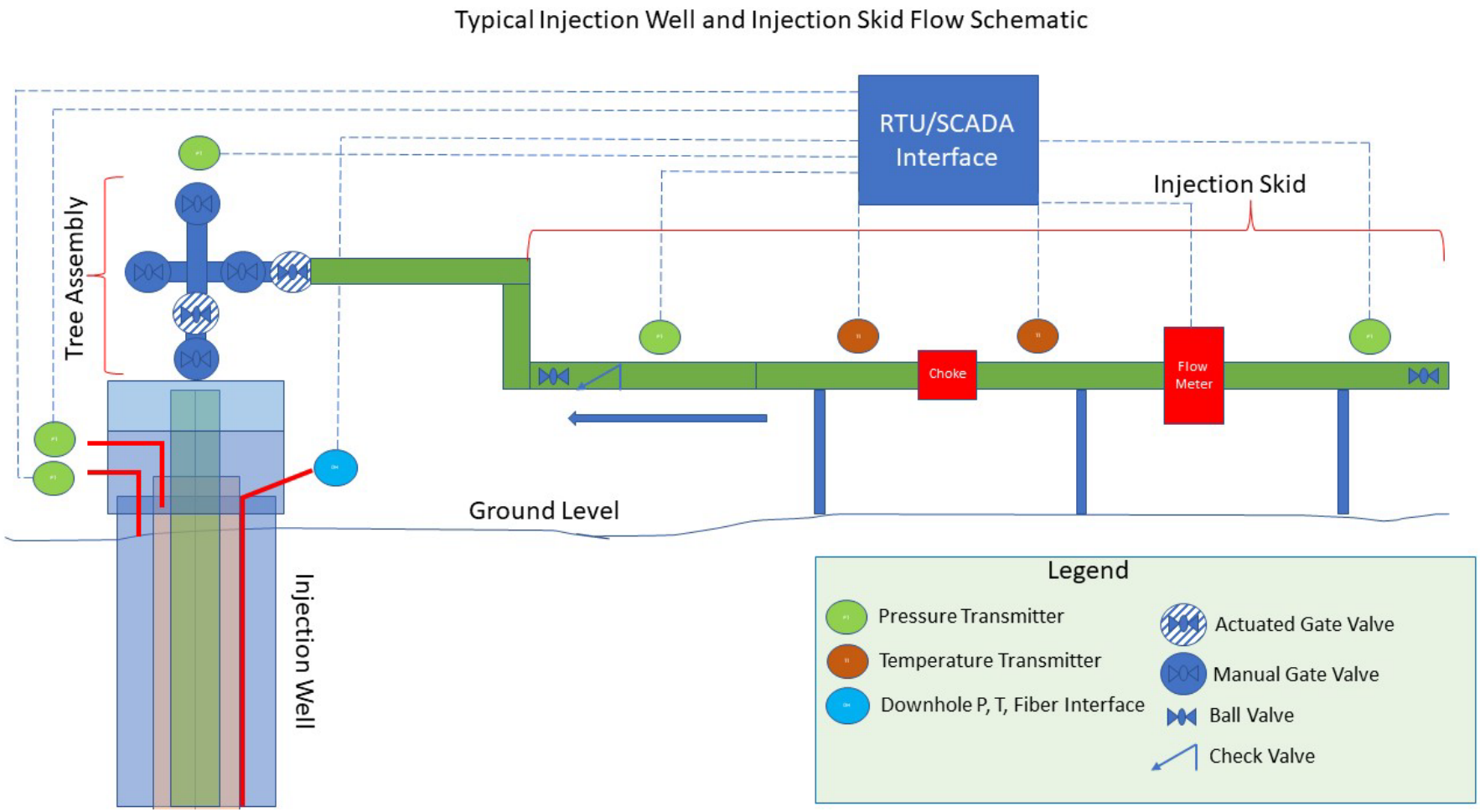


Figure 4-11 –Preliminary Wellhead Design, Orchard No. 1 to No. 7



*RTU – remote telemetry unit

Figure 4-12 – Typical Injection Well and Injection Skid Flow Schematic

4.3.9 Testing and Logging During Drilling and Completion Operations

4.3.9.1 Deviation Surveys

Deviation checks will be taken every 100 ft during drilling operations for each section of each well, regardless of hole size. The overall maximum allowable deviation of the wellbore is 3 degrees, and the maximum allowable deviation for any 100-ft segment is 1 degree for each well.

4.3.9.2 Coring Plan

As discussed in the drilling procedures in *Appendix C-1*, core samples will be collected during the drilling of the Orchard wells. Specifically, Orchard intends to obtain whole core in Well Nos. 1, 3, 6, 7 and MW No. 1. The core sampling will target the UCZ, the injection interval, and the lower confining zone. The estimated depths for each core section are provided in Table 4-56. In addition, Table 4-56 specifies whole core to be acquired in the Orchard MW No. 1 in the Queen formation, the first permeable zone above the UCZ. Decisions regarding rotary side wall cores will be determined based on each openhole log and, if obtained, the whole core recovery will supplement the necessary analysis as needed.

Whole core will be acquired, preserved as necessary, and transported to lab facilities for further analysis. Whole core will be subjected to routine whole core analysis including spectral gamma, photography, CT scan and then slabbed and will be plugged in selected intervals. Core plugs will be further analyzed for the relevant reservoir properties. Orchard intends to conduct special core analysis (SCAL) on selected samples to measure mechanical properties, capillary pressure and other reservoir properties. Table 4-57 provides additional specifics of anticipated core analysis.

Table 4-56 – Core Plan Summary Table

Well Number	1	2	3	4	5	6	7	MW 1	MW 2	MW 3
Well Type	**Injector**	**Injector**	**Injector**	**Injector**	**Injector**	**Injector**	**Injector**	**Above Zone**	**In Zone**	**Above Zone**
Comment								Queen Fm	Existing Well	Queen Fm
Whole Core	Y		Y			Y	Y	Y		
Core in Injection Zone	Y		Y			Y	Y			
Core in UCZ	Y		Y			Y	Y			
Core in LCZ	Y		Y			Y	Y			
Above Confining Zone										
Top (MD - Ft)								4,600		
Bottom (MD- Ft)								4,630		
Whole core length (Ft)								30		
Injection Zone										
Top (MD - Ft)	5,720		5,390			5,510	5,710			
Bottom (MD - Ft)	5,780		5,450			5,570	5,770			
Whole core length (Ft)	60		60			60	60			
Upper Confining Zone										
Top (MD - Ft)	5,320		5,100			4,920	5,310			
Bottom (MD - Ft)	5,380		5,160			4,980	5,370			
Whole core length (Ft)	60		60			60	60			
Lower Confining Zone										
Top (MD - Ft)	6,570		6,350			6,300	6,560			
Bottom (MD - Ft)	6,630		6,410			6,360	6,620			
Whole core length (Ft)	60		60			60	60			
Sidewall Core	As needed, based on openhole log analysis and whole core recovery									

Table 4-57 – Proposed Core Analysis

Core Interval	Analysis	Upper Confining Zone	Injection Zone	Lower Confining Zone	Above Zone Monitoring Interval
Routine Core Analysis					
Whole Core[1]	Spectral Gamma Ray	X	X	X	X
	Core Photography	X	X	X	X
	CT Scan	X	X	X	X
	Geologic Core Description	X	X	X	X
Plug Samples[2]	2D CT Plug Scan		X		
	Fluid Saturation		X		X
	Porosity	X[3]	X	X[3]	X
	Permeability	X[3]	X	X[3]	X
	Thin Section description	X	X	X	
Special Core Analysis (SCAL)					
Plug Samples[2]	Capillary Pressure	X	X		
	Triaxial Compressive Strength	X	X	X	
	X-Ray Diffraction		X		
	Archie Exponents		X		
	Relative Permeability		X		

1. Entire core
2. Plugs selections based on core recovery and openhole logs
3. If possible

4.3.9.3 Logging Plan

An extensive suite of electric logs (detailed in Tables 4-58 and 4-59) will be run in the openhole sections and each casing string. Orchard Storage will provide a schedule of all logging plans to the Director at least 30 days prior to conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

Table 4-58 – Injection Well Openhole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Depths of Survey
1	Surface Casing	Triple Combo (Gamma Ray (GR), Spontaneous Potential (SP), Photoelectric (PE), Resistivity, Neutron, Density)	Identification of Rock Properties	14-3/4 in.	0 – surface casing point*
2		Sonic (Dipole)			
3		Openhole Caliper			
4	Production Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock and Fluid Properties	9-7/8 in.	Surface casing point - TD
5		Sonic (Dipole)			
6		Openhole Caliper			
7		Fullbore Formation Microimager (FMI)			UCZ to TD
8		Sidewall Cores (as needed)			
9		Repeat Formation Tester (RFT)/ Modular Formation Dynamics Tester (MDT)			Selected Intervals
10		Spectral GR			UCZ to TD

* See wellbore schematics for expected surface casing points.

The RFT/MDT highlighted in the openhole logging plan will be used to collect representative baseline samples of the injection zone formation fluids prior to the start of injection. These samples will be collected, transferred to appropriate shipping containers for transport to a lab to perform the necessary testing to characterize the formation fluids for baseline chemistry and composition. The detailed parameters to be collected are provided in Table 17 in the Quality Assurance and Surveillance Plan provided in Appendix E.

Table 4-59 – Injection Well Casedhole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension	Depths of Survey
1	Surface Casing	Ultrasonic, Casing Collar Locator (CCL), Cement Bond Log (CBL), Cement Mapping Tool (CMT), GR, Temperature, VDL	Cement Investigation	10-3/4 in.	0 – Surface casing point
2	Production Casing	Ultrasonic, CCL, CBL, CMT, GR, Temp (Bond Log), VDL	Cement Investigation	7 in.	Surface casing point - TD
3		Pulsed Neutron Log – Baseline			UCZ to TD

4.3.9.4 Formation Fluid Testing

Before setting the production casing string, samples of the formation fluid will be obtained by running an openhole fluid recovery tool. Recovery sections will be determined based on openhole evaluations. Multiple samples will be taken per section based upon results of the openhole logs. Data collected during testing and logging will include formation fluid temperature, pH, conductivity, reservoir pressure and static fluid level. Additionally, drawdown and buildup tests, as described in *Section 5 – Testing and Monitoring Plan*, will be performed to further quantify reservoir properties.

4.3.9.5 Fracture Pressure Determination, Injection Zone - Step-Rate Test and Core Analyses

After the initial injection interval is perforated, a step-rate test will be performed in the injection zone prior to any stimulation work, as discussed in *Section 5*. The purpose of this test is to quantify the injectivity potential and the fracture pressure of the injection zone. Additionally, the special core analysis from the injection zone will be used to further determine the fracture pressure of this zone.

4.3.9.6 Fracture Pressure Determination, Upper Confining Zone – Core Analyses

Fracture pressure determination for the confining zone will be obtained as part of the special core analysis of the samples from the confining zone. No step-rate test will be performed in the confining zone to avoid fracturing of the confining zone.

4.3.10 Completion/Stimulation Plans

Following the approval to inject, the injection zone will be stimulated to create fractures with a half-length on the order of 27 ft. This fracture half-length will limit vertical growth of the fractures. Actual stimulation design will be determined based on log analysis and core results. This

stimulation design is expected to yield a completion skin value around -3.5. The fracture stimulation will serve two purposes, the first of which is that the stimulation will create a negative completion skin that will reduce injection pressure vs. an unstimulated case. Second, stimulation of the perforated intervals throughout the injection zone will ensure good injection conformance, distributing injected CO_2 throughout the injection interval.

Orchard anticipates that the stimulation fluid would be a slickwater fracture fluid designed appropriately to generate the desired response in the injection formation once fully defined from drilling operations. Final fluid composition will be determined and identified based on log and core analysis. Variables to consider will include lithologies, porosity/permeability, mechanical properties including the fracture gradients of injection and confining zones. The stimulation plan will be designed to ensure that the proposed fracture stimulation will not impact the upper confining zone. To ensure that confinement is maintained, the plan will include:

- Modeling to show that the stimulation fluid(s) will not react with the upper confining zone in such a way as to lessen the confining nature of the zone.
- Injection pressures during stimulation will not create or propagate fractures in the confining zone.

4.3.11 Orchard Injection Well Operating Strategy

The Orchard Project injection wells will be operated in accordance with the following parameters provided in Table 4-60. The BHP output from the dynamic simulation model is calculated at the reference layer (for this model, the shallowest perforated layer). Reference depth for BHP is tabulated for each well on Table 4-6.

Under downhole wellbore and reservoir conditions, the CO_2 will stay in the supercritical phase throughout the project life. Figures 4-13 through 4-19 show the plots of the maximum pressure increase vs. time at the Orchard injection well locations. These plots represent the maximum of all grid blocks penetrated by the injection well at any given time. The maximum annular pressure will be 200 psi over the maximum injection pressure.

Table 4-60 – Orchard Injection Well Operating Parameters

Parameter	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
Injection Interval (ft)	5,473–6,597	5,345–6,490	5,230–6,563	5,183–6,257	5,168–6,264	5,051–6,365	5,453–6,514
Maximum Injection Volume (MT/yr)	610,000	574,000	571,000	475,000	1,145,000	1,432,000	667,000
Average Injection Volume (MT/yr)	303,000	283,000	278,000	211,000	458,000	483,000	303,000
Maximum Injection Rate (MMscf/d)	32.0	30.0	30.0	25.0	60.0	75.0	35.0
Average Injection Rate (MMscf/d)	15.9	14.8	14.6	11.1	24.0	25.3	15.9
Injection Pressure Limit (90% of fracture gradient)	3,284	3,207	3,138	3,110	3,101	3,031	3,272
Maximum Bottomhole Pressure (psi)	2,816	2,806	2,736	2,683	2,659	2,448	2,725
Maximum Surface Injection Pressure (psi)	933	955	934	899	936	845	860
Expected Surface Injection Pressure (psi)	868	888	934	850	873	830	830
Maximum Annular Pressure (psi)	1,500	1,450	1,425	1,514	1,538	1,971	1,478

Surface and bottomhole injection pressures will be continuously monitored during injection, with surface injection rates and pressures adjusted as necessary, to ensure that bottomhole pressures remain below maximum pressure limits. The maximum injection pressure limits will be set to 90% of the formation fracture pressure, as determined from step-rate and/or microfracture tests. These tests will be performed during the early stages of project development, prior to commencement of injection. In the current simulation case, the maximum injection bottomhole gradient was set to 0.6 psi/foot, which corresponds to 90% of an estimated 0.67 psi/foot fracture gradient. The fracture pressure gradient is calculated using the equation developed by Eaton (Eaton, 1969) using typical values, as shown in the example below:

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

$$FG = \frac{0.31}{1-0.31}(1.0 - 0.40) + 0.40$$

$$FG = 0.67\ psi/ft$$

Where	*FG*	=	Fracture gradient, psi/foot
	OBG	=	Overburden gradient
	PG	=	Pore pressure gradient
	ν	=	Poisson's Ratio

It should be noted that the calculation above is an example. Fracture pressure and injection pressure limits will be updated once step-rate and/or microfracture tests have been completed during project development.

Figures 4-13 through 4-19 show the injection rates and bottomhole pressures for the Orchard injection wells and the anticipated maximum injection pressure limits. The maximum injection pressure limit has been determined by applying the 0.6 psi (90% of 0.67 psi estimated fracture pressure) limit to the depth of the shallowest perforations. At no time does the modeled injection pressure exceed this injection pressure limit.

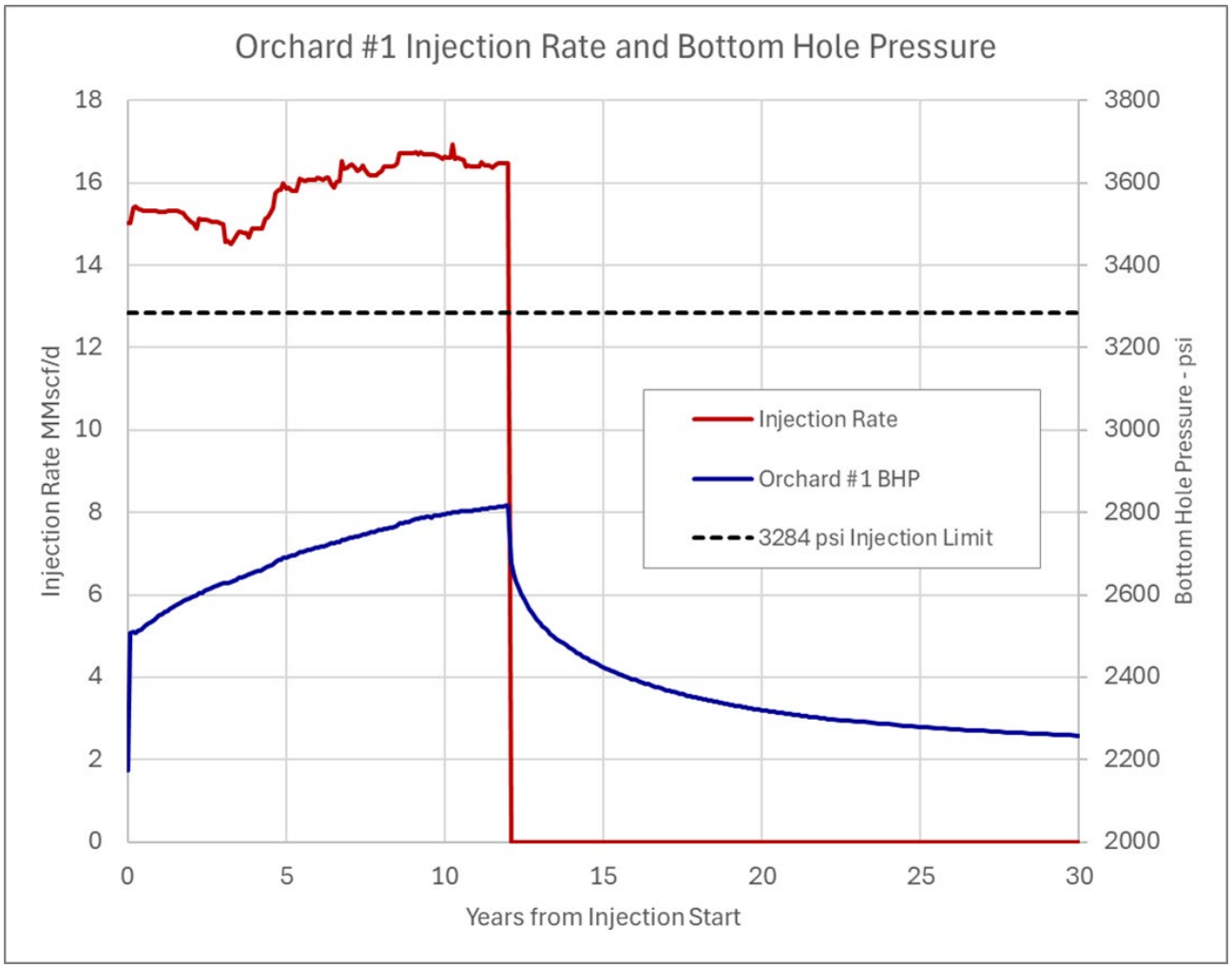


Figure 4-13 – Injection Pressure Plot, Orchard No. 1

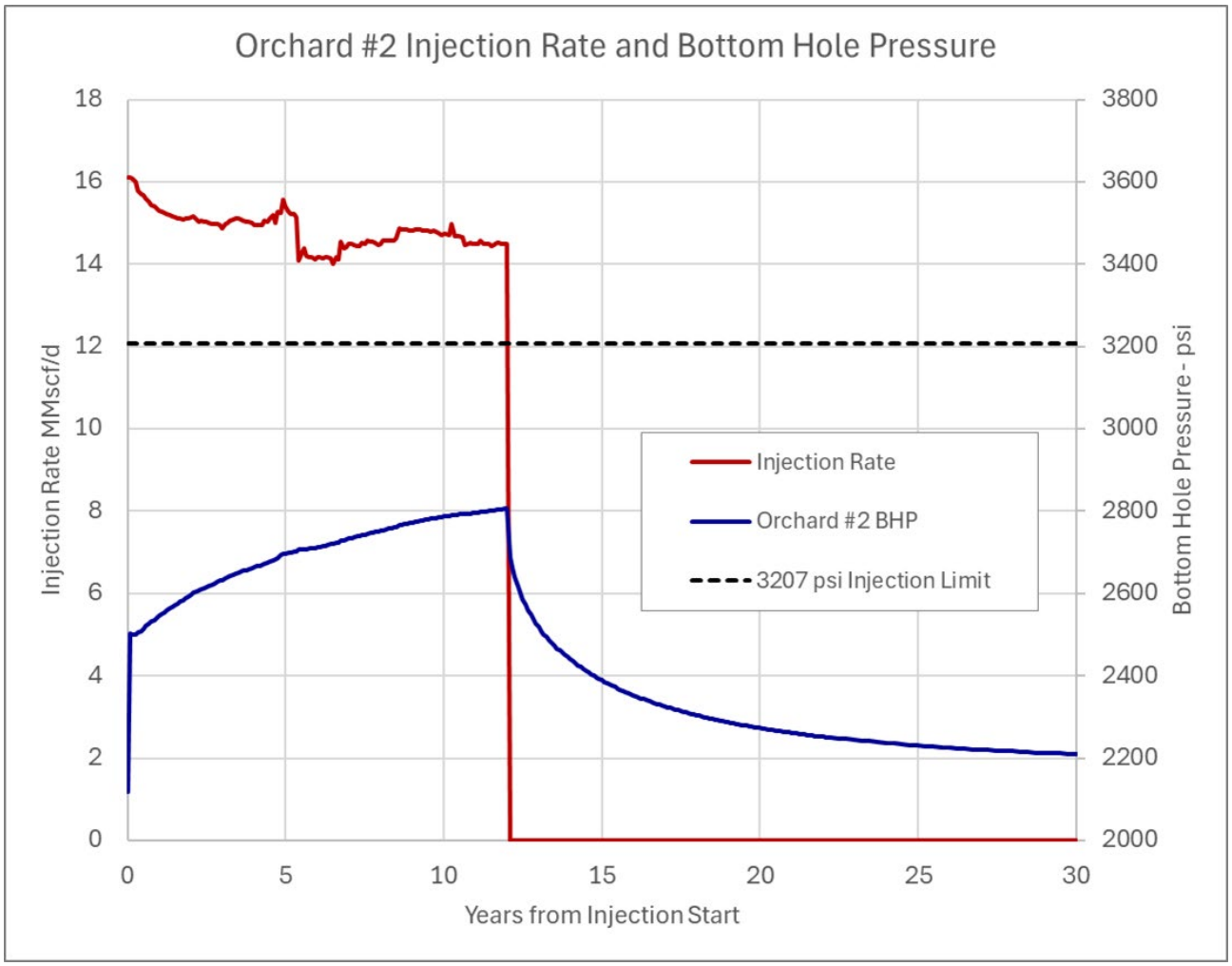


Figure 4-14 – Injection Pressure Plot, Orchard No. 2

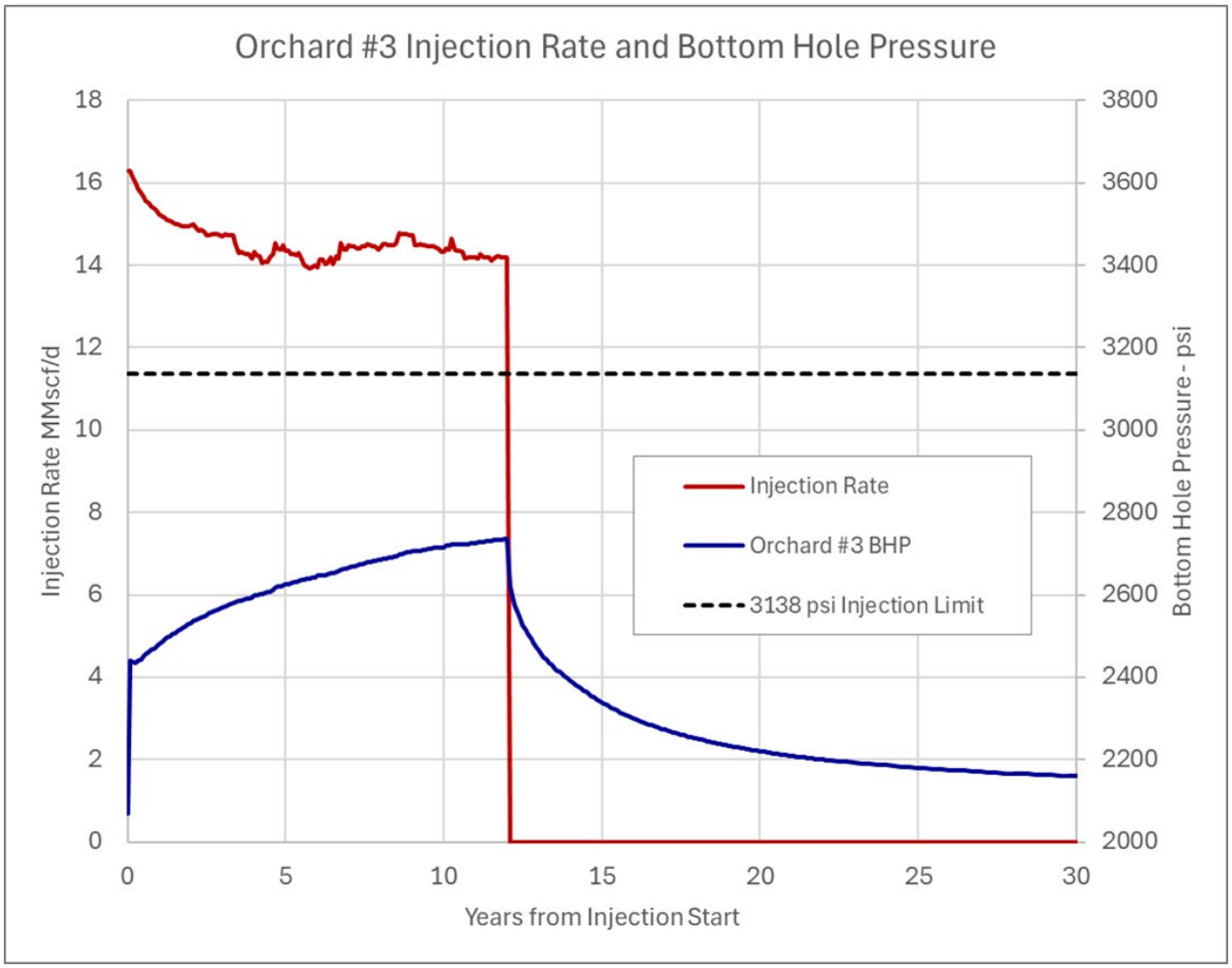


Figure 4-15 – Injection Pressure Plot, Orchard No. 3

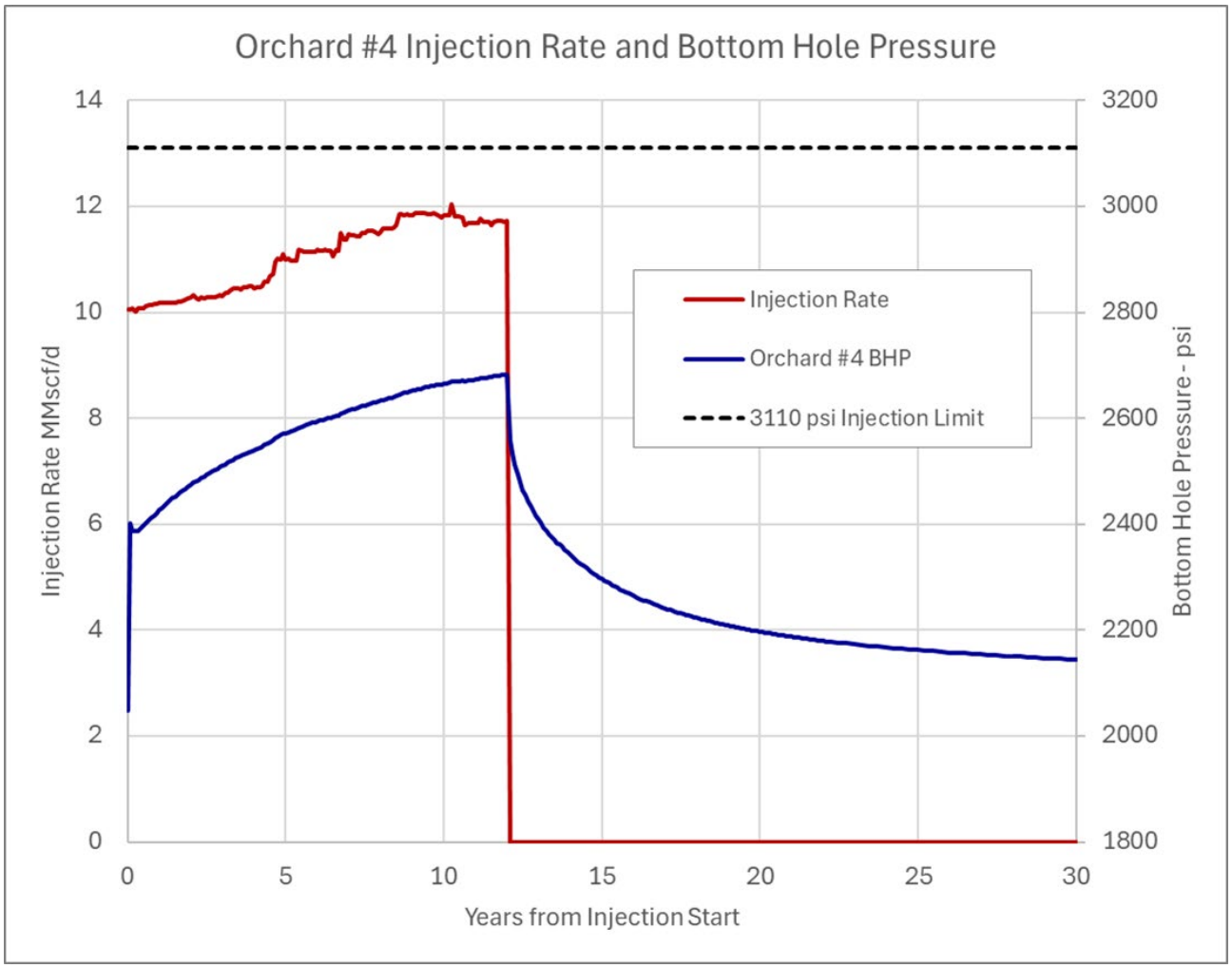


Figure 4-16 – Injection Pressure Plot, Orchard No. 4

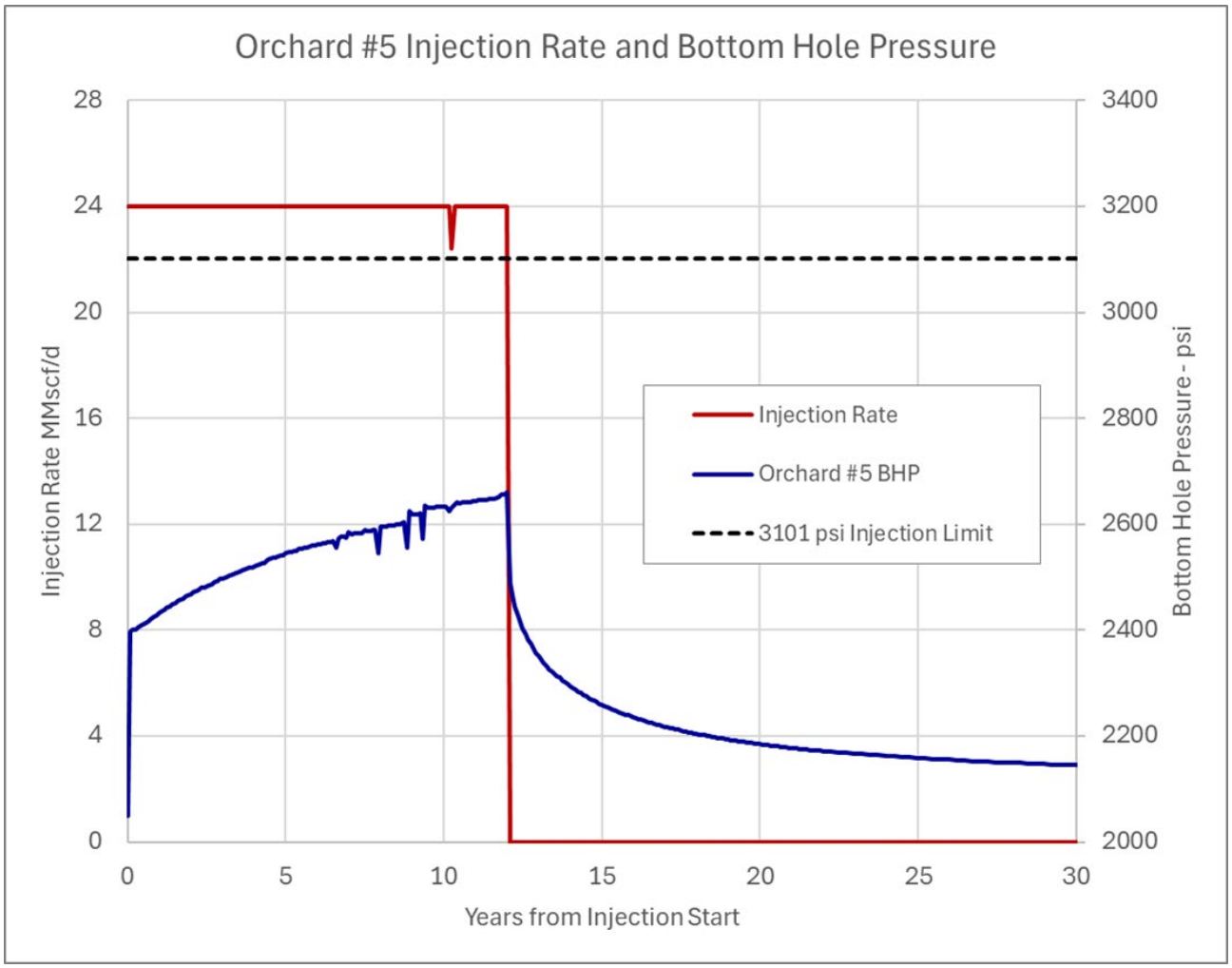


Figure 4-17 – Injection Pressure Plot, Orchard No. 5

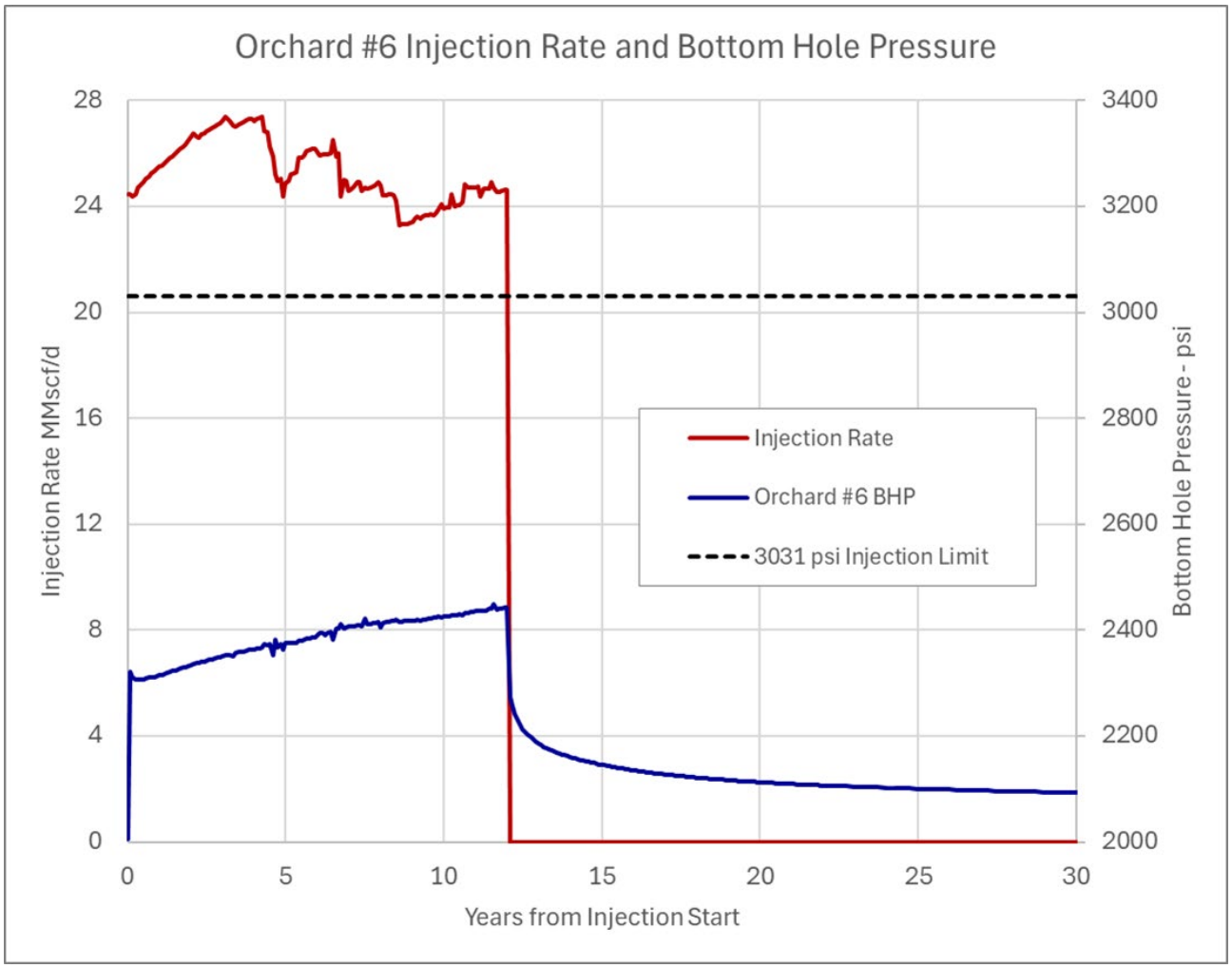


Figure 4-18 – Injection Pressure Plot, Orchard No. 6

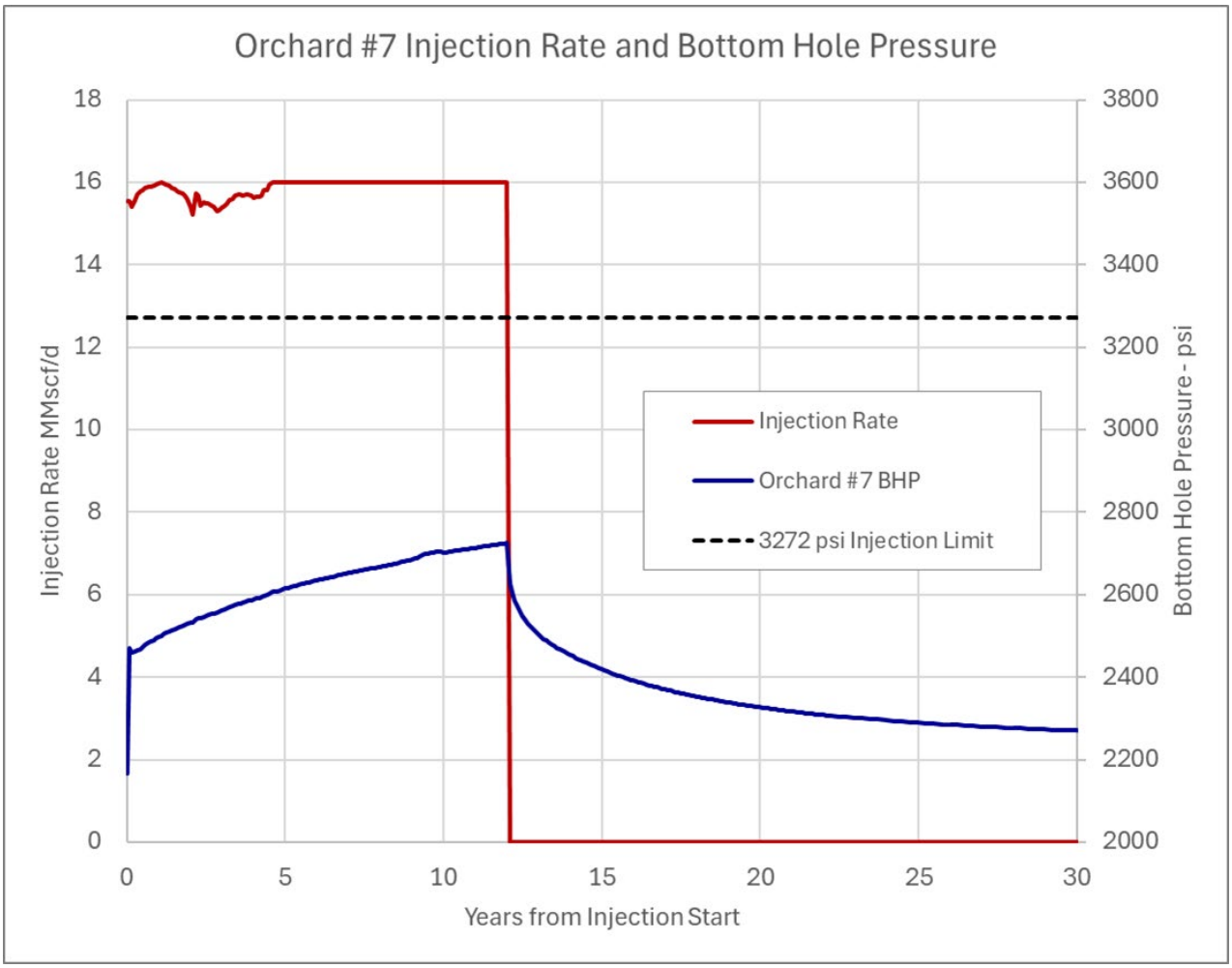


Figure 4-19 – Injection Pressure Plot, Orchard No. 7

The completion and operating strategy for all seven injection wells is as follows:

- The gross injection interval will be perforated at the initial completion.
- The injectate fluids will be injected throughout the entire injection interval.
- Plume migration surveys will be conducted every five years to contrast actual plume development with the simulated plume model.
- The wellbore will have continual monitoring of bottomhole pressures and temperatures throughout the life of the well.

4.3.12 Orchard Injection Wells Operational Summary

Orchard No. 1 through No. 7 are designed to maximize the available pore space and safely sequester CO_2. Formation pressures and temperatures will be measured within each wellbore and used to update the plume model and refine future injection strategies. This process will provide accurate evaluation and assurance of where the CO_2 is moving and at what rate, allowing for alteration to the injection and operation strategy if required. After injection ceases, the wells will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*.

4.4 Above Confining Zone Monitoring Wells

Orchard Storage plans to drill and complete two above confining zone monitoring wells, Orchard MW No. 1 and Orchard MW No. 3. These wells are intended to monitor the first permeable zone above the confining interval, the Queen formation. The monitoring wells will be located in the expected critical pressure front and will monitor for indications of CO_2 leaking out of the confining zone. Temperature and pressure anomalies within the Queen are an early warning of injectate from Orchard No. 1–No. 7 moving out of the injection zone. These wells will not penetrate the confining zone and therefore will not need to consider acid-resistant materials in their construction.

4.4.1 General Outline of Monitoring Well Design, Orchard MW No. 1 and MW No. 3

The Orchard MW No. 1 and MW No. 3 wells were designed with the following specifications (as shown in Figures 4-20 and 4-21):

- Conductor
  - 13-3/8 in. to +/- 120 ft
- Surface Casing
  - To be set below the lowermost USDW, per the GAU (estimated setting depth is 2,000 ft).
  - 8-5/8 in. OD casing; 12-1/4 in. hole size
  - Cemented back to surface
- Production Casing
  - 5-1/2 in. casing set to TD of well at base of lower confining layer
    - Casing 15.5 lb/ft J-55
  - 7-7/8 in. hole size
    - Salt blend cement back to surface
- Tubing – 2-7/8 in., 6.5 lb/ ft, J-55, 8rd EUE
- Wellhead
  - 8-5/8 in. SOW x 8-5/8 in. 5M – casing head
  - 8-5/8 in. x 5-1/2 in. – casing hanger
  - 8-5/8 in. 5M x 7-1/16 in. 5M casing spool
  - 7-1/16 in. 5M x 2-7/8 in. tubing head with 1 blind flanged outlet and 1 outlet with a 2-1/16 in. manual gate valve
    - Production tree – 2-9/16 in. 5M, manual gate valve with crown with cap, needle valve, and gauge

Complete drilling prognoses have been included in *Appendix C-1*. The mud and cement programs included in the prognoses are representative and may be modified before starting construction.

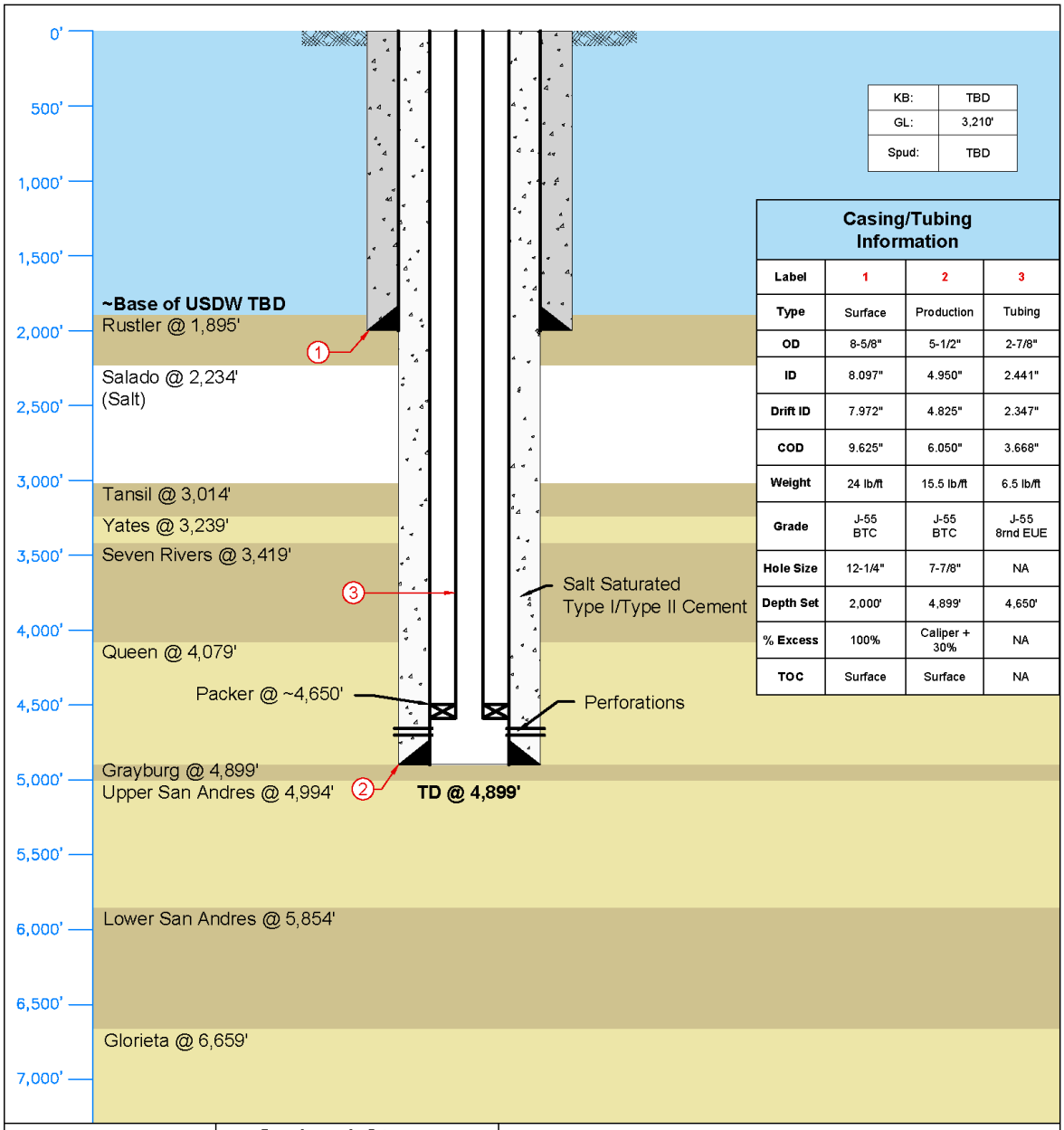


Figure 4-20 – Orchard MW No. 1 Monitoring Wellbore Schematic

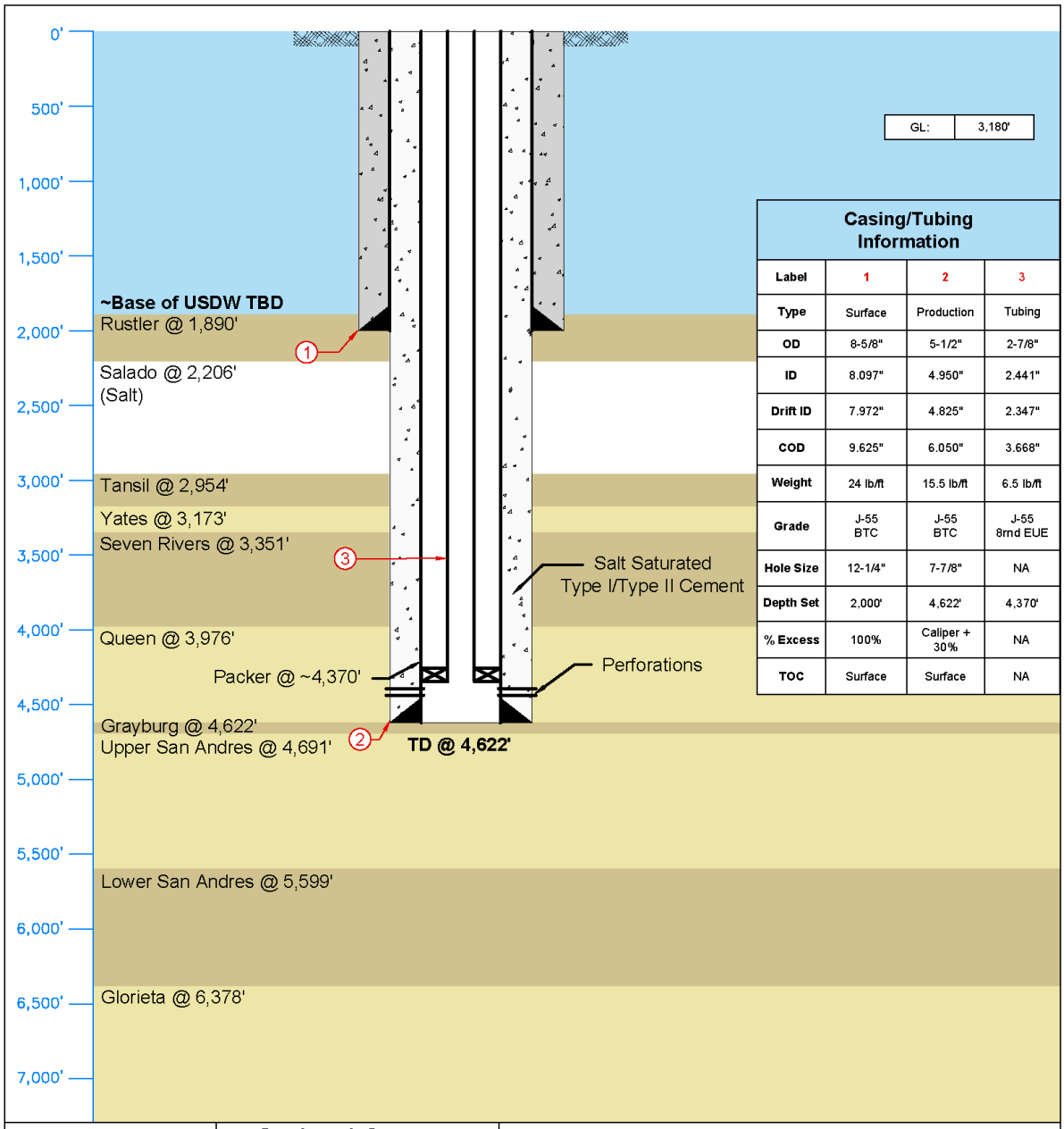


Figure 4-21 – Orchard MW No. 3 Monitoring Wellbore Schematic

4.4.1.1 Conductor Casing

To ensure that hole integrity can be maintained during the initial drilling of the well, 13-3/8 in. conductor will be used. The 13-3/8 in., 48 lb/ ft conductor pipe will be set at approximately 120 ft. The 12.715 in. ID of conductor pipe size was selected to facilitate the drilling of the surface casing borehole with a 12-1/4 in. bit.

Once the conductor pipe is established, the inner portions can be flushed out and evacuated, and drilling can commence.

4.4.1.2 Surface Casing

The surface hole will be drilled with a 12-1/4 in. bit with casing set below the USDW. A string of 8-5/8 in. casing will be run and cemented, with the casing centered in the open hole using centralizers. Being centralized, the size of the annulus chosen will provide a consistent cement thickness between the casing and the open hole. This will help to ensure a quality cement bond and create two barriers between the USDW formation and wellbore during the remaining drilling operations. Cement will be circulated to the surface, and a top job will be provided, if needed, should the cement level fall after the cement has been circulated to the surface. After cementing, a cement bond log will be run to evaluate and verify good bonding throughout the surface hole. Once the production casing has been run and cemented to the surface, there will be four barriers between the USDW formation and the wellbore.

Summaries of engineering calculations for the surface casing are provided in Table 4-61 through 4-63.

Table 4-61 – Monitoring Well Surface Casing Engineering Calculations, Orchard MW No. 1 and MW No. 3

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Dri ft ID (in.)
8-5/8 in., 24 lb/ft, J-55, BTC (0 to 2,000 ft TD)	24	2,000	244,000	1,370	2,950	0.0637	8.097	7.972
Design Criteria			48,000	1,300	1,300			
Safety Factor			5.08	1.05	2.27			

Table 4-62 – Monitoring Well Surface Casing Annular Geometries, Orchard MW No. 1 and MW No. 3

Section	ID (in.)	MD (ft)	TVD (ft)
Conductor Casing	12.715	120	120
Openhole	12.25	2,000	2,000

Table 4-63 – Monitoring Well Surface Casing Cement Calculations, Orchard MW No. 1 and MW No. 3

Section	Footage (ft)	Capacity (ft^3/ ft)	% Excess (%)	Cement Volume (ft^3)
Drive Pipe/Casing Annulus	120	0.4760	0%	57
Openhole/Casing Annulus	1,880	0.4127	100%	1,552
Shoe Track	45	0.3576	0%	16

To ensure that cement returns to the surface are achieved, 100% excess openhole volumes were used. The equipment and cement will be on location to perform a top job if needed.

4.4.1.3 Production Casing

The production (i.e., long-string) casing is the final, permanently cemented string of casing installed in the well, to be run from the surface to TD then cemented back to the surface. As this well does not penetrate the UCZ, acid-resistant cements and tubulars were not considered.

The engineering and design parameters for the production casing for Orchard MW No. 1 are summarized in Tables 4-64 through 4-66.

Table 4-64 – Monitoring Well Production Casing Engineering Calculations, Orchard MW No. 1

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
5-1/2 in., 15.5 lb/ft, J-55, BTC (0 to 4,899 ft TD)	15.5	4,899	248,000	4,040	4,810	0.0238	4.950	4.825
Design Criteria			75,935	3,184	3,184			
Safety Factor			3.27	1.27	1.51			

Table 4-65 – Monitoring Well Production Casing Annular Geometries, Orchard MW No. 1

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	8.097	2,000	2,000
Openhole	7.875	4,899	4,899

Table 4-66 – Monitoring Well Production Casing Cement Calculations, Orchard MW No. 1

Section	Footage (ft)	Capacity (ft^3/ ft)	% Excess (%)	Cement Volume (ft^3)
Surface Casing/Casing Annulus Lead Cement	2,000	0.1926	0%	385
Openhole/5-1/2 in. Casing Annulus Lead Cement	2,899	0.1733	30%	653
Shoe Track	90	0.1336	0%	12

The engineering and design parameters for the production casing for Orchard MW No. 3 are summarized in the following tables (4-67 through 4-69):

Table 4-67 – Monitoring Well Production Casing Engineering Calculations, Orchard MW No. 3

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
5-1/2 in., 15.5 lb/ft, J-55, BTC (0 – 4,622 ft TD)	15.5	4,622	248,000	4,040	4,810	0.0238	4.950	4.825
Design Criteria			71,641	3,004	3,004			
Safety Factor			3.46	1.34	1.60			

Table 4-68 – Monitoring Well Production Casing Annular Geometries, Orchard MW No. 3

Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	8.097	2,000	2,000
Openhole	7.875	4,622	4,622

Table 4-69 – Monitoring Well Production Casing Cement Calculations, Orchard MW No. 3

Section	Footage (ft)	Capacity (ft^3/ ft)	% Excess (%)	Cement Volume (ft^3)
Surface Casing/Casing Annulus Lead Cement	2,000	0.1926	0%	395
Openhole/5-1/2 in. Casing Annulus Lead Cement	2,622	0.1733	30%	591
Shoe Track	90	0.1336	0%	12

4.4.1.4 Centralizers

The bow-spring centralizer placement for the 8-5/8 in. surface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the 2,000 ft of 8-5/8 in. x 12-1/4 in. annular void. The recommended locations will be as follows:

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

A total of 14 centralizers will be run on the surface casing.

The bow-spring centralizer placement for the 5-1/2 in. production casing strings is designed to ensure a continuous, uniform column of cement throughout the 5-1/2 in. x 7-7/8 in. openhole annular void as well as the 5-1/2 in. x 8-5/8 in. casing annulus. The recommended locations will be as follows:

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

Approximately 45 total centralizers will be run on the production casing.

4.4.1.5 Tubing

The tubing strings will consist of 2-7/8 in. tubing and a permanent packer assembly. The tubing string will be used to collect fluid samples above the UCZ.

Tables 4-70 and 4-71 list the tubing specifications, design criteria, and calculated safety factors. Since there will be no injection in this well, the collapse design assumes evacuated tubing with brine on the backside, with 500 psi applied on the annulus. The burst assumes an evacuated annulus, a full column of 11 lb/gal mud with 1,000 psi applied.

Table 4-70 – Monitoring Well Tubing Engineering Calculations- Orchard MW No. 1

Description	Casing Wt. (lb/ ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ ft)	ID (in)	Drift ID (in)
2-7/8 in., 6.5 lb/ft, J-55, 8rd EUE (0 – 4,650 ft)	6.5	4,650	99,660	7,680	7,260	0.0058	2.441	2.347
Design Criteria			30,225	2,918	3,660			
Safety Factor			3.30	2.63	1.98			

Table 4-71 – Monitoring Well Tubing Engineering Calculations- Orchard MW No. 3

Description	Casing Wt. (lb/ ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ ft)	ID (in)	Drift ID (in)
2-7/8 in., 6.5 lb/ft, J-55, 8rd EUE (0 – 4,370 ft)	6.5	4,370	99,660	7,680	7,260	0.0058	2.441	2.347
Design Criteria			28,405	2,772	3,500			
Safety Factor			3.51	2.77	2.07			

4.4.1.6 Packer

The production tubing will be run in the well with a 5-1/2 in. x 2-7/8 in. permanent packer, with a latch-in seal assembly as shown in Figure 4-22.

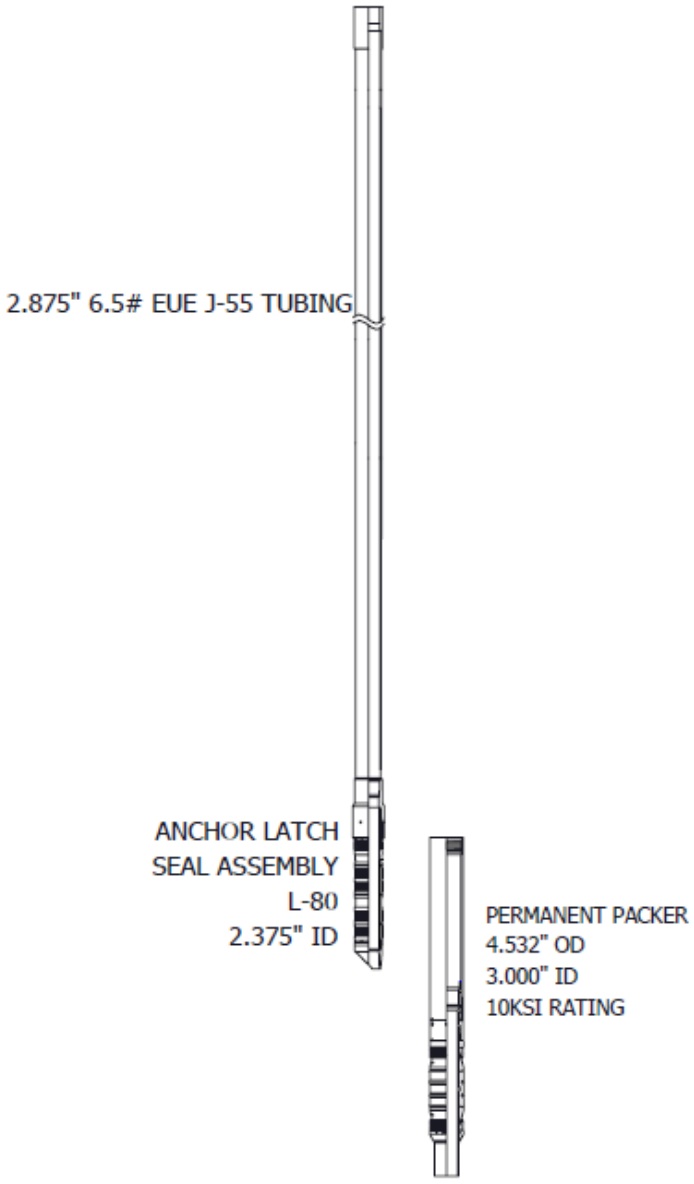


Figure 4-22 – 5-1/2 in. Seal Assembly & Permanent Packer

4.4.1.7 Wellhead Discussion

The wellheads are designed to accommodate anticipated working pressure. The final pressure rating will be confirmed before beginning the manufacturing process. The wellheads will be configured as shown in Figure 4-23 (note: the manufacturer may differ from the one shown).

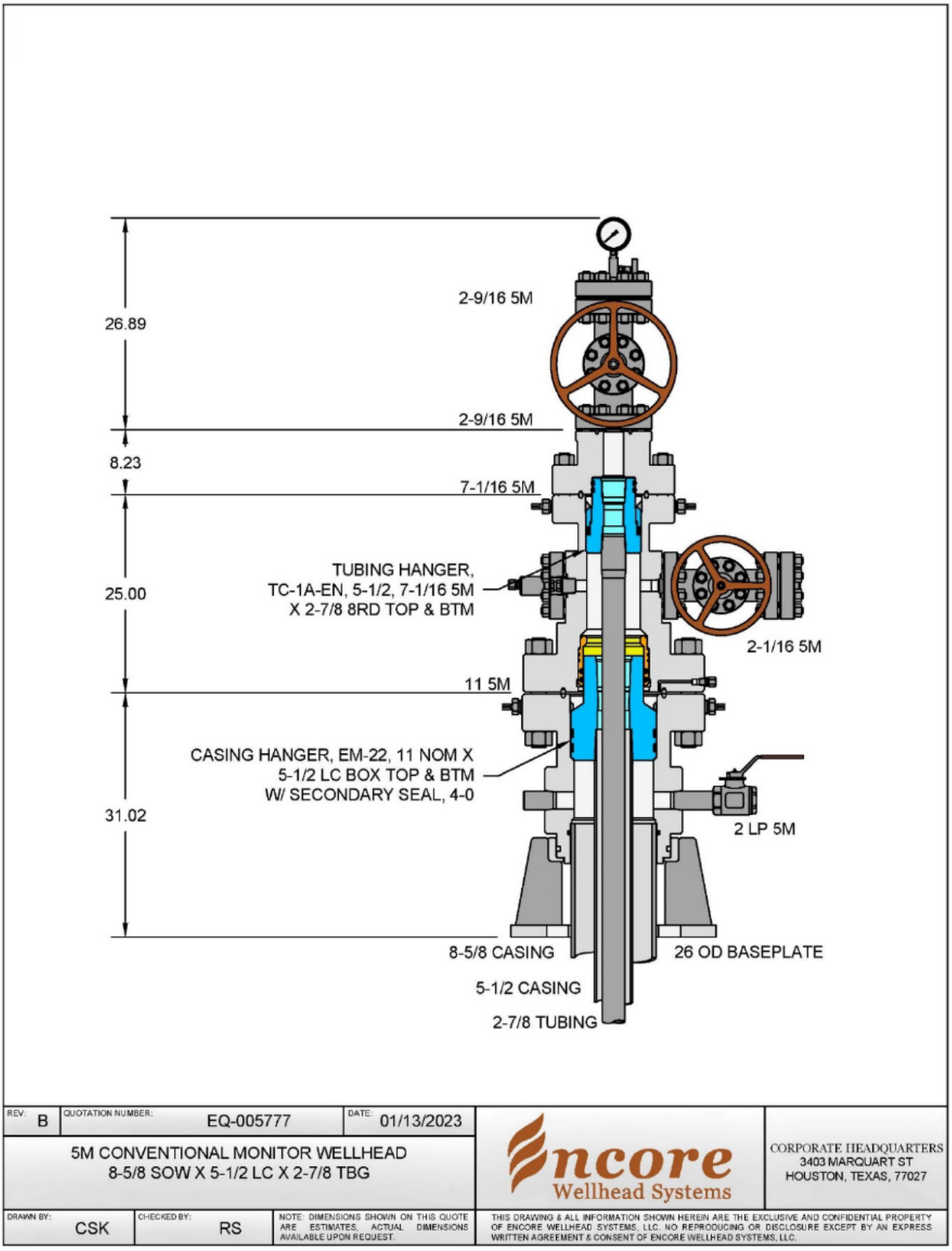


Figure 4-23 – Orchard Monitoring Wells Preliminary Wellhead Design

4.4.2 Testing and Logging of Orchard MW No. 1 and MW No. 3

A suite of electric logs will be run in the openhole sections and each casing string for Orchard MW No. 1 and MW No. 3. The logging plan is detailed in Tables 4-72 and 4-73. Orchard Storage will provide a schedule of all logging plans to the Director at least 30 days prior to conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

Table 4-72 – Openhole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	MW No. 1	MW No. 3
1	Surface Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties	12-1/4 in.	0 to 2,000 ft	0 to 2,000 ft
2		Sonic (Dipole)				
3	Production Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties	7-7/8 in.	2,000 to 4,899 ft	2,000 to 4,622 ft
4		Sonic (Dipole)				
5		Spectral GR				

Table 4-73 – Casedhole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension	MW No. 1	MW No. 3
1	Surface Casing	Ultrasonic, CCL, CBL, CMT, GR, Temp (Bond Log)	Cement Investigation	8-5/8 in.	0 to 2,000 ft	0 to 2,000 ft
2	Production Casing	Ultrasonic, CCL, CBL, CMT, GR, Temp (Bond Log)	Cement Investigation	5-1/2 in.	2,000 to 4,899 ft	2,000 to 4,622 ft
3		Pulsed Neutron Log – Baseline				

4.4.3 Overview of Well Completion Program

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

- Make bit and scraper run to TD.
- Run casedhole logs as described in Table 4-70.
- Test the casing.
- Perforate the Queen formation, specific depths to be determined with openhole logs.
- Pump-in test to ensure fluid and pressure communication with the formation.
- Displace the hole with corrosion-resistant packer fluid.

- Run tubing and packer to depth, set and test the same.

4.5 In-Zone Monitoring Well

Orchard Storage is proposing to use an existing well, the Valiant 1D (API No. 42-165-38785) as an in-zone monitoring well. This well will be in the pressure front AOR and used to not only monitor pressures and temperatures of the injection interval but also determine the extent of the CO_2 plume from the Orchard No. 1 to No. 7 injection wells. Because this well is not in the CO_2 plume, it will not require specialty metallurgy considerations.

4.5.1 Orchard MW No. 2 Conversion

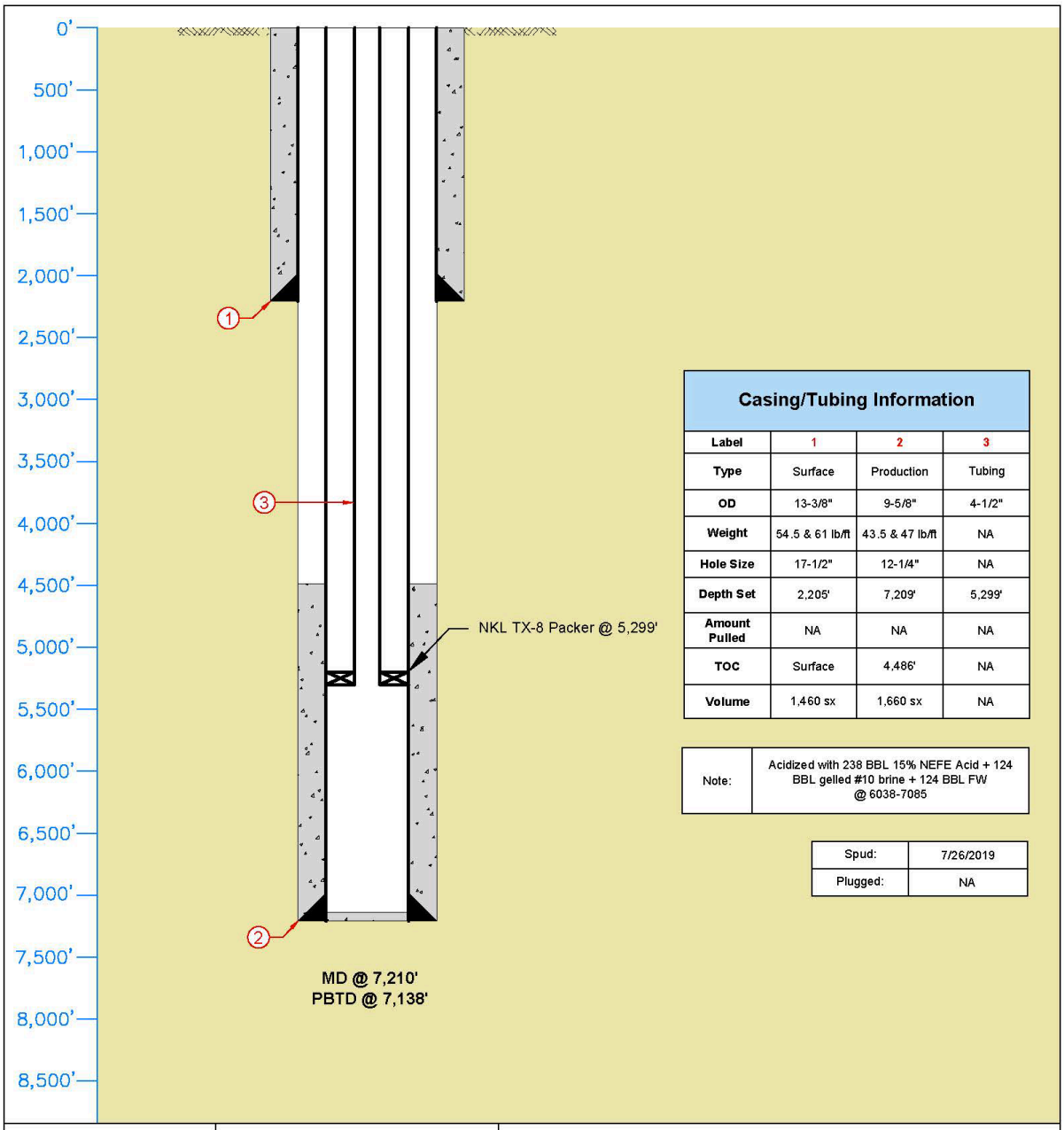
The Valiant 1D (API No. 42-165-38785) is currently classified by the TRRC as a shut-in saltwater disposal well that was completed in the San Andres, Glorieta, and Clearfork formations. Orchard Storage proposes to recomplete this well as an in-zone monitoring well (MW No. 2). Orchard has acquired this wellbore, which had a full suite of openhole logs that were run along with extensive side wall cores in 2019. The cement bond logs for this well indicate that the top of cement behind the 9-5/8 in. production string is at approximately 4,486 ft, and therefore Orchard Storage plans to squeeze cement across the upper confining interval to ensure brine does not migrate to the USDW. A copy of this log is provided in Appendix O. Pressure and temperature gauges will be installed on the tubing in the final completion.

4.5.1.1 Recompletion Program

Orchard Storage proposes the following steps to recomplete this well:

- Move in and rig up workover unit.
- Install the wellhead or other pressure-control equipment.
- Unseat packer and pull tubing out of hole.
- Run in hole with bit and scraper to approximately 6,030 ft.
- Run in hole and set 9-5/8 in. cast-iron bridge plug at 6,000 ft.
- Place 25 sacks of cement above bridge plug.
- Run cement bond log to ensure adequate cement coverage through the confining interval.
- Run in hole with bit and scraper to approximately 5,800 ft.
- Perforate the injection zone, at approximately 5,290 ft-5,800 ft.
- Pump-in test to ensure fluid and pressure communication with the formation.
- Displace the hole with corrosion-resistant packer fluid.
- Run 2-7/8 in. tubing and 9-5/8 in. x 2-7/8 in. packer to depth, set and test the same.

Figure 4-24 shows the current schematic for the existing wellbore. Figure 4-25 shows the proposed recompletion design.



Casing/Tubing Information

Label	1	2	3
Type	Surface	Production	Tubing
OD	13-3/8"	9-5/8"	4-1/2"
Weight	54.5 & 61 lb/ft	43.5 & 47 lb/ft	NA
Hole Size	17-1/2"	12-1/4"	NA
Depth Set	2,205'	7,209'	5,299'
Amount Pulled	NA	NA	NA
TOC	Surface	4,486'	NA
Volume	1,460 sx	1,660 sx	NA

Note:	Acidized with 238 BBL 15% NEFE Acid + 124 BBL gelled #10 brine + 124 BBL FW @ 6038-7085

Spud:	7/26/2019
Plugged:	NA

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS

Texas License F-9147

12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Reliance Energy, Inc.	Valiant 1D	
Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
Location: 32.855656, -102.383807	**Site:**	**Survey:**
API No: 42-165-38785	**Field:**	**Well Type/Status:** Injection (Shut-in)
Serial No: NA	**Project No:**	**Date:** 1/10/2023
Drawn: JGC	**Reviewed:**	**Approved:**
Rev No: 0	**Notes:**	

Figure 4-24 – Valiant 1D Current Wellbore Schematic

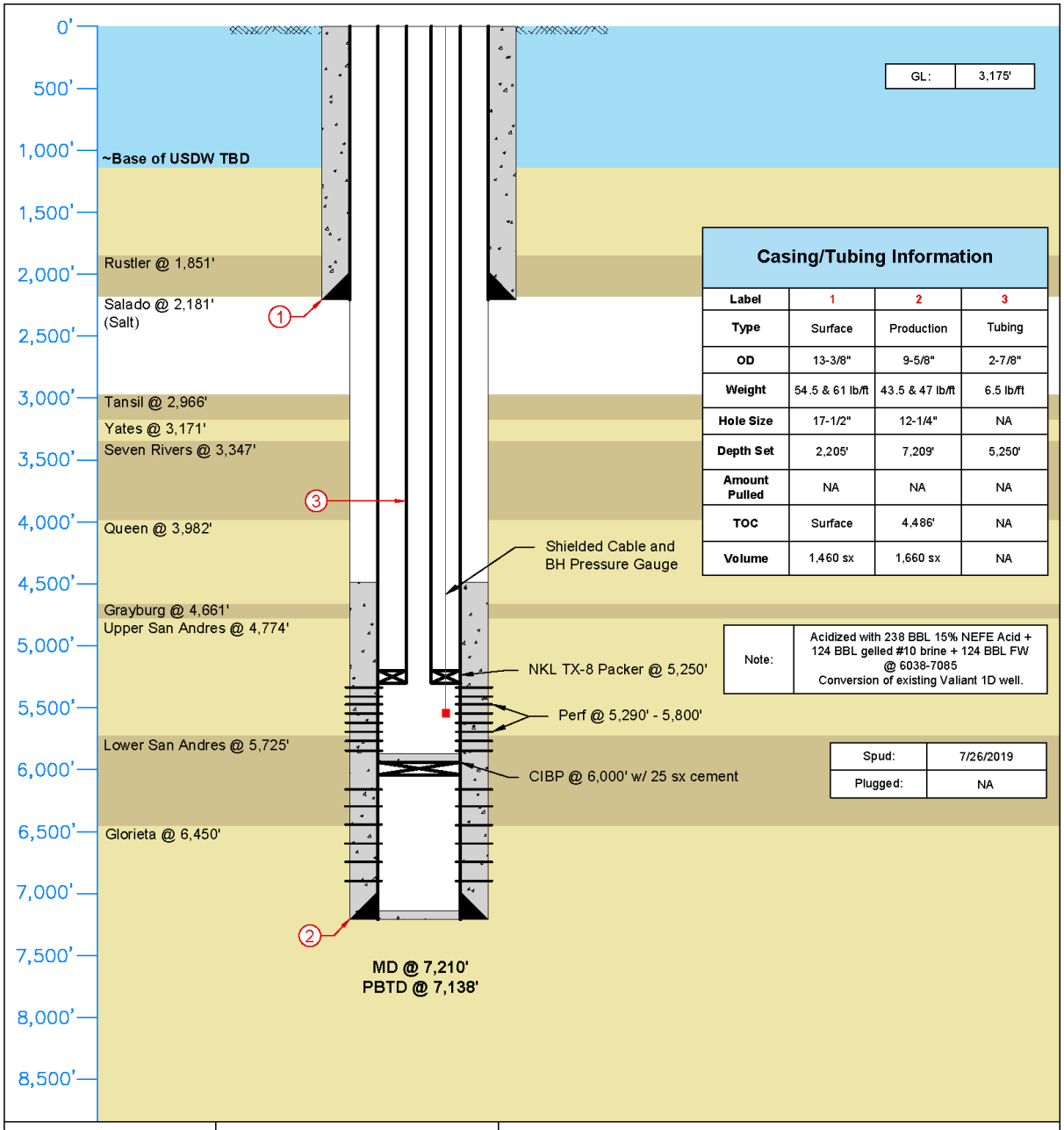


Figure 4-25 – Orchard MW No. 2 Proposed Wellbore Schematic

4.5.1.2 Tubing

The tubing strings will consist of 2-7/8 in. tubing and a permanent packer assembly. The tubing string will be used to collect fluid samples above the UCZ.

Table 4-74 lists the tubing specifications, design criteria, and calculated safety factors for Orchard MW No. 2. Since there will be no injection in this well, the collapse design assumes evacuated tubing with brine on the backside, with 500 psi applied on the annulus. The burst assumes an evacuated annulus, a full column of 11 lb/gal mud with 1,000 psi applied.

Table 4-74 – Monitoring Well Tubing Engineering Calculations – Orchard MW No. 2

Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
2-7/8 in., 6.5 lb/ft, J-55, 8rd EUE (0– 5,250 ft)	6.5	5,250	99,660	7,680	7,260	0.0058	2.441	2.347
Design Criteria			34,125	3,230	4,003			
Safety Factor			2.92	2.38	1.81			

4.5.1.3 Packer

The production tubing will be run in the well with a 5-1/2 in. x 2-7/8 in. permanent packer, with a latch-in seal assembly as shown in Figure 4-22 (in *Section 4.4.1.6*).

4.5.2 Monitoring Well Operational Strategy Summary

Continuous monitoring will be implemented with the use of SCADA to monitor the tubing pressure as well as the tubing and casing annulus pressure. If pressure or temperature anomalies are observed, injection will be stopped, and the incident will be assessed.

The location for this project is ideally situated for carbon sequestration monitoring purposes. Combining the best engineering practices in the design of the well with a state-of-the-art monitoring system and robust reservoir management strategy, this monitoring well will help to safely store CO_2 for years to come.

Detailed drilling and completion procedures are provided in *Appendix C-1.*

Appendix C – Well Construction Schematics and Procedures:

Appendix C-1	Injection Well Drilling and Completion Prognoses
Appendix C-2	Injection Wellbore Schematics
Appendix C-3	Monitoring Wellbore Schematics
Appendix C-4	Monitoring Well Drilling and Completion Prognoses
Appendix C-5	Additional Cement Plan Support
Appendix C-6	Groundwater Authority Unit Determinations
Appendix C-7	Injection Wellhead Design
Appendix C-8	Proposed Directional Survey, Orchard No. 1
Appendix C-9	Stimulation Procedure

Appendix D – Metallurgy Report

4.6 References

Bradley, R., & Kalaswad, S. (2003). *The Groundwater Resources of the Dockum Aquifer in Texas.* Austin: Texas Water Development Board.

Craft, B., Holden, W., & Graves, E. (1962). Pipe Flow of Newtonian Liquids. In B. Craft, W. Holden, & E. Graves, *Well Design: Drilling and Production* (pp. 18-24). Englewood Cliffs: Prentice-Hall, Inc.

Eaton, B. (1969). Fracture Gradient Prediction and Its Application in Oilfield Operations. *Journal of Petroleum Technology*, 1353-1360.

Linstrom, P., & Mallard, W. (2025). *Thermophysical Properties of Fluid Systems*. Retrieved from NIST Chemistry WebBook, NIST Standard Reference Database Number 69: https://webbook.nist.gov/chemistry/fluid/

McCain, W. (1991). *The Properties of Petroleum Fluids, Second Edition.* Tulsa: PenWell Books.

Ramey, H. J. (1962). Wellbore Heat Transmission. *Journal of Petroleum Technology*, 427-435.

Rettman, P., & Leggat, E. (1966). *Ground Water Resources of Gaines County, Texas.* Austin: United States Geological Survey.

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 5 – Testing and Monitoring Plan

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 5 – TESTING AND MONITORING PLAN

TABLE OF CONTENTS

5.1 Introduction 3
5.2 Reporting Requirements 3
5.3 Testing Plan Review and Updates 4
5.4 Testing Strategies 5
5.4.1 Openhole Logging 5
5.4.2 Initial Step-Rate Injectivity Test 6
5.4.3 Chemical Composition Confirmation Testing 8
5.4.4 Mechanical Integrity Testing – Annulus Pressure Test 9
5.4.5 External Mechanical Integrity Testing – Temperature and Oxygen Activation Logs 10
5.4.6 Pressure Falloff Testing 11
5.4.7 Injection Conformance Monitoring 12
5.4.8 Cement Evaluation and Casing Inspection Logs 12
5.4.9 Logging and Testing Reporting 14
5.5 Monitoring Programs 15
5.5.1 Continuous Injection Stream Monitoring 15
5.5.2 Corrosion Coupon Monitoring 17
5.5.3 Soil Gas Monitoring 17
5.5.4 Groundwater Quality Monitoring 18
5.5.5 Monitoring Wells 21
5.5.6 Seismic Monitoring 22
5.5.7 Injection Plume Monitoring 23
5.5.8 VSP Monitoring Conclusion 44
5.6 Conclusion 44
5.7 References 45

Figures

Figure 5-1 – Example of a Step-Rate Injectivity Test 8
Figure 5-2 – Typical Injection Well and Injection Skid Flow Schematic 16
Figure 5-3 – Location of Groundwater, In-Zone and Above-Zone Monitoring Wells 19
Figure 5-4 – Nearest TexNet Seismic Monitoring Station 23
Figure 5-5 – Shell Canada Quest Project VSP Acquisition Patterns 25
Figure 5-6 – RocDoc Well Viewer 26
Figure 5-7 – Application of Petro-Elastic Model to Rock Physics Model 27
Figure 5-8 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation 28
Figure 5-9 – Illustration of a Vertical Seismic Profile Survey 29
Figure 5-10 – Illustration of a Checkshot Survey 30
Figure 5-11 – Time-Lapse/4D Processing Workflow Diagram 31
Figure 5-12 – Example of Time-Lapse/4D Model 32
Figure 5-13 – Baseline and subsequent VSP used to determine difference in amplitude 32

Figure 5-14 – SureVIEW with CoreBright Optical Fiber 34
Figure 5-15 – SureVIEW WIRE Illustration 38
Figure 5-16 – TEC Illustration 40
Figure 5-17 – SureSENS QPT Elite Gauge Illustration 41
Figure 5-20 – External Sensor Illustration 41
Figure 5-19 – SureSENS QPT Gauge Carrier Illustration 43
Figure 5-20 – Steel Blast Protector Illustration 43
Figure 5-21 – Image of Cross Coupling Protector 43

Tables

Table 5-1 – Injection Well Openhole Logging Plan 5
Table 5-2 – Proposed Step-rate Injection Test 7
Table 5-3 – Step-Rate Injectivity Test Example 7
Table 5-3 – Injectivity Test Parameters and Analytes Measured and Measurement Frequency 9
Table 5-4 – PEC Tool List 14
Table 5-6 – Groundwater Quality Parameters Measured and Measurement Frequency 18
Table 5-7 – Reservoir Fluid Parameters Measured and Measurement Frequency 21
Table 5-6 – SureVIEW Downhole Specifications 35
Table 5-7 – SureVIEW DTS Specifications 36
Table 5-8 – SureVIEW DAS VSP Specifications 36
Table 5-9 – SureVIEW WIRE Cable Specifications 39
Table 5-10 – TEC Specifications, Part I 40
Table 5-11 – TEC Specifications, Part II 40
Table 5-12 – QPT Elite Pressure Interface – Pressure-Testable Manifold Specifications 42

5.1 Introduction

The operating plans for the proposed Orchard Storage Company LLC (Orchard Storage) Orchard No. 1 through No. 7 injection wells include robust testing and monitoring programs, which are designed to satisfy the requirements of 16 Texas Administrative Code (TAC) ***§*5.203 (j)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**]. This section discusses the key details of this program.

5.2 Reporting Requirements

In compliance with 16 TAC **§5.207** [40 CFR **§146.91**] requirements, Orchard Storage will provide the following routine reports to the Underground Injection Control (UIC) Director.

Per-Occurrence Reporting:

- Any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between Underground Sources of Drinking Water (USDWs)
    - Verbal Notification – Reported within 24 hours of the event
- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported ASAP after 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 storage reservoir
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported ASAP after the event
- Any changes to the physical, chemical, or other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
    - Written Notification – Reported on semi-annual report
- Description of any event that exceeds operating parameters for either annulus pressure or injection pressure, as specified in the permit
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within ASAP after 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 ASAP after the event
- Any release of CO_2 into the atmosphere or biosphere
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported ASAP after the event

Semiannual Reports:

- Summary of wellhead pressure monitoring
- Any changes to the source of the CO_2 stream
- Any changes to the physical, chemical, or other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
- Monthly average, plus maximum and minimum values, of injection pressure, flow rate, temperature, volume, and annular pressure
- Description of any event that exceeds operating parameters for either annulus pressure or injection pressure, as specified in the permit
- Monthly volume and/or mass of the CO_2 stream injected over the reporting period, and the volume injected cumulatively over the life of the project
- Monthly volume of annulus fluid 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 the monitoring and operational data supports the current delineation of the AOR on file with the Texas Railroad Commission (TRRC)
- Proof of good faith claim to sufficient property rights for the storage facility operation
- Tons of CO_2 injected

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

- Any well workover
- Any test of the injection well conducted, if required by the UIC Director
- Any periodic mechanical integrity tests (MITs)

Notification in writing to the UIC authority (16 TAC §5.206(c)), 30 days in advance of:

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

Orchard Storage will submit all reports, submittals, and notifications to the Environmental Protection Agency (EPA) and TRRC and ensure that all records are retained throughout the project's life. Per 16 TAC **§5.207(e)** [40 CFR **§146.91(f)**], these records will be maintained for 10 years after site closure—and, after the retention period, delivered to the UIC Director upon request. Monitoring data will be retained for 10 years post-collection, while well-plugging reports, post-injection site care data, and the site closure report will also be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

Per 16 TAC **§5.207(a)(3)** [40 CFR **§146.90(j)**], the Testing and Monitoring Plan will be reviewed and revised, as necessary, at least every 5 years—to incorporate collected monitoring data. Plan amendments will also be submitted within 90 days of an AOR reevaluation following significant facility changes, such as the development of offset monitoring wells or newly permitted injection wells within the AOR, or as required by the UIC Director. An amendment to the Testing and Monitoring Plan that has changed as a result of routine review (every 5 years) will be submitted to the UIC Director within one year as stipulated by 146.90(j)(1).

5.4 Testing Strategies

5.4.1 Openhole Logging

Orchard Storage plans to run an advanced suite of openhole logs to obtain data for parameters used in static and dynamic subsurface modeling. The Baker Technology log descriptions provided below simply exemplify the types of logs to be run; the specific logging vendor will be selected just prior to drilling the well, as commercial and supply chain issues may affect the final vendor selection.

A list of planned openhole logs is provided in Table 5-1.

Table 5-1 – Injection Well Openhole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Openhole Diameter	Depths of Survey
1	Surface Casing	Triple Combo (Gamma Ray (GR), Spontaneous Potential (SP), Photoelectric (PE), Resistivity, Neutron, Density)	Identification of Rock Properties	14-3/4 in.	0 - 2,000 ft
2		Sonic (Dipole)			
3	Production Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties	9-7/8 in.	2,000 ft - TD
4		Sonic (Dipole)			
5		Fullbore Formation Microimager (FMI)			UCZ to TD
6		Sidewall Cores			
7		Repeat Formation Tester (R FT)/ Modular Formation Dynamics Tester (MDT)			Selected Intervals
8		Spectral GR			UCZ to TD

Baker Hughes Rockview™ Formation Lithology eXplorer (FLeX) – mineralogical characterization tool equipped with a pulsed neutron spectrometer. Allowing for a resolution of uncertainties

compared to traditional petrophysical evaluation methods, this tool includes enhanced porosity determination, clay type/volume determination, and lithofacies identification.

Baker Hughes MR eXplorer (MReX) – nuclear magnetic resonance-based instrument. By alternating static and pulsed radio frequency magnetic fields, the pore-space-fluid hydrogen protons are aligned and spun when interacting with the two magnetic fields. These "spin-echoes" can be recorded and analyzed based on amplitude and echo decay rates. This gives information on the porosity, pore size, and type of present fluid. Reliable data acquisition is available in almost every borehole environment.

Baker Hughes UltrasonicXplorer (UXPL) – borehole acoustic imaging service using a rotating acoustic transducer. This tool provides high-resolution feedback during drilling, completion, and production operations. It also documents stratigraphic features, unconformities, dip/strike, and borehole shape. The design allows for use in large-diameter boreholes and any mud type, and provides full 360° coverage.

Baker Hughes STAR-XR – high-resolution formation resistivity imaging in conductive mud systems. This tool carries 144 sensors downhole to measure geologic features, coupled with enhanced petrophysical reservoir evaluation. It identifies structural dips, depositional environments, borehole stability, and net pay in thinly bedded sequences. The STAR-XR is also applicable in the well-to-well correlation of sedimentary and stratigraphic information.

Baker Hughes XMAC F1 (XMAC-F1) – acoustic services using monopole and dipole measurements, building on the previous XMAC ELITE—able to log at twice the speed and measure shear slowness up to 1,200 microseconds per foot (μs/ft). The XMAC-F1 service provides (1) quality compressional and shear-wave measurements in both low-velocity and unconsolidated formations, (2) enhanced value and understanding of petrophysics, (3) reservoir characterization, and (4) rock mechanical properties.

5.4.2 Initial Step-Rate Injectivity Test

Before beginning CO_2 injection, Orchard Storage will conduct a step-rate injectivity test to attempt to measure the fracture gradient of the proposed Orchard No. 1 through No. 7 injection wells, in compliance with 16 TAC **§5.203(f)(2)(A)** [40 CFR **§146.87(d)(1)**] and 16 TAC **§5.203(f)(2)(C)** [40 CFR **§146.87(e)(3)**]. Bottomhole, surface readout pressure, and temperature gauges will be run to the total depth of each wellbore, with the initial bottomhole pressure and temperature readings measured before injection. All gauges will be calibrated before testing. Initial bottomhole pressure and temperature reading will be taken before starting the injection test.

5.4.2.1 Testing Method

The step-rate test will be performed using brine/water. Brine/water injection rates observed during step-rate testing can be converted to the equivalent CO_2 injection rate by accounting for the difference in fluid properties. The injection rate can be converted from a volumetric rate to a mass rate (i.e., barrels per day (bbl/D) to standard cubic feet per day (scf/D)). The mass rate is more suitable for measuring a compressible fluid, such as CO_2.

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 injection of brine will begin at 0.5 barrels per minute (bpm) and be held for a minimum of 30 minutes. The injection rates will be stepped up in increments until at least three measurements have been taken, both below and above the estimated formation-fracture initiation pressure, or to a maximum rate of 30% above the planned maximum injection rate, whichever occurs first. Each stage will require a hold duration of at least 30 minutes—or until the pressure has stabilized.

Table 5-2 – Proposed Step-rate Injection Test

Step	Duration (min)	Rate (bpd)	Rate (bph)	Rate (bpm)	Volume (bbl)
1	30	720	30	0.5	15
2	30	1,440	60	1.0	30
3	30	2,160	90	1.5	45
4	30	2,880	120	2.0	60
5	30	3,600	150	2.5	75
6	30	4,320	180	3.0	90
7	30	5,040	210	3.5	105
8	30	5,760	240	4.0	120
9	30	6,480	270	4.5	135
Total	30			5.0	**675**

A plot of the stabilized injection pressure and rates at each step will be developed. Table 5-3 shows an example of a step-rate test, and the resulting plot is shown in Figure 5-1. The plot should slope linearly unless the fracture initiation pressure is exceeded.

Table 5-3 – Step-Rate Injectivity Test Example

Step	Rate (bpm)	Time (min)	Pressure (psi)
0	0	0	0
1	0.25	30	180
2	0.50	30	190
3	0.7	30	200
4	1.0	30	220
5	5.0	30	400
6	10.0	30	1,600
7	15.0	30	1,800
8	20.0	30	2,000
9	25.0	30	2,200

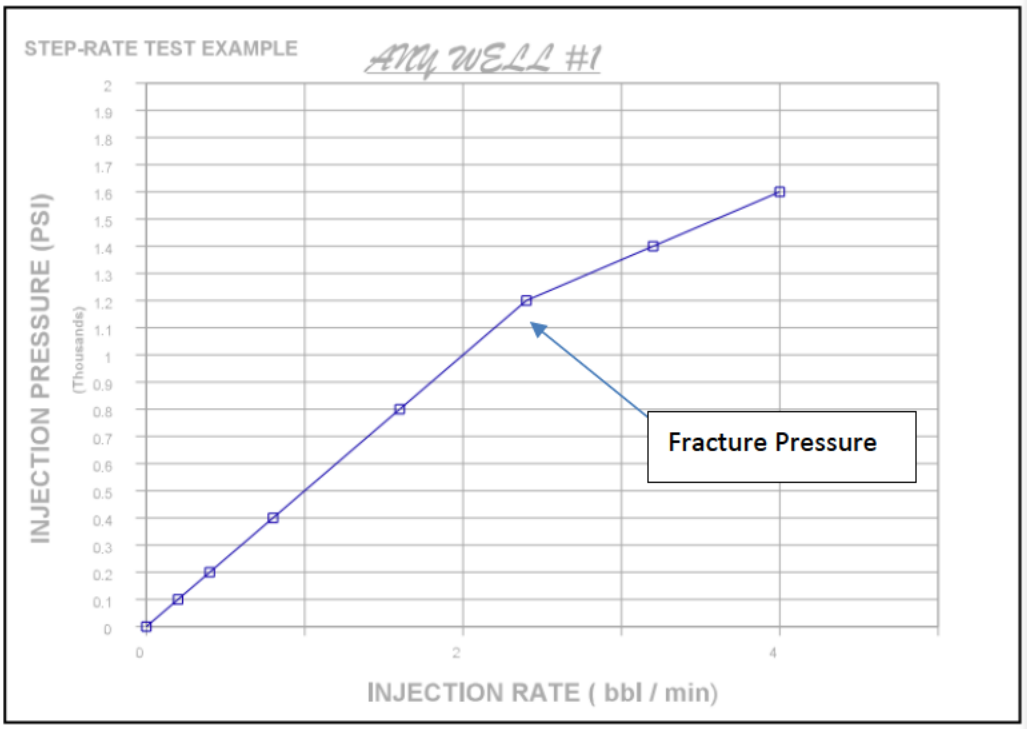


Figure 5-1 – Example of a Step-Rate Injectivity Test[1]

Upon reaching a stabilized pressure after completing the final step, pressures will be recorded at the highest frequency of the gauge, for a period indicated by the step-up phase of testing, to calculate the rate of pressure bleed-off.

5.4.3 Chemical Composition Confirmation Testing

In compliance with 16 TAC **§5.203(j)(2)(A)** [40 CFR **§146.90(a)**] requirements, Orchard Storage will sample the CO_2 injection stream and evaluate any potential interactions of carbon dioxide and other injectate components. CO_2 injection stream samples will be taken quarterly for chemical analysis of the parameters listed in Table 5-3, plus continuous pressure and temperature analysis.

5.4.3.1 Sampling Methods

Carbon dioxide stream samples will be collected from the CO_2 pipeline, in a location where injection conditions are representative. 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.

[1] https://www.epa.gov/sites/default/files/documents/INFO-StepRateTest.pdf

Table 5-4 – Injectivity Test Parameters and Analytes Measured and Measurement Frequency

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

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

5.4.4 Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 16 TAC **§5.203 (h)(1)(C)** [40 CFR **§146.89(b)**], Orchard Storage will demonstrate mechanical integrity by performing annular pressure tests when the wells are completed, before the start of injection, and after any workover operation involving the removal and replacement of the tubing and packer.

The annular pressure tests should demonstrate the mechanical integrity of the casing, tubing, and packer. These tests are conducted by pressuring the annulus to a minimum of 500 pounds per square inch (psi) fluid pressure, then using a block valve to isolate the test pressure source from the test pressure gauge upon test initiation—with all ports into the casing annulus closed except the one monitored by the test pressure gauge. The test pressure gauge will be the electronic pressure monitor connected to SCADA with a chart-style pressure recorder used for back-up to continuously monitor pressures.

Pressures will be continuously recorded while the annulus is isolated, until the pressure stabilizes, then the test pressures will be monitored and recorded for a minimum duration of 30 minutes during the test. Any loss of test pressure exceeding 5% during the minimum 30 minutes will indicate a lack of mechanical integrity.

All annulus pressure test results will be submitted to the TRRC on Form H-5 within 30 days of completing the log run.

5.4.5 External Mechanical Integrity Testing – Temperature and Oxygen Activation Logs

In adherence to the requirements of 16 TAC **§5.203 (h)(1)(D)** [40 CFR **§146.89(c)**], Orchard Storage will perform an annual external MIT by deploying a temperature log and an oxygen activation log (OAL) through the tubing. Both logs will be run before initiating injection operations, to establish a baseline against which future logs can be compared. The well will be shut in for approximately 36 hours before running these logs, to allow temperatures to stabilize. Satisfactory mechanical integrity is demonstrated by the proper correlation between the baseline and subsequent logs.

All logs recorded during the MIT will be submitted to the EPA/TRRC within 30 days of completing the log runs.

5.4.5.1 Temperature Log Procedure

When conducting a temperature survey via wireline, the tool will log from the surface to the total depth (TD) of the wells. No logging runs should precede the temperature log, to ensure static conditions in the wellbore. The recommended logging speed is 30 ft per minute, and all depths should be zeroed to the bradenhead flange. The following list highlights the general procedure for the wireline-temperature logging operation for the proposed injection wells:

1. Allow the well to stabilize for 36 hours.
2. Rig up the wireline unit to the wellhead and make up the logging tool (temperature probe and casing collar locator (CCL)).
3. Zero the end of the tool string at the bradenhead flange.
4. Run in the hole while logging from surface to TD at 30 ft per minute. Correlate collar depths to the CCL.
5. Pull out of hole and rig down wireline unit.

5.4.5.2 Oxygen Activation Log Procedure

1. Rig up the wireline unit to the wellhead and make up the logging tool and casing collar locator (CCL)).
2. Conduct a baseline GR log and casing collar locator log from the top of the injection zone to the surface to establish the contribution of naturally occurring background radiation.
3. Stationary readings will be taken while injecting fluid at the normal rate, maintaining constant rate and pressure.
4. Prior to taking the stationary reading, the OAL will be calibrated in a section with no vertical flow behind casing to ensure accurate, repeatable tool response and for measuring background counts.
5. Stationary readings will be taken for at least 15 minutes for each reading at:
    - At the base of the UCZ, at least 10 feet above the top of the injection interval so that turbulence does not affect the readings.
    - At the top of the UCZ
    - Midway between the base of the lowest USDW and the UCZ
    - At the base of the lowest USDW

6. If flow is indicated by the OAL at a location, move uphole or downhole as necessary at no more than 50 ft intervals and take stationary readings to determine the area of fluid migration.
7. Pull out of hole and rig down wireline unit.

5.4.6 Pressure Falloff Testing

Orchard Storage will perform an initial pressure falloff test upon completion of the wells, prior to operation, in accordance with 16 TAC **§5.203 (f)(2)(B)** [40 CFR **§146.87(e)**]. Orchard Storage will then perform a required pressure falloff test every 5 years per 16 TAC **§5.203 (j)(2)(F)** [40 CFR **§146.90(f)**]. The tests will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

5.4.6.1 Testing Method

Injection rates and pressures will be held as constant as is practical prior to the test. Pressure and rate data will be recorded continuously before and during the falloff period. Pressure gauges to supplement the permanent gauges will be run into the well, if needed, several days prior to initiation of the falloff test—to allow for a period of stable injection prior to shut-in. The length of time for stabilization prior to shut-in will be determined in advance, using pressure-transient well-test design methods that incorporate anticipated rates and formation properties.

Ideally, the falloff test will be run sufficiently long to allow identification and analysis of the Infinite Acting Flow Regime (IARF). Given the heterogeneous nature of the injection interval, it may not be possible to identify this IARF through simple, semi-log straight-line plots. Specialized software for analytical modeling of the pressure-transient response (e.g., Kappa Engineering's "Saphir") will be used to analyze the pressure and pressure-derivative response, to ensure that the test is run sufficiently long to obtain data that includes the IARF effects.

5.4.6.2 Analytical Methods

Mechanical integrity will be determined through standard diagnostic plotting. This determination is accomplished via analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots, using specialized pressure-transient analysis software. The analysis will integrate additional data beyond the rate and pressure data of the injection wells. The additional data may include operational history, offset wells' injection and operational history, and distributed temperature sensing (DTS) sensor data from the injection wells being tested. Depending on the complexity of the pressure response, it may be necessary to incorporate numerical modeling into the interpretation workflow.

Comparing pressure falloff tests can expose significant changes in the wells or reservoir conditions before initial injection with later tests. The effects of the fluid flow as well as the injected fluid's compressibility will be considered and incorporated into the analysis. The well parameters resulting from falloff testing will be compared against those used in AOR determination and computational site modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary.

5.4.6.3 Quality Assurance/Control

All field equipment will undergo inspection and testing before operation. Manufacturer calibration recommendations will be adhered to during the pressure gauge use in the falloff test. Documentation certifying proper calibration will also be enclosed with the test results. Further validation of the test results will be recorded using a second bottomhole pressure gauge.

5.4.7 Injection Conformance Monitoring

The Orchard No. 1 through No. 7 injection wells will have seismic distributed acoustic sensing (sDAS) fiber optic cable permanently installed, providing the ability to monitor injection conformance in the wells, in near-real time. Orchard No. 1 through No. 7 will be perforated over a large interval of the lower portion of the Upper San Andres and the upper portion of the Lower San Andres. The sDAS system will allow discreet temperature monitoring across the perforated interval. The temperature measurement will be used to evaluate relative injection volumes across the open interval and will alert to changes in injection rate at specific perforated intervals. If the rate changes at a specific set of perforations, this data can be used, along with other pressure and rate information, to gain valuable insight into injection conformance. The use of this data will allow changes to operating or completion parameters as necessary for storage-zone management purposes.

Per 16 TAC **§5.206 (d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], automatic shut-off systems and alarms will be installed to alert the operator and shut in the well when operating parameters such as annulus pressure, injection rate, etc., diverge from permitted ranges or gradients.

5.4.8 Cement Evaluation and Casing Inspection Logs

Per 16 TAC **§5.203 (h)(2)** [40 CFR **§146.89(d)**], a comprehensive casedhole logging suite will be run on the production casing strings at the time of initial well completion. This suite of logs will include a radial cement investigation, a multi-arm caliper, and a digital log, to establish the condition of the casing metal. These surveys will characterize the original state of the wellbore materials. Conventional casing inspection logs will be run prior to tubing installation. Following the tubing and packer installation, initial through-tubing inspection logs will be run. This survey will serve as the baseline for future casing inspection efforts.

Casing inspection logs will be performed every 5 years using a combination of conventional casing inspection logs and through-tubing surveys. The tools to be run at that time are detailed as follows.

- The 5-year casing inspection involves specific tools below *and* above the packer:
    - Casing section *below the packer*:
        - 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

    - Casing section *from packer to surface*:
        - Through-tubing casing inspection log
- If tubing must be removed, conventional casing inspection logs only will be run, consisting of:
    - Multiple-armed calipers to measure the 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

Orchard Storage will provide a schedule of all logging plans to the UIC Director at least 30 days prior to conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

5.4.8.1 Casing Log Equipment Overview

Through-tubing logging technology provides the ability to evaluate casing deformation and eccentricity measurements, in conjunction with other well-integrity tools such as multi-finger calipers and multiple pipe-thickness logging tools. This technology provides quality measurements without requiring the removal of the tubing and packer (Yang et al., 2021).

The following descriptions of the through-tubing logging tools that will be run are provided for information purposes. The final vendor will be selected prior to operations based on availability and commercial considerations.

The GOWell instruments listed in Table 5-4 utilize Pulsed Eddy Current (PEC) decay technology to measure the thicknesses of multiple concentric tubulars. Basic PEC decay technology theory is included in the supplemental information at the end of this document. These tools can be run stand-alone or combined with other logs—such as multi-finger imaging caliper, temperature, noise, pressure, fluid density, capacitance, flowmeter, gamma ray, and casing collar locator.

GOWell PEC decay measurements are not affected by wellbore fluid type, chemical precipitates, or other foreign material deposits. They are also not affected by the type or distribution of annular materials such as cement, mud, liquid, or gas.

Table 5-5 – PEC Tool List

Pulsed Eddy Current Decay Thickness Instruments					
Tool	Tool O.D.	Max # concentric pipes	Max O.D.	Max Combined Wall Thicknesses	Ratings (degF/K psi)
MTD-B/C	1-11/16"	2	10-3/4"	1.75"	350/15
MTD-G	1-11/16"	3	16"	2.5"	350/15
ePDT-II	2" / 1-11/16"	3-5	30" / 18-5/8"	3.5"	350/20

Technical specification documents are included in *Appendix E-2,* as part of the Quality Assurance and Surveillance Plan. Logging speeds depend on the size and number of tubulars to be logged. In general, multiple tubulars and larger sizes will necessitate slower data acquisition speeds, which range from 30 feet (ft) per minute to 5 ft per minute, based on the complexity of the wellbore configuration.

GOWell PEC decay instruments measure the increase or decrease of metal thickness for each concentric tubular. PEC decay data combined with inspection of the tubular's ID, using an imaging caliper or other methods, can reliably predict the inside-vs.-outside location of corrosion or flaws on the innermost tubular. Internal wear based on drilling or other known causes of internal damage is readily assessed with the assumption that the measured metal loss in such cases is "internal."

The degree of penetration is reported in percent wall loss from the nominal and absolutes value of Metal thickness, expressed in inches or millimeters. Due to well-understood and long-established physics principles of PEC decay, reported metal gain or loss is assumed to be distributed evenly around the pipe's circumference.

The GOWell PEC decay instruments' measure of the increase or decrease of metal thickness includes both internal and external corrosion effects. This overall metal thickness/degree of penetration is valid in identifying areas of well integrity concern. Additionally, integrity assessment of the production tubulars (i.e., tubing(s) and first casing) is only part of whether a wellbore and its associated tubulars are in such a condition as to be protective of public health, safety, and the environment. The newer generation GOWell PEC decay instruments provide an opportunity to assess the state of the protection tubulars (i.e., second casing, surface casing, etc.). Protection string(s) data is acquired simultaneously with the tubing and production string data.

5.4.9 Logging and Testing Reporting

A report that includes log and test results obtained during the drilling and construction of Orchard No. 1 through No. 7, and interpreted by a knowledgeable log analyst, will be submitted to the UIC Director as per 16 TAC **5.203 (h)(2)** [40 CFR **§146.87(a)**].

5.5 Monitoring Programs

5.5.1 Continuous Injection Stream Monitoring

Orchard Storage will continuously monitor the injection pressures, rates and volumes, and annulus pressures to meet the 16 TAC ***§*5.203 (j)(2)(B)** [40 CFR **§146.90(b)**] requirements. A Supervisory Control and Data Acquisition (SCADA) system will be installed Project Orchard Site to facilitate the operational data collection, monitoring, and reporting. Per 16 TAC ***§*5.206 (d)(2)(B)**, the total volume of CO_2 injected into the Orchard Project facility will be metered through either a master meter or a series of master meters. The volume or mass of CO_2 injected into Orchard No. 1 through No. 7 will be metered through individual well meters.

Continuous monitoring of the injected CO_2 stream pressure and temperature will be performed using digital pressure gauges installed in the CO_2 flowline, near the flowline-wellhead interface. The on-site SCADA system will be connected to the flowline. A flowmeter will also be installed on each of the injection wells and connected to the SCADA system at the CO_2 storage site, to ensure continuous monitoring and control of the CO_2 injection rate.

The wellhead will accommodate continuous annular pressure measurement and injection pressure measurement.

Downhole measurement will be accomplished using fiber-optic-based sDAS and DTS sensors. Additionally, a tubing encapsulated conductor (TEC) will power and communicate with permanently installed pressure gauges. This equipment will be run with the casing and cemented in the annulus behind the long-string casing. The vertical seismic profile (VSP) technology and downhole sensing discussion in *Section 5.5.7* describes the systems in detail.

Figure 5-2 provides an illustration of the control and monitoring systems to be installed at Orchard No. 1 through No. 7.

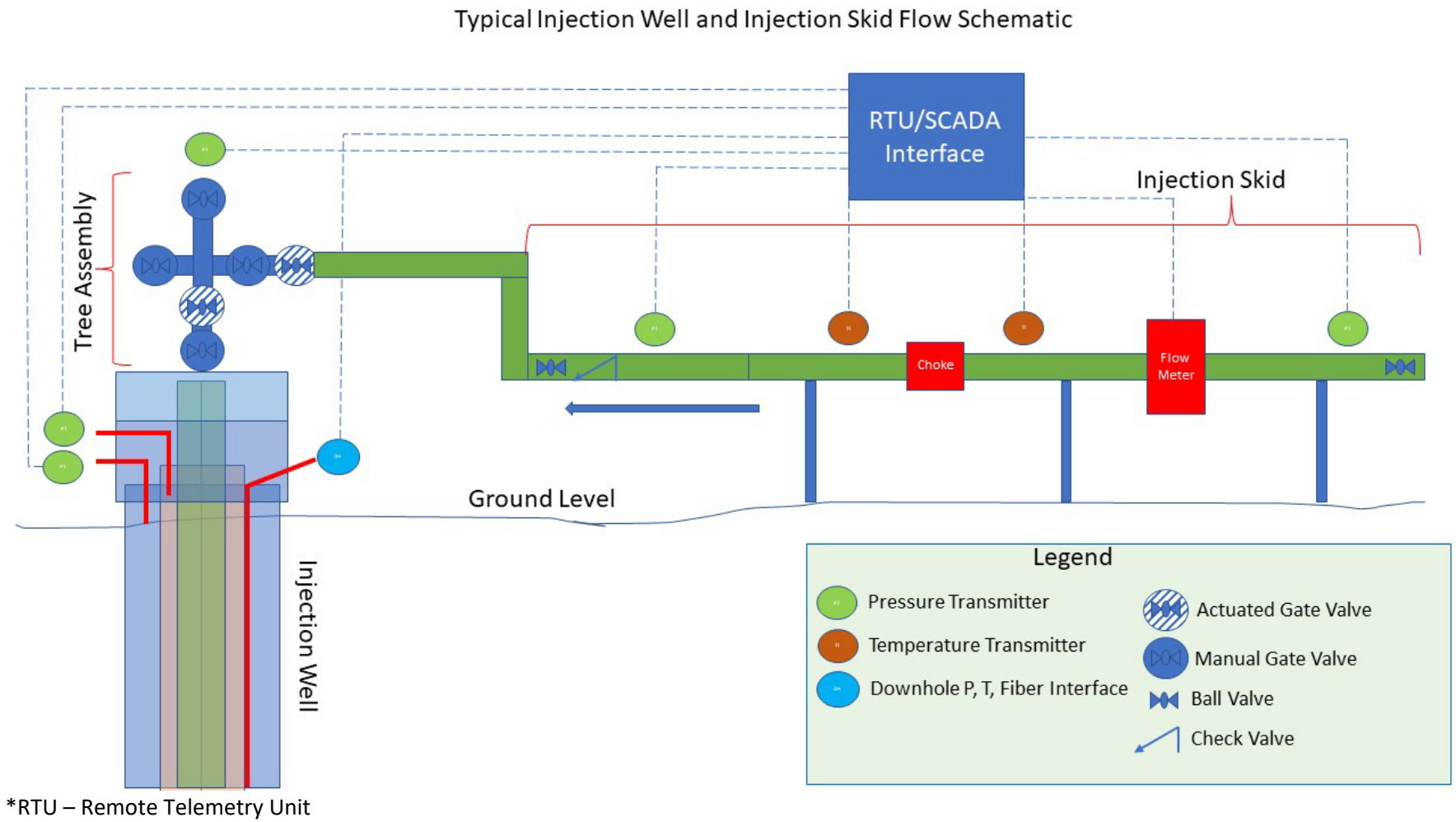


Figure 5-2 – Typical Injection Well and Injection Skid Flow Schematic

5.5.1.1 Analytical Methods

Orchard Storage will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will include trends, to help determine any need for equipment maintenance or calibration. These data reports will be submitted semiannually.

5.5.2 Corrosion Coupon Monitoring

Orchard Storage will monitor for corrosion of the well tubing and casing materials per the 16 TAC ***§*5.203 (j)(2)(C)** [40 CFR ***§*146.90(c)**] requirements, employing a corrosion coupon monitoring system for this evaluation. Additionally, the casing inspection logs to be run every 5 years will provide information regarding corrosion of the tubulars.

5.5.2.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection flowline, tubing, and production casing, will be placed in the CO_2 injection flowline. These coupons will be removed quarterly and examined for corrosion per American Society for Testing and Materials (ASTM) standards for corrosion-testing evaluation. After removal, the coupons will be visually inspected for signs of corrosion, including pitting, and measured for weight and size. The corrosion rate will be estimated by applying a weight-loss calculation method that divides the weight loss, recorded during the exposure period, by the duration of that period. If corrosion rates exceed 5 mpy, additional review and investigation will be initiated. The goal of the additional investigation will be to determine if the elevated corrosion rate was an anomaly or a result of an operating event. The results of this investigation may lead to other actions such as more frequent coupon monitoring.

5.5.3 Soil Gas Monitoring

Soil gas monitoring will be used to check the chemical compositions of the near-surface environment and soil vadose zone. These environments are subjected to strong seasonal effects and influenced by a wide range of natural processes and human activities. As with any of these types of monitoring, establishing a baseline condition is very important. Orchard Storage intends to install soil gas monitoring stations at least 1 year prior to injection, to better understand baseline and background conditions through multiple seasons. Soil gas monitoring implants will be installed adjacent to the pad site of each injection well in an undisturbed location. Ideally, the location of the stations will be selected to minimize the agricultural impacts of plowing, planting, irrigation, and harvesting. Best industry practices have shown that fixed soil-gas profile stations provide the most accurate data. Orchard anticipates utilizing Geoprobe™ permanent soil gas implant systems.

To establish a statistically relevant base of soil gas readings, Orchard intends to sample each of the permanent sampling points a minimum of eight times per year and no more than twelve times per year. As sampling continues, the sampling frequency may be adjusted to meet actual observed conditions. Sampling will be conducted utilizing vacuum canister-type samplers. The quantity of samples to be collected will be optimized based on observed soil diffusion rates to avoid unrepresentative samples. Samples will be collected and sent to a third-party lab for analysis. Quality assurance and traceability methods will be used to ensure proper handling of samples and lab techniques.

5.5.4 Groundwater Quality Monitoring

To meet 16 TAC **§5.203 (j)(2)(C)** [40 CFR **§146.90(d)**] requirements, groundwater quality and geomechanical monitoring will be conducted above the confining zone to detect potential changes that could result from fluid leakage from the injection zone. Orchard Storage plans to drill five groundwater monitoring wells across the Orchard Project area. These wells will be placed across the anticipated pressure front to measure any change from baseline parameters that would indicate the migration of CO_2 into the USDW (Figure 5-3). The groundwater monitor wells will be located to ensure representative samples are obtained to reflect similar physical, chemical, geological, and biological characteristics to the Orchard Storage facility. The groundwater monitoring wells will be drilled at least six months ahead of drilling injection wells to allow for effective baseline testing of the groundwater properties as listed in Table 5-6. Orchard will acquire openhole logs in the form of gamma ray, resistivity, and porosity measurements during the drilling of these monitoring wells. Following the baseline efforts, sampling will occur quarterly. The parameters to be measured are provided in Table 5-6. Details regarding these parameters are provided in the Quality Assurance and Surveillance (QASP) plan, Section 6.2.1, Table 17.

Table 5-6 – Groundwater Quality Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Total dissolved solids (TDS)	Quarterly
Dissolved Gases	Quarterly
pH	Quarterly
Specific conductivity (SC)	Quarterly
Temperature	Quarterly
Density	Quarterly
Other parameters including major anions and cations, trace metals (total and dissolved), hydrocarbons, and volatile organic compounds, inorganic compounds	Quarterly

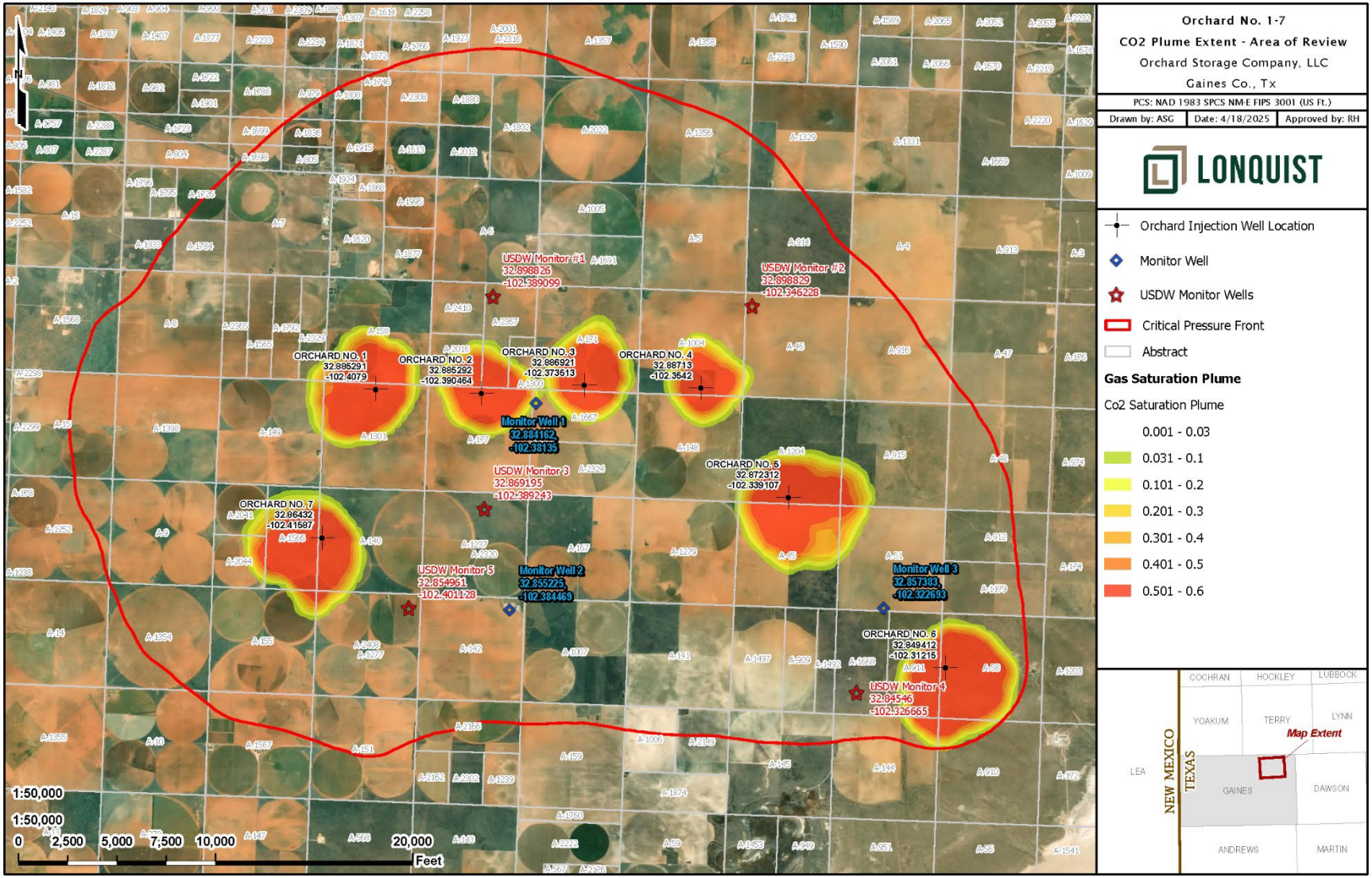


Figure 5-3 – Location of Groundwater, In-Zone and Above-Zone Monitoring Wells

5.5.4.1 Sampling Methods

Fluid samples will be acquired from the groundwater monitoring wells using an electric submersible pump. The pump will evacuate a minimum of two wellbore volumes of liquid prior to collecting a representative sample at the surface.

5.5.4.2 Analytical Methods

Orchard Storage will test water samples and maintain results for the parameters that were listed in Table 5-6. If the CO_2 injectate contains unique impurities, then groundwater samples will also be tested to flag any concentrations of these impurities exceeding the baseline. Testing results will be stored in an electronic database.

Potential signs that fluid may be leaking from the injection interval(s) in the form of CO_2 or brine may be detected upon observation of the following trends:

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

If a significant change is observed, further investigation may be warranted. "Significant" changes for specific constituents will be established once the baseline values are obtained and analyzed. Specific variability of individual parameters is best established after the baseline data (pre-injection) is obtained and analyzed using statistical analysis methods as appropriate to account for naturally occurring and environmental variations in the parameters. Deviations of greater than 35% of the baseline data values will trigger an alarm and initiate action to recognize and mitigate potential CO_2 or brine leaks into groundwater. This 35% limit assumes that the laboratory sampling and analysis will have approximately 25% uncertainty and 10% uncertainty caused by heterogeneity within the injection reservoir. Care will be taken when establishing these limits to reduce the number of false positives that may occur. All the analytical measurement values will be taken in context with pressure readings within the aquifer, the above-zone monitoring interval, and location relative to the CO_2 plume and injection zone pressure front.

The relative benefit of each analytical measurement will be evaluated throughout the project life to identify the analytes that provide the most benefit to the overall monitoring objectives related to the groundwater monitoring. Any modifications to the monitoring plan will be made in consultation with the appropriate UIC regulator.

5.5.4.3 Laboratory to Be Used/Chain of Custody Procedures

Water sample results will be submitted to the TRRC after analysis at a state-approved laboratory. Orchard Storage will observe standard chain-of-custody procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including problems encountered.

5.5.4.4 Quality Assurance and Surveillance Measures

Orchard Storage will collect duplicate samples and trip blanks for quality assurance/quality control (QA/QC) purposes. These duplicate samples will validate test results and ensure that samples have not been contaminated.

5.5.4.5 Plan for Guaranteeing Access to All Monitoring Locations

The installation of groundwater monitoring wells is part of the surface-use lease agreements with the landowners across the plume area, ensuring access to the well locations for sampling and maintenance purposes. Unauthorized access will be prevented by capping and locking out the well.

5.5.5 Monitoring Wells

Two above-zone monitoring wells, Orchard MW No. 1 and MW No. 3, will be drilled and completed on the Orchard Storage property, as shown previously in Figure 5-3. These wells will continuously monitor the pressure of the first mappable sand (Queen formation) identified above the upper confining interval. Orchard Storage plans to drill these wells in the same drilling campaign as the injection wells. The monitor wells will be logged, one will be cored, and both will be tested utilizing openhole sampling tools (RFT/MDT) to acquire representative fluid samples. Annular pressure tests will be conducted on the wells after construction and every 5 years thereafter or after well work has been completed. The native state logs and fluid samples will be used as baseline data to compare to ongoing injection operations testing. Baseline fluid testing will include TDS, pH, and hydrochemistry, as shown in Table 5-7. Details regarding these parameters are provided in the QASP plan, Section 6.2.1, Table 17.

Table 5-7 – Reservoir Fluid Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Total dissolved solids (TDS)	Baseline
pH	Baseline
Specific conductivity (SC)	Baseline
Temperature	Baseline
Density	Baseline
Other parameters, including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds	Baseline

Pressures will also be taken to establish a baseline pressure for the above zone interval. Changes in pressures that are unexpected and exceed three standard deviations from the average of previous readings will trigger further investigative action. This additional investigation may include fluid sampling for comparison to the baseline using through tubing sampling, if needed.

The Orchard MW No. 2 well is an existing wellbore that will be utilized as an in-zone monitoring well. Orchard MW No. 2 will be equipped with permanent downhole gauges to continuously

monitor pressures within the San Andres injection interval. None of the three monitoring wells will intersect the CO_2 plume directly.

5.5.6 Seismic Monitoring

As discussed in *Section 1 – Site Characterization*, this area is seismically quiet. The Bureau of Economic Geology in Texas maintains a seismic monitoring system known as TexNet. The closest monitoring station to the Orchard Project is approximately 20 miles to the south, as shown in Figure 5-4. Orchard Storage will review the TexNet website daily for any seismic activity in or around the facility area. Orchard Storage will implement the following response plan:

- If an event greater than 2.5 is detected within 5.6 miles (9.0 km) of an injection well(s), Orchard Storage will compare it with the injection history and publicly available data from nearby oil and gas activity to determine if a correlation to injection activity can be determined.
- A seismic event greater than 3.5 and less than 5.0 within 5.6 miles of an injection well(s) will trigger a review within 24 hours to determine if the event may potentially be contributed to by injection. Injection rates may be reduced temporarily into wells within 5.6 miles of the seismic event or in accordance with guidance from the UIC Director.
- If an event greater than 5.0 magnitude occurs within 5.6 miles of an injection well(s), the injection rate in those wells will be stopped to determine if a relationship between the injection activity and the event exists. The UIC Director will be notified, and Orchard Storage will work with the Director to determine a plan to further evaluate the seismicity event and establish target volumes and pressures for injection.

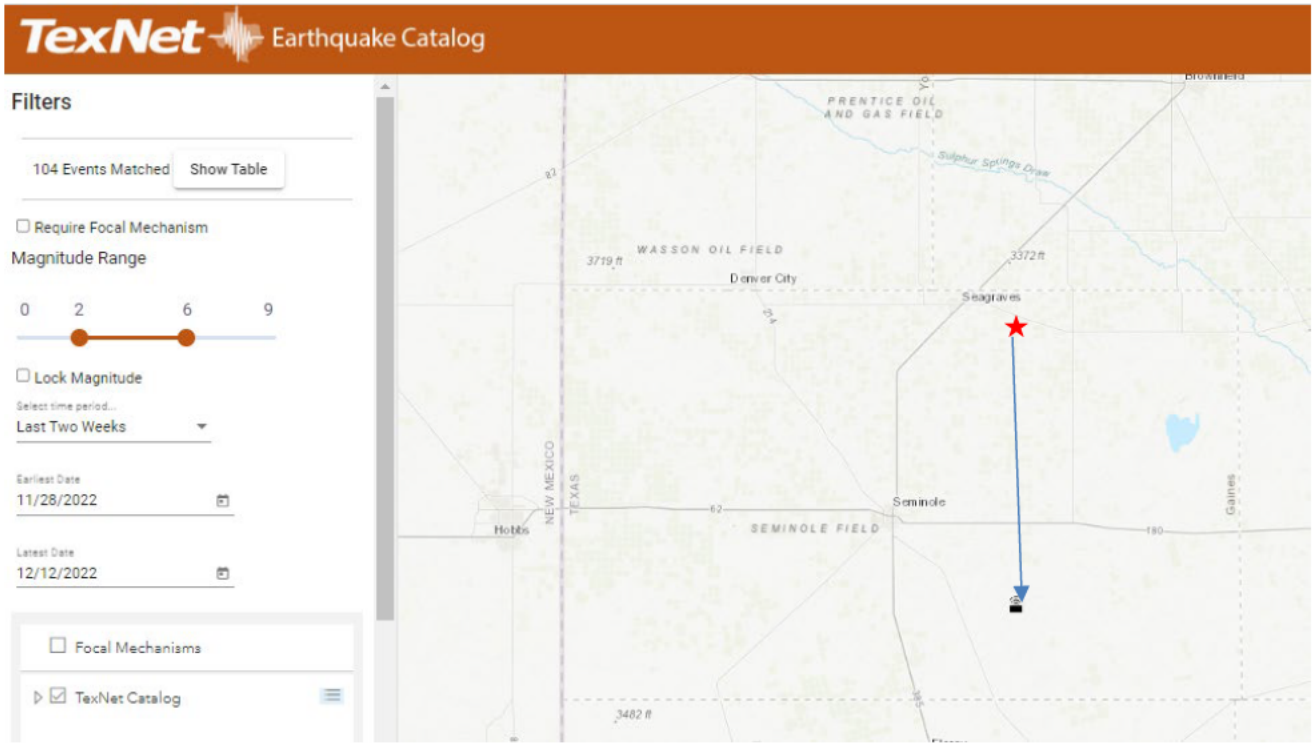


Figure 5-4 – Nearest TexNet Seismic Monitoring Station (red star indicating approximate location of the Orchard Project).

5.5.7 Injection Plume Monitoring

Orchard Storage will use both direct and indirect methods to track the CO_2 plume and the pressure front tracking, in accordance with 16 TAC **§5.203 (j)(2)(E)** [40 CFR **§146.90(g)**]. The critical pressure front will be directly monitored by using continuously recorded pressures and temperatures to calculate the extent of this pressure increase. The CO_2 plume will be indirectly monitored using seismic survey technology such as vertical seismic profiling (VSP).

Orchard Storage will use these methods to verify reservoir conditions during injection, track plume and critical pressure front migration, and validate the reservoir model. Continuous pressure and temperature monitoring of the injection reservoir will allow for monitoring of reservoir conditions and inform calculations, while VSP surveys will determine the actual CO_2 plume migration. The VSP surveys will be run prior to injection initiation to establish a baseline, periodically as needed, and every 5 years at a minimum. These results will be submitted to the UIC Director as part of the semi-annual reports for this facility.

5.5.7.1 Direct Monitoring: Rate Transient Analysis

Rate transient analysis, in conjunction with reservoir simulations using known reservoir characteristics, will allow for calculating more complex parameters within the injection interval. Direct monitoring will be based on continuous pressure, temperature, and injection rate data to calculate the properties of the reservoir and verify the plume model results.

The reservoir model built during the site evaluation phase will be used to predictively monitor the reservoir conditions during injection operations. Through flow simulation and transient flow analyses, the reservoir model will be updated with injection activity regularly, to evaluate the injection stream's effect on reservoir conditions. This analysis can be performed to monitor the magnitude and extent of temperature and pressure 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.

Additionally, any shut-in periods can be observed and treated as a pressure falloff test. To do this, the shut-in wellhead pressure, bottomhole pressure, and temperature readings will be recorded and used for pressure-transient analysis of the reservoir. The analysis results will include the radius and magnitude of pressure buildup and reservoir performance characteristics such as permeability and transmissibility. Analysis results will then confirm, and adjust as necessary, the previous model realizations.

Through predictive modeling and analysis of recorded pressure and temperature data, Orchard Storage 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.

5.5.7.2 Indirect Monitoring: Vertical Seismic Profile

Orchard Storage will use time-lapse VSP as the first method to indirectly monitor the CO_2 plume extent and development per the 16 TAC **§5.203 (j)(2)(E)** [40 CFR **§146.90(g)(2)**] requirements. A fiber optic cable with sDAS/DTS will be installed and cemented in the annulus behind the long-string casing. This system will enable real-time reservoir monitoring using pressure and temperature gauges and the periodic VSP. The sDAS/DTS fiber optic cable, designed with sensors spaced one meter apart, will be used to generate a VSP at the highest possible resolution. Three-dimensional models of the CO_2 plume can be created using a walk-away seismic source. The data is captured by monitoring the injection well and repositioning the surface acoustic source. Vibrator trucks will be utilized as the acoustic source, and locations will be determined based on well location and conditions.

As an example of where this technology has been proven, Shell Canada used it for plume movement monitoring at its Quest Project (Bacci, O'Brien, Frank, and Anderson, 2017). Figure 5-5 illustrates the acquisition pattern strategy employed for plume development surveys from two separate wells.



Figure 5-5 – Shell Canada Quest Project VSP Acquisition Patterns

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 therefore be visualized.

The work steps involved in a time-lapse VSP survey primarily include the following:

1) Rock Physics Model
2) Petro-Elastic Model
3) Feasibility
4) Baseline Survey (Data Acquisition)
5) Repeat/Time-Lapse Survey (Data Acquisition)
6) Interpretation

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 a high degree of confidence, provided 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 whether 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

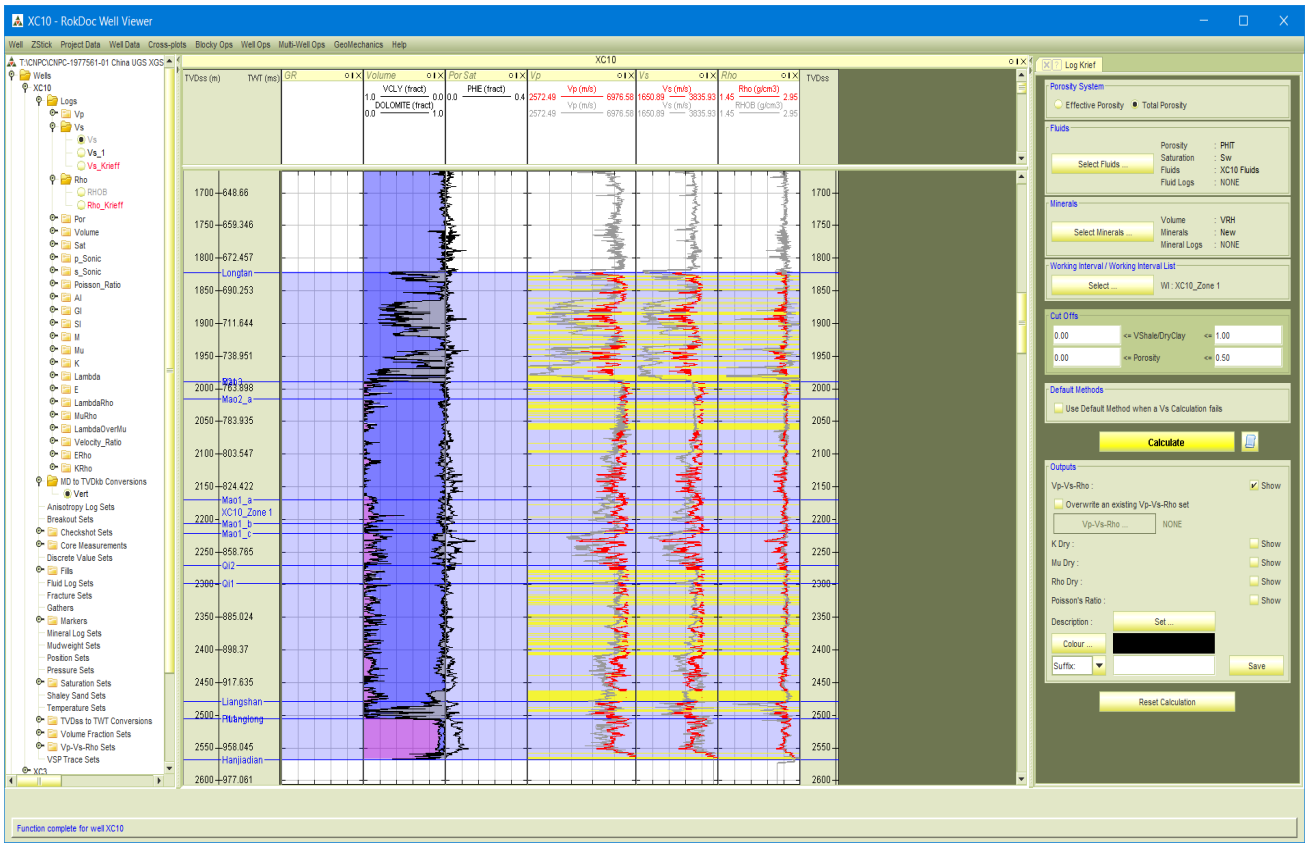


Figure 5-6 – RocDoc Well Viewer

The RocDoc Well Viewer (Figure 5-6), developed by Baker Atlas, is an evaluation product that enables QC of the deterministic inversion of the reconstructed mineral content compared to the observed petrophysical response. The inversion allows for the stabilization of inverted results, evaluation of uncertainty in predicted attributes, and calculation of in situ reservoir properties.

5.5.7.4 Petro-Elastic Model

The rock physics model will generate a zero-order dry rock model, which is then used to establish a petro-elastic model by perturbing the elastic parameters for varying degrees of saturation.

Figure 5-7 illustrates the combination of the rock physics model (shown in red) and the petro-elastic model at 52% water saturation (in blue). Changes in saturation result in changes primarily to the compressional wave velocity for this type of rock. The effect of gas replacement of the reservoir fluid can be estimated using the fluid saturation and fluid replacement from the rock physics model.

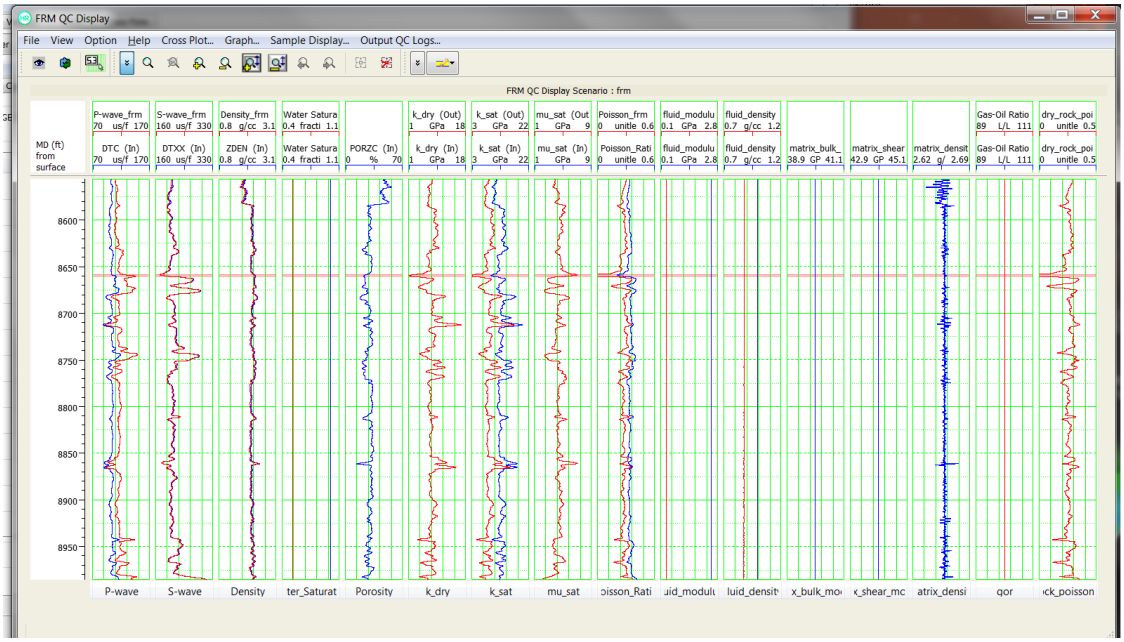


Figure 5-7 – Application of Petro-Elastic Model to Rock Physics Model

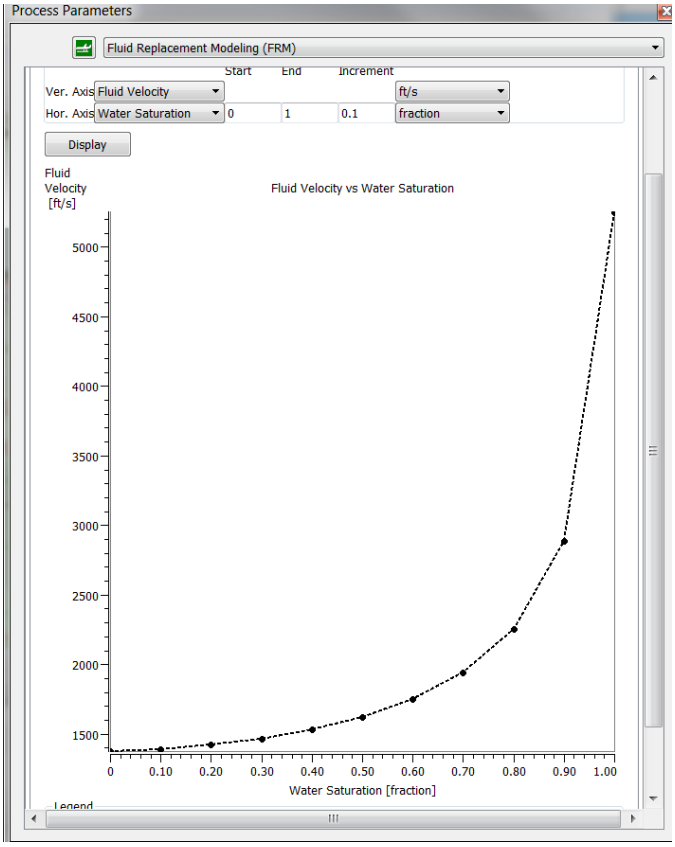


Figure 5-8 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation

Predicting velocity and density as functions of injectate saturation is the final result of the petro-elastic model (Figure 5-8). 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 petro-elastic model. This will be conducted after recovering core material from the injection 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 injection wells 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 details 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 transition zones between formations. Geoscientists can use the variation in sonar velocities to understand subsurface lithology.

Figure 5-9 depicts a standard VSP survey with a geophone configuration.

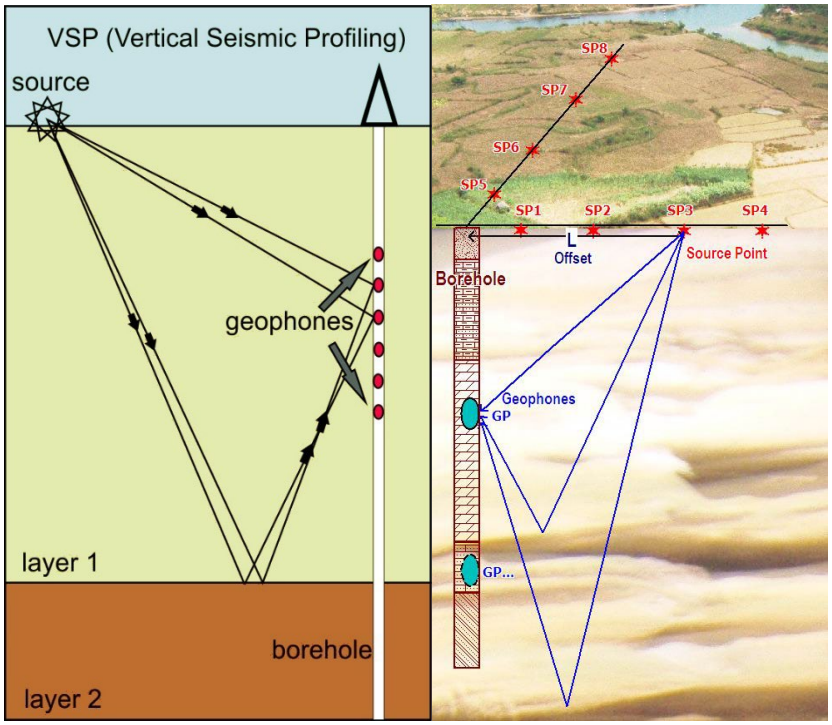


Figure 5-9 – Illustration of a Vertical Seismic Profile Survey

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 5-10. Geophones are situated vertically along the wellbore while all shots are fired from the surface. This allows them 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. These are commonly used to generate more accurate VSP, 2D, 3D, and 4D surveys.

The 1D survey methodology assumes that each formation is homogeneous in the horizontal direction, so the surveys can only provide average sonic 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 variation of 1D seismic surveys 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, they can provide a way to a 1D understanding of variation in velocities.

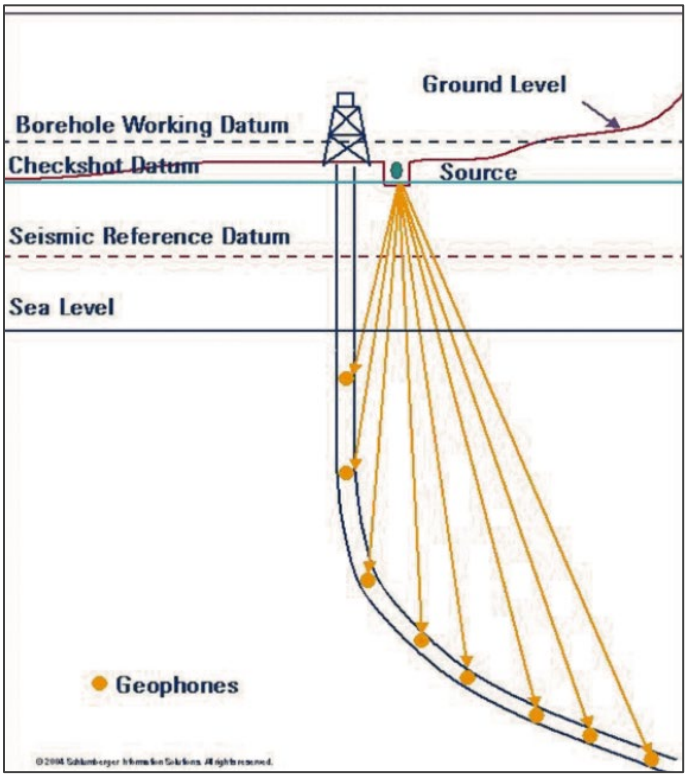


Figure 5-10 – Illustration of a Checkshot Survey

A 1D offset model will be constructed for each case, and differences in reflection amplitudes measured.

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; 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 located 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 of an environmental impact than 3D surveys. They 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 that have been recorded at various time intervals—Year 1, Year 5, Year 10, etc.). The wheel-spoke pattern of 2D survey lines, with the injector and VSP receiving fiber optic at its center, can be interpreted as similar to a 3D survey. Changing volumes of gas buildup, represented by either log shifts on 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 5-11 illustrates a basic workflow example:

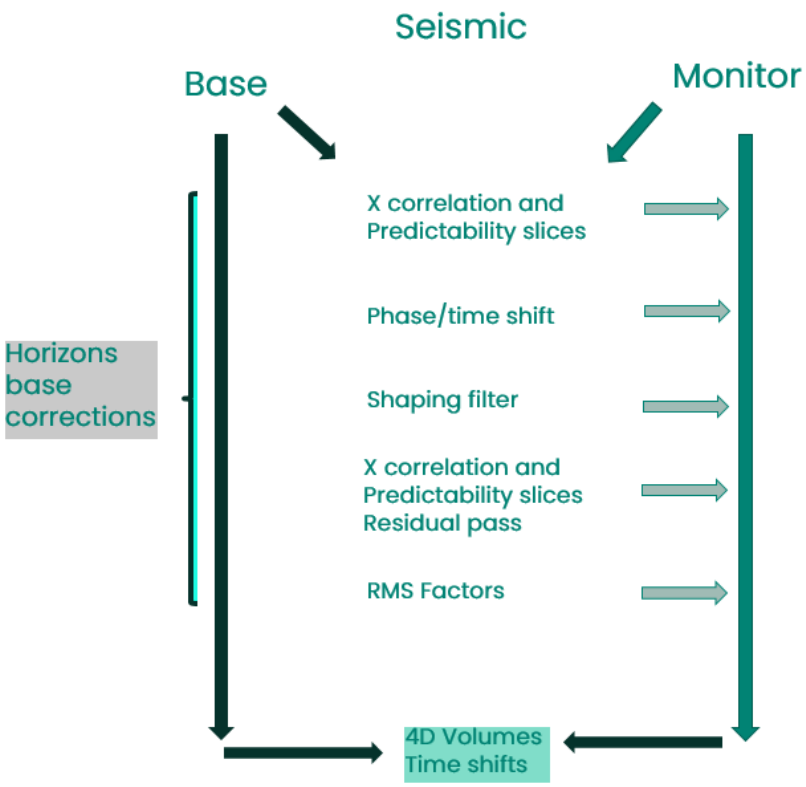


Figure 5-11 – Time-Lapse/4D Processing Workflow Diagram

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-lapsed development of the injectate plume.

To ensure consistency, all seismic volumes will be processed using the same software and for each workflow step outlined below. Figure 5-12 presents a 4D time-lapse model visualization in 3D with analysis software. Color coding is used to display amplitude over time for each horizon. A similar output will be generated from Orchard Storage's VSP surveys at the Orchard Project site.

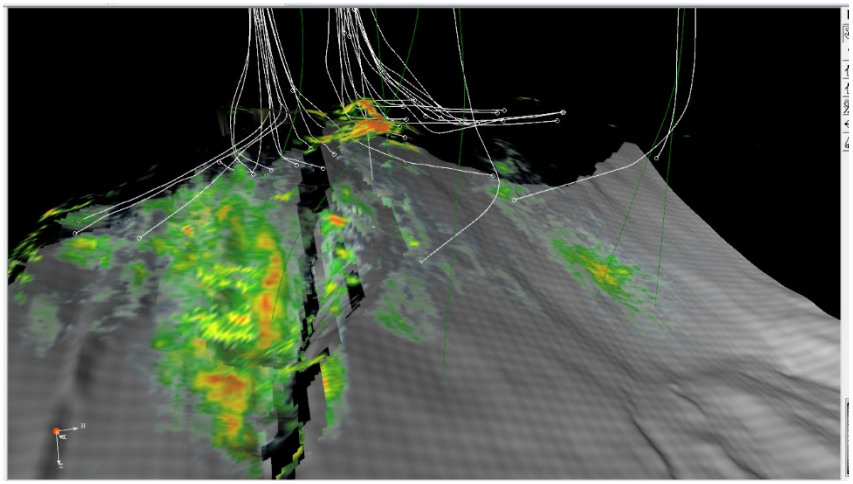


Figure 5-12 – Example of Time-Lapse/4D Model (showing time-lapsed gas-replacement of connate fluids)

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 5-13 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.

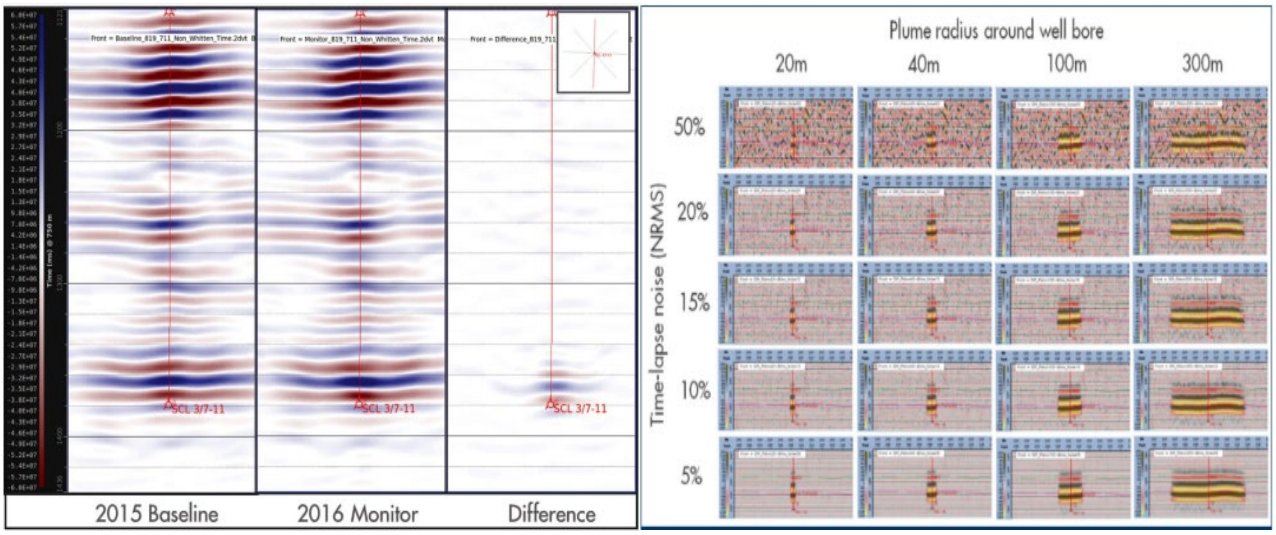


Figure 5-13 – Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection measured from the injector well itself. At right is the estimation of the plume growth over time.

5.5.7.10 Baseline Survey

Conducting a quality VSP baseline survey is of critical importance, as it is the only opportunity to capture an image of the reservoir before injection operations or offset activity—natural or man-made—impact it. Without this, 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, in the event that the initial reservoir models are not accurately forecasting plume migration.

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 an sDAS fiber optic cable—to be installed in the Orchard No. 1 through No. 7 wells and connected to an interrogator box at the surface. The sDAS system is synchronized to the seismic acquisition system controlling both the receiver (the sDAS fiber-optic array cemented in the injection well) and the source (seismic vibrator trucks).

5.5.7.12 Wellbore Overview

The proposed wellbore design consists of 10-3/4 inch (in.) surface casing to be run below the USDW and cemented in place per EPA Class VI standards. The production casing will be a 7 in. long-string run to an approximate depth of 6,800 ft across the planned injection zone. To ensure sufficient corrosion resistance for CO_2 injection, corrosion-resistant alloy (CRA) material will be utilized across the injection zone. The injection string will be comprised of 4-½ in. CRA material, and the completion and monitoring assembly will employ a 4-½ in. x 7 in. Premier V0-rated injection packer with releasable anchor seal assembly—also manufactured from CRA material.

Fiber optic cable will be installed on the 7 in. casing string along its outer diameter (OD). This cable will consist of DTS/sDAS/Well Integrity Real-time Evaluation (WIRE) equipment. The DTS fiber will rapidly detect temperature profiles near the production casing and verify cement circulation during the cement job. The CO_2 plume growth will be monitored through repeated VSP seismic processing using the sDAS fiber (as described previously). High-density strain monitoring of the wellbore and surrounding formation is performed using the WIRE-fiber monitoring system to detect, localize, and classify reservoir compaction, shearing, and integrity instances. Approximately 6,800 ft of ¼ in. TEC with pressure and temperature gauges will be installed on the OD of the 7 in. casing, which will be ported to read the pressure inside of the production casing. The tubing gauge will allow for continuous bottomhole pressure and temperature monitoring during injection, throughout the project life, so long as cement does not squeeze off the injector perforations during plugging operations.

Protective casing clamps will be installed on each casing joint collar to ensure the cable has been securely run to depth. Orchard Storage will install blast protectors on each joint in the injection zone to locate the cable on the casing string and ensure no damage has occurred to the fiber optic cable and TEC line during oriented wireline perforating. Enhanced location detection through the magnetic resonance tools is also achieved with the addition of metal in the blast protectors.

5.5.7.13 Equipment Overview

This section discusses the typical hardware setup and use of in situ monitoring equipment for temperature and pressure that will employ fiber optic cable to communicate with a surface-located interrogator box, to record real-time or periodic data. Specific vendor-proprietary equipment will be provided when the vendor is selected nearer to the time the wells are drilled.

SureVIEW with CoreBright Optical Fiber

SureVIEW downhole cable uses CoreBright optical fiber, which leads the industry in resisting hydrogen darkening—the primary cause of failure for fiber optic systems in high-temperature applications. CoreBright is constructed from pure silica that minimizes hydrogen darkening, combined with a layer of hydrogen-absorbing gel. Figure 5-14 illustrates the optical fiber, and Table 5-6 provides the specifications.

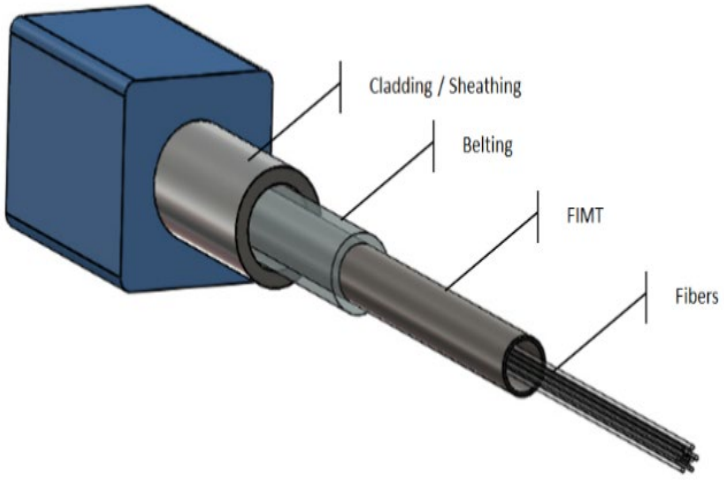


Figure 5-14 – SureVIEW with CoreBright Optical Fiber

Table 5-8 – SureVIEW Downhole Specifications

Description	Specifications
Maximum Pressure	25,000 psi
Overpressure	1.2x maximum pressure
Operating Temperature	• 150°C / 302°F for standard • 250°C / 482°F for high temperature • Higher temperature solutions available upon request
Sheath Material	A825, 316LSS
Crush	>5,000lbf
Fibers	Maximum of 12, any combination of SM and MM
Fiber Protection	• Standard Temperature: Hydrogen-scavenging gel, carbon coating, acrylate buffer • High Temperature: High-temperature stabilized gel, polyimide buffer, optional carbon coating
Dimensions	0.25 inch outside diameter (excluding encapsulation)

SureVIEW DTS

The SureVIEW DTS interrogator provides continuous monitoring, rapidly updating temperature profiles along the length of the completions. Its specifications are listed in Table 5-7.

Table 5-9 – SureVIEW DTS Specifications

Description	Value
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 µm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW sDAS

The SureVIEW sDAS interrogator offers all the benefits of fiber-optic acoustic monitoring, from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring, combined in a single interrogator (specifications shown in Table 5-8).

Table 5-10 – SureVIEW DAS VSP Specifications

Technical Specifications	
Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110-240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC
Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 με

SureVIEW WIRE

The SureVIEW WIRE structural-integrity management system enables high-density strain monitoring of the wellbore and surrounding formation to detect, localize, and classify reservoir compaction, shearing, and integrity issues. The cable is deployed in the well along the outside of the casing, where it is cemented into place and brought online. Once online, data can be closely observed across the entire geological interface. An illustration of this technology is shown in Figure 5-15 and the technical specifications are provided in Table 5-9.

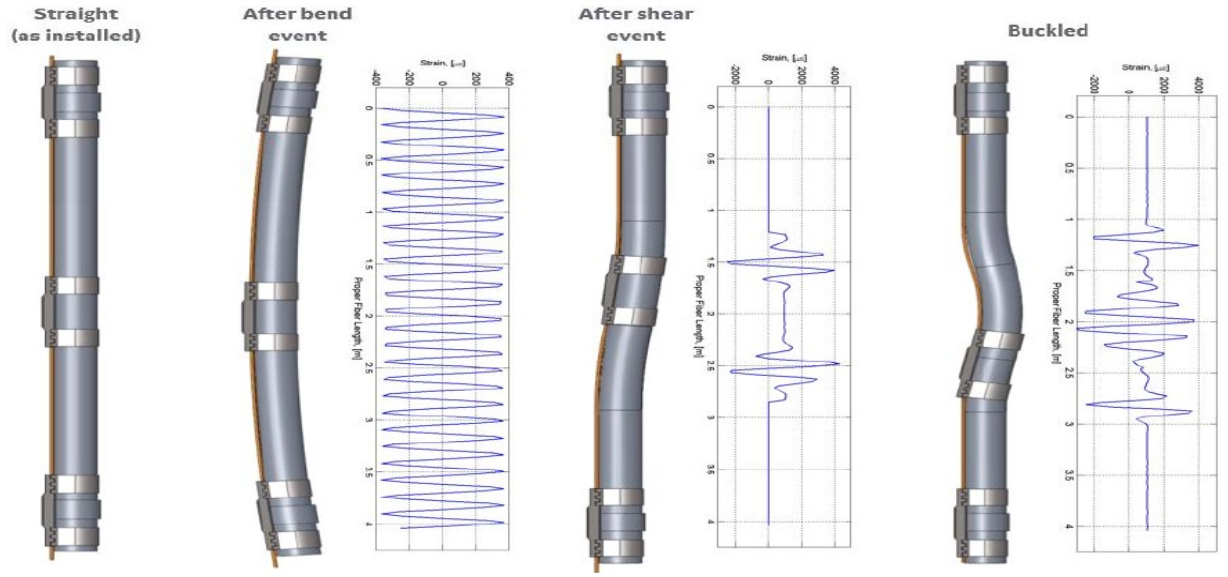


Figure 5-15 – SureVIEW WIRE Illustration

Table 5-11 – SureVIEW WIRE Cable Specifications

SureVIEW™ WIRE Cable	
Specifications	

Low Temperature Cable	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 120 Deg C Temperature Rating
	• 15,000 psi Pressure Rating

High Temperature	• 1/4″ OD
	• 0.035″ Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 225 Deg C Temperature Rating
	• 15,000 psi 15,000 psi Pressure Rating

**may require multiple cables spliced to achieve desired length*	

Tubing Encapsulated Conductor

The TEC is installed to support the Quartz Pressure Temperature (QPT) Elite gauges electrically and is designed for prolonged life in the most hostile downhole environments. The primary function of the TEC is to transmit electronic digital signals and power between subsurface components and a surface interface module used to conduct reservoir management. The TEC is produced as a single, solid conductor wire coated with a protective sheath and encapsulated in a metal-clad CRA tube. Figure 5-16 illustrates the TEC design, and Tables 5-10 and 5-11 list the technical specifications.

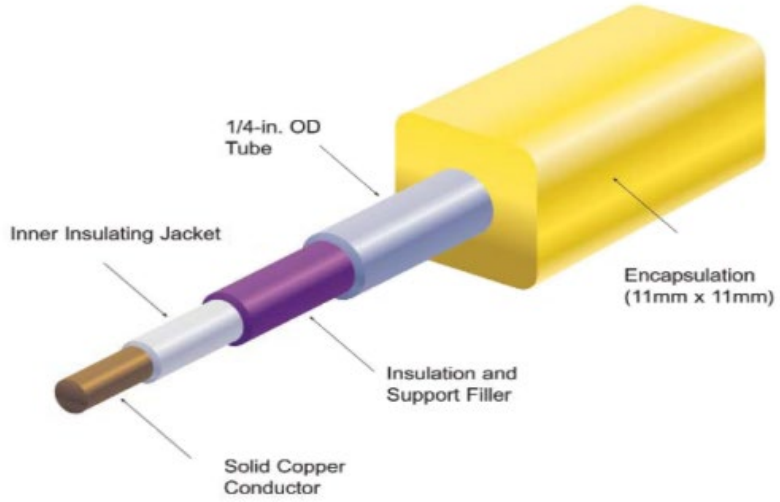


Figure 5-16 – TEC Illustration

Table 5-12 – TEC Specifications, Part I

Description	Value	
Size 0.035-in. Wall TEC		
Materials	316L stainless UNS S31603	Alloy 825 UNS N08825
Weight	198 kg/km (133 lb/1,000 ft)	199 kg/km (135 lb/1,000 ft)
Armor resistance at 20°C	51.2 Ohms/km (15.6 Ohms/1,000 ft)	73.9 Ohms/km (22.5 Ohms/1,000 ft)
Capacitance at 20°C	98 pF/m	
Collapse pressure rating (psi)*	30,000	

Table 5-13 – TEC Specifications, Part II

Wall (in.)	Alloy	Tensile (psi)				Yield (psi)			
		Minimum	Maximum	Average	STD	Minimum	Maximum	Average	STD
0.035	316L	122,000	178,000	153,000	6,800	100,000	158,000	125,000	8,200
0.049		141,000	154,000	145,000	5,100	113,000	130,000	119,000	6,400
0.035	A825	123,000	182,000	144,000	8,400	108,000	150,000	126,000	7,100
0.049		113,000	157,000	139,000	7,300	89,000	139,000	122,000	7,500

SureSENS Quartz Pressure Temperature Elite Gauge

The reliable, accurate SureSENS QPT Elite gauge (Figure 5-17) measures static and dynamic pressures and temperatures. The highly robust gauge ensures mechanical integrity by deep penetration and high-vacuum, electron-beam fusion welds without filling material. Only two fittings (the pressure port and the TEC) are required to interface the gauge with the carrier. The fittings can be externally tested in the direction that they will experience pressure, thereby eliminating the need for an internal pressure test tool.



Figure 5-17 – SureSENS QPT Elite Gauge Illustration

QPT Elite Pressure Interface – Pressure Testable Manifold

The gauge-pressure interface connection to the carrier is via a pressure-testable manifold interface attached to the mandrel. Triple metal seal rings are pressure-tested to ensure integrity before deployment. The three metal seals provide redundant metal-to-metal sealing, tested in the same direction as the applied pressure in the final installation. This provides a true, unique metal-to-metal design that is bidirectional and dual-testable. Figure 5-18 illustrates the design, and Table 5-12 lists the technical specifications.

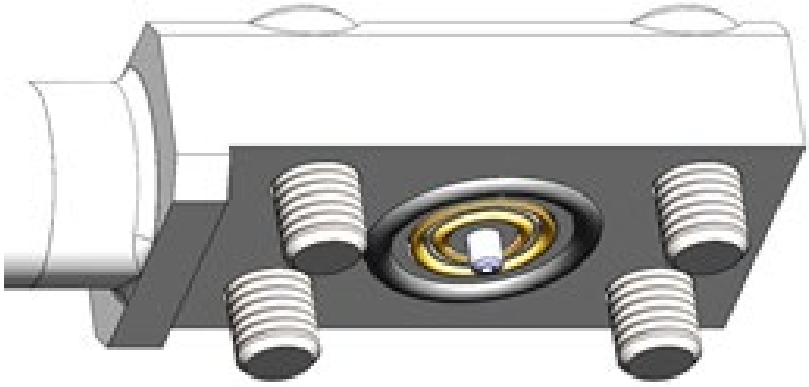


Figure 5-18 – External Sensor Illustration

Table 5-14 – QPT Elite Pressure Interface – Pressure-Testable Manifold Specifications

Length	25.5 in. to 26.5 in. (64.77 cm to 67.31 cm)					
Height/Width	0.750 in. (19.05 mm) / 1.318 in. to 2.50 in. (33.50 mm to 63.50 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options	10,000 psi (689.5 bar)	15,000 psi (1103.2 bar)	20,000 psi (1379.0 bar)	25,000 psi (1723.6 bar)	30,000 psi (2068.4 bar)	35,000 psi (2413.7 bar)
Material	Inconel 718	MP35N				
Pressure range	15 psi to 11,000 psi (1 bar to 758.4 bar)	15 psi to 18,000 psi (1 bar to 1241.1 bar)	15 psi to 23,000 psi (1 bar to 1620.3 bar)	15 psi to 28,000 psi (1 bar to 1930.5 bar)	15 psi to 33,000 psi (1 bar to 2275.3 bar)	15 psi to 37,500 psi (1 bar to 2585.5 bar)
Temperature rating (operating)	-99.4°F to 302°F (-73°C to 150°C)	-99.4 to 437°F (-73°C to 225°C)				
Storage temperature	-40°F to 302°F (-40°C to 150°C)					
Temperature shock	5.4°F (3°C) per minute					
Vibration	>10 G, 10 Hz-2 kHz					
Shock	500 G					
Pressure measurement range (calibrated)	200 psi to 10,000 psi (13.8 bar to 689.5 bar)	200 psi to 16,000 psi (13.8bar to 1103.2 bar)	200 psi to 20,000 psi (13.8 bar to 1379.0 bar)	200 psi to 25,000 psi (13.8 bar to 1723.6 bar)	200 psi to 30,000 psi (13.8 bar to 2068.4 bar)	200 psi to 35,000 psi (13.8 bar to 2413.7 bar)
Pressure accuracy	+-0.015% 1.5 psi at full scale	+-0.02% 3.2 psi at full scale	+-0.02% 4.0 psi at full scale	+-0.02% 5.0 psi at full scale	+-0.025% 7.5 psi at full scale	+ -0.03% 10.5 psi at full scale
Pressure resolution	0.0001 psi					
Pressure stability	0.02% full scale, 2.0 psi/year	+-0.02% full scale, 3.2 psi/year	+-0.02% full scale, 4.0 psi/year	+-0.02% full scale, 5.0 psi/year	+-0.02% full scale, 7.5 psi/year	+ -0.03% full scale, 10.5 psi/year
Temperature measurement range (calibrated)	77°F to 302°F (25°C to 150°C)	77°F to 437°F (25°C to 225°C)				
Temperature accuracy	0.27°F (0.15°C)					
Temperature resolution	0.0001°F					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission	50,000 ft (15,240 m)					

SureSENS QPT Gauge Carriers

The carrier body is machined from a single bar stock with no requirement for welding or heat-treating processes (Figure 5-19). The gauge assembly is installed in a recessed pocket in the carrier, providing protection for the gauge without needing a cover plate. The uphole end of the gauge is secured to the carrier by a clamp, which is fastened to the carrier by socket head screws. All tubular completion products are designed to meet or exceed the tubing/casing specifications supplied by the customer. All tubular products are also inspected and tested per American Petroleum Institute (API) 5CT requirements for drift and pressure.



Figure 5-19 – SureSENS QPT Gauge Carrier Illustration

Steel Blast Protectors

The blast protectors are installed above and below each zone, over the fiber and TEC lines. The protectors have round steel bars that run the length of and are welded into the channel on both sides of the cables—to increase magnetic mass/signature for detection by the High-Resolution Vertilog (HRVRT) tool, to position the guns away from the cables (Figure 5-20).

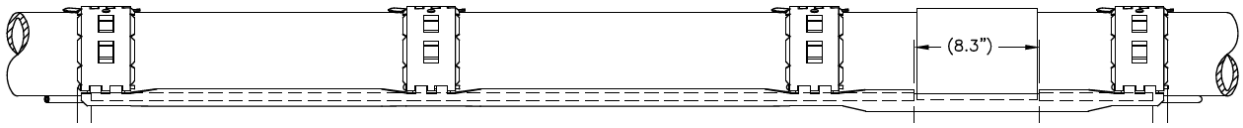


Figure 5-20 – Steel Blast Protector Illustration

Cross-Coupling Protectors

To protect the downhole cable, cross-coupling cable protectors are mounted at each tubing joint coupling, to protect the cable transitions across the coupling as shown in Figure 5-21. There is a potential for the downhole cable to be damaged due to abrasion or crushing between the tubing and casing internal wall during the installation process, resulting in the loss of functionality of the associated downhole equipment.



Figure 5-21 – Image of Cross Coupling Protector

5.5.8 VSP Monitoring Conclusion

The VSP method for quantifying CO_2 plume development over time has been demonstrated in several worldwide cases. Using offset petrophysical data, modeling results will generate a modeled differential in compressional velocity and density that will produce detectable changes in the reservoir, where the connate fluid has been replaced by carbon dioxide. This information provides confidence that deploying the method in a time-lapse format will generate a 4D image of the extent and future development of the plume. Further, employing the VSP in the injection wells with a permanently installed fiber optic sensor will create an image centered on the injection location, with higher resolution than a traditional wireline-deployed geophone array. This method eliminates the need for additional penetrations within the injection formations for monitoring purposes.

The fiber optic configuration installed in Orchard No. 1 through No. 7, coupled with pressure and temperature monitoring, will be used in indirect-pressure plume calculations.

Most importantly, the need to add artificial penetrations for monitoring purposes is reduced, as the VSP system plus direct-plume calculations will allow for accurate monitoring of plume migration. This reduces the risk of inadvertently forming a conduit from the confinement intervals in the monitoring wells.

5.6 Conclusion

The testing and monitoring plans developed for Orchard No. 1 through No. 7 are designed to acquire essential data to support static and dynamic reservoir modeling, track the growth of the CO_2 plume, and ensure that CO_2 does not reach USDWs or pose a risk to health, safety, or the environment.

A higher resolution map of the monitoring wells is included as Appendix E-1 and the Quality Assurance Surveillance Plan and associated specification sheets for the planned technologies are provided in *Appendix E-2*.

5.7 References

Bacci, Vicente Oropeza; O'Brien, Simon; Frank, Jordan; and Anderson, Mark. (2017). Using Walk-away DAS Time-lapse VSP for CO_2 Plume Monitoring at the Quest CCS Project. Shell Canada, Calgary AB, Canada. NADA.

Daley, Thomas M.; Myer, Larry R.; Hoversten, G.M.; Peterson, John E.; and Korneev, Valeri A. (2005). Borehole Seismic Monitoring of Injected CO_2 at the Frio Site. Lawrence Berkeley National Laboratory, Berkeley CA, USA.

Datta-Gupta, A. et al. (2017). Time-Lapse Seismic Monitoring and Performance Assessment of CO_2 Sequestration in Hydrocarbon Reservoirs. Texas A&M Engineering Experiment Station.

Huppert, Herbert E. and Neufeld, Jerome A. (2013). Fluid Mechanics of Carbon Dioxide Sequestration. Institute of Theoretical Geophysics and Department of Applied Mathematics and Theoretical Physics, University of Cambridge, United Kingdom. *Annual Review of Fluid Mechanics.*

Maurya, S.P. and Singh, N.P. (2019). Seismic modeling of CO_2 fluid substitution in a sandstone reservoir: A case study from Alberta, Canada. *J Earth Syst Sci 128, P. 236*.

Yang, Quinshan; Quin, Kuang; Olson, Jeff; and Rourke, Marvin. (2021). Through-Tubing Casing Deformation and Tubing Eccentricity Image Tool for Well Integrity Monitoring and Plug Abandonment. SPWLA 62nd Annual Logging Symposium, May 17-20, 2021.

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 6 – Plugging and Abandonment Plan

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 6 – INJECTION WELL PLUGGING PLAN

TABLE OF CONTENTS

6.1 Injection Well Plugging Plan Overview 3
6.1.1 Injection Well Pre-Plugging Activities 3
6.1.2 Injection Well Plugging Activities 4
6.1.3 Injection Well Plugging Cement Composition 4
6.1.4 Orchard No. 1 Plugging and Abandonment 6
6.1.5 Orchard No. 2 Plugging and Abandonment 9
6.1.6 Orchard No. 3 Plugging and Abandonment 12
6.1.7 Orchard No. 4 Plugging and Abandonment 15
6.1.8 Orchard No. 5 Plugging and Abandonment 18
6.1.9 Orchard No. 6 Plugging and Abandonment 21
6.1.10 Orchard No. 7 Plugging and Abandonment 24
6.2 Monitoring Well Plugging Plan and Regulatory Requirements 27
6.2.1 Monitoring Well Pre-Plugging Activities 27
6.2.2 Monitoring Well Plugging Activities 27
6.2.3 Monitoring Well Plugging Cement Composition 28
6.2.4 Plugging Plan, Orchard MW No. 1 29
6.2.5 Plugging Plan, Orchard MW No. 2 32
6.2.6 Plugging Plan, Orchard MW No. 3 35

Figures

Figure 6-1 – Wellbore Schematic for Orchard No. 1 Before Plugging and Abandoning 6
Figure 6-2 – Plugging Schematic for Orchard No. 1 8
Figure 6-3 – Wellbore Schematic for Orchard No. 2 Before Plugging and Abandoning 9
Figure 6-4 – Plugging Schematic for Orchard No. 2 11
Figure 6-5 – Wellbore Schematic for Orchard No. 3 Before Plugging and Abandoning 12
Figure 6-6 – Plugging Schematic for Orchard No. 3 14
Figure 6-7 – Wellbore Schematic for Orchard No. 4 Before Plugging and Abandoning 15
Figure 6-8 – Plugging Schematic for Orchard No. 4 17
Figure 6-9 – Wellbore Schematic for Orchard No. 5 Before Plugging and Abandoning 18
Figure 6-10 – Plugging Schematic for Orchard No. 5 20
Figure 6-11 – Wellbore Schematic for Orchard No. 6 Before Plugging and Abandoning 21
Figure 6-12 – Plugging Schematic for Orchard No. 6 23
Figure 6-13 – Wellbore Schematic for Orchard No. 7 Before Plugging and Abandoning 24
Figure 6-14 – Plugging Schematic for Orchard No. 7 26
Figure 6-15 – Wellbore Schematic for Orchard MW No. 1 Before Plugging and Abandoning 29
Figure 6-16 – Plugging Schematic for Orchard MW No. 1 31
Figure 6-17 – Wellbore Schematic for Orchard MW No. 2 Before Plugging and Abandoning 32
Figure 6-18 – Plugging Schematic for Orchard MW No. 2 34
Figure 6-19 – Wellbore Schematic for Orchard MW No. 3 Before Plugging and Abandoning 35

Figure 6-20 – Plugging Schematic for Orchard MW No. 3 37

Tables

Table 6-1 – Plugging Details for Orchard No. 1 7
Table 6-2 – Plugging Details for Orchard No. 2 10
Table 6-3 – Plugging Details for Orchard No. 3 13
Table 6-4 – Plugging Details for Orchard No. 4 16
Table 6-5 – Plugging Details for Orchard No. 5 19
Table 6-6 – Plugging Details for Orchard No. 6 22
Table 6-7 – Plugging Details for Orchard No. 7 25
Table 6-8 – Plugging Details for Orchard MW No. 1 30
Table 6-9 – Plugging Details for Orchard MW No. 2 33
Table 6-10 – Plugging Details for Orchard MW No. 3 36

6.1 Injection Well Plugging Plan Overview

As described in *Section 4 – Engineering Design and Operating Strategy*, the Orchard Storage Company LLC (Orchard Storage) injection wells Orchard No. 1 through No. 7 will be completed as a single injection interval within the San Andres formation. After the conclusion of the 12 years of injection operations and the post injection site care period, the wells will be permanently plugged. Complete plugging and abandonment prognoses are included in *Appendix G-1*.

The following outline describes the procedures and types of plugs that will be set to isolate the injection interval, to prevent contamination of the Underground Sources of Drinking Water (USDWs), and to properly plug and abandon Orchard No. 1 through No. 7 according to Title 16, Texas Administrative Code (16 TAC) **§5.203** and 16 TAC **§3.14** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**] regulations.

6.1.1 Injection Well Pre-Plugging Activities

1. Orchard Storage will comply with all reporting and notification provisions.
    a. The Environmental Protection Agency (EPA) Underground Injection Control (UIC) Director will be notified 60 days in advance of planned plugging efforts [40 CFR ***§*146.92(c)**].
    b. The Texas Railroad Commission (TRRC) and the UIC Director will be notified at least 60 days before plugging a well. If any changes are proposed to the original well-plugging plan, a revised plan will be submitted [16 TAC ***§*5.201(k)(3)(A)**].
    c. A notice of intention to plug and abandon (Form W-3A) will be filed with the appropriate TRRC district office and the UIC Director at least 5 days prior to the beginning of plugging operations.
    d. Plugging operations will not start until the Director approves the proposed procedure.
    e. The district office will be notified at least 4 hours before commencing plugging operations.
2. Casing inspection and cement bond logs will be run prior to plugging.
3. Bottomhole reservoir pressure will be measured using the downhole pressure gauges permanently installed behind the 7-inch (in.) production casing string. Details for this system are provided in *Section 5 – Testing and Monitoring Plan* (16 TAC **§5.203 (h)(1)(C)** [40 CFR **§146.89(b)**]).
4. External mechanical integrity will be demonstrated through approved temperature logging methods as described in *Section 5*, per 16 TAC **§5.203 (h)(1)(D)** [40 CFR **§146.89(c)**].
5. The injection well will be flushed with at least a 9.5 ppg inert pH buffer fluid such as brine containing additives that may include biocide, corrosion inhibitor and oxygen scavenger. Examples of these type additives are included as Appendix G-2. This buffer fluid will be pumped prior to pulling the injection tubing and packer seal assembly (16 TAC **§5.203** and **§3.14** [40 CFR **§146.92(a)**])
6. Tubing and packer seal assembly will be pulled prior to plugging and abandonment (P&A) operations.

6.1.2 Injection Well Plugging Activities

1. Pull seal assembly from the packer to just above the packer.
2. Fill the wellbore with at least 9.5 pounds per gallon (ppg) of 40 viscosity-treated drilling mud, and ensure the well is in static condition.
3. Pull tubing and seal assembly and remove from the well.
4. Isolate the gross injection interval:
    a. Set a permanent bridge plug made of corrosion-resistant alloy (CRA) at approximately 50 feet (ft) below the upper confinement zone in the 7 in. casing.
    b. Place a 300 ft acid-resistant cement plug above the permanent bridge plug.
    c. Displace the cement with at least 9.5 ppg of 40 viscosity-treated drilling mud.
    d. The plug will be qualified by tagging the top and conducting a successful pressure test.
5. Spot a ~400 ft cement plug from at least 50 ft below the surface-casing setting depth, to a minimum of 50 ft into the base of the USDW. Displace cement with at least 9.5 ppg of 40 viscosity-treated drilling mud.
6. Spot a ~100 ft cement plug from at least 50 ft below the base of usable-quality water to a minimum of 50 ft above the base of usable-quality water. Displace cement with at least 9.5 ppg of 40 viscosity-treated drilling mud.
7. Set a 50 ft cement plug from 50 ft to the surface.
8. Cut casing 3 ft below ground level and weld on a ½-in. steel plate.

In the unforeseen event that a plug fails or other unexpected issues occur, corrective action will be taken to ensure proper placement of the plug(s). Any modifications to the plugging plan to address such issues will be done in coordination with the UIC Division and approved by the Director.

A proposed corrective action plan to address plug failures would include the following.

1. Tag and pressure test to confirm improper placement or bonding of plugs set during the planned plugging operation
2. Mill existing plug to base of plug (if Plug 1 failed, drill out plug to +/- 50 ft above bridge plug)
3. Spot a new plug of equal height/volume at the proposed setting depth, utilizing the blend specified in the original plugging plan
4. Wait on cement, tag, and pressure test plug to confirm placement
5. Proceed with the proposed plugging plan

Within 60 days after plugging, Orchard Storage will submit, pursuant to 40 CFR **§146.91(e)**, a certified well-plugging report to the Director. The report will be retained for 10 years following site closure. Also note that a complete well-plugging record (Form W-3), pursuant to 16 TAC **§5.203**, will be filed within **30 days** to the appropriate TRRC district office after plugging operations are completed.

6.1.3 Injection Well Plugging Cement Composition

The cement that will be used across the upper confining zone will be composed of the same corrosion-resistant cement blend used to set the long string casing across the upper confining and

injection zones and will contain the same ingredients and additives. Details for the proposed corrosion-resistant cement blend are provided in Appendix C-1 for each well.

Since the upper confining zone plug isolates all sequestered injectate, the plugs above this zone will not contact the injectate or formation fluids; therefore, Class H cement is proposed for each of the shallower plugs.

6.1.4 Orchard No. 1 Plugging and Abandonment

Figure 6-1 shows the original wellbore schematic for Orchard No. 1, prior to beginning plugging operations.

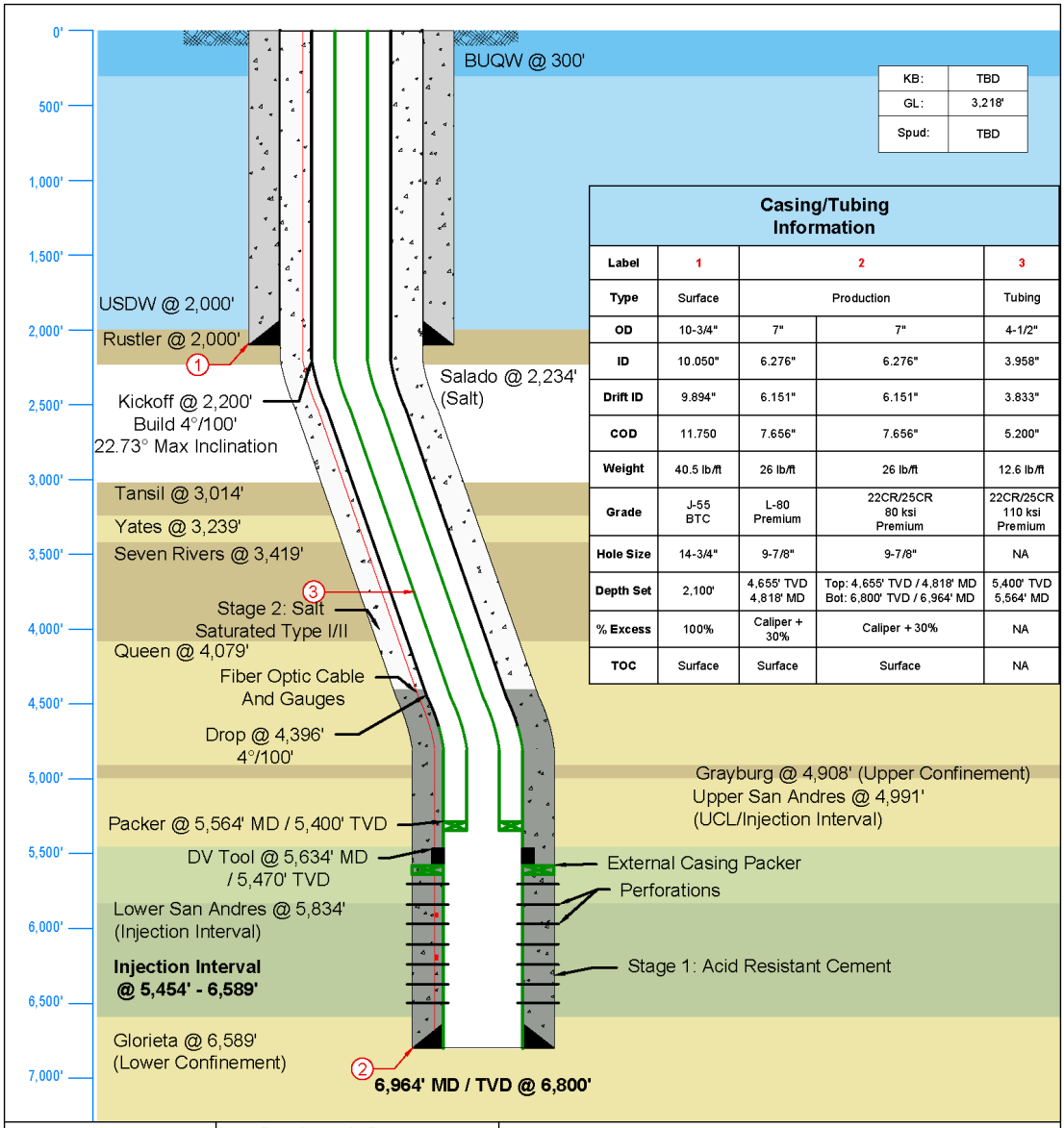


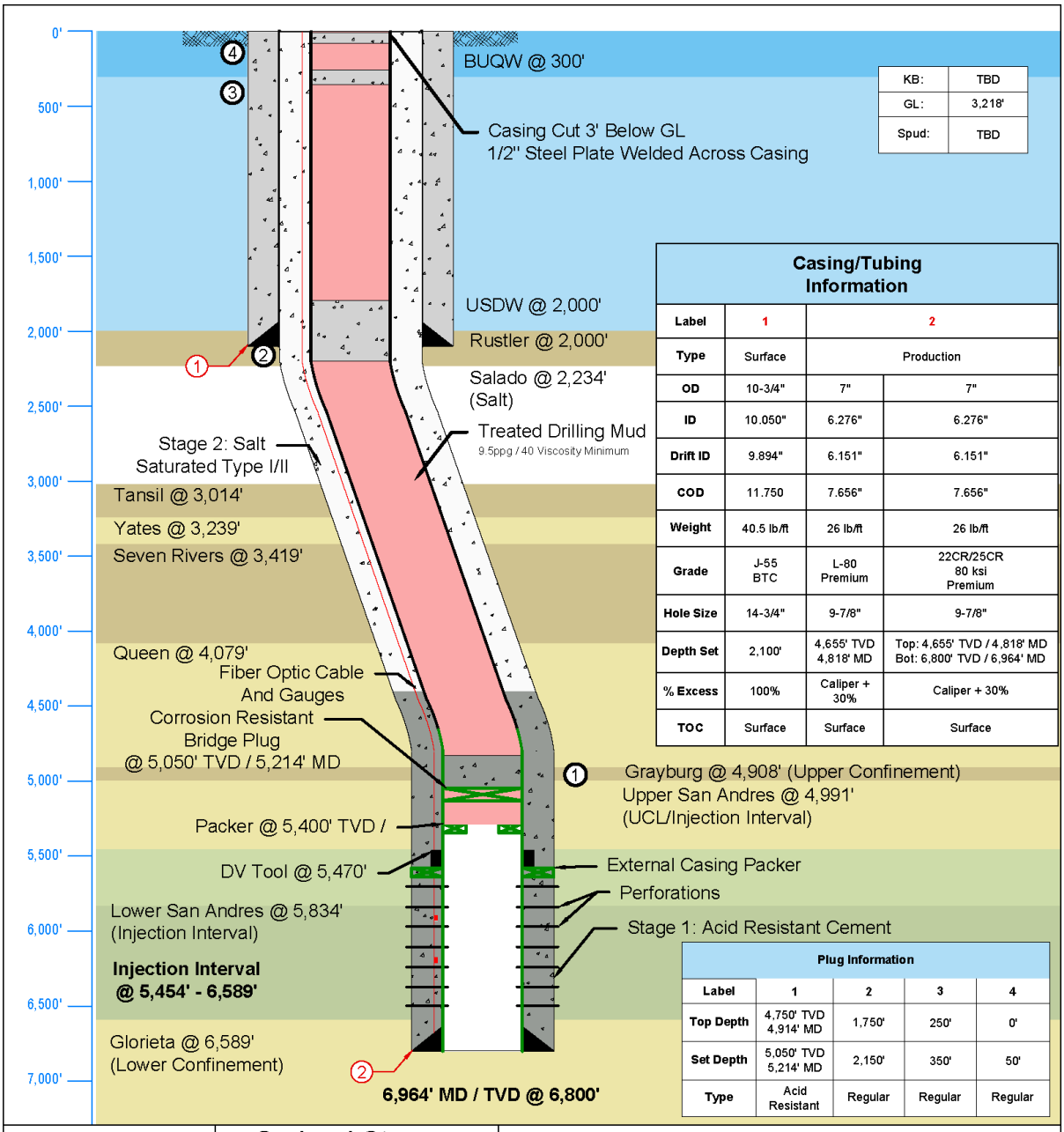
Figure 6-1 – Wellbore Schematic for Orchard No. 1 Before Plugging and Abandoning

6.1.4.1 Plug Details

Table 6-1 shows the planned plugging details for Orchard No. 1. Figure 6-2 shows a schematic of the injection well after it is plugged.

Table 6-1 – Plugging Details for Orchard No. 1

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing Outer Diameter (OD, in.)	7	7	7	7	7
Casing Inner Diameter (ID, in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft, TVD)	5,050	4,750	1,750	250	0
Bottom of Plug (ft)	5,050	5,050	2,150	350	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation



KB:	TBD
GL:	3,218'
Spud:	TBD

Casing/Tubing Information

Label	1	2	
Type	Surface	Production	
OD	10-3/4"	7"	7"
ID	10.050"	6.276"	6.276"
Drift ID	9.894"	6.151"	6.151"
COD	11.750	7.656"	7.656"
Weight	40.5 lb/ft	26 lb/ft	26 lb/ft
Grade	J-55 BTC	L-80 Premium	22CR/25CR 80 ksi Premium
Hole Size	14-3/4"	9-7/8"	9-7/8"
Depth Set	2,100'	4,655' TVD 4,818' MD	Top: 4,655' TVD / 4,818' MD Bot: 6,800' TVD / 6,964' MD
% Excess	100%	Caliper + 30%	Caliper + 30%
TOC	Surface	Surface	Surface

Plug Information

Label	1	2	3	4
Top Depth	4,750' TVD 4,914' MD	1,750'	250'	0'
Set Depth	5,050' TVD 5,214' MD	2,150'	350'	50'
Type	Acid Resistant	Regular	Regular	Regular

LONQUIST SEQUESTRATION LLC

Texas License F-22610

12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Orchard Storage Company, LLC	Orchard #1	
Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
Location:	**District:**	**Survey:**
API No: TBD	**Field:**	**Well Type/Status:** Injection
State Gas ID No:	**Project No:** LS167	**Date:** 7/16/2025
Drawn: CJL	**Reviewed:**	**Approved:**
Rev No: 0	**Notes:**	

Figure 6-2 – Plugging Schematic for Orchard No. 1

6.1.5 Orchard No. 2 Plugging and Abandonment

Figure 6-3 shows the original wellbore schematic for Orchard No. 2, prior to beginning plugging operations.

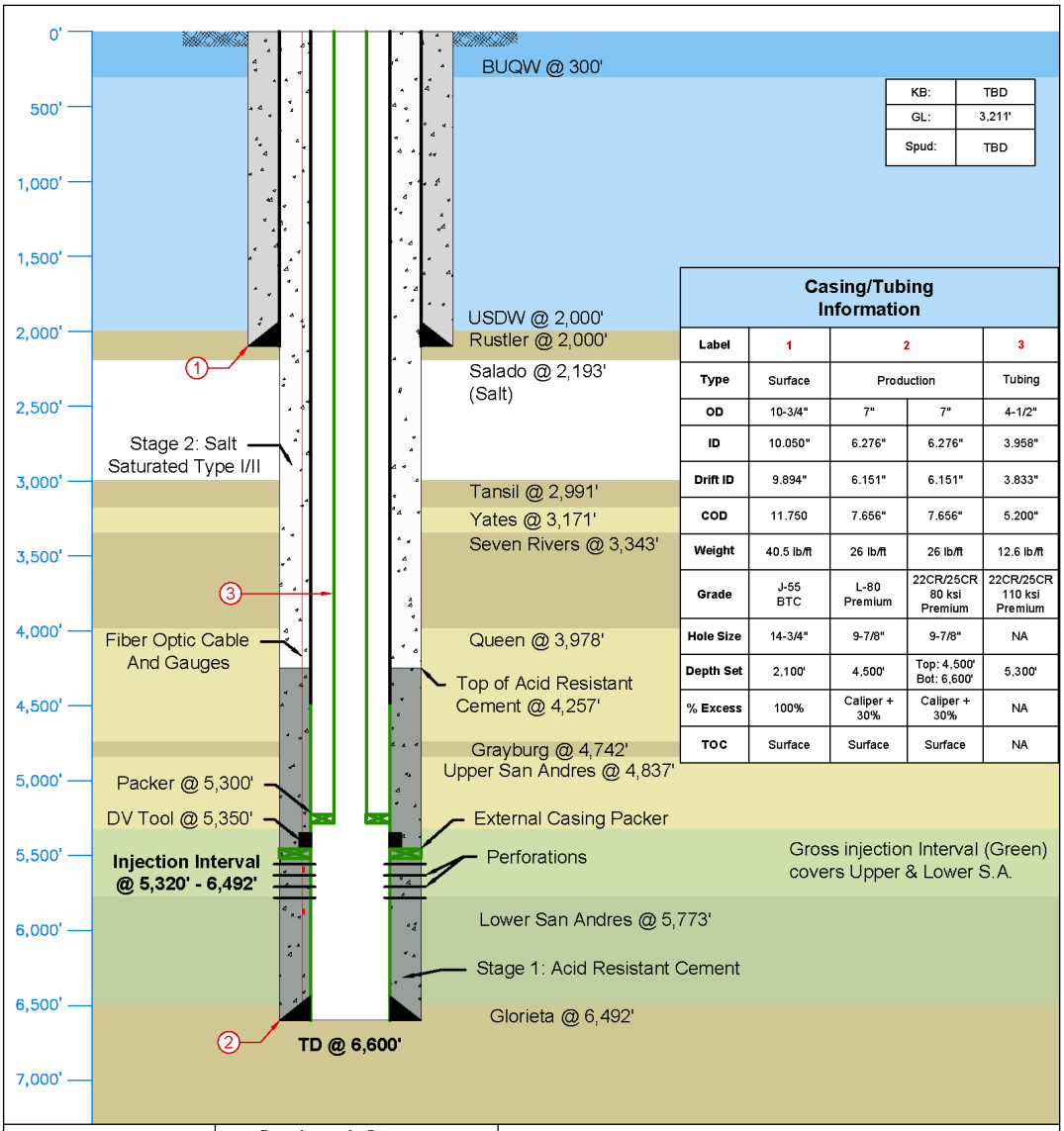


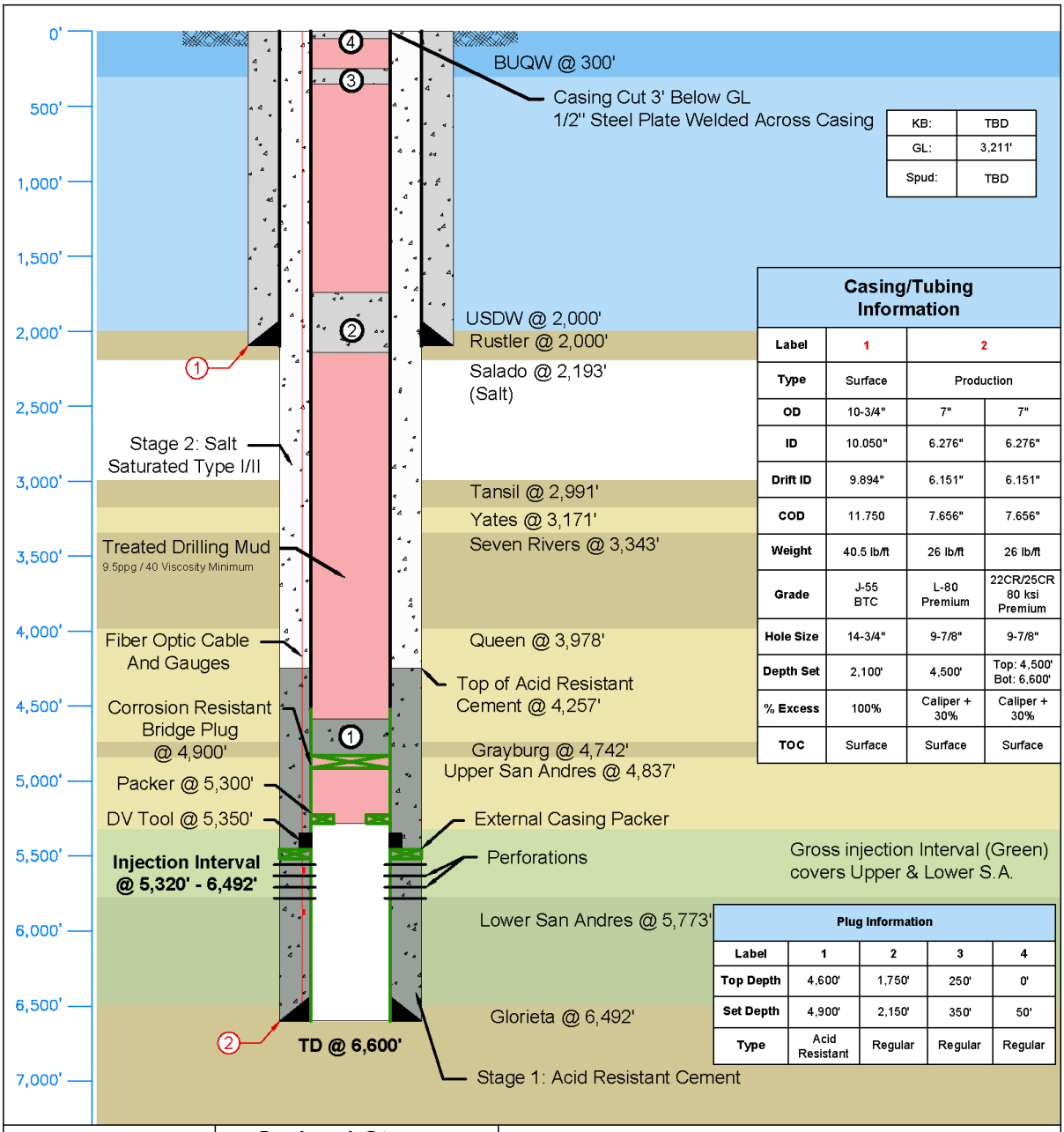
Figure 6-3 – Wellbore Schematic for Orchard No. 2 Before Plugging and Abandoning

6.1.5.1 Plug Details

Table 6-2 shows the planned plugging details for Orchard No. 2. Figure 6-4 shows a schematic of the injection well after it is plugged.

Table 6-2 – Plugging Details for Orchard No. 2

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing OD (in.)	7	7	7	7	7
Casing ID (in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft)	4,900	4,600	1,750	250	0
Bottom of Plug (ft)	4,900	4,900	2,150	350	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation

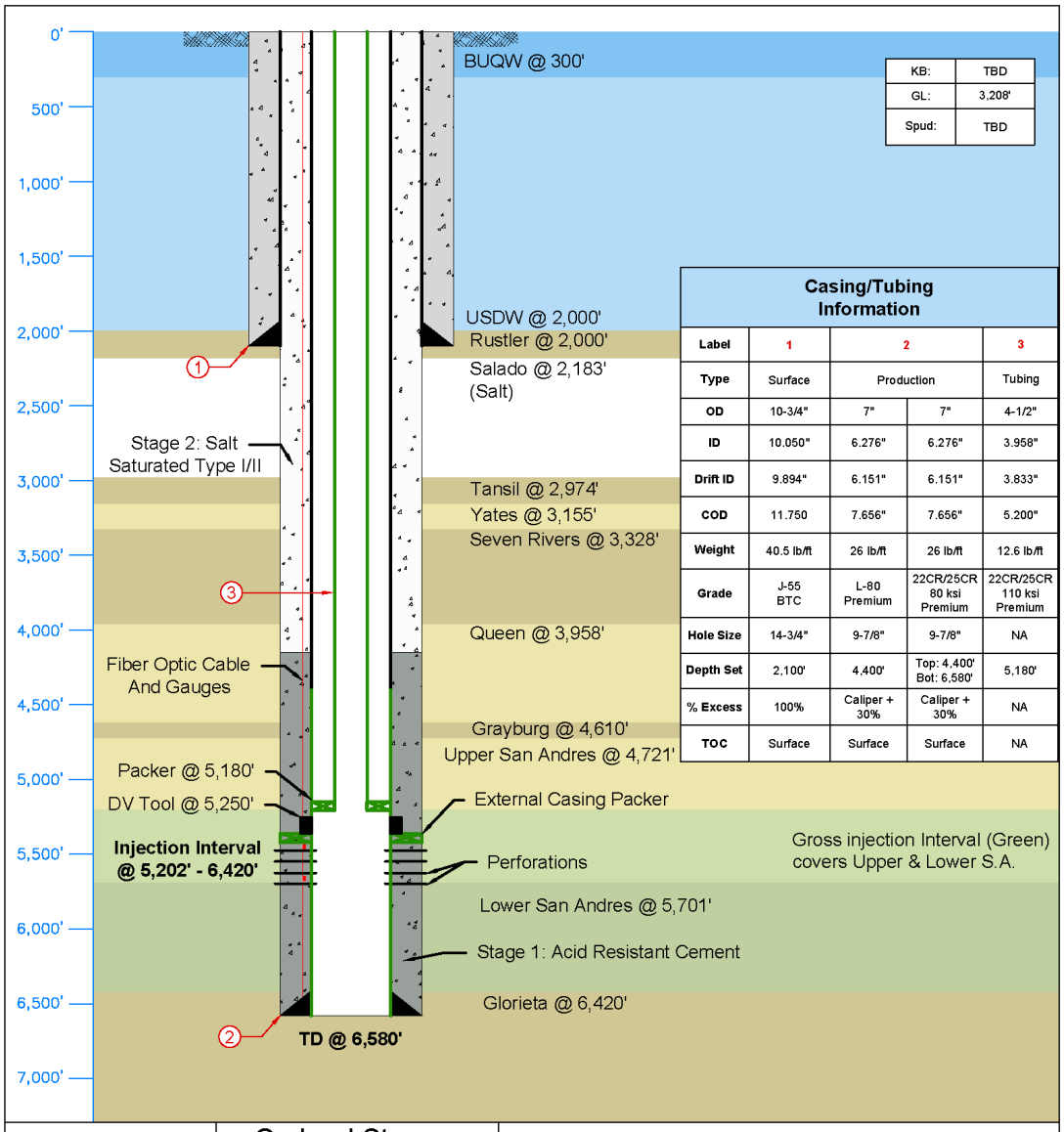


LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #2	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: TBD	**District:** 08	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** P & A
Texas License F-22610	**State Gas ID No:**	**Project No:** LS175	**Date:** 1/31/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:** MF	**Approved:**
	Rev No: 0	**Notes:**	

Figure 6-4 – Plugging Schematic for Orchard No. 2

6.1.6 Orchard No. 3 Plugging and Abandonment

Figure 6-5 shows the original wellbore schematic for Orchard No. 3, prior to beginning plugging operations.



KB:	TBD
GL:	3,208'
Spud:	TBD

Casing/Tubing Information

Label	1	2		3
Type	Surface	Production		Tubing
OD	10-3/4"	7"	7"	4-1/2"
ID	10.050"	6.276"	6.276"	3.958"
Drift ID	9.894"	6.151"	6.151"	3.833"
COD	11.750	7.656"	7.656"	5.200"
Weight	40.5 lb/ft	26 lb/ft	26 lb/ft	12.6 lb/ft
Grade	J-55 BTC	L-80 Premium	22CR/25CR 80 ksi Premium	22CR/25CR 110 ksi Premium
Hole Size	14-3/4"	9-7/8"	9-7/8"	NA
Depth Set	2,100'	4,400'	Top: 4,400' Bot: 6,580'	5,180'
% Excess	100%	Caliper + 30%	Caliper + 30%	NA
TOC	Surface	Surface	Surface	NA

LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #3	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: TBD	**District:** 8A	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** Injection
Texas License F-22610	**State Gas ID No:**	**Project No:** LS175	**Date:** 1/31/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 6-5 – Wellbore Schematic for Orchard No. 3 Before Plugging and Abandoning

6.1.6.1 Plug Details

Table 6-3 shows the planned plugging details for Orchard No. 3. Figure 6-6 shows a schematic of the injection well after it is plugged.

Table 6-3 – Plugging Details for Orchard No. 3

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing OD (in.)	7	7	7	7	7
Casing ID (in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft)	4,790	4,490	1,750	250	0
Bottom of Plug (ft)	4,790	4,790	2,150	350	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation

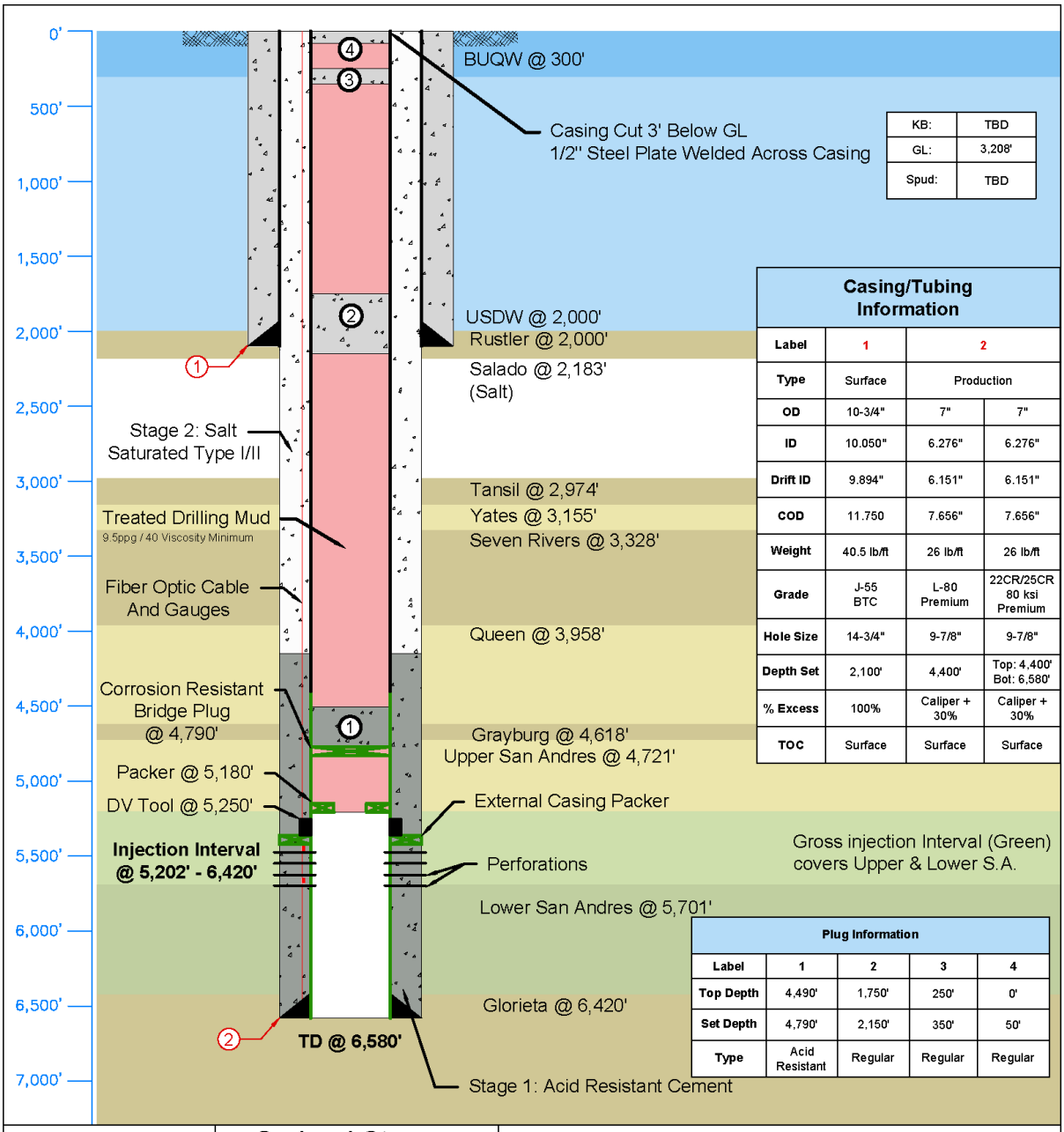


Figure 6-6 – Plugging Schematic for Orchard No. 3

6.1.7 Orchard No. 4 Plugging and Abandonment

Figure 6-7 shows the original wellbore schematic for Orchard No. 4, prior to beginning plugging operations.

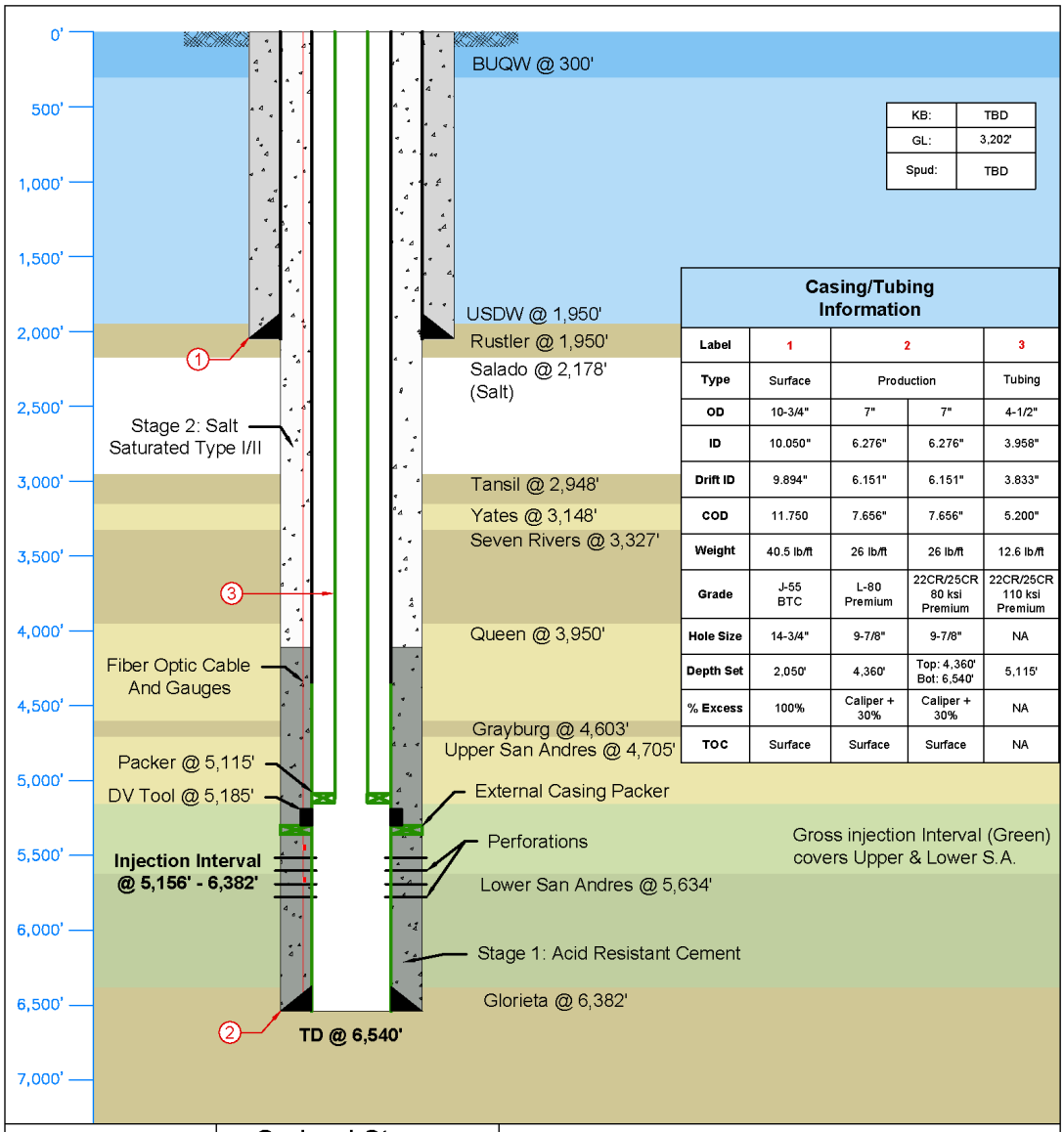


Figure 6-7 – Wellbore Schematic for Orchard No. 4 Before Plugging and Abandoning

6.1.7.1 Plug Details

Table 6-4 shows the planned plugging details for Orchard No. 4. Figure 6-8 shows a schematic of the injection well after it is plugged.

Table 6-4 – Plugging Details for Orchard No. 4

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing OD (in.)	7	7	7	7	7
Casing ID (in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft)	4,760	4,460	1,700	250	0
Bottom of Plug (ft)	4,760	4,760	2,100	350	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation

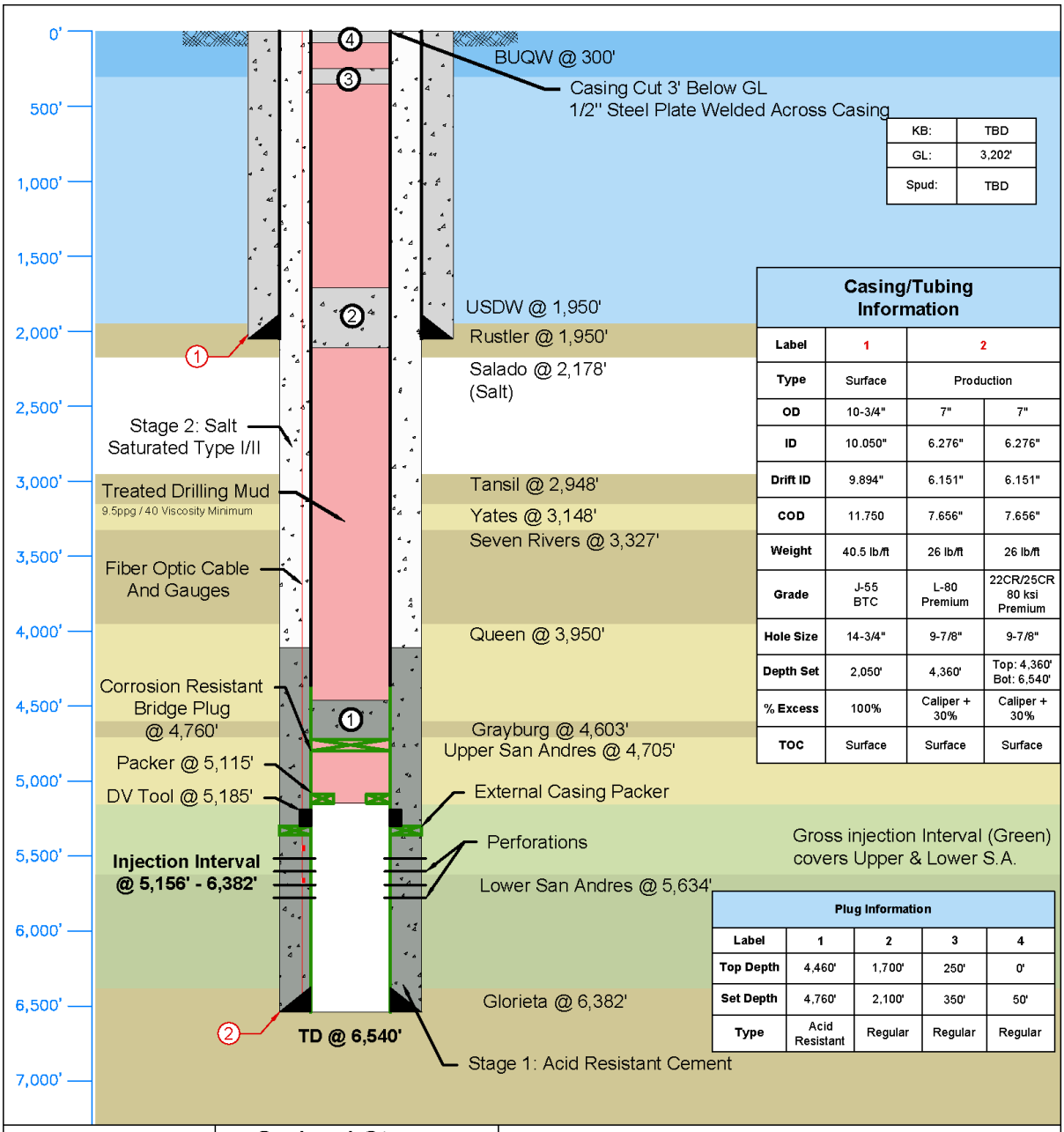


Figure 6-8 – Plugging Schematic for Orchard No. 4

6.1.8 Orchard No. 5 Plugging and Abandonment

Figure 6-9 shows the original wellbore schematic for Orchard No. 5, prior to beginning plugging operations.

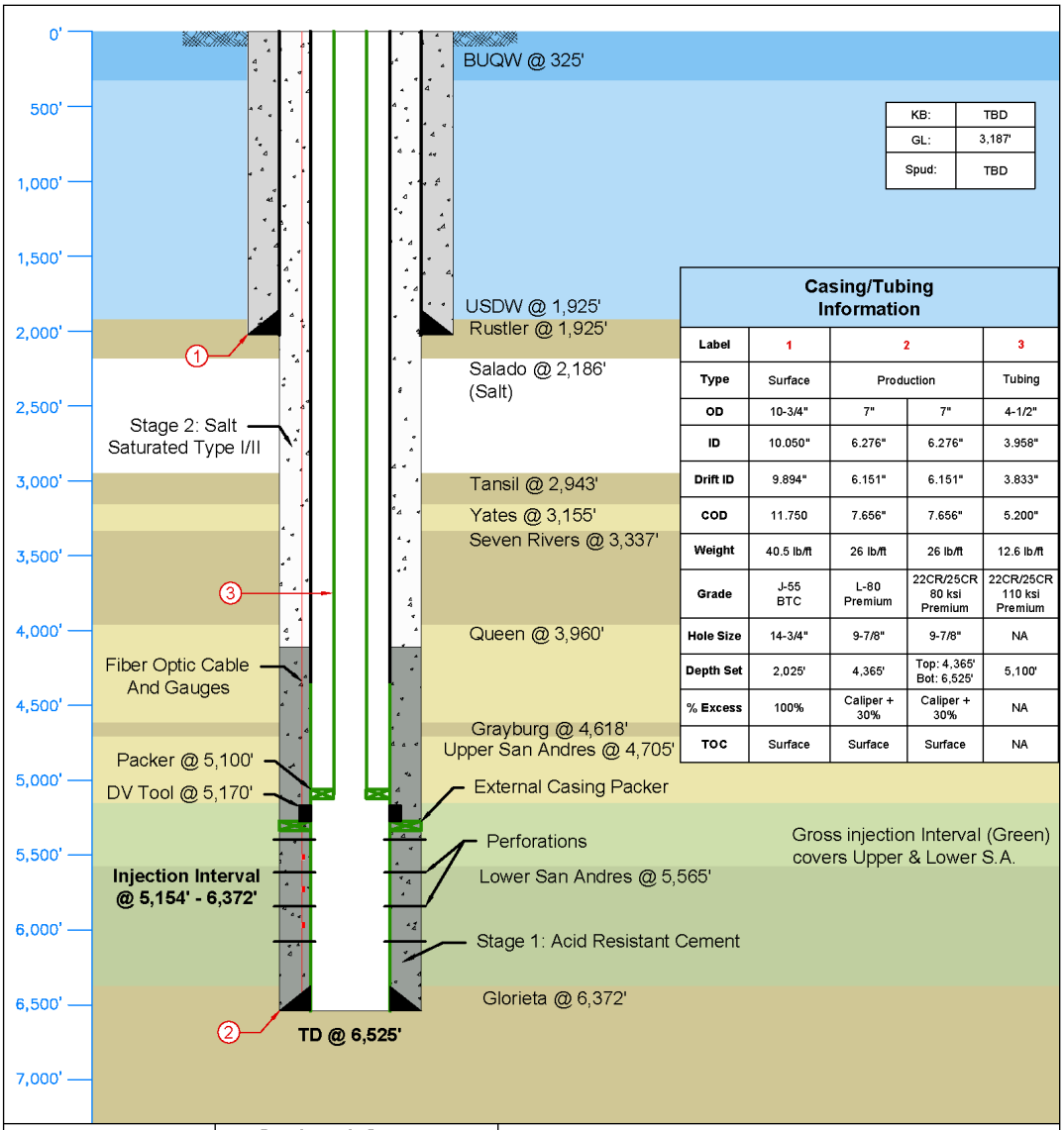


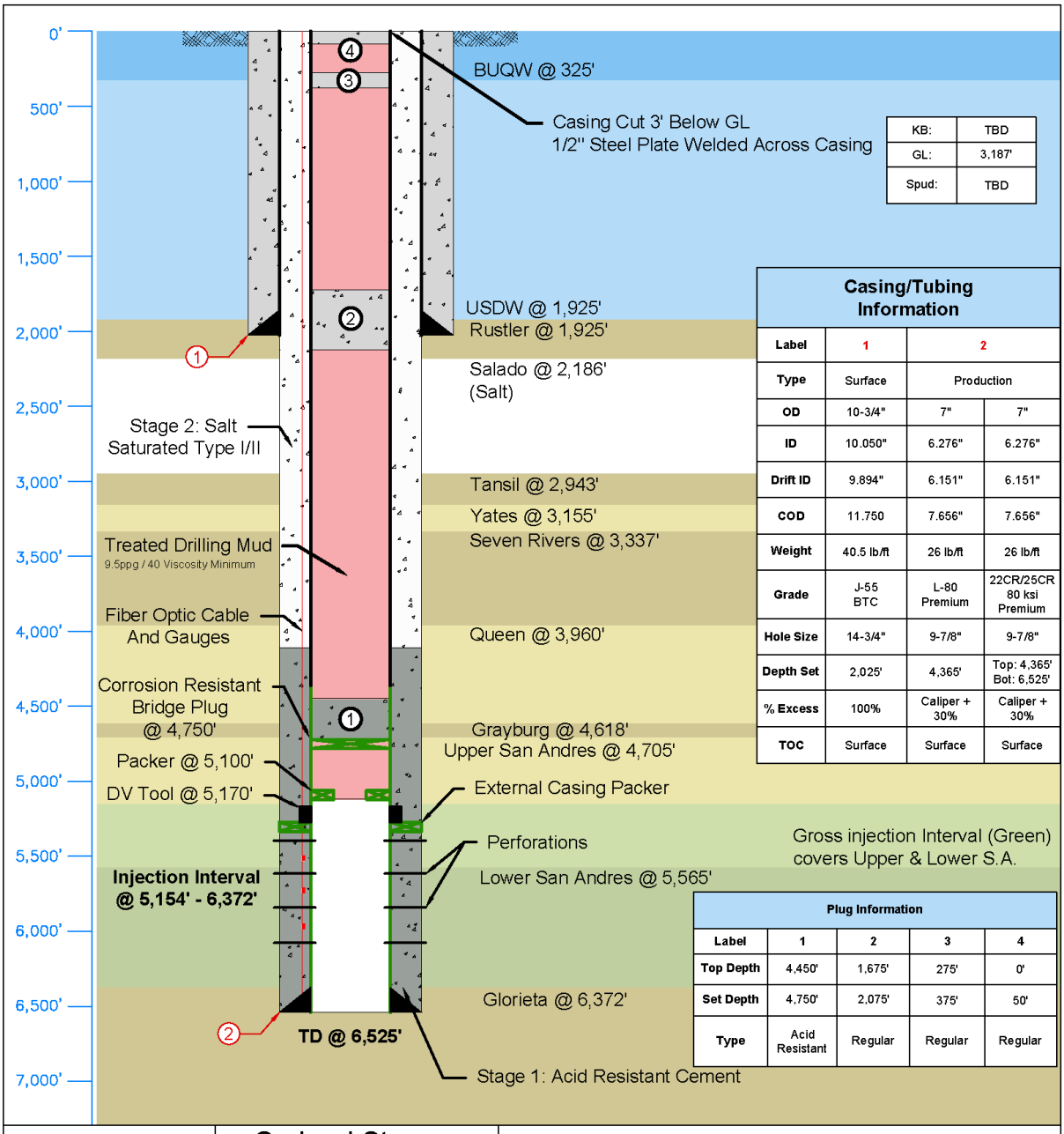
Figure 6-9 – Wellbore Schematic for Orchard No. 5 Before Plugging and Abandoning

6.1.8.1 Plug Details

Table 6-5 shows the planned plugging details for Orchard No. 5. Figure 6-10 shows a schematic of the injection well after it is plugged.

Table 6-5 – Plugging Details for Orchard No. 5

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing OD (in.)	7	7	7	7	7
Casing ID (in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft)	4,750	4,450	1,675	275	0
Bottom of Plug (ft)	4,750	4,750	2,075	375	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation



KB:	TBD
GL:	3,187'
Spud:	TBD

Casing/Tubing Information

Label	1	2	
Type	Surface	Production	
OD	10-3/4"	7"	7"
ID	10.050"	6.276"	6.276"
Drift ID	9.894"	6.151"	6.151"
COD	11.750	7.656"	7.656"
Weight	40.5 lb/ft	26 lb/ft	26 lb/ft
Grade	J-55 BTC	L-80 Premium	22CR/25CR 80 ksi Premium
Hole Size	14-3/4"	9-7/8"	9-7/8"
Depth Set	2,025'	4,365'	Top: 4,365' Bot: 6,525'
% Excess	100%	Caliper + 30%	Caliper + 30%
TOC	Surface	Surface	Surface

Plug Information

Label	1	2	3	4
Top Depth	4,450'	1,675'	275'	0'
Set Depth	4,750'	2,075'	375'	50'
Type	Acid Resistant	Regular	Regular	Regular

LONQUIST SEQUESTRATION LLC

Texas License F-22610

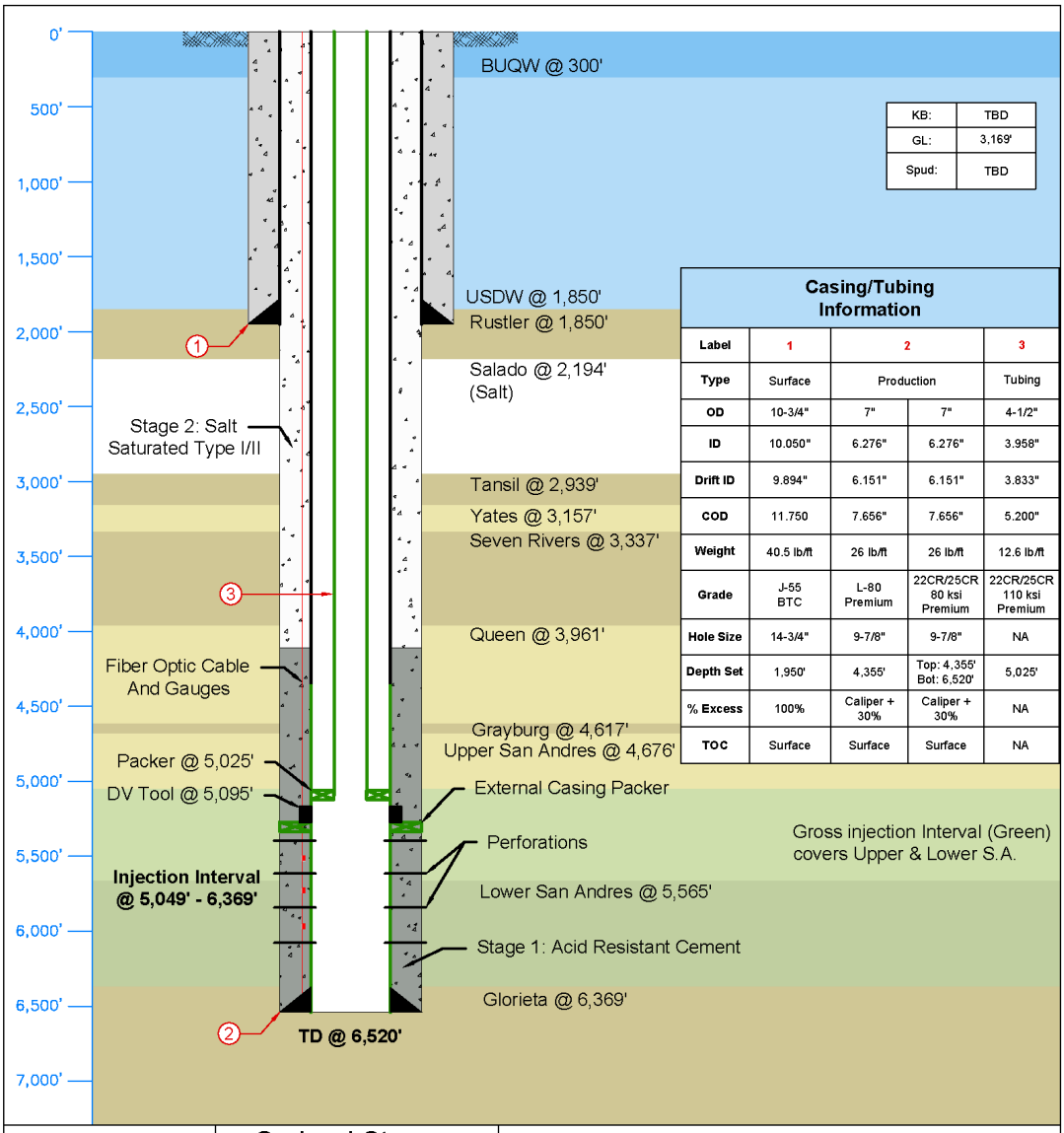
12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Orchard Storage Company, LLC	Orchard #5	
Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
Location: TBD	**District:** 8A	**Survey:**
API No: TBD	**Field:**	**Well Type/Status:** P & A
State Gas ID No:	**Project No:** LS175	**Date:** 1/31/2025
Drawn: JGC	**Reviewed:**	**Approved:**
Rev No: 0	**Notes:**	

Figure 6-10 – Plugging Schematic for Orchard No. 5

6.1.9 Orchard No. 6 Plugging and Abandonment

Figure 6-11 shows the original wellbore schematic for Orchard No. 6, prior to beginning plugging operations.



Casing/Tubing Information

Label	1	2		3
Type	Surface	Production		Tubing
OD	10-3/4"	7"	7"	4-1/2"
ID	10.050"	6.276"	6.276"	3.958"
Drift ID	9.894"	6.151"	6.151"	3.833"
COD	11.750	7.656"	7.656"	5.200"
Weight	40.5 lb/ft	26 lb/ft	26 lb/ft	12.6 lb/ft
Grade	J-55 BTC	L-80 Premium	22CR/25CR 80 ksi Premium	22CR/25CR 110 ksi Premium
Hole Size	14-3/4"	9-7/8"	9-7/8"	NA
Depth Set	1,950'	4,355'	Top: 4,355' Bot: 6,520'	5,025'
% Excess	100%	Caliper + 30%	Caliper + 30%	NA
TOC	Surface	Surface	Surface	NA

LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #6	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: TBD	**District:** 8A	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** Injection
Texas License F-22610	**State Gas ID No:**	**Project No:** LS175	**Date:** 1/31/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

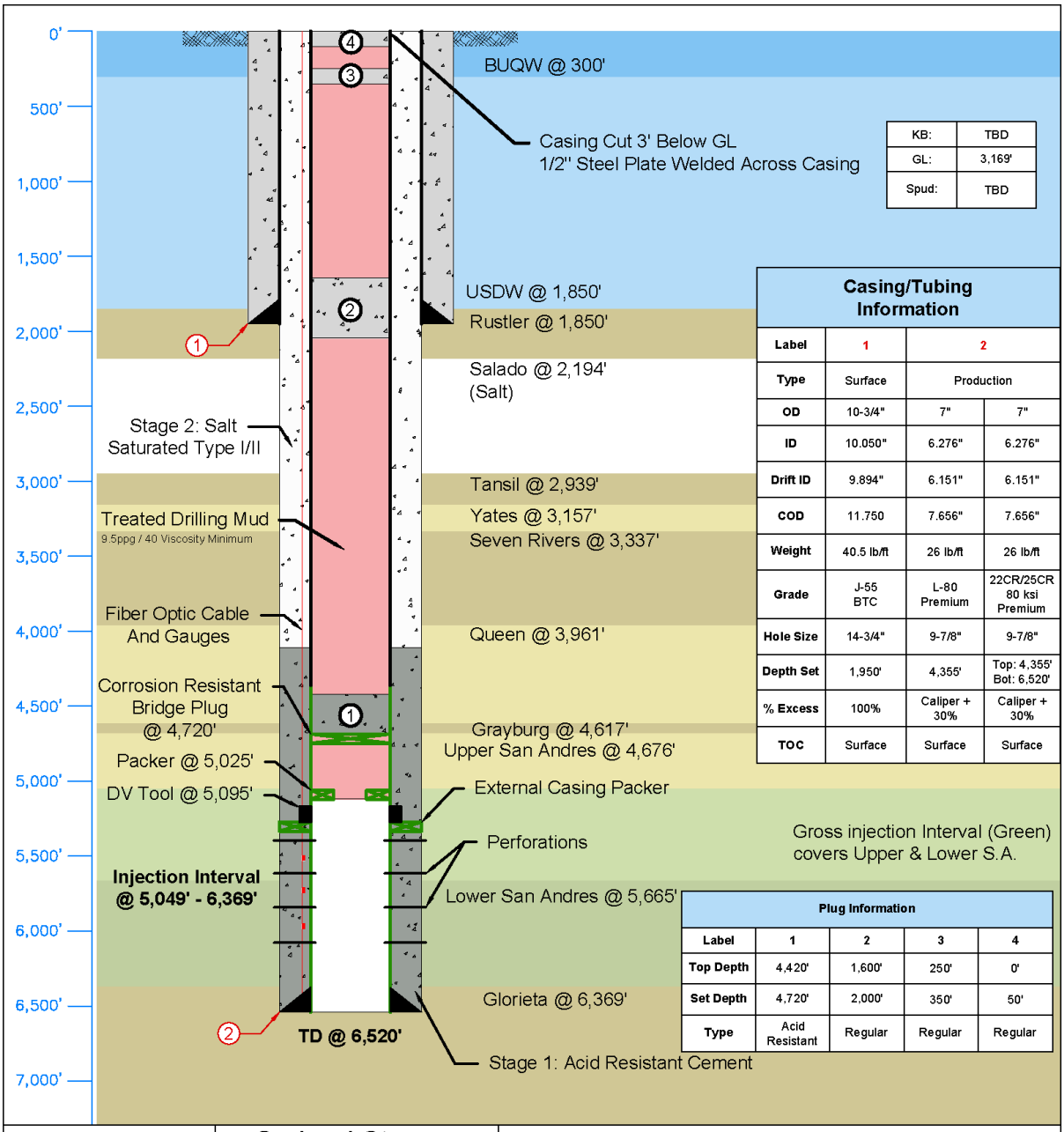
Figure 6-11 – Wellbore Schematic for Orchard No. 6 Before Plugging and Abandoning

6.1.9.1 Plug Details

Table 6-6 shows the planned plugging details for Orchard No. 6. Figure 6-12 shows a schematic of the injection well after it is plugged.

Table 6-6 – Plugging Details for Orchard No. 6

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing OD (in.)	7	7	7	7	7
Casing ID (in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft)	4,720	4,420	1,600	250	0
Bottom of Plug (ft)	4,720	4,720	2,000	350	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation



LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #6	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: TBD	**District:** 8A	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** P & A
Texas License F-22610	**State Gas ID No:**	**Project No:** LS175	**Date:** 1/31/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 6-12 – Plugging Schematic for Orchard No. 6

6.1.10 Orchard No. 7 Plugging and Abandonment

Figure 6-13 shows the original wellbore schematic for Orchard No. 7, prior to beginning plugging operations.

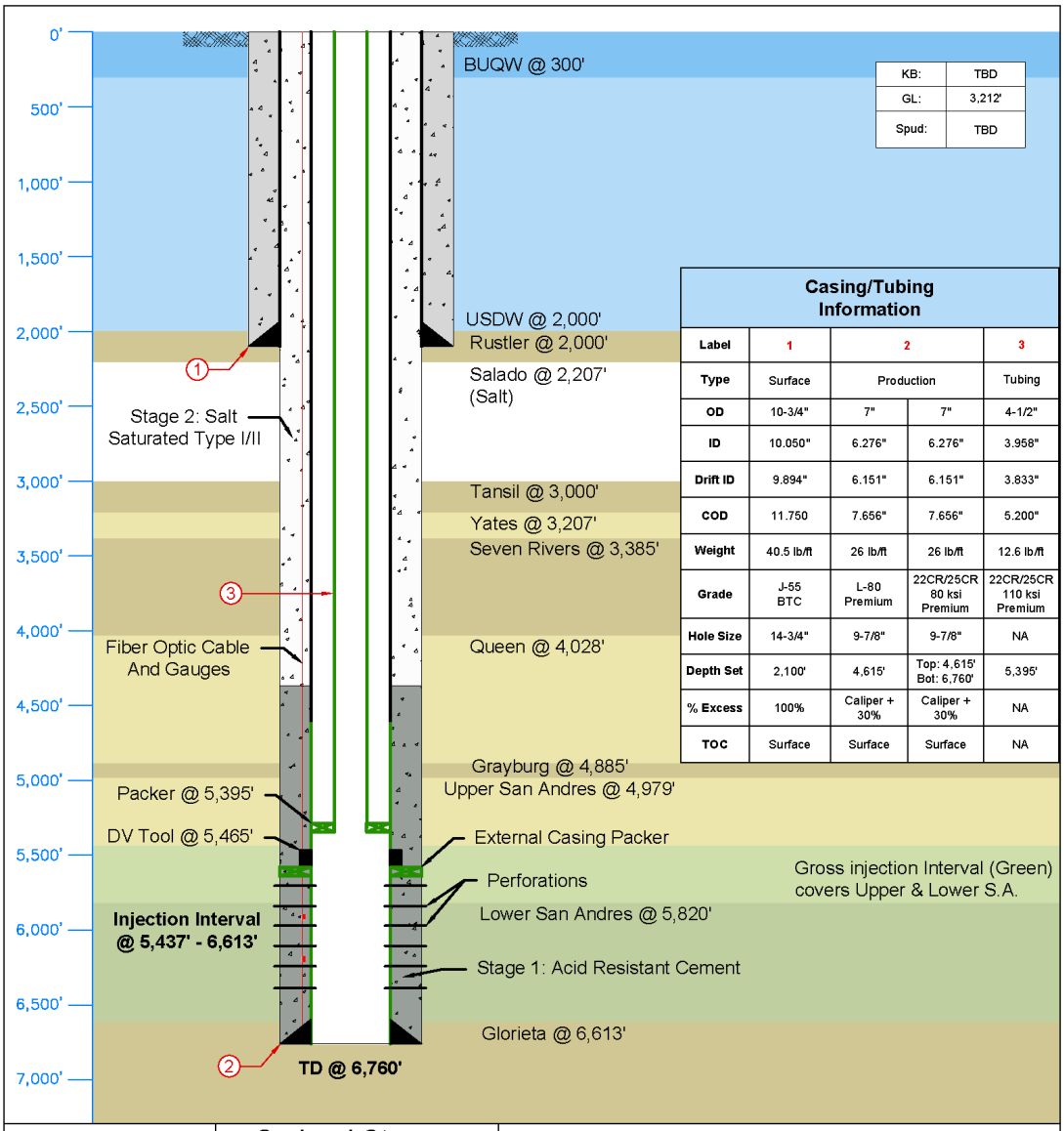


Figure 6-13 – Wellbore Schematic for Orchard No. 7 Before Plugging and Abandoning

6.1.10.1 Plug Details

Table 6-7 shows the planned plugging details for Orchard No. 2. Figure 6-14 shows a schematic of the injection well after it is plugged.

Table 6-7 – Plugging Details for Orchard No. 7

Plug Number	1	2	3	4	5
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Isolate BUQW	Surface Plug
Casing OD (in.)	7	7	7	7	7
Casing ID (in.)	6.276	6.276	6.276	6.276	6.276
Top of Plug (ft)	5,020	4,720	1,750	250	0
Bottom of Plug (ft)	5,020	5,020	2,150	350	50
Cement Volume (sacks)	NA	59	67	17	9
Slurry Volume (ft^3)	NA	65	86	22	11
Slurry Weight (lb/gal)	NA	14.5	15.6	15.6	15.6
Type of Cement or Other Material	CRA Bridge Plug	Acid-Resistant Cement	Type I Cement	Type I Cement	Type I Cement
Placement	Wireline	Circulation	Circulation	Circulation	Circulation

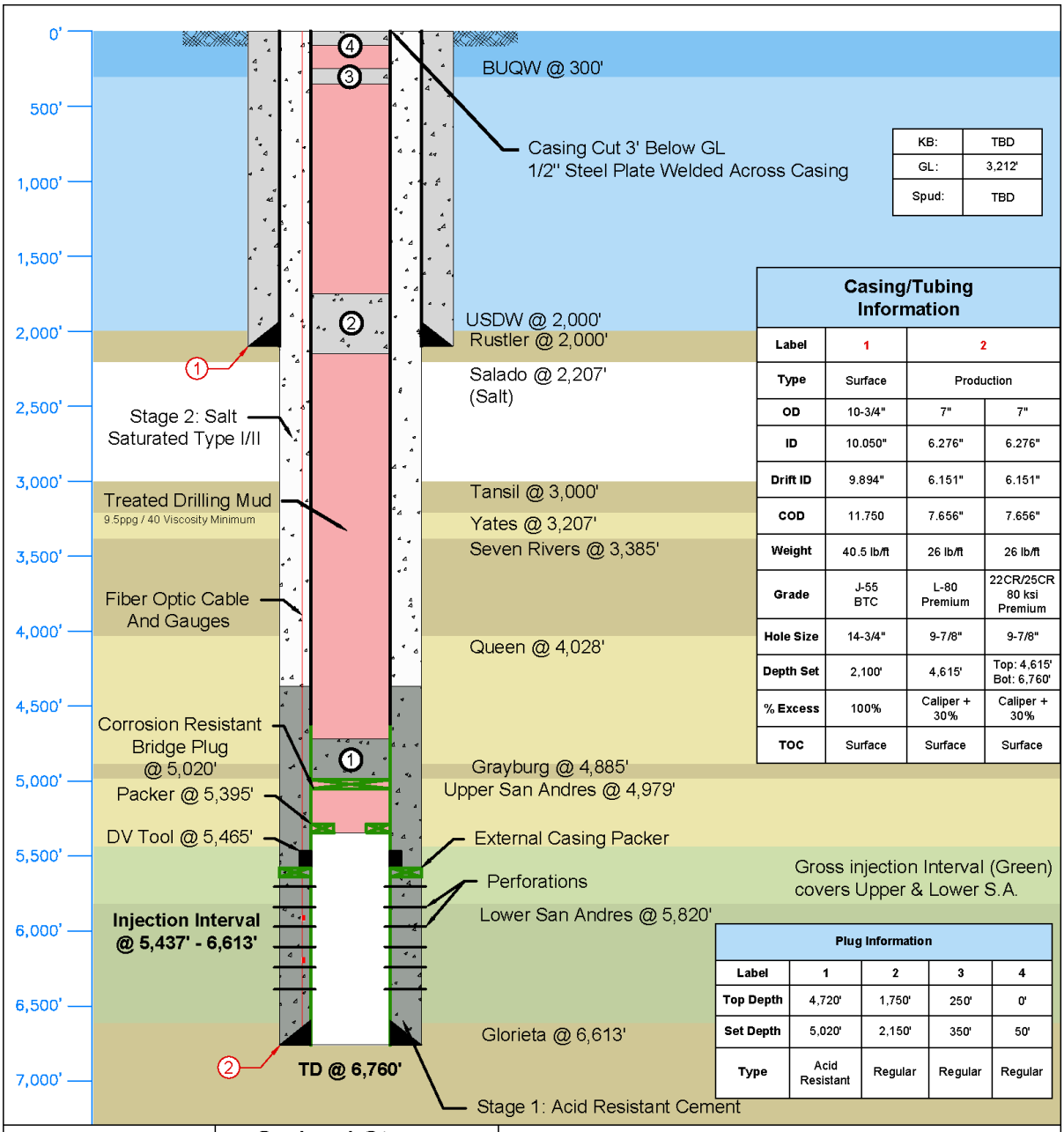


Figure 6-14 – Plugging Schematic for Orchard No. 7

6.2 Monitoring Well Plugging Plan and Regulatory Requirements

As described in *Section 4 – Engineering Design and Operating Strategy*, Orchard MW No. 1 and MW No. 3 will be completed as a single perforated interval just above the upper confinement layer. The Orchard MW No. 2 will be recompleted as an in-zone monitoring well. At the conclusion of the post-injection site care period, the well will be permanently plugged. Complete plugging and abandonment prognoses are in *Appendix G-3*.

The following outline describes the procedures and types of plugs that will be set to isolate the perforated interval and to prevent contamination of the USDWs. Orchard MW No. 1 will be properly plugged and abandoned according to 16 TAC **§5.203** and **§3.14** [40 CFR **§146.92**] regulations.

6.2.1 Monitoring Well Pre-Plugging Activities

1. Orchard Storage will comply with all reporting and notification provisions.
   a. The UIC Director will be notified 60 days in advance of planned plugging efforts [40 CFR ***§*146.92(c)**].
   b. The TRRC and the UIC Director will be notified at least 60 days before plugging a well. If any changes are proposed to the original well-plugging plan, a revised plan will be submitted [16 TAC ***§*5.201(k)(3)(A)**].
   c. A notice of intention to plug and abandon (Form W-3A) will be filed with the appropriate TRRC district office and the UIC Director at least 5 days prior to the beginning of plugging operations.
   d. Plugging operations will not start until the proposed procedure has been approved by the UIC Director.
   e. The district office will be notified at least 4 hours before commencing plugging operations.

2. Casing inspection and cement bond logs will be run prior to plugging.

3. External mechanical integrity will be demonstrated through approved temperature logging methods as described in *Section 5 – Testing and Monitoring Plan*, per 16 TAC **§5.203 (h)(1)(D)** [40 CFR **§146.89(c)**].

4. The monitoring well will be flushed with at least a 9.5 ppg inert pH buffer fluid such as a brine containing additives such as biocide, corrosion inhibitor and oxygen scavenger. Examples of these type additives are included as Appendix G-2. This buffer fluid will be pumped prior to pulling the injection tubing and packer seal assembly (16 TAC **§5.203** and **§3.14** [40 CFR **§146.92(a)**]).

5. Tubing and packer seal assembly will be pulled prior to P&A operations.

6.2.2 Monitoring Well Plugging Activities

1. Pull seal assembly from the packer to just above the packer.

2. Fill the wellbore with at least 9.5 ppg, 40 viscosity-treated drilling mud, and ensure the well is in static condition.

3. Pull tubing and seal assembly and remove from the well.

4. Isolate the gross injection interval:

a. Set a permanent cast-iron bridge plug ~50 ft above the packer and ~300 ft above the upper confinement layer in the 5-1/2 in. casing.
b. Place a 300 ft cement plug above the bridge plug.
c. Displace cement with minimum 9.5 ppg, 40 viscosity-treated drilling mud.
d. The plug will be qualified by tagging the top of the cement and conducting a successful pressure test.

5. Spot a 400 ft cement plug from at least 50 ft below the surface-casing setting depth, to a minimum of 50 ft into the base of the USDW. Displace cement with minimum 9.5 ppg, 40 viscosity-treated drilling mud.
6. Set a 50 ft cement plug from 50 ft to the surface.
7. Cut casing 3 ft below ground level and weld on a ½ in. steel plate.

Within **60 days** after plugging, Orchard Storage will submit, pursuant to [40 CFR **§146.91(e)**], a certified plugging report to the UIC Director. The well-plugging report will be retained for 10 years following site closure. Also note that a complete well-plugging record (Form W-3), pursuant to 16 TAC **§5.203**, will be filed within **30 days** to the appropriate TRRC district office after plugging operations are completed.

6.2.3 Monitoring Well Plugging Cement Composition

Since the monitoring wells will not encounter the CO_2 plume, corrosion-resistant plugs are not necessary in these wells. Standard Class H will be used to plug the monitoring wells.

6.2.4 Plugging Plan, Orchard MW No. 1

6.2.4.1 Monitoring Wellbore Profile Prior to Plugging and Abandonment, Orchard MW No. 1

The original wellbore schematic for Orchard MW No. 1, prior to beginning plugging operations, is provided in Figure 6-15.

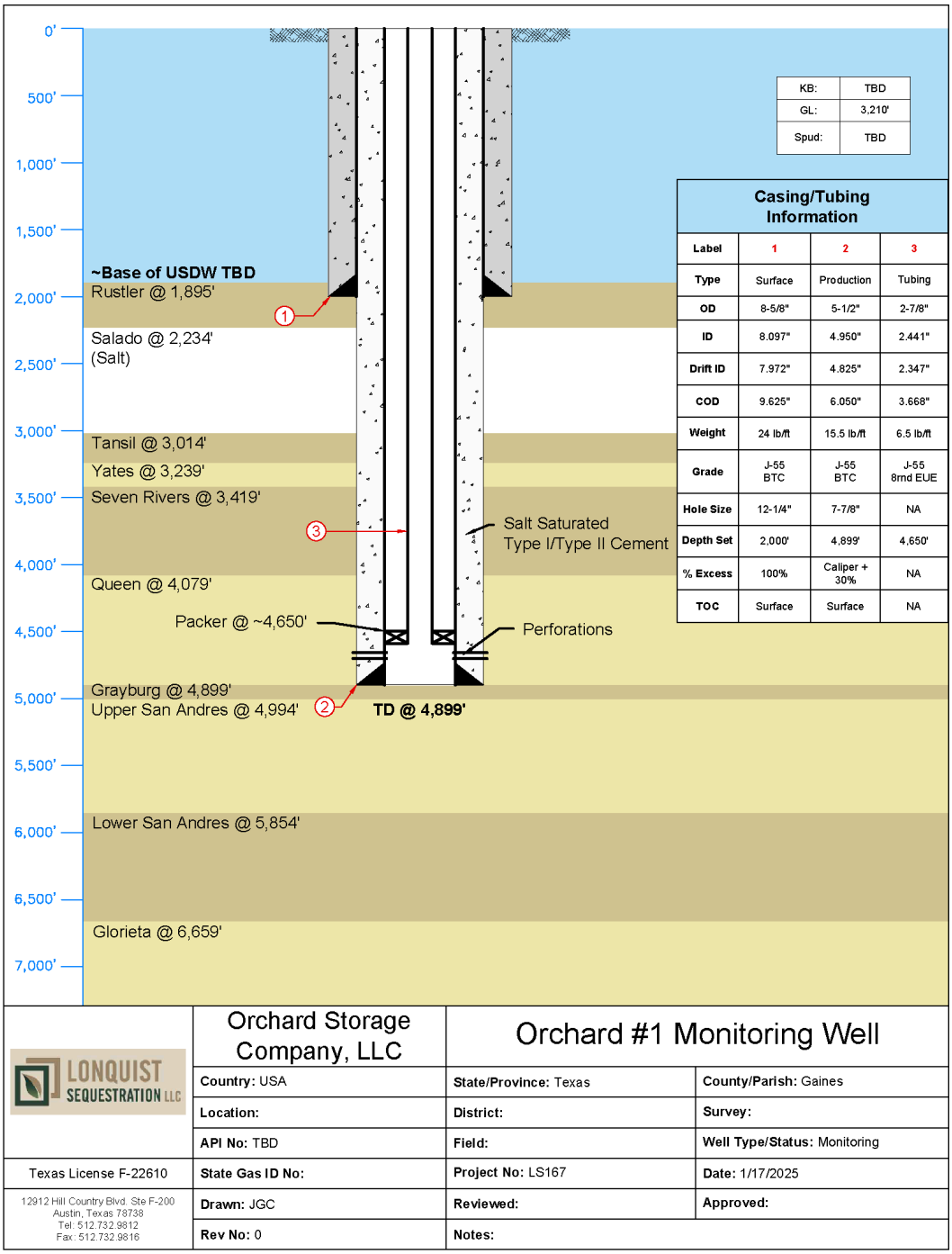
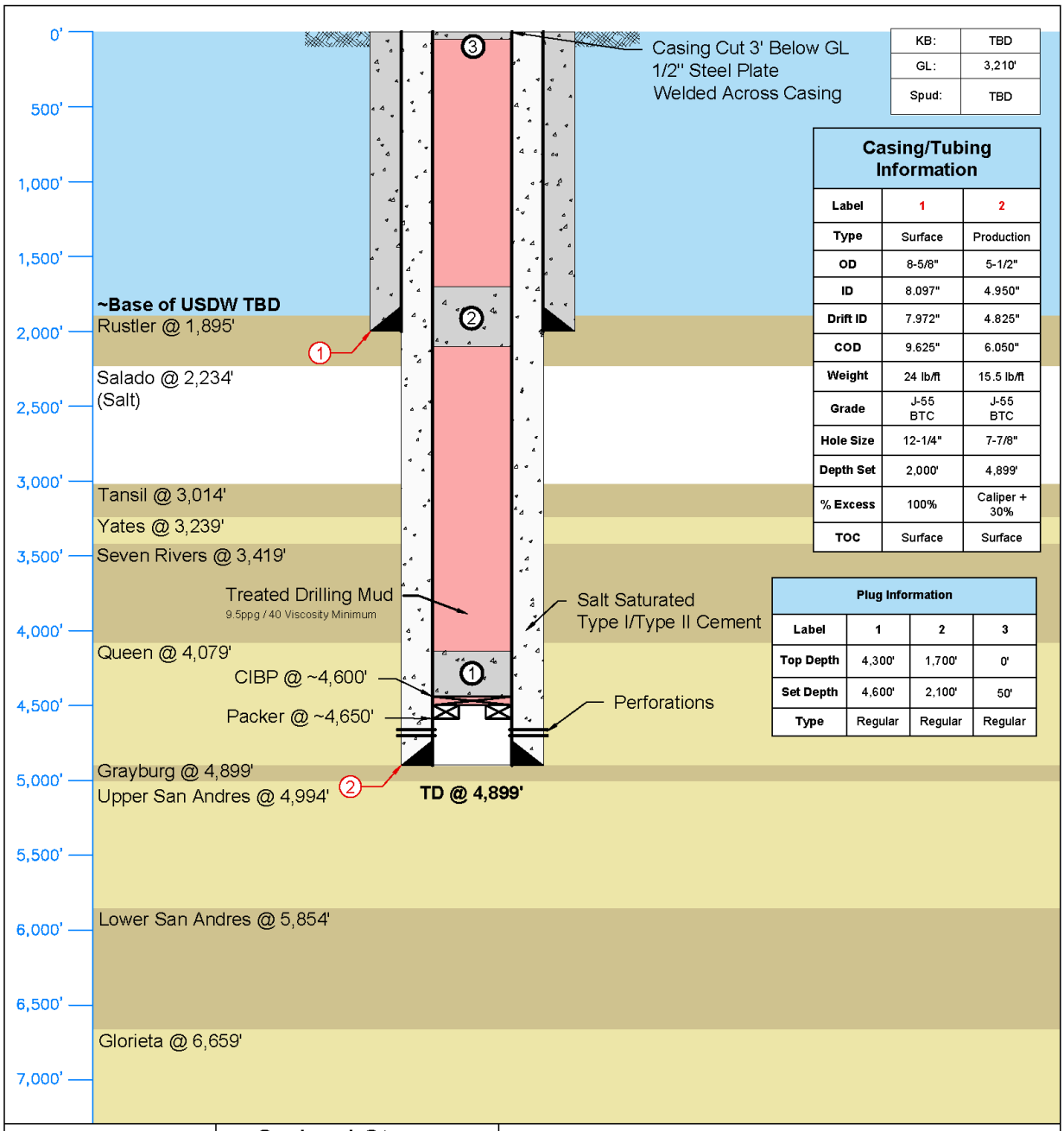


Figure 6-15 – Wellbore Schematic for Orchard MW No. 1 Before Plugging and Abandoning

6.2.4.2 Plug Details

Table 6-8 – Plugging Details for Orchard MW No. 1

Plug Number	1	2	3	4
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Surface Plug
Casing OD (in.)	5-1/2	5-1/2	5-1/2	5-1/2
Casing ID (in.)	4.950	4.950	4.950	4.950
Top of Plug (ft)	4,600	4,300	1,700	0
Bottom of Plug (ft)	4,600	4,600	2,100	50
Cement Volume (sacks)	NA	32	42	6
Slurry Volume (ft^3)	NA	41	54	7
Slurry Weight (lb/gal)	NA	16.4	16.4	11
Type of Cement or Other Material	Cast Iron Bridge Plug	Class H Cement	Class H Cement	Class H Cement
Placement	Wireline	Circulation	Circulation	Circulation



LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #1 Monitoring Well	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location:	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:** P & A
Texas License F-22610	**State Gas ID No:**	**Project No:** LS167	**Date:** 1/17/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 6-16 – Plugging Schematic for Orchard MW No. 1

6.2.5 Plugging Plan, Orchard MW No. 2

6.2.5.1 Monitoring Wellbore Profile Prior to Plugging and Abandonment, Orchard MW No. 2

The original wellbore schematic for Orchard MW No. 2, prior to beginning plugging operations, is provided in Figure 6-17.

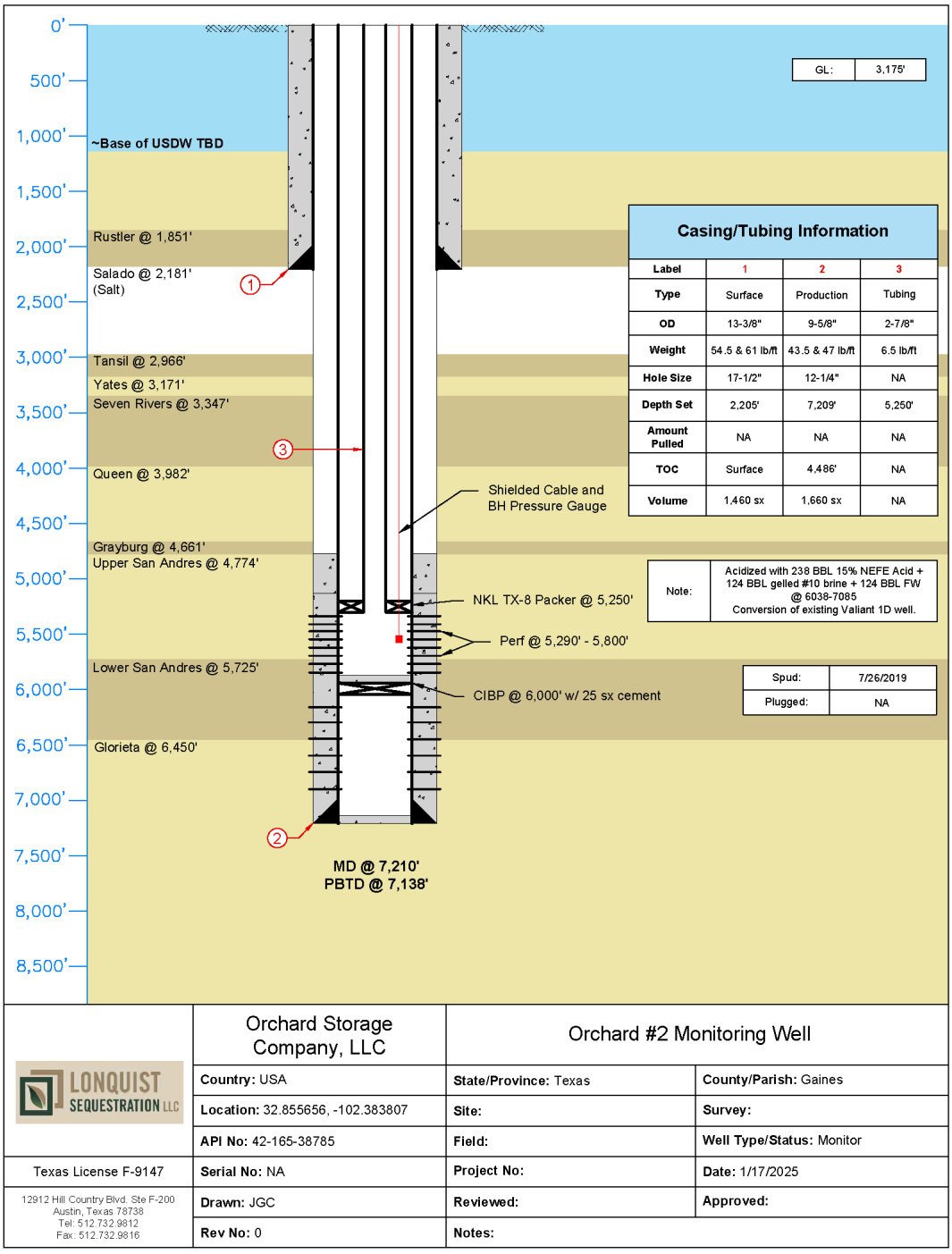
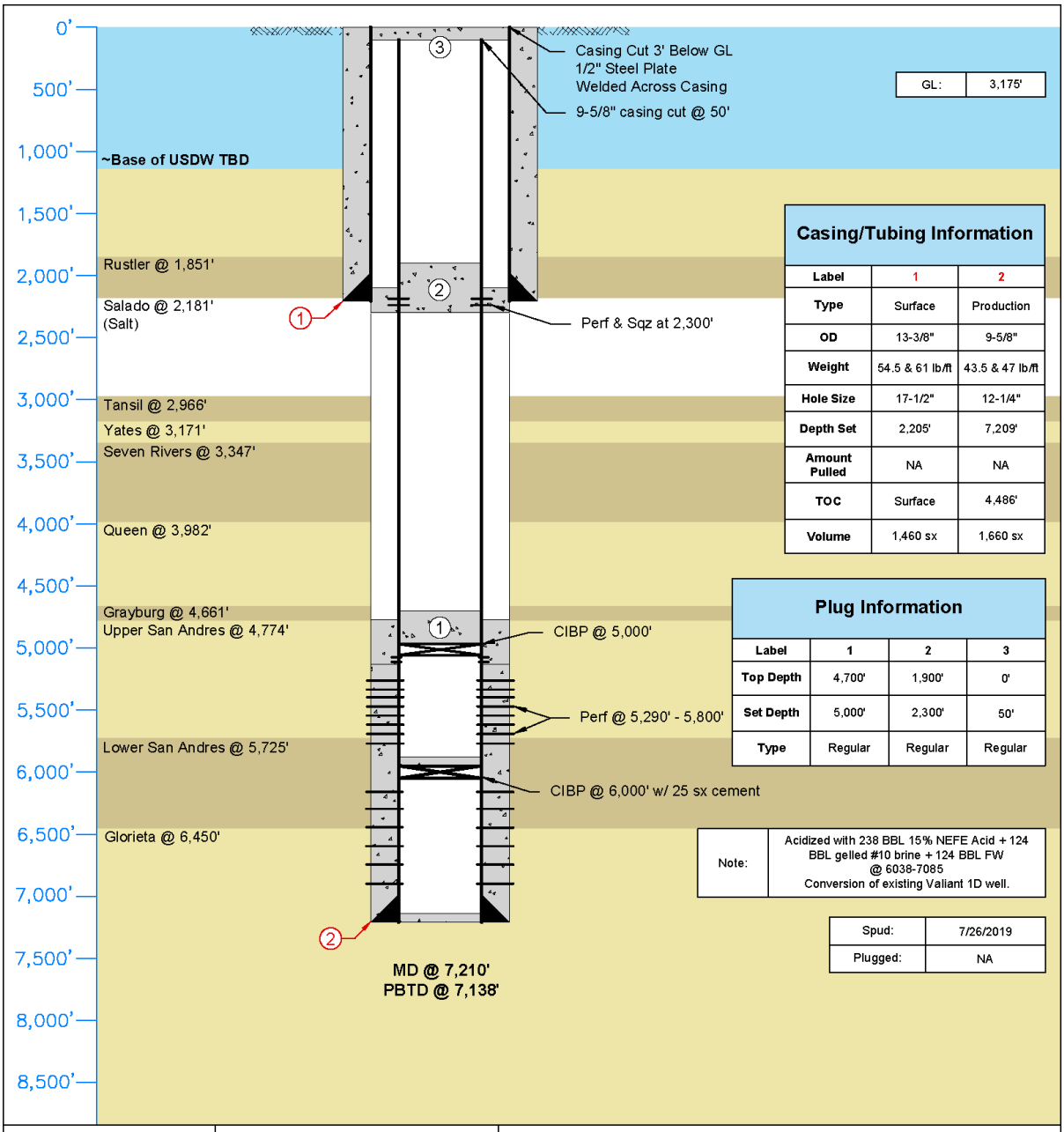


Figure 6-17 – Wellbore Schematic for Orchard MW No. 2 Before Plugging and Abandoning

6.2.5.2 Plug Details

Table 6-9 – Plugging Details for Orchard MW No. 2

Plug Number	1	2	3	4
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Surface Plug
Casing OD (in.)	9-5/8	9-5/8	9-5/8	9-5/8
Casing ID (in.)	8.681	8.681	8.681	8.681
Top of Plug (ft)	5,000	4,700	1,900	0
Bottom of Plug (ft)	5,000	5,000	2,300	50
Cement Volume (sacks)	NA	96	127	19
Slurry Volume (ft^3)	NA	124	165	21
Slurry Weight (lb/gal)	NA	16.4	16.4	11
Type of Cement or Other Material	Cast Iron Bridge Plug	Corrosion Resistant	Class H Cement	Class H Cement
Placement	Wireline	Circulation	Circulation	Circulation



LONQUIST SEQUESTRATION LLC	Orchard Storage Company, LLC	Orchard #2 Monitoring Well	
	Country: USA	**State/Province:** Texas	**County/Parish:** Gaines
	Location: 32.855656, -102.383807	**Site:**	**Survey:**
	API No: 42-165-38785	**Field:**	**Well Type/Status:** P & A
Texas License F-9147	**Serial No:** NA	**Project No:**	**Date:** 1/17/2025
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** JGC	**Reviewed:**	**Approved:**
	Rev No: 0	**Notes:**	

Figure 6-18 – Plugging Schematic for Orchard MW No. 2

6.2.6 Plugging Plan, Orchard MW No. 3

6.2.6.1 Monitoring Wellbore Profile Prior to Plugging and Abandonment, Orchard MW No. 3

The original wellbore schematic for Orchard MW No. 3, prior to beginning plugging operations, is provided in Figure 6-19.

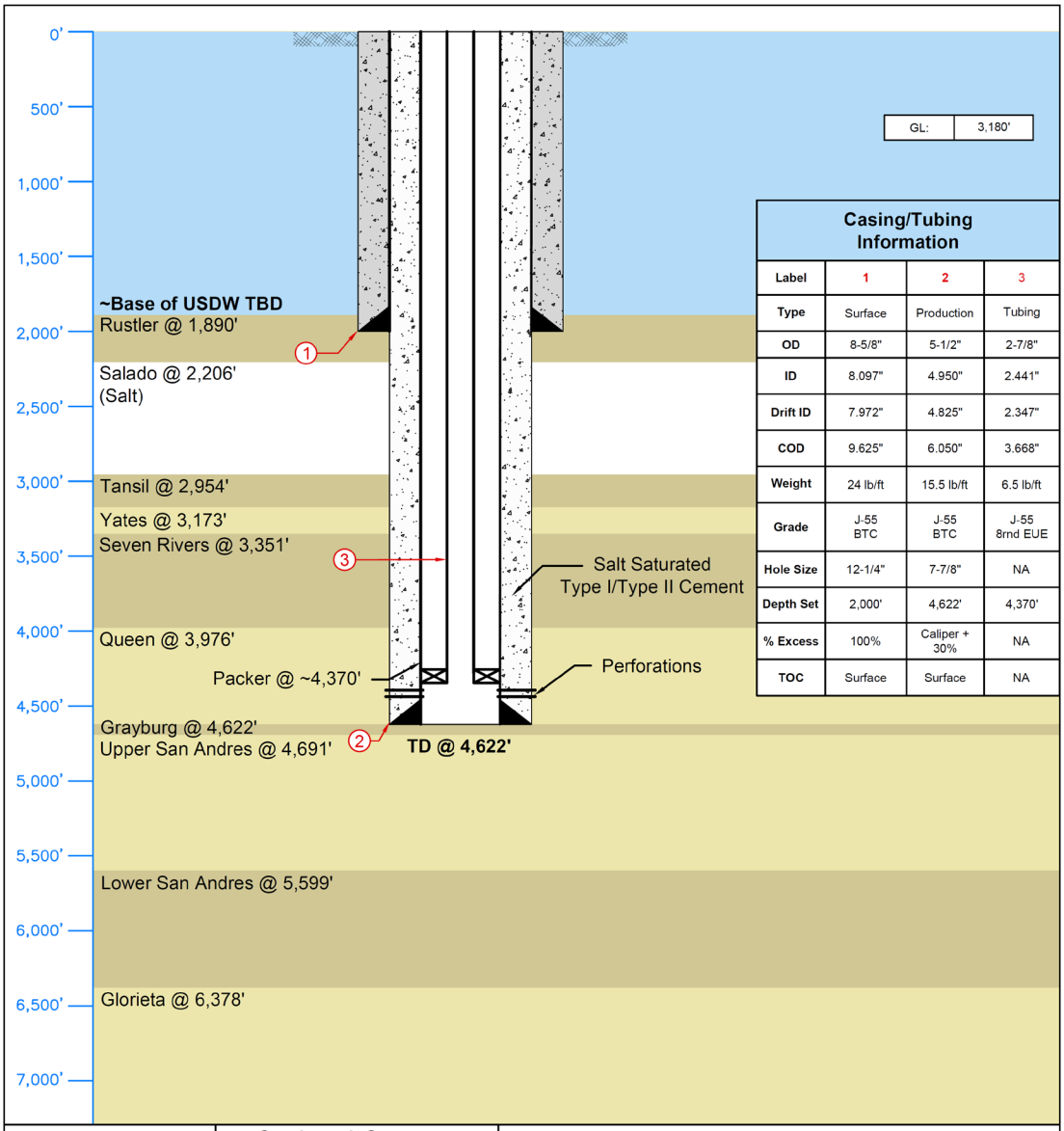


Figure 6-19 – Wellbore Schematic for Orchard MW No. 3 Before Plugging and Abandoning

6.2.6.2 Plug Details

Table 6-10 – Plugging Details for Orchard MW No. 3

Plug Number	1	2	3	4
Purpose	Isolate Confining Zone	Isolate Confining Zone	Isolate USDW	Surface Plug
Casing OD (in.)	5-1/2	5-1/2	5-1/2	5-1/2
Casing ID (in.)	4.950	4.950	4.950	4.950
Top of Plug (ft)	4,320	4,020	1,700	0
Bottom of Plug (ft)	4,320	4,320	2,100	50
Cement Volume (sacks)	NA	32	42	6
Slurry Volume (ft^3)	NA	41	54	7
Slurry Weight (lb/gal)	NA	16.4	16.4	11
Type of Cement or Other Material	Cast Iron Bridge Plug	Class H Cement	Class H Cement	Class H Cement
Placement	Wireline	Circulation	Circulation	Circulation

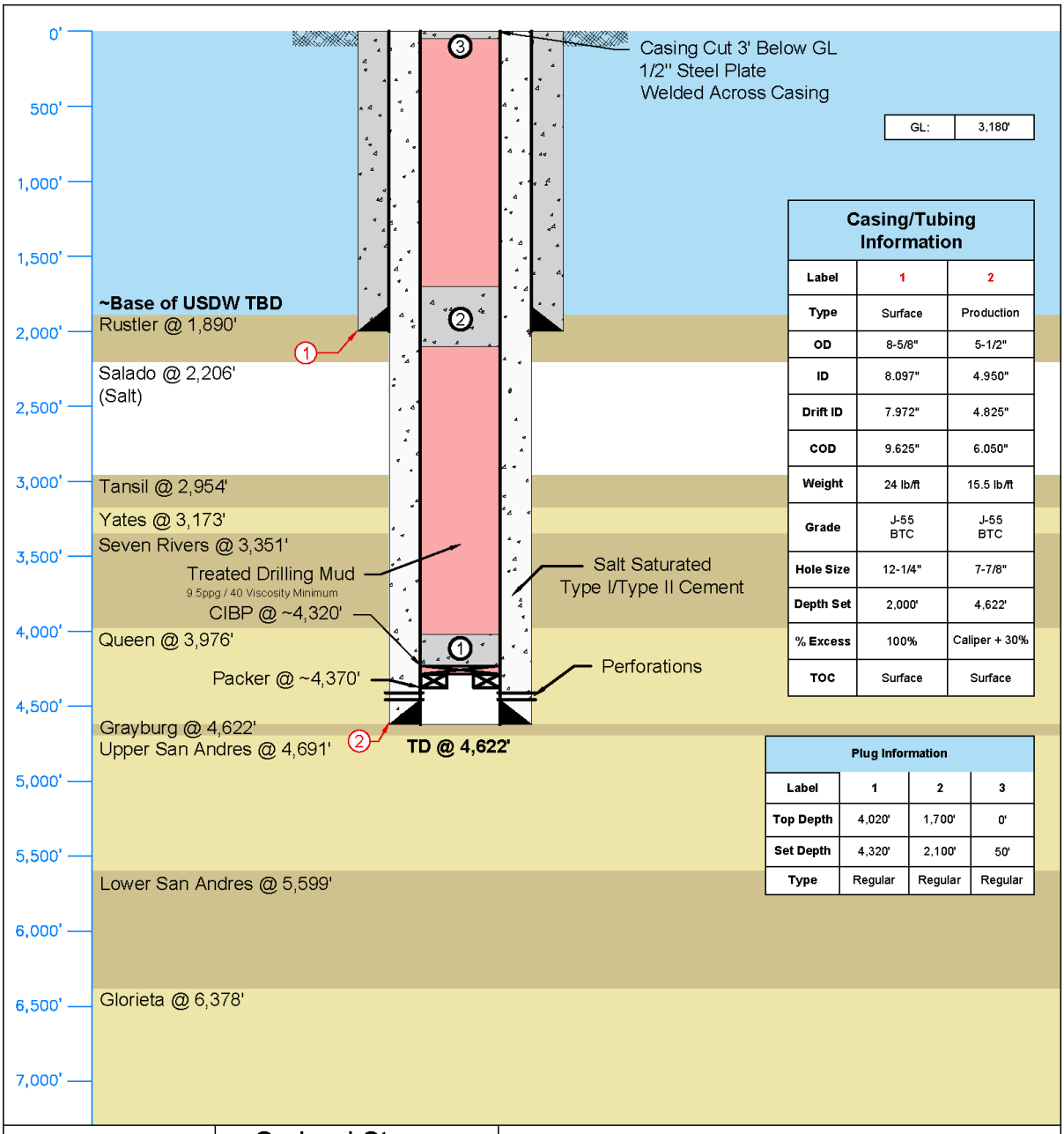


Figure 6-20 – Plugging Schematic for Orchard MW No. 3

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 7 – Post-Injection Site Care and Site Closure Plan

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

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

TABLE OF CONTENTS

7.1. Overview 3
7.2. Post-Injection Pressure Differentials 3
7.3. CO_2 Plume Position and Pressure Front at End of Injection and at Closure 9
7.4. Post-Injection Monitoring Plan 25
7.4.1. Post-Injection Monitoring Activities 27
7.4.2. Demonstration of Non-Endangerment of USDW 27
7.5. Site Closure Plan 28
7.5.1. Pre-closure 28
7.5.2. Plugging Activities 28
7.5.3. Site Restoration 28
7.5.4. Documentation of Site Closure 28

Figures

Table 7-1 – Critical Pressures for Orchard No. 1 to 7 4
Figure 7-1 – Maximum Pressure Differential Over Time for Orchard No. 1 4
Figure 7-2 – Maximum Pressure Differential Over Time for Orchard No. 2 5
Figure 7-3 – Maximum Pressure Differential Over Time for Orchard No. 3 5
Figure 7-4 – Maximum Pressure Differential Over Time for Orchard No. 4 6
Figure 7-5 – Maximum Pressure Differential Over Time for Orchard No. 5 6
Figure 7-6 – Maximum Pressure Differential Over Time for Orchard No. 6 7
Figure 7-7 – Maximum Pressure Differential Over Time for Orchard No. 7 7
Table 7-2 – Maximum Pressure Differential by Year, Post-Injection (50 Years) for Orchard No. 1 to No. 7 8
Figure 7-8 – Stabilized Combined CO_2 Plumes and Pressure Front Extent 10
Figure 7-9 – Orchard No. 1 West-East Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 11
Figure 7-10 – Orchard No. 1 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 12
Figure 7-11 – Orchard No. 2 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 13
Figure 7-12 – Orchard No. 2 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 14
Figure 7-13 – Orchard No. 3 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 15
Figure 7-14 – Orchard No. 3 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 16
Figure 7-15 – Orchard No. 4 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 17
Figure 7-16 – Orchard No. 4 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 18
Figure 7-17 – Orchard No. 5 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 19

Figure 7-18 – Orchard No. 5 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 20
Figure 7-19 – Orchard No. 6 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 .. 21
Figure 7-20 – Orchard No. 6 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 22
Figure 7-21 – Orchard No. 7 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 .. 23
Figure 7-22 – Orchard No. 7 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 24
Figure 7-23 – Location of Groundwater, In-Zone and Above-Zone Monitoring Wells 26
Table 7-3 – Post-Injection Monitoring and Reporting Frequency 27

Tables

Table 7-1 – Critical Pressures for Orchard No. 1 to 7 4
Table 7-2 – Maximum Pressure Differential by Year, Post-Injection (50 Years) for Orchard No. 1 to No. 7 8
Table 7-3 – Post-Injection Monitoring and Reporting Frequency 27

7.1. Overview

This Post-Injection Site Care (PISC) and Site Closure Plan is prepared to meet the requirements of 16 Texas Administrative Code (TAC) **§5.206(k)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93**]. This section provides a comprehensive overview of (1) the anticipated plumes and pressure front behavior at the end of the injection phase, (2) post-injection monitoring plans, (3) a discussion demonstrating non-endangerment to the Underground Source of Drinking Water (USDW), and (4) site closure plans. This plan provides the activities that Orchard Storage Company LLC (Orchard Storage) will perform once injection has ceased. The program will conclude with the site closure activities, once it is demonstrated that no additional monitoring is needed to ensure that this project does not endanger the USDW. This plan will be maintained during the life of the project and reevaluated every 5 years and submitted to the Underground Injection Control (UIC) Director.

7.2. Post-Injection Pressure Differentials

To meet the requirements of 16 TAC **§5.203(m)(2)** [40 CFR **§146.93(a)(2)**], Figures 7-1 through 7-7 show the expected pressure differentials for Orchard No. 1 through No. 7, respectively, in the injection zone from start of injection through 50 years post injection, as determined by the plume model described in *Section 2 – Plume Model*. Table 7-2 then shows the same for all seven injection wells at 50 years post-injection.

The expected pressure differential relative to pre-injection pressures for each of the Orchard injection wells is presented in Figures 7-1 through 7-7, respectively. The differential pressure is calculated based on the difference between each respective well's bottom hole pressure and its initial pre-injection bottom hole pressure.

Figures 7-1 through 7-7 also present the maximum differential pressure (Δp) vs. time, plotted as circles, for each injector. The horizontal axis represents time in years, relative to the start of injection. The vertical axis represents the Δp value in psi. The dashed horizontal line shows the value of the critical pressure differential calculated for each well, and a vertical dashed line flags the time at which injection ceases for this project.

The maximum Δp values increase with time until injection ends after 12 years. After injection ceases, the Δp values drop sharply for the first 5 years after injection ends then continues to drop over the remaining PISC period.

Critical pressure is the pressure differential required to lift formation fluids up to the base of the lowest USDW. The assumptions used to calculate critical pressure are discussed in more detail in Section 2.4.1. Table 7-1 provides the calculated critical pressures for each well from Section 2.4.1.

Table 7-1 – Critical Pressures for Orchard No. 1 to 7

Well No.	Critical Pressure Increase (psi)
1	231
2	231
3	231
4	225
5	225
6	213
7	214

The pressure differential in the injection zone drops below the critical pressure within 10 years after injection ceases.

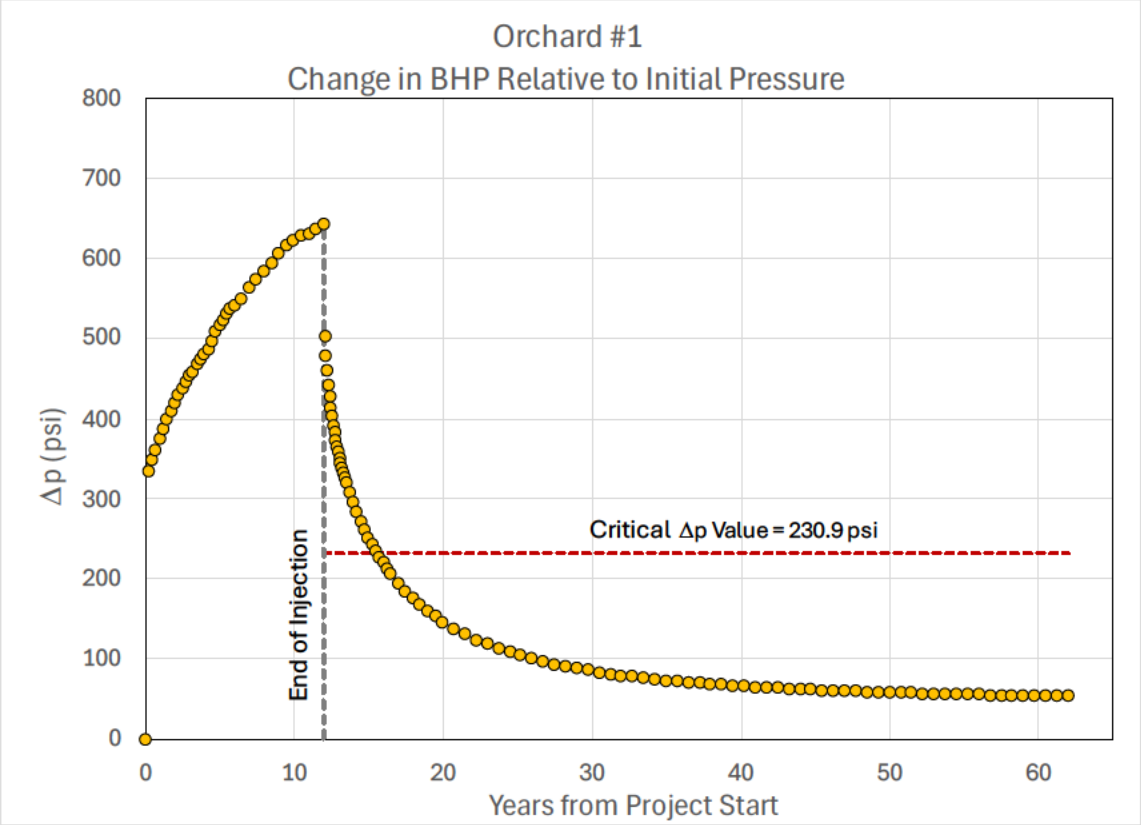


Figure 7-1 – Maximum Pressure Differential Over Time for Orchard No. 1

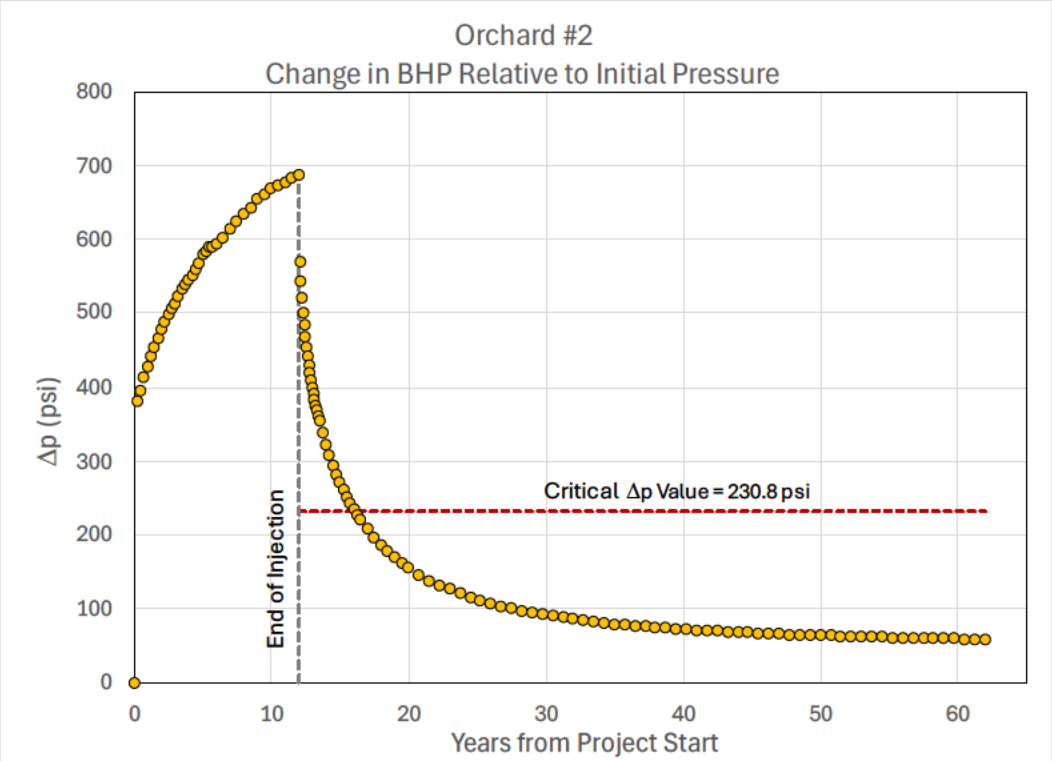


Figure 7-2 – Maximum Pressure Differential Over Time for Orchard No. 2

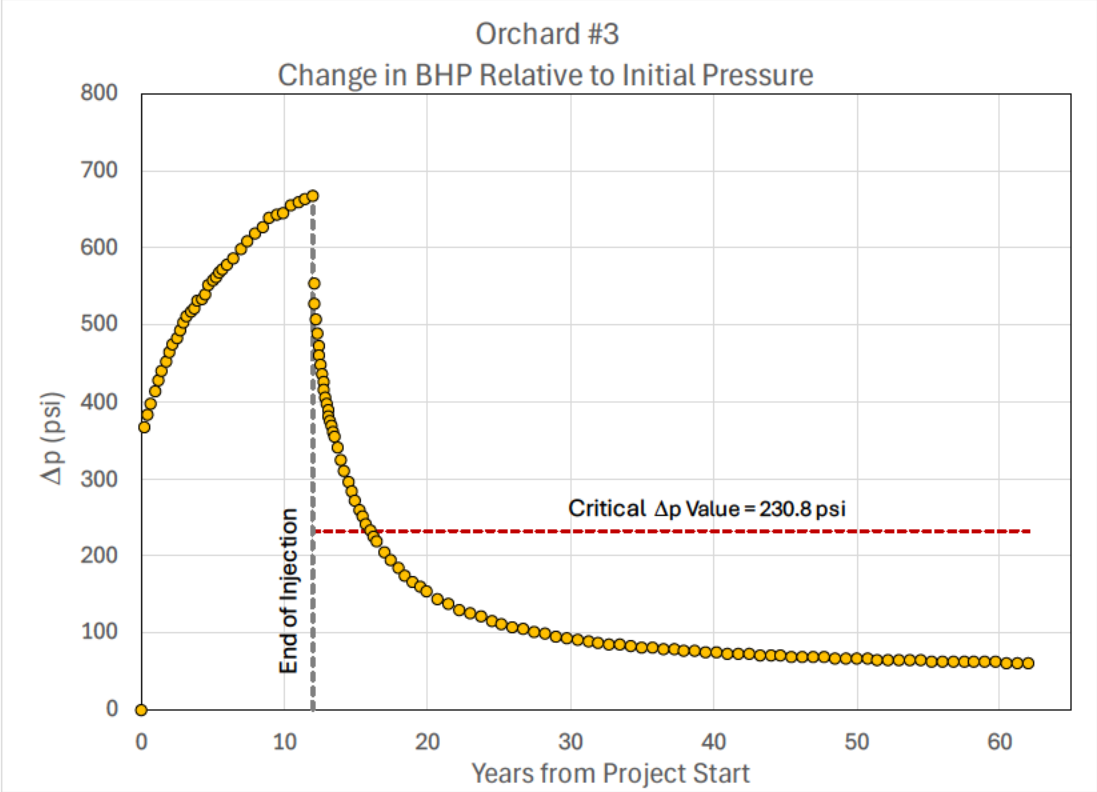


Figure 7-3 – Maximum Pressure Differential Over Time for Orchard No. 3

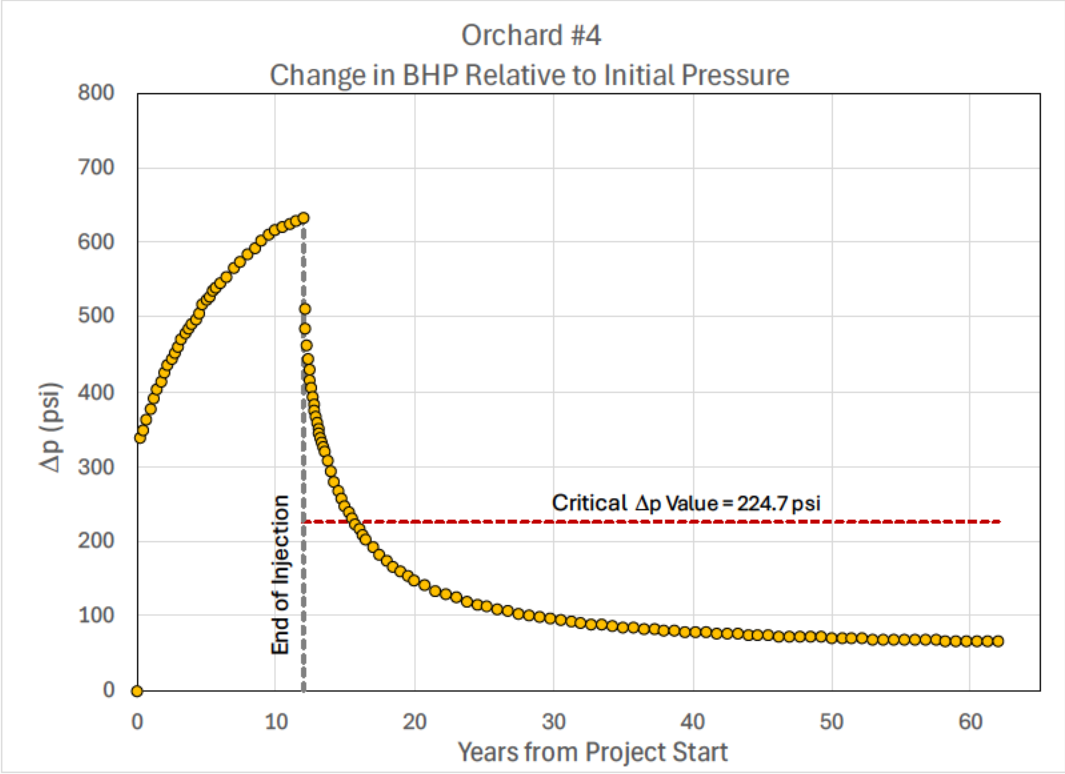


Figure 7-4 – Maximum Pressure Differential Over Time for Orchard No. 4

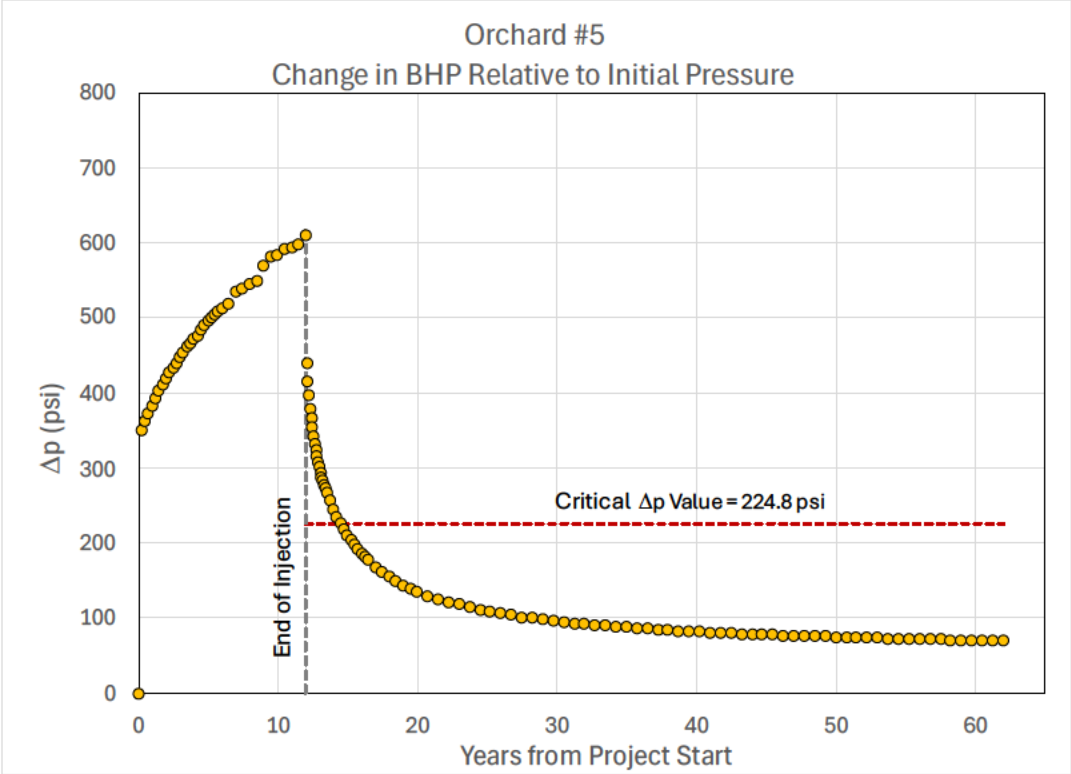


Figure 7-5 – Maximum Pressure Differential Over Time for Orchard No. 5

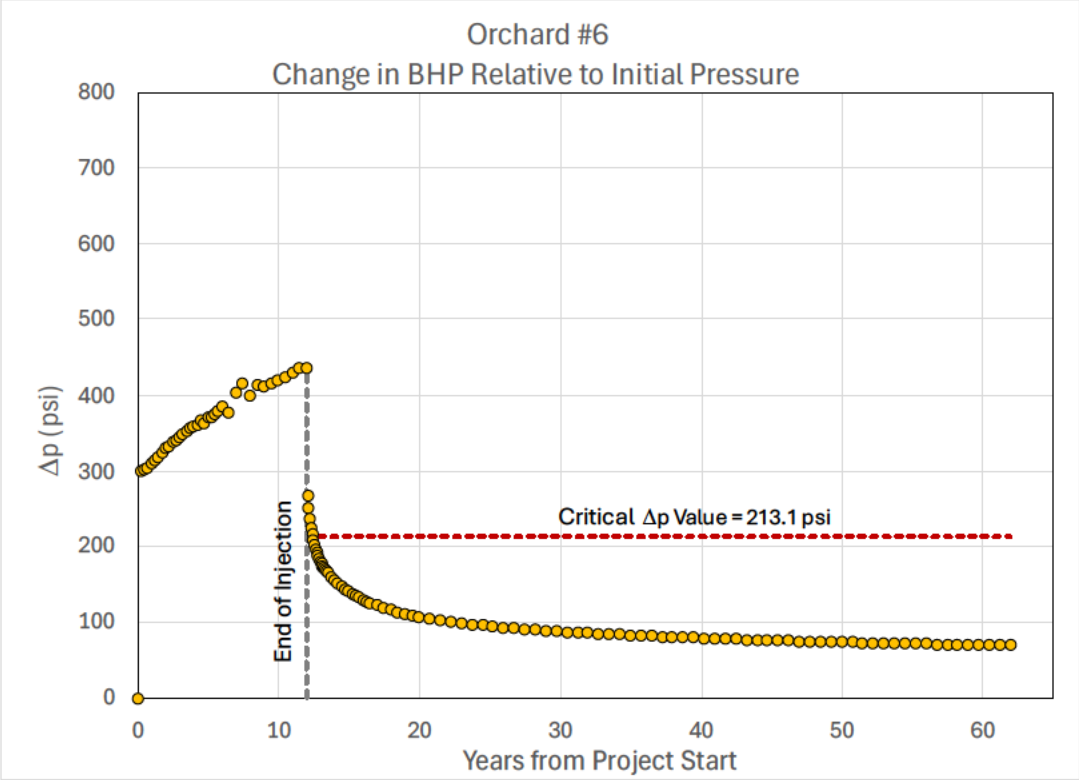


Figure 7-6 – Maximum Pressure Differential Over Time for Orchard No. 6

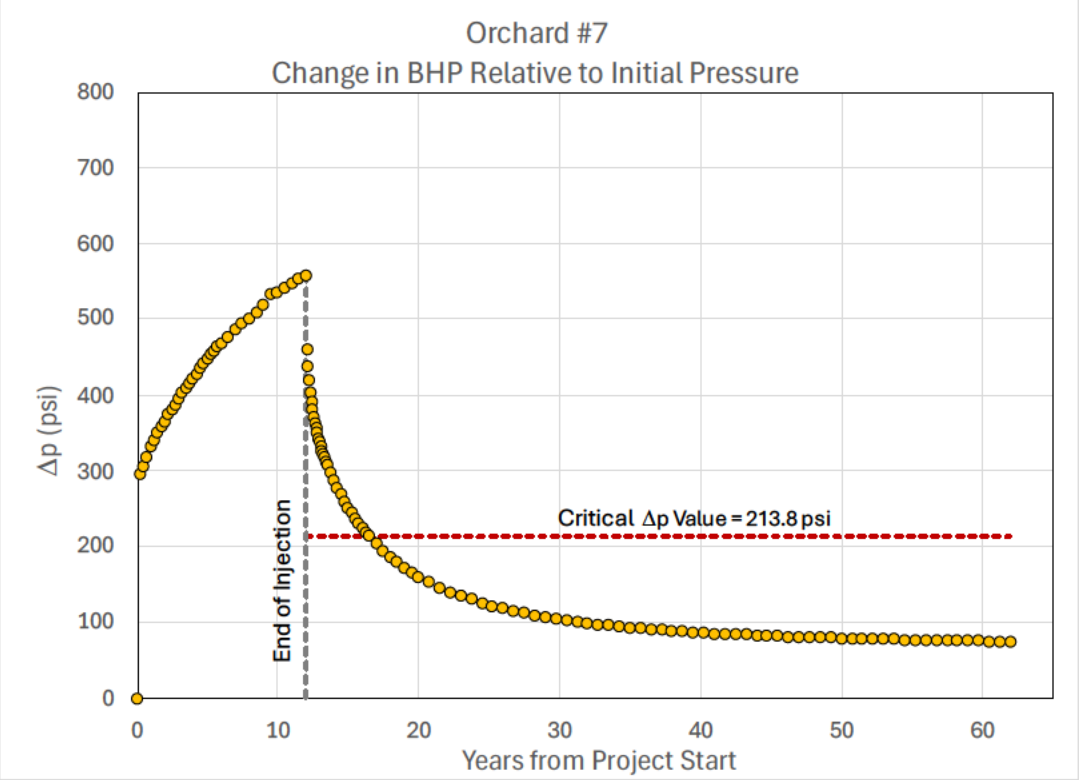


Figure 7-7 – Maximum Pressure Differential Over Time for Orchard No. 7

Table 7-2 – Maximum Pressure Differential by Year, Post-Injection (50 Years) for Orchard No. 1 to No. 7

Year	Maximum Pressure Differential (psi)						
	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
0 (end of injection)	642.5	688.2	668.5	633.7	610.4	436.8	558.5
1	358.0	399.9	397.8	359.0	301.2	180.3	337.4
2	294.7	322.4	324.4	293.4	245.1	155.2	287.6
3	251.3	271.1	270.9	247.5	210.3	140.3	251.8
4	219.5	234.7	232.6	215.6	186.3	130.0	224.9
5	195.1	207.4	204.6	192.1	168.7	122.3	203.6
6	175.6	186.0	183.2	174.0	155.1	116.2	186.4
8	146.4	154.8	152.6	147.9	135.6	107.4	160.1
10	125.8	133.3	132.0	130.2	122.3	101.2	141.5
12	111.9	119.0	118.4	118.5	113.5	97.0	128.9
14	100.4	107.2	107.4	108.8	106.1	93.3	118.3
16	91.6	98.2	98.9	101.3	100.4	90.4	110.2
18	84.6	91.2	92.3	95.5	95.8	87.8	103.8
20	79.2	85.7	87.1	90.8	92.0	85.6	98.8
22	74.8	81.2	82.8	86.9	88.9	83.7	94.7
24	71.2	77.5	79.3	83.7	86.3	82.1	91.4
26	68.2	74.5	76.4	81.0	84.0	80.6	88.7
28	65.7	71.9	73.9	78.7	82.0	79.2	86.4
30	63.7	69.7	71.8	76.7	80.2	77.9	84.5
32	61.9	67.9	70.0	74.9	78.7	76.8	82.8
34	60.3	66.3	68.4	73.4	77.3	75.7	81.4
36	59.0	64.8	67.0	72.0	76.1	74.7	80.2
38	57.8	63.6	65.8	70.8	74.9	73.8	79.2
40	56.8	62.5	64.6	69.7	73.9	72.9	78.2
46	54.2	59.8	61.9	66.9	71.2	70.6	76.0
50	52.9	58.4	60.4	65.5	69.8	69.2	74.8

7.3. CO_2 Plume Position and Pressure Front at End of Injection and at Closure

To meet the requirements of 16 TAC **§5.203(m)(3)** [40 CFR **§146.93(a)(2)**], Figure 7-8 shows the predicted maximum, stabilized position of the combined carbon dioxide plumes and associated pressure front at the time of site closure. These plumes, as discussed in Section 2 – Plume Model, are delineated based on a 2% gas saturation cutoff and includes 50 years after the end of injection. The color codes on the plumes show the modeled gas saturation at a given point from the respective injection well. Figures 7-9 and 7-10 present the east-west and north-south cross-sectional views of the stabilized plume at the end of injection and at the time of site closure (50 years post-injection) for Orchard No. 1. Figures 7-11 through 7-22 then show the same for Orchard No. 2 through No. 7, respectively.

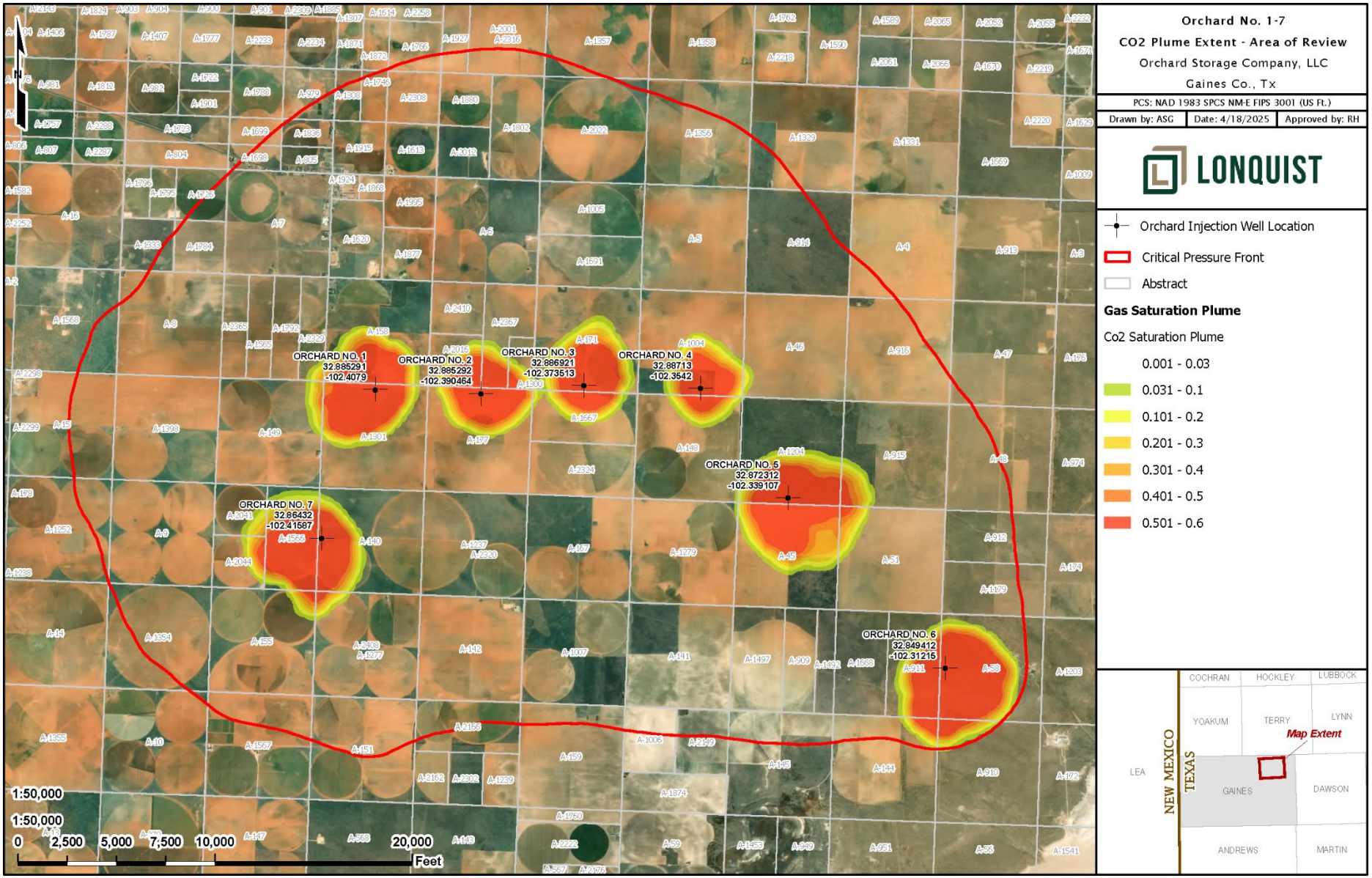


Figure 7-8 – Stabilized Combined CO_2 Plumes and Pressure Front Extent

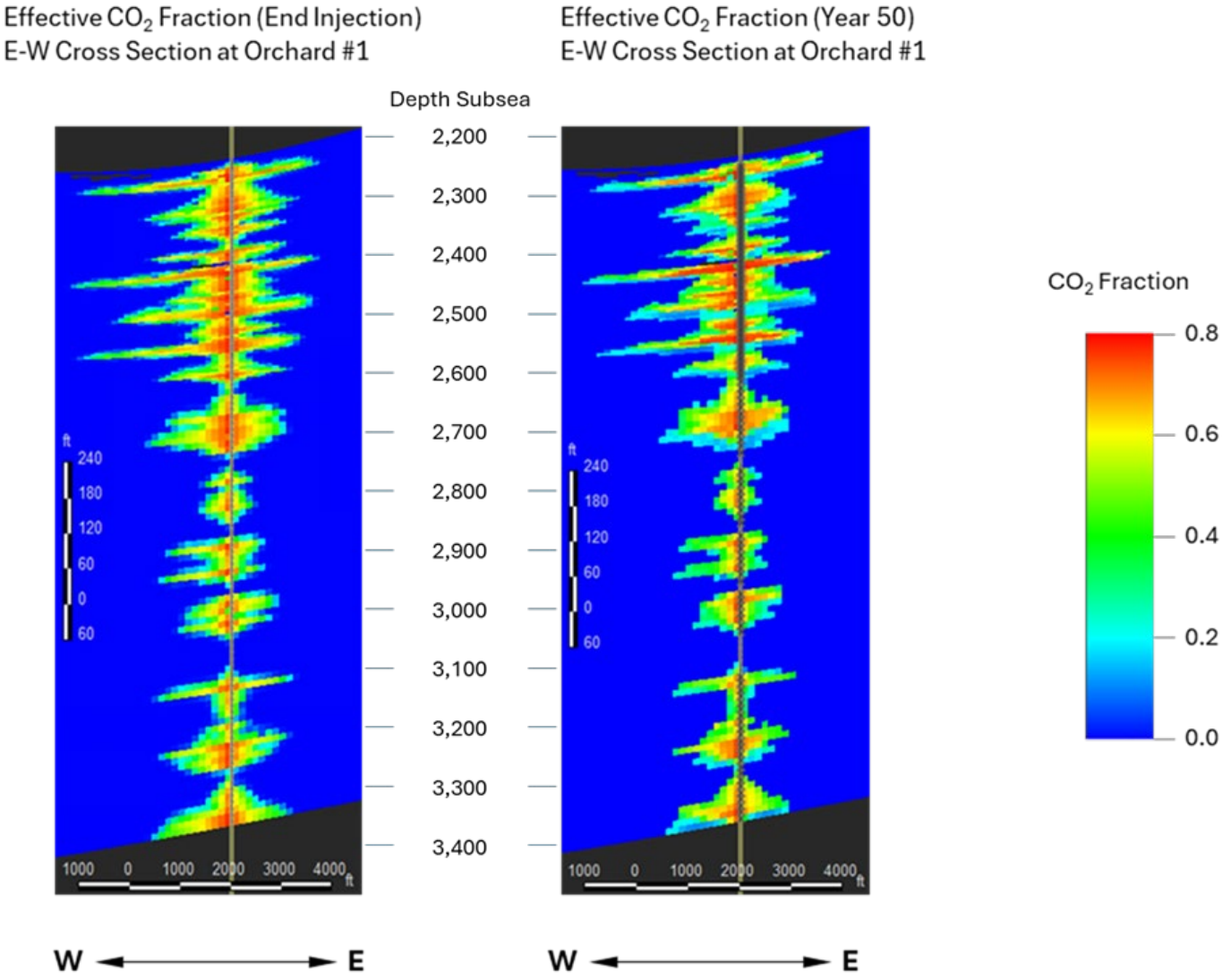


Figure 7-9 – Orchard No. 1 West-East Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

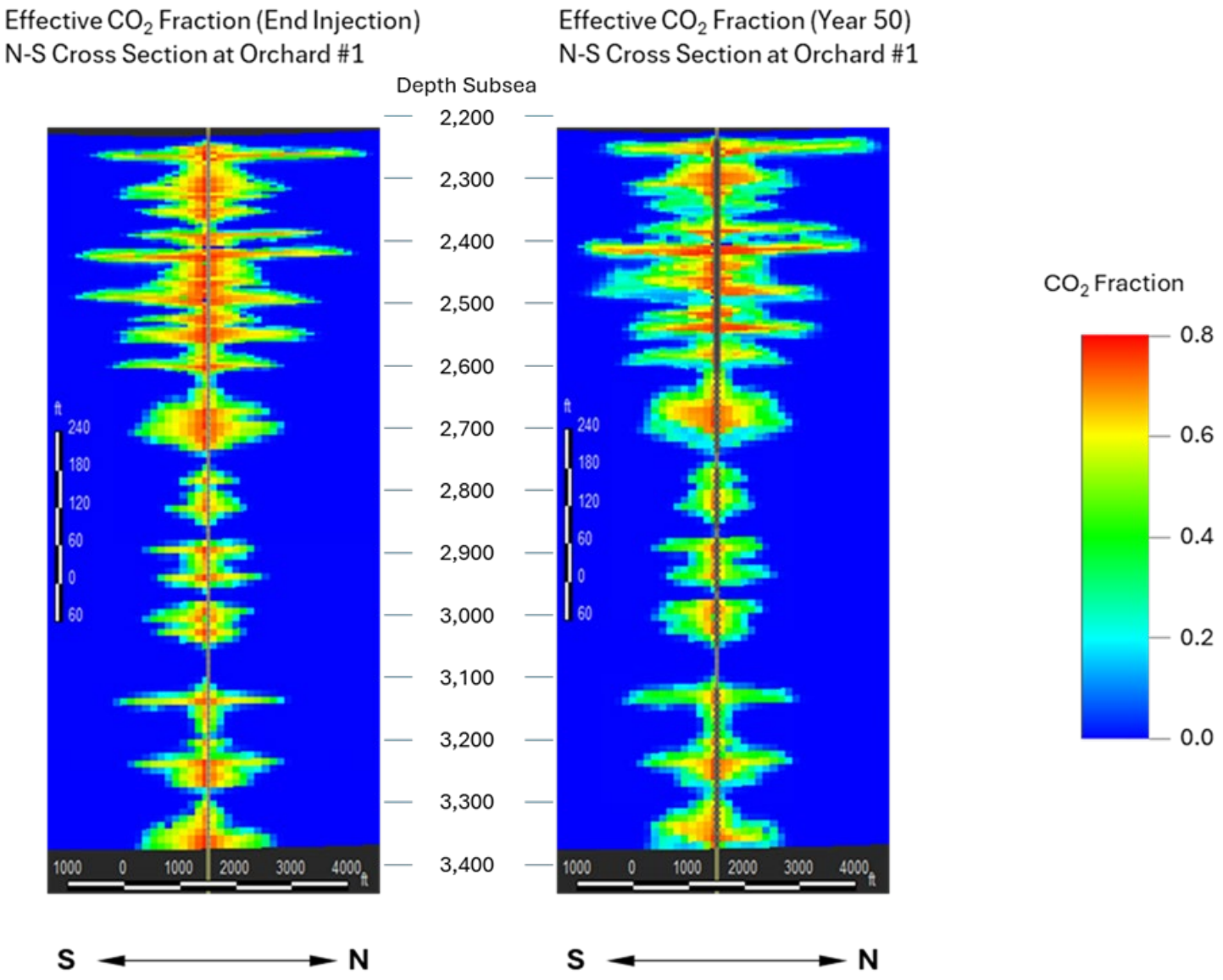


Figure 7-10 – Orchard No. 1 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

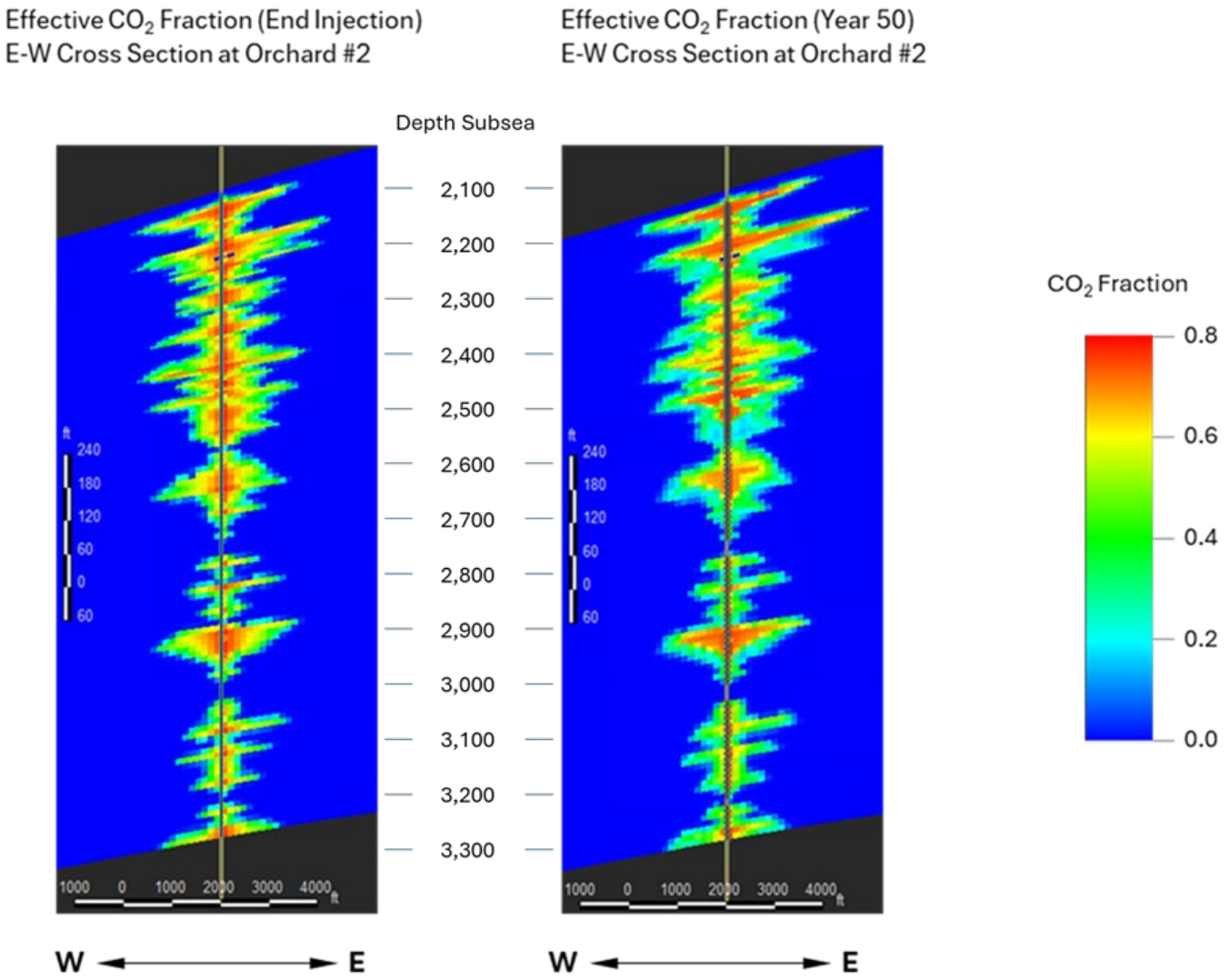


Figure 7-11 – Orchard No. 2 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

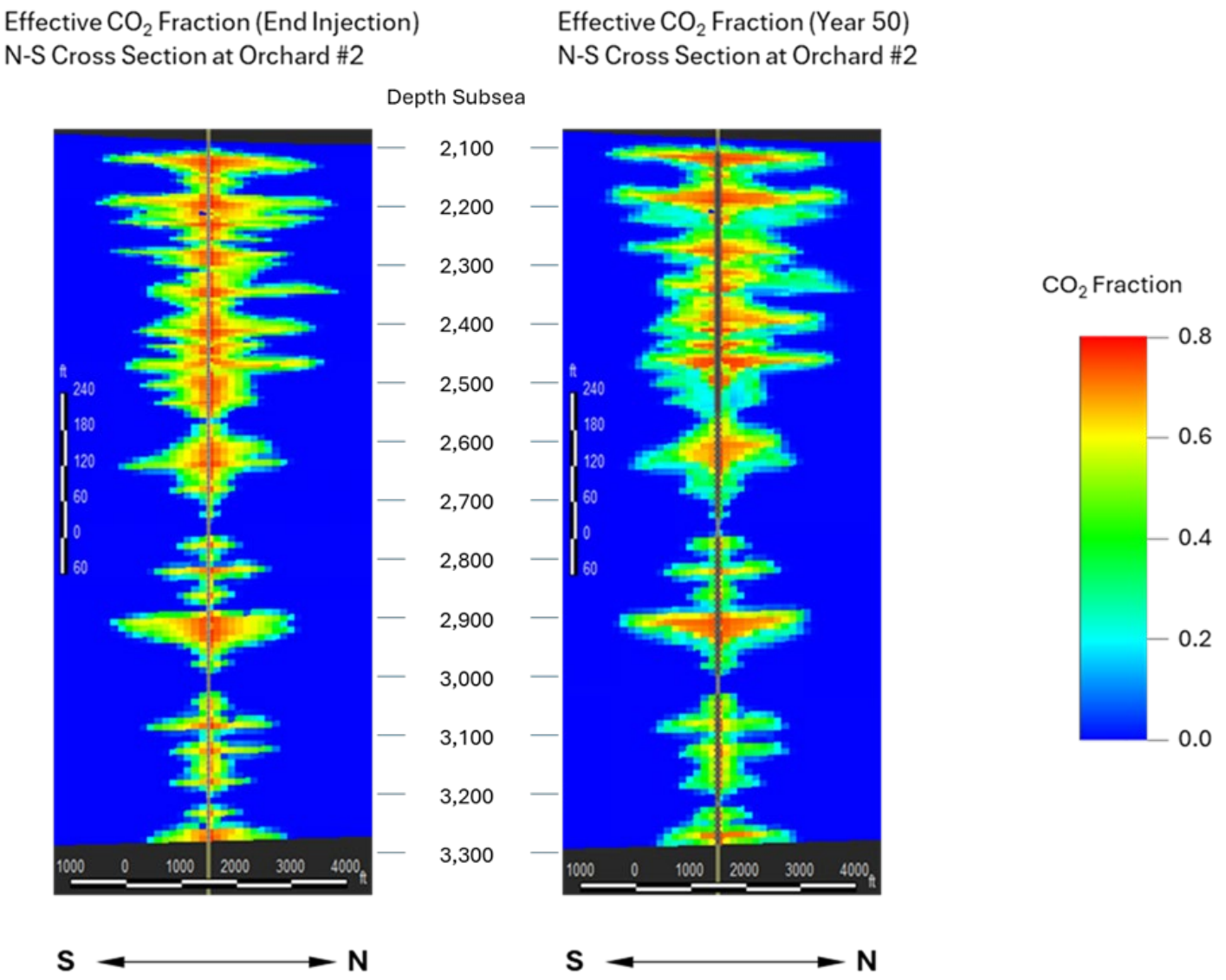


Figure 7-12 – Orchard No. 2 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

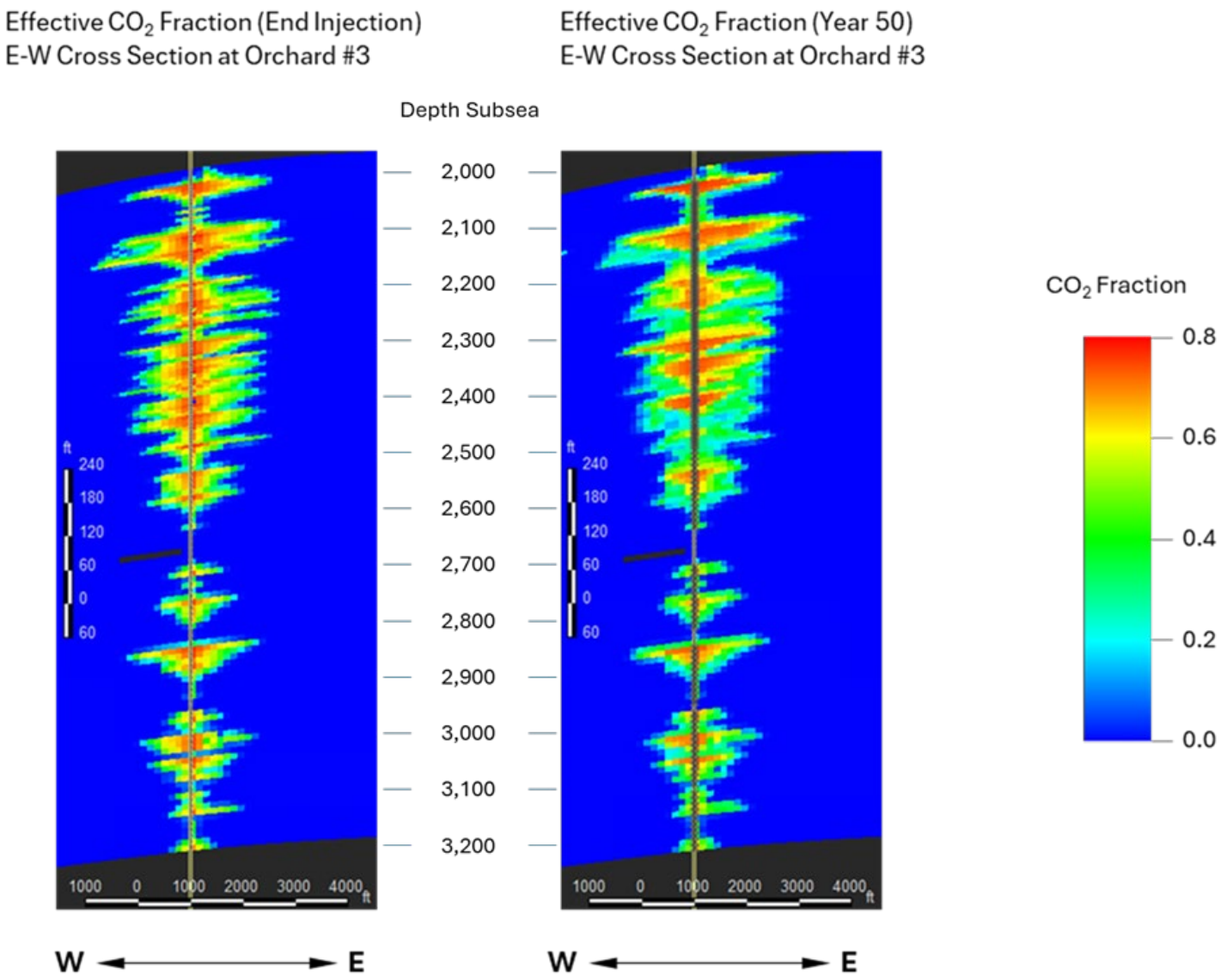


Figure 7-13 – Orchard No. 3 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

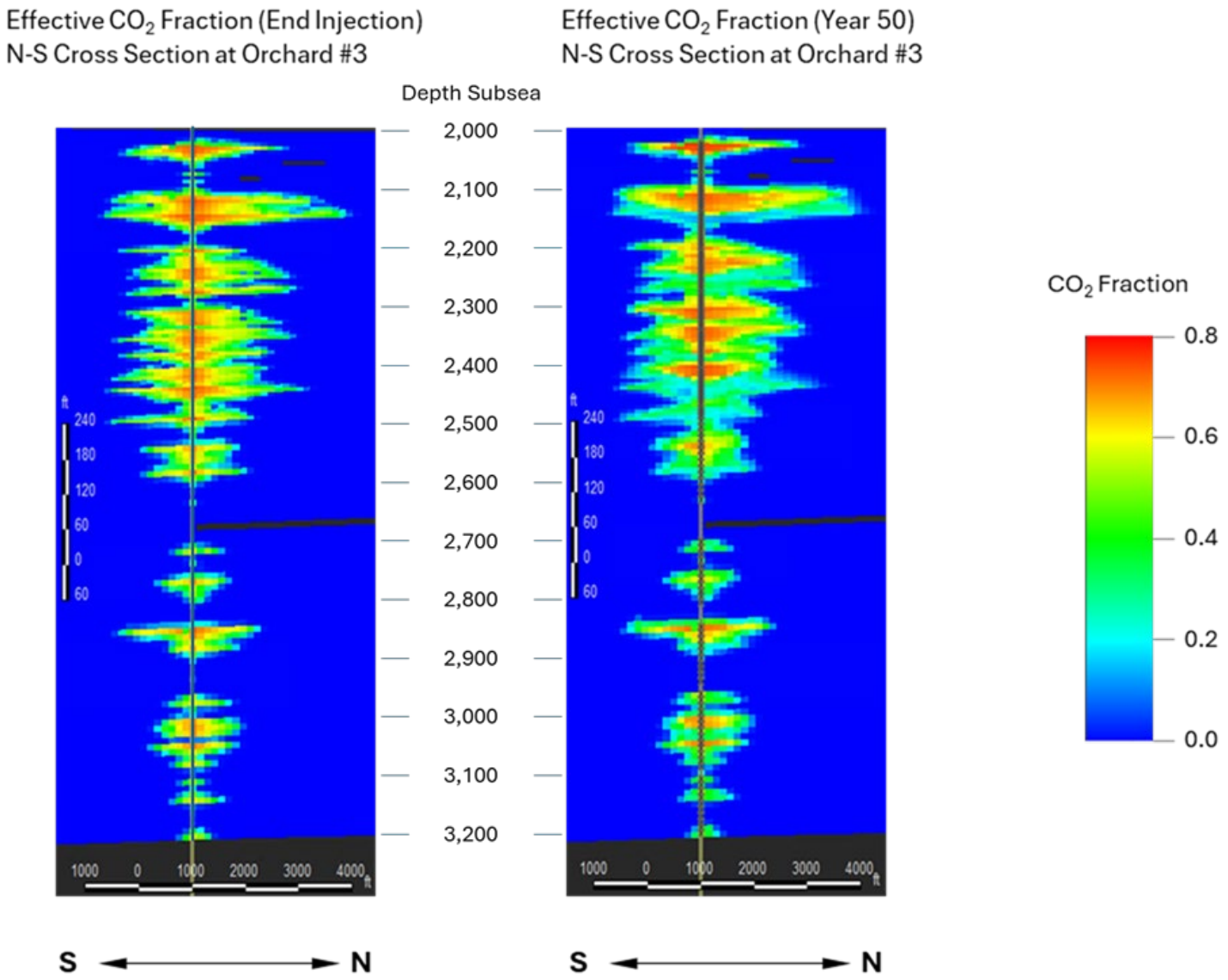


Figure 7-14 – Orchard No. 3 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

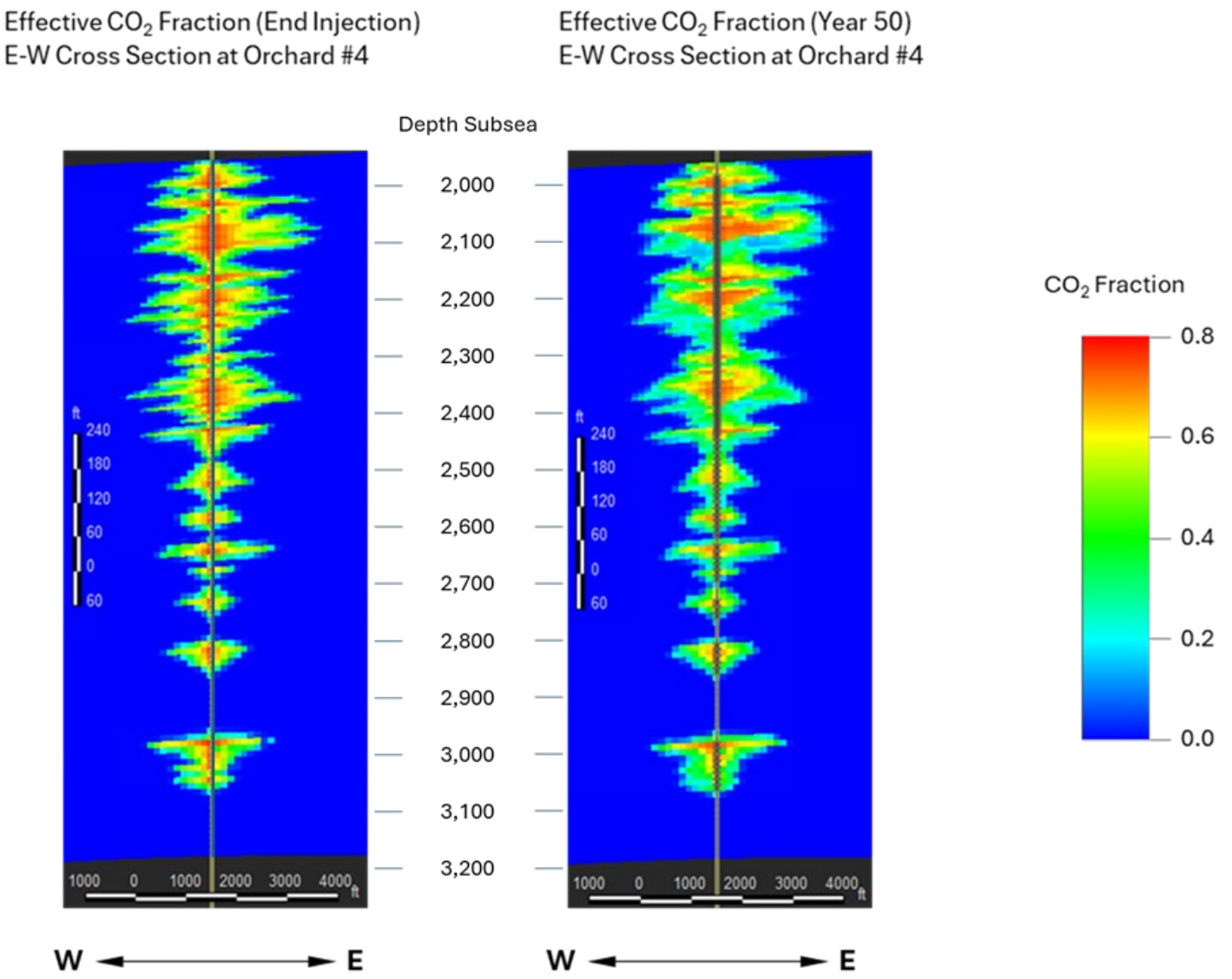


Figure 7-15 – Orchard No. 4 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

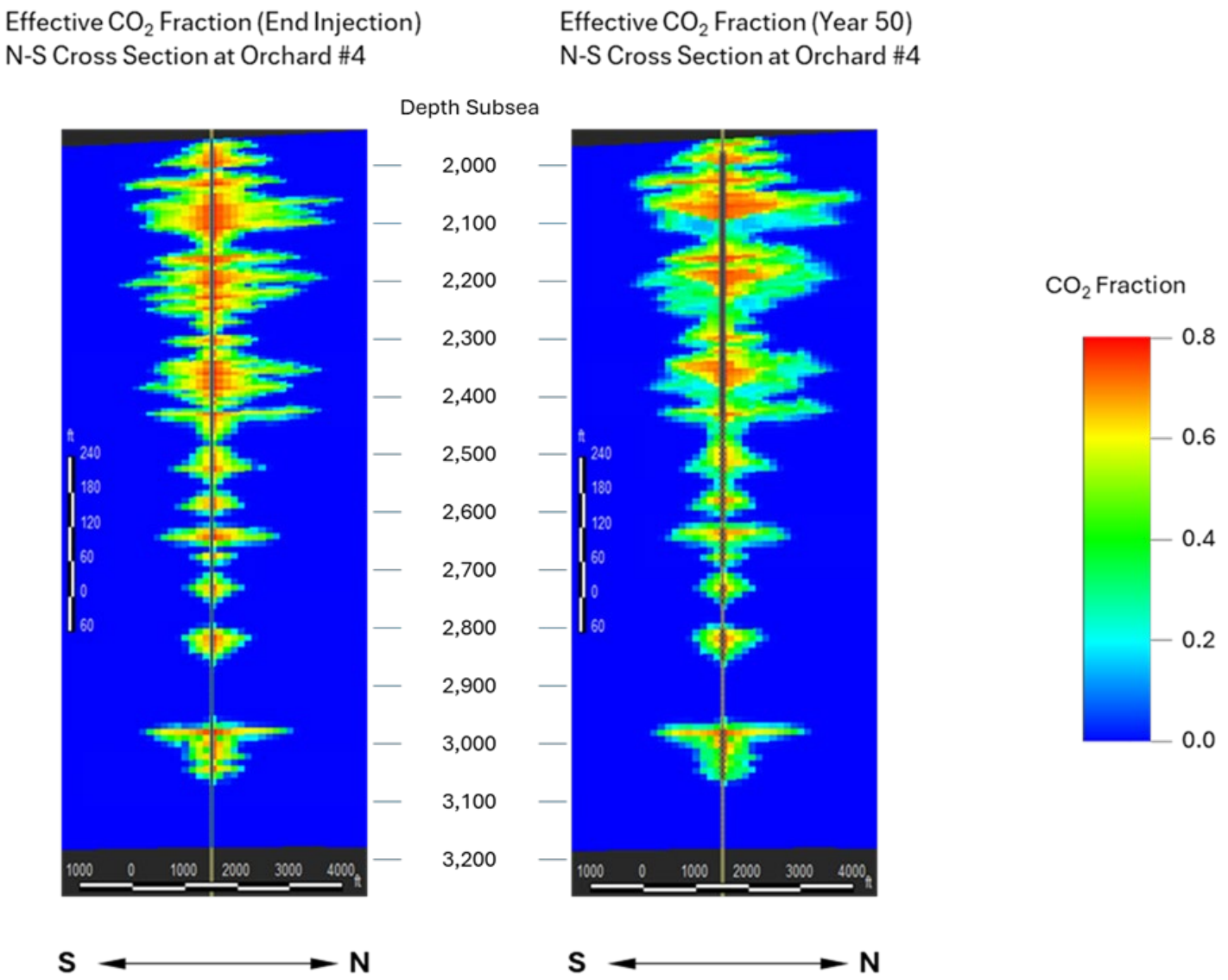


Figure 7-16 – Orchard No. 4 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

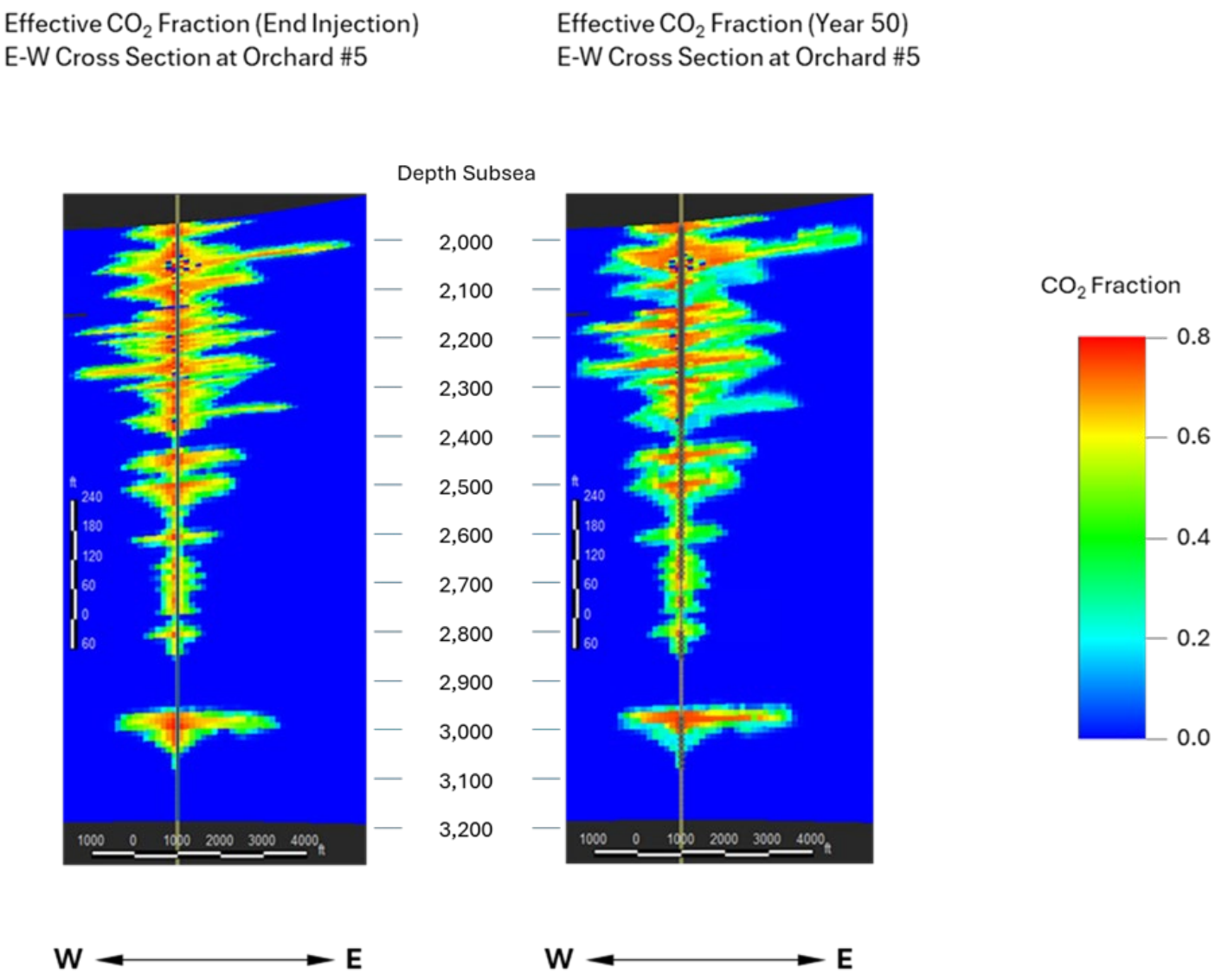


Figure 7-17 – Orchard No. 5 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

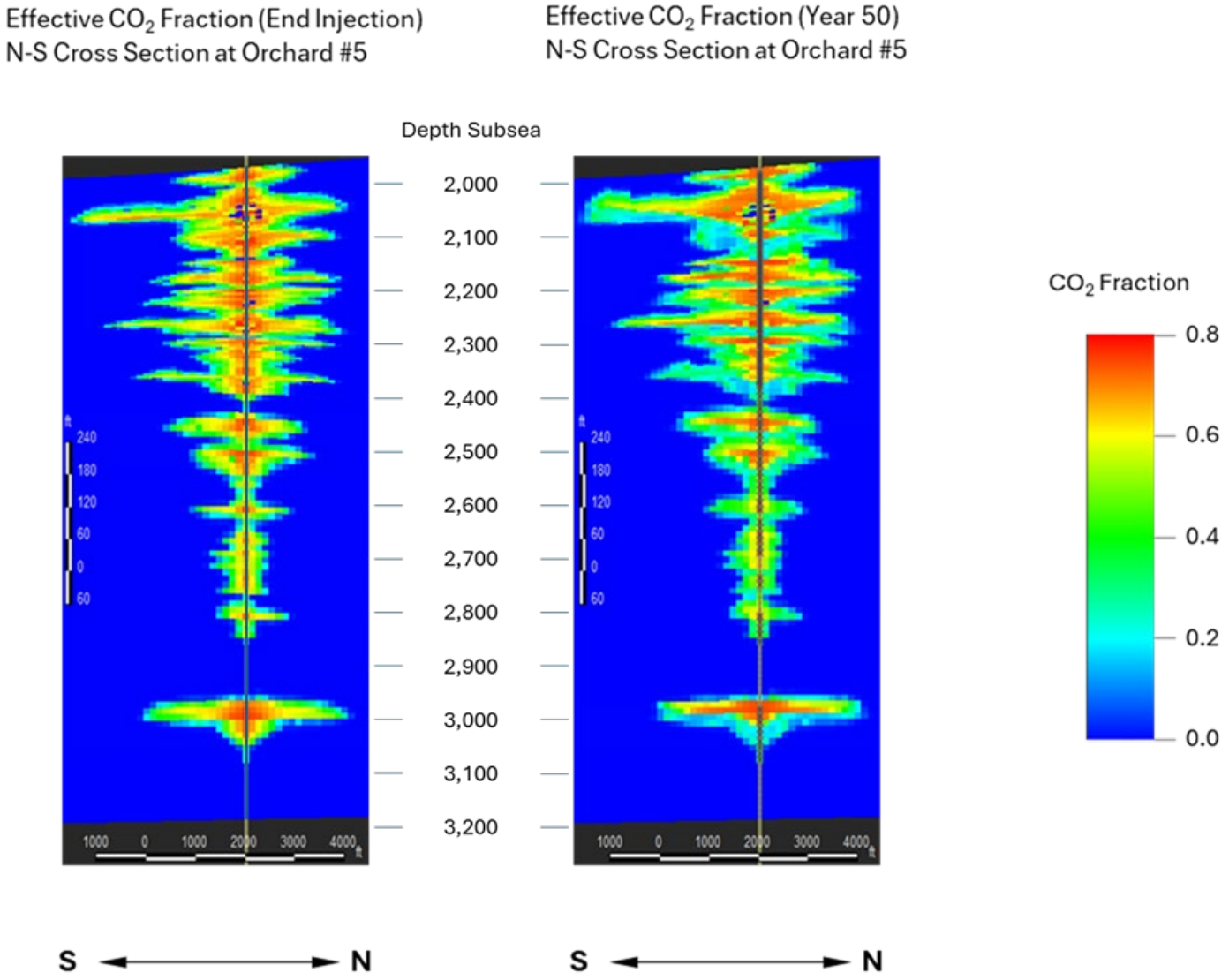


Figure 7-18 – Orchard No. 5 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

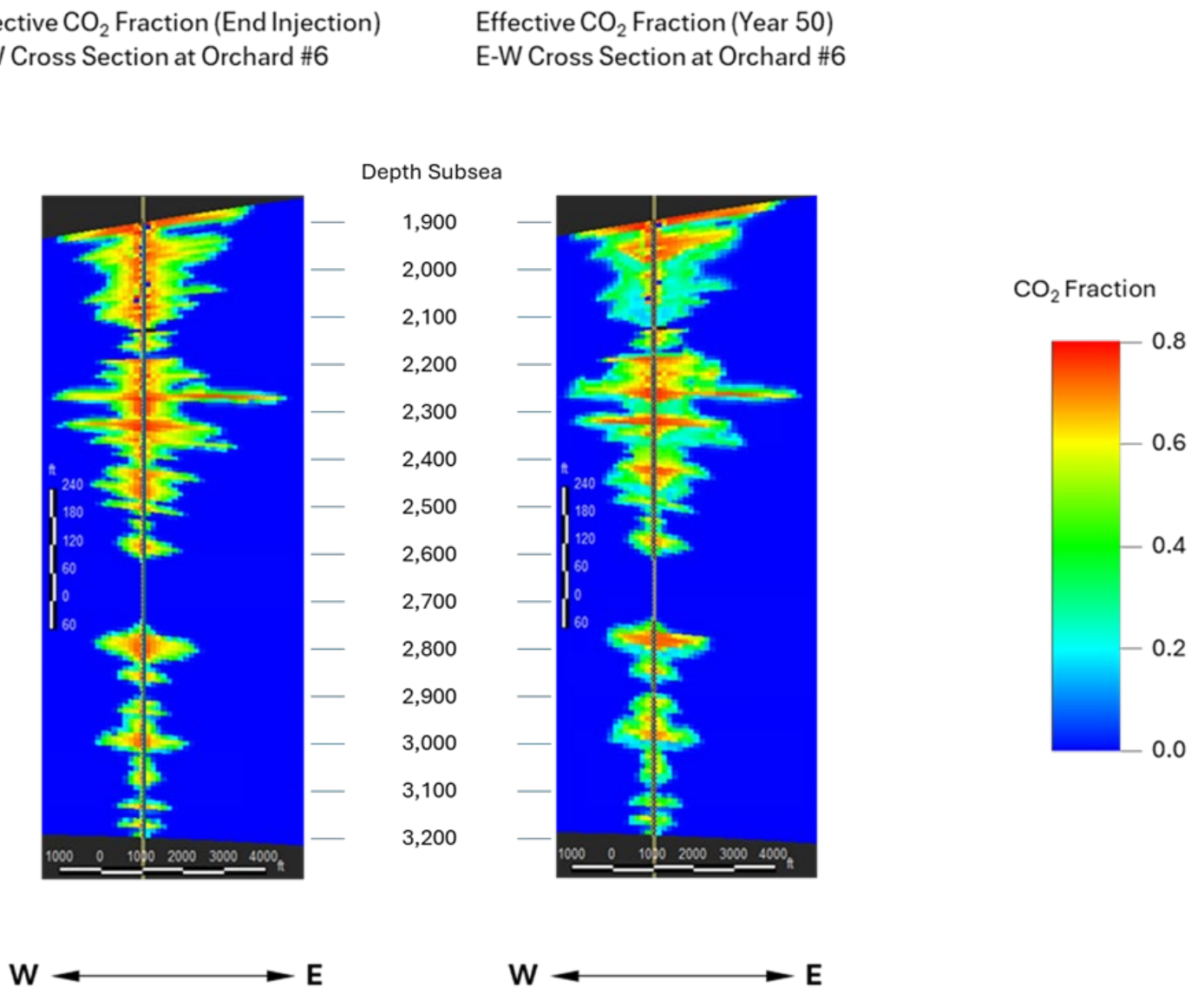


Figure 7-19 – Orchard No. 6 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

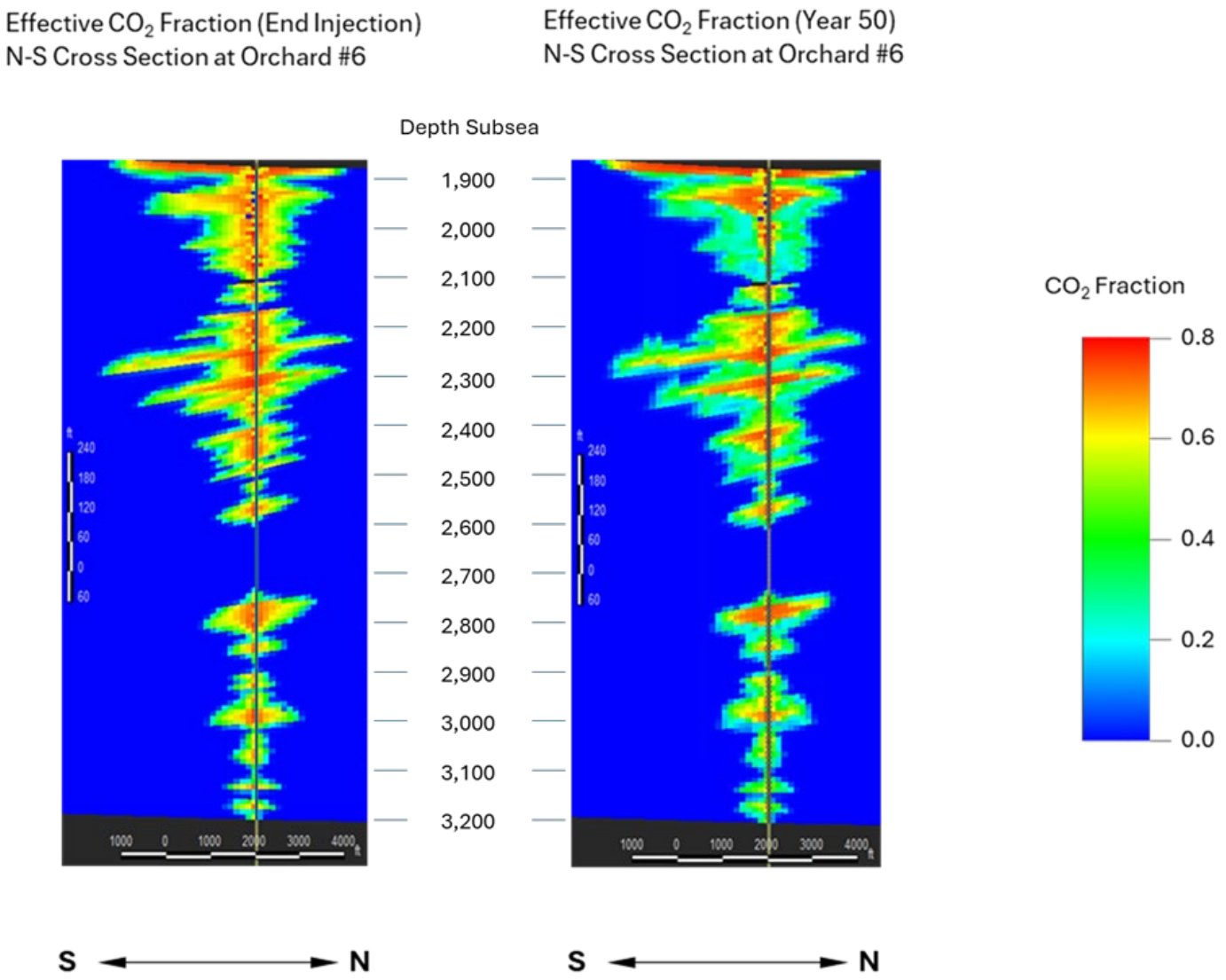


Figure 7-20 – Orchard No. 6 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

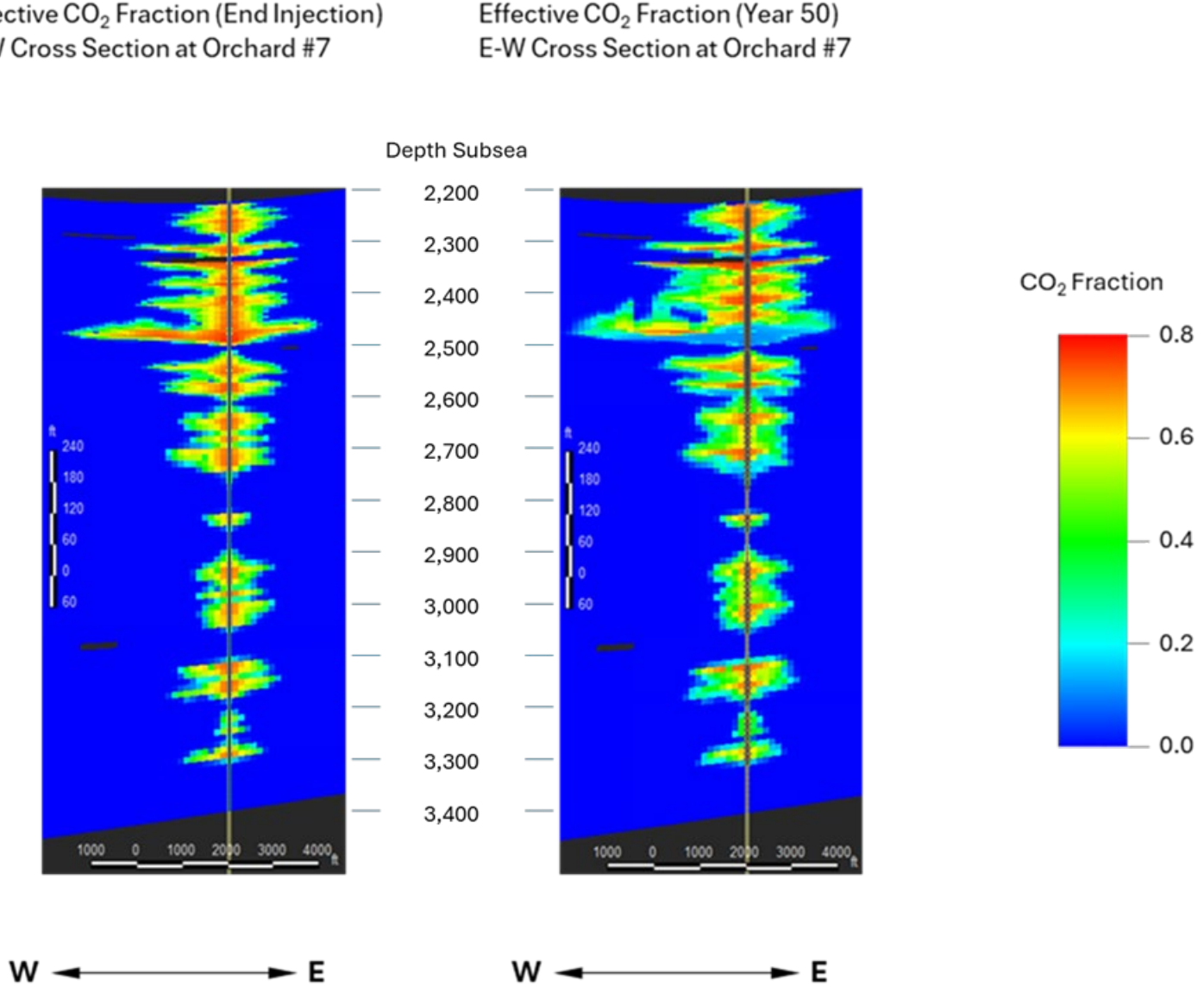


Figure 7-21 – Orchard No. 7 East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

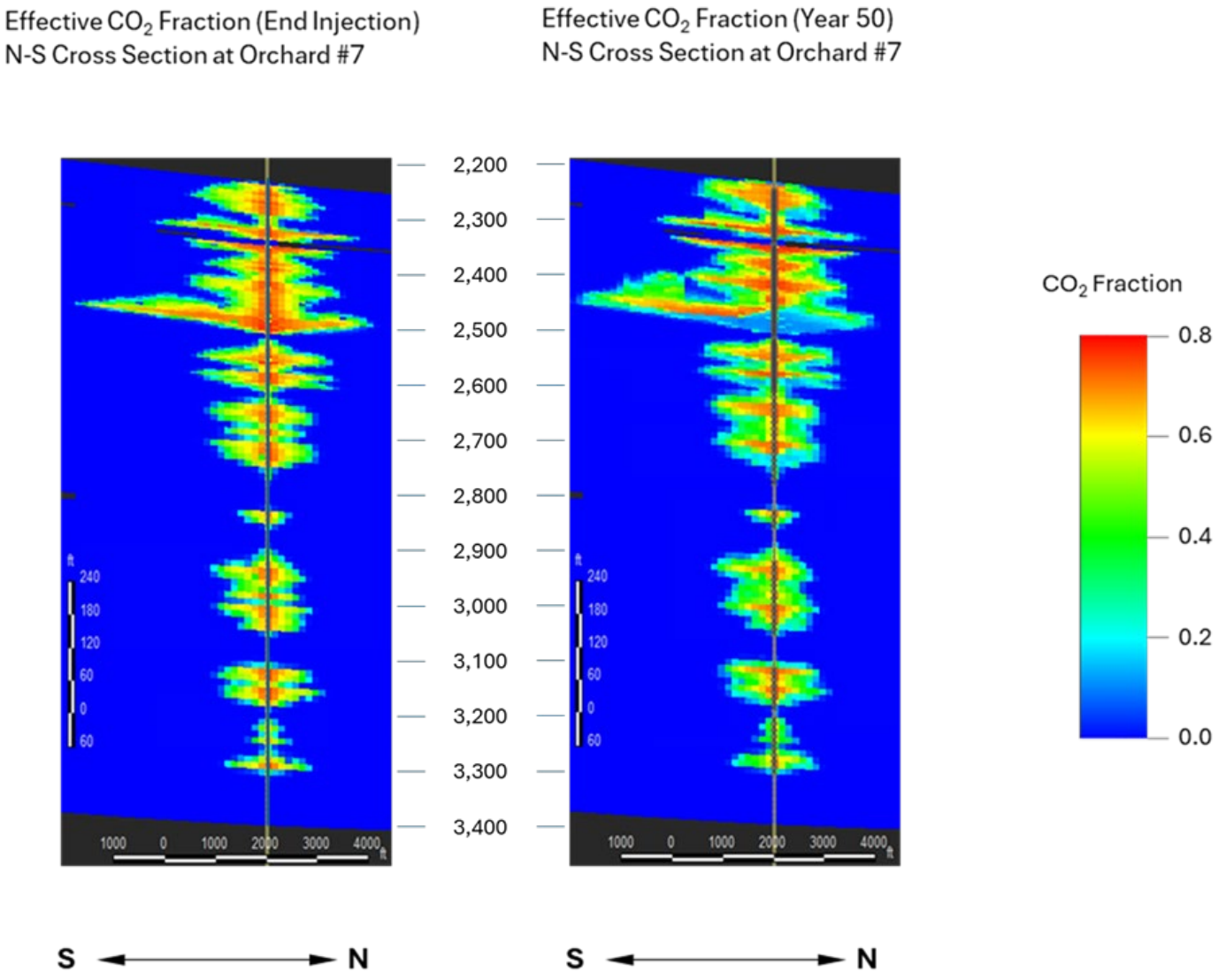


Figure 7-22 – Orchard No. 7 North-South Cross-Sectional Views of CO_2 Saturation, Years 0 and 50

7.4. Post-Injection Monitoring Plan

As required by 16 TAC **§5.206(k)(2)** [40 CFR **§146.93(b)**], Orchard Storage will continue to monitor the site until the project no longer poses an endangerment to USDWs via the fiber optic cable with sDAS/DTS installed and cemented in the annulus behind the long-string casing of each injector, the five groundwater monitoring wells, and the three above-zone monitoring wells across the Orchard Project area. These wells will be placed across the anticipated pressure front to measure any change from baseline parameters that would indicate the migration of CO_2 into the USDW (Figure 7-23).

Details about the monitoring plan for the injector wells can be found in Section 5.5.7, while details about the monitoring plan for the five groundwater monitoring wells can be found in Section 5.5.4, and details about the monitoring plan for the three monitoring wells can be found in Section 5.5.5.

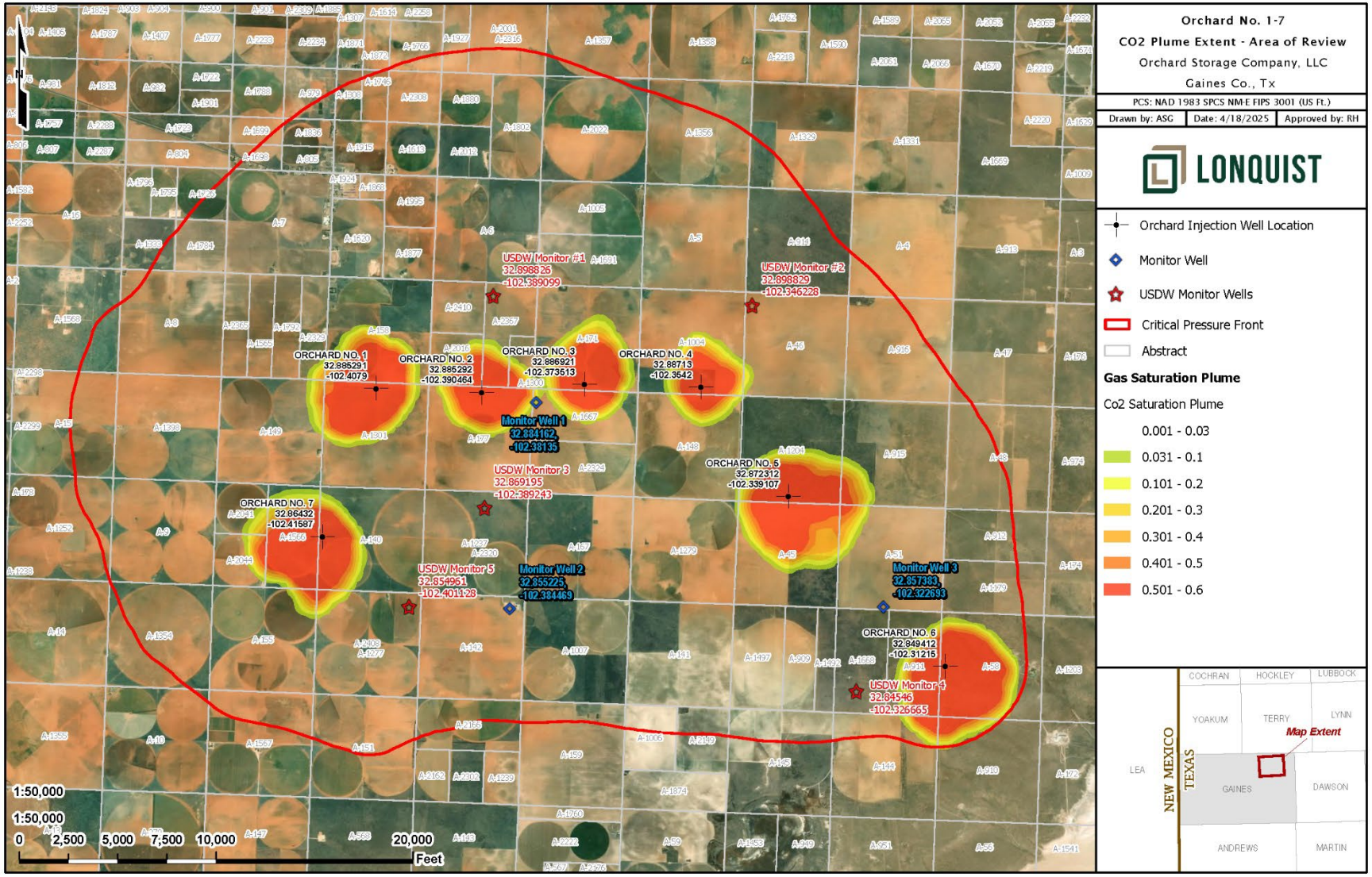


Figure 7-23 – Location of Groundwater, In-Zone and Above-Zone Monitoring Wells

7.4.1. Post-Injection Monitoring Activities

Post-injection monitoring will be utilized to track the movement of the plume and pressure front per 16 TAC **§5.206 (k)(2)** [40 CFR **§146.93(b)**]. The Testing and Monitoring Plan will be extended and used to confirm not only that the injection project is continuing to conform to the permit conditions, but also that any unexpected USDW endangerment is identified and mitigated. Testing and monitoring activities, as described in *Section 5 – Testing and Monitoring Plan*, will be performed and reported to the UIC director at the frequency shown in Table 7-3.

Table 7-3 – Post-Injection Monitoring and Reporting Frequency

Testing/Monitoring Activity	Frequency	Reporting Schedule
Groundwater Monitoring Well Geochemical Analysis	Every 5 years	Within 30 days after data collection and analysis
Soil Gas Monitoring	Annually	Within 30 days after data collection and analysis
Seismic Monitoring	Continuously	Annually
Pressure and Temperature Monitoring (Injection and Monitor Wells)	Continuously	Annually
Indirect Plume and Pressure Front Monitoring (Vertical Seismic Profile (VSP))	Every 5 years	Within 30 days after data collection and analysis
Direct Plume Calculations Based on Pressure and Temperature Data	Annually	Annually

All testing and monitoring activities listed will be performed and analyzed as discussed in *Section 5*, including quality assurance/quality control measures.

7.4.2. Demonstration of Non-Endangerment of USDW

Before the approval of the site closure authorization, Orchard Storage will provide documentation that the USDW is not at risk of endangerment from the CO_2 plume, future plume migration, or any induced pressure within the pressure front capable of lifting fluids to the USDW as required by 16 TAC **§5.206(k)(3)** [40 CFR **§146.93(c)**]. The monitoring strategy for doing so is outlined in Section 5.5.7. Orchard Storage will submit a report to the UIC Director demonstrating the non-endangerment of the USDW, including site-specific conditions, updated plume model, predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model.

7.5. Site Closure Plan

Orchard Storage will perform site closure activities to meet the requirements of 16 TAC **§5.203(m)(3)** [40 CFR **§146.93(e)**]. These activities include removing surface equipment, plugging all wells, site restoration, and submission of final site-closure reports.

7.5.1. Pre-closure

Notice of intent to close the site will be submitted to the UIC Director at least 120 days before closing operations, per 16 TAC **§5.206(k)(4)** [40 CFR **§146.93(d)**]. Orchard will 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. Relevant notifications and applications, such as plugging requests, must be submitted to and approved by the Texas Railroad Commission (TRRC)/EPA before commencing such activities. No facility closure activities will be executed until the UIC Director has authorized closure.

7.5.2. Plugging Activities

The Orchard No. 1 through No. 7 injection wells and related monitoring wells will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*. The plugging and abandonment procedures are designed to prevent the migration of CO_2 or formation fluids from the injection interval to the USDW. Before the wells are plugged, their mechanical integrity will be determined by an annulus pressure test, casing inspection log, and temperature log as described in *Section 5 – Testing and Monitoring Plan*. Plugging schematics and procedures are provided in *Appendix G.*

7.5.3. Site Restoration

Once the injection and monitoring wells are plugged and capped below grade, all surface equipment will be decommissioned and removed from the site. The sites will be restored as agreed with the surface owners.

7.5.4. Documentation of Site Closure

Within 90 days of site closure, a final report must be submitted to the UIC Director, per 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 which shall indicate the location of the injection wells relative to permanently surveyed benchmarks
- Documentation of well-plugging report
- Documentation of notification and information to appropriate authorities that have authority over drilling activities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone
- 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 with

- a complete legal description of the affected party;
- the fact that the land was used to sequester CO_2;
- confirmation that the survey plat has been filed with the TRRC/Environmental Protection Agency (EPA);
- the address of the office of the EPA, to which the operator sent a copy of the survey plat; and
- the total volume of fluid injected, the injection zones into which it was injected, and the period over which the injection occurred.

Orchard Storage will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, Orchard Storage will deliver all records to the UIC Director, which will thereafter be retained at a location designated by the director for that purpose.

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 8 – Emergency Response and Remediation Plan

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

TABLE OF CONTENTS

8.1 Emergency and Remedial Response Plan Overview 2
8.2 Resources/Infrastructure in the AOR 2
8.3 Degree of Risk for Emergency Events 4
8.4 Emergency and Remedial Response Cost Estimates 4
8.5 Infrastructure/Resource-Specific Events and Response Plans 6
8.5.1 Water Quality Contamination 7
8.5.2 CO_2 Release to the Surface 7
8.5.3 Storage Rights Infringement 9
8.5.4 Mineral Rights Infringement 9
8.5.5 Entrained Contaminant (Non-CO_2) in Injection Stream 10
8.5.6 Well Blowout 11
8.5.7 Surface Spill 12
8.5.8 Loss of Mechanical Integrity 12
8.5.9 Induced Seismicity 13
8.5.10 Accidents/Unplanned Events 15
8.6 Training 16
8.7 Communications Plan and Emergency Notification Procedures 16
8.7.1 Communications Strategy 18
8.8 Emergency and Remedial Response Plan Review and Updates 19
8.9 References 19

Figure

Figure 8-1 – Map of the Orchard Project AOR Showing Resources and Infrastructure 3
Figure 8-2 – Incident Command Structure 17

Tables

Table 8-1 – Local Public Safety and Medical Resources 2
Table 8-2 – Risk Activity Table 4
Table 8-3 – Monte Carlo Analysis Summary 5
Table 8-4 – Emergency Severity Matrix 6
Table 8-5 – Earthquake Response Plan Trigger Levels and Thresholds 14
Table 8-6 – Earthquake Emergency Conditions Response Actions 14
Table 8-7 – Emergency Services – **CALL 911** 17
Table 8-8 – Internal Emergency Contacts 18

8.1 Emergency and Remedial Response Plan Overview

This Emergency and Remedial Response Plan for the proposed Orchard No. 1 through No. 7 Class VI injection wells (Orchard Project) was prepared to meet the requirements of 16 Texas Administrative Code (TAC) **§5.206(h)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.94**]. This section is organized into six distinct parts. The parts address the issues of (1) potentially affected infrastructure and parties, (2) definitions of degrees of severity, (3) specific events and their response plans, (4) training, (5) communications plans and notification procedures, and (6) review and updates to this plan. These sections aim to ensure an expeditious, appropriate response to protect any Underground Sources of Drinking Water (USDWs) and maximize the protection of the environment, surrounding community, and company property. This plan will remain in place during the construction, operation, closure, and post-closure periods of the Orchard Project.

8.2 Resources/Infrastructure in the AOR

The Orchard Project is located in Gaines County, Texas, 1.75 miles south-southeast from Loop, Texas (population 291) and approximately 10 miles southeast of Seagraves, Texas (population 2,873). The project area is primarily agricultural and therefore has minimal potential impacts to local infrastructure. One residence was identified within the area of review (AOR), as delineated in *Section 3 – Area of Review and Corrective Action Plan*, shown in Figure 8-1. Local public safety and medical resources (Table 8-1) may be activated to supplement any Orchard Storage Company LLC (Orchard Storage) response to an emergency or adverse event, if required to minimize the event's impact.

Table 8-1 – Local Public Safety and Medical Resources

Name	Location	Distance	Response Time*
Gaines County Sheriff	Seagraves	10 miles	20 minutes
Seagraves Police	Seagraves	10 miles	20 minutes
Brownfield Fire Department	Brownfield	23 miles	25 minutes
Seagraves Volunteer Fire Department	Seagraves	10 miles	25 minutes
Memorial Hospital	Seminole	26 Miles	26 minutes
Yoakum County Hospital	Denver City	26 miles	28 minutes

*This table is arranged in ascending order of response times.

Figure 8-1 shows the location of the Orchard Project AOR, with infrastructure identified. A large-scale version of this map is provided in *Appendix F*.

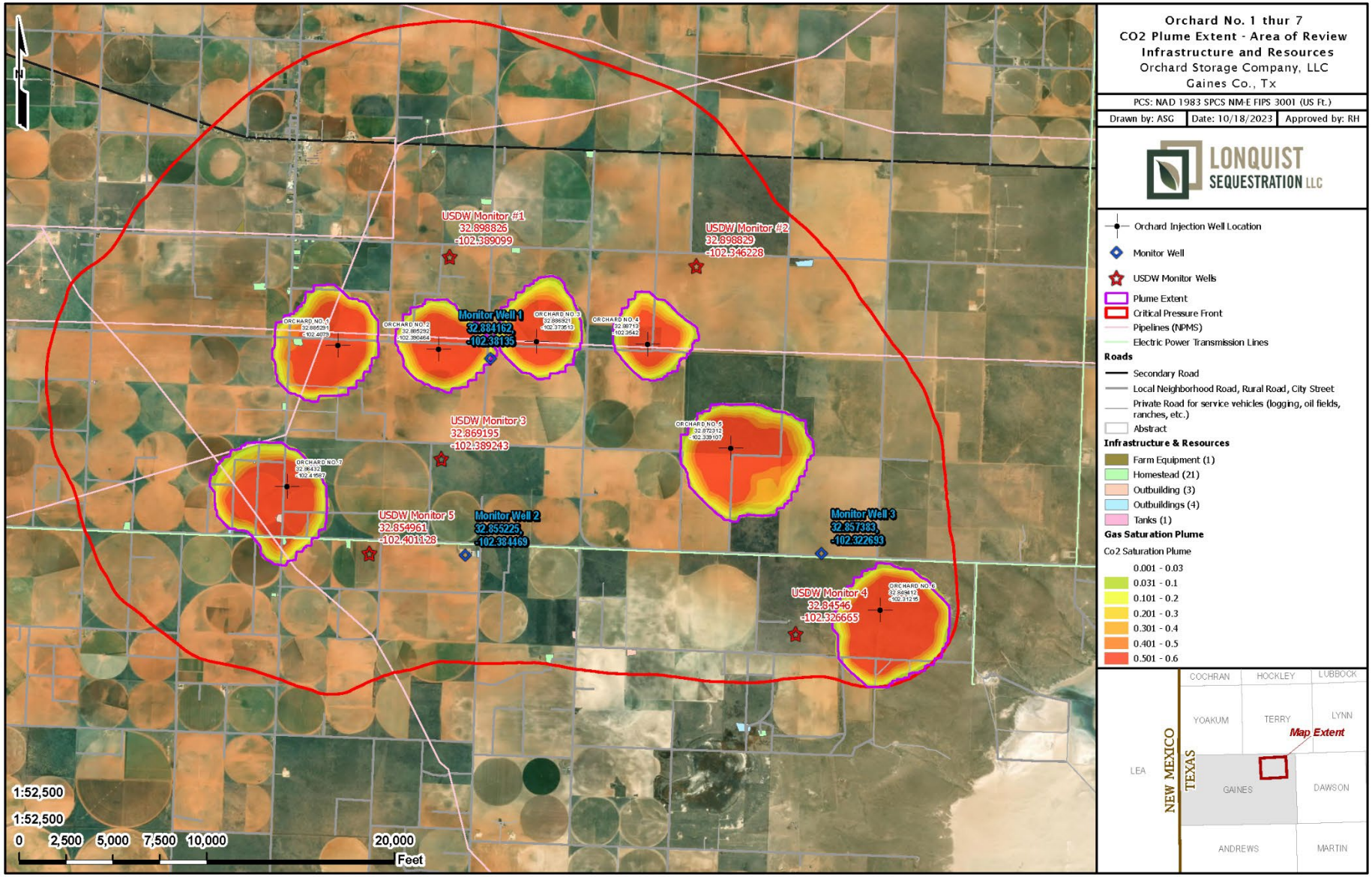


Figure 8-1 – Map of the Orchard Project AOR Showing Resources and Infrastructure

8.3 Degree of Risk for Emergency Events

Response actions will depend on the degree of severity of the event triggering an emergency response. Incident response will be managed via the Incident Command System (ICS) to organize, scale, and coordinate the response with third parties and communicate via a common emergency response language. Response teams will be assembled, organized, and scaled as necessary, depending on the severity of the event. At a minimum, response teams will be comprised of Orchard Project operations specialists and the Orchard Storage team. The teams will be expanded as needed to include specialty environmental-response resources, specialty well-intervention specialists, local first responders, and Gaines County officials. All responses will be coordinated and communicated as necessary with the relevant regulatory bodies.

A matrix of USDW-specific risks was developed to aid in identifying risk events and their relative probability of occurrence—summarized in Table 8-2. The methodology for determining the annual probability values and related financial assurance values is described in more detail in *Section 8.4.*

Table 8-2 – Risk Activity Table

Risk Event Type	Annual Probability	Number of Wells
Deep Oil-and-Gas Well Leak	Claimed as PBI	
CO_2 Injection Well Leak		
Deep CO_2 Monitoring Well Leak		
Rapid Leakage Through Caprock		
Slow Leakage Through Caprock		
Release Through Existing Faults		
Release Through Induced Faults		
Leakage Through Caprock/Faults then Shallow Well		
Pipeline Release		

*This includes additional undocumented wells for conservatism in the analysis.

8.4 Emergency and Remedial Response Cost Estimates

This section summarizes the estimates of emergency and remedial response (ERR) costs for the Orchard Project. Such costs and the related methodology are at a *project* level, incorporating all of the project injection wells, the associated pore space occupancy plumes, and the critical pressure plume. These estimates are consistent with the Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Program's Class VI regulatory requirements and are intended to inform the face value of the financial assurance necessary to satisfy ERR actions for the project.

Estimating possible ERR cost estimates for carbon capture and storage (CCS) necessitates understanding the interactions between the CCS stream, the geophysical environment in which it

will be stored, and nearby populations. The long-term nature of the Orchard Project, the low probability of a release event, the variability in potential incident-conditions at the site, the size of the potentially impacted population, and the likely exposure pathways inform these estimates.

Monte Carlo analysis, risk-based, probabilistic modeling has been tailored to Orchard Project-specific risks and uncertainties, to (1) generate reasonable, upper-bound estimates of the ERR costs—and (2) provide a sensible, conservative, and objective basis for determining the face amount of the financial assurance instrument(s) necessary to support the Class VI permit.

The cost-estimation method applied to the Orchard Project is based on a peer-reviewed (Trabucchi et al., 2014) probabilistic approach—a model reflective of site-specific factors associated with the project. Specifically, the model's input parameters include the geologic location and specific chemical composition of the CO_2 stream, as well as site-specific conditions that exist within the established AOR. The analysis adopts several conservative input assumptions and incorporates probabilistic calculations that allow for multiple release incidents through operation and post-injection site care. The annual probability values that were shown in Table 8-2 are derived from the FutureGen Project Environmental Impact Statement and associated database (DOE Office of NEPA Policy and Compliance, 2007). Furthermore, the cost estimates are based upon response actions that are generally accepted and commonly used to respond to contamination incidents that could impair the public's ability to safely access USDWs.

Based on a model run of 50,000 Monte Carlo trials and the addition of a $250,000 project-specific adjustment—to account for the presence of a small population center within the otherwise highly rural AOR—the upper-bound cost estimate to satisfy ERR is estimated to be Claimed as PBI *in 2025 dollars*. This estimate specifically accounts for an array of possible risk events of potential concern, as was identified in Table 8-2. Table 8-3 summarizes the statistical results of the Monte Carlo simulations. Claimed as PBI [redacted]

Table 8-3 – Monte Carlo Analysis Summary

Summary Statistic	Cost (2025$)	Number of Events Occurring
Average	Claimed as PBI [redacted]	
Median		
Standard Deviation		
5th Percentile		
95th Percentile		
99th Percentile		
Minimum		
Maximum		

8.5 Infrastructure/Resource-Specific Events and Response Plans

This section outlines general response procedures to be followed during possible emergency events. The events included in this section may not necessarily present potential impacts to the USDW but are events that require adequate response to assure safe and responsible operations. The responses are not intended to be exhaustive and will vary depending on the incident's specific requirements. Each situation will be evaluated based on the specific event, using best operating and engineering practices to prioritize life, safety, incident stabilization, containment, and repair or remediation. When an event has been detected, the response actions will address emergency and remedial measures related to the movement of the injectate or formation fluids that may cause an endangerment to the USDW and other events that threaten health, safety, or the environment. Table 8- describes a three-tier matrix that will be used to assist the Orchard Response team to characterize the severity of an emergency event.

Table 8-4 – Emergency Severity Matrix

Emergency Condition	Definition
General Emergency – High Risk	Specific events have occurred or have imminent risk to human health, resources, infrastructure with potential for loss of containment integrity. Emergency actions are required, including alerts to local authorities. Incident Command is initiated.
Site Area Emergency – Medium Risk	An event has the potential to escalate to a major emergency if no action is taken to remediate the event. Can be an actual or likely major failure of a system needed to protect human health, resources or infrastructure. Potential serious near-term risk. Incident Command may be initiated.
Minor Emergency – Low Risk	Event does not have an immediate risk to human health, resources or infrastructure. Event should be investigated and remediated to prevent further escalation.

These emergency condition rankings are intended to be applied to any event that is an excursion from normal operating conditions. Example incidents and potential responses are provided in Sections 8.5.1 through 8.5.10.

If, at any time during Orchard Project operations, an employee or facility operator encounters a situation where the injected CO_2 stream may endanger the USDW, the following actions will be carried out:

1. Alert the Orchard Storage Superintendent.
2. Immediately cease injection.
3. Take all steps reasonably necessary to identify and characterize any release.

4. Notify the UIC Director within 24 hours.
5. Implement the Emergency and Remedial Response Plan approved by the UIC Director.

8.5.1 Water Quality Contamination

Water quality within the USDW could be adversely impacted by an event that results in brine, CO_2, or other contaminants leaking into the USDW.

Risk Level: Low

Prevention

As described in *Section 3 – Area of Review and Corrective Action Plan* and *Section 4 – Engineering Design and Operating Strategy*, Orchard Storage will apply best engineering and operating practices to prevent USDW contamination.

Detection

This may be detected through elevated concentrations of indicator parameters (e.g., chloride content, TDS, pH, elevated pressure) in groundwater samples or other evidence of fluid or CO_2 leakage into the USDW. In addition, the CO_2 plume will be monitored as outlined in *Section 5 – Testing and Monitoring Plan.*

Potential Response Actions

- Immediately notify the Orchard Storage Superintendent.
- Stop the injection.
- The Orchard Storage Superintendent will notify the UIC Director within 24 hours (16 TAC **§5.207(a)(2)(A)** [40 CFR **146.91(c)**].
- The Superintendent and team will make an initial assessment of the incident. A preliminary plan will be developed to stabilize, contain, and repair/remediate.
- Use a vertical seismic profile (VSP)—*if warranted*—to assess the location and degree of CO_2 movement, as described in *Section 5*.
- Restart the injection, if possible, at a reduced rate.
- Continue monitoring the USDW and plume to determine if migration continues.
- Treat the groundwater—*if the groundwater/USDW is impacted*—to remove CO_2, and provide an alternative water supply if necessary.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when the injection can be expected to resume.

8.5.2 CO_2 Release to the Surface

A CO_2 release at the surface can create a potential risk to health, safety, and the environment. This can be from major mechanical and integrity failures of the distribution and storage facilities,

unidentified orphan wells, well-integrity issues, operating equipment over designed pressures, and geological complications.

Risk Level: Low

Prevention

- Proper operation and preventive maintenance of all surface facility equipment will be carried out.
- Due diligence will be exercised when collecting information from offset wells in the AOR.
- Continuous injection pressure, temperature and rate monitoring, annulus pressure tests, etc., will all be performed according to *Section 5*.
- Tubing and annular pressures will be monitored continuously and maintained below the maximum allowed values.
- The surface tree will be regularly maintained and tested for integrity.

Detection

The Supervisory Control and Data Acquisition (SCADA) system will detect any critical parameter excursion—and alarm and/or shut in as necessary.

Potential Response Actions

- Alert the Orchard Storage Superintendent.
- The Superintendent will notify the UIC Director within 24 hours (16 TAC **§5.207(a)(2)(A)** [40 CFR **146.91(c)**].
- The Superintendent and team will assess relevant facts to determine the severity of the event.
- For a Major or Serious Emergency (e.g., single large-volume CO_2 release):
    - Shut in the well or injection component as required.
    - Bleed injectant from the flowline and facilities, if applicable.
    - Limit access to the immediate area (i.e., authorized personnel only).
    - Communicate with the local emergency response, if applicable.
    - Monitor the well parameters to diagnose integrity loss and develop a remedial action plan.
    - Mobilize the necessary equipment—*if applicable*—to de-complete the well, to further diagnose and develop a remedial action plan.
    - Develop a remediation plan and communicate the same to the UIC Director and the Texas Railroad Commission (TRRC).
- For a Minor Emergency (e.g., low-level CO_2 release):
    - Shut in the well, if necessary.
    - Bleed injectant from the flowline and facilities, if applicable.
    - Monitor the well parameters to diagnose integrity loss and develop a remedial action plan.

- Develop a remediation plan and communicate the same to the UIC Director and the TRRC.

8.5.3 Storage Rights Infringement

Storage rights infringement could occur if the CO_2 plume extends beyond the acquired pore-space lease area. Orchard Storage is acquiring pore space rights related to modeled plumes plus a substantial buffer to accommodate plume volumes.

Risk Level: Low

Prevention

- Active monitoring of injection parameters
- Periodic plume modeling and use of VSP imaging to monitor plume movement

Detection

- Downhole monitoring of injection pressures, temperatures, and conformance will inform flow-model adjustments that might result in plume movement that modeling has not predicted.
- VSP profiling to map plume movement would indicate that the plume has moved to an area where pore space rights are *not* in place.
- Pressure-transient analysis and interference testing between wells may provide insight into the plume location.

Potential Response Actions

- Verify the plume movement.
- Alert the Orchard Storage Superintendent.
- The Superintendent will notify the UIC Director within 24 hours (16 TAC **§5.207(a)(2)(A)** [40 CFR **146.91(c)**].
- The Superintendent and team will assess relevant facts to determine the severity of the event.
- Stop or reduce the injection, to minimize impact.
- Acquire more pore space to accommodate the plume.

8.5.4 Mineral Rights Infringement

Mineral rights infringement could occur if the plume extends into adjacent oil-and-gas mineral leases. The failure may be due to a confining-zone breach, natural seismic events, or plume growth beyond modeled limits. The unexpected plume migration can have several effects, such as increasing pressure in hydrocarbon bearing zones and/or economically impacting nearby producing minerals.

Risk Level: Medium

Prevention

- Active monitoring of injection parameters
- Periodic plume modeling and use of VSP imaging to monitor plume movement

Detection

- VSP profiling to map plume movement would indicate that the plume has moved to an area where pore space rights are not in place.
- Adjacent hydrocarbon leases could report an unexpected increase in well pressure and production.
- Downhole monitoring of injection pressures, temperatures, and conformance will inform flow-model adjustments that might result in plume movement that modeling has not predicted.
- Pressure-transient analysis and interference testing between wells may provide insight into the plume location.

Potential Response Actions

- Alert the Orchard Storage Superintendent.
- The Superintendent will notify the UIC Director within 24 hours (16 TAC **§5.207(a)(2)(A)** [40 CFR **146.91(c)**].
- The Superintendent and team will assess relevant facts to determine the severity of the event.
- Stop or reduce the injection to minimize impact.
- Verify plume movement and location.
- Develop a mitigation or acquisition plan.

8.5.5 Entrained Contaminant (Non-CO_2) in Injection Stream

During injection operations, a change in composition or properties of the injected CO_2 stream could impact the metallurgy of the CO_2 injection system (flowlines, wellhead/tree, downhole tubulars). In addition, certain contaminants may initiate microbial activity downhole that would in turn create additional corrosion issues. This event is unlikely to occur as the CO_2 supply is via a commercial common-carrier CO_2 line that has a tightly controlled CO_2 specification.

Risk Level: Low

Prevention

Active, continuous monitoring of the incoming CO_2 stream will alert operators to any contamination of the CO_2 stream. The stream composition monitoring plus the active monitoring of asset integrity

via corrosion coupons, as described in *Section 5 – Testing and Monitoring Plan*, will provide early leading indications of potential problems.

Detection

Constituent property deviations from the incoming CO_2 specification will be alarmed via the SCADA system. The Orchard Storage operations team can therefore assess the severity in near-real time and react accordingly.

Potential Response Actions

- Alert the Orchard Storage Superintendent.
- The Superintendent and team will assess relevant facts to determine the severity of the event.
- The Superintendent will notify the UIC Director within 24 hours (16 TAC **§5.207(a)(2)(A)** [40 CFR **146.91(c)**].
- Develop a mitigation plan that may include the use of corrosion chemicals or biocides as necessary.

8.5.6 Well Blowout

A well-control event could occur during the drilling phase of either the injection well or the monitoring wells. During that period of the well construction, an unexpected influx of formation fluid could enter the wellbore and cause a sudden release of fluids.

Risk Level: Low

Prevention and Detection

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

Potential Response Actions

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

Response Personnel: On-site drilling personnel and supervisors

Equipment: Drilling rig, mud logging equipment, blowout preventers with annular rams, and drilling fluid materials to increase mud weight adequately. Blowout preventers will be tested regularly to ensure operability.

8.5.7 Surface Spill

During drilling and completion or workover operations, an accidental release of drilling fluids, hydrocarbons, chemicals, etc., could occur.

Risk Level: Medium

Prevention and Detection

- Properly maintain blowout preventers to prevent accidental release of drilling fluids or hydrocarbons.
- Ensure adequate spill-prevention equipment is available on the drilling or workover rig.

Potential Response Actions

- Contain the spill using available equipment such as absorbents, booms, etc.
- Notify the appropriate regulatory authority and supervisory personnel.
- Immediately take samples around the point of entry.
- Initiate the spill prevention, control, and countermeasures plan for the facility.

Response Personnel: Drilling/workover crews or operations personnel

Equipment: Absorbents, containment equipment

8.5.8 Loss of Mechanical Integrity

Well-barrier components failing, causing fluid migration along the wellbore, could be due to a cement failure behind the casing, an improperly seated packer, or a tubing leak.

Risk Level: Low

Prevention and Detection

The appropriate wellbore design will be implemented in the construction phase, including proper cement and metallurgy of the casing and tubing. Pressure and rate monitoring, annulus pressure tests, mechanical integrity tests, etc., will all be performed per the Testing and Monitoring Plan (*Section 5*).

Potential Response Actions

- Stop the injection and notify the UIC Director within 24 hours.

- Close the wellhead valve.
- Monitor the well and annulus pressures.
- Determine the cause and severity of the failure, to determine if any of the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer.
- Install a chemical sealant barrier and/or attempt a cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in *Section 5*.
- Notify the UIC Director when the injection can be expected to resume.

8.5.9 Induced Seismicity

While there is a low probability of faults or fracture zones within the vicinity of the Orchard Project area injection zone that would pose an induced seismicity risk caused by CO_2 injection, areas with active disposal wells may have an increased induced-seismicity risk by injecting into deeper intervals where seismic data has revealed faults. There are very few active disposal wells within the project site.

Risk Level: Low

Prevention and Detection

The Bureau of Economic Geology in Texas maintains a seismic monitoring system known as TexNet. The closest monitoring station to the Orchard Project is approximately 20 miles to the south. Orchard Storage will review the TexNet website regularly for any seismic activity in or around the facility area. If an event greater than 2.5 M is detected, Orchard Storage will compare it with the injection history and publicly available data from nearby oil and gas activity to determine if a correlation to injection activity can be determined.

Potential Response Actions

Orchard Storage will notify the TRRC within 24 hours of an earthquake with a hypocenter less than 9.08 km from any injection well in the Orchard Project area that triggers a response plan (Magnitude (M) > 2.5, as measured from the TexNet monitoring system), as outlined in Table 8-5. Orchard Storage would then enact the corresponding actions outlined in Table 8-6.

The 9.08 km radius is based on the TRRC standard radius for evaluating induced seismicity risks for wells with total depths less than 10,000 ft.

Table 8-5 – Earthquake Response Plan Trigger Levels and Thresholds

Trigger Level	Threshold	Emergency Condition Enacted
Level 0	Event less than 2.5 M detected within 9.08 km of an injection well	No Emergency – No Risk
Level 1	Event greater than or equal to 2.5 M but less than 3.5 M detected within 9.08 km of an injection well	Minor Emergency – Low Risk
Level 2	Event greater than or equal to 3.5 M but less than 5.0 M detected within 9.08 km of an injection well	Site Area Emergency – Medium Risk
Level 3	Event greater than or equal to 5.0 M detected within 9.08 km of an injection well	General Emergency – High Risk

Table 8-6 – Earthquake Emergency Conditions Response Actions

Trigger Level Emergency Condition Enacted	Response Action
Level 0 No Emergency – No Risk	N/A
Level 1 Minor Emergency – Low Risk	• Inspect the facility and any injection wells within the 9.08 km radius of earthquake hypocenter for damage. • Review the injection history and publicly available data from nearby oil and gas activity to determine if a correlation to injection activity can be determined. • Prepare and retain an assessment report of the incident and continue to monitor for continued seismic activity.
Level 2 Site Area Emergency – Medium Risk	• Level 1 Response Actions + • For wells located within the 9.08 km radius of earthquake hypocenter, initiate operational plans to reduce injection rate down to 80% of permitted rate, either by diversion to unaffected wells within the project area, if able, and/or by other means as necessary. • This curtailment shall remain in place for at least 7 days, unless otherwise negotiated with TRRC personnel, while continued seismic activity monitoring occurs.

Trigger Level Emergency Condition Enacted	Response Action
Level 3 General Emergency – High Risk	• Level 2 Response Actions + • Further curtailment of affected injection wells injection rate down to 40% of permitted rate either by diversion to unaffected wells within the project area, if able, and/or by other means as necessary. • This curtailment shall remain in place while continued seismic activity monitoring occurs until next steps are negotiated with TRRC personnel.

8.5.10 Accidents/Unplanned Events

Unforeseen events may occur during Orchard Project operations, such as surface infrastructure damage, pipeline leak, or weather-related events.

Risk Level: Low

Prevention

The site and equipment will be maintained regularly to prevent or minimize damage. The site will also be securely fenced to prevent unauthorized entry. Signage will be placed at the site entrance as required by the TRRC, with Orchard Storage and contact information. Operations will monitor the weather to be prepared for any adverse conditions that may occur. The SCADA and safety-shutdown systems will be maintained.

Detection

The SCADA system is designed to alert the operations team of any unexpected conditions within the injection operations. The safety shutdown system will be designed to shut down injection in the event of an emergency condition.

Potential Response Actions

- Alert the Orchard Storage Superintendent.
- The Superintendent will notify the UIC Director within 24 hours (16 TAC **§5.207(a)(2)(A)** [40 CFR **146.91(c)**].
- The Superintendent and team will assess relevant facts to determine the severity of the event.
- For a Major or Serious Emergency:
    - Shut in the well or injection component as required.
    - Bleed injectant from the flowline and facilities, if applicable.
    - Notify the appropriate regulatory authority and supervisory personnel.

- Limit access to the immediate area (i.e., authorized personnel only).
- Communicate with the local emergency response, if applicable.
- Monitor the well parameters to diagnose integrity loss and develop a remedial action plan.
- Mobilize the necessary equipment—*if applicable*—to de-complete the well, to further diagnose and develop a remedial action plan.
- Develop a remediation plan and communicate the same to the UIC Director and TRRC.

8.6 Training

Orchard Storage staff will attend, at a minimum, formal annual training associated with Health, Safety, and Environment (HSE). This training will include all the required Occupational Safety and Health Administration (OSHA) training (Hazardous Waste Operations and Emergency Response (HAZWOPER), etc). The staff will be trained in the ICS to ensure efficient response to incidents. In addition, the Orchard Storage staff will be provided technical training regarding the specific properties associated with CO_2 and standard operating procedures related to CO_2 storage.

Training will be reinforced by emergency drills that create scenarios to highlight specific incident responses. These drills will be as realistic as possible and may include local-county first responders. All training and emergency drills will be documented for verification.

Orchard Storage intends to implement an active outreach program with county first responders and the resident neighbors in the project storage area. Before starting CO_2 injection operations, Orchard Storage will provide a copy of this Emergency and Remedial Response Plan to local first responders and discuss potential response scenarios.

Per 16 TAC **§5.206 (h)(2)(C)**, Orchard Storage will provide training schedules, dates, and course outlines to the Commission annually and upon request.

8.7 Communications Plan and Emergency Notification Procedures

Orchard Storage intends to, as noted earlier, implement the ICS to respond to emergencies. The system, widely utilized by emergency response professionals, provides a common language and hierarchy to emergency response—a unified command—so that multiple agencies can effectively work together. The system can also be scaled to fit the incident.

A high-level structure for the ICS in Figure 8-2:



Figure 8-2 – Incident Command Structure

The chain-of-command members will be developed after the operating company has been formed and commercial agreements arranged. This section will then be updated to reflect the nomination of said members. As these positions are filled, relevant phone numbers, including one for the local Orchard Storage office, will be provided.

Emergency response contacts are provided in Tables 8-7 and 8-8. Emergency contacts will be reviewed and updated periodically throughout the life of the project.

Table 8-7 – Emergency Services – **CALL 911**

Contact*	Phone #
Gaines County Sherriff	Seminole Office 432-758-4023 ~ ~ ~ Seagraves Office 806-546-0520
Gaines County Emergency Management	432-758-5411
Texas Department of Public Safety (Seminole Office)	432-758-3112
US EPA Region VI	214-665-2294
EPA National Response Center	800-424-8802
TRRC Emergency Number	844-773-0305

*These numbers are listed in a relative daisy chain here only to suggest first and successive orders of response. Prioritization of calling turns on the event(s) necessitating the call(s) to any one or more of these numbers.

Table 8-8 – Internal Emergency Contacts

Contact	Phone No.
Michael Blincow	972-310-0100
Keith Tracy	405-308-7289

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

Prior to commencing operations, Orchard Storage will develop Emergency Operating Procedures that will include the following:

- Procedures for requesting assistance and for follow-up action, to remove the public from an area of exposure
- Provisions for advance briefing of the public within the AOR on subjects such as the hazards and characteristics of CO_2
- The manner in which the public will be notified of an emergency and, in case of one, the steps to be taken
- Proposed actions—*if necessary*—designed to minimize and respond to risks associated with potential seismic events, including seismic monitoring
- Communications Plan to guide

8.7.1 Communications Strategy

Orchard Storage will provide a summary of the emergency response plans and an emergency contact list to all adjacent landowners before beginning CO_2 injection operations. If an incident occurs requiring an emergency response, Orchard Storage will communicate with first responders, regulatory agencies, impacted surface owners, and/or the public as appropriate. Accurate, timely, well-conceived and effective emergency messages can help ensure public safety, protect property, facilitate response efforts, elicit cooperation and instill public confidence. The information provided and its timing and frequency will depend on the severity of the event and if environmental impacts occurred.

The information to be provided may include:

- Description of the event
- Severity
- Potential impact to the environment
- Investigation steps
- Mitigation actions taken or planned
- Current status

8.8 Emergency and Remedial Response Plan Review and Updates

This Emergency and Remedial Response Plan will be reviewed annually to ensure its applicability. Additionally, the plan will be reviewed after any AOR reevaluation and following any significant changes to the project that would necessitate such a review. The results of this review will be shared with the UIC Director. If no amendments are needed based on the review, an explanation of such will be provided.

Any amendments to this plan must be approved by the UIC Director and incorporated into the permit. This plan will also be reviewed and submitted to the UIC Director within 1 year of an AOR evaluation—following any significant changes to the facility (e.g., addition of injection or monitoring wells), change in personnel, or when the UIC Director requires it.

8.9 References

DOE Office of NEPA Policy and Compliance. 2007. Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement (revised April 2007).

Trabucchi, C., Donlan, M., Spirt, V., Friedman, S., and Esposito, R. 2014. Application of a Risk-Based Probabilistic Model (CCSvt model) to Value Potential Risks Arising from Carbon Capture and Storage. Energy Procedia 63.

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 9 – Financial Assurance Plan

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

May 2023
Revised July 2025

LONQUIST

SECTION 9 – FINANCIAL ASSURANCE

TABLE OF CONTENTS

9.1 Financial Responsibility 2
9.2 Financial Assurance 2
9.3 Corrective Action Plan 4
9.4 Injection Well Plugging and Abandonment....4
9.5 Monitoring Well Plugging and Abandonment....4
9.6 Post-Injection Site Care and Site Closure 4
9.6.1 Post-Injection Monitoring 5
9.6.2 Site Closure....5
9.7 Emergency and Remedial Response Plan....5
9.8 Updates to Financial Assurance 6

Tables

Table 9-1 – Summary of Costs Associated with Financial Security....3
Table 9-2 – Monte Carlo Analysis Summary 6

9.1 Financial Responsibility

To meet the requirements of 16 Texas Administrative Code (TAC) **§5.205** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(14)** and **§146.85(a)**], this section was prepared to summarize actions that Orchard Storage Company LLC (Orchard Storage) will take to demonstrate financial responsibility for corrective action (Bond, in future if necessary), injection well plugging (Bond), post-injection site care (Bond) and site closure (Bond), and emergency and remedial response (Insurance). This section also provides cost estimates to conduct these activities on a project basis. The costs included account for the proposed seven Class VI injection wells plus monitoring wells (Orchard Project), within the pressure front area of review (AOR).

Orchard Storage will annually provide to the Underground Injection Control (UIC) Director evidence of financial responsibility as required by 16 TAC **§5.205** [40 CFR **§146.85**]. This evidence ensures that Orchard Storage has enough financial resources to cover corrective action, injection well plugging, PISC and site closure, and emergency and remedial response, if financial difficulties are encountered. This annual report will be submitted until the UIC Director has determined that the facility has reached the end of the PISC period. The following financial information will account for the entire AOR and be submitted to aid in the UIC Director's determination of financial responsibility:

- The 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 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))
- The operator's most recently audited financial statements, if the person is not required to file a report with the U.S. Securities and Exchange Commission

9.2 Financial Assurance

As required by 16 TAC **§5.205** [40 CFR **§146.85**], the following financial instruments will be secured and used to provide sufficient funding for the following activities:

- Corrective Action – (Not applicable)
- Injection Well Plugging – Bond
- Post-Injection Site Care and Site Closure – Bond
- Emergency and Remedial Response – Insurance

Claimed as PBI has confirmed that Orchard Storage will be able to obtain these instruments, per the letter provided in *Appendix H*.

Table 9-1 summarizes the cost estimates for those activities—estimates that will be revised annually and account for any changes in the AOR, Emergency and Remedial Response Plan, and Injection Well Plugging Plan. The values shown in this table are in 2025 dollars.

Table 9-1 – Summary of Costs Associated with Financial Security

Financial Assurance Item	Unit Cost	No. of Wells	Total
Corrective Action (Project Total)			**$0**
Injection Wells (7) + IZM Well (1) Plugging (Project Total)			**$3,076,000**
Workover Rig	Claimed as PBI	8	Claimed as PBI
Rental Tools		8	
Mud/Brine		8	
Fracture Tanks		8	
Wireline		8	
Final Mechanical Integrity Test and Casing Logs		8	
Cement		8	
Bridge Plugs/Packers		8	
Casing Crew		8	
Miscellaneous		8	
AZM Wells (2) Plugging (Project Total)			**$581,000**
Workover Rig	Claimed as PBI	2	Claimed as PBI
Rental Tools		2	
Mud/Brine		2	
Fracture Tanks		2	
Wireline		2	
Final Mechanical Integrity Test and Casing Logs		2	
Cement		2	
Bridge Plugs/Packers		2	
Casing Crew		2	
Miscellaneous		2	
Post-Injection Site Care and Site Closure			**$6,646,000**
Vertical Seismic Profile Surveys			Claimed as PBI
Groundwater and Soil Monitoring			
Operations and Maintenance of Monitoring Wells			
Monitoring Well Plugging			
Subsurface Facilities Closure			
Emergency and Remedial Response			**$9,100,000**
Deep Oil-and-Gas Well Leak			**Monte Carlo Model Results**
CO_2 Injection Well Leak			
Deep CO_2 Monitoring Well Leak			
Rapid Leakage Through Caprock			
Slow Leakage Through Caprock			
Release Through Existing Faults			
Release Through Induced Faults			

This instrument will remain in effect until site closure. The financial instrument will, at a minimum, contain provisions for cancelation, renewal, and continuation. If Orchard Storage faces adverse economic conditions, it will notify the Commission and file a bankruptcy notice via certified mail to the UIC Director.

9.3 Corrective Action Plan

Ten wells in the pressure front and CO_2 plume AOR will require corrective action. Each of these wells will be plugged prior to beginning injection, according to the procedures outlined in Section 3 – Area of Review and Corrective Action. The cost to reenter and properly plug the ten wells identified is estimated to be $300,000 per well. Since the corrective action will occur prior to the start of injection, no financial assurance is required for these corrective action wells. As required by 16 TAC **§5.206(g)(1)** [40 CFR **146.84(e)**], the AOR will be reevaluated every 5 years to determine if any new penetrations have occurred. Note, the Corrective Action Plan identified two additional wells that are not corrective action wells but will be reentered and reworked, prior to beginning injection at the Orchard Project. One well, API 42-165-38785 will be converted to an in-zone monitor well during the construction phase and therefore is included in the monitoring well plugging costs.

9.4 Injection Well Plugging and Abandonment

Plugging and abandonment (P&A) procedures for the Orchard Project injection wells were prepared to meet the requirements of 16 TAC **§5.203(k)** [40 CFR **§146.92**]. These plans are intended to ensure that the wells do not serve as migration pathways of the injected fluid from the storage formation and into the Underground Source of Drinking Water (USDW), following the cessation of injection operations and after site closure. A detailed P&A plan is discussed in *Section 6 – Injection Well Plugging Plan,* in addition to the itemized list of cost estimates just provided in Table 9-1. Funds will be guaranteed to ensure that P&A operations are effectively managed.

9.5 Monitoring Well Plugging and Abandonment

The P&A procedures for the three Orchard Project monitoring wells were prepared to meet the requirements of 16 TAC **§5.203(k)** [40 CFR **§146.92**]. As noted, a more detailed P&A plan is discussed in *Section 6,* and all expenses relating to personnel and equipment were accounted for in Table 9-1. Pressure test costs are also included to prove the integrity of the wells.

9.6 Post-Injection Site Care and Site Closure

The Post-Injection Site Care and Site Closure Plan (PISC)—discussed in *Section 7* and its associated costs just highlighted in Table 9-1—was designed to meet the requirements of 16 TAC **§5.206 (k)** [40 CFR **§146.93**].

9.6.1 Post-Injection Monitoring

The collection monitoring information will be used to confirm the protection of the USDW during post-injection activities, to support the final demonstration of non-endangerment. The associated cost in Table 9-1 accounts for performing groundwater monitoring and tracking the CO_2 plume and pressure front post-injection. Costs are estimated using ongoing vertical seismic profile (VSP) costs Claimed as PBI plus soil-gas sampling Claimed as PBI and water sampling Claimed as PBI every 5 years for 50 years. Operations and maintenance costs are based on ongoing personnel, Supervisory Control and Data Acquisition (SCADA), and monitoring equipment costs for the PISC period, estimated at Claimed as PBI

9.6.2 Site Closure

Site closure will occur when the UIC Director has released the owner from all post-injection site duties. The cost estimates given in Table 9-1 reflect the expected amount to close the site and restore the facility to its natural state, including dismantling surface facilities (removing storage vessels, piping, pumps, surface equipment, etc.). Concrete and debris removal is also included in the surface facilities costs. Funds will be allocated for site restoration to leave a minimal environmental impact.

9.7 Emergency and Remedial Response Plan

The Emergency and Remedial Response Plan detailed in *Section 8* was prepared to meet the requirements of 16 TAC **§5.206(h)** [40 CFR **§146.94**]. Monte Carlo analysis, risk-based, probabilistic modeling has been tailored to Orchard Project-specific risks and uncertainties, to (1) generate reasonable, upper-bound estimates of the ERR costs—and (2) provide a sensible, conservative, and objective basis for determining the face amount of the financial assurance instrument(s) necessary to support the Class VI permit.

The cost-estimation method applied to the Orchard Project is based on a peer-reviewed (Trabucchi et al., 2014) probabilistic approach—a model reflective of site-specific factors associated with the project. Specifically, the model's input parameters include the geologic location and specific chemical composition of the CO_2 stream, as well as site-specific conditions that exist within the established AOR. The analysis adopts several conservative input assumptions and incorporates probabilistic calculations that allow for multiple release incidents through operation and post-injection site care. The annual probability values that were shown in Section 8, Table 8-2 are derived from the FutureGen Project Environmental Impact Statement and associated database (DOE Office of NEPA Policy and Compliance, 2007). Furthermore, the cost estimates are based upon response actions that are generally accepted and commonly used to respond to contamination incidents that could impair the public's ability to safely access USDWs.

Based on a model run of 50,000 Monte Carlo trials and the addition of a $250,000 project-specific adjustment—to account for the presence of a small population center within the otherwise highly rural AOR—the upper-bound cost estimate to satisfy ERR is estimated to be Claimed as PBI *in 2025*

dollars. This estimate specifically accounts for an array of possible risk events of potential concern as was identified in Section 8, Table 8-2. Table 9-2 summarizes the statistical results of the Monte Carlo simulations. Claimed as PBI [redacted]

Table 9-2 – Monte Carlo Analysis Summary

Summary Statistic	ERR Coverage Value (2025$)	No. of Events Occurring
Average	Claimed as PBI [redacted]	
Median		
Standard Deviation		
5th Percentile		
95th Percentile		
99th Percentile		
Minimum		
Maximum		
Maximum, Inclusive of Additional Project-Specific Adjustment ($250,000)		

9.8 Updates to Financial Assurance

As required by 16 TAC **§5.205(c)(2)(E)** [40 CFR **§146.85(c)**], Orchard Storage will, during the active life of this project, adjust the cost estimate for inflation within 60 days before the anniversary date of the establishment of the bond and insurance products—and provide this adjustment to the UIC Director. Orchard Storage will also provide written updates of adjustments to the cost estimates within 60 days of any amendments to the AOR and Corrective Action Plan, the Injection Well Plugging Plan, the PISC and Site Closure Plan, and the Emergency and Remedial Response Plan. If the updated cost estimate increases to an amount greater than the face value of the bond and insurance products in use, Orchard Storage will obtain an increase in the requisite financial instruments at an amount at least equal to the current cost estimate—or get other financial instruments to cover the increase and supply evidence of such to the UIC Director. If the estimated value is reduced due to changes in the operational cycle of the project, the bond will be reduced in value accordingly.



Cert By: Lonquist Sequestration, LLC (F-22610)

Ben H. Bergman P.E.

Ben H. Bergman P.E., Senior Engineer
Texas Registration No. 95591
Date Signed: July 28th, 2025, Houston, TX