Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1
Orchard No. 2
Orchard No. 3
Orchard No. 4
Orchard No. 5
Orchard No. 6
Orchard No. 7

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

Revised April 2024

LONQUIST SEQUESTRATION LLC

FOREWORD

Orchard Storage Company LLC is proposing to develop a carbon sequestration facility in Gaines County, Texas, [redacted] 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, Michael Blincow, 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.

Michael Blincow
Sr. Vice President Subsurface Operations

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.

Ben H. Bergman, P.E.
Senior Engineer

Texas License No. 95591
Date Signed:

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:

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

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REQUIREMENTS MATRIX

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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.	
§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)(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.	4.2.1
§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.	4.2.2
§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, 3.10
§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
§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)(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
§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
§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
§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;	
§146.82(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.	8.1

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)	Surface Map Information	Surface map and information. Only information of public record is required to be included on this map.	Intro, 3.9
§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.	3.8
§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;	3.9, 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)(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	3.9, 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.	3.9, Appendix B-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)(3)	Surface Map Information	The applicant must identify on the map any known or suspected faults expressed at the surface.	3.9,N/A
§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(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)(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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.	3.9, Appendix B
§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)(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;	1.6.2
§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:	4.2.6
§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;	4.2.6, Intro
§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;	4.2.6
§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.	4.2.3
§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	4.2.4.2
§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	4.2.5
§146.82(b)	Required class VI permit Information	The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.				
§146.82(c)	Required class VI permit Information	Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:				
§146.82(c)(1)	Required class VI permit Information	The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;				

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(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
§146.82(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				
§146.82(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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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;	1.9.4
§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
§146.83(b)	Minimum Criteria for siting	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.				
§146.84	Area of review and corrective action		§5.203 (d)	AOR and corrective action	Area of Review and Corrective Action	Section 3
§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(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	3.3
§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.	3.10
§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;	3.2, 3.3, 3.4
§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;	3.11.1

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§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	3.11.1
§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	3.11.1
§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)	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;	3.11.1
§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)(ii)	AOR and corrective action	how corrective action will be adjusted if there are changes in the AOR;	3.11.1
§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	3.11.1
§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)(iv)	AOR and corrective action	how site access will be secured for future corrective action.	3.11.1
§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:				

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)(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;	2.3.3
§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)(III)	AOR and corrective action	from initiation of injection to the end of the injection period proposed by the applicant; and	2.3.3
§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)(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.	2.3.3, 2.4
§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	2.2.1.1, 2.2.2, 2.2.3, 2.2.4
§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;	2.2.4, 2.2.5

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§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	2.2.1, 2.2.2, 2.3.1
§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
§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.	3.9 N/A
§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.	3.9 N/A
§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.	3.9 N/A
§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:	3.11.1
§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	3.11.1

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§146.84(e)(3)	Area of review and corrective action	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	§5.206 (g)(3)	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.	
§146.84(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
§146.84(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.				3.7
§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
§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
§146.85	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)(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	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.	

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§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	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	Cover sheets
§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)(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.	Cover sheets
§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	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)	Fees, financial responsibility, and financial assurance	Financial assurance.	9.1
§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	TBD
§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
§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;	9.6.1

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§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(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(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(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
§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)(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)(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.	

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§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.	
§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				9.2
§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:				
§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.				

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§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).				
§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.				

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§146.85(a)(6)(iii)		An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.				
§146.85(a)(6)(iv)		An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.				
§146.85(a)(6)(v)		An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than –0.1; and a net profit (revenues minus expenses) greater than 0.				
§146.85(a)(6)(vi)		An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.				
§146.85(a)(6)(vii)		An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.				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

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§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.				
§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.				

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§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	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(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)	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.	4.2.4.2
§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;	4.2.3.2, 4.2.3.3
§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	4.2.3.4
§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.	4.2.1
§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	
§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.	4.2.1
§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

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§146.86(b)(1)(ii)	Injection well construction requirements	Injection pressure, external pressure, internal pressure, and axial loading;				4.2.3, 4.2.3.6
§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);	4.2.3.2, 4.2.3.3, 4.2.3.4
§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
§146.86(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
§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	4.2.3.3, Appendix C
§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)(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).	4.2.3.5
§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)(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.	4.2.4.2
§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.				4.2.1, Appendix D
§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(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

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§146.86(c)(3)(ii)	Injection well construction requirements	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;				4.2.3
§146.86(c)(3)(iii)	Injection well construction requirements	Maximum proposed injection pressure;				4.2.6
§146.86(c)(3)(iv)	Injection well construction requirements	Maximum proposed annular pressure;				4.2.6
§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;	4,2,6
§146.86(c)(3)(vi)	Injection well construction requirements	Size of tubing and casing; and				4.2.3.4, 4.2.3.6
§146.86(c)(3)(vii)	Injection well construction requirements	Tubing tensile, burst, and collapse strengths.				4.2.3.6
§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.	4.2.4.1, 4.2.4.2, 4.2.4.3, 5.4.9
§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.	4.2.4.1, 4.2.4.2, 4.2.4.3, 5.4.9
§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.	
§146.87(a)(2)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the surface casing:				
§146.87(a)(2)(i)	Logging, sampling, and testing prior to injection well operation	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§5.203 (f)(1)(B)	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.	4.2.4.2
§146.87(a)(2)(ii)	Logging, sampling, and testing prior to injection well operation	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.				4.2.4.2

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			§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.	4.2.4.2
§146.87(a)(3)	Logging, sampling, and testing prior to injection well operation	Before and upon installation of the long string casing:	§5.203 (f)(1)(D)	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.	4.2.4.2
§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.	4.2.4.2
§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.	4.2.4.2
§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;	
§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.	
§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.	4.2.4.1
§146.87(c)	Logging, sampling, and testing prior to injection well operation	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§5.203 (f)(3)(A)	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.	4.2.4.3
§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.	
§146.87(d)(1)	Logging, sampling, and testing prior to injection well operation	Fracture pressure;				1.5.3, 4.2.4.4
§146.87(d)(2)	Logging, sampling, and testing prior to injection well operation	Other physical and chemical characteristics of the injection and confining zone(s); and				1.2.4, 4.2.4.2

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§146.87(d)(3)	Logging, sampling, and testing prior to injection well operation	Physical and chemical characteristics of the formation fluids in the injection zone(s).				1.6.1, 4.2.4.3
§146.87(e)	Logging, sampling, and testing prior to injection well operation	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):				
§146.87(e)(1)	Logging, sampling, and testing prior to injection well operation	A pressure fall-off test; and,	§5.203 (f)(2)(B)	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(e)(2)		A pump test; or				
§146.87(e)(3)		Injectivity tests.				5.4.2
§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.	4.2.4.2, 4.3.2, 5.4.8
§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.	4.2.5, 4.2.6
§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.				
§146.88(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.	
§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.	4.2.3.7
§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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.	
§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
§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	8.4.8
§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;	8.4.8
§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	8.4.8
§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	8.4.8
§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	8.4.8
§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	8.4.8
§146.89	Mechanical Integrity	Mechanical Integrity	§5.203 (h)	Mechanical integrity testing	Mechanical integrity testing.	
§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
§146.89	Mechanical Integrity	Mechanical Integrity	§5.206 (f)	Mechanical integrity	Mechanical Integrity	
§146.89(a)	Mechanical Integrity	A Class VI well has mechanical integrity if:				
§146.89(a)(1)	Mechanical Integrity	There is no significant leak in the casing, tubing, or packer; and				
§146.89(a)(2)	Mechanical Integrity	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.				

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§146.89(b)	Mechanical Integrity	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§5.203 (h)(1)(C)	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).	
§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).	
§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
§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.				
§146.89(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.	

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§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.	5.2
§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)(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.	5.2
§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;	5.4.3
§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
§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

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§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	5.5.2.1
§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:	
§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;	4.3.4
§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	5.5.4
§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;	5.5.4
§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(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(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)(1)		Direct methods in the injection zone(s); and,				5.5.7.1
§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;	5.5.7.2
§146.90(h)		The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.				
§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

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§146.90(h)(3)		If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;				
§146.90(i)	Testing and monitoring requirements	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	§5.203 (j)(2)(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.	
§146.90(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	
§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
§146.90(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
§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	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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
§146.91(a)	Reporting requirements	Semi-annual reports containing:	§5.207 (a)(2)(C)	Reporting and Record-Keeping	Semi-annual reports containing:	
§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)(i)	Reporting and Record-Keeping	a summary of well head pressure monitoring;	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)(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
§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
§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)(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)(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
§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(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(c)(5)	Reporting requirements	Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.				5.2
§146.91(d)	Reporting requirements	Owners or operators must notify the Director in writing 30 days in advance of	§5.206 (i)	Commission witnessing of testing and logging.	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
§146.91(d)(2)	Reporting requirements	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and				
§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
§146.91(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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§146.91(f)	Reporting requirements					
§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(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
§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.				
§146.92	Injection Well Plugging	Injection well plugging	§5.203 (k)	Well Plugging Plan	Injection well plugging	
§146.92(a)	Injection Well Plugging	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, 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(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)	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:	6.1.3, 6.2.3, Appendix G
§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(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(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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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
§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(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
§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(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)(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(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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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)(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
§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)(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
§146.93(b)(4)						

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
§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:				
§146.93(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;	
§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;	
§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;	
§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;	
§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;	
§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;	
§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;	
§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;	
§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;	
§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	
§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;	

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§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.	
§146.93(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

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§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
§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
§146.94	Emergency and remedial response	Emergency and remedial response	§5.206 (h)	Emergency, mitigation, and remedial response	Emergency mitigation, and remedial response	
§146.94(a)	Emergency and remedial response	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW 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:	
§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;	8.4
§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)(1)	Emergency and remedial response	Immediately cease injection;	§5.206 (d)(2)(F)(ii)(I)			8.4
§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)			8.4
§146.94(b)(3)	Emergency and remedial response	Notify the Director within 24 hours; and	§5.206 (d)(2)(F)(ii)(III)			8.4
§146.94(b)(4)	Emergency and remedial response	Implement the emergency and remedial response plan approved by the Director.				8.4

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§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.	
§146.94(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
			§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.**	Intro
			§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:	Intro
			§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.	
			§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.	

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			§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."	Intro
			§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.	Intro
			§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.	
			§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
			§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.	3.2
			§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.	4.2.1
			§5.203 (e)(2)(E)	Injection well construction	type of packer and packer setting depth	4.2.3.7
			§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.	4.2.4.2
			§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.	4.2.4.2
			§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.	

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			§5.203 (i)(2)	Operating Information	Maximum injection pressure. The director will approve a maximum injection pressure limit that:	4.2.6
			§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;	4.2.3
			§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	4.2.6
			§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;	Section 5.5.5
			§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;	4.3.4
			§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	TBD
			§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.	TBD
			§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;	3.5, 3.6
			§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;	8.4.9
			§5.203 (l)(C)	Emergency and remedial response plan	CO2 release detection and prevention measures;	8.4.2
			§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;	8.6
			§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;	8.6
			§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,	8.6
			§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	8.6

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			§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	8.6
			§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
			§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);	1.7
			§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	
			§5.206 (b)(12)	Permit Standards	the applicant submitted to the director financial assurance in accordance with §5.205(c) of this title.	9.2
			§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;	
			§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);	TBD
			§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;	TBD
			§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;	TBD
			§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

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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
			§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.	
			§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.	4.2.6
			§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
			§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;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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
			§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.	
			§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.	
			§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
			§5.206 (f)(3)	Permit Standards	The operator must either repair and successfully retest or plug a well that fails a mechanical integrity test.	
			§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.	8.5
			§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.	8.5
			§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.	8.5
			§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.	
			§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
			§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
			§5.206 (k)(3)(A)	Permit Standards	the estimated magnitude and extent of the facility footprint (the CO_2 plume and the area of elevated pressure);	7.3
			§5.206 (k)(3)(B)	Permit Standards	that there is no leakage of either CO_2 or displaced formation fluids that will endanger USDWs;	7.4.2

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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
			§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.	
			§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.	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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.	1.7 ???
			§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.	
			§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
			§5.207 (a)(D)	Reporting and Record-Keeping	Annual reports. The operator must submit an annual report detailing:	5.2
			§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
			§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 (a)(2)(D)(i)	Reporting and Record-Keeping	corrective action performed;	
			§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:	
			§5.207 (c)	Reporting and Record-Keeping	Signatories to reports.	
			§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;	

EPA 40 CFR	CFR Category	CFR Text	16 TAC Chapter 5	TAC Category	Description	Permit Application
			§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 (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.	
			§5.207 (c)(1)(C)	Reporting and Record-Keeping	the written authorization is submitted to the director.	

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

Revised April 2024

LONQUIST SEQUESTRATION LLC

SECTION 0 – INTRODUCTION

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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]

[redacted] 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. [redacted] 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), [redacted] 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.

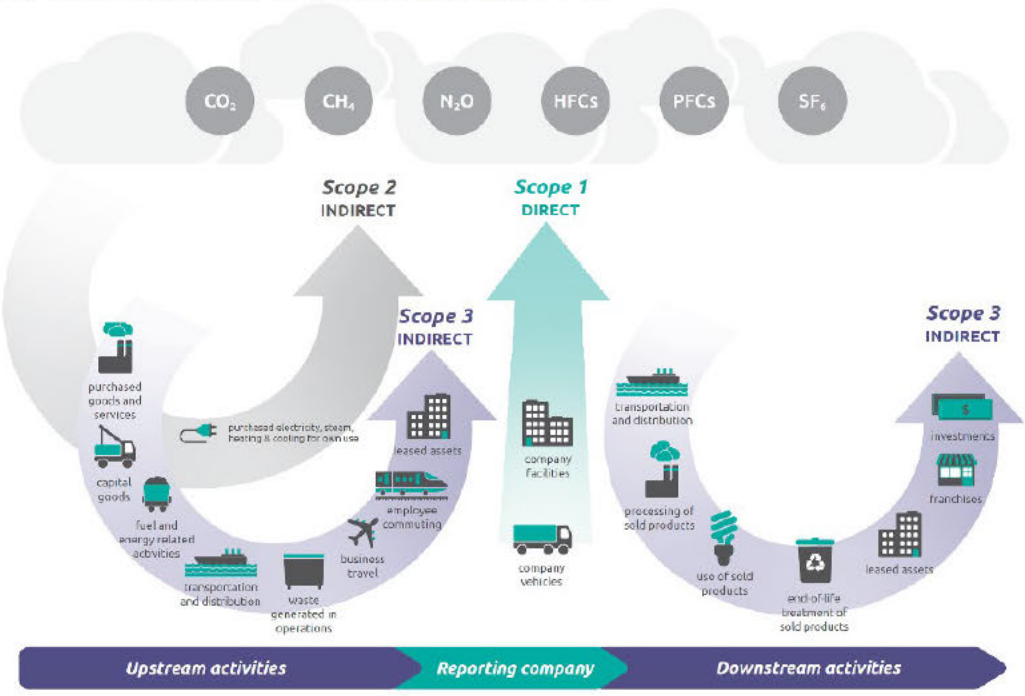


Figure 0-1 – Emission Sources[4]

[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**].

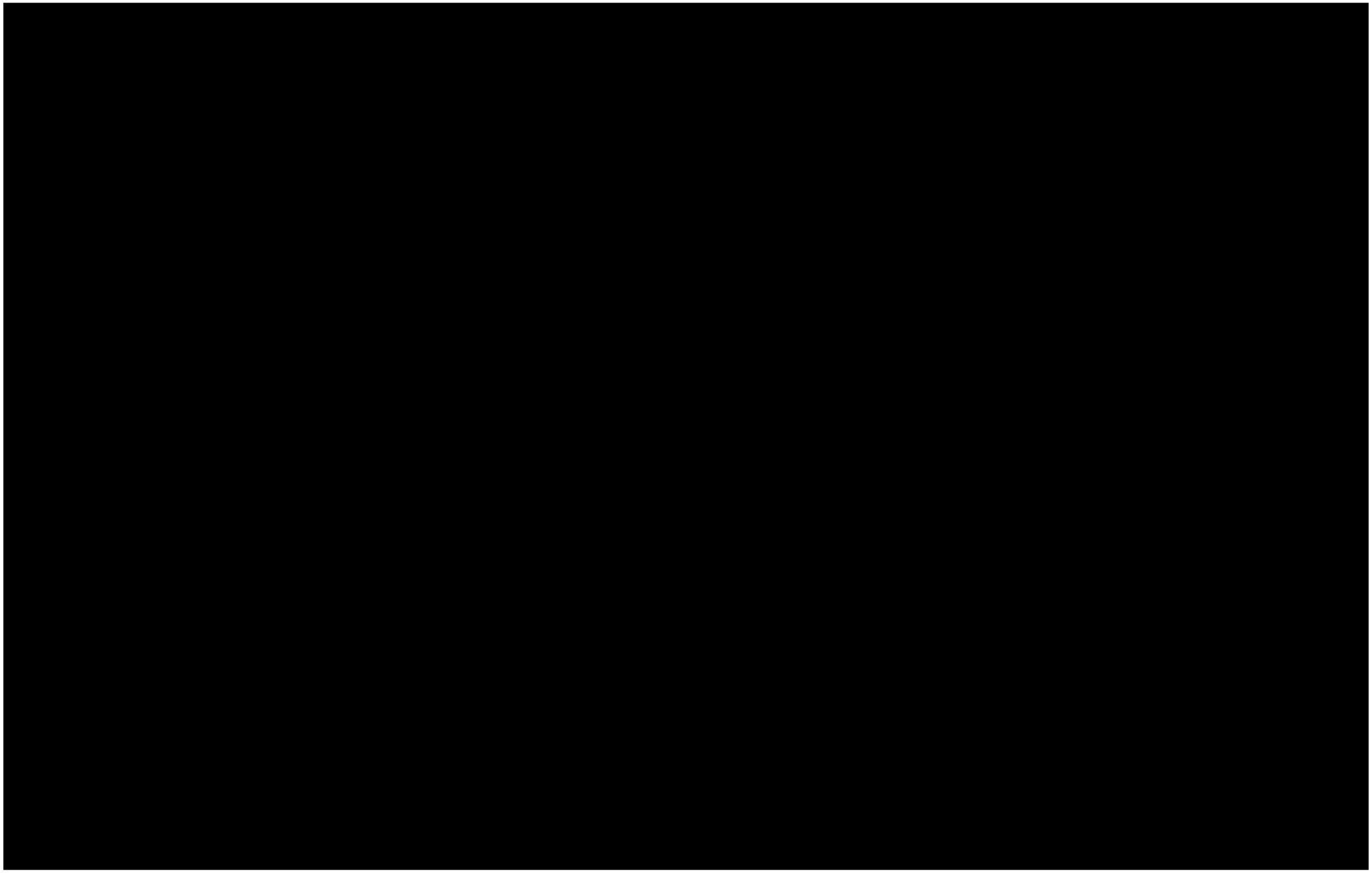


Figure 0-2 – Project Overview Map.

Each of the Orchard wells will target the [redacted] formation for injection. The [redacted] is a [redacted] 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 ch[redacted]

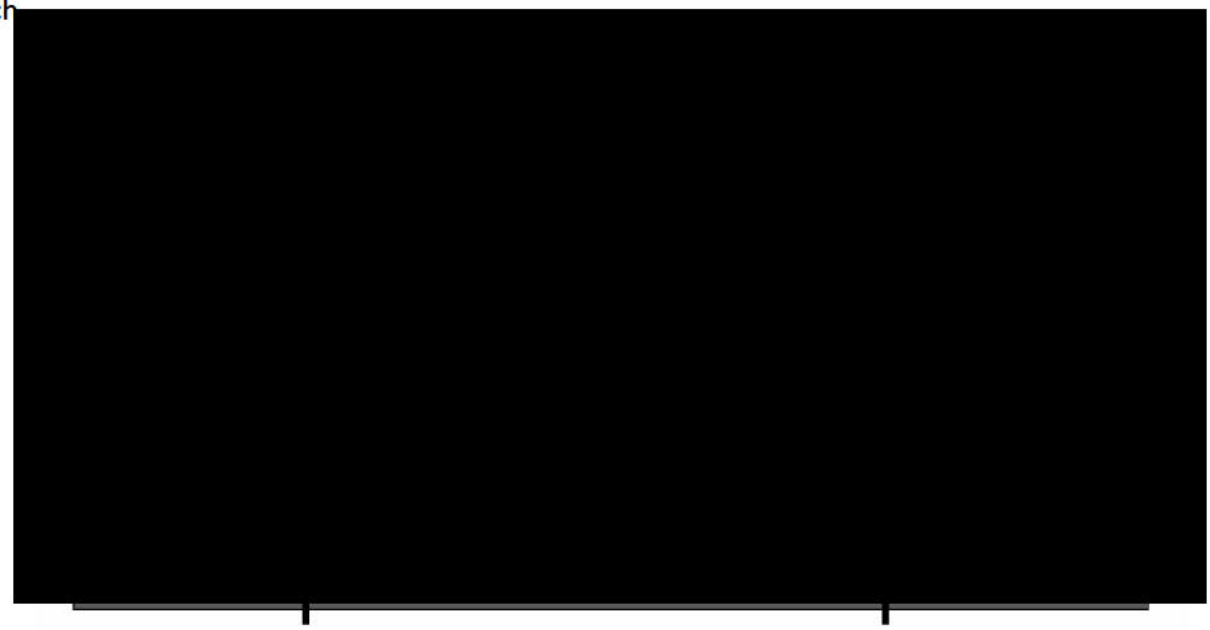


Figure 0-3 – Permian Basin West-East Cross Section[5]

By injecting 2 MMT/yr of CO_2, [redacted] 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.
- [redacted]

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

- [redacted]
- [redacted] to breach containment and contaminate Underground Sources of Drinking Water (USDWs), were observed.
- No artificial penetrations, which could cause CO_2 to breach containment and contaminate USDWs, were identified in the CO_2 plume area of review (AOR) of the Orchard Project.
- No Environmental Protection Agency (EPA)-identified environmental justice communities exist within the Orchard Project area.
- No adverse disproportionate effects on populations in environmental justice areas will arise from the construction, operation, and maintenance of the Orchard Project.

Pore Space Agreement Discussion

The Orchard Project CO_2 plume AORs contain [redacted] 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 [redacted] 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 [redacted] years, with a perforated interval in the [redacted] formation, ranging from [redacted] ft in thickness, acting as the injection and storage reservoir.

The injectate stream, from an existing [redacted] The injectate will consist of a minimum of [redacted] and meet the specifications shown in Table 0-1 and Appendix A-2.

Table 0-1 – Injectate Major Components

Component	Value
CO_2	[redacted]
Water	
Temperature	
H_2S	
Nitrogen	
Sulphur	
Oxygen	
Hydrocarbons	
Glycol	
Carbon Monoxide	
NO_x	
SO_x	
Particulates	
Amines	
Hydrogen	
Mercury	
Ammonia	
Argon	
Liquids	
Lube Oil	

Surface Facility Details

Minimal surface equipment will be required [redacted] as shown in Figure 0-4. The valve station is located [redacted]

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.*

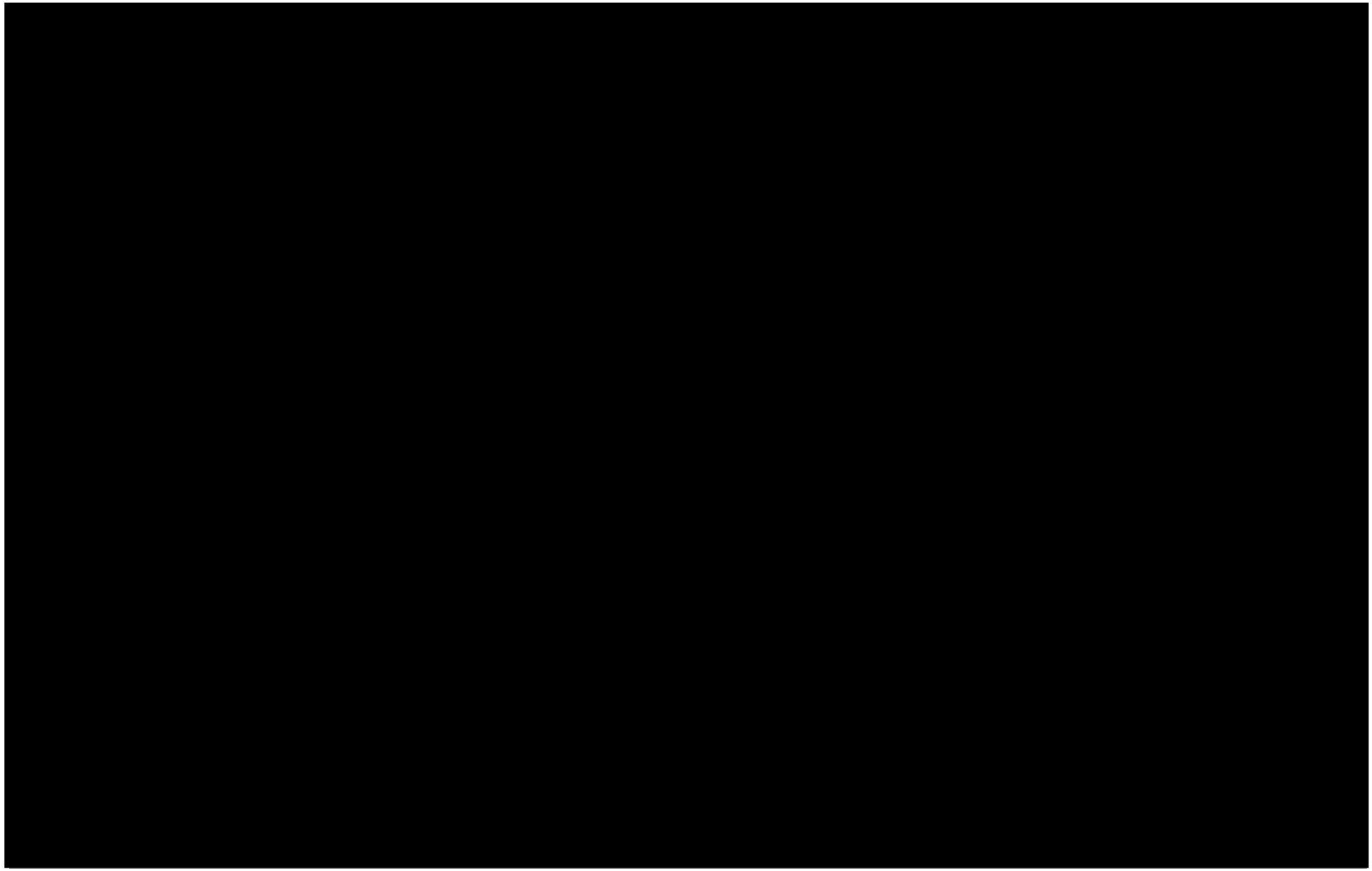


Figure 0-4 – Distance from Valve Station to Orchard No. 1

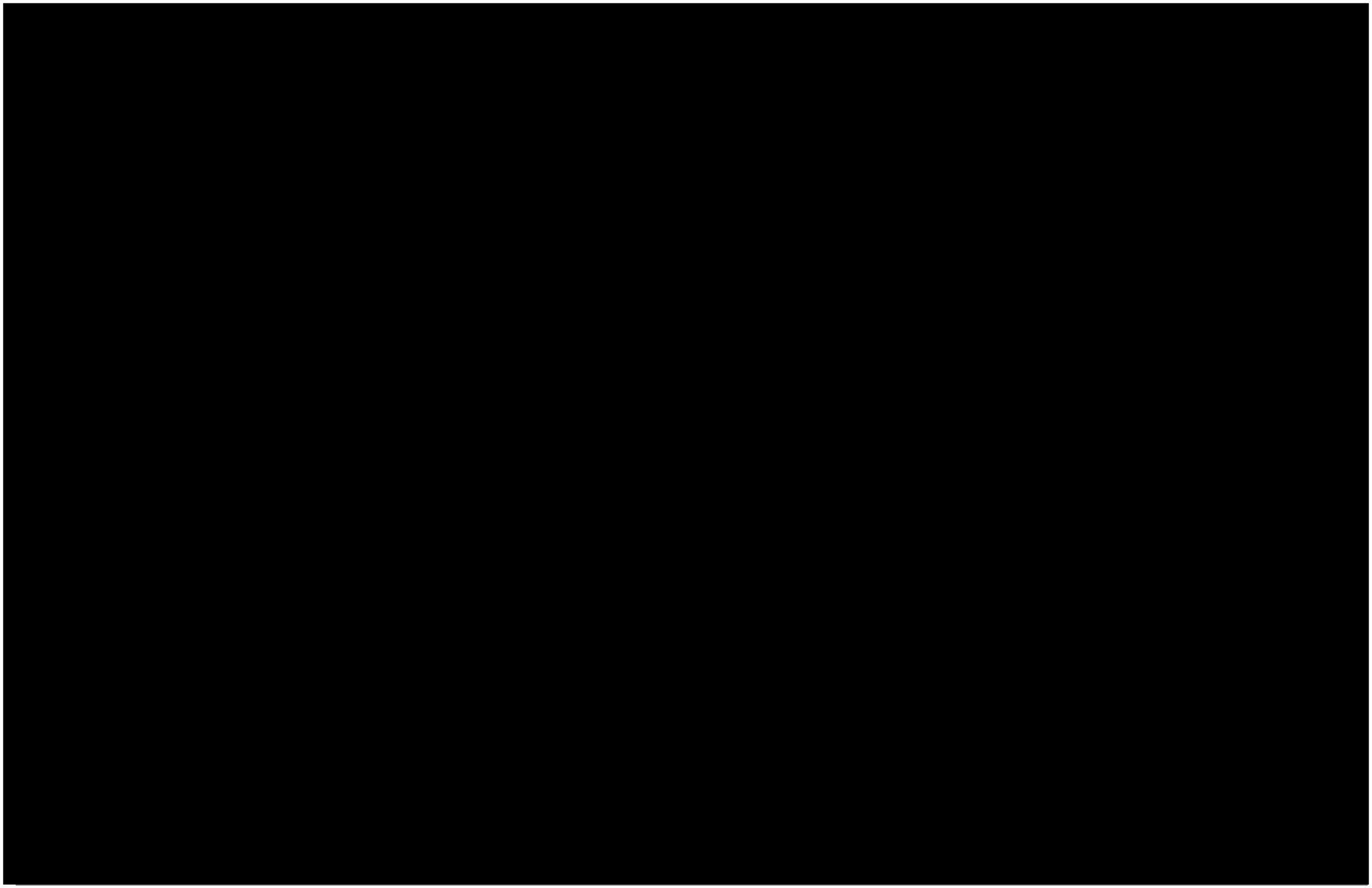


Figure 0-5 – Aerial Map of Orchard Project.

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
- Environmental justice issues
- 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 [redacted] 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	[redacted]	
Orchard No. 2	Gaines		
Orchard No. 3	Gaines		
Orchard No. 4	Gaines		
Orchard No. 5	Gaines		
Orchard No. 6	Gaines		
Orchard No. 7	Gaines		

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 eight existing artificial penetrations that will require corrective action. These wells are only found in the pressure front AOR for the project and are not in any of the CO_2 plumes. 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 [redacted] 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	Gaines	[redacted]		
Orchard No. 2	Gaines			
Orchard No. 3	Gaines			
Orchard No. 4	Gaines			
Orchard No. 5	Gaines			
Orchard No. 6	Gaines			
Orchard No. 7	Gaines			

Applicant:

Name: Orchard Storage Company LLC

Address:
4200 Westheimer Road
Suite 975
Houston, Texas 77027

Facility contacts: [redacted]

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 0-3 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.

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

Revised April 2024

LONQUIST SEQUESTRATION LLC

SECTION 1 – SITE CHARACTERIZATION

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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 320-325 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).

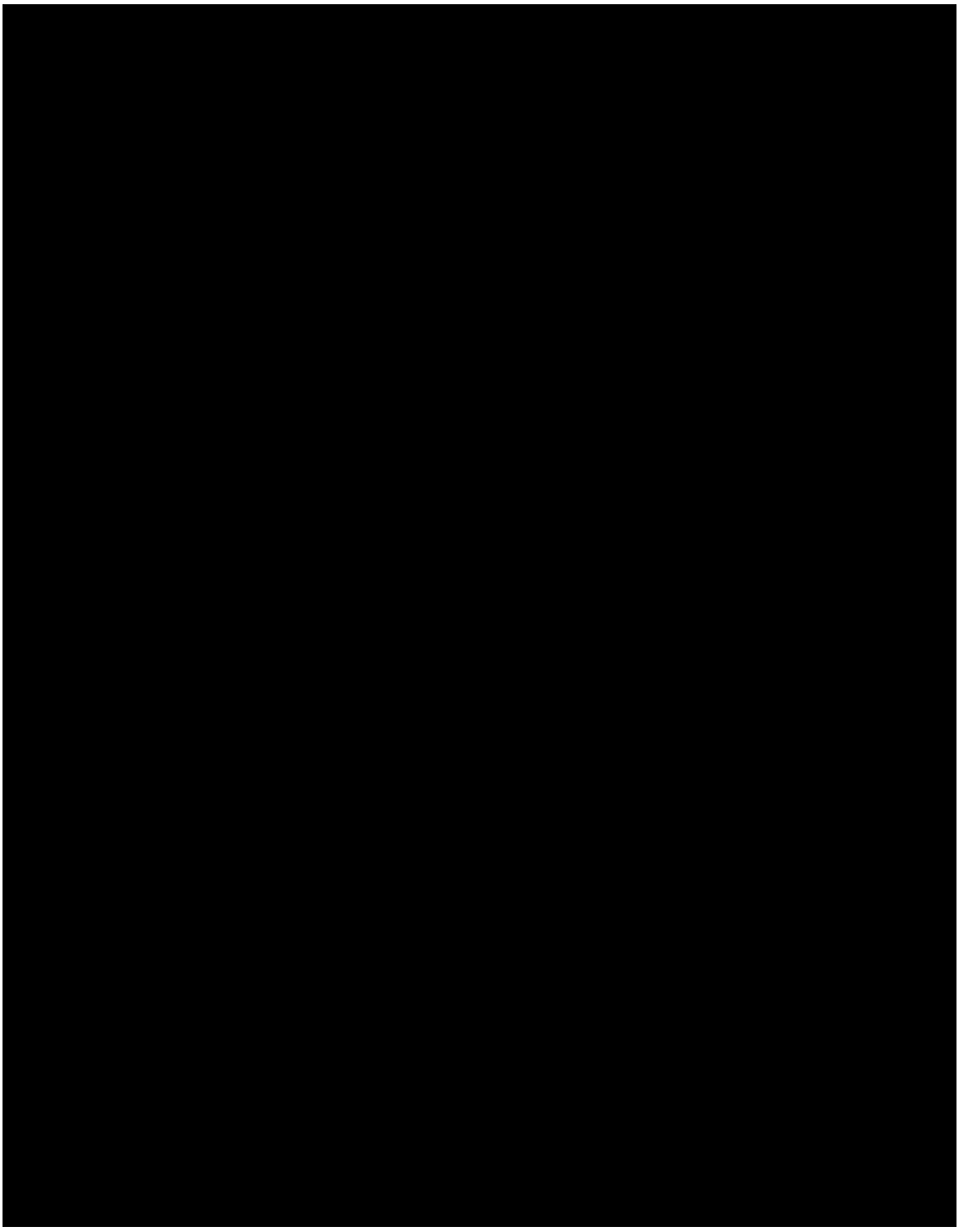


Figure 1-1 – Permian Basin sub-basins with the Orchard location indicated by the black star (from Merrill et al., 2015).

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.

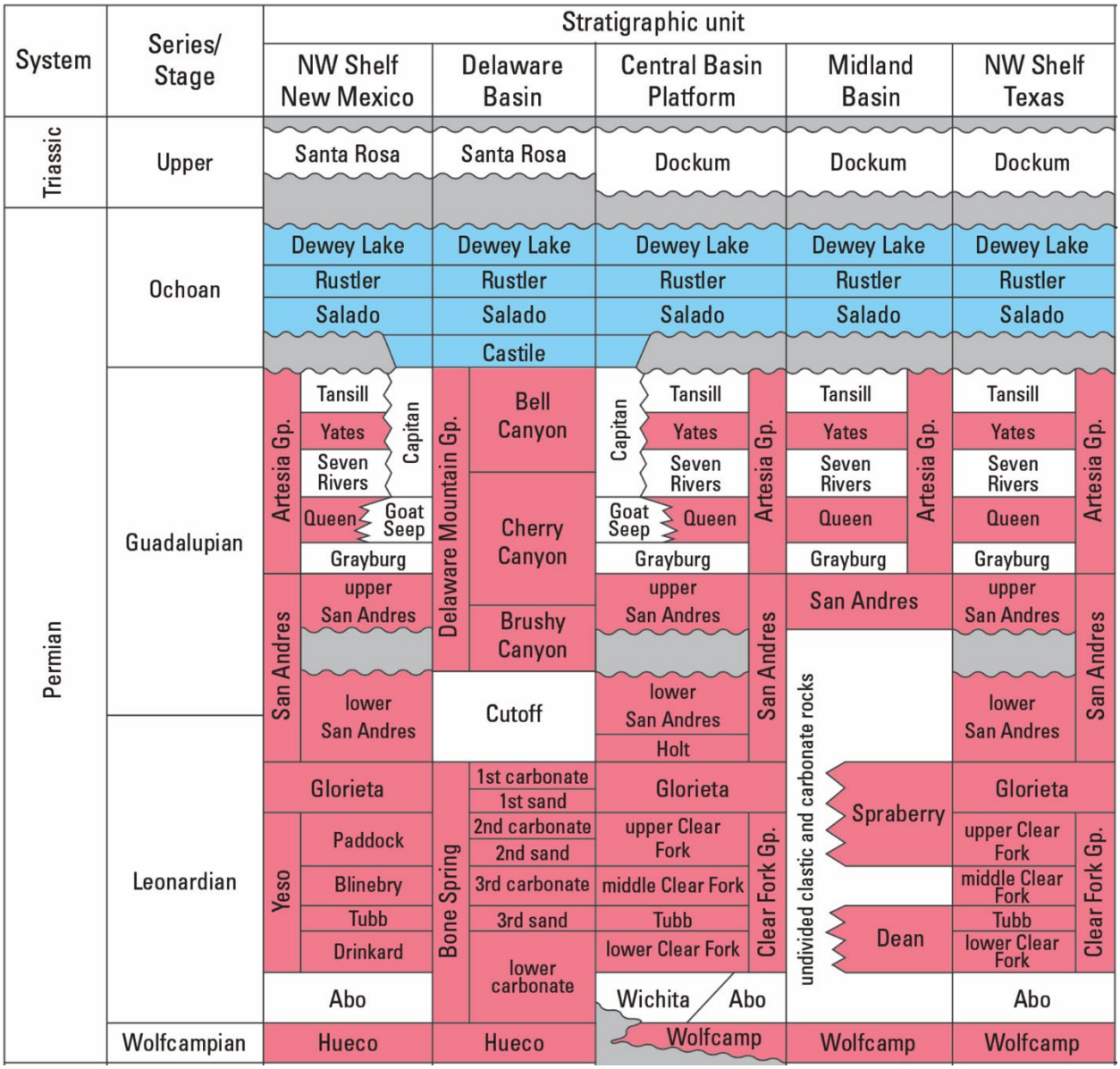
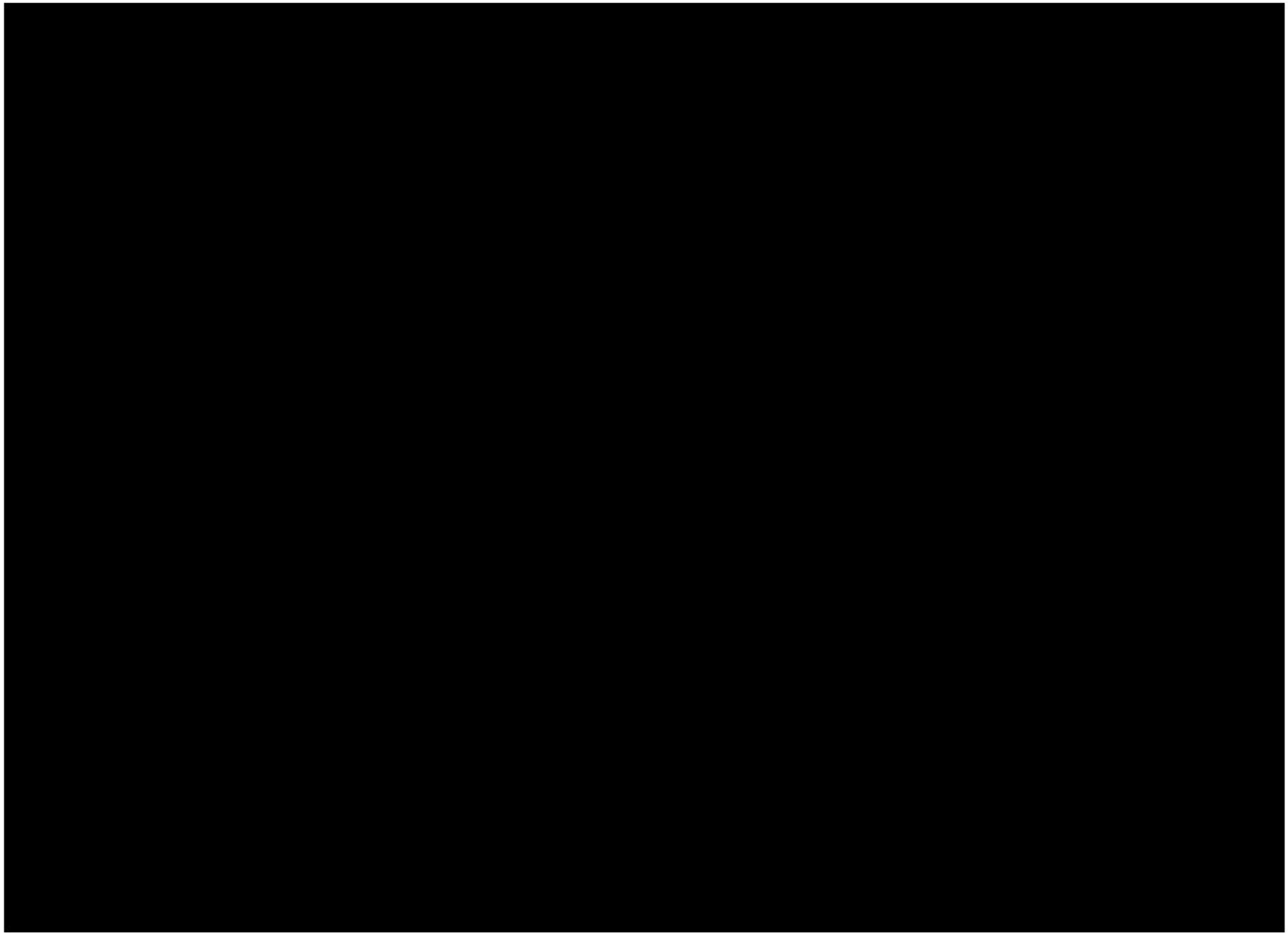
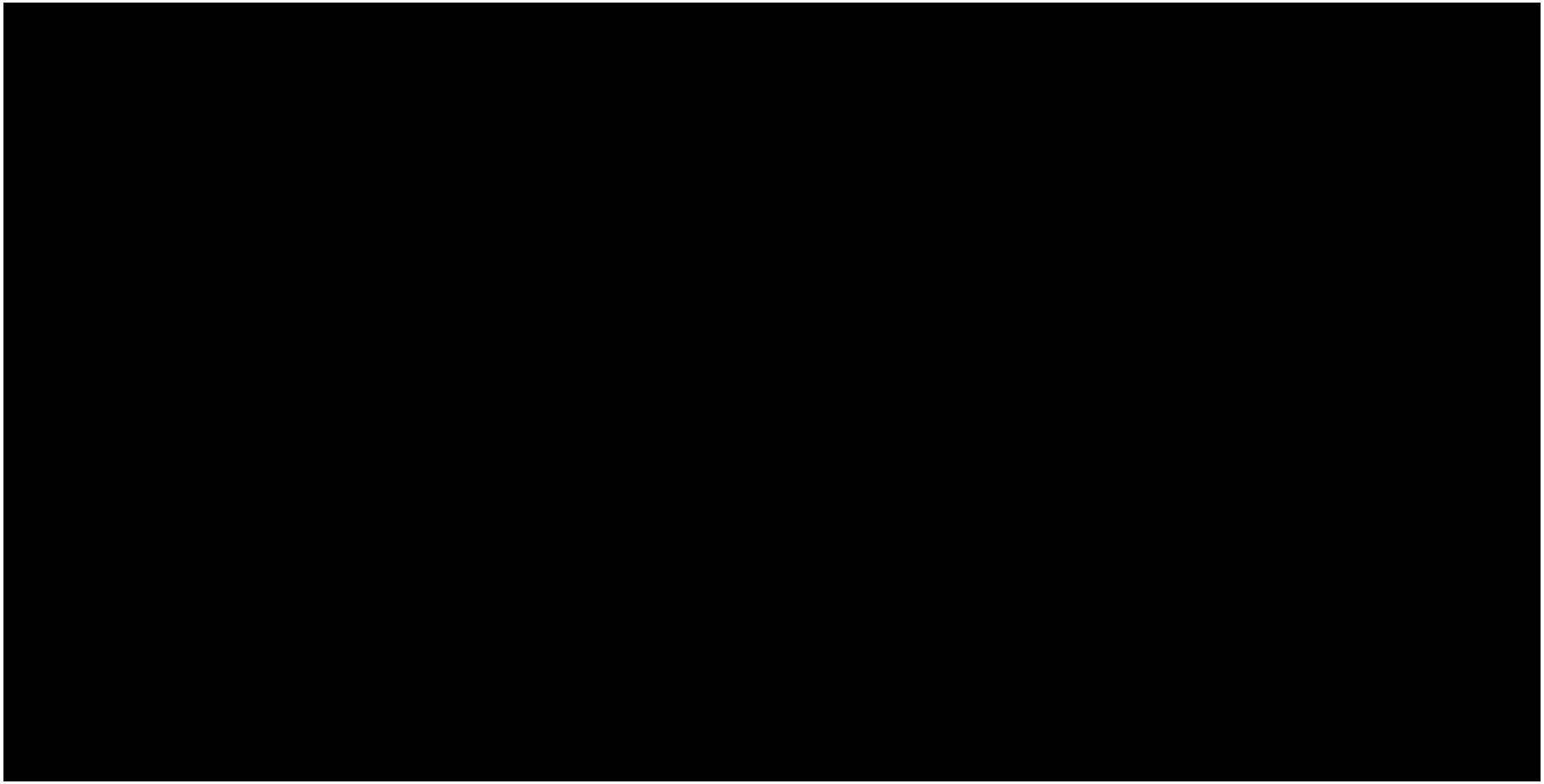


Figure 1-2 – Generalized stratigraphic column of geologic units in the Paleozoic strata of the Permian Basin (Merrill et al., 2015).

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. [redacted]

[redacted]





1.2.3 Regional Depositional Model

Facies are associated with shelf-to-basin changes across the region. The proposed Orchard No. 1–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.

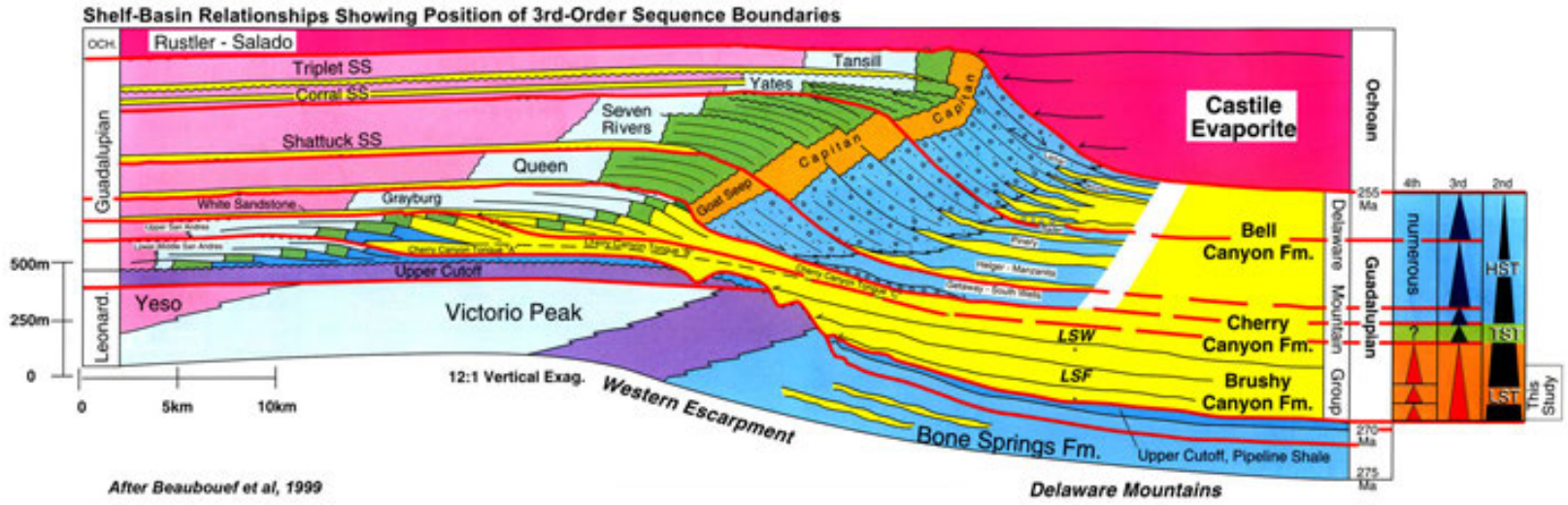


Figure 1-5 – Upper Permian stratigraphy of the Northwest Shelf of the Delaware Basin (after Beaubouef et al., 1999).

1.2.4 Major Stratigraphic Units

[redacted]

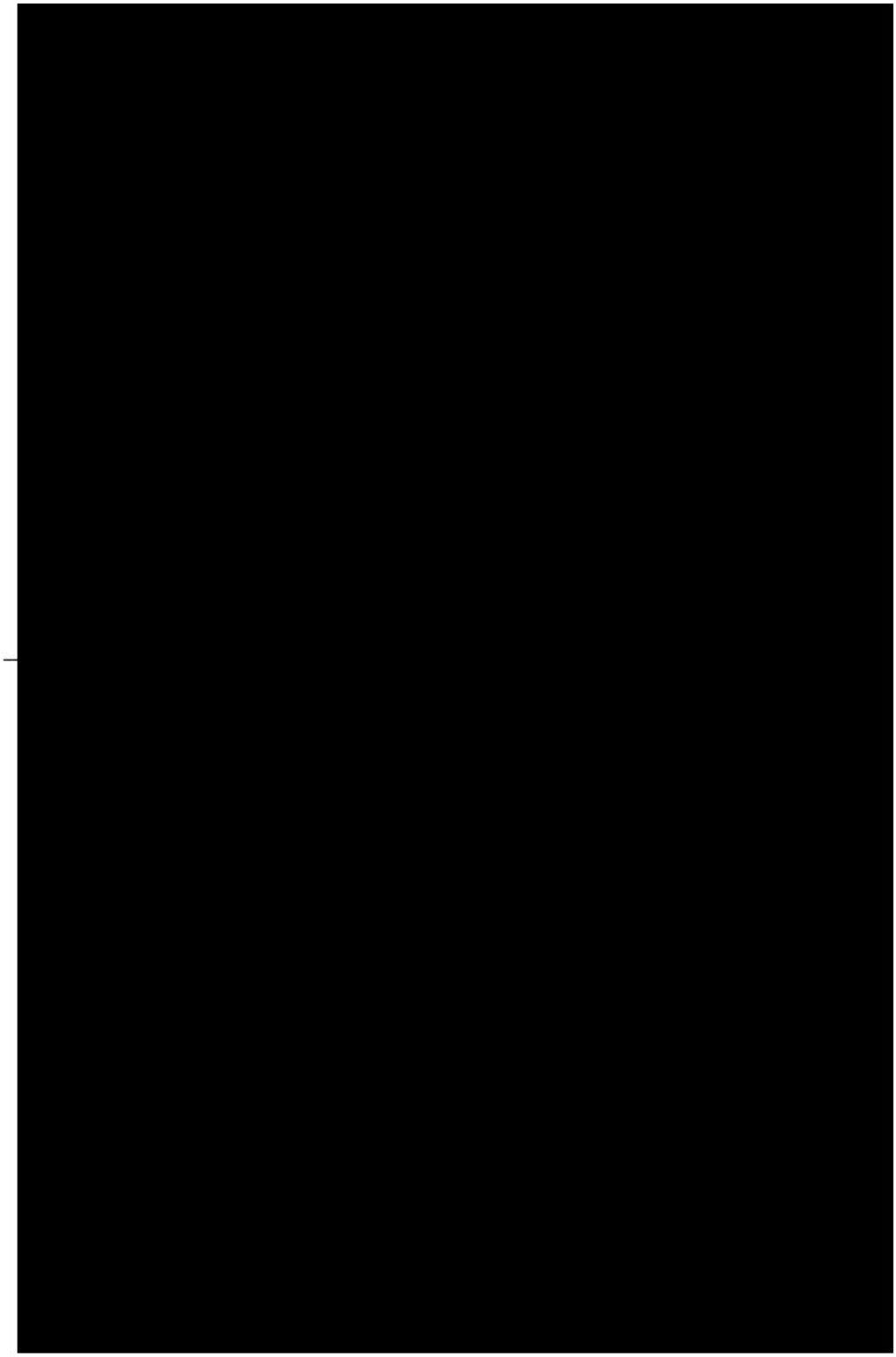


Figure 1-6 – Reference map showing the location of cross section B-B′ (Figure 1-7) from west to east through the Orchard location (indicated by the black star).



Figure 1-7 – A west-to-east cross section illustrating the change of lithofacies and stratigraphy in the [redacted]

[redacted]



Figure 1-8 – Base map showing the location of the Orchard Project (black star) [redacted]

[redacted]



Figure 1-9 – A simplified depositional facies model relative to the position on [redacted]



Figure 1-10 –



Figure 1-11 – Schematic cross section showing the hierarchy of composite/high-frequency sequences for the



Figure 1-12 – A schematic cross section of the dominant lithofacies across the high-frequency cycles shown previously, based on observations from several regional [redacted]

[redacted]

[redacted]



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

[redacted]asin and the Central Basin Platform (Homann, GMK). The Reeves Field is situated northwest of the [redacted]

[redacted]

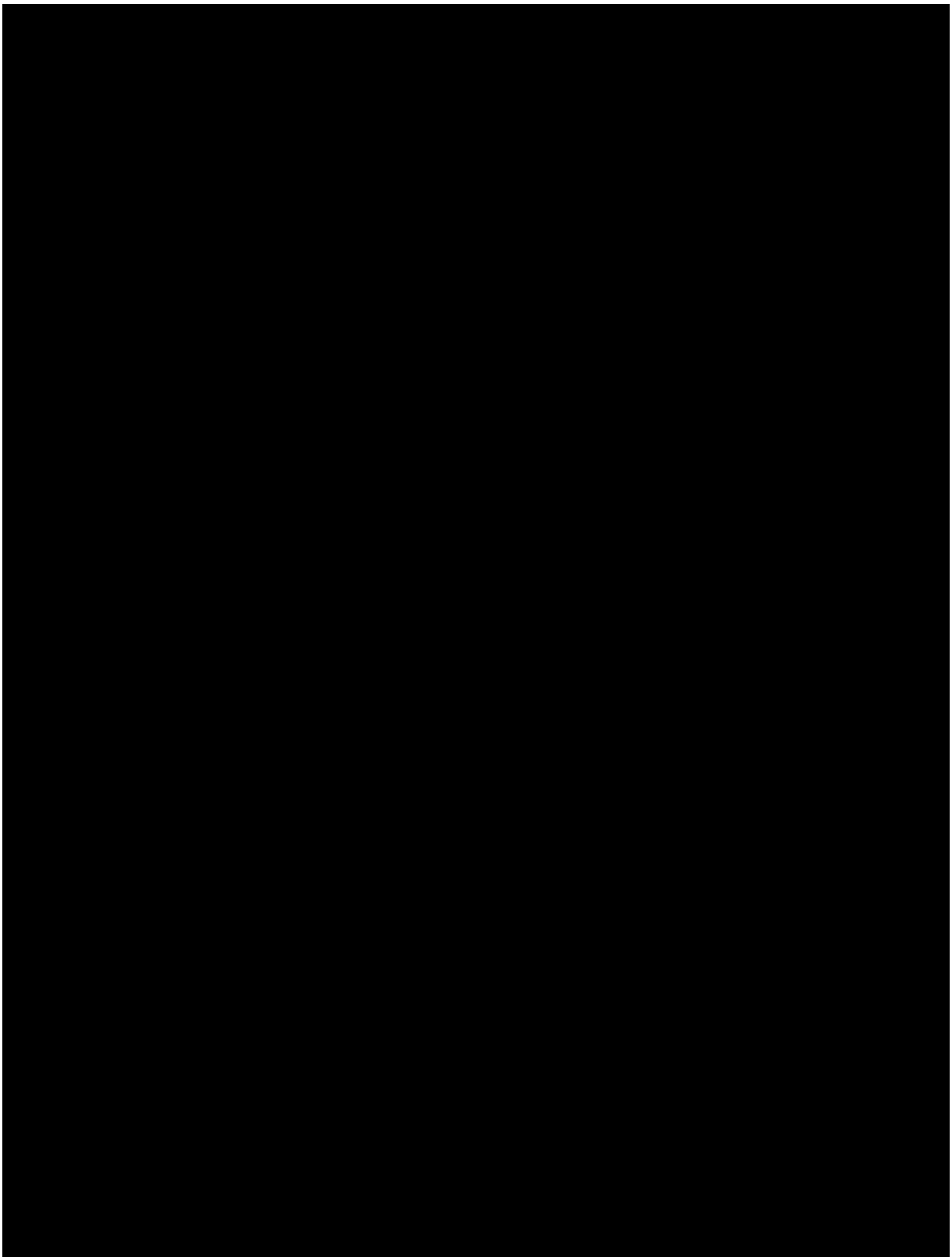
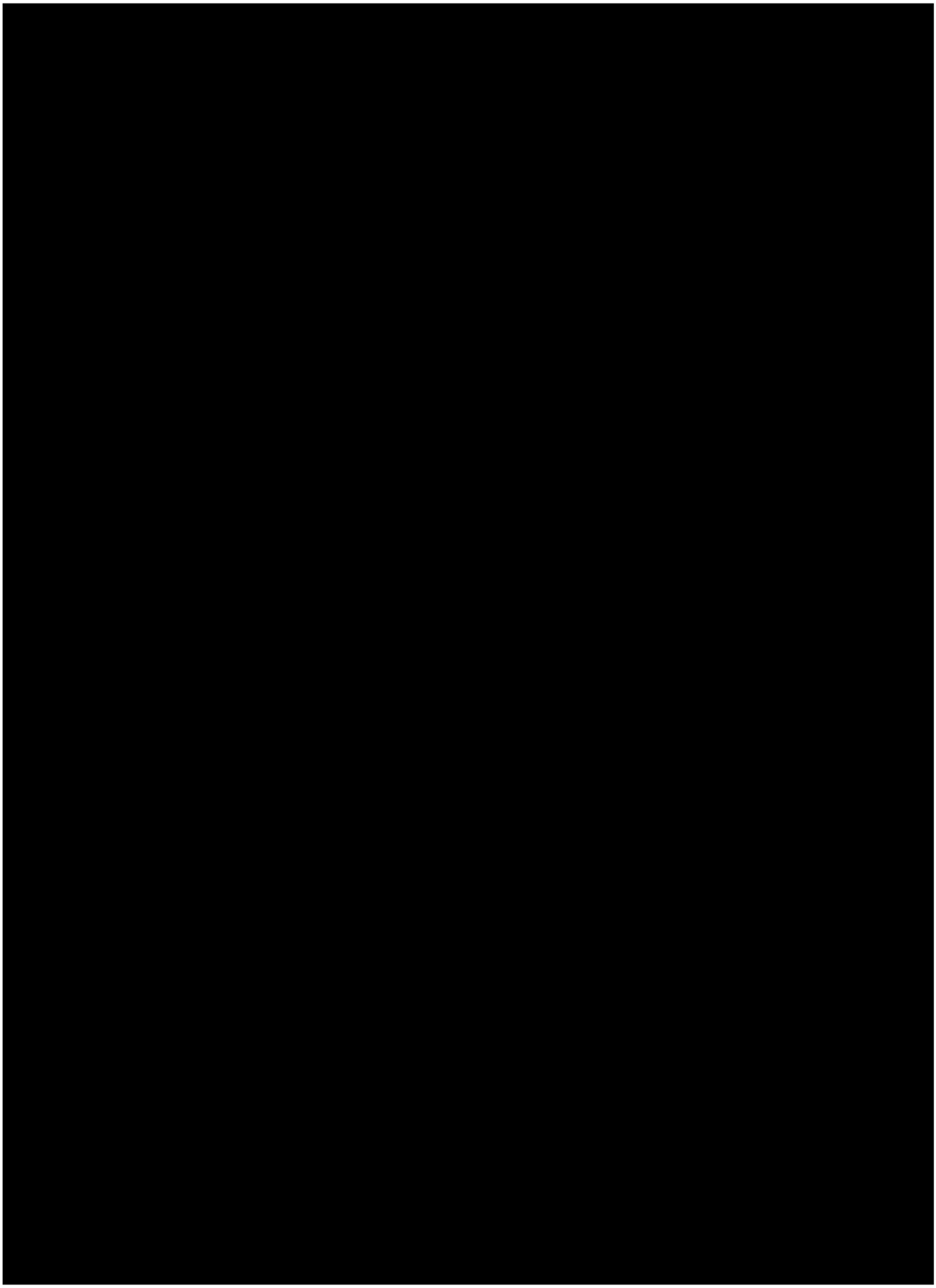


Figure 1-14 – Simplified map highlighting the regional patterns of dominant lithologies in the confining zone part of the [redacted]



[redacted]

1.3. Site Geology

The proposed Orchard No. 1–No. 7 site is located [redacted] 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.

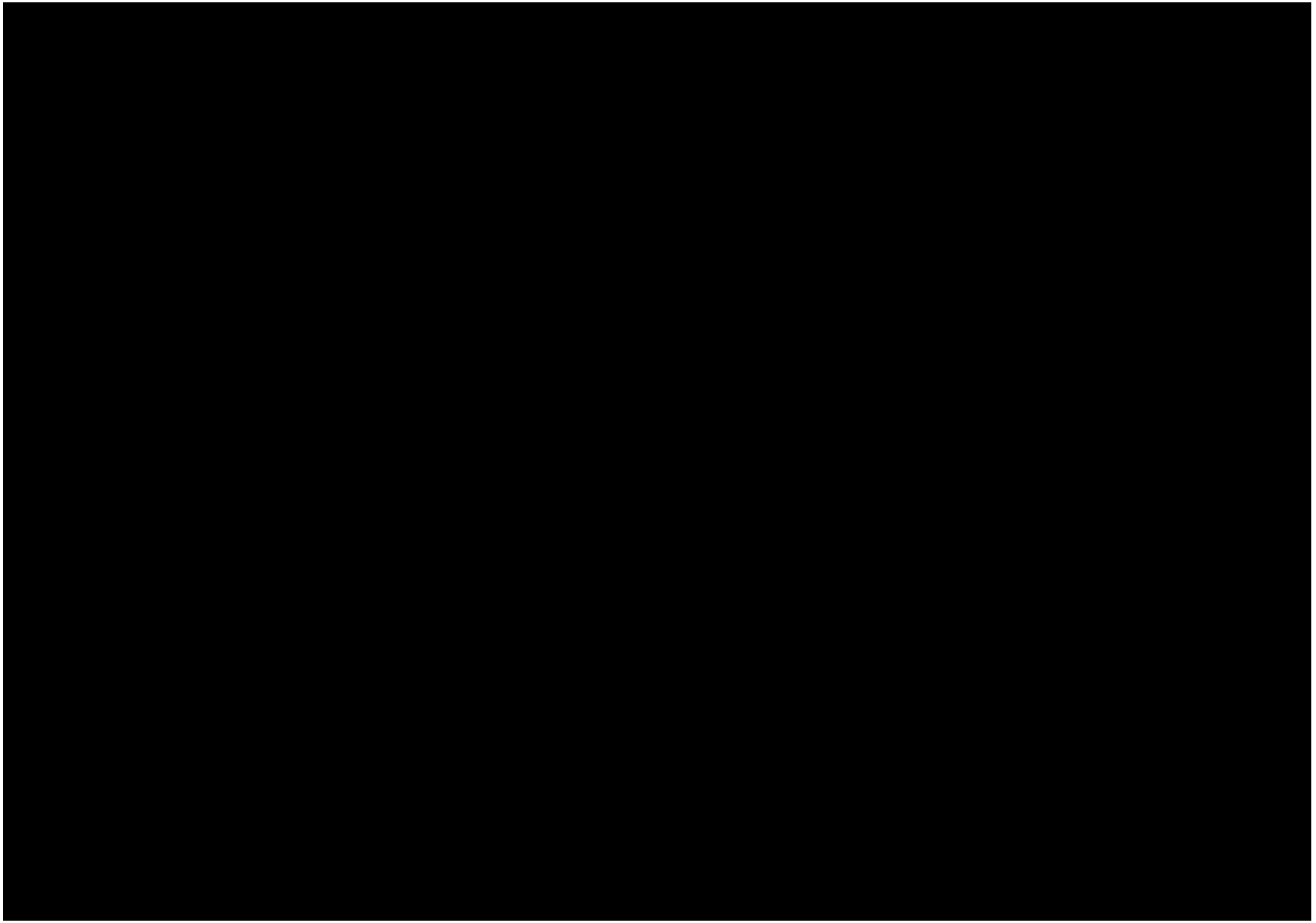


Figure 1-15 – Map of the Orchard No. 1–No. 7 locations (indicated by the blue diamonds) relative to existing wells within the wider area (black, dashed outline) and associated with hydrocarbon-producing play areas.

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–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

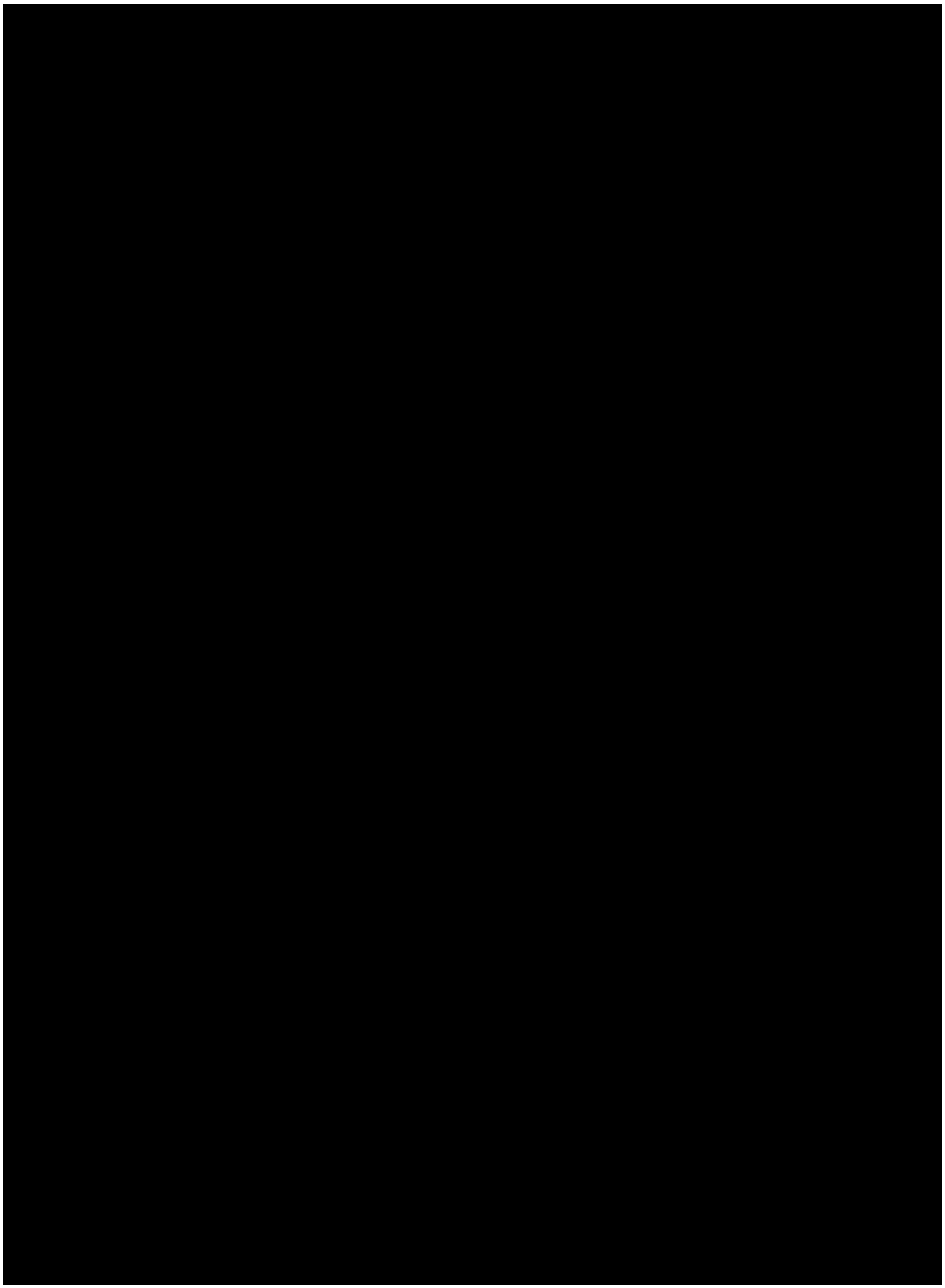
Well Logs

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 [redacted]

Thirty-three 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 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
[redacted]				



[redacted]

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 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.

Core

Two wells within the vicinity of the proposed Orchard No. 1–No. 7 wells are sources of site-specific core—from the top of the injection zone and base of the upper confining zone, respectively. Slabbed cores from two [redacted] were observed, plugged, described, and used for laboratory testing, courtesy of the Texas Bureau of Economic Geology. Table 1-2 provides a list of the cored intervals and testing program completed by Core Lab Houston. The Core Lab Final Core Reports are included in Appendix J-1 and J-2.

Table 1-2 – Cored Intervals and Testing Program

[redacted]

[redacted]

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, [redacted] The seismic line is [redacted] through the project area.

1.3.2 Injection Zone

[redacted]

[redacted]



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



Figure 1-18 – Depth structure map (TVD SS) for the base of the injection zone in the [redacted]

[redacted]

[redacted]

[redacted]



Figure 1-19 – Thickness map (ft) of the injection zone within the [redacted]



Figure 1-20 – Well log data and petrop [redacted] No. 1–No. 7 by approximately [redacted]
Track 1: @IGR is potassium-thorium (GAPI), and Track 8: v is Poisson's ratio, G is Shear modulus, E is Young's modulus, S [redacted] b is Bulk mod [redacted] ot 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 five wells (Figure 1-23 shows the well locations).

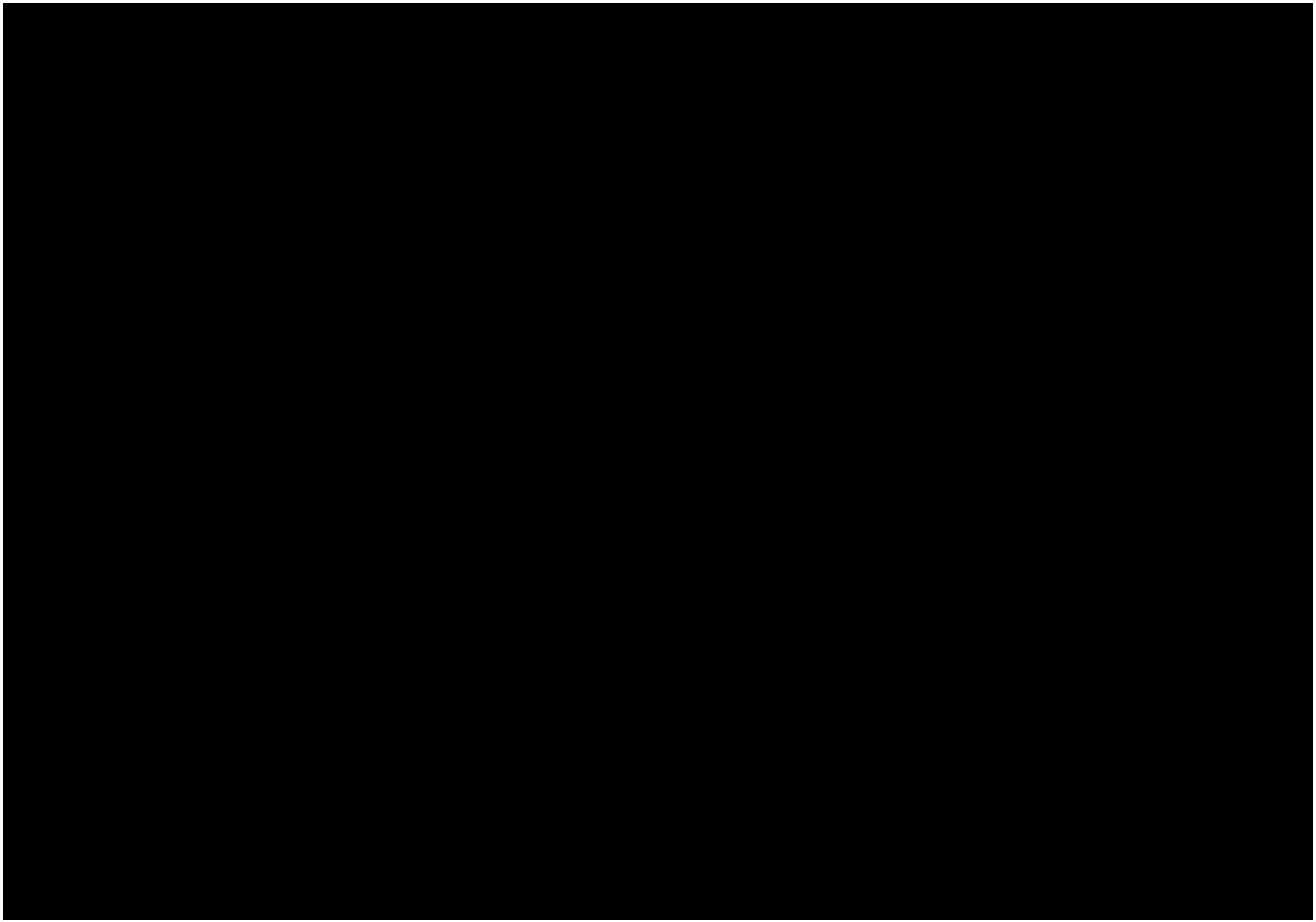


Figure 1-23 – Map showing the two cross sections in Figure 1-21 (indicated by the blue dashed line) and Figure 1-22 (green dashed line).The red vertical line indicates the location of the 2D seismic line.

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 [redacted] 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.

Lithology

[redacted]

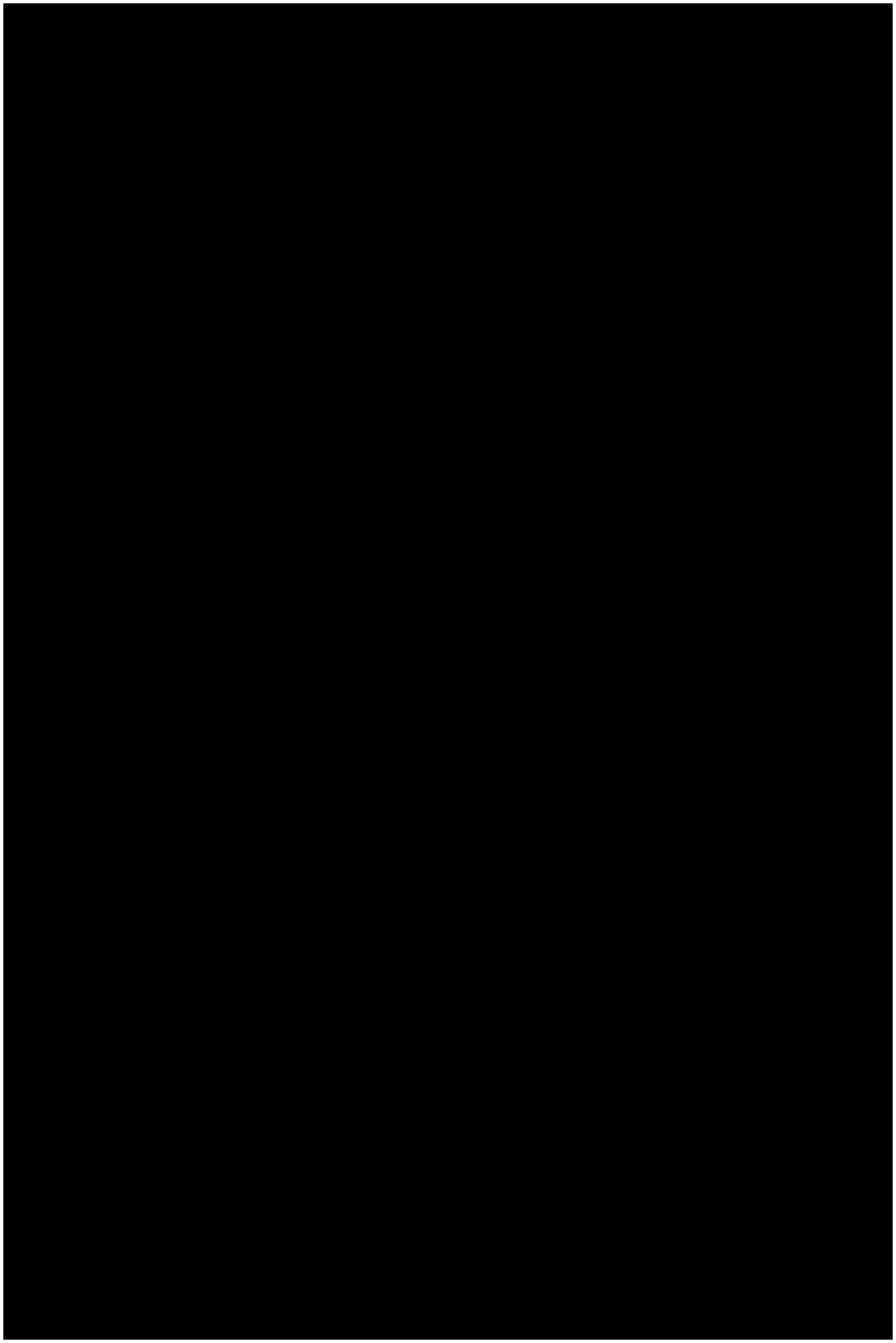
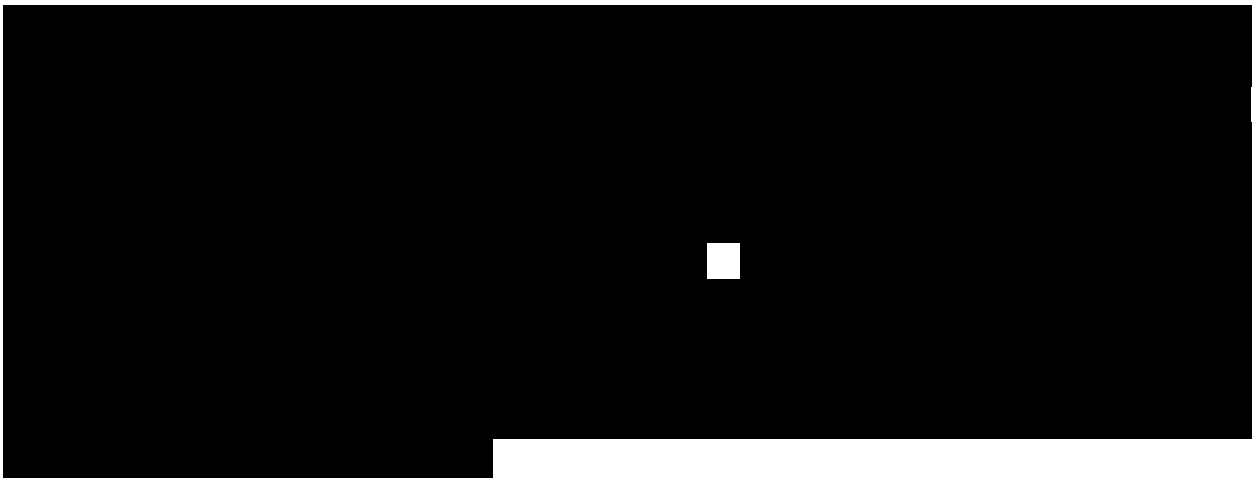


Figure 1-24 – Well log and core data for well [redacted] Core plugs measured porosity and permeability (air) (indicated by white dots), core "rock types" (multi-colored bands), and mini-permeameter measured permeability (air) (black dots).

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

[redacted]

Figures 1-25 to 1-29 show thin-section photographs and interpretations.



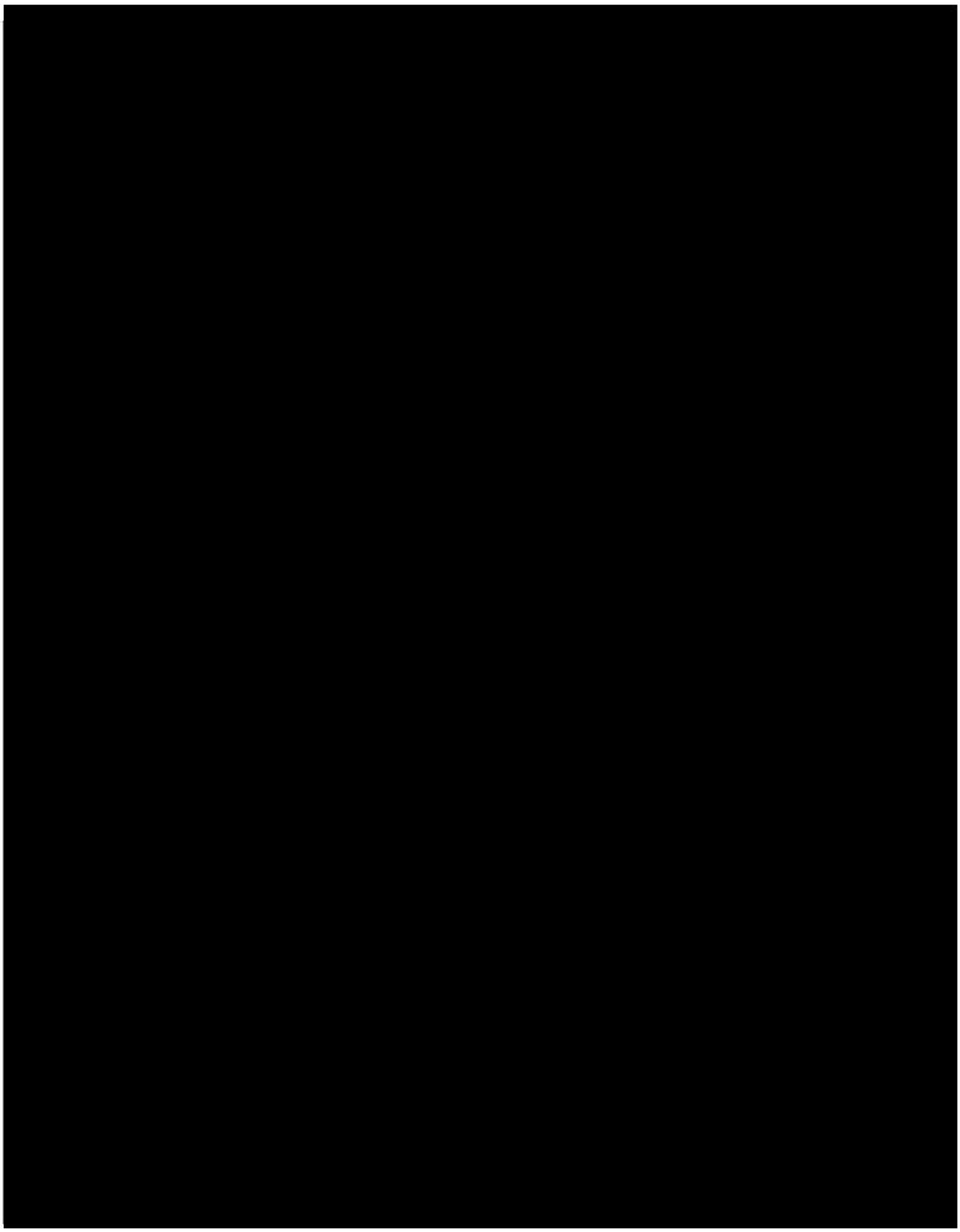
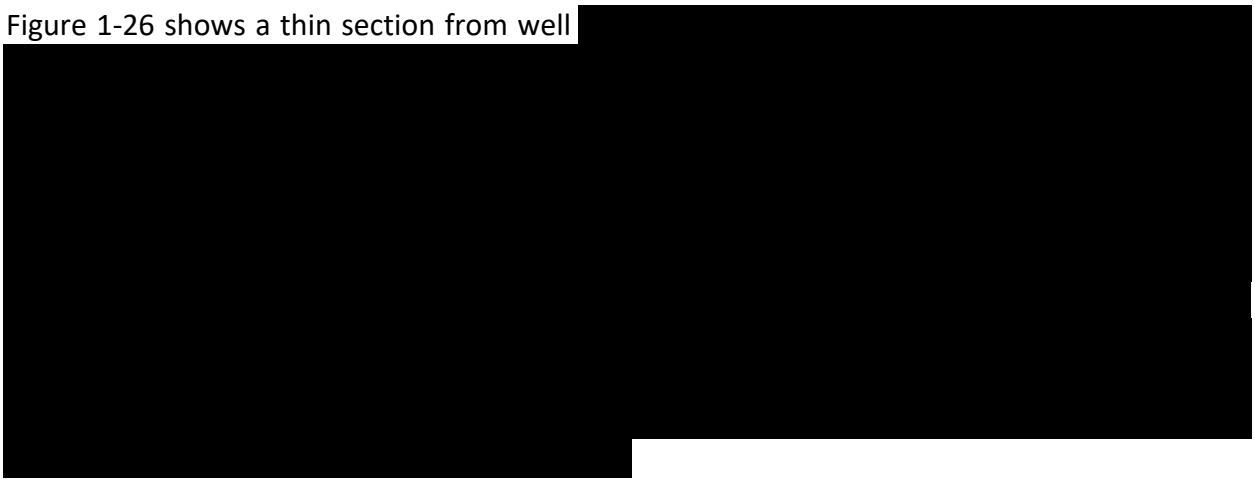


Figure 1-25 – Thin section from well API No. [redacted]

Figure 1-26 shows a thin section from well [redacted]



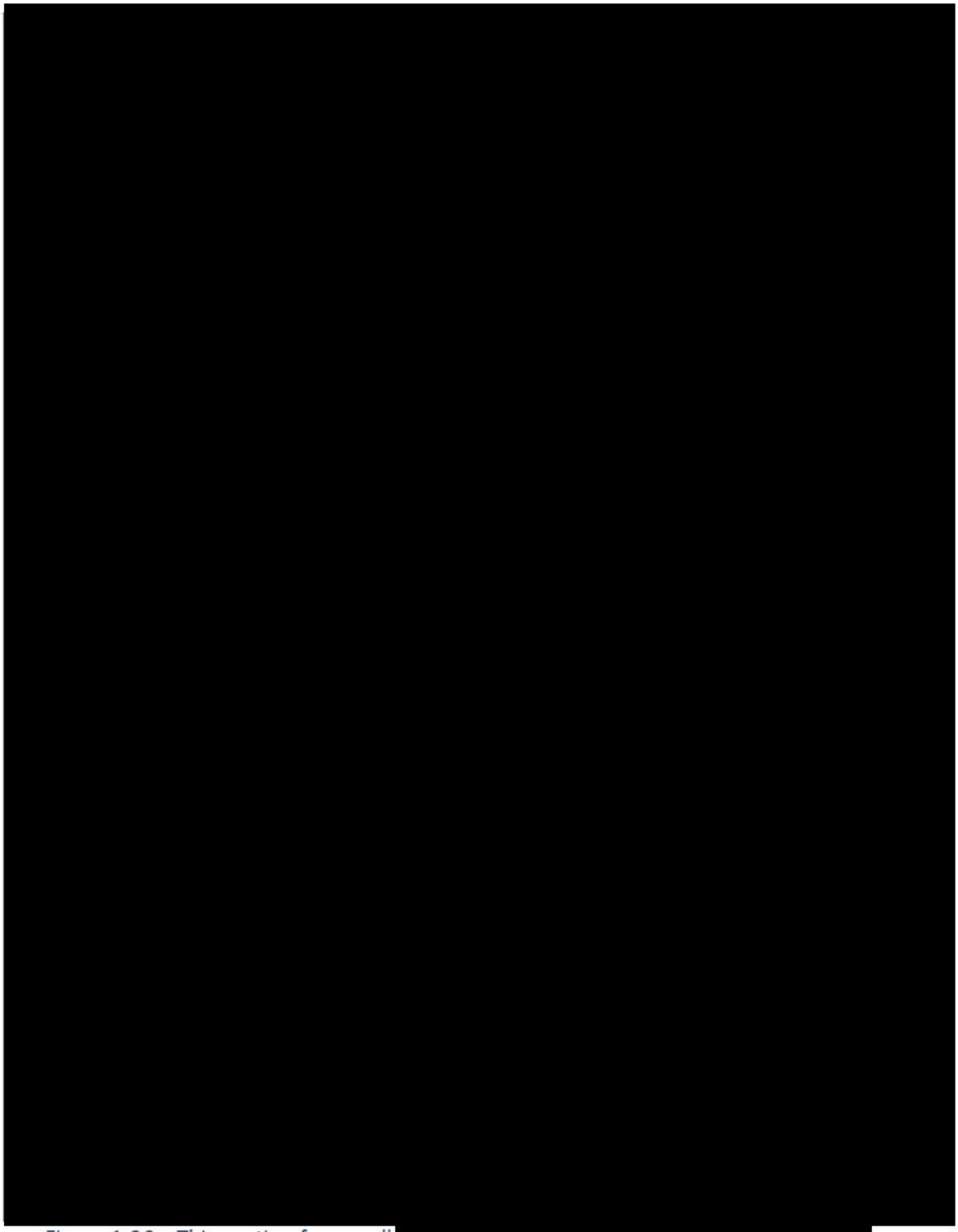
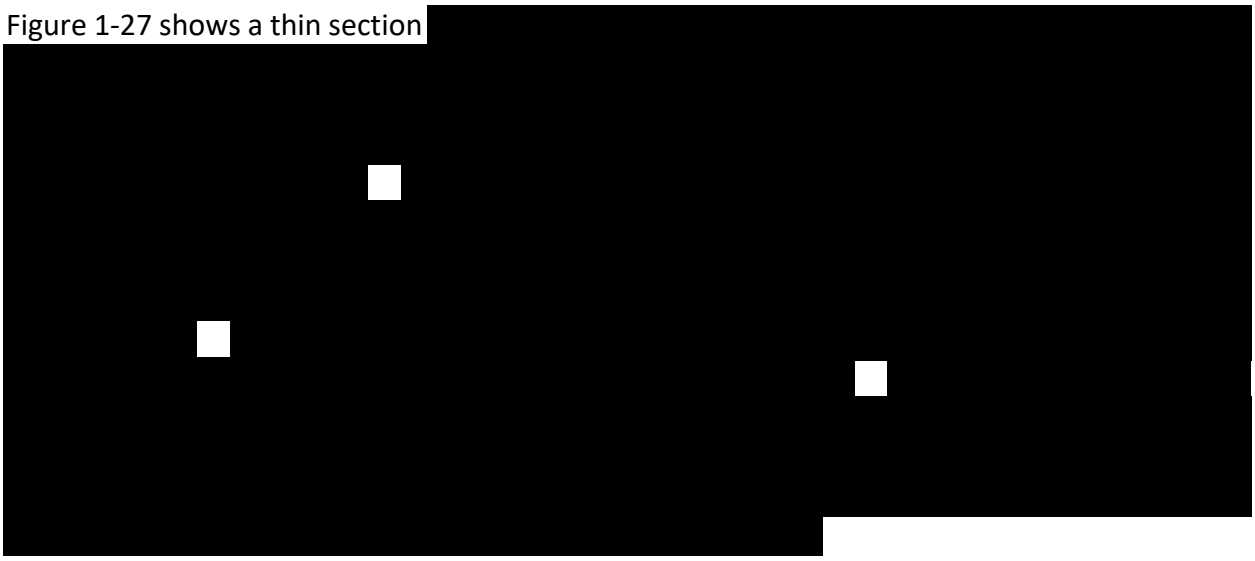


Figure 1-26 – Thin section from well [redacted]

Figure 1-27 shows a thin section



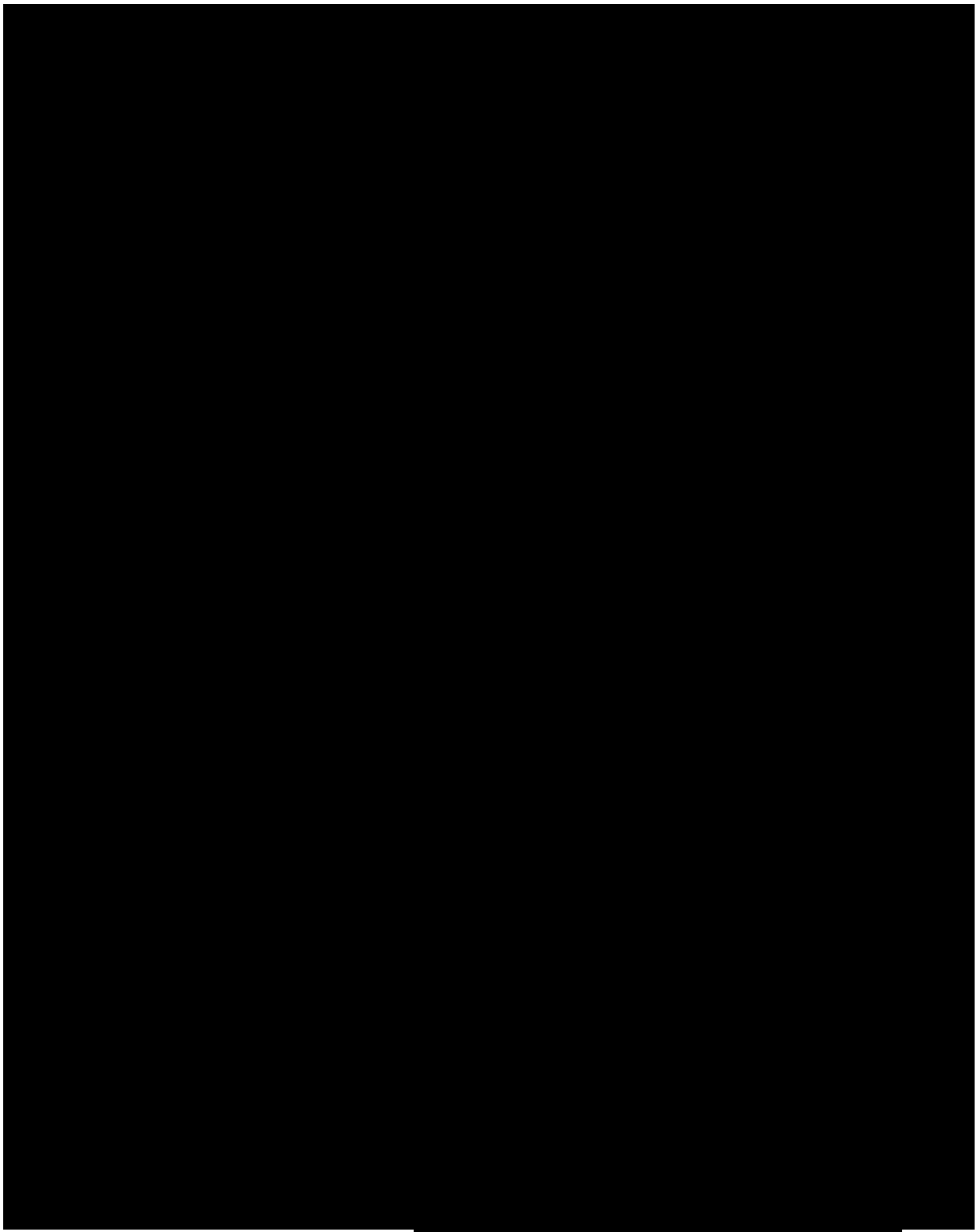


Figure 1-27 – Thin section from well [redacted]

Figure 1-28 shows a thin section [redacted]

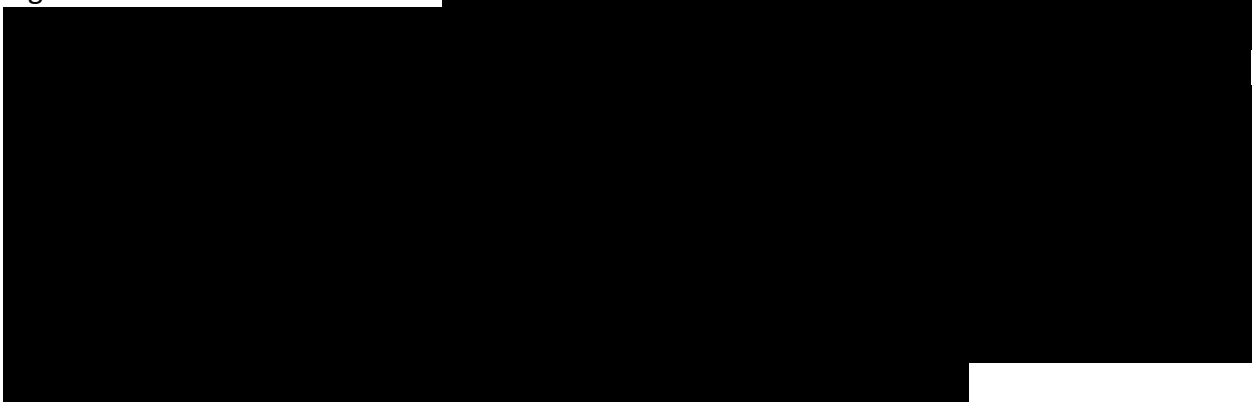
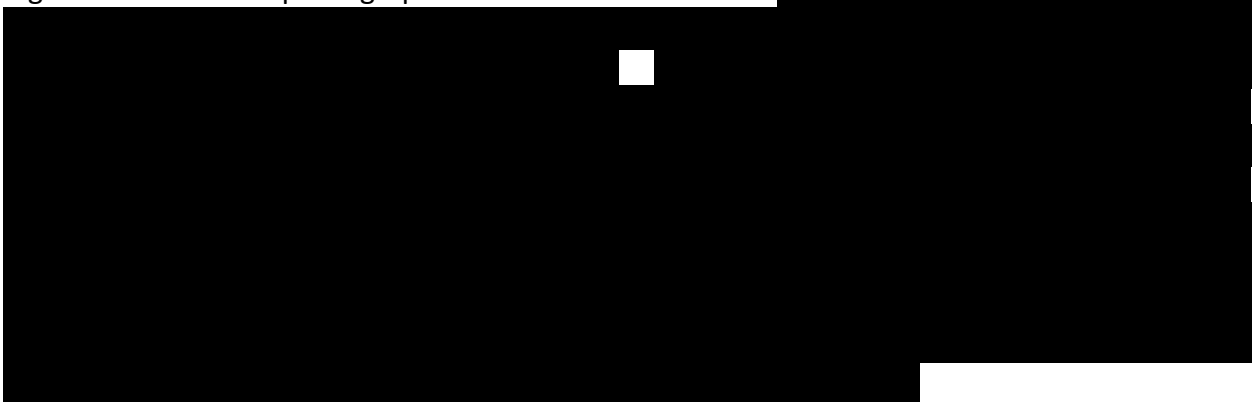




Figure 1-28 – Thin section from well [redacted]

Figure 1-29 shows a photographed thin section from well [redacted]



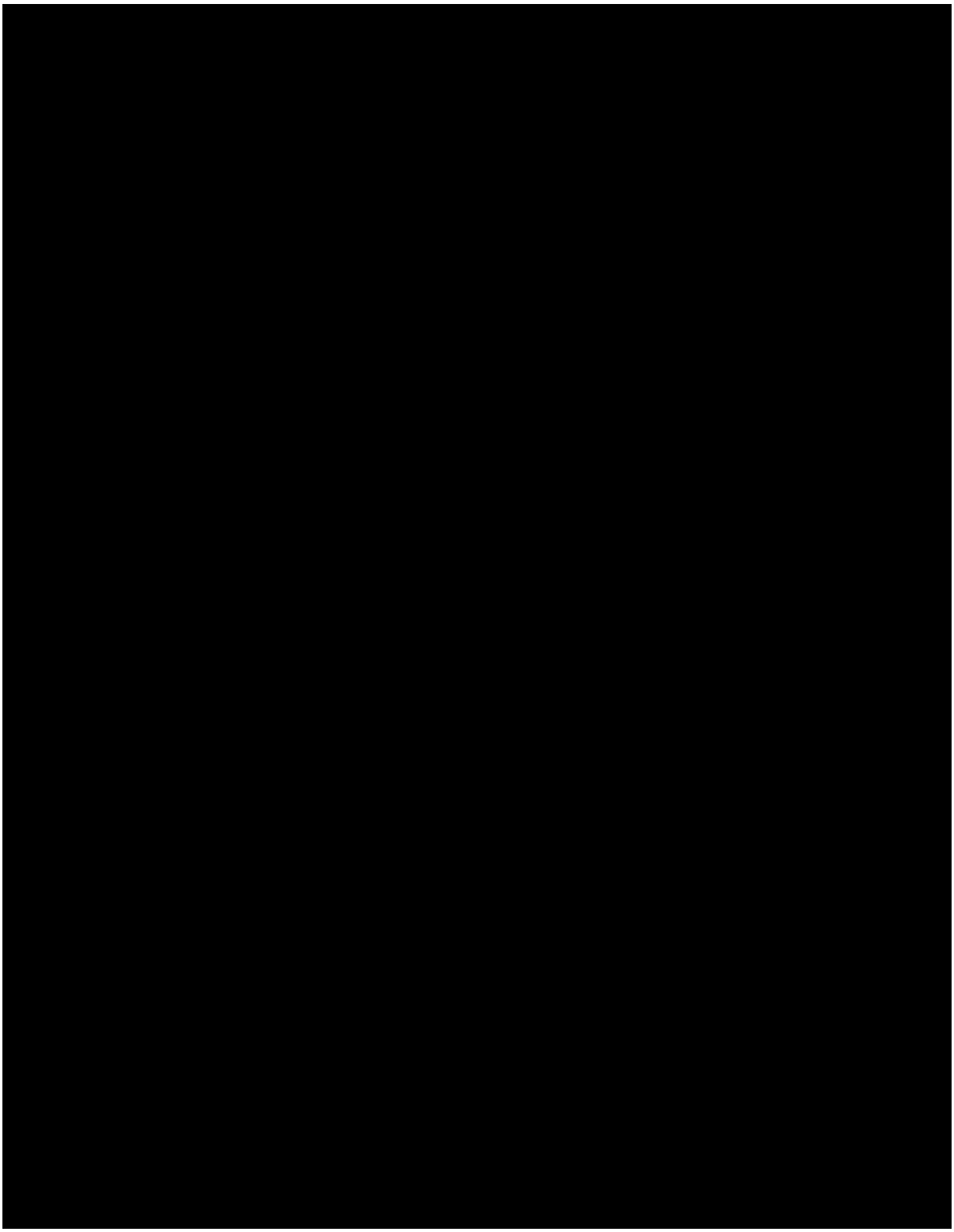


Figure 1-29 – Thin section from well [redacted]

Figures 1-30 to 1-33 show photographs of the [redacted]

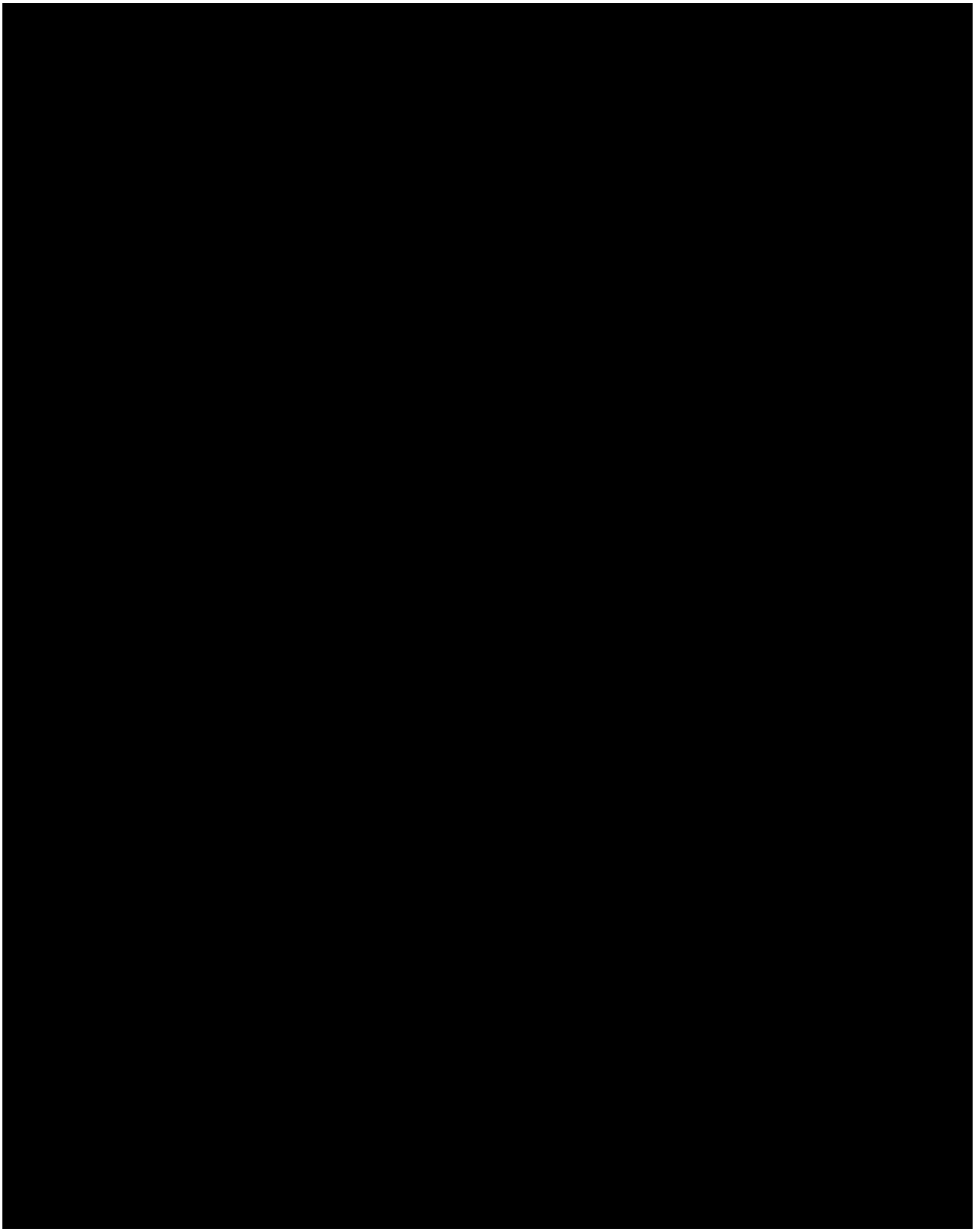


Figure 1-30 – White-light photograph of slabbed core of well [redacted]

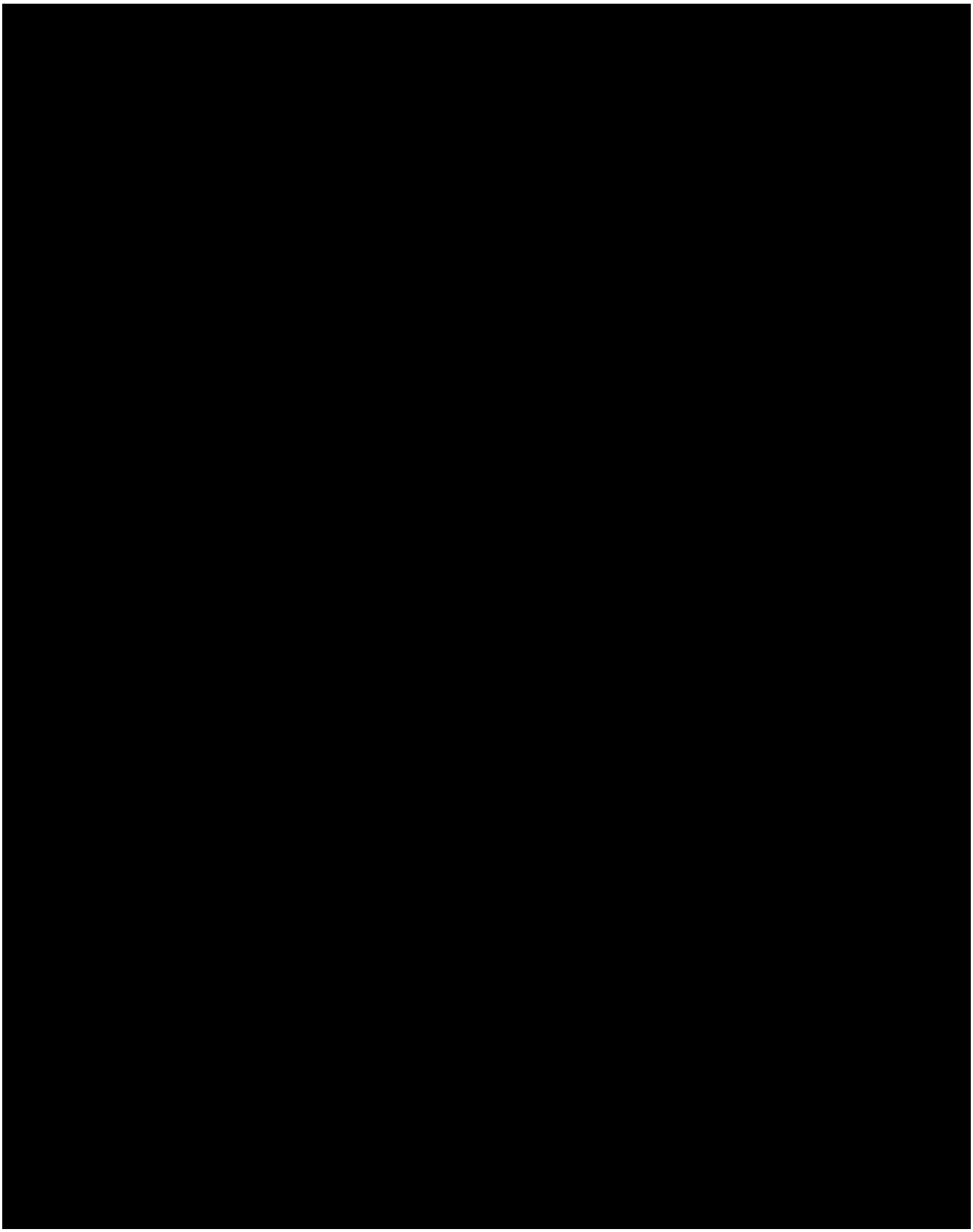


Figure 1-31 – White-light photograph of slabbed core of well [redacted]

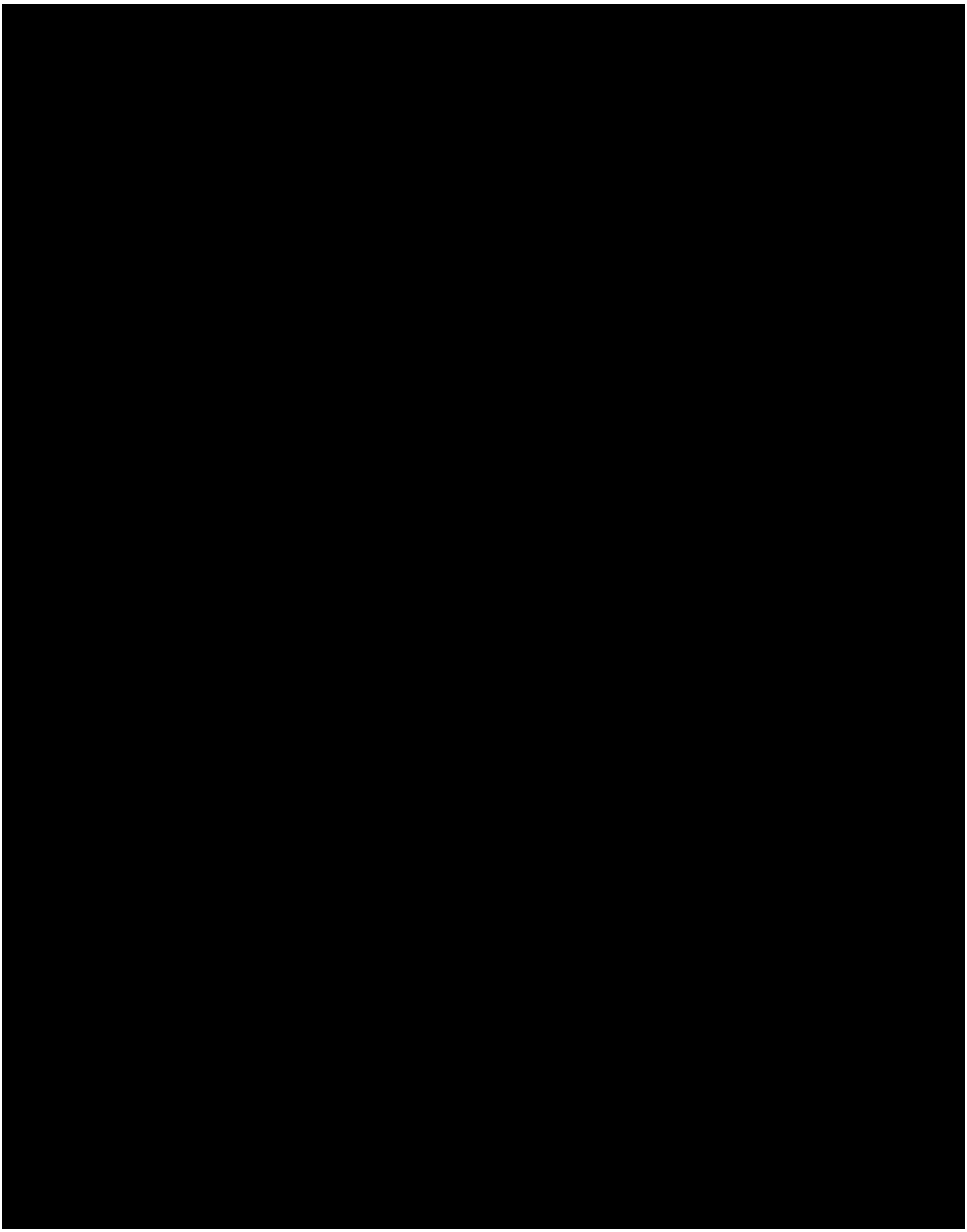


Figure 1-32 – White-light photograph of slabbed core of well [redacted]

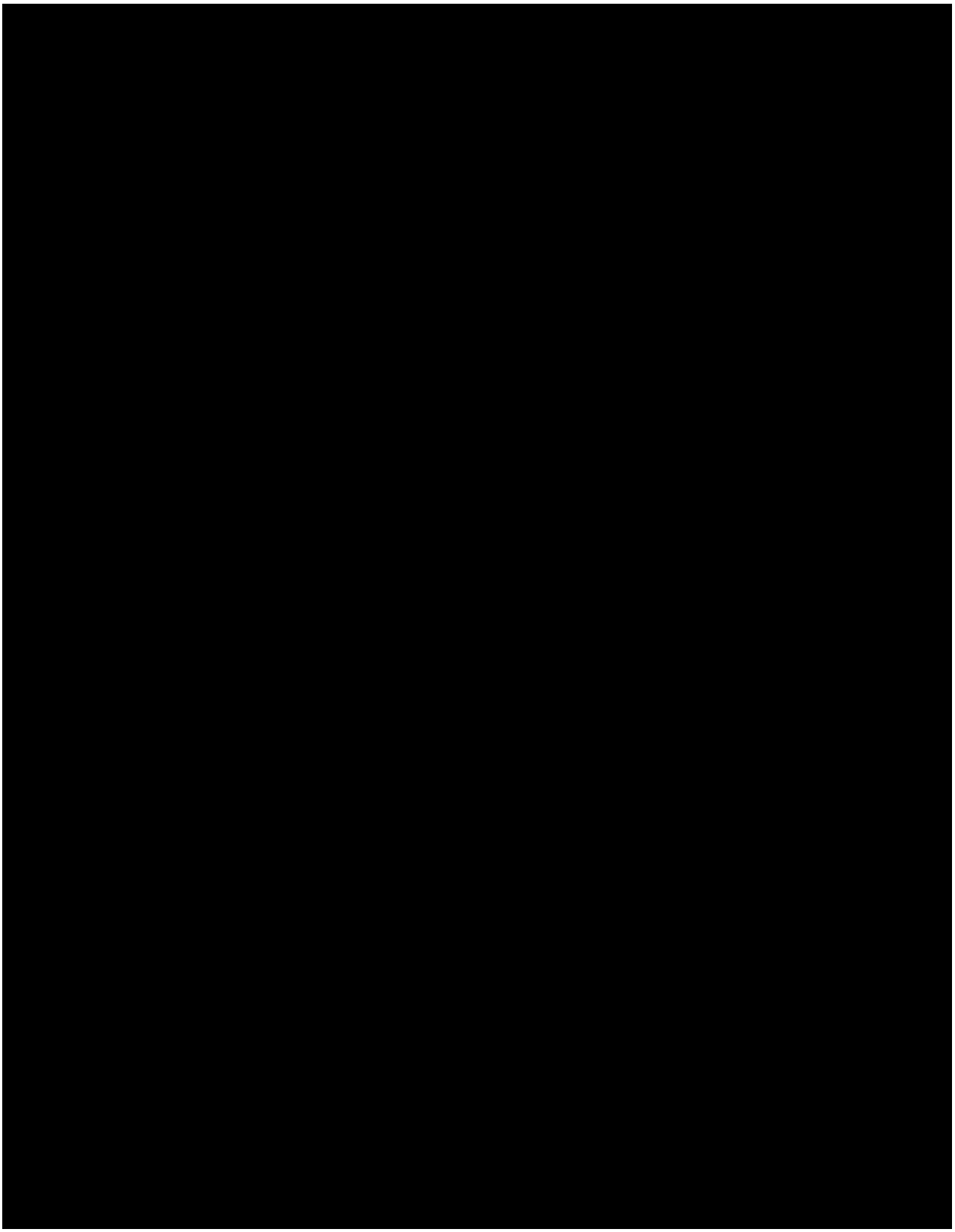


Figure 1-33 – White-light photograph of slabbed core of well [redacted]

Well log data shown in the type well [redacted] was quantitatively used to understand the dominant lithology in [redacted]. Other well data were used to qualitatively understand whether the dominant lithology in the injection zone is [redacted]. 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.*

Porosity

Density porosity was derived using the bulk density log and an estimated matrix density for the [redacted]

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).

[redacted] or 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 [redacted] injection interval.

Figure 1-34 shows an average porosity map for the [redacted] 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 [redacted]. 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., [redacted]). 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 1-34 – Average porosity map of the [redacted] injection zone.

The average porosity map indicates several changes outside of the Orchard Project area. [redacted]

Core plugs were acquired, and 28 conventional porosity and permeability measurements (in both ambient and stressed conditions) were taken in the Orchard Project area. Table 1-3 shows the results of conventional plug analysis for well [redacted] Samples [redacted] are vertical plugs, and the remainder are horizontal. The complete core analysis report for this well is provided in Appendix J-2.

Table 1-3 – Results of conventional plug analysis for well [redacted] (Appendix J-2, pg 22).

[redacted]

X-ray diffraction results showed [redacted] the injection zone. This may correlate to the low total gamma ray well-log expression observed in the cored well and other nearby wells. Discussion of rock mineralogy continues in *Section 1.6*.

[redacted] 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.

Permeability (Horizontal)

The average calculated matrix permeability for [redacted]. Permeability was derived using [redacted] 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 [redacted]

Figure 1-35 shows the continuum of rock fabrics and associated porosity-permeability transforms: [redacted]

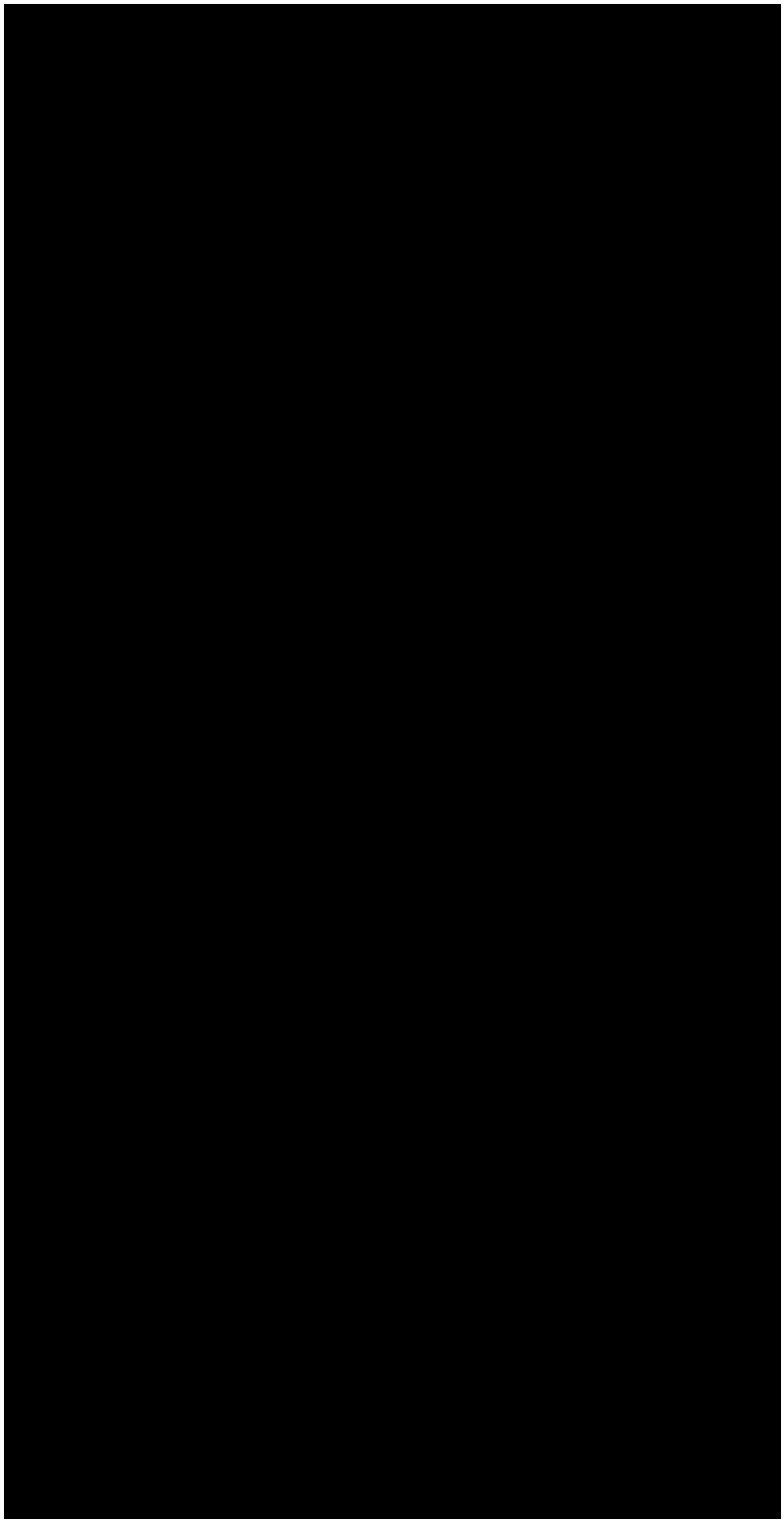


Figure 1-35 – The continuum of rock fabrics and associated porosity-permeability transforms:

[redacted]

The basis for designing two permeability scenarios was the regional geologic model for the possible range and dominant lithofacies expected in the [redacted]

Figure 1-36 shows a chart of core-plug porosity versus permeability (air) measurements for well [redacted] Points are colored by "rock type" interpretations from the slabbed core description. Table 1-4 shows the permeability, determined using the pressure-decay profile permeameter (Core Lab Houston).

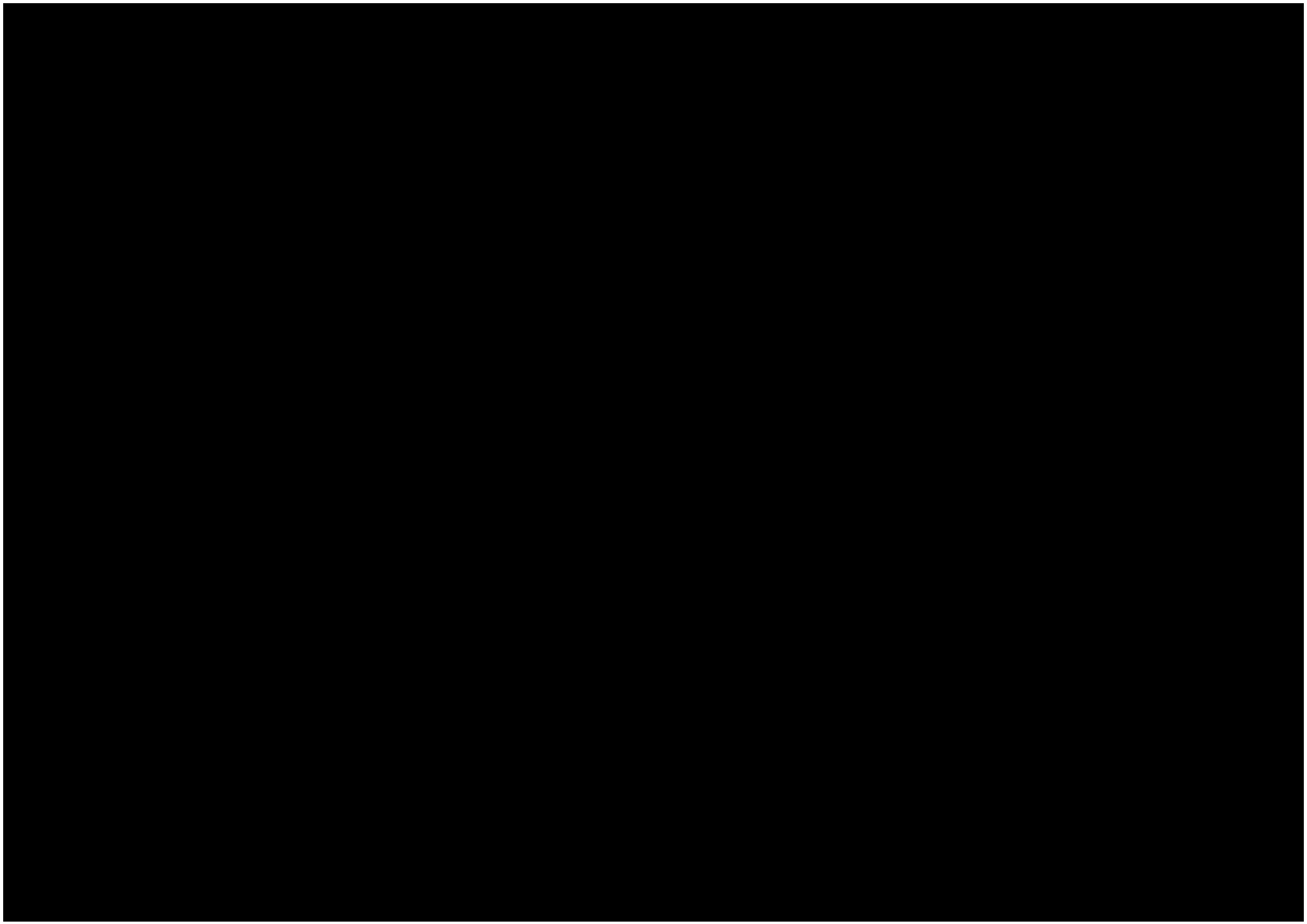


Figure 1-36 – A chart of core-plug porosity versus permeability (air) measurements for well [redacted] Points are colored by "rock type" interpretations from the slabbed core description.

Table 1-4 – Permeability determined using the pressure-decay profile permeameter [redacted]

Depth (ft)	Ka (mD)	Core	Oil-Staining Intensity (0 is lowest)
[redacted]			

The [redacted] for the 3D numerical model permeability for area of review (AOR) delineation was [redacted] No correction was applied to porosity used for calculating permeability [redacted], as porosity is treated as equal to interparticle porosity. [redacted]

Permeability measurements using the pressure-decay profile permeameter provided an understanding of the possible permeability ranges for the 60 ft of the available core at the top of the injection zone. Samples were taken every 2 ft along the slabbed core. [redacted]

Residual oil staining was observed in person on the core as well as in the white-light photographs. These "high intensity" oil-staining occurrences correlate to the core description of the rock types, where grain-rich rocks represent higher permeability than mud-rich sections.

Conventional porosity and permeability measurements of 22 plugs (28 measurements total) demonstrated a similar set of results as was described in Table 1-3. Permeability measurements (both stressed and unstressed) plotted closer to [redacted] based on their measured porosity values. Most samples reflect lower porosity than average well-log-derived values for the [redacted] which may be attributable to the core being from the lower porosity 60 ft at the top of the injection zone. [redacted] based on well logs in the Orchard Project area.

Permeability (Vertical)

Vertical permeability is an order of magnitude lower than horizontal permeability in [redacted] The ratio between vertical and horizontal permeability (kv/kh) for [redacted]

[redacted]

Water Saturation

The Orchard Project area is absent hydrocarbon production due to the migration of hydrocarbons out of the area, therefore leaving behind a residual oil zone. Water saturation was derived using Archie's methodology as follows:

$$Sw^n = ((a*Rw)/(Rt*phi^m))$$

Where:
Sw = water saturation
n = saturation exponent
a = tortuosity factor

m = cementation exponent
Rw = resistivity of formation water at formation temperature
Rt = resistivity of the formation.

Figure 1-37 shows the mud-log gas readings and the petrophysical water-saturation well log derived using that Archie equation, while Figure 1-38 shows a snapshot of the mud-log sample description and gas readings for well [redacted]

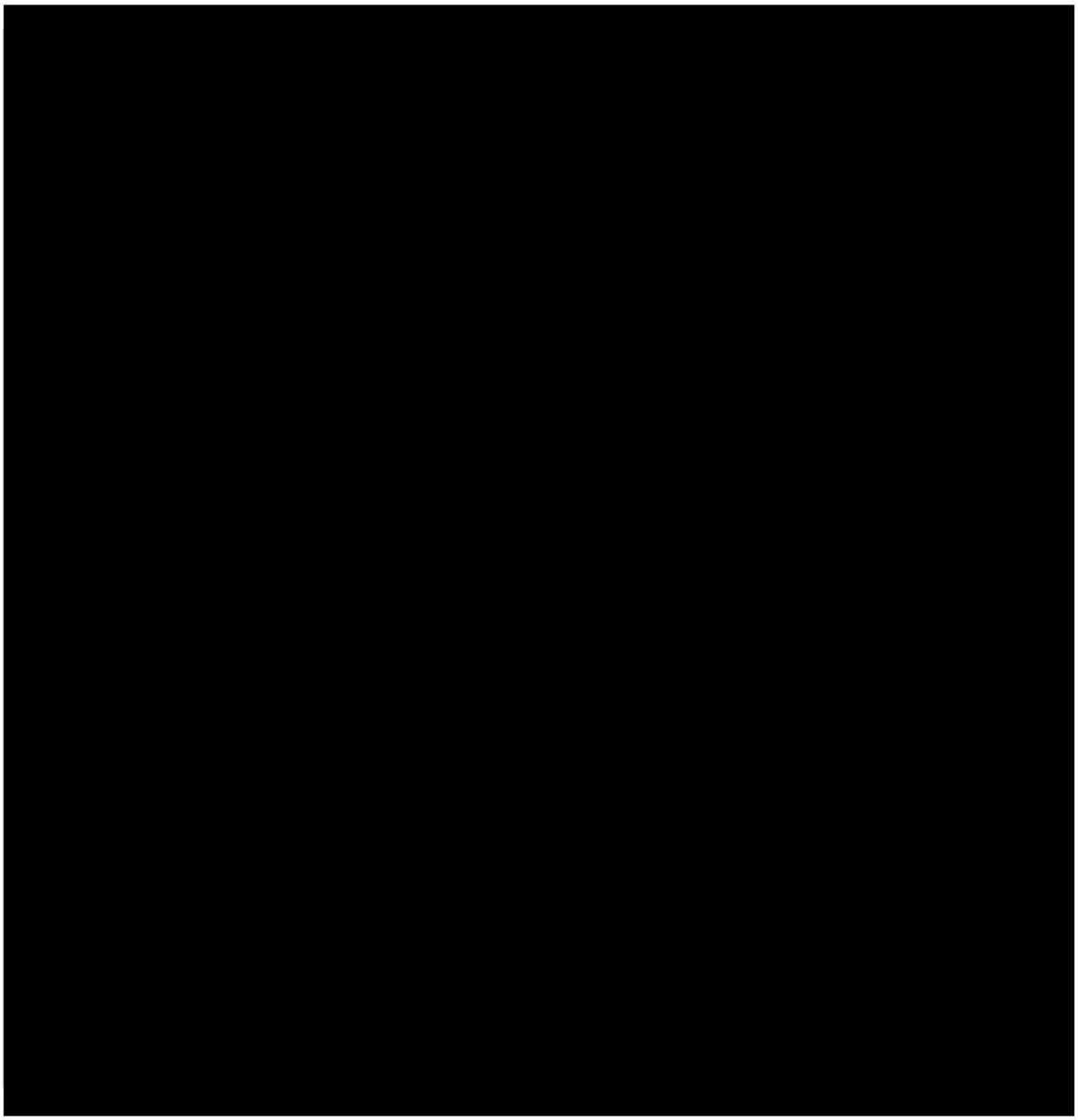


Figure 1-37 – Mud log gas readings (second track from the right) and the petrophysical water-saturation well log derived using Archie's methodology (last track) for [redacted]

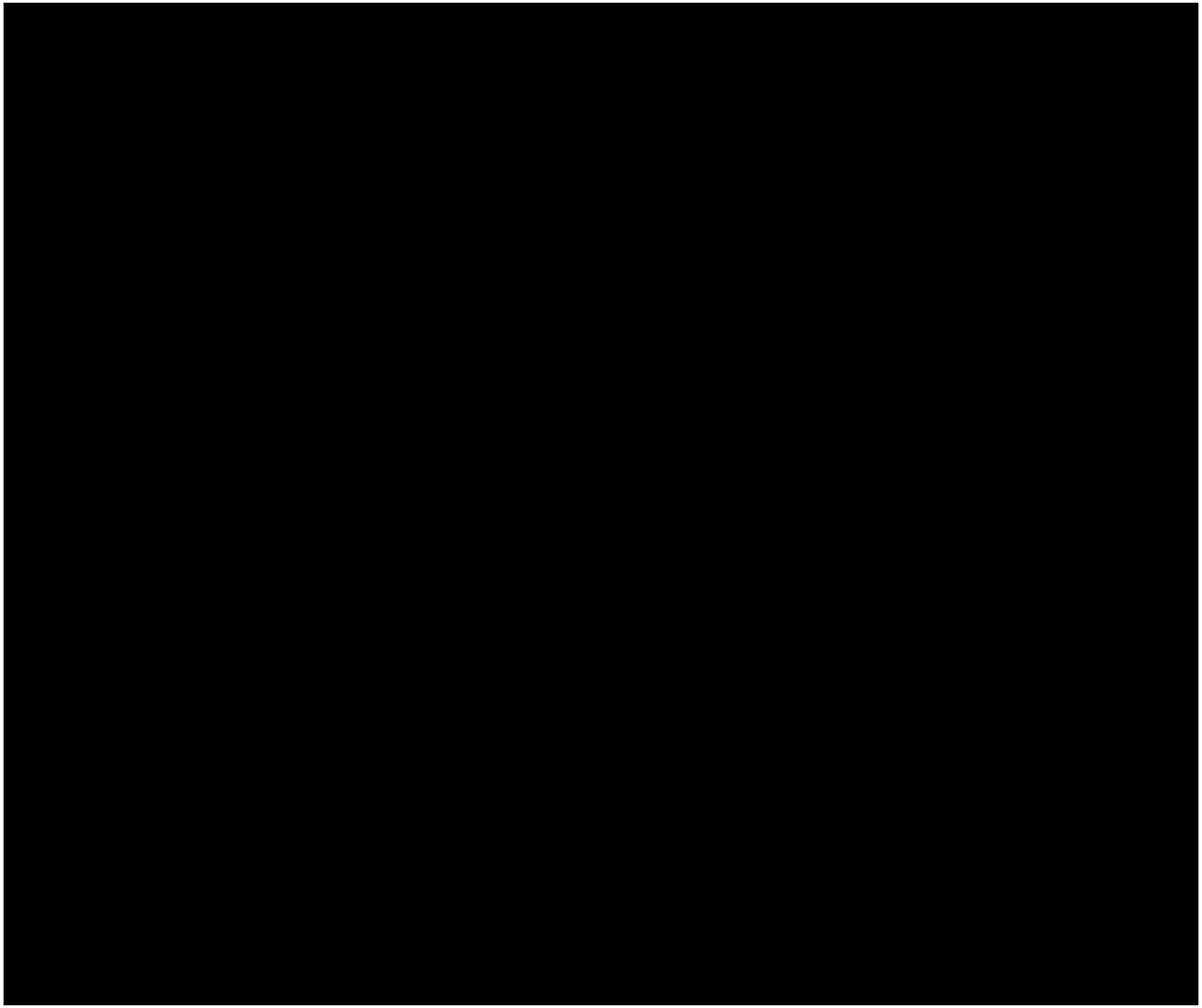


Figure 1-38 – A snapshot of the mud-log sample description and gas readings for well [redacted]

[redacted]

The average water saturation in the [redacted] injection zone is approximately [redacted] based on the petrophysical calculation. The [redacted] is treated as having 100% water saturation based on the high calculated water-saturation values. [redacted] correlate to the top portion of the injection zone having the lowest calculated water saturation. [redacted] of the Orchard Project area also show similar [redacted] in the equivalent interval in the [redacted] injection zone.

A discussion of how the water saturation is accounted for in the 3D numerical model is presented in *Section 3 – Area of Review and Corrective Action Plan.*

[redacted]

Table 1-5 compares the different sets of Archie parameters.

Table 1-5 – Comparison Between Two Different Sets of Archie Parameters

Archie Parameter	[redacted]
a	
m	
n	
Rw	

1.3.3 Primary Upper Confining Zone

The top portion of the [redacted], comprise the primary confining zone overlying the injection zone. The combined thickness of the Upper [redacted] confining zone is [redacted] ft in the Orchard Project area. The top and bottom depths are approximately [redacted], respectively.

Figure 1-39 shows a depth structure map for the top of the upper confining zone ([redacted] (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 1-40 shows a thickness map of the [redacted]

confining zone. Figure 1-41 is a structure map of [redacted]. Figure 1-42 shows a thickness map for the [redacted] and Figure 1-43 is an isopach of the [redacted] confining zone.

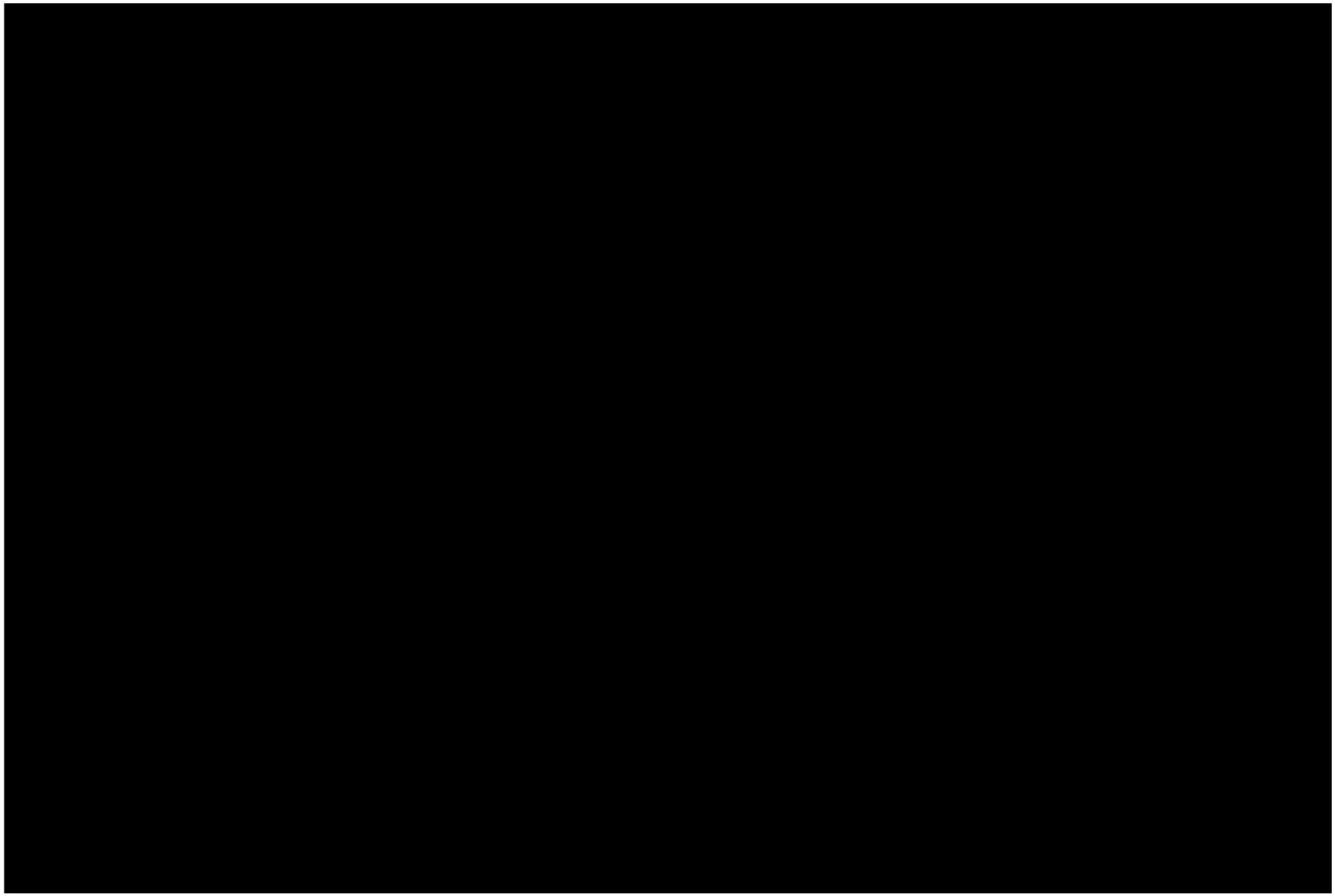


Figure 1-39 – Depth structure map (TVD SS) for the top of the upper confining zone [redacted]

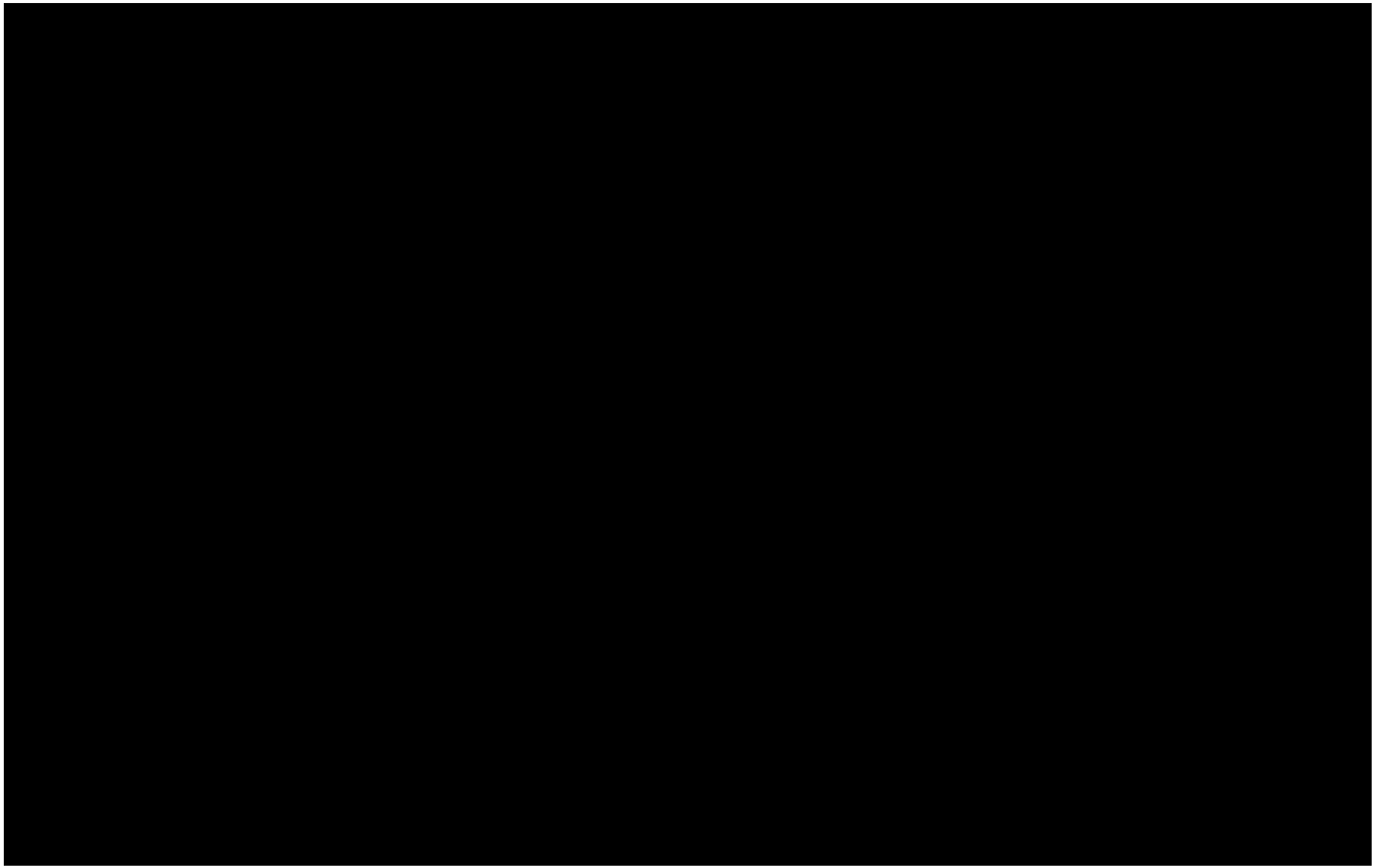


Figure 1-40 – Thickness Map of the Upper Confining Zone

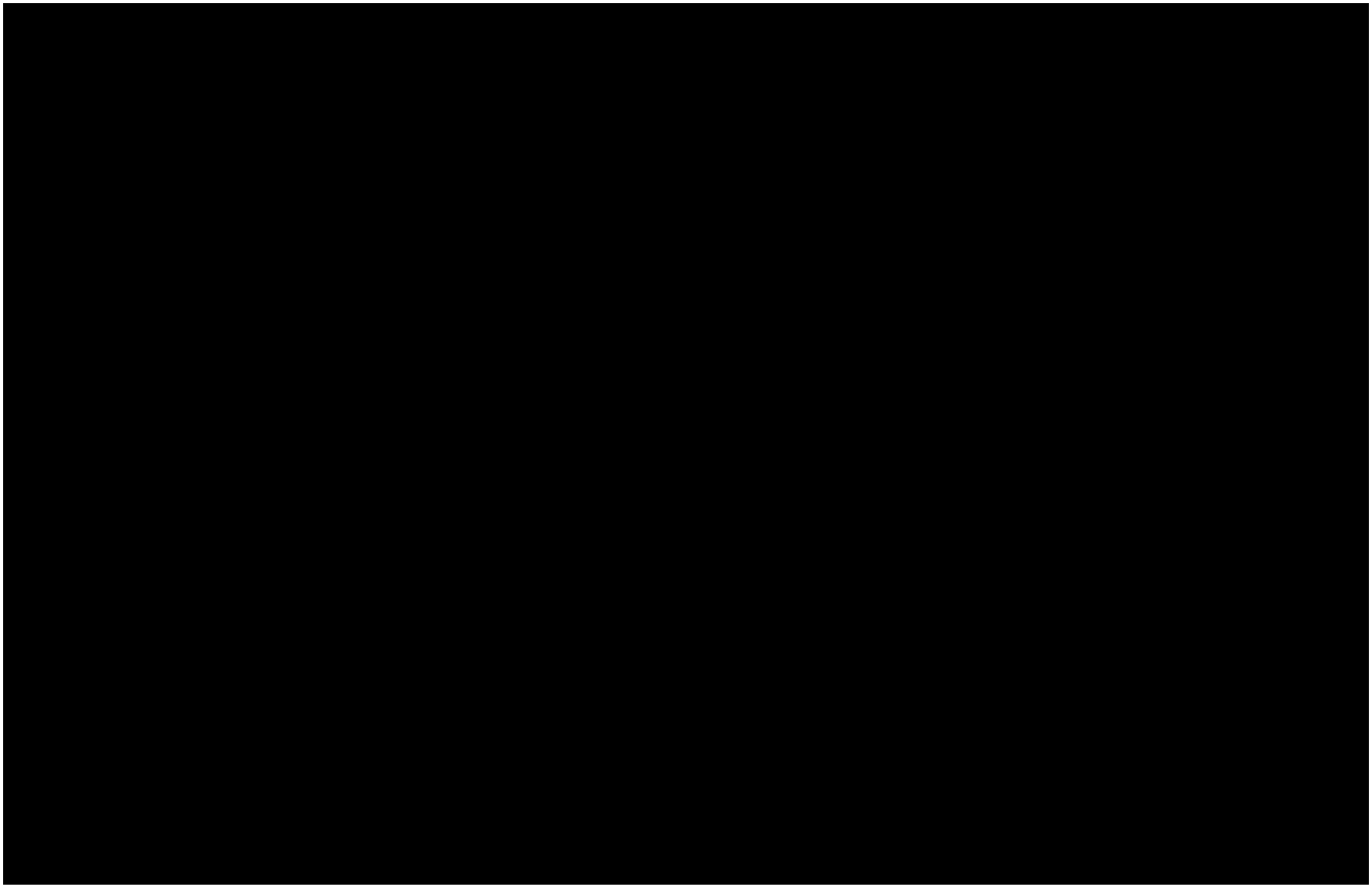


Figure 1-41 – Structure Map of the [redacted]

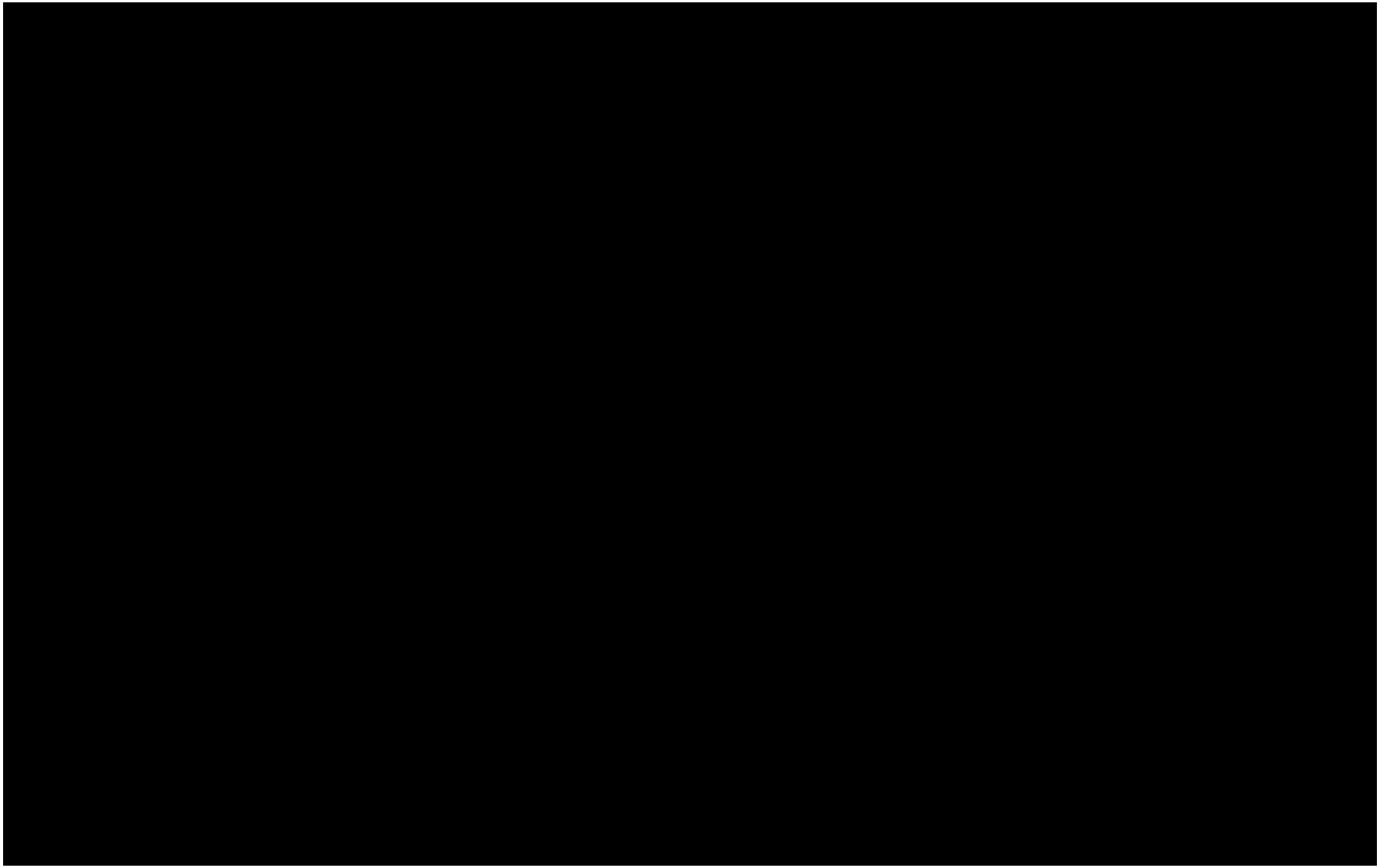


Figure 1-42 – Thickness Map of the [redacted]

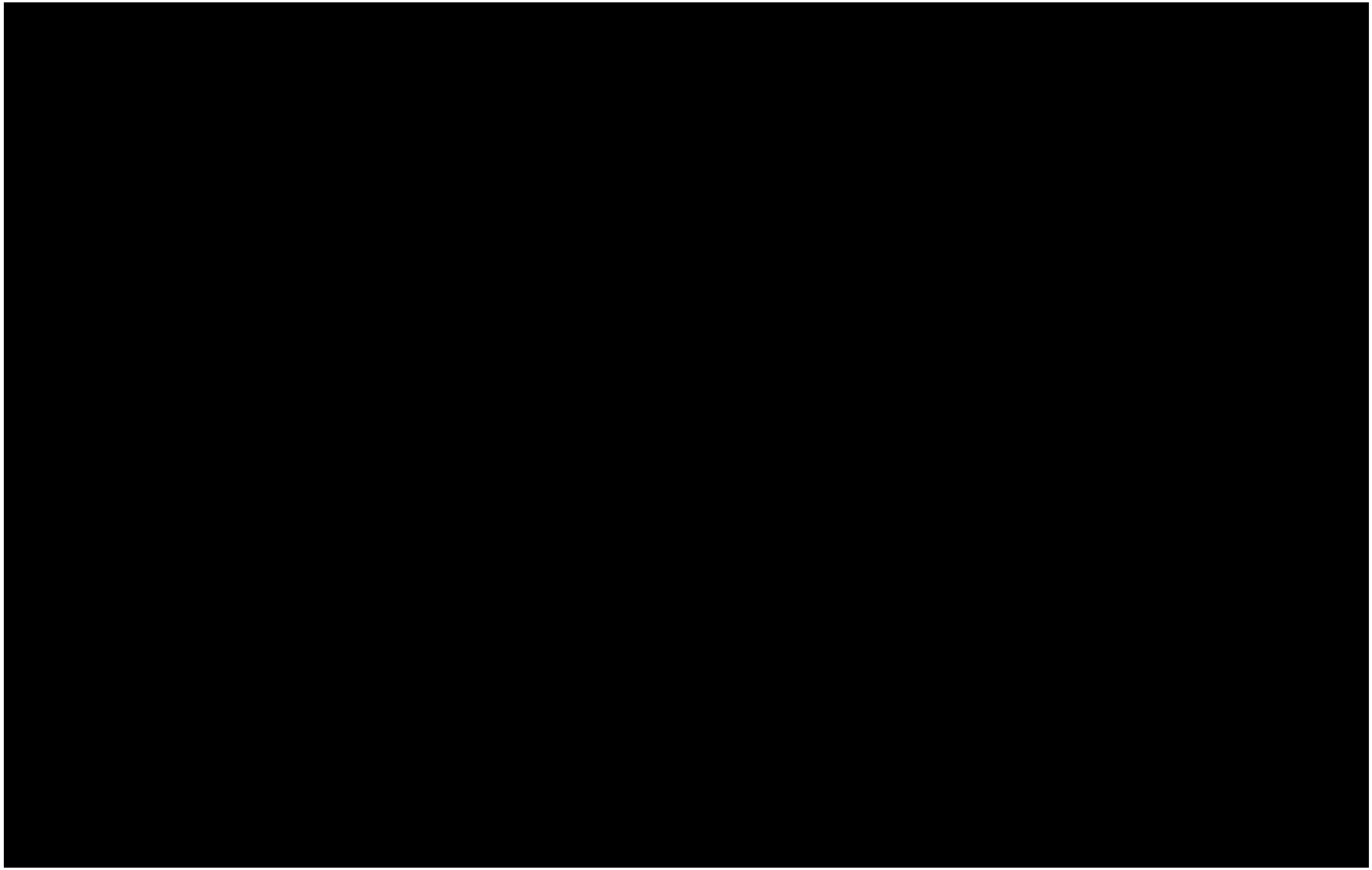


Figure 1-43 – Isopach Map of Combined [redacted]

Lithology

The primary upper confining zone in the Orchard Project area can 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.

[redacted] combine predominantly [redacted] This interval is laterally homogenous and vertically heterogeneous over the region, indicating effective confinement wider than the scope of the project area.

[redacted] The core in the lower part of the confining zone helps to demonstrate the transition of lithofacies from an injection zone to the beginnings of a confining zone. Figure 1-45 shows a map of the location of the cross section in Figure 1-44.



Figure 1-44 – A cross section of wells [redacted].

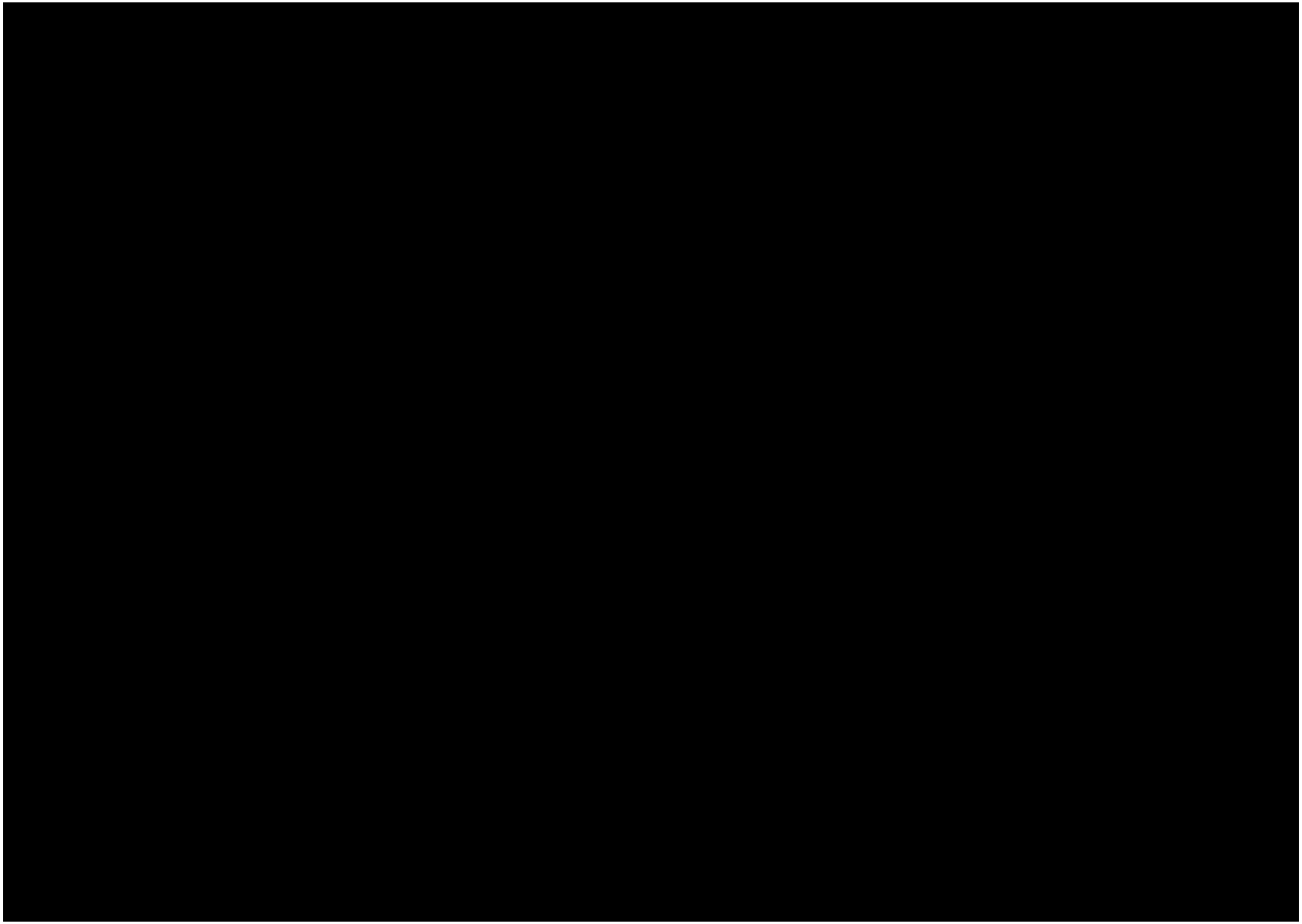


Figure 1-45– Map showing the location of the cross section (indicated by the black dashed line) in Figure 1-41 and N-S 2D Seismic Line (A-A') in Figure 1-61, 1-62, 1-63)

The site-specific slabbed core from [redacted] 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 [redacted]

[redacted] the Orchard Project [redacted] In the project area, however, the well logs exhibit more of a laterally consistent low-porosity lithofacies in the basal part of the confining zone and are likely representative of lower-energy settings, 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 1-46 through 1-57). These vertical core plug samples demonstrate how the basal part of the confining zone to the [redacted] Orchard Project area is highly heterogeneous and dominantly low porosity.

Figure 1-46 shows a thin section from [redacted]

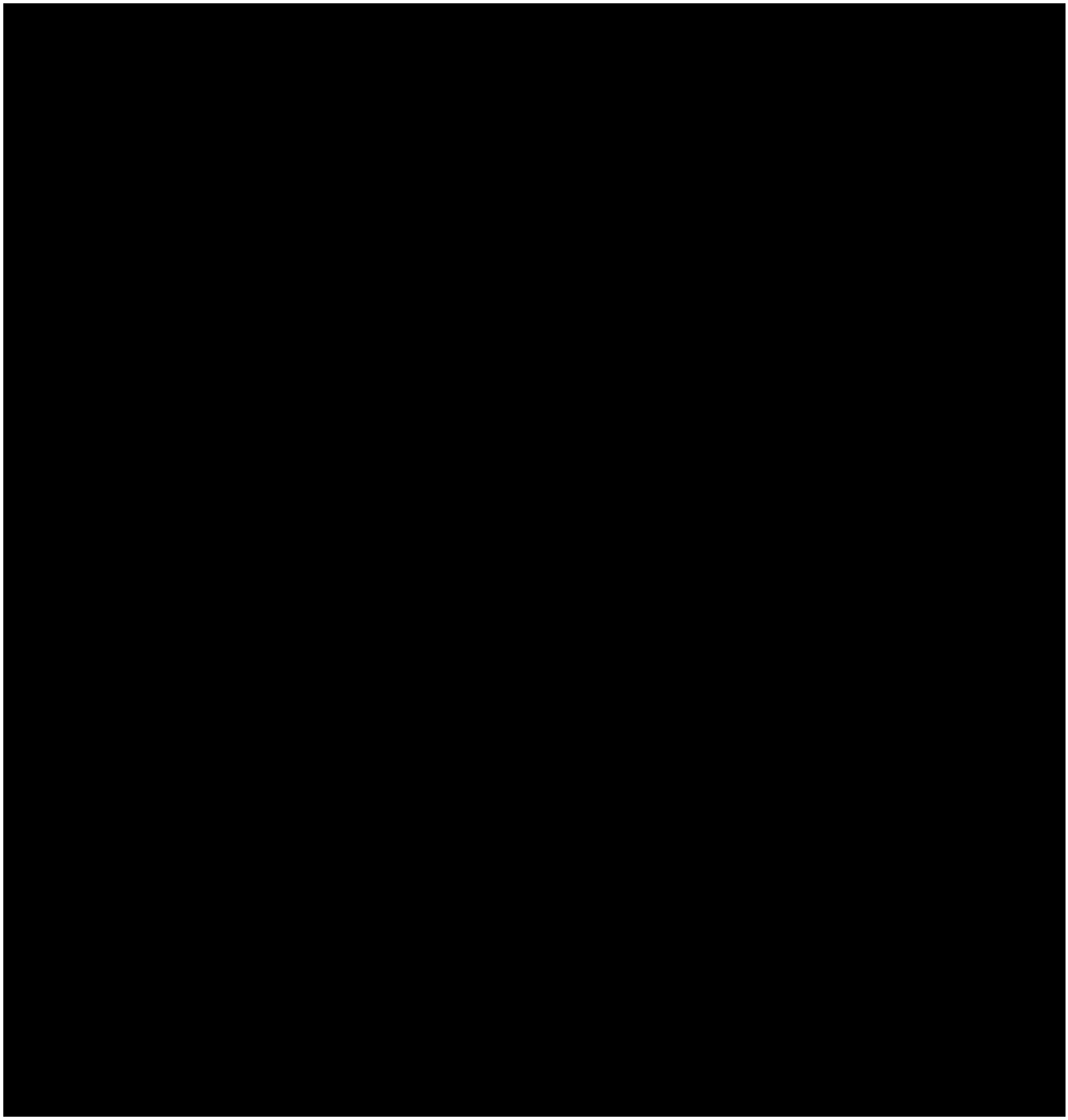


Figure 1-46 – Thin section from well [redacted]



Figure 1-47 – Photograph of slabbed core for well [redacted], where the thin section in Figure 1-47 was acquired.

Figure 1-48 shows a thin section from well [redacted]



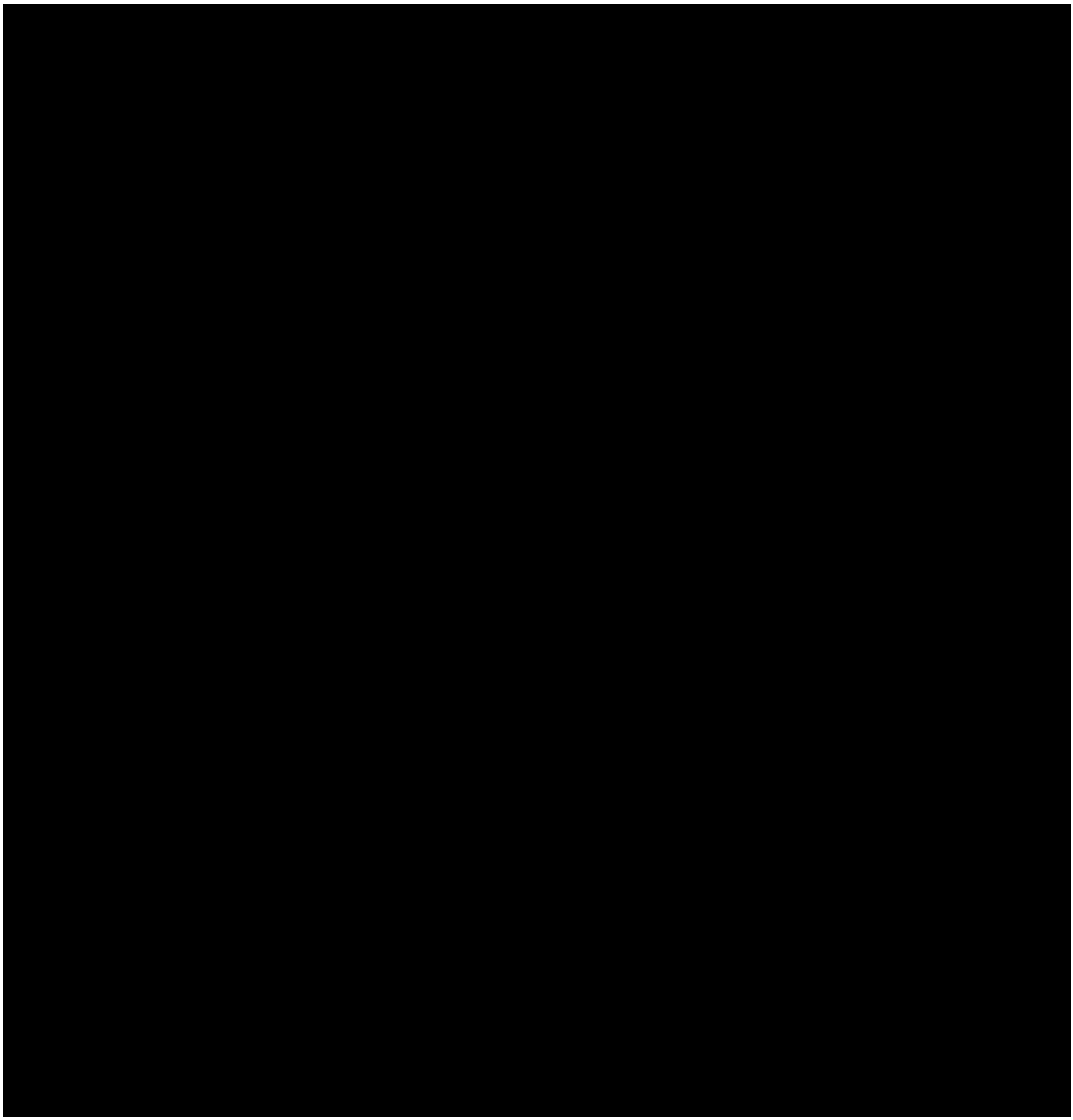


Figure 1-48 – Thin section from well [redacted].

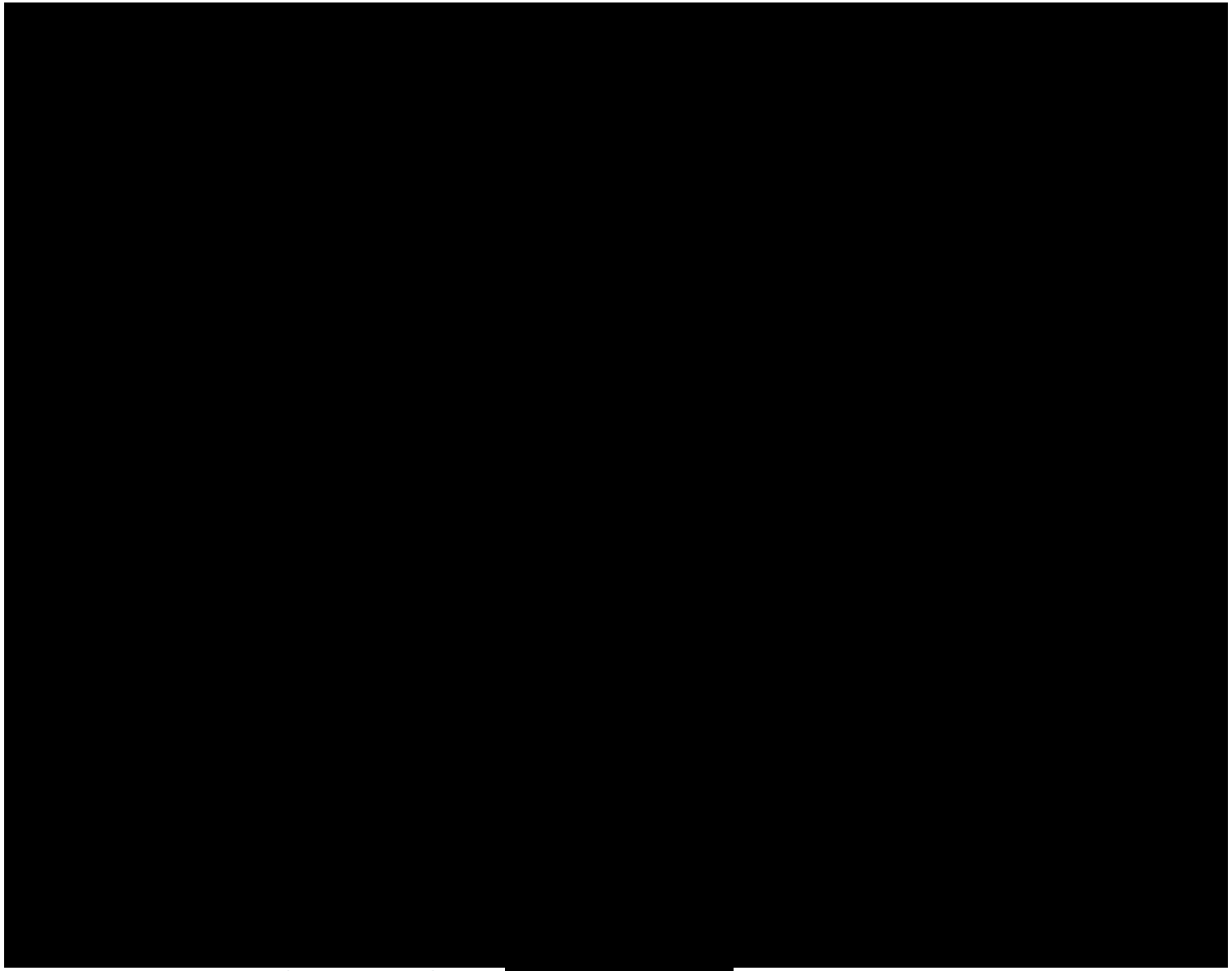


Figure 1-49 – Photograph of slabbed core for well [redacted] where the thin section in Figure 1-48 was acquired.

Figure 1-50 shows a thin section from well [redacted]



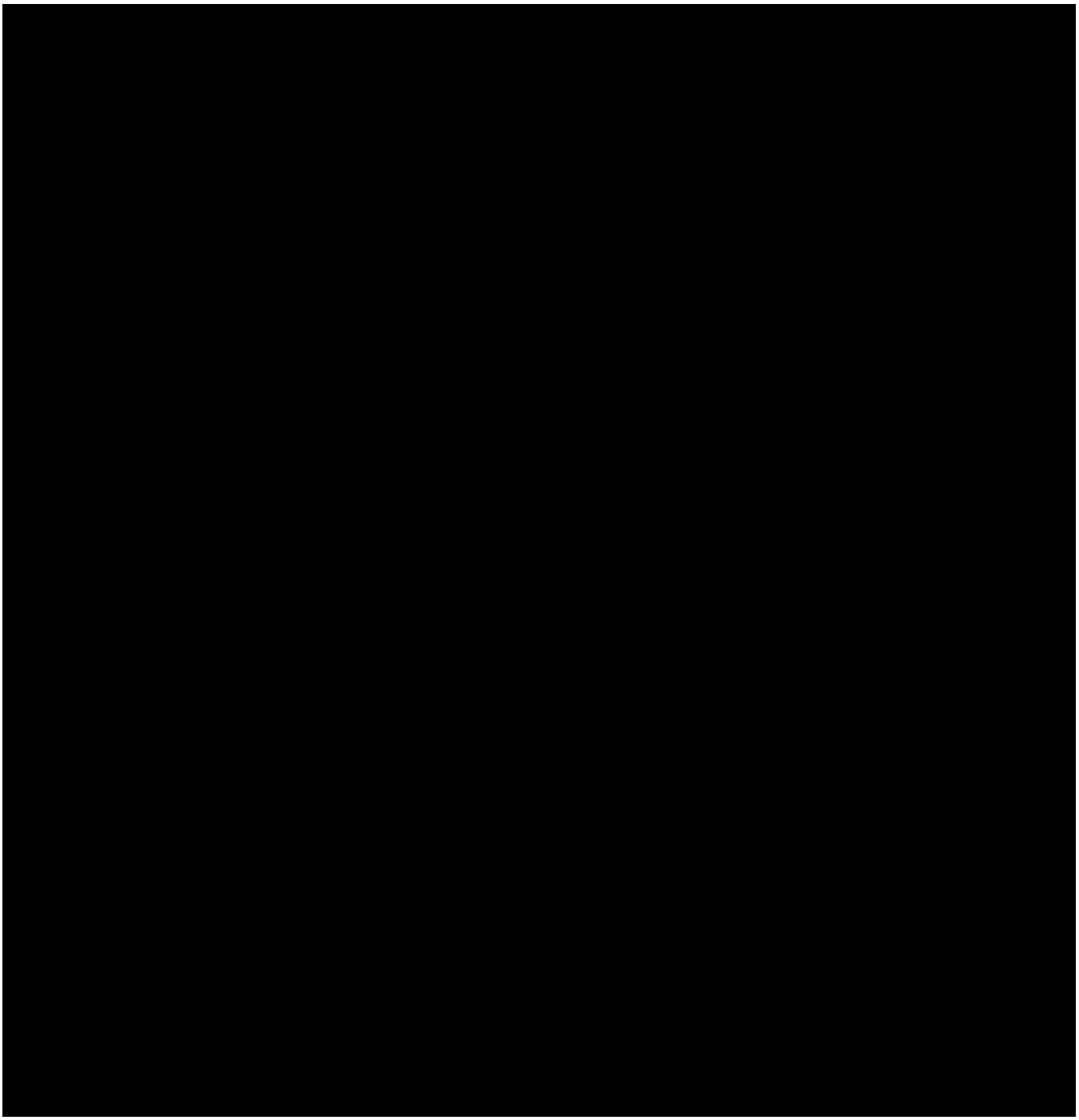


Figure 1-50 – Thin section from well [redacted]

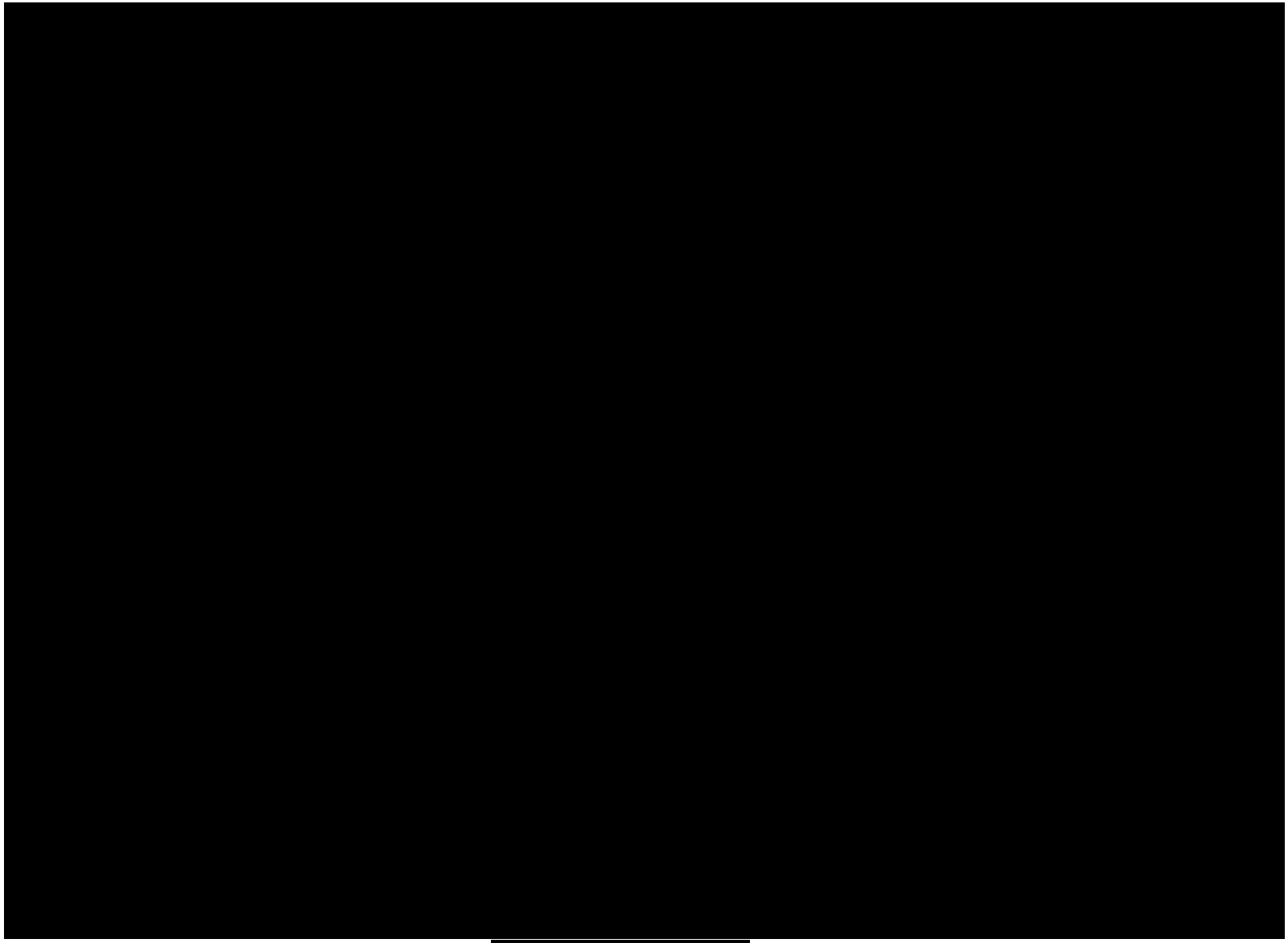
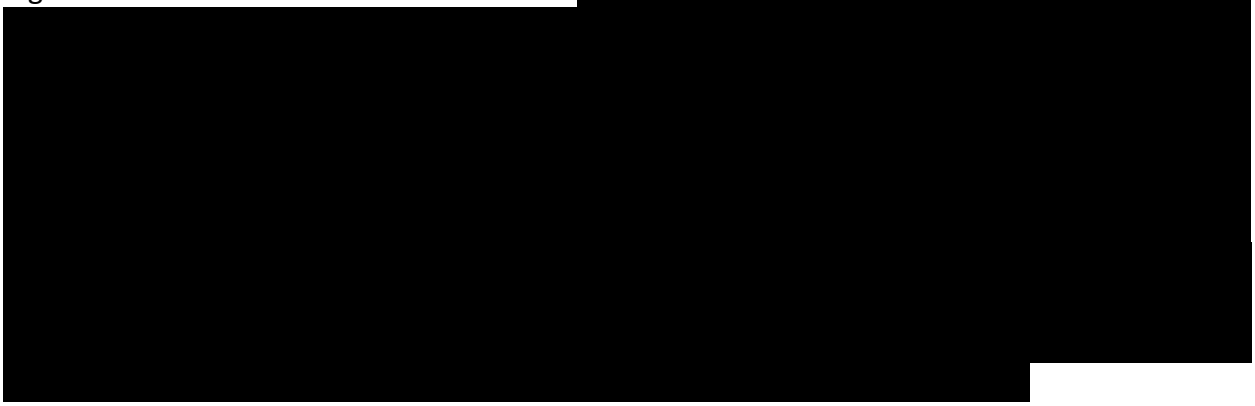


Figure 1-51 – Photograph of slabbed core for [redacted], where the thin section in Figure 1-50 was acquired.

Figure 1-52 shows a thin section from well [redacted]



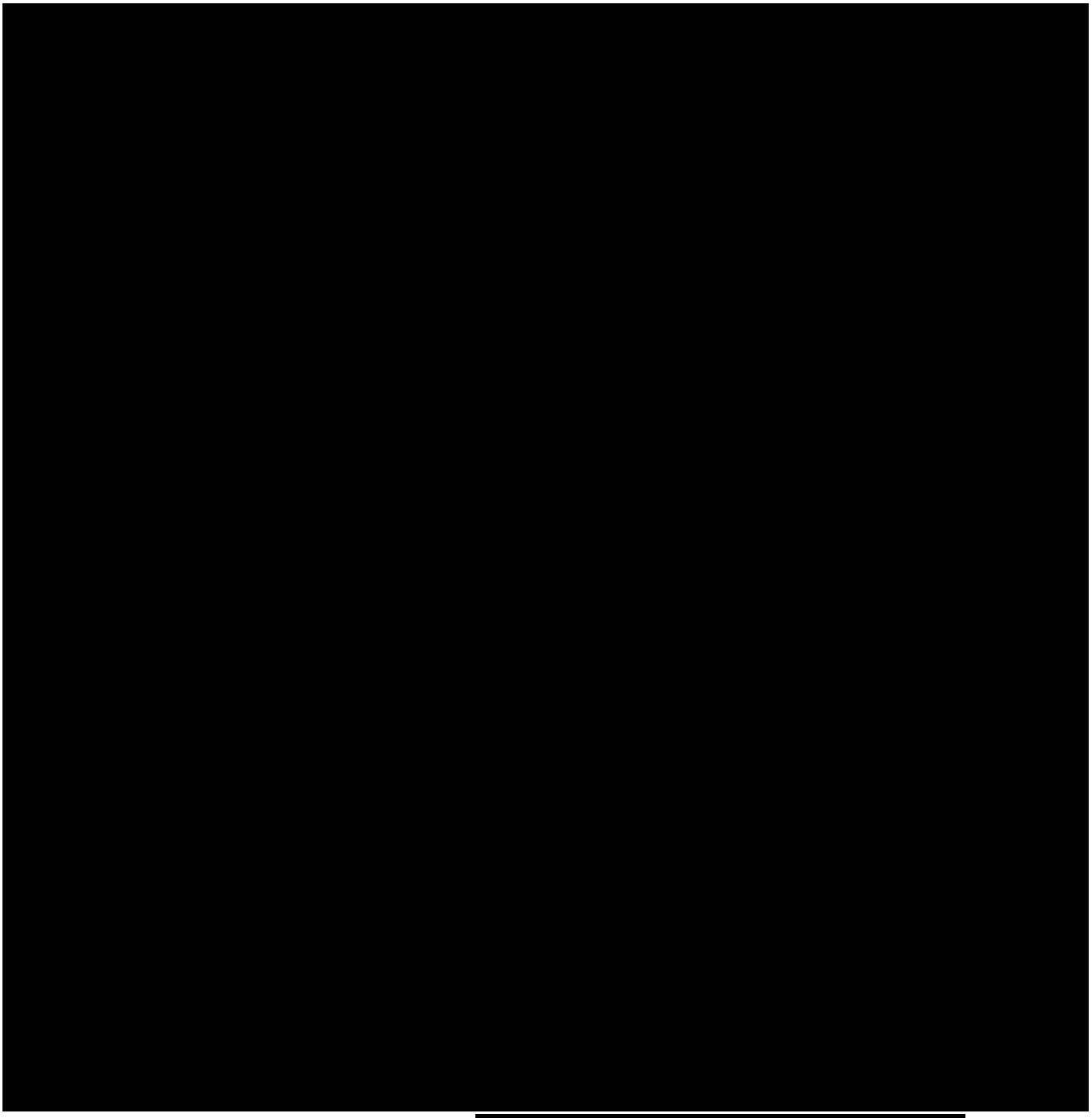


Figure 1-52 – Thin section from well [redacted]

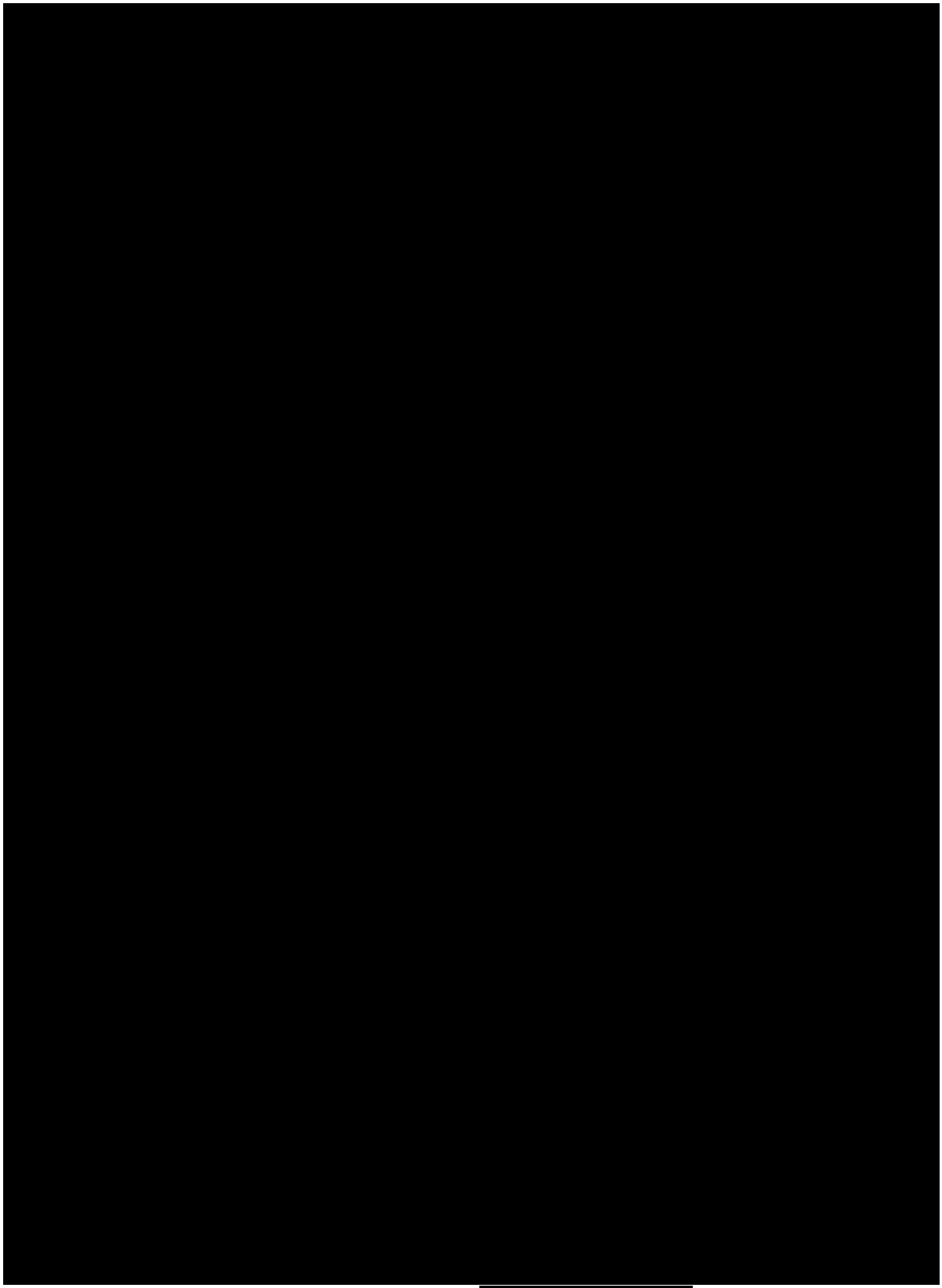
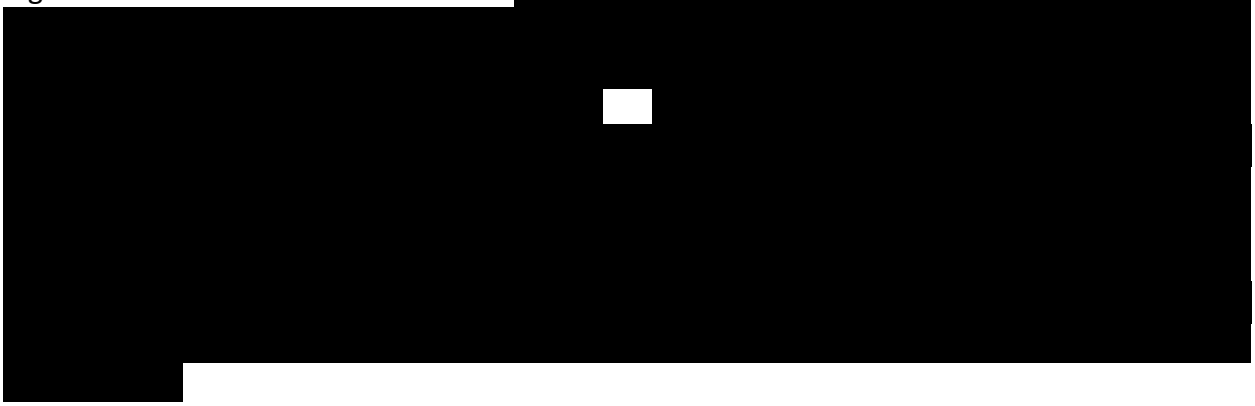


Figure 1-53 – Photograph of slabbed core for well [redacted] where the thin section in Figure 1-52 was acquired.

Figure 1-54 shows a thin section from [redacted]



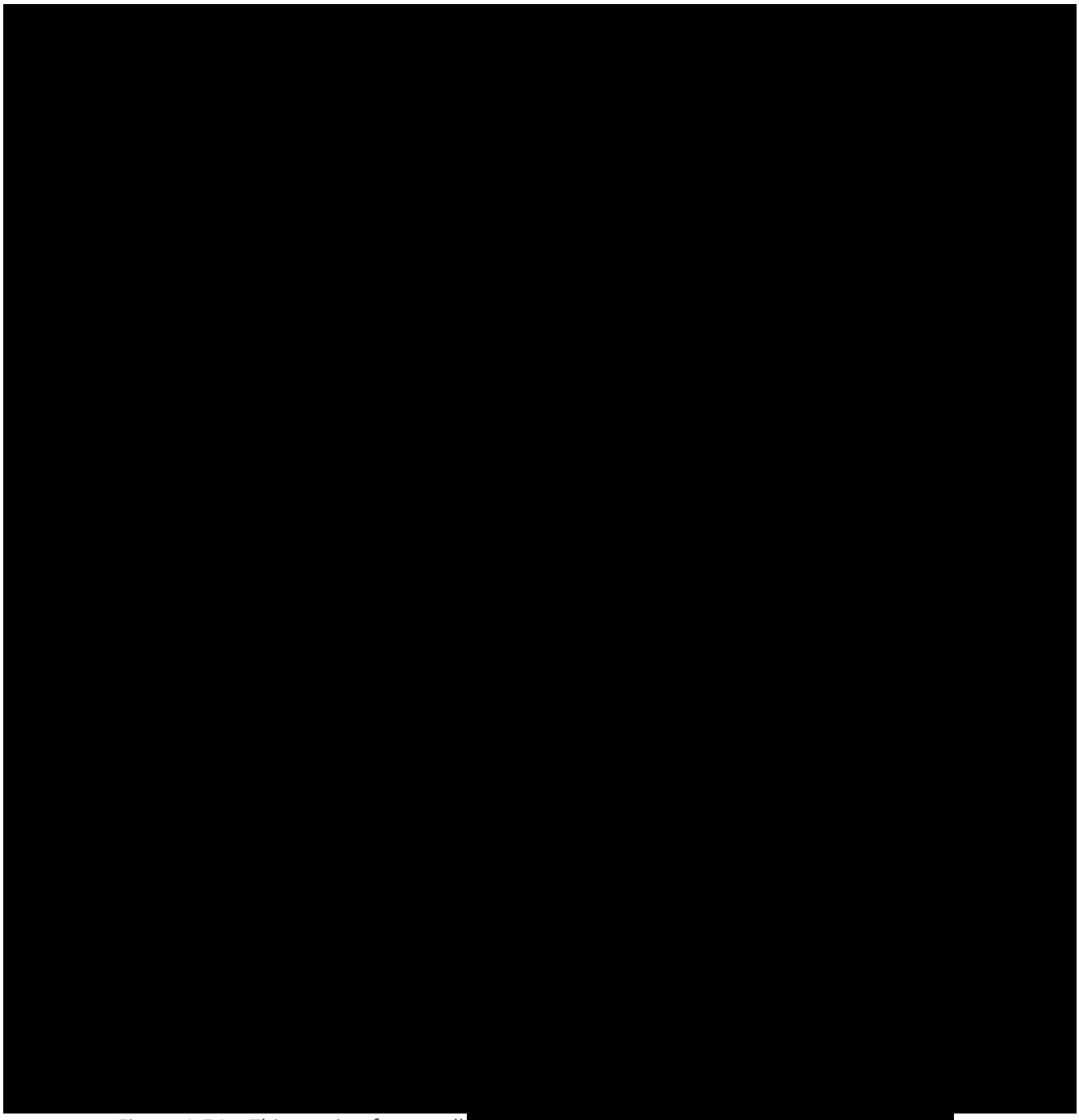
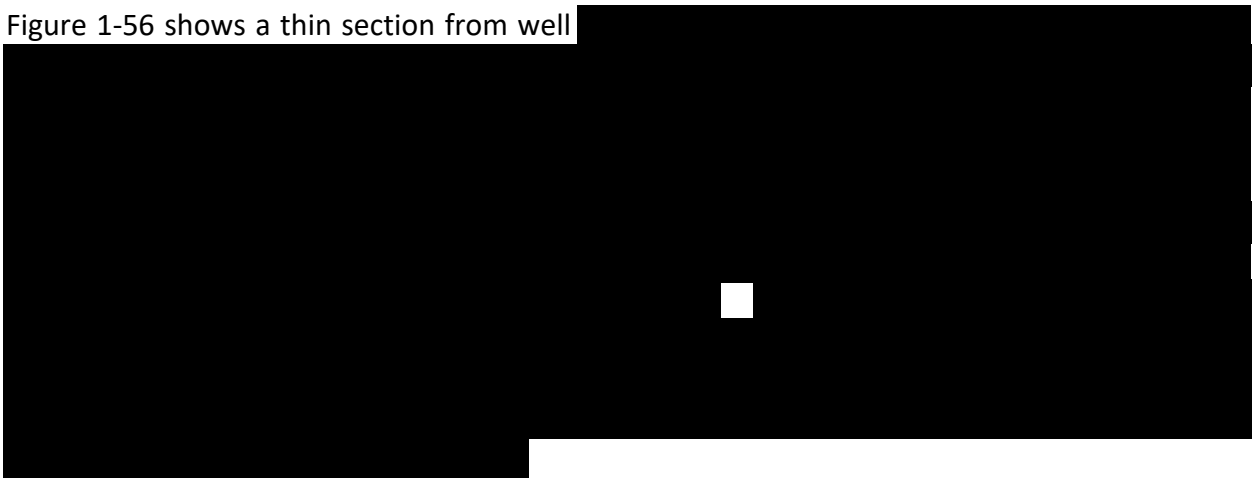


Figure 1-54 – Thin section from well [redacted]



Figure 1-55 – Photograph of slabbed core for well [redacted] where the thin section in Figure 1-54 was acquired.

Figure 1-56 shows a thin section from well [redacted]



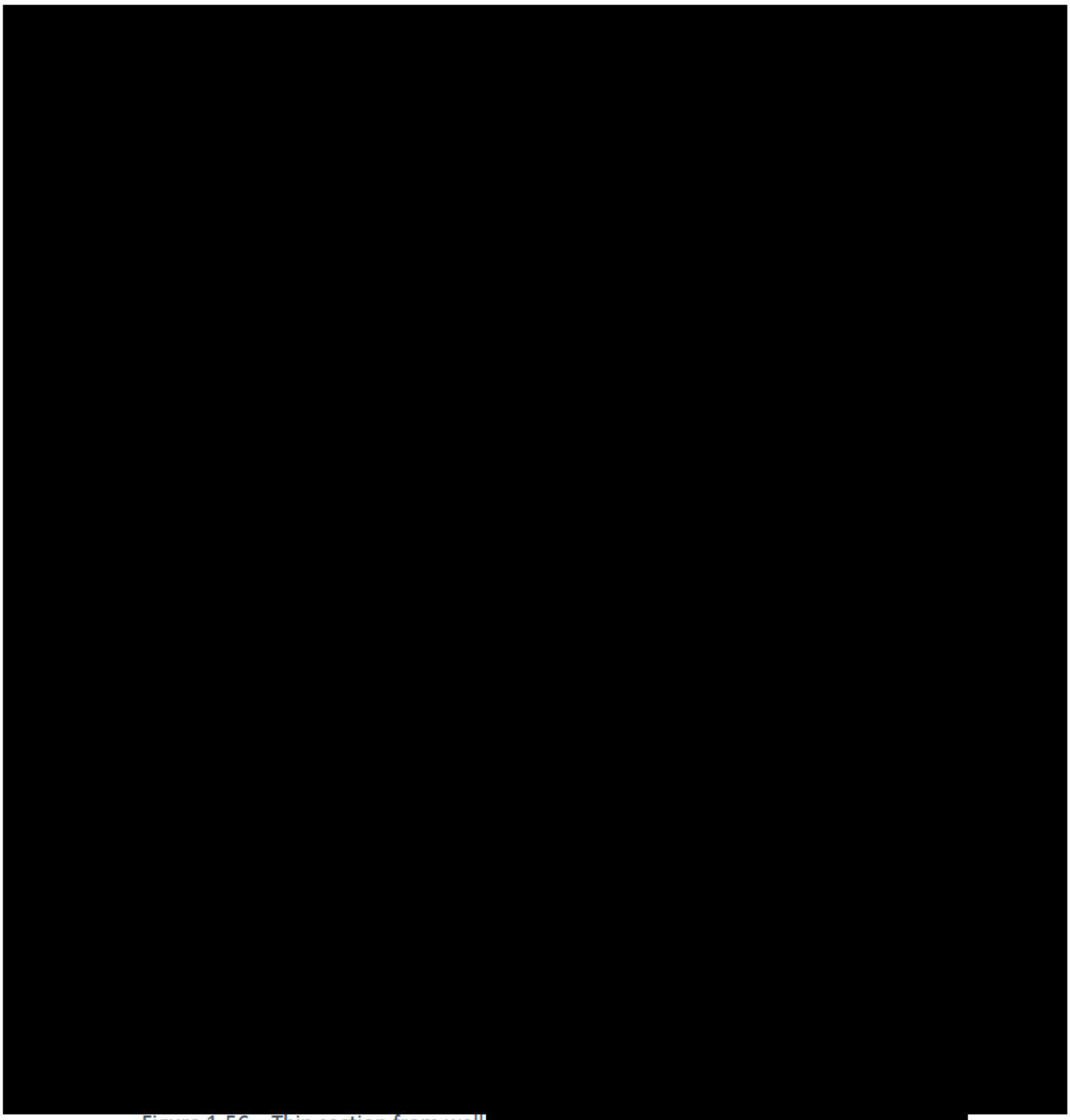


Figure 1-56 – Thin section from well



Figure 1-57 – Photograph of slabbed core for well [redacted] where the thin section in Figure 1-56 was acquired.

The shallowest plug acquired from this core (as was shown in Figure 1-49) 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 [redacted] 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.

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 [redacted]

The average porosity derived from well logs using this approach is approximately [redacted] 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 [redacted]. Furthermore, the nearest well [redacted] 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 [redacted] 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.

Permeability (Horizontal and Vertical)

The average calculated matrix permeability for the confining zone is null, based on the average calculated porosity. [redacted] The confining interval core analysis indicates a very low permeability, typical of suitable confining intervals.

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*.

Figure 1-58 shows the [redacted]

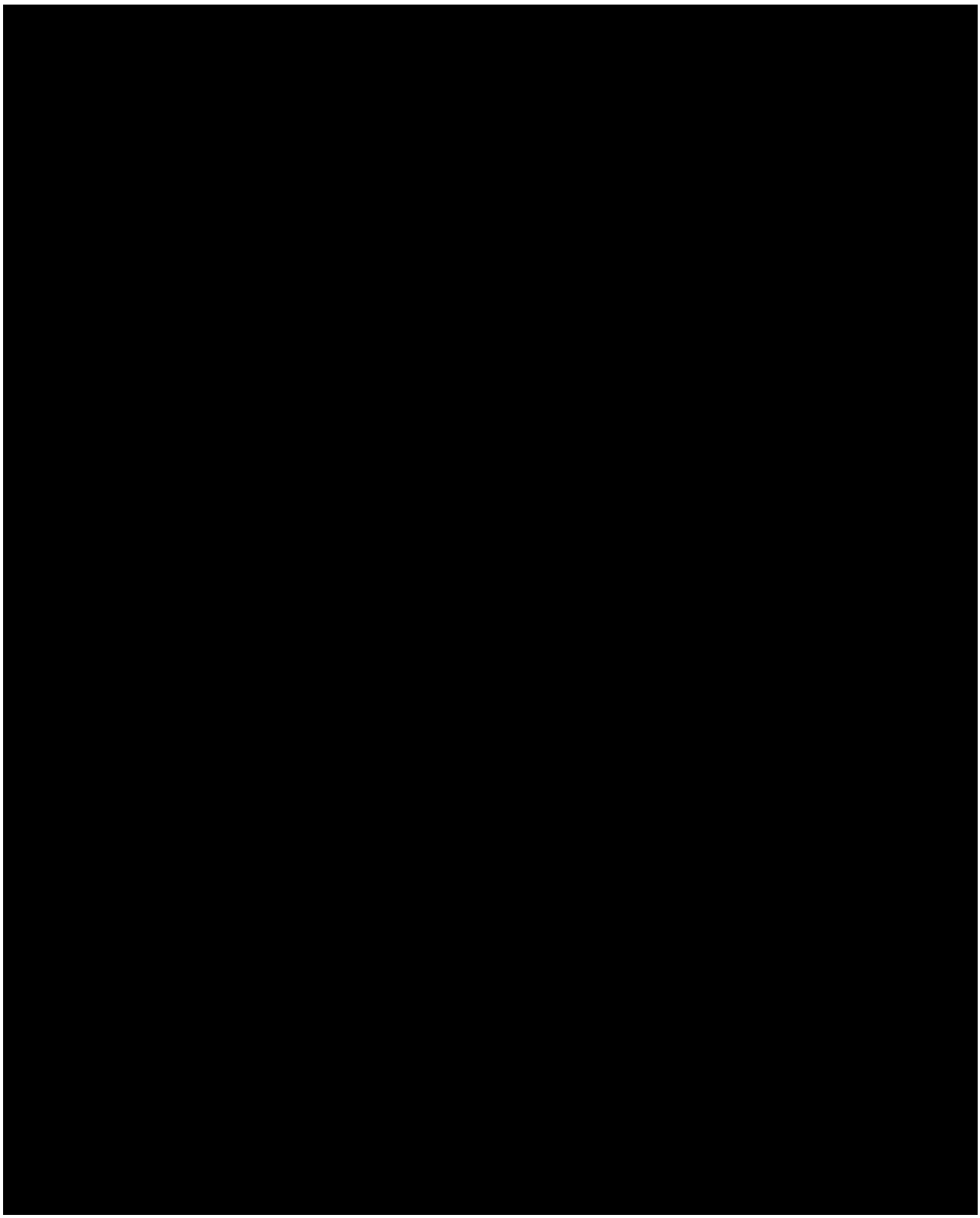


Figure 1-58 – Mercury saturation versus injection pressure results from high-pressure mercury injection testing (Core Lab Houston) for well [redacted]

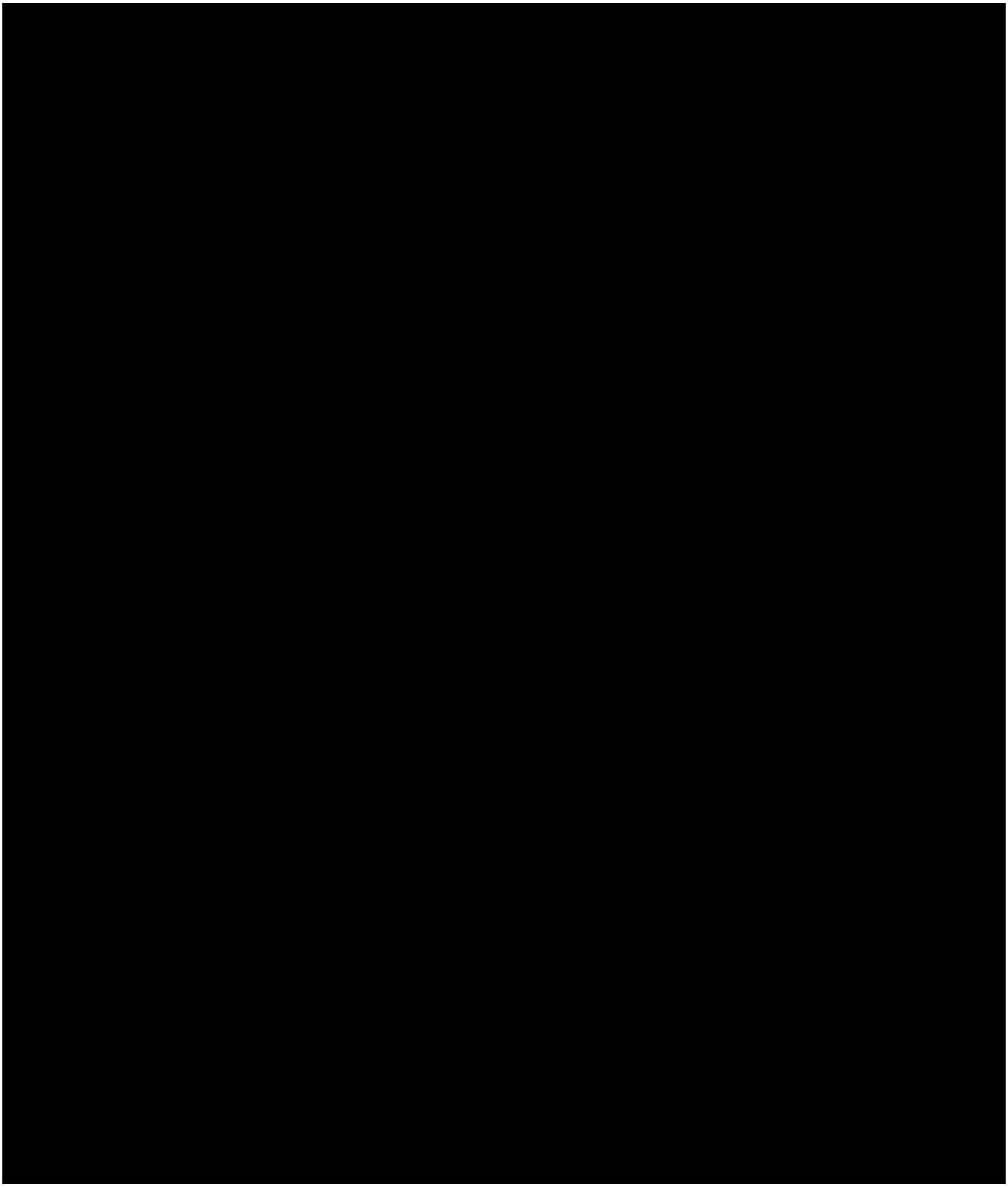


Figure 1-59 – Pore-throat size and distribution results from high-pressure mercury injection testing (Core Lab Houston) for well [redacted]

Water Saturation

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

1.3.4 Primary Lower Confining Zone



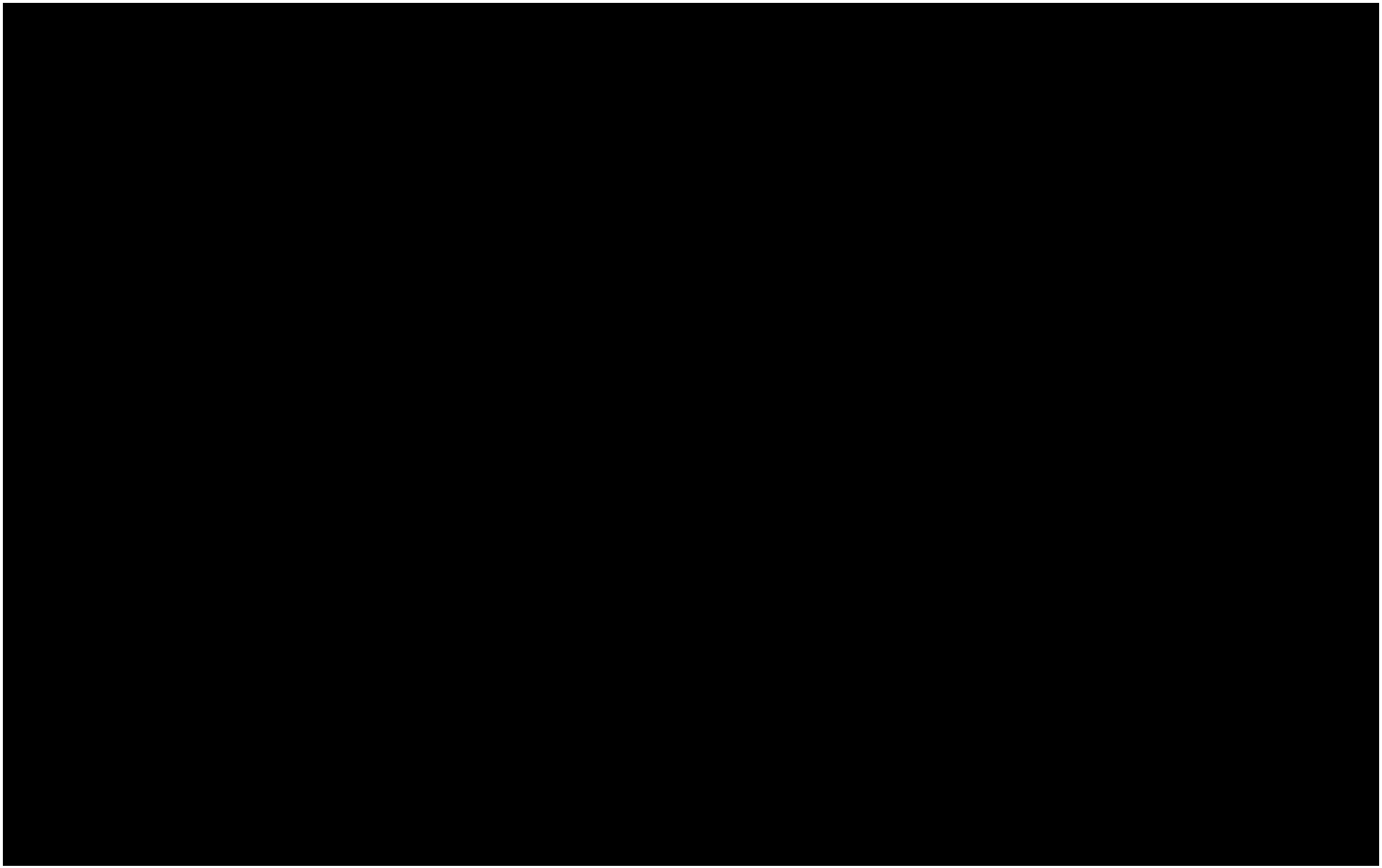


Figure 1-60 – Depth structure map (TVD SS) of the base of the [redacted] (lower confining zone).



Figure 1-61 – Thickness map of the [redacted] (lower confining zone).

Lithology

[redacted]

[redacted]



Figure 1-62 – Simplified depiction of a cross section oriented north-south to the east of the Orchard Project vicinity. It shows the dominant lithology changes across

[redacted]

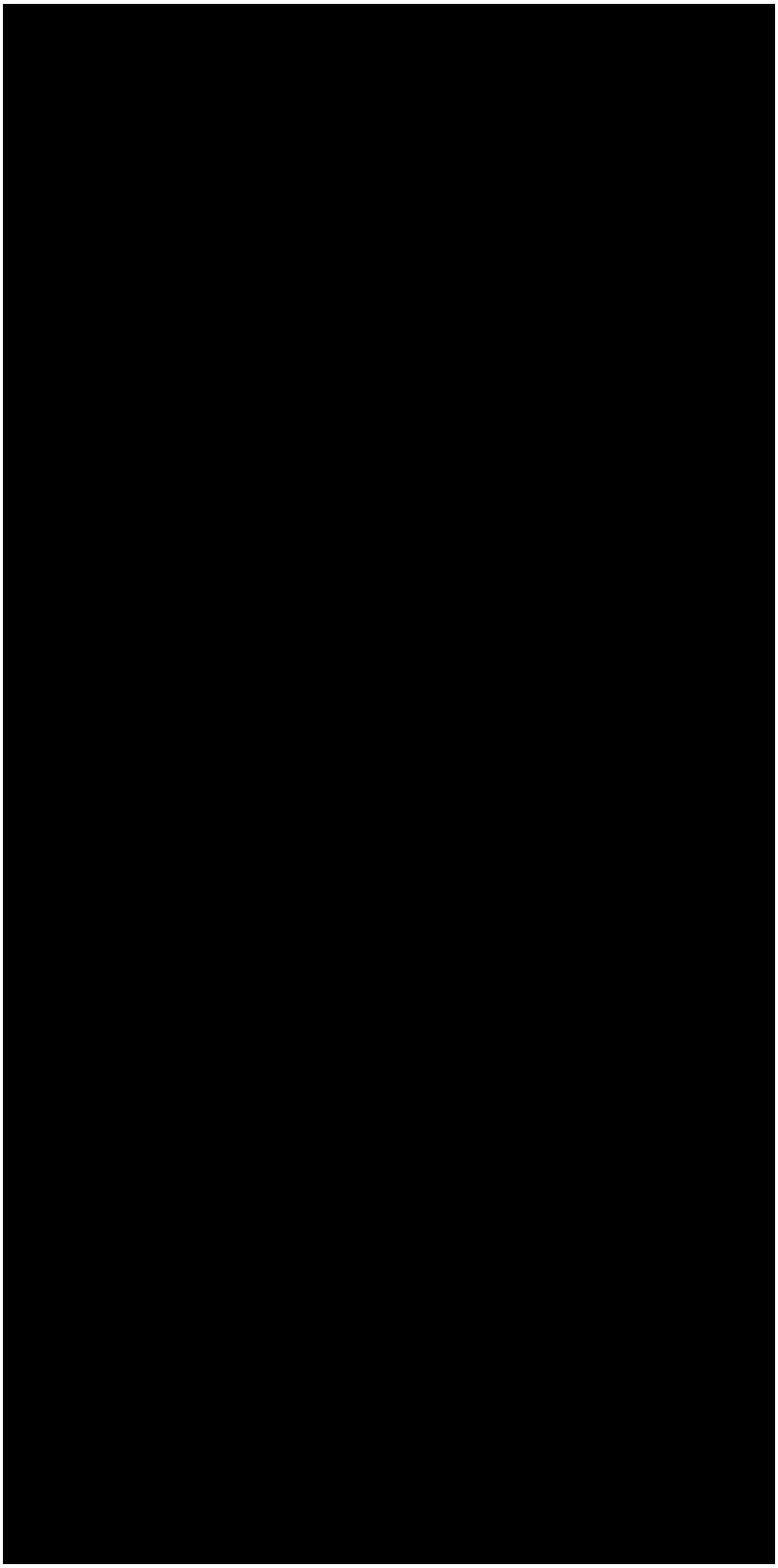


Figure 1-63 – A snapshot of the mud-log sample lithologic interpretation (track 2) for the [redacted]

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 [redacted]

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. [redacted]

The average porosity derived from well logs using this approach is approximately [redacted] in the confining zone. The porosity is consistent vertically, based on [redacted] However, the closest well ([redacted] 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.

Permeability (Horizontal and Vertical)

The average calculated matrix permeability for the confining zone is null, based on the average calculated porosity. [redacted]

Water Saturation

The 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 1-64 shows a [redacted] 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 1-45. The nearby well API No. [redacted]0, located approximately [redacted] 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) [redacted]

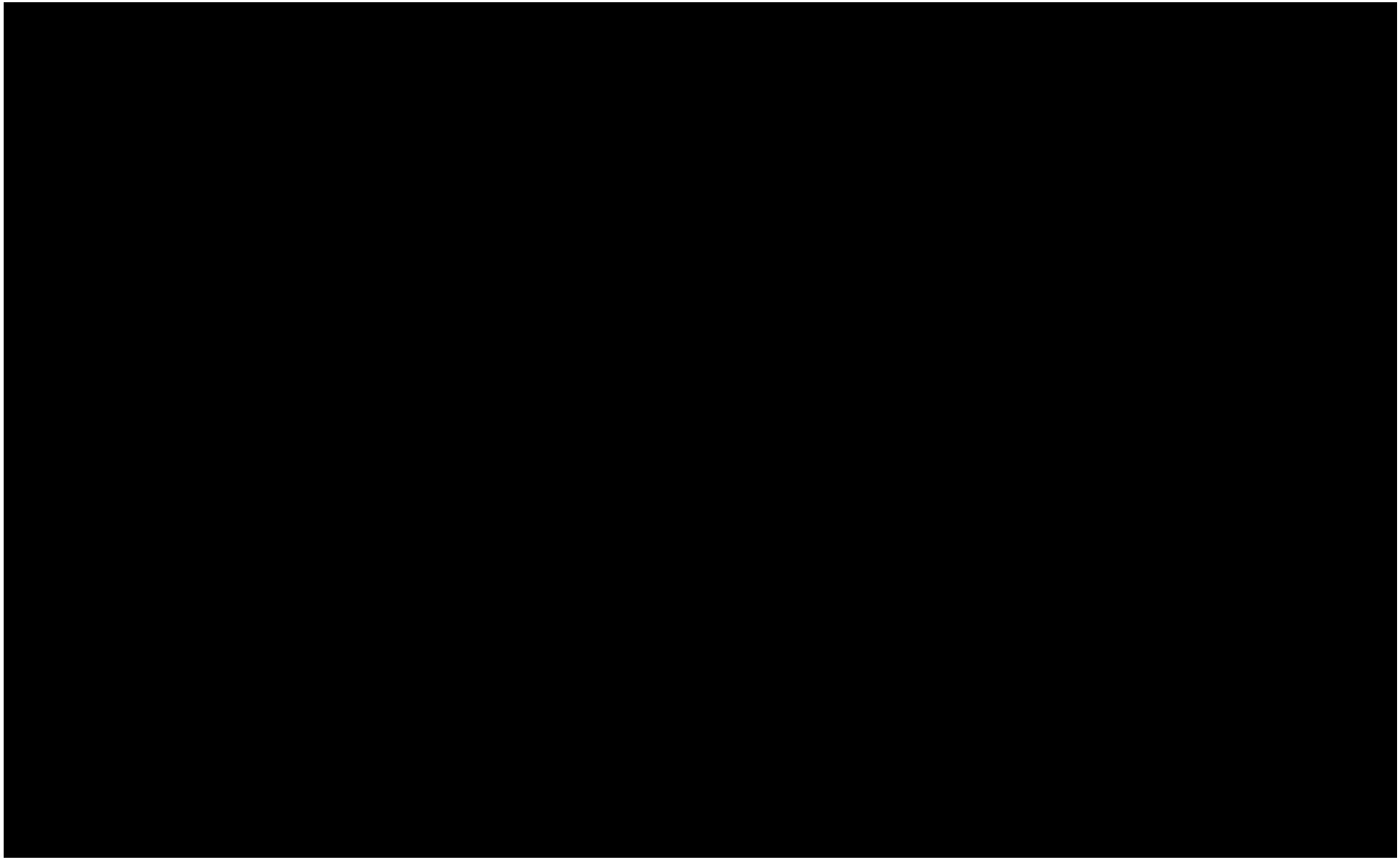


Figure 1-64 – A [redacted] long 2D seismic line running north (left) to south (right) through the Orchard Project area. The Y-axis is two-way travel time (milliseconds) and the X-axis is CDP traces.

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 [redacted] avelets 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. [redacted]

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 1-65 shows the same [redacted] 2D seismic line (A-A') from Figure 1-64—with [redacted] 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 [redacted] 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. [redacted]



Figure 1-65 – The same [redacted] long 2D seismic line from Figure 1-64, but with interpreted horizons and faults shown.

This 2D seismic line trajectory (north to south) is roughly perpendicular to the dominant regional depositional trend [redacted] 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 [redacted], as described in *Section 1.3*.

1.4.1 Horizon Interpretation

Several seismic horizons were interpreted from the [redacted] on the 2D seismic line (A-A'). Most seismic horizons matched the well tops in well [redacted] The tops of the [redacted] 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 1-65, 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 S[redacted] formations, rather than the current well-top stratigraphic framework. At [redacted]

At CDPs [redacted]

As mentioned above, the [redacted] seismic horizon matching well log data and well top picks. The upper confining zone is represented between the [redacted] 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 [redacted]. The blue dashed seismic horizons that were displayed in Figure 1-65, 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 [redacted]

Figure 1-66 shows the [redacted] pseudo-well tie with well log data, a synthetic seismogram, and seismic data for comparison. Figure 1-67 shows the time-to-depth relationship for the pseudo-well tie.



Figure 1-66 – The same 2D seismic line from Figures 1-64 and 1-65, showing the [redacted] pseudo-well tie, with well log data, a synthetic seismogram overlayed, and seismic data for comparison.

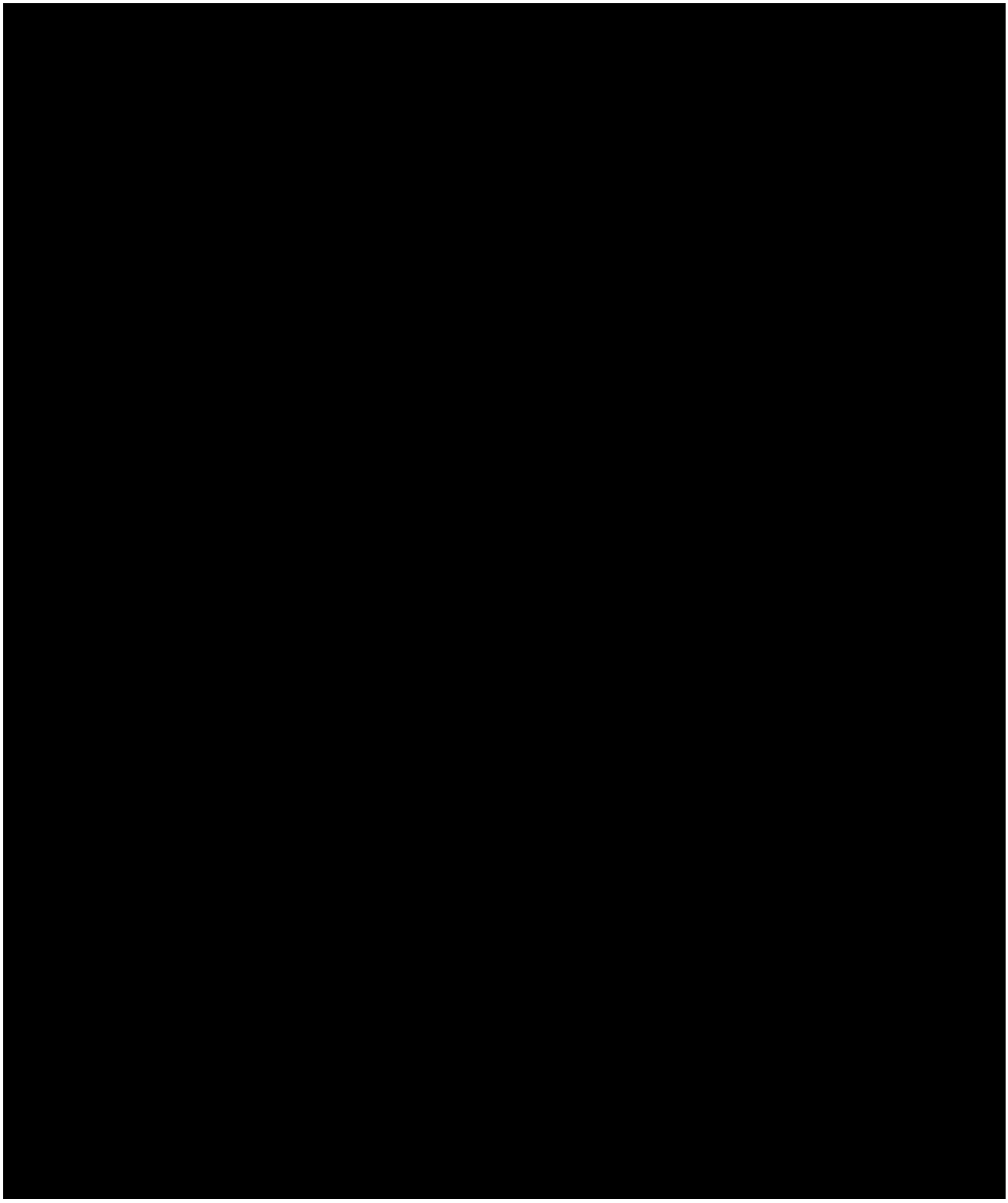


Figure 1-67 – The time-to-depth profile, or relationship, used for the [redacted] pseudo-well tie.

The velocity model was derived from the sonic log and adjusted using replacement velocities above the top of the shallowest sonic depth [redacted]. The time-to-depth relationship for the [redacted] 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 [redacted] were obtained from well [redacted] located [redacted] 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 [redacted] formation, but not necessarily more accurate below the [redacted] The velocities are almost constant through the [redacted] well tops. There are minor perturbations, but the major velocity variations are above the [redacted].

Across the Orchard Project area, [redacted] The dip angle of the injection zone top through the project area is approximately [redacted]. The dip angle of the upper confining zone top through the project area is [redacted] The dip angle of the lower confining zone top through the area is approximately [redacted]

Figure 1-68 shows a depth map of the top of the injection zone, colored by the dip angle.



Figure 1-68 – Depth structure map (TVD SS) of the top of the injection zone, colored by dip angle.

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. [redacted] No significant dip at the [redacted] horizon was noticeable due to the 2D line (A-A') being perpendicular to the prevailing dip azimuth (to the southwest). [redacted]

The [redacted] that were illustrated in Figure 1-65 (interpreted with a bold-line seismic horizon and a dashed-green-line seismic horizon, respectively, in *Section 1.4*) are part of a [redacted]

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 [redacted]r. The fault interpretation correlates to the regional fault model, where most tectonic deformation ends in the [redacted] 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). [redacted]

Figure 1-69 shows the [redacted]

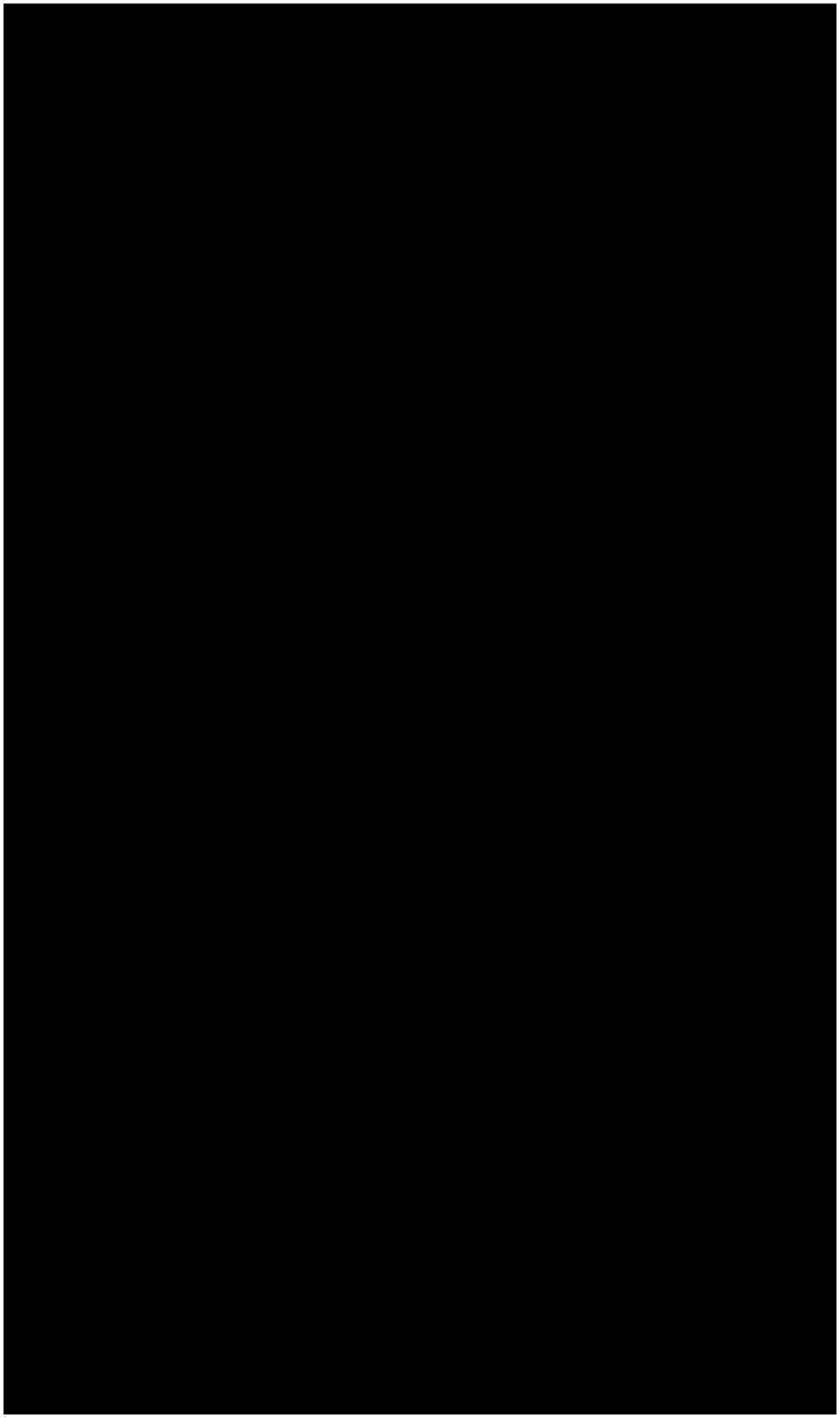


Figure 1-69 – Diagram showing tectonic events by geologic age for the [redacted]

Figure 1-70 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 (taken from https://www.beg.utexas.edu/texnet-cisr/fault-maps).



Figure 1-70 – 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 & 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 generate the geomechanical model for this site characterization. The model contains three parts:

- Elastic moduli
- Local stress conditions
- Fracture gradients

1.5.1 Elastic Moduli

Dynamic elastic moduli were calculated based on [redacted] as this well had both shear and compressive sonic well logs available through the injection and confining zones. Figure 1-20 (in *Section 1.3.2*) provided the type well, showing the petrophysical analysis and dynamic elastic moduli.

The geomechanical well logs demonstrate the elastic mismatch between the injection zone and the upper and lower confining zones. The differing geomechanical properties reduce the ability of any fractures caused by injection well operations to propagate above or below the injection zone.

Static elastic moduli were estimated from core analysis using samples from [redacted] Triaxial tests were performed on six vertical core plugs (three from each well), including the basal part of the upper confining zone and the upper part of the injection zone.

Table 1-6 shows the triaxial test results for the six samples. A pronounced elastic moduli variation is exhibited between the injection and upper confining zones, as was observed by the dynamic elastic moduli calculations. This difference adds confidence in the upper confinement zone's ability to prevent the initiation and propagation of fluid-conductive fractures upwards due to the increased pore pressure in the injection zone below.

Table 1-6 – Triaxial Test Results for Six Samples

Well API No.	Depth (ft)	Zone	Confining Pressure (psi)	Bulk Density (g/cm^3)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
[redacted]							

Figure 1-71 shows photographs of samples taken after the triaxial testing was completed [redacted]

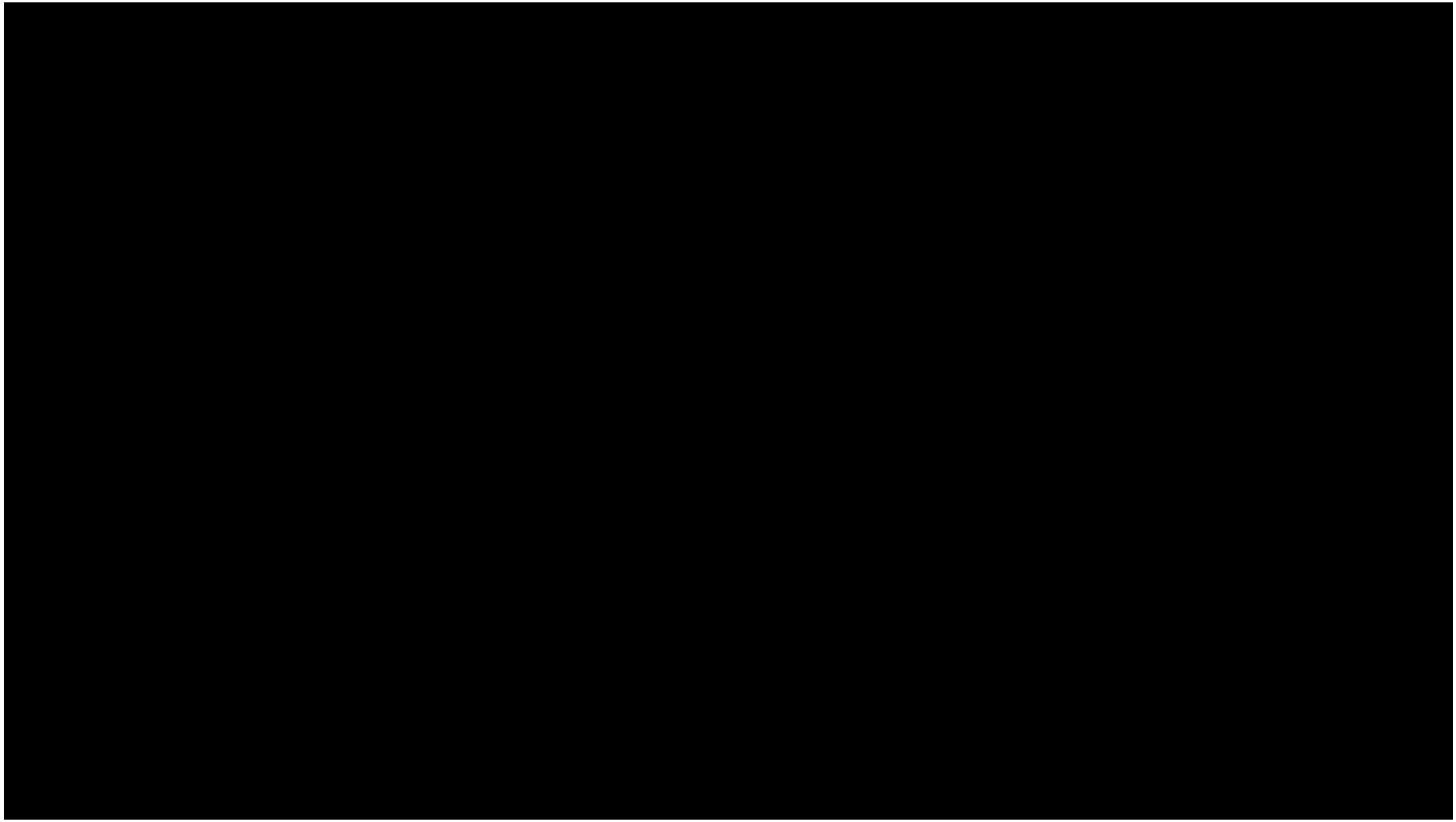


Figure 1-71 – Photographs of samples taken after triaxial testing for well [redacted] The injection zone samples' deformation style appears to be a mix between tensile and shear.

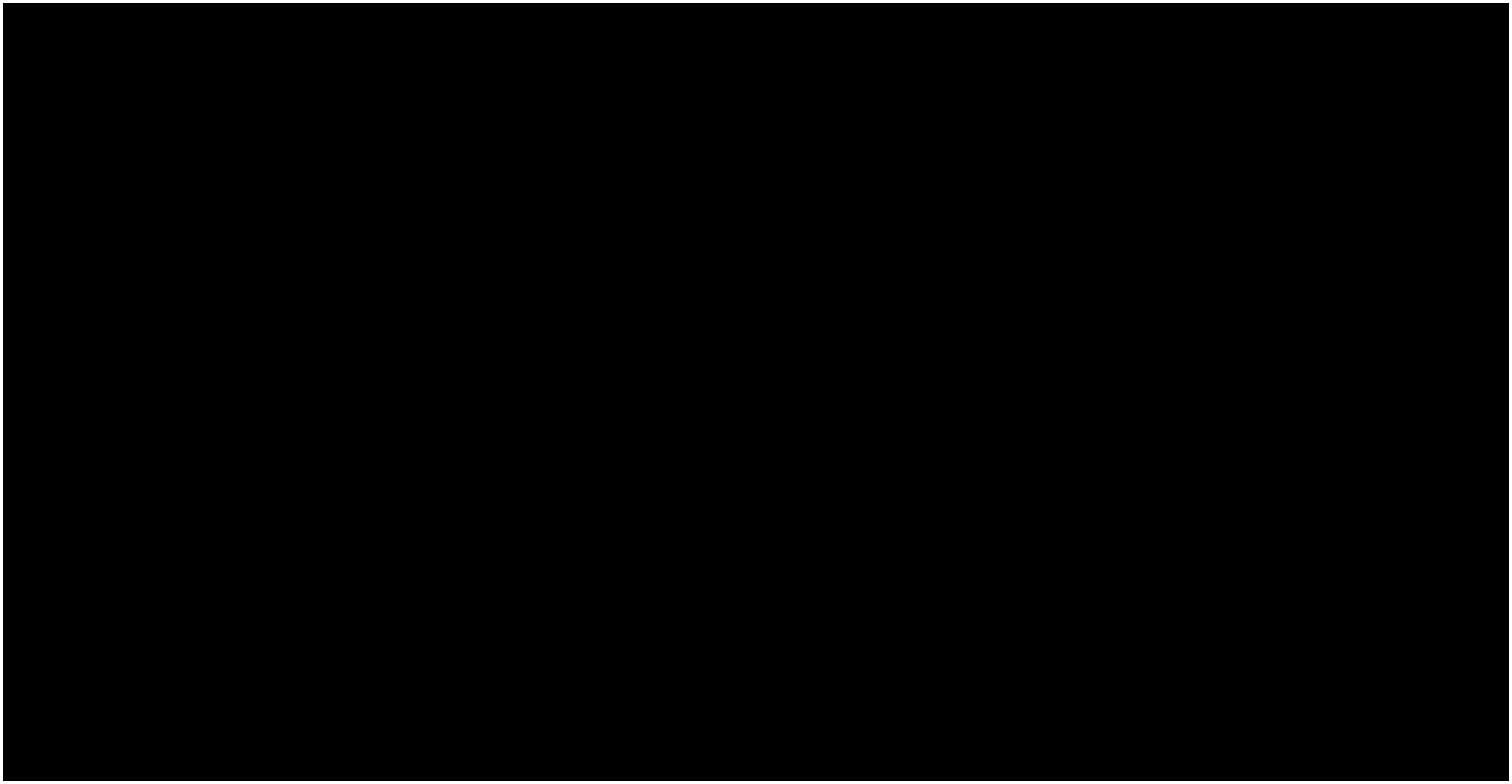


Figure 1-72 – Photographs of samples taken after triaxial testing for well [redacted]. The confining zone samples' deformation style appears to be a mix between tensile and shear.

1.5.2 Local Stress Conditions

The lithostatic, or overburden, stress (S_v) gradient used in the geomechanical model [redacted] per square inch (psi)/ft. The pore pressure gradient is estimated at [redacted] psi/ft.

The azimuth of maximum horizontal stress (S_H maximum) in the Orchard Project area is approximately [redacted] (Snee & Zoback, 2018) as shown in Figure 1-73. This study also demonstrated that the principal stress regime is normal in the project area. [redacted]

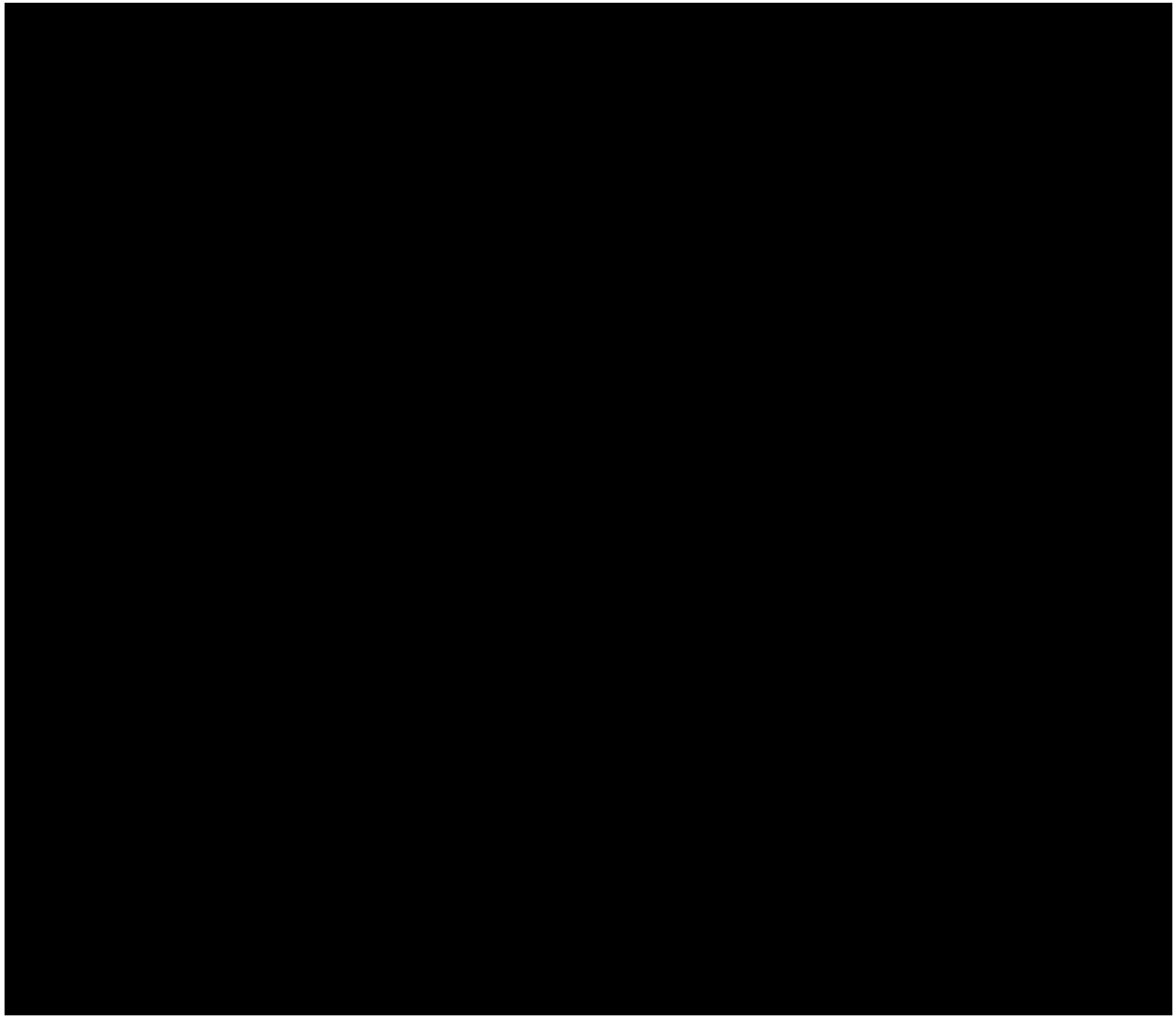


Figure 1-73 – Regional map showing the maximum horizontal stress orientation across the Permian Basin derived from a combination of well data and seismicity (Snee & Zoback, 2018).

A method to predict a simplified fracture gradient is the standard Eaton equation (i.e., S_h minimum horizontal stress, or fracture closure pressure). Eaton's equation is shown below:

$$P_f = (v / 1 - v) * (S_v - P_p) + P_p$$

Where:
P_f = fracture closure pressure gradient
v = Poisson's ratio
S_v (overburden stress gradient) = 1.0
P_p (pore pressure gradient) = 0.433.

Biot's constant was based on approximate dynamic elastic moduli calculated using the equation based on data from Detournay & Cheng (1993):

$$a = 0.62 + 0.935*phi$$

Where phi = porosity.

The minimum stress equation (Barree, 2009) used to estimate the fracture closure pressure is below:

$$Pf = (v / 1 - v) * (S_v - a_v * P_p) + a_h * P_p ~~[+ \varepsilon_x * E + \sigma_t]~~$$

Where:
P_f = fracture closure pressure gradient
v = Poisson's ratio
S_v (overburden stress gradient) = 1.0
P_p (pore pressure gradient) = 0.433
a = Biot's constant (vertical is calculated and horizontal = 1).

(Not used, but shown above, ε_x is regional horizontal strain, E is Young's modulus, and σ_t is regional horizontal tectonic stress.[1])

The following dynamic elastic moduli [redacted] were calculated using well logs using methods summarized in Crain's Petrophysical Handbook:

- Shear Modulus (G)
- Poisson's ratio (*v*)

[1] Note: The above results do not account for external stress boundary conditions, and are not representative of the (higher value) breakdown pressure of the injection and confining zones.

- Young's modulus (E)
- Bulk modulus (Kb)
- Biot's constant (a)
- Minimum horizontal stress (S_h)

1.5.3 Injection Zone Fracture Gradient

The minimum horizontal stress and fracture gradient were calculated using the elastic moduli calculated from three triaxial tests in the upper part of the injection zone. Table 1-7 shows the estimated fracture gradient at triaxial test depths and select depths in the injection zone and confining zone.

Table 1-7 – Estimated fracture gradient in the injection zone and confining zone using well logs (dynamic elastic moduli) and well core (static elastic moduli) samples.

Depth (ft)	Zone	Sample	Lithostatic Stress (psi)	Pore Pressure (psi)	Porosity (dolomite)	Biot's Constant	Minimum Fracture Closure Gradient (psi/ft)
[redacted]							

The triaxial core test results were used to generate failure envelopes for the [redacted] injection interval. Mohr circle analysis was applied to two stress conditions at a depth of [redacted] TVD. Figure 1-74 shows that, at in situ conditions, the rock is stable—as expected. Figure 1-75 shows an *unstable* condition based on the triaxial core failure data, with the predicted Mohr circle at an unstable state of stress. Cohesive strength was derived using the approximate differential stress of [redacted] test core samples. Table 1-8 provides the parameters used to develop the Mohr circle analysis.

Table 1-8 – Mohr Circle Analysis Parameters

Parameter	Value
[redacted]	



Figure 1-74 – Mohr Circle Analysis—Stable State of Stress (in Megapascals)



Figure 1-75 – Mohr Circle Analysis—Unstable State of Stress (in Megapascals)

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 [redacted] 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 1-76 and 1-77 show examples of historical results from several laboratory analyses within the [redacted]. 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 [redacted] in the project area, is [redacted] parts per million.

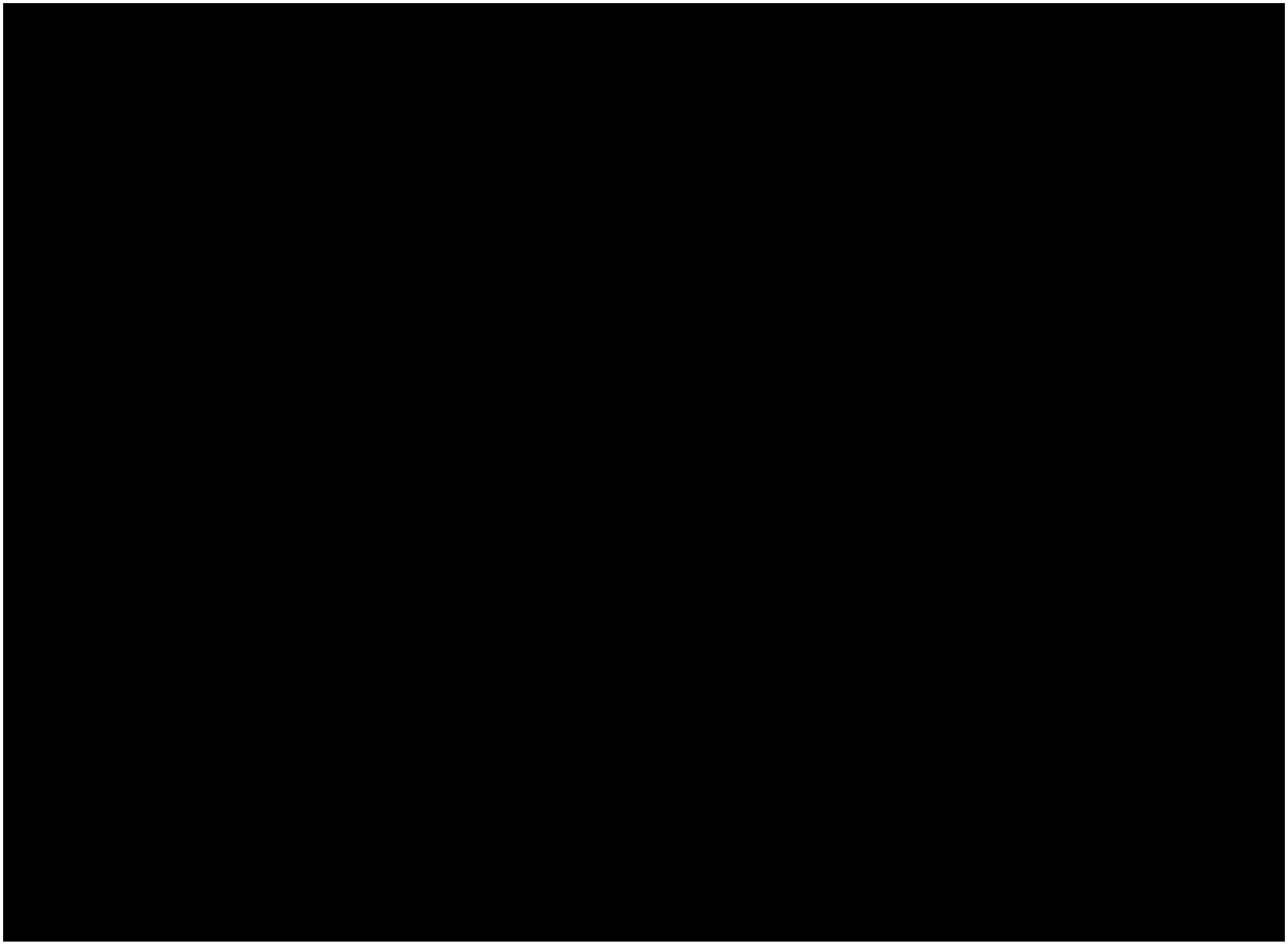


Figure 1-76 – Tabulated records of water quality from the Texas Water Development Board's Saline Water Resources Survey of the State of Texas for Gaines County (1971).

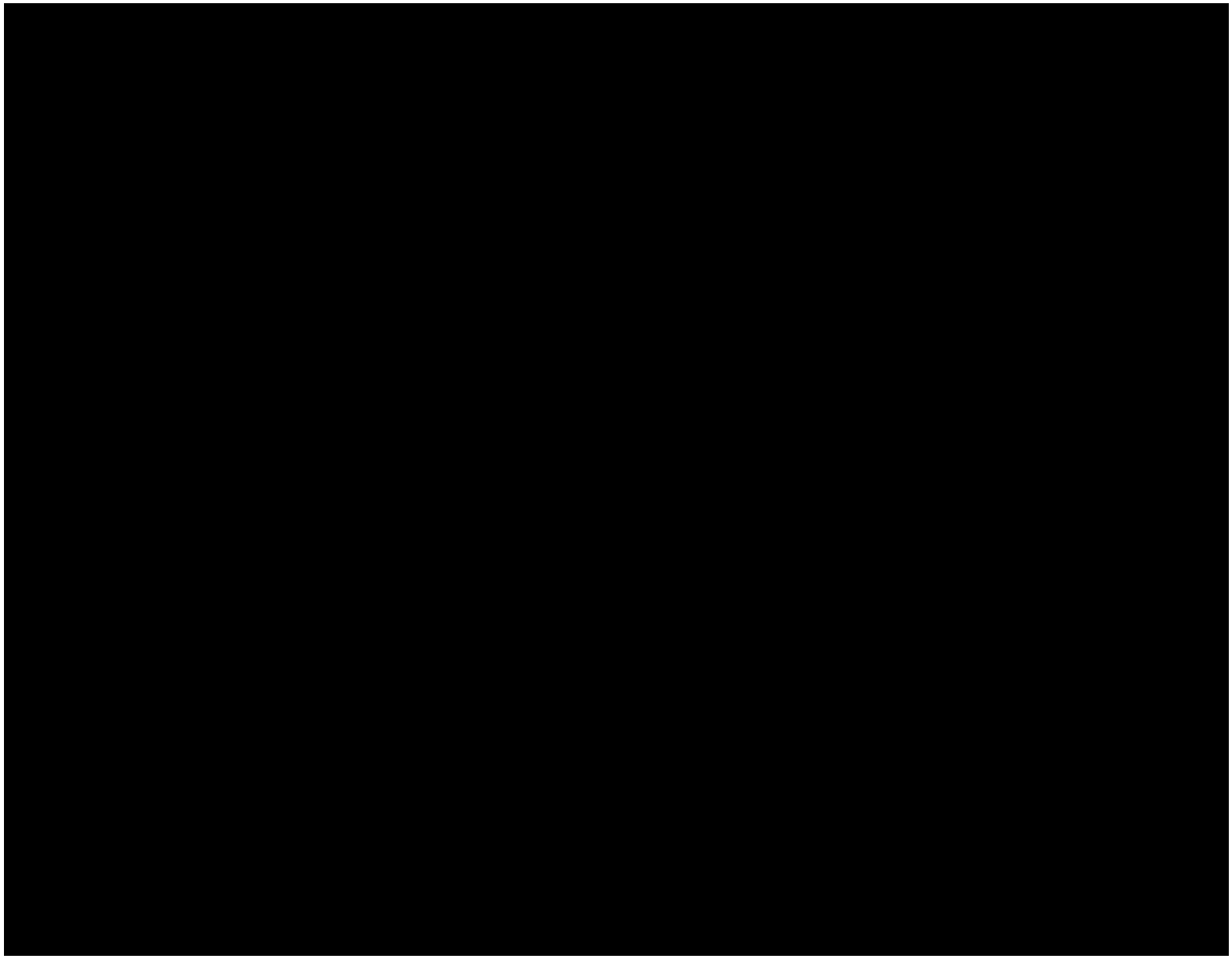


Figure 1-77 – Tabulated records of water quality (continued) from the Texas Water Development Board's Saline Water Resources Survey of the State of Texas for Dawson County (1971).

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)

Three x-ray diffraction (XRD) samples (two in the injection zone and one in the confining zone) were acquired from existing core. Table 1-9 shows the mineralogy determined by XRD for both cored wells.

Table 1-9 – Mineralogy determined by XRD for both cored wells [redacted]

[redacted]

[redacted]

1.6.3 Simulated Interactions (Injection Zone and Upper Confining Zone)

No geochemical modeling or simulations were done to identify major reactions that may occur in either the injection or confining zone. Regional research and analog projects offer some insight into possible interactions with fluid or rocks with injected supercritical CO_2 in the near- and long-term.

A Department of Energy (DOE) funded investigation in 2002, led by Grigg et al. (New Mexico [redacted]

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 [redacted] n 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, [redacted] oil and gas wells were drilled. Of the [redacted] wells drilled, [redacted] produced at economic quantities (cumulative production greater than 100,000 barrels of oil equivalent). [redacted]

[redacted]

[redacted]

Other oil and gas activity in the immediate Orchard Project area is minimal. [redacted] 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 1-78 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.

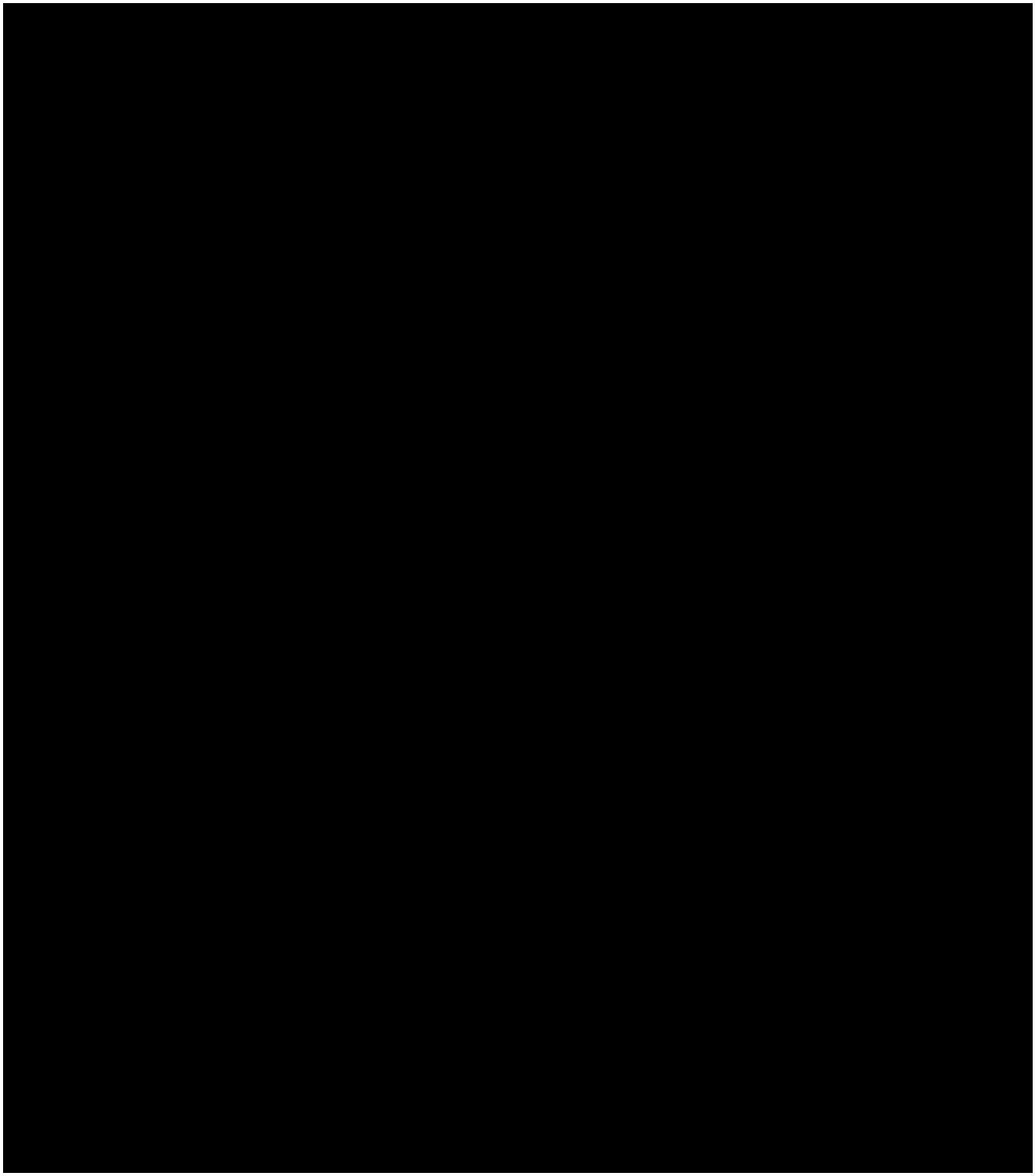


Figure 1-78 – Two maps of historical seismic events in the Permian Basin area; the upper map is from USGS, the lower from TexNet. Neither data source shows seismicity occurrences in the Orchard Project vicinity (indicated by the black star).

The Bureau of Economic Geology's TexNet site identifies a permanent active monitoring station [redacted] 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

[redacted]

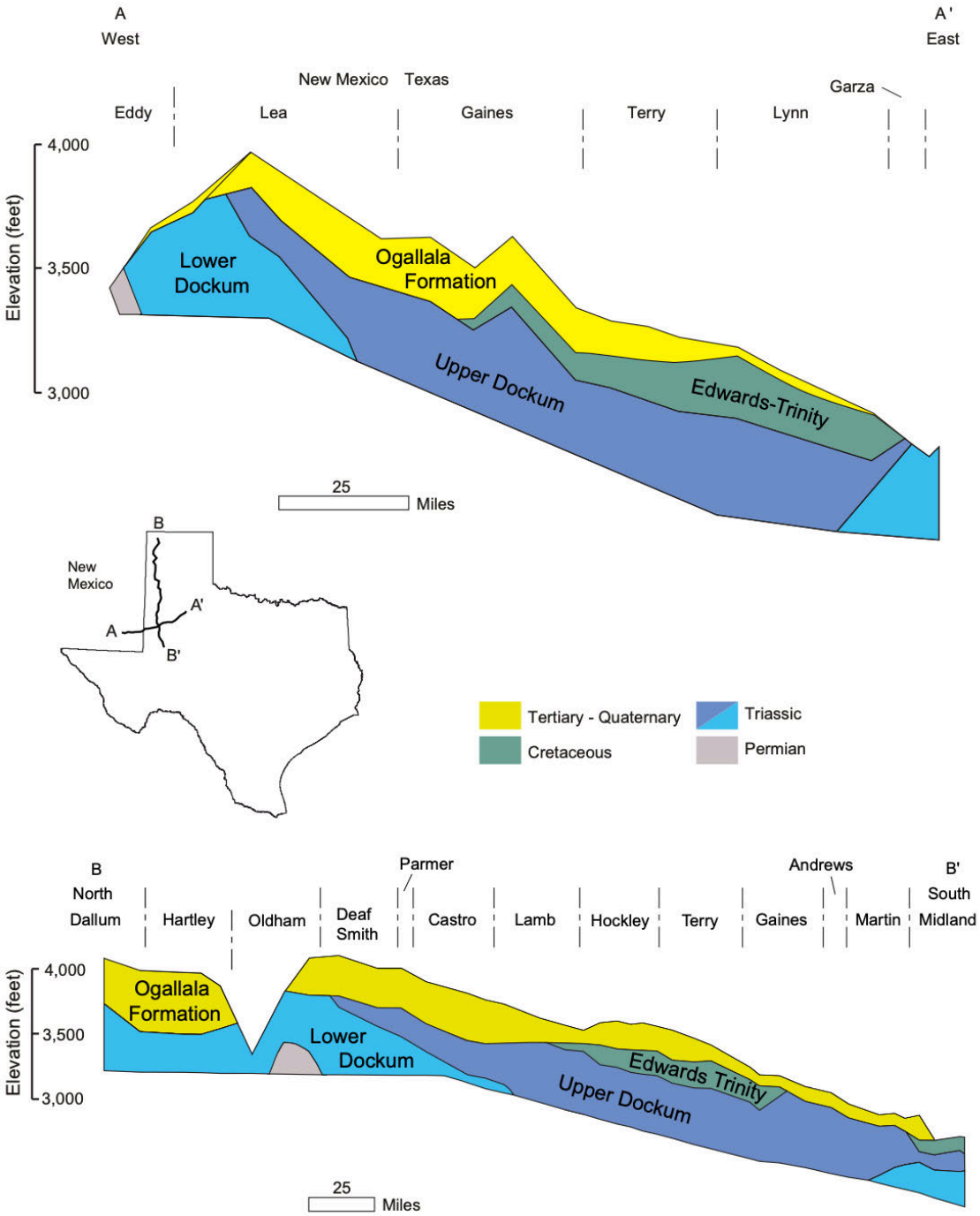
1.9.2 Leakage Pathways

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

[redacted]

Figure 1-79 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 1-79 – 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 1-80 features a map showing the distribution of TDS in groundwater from the Dockum aquifer (Ewing et al., 2008).

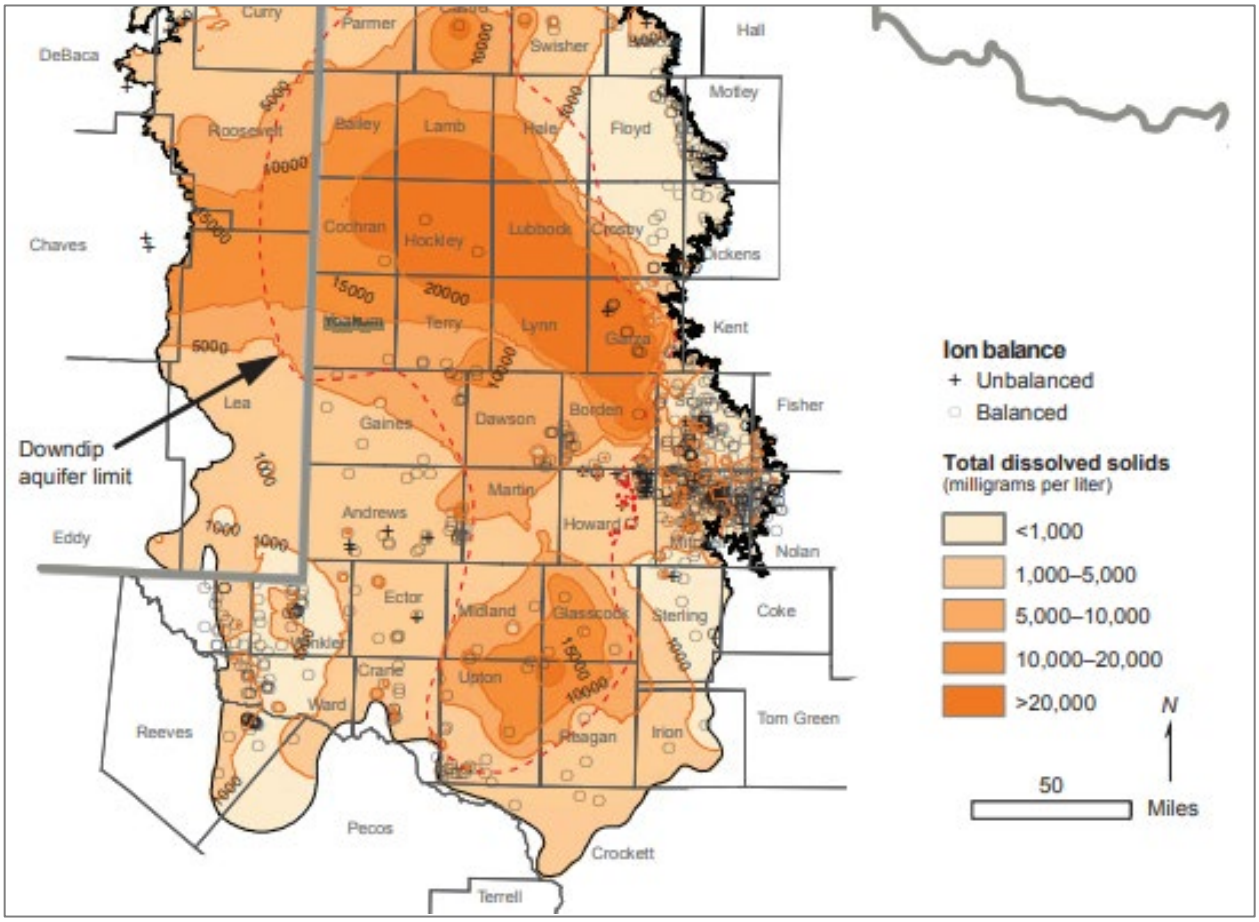


Figure 1-80 – Map showing the distribution of TDS in groundwater from the Dockum aquifer (Ewing et al., 2008).

The Texas Railroad Commission (TRRC) Groundwater Advisory Unit (GAU) identified the base of a USDW at a depth of [redacted]

[redacted]

[redacted]

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' locations. [redacted]

Similar results were produced when using the CO2-SCREEN[2] tool. Using the saline model parameters, the range of total storage capacity in the [redacted]

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. [redacted]

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.

[2]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 [redacted]

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. References

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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

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LONQUIST SEQUESTRATION LLC

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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 modeling software used to evaluate this project was Computer Modelling Group's GEM 2022.30 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM uses equation-of-state (EOS) algorithms and some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics, to produce highly accurate and reliable simulation models for carbon sequestration.

For purposes of injection into a reservoir, CO_2 can be a relatively complex component in the supercritical phase as seen in downhole conditions. The GEM simulator utilizes the compositional methods described, along with equations specific to CO_2, to effectively model and simulate plume behavior within the injection intervals.

The Orchard No. Project will target [redacted] for injection of CO_2. [redacted] the confining interval overlying the injection interval. The dynamic flow model incorporates [redacted] below the impermeable upper confining zone. For purposes of model construction and discussion of the simulation results, the term [redacted]

2.2 Model Inputs

2.2.1 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 2-1 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 2-2 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 [redacted] (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 2-3 through 2-14 then illustrate the same for Orchard No. 2 through No. 7, respectively.



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



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



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



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



Figure 2-5 – Orchard No. 3 east-west cross-sectional view depicting movement of CO_2 phase during injection.



Figure 2-6 – Orchard No. 3 east-west cross-sectional view depicting movement of CO_2 phase post-injection.



Figure 2-7 – Orchard No. 4 east-west cross-sectional view depicting movement of CO_2 phase during injection.



Figure 2-8 – Orchard No. 4 east-west cross-sectional view depicting movement of CO_2 phase post-injection.



Figure 2-9 – Orchard No. 5 east-west cross-sectional view depicting movement of CO_2 phase during injection.



Figure 2-10 – Orchard No. 5 east-west cross-sectional view depicting movement of CO_2 phase post-injection.



Figure 2-11 – Orchard No. 6 east-west cross-sectional view depicting movement of CO_2 phase during injection.



Figure 2-12 – Orchard No. 6 east-west cross-sectional view depicting movement of CO_2 phase post-injection



Figure 2-13 – Orchard No. 7 east-west cross-sectional view depicting movement of CO_2 phase during injection



Figure 2-14 – 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.

2.2.1.1 Upper Confining Zone

Vertical movement of CO_2 will be contained by the low permeability [redacted] will act as a barrier to vertical movement of the relatively buoyant CO_2 through capillary pressure and relative permeability effects.

2.2.1.2 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).

The imbibition process becomes important after injection ceases and gravity forces begin to drive CO2 movement. As CO2 moves out of a rock volume, brine will flow to fill what the CO2 "vacated." The residual (i.e., trapped) CO2 saturation in a simulator grid block will be a function of the maximum trapped gas parameter and the CO2 saturation at the beginning of the imbibition process (Land C. , 1968). The trapped CO2 saturation will be at the maximum value for rock volumes in which the liquid saturation was displaced down to its residual value by the CO2 phase prior to the imbibition.

Typical maximum trapped-gas-saturation parameters range from around 30% to more than 40%. [redacted] A statistical representation of the trapped gas data from Keelan is shown in Figure 2-15. 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 GEM simulator used to characterize the CO_2 plume movement, the maximum trapped gas saturation parameter was set to [redacted] of the pore volume. This represents a conservative value (i.e., more favorable to the spread of a CO_2 plume) as compared to a median value of [redacted].



Figure 2-15 – Trapped Gas Saturation Experimental Data

The effect of trapped gas was illustrated in Figure 2-2 for Orchard No. 1 (then in Figures 2-4, 2-6, 2-8, 2-10, 2-12, and 2-14 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.

2.2.1.3 Solubility Trapping in Brines

The solubility of [redacted] in the water phase is incorporated into the GEM simulator. 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 contrasts 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.

2.2.1.4 Solubility Trapping in [redacted]

[redacted] of the pore volume in the top seven simulation layers of the storage interval. These layers are termed the [redacted] The aggregate thickness for these seven layers ranges from around [redacted] thick across the project area, as shown in Table 2-1. The gross injection interval in the current simulation model and the modeled thickness of the ROZ for each of the Orchard injection wells are as follows:

Table 2-1 – Gross Injection Interval and Modeled ROZ Parameters

Well Name	Gross Injection Interval (ft)	Modeled ROZ Thickness (ft)	ROZ Open for Injection (ft)
Orchard No. 1	[redacted]		
Orchard No. 2			
Orchard No. 3			
Orchard No. 4			
Orchard No. 5			
Orchard No. 6			
Orchard No. 7			

[redacted] input into the simulation model as an initial estimate, allowing for characterization of the mechanisms for the trapping of CO_2 [redacted]

Under the right conditions of pressure, temperature, and reservoir oil composition, CO_2 is an attractive injectant for use as a miscible solvent in enhanced oil recovery (EOR) projects. [redacted] The attractiveness of CO_2 as an EOR solvent arises from its high degree of miscibility with the in-place reservoir 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).

[redacted]

Because of the significant amount of CO_2 contained [redacted] 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:

$$S_{CO_2\,e} = S_o \cdot x_{CO_2} + S_g \cdot y_{CO_2} + S_w \cdot w_{CO_2}$$

[redacted]

Figure 2-16 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 below (image a versus b, and c versus d, respectively) is seen in the shallower 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 2-17 through 2-22 then show the same for Orchard No. 2 through No. 7, respectively.



Figure 2-16 – Orchard No. 1 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.



Figure 2-17 – Orchard No. 2 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.



Figure 2-18 – Orchard No. 3 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.



Figure 2-19 – Orchard No. 4 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.



Figure 2-20 – Orchard No. 5 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.



Figure 2-21 – Orchard No. 6 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.



Figure 2-22 – Orchard No. 7 east-west cross-sectional view depicting CO_2 phase versus effective total CO_2.

2.2.1.5 Structural Trapping

Within our area of interest, there is no evidence of structure to trap CO_2. 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.

2.2.1.6 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. For aqueous reactions, the following three formulae can be used:

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

Those common ionic reactions can occur in the reservoir between water and/or CO_2. The following formulae show the mineral reactions that may be used within the model. Each of these is a common mineral that may be found in carbonates in an underground aquifer and cause the precipitation of carbon oxides in a solid state:

$$Anhydrite\ (CaSO_4) = Ca^{2+} + SO_4^{2-}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO_3^-$$
$$Dolomite\ (CaMg(CO_3)_2) + 2H^+ = Ca^{2+} + 2(HCO_3^-) + Mg^{2+}$$
$$Illite\ (K_6Mg_{25}Al_{2.3}Si_{3.5}O_{10}(OH)_2) + 8H^+ = 2.3Al^{3+} + 5H_2O + 0.6K^+ + 0.25Mg^{2+} + 3.5SiO_2$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO_2$$
$$K - Feldspar\ (KAlSi_3O_8) + 4H^+ = 2H_2O + Al^{3+} + 3SiO_2$$

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 GEM simulator, the geochemical processes have not been included in the simulation cases.

2.2.1.7 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 2-23, 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 2-23 – Balance of Injected CO_2

2.2.2 Structural and Stratigraphic Elements

The model was built using the geologic data described 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. Specifically, *Section 1.3.2* discussed the stratigraphy of the modeled injection zone. The simulation model was built for the approximately



Figure 2-24 – Horizontal Permeability at Orchard No. 1 Injector (East-West Section)



Figure 2-25 – Horizontal Permeability at Orchard No. 2 Injector (East-West Section)



Figure 2-26 – Horizontal Permeability at Orchard No. 3 Injector (East-West Section)



Figure 2-27 – Horizontal Permeability at Orchard No. 4 Injector (East-West Section)



Figure 2-28 – Horizontal Permeability at Orchard No. 5 Injector (East-West Section)



Figure 2-29 – Horizontal Permeability at Orchard No. 6 Injector (East-West Section)



Figure 2-30 – Horizontal Permeability at Orchard No. 7 Injector (East-West Section)

Tables 2-2 through 2-8 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 2-2 – Orchard No. 1 Model Porosity and Permeability Summary

		Porosity	Perm (mD)

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

		Porosity	Perm (mD)
[redacted]			

Table 2-4 – Orchard Well No. 3 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
[redacted]			

Table 2-5 – Orchard No. 4 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
[redacted]			

Table 2-6 – Orchard No. 5 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
[redacted]			

Table 2-7 – Orchard No. 6 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
[redacted]			

Table 2-8 – Orchard No. 7 Model Porosity and Permeability Summary

		Porosity	Perm (mD)
[redacted]			

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 hydrocarbon fields. In the Orchard simulator model, a value of 0.03 was chosen. This can be considered as a moderate vertical permeability ratio.

While the k_v/k_h ratio of 0.03 may seem low, the flow between simulator grid blocks—and in the physical world—is controlled by transmissibility rather than permeability alone. For constant viscosity and relative permeability, the transmissibility can be represented by the equation $T = \frac{k \times A}{L}$, where A is the cross-sectional area to flow and L is the length over which the flow (e.g., grid block center to center) travels. For simulator grid-cell dimensions, vertical flow between grid cells has a large area and small distance, while the horizontal flow between cells has a relatively large distance

across a (relatively) small cross-sectional area. In the Orchard simulation model, typical grid blocks are 492 ft x 492 ft (150 meters square) by 20 ft thick. The vertical A/L term will therefore be 600 times larger than the horizontal term. With a k_v/k_h ratio of 0.03, vertical transmissibility is still nearly 20 times higher than the horizontal transmissibility.

2.2.3 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 the following equation. The gas relative permeability applies to the supercritical CO_2 phase.

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

And

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

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 2-31 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.



Figure 2-31 – Gas-Liquid Relative Permeability Relationship

The red curve shows the relative permeability to the supercritical CO_2 phase, starting at a maximum value of 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 and increasing together with the liquid saturation.

The value of for the CO_2 phase relative-permeability endpoint may be considered low relative to "conventional" relative-permeability data used in the energy industry. Figure 2-32 shows a statistical distribution of the CO_2 endpoint relative-permeability data for carbonates, taken from the 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 2-32 indicates, denote a log-normal distribution.



Figure 2-32 – Probability Distribution of CO_2 Endpoint Relative Permeability

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:

$$f_g = \frac{1}{1 + \frac{\mu_g}{\mu_w}\frac{k_{rw}}{k_{rg}}}$$

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 2-33 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 (0.36) 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 [redacted] 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 that Figure 2-16 displayed (for Orchard No. 1, with similar figures there following for Orchard No. 2 through No. 7 respectively, in *Section 2.2.1.4*).



Figure 2-33 – 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.

2.2.3.1 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 [redacted] 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.

2.2.4 Initial Conditions

[redacted] as Table 2-9 shows.

Table 2-9 – Reservoir Pressure Gradient Data for Nearby [redacted]

Field	San Andres Reservoir Pressure Gradient
[redacted]	

The formation temperature in the simulation model was initialized to a constant temperature of [redacted] This is based on bottomhole temperature data reported on well-log headers for several nearby wells and provided in Table 2-10. Temperature gradients were calculated from an estimated surface soil temperature of 65°F.

Table 2-10 – Formation Temperature for Orchard Area Wells

Well ID No.	Maximum Temperature (°F)	Depth (ft)	Calculated Gradient (°F/100 ft)
[redacted]			

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 2-34, which yields a median temperature gradient for the Orchard Project area of [redacted]. Incorporating that median gradient with a formation datum depth approximately [redacted] ft below surface yields a temperature of [redacted]. That was increased to [redacted] to reflect the suppression of measured wellbore temperatures due to mud circulation [redacted]



Figure 2-34 – Orchard Area Temperature Gradients

The EOS fluid property model used in this simulation model is summarized in *Appendix 2-2*.

, the storage interval is essentially brine filled, with trace amounts of hydrocarbon present. This inclusion of trace volumes of hydrocarbons significantly helps the computational stability for the GEM simulator. Dissolved solids content for the formation brine was set to parts per million (ppm). This value was chosen as the median dissolved solids for water samples in and around the Orchard area, as plotted in Figure 2-35.

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 pounds per cubic foot (lb/ft^3), yielding a gradient of 0.448 psi/foot at downhole conditions.



Figure 2-35 – Normal Probability Plot of Gaines County TDS Data in the San Andres Formation

2.2.5 Injection Rate

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 [redacted] The limiting pressure gradient will be updated to 90% of the fracture gradient, when measured with the step-rate test.

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), [redacted] 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.

2.2.6 Injected Fluids Composition

While the simulation model was constructed with a nine-component EOS to describe the fluids found in the [redacted] 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 [redacted] 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.

2.2.7 Completion Plan

The proposed Orchard No. No. injection wells will be perforated and stimulated in all permeable layers through the [redacted] (i.e., injection interval). This is simulated in the model by opening layers with permeabilities greater than 1.5 millidarcys (mD) based on the petrophysical evaluation. This completion strategy will be implemented for all the injectors planned in the Orchard Project. Actual model perforation selection was done based on a qualitative inspection of permeabilities at each well location. The interval and timing inputs to the model for No. No. the injection wells are shown in Table 2-11. Figures 2-36 through 2-42 show a cross-sectional view of grid block permeability at the Orchard No. 1–No. 7 well locations, respectively. In each, the "perforated" grid blocks are flagged on the wellbore diagrams with green circles.

Table 2-11 – Orchard No. 1–No. 7 Model Completion Timing

Injection Well	Year	Duration	Top (ft)	Thickness (ft)	Net Pay (ft)	Geologic Layer
[redacted]						

[redacted]

[redacted]

Figure 2-36 – Orchard No. 1 Perforations

[redacted]

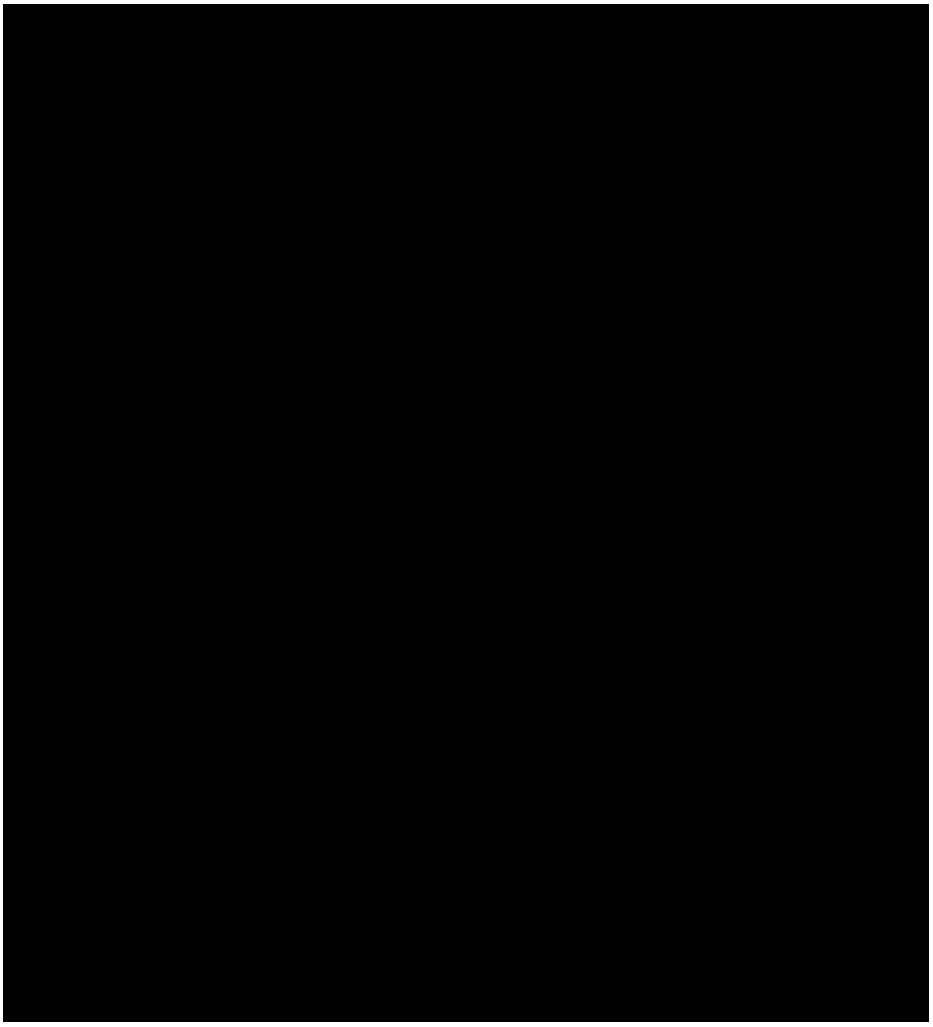


Figure 2-37 – Orchard No. 2 Perforations

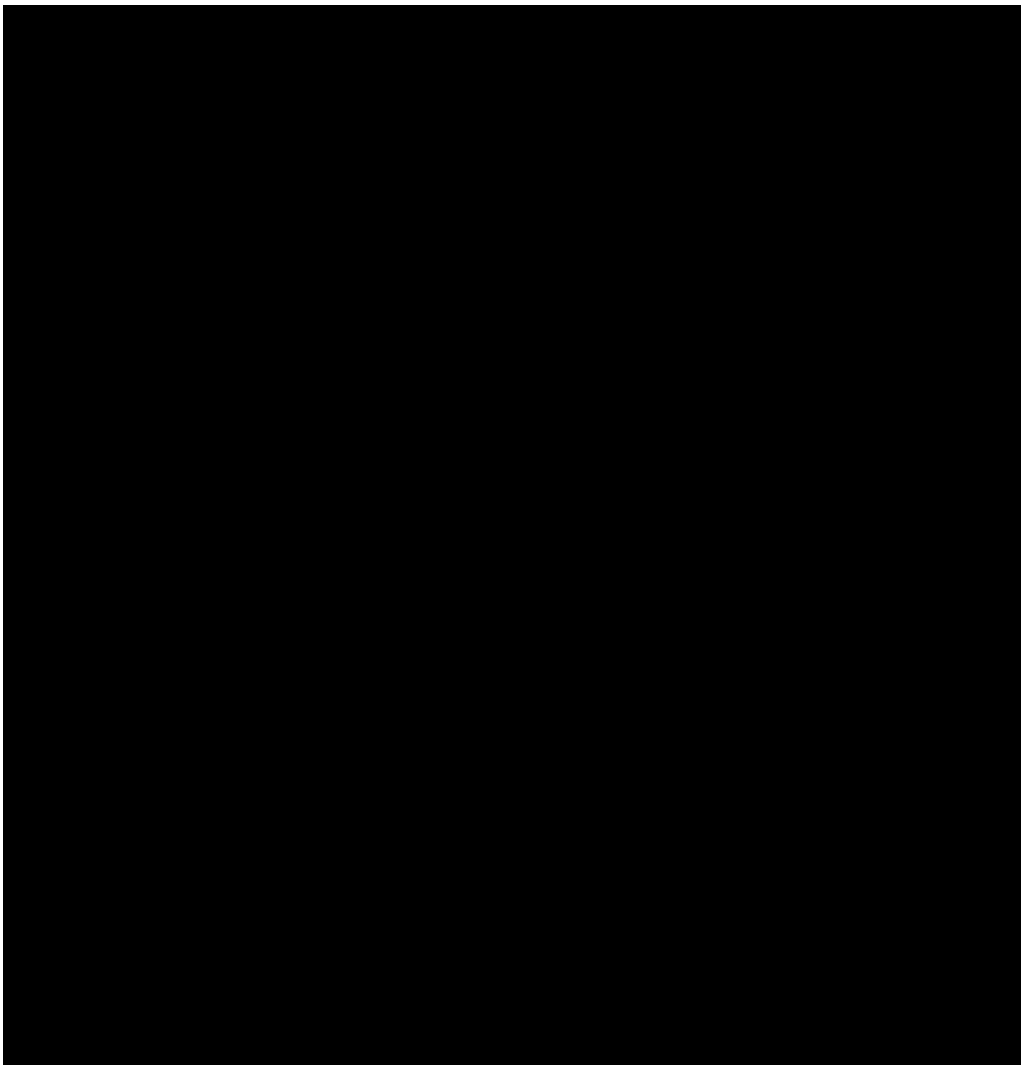


Figure 2-38 – Orchard No. 3 Perforations

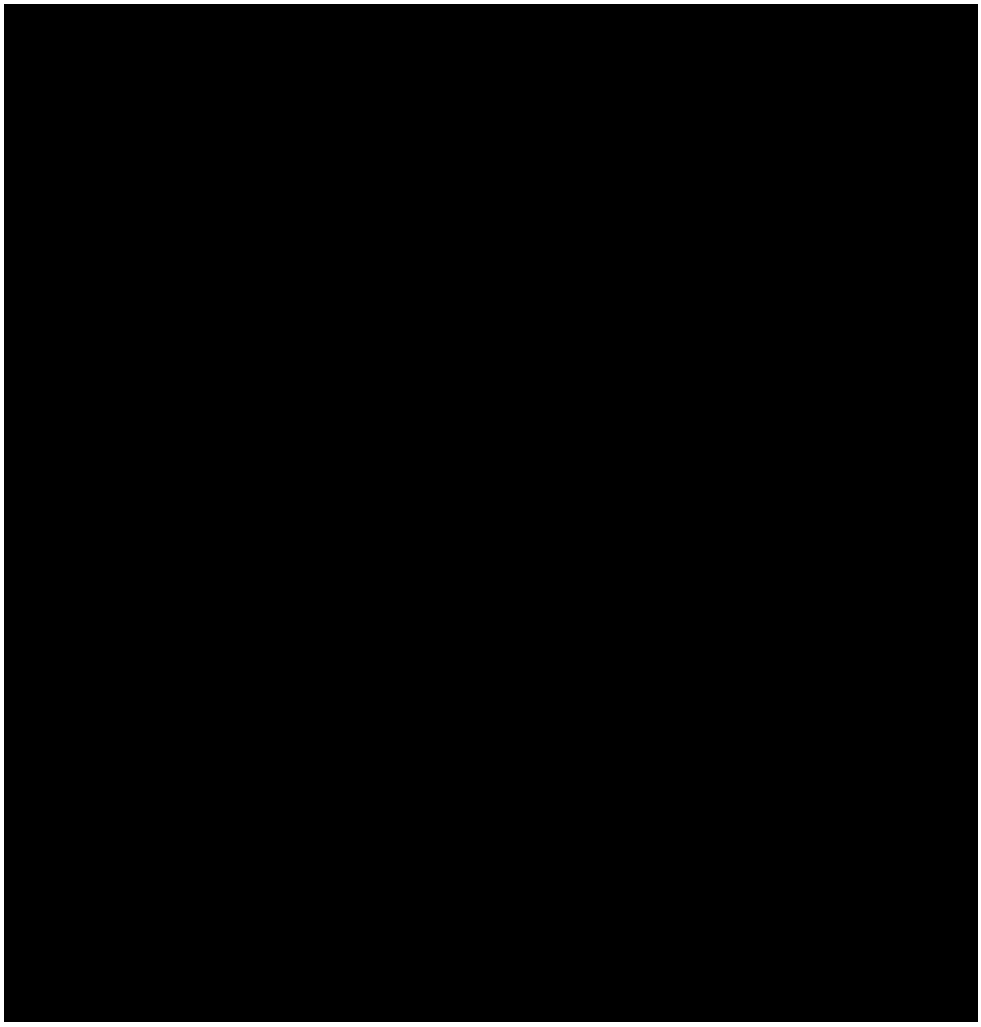


Figure 2-39 – Orchard No. 4 Perforations



Figure 2-40 – Orchard No. 5 Perforations





Figure 2-41 – Orchard No. 6 Perforations

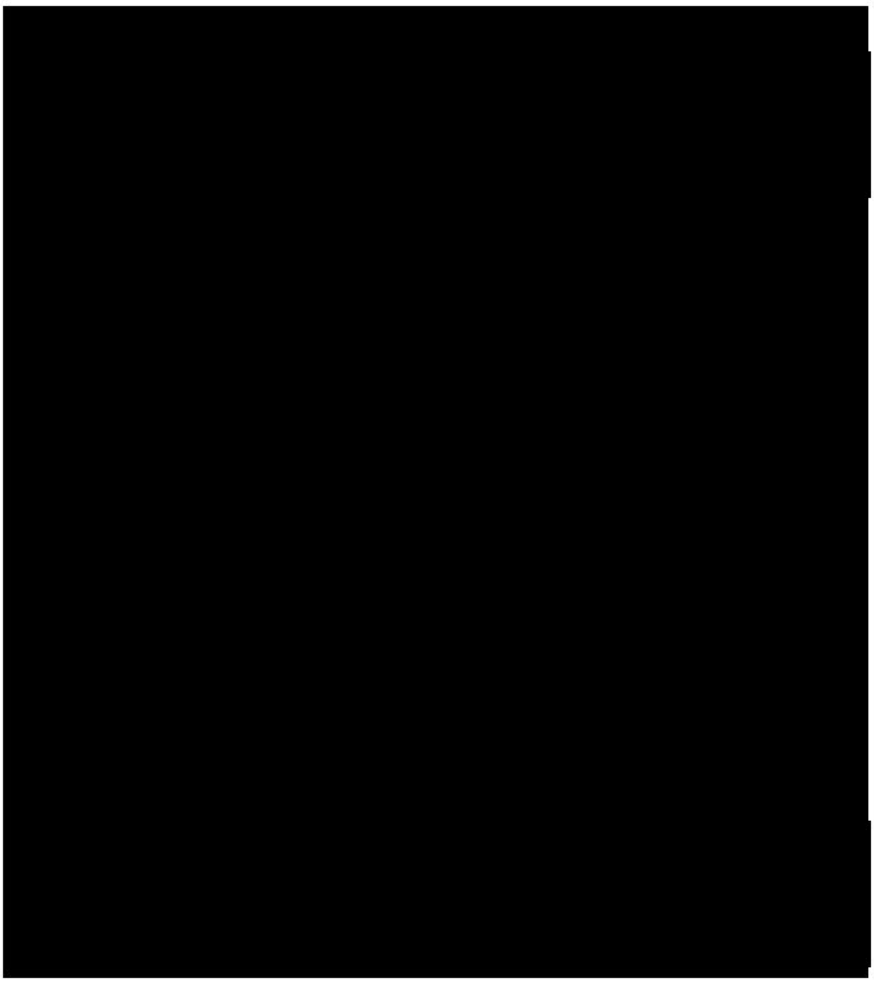


Figure 2-42 – Orchard No. 7 Perforations



The stimulation aspect of the completion strategy was modeled by assigning a skin value of -3.5 to all wells upon initial completion. This skin value corresponds to a small fracture stimulation with a half-length around 25 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.

2.3 Model Orientation and Gridding Parameters

2.3.1 Spatial Conditions

The simulation of the CO_2 injection and migration was performed for the [redacted] Figure 2-36 through Figure 2-42 (*Section 2.2.2*) showed a representation of permeability near the planned injection wells. No.

The reservoir simulator covers [redacted] 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 170 x 140 x 61 grid blocks in the x, y, and z dimensions, respectively. Block x and y dimensions are a constant 150 meters (492 ft). The model covers an area of 15.9 x 13.1 miles (east-west and north-south, respectively), with a total area of 246 square miles—that is, 1.45 million active grid blocks. Grid block thicknesses vary throughout the model, as shown in Table 2-12. Boundary conditions are described in *Section 2.3.2*.

Table 2-12 – Model Layer Parameters

Well Name	[redacted]
Orchard No. 1	
Orchard No. 2	
Orchard No. 3	
Orchard No. 4	
Orchard No. 5	
Orchard No. 6	
Orchard No. 7	

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 [redacted] Tables 2-13 through 2-19 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 2-13 – Simulator Permeability Values in Area of Orchard No. 1 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

Table 2-14 – Simulator Permeability Values in Area of Orchard No. 2 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

Table 2-15 – Simulator Permeability Values in Area of Orchard No. 3 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

Table 2-16 – Simulator Permeability Values in Area of Orchard No. 4 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

Table 2-17 – Simulator Permeability Values in Area of Orchard No. 5 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

Table 2-18 – Simulator Permeability Values in Area of Orchard No. 6 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

Table 2-19 – Simulator Permeability Values in Area of Orchard No. 7 Well

	Average Permeability (mD)	Minimum Permeability (mD)	Maximum Permeability (mD)
[redacted]			

The distribution of cumulative injection [redacted] injection interval. Also notable is the wide range between minimum and maximum permeabilities in Table 2-13 through 2-19. A more useful measure of heterogeneity would be to look at the ratio of 10th to 90th percentile values. Comparing that ratio for permeability within individual layers to the entire volume provides insight into the relative amounts of heterogeneity in the vertical vs. horizontal directions. Table 2-20 shows ratios of 90th to 10th percentile values for permeability in the [redacted] injection intervals for all seven injection wells. The first column shows the ratio for the entire volume centered on each of Orchard No. No. injection wells, while the second shows the average of that ratio for data populations by layer. This table illustrates that, within the Orchard No. Project area, the lateral variation of permeability is approximately one order of magnitude less than the overall variation, which is dominated by vertical heterogeneity.

Table 2-20 – Comparison of Statistical Measures for Permeability for Orchard No. 1–No. 7

Zone	P_{90} / P_{10} ratio – entire volume	P_{90} / P_{10} ratio – average of layer values
[redacted]		

From a wellbore injectivity perspective, the wells penetrate many layers that would be considered "non-pay" due to relatively low permeabilities. These non-pay intervals are important in the reservoir simulation model, as even the low-permeability grid cells provide significant pore-volume compressibility to the model.

2.3.2 Boundary Conditions

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. Each of the lateral edges of the model has been connected to one or more numerical aquifers, using the Fetkovich water-influx calculation option (Fetkovich, 1971), to characterize connections between the modeled area and surrounding region. The use of Fetkovich-type numerical aquifers allows for the definition of aquifers having finite connectivity to the reservoir model. In this setup, bounding aquifers on the north, west, and south simulation boundaries are very large and effectively infinite. [redacted] Analysis of the early

performance data is discussed in *Section 2.3.2.1*. [redacted]

The Fetkovich method uses an aquifer productivity index—or, in this case, an injectivity index parameter with units of reservoir barrels per day per psi. This parameter is defined in the simulator based on reservoir properties (thickness, permeability) on the model face and the size of the aquifer: $effective\ {}^{r_a}/_{r_r}$, equivalent to an ${}^{r_e}/_{r_w}$ term in the radial flow equation, where "r_a" refers to the effective outer radius of the aquifer, and "r_r" refers to the effective outer radius of the reservoir simulator.

As a result of this definition of the boundaries, the model is connected to large regional reservoir volumes on three sides, with transmissibility between the simulator and aquifer volumes based on average permeabilities on each respective face. Connectivity to the east side is also based on the permeabilities on that face. However, the reservoir volume, though substantial (12 x 10^9 reservoir barrels), only amounts to 7% of the pore volume contained by the active reservoir simulation grid.

2.3.2.1 [redacted] 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 [redacted] reservoir pressures stayed above the bubble point during early production, [redacted]. 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 [redacted], 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 [redacted] tabulated in Table 2-21, a match to the pressure decline vs. cumulative production (Figure 2-43) was obtained for an oil-in-place (OIP) estimate of [redacted]

Table 2-21 – [redacted] Reservoir Parameters

Parameter	Value
Initial Reservoir Pressure (psi)	[redacted]
Initial Water Saturation (%)	
Initial Oil Formation Volume Factor (RB/STB*)	
Oil Compressibility (psi^{-1})	
Water Compressibility (psi^{-1})	
Formation Compressibility (psi^{-1})	

*Reservoir barrel per stock-tank barrel.



Figure 2-43 – [redacted] Material Balance

The results of the material-balance match are significant when considering the regional connectivity of the [redacted] 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 [redacted] 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. [redacted] currently operates at higher than initial pressures, approximately [redacted] Contrary to the performance-based evidence

described above [redacted]

2.3.3 Model Time Frame

The reservoir simulation model was run for a period of [redacted] 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 2.2.1*. Figure 2-44 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 2.2.1.4.*



Figure 2-44 – 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. The figure shows how the plume stabilizes to a very slow growth rate within the first few years post-injection.

2.4 CO_2 Plume Model Results

Model cases were run that included all wells, to ensure overall injectivity while honoring injection pressure limits. Figure 2-45 shows the stabilized CO_2 plumes for all seven injection wells at 50 years post-injection. Figures 2-46 through 2-59 display cross sections of the CO_2 plumes for Orchard No. 1–No. 7, respectively, taken at the end of injection and 50 years post-injection.



Figure 2-45 – Stabilized CO_2 Plumes, 50 Years Post-Injection



Figure 2-46 – Orchard No. 1 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-47 – Orchard No. 1 North-South Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-48 – Orchard No. 2 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-49 – Orchard No. 2 North-South Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-50 – Orchard No. 3 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-51 – Orchard No. 3 North-South Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-52 – Orchard No. 4 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-53 – Orchard No. 4 North-South Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-54 – Orchard No. 5 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-55 – Orchard No. 5 North-South Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-56 – Orchard No. 6 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-57 – Orchard No. 6 North-South Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-58 – Orchard No. 7 East-West Cross-Sectional Views of Effective CO_2 Saturation



Figure 2-59 – Orchard No. 7 North-South Cross-Sectional Views of Effective CO_2 Saturation

Figure 2-44 demonstrated how the plume areal extent stabilizes during the first few years post-injection. While the plume areas quickly stabilize, the trapping of the CO_2 phase progresses over many years (discussed in *Section 2.2.1.7*). Figures 2-60 and 2-61 show how the trapped CO_2 volumes will change over time for the Orchard Project.



Figure 2-60 – Total Metric Tons of CO_2 and Trapping Mechanisms Over Time



Figure 2-61 – Percent of CO_2 in Each State Over Time

2.4.1 Critical Pressure Front

The second component to defining the AOR is determining the extent of the critical pressure front. The worst-case scenario for moving reservoir fluids to the Underground Source of Drinking Water (USDW) would be through either an improperly plugged and abandoned wellbore, or a subsurface feature that is open in the base of the USDW and at the top of the injection interval. This resultant pressure is referred to as 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 hydrostatic case.

The base of the USDW is expected to be at [redacted] above sea level as observed on offset data from API No. [redacted] Critical pressure is calculated at the top perforated interval for the Orchard No. 6 well, which represents the shallowest perforation top of all seven of the Orchard injectors.

The fluid in the injection zone is assumed to be brine with [redacted] of TDS, based on data from the U.S. Geological Survey's National Produced Waters Geochemical Database, taken for wells close

to the Orchard Project area (and distributed as displayed in Figure 2-43, in *Section 2.3.2.1*). The density of the formation brine in the injection zone was calculated to be [redacted], using correlations by McCain (McCain, 1991). The fluid gradient within the storage interval will therefore be [redacted]

The USDW intervals have been split into two segments—one shallow, one deep—to calculate the pressure at the base USDW. The shallower segment consists of the primary Ogallala aquifer and the underlying secondary Edwards-Trinity (High Plains) aquifer, intervals that Orchard-area water wells currently use. Average TDS values for those two aquifers are [redacted] respectively, yielding a fluid gradient of [redacted] psi per foot for both. The estimated thickness of this shallower segment is [redacted] based on drillers' logs from the [redacted] water wells.

Properties for the USDW segment *below* the Ogallala are based on known data for the Dockum group, which underlies the Ogallala. This deeper segment is known to have significantly higher TDS than that found in the Ogallala. [redacted] The density value derived using McCain yields a pressure gradient of 0.434 psi/foot. (*Appendix 2-1* discusses the McCain correlation.)

To calculate the pressure at the base of the USDW, the hydraulic head was determined in the Ogallala aquifer (i.e., shallow segment). The Texas Water Development Board's (TWDB) database of groundwater source wells in Texas contains information for wells in which liquid levels are routinely measured. Currently designated as Groundwater Conservation District (GCD) observation wells by the TWDB, four of such wells were found within the Orchard AOR and have good quality data from late 2021 and 2022. Table 2-20, which lists those wells, presents their elevations of water level (i.e., the hydraulic head in Ogallala) and date of measurement.

Table 2-22 – Ogallala Aquifer GCD Observation Well Data

Water Well No.	Water Level (Feet Above Sea Level)	Measurement Date
[redacted]		

From this data, water well [redacted] has the deepest liquid level, at an elevation of [redacted] t above sea level. Using that ground-level elevation and a thickness of [redacted] t for the shallower segment, the following input parameters were used to calculate critical pressure, tabulated in Table 2-21. For brevity in the table, the shallow segment (Ogallala and Edwards – Trinity (High Plains) aquifers) is termed "Ogallala."

Table 2-23 – Inputs for Critical Pressure Calculation (Subsea Elevations)

Input Variable	Value
Hydraulic head elevation of Ogallala aquifer (ft)	[redacted]
Fluid gradient in Ogallala aquifer (psi/ft)	
Base Ogallala elevation (ft)	
Hydrostatic pressure differential in Ogallala (psi)	
Calculated pressure at base of Ogallala (psia)	
USDW fluid gradient below Ogallala (psi/ft)	
Fluid column below Ogallala (ft)	
Hydrostatic pressure differential in lower USDW segment (psi)	
Initial fluid pressure at the base of USDW (P_u) – (psia)	
Injection zone pressure gradient ($\rho_i g$)	
Representative elevation of USDW (z_u) – (ft)	
Representative elevation of injection zone (z_i) – (ft)	

The pressure at the base of the USDW (P_u) was calculated in two steps. First, for the column of fresh water in the Ogallala, P_O was calculated at its base:

(Eq. 1) $\Delta P_O = \rho g \cdot (z_h - z_O)$ [redacted]

Where z_h and z_o represent the respective elevations for the top of the water column and base of the Ogallala aquifer. Pressures have been converted to absolute pressure for consistency with pressures calculated within the plume simulation model.

Second, to arrive at the pressure at the base USDW (P_u), a similar calculation was employed:

(Eq. 2) $$P_u = P_O + \rho g \cdot (z_O - z_u)$$ [redacted]

Where z_u is the representative elevation of the USDW.

Representative elevation and pressure for the injection zone was chosen from Orchard No. 6, which has the shallowest injection interval of the seven Orchard injectors. Elevation (z_i) for the shallowest injection in Orchard No. 6 is at [redacted]. Pressure at that elevation (P_i) is calculated by correcting the simulator initial pressure ([redacted]) at datum elevation of [redacted] to the depth of the shallowest injection zone, using the pressure gradient of [redacted] psi per foot:

(Eq. 3) [redacted]

The pressure front ($P_{i,f}$) calculations for the injection zone are:

(Eq. 4) $$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i)$$

Where P_u is the initial fluid pressure in the USDW, ρ_i is the injection-zone fluid density, g is the acceleration due to gravity, z_u is the representative elevation of the USDW, and z_i is the representative elevation of the injection zone.

The critical pressure rise ($\Delta P_{i,f}$) is then calculated:

(Eq. 4) $$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i$$ [redacted]

The resulting rise in critical pressure for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by [redacted] psi without risk of fluid migration to the USDW.

The expected pressure differential relative to pre-injection pressures for each of the Orchard No. No. injection wells is presented in Figures 2-62 through 2-68, respectively. The differential pressure, calculated for each grid block in the simulation model, is a snapshot of the difference between the pressure prior to the start of injection and the pressure at a given time post-injection. The data plotted on the graph represent the maximum for that differential pressure for all simulator grid blocks penetrated by each of the Orchard injectors.

Figures 2-62 through 2-68 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 maximum Δp value in psi. The dashed horizontal line shows the value of the critical pressure differential calculated at [redacted] psi, and a vertical dashed line flags the time at which injection ceases for this project.

The dominant mechanisms for CO_2 flow in the storage interval will change over time (discussed in *Section 2.2.1*). Likewise, the values and location for the maximum differential pressure will be controlled by different mechanisms over the life of the project. During injection, the highest Δp values are dominated by the horizontal flow away from the wellbore in the more permeable layers. These are the layers into which the majority of CO_2 is injected. The maximum Δp values increase with time until injection ends [redacted]. While the storage interval is effectively infinite-acting, pressures near the wellbore will increase with continued injection due to transient pressure effects, as the effective radius influenced by the injection pressure expands with continued injection.



Figure 2-62 – Orchard No. 1 Maximum Pressure Buildup of All Layers



Figure 2-63 – Orchard No. 2 Maximum Pressure Buildup of All Layers



Figure 2-64 – Orchard No. 3 Maximum Pressure Buildup of All Layers



Figure 2-65 – Orchard No. 4 Maximum Pressure Buildup of All Layers



Figure 2-66 – Orchard No. 5 Maximum Pressure Buildup of All Layers



Figure 2-67 – Orchard No. 6 Maximum Pressure Buildup of All Layers



Figure 2-68 – Orchard No. 7 Maximum Pressure Buildup of All Layers

After injection ceases, the pressures in the more permeable layers will bleed off rapidly. During the first 10 years post-injection, the maximum pressure falls below the critical Δp value of [redacted] psi, as Figures 2-62 through 2-68 show. Within this time, the maximum Δp value becomes dominated by the lowest permeability grid blocks at or near the wellbore. Those low permeability grid blocks were pressured up due to vertical flow [redacted]. The rate at which the (maximum Δp) pressure declines is dominated by the low permeability in those blocks.



Orchard #1: Pressure Differential from Pre-Injection Values
E-W Cross Section



Figure 2-69 – Orchard No. 1 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)

Orchard #2: Pressure Differential from Pre-Injection Values
E-W Cross Section



Figure 2-70 – Orchard No. 2 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)

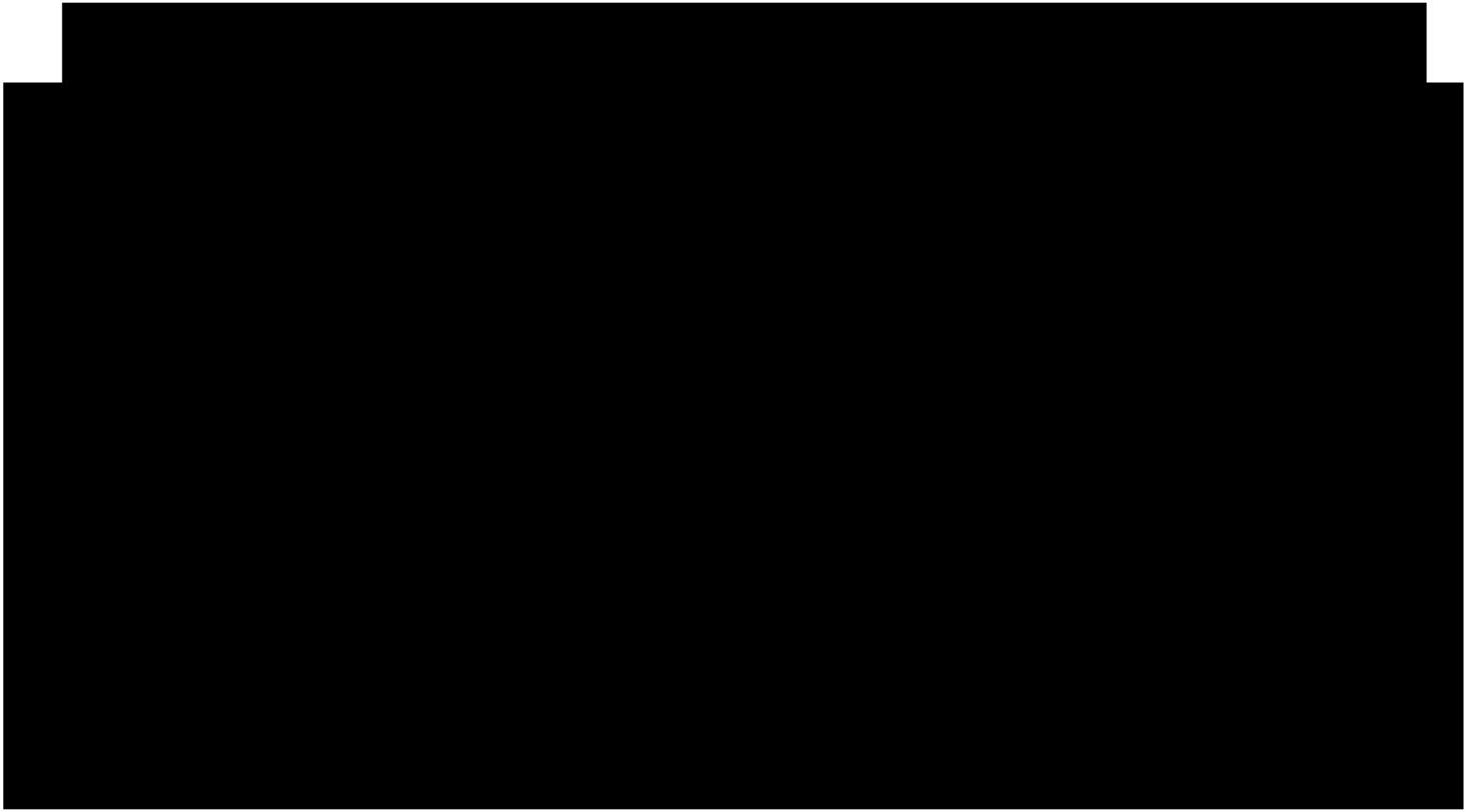


Figure 2-71 – Orchard No. 3 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)

Orchard #4: Pressure Differential from Pre-Injection Values
E-W Cross Section



Figure 2-72 – Orchard No. 4 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)

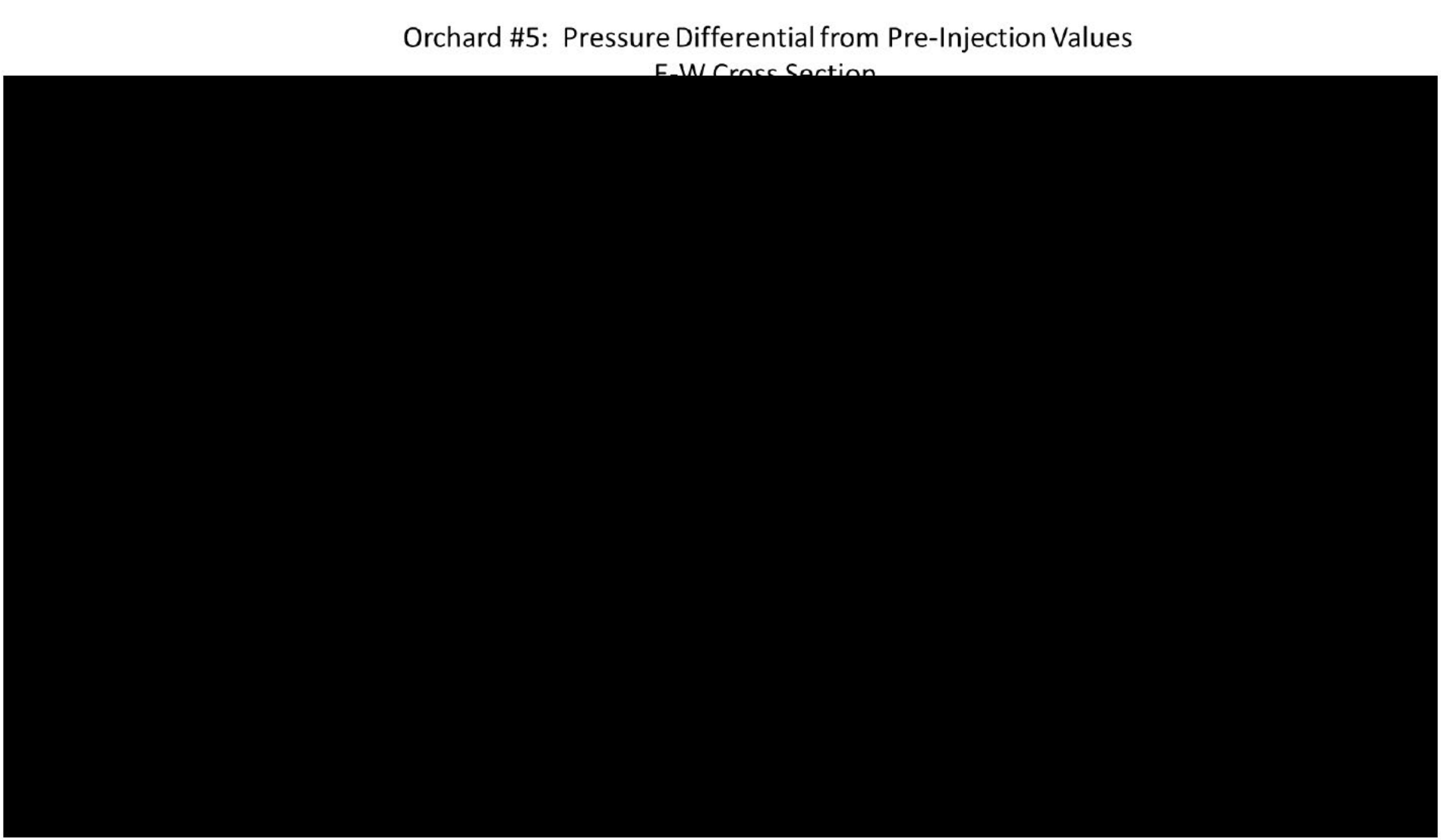


Figure 2-73 – Orchard No. 5 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)



Figure 2-74 – Orchard No. 6 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)

Orchard #7: Pressure Differential from Pre-Injection Values
E-W Cross Section



Figure 2-75 – Orchard No. 7 East-West Cross-Sectional Snapshots of Δp Relative to Pre-injection Pressures (psi)

2.5 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 2-76 shows a reference line (in red) for the critical pressure differential with a value of [redacted] psi. 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 2-76 – Stabilized CO_2 Plumes and Critical Pressure Front at the Orchard Project

Figures 2-77 through 2-83 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 [redacted] influenced by overall project-area pressure buildup within the pressure front—pressure that starts to fall off after the injection well is shut in. [redacted] 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 2-77 – Injection Rate and BHP Data for Orchard No. 1



Figure 2-78 – Injection Rate and BHP Data for Orchard No. 2



Figure 2-79 – Injection Rate and BHP Data for Orchard No. 3



Figure 2-80 – Injection Rate and BHP Data for Orchard No. 4



Figure 2-81 – Injection Rate and BHP Data for Orchard No. 5



Figure 2-82 – Injection Rate and BHP Data for Orchard No. 6



Figure 2-83 – 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 2-46 through 2-59 (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 2.2.1*). Those figures presented snapshots of the predicted distribution of the CO_2, taken at the end of injection and 50 years thereafter.

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[redacted]

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

Revised April 2024

LONQUIST SEQUESTRATION LLC

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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: **GEM 2022.30**

Model Authors/Institution: Computer Modelling Group, Ltd.

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

3.3 Model Inputs and Assumptions

The input parameters for the GEM model are summarized in Table 3-1. These parameters are based on the values estimated at each injection well location.

Table 3-1 – Model Input Parameters and Assumptions for Orchard No. 1–No. 7

Well	Injection Rate (MT/yr*)	Injection rate (MMscf/d**)	[redacted]	Bottomhole Temperature (°F)	Fracture Gradient (psi/ft***)	Maximum Allowable Injection Gradient (psi/ft)	Brine Salinity (ppm^)	Injectate Composition
Orchard No. 1	[redacted]							
Orchard No. 2								
Orchard No. 3								
Orchard No. 4								
Orchard No. 5								
Orchard No. 6								
Orchard No. 7								

*MT/yr – metric tons per year
**MMscf/d – million standard cubic foot per day
***psi/ft – pounds per square inch per foot
^ppm – parts per million

3.4 Site Geology and Hydrology

A 3D computational model of the geologic layers from the top of [redacted] work were used as inputs to create static (*geologic*) and dynamic (*simulation*) models.

3.4.1 Surfaces

Surfaces from the [redacted] were created using the convergent interpolation algorithm, to interpolate between the tops of wells near the Orchard injection well sites and within the wider area. The extrapolation of depth values was restricted to the maximum and minimum of the input data, and a grid increment of 150 x 150 meters was used.

3.4.2 Mesh

The 3D mesh (or grid) was created using the surfaces as inputs. The horizontal (I-J) grid dimensions in the static model are 150 x 150 meters. The vertical layering (K) scheme is proportional. Table 3-2 shows the cell count and average thickness for the vertical cells in the static model within the Orchard Project area. Figure 3-1 shows a map of the static model grid boundary.

Table 3-2 – Vertical Layering Design in the Static Model

Name	Cell Count	Average Thickness (ft)
[redacted]		



Figure 3-1 – Map of the Static Model Grid Boundary

3.4.3 Property Distribution

Properties (e.g., porosity, permeability) were populated in all cells within [redacted] zone layers in the 3D static model. This version of the static and dynamic models [redacted]

3.4.3.1 Facies

The site-characterization results incorporate facies determinations to build the porosity and permeability models for the [redacted] njection zone.

3.4.3.2 Porosity

Cross-plot porosity was calculated for wells with both neutron and density well logs. The porosity was upscaled from well logs (resolution approximately 0.25 ft) to grid cells (resolution approximately 10 ft) via arithmetic averaging. Figure 3-2 shows a comparison of the well logs and the upscaled porosity values within grid cells for the type well. A normalized score of the porosity data using all the upscaled porosity data was completed prior to distributing porosity among well locations in the grid.

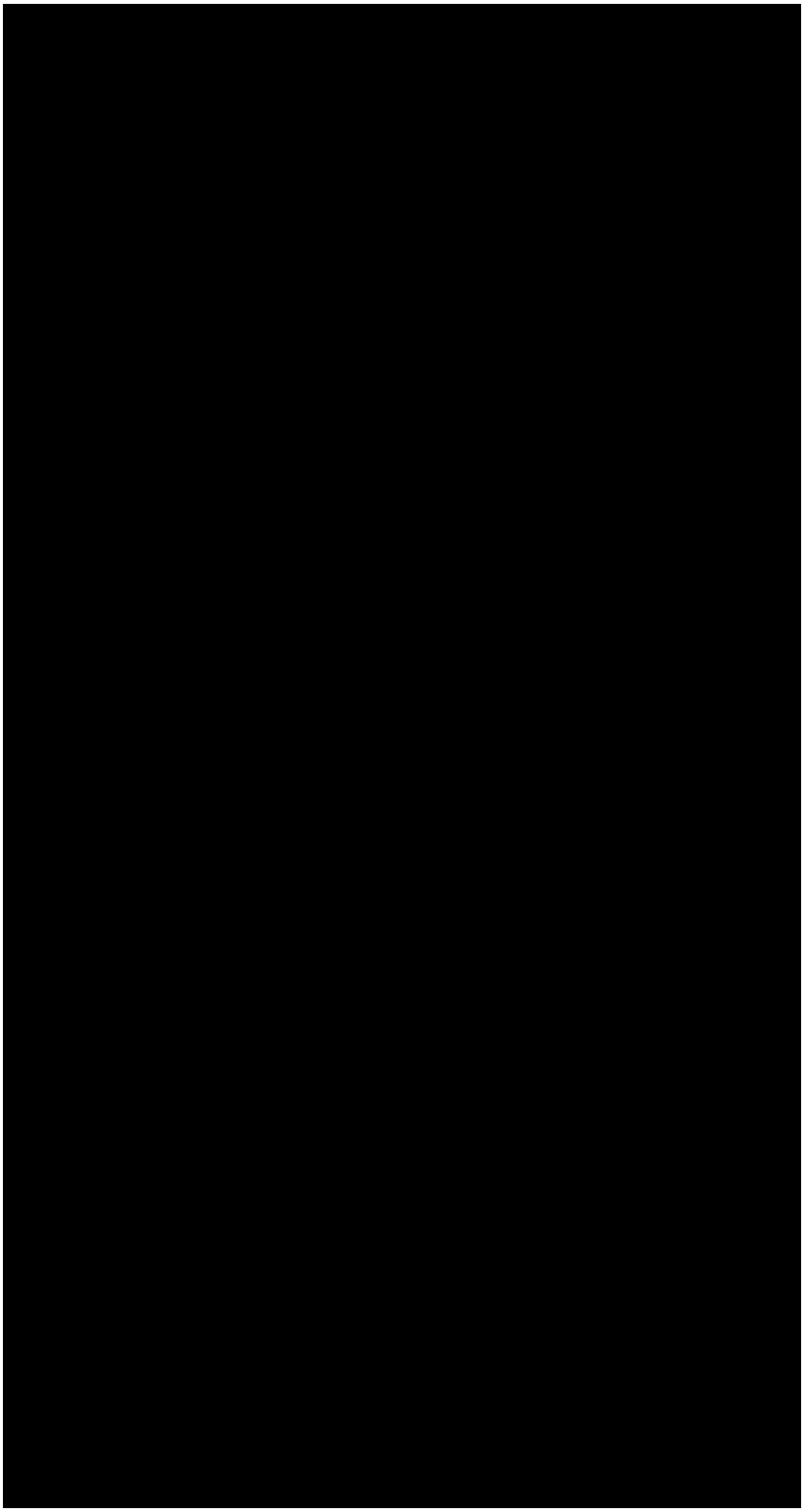


Figure 3-2 – Well API No. [redacted] well logs. The right-side track shows the calculated cross-plot porosity (XPHI in black) underlain with the upscaled porosity averaged into grid cells.

Figure 3-3 shows the curve used to define the data transform for the [redacted] of the injection zone. Table 3-3 summarizes that data.



Figure 3-3 – Histogram comparing the well logs, upscaled cells, and 3D property of porosity (decimal) for the Upper San Andres injection zone.

Table 3-3 – Porosity Summary Data for the Upper San Andres Injection Zone

Min	Max	Avg	Std. Dev.
[redacted]			

Figure 3-4 shows the defined curve used to define the data transform for the [redacted] the injection zone. Table 3-4 summarizes that data.



Figure 3-4 – Histogram comparing the well logs, upscaled cells, and 3D property of porosity (decimal) for the Lower San Andres injection zone.

Table 3-4 – Porosity Summary Data for the Lower San Andres Injection Zone

Min	Max	Avg	Std. Dev.
[redacted]			

Porosity was modeled by distributing upscaled porosity cell statistics into all other cells within the injection zone in the model, using kriging geostatistical methods to distribute porosity. A

simple variogram was selected using default parameters. The nugget was 0.0001, the type was spherical, and the anisotropy-range major and minor direction areas were equal (12,675 m [7.9 miles]). [redacted]

The output data range is controlled by the minimum and maximum values observed during the data preparation stage. [redacted]

The rationale behind the geostatistical distribution was to minimize horizontal heterogeneity, which is highly sensitive to variogram parameters in each vertical layer. The porosity in each layer was tied to the upscaled porosity cells between well locations. Figures 3-5 and 3-6 show the histograms comparing the well logs, upscaled cells, and 3D property of porosity for the [redacted]



Figure 3-5 – Histogram showing the upscaled porosity (decimal) data transform used for the [redacted]



Figure 3-6 – Histogram showing the upscaled porosity (decimal) data transform used for the [redacted] injection zone.

Figures 3-7 and 3-8 show selected snapshots of cross sections (approximately north-south and west-east, respectively) of the porosity 3D property from the static model.



Figure 3-7 – Approximate North-South Cross Sections of the Porosity 3D Property of the Static Model



Figure 3-8 – Approximate West-East Cross Sections of the Porosity 3D Property of the Static Model

3.4.3.3 Permeability

Permeability was calculated for each cell with porosity for the injection zone within the 3D static model, by applying the

$$k = (2.040 * 10^{6}) * (Ø^{6.38})$$

Where
k = permeability (mD)
Ø = interparticle porosity [in this case equivalent to total porosity] (fraction).

Permeability values below 0.001 mD were truncated to 0.001 mD.

Figures 3-9 and 3-10 show selected snapshots of cross sections (approximately north-south and west-east) of the permeability 3D property from the static model.



Figure 3-9 – Approximate North-South Cross Sections of the Permeability 3D Property of the Static Model



Figure 3-10 – Approximate West-East Cross Sections of the Permeability 3D Property of the Static Model

3.4.3.4 Water Saturation

Water saturation was initiated in the dynamic simulation model.

3.4.3.5 Upscaling

The geocellular model grid was upscaled for export to the GEM simulator model. The number of layers in the primary storage interval [redacted] was reduced to 50% of that used in the original static grid. Lateral porosity and permeability properties were upscaled by an arithmetic averaging (i.e., volume-weighted) method.

The upscaled grid includes 3.25 million grid blocks with dimensions of 253 x 169 x 76 cells in x, y, and z, respectively. The number of active cells was further reduced in the simulator (without upscaling) to 1.45 million, yielding 170 x 140 x 61 grid blocks. This was done by specifying null values for peripheral grid blocks and unused layers. The resulting active simulation grid encompasses layers in the [redacted] injection interval and covers an area of [redacted]

3.5 Area of Review: Pore Occupancy Plume

The first AOR is related to the CO_2 pore 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. [redacted]

Results from reservoir modeling simulations indicate that the carbon dioxide plume growth and extents will remain within this leased area.

3.6 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.

Nearby Texas Railroad Commission (TRRC) Groundwater Advisory Unit (GAU) letters have indicated that the bottom of the deepest USDW is expected to occur at approximately [redacted] ft. Table 3-5 lists the details for the nearby GAU determinations relative to Orchard No. 1 through No. 7. Figure 3-11 maps the location of these GAU wells relative to the seven Orchard injection wells.

Table 3-5 – USDW Depths from Offset GAU Letters

API No.	Well Name	USDW Depth (ft)	Distance from Orchard Wells (mi)
[redacted]			



Figure 3-11 – Location of Wells Used to Estimate USDW Depth

The base of the USDW is expected to be at [redacted] The critical pressure was calculated at the top of the injection zone for each of the seven injection wells as follows (all elevations subsea):

- Orchard No. 1 – [redacted]
- Orchard No. 2 –
- Orchard No. 3 –
- Orchard No. 4 –
- Orchard No. 5 –
- Orchard No. 6 –
- Orchard No. 7 –

Brine was assumed as the fluid in the injection zone with [redacted] ppm of total dissolved solids (TDS), based on data from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database (https://www.usgs.gov/data/us-geological-survey-national-produced-waters-geochemical-database-v23), taken for wells close to the Orchard Project area. The distribution of the TDS data for those wells is shown in Figure 3-12. The density of the formation brine in the injection zone was calculated to be [redacted] lb/ft^3, using correlations by McCain (1991).

[redacted]

Figure 3-12 – TDS Data on the Normal Probability Plot for Offset Wells in the [redacted]

The USDW intervals were broken into two segments—one shallow, one deep—for calculating the base USDW pressures. The shallower segment consists of the primary Ogallala aquifer and the underlying secondary Edwards-Trinity (High Plains) aquifer, intervals that Orchard-area water wells currently use. Average TDS values for the two aquifers are [redacted]

Properties for the segment of the USDW *below* the Ogallala are based on known data for the Dockum group, which underlies the Ogallala. This deeper segment is known to have significantly higher TDS than that found in the Ogallala. [redacted] Discussion of the McCain correlation can be found in *Appendix 2-1* of *Section 2 – Plume Model.*

To calculate the pressure at the base of the USDW, the hydraulic head was determined in the Ogallala aquifer (i.e., shallow segment). The Texas Water Development Board's (TWDB) database of groundwater source wells in Texas contains information for wells in which liquid levels are routinely measured. Currently designated as Groundwater Conservation District (GCD) observation wells by the TWDB, four such wells were found within the Orchard AOR and have good quality data from late 2021 and 2022. Table 3-6, which lists those wells, presents their elevations of water level (i.e., the hydraulic head in Ogallala) and date of measurement.

Table 3-6 – Ogallala Aquifer GCD Observation Well Data

Water Well No.	Water Level (Feet Above Sea Level)	Measurement Date
[redacted]		

From these data, water well [redacted] has the deepest liquid level, at an elevation of [redacted] above sea level. Using that ground-level elevation and a thickness of [redacted] ft for the shallower segment, the following input parameters were used to calculate critical pressure, tabulated in Table 3-7. For brevity in the table, the shallow segment (Ogallala and Edwards – Trinity (High Plains) aquifers) is termed "Ogallala."

Table 3-7 – Inputs for Critical Pressure Calculation

Inputs for Critical Pressure Calculation	[redacted]
Hydraulic Head Elevation of Ogallala Aquifer (ft)	
Fluid Gradient in Ogallala Aquifer (psi/ft)	
Base Ogallala Elevation (ft)	
Hydrostatic pressure differential in Ogallala (psi)	
Calculated Pressure at Base of Ogallala (psia)	
USDW Fluid Gradient Below Ogallala (psi/ft)	
Fluid Column below Ogallala (ft)	
Hydrostatic Pressure Differential in Lower USDW Segment (psi)	
Initial Fluid Pressure in USDW (psia)	
Injection Zone Pressure Gradient (ρig) (psi/ft)	
Representative Elevation of USDW (z_u) – (ft)	
Representative Elevation of Injection Zone (z_i) – (ft)	

The pressure at the base of the USDW (P_u) was calculated in two steps. First, for the column of fresh water in the Ogallala, P_O was calculated at its base:

(Eq. 1) $\Delta P_O = \rho g \cdot (z_h - z_O)$ [redacted]

Where z_h and z_o represent the respective elevations for the top of the water column and base of the Ogallala aquifer. Pressures have been converted to absolute pressure for consistency with pressures calculated within the plume simulation model.

Second, to arrive at the pressure at the base USDW (P_u), a similar calculation was employed:

(Eq. 2) $P_u = P_O + \rho g \cdot (z_O - z_u)$ [redacted]

Where z_u is the representative elevation of the USDW.

Representative elevation and pressure for the injection zone was chosen from Orchard No. 6, which has the shallowest injection interval of the seven Orchard injectors. Elevation (z_i) for the

[redacted] Pressure at that elevation (P_i) is calculated by correcting the simulator initial pressure ([redacted] to the depth of the shallowest injection zone, using the pressure gradient of [redacted] psi per foot:

[redacted]

The pressure front ($P_{i,f}$) calculations for the injection zone are:

(Eq. 4) $$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i)$$

Where P_u is the initial fluid pressure in the USDW, ρ_i is the injection-zone fluid density, g is the acceleration due to gravity, z_u is the representative elevation of the USDW, and z_i is the representative elevation of the injection zone.

The critical pressure rise ($\Delta P_{i,f}$) is then calculated as follows:

(Eq. 4) $$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i$$

[redacted]

The resulting rise in critical pressure for the uppermost stage is positive, indicating that the reservoir pressure may be safely increased by [redacted] psi without risk of fluid migration to the USDW.

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.

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 3.5*:

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

3.7 Operating Strategies Influencing Reservoir Modeling Results

The seven injection wells target an average of [redacted] Carbon dioxide injection will occur [redacted] 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 GEM simulator was employed to produce the outputs—shown in Figures 3-13 through 3-26 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.

[redacted]



Figure 3-14 – Orchard No. 1 GEM Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-15 – Orchard No. 2 GEM Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-16 – Orchard No. 2 GEM Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-17 – Orchard No. 3 GEM Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-18 – Orchard No. 3 GEM Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-19 – Orchard No. 4 GEM Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-20 – Orchard No. 4 GEM Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-21 – Orchard No. 5 GEM Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-22 – Orchard No. 5 GEM Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-23 – Orchard No. 6 GEM Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-24 – Orchard No. 6 GEM Plume Model Results – Oblique Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-25 – Orchard No. 7 GEM Plume Model Results – Cross-Sectional View, Colored by CO_2 Saturation



Figure 3-26 – Orchard No. 7 GEM 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 3-27. These extents were used to determine the initial project AOR for pore space occupancy and corrective action.

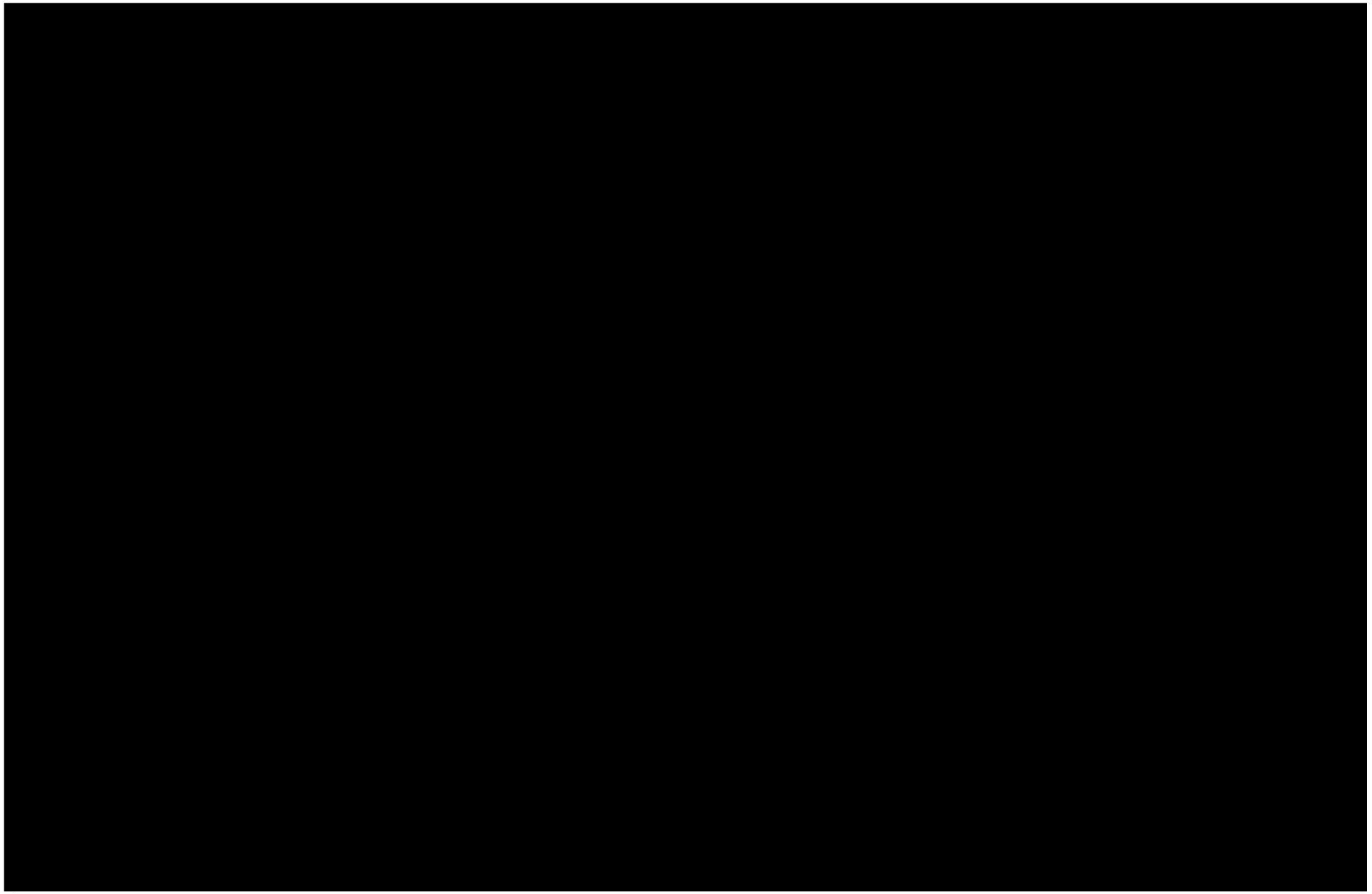


Figure 3-27 – GEM Plume Model Results – Plan View of Stabilized Plume (Colored by CO_2 Saturation)

These plume extents were digitized from the GEM output and imported into ArcGIS for use as the defined area of influence for establishing the Orchard No. 1–No. 7 AORs. As discussed in *Section 3.5*, 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.

Figure 3-28 displays the CO_2 occupancy plume AORs for the project.

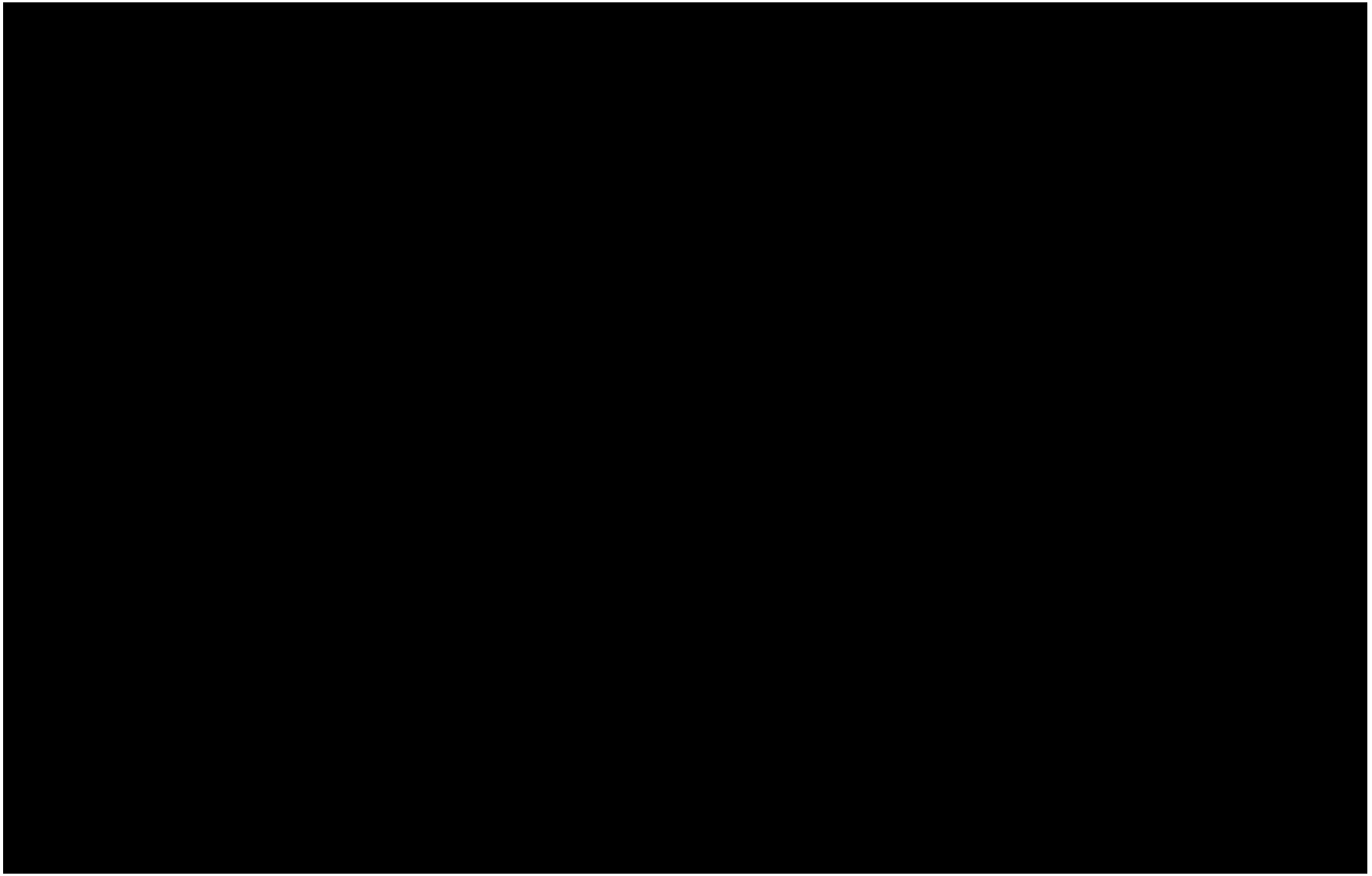


Figure 3-28 –CO_2 Occupancy Plume AOR Map

3.8 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 [redacted]

The proposed location of the Orchard No. 1–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 3-29). 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, [redacted] illing. Of the [redacted] wells, [redacted] drilled through the upper confining layer (Figure 3-31). The details for all these wells are included in *Appendix B-1.*

Additionally, [redacted] freshwater wells were identified (Figure 3-32), details for which are provided in *Appendix B-3*.

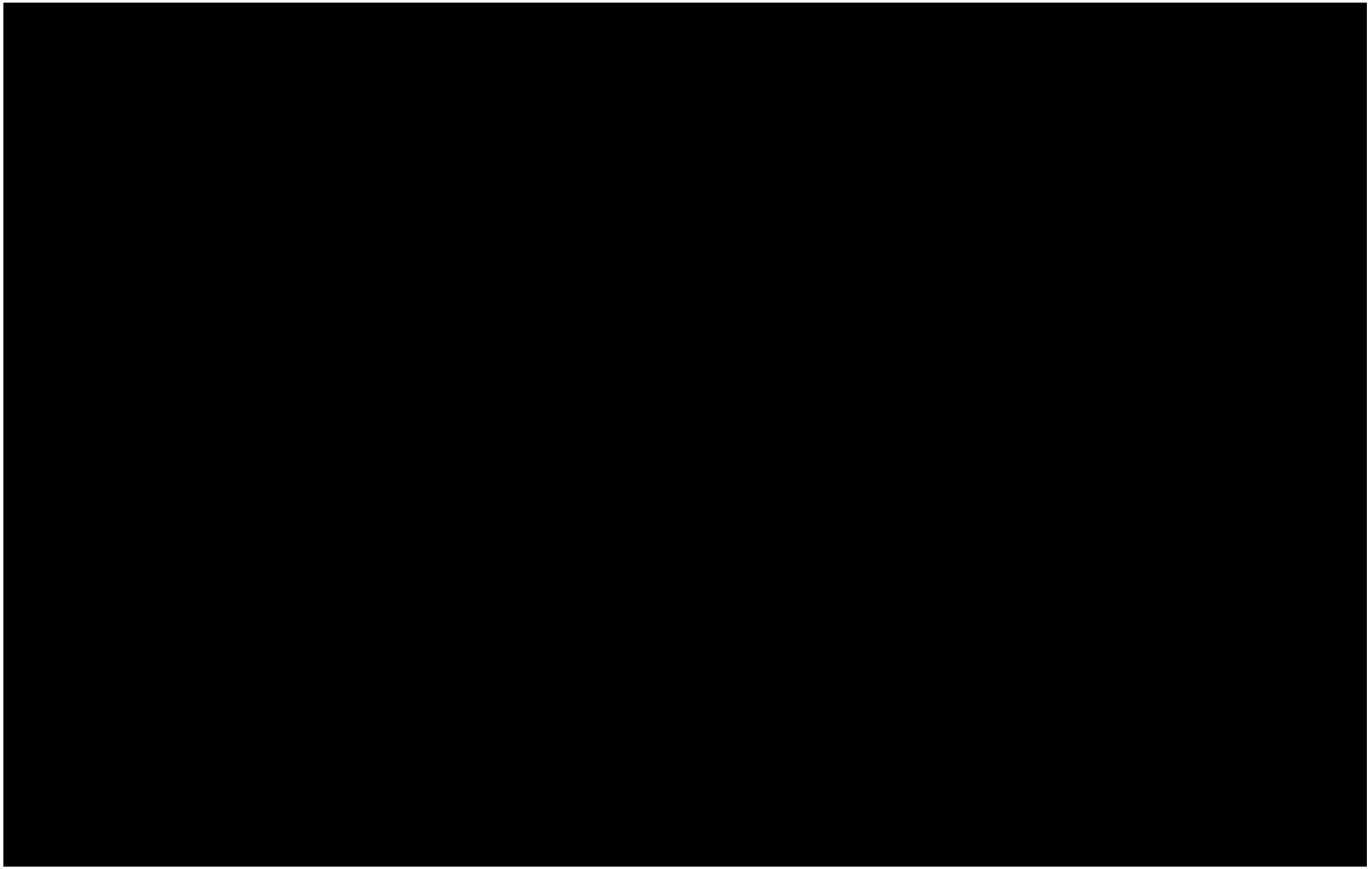


Figure 3-29 – CO_2 Plume AOR

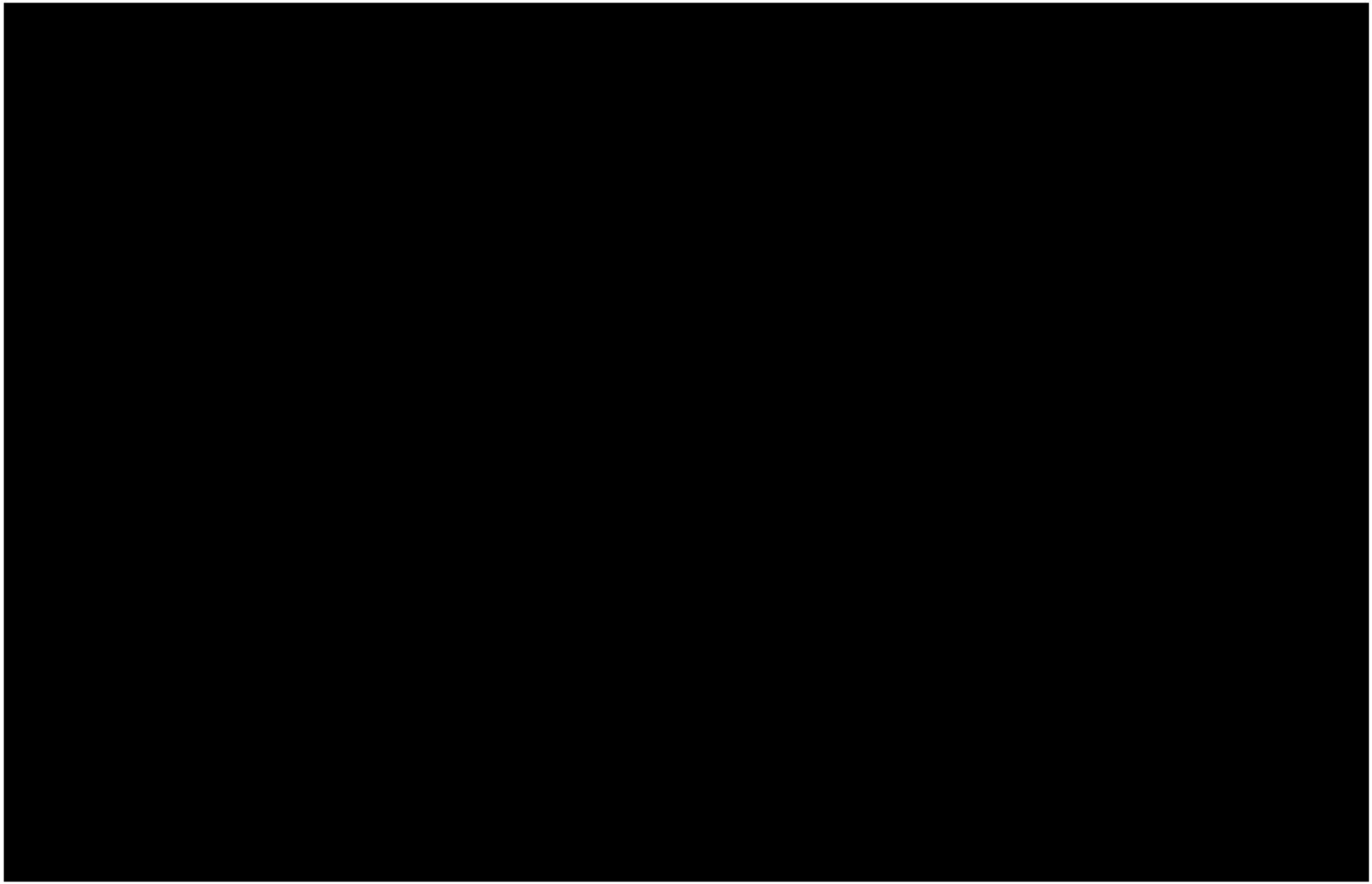


Figure 3-30 – Map of Oil and Gas Wells Within Orchard No. 1–No. 7 AOR

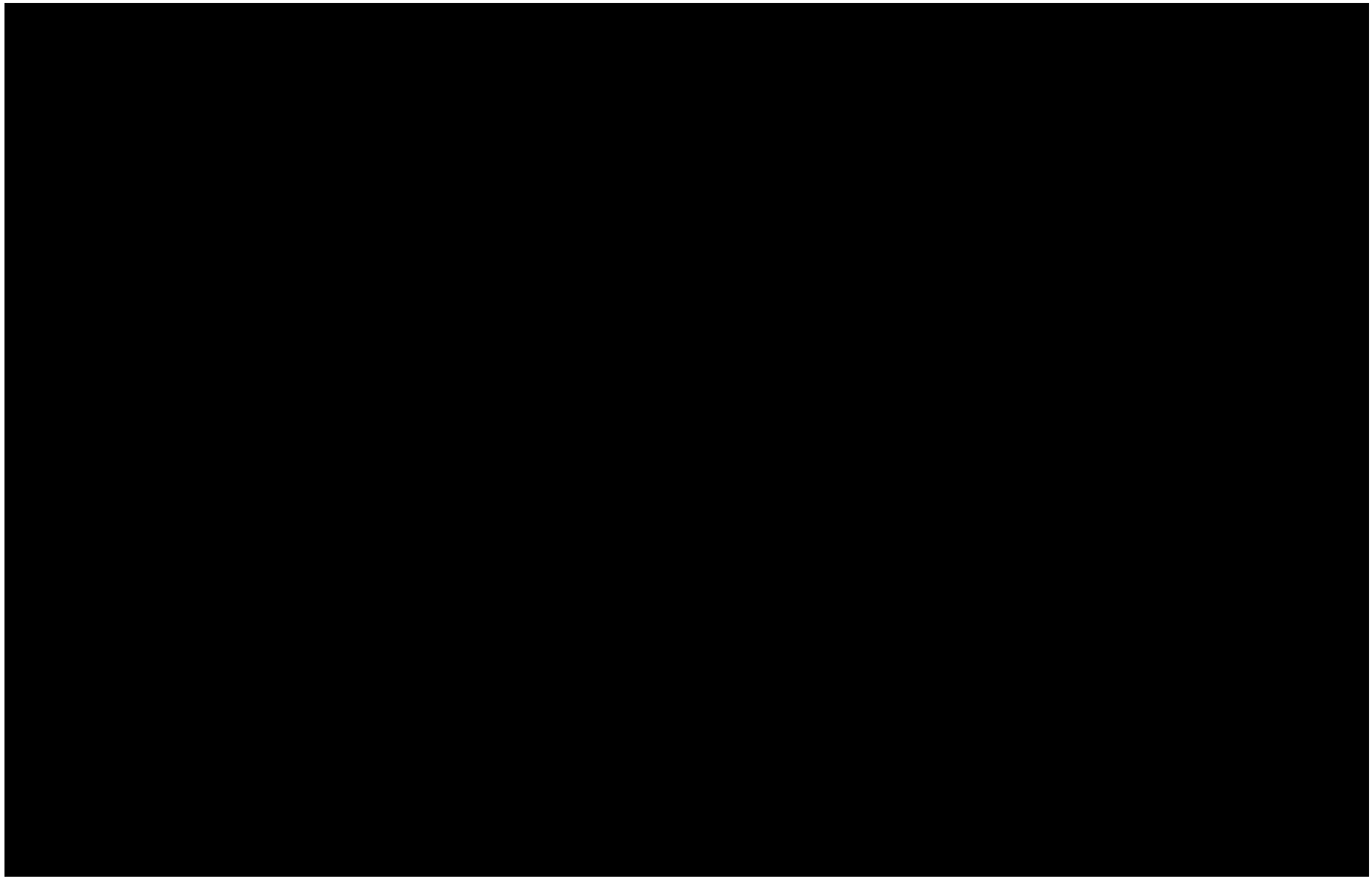


Figure 3-31 – Map of Penetrating Oil and Gas Wells Within Orchard No. 1–No. 7 AOR

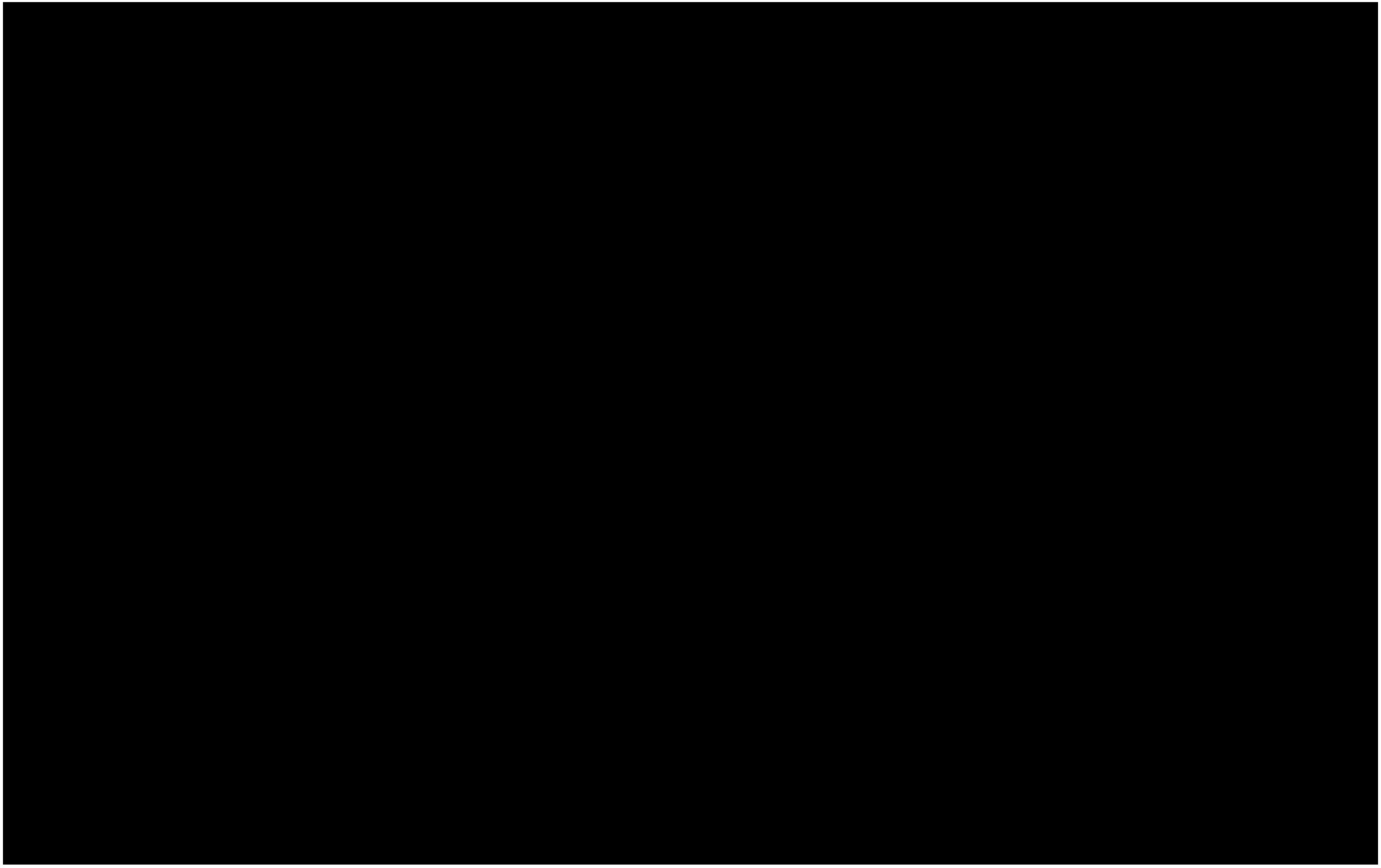


Figure 3-32 – Map of Freshwater Wells Within Orchard No. 1–No. 7 AOR

A search of the EPA's "Cleanups in My Community Map"[1] found [redacted] 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 3-33.

[1] https://cimc.epa.gov/ords/cimc/f?p=cimc:map::::71

[2] https://coastal.beg.utexas.edu/txmineralresources/No. !/

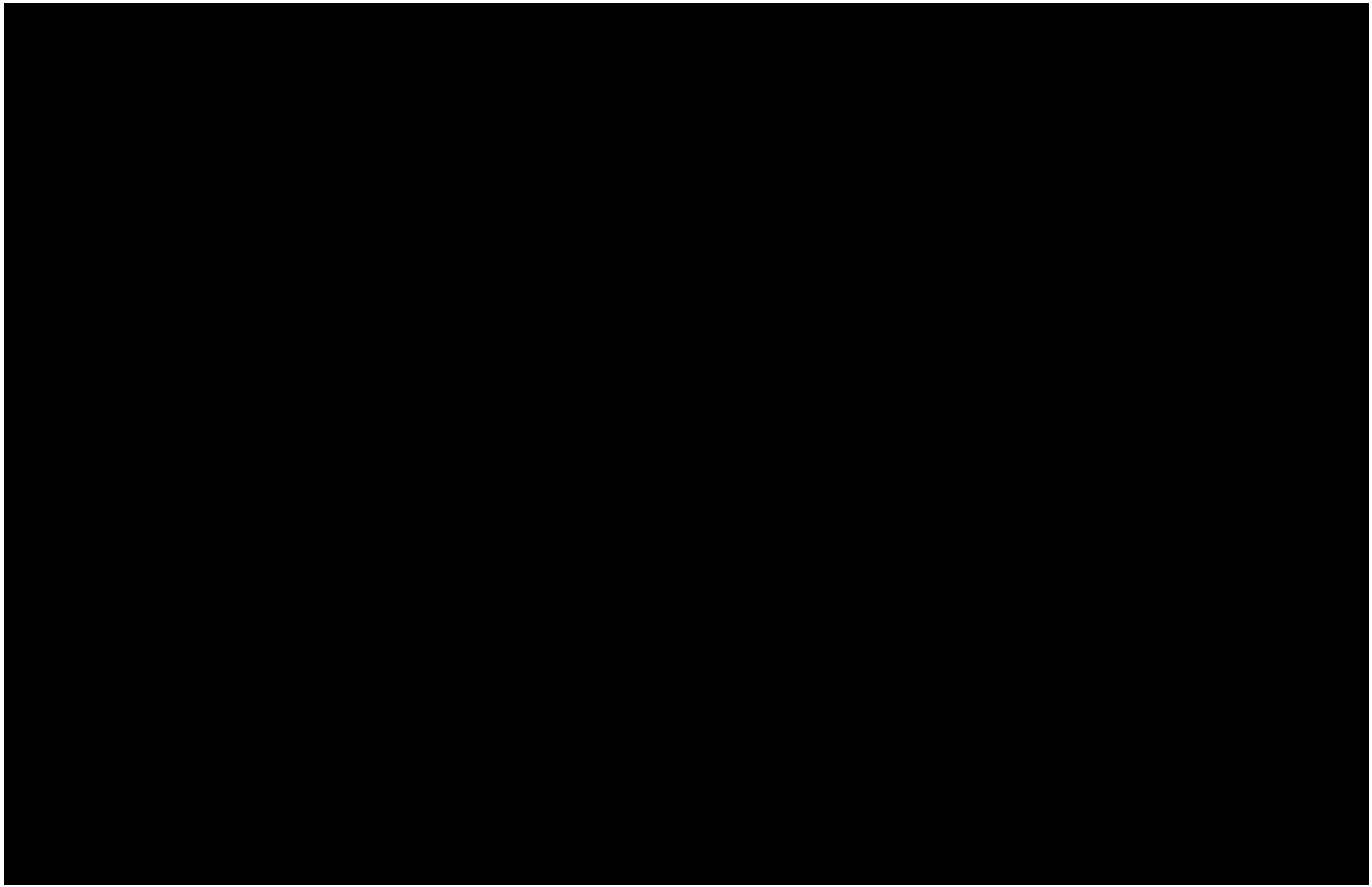


Figure 3-33 – Map of Known Cleanup Sites, Mines, and Springs in AOR

3.9 Corrective Action Plan and Schedule

As explained in *Sections 3.5* and *3.6*, the plume extent AOR considers the pore space occupied by the CO_2 plume as determined by the reservoir modeling results. No wells were found to be present within the bounds of the pore space AOR.

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 3.6*. [redacted] The penetrating wells 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-10, [redacted] 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. [redacted] wells will require corrective action. Most of these wells were plugged correctly to protect the base of usable quality water, which occurs at approximately [redacted] Historically, many wells were not plugged explicitly to protect the base of the USDW (i.e., Rustler formation). Therefore, these eight wells will be reentered and plugged to protect the Rustler from possible movement of brine. Additionally, [redacted] 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 will be plugged and abandoned and the other will be converted to an in-zone monitoring well.

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.

3.9.1 Corrective Action Plan

Table 3-8 lists the [redacted] that require corrective action, the two that will be acquired and worked over, 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 [redacted] wells' post-corrective actions.

Table 3-8 – Wells in the Pressure Front AOR Requiring Corrective Action

API No.	Status	Spud Date	Initial Plug Date	Elevation (ft)	TVD (ft)	Action Type
[redacted]						

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 [redacted].
- If needed, set a cement plug inside the casing, [redacted]
- 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.

3.9.2 Review of Wells Needing Corrective Action

This section provides a brief summary of the eight wells requiring corrective action and the two additional wells to be acquired. Figures 3-34 to 3-51 provide both the current and the proposed wellbore schematics for each well.

[redacted]

[redacted]

[redacted]

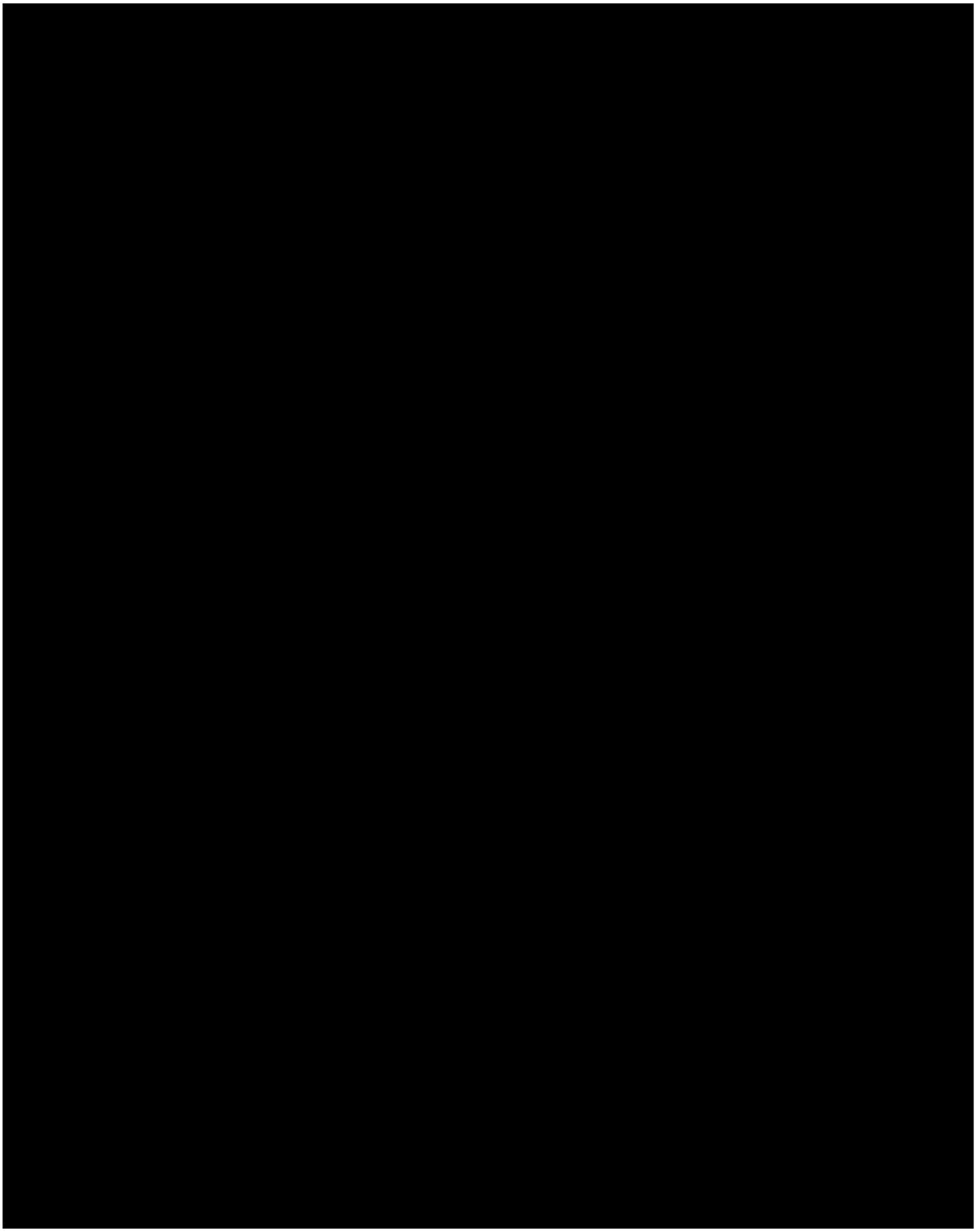


Figure 3-35 – Well API No. [redacted] Proposed Plugged Schematic

[redacted]

[redacted]

[redacted]

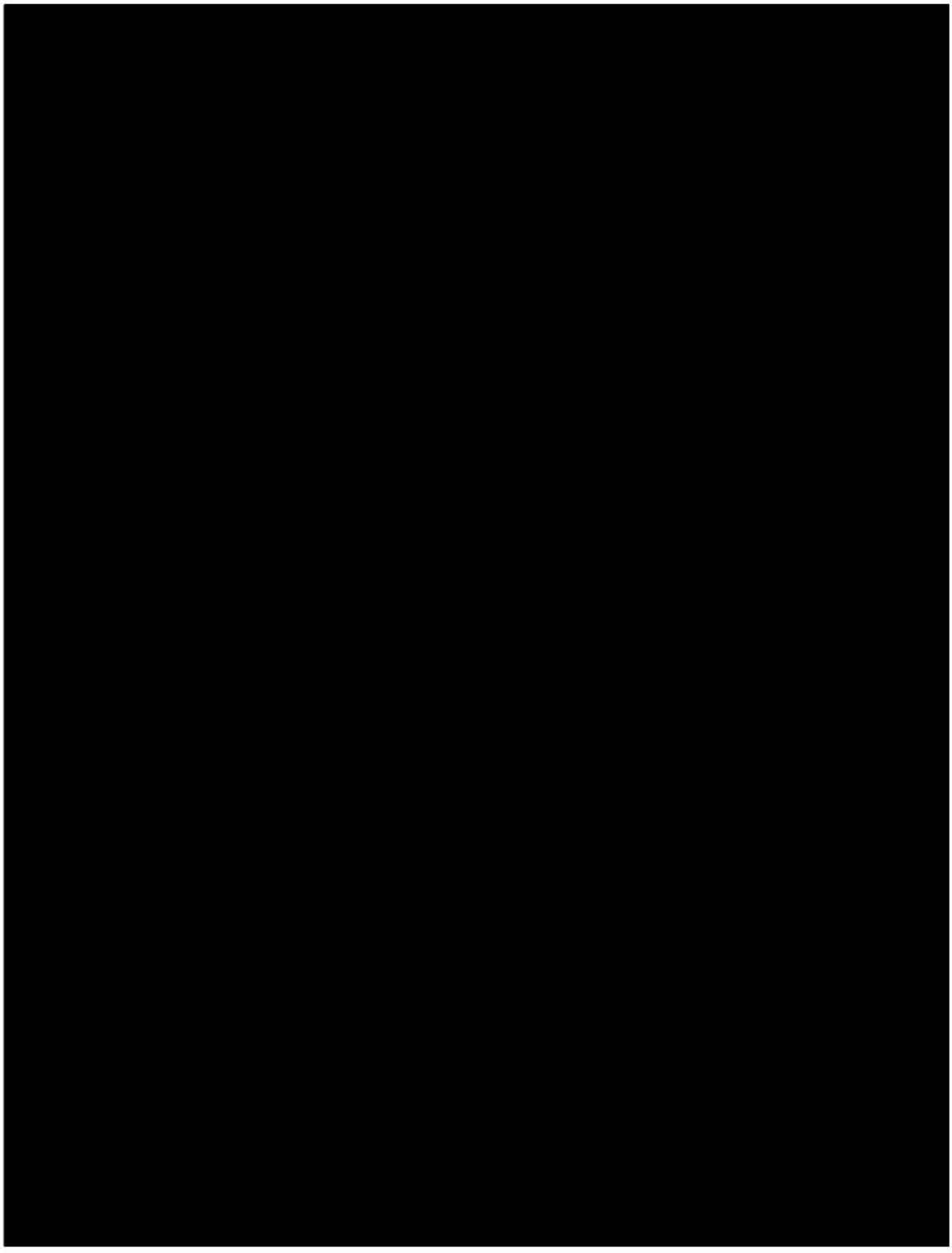


Figure 3-37 – Well API No. [redacted] Proposed Plugged Schematic

[redacted]

[redacted]

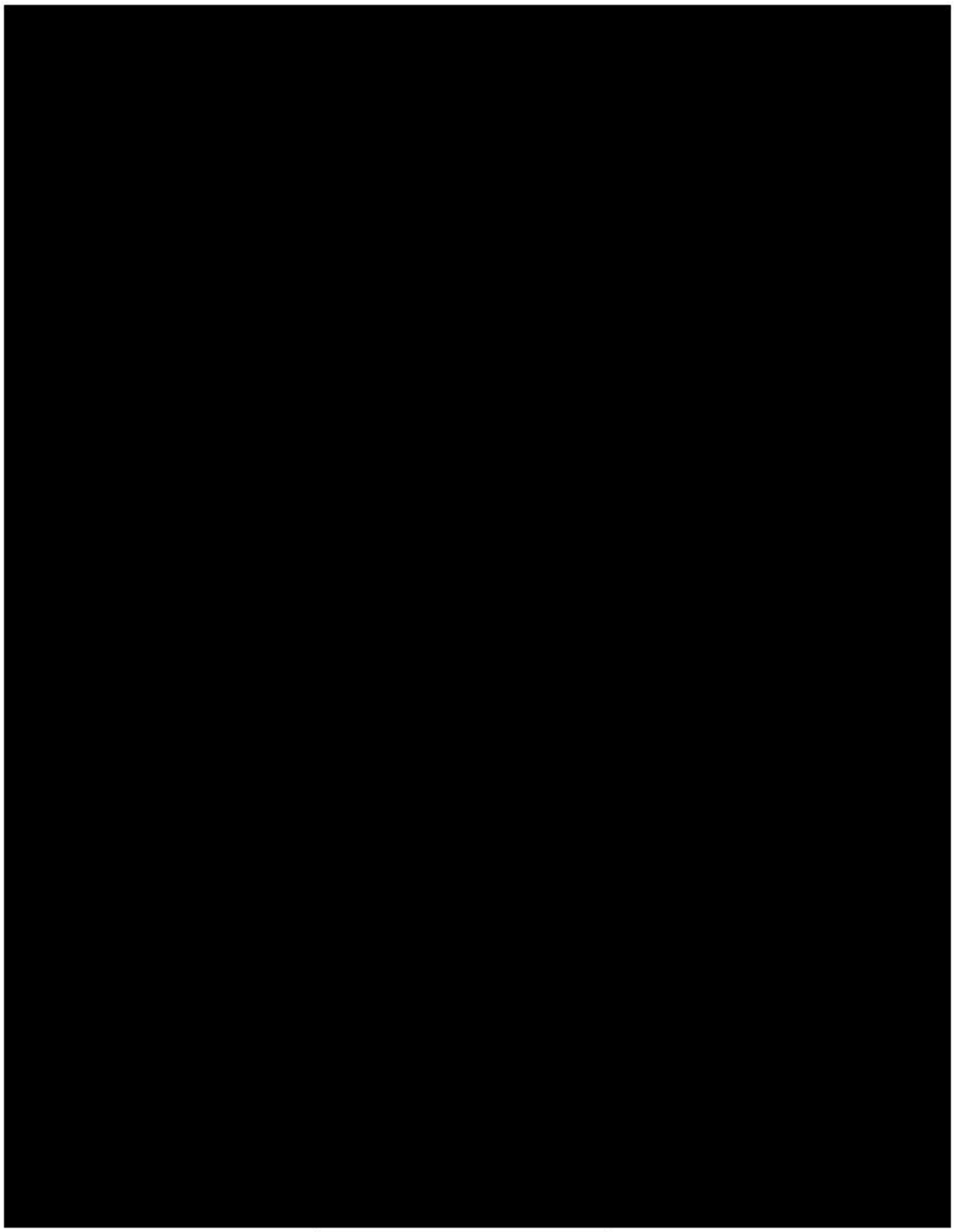


Figure 3-38 – [redacted] Current Schematic

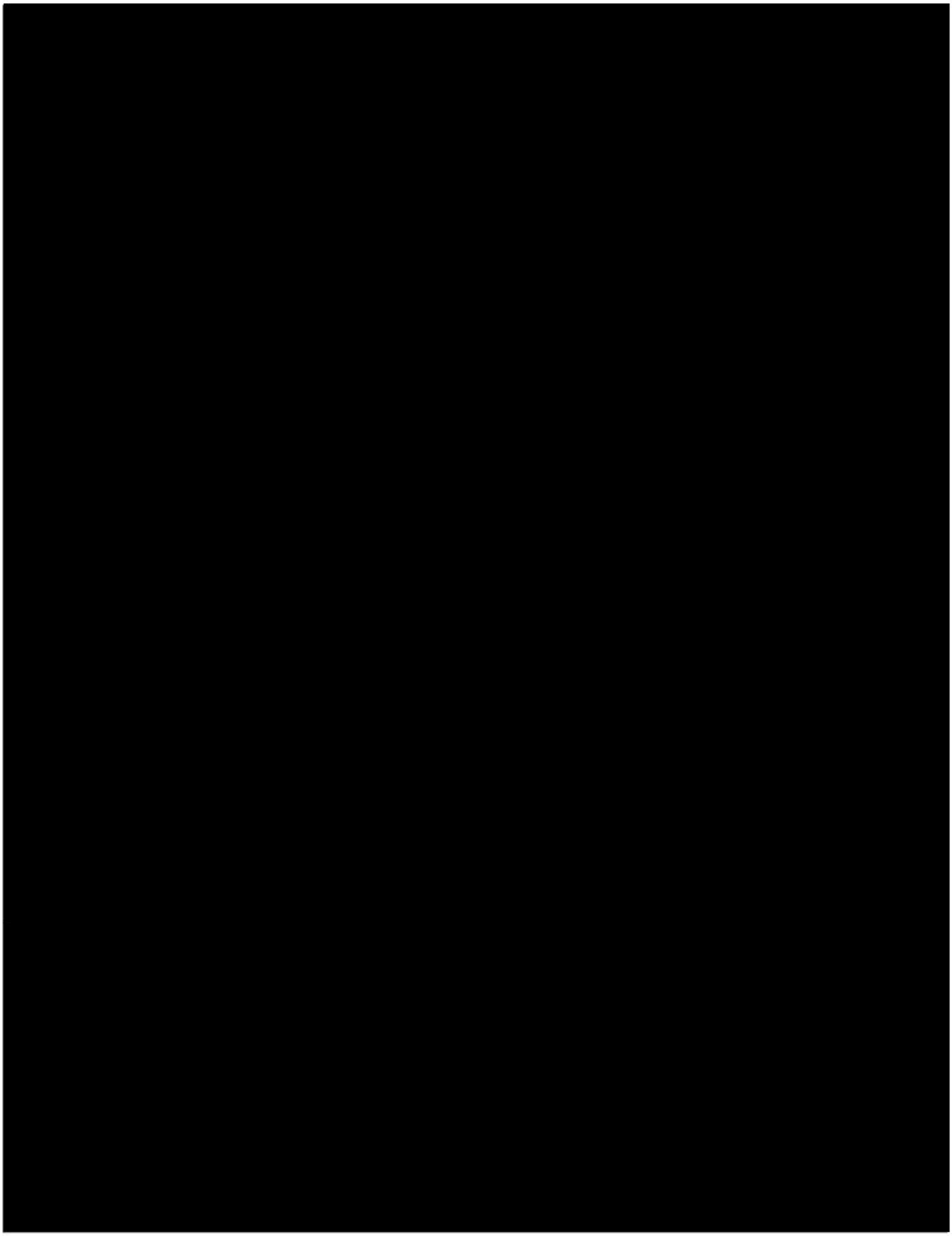


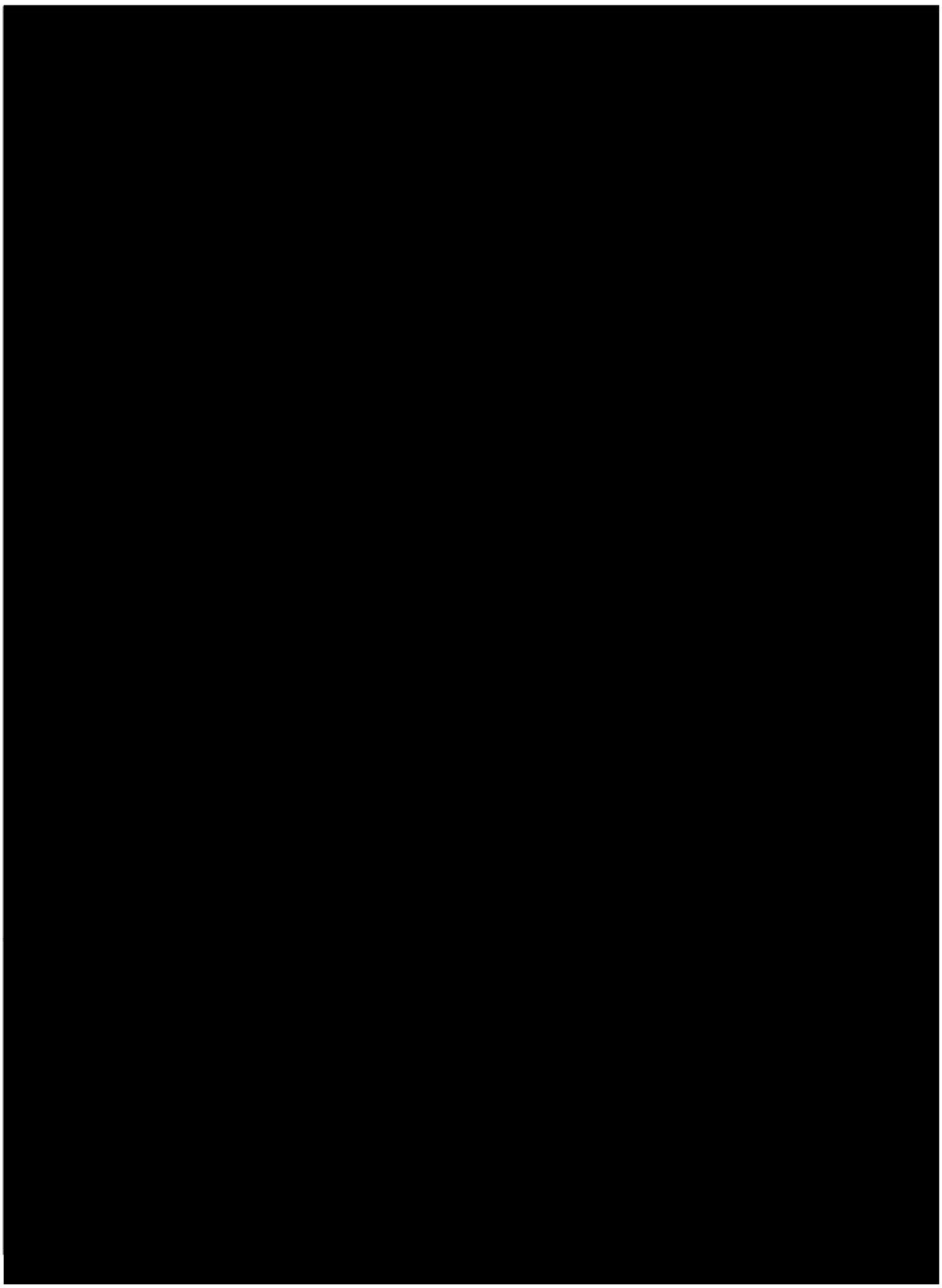
Figure 3-39 – Well [redacted] Proposed Plugged Schematic

[redacted]

[redacted]

[redacted]

Figure 3-40 – Well API No. [redacted] Current Schematic



[redacted]

[redacted]

[redacted]

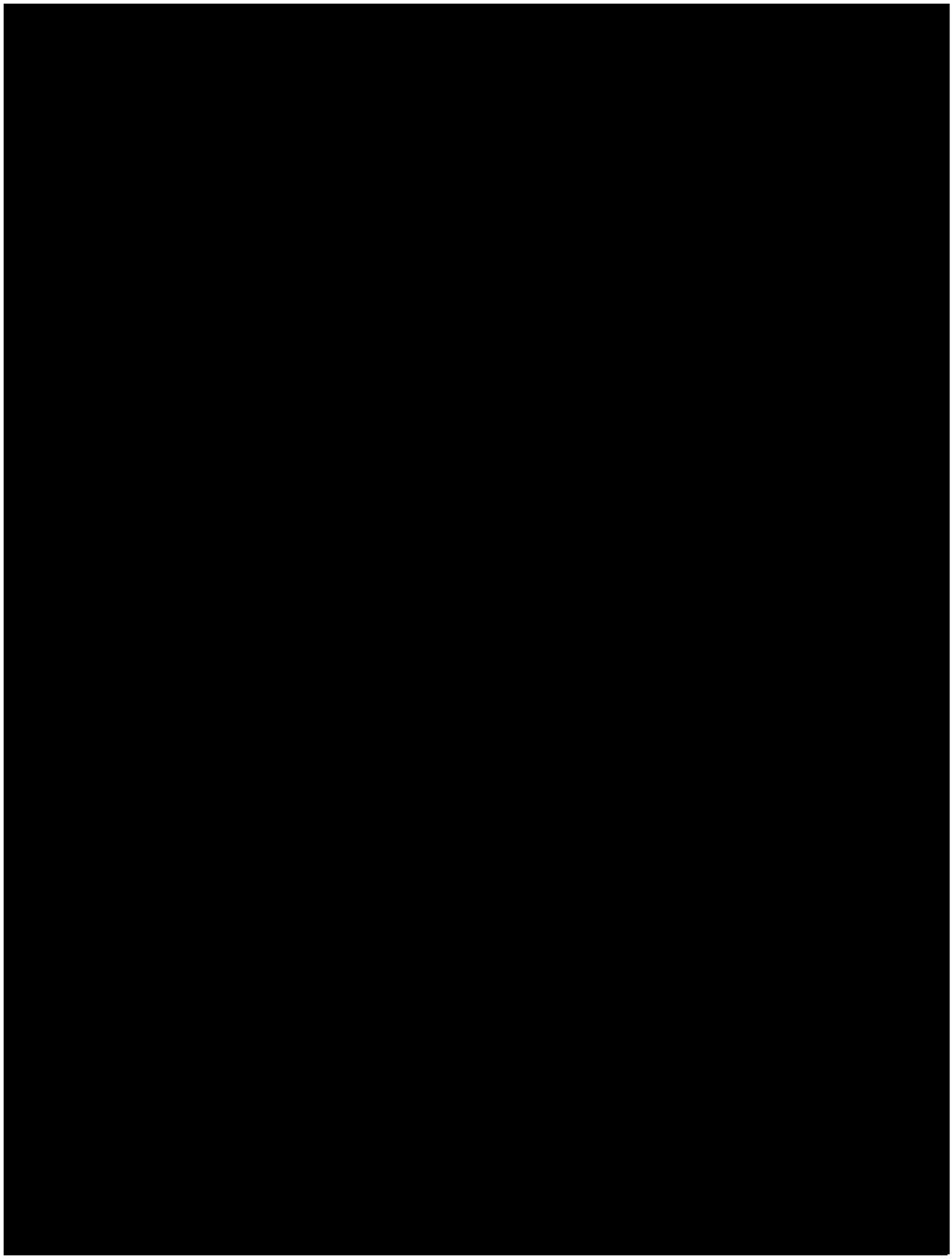


Figure 3-43 – [redacted] Proposed Plugged Schematic

[redacted]

[redacted]

[redacted]

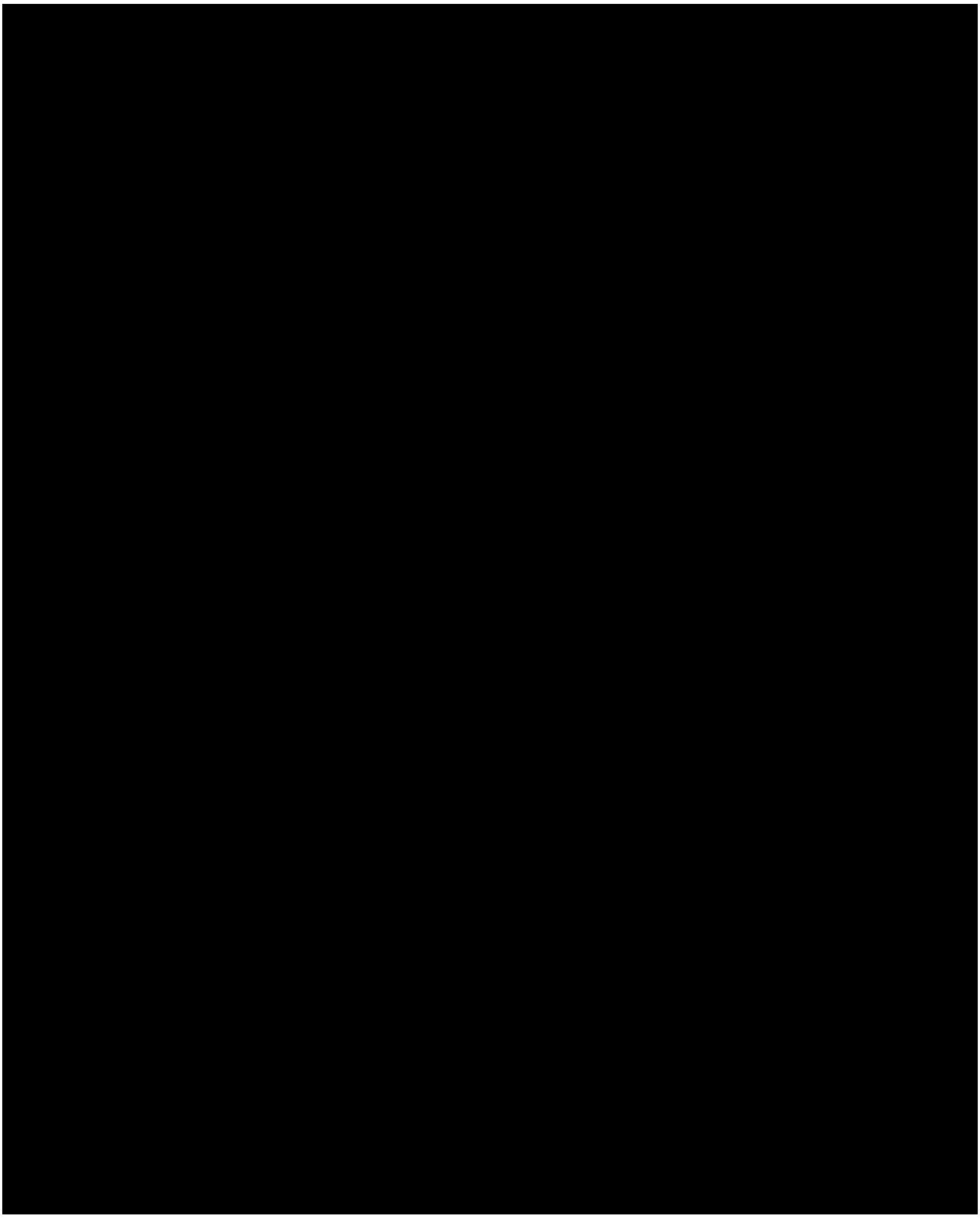


Figure 3-45 – Well API No. [redacted] Proposed Plugged Schematic

[redacted]

[redacted]

[redacted]

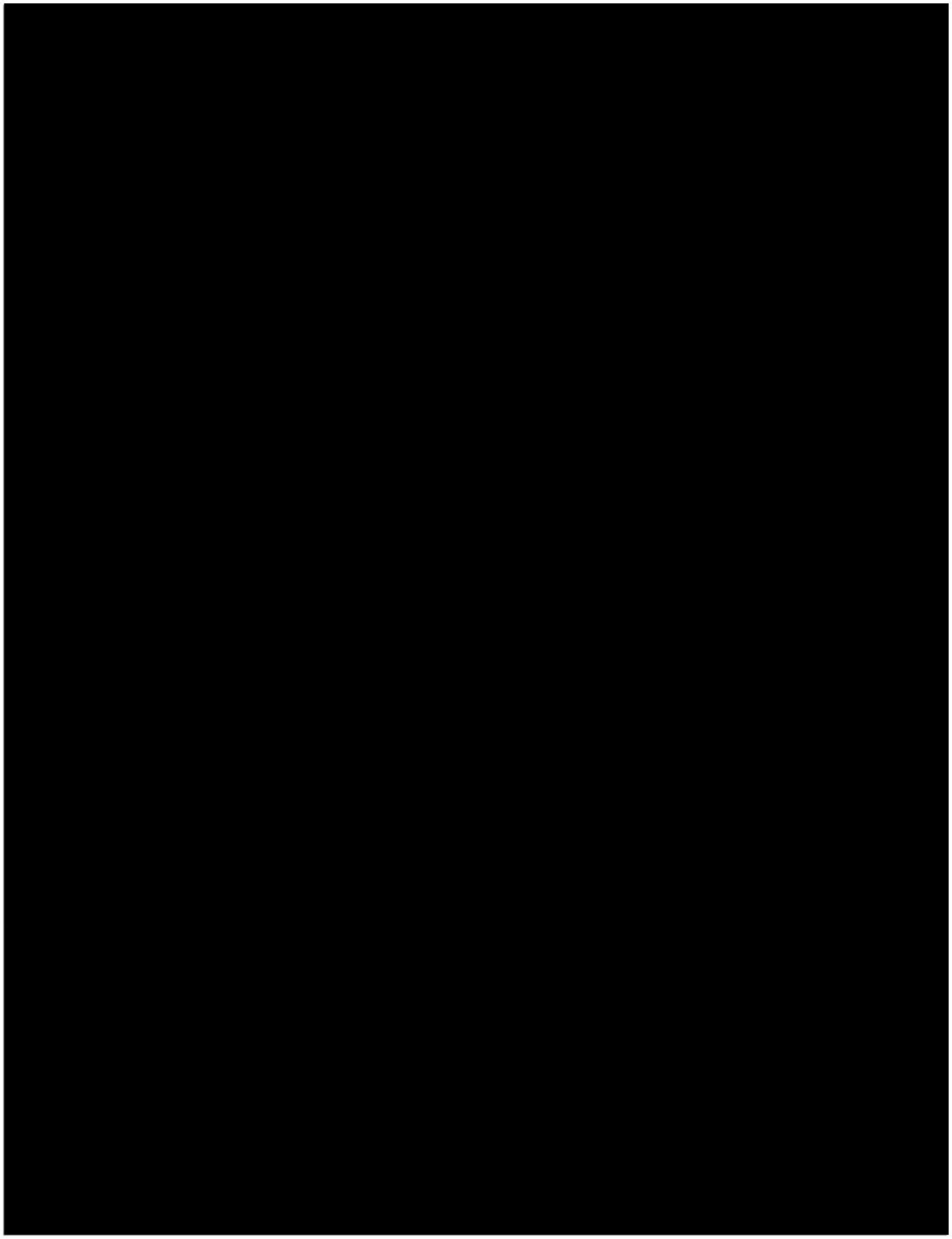


Figure 3-47 – Well [redacted] Proposed Plugged Schematic

Well Name: [redacted]

[redacted]

[redacted]

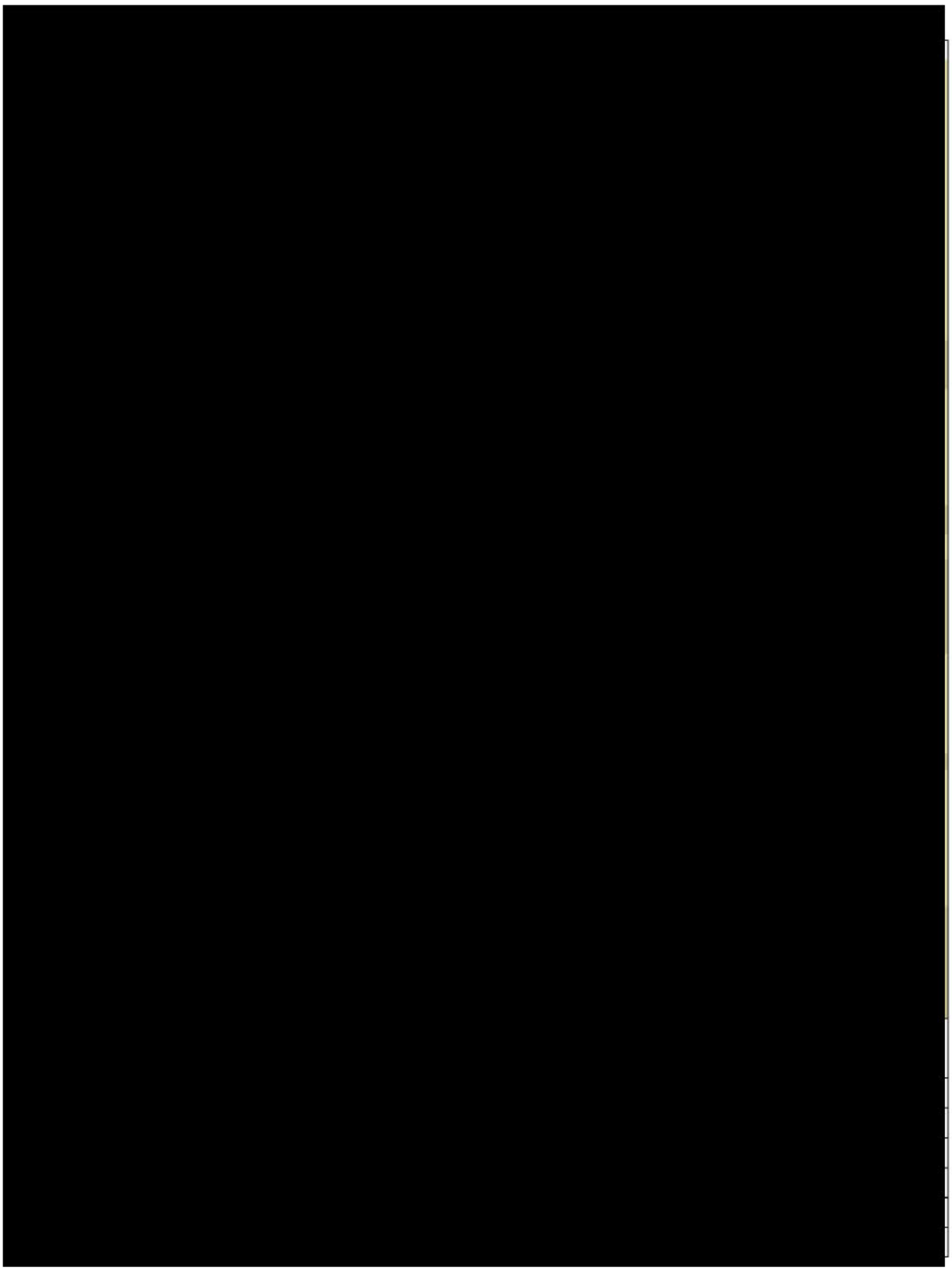


Figure 3-49 – Well API No. [redacted]1 Proposed Plugged Schematic

[redacted]

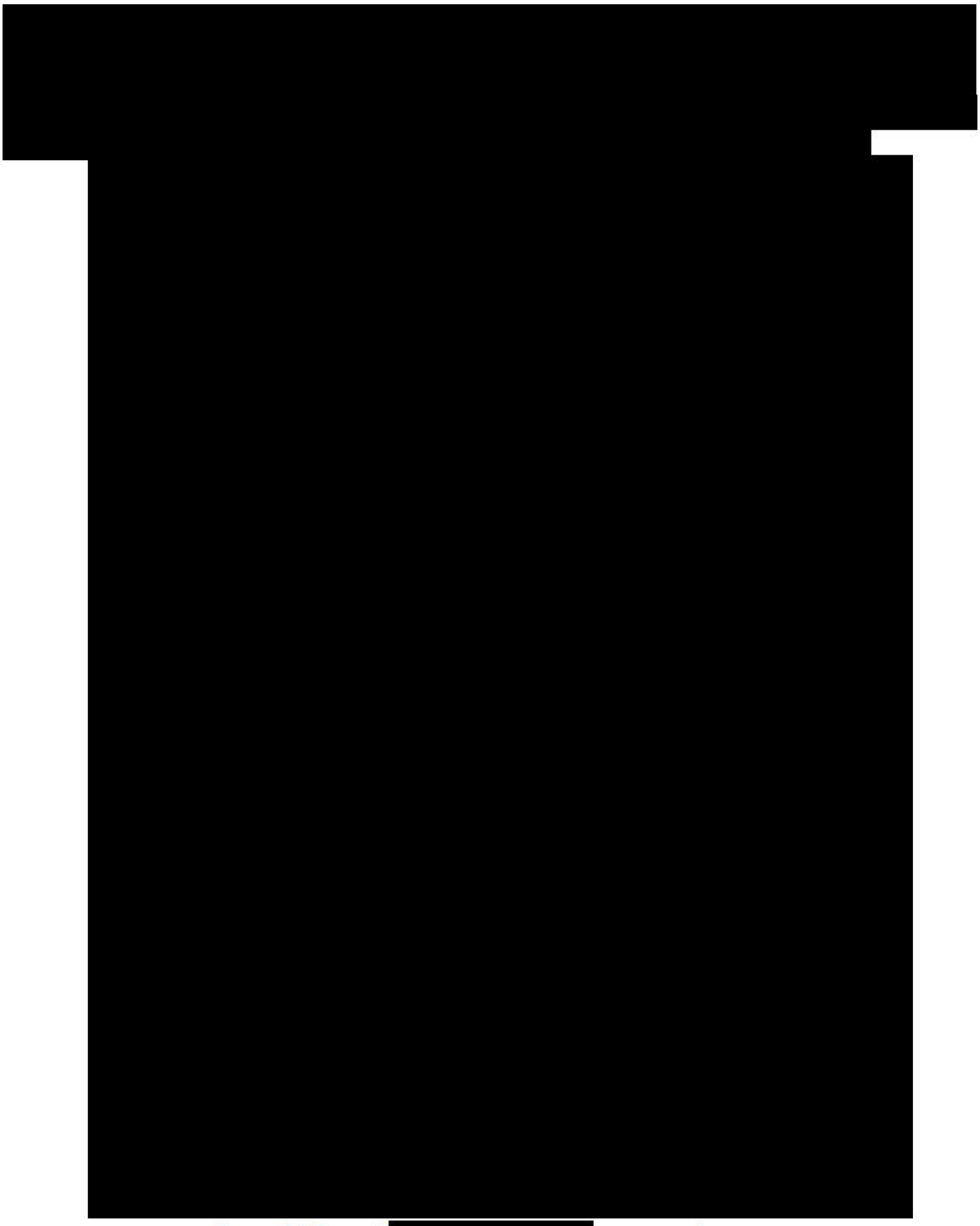


Figure 3-50 - Well [redacted] Current Schematic

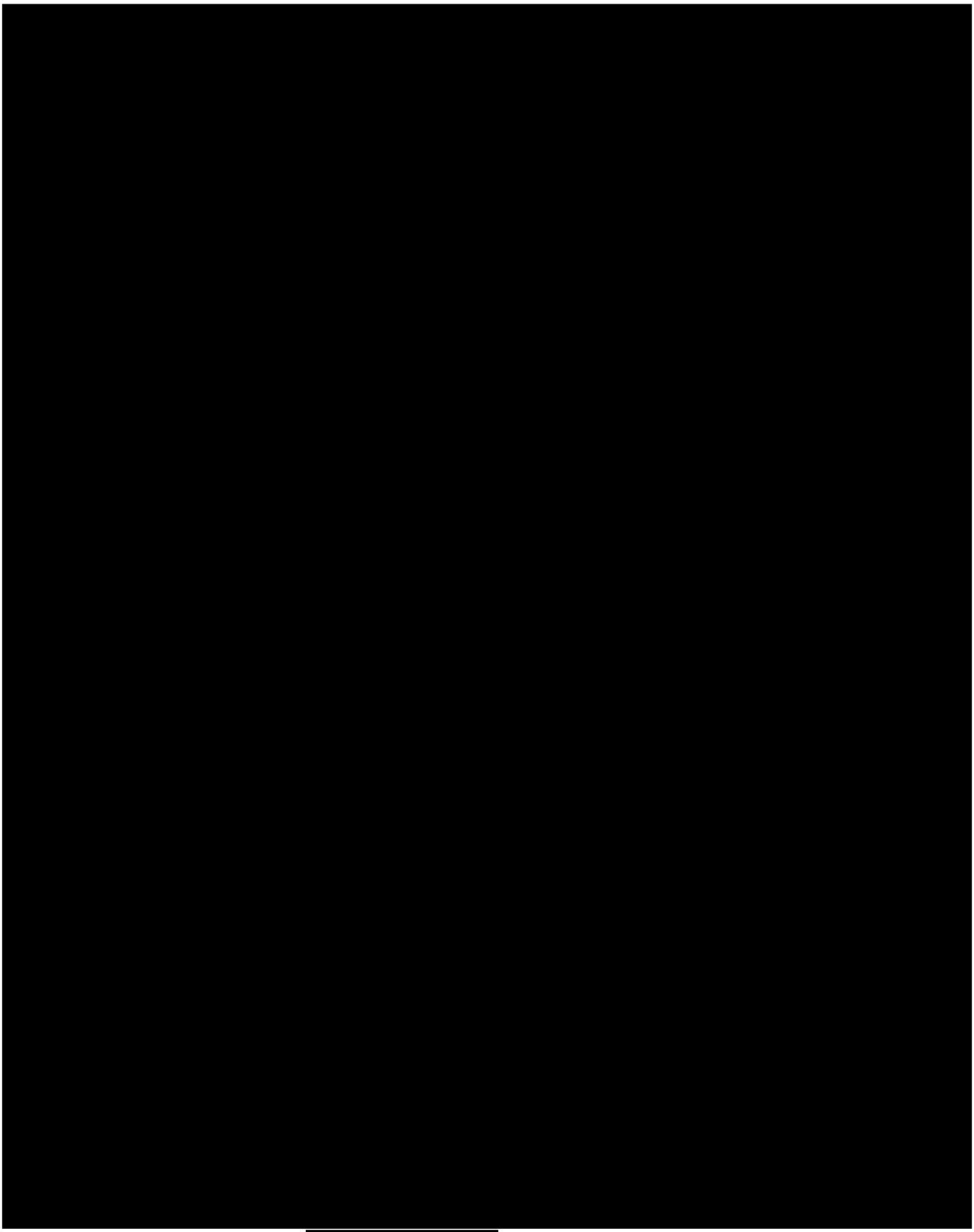


Figure 3-51- Well [redacted] Proposed Monitoring Well Schematic

[redacted]

[redacted]

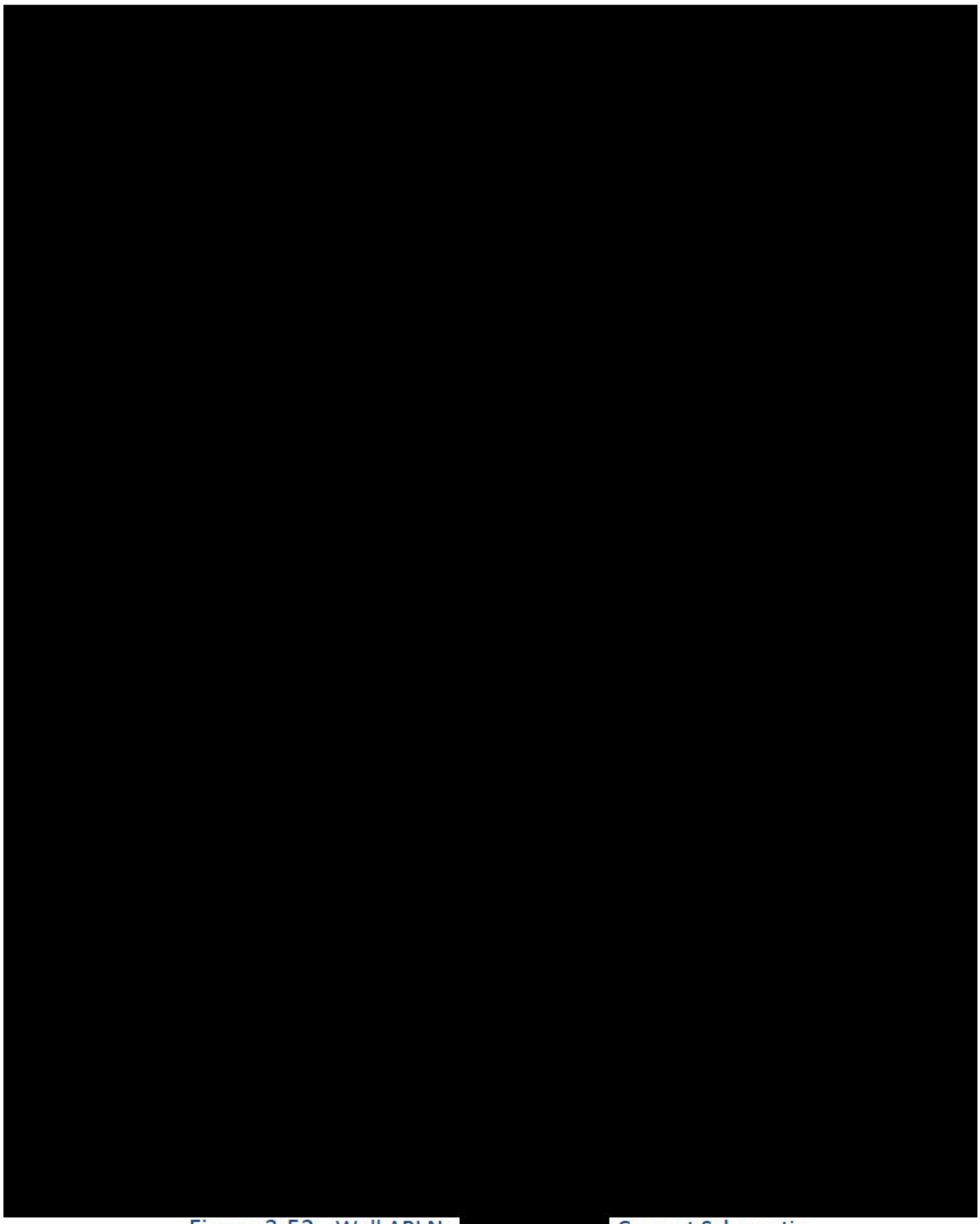


Figure 3-52 - Well API No [redacted] Current Schematic

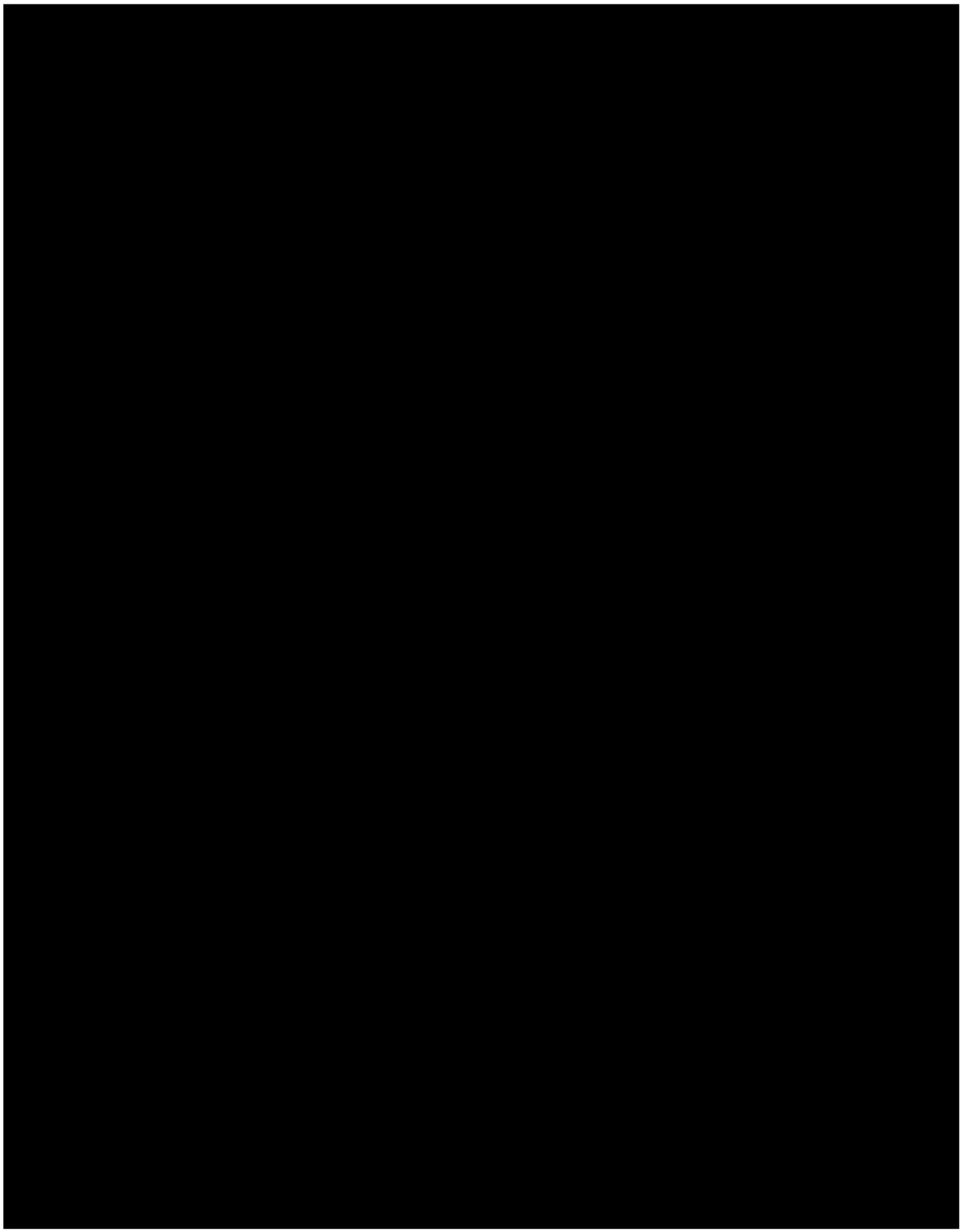


Figure 3-53 - Well [redacted] Proposed P&A Schematic

3.10 Area of Review Revaluation Plan and Schedule

3.10.1 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 3-9 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 3-9 – 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

3.11 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 [redacted] 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*.

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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

Revised April 2024

LONQUIST SEQUESTRATION LLC

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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—thereby making the wells 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 fts 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 layer (UCL) [redacted] The annulus from total depth (TD) to 500 ft above the UCL will be cemented with an acid-resistant cement.

[redacted]

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
  - [redacted]
- Surface Casing
  - [redacted]
  - Cemented back to surface
- Production Casing
  - [redacted]
  - [redacted]
  - Cemented back to surface
    - Cement to be comprised of the following:
      - +/- 500 ft above the top of the UCL to surface – Type I/II salt saturated cement
      - TD to 500 ft above the UCL – acid-resistant cement
- Injection Tubing
  - [redacted]
  - Annular fluid to consist of corrosion-inhibitor fluid
- Permanent Packer (displayed in Figure 4-1)
  - [redacted]
- Wellhead (displayed in Figure 4-30, in *Section 4.2.10*)
  - [redacted]

o [redacted]

Figure 4-1 illustrates how the production tubing will be run into the well with a [redacted].



Figure 4-1 – [redacted]

Before setting the packer, the tubing/production casing annulus will be filled with a noncorrosive fluid as approved by the UIC Director. 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–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*. 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 252 and 663 million metric tons per year (MMT/yr), on average, of captured carbon gas into the Orchard injection wells. These masses translate to rates of approximately 13.3 to 16.4 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 [redacted] 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 in the Orchard injection wells.

Table 4-2 – [redacted]

Component	Value
CO_2	[redacted]
Water	
Temperature	
H_2S	
Nitrogen	
Sulphur	

Oxygen	[redacted]
Hydrocarbons	
Glycol	
Carbon Monoxide	
NO_x	
SO_x	
Particulates	
Amines	
Hydrogen	
Mercury	
Ammonia	
Argon	
Liquids	
Lube Oil	

Parameters for the injectate composition were [redacted], 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
[redacted]	

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 and 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 pressure was determined by calculating a multi-segment pressure traverse starting with the known bottomhole pressure.

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-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 (Mid-Perforation) - (°F)							
Formation Pressure (Mid-Perforation) - (psi)							
Formation Density at Reservoir Conditions (lb/ft^3)							
Injectate Density in Formation (lb/ ft^3)							
Wellhead Injection Pressure (typical) - (psi)							
Wellhead Injection Temperature (typical) - (°F)							
Bottomhole Injection Pressure (typical)							
Bottomhole Injection Temperature (typical) - (°F)							
Average Wellbore Density (lb/ ft^3)							
Pipe Friction Pressure Loss (psi)							
Fluid Column Head Pressure (psi)							

*lb/ft^3 – pounds per cubic foot

Table 4-5 – Input Parameters for Wellbore Calculations, Orchard No. 1-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)	[redacted]							
Pipeline Delivery Pressure (psi)								
Pipeline Delivery Temperature (°F)								
Depth for BHP value (ft)								
Injection Rate (Typical) - (MMscf/d)								
Tubing Inner Diameter (in.)								

*BHP – bottomhole pressure

Table 4-6 – Injection Depth References by Well

Reference Point	Depth Reference	Well Number						
		1	2	3	4	5	6	7
Surface elevation	[redacted]							
Top of injection zone								
Base of injection zone								
Upper perforation								
Lower perforation								
Top of injection zone								
Base of injection zone								
Upper perforation								
Lower perforation								
Total well depth								

The pressure differential (Dp) between the top and base of each segment is affected by a combination of the friction pressure and hydrostatic head. Friction pressure drops were calculated using conventional pipe-flow relations, as described by Craft et al. (Craft, Holden, & Graves, 1962). The hydrostatic head component of the Dp is calculated based on the injected fluid density within that segment, evaluated at that segment fts average temperature and pressure. The multi-segment approach of calculating the pressure traverse allows for consideration of variations in the injected fluid fts density and viscosity with temperature and pressure.

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.

From a starting pipeline-outlet pressure and temperature, the JT effects on the injected fluid temperature were calculated over a range of pressures, using Computer Modelling Group fts (CMG) WinProp Equation-of-State (EOS) simulation software. The EOS simulator was used to generate tables of temperature vs. pressure at constant enthalpy, referenced to pipeline outlet conditions. Figure 4-2 shows how injected fluid temperature varies with pressure at different pipeline outlet temperatures. Heat transfer from the surrounding formation has been estimated to add 8°F to the BHT as determined by JT effects. Wellhead temperature is determined by the JT effects between the pipeline outlet and the calculated wellhead pressure, with no additional heat transfer from the surrounding environment.



Figure 4-2 – Injected Fluid Temperature Vs. Pressure

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.

- [redacted]

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.

4.3.1 Orchard Well No. 1 Design

Figure 4-4 provides the design schematic for Orchard No. 1.

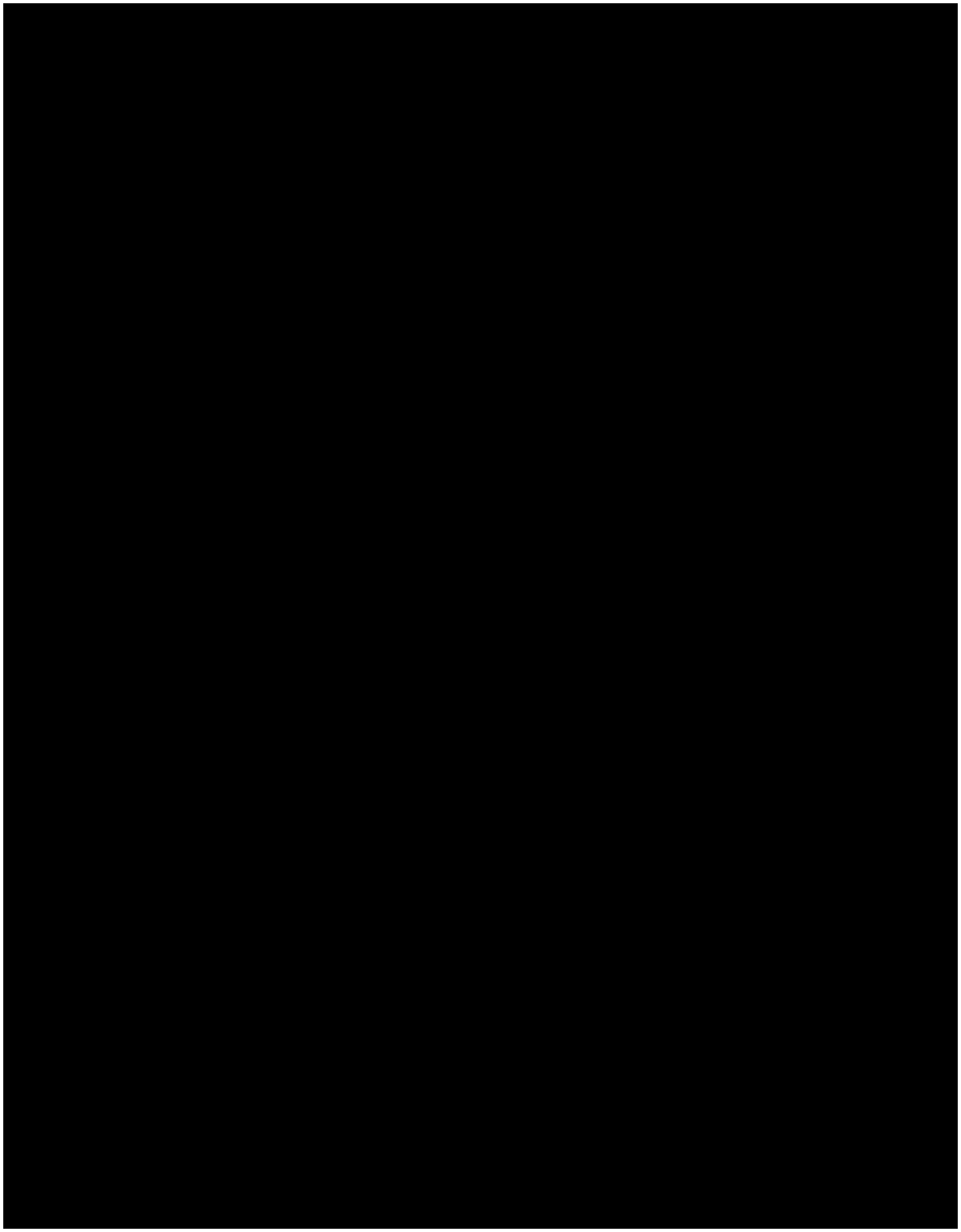


Figure 4-4 – Orchard No. 1 Wellbore Schematic

4.3.1.1 Conductor Casing

[redacted]

4.3.1.2 Surface Casing

The surface hole will be drilled with a [redacted]. bit with casing set approximately [redacted], which is below the lowermost USDW. A string of [redacted] 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 for Orchard No. 1 are provided in the following 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.)	Dri ft ID (in.)
[redacted]								

*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)
[redacted]			

*
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)
[redacted]				

* ft /ft – cubic feet per foot

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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:

- [redacted]
- 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 UCL 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, page 8) and is included in *Appendix D*. When dry, CO_2 is not considered corrosive. [redacted]. 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 UCL. This 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 UCL to surface will be cemented with a Type I/II salt saturated cement (Figure 4-2, page 8).

The engineering and design parameters for the production casing are summarized in the following 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.)
[redacted]								

Table 4-11 – Injection Well Production Casing Annular Geometries, Orchard No. 1

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

Table 4-12 – Injection Well Production Casing Cement Calculations, Orchard No. 1

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

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.

4.3.1.5 Centralizers

The bow-spring centralizer placement for the [redacted] 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 [redacted] 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

[redacted] centralizers will be run on the surface casing.

Centralizer placement for the [redacted] 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 C* of this application.) Considering the potential for the presence of carbonic acid, [redacted]

Table 4-13 lists the tubing specifications, design criteria, and calculated safety factors for Orchard No. 1. The burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 pounds per gallon (lb/gal) mud with 4,000 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.)
[redacted]								

4.3.2 Orchard Well No. 2 Design

Figure 4-5 provides the design schematic for Orchard No. 2.

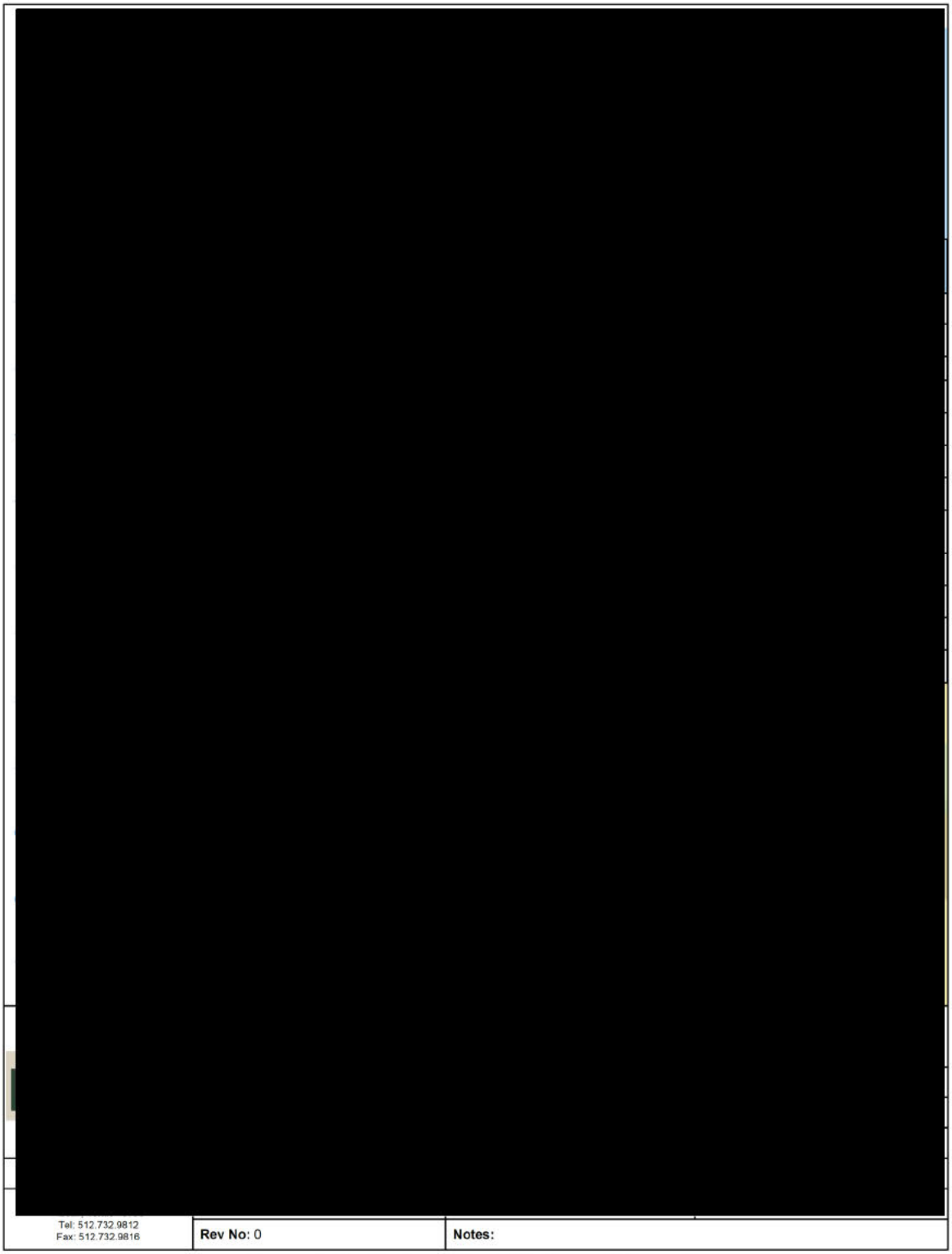


Figure 4-5 – Orchard No. 2 Wellbore Schematic

4.3.2.1 Conductor Casing

[redacted]

4.3.2.2 Surface Casing

The surface hole will be drilled with a [redacted] bit with casing set approximately [redacted], which is below the lowermost USDW. A string of [redacted] 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 (4-14 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.)
[redacted]								

Table 4-15 – Injection Well Surface Casing Annular Geometries, Orchard No. 2

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

Table 4-16 – Injection Well Surface Casing Cement Calculations, Orchard No. 2

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

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 following 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.)
[redacted]								

Table 4-18 – Injection Well Production Casing Annular Geometries, Orchard No. 2

Section	ID (in)	MD (ft)	TVD (ft)
[redacted]			

Table 4-19 – Injection Well Production Casing Cement Calculations, Orchard No. 2

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

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 [redacted] 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 [redacted] 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

[redacted] centralizers will be run on the surface casing.

Centralizer placement for the [redacted] 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 burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 lb/gas mud with 4,000 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.)
[redacted]								

4.3.3 Orchard Well No. 3 Design

Figure 4-6 provides the design schematic for Orchard No. 3.

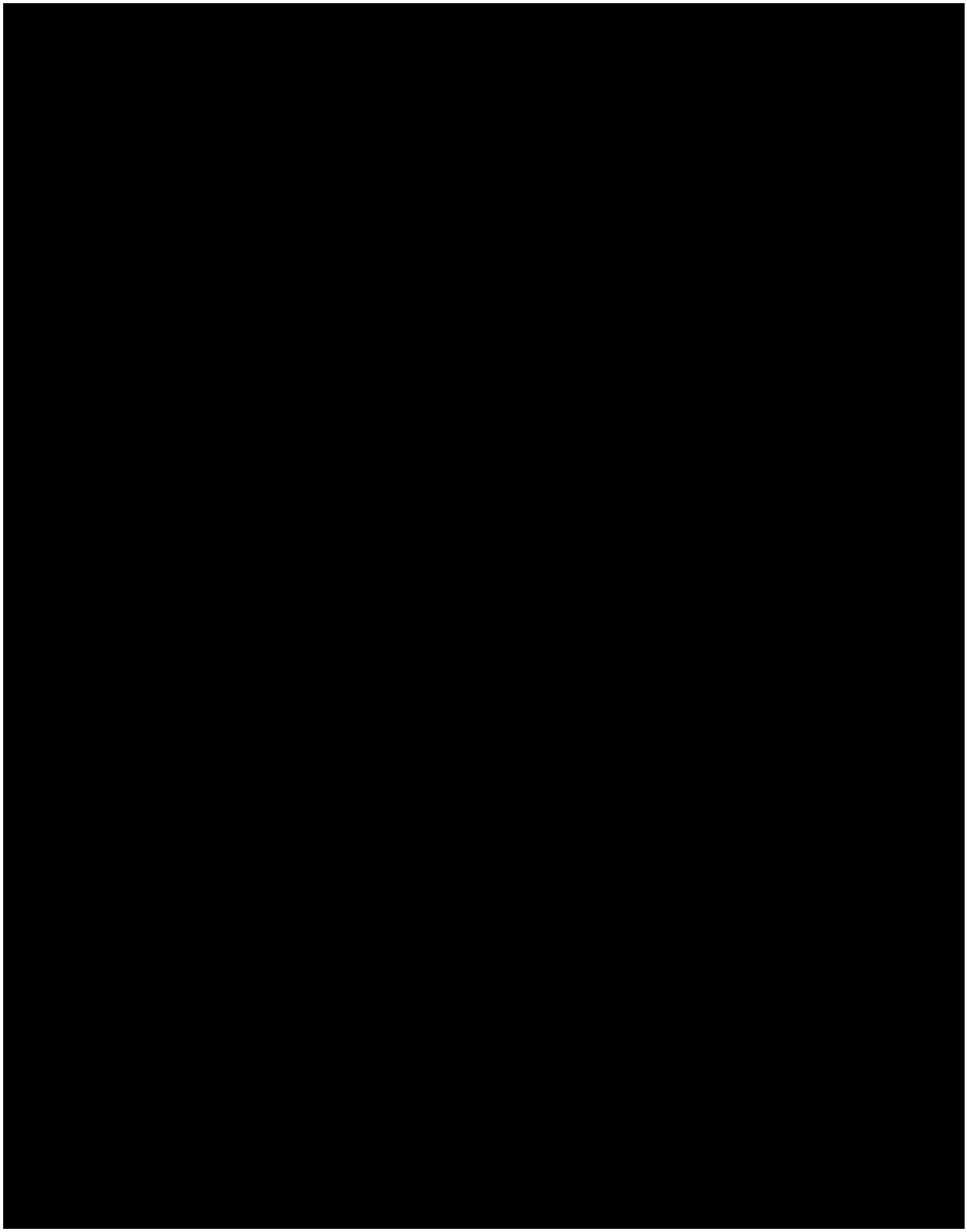


Figure 4-6 – Orchard No. 3 Wellbore Schematic

4.3.3.1 Conductor Casing

[redacted]

4.3.3.2 Surface Casing

The surface hole will be drilled with a [redacted]. bit with casing set approximately [redacted] ft, which is below the lowermost USDW. A string of [redacted]. 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 (4-21 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.)
[redacted]								

Table 4-22 – Injection Well Surface Casing Annular Geometries, Orchard No. 3

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

Table 4-23 – Injection Well Surface Casing Cement Calculations, Orchard No. 3

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

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 the following 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.)
[redacted]								

Table 4-25 – Injection Well Production Casing Annular Geometries, Orchard No. 3

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

Table 4-26 – Injection Well Production Casing Cement Calculations, Orchard No. 3

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

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 [redacted] 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 [redacted]. 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 [redacted] centralizers will be run on the surface casing.

Centralizer placement for the [redacted] 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

The injection tubing size was selected based on the injection volumes, rates, and injectate composition.

Table 4-27 lists the tubing specifications, design criteria, and calculated safety factors. The burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 pounds per gallon mud with 4,000 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.)
[redacted]								

4.3.4 Orchard Well No. 4 Design

Figure 4-7 provides the design schematic for Orchard No. 4.

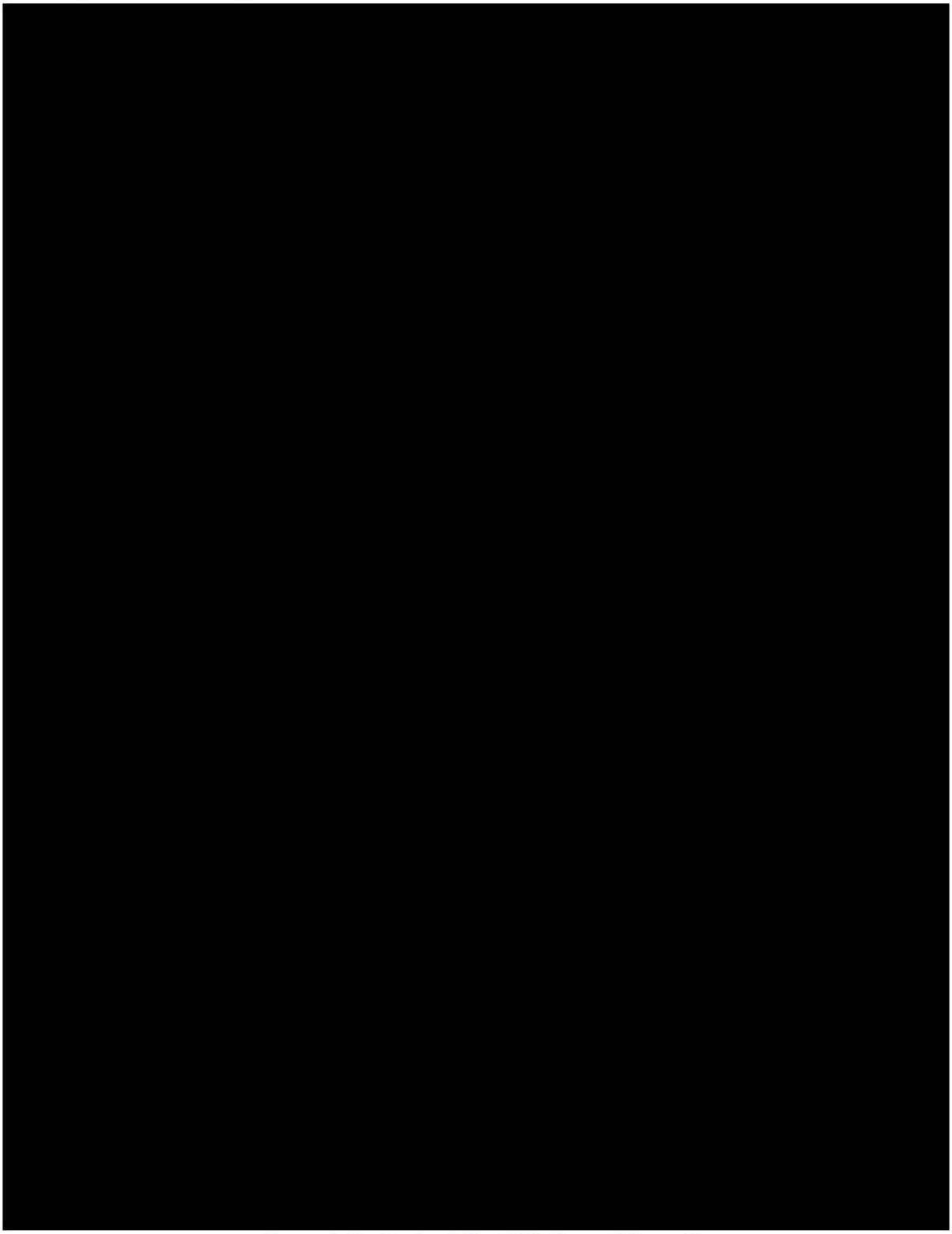


Figure 4-7 – Orchard No. 4 Wellbore Schematic

4.3.4.1 Conductor Casing

The [redacted]

4.3.4.2 Surface Casing

The surface hole will be drilled with a [redacted] in. bit with casing set approximately [redacted]00 ft, which is below the lowermost USDW. A string of [redacted] 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 (4-28 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.)
[redacted]								

Table 4-29 – Injection Well Surface Casing Annular Geometries, Orchard No. 4

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

Table 4-30 – Injection Well Surface Casing Cement Calculations, Orchard No. 4

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

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 the following 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.)
[redacted]								

Table 4-32 – Injection Well Production Casing Annular Geometries, Orchard No. 4

Section	ID (in)	MD (ft)	TVD (ft)
[redacted]			

Table 4-33 – Injection Well Production Casing Cement Calculations, Orchard No. 4

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

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 [redacted] 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 [redacted] 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

[redacted] will be run on the surface casing.

Centralizer placement for the [redacted] 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 burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 lb/gal mud with 4,000 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.)
[redacted]								

4.3.5 Orchard Well No. 5 Design

Figure 4-8 provides the design schematic for Orchard No. 5.

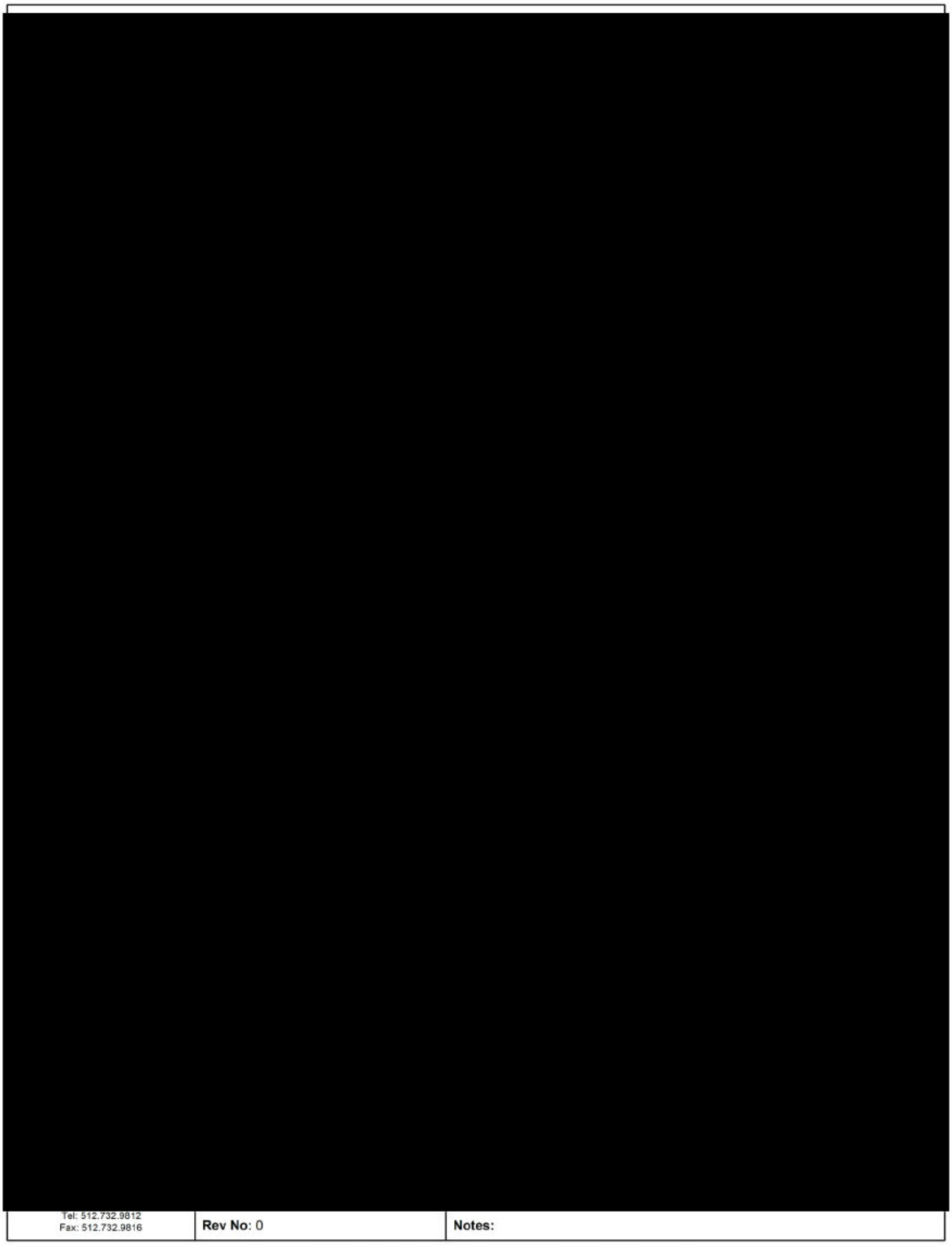


Figure 4-8 – Orchard No. 5 Wellbore Schematic

4.3.5.1 Conductor Casing

[redacted]

4.3.5.2 Surface Casing

The surface hole will be drilled with a [redacted] in. bit with casing set approximately [redacted] ft, which is below the lowermost USDW. A string of [redacted] 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.)
[redacted]								

Table 4-36 – Injection Well Surface Casing Annular Geometries, Orchard No. 5

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

Table 4-37 – Injection Well Surface Casing Cement Calculations, Orchard No. 5

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

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 the following 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.)
[redacted]								

Table 4-39 – Injection Well Production Casing Annular Geometries, Orchard No. 5

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

Table 4-40 – Injection Well Production Casing Cement Calculations, Orchard No. 5

[redacted]

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 [redacted]. 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 [redacted] 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

[redacted] centralizers will be run on the surface casing.

Centralizer placement for the [redacted] 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 burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 lb/gal mud with 4,000 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.)
[redacted]								

4.3.6 Orchard Well No. 6 Design

Figure 4-9 provides the design schematic for Orchard No. 6.

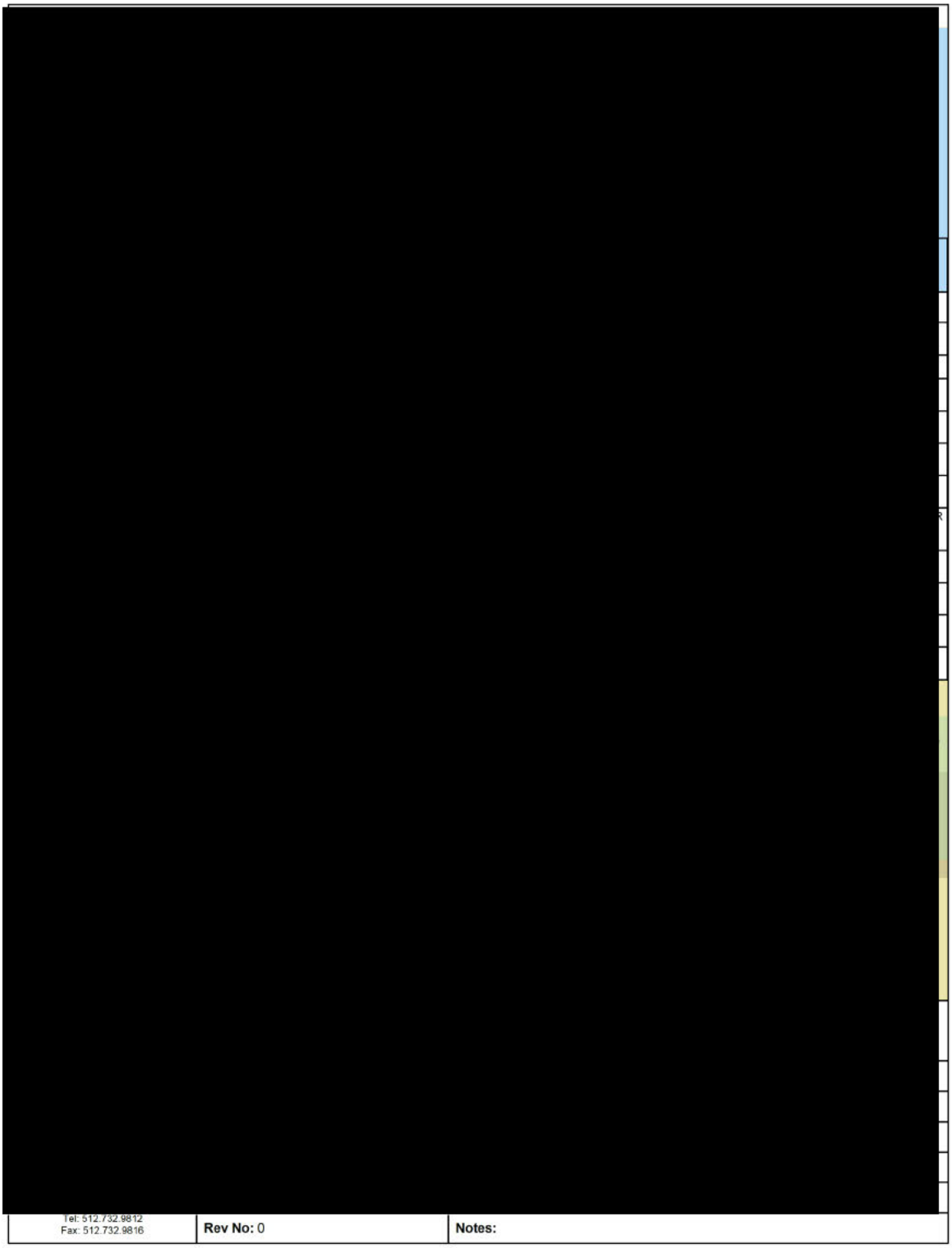


Figure 4-9 – Orchard No. 6 Wellbore Schematic

4.3.6.1 Conductor Casing

[redacted]

4.3.6.2 Surface Casing

The surface hole will be drilled with a [redacted] in. bit with casing set approximately [redacted] which is below the lowermost USDW. A string of [redacted] 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 (4-42 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.)
[redacted]								

Table 4-43 – Injection Well Surface Casing Annular Geometries, Orchard No. 6

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

Table 4-44 – Injection Well Surface Casing Cement Calculations, Orchard No. 6

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

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 the following 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.)
[redacted]								

Table 4-46 – Injection Well Production Casing Annular Geometries, Orchard No. 6

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

Table 4-47 – Injection Well Production Casing Cement Calculations, Orchard No. 6

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

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 [redacted] 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 [redacted]. 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

[redacted] centralizers will be run on the surface casing.

Centralizer placement for the [redacted] 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 burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 pounds per gallon mud with 4,000 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.)
[redacted]								

4.3.7 Orchard Well No.7 Design

Figure 4-10 provides the design schematic for Orchard No. 7

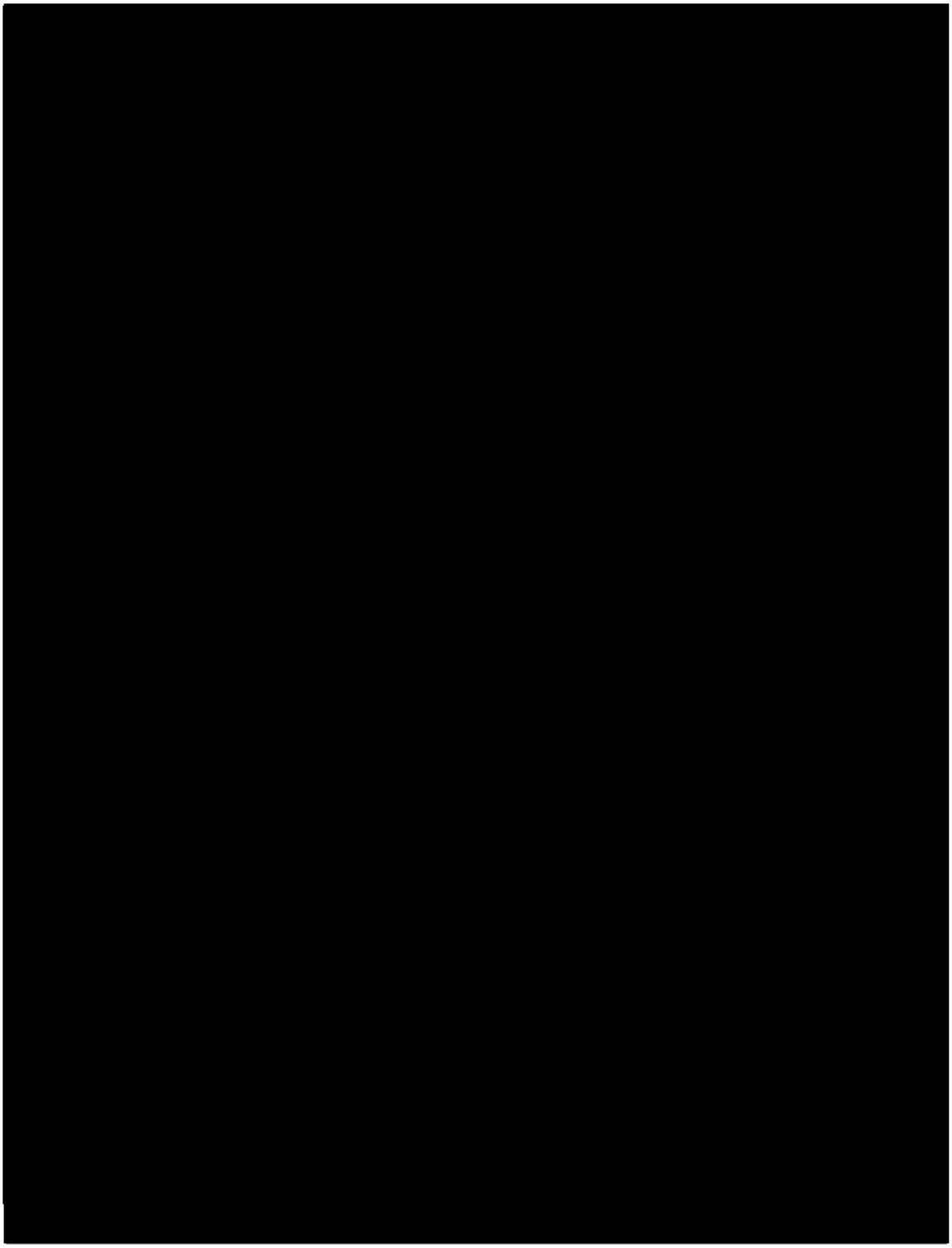


Figure 4-10 – Orchard No. 7 Wellbore Schematic

4.3.7.1 Conductor Casing

[redacted]

4.3.7.2 Surface Casing

The surface hole will be drilled with a [redacted] bit with casing set approximately [redacted], which is below the lowermost USDW. A string of [redacted] 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 (4-49 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.)
[redacted]								

Table 4-50 – Injection Well Surface Casing Annular Geometries, Orchard No. 7

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

Table 4-51 – Injection Well Surface Casing Cement Calculations, Orchard No. 7

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

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 the following 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.)
[redacted]								

Table 4-53 – Injection Well Production Casing Annular Geometries, Orchard No. 7

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

Table 4-54 – Injection Well Production Casing Cement Calculations, Orchard No. 7

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

[redacted]

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 [redacted] 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 [redacted] 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 [redacted] centralizers will be run on the surface casing.

Centralizer placement for the [redacted] 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 burst design assumes evacuated tubing with brine on the backside, and 4,000 psi applied. The collapse assumes an evacuated annulus, a full column of 12 pounds per gallon mud with 4,000 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.)
[redacted]								

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–No.7 injections 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–No. 7.



Figure 4-11 –Preliminary Wellhead Design, Orchard No. 1 to No. 7



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 Coring Plan

As discussed in the drilling procedures in *Appendix C-2*, core samples will be collected during the drilling of Orchard No. 1–No.7 in the UCL, the gross injection interval, and the lower confining layer. Orchard Storage intends to obtain whole core in the upper and lower confining layers in the injection zone in wells 1, 4 and 6. Rotary side wall cores will be obtained in the remaining injectors and will be used to supplement the whole core as needed.

4.3.9.2 Logging Plan

An extensive suite of electric logs (detailed in Tables 4-56 and 4-57) will be run in the open-hole 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 4-56 – Injection Well Open-Hole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Open Hole Diameter	Depths of Survey
1	Surface Casing	Triple Combo (Gamma Ray (GR), Spontaneous Potential (SP), Photoelectric (PE), Resistivity, Neutron, Density)	Identification of Rock Properties	[redacted]	[redacted]
2		Sonic (Dipole)			
3	Production Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties		
4		Sonic (Dipole)			
5		Fullbore Formation Microimager (FMI)			
6		Sidewall Cores			
7		Repeat Formation Tester (R FT)/ Modular Formation Dynamics Tester (MDT)			
8		Spectral GR			

Table 4-57 – Injection Well Cased-Hole 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	Cement Investigation	[redacted]	
2	Production Casing	Ultrasonic, CCL, CBL, CMT, GR, Temp (Bond Log)	Cement Investigation		
3		Pulsed Neutron Log – Baseline			

4.3.9.3 Formation Fluid Testing

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

4.3.9.4 Step-Rate Test

After the initial injection interval is perforated, a step-rate test will be performed 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.

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 25 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. The fractures will either be etched, created by acid-fracturing, or conventionally propped. This stimulation design is expected to yield a completion [redacted] 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.

4.3.11 Orchard Injection Well Operating Strategy

The Orchard Project injection wells will be operated per the following parameters provided in Table 4-58. 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.

These figures also show that the differential pressures will decline rapidly once injection ceases, falling below the critical value necessary to move fluids to a USDW through a hypothetical wellbore conduit within the first year.

Table 4-58 – 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)							
Maximum Injection Volume (MT/yr)							
Average Injection Volume (MT/yr)							
Maximum Injection Rate (MMscf/d)							
Average Injection Rate (MMscf/d)							
Maximum Surface Injection Pressure (psi)							
Expected Surface Injection Pressure (psi)							
Maximum Annular Pressure (psi)							



Figure 4-13 – Maximum Pressure Increase for All Layers at Orchard No. 1



Figure 4-14 – Maximum Pressure Increase for All Layers at Orchard No. 2



Figure 4-15 – Maximum Pressure Increase for All Layers at Orchard No. 3



Figure 4-16 – Maximum Pressure Increase for All Layers at Orchard No. 4



Figure 4-17 – Maximum Pressure Increase for All Layers at Orchard No. 5



Figure 4-18 – Maximum Pressure Increase for All Layers at Orchard No. 6



Figure 4-19 – Maximum Pressure Increase for All Layers at Orchard No. 7

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. Figures 4-20 through 4-26 show the injection rates and bottomhole pressures for the Orchard injection wells, together with the critical pressure and anticipated maximum injection pressure limit.



Figure 4-20 – Injection Pressure Plot, Orchard No. 1



Figure 4-21 – Injection Pressure Plot, Orchard No. 2



Figure 4-22 – Injection Pressure Plot, Orchard No. 3



Figure 4-23 – Injection Pressure Plot, Orchard No. 4



Figure 4-24 – Injection Pressure Plot, Orchard No. 5



Figure 4-25 – Injection Pressure Plot, Orchard No. 6



Figure 4-26 – 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

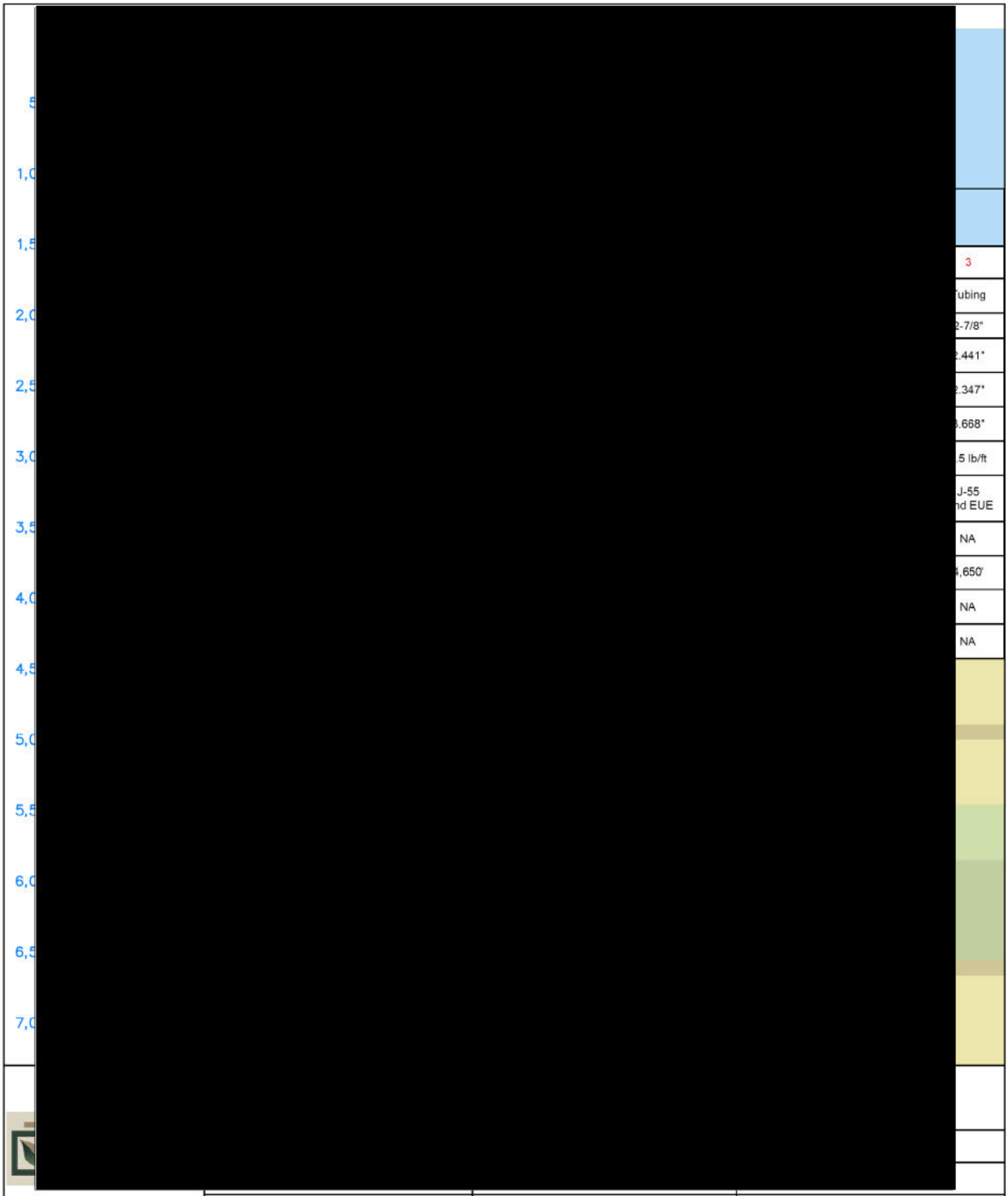
Orchard Storage plans to drill and complete two above confining zone monitoring wells, Orchard MW No. 1 and Orchard MW No. 3. These wells are intended to monitor the first permeable zone above the confining interval, [redacted] The monitoring wells will be located in the expected critical pressure front and will monitor for indications of CO_2 leaking out of the confining zone. Temperature and pressure anomalies within [redacted] 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 4-27 and 4-28):

- Conductor
  - [redacted]
- Surface Casing
  - To be set below the lowermost USDW, per the GAU (estimated setting depth is [redacted] ft).
  - [redacted]
  - Cemented back to surface
- Production Casing
  - [redacted]
- Tubing – [redacted]
- Wellhead
  - [redacted]

Complete drilling prognoses have been included in *Appendix C*. The mud and cement programs included in the prognoses are representative and may be modified before starting construction.



	API No: TBD	**Field:**	**Well Type/Status:** Monitoring
Texas License F-22610	**State Gas ID No:**	**Project No:** LS167	**Date:** 1/27/2023
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 4-27 – Orchard MW No. 1 Monitoring Wellbore Schematic

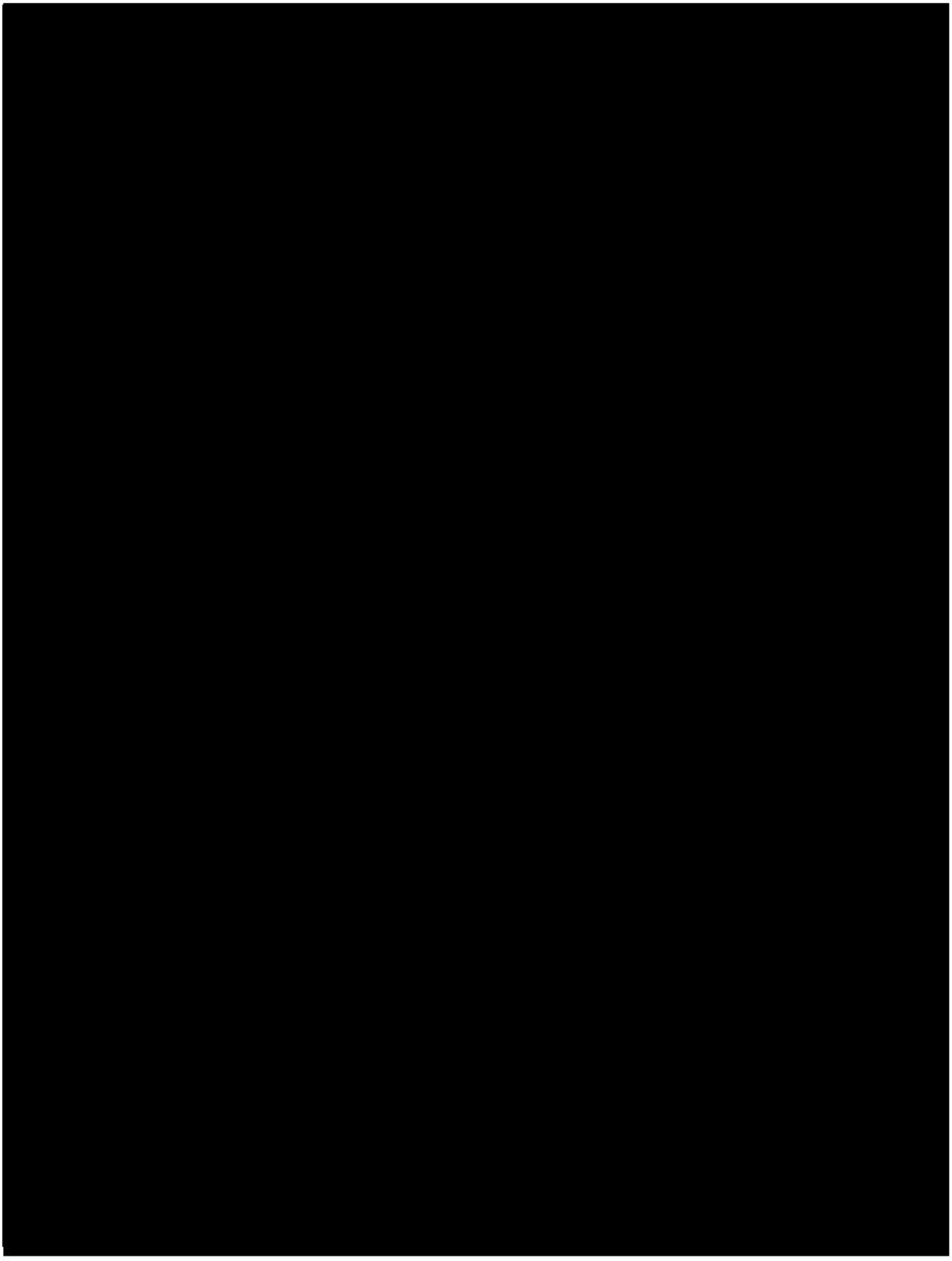


Figure 4-28 – Orchard MW No. 3 Monitoring Wellbore Schematic

4.4.1.1 Conductor Casing

To ensure that hole integrity can be maintained during the initial drilling of the well, [redacted]

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 [redacted] bit with casing set below the USDW. A string of [redacted]. 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 the following tables (4-59 through 4-61):

Table 4-59 – 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.)
[redacted]								

Table 4-60 – Monitoring Well Surface Casing Annular Geometries, Orchard MW No. 1 and MW No. 3

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

Table 4-61 – 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)
[redacted]				

To ensure that cement returns to the surface are achieved, 100% excess open-hole 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 UCL, 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 the following tables (4-62 through 4-64):

Table 4-62 – 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.)
[redacted]								

Table 4-63 – Monitoring Well Production Casing Annular Geometries, Orchard MW No. 1

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

Table 4-64 – Monitoring Well Production Casing Cement Calculations, Orchard MW No. 1

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

The engineering and design parameters for the production casing for Orchard MW No. 3 are summarized in the following tables (4-65 through 4-67):

Table 4-65 – 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.)
[redacted]								

Table 4-66 – Monitoring Well Production Casing Annular Geometries, Orchard MW No. 3

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

Table 4-67 – Monitoring Well Production Casing Cement Calculations, Orchard MW No. 3

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

4.4.1.4 Centralizers

The bow-spring centralizer placement for the [redacted]urface casing is designed to protect any shallow aquifer zones per state regulations. The specific placement ensures a continuous, uniform column of cement throughout the [redacted] 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

[redacted] centralizers will be run on the surface casing.

The bow-spring centralizer placement for the [redacted] production casing strings is designed to ensure a continuous, uniform column of cement throughout t[redacted] 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

[redacted] total centralizers will be run on the production casing.

4.4.1.5 Tubing

The tubing strings will consist of [redacted] in. tubing and a permanent packer assembly. The tubing string will be used to collect fluid samples above the UCL.

Tables 4-68 and 4-69 list the tubing specifications, design criteria, and calculated safety factors. Since there will be no injection in this well, the burst design assumes evacuated tubing with brine on the backside, with 500 psi applied on the annulus. The collapse assumes an evacuated annulus, a full column of 11 pounds per gallon mud with 1,000 psi applied.

Table 4-68 – 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)
[redacted]								

Table 4-69 – 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)
[redacted]								

4.4.1.6 Packer

The production tubing will be run in the well with a [redacted] permanent packer, with a latch-in seal assembly as shown in Figure 4-29.

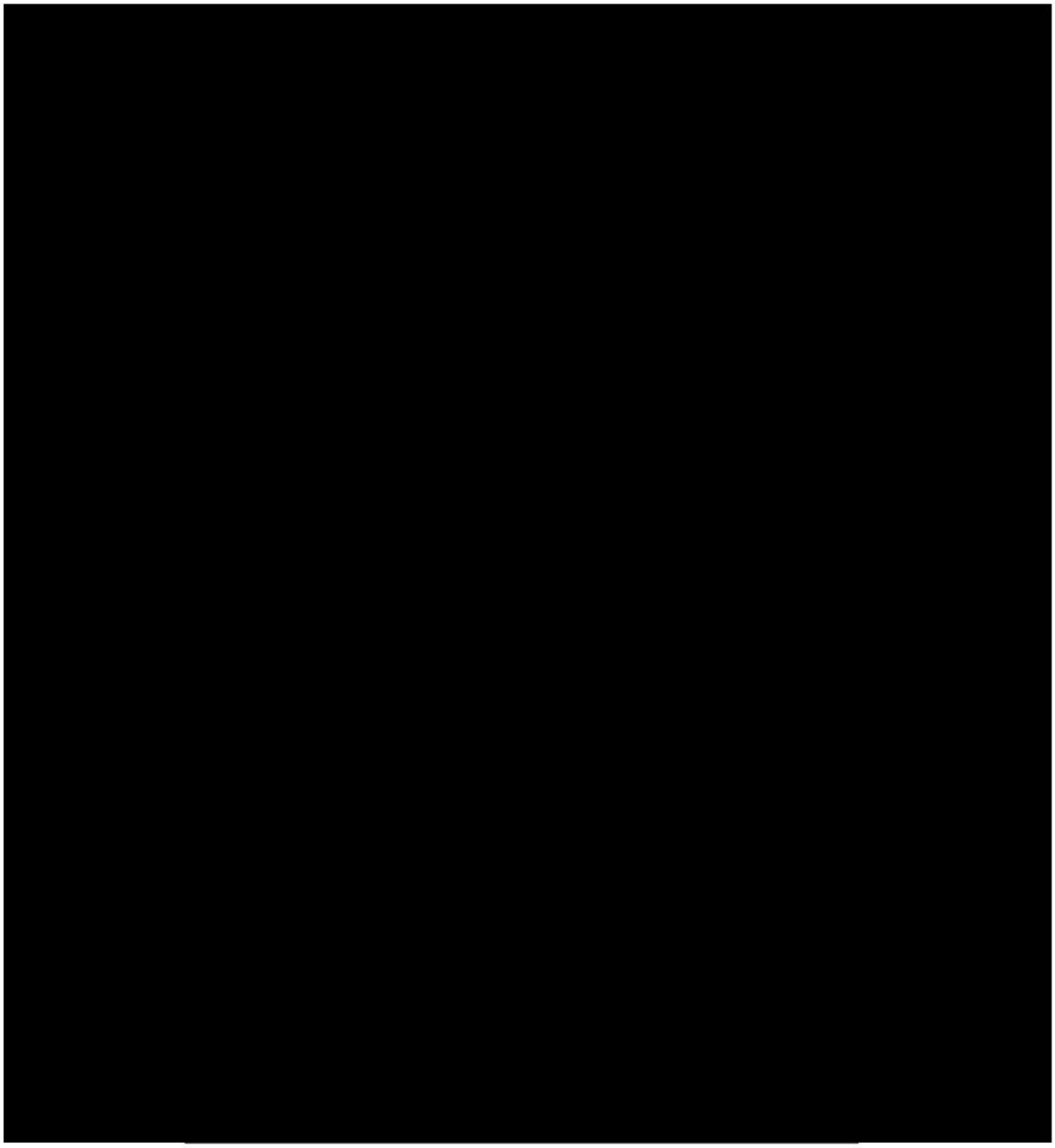


Figure 4-29 – [redacted]. Seal Assembly & Permanent Packer

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 4-30 (note: the manufacturer may differ from the one shown).

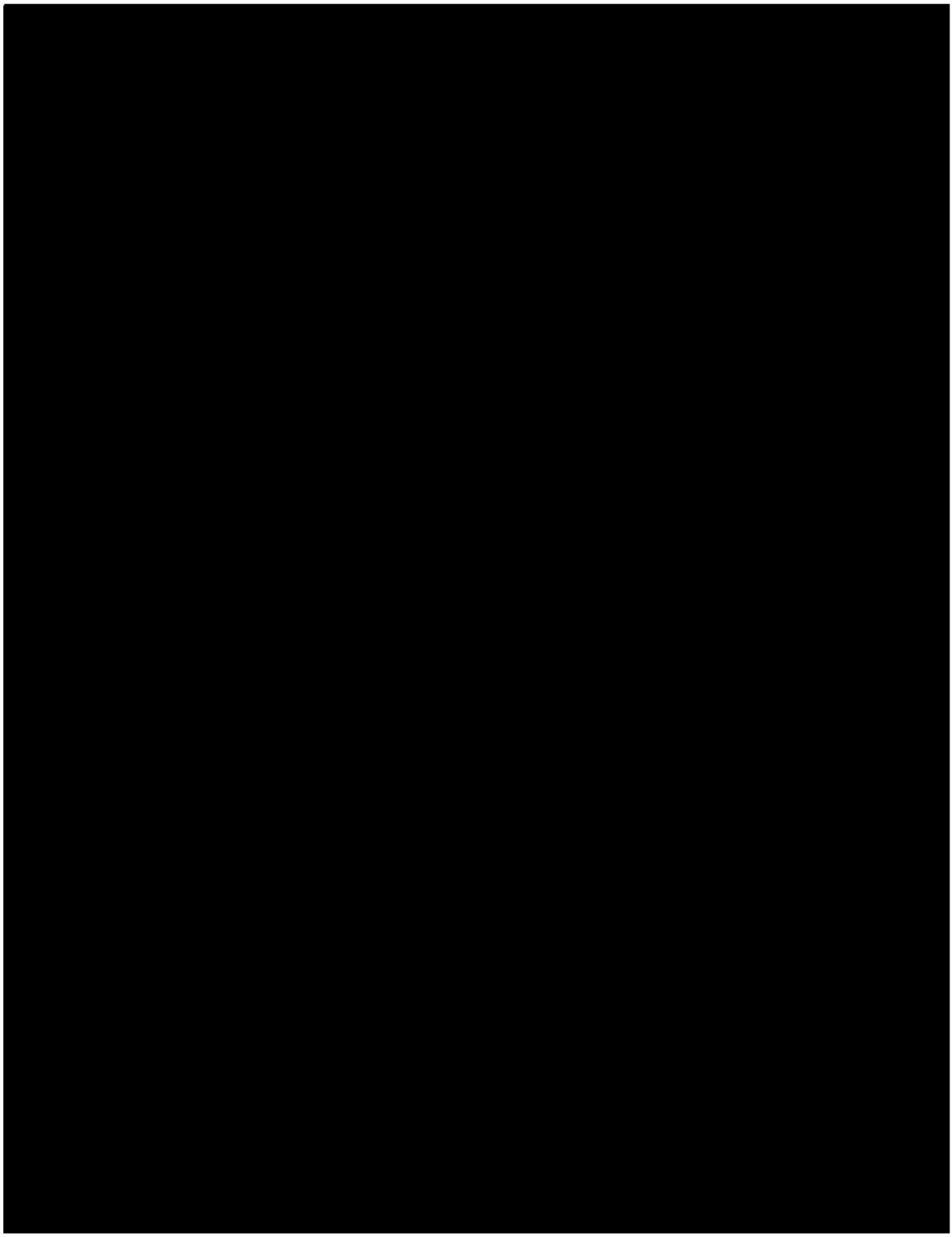


Figure 4-30 – Orchard Monitoring Wells Preliminary Wellhead Design

4.4.2 Testing and Logging of Orchard MW No. 1 and MW No. 3 During Drilling and Completion Operations

A suite of electric logs will be run in the open-hole sections and each casing string for Orchard MW No. 1 and MW No. 3. The logging plan is detailed in Tables 4-70 and 4-71. 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 4-70 – Open-Hole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Open Hole Diameter	MW No. 1	MW No. 3
1	Surface Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties			
2		Sonic (Dipole)				
3	Production Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties			
4		Sonic (Dipole)				
5		Spectral GR				

Table 4-71 – Cased-Hole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Casing Dimension	Depths of Survey	
1	Surface Casing	Ultrasonic, CCL, CBL, CMT, GR, Temp (Bond Log)	Cement Investigation			
2	Production Casing	Ultrasonic, CCL, CBL, CMT, GR, Temp (Bond Log)	Cement Investigation			
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 cased hole logs as described in Table 4-70.
- Test the casing.
- Perforate the Queen formation, specific depths to be determined with open-hole 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 [redacted] 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–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 [redacted] is currently classified by the TRRC as a [redacted] Orchard Storage proposes to recomplete this well as an in-zone monitoring well. [redacted] Pressure and temperature gauges will be installed on the tubing.

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.
- [redacted]

- [redacted]

Figure 4-31 shows the current schematic for the existing wellbore. Figure 4-32 shows the proposed recompletion design.

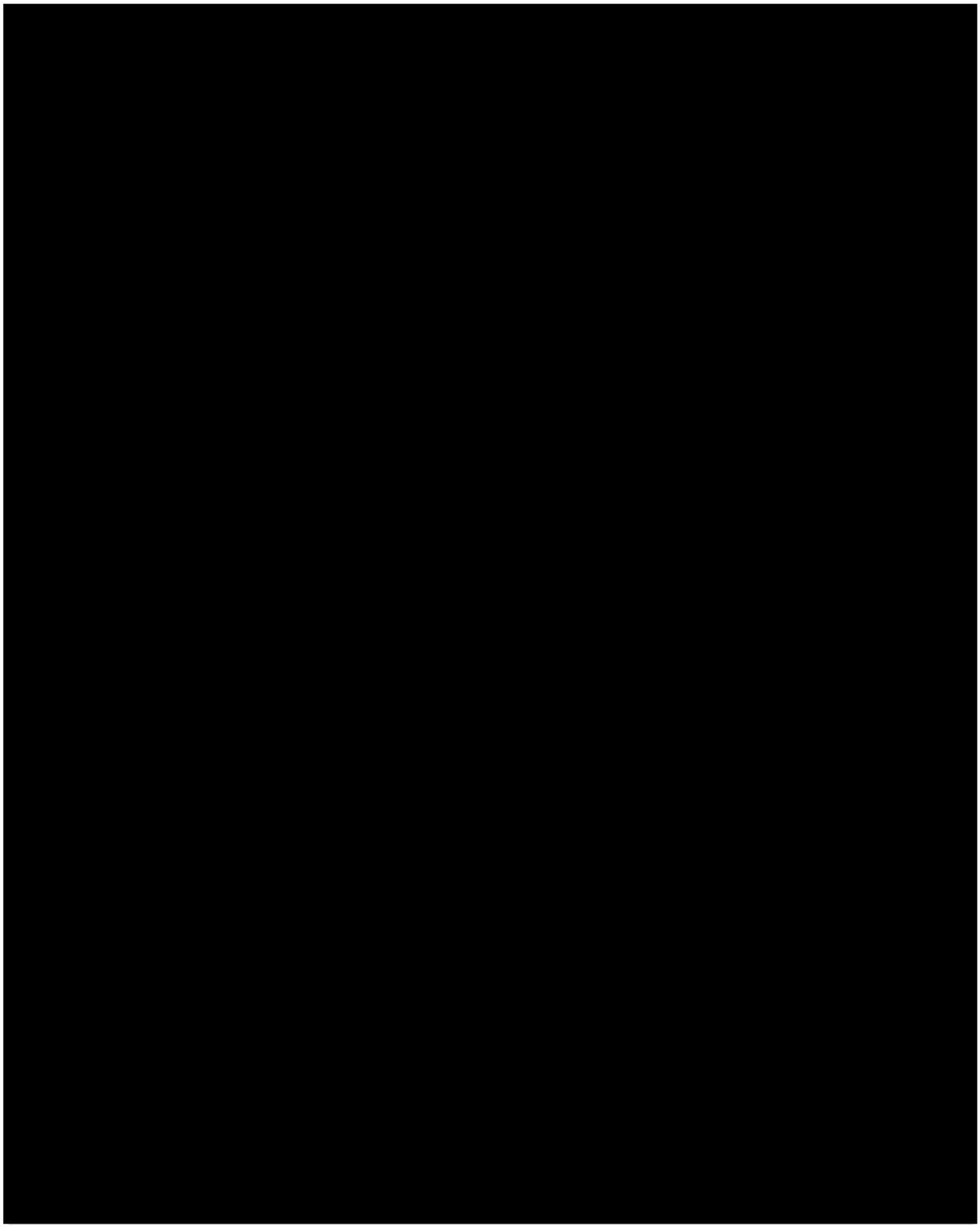


Figure 4-31 – [redacted] Current Wellbore Schematic

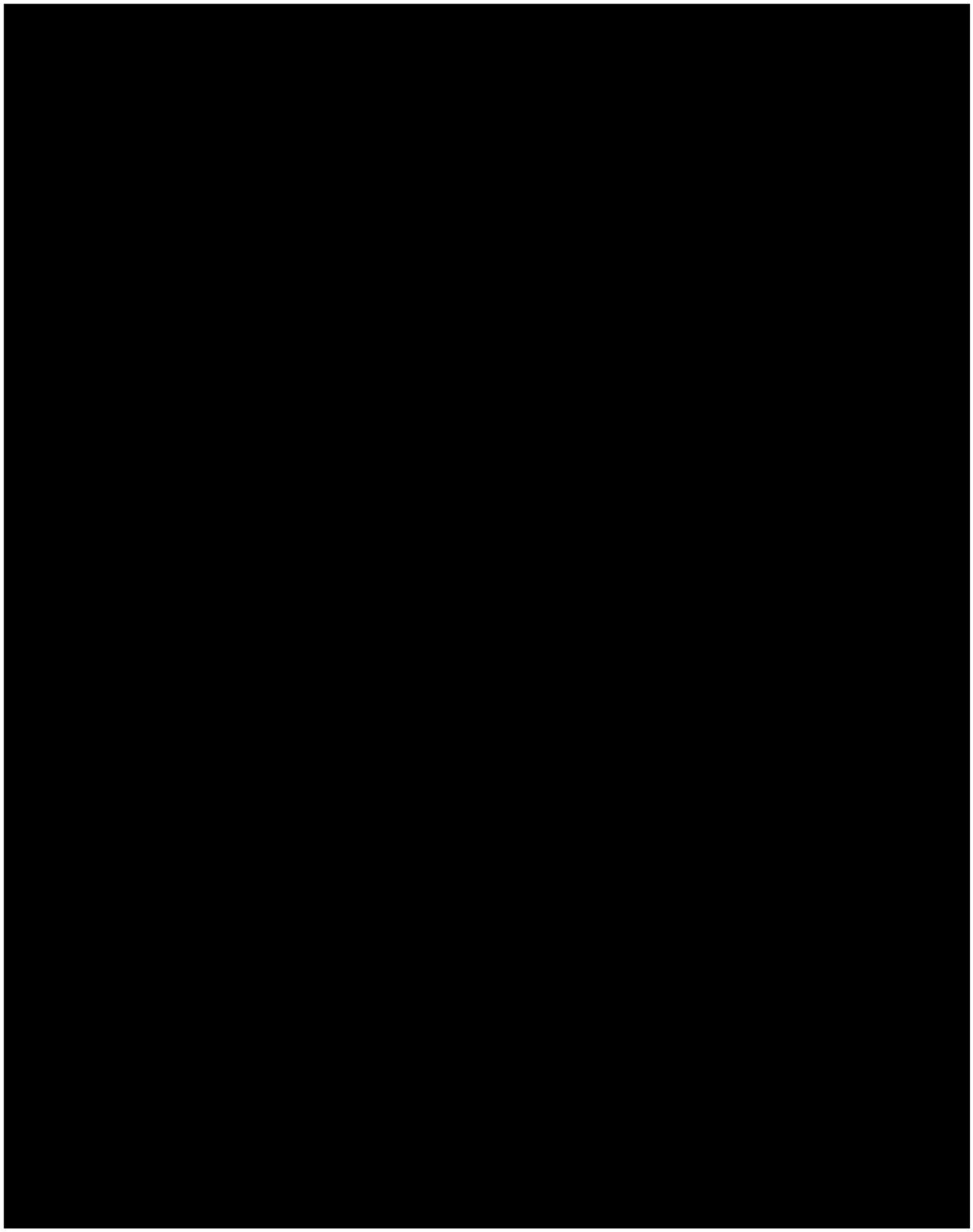


Figure 4-32 – Orchard MW No. 2 Proposed Wellbore Schematic

4.5.1.2 Tubing

The tubing strings will consist of [redacted] tubing and a permanent packer assembly. The tubing string will be used to collect fluid samples above the UCL.

Table 4-72 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 burst design assumes evacuated tubing with brine on the backside, with 500 psi applied on the annulus. The collapse assumes an evacuated annulus, a full column of 11 pounds per gallon mud with 1,000 psi applied.

Table 4-72 – 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.)
[redacted]								

4.5.1.3 Packer

The production tubing will be run in the well with a [redacted] permanent packer, with a latch-in seal assembly as shown in Figure 4-41 (in *Section 4.3.1.6*).

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.*

Appendix C – Well Construction Schematics and Procedures:

- Appendix C-2 Injection Well Drilling and Completion Prognoses
- Appendix C-3 Monitoring Well Drilling and Completion Prognoses

4.6 References

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.

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

Revised April 2024

LONQUIST SEQUESTRATION LLC

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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 within five working days of the event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of the event
- Any significant data that indicate the presence of leaks in the well or lack of confinement to the storage reservoir
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within five working days of 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 within 72 hours of composition change
- 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 72 hours of the event
- Description of any event that triggers a shutoff device, either downhole or at the surface, and the response taken
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 72 hours of the event
- Any release of CO_2 into the atmosphere or biosphere
    - Verbal Notification – Reported within 24 hours of the event

Semiannual Reports:

- Summary of wellhead pressure monitoring
- Any changes to the source of the CO_2 stream
- Any 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 1 year of an AOR reevaluation following significant facility changes, such as the development of offset monitoring wells or newly permitted injection wells within the AOR, or as required by the UIC Director.

5.4 Testing Strategies

5.4.1 Open-Hole Logging

Orchard Storage plans to run an advanced suite of open-hole 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 open-hole logs is provided in Table 5-1.

Table 5-1 – Injection Well Open-Hole Logging Plan

Trip	Hole Section	Logging Suite	Target Data Acquisition	Open Hole Diameter	Depths of Survey
1	Surface Casing	Triple Combo (Gamma Ray (GR), Spontaneous Potential (SP), Photoelectric (PE), Resistivity, Neutron, Density)	Identification of Rock Properties	[redacted]	[redacted]
2		Sonic (Dipole)			
3	Production Casing	Triple Combo (GR, SP, PE, Resistivity, Neutron, Density)	Identification of Rock Properties		
4		Sonic (Dipole)			
5		Fullbore Formation Microimager (FMI)			
6		Sidewall Cores			

7		Repeat Formation Tester (R FT)/ Modular Formation Dynamics Tester (MDT)		[redacted]
8		Spectral GR		

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 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.

5.4.2.1 Testing Method

Specific wellbore and injection zone properties will define the final test parameters. The following test method outlines the expected test injection rates and times. The injection of brine will begin at 1.5 barrels per minute (bpm) and be held for a minimum of 30 minutes. The injection rates will be stepped up in 2.0–3.0 bpm increments until at least three measurements have been taken, both below and above the estimated formation-fracture initiation pressure. Each stage will require a hold duration of at least 30 minutes—or until the pressure has stabilized.

A plot of stabilized injection *pressure* versus injection *rate* at each step should graphically represent a linearly sloped line, until the fracture initiation pressure has been exceeded. Table 5-2 shows a step-rate test example, and Figure 5-1 is the corresponding graphical representation.

Table 5-2 – Step-Rate Injectivity Test Example

Step	Rate (bpm)	Time (min)	Pressure (psi)
0	0	0	0
1	0.2	30	100
2	0.4	30	200
3	0.8	30	400
4	1.6	30	802
5	2.4	30	1,201
6	3.2	30	1,400
7	4.0	30	1,600

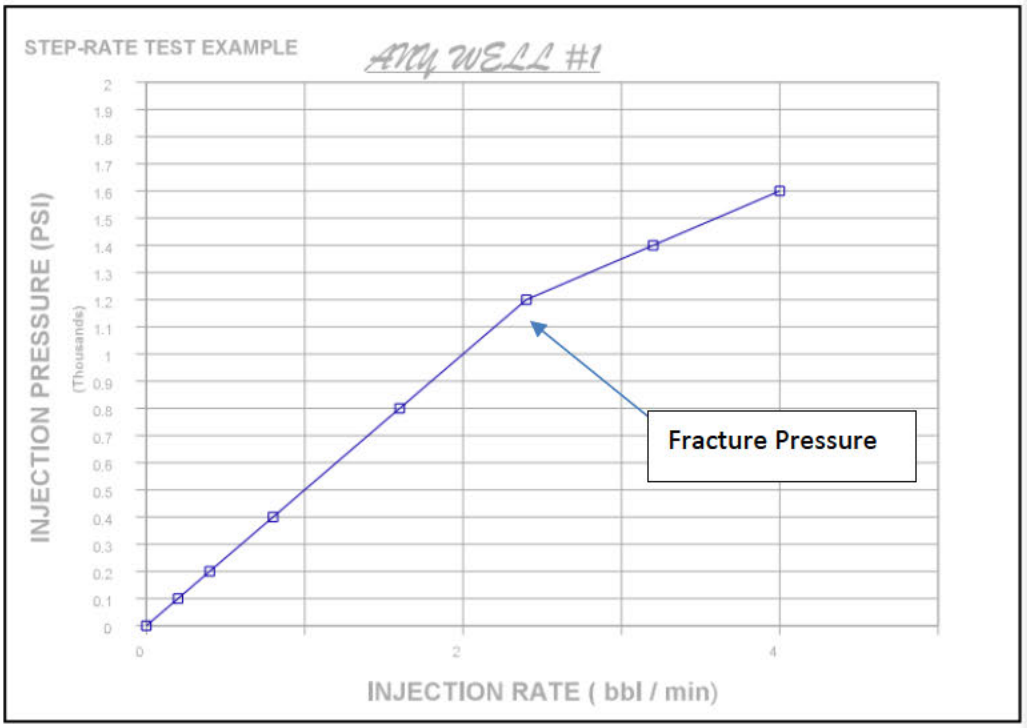


Figure 5-1 – Example of a Step-Rate Injectivity Test[1]

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 5-3 – 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 will be monitored and recorded for a minimum duration of 30 minutes using a pressure gauge, with sensitivities that can indicate a loss of 5%. 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 Log

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 through the tubing. Temperature 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 the temperature logs, to allow temperatures to stabilize. Satisfactory mechanical integrity is demonstrated by the proper correlation between the baseline and subsequent logs.

All temperature logs recorded during the MIT will be submitted to the TRRC within 30 days of completing the log run.

5.4.6 Pressure Falloff Testing

Orchard Storage will 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 [redacted] 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 cased-hole 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 survey will characterize the original state of the wellbore materials. 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 5-4 – 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*. 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.

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.

5.5.3 Soil Gas Monitoring

Soil gas monitoring will be used to check 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 process 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 conditions through multiple seasons. Best industry practice has shown that fixed soil-gas profile stations provide the most accurate data. The location of the stations will be selected to minimize the agricultural impacts of plowing, planting, irrigation, and harvesting. Samples will be collected and sent to a reputable 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 parameters to be measured are provided in Table 5-5.



Figure 5-3 – Location of Groundwater, In-Zone and Above-Zone Monitoring Wells

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

Parameter/Analyte	Frequency
Total dissolved solids (TDS)	Quarterly
pH	Quarterly
Specific conductivity (SC)	Quarterly
Temperature	Quarterly
Density	Quarterly
Other parameters including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds	Quarterly

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 5-4. 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) 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. These next steps could include, but not be limited to, using a pressure jar to collect a sample of the fluid and dissolved CO_2.

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 [redacted] identified above the upper confining interval. Any deviations from baseline pressures or temperature will initiate additional investigations in the area. If necessary, fluid samples can be obtained from this well.

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 pressure[redacted] interval.

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 [redacted] 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 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.



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.

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

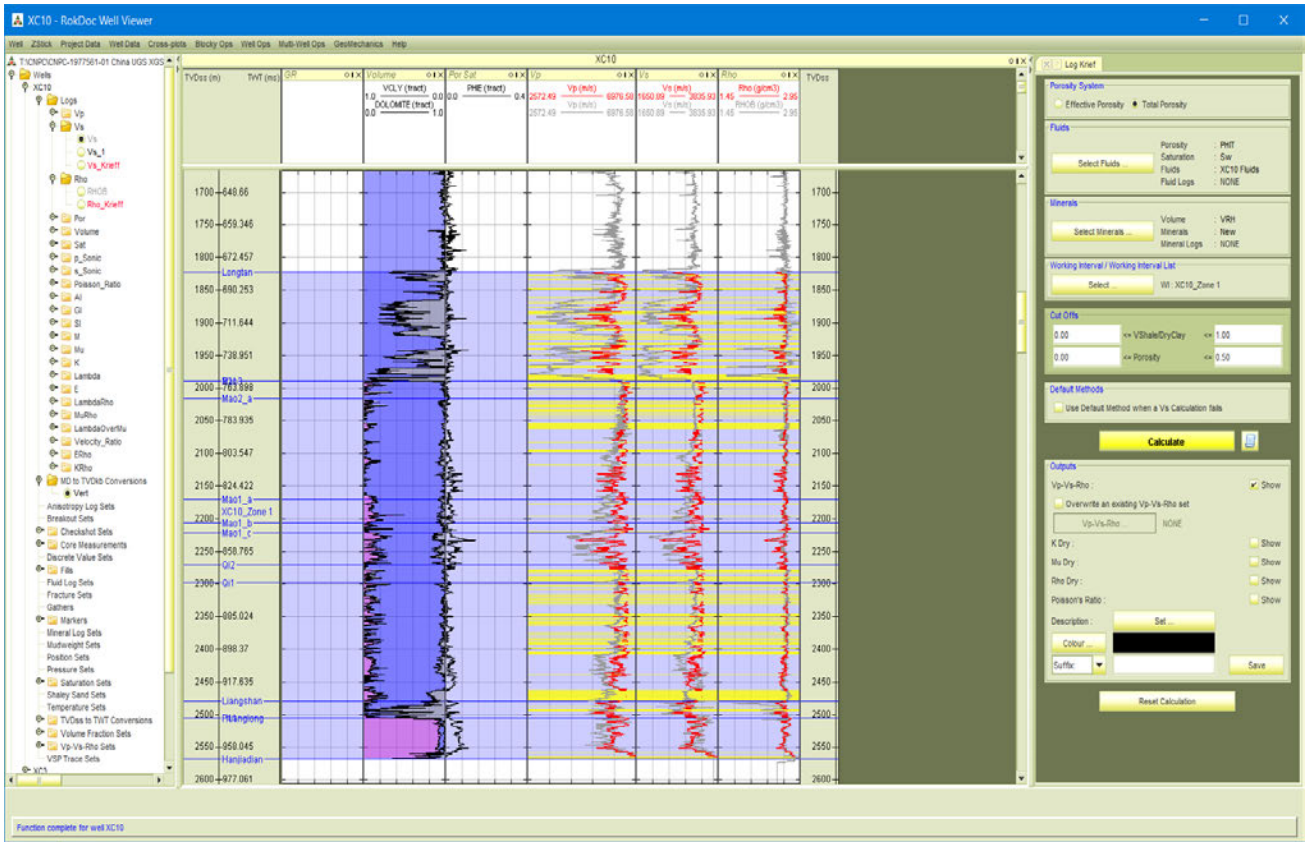


Figure 5-6 – RocDoc Well Viewer

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.

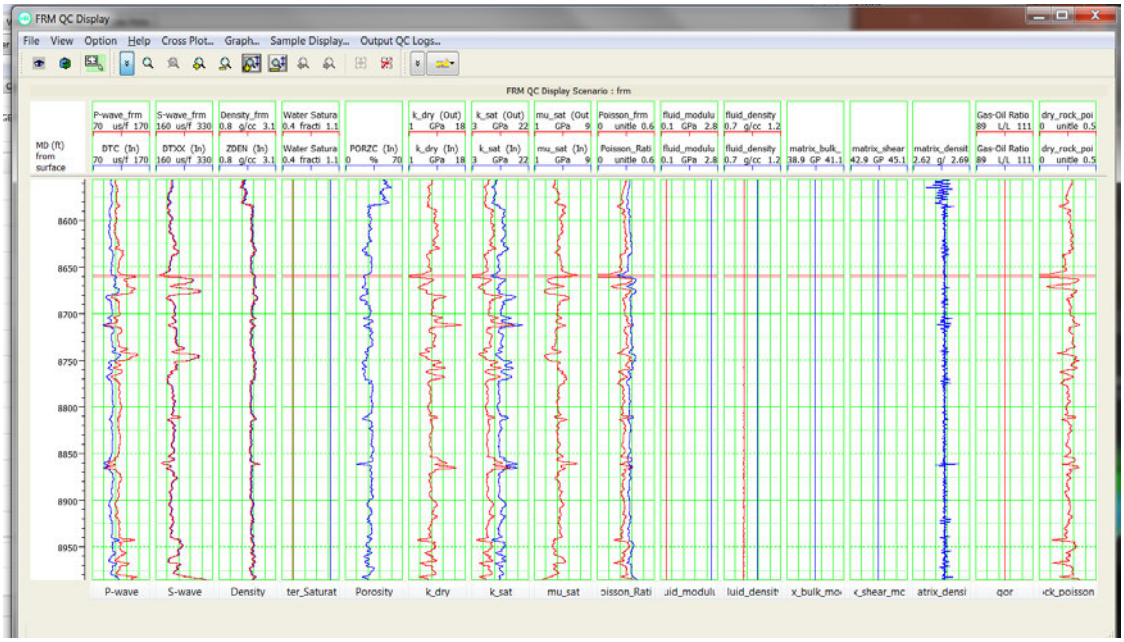


Figure 5-7 – Application of Petro-Elastic Model to Rock Physics Model

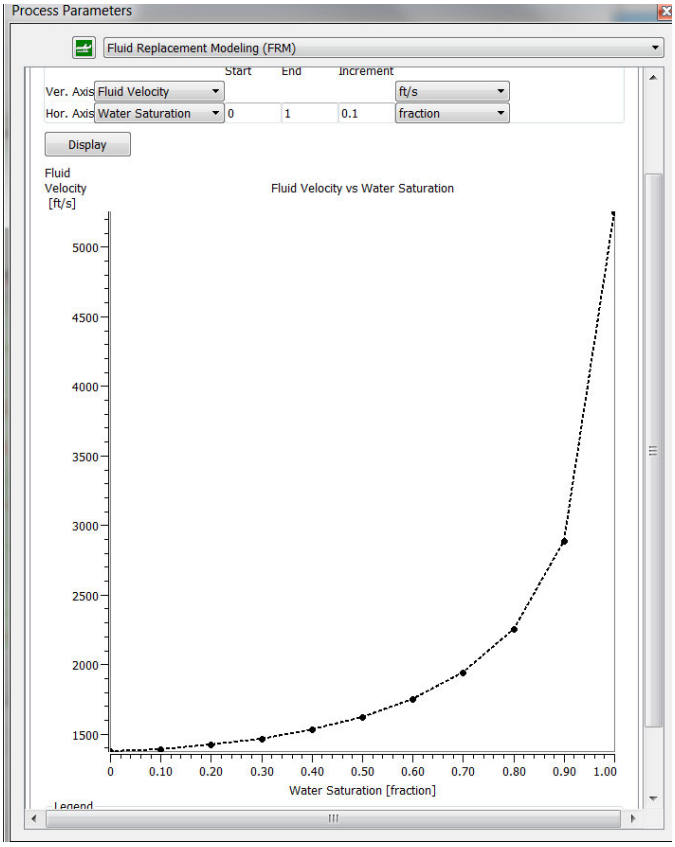


Figure 5-8 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation

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 open-hole log readings that will be taken while drilling the stratigraphic test well for this project.

5.5.7.5 1D and 2D Models

Changes in the magnitude of the CO_2 plume are measured for different scenarios using 1D and 2D models. This section 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 of 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.

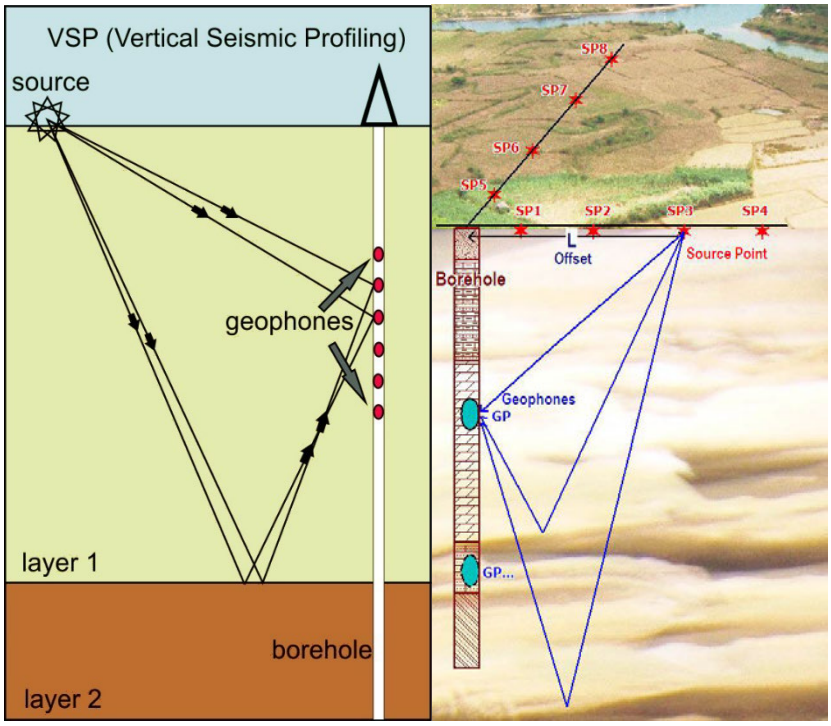


Figure 5-9 – Illustration of a Vertical Seismic Profile Survey

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.

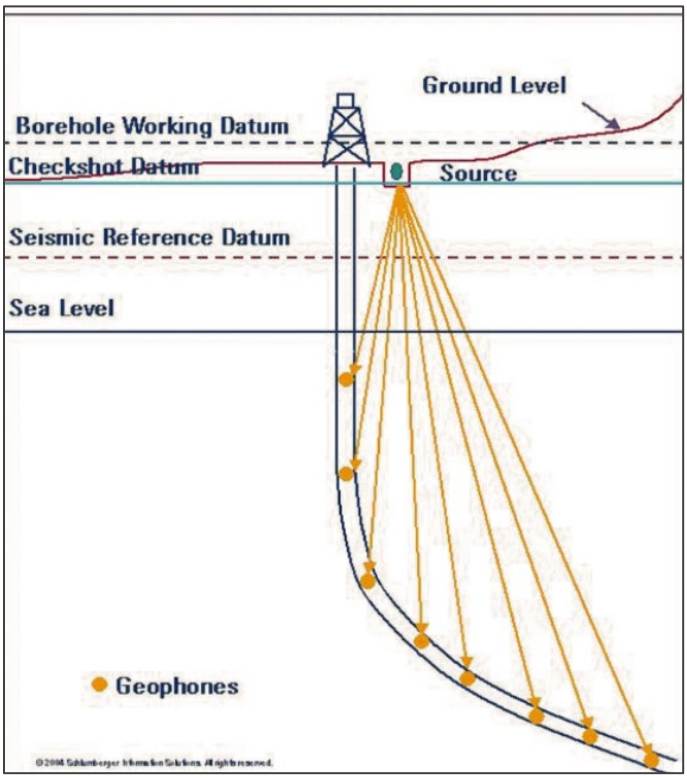


Figure 5-10 – Illustration of a Checkshot Survey

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:

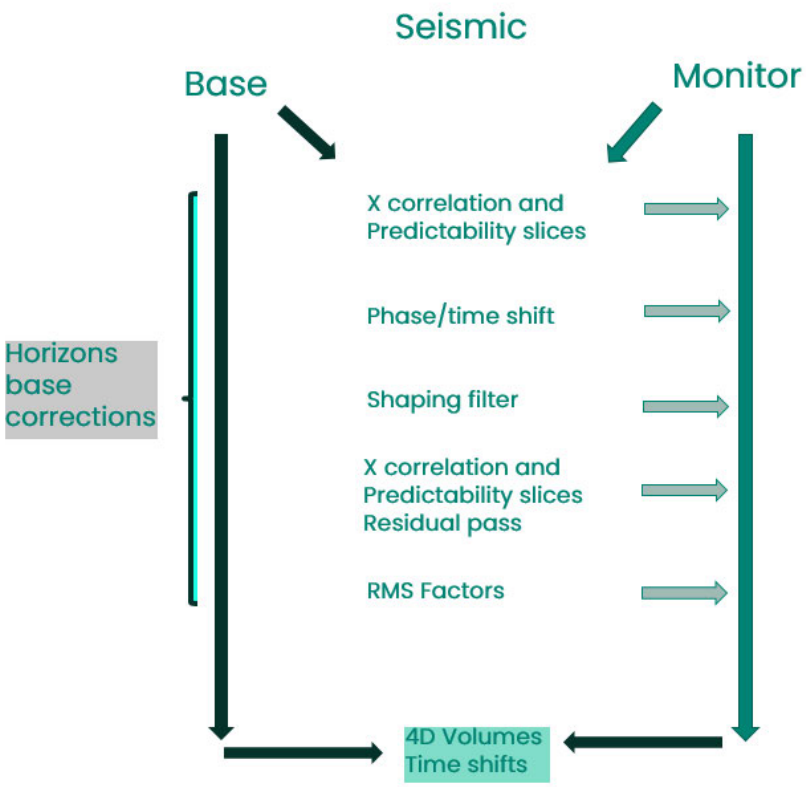


Figure 5-11 – Time-Lapse/4D Processing Workflow Diagram

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.

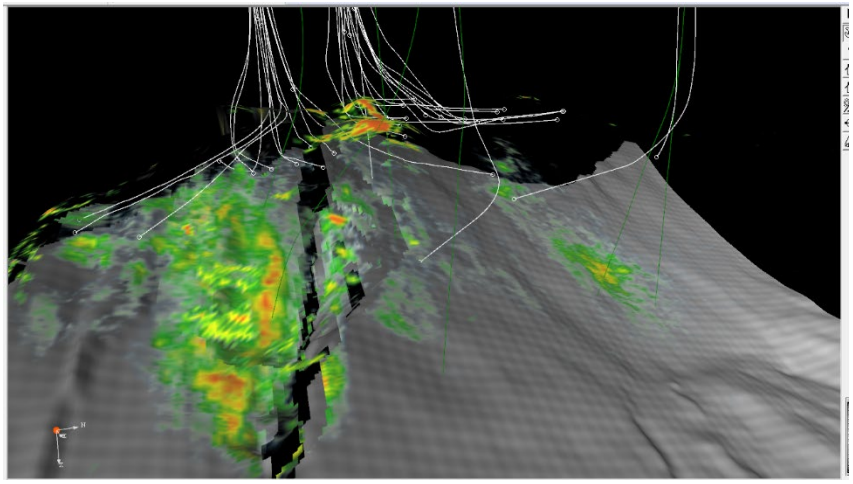


Figure 5-12 – Example of Time-Lapse/4D Model (showing time-lapsed gas-replacement of connate fluids)

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.

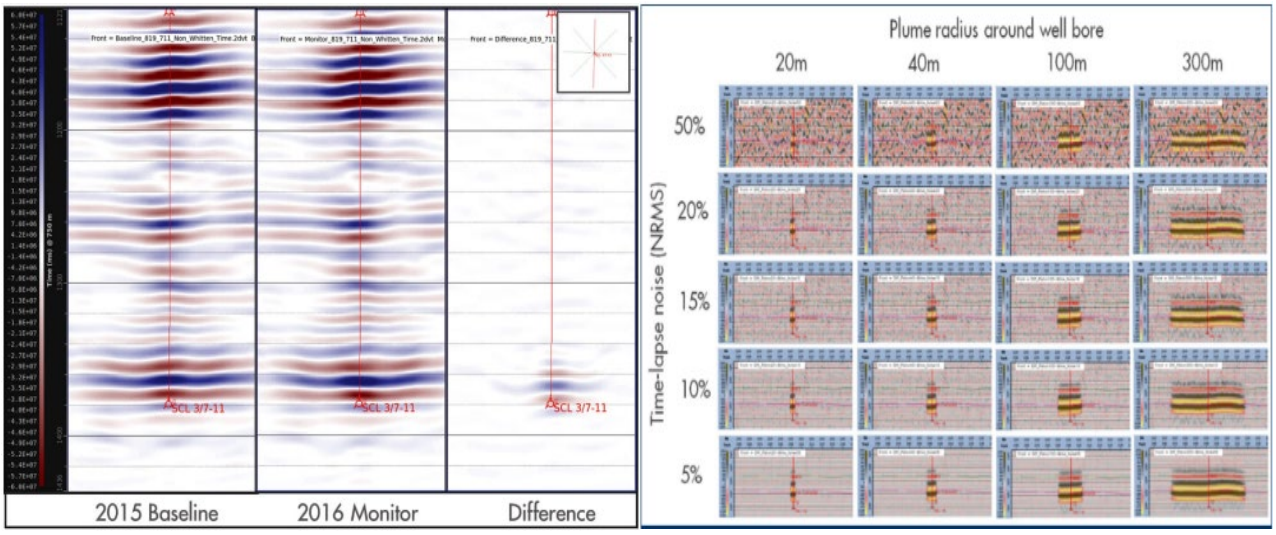


Figure 5-13 – Baseline and subsequent VSP used to determine difference in amplitude attributed to CO_2 injection measured from the injector well itself. At right is the estimation of the plume growth over time.

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



Fiber optic cable will be installed on the [redacted] 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 [redacted]. TEC with pressure and temperature gauges will be installed on the OD of the [redacted] 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.

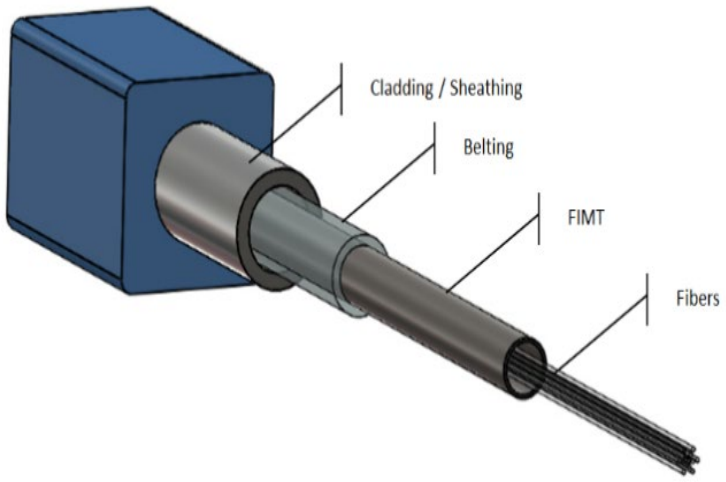


Figure 5-14 – SureVIEW with CoreBright Optical Fiber

Table 5-6 – 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 5-7 – 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 5-8 – 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.

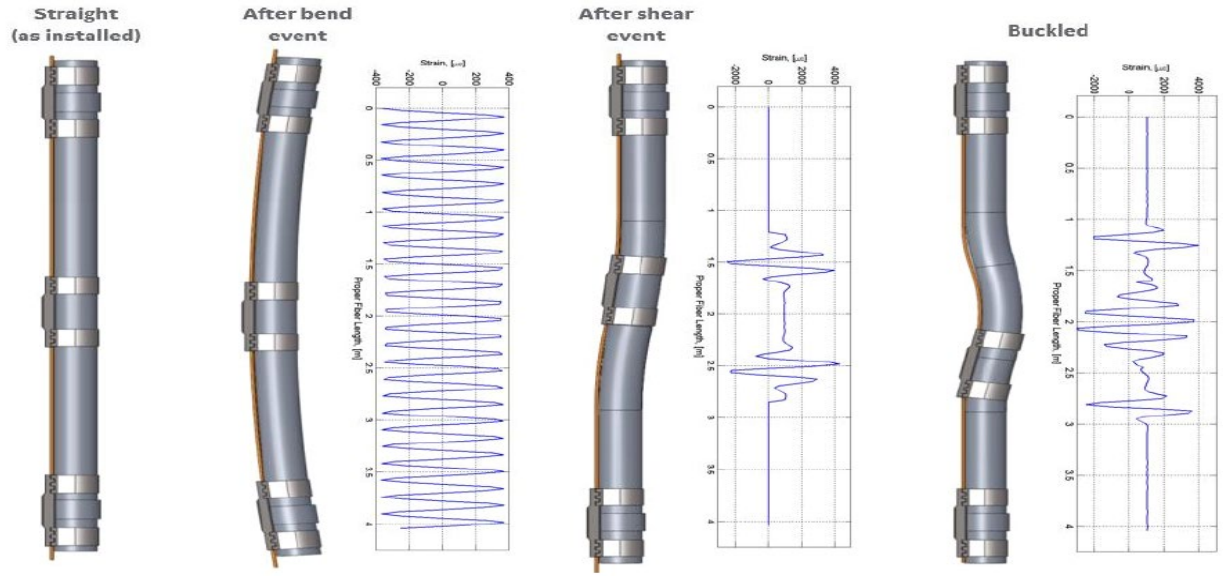


Figure 5-15 – SureVIEW WIRE Illustration

Table 5-9 – 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.

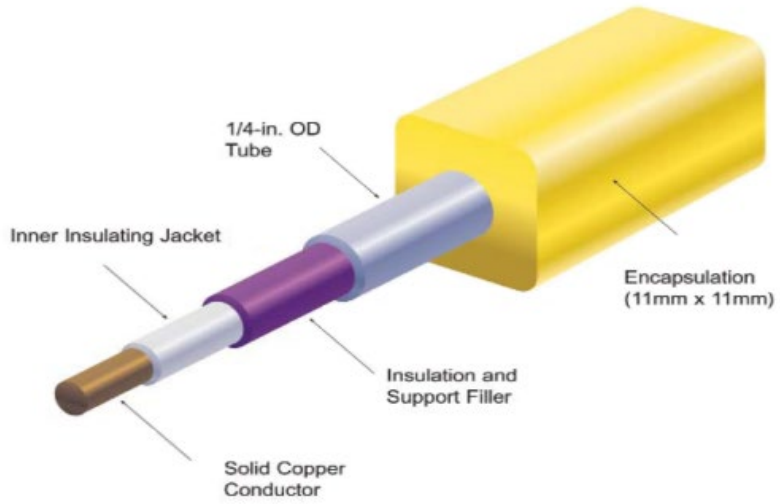


Figure 5-16 – TEC Illustration

Table 5-10 – 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 5-11 – 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.

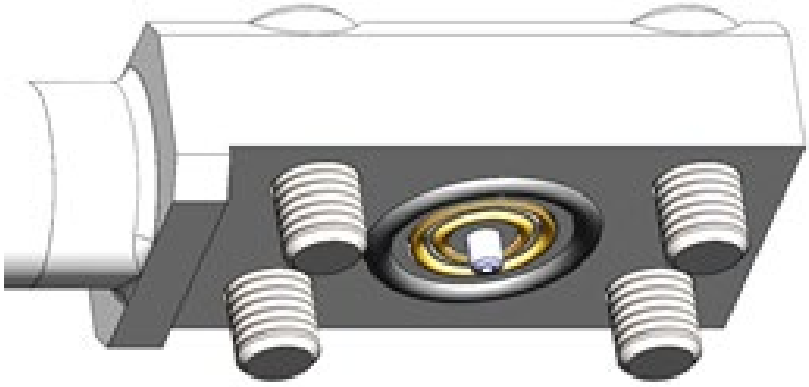


Figure 5-18 – External Sensor Illustration

Table 5-12 – 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)	16,000 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).

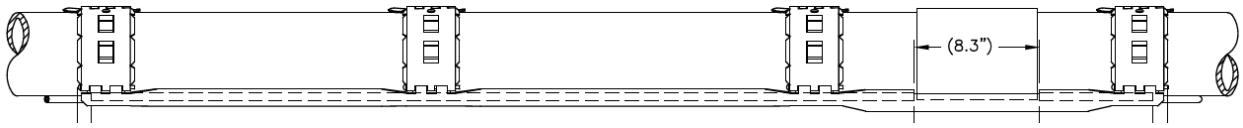


Figure 5-20 – Steel Blast Protector Illustration

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 larger scale map of the monitoring wells plus specification sheets for the planned technologies are provided in *Appendix E-2*.

5.7 References

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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

Revised April 2024

LONQUIST SEQUESTRATION LLC

SECTION 6 – INJECTION WELL PLUGGING PLAN

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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 [redacted]. After the conclusion of the [redacted] injection operations, the wells will be permanently plugged. Complete plugging and abandonment prognoses are included in *Appendix G*.

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 [redacted] n.) 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. Injection well will be flushed with a buffer fluid prior to pulling the injection tubing and packer (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 [redacted].
    b. Place a 300 ft acid-resistant cement plug above the permanent bridge plug to cover the length of the upper confining zone.
    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. 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 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 Orchard No. 1 Plugging and Abandonment

Figure 6-1 shows the original wellbore schematic for Orchard No. 1, prior to beginning plugging ope

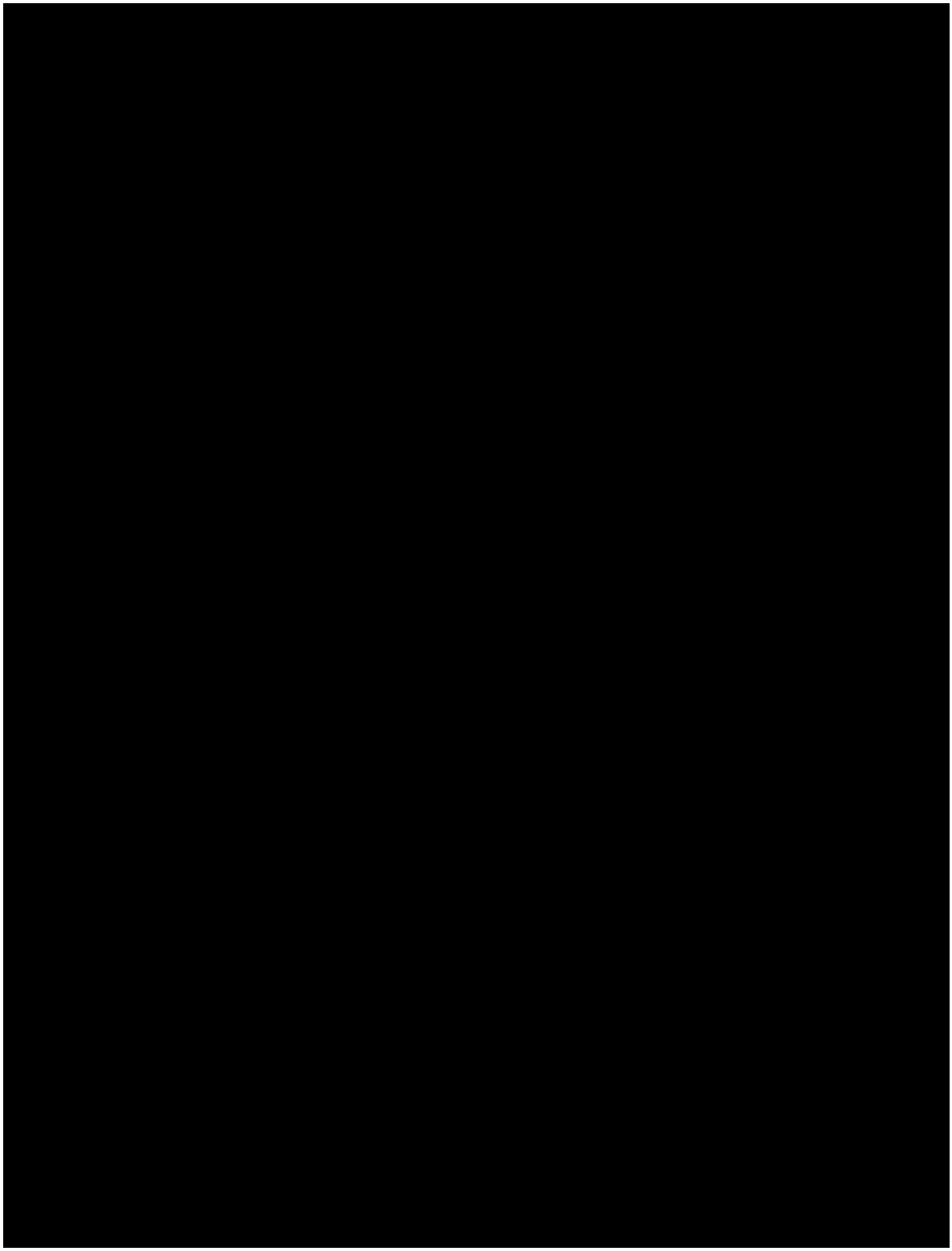


Figure 6-1 – Wellbore Schematic for Orchard No. 1 Before Plugging and Abandoning

6.1.3.1 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
Purpose	[redacted]			
Casing Outer Diameter (OD)				
Casing Inner Diameter (ID)				
Top of Plug				
Bottom of Plug				
Cement Volume (sacks)				
Slurry Volume (ft^3)				
Slurry Weight (lb/gal)				
Type of Cement or Other Material				
Placement				

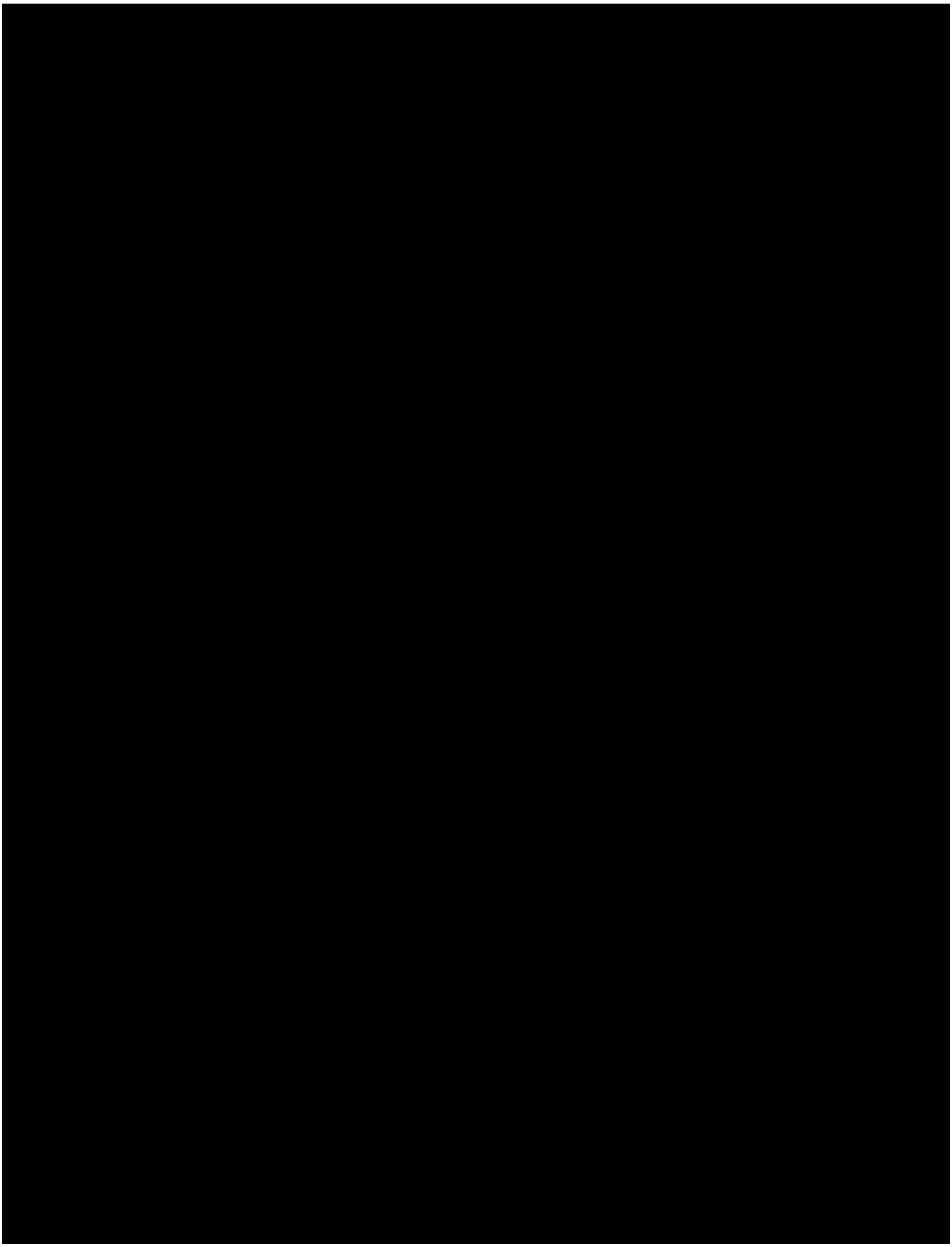


Figure 6-2 – Plugging Schematic for Orchard No. 1

6.1.4 Orchard No. 2 Plugging and Abandonment

Figure 6-3 shows the original wellbore schematic for Orchard No. 2, prior to beginning plugging operations.

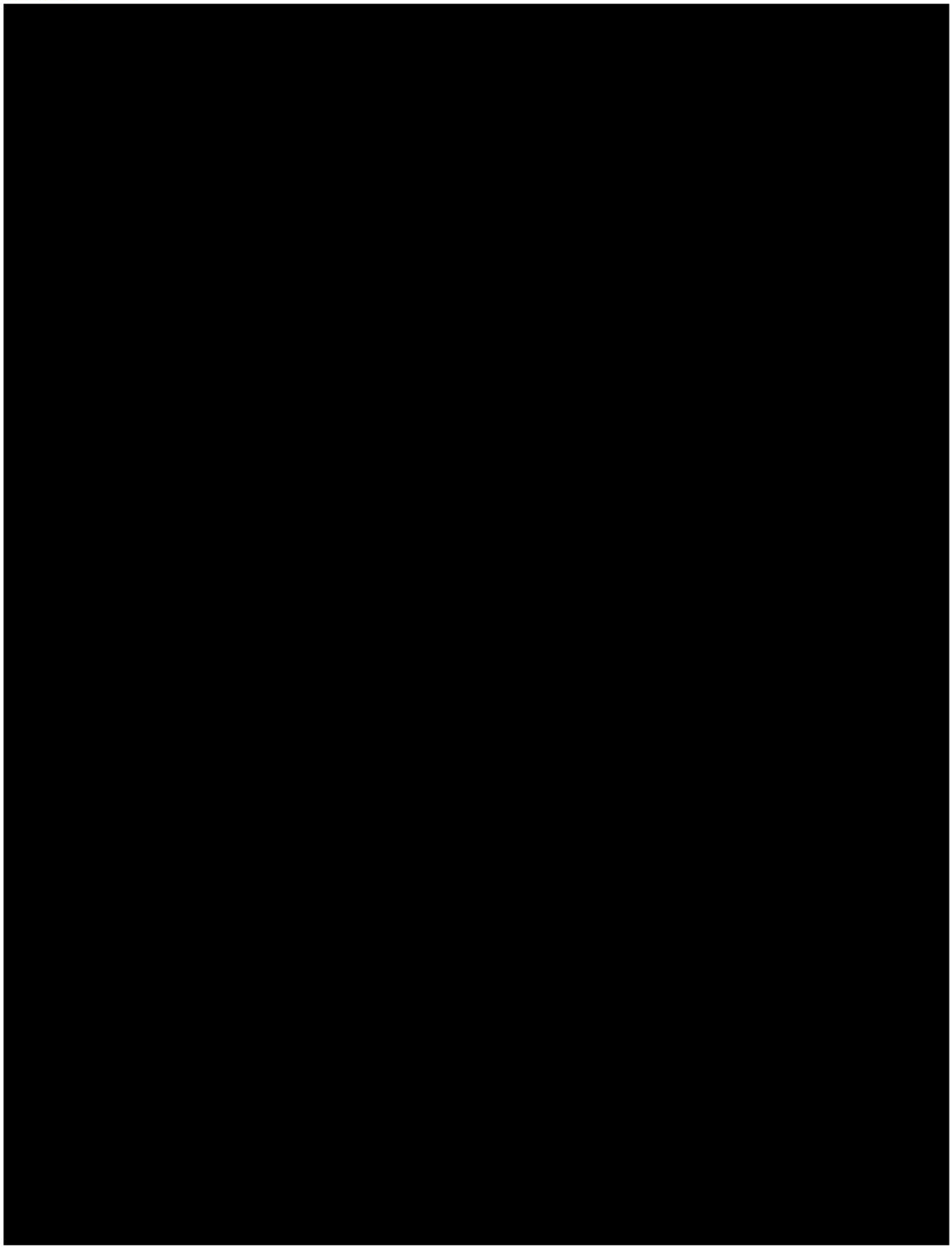


Figure 6-3 – Wellbore Schematic for Orchard No. 2 Before Plugging and Abandoning

6.1.4.1 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
Purpose				
Casing OD				
Casing ID				
Top of Plug				
Bottom of Plug				
Cement Volume (sacks)				
Slurry Volume (ft^3)				
Slurry Weight (lb/gal)				
Type of Cement or Other Material				
Placement				

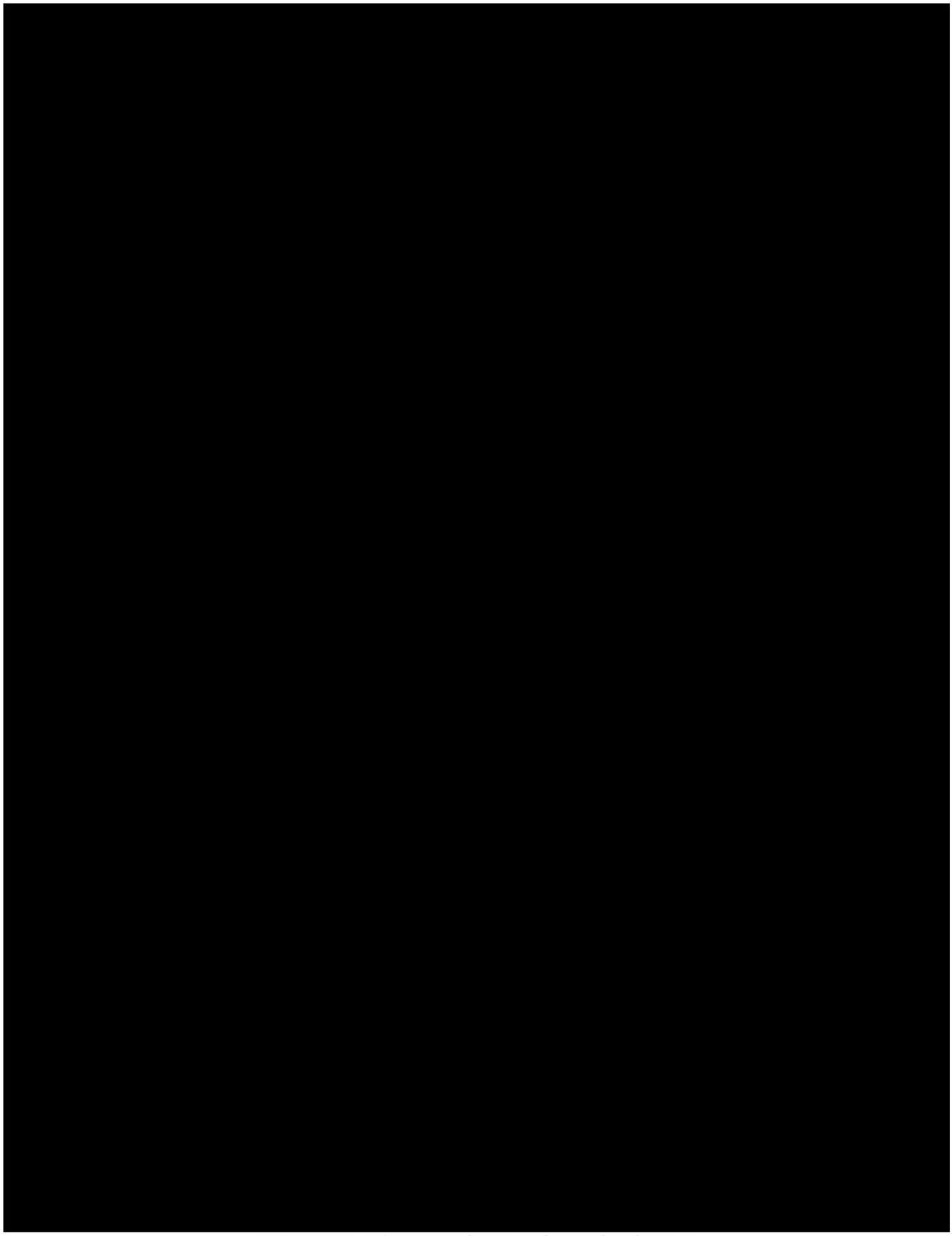


Figure 6-4 – Plugging Schematic for Orchard No. 2

6.1.5 Orchard No. 3 Plugging and Abandonment

Figure 6-5 shows the original wellbore schematic for Orchard No. 3, prior to beginning plugging op

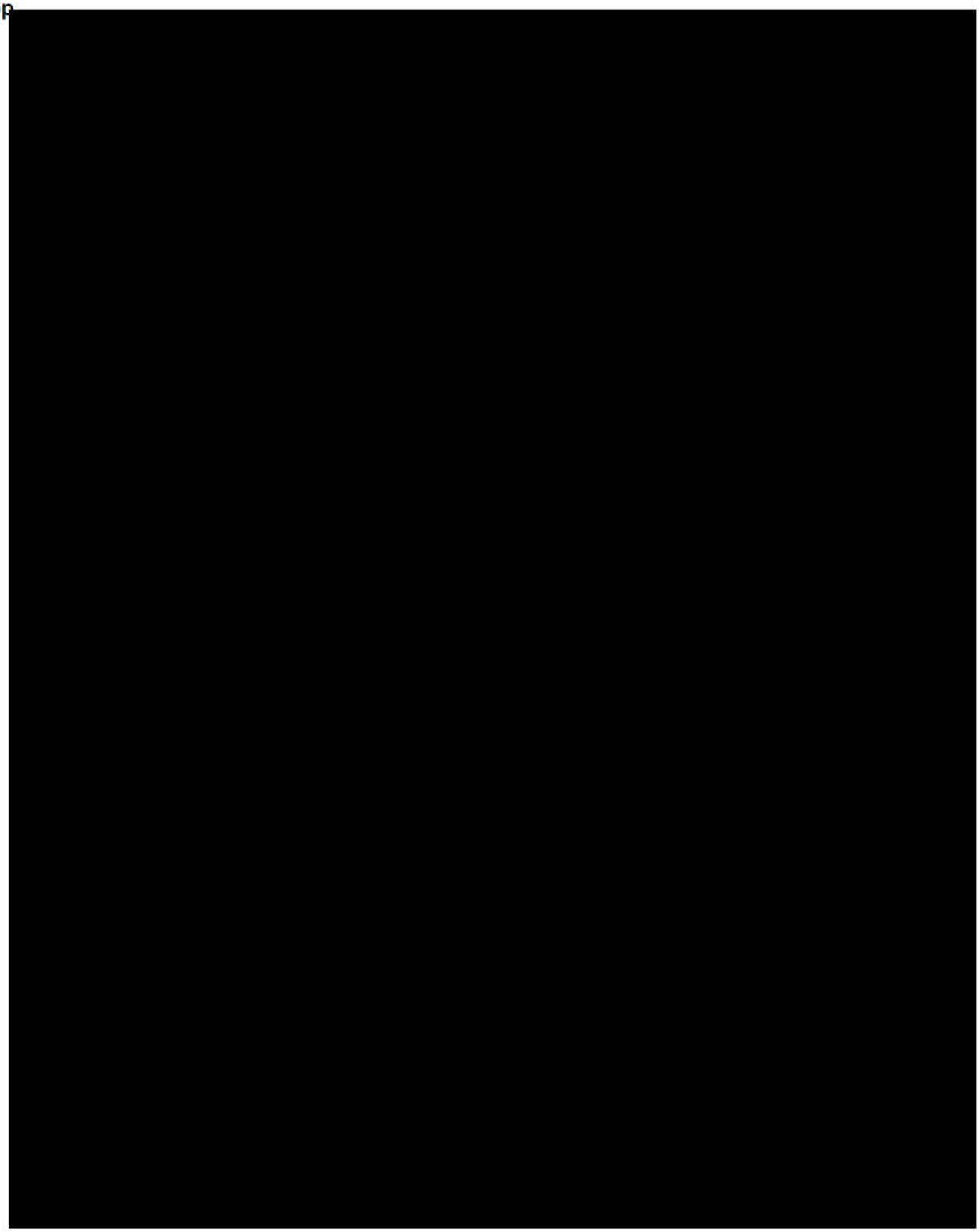


Figure 6-5 – Wellbore Schematic for Orchard No. 3 Before Plugging and Abandoning

6.1.5.1 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	[redacted]
Purpose	
Casing OD	
Casing ID	
Top of Plug	
Bottom of Plug	
Cement Volume (sacks)	
Slurry Volume (ft^3)	
Slurry Weight (lb/gal)	
Type of Cement or Other Material	
Placement	

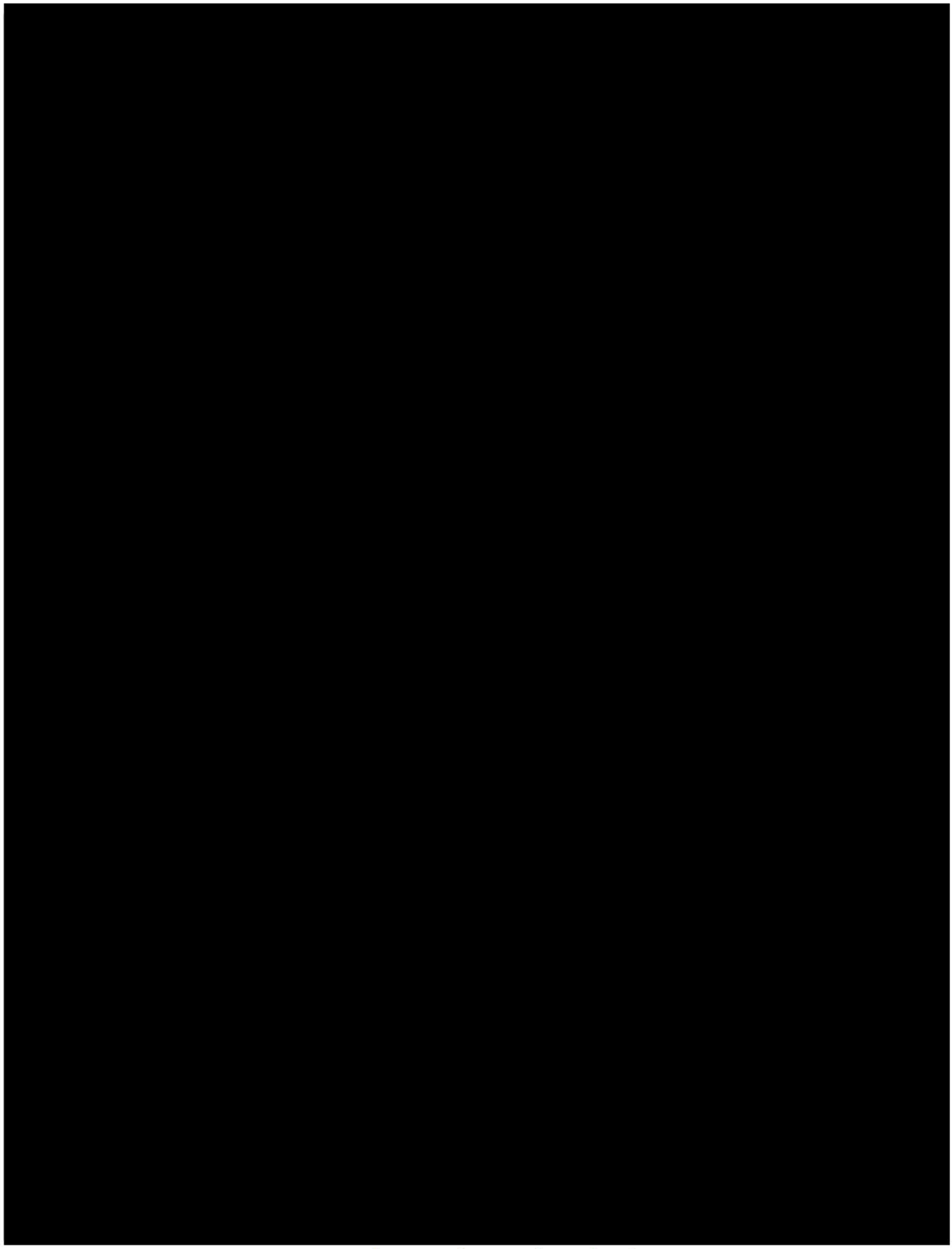


Figure 6-6 – Plugging Schematic for Orchard No. 3

6.1.6 Orchard No. 4 Plugging and Abandonment

Figure 6-7 shows the original wellbore schematic for Orchard No. 4, prior to beginning plugging operations.

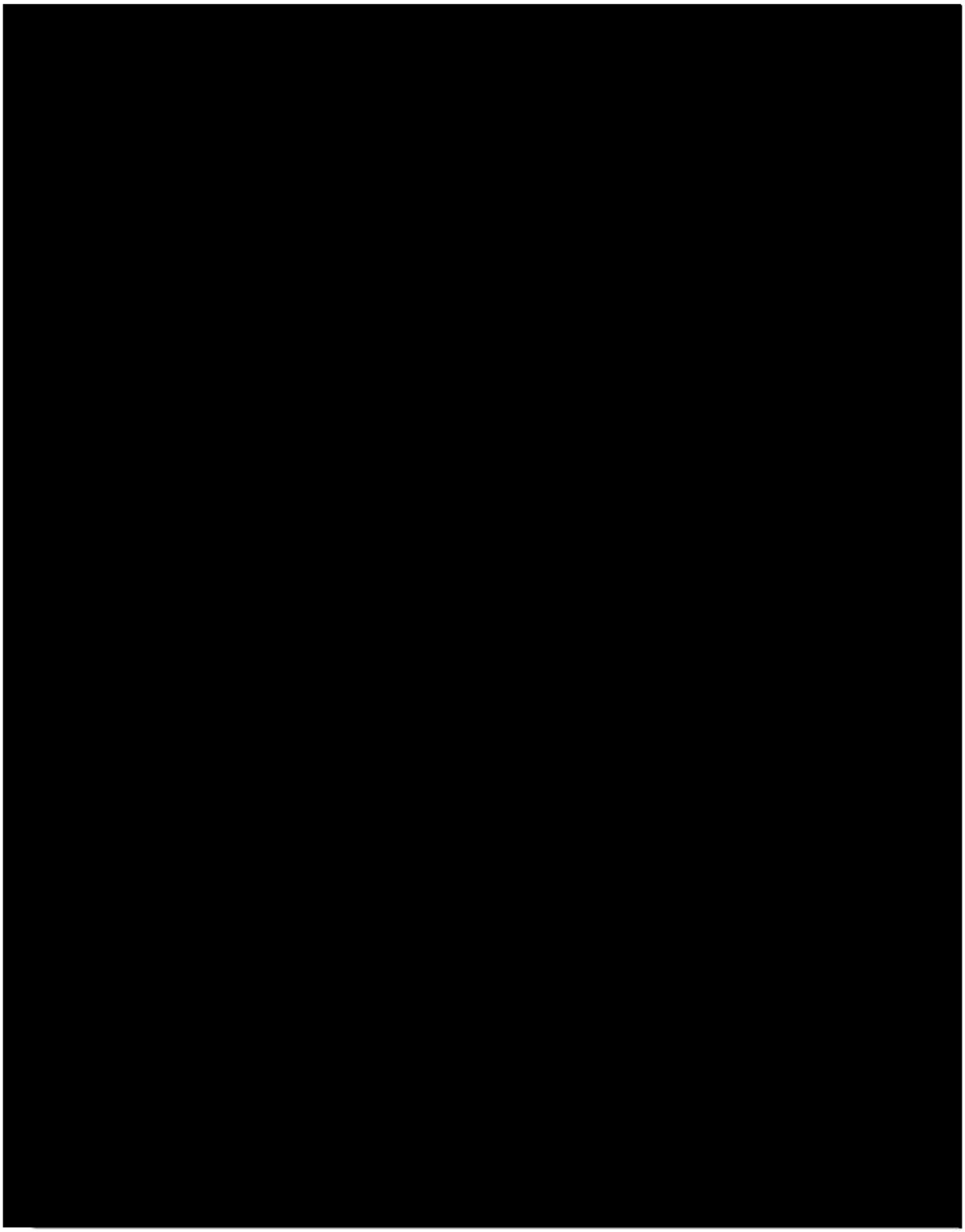


Figure 6-7 – Wellbore Schematic for Orchard No. 4 Before Plugging and Abandoning

6.1.6.1 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
Purpose				
Casing OD				
Casing ID				
Top of Plug				
Bottom of Plug				
Cement Volume (sacks)				
Slurry Volume (ft^3)				
Slurry Weight (lb/gal)				
Type of Cement or Other Material				
Placement				

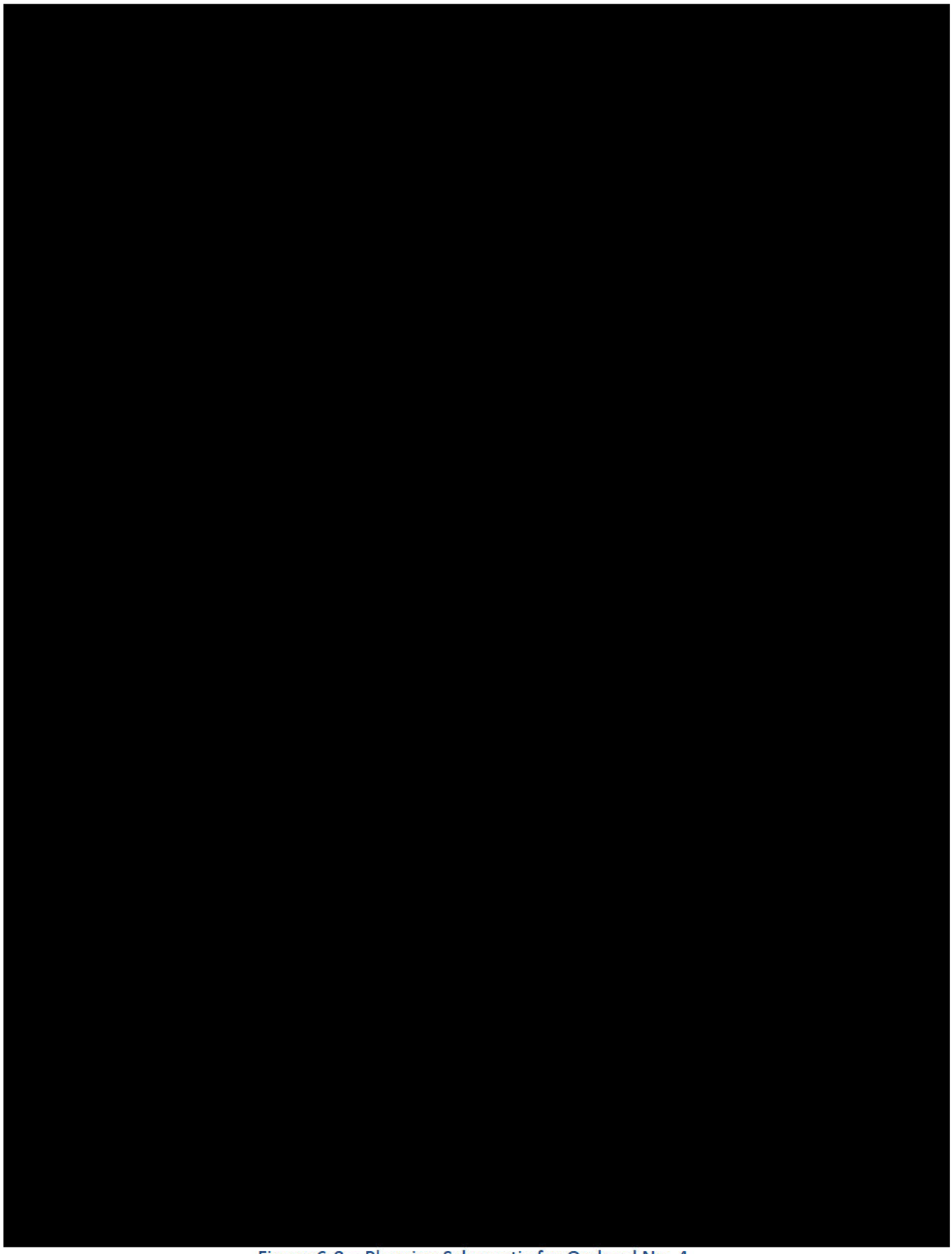


Figure 6-8 – Plugging Schematic for Orchard No. 4

6.1.7 Orchard No. 5 Plugging and Abandonment

Figure 6-9 shows the original wellbore schematic for Orchard No. 5, prior to beginning plugging operations.

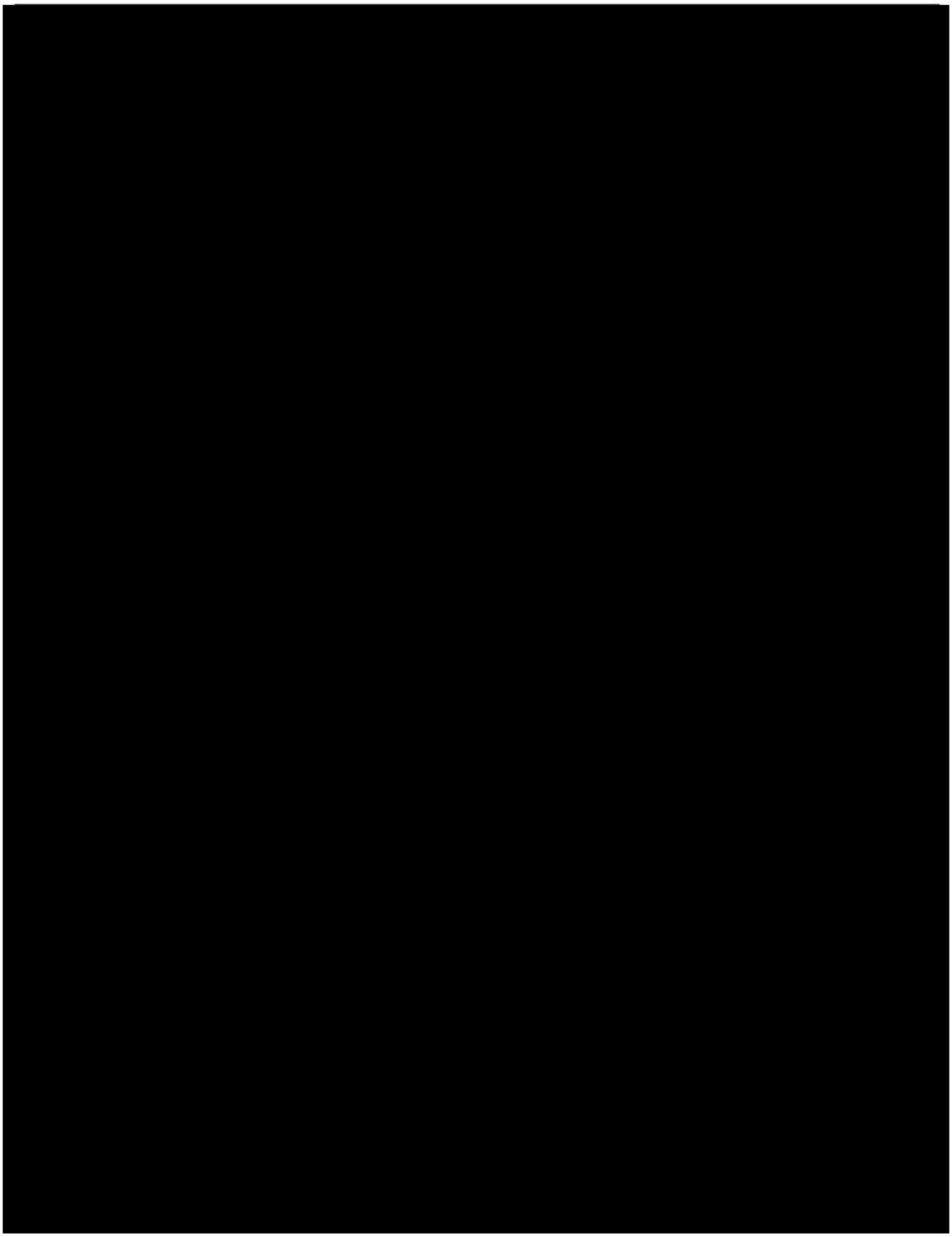


Figure 6-9 – Wellbore Schematic for Orchard No. 5 Before Plugging and Abandoning

6.1.7.1 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
Purpose	[redacted]			
Casing OD				
Casing ID				
Top of Plug				
Bottom of Plug				
Cement Volume (sacks)				
Slurry Volume (ft^3)				
Slurry Weight (lb/gal)				
Type of Cement or Other Material				
Placement				

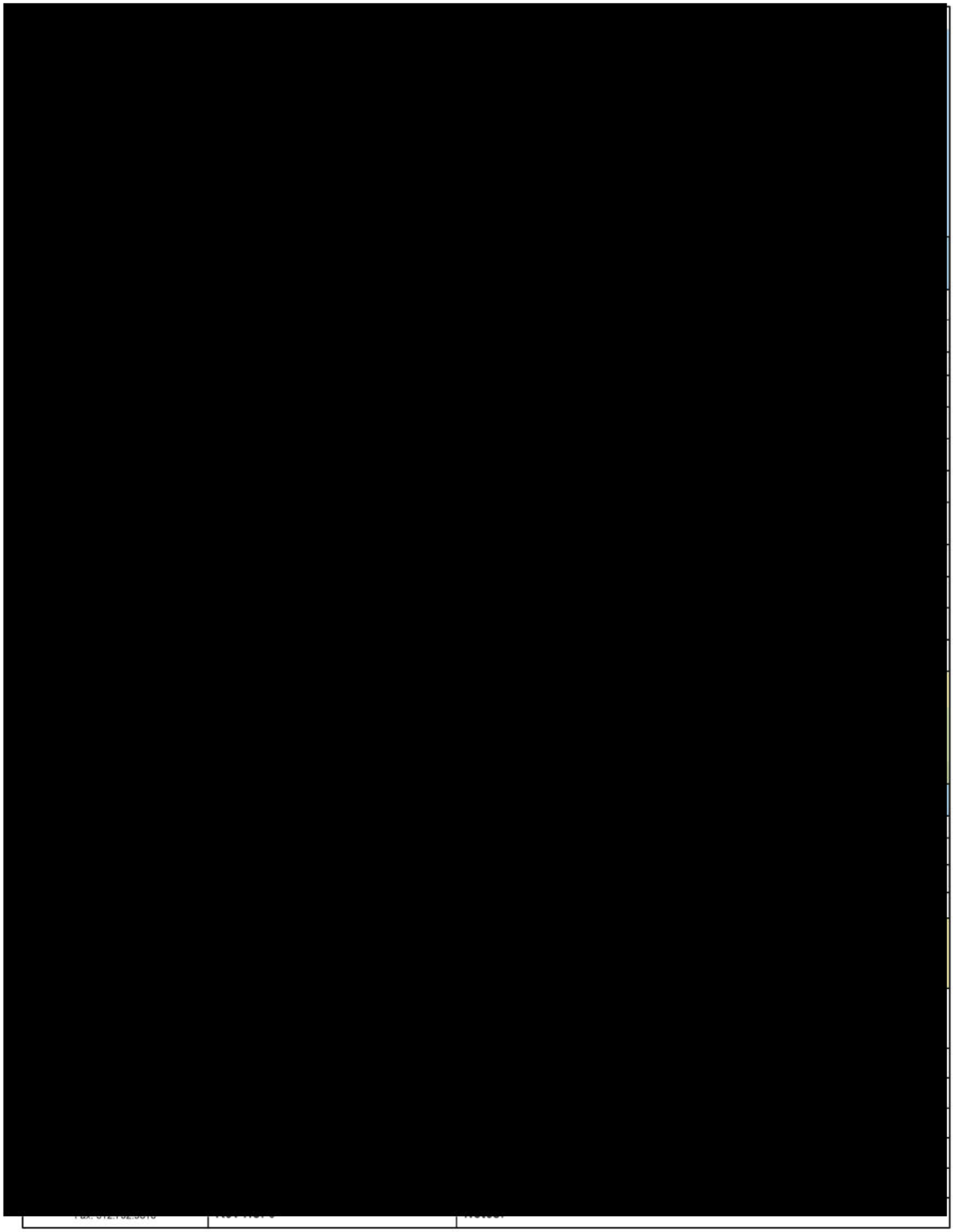


Figure 6-10 – Plugging Schematic for Orchard No. 5

6.1.8 Orchard No. 6 Plugging and Abandonment

Figure 6-11 shows the original wellbore schematic for Orchard No. 6, prior to beginning plugging operations.

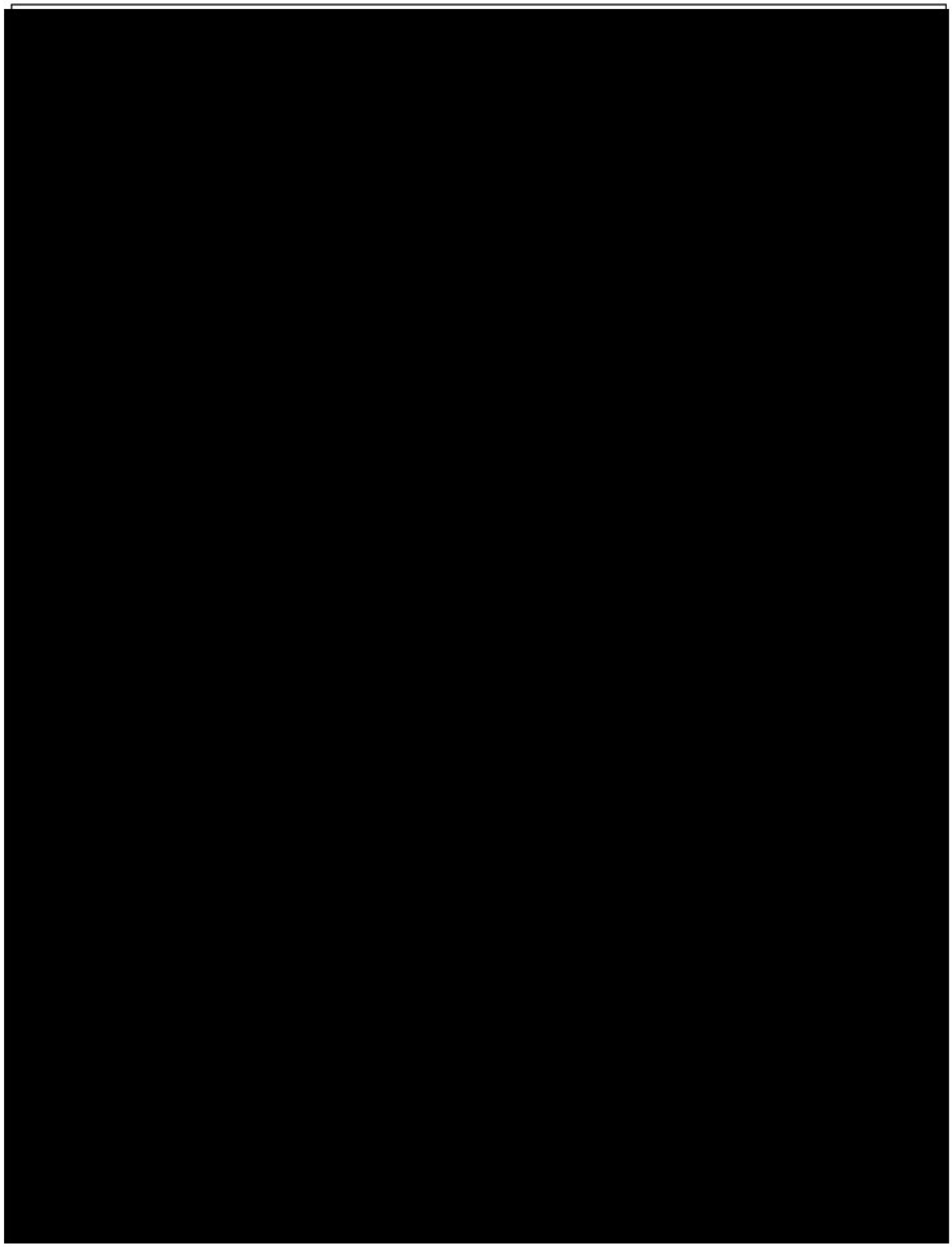


Figure 6-11 – Wellbore Schematic for Orchard No. 6 Before Plugging and Abandoning

6.1.8.1 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
Purpose	[redacted]			
Casing OD				
Casing ID				
Top of Plug				
Bottom of Plug				
Cement Volume (sacks)				
Slurry Volume (ft^3)				
Slurry Weight (lb/gal)				
Type of Cement or Other Material				
Placement				

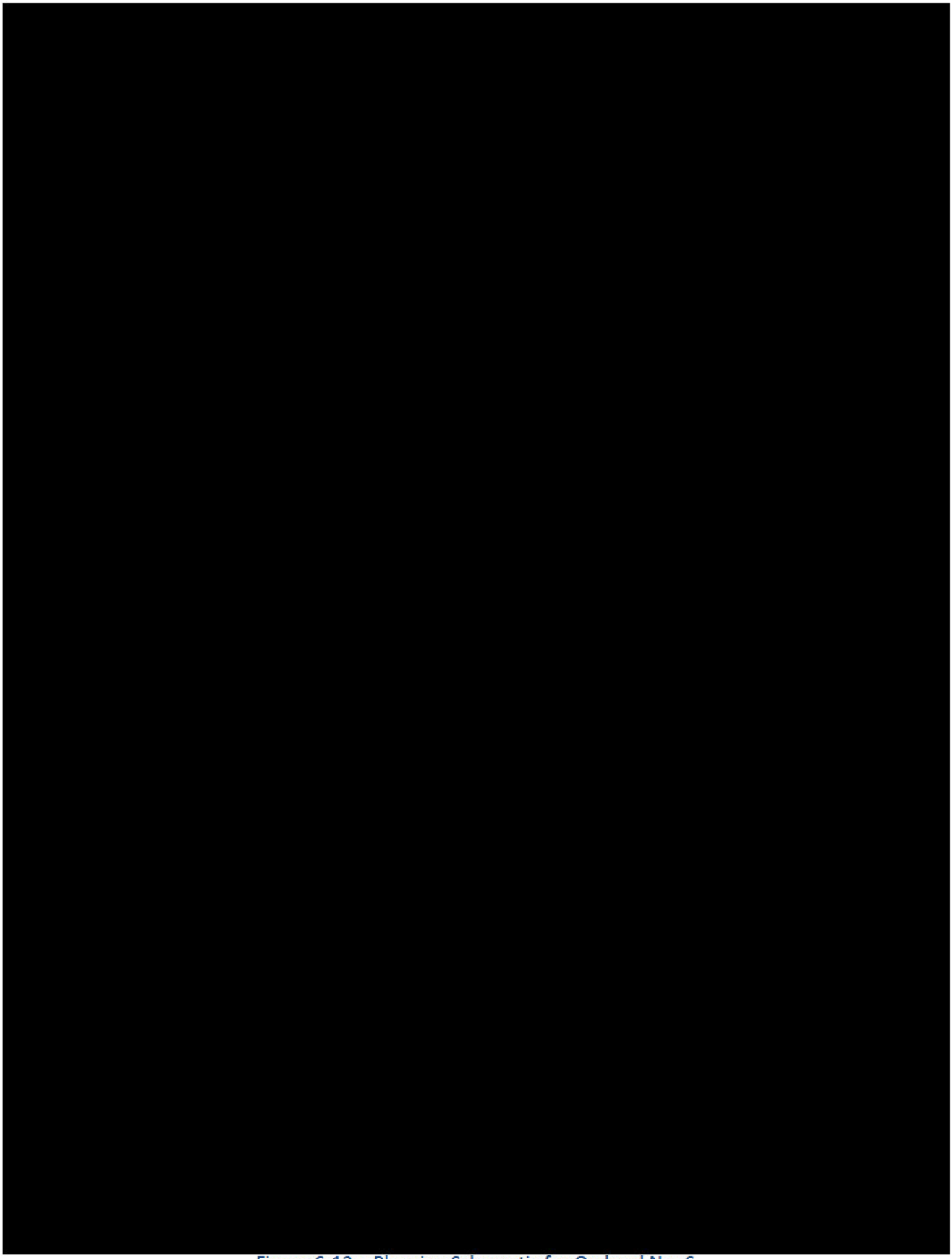


Figure 6-12 – Plugging Schematic for Orchard No. 6

6.1.9 Orchard No. 7 Plugging and Abandonment

Figure 6-13 shows the original wellbore schematic for Orchard No. 7, prior to beginning plugging ope

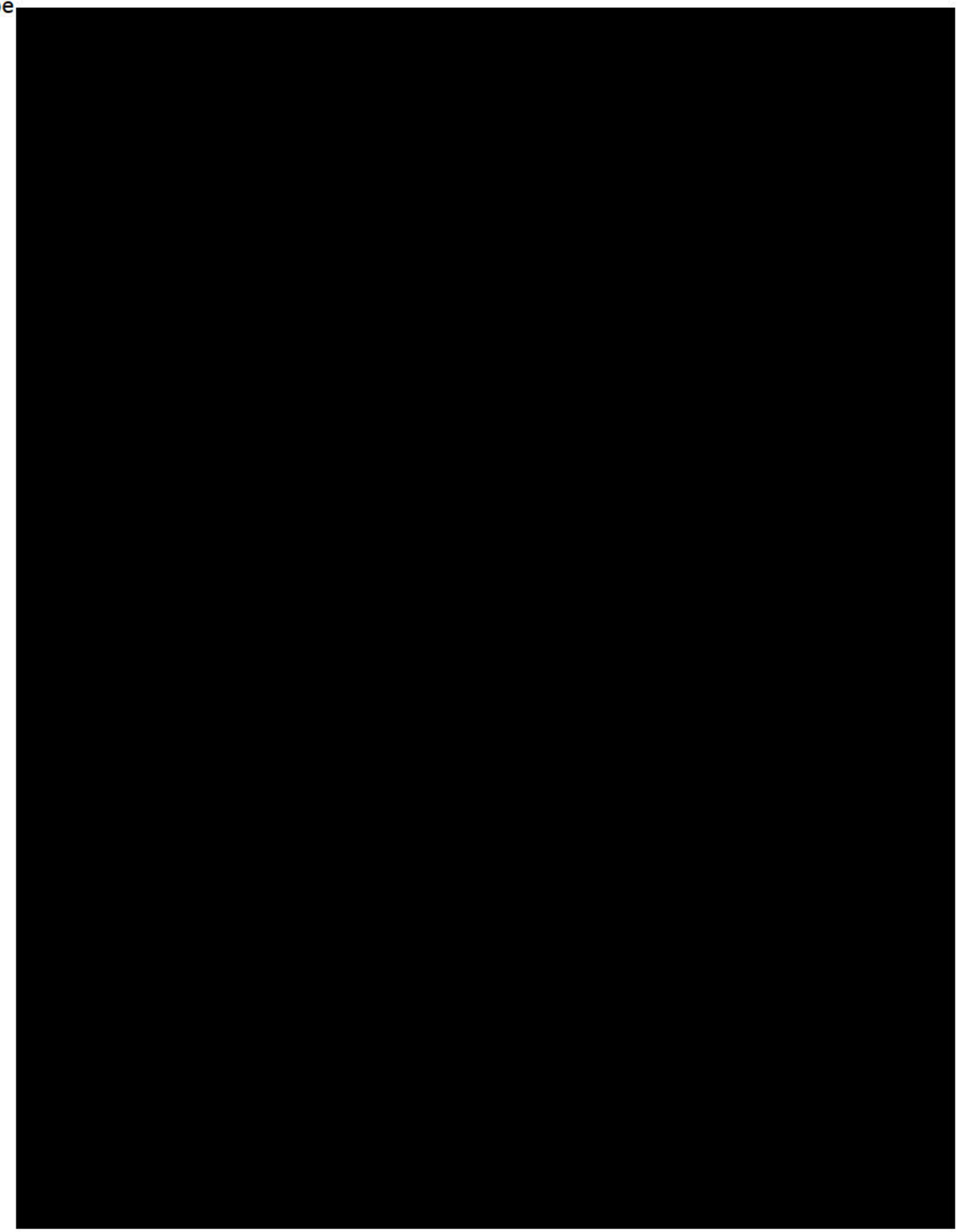


Figure 6-13 – Wellbore Schematic for Orchard No. 7 Before Plugging and Abandoning

6.1.9.1 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	[redacted]			
Purpose				
Casing OD				
Casing ID				
Top of Plug				
Bottom of Plug				
Cement Volume (sacks)				
Slurry Volume (ft^3)				
Slurry Weight (lb/gal)				
Type of Cement or Other Material				
Placement				

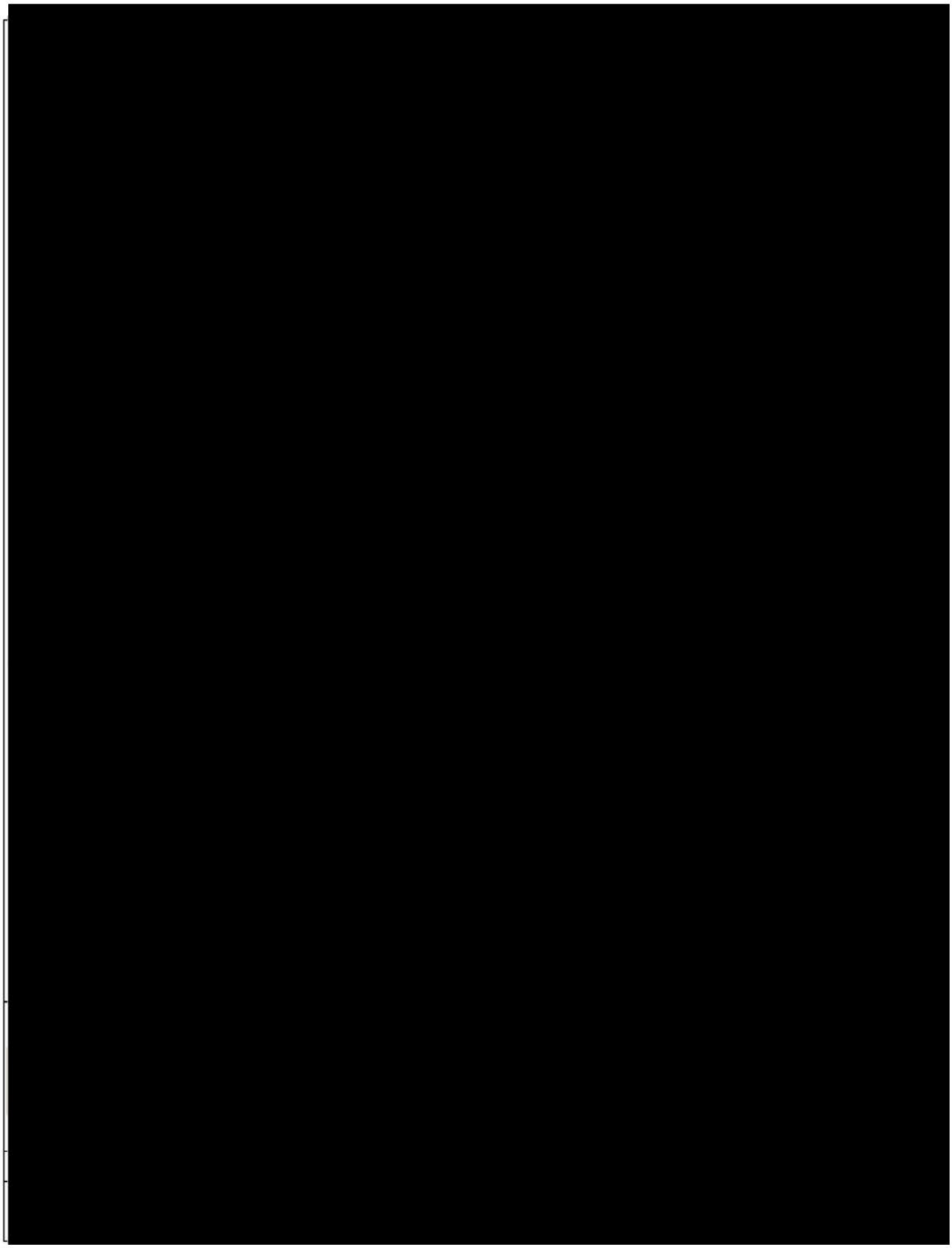


Figure 6-14 – Plugging Schematic for Orchard No. 7

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*.

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 a buffer fluid 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 [redacted] 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 Plugging Plan, Orchard MW No. 1

6.2.3.1 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.

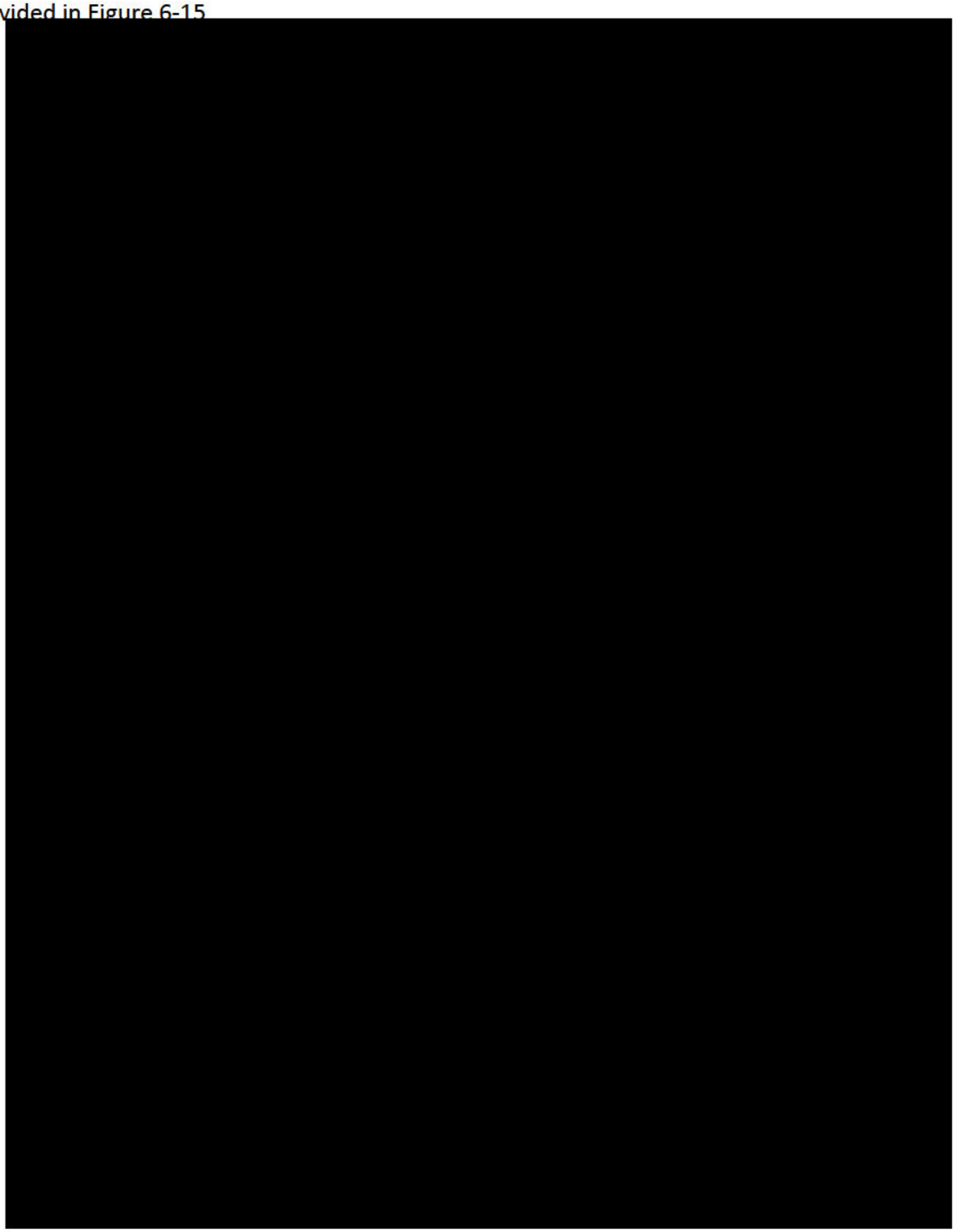


Figure 6-15 – Wellbore Schematic for Orchard MW No. 1 Before Plugging and Abandoning

6.2.3.2 Plug Details

Table 6-8 – Plugging Details for Orchard MW No. 1

Plug Number	[redacted]
Purpose	
Casing OD	
Casing ID	
Top of Plug	
Bottom of Plug	
Cement Volume (sacks)	
Slurry Volume (ft^3)	
Slurry Weight (lb/gal)	
Type of Cement or Other Material	
Placement	

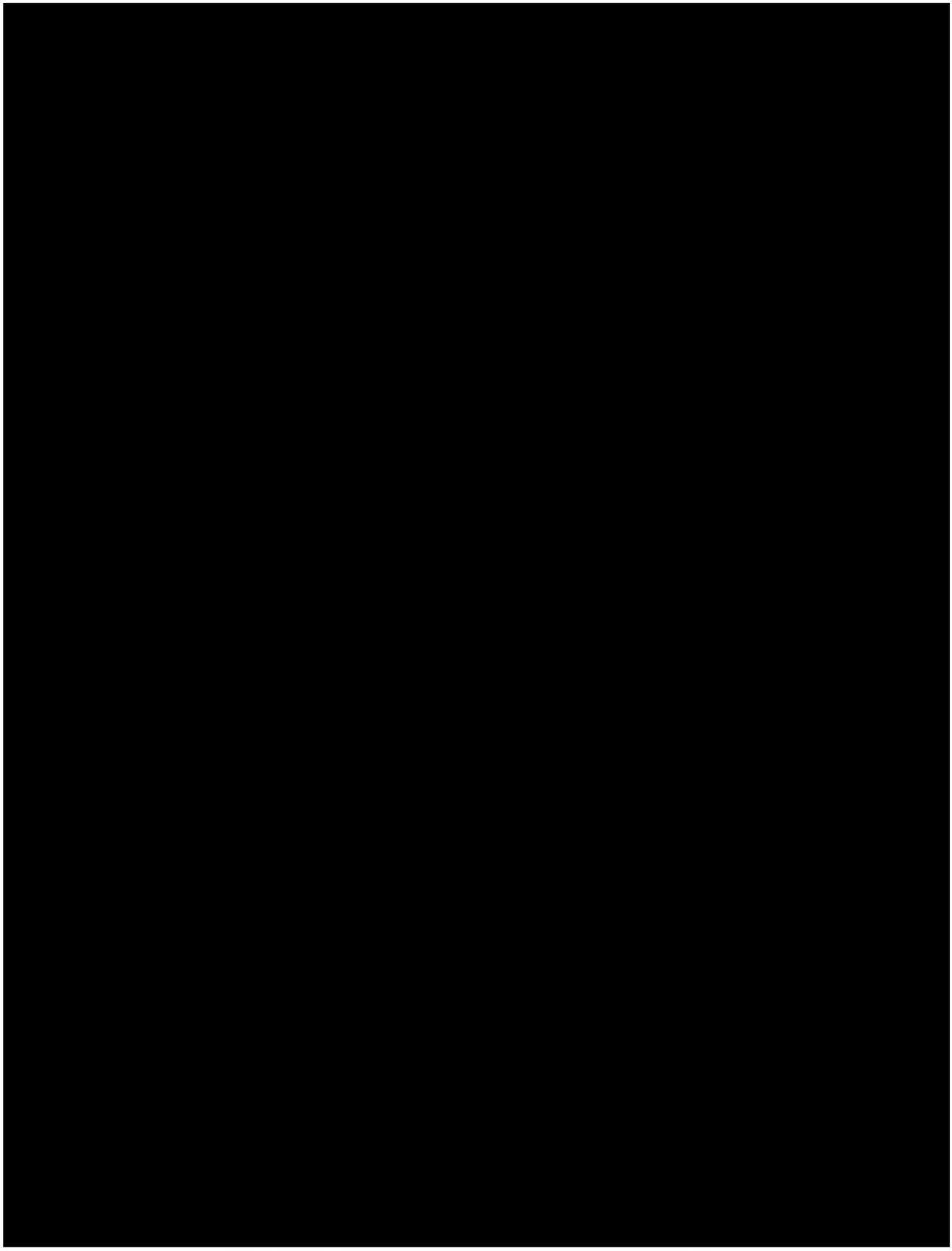


Figure 6-16 – Plugging Schematic for Orchard MW No. 1

6.2.4 Plugging Plan, Orchard MW No. 2

6.2.4.1 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 provid

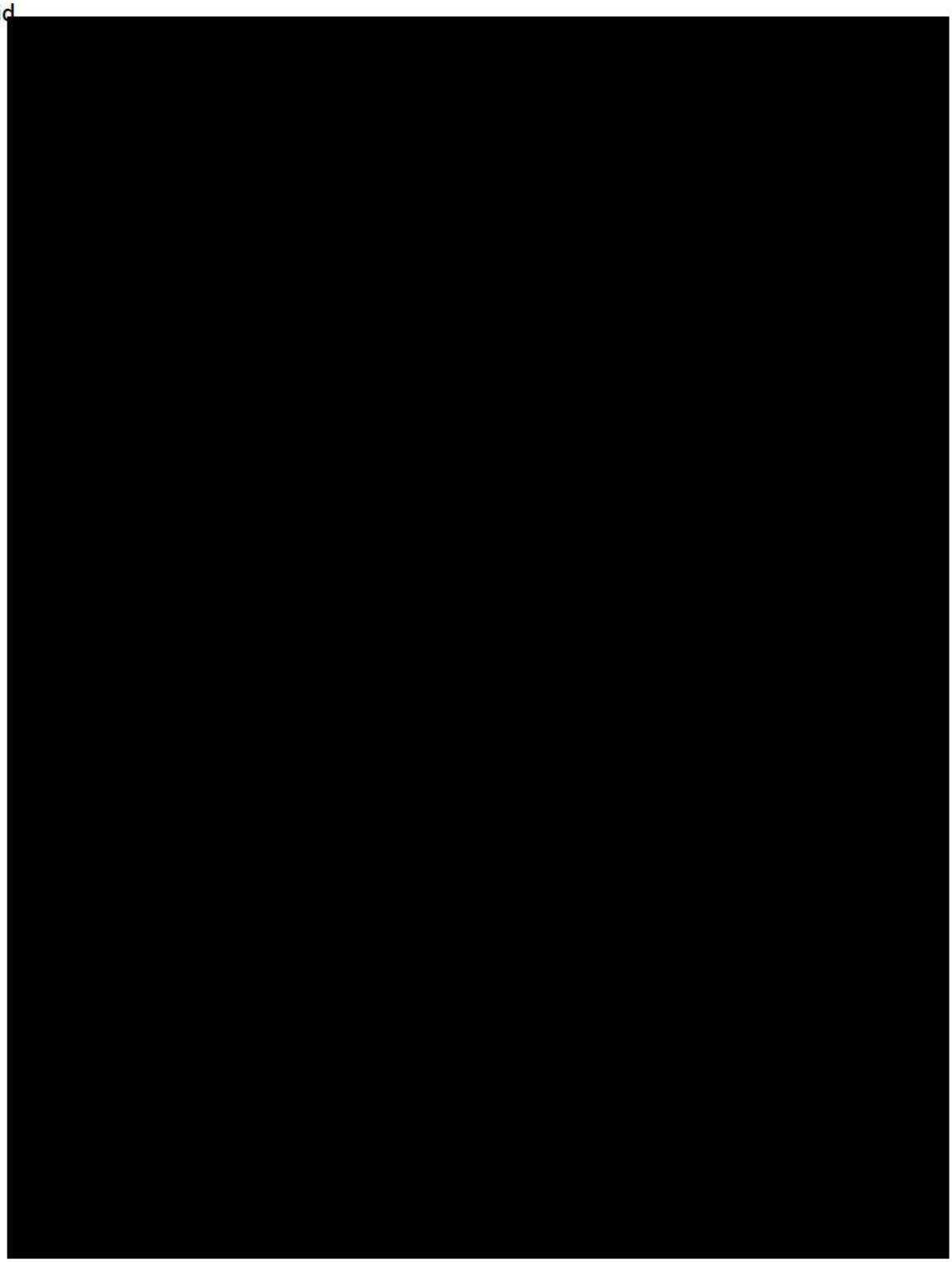


Figure 6-17 – Wellbore Schematic for Orchard MW No. 2 Before Plugging and Abandoning

6.2.4.2 Plug Details

Table 6-9 – Plugging Details for Orchard MW No. 2

Plug Number	[redacted]
Purpose	
Casing OD	
Casing ID	
Top of Plug	
Bottom of Plug	
Cement Volume (sacks)	
Slurry Volume (ft^3)	
Slurry Weight (lb/gal)	
Type of Cement or Other Material	
Placement	

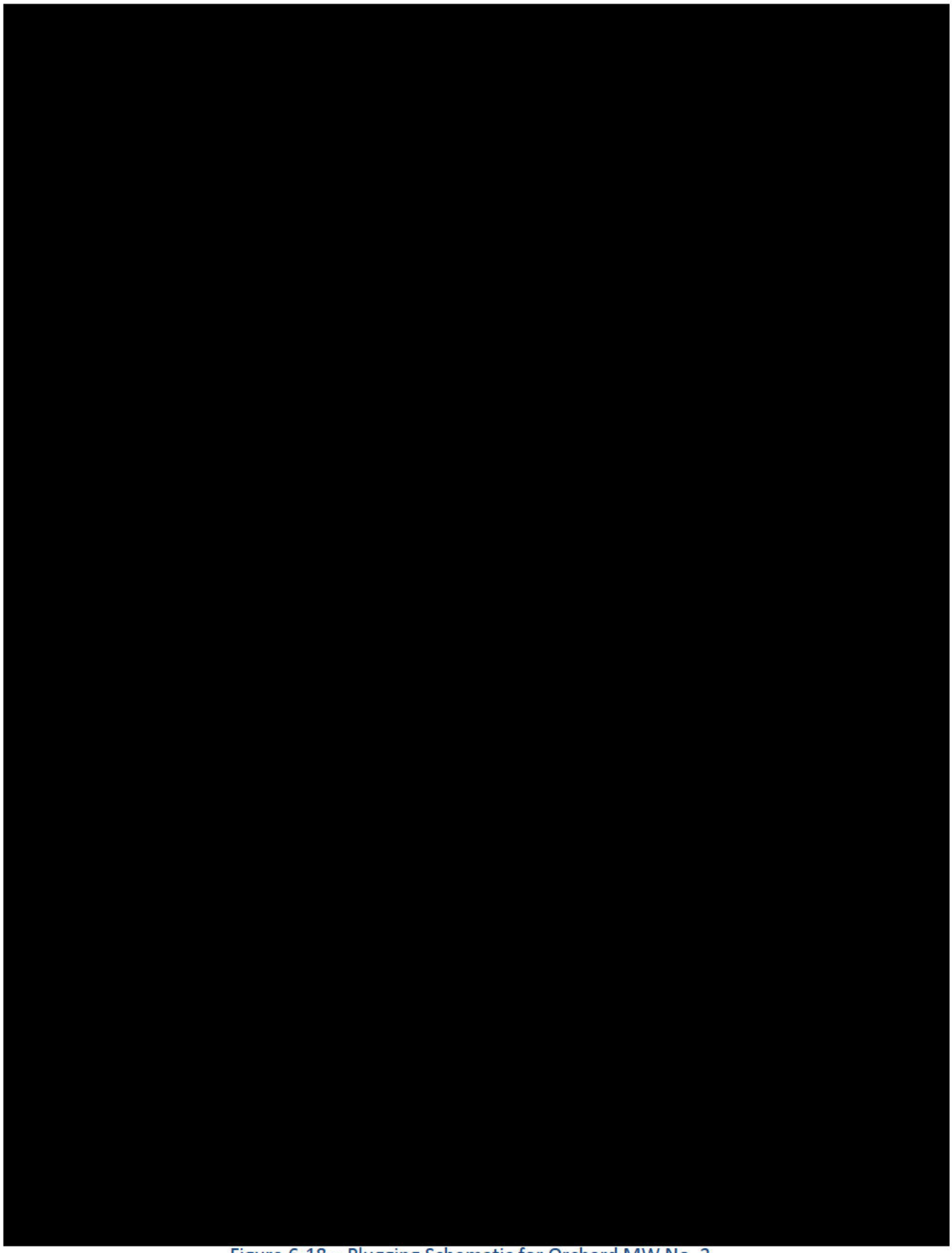


Figure 6-18 – Plugging Schematic for Orchard MW No. 2

6.2.5 Plugging Plan, Orchard MW No. 3

6.2.5.1 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.

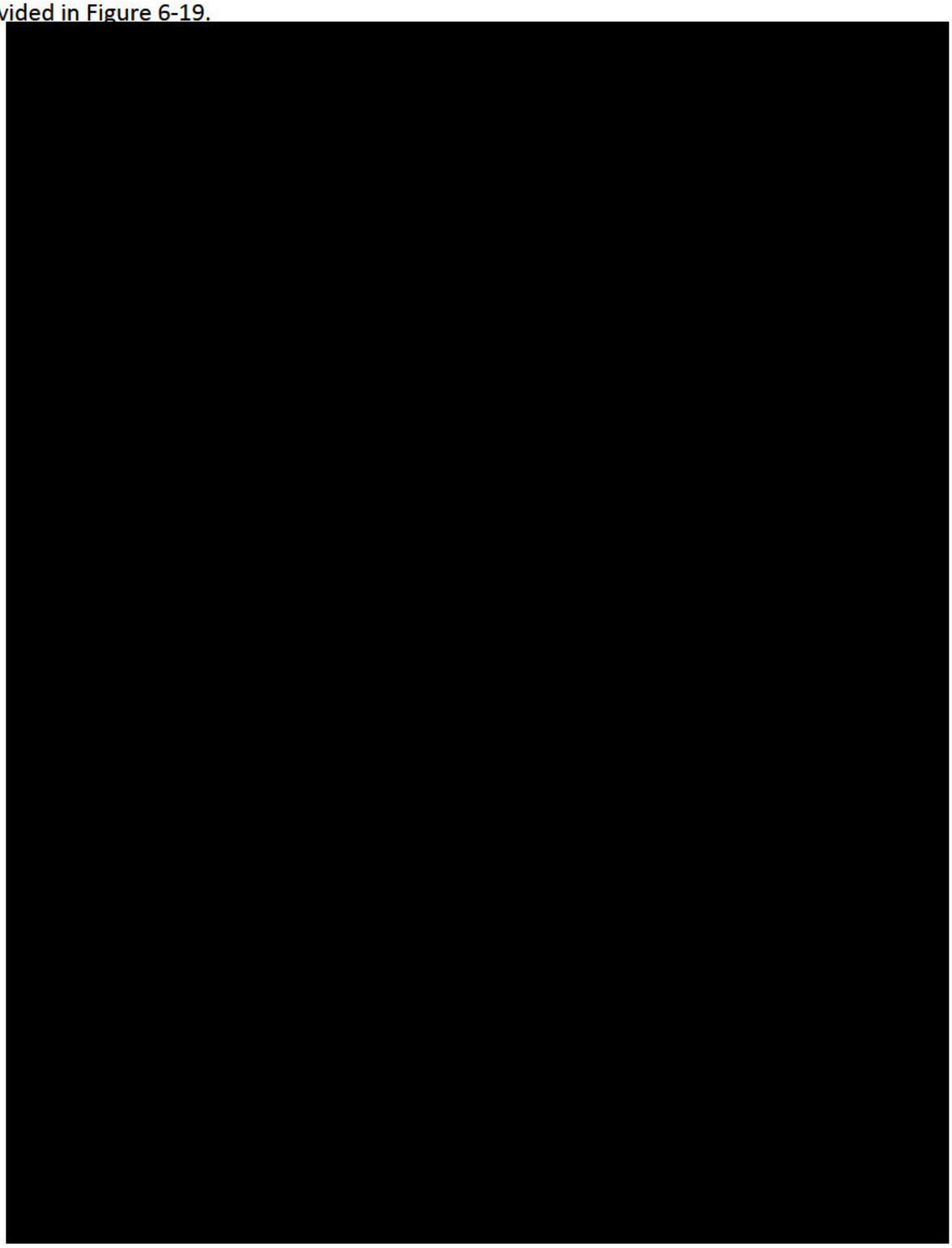


Figure 6-19 – Wellbore Schematic for Orchard MW No. 3 Before Plugging and Abandoning

6.2.5.2 Plug Details

Table 6-10 – Plugging Details for Orchard MW No. 3

Plug Number	[redacted]
Purpose	
Casing OD	
Casing ID	
Top of Plug	
Bottom of Plug	
Cement Volume (sacks)	
Slurry Volume (ft^3)	
Slurry Weight (lb/gal)	
Type of Cement or Other Material	
Placement	

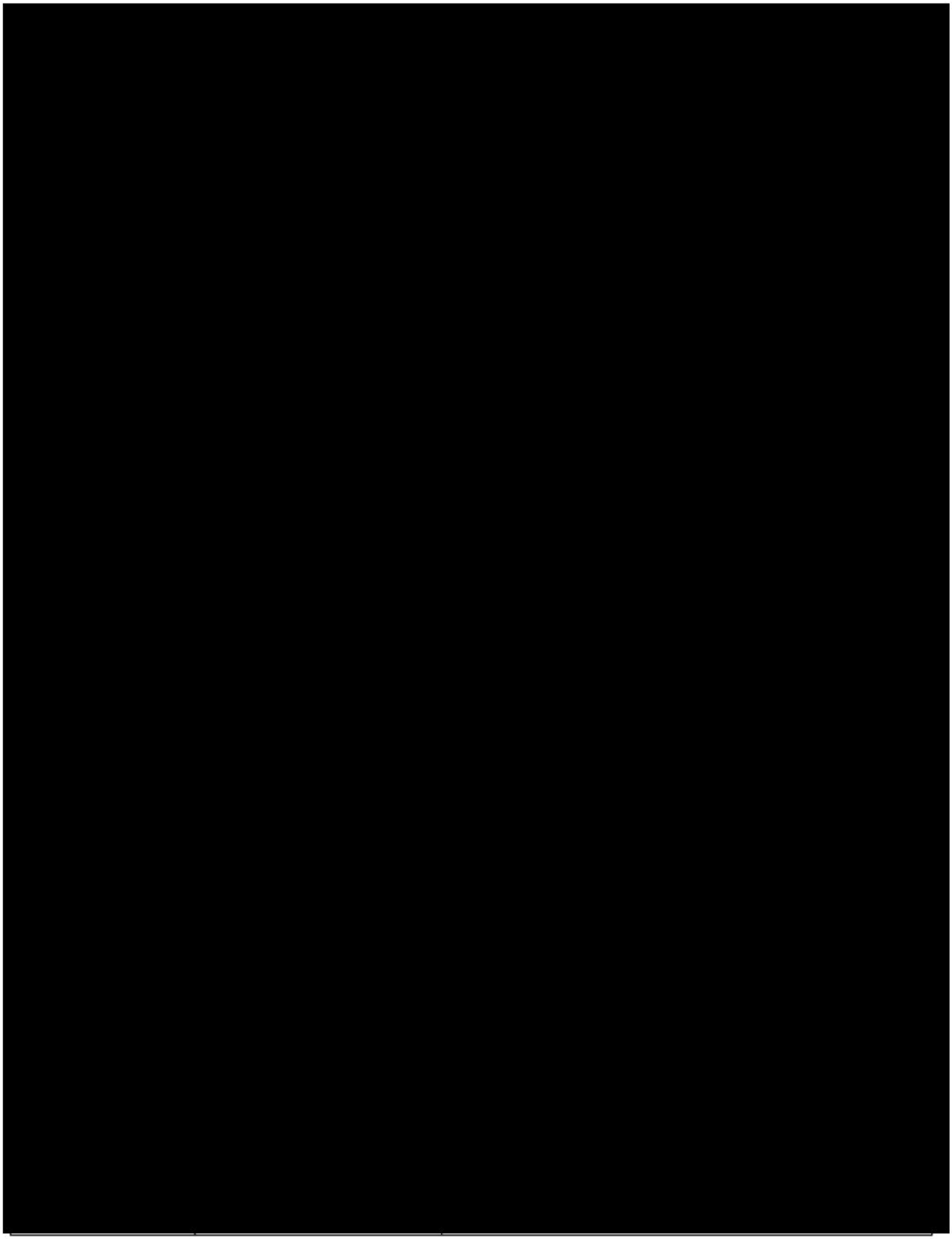


Figure 6-20 – Plugging Schematic for Orchard MW No. 3

Detailed schematics and procedures are located in *Appendix G*.

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- Appendix G-2 Injection Well – Plugged Wellbore Schematics
- Appendix G-3 Orchard MW No. 1 – Plugging Procedure
- Appendix G-4 Orchard MW No. 1 – Plugged Wellbore Schematic
- Appendix G-5 Orchard MW No. 2 – Plugging Procedure
- Appendix G-6 Orchard MW No. 2 – Plugged Wellbore Schematic
- Appendix G-7 Orchard MW No. 3 – Plugging Procedure
- Appendix G-8 Orchard MW No. 3 – Plugged Wellbore Schematic

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

Revised April 2024

LONQUIST SEQUESTRATION LLC

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

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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 7-1 then shows the same for all seven injection wells at 50 years post-injection.



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 7-1 – Maximum Pressure Differential by Year, Post-Injection (50 Years) for Orchard No. 1–No. 7

Year	Orchard No. 1	Orchard No. 2	Orchard No. 3	Orchard No. 4	Orchard No. 5	Orchard No. 6	Orchard No. 7
[redacted]							

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 position of the combined carbon dioxide plumes and associated pressure front at site closure. Figures 7-9 and 7-10 present the cross-sectional views of the stabilized plume at the end of injection and at the time of site closure for Orchard No. 1. Figures 7-11 through 7-22 then show the same for Orchard No. 2 through No. 7, respectively.

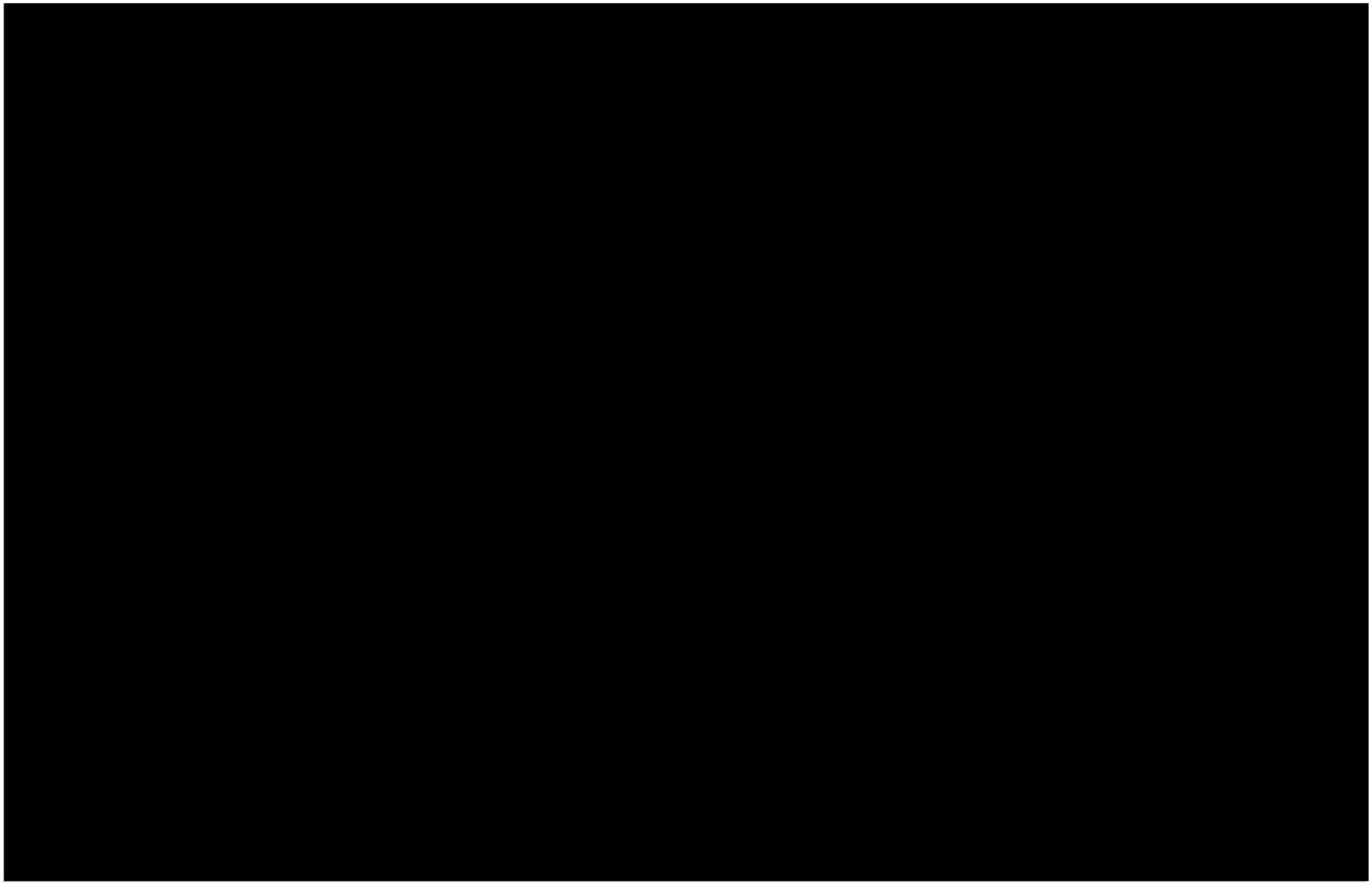


Figure 7-8 – Stabilized Combined CO_2 Plumes and Pressure Front Extent



Figure 7-9 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 1



Figure 7-10 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 1



Figure 7-11 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 2



Figure 7-12 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 2



Figure 7-13 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 3



Figure 7-14 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 3



Figure 7-15 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 4



Figure 7-16 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 4



Figure 7-17 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 5



Figure 7-18 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 5



Figure 7-19 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 6



Figure 7-20 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 6



Figure 7-21 – East-West Cross-Sectional Views of CO_2 Saturation, Years 0 and 50 for Orchard No. 7



Figure 7-22 – North-South Cross-Sectional View of CO_2 Saturation, Years 0 and 50 for Orchard No. 7

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.

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 at the frequency shown in Table 7-2.

Table 7-2 – 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, as required by 16 TAC **§5.206(k)(3)** [40 CFR **§146.93(c)**]. 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)**]. If any changes have been made to the original PISC and Site Closure Plan, a revised plan must also be submitted. Relevant notifications and applications, such as plugging requests, must be submitted to and approved by the Texas

Railroad Commission (TRRC) 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
- Documentation of well-plugging report
- 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

Revised April 2024

LONQUIST SEQUESTRATION LLC

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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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, [redacted] 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*
[redacted]			

*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*.

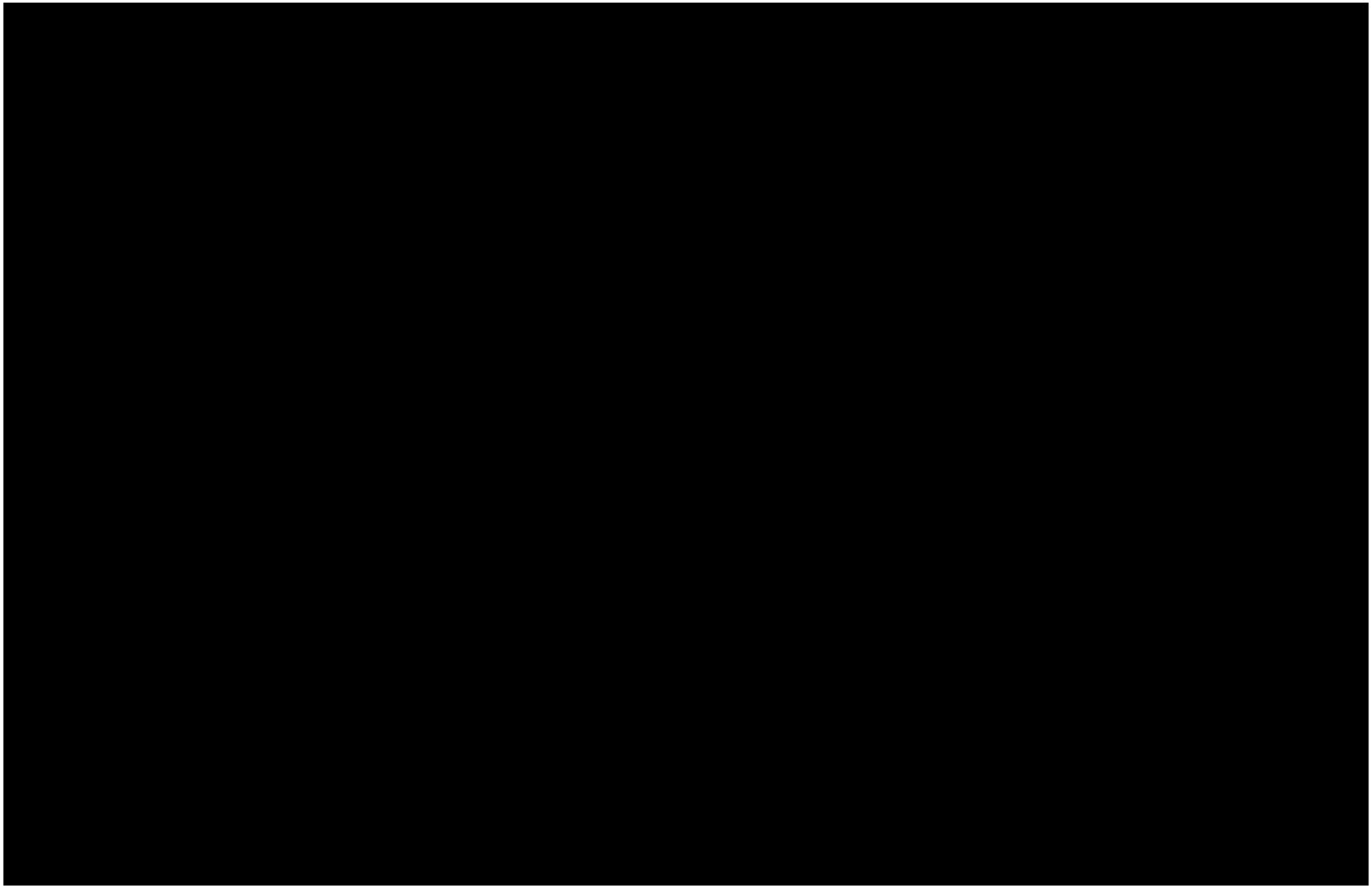


Figure 8-1 – Map of the Orchard Project AOR Showing Resources and Infrastructure

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	[redacted]	
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 [redacted] he upper-bound cost estimate to satisfy ERR is estimated to be $9.1 million *in 2023 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. [redacted]

Table 8-3 – Monte Carlo Analysis Summary

Summary Statistic	Cost	Number of Events Occurring
Average	[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.

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) 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 [redacted]

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 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, 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 is as follows:



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 Table 8-4.

Table 8-4 – Emergency Services – CALL 911

Contact*	Phone #
[redacted]	
Environmental Services Contractor	TBD
UIC Program Director	TBD
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 all-important numbers.

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

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.

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

Revised April 2024

LONQUIST SEQUESTRATION LLC

SECTION 9 – FINANCIAL ASSURANCE

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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 injection well plugging, post-injection site care (PISC) and site closure, and emergency and remedial response. 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 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 – Bond
- Injection Well Plugging – Bond
- Post-Injection Site Care and Site Closure – Insurance
- Emergency and Remedial Response – Insurance

Alliant Insurance Services 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.

Table 9-1 – Summary of Costs Associated with Financial Security

Financial Assurance Item	Unit Cost	# of Wells	Total
Corrective Action (Project Total)			
Plugging Costs (per well x 8)			
Injection Well Plugging (Project Total)			
Workover Rig			
Rental Tools			
Mud/Brine			
Fracture Tanks			
Wireline			
Final Mechanical Integrity Test and Casing Logs			
Cement			
Bridge Plugs/Packers			
Casing Crew			
Miscellaneous			
Post-Injection Site Care and Site Closure			
Vertical Seismic Profile Surveys			
Groundwater and Soil Monitoring			
Operations and Maintenance of Monitoring Wells			
Monitoring Well Plugging			
Subsurface Facilities Closure			
Emergency and Remedial Response			
Deep Oil-and-Gas Well Leak			
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

[redacted] in the pressure front AOR will require corrective action. The cost to reenter and properly plug the [redacted] identified is estimated to be [redacted] per well. 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.

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 PISC and Site Closure Plan—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. [redacted]

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 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 [redacted] the upper-bound cost estimate to satisfy ERR is estimated to be [redacted] *in 2023 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. [redacted]

Table 9-2 – Monte Carlo Analysis Summary

Summary Statistic	Cost	# of Events Occurring
Average	[redacted]	[redacted]
Median		
Standard Deviation		
5th Percentile		
95th Percentile		
99th Percentile		
Minimum		
Maximum		

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.

Orchard Storage Company LLC

Underground Injection Control – Class VI Permit Application for

Orchard No. 1 to No. 7

Section 10 – Environmental Justice Assessment

Gaines County, Texas

Prepared for *Orchard Storage Company LLC*
Houston, Texas

By
Lonquist Sequestration, LLC
Austin, TX

Revised April 2024

LONQUIST SEQUESTRATION LLC

SECTION 10 – ENVIRONMENTAL JUSTICE ANALYSIS

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10.1 Introduction

The purpose of this environmental justice (EJ) evaluation is to determine if the proposed Orchard Class VI injection wells (Orchard Project)—to sequester CO_2 in the Permian Basin—could have a significant and adverse disproportionate environmental impact on defined communities or populations.

Environmental justice is defined as the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies (Environmental Protection Agency (EPA) 1998). Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, was published in the Federal Register (59 FR 7629) on February 11, 1994. Executive Order 12898 requires federal agencies to identify and address the potential for disproportionately high and adverse human health or environmental effects, resulting from the implementation of their programs, policies, and activities on minority and low-income populations.

The assessment of potential EJ impacts is guided by the Council on Environmental Quality's (CEQ) *Environmental Justice Guidance Under the National Environmental Policy Act* [NEPA] (CEQ 1997) and the *U.S. Environmental Protection Agency's Promising Practices for EJ Methodologies in NEPA Reviews* (EPA, 2016). Determination of EJ impacts requires three steps: (1) determining the geographic distribution of minority and low-income populations in the affected area; (2) assessing whether the action under consideration would produce impacts that are high and adverse; and (3), if impacts *are* high and adverse, determining whether these impacts would disproportionately affect minority and low-income populations. This analysis is based on the EPA definition, which considers an EJ area or community to be a location with a "meaningfully greater" percentage of minority population than the general population, or locations in which minority populations comprise more than 50% of the affected area's population.

Consistent with *Promising Practices*, EJ areas have been identified according to the following criteria, based on block group-level data from the U.S. Census Bureau's American Community Survey (ACS)[1]:

- For minority populations, use the **50%** and **meaningfully greater analysis methods**. This means, if the minority-population percentage of the block groups in the affected area exceeds 50% *OR* the minority population in the block group affected is 20% higher than the minority-population percentage in the county or state, then an EJ community is present.

[1]ACS is an ongoing survey program that provides updated demographic, social, housing, and economic data. ACS surveys 3.5 million households annually, covering more than 40 topics.

- For low-income populations, use the **low-income threshold criteria** method. This means, if the low-income population in the identified block group is 20% higher than the low-income population percentage of the county or state, then an EJ community is present.

For this evaluation, populations were reviewed relative to both the federal poverty level and the EPA's own "low-income" measure of twice the federal poverty level—using their "EJScreen" tool (described in *Section 10.3.1*).

The Orchard Project Class VI injection wells will not generate air emissions or have other significant environmental impacts during operation or construction. Therefore, Orchard Storage Company LLC (Orchard Storage) has defined the "Impact Study Area" for EJ considerations to consist of a 1-mile radius around each of the project well locations.

10.2 Existing Conditions

10.2.1 Demographics in the Vicinity of the Site

The Orchard Project injection wells and their respective 1-mile buffers are wholly located within Census Tract [redacted] in Gaines County, Texas. The site is [redacted] Figures 10-1 to 10-7 show the injection well sites, one mile buffer and the host block group.



Figure 10-1 – Location of Orchard No. 1



Figure 10-2 – Location of Orchard No. 2



Figure 10-3 – Location of Orchard No. 3



Figure 10-4 – Location of Orchard No. 4



Figure 10-5 – Location of Orchard No. 5



Figure 10-6 – Location of Orchard No. 6



Figure 10-7 – Location of Orchard No. 7

Orchard Storage reviewed the most current ACS data from the U.S. Census Bureau, from 2016 to 2020 (2020 vintage), to determine the presence of minority and/or low-income communities (i.e., areas with EJ concerns). Table 10-1 summarizes the demographics of the Impact Study Area.

Table 10-1 – Minority and Low-Income Populations in Orchard Project Impact Study Area

Area	Population Below Poverty Level	Low-Income Population (2x Below Poverty Level)	Minority Population (Non-White and/or Hispanic)	Potential EJ Area
State of Texas	14.2%	33.2%	58.6%	No
Gaines County	14.8%	42.1%	44.8%	No
[redacted]				

*Block Group

Source: U.S. Census Bureau, 2022

As shown above, 58.6% of the statewide population identify as minority individuals, with 33.2% of the households considered low income. Gaines County has a lower proportion of residents identifying as minority individuals, with 42.1% of households being low income (i.e., twice below the poverty level). The host community, [redacted] in Gaines County, with a population of [redacted] is estimated to have [redacted] minority residents. Within that block group, [redacted] of

households are considered low income, and [redacted] are considered below the poverty level. Therefore, [redacted]—in which the project site is located—is not considered a likely EJ area.

10.2.2 Limited English Proficiency in Vicinity of the Site

Table 10-2 presents the limited English-speaking households in the census block groups crossed by the Orchard Project. "Limited English-speaking" denotes households in which no member over the age of 13 speaks either (1) English only or (2) a non-English language—and also speaks English "very well." In other words, all members over the age of 13 have at least some difficulty with English. In total, the only block group in the Impact Study Area has [redacted] are estimated to be Spanish speaking, limited English-speaking households.

Table 10-2 – Limited English Proficiency Households in Orchard Project Impact Study Area

Area	Spanish Language, Limited English-Speaking Households	Other Indo-European Languages, Limited English-Speaking Households	Asian and Pacific Island Languages, Limited English-Speaking Households	Other Languages, Limited English-Speaking Households
State of Texas	6.10%	0.28%	0.73%	0.17%
Gaines County	7.43%	25.11%	19.16%	0.63%
[redacted]				

Source: ACS Table ID C16002, U.S. Census Bureau, 2022

10.2.3 Demographics of Region

Economic impacts of the Orchard Project are anticipated to extend throughout the areas within roughly a one-hour drive of the project. The majority of the construction workforce is expected to be drawn from this area, located within a 50-mile radius of the project. This 12-county region includes the population center of Lubbock, Texas, as well as three CDPs within Gaines County. As shown in Table 10-3, the demographics of the county are typical for the region in terms of both minority and low-income populations. Gaines does have a somewhat higher percentage of households with limited English proficiency.

Table 10-3 – Demographics of Region Surrounding the Orchard Project

Area	Population Below Poverty Level	Low-Income Population (2x Below Poverty Level)	Minority Population (Non-White and/or Hispanic)	Limited English Proficiency Households
State of Texas	14.2%	33.2%	58.6%	7.3%
Gaines County*	14.8%	42.1%	44.8%	11.5%
[redacted]				
Andrews County	10.4%	25.5%	40.5%	9.7%
Dawson County	22.8%	48.5%	35.7%	5.9%
Martin County	10.7%	42.1%	53.0%	3.8%
Terry County	15.7%	46.8%	40.2%	9.1%
Yoakum County	9.0%	24.2%	32.2%	17.8%
State of New Mexico	18.6%	39.5%	63.3%	5.1%
Lea County	16.6%	36.0%	36.1%	6.1%

*Host county

Source: U.S. Census Bureau, 2022

10.3 EJScreen Analysis

10.3.1 EJ Index

The EPA developed an EJ mapping and screening tool called EJScreen, based on nationally consistent data and an approach that combines environmental and demographic indicators in maps and reports. To evaluate a facility, EJScreen approximates site boundaries and, with the appropriate buffer applied, generates what the EPA terms a "Standard Report," which includes socioeconomic and environmental data on the facility site and its buffer.

EJScreen's EJ Index is a series of environmental and demographic data sets that are used to populate 12 EJScreen indicators (indices). An EJ Index combines demographic information with a single environmental indicator—such as proximity to traffic—to help identify communities that may have a high combination of environmental burdens and vulnerable populations. The EJ Index is higher in block groups with large numbers of mainly minority and/or low-income residents with a higher environmental indicator value. For each environmental factor, the EJ Index equals the environmental-indicator percentile multiplied by the demographic index for the host block group. The EPA has identified the 80th percentile filter as an initial starting point for screening an EJ Index.

The EJScreen evaluation of the Orchard Project, using a 1-mile buffer, resulted in the EJ Index presented in Table 10-4.

Table 10-4 – EJ Index Measures in the Impact Study Area, per EJScreen

EJ Index—Selected Variables	Percentile in State	Percentile in U.S.
Particulate Matter 2.5 (microgram per cubic meter ($\mu g/m^3$))		
Ozone (parts per billion (ppb))		
2017 Diesel Particulate Matter ($\mu g/m^3$)		
2017 Air Toxics Cancer Risk (lifetime risk per million)		
2017 Air Toxics Respiratory Hazards Index		
Traffic Proximity (daily traffic count/distance to road)		
Lead Paint (% pre-1960 housing)		
Superfund Proximity (site count/km distance)		
Risk Management Plan (RMP) Facility Proximity (facility count/km distance)		
Hazardous Waste Proximity (facility count/km distance)		
Underground Storage Tanks (count/km^2)		

Source: U.S. EPA, 2022 (Note: None of the EJ Index measures are at or above the 80th percentile at either the state or national level.)

As Table 10-4 shows for the Impact Study Area, none of the EJ Index measures, which identify communities with a high combination of environmental burdens and vulnerable populations, are at or above the EPA's screening threshold of the 80th percentile for the state and/or the nation. Based on EJScreen results for the project area, a combination of high environmental burdens and vulnerable populations appears to be absent from the Impact Study Area—and thus would not be considered an EJ area of concern to the EPA.

10.3.2 Sensitive Receptors

Sensitive receptors are areas and facilities where the occupants are more susceptible to the adverse effects of exposure to toxic chemicals, pesticides, and other pollutants. Sensitive receptors include, but are not limited to, hospitals, schools, daycare facilities, parks and playgrounds, elderly housing, and convalescent facilities. The review of the area found no sensitive receptors within 1 mile of the Orchard Project.

10.4 Project Impacts and Mitigation

Neither the Orchard Project's construction nor its operation and maintenance will result in significant and adverse disproportionate effects on EJ populations, from impacts to traffic noise, visual resources, or transportation. Resource-specific best-management practices for these resources will be employed, including screening measures for visual resources and the local school districts for transportation-related effects. The Orchard Project will *not* result in any significant and adverse disproportionate environmental impacts on any EJ communities, because

there are no EJ communities within the study area. Therefore, no measures for impact avoidance, mitigation, or offset are required.

To mitigate *potential* impacts, on-site personnel will ensure (1) no leakage from below-ground storage, (2) persistent water-quality monitoring of nearby water sources, (3) regular soil-gas sampling, and (4) ambient-air-quality monitoring for CO_2 leakage at the well site. The Orchard Project's plans anticipate one month of construction with daily well visits and periodic maintenance to ensure quality.

10.5 Summary of Environmental Justice Analysis

A review of the demographics of the block group in which the Impact Study Area is located found that the area does *not* meet the established criteria of an EJ area, based on both minority and low-income populations. Further, EJScreen did not identify any EJ Index measures at or above the 80th percentile for the Orchard Project vicinity. No significant environmental or human health impacts are anticipated in relation to the project. Therefore, no adverse disproportionate effects on populations in EJ areas will arise from the construction and operation and maintenance of the project.

10.6 References

U.S. Census Bureau (2022). 2016-2020 American Community Survey 5-Year Estimates. Retrieved November 2022, from URL https://data.census.gov

U.S. Environmental Protection Agency (2022). EJScreen Tool. Retrieved November 2022, from URL https://www.epa.gov/ejscreen

U.S. Environmental Protection Agency (1998). Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses. April 1998.