TESTING AND MONITORING PLAN
40 CFR 146.90

Sugarberry CCS Hub

Facility Information

Facility Name: Sugarberry CCS Hub

Facility Contact: Sugarberry CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

RRC Organization Report Number: 102245

Well Locations: Projection WGS84

Well	County/State	Latitude	Longitude
SB-01	Hopkins, TX	33.202707	-95.338539
SB-02	Hopkins, TX	33.189225	-95.375952
SB-03	Hopkins, TX	33.196028	-95.405035
SB-04	Hopkins, TX	33.219565	-95.434859
SB-05	Hopkins, TX	33.207361	-95.385666

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List of Acronyms/Abbreviations

°C	Degrees Celsius
°F	Degrees Fahrenheit
ANSI	American National Standards Institute
AoR	Area of Review
APHA	American Public Health Association
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CCS	Carbon Capture and Storage
CFR	Code of Federal Regulations
CIL	Casing Inspection Log
CO_2	Carbon Dioxide
DAS	Distributed Acoustic Sensing
DID	Discharge Ionization Detector
DFOS	Distributed Fiber Optic Sensing
DSS	Distributed Strain Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
FID	Flame Ionization Detector
Ft-BGS	Feet Below Ground Surface
Ft/hr	Feet per Hour
Ft-MSL	Feet Relative to Mean Sea Level
GC	Gas Chromatography
GC-P	Gas Chromatography-Pyrolysis
GS	Geologic Sequestration
HDPE	High-Density Polyethylene
H_2S	Hydrogen Sulfide
ICP	Inductively Coupled Plasma
ISBT	International Society of Beverage Technologists
lb/MMSCF	Pounds per million standard cubic feet of gas per day
mA	Milliamperes
MIT	Mechanical Integrity Testing
Mol%	Percentage of Total Moles
MS	Mass Spectrometry
NACE	National Association of Corrosion Engineers
OES	Optical Emission Spectrometry
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture
ppmv	Parts per million – volume
ppmw	Parts per million – weight
psi	Pounds per square inch
QASP	Quality Assurance and Surveillance Plan
QA	Quality Assurance
QC	Quality Control

List of Acronyms/Abbreviations (cont.)

RCRA	Resource Conservation and Recovery Act
RRC	Railroad Commission of Texas
S&A	Sampling and Analysis
SCD	Sulfur Chemiluminescence Detector
TAC	Texas Administrative Code
TBD	To be Determined
TCD	Thermal Conductivity Detector
TD	Total Depth
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
VSP	Vertical Seismic Profile

A. Introduction

This Testing and Monitoring Plan describes how Sugarberry CCS, LLC will monitor the Sugarberry CCS Hub pursuant to 40 CFR 146.90 and 16 TAC 5.203(j). The goals of this plan are to implement data collection to demonstrate the injection wells are operating as planned, the CO_2 plume and pressure front are moving as predicted, and there is no endangerment to Underground Sources of Drinking Water (USDWs). The scope of this Plan includes testing the engineered systems in addition to monitoring the natural environment.

These monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the injection zone (i.e., storage reservoir) to support Area of Review (AoR) re-evaluations and a non-endangerment demonstration. Results of the testing and monitoring activities described below may trigger action according to the **Emergency and Remedial Response Plan (ERRP; Section 10).**

B. Overall Strategy and Approach for Testing and Monitoring

B.1. Objectives

Sugarberry CCS, LLC's integrated testing and monitoring strategy will cover three (3) main aspects of the geologic sequestration (GS) project during the injection phase:

1. Well Integrity
2. Operational Parameters
3. Geologic System Changes imposed by Injection Practices

This plan is focused on the injection phase of the GS project. It is aligned with the pre-operational testing plan and the post-injection site care and closure plan since there is overlap in testing and monitoring activities that occur in these separate phases. For details on the pre-operational and post-injection testing and monitoring activities, please refer to those plans **(Section 5 and Section 9, respectively)**. Proposed baseline and operational monitoring are summarized in **Table 7-1** and discussed in the respective subsections of this plan.

Demonstrating the mechanical integrity of the wells in the system is a key aspect of protecting USDWs from endangerment due to injection activities and is a requirement of the Underground Injection Control (UIC) Class VI program. Operational testing and monitoring activities include CO_2 stream analysis; continuous monitoring of CO_2 injection rate, volume, and pressure; corrosion monitoring of the casing; and pressure fall-off testing of the injection formation. Monitoring and testing of the geologic system includes ground water quality and geochemical monitoring at multiple intervals above the confining zone (above-zone and USDW); direct/indirect pressure front monitoring; and direct/indirect CO_2 plume monitoring.

B.2. Plan Strategy and Approach

The purpose of this Testing and Monitoring Plan is to support demonstration of USDW non-endangerment throughout the injection and post-injection phases. This plan aims to ensure sufficient geospatial and monitoring data will be collected and used to validate rigorous numerical monitoring and achieve this purpose. The Sugarberry CCS Hub project location has a low risk profile based on its rural location, well-understood geology (due to historical hydrocarbon production in the area), lack of active neighboring injection wells (that could lead to project interference), and lack of historical seismic activity and faults impacting the AoR. As such, locations within the monitoring network are based primarily on the predicted migration of the pressure front and CO_2 plume throughout the injection and post-injection phases, as well as the location of artificial penetrations identified as potential conduits for fluid migration in the **Area of Review and Corrective Action Plan (Section 2).** The monitoring network covers the full extent of the calculated AoR, which is approximately 32 square miles.

As outlined in **Table 7-1**, many operational parameters will be continuously monitored prior to and during injection, which allow Sugarberry CCS, LLC to be responsive to deviations from expected operating conditions. Pre-operational (baseline) data will also be collected and characterized for geochemical, geophysical, and other physical monitoring locations (**Table 7-1**). Data collected during the injection period will be compared to these baseline data to comply with the Class VI rule, demonstrate USDW non-endangerment, verify predictions from computational modeling, and provide support for future project decision making. Details for how operational data will be compared to baseline data and how deviations will be identified are specified in the respective monitoring method subsections of this plan.

Sugarberry CCS, LLC will review this plan at a minimum of every five (5) years. After review, Sugarberry CCS, LLC will revise the plan based on the monitoring data and submit a revised Testing and Monitoring Plan or demonstrate to the UIC Program Director, using monitoring evidence, that no revisions to the plan are needed. Sugarberry CCS, LLC recognizes the nexus of data collection and modeling as the primary pathway to implement the UIC permit, define the post-injection site care (PISC) protocol, and close the CO_2 storage site. As such, Sugarberry CCS, LLC is establishing a monitoring program capable of tracking the injected CO_2 and pressure front and developing time-lapse datasets for numerical modeling.

It is important to note that this Testing and Monitoring Plan will be revised and refined as new site characterization data, computational modeling data, and pre-operational and operational data become available. Selection of methods and strategies may need to be altered to remain representative of the site-specific risk profile or identified potential concerns.

The near-surface and subsurface monitoring protocols to be used in the Testing and Monitoring Plan at the Sugarberry CCS Hub will provide valuable information to evaluate the performance of the CO_2 injection and storage operations and include:

- In-zone, above-zone, and USDW fluid sample analyses;
- Above-zone and in-zone direct pressure and temperature measurements;
- Surface to total depth (TD) pressure and temperature sensing at injection wells and in-zone observation wells;
- Through-casing CO_2 saturation profiling; and
- Indirect repeat geophysical imaging.

Sugarberry CCS, LLC plans to drill nine (9) observation wells prior to commencing injection, which are placed to capture pressure front and CO_2 plume migration over time (**Figure 7-1**). This includes four (4) wells completed as in-zone observation wells (IOB wells IOB-01, IOB-02, IOB-03, and IOB-04) within the sand injection intervals of the Woodbine and Paluxy Formations; three (3) wells completed as above-zone observation wells (AOB wells AOB-01, AOB-04, and AOB-05) to monitor the sands within the upper Eagle Ford Formation (Sub-Clarksville Sand Member); and two (2) USDW observation wells (UOB wells UOB-01 and UOB-04) to monitor shallow sands containing USDWs within the Taylor Group. See **Figure 2-2 of the AoR and Corrective Action Plan (Section 2)** for a representative stratigraphic column at the Sugarberry CCS Hub. As detailed in **Section F.1** of this plan, injection wells (SB-01 through SB-05) will additionally have the capability to monitor in-zone (pressure and geochemistry) and pressures within the above-zone at locations that do not have AOB wells proposed (i.e., SB-02 and SB-03).

Table 7-1 (below) summarizes the proposed testing and monitoring program for the Sugarberry CCS Hub. **Tables 7-2 through 7-9** summarize the details of the various proposed testing and monitoring methods. **Appendix 7-A** shows a simplified layout of a typical well within the storage complex and depicts the location of testing and monitoring equipment.

The proposed injection period for the Sugarberry CCS Hub is 30 years. Wells SB-04 and SB-05 are planned to stop injecting after 20 years, at which time they will be considered in-zone observation (IOB) wells and follow the proposed monitoring and reporting methods for IOB wells until the end of the injection period at 30 years. SB-01, SB-02, and SB-03 are planned for injection for the full 30 years. This monitoring and reporting scheme is outlined in **Appendix 7-B.**

Table 7-1. Summary of the Proposed Sugarberry CCS Hub Testing and Monitoring Program

<table>
<tr><th>Monitoring Category</th><th colspan="2">Monitoring Parameter/Method</th><th>Baseline Frequency (One year minimum)</th><th>Injection Phase Frequency (30 years)</th></tr>
<tr><td>Monitoring Plan Update</td><td colspan="2">Review at a minimum of every 5 years (with AoR reevaluation) and Update as Required</td><td>N/A</td><td>Update as Required</td></tr>
<tr><td rowspan="2">CO_2 Stream Analysis</td><td colspan="2">Chemical Characteristics</td><td>Characterize stream prior to injection</td><td>Continuous chromatography; Annual discrete samples</td></tr>
<tr><td colspan="2">Physical Characteristics</td><td>Characterize stream prior to injection</td><td>Continuous</td></tr>
<tr><td rowspan="4">CO_2 Injection Process Monitoring (SB-01 through SB-05)</td><td colspan="2">Injection Rate</td><td>N/A</td><td>Continuous</td></tr>
<tr><td colspan="2">Injection Physical Characteristics</td><td>N/A</td><td>Continuous</td></tr>
<tr><td colspan="2">Annulus Pressure Monitoring</td><td>N/A</td><td>Continuous</td></tr>
<tr><td colspan="2">Annulus Volume Added</td><td>N/A</td><td>Continuous</td></tr>
<tr><td>Hydrogeologic Testing</td><td colspan="2">Pressure Fall-Off Testing – Wells SB-01 through SB-05</td><td>1 Prior to Injection</td><td>3 Years After Starting Injection, 1 Every 5 years After</td></tr>
<tr><td rowspan="2"></td><td rowspan="2"><u>Internal</u> Annulus</td><td>Pressure Test</td><td>1 Prior to Injection</td><td>N/A</td></tr>
<tr><td>Pressure Monitoring</td><td>N/A</td><td>Continuous</td></tr>
</table>

<table>
<tr><th>Monitoring Category</th><th colspan="2">Monitoring Parameter/Method</th><th>Baseline Frequency (One year minimum)</th><th>Injection Phase Frequency (30 years)</th></tr>
<tr><td>Injection Well Mechanical Integrity Testing</td><td><u>External</u></td><td>1. DTS and
2. Temp. Log or
3. Noise Log</td><td>Begin DTS monitoring prior to injection and conduct 1 MIT Prior to Injection
(2 OR 3)</td><td>Continuous (DTS) AND 1 MIT Annually
(2 OR 3)</td></tr>
<tr><td>Corrosion Monitoring</td><td colspan="2">Corrosion Coupon Testing</td><td>N/A – measure and record coupon mass and thickness prior to deployment</td><td>Quarterly</td></tr>
<tr><td rowspan="2">Groundwater Geochemical Monitoring</td><td rowspan="2">Direct Fluid Sampling and Analysis</td><td>USDW (UOB) wells UOB-01, UOB-04</td><td rowspan="2">Minimum of four events – 1 year prior to injection</td><td rowspan="2">Quarterly for first year, Annual thereafter</td></tr>
<tr><td>Above-Zone (AOB) wells AOB-01, AOB-04, AOB-05</td></tr>
<tr><td>Direct Plume Monitoring</td><td colspan="2">In-zone fluid sampling and geochemical monitoring – Injection Wells SB-01 through SB-05 only</td><td>Minimum of four events – 1 year prior to injection</td><td>Annual, during shut-down for MITs</td></tr>
<tr><td>Direct Pressure Front Monitoring</td><td colspan="2">Wellhead Pressure Gauges (injection wells)
and
Downhole Pressure Gauges (all injection and observation wells)</td><td>Continuous, After Well Construction</td><td>Continuous</td></tr>
<tr><td rowspan="3">Indirect Plume Monitoring Techniques</td><td rowspan="2">Fiber & Wireline</td><td>Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) via fiber optics (Injection [SB-01 through SB-05] and In-Zone [IOB-01 through IOB-04] Wells)</td><td>Continuous, After Well Construction</td><td>Continuous</td></tr>
<tr><td>PNC Logging (Injection Wells SB-01 through SB-05 Only)</td><td>1 Prior to Injection</td><td>3 years after starting injection, 1 every 5 years after</td></tr>
<tr><td>Repeat Seismic</td><td>3D DAS VSP (Injection [SB-01 through SB-05] and In-Zone [IOB-01 through IOB-04] Wells)
OR
AoR-based Seismic Survey</td><td>1 Prior to Injection</td><td>3 years after starting injection, 1 every 5 years after</td></tr>
<tr><td>Indirect Pressure Front Monitoring</td><td>Passive Seismic</td><td>DAS Passive Seismicity Monitoring (Injection and In-Zone Wells)</td><td>Continuous, After Well Construction</td><td>Continuous</td></tr>
<tr><td colspan="5">1. The proposed testing and monitoring program during the PISC phase is detailed in Section 9 (Post-Injection Site Care and Site Closure Plan).
2. One baseline geochemical sample will be collected and analyzed from the in-zone during drilling at the injection wells (SB-01 through SB-05) and in-zone observation wells (IOB-01 through IOB-04).</td></tr>
</table>

B.3. Quality Assurance Procedures

Data quality assurance and surveillance procedures for this sequestration project were designed to maintain compliance with the requirements under 40 CFR 146.90(k). Quality Assurance (QA) requirements for the measurements to be conducted as part of this Plan are described in the **Quality Assurance and Surveillance Plan (QASP), which is Section 7.1** of this application. The direct measurements outlined in this Plan are essential to the success of this CO_2 storage project; therefore, it is imperative that the measurements be performed based on industry best practices and recommended QA protocols of service contractors and equipment manufacturers.

B.4. Reporting Procedures and Recordkeeping

Sugarberry CCS, LLC will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR 146.91 (UIC Program Director) and to the Texas Railroad Commission (RRC) under 16 TAC 5.207 (RRC Director). All reports will be certified in compliance with 16 TAC 5.207(d) and signed by a responsible corporate officer or a duly authorized representative in accordance with 16 TAC 5.207(c)(1). The following reporting requirements apply to the Sugarberry CCS Hub.

B.4.A. 24-Hour Notification of an Event and 5-Day Report

In the event of the following, Sugarberry CCS, LLC will notify the EPA UIC Program Director and RRC Director via phone as soon as practicable but no later than 24 hours of discovery of the following per 40 CFR 146.91(c) and 16 TAC 5.207:

- 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 CO_2 to the geologic storage reservoir;
- Any evidence that the injected CO_2 stream or associated pressure front may cause endangerment to a USDW;
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
- Any triggering of a shut-off system downhole or at surface; or
- Any failure to maintain mechanical integrity.

Within five (5) days of discovery, Sugarberry CCS, LLC will additionally provide a written report to the UIC Program Director and RRC Director. The report will include the following information (16 TAC 5.207(a)(2)(A)):

- Description of the noncompliance and its cause;
- Period of noncompliance including exact dates and times;
- If the noncompliance has not been corrected, the anticipated time it is expected to continue; and
- Steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

B.4.B. 30-Day Notification of Planned Activity and Results Reporting

Sugarberry CCS, LLC will provide written notice to the UIC Program Director and RRC Director at least 30 days in advance of the following activities at any of the permitted injection wells (40 CFR 146.91(d) and 16 TAC 5.207(a)(2)(B)):

- Any planned well workovers, repairs, and maintenance to enhance well lifespan and performance;
- Any planned stimulation activities other than stimulation for formation testing conducted under the initial collection of geologic information (40 CFR 146.82); or
- Any other planned test of the injection wells by Sugarberry CCS, LLC.

Within 30 days of a well workover, MIT, or other injection well test, Sugarberry CCS, LLC will submit the results to the UIC Program Director and RRC Director (40 CFR 146.91(b); 16 TAC 5.207(a)(1) and 5.207 (a)(2)(B)). Results of an internal MIT will be submitted using RRC Form H-5 (16 TAC 5.207(b)(1)).

B.4.C. Semi-Annual Testing and Monitoring Report

Sugarberry CCS, LLC will submit a semi-annual report to the UIC Program Director and RRC Director that will include summary and discussion of the following information (40 CFR 146.91(a); 16 TAC 5.207(a)(2)(C)):

- Summary of well head pressure monitoring;
- Changes to the source and physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;
- Monthly average, minimum, and maximum values for operating injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure (results of injection pressure and rate monitoring of each injection well must be reported on RRC's Form H-10 per 16 TAC 5.207(b));
- Monthly annulus fluid volume added;
- Description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;
- Monthly volume or mass of CO_2 injected over the current reporting period and the volume injected cumulatively over the life of the project;
- Description of any event that triggers a shutdown device (40 CFR 146.88(e)) and the response taken; and
- Results of monitoring prescribed under 40 CFR 146.90 and 16 TAC 5.206(e).

B.4.D. Annual Geologic Storage Facility Report

Per 16 TAC 5.207(a)(2)(D), Sugarberry CCS, LLC will submit an annual report to the RRC Director that includes the following information:

- Corrective action performed;
- New wells installed and the type, location, number, and information required in 16 TAC 5.203(e);

- Re-calculated AoR or a submitted statement signed by an appropriate company official confirming that monitoring and operational data support the current delineation of the AoR on file with the RRC;
- Updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;
- Tons of CO_2 injected; and
- Any other information as required by the permit.

B.4.E. Recordkeeping

Per 40 CFR 146.91(f) and 16 TAC 5.207(e), Sugarberry CCS, LLC will retain the following records as described:

- All site characterization data and data collected for the permit application under 40 CFR 146.82, will be retained throughout the life of the geologic sequestration project and for at least 10 years following site closure;
- Data on the nature and composition of all injected fluids will be retained for at least 10 years after site closure;
- Any monitoring data collected through this **Testing and Monitoring Plan** will be retained for at least 10 years after it is collected;
- Well plugging reports and all PISC data will be retained for at least 10 years after site closure; and
- All documentation of good faith claims to necessary and sufficient property rights to operate the geologic storage facility will be retained through duration of the project until the UIC Program Director issues the final certificate of closure.

C. Carbon Dioxide Stream Analysis [40 CFR 146.90(a), 16 TAC 5.203(j)(2)(A)]

Sugarberry CCS, LLC will analyze the CO_2 stream prior to and during the operational period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a) and 16 TAC 5.203(j)(2)(A). Sugarberry CCS, LLC expects multiple sources of CO_2 from the region, with additional sources to be added throughout the life of the project. Each source will have a different gas stream composition based on the source's capture process. The composition of the final injected gas stream will change depending on which sources are operational. As such, Sugarberry CCS, LLC will continuously monitor the CO_2 stream chemical composition (at known in-situ conditions of temperature and pressure at injection point) to ensure it meets minimum composition specifications that will be refined when sources are finalized, and capture equipment is operational. The CO_2 stream is expected to have a mol% CO_2 concentration of at least 96% with other chemical constituents as seen in **Table 7-2**. Sugarberry CCS, LLC will additionally collect physical samples for laboratory analysis as outlined below.

A continuous gas chromatograph and sampling port (for collection of physical samples) will be installed within the main trunk line prior to the CCS Hub manifold, downstream of all CO_2 sources to ensure the quality meets specifications and that Sugarberry CCS, LLC can isolate the delivery of the stream in the event it is out of specification (e.g., high water content, H_2S, etc.).

C.1. Sampling Location and Frequency

Sugarberry CCS, LLC will continuously analyze the CO_2 stream using a gas chromatograph during the injection phase to collect representative chemical characteristic data. The CO_2 stream will be analyzed prior to initiating injection to characterize the anticipated injection stream. The chromatograph will be placed downstream of all source points within the main trunk line prior to the Sugarberry CCS Hub manifold. Sampling and monitoring will occur continuously at 30-minute intervals. To supplement continuous gas chromatograph monitoring, physical samples will be collected from a sampling port annually for the parameters analyzed continuously by the chromatograph. This sampling port will be near the gas chromatograph downstream of all CO_2 sources within the main trunk line prior to the Sugarberry CCS Hub manifold. Sugarberry CCS, LLC will report the results of the CO_2 stream analysis in semi-annual reports as discussed in **Section B.4.C.**

In the event of unplanned disruptions to permitted injection activities that may affect the chemical composition of the final CO_2 stream, Sugarberry CCS, LLC will increase the frequency of CO_2 stream reporting at the UIC Program Director's discretion to confirm that there are no significant changes, and injection is continuing to operate as permitted.

The basis for identifying a deviation in sample results and resulting additional monitoring will be outlined in this plan once initial data for the CO_2 source stream are collected, analyzed, and reviewed in the context of the specifications listed in **Table 7-2**.

C.2. Analytical Parameters

Sugarberry CCS, LLC will analyze the CO_2 for the constituents identified in **Table 7-2** using a gas chromatograph and physical sampling. It is important to sample the CO_2 feedstock from the pipeline upstream from the injection point to accurately represent the different impurities that may be present in the stream. Even small amounts of certain impurities can affect the economics of geologic storage downhole or compressor or pipeline operations (Last and Schmick, 2011). More details about the CO_2 stream analysis can be found in **Section B.1.A. of the QASP (Section 7.1).** Analytical methods are specified in **Table 7.1.5. of the QASP.**

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Table 7-2. Summary of CO_2 Stream Analytical Parameters

Parameter[1]	Specification	Unit
Minimum CO_2	>95	Mol%, dry basis
No Free Liquids	NA	NA
Carbon Monoxide (CO)	< 1000	ppmv
Water (H_2O)	< 20	lb./MMSCF
Total Hydrocarbons	< 2	Mol%, dry
Amine	< 20	ppmv
Ammonia (NH_3)	< 40	ppmv
Total Organic Compounds	< 50	ppmv
Hydrogen Sulfide (H_2S)	< 40	ppmv
SO_x	< 100	ppmv
Total Sulfur	< 100	ppmv
NOx	< 100	ppmv
Glycol	< 1	ppmv
Hydrogen (H_2)	< 1	Mol%
Inert Gasses (Non-Condensable)	< 5	Mol%, dry
Oxygen (O_2)	< 100	ppmv
Particulate Matter	< 1	ppmw

1. *This list is subject to change based on source injectate stream composition results.*
2. *Minimum-Maximum stream temperature should range from 40 to 130 degrees Fahrenheit.*

C.3. Sampling Methods

The CO_2 stream will be sampled continuously with an on-site gas chromatograph. Physical samples will also be taken through a sampling port near the gas chromatograph. The sampling port will allow the collection of representative grab samples into containers that can be sealed and shipped to the laboratory. For additional details, refer to **Sections B.1.A. and B.2. of the QASP (Section 7.1).**

C.4. Laboratory to be Used/Chain of Custody and Analysis Procedures

Sample analysis will be conducted by a third-party laboratory using the methods specified in **Section A.4 of the QASP (Section 7.1)** or an equivalent method. See **Section B.3.E of the QASP** for further information on chain of custody procedures.

D. Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b) and 16 TAC 5.203(j)(2)(B)]

Sugarberry CCS, LLC will install and use continuous recording devices to monitor parameters, as specified in **Table 7-1**, in accordance with 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b) and 16 TAC 5.203(j)(2)(B). The information is utilized to verify compliance with the operational conditions of the permit and informs AoR reevaluation.

D.1. Monitoring Location and Frequency

Sugarberry CCS, LLC will perform the activities identified in **Table 7-3** to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

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Table 7-3. Sampling Devices, Locations, and Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	1) Tubing Pressure Gauge 2) Downhole Pressure Gauge 3) DAS	For 1 and 2: SB (01-05) Injection Wellheads For 3: SB (01-05), IOB (01-04)	5 sec. / 4 hours	5 min. / 4 hours
Injection rate	Coriolis Mass Flow Meter	SB (01-05) Injection Wellhead	5 sec. / 4 hours	5 min. / 4 hours
Injection volume	Coriolis Mass Flow Meter	SB (01-05) Injection Wellhead	5 sec. / 4 hours	5 min. / 4 hours
Annular pressure	Annular Pressure Gauge	SB (01-05) Injection Wellhead	5 sec. / 4 hours	5 min. / 4 hours
Annulus fluid volume	Fluid Tank Volume Meter	SB (01-05) Injection Wellhead	5 sec. / 4 hours	5 min. / 4 hours
CO_2 stream temperature	1) DTS	SB (01-05)	1) 10 min. / 10 min. 2) 5 sec. / 4 hours 3) 3.5 sec. / 4 hours	1) 10 min. / 10 min. 2) 5 sec. / 4 hours 3) 3.5 sec. / 4 hours

Notes:

1. *All downhole gauges will be placed above the packer and ported through to the respective well monitoring zone.*
2. *In-zone observation wells will be equipped with downhole pressure gauges and DTS/DAS fiber optics for continuous monitoring according to the minimum sampling and recording frequencies specified above.*
3. *Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.*
4. *Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.*

D.2. Monitoring Details

All critical system parameters (e.g., pressure, temperature, and flow rate) will have continuous monitoring with electronic signals transmitted back to a distributed control system (DCS) at each wellhead. The system will automatically sound an alarm and shutdown operations if specified control parameters exceed their normal operating range. Sugarberry CCS, LLC will perform the activities identified above in **Table 7-3** to monitor critical operational parameters. Surface and downhole pressure instruments will be calibrated in accordance with manufacturer specifications. Downhole and surface pressure gauge specifications are provided in the **QASP (Section 7.1; Table 7.1.12).**

D.2.A. Injection Pressure, Rate, Volume

Sugarberry CCS, LLC will continuously monitor injection rate, volume, and pressure for each injection well pursuant to 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b) and 16 TAC 5.203(j)(2)(B). Monthly average, maximum, and minimum values for each will be reported to the UIC and RRC Program Directors in the semi-annual reports. Injection rate (i.e., flow) and volume will be monitored with Coriolis mass flow meters. The flow meters will be located at each injection well pad. The flow meter will be calibrated according to the entire expected range of flow rates. For additional details on the instrumentation, see the **QASP (Section 7.1; Table 7.1.11.).** Sugarberry CCS, LLC will include measurements to account for flow rate of injected fluid, concentration of the fluid stream, injectate density, injectate temperature, and energy inputs required for operation. Flow meters will be temperature and pressure compensated and calibrated according to manufacturer specifications. Flow rate data will allow Sugarberry to assess the cumulative mass of CO_2 injected to confirm compliance with operational requirements of the permit.

Injection pressure will be continuously monitored using wellhead and downhole pressure gauges. Each injection well will be equipped with permanent downhole pressure gauges that will continuously monitor the injection zone pressure to ensure that the injection zone pressures do not exceed 90% of the reservoir fracture pressure, as required by 40 CFR 146.88(a), and ensure operating conditions are met. Additionally, each injection well will be equipped with a wellhead pressure logger that will ensure surface pressures are maintained below the maximum allowable pressure for each well. If pressure limits are exceeded, the system will shut down.

D.2.B. Annulus Pressure and Annulus Fluid Volume

Sugarberry CCS, LLC will use the procedure below to monitor annular pressure to limit the potential for any unpermitted fluid movement into or out of the injection well annulus:

- The annulus between the tubing and the long string of casing will be filled with a brine solution. This solution will meet specified parameters such as a brine specific gravity, brine density, and annulus hydrostatic gradient and will contain a corrosion inhibitor.
- During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of an estimated 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer.
- The pressure within the annular space, over the interval above the packer to the confining layer, must be greater than the pressure of the injection zone formation.
- The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

The annular monitoring system will consist of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank. An alarm will sound, and shutdown procedures will be initiated, if specified control parameters exceed their permitted operating range. The annular pressure between the tubing and the long-string casing will be maintained at a higher pressure than the injection pressure, at bottom hole conditions during injection, and will be monitored by the Sugarberry CCS, LLC control system gauges. The annulus head tank pressure will be controlled by pressure regulators or pumps; one set of regulators or pumps will be used to maintain pressure above injection pressure, if needed by adding fluid and the other set will be used to relieve pressure, if needed, by venting gas or fluid from the annulus head tank. Any changes to the composition of annular fluid will be submitted to the UIC Program Director and RRC Director for approval.

If system communications are lost for 60 minutes or more, project personnel will observe and monitor manual gauges in the field every eight hours or once per shift for both wellhead surface pressure and annulus pressure, while also recording hard copies of the data until communication is restored.

Average annular pressure, annulus tank fluid level, and volume of fluid added or removed from the system will be recorded daily and reported as monthly averages, minimums, and maximums in the semi-annual report. If there are any significant changes in the casing-tubing annular pressure that attributes to well mechanical integrity, an investigation will commence as detailed in the **Emergency and Remedial Response Plan (ERRP, Section 10).**

D.2.C. Injection Temperature

Sugarberry CCS, LLC will continuously monitor injection temperature at the surface to total depth for each injection well via DTS. The Class VI rule requires that temperature logs be conducted immediately after well cementing to evaluate the presence of cement behind the casings (40 CFR 146.87(a)(2)(ii)). The wellhead pressure logger will also continuously measure and record wellhead temperature and be used as a backup should the DTS fail. The temperature logs can additionally be used to comply with cement evaluation and external MITs.

The DTS fiber optic wire will be run from the surface to the well's total depth. This technology will continuously measure the temperature in the formations outside the casing throughout the entire well column.

E. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c) and 16 TAC 5.203(j)(2)(C), Sugarberry CCS, LLC will monitor injection well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. The well installation will include corrosion resistant construction materials as discussed in **Construction Details Plan (Section 4).**

Sugarberry CCS, LLC will monitor corrosion using the corrosion coupon method and collect samples according to the description below.

E.1. Monitoring Location and Frequency

Corrosion monitoring will occur on a quarterly basis during the injection phase using the corrosion coupon method. The coupons will be deployed and located within a piping loop at the wellhead. Monitoring will occur by the following dates each year:

- Three (3) months after the date of injection authorization;
- Six (6) months after the date of injection authorization;
- Nine (9) months after the date of injection authorization; and
- Twelve (12) months after the date of injection authorization.

E.2. Sample Description

Samples of materials used in the construction of the injection wells and pipeline that will encounter CO_2 will be included in the corrosion monitoring program. The coupons will be comprised of those items listed in **Table 7-4**. Each coupon will be weighed, measured, and photographed prior to initial exposure according to applicable ASTM methods as a baseline assessment.

Table 7-4. List of Equipment with Material of Construction

Equipment Coupon	Material of Construction
Wellhead and Christmas Tree	Corrosion-resistant alloy (e.g., stainless steel)
Conductor Casing	API J-55
Surface Casing	API J-55
Long String Casing	API L-80 (0-3,300' depth) API 13CR-110 (3,600-4,100' depth; 4,220-5,350' depth) API 22CR-110 or better (3,300-3,600' depth; 4,100-4,220' depth; 5,350-5,500' depth)
Injection Tubing	API 22CR-110 or better
Packers	Baker Hughes Removable CRA Feed Through Premier (Chromium Alloy)
*Note: Well construction details are provided in **Section 4 (Construction Details Plan)** of this application.*	

E.3. Monitoring Details

Each sample will be attached to an individual holder and then inserted into a flow-through pipe arrangement attached to the pipeline. The corrosion monitoring systems will be located upstream of the wellhead and downstream of the injection well control valve. The corrosion loop system routes a parallel stream of high-pressure CO_2 from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. The loop will allow for corrosion inspection and injection to occur simultaneously. The corrosion equipment is placed close to the wellhead prior to the Coriolis mass flow meter to provide representative exposure of the CO_2 composition, temperature, and pressures that will be observed at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design plan and will allow CO_2 injection to continue during sample collection.

The coupons will be handled and assessed for corrosion in accordance with ASTM International (ASTM) Method G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM International, 2017). The coupons will be analyzed in accordance with the NACE RP0775-2018 (NACE, 2018) standard to assess and document corrosion wear rates based on mass loss. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration of exposure (i.e., weight loss method). The U.S. EPA UIC Class VI Testing and Monitoring Guidance (2013) suggests that target corrosion rates of one mil per year (approximately 25 micrometers or one-thousandth of an inch per year) or less are common in wells in the oil industry. NACE SP0775-2023 categorizes average general corrosion rates for carbon steel of less than 2 mils/year as low and maximum pitting rates of less than 5 mils/year as low (NACE, 2023). As such, a detected general corrosion rate of greater than 2 mil/year or pitting rate of greater than 5 mils/per year will initiate consultation with the EPA and more frequent monitoring may be invoked if appropriate. A casing inspection log will be run to assess thickness and quality of the casing if rates exceed these thresholds. Corrosion monitoring is implemented in this project as a loss of containment prevention measure, coupled with the use of corrosion-resistant well construction materials.

Casing and tubing will be further evaluated for corrosion on an as-needed basis by running wireline casing inspection logs. Furthermore, wireline tools can be lowered into the well to directly measure properties of the well tubulars that indicate corrosion. These tools will provide circumferential images with high resolution such that pitting depths, due to corrosion, can often be accurately measured.

The different types of logs that may be used to monitor and assess the condition of well tubing and casing include:

- Mechanical tools, such as caliper logs, which measure the internal diameter of the casing in several directions and allow the detection of loss of thickness of the well casing;

- Ultrasonic imaging tools, which use a high transducer frequency to measure anomalies in the tubing or casing in terms of wall thickness (Schlumberger, 2009); and

- Electromagnetic tools, which can accurately measure corrosion effects, such as pitting depths and metal loss in tubing or casing.

F. <u>Groundwater Quality and Geochemical Monitoring</u>

Sugarberry CCS, LLC will monitor groundwater quality, geochemical changes, and pressure changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d) and 16 TAC 5.203(j)(2)(D). Sugarberry CCS, LLC will additionally monitor pressure changes within the injection zone via in-zone observation wells. The following subsections detail the proposed groundwater geochemical monitoring program for the Sugarberry CCS Hub.

F.1. Monitoring Location and Frequency

Table 7-5 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring. Monitoring methods include direct fluid sampling and geochemical analysis (**Table 7-5 and 7-6**) and monitoring for pressure and static fluid level changes via downhole pressure (P) gauges. **Figure 7-1** shows the proposed monitoring locations within the delineated AoR. **Figures 7-2 through 7-7** show the monitoring locations relative to the predicted CO_2 plume extent during the injection period. **Figures 7-8 through 7-10** show the monitoring locations relative to predicted pressure differentials during the injection period. While this plan is focused on monitoring during the injection period, baseline monitoring will be conducted in all proposed observation wells to understand natural groundwater quality and pressure profiles of the various monitoring zones before injection begins **(Table 7-5**). Monitoring details for the PISC phase of the project are detailed in the **Post-Injection Site Care and Site Closure Plan (Section 9).**

F.1.A. Monitored Units

Groundwater observation wells designated IOB will directly monitor pressure changes within the injection intervals (in-zone observation wells) (**Table 7-5**). These observation wells will be constructed as dual completions, with monitoring capabilities in both the Woodbine and Paluxy injection intervals separated by packers. Additional detail regarding direct pressure monitoring via these in-zone observation wells is specified in **Section I.4** of this plan. While the CO_2 plume is not anticipated to reach these locations until the PISC period based on current modeling results, monitoring these locations before and during injection will allow Sugarberry CCS, LLC to monitor the far-field pressure front in comparison to modeled pressure changes. This will help Sugarberry CCS, LLC understand the influence of facies changes and other subsurface geologic structures (i.e., Talco Fault Zone approximately three miles to the north of the AoR) on pressure buildup and to calibrate the model accordingly prior to commencing injection.

Observation wells designated AOB will monitor the lowermost permeable unit directly above the upper confining zone (above-zone monitoring), the uppermost portion of the Eagle Ford (Sub-Clarksville Sand Member)The in-zone pressure monitoring data, coupled with above-zone pressure and geochemical monitoring data, will provide the first evidence of any vertical loss of containment.

Observation wells designated UOB will monitor potential USDWs within the AoR as an additional protective measure. The early indications of leakage to the above-zone and shallow USDWs would be manifested primarily as aquifer pressure increases and would be captured by downhole pressure gauges. Later indications of leakage may be a change in the composition of formation water (e.g., lowering of pH and increased CO_2 concentration), which is more difficult to spatially capture compared to pressure changes. AOB and UOB wells have been located near the proposed injection wells since this is where the pressure differential will be highest within the injection zones and where caprock integrity concerns are highest.

According to the RRC Groundwater Advisory Unit GW-1 determination, the lowermost USDW boundary is identified at approximately 1,600 to 1,800 feet below ground surface at the injection wells based on petrophysical analysis, with an estimate of 1,600 feet below ground surface for the overall project. There are no clear sands present at or above the lowermost USDW boundary, though there are thin sands present that appear to be part of the Taylor Group at a shallower interval (about 400 feet below mean sea level). These sands may be continuous and correlative in the vicinity of the injection wells and may be stratigraphically related to regional aquifer systems utilized for drinking water by municipalities in the vicinity of the hub (e.g., Sulphur Springs). The Sugarberry CCS Hub is in an area with no delineated regional major or minor subsurface aquifers and there are currently no groundwater or production wells in the shallow sands within the delineated AoR. There are three wells within the AoR that are identified as water wells from the Texas Water Development Board's Brackish Groundwater Database. However, as discussed in the

AoR and Corrective Action Plan (Section 2), these wells extend through the confining zone and into the injection zones or deeper and were used for oil or gas resource production rather than a potable water source.

Sugarberry CCS, LLC views monitoring for pressure changes at all observation wells and monitoring groundwater quality via the above-zone observation wells (Sub-Clarksville Sand Member) as the most effective strategy for identifying early loss of containment at the Sugarberry CCS Hub. To be protective of potential USDWs within the AoR, Sugarberry CCS, LLC will monitor shallow sands of the Taylor Group that may be related to regional aquifers and may be USDWs at two locations (see **Figures 7-1 through 7-7**). These sands and related water quality will be characterized at each drilling location within the AoR to confirm their depths and whether they are USDWs. The screened intervals for the two (2) UOB locations will be set at the time of this analysis. Estimated tops for these target intervals are provided in **Table 7-5**. Sugarberry CCS, LLC may add additional USDW observation wells dependent on this analysis and the characteristics of potential USDWs within the AoR.

F.1.B. Well Placement

Well locations were placed based on current predictions of pressure front migration (**Figures 7-8 through 7-10; Tables 7-5 and 7-9**) and CO_2 plume migration over time (**Figures 7-1 through 7-7; Table 7-5 and 7-8**). Wells IOB-01, IOB-02, and IOB-04 are positioned up-dip of the injection wells to track and capture CO_2 plume and pressure front migration directly within the injection zones via vertical seismic profiles (VSPs) and pressure monitoring throughout the injection and post-injection periods. Well IOB-03 will be placed down-dip of the injection wells to confirm down-dip pressure changes for the duration of the project. In addition, each of the injection wells (SB-01 through SB-05) will monitor the in-zone for pressure changes and will contain an external sampling port to allow annual geochemical sampling of the in-zone during annual well shutdowns for conducting MITs. Wells SB-02 and SB-03 will additionally have pressure gauges external to the casing that will allow pressure monitoring of the above-zone at these locations since there are no co-located AOB wells proposed.

Wells AOB-01, AOB-04, and AOB-05 are placed near injection wells SB-01, SB-04, and SB-05, respectively, to monitor for CO_2 breakthrough and pressure changes immediately above the confining zone in the up-dip area of the hub in the event of injection well integrity issues or other leakage related to the injection wellbores. Wells UOB-01 and UOB-04 are placed near SB-01/AOB-01 and SB-04/AOB-04, respectively, to monitor shallow USDWs within the AoR for pressure and geochemical changes as an additional protective measure.

F.1.C Monitoring Frequency

Proposed monitoring frequencies are provided below in **Table 7-5**. Collecting baseline data at each of the monitoring locations will provide an understanding of natural geochemical variability and static pressure profiles within each of the monitored units prior to initiating injection. These data will be used to calibrate the model and reevaluate the AoR prior to commencing injection. The basis for identifying a deviation from baseline and potential triggers for additional sampling during operations will be outlined in this plan once baseline data are collected, analyzed, and evaluated statistically and in the context of calibrated model results.

Table 7-5. Monitoring of Groundwater Quality and Geochemical Changes within the AoR

Target Formation	Monitoring Activity	Monitoring Location(s)	Estimated Depth (Top to Base) (ft-BGS)	Frequency
USDW: Sands that are characterized as USDWs in the shallow subsurface (Taylor Group)	Geochemical Monitoring via Direct Fluid Sampling during and after injection.	UOB-01 UOB-04	UOB-01: 782 (top) UOB-04: 731 (top)	Baseline: Minimum of one year prior to injection and four events Operational: Quarterly for first year[1], annually thereafter[2]
	Downhole P Gauges			Continuous
Above-Zone: Sands within the Upper Eagle Ford (Sub-Clarksville Sand Member)	Geochemical Monitoring via Direct Fluid Sampling during and after injection.	AOB-01 AOB-04 AOB-05	AOB-01: 3,082-3,182 AOB-04: 3,064-3,164 AOB-05: 3,102-3,202	Baseline: Minimum of one year prior to injection and four events Operational: Quarterly for first year[1], annually thereafter[2]
	Downhole P Gauges			Continuous
In-Zone: Sand injection intervals within the Woodbine and Paluxy Formations	Downhole P Gauges	IOB-01 IOB-02 IOB-03 IOB-04	IOB-01: 3,458-4,108 (Woodbine) and 4,958-5,208 (Paluxy) IOB-02: 3,485-4,135 (Woodbine) and 4,985-5,235 (Paluxy) IOB-03: 3,856-4,356 (Woodbine) and 5,356-5,656 (Paluxy) IOB-04: 3,498-4,148 (Woodbine) and 4,998-5,248 (Paluxy)	Continuous[6]

Target Formation	Monitoring Activity	Monitoring Location(s)	Estimated Depth (Top to Base) (ft-BGS)	Frequency
	Geochemical Monitoring via Direct Fluid Sampling	SB-01 SB-02 SB-03 SB-04 SB-05	SB-01: 3,482-4,132 (Woodbine) and 4,982-5,232 (Paluxy) SB-02: 3,525-4,175 (Woodbine) and 5,025-5,275 (Paluxy) SB-03: 3,779-4,279 (Woodbine) and 5,279-5,579 (Paluxy) SB-04: 3,513-4,163 (Woodbine) and 5,013-5,263 (Paluxy) SB-05: 3,606-4,006 (Woodbine) and 5,106-5,406 (Paluxy)	Annually[5, 6]

1. *Quarterly Sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, 12 months after the date of authorization of injection.*
2. *Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.*
3. *ft-BGS = feet below ground surface.*
4. *SB-02 and SB-03 will have external pressure sensors outside of the casing to monitor for pressure changes in the above-zone.*
5. *Each injection well (SB-01 through SB-05) will have a sampling port to collect geochemical samples from the in-zone annually while injection is shut-down to conduct MITs [16 TAC5.203(j)(2)(D)].*
6. *One baseline geochemical sample will be collected and analyzed during construction for each injection well (SB-01 through SB-05) and in-zone observation well (IOB-01 through IOB-04).*

F.2. Analytical Parameters

Table 7-6 identifies the parameters to be monitored and the analytical methods Sugarberry CCS, LLC will use. Acquired groundwater monitoring data will be periodically evaluated throughout the injection phase, and if listed parameters are determined to have a non-significant impact on meeting project monitoring objectives, they will be removed from the groundwater geochemistry analysis strategy in consultation with, and at the discretion of, the UIC Program Director. The main suite of analytical parameters includes major cations and anions that will allow geochemical fingerprinting of each monitored zone, as well as minor and trace cations and anions and other geochemical parameters that are likely to be the strongest indicators of CO_2 and formation fluid leakage.

Table 7-6. Summary of Analytical and Field Parameters for Groundwater Samples

Parameters	Analytical Methods
All Monitored Zones	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B (U.S. EPA, 2014) or EPA Method 200.8 (U.S. EPA, 1994)
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D (U.S. EPA, 2014) (U.S. EPA, 2014) or EPA Method 200.7 (U.S. EPA, 1994)
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0 (U.S. EPA, 1993)
Isotopes*: δ13 C of Dissolved Inorganic Carbon	Isotope radio mass spectrometry
Dissolved CO_2	Coulometric titration, ASTM D513-16 (ASTM, 2016)
Total Dissolved Solids	Gravimetry, APHA 2540C (APHA)
Water Density	ASTM D4052
Alkalinity	APHA 2320B (APHA, 1997)
pH (field)	EPA 150.1 (U.S. EPA, 1982)
Specific Conductance (field)	APHA 2510 (APHA, 1992)
Temperature (field)	Thermocouple

F.3. Sampling Methods

Groundwater sampling, sample preservation, and QA will be conducted based on the methods and practices described in **Section B of the QASP (Section 7.1)**.

F.4. Laboratory to be Used/Chain of Custody Procedures

Sample analyses will be conducted by a third-party laboratory certified to conduct the noted analyses in the State of Texas. Sample handling and chain of custody procedures will be conducted in accordance with the practices described in **Section B of the QASP (Section 7.1)**.

G. Mechanical Integrity Testing

Sugarberry CCS, LLC will conduct MITs as presented in **Table 7-7** periodically during the injection phase to verify the injection well maintains external and internal mechanical integrity (MI) as required at 146.89(c) and 146.90 and 16 TAC 5.203(j)(2)(F). A well is considered to have maintained mechanical integrity if:

1. There is no internal leak in the casing, tubing, or packer. In a properly functioning Class VI well system, the pressure will normally be higher in the annulus than in the tubing;

2. There is no significant external fluid movement out of the injection zone through channels adjacent to the wellbore; and

3. Corrosion monitoring, pursuant to 40 CFR 146.90(c) and 16 TAC 5.203(j)(2)(C), reveals no loss of mass or thickness that may indicate the deterioration of well components (casing, tubing, or packer).

Sugarberry CCS, LLC will demonstrate internal and external mechanical integrity prior to initiating injection (40 CFR 146.87; 16 TAC 5.203(h)), during the injection phase (40 CFR 146.89, 146.90; 16 TAC 5.203(j)(2)(F)), and prior to well plugging after injection has ceased (40 CFR 146.92; 16 TAC 5.203(j)(2)(F)).

G.1. Testing Location and Frequency

Prior to injection, conducting an external MIT will verify the well was properly constructed and establish a baseline from which to compare MITs conducted during the injection phase (**Table 7-7**). During the injection phase, an external MIT will be conducted annually on each injection well as required by 40 CFR 146.89(c) and 146.90(e), up to 30 days before the anniversary date of authorization of injection each year. After cessation of injection and prior to plugging the injection wells, final external MITs will be conducted as required by 40 CFR 146.92(a). In addition, an external MIT will be conducted on the in-zone observation wells every five years, up to 30 days before the anniversary date of authorization of injection. Because these observation wells will penetrate through the upper confining zone, it is important to ensure these wells maintain MI to prevent loss of containment from the reservoir.

To supplement these MITs, the installed DTS fiber optic cable will continuously monitor for leak detection outside the long string casing. These sensors will be installed at all injection wells and in-zone observation wells to continuously monitor external MI. Internal MI will also be monitored at the injection wells prior to injection (initial annulus pressure test) and throughout the injection phase (annular pressure monitoring).

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Table 7-7. MITs

Test Description	Frequency	Location
Internal MIT 1) Annulus Pressure Test 2) Annulus Pressure Monitoring	1) Prior to Injection 2) Continuous throughout life of the well	SB (01-05)
External MIT DTS	Continuous throughout life of the well	Depths: Surface to Total Depth SB (01-05) IOB (01-04)
*External MIT*** Standard Temperature Logging	1) Annually for injection wells during the injection phase 2) Every five years on in-zone observation wells	Outside of injection well [SB (01-05)] or observation well [IOB (01-04)] casing
*External MIT*** Standard Noise Logging	1) Annually for injection wells during the injection phase 2) Every five years on in-zone observation wells	Outside of injection well [SB (01-05)] or observation well [IOB (01-04)] casing
*** Either the Standard Temperature Logging or Standard Noise Logging method will be employed for the annual injection well MITs and five-year in-zone observation well MITs.*		

G.2. Testing Details

Temperature logging is used to identify temperature anomalies near the well bore, which can indicate potential leakage. To conduct temperature logging, the injection well must be shut-in (i.e., temporary cessation of injection) to allow any temperature effects related to injection to dissipate and for temperature to equilibrate towards a static level. Thirty-six (36) hours is generally thought to be a sufficient shut-in period (U.S. EPA, 2013; U.S. EPA Region 5, 2008); therefore, this will be the minimum shut-in period for conducting temperature logging. The temperature logging tool is a wireline tool that is slowly lowered into the well casing, while measurements are collected in real time. A baseline temperature survey is conducted prior to injection. Intermediate and final temperature survey(s) will follow injection. Any leakage of fluids out of the injection well will be an anomaly in the otherwise linear temperature log, as the temperature within the surrounding formation will be altered from the leaking fluid. All logs will be compared to the baseline log taken prior to injection.

Standard noise logging is used to detect turbulent flow resulting from irregular channels formed within well cement, indicating potential leakage. Unlike temperature logging, noise logging can be completed while injection is still occurring. As recommended by U.S. EPA (2013), measurements will be made at intervals of 100 feet to first create a log on a coarse grid. If any anomalies are found on the coarse log, a finer grid will be constructed on the coarse intervals with high noise levels at intervals of 20 feet. In addition, measurements will be made at 10-foot intervals through the first 50 feet above the injection interval and at intervals of 20 feet within 100 feet above that zone and the base of the lowermost USDW. Additional measurements may be taken as needed to distinguish at what depths the noise is produced. As with temperature logging, all logs will be compared to the baseline log taken prior to injection, and any departures will be considered an anomaly. The U.S. EPA UIC Program Class VI Well Testing and Monitoring Guidance (2013) suggests that: "Ambient noise while injecting that produces a signal greater than 10 millivolts (mV) may indicate leakage and potential loss of external mechanical integrity." Therefore, this will constitute a failure of the noise log MIT.

Temperature and noise logging via DTS/DAS will allow continuous monitoring for leak detection along the entire length of the long string casing (injection wells) or observation well casing (in-zone observation wells). The use of permanent fiber optics for mechanical integrity testing avoids the need to shut-in the injection well. The sensors have robust sensitivity and report monitoring data in real-time. This will be a supplemental monitoring method in addition to standard testing methods highlighted above.

As discussed in **Section D** of this plan, Internal MITs are also required by the Class VI rule in order to demonstrate that there are no leaks in the injection well construction materials. For the initial annular pressure test, a loss of mechanical integrity can then be detected by a loss of pressure which indicates the annular space is not sealed and is communicating with the tubing; loss of mechanical integrity, or a failed test, is one where there is a pressure loss of 10% or more within a 30-minute test period. The initial annulus test parameters such as these pass/fail criteria, test pressure, and duration will be designed pursuant to 16 TAC 3.9(12). Following the initial annulus pressure test, injection pressure, rate, and volume along with annulus pressure and volume will be continuously monitored throughout the injection phase and prior to well plugging to demonstrate internal mechanical integrity pursuant to 40 CFR 146.88, 146.89, 146.90, and 146.92.

MIT gauges and meters will be calibrated according to the manufacturer's specifications. Wellhead and downhole gauge specifications are described in detail in the **QASP (Section 7.1; Table 7.1.8. through 7.1.16.)**. Should loss of mechanical integrity be demonstrated through monitoring, Sugarberry CCS, LLC will take all steps necessary to evaluate whether there may have been a release of the injected CO_2 stream or formation fluids into an unauthorized zone. If there is substantial endangerment to public health or the environment from any fluid movement out of the intended storage complex, Sugarberry CCS, LLC will implement the **Emergency and Remedial Response Plan (Section 10;** 40 CFR 146.94**)**, follow reporting requirements of 40 CFR 146.91, restore and demonstrate mechanical integrity, and receive approval from the UIC Program Director prior to resuming injection or plugging of the well. In the case of unscheduled or remedial well activity, the UIC Program Director will receive a remediation plan that includes a MIT activity to demonstrate well integrity following intervention per the **Emergency and Remedial Response Plan (Section 10;** 40 CFR 146.94**)**.

If the well loses mechanical integrity before the next scheduled test date, it will be repaired and retested within 30 days of losing mechanical integrity. If the well loses mechanical integrity prior to the next scheduled test date, and is repaired, Sugarberry CCS, LLC will, in the next quarterly report, document the type of failure, the cause, the required repairs, and run a new test of mechanical integrity pursuant to 40 CFR 146.89.

H. Pressure Fall-Off Testing

Sugarberry CCS, LLC will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f) and 16 TAC 5.203(j)(2)(G) using the EPA

Region 6 UIC Pressure Falloff Testing Guideline, Third Revision (U.S. EPA, 2002). Pressure fall-off tests are designed to determine if reservoir pressures are tracking predicted pressures and modeling inputs. The results of pressure fall-off tests will confirm site characterization information, inform AoR reevaluations, and verify that projects are operating properly, and the injection zone is responding as predicted.

H.1. Testing Location and Frequency

The minimum frequency at which Sugarberry CCS, LLC will perform pressure fall-off testing is as follows:

- Prior to injection (baseline); and
- Three (3) years from the start of injection and every five (5) years thereafter until injection wells are plugged and abandoned.

Sugarberry CCS, LLC will conduct fall-off testing according to the testing details below. Sugarberry CCS, LLC will notify the permitting agency 30 days before testing commences and submit any changes to the schedule 30 days prior to the next scheduled test and will additionally provide the UIC Program Director with the opportunity to witness fall-off testing activities.

H.2. Testing Details

A pressure fall-off test includes a period of normal injection followed by a period of no injection or shut-in and observance of pressure decay at the well. This injection period will consist of, at a minimum, one week of continuous injection; however, several months of injection prior to the fall-off test will be part of the pre-shut-in injection period and subsequent analysis. Prior to the fall-off test, average injection rates will be maintained. If this rate causes an elevation in bottom hole pressure above average values, the rate may be decreased until bottom hole pressure returns to average values. Injection rates on a well-by-well basis will be continuously recorded and employed in the analysis of the continuously recorded subsurface pressure data. Following the injection period, Sugarberry CCS, LLC and/or a third-party contractor will shut-in each well at the wellhead instantaneously in coordination with the injection compression facility operators. The shut-in period of the fall-off test will be at least four days or until adequate pressure transient data are collected to calculate the average pressure. Sugarberry CCS, LLC will comply with notification and reporting requirements described in **Section B.4** of this plan, reporting pressure fall-off data and interpretation of the reservoir ambient pressure following the test.

All data will be measured using dedicated downhole pressure gauges, along with wellhead sensors, so testing results can be determined in real-time. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at intervals of five seconds or less for the duration of the test. It is recommended to run the test three to five times the total time required to reach radial flow conditions. Both wellhead and downhole pressure gauges will meet or exceed ASME B 40.1 Class 2A (ASME, 2013). Wellhead and downhole gauge specifications are described in detail in the **QASP (Section 7.1; Table 7.1.8. through 7.1.16.)**. As an alternative method to utilizing downhole pressure gauges, Sugarberry CCS, LLC may deploy a wireline pressure logger for use during pressure fall-off testing.

I. Carbon Dioxide Plume and Pressure Front Tracking

Sugarberry CCS, LLC will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g) and 16 TAC 5.203(j)(2)(E). The purpose is to monitor the free-phase CO_2 plume location, thickness, and saturation; track the pressure front within the storage complex over the life of the project; validate computational modeling results; and verify that operations are not leading to reservoir containment risks. Monitoring the plume and pressure front are integral to protection of USDWs near the project.

I.1. Plume Monitoring Location and Frequency

Table 7-8 presents the methods that Sugarberry CCS, LLC will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies that Sugarberry CCS, LLC will employ. Sugarberry CCS, LLC will utilize a combination of direct and indirect methods to detect, track, and monitor the CO_2 plume during the injection phase.

Sugarberry CCS, LLC will directly monitor CO_2 plume migration via geochemical sampling from the injection zones at injection wells SB-01 through SB-05 during annual MITs. The parameters to be analyzed as part of direct fluid sampling in the injection zone and associated analytical methods were presented in **Table 7-6**. Sugarberry CCS, LLC will additionally indirectly monitor plume migration via DTS, PNC logging, and repeat seismic profiling. The locations of wells are summarized in **Table 7-5** and shown relative to the modeled CO_2 plume on **Figures 7-1 through 7-7**. Quality assurance procedures for these methods are presented in **Sections A.3 and A.4 of the QASP (Section 7.1)**.

I.2. Plume Monitoring Details

Sugarberry CCS, LLC will directly monitor CO_2 plume migration via in-zone monitoring at the injection wells. This direct method will be used in combination with the indirect geophysical monitoring of the CO_2 plume discussed below.

DTS/DAS fiber optic cables will be installed at all injection wells and in-zone observation wells to continuously monitor temperature and acoustic changes along the injection wellbore to detect intervals within the reservoir accepting CO_2 and to detect any potential CO_2 breakthrough at in-zone observation wells. Information on gauges and other equipment and their related specifications are discussed in the **QASP (Section 7.1)**.

Pulsed neutron capture (PNC) logging is a useful indirect plume monitoring method because it can measure water saturation within the reservoir behind the cased hole. Once injection begins, PNC logging provides the ability to record which intervals are accepting CO_2 as it reduces the saturation (from 100%) of native formation fluids. One baseline survey will be run in the injection wells and the in-zone, above-zone, and USDW wells prior to injection. Repeat PNC logging will be run in all injection wells three years after injection begins, every five years thereafter during the injection period, and before the plugging and abandonment of any injection well or AoR re-evaluation. For the in-zone wells, repeat PNC logging will be phased in three years prior to predicted plume migration to the observation well and every five years thereafter. For the above-zone and USDW observation wells, repeat PNC logging during the injection period will only occur if loss of containment is detected and will then be used as a containment verification technology.

In combination, these direct and indirect methods will allow Sugarberry CCS, LLC to monitor the CO_2 plume evolution within the reservoir and provide evidence for its containment throughout the life of the project. At the injection wells, DTS data will help reveal intervals with higher injectivity within the injection zone. PNC logging at injection wells will also reveal intervals with higher injectivity and provide quantitative measurements of CO_2 saturation within those intervals. DAS fiber optics will allow 3D imaging of the CO_2 plume within the reservoir and provide the capability to image the plume should it migrate out of the reservoir (3D DAS Vertical Seismic Profile [VSP]). VSPs using DAS offer higher resolution images of the subsurface compared to surface seismic, as well as better repeatability (El-kaseeh et al., 2018). The data collected from these various methods will be utilized for verifying and updating the computational model with plume migration predictions.

The basis for identifying a deviation from baseline during operations for the various proposed plume monitoring methods will be outlined in detail in this plan once construction, testing, logging, and baseline data collection are completed and evaluated relative to calibrated computational modeling results. In addition, Sugarberry CCS, LLC will describe the steps that will be taken if a deviation occurs during the operational period.

Table 7-8. Plume Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
Injection Zones	In-zone fluid geochemical monitoring	SB (01-05) during MITs	See **Figures 7-1 through** 7-7.	Annual, during MITs
INDIRECT PLUME MONITORING				
Injection Zones	DTS	SB-(01-05); IOB-(01-04)	Distributed measurements across target interval	Continuous (pre-operational and operational phases)
	PNC Logging[1]	SB-(01-05); IOB-(01-04); above-zone AOB-(01, 04, 05) and UOB-(01, 04) baseline only[1]	Distributed measurements across target interval	<u>Pre-Operational:</u> One baseline survey for PNC logging and 3D DAS VSP or seismic. <u>Operational:</u> Three years after injection begins, and every five years thereafter during the injection period; up to 45 days before the anniversary date of authorization of injection[2].
	1) 3D DAS VSP; OR 2) 3D seismic survey	1) SB-(01-05); IOB-(01-04); OR 2) AoR based seismic survey	1) Distributed measurements across target interval 2) Full AoR coverage focused on plume extent area	

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
1. Repeat PNC logging will only occur in AOB and UOB wells if CO_2 breakthrough and containment loss occurs. 2. For in-zone wells, repeat PNC logging will be phased in three years prior to predicted plume migration to the monitoring well and every five years thereafter.				

I.3. Pressure Front Monitoring Location and Frequency

Table 7-9 presents the methods that Sugarberry CCS, LLC will use to monitor the position of the pressure front, including the activities, locations, and frequencies proposed. **Figures 7-8 through 7-10** show the monitoring locations relative to predicted pressure differentials during the injection period.

Sugarberry CCS, LLC will use permanent electronic downhole pressure gauges (Baker Hughes SureSENS QPT gauge or equivalent) to directly monitor the pressure front, which will be placed above the packer and ported through to monitor each well's respective monitoring zone pressure on a continuous basis. Wellhead pressure gauges will additionally be installed as a backup in the event downhole gauges fail. These gauges will be installed in all injection wells, in-zone observation wells, above-zone observation wells, and USDW observation wells. Quality assurance procedures for these methods are presented in **Sections A.3 and A.4 of the QASP (Section 7.1)**.

I.4. Pressure Front Monitoring Details

As discussed above, electronic downhole pressure gauges will be installed at the injection wells, in-zone observation wells, above-zone observation wells, and USDW observation wells. In addition, external pressure gauges will be utilized at SB-02 and SB-03 to monitor pressure within the above-zone since co-located AOB wells are not proposed at those locations. The primary purpose of these devices is to monitor for the presence of the elevated pressure front within the injection zones and to monitor for pressure changes in the above-zone and USDWs for the detection of loss of containment. The downhole gauges will be comprised of corrosion resistant material and will continuously record formation pressure and temperature from fixed-point locations at a set sampling interval. While the AoR is not governed by the pressure front for the Sugarberry CCS Hub, monitoring the pressure differentials and comparing these measurements to the model predictions will allow appropriate model calibration throughout the life of the project and protect USDWs.

In addition to the capability to image the CO_2 plume, DAS has the capability to monitor microseismicity. DAS continuously detects and reports seismic events as small as magnitude -1.4 in real-time. Microseismicity via DAS will be continuously monitored during the pre-operational and operational phases.

The basis for identifying a deviation from baseline during operations for the various proposed pressure front monitoring methods will be outlined in detail in this plan once construction, testing, logging, and baseline data collection are completed and evaluated relative to calibrated computational modeling results. In addition, Sugarberry CCS, LLC will describe the steps that will be taken if a deviation occurs during the operational period.

Table 7-9. Pressure-front Monitoring Activities

<table>
<tr><th>Target Formation</th><th>Monitoring Activity</th><th>Monitoring Location(s)</th><th>Spatial Coverage</th><th>Frequency</th></tr>
<tr><td colspan="5">DIRECT PRESSURE-FRONT MONITORING</td></tr>
<tr><td>Injection Zones</td><td rowspan="3">Pressure Gauges</td><td>SB-(01-05); IOB-(01-04)</td><td>Above the packer – ported to Injection Zones</td><td rowspan="3">Continuous (pre-operational and operational phases)</td></tr>
<tr><td>Above-Zone</td><td>AOB-01, AOB-04, AOB-05</td><td>Above the packer – ported to Above-Zone</td></tr>
<tr><td>USDW</td><td>UOB-01, UOB-04</td><td>Above the packer – ported to USDW</td></tr>
<tr><td colspan="5">INDIRECT PRESSURE-FRONT MONITORING</td></tr>
<tr><td>Injection Zones</td><td>DAS passive seismicity</td><td>SB-(01-05); IOB-(01-04)</td><td>Distributed measurements across target intervals</td><td>Continuous (pre-operational and operational phases)</td></tr>
</table>

J. <u>Soil Gas Monitoring/Other Testing and Monitoring</u>

Not applicable.

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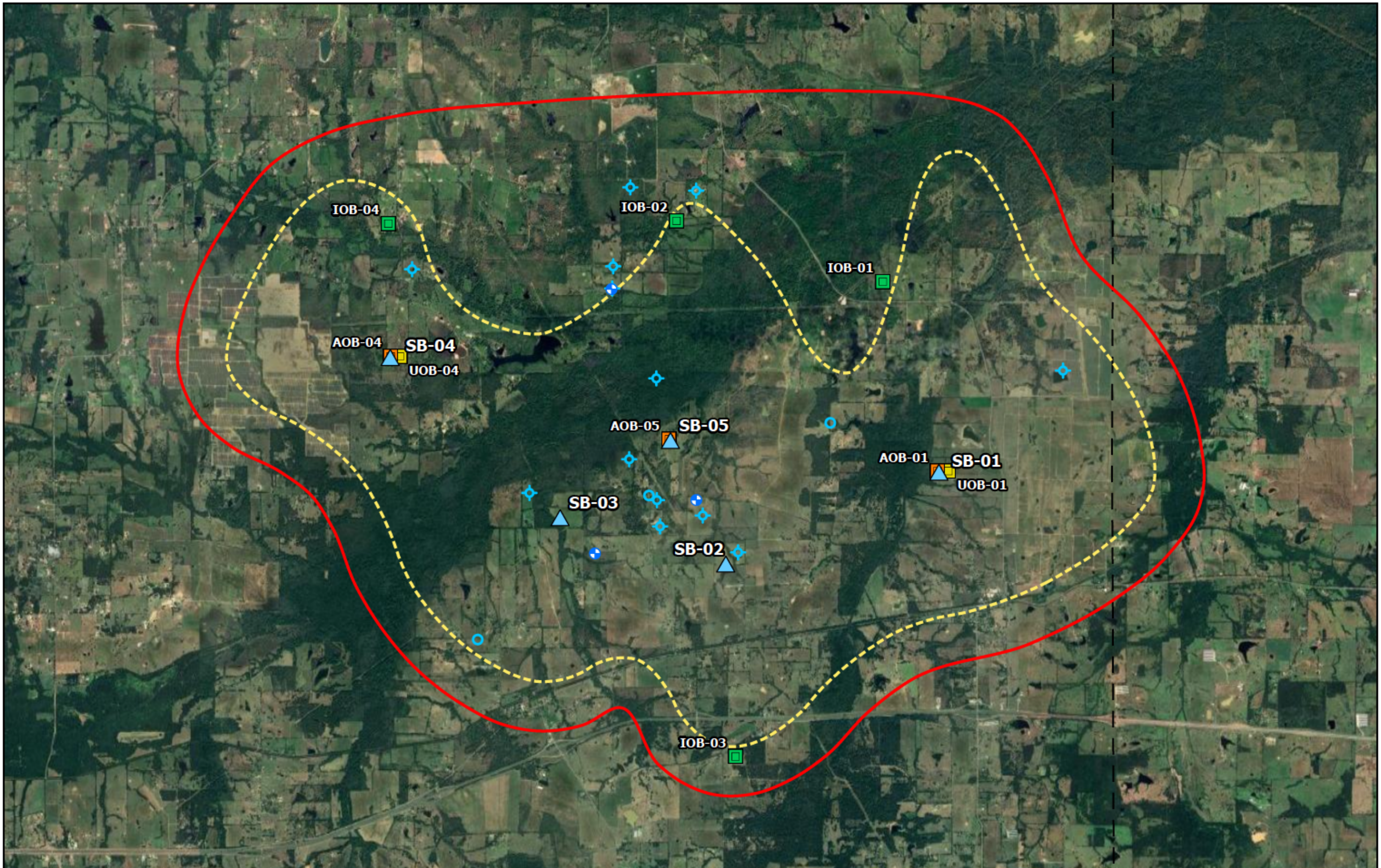
FIGURES



Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

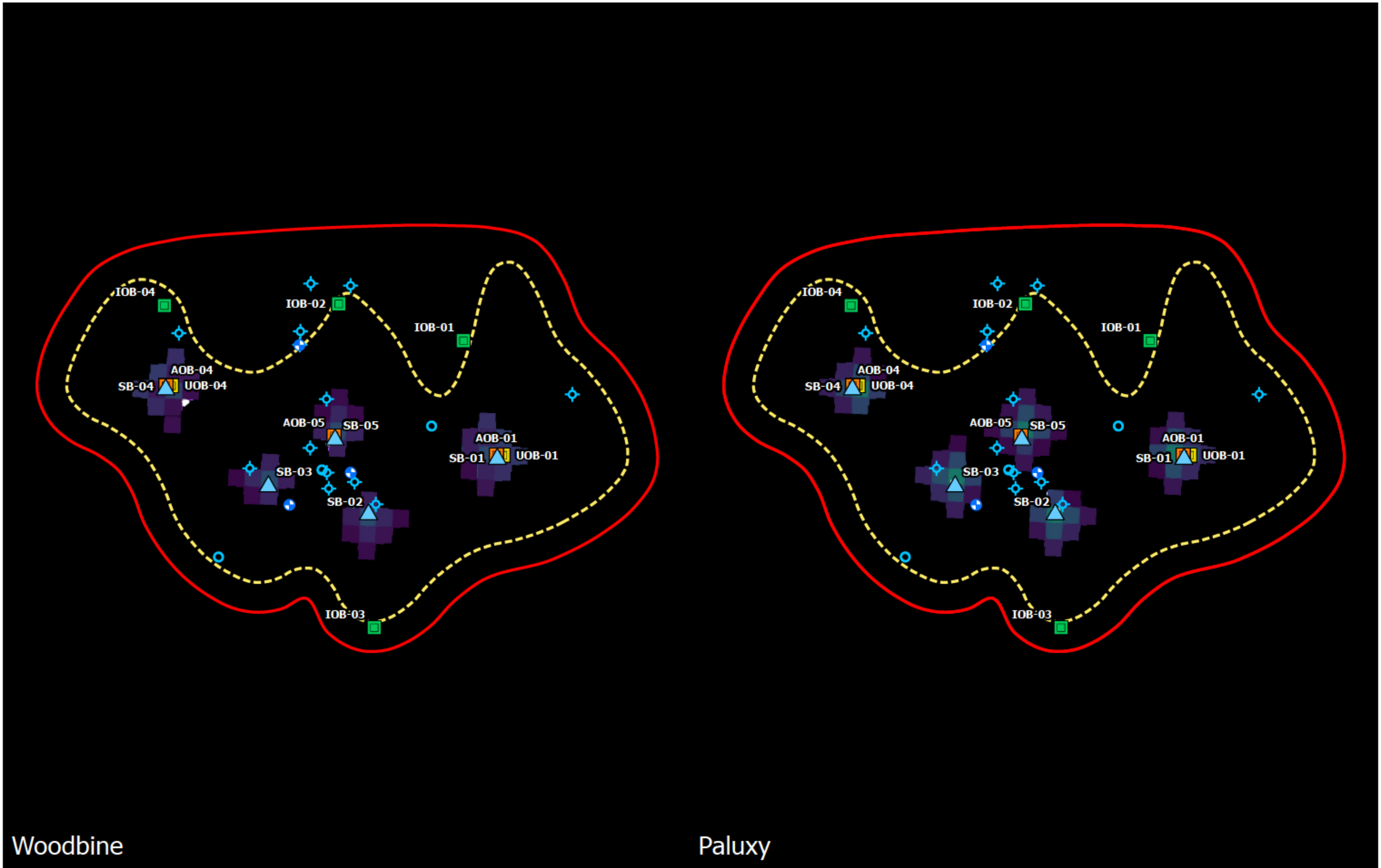
- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

FIGURE 7-1
OVERVIEW OF THE PROPOSED MONITORING NETWORK WITHIN THE AOR
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

0 1 2 Miles N



Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

CO_2 Saturation (Decimal fractions)

0.5 0.45 0.4 0.35 0.3 0.25 0.2 0.15 0.1 0.05 0.0

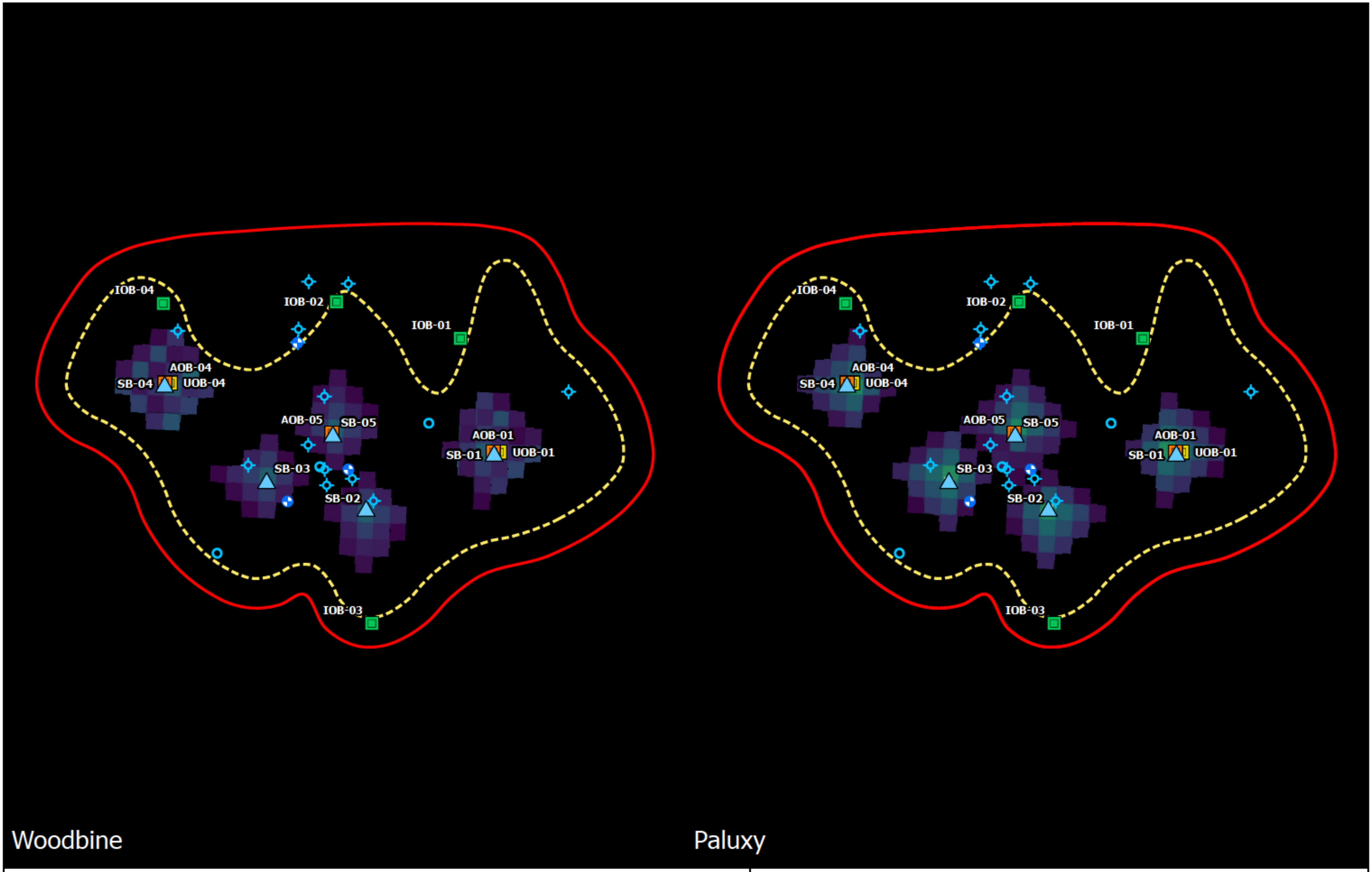
FIGURE 7-2
PREDICTED CO_2 PLUME EXTENT – YEAR 5
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

0 1 2 3 Miles

N



Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations
- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

CO_2 Saturation (Decimal fractions)

0.5 0.45 0.4 0.35 0.3 0.25 0.2 0.15 0.1 0.05 0.0

FIGURE 7-3
PREDICTED CO_2 PLUME EXTENT – YEAR 10
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

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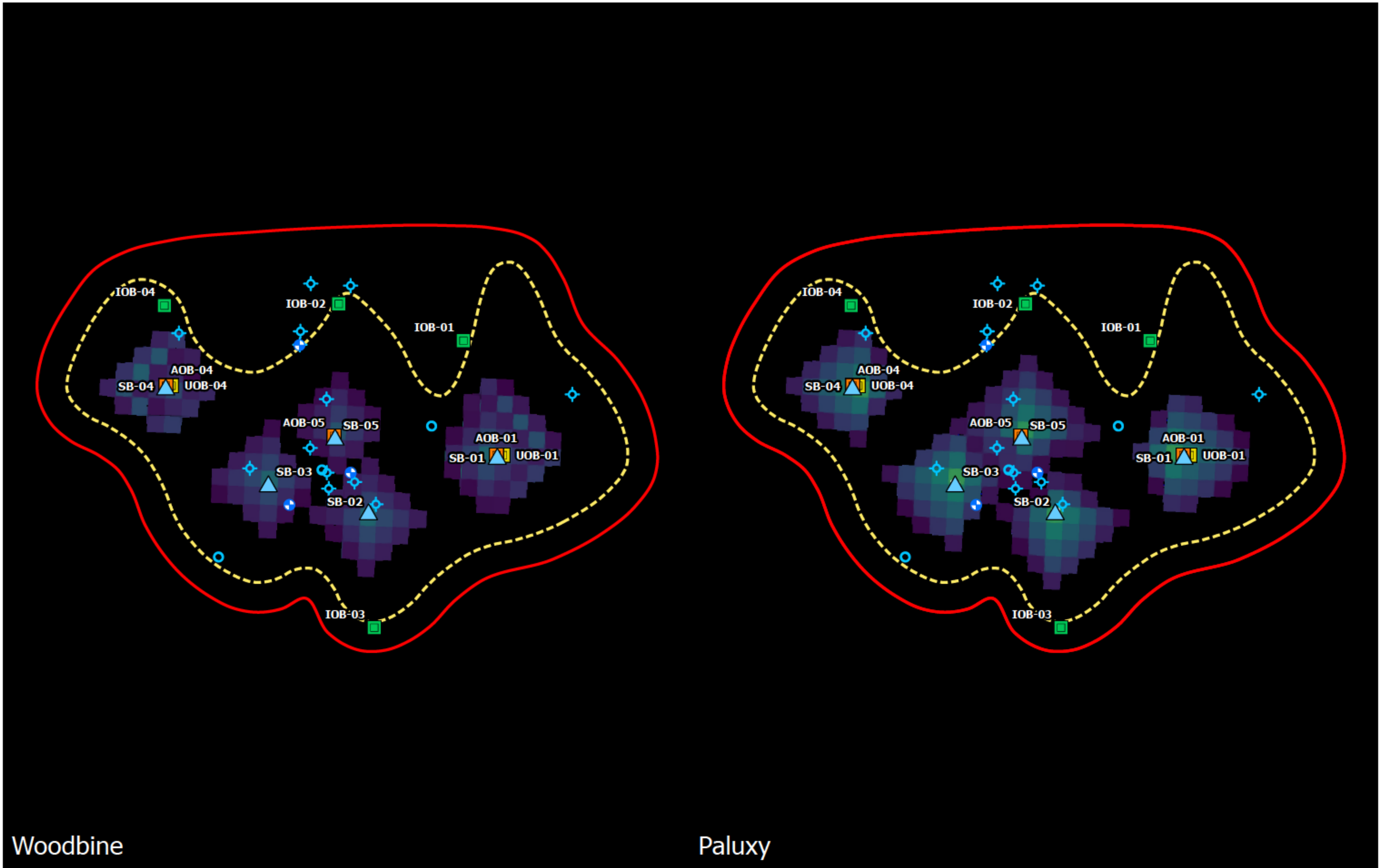
0 1 2 3 Miles

N



Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

CO_2 Saturation (Decimal fractions)

0.5 0.45 0.4 0.35 0.3 0.25 0.2 0.15 0.1 0.05 0.0

FIGURE 7-4
PREDICTED CO_2 PLUME EXTENT – YEAR 15
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

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0 1 2 3 Miles

N

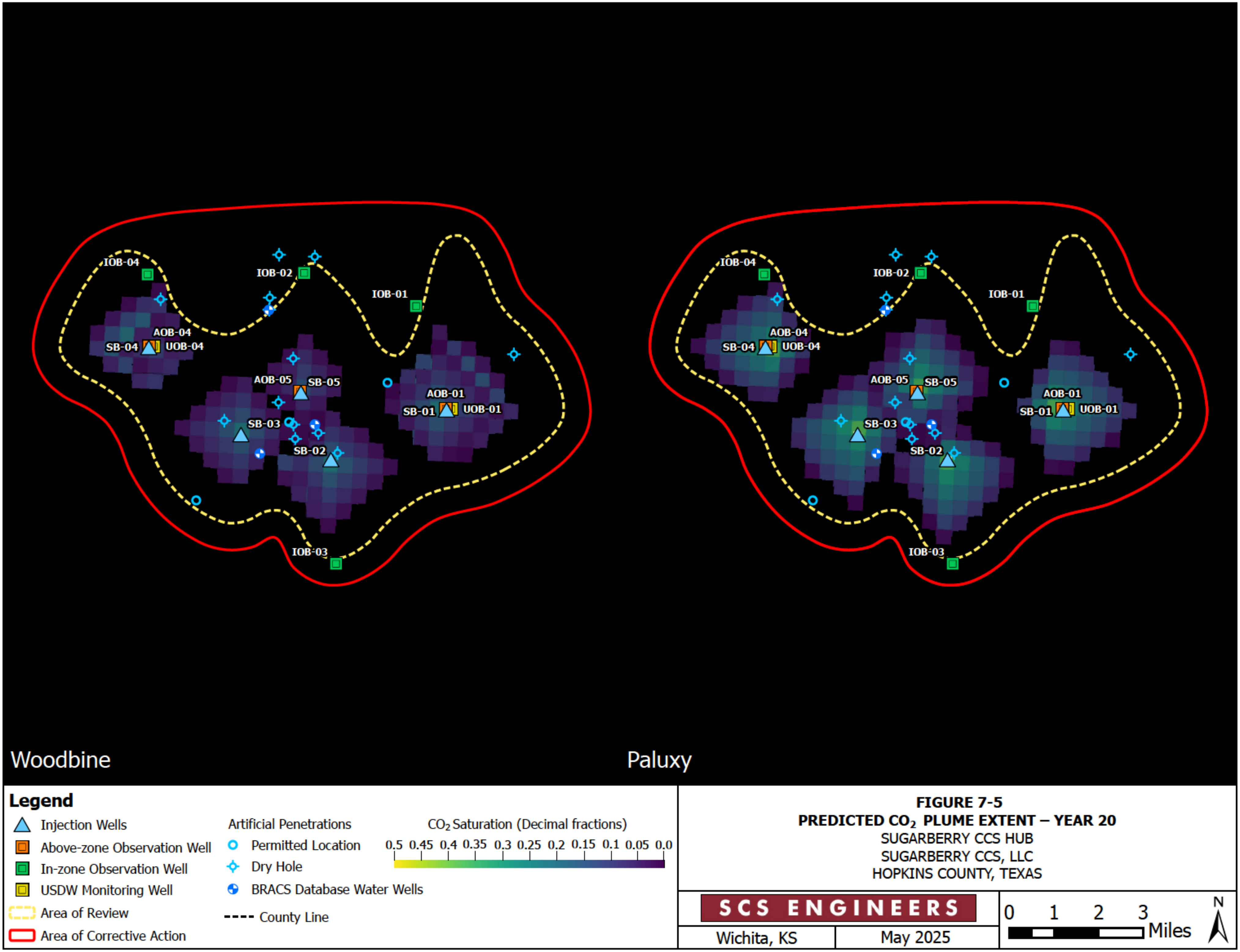

FIGURE 7-5
PREDICTED CO_2 PLUME EXTENT – YEAR 20
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

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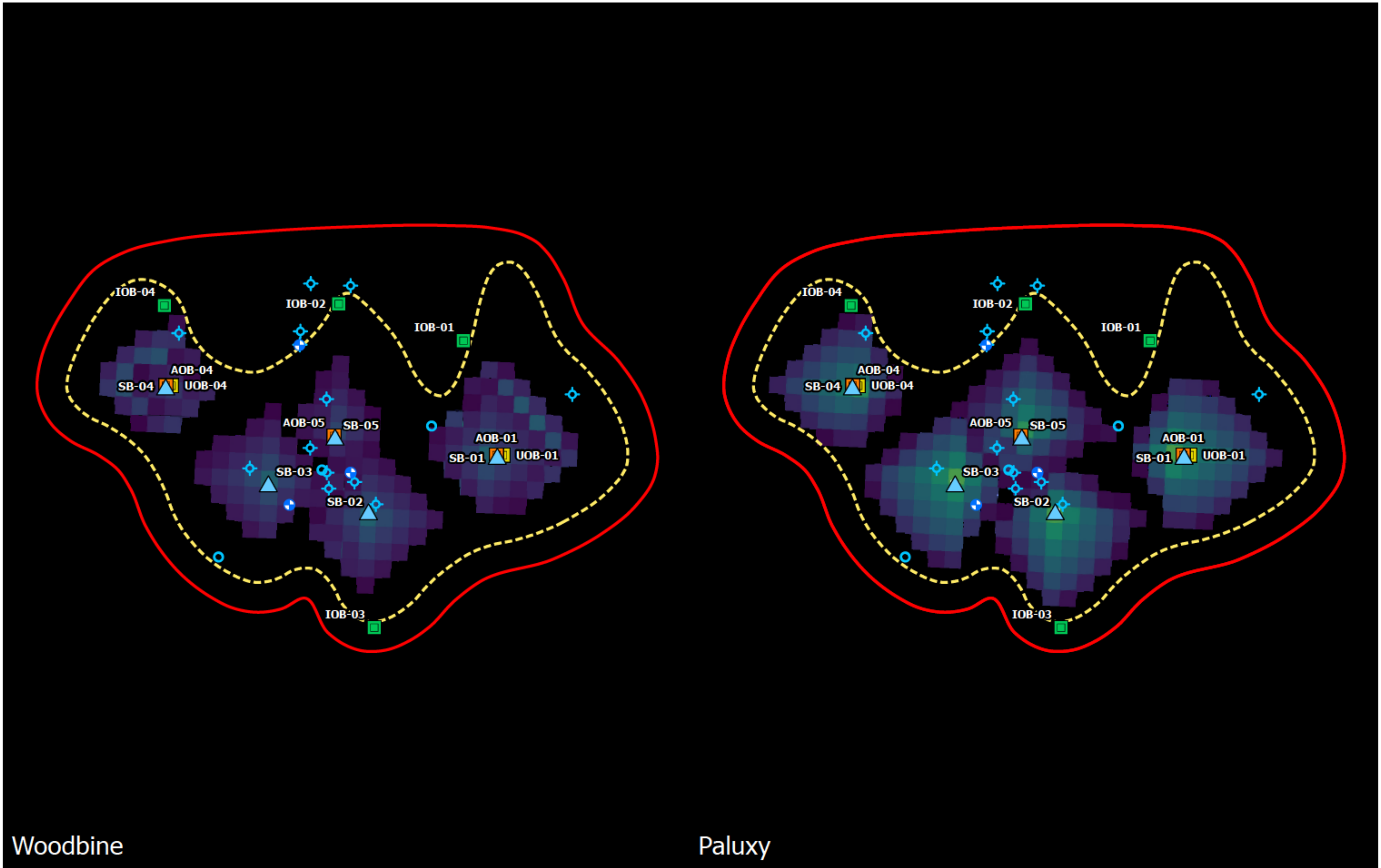

Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

CO_2 Saturation (Decimal fractions)

0.5 0.45 0.4 0.35 0.3 0.25 0.2 0.15 0.1 0.05 0.0

FIGURE 7-6
PREDICTED CO_2 PLUME EXTENT – YEAR 25
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

0 1 2 3 Miles

N

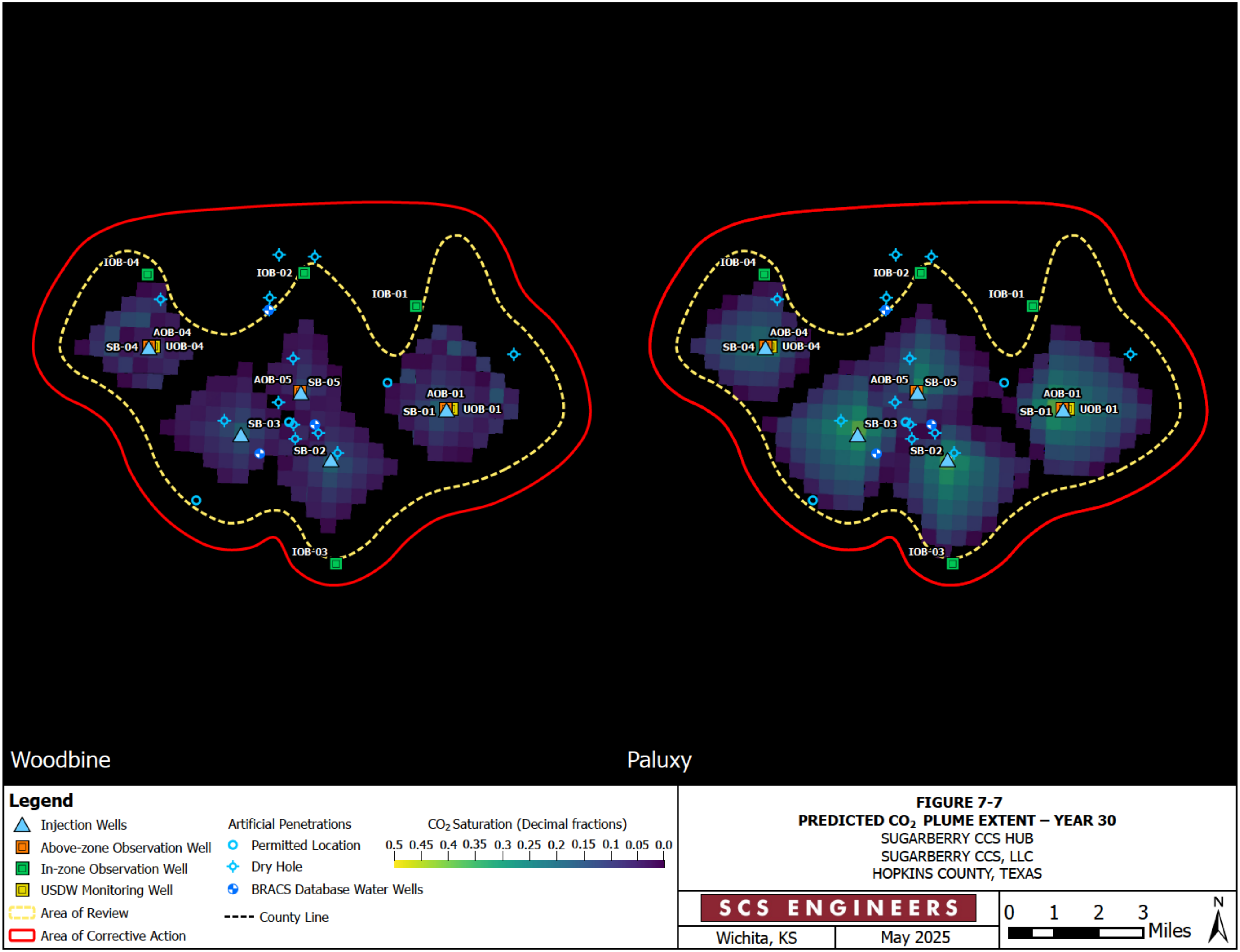

FIGURE 7-7
PREDICTED CO_2 PLUME EXTENT – YEAR 30
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

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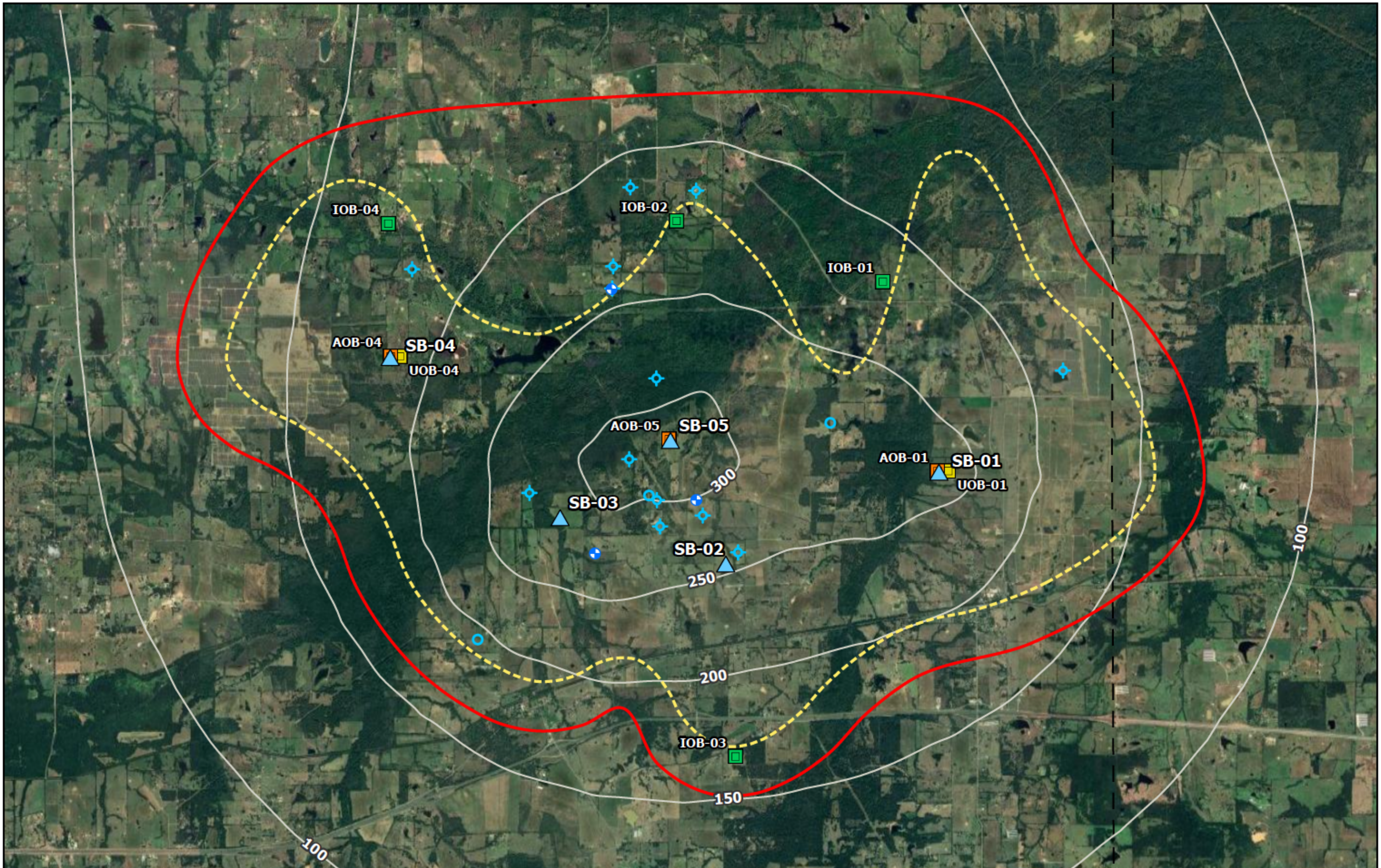


Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

Pressure Contour Intervals (50 psi)

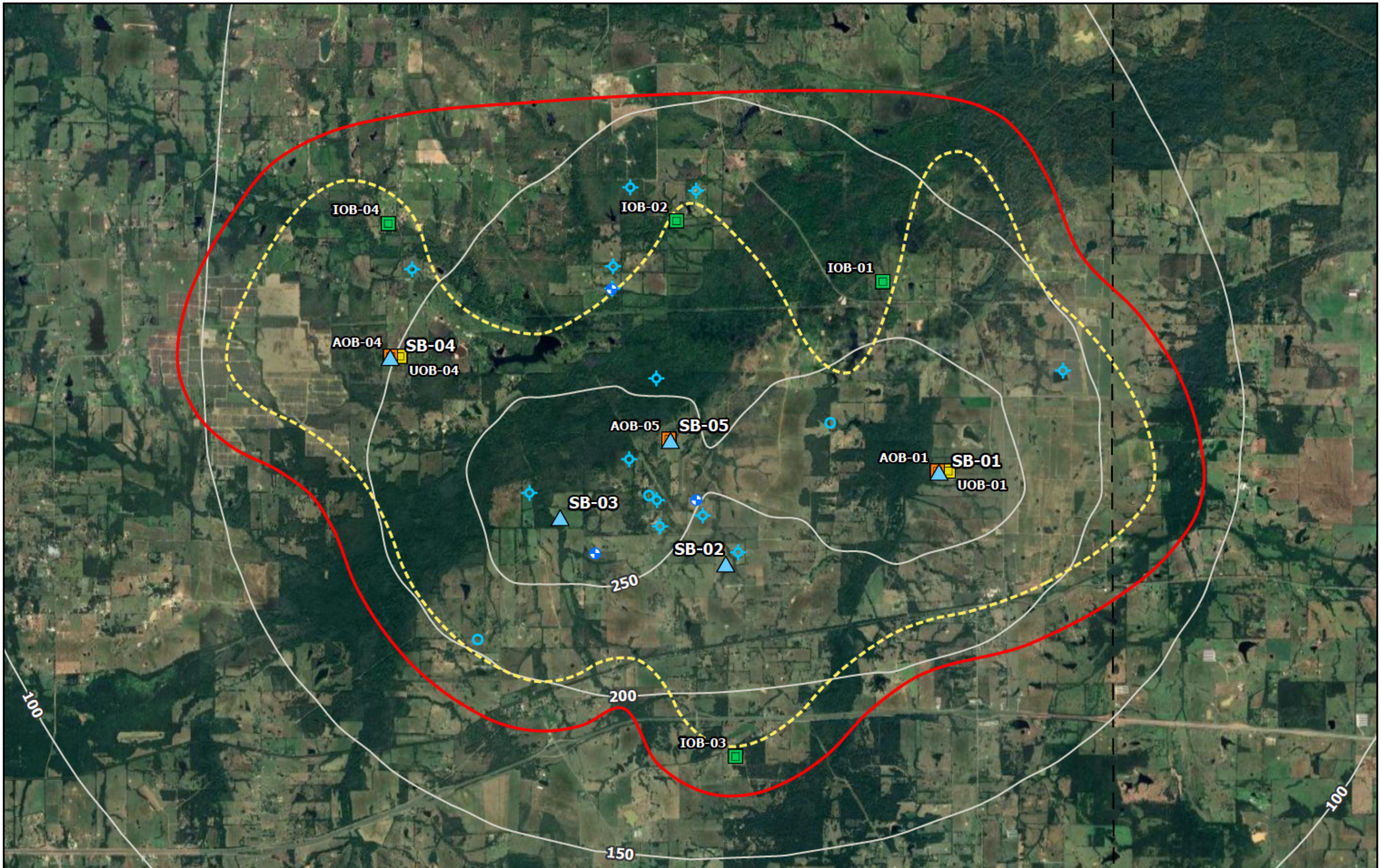
Note:
Pressure contours are modeled at the top of the Woodbine injection zone/base of the Eagle Ford confining zone.

FIGURE 7-8
PREDICTED PRESSURE DIFFERENTIAL - YEAR 10
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

0 1 2 Miles
N



Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

- Permitted Location
- Dry Hole
- BRACS Database Water Wells
- County Line

Pressure Contour Intervals (50 psi)

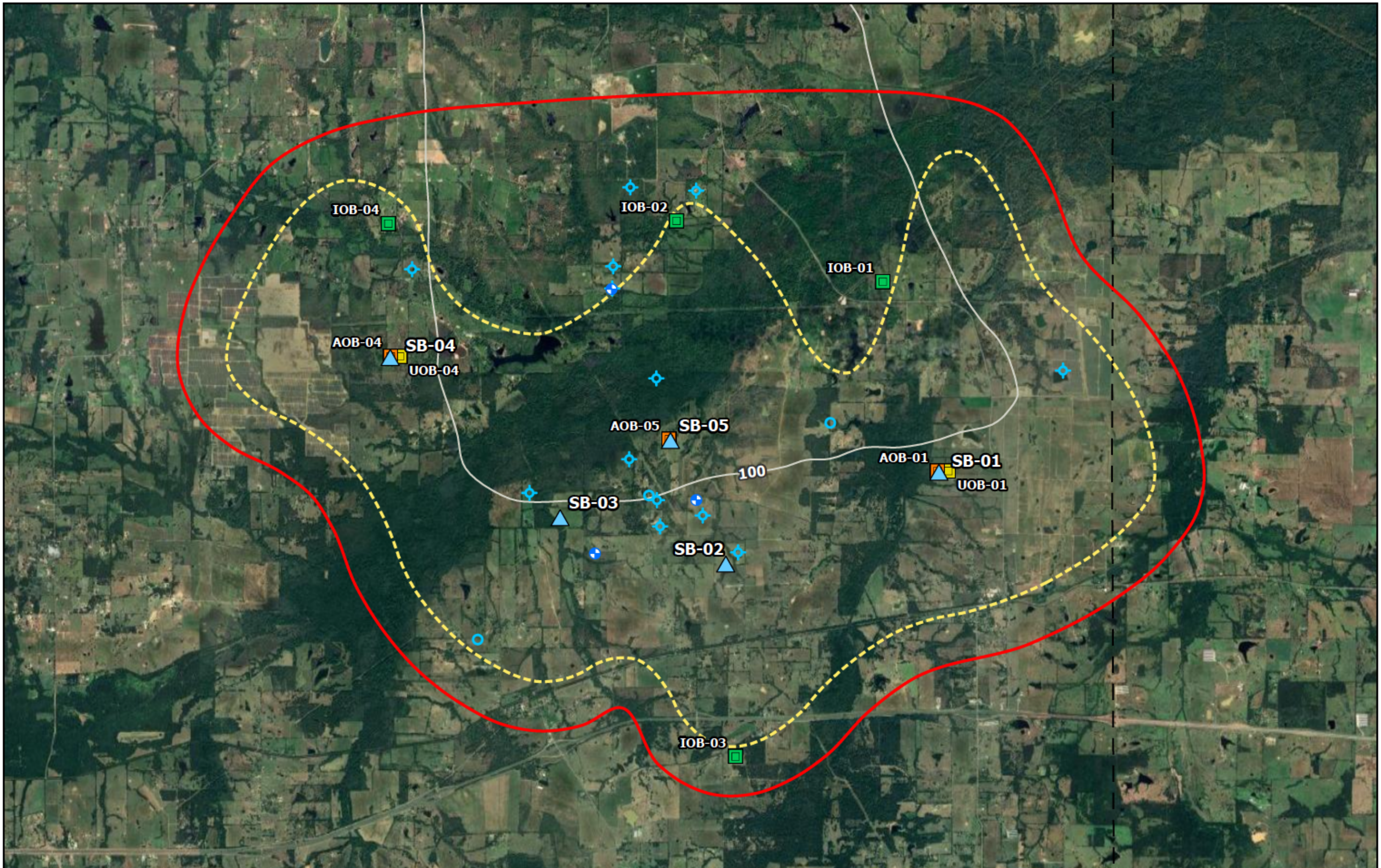
Note:
Pressure contours are modeled at the top of the Woodbine injection zone/base of the Eagle Ford confining zone.

FIGURE 7-9
PREDICTED PRESSURE DIFFERENTIAL - YEAR 20
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

0 1 2 Miles
N



Legend

- Injection Wells
- Above-zone Observation Well
- In-zone Observation Well
- USDW Monitoring Well
- Area of Review
- Area of Corrective Action

Artificial Penetrations

- Permitted Location
- Dry Hole
- BRACS Database Water Wells

County Line

Pressure Contour Intervals (50 psi)

Notes:
- Pressure contours are modeled at the top of the Woodbine injection zone/base of the Eagle Ford confining zone.
- Pressure is higher north of the 100 psi contour.

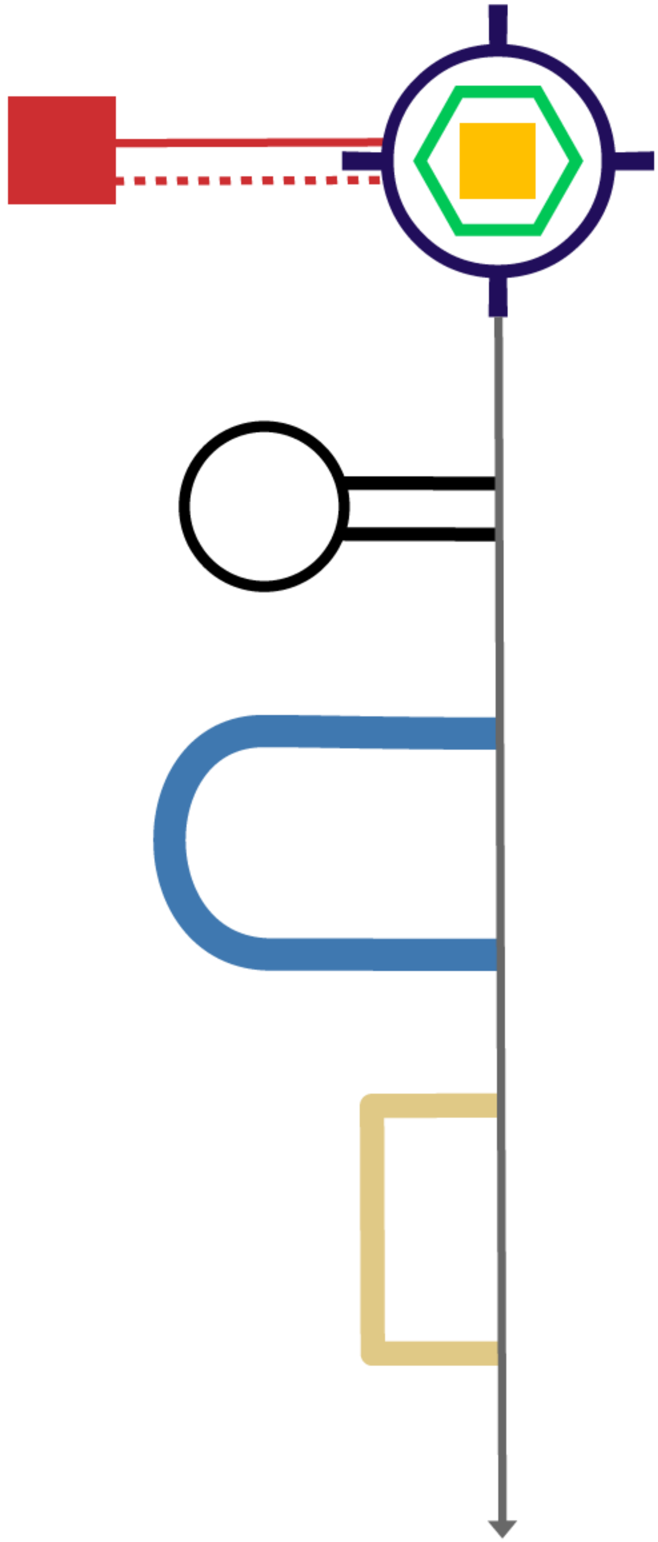
FIGURE 7-10
PREDICTED PRESSURE DIFFERENTIAL - YEAR 30
SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

0 1 2 Miles N

APPENDIX 7-A



Legend

- Well
- DTS/DAS
- Master Control Valve (All Injection and Observation Wells)
- Downhole P Gauge (All Injection and Observation Wells)
- Surface P Gauge (Injection Wells Only)
- Coriolis Flow Meter (Injection Wells Only)
- Corrosion Loop (Injection Wells Only)

CONCEPTUAL PLAN VIEW ILLUSTRATION OF THE LOCATION OF TESTING AND MONITORING EQUIPMENT AT A GIVEN WELL IN THE STORAGE COMPLEX

SUGARBERRY CCS HUB
SUGARBERRY CCS, LLC
HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025

APPENDIX 7-B

Reporting Schema	Year								
	0	10	20	30	40	50	60	70	80
SB-01	Injection Well Reporting				IOB Well Reporting				
SB-02	Injection Well Reporting				IOB Well Reporting				
SB-03	Injection Well Reporting				IOB Well Reporting				
SB-04	Injection Well Reporting			IOB Well Reporting					
SB-05	Injection Well Reporting			IOB Well Reporting					

Legend

- Testing & Monitoring Plan
- PISC Plan

REPORTING SCHEMA FOR INJECTION WELLS RELATIVE TO PROJECT PHASE

SUGARBERRY CCS HUB

SUGARBERRY CCS, LLC

HOPKINS COUNTY, TEXAS

SCS ENGINEERS

Wichita, KS | May 2025