SUMMARY OF REQUIREMENTS
CLASS VI OPERATING & REPORTING CONDITIONS
40 CFR 146.88

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

AoR	Area of Review
BHP	Bottom Hole Pressure
CCS	Carbon Capture and Sequestration
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
F	Fahrenheit
Ft	Feet/Foot
Ft/s	Feet per Second
GPM	Gallon per Minute
H_2	Hydrogen
HCL	Hydrochloric acid
IN	Inch
ID	Inner diameter
lb/gal	Pounds per gallon
LLC	Limited Liability Company
MASP	Maximum Allowable Surface Pressure
O_2	Oxygen
OD	Outside Diameter
MIT	Mechanical Injection Test
MMt	Million Metric Tons
MMt/yr	Million Metric Tons per Year
NOx	Nitrogen Oxides
PPMV	Parts per Million by Volume
PPMW	Parts per Million by Weight
psi	Pounds per Square Inch
psi/ft	Pounds per Square Inch per Foot
P/T	Pressure/Temperature
RRC	Railroad Commission of Texas
SOx	Sulfur Oxides
TAC	Texas Administrative Code
UIC	Underground Injection Control
Yr	Year

A. Introduction

Sugarberry CCS, LLC will construct five new UIC Class VI wells (SB-01, SB-02, SB-03, SB-04 and SB-05) that will be utilized for the permanent sequestration of supercritical carbon dioxide (CO_2). This **Summary of Requirements** addresses the Class VI operating and reporting conditions required in 40 CFR 146.82(a)(7) and (a)(1) and 16 TAC 5.203(i).

B. Injection Well Operation

GEOS (V.0.2.0, Livermore, CA) was used to model the injection rate and injection duration of supercritical CO_2 into the Woodbine and Paluxy injection zones for the injection wells. The model assumes dual completions in the Woodbine and Paluxy Formation injection intervals. Reference the **Area of Review and Corrective Action Plan (Section 2)** for model inputs and results. Target injection rates, target injection rate durations, target surface injection pressures, and bottom hole pressure (BHP) constraints were provided as inputs to the GEOS simulator. The target injection rates, and injection rate durations, are based on the expected volumes of CO_2 produced by future emitters in the area, including power plants, cogeneration plants, hydrogen production facilities, gas processing facilities, refineries, and petrochemical facilities near the Sugarberry CCS Hub. The target surface injection pressure is based on pipeline constraints as well as the pressure and temperature constraints (P/T) required to maintain CO_2 in a supercritical state. The BHP constraint used in the simulations is based on a typical formation fracture gradient for sandstones and, in accordance with 40 CFR 146.88, indicates that the injection rate and associated injection pressure cannot exceed 90% of the fracture gradient for each formation. The maximum allowable surface pressure (MASP) identified for injection at the Sugarberry CCS Hub is 2,200 psi and is based on expected CO_2 transport pipeline specifications. For the GEOS simulations, a standard surface pressure of 1,250 psi was utilized, which is below the MASP and meets the P/T requirements for supercritical CO_2 transport.

B.1. Injection Well Startup and Operation Procedures

Sugarberry CCS, LLC will initiate injection and will monitor operations in accordance with 40 CFR 146.90(b). Startup procedures will be implemented in a multi-step fashion, utilizing real-time surface and downhole pressure and temperature data from the injection wells, in-zone and above-zone observation wells.

A series of progressively higher injection rates will be used during the startup, with time and pressure values recorded for each rate and time step. The injection pressures will not exceed the maximum permitted bottomhole injection pressure, which is 90% of the top of the injection interval depth fracture pressure described above.

Injection data (rate, pressure and temperature) will be continuously recorded in the injection wells and formation data (pressure) will be continuously recorded in the observation wells. During the startup period, Sugarberry CCS, LLC will plot injection rate and the corresponding pressure values to graphically demonstrate well integrity. If signs of anomalous pressure behavior are detected, Sugarberry CCS, LLC will conduct additional monitoring to characterize any anomalies. If anomalous pressure is observed, which may indicate downhole pressure that could lead to formation fracturing, injection will cease and the injection well will be shut-in. Sugarberry CCS, LLC will notify the UIC Program Director within 24 hours and consult before resuming injection.

During startup and throughout operation of the injection wells, Sugarberry CCS, LLC will collect and report the operational data as required by 40 CFR 146.91(a) and outlined in **Testing and Monitoring Plan (Section 7)**. If requested, the final injection well startup procedures will be provided to the UIC Program Director.

Table 6-1 provides the anticipated injection well operating conditions at Sugarberry CCS Hub. These conditions form the basis of well design and material selection for the injection wells. Injection rates for wells SB-01 through SB-05 are assumed to be held constant throughout their designated lifespan, but injection rate duration varies by well location. At wells SB-01, SB-02, and SB-03, CO_2 will be injected into the Paluxy injection interval for 30 years and the Woodbine injection interval for 20 years. At wells SB-04 and SB-05, CO_2 will be injected into the Paluxy injection interval for 20 years and the Woodbine injection interval for 10 years. Injection into the Woodbine and Paluxy is concurrent as detailed in the **AoR and Corrective Action Plan (Section 2)**.

Table 6-1. Injection Well Operating Conditions

Parameter	Value	Notes
Maximum Injection Pressure at Surface	2,200 psi	MASP as determined by CO_2 surface pipe pressure ratings
Maximum Injection Pressure Downhole[1]	Woodbine – 1,886 psi Paluxy – 3,182 psi	Determined by using 90% of fracture gradient of 0.7 psi/ft[2]
Average Injection Pressure at Surface	1,250 psi	Expected pressure to maintain CO_2 in supercritical state
Average Injection Pressure Downhole[3]	Woodbine – <1,886 psi Paluxy – <3,182 psi	Determined to be less than the maximum injection pressure by using 90% of fracture gradient of 0.7 psi/ft[1]

[1] The maximum injection pressure downhole is the bottom-hole pressure model input constraint, detailed in Section C of the **Area of Review and Corrective Action Plan (Section 2)**.
[2] The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined using a fracture gradient of 0.7 psi/ft. This fracture gradient is considered a conservative estimate for Gulf Coast strata as provided in Eaton (1969) and Anderson (1973).
[3] The average injection pressure downhole is the resulting bottom-hole pressure required to maintain the targeted injection rate without exceeding the modeled constraint, detailed in Section C of the **Area of Review and Corrective Action Plan (Section 2)**. Specific ranges and values will be provided upon receipt of the pre-injection testing results.

Parameter	Value	Notes
Maximum Injection Rate	Woodbine – 0.25 MMt/yr Paluxy – 0.65 MMt/yr Combined – 0.90 MMt/yr	Assumes combined flow will be separated into distinct flow regimes at each injection zone via sliding sleeves
Average Injection Rate	Equal to Maximum Injection Rate	
Maximum Injection Volume	Woodbine – 20 MMt Paluxy – 84.5 MMt	
Average Injection Volume	Equal to Maximum Injection Volume	
Volume Flow Rate[4]	Woodbine – 19.8 kg/s Paluxy – 51.5 kg/s Combined – 71.3 kg/s	Maximum flow rate in tubing
Flow Velocity in Tubing	5.5-in: 11.47 ft/s	Maximum flow velocity assuming 5.5-in OD tubing with 4.67-in ID
Annulus Pressure	1,375 psi	~10% higher than expected injection pressure
Annulus Pressure/Tubing Differential	125 psi	
Minimum annulus pressure at wellhead	100 psi	Minimum Requirement
Minimum differential pressure (directly above and across upper packer)	100 psi	Minimum Requirement
In-Situ Pressure at Top of Injection Zone Perforations	Woodbine –1,377 psi Paluxy – 2,323 psi	Determined using the pore pressure gradient of 0.46 psi/ft[5]
Maximum pressure at top perforation	Woodbine – 1,886 psi Paluxy – 3,182 psi	Determined by using 90% of fracture gradient of 0.7 psi/ft[1]
Planned Injection Duration	–Years 1 through 30	Planned total of 24.5 MMt CO_2 per well injected in SB-

[4] Output from GEOS simulation and detailed in Section B of the **Area of Review and Corrective Action Plan (Section 2)**.
[5] Derived from documentation of GEOS simulation.

Parameter	Value	Notes
Wells SB-01, SB-02, SB-03		01, SB-02, & SB-03 over 30 years
Planned Injection Duration Wells SB-04, SB-05	Years 1 through 20	Planned total of 15.5 MMt CO_2 per well injected in SB-04 & SB-05 over 20 years
Injection Type	Continuous	Continuous w/ intermittent downtime for maintenance

Sugarberry CCS, LLC will constrain CO_2 stream composition from customer sources through implementation of a gas tariff on the project's pipeline. This gas tariff will be filed with the Railroad Commission of Texas to establish the pipeline as a Common Carrier. The gas tariff mandates maximum allowable concentrations, shown in **Table 6-2** below, to which customers are committed to meeting under the services agreement.

CO_2-induced corrosion affecting well components is not likely due to the anticipated low water content within the CO_2 stream. Sugarberry CCS, LLC will monitor for potential corrosion induced by the injectate as outlined in **Section E of the Testing and Monitoring Plan (Section 7)**.

Table 6-2. CO_2 Stream Characteristics

Parameter	Value	Notes
CO_2 Stream Characteristics	Carbon Dioxide (CO_2) >95 Mol% dry Carbon Monoxide (CO) <1000 ppmv Water (H_20) <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 NO_x <100 ppmv Glycol <1 ppmv	Represents gas tariff established for the project pipeline

Parameter	Value	Notes
	Hydrogen (H_2) <1 mol% Inert Gasses (Non-Condensable) <5 Mol%, dry Oxygen (O_2) <20 ppmv Particulate Matter <1 ppmw Max Temperature 130° F Min Temperature 40° F	
CO_2 Stream Density	5.85 lb/gal	At 1,250 psi and 89.3° F

B.2. Routine Shutdown, Workover, and Maintenance Procedures

Routine well maintenance and workovers will be conducted to ensure safe and compliant operating conditions. The procedures for well maintenance will vary depending on the specific needs of the procedure. All maintenance and workover operations will be closely monitored to prevent any loss of mechanical integrity. Barriers, such as downhole plugs, will be used to minimize the risk of leakage. As outlined in the **Testing and Monitoring Plan (Section 7)**, Sugarberry CCS, LLC will notify the UIC Program Director of any planned workover or injection well test at least 30 days in advance. The results of injection well testing or workover will be provided within 30 days after the test or workover is completed, in accordance with 40 CFR 146.91.

Each injection well is designed to allow the installation of a temporary plug below the tubing, enabling the removal and replacement of the tubing as needed while maintaining a barrier in place. The bottomhole temperature and pressure gauge is set above the packer, allowing for replacement if necessary, without removing the packer from the well.

For injection shutdowns occurring under routine conditions the permittee will reduce CO_2 injection to ensure protection of health, safety, and the environment. Procedures that address immediately shutting in the well are in the **Emergency and Remedial Response Plan (Section 10)**.

C. Injection Well & Project Reporting Requirements

Table 6-3 below provides the reporting requirements and frequencies for the proposed injection wells. **Table 6-4** contains overall project reporting requirements and frequencies. Reference the **Testing and Monitoring Plan (Section 7)** for a comprehensive list of all testing and monitoring frequencies and methodologies.

Table 6-3. Class VI Injection Well Reporting Requirements

Activity	Reporting Requirements
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Table 6-4. Class VI Project Reporting Requirements

Activity	Reporting Requirements
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update
Re-evaluation of the AoR and other affected plans	Every 5 years or based on the triggers specified in the **Area of Review and Corrective Action Plan (Section 2)**

References

Anderson, R.A., Ingram, D.S., and Zanier, A.M. (1973). Determining Fracture Pressure Gradients From Well Logs. Journal of Petroleum Technology (Nov 1973) 1259-1268. American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc. Transactions.

Eaton, Ben A., (1969). Fracture Gradient Prediction and Its Application in Oilfield Operations. Journal of Petroleum Technology (Oct 1969) 1353-1360. American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc. Transactions (volume 246).

GEOS V.0.2.0 (2023). Developed cooperatively by Lawrence Livermore National Laboratory, Stanford University, TotalEnergies, and Chevron. Livermore, CA. Online GEOS User Guide (https://geosx-geosx.readthedocs-hosted.com/en/latest/index.html)