Underground Injection Control
Carbon Sequestration
Class VI Permit Application

INJECTION WELL OPERATIONS
40 CFR 146.82(7) & (10)
Section 7.0

Tallgrass High Plains Carbon Storage, LLC
Western Nebraska Sequestration Hub

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7.0 INJECTION WELL OPERATIONS

WESTERN NEBRASKA SEQUESTRATION HUB

Facility Information

Facility name: Western Nebraska Sequestration Hub
Conestoga I-1

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Well location: Kimball County, Nebraska
[redacted]

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ACRONYMS AND ABBREVIATIONS

°	degrees
A	
AoR	area of review
B	
BHP	bottomhole pressure
C	
CFR	Code of Federal Regulations
CO_2	carbon dioxide
E	
EPA	U.S. Environmental Protection Agency
F	
F	Fahrenheit
M	
MMcf	million cubic feet
Mt	million tons
Mta	million tons per annum
mol%	mole percent
P	
psi	pounds per square inch
psig	pounds per square inch gauge
ppm	parts per million
U	
USDW	underground source of drinking water

7.0 Injection Well Operations [40 CFR 146.82(A)(7) and (10)]

7.1 Operational Procedures [40 CFR 146.82(a)(10)]

The following information (**Table 7.1**) provides the operating parameters and engineering criteria during injection operations required under 40 CFR 146.82(a)(7) and (10). Using these criteria, the injection well will be operated to prevent the migration of carbon dioxide (CO_2) from the approved zone and into an underground source of drinking water (USDW).

Table 7.1—Proposed injection well operating parameters.

Item	Values	Description/Comments
Injected Volume		
Total Injected Volume (Mt)	27.1	Based on expected injection
Injection Rates		
Proposed Average Daily Injection Rate (Mta)	2.26	Based on expected injection
Calculated Maximum Injection Rate (Mta)	2.28	Modeled maximum injection rate based on wellhead pressure limit of [redacted] psi
Pressure		
Formation Fracture Pressure at Top Perforation (psi)	[redacted]	
Average Operating Surface Injection Pressure (psi)		
Maximum Operating Surface Injection Pressure (psi)		
Average Operating BHP (psi)		
Maximum BHP (psi)		
Tubing-Casing Annular Pressure		

Notes: Mt = million metric tons, Mta = million metric tons per annum, psi = pounds per square inch, BHP = bottomhole pressure.

7.1.1 Injection Rate

The injection rate for CO_2 into the Lyons Formation is modeled and estimated to be constant at 2.26 Mta.

7.1.2 Maximum Injection Pressure

The fracture gradient of the Lyons Formation is estimated to be [redacted] psi/ft. The maximum allowable sand face pressure gradient is calculated by multiplying the fracture gradient by 90%. This yields a maximum injection pressure gradient of [redacted] psi/ft × 90% = [redacted] psi/ft, or [redacted] psi at the top perforation. However, the injection operations at the WNS Hub are limited by surface facilities and therefore the surface wellhead pressure will be limited to [redacted] psi. The maximum bottomhole injection pressure modeled will be [redacted] psi.

7.1.3 CO_2 Volume

The total volume of CO_2 injected and stored in the Lyons Formation is estimated to be 27.1 Mt.

7.1.4 Annulus Pressure

The annulus will be filled with base oil with a nitrogen cap. Significant temperature fluctuation can occur downhole during startup and shutdown of injection operations. The requirement to maintain the annulus pressure at least 100 psi above the tubing pressure will be affected by changes in annulus temperature and, consequently, pressure. The nitrogen cap will provide a compressible cushion to absorb pressure fluctuations in the annulus. The annulus pressure will be at least 100 psi above the tubing wellhead pressure. With the tubing wellhead pressure limited to [redacted] psi, the expected maximum allowable annulus pressure is [redacted] psi. Modeling indicated that a maximum injection pressure of [redacted] psi would result in an annulus pressure of [redacted] psi. Therefore, the annulus pressure is expected to range from [redacted] psi to a maximum of [redacted] psi.

7.1.5 Well Stimulation Procedures

Conestoga I-1 may require a stimulation program over selected intervals after well perforation, depending on downhole conditions. The zones will be chosen based on well log, core, and formation testing evaluations. Throughout the project timeline, additional well data will become available from the drilling and data collection from the Conestoga I-1. Core testing will be performed for fluid compatibility and reactivity. Additional data will be used to design stimulation procedures submitted to EPA Region 7 for approval. Any downhole-injected chemicals will comply with state and federal regulations. See *Section 12—Stimulation Program* for details on the planned stimulation program, should it be needed.

7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The Project will include multiple sources of CO_2 with the expected injectate stream composition at injection shown in **Table 7.2**. The CO_2 stream must meet High Plains' pipeline specifications and will be approximately [redacted]% or greater CO_2 concentration. The maximum temperature at source and at injection is [redacted] °F. Future samples and laboratory testing will validate the injectate stream composition.

Table 7.2—Expected composition of an injectate stream.

Constituent	Limit
[redacted]	[redacted]

Notes: mol% = mole percent, ppm = parts per million, MMcf = millions of cubic feet, psig = pounds per square inch gauge

High Plains plans to inject an average of 2.26 Mta of CO_2 for 12 years into Conestoga I-1. The total volume to be injected is 27.1 Mt over the life of the Project. The maximum bottomhole injection pressure of [redacted] psi is less than 90% of the formation fracture pressure ([redacted]si), reducing the risk to USDWs. The estimated Lyons Formation reservoir temperature is [redacted]F, and the fluid in the injection zone is assumed to be brine with [redacted] mg/L TDS. All values will be confirmed during testing of the Conestoga I-1.