Underground Injection Control
Carbon Sequestration
Class VI Permit Application

CONSTRUCTION DETAILS

40 CFR 146.86

Section 5.0

Tallgrass High Plains Carbon Storage, LLC
WESTERN NEBRASKA SEQUESTRATION HUB

January 2025

Prepared by:

Jessica Gregg (Director, Geoscience Compliance)
Tallgrass High Plains Carbon Storage, LLC
370 Van Gordon St
Lakewood, CO 80228

5.0 CONSTRUCTION DETAILS

WESTERN NEBRASKA SEQUESTRATION HUB

Facility Information

Facility Name: Western Nebraska Sequestration Hub
Conestoga I-1

Facility Contacts:

Craig Spreadbury | Vice President, Carbon Capture & Sequestration
Tallgrass High Plains Carbon Storage, LLC
370 Van Gordon St
Lakewood, CO 80228
craig.spreadbury@tallgrass.com

Jessica Gregg | Director, Geoscience Compliance
Tallgrass High Plains Carbon Storage, LLC
370 Van Gordon St
Lakewood, CO 80228
jessica.gregg@tallgrass.com

Well Location: Kimball County, Nebraska
[redacted]

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ACRONYMS AND ABBREVIATIONS

25CR	25 chromium
A	
AoR	area of review
API	American Petroleum Institute
B	
bbl	barrel
BHA	bottomhole assembly
BTC	buttress thread coupling
BTU	British Thermal Units
C	
C	Celsius
CO_2	carbon dioxide
CRA	corrosion resistant alloys
E	
EPA	Environmental Protection Agency
F	
F	Fahrenheit
ft	foot or feet
H	
H_2S	hydrogen sulfide
HC1	hydrochloric acid
HF	hydrofluoric acid
I	
ID	inner diameter
in.	inch or inches
K	
KB	kelly bushing
L	
lbf	pounds (force)
lbm	pounds (mass)
lbm/ft	pounds per foot
LOC	loss control materials
M	
Mta	million tons per annum (year)
MSE	matrix stimulation engineering
N	
NOGCC	Nebraska Oil and Gas Conservation Commission
O	
OD	outside diameter

OBM	oil based mud
OEM	original equipment manufacturer
P	
P-GAUGE	pressure gauge
P/T	pressure and temperature
PPG	pounds per gallon
psi	pounds per square inch
psi/ft	pounds per square inch per foot
R	
RCN	rubber coated nylon
S	
SS	sandstone or subsea
SH	shale
T	
TH.	thickness
TOC	top of cement
TD	total depth
TDS	total dissolved solids
U	
USDW	underground source of drinking water
W	
w/m	watts per meter
WBM	water based mud
WT	weight

5.0 CONSTRUCTION DETAILS

5.1 Introduction

Tallgrass High Plains Carbon Storage, LLC (High Plains) has planned one new injection well for the Project, Conestoga I-1. The construction details for the Conestoga I-1 are described in detail in this section. The Conestoga I-1 will be drilled and constructed for carbon dioxide (CO_2) injection. This section meets the requirements of 40 CFR §146.82(a)(9), (11), and (12) by providing the text, tables, and figures to fulfill the injection well construction data requirements listed in 40 CFR §146.86. The wellbore diagram of the proposed design for Conestoga I-1 is included in **Figure 5.1**. Detailed specifications of the casing, cement, tubing, and packer for the Conestoga I-1 are presented in **Table 5.3**.

An additional well design for the Conestoga M-1 monitoring well is included in **Section 5.4**, with the design shown in **Figure 5.2**. The Conestoga M-1 will reach total depth (TD) above the injection zone for the Project. The well has been designed to allow the first permeable zone (Sundance Formation) above the upper confining zone to be monitored. This monitoring well is being permitted for construction through the Nebraska Oil and Gas Conservation Commission (NOGCC). The well design for the Conestoga M-1 is shown in the diagrams below, and an updated as-built diagram will be provided after well construction.

Bottomhole assemblies and drill string modeling will be performed to prevent excessive deviation. Deviation surveys will be taken while drilling, and the well will be corrected for direction and/or inclination if required. All downhole equipment will be operated within OEM specifications to prevent damage to the bottomhole assembly (BHA) and drill string. If drilling equipment is lost downhole, fishing services are available for recovery. A loss circulation response plan will be implemented in collaboration with the drilling fluid services provider, and materials will be made available on-site. Cement modeling will be conducted prior to the design proposal, and the cement provider will adhere to all regulatory requirements, API specifications, and recommended practices.

5.2 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

Stimulation to enhance the injectivity potential of the injection zone may be necessary. Stimulation may involve but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection formation. Advance notice of all proposed stimulation activities will be provided to the Director, as detailed below, prior to conducting the stimulation. High Plains will describe any fluids to be utilized for stimulation activities and demonstrate that the stimulation will not interfere with containment. High Plains will submit proposed procedures for all stimulation activities to the Director in writing at least 30 days in advance, per 40 CFR 146.91(d)(2). Within the 30-day notice period, EPA may deny the stimulation, approve the stimulation as proposed, or approve the stimulation with conditions. High Plains will carry out the stimulation procedures including any conditions, as approved or set forth by EPA, as discussed in *Section 12—Stimulation Program.*

5.2.1 Introduction

Matrix stimulation is the process of injecting a fluid (acid or solvent) into an existing or newly completed well below the fracturing pressure to remove or bypass damage. This technique is common and has been used extensively to improve production or injection rates. The primary goal of matrix stimulation in sandstones is to restore the natural permeability, i.e., to obtain the undamaged flow capacity in the injection zone by removing the formation damage. Dramatic rate-increasing results may be achieved via matrix stimulation if treatments are appropriately engineered, which includes tasks done within a predefined methodology, Matrix Stimulation Engineering (MSE), and the practical application of scientific and mathematical principles to matrix stimulation. The MSE process steps are:

- Formation Damage Determination
- Fluid Selection
- Treatment Design
- Execution
- Treatment Evaluation

The matrix stimulation process below includes procedures for two time periods: before the beginning of the injection and during the injection period. The latter will be determined based on injection performance and routine analysis.

5.2.2 Stimulation Fluids *(if downhole well conditions deem necessary)*

High Plains will use industry-standard acid blends for matrix stimulation, including but not limited to mixtures of [redacted]

5.2.3 Additives *(if downhole well conditions deem necessary)*

High Plains may use combinations of the following additives to aid matrix stimulation while mitigating tubular corrosion and damage to the sequestration zone, including but not limited to [redacted] Chemical additives proposed for the stimulations will be tested and confirmed to be compatible with tubular, injection and confining zones, and reservoir fluids prior to use.

5.2.4 Diverters *(if downhole well conditions deem necessary)*

High Plains may use [redacted]. The need for diverters will depend on the specific stimulation design for a well, anticipated pump rates, the length of the perforated interval, perforation density, and the selected technique for conveying acid to the formation (e.g., pumping through regular jointed pipe tubing or pumping down coiled tubing).

5.2.5 Stimulation Procedures

5.2.5.1 *Pre-Injection Stimulation (if downhole well conditions deem necessary)*

The stimulation practice prior to beginning injection is to remove existing damage from drilling and completion fluids that reduce the injectivity performance of the well. This step is usually carried out using acid or non-acid-based systems containing dispersant-type surfactants and chelating agents to remove mud solids from the critical matrix region. [redacted]

5.2.5.2 *During-Injection Stimulation (if downhole well conditions deem necessary)*

Matrix stimulation using various acid systems, [redacted], can remove existing damage and restore injectivity. [redacted]

The treatment sequence of the stimulation treatment and its purpose is detailed below:

[redacted]

5.3 Injection Well Construction [40 CFR 146.82(a)(12)]

Permanently sequestering and preventing movement of the CO_2 injectate into a USDW is a critical design criterion for Class VI wells. The design and operations of the injection and monitoring wells consider the injection volume, rate, chemical composition, and physical properties of the injectate fluid. Also considered in well design are the corrosive nature of the injectate fluid, formation fluid, and the interaction of those fluids with wellbore components. Detailed operating parameters for the well can be found in *Section 7*. The construction and operation of Conestoga I-1 are designed to manage pore space utilization in the reservoir and to contain the CO_2 in the authorized injection interval. **Table 5.1** provides a summary of key well-design details.

Table 5.1—Well design details for Conestoga I-1.

Well Name	Injection Zone Formation Name(s)	Injection Well Total Depth (ft)	Injection Zone Depths (ft)
Conestoga I-1	Lyons	[redacted]	[redacted]

Specialty metallurgy is often required to handle the potential for corrosive fluids, commonly referred to as Corrosion Resistant Alloys (CRA) in the industry. CO_2 alone is not corrosive, but when combined with water, it can create carbonic acid with a pH as low as 3. In addition, other compounds, such as hydrogen sulfide (H_2S), can create a corrosive environment. The metallurgy selection for the Conestoga I-1 considers injectate and formation fluid makeup and is designed to withstand the potentially harsh environment of injecting CO_2. **Table 5.2** shows the expected composition of the injectate steam and **Table 5.3** provides water chemistry from four averaged water samples from the Juniper M-1 characterization well. Future samples and laboratory testing from the Conestoga I-1 injection site will validate the injectate stream composition and formation fluids. The casing and cement are engineered to protect the USDW and prevent the injectate or formation fluids from migrating out of the injection interval.

<u>The injection and monitoring well designs will meet or exceed the following standards:</u>

- American Petroleum Institute Specification 5CT
- American Petroleum Institute RP 5C1
- American Petroleum Institute RP 10D-2
- American Petroleum Institute Specification 11D1

The design and construction of Conestoga I-1 is dedicated to CO_2 injection. All well materials, including but not limited to the casing, cement, tubing, and packer, are compatible with all fluids these materials are expected to come into contact with and meet or exceed standards developed for such materials by the American Petroleum Institute or comparable standards.

Table 5.2 – Expected composition of an injectate stream.

Constituent	Limit
CO_2	[redacted]
Carbon Monoxide (CO)	
Hydrogen (H_2)	
Hydrogen Sulfide (H_2S)	
Total Sulfur	
Total Nitrogen Oxides (NO_X)	
Oxygen (O_2)	
Water (H_2O)	
Hydrocarbons	
Glycol	
Maximum dew point at 400 psig	
Non-condensable gases	

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

Table 5.3 - Formation water chemistry from the injection formation.

Parameter	Results (mg/L)
Alkalinity, as Bicarbonate (HCO_3^-)	[redacted]
Alkalinity, as Carbonate (CO_3^{2-})	
Alkalinity, as Hydroxide (OH^-)	
Boron	
Barium	
Bromide	
Calcium	
Chloride	
Dissolved Inorganic Carbon (DIC)	
Dissolved Organic Carbon (DOC)	
Iron	
Lead	
Lithium	
Magnesium	
Potassium	
Sodium	
Sulfate	
Strontium	
TDS	
Zinc	

5.3.1 Mechanical Integrity Testing

Annulus Pressure Test

All annuli, except the tubing annulus, will be cemented to the surface. High Plains will ensure mechanical integrity by performing an annular pressure test after installing the tubing. The annular pressure test will demonstrate the mechanical integrity of the casing above the packer, tubing, and packer sealing element. The procedure outlines how this test will be conducted:

1. Move in and rig up the pump unit.
2. Perform fingerprint pressure up at the planned pump rate against a closed valve to ensure no leaks are present upstream of the tubing annulus.
3. Line up to pump down the tubing annulus.
4. Begin pumping down the tubing annulus at the same rate the fingerprint pressure up was performed.
5. Test pressure will be equal to or less than 80% of exposed equipment but no greater than the limited surface injection pressure or 500 psi, whichever is less.
6. All ports into the casing annulus closed except the one monitored by the test pressure gauge.
7. The test pressure will be monitored and recorded for a minimum duration of 30 minutes.
8. Any discernable loss (> 10%) of pressure during the testing period will be considered a failed test.

5.3.2 Injection Well Construction Details

5.3.2.1 *Casing and Cementing (40 CFR 146.86(b)(iv))*

This injection well is designed to inject approximately 2.26 million metric tons per year at a wellhead pressure of [redacted] psi and a maximum annular pressure of 2,050 psi. 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.

The hole sizes planned are shown in **Table 5.4.** As shown in **Table 5.5**, the proposed wellbore design consists of [redacted]-in. surface casing below the USDW and will be cemented to the surface per EPA's Class VI requirements. The production casing will be a [redacted] in. "long string" beginning at the surface to an approximate depth of [redacted] ft across the planned injection zone in the Lyons Formation. The injection zone will span approximately [redacted] ft. To ensure sufficient corrosion resistance for CO_2 injection, CRA material will be used across the injection zone and the confining interval (Goose Egg Formation).

Expected loads on the surface casing, production casing, and production tubing were found to be within equipment specifications. Modeled loads (downhole stresses) with design limits and equipment specification limits can be found in **Appendix 1**.

Table 5.4—Openhole diameters and intervals.

Name	Depth Interval (MD, ft)	Openhole Diameter (in.)	Comment
Conductor	[redacted]		
Surface			To protect USDW
Production			

Table 5.5—Casing specifications.

Name	Depth Interval (ft, MD)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (lbm/ft)	Grade (API)	Design Coupling	Thermal Conductivity (BTU/ft·h·°F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	[redacted]								
Surface									
Production									

The proposed cement program is outlined in **Table 5.6**. Additives will be used as required to achieve the desired design, but no extenders shall be used. If fluid losses are observed, loss control materials (LCM) may be used. The standard pump and plug method will be used in a single stage. If losses are observed, the production string may be cemented in two stages. Modified Class G acid-resistant cement, with reduced Portland content or equivalent, will be placed in the lower portion of the well from the total depth across both the injection and confining zones. The excess percentage given will be updated based on caliper measurements of the open wellbore.

Table 5.6—Proposed cement program.

Hole Size (in.)	Section	Lead		Tail		Excess
		Slurry	Interval (ft)	Slurry	Interval (ft)	
[redacted]						

Using CRA casing and acid-resistant cement across the Lyons and the upper confining zone will ensure that the injectate will not migrate out of the intended storage zone.

5.3.2.2 *Tubing and Packer*

Like the casing string, the tubing must be selected considering the injectate and the potential for a corrosive environment. **Table 5.7** represents the tubing specifications that will be utilized for the injection well. Taking into consideration the possibility of a water and CO_2 mixture leading to the presence of carbonic acid, the injection tubing will be comprised of two different materials. The upper portion of the string will extend to a depth of [redacted] ft above the packer) and will be an [redacted] material. The lower portion of the tubing string will begin [redacted] ft above the packer and extend down to [redacted] ft and will be [redacted] material.

The [redacted]-in. outside diameter (OD) tubing size was selected by considering the total proposed injection volume of CO_2 during the project life. Premium tubing connections using gas-tight sealing surfaces will ensure the integrity of the tubing string and avoid weakness at the connections.

The packer provides a means for anchoring the tubing string, structural stability for the tubing, and isolation of the overlying annulus space from the injection interval so that the annulus can be monitored for tubing and packer leaks. The packer will be installed inside the [redacted]-in. long-string casing at a point near the top of the injection interval. **Table 5.8** details the packer design. The packer will be rated to withstand the differential pressure it will experience during installation, workovers, and the injection phase, plus a safety factor.

Like the casing string, it is important to consider the injectate and the potential for a corrosive environment when selecting the metallurgy of the tubing. Although the injectate stream is anticipated to be dry and non-corrosive, the planned design allows for the possibility of a surface upset or invasion of connate water from the reservoir. Considering the possibility of a water and CO_2 mixture leading to the presence of carbonic acid, the lower portion of the injection string will be comprised of [redacted]. CRA tubulars. In addition, the [redacted] CRA retrievable injection packer will be manufactured using carbon dioxide-compatible elastomer materials.

Table 5.7—Tubing specification.

Name	Depth Interval (MD, ft)	Outside Diameter (in.)	Inside Diameter (in.)	Weight (lbm/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)*	Collapse strength (psi)*
[redacted]								

* Taken from the VAM TOP® connection datasheet

Table 5.8—Packer specifications.

Packer Type and Material	Packer Setting Depth (MD, ft)	Length (ft)	Nominal Casing Weight (lbm/ft)	Packer Main Body Outer Diameter (in.)	Packer Inner Diameter (in.)	Tensile Rating (lbf/1,000 ft)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (in.)	Min. Casing Inner Diameter (in.)
[redacted]						[redacted]				

5.3.2.3 *Injection Well Monitoring Devices*

Quartz transducer pressure gauges will be installed on the tubing of the injection well, these gauges will have an accuracy within 3.2 psi. During and after injection, High Plains will implement a continuous monitoring plan consisting of the following elements:

<u>Continuous Recording of Injection Mass Flow Rate</u>

A Coriolis flow meter transmitter for the injection well will measure the continuous mass flow rate of CO_2 injected into the storage complex. The CO_2 flow transmitters will be networked to the main CO_2 storage site control center via a supervisory control and data acquisition SCADA-like system.

<u>Continuous Recording of Injection Pressure</u>

A pressure transmitter will measure the continuous injection pressure of the injectate steam at the injection well. The pressure transmitter will be networked to the main CO_2 storage site control center via a SCADA-like system. If the injection pressure exceeds 90% of the Lyons fracture pressure, the system will send an alarm to the control center for corrective action.

<u>Continuous Recording of Annulus Pressure</u>

The continuous annulus pressure between the long string, [redacted] in. casing, and the [redacted] n. tubing will be networked to the control room via a SCADA-like system, providing the operators an alarm and high-pressure shut-down.

<u>Bottomhole Pressure and Temperature</u>

Quartz transducer pressure and temperature gauges will be installed in the injection well and the monitoring well to continuously monitor CO_2 injection pressure and temperature (P/T). Pressure (internal tubing and tubing annulus) and temperature readings on the injection well will be measured above and close to the packer. The monitor well will record pressure and temperature above the confining zone. The P/T data will be networked to the main CO_2 storage site control center via a SCADA-like system.

5.3.3 Injection Well Construction Procedure

The following is an outline procedure describing the steps to construct Conestoga I-1:

[redacted]

5.3.4 Injection Well Construction Diagram

[redacted]

Figure 5.1—Proposed well construction diagram for the Conestoga I-1.

5.4 Monitor Well Design

The Conestoga M-1 will be utilized as a monitoring well for this Project. The well has been designed to monitor the first reasonably permeable zone above the confining zone. This well is being permitted through the Nebraska Oil and Gas Conservation Commission (NOGCC). The proposed well design for the Conestoga M-1 is shown in the diagram below and an updated as-built diagram will be provided after well construction.

5.4.1 Monitoring Well Construction Diagram

[redacted]

Figure 5.2—Planned well construction diagram for the Conestoga M-1.

Appendix 1—Modeled Downhole Stresses

All anticipated loads to which the surface casing may be exposed were modeled in Landmark's WELLCAT™ casing design software. **Figure 5.3** below illustrates that all loads are within design criteria and do not exceed specifications.

[redacted]

Figure 5.3—Modeled downhole stresses (surface casing).

All anticipated loads to which the production casing may be exposed were modeled in Landmark's WELLCAT™ casing design software. **Figure 5.4** below illustrates all loads are within design criteria and do not exceed specifications.

[redacted]

Figure 5.4—Modeled downhole stresses (production casing).

All anticipated loads to which the production tubing may be exposed were modeled in Landmark's WELLCAT™ casing design software. **Figure 5.5** below illustrates all loads are within design criteria and do not exceed specifications.

[redacted]

Figure 5.5—Modeled downhole stresses (production tubing).