CLASS VI INJECTION WELL OPERATIONS PROGRAM

40 CFR 146.88

TRILLIUM CARBON STORAGE COMPLEX (TCSC)

Facility Information

Facility Name: Trillium Carbon Storage Complex (TCSC)
TCSC-1, TCSC-2, TCSC-3, TCSC-4, TCSC-5

Facility Contact: Claimed as PBI [redacted]

Facility Address: Claimed as PBI [redacted]

Well Location: Claimed as PBI [redacted]

Well Name	Latitude	Longitude
TCSC-1	Claimed as PBI [redacted]	[redacted]
TCSC-2	Claimed as PBI [redacted]	[redacted]
TCSC-3	Claimed as PBI [redacted]	[redacted]
TCSC-4	Claimed as PBI [redacted]	[redacted]
TCSC-5	Claimed as PBI [redacted]	[redacted]

Table of Contents

List of Figures

List of Tables

Abbreviations and Acronyms

2D	2-Dimensional
3D	3-Dimensional
AoR	Area of Review
bbl/d	Barrels per day
BHP	Bottom Hole Pressure
CCS	Carbon capture, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
D_H	Hydraulic Diameter
DRM	Dynamic Reservoir Model
EoS	Equation of State
EPA	Environmental Protection Agency
f_D	Darcy's Friction Factor
ft.	Feet
g	Acceleration due to Gravity
GEM	General Equation of State
KB	Kelly Bushing
$k_{r,CO2}$	CO_2 Relative Permeability
kh	Permeability-Thickness Product
k_h	Absolute Horizontal Permeability
k_v	Absolute Vertical Permeability
$k_{r,w}$	Water Relative Permeability
mg/L	milligrams per liter
MIP	Mercury Intrusion Porosimetry
MMt	Millions of Metric tons
MMt	Millions of Metric tons per annum
ΔP	Pressure Drop
ΔP_{TH}	Threshold Pressure
PISC	Post-Injection Site Care
P_{grid}	Grid Block Pressure
pH	Potential Hydrogen
ppm	Parts per Million
psi	Pounds per square inch
psia	Pounds per square inch, absolute
ρ	Fluid Density
ρ_i	Injection Zone Fluid Density
ρ_u	Underground Source for Drinking Water Fluid Density
RCA	Routine Core Analysis
R_e	Reynolds Number
SCA	Specialized Core Analysis
SEM	Static Earth Model
S_{grmax}	Maximum Residual Gas Saturation
SS	Subsea

S_{wcon}	Connate Water Saturation
S_{wirr}	Irreducible Water Saturation
T_{grid}	Grid Block Temperature
TVD	True Vertical Depth
UIC	Underground Injection Control
USD	Underground Source of Drinking Water
U.S.	United States Department of Energy
U.S.	United States Environmental Protection Agency
v	Fluid Velocity
z_i	Injection Zone Top Depth
z_u	Underground Source for Drinking Water Bottom Depth

6. WELL OPERATIONS PLAN

6.1. EXECUTIVE SUMMARY

Pursuant to the 40 CFR §146.82, Trillium Piketon, LLC (Trillium) prepared this document to describe the planned operation of the CO_2 injection wells for the Trillium Carbon Storage Complex (TCSC) project. The locations for the injection wells TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5 are displayed in **Figure 6-1** below. The proposed construction procedures and specifications are detailed in this document.

Claimed as PBI [redacted]

Figure 6-1. Aerial view of TCSC displaying the location of all injection and monitoring wells relative to project elements. A) represents the laterals of TCSC-1 and TCSC-3. B) represents the laterals of TCSC-2 and TCSC-4. C) represents the lateral of TCSC-5. Please reference Figure 7-3 of the Testing and Monitoring plan for a zoomed in view of the TCSC-3 injection well pad. CO_2 plume and pressure front boundaries represent the combined maximum extent from both the Claimed as PBI **and** Claimed as PBI [redacted] **storage reservoirs.**

6.2. INJECTION RATES

The injection wells will be constructed as shown in their Injection Well Construction Plans. Injection in TCSC-1 and TCSC-2 will be facilitated through tubing set in the long-string casing in a packer before the perforations in the [redacted]. Injection in TCSC-3, TCSC-4, and TCSC-5 will be facilitated through tubing set in the long-string casing in a packer before the perforations in the [redacted] formation. The operational values detailed in **Table 6-1**, **Table 6-2**, **Table 6-3**, **Table 6-4**, and **Table 6-5**. were obtained by using PipeSIM to conduct the nodal analysis presented in the Injection Well Construction Plan. The nodal analysis was used to determine the range of possible injection rates. Using the analysis an average injection rate of [redacted] MMtpa ([redacted] metric tons per day) of CO_2, [redacted] MMtpa ([redacted] metric tons per day) of CO_2, [redacted] MMtpa ([redacted] metric tons per day) of CO_2, [redacted] MMtpa ([redacted] metric tons per day) of CO_2, and [redacted] MMtpa ([redacted] metric tons per day) of CO_2 for TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5, respectively. Also, a maximum rate of [redacted] MMtpa ([redacted] metric tons per day) of CO_2, [redacted] MMtpa ([redacted] metric tons per day) of CO_2, [redacted] MMtpa ([redacted] metric tons per day) of CO_2, [redacted] MMtpa ([redacted] metric tons per day) of CO_2, and [redacted] MMtpa ([redacted] metric tons per day) of CO_2 for TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5, respectively, to meet project requirements. The total annual injection rate for the project will be [redacted] MMtpa of CO_2. The expected wellhead pressures during injection operations will likely be between [redacted] psi and [redacted] psi, [redacted] psi and [redacted] psi, [redacted] psi and [redacted] psi, [redacted] psi and [redacted] psi, and [redacted] psi and [redacted] psi, TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5, respectively. **Table 6-1**, **Table 6-2**, **Table 6-3**, **Table 6-4**, and **Table 6-5** summarize the proposed operational parameters for the injection wells. Operational parameters are expected to remain constant throughout the duration of the injection period.

Table 6-1. Injection Well TCSC-1 Operational Parameters

Parameters/Conditions	Proposed Value	Unit
Maximum Injection Pressure		
Surface	[redacted]	psi
Downhole	[redacted] (90% frac press: [redacted])	psi
Average Injection Pressure		
Surface	[redacted]	psi
Downhole	[redacted]	psi
Maximum Injection Rate	[redacted]	Metric tons/year
Average Injection Rate	[redacted]	Metric tons/year
Maximum Injection Volume and/or Mass ([redacted] period)	[redacted]	Metric tons
Average Injection Volume and/or Mass ([redacted] period)	[redacted]	Metric tons
Annular Pressure		
Annular Fluid Weight	[redacted]	ppg
Maximum Annulus Pressure	[redacted]	psi
Annulus Pressure/Tubing Differential	[redacted]	psi
Maximum Annulus Pressure at the Wellhead	[redacted]	psi

Table 6-2. Injection Well TCSC-2 Operational Parameters

Parameters/Conditions	Proposed Value	Unit
Maximum Injection Pressure		
Surface	[redacted]	psi
Downhole	[redacted] (90% frac press: [redacted])	psi
Average Injection Pressure		
Surface	[redacted]	psi
Downhole	[redacted]	psi
Maximum Injection Rate	[redacted]	MMtpa
Average Injection Rate	[redacted]	MMtpa
Maximum Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
Average Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
Annular Pressure		
Annular Fluid Weight	[redacted]	ppg
Maximum Annulus Pressure	[redacted]	psi
Annulus Pressure/Tubing Differential	[redacted]	psi
Maximum Annulus Pressure at the Wellhead	[redacted]	psi

Table 6-3. Injection Well TCSC-3 Operational Parameters

Parameters/Conditions	Proposed Value	Unit
	Maximum Injection Pressure	
Surface	[redacted]	psi
Downhole	[redacted] (90% frac press: [redacted]	psi
	Average Injection Pressure	
Surface	[redacted]	psi
Downhole	[redacted]	psi
Maximum Injection Rate	[redacted]	MMtpa
Average Injection Rate	[redacted]	MMtpa
Maximum Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
Average Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
	Annular Pressure	
Annular Fluid Weight	[redacted]	ppg
Maximum Annulus Pressure	[redacted]	psi
Annulus Pressure/Tubing Differential	[redacted]	psi
Maximum Annulus Pressure at the Wellhead	[redacted]	psi

Table 6-4. Injection Well TCSC-4 Operational Parameters

Parameters/Conditions	Proposed Value	Unit
	Maximum Injection Pressure	
Surface	[redacted]	psi
Downhole	[redacted] (90% frac press: [redacted]	psi
	Average Injection Pressure	
Surface	[redacted]	psi
Downhole	[redacted]	psi
Maximum Injection Rate	[redacted]	MMtpa
Average Injection Rate	[redacted]	MMtpa
Maximum Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
Average Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
	Annular Pressure	
Annular Fluid Weight	[redacted]	ppg
Maximum Annulus Pressure	[redacted]	psi
Annulus Pressure/Tubing Differential	[redacted]	psi
Maximum Annulus Pressure at the Wellhead	[redacted]	psi

Table 6-5. Injection Well TCSC-5 Operational Parameters

Parameters/Conditions	Proposed Value	Unit
Maximum Injection Pressure		
Surface	[redacted]	psi
Downhole	[redacted] (90% frac press: [redacted])	psi
Average Injection Pressure		
Surface	[redacted]	psi
Downhole	[redacted]	psi
Maximum Injection Rate	[redacted]	MMtpa
Average Injection Rate	[redacted]	MMtpa
Maximum Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
Average Injection Volume and/or Mass ([redacted] period)	[redacted]	Million metric tons
Annular Pressure		
Annular Fluid Weight	[redacted]	ppg
Maximum Annulus Pressure	[redacted]	psi
Annulus Pressure/Tubing Differential	[redacted]	psi
Maximum Annulus Pressure at the Wellhead	[redacted]	psi

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined using the well log data for well with [redacted] TCSC injection wells. The calculated value was then multiplied by 0.9, per 40 CFR 146.88(a).

6.3. SPECIFICATIONS OF CO_2 STREAM

The CO_2 will come into the site meeting the specifications presented in the Testing and Monitoring Plan. The CO_2 will enter a header and be piped to each injection well. Each well will inject continuously. The wells will be connected to the source that has a maximum pressure of [redacted] psi, so no pumps will be needed to maintain injection pressure. The CO_2 will come from two sources of CO_2 which feed into the primary pipeline transporting CO_2 to the TCSC storage sites, for more information on the sites please refer to **section 1.8.2.** of the project narrative. **Table 6-6** below displays the anticipated chemical composition of the CO_2 stream. The CO_2 stream will contain less than [redacted]. Initially, the CO_2 stream will be originally at [redacted] and between [redacted] psi and [redacted] psi, with estimated densities ranging from [redacted] lb/ft^3 to [redacted] lb/ft^3 at the well head. After injection downhole into the [redacted], the CO_2 stream is anticipated heat to near formation temperature of [redacted]°F under approximately [redacted] psi, with an estimated density of [redacted] lb/ft^3. The CO_2 stream when injected into the [redacted] is anticipated to heat to near formation temperature of [redacted]°F under approximately [redacted] psi, with an estimated density of [redacted] lb/ft^3. Upon injection into the [redacted] formation, the CO_2 will on average be injected in [redacted] It will then turn to [redacted] While injecting into the [redacted] formation, the [redacted] from the wellhead to the formation.

Table 6-6. Specifications of the Anticipated CO2 Stream Composition

Parameter[A]	Expected Value	Unit
Physical Characteristics		
Pressure[B]	[redacted]	psi
Temperature[C]	[redacted]	°F
Chemical Characteristics		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[A]This list is subject to change based on source injectate stream composition results.

[B]Represents pressure at the CO_2 outlet. [redacted]

[C]Represents the temperature the injectate stream [redacted]

6.4. ESTIMATED MAXIMUM ALLOWABLE SURFACE PRESSURE

The maximum allowable surface pressure (MASP) was estimated by using the same PIPESIM injection model to calculate the wellhead pressure assuming the maximum allowed bottomhole pressure was reached as the CO_2 entered the formation through the perforations at the maximum injection rate of CO_2. The bottomhole pressure was set to 90% of the estimated hydraulic fracture pressure at the mid perf depth for TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5 was [redacted] psi, [redacted] psi, [redacted] psi, [redacted] psi, and [redacted] psi, respectively.

These were calculated from 90% of a [redacted] psi/ft fracture gradient. All estimates assumed an average surface elevation of [redacted] ft. Within the [redacted], TCSC-1's hydraulic fracture pressure at the top perforation is [redacted] psi ([redacted] ft * [redacted] /ft) and TCSC-2's 1's hydraulic fracture pressure at the top perforation is [redacted] psi ([redacted] ft * [redacted] /ft). The relevant result is that 90% of the fracture pressures are [redacted] psi and [redacted] psi.

Additionally, the estimated hydraulic fracture gradient and the hydraulic fracture pressure at the top-perforation depth of the [redacted] for TCSC-3, TCSC-4, and TCSC-5 in the model was [redacted] psi ([redacted] psi/ft * [redacted] ft), [redacted] psi ([redacted] psi/ft * [redacted] ft), and [redacted] psi ([redacted] psi/ft * [redacted] ft), respectively. The relevant result is that 90% of those fracture pressures are [redacted] psi, [redacted] psi, and [redacted] psi.

The results estimate the MASP at the calculated 90% fracture pressures for TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5 are [redacted] psi, [redacted] psi, [redacted] psi, [redacted] psi, and [redacted] psi, respectively, and as shown in **Figure 6-2. Figure 6-2** also shows that as the CO_2 reaches the targe TVD at the lateral the pressure decreases across the lateral as the CO_2 turns to reservoir conditions. Except during Director-approved well stimulation events (if required), Trillium will ensure that the downhole pressures will not exceed 90% of the fracture pressure to maintain the integrity of the TCSC.

Claimed as PBI

[redacted]

Figure 6-2. Pressure versus depth profile at the maximum allowable operating pressures, constrained by the fracture pressure at the top perf. The results show that for TCSC-1, TCSC-2, TCSC-3, TCSC-4, and TCSC-5 the MASP's are [redacted] psi, [redacted] psi, [redacted] psi, [redacted] psi, and [redacted] psi, respectively

6.5. INJECTION WELL OPERATIONAL MONITORING

Each injection well will be monitored to ensure safe operations. Safety monitoring includes monitoring the injection pressure at the wellhead and bottomhole, monitoring the pressurized annulus, continuous fiberoptic temperature monitoring along the well or equivalent, and corrosion coupon monitoring to identify corrosion. Each system is fully described in the ***Testing and Monitoring Plan Section 7.2.2***.

Each injection well will have a wellhead pressure gauge and data logger, both tied into the injection control system and set to trigger an alarm at the project control room and shut down injection in the well if the MASP is reached. Injection parameters including pressure, rate, volume and/or mass, and temperature of the CO_2 stream will be continuously measured and recorded. The pressure and fluid volume of the annulus between the tubing and long-string casing will also be continuously measured. All automatic shutdowns will be investigated prior to bringing injection activities back online in the well to ensure that that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, Trillium will immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring indicates that the well may be lacking mechanical integrity, Trillium will:

(1) Immediately cease injection in the affected well and in any other wells that may exacerbate the leakage risk of the affected well

(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone

(3) Notify the Director in writing within 24 hours

(4) Restore and demonstrate mechanical integrity prior to resuming injection

(5) Notify the Director when injection can be expected to resume

The annular space between the tubing and long string casing of each injection well will be pressurized with a non-corrosive fluid. The annulus will be monitored continuously to ensure integrity of the well. The annulus will be filled with a [redacted] and [redacted] pounds per gallon (ppg) sodium chloride brine with a corrosion inhibitor and oxygen scavenger additives. The minimum pressure held on the annulus at the wellhead will be [redacted] psia, including times of shut-in. Additional pressure may be required on the annulus; if this is the case, the value will be set in conjunction with US EPA Region 05.

The fiberoptic line cemented into the annulus on the outside of the long-string casing will be used to continuously monitor temperature along the length of the casing. Rapid temperature changes or other excursions from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

6.6. WORKOVER AND MAINTENANCE

Trillium will continuously monitor and maintain mechanical integrity of each injection well. Well maintenance and workovers will be part of normal operations to keep each injection well in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the procedure. All maintenance and workover operations will be monitored to ensure there is no loss of mechanical integrity. Barriers will be kept in place to ensure leakage risk is minimized. Each injection well is designed to allow the installation of a temporary plug in the below the tubing to allow the tubing to be removed and replaced as needed while keeping a barrier in place. The bottomhole temperature and pressure gauge is set above the packer to allow for replacement, if needed, without removing the packer from the well.

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the CO_2 injection will be kept at the same rate of [redacted] tons a day. The wells have been designed to comfortably handle the increased rates.

6.7. REPORTING REQUIREMENTS

Trillium will follow the reporting requirements as seen below in **Table 6-7** and **Table 6-8**. See ***section 7.1.6*** *in the* ***Testing and Monitoring Plan*** to find more information regarding the Reporting Requirements.

Table 6-7. 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 6-8. 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