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

Project Name: Tri-State CCS Buckeye 2

Facility Information

Facility Contact: Tri-State CCS, LLC
14302 FNB Parkway
Omaha, Nebraska 68154
402-691-9500

Well Locations: Jefferson and Harrison Counties, Ohio

Well Name	Latitude (WGS 84)	Longitude (WGS 84)	County
TB2-1	40.52542700	-80.69641700	Jefferson
TB2-2	40.49732800	-80.83907000	Jefferson
TB2-3	40.49763300	-80.71967780	Jefferson
TB2-4	40.45937700	-80.89751600	Jefferson
TB2-5	40.41380300	-80.84988900	Jefferson
TB2-6	40.29706900	-80.83528000	Jefferson
TB2-7	40.29258500	-80.80013900	Jefferson
TB2-8	40.27538400	-80.73308700	Jefferson
TB2-9	40.24805800	-80.71799700	Jefferson
TB2-10	40.22659200	-80.80370600	Jefferson
TB2-11	40.40687700	-80.92462500	Harrison
TB2-12	40.39183000	-80.98459000	Harrison
TB2-13	40.37394700	-80.91794600	Harrison
TB2-14	40.35175500	-81.05526700	Harrison
TB2-15	40.32634200	-80.94335800	Harrison
TB2-16	40.32545800	-80.96751800	Harrison
TB2-17	40.27392800	-80.88990500	Harrison
TB2-18	40.25624300	-80.92103300	Harrison
TB2-19	40.21935400	-80.94936500	Harrison
TB2-20	40.19950300	-80.94510400	Harrison

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List of Acronyms

^{0}F	Degree Fahrenheit
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
ft	Feet
KIC	Knox Injection Complex
lb	Pound
LLC	Limited Liability Company
MASP	Maximum Allowable Surface Pressure
MIC	Medina Injection Complex
MIT	Mechanical Integrity Testing
MMSCF	Million Standard Cubic Feet
MMt	Million Metric Tonnes
MMt/y	Million Metric Tonnes per Year
Mol%	Molecular Percentage of Total Moles in a Mixture made up by One Constituent
O_2	Oxygen
ppmv	Parts per Million, Volume
ppmw	Parts per Million, Weight
psi	Pounds per Square Inch
psig	Pounds per Square Inch, Gauge
UIC	Underground Injection Control

1. Introduction

Tri-State CCS, LLC seeks to safely inject carbon dioxide (CO_2) at a maximum rate of either 0.3 MMt/y or 0.5 MMt/y into 20 injection wells located at Tri-State CCS Buckeye 2 (the "project) in Jefferson and Harrison counties, Ohio, while maintaining well integrity and remaining below 90% of the fracture pressure in both of the injection complexes, i.e., Knox Injection Complex (KIC) and Medina Injection Complex (MIC). The operational details provided in this document satisfy 40 CFR 146.82(a)(7) and (10). The operational design described in this document has been developed to adhere to requirements set forth in 40 CFR 146.88.

2. Operational Procedures [40 CFR 146.82(a)(10)]

The injection wells will be drilled for CO_2 injection into the Rose Run Sandstone in the KIC and Medina Group in the MIC. Injection will begin with the Rose Run Sandstone and will continue for 30 years. Once the total planned injection is achieved, the tubing and completion will be retrieved, and the KIC will be plugged off with CO_2 resistant cement. The shallower Medina Group will then be perforated, and the same tubing will be inspected to determine if it can be reused for injection. If needed, replacement tubing will be procured, and injection will continue in the Medina Group for an additional 30 years.

2.1. Injection Rates

See Appendix A of this document for an injection summary of each well. To define the operating conditions for the injection wells, Tri-State CCS, LLC used four boundary cases which define the maximum and the minimum downhole injection pressure limitation based on the 90% of the hydraulic fracture pressure limit at the top perforation, depending on which injection zone is being targeted. These operating boundaries correspond to specific wells and injection zones, namely the deepest and shallowest top perforation of both the injection zones, i.e., KIC and MIC, and are identified in Table 1. Injection well design was based on a boundary case pair, either A and B for wells with a maximum injection rate of 0.3 MMt/y or C and D for wells with a maximum injection rate of 0.5 MMt/y.

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Table 1: Boundary Definitions for Project Injection Wells; These include the Boundary Well and Injection Zone Pair which define the Individual Boundary Cases.

Boundary Case	Applicable Wells	Boundary Well	Boundary Injection Zone	Injection Interval Top, TVD (ft)[1]	Definition
A	TB2-11, TB2-13, TB2-15, TB2-16, TB2-17, TB2-18	TB2-17	Rose Run Sandstone	10,508	Deepest KIC top perforation of TB2-17.
B		TB2-11	Medina Group	6,445	Shallowest MIC top perforation of TB2-11.
C	TB2-1, TB2-2, TB2-3, TB2-4, TB2-5, TB2-6, TB2-7, TB2-8, TB2-9, TB2-10, TB2-12, TB2-14, TB2-19, TB2-20	TB2-9	Rose Run Sandstone	11,597	Deepest KIC top perforation of TB2-9.
D		TB2-14	Medina Group	6,262	Shallowest MIC top perforation of TB2-14.

[1]These depths are approximate and subject to change based on actual formation tops as encountered during drilling of these injection wells and regional data from Carbon Storage Assurance Facility Enterprise (CarbonSAFE) stratigraphic test wells planned in Jefferson and Harrison counties, as available.

As outlined in subsection 2.1 of the Construction Details, injection wells that are based on the boundary A and B wells' design have 3.5-inch tubing, and injection wells that are based on the boundary C and D wells' design have 4.5-inch tubing.

Table 2 summarizes the proposed operational parameters for the boundary wells. All the injection wells and injection zones will be operated within the conditions identified by these boundaries. The parameters for individual injection wells are expected to remain constant throughout the injection period. However, some variability in operational parameters may stem from variations in volume from the CO_2 sources, which may impact injection volumes during limited periods of time. The injection pressure values detailed in Table 2 were modeled using Petroleum Experts' PROSPER software for the boundary wells, and results can be found in subsection 2.1 of the Construction Details for each injection well.

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Table 2: Injection Well Operating Conditions Envelope Defined by Boundary Cases as Identified in Table 1.

Parameters/Conditions	Limit or Permitted Value				Units
	Boundary A (TB2-17, KIC)	Boundary B (TB2-11, MIC)	Boundary C (TB2-9, KIC)	Boundary D (TB2-14, MIC)	
Maximum Injection Pressure					
Surface	2,670	1,775	2,805	1,685	psig
Downhole	6,620	4,060	7,306	3,945	psig
Average Injection Pressure					
Surface	2,610	1,705	2,765	1,675	psig
CO_2 Injection Rate					
Maximum [1]	0.3	0.3	0.5	0.5	MMt/y
Average [1, 2]	0.08	0.06	0.23	0.06	MMt/y
Injection Volume[3]					
Maximum Injection Volume and/or Mass (30-year period)	210	210	54	54	MMt
Average Injection Volume and/or Mass (30-year period)	65.5	30.2	11.5	15.5	MMt
Annular Pressure					
Minimum Annulus Pressure at Wellhead	100	100	100	100	psig
Minimum Differential Pressure (directly above and across packer)	100	100	100	100	psi
Maximum Proposed Annulus Pressure at the Wellhead	2,770	1,875	2,905	1,785	psig

[1] Current reservoir modeling is informed by limited site-specific data and may vary from the average injection rate achieved during operation. Once reservoir characterization data has been collected from the Pre-Operational Testing Program and CarbonSAFE stratigraphic test wells in Jefferson and Harrison counties, as available, the average and the maximum injection rates will be finalized. Accordingly, the injection pressures will also change depending on the identified maximum injection rates and the 90% of the fracture pressure at the top of the injection zone in each of the injection wells.
[2] The average rates are for the wells and injection zones which make up the defined boundaries (Table 1)
[3] The average volumes are based on average injection rates for identified wells falling within boundary pairs (Table 1). See Appendix A for injection summary of each well. These rates are used to compute average volumes and scaled for the total number of wells falling within the boundary pairs.

Using the maximum CO_2 injection rates as summarized in Table 2, the injection tubing string sizes were selected for the four boundary cases to meet the project requirements as highlighted in the Construction Details of these wells. Maximum wellhead injection pressures were calculated based on 90% of the hydraulic fracture gradient, depending on which injection interval is being targeted for each boundary case. When calculating the boundary operating envelope, for the first 30 years of injection in the KIC, the maximum injection pressures were modeled at the depth of the deepest top perforation in the Rose Run Sandstone. For the subsequent planned 30 years of injection in the MIC, the maximum injection pressures were modeled at the depth of the shallowest top perforation in the Medina Group. These pressure limits represent 90% of fracture pressure at the depth of the shallowest perforated interval for a specific boundary case using maximum injection rate which is considered the maximum allowable surface pressure (MASP). The MASP for each individual well falls within the design envelope defined by their respective boundaries, A and B or C and D.

Average reservoir pressures were modeled for each injection well and injection zone. Modeling to calculate said pressure assumed that the reservoir is pressure limited and the downhole pressure is equal to 90% of hydraulic fracture pressure at the top perforation, depending on which injection interval is being targeted. If data collection from the CarbonSAFE site characterization and pre-operational testing program indicates the reservoir is not pressure limited, the average injection pressure will be recalculated accordingly. Appendix A provides anticipated average injection rates for all the proposed injection wells.

Based on expected operating ranges, Tri-State CCS, LLC proposes to maintain a 100-psi positive pressure differential in the annular space directly above the packer relative to the adjacent tubing during injection, per 40 CFR 146.88(c). Maximum annulus pressures at the wellhead are also summarized in Table 2. These pressures are specific to the boundary conditions as defined, and the maximum proposed annular pressure at the wellhead will vary for other wells and injection zone pairs depending on their actual MASP values. No injection will take place between the long string casing and surface casing to protect the USDW, per 40 CFR 146.88(b).

Final design criteria to operate the injection wells will be developed following data collection from the pre-operational testing program and CarbonSAFE stratigraphic wells, as available. This will include appropriate recalculation of MASP as well as average operating conditions for each of the proposed injection wells.

2.2. CO_2 Stream Specifications

In accordance with 40 CFR 146.82(a)(7)(iii) and (iv), this subsection provides information on the sources and chemical and physical characteristics of the CO_2 stream. The CO_2 will be sourced from industrial facilities and power plants located in the Tri-State area and transported by pipeline to the Tri-State CCS Hub. The sources of CO_2 for the Tri-State CCS Hub have not yet been placed under contract, although the stream composition will be constrained through the implementation of a gas tariff on the pipeline operated by Tri-State CCS, LLC. The tariff will mandate maximum allowable concentrations that sources are committed to meeting under the services agreement. The tariff requirements are designed to deliver CO_2 to the injection wells that is nonhazardous and free from water, hydrogen sulfide, and other compounds that could contribute to corrosion, other safety issues, or impacts to the formation and caprock. Additionally, the tariff will ensure any compounds used in the capture process like amine and ammonia, are at low enough concentrations to be considered nonhazardous. The tariff is being supplied to all potential customers to use as a design requirement for their capture equipment.

The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore. The injectate stream composition coming into the storage field will vary throughout the injection phase of the project. To account for this, Tri-State CCS, LLC plans to continuously monitor the CO_2 stream chemical composition to ensure it meets minimum composition specifications that will be refined when sources are finalized, and capture equipment is operational (see Section 3.0 of the Testing and Monitoring Plan). The CO_2 injection stream coming into the storage site is expected to have at least the specifications presented in Table 3, with a CO_2 concentration of 95% or higher. Tri-State CCS, LLC will engage with individual customers/sources to enforce a tariff specification that meets or exceeds this composition, and any CO_2 stream that does not meet this specification will be rejected per terms of the services agreement.

Table 3: Specifications of the anticipated CO_2 stream composition.

Component	Specification	Unit
Carbon Dioxide (CO_2)	> 95	Mol%, dry
Carbon Monoxide (CO)	< 1,000	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
NO_x	< 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

Table 4 shows the estimated density and temperature of the injectate under normal operating conditions both at the surface and downhole at reservoir conditions during planned injection operations for the boundary cases. The CO_2 stream is expected to average around 60 ºF at the wellhead. After injection into the KIC or MIC, the CO_2 stream is anticipated to be supercritical and heat to near formation temperature at or above the native reservoir pressures. The temperature and density values for each of the 20 injection wells will fall within boundary wells A and B or C and D.

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Table 4: Estimated Surface and Downhole Temperature and Densities During Injection at the boundary wells under Maximum Injection Rate Conditions.

Parameters/Conditions	Limit or Permitted Value				Units
	Boundary A (TB2-17, KIC)	Boundary B (TB2-11, MIC)	Boundary C (TB2-9, KIC)	Boundary D (TB2-14, MIC)	
Temperature					
Surface (CO_2 stream)	60.0	60.0	60.0	60.0	°F
Downhole	125.22	96.82	128.26	94.3	°F
CO_2 Density					
Surface	56.41	53.09	56.79	52.65	lb/ft^3
Downhole	56.79	54.63	57.65	54.68	lb/ft^3

2.3. Estimated Maximum Allowable Surface Pressure

Using Petroleum Experts' PROSPER software, the MASP for CO_2 injection was modeled for the four boundary cases. The boundary case pairs, i.e., either A and B or C and D, define the boundaries for the other injection wells. The boundary A and B well design is 3.5-inch tubing, and the boundary C and D well design is 4.5-inch tubing. This was determined by the downhole pressure at either KIC or MIC, depending on which injection interval is being targeted. MASP represents 90% of the fracture pressure, per 40 CFR 146.88(a), at the depth of the top perforation for each identified boundary case using a maximum injection rate of 0.3 MMt/y for the boundary A and B wells and 0.5 MMt/y for the boundary C and D wells. For each of the four boundary cases, the maximum surface injection pressure, as reported in Table 2, is equal to the MASP. The MASP for each injection well will not exceed the MASP values identified by injection complex for the applicable boundary cases in Table 1.

As an example, the MASP calculated for the boundary A well (TB2-17 in the KIC) based on downhole pressure of 6,620 psig and maximum injection rate of 0.3 MMt/y is approximately 2,670 psig, as shown in Figure 1. The downhole pressure of 6,620 psig corresponds to 90% of fracture pressure at a depth of 10,508 ft determined using a frac gradient of 0.7 psi/ft as discussed in subsection 1.9 of the Area of Review and Corrective Action Plan.

Figure 1 through Figure 4 show the multiple maximum injection pressure cases for each of the boundary cases. At injection pressures below MASP, the downhole pressure at the top perforation of the KIC or MIC, depending on the injection interval, stays below 90% of the fracture pressure. At injection pressures higher than MASP, the downhole pressure at the top perforation exceeds the 90% fracture pressure limit. This indicates that at or below the MASP, the injection operations will not fracture the rock, as required by 40 CFR 146.88(a).

The operational MASP for each injection well will be calculated following data collection from the pre-operational testing program and CarbonSAFE stratigraphic wells, as available.

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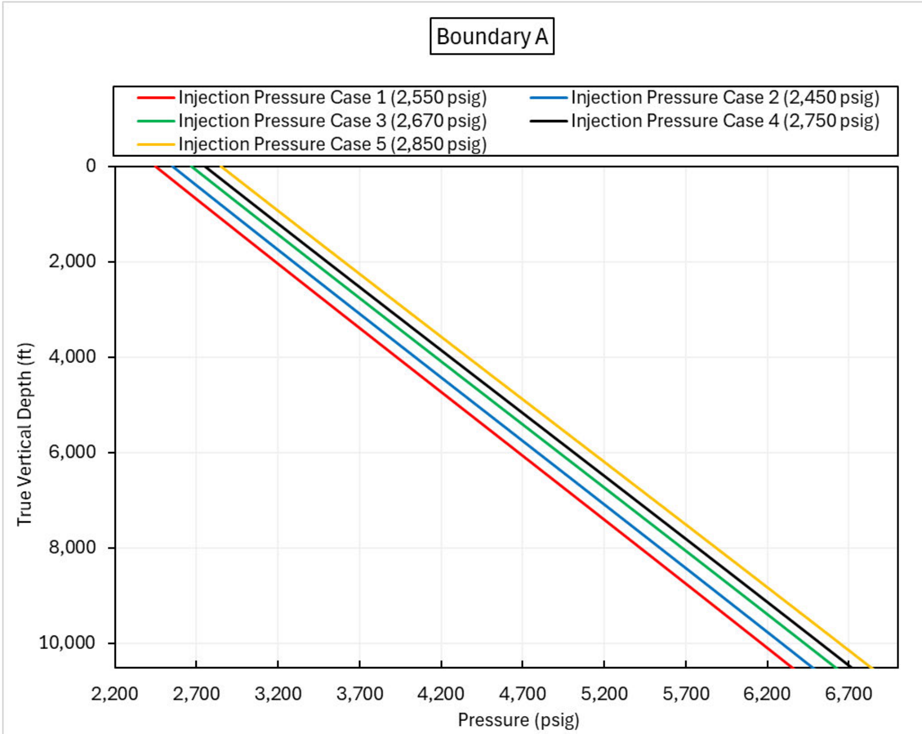

Figure 1: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of KIC Injection Interval (10,508 ft) for the Boundary A well.

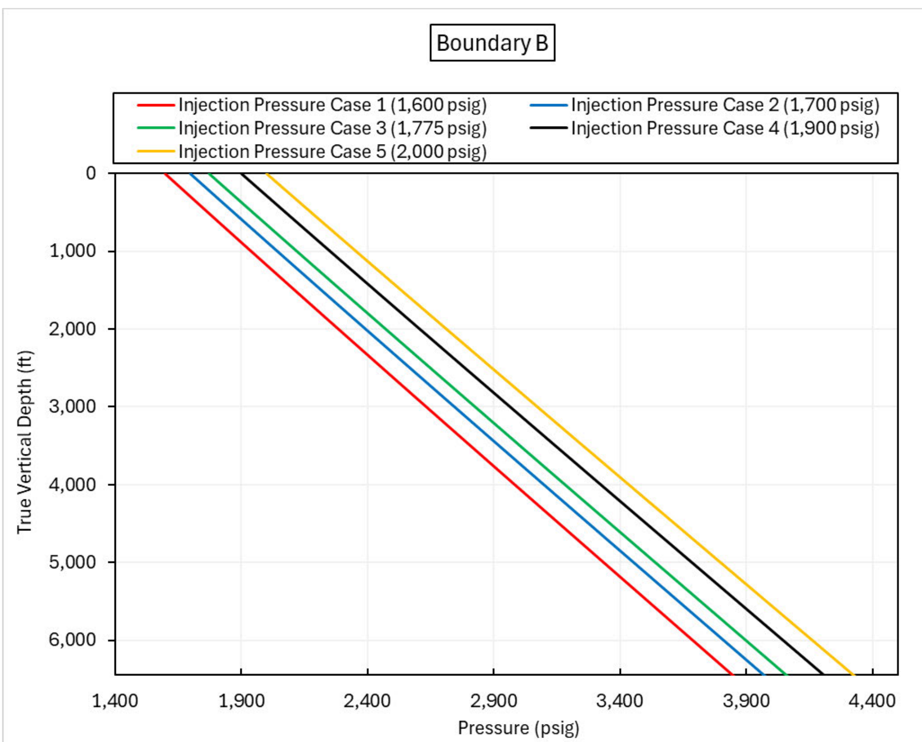

Figure 2: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of MIC Injection Interval (6,445 ft) for the Boundary B well.

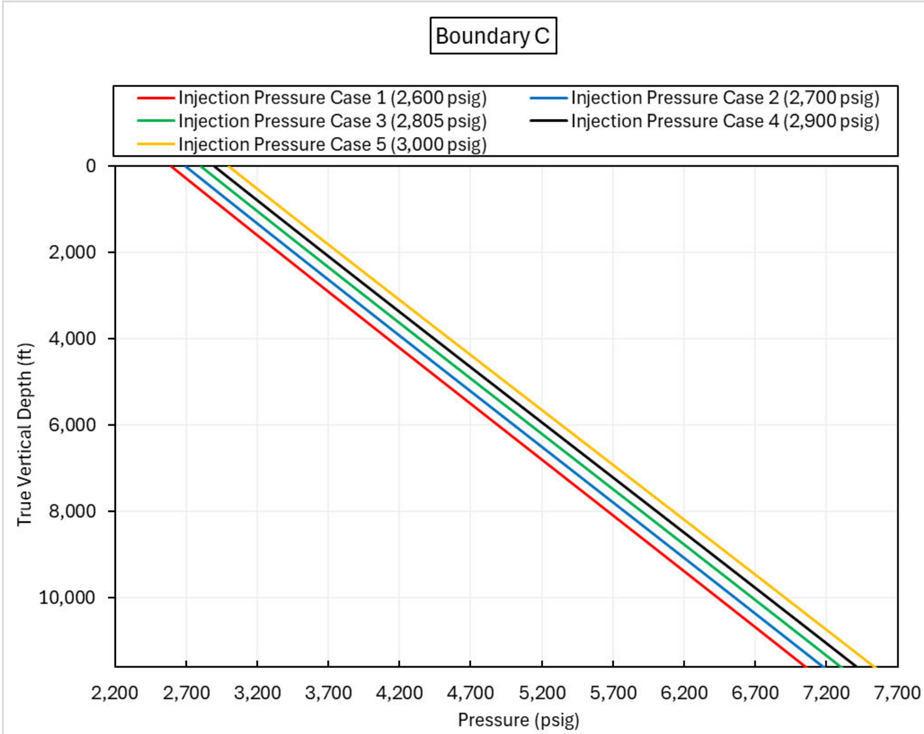

Figure 3: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of KIC Injection Interval (11,597 ft) for the Boundary C well.

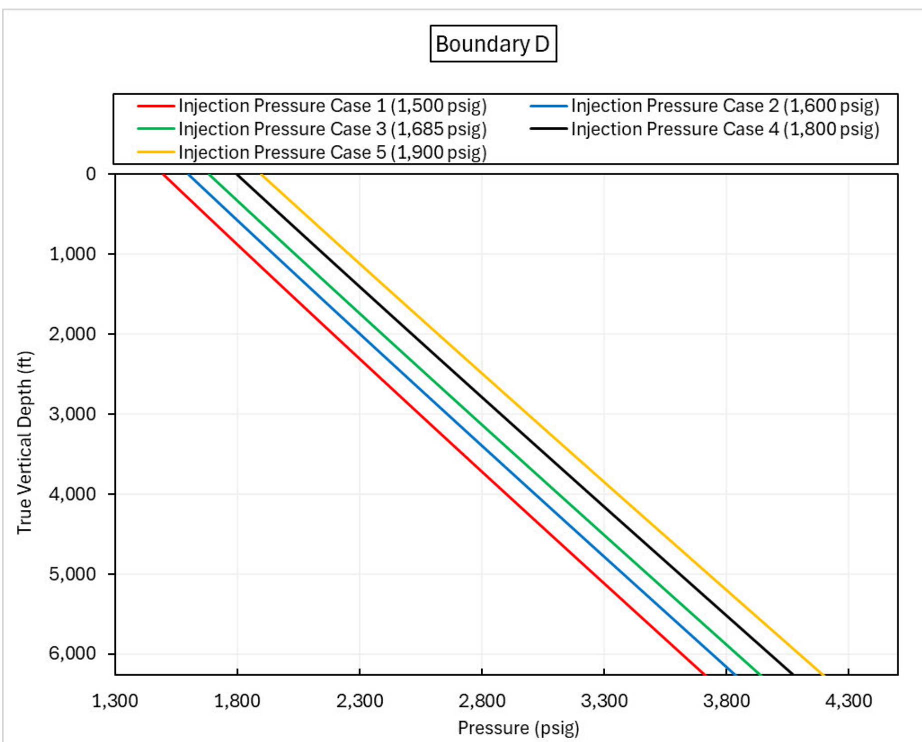

Figure 4: Pressure Profiles to Calculate Maximum Injection Pressure at 90% of Fracture Pressure at the Top of MIC Injection Interval (6,262 ft) for the Boundary D well.

2.4. Injection Well Operational Monitoring

Each injection well will be monitored to ensure safe operations, in compliance with 40 CFR 146.88(e)(2). Operational safety monitoring includes continuous monitoring of the injection pressure at the wellhead and downhole, continuous monitoring of flow rate, volume and/or mass, and temperature of CO_2 stream. Continuous monitoring of the pressurized annulus, continuous fiber optic temperature monitoring along the well, and corrosion coupon monitoring to identify and monitor corrosion of materials used in construction of compression equipment, pipeline, and wells which encounter CO_2. Each of these monitoring systems is fully described in Sections 3.0, 4.0 and 5.0 of the Testing and Monitoring Plan.

In adherence to 40 CFR 146.88(e), each injection well will have a wellhead pressure gauge (tubing and annular pressure) and flow computer, 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: (1) the MASP is reached; (2) the CO_2 injection rate exceeds maximum permitted rate; or (3) the annulus fluid pressure drops below the injection pressure at the packer. Injection parameters, including pressure, rate, volume and/or mass flowrate, and temperature of the CO_2 stream, will be continuously measured and recorded. The pressure and fluid volume changes of the annulus between the tubing and casing will also be continuously recorded.

In adherence to 40 CFR 146.88(f), all automatic shutdowns will be investigated prior to bringing injection back online to ensure 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, Tri-State CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. Response actions to be taken in the event that mechanical integrity is lost are outlined in Appendix A of the Emergency and Remedial Response Plan.

The annular space between the tubing and long string casing of each injection well will be pressurized with brine containing appropriate corrosion inhibiting additives and monitored for changes in pressure and volume as required by 40 CFR 146.88(c). The fiber optic cable cemented onto the outside of the long-string casing will be used to continuously monitor temperature along the length of the casing through the primary confining units. For injection into the MIC, the confining unit is the Rochester Shale Formation, and for injection into the KIC, the confining unit is the Wells Creek Shale Formation. Rapid temperature changes or other deviations from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

3. <u>Workover and Maintenance</u>

In adherence to 40 CFR 146.88(d), Tri-State CCS, LLC will monitor and maintain mechanical integrity of each injection well at all times. 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. As outlined in subsection 2.5 of the Testing and Monitoring Plan, and in adherence to 40 CFR 146.91(d), Tri-State CCS, LLC will notify the Underground Injection Control (UIC) Program Director of any planned workover or injection well test at least 30 days in advance, and the results of any mechanical integrity test (MIT), workover, or injection well test will be provided within 30 days after the test or maintenance is completed (40 CFR 146.91(b)).

4. Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), Tri-State CCS, LLC will reduce CO_2 injection at a rate of up to 60,000 tonnes per day over a maximum of 2 days to ensure protection of health, safety, and the environment. See the Emergency and Remedial Response Plan for procedures on immediately shutting in an injection well.

5. Operational Contingency Plans

Contingency plans will be in place to identify situations where potential plant and/or process upset conditions may occur and take appropriate measures which are protective to the local area and the environment by shutting in the wells and monitoring their pressure fall-off. Operational contingency plans for all the project injection wells include potential downtime periods when annual injection well testing, maintenance, well service, and stimulation occur.

The availability of multiple wells and adhering to proper operations practices, including regular well maintenance and service, will reduce most injection well down-time and should eliminate the unlikely occurrence of one or more wells being simultaneously unavailable for use. In the unlikely event that all wells are temporarily unavailable or are out of commission, CO_2 may be vented to the atmosphere for that limited period until operations and injectivity are re-established. Additional detailed monitoring and other contingency planning for potential events that may occur during well injection operations are provided in the Testing and Monitoring Plan and in the Emergency and Remedial Response Plan.

6. Reporting Requirements

Federal reporting requirements for all the injection wells are listed below in Table 5 per 40 CFR 146.91(a), and project reporting requirements are listed below in Table 6, per 40 CFR 146.91(b) and (c). All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit application.

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Table 5: Class VI Injection Well Reporting Requirements.

Activity	Reporting Requirements
Changes to physical, chemical, or other characteristics of CO_2 stream	Semi-annually
Monthly average, maximum, and minimum injection pressure, injection rate, injection volume, and pressure on the annulus, monthly annulus fluid volume changes	Semi-annually
Monthly and cumulative CO_2 injected over life of project	Semi-annually
Automatic shut-off events (description and response)	Semi-annually
Operating parameter exceedance events	Semi-annually
Results of monitoring in Testing and Monitoring Plan (i.e., corrosion monitoring, etc.)	Semi-annually
External MITs, well workover, other required tests	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 6: 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 the Financial Assurance Demonstration of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Appendix A: Injection Well Summary

Table 7 lists the planned project injection wells including their expected injection interval depths, anticipated average reservoir pressures, maximum downhole pressures (90% of fracture pressure), and average injection rates. As proposed in this plan, boundaries A and B or C and D define the operating conditions design envelope, and all twenty injection wells will operate within the defined boundaries with respect to operating conditions.

Table 7: Injection Well Summary.

Well Name	Injection Zone	Injection Interval Top, TVD (ft)[2]	Injection Interval Bottom, TVD (ft)[2]	Average Reservoir Pressure from Reservoir Model (psi)[1]	Maximum Downhole Pressure (psi)[2]	Average Injection Rate (MMt/y)[1]	Maximum Injection Rate (MMt/y)
TB2-1	KIC	10,352	10,456	6,521	6,522	0.20	0.5
	MIC	7,004	7,142	4,412	4,413	0.070	
TB2-2	KIC	9,843	9,938	6,201	6,201	0.17	0.5
	MIC	6,643	6,799	4,185	4,185	0.073	
TB2-3	KIC	10,368	10,470	6,531	6,532	0.20	0.5
	MIC	7,049	7,203	4,440	4,441	0.077	
TB2-4	KIC	9,680	9,772	6,098	6,098	0.14	0.5
	MIC	6,365	6,538	4,009	4,010	0.069	
TB2-5	KIC	10,088	10,172	6,355	6,355	0.13	0.5
	MIC	6,679	6,864	4,207	4,208	0.079	
TB2-6	KIC	10,794	10,875	6,800	6,800	0.10	0.5
	MIC	7,207	7,375	4,540	4,540	0.071	
TB2-7	KIC	11,009	11,097	6,936	6,936	0.13	0.5
	MIC	7,349	7,497	4,630	4,630	0.070	
TB2-8	KIC	11,409	11,516	7,187	7,188	0.19	0.5
	MIC	7,620	7,774	4,800	4,801	0.079	
TB2-9	KIC	11,597	11,711	7,306	7,306	0.23	0.5
	MIC	7,806	7,967	4,917	4,918	0.089	
TB2-10	KIC	10,932	11,027	6,887	6,887	0.15	0.5
	MIC	7,247	7,405	4,565	4,566	0.069	
TB2-11	KIC	9,886	9,972	6,228	6,228	0.098	0.3
	MIC	6,445	6,628	4,060	4,060	0.063	
TB2-12	KIC	9,813	9,903	6,182	6,182	0.13	0.5
	MIC	6,436	6,603	4,054	4,055	0.065	
TB2-13	KIC	10,158	10,239	6,399	6,400	0.094	0.3
	MIC	6,673	6,865	4,203	4,204	0.073	
TB2-14	KIC	9,604	9,699	6,050	6,051	0.16	0.5
	MIC	6,262	6,420	3,945	3,945	0.064	
TB2-15	KIC	10,069	10,145	6,343	6,343	0.070	0.3
	MIC	6,675	6,861	4,205	4,205	0.063	
TB2-16	KIC	10,052	10,132	6,332	6,333	0.092	0.3
	MIC	6,681	6,860	4,209	4,209	0.067	
TB2-17	KIC	10,508	10,584	6,620	6,620	0.077	0.3
	MIC	7,064	7,228	4,450	4,450	0.061	
TB2-18	KIC	10,240	10,316	6,451	6,451	0.085	0.3
	MIC	6,884	7,036	4,336	4,337	0.057	

Well Name	Injection Zone	Injection Interval Top, TVD (ft)[2]	Injection Interval Bottom, TVD (ft)[2]	Average Reservoir Pressure from Reservoir Model (psi)[1]	Maximum Downhole Pressure (psi)[2]	Average Injection Rate (MMt/y)[1]	Maximum Injection Rate (MMt/y)
TB2-19	KIC	10,286	10,369	6,480	6,480	0.12	0.5
	MIC	6,937	7,091	4,370	4,370	0.065	
TB2-20	KIC	10,183	10,269	6,415	6,415	0.12	0.5
	MIC	6,922	7,096	4,360	4,361	0.069	

[1] Average reservoir conditions are based on reservoir modeling using limited site-specific data and may change once additional site-specific data is collected from pre-operational testing.

[2] Injection interval depths and maximum downhole pressures also subject to change as additional site characterization data becomes available from pre-operational testing and the planned CarbonSAFE stratigraphic test wells in Jefferson and Harrison counties, as available.