TESTING AND MONITORING PLAN
40 CFR 146.90

Project Name: Tri-State CCS Redbud 1

Facility Information

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

Well location: Fairhaven, Hancock County, West Virginia

Well Name	Latitude	Longitude
TR1-1	40.59722582	-80.5716718
TR1-2	40.55529898	-80.6001

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List of Acronyms

°F	Fahrenheit
Al	Aluminum
ANSI	American National Standards Institute
AOB-#	Above-Zone Observation wells
AoR	Area of Review
AP	Artificial Penetrations
APHA	American Public Health Association
As	Arsenic
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
Ba	Barium
BH	Bottom Hole
Br	Bromine
Ca	Calcium
CBL	Cement Bond Log
CCS	Carbon Capture and Storage
Cd	Cadmium
CI	Casing Inspection
Cl	Chlorine
CO_2	Carbon Dioxide
Cr	Chromium
CSR	West Virginia Code of Regulations
Cu	Copper
DH	Downhole
DIC	Dissolved Inorganic Carbon
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
Fe	Iron
ft	feet
GC-P	Gas Chromatography-Pyrolysis
gm	Gram
GS	Geologic Sequestration
GW-#	Shallow Groundwater Wells
H2S	Hydrogen Sulfide
ICP	Inductively Coupled Plasma
IOB-#	In-Zone Observation wells
K	Potassium
lb	pound

Mg	Magnesium
MIT	Mechanical Integrity Testing
MMscf	Million Standard Cubic Feet
Mt/y	Thousand Metric Tonnes per Year
Mn	Manganese
mol%	Percentage of Total Moles in a Mixture made up by One Constituent
MS	Mass Spectrometry
Na	Sodium
NACE	National Association of Corrosion Engineers
NO_3	Nitrate
OES	Optical Emission Spectrometry
P	Pressure
P/T	Pressure-Temperature
Pb	Lead
pH	potential of Hydrogen
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture
ppmv	Parts per Million, Volume
psi	Pounds per Square Inch
psia	Pounds per Square Inch, Absolute
QASP	Quality Assurance and Surveillance Plan
SAPT	Standard Annular Pressure Test
Sb	Antimony
Se	Selenium
Si	Silicon
SO4	Sulfate
SSTVD	Sub-Sea True Vertical Depth
T	Temperature
TBD	To be Determined
TD	Total Depth
TDS	Total Dissolved Solids
Ti	Titanium
TR1-#	Tri-State CCS Redbud 1 Injection Wells
TVD	True Vertical Depth
UIC	Underground Injection Control
UOB-#	Deep Observation Wells
USDW	Underground Source of Drinking Water
WVDEP	West Virginia Department of Environmental Protection

1. Introduction

This Testing and Monitoring Plan (the "plan") describes how Tri-State CCS, LLC will monitor the Tri-State CCS Redbud 1 (the "project") pursuant to 40 CFR 146.90. Data collected during the implementation of this Plan will be used to demonstrate that the wells are operating as planned, the carbon dioxide (CO_2) plume and pressure front are moving as predicted, and to confirm there is no endangerment to Underground Sources of Drinking Water (USDWs). The monitoring data will also be used to validate and adjust the geological models used to predict the distribution of CO2 within the storage reservoir to support Area of Review (AoR) reevaluations and a non-endangerment demonstration. Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (ERRP). In addition, Tri-State CCS, LLC will follow reporting requirements pursuant to 40 CFR 146.91.

2. Overall Strategy and Approach for Testing and Monitoring

Tri-State CCS, LLC's testing and monitoring will cover three main aspects of the geologic sequestration (GS) project during the project injection phase:

1. Well Integrity
2. Operational Parameters
3. Geologic System Changes

Demonstrating the mechanical integrity of the wells in the system is a key aspect of protecting USDWs from endangerment due to injection activities (40 CFR 146.89). Operational testing and monitoring include analysis of the CO_2 stream; continuous monitoring of injection rate, volume, and pressure; corrosion monitoring; and pressure fall-off testing. Monitoring and testing of the geologic system changes include ground water quality and geochemical monitoring above the confining zone; direct pressure front monitoring; and direct/indirect CO_2 plume monitoring.

2.1. Plan Strategy and Approach

The purpose of the Testing and Monitoring Plan is to ensure that sufficient geospatial and monitoring data will be collected and used to validate rigorous numerical modeling and support demonstration of USDW non-endangerment over the life of the project. The Plan will be reviewed by Tri-State CCS, LLC at least every five years. After review, Tri-State CCS, LLC will either submit an amended Testing and Monitoring Plan or demonstrate to the UIC Program Director that no amendment to the plan is needed.

Tri-State CCS, LLC recognizes the nexus of data collection and modeling is the primary pathway to exit the UIC permit, define the post-injection site care (PISC) protocols, and close the CO_2 storage site. As such, Tri-State CCS, LLC is establishing a monitoring program capable of tracking the injected CO_2 plume and pressure front and developing time-lapse datasets for numerical modeling. The near surface/subsurface monitoring protocols to be used in the project's Testing and Monitoring Plan will provide valuable information to evaluate the performance of the CO_2 injection and storage operations and is to include:

- Above-zone and shallow USDW fluid sample analyses;
- Above-zone and in-zone direct pressure and temperature measurements;
- Surface to total depth (TD) temperature sensing; and
- Through-casing CO_2 saturation profiling.

Tri-State CCS, LLC plans to drill up to 10 wells (Table 1), strategically placed in specific formations (Figure 1), to ensure USDW non-endangerment. These wells include two (2) multi-zone injection wells completed in the Lockport Dolomite and Medina Groups, two (2) offset in-zone observation wells completed in the Lockport Dolomite and Medina Groups, two (2) above-zone observation wells completed in the Oriskany Formation, two (2) deep observation wells completed in the lowermost USDW of the Mauch Chunk Formation, and up to two (2) shallow USDW wells completed in the Pennsylvanian unit.

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System	Series	Subseries / Group	Stratigraphic Unit (SU) (Group or Major Formation)	Aquifer, Confining Zone or Reservoir	Depth / Inverval Thickness (ft) Well TR1-1	Depth / Inverval Thickness (ft) Well TR1-2
			Pennsylvanian (undivided)	Freshwater Aquifers	@ surface	@ surface
Mississippian	Upper	Chester / Meramecian	Mauch Chunk Fm.	Lowermost USDW	**650' (to base)**	**550' (to base)**
Mississippian	Upper	Chester / Meramecian	Greenbriar Ls. Fm.	*Seal (Limestone)*		
Mississippian	Lower	Osagean / Kinderhookian; Pocono Grp.	Big Injun Ss.	Conventional Oil Reservoir		
Mississippian	Lower	Osagean / Kinderhookian; Pocono Grp.	Sunberry Sh.	*Seal (Shale)*		
Mississippian	Lower	Osagean / Kinderhookian; Pocono Grp.	Berea Ss.	Conventional Oil Reservoir		
Devonian	Upper		Ohio Shale Grp.	*Seal (Shale)*	3,000'+ thick	3,000'+ thick
Devonian	Upper		Olentangy Shale Fm.	*Seal (Shale)*		
Devonian	Middle	Hamilton Grp.	Tully Ls.; Mahantango Shale Fm.	*Seal (Shale)*		
Devonian	Middle	Hamilton Grp.	Marcellus Shale Fm.	Unconventional Oil Reservoir		
Devonian	Lower		Onondaga Ls. Fm.	*Seal (Limestone)*	**4,600' / 201'**	**4,615' / 223'**
Devonian	Lower		Oriskany Ss. Fm.	Conventional Oil/Gas Reservoir	**4,801' / 25'**	**4,838' / 23'**
Devonian	Lower		Helderberg Grp.	*Seal (Limestone)*	**4,826' / 430'**	**4,861' / 284'**
Silurian	Upper		Bass Islands Dolomite Grp.	*Seal*	**5,257' / 68'**	**5,145' / 25'**
Silurian	Upper	Salina Grp.	Salina "D" - "G"; Salina "A" - "C"	**Primary Confining Zone** *Seal (Evaporite/Salt)*	**5,325' / 1,007'**	**5,170' / 912'**
Silurian	Upper		Lockport Dolomite Grp. 1	**Primary Injection Zone**	**6,332' / 306'**	**6,082' / 299'**
Silurian	Upper / Lower	Clinton Grp.	Rochester Shale Fm.; Dayton / Keefer Fm.	**Primary Confining Zone**	**6,638' / 292'**	**6,381' / 293'**
Silurian	Lower		Medina (Tuscarora Ss.) Grp. *(informal - "Clinton" & "Medina" sands)* 2	**Primary Injection Zone**	**6,930' / 152'**	**6,674' / 147'**
Ordovician	Upper		Queenston Shale (Juniata Fm.)	**Primary Confining Zone**	**7,081' /**	**6,821' /**
Ordovician	Upper		Utica Shale Fm.	Unconventional Oil Reservoir	**2,622' thick**	**2,756' thick**
Ordovician	Upper		Trenton Ls. Grp.	*Seal (Limestone)*		
Ordovician	Upper		Black River Ls. Grp.	*Seal (Limestone)*		
Ordovician	M.		Wells Creek Fm.	*Seal (Limestone)*	**9,704' / 170'**	**9,578' / 169'**
Ordovician	L.	Knox Grp.	Beekmantown Fm.	Possible Injection Zone(s)	**9,875' / 401'**	**9,747' / 378'**
Cambrian	Up.	Knox Grp.	Rose Run A	Possible Injection Zone(s)	**10,276' / 126'**	**10,126' / 127'**
Cambrian	Up.	Knox Grp.	Copper Ridge Dolomite Fm.	Possible Injection Zone(s)	**10,402' / 387'**	**10,253' / 388'**
Cambrian	Up.		Conasauga Fm.	*Lower Seal / Confining Unit*	**10,789'**	**10,641'**

Figure 1: Generalized stratigraphic column identifying primary and secondary storage complexes with corresponding storage reservoirs and confining zones at the injection wells TR1-1 and TR1-2. Lowermost USDW is also identified for reference. (*Depth is to the top of the Stratigraphic Unit (SU).)

Table 1: Project well summary. Zone depth are estimates, actual depths will be determined after well data collection.

Well Types	Well Acronym	CCS System Zone	Zone Formation	Zone Depth (ft MD)	Quantity
Shallow Groundwater	TR1-GW-1, TR1-GW-2	Shallow USDW	Pennsylvanian	TBD	Up to 2
Deep Observation	TR1-UOB-1, TR1-UOB-2	Lowermost USDW	Mauch Chunk Formation	~ 650	2
Above-Zone Observation	TR1-AOB-1, TR1-AOB-2	1st Permeable Zone	Oriskany Formation	~ 4830, ~ 4850	2
In-Zone Observation	TR1-IOB-1, TR1-IOB-2	Reservoir	Lockport Dolomite Grp,	~ 6350, ~ 6100	2
			Medina Grp.	~ 6940, ~ 6700	
Injection	TR1-1, TR1-2	Reservoir	Lockport Dolomite Grp.	~ 6550, ~ 6300	2
			Medina Grp.	~ 6940, ~ 6700	

Tri-State CCS, LLC will ensure a certified monitoring well drilling professional is on site in direct charge of actively drilling, constructing, and testing all monitoring wells (47 CSR 59-4). Tri-State CCS, LLC will report to the West Virginia Department of Environmental Protection (WVDEP) within 60 days of the completion of the monitoring wells (47 CSR 60-6). Tri-State CCS, LLC will follow monitoring well drilling and construction guidelines as codified under 47 CSR 60-7 through 60-18. When the monitoring wells are abandoned (either prematurely or at the end of the project), specified abandonment procedures and reporting will be followed in accordance with 47 CSR 60-19. If driven-point wells are utilized, the specific requirements under 47 CSR 60-20 will be followed for installation.

2.2. Baseline Testing and Monitoring

Baseline testing and monitoring for this project includes CO_2 stream characterization, internal and external mechanical integrity, groundwater quality, direct pressure and temperature, indirect CO_2 plume, and hydrogeologic testing (Table 2).

CO_2 stream analysis is a critical element of baseline characterization that will provide the chemical profiles, of which the injectate is monitored for, in the observation wells. Tri-State CCS, LLC will analyze the contents of the CO_2 stream prior to injection, at a sufficient frequency, to yield representative chemical and physical profile data in accordance with 40 CFR 146.90(a).

Mechanical integrity, internal and external, is a key component of the baseline testing and monitoring program (40 CFR 146.87) to ensure there are no significant leaks in the injection tubing, packer, or casing (internal) and through channels adjacent to the injection well bore (external) per 40 CFR 146.89(a)(1) and 40 CFR 146.89(a)(2), respectively. A demonstration of internal mechanical integrity will be conducted using an annulus pressure test prior to injection in all injection wells (Section 6). External mechanical integrity will be demonstrated in all injection and in-zone observation wells once prior to injection, using a distributed temperature sensing (DTS) fiber optic cable mechanical integrity test (MIT). For this plan, DTS will be used in lieu of a temperature log to run MITs (Section 6) unless there is a failure of installed fiberoptic monitoring, such as cable shear or surface equipment failure, in which case, temperature log will be used to run MITs.

Groundwater quality and geochemical changes will be monitored in all project wells (Table 2) per 40 CFR 146.90(d). Groundwater sampling procedures will be formulated using permanent downhole and wellhead pressure gauges. These gauges will continuously record and transmit pressure data about the groundwater in the reservoir units mentioned above and allow for an estimate of the water to be purged prior to sample collection. Groundwater chemistry will be baselined through fluid sampling and analysis in the injection interval of the Lockport Dolomite and Medina Groups (TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2), the first permeable unit above the confining zone in the Oriskany Formation (TR1-AOB-1, TR-AOB-2), the lowermost USDW, in the Mauch Chunk Formation (TR1-UOB-1, TR1-UOB-2), and the shallow Pennsylvanian aquifers (TR1-GW-1, TR1-GW-2). Analytes will be tested to create a baseline (see Table 9), representative of the pre-operational groundwater geochemistry, that can be compared to operational (injection phase) geochemistry groundwater monitoring data (Section 5). Groundwater sampling and analysis will occur quarterly, one year prior to injection, to capture seasonal variations in the groundwater geochemistry. Carbon isotope analyses will be run for all baseline analyses to enable Tri-State CCS, LLC to differentiate project and natural/background CO_2. During injection operations, isotopic analyses will only occur if loss of containment is detected to help verify project containment.

Groundwater quality and geochemistry baseline data will help verify containment during injection operations by detecting changes in injection phase data from the baseline data. Changes in the groundwater quality and geochemistry mentioned below can be an indication of loss of containment:

- Increase in total dissolved solids (TDS) can indicate native brines have infiltrated the overlying reservoirs.
- Increasing CO_2 concentration and/or decreasing pH can indicate infiltration of CO_2 into monitoring zones.
- Increased reservoir pressure and/or temperature changes may indicate reservoir zone and monitoring zone connectivity.
- Increase in leached constituents (lead, arsenic, etc.) could be due to the presence of CO_2.
- Significant cation and anion signature change could be due to the presence of CO_2.
- Increase of injectate impurities may indicate CO_2 migration into overlying monitoring zones.

Baseline pressure monitoring will occur in the injection, in-zone, above-zone, and deep (lowermost USDW) wells per 40 CFR 146.90(g)(1) and will occur continuously using both downhole and wellhead pressure gauges. Direct baseline pressure monitoring in injection and in-zone wells will help reveal natural variations in subsurface pressure. This reservoir zone pressure data will help calibrate model predictions of pressure front propagation and allow for adequate baseline data to help decrease the frequency of false positive and negative loss of containment detection events when compared to injection phase monitoring data. Direct pressure monitoring in the above-zone and deep observation wells will allow for a comparison to injection phase monitoring pressure data for early detection of containment loss due to increased pressures from potential out-of-zone reservoir brine and/or CO_2.

Indirect CO_2 plume baseline monitoring will occur at the project per 40 CFR 146.90(g)(2). Tri-State CCS, LLC plans to implement indirect CO_2 plume monitoring using DTS, and pulsed neutron capture (PNC) logging. Baseline data will be acquired prior to injection for comparison to injection phase monitoring data.

PNC logging tools can detect elevated oxygen around the wellbore in the rock formation and therefore the presence of CO_2. PNC logging will be conducted once prior to injection in all injection, in-zone, above-zone, and deep observation wells. This baseline logging data will allow for comparison to injection phase monitoring data to determine the vertical location of CO_2 within the injection and in-zone wells, and for early detection of containment loss for above-zone and deep observation wells. During injection, PNC logging will only be run in the injection wells, any wells with CO_2 breakthrough, and in any well with monitoring data indicating loss of containment. For the zones above the confining zone, PNC logging will be mainly used as a verification technique to help prove the absence of CO_2. Groundwater sampling and analysis will also be used to verify elevated levels of CO_2 and determine if the elevated CO_2 is project related.

DTS data will be used to indirectly monitor the location of the CO_2 saturation plume. Differences in the reservoir temperature and injectate stream temperature will be detected allowing for interpretation of the vertical location of the CO_2 plume near the wellbore. As mentioned above, all injection and in-zone wells will contain DTS on the long string casing and record continuous temperature measurements after well construction and prior to injection. Injection phase monitoring data will be compared to baseline data to determine vertical extent of CO_2 in the injection wells (and eventually the in-zone observation wells), and CO_2 breakthrough in the in-zone observation wells. Reservoir units taking CO_2, detected via DTS, will then be used to calibrate reservoir models for better prediction of CO_2 saturation plume behavior through time.

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Hydrogeologic testing, which includes pressure fall-off testing, will be conducted once prior to injection at each injection well. This data will be used to better understand any injectivity heterogeneity within the reservoir and to better predict plume movement in reservoir models. During the injection phase, hydrogeologic test data can be compared to DTS and PNC logging data for confirmation of the injection zone interval taking fluid and any potential changes in the reservoir injectivity as a result of injection operations.

All necessary data will be collected during the pre-injection phase (Table 2) to represent the in-situ properties prior to injection. Data collected during the injection phase (Table 4) will then be compared to pre-injection phase baseline measurements to ensure containment and protection of groundwater resources.

Table 2: Pre-injection testing and monitoring technologies, frequencies, and locations.[1]

Monitoring Parameter	Technology/Test	Baseline Phase Frequency (1 year)	Location
Internal MIT	Annulus Pressure Test	1 Prior to Injection	TR1-1, TR1-2
External MIT	1) DTS 2) Ultra Sonic CBL 3) Electromag. CI Logs	1 Prior to Injection	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2
Groundwater Quality	1) Fluid Sampling &Analysis 2) BH P Gauges	1) Quarterly 2) Continuous	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2; TR1-AOB-1; TR1-AOB-2; TR1-UOB-1, TR1-UOB-2
Direct Pressure Monitoring	1) P Gauges – Tubing 2) Downhole P Gauges	Continuous	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2; TR1-AOB-1; TR1-AOB-2, TR1-UOB-1, TR1-UOB-2
Indirect CO_2 Plume Monitoring Techniques	DTS	1 Year Prior to Injection	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2
	PNC Logging	1 Prior to Injection	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2; TR1-AOB-1; TR1-AOB-2; TR1-UOB-1, TR1-UOB-2
Hydrogeologic Testing	Pressure Fall-Off Testing		TR1-1, TR1-2

[1] Refer to Pre-Operational Testing Plan for additional details.

2.3. Conceptual Monitoring Network Design

This plan describes injection phase components of the geologic testing and monitoring program which includes hydraulic, geochemical, and physical components for characterizing the complex transport processes associated with CO_2 injection. Table 3 lists the planned testing and monitoring frequencies for the pre-injection, injection, and post-injection phases of this project. Table 4 provides a listing of all the planned testing and monitoring activities during the injection phase, including frequencies and actual tests or technologies planned to be used. The injection wells and in-zone observation wells will be monitored to characterize reservoir pressure, monitor CO_2 transport response, and guide operational and regulatory decision-making. Figure 2 shows a simplified layout of the storage complex depicting the location of testing and monitoring equipment. The exact locations are tentative and may vary depending on field conditions.

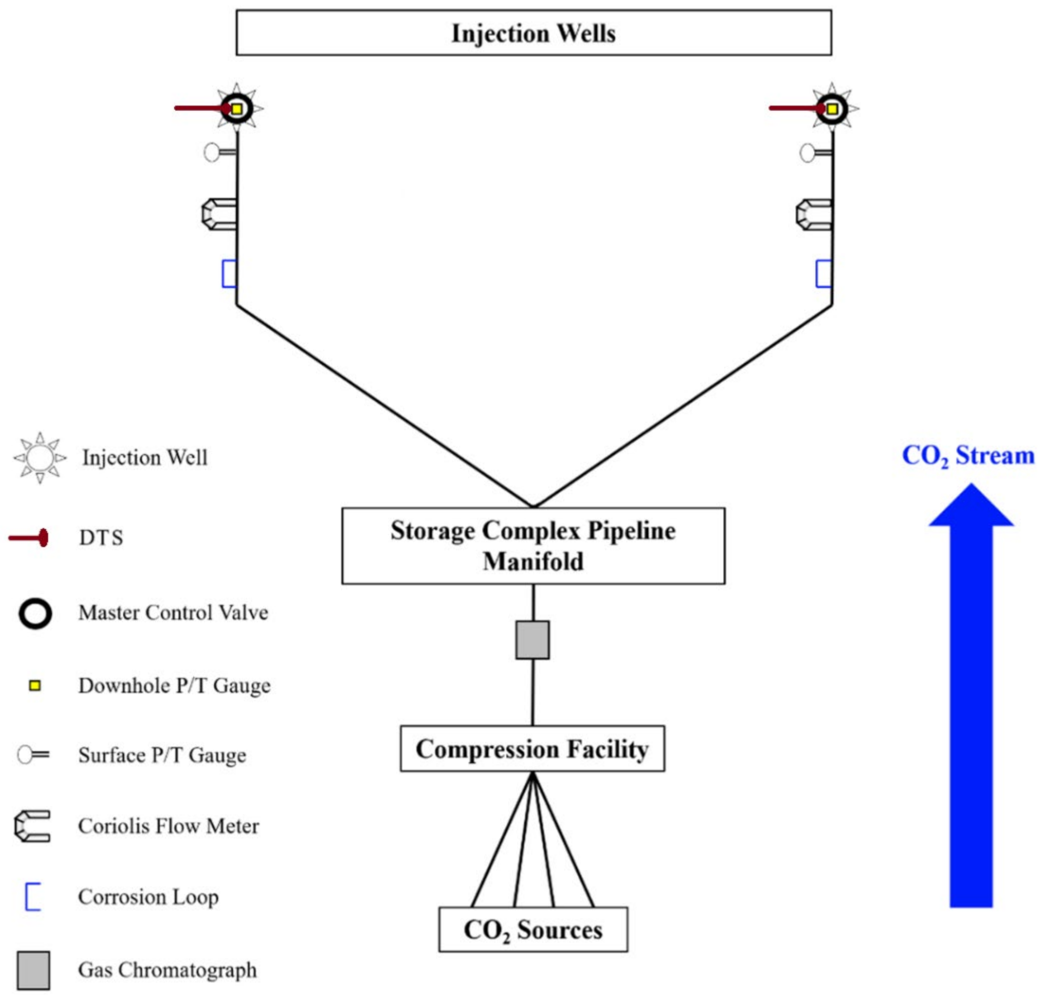

Figure 2: Simplified layout of storage complex depicting location of testing and monitoring equipment. The locations as depicted are tentative and may vary depending on field conditions.

Above-zone observation wells will monitor the first permeable zone above the primary confining zone for pressure, temperature, and fluid chemistry changes for early detection of containment loss. In-zone observation wells, in combination with the above-zone observation wells, will provide the first indication of containment loss.

Tri-State CCS, LLC has implemented a well-based monitoring plan to track the CO_2 and pressure plume evolution to ensure protection of groundwater resources. Monitoring technology in injection and in-zone observation wells will help track the CO_2 and pressure plume front movement through time. The above-zone observation wells will be completed in the permeable unit of the Oriskany Formation to detect physical and chemical changes in the groundwater to ensure early detection of containment loss to protect USDWs. All observation wells will have direct monitoring of pressure and temperature in multiple zones.

Protection of USDWs, required by the EPA's UIC Class VI GS Rule (75 FR 77230), is a primary objective of the project's monitoring program as demonstrated by the two (2) above-zone, two (2) deep, and up to two (2) shallow groundwater observation wells. Fluid samples will be collected from the wells in the Oriskany Formation (above-zone) and Mauch Chunk Formation (lowermost USDW). The associated networks of above-zone and shallow ground water monitoring locations are designed to provide: 1) a thorough assessment of baseline conditions at the site, and 2) spatially distributed monitoring locations that can be routinely sampled throughout the life of the project.

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Table 3: Testing and monitoring frequencies for all project phases.

Monitoring Category	**Monitoring Parameter/Method**		**Baseline Frequency (1 year)**	**Injection Phase Frequency (30 years)**	**Post-Injection Frequency (50 years)**
Monitoring Plan Update	Review Every 5 Years *Updated as Required*		N/A	Update As Required	Update As Required
CO_2 Injection Stream Analysis	Chemical Characteristics		N/A	Continuous	N/A
	Physical Characteristics		N/A	Continuous	N/A
CO_2 Injection Process Monitoring	Injection Rate		N/A	Continuous	N/A
	Injection Physical Characteristics		N/A	Continuous	N/A
	Annulus Pressure Monitoring		N/A	Continuous	N/A
	Annulus Volume Added		N/A	Continuous	N/A
Hydrogeologic Testing	Pressure Fall-Off Testing		1 Prior to Injection	3 Years After Injection, 1 Every 5 years After	N/A
Injection Well Mechanical Integrity Testing	<u>Internal</u> *Annulus*	Pressure Test	1 Prior to Injection	N/A	N/A
		Pressure Monitoring	N/A	Continuous	Continuous
	<u>External</u> *Temp.*	1) DTS *AND/OR* 2) Temp. Log 3) PNC Logging 4) Ultra Sonic CBL 5) Electromag. CI Logs	1 MIT Prior to Injection: 1 *OR* 2 *AND* 3-5	1 MIT Annually: 1 *OR one of* 2-5	N/A
Corrosion Monitoring	Corrosion Coupon Testing		N/A	Quarterly	N/A
Groundwater Quality and Geochemistry Monitoring	*Fluid Sampling and Analysis*	*Lowermost USDW*	Quarterly – 1 Year Prior to Injection	Quarterly for 1^{st} Year, Annually Thereafter.	Annually
		Above-Zone			
		In-Zone			N/A
Direct Pressure Plume Monitoring	Wellhead P Gauges Downhole P Gauges		Continuous, After Well Construction	Continuous	Continuous
Indirect Plume Monitoring Techniques	*Fiber & Wireline*	DTS	1 Year Prior to Injection	Continuous	Continuous
		PNC Logging	1 Prior to Injection	3 Years After Injection, 1 Every 5 Years After[1]	1 Every 5 Years[1]

[1] Apart from injection wells, PNC logging or equivalent will only occur in wells with CO_2 breakthrough or wells with detected containment loss at the frequency specified in the table above. Based on actual wellbore/reservoir conditions post-breakthrough or contamination, the logging frequency may be modified in consultation with the UIC Program Director.

Observation wells have been strategically placed to mitigate the highest risks to USDWs within the AoR. In-zone wells (TR1-IOB-1, TR1-IOB-2) have been strategically placed to image the CO_2 plume and track the pressure front evolution. These wells have been placed at the edge of the maximum CO_2 plume extent but within the maximum pressure front extent and act as sentry wells bounding the CO_2 plume. Locations are subject to change based on data collected via the CarbonSAFE stratigraphic well which will be repurposed as TR1-AOB-2. Monitoring data from these wells will be used to update and history match the pressure response in reservoir models. TR1-IOB-1 is placed to the southwest of TR1-1 and TR1-IOB-2 is placed northwest of TR1-2. Both these observation wells are planned close to the maximum modeled extent of the CO_2 plume, 50 years post injection. These will allow Tri-State CCS, LLC to continuously monitor the injection zones at the edges of the modeled plume front to verify the pressures are acting as predicted and allow early detection of any CO_2 movement outside of the modeled plume extent.

The two above-zone (TR1-AOB-1, TR1-AOB-2) observation wells will monitor conditions in the first permeable zone above the primary confining zone to ensure containment of reservoir brine and CO_2. High pressure zones around the injection wells with natural (i.e., faults) or artificial penetrations pose the highest risk to containment and USDWs (Figure 3). Tri-State CCS, LLC has therefore placed above-zone wells relatively close to the injection wells for early detection of containment loss. An existing stratigraphic test well, associated with a prior CarbonSAFE project, will be repurposed as above-zone monitoring well TR1-AOB-2.

The two deep (lowermost USDW) observation wells (TR1-UOB-1, TR1-UOB-2) are planned to be placed to ensure containment in the AoR and ultimately provide evidence for the non-endangerment demonstration required for site closure. Specifically, TR1-UOB-1 and TR1-UOB-2 will be placed on each injection well pad site to monitor the USDW directly above and around each injection well.

Up to two shallow groundwater observation wells (TR1-GW-1, TR1-GW-2) will be placed at strategic locations as backup monitoring should Tri-State CCS, LLC need to monitor the shallow groundwater. Wells have not been placed at this time, but placement will consider potential contamination near the AoR, high-risk areas such as high pressures, and community concerns. Minimal surface disruption is anticipated by completing multiple project wells on a single well pad, where possible.

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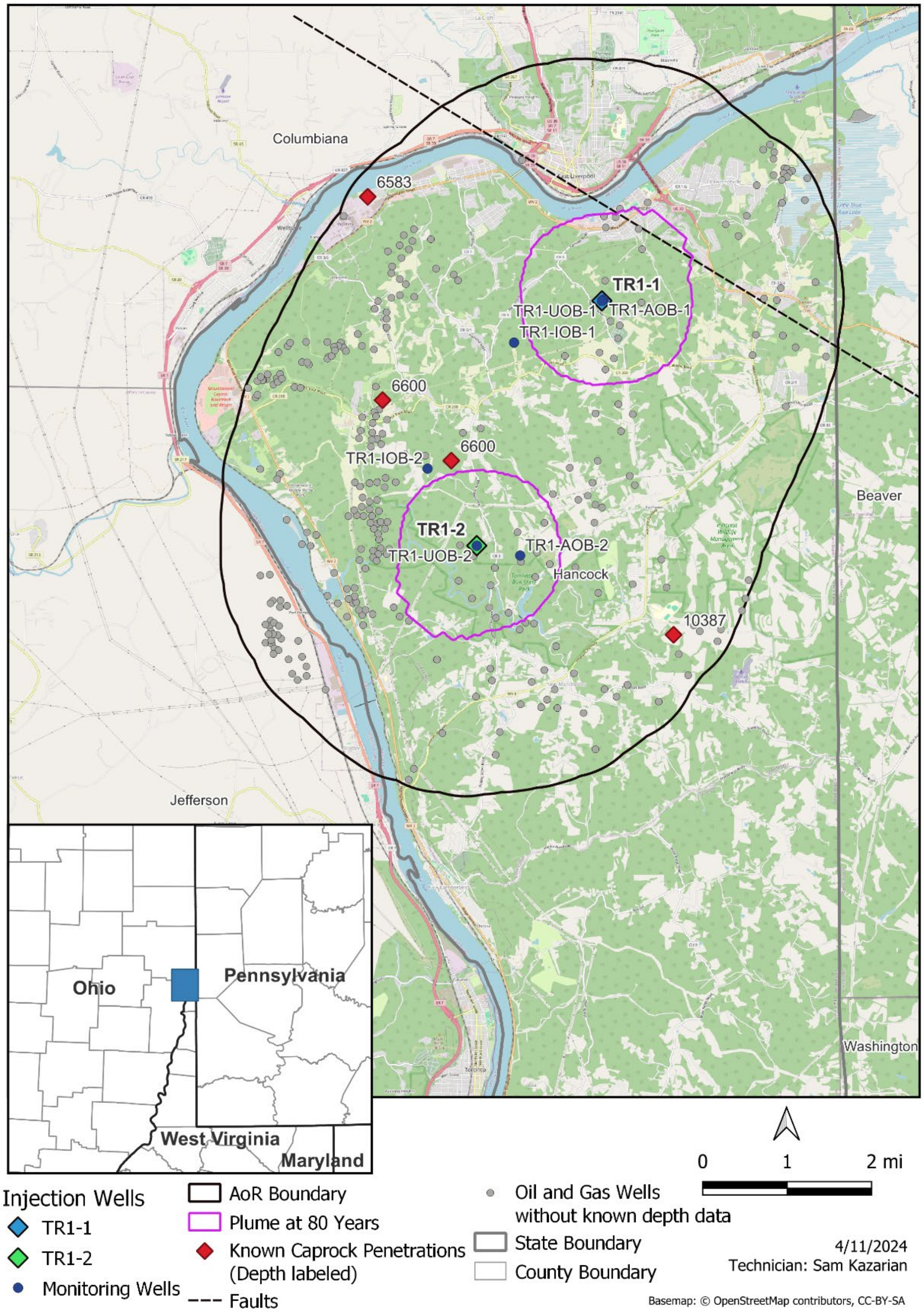

Figure 3: Map of project showing AoR boundary and the proposed injection and observation well locations. The in-zone observation (TR1-IOB), above-zone observation (TR1-AOB), and deep (lowermost USDW) observation (TR1-UOB) wells are identified, as well as known caprock penetrations and oil and gas wells without depth data. Projected fault does not breach containment.

Table 4: Injection phase testing and monitoring frequencies and locations

Monitoring Parameter	Technology/Test	Injection Phase Frequency (30 years)	Location
Injectate Chemical Characteristics	1) Gas Chromatograph 2) Injectate Sampling & Analysis	1) Continuous 2) Annually	Prior to Injection Wells Manifold
Injection Rate	Mass Flow Meter	Continuous	Each Injection Well Pad (TR1-1, TR1-2)
Injection Physical Characteristics	1) P Gauges – Tubing 2) DH P Gauges	Continuous	TR1-1, TR1-2
Annulus Pressure Monitoring	P Gauge - Annulus	Continuous	TR1-1, TR1-2
Annulus Volume Added	Fluid Tank Volume Meter or suitable alternative	Continuous	TR1-1, TR1-2 Well Pads
Internal MIT	P Gauge - Annulus	Continuous	TR1-1, TR1-2
External MIT	DTS, *OR one of:* Temp. Log, PNC Log, Ultra Sonic CB Log, Electromag. CI Logs	1 MIT Annually	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2
Corrosion	Coupon Analysis	Quarterly	TR1-1, TR1-2 Corrosion Loops
Groundwater Quality & Geochemistry	1) Fluid S&A 2) BH P Gauges	1) Quarterly for 1st Year, Then Annually[1] 2) Continuous	TR1-IOB-1, TR1-IOB-2; TR1-AOB-1; TR1-AOB-2; TR1-UOB-1, TR1-UOB-2
Direct Pressure & Temperature Monitoring	1) P Gauges – Tubing 2) DH P Gauges 3) DTS[3]	Continuous	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2; TR1-AOB-1; TR1-AOB-2; TR1-UOB-1, TR1-UOB-2
Indirect CO_2 Plume Monitoring Techniques	DTS	Continuous	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2
	PNC Logging[2]	3 Years After Injection, 1 Every 5 Years Thereafter	TR1-1, TR1-2; TR1-IOB-1, TR1-IOB-2
Hydrogeologic Testing	Pressure Fall-Off Testing		TR1-1, TR1-2

[1]Sampling and analysis frequencies may be reduced based on project-specific benchmarks that will be defined from baseline monitoring data and/or injection phase monitoring data.

[2]Apart from injection wells, PNC logging or equivalent will only occur in wells with CO_2 breakthrough or wells with detected containment loss at the frequency specified in the table above.

[3]Injection zone temperature monitoring using DTS is not planned for TR-1, TR-2 wells.

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2.4. Quality Assurance Procedures

A Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities, required pursuant to 40 CFR 146.90(k), is provided as Appendix A to this Testing and Monitoring Plan.

2.5. Reporting Procedures

Tri-State CCS, LLC will report the results of all testing and monitoring activities to the UIC Program Director in compliance with the requirements under 40 CFR 146.91. The following reporting requirements apply to the project.

24-Hour Notification of an Event. Tri-State CCS, LLC will notify the UIC Program Director via phone as soon as practicable but within 24 hours of discovery of the following events (40 CFR 146.91(c)):

- Any evidence that the injected CO_2 stream or associated pressure front may cause endangerment to a USDW;
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
- Any triggering of a shut-off system downhole or at the surface; or
- Any failure to maintain mechanical integrity.

30-Day Notification of Planned Activity and Results Reporting. Tri-State CCS, LLC will provide written notice to the UIC Program Director at least 30 days in advance of the following activities at an injection well (40 CFR 146.91(d)):

- Any planned well workover;
- Any planned stimulation activities, other than stimulation for formation testing conducted under the initial collection of geologic information; or
- Any other planned test of the injection well, including mechanical integrity testing by Tri-State CCS, LLC.

Within 30 Days of a well workover, MIT, or other injection well test, Tri-State CCS, LLC will submit the results to the UIC Program Director (40 CFR 146.91(b)).

Semi-Annual Testing and Monitoring Report. Tri-State CCS, LLC will submit a semi-annual report to the UIC Program Director that will include the following (40 CFR 146.91(a)):

- Any changes to the source as well as physical, chemical, and other relevant characteristics of the CO_2 stream;
- Monthly average, minimum, and maximum values for the operating injection pressure, injection flow rate, temperature, injection volume or mass, and annular pressure;
- Monthly annulus fluid volume added;
- Description of any event that significantly exceeds operating parameters for annulus or injection pressure;

- Description of any event that triggers a shutdown device (40 CFR 146.88(e)) and the response taken;
- The monthly volume or mass of CO_2 injected over the current reporting period and cumulative volume, or mass of CO_2 injected since the start of injection;
- Any other data collected or results from the implementation of the Testing and Monitoring Plan (40 CFR 146.90).

Recordkeeping. Tri-State CCS, LLC will retain the following records, per 40 CFR 146.91(f), for the time specified:

- All site characterization data and data collected for the permit application will be retained throughout the life of the geologic sequestration project and for at least 10 years following site closure;
- Data on the nature and composition of all injected fluids will be retained for at least 10 years after site closure;
- Any monitoring data collected through the Testing and Monitoring Plan will be retained for at least 10 years after it is collected;
- Well plugging reports and all PISC data will be retained for at least 10 years after site closure.

3. Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

Tri-State CCS, LLC will analyze the CO_2 stream during the injection phase to collect representative characteristic data on the chemical composition of the CO_2 stream, pursuant to 40 CFR 146.90(a). Tri-State CCS, LLC expects multiple sources of CO_2 from the region, with additional sources to be added throughout the life of the project. Each source will have a different gas stream composition based on the source's capture process and therefore the composition of the final injected gas stream will change depending on which sources are operational at any given time. As a result, the injectate stream composition 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. The CO_2 stream coming into the storage site is expected to have a mol% CO_2 concentration of at least 96% with other chemical constituents as seen in Table 5.

A continuous gas chromatograph and sampling port will be installed downstream of all CO_2 sources and prior to the storage complex pipeline manifold to ensure the quality meets specification and that Tri-State CCS, LLC can isolate the delivery of the stream in the event it is out of specification (e.g., high water, H_2S, etc.).

3.1. Sampling Location and Frequency

Tri-State CCS, LLC will continuously analyze the CO_2 stream during the injection phase to collect representative chemical characteristic data. Baseline parameters will be established at the start of injection, and monitoring will occur continuously throughout the injection phase using a gas chromatograph. This chromatograph will be placed downstream of all CO_2 source points and prior to the storage complex pipeline manifold. Gas chromatograph sampling and monitoring will occur continuously at 30-minute intervals. To supplement this gas chromatograph monitoring, physical samples will also be collected from a sampling port annually for H_2S and total sulfur; this sampling port will be near the gas chromatograph downstream of all CO_2 sources and prior to the pipeline manifold. Tri-State CCS, LLC will report the results of the CO_2 stream analysis in semi-annual operational reports.

In the event of unplanned disruptions to permitted injection activities that may affect the chemical composition of the final CO_2 stream, Tri-State CCS, LLC will increase the frequency of CO_2 stream reporting to the UIC Program Director to confirm there are no significant changes and injection is continuing to operate as permitted.

3.2. Analytical Parameters

Tri-State CCS, LLC will analyze the CO_2 stream for the constituents identified in Table 5 using a gas chromatograph and through physical sampling. The list of parameters will be altered if analysis from the CO_2 stream demonstrates additional constituents to be considered. Any additional details concerning analysis of the CO_2 stream can be found in the Quality Assurance and Surveillance Plan (QASP), included as Appendix E. Amendments to this plan must be approved by the UIC Program Director.

3.3. Sampling Methods

The CO_2 stream will be sampled continuously at 30-minute intervals with an on-site gas chromatograph. Physical samples will also be taken through a sampling port near the gas chromatograph downstream of all CO_2 sources and prior to the storage complex pipeline manifold. For more information refer to subections 2.2 and 2.3 of the QASP.

Table 5: Summary of analytical parameters for CO_2 stream.

Component	Specification	Unit
Minimum CO_2	> 96	Mol%, dry
Water Content	< 20	lb/MMSCF
Impurities (Dry Basis)		
Total Hydrocarbons	< 2	Mol%, dry
Inert Gases (N_2, Ar, O_2)	< 4	Mol%, dry
Hydrogen	< 1	mol%
Alcohols, Aldehydes, Esters	<500	ppmv
Hydrogen Sulfide	< 50	ppmv

Component	Specification	Unit
Total Sulfur	< 100	ppmv
Oxygen	< 20	ppmv
Carbon Monoxide	< 1000	ppmv
Glycol	< 1	ppmv

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

4. Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

Tri-State CCS, LLC will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream pursuant to 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Tri-State CCS, LLC will monitor injection operations using a distributive process control system. The surface facility equipment and control system will limit maximum instantaneous rate to 300 Mt/y or limit the wellhead pressures to 1,773 psia (TR1-1) and 1,765 psia (TR1-2). This pressure corresponds to well below the regulatory requirement to not exceed 90% of the injection zone's fracture pressure (40 CFR 146.88(a)). For the Medina Group and Lockport Dolomite Group injection depths, the maximum injection pressures are estimated to be 4,049 psi/3,900 psi for TR1-1 and 3,947 psi/3,800 psi for TR1-2. See Summary of Requirements for more details on operational conditions.

All critical system parameters (e.g., pressure, temperature, and flow rate) will have continuous electronic monitoring with signals transmitted back to a master control system. The system will automatically sound an alarm and shutdown operations should specified control parameters exceed their normal operating range at any time. Tri-State CCS, LLC supervisors and operations personnel will have the capability to monitor and control all operations remotely with this system.

4.1. Monitoring Location and Frequency

Tri-State CCS, LLC will perform the activities identified in Table 6 to monitor operational parameters. Surface and downhole pressure and temperature instruments will be calibrated annually over the full operational range using ANSI or other recognized standards. Bottom hole (BH) pressure gauges shall have a drift stability of less than three (3) psi over the operational period of the instrument and an accuracy of ± five (5) psi. Sampling rates will be at least once every five (5) seconds, except during reported non-routine operational conditions such as well workovers. Temperature sensors will be accurate to within one (1) degree Celsius. Downhole and surface pressure gauge specifications are described in more detail in subsection 1.4 of the QASP.

Injection rate (i.e., injection flow) will be monitored with Coriolis mass flow meters. The flow meters will be located on each injection well pad. The flow meter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The flow meter will be calibrated for the entire expected range of flow rates. See subsection 1.4 QASP for additional details.

Table 6: Continuous recording sampling methods, locations, and frequencies

Parameter	Device(s)	Location	Min. Sampling Frequency (continuous inj./ shut-in)	Min. Recording Frequency (continuous inj./ shut-in)
Injection Pressure Monitoring	1) Tubing P Gauge 2) Downhole P Gauge[1]	1) TR1-1, TR1-2, TR1-IOB-1, TR1-IOB-2 2) TR1-1, TR1-2, TR1-IOB-1, TR1-IOB-2	5 sec. / 4 hours	5 mins. / 4 hours
Injection Rate	Coriolis Mass Flow Meter	TR1-1, TR1-2	5 sec. / 4 hours	5 mins. / 4 hours
Injection Volume	Coriolis Mass Flow Meter	TR1-1, TR1-2	5 sec. / 4 hours	5 mins. / 4 hours
Annular Pressure	Annular P Gauge	TR1-1, TR1-2	5 sec. / 4 hours	5 mins. / 4 hours
Annulus Fluid Volume	Fluid Tank Volume Meter	TR1-1, TR1-2	5 sec. / 4 hours	5 mins. / 4 hours
Injection Temperature Monitoring	DTS	TR1-1, TR1-2, TR1-IOB-1, TR1-IOB-2	10 min. / 12 hours	10 min. /12 hours

[1]All downhole gauges will be placed above packer and ported through it to the respective well monitoring zone. Additionally, individual injection zones will have independent downhole monitoring gauges (see Table 1).

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4.2. Injection Rate, Volume, and Pressure Monitoring

Tri-State CCS, LLC will continuously monitor injection rate, volume, and pressure for each injection well pursuant to 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Storage site injection rate and volume will be monitored using Coriolis mass flow meters that will be located at each well pad, immediately upstream of each injector wellhead, in accordance with manufacturer specifications. Individual Coriolis mass flow meters will be used at the storage site to record each injection wells' injection rate and volume. Tri-State CCS, LLC will include measurements to account for flow rate of injected fluid, concentration of the fluid stream, injectate density, injectate temperature, and energy inputs required for operation. Flow meters will be temperature and pressure compensated and calibrated according to manufacturer specifications. Flow rate data will be used to determine the cumulative mass of CO_2 injected and to confirm compliance with operational requirements of the Class VI UIC permit.

Injection pressure will be continuously monitored using wellhead and downhole pressure gauges. Each injection well will be equipped with permanent downhole pressure gauges that will continuously monitor both injection zone (Lockport Dolomite Group and Medina Group) pressures to ensure they do not exceed 90 percent of the reservoir fracture pressure as required by 40 CFR 146.88(a) and to ensure compliance with operating conditions. Additionally, each injection well will be equipped with a wellhead pressure logger that will ensure Tri-State CCS, LLC maintains surface pressures below the maximum allowable pressure for each well. This pressure limit is equal to the top perforation or completion depth, in true vertical depth (TVD), multiplied by the difference between the injection gradient and the injectate fluid gradient. Surface tubing pressure will be kept below 1,773 psi and 1,765 psi for TR1-1 and TR1-2, respectively.

4.3. Annulus Pressure & Fluid Volume Monitoring

Tri-State CCS, LLC will use the procedure below to monitor annular pressure to limit the potential for any unpermitted fluid movement into or out of the injection well annulus:

- The annulus between the tubing and the long string of casing will be filled with brine. Brine will meet specified parameters such as a brine specific gravity, brine density, and annulus hydrostatic gradient. The brine will contain a corrosion inhibitor. The exact brine composition will be finalized after the well has been drilled.
- The surface annulus pressure will be kept within a range from 100 psi to 1,833 psi for TR1-1 and 1,865 psi for TR1-2.
- During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of an estimated 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer.
- The pressure within the annular space, over the interval above the packer to the confining layer, will always be greater than the pressure of the injection zone formations.
- The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

Figure 4 shows the process instrument diagram used for injection well annulus protection systems. The annular monitoring system will consist of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indicator. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using compressed nitrogen.

The annular pressure between the tubing and the long-string casing will be maintained at a higher pressure than the injection pressure at bottom hole conditions, during injection, and will be monitored by the Tri-State CCS, LLC control system gauges. The annulus head tank pressure will be controlled by pressure regulators or pumps; one set of regulators or pumps will be used to maintain pressure above injection pressure, if needed by adding compressed nitrogen or CO_2, and the other set will be used to relieve pressure, if needed, by venting gas or fluid from the annulus head tank. Any changes to the composition of annular fluid will be submitted to the UIC Program Director for approval.

If system communication were to be lost for greater than 60 minutes, project personnel will observe and monitor manual gauges in the field every eight hours or once per shift for both wellhead surface pressure and annulus pressure, while also recording hard copies of the data until communication is restored. Average annular pressure, annulus tank fluid level, and volume of fluid added or removed from the system will be recorded daily and reported as monthly averages in the semi-annual report.

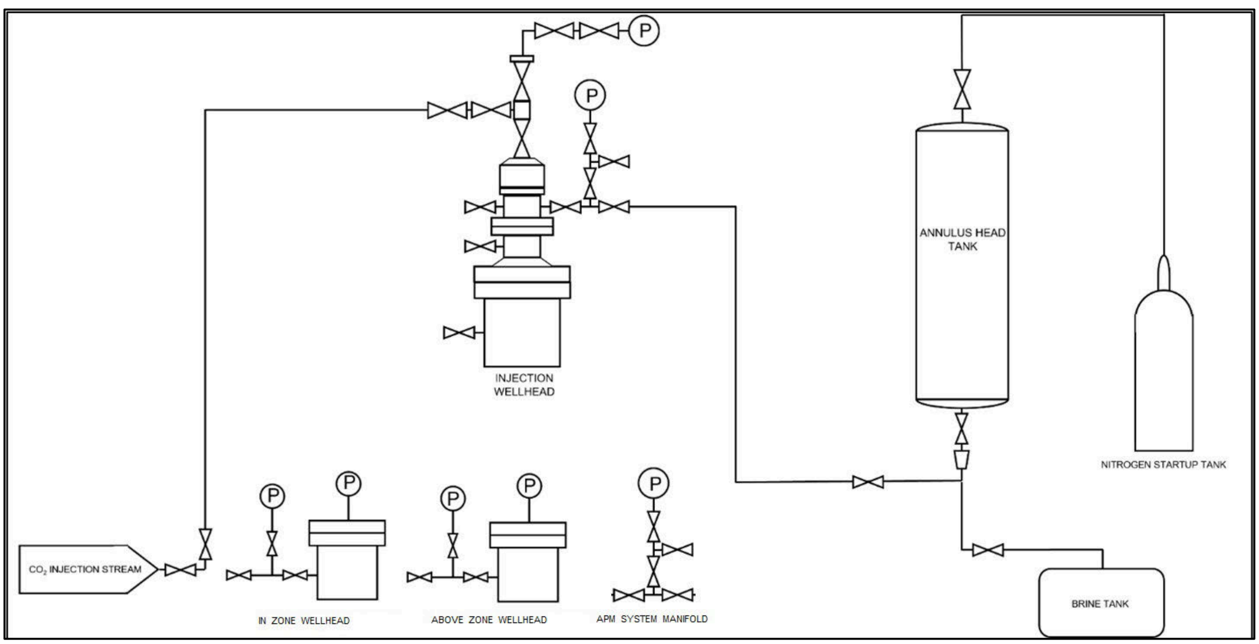

Figure 4: Annular monitoring system.

4.4. Injection Temperature Monitoring

Tri-State CCS, LLC will continuously monitor injection temperature at the surface and downhole for each injection well. The wellhead pressure logger will also continuously measure and record wellhead temperature and be used as a backup should the DTS fail. Tri-State CCS, LLC will supply downhole temperature measurements using DTS fiber optic cable.

In-well pressure and temperature measurements will be taken using permanent downhole gauges. Specifically, two downhole injection zones (Medina Group and Lockport Dolomite Group) will be monitored by independent gauges. Fiber optic technology will be implemented in the injection and observation wells. DTS fiber optic wire will be run from the surface to the wells' total depth (TD). This technology will continuously measure the temperature in the formations outside the casing throughout the entire well column.

5. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), Tri-State CCS, LLC will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

Tri-State CCS, LLC will monitor corrosion using corrosion coupons and collect samples according to the description below.

5.1. Monitoring Location and Frequency

Corrosion monitoring will occur on a quarterly basis during the injection phase, by the following dates each year:

- Three months after the date of injection authorization;
- Six months after the date of injection authorization;
- Nine months after the date of injection authorization; and
- Twelve months after the date of injection authorization.

The corrosion monitoring systems will be located upstream of the wellhead, prior to the Coriolis mass flow meters, and downstream of the injection well control valve (Figure 4). This system will allow for continuation of CO_2 injection during sample removal.

5.2. Sample Description

Samples of materials used in the construction of compression equipment, pipeline, and any wells which encounter CO_2 will be included in the corrosion monitoring program. The samples will be comprised of those items listed in Table 7. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 7: List of equipment coupons with material of construction

Equipment Coupon	Material of Construction
Pipeline	API 5L X60, API 5L X65 PSL2 carbon steel
Long String Casing [0' – 6,200', 6,200' - 7,170']	26 lb/ft, VM-80, 13Cr, 26 lb/ft, VM-80, 25Cr (VAM)
Injection Tubing	9.2 lb/ft, VM-80 25Cr (VAM)
Wellhead	Carbon or alloy steel or Stainless steel
Packers	CRA (TBD)[1]

[1]Corrosion Resistant Alloy (exact material grade will be finalized later)

5.3. Monitoring Details

Tri-State CCS, LLC will monitor for corrosion using corrosion coupons in a closed loop system. Each sample will be attached to an individual holder and then inserted into a flow-through pipe arrangement (Figure 5) attached to the pipeline. The corrosion monitoring systems will be located upstream of the wellhead and downstream of the injection well control valve (Figure 2). The corrosion loop system routes a parallel stream of high-pressure CO_2 from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. The loop will allow for corrosion inspection and injection to occur simultaneously. The corrosion equipment is placed close to the wellhead prior to the Coriolis mass flow meter to provide representative exposure of the CO_2 composition, temperature, and pressures that will be observed at the wellhead and injection tubing.

Corrosion coupons will be handled and evaluated for corrosion using the NACE RP0775-2018 (NACE, 2018) standard or a similarly accepted standard practice for preparing, cleaning, and evaluating corrosion test specimens. The coupons will be photographed, visually inspected (under minimum of 10x power), dimensionally measured to within 0.0001 inch, and weighted to within 0.0001 gram. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration of exposure (i.e., weight loss method). Corrosion monitoring is implemented in this project as a loss of containment prevention measure.

Casing and tubing will be evaluated for corrosion on an as-needed basis by running wireline casing inspection logs. Furthermore, wireline tools can be lowered into the well to directly measure properties of the well tubulars that indicate corrosion. These tools will provide circumferential images with high resolution such that pitting depths, due to corrosion, can often be accurately measured.

The different types of logs that may be used to monitor and assess the condition of well tubing and casing include:

- <u>Mechanical Casing Evaluation Tools:</u> referred to as calipers, these tools have multiple articulated arms attached to the tool that measure the inner diameter of the tubular as the caliper is raised or lowered throughout the well.

- Ultrasonic Tools: these tools measure wall thickness in addition to the inner diameter of the well tubular and can also provide information about the outer surface of the casing or tubing.
- Electromagnetic Tools: these tools are capable of distinguishing between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated.

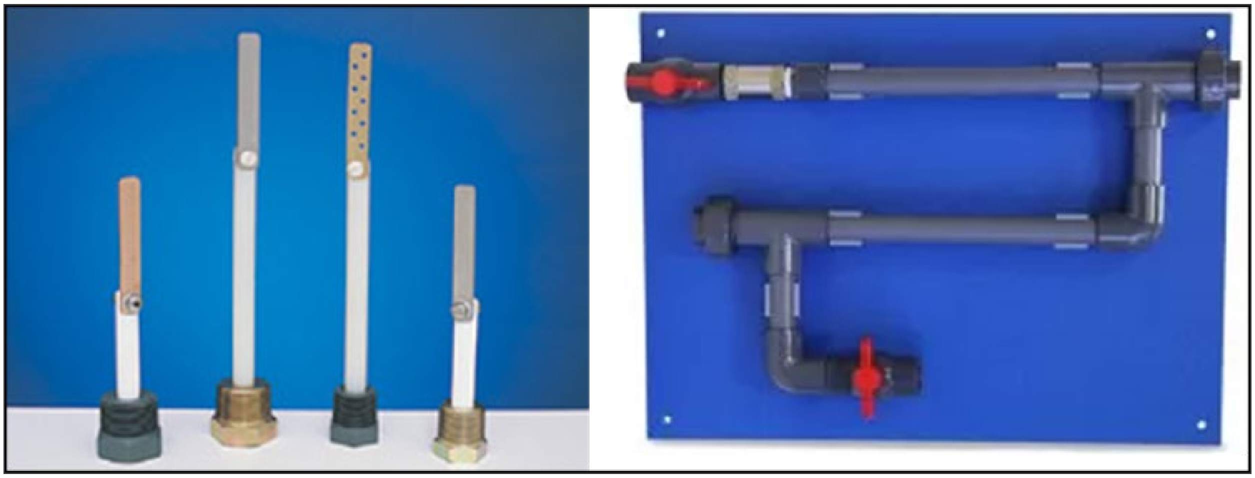

Figure 5: (Left) Example of corrosion coupon holders. (Right) Flow through pipe arrangement example.

6. Above Confining Zone Monitoring

Tri-State CCS, LLC will monitor groundwater quality and geochemistry in the reservoir, first permeable unit above the confining zone, and lowermost USDW during the pre-injection and injection phases pursuant to 40 CFR 146.90(d). During the post-injection phase of the project, groundwater quality and geochemistry will be monitored in only the first permeable unit above the confining zone and the lowermost USDW. Groundwater geochemistry monitoring will be conducted using direct fluid sampling and analysis. Formation pressure will be monitored directly using downhole pressure gauges.

Baseline monitoring will be conducted in all project wells completed in the Lockport Dolomite and Medina Groups (primary injection zones), the Oriskany Formation (first permeable unit above the confining zone), and the Mauch Chunk Formation (lowermost USDW) to understand groundwater fluid chemistry and quality prior to injection (Table 2). This section describes groundwater monitoring during the injection phase of the project with a focus on the following zones:

- Lockport Dolomite and Medina Groups (Injection Zones);
- Oriskany Formation (first permeable zone above the Salina Group confining zone); and
- Mauch Chunk Formation (lowermost USDW).

During the injection phase of the project, in-zone groundwater quality monitoring will only occur in the in-zone observation wells (TR1-IOB-1, TR1-IOB-2). In-zone monitoring results, coupled with monitoring results from above-zone observation wells in the first permeable unit (Oriskany Formation), will provide the first evidence of any loss of containment. Statistical approaches such as outlier testing will be used to identify deviations from the baseline. If a loss of containment is detected and verified, a modeling evaluation of any observed injectate migration above the confining zone will be used to evaluate the magnitude of containment loss and generate bounding predictions regarding anticipated impacts on shallower reservoirs, USDW aquifers, and ecology.

6.1. Monitoring Location and Frequency

The proposed locations of the two above-zone (TR1-AOB-1, TR1-AOB-2) and two in-zone (TR1-IOB-1, TR1-IOB-2) observation wells are spatially displayed in Figure 3. While the two deep (lowermost USDW; TR1-UOB-1, TR1-UOB-2) observation wells are tentatively planned to be sited at the two injection well pads; their exact location, as well as that of the planned shallow groundwater monitoring wells will be finalized as the project progresses. The identified locations are subject to change based on new information and subsequent changes in the current monitoring plan. The proposed monitoring technologies, locations, depth intervals, and frequencies for geochemical monitoring are displayed in Table 8 below.

Table 8: Monitoring geochemical and physical changes.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage[3]	Frequency
Mauch Chunk Formation (Lowermost USDW)	*Geochemical Monitoring*: Direct Fluid Sampling	Deep observation wells [TR1-UOB-1, TR1-UOB-2]	2 Well Locations Vertical (ft. MD): TR1-UOB-1: ~650 ft TR1-UOB-2: ~550 ft	[1]Quarterly for first year, [2]annually thereafter.
	Physical Monitoring: Downhole P Gauges			Continuous
Oriskany Formation (First permeable unit over confining zone)	*Geochemical Monitoring*: Direct Fluid Sampling	Above-zone observation well [TR1-AOB-1, TR1-AOB-2]	2 Well Locations Vertical (ft. MD): TR1-AOB-1: ~4830 TR1-AOB-2: ~4850	[1]Quarterly for first year, [2]annually thereafter
	Physical Monitoring: Downhole P Gauges			Continuous
Lockport Dolomite and Medina Grps (Injection Interval)	*Geochemical Monitoring*: Direct Fluid Sampling	In-Zone Observation Wells [TR1-IOB-1, TR1-IOB-2]	2 Well Locations Vertical (ft. MD): TR1-IOB-1: ~6350/ ~6940 Lockport Dolomite Grp/Medina Grp TR1-IOB-2: ~6550/ ~6700 Lockport Dolomite Grp/Medina Grp	[1]Quarterly for first year, [2]annually thereafter
	Physical Monitoring: Downhole P Gauges			Continuous

[1]Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.
[2]Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.
[3]Actual depths will depend on monitoring requirements. For example, actual depths within Oriskany Formation will likely be the strata immediately above the underlying seal (Helderberg Grp.).

6.2. Analytical Parameters

Fluid samples collected from units above the confining zone will be analyzed for geochemical parameters listed in Table 9. Acquired groundwater monitoring data will be periodically evaluated throughout the injection phase, and if listed parameters are determined to have a non-significant impact on meeting project monitoring objectives, they will be removed from the groundwater geochemistry analysis strategy. Additionally, the monitored parameters will be reevaluated and updated as needed if new sources of CO_2 are added to the injection stream. Shallow groundwater observation wells will be analyzed for groundwater geochemistry during baseline testing and monitoring. These wells will not be sampled and analyzed during the injection phase but may be used to provide additional evidence for groundwater protection should the operator or UIC Program Director deem it necessary.

Table 9: Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Shallow Groundwater (Pennsylvanian) Observation Wells	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B (U.S. EPA, 2014a) or EPA Method 200.8 (U.S. EPA, 1994a)
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D (U.S. EPA, 2014b) or EPA Method 200.7 (U.S. EPA, 1994b)
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0 (U.S. EPA, 1993)
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16 (ASTM, 2016) Gravimetry, APHA 2540C (APHA) Oscillating body method APHA 2320B (APHA, 1997) EPA 150.1 (U.S. EPA, 1982) APHA 2510 (APHA, 1992) Thermocouple
Deep (Mauch Chunk Formation (Aquifer)), Above-Zone (Oriskany Formation), and In-Zone (Lockport Dolomite and Medina Grps) Observation Wells	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B (U.S. EPA, 2014a) or EPA Method 200.8 (U.S. EPA, 1994a)
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D (U.S. EPA, 2014b) or EPA Method 200.7 (U.S. EPA, 1994b)

Parameters	Analytical Methods
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0 (U.S. EPA, 1993)
Isotopes: δ^{13} C of DIC	Isotope ratio mass spectrometry
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16 (ASTM, 2016) Gravimetry, APHA 2540C (APHA) Oscillating body method APHA 2320B (APHA, 1997) EPA 150.1 (U.S. EPA, 1982) APHA 2510 (APHA, 1992) Thermocouple

Abbreviations: ICP=inductively coupled plasma; MS= mass spectrometry; OES = Optical emission spectrometry; GC-P=Gas Chromatography-Pyrolysis.

6.3. Sampling Methods

Groundwater sampling, sample preservation, and quality assurance will be conducted in accordance with methods/procedures described in subsection 2.2 of the QASP.

6.4. Laboratory to be Used/Chain of Custody Procedures

Sample handling and chain of custody will be conducted in accordance with procedures described in subsection 2.3 of the QASP.

7. Mechanical Integrity Testing

Tri-State CCS, LLC is committed to maintaining injection well mechanical integrity throughout the life of the project. A well has mechanical integrity if:

- There is no internal leak in the casing, tubing, or packer;
- There is no significant external fluid movement out of the sequestration zone through channels adjacent to the wellbore; and
- Corrosion monitoring, pursuant to Subsection 40 CFR 146.90(c), reveals no loss of mass or thickness that may indicate the deterioration of well components (casing, tubing, or packer).

Tri-State CCS, LLC will demonstrate internal and external mechanical integrity prior to injection (40 CFR 146.87), during the injection phase (40 CFR 146.89; 146.90), and prior to well plugging after injection has ceased (40 CFR 146.92). For more information on testing details and locations prior to injection, please refer to subsection 2.2 of this plan and the Pre-Operational Testing Plan.

Internal mechanical integrity will be demonstrated with an initial annulus pressure test and thereafter with continuous tubing and annulus monitoring. External mechanical integrity will be demonstrated with DTS fiber optic cables in all injection and in-zone observation wells. More details on these methods and their frequencies are discussed in the following subsections and in Table 10. If the DTS fiber optic cables fail, other methods listed in Table 3 will be used to demonstrate external mechanical integrity.

Tri-State CCS, LLC will comply with notification and reporting requirements described in subsection 2.5 above.

The gauges and meters used for mechanical integrity testing will be calibrated according to the manufacturer's specifications. Should loss of mechanical integrity be demonstrated through monitoring, Tri-State CCS, LLC will take necessary steps to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is substantial endangerment to public health or the environment from any fluid movement out of the intended storage complex, Tri-State CCS, LLC will implement the ERRP (40 CFR 146.94), follow reporting requirements of 40 CFR 146.91, and restore and demonstrate mechanical integrity prior to resuming injection or plugging of the well. In the case of unscheduled or remedial well activity, the UIC Program Director will receive a remediation plan that includes MIT activity to demonstrate well integrity following intervention per the ERRP (40 CFR 146.94).

If a well loses mechanical integrity prior to the next scheduled test date, the well will be repaired and retested within 30 days of losing mechanical integrity. In addition, Tri-State CCS, LLC will, in the next quarterly report, document the type of failure, the cause, the required repairs, and conduct a new test of mechanical integrity following the requirements of section 40 CFR 146.89.

7.1. Testing Location and Frequency

Prior to injection, internal mechanical integrity will be demonstrated in all injection wells with an initial annulus pressure test (40 CFR 146.87(a)(4)). Following this initial pressure test and during the injection phase, Tri-State CCS, LLC will demonstrate internal mechanical integrity in all injection wells by continuously monitoring the injection tubing and annular space pursuant to 40 CFR 146.88, 146.89, and 146.90. External mechanical integrity will be demonstrated with DTS fiber optic cables in all injection and in-zone observation wells. DTS fiber optic cables allow for continuous monitoring and will demonstrate external mechanical integrity prior to injection (40 CFR 146.87), during the injection phase (40 CFR 146.89; 146.90), and prior to well plugging after injection has ceased (40 CFR 146.92).

Table 10 summarizes internal and external MIT methods, locations, and frequency. For more information on testing details and locations prior to injection, refer to subsection 2.2 of this plan and the Pre-Operational Testing Plan. If the DTS fiber optic cables fail, other methods listed in Table 3 will be used to demonstrate external mechanical integrity.

Table 10: Mechanical integrity testing (MIT) location and frequency.

Monitoring Category	Monitoring Method	Frequency	Location
Internal MIT	1) Annulus Pressure Test 2) Annulus Pressure Monitoring	1) Prior to Injection 2) Continuous	TR1-1, TR1-2
External MIT	DTS	Continuous	Depths: *Surface to TD* TR1-1, TR1-2 TR1-IOB-1, TR1-IOB-2

7.2. Testing Details

Internal mechanical integrity will first be demonstrated through an initial annulus pressure test (40 CFR 146.87). The standard annular pressure test (SAPT) will include pressurizing the annulus to a specified level and observing its pressure for an established period (U.S. EPA, 2008; U. S. EPA, 2013). A loss of mechanical integrity can then be detected by changes in pressure which indicates the annular space is not sealed and is communicating with the tubing. As an example, as per U.S. EPA (2008), loss of mechanical integrity, or a failed test, is one where there is a pressure loss of 3% or more within a 60-minute test period (*EPA Region 5 Determination of the Mechanical Integrity of Injection Wells*). This test is also discussed in subsection 2.5 of the Pre-Operational Testing Plan. The actual test procedure, including the pressure loss limits and test duration, will be determined in consultation with the UIC Program Director before the test. Following the initial annulus pressure test, injection pressure, rate, and volume along with annulus pressure and volume will be continuously monitored throughout the injection phase and prior to well plugging to demonstrate internal mechanical integrity pursuant to 40 CFR 146.88, 146.89, 146.90, and 146.92. Specific details for continuous monitoring of the CO_2 stream and annulus are discussed in subsections 3 and 4.3, respectively, of this plan.

External mechanical integrity will be demonstrated with DTS fiber optic cables that run throughout each injection and in-zone observation well. External mechanical integrity tests are designed to detect fluids that have escaped from the wellbore and could migrate into USDWs (U.S. EPA, 2013). The DTS fiber optic cables can detect fluid movement along channels adjacent to the wellbore in real-time by continuously monitoring the temperature from surface to total depth. Prior to injection, a temperature baseline profile will be recorded to identify injection phase temperature anomalies indicative of fluid flow beyond, and leaks into, the casing. These continuous DTS fiber optic measurements can therefore demonstrate external mechanical integrity and replace the need for yearly temperature logging (except for calibration) while satisfying 40 CFR 146.87, 146.88, 146.89, 146.90, and 146.92.

Both wellhead and downhole pressure gauges will meet or exceed ASME B 40.1 Class 2A (ASME, 2013) (0.5% accuracy across full range). Wellhead and downhole gauge specifications are described in detail in subsection 1.4 of the QASP.

8. <u>Pressure Fall-Off Testing</u>

Tri-State CCS, LLC will perform pressure fall-off testing of the injection wells pursuant to 40 CFR 146.90(f) and will use the *EPA Region 5 Planning, Executing, and Reporting Pressure Transient Tests* (U.S. EPA, 1998). Pressure fall-off tests are designed to determine if reservoir pressures are tracking predicted pressures and modeling inputs. The results of pressure fall-off tests will confirm site characterization information, inform AoR reevaluations, and verify the project is operating properly, and the injection zone is responding as predicted.

8.1. Testing Location and Frequency

The minimum frequency at which Tri-State CCS, LLC will perform pressure fall-off testing is as follows:

- Prior to injection (baseline); and
- Three years from the start of injection and every five years thereafter until well plugging and abandonment.

Pressure fall-off tests will be conducted in every injection well during periodic well workovers, or at a minimum three years after injection and once every five years thereafter, to calculate the changes in reservoir injectivity.

Table 11: Injection phase pressure fall-off testing frequency and schedule.

Monitoring Method	Frequency	Location
Pressure fall-off testing	1 prior to injection, 1 three years from the start of injection, and 1 every five years thereafter until well abandonment	TR1-1, TR1-2

8.2. Testing Details

A pressure fall-off test includes a period of injection followed by a period of no-injection or shut-in. Normal injection with the project's CO_2 stream will be used during the injection period preceding the shut-in portion of the fall-off tests. This injection period should be at least 150% of the expected fall-off period; however, several weeks or even months of injection prior to the fall-off test will likely be part of the pre-shut-in injection period and subsequent analysis; as prescribed by *EPA Region 5 Planning, Executing, and Reporting Pressure Transient Tests* (U.S. EPA, 1998). Prior to the fall-off test, this rate will be maintained, i.e., stabilized in accordance with the program design. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. Injection rates on a well-by-well basis will be continuously recorded and employed in the analysis of the continuously recorded subsurface pressure data. Following the injection period, Tri-State CCS, LLC and/or a third-party vendor will shut-in each well at the wellhead instantaneously in coordination with the injection compression facility operators. The shut-in period of the fall-off test should be an appropriate length to allow adequate pressure transient data to be collected for calculating the average pressure. Tri-State CCS, LLC will comply with notification and reporting requirements described in subsection 2.5 above, reporting pressure fall-off data and interpretation of the reservoir ambient pressure following the test.

All data will be measured using permanent downhole pressure gauges, along with wellhead sensors, so testing durations can be determined in real-time. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at intervals of five seconds or less for the duration of the test. Both wellhead and downhole pressure gauges will meet or exceed ASME B 40.1 Class 2A (ASME, 2013) (0.5% accuracy across full range). The wellhead pressure gauge range will be 0-15,000 psi. The downhole gauge range will be 200-10,000 psi for pressure. Wellhead and downhole gauge specifications are described in detail in subsection 1.4 of the QASP.

9. Carbon Dioxide Plume and Pressure Front Tracking

Tri-State CCS, LLC will implement indirect methods (Table 12) to track the CO_2 plume evolution and direct methods (Table 13) to track the pressure front propagation at specified locations and frequencies, per 40 CFR 146.90(g). This plan is designed to monitor the free-phase CO_2 plume location, thickness, and saturation; track the pressure development within the storage complex over time; validate computational modeling results; and demonstrate that operations are not leading to reservoir CO_2 or brine containment risks.

Direct pressure monitoring will be implemented to track the pressure front evolution throughout the project's life using permanent downhole and surface pressure gauges. Gauges ported in the two reservoirs (Lockport Dolomite and Medina Groups) will record corresponding reservoir pressures and allow for better pressure front modeling. Pressure gauges ported to monitor the first permeable zone (Oriskany Formation) or lowermost USDW (Mauch Chunk Formation) will allow Tri-State CCS, LLC to monitor any anomalous pressure changes above the primary confining zone for early detection of containment loss.

Monitoring locations relative to the predicted location of the CO_2 plume within the AoR at five and ten-year intervals throughout the injection phase are shown in Figure 6. Two types of pressure front and CO_2 plume monitoring will occur at the project: 1) plume monitoring within the reservoir, and 2) containment confirmation above the primary confining zone. Direct pressure measurements will be implemented for pressure front tracking, and several indirect methods will be employed to track the CO_2 plume migration.

DTS technology will be run on the outside of the long string casing along the entirety of the wellbore and will record temperature measurements that can reveal the vertical location of near wellbore CO_2. This indirect CO_2 monitoring technology will be installed during well construction and will operate continuously during the baseline, injection, and post-injection periods. In practice, DTS systems typically provide temperature measurements at 1-meter (m) spacing along the entire cable.

PNC logging wireline tools will be run to monitor the vertical saturations and profile of CO_2 within formations of interest at monitoring well locations as required. In case of DTS failure, Tri-State CCS, LLC in consultation with the UIC Program Director will develop an alternate testing plan, such as an alternate PNC logging program at the monitoring wells.

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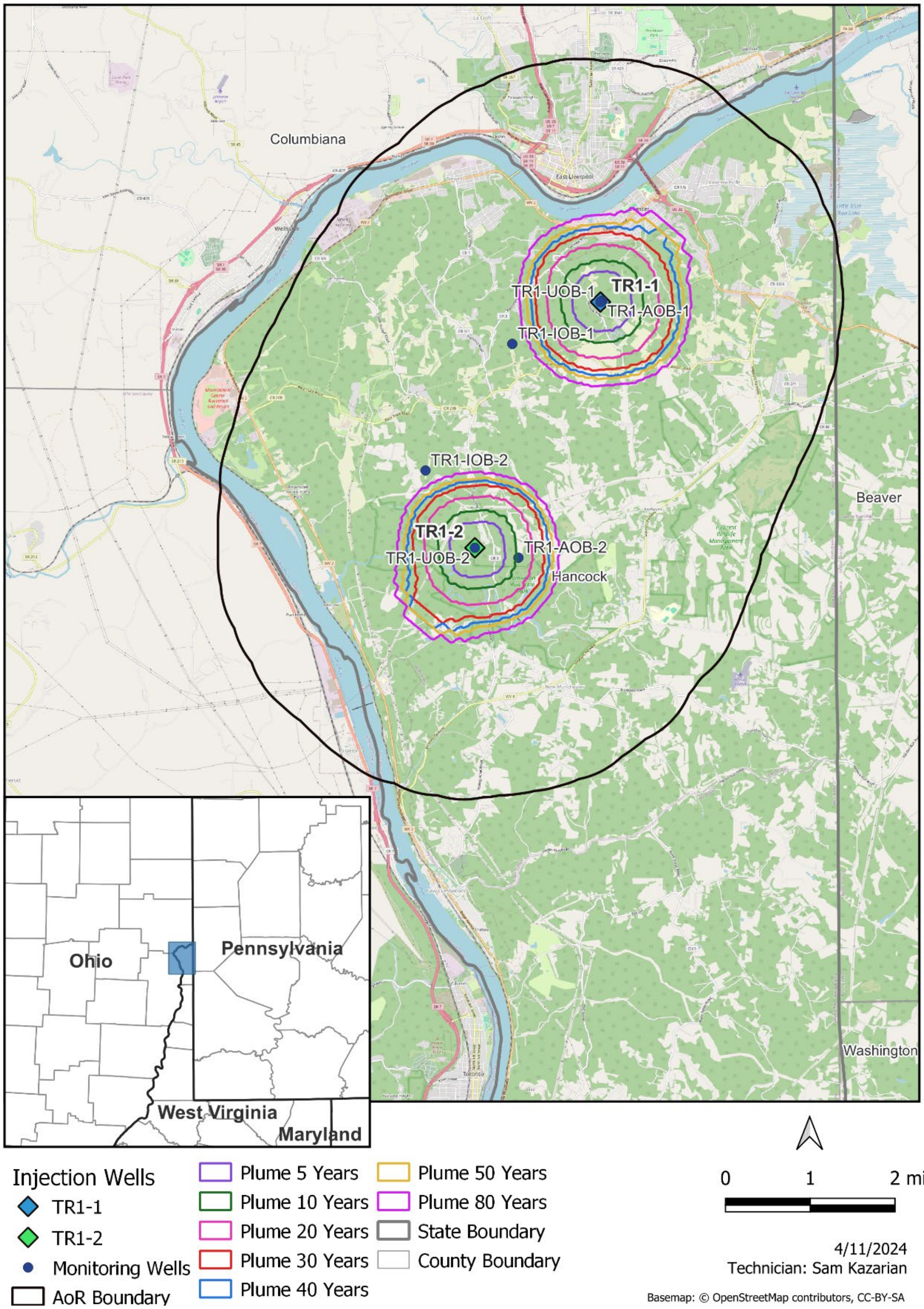

Figure 6: CO_2 plume evolution map.

9.1. Plume Monitoring Location and Frequency

As summarized in Table 12 below, Tri-State CCS, LLC will utilize a combination of indirect methods to detect, track, and monitor the CO_2 plume during the injection phase. Locations of the observation wells with respect to the plume extents throughout the project are represented in Figure 6. Locations are subject to change based on final site characterization and land access agreements.

DTS will be installed in all injection wells (TR1-1, TR1-2) and in-zone observation wells (TR1-IOB-1, TR1-IOB-2) and will continuously monitor temperature changes along the injection wellbore to detect units within the reservoir taking CO_2 and to detect any potential CO_2 breakthrough at in-zone observation wells. Repeat PNC logging will be run in both injection wells three years after injection begins, every five years thereafter during the injection period, and before the plugging and abandonment of any injection well or AoR re-evaluation. For the in-zone (TR1-IOB-1, TR1-IOB-2), above-zone (TR1-AOB-1, TR1-AOB-2), and deep observation wells (TR1-UOB-1, TR1-UOB-2), repeat PNC logging will only occur if containment loss is detected and will then be used as a containment verification technology.

9.2. Plume Monitoring Details

The two technologies mentioned above will allow Tri-State CCS, LLC to monitor the CO_2 plume evolution within the reservoir and provide evidence for its containment (Table 12). At the injection wells, DTS data will help reveal relatively high injectivity units within the reservoir zone taking fluid. At the in-zone observation wells, the DTS data will allow for detection of CO_2 breakthrough. PNC logging at injection wells will also reveal units with higher injectivity as well as provide quantitative measurements of CO_2 saturation within those units. Statistical approaches, e.g., normality testing, etc., will be used to identify CO_2 breakthrough at monitoring locations. PNC logging will occur in the injection wells as per the scheduled specified in this section. PNC logging will also be run in any in-zone observation well with CO_2 breakthrough, or any above-zone/deep observation wells with detected containment loss. Data from these technologies will be used to update reservoir models for more accurate CO_2 plume migration predictions as required.

Table 12: Indirect CO_2 plume injection phase monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
INDIRECT PLUME MONITORING			
Lockport Dolomite and Medina Grps (Injection Interval)	DTS	TR1-1, TR1-2 TR1-IOB-1, TR1-IOB-2	Continuous
	PNC Logging	TR1-1, TR1-2	Three years after injection begins, and every five years thereafter during the injection period.
	PNC Logging	TR1-IOB-1, TR1-IOB-2; TR1-AOB-1, TR1-AOB-2; TR1-UOB-1, TR1-UOB-2	PNC logging will only occur in wells with detected CO_2 breakthrough and suspected containment loss.

9.3. Pressure-Front Monitoring Location and Frequency

Tri-State CCS, LLC will use permanent electronic downhole pressure gauges placed above the packer and ported through to monitor each well's respective monitoring zone (see Table 1) pressures continuously. This includes injection zones in both the Lockport Dolomite Group and the Medina Group. Wellhead pressure gauges will be installed as a backup pressure measurement should the downhole gauges fail. Downhole and surface pressure gauges will be installed in all injection wells and in-zone, above-zone, and deep observation wells (Table 13).

9.4. Pressure-Front Monitoring Details

Tri-State CCS, LLC will directly monitor the presence of the elevated pressure front by deploying electronic downhole pressure gauges within every completion zone of each injection well, as well as within the in-zone, above-zone, and deep observation wells. Injection and in-zone observation wells will monitor the evolution of the CO_2 plume in the Lockport Dolomite Group and Medina Group reservoirs during injection. Above-zone and deep observation wells will monitor for pressures and temperature changes indicating potential containment loss in the Oriskany Formation and Mauch Chunk Formation (Aquifer), respectively. All downhole gauges and instruments will be comprised of a corrosion resistant chrome alloy and will continuously record formation pressure and temperature from fixed-point locations at a set sampling interval.

Table 13: Direct pressure-front injection phase monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PRESSURE-FRONT MONITORING				
Lockport Dolomite and Medina Grps	P Gauges	TR1-1, TR1-2 & TR1-IOB-1, TR1-IOB-2	Above the Packer – Ported to Upper Lockport Dolomite and upper Medina Grps. respectively	Continuous
Oriskany Formation		TR1-AOB-1, TR1-AOB-2	Above Packer - Ported to Oriskany Formation	Continuous
Mauch Chunk Formation (aquifer)		TR1-UOB-1, TR1-UOB-2	Above Packer - Ported to Mauch Chunk Formation (Aquifer)	Continuous

Quality assurance procedures for these methods are presented in Section 2 of the QASP.

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