TESTING AND MONITORING PLAN
40 CFR 146.90

Project Name: Tri-State CCS Buckeye 1

Facility Information

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

Well location: Carroll County, Ohio

Well Name	Latitude (WGS 84)	Longitude (WGS 84)
TB1-1	40.66628014	-81.07152167
TB1-2	40.64546393	-81.01533077
TB1-3	40.61071400	-81.02898600
TB1-4	40.51123391	-81.02586036

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List of Acronyms

°F	Fahrenheit
Al	Aluminum
ANSI	American National Standards Institute
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
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
CSP	Crosswell Seismic Profile
Cu	Copper
DH	Downhole
DIC	Dissolved Inorganic Carbon
DTS	Distributed Temperature Sensing
ERRP	Emergency and Remedial Response Plan
Fe	Iron
ft	feet
GC-P	Gas Chromatography-Pyrolysis
gm	Gram
GS	Geologic Sequestration
H_2S	Hydrogen Sulfide

ICP	Inductively Coupled Plasma
K	Potassium
lb	pound
Mg	Magnesium
MIT	Mechanical Integrity Testing
MMscf	Million Standard Cubic Feet
MMt/y	Million 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
ODNR	Ohio Department of Natural Resources
OES	Optical Emission Spectrometry
P	Pressure
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
psig	Pounds per Square Inch, Gauge
QASP	Quality Assurance and Surveillance Plan
SAPT	Standard Annular Pressure Test
Sb	Antimony
Se	Selenium
Si	Silicon
SO_4	Sulfate
T	Temperature
TBD	To be Determined
TD	Total Depth
TDS	Total Dissolved Solids
Ti	Titanium
TB1-(#)-(#)	Tri-State CCS Buckeye 1 Injection Wells
TB1-AOB-(#)	Above-Zone Observation wells
TB1-GW-(#)	Shallow Groundwater Wells
TB1-IOB-(#)	In-Zone Observation wells
TB1-UOB-(#)	Deep Observation Wells
TVD	True Vertical Depth

UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
U.S. EPA	U.S. Environmental Protection Agency
VSP	Vertical Seismic Profile

1. Introduction

This Testing and Monitoring Plan (the "Plan") describes how Tri-State CCS, LLC will monitor Tri-State CCS Buckeye 1 in Carroll County, Ohio (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 and 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 CO_2 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 as described in subsection 2.5 below.

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

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.

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 groundwater quality and geochemical monitoring above the confining zone; direct pressure front monitoring; and direct/indirect CO_2 plume monitoring.

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 19 wells (Table 1), strategically placed in specific formations (Figure 1, Figure 2, and Figure 3), to ensure USDW non-endangerment. These wells include four (4) injection wells completed in the Knox Group initially, four (4) offset in-zone observation wells completed in the Medina and Knox Group, three (3) above-zone observation wells completed in the first permeable units identified as above-zone formation for both the Knox Group and the Medina Group, four (4) deep observation wells completed in the lowermost USDW of the Sharon Sandstone, and up to four (4) shallow USDW wells completed in Pennsylvanian age strata. Note that the first permeable unit above the confining zone for each injection complex will be defined as the first unit having porosity >/= 3% and permeability >/= 1 md. These cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing planned for each injection well.

Tri-State CCS, LLC plans to use multi-zone completions in the in-zone and above-zone observations wells. In the in-zone observation wells, both the Medina and the Knox Groups will be instrumented, whereas in the above-zone observation wells, both the identified permeable units above the confining zones for the Knox and Medina Groups will be instrumented as required at the time of well completion.

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System	Series	Stratigraphic Unit (Group or Major Formation)	Aquifer, Confining Zone, or Reservoir	Oil Gas Prod.	Average Depth (ft)	Average Thickness (ft)	Depth/Interval Thickness (ft) TB1-1 Depth (ft TVD)	TB1-1 Thickness (ft)	TB1-2 Depth (ft TVD)	TB1-2 Thickness (ft)	TB1-3 Depth (ft TVD)	TB1-3 Thickness (ft)	TB1-4 Depth (ft TVD)	TB1-4 Thickness (ft)
Pennsylvanian		Pennsylvanian (undivided)	Freshwater Aquifers											
Pennsylvanian		Pottsville Group (Base Sharon Mbr)	Lowest USDW		855		~755		~720		~900		~1,050	
Mississippian	U	Greenbriar Ls Fm	*Seal (Limestone)*											
Mississippian	Lower	Pocono Grp – Big Injun SS	Conventional Oil Reservoir	●●										
Mississippian	Lower	Pocono Grp – Sunberry Sh	*Seal (Shale)*											
Mississippian	Lower	Pocono Grp – Berea SS	Conventional Oil Reservoir	●●										
Devonian	Upper	Ohio Shale Grp	*Seal (Shale)*			3,093		~2,990 Thick		~3,070 Thick		~3,160 Thick		~3,150 Thick
Devonian	Upper	Olentangy Shale Fm / *Tully Ls*	*Seal (Shale)*											
Devonian	Middle	Hamilton Grp – Mahantango Shale Fm	*Seal (Shale)*											
Devonian	Middle	Hamilton Grp – Marcellus Shale Fm	Unconventional Oil Reservoir	●●										
Devonian	Middle	Onondaga Ls Fm	*Seal (Limestone)*		3,741	185	3,741	190	3,787	174	4,064	188	4,200	189
Devonian	Lower	Oriskany SS Fm	Conventional Oil/Gas Reservoir	●●	3,931	11	3,931	11	3,960	13	4,252	11	4,389	9
Devonian	Lower	Helderberg Grp	*Seal (Limestone)*		3,942	206	3,942	234	3,973	225	4,263	199	4,398	166
Silurian	Upper	Bass Islands Dolomite Grp	*Seal (Dolomite)*		4,175	53	4,175	50	4,198	55	4,462	50	4,564	58
Silurian	Upper	Salina Grp – Salina "D" – "G"; Salina "A" – "C"	**Upper Confining Zone (Evaporite/Salt)**		4,225	848	4,225	794	4,253	824	4,512	853	4,622	920
Silurian	Upper	**Lockport Dolomite Grp** 1	**Possible Injection Zone**		5,024	290	5,024	300	5,076	290	5,364	279	5,541	293
Silurian	Upper	Clinton Grp – Rochester Shale Fm; Dayton/Keefer Fm	**Middle Confining Zone**		5,324	241	5,324	233	5,366	249	5,643	249	5,834	235
Silurian	L	**Medina (Tuscarora SS) Grp** 2 *Informal – "Clinton" & "Medina" sands*	**Injection Zone**	●●	5,557	171	5,557	165	5,615	160	5,892	169	6,069	191
Ordovician	Upper	Queenston Shale (Juniata Fm)	**Lower Confining Zone**		5,722	↑	5,722	↑		↑		↑		↑
Ordovician	Upper	Utica Shale Fm	Unconventional Oil Reservoir	●●		2,547		2,500	5,775	2,583	6,060	2,551	6,260	2,555
Ordovician	Upper	Trenton Grp	*Seal (Limestone)*											
Ordovician	Upper	Black River Ls Grp	*Seal (Limestone)*			↓		↓		↓		↓		↓
Ordovician	M	Wells Creek Fm	**Upper Confining Zone**		8,222	97	8,222	83	8,357	98	8,611	99	8815	108
Ordovician	L	Knox Grp – Beekmantown Dolomite	**Upper Confining Zone**	●●	8,305	256	8,305	199	8,455	238	8,711	253	8923	335
Cambrian	Upper	Knox Grp – **Rose Run SS** 3	**Injection Zone**	●●	8,505	103	8,505	70	8,693	93	8,963	100	9258	150
Cambrian	Upper	Knox Grp – Copper Ridge Dolomite Fm	**Lower Confining Zone**	●●	8,575	361	8,575	384	8,786	364	9,063	359	9407	337
Cambrian	Upper	Conasauga Group	*Lowest Seal/Confining Unit*		8,959		8,961		9,149		9,422		9740	

Figure 1: Generalized stratigraphic column for the project. Potential secondary Injection Complex: Lockport Injection Complex; Primary Complexes: Medina Injection Complex and Knox Injection Complex. (*Depth is to the top of the Stratigraphic Unit (SU), except where noted.)

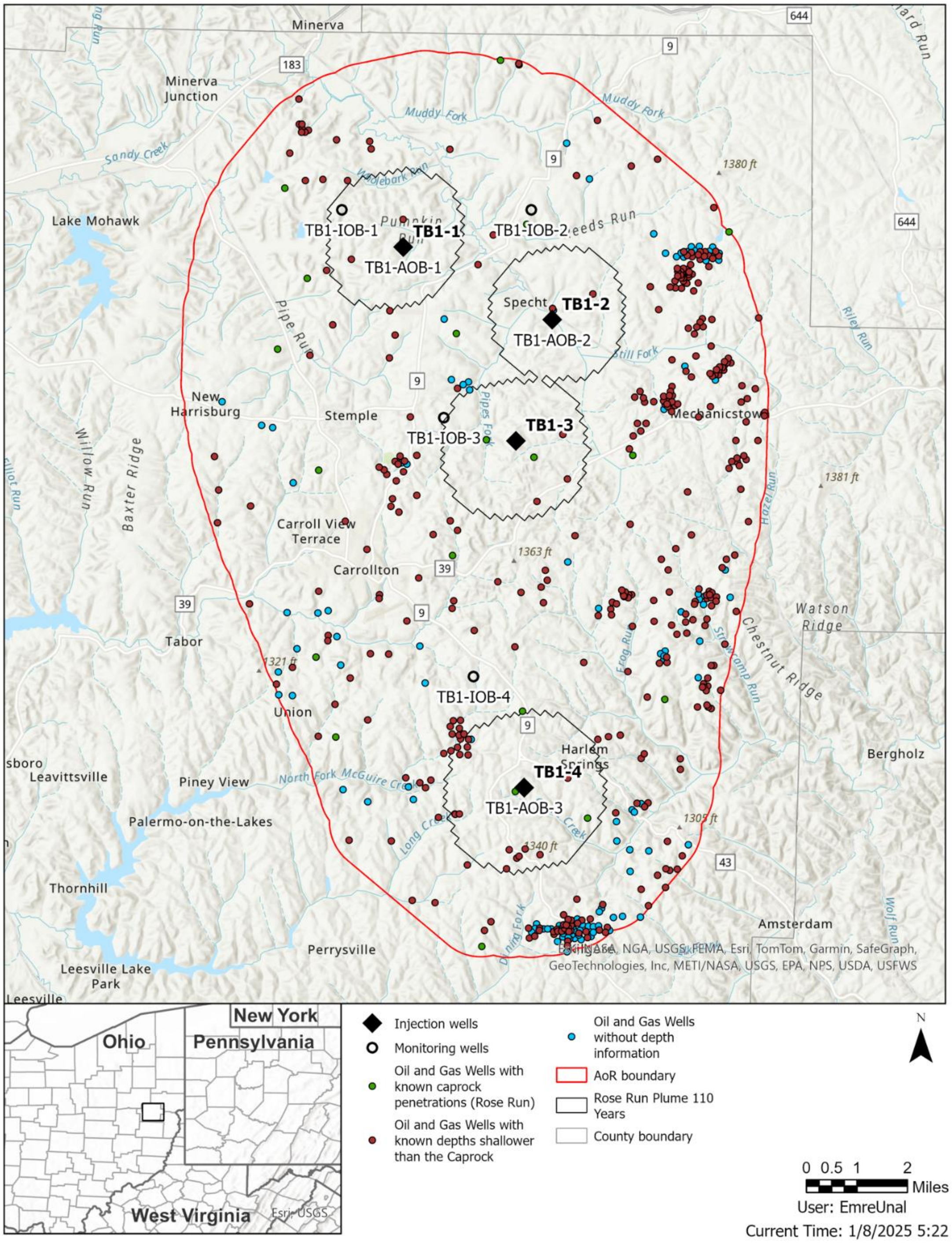

Figure 2: Map of project showing AoR boundary, CO_2 plume associated with injection into KIC, and the proposed injection and observation well locations. The in-zone observation (TB1-IOB), above-zone observation (TB1-AOB), and deep (lowermost USDW) observation (TB1-UOB) wells are identified, as well as known confining zone (Wells Creek Formation) penetrations, oil and gas wells with known depths shallower than confining zone, and wells without known depths. TB1-AOB wells are collocated at the same well pad as the corresponding injection wells.

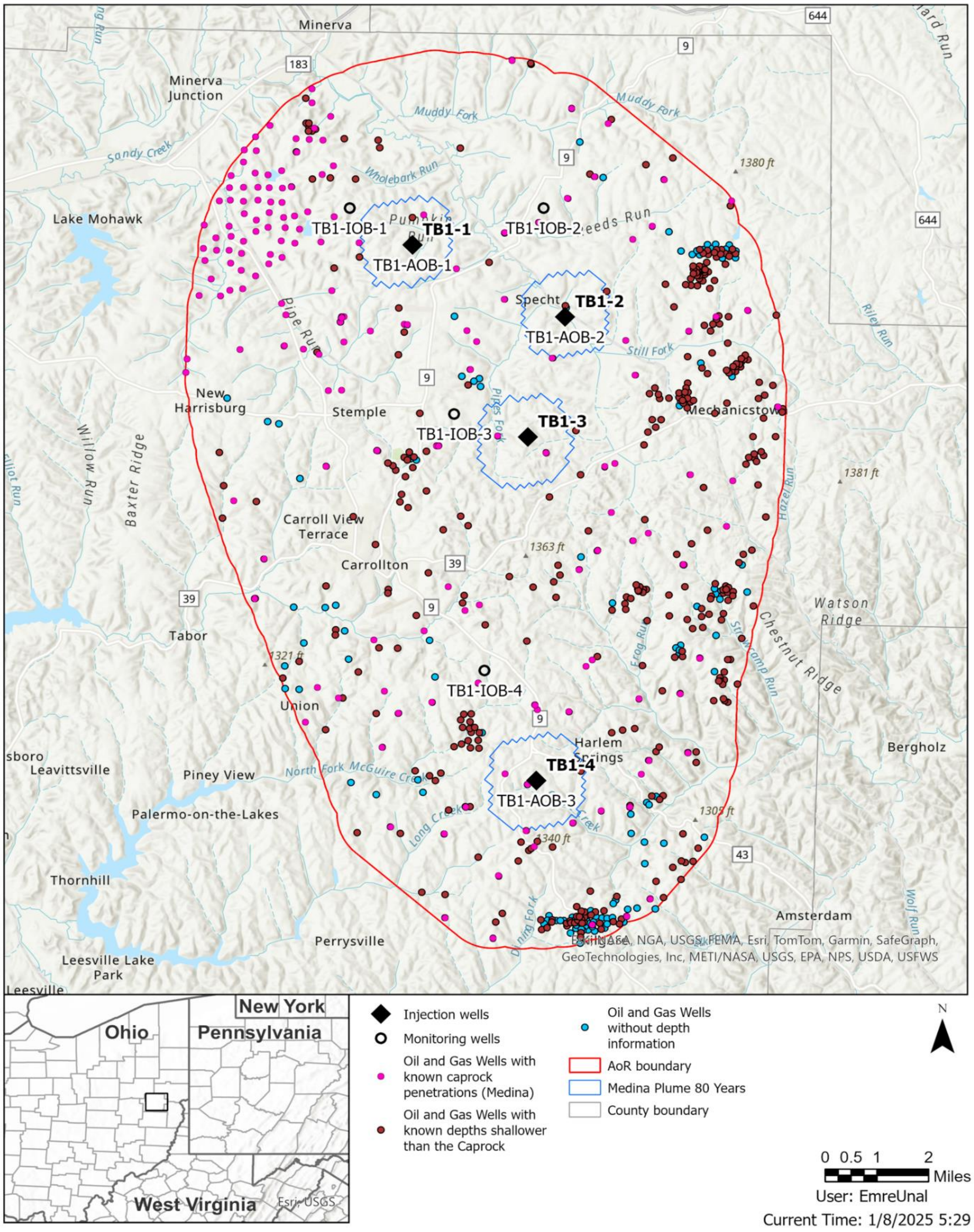

Figure 3: Map of project showing AoR boundary, CO_2 plume associated with injection into MIC, and the proposed injection and observation well locations. The in-zone observation (TB1-IOB), above-zone observation (TB1-AOB), and deep (lowermost USDW) observation (TB1-UOB) wells are identified, as well as known confining zone (Rochester Shale) penetrations, oil and gas wells with known depths shallower than confining zone, and wells without known depths. TB1-AOB wells are collocated at the same well pad as the corresponding injection wells.

Table 1: Tri-State CCS Buckeye 1 well summary. Zone depths are estimates; actual depths will be determined after well data collection.

Well Types	Well Acronym	Zone Depth (ft MD)	CCS System Zone	Zone Formation	Quantity
Shallow Groundwater (GW)	TB1-GW-1, TB1-GW-2, TB1-GW-3, TB1-GW-4	TBD	Shallow USDW	Pennsylvanian	Up to 4
Deep Observation (UOB)	TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4	~ 753, ~ 715, ~ 902, ~ 1,051	Lowermost USDW	Sharon Sandstone	4
Above-Zone Observation (AOB)	TB1-AOB-1, TB1-AOB-2, TB1-AOB-3	TBD [1]	1st Permeable Zone above the Medina Group	TBD [1]	3
		TBD [1]	1st Permeable Zone above the Knox Group	TBD [1]	
In-Zone Observation (IOB)	TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4	~ 5,524, ~ 5,643, ~ 5,787, ~ 5,901	Reservoir	Medina Group	4
		~ 8,426, ~ 8,634, ~ 8,832, ~ 9,075		Knox Group	
Injection	TB1-1, TB1-2, TB1-3, TB1-4	~ 5,557, ~ 5,615, ~ 5,892, ~ 6,069	Reservoir	Medina Group	4
		~ 8,505, ~ 8,693, ~ 8,963, ~ 9,258		Knox Group	

[1] The first permeable unit for the two injection complexes will be defined as the first unit above the confining zones of the injection complex with porosity >/= 3% and permeability >/= 1 md. These cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well.

As stated in the Pre-Operational Testing Program, Tri-State CCS, LLC plans to obtain a permit to drill from the Ohio Department of Natural Resources (ODNR) for each observation well and, subsequently, will construct these observation wells in compliance with state requirements at ORC 1509 and OAC 1501:9.

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. 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 the cemented casing string. For this Plan, DTS will be used in lieu of a temperature log to run MITs unless there is a failure of installed fiberoptic monitoring, such as cable shear or surface equipment failure, in which case, a temperature log will be used to run MITs. Additionally, though not anticipated in the design, a temperature log will be used in case of any uncemented sections within the injection wellbores.

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 (DH) and wellhead pressure gauges. These gauges will continuously record and transmit pressure data from the groundwater in the reservoir intervals 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 intervals of the Medina and Knox Groups in the injection wells, the first permeable unit above the confining zones (TB1-AOB-1, TB1-AOB-2, TB1-AOB-3), the lowermost USDW in the Sharon Sandstone (TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4), and potentially the shallow Pennsylvanian aquifers (up to 4 shallow USDW monitoring wells). The first permeable units above the confining zones will be identified based on data from the CarbonSAFE stratigraphic wells and pre-operational testing program. Analytes will be tested to create a baseline, representative of the pre-operational groundwater geochemistry, that can be compared to operational (injection phase) geochemistry groundwater monitoring data. 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 DH 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 between 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 in the cemented long string casing and record continuous temperature measurements after well construction and prior to injection. Injection phase monitoring data will be used 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 intervals 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.

Hydrogeologic testing, which includes pressure fall-off testing, will be conducted once prior to injection at each injection well. This includes prior to injection into the Knox Injection Complex (KIC) and subsequently, upon recompletion of the wells, injection into the Medina Injection Complex (MIC). 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 because of injection operations.

Some of the injection and/ or in-zone observation wells will include DAS fiberoptic monitoring technology in addition to DTS. This will allow potential time lapse 3D DAS Vertical Seismic Profile (VSP) or Crosswell Seismic Profile (CSP) surveys for indirect plume front monitoring. A decision on specific wells to be used for seismic profiling will depend on modeling studies and independent observations from the monitoring program as implemented at the site. Additionally, the same infrastructure could be used for passive seismic monitoring. The exact wells with DAS deployment will be finalized at a later stage once additional site-specific characterization data becomes available.

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 will then be compared to pre-injection phase baseline measurements to ensure containment and protection of groundwater resources. Since the injection wells are planned to be repurposed for MIC injection once KIC injection is complete, baseline measurements for MIC will be captured at the end of KIC injection with final frequency as identified in consultation with and approval of the UIC Program Director.

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

Monitoring Parameter	Technology/Test	Baseline Phase Frequency (1 year)	Location
Internal MIT	Annulus Pressure Test	1 Prior to Injection	TB1-1, TB1-2, TB1-3, TB1-4 [1]
External MIT	1) DTS 2) Ultra Sonic CBL 3) Electromag. CI Logs	1 Prior to Injection	TB1-1, TB1-2, TB1-3, TB1-4 [1] TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4
Groundwater Quality	1) Fluid Sampling & Analysis 2) Downhole P Gauges	1) Quarterly prior to KIC injection. 1 prior to MIC injection 2) Continuous	TB1-1, TB1-2, TB1-3, TB1-4 [1] TB1-AOB-1, TB1-AOB-2, TB1-AOB-3 [3] TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4 [3]
Direct Pressure Monitoring	1) P Gauges – Tubing 2) Downhole P Gauges	Continuous	TB1-1, TB1-2, TB1-3, TB1-4 [2] TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4

Monitoring Parameter	Technology/Test	Baseline Phase Frequency (1 year)	Location
			TB1-AOB-1, TB1-AOB-2, TB1-AOB-3 TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4
Indirect CO_2 Plume Monitoring Techniques	DTS	1 Year Prior to Injection	TB1-1, TB1-2, TB1-3, TB1-4 [2] TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4
	PNC Logging	1 Prior to Injection	TB1-1, TB1-2, TB1-3, TB1-4 [2] TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4 TB1-AOB-1, TB1-AOB-2, TB1-AOB-3 TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4
Hydrogeologic Testing	Pressure Fall-Off Testing		TB1-1, TB1-2, TB1-3, TB1-4 [2]

[1] Groundwater sampling will be quarterly prior to. planned initial KIC injection and once prior to MIC injection after the well has been recompleted. This sampling will target the corresponding injection formations.

[2] Testing and monitoring will be repeated for the injection wells as they undergo recompletion for MIC injection once KIC injection is complete.

[3] Fluid sampling and analysis will start in the identified above-zone (first permeable) unit for MIC one year prior to anticipated start of injection in Medina Group.

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 4 shows a simplified layout of the storage complex depicting the location of testing and monitoring equipment on the injection wells. The exact locations are tentative and may vary depending on field conditions.

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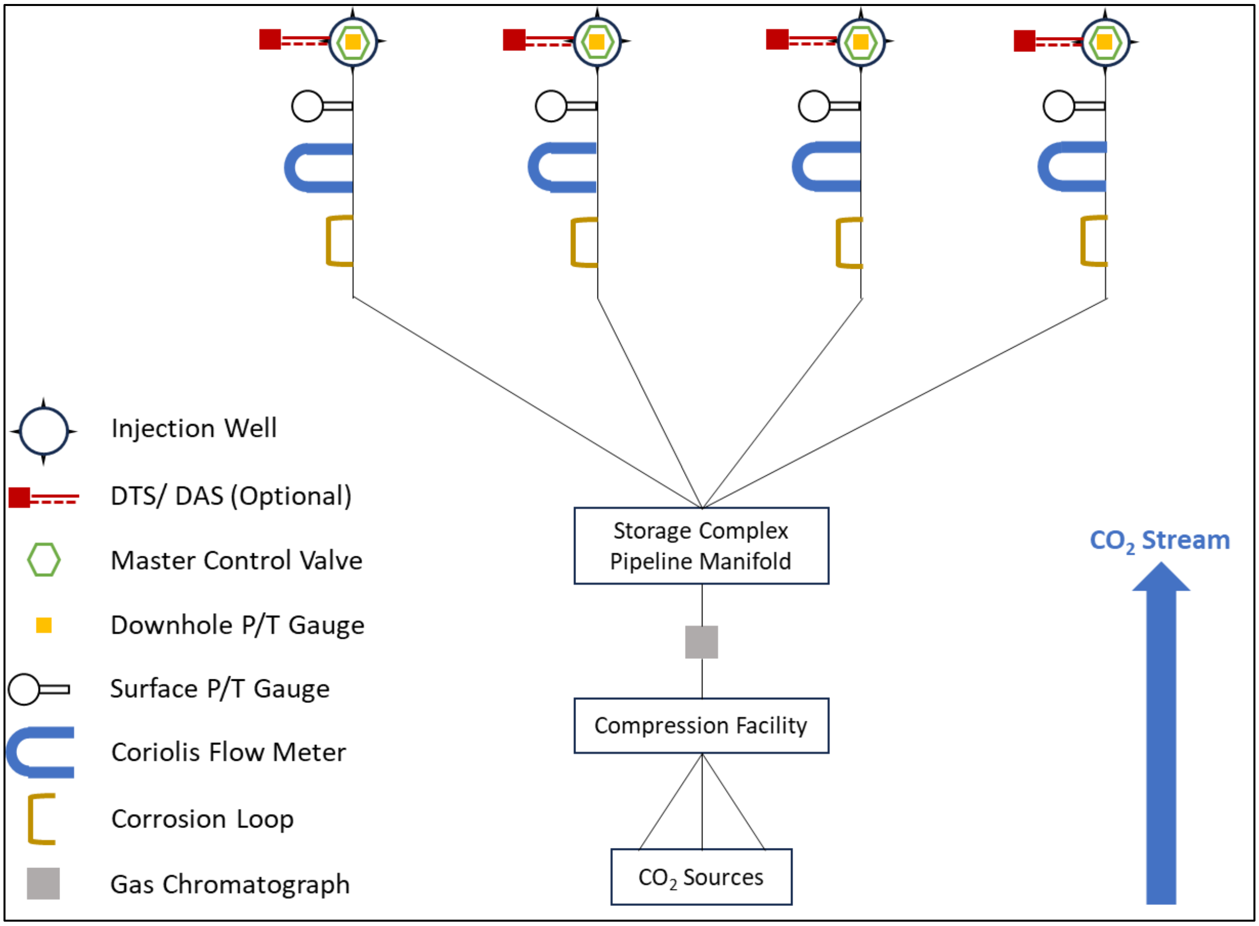

Figure 4: Simplified layout of storage complex depicting location of testing and monitoring equipment at injection well locations. The locations as depicted are tentative and may vary depending on field conditions. Some of the testing infrastructure may be repurposed for the shallower MIC injection at the same locations.

Above-zone observation wells will monitor the first permeable zone above the primary confining units for both the MIC, and the KIC injection zones. Specifically, pressure, temperature, and fluid chemistry changes will be monitored for early detection of containment loss. As noted earlier, the exact units to be monitored in these wells will be defined as the first unit above the confining zones of the injection complex with porosity >/= 3% and permeability >/= 1 md (cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well). 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 pressure and plume evolution to ensure protection of groundwater resources. Monitoring technology in injection and in-zone observation wells will help track the CO_2 pressure and plume front movement through time. The above-zone observation wells will 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 three (3) above-zone, four (4) deep, and up to four (4) shallow groundwater observation wells. Fluid samples will be collected from the wells in the identified above-zone formations (first permeable units above the confining zones of the two injection complexes), and in the Sharon Sandstone (lowermost USDW). The associated networks of above-zone and shallow groundwater 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.

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[1]	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[1]	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) Electromagnetic CI Logs	1 MIT Prior to Injection [1]: 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* *Above-Zone*	Quarterly – 1 Year Prior to Injection [1]	Quarterly for 1st Year, Annually Thereafter	Annually

Monitoring Category	Monitoring Parameter/Method		Baseline Frequency (1 year)	Injection Phase Frequency (30 years)	Post-Injection Frequency (50 years)
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[1]	3 Years After Injection, 1 Every 5 Years After [1]	1 Every 5 Years [2]
		Repeat 3D DAS VSP/ CSP/ Microseismic [3]	TBD	TBD	TBD

[1] Testing will be repeated for the injection wells as they undergo recompletion for MIC injection once KIC injection is complete. Fluid sampling and analysis will start in the identified above-zone (first permeable) unit for MIC one year prior to anticipated start of injection in Medina Group.

[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. Based on actual wellbore/reservoir conditions post-breakthrough or contamination, the logging frequency may be modified in consultation with the UIC Program Director.

[3] DAS will be used for additional monitoring including potential repeat VSP/ CSP surveys or continuous microseismic monitoring based on additional site characterization. Final decision on additional monitoring will be made with consultation and approval of UIC Program Director.

Observation wells have been strategically placed to mitigate the highest risks to USDWs within the AoR (Figure 3 and Figure 4). In-zone wells (TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4) have been strategically placed to image the CO_2 plume and track the pressure front evolution. These wells have been planned at the edges or outside of the maximum CO_2 plume extent but within the maximum pressure front extent and will act as sentry wells bounding the CO_2 plume. Locations are subject to change based on new insights from additional data characterization in the pre-injection phase of the project. Monitoring data from these wells will be used to update and history match the pressure response in reservoir models. TB1-IOB-1 is placed to the northwest of TB1-1. TB1-IOB-2 is placed to the north of TB1-2. Similarly, TB1-IOB-3 is located to the northwest of TB1-3, and TB1-IOB-4 is located to the north of TB1-4. These four in-zone observation wells are planned close to the maximum modeled extent of the CO_2 plume, which is in the KIC, 50 years post-injection. These will allow Tri-State CCS, LLC to continuously monitor the injection zones at the edges and between the modeled plume fronts to verify the pressures are acting as predicted and allow early detection of any CO_2 movement outside of the modeled plume extent.

The three above-zone (TB1-AOB-1, TB1-AOB-2, TB1-AOB-3) observation wells will monitor conditions in the first permeable zone above the primary confining zone for each injection complex, i.e., KIC and MIC, to ensure containment of reservoir brine and CO_2. The above zone units will be defined as the first unit above the confining zones of the injection complex with porosity >/= 3% and permeability >/= 1 md (cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well). While the well completions for these above-zone monitoring wells will include required instrumentation and monitoring for both these zones, active monitoring will only occur in the zone which corresponds to the active injection complex. High pressure zones around the injection wells with natural (i.e., faults) or artificial penetrations (AP) pose the highest risk to containment and USDWs (Figure 3, Figure 4). Records of oil and gas wells that penetrate the confining zones are discussed in subsection 4.1 of the Area of Review and Corrective Action Plan. Tri-State CCS, LLC has placed above-zone wells relatively close to the injection wells for early detection of containment loss.

The four deep (lowermost USDW) observation wells (TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TR2-UOB-4) 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, these wells will be placed on each injection well pad site to monitor the USDW, i.e., the Sharon Sandstone, directly above and proximal to each injection well.

Up to four shallow groundwater observation wells (TB1-GW-1, TB1-GW-2, TB1-GW-3, TB1-GW-4) 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 (specifically, concerns around contamination of groundwater sources in use by the communities within the AoR). Minimal surface disruption is anticipated by completing multiple project wells on a single well pad, where possible.

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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: TB1-1, TB1-2, TB1-3, TB1-4
Injection Physical Characteristics	1) P Gauges – Tubing 2) DH P Gauges	Continuous	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4
Annulus Pressure Monitoring	P Gauge - Annulus	Continuous	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4
Annulus Volume Added	Fluid Tank Volume Meter or suitable alternative	Continuous	Each injection well pad: TB1-1, TB1-2, TB1-3, TB1-4
Internal MIT	P Gauge - Annulus	Continuous	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4
External MIT	DTS, *OR one of:* Temp. Log, PNC Log, Ultra Sonic CB Log, Electromagnetic CI Logs	1 MIT Annually	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4 In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4
Corrosion	Coupon Analysis	Quarterly	Corrosion loops at injection wells: TB1-1, TB1-2, TB1-3, TB1-4
Formation Water Quality & Geochemistry	1) Fluid Sampling & Analysis 2) DH P Gauges	1) Quarterly for 1st Year, Then Annually[1] 2) Continuous	Above zone observation wells: TB1-AOB-1, TB1-AOB-2, TB1-AOB-3 [4] Deep observation wells: TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4
Direct Pressure & Temperature Monitoring	1) P Gauges – Tubing 2) DH P Gauges 3) DTS [3]	Continuous	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4 In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4 Above zone observation wells: TB1-AOB-1, TB1-AOB-2, TB1-AOB-3 [4] Deep observation wells: TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4
Indirect CO_2 Plume Monitoring Techniques	DTS	Continuous	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4

Monitoring Parameter	Technology/Test	Injection Phase Frequency (30 years)	Location
			In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4
	PNC Logging [2]	3 Years After Injection, 1 Every 5 Years Thereafter	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4 In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4
	Repeat 3D DAS VSP/ CSP, Microseismic [3]		TBD
Hydrogeologic Testing	Pressure Fall-Off Testing		Injection wells: TB1-1, TB1-2, TB1-3, TB1-4

[1] Sampling and analysis frequencies may be changed 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] Decisions on frequency and DAS based indirect plume monitoring plan will depend on data from the rest of the monitoring program and will be developed in consultation with the UIC Program Director. Similarly, decision on implementing microseismic monitoring will be based on observations from additional site characterization data.

[4] The injection into KIC and MIC is planned to be sequential. The planned water quality, pressure, and temperature monitoring in the above-zone observation wells will only target the corresponding first permeable unit above the confining zone associated with the active injection zone, i.e., KIC followed by MIC. The monitoring location will change once the injection zone changes. This change is anticipated to occur after 30 years of planned injection into Knox Group. The identified monitoring frequency is associated with two separate units which will both be appropriately instrumented during well construction.

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(e)):

- 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 DH 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 (40 CFR 146.82) 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

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 95% 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 a minimum of 24-hour intervals. Tri-State CCS, LLC plans to conduct routine calibration of the gas chromatograph according to manufacturer specifications. 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 the Semi-Annual Testing and Monitoring Report.

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 gas chromatograph will be installed to continuously detect CO2 purity, total hydrocarbons, inert gases, hydrogen, alcohols, oxygen, carbon monoxide, and glycol. 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 QASP, included as Appendix A. 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 a minimum of 24-hour 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 subsections 2.2 and 2.3 of the QASP.

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Table 5: Summary of analytical parameters for CO_2 stream.[1]

Component	Specification	Unit
Carbon Dioxide (CO_2)	> 95	Mol%, dry
No free liquids		
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
Max Temperature	130	F
Min Temperature	40	F

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

4. Continuous Recording of Operational Parameters

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 0.5 MMt/y. Alternatively, they will limit the maximum allowable surface pressures as identified in Table 6, which highlights the planned operating conditions for the injection wells. This pressure corresponds to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure (40 CFR 146.88(a)). See Summary of Requirements for more details on operational conditions.

Table 6: Operating conditions to be continuously monitored and controlled.

Parameter	Well	Limit	
		KIC	MIC
Max. Instantaneous Rate (MMt/y)	TB1-1	0.5	0.5
	TB1-2	0.5	0.5
	TB1-3	0.5	0.5
	TB1-4	0.5	0.5
Max. Estiamted Allowable Surface Pressure (psig)	TB1-1	2,479	1,751
	TB1-2	2,524	1,765
	TB1-3	2,588	1,837
	TB1-4	2,655	1,882
Max. injection pressure (psig)	TB1-1	5,358	3,501
	TB1-2	5,477	3,537
	TB1-3	5,647	3,712
	TB1-4	5,832	3,823
Minimum annulus pressure at surface (psig)	TB1-1	100	100
	TB1-2	100	100
	TB1-3	100	100
	TB1-4	100	100
Maximum annulus pressure at surface (psig)	TB1-1	2,579	1,851
	TB1-2	2,624	1,865
	TB1-3	2,688	1,937
	TB1-4	2,755	1,982

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 7 to monitor operational parameters. Surface and DH pressure and temperature instruments will be calibrated annually over the full operational range using ANSI or other recognized standards. DH 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. DH 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 of the QASP for additional details.

Table 7: 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) TB1-1, TB1-2, TB1-3, TB1-4, TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4 2) TB1-1, TB1-2, TB1-3, TB1-4; TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4	5 sec. / 4 hours	5 mins. / 4 hours
Injection Rate	Coriolis Mass Flow Meter	TB1-1, TB1-2, TB1-3, TB1-4	5 sec. / 4 hours	5 mins. / 4 hours
Injection Volume	Coriolis Mass Flow Meter	TB1-1, TB1-2, TB1-3, TB1-4	5 sec. / 4 hours	5 mins. / 4 hours
Annular Pressure	Annular P Gauge	TB1-1, TB1-2, TB1-3, TB1-4	5 sec. / 4 hours	5 mins. / 4 hours
Annulus Fluid Volume	Fluid Tank Volume Meter	TB1-1, TB1-2, TB1-3, TB1-4	5 sec. / 4 hours	5 mins. / 4 hours
Injection Temperature Monitoring	DTS	TB1-1, TB1-2, TB1-3, TB1-4; TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4	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. During initial phase of injection into the KIC, the downhole gauges will be set in the Knox Group. At the end of the initial phase (30 years of planned injection), the injection wells will undergo recompletion, and gauges will be set in the Medina Group to monitor injection into the MIC.

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 DH pressure gauges. Each injection well will be equipped with permanent DH pressure gauges that will continuously monitor the active injection zone interval (either the Medina or Knox Group) pressures to ensure it does not exceed 90 percent of the reservoir fracture pressure as required by 40 CFR 146.88(a) and to ensure compliance with operating conditions. In the injection wells, during injection into KIC, the Knox Group will have the ported DH instrumentation. Once the planned injection in KIC is complete and the injection well is being recompleted, the DH instrumentation will be installed in the Medina group for MIC monitoring. 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 the maximum allowable surface pressure limits as identified in Table 6.

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 exact brine composition will be finalized after the well has been drilled.
- The surface annulus pressure will be kept within a range as identified in Table 6. The tubing-casing annulus pressure will exceed the operating injection pressure.
- 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 5 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 DH conditions, during injection into the KIC or MIC, 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 Testing and Monitoring Report.

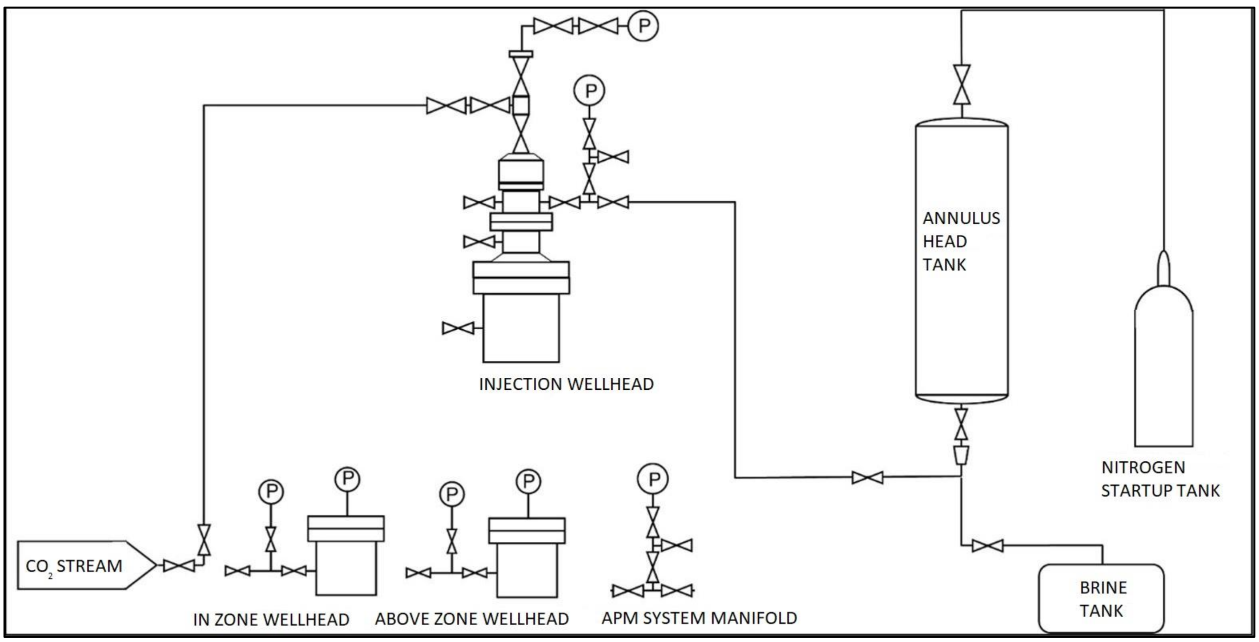

Figure 5: Annular monitoring system.

4.4. Injection Temperature Monitoring

Tri-State CCS, LLC will continuously monitor injection temperature at the surface and DH 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 DH temperature measurements using DTS fiber optic cable.

In-well pressure measurements will be taken using permanent DH gauges. Specifically, two DH injection zones (Medina and Knox Groups) will be monitored by gauges at required depths. Fiber optic technology will be implemented in the injection and observation wells. DTS fiber optic cable 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. <u>Corrosion Monitoring</u>

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, based on the date of issuance of the authorization to inject. 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 5). 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 8. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 8: 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	Non-injection Zones [2]	26 lb/ft, L80, Premium Connection
Long String Casing	Injection Zones [2]	26 lb/ft, 22Cr-110, Premium Connection
Injection Tubing	Both KIC and MIC injection	9.2 lb/ft, 22Cr-110, Premium Connection
Wellhead		Carbon/ low alloy steel or Stainless steel or CRA [1]
Packers	KIC Injection Zone	Baker Hughes Premier Packer
	MIC Injection Zone	22Cr-110 or Higher Alloy

[1] Corrosion Resistant Alloy
[2] For exact depth, refer to the well construction plans for each injection well.

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 6) attached to the pipeline. All wells will be equipped with corrosion loops. Corrosion coupons will be installed at wells as needed to monitor different gas compositions. The corrosion monitoring system will be located upstream of the wellhead and downstream of the injection well control valve (Figure 4). 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.
- <u>Ultrasonic Tools:</u> 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.
- <u>Electromagnetic Tools:</u> these tools are capable of distinguishing between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated.

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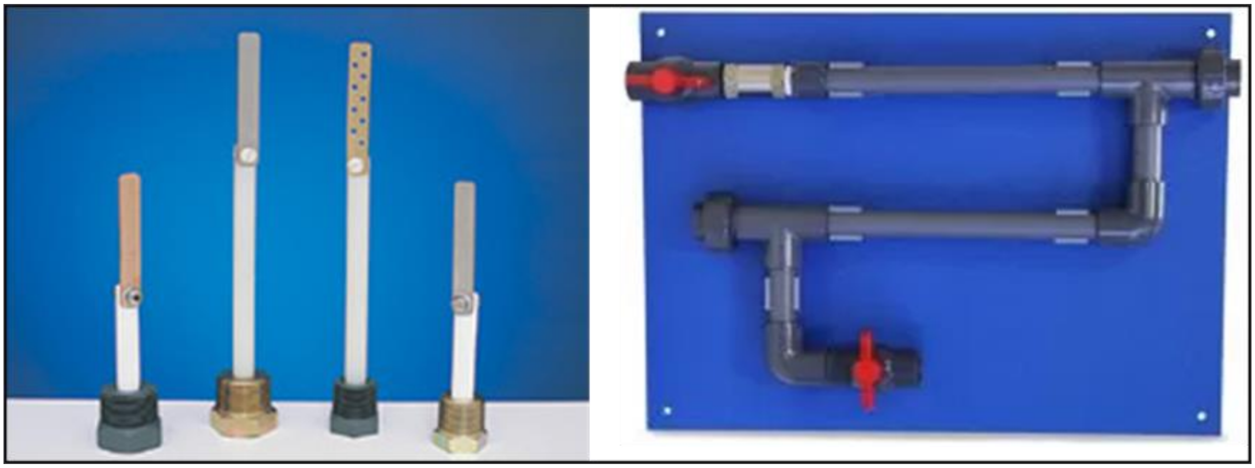

Figure 6: (Left) Example of corrosion coupon holders. (Right) Flow through pipe arrangement example.

6. Above Confining Zone Monitoring

Tri-State CCS, LLC will monitor formation water quality and geochemistry in the first permeable unit above the confining zone (Wells Creek Formation confining zone for the KIC or Rochester Shale confining zone for the MIC) of the active injection zone and in the lowermost USDW (Sharon Sandstone) during the pre-injection, injection, and post-injection phases pursuant to 40 CFR 146.90(d). As noted earlier, the first permeable units above the confining zone for the KIC and MIC will be defined as having porosity >/= 3% and permeability >/= 1 md. These cutoffs are subject to change based on data from the CarbonSAFE stratigraphic wells and pre-operational testing program. Additional monitoring may be conducted if plume migration is suspected outside of the expected behavior based on modeling results. Groundwater geochemistry monitoring will be conducted using direct fluid sampling and analysis. Formation pressure will be monitored directly using DH pressure gauges.

Baseline monitoring will be conducted in all project wells completed in the Medina and Knox Groups (primary injection zones), the first permeable units identified above the confining zones for both the KIC and the MIC, and the Sharon Sandstone (lowermost USDW) to understand formation and 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:

- Unit with porosity >/= 3% and permeability >/= 1 md above the confining zone for each injection complex (first permeable zone). Note that the cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well; and
- Sharon Sandstone (lowermost USDW).

During the injection phase of the project, routine formation water quality monitoring will occur in all above-zone and lowermost USDW observation wells. The DH pressure behavior in the in-zone observations wells, in addition to the monitoring results from above-zone observation wells in the first permeable unit above the upper confining zones, 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 three above-zone (TB1-AOB-1, TB1-AOB-2, TB1-AOB-3) and four in-zone (TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4) observation wells are spatially displayed in Figure 3 and Figure 4. Notably, the above zone observation wells are located at the same well pad as the corresponding injection wells. While the four deep (lowermost USDW; TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4) observation wells are tentatively planned to be sited at the injection well pads; their exact location, as well as that of the up to four 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 9 below.

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Table 9: Monitoring geochemical and physical changes.

<table>
<tr><th>Target Formation</th><th>Monitoring Activity</th><th>Monitoring Location(s)</th><th>Spatial Coverage [3]</th><th>Frequency</th></tr>
<tr><td rowspan="2">Sharon Sandstone (Lowermost USDW)</td><td>Geochemical Monitoring:
Direct Fluid Sampling</td><td rowspan="2">Deep observation wells [TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4]</td><td rowspan="2">4 Well Locations

Vertical (ft. MD):
TB1-UOB-1: ~753 ft
TB1-UOB-2: ~715 ft
TB1-UOB-3: ~902 ft
TB1-UOB-4: ~1,051 ft</td><td>Quarterly for first year [1], annually thereafter. [2]</td></tr>
<tr><td>Physical Monitoring:
Downhole P Gauges</td><td>Continuous</td></tr>
<tr><td rowspan="2">TBD
(First permeable unit over confining zones of each injection complex)</td><td>Geochemical Monitoring:
Direct Fluid Sampling</td><td rowspan="2">Above-zone observation wells [TB1-AOB-1, TB1-AOB-2, TB1-AOB-3]</td><td rowspan="2">3 Well Locations

Vertical (ft. MD): [4]
TB1-AOB-1: ~TBD
TB1-AOB-2: ~TBD
TB1-AOB-3: ~TBD</td><td>Quarterly for first year [1], annually thereafter [2]</td></tr>
<tr><td>Physical Monitoring:
Downhole P Gauges</td><td>Continuous</td></tr>
<tr><td>Medina and Knox Groups (Injection Interval)</td><td>Physical Monitoring:
Downhole P Gauges</td><td>In-Zone Observation Wells [TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4]</td><td>4 Well Locations

Vertical (ft. MD)
<table><tr><th>Well</th><th>Medina Group</th><th>Knox Group</th></tr><tr><td>TB1-IOB-1</td><td>~ 5,524</td><td>~ 8,426</td></tr><tr><td>TB1-IOB-2</td><td>~ 5,643</td><td>~ 8,634</td></tr><tr><td>TB1-IOB-3</td><td>~ 5,787</td><td>~ 8,832</td></tr><tr><td>TB1-IOB-4</td><td>~ 5,901</td><td>~ 9,075</td></tr></table></td><td>Continuous [5]</td></tr>
</table>

[1] Quarterly sampling will take place every 3 months of the first year based on 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.

[4] The first permeable unit for the two injection complexes will be defined as the first unit above the confining zones of the injection complex with porosity >/= 3% and permeability >/= 1 md. These cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well. Final depths will depend on the final identified monitoring units.

[5] The in-zone observation wells will be instrumented to monitor both of the injection zones, i.e., KIC and MIC when these wells are completed. Tri-State CCS, LLC plans to monitor both zones continuously during the injection phase for both the KIC and, subsequently, the MIC injection.

6.2. Analytical Parameters

Fluid samples collected from intervals above the Wells Creek Formation and Rochester Shale (confining zones) will be analyzed for geochemical parameters listed in Table 10. 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. Up to four 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 Tri State CCS, LLC or the UIC Program Director deem it necessary.

Table 10: Summary of analytical and field parameters for groundwater 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 (Sharon Sandstone (Lowermost USDW)), and Above-Zone (TBD [1]) 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)
Isotopes: δ^{13} C of DIC	Isotope ratio mass spectrometry

Parameters	Analytical Methods
Dissolved CO_2	Coulometric titration, ASTM D513-16 (ASTM, 2016)
Total Dissolved Solids	Gravimetry, APHA 2540C (APHA)
Water Density	Oscillating body method
Alkalinity	APHA 2320B (APHA, 1997)
pH (field)	EPA 150.1 (U.S. EPA, 1982)
Specific conductance (field)	APHA 2510 (APHA, 1992)
Temperature (field)	Thermocouple

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

[1] The first permeable unit for the two injection complexes will be defined as the first unit above the confining zones of the injection complex with porosity >/= 3% and permeability >/= 1 md. These cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well. These units once identified will be the monitored formations in the above-zone observation wells.

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 and Table 2 of this Plan and the Pre-Operational Testing Program.

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 11. 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 Emergency and Remedial Response Plan (ERRP) (40 CFR 146.94), follow reporting requirements of 40 CFR 146.91 (see subsection 2.5 above) and in the ERRP, 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 Semi-Annual Testing and Monitoring Report, document the type of failure, the cause, and 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 11 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 Program. If the DTS fiber optic cables fail, other methods listed in Table 3 will be used to demonstrate external mechanical integrity.

Table 11: 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	TB1-1, TB1-2, TB1-3, TB1-4
External MIT	DTS	Continuous	Depths: Surface to Casing TD (Cemented Casing String) TB1-1, TB1-2, TB1-3, TB1-4 Depths: Surface to TD [TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4]

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

8. Pressure Fall-Off Testing

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 12).

Table 12: 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.[1]	TB1-1, TB1-2, TB1-3, TB1-4

[1]The identified frequency of PFO testing applies individually to the two injection zones, i.e., KIC and MIC. The PFO testing in MIC will only begin once injection into KIC ceases and the wells have undergone recompletion.

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 DH 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 for each injection zone, i.e., KIC followed by MIC, 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 earlier, reporting pressure fall-off data and interpretation of the reservoir ambient pressure following the test. Notably, once the post-injection tests are complete following the initial 30-year injection period for the KIC, Tri-State CCS, LLC will recomplete the injection wells for injection into the MIC. Post-injection tests will be repeated for the Medina Group at the end of injection into the MIC.

All data will be measured using permanent DH pressure gauges, along with wellhead sensors, so testing durations can be determined in real-time. Because surface readout will be used and DH 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 DH 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 DH gauge range will be 200-10,000 psi for pressure. Wellhead and DH 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 13) to track the CO_2 plume evolution and direct methods (

Table 14) 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 DH and surface pressure gauges. Gauges ported in the two reservoirs (Medina and Knox Groups) will record corresponding reservoir pressures and allow for better pressure front modeling. Pressure gauges ported to monitor the first permeable zone above the confining zone (Wells Creek Formation confining zone for the KIC or Rochester Shale Formation confining zone for the MIC) or lowermost USDW (Sharon Sandstone) 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 7. 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 (Wells Creek Formation for the KIC and Rochester Shale Formation for the MIC). 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 and will be cemented in place along the entirety of the cased 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 or temperature logging at the monitoring wells.

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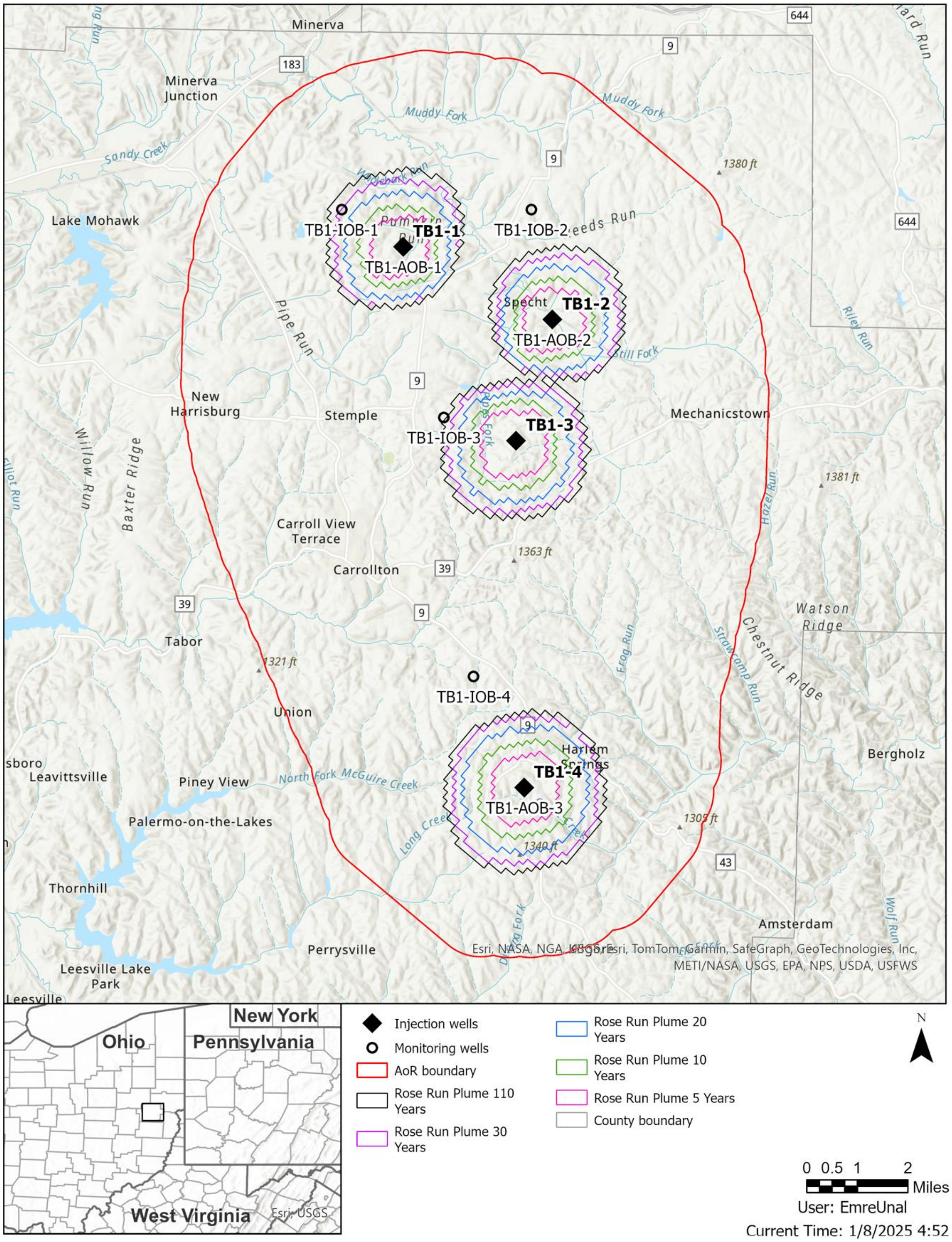

Figure 7: Project CO_2 plume evolution map after 30 years of injection and 80 years post-injection into the KIC.

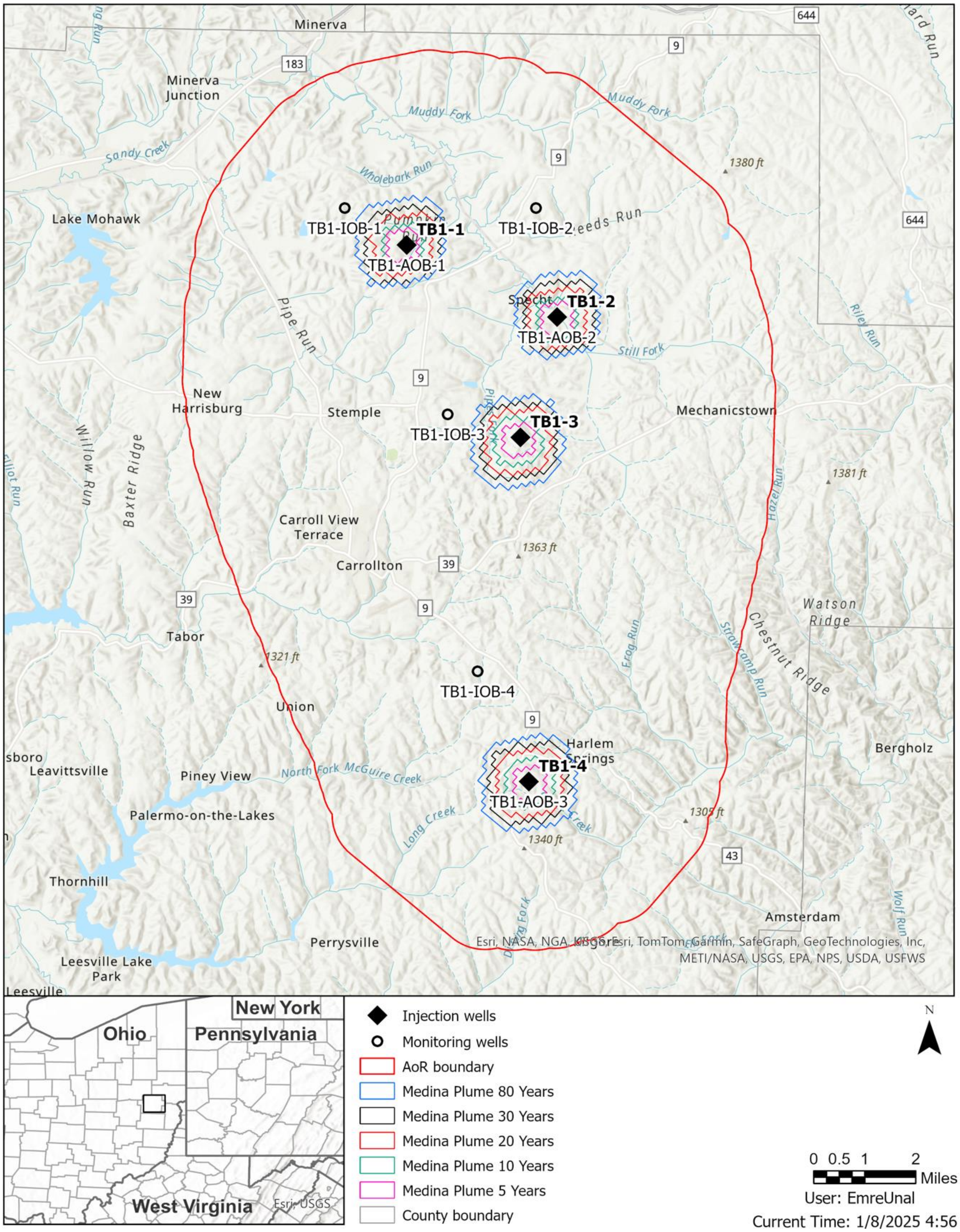

Figure 8: Project CO2 plume evolution map after 30 years of injection and 50 years post-injection into the MIC.

9.1. Plume Monitoring Location and Frequency

As summarized in Table 13 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 7. Locations are subject to change based on final site characterization and land access agreements.

DTS will be installed in all injection wells and in-zone observation wells. In the in-zone observation wells, DTS will continuously monitor temperature changes along the wellbore to detect any potential CO_2 breakthrough within the reservoir. In the injection wells with DTS deployment, this will allow continuous monitoring of the wellbore for any signs of vertical CO_2 migration away from the injection zones. Repeat PNC logging will be run in each injection well 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. The planned PNC logging frequency is separate for the two identified injection zones, i.e., KIC and MIC. The final PNC log in the KIC is expected before the plugging and recompletion of the injection wells at the end of the 30-year injection period into the KIC. For the in-zone, above-zone, and deep (lowermost USDW) observation wells, repeat PNC logging will only occur if containment loss is detected and will then be used as a containment verification technology. DAS fiber optic cable will be installed in some of the injection and in-zone observation wells for repeat (time lapse) seismic profile surveys.

9.2. Plume Monitoring Details

The two technologies mentioned above will allow Tri-State CCS, LLC to monitor the CO_2 plume evolution within each reservoir and provide evidence for its containment (Table 13). At the injection wells, where applicable, DTS or temperature logging data will help validate containment of the CO_2 plume within the injection zones in proximity of the wells. At the in-zone observation wells, the DTS data will allow for detection of CO_2 breakthrough. PNC logging at injection wells will reveal intervals with higher injectivity as well as provide quantitative measurements of CO_2 saturation within those intervals. Statistical approaches, e.g., normality testing, will be used to identify CO_2 breakthrough at monitoring locations. PNC logging will occur in the injection wells as per the schedule 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 in case of detected containment loss. DAS fiber optics will provide Tri-State CCS, LLC the ability to image the CO_2 plume in 3D within the reservoir as well as image the CO_2 plume should it migrate out-of-zone. Exact well locations with DAS deployment will be finalized based on final site characterization and land access agreements. Data from these technologies will be used to update reservoir models for more accurate CO_2 plume migration predictions as required.

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Table 13: Indirect CO_2 plume injection phase monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
INDIRECT PLUME MONITORING			
Medina and Knox Groups (Injection Intervals)	DTS	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4 In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4	Continuous
	PNC Logging	Injection wells: TB1-1, TB1-2, TB1-3, TB1-4	Three years after injection begins, and every five years thereafter during the injection period. [1]
	PNC Logging	In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4 Above zone observation wells: TB1-AOB-1, TB1-AOB-2, TB1-AOB-3 Deep observation wells (lowermost USDW): TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4	PNC logging will only occur in wells with detected CO_2 breakthrough and suspected containment loss.
	Repeat 3D DAS VSP/ CSP	TBD [2]	TBD

[1] Logging frequency in the injection wells is for each injection zone. Specifically, the final PNC log in the KIC is expected before the plugging and recompletion of the injection wells at the end of the 30-year injection period in the KIC.

[2] While DAS is planned to be included in some of the wells, the exact wells and the exact frequency will depend on the evolution of the plume and independent observations from other monitoring methods over time.

9.3. Pressure-Front Monitoring Location and Frequency

Tri-State CCS, LLC will use permanent electronic DH pressure gauges placed above the packer and ported through to monitor each well's respective monitoring zone (see Table 1) pressures continuously. Wellhead pressure gauges will be installed as a backup pressure measurement should the DH gauges fail. DH and surface pressure gauges will be installed in all injection wells and in-zone, above-zone, and deep observation wells (Table 14).

9.4. Pressure-Front Monitoring Details

Tri-State CCS, LLC will directly monitor the presence of the elevated pressure front by deploying electronic DH pressure gauges to monitor the 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 Medina and Knox Groups during injection. Above-zone and deep observation wells will monitor for pressures and temperature changes indicating potential containment loss to the first permeable units above the two confining zones (Wells Creek Formation for the KIC or Rochester Shale for the MIC) and in the Sharon Sandstone (Lowermost USDW), respectively. All DH 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 14: Direct pressure-front injection phase monitoring activities.

<table>
<tr><th>Target Formation</th><th>Monitoring Activity</th><th>Monitoring Location(s)</th><th>Spatial Coverage</th><th>Frequency</th></tr>
<tr><td colspan="5">DIRECT PRESSURE-FRONT MONITORING</td></tr>
<tr><td>Sharon Sandstone (USDW Aquifer)</td><td rowspan="3">P Gauges</td><td>Deep observation (lowermost USDW) wells: TB1-UOB-1, TB1-UOB-2, TB1-UOB-3, TB1-UOB-4</td><td>Above Packer - Ported to Sharon Sandstone (Aquifer)</td><td>Continuous</td></tr>
<tr><td>TBD [1] (First Permeable Unit Above the Confining Zones of KIC and MIC)</td><td>Above zone observation wells: TB1-AOB-1, TB1-AOB-2, TB1-AOB-3</td><td>Above Packer - Ported to the formations to be monitored</td><td>Continuous</td></tr>
<tr><td>Medina Group and Knox Group (Injection Intervals)</td><td>Injection wells: TB1-1, TB1-2, TB1-3, TB1-4

In-zone observation wells: TB1-IOB-1, TB1-IOB-2, TB1-IOB-3, TB1-IOB-4</td><td>Above the Packer – Ported to Upper Medina and Knox Groups depending on the active injection zone in a given well</td><td>Continuous</td></tr>
</table>

[1] The first permeable unit for the two injection complexes will be defined as the first unit above the confining zones of the injection complex with porosity >/= 3% and permeability >/= 1 md. These cutoffs are subject to change based on subsurface data collected for the CarbonSAFE stratigraphic wells and the pre-operational testing for each injection well.

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

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