TESTING AND MONITORING PLAN
40 CFR 146.90

Project Name: Tri-State CCS Buckeye 2

Facility Information

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

Well Locations: Jefferson and Harrison Counties, Ohio

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

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List of Acronyms

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
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
ERRP	Emergency and Remedial Response Plan
Fe	Iron
ft	feet
GC-P	Gas Chromatography-Pyrolysis
GS	Geologic Sequestration
H_2S	Hydrogen Sulfide
ICP	Inductively Coupled Plasma
K	Potassium
KIC	Knox Injection Complex
lb	pound

LLC	Limited Liability Company
MD	Measured Depth
md	millidarcy
Mg	Magnesium
MIC	Medina Injection Complex
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
ppmw	parts per million, weight
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
TBD	To Be Determined
TD	Total Depth
TDS	Total Dissolved Solids
Ti	Titanium
TB2-(#)	Tri-State CCS Buckeye 2 injection well
TB2-AOB-(#)	Above-zone observation well
TB2-GW-(#)	Shallow groundwater well
TB2-IOB-(#)	In-zone observation well
TB2-UOB-(#)	Lowermost USDW observation well

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 2 in Jefferson and Harrison counties, Ohio (the "project") pursuant to 40 CFR 146.90. Data collected during the implementation of this Plan will be used to demonstrate that the Class VI Underground Injection Control (UIC) 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 are 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 sixty one (61) wells, strategically placed in specific formations, to ensure USDW non-endangerment (see Table 1 for details). These wells include twenty (20) injection wells completed in the Rose Run Sandstone in the Knox Injection Complex (KIC) initially, thirteen (13) offset in-zone observation wells completed in the Medina Group and Rose Run Sandstone, seven (7) above-zone observation wells completed in the first permeable units identified as above-zone formation for both the KIC and Medina Injection Complex (MIC), eleven (11) lowermost USDW observation wells completed in the Sharon Sandstone, and up to ten (10) shallow groundwater wells completed in Pennsylvanian age strata (Figure 1: Generalized stratigraphic column for the project with average values from all injection wells and specific values for Wells TB2-1 to TB2-10. Possible Injection Complex: Lockport Injection Complex: 1; proposed Primary Complexes: Medina Injection Complex: 2; and Knox Injection Complex: 3. (*Depth is to the top of the Stratigraphic Unit (SU), except where noted.) Modified from Childs, 1985; Patchen et al., 1985b; Riley et al., 2010; Wickstrom et al., 2010; WVGES, 2019. and Figure 2). 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 from the pre-operational testing planned for each injection well. Figure 3 shows the project's area of review (AoR), CO_2 plume associated with injection into the MIC and KIC, respectively, and the proposed injection and observation well locations. The above-zone (TB2-AOB), lowermost USDW (TB2-UOB), and shallow groundwater (TB2-GW) observation wells are co-located on selected injection well pads.

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 Group and Rose Run Sandstone will be instrumented, whereas in the above-zone observation wells, both the identified permeable units above the confining zones for the KIC and MIC 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)	TB2-1 Depth (ft)	TB2-1 Thickness (ft)	TB2-2 Depth (ft)	TB2-2 Thickness (ft)	TB2-3 Depth (ft)	TB2-3 Thickness (ft)	TB2-4 Depth (ft)	TB2-4 Thickness (ft)	TB2-5 Depth (ft)	TB2-5 Thickness (ft)	TB2-6 Depth (ft)	TB2-6 Thickness (ft)	TB2-7 Depth (ft)	TB2-7 Thickness (ft)	TB2-8 Depth (ft)	TB2-8 Thickness (ft)	TB2-9 Depth (ft)	TB2-9 Thickness (ft)	TB2-10 Depth (ft)	TB2-10 Thickness (ft)
Pennsylvanian		Pennsylvanian (undivided)	Freshwater Aquifers																							
Pennsylvanian		Pottsville Group (Base Sharon Mbr)	Lowest USDW		865		680		784		984		844		820		933		915		928		966		755	
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)*			3920		3760		3848		3868		3662		3808		4030		4166		4331		4391		4246
Devonian	Upper	Olentangy Shale Fm	*Seal (Shale)*																							
Devonian	Middle	Hamilton Grp – Mahantango Shale Fm; Tully Ls	*Seal (Shale)*																							
Devonian	Middle	Hamilton Grp – Marcellus Shale Fm	Unconventional Oil Reservoir	●●																						
Devonian	Middle	Onondaga Ls Fm	*Seal (Limestone)*		4786	180	4797	210	4632	177	4852	192	4506	179	4628	177	4963	176	5081	175	5259	172	5357	175	5001	178
Devonian	Lower	Oriskany SS Fm	Conventional Oil/Gas Reservoir	●●	4966	29	5008	18	4809	19	5044	25	4685	17	4805	27	5139	36	5255	38	5431	44	5532	43	5179	33
Devonian	Lower	Helderberg Grp	*Seal (Limestone)*		4995	224	5026	224	4828	154	5069	231	4702	154	4832	174	5175	251	5293	254	5475	272	5575	267	5212	166
Silurian	Upper	Bass Islands Dolomite Grp	*Seal (Dolomite)*		5219	102	5270	76	4982	103	5300	111	4855	79	5006	92	5426	150	5547	134	5748	110	5842	127	5379	202
Silurian	Upper	Salina Grp – Salina "D" – "G"; Salina "A" – "C"	**Upper Confining Zone (Evaporite/Salt)**		5321	993	5345	1097	5085	959	5410	1064	4935	845	5098	974	5575	1019	5680	1050	5858	1158	5969	1211	5581	1053
Silurian	Upper	**Lockport Dolomite Grp** 1	**Possible Injection Zone**		6314	290	6442	262	6044	359	6474	291	5779	316	6072	319	6594	301	6730	304	7016	317	7179	329	6633	325
Silurian	Upper	Clinton Grp – Rochester Shale Fm; Dayton/Keefer Fm	**Middle Confining Zone**	●●	6604	291	6705	297	6403	238	6765	282	6095	268	6391	286	6895	309	7034	313	7333	285	7509	295	6959	286
Silurian	L	**Medina (Tuscarora SS) Grp** 2 *Informal – "Clinton" & "Medina" sands*	**Injection Zone**	●●	6895	168	7001	141	6641	158	7047	157	6363	176	6677	188	7205	170	7347	151	7618	157	7803	164	7244	161
Ordovician	Upper	Queenston Shale (Juniata Fm)	**Lower Confining Zone**	●●	7063		7143		6799		7203		6539		6865		7375		7497		7775		7968		7405	
Ordovician	Upper	Utica Shale Fm	Unconventional Oil Reservoir	●●																						
Ordovician	Upper	Trenton Ls Grp	*Seal (Limestone)*			↑ 2747 ↓		↑ 2666 ↓		↑ 2523 ↓		↑ 2626 ↓		↑ 2618 ↓		↑ 2677 ↓		↑ 2873 ↓		↑ 2981 ↓		↑ 3137 ↓		↑ 3159 ↓		↑ 3047 ↓
Ordovician	Upper	Black River Ls Grp	*Seal (Limestone)*																							
Ordovician	M	Wells Creek Fm	**Upper Confining Zone**		9810	115	9809	134	9322	115	9830	129	9157	98	9542	94	10248	111	10478	110	10912	115	11127	118	10453	124
Ordovician	L	Knox Grp – Beekmantown Fm	**Upper Confining Zone**	●●	9925	416	9943	407	9437	404	9959	407	9255	422	9636	450	10358	433	10588	418	11028	379	11245	350	10577	353
Cambrian	Upper	Knox Grp – **Rose Run** 3	**Injection Zone**	●●	10341	93	10350	107	9841	98	10365	105	9678	94	10086	87	10791	84	11006	92	11407	110	11595	116	10929	99
Cambrian	Upper	Knox Grp – Copper Ridge Dolomite Fm	**Lower Confining Zone**	●●	10434	832	10457	812	9939	546	10471	815	9772	476	10173	697	10876	1048	11098	1169	11517	1427	11711	1541	11028	1311
Cambrian	Upper	Conasauga Group	*Lowest Seal/Confining Unit*		11266		11268		10485		11286		10248		10870		11924		12267		12944		13252		12338	

Figure 1: Generalized stratigraphic column for the project with average values from all injection wells and specific values for Wells TB2-1 to TB2-10. Possible Injection Complex: Lockport Injection Complex: 1; proposed Primary Complexes: Medina Injection Complex: 2; and Knox Injection Complex: 3. (*Depth is to the top of the Stratigraphic Unit (SU), except where noted.) Modified from Childs, 1985; Patchen et al., 1985b; Riley et al., 2010; Wickstrom et al., 2010; WVGES, 2019.

System	Series	Stratigraphic Unit (Group or Major Formation)	Aquifer, Confining Zone, or Reservoir	Oil Gas Prod.	TB2-11 Depth (ft)	TB2-11 Thickness (ft)	TB2-12 Depth (ft)	TB2-12 Thickness (ft)	TB2-13 Depth (ft)	TB2-13 Thickness (ft)	TB2-14 Depth (ft)	TB2-14 Thickness (ft)	TB2-15 Depth (ft)	TB2-15 Thickness (ft)
Pennsylvanian		Pennsylvanian (undivided)	Freshwater Aquifers											
Pennsylvanian		Pottsville Group (Base Sharon Mbr)	Lowest USDW		807		768		803		726		877	
Mississippian	U	Greenbriar Ls Fm	*Seal (Limestone)*											
Mississippian	Lower	Pocono Grp – Big Injun SS	Conventional Oil Reservoir	●●										
Mississippian	Lower	Pocono Grp – Sunbery Sh	*Seal (Shale)*											
Mississippian	Lower	Pocono Grp – Berea SS	Conventional Oil Reservoir	●●										
Devonian	Upper	Ohio Shale Grp	*Seal (Shale)*			3637		3720		3824		3631		3795
Devonian	Upper	Olentangy Shale Fm	*Seal (Shale)*											
Devonian	Middle	Hamilton Grp – Mahantango Shale Fm; *Tully Ls*	*Seal (Shale)*											
Devonian	Middle	Hamilton Grp – Marcellus Shale Fm	Unconventional Oil Reservoir	●●										
Devonian		Onondaga Ls Fm	*Seal (Limestone)*		4444	184	4488	184	4627	181	4357	163	4672	179
Devonian	Lower	Oriskany SS Fm	Conventional Oil/Gas Reservoir	●●	4628	20	4672	14	4808	26	4520	22	4851	33
Devonian	Lower	Helderberg Grp	*Seal (Limestone)*		4648	228	4686	212	4834	237	4542	250	4883	234
Silurian	Upper	Bass Islands Dolomite Grp	*Seal (Dolomite)*		4877	81	4898	69	5071	94	4792	46	5118	85
Silurian	Upper	Salina Grp – Salina "D" – "G"; Salina "A" – "C"	**Upper Confining Zone (Evaporite/Salt)**		4958	923	4967	940	5165	959	4838	875	5203	946
Silurian	Upper	**Lockport Dolomite Grp** ①	**Possible Injection Zone**		5881	265	5907	229	6124	243	5712	236	6149	230
Silurian	Upper	Clinton Grp – Rochester Shale Fm; Dayton/Keefer Fm	**Middle Confining Zone**		6146	296	6135	298	6367	304	5948	311	6379	294
Silurian	L	**Medina (Tuscarora SS) Grp** ② *Informal – "Clinton" & "Medina" sands*	**Injection Zone**	●●	6443	186	6434	170	6671	195	6259	161	6672	189
Ordovician	Upper	Queenston Shale (Juniata Fm)	**Lower Confining Zone**		6629	↑	6604	↑	6865	↑	6420	↑	6862	↑
Ordovician	Upper	Utica Shale Fm	Unconventional Oil Reservoir	●●										
Ordovician	Upper	Trenton Ls Grp	*Seal (Limestone)*			2711		2666		2735		2633		2643
Ordovician	Upper	Black River Ls Grp	*Seal (Limestone)*			↓		↓		↓		↓		↓
Ordovician	M	Wells Creek Fm	**Upper Confining Zone**		9340	85	9270	86	9600	84	9053	110	9504	100
Ordovician	L	Knox Grp – Beekmantown Fm	**Upper Confining Zone**	●●	9425	459	9356	455	9684	471	9164	437	9604	462
Cambrian	Upper	Knox Grp – **Rose Run** ③	**Injection Zone**	●●	9884	89	9810	93	10156	84	9601	98	10066	79
Cambrian	Upper	Knox Grp – Copper Ridge Dolomite Fm	**Lower Confining Zone**	●●	9972	601	9904	535	10239	688	9699	450	10146	646
Cambrian	Upper	Conasauga Group	*Lowest Seal/Confining Unit*		10573		10439		10927		10150		10792	

Stratigraphic Unit (Group or Major Formation)	TB2-16 Depth (ft)	TB2-16 Thickness (ft)	TB2-17 Depth (ft)	TB2-17 Thickness (ft)	TB2-18 Depth (ft)	TB2-18 Thickness (ft)	TB2-19 Depth (ft)	TB2-19 Thickness (ft)	TB2-20 Depth (ft)	TB2-20 Thickness (ft)
Pennsylvanian (undivided)										
Pottsville Group (Base Sharon Mbr)	861		931		832		921		812	
Greenbriar Ls Fm										
Pocono Grp – Big Injun SS										
Pocono Grp – Sunbery Sh										
Pocono Grp – Berea SS										
Ohio Shale Grp		3839		3974		3935		3965		3979
Olentangy Shale Fm										
Hamilton Grp – Mahantango Shale Fm; *Tully Ls*										
Hamilton Grp – Marcellus Shale Fm										
Onondaga Ls Fm	4700	177	4905	178	4767	179	4886	184	4791	186
Oriskany SS Fm	4878	33	5083	32	4946	31	5070	29	4978	30
Helderberg Grp	4910	216	5116	227	4977	238	5099	241	5008	231
Bass Islands Dolomite Grp	5127	63	5342	140	5215	94	5340	89	5238	99
Salina Grp – Salina "D" – "G"; Salina "A" – "C"	5189	970	5483	987	5309	974	5429	897	5338	968
Lockport Dolomite Grp ①	6159	224	6470	303	6283	313	6329	316	6306	318
Clinton Grp – Rochester Shale Fm; Dayton/Keefer Fm	6383	296	6772	289	6596	286	6641	293	6624	295
Medina (Tuscarora SS) Grp ②	6679	182	7062	166	6882	154	6935	157	6919	178
Queenston Shale (Juniata Fm)	6861	↑	7228	↑	7036	↑	7091	↑	7097	↑
Utica Shale Fm										
Trenton Ls Grp		2631		2722		2647		2663		2580
Black River Ls Grp		↓		↓		↓		↓		↓
Wells Creek Fm	9492	100	9951	132	9683	147	9754	154	9677	150
Knox Grp – Beekmantown Fm	9592	458	10082	423	9830	407	9909	374	9826	354
Knox Grp – **Rose Run** ③	10050	83	10505	79	10237	80	10283	86	10181	89
Knox Grp – Copper Ridge Dolomite Fm	10133	611	10584	881	10317	788	10369	780	10269	823
Conasauga Group	10744		11465		11105		11149		11093	

Figure 2: Generalized stratigraphic column for the project with Wells TB2-11 to TB2-20. Possible Injection Complex: Lockport Injection Complex: 1; proposed Primary Complexes: Medina Injection Complex: 2; and Knox Injection Complex: 3. (*Depth is to the top of the Stratigraphic Unit (SU), except where noted.) Modified from Childs, 1985; Patchen et al., 1985b; Riley et al., 2010; Wickstrom et al., 2010; WVGES, 2019.

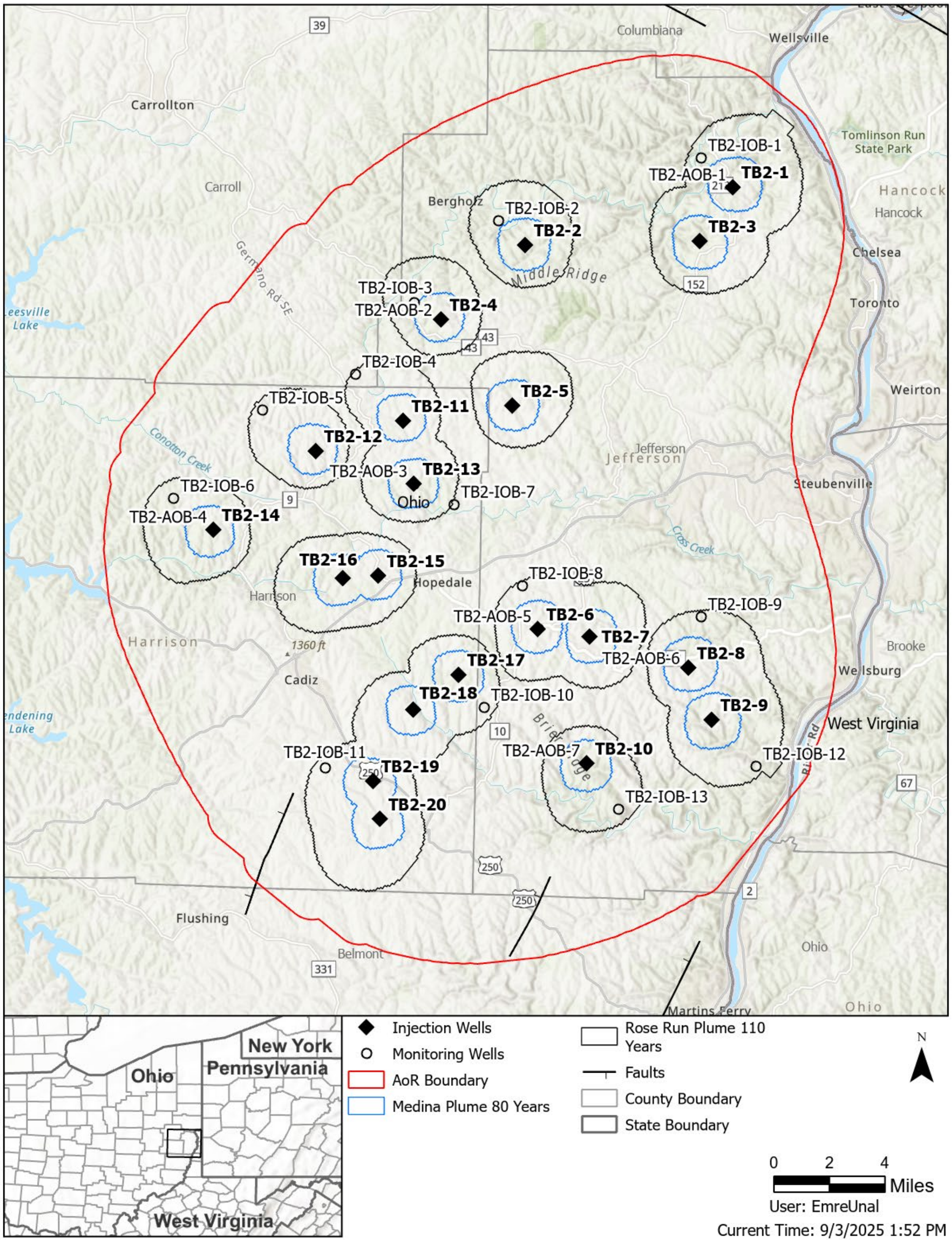

Figure 3: Map of project showing AoR, CO_2 plume associated with injection into KIC and MIC, and the proposed injection and observation well locations. The in-zone observation (TB2-IOB) well locations are identified. The above-zone (TB2-AOB), lowermost USDW (TB2-UOB), and shallow groundwater observation (TB2-GW) wells are co-located on the same well pad as some of the planned injection wells (Table 1). Identified faults within the AoR are also displayed

Table 1: Project 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	Latitude[5] (WGS 84)	Longitude[5] (WGS 84)	Quantity	Construction Material
Shallow Groundwater (GW)	TB2-GW-1, TB2-GW-2, TB2-GW-5, TB2-GW-9, TB2-GW-10, TB2-GW-12, TB2-GW-13, TB2-GW-14, TB2-GW-17, TB2-GW-20,	TBD TBD TBD TBD TBD TBD TBD TBD TBD TBD		Shallow USDW	Pennsylvanian	40.52539 40.497284 40.413765 40.248017 40.226549 40.391789 40.373907 40.351714 40.273886 40.199463	-80.696419 -80.83907 -80.849888 -80.717998 -80.803704 -80.98459 -80.917945 -81.055267 -80.889903 -80.945104	Up to 10	Surface to Casing TD: Steel meeting ASTM Standard A53/A53M-06 (ASTM, 2022) or Schedule 40 or 80 PVC
Lowermost USDW Observation (UOB)	TB2-UOB-1, TB2-UOB-2, TB2-UOB-5, TB2-UOB-9, TB2-UOB-10, TB2-UOB-12, TB2-UOB-13, TB2-UOB-14, TB2-UOB-17, TB2-UOB-19, TB2-UOB-20,	~ 1,037 ~ 784 ~ 820 ~ 966 ~ 755 ~ 768 ~ 803 ~ 726 ~ 931 ~ 921 ~ 812		Lowermost USDW	Sharon Sandstone	40.525467 40.497336 40.413845 40.248098 40.226634 40.391871 40.37399 40.351797 40.273969 40.219362 40.199542	-80.696417 -80.839182 -80.849889 -80.717998 -80.803706 -80.984588 -80.917947 -81.055265 -80.889906 -80.949189 -80.945104	11	
Above-Zone Observation (AOB)	TB2-AOB-1, TB2-AOB-2, TB2-AOB-3, TB2-AOB-4, TB2-AOB-5, TB2-AOB-6, TB2-AOB-7	TBD [1] TBD [1] TBD [1] TBD [1] TBD [1] TBD [1] TBD [1]	TBD [1] TBD [1] TBD [1] TBD [1] TBD [1] TBD [1] TBD [1]	1st Permeable Zone above the Medina or Knox Group	TBD [1]/ TBD [1]	40.52542649 40.45937683 40.37394688 40.35175510 40.29706879 40.27538356 40.22659170	-80.69623715 -80.89733611 -80.91776658 -81.05508754 -80.83510049 -80.73290777 -80.80352687	7	Surface Casing – • Surface to 50 ft below USDW: J55[2] Long-String – • Surface to Casing TD: L80[3]
		MIC	KIC						
In-Zone Observation (IOB)	TB2-IOB-1, TB2-IOB-2, TB2-IOB-3, TB2-IOB-4, TB2-IOB-5, TB2-IOB-6, TB2-IOB-7, TB2-IOB-8, TB2-IOB-9, TB2-IOB-10, TB2-IOB-11, TB2-IOB-12, TB2-IOB-13	~ 6,371 ~ 6,297 ~ 6,358 ~ 6,357 ~ 6,285 ~ 6,298 ~ 6,763 ~ 7,162 ~ 7,504 ~ 7,261 ~ 6,796 ~ 7,999 ~ 7,746	~ 9,642 ~ 9,508 ~ 9,664 ~ 9,713 ~ 9,591 ~ 9,605 ~ 10,262 ~ 10,726 ~ 11,315 ~ 10,749 ~ 10,110 ~ 11,793 ~ 11,457	Reservoir	Medina Group/ Knox Group	40.541105 40.510122 40.468195 40.431615 40.413533 40.368447 40.362780 40.319828 40.301764 40.256646 40.226711 40.223130 40.202376	-80.717615 -80.857076 -80.915676 -80.956484 -81.020491 -81.081832 -80.890556 -80.845370 -80.723694 -80.872549 -80.981764 -80.688252 -80.782592	13	Surface Casing – • Surface to 50 ft below USDW: J55[2] Intermediate Casing – • Surface to 100 ft below base of shallow oil & gas production unit: J55[2] Long-String Casing – • Surface to 150 ft above top of MIC: L80[3] • 150 ft above top of MIC to 150 ft below bottom of MIC: 22Cr-80[4] • 150 ft below bottom of MIC to 150 ft above top of KIC: L80[3] • 150 ft above top of KIC to Casing TD: 22Cr-80[4]

Well Types	Well Acronym	Zone Depth (ft MD)		CCS System Zone	Zone Formation	Latitude[5] (WGS 84)	Longitude[5] (WGS 84)	Quantity	Construction Material
		MIC	KIC						
Injection	TB2-1,	~ 7,001	~ 10,350	Reservoir	Medina Group/ Knox Group	40.525427	-80.696417	20	See subsection 2.5 of the Construction Details for each injection well.
	TB2-2,	~ 6,641	~ 9,841			40.497328	-80.839070		
	TB2-3,	~ 7,047	~ 10,365			40.497633	-80.719678		
	TB2-4,	~ 6,363	~ 9,678			40.459377	-80.897516		
	TB2-5,	~ 6,677	~ 10,086			40.413803	-80.849889		
	TB2-6,	~ 7,205	~ 10,791			40.297069	-80.835280		
	TB2-7,	~ 7,347	~ 11,006			40.292585	-80.800139		
	TB2-8,	~ 7,618	~ 11,407			40.275384	-80.733087		
	TB2-9,	~ 7,803	~ 11,595			40.248058	-80.717997		
	TB2-10,	~ 7,244	~ 10,929			40.226592	-80.803706		
	TB2-11,	~ 6,443	~ 9,884			40.406877	-80.924625		
	TB2-12,	~ 6,434	~ 9,810			40.391830	-80.984590		
	TB2-13,	~ 6,671	~ 10,156			40.373947	-80.917946		
	TB2-14,	~ 6,259	~ 9,601			40.351755	-81.055267		
	TB2-15,	~ 6,672	~ 10,066			40.326342	-80.943358		
	TB2-16,	~ 6,679	~ 10,050			40.325458	-80.967518		
	TB2-17,	~ 7,062	~ 10,505			40.273928	-80.889905		
	TB2-18,	~ 6,882	~ 10,237			40.256243	-80.921033		
	TB2-19,	~ 6,934	~ 10,283			40.219354	-80.949365		
	TB2-20	~ 6,919	~ 10,181			40.199503	-80.945104		

[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 during pre-operational testing for each injection well.

[2] J55 or other steel meeting API Specification 5CT (API, 2019) depending on availability.

[3] L80 or other steel meeting API Specification 5CT (API, 2019) depending on availability.

[4] 22Cr-80 or higher grade/yield strength corrosion resistant alloy meeting API Specification 5CRA (API, 2023) depending on availability, most current applicable materials testing results from API, AMPP, or other standard bodies focused on CCS or alternative project specific testing and modeling.

[5] Surface hole locations for observation wells may change slightly depending on local conditions. Any changes to the observation well locations will be submitted to the UIC Program Director.

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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 Group and Rose Run Sandstone in the injection wells, the first permeable unit above the confining zones in the above-zone observation wells, the Sharon Sandstone in the lowermost USDW observation wells, and potentially the shallow Pennsylvanian aquifers (up to ten shallow groundwater wells). The first permeable units above the confining zones will be identified based on data from the 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 lowermost USDW observation 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 lowermost USDW 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 lowermost USDW 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 lowermost USDW observation wells. During injection, PNC logging will only be run in the injection wells, any wells with CO_2 breakthrough, and in any well with monitoring data indicating loss of containment. For the zones above the confining zone, PNC logging will be mainly used as a verification technique to help prove the absence of CO_2. Groundwater sampling and analysis will also be used to verify elevated levels of CO_2 and determine if the elevated CO_2 is project related.

DTS data will be used to indirectly monitor the location of the CO_2 saturation plume. Differences in the reservoir temperature and injectate stream temperature will be detected allowing for interpretation of the vertical location of the CO_2 plume near the wellbore. As mentioned above, injection and in-zone wells will contain DTS on the long string casing and record continuous temperature measurements after well construction and prior to injection. Injection phase monitoring data will be compared to baseline data to determine vertical extent of CO_2 in the injection wells (and eventually the in-zone observation wells), and CO_2 breakthrough in the in-zone observation wells. Reservoir 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 KIC and subsequently, upon recompletion of the wells, injection into the 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. Additionally, the same infrastructure could be used for passive seismic 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, and will be finalized at a later stage once additional site-specific characterization data become 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 the 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	Injection Wells [2]
External MIT	1) DTS 2) Ultra Sonic CBL 3) Electromag. CI Logs	1 Prior to Injection	Injection Wells; [2] In-Zone Observation Wells
Groundwater Quality	1) Fluid Sampling & Analysis 2) Downhole P Gauges	1) Quarterly prior to KIC injection. 1 prior to MIC injection 2) Continuous	Injection Wells; [1] Above-Zone Observation Wells; [3] Lowermost USDW Observation Wells[3]
Groundwater Quality	1) Fluid Sampling & Analysis 2) Downhole P Gauges	1) Quarterly prior to KIC injection. 1 prior to MIC injection 2) Continuous	

Monitoring Parameter	Technology/Test	Baseline Phase Frequency (1 year)	Location
Direct Pressure Monitoring	1) P Gauges – Tubing 2) Downhole P Gauges	Continuous	Injection Wells; [2] In-Zone Observation Wells; Above-Zone Observation Wells; Lowermost USDW Observation Wells
Indirect CO_2 Plume Monitoring Techniques	DTS	1 Year Prior to Injection	Injection Wells; [2] In-Zone Observation Wells
	PNC Logging	1 Prior to Injection	Injection Wells; [2] In-Zone Observation Wells; Above-Zone Observation Wells; Lowermost USDW Observation Wells
Hydrogeologic Testing	Pressure Fall-Off Testing		Injection Wells [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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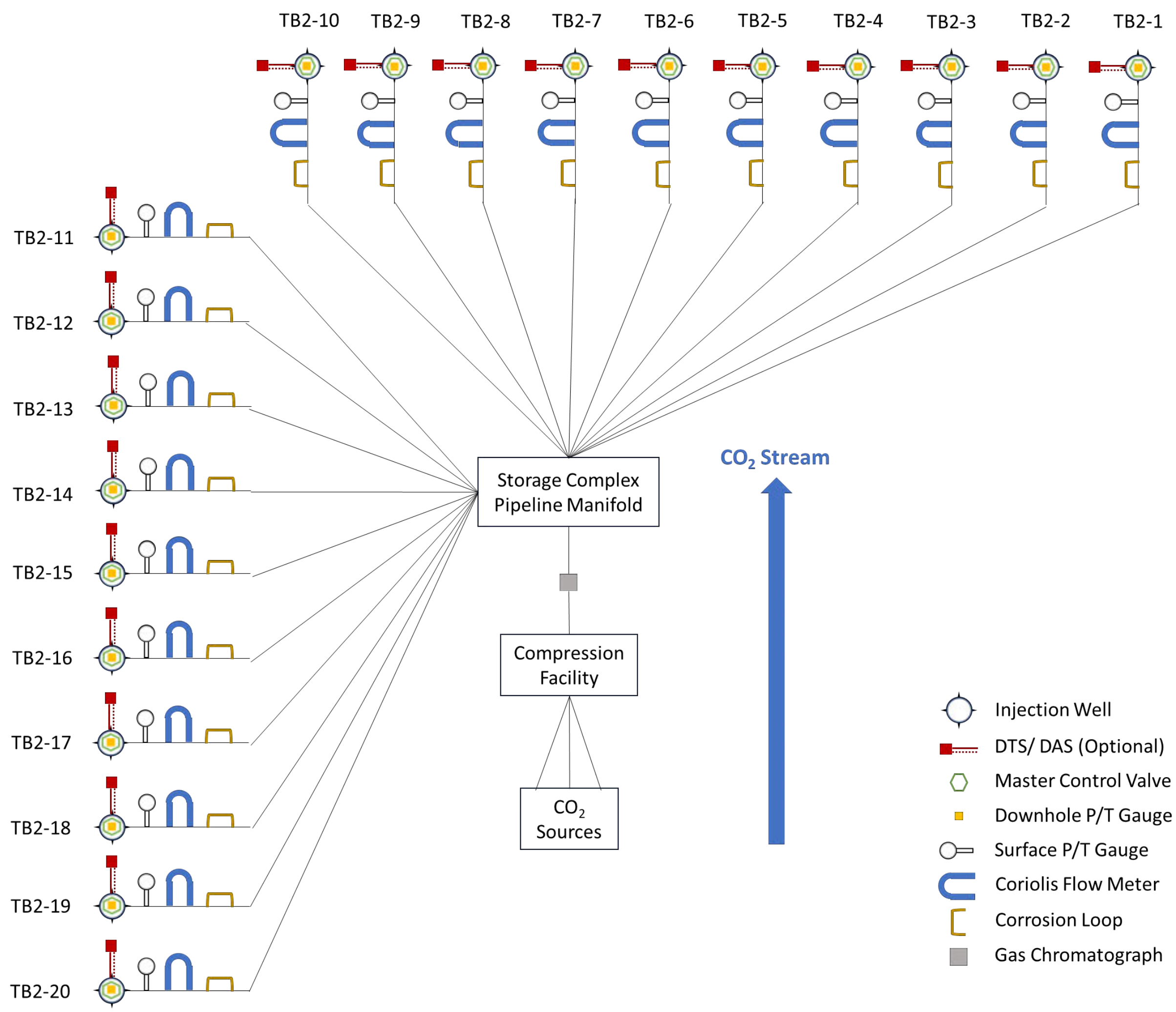

Figure 4: Simplified layout of storage complex depicting location of testing and monitoring equipment at twenty (20) injection well locations. The relative location of each well as depicted and the exact number of pipeline manifolds may not be accurate and may vary depending on field conditions and CO_2 sources. 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 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 $\geq 3\%$ and permeability ≥ 1 md (cutoffs are subject to change based on subsurface data collected during 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 U.S. EPA's UIC Class VI GS Rule (75 FR 77230), is a primary objective of the project's monitoring program as demonstrated by the 7 above-zone, 11 lowermost USDW, and up to ten 10 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.

<table>
<tr><th>Monitoring Category</th><th colspan="2">Monitoring Parameter/Method</th><th>Baseline Frequency (1 year)</th><th>Injection Phase Frequency (30 years)</th><th>Post-Injection Frequency (50 years)</th></tr>
<tr><td>Monitoring Plan Update</td><td colspan="2">Review Every 5 Years
Updated as Required</td><td>N/A</td><td>Update As Required</td><td>Update As Required</td></tr>
<tr><td rowspan="2">CO_2 Injection Stream Analysis</td><td colspan="2">Chemical Characteristics</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td colspan="2">Physical Characteristics</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td rowspan="4">CO_2 Injection Process Monitoring</td><td colspan="2">Injection Rate</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td colspan="2">Injection Physical Characteristics</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td colspan="2">Annulus Pressure Monitoring</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td colspan="2">Annulus Volume Added</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td>Hydrogeologic Testing</td><td colspan="2">Pressure Fall-Off Testing</td><td>1 Prior to Injection[1]</td><td>3 Years After Injection, One (1) Every 5 Years After</td><td>N/A</td></tr>
<tr><td rowspan="3">Injection Well Mechanical Integrity Testing</td><td rowspan="2"><u>Internal</u>
Annulus</td><td>Pressure Test</td><td>1 Prior to Injection[1]</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Pressure Monitoring</td><td>N/A</td><td>Continuous</td><td>Continuous</td></tr>
<tr><td><u>External</u>
Temp.</td><td>1) DTS AND/OR
2) Temp. Log
3) PNC Logging
4) Ultra Sonic CBL
5) Electromagnetic CI Logs</td><td>1 MIT Prior to Injection [1]:

1 OR 2 AND 3-5</td><td>1 MIT Annually:

1 OR One of 2-5</td><td>N/A</td></tr>
<tr><td>Corrosion Monitoring</td><td colspan="2">Corrosion Coupon Testing</td><td>N/A</td><td>Quarterly</td><td>N/A</td></tr>
</table>

Monitoring Category	Monitoring Parameter/Method		Baseline Frequency (1 year)	Injection Phase Frequency (30 years)	Post-Injection Frequency (50 years)
Groundwater Quality and Geochemistry Monitoring	*Fluid Sampling and Analysis*	*Lowermost USDW*	Quarterly – 1 Year Prior to Injection [1]	Quarterly for 1st Year, Annually Thereafter	Annually
		Above-Zone			
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, One (1) Every 5 Years After [1]	One (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). In-zone observation wells (TB2-IOB-1 through TB2-IOB-13) 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.

The 13 in-zone observation wells are planned close to the maximum modeled extent of multiple CO_2 plumes associated with the injection wells in the KIC, 30 years from the start of 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. At this time, strategic placement of the in-zone observation wells is as follows:

- TB2-IOB-1 is placed to the northwest of TB2-1 and TB2-3 wells;
- TB2-IOB-2 is placed to the northwest of TB2-2;
- TB2-IOB-3 is located to the northwest of TB2-4;
- TB2-IOB-4 is located to the northwest of TB2-11 and TB2-13 and to the west of TB2-5;
- TB2-IOB-5 is located to the northwest of TB2-12;
- TB2-IOB-6 is located to the northwest of TB2-14
- TB2-IOB-7 is located to the southeast of TB2-13;
- TB2-IOB-8 is located to the northwest of TB2-6 and TB2-7;
- TB2-IOB-9 is located to the north of TB2-8 and TB2-9;
- TB2-IOB-10 is located to the southeast of TB2-17 and east of TB2-18;
- TB2-IOB-11 is located to the northwest of TB2-19 and TB2-20;
- TB2-IOB-12 is located to the southeast of TB2-8 and TB2-9; and
- TB2-IOB-13 is located to the south of TB2-10 well.

Many of the planned in-zone observation wells are positioned north or northwest of nearby injection wells as mentioned above. This is governed by the expected regional northwest-southeast dip orientation as discussed in subsection 2.4 of the Application Narrative. These locations should allow detection of plume or pressure response up-dip of the injection wells. The 7 above-zone 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 zone of the injection complex with porosity ≥ 3% and permeability ≥ 1 md (cutoffs are subject to change based on subsurface data collected for pre-operational testing for each injection well). While the well completions for these above-zone observation wells will include required instrumentation and monitoring for both of 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 (See subsection 4.1 of the Area of Review and Corrective Action Plan for discussion of APs in the AoR). Tri-State CCS, LLC intends to place above-zone wells relatively close to the injection wells for early detection of containment loss.

The 11 lowermost USDW observation wells 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 selected injection well pad sites to monitor the USDW, i.e., the Sharon Sandstone, directly above and proximal to each injection well.

Up to 10 shallow groundwater observation wells will be placed at strategic locations as backup monitoring should Tri-State CCS, LLC need to monitor the shallow groundwater. Wells have temporarily been placed at selected injection well pad sites, but final 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.

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
Injection Physical Characteristics	1) P Gauges – Tubing 2) DH P Gauges	Continuous	Injection Wells
Annulus Pressure Monitoring	P Gauge - Annulus	Continuous	Injection Wells
Annulus Volume Added	Fluid Tank Volume Meter or suitable alternative	Continuous	Each injection well pad
Internal MIT	P Gauge - Annulus	Continuous	Injection Wells
External MIT	DTS, *OR one of:* Temp. Log, PNC Log, Ultra Sonic CB Log, Electromagnetic CI Logs	1 MIT Annually	Injection Wells; In-Zone Observation Wells
Corrosion	Coupon Analysis	Quarterly	Corrosion loops at injection wells
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; [4] Lowermost USDW Observation Wells
Direct Pressure & Temperature Monitoring	1) P Gauges – Tubing 2) DH P Gauges 3) DTS [3]	Continuous	Injection Wells; In-Zone Observation Wells; Above-Zone Observation Wells; [4] Lowermost USDW Observation Wells
Indirect CO_2 Plume Monitoring Techniques	DTS	Continuous	Injection Wells; In-Zone Observation Wells
	PNC Logging [2]	3 Years After Injection, 1 Every 5 Years Thereafter	Injection Wells; In-Zone Observation Wells
	Repeat 3D DAS VSP/ CSP, Microseismic [3]		TBD
Hydrogeologic Testing	Pressure Fall-Off Testing		Injection Wells

[1] Sampling and analysis frequencies may be changed in consultation with the UIC Program Director 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

the KIC. 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. The stream composition from each source will be constrained through the implementation of a gas tariff on the pipeline operated by Tri-State CCS, LLC. The tariff will mandate maximum allowable concentrations that sources are committed to meeting under the services agreement thus ensuring that the CO_2 delivered to the injection wells is nonhazardous and free from compounds that could contribute to corrosion, other safety issues, or impacts to the formation and caprock.

Since each source will have a different gas stream composition based on the source's capture process, 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. In case more than one manifold is in use to distribute CO_2 among the 20 injection wells, more than one chromatograph will be installed as required. 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 CO_2 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.

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 either 0.3 MMt/y or 0.5 MMt/y depending on the injection well. Alternatively, they will limit the maximum allowable surface pressures to be between those defined by the boundary cases identified in Table 6. The inequalities in Table 6 define the range of values that the maximum parameter value can take to be considered within safe operating conditions. This pressure will correspond to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure (40 CFR 146.88(a)). See subsection 2.1 of the Summary of Requirements – Class VI Operating and Reporting Conditions for more details on operational conditions.

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

Parameter	Boundary Case Values [1]			
	Boundary A[2] (KIC)	Boundary B[2] (MIC)	Boundary C[3] (KIC)	Boundary D[3] (MIC)
Max. Instantaneous Rate (MMt/y)	≤0.3	≤0.3	≤0.5	≤0.5
Max. Estimated Allowable Surface Pressure (psig)	≤2,670	>1,775	≤2,805	>1,685
Max. injection pressure (psig)	<6,620	>4,060	≤7,306	≥3,945
Minimum annulus pressure at surface (psig)	100	100	100	100
Maximum annulus pressure at surface (psig)	≤2,770	>1,875	≤2,905	≥1,785

[1] Boundary A is defined by KIC injection in TB2-17, Boundary B is defined by MIC injection in TB2-11, Boundary C is defined by KIC injection in TB2-9, and Boundary D is defined by MIC injection in TB2-14. For further details, see subsection 2.1 of the Summary of Requirements – Class VI Operating and Reporting Conditions.

[2] Applicable injection wells defined by Boundaries A & B are TB2-11, TB2-13, TB2-15, TB2-16, TB2-17, TB2-18.

[3] Applicable injection wells defined by Boundaries C & D are TB2-1, TB2-2, TB2-3, TB2-4, TB2-5, TB2-6, TB2-7, TB2-8, TB2-9, TB2-10, TB2-12, TB2-14, TB2-19, TB2-20.

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 American National Standards Institute (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.

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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) Injection Wells; In-Zone Observation Wells 2) Injection Wells; In-Zone Observation Wells	5 sec. / 4 hours	5 mins. / 4 hours
Injection Rate	Coriolis Mass Flow Meter	Injection Wells	5 sec. / 4 hours	5 mins. / 4 hours
Injection Volume	Coriolis Mass Flow Meter	Injection Wells	5 sec. / 4 hours	5 mins. / 4 hours
Annular Pressure	Annular P Gauge	Injection Wells	5 sec. / 4 hours	5 mins. / 4 hours
Annulus Fluid Volume	Fluid Tank Volume Meter	Injection Wells	5 sec. / 4 hours	5 mins. / 4 hours
Injection Temperature Monitoring	DTS	Injection Wells; In-Zone Observation Wells	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 Rose Run Sandstone. 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 MIC or KIC) 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 the KIC, the Rose Run Sandstone will have the ported DH instrumentation. Once the planned injection in the

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.

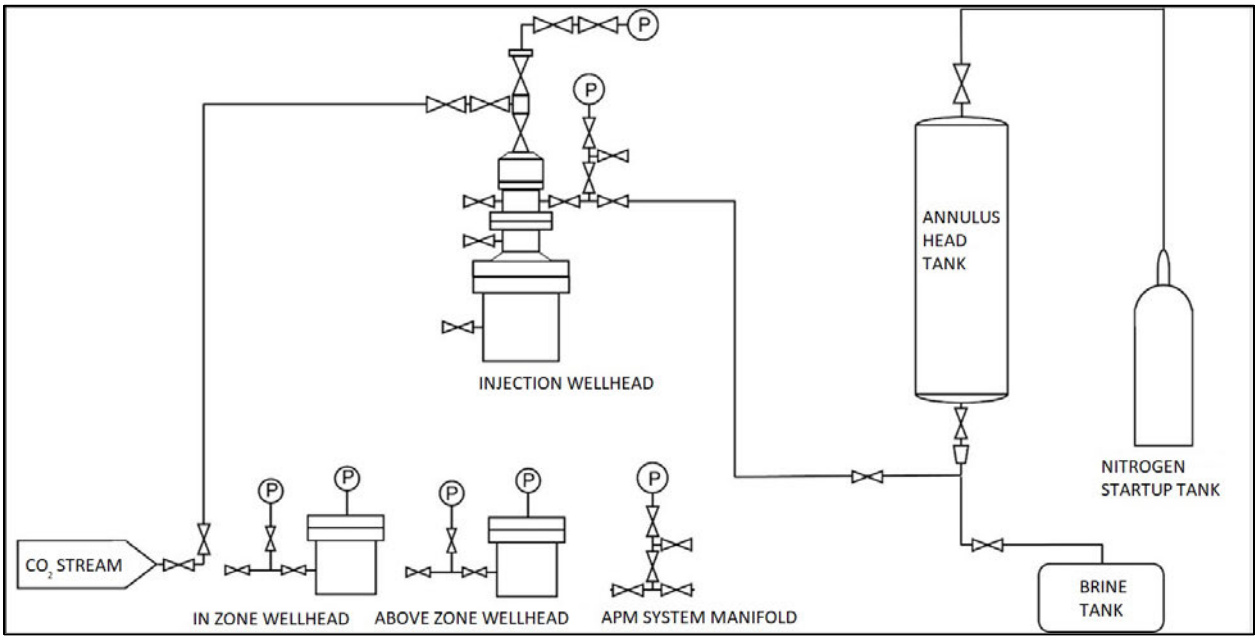

Figure 5: Annular monitoring system.

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 (Rose Run Sandstone and Medina Group) 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. Corrosion Monitoring

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

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

5.1. Monitoring Location and Frequency

Corrosion monitoring will occur on a quarterly basis during the injection phase, 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 all types of materials used in the construction of compression equipment, pipeline, and wells that will be in contact with the CO_2 stream will be included in the corrosion monitoring program. As an example, 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.[1]

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, P110, Premium Connection
Long String Casing	Injection Zones [2]	26 lb/ft, 22Cr-110 or higher alloy, Premium Connection
Injection Tubing	Both KIC and MIC injection	12.6 lb/ft, 22Cr-110, Premium Connection
Wellhead		Carbon/ low alloy steel or Stainless steel or CRA [3]
Packers	KIC Injection Zone	Baker Hughes Premier Packer
	MIC Injection Zone	22Cr-110 or Higher Alloy

[1] For additional well design details, please refer to the Construction Details for each injection well.

[2] For exact depth, refer to the Construction Details for each injection well for each injection well.

[3] Corrosion Resistant Alloy

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 gas compositions that meet the minimum composition shown in Table 5 but may have slight differences based on the source or sources that comprise the CO_2 stream. 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:

- Mechanical Casing Evaluation Tools: referred to as calipers, these tools have multiple articulated arms attached to the tool that measure the inner diameter of the tubular as the caliper is raised or lowered throughout the well.
- Ultrasonic Tools: these tools measure wall thickness in addition to the inner diameter of the well tubular and can also provide information about the outer surface of the casing or tubing.
- Electromagnetic Tools: these tools are capable of distinguishing between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated.

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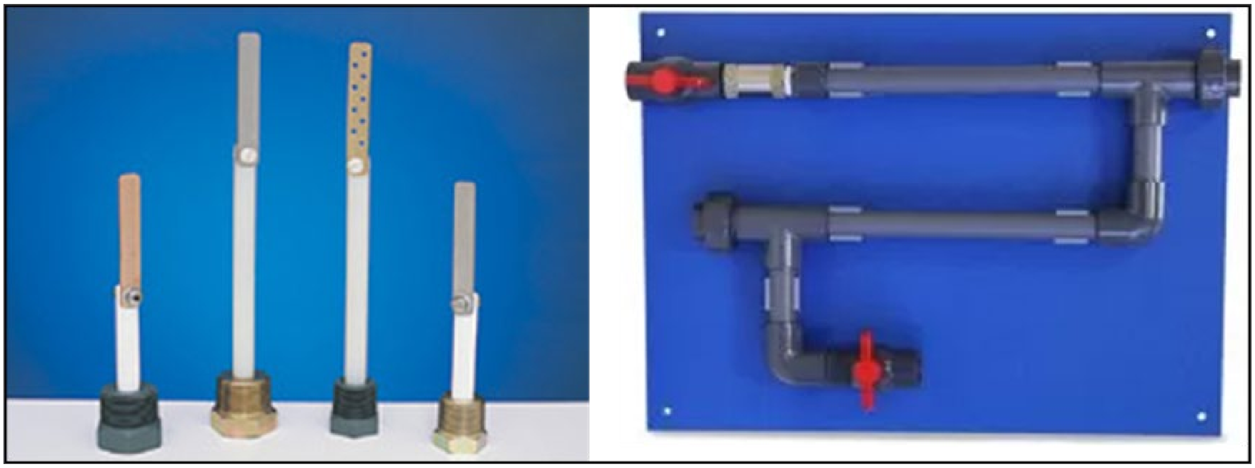

Figure 6: (Left) Example of corrosion coupon holders. (Right) Flow through pipe arrangement example.

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 Formation 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 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 Rose Run Sandstone and Medina Group (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 from 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 above-zone and in-zone observation wells are spatially displayed in Figure 3. Notably, the above zone observation wells are co-located at selected injection well pads. While the lowermost USDW observation wells are tentatively planned to be sited at selected injection well pads, their exact location, as well as that of the shallow groundwater observation 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.

Table 9: Monitoring geochemical and physical changes.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage [3]	Frequency
Sharon Sandstone (Lowermost USDW)	*Geochemical Monitoring*: Direct Fluid Sampling	Lowermost USDW Observation Wells	11 Well Locations Vertical (ft. MD): TB2-UOB-1: ~ 1,037 TB2-UOB-2: ~ 784 TB2-UOB-5: ~ 820 TB2-UOB-9: ~ 966 TB2-UOB-10: ~ 755 TB2-UOB-12: ~ 768 TB2-UOB-13: ~ 803 TB2-UOB-14: ~ 726 TB2-UOB-17: ~ 931 TB2-UOB-19: ~ 921 TB2-UOB-20: ~ 812	Quarterly for first year [1], annually thereafter. [2]
	Physical Monitoring: Downhole P Gauges			Continuous
TBD (First permeable unit over confining zones of each injection complex)	*Geochemical Monitoring*: Direct Fluid Sampling	Above-Zone Observation Wells	7 Well Locations Vertical (ft. MD): [4] TB2-AOB-1: ~TBD TB2-AOB-2: ~TBD TB2-AOB-3: ~TBD TB2-AOB-4: ~TBD TB2-AOB-5: ~TBD TB2-AOB-6: ~TBD TB2-AOB-7: ~TBD	Quarterly for first year [1], annually thereafter [2]
	Physical Monitoring: Downhole P Gauges			Continuous
Rose Run Sandstone and Medina Group	*Physical Monitoring*: Downhole P Gauges	In-Zone Observation Wells	13 Well Locations Vertical (ft. MD)	Continuous [5]

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage [3]			Frequency
(Injection Interval)			**Well**	**Medina Group (ft MD)**	**Rose Run Sandstone (ft MD)**	
			TB2-IOB-1	~ 6,371	~ 9,642	
			TB2-IOB-2	~ 6,297	~ 9,508	
			TB2-IOB-3	~ 6,358	~ 9,664	
			TB2-IOB-4	~ 6,357	~ 9,713	
			TB2-IOB-5	~ 6,285	~ 9,591	
			TB2-IOB-6	~ 6,298	~ 9,605	
			TB2-IOB-7	~ 6,763	~ 10,262	
			TB2-IOB-8	~ 7,162	~ 10,726	
			TB2-IOB-9	~ 7,504	~ 11,315	
			TB2-IOB-10	~ 7,261	~ 10,749	
			TB2-IOB-11	~ 6,796	~ 10,110	
			TB2-IOB-12	~ 7,999	~ 11,793	
			TB2-IOB-13	~ 7,746	~ 11,457	

[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 during 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 various units 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 ten 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.

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Table 10: Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods
Lowermost USDW (Sharon Sandstone) and Above-Zone (TBD [1]) Observation Wells	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, U.S. EPA Method 6020B (2014a) or U.S. EPA Method 200.8 (1994a)
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, U.S. EPA Method 6010D (2014b) or U.S. EPA Method 200.7 (1994b)
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, U.S. EPA Method 300.0 (1993)
Isotopes: δ^{13} C of DIC	Isotope ratio mass spectrometry
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16 (2016) Gravimetry, APHA 2540C (1997) Oscillating body method APHA 2320B (1997) U.S. EPA 150.1 (1982) APHA 2510 (1997) 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 during 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 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	Injection Wells
External MIT	DTS	Continuous	Injection Wells -- Depths: Surface to Casing TD (Cemented Casing String) In-Zone Observation Wells -- Depths: Surface to TD

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, 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	One (1) prior to injection, one (1) three years from the start of injection, and one (1) every five years thereafter until well abandonment.[1]	Injection Wells

[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 injection 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 (Rose Run Sandstone and Medina Group) 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 and Figure 8. 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 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 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 observation 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 observation wells.

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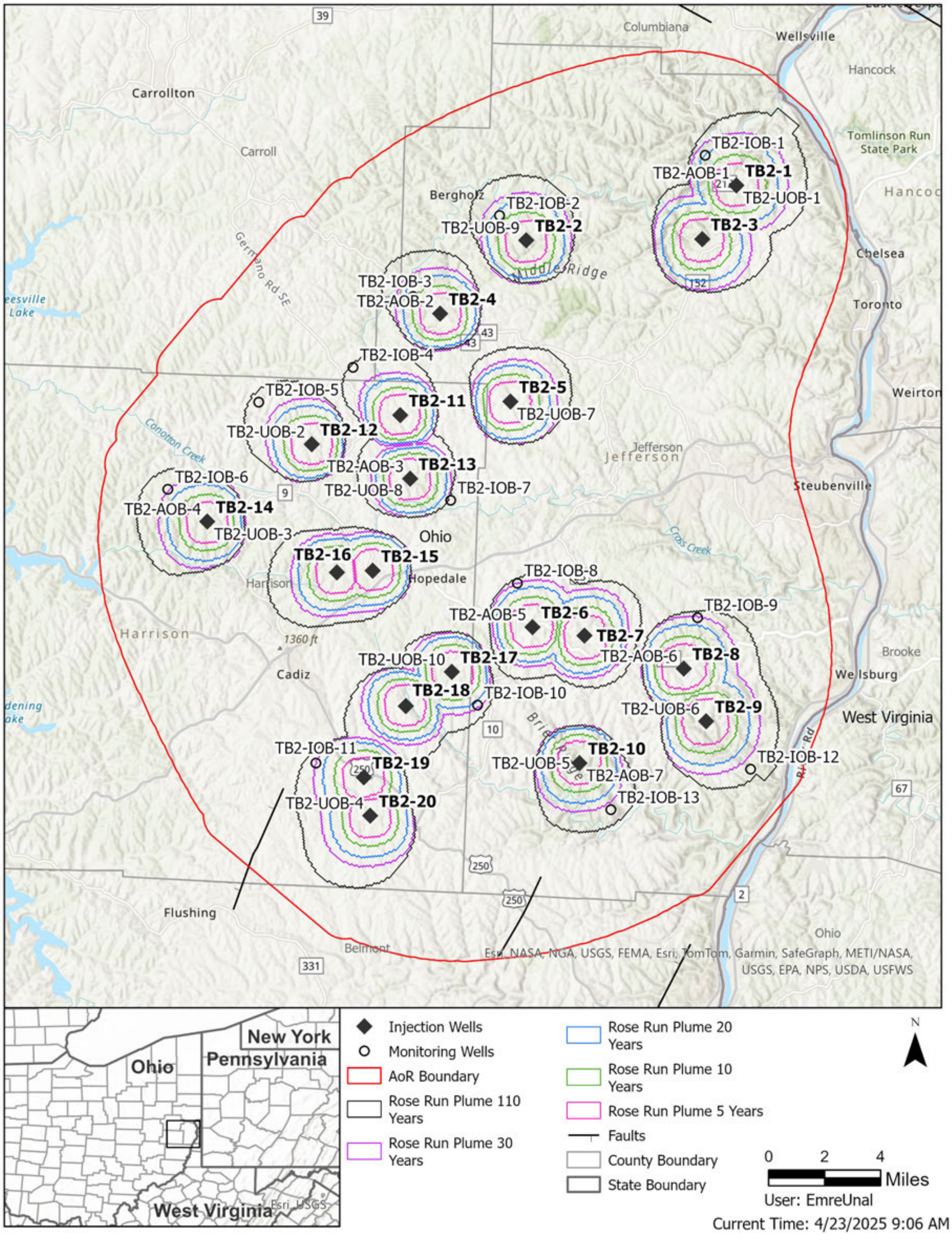

Figure 7: Project CO_2 plume evolution map after 30 years of injection and 80 years post-injection into the KIC.

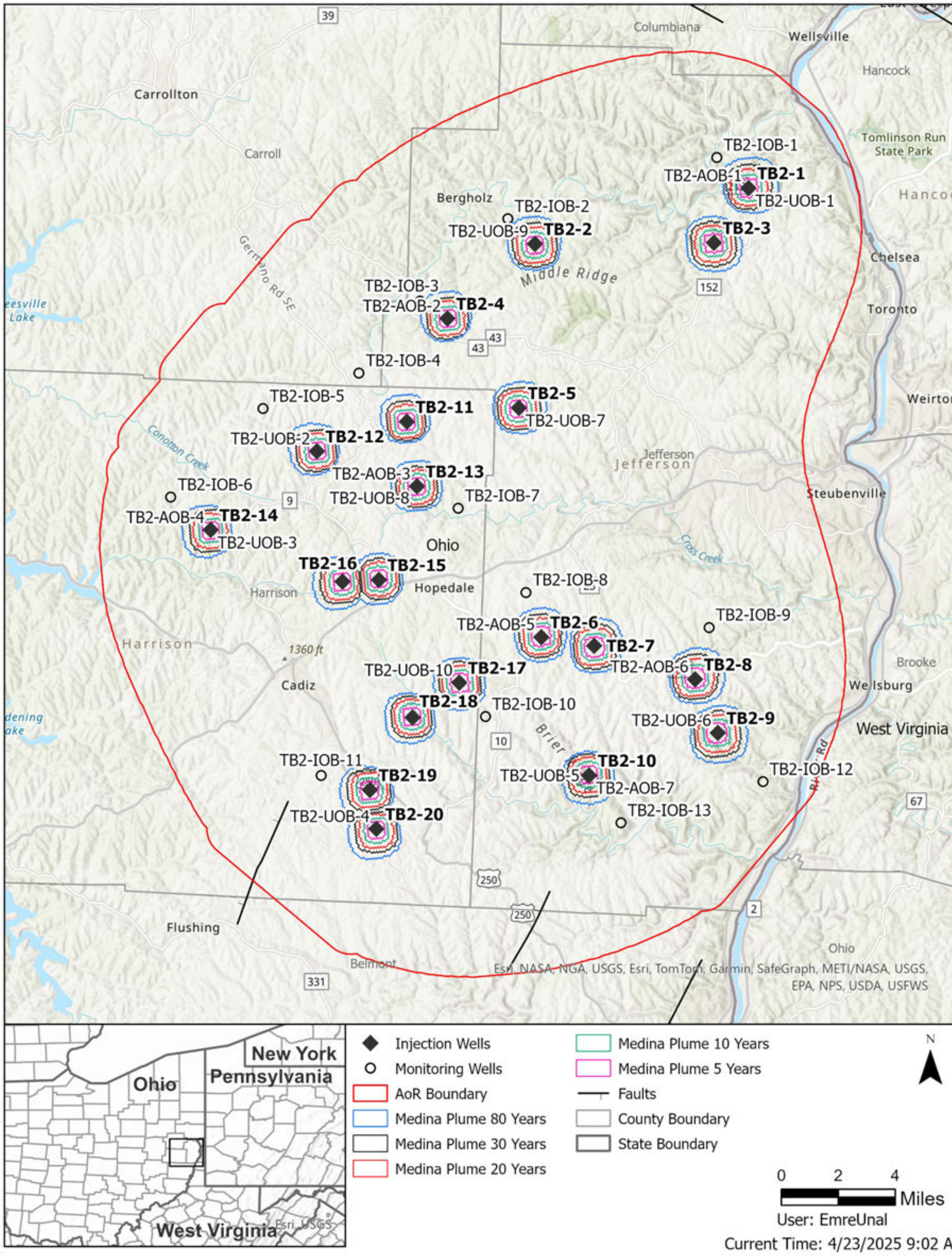

Figure 8: Project CO_2 plume evolution map after 30 years of injection and 50 years post-injection into the MIC.

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 and Figure 8. 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 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 reveal relatively high injectivity units within the reservoir zone taking fluid. At the in-zone observation wells, the DTS data will allow for detection of CO_2 breakthrough. PNC logging at injection wells will also reveal units with higher injectivity as well as provide quantitative measurements of CO_2 saturation within those units. Statistical approaches, e.g., normality testing, etc., will be used to identify CO_2 breakthrough at monitoring locations. PNC logging will occur in the injection wells as per the schedule specified in this section. PNC logging will also be run in any in-zone observation well if there is a suspected CO_2 breakthrough, or any above-zone/ lowermost USDW observation wells with 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. This data may 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
Rose Run Sandstone and Medina Group (Injection Intervals)	DTS	Injection Wells; In-Zone Observation Wells	Continuous
	PNC Logging	Injection Wells	Three years after injection begins, and every five years thereafter during the injection period.[1]
	PNC Logging	In-Zone Observation Wells; Above-Zone Observation Wells; Lowermost USDW Observation Wells	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 (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 lowermost USDW 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 lowermost USDW observation wells. Injection and in-zone observation wells will monitor the evolution of the CO_2 plume in the Rose Run Sandstone and Medina Group reservoirs during injection. Above-zone and lowermost USDW 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 Formation 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.

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Table 14: Direct pressure-front injection phase monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Sharon Sandstone (Lowermost USDW)	P Gauges	Lowermost USDW Observation Wells	Above Packer - Ported to Sharon Sandstone (Aquifer)	Continuous
TBD [1] (First Permeable Unit Above the Confining Zones of KIC and MIC)		Above-Zone Observation Wells	Above Packer - Ported to the formations to be monitored	Continuous
Rose Run Sandstone and Medina Group (Injection Intervals)		Injection Wells; In-Zone Observation Wells	Above the Packer – Ported to Upper Medina and Knox Groups depending on the active injection zone in a given well	Continuous

[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 $\geq$ 3% and permeability $\geq$ 1 md. These cutoffs are subject to change based on subsurface data collected during 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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Appendix A: Quality Assurance and Surveillance Plan (QASP)

The appendix is available as a separate attachment named "07_TB2_AppA_QASP_R0_20250926.pdf"