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7. TESTING AND MONITORING PLAN
40 CFR 146.90

HEARTLAND GREENWAY STORAGE PROJECT

Facility Information

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7.1. Overall Strategy, Approach, and Conceptual Design for Testing and Monitoring

The Testing and Monitoring Plan describes how Heartland Greenway Carbon Storage, LLC (HGCS) will monitor the Heartland Greenway Storage Site (HGSS) pursuant to 40 CFR 146.90.[1] In addition to demonstrating that the wells are operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support 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*.

7.1.1. Plan Objectives

HGCS's testing and monitoring will cover three main aspects of the GS project during the project injection phase:

1. Well Integrity

2. Operational Parameters

[1] EPA (U.S. Environmental Protection Agency). 2010. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells Final Rule (40 CFR 146.93). Washington, D.C.

3. Geologic System Changes

Demonstrating the mechanical integrity of the wells in the system is a key aspect of protecting USDWs from endangerment due to injection activities and is a requirement of the UIC Class VI program. The operational testing and monitoring includes: 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 includes: ground water quality and geochemical monitoring above the confining zone; direct pressure front monitoring, and direct/indirect CO_2 plume monitoring.

7.1.2. Plan Strategy and Approach

The Testing and Monitoring Plan aims 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 and will be reviewed by HGCS every five years. HGCS will submit an amended Testing and Monitoring Plan or demonstrate to the Program Director that no amendment to the plan is needed. HGCS recognizes that the nexus of data collection and modeling is prescribed as the primary pathway to exit the UIC permit, define the post-injection site care (PISC) protocols, and close the CO_2 storage project as noted in the CCS Protocol. As such, HGCS established a monitoring program capable of tracking the injected CO_2 and developing time-lapse datasets for numerical modeling, both of which are critical for demonstrating the capacity to 1) predict the evolution of the CO_2 plume and pressure front and 2) demonstrate non-endangerment to allow for exiting the CO_2 storage site established by the UIC .

The surface/subsurface monitoring protocols to be used in the Testing and Monitoring Plan at HGSS will provide valuable information to evaluate the performance of the CO_2 injection and storage operations and 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.

For example, the above datasets can be used in conjunction with rigorous geologic characterization to validate robust numerical reservoir models for tracking the CO_2 plume and pressure front, which is essential for establishing non-endangerment of the USDWs.

This plan describes components of the geologic testing and monitoring program, which includes hydraulic, geophysical, and geochemical components for characterizing the complex fate and transport processes associated with CO_2 injection. The injection wells and in-zone monitoring wells in the target injection interval (Mt. Simon) will be monitored for the duration of the project to characterize pressure and CO_2 transport response and to guide operational and regulatory decision-making. In-zone monitoring results, along with those from above-zone monitoring wells installed directly above the Eau Claire shale primary confining zone in the first permeable unit (Ironton Formation) will provide the first indication of any unanticipated containment loss.

Deep above-zone monitoring wells will be completed in the permeable unit of the Ironton Formation to detect changes in the groundwater conditions and to ensure protection of USDWs. All monitoring wells will have direct monitoring of pressure and temperature in multiple zones. Protection of USDW's, required by the EPA's UIC Class VI GS Rule (75 FR 77230)[2], is a primary objective of the monitoring program at the HGSS as demonstrated by the six above-zone and 17 shallow USDW monitoring wells. Fluid samples will be collected from these wells in the Ironton Formation (above-zone) and shallow sand and gravel aquifer (shallowest USDW in Christian County). The six above-zone monitoring wells will provide early detection of any out-of-zone CO_2 allowing HGCS to demonstrate non-endangerment to USDW or groundwater aquifers. The associated networks of above-zone and shallow ground water monitoring locations are designed to provide 1) a thorough assessment of baseline conditions at the site and 2) spatially distributed monitoring locations near point sources that can be routinely sampled throughout the life of the project.

HGCS's characterization of the subsurface environment indicates that there is minimal risk of contaminating USDWs. Minimal surface disruption is anticipated by completing multiple monitoring wells on a single well pad, where applicable. No known faults, existing well penetrations, or other potential pathways pose a leakage risk within the AoR of the project. In-zone project wells will represent the only and highest existing risk and will be monitored for potential CO_2 leakage.

7.1.3. Conceptual Monitoring Network Design

The monitoring network design was developed based on the characterization and modeling of the HGSS. This section describes the indirect and direct monitoring network that will be used to support collection of the various characterization and monitoring measurements needed to track development of the CO_2 plume within the injection zone and identify/quantify any potential release of CO_2 from containment.

For a general schematic of pipeline monitoring equipment locations refer to the QASP Attachment B. Figure 7-1 shows the well monitoring network that will be used to ensure confinement of CO_2 within the reservoir and provide evidence of non-endangerment of USDWs.

[2] Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide. 75 FR 75078.

Well locations on the map show the approximate locations and are subject to change based on surface land access agreements currently under negotiation. Changes made should be no more than ± 300 feet from the location indicated on Figure 7-1. The figure also shows the maximum plume extent and maximum lateral pressure front that define area of review (AoR). Description of the AoR delineation for the HGSS can be found in the *AoR and Corrective Action Plan* section of this permit. Note that the monitoring design will be modified as required based on landownership approval of well locations, the results of the 3D DAS VSP feasibility study, and any additional site-specific characterization data collected at the HGSS .

Sensitive, Confidential, or Privileged Information

[redacted]

Figure 7-1. The HGSS showing the locations of injection wells (yellow circles), in-zone monitoring wells (white squares with red labels), above-zone monitoring wells (white squares with blue labels), shallow groundwater monitoring wells.

Sensitive, Confidential, or Privileged Information

[redacted]

[redacted] This monitoring network is designed for early detection of out-of-zone CO_2 and brine migration at to ensure protection of USDWs. In-zone monitoring wells were chosen at locations on the margin of the final CO_2 plume extent to bound and ensure its containment. Above-zone wells were chosen in regions above the storage complex that are predicted to experience the highest-pressure differentials (i.e., highest leakage risk) for increased early leak detection to reduce risk of USDW contamination. Both sets of well locations were also chosen to provide data with necessary spatial coverage to track both plumes during injection and to optimize monitoring during the PISC. Shallow groundwater well locations were chosen at each well nest to monitor groundwater. All monitoring well data will contribute to the non-endangerment demonstration for site closure. Below are descriptions of the various wells and respective monitoring technologies to be deployed in each well type:

- **CO_2 Injection Wells (NCV-[1-6]).** Six CO_2 injection wells are centrally located within the HGSS and will be drilled to the Precambrian and then plugged back and completed in the Mt. Simon formation. These wells will be equipped with continuous distributed temperature sensing (DTS) fiberoptic systems and downhole pressure/temperature gauges. The DTS fiberoptic cable will run from surface to TD and identify temperature changes that could be caused by external mechanical integrity issues in the well. The downhole pressure/temperature gauges will be set near the injection interval to monitor pressure to ensure pressures do not exceed 90% the fracture pressure. Each well will be perforated in the injection interval (Mt. Simon A and B).

- **In-Zone Monitoring Wells (NCV-OB-MS [1-6]).** Six in-zone monitoring wells will be drilled and completed in the Precambrian basement. These wells will be equipped with continuous monitoring equipment such as DTS, distributed acoustic sensing (DAS) fiberoptic systems, and downhole pressure/temperature gauges. The DTS fiberoptic cables will run from surface to TD to help identify CO_2 breakthrough and location within the Mt. Simon formation. The DTS will also serve to monitor the mechanical integrity of the well by identifying temperature changes that could be caused by mechanical integrity well issues. The DAS fiberoptic cables will run from surface to TD and monitor induced seismicity that may pose a risk to the project and for timelapse 3D DAS VSP plume imaging. Downhole pressure and temperature gauges will be set at the Eau Claire caprock, top of the injection interval (Mt. Simon B), and below the injection zone in the Argenta Sand to measure pressure changes associated with the project. Well locations were selected to bound and be within the CO_2 plume to ensure lateral containment.

- **Above-Zone Monitoring Wells (NCV-OB-I [1-6]).** Six above-zone monitoring wells will be drilled and completed in the Ironton Formation. These wells will be equipped with DTS, DAS, and downhole pressure/temperature gauges. The DTS fiberoptic cables will run from surface to TD to identify temperature changes that could be associated with fugitive CO_2 breakthrough. The DTS will also identify temperature changes that could be caused by any external mechanical integrity well issues. DAS fiberoptic cables will run from surface to TD and monitor induced seismicity that may pose a risk to the project and for timelapse 3D DAS VSP plume imaging. Downhole pressure and temperature gauges will be set in the Ironton Formation to continuously record to look for changes that might indicate a potential brine or CO_2 leak. Baseline geochemistry measurements of the reservoir and injection zone formation fluids will be taken, and results compared to injection phase fluid sample geochemistry. Above-zone well locations were strategically chosen to be above the predicted plume to allow early detection of any vertical leakage out of the injection zone.
- **Shallow Ground Water Monitoring Wells (NCV-OB-SG [1-17]).** Seventeen shallow ground water wells will be completed in a known, shallow USDW. The likely target zone for these shallow ground monitoring wells will be in Quaternary sediments less than 200 feet deep. Ground water sampling will be conducted quarterly during the start of the injection phase with a reduction in sample frequency occurring based on project specific benchmarks. Shallow ground water wells are sited close to every well in the project as the deeper wells represent high leakage risk locations within the project AoR.

The monitoring network will address CO_2 subsurface movement uncertainties by adopting an "adaptive" monitoring approach (i.e., the monitoring approach will be adjusted as needed based on observed monitoring and updated modeling results). This monitoring approach will involve continually evaluating monitoring results and adjusting the monitoring program as needed, including the option to install additional wells in outyears to verify CO_2 plume and pressure front evolution and/or evaluate leakage potential. Any changes to the testing and monitoring approach will be made in consultation with the Program Director.

A summary of the planned monitoring and testing activities and frequencies that HGCS will employ during the project duration are provided in Table 7-1.

Table 7-1. Monitoring Frequencies by Method and Project Phase.

Monitoring Category	Monitoring Method	Baseline Frequency (1 year)	Injection Phase Frequency (30 years)	Post-Injection Frequency (15 years)
Monitoring Plan Update	Reviewed every 5 years. Updated as required	N/A	As required	As required

Monitoring Category	Monitoring Method		Baseline Frequency (1 year)	Injection Phase Frequency (30 years)	Post-Injection Frequency (15 years)
CO_2 Injection Stream Analysis	Continuous monitoring of injection stream composition		N/A	Continuous	N/A
CO_2 Injection Process Monitoring	Continuous monitoring of injection process (injection rate, pressure, and temperature; annulus pressure and volume)		N/A	Continuous	N/A
Hydrogeologic Testing	Injection well pressure fall-off testing		1 Prior to injection	1 per every 5 years	N/A
Injection Well Mechanical Integrity Testing	*Internal*	Continuous annulus pressure monitoring of pressurized annulus	After well completion *(injectors)*	Continuous *(injectors)*	NA
	External	Distributed Temperature Sensing	After well completion *(injectors/monitors)*	Continuous *(injectors/monitors)*	Continuous *(monitors)*
Corrosion Monitoring	Corrosion coupon testing (well and pipeline materials)		N/A	Quarterly	N/A
Groundwater Quality and Geochemistry Monitoring (Above-Zone)	Above-Zone & Shallow Groundwater Fluid sampling		Quarterly, 1 yr. prior to injection	Quarterly*	1 per every 5 years*
Direct Pressure Monitoring	Electronic P/T gauges		1 yr. prior to injection	Continuous	Continuous
Indirect Plume Monitoring Techniques	*Fiber/Wireline*	DTS-DAS	1 yr. prior to injection	Continuous	Continuous
		PNC Logging	1 yr. prior to injection	Variable (min. 1 per every 5 years.)	1 per every 5 years
	Seismic	Timelapse 3D DAS-VSP Surveys	1 prior to injection	1 per every 5 years	1 per every 5 years

*Frequency to be reduced based on baseline results and project specific benchmarks.

7.1.4. 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 in the Appendix to this Testing and Monitoring Plan.

7.1.5. Reporting Procedures

HGCS will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

7.2. Carbon Dioxide Stream Analysis

HGCS will continuously analyze the source CO_2 streams during the operation period to yield data representative of its chemical and physical characteristics pursuant to 40 CFR 146.90(a). Project CO_2 will be sourced from ethanol generation, fertilizer generation, and post combustion generation. A Programmable Logic Controller (PLC), and a flow computer for measurement will be used at each booster station, capture site and sequestration site as the basic process control system. A small PLC or RTU will be used for monitoring and control at the block valve stations. Downstream of each capture location and prior to inlet to the HGS pipeline system, a Rosemount 700XE or similar gas chromatograph (Figure 7-2) will be utilized to sample CO_2 streams at intervals between 15-45 min that will establish the composition of the stream and correlate to the measurement quantity captured by the Sr Orifice (Daniel Sr Orifice or similar) custody transfer meter. A continuous gas analyzer (Rosemount XEXF or similar) will also be installed upstream of the metering facility that will monitor (every 2-10 sec) the stream to ensure the quality of stream meets the specified HGSS CO_2 quality specifications (Table 7-2) and can isolate the delivery to the stream in the event of out of tolerance (high water/H_2S/etc.) stream.

7.2.1. Location and Frequency

The gas chromatograph will be placed at every source receipt point located prior to entering the shared stream pipeline. A master gas chromatograph will be placed downstream of all source points prior to entering the storage complex pipeline. Measurements will be taken and recorded at a minimum frequency of one record every 15 minutes and analyzed for compliance with the minimum CO_2 composition requirements set forth by HGCS.

7.2.2. Analytical Parameters

The gas chromatograph will be measure for the minimum composition of the injectate found in Figure 7-2 and any additional analytes from the expected CO_2 composition upstream from capture equipment for all source types which can be found in the QASP.

Table 7-2. Required CO_2 Composition Downstream of Capture Equipment.

Component		Value	Unit
Minimum CO_2		>98	mol%, dry basis
Water Content		<20	Lb./MMscf
Impurities (dry basis)	Inerts (N2, Ar, O2)	<2	mol%
	Total Hydrocarbons	<2	mol%
Hydrogen		<1	mol%
Glycol		<1	ppmv
Hydrogen Sulfide		<100	ppmv
Total Sulfur		<100	ppmv
Oxygen		<100	ppmv
Carbon Monoxide		<100	ppmv

Figure 7-2. Emerson Rosemount 700XA process gas chromatograph to be used at each entry node.

7.3. Continuous Recording of Operational Parameters

HGCS 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).

Additionally, utility meters will be installed at each well nest location to record electricity consumption and be incorporated into the mass balance equation used to quantify the amount of CO_2 sequestered at the site as required under the Greenhouse Gas (GHG) Reporting Program Subpart RR of part 98.[3]

HGCS will control continuous monitoring using a distributive process control system that continuously and automatically transmits monitoring data to surface equipment and the control system. The HGCS operations staff will use this system to continuously monitor, control, record, and automatically alarm and shutdown operations if specified control parameters exceed their normal operating range. More specifically, 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. HGCS supervisors and operators will have the capability to monitor the status of the entire system from distributive control centers. Further details on the distributive process control system can be found in the QASP.

HGCS will perform the activities identified in Table 7-3. Sampling Locations for Continuous Monitoring. to monitor operational parameters and verify internal mechanical integrity of injection and monitoring. Surface and downhole pressure and temperature instruments will be calibrated annually over the full operational range using ANSI or other recognized standards. Pressure transducers shall have a drift stability of less than 1 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least one every 5 seconds. Temperature sensors will be accurate to within one degree Celsius.

Injection rate (i.e., injection flow) will be monitored with Coriolis mass flowmeters. The flow meters will be located after the last source receipt point and prior to the storage complex. The flowmeter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The flowmeter will be calibrated for the entire expected range of flow rates.

Table 7-3. Sampling Locations for Continuous Monitoring.

Parameter	Device(s)	Location
Injection Pressure Monitoring	Pressure Gauge Downhole Pressure Gauge	Sensitive, Confidential, or Privileged Information [redacted]
Annular Pressure Monitoring	Continuous Annular Pressure Gauge	[redacted]

[3] EPA (U.S. Environmental Protection Agency). 2010. General Technical Support Document For Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU, Greenhouse Gas Reporting program. Office of Air and Radiation. Washington, D.C.

Parameter	Device(s)	Location
Injection Temperature Monitoring	Temperature Gauge Downhole Temperature Gauge Distributed Temperature Sensing (DTS)	Sensitive, Confidential, or Privileged Information [redacted]
Injection Rate & Volume Monitoring	Daniel Sr Orifice Mass Flow Meter	[redacted]

7.3.1. Injection Rate, Volume, and Pressure Monitoring

HGCS will continuously monitor injection rate, volume, and pressure for each CCS 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 placed at location based on manufacturer specifications: immediately upstream of each injector wellhead and downstream of capture, compression, and transport of gas to other injector wells. A total of six mass flow meters will be used at the storage site to record each injection wells rate and volume. HGCS 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 volume of CO_2 injected and to confirm compliance with operational conditions of the Permanence Certification.

Injection pressure will be continuously monitored using wellhead and downhole pressure gauges. Each injection well will be equipped with permanent downhole pressure gauges that will continuously monitor the injection zone pressure to ensure that the injection zone pressures do not exceed 90 percent the reservoir fracture pressure as required by 40 CFR 146.88(a) and will ensure HGCS is compliant with operating conditions. Additionally, each injection well will be equipped with a wellhead pressure logger that will ensure HGCS 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, multiplied by the difference between the injection gradient and the injectate fluid gradient.

The HGCS's surface facility equipment and control system will limit injection zone pressures to ensure they do not exceed 90% of the injection zone fracture pressure pursuant to Section 40 CFR 146.88(a) and surface pressures to the maximum allowable pressure for each well.

7.3.2. Annulus Pressure & Fluid Level Monitoring

HGCS 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:

1. The annulus between the tubing and the long string of casing will be filled with brine. Parameters such as brine specific gravity, brine density, and the annulus hydrostatic gradient. The brine will contain a corrosion inhibitor.
2. The surface annulus pressure will be kept at a minimum pressure (psi) during injection that is specific to the geologic conditions at each injection well.
3. 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.
4. The pressure within the annular space, over the interval above the packer to the confining layer, will be greater than the pressure of the injection zone formation at all times.
5. 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 7-3 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 indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using compressed nitrogen. The HGCS's surface facility equipment and control system will alarm if the surface annulus pressure and annulus pressure differential drop toward their lower limits.

7.3.3. Injection Temperature Monitoring

HGCS will continuously monitor injection temperature at the surface and downhole for each CCS injection well. The wellhead pressure logger will also continuously measure and record wellhead temperature and be used as a backup should the DTS and/or permanent downhole pressure/temperature gauges fail. HGCS will supply two downhole temperature measurements: permanent downhole temperature gauges and DTS fiberoptic wire. In-well pressure and temperature measurements will be taken using Baker Hughes SureSENS QPT Elite permanent downhole gauge. Silixa's XT- or ULTIMA-DTS fiberoptic technology will be implemented in the injection and monitoring wells. Both technologies are further discussed in subsequent sections of this plan. Each injection well will contain a permanent temperature gauge proximate to the packer that will measure the temperature of the injectate as it reaches the injection zone. The DTS fiberoptic wire will be run from surface to well total depth (TD) in the injection and monitoring wells. In practice, DTS systems typically provide temperature measurements at 1-meter (m) spacing along the entire cable. This technology will continuously measure the temperature in the formations outside the casing throughout the whole well column. The DTS data will allow for continuous monitoring of external mechanical integrity throughout the operation and post-injection phases of the project.

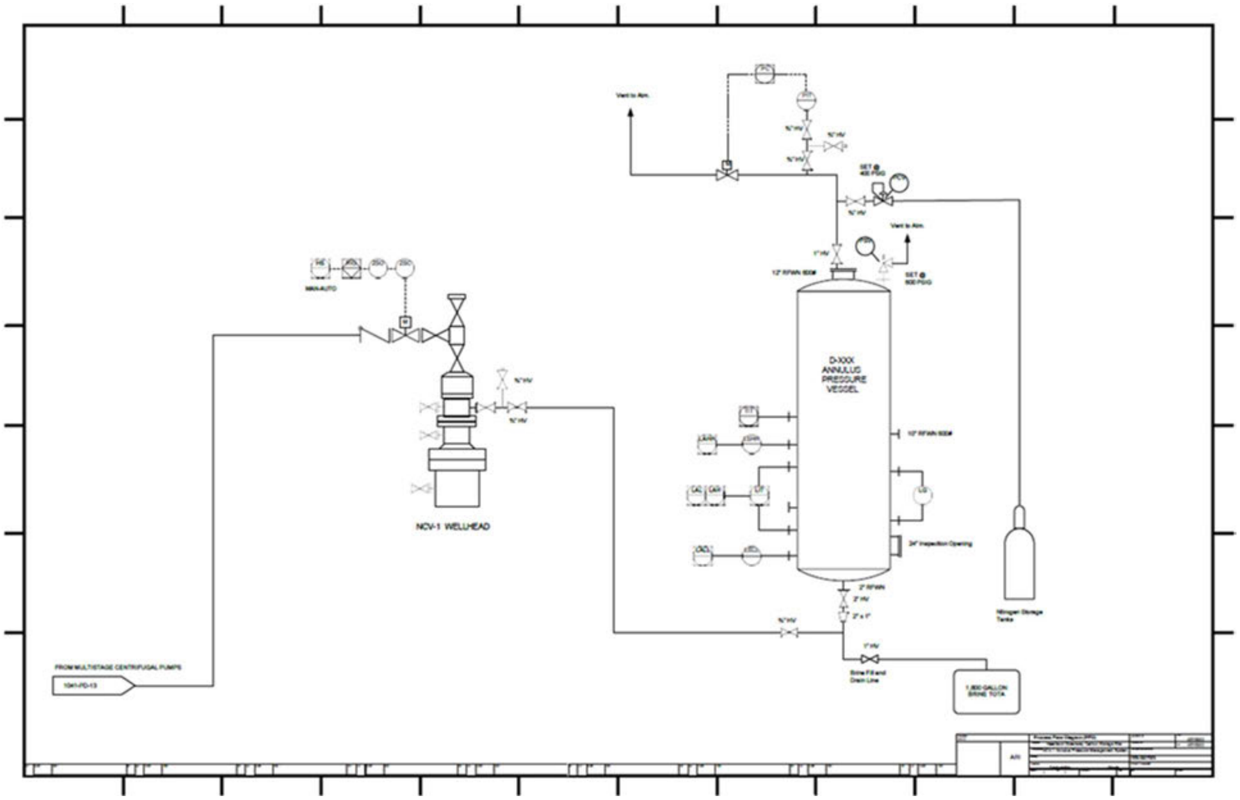

Figure 7-3. Annular Monitoring System General Layout.

7.4. <u>Corrosion Monitoring</u>

7.4.1. Monitoring Location and Frequency

HGCS will monitor well material for corrosion during injection operations pursuant to 40 CFR 146.90(c). Monitoring will look for loss of mass, thickness, cracking, pitting, and other indicators of corrosion to ensure well components meet the minimum standards for material strength and performance. Corrosion monitoring will occur on a quarterly basis during the injection period, by the following dates each year:

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

HGCS will monitor for corrosion using corrosion coupons in a closed loop system.

7.4.2. Sample Description

Samples of materials used in the construction of compression equipment, pipeline and any wells which encounter CO_2 will be included in the corrosion monitoring program. The samples will be comprised of those items listed in Table 7-4. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 7-4. List of Equipment Coupons with Material of Construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel, API 5L PSL-2, X70, ERW
Long String Casing	Carbon Steel
Long String Casing	13CR80 alloy
Injection Tubing (*Surface to Terminal Depth)	13CR80 Alloy
Wellhead	Chrome Alloy
Surface Manifold (Christmas Tree)	Chrome Alloy
Packers	13CR80 Alloy

*Refer to the *Well Construction* and *Operations Plans* section for specific elevations for each injection well

7.4.3. Sample Exposure

Each sample will be attached to an individual holder and then inserted into a flow-through pipe arrangement (Figure 7-5) attached to the pipeline. The corrosion monitoring systems will be located upstream of the wellhead and downstream the injection well control valve (Figure 7-4). 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 samples to the CO_2 composition, temperature, and pressures that will be observed at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design plan and will allow for continuation of CO_2 injection during sample removal.

7.4.4. *Sample Monitoring and Handling*

Corrosion coupons will be handled and evaluated for corrosion using the American Society of Testing and Materials (ASTM 2003)[4], Standard practice for preparing, cleaning, and evaluating corrosion test specimens (ASTM 2017)[5]. 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 gm.

[4] American Society for Testing and Materials (ASTM) Standard G1. 2003. Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens, ASTM International, West Conshohocken, PA. DOI: 10.1520/G0001-03, www.astm.org.

[5] American Society for Testing and Materials (ASTM), 2017, Method G1-03e1, Standard Practice for Preparing, Cleaning, And Evaluating Corrosion Test Specimens, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

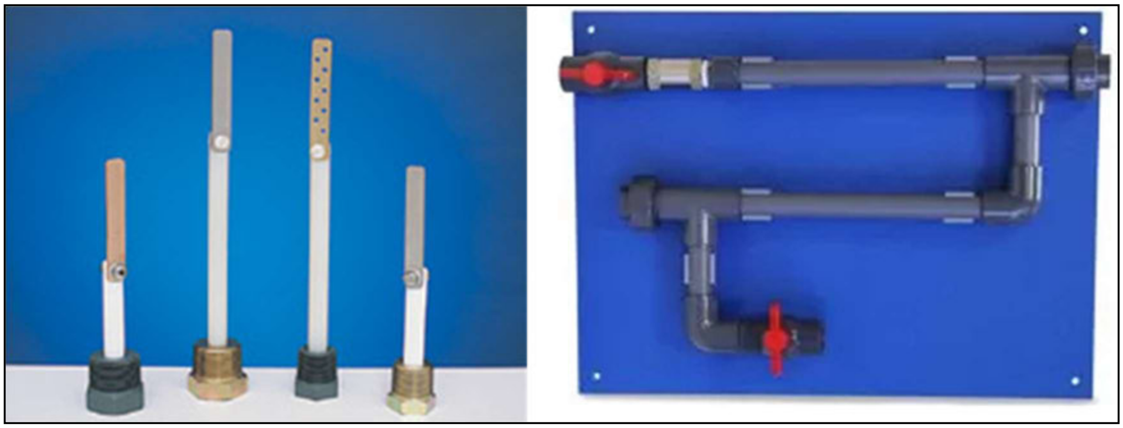

Figure 7-5. (Left) Example of corrosion coupon holders. (Right) Flow through pipe arrangement example.

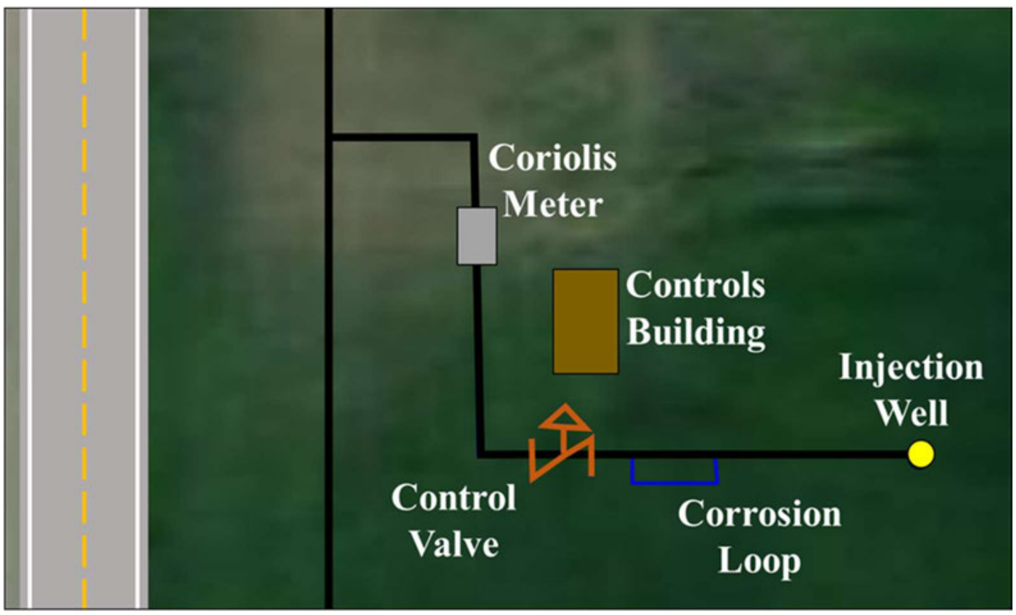

Figure 7-4. Simple layout of NCV-4 well pad location with the Coriolis mass flow meter, control valve, corrosion loop, wellhead, and controls building.

7.5. Above Confining Zone Monitoring

HGCS will monitor groundwater quality and geochemical changes above the confining zone during the baseline pursuant to Section 40 CFR 146.95(f)(3)(i), injection, and post-injection periods as recommended in 40 CFR 146.90(d). This section will discuss the monitoring plan for the injection phase of the project. Groundwater quality and geochemistry monitoring will be conducted through direct fluid sampling and distributed temperature sensing (DTS). Baseline monitoring will be conducted in the Mt. Simon (injection zone) to understand in-zone brine fluid chemistry and to better identify any out-of-zone fluid migration. Baseline groundwater sampling will also occur in the above-zone formations: Ironton (first permeable rock above the confining zone), and major shallow Quaternary sand and gravel aquifers in the region. This section of the permit will focus on the groundwater monitoring during the injection phase of the project with a focusing on the following zones:

- The Cambrian Ironton Sandstone - First permeable zone above the Eau Claire confining zone.
- Shallow Quaternary unconsolidated sediment - local source of drinking water.

In-zone monitoring results, along with those from above-zone monitoring wells (early-detection) installed directly above the primary confining zone (Eau Claire) in the first permeable unit (Ironton), will provide the first indication of any unanticipated containment loss. If a containment loss is detected, a modeling evaluation of any observed CO_2 migration above the confining zone would be used to assess the magnitude of containment loss and make bounding predictions regarding the expected impacts on shallower intervals, and ultimately, the potential for adverse impacts on USDW aquifers and other ecological impacts.

7.5.1. Monitoring Location and Frequency

The proposed locations of the 17 Quaternary shallow groundwater and six above-zone Cambrian Ironton monitoring wells can be seen in **Figure 7-1**. These locations are subject to change based on the results of the ongoing land/pore space rights acquisition. The planned monitoring methods, locations, depth intervals and frequencies for groundwater quality above the confining zone are displayed below (Table 7-5). Direct fluid sampling methods and frequency in the injection phase will be dependent on the results of the baseline groundwater fluid sampling.

Table 7-5. Monitoring of groundwater quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Quaternary Unconsolidated sediment (Local drinking water)	Direct fluid sampling	NCV-OB-SG (1-17)	Lateral: 17 point locations Vertical (ft. MD): NCV-OB-SG (1-17) <200	*Quarterly***
Ironton Formation (above-zone)	Direct Fluid Sampling	NCV-OB-I [1-6]	Lateral: 6 point locations Vertical (ft. MD): NVC-OB-I 1: 4823 NVC-OB-I 2: 4748 NVC-OB-I 3: 4710 NVC-OB-I 4: 4642 NVC-OB-I 5: 4607 NVC-OB-I 6: 4627	*Quarterly***
	Direct Pressure Monitoring (P/T Gauge)	NCV-OB-I [1-6]	Lateral: 6 interval each Vertical (ft. MD): NVC-OB-I 1: 4793 NVC-OB-I 2: 4718 NVC-OB-I 3: 4680 NVC-OB-I 4: 4612 NVC-OB-I 5: 4577 NVC-OB-I 6: 4597.5	Continuous

* Depth Intervals are approximate and contingent upon conditions encountered while drilling

** Frequency to be reduced based on baseline results and project specific benchmarks.

7.5.2. Analytical Parameters

Fluid samples collected will be analyzed for geochemical parameters listed below in Table 7-6. Monitoring data will be continuously evaluated throughout the active injection phase, and if specific parameters are determined to be minimally beneficial to meeting the project objectives or cost prohibitive, they will be removed from the strategy.

Table 7-6. Summary of analytical and field parameters for ground water samples.

Parameters	**Analytical Methods**
Unconsolidated sediment (Quaternary), and Ironton Sandstone (Above-Zone)	

Parameters	Analytical Methods
Cations: **Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl**	ICP-MS, EPA Method 6020B[6]
Cations: **Ca, Fe, K, Mg, Na, and Si**----------------------------------	ICP-OES, EPA Method 6010D[7]
Anions: **Br, Cl, F, NO_3, and SO_4**------------------------------------	Ion Chromatography, EPA Method 300.0[8]
Dissolved CO_2-- **Total Dissolved Solids** ------------------------------------ **Alkalinity**-- **pH (field)**-- **Specific conductance (field)**----------------------------- **Temperature (field)**-------------------------------------- **Isotopes: $\delta^{13}C$ of DIC**--------------------------------------	Coulometric titration, ASTM D513-16[9] Gravimetry, APHA 2540C[10] APHA 2320B[11] EPA 150.1[12] APHA 2510[13] Thermocouple Isotope ratio mass spectrometry

[6] U.S. EPA. 2014. "Method 6020B (SW-846): Inductively Coupled Plasma-Mass Spectrometry," Revision 2. Washington, DC.

[7] U.S. EPA. 2014. "Method 6010D (SW-846): Inductively Coupled Plasma-Optical Emission Spectrometry," Revision 4. Washington, DC..

[8] U.S. EPA. 1993. "Method 300.0: Methods for the Determination of Inorganic Substances in Environmental Samples" Revision 2.1. Washington, DC.

[9] ASTM Standard D513-16. 1988 (2016). "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water," ASTM International, West Conshohocken, PA. DOI: 10.1520/D0513-16, www.astm.org.

[10] American Public Health Association (APHA), SM 2540 C, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 20th Edition (SDWA) and 21st Edition (CWA).

[11] Method 2320 B, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 21st Edition, 1997.

[12] U.S. EPA. 1971 (1982). "Method 150.1: pH in Water by Electromagnetic Method", Cincinnati, OH.

[13] American Public Health Association (APHA), SM 2510, 1992. Standard Methods For the Examination of Water and

ICP – Inductively Coupled Plasma; MS – Mass Spectrometry; OES – Optical Emission Spectrometry

7.5.3. Sampling Methods

Sampling will be performed as described in Section B of the QASP, which describes groundwater sampling methods to be implemented, including sampling SOPs (Sections B.2.a-b), and sample preservation (Section B.2.g).

Quality control will be ensured using the methods described in Section B.5 of the QASP.

7.5.4. Laboratory to be used/chain of custody procedures

Sample handling and chain of custody will be performed as described in Section B.3 of the QASP.

7.6. Mechanical Integrity

HGCS will maintain project injection well mechanical integrity throughout the project. A well has mechanical integrity if:

1. There is no internal leak in the casing, tubing, or packer;
2. There is no significant external fluid movement out of the sequestration zone through channels adjacent to the wellbore; and
3. 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).

Internal and external mechanical integrity will be demonstrated during the operation phase of the project. Internal mechanical integrity is required pursuant to 40 CFR 146.90 and 40 CFR 146.89 and will be demonstrated through annulus pressure monitoring. Annulus pressure tests jeopardize the integrity of the pressurized annulus in the injection well and therefore continuous annulus pressure monitoring will be used in place of an annulus pressure test. External mechanical integrity will be demonstrated using continuous DTS fiberoptic cables in the injection, in-zone, and above-zone wells meeting the minimum frequency. Continuous DTS replaces the need for a temperature log and will identify fluid movement along channels adjacent to the well bore in real-time. In addition to identifying injection-related flows behind casing, often small casing leaks can be located using temperature profiles. Mechanical Integrity Testing (MIT) will be

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Wastewater., APHA-AWWA-WPCF, 23th Edition.

conducted every five years in accordance with industry standards and the US EPA Region V's guidance: *Determination of The Mechanical Integrity of Injection Wells*.[14]

The HGCS will notify the Program Director 30 days prior to the intent to conduct mechanical integrity demonstrations. MIT gauges and meters will be calibrated according to the manufacturer's specifications. A descriptive report that includes the results of any mechanical integrity testing will be submitted with the application for CCS Project Certification, and annually, thereafter through the active life of the CCS Project.

Should loss of mechanical integrity be demonstrated through monitoring HGCS will take all steps necessary 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 evidence of substantial endangerment to public health or the environment from any fluid movement out of the intended storage complex, HGCS will implement the Emergency and Remedial Response Plan (40 CFR 146.94), follow reporting requirements (40 CFR 146.91), and restore and demonstrate mechanical integrity prior to resuming injection or plugging the well. If the well loses mechanical integrity prior to the next scheduled test date, then the well will be repaired and retested within 30 days of losing mechanical integrity. If the well lost mechanical integrity prior to the next scheduled test date, and it was repaired, HGCS will submit a descriptive report documenting the type of failure, the cause, the required repairs, and a new test of mechanical integrity following the requirements of section 40 CFR 146.89 in the next quarterly report.

7.6.1. Testing Location and Frequency

Internal mechanical integrity testing will be demonstrated prior to commencement of injection operations pursuant to Section 40 CFR 146.87(a)(4) and is discussed in the Pre-Injection Testing section of this permit. Thereafter, the internal mechanical integrity of each well will be continuously monitored by HGCS using the annulus pressure monitoring pursuant to Section 40 CFR 146.90(b). External mechanical integrity testing will be conducted prior to injection using DTS fiberoptic cables in the wells pursuant to section 40 CFR 146.87(a)(2). External mechanical integrity will be continuously monitored after the external mechanical integrity test pursuant to Section 40 CFR 146.90(e) and run just prior to plugging of the well.

Internal MIT will be conducted using annulus pressure monitoring at each of the 6 injection wells. External mechanical integrity will be demonstrated using the DTS fiberoptic cable at the

[14] EPA (U.S. Environmental Protection Agency). 2008. Determination of the Mechanical Integrity of Injection Wells, Region 5, Underground Injection Control (UIC) Branch Regional Guidance #5. Chicago, Illinois.

six injection wells, six in-zone monitoring wells, and six above-zone monitoring wells. Table 7-7 outlines the location and frequency of the proposed mechanical integrity methods.

Table 7-7. Mechanical Integrity Testing (MIT) Location and Frequency.

Monitoring category	Monitoring Method	Frequency	Location
Internal MIT	Annulus pressure monitoring	Prior to injection: Continuous	Sensitive, Confidential, or Privileged Information [redacted]
External MIT	DTS fiberoptic cable	Within 3 months post injection: Continuous	

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

HGCS will perform a pressure fall-off test of each injection well at least once every five years pursuant to section 40 CFR 146.90(f). HGCS will follow the *UIC Pressure Falloff Testing Guideline, Third Revision* (2002)[15]. 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 that projects are operating properly, and the injection zone is responding as predicted.

7.7.1. Testing Location and Frequency

The minimum frequency at which HGCS will perform pressure fall-off testing is as follows:

- Prior to injection (baseline);
- During injection, at least once every 5 years; and
- At the end of the injection period and/or prior to well abandonment.

Pressure fall-off tests will be conducted during periodic well workovers, or at a minimum once every five years, during injection to calculate the annual ambient average reservoir pressure (Table 7-8). The pressure falloff tests will be conducted prior to the start of CO_2 injection, periodically during the injection phase, and prior to well abandonment at the HGSS. At a minimum, HGCS will attempt all planned pressure fall-off tests to be preceded by one week of

[15] USEPA. 2002. EPA Region 6 UIC Pressure Falloff Testing Guideline, Third Revision (August 8, 2002). Available on the Internet at: http://www.epa.gov/region6/water/swp/uic/guideline.pdf.

continuous CO_2 injection at constant rate. The well will be shut-in for at least four days or longer until adequate pressure transient data are measured and recorded to calculate the average pressure. These data will be measured using the permanent downhole gauges so a real-time decision on test duration can be made after the data are analyzed for average pressure.

Table 7-8. Injection phase pressure fall-off testing frequency and schedule.

Monitoring Method	Frequency	Location
Pressure fall-off testing	Minimum of once every 5 years	Sensitive, Confidential, or Privileged Information [redacted]

7.7.2. Testing Details

A pressure fall-off test has a period of injection followed by a period of no-injection or shut-in. Normal injection will be used during the injection period preceding the shut-in portion of the falloff tests. The average injection rate is estimated to be approximately 2,740 MT/day per well (equivalent to 1 million MT/year per well). Prior to the fall-off test this rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. At a minimum, one week of continuous injection will precede the shut-in portion of the fall-off test; however, several months of injection prior to the fall-off will likely be part of the pre-shut-in injection period and subsequent analysis. This data will be measured using the permanent downhole pressure-temperature gauges so a final decision on test duration can be made in real time.

HGCS and/or a third-party vendor will shut-in each well at the wellhead instantaneously with coordination with the injection compression facility operators. The shut-in period of the fall-off test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because permanent downhole pressure-temperature gauges will be used, the shut-in duration can be determined in real-time. Pressure measurements will be taken continuously for a period while monitoring pressures decay. A report containing the pressure fall-off data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency 30 days following the test. Both wellhead and downhole pressure gauges will be used for this test and will be of a type that meets or exceeds ASME B 40.1 Class 2A[16] (0.5% accuracy across full range). Wellhead pressure gauge range will be 0-15,000 psi. Downhole gauge range will be 200-10,000 psi for pressure and 77 to 302 °F for temperature.

[16] American Society of Mechanical Engineers (ASME), 2013, B40.100, Pressure Gauges and Gauge Attachments, American Society of Mechanical Engineers.

7.8. <u>Carbon Dioxide Plume and Pressure Front Tracking</u>

HGCS will track the extent of the free-phase CO_2 plume, and the pressure development within the storage complex using direct well based and indirect methods pursuant to 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.

7.8.1. Plume monitoring location and frequency

Table 7-9 and Table 7-10 present the direct and indirect methods that HGCS will implement to monitor the position of the CO_2 plume its associated pressure front, including the monitoring activities, locations, and frequencies. Locations are subject to change based on final land access agreements.

HGSS monitoring locations relative to the predicted location of the CO_2 plume and pressure front at 5- and 10-year intervals throughout the injection phase are shown in Figure 7-6. The predicted amount of CO_2 in the mobile gas, trapped gas, and dissolved (aqueous) phases after 30 years of injection is shown in Figure 7-6. Pressure and temperature monitoring for in-zone wells will occur within the Argenta, top of the injection zone, and directly below the Eau Claire caprock in the Mt. Simon E unit.

7.8.2. Plume monitoring details

As summarized in Table 7-9 and Table 7-10 below, HGCS will utilize a combination of direct and indirect methods to detect, track and monitor the CO_2 plume. Direct CO_2 plume monitoring methods will include the deployment of electronic downhole pressure-temperature (P/T) gauges (Baker Hughes SureSens Quartz P/T gauge) at fixed-point locations within every injection, in-zone and above-zone monitoring well to monitor the absence or presence of the CO_2 within the injection reservoir (Mount Simon) and caprock (Eau Claire). Injection wells, NCV [1-6], will be monitored for pressure and temperature in the injection zone (Mt. Simon B). In-zone monitoring wells, NCV-OB-MS [1-6], will be monitored for pressure and temperature in three zones: Argenta Formation just above the basement, top of the Mt. Simon B unit in the injection interval, and at the top of the Mt. Simon E unit just below the caprock. Measurements in these three zones allow for insights into the pressure propagation in 3 dimensions as well as a direct measurement of temperature to compliment the DTS data. The above-zone wells (NCV-OB-I) will measure pressure and temperature in the first permeable rock immediately overlying the caprock. Early detection of out-of-zone CO_2 and/or brine will occur using pressure and temperature measurements in the Ironton Formation. All downhole gauges will be comprised of a corrosion resistant chrome alloy and will continuously record formation pressure and temperature from fixed-point locations. Refer to Section A.4 of the QASP for P/T gauge product specifications and quality control procedures.

HGCS will utilize several indirect methods to monitor and track CO_2 plume development (summarized in Table 7-10**)**. Indirect CO_2 plume monitoring techniques to be deployed are distributed temperature sensing (DTS), Pulse Neutron Capture/Reservoir Saturation Logging (PNC/RST Logging), and time-lapse distributed acoustic sensing (DAS)-based 3-dimensional (3D) vertical seismic profiling (VSP) (hereby referred to as DAS-3DVSP).

DTS technology will be run on the outside of the long string casing along the entirety of the wellbore and will record temperature measurements. In-zone wells with DTS will be acquire profiles from TD up to the top of the Eau Claire. Above-zone wells will acquire a temperature profile for the entire length of the Ironton Formation. DTS technology will be installed during initial drilling at locations specified in Table 7-10 and will operate continuously during the baseline, injection, and post-injection periods. In practice, DTS systems typically provide temperature measurements at 1-meter (m) spacing along the entire cable. Please refer to Section A.4 of the QASP for DTS product specifications and quality control procedures.

PNC wireline tools will be run to monitor CO_2 and brine saturations within formations of interest. A PNC/RST log will be run one year prior to injection to establish baseline conditions and will then be re-run once every 5 years prior to AoR re-evaluation. This data will compliment seismic data and confirm CO_2 containment within the reservoir. PNC/RST log data will be acquired within all formations of interest within locations specified in Table 7-10. Please refer to section A.4 of the QASP for PNC/RST logging tool product specifications and quality control procedures.

DAS-3D VSP will be acquired from all wells with installed DAS fiber-optic cables to track CO_2 plume migration and prove containment within the reservoir. The typical resolution limit of surface seismic is 5% saturation. DAS technology used for the Heartland Greenway CO_2 project will be iDAS™ technology developed by Silixa or equivalent. DAS-3D VSP feasibility studies will be conducted once well locations are final to determine the resolution and surface source locations. In the unlikely event that Silixa cannot image the plume with sufficient resolution 3D surface seismic will be conducted to image the plume. 3D seismic (VSP or surface based) will be acquired 1-year prior to injection to establish baseline conditions, every five years during injection phase and then at a variable frequency during the post-injection phase based on CO_2 plume modelling results. Please refer to Section A.4 of the QASP for DAS-3D VSP product specifications and quality control procedures.

Table 7-9. Direct Methods of CO_2 Plume and Pressure Front Tracking.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Sensitive, Confidential, or Privileged Information [redacted]	Pressure/Temperature Gauges	Sensitive, Confidential, or Privileged Information [redacted]		Continuous
	Pressure/Temperature Gauges			Continuous
	Pressure/Temperature Gauges			Continuous
				Continuous
	Pressure/Temperature Gauges			Continuous

Table 7-10. Indirect Methods of CO2 Plume and Pressure Front Tracking.

Monitoring Activity	Target Formations	Monitoring Locations	Spatial Coverage	Frequency
Sensitive, Confidential, or Privileged Information [redacted]	Ironton	Sensitive, Confidential, or Privileged Information [redacted]		Injection: *Continuous*
	Eau Claire Mount Simon			

	Argenta	Sensitive, Confidential, or Privileged Information [redacted]	
Sensitive, Confidential, or Privileged Info [redacted]	Ironton		Injection: *1 per every 5 years*
	Eau Claire Mount Simon Argenta		
	All Formations		Injection: *1 per every 5 years*

*Use of specific techniques and survey configurations are dependent on results of feasibility studies and are subject to change based on technical/practical feasibility

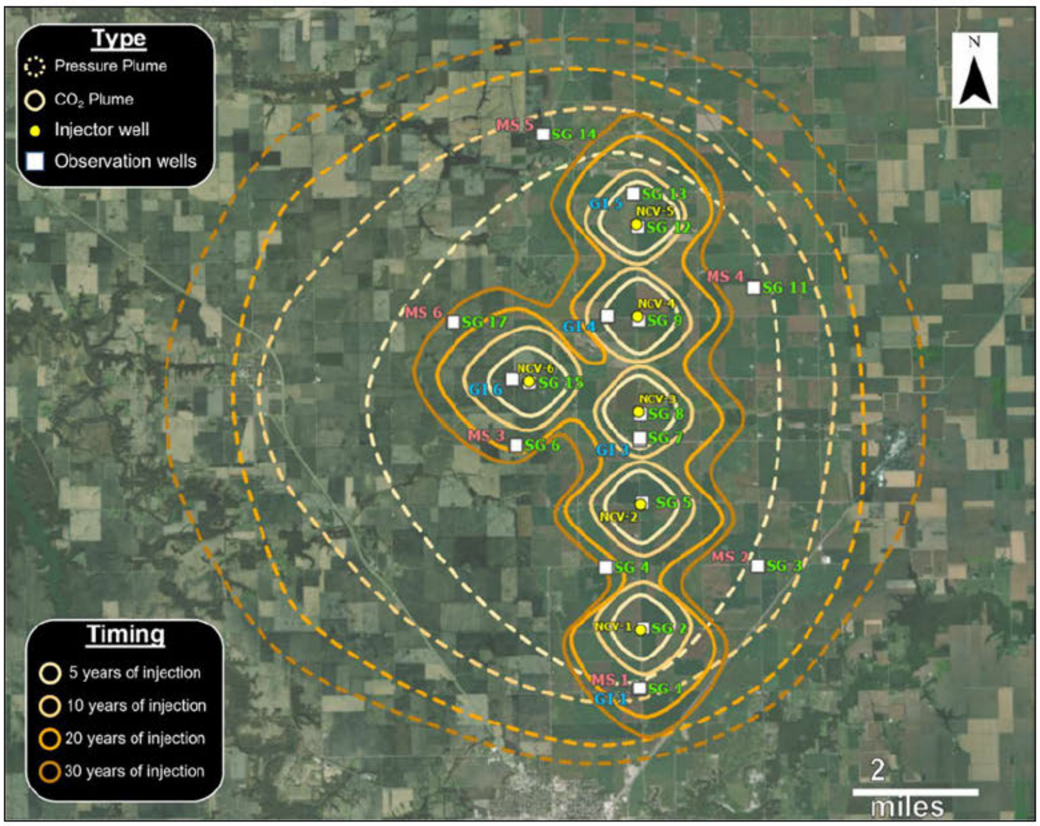

Figure 7-6. Injection CO_2 Plume and Pressure Front Evolution.

7.8.3. Pressure-front monitoring location and frequency

See Table 7-9 above for locations of electronic downhole pressure-temperature gauges and frequency of data acquisition.

7.8.4. Pressure-front monitoring details

HGCS will directly monitor the presence of the elevated pressure front by deploying several electronic downhole pressure-temperature (P/T) gauges (Baker Hughes SureSens Quartz P/T gauge) within every completion zone within injection, in-zone and above-zone monitoring wells to monitor the absence or presence of the CO_2 within the injection reservoir (Mount Simon) and caprock (Eau Claire) in addition to other critical geological units. HGCS will also deploy bottom-hole gauges comprised of similar materials within terminal depth locations of each well to monitor pressure conditions at the fixed-point interval. All downhole gauges 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. Refer to Section A.4 of the QASP for P/T gauge product specifications.

Comparison of observed and simulated arrival responses (DTS/PNC/Pressure-Temperature gauges) at the in-zone well locations will continue throughout the life of the project and will be used to calibrate and verify the model, while improving the model's predictive capability for assessing the long-term environmental impacts of any observed loss of CO_2 containment.