

ATTACHMENT C: TESTING AND MONITORING PLAN

Facility Information

Facility name: Archer Daniels Midland, CCS#2 Well
IL-115-6A-0001
4666 Faries Parkway, Decatur, IL

Well location: Decatur, Macon County, IL;
39°53'09.32835", -88°53'16.68306"

This Testing and Monitoring Plan describes how ADM will monitor the CCS#2 site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is 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 CO₂ within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities pursuant to 40 CFR 146.90(k) is provided in the Appendix to this Testing and Monitoring Plan.

Carbon Dioxide Stream Analysis

ADM will analyze the CO₂ stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

Sampling will take place quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

ADM will sample and analyze the CO₂ stream as described in Section 6A.1 of the permit application and presented below.

Analytical Parameters

ADM will analyze the CO₂ for the constituents identified in Table 1 using the methods listed. Sampling will take place quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

Table 1. Summary of analytical parameters for CO₂ gas stream.

Parameters	Analytical Methods ⁽¹⁾
Oxygen	ISBT 4.0 (GC/DID) GC/TCD

Parameters	Analytical Methods ⁽¹⁾
Nitrogen	ISBT 4.0 GC/DID GC/TCD
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Total Hydrocarbons	ISBT 10.0 THA (FID)
Methane	ISBT 10.1 GC/FID)
Acetaldehyde	ISBT 11.0 (GC/FID)
Sulfur Dioxide	ISBT 14.0 (GC/SCD)
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Ethanol	ISBT 11.0 (GC/FID)
CO ₂ Purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Sampling Methods

CO₂ stream sampling will occur in the compressor building after the last stage of compression. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the authorized laboratory.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers.

Laboratory to be Used/Chain of Custody Procedures

Samples will be analyzed by a third party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of-custody procedures described in Section B.3 of the QASP will be employed.

Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure

ADM 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, and the annulus fluid volume added.

ADM will perform the activities identified in Table 2 to verify internal mechanical integrity of the injection well and monitor injection pressure, rate, volume and annular pressure as required at 40 CFR 146.88, 146.89, and 146.90(b). All monitoring will be continuous for the duration of the operation period, and at the locations shown in the table. The injection well will have

pressure/temperature gauges at the surface and in the tubing at the packer. In addition there will be distributed temperature sensing (DTS) fibers in the injection well.

Table 2. Sampling Locations for Continuous Monitoring.

Test Description	Location
Annular Pressure Monitoring	Surface
Injection Pressure Monitoring	Surface
Injection Pressure Monitoring	Reservoir - Proximate to packer
Injection Rate Monitoring	Surface
Injection Volume Monitoring	Surface
Temperature Monitoring	Surface
Temperature Monitoring	Reservoir - Proximate to packer
Temperature Monitoring	Along wellbore to packer using DTS

Above-ground pressure and temperature instruments shall be calibrated over the full operational range at least annually using ANSI or other recognized standards. In lieu of removing the injection tubing, downhole gauges will demonstrate accuracy by using a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. 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 once per 5 seconds. Temperature sensors will be accurate to within one degree Celsius. DTS sampling rate will be once per 10 seconds.

Flow will be monitored with a Coriolis mass flowmeter at the compression facility. 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.

Injection Rate and Pressure Monitoring

ADM will monitor injection operations using the distributive process control system, as described in Section 6A.2.2.3 of the CCS#2 permit application and presented below.

The Surface Facility Equipment & Control System will limit maximum flow to 3,300 MT/day and/or limit the well head pressure to 2,284 psig, which corresponds to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure. All injection operations will be continuously monitored and controlled by the ADM operations staff using the distributive process control system. This system will continuously monitor, control, record, and will alarm and shutdown 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. ADM supervisors and operators will have the capability to monitor the status of the entire system from distributive control centers but mainly from two locations: the phase 1 compression control

room (near the CO₂ collection and blower facility), and the phase 2 main compression control room.

Calculation of Injection Volumes

Flow rate is measured on a mass basis (kg/hr). The downhole pressure and temperature data will be used to perform the injectate density calculation.

The volume of carbon dioxide injected will be calculated from the mass flow rate obtained from the mass flow meter installed on the injection line. The mass flow rate will be divided by density and multiplied by injection time to determine the volume injected.

Density will be calculated using the correlation developed by Ouyang (2011). The correlation uses the temperature and pressure data collected to determine the carbon dioxide density. The density correlation is given by:

$$\rho = A_0 + A_1 * P + A_2 * P^2 + A_3 * P^3 + A_4 * P^4$$

Where ρ is the density, P is the pressure in psi, and A are coefficients determined by the equations:

$$A_i = b_{i0} + b_{i1} * T + b_{i2} * T^2 + b_{i3} * T^3 + b_{i4} * T^4$$

T is the temperature in degrees Celsius and the b coefficients are presented in Table 3 and Table 4 below.¹

Table 3. Injection volume calculation b coefficients, pressure < 3000 psi.

	b_{i0}	b_{i1}	b_{i2}	b_{i3}	b_{i4}
i=0	-2.148322085348E+05	1.168116599408E+04	-2.302236659392E+02	1.967428940167E+00	-6.184842764145E-03
i=1	4.757146002428E+02	-2.619250287624E+01	5.215134206837E-01	-4.494511089838E-03	1.423058795982E-05
i=2	-3.713900186613E-01	2.072488876536E-02	-4.169082831078E-04	3.622975674137E-06	-1.155050860329E-08
i=3	1.228907393482E-04	-6.930063746226E-06	1.406317206628E-07	-1.230995287169E-09	3.948417428040E-12
i=4	-1.466408011784E-08	8.338008651366E-10	-1.704242447194E-11	1.500878861807E-13	-4.838826574173E-16

Table 4. Injection volume calculation b coefficients, pressure > 3000 psi.

	b_{i0}	b_{i1}	b_{i2}	b_{i3}	b_{i4}
i=0	6.897382693936E+02	2.730479206931E+00	-2.254102364542E-02	-4.651196146917E-03	3.439702234956E-05
i=1	2.213692462613E-01	-6.547268255814E-03	5.982258882656E-05	2.274997412526E-06	-1.888361337660E-08
i=2	-5.118724890479E-05	2.019697017603E-06	-2.311332097185E-08	-4.079557404679E-10	3.893599641874E-12
i=3	5.517971126745E-09	-2.415814703211E-10	3.121603486524E-12	3.171271084870E-14	-3.560785550401E-16
i=4	-2.184152941323E-13	1.010703706059E-14	-1.406620681883E-16	-8.957731136447E-19	1.215810469539E-20

¹ Ouyang 2011, "New Correlations for Predicting the Density and Viscosity of Supercritical Carbon Dioxide Under Conditions Expected in Carbon Capture and Sequestration Operations," The Open Petroleum Engineering Journal, 2011, 4, 13-21.

The final volume basis will be calculated as follows:

$$\text{Volume basis (m}^3\text{/hr)} = \text{Mass basis (kg/hr)} / \text{density (kg/m}^3\text{)}$$

Continuous Monitoring of Annular Pressure

ADM will use the procedures below to monitor annular pressure, as described in Section 6A.3.1 of the CCS #2 permit application.

The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus:

1. The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity of 1.26 and a density of 10.5 lbs/gal. The hydrostatic gradient is 0.546 psi/ft. The brine will contain a corrosion inhibitor.
2. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) during injection.
3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer set at 6,312 ft KB.
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 1 shows the process instrument diagram for the injection well annulus protection system.

The annular monitoring system consists 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 either compressed nitrogen or CO₂.

The annulus pressure will be maintained between approximately 425-525 psi and monitored by the ADM control system gauges. The annulus head tank pressure will be controlled by pressure regulators—one set of regulators to maintain pressure above 400 psi by adding compressed nitrogen or CO₂ and the other to relieve pressure above 525 psi by venting gas off the annulus head tank.

Any changes to the composition of annular fluid will be reported in the next report submitted to the permitting agency.

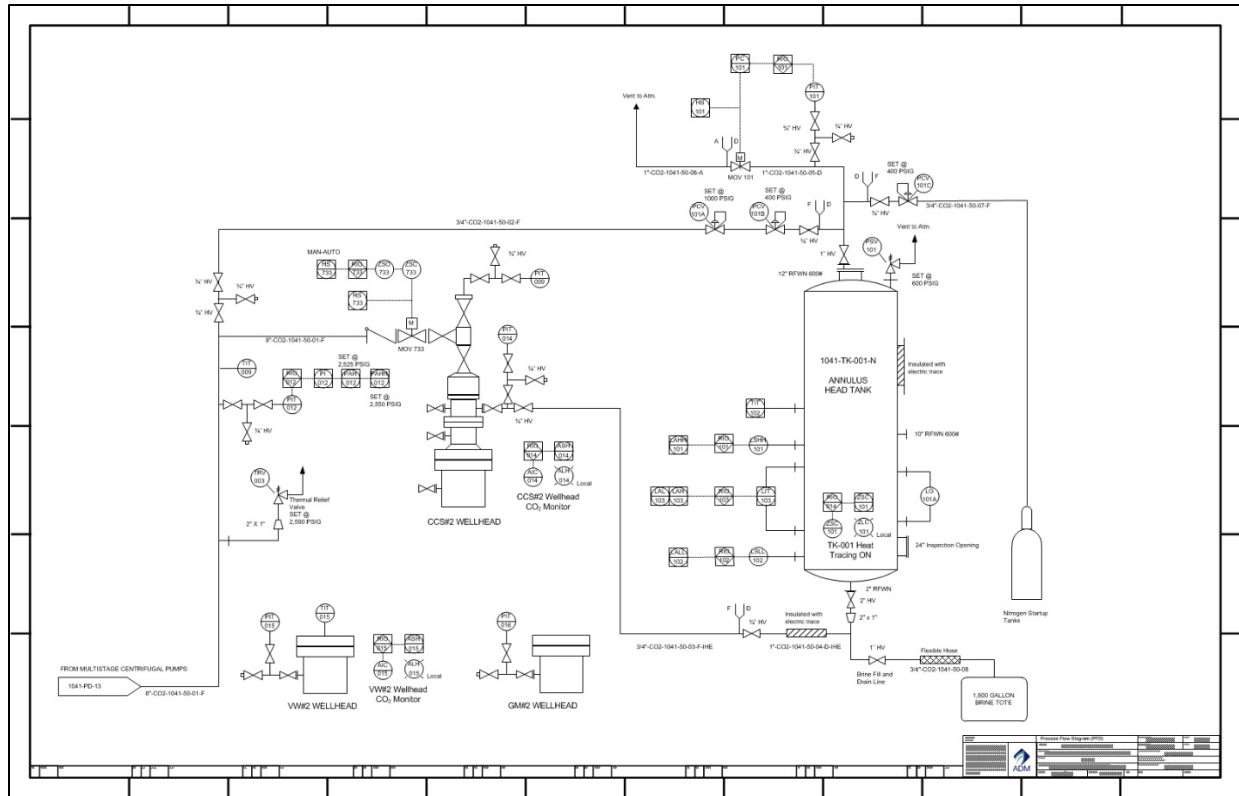


Figure 1. The annular monitoring system general layout.

If system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours or twice per shift for both wellhead surface pressure and annulus pressure, and record hard copies of the data until communication is restored.

Average annular pressure and annulus tank fluid level will be recorded daily. The volume of fluid added or removed from the system will be recorded.

Casing-Tubing Pressure Monitoring

ADM will monitor the casing-tubing pressure as described in Appendix G of the CCS#2 permit application and presented below.

During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. Surface pressure of the casing-tubing annulus is anticipated to be from 425 to 525 psi. As detailed in the Emergency and Remedial Response Plan (Attachment F to this permit), significant changes in the casing-tubing annular pressure attributed to well mechanical integrity will be investigated.

Collection and recording of monitoring data will occur at the frequencies described in Table 5.

Table 5. Sampling and Recording Frequencies for Continuous Monitoring.

Well Condition	Minimum sampling frequency: once every ⁽¹⁾⁽⁴⁾	Minimum recording frequency: once every ⁽²⁾⁽⁴⁾
For continuous monitoring of the injection well when operating:	5 seconds	5 minutes ⁽³⁾
For the injection well when shut-in:	4 hours	4 hours

Note 1: Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.

Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Note 3: This can be an average of the sampled readings over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified over that recording interval.

Note 4: DTS sampling frequency is once every 10 seconds and recorded on an hourly basis.

Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), ADM 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.

This monitoring will occur quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

ADM will monitor corrosion using the corrosion coupon method and collect samples according to the description below and in Section 6A.3.5 of the CCS#2 permit application.

Sample Description

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO₂ stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 6 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see “Sample Handling and Monitoring” below).

Table 6. List of Equipment Coupon with Material of Construction.

Equipment Coupon	Material of Construction
Pipeline	CS A106B
Long String Casing (Surface - 4,800')	Carbon Steel
Long String Casing (4,800' – TD)	Chrome Alloy
Injection Tubing	Chrome alloy
Wellhead	Chrome alloy

Equipment Coupon	Material of Construction
Packers 1	Chrome alloy

Sample Exposure

Each sample will be attached to an individual holder (Figure 2a) and then inserted in a flow-through pipe arrangement (Figure 2b). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high pressure CO₂ will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO₂ past this point; therefore this location will provide representative exposure of the samples to the CO₂ composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.



Figure 2a. Coupon Holder.

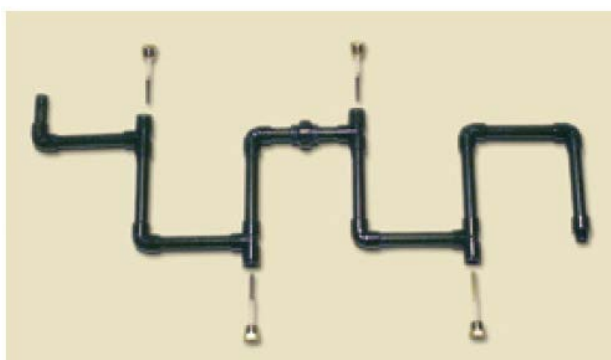


Figure 2b. Flow-through Pipe Arrangement.

Sample Handling and Monitoring

The coupons will be handled and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons will be photographed, visually inspected with a minimum of 10x power, dimensionally measured (to within 0.0001 inch), and weighed (to within 0.0001 gm).

Groundwater Quality Monitoring

ADM will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

The groundwater monitoring plan focuses on the following zones:

- Quaternary and/or Pennsylvanian strata – the source of local drinking water.

- The St. Peter Formation – the lowermost USDW.
- The Ironton-Galesville Sandstone – the zone above the Eau Claire confining zone.

All of the monitoring locations are located on ADM property. Figure 3 shows the project area and the location of existing shallow groundwater monitoring wells and planned deep monitoring wells. Table 7 and Table 8 show the planned monitoring methods, locations, and frequencies for groundwater quality monitoring above the confining zone. ADM will also monitor in the Mt. Simon Sandstone (the injection zone). Monitoring in this layer will be to track the carbon dioxide plume and is described under “Carbon Dioxide Plume and Pressure Front Tracking” below.

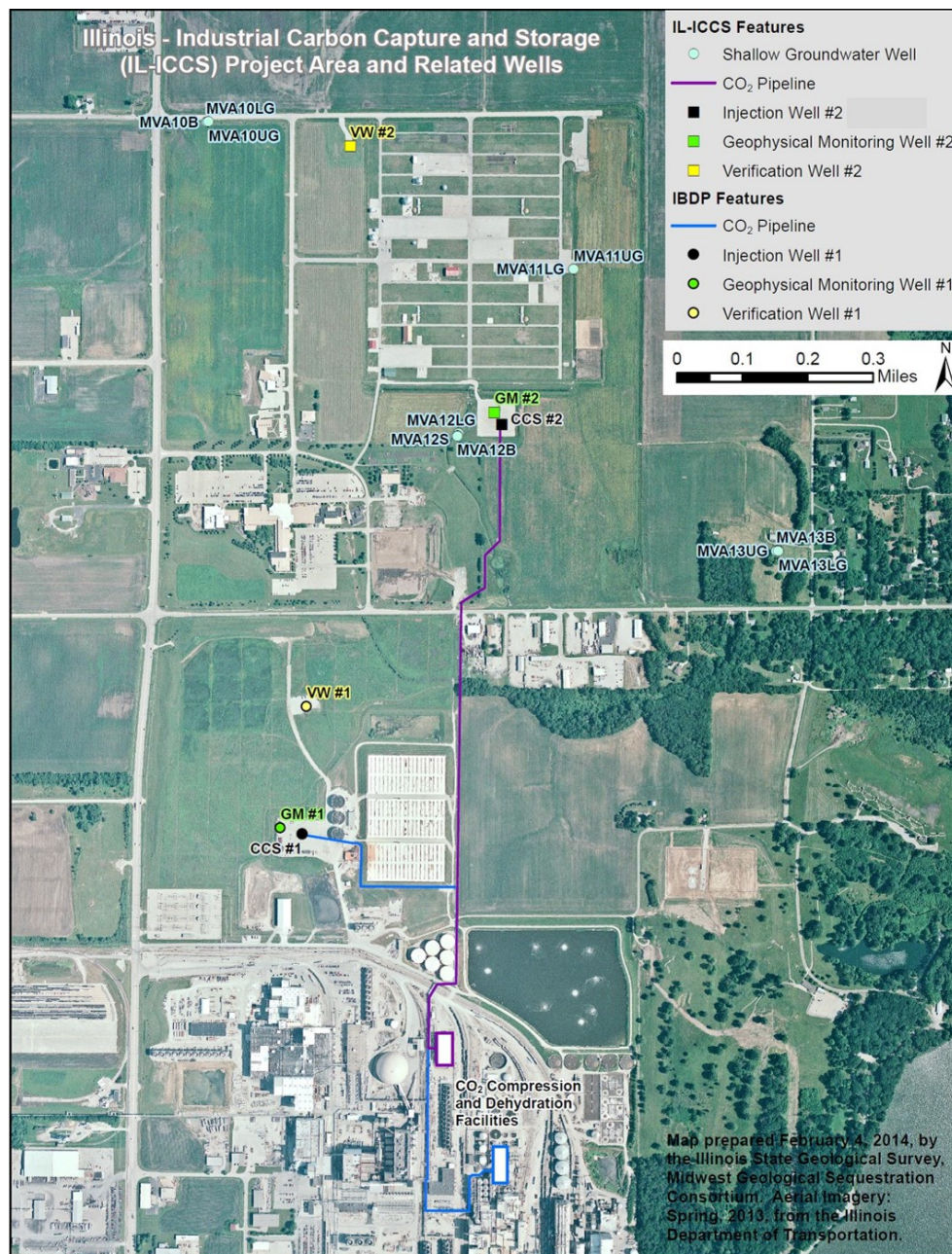


Figure 3. Location of shallow groundwater monitoring wells and deep monitoring wells.

Table 7. Direct Monitoring of Groundwater Quality and Geochemical Changes above the Confining Zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency ⁽¹⁻⁵⁾
Quaternary and/or Pennsylvanian strata	Fluid sampling	Shallow monitoring wells: MVA10LG, MVA11LG, MVA12LG, MVA13LG	4 point locations, 1 sampling interval each. Approx. depths: MVA10LG - 101 ft, MVA11LG - 107 ft, MVA12LG - 95 ft, MVA13LG - 80 ft	Baseline; Year 1-2: Quarterly; Year 3-5: Semi-Annual
	DTS	CCS#1	1 point location, distributed measurement to 6325 KB/5631 MSL	Continuous
		CCS#2	1 point location, distributed measurement to 6211 KB/5520 MSL	Continuous
St. Peter	Fluid sampling	GM#2	1 point location, 1 interval: 3450 KB/2759 MSL	Baseline; Year 1-5: Annual
	Pressure/temperature monitoring	GM#2	1 point location, 1 interval: 3450 KB/2759 MSL	Continuous
	DTS	CCS#1	1 point location, distributed measurement to 6325 KB/5631 MSL	Continuous
		CCS#2	1 point location, distributed measurement to 6211 KB/5520 MSL	Continuous
Ironton-Galesville	Fluid sampling	VW#1	1 point location, 1 interval: 4918 - 5000 KB, 4224 - 4306 MSL	Baseline; Year 1-3: Annual; Year 4-5: None
		VW#2	1 point location, 1 interval: 5010 KB/4307 MSL	Baseline; Year 1-5: Annual
	Pressure/temperature monitoring	VW#1	1 point location, 1 interval: 4918 - 5000 KB, 4224 - 4306 MSL	Year 1-3: Continuous; Year 4-5: None
		VW#2	1 point location, 1 interval: 4902 KB/4199 MSL	Continuous
	DTS	CCS#1	1 point location, distributed measurement to 6325 KB/5631 MSL	Continuous
		CCS#2	1 point location, distributed measurement to 6211 KB/5520 MSL	Continuous

Note 1: Baseline sampling and analysis will be completed before injection is authorized.

Note 2: Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

Note 3: Semi-annual sampling will be performed each year by: 6 months after the date of authorization of injection and 12 months after the date of authorization of injection.

Note 4: Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.

Note 5: Continuous monitoring is described in Table 5 of this plan.

Table 8. Indirect Monitoring of Groundwater Quality and Geochemical Changes above the Confining Zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency ^(1,2)
Quaternary and/or Pennsylvanian strata	Pulse Neutron Logging/Reservoir Saturation Tool (RST) logs	VW#1	1 point location (12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		VW#2	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#1	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#2	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
St. Peter	Pulse Neutron Logging/RST	VW#1	1 point location (12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		VW#2	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#1	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#2	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
Ironton-Galesville	Pulse Neutron Logging/RST	VW#1	1 point location (12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		VW#2	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#1	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#2	1 point location (6-12 inches outside well bore) & continuous to full well depth	Baseline, Year 2, Year 4

Note 1: Baseline sampling and analysis will be completed before injection is authorized.

Note 2: Logging will take place up to 45 days before the anniversary date of authorization of injection each year or will be alternatively scheduled with the prior approval of the UIC Program Director.

Table 9 identifies the parameters to be monitored and the analytical methods ADM will employ.

Table 9. Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods ⁽¹⁾
<i>Quaternary/Pennsylvanian</i>	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO ₃ , and SO ₄	Ion Chromatography, EPA Method 300.0
Dissolved CO₂	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
<i>St. Peter</i>	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO ₃ , and SO ₄	Ion Chromatography, EPA Method 300.0
Dissolved CO₂	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}\text{C}$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
<i>Ironton-Galesville</i>	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B

Parameters	Analytical Methods ⁽¹⁾
Anions: Br, Cl, F, NO ₃ , and SO ₄	Ion Chromatography, EPA Method 300.0
Dissolved CO₂	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}\text{C}$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density(field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

Sampling will be performed as described in Section B.2 of the QASP; this section of the QASP describes the groundwater sampling methods to be employed, including sampling SOPs (Section B.2.a/b), and sample preservation (Section B.2.g).

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

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

External Mechanical Integrity Tests (MITs)

ADM will conduct at least one of the tests presented in Table 10 during the injection phase to verify external MI as required at 40 CFR 146.89(c) and 146.90. MITs will be performed annually, up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.

Table 10. MITs.

Test Description	Location
Temperature Log	Along wellbore using DTS or wireline well log
Noise Log	Wireline Well Log
Oxygen Activation Log	Wireline Well Log

Description of MIT(s) That May be Employed

Temperature Logging Using Wireline

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. The following procedures, as described in Appendix G of the CCS #2 permit application, will be employed for temperature logging:

The well should be in a state of injection for at least 6 hours prior to commencing operations in order to cool injection zones.

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a temperature survey from the Base of the Maquoketa Formation (or higher) to the deepest point reachable in the Mt. Simon while injecting at a rate that allows for safe operations.²
3. Stop injection, pull tool back to shallow depth, wait 1 hour.
4. Run a temperature survey over the same interval as step 2.
5. Pull tool back to shallow depth, wait 2 hours.
6. Run a temperature survey over the same interval as step 2.
7. Pull tool back to shallow depth, wait 2 hours.
8. Run a temperature survey over the same interval as step 2.
9. Evaluate data to determine if additional passes are needed for interpretation. Should CO₂ migration be interpreted in the top most section of the log, additional logging runs over a higher interval will be required to find the top of migration.
10. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 2.
11. Rig down the logging equipment.
12. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

Temperature Logging Using DTS Fiber Optic Line

CCS#2 is equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DTS line is used for real time temperature monitoring and, like a conventional temperature log,

² Should operational constraints or safety concerns not allow for a logging pass while injecting, an acceptable, alternate plan is to stop injecting immediately prior to the first logging pass.

can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone.
2. During injection operation, record the temperature profile for 6 hours prior to shutting in well.
3. Stop injection and record temperature profile for 6 hours.
4. Evaluate data to determine if additional cooling time is needed for interpretation.
5. Start injection and record temperature profile for 6 hours.
6. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance making this technology superior to wireline temperature logging.

Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging will be carried out while injection is occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a noise survey from the Base of the Maquoketa Formation (or higher) to the deepest point reachable in the Mt. Simon while injecting at a rate that allows for safe operations.
3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.
4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.
5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:
 - a. The base of the lowermost bleed-off zone above the injection interval and
 - b. The base of the lowermost USDW (St. Peter).
6. Additional measurements may be made to pinpoint depths at which noise is produced.

7. Use a vertical scale of 1 or 2 inches per 100 feet.
8. Rig down the logging equipment.
9. Interpret the data as follows: Determine the base noise level in the well (dead well level). Identify departures from this level. An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations. Determine the extent of any movement; flow into or between USDWs indicates a lack of mechanical integrity; flow from the injection zone into or above the confining zone indicates a failure of containment.

Oxygen Activation (OA) Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging will be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.
2. Conduct a baseline Gamma Ray Log and casing collar locator log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool.³
3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.
4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.
5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a “no vertical flow behind the casing” section of the well to ensure accurate, repeatable tool response and for measuring background counts.
6. Take, at a minimum, a 15 minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.
7. Take, at a minimum, a 15 minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.
8. Take, at a minimum, a 15 minute stationary reading adjacent to the top of the confining zone.
9. Take, at a minimum, a 15 minute stationary reading at the base of the lowermost USDW.
10. If flow is indicated by the OA log at a location, move uphole or downhole as necessary at no more than 50 foot intervals and take stationary readings to determine the area of fluid migration.

³ Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

11. Interpret the data: Identification of differences in the activated water's measured gamma ray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected may indicate flow in the annulus or behind the casing. The flow velocity is determined by measuring the time that the activated water passes a detector.

Pressure Fall-Off Testing

ADM will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

Pressure fall-off testing will be performed:

- During injection, approximately half way through the injection phase (i.e., year 2.5); and
- At the end of the injection period.

ADM will conduct pressure fall-off testing according to the procedures below, as described in Section 6A.3.4 of the CCS #2 permit application.

Pressure Fall-off Test Procedure

A pressure falloff test has a period of injection followed by a period of no-injection or shut-in. Normal injection using the stream of CO₂ captured from the ADM facility will be used during the injection period preceding the shut-in portion of the falloff tests. The normal injection rate is estimated to be 2,750 MT/day (the last 3 years of the planned 5-year injection period). Prior to the falloff test this rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. Injection will have occurred for 2.5 years prior to this test, but there may have been injection interruptions due to operations or testing. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis. This data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at five second intervals or less for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure falloff test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (0.5% accuracy across full range). Wellhead pressure gauge range will be 0-4,000 psi. Downhole gauge range will be 0-10,000 psi.

Carbon Dioxide Plume and Pressure Front Tracking

ADM will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Table 11 and Table 12 present the direct and indirect methods that ADM will use to monitor the position of the CO₂ plume and pressure front, including the activities, locations, and frequencies ADM will employ.

ADM will conduct fluid sampling and analysis to detect changes in groundwater in order to directly monitor the carbon dioxide plume. The parameters to be analyzed as part of fluid sampling in the Mt. Simon (i.e., the injection zone) and analytical methods are presented in

Pressure at Top of CCS2 Injection Interval

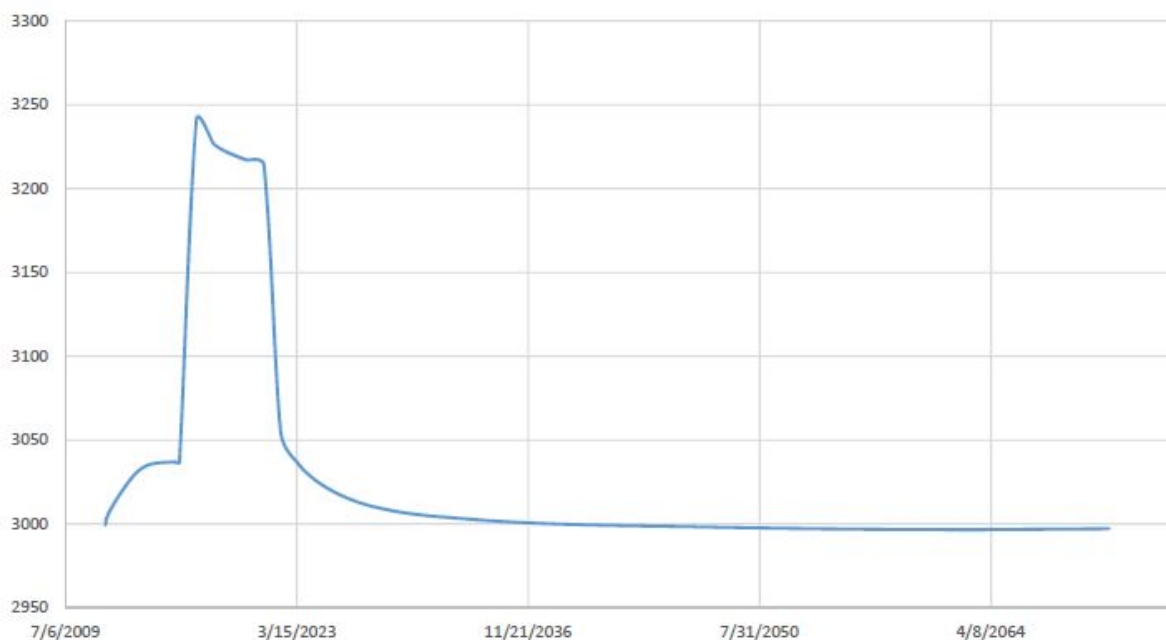


Figure 10. Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection.

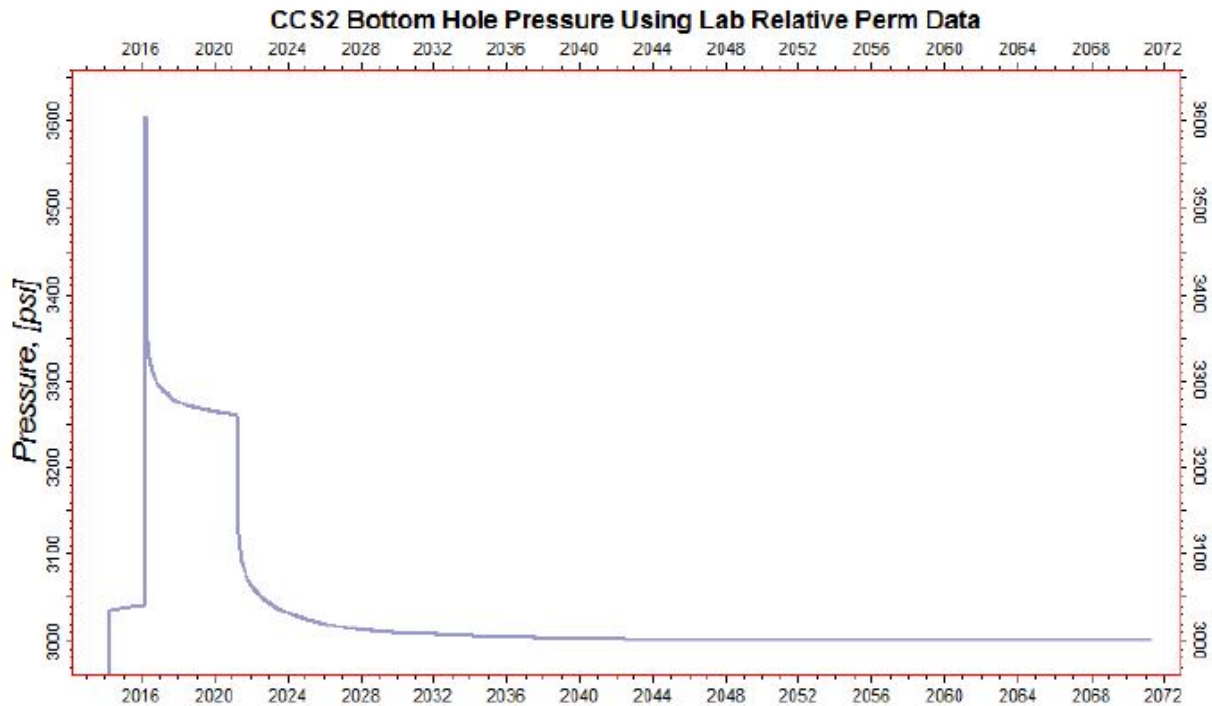


Figure 11. Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection.

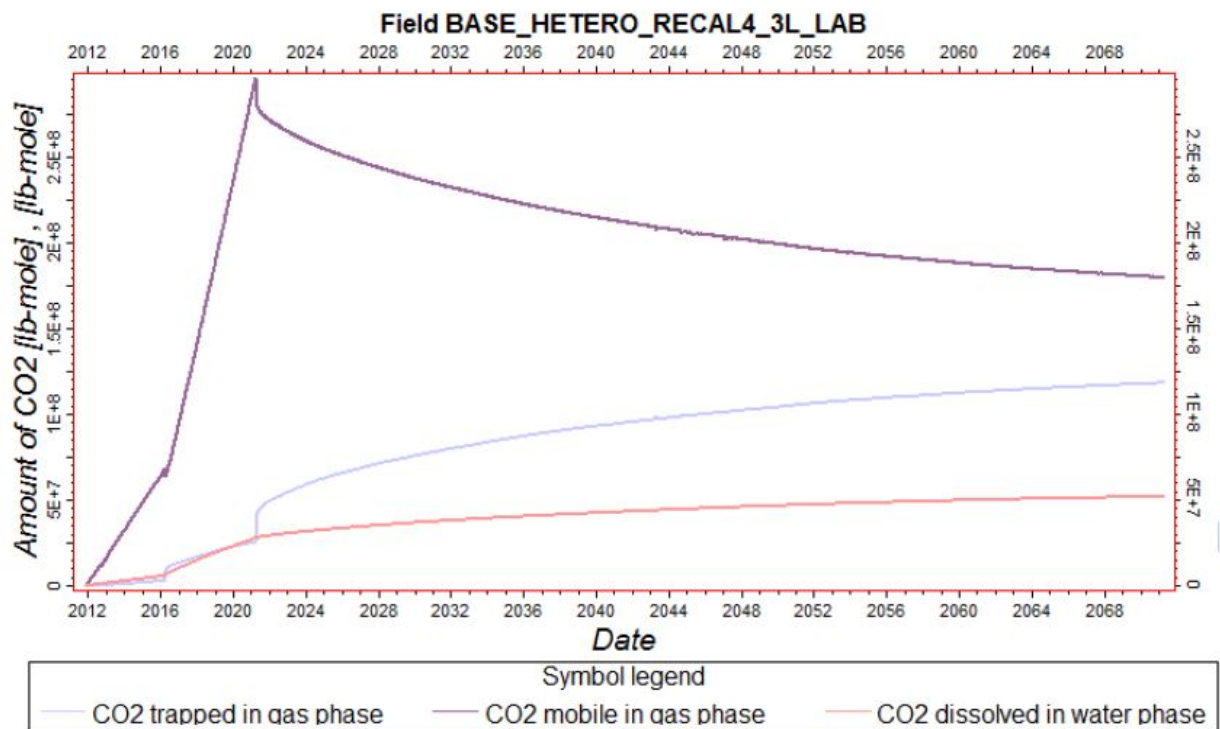


Figure 12. Predicted CO₂ phase distribution, simulated for 50 years after the commencement of injection.

. ADM will deploy pressure/temperature monitors and DTS to directly monitor the position of the pressure front.

Indirect plume monitoring will be employed using pulsed neutron capture/RST logs to monitor CO₂ saturation. Time-lapse 3D vertical seismic profiles (VSPs) will be used to image the developing CO₂ plume for indirect plume monitoring. Passive seismic monitoring combination of borehole and surface seismic stations to detect local events over M 1.0 within the AoR will also be performed. Quality assurance procedures for seismic monitoring methods are presented in Section B.9 of the QASP.

Table 11. Plume Monitoring Activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency ⁽¹⁻⁴⁾
Direct Plume Monitoring				
Mt. Simon	Fluid sampling	VW#1	1 point location, 1 interval: 6837 - 6632 KB, 6148 - 5938 MSL	Baseline; Year 1-3: Annual
		VW#2	1 point location, 3 intervals: 6710, 6500, 5810 KB; 6007, 5797, 5107 MSL	Annual
Indirect Plume Monitoring				
Mt. Simon	Pulse Neutron Logging/RST	VW#1	1 point location (12" outside wellbore) & continuous to full well depth	Baseline, Year 2, Year 4
		VW#2	1 point location (12" outside wellbore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#1	1 point location (12" outside wellbore) & continuous to full well depth	Baseline, Year 2, Year 4
		CCS#2	1 point location (12" outside wellbore) & continuous to full well depth	Baseline, Year 2, Year 4
Mt Simon	Time-lapse VSP survey	GM#1	Fold Image Coverage ~ 30 acres	In 2013, 2014, 2015
	3D surface seismic survey	Full coverage focusing on the northern extent of plume area	Fold Image Coverage ~ 2,000 acres	Baseline, Year 2 (2019)

Note 1: Baseline monitoring will be completed before injection is authorized.

Note 2: Annual monitoring will be performed up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.

Note 3: Logging surveys will take place up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.

Note 4: Seismic surveys will be performed in the 4th quarter before or the 1st quarter of the calendar year shown or alternatively scheduled with the prior approval of the UIC Program Director.

Table 12. Pressure-Front Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
Mt. Simon	Pressure/ temperature monitoring	VW#1	1 point location, 1 interval: 6945 - 5654 KB, 6251 - 4960 MSL	Year 1-3: Continuous; Year 4-5: None
		VW#2	1 point location, 4 intervals: 7041, 6681, 6524, 5848 KB; 6338, 5978, 5821, 5145 MSL	Continuous
		CCS#1	1 point location, 1 interval: PT @ 6325 KB/5631 MSL; Perfs @ 6982 - 7050 KB, 6288 - 6356 MSL	Continuous
		CCS#2	1 point location, 1 interval: PT @ 6270 KB/5579 MSL; Perfs @ 6630 - 6825 KB, 5939 - 6134 MSL	Continuous
	DTS	CCS#1	1 point location, distributed measurement to 6325 KB/5631 MSL.	Continuous
		CCS#2	1 point location, distributed measurement to 6211 KB/5520 MSL.	Continuous
Other Plume/Pressure-Front Monitoring				
Multiple	Passive seismic	A combination of borehole and surface seismic stations located within the AoR.	The passive seismic monitoring system has the ability to detect seismic events over M1.0 within the AoR.	Continuous

Table 13. Summary of analytical and field parameters for fluid sampling in the Mt. Simon.

Parameters	Analytical Methods ⁽¹⁾
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO ₃ , and SO ₄	Ion Chromatography, EPA Method 300.0
Dissolved CO ₂	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}\text{C}$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1

Parameters	Analytical Methods ⁽¹⁾
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

Monitoring locations relative to the predicted location of the CO₂ plume and pressure front at 1-year intervals throughout the injection phase are shown in Figure 4. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the commencement of injection through Figure 9. Predicted pressure profiles at the top of the injection interval and bottom-hole pressure at CCS#2 are shown in Figure 10 and Figure 11. The predicted amount of CO₂ in the mobile gas, trapped gas, and dissolved (aqueous) phases for 50 years after the commencement of injection is shown in Figure 12.

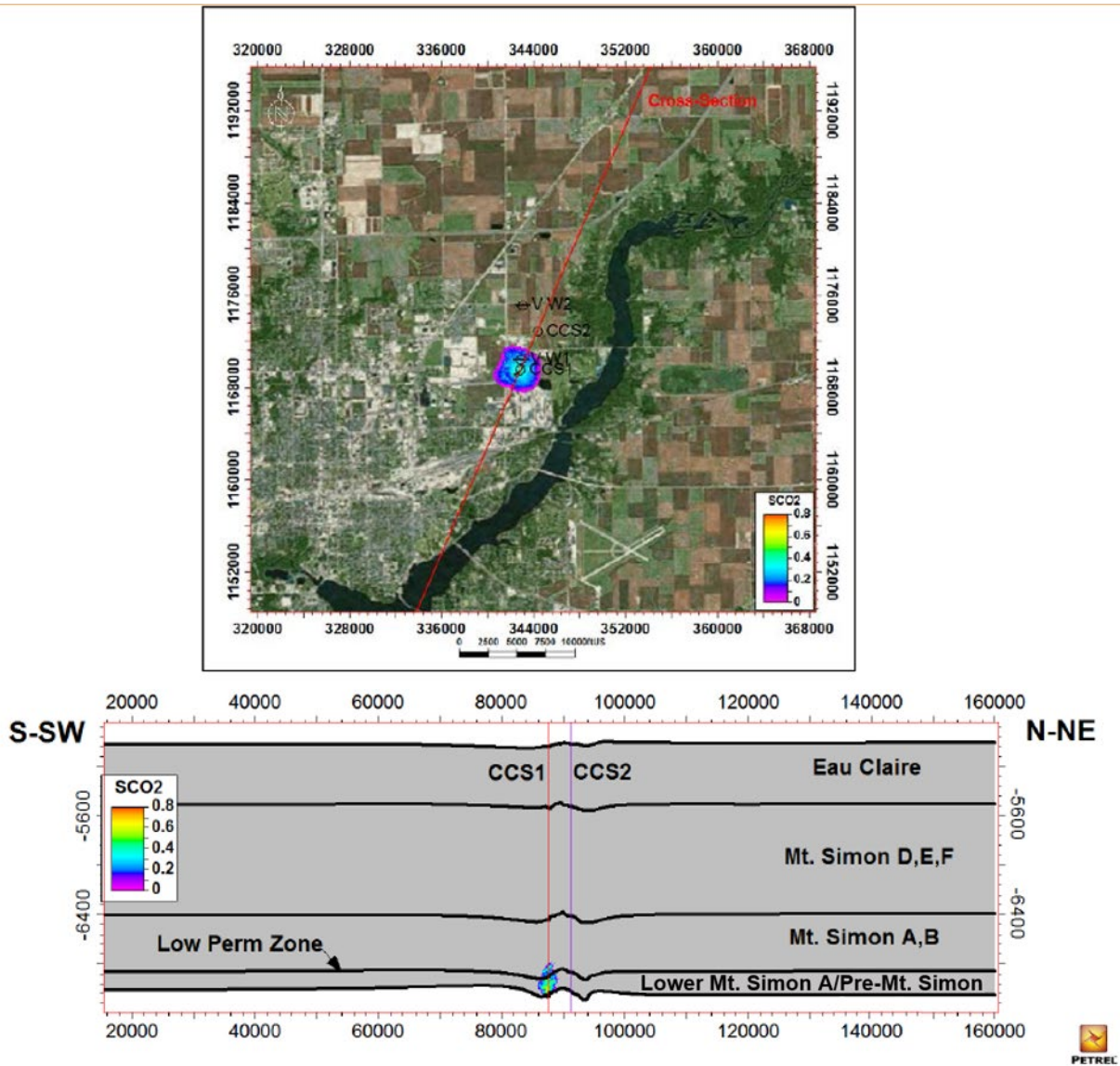


Figure 4. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the commencement of injection for CCS #2.

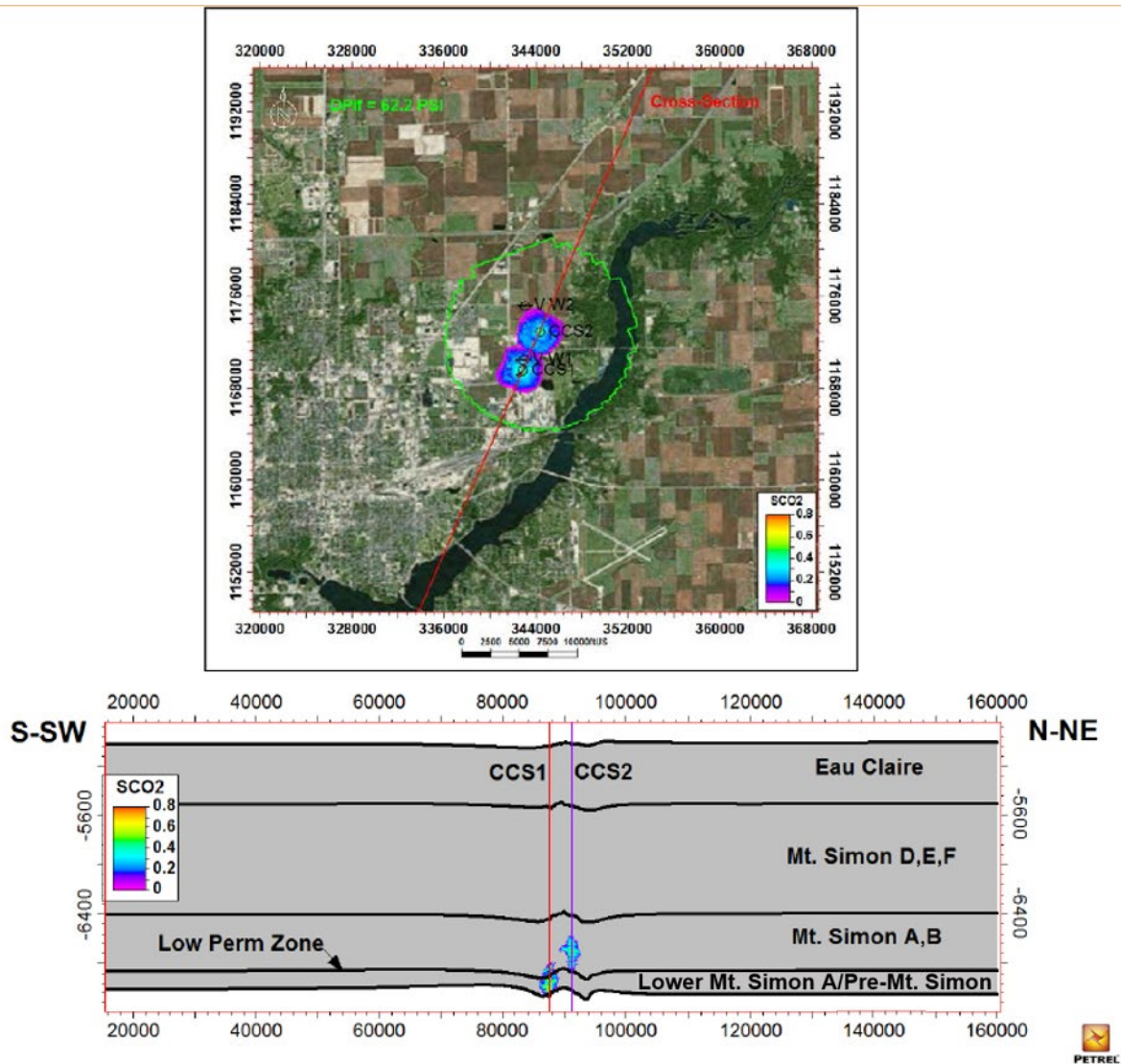


Figure 5. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 1 year of injection at CCS #2.

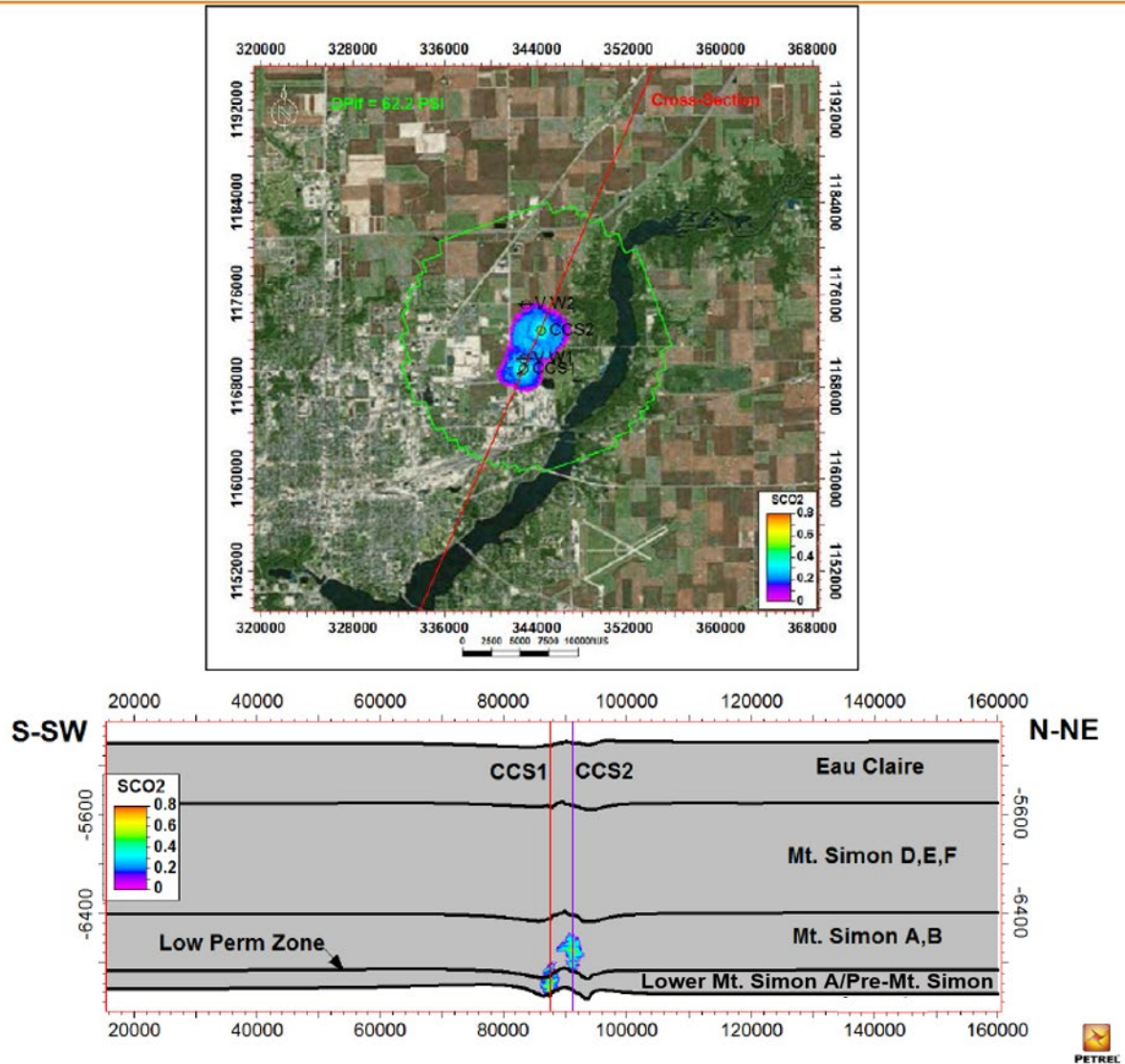


Figure 6. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 2 years of injection at CCS #2.

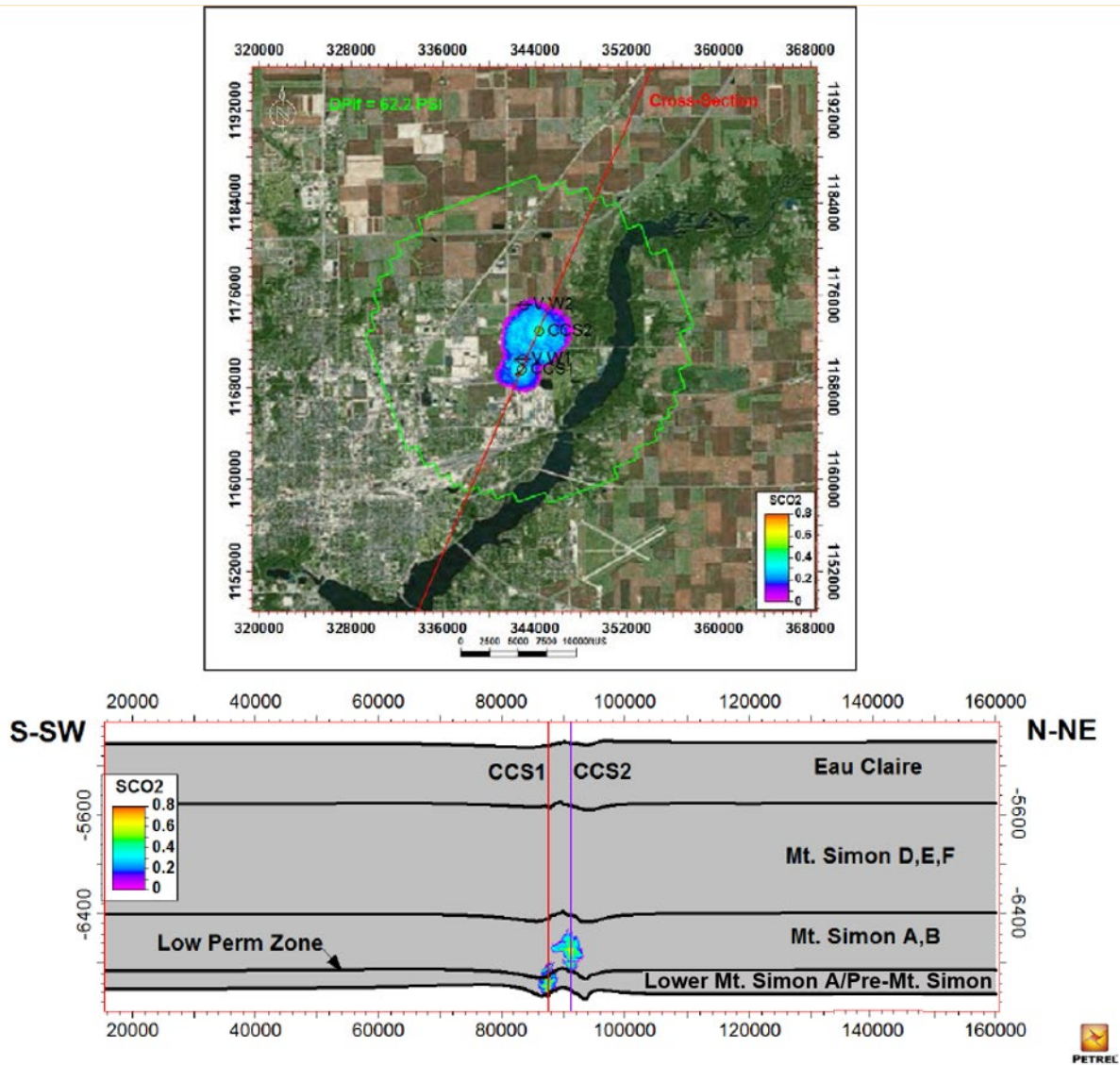


Figure 7. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 3 years of injection at CCS #2.

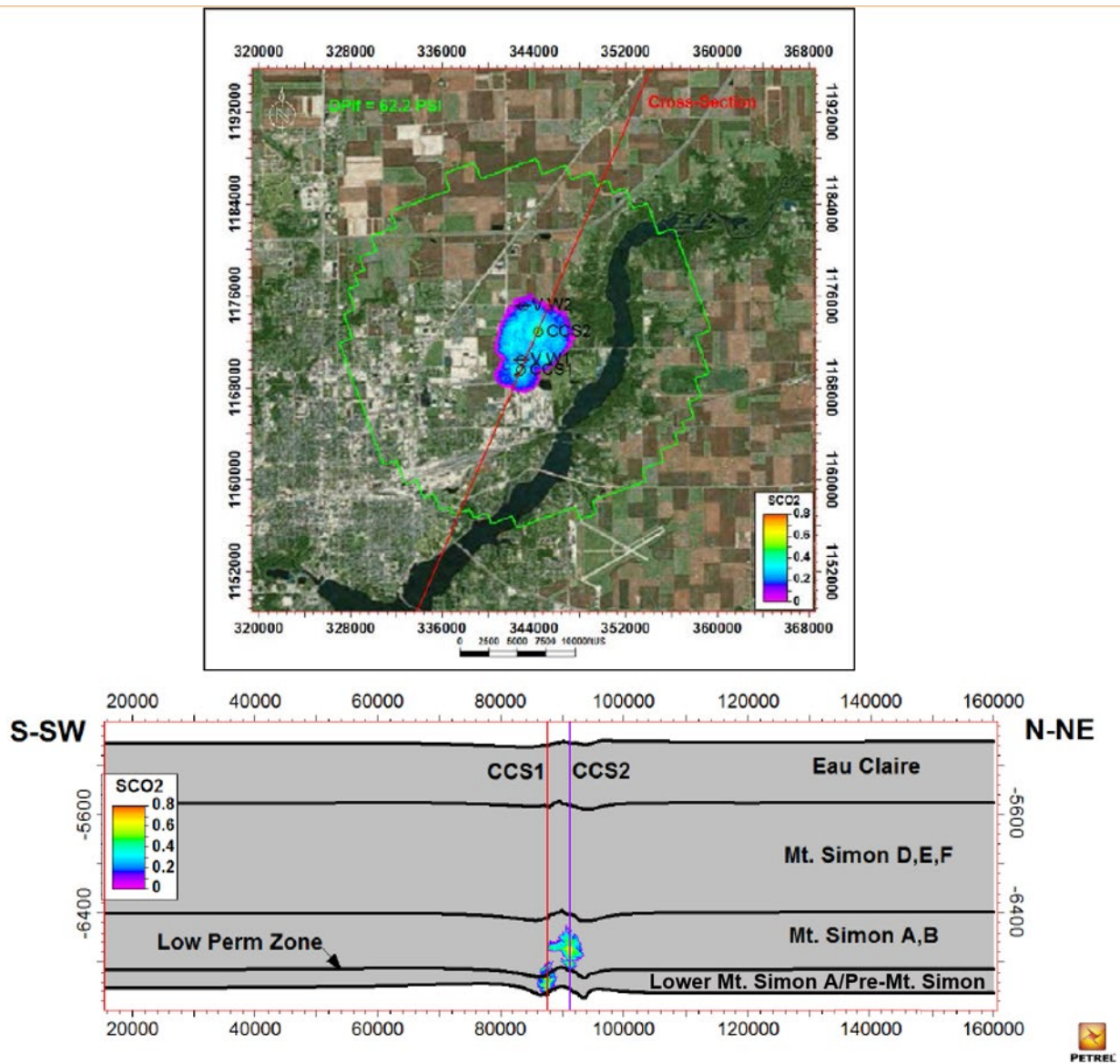


Figure 8. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 4 years of injection at CCS #2.

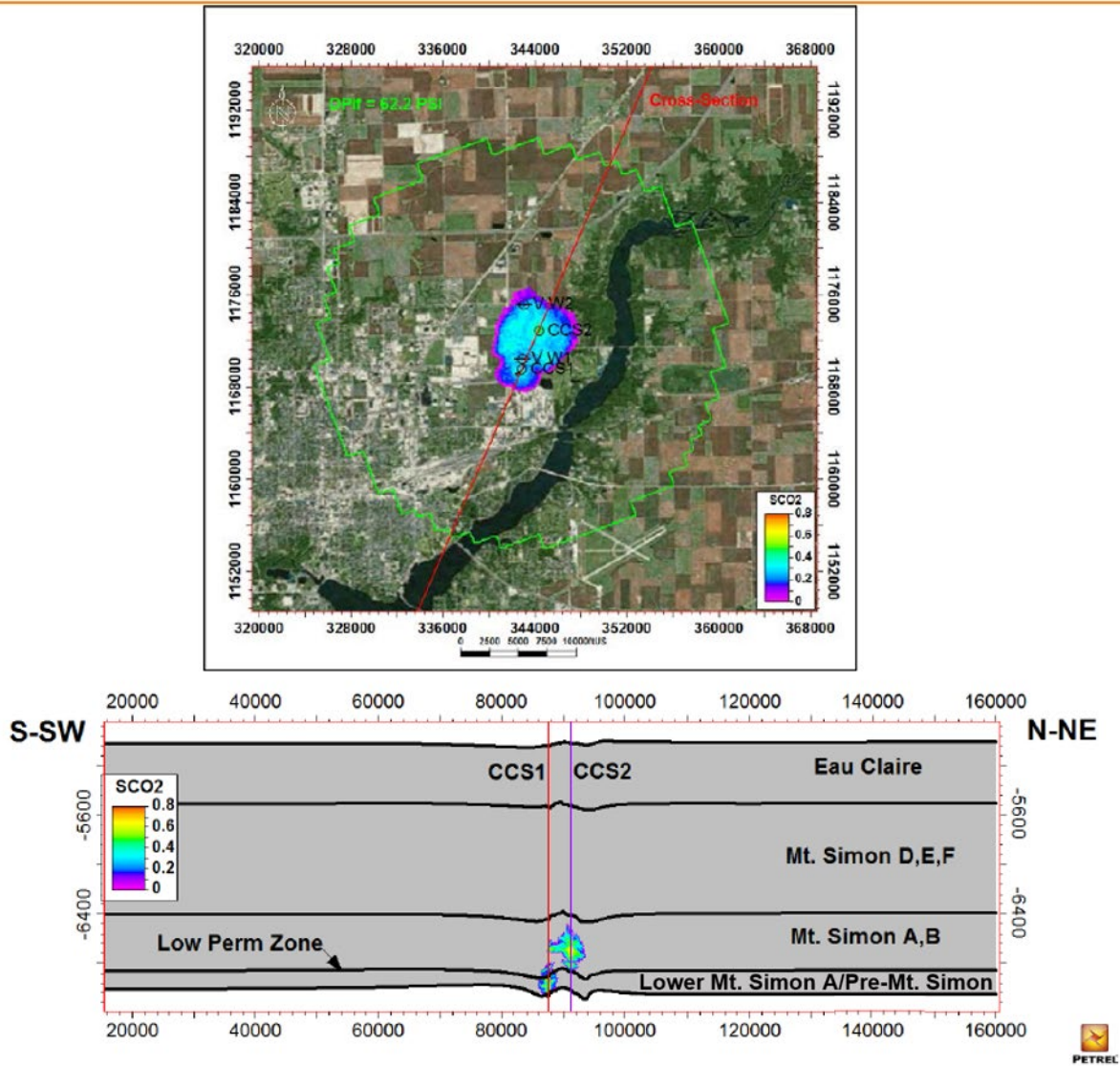


Figure 9. Predicted extent of the CO₂ plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 5 years of injection at CCS #2.

Pressure at Top of CCS2 Injection Interval

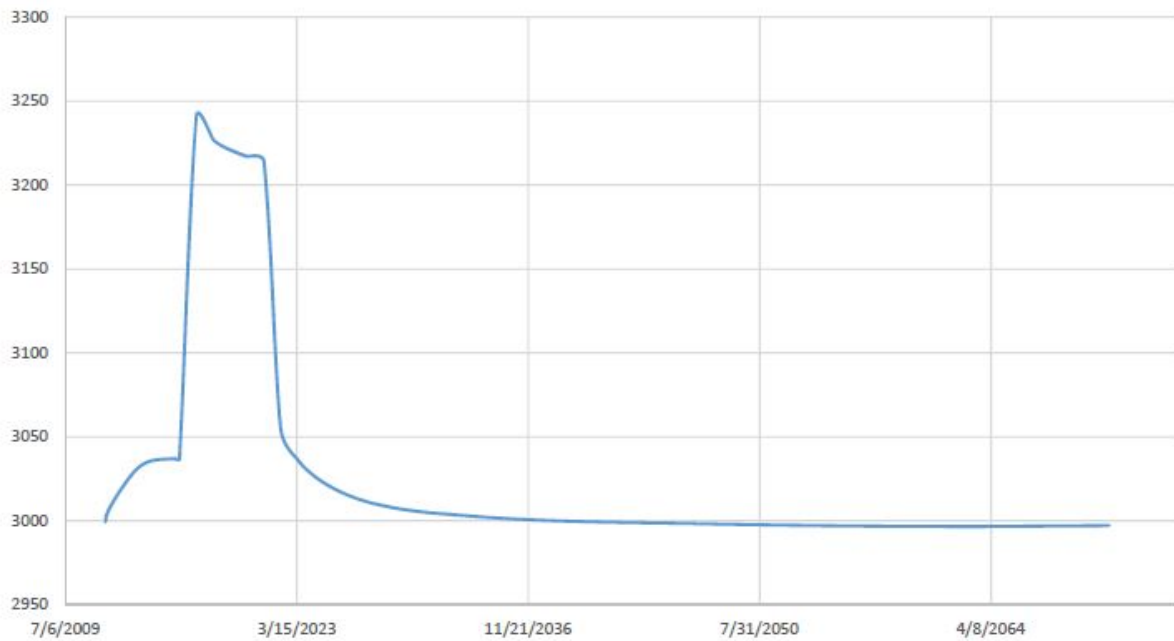


Figure 10. Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection.

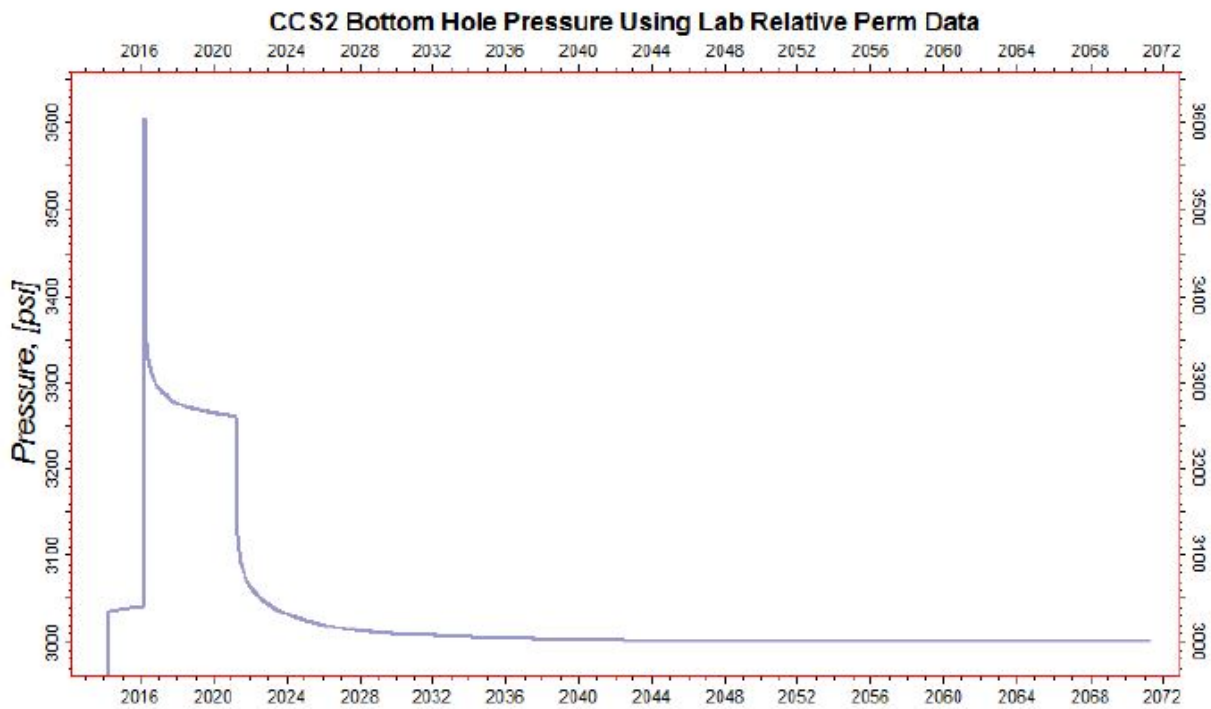


Figure 11. Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection.

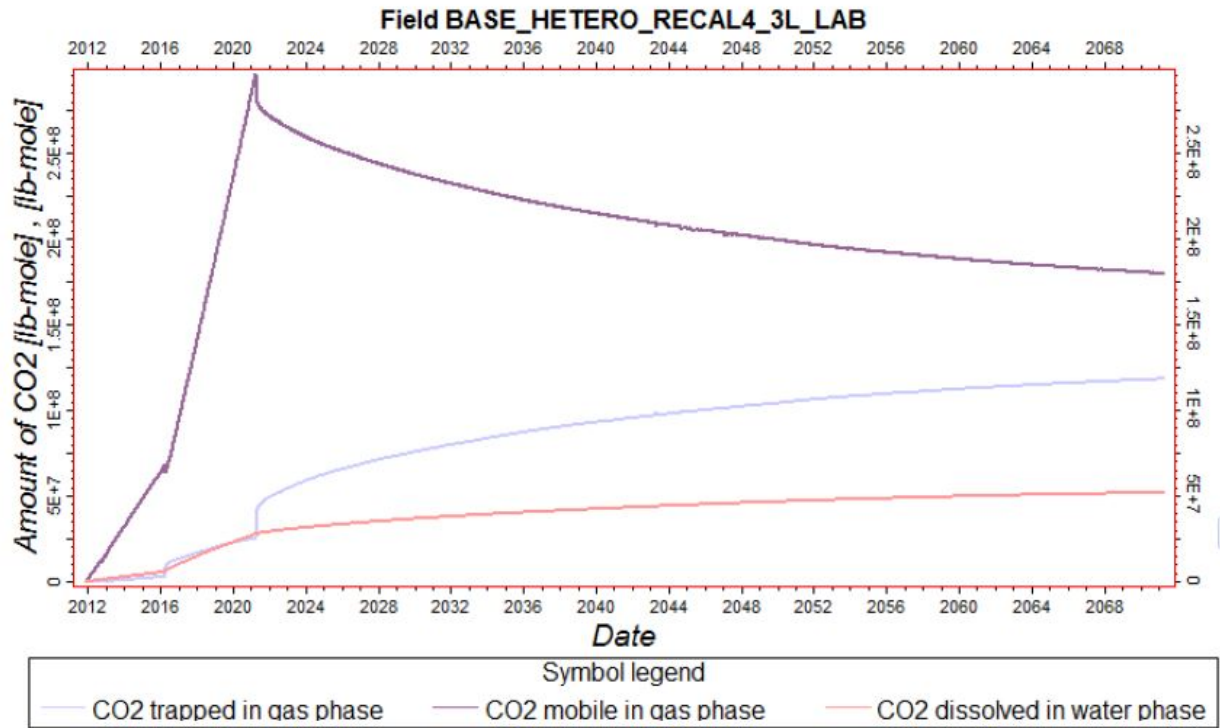


Figure 12. Predicted CO₂ phase distribution, simulated for 50 years after the commencement of injection.

Appendix

Quality Assurance and Surveillance Plan.