Monitoring, Reporting, and Verification Plan CCS#2			
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SUMMARY OF CURRENT REVISION:

Date	Version	Author	Reason(s) for revision
01/09/2017	3.0	Outzen	Modified Reference 1. Removed References 3, 4, and 5. Updated figure 2 to reflect current Active Monitoring Area. Updated Table 1. Update Section 9.1.2.4 to reflect current monitoring practice. Updated Section 10 to reflect current practice. Updated Section 12 to reflect current implementation schedule. Minor formatting and grammar corrections.

1.0 PURPOSE

This Monitoring, Reporting, and Verification (MRV) Plan has been prepared by the Archer Daniels Midland Company (ADM) for Carbon Capture and Sequestration well #2 (CCS #2) located in Decatur, Illinois, for the United States Environmental Protection Agency (USEPA). The MRV Plan was developed in accordance with the regulations at 40 CFR 98, Subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide).

2.0 SCOPE

This procedure is applicable to:

Archer Daniels Midland Company (ADM)
Permit Number: IL-115-6A-0001 (UIC Class VI)
Facility Name: CCS#2
UNDERGROUND INJECTION CONTROL PERMIT – CLASS VI
PERMIT NO. IL-115-6A-0001 (FACILITY NAME: CCS#2)

A map showing the ADM facility is provided as Figure 1.

3.0 DEFINITIONS

None

4.0 PRINCIPLE

None

5.0 SAFETY

There are no specific safety guidelines associated with this procedure.

6.0 PROJECT DESCRIPTION

ADM will capture carbon dioxide gas from their fuel ethanol production unit and compress the gas into a dense-phase liquid for injection into the Mt. Simon Sandstone approximately 7,000 feet below the ground surface. This project is identified as the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project.

The IL-ICCS project plans to inject up to 3,300 metric tons of carbon dioxide (CO2) daily, or 5.5 million metric tons over a five (5) year period.

The IL-ICCS project is the second carbon sequestration project at the Decatur facility. The Illinois State Geological Survey (ISGS) manages the Illinois Basin Decatur Project (IBDP) which completed its goal of injecting 1 million metric tons of CO2 over a three-year period from November 2011 to November 2014.

Further information can be found in the following documents which are referenced throughout this MRV Plan:

Reference 1 – USEPA Underground Injection Control Permit, Class VI, for ADM CCS#2, Permit No. IL-115-6A-0001, proposed modification published November 22, 2016, including Attachments A, B, C (with Quality Assurance & Surveillance Plan), D, E, F, G, H, and I

Reference 2 – ADM Permit Application for Underground Injection Control Permit, July 2011, including Appendices A-H (Permit Application)

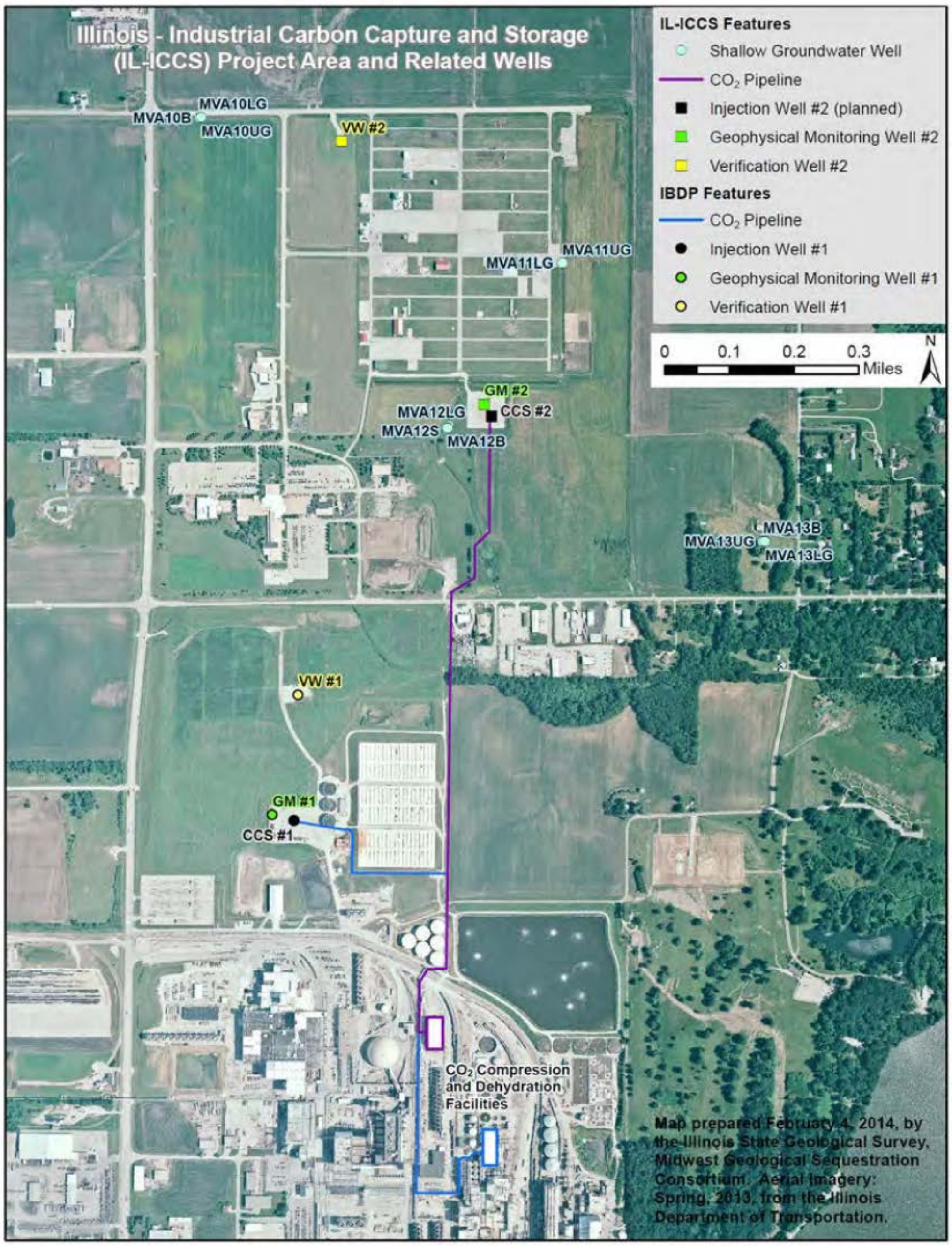

Figure 1. Aerial Photographic Map of ADM CCS#2 Facilities.

7.0 Delineation of Monitoring Areas

The area to be monitored is the Area of Review (AOR) identified in Reference 1, Section G.1 and Attachment B. Based on the predicted area of the CO2 plume as estimated using the reservoir flow model, ADM will use the AOR as shown in Reference 1, Attachment B, Figure 7, plus a one-half mile buffer, as the maximum monitoring area (MMA).

The active monitoring area (AMA) is defined in 40 CFR 98.449 as “the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free phase CO2 plume at the end of year t+5.”

For CCS#2, the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care (PISC) period, and will consist of the AOR as shown in Attachment B of Reference 1. Figure 2 shows the extent of the AMA.

The AMA will incorporate, as described in the Testing and Monitoring Plan (Reference 1, Attachment C):

- Continuous monitoring of injection pressure, annulus pressure, and temperature monitoring at the injection well;
- Groundwater quality monitoring in the local drinking water strata, the lowermost underground source of drinking water (USDW), and the strata immediately above the Eau Claire confining zone;
- External mechanical integrity testing (MIT) and pressure fall-off testing at the injection well;
- Plume and pressure front monitoring in the Mt. Simon using direct and indirect methods (i.e., brine geochemical monitoring, pulse neutron / RST logs, VSP and 3D seismic surveys).

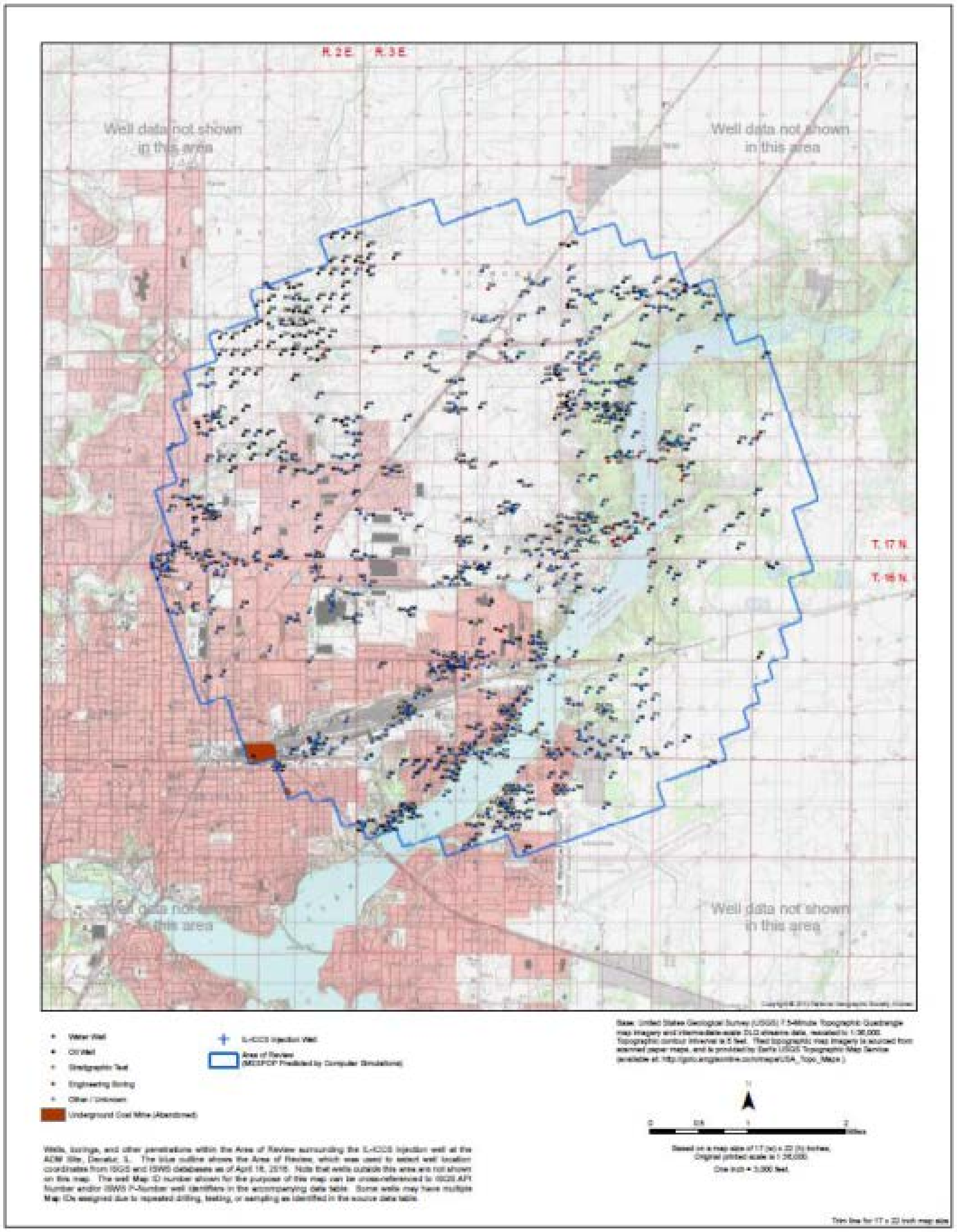

Figure 2. Active Monitoring Area (AMA) consists of the AoR (green outline) shown above.

8.0 EVALUATION OF LEAKAGE PATHWAYS

ADM has defined the potential leakage pathways within the AOR as:

1. Leakage from surface components (pipeline and wellhead)
2. Leakage through abandoned oil & gas wells
3. Leakage through fractures, faults, and bedding plane partings
4. Leakage through confining zone limitations
5. Leakage through injection well or monitoring wells

A qualitative evaluation of each potential leakage pathways is described in the below paragraphs. Risk estimates utilize the qualitative descriptions found in the geosphere risk assessment described for the Weyburn CO2 storage site in Canada[1].

8.1 Leakage from Surface Components

The most probable potential for leakage of CO2 to the surface is from surface components of the injection system: the pipeline that transports CO2 to the injection well (approximately 5,000 feet in length), and the wellhead itself. Leakage is most likely to be the result of aging and use of the surface components over time, most likely at flanged connection points. Leakage could also occur as ventilation from relief valves to dissipate over-pressure in the pipeline. Additionally, leakage may occur as the result of an accident or natural disaster which damages the surface components and allows CO2 to be released.

As a result, we conclude that the risk of leakage through this pathway is possible. The magnitude of such a leak will vary, depending on the failure mode of the component: a sudden break or rupture has the potential to allow several thousand pounds of CO2 to be released to the atmosphere almost immediately; a slowly deteriorating seal at a flanged connection may release only a few pounds of CO2 to the atmosphere over the course of several hours or days. Leakage or venting from surface components will be a risk only during the operation phase of injection (5 year period); following the injection phase, surface components will not store or transport CO2 and will therefore no longer be a leakage risk.

[1] "Geosphere risk assessment conducted for the IEAGHG Weyburn-Midale CO2 Monitoring and Storage Project," Bowden, A.R., Pershke, D. F., Chalaturnyk, R. International Journal of Greenhouse Gas Control 16S (2013) S276–S290. Reference Table 4, p. S284.

8.2 Leakage through Abandoned Oil & Gas Wells

As discussed in Attachment B of Reference 1, the only wells that currently penetrate the confining zone (Eau Claire Formation) are the IBDP injection and verification wells, and the IL-ICCS injection and verification wells, all of which were constructed in accordance with UIC Class VI requirements and are actively or will be monitored for **integrity on a** regular basis. No other wells in the AOR have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone).

As a result, we conclude that the risk of leakage through this pathway is almost impossible (and should in fact be zero) since no abandoned wells penetrate the confining zone. The magnitude and timing of such a leak are therefore not estimated.

Although leakage through abandoned wells will not occur as a primary pathway, it is possible that leakage that has migrated through the confining zone and into the more recent geologic strata may enter an abandoned well and migrate through the well to the surface; however, such leakage is expected to be detected by other monitoring methods (such as groundwater monitoring) as discussed in Section 5 of this MRV Plan.

8.3 Leakage through Fractures, Faults, and Bedding Plane Partings

As discussed in Section 2.2 of Reference 2, there are no regional faults or folds mapped within a 15-mile radius of the proposed IL-ICCS site. 2D and 3D seismic survey data collected and analyzed as part of the IBDP and IL-ICCS projects confirm the lack of faults or folds. Also as discussed in Section 2.2 of Reference 2, the risk of a significant seismic event in the IL-ICCS project area (which could open fractures in the confining zone and overlying geologic strata and allow leakage from the injection zone) is minimal.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude and timing of such a leak, if it were to occur, would be dependent on the magnitude of the seismic event. If such an event were to occur during the injection period or after, it is possible that entire mass of CO2 that was injected into the reservoir up to that time may eventually be released to the surface; the timing of such a leak would occur over the course of several months to years following the seismic event

8.4 Leakage through Confining Zone Limitations

As discussed in Sections 2.2 and 2.5 of Reference 2, the Eau Claire Formation does not have any known penetrations (save for IBDP and IL-ICCS wells) within a 17-mile radius of the project site, has a laterally extensive shale component, and has only a slight dip (<1 degree). The type of leakage event through a confining zone limitation is conceived as an undiscovered local anomaly in the Eau Claire Formation, small in size, which would allow CO2 to leak through the confining zone into overlying strata.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude of such a leak, if it were to occur, is likely to be very small, due to the known low permeability of the Eau Claire and the overlying secondary seal strata (Makoqueta Shale and New Albany Shale) that are also low permeability geologic units. For the same reason, it is believed that the timing of such a leak to the surface may be extremely slow (e.g., over the course of decades or longer), as the leak must pass upward through the confining zone, the secondary confining strata, and other geologic units.

8.5 Leakage through Injection or Monitoring Wells

As discussed in Sections I,K, L, and M of Reference 1 and further detailed in Attachments C (Testing and Monitoring Plan) and G (Well Construction) of Reference 1, design, construction, operation, maintenance, and monitoring plans for the injection-zone wells have been developed in accordance with UIC Class VI standards to minimize the potential for loss of well integrity. Additionally, the IBDP project at the ADM Decatur facility has provided prior experience in well construction, operations and maintenance, and monitoring that has been applied in the IL-ICCS project to further reduce the risk of a leakage pathway.

As a result, we conclude that the risk of leakage through this pathway is highly improbable. If a leak were to occur through this pathway, the magnitude of the leak is likely to be on the order of several hundred to several thousand pounds of CO2, depending on the location of the leak relative to the surface and the complexity of logistics required to seal the leak; since injection-zone wells are continuously monitored, early detection of a leak is anticipated, with resulting operations to be shut down and the well shut in to minimize the mass of CO2 leakage. The timing of CO2 release to the surface would be dependent on the location of the leak relative to the surface, and the resulting geologic strata into which the CO2 is released.

Table 1 shows IL-ICCS project injection and monitoring wells, with well depth, age, and construction information.

TABLE 1. IL-ICCS PROJECT WELL DATA

WELL ID	DEPTH	AGE	CONSTRUCTION
MVA 10LG	101 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 11LG	135 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 12LG	95 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 13LG	140 feet	3 years	Per Illinois Dept. of Public Health regulations
CCS#1	7,236 feet KB	6 years	Per UIC Class VI regulations
GM#1	3,496 feet KB	6 years	Per UIC Class VI regulations
VW#1	7,272 feet KB	6 years	Per UIC Class VI regulations

CCS#2	7,200 feet KB	1 year	Per UIC Class VI regulations
GM#2	3,555 feet KB	3 years	Per UIC Class VI regulations
VW#2	7,237 feet KB	1 year	Per UIC Class VI regulations

9.0 Detection, Verification, and Quantification of Leakage

9.1 Leakage Detection

Leakage detection for the IL-ICCS project will incorporate several monitoring programs: visual inspection of the pipeline to the injection well, injection well monitoring and MIT, CO2 plume / pressure front monitoring, and groundwater quality monitoring. Table 2 provides general information on the leakage pathways, monitoring programs to detect such leakage, spatial coverage of the monitoring program, and the monitoring timeline. Further details are provided in Reference 1, Attachment C (Testing and Monitoring Plan).

TABLE 2. LEAKAGE DETECTION MONITORING

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Monitoring Timeline
Surface Components	Visual Inspection Injection Well Monitoring & MIT	From flow meter to injection wellhead Injection well (from surface to injection formation)	Monthly for duration of injection (5 years) For duration of injection (5 years)
Abandoned Oil & Gas Wells	Plume / Pressure Front Monitoring Groundwater Quality Monitoring	From injection wellhead to edge of AMA Groundwater monitoring locations (see Figure 1)	For duration of injection (5 years); and in Years 1 and 10 following injection Quarterly to annual during injection (5 years)
Fractures & Faults	Plume / Pressure Front Monitoring Groundwater Quality Monitoring	From injection wellhead to edge of AMA Groundwater monitoring locations (see Figure 1)	For duration of injection (5 years); and in Years 1 and 10 following injection Quarterly to annual during injection (5 years)
Confining Zone Limitations	Plume / Pressure Front Monitoring Groundwater Quality Monitoring	From injection wellhead to edge of AMA Groundwater monitoring locations (see Figure 1)	For duration of injection (5 years); and in Years 1 and 10 following injection Quarterly to annual during injection (5 years)
Injection or Monitoring Wells	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)

9.1.1 Surface Leakage Detection

Controlled or planned emissions from maintenance would occur when a section of a pipe containing CO_2 is isolated and vented so that a part can be maintained or repaired. Examples include replacement of instruments and valves as well as replacement of gaskets in the event of a leaking flange. Planned emissions due to maintenance will be limited to the extent possible. Controlled emissions will be tracked and reported as “leakage” (as the CO_2 will be vented rather than injected).

Unintentional (fugitive) emissions could arise from leakage of CO_2 at flanges and seals, at defects or cracks in the casing wall, or at pressure relief valves along the pipeline. Leakage from the pipeline or wellhead would be detected visually by ice crystal formation (due to the temperature reduction associated with release of supercritical CO_2 to the atmosphere) around the leakage point. Visual monitoring for these emissions will be performed monthly to detect fugitive emissions.

Visual inspection will not be possible for the one segment of pipeline that is underground. This section of the pipeline is 100% welded with no valves or flanges that could act as a leakage source; therefore, the potential for leakage in this segment is very low. Leak detection for this segment of pipeline would be limited to observation of abnormal pressure drop during a period of well shut-in and there is an absence of leakage detected in the aboveground pipeline. Well shut-in will be planned to occur on an annual basis.

9.1.2 Subsurface Leakage Detection

Leakage from the subsurface would be detected by one or more of the monitoring systems in the form of multiple measurements that are outside of the statistical baseline values (see Section 10,) are persistent over a time period (i.e., not a one-time anomalous measurement), and cannot be explained by a variation in injection operations or unanticipated conditions in the injection formation.

In all cases where monitoring data suggest a leak, data verification procedures will be followed as outlined in the Quality Assurance and Surveillance Plan (QASP, located in Reference 1, Attachment C, Appendix A). Data verification efforts should eliminate the possibility that a “false positive” leak detection occurs.

Injection Well Monitoring and MIT. Injection well monitoring will include pressure and temperature monitoring, and the use of one or more approved methods for MIT as described in the Final Permit (Reference 1). The injection well monitoring methods are briefly described below; further information on testing and monitoring procedures can be found in Reference 1, Attachment C.

1. Injection Well Pressure and Temperature. Pressure and temperature will be continuously monitored during injection operations, at the surface (wellhead), at the injection zone, and in the well annulus. Anomalous measurements will trigger further investigation, and if not attributable to operational or injection zone conditions, such measurements could indicate CO_2 leakage.

2. Wireline Temperature Log. 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.

   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.

3. Temperature Log using Distributed Temperature Sensing (DTS). 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, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity.

   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.

4. Pulse Neutron Logging. Logging data will be recorded across the wellbore from the surface down to primary caprock.

   Data analysis will identify the mobilization of CO_2 or differences in the salinity of the reservoir fluids in the observation zone above the Eau Claire Shale seal. Differences between the measured and baseline value(s) may indicate the movement of fluids in the annulus or behind the casing.

Groundwater Quality and Geochemical Monitoring. The groundwater quality monitoring network, which includes both injection-zone monitoring and monitoring above the primary confining zone, is designed to detect unforeseen leakage from the Mt. Simon as soon after the first occurrence as possible.

Three aquifers above the primary confining zone are monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone: these include the aquifer immediately above the confining zone (Ironton/Galesville Sandstone), the St. Peter Sandstone, which is considered to be the lowermost USDW at the site (direct monitoring of the lowermost USDW aquifer is required by the EPA's UIC Program for CO_2 geologic sequestration), and the local source of drinking water, Quaternary / Pennsylvania strata (shallow groundwater). Shallow groundwater samples will be collected on a quarterly basis in years 1-2 of injection, semi-annual sampling for years 3-5 of injection, and annual sampling during post-injection; deep groundwater quality samples will be collected on an annual basis (see Reference 1, Attachment C for further detail on monitoring frequency).

In addition to direct monitoring specifically for the presence of CO_2, wells monitoring the deeper formations (St. Peter and Ironton/Galesville) are monitored for changes in geochemical and isotopic signatures that provide indication of CO_2 and/or brine leakage.

Plume and Pressure Front Monitoring. Direct and indirect methods will be utilized to monitor the CO_2 plume and pressure front. The plume will be directly monitored via annual fluid sampling in the Mt. Simon using VW#1 and VW#2. Indirect monitoring will consist of pulse neutron logging / reservoir saturation testing in VW#1, VW#2, CCS#1, and CCS#2 every two years during the injection phase, and seismic surveys / monitoring (reference Attachment C of Reference 1 for details).

Time lapse–vertical seismic profile (VSP) surveys were conducted annually using GM#1 in 2013, 2014, and 2015. The extent of the VSP survey is limited to approximately 30 acres in the vicinity of CCS #1. A baseline 3D seismic survey was conducted over the full AOR in January 2011, and a subsequent 3D survey conducted after the completion of the IBDP's injection period, in January 2015. These 3D surveys extended roughly 3,000 acres, centered near the location of CCS#2, and provided fold image coverage of roughly 2,000 acres.

Reduced-scale 3D surveys (roughly 2,000 acres, with fold image coverage of roughly 650 acres), with a focus on the vicinity north of CCS#2, will be conducted in years 1 and 10 following the conclusion of injection operations (i.e., scheduled for 2020 and 2030).

Seismic survey data interpretations should detect any faults or fractures in the subsurface strata that may indicate leakage or the potential for leakage, and will provide information on the extent of the CO_2 plume within the Mt. Simon.

Additionally, ADM will maintain a network of seismic monitoring stations (USGS will also maintain a similar seismic monitoring network) to detect seismic events greater than magnitude-1.0 (M1.0) within an 8-mile radius of the CCS#2 site, which could indicate activation of pre-existing planes of weakness (faults) that could compromise the seal formation.

Monitoring systems are anticipated to have a high capability to detect leakage that occurs. The monitoring program criteria and objectives are detailed in Section A.4 of the QASP

9.2 Leakage Verification

Once potential leakage has been detected, the following steps will be used to verify the potential location and source of leakage. Concurrent actions to minimize the detected leak (e.g., isolating the pipeline, shutting down injection operations) will be implemented.

If leakage is detected and verified, corrective action responses will be implemented in accordance with Area of Review and Corrective Action Plan (Reference 1, Attachment B) and/or the Emergency and Remedial Response Plan (Reference 1, Attachment F).

9.2.1 Surface Leakage

9.2.1.1 Obtain photographic documentation of the leakage point. (Visual signs of ice buildup or a plume are evidence of a leak.)

9.2.1.2 Identify and document the leak location on a map and/or P&I diagram of the pipeline.

9.2.2 Subsurface Leakage

If leakage is detected via surface or subsurface monitoring, and the quality assurance process has confirmed anomalous data readings:

9.2.2.1 Well Pressure / Temperature Monitoring

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.2 Mechanical Integrity Testing

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.3 Groundwater Quality / Geochemical Monitoring

a. Identify and document the aquifer in which the anomalous readings were measured.
b. Collect confirmation sample(s) and/or additional data in accordance with the QASP to verify result(s).

c. Use spatial and/or temporal analyses of available data (e.g., water quality, well measurements, reservoir flow model) to estimate the location and timing of the leakage.

9.2.2.4 Plume / Pressure Front Monitoring:

a. Determine whether injection formation characteristics (e.g., unanticipated conditions or heterogeneity) or model uncertainty are the cause of the anomalous data.
b. If step 9.2.2.4a does not determine the cause of the anomalous data, then it will be assumed that CO_2 leakage has been verified.

9.3 Leakage Quantification

9.3.1 Surface Leakage

The leakage rate from a pinhole, crack, or other defect in the pipeline or wellhead will be estimated once leakage has been detected and confirmed, using a methodology selected by ADM. Leakage estimating methods may potentially consist of either a form of mass balance equation or models. The selected method will be based on known data such as the size of the opening and the measured pressure, density, and temperature of CO_2 in the conduit at the time the leak was discovered.

Once a leakage rate has been estimated, the quantity (mass) of leakage may be estimated by calculating the approximate length of time that leakage occurred (e.g., based on time that leak was discovered and prior time that pipeline integrity was last verified). It is understood that this quantification method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

9.3.2 Subsurface Leakage

The ease with which leakage rate from the subsurface may be quantified will depend on the monitoring system that detected the leak. For example, leakage that is detected from pressure/temperature readings or MIT results may be more easily quantified (due to its location close to the injection source) than leakage that is detected from groundwater quality monitoring or from measurements of the CO_2 plume / pressure front.

Should leakage be detected and verified based on pressure/temperature readings or MIT results, ADM will select an estimation method to quantify leakage. One potential method under consideration is to use a form of mass balance equation; as with pipeline or wellhead leakage estimates, this method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

Similarly, should leakage be detected and verified based on groundwater monitoring data or plume / pressure front monitoring, ADM will select a method to estimate the quantity of leakage. One potential estimation method is to use the reservoir model to simulate a leak, use observed data to calibrate the "leaky" model. Once calibrated, the resulting model should provide a reasonably accurate estimate of the leakage quantity. ADM reserves the right to utilize other estimation methods (e.g., groundwater data evaluation) to evaluate leakage quantities.

9.3.3 Leakage Emitted to Surface

Mass balance calculations (see Section 11) require the estimation of leakage emitted to the surface / atmosphere. In the case of surface leakage (from pipeline or wellhead), the entire quantity of CO_2 that has leaked will be released to the atmosphere. For subsurface leakage, ADM will initially assume that the entire estimated quantity of CO_2 that has leaked will eventually reach the surface, unless modeling or other analysis is used to demonstrate that some portion of the leak will remain within the subsurface strata and will not reach the surface.

10.0 DETERMINATION OF EXPECTED BASELINES

Baseline data will consist of the following:, groundwater quality and geochemistry, MIT data, injection well pulse neutron & temperature logs, injection well DTS profile, seismic and pressure front data

10.1 Injection Well Monitoring

The following data will be collected over an established timeframe determined by ADM prior to injection operations:

1. Injection well pulse neutron and temperature logs (surface to confining zone)
2. Injection well DTS temperature profile (surface to confining zone) during well shut-in.

The average of these values will be used as the baseline for these parameters. Baseline logs for CCS#2 were collected on September 30, 2015. The baseline injection well DTS temperature profile during well shut-in was completed on December 31, 2016.

Anticipated annulus pressure as noted in Reference 1, Attachment A & C is discussed as follows:

1. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) during injection.
2. During period of well shut down, the surface annulus pressure will be kept at a minimum of 100 psi.
3. At all times, 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 6,320 feet below Kelly Bushing (KB).

[Note: Surface annulus pressure downhole annulus/tubing differential pressure and injection pressure measurements are not considered baseline parameters. Injection pressure (at surface and at depth) measurements will be collected continuously once CO_2 injection starts. Injection pressure will be a function of the mass flow rate, density, and pressure of the delivered CO_2; thus, the baseline injection pressure range will be based on the anticipated range of the mass flow rate, density, and pressure of the delivered CO_2. Injection pressure will be used for comparison against other baseline data and model predictions. Maximum injection pressure at the surface is limited to 2,284 psig.]

10.2 Groundwater Quality and Geochemical Change Monitoring

Groundwater quality and geochemistry will consist of the following data collection:

Shallow groundwater monitoring (4 sites)

- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density

Lowermost USDW (St. Peter Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Lowermost aquifer above confining zone (Ironton-Galesville Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Further details on testing and monitoring may be found in Reference 1, Attachment C.

Baseline groundwater quality and geochemistry will be developed in accordance with approved USEPA statistical methods using software (e.g., USEPA's ProUCL) to calculate the accepted range of data values (e.g., data within the 95% confidence limit). Data values collected during injection and post-injection periods that are outside of the accepted range will be an indicator that leakage may have occurred, subject to data verification per the QASP. Baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.

10.3 Mechanical Integrity Testing

Baseline MIT data will be collected following installation of CCS#2 and VW#2, and will consist of logged data from the well (e.g., cement evaluation, pressure data, or other logging type as described in Section 5.1). Baseline MIT data will be compared to subsequent MIT data (collection frequency as noted in Reference 1, Attachment C) to evaluate whether well integrity has been compromised. Baseline MIT data were collected from CCS#2 on (05/31/2015, 06/10/2015, 07/06/2015, 07/25/2015, 09/29/2015, & 09/30/2015), and from VW#2 on (11/01/2012 & 09/10/2015), and consisted of running a cement evaluation log and temperature log on CCS#2, pressure testing the casing & annulus on CCS#2, running a cement evaluation log on VW#2, and pressure testing the annulus on VW#2..

10.4 Plume and Pressure Front Monitoring

Baseline pulse neutron logging measurements will be collected in VW#1, VW#2, CCS#1, and CCS#2. Logged data will indicate, at minimum, CO_2 saturation within the Mt. Simon. Baseline data will be compared to data collected during Years 2 and 4 of injection operations. Baseline RST values for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/30/2016) were collected

Baseline 3D VSP and surface seismic surveys have been completed (performed in 2011 and 2015). Seismic data collected in 2020 and 2030 (post-injection) will be compared to baseline surveys to evaluate plume location and configuration relative to the reservoir model prediction.

Data from seismic event monitors in the vicinity of the IL-ICCS project will be used to compare seismicity during and following injection operations with pre-injection seismicity. Increased seismicity, while not directly correlating to a leak, may provide additional information in the event of a leak detected from other monitoring data.

11.0 SITE SPECIFIC MODIFICATIONS TO THE MASS BALANCE EQUATIONS

40 CFR 98, Subpart RR requires greenhouse gas (GHG) reporting for geologic sequestration (GS) of carbon dioxide. 40 CFR 98.442 through 98.447 details the data calculations, monitoring, estimating, reporting and recordkeeping requirements for GS projects. This section describes how ADM will calculate the mass of CO_2 injected, emitted, and sequestered.

The mass (in metric tons, MT) of CO_2 sequestered in the Mt. Simon will consist of the following components (equations referenced from Subpart RR of 40 CFR 98):

- Annual mass of CO_2 injected (CO2I, Equation RR-4)

  Parameter CO2I will be measured using flow meter FE006 (Coriolis meter) as referenced in P&ID No. 1041-PD-13 in Appendix C of Reference 2. Flow rate is measured on a mass basis (kg/hr). Annual mass will be calculated based on the quarterly mass flow rate measurements multiplied by the quarterly CO_2 concentrations provided to USEPA by ADM for CCS#2.

- Annual mass of CO_2 emitted by surface leakage (CO2E, Equation RR-10)

- Annual mass of CO_2 emitted from equipment leaks and vented emissions (CO2FI,)

Equipment that may emit CO_2 to the atmosphere include three thermal pressure relief valves along the pipeline (TRV-001, TRV-002, and TRV-003), and two pressure relief valves (PSV101 and MOV101) located on the annulus head tank. Process & instrumentation diagrams (P&ID) 1041-PD-13, 1041-PD-40, and 1041-PD-50 illustrate the location of these valves.

- Annual mass of CO_2 sequestered = CO2I – CO2E – CO2FI (Equation RR-12)

Parameters CO2E and CO2FI will be measured using the leakage quantification procedure described in Section 5.3. ADM will estimate the mass of CO_2 emitted from relief valves or leakage points based on operating conditions at the time of the release – pipeline pressure and flow rate, set point of relief valves, the size of the valve opening or leakage point opening, and the estimated length of time that the emission occurred. It is noted that this estimation method may have a large margin of error; therefore, ADM may include a statistical estimate of the calculation error to document the likely range of the emitted quantity.

12.0 ESTIMATED SCHEDULE FOR IMPLIMENTATION

The anticipated date for injection operations to begin at CCS#2 is 1st Quarter 2017. At that time, ADM will begin implementation of the leakage detection process. Also by that time, ADM expects to begin data collection for the purpose of calculating the total amount of CO_2 sequestered in the Mt. Simon formation.

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13.0 QUALITY ASSURANCE PROGRAM

Quality assurance procedures for the IL-ICCS project are provided in the Quality Assurance and Surveillance Plan (QASP) found in Reference 1, Attachment C, Appendix A.

- Section A of the QASP details project organization, project reasoning and regulatory information, project description, quality objectives and criteria, training and certification requirements, and project documentation/ recordkeeping.
- Section B details acquisition and generation of project data: sampling design, methods, handling and custody; sample analytical methods; quality control; instrument/equipment inspection, testing, calibration, operation and maintenance; use of indirect measurements; and data management.
- Section C details project assessments, corrective actions, and internal reporting.
- Section D discusses data validation and use.

14.0 RECORDS RETENTION

ADM will maintain and submit records required under Section N of the Final Permit issued by USEPA. Reports will be maintained in electronic format at the ADM Decatur facility unless the USEPA Director is otherwise notified by ADM.

SUMMARY OF PREVIOUS REVISIONS:

Date	Version	Author	Reason(s) for revision
01/06/2016	1.0	Outzen	New Document
01/07/2016	2.0	Outzen	Minor Formatting changes.