U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

CLASS VI

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 W. JACKSON BOULEVARD
CHICAGO, IL 60604-3590

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

Permit Number: IL-115-6A-0001
Facility Name: CCS#2

Pursuant to the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 124, 144, 146, and 147,

Archer Daniels Midland of Decatur, IL

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of Illinois, Macon County, T 17N, R 3E of 3rd Principal Meridian, Section 32, 39º53'09.32835"N, -88º53'16.68306"W, for injection of the Carbon Dioxide (CO_2) stream generated by ADM's fuel ethanol production unit and as characterized in the permit application and the administrative record as a liquid, supercritical fluid, or gas into the Mount Simon at depths between 5,553 feet and 7,043 feetbelow ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection is the Eau Claire Formation. Injection shall not commence until the operator has received written authorization from the Director of the Water Division of EPA Region 5, in accordance with Section Q of this permit.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit as enforceable conditions: A, B, C, D, E, F, G, H and I.

This permit shall become effective on ____________________, and shall remain in full force and effect during the operating life of the facility and the post-injection site care period until site closure is authorized and completed, unless this permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 144.39, 144.40, or 144.41. This permit shall also remain in effect upon delegation of primary enforcement responsibility to the State of Illinois until such time as the State issues its own permit to the permittee or the State chooses to adopt this permit as a State permit. The permit will expire in one year if the permittee fails to commence construction, unless a written request in electronic format for an extension of this one-year period has been approved by the Director. The permittee may request an expiration date sooner than the one-year period, provided no construction on the well has commenced. This permit will be reviewed at least every five years from the effective date specified above.

Signed and Dated: ______________________

DRAFT

____

Christopher Korleski
Director, Water Division

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a). Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable regulations.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination** – The Director of the Water Division of Region 5 of the U. S. Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Minor Modifications** – Upon the consent of the permittee, the Director may modify a permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not processed as a minor modification under 40 CFR 144.41 must be made for cause, and with part 124 draft permit and public notice as required in 40 CFR 144.39.

3. **Transfer of Permits** – This permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section N(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim must be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2. Claims of confidentiality for the following information will be denied:

1. The name and address of the permittee; and

2. Information which deals with the existence, absence or level of contaminants in drinking water.

E. DEFINITION

All terms used in this permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Duty to Comply** – The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. **Duty to Reapply** – If the permittee wishes to continue an activity regulated by this permit after the expiration or termination of this permit, the permittee must apply for and obtain a new permit.

3. **Penalties for Violations of Permit Conditions** – Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

4. **Need to Halt or Reduce Activity Not a Defense** – It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. **Duty to Mitigate** – The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information** – The permittee shall furnish to the Director in an electronic format, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this permit.

8. **Inspection and Entry** – The permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit;

   (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

9. **Signatory Requirements** – All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan (Attachment B of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.84.

2. At the fixed frequency specified in the Area of Review and Corrective Action Plan, or more frequently when monitoring and operational conditions warrant, the permittee must reevaluate the area of review and perform corrective action in the manner specified in 40 CFR 146.84 and update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

3. Following each AoR reevaluation or a demonstration that no evaluation is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the AoR results. Once approved by the Director, the revised Area of Review and Corrective Action Plan will become an enforceable condition of this permit.

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The approved financial assurance mechanism is found in Attachment H and in the administrative record of this permit.

   The financial instrument(s) must be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of 40 CFR 146.84);

   (b) Injection well plugging (that meets the requirements of 40 CFR 146.92);

   (c) Post injection site care and site closure (that meets the requirements of 40 CFR 146.93);

   (d) Emergency and remedial response (that meets the requirements of 40 CFR 146.94).

2. **Cost Estimate Updates** – During the active life of the geologic sequestration project, the permittee must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. The permittee must also provide to the Director written updates in an electronic format of adjustments to the cost estimate within 60 days of any amendments to the Project Plans included as Attachments B – F of this permit, which address items (a) through (d) in Section H(1) of this permit.

3. **Notification** –

   (a) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has received written approval from the Director.

(b) The permittee must notify the Director by certified mail and in an electronic format of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action and/or Emergency and Remedial Response.

(i) In the event that the permittee or the third party provider of a financial responsibility instrument is going through a bankruptcy, the permittee must notify the Director by certified mail and in an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the permittee as debtor, within 10 days after commencement of the proceeding.

(ii) A guarantor of a corporate guarantee must make such a notification if he or she is named as debtor, as required under the terms of the guarantee.

(iii) A permittee who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

4. **Establishing Other Coverage** – The permittee must establish other financial assurance or liability coverage acceptable to the Director, within 60 days of the occurrence of the events in Section H(2) or H(3) of this permit.

I. CONSTRUCTION

1. **Siting** – The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

2. **Casing and Cementing** – Casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must prevent the movement of fluids into or between USDWs for the expected life of the well in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in Attachment G of this permit and in the administrative record for this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

3. **Tubing and Packer Specifications** – Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone immediately above the injection

zone. The tubing and packer used in the well are represented in engineering drawings contained in Attachment G of this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

J. PRE-INJECTION TESTING

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at 40 CFR 146.87. This testing shall include:

   (a) Logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

   (i) Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

   (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

   (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

   (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and

   (v) Any alternative methods that are required by and/or approved by the Director pursuant to 40 CFR 146.87(a)(5).

   (b) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b);

   (c) Records of the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 CFR 146.87(c);

   (d) Tests to provide information about the injection and confining zones, including calculated fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(d); and

   (e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

   (i) A pressure fall-off test and

   (ii) A pumping test or injectivity tests.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for logging and testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee must provide

the Director or their representative with the opportunity to witness all logging, sampling, and testing required under this Section.

K. OPERATIONS

1. **Injection Pressure Limitation** – Except during stimulation, the permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment A.

2. **Stimulation Program** – Pursuant to requirements at 40 CFR 146.82(a)(9), all stimulation programs proposed by the permittee must be approved by the Director as a permit modification and incorporated into Attachment I of this permit.

3. **Additional Injection Limitation** – No injectate other than that identified on page 1 of this permit shall be injected except fluids used for stimulation, rework, and well tests as approved by the Director.

4. **Annulus Fluid** – The permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

5. **Annulus/Tubing Pressure Differential** – Except during workovers or times of annulus maintenance, the permittee must maintain on the annulus a pressure that exceeds the operating injection pressure as specified in Attachment A of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

6. **Automatic Alarms and Automatic Shut-off System** –

   (a) The permittee must:

      (i) Install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      (ii) Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

   (b) Testing under this Section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative unless the Director authorizes an unwitnessed test in advance. The permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section N(4) of this permit.

7. **Precautions to Prevent Well Blowouts** – At all times, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall follow procedures such as those below to assure that a backflow or blowout does not occur:

   (a) Limit the temperature and/or corrosivity of the injectate; and

   (b) Develop procedures necessary to assure that pressure imbalances do not occur.

8. **Circumstances Under Which Injection Must Cease** –

   Injection shall cease when any of the following circumstances arises:

   (a) Failure of the well to pass a mechanical integrity test;

   (b) A loss of mechanical integrity during operation;

   (c) The automatic alarm or automatic shut-off system is triggered;

   (d) A significant unexpected change in the annulus or injection pressure;

   (e) The Director determines that the well lacks mechanical integrity; or

   (f) The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

9. **Approaches for Ceasing Injection** –

   (a) The permittee must shut-in the well by gradual reduction in the injection pressure as outlined in Attachment C of this permit; or

   (b) The permittee must immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

L. MECHANICAL INTEGRITY

1. **Standards** – Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity

tests/demonstrations must be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. In order to conduct testing without an EPA representative, the following procedures must be followed.

(a) The permittee must submit prior notification in an electronic format within the time period specified in Section L(3) of this permit, including the information that no EPA representative is available, and receive permission from the Director to proceed;

(b) The test must be performed in accordance with the Testing and Monitoring Plan (Attachment C of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest;

(c) A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section N(4) of this permit.

2. **Mechanical Integrity Testing** – The permittee shall conduct a casing inspection log and mechanical integrity testing as follows:

(a) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A pressure test with liquid or gas; and

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A tracer survey such as an oxygen activation log; or

(ii) A temperature or noise log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(c) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, injection rate, injection volumes; pressure on the annulus between tubing and long string casing; and annulus fluid volume as specified in 40 CFR 146.88(e), and 146.89(b).

(d) At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89(c):

(i) An Administrator-approved tracer survey such as an oxygen-activation log; or

(ii) A temperature or noise log. The Director may require such tests whenever the well is worked over; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(e) After any workover that may compromise the internal mechanical integrity of the well, the well shall be tested by means of a pressure test approved by the Director and the well must pass the test to demonstrate mechanical integrity.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of 40 CFR 146.92(a).

(g) The Director may require the use of any other tests to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator pursuant to requirements at 40 CFR 146.89(e).

3. **Prior Notice and Reporting** –

(a) The permittee shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity in an electronic format at least 30 days prior to such demonstration. At the discretion of the Director a shorter time period may be allowed.

(b) Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within the time period specified in Section N(4) of this permit.

4. **Gauge and Meter Calibration** – The permittee shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

5. **Loss of Mechanical Integrity** –

(a) If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:

(i) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments C or F of this permit;

(ii) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, implement the Emergency and Remedial Response Plan (Attachment F of this permit);

(iii) Follow the reporting requirements as directed in Section N of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) Notify the Director in an electronic format when injection can be expected to resume.

(b) If a shutdown (*i.e.*, down-hole or at the surface) is triggered, the permittee must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity Testing on Request From Director** – The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

M. TESTING AND MONITORING

1. **Testing and Monitoring Plan** –

(a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan (Attachment C of this permit) and with the requirements at 40 CFR 144.51(j), 146.88(e), and 146.90. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test. In performing all testing and monitoring under this permit, the permittee must follow the procedures approved by the Director. If the permittee is unable to follow the EPA approved procedures, then, the permittee must contact the Director at least 30 days prior to testing to discuss options, if any are feasible. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take an appropriate action, including but not limited to, requiring the permittee to re-run the test.

(b) The permittee must update the Testing and Monitoring Plan as required at 40 CFR 146.90 (j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G.2. of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation; following any significant changes to the facility such as addition of monitoring wells or newly permitted injection wells within the AoR; or when required by the Director.

(c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis** – The permittee shall analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(a).

3. **Continuous Monitoring** – The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, volume, the pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The permittee shall maintain for EPA's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Corrosion Monitoring** – The permittee shall perform corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c) to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 CFR 146.86(b).

5. **Ground Water Quality Monitoring**– The permittee shall monitor ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones. This monitoring shall be performed for the parameters identified in the Testing and Monitoring Plan at the locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d).

6. **External Mechanical Integrity Testing** – The permittee shall demonstrate external mechanical integrity as described in the Testing and Monitoring Plan and Section L of this permit to meet the requirements of 40 CFR 146.90(e).

7. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

8. **Plume and Pressure Front Tracking** –The permittee shall track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) as described in the Testing and Monitoring Plan.

   (a) The permittee shall use direct methods to track the position of the carbon dioxide plume and the pressure front in the injection zone as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(1).

   (b) The permittee shall use indirect methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2).

9. **Surface Air and/or Soil Gas Monitoring** – The permittee shall conduct any surface air monitoring and/or soil gas monitoring required by the Director to detect movement of carbon dioxide that could endanger a USDW at the frequency and locations described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(h).

10. **Additional Monitoring** – If required by the Director as provided in 40 CFR 146.90(i), the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 40 CFR 146.86(a). This monitoring shall be performed as described in a modification to the Testing and Monitoring Plan.

N. REPORTING AND RECORDKEEPING

1. **Electronic Reporting** – Electronic reports, submittals, notifications and records made and maintained by the permittee under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director at:

   https://epa.velo.pnnl.gov/operators

2. **Semi-Annual Reports** – The permittee shall submit semi-annual reports containing:

   (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

   (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

   (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

(d) A description of any event which triggers the shut-off systems required in Section (K)(6) of this permit pursuant to 40 CFR 146.88(e), and the response taken;

(e) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume and/or mass injected cumulatively over the life of the project;

(f) Monthly annulus fluid volume added or produced; and

(g) Results of the continuous monitoring required in Section M(3) including:

(i) A tabulation of: (1) daily maximum injection pressure, (2) daily minimum annulus pressure, (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure, (4) daily volume, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and

(ii) Graph(s) of the continuous monitoring as required in Section M(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and

(h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section M of this permit.

3. **<u>24-Hour Reporting</u>** –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment and/or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section (K)(6) of this permit (i.e., down-hole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section(N)(3)(a) of this permit. The submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

4. **Reports on Well Tests and Workovers** – Report, within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit.

5. **Advance Notice Reporting** –

(a) **Well Tests** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.

(b) **Planned Changes** – The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid shall be submitted to the Director for review and written approval at least 30 days prior to injection; this approval may result in a permit modification.

(c) **Anticipated Noncompliance** – The permittee shall give at least 14 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. **Additional Reports** –

(a) **Compliance Schedules** – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 30 days following each schedule date.

(b) **Transfer of Permits** – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(c) **Other Noncompliance** – The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section N(3)(b) of this permit.

(d) **Other Information** – When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).

(e) **Report on Permit Review** – Within 30 days of receipt of this permit, the permittee shall certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

7. Records –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g. modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The retention periods specified in Section N(7)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Section N(7)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The name(s) of the individual(s) who performed the sampling or measurements;

(iii) A precise description of both sampling methodology and the handling of samples;

(iv) The date(s) analyses were performed;

(v) The name(s) of the individual(s) who performed the analyses;

(vi) The analytical techniques or methods used; and

(vii) The results of such analyses.

O. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

1. **Well Plugging Plan** – The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment D of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.92.

2. **Revision of Well Plugging Plan** – If the permittee finds it necessary to change the Well Plugging Plan (Attachment D of this permit), a revised plan shall be submitted in an electronic format to the Director for written approval. Any amendments to the Well Plugging Plan must be approved by the Director and must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41.

3. **Notice of Plugging and Abandonment** – The permittee must notify the Director in writing in an electronic format pursuant to 40 CFR 146.92(c), at least 60 days before plugging, conversion or abandonment of a well. At the discretion of the Director, a shorter notice period may be allowed.

4. **Plugging and Abandonment Approval and Report** –

(a) The permittee must receive written approval of the Director before plugging the well and shall plug and abandon the well in accordance with 40 CFR 146.92, as provided in the Well Plugging Plan (Attachment D of this permit).

(b) Within 60 days after plugging, the permittee must submit in an electronic format a plugging report to the Director. The report must be certified as accurate by the permittee and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for 10 years following site closure. The report must include:

(i) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Director (Attachment D of this permit); or

(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger underground sources of drinking water, the permittee shall replug the well as required by the Director.

5. **Temporary Abandonment** – If the permittee ceases injection into the well for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, 40 CFR 144.52 (a)(6), and 40 CFR 146.92, or make a demonstration of non-endangerment of this well while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

6. **Post-Injection Site Care and Site Closure Plan** –

(a) The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan, found as Attachment E of this permit, which meets the requirements of 40 CFR 146.93 and is an enforceable condition of this permit. The permittee shall:

(i) Upon cessation of injection, either submit in an electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(ii) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval. The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

(b) The permittee shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered, as specified in the Post-Injection Site Care and Site Closure Plan and in 40 CFR 146.90, and 40 CFR 146.93, including:

(i) Ground water quality monitoring;

(ii) Tracking the position of the carbon dioxide plume and pressure front including direct pressure monitoring and geochemical plume monitoring and the use of indirect methods;

(iii) Any other required monitoring, e.g., soil gas and/or surface air monitoring described in the Post-Injection Site Care and Site Closure Plan;

(iv) The permittee shall submit in an electronic format the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan; and

(v) The permittee shall continue to conduct post-injection site monitoring for at least 50 years or for the duration of any alternative timeframe approved pursuant to 40 CFR 146.93(c) and the Post-Injection Site Care and Site Closure Plan.

(c) The post-injection monitoring must continue until the project no longer poses an endangerment to USDWs and the demonstration pursuant to 40 CFR 146.93(b)(2) and as described in Section O(5)(c) of this permit is approved by the Director.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section O(5)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including extend the monitoring period) if the carbon dioxide plume and the associated pressure front have not stabilized or there is a concern that USDWs are being endangered.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment E of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachment E of this permit – the Post-Injection Site Care and Site Closure Plan – in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified at 40 CFR 146.93(f).

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the information listed at 40 CFR 146.93(g).

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report , records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

P. EMERGENCY AND REMEDIAL RESPONSE

1. The Emergency and Remedial Response Plan describes actions the permittee must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment F of this permit), which is an enforceable condition of this permit, and with 40 CFR 146.94.

2. If the permittee obtains evidence that the injected carbon dioxide and/or associated pressure front may cause endangerment to a USDW, the permittee must:

   (a) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments C or F of this permit;

   (b) Take all steps reasonably necessary to identify and characterize any release;

   (c) Notify the Director within 24 hours; and

   (d) Implement the Emergency and Remedial Response Plan (Attachment F of this permit) approved by the Director.

3. At the frequency specified in the Area of Review and Corrective Action Plan, or more frequently when monitoring and operational conditions warrant, the permittee shall review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The permittee shall also incorporate monitoring and operational data and in response to AoR reevaluations required under Section G.2. of this permit or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation; following any significant changes to the facility such as addition of injection wells; or when required by the Director.

4. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

Q. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program as specified in Section J of this permit and in 40 CFR 146.87 are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment B of this permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with 40 CFR 146.86 and Section I of this permit;

6. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of the permit;

7. The Director has approved demonstration of the alarm system and shut-off system under Section K.6 of this permit; and.

8. The Director has given written authorization to commence injection.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by 40 CFR Parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. WELL PLUGGING PLAN

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. CONSTRUCTION DETAILS

H. FINANCIAL ASSURANCE DEMONSTRATION

I. STIMULATION PROGRAM

ATTACHMENT A: SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

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

Facility contact: Mr. Steve Merritt, Plant Manager
4666 Faries Parkway, Decatur, IL
(217) 424-5750, steve.merritt@adm.com

Well location: Decatur, Macon County, IL;
39º53'09.32835", -88º53'16.68306"

Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE	UNIT
Maximum Injection Pressure - Surface	2284	psig
Minimum Annulus Pressure	100	psig
Minimum Annulus Pressure/Tubing Differential (directly above and across packer)	100	psig

The injection pressure will be measured at the wellhead.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined using the fracture gradient obtained from injectivity data from the nearby CCS#1 well multiplied by 0.9 (146.88 (a)).

Routine Shutdown Procedure:
Under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 500 tons per day over a 6 day period to ensure protection of health, safety, and the environment. (Procedures that address immediately shutting in the well are in Attachment F (Emergency and Remedial Response Plan) of this permit).

Class VI Injection Well Reporting Frequencies

ACTIVITY	MINIMUM REPORTING FREQUENCY
CO_2 stream characterization	Semi-annually
Pressure, flow, rate, volume, pressure on the annulus, annulus fluid level and temperature	Semi-annually
Corrosion monitoring	Semi-annually
External MIT	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in Attachment C (the Testing and Monitoring Plan) of this permit.

Class VI Project Reporting Frequencies

ACTIVITY	MINIMUM REPORTING FREQUENCY
Ground water quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Surface air and/or soil gas monitoring	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial Responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in Attachment C (the Testing and Monitoring Plan) of this permit.

Start-up Monitoring and Reporting Procedures

These additional procedures describe how ADM will: A) initiate injection as detailed in the table below and conduct start-up specific monitoring of the CCS#2 site pursuant to 40 CFR 146.90 and B) submit monthly reports during the first six months of injection.

A) Multi-stage (step-rate) start-up procedure and start-up period[1]:

1) This procedure will be done using the existing surface and downhole pressure and temperature gauges in CCS#2, CCS#1, VW#1, VW#2, and GM#2.

2) During the start-up period the permittee will submit a daily report summarizing and interpreting the operational data. At the agency's request, the permittee will schedule a daily conference call to discuss the operational data.

3) A series of successively higher injection rates have been determined as shown in the table below, and the elapsed time and pressure values are read and recorded for each rate and time step. Each rate step will last 24 hours. At no point during the procedure will the injection pressure exceed the maximum injection pressure (2284 psig) measured at the wellhead.

4) A spinner log will be conducted during each change (step) in rate.

5) Planned Injection Rates:

Rate (Tonnes per day)	Duration (hrs.)	Percent of Permit Maximum Injection Rate (%)
550	24	16.7%
1100	24	33.3%
1650	24	50.0%

[1] Applies only to the initial start of injection operations until the well reaches full injection rate.

Rate (Tonnes per day)	Duration (hrs.)	Percent of Permit Maximum Injection Rate (%)
2200	24	66.7%
2750 (or max. available CO_2)	24	83.3%

6) Injection rates will be controlled by starting an additional compressor (fix volume with no spillback); thus, the flow will remain constant throughout the duration of the step rate period.

7) Injection rates will be measured (using the Coriolis flow meter) and data will be recorded.

8) Surface and downhole pressure and temperatures will be measured and data will be recorded at CCS#2, CCS#1, VW#1, VW#2, and GM#2.

9) During the startup period, a plot of injection rates and the corresponding stabilized pressure values will be graphically represented. During the start-up period, the project team will look for any evidence of anomalous pressure behavior.

10) If during the start-up period, anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate to better characterize the anomaly.

11) If during the start-up period, the project team determines that anomalous pressure behavior indicates formation fracturing, injection will be stopped and the line valve closed allowing the pressure to bleed-off into the injection zone.

a. The instantaneous shut-in pressure (ISIP), will be measured and the microseismic data will be reviewed for event signatures.

b. The permittee will notify the agency within 24 hours of the determination.

c. The permittee will consult with the agency before initiating further injection.

B) Additional Start-up Monthly Monitoring and Reporting[2]:

On a monthly basis, during the first six (6) months of injection, the permittee will provide the agency with a report that summarizes and provides interpretation of the microseismic and operating data described above in Part A of this section. The report shall be submitted within 30 days after the end of the reporting period.

[2] During the first six months of injection.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Facility Information

Facility name:	Archer Daniels Midland, CCS#2 Well IL-115-6A-0001
Facility contact:	Mr. Steve Merritt, Plant Manager, 4666 Faries Parkway, Decatur, IL, (217) 424-5750, steve.merritt@adm.com
Well location:	Decatur, Macon County, IL; 39º53'09.32835", -88º53'16.68306"

Computational Modeling

Model Name and Authors/Institution

ECLIPSE 300 (v2011.2) reservoir simulator with the CO2STORE module, Schlumberger.

Description of Model

Model Description

ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The CO_2STORE module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (i.e., 'liquid'), a CO_2-rich phase (i.e., 'gas'), and a solid phase, which is limited to several common salt compounds (e.g. NaCl, $CaCl_2$, and $CaCO_3$). Mutual solubilities and physical properties (e.g. density, viscosity, enthalpy, etc.) of the H_2O and CO_2 phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperature ranges between 12°C-100°C and pressures up to 60 MPa. Details of this method can be found in Spycher and Pruess (2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components may exist in both the liquid and solid phases.
- The CO_2-rich phase (i.e., 'gas') density is obtained by using the Redlich-Kwong equation of state. The model was accurately tuned and modified as further described below (Redlich and Kwong, 1949).
- The brine density is first approximated as pure water then corrected for salt and CO_2 concentration by using Ezrokhi's method (Zaytsev and Aseyev, 1992).
- The CO_2 gas viscosity is calculated per the methods described by Vesovic et al. (1990) and Fenghour et al. (1999).

The gas density was obtained using a modified Redlich-Kwong equation of state following a method developed by Spycher and Pruess, where the attraction parameter is made temperature dependent:

$$P = \left(\frac{RT_K}{V - b_{mix}}\right) - \left(\frac{a_{mix}}{T_K^{1/2} V(V + b_{mix})}\right)$$

where V is the molar volume, P is the pressure, T_K is the temperature in Kelvin, R is the universal gas constant, and a_{mix} and b_{mix} are the attraction and repulsion parameters.

The transition between liquid CO_2 and gaseous CO_2 can lead to rapid density changes of the gas phase; the simulator uses a narrow transition interval between the liquid and gaseous density to represent the two phase CO_2 region.

Because the compression facility controls the CO_2 delivery temperature to the injection well between 80°F and 120°F, the temperature of the injectate will be comparable to the reservoir formation temperature within the injection interval. Therefore, the simulations were carried out based on isothermal operating conditions. With respect to time step selection, the software algorithm optimizes the time step duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, time step size ranged from $8.64\text{x}10^1$ to $8.64\text{x}10^5$ seconds or 0.001 to 10 days. In all cases, the maximum solution change over a time step is monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of temperature and pressure calculation results occur on successive iterations. New time steps are chosen so that the predicted solution change is less than a specified target.

Description of AoR Delineation Modeling Effort

The 3D geologic model developed for the initial injection simulations was based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout the construction of the IBDP wells (CCS#1 and VW#1). Structurally, the model is also based on the interpretation of both two dimensional (2D) and three dimensional (3D) seismic survey data in conjunction with dipmeter log data acquired from the IBDP wells. Petrophysical and transport properties based on the interpreted well log data and the analysis of core samples recovered from the IBDP wells were then distributed throughout each layer in the geocellular model. Following the collection of testing and logging data during construction and pre-operational testing of CCS#2 and VW#2, the geologic model was updated pursuant to 40 CFR 146.82(c)(1).

The original, pre-construction phase model implemented porosity and permeability well logs from CCS#1, VW#1, and VW#2. Seismic inversion was performed on the 3D surface seismic cube resulting in a seismic porosity cube. This seismic porosity cube was integrated with logs to guide interpolation of porosity throughout the 3D model. For the Mt. Simon, the PorosityCube was sampled into the geomodel's 3D grid and was also used to describe lateral heterogeneity beyond the seismic survey's footprint. A workflow was prepared to document log upscaling and property modeling. To update the reservoir model following pre-injection testing, logs from CCS#2 were used to update the 3D geologic model to reflect new information while remaining true to the original seismic property-driven distributions that did not require updates. The following steps were followed to incorporate CCS#2 well log data into the model domain permeability and porosity distributions:

1. Log (ELAN) permeability curves were upscaled into the static geologic model.
2. Permeability was log transformed.
3. General distribution was developed from log-permeability data.
4. The log permeability distribution was updated through co-simulation of VW#2 and CCS#2 log-permeability data with the existing 3D model log-permeability distribution and using the general log-permeability pdf developed from the data. The result honors the new log data at and near the wells and honors the seismic driven distribution as a trend away from VW#2 and CCS#2.
5. Permeability was inverse log transformed.
6. Steps 3 through 5 were done on a zone-by-zone basis.
7. The new permeability distribution was upscaled into a reservoir model grid and the existing permeability distribution for the CCS#2 injection zone was replaced with the newly computed permeability distribution within the CCS#2 injection zone across the entire lateral extent of the reservoir model grid.

In November 2011, injection of CO_2 into CCS#1 began and, as of project completion in November 2014, 999,215 metric tons of CO_2 had been injected. Operational data from this project was used to calibrate the reservoir model being used for both the IBDP and IL-ICCS projects. Data obtained includes injection well bottom hole pressure (BHP), multi-zone pressure data from VW#1, Spinner data, i.e. injection profile logs in CCS#1, and reservoir saturation tools (RST) from both IBDP wells. These datasets have provided additional information to allow calibration of various reservoir parameters including intrinsic permeabilities, relative permeabilities, wellbore skin values, vertical to horizontal permeability ratios, and rock compressibility. These calibrations allow the model to be updated periodically to improve the accuracy between the model prediction versus the actual result.

Monitoring data used for pressure matching includes:

- Injection rate;
- Injection bottom hole pressure – real-time data collected from a down hole gauge in the injection well about 600 ft above the perforations;
- Westbay multilevel ground water characterization and monitoring system pressures – real-time pressures located at specific zones in the verification well 1000 ft. north of the injection well. Five out of ten zones were used for model calibration;
- Spinner data-flow partitioning between perforations – log run in injection well through March 2013; and
- RST well logs – CO_2 saturations around CCS#1 and VW#1 – logs run through March 2013.

More detailed information on model inputs and assumptions is given in the following subsections.

Model Inputs and Assumptions

The geologic/hydrogeologic and operational information that serve as inputs to the model are described in the following subsections. The model update meets the requirements of 40 CFR 146.82(c)(1) and simulates three years of injection in CCS#1, followed by five years of injection in CCS#2, followed by a 50-year post-injection period.

Site Geology and Hydrology

The Class VI well targets an injection zone in the Cambrian Mt. Simon Sandstone of the Illinois Basin (see coordinates above under “Facility Information”). Information on the injection and confining zones was collected during the drilling and testing of the nearby IBDP injection well CCS#1, as well as existing Illinois State Geological Survey (ISGS) studies and reports. Data from an ISGS database of core sample data and additional core sample analyses from sites within approximately 30–80 miles of the injection well were also used. Wireline log results from CCS#2 and VW#2 and core analyses from VW#2 were compared to data collected from CCS#1 and the ISGS database. The results show good agreement, validating the local site geology and hydrogeology as defined by data from CCS#1 and other nearby wells.

The Mt. Simon Sandstone is the first sedimentary unit overlying the Precambrian granitic basement rock. The depositional environment of the Mt. Simon has “commonly been interpreted to be a shallow, sub-tidal marine environment,” based on surface study of the upper Mt. Simon or studies of Wisconsin or Ozark Dome outcrops. However, based on core sample and log analysis from the CCS#1 well, and verified from pre-injection testing on CCS#2 and VW#2, the upper Mt. Simon is interpreted to have been deposited “in a tidally influenced system similar to the reservoirs used for natural gas storage in northern Illinois,” while the basal 600 ft (the target injection zone) represents an “arkosic sandstone that was originally deposited in a braided river-alluvial fan system.” In this lower zone, “abundant amounts” of secondary porosity occur due to the dissolution of feldspar grains.

Directly overlying the Mt. Simon Sandstone is the Cambrian Eau Claire Formation. Based on data from CCS#1, in the area of the injection well, the Eau Claire consists of a basal shale layer overlain by very fine-grained limestone interbedded with thin siltstone layers. The Eau Claire serves as a confining zone for gas storage projects elsewhere in the Illinois Basin. Two other regional shale units are identified as secondary confining zones—the Ordovician Maquoketa Formation and the Devonian New Albany Shale—though these units lie above the lowermost USDW. No resolvable faults or folds were identified in the injection or confining zones based on 3D seismic data collected in 2011. Pre-injection testing in CCS#2 and VW#2 confirmed the absence of faults and folds based on the results of fracture finder logs.

Only limited data and modeling results are available on ground water flow in the deep Illinois Basin, which is based on modeling results from Gupta and Bair (1997). Flow patterns in the Mt. Simon are “influenced by the geologic structure with flow away from arches such as the Kankakee Arch and toward the deeper parts of the Illinois Basin.” In the model, an initial fluid pressure of 3,205 psi (at elevation -6,345 ft MSL), an initial temperature of 112ºF (at elevation -5,365 ft MSL; gradient 1ºF/ft), and an initial salinity of 200,000 ppm were used. MSL is defined as mean sea level. Like other areas with humid climates (Freeze and Cherry, 1979), the water table in central Illinois is expected to reflect the elevation of the land surface. Steady-state ground water flow modeling for the IBDP site indicates that shallow ground water flows toward the east and southeast toward the Sangamon River and Lake Decatur.

The lowermost USDW is the Ordovician St. Peter Sandstone, based on TDS sampling of the upper St. Peter during the drilling of CCS#1.

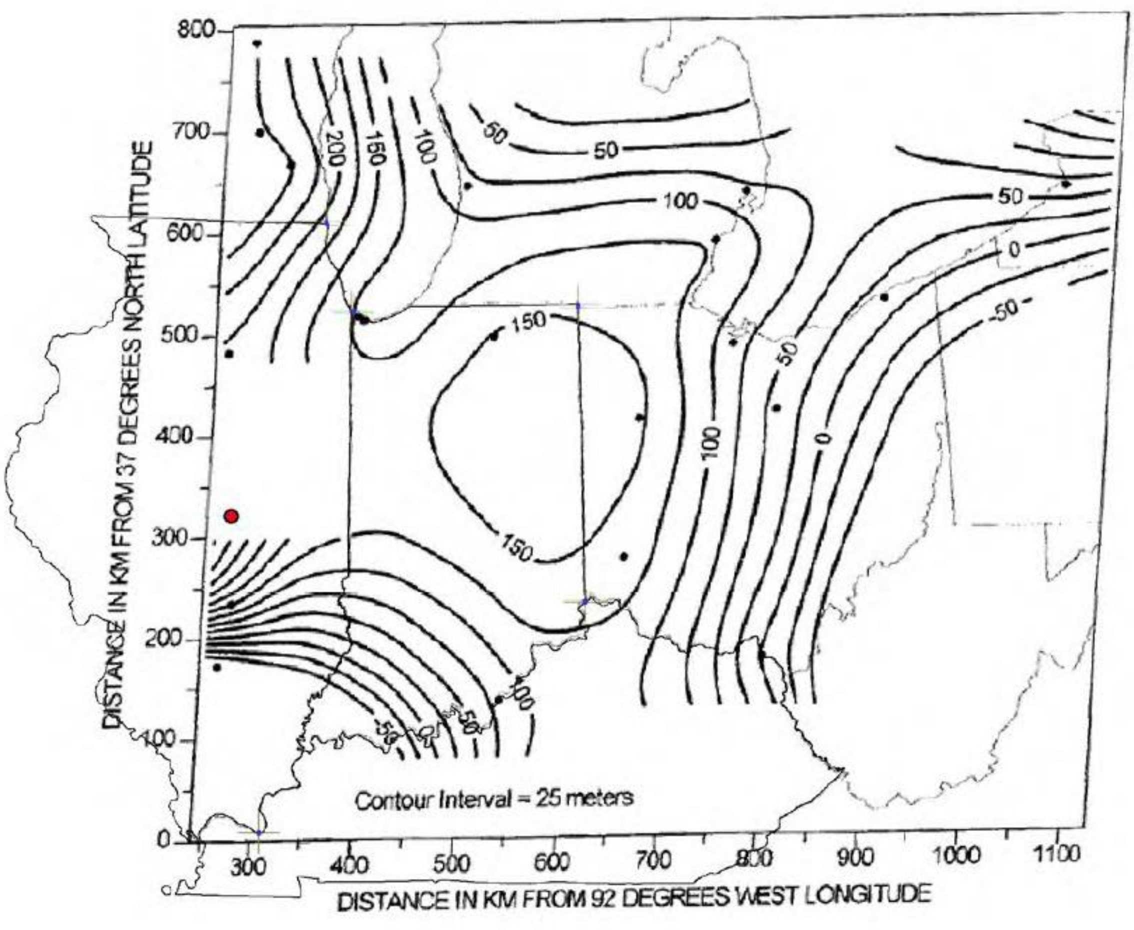


Figure 1. Observed head in the Mt. Simon Sandstone. The red dot represents the location of CCS#1 (potentiometric surface = 76 m/249 ft above mean sea level).

Model Domain

The static geological model includes the entire Mt. Simon and the overlying seal (the Eau Claire), spanning a 40 × 40 mile area. The final reservoir model was represented by a 146 × 146 × 148 grid in a Cartesian system with 146 grid points in the x-direction, 146 grid points in the y-direction, and 148 grid points in the z-direction, for a total of 3,154,768 grid points. Model domain information is summarized in Table 1.

Table 1. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD27		
Coordinate System Units	ft		
Zone	SPCS27-1201		
FIPSZONE	1,201	**ADSZONE**	3,776
Coordinate of x_{min}	277,028.18	**Coordinate of x_{max}**	408,692.78
Coordinate of y_{min}	1,103,729.25	**Coordinate of y_{max}**	1,235,364.89
Coordinate of z_{min}	-7113.19	**Coordinate of z_{max}**	-4272.78

Porosity

Injection Zone Porosity

The total porosity of the injection zone was determined based on neutron and density logs of CCS#2, while effective porosity was determined from helium porosimetry on a "limited number" of core samples. The results of these methods compared well to each other, and so neutron-density crossplot porosity was used to approximate effective porosity. Pre-injection testing in CCS#2 identified an optimal injection interval of 6,630 to 6,825 ft KB, with multiple perforations of 6,630 – 6,670; 6,680 – 6,725; 6,735 – 6,775; and 6,781 – 6,825 (all in ft KB). The AoR was modeled using these perforation intervals, with an average effective porosity throughout the injection zone of 22%. Within the AoR, KB (Kelly Bushing) is approximately 682 ft above MSL.

Additionally, the open-hole log based porosity was classified using Schlumberger Elemental Log Analysis (ELAN) as described in the CCS#2 Geophysical Log Descriptive Report. In the log analysis, the log analyst stated that the lower zone of the Mt. Simon has an average porosity of 22%, though there are intervals where the porosity approaches 30%.

Based on the analysis of log results from CCS#2, ADM identified five porosity/permeability zones within the Mt. Simon.. These zones, with the average porosity and permeability values indicated by ADM, are illustrated in Figure 2. Pre-injection testing identified a high porosity/permeability region extending from the base of the Mt. Simon at 7,043 ft KB up to 6,427 ft KB; this overall interval included two sub-units with similar but varying porosity and permeability. The middle section of the Mt. Simon had lower porosity and permeability, extending from 6,427 to 5,907 ft KB. The upper unit from 5,907 to 5,553 ft KB also has high porosity and permeability, but was determined to be too close to the confining zone for injection.

Confining Zone Porosity

The median porosity of the Eau Claire Formation is 4.7%, based on information from an ISGS database of UIC well core samples. Pre-injection testing in CCS#2 and VW#2 indicated very small pore sizes based on CMR data, resulting in generally very low permeability (see "Confining Zone Permeability" below).

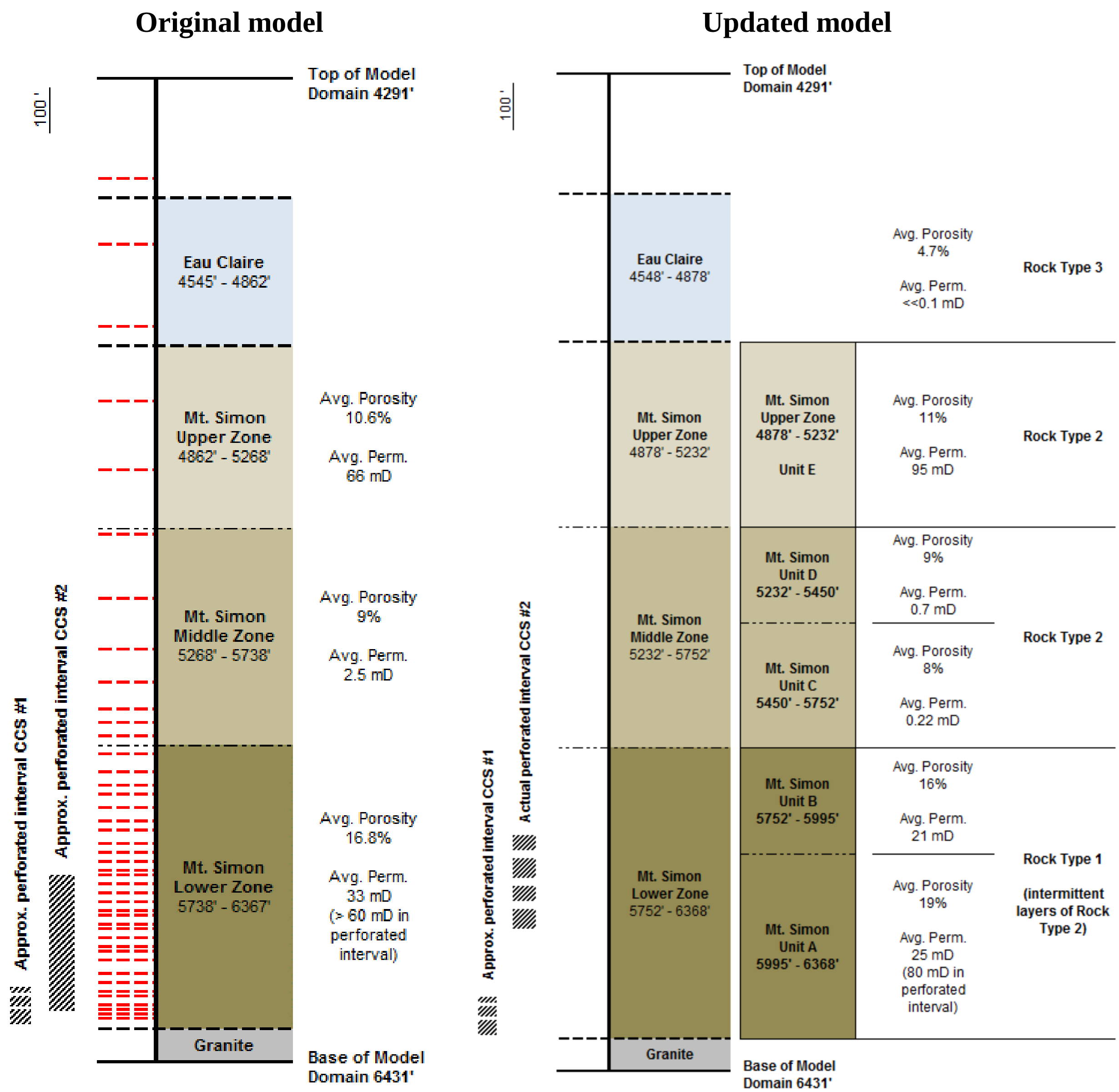


Figure 2. Reproduced layers of the geologic model and average porosity/permeability values, as identified by ADM based on log analysis, along with the approximate screened intervals of CCS #1 and CCS #2. The column on the left was produced during evaluation of the final AoR model prior to pre-injection testing; the right column incorporates the results of geophysical testing in CCS#2 and VW#2 during pre-injection testing. The updated column shows both the three primary rock types and the five rock types indicated by the wireline logs. Horizontal distances are not to scale, and the representation of layer thickness is approximate.

<u>*Permeability*</u>

Injection Zone Permeability

For the pre-construction modeling effort, ADM determined intrinsic permeability for areas of the injection zone based on available core analyses and CCS#1 well testing results, and developed a core porosity-permeability transform based on grain size to estimate permeability over intervals without core samples. From this method, ADM calculated a geometrical average intrinsic permeability of 194 mD for the CCS#1 injection interval. In the updated modeling effort following pre-operational testing and logging, ADM incorporated the logging and core analyses in CCS#2 and VW#2 using the methods described earlier in this plan. The well log data collected during pre-operational testing were simulated with the existing 3D permeability distribution to develop a new geological model.

ADM also reported additional permeability values based on pressure transient analysis of data from CCS#1 pressure fall-off tests. Using PIE pressure transient software, ADM estimated permeability of 185 mD over 75 ft of vertical thickness in the injection zone. ADM also directly calculated permeability for this interval from core samples and well log analyses, with a result of 80 mD in the perforated interval. Multiple regions in the perforated interval had much higher permeability (above 100mD), as shown in Figure 2.

Confining Zone Permeability

During pre-operational testing, ADM collected 33 horizontal and 3 vertical whole core samples, and 2 rotary sidewall core samples, all from VW#2. Three hundred fifty-one (351) core plugs were drilled from the whole core collected from VW#2 and were suitable for routine core property measurements. The rock properties derived from these samples were primarily used to validate and calibrate the ELAN petrophysical model based on well logs. While no core samples were taken from the shale zone of the Eau Claire A at VW#2, 36 plugs of the upper interval Eau Claire C (very fine sandstone, microcrystalline limestone, and siltstone) were available for testing. Of the plugs tested for vertical permeability, the average permeability was 0.036 mD. While no core samples were taken from the shale zone of the Eau Claire A at CCS#1, 12 plugs of the lower portion of the upper interval Eau Claire B/C (very fine sandstone, microcrystalline limestone, and siltstone) were available for testing. Average horizontal permeability for these sidewall rotary core samples was determined to be 0.000344 mD. However, the vertical permeability of the actual shale interval is expected to be much lower because vertical permeability of plugs “is generally lower than horizontal permeability and shale permeability is generally much lower than sandstone, limestone, and siltstone.” Based on the analysis of log results from CCS#1 and confirmed by well logs in CCS#2, the Eau Claire, extending from the top of the Mt. Simon to -4,545 ft MSL (-5,227 ft KB), is described as having “only a few small intervals of less than a few feet that have any permeability greater than 0.1 mD,” which do not appear to be continuous.

ADM also cited a median permeability value of 0.000026 mD from the ISGS UIC core database. In addition, based on a set of core samples from a site approximately 80 miles to the north of the proposed Class VI location, of the 110 analyses conducted, most were in the range of < 0.001 to 0.001 mD, with five in the range of 0.100 to 0.871 mD (the maximum value in the data set). This indicates that even the more permeable beds in the Eau Claire Formation are expected to be relatively tight and tend to act as sealing lithologies.

Operational Information

The proposed injection well, CCS#2, is part of the IL-ICCS project. The other CO_2 injection well on ADM's property, IDBP well CCS#1, was completed in 2009. The AoR modeling accounts for both injection operations, and the details are presented in .

Table 2. Operating details for CCS#1 and CCS#2, as used in the model.

Parameters and units		CCS#1			CCS#2			
Model coordinates (ft)	X	342,848.58			344,366.37			
	Y	1,169,545.00			1,172,887.91			
Screened intervals		3			4			
Screen depth (ft, KB = 682 ft)	Ztop	6976	6982	7024	6630	6680	6735	6787
	Zbottom	6978	7012	7050	6670	6725	6775	6825
Screen elevation (ft)	Ztop	6294	6300	6342	5948	5998	6053	6105
	Zbottom	6296	6330	6368	5988	6043	6093	6143
Screened interval length (ft)		2	30	26	40	45	40	38
Wellbore diameter (in.)		12.25			12.25			
Injection duration (years)		3			5			
Injection rate (MMT/year)		0.333			1			
Fracture gradient (psi/ft)		0.715			0.715			
Max. injection pressure, as submitted (psi)		5,024			4,266			
Elevation (subsurface depth - KB) corresponding to max. pressure, as submitted by ADM (ft)		6,343			6,630			
Max. injection pressure (90% of frac. pres.) at the top of the screened interval, calculated from frac. gradient (psi)		4,489.06			4,266.41			
Subsurface elevation at the top of the screened interval, calculated from frac. gradient (ft)		6,976			6,630			

Fracture Pressure and Fracture Gradient

Injection Zone

A step rate test at CCS#1, in the interval of -7,025 ft KB to -7,050 ft KB was conducted to estimate the fracture pressure of the injection zone. The result from the uppermost perforation of CCS#1 (-7,025 ft KB) was 5,024 psig, corresponding to a fracture gradient of 0.715 psi/ft. Based on this result, ADM estimated the maximum injection pressure for CCS#1 as 3,995 psi based on the calculated fracture pressure at -6,345 ft MSL. As shown in Table 2, the elevation that corresponds to the top of the injection interval at CCS#1 is -6,283 ft MSL, which corresponds to a fracture pressure of 4,398.1 psi using the 0.7 psi/ft fracture gradient. Therefore, a maximum injection pressure of 3,958.29 psi at the top of the perforated interval (90% of the fracture pressure) is used for CCS#1.

Using the same approach for CCS#2, the maximum injection pressure value is calculated to be 4,266 psi at elevation -6,630 ft MSL. Similarly, the maximum injection pressure is calculated for the top of the injection interval, which corresponds to an elevation of -5,948 ft MSL. Based on the fracture gradient of 0.715, the maximum injection pressure at this point is calculated to be 3,792.6 psi. These values are given in above.

It was determined that these values (calculated based on CCS#1 results) accurately represent the system and will continue to be used for the fracture gradient and fracture pressure for CCS#2, until and unless more accurate project-specific data are available. A step-rate test run after the construction of CCS#2 yielded results that do not contradict initial fracture pressure gradient estimates, although some testing did produce inconclusive results. Injection pressure limits based upon this fracture pressure gradient should not create new fractures or extend any existing fractures. However, additional precautions for initial injection operations and monitoring have been added to Attachment A of this permit.

Confining Zone

A "mini-frac" field test was used to determine in-situ fracture pressure in the confining zone. Fracture pressure results (from four short-term injection/fall-off test periods, 15 to 60 minutes each) ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire shale zone.

Initial Conditions

Fluid sampling and testing were conducted in August 2015 in VW#2, including in-situ measurements of formation pressure and temperature and the collection of eight fluid samples at five depths. A temperature log was run in CCS#2 in 2015. The results are as follows:

- Temperature increased consistently with depth from 60 °F at 50' to 100 °F at 6,950 KB with an average temperature gradient of 0.0058 °F/ft.
- Formation pressure was 3,200 psi at 6,980 KB with a pressure gradient of 0.46 psi/ft. The pressure ranged from 2,626 psi at 5,848 KB to 3,211 psi at 7,041 KB.
- Fluid density ranged from 1,101 g/L to 1,136 g/L, with an average of 1,124 g/L (of the four samples collected).
- TDS ranged from 149,830 ppm at 5,848 KB to 199,950 ppm at 7,041 KB with an average of 184,053 ppm (of the four samples collected).

Original initial condition information submitted by ADM during permitting:

- Temperature ranged from 119.8°F at 5,772 ft to 125.8°F at 6,912 ft.
- Formation pressure ranged from 2,583 psi at 5,772 ft to 3,206 psi at 7,045 ft.
- Fluid density ranged from 1,090 g/L to 1,137 g/L, with an average of 1,119 g/L (of the five samples taken).
- TDS ranged from 164,500 ppm at 5,772 ft to 228,100 ppm at 7,045 ft, with an average of 196,700 ppm.

The values presented above from pre-operational testing activities are consistent with the values presented in the initial permit application and pre-construction modeling effort.

Boundary Conditions

No-flow boundary conditions were applied to the upper and lower boundaries of the model, with the assumption that the reservoir and the caprock are continuous throughout the region. A pore volume multiplier of 10,000 was applied to each cell in the horizontal boundaries of the ECLIPSE model in order to simulate an extensive reservoir. The horizontal boundaries were selected as: hydrostatic initial conditions for the aqueous phase, no-flow conditions for the gas phase, and initial conditions for salt. No changes were made to the boundary conditions following pre-operational testing.

AoR Pressure Front Delineation

To delineate the pressure front, the minimum or critical pressure ($P_{i,f}$) necessary to reverse flow direction between the lowermost USDW and the injection zone—and thus cause fluid flow from the injection zone into the formation matrix—must be calculated. ADM calculated $P_{i,f}$ using the method provided in the March 2011 draft of the *UIC Program Class VI Well Area of Review and Corrective Action Evaluation Guidance*, where the pressure front is given by:

$$P_{i,f} = P_u \cdot \frac{\rho_i}{\rho_u} + \rho_i g \cdot (z_u - z_i)$$

Where:

- P_u = initial pressure of the lowermost USDW,
- ρ_i = fluid density of the injection zone,
- ρ_u = fluid density of the lowermost USDW,
- g = acceleration due to gravity,
- z_u = elevation of the lowermost USDW, and
- z_i = elevation of the injection zone.

Using this method, ADM calculated a $P_{i,f}$ value equal to 171 psi (1.18 MPa).

As an alternative approach for estimating a critical pressure in the injection zone, in December 2013, ADM applied a method developed and published by Nicot et al. (2008):

$$\frac{\Delta P}{g} = \frac{\xi}{2}(z_u - z_i)^2$$

This method estimates a pressure differential that would displace fluid initially present in a hypothetical borehole into the lowermost USDW and is based on two assumptions: (1) hydrostatic conditions; and (2) initially linearly varying densities in the borehole and constant density once the injection zone fluid is lifted to the top of the borehole.

ADM used the Nicot method to calculate the pressure differential based on an injection depth of -6,800 ft KB and a lowermost USDW depth of approximately -3,300 ft KB. The results yield an estimate of approximately 85.9 psi (0.59 MPa).

Model Calibration

The site model has been calibrated using operational data obtained from the IBDP project through January 2013. The IBDP injection rate was input into the simulation to calculate the bottom hole pressures and pressures at five different zones at the verification well. The simulated pressures compared well to the observed pressures. Reservoir permeability and skin were the main parameters impacting the injection pressure calibration and were used as fitting parameters. Actual spinner data was used to set the fractions of the total injection between the two sets of perforations in the injection well. These data along with the simulation allowed for fine tuning of the well bore skin values at respective perforations together with the permeability to match injection bottom hole pressure (Figure 3). Once the injection bottom hole pressure was calibrated, simulated pressures at five different zones at the verification well were fine-tuned calibrating the k_v/k_h ratio of the tight sections and compressibility of the reservoir rock (Figure 4).

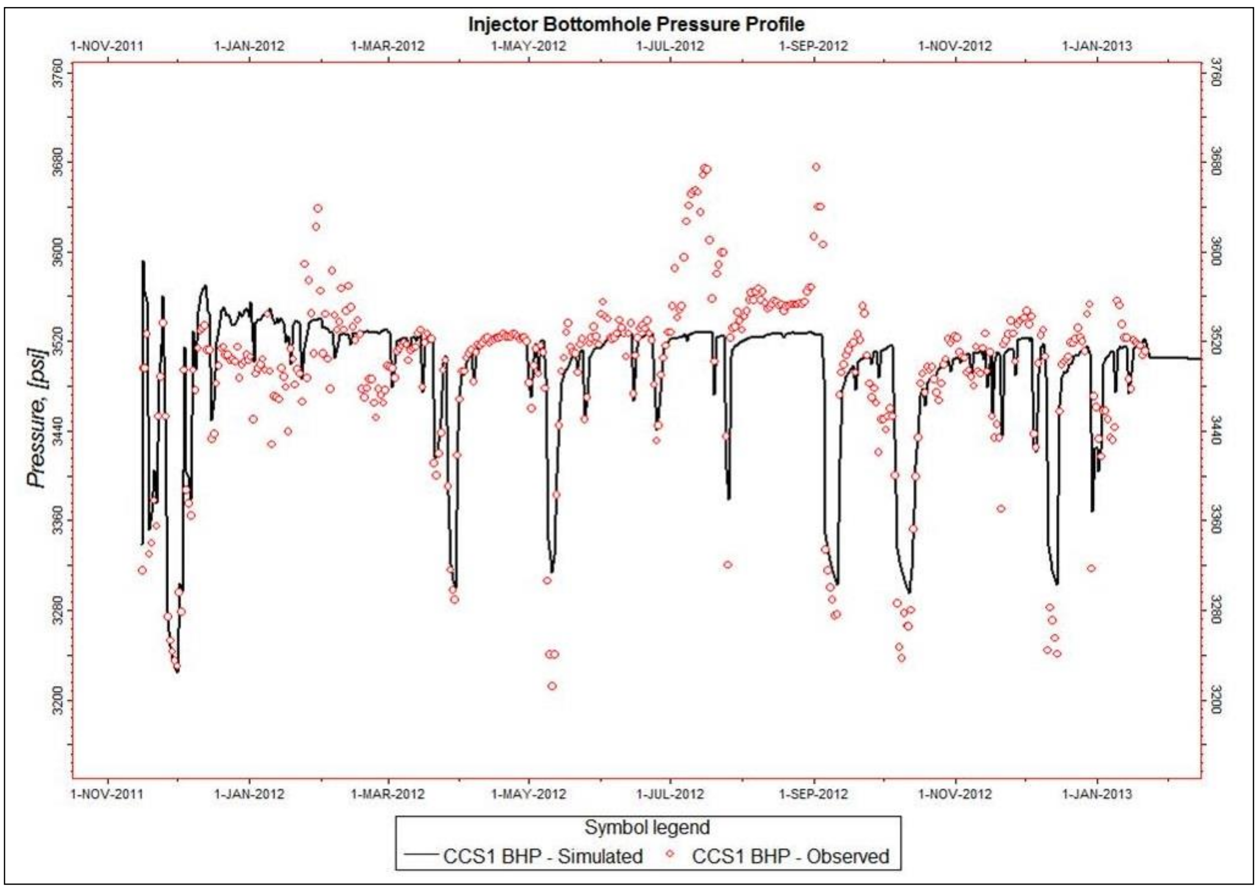


Figure 3. History Matched Injection Bottom Hole Pressure (BHP) for CCS#1, submitted February 2014.

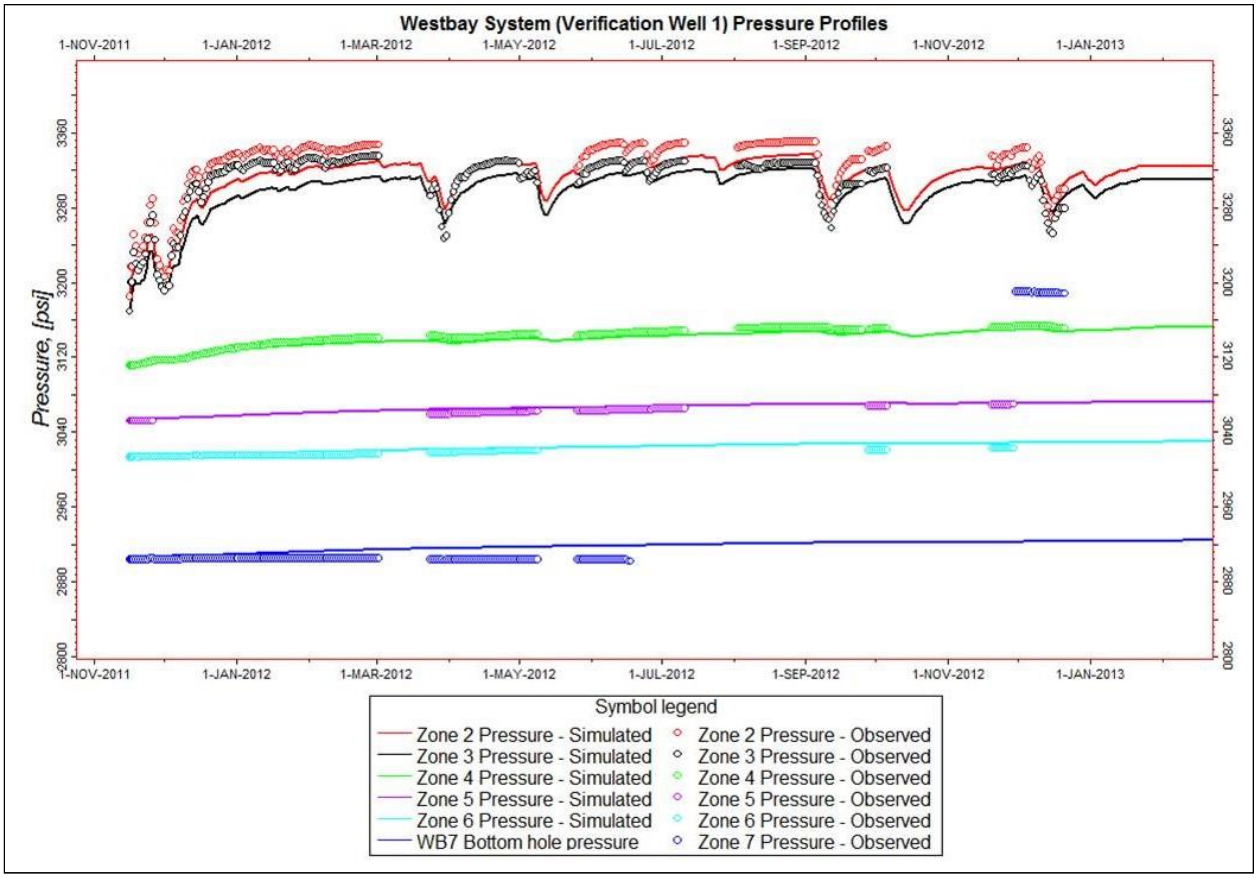


Figure 4. History Matched Pressures at VW#1 for CCS#1, submitted February 2014.

RST well logs helped estimate the location, saturation, and thickness of the CO_2 column around the injection and verification wells. This information helped fine tune the end points of relative permeability curves which dominate the CO_2 and brine flow in the reservoir. Figure 5 and Figure 6 show the relative permeability curves and the constitutive relationships for the reservoir rock types used to characterize the lower and middle Mt. Simon storage units. Figure 5 shows the relative permeability with respect to brine saturation (S_w), for the CO_2-brine system during drainage and imbibition. Where: brine drainage (krw) represents the relative permeability of brine during drainage, brine imbibition (krw) represents the relative permeability of brine during imbibition, CO_2 drainage (krg) represents the relative permeability of CO_2 during drainage, and CO_2 imbibition (krg) represents the relative permeability of CO_2 during imbibition. Please note that drainage is defined as CO_2 replacing brine in the pores and imbibition is defined as brine replacing CO_2 in the pores.

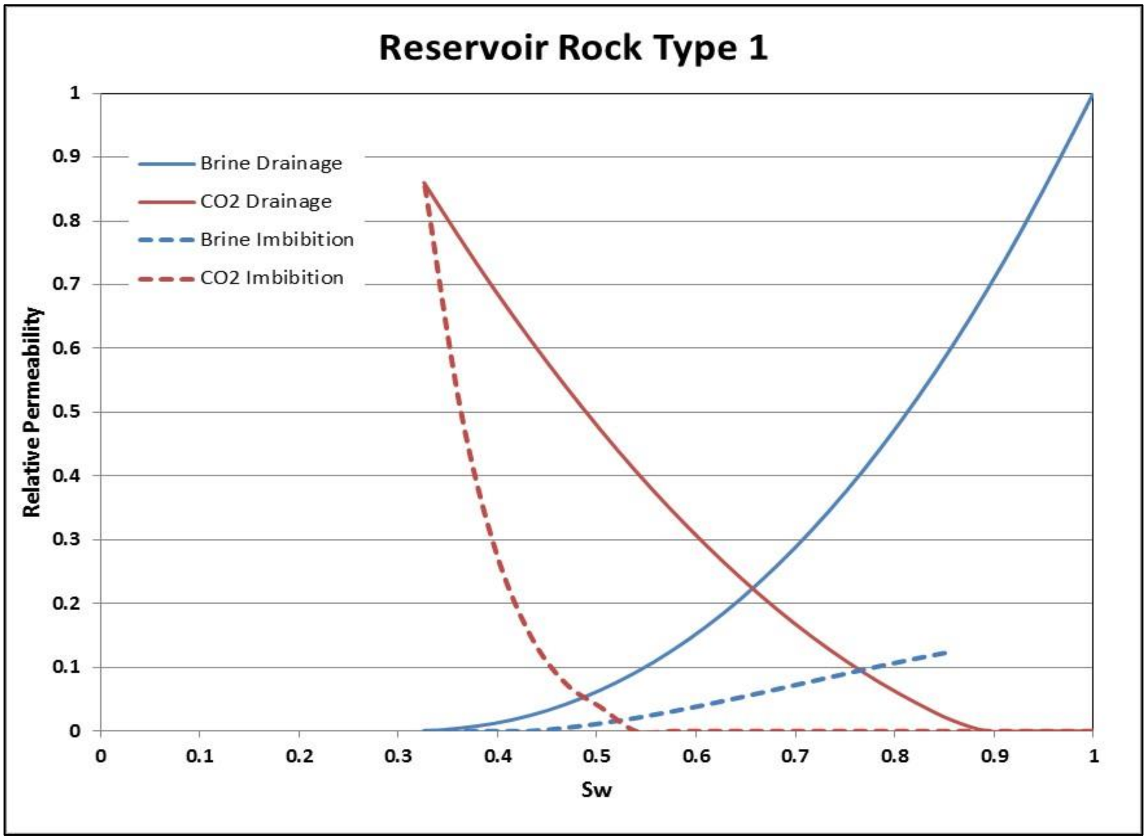


Figure 5. Calibrated Relative Permeability Curves – Type 1 LL Mt. Simon, submitted March 2016.

Rock Type		Rel. Perm		Capillary Pressure (P_c)
		CO2	Brine	
1	Drainage	From lab data See Figure 5	From lab data See Figure 5	van Genuchten model (data from Battelle, 2011) $S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$ $P_c=\alpha^{-1}[(Se^{-1/m} - 1]^{1/n}$ $\alpha = 0.5$ m=0.8 n=1/(1-m)
	Imbibition (hysteresis)	From lab data See Figure 5	From lab data See Figure 5	No Hysteresis
2	Drainage	Brooks-Corey (see Krevor et al. 2012) $S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$ $K_{rg}=k_{rg}(S_{w,ir})\ (1-S_e)^2\ (1-S_e^{Nco2})$ $N_{co2} = 4$	Brooks-Corey (see Krevor et al. 2012) $S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$ $K_{rw} = S_e^{Nw}$ $N_w=9$	Brooks-Corey (see Krevor et al. 2012) $P_c=P_e*S_e^{-1/\lambda}$ $P_e=0.667$ $\lambda = 0.55$
	Imbibition (hysteresis)	Land's model $K_{rg}=k_{rg}(S_{w,ir})\ (1-S_e)^2\ (1-S_e^{Nco2})$ where $S_e=(S_{w,bt}-S_{w,ir})/(1-S_{w,ir})$ $S_{w,bt} = 1- S_{co2,bt}$ $S_{co2,bt} = S^*_{co2,c}\ (1-S_{w,ir})$ $S^*_{co2,c} = 0.5\ \{(S^*_{co2}- S^*_{co2,r}) + [(S^*_{co2}- S^*_{co2,r})^2 + 4/C\ (S^*_{co2}- S^*_{co2,r})]^{0.5}\}$ $S^*_{co2} = S_{co2}/(1-S_{w,ir})$ $S^*_{co2,r} = S^*_{co2,i}/(1+C\ S^*_{co2,i})$ $S^*_{co2,i} = S_{co2,i}/(1-S_{w,ir})$ C=2.1 $N_{co2} = 4$	No Hysteresis	Land's model $P_c=P_e*S_e^{-1/\lambda}$ where $P_e=0.667$ $\lambda = 0.55$ $S_e=(S_{w,bt}-S_{w,ir})/(1-S_{w,ir})$ $S_{w,bt} = 1- S_{co2,bt}$ $S_{co2,bt} = S^*_{co2,c}\ (1-S_{w,ir})$ $S^*_{co2,c} = 0.5\ \{(S^*_{co2}- S^*_{co2,r}) + [(S^*_{co2}- S^*_{co2,r})^2 + 4/C\ (S^*_{co2}- S^*_{co2,r})]^{0.5}\}$ $S^*_{co2} = S_{co2}/(1-S_{w,ir})$ $S^*_{co2,r} = S^*_{co2,i}/(1+C\ S^*_{co2,i})$ $S^*_{co2,i} = S_{co2,i}/(1-S_{w,ir})$ C=2.1
3	Drainage	van Genuchten model $S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$ $K_{rg}=k_{rg}(S_{w,ir})\ (1-S_e)^{1/2}\ (1-S_e^{1/m})^{2m}$ m=0.41	van Genuchten model $S_e=(S_w-S_{w,ir})/(1-S_{w,ir})$ $K_{rw} = S_e^{1/2}[1-(1-S_e^{1/m})^m]^2$ m=0.41	van Genuchten model (entry pressure obtained from Lahann et al. , 2014) $P_c=\alpha^{-1}[(Se^{-1/m} - 1]^{1/n}$ n=1/(1-m) α=6.495E-2 m=0.41
	Imbibition (hysteresis)	No Hysteresis	No Hysteresis	No Hysteresis

Figure 6. Constitutive relationships for rock types used in AoR modeling, submitted March 2016.

Using the calibrated model, a predictive simulation was run to evaluate plume development and pressure perturbation during the course of injection.

Computational Modeling Results

The map below presents the AoR based on the modeling results (the maximum extent of the plume and pressure front), along with wells identified within the AoR.

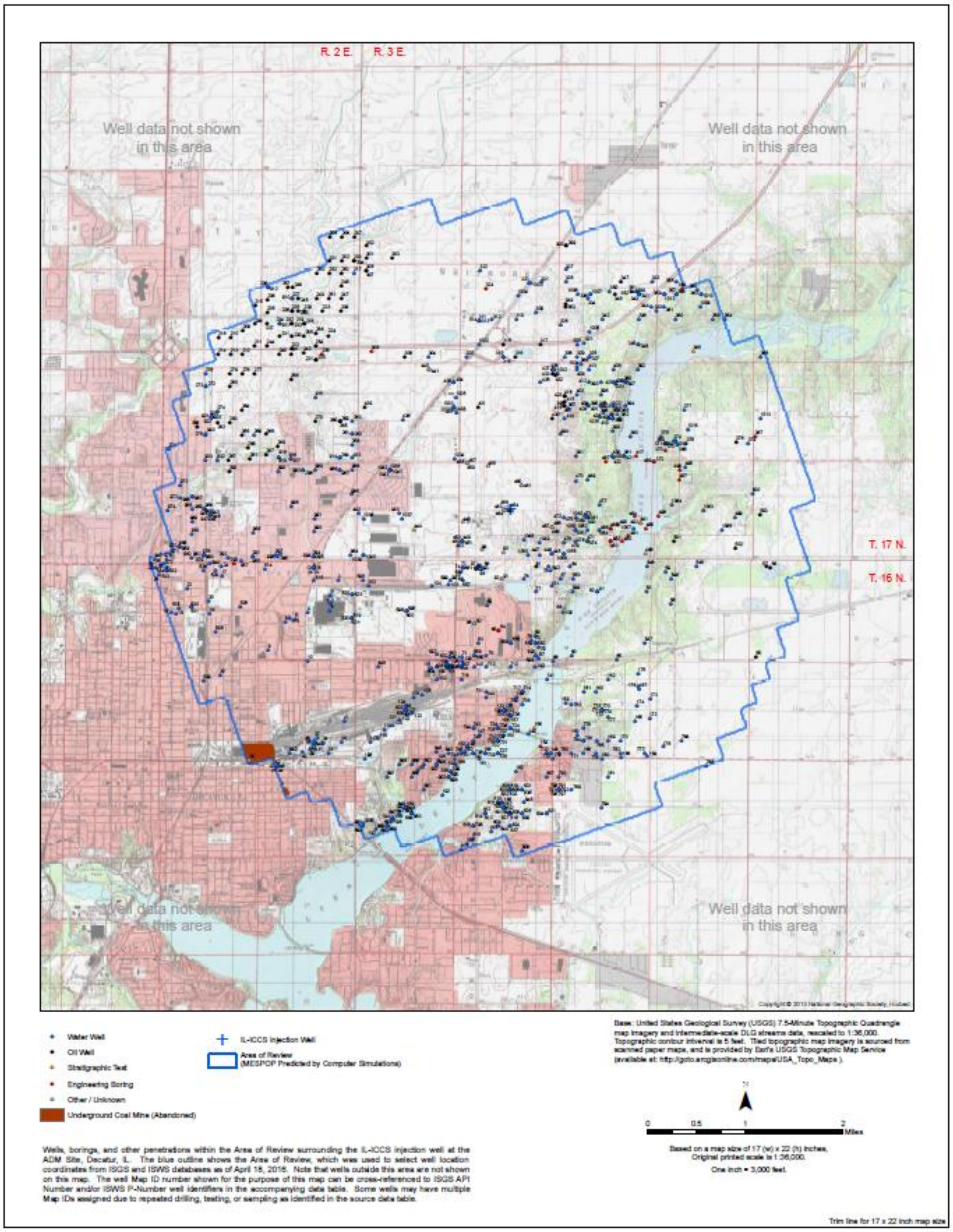


Figure 7. Map of the AoR as delineated by the reservoir model simulation.

The surface area of the AoR is 34.17 square miles. The predicted evolution of the plume and pressure front relative to monitoring locations is shown in the Testing and Monitoring Plan (Attachment C to this permit) and the Post-Injection Site Care (PISC) and Site Closure Plan (Attachment E to this permit).

Corrective Action Plan and Schedule

Based on information from the Illinois State Geological Survey (ISGS) and the Illinois State Water Survey (ISWS) gathered in April 2016, ADM identified a total of 1,065 wells within the AoR. According to Illinois Department of Natural Resources (IDNR) drilling records (and confirmed by ISGS), no additional oil and gas wells were drilled in Macon County between April and September 2016. Except for the wells associated with the IBDP and IL-ICCS projects (as described below), no wells were identified that penetrate the confining zone within the AoR.

Tabulation of Wells within the AoR

Wells within the AoR

The only existing wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are wells associated with the IBDP and IL-ICCS projects:

- The IBDP injection well, CCS#1 (which is currently permitted as a Class VI well in its post-injection phase and will be used as a monitoring well during the IL-ICCS project).
- The IBDP verification well, VW#1 (which will continue to be used as a monitoring well during the IL-ICCS project).
- The IL-ICCS injection well, CCS#2.
- The IL-ICCS verification well, VW#2.

The latest estimate shows that a total of 1,065 wells are located within the AoR. Water wells (725 of 1,065 wells) are the most common well type. The domestic water wells generally have depths of less than 60 m (200 ft). Other wells include stratigraphic test holes, non-domestic water wells, and oil and gas wells. As part of the original permit application, all wells within the 4 townships-area of the injection well site were also identified (total of 3,761 wells at that time). Information regarding these wells was provided as a supplement to the permit application (available in an electronic format).

Ten oil and gas wells are located within approximately 2.4 km (1.5 miles) of the injection well location. The closest well is located in the northeast quarter of Section 5, T16N, R3E. This well (API number 121150061800) was drilled as a gas well in 1933 and was -27 m (-88 ft KB) deep. There is no record of this well being plugged. This well was likely collecting naturally occurring methane from the Quaternary sediments. The other 9 wells are located in Section 5, T16N, R3E or Section 28 and Section 29, T17N, R3E. The deepest of these oil wells is API number 121152369400, located in the northeast quarter of Section 34. This well was drilled into the Ordovician and was -905 m KB (-2,970 ft KB) deep.

Wells Penetrating the Confining Zone

With the exception of the injection and verification wells previously detailed, there are no known wells within the area of review that penetrate deeper than -905 m KB (-2,970 ft KB). The depth to the top of the injection zone (Mt. Simon Sandstone) is -1,690 m KB (-5,545 ft KB). Therefore, there are only four known wells that penetrate into the uppermost injection zone: the IBDP wells CCS#1 and VW#1, and the IL-ICCS wells CCS#2 and VW#2.

If any of these wells are taken out of service during the life of the project, ADM will provide information to EPA to confirm that they have been properly plugged to ensure USDW protection pursuant to requirements at 40 CFR Part 146. If any additional wells that penetrate the confining zone are identified (e.g., if the AoR is re-delineated to cover a larger area as the result of an AoR reevaluation), ADM will complete corrective action as needed pursuant to 40 CFR 146.84(d).

Wells Requiring Corrective Action

Based on information about the wells in existence at the time of permit issuance, no corrective action is required prior to initiation of injection.

Plan for Site Access

This is not applicable because no corrective action is required at this time.

Justification of Phased Corrective Action

This is not applicable because no corrective action is required at this time.

Area of Review Reevaluation Plan and Schedule

ADM will take the following steps to evaluate project data and, if necessary, reevaluate the AoR. AoR reevaluations will be performed during the injection and post-injection phases. ADM will:

- Review available monitoring data and compare it to the model predictions. ADM will analyze monitoring and operational data from the injection well (CCS#2), the monitoring and geophysical wells, other surrounding wells, and other sources to assess whether the predicted CO_2 plume migration is consistent with actual data. Monitoring activities to be conducted are described in the Testing and Monitoring Plan (Attachment C to this permit) and the PISC and Closure Plan (Attachment E to this permit). Specific steps of this review include:
    - Reviewing available data on the position of the CO_2 plume and pressure front (including pressure and temperature monitoring data and RST saturation and seismic survey data). Specific activities will include:
        - Correlating data from time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (e.g., 3D surveys) to locate and track the movement of the CO_2 plume. A good correlation between the data sets will provide strong evidence in validating the model's ability to represent the storage

system. Also, 2D and 3D seismic surveys will be employed to determine the plume location as described in the Testing and Monitoring Plan and/or the PISC and Site Closure Plan (as applicable).

        - Reviewing downhole reservoir pressure data collected from various locations and intervals using a combination of surface and downhole pressure gauges.

    - Reviewing ground water chemistry monitoring data taken in the shallow (i.e., in Quaternary and/or Pennsylvanian strata) monitoring wells, the St. Peter, and the Ironton-Galesville to verifying that there is no evidence of excursion of carbon dioxide or brines that represent an endangerment to any USDWs.

    - Reviewing operating data, e.g., on injection rates and pressures, and verifying that it is consistent with the inputs used in the most recent modeling effort.

    - Reviewing any geologic data acquired since the last modeling effort, e.g., additional site characterization performed, updates of petrophysical properties from core analysis, etc. Identifying whether any new data materially differ from modeling inputs/assumptions.

- Compare the results of computational modeling used for AoR delineation to monitoring data collected. Monitoring data will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. ADM will demonstrate this degree of accuracy by comparing monitoring data against the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the storage site.

- If the information reviewed is consistent with, or is unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of plume and pressure front movement, ADM will prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AoR is needed. The report will include the data and results demonstrating that no changes are necessary.

- If material changes have occurred (e.g., in the behavior of the plume and pressure front, operations, or site conditions) such that the actual plume or pressure front may extend beyond the modeled plume and pressure front, ADM will re-delineate the AoR. The following steps will be taken:

    - Revising the site conceptual model based on new site characterization, operational, or monitoring data.

    - Calibrating the model in order to minimize the differences between monitoring data and model simulations.

    - Performing the AoR delineation as described the Computational Modeling Section of this AoR and Corrective Action Plan.

- Review wells in any newly identified areas of the AoR and apply corrective action to deficient wells. Specific steps include:

- Identifying any new wells within the AoR that penetrate the confining zone and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion.
- Determining which abandoned wells in the newly delineated AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs.
- Performing corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with carbon dioxide.

- Prepare a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to EPA within one year of the reevaluation. The report will include maps that highlight similarities and differences in comparison with previous AoR delineations.
- Update the AoR and Corrective Action Plan to reflect the revised AoR, along with other related project plans, as needed.

AoR Reevaluation Cycle

ADM will reevaluate the above described AoR every five years during the injection and post-injection phases.

In addition, monitoring and operational data will be reviewed periodically (likely annually) by ADM during the injection and post-injection phases. Given inconclusive results in the CCS#2 step-rate test, ADM will modify their monitoring and reporting schedule to collect and review data more regularly during the first six months of the injection phase. Specifically, pressure and seismic results will be reviewed on a monthly basis to identify any deviations from expected conditions (see Attachment A of this permit for more detail). The reservoir flow model will be history matched against the observed parameters measured at the monitoring wells. Pressure will be monitored as described in the Testing and Monitoring Plan. The time lapse pressure monitoring data will be compared to the model predicted time lapse pressure profiles. ADM will provide a brief report of this review to the UIC Program Director and discuss the findings.

If data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume and/or pressure front is occurring or there are deviations from modeled predictions such that the actual plume or pressure front may extend vertically or horizontally beyond the modeled plume and pressure front, ADM will initiate an AoR reevaluation prior to the next scheduled reevaluation. Such deviations may be evidenced by the results of direct or indirect monitoring activities including MIT failures or loss of MI; observed pressure and saturation profiles; changes in the physical or chemical characteristics of the CO_2; any detection of CO_2 above the confining zone (e.g., based on hydrochemical/physical parameters); microseismic data indicating slippage in or near the confining zone or microseismic data within the injection zone that indicates slippage and propagation into the confining zone; or arrival of the CO_2 plume and/or pressure front at certain monitoring locations that diverges from expectations, as described below.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled reevaluation of the AoR will be based on quantitative changes of the monitoring parameters in the deep monitoring wells, including unexpected changes in the following parameters: pressure, temperature, neutron saturation, and the deep ground water (> 3,000 ft below KB) constituent concentrations indicating that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes include:

- ***Pressure:*** Changes in pressure that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.
- ***Temperature:*** Changes in temperature that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.
- ***RST Saturation:*** Increases in CO_2 saturation that indicate the movement of CO_2 into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)
- ***Deep ground water constituent concentrations:*** Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brines into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)
- ***Exceeding Fracture Pressure Conditions:*** Pressure in any of the injection or monitoring wells exceeding 90 percent of the geologic formation fracture pressure at the point of measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan (Attachment C to this permit) and the operating procedures in Attachment A to this permit provides discussion of pressure monitoring and specific procedures that will be completed during the injection start-up period.
- ***Exceeding Established Baseline Hydrochemical/Physical Parameter Patterns:*** A statistically significant difference between observed and baseline hydrochemical/physical parameter patterns (e.g., fluid conductivity, pressure, temperature) immediately above the confining zone. The Testing and Monitoring Plan (Attachment C to this permit) provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.
- ***Compromise in Injection Well Mechanical Integrity:*** A significant change in pressure within the protective annular pressurization system surrounding each injection well that indicates a loss of mechanical integrity at an injection well.
- ***Seismic Monitoring Identification of Subsurface Structural Features:*** Seismic monitoring data that indicates the presence of a fault or fracture in or near the confining zone or a fault or fracture within the injection zone that indicates propagation into the confining zone. The Testing and Monitoring Plan provides extended information about the microseismic monitoring network.

An unscheduled AoR reevaluation may also be needed if it is likely that the actual plume or pressure front may extend beyond the modeled plume and pressure front because any of the following has occurred:

- Seismic event greater than M3.5 within 8 miles of the injection well;
- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected); or
- If new site characterization data changes the computational model to such an extent that the predicted plume or pressure front extends vertically or horizontally beyond the predicted AoR.

ADM will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required.

If an unscheduled reevaluation is triggered, ADM will perform the steps described at the beginning of this section of this Plan.

ATTACHMENT C: TESTING AND MONITORING PLAN

Facility Information

Facility name:	Archer Daniels Midland, CCS#2 Well IL-115-6A-0001
Facility contact:	Mr. Steve Merritt, Plant Manager, 4666 Faries Parkway, Decatur, IL (217) 424-5750, steve.merritt@adm.com
Well location:	Decatur, Macon County, IL; 39º53'09.32835", -88º53'16.68306"

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 CO_2 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 CO_2 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 CO_2 stream as described in Section 6A.1 of the permit application and presented below.

Analytical Parameters

ADM will analyze the CO_2 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 CO_2 gas stream.

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

CO_2 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 CO_2 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

[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.

	b_{i0}	b_{i1}	b_{i2}	b_{i3}	b_{i4}
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

The final volume basis will be calculated as follows:

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

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 CO_2 .

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 CO_2 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.

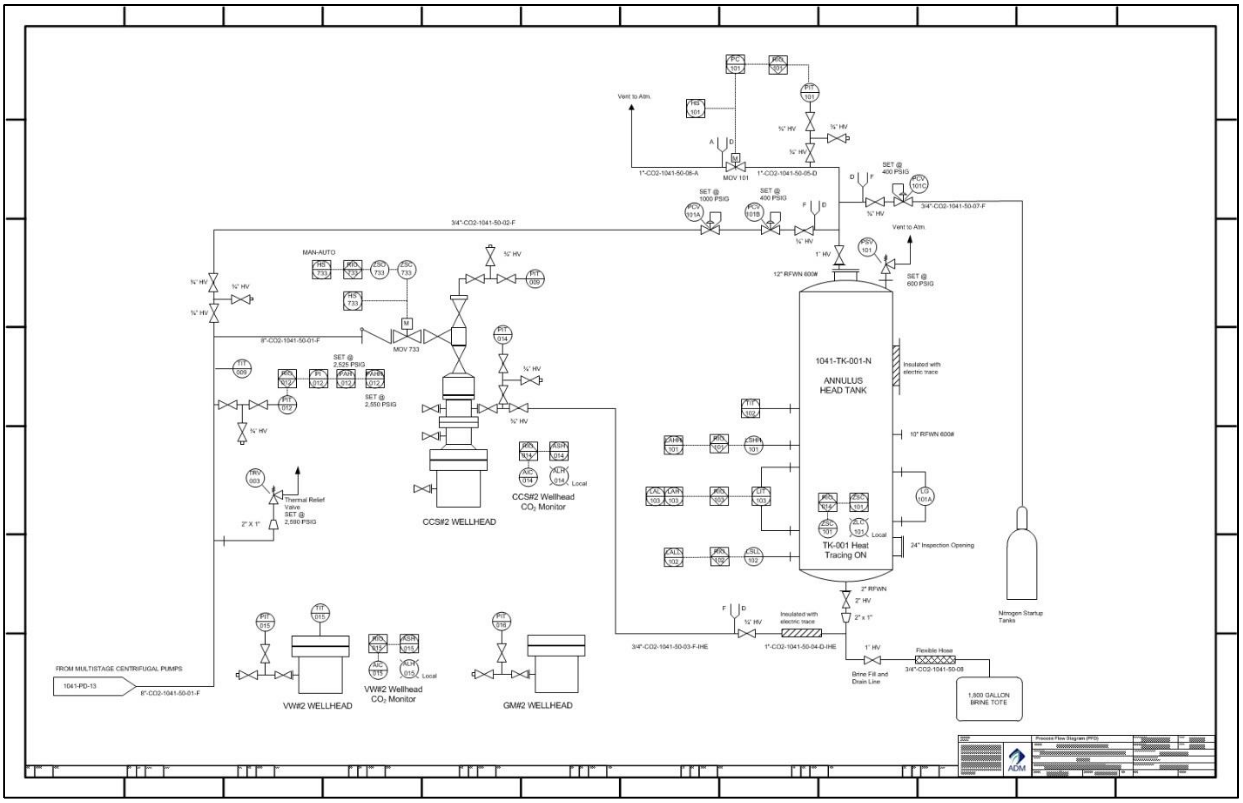


Figure 1. The annular monitoring system general layout.

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 CO_2 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

<u>Sample Exposure</u>

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 CO_2 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 CO_2 past this point; therefore this location will provide representative exposure of the samples to the CO_2 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.

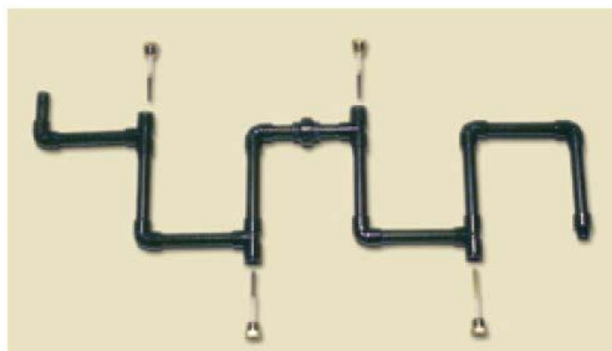


Figure 2b. Flow-through Pipe Arrangement.

<u>Sample Handling and Monitoring</u>

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 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.

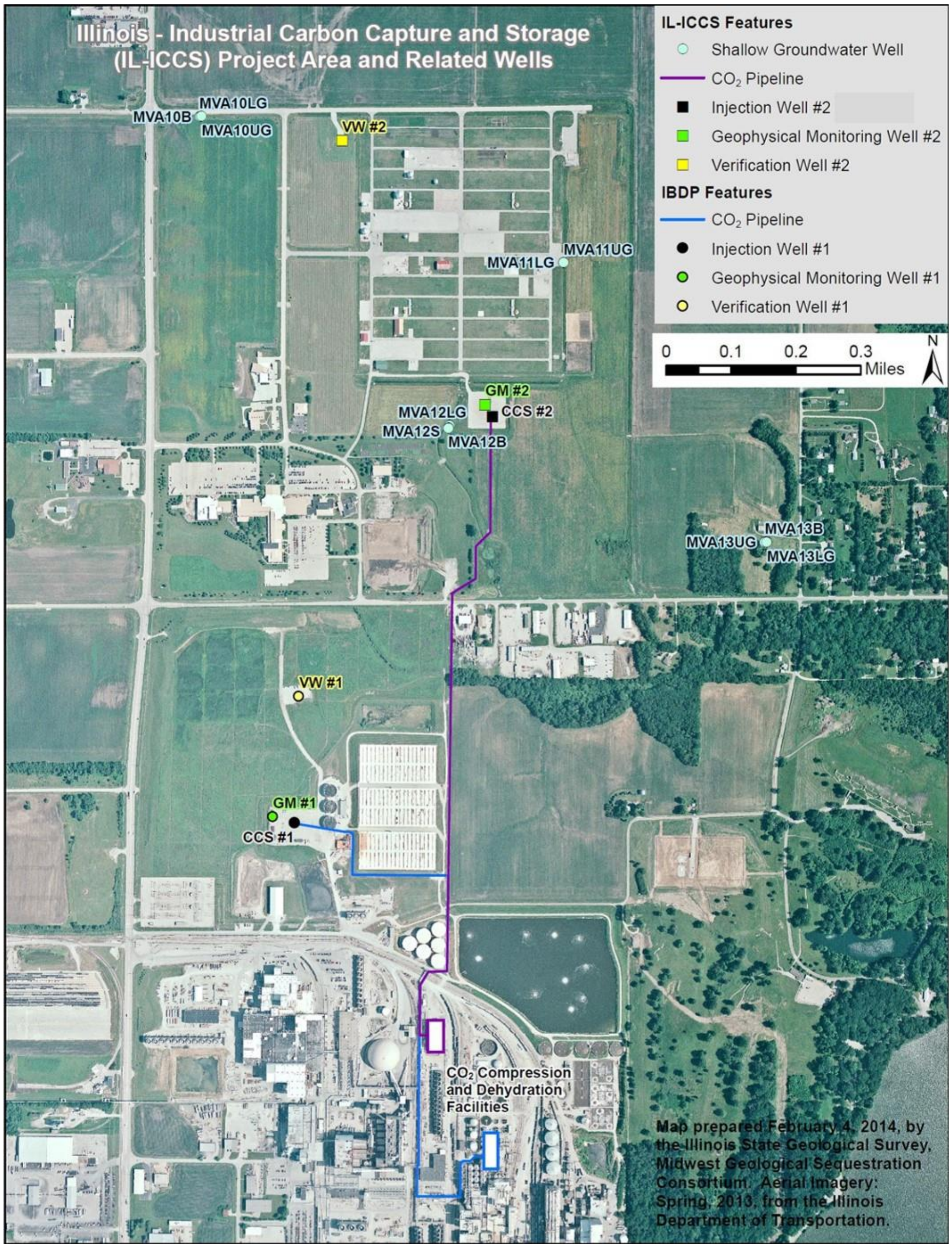


Figure 3. Location of shallow groundwater monitoring wells and deep monitoring wells.

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)]
Quaternary/Pennsylvanian	
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
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
St. Peter	
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: $\delta^{13}C$ 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
Ironton-Galesville	
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 CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ 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 CO_2 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 CO_2 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 CO_2 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

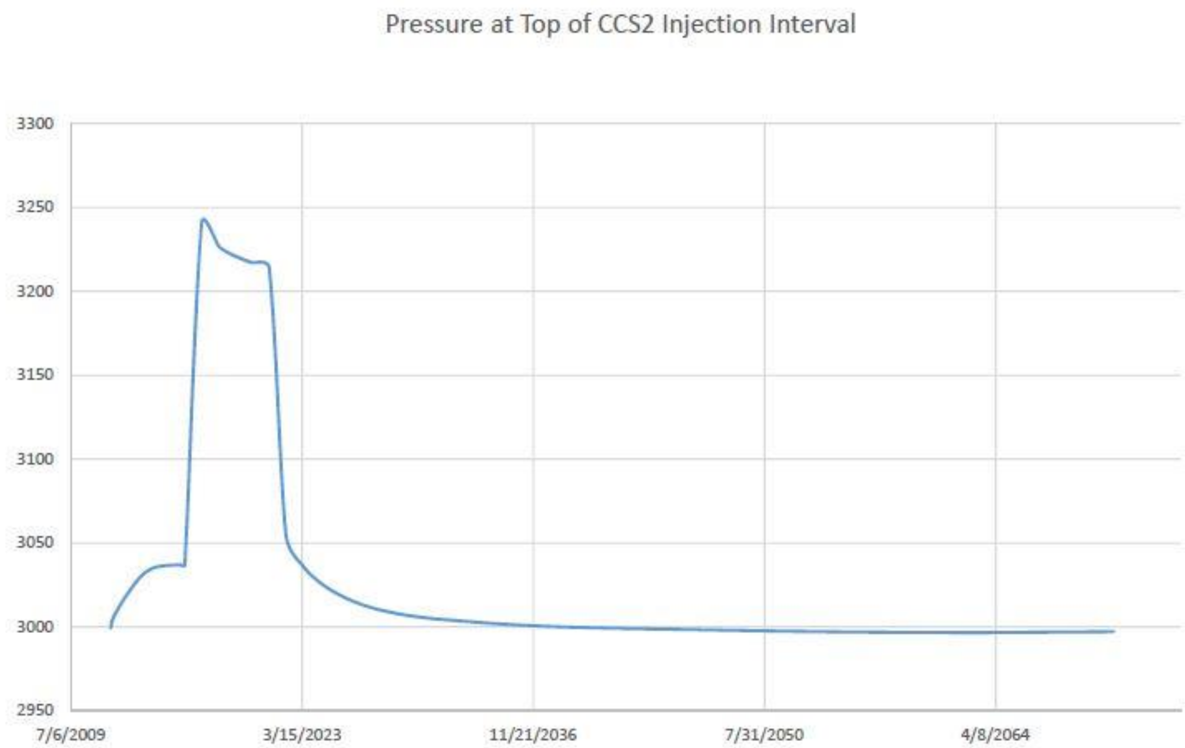


Figure 10. Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection.

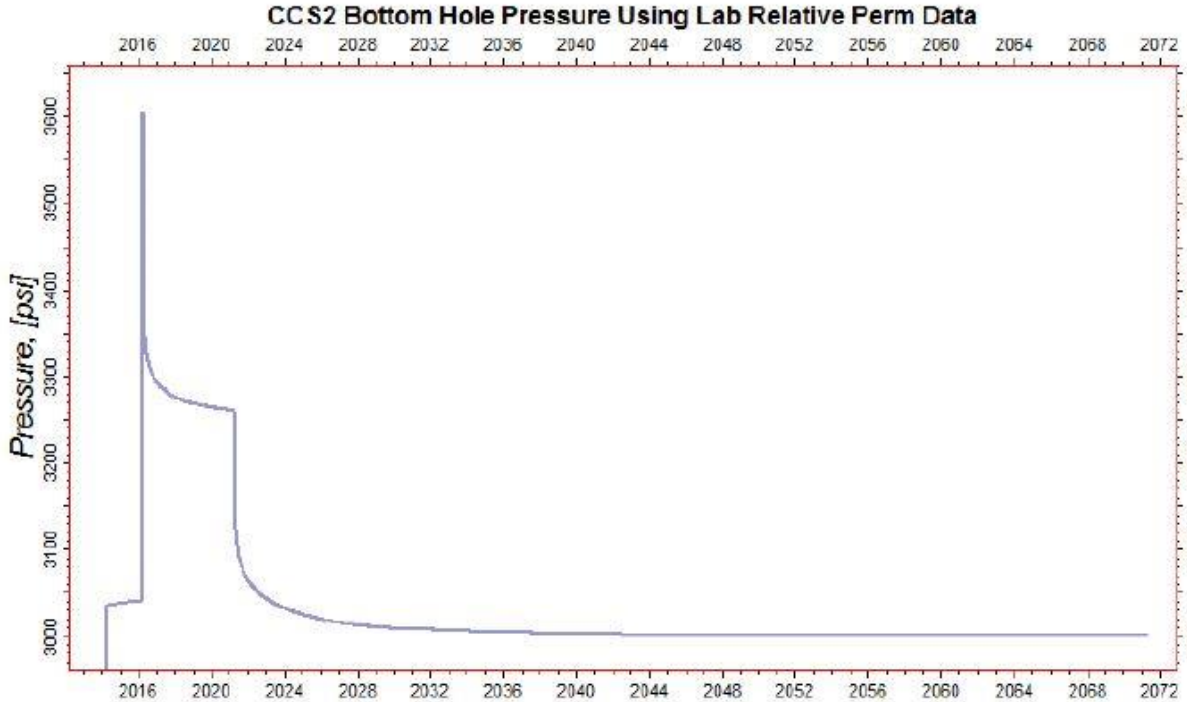


Figure 11. Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection.

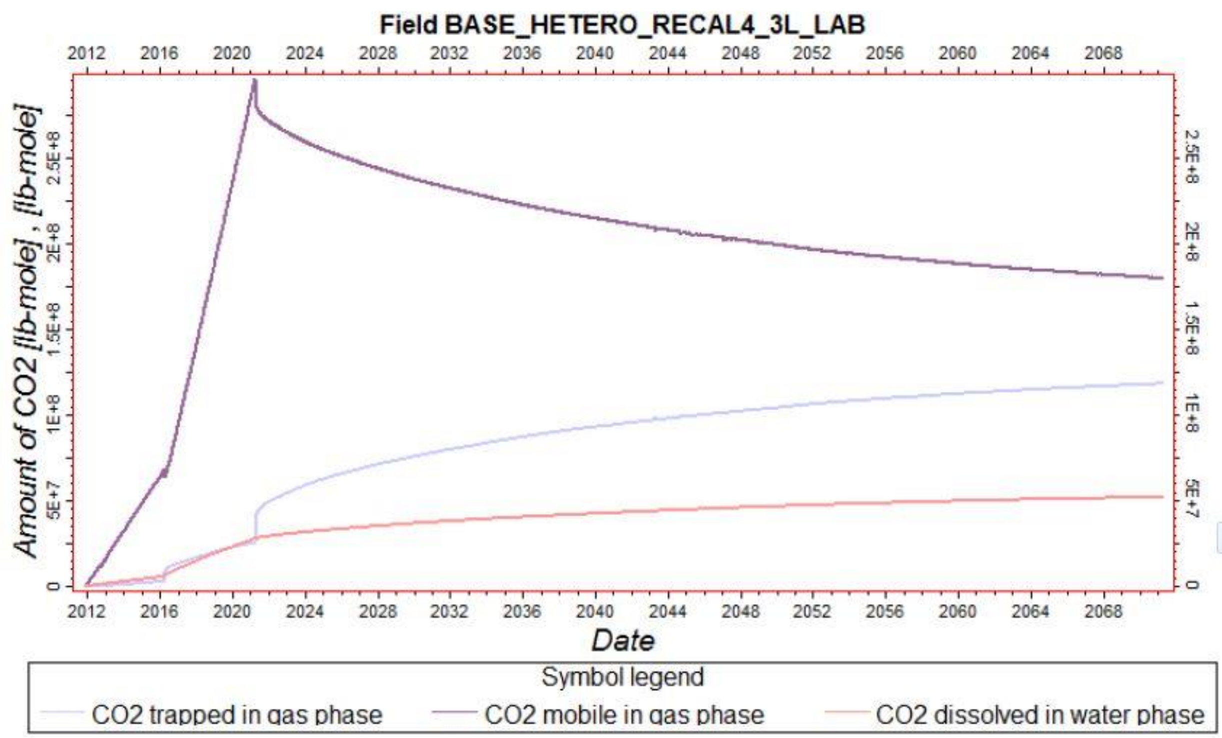


Figure 12. Predicted CO_2 phase distribution, simulated for 50 years after the commencement of injection.

. 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 CO_2 saturation. Time-lapse 3D vertical seismic profiles (VSPs) will be used to image the developing CO_2 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: $\delta^{13}C$ 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 CO_2 plume and pressure front at 1-year intervals throughout the injection phase are shown in Figure 4. Predicted extent of the CO_2 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 CO_2 in the mobile gas, trapped gas, and dissolved (aqueous) phases for 50 years after the commencement of injection is shown in Figure 12.

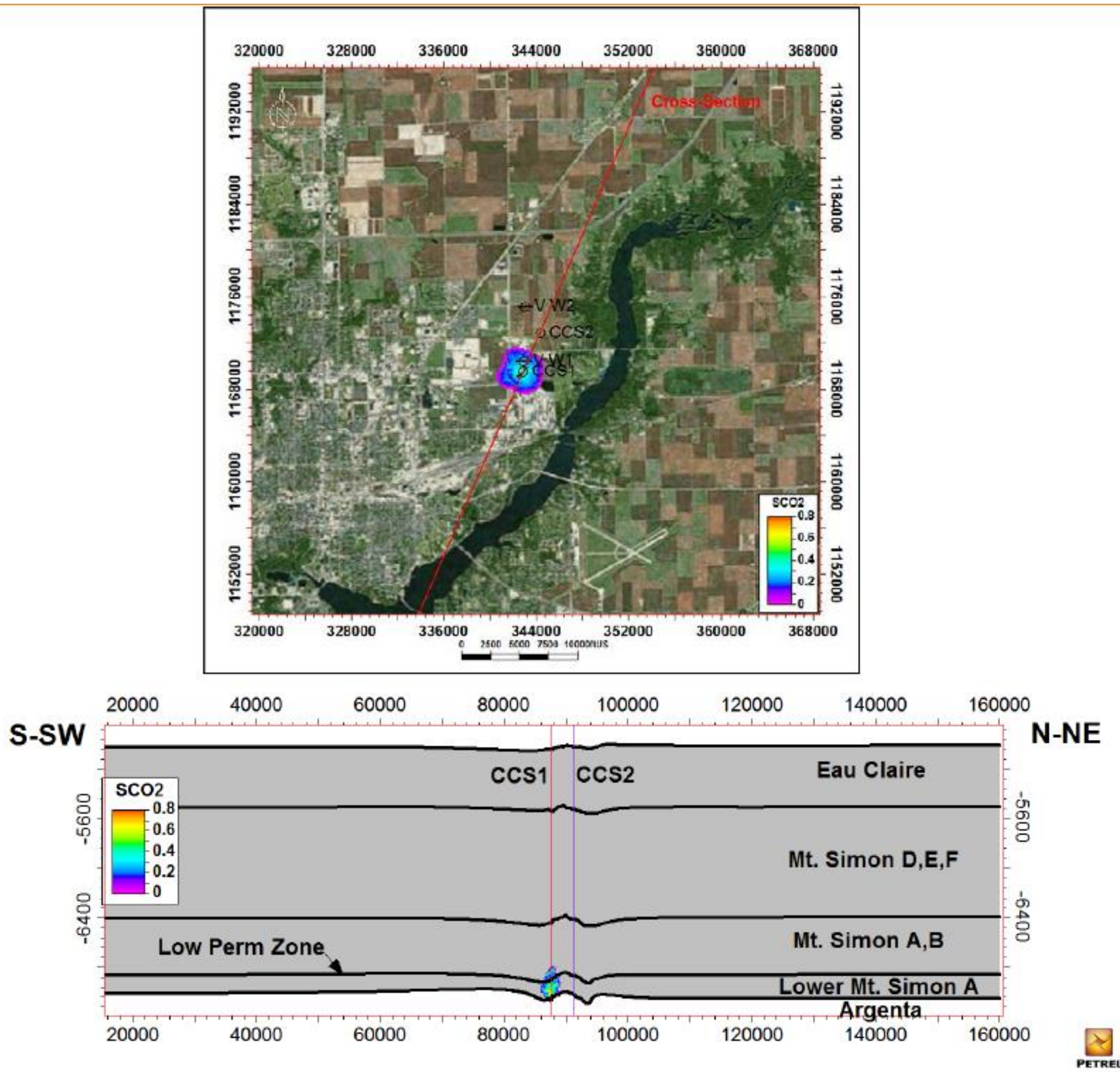


Figure 4. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the commencement of injection for CCS #2.

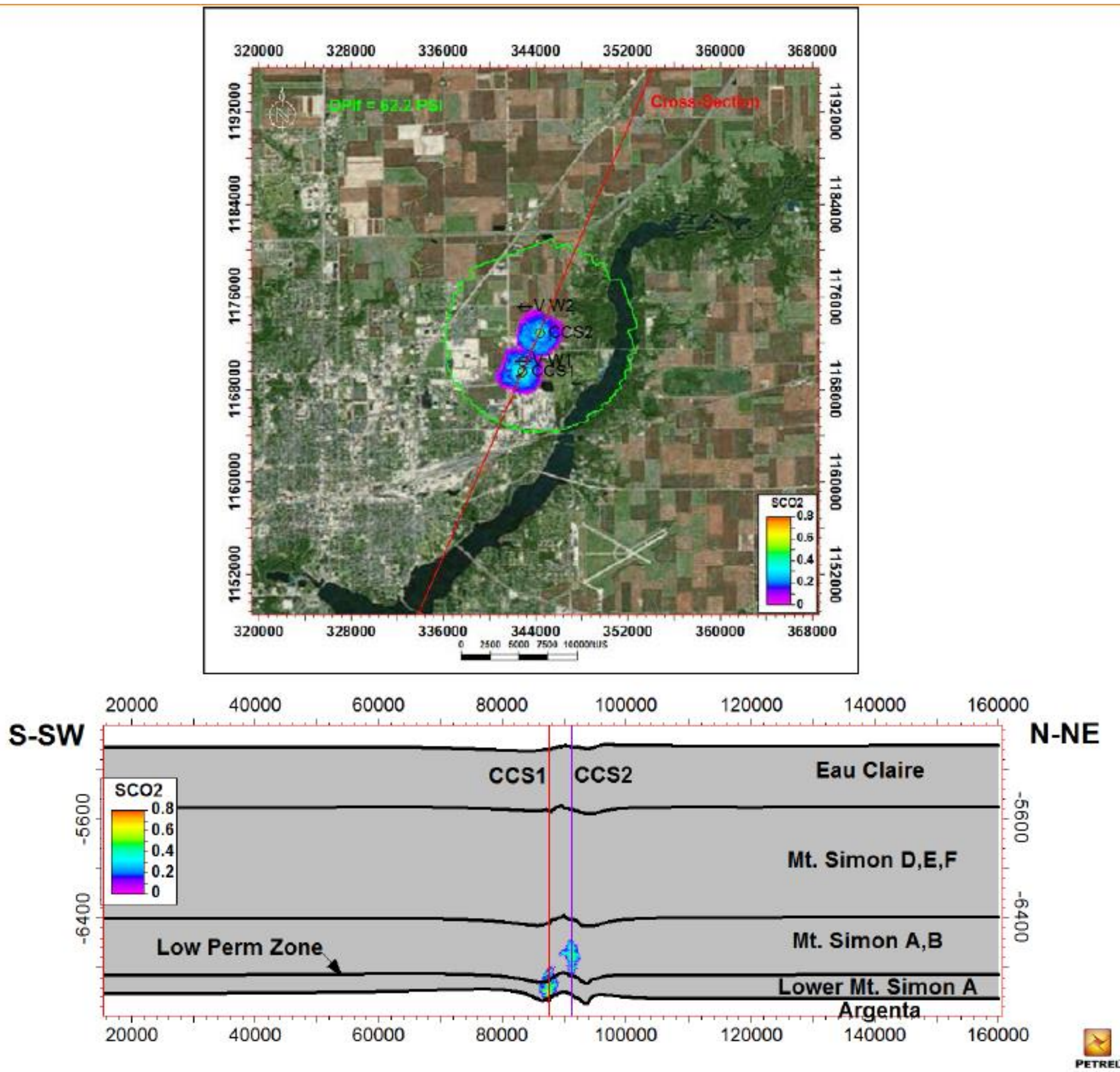


Figure 5. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 1 year of injection at CCS #2.

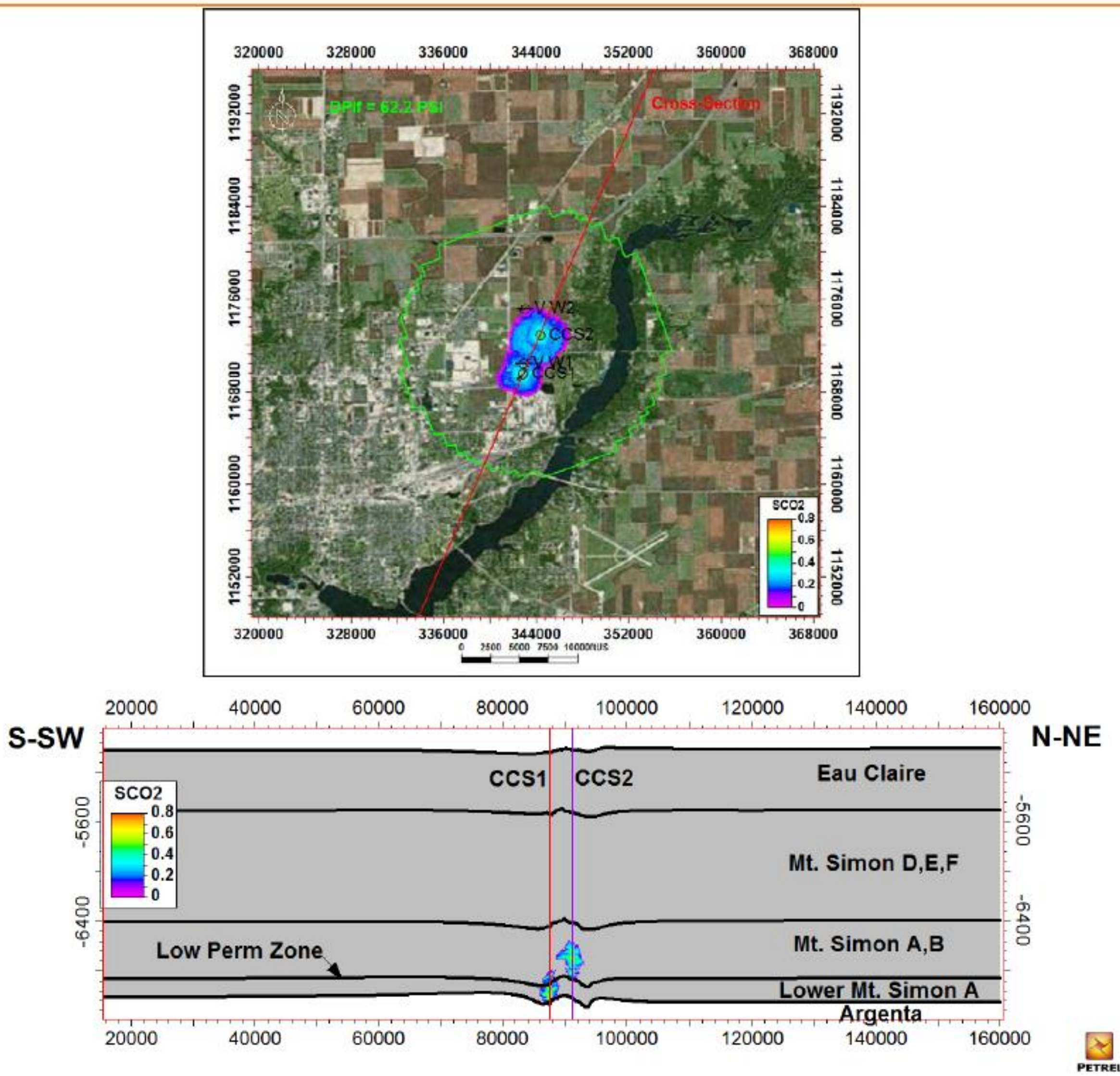


Figure 6. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 2 years of injection at CCS #2.

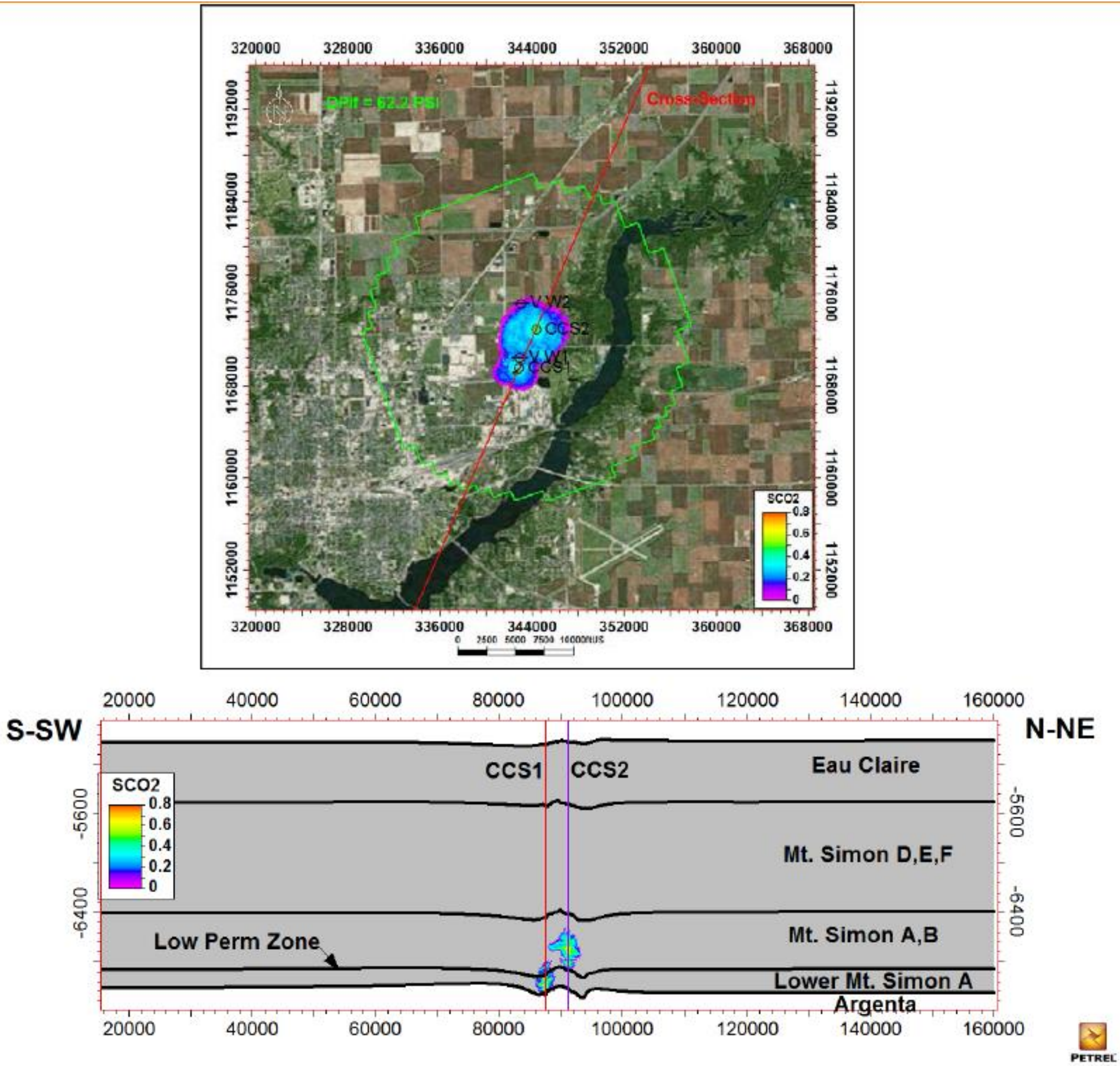
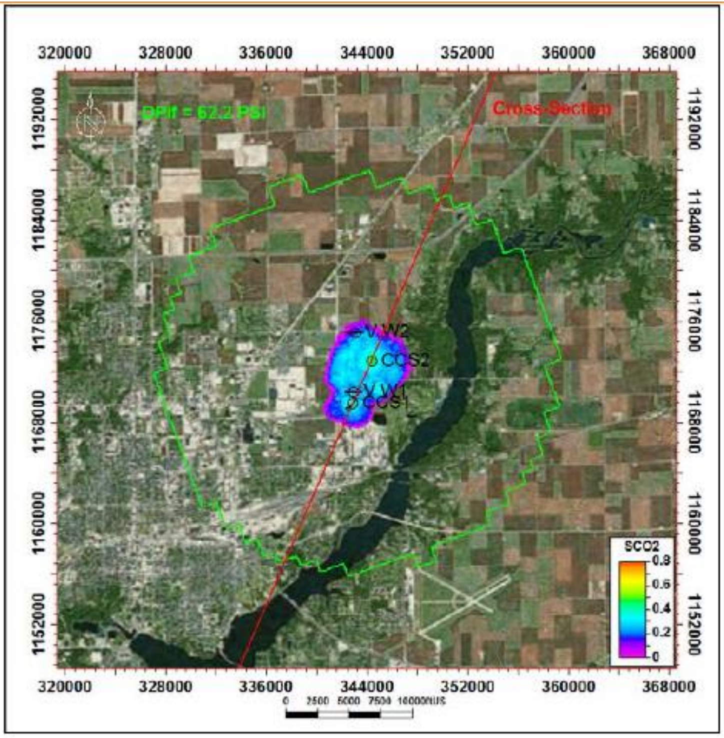


Figure 7. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 3 years of injection at CCS #2.



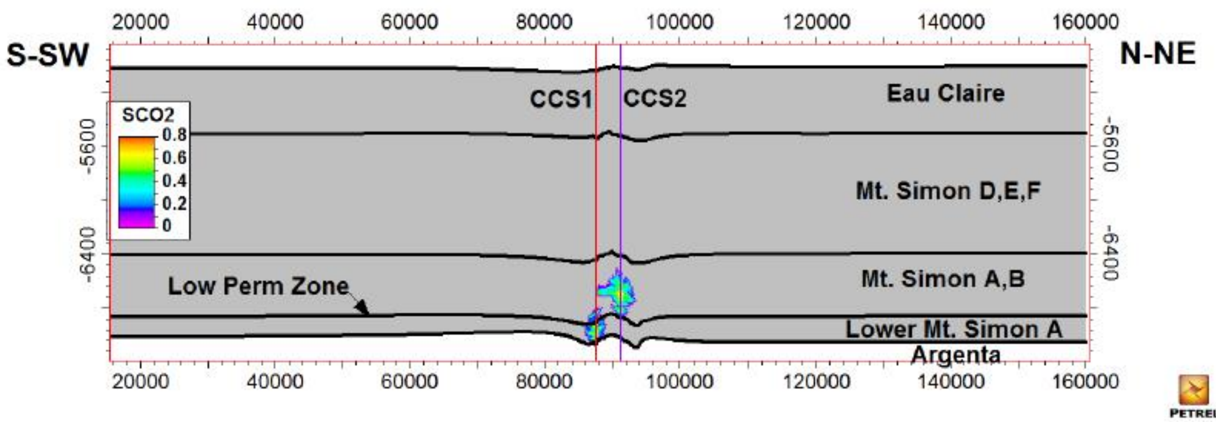


Figure 8. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 4 years of injection at CCS #2.

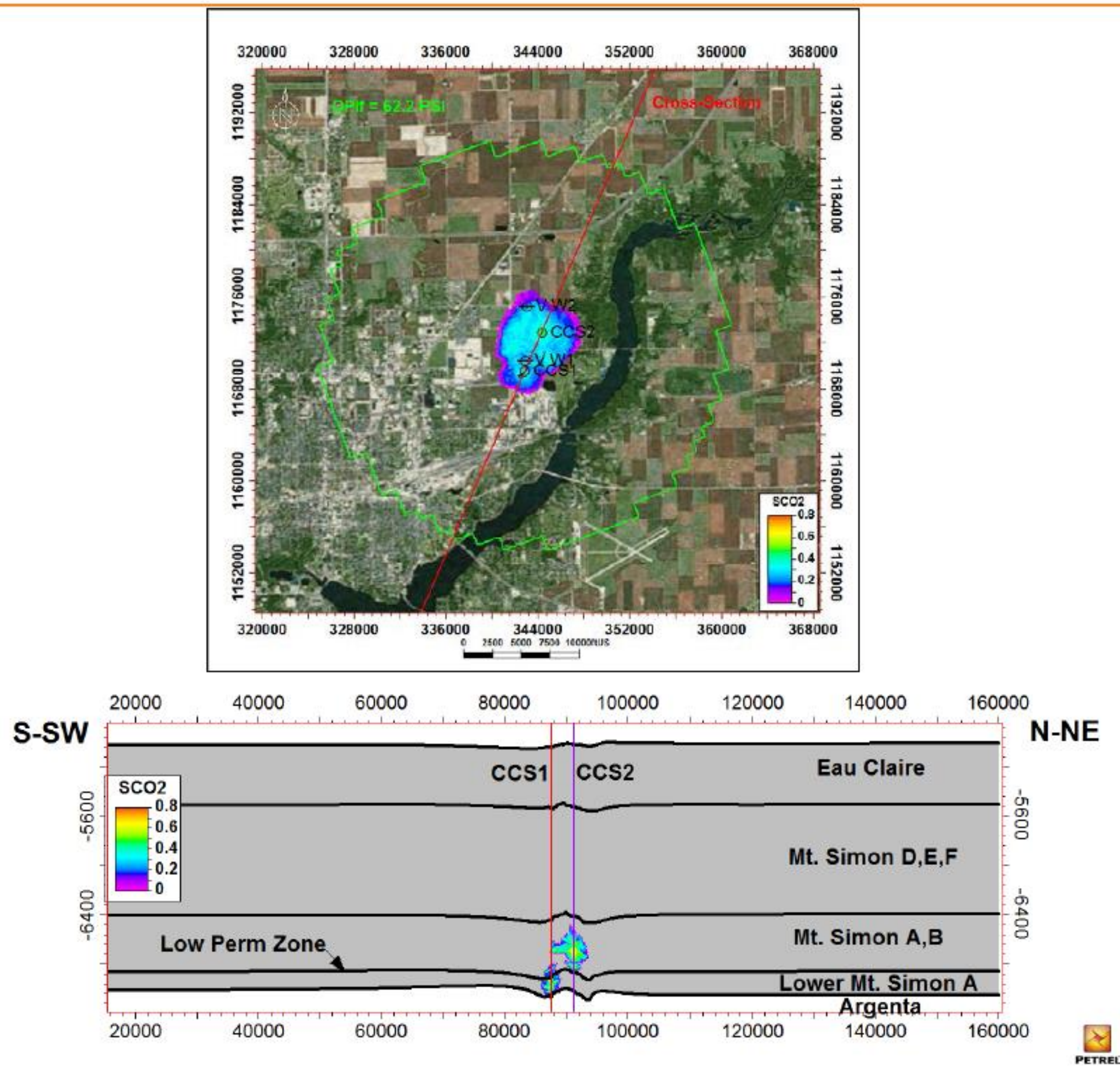


Figure 9. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 5 years of injection at CCS #2.

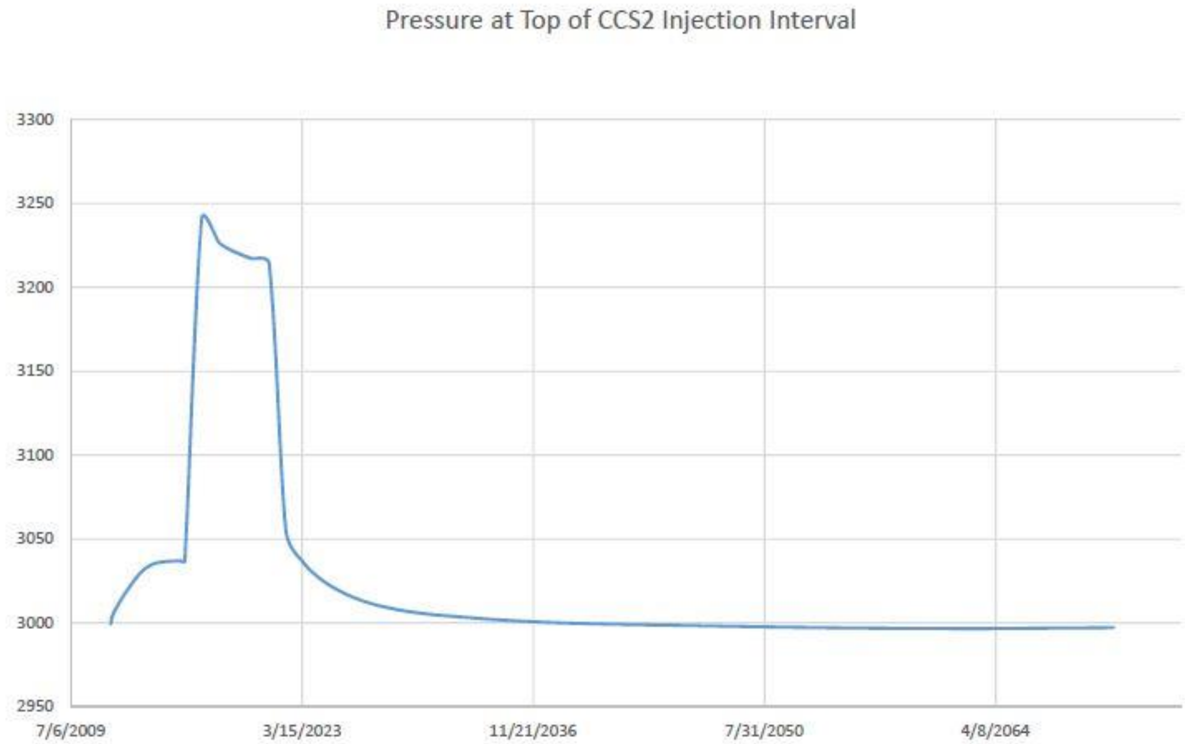


Figure 10. Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection.

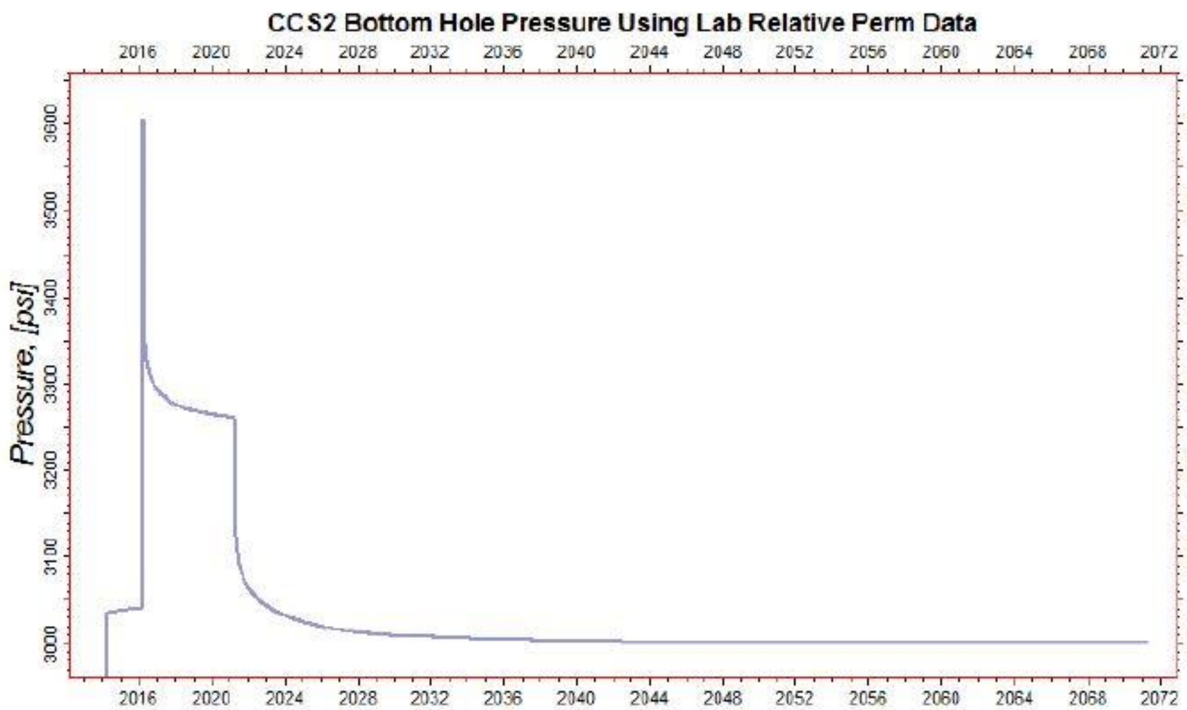


Figure 11. Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection.

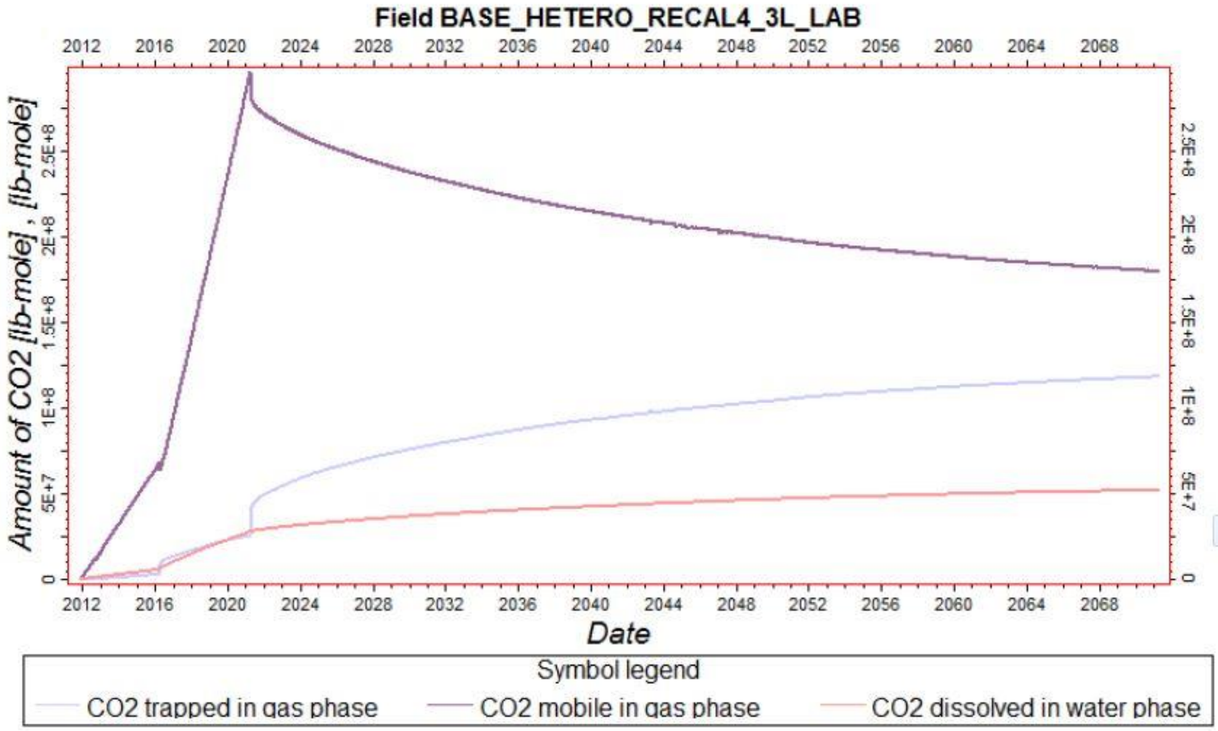


Figure 12. Predicted CO_2 phase distribution, simulated for 50 years after the commencement of injection.

Appendix

Quality Assurance and Surveillance Plan.

Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) Project
Class VI Injection Well: Quality Assurance and Surveillance Plan

U.S. EPA ID Number (IL-115-6A-0001)

October 2016

Prepared by:
Archer Daniels Midland Company (ADM)

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Distribution List

The following project participants should receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project. The ADM Corn Plant Manager will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved Quality Assurance and Surveillance Plan. Names in bold are the primary points of contact with addresses listed below.

<u>ADM</u>
Steve Merritt
Dean Frommelt
Ed Taylor
Mark Atkinson

Archer Daniels Midland Company – Corn Processing
Facilities Contact : Mr. Steve Merritt, Corn Plant Manager
Mailing Address : 4666 Faries Parkway
Decatur, IL 62526
Phone : 217-424-5750

A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The project, led by Archer Daniels Midland Company (ADM), includes participation from several subcontractors. The Testing and Monitoring Activities responsibilities will be shared between ADM and their designated subcontractor and the program will be broken in six subcategories:

I) Shallow Groundwater Sampling

II) Deep Groundwater Sampling

III) Well Logging

IV) Mechanical Integrity Testing (MIT)

V) Pressure/Temperature Monitoring

VI) CO_2 Stream Analysis

VII) Geophysical Monitoring

A.1.c. Independence from Project QA Manager and Data Gathering

The majority of the physical samples collected and data gathered as part of the MVA program is analyzed, processed, or witnessed by third parties independent and outside of the project management structure.

A.1.d. QA Project Plan Responsibility

ADM will be responsible for maintaining and distributing official, approved QA Project Plan. ADM will periodically review this QASP and consult with USEPA if/when changes to the plan are warranted.

A.1.e. Organizational Chart for Key Project Personnel

Figures 1 shows the organization structure of the project. ADM will provide to the UIC Program Director a contact list of individuals fulfilling these roles.

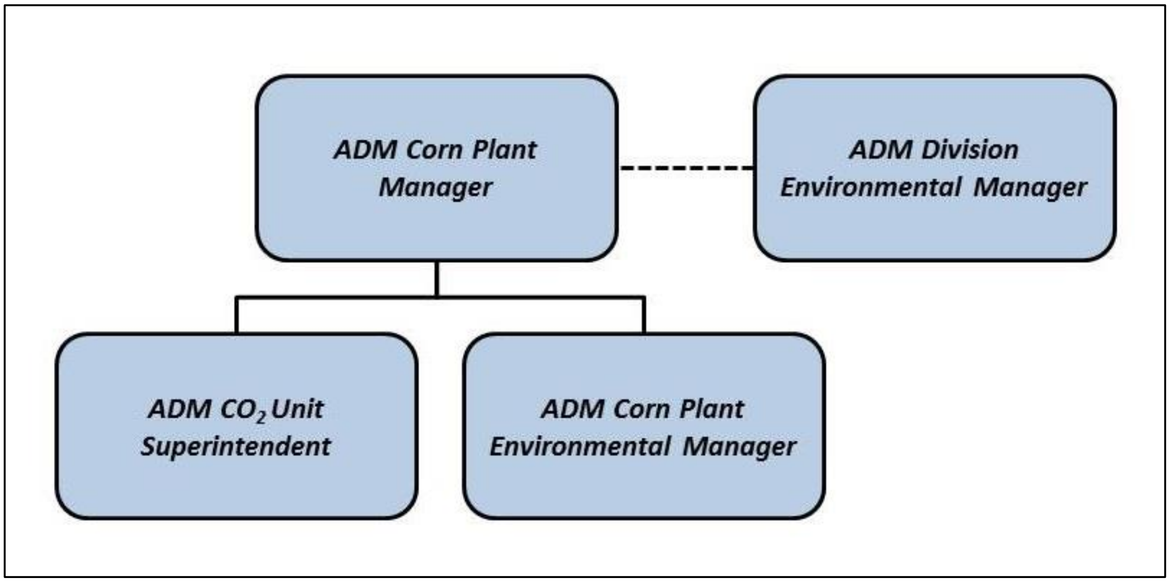

Figure 1. Archer Daniels Midland Company project organization structure.

A.2. Problem Definition/Background

A.2.a Reasoning

The Illinois Industrial Carbon Capture and Storage (IL-ICCS) Project's monitoring, verification, and accounting (MVA) program has operational monitoring, verification, and environmental monitoring components. Operational monitoring is used to ensure safety with all procedures associated with fluid injection, monitor the response of storage unit, and the movement of the CO_2 plume. Key monitoring parameters include the pressure of injection well tubing & annulus, storage unit, above seal strata, and the lowermost USDW reservoir. Other monitoring parameters include injection rate, total mass & volume injected, injection well temperature profile, and passive seismic. The verification component will provide information to evaluate if leakage of CO_2 through the caprock is occurring. This includes pulse neutron logging , pressure, and temperature monitoring. The environmental monitoring components will determine if the injectate is being released into the shallow subsurface or biosphere. This monitoring includes pulse neutron logging and ground water monitoring.

A robust MVA program has been developed for the IL-ICCS project based on the experience gained through the Illinois Basin–Decatur Project (IBDP). The knowledge and experience gained through the IBDP provides a high level of confidence that the storage unit (Mt Simon) is capable to accept and permanently retain the injectate. The primary goal of the IL-ICCS MVA program is to demonstrate that project activities are protective of human health and the environment. To help achieve this goal, this Quality Assurance Surveillance Plan (QASP) was developed to insure the quality standards of the testing and monitoring program meet the requirements of the U.S. Environmental Protection Agency's (USEPA) Underground Injection Control (UIC) Program for Class VI wells.

A.2.b. Reasons for Initiating the Project

The goal of the IL-ICCS injection project is to demonstrate the ability of the Mt. Simon Sandstone to accept and retain industrial-scale volumes of CO_2 for permanent geologic sequestration to reduce atmospheric concentrations of CO_2. In order to demonstrate that this can be done safely and at commercial scale, a rigorous MVA plan is proposed to ensure the injected CO_2 is retained within the intended storage reservoir.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

The Class VI Rule requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to ensure that the injection well maintains its mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that underground sources of drinking water (USDWs) are not endangered. These monitoring activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of ground water quality in several zones, tracking of the CO_2 plume and associated pressure front. This document details both the measurements that will be taken as well as the steps to ensure that the quality of all the data is such that the data can be used with confidence in making decisions during the life of the project.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed and Work Schedule

Table 1 describes the Testing and Monitoring tasks, reasoning, responsible parties, locations and testing frequency. Tables 2 and 3 summarize the instrumentation and geophysical surveys, respectively.

Table 1. Summary of testing and monitoring.

			Frequency					
Parameter	**Location**	**Method**	**Pre-injection—Baseline**	**Operation Period—5 years**	**PISC Period—10 years**	**Analytical Technique**	**Lab/Custody**	**Purpose**
Carbon dioxide stream analysis	Compressor	Direct sampling	2 years: Quarterly	Quarterly	None	Chemical analysis	TBD	Monitor injectate
	After CO_2 dehydration	Direct sampling	2 years: Quarterly	Quarterly	None	Chemical analysis	TBD	Monitor injectate
Continuous recording								
Injection rate and volume	After compression	Flow meter	N/A	Continuous	N/A	Direct measurement	N/A	Monitor rate and volume
Injection pressure	CCS2 Wellhead	Pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injection pressure
Annular pressure	CCS2 Wellhead	Pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor annular pressure
DTS Fiber Optic Temperature	CCS2 Wellbore	Fiber optic cable	N/A	Continuous	Yr 1- Continuous Yr 2-10 - N/A	Direct measurement	N/A	Wellbore integrity
Downhole pressure/temperature	CCS2: Mt Simon	Downhole gauge	N/A	Continuous	Yr 1-3 Continuous Yr 4-10 – Annual	Direct measurement	N/A	Monitor reservoir
Corrosion monitoring	After compression	Coupon	N/A	Quarterly	N/A	Chemical analysis	TBD	Monitor injectate, wellbore integrity
Mechanical Integrity	CCS2	Various	Prior to operation	Annually	Prior to P/A	§ 146.87 (a)(4) § 146.89 (c)(2)	N/A	Wellbore integrity
DTS Fiber Optic	CCS2	Fiber optic cable	Continuous	Continuous	Yr 1 Continuous Yr 2-10 – N/A	Direct measurement	N/A	Wellbore integrity
Cement evaluation	CCS2	Logging	Baseline	N/A	N/A	Cement evaluation log	N/A	Wellbore integrity
Pressure fall off testing	CCS2: Mt. Simon	Pressure gauge	N/A	During injection-approximately half way through the injection phase and at the end of the injection period.	N/A	Direct measurement	N/A	Wellbore integrity
Microseismic	Various monitoring stations	Multilevel geophones and seismometers	Continuous	Continuous	Continuous	Direct measurement	N/A	Reservoir integrity

Table 1. Summary of testing and monitoring (continued).

Direct Geochemical Measurement			Frequency					
Level	**Location Depth**	**Method**	**Pre-injection—Baseline**	**Operation Period—5 years**	**PISC Period—10 years**	**Analytical Technique**	**Parameters**	**Purposes**
Shallow groundwater (Quaternary & Pennsylvanian)	Figure 2	In-situ	2 years: Quarterly	Year 1–2: Quarterly Year 3–5: Bi-annually	Annually	Chemical analysis	Table 4	Detection of changes in groundwater quality for a shallow USDW.
Lowermost USDW (St. Peter)	GM2	Swab valve or other method	1 sample	Annually	Annually	Chemical analysis	Table 5	Detection of changes in groundwater quality in lowermost USDW.
Above confining zone (Ironton-Galesville)	VW1	In-situ	1 sample	Baseline; Year 1-3: Annual Year 4-5: N/A	None	Chemical analysis	Table 6	Detection of changes in groundwater quality for reservoir directly above the confining zone.
	VW2	In-situ	1 sample	Annually	Annually	Chemical analysis	Table 6	Detection of changes in groundwater quality for reservoir directly above the confining zone.
In-zone monitoring (Mt. Simon)	VW1	In-situ	1 sample	Baseline; Year 1-3: Annual Year 4-5: N/A	None	Chemical analysis	Table 7	Detection of changes in groundwater quality, geochemical monitoring and CO_2 detection in storage reservoir.
	VW2	In-situ	1 sample	Annually	Annually	Chemical analysis	Table 7	Detection of changes in groundwater quality, geochemical monitoring and CO_2 detection in storage reservoir.

* Samples collected using downhole sampling tool run into well on wireline.
* Swab samples collected at surface after well has been swabbed with ample volume to ensure reservoir fluid at surface.

Table 1. Summary of testing and monitoring (continued).

Indirect Methods of CO_2 Plume Tracking					
Method	**Location**	**Pre-injection—Baseline**	**Operation Period—5 years**	**PISC Period—10 Years**	**Purpose**
Time lapse VSP	GM1	2013, 2014, 2015	None	None	Indirect measurement of plume size
Time lapse 3D	Injection area	Baseline survey	Year 2 (2019)	Year 1 and Year 10	Indirect measurement of plume size

Table 2. Instrumentation summary. T = Temperature; P = Pressure; DTS = Distributed Temperature System; F = Flow.

			Operational Period—5 Years		PISC Period—10 Years		
Monitoring Location	**Instrument Type**	**Monitoring Target (Formation or Other)**	**Data Collection Location(s)**	**Frequency**	**Data Collection Location(s)**	**Frequency**	**Explanation**
CO_2 Facility	T, P, F	Surface	Discharge High Pressure Pumps	Continuous	Discharge high pressure pumps	NA	Monitoring the operational, equipment, and permit parameters
CCS#1	DTS	All strata	Distributed measurement to 6325 KB/5631 MSL.	Continuous	Distributed measurement to 6325 KB/5631 MSL.	Yr 1: Continuous Yr 2–10: None	Monitoring operational parameters and well integrity
	T, P	Mt. Simon	1 interval PT @ 6325 KB/5631 MSL Perfs @ 6982–7050 KB 6288–6356 MSL	Continuous 1 interval	1 interval PT @ 6325 KB/5631 MSL Perfs @ 6982–7050 KB 6288–6356 MSL	Yr 1–3: Continuous Yr 4–10: Annual	Monitoring operational and equipment parameters
	Geophones	All strata	3 interval array	Note 1.	3 intervals	Note 1.	Note 1: Operator will maintain a passive seismic monitoring system that has the ability to detect seismic events over M1.0 within the AoR.
CCS#2	T, P	Surface well head	Tubing	Continuous	Tubing	Continuous	Monitoring operational, equipment, and permit parameters
	P		Annulus	Continuous	Annulus	Continuous	Monitoring well integrity
	DTS	All geologic strata	Distributed measurement to 6211 KB/5520 MSL.	Continuous	Distributed measurement to 6211 KB/5520 MSL.	Yr 1: Continuous Yr 2–10: None	Monitoring operational parameters and well integrity
	T, P	Mt. Simon	1 point location, 1 interval: PT @ 6270 KB/5579 MSL; Perfs @ 6630 - 6825 KB, 5939 - 6134 MSL	Continuous	1 point location, 1 interval: PT @ 6270 KB/5579 MSL; Perfs @ 6630 - 6825 KB, 5939 - 6134 MSL	Yr 1–3: Continuous Yr 4–10: Annual	Monitoring operational, equipment, and permit parameters
VW1	T, P	Ironton-Galesville	1 interval 4918–5000 KB 4224–4306 MSL	Year 1-3: Continuous Year 4-5: None	1 interval 4918–5000 KB 4224–4306 MSL	None	Monitoring seal formation integrity
		Mt. Simon	1 interval 6945–5654 KB 6251–4960 MSL	Year 1-3: Continuous Year 4-5: None	1 interval 6945–5654 KB 6251–4960 MSL	None	Monitoring plume pressure and temperature front

Table 2. Instrumentation summary. T = Temperature; P = Pressure; DTS = Distributed Temperature System; F = Flow (continued).

			Operational Period—5 Years		**PISC Period—10 Years**		
Monitoring Location	**Instrument Type**	**Monitoring Target (Formation or Other)**	**Data Collection Location(s)**	**Frequency**	**Data Collection Location(s)**	**Frequency**	**Explanation**
VW2	T, P	Ironton-Galesville	1 point location, 1 interval: 4902 KB/4199 MSL	Baseline Continuous	1 point location, 1 interval: 4902 KB/4199 MSL	Yr 1–3: Continuous Yr 4–10: Annual	Monitoring seal formation integrity
	T,P	Mt. Simon	1 point location, 4 intervals: 7041, 6681, 6524, 5848 KB; 6338, 5978, 5821, 5145 MSL	Continuous	1 point location, 4 intervals: 7041, 6681, 6524, 5848 KB; 6338, 5978, 5821, 5145 MSL	Continuous	Monitoring plume pressure and temperature front
GM1	Geophones	All strata	20 interval array	Note 1.	20 interval array	Note 1.	Note 1: Operator will maintain a passive seismic monitoring system that has the ability to detect seismic events over M1.0 within the AoR.
GM2	T,P	St. Peter	1 point location, 1 interval: 3450 KB/2759 MSL	Continuous	1 point location, 1 interval: 3450 KB/2759 MSL	Yr 1–3: Continuous Yr 4–10: Annual	Monitoring seal formation integrity
	Geophones	All strata	5 interval array	Note 1.	5 interval array	Note 1.	Note 1: Operator will maintain a passive seismic monitoring system that has the ability to detect seismic events over M1.0 within the AoR.
Seismic Stations	Seismometers & geophones	All strata	Combination of surface and borehole monitoring stations	Note 1.	Various	Note 1.	Note 1: Operator will maintain a passive seismic monitoring system that has the ability to detect seismic events over M1.0 within the AoR.

Table 3. Geophysical surveys summary.

Monitoring Activity	Well	Tools or Survey Description	Pre-Injection - Baseline	Operation Period - 5 Years	PISC Period - 10 Years	Explanation
Logging	GM#1	CBL	1 Baseline	None	None	Mechanical Integrity
	GM#2	CBL	1 Baseline	None	None	Mechanical Integrity
	VW#1	Cement evaluation tool	1 Baseline	None	None	Mechanical Integrity
		Pulse neutron	1 Baseline	Year 2, 4	Year 1, 3, 5, 7, 10	Fluid movement, salinity, CO_2 detection, mechanical integrity
	VW#2	Cement evaluation tool	1 Baseline	None	None	Mechanical Integrity
		Pulse neutron	1 Baseline	Year 2, 4	Year 1, 3, 5, 7, 10	Fluid movement, salinity, CO_2 detection, mechanical integrity
	CCS#1	Pulse neutron	1 Baseline	Year 2, 4	Year 1, 3, 5, 7, 10	Fluid movement, salinity, CO_2 detection, mechanical integrity
		Casing inspection	1 Baseline	None	None	Mechanical Integrity
		Cement evaluation tool	1 Baseline	None	None	Mechanical Integrity
	CCS#2	Pulse neutron	1 Baseline	Year 2, 4	Year 1, 3, 5, 7, 10	Fluid movement, salinity, CO_2 detection, mechanical integrity
		Casing inspection	1 Baseline	None	None	Mechanical Integrity
		Cement evaluation tool	1 Baseline	None	None	Mechanical Integrity
Seismic	GM#1	Time-lapse VSP survey	2013, 2014, 2015	None	None	Monitor spatial extent of plume
	Area	3D surface seismic survey	1 Baseline	Year 2 (2019)	Year 1, Year 10	Monitor spatial extent of plume

A.3.c. Geographic Locations

Figure 2 shows the IL-ICCS site and monitoring infrastructure.

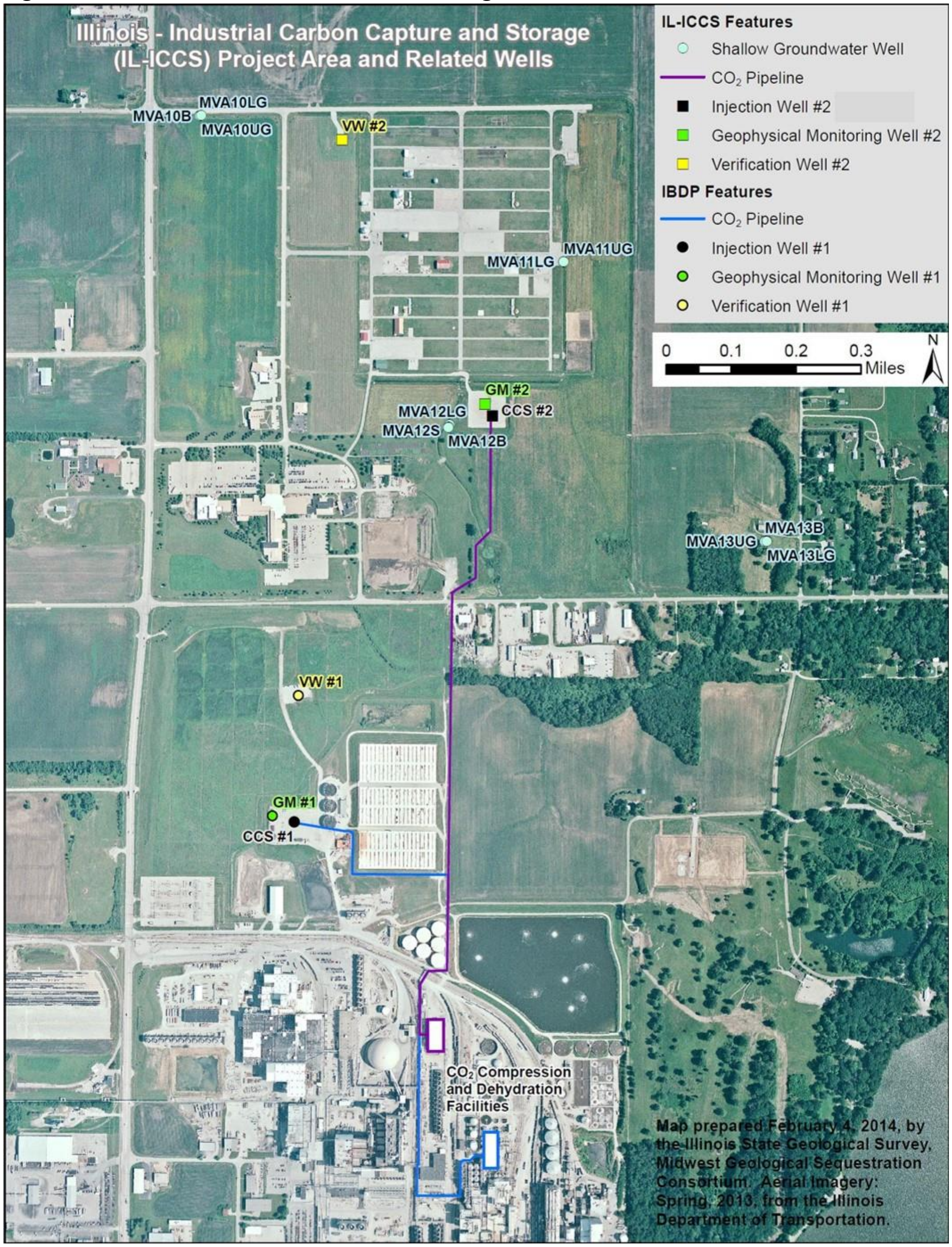

Figure 2. IL-ICCS Project area showing location of shallow groundwater monitoring wells and deep monitoring wells.

A.3.d. Resource and Time Constraints

At the conclusion of the IBDP project, the availability of wells associated with that project (VW#1, GM#1, CCS#1) are potential resource constraints for IL-ICCS. Under its current state-issued UIC permit, IBDP post-injection monitoring will continue for at least 2 to 3 years after injection ceases in November 2014. Thereafter, the status and availability of the IBDP wells for use by the IL-ICCS project is uncertain. No additional resource or time constraints have been identified for the IL-ICCS testing and monitoring plan beyond project funding levels and the proposed timeline.

A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

The overall QA objective for monitoring is to develop and implement procedures for subsurface monitoring, field sampling, laboratory analysis, and reporting which will provide results that will meet the characterization and non-endangerment goals of this project. Groundwater monitoring will be conducted during the pre-injection, injection, and post-injection phases of the project. Shallow and deep groundwater monitoring wells will be used to gather water-quality samples and pressure data. All the groundwater analytical and field monitoring parameters for each interval are listed in Table 4 through Table 7. Table 8, Table 9 and Table 10 show analytical parameters for CO2 stream gas monitoring, corrosion coupon assessment, and gauge specifications. Table 11 shows the monitoring outputs. The list of analytes may be reassessed periodically and adjusted to include or exclude analytes based on their effectiveness to the overall monitoring program goals.

Key testing and monitoring areas include:

I. Shallow Groundwater Sampling
   - Aqueous chemical concentrations

II. Deep Formation Fluid Sampling
   - Aqueous chemical concentrations

III. Well Logging
   - pulse neutron

IV. Mechanical Integrity Testing (MIT)
   - Pulsed neutron, temperature, cement evaluation logging

V. Pressure/Temperature Monitoring
   - Pressure/temperature from in-situ gauges
   - Pressure/temperature from surface gauges

VI. CO_2 Stream Analysis
   - CO_2 Purity (% v/v, [GC])
   - Oxygen (O_2, ppm v/v)
   - Nitrogen (N_2, ppm v/v)
   - Carbon Monoxide (CO, ppm v/v)
   - Oxides of Nitrogen (NOx, ppm v/v)
   - Total Hydrocarbons (THC, ppm v/v as CH_4)

- Methane (CH_4, ppm v/v)
- Acetaldehyde (AA, ppm v/v)
- Sulfur Dioxide (SO_2, ppm v/v)
- Hydrogen Sulfide (H_2S ppm v/v)
- Ethanol (ppm v/v)

VII. Geophysical Monitoring

- Seismic data files (e.g., segd file)
- Processed time-lapse report

Table 4. Summary of analytical and field parameters for Quaternary/Pennsylvanian groundwater samples. All analysis will all be performed by ADM or a designated third party laboratory.
ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved CO_2	Coulometric titration, ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	Gravimetry; APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

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

Table 5. Summary of analytical and field parameters for St Peter Reservoir groundwater samples. All analysis will be performed by ADM or a designated third party laboratory. ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis.

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved CO_2	Coulometric titration, ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry[2]	12.2 mg/L HCO_3^- for $\delta^{13}C$	±0.15‰ for $\delta^{13}C$	10% duplicates; 4 standards/batch
Total Dissolved Solids	Gravimetry; APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
Water Density(field)	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
Alkalinity	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

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

Note:2: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

Table 6. Summary of analytical and field parameters for Ironton-Galesville groundwater samples. Note: Cation, anion, TDS, and alkalinity measurements will all be performed by a laboratory meeting the requirements under the USEPA Environmental Laboratory Accreditation Program. Isotope and dissolved CO_2 analyses will be performed by ADM or a designated laboratory. ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis.

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved CO_2	Coulometric titration, ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry[2]	12.2 mg/L HCO_3^- for $\delta^{13}C$	±0.15‰ for $\delta^{13}C$	10% duplicates; 4 standards/batch
Total Dissolved Solids	Gravimetry; APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
Water Density(field)	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
Alkalinity	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

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

Note:2: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

Table 7. Summary of analytical and field parameters for Mt Simon groundwater samples. All analysis will be performed by ADM or a designated third party laboratory. ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis.

Parameters	Analytical Methods(1)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved CO_2	Coulometric titration, ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry[2]	12.2 mg/L HCO_3^- for $\delta^{13}C$	±0.15‰ for $\delta^{13}C$	10% duplicates; 4 standards/batch
Total Dissolved Solids	Gravimetry; APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
Water Density(field)	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
Alkalinity	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

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

Note:2: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

Table 8. Summary of analytical parameters for CO_2 gas stream. All analysis will be performed by ADM or a designated third party laboratory.

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
	GC/TCD	0.1 % to 100 %	5 - 10 % relative across the range, RT ± 0.1 min	daily standard, duplicate analysis within 10 % of each other
Nitrogen	ISBT 4.0 GC/DID	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
	GC/TCD	0.1 % to 100 %	5 - 10 % relative across the range, RT ± 0.1 min	daily standard, duplicate analysis within 10 % of each other
Carbon Monoxide	ISBT 5.0 Colorimetric	5 uL/L to 100 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis
	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
Oxides of Nitrogen	ISBT 7.0 Colorimetric	0.2 uL/L to 5 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis
Total Hydrocarbons	ISBT 10.0 THA (FID)	1 uL/L to 10,000 uL/L (ppm by volume)	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Methane	ISBT 10.1 GC/FID)	0.1 uL/L to 1,000 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Acetaldehyde	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Sulfur Dioxide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Ethanol	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm-Nagel	99.00% to 99.99%	± 10 % of reading	User calibration per manufacturer recommendation
	ALI method SAM 4.1 subtraction method (GC/DID)	1 ppm for each target analyte (analyte dependent) - refer to Oxygen and Nitrogen analysis.	5-10 % relative across the range	duplicate analysis within 10 % of each other
	GC/TCD	0.1 % to 100 %	5-10 % relative across the range, RT ± 0.1 min	standard with every sample, duplicate analysis within 10 % of each other

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

Table 9. Summary of analytical parameters for corrosion coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2005	.005mg	+/-2%	Annual Calibration of Scale (3rd Party Aldinger Co. – Cert #664896F)
Thickness	NACE RP0775-2005	.001mm	+/-005mm	Factory calibration

Table 10. Summary of measurement parameters for field gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure (PIT-012)	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual Calibration of Scale (3rd party)
Injection Tubing Temperature (TIT-019)	ANSI Z540-1-1994	+/- 0.001 F / 0-500 F	+/- 0.01 F	Annual Calibration of Scale (3rd party)
Annulus Pressure (PIT-014)	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual Calibration of Scale (3rd party)
Injection Tubing Pressure (PIT-009)	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual Calibration of Scale (3rd party)
Injection Mass Flow Rate (FIT-006)	UNKNOWN	+/- 0.1000% of rate / 50,522-303,133 lb/hr	+/- 0.01 lbs/hr	Annual Calibration of Scale (3rd party)
Westbay Pressures (MOSDAX)	UNKNOWN	+/0 0.01 psi / 0-4000 PSI	+/- 0.1 psi	Annual Calibration of Scale (3rd party)

Table 11. Actionable testing and monitoring outputs.

	Project Action Limit	Detection Limit	Anticipated Reading
MIT—Pulse neutron logging	Action taken when RST indicates CO_2 outside of expected range	+/- 0.5 SIGM	Brine saturated ~ 60 CO_2 saturated ~ 8
Wellbore integrity—annular pressure gauge	<3% pressure loss over 1 hour	Refer to Appendix A (annular pressure gauge table)	>3% pressure loss over 1 hour
Surface and downhole pressure gauges	Action will be taken when pressures are well outside of modeled/expected range	Refer to Table 11 and 12 for surface gauges Refer to Table 9 for downhole gauge	Within injection formation: >80% fracture gradient 0.71 psi/ft
Wellbore integrity—DTS fiber optic temperature	Action will be taken when there is an anomaly in temperature profile	Refer to Appendix A	DTS provides continuous temperature profile
Seismic data files	Detected CO_2 outside the AOR	Dependent on fluid saturation, and formation velocities	CO_2 plume migration similar to modeled outcome

A.4.b. Precision

For groundwater sampling, data accuracy will be assessed by the collection and analysis of field blanks to test sampling procedures and matrix spikes to test lab procedures. Field blanks will be taken no less than one per sampling event to spot check for sample bottle contamination. Laboratory assessment of analytical precision will be the responsibility of the individual laboratories per their standard operating procedures.

Table 12 summarizes the specifications of each monitoring method. For direct pressure and logging measurements, precision data is presented in Table 13.

A.4.c. Bias

Laboratory assessment of analytical bias will be the responsibility of the individual laboratories per their standard operating procedures and analytical methodologies. For direct pressure or logging measurements, there is no bias.

A.4.d. Representativeness

For groundwater sampling, data representativeness expresses the degree to which data accurately and precisely represents a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The sampling network has been designed to provide data representative of site conditions. For analytical results of individual groundwater samples, representativeness will be estimated by ion and mass balances. Ion balances with ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help determine the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

A.4.e. Completeness

For groundwater sampling, data completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for groundwater sampling will be acceptable to meet monitoring goals. For direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

A.4.f. Comparability

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be very comparable to future data sets because of the use of standard methods and the level of QA/QC effort. If historical groundwater quality data become available from other sources, their applicability to the project and level of quality will be assessed prior to use with data gathered on this project. Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained data.

A.4.g. Method Sensitivity

Table 14 through Table 19 provide additional details on gauge specifications and sensitivities.

Table 12. Pressure and temperature—downhole quartz gauge specifications.

Calibrated working pressure range	Atmospheric to 10,000 psi
Initial pressure accuracy	<+/-2 psi over full scale
Pressure resolution	0.005 psi at 1-s sample rate
Pressure drift stability	<+/-1 psi per year over full scale
Calibrated working temperature range	77–266°F
Initial temperature accuracy	<+/-0.9°F per +/-0.27°F
Temperature resolution	0.009°F at 1-s sample rate
Temperature drift stability	<+/-0.1°F per year at 302
Max temperature	302°F

Table 13. Representative Logging tool specifications.

	RST	CBL	USI	Isolation Scanner
Logging speed	1,800 ft/hr	3,600 ft/hr	Standard resolution: 2,700 ft/hr High resolution: 563 ft/hr	Standard resolution: 2,700 ft/hr High resolution: 563 ft/hr
Vertical resolution	15 inches	3 ft	Standard resolution: 0.6 in High speed: 6 in	High resolution: 0.6 in High speed: 6 in
Investigation	Formation	Casing, annulus, and formation	Casing and annulus	Casing and annulus
Temperature rating	302°F	350°F	350°F	350°F
Pressure rating	15,000 psi	20,000 psi	20,000 psi	20,000 psi

Table 14. Pressure Field Gauge PIT-009—Injection Tubing Pressure.

Calibrated working pressure range	0 to 3000 psi and 4–20 mA
Initial pressure accuracy	< 0.04375%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	To be determined after first year

Table 15. Pressure Field Gauge PIT-014—Annuls Pressure.

Calibrated working pressure range	0 to 3000 psi and 4–20 mA
Initial pressure accuracy	< 0.02500%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	To be determined after first year

Table 16. Pressure Field Gauge PIT-012.

Calibrated working pressure range	0 to 3000 psi and 4–20 mA
Initial pressure accuracy	< 0.03125%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	To be determined after first year

Table 17. Temperature Field Gauge TIT-019 —Injection Tubing Temperature.

Calibrated working temperature range	0 to 500°F and 4–20 mA
Initial temperature accuracy	< 0.0055 %
Temperature resolution	0.001°F and 0.0001 mA
Temperature drift stability	To be determined after first year

Table 18. Mass Flow Rate Field Gauge—FT-006 CO_2 Mass Flow Rate.

Calibrated working flow rate range	50,522 to 303,133 lbs/hr and 4–20 mA
Initial mass flow rate accuracy	< 0.18%
Mass flow rate resolution	0.0001 lb/hr
Mass flow rate drift stability	To be determined after first year

Table 19. Westbay Field Gauge—Westbay (MOSDAX) Pressure.

Calibrated working pressure range	0 to 4000 psi
Initial pressure accuracy	< 0.01 %
Pressure resolution	0.001 psi
Pressure drift stability	To be determine after first year

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

The geophysical survey equipment and wireline logging tools will be operated by trained, qualified, and certified personnel, according to the service company which provides the equipment. The subsequent data will be processed and analyzed according to industry standards (Appendix B). No specialized certifications are required for personnel conducting groundwater sampling, but field sampling will be conducted by trained personnel. Groundwater sampling will be conducted by personnel trained to understand and follow the project specific sampling procedures. Upon request ADM will provide the agency with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. ADM will include the technician's training certification with the biannual report.

A.5.b/c. Training Provider and Responsibility

Training for personnel will be provided by the operator or by the subcontractor responsible for the data collection activity.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

A semi-annual report from ADM to USEPA will contain all required project data, including testing and monitoring information as specified by the UIC Class VI permit. Data will be provided in electronic or other formats as required by the UIC Program Director.

A.6.b. Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well logs, test results, or other data will be provided as required by the UIC Program Director.

A.6.c/d. Data Storage and Duration

ADM or a designated contractor will maintain the required project data as provided elsewhere in the permit.

A.6.e. QASP Distribution Responsibility

The ADM Corn Plant Manager will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved Quality Assurance and Surveillance Plan.

B. Data Generation and Acquisition

B.1. Sampling Process Design (Experimental Design)

Discussion in this section is focused on groundwater and fluid sampling and does not address monitoring methods that do not gather physical samples (e.g., logging, seismic monitoring, and pressure/temperature monitoring). During the pre-injection and injection phases, groundwater sampling is planned to include an extensive set of chemical parameters to establish aqueous geochemical reference data. Parameters will include selected constituents that: (1) have primary and secondary USEPA drinking water maximum contaminant levels, (2) are the most responsive to interaction with CO_2 or brine, (3) are needed for quality control, and (4) may be needed for geochemical modeling. The full set of parameters for each sampling interval is given in Table 4-Table **7**. After a sufficient baseline is established, monitoring scope may shift to a subset of indicator parameters that are (1) the most responsive to interaction with CO_2 or brine and (2) are needed for quality control. Implementation of a reduced set of parameters would be done in consultation with the USEPA. Isotopic analyses will be performed on baseline samples to the degree that the information helps verify a condition or establish an understanding of non-project related variations. For non-baseline samples, isotopic analyses may be reduced in all monitoring wells if a review of the historical project results or other data determines that further sampling for isotopes is unneeded. During any period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO_2 or brine migration, the analytical list would be expanded to the full set of monitoring parameters. The Ironton-Galesville groundwater samples will be analyzed using a laboratory meeting the requirements under the USEPA Environmental Laboratory Accreditation Program. All other samples will be analyzed by the operator or a third party laboratory. Dissolved CO_2 will be analyzed by methods consistent with Test Method B of ASTM D 513-06, "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water" or equivalent. Isotopic analysis will be conducted using established methods.

B.1.a. Design Strategy

CO_2 Stream Monitoring Strategy

The primary purpose of analyzing the carbon dioxide stream is to evaluate the potential interactions of carbon dioxide and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports the determination of whether the injectate meets the qualifications of hazardous waste under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq. (1976), and/or the Comprehensive Environmental Response, Compensation, and Liability Act, (CERCLA) 42 U.S.C. 9601 et seq. (1980). Additionally, monitoring the chemical and physical characteristics of the carbon dioxide (e.g., isotopic signature, other constituents) may help distinguish the injectate from the native fluids and gases if unintended leakage from the storage reservoir occurred. Injectate monitoring is required at a sufficient frequency to detect changes to any physical and chemical properties that may result in a deviation from the permitted specifications.

Calibration of transmitters used to monitor pressures, temperatures, and flow rates of CO_2 into the injection well at the injection well and at the verification well shall be conducted annually (e.g., Durkin Equipment Company, St. Louis, MO). Reports shall contain test equipment used to calibrate the transmitters, including test equipment manufacturers, model numbers, serial numbers, calibration dates and expiration dates.

Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to aid in ensuring the mechanical integrity of the equipment in contact with the carbon dioxide. Coupons shall be sent quarterly to a company for analysis (e.g., SGS) and an analysis conducted in accordance with NACE Standard RP-0775 (or similar) to determine and document corrosion wear rates based on mass loss.

Shallow Groundwater Monitoring Strategy

Four dedicated monitoring wells have been selected for shallow groundwater monitoring. These wells have already been installed and screened in the Quaternary-age deposits to depths less than 150 ft below ground surface (bgs). The local Quaternary-age deposits are used predominantly as private water well sources in the area. The wells are designated as IL-ICCS-MVA 10LG, IL-ICCS-MVA 11LG, IL-ICCS-MVA 12LG, and IL-ICCS-MVA 13LG (Figure 2). The wells were selected to give a spatial distribution around the planned CO_2 injection well (CCS#2) location.

Deep Groundwater Monitoring Strategy

Monitoring of the deeper St. Peter and Ironton-Galesville Sandstones will be used for early leakage detection in formations that are much closer to the Mt. Simon Sandstone injection reservoir. Fluid sampling at wells VW#1, VW#2, and GM#2 in combination with pressure monitoring, temperature monitoring, and pulse neutron logging will be used to determine if leakage is occurring at or near the injection well. The Ironton-Galesville Sandstone, has sufficient permeability (over 100 mD) such that pressure monitoring at the verification wells would detect a failure of the confining zone should it occur. MIT testing and DTS monitoring at the injection well will also provide data to insure the mechanical integrity of the well is maintained. With the planned sampling and monitoring frequencies, it is expected that baseline conditions can be documented, natural variability in conditions can be characterized, unintended brine or CO_2 leakage could be detected if it occurred, and sufficient data will be collected to demonstrate that the effects of CO_2 injection are limited to the intended storage reservoir. No groundwater fluid sampling is planned for the Mt Simon intervals where free phase CO_2 has broken through.

GM#2 Sampling

The IL-ICCS geophysical monitoring well, GM#2, will be used for fluid sampling of the St. Peter Sandstone, a USEPA identified USDW. At prescribed frequencies (in consultation with USEPA), fluid sampling will occur using a portable swabbing rig or other available sampling technologies. Samples will be analyzed for constituents listed in Table 5 to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the seal formation.

VW#1 Sampling

The IBDP verification well, VW#1, will be used to monitor the pressure and temperature in the Ironton-Galesville Sandstone above the Eau Claire Formation, the primary reservoir seal. This well will serve as an early leak detection system by allowing the operator to monitor for changes above the primary caprock. Groundwater samples will collected and analyzed for constituents listed in Table 6 to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the seal formation. The well has been completed with a Westbay multilevel sampling system and fluid samples will be collected as described by Locke et al. (2013).

VW#2 Sampling

The IL-ICCS verification well, VW#2, will allow monitoring within the Mt. Simon injection zone as well as immediately above the Eau Claire Formation. This well will serve as an early leak detection system by allowing the operator to monitor for changes above the primary caprock. VW#2 will be equipped with a multilevel pressure and temperature monitoring system with fluid sampling capability at four (4) intervals. The system uses packers to isolate each perforation interval and hydraulically operated sliding sleeves to facilitate sampling. Pressure and temperature will be continuously monitored and recorded in each of the five (5) perforation intervals. The pressure inside the tubing just above the uppermost packer (~4900 Kb) will be monitored and recorded. At prescribed frequencies (in consultation with USEPA), fluid sampling will occur by opening the appropriate sliding sleeve across from the zone to be sampled. Each sample interval will be analyzed for constituents list in Table 6 for the Ironton Galesville or Table 7 for the Mt Simon to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the seal formation.

B.1.b Type and Number of Samples/Test Runs

Groundwater sampling frequencies are detailed in Table 1.
CO_2 gas stream and corrosion coupon frequencies are detailed in Table 1.

B.1.c. Site/Sampling Locations

Shallow groundwater monitoring will use existing wells IL-ICCS-MVA 10LG, IL-ICCS-MVA 11LG, IL-ICCS-MVA 12LG, and IL-ICCS-MVA 13LG (Figure 2) as noted in Section B.1.a. Deep groundwater monitoring will use existing wells VW#1, VW#2, and GM#2 (Figure 2) as noted in Section B.1.a.
CO_2 gas stream and corrosion coupon sampling locations will occur in the compressor building after the last stage of compression.

B.1.d. Sampling Site Contingency

The shallow and deep groundwater monitoring wells are located on property of the project participants (e.g., ADM, Richland Community College) and access permissions have already been granted. No problems of site inaccessibility are anticipated. If inclement weather makes site access difficult, sampling schedules will be reviewed and alternative dates may be selected that would still meet permit-related conditions.

No problems of site inaccessibility are anticipated for CO_2 gas stream or corrosion coupon sampling. If inclement weather makes site access difficult, sampling schedules will be reviewed and alternative dates may be selected that would still meet permit related conditions.

B.1.e. Activity Schedule

The groundwater sampling activities and frequencies are summarized in Table 1.
The CO_2 gas stream and corrosion coupon sampling activities and frequencies are summarized in Table 1.

B.1.f. Critical/Informational Data

During both groundwater sampling and analytical efforts, detailed field and laboratory documentation will be taken. Documentation will be recorded in field and laboratory forms and notebooks. Critical information will include time and date of activity, person/s performing activity, location of activity (well-field sampling) or instrument (lab analysis), field or laboratory instrument calibration data, field parameter values. For laboratory analyses, much of the critical data are generated during the analysis and provided to end users in digital and printed formats. Noncritical data may include appearance and odor of the sample, problems with well or sampling equipment, and weather conditions.

B.1.g. Sources of Variability

Potential sources of variability related to monitoring activities include (1) natural variation in fluid quality, formation pressure and temperature and seismic activity; (2) variation in fluid quality, formation pressure and temperature, and seismic activity due to project operations; (3) changes in recharge due to rainfall, drought, and snowfall; (4) changes in instrument calibration during sampling or analytical activity; 5) different staff collecting or analyzing samples; (6) differences in environmental conditions during field sampling activities; (7) changes in analytical data quality during life of project; and (8) data entry errors related to maintaining project database.

Activities to eliminate, reduce, or reconcile variability related to monitoring activities include (1) collecting long-term baseline data to observe and document natural variation in monitoring parameters, (2) evaluating data in timely manner after collection to observe anomalies in data that can be addressed be resampled or reanalyzed, (3) conducting statistical analysis of monitoring data to determine whether variability in a data set is the result of project activities or natural variation, (4) maintaining weather-related data using on-site weather monitoring data or data collected near project site (such as from local airports), (5) checking instrument calibration before, during and after sampling or sample analysis, (6) thoroughly training staff, (7) conducting laboratory quality assurance checks using third party reference materials, and/or blind and/or replicate sample checks, and (8) developing a systematic review process of data that can include sample-specific data quality checks (i.e., cation/anion balance for aqueous samples).

B.2. Sampling Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section, and is omitted.

B.2.a/b. Sampling SOPs

Groundwater samples will be collected primarily using a low-flow sampling method consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow-through cell is not used, field parameters will be measured in grab samples. Groundwater wells will be purged to ensure samples are representative of formation water quality. Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities begin. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells. Groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell consistent with standard methods (e.g., APHA, 2005) given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table 20.

Table 20. Stabilization criteria of water quality parameters during shallow well purging.

FIELD PARAMETER	STABILIZATION CRITERIA
pH	+/- 0.2 units
Temperature	+/- 1°C
Specific Conductance	+/- 3% of reading in µS/cm
Dissolved Oxygen	+/- 10% of reading or 0.3 mg/L whichever is greater

After field parameters have stabilized, samples will be collected. Samples requiring filtration will be filtered through 0.45 µm flow-through filter cartridges as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis.

For deep groundwater sampling of VW#1, ISGS-SOP-WB-V1.14 (dated August 10, 2012) will be used for the collection and processing of Westbay samples. Wells GM#2 and VW#2 will not have a Westbay installation for sampling and are anticipated to use a wireline sampling system with a sampling device (e.g., Kuster sampler or similar) capable of collecting a sample from a discrete interval. Samples from GM#2 and VW#2 will be processed in a manner consistent with ISGS-SOP-WB-V1.14.

VW#1 was developed and purged extensively at the time of completion and similar plans to develop VM#2 are in place and will be executed when completion occurs. Prior to sampling, each zone will be purged to ensure representative samples are collected. Due to the extensive well development, the amount of fluid to be purged at the time of sampling will be relatively small. If a three-foot zone is perforated (similar to VW#1), then the annular space between the 2-7/8-in. tubing and the 5-1/2-in. casing is only 1.92 gal. Thus, relatively small purge volumes will adequately refresh each isolated sampling interval. Similar purging techniques will be used for VW#1 and VW#2. Additional information about sampling procedures at VW#1 are given in Locke et al. (2013).

For VW#2, it is anticipated that air lifting with nitrogen will be used to draw fluid into the well for purging. A gas lift valve will be placed in the tubing string at approximately 1,200 ft below ground surface at the time of the completion. The sampler will be positioned at the same elevation as the discrete perforated interval, and a sample would be collected after sufficient purging.

B.2.c. In-situ Monitoring.

In-situ monitoring of groundwater chemistry parameters is not currently planned.

B.2.d. Continuous Monitoring.

Pressure data will be collected from shallow groundwater wells on a periodic basis (e.g., hourly to daily) using dedicated pressure transducers with data loggers to generally characterize shallow water level trends. These data are informational only.

B.2.e. Sample Homogenization, Composition, Filtration.

Described in section B.2.b.

B.2.f. Sample Containers and Volumes

For CO_2 stream monitoring, samples will be collected in a clean sample container rated for the appropriate collection pressure (i.e. mini cylinders or polybags provided by Airborne Labs International Inc., Somerset, NJ).

Assay for CO_2 Quarterly Gas Analysis:

- CO_2 Purity (% v/v, [GC])
- Oxygen (O_2, ppm v/v)
- Nitrogen (N_2, ppm v/v)
- Carbon Monoxide (CO, ppm v/v)
- Oxides of Nitrogen (NOx, ppm v/v)
- Total Hydrocarbons (THC, ppm v/v as CH_4)
- Methane (CH_4, ppm v/v)
- Acetaldehyde (AA, ppm v/v)
- Sulfur Dioxide (SO_2, ppm v/v)
- Hydrogen Sulfide (H_2S ppm v/v)
- Ethanol (ppm v/v)

For shallow and deep groundwater samples, all sample bottles will be new. Sample bottles and bags for analytes will be used as received (ready for use) from the vendor or contract analytical laboratory for the analyte of interest. A summary of sample containers is presented in Table 22.

B.2.g. Sample Preservation

For groundwater and other aqueous samples, the preservation methods in Table 22 will be used.

No preservation is required or used for CO_2 gas stream, and additional details of sampling requirements are shown in Table 21. Corrosion coupon sampling only requires that the coupons be physically separated (e.g., sleeves, baggies) during transportation to prevent physical abrasion.

Table 21. Summary of sample containers, preservation treatments, and holding times for CO_2 gas stream analysis.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample Storage Cabinets	5 Business Days

B.2.h. Cleaning/Decontamination of Sampling Equipment

Dedicated pumps (e.g., bladder pumps) will be installed in each groundwater monitoring well to minimize potential cross contamination between wells. These pumps will remain in each well throughout the project period except for maintenance. Prior to installation, the pumps will be cleaned on the outside with a non-phosphate detergent. Pumps will be rinsed a minimum of three times with deionized water and a minimum of 1 L of deionized water will be pumped through pump and sample tubing. Individual cleaned pumps and tubing will be placed in plastic garbage bags for transport to the field for installation. All field glassware (pipets, beakers, filter holders, etc.) are cleaned with tap water to remove any loose dirt, washed in a dilute nitric acid solution, and rinsed three times with deionized water before use.

CO_2 gas stream sampling containers will be either disposed or decontaminated by the analytical lab. No sampling equipment will be utilized with the corrosion coupons or annual field gauge calibrations.

B.2.i Support Facilities

For sampling of groundwater, the following are required: air compressor, vacuum pump, generator, multi-electrode water quality sonde, analytical meters (pH, specific conductance, etc.). Field activities are usually completed in field vehicles and portable laboratory trailers located on site.

Sampling tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers. Sampling will occur within the existing CO_2 compression building.

Similarly, corrosion coupons will be removed from the CO_2 injection line within the existing CO_2 compression building.

Field gauges will be removed from the injection well and verification well utilizing existing standard industry tools and equipment. Deployment and retrieval of verification well gauges will be done using procedures and equipment recommended by the vendor, subcontractor, or is standard per industry practice.

B.2.j. Corrective Action, Personnel, and Documentation

Field staff will be responsible for properly testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then equipment will be returned to the manufacturer for repair or replaced. Significant corrective actions affecting analytical results will be documented in field notes.

B.3. Sample Handling and Custody

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section, and is omitted.

Sample holding times (Table 22) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4°C until analysis. The samples will be maintained at their preservation temperature and sent to the designated laboratory within 24 hours. Analysis of the samples will be completed within the holding time listed in Table 22. As appropriate, alternative sample containers and preservation techniques approved by the UIC Program Director will be used to meet analytical requirements.

B.3.a Maximum Hold Time/Time Before Retrieval

See Table 22.

B.3.b. Sample Transportation

See description at the beginning of Section B.3.

B.3.c. Sampling Documentation

Field notes will be collected for all groundwater samples collected. These forms will be retained and archived as reference. The sample documentation is the responsibility of groundwater sampling personnel.

An analysis authorization form shall be provided with each CO_2 gas stream sample provided for analysis as shown by the example in Figure 4.

B.3.d. Sample Identification

All sample bottles will have waterproof labels with information denoting project, sampling date, sampling location, sample identification number, sample type (freshwater or brine), analyte, volume, filtration used (if any), and preservative used (if any). See Figure 3 for an example of a label.

Table 22. Summary of anticipated sample containers, preservation treatments, and holding times.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding time	Relative Sampling Depth
Cations: Ca, Fe, K, Mg, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Tl	250 ml/HDPE	Filtered, nitric acid, cool 4°C	60 days	Shallow
Dissolved CO_2	2 × 60 ml/HDPE	Filtered, cool 4°C	14 days	Shallow
Dissolved CO_2	60 ml/HDPE	Filtered, cool 4°C	14 days	Deep
Isotopes: ^{3}H, δD, δ^{18}O, δ^{34}S, and δ^{13}C	2 × 60 ml/HDPE	Filtered, cool 4°C	4 weeks	Shallow
Isotopes: δ^{34}S	250 ml/HDPE	Filtered, cool 4°C	4 weeks	Deep
Isotopes: δD, δ^{18}O, δ^{13}C	60 ml/HDPE	Filtered, cool 4°C	4 weeks	Deep
Alkalinity, anions (Br, Cl, F, NO_3, SO_4**)**	500 ml/HDPE	Filtered, cool 4°C	45 days	Shallow
Field Confirmation: Temperature, dissolved oxygen, specific conductance, pH	200 ml/glass jar	None	< 1 hour	Deep
Field Confirmation: Density	60 ml/HDPE	Filtered	< 1 hour	Deep

IL-ICCS_10LG_20A (fresh water)
01-23-2014
Metals, 60 ml, filtered, HNO_3

Figure 3. Example label for groundwater sample bottles.

B.3.e. Sample Chain-of-Custody

For CO_2 stream analysis, an analysis authorization form (Figure 4) will accompany the sample to the lab at which point a chain-of-custody accompanies the sample through their processes.

For groundwater samples, chain-of-custody will be documented using a standardized form. A typical form is shown in Figure 5, and it or a similar form will be used for all groundwater sampling. Copies of the form will be provided to the person/lab receiving the samples as well as the person/lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain-of -custody form and record keeping is the responsibility of groundwater sampling personnel.

B.4. Analytical Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section, and is omitted.

B.4.a. Analytical SOPs

Analytical SOPs are referenced in Table 4-Table 7. Other laboratory specific SOPs utilized by the laboratory will be determined after a contract laboratory has been selected. Upon request ADM will provide the agency with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. ADM will include the technician's training certification with the biannual report.

B.4.b. Equipment/Instrumentation Needed

Equipment and instrumentation is specified in the individual analytical methods referenced in Table 4-Table 7.

B.4.c. Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.d. Analytical Failure

Each laboratory conducting the analyses in Table 4-Table 7 will be responsible for appropriately addressing analytical failure according to their individual SOPs.

B.4.e. Sample Disposal

Each laboratory conducting the analyses in in Table 4-Table 7 will be responsible for appropriate sample disposal according to their individual SOPs.

B.4.f Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but generally turnaround of verified analytical results within one month will be suitable for project needs.

B.4.g. Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project. If nonstandard methods are needed or proposed in the future, the USEPA will be consulted on additional appropriate actions to be taken.

Airborne Labs International, Inc.

22C World's Fair Drive, Somerset, NJ 08873 Fax: 732-302-3035 Phone: 732-302-1950
E-mail: airbornelabs@aol.com Website: www.airbornelabs.com

Analysis Authorization

*This form **MUST** be completed & returned with a sample shipment*

1.) Report Results to*:

Company:	______________	**Sampled On (mm/dd/yy):**	______________
Address:	______________	**P.O. #:**	______________
Address:	______________	**Credit Card:**	Visa Amex MasterCard Discover
Address:	______________	**Card #:**	______________
Address:	______________	**Cardholder:**	______________
Attention:	______________	**Exp. Date:**	______________
Telephone:	(_____)______________	**Check #:**	______________
Fax:	(_____)______________	**Other:**	______________
E-Mail:	______________	**Pricing Discussed/Quoted? Y N**	

*Please attach complete billing address if different from reporting address.

2.) Number of Samples Submitted: ________ **Container Type(s):** ______________

3.) Sample Description (circle): Liquid CO_2 CO2 (Final) Vapor CO2 Feedgas* CO_2 In-Process Food Grade CO_2 LIN LOX LAR RELOX (Reboiler) ABO

*IF CO_2 Feedgas –Identify source (e.g. Ethanol/Ammonia/Nat. Well/Ethylene/Combustion, Self-Gen, etc.) ______________

Aviator Breathing Oxygen (ABO) Natural Gas Refinery Gas Syn Gas Propane Butane Air Oxygen
Nitrogen Argon Hydrogen Helium Neon Xenon Krypton Freon® Refrigerant
Gas Mixture Fuel Oil Lubricant
Other (Describe): ______________

4.) Sample Type (Check) : Industrial____Medical______ MilSpec_____ Other_____
(attach a log for multiple samples)

5.) Sample ID: ______________

6.) Potential Hazards/Safety Issues: ______________

7.) Analytical Test(s) Requested (check program or select individual tests required where applicable):

Std ISBT/Vendor CO_2 Test Program_____ Std CO_2 Feedgas Program_____ Std CGA Test Program_____ Std Medical Gas_____
Std Contract Program_____ Std ASTM Test Program____ MIL Spec Test Program____

%Purity THC CH_4 TNMHC Vol Hydrocarbons (C1-C6) BTEX Water Vapor NVR/NVOR Oil/Grease Total Sulfur H_2S SO_2
COS MeSH t-Butyl Mercaptan Vol Sulfur Compnds Odorants Total Nitrogen N_2 NO_x NH_3 NO NO_2 HCN Nitrous Oxide (N_2O)
PH_3 Oxygen Argon Hydrogen Helium CO CO_2 Xenon Neon Krypton Vinyl Chloride Acetaldehyde Vol Oxygenates GC/MS Scan
IR Scan IR Microscope Halogenated Hydrocarbons SF_6 Gas Mixture% Btu (Heat) Content % CHNO Sediment Wt Patch Test
Viscosity Flash/Fire Point Density Specific Gravity Trace Metals TAN TBN XRF SEM-XRF Scan Light Microscope

Other Testing: ______________

8.) Sample Disposition

Retain for ______ Period Perform Clean-up/Maintenance Actions & Return* ____ Report for Instructions ____

Other: ______________

*Supply all return address & shipping instructions

9.) Report Disposition (circle one): E-Mail Fax Mail Telephone Other:______________
(Reports will be sent to the address & contact(s) specified at the top of this form)

10.) Priority Conditions (circle), Note: Additional fees will apply for non-std test scheduling:

Standard 2-Work Day 1-Work Day Same Day Emergency Other:______________

Analytical testing cannot be performed unless this form is completed & returned

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Figure 4. Example of CO_2 gas stream analysis authorization form.

CHAIN OF CUSTODY RECORD (Page __ of __)

PRAIRIE RESEARCH INSTITUTE

Illinois State Water Survey – Analytical Services Group
Illinois State Geological Survey – Geochemistry Section

For Midwest Geological Sequestration Consortium (MGSC) Projects

	MGSC ID	ISGS MVA ID	Matrix	Date Collected	Time Collected	Sampling Team	Circle analyses to be performed
1							anions, cations, TDS, alk, NH_3, NVOC
2							anions, cations, TDS, alk, NH_3, NVOC
3							anions, cations, TDS, alk, NH_3, NVOC
4							anions, cations, TDS, alk, NH_3, NVOC
5							anions, cations, TDS, alk, NH_3, NVOC
6							anions, cations, TDS, alk, NH_3, NVOC
7							anions, cations, TDS, alk, NH_3, NVOC
8							anions, cations, TDS, alk, NH_3, NVOC
9							anions, cations, TDS, alk, NH_3, NVOC
10							anions, cations, TDS, alk, NH_3, NVOC
11							anions, cations, TDS, alk, NH_3, NVOC
12							anions, cations, TDS, alk, NH_3, NVOC
12							

CHAIN OF CUSTODY		
Relinquished by:	Print Name:	Date and Time:
Received by:	Print Name:	Date and Time:
General Remarks: - Field parameters are to be recorded on separate sheets by sampling teams. - Any special laboratory instructions or remarks should be made below.		
Data Contacts:	Fund:	
Billing Contact:	Billing Address:	
Send Data To:		

Remarks:

Rev. Oct. 2011 (RL)

Figure 5. Example chain-of-custody form.

B.5. Quality Control

Geophysical monitoring and pressure/temperature monitoring does not apply to this section, and is omitted. For log quality control, please refer to Appendix B.

B.5.a. QC activities

Blanks

For shallow groundwater sampling, a field blank will be collected and analyzed for the inorganic analytes in Table 4-Table 7 at a frequency of 10% or greater. Field blanks will be exposed to the same field and transport conditions as the groundwater samples. Blanks will also be utilized for deep groundwater sampling and analyzed for the inorganic analytes in Table 4-Table 7 at a frequency of 10% or greater. Field blanks will be used to detect contamination resulting from the collection and transportation process.

Duplicates

For each shallow groundwater sampling round, a duplicate groundwater sample is collected from a well from a rotating schedule. Duplicate samples are collected from the same source immediately after the original sample in different sample containers and processed as all other samples. Duplicate samples are used to assess sample heterogeneity and analytical precision.

B.5.b. Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will be done by evaluating the ratio of the measured total dissolved solids (TDS) to the calculated TDS (i.e., mass balance) per APHA method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and interlaboratory results, if available. Suspect ion analyses are then brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance is recalculated, and if the error is still not resolved, suspect data are identified and may be given less importance in data interpretations.

B.5.c. Calculating Applicable QC Statistics

Charge Balance

The analytical results are evaluated to determine correctness of analyses based on anion-cation charge balance calculation. Because all potable waters are electrically neutral, the chemical analyses should yield equally negative and positive ionic activity. The anion-cation charge balance will be calculated using the formula:

$$\%\ difference = 100\frac{\sum cations - \sum anions}{\sum cations + \sum anions}, \qquad \text{(Equation 1)}$$

where the sums of the ions are represented in milliequivalents (meq) per liter and the criteria for acceptable charge balance is ±10%.

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the formula:

$$1.0 < \frac{measured\ TDS}{calculated\ TDS} < 1.2, \qquad \text{(Equation 2)}$$

where the anticipated values are between 1.0 and 1.2.

Outliers

A determination of one or more statistical outliers is essential prior to the statistical evaluation of groundwater. This project will use the USEPA's Unified Guidance (March 2009) as a basis for selection of recommended statistical methods to identify outliers in groundwater chemistry data sets as appropriate. These techniques include Probability Plots, Box Plots, Dixon's test, and Rosner's test. The EPA-1989 outlier test may also be used as another screening tool to identify potential outliers.

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained as per wireline industry best practices (Appendix B).

For groundwater sampling, field equipment will be maintained, factory serviced, and factory calibrated per manufacturer's recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection and maintenance will be the responsibility of the analytical laboratory per standard practice, method-specific protocol, or NELAP requirement.

B.7. Instrument/Equipment Calibration and Frequency

Geophysical monitoring does not apply to this section, and is omitted.

B.7.a. Calibration and Frequency of Calibration

Pressure/temperature gauge calibration information is located in Table 12-Table 19. Logging tool calibration will be at the discretion of the service company providing the equipment, following standard industry practices noted in Appendix B. Calibration frequency will be determined by standard industry practices.

For groundwater sampling, portable field meters or muliprobe sondes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) are calibrated according to manufacturer recommendations and equipment manuals (Hach, 2006) each day before sample collection begins. Recalibration is performed if any components yield atypical values or fail to stabilize during sampling.

B.7.b. Calibration Methodology

Logging tool calibration methodology will follow standard industry practices in Appendix B.

For groundwater sampling, standards used for calibration are typically 7 and 10 for pH, a potassium chloride solution yielding a value of 1413 microseimens per centimeter (µS/cm) at 25°C for specific conductance, and a 100% dissolved O_2 solution for dissolved oxygen. Calibration is performed for the pH meters per manufactuer's specifications using a 2-point calibration bounding the range of the sample. For coulometry, sodium carbonate standards (typically yielding a concentration of 4,000 mg CO_2/L) are routinely analyzed to evaluate instrument.

B.7.c. Calibration Resolution and Documentation
Logging tool calibration resolution and documentation will follow standard industry practices in Appendix B.

For groundwater sampling, calibration values are recorded in daily sampling records and any errors in calibration are noted. For parameters where calibration is not acceptable, redundant equipment may be used so loss of data is minimized.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

Supplies and consumables for field and laboratory operations will be procured, inspected, and accepted as required from vendors approved by ADM or the respective subcontractor responsible for the data collection activity. Acquisition of supplies and consumables related to groundwater analyses will be the responsibility of the laboratory per established standard methodology or operating procedures.

B.9. Nondirect Measurements

Seismic Monitoring Methods

B.9.a Data Sources
For time lapse seismic surveys, repeatability is paramount for accurate differential comparison. Therefore, to ensure survey quality, the locations for the shots and acquisition methodology of sequential surveys will be consistent. Once these surveys are conducted, they will be compared to a baseline survey to track and monitor plume development.

For in-zone pressure monitoring, the in-zone pressure gauges in VW#1 and VW#2 will be used to gather pressure data.

B.9.b. Relevance to Project
Time lapse seismic surveys will be used to track changes in the CO_2 plume in the subsurface. Processing and comparing subsequent surveys to a baseline will allow project managers to monitor plume growth, as well as to ensure that the plume does not move outside of the intended storage reservoir. Numerical modeling will be used to predict the CO_2 plume growth and migration over time by combining the processed seismic data with the existing geologic model.

In-zone pressure monitoring data will be used in numerical modeling to predict plume and pressure front behavior and confirm the plume stage within the AOR.

B.9.c. Acceptance Criteria
Following standard industry practices will ensure that the gathered seismic data will be used for accurate modeling and monitoring. Similar ground conditions, shot points located within tolerable limits, functional geophones, and similar seismic input signal will be used from survey to survey to ensure repeatability.

When processing seismic data, several QA checks will be done in accordance with industry standards including reformatting to Omega structured files, geometry application, amplitude compensation, predictive deconvolution, elevation statics correction, RMS amplitude gain, velocity analysis every 2 km, NMO application using picked velocities, CMP stacking, random noise attenuation, and instantaneous gain.

B.9.d. Resources/Facilities Needed

ADM will subcontract all necessary resources and facilities for the seismic monitoring, in-zone pressure monitoring, and groundwater sampling.

B.9.e. Validity Limits and OperatingCconditions

For seismic surveys and numerical modeling, intraorganizational checks between trained and experienced personnel will ensure that all surveys and numerical modeling are conducted conforming to standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

ADM or a designated contractor will maintain the required project data as provided elsewhere in the permit. Data will be backed up on tape or held on secure servers.

B.10.b. Record-keeping and Tracking Practices

All records of gathered data will be securely held and properly labeled for auditing purposes.

B.10.c. Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper industry techniques. ADM SCADA system and vendor data acquisition systems will interface with one another and all subsequent data will be held on a secure server.

B.10.d. Responsibility

The primary project managers will be responsible for ensuring proper data management is maintained.

B.10.e. Data Archival and Retrieval

All data will be held by ADM.   These data will be maintained and stored for auditing purposes as described in section B.10.a.

B.10.f. Hardware and Software Configurations

All ADM and vendor hardware and software configurations will be appropriately interfaced.

B.10.g. Checklists and Forms

Checklists and forms will be procured and generated as necessary.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Please refer to Table 1 in section A.3.a/b. (Summary of work to be performed and work schedule); groundwater quality data will be collected at the frequency outlined in that table. After completion of sample analysis, results will be reviewed for QC criteria as noted in section B.5. If the data quality fails to meet criteria set in section B.5., samples will be reanalyzed, if still within holding time criteria. If outside of holding time criteria, additional samples may be collected or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

Organizations gathering data will be responsible for conducting their internal assessments. All stop work orders will be handled internally within individual organizations.

C.1.c. Assessment Reporting

All assessment information should be reported to the individual organizations project manager outlined in A.1.a/b.

C.1.d. Corrective Action

All corrective action affecting only an individual organization's data collection responsibility should be addressed, verified, and documented by the individual project managers and communicated to the other project managers as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the distribution list for the QASP. Assessments may require integration of information from multiple monitoring sources across organizations (operational, in-zone monitoring, above-zone monitoring) to determine whether correction actions are required and/or the most cost-efficient and effective action to implement. ADM will coordinate multiorganization assessments and corrective actions as warranted.

C.2. Reports to Management

C.2.a/b. QA status Reports

QA status reports should not be needed. If any testing or monitoring techniques are changed, the QASP will be reviewed and updated as appropriate in consultation with USEPA. Revised QASPs will be distributed by ADM to the full distribution list at the beginning of this document.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Groundwater quality data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet with periodic data review and analysis. ADM will retain copies of the laboratory analytical test results and/or reports. Analytical results will be reported on a frequency based on the approved UIC permit conditions. In the periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general groundwater quality and identify intrawell variability with time. After sufficient data have been collected, additional methods, such as those described in the USEPA 2009 Unified Guidance (USEPA, 2009), will be used to evaluate intrawell variations for groundwater constituents, to evaluate if significant changes have occurred that could be the result of CO_2 or brine seepage beyond the intended storage reservoir.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

See sections D.1.a. and B.5.

Appropriate statistical software will be used to determine data consistency.

D.2.b. Data Verification and Validation Responsibility

ADM or its designated subcontractor will verify and validate groundwater sampling data.

D.2.c. Issue Resolution Process and Responsibility

ADM or its designated Coordinator will overview the groundwater data handling, management, and assessment process. Staff involved in these processes will consult with the Coordinator to determine actions required to resolve issues.

D.2.d. Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet permit requirements. Table 23 provides an example of the type of information used for data verification of groundwater quality data.

Table 23. Example table of criteria used to evaluate data quality.

MVA ID	Anion charge	Cation charge	Charge balance	CB rating	Calculated TDS	Measured TDS	TDS ratio	TDS rating
ICCS_10B_01A	14.4	13.60	-2.84	pass	760.50	785	1.0	pass
ICCS_10B_02A	14.26	15.06	2.73	pass	783.03	777	1.0	pass
ICCS_10B_03A	14.39	14.96	1.94	pass	786.86	806	1.0	pass
ICCS_10B_04A	14.39	14.79	1.38	pass	780.15	777	1.0	pass
ICCS_10B_04B	14.33	14.90	1.96	pass	780.95	785	1.0	pass

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

Statistical software will be used to determine groundwater data consistency using methods consistent with USEPA 2009 Unified Guidance (USEPA, 2009).

D.3.b. Data Limitations Reporting

The organization-level project managers will be responsible for ensuring that data developed by their respective organizations is presented with the appropriate data-use limitations.

ADM will use the current operating procedure on the use, sharing, and presentation of results and/or data for the IL-ICCS project. This procedure has been developed to ensure quality, internal consistency and facilitate tracking and record keeping of data end users and associated publications.

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Appendices

APPENDIX A. DTS and Down-hole Pressure Gauge Information

APPENDIX B. Log Quality Control Reference Manual (LQCRM)

ATTACHMENT D: INJECTION WELL PLUGGING PLAN

Facility Information

Facility name:	Archer Daniels Midland, CCS#2 Well IL-115-6A-0001
Facility contact:	Mr. Steve Merritt, Plant Manager, 4666 Faries Parkway, Decatur, IL, (217) 424-5750, steve.merritt@adm.com
Well location:	Decatur, Macon County, IL; 39º 53’ 09.32835”, 88º53’16.68306”

Injection well plugging and abandonment will be conducted according to the procedures below, which are based on information submitted by ADM in May of 2016.

Upon completion of the project, or at the end of the life of the CCS #2 injection well, the well will be plugged and abandoned to meet the requirements at 40 CFR 146.92. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and to protect any USDWs. Any necessary revisions to the well plugging plan to address new information collected during logging and testing of the well will be made after construction, logging and testing of the well have been completed. The final plugging plan will be submitted to the UIC Program Director.

After injection has ceased, the well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. Bottom hole pressure measurements will be made and the well will be logged and pressure tested to ensure mechanical integrity inside and outside the casing prior to plugging. If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding with the plugging operations. Detailed plugging procedure is provided below. All casing in this well will be cemented to surface at the time of construction and will not be retrievable at abandonment. After injection is terminated permanently, the injection tubing and packer will be removed. After the tubing and packer are removed, the balanced-plug placement method will be used to plug the well. If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well, and the cement retainer method will be used for plugging the injection formation below the abandoned packer.

All of the casing strings will be cut off at least 3 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

Planned Tests or Measures to Determine Bottom-hole Reservoir Pressure

ADM will record bottom hole pressure from a down hole pressure gauge and calculate kill fluid density.

Planned External Mechanical Integrity Test(s)

ADM will conduct at least one of the following tests to verify external MI prior to plugging the injection well as required in 40 CFR 146.92(a).

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

Information on Plugs

The cement(s) formulated for plugging will be compatible with the carbon dioxide stream. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The operator will report the wet density and will retain duplicate samples of the cement used for each plug. Figure 1 presents a plugging schematic.

	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of Boring in Which Plug Will be Placed (inches)	8.681	8.835					
Depth to Bottom of Tubing or Drill Pipe (ft)	7100	4000					
Sacks of Cement to be Used (each plug)	1378	1443					
Slurry Volume to be Pumped (cu. ft)	1530	1703					
Slurry Weight (lb/gal)	15.9	15.9					
Calculated Top of Plug (ft)	4000	Surf					
Bottom of Plug (ft)	7100	4000					
Type of Cement or Other Material	CO_2 resistant	Class A					
Method of Emplacement (e.g., balance method, retainer method, or two-plug method)						Balance Method	

Narrative Description of Plugging Procedures

Notifications, Permits, and Inspections

Notifications, permits, and inspections procedures are planned to include:

1. In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2. Move-in (MI) Rig onto CCS #2 and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.
3. Conduct and document a safety meeting.
4. Record bottom hole pressure from down hole gauge and calculate kill fluid density
5. Open up all valves on the vertical run of the tree and check pressures.
6. Test the pump and line to 2,500 psi. Fill tubing with kill weight brine (9.5 ppg or determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system. Test casing annulus to 1000 psi and monitor as in annual MIT. If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.
7. If the well is not dead or the pressure cannot be bled off of tubing, rig up (RU) slickline and set plug in lower profile nipple below packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down tree, nipple up blow-out preventers (BOPs), and perform a function test. BOP's should have appropriate sized single pipe rams on top and blind rams in the bottom ram for tubing. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all Texas Iron Works (pressure valve), BOP's choke and kill lines, and choke manifold to 250 psi low and 3,000 psi high. NOTE: Make sure casing valve is open during all BOP tests. After testing BOPs pick up tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and circulate until well is dead.
8. Pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are at least 2 well control barriers in place at all times.
9. Pull seal assembly, pick up workstring, and trip in hole (TIH) with the packer retrieving tools. Latch onto the packer and pull out of hole laying down same. Next, confirm the well's mechanical integrity by performing one of the permitted external mechanical integrity tests presented in the table under "Planned External Mechanical Integrity Test(s)" above.

   Contingency: If unable to pull seal assembly, RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. If unable to pull the packer, pull the work string out of hole and proceed to next step. If problems are noted, update cement remediation plan (if needed) and execute prior to plugging operations.

10. TIH with work string to total depth (TD). Keep the hole full at all times. Circulate the well and prepare for cement plugging operations.
11. The lower section of the well will be plugged using CO_2 resistant cement from TD around 7100 ft to around 1000ft above the top of the Eau Claire formation (to approximately 4000 ft). This will be accomplished by placing plugs in 500 ft incremental lifts. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 1378 sacks of cement will be required. *Actual cement volume will depend upon actual weight of the casing within the plugged zone as well as the length of plug set as determined during the plugging operation.* It is anticipated that at least six plugs of 500 feet in length will be necessary. No more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug. (Calculations: Assume 47 lb/ft casing for this interval 3100ft x .4110 cu ft/ft x 1.20/ 1.11 cu ft/sk = 1378 sacks.)
12. Circulate the well and ensure it is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 180 sacks Class A/H mixed at 15.9 ppg with yield 1.18 cu ft/sk). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 8 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. After waiting overnight, trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. *Calculate volume for final plug*. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug. Total of approximately 1443 sacks total cement used in all remaining plugs above 4000 feet. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 feet, or as per permitting agency directive. (Calculations assume 40#/ft casing and no excess because this section is inside the intermediate casing 4000 ft x .4257 cu ft/ft / 1.18 cu ft/sk = 1443 sacks.
13. The procedures described above are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect USDWs, and any significant modifications due to unforeseen circumstances will be described in the Plugging report. Complete plugging forms and send in with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and plugging contractor, and shall be submitted within 60 days after plugging is completed.

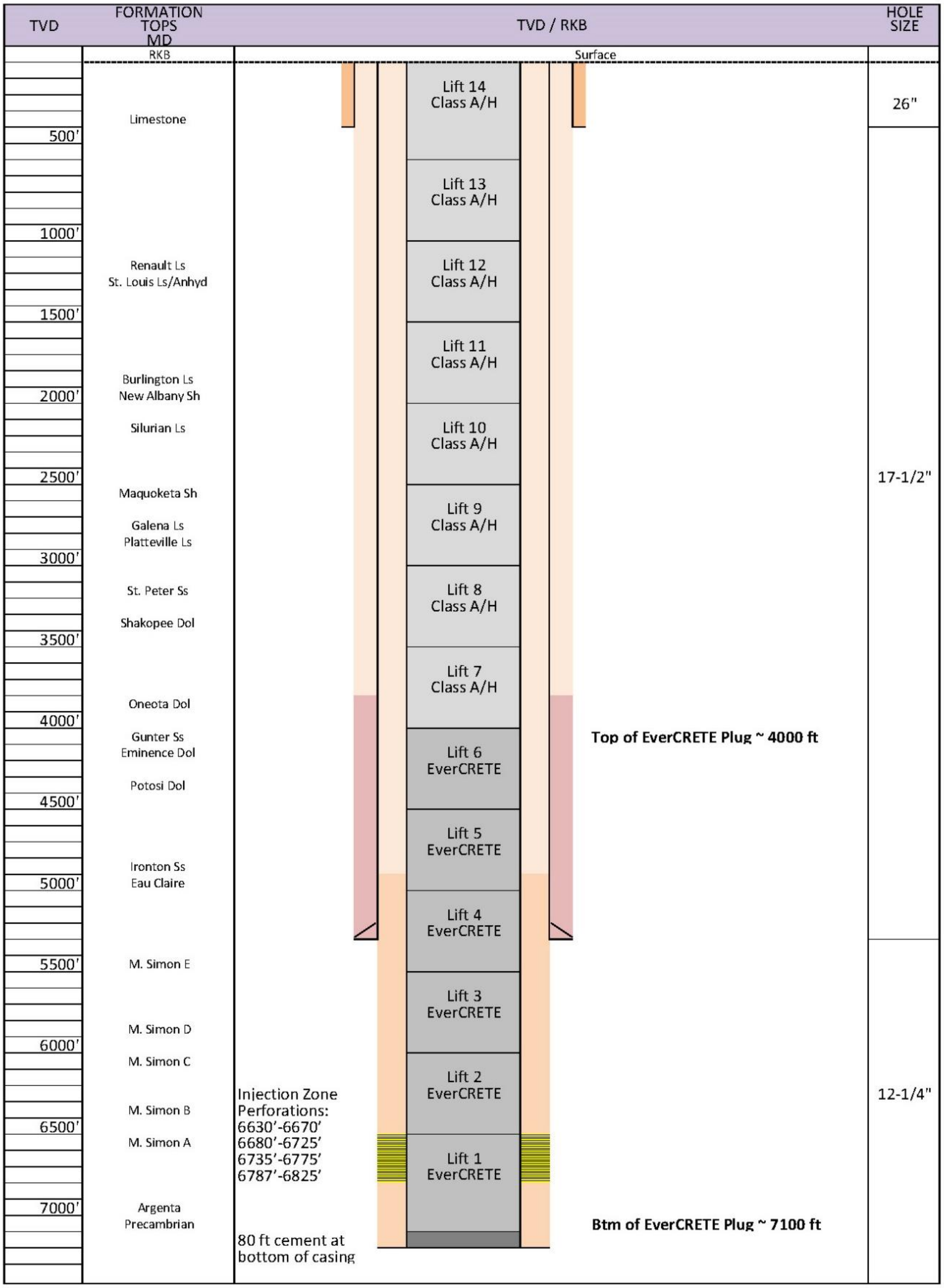

Figure 1. CCS#2 Injection Well Plugging Schematic.

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Facility Information

Facility name:	Archer Daniels Midland, CCS#2 Well IL-115-6A-0001
Facility contact:	Mr. Steve Merritt, Plant Manager, 4666 Faries Parkway, Decatur, IL, (217) 424-5750, steve.merritt@adm.com
Well location:	Decatur, Macon County, IL; 39º53'09.32835", -88º53'16.68306"

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that ADM will perform to meet the requirements of 40 CFR 146.93. ADM will monitor groundwater quality and track the position of the carbon dioxide plume and pressure front for ten (10) years. This alternative post-injection site care timeframe was approved by EPA, but ADM may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, ADM will plug all monitoring wells, restore the site to its original condition, and submit a Site Closure report and associated documentation.

Pre- and Post-Injection Pressure Differential

The formation pressure at the injection well is predicted to decline rapidly within the first 4 years following cessation of injection. Based on the modeling of the pressure front as part of the AoR delineation, pressure is expected to decrease to pre-injection levels by the end of the PISC timeframe. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the Area of Review and Corrective Action Plan (Attachment B to this permit).

Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure

Figure 1 shows the predicted extent of the plume and pressure front at the end of the 10 year PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted in May 2016, per 40 CFR 146.84.

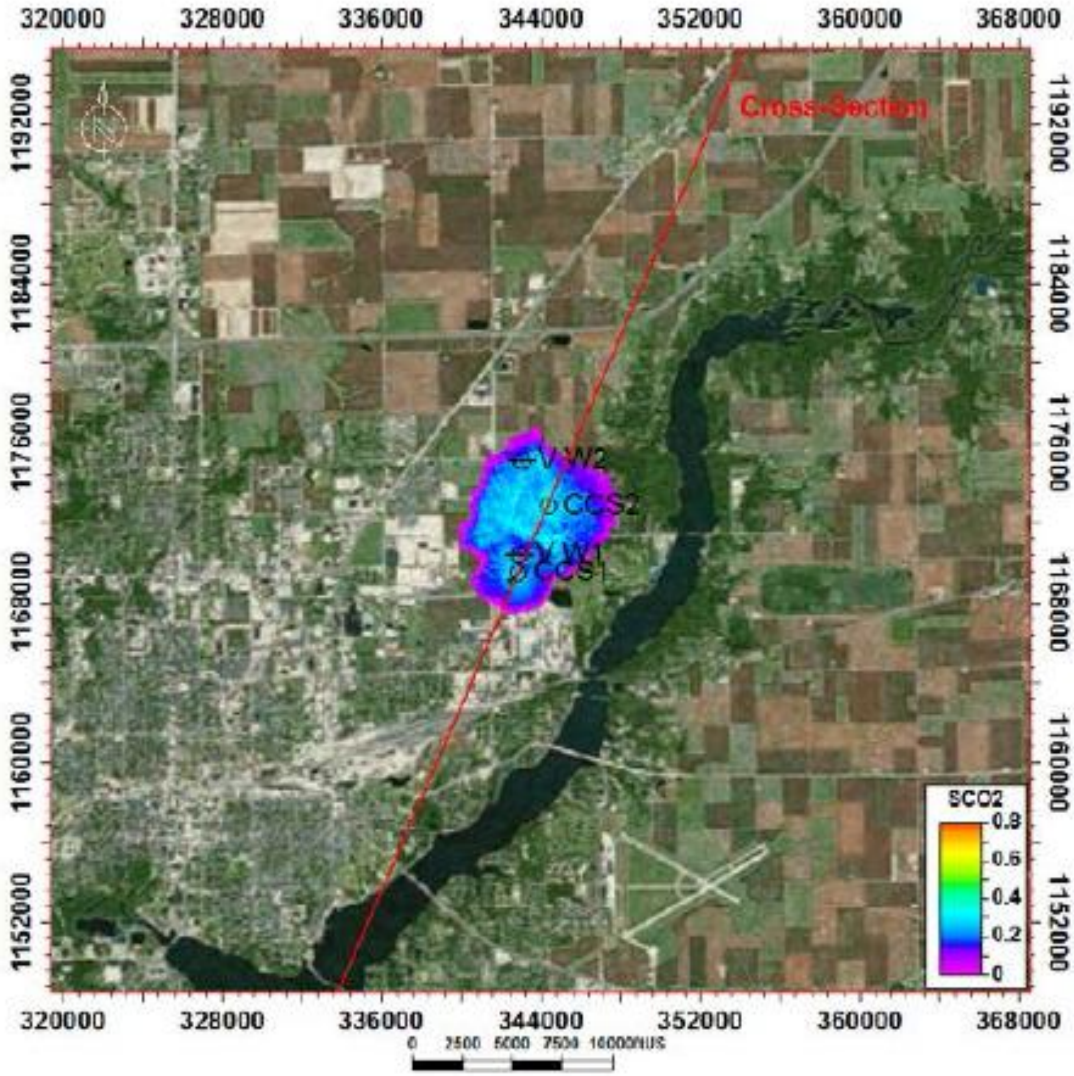

Figure 1. Predicted extent of the CO_2 plume 10 years after the cessation of injection (Est Yr 2031). Pressure front (DPif = 62.2 psi) not shown because pressure is expected to decrease below that level at site closure.

Post-Injection Monitoring Plan

Performing groundwater quality monitoring and plume and pressure front tracking as described in the following sections during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days of the anniversary date of the date on which injection ceases, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Groundwater Quality Monitoring

Table 1 and Table 2 present the planned direct and indirect monitoring methods, locations, and frequencies for groundwater quality monitoring above the confining zone in the Quaternary and/or Pennsylvanian strata, the St. Peter Formation, and the Ironton-Galesville Sandstone. All of the monitoring wells are located on ADM property. Table 3 identifies the parameters to be monitored and the analytical methods ADM will employ, and Figure 2 shows the locations of the monitoring wells.

Table 1. Post-Injection Phase Direct Groundwater Monitoring Above Confining Zone.[1,2]

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Quaternary and/or Pennsylvanian strata	Fluid sampling	Shallow monitoring wells: MVA10LG, MVA11LG, MVA12LG, MVA13LG	Annual	Annual	Annual	Annual
	Distributed Temperature Sensing (DTS)	CCS#1	Continuous	None	None	None
		CCS#2	Continuous	None	None	None
St. Peter	Fluid sampling	GM#2	Annual	Annual	Annual	Annual
	Pressure/ temperature monitoring	GM#2	Continuous	Continuous	Annual	Annual
	DTS	CCS#1	Continuous	None	None	None
		CCS#2	Continuous	None	None	None
Ironton-Galesville	Fluid sampling	VW#2	Annual	Annual	Annual	Annual
	Pressure/ temperature monitoring	VW#2	Continuous	Continuous	Annual	Annual
	DTS	CCS#1	Continuous	None	None	None
		CCS#2	Continuous	None	None	None

Note 1: Collection and recording of continuous monitoring data will occur at the frequencies described in Table 4.

Note 2: Annual sampling and monitoring will occur up to 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the Director.

Table 2. Post-Injection Phase Indirect Groundwater Monitoring Above the Confining Zone [1]

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Quaternary and/or Pennsylvanian strata	Pulse Neutron Logging/RST	VW#1	Year 1	Year 3	Year 5, Year 7	Year 10
		VW#2	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#1	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#2	Year 1	Year 3	Year 5, Year 7	Year 10

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
St. Peter	Pulse Neutron Logging/RST	VW#1	Year 1	Year 3	Year 5, Year 7	Year 10
		VW#2	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#1	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#2	Year 1	Year 3	Year 5, Year 7	Year 10
Ironton-Galesville	Pulse Neutron Logging/RST	VW#1	Year 1	Year 3	Year 5, Year 7	Year 10
		VW#2	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#1	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#2	Year 1	Year 3	Year 5, Year 7	Year 10

Note 1: Logging surveys will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the Director.

Table 3. Summary of Analytical and Field Parameters for Groundwater Samples.

Parameters	Analytical Methods [1]
Quaternary/Pennsylvanian	
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
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
St. Peter	
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: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry

Parameters	Analytical Methods (1)
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
Ironton-Galesville	
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: $\delta^{13}C$ 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 prior approval of the Director.

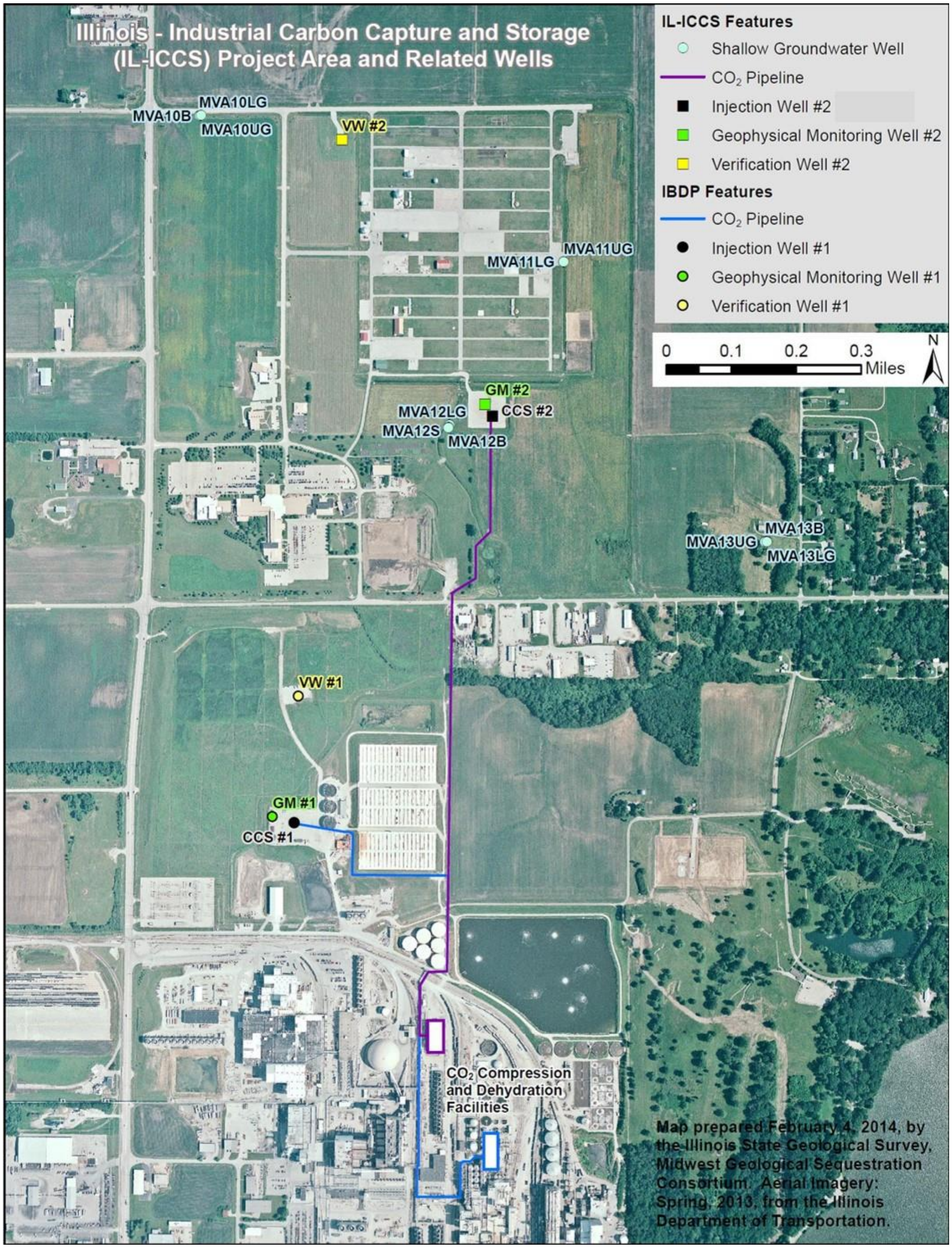

Figure 2. Location of shallow groundwater monitoring wells and deep monitoring wells.

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.

Collection and recording of continuous monitoring data will occur at the frequencies described in Table 4.

Table 4. 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:	5 seconds	5 minutes [(3)]
For the 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.

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.

Table 5 presents the direct and indirect methods that ADM will use to monitor the CO_2 plume, 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 (and associated analytical methods) are presented in Table 6. Indirect plume monitoring will be employed using pulsed neutron capture/reservoir saturation tool (RST) logs to monitor CO_2 saturation and 3D surface seismic surveys. Quality assurance procedures for seismic monitoring methods are presented in Section B.9 of the QASP.

Table 5. Post-Injection Phase Plume Monitoring.[(1,2)]

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Direct Plume Monitoring						
Mt. Simon	Fluid sampling	VW#2	Annual	Annual	Annual	Annual

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Indirect Plume Monitoring						
Mt. Simon	Pulse Neutron Logging/RST	VW#1	Year 1	Year 3	Year 5, Year 7	Year 10
		VW#2	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#1	Year 1	Year 3	Year 5, Year 7	Year 10
		CCS#2	Year 1	Year 3	Year 5, Year 7	Year 10
	3D surface seismic survey	Northern extent of plume area (fold coverage ~ 600 acres)	Once (Year 1) (Est 2020)	None	None	Once (Year 10) (Est 2030)

Note 1: Sampling and geophysical surveys will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the Director.

Note 2: 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 Director.

Table 6. 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: $\delta^{13}C$ 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 Director.

Table 7 presents the direct and indirect methods that ADM will use to monitor the pressure front, including the activities, locations, and frequencies ADM will employ. ADM will deploy pressure/temperature monitors and distributed temperature sensors to directly monitor the position of the pressure front. Passive seismic monitoring using a 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 7. Post-Injection Phase Pressure Front Monitoring.[1,2]

<table>
<tr><th>Target Formation</th><th>Monitoring Activity</th><th>Monitoring Location(s)</th><th>Frequency: Year 1</th><th>Frequency: Years 2-3</th><th>Frequency: Years 4-9</th><th>Frequency: Year 10</th></tr>
<tr><td colspan="7">Direct Pressure Front Monitoring</td></tr>
<tr><td rowspan="5">Mt. Simon</td><td rowspan="3">Pressure/ temperature monitoring</td><td>VW#2</td><td>Continuous 4 Intervals</td><td>Continuous 4 Intervals</td><td>Continuous 4 Intervals</td><td>Continuous 4 Intervals</td></tr>
<tr><td>CCS#1</td><td>Continuous</td><td>Continuous</td><td>Annual</td><td>Annual</td></tr>
<tr><td>CCS#2</td><td>Continuous</td><td>Continuous</td><td>Annual</td><td>Annual</td></tr>
<tr><td rowspan="2">Distributed Temperature Sensing (DTS)</td><td>CCS#1</td><td>Continuous</td><td>None</td><td>None</td><td>None</td></tr>
<tr><td>CCS#2</td><td>Continuous</td><td>None</td><td>None</td><td>None</td></tr>
<tr><td colspan="7">Other Monitoring</td></tr>
<tr><td>Multiple</td><td>Passive seismic</td><td>A combination of borehole and surface seismic stations located within the AoR.</td><td>Continuous</td><td>Continuous</td><td>Continuous</td><td>Continuous</td></tr>
</table>

Note 1: Collection and recording of continuous monitoring data will occur at the frequencies described in Table 4.

Note 2: Annual monitoring surveys will occur up to 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the Director.

Monitoring locations relative to the predicted location of the CO_2 plume and pressure front at 5-year intervals throughout the post-injection phase are shown in Figure 3 through Figure 5. Predicted pressure profiles at the top of the injection interval and bottom-hole pressure at CCS#2 for 50 years after the commencement of injection are shown in Figure 6 and Figure 7. The predicted amount of CO_2 in the mobile gas, trapped gas, and dissolved (aqueous) phases for 50 years after the commencement of injection is shown in Figure 8.

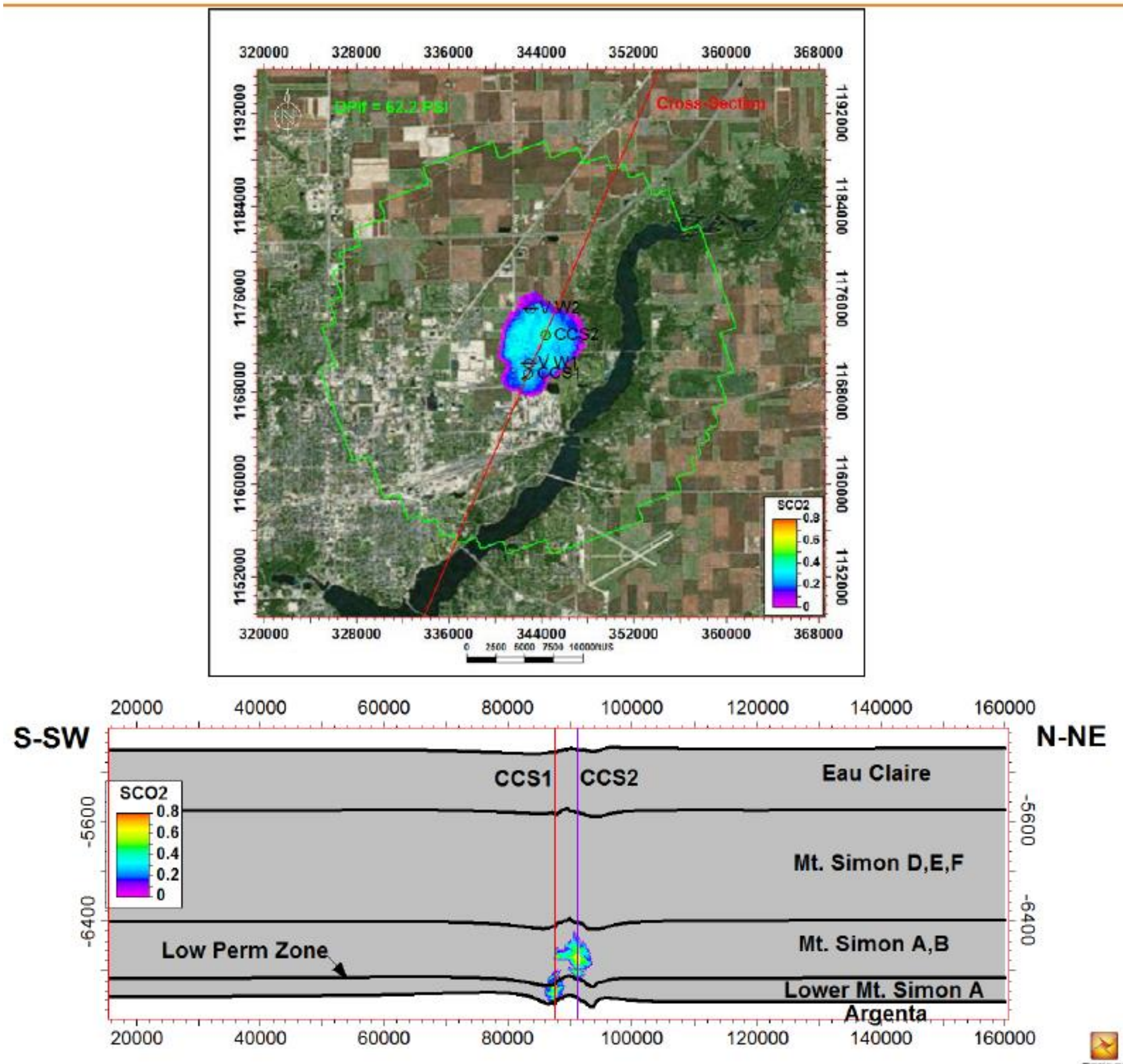

Figure 3. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the beginning of the post-injection phase.

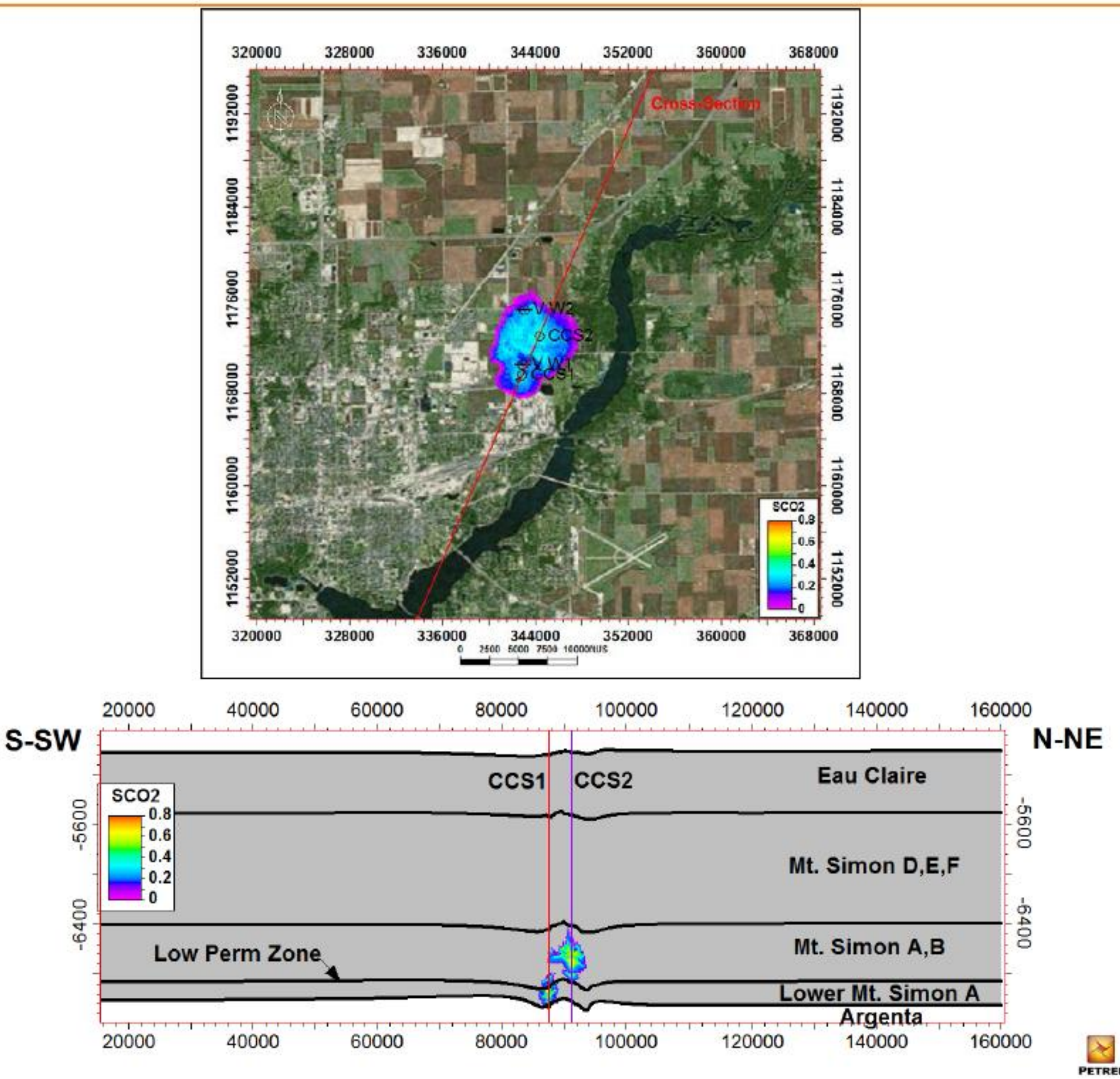

Figure 4. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the end of 5 years after the cessation of injection.

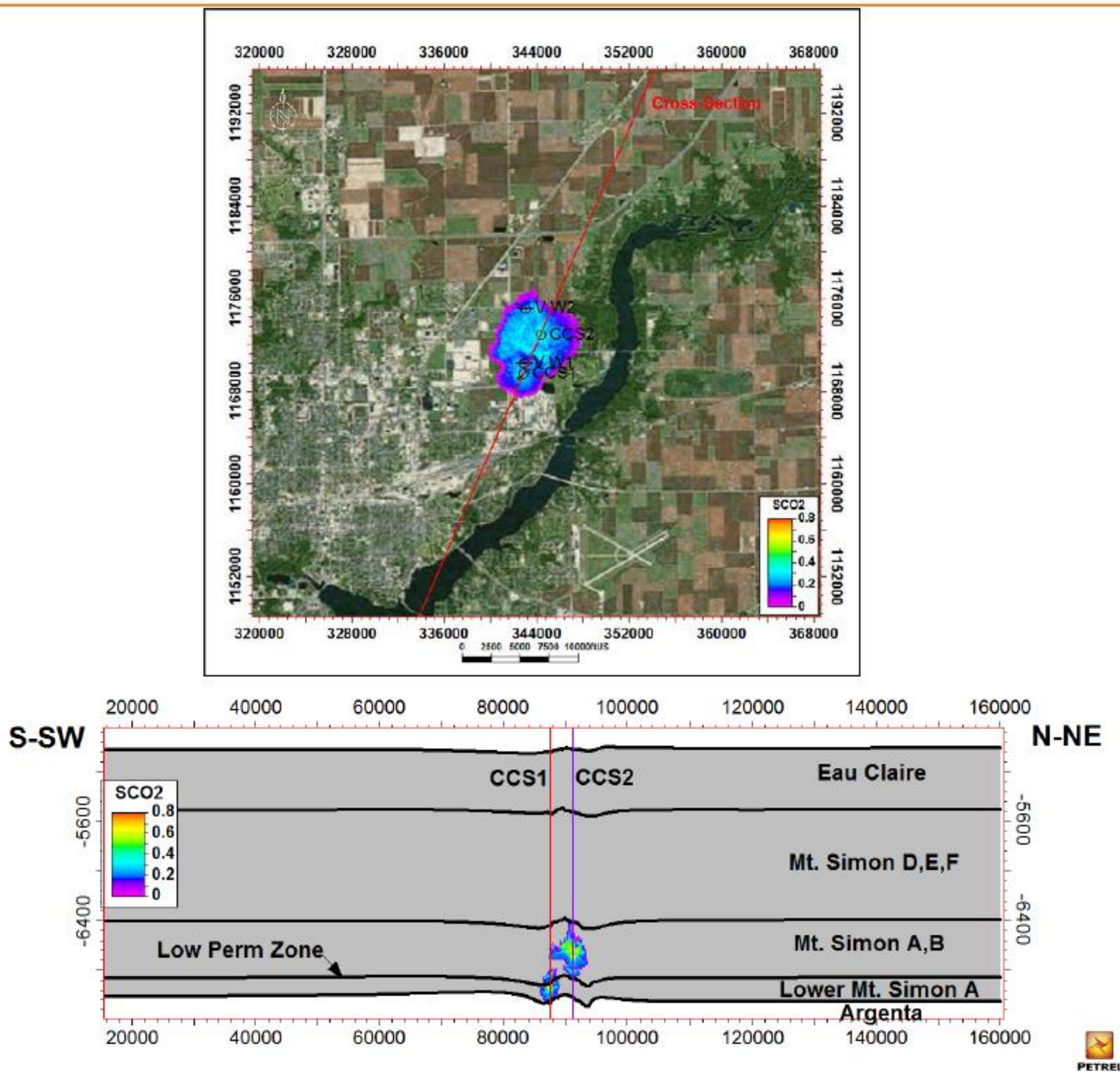

Figure 5. Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the end of 10 years after the cessation of injection (predicted time of site closure).

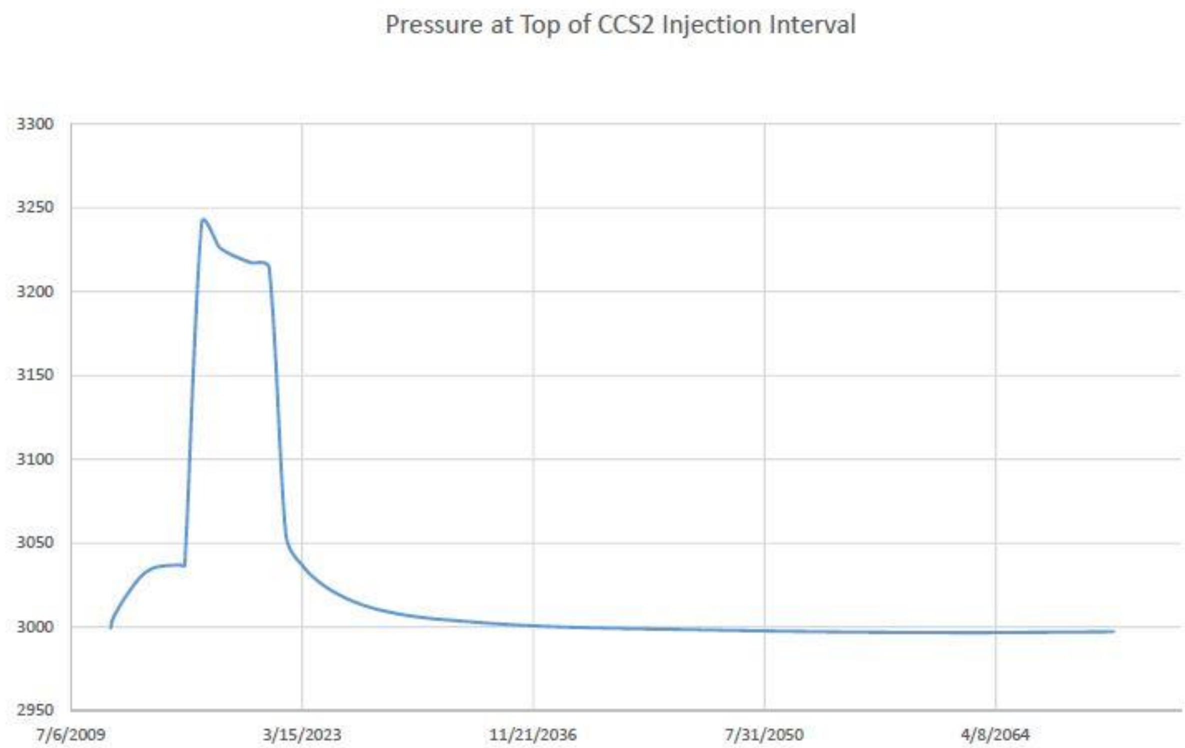

Figure 6. Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection.

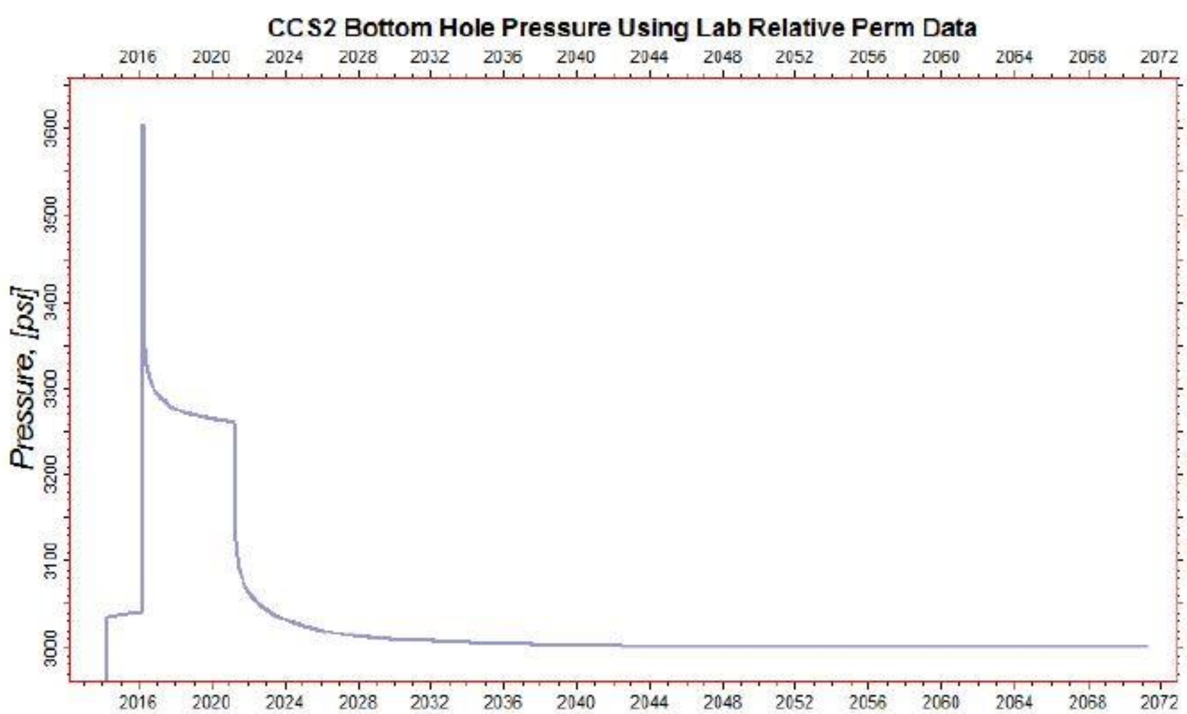

Figure 7. Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection.

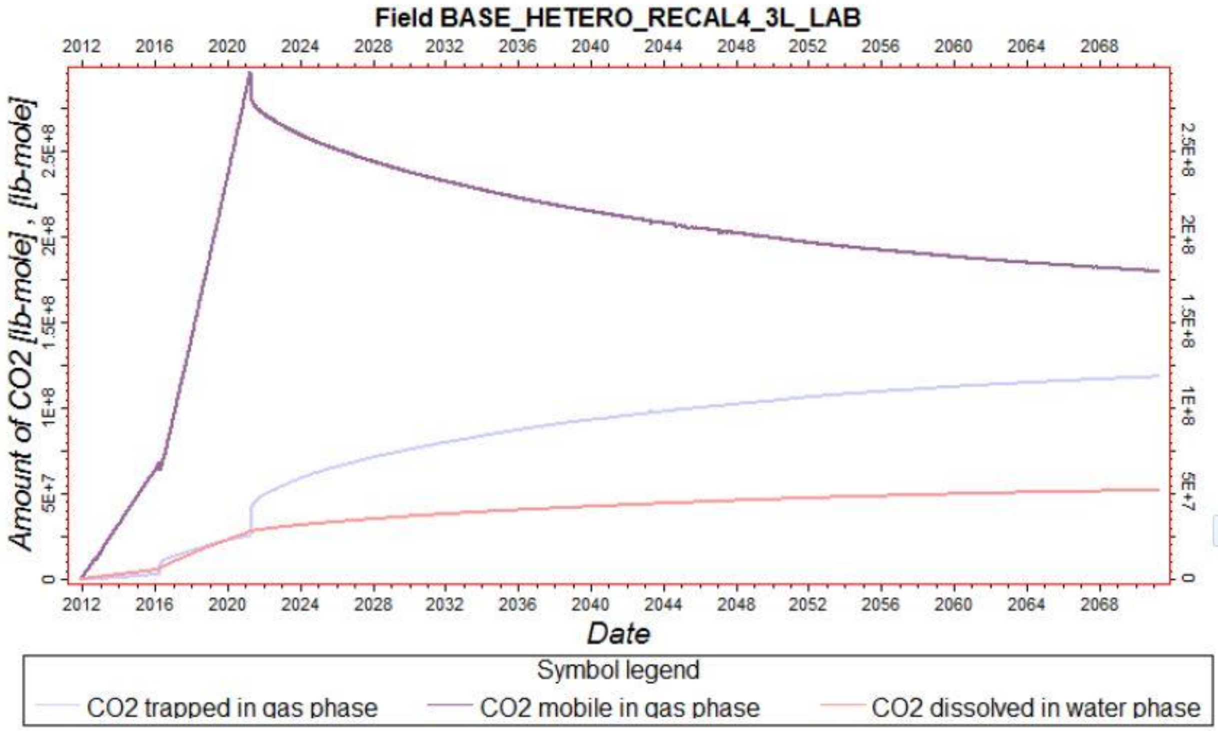

Figure 8. Predicted CO_2 phase distribution, simulated for 50 years after the commencement of injection.

Schedule for Submitting Post-Injection Monitoring Results

All post-injection site care monitoring data and monitoring results (i.e., resulting from the groundwater monitoring and plume and pressure front tracking described above) will be submitted to the Director in annual reports. These reports will be submitted each year, within 60 days following the anniversary date of the date on which injection ceases or alternatively with the prior approval of the Director.

The annual reports will contain information and data generated during the reporting period; i.e. seismic data acquisition, well-based monitoring data, sample analysis, and the results from updated site models.

Alternative Post-Injection Site Care Timeframe

ADM will conduct post-injection monitoring for ten years following the cessation of injection operations. ADM demonstrated that an alternative PISC timeframe is appropriate, pursuant to 40 CFR 146.93(c)(1). This demonstration is based on the computational modeling to delineate the AoR; predictions of plume migration, pressure decline, and carbon dioxide trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest USDWs.

ADM will conduct all of the monitoring described under "Groundwater Quality Monitoring" and "Carbon Dioxide Plume and Pressure Front Tracking" above and report the results as described under the "Schedule for Submitting Post-Injection Monitoring Results." This will continue until ADM demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs, per the requirements at 40 CFR 146.93(b)(2) or (3).

If any of the information on which the demonstration was based changes or the actual behavior of the site varies significantly from modeled predictions, e.g., as a result of an AoR reevaluation, ADM may update this PISC and Site Closure Plan pursuant to 40 CFR 146.93(a)(4). ADM will update the PISC and Site Closure Plan, within six months of ceasing injection or demonstrate that no update is needed and as necessary during the duration of the PISC timeframe.

Non-Endangerment Demonstration Criteria

Prior to authorization of site closure, ADM will submit a demonstration of non-endangerment of USDWs to the Director, per 40 CFR 146.93(b)(2) or (3).

To make the non-endangerment demonstration, ADM will issue a report to the Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include (or appropriately reference): all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Director to review the analysis. The report will include the following components:

Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan (Attachment C of this permit) and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

Comparison of Monitoring Data and Model Predictions and Model Documentation

The results of computational modeling used for AoR delineation and for demonstration of an alternative PISC timeframe will be compared to monitoring data collected during the operational and the PISC period. The data will include the results of time-lapse temperature and pressure monitoring, groundwater quality analysis, passive seismic monitoring, and geophysical surveys (i.e. logging, operating-phase VSP, and 3D surface seismic surveys) used to update the computational model and to monitor the site. Data generated during the PISC period will be used to help show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. The operator will demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period against the model's predicted properties (i.e. plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the storage site. The validation of the computational model with the large volume of available data will be a significant element to support the non-endangerment demonstration. Further, the validation of the complete model over the areas, and at the points, where direct data collection has taken place will help to ensure confidence in the model for those areas where surface infrastructure preclude geophysical data collection and where direct observation wells cannot be placed.

Evaluation of Carbon Dioxide Plume

The operator will use a combination of time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (2D or 3D surveys) to locate and track the extent of the CO_2 plume. Figure 9, Figure 10, and Figure 11 present examples of how the data may be correlated against the model prediction. In Figure 9, a series of RST logs are compared against the model's predicted plume vertical extent at a specific point location at a specified time interval. A good correlation between the two data sets will help provide strong evidence in validating the model's ability to represent the storage system. Similarly, Figure 10 illustrates a comparison of the time-lapse VSPs against the predicted spatial extent of the plume at a specified time interval. Also, limited 2D and 3D seismic surveys will be employed to determine the plume location at specific times. The data produced by these activities will be compared against the model using statistical methods to validate the model's ability to accurately represent the storage site. Figure 11 presents an example of how the data from time-lapse 3D seismic surveys may be correlated against the model prediction.

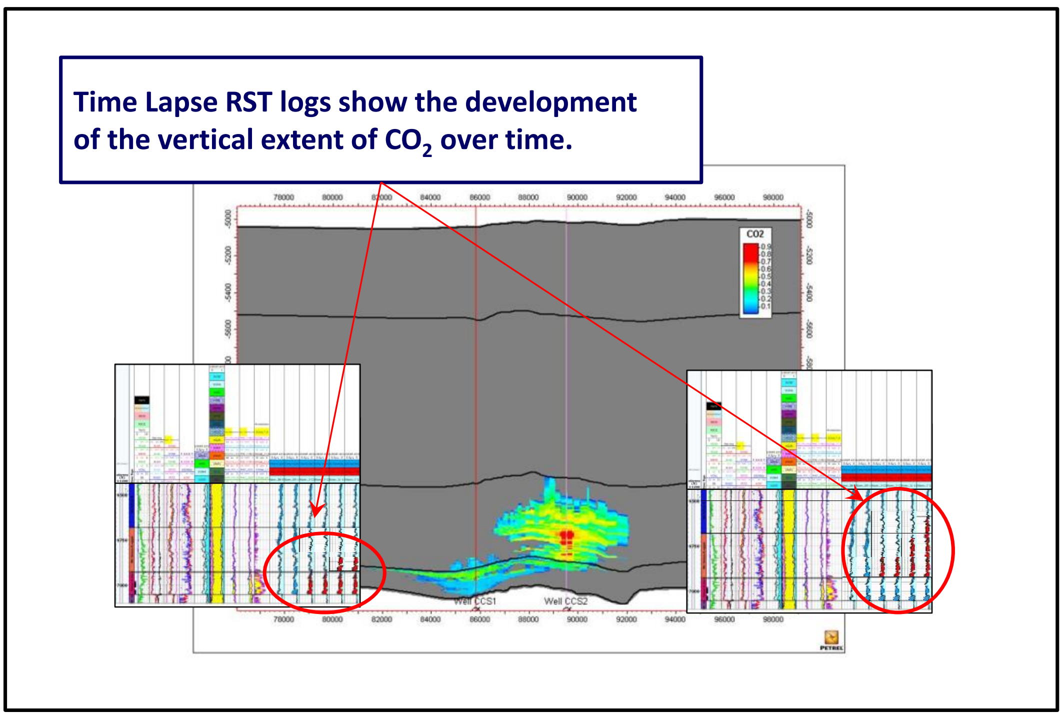

Figure 9. Comparison of the time-lapse RST logs against the predicted vertical extent of the plume at a specific time interval during the operational and PISC period can provide validation of the model's accuracy.

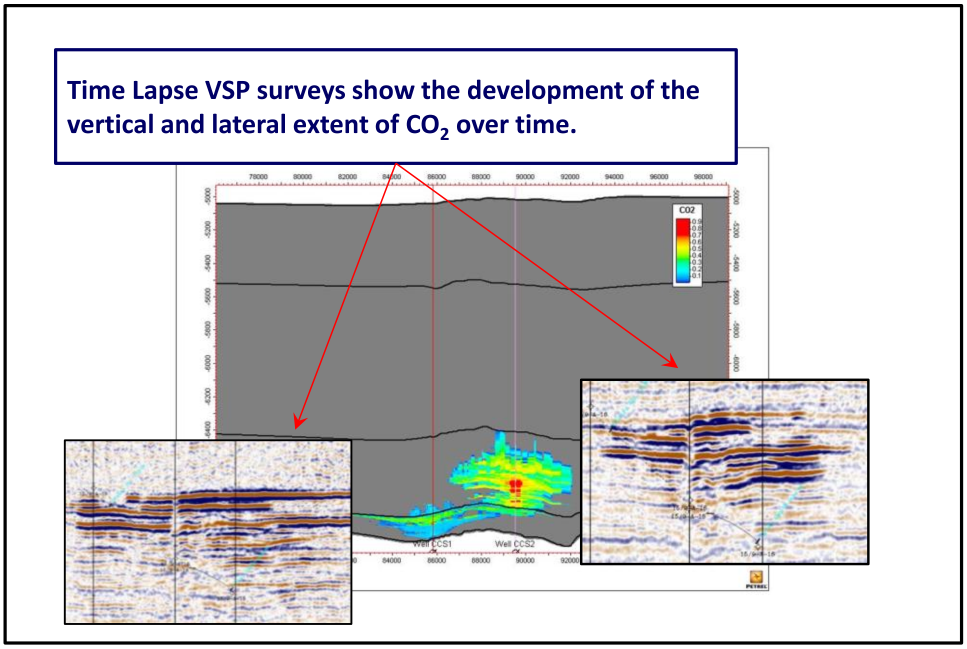

Figure 10. Comparison of the time-lapse VSPs against the predicted spatial extent of the plume at specific time intervals during the operational and PISC period can provide validation of the model's accuracy.

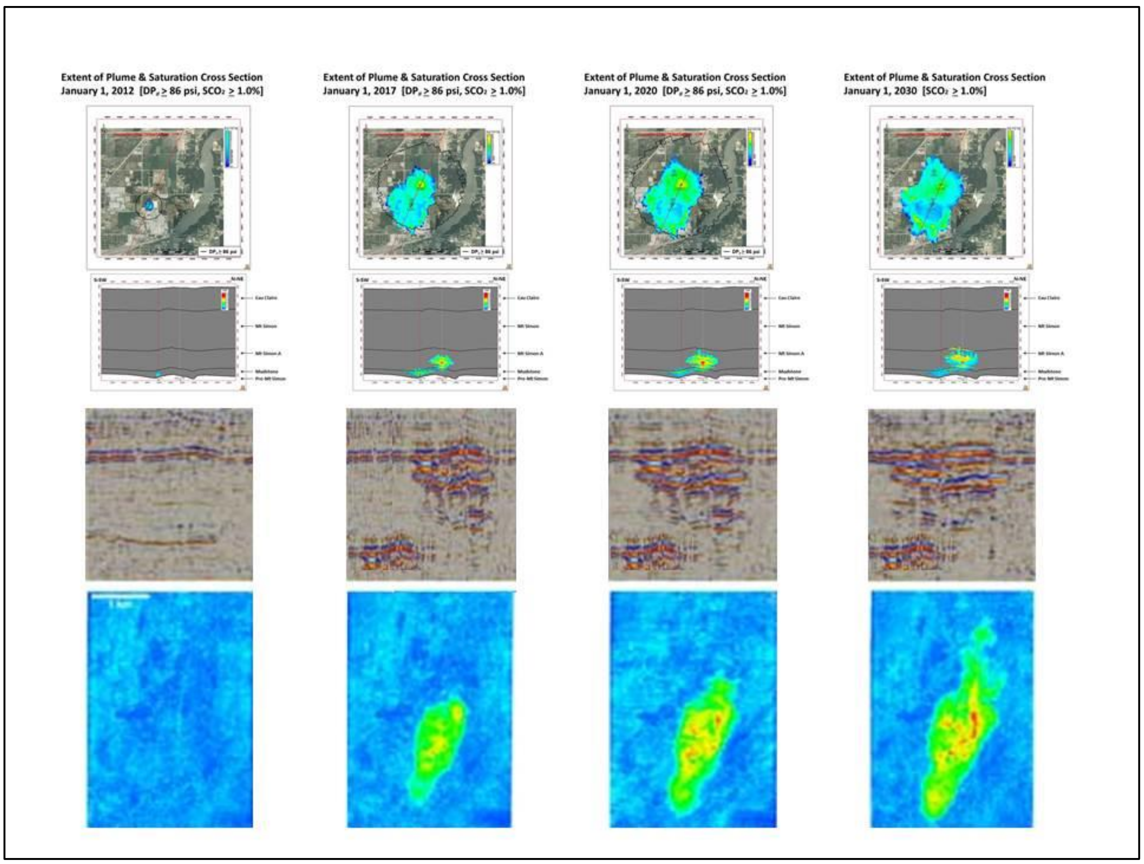

Figure 11. Comparison of the time-lapse surface 3D against the predicted spatial extent of the plume at specific time intervals during the operational and PISC period can provide validation of the model's accuracy.

Regarding the separate-phase carbon dioxide plume, the PISC monitoring data will be used to support a demonstration of the stabilization of the CO_2 plume as the reservoir pressure returns toward its pre-injection state. The storage interval (Mt. Simon) is considered to be an open reservoir system with a regional dip oriented NW (up-dip) to SE (down-dip) and having excellent porosity (20%) and permeability (120 mD). Locally, the storage interval has thin stratigraphic bands of low permeability siltstone to mudstone. These bands act as baffles that restrict the plume's vertical movement. Modeling performed to delineate the plume and pressure front predicts that, during the PISC period, the CO_2 will gradually rise through the reservoir until it encounters a baffle at which time it pools and spreads laterally. Based on the results of a 50 year post injection simulation, the top of the CO_2 plume is about 900 vertical feet below the primary seal formation (Eau Claire Shale). Additionally, the model predicts that over half the CO_2 will have become immobilized within the formation. This, in conjunction with the reservoir pressure returning to its pre-injection state, will be used to indicate there is essentially no driving force to cause significant plume movement. Indeed, the middle Mt. Simon contains intervals of eolian sandstone which are very tightly cemented by quartz overgrowths with some facies having permeabilities <0.01 mD. These intervals will act as more than a baffle and will significantly impede any vertical plume migration due to buoyancy forces.

The stabilization of the site conditions combined with the site's characteristic of not having any local penetrations of the seal formation will be the central focus of the operator's demonstration of non-endangerment. Equalization of plume to the site's pre-injection conditions will be one element in demonstrating non-endangerment. To demonstrate this, a case was examined to determine how long it would take a slowly expanding plume to reach the nearest penetration of the seal formation. Shown in Figure 15, the closest penetration of the seal formation is approximately 17 miles from the injection well. Assuming the plume continues to grow at 1% per year, it would take over 600 years for the plume to reach this plugged and abandoned well. Because this well is down dip from the injection well, it is likely the plume will never reach this location.

Evaluation of Mobilized Fluids

In addition to carbon dioxide, mobilized fluids may pose a risk to USDWs. These include native fluids that are high in TDS and therefore may impair a USDW, and fluids containing mobilized drinking water contaminants (e.g., arsenic, mercury, hydrogen sulfide). The geochemical data collected from monitoring wells will be used to demonstrate that no mobilized fluids have moved above the seal formation and therefore after the PISC period would not pose a risk to USDWs. In order to demonstrate non-endangerment, the operator will compare the operational and PISC period samples from layers above the injection zone, including the lowermost USDW, against the pre-injection baseline samples. This comparison will support a demonstration that no significant changes in the fluid properties of the overlying formations have occurred and that no mobilized formation fluids have moved through the seal formation. This validation of seal integrity will help demonstrate that the injectate and or mobilized fluids would not represent an endangerment to any USDWs.

Additionally, RST logs will be used to monitor the salinity of the reservoir fluids in the observation zone above the Eau Claire Shale seal. Figure 12 shows the relationship between salinity and sigma for two different temperatures while Table 8 shows the compositions of the groundwater at various intervals. This table shows the difference between the salinity level of the Mt Simon and the Ironton-Galesville (the interval directly above the confining zone). By comparing the time lapse RST logs against the pre-injection baseline logs, the operator will be able to monitor any changes in reservoir fluid salinity. RST logs indicating steady salinity levels within each zone would indicate no movement of fluids out of the storage unit, confirming the integrity of the well and seal formation.

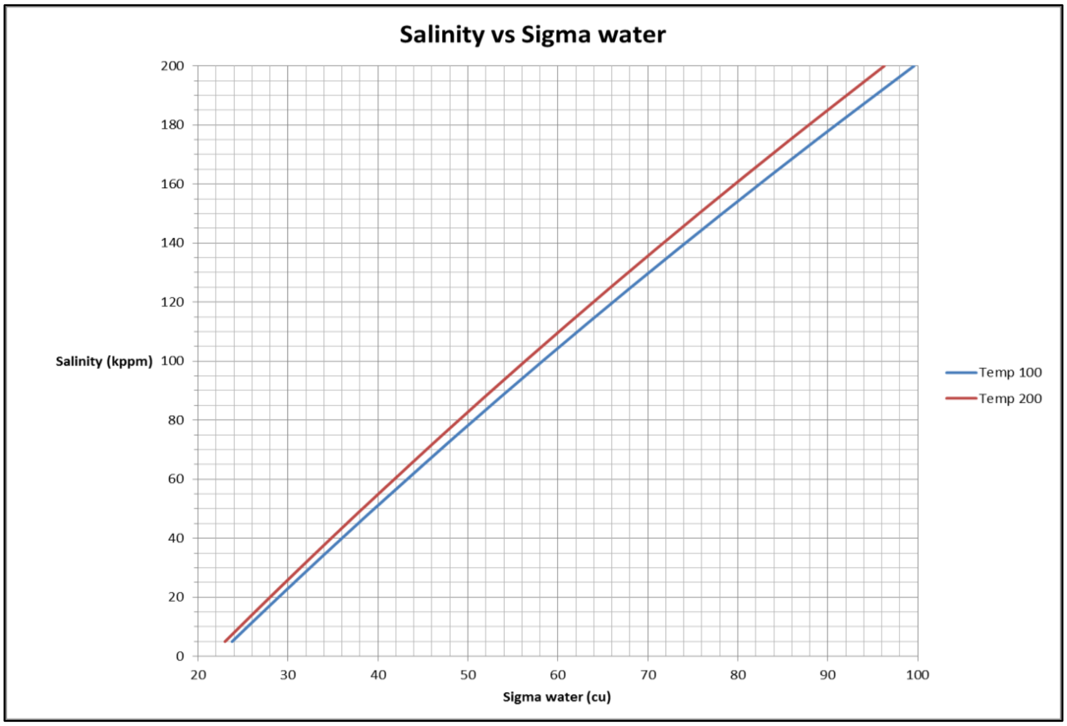

Figure 12. The red and blue lines show the relationship between salinity and sigma for at 100°F and 200°F.

Table 8. Fluid parameters for the Pennsylvanian, Ironton-Galesville, and Mt Simon.

Constituent	Pennsylvanian	Ironton-Galesville	Mt. Simon
Conductivity (mS/cm)	1.5	80	170
TDS (mg/L)	1,000	65,600	190,000
Cl^- (mg/L)	170	36,900	120,000
Br^- (mg/L)	1	180	680
Alkalinity (mg/L)	380	130	80
Na^+ (mg/L)	140	17,200	50,000
Ca^{2+} (mg/L)	100	5,200	19,000
K^+ (mg/L)	1	520	1,700
Mg^{2+} (mg/L)	50	950	1,800
pH (units)	7.2	6.9	5.9

Evaluation of Reservoir Pressure

The operator will also support a demonstration of non-endangerment to USDWs by showing that, during the PISC period, the pressure within the Mt. Simon rapidly decreases toward its pre-injection static reservoir pressure. Because the increased pressure during injection is the primary driving force for fluid movement that may endanger a USDW, the decay in the pressure differentials will provide strong justification that the injectate does not pose a risk to any USDWs.

The operator will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared against the pressure predicted by the computational model. Agreement between the actual and the predicted values will help validate the accuracy of the model and further demonstrate non-endangerment. Figure 13 provides an illustrative example of how the operator will demonstrate agreement between the computational model prediction and the actual measured parameters at the various monitoring wells and respective measurement depths. This figure shows that during the 10 years of the PISC period, the actual reservoir pressure (red line) falls to pre-injection levels and has a decay rate similar to the rate predicted by the model. Based on risk-based criteria listed in the PISC and Site Closure Plan, pressure decline toward pre-injection levels is one factor indicative of USDW non-endangerment. The close alignment between the predicted and actual pressures will further validate the model's accuracy in representing the reservoir system.

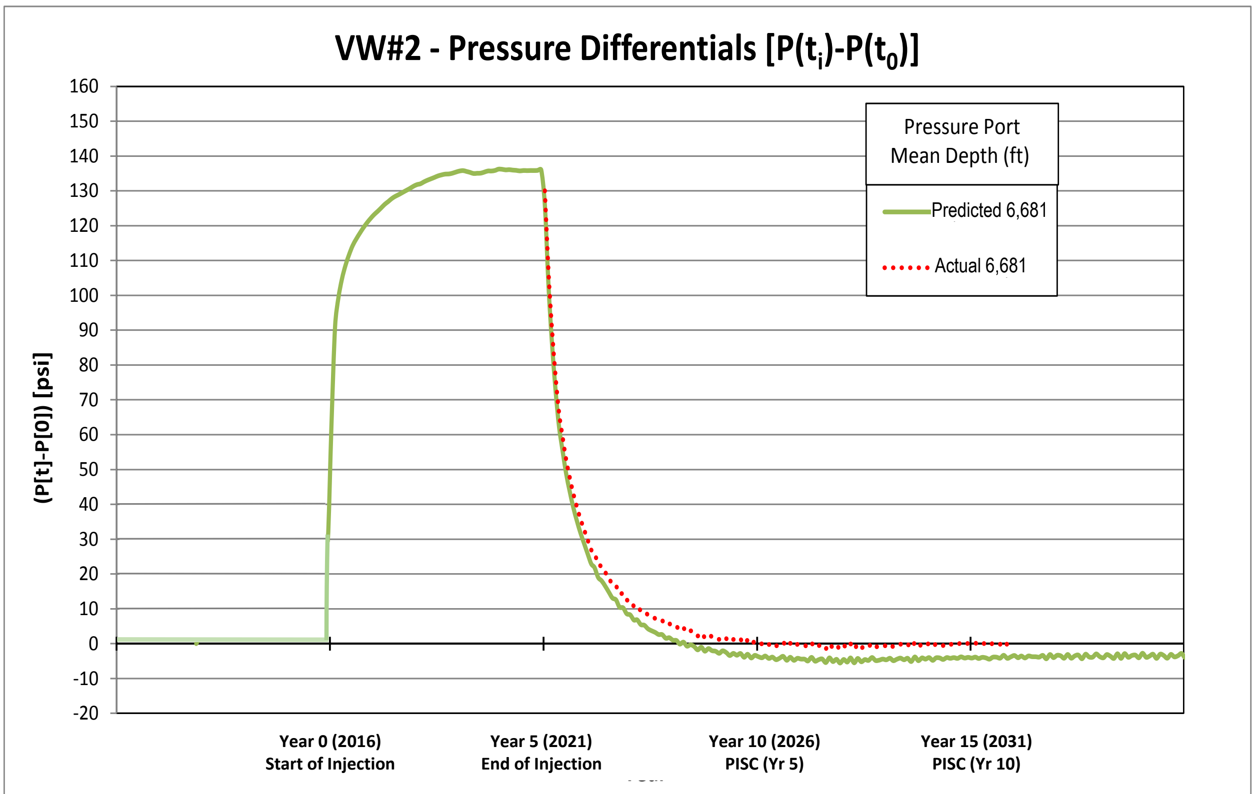

Figure 13. Illustration of Verification Well #2 comparison of actual dP versus the predicted monitoring interval dP during PISC period through year 2031.

One of the key comparisons that may be made is between the observed injection reservoir pressure and the model predicted pressure. Figure 14 shows an illustrative example of differential reservoir pressure predicted for three years after injection ceases, relative to original static reservoir pressure. The contour southwest of the CCS#2 well is the 10 psi contour as predicted by the computational model. Direct observations will be utilized during the PISC period to verify that pressure observations at CCS#2 have declined in conformance with the model. Pressure decline to this level within this time frame is an indication of the excellent lateral continuity within the regionally extensive, open Mt. Simon reservoir. Observed reduction of reservoir pressure to this extent would help validate the model and indicate substantial reduction in the potential of injection-pressure induced brine or CO_2 migration.

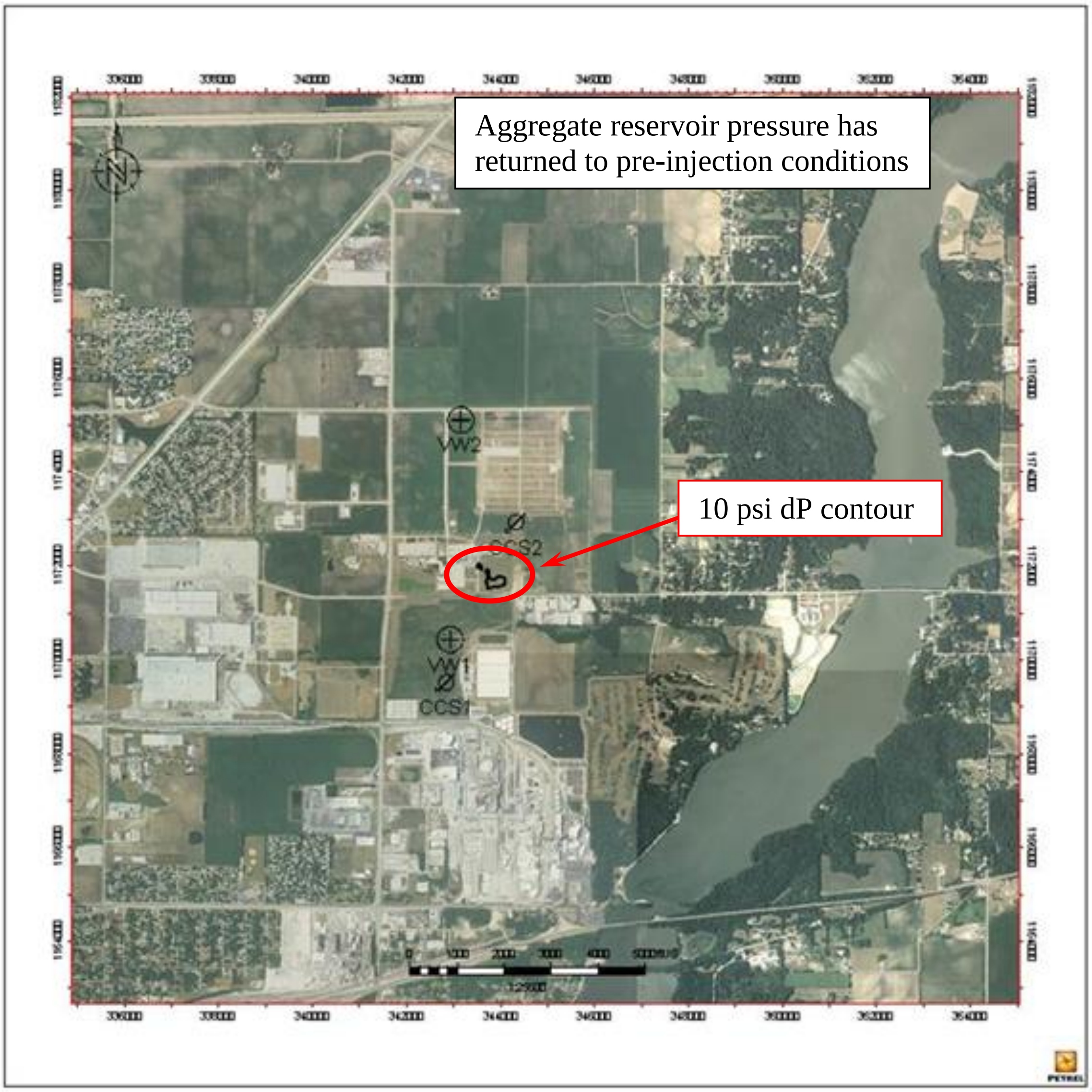

Figure 14. Example of how direct pressure measurements at CCS#1, CCS#2, & VW#2 will support the 10 psi differential pressure contour as predicted by the flow model (inside red circle), shown at April 1, 2024.

Evaluation of Potential Conduits for Fluid Movement

Other than the project wells, there are no identified potential conduits for fluid movement or leakage pathways within the AoR. As shown in Figure 15, the closest penetration of the confining zone is approximately 17 miles from the injection well. Based on the computational model, if the plume were to continue to grow at 1% per year it would take over 600 years for the plume to reach this well. Because this well is down dip from the injection well, it is likely the plume will never reach this location. Based on this information, the potential for fluid movement through artificial penetrations of the seal formation does not present a risk of endangerment to any USDWs.

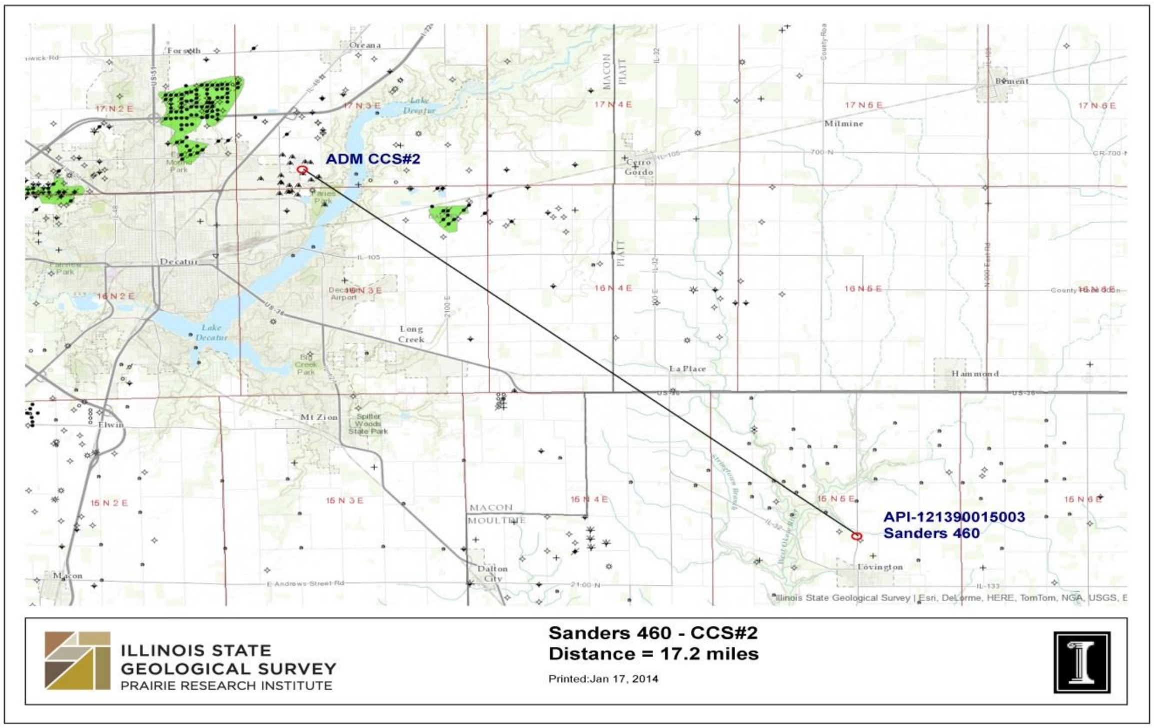

Figure 15. The closest penetration the seal formation (Eau Claire) is 17.2 miles from CCS#2. Based on a plume growth of 1.0% per year, it would take over 600 years for the project's CO_2 plume to reach this well.

Evaluation of Passive Seismic Data

Finally, passive seismic monitoring will be used to help further demonstrate seal formation integrity. The operator will provide seismic monitoring data showing that no seismic events have occurred that would indicate fracturing or fault activation near or through the seal formation. This validation of seal integrity will provide further support for a demonstration that the CO_2 plume is no longer an endangerment to any USDWs. Figure 16 illustrates how these data could be presented. This figure shows a subset of locatable microseismic events occurring during part of the IBDP project's operational period. From this figure one can see that a majority of the microseismic events occur in the lower Mt Simon and the Precambrian basement. No events are observed near the Eau Claire seal formation indicating that no fracturing or fault activation is occurring within this formation. This provides additional verification of the Eau Claire formation's seal integrity and indicates that to date the response to the imposed fluid pressures due to injection are confined to the vicinity of the injection zone and below.

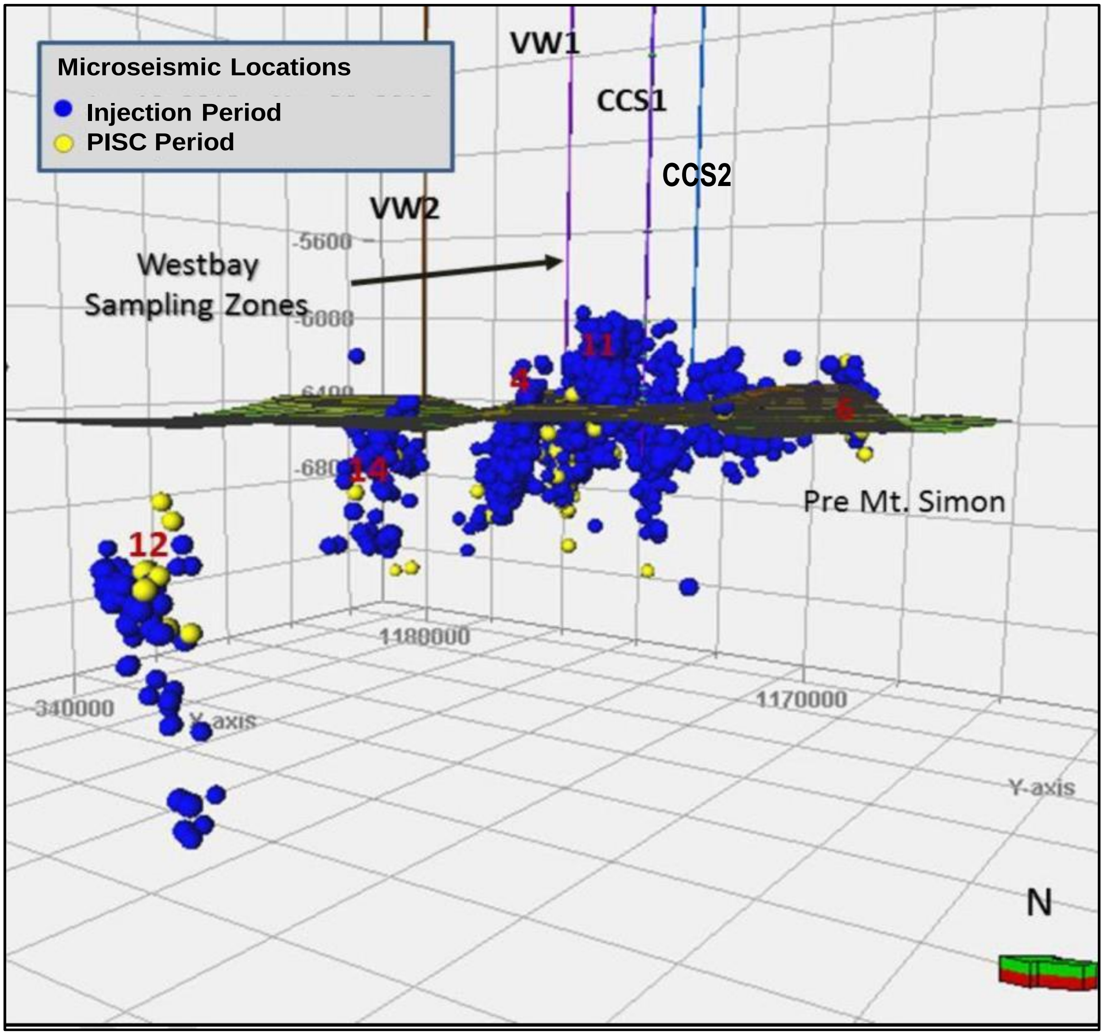

Figure 16. Visual representation showing the microseismic activity occurring during the injection and post injection periods. (Figure provided by IBDP project)

Site Closure Plan

ADM will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. ADM will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, ADM will plug the verification well(s) and geophysical well(s); restore the site and move out all equipment; and submit a site closure report to the Director. The activities, as described below, represent the planned activities based on information provided to EPA in November 2013. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the Director for approval with the notification of the intent to close the site.

Plugging the Verification Well(s)

The well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. A final external MIT will be conducted to ensure mechanical integrity. Detailed plugging procedures are provided below. All casing in this well will be cemented to surface and will not be retrievable at abandonment. After injection ceases and after the appropriate post-injection monitoring period is finished, the completion equipment will be removed from the well.

Type and Quantity of Plugging Materials, Depth Intervals

Well cementing software (e.g., Schlumberger's CemCade) will be used to model the plugging and aid in the plug design. The cements used for plugging will be tested in the lab prior to plug placement and both wet and dry samples will be collected during plugging for each plug to ensure quality of the plug.

All of the casing strings will be cut off at least 3 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

Volume Calculations

Volumes will be calculated for the specific abandonment wellbore environment based on desired plug diameter and length required. The methodology employed will be to:

1) Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.
2) Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

Plugging and Abandonment Procedure

At the end of the serviceable life of the verification well, the well will be plugged and abandoned. In summary, the plugging procedure will consist of removing all components of the completion system and then placing cement plugs along the entire length of the well. Prior to placing the cement plugs, casing inspection and temperature logs will be run confirming external mechanical integrity. If a loss of integrity is discovered then a plan to repair using the cement squeeze method will be prepared and submitted to the agency for review and approval. At the surface, the well head will be removed; and the casing will be cut off 3 feet below surface. A detailed procedure follows:

1. Move in workover unit with pump and tank.
2. Record bottom hole pressure using down hole instrumentation and calculate kill fluid density. Pressure test annulus as per annual MIT requirements.
3. Fill both tubings with kill weight brine as calculated from Bottom hole pressure measurement (expected approximately 9.5 ppg).
4. Nipple down well head and nipple up BOPs.
5. Remove all completion equipment from well.
6. Keep hole full with workover brine of sufficient density to maintain well control.
7. Log well with CBL, temperature, mechanical inspection log to confirm external mechanical integrity.
8. Pick up work string (either 2 7/8'' or 3 ½'') and trip in hole to PBTD.
9. Circulate hole two wellbore volumes to ensure that uniform density fluid is in the well.
10. The lower section of the well will be plugged using CO_2 resistant cement from TD around 7150ft to around 800ft above the top of the Eau Claire formation (to approximately 4200 ft). This will be accomplished by placing plugs in 500 foot increments. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 360 sacks of cement will be required (to incorporate a safety factor, 423 sacks are assumed: 3000 ft X .1305 cu ft/ft x 1.2 excess / 1.11 cf/sk = 423 sacks). Actual cement volume will depend upon actual weight of the casing within the plugged zone. This will require at least six plugs of 500 feet in length. No more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug.
11. Pull ten stands of tubing (600 ft) out and shut down overnight to wait on cement curing.
12. After appropriate waiting period, TIH ten stands and tag the plug. Resume plugging procedure as before and continue placing plugs until the last plug reaches the surface.
13. Nipple down BOPs.
14. Remove all well head components and cut off all casings below the plow line.
15. Finish filling well with cement from the surface if needed. Total of approximately 464 sacks total cement used in all remaining plugs above 4200 feet (4200 ft X .1305 cu ft/ft / 1.18 cu ft/sk = 464 sks). Cement calculations based on using Class A cement from 4000 ft back to surface with a density of 15.6 ppg and a yield of 1.18 cu ft /sk. Lay down all work string, etc. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 feet, or as per permitting agency directive.
16. If required, install permanent marker back to surface on which all pertinent well information is inscribed.
17. Fill cellar with topsoil.

18. Rig down workover unit and move out all equipment. Haul off all workover fluids for proper disposal.
19. Reclaim surface to normal grade and reseed location.
20. Complete plugging forms and send in with charts and all lab information to the regulatory agency. Plugging report shall be certified as accurate by ADM and shall be submitted within 60 days after plugging is completed.

Note: 7,000 ft 5 ½" 17 #/ft (7000 ft X .1305 cu ft/ft = 914 cu ft) casing requires an estimated 914 cubic feet of cement to fill 14 plugs. An excess factor of 20% is being suggested on the lower 3000ft to accommodate cement that might be lost to the formation so total material used would be 423 sacks of EverCRETE CO_2 resistant cement and 442 sack Class A/H cement.

Approximately five days are required from move in to move out, depending on the operations at hand and the physical constraints of the well, weather, and other conditions.

See Figure 17 below for a plugging schematic.

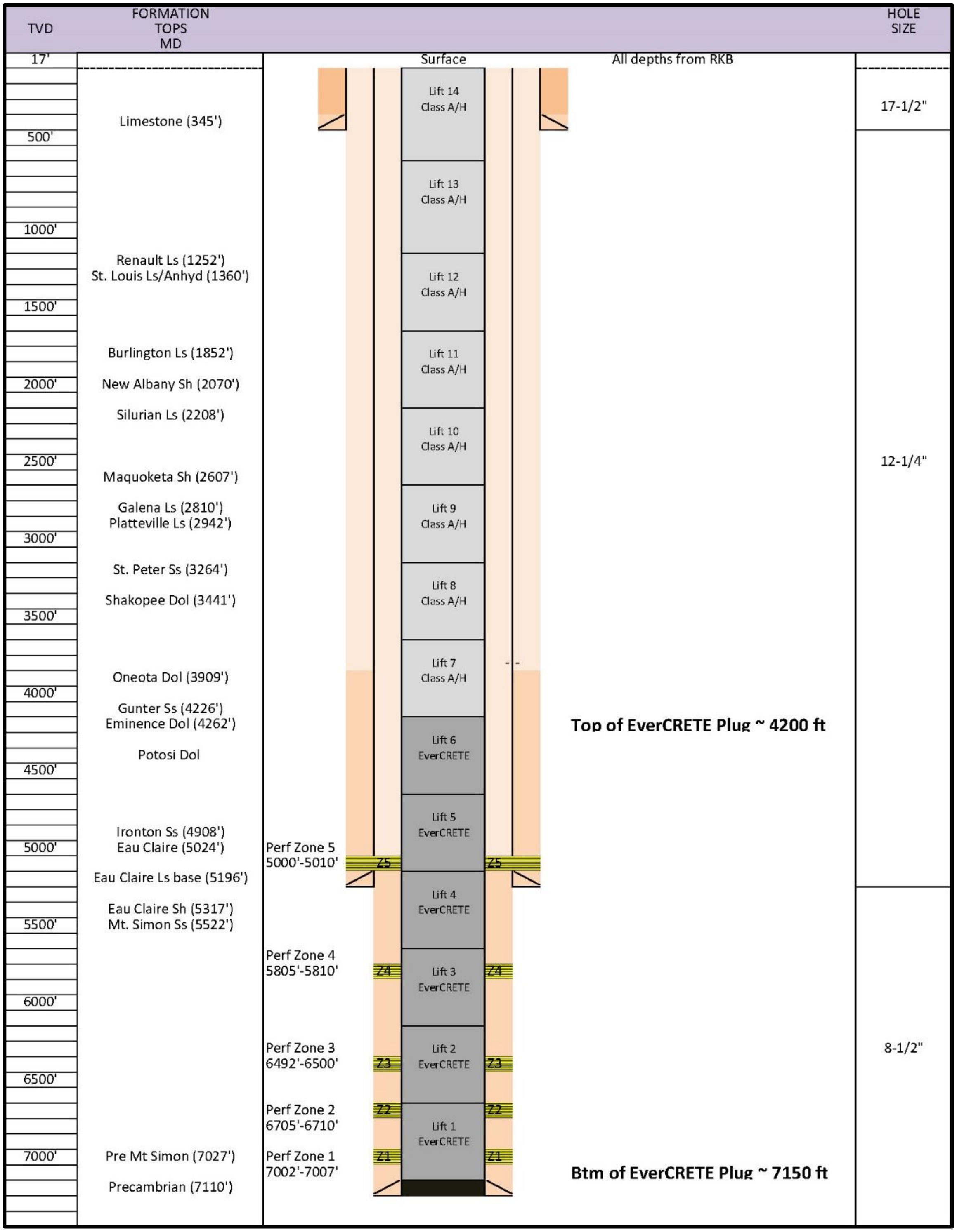

Figure 17. Representative Plugging Schematic - Verification Well.

Plugging the Geophysical Well(s)

At the end of the serviceable life of the well, the well will be plugged and abandoned utilizing the following procedure:

1. Notify the permitting agency of abandonment at least 60 days prior to plugging the well.
2. Remove any monitoring equipment from well bore. Well will contain fresh water or a mixture of fresh water and native St. Peter formation water.
3. Nipple down well head and connect cement pump truck to 4 ½ inch casing. Establish injection rate with fresh water. Mix and pump 247 sacks Class A cement (15.9 ppg). Slow injection rate to ½ bbl/min as cement starts to enter St. Peter perforations. Continue squeezing cement into formation until a squeeze pressure of 500 psi is obtained. Monitor static cement level in casing for 12 hours and fill with cement if needed to top out. Plan to have 50 sacks additional cement above calculated volume on location to top out if needed. (To incorporate a safety factor, 255 sacks are assumed: 3450 ft X .0873 cu ft/ft / 1.18 cu ft/sk = 255 sacks.)
4. After cement cures, cut off all well head components and cut off all casings below the plow line.
5. Install permanent marker at surface, or as required by the permitting agency.
6. Reclaim surface to normal grade and reseed location.

See Figure 18 below for a plugging schematic.

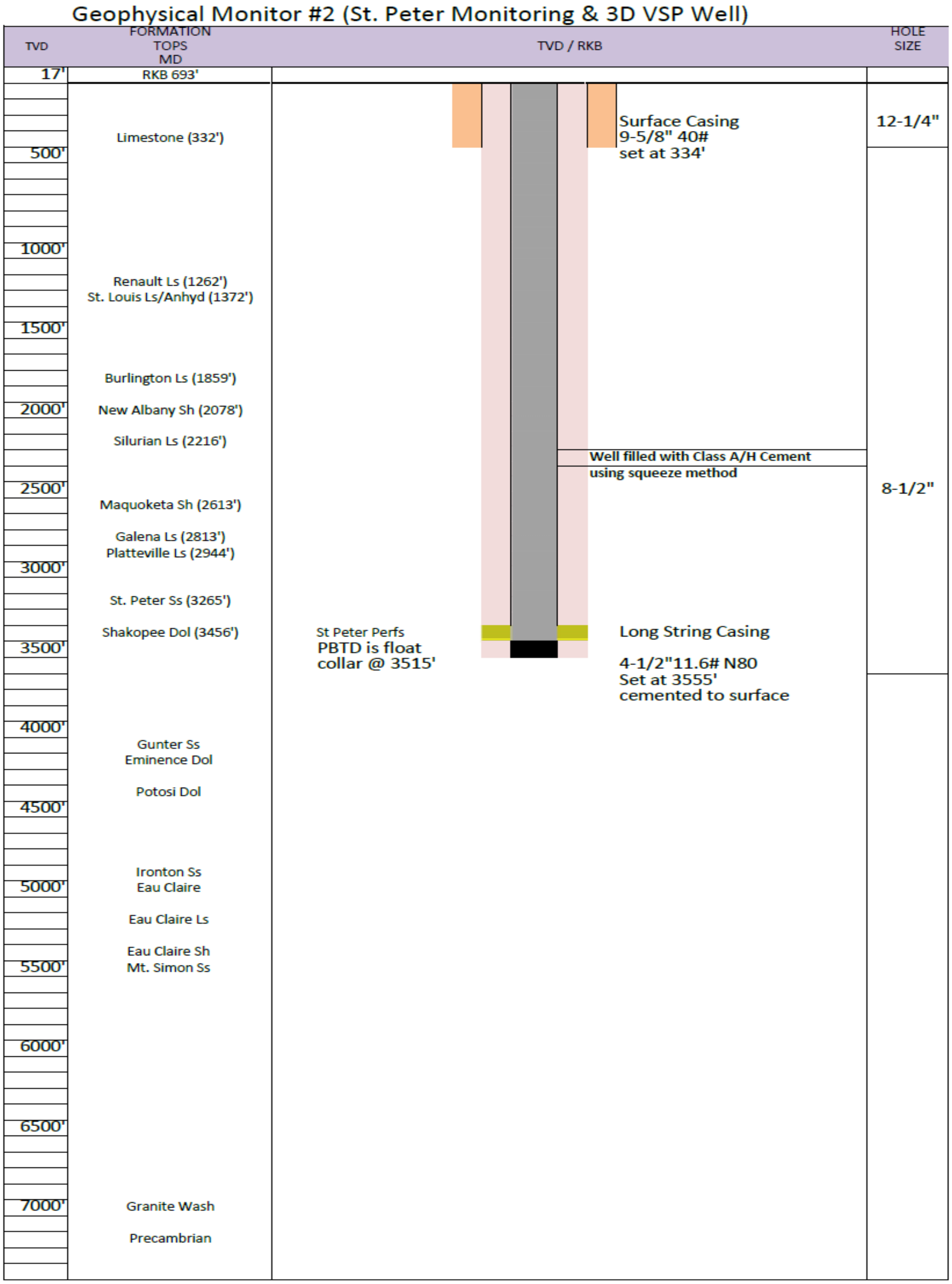

Figure 18. Representative Plugging schematic - geophysical well.

Planned Remedial/Site Restoration Activities

To restore the site to its pre-injection condition following site closure, ADM will be guided by the state rules for plugging and abandonment of wells located on leased property under The Illinois Oil and Gas Act: Title 62: Mining Chapter I: Department of Natural Resources - Part 240, Section 240.1170 - Plugging Fluid Waste Disposal and Well Site Restoration.

The following steps will be taken:

1. The free liquid fraction of the plugging fluid waste, which may consist of produced water and/or crude oil, shall be removed from the pit and disposed of in accordance with state and federal regulations (e.g., injection or in above ground tanks or containers pending disposal) prior to restoration. The remaining plugging fluid wastes shall be disposed of by on-site burial.
2. All plugging pits shall be filled and leveled in a manner that allows the site to be returned to original use with no subsidence or leakage of fluids, and where applicable, with sufficient compaction to support farm machinery.
3. All drilling and production equipment, machinery, and equipment debris shall be removed from the site.
4. Casing shall be cut off at least four (4) feet below the surface of the ground, and a steel plate welded on the casing or a mushroomed cap of cement approximately one (1) foot in thickness shall be placed over the casing so that the top of the cap is at least three (3) feet below ground level.
5. Any drilling rat holes shall be filled with cement to no lower than four (4) feet and no higher than three (3) feet below ground level.
6. The well site and all excavations, holes and pits shall be filled and the surface leveled.

Site Closure Report

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the verification and geophysical wells (and the injection well if it has not previously been plugged),
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

ADM will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,

- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the operator for a period of 10 years following site closure. Additionally, the operator will maintain the records collected during the PISC period for a period of 10 years after which these records will be delivered to the Director.

Quality Assurance and Surveillance Plan (QASP)

The Quality Assurance and Surveillance Plan is presented in the Appendix of the Testing and Monitoring Plan.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN

This plan is provided to meet the requirements of 40 CFR 146.94. As steps to prevent unexpected carbon dioxide (CO_2) movement have already been undertaken in accordance with risk analysis, this plan is about actions to be taken, and to be prepared to take, if unexpected fluid movement or any other emergency events occur.

Facility Name:	Archer Daniels Midland, CCS#2 Well IL-115-6A-0001
Facility Contacts:	A site-specific list of facility contacts will be developed and maintained during the life of the project.
Injection Well Location:	39º53'09.32835", -88º53'16.68306" Near the center of Section 32 Township 17N, Range 3E (Whitmore Township) Decatur, Macon County, Illinois

This emergency and remedial response plan (ERRP) describes actions that the owner / operator (ADM) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the operation or post-injection site care periods.

If ADM obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, ADM must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: ADM will immediately cease injection. However, in some circumstances, ADM will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

Part 1: Local Resources and Infrastructure

Resources in the vicinity of the IL-ICCS project that may be impacted as a result of an emergency event at the project site include: underground sources of drinking water (USDWs); potable water wells; the Sangamon River; Bois Du Sangamon Nature Preserve; and Lake Decatur.

Infrastructure in the vicinity of the IL-ICCS project that may be impacted as a result of an emergency at the project site include: the wellhead; Richland Community College structures; and ADM facilities. A map of the local area is provided as Figure F-2 at the end of this plan.

Part 2: Potential Risk Scenarios

The following events related to the IL-ICCS project could potentially result in an emergency response:

- Injection or monitoring (verification) well integrity failure;
- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);
- Fluid (e.g. brine) leakage to a USDW;
- CO_2 leakage to USDW or land surface; or
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as follows:

TABLE F-1. DEGREES OF RISK FOR EMERGENCY EVENTS

Emergency Condition	Definition
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious Emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure.

In the event of an emergency requiring cessation of injection, CO_2 slated for injection may be released to the atmosphere.

Part 3: Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

In the event of an emergency requiring outside assistance, the lead project contact shall call the ADM Security Dispatch at (217) 424-4444 and ADM Corporate Communications at (217) 424-5413.

Well Integrity Failure.
Integrity loss of the injection well and/or verification well may endanger USDWs. Integrity loss may have occurred if the following events occur:

a. Automatic shutdown devices are activated.
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit;
    - Annulus pressure indicates a loss of external or internal well containment;

ADM is required to notify the UIC Program Director within 24 hours (40 CFR 146.91(c)(3)of <u>any triggering</u> of a shut-off system (i.e., down-hole or at the service).

b. Mechanical integrity test results identify a loss of mechanical integrity.

Response Actions:

- Immediately notify the ADM plant superintendent or designee.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- The plant superintendent will make an initial assessment of the situation and determine which other project personnel to notify.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious Emergency:
    - Initiate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
    - Limit access to wellhead to authorized personnel only.
    - Communicate with ADM personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
    - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor Emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, inititate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
    - Reset automatic shutdown devices.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).

Injection Well Monitoring Equipment Failure.
The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Response Actions:

- Immediately notify the ADM plant superintendent or designee.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- The plant superintendent will make an initial assessment of the situation and determine which other project personnel to notify.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious Emergency:
    - Initiate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
    - Limit access to wellhead to authorized personnel only.
    - Communicate with ADM personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor Emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
    - Reset or repair automatic shutdown devices.
    - Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).

Potential Brine or CO_2 Leakage to USDW. Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW.

Response Actions:

- Immediately notify the ADM plant superintendent or designee.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- The plant superintendent will make an initial assessment of the situation and determine which other project personnel to notify.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- For all Emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
        - Collect a confirmation sample(s) of groundwater and analyze for indicator parameters. (Potential indictors are listed in Tables 7 and 11 of Attachment C, the Testing and Monitoring Plan.)
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the impacted groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the impacted USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by ADM and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

Natural Disaster. Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster impacting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may impact surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, perform the following:

Response Actions:

- Immediately notify the ADM plant superintendent or designee.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c). The plant superintendent will make an initial assessment of the situation and determine which other project personnel to notify.
- Project contacts will determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious Emergency:
    - Initiate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
    - Limit access to wellhead to authorized personnel only.
    - Communicate with ADM personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure.
    - Determine if any leaks to ground water or surface water occurred.
    - If contamination or endangerment is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor Emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, inititate shutdown plan.
    - Shut in well (close flow valve).
    - Vent CO_2 from surface facilities.
    - Limit access to wellhead to authorized personnel only.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of any failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).

Induced Seismic Event. Induced seismic events typically refer to minor seismic events that are caused by human activity which alters the stresses and fluid pressures in the earth's crust. Induced seismicity could potentially result from the injection of fluids into subsurface formations that lubricate and or change the stress state of pre-existing faults which causes fault plane movement and energy release. Most induced seismic events are extremely small (microseismic) but in some instances are great enough to be felt by humans. Case histories of induced seismic events associated with fluid disposal wells show seismic events as far away as about 10 to 12 km (6.2 to 7.4 miles). Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside an eight (8) mile radius from the wellhead. Therefore this portion of the response plan is developed for any seismic event with an epicenter within a eight (8) mile radius of the injection well.

To monitor the area for seismicity, the site has installed five (5) surface seismic monitoring stations and three (3) borehole monitoring stations that continuously record the site's seismic activity. In addition to these stations, the USGS has deployed a network of nine (9) surface seismic monitoring stations and three (3) borehole monitoring stations. Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions. In the following table the ADM Decatur Seismic Monitoring System is presented. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table F-2a. ADM Decatur Seismic Monitoring System [1]

Operating State	Threshold Condition	Response Action
Green	Seismic events less than or equal to M1.5 [2]	1. Continue normal operation within permitted levels.
Yellow	Five (5) or more seismic events within a 30 day period having a magnitude greater than M1.5 [2] but less than or equal to M2.0[2].	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director and ISGS of the operating status of the well.
Orange	Seismic event greater than M1.5 [2]; and Local observation or felt report [3].	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director, ISGS, and ADM Communications of the operating status of the well. 3. Review seismic and operational data. 4. Report findings to the UIC Program Director and issue corrective actions [5].
	Seismic event greater than M2.0 [2] and no felt report	

1. Seismic events < M1.0 with an epicenter within an 8 mile radius of the injection well.
2. Determined by the local ADM or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.
3. Confirmed by local reports of felt ground motion or reported on the USGS “Did You Feel It?” reporting system.
4. Onset of damage is defined as cosmetic damage to structures – such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.
5. Within 25 business days (five weeks) of change in operating state.

Table F-2b. ADM Decatur Seismic Monitoring System [1]

Operating State	Threshold Condition	Response Action
Magenta	Seismic event greater than M2.0 [2]; and Local observation or report [3].	1. Initiate rate reduction plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, ISGS, and ADM Communications of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with ADM personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. If USDW contamination is detected, a. Notify the UIC Program Director within 24 hours of the determination. b. Initiate shutdown plan. c. Shut in well (close flow valve). d. Vent CO_2 from surface facilities. e. Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 9. Review seismic and operational data. 10. Report findings to the UIC Program Director and issue corrective actions [5].

1. Seismic events < M1.0 with an epicenter within an 8 mile radius of the injection well.
2. Determined by the local ADM or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.
3. Confirmed by local reports of felt ground motion or reported on the USGS “Did You Feel It?” reporting system.
4. Onset of damage is defined as cosmetic damage to structures – such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.
5. Within 25 business days (five weeks) of change in operating state.

Table F-2c. ADM Decatur Seismic Monitoring System [1]

Operating State	Threshold Condition	Response Action
Red	Seismic event greater than M2.0 [2]; Local observation or report [3]; and Local report and confirmation of damage [4].	1. Initiate shutdown plan. 2. Shut in well (close flow valve). Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, ISGS, and ADM Communications of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with ADM personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. If USDW contamination is detected, a. Notify the UIC Program Director within 24 hours of the determination. b. Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 9. Review seismic and operational data. 10. Report findings to the UIC Program Director and issue corrective actions [5].
	Seismic event >M3.5 [2]	

1. Seismic events < M1.0 with an epicenter within an 8 mile radius of the injection well.
2. Determined by the local ADM or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.
3. Confirmed by local reports of felt ground motion or reported on the USGS “Did You Feel It?” reporting system.
4. Onset of damage is defined as cosmetic damage to structures – such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.
5. Within 25 business days (five weeks) of change in operating state.

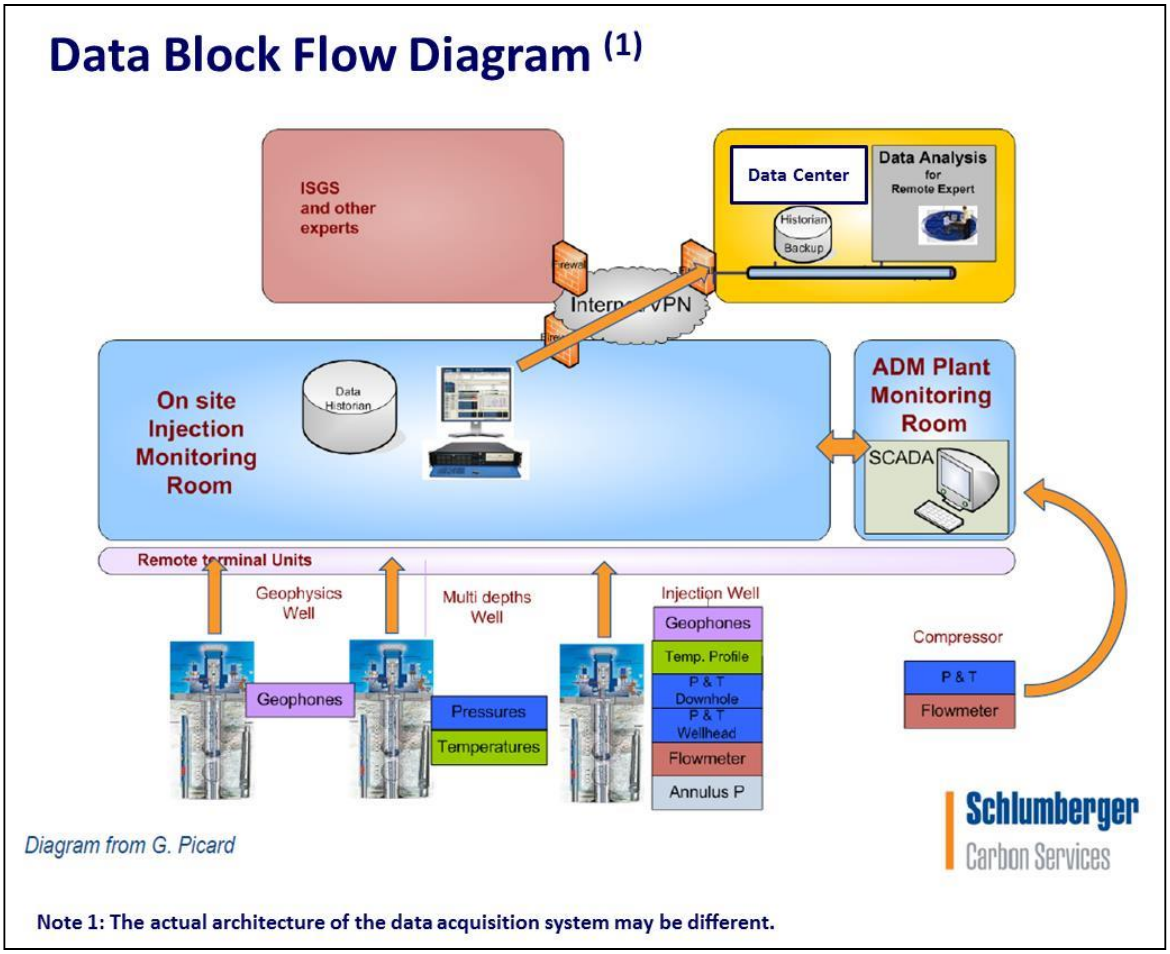

Figure F-1. The process by which seismic data are acquired, transmitted, processed, and evaluated by ADM to support the process.

1. Seismic data is recorded in real time from all stations.
2. Data from specific borehole and surface stations is transferred to a central data acquisition system where it is processed to determine the magnitude of the seismic event.
3. An email alert notification is sent out for events with magnitudes greater than M1.0.
4. If the seismic activity results in the site's operational state escalating above yellow, additional data from remote seismic stations will be retrieved.
5. The seismic data will undergo additional processing to refine the magnitude and determine location of the event(s).
6. The data will be evaluated by subject matter experts and a report of findings and recommendations will be issued within 25 business days.

<u>Part 4: Response Personnel and Equipment</u>
Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. The injection well and areas to the west and southwest are located within the limits of the City of Decatur; however, adjacent areas to the southeast, east, and north are outside of city limits. Therefore, both city and county emergency responders (as well as state agencies) may need to be notified in the event of an emergency.

Site personnel to be notified (not listed in order of notification):

1. ***ADM Project Engineer(s)***
2. ***ADM Plant Safety Manager(s)***
3. ***ADM Environmental Manager(s)***
4. ***ADM Plant Manager***
5. ***ADM Plant Superintendent***
6. ***ADM Corporate Communications***

A site-specific emergency contact list will be developed and maintained during the life of the project. ADM will provide the current site-specific emergency contact list to the UIC Program Director.

Local Authorities (including but not limited to):

Agency:	**Phone No.**
City of Decatur Police Department	217-424-2711
City of Decatur Fire Department	217-424-2811
Macon County Sheriff	217-424-1311
Illinois State Police	217-786-7107
Illinois Emergency Management Agency	800-782-7860
Macon County Emergency Management Agency	217-424-1327
Bodine Environmental Services	800-637-2379
UIC Program Director (US EPA Region V)	312-353-7648
US EPA National Response Center (24 hr)	800-424-8802
Illinois State Geological Survey	217-244-8389, 4068
	217-649-1744

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, the designated Subcontractor Project Manager shall be responsible for its procurement.

Part 5: Emergency Communications Plan

ADM will communicate to the public about any event that requires an emergency response, in consultation with the UIC Program Director.

In the event of an emergency requiring outside assistance, the project contact lead shall call the ADM Security Dispatch at (217) 424-4444 and ADM Corporate Communications at (217) 424-5413.

- Emergency communications with the public will be handled by ADM Corporate Communications.
- ADM Corporate Communications, in consultation with the UIC Program Director, will determine the method, frequency, and extent of public communication based upon the emergency event's severity and impact to the public.
- ADM will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response (including any updates, as necessary).
- ADM Corporate Communications will manage all ADM media communications with the public (through either interview, press release, Web posting, or other) in the event of an emergency situation related to the injection project.
- The individual to be designated by ADM will be the first contact during an emergency event.
- This individual will contact the crisis communication team as appropriate. Emergency responses to the media from ADM will be dealt with ONLY by the personnel so designated by ADM.
- Those individuals should try to be reachable 24 hours a day for contact in the event of an emergency.

In the event that anyone else at ADM is contacted to comment on any situation deemed an "emergency event," the media contact should be directed to ADM's 24/7 media line at 217-424-5413 or Media@adm.com.

Part 6: Plan Review

This ERRP shall be reviewed:

- at least once every five (5) years following its approval by the permitting agency,
- within one (1) year of an area of review (AoR) re-evaluation,
- within a prescribed period (to be determined by the permitting agency) following any significant changes to the injection process, the injection facility or an emergency event, or
- as required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within six (6) months following an event that initiates the ERRP review procedure.

Part 7: Staff Training and Exercise Procedures

ADM will integrate the ERRP into the plant specific standard operating procedures and training program as described in the SOP entitled 180.60.ENV.130 "*Environmental Training, Awareness and Competence.*" Periodic training will be provided, not less than annually, to well operators, plant safety and environmental personnel, the plant manager, plant superintendent, and corporate communications. The training plan will document that the above listed personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

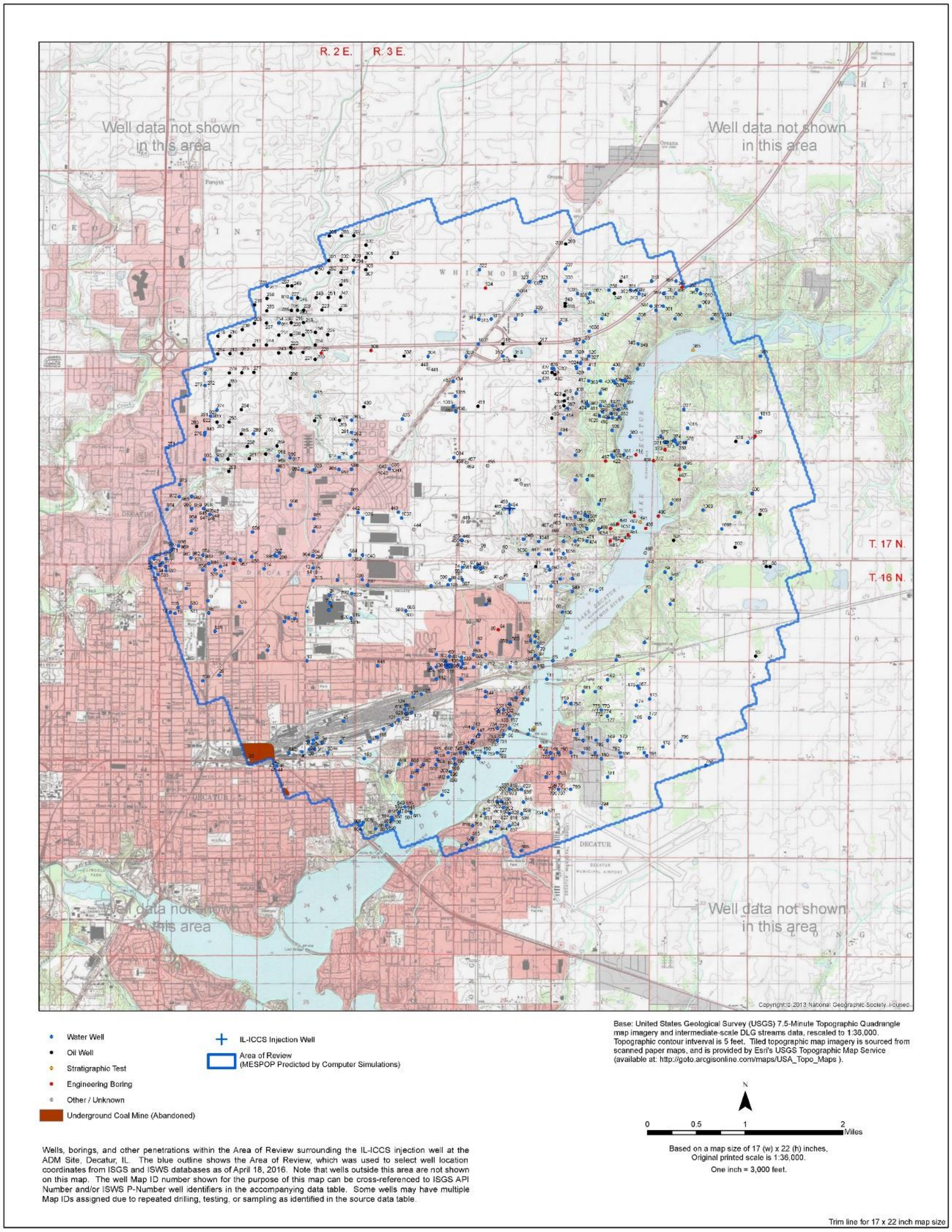

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Figure F-2. Local area map for the IL-ICCS project. Emergency & remedial response activities will most likely be within the "area of review" highlighted on the map. Source: ISGS and ISWS well databases, current as of September May 10, 20161.

ATTACHMENT G: CONSTRUCTION DETAILS

Facility name:	Archer Daniels Midland, CCS#2 Well IL-115-6A-0001
Facility contact:	Mr. Steve Merritt, Plant Manager 4666 Faries Parkway, Decatur, IL (217) 424-5750, steve.merritt@adm.com
Well location:	Decatur, Macon County, IL; 39º 53’ 09.32835”, -88º 53’ 16.68306”

Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0 - 347	26	To bedrock
Intermediate	347- 5,234	17 ½	To primary seal
Long	5,234 - 7,190	12 ¼	To Total Depth

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)
Surface[1]	0 -347	20	19.124	94	J55	Short	31
Intermediate[2]	0 -5,234	13 3/8	12.515	61	J55	Long or Buttress	31
Long[3] (carbon)	0 - 4,818	9 5/8	8.835	40.0	L80-HC	Long or Buttress	31
Long[3](chrome)	4,818 - 7,190	9 5/8	8.681	47.0	13CR80	Special	16

Note 1: Surface casing is 347 ft of 20 inch casing. After drilling a 26" hole to 347' true vertical depth (TVD), 20", 94 ppf, J55, short thread and coupling (STC) casing was set and cemented to surface. Coupling outside diameter is ~21 inches.

Note 2: Intermediate casing: 5,234 ft of 13 3/8 inch casing. After a shoe test or formation integrity test (FIT) was performed, a 17 1/2" hole was drilled to 5,234' TVD. 13-3/8", 61 ppf, J55, long thread and coupling (LTC) or buttress thread and coupling (BTC) was cemented to surface. Coupling outside diameter is ~14 3/8 inches.

Note 3: Long string casing: 0-4,818 ft of 9 ⅝ inch, L80-HC casing; 4,818' – 7,190' of 9 ⅝ inch, 13CR80. After a shoe test was performed and the integrity of the casing was tested, a 12 ¼" hole was drilled to 7190' TVD or through the Mt. Simon, where the long string casing was run and specially cemented. Coupling outside diameter is 10 ⅝ inches for L80-HC and 10.485 inches for the 13CR80.

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing[1,2,3]	0-6,350	5 ½	3.963	17	13CR80	Special	8,960	7,820

Note 1: Maximum allowable suspended weight based on joint strength of injection tubing. Specified yield strength (weakest point) on tubular and connection is 306,000 lbs.

Note 2: Weight of injection tubing string (axial load) in air (dead weight) is 88,200 lbs.

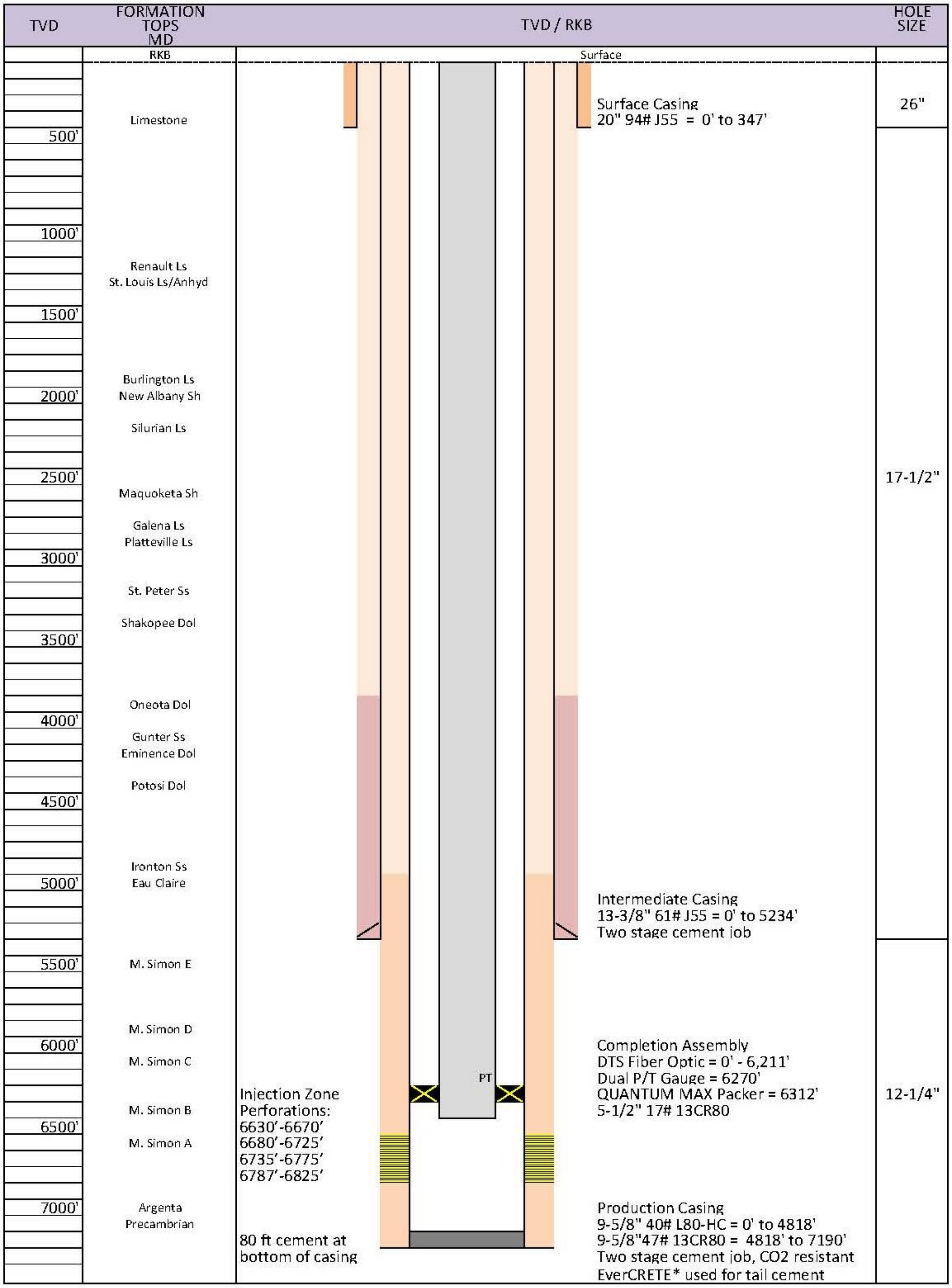
Note 3: Thermal conductivity of tubing @ 77°F is 16 BTU / ft.hr.°F.

The injection well has approximately 80 feet of cement above the casing shoe to prevent the injection fluid from coming in contact with the Precambrian granite basement. The figure on the following page is the “as built” well construction schematic for CCS#2.

IL-ICCS CCS #2 Well Schematic

Depths are reference to Kelly Bushing = 691.2 ft. above MSL

KB = 15.5 ft. above ground, site elevation = 675.7 ft. above MSL



ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION

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

Facility contact: Mr. Steve Merritt, Plant Manager
4666 Faries Parkway, Decatur, IL
(217) 424-5750, steve.merritt@adm.com

Well location: Decatur, Macon County, IL;
39º53’09.32835”, -88º53’16.68306”

ADM is providing financial responsibility pursuant to 40 CFR 146.85. ADM is using a corporate guarantee to cover the costs of: corrective action, emergency and remedial response, injection well plugging, and post-injection site care and site closure.

The updated costs of each of these activities, submitted pursuant to 40 CFR 146.82(c) on October 25, 2016, are presented in Table 1:

Table 1. Cost Estimates for Activities to be Covered by Financial Responsibility

Activity	Total Cost (in Millions of $)
Performing Corrective Action on Wells in AoR	$0.25
Plugging Injection Wells	$0.65
Post-Injection Site Care	$7.80
Site Closure	$0.59
Emergency and Remedial Response	$33.81

Attachment 1: CFO Letter

Archer Daniels Midland Company
Global Headquarters
77 W. Wacker Drive, Suite 4600
Chicago, Illinois 60601
t (312) 634.8100 / f (312) 634.8105

ADM.COM

March 11, 2016

Via Electronic Submittal

Tinka Hyde, Director, Water Division
US Environmental Protection Agency
Region 5
77 West Jackson Boulevard
Chicago, IL 60604-3590

Dear Director Hyde:

I am the chief financial officer of Archer Daniels Midland Company, headquartered at 77 W. Wacker Drive, Suite 4600, Chicago, IL 60601. This letter is in support of this firm's use of the financial test to demonstrate financial assurance.

This firm is the owner or operator of the following injection wells for which financial assurance for the current corrective action, injection well plugging, post injection site care, site closure, and emergency & remedial response is demonstrated through the financial test. This firm will maintain active coverage from the effective date of the Class VI permit for the injection well until site closure is authorized by the United States Environmental Protection Agency. The corrective action, injection well plugging, post injection site care, site closure, and emergency & remedial response baseline cost estimate covered by this financial test is established in Appendix H for each of EPA UIC Permits indicated below. The baseline cost is escalated on annual basis.

EPA UIC Permit #:	IL-115-6A-0001	IL-115-6A-0002
Well Name:	CCS#2	CCS#1
Location:	39°53'08.3502"N, 88°53'13.4118"W	39°52'37.06469"N, 88°53'36.25685"W
2016 Escalated Total Cost:	$92,523,088	

This firm is required to file a Form 10K with the Securities and Exchange Commission (SEC) for the latest fiscal year. The fiscal year of this firm ends on December 31. In Table 1, the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year ended December 31, 2015. Table 2 shows the firm's bond rating test.

Table 1: Financial Coverage Criteria

1. (a) Cost in current dollars for corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response (i.e., all obligations secured by the owner or operator using the financial test)		$ 92,500,000
(b) Sum of the company's financial responsibilities currently met using the financial test or corporate guarantee, including CERCLA and RCRA		$ 2,000,000
(c) Total of lines a and b		$ 94,500,000
2. Tangible net worth*		$14,227,000,000
3. Current assets*		$21,829,000,000
4. Current liabilities*		$13,505,000,000
5. Net working capital [line3 minus line 4]		$8,324,000,000
6. Total assets*		$40,157,000,000
7. Total assets in U.S.*		$28,186,000,000
	Yes	No
8. Is line 2 at least $100 million?	X	
9. Is line 2 at least 6 times line 1(c)?	X	
10. Is line 5 at least 6 times line 1(c)?	X	
11. Is line 7 at least 90% of Line 6? If not, completed line 12.		X
12. Is line 7 at least 6 times line 1(c)?	X	

Table 2: Bond Rating Test

1. Current bond rating of most recent issuance of this firm and name of rating service (rating service must be either Standard & Poor's or Moody's)	A (S&P)
2. Date of issuance of bond	10/16/2012
3. Date of maturity of bond	04/16/2043
4. Committee on Uniform Securities Identification Procedures (CUSIP) number	039483BH4

I hereby certify that the wording of this letter is consistent with the wording specified in the Underground Injection Control VI Program Financial Responsibility Guidance (July 2011).

Ray G. Young
Executive Vice President and
Chief Financial Officer
Archer Daniels Midland Company

ATTACHMENT I: STIMULATION PROGRAM

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

Facility contact: Mr. Steve Merritt, Plant Manager
4666 Faries Parkway, Decatur, IL
(217) 424-5750, steve.merritt@adm.com

Well location: Decatur, Macon County, IL;
39º53’09.32835”, -88º53’16.68306”

The need for stimulation to enhance the injectivity potential of the Mount Simon Sandstone is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 5 for review and approval prior to conducting any stimulation.

United States Environmental Protection Agency

EPA Seeks Comments on Plan to Modify an Existing Carbon Storage Permit

Archer Daniels Midland Co.
Decatur, Illinois

November 2016

This map shows where the injection well is located.

The U.S. Environmental Protection Agency plans to modify a permit for an injection well owned by the Archer Daniels Midland Company, 4666 Faries Parkway, Decatur, Illinois. The existing permit is for one injection well, CCS#2, that ADM wants to use to inject and store carbon dioxide, or CO_2, underground. The CO_2 is created when ADM makes ethanol. ADM plans to inject 1.1 million metric tons of CO_2 per year into this well over five years.

EPA first issued this permit in 2014. The proposed modifications will update the permit and attachments because of new information obtained during well construction and pre-injection testing. Only the conditions proposed for modification are re-opened for comment. A detailed list of the proposed modifications is available for viewing on EPA's website, at the Decatur Public Library, or by contacting EPA.

EPA is accepting comments from the public (*see box at left*) on this proposed permit modification approval. Comments may be submitted in writing or at the public hearing *(see box at left)*. The public comment period, which ends **Wednesday, December 14, 2016**, includes 30 days for comments as required by law, plus an additional three days for any delay caused by mailing. EPA will consider all comments it receives, and then issue a final decision along with a response to the significant comments.

The Safe Drinking Water Act requires EPA to regulate injection of fluids through wells to protect the quality of underground sources of drinking water. Issuing permits is one way EPA does this. You can find the regulations governing underground injection wells at Title 40 of the Code of Federal Regulations, Parts 144 and 146.

To learn more about EPA's Underground Injection Control program, or to join our mailing list visit https://go.usa.gov/3JwFP.

You are invited

EPA will hold a formal public hearing on the ADM draft modified permit at: Decatur Public Library, 130 N. Franklin Street

December 13, 2016

Public Hearing, 6 – 7 p.m.
Oral and written comments will be recorded or accepted. EPA will provide a summary of its proposed decision but will not answer questions during the hearing.

How to comment

In addition to accepting comments at the public hearing, EPA will accept written comments from November 10 until December 14, 2016. Please refer to Archer Daniels Midland, IL-115-6A-0001, when providing comments.

Mail or email your comments to:
Andrew Greenhagen
U.S. EPA, Water Division
UIC Branch (WU-16J)
77 W. Jackson Blvd.
Chicago, IL 60604-3590
Email: greenhagen.andrew@epa.gov
Phone: 312-353-7648

Web resources

https://go.usa.gov/3JwFP

Information Repository

The draft modified permit and fact sheet are available at:
Decatur Public Library
130 N. Franklin St.

You may call EPA toll-free at 800-621-8437, 8:30 a.m. – 4:30 p.m., weekdays.

How did EPA make its decision?

EPA made its draft decision to modify the permit by evaluating technical information and project-specific data that was obtained during well construction and pre-injection testing. EPA is proposing modifications related to:

- Size of the Area of Review (the region surrounding the well that ADM and EPA examined to ensure the protection of underground sources of drinking water)
- Final injection and monitoring well construction
- Injection start-up procedures
- Other administrative edits for clarity

ADM constructed the well and performed required pre-operational testing in 2015. They then submitted updated information to EPA. EPA considered the additional data to propose these permit modifications.

What happens next in the permit process?

EPA will review all public comments before making a final decision on whether or not to approve the permit modifications. The Agency will respond to all significant comments on the draft modified permit.

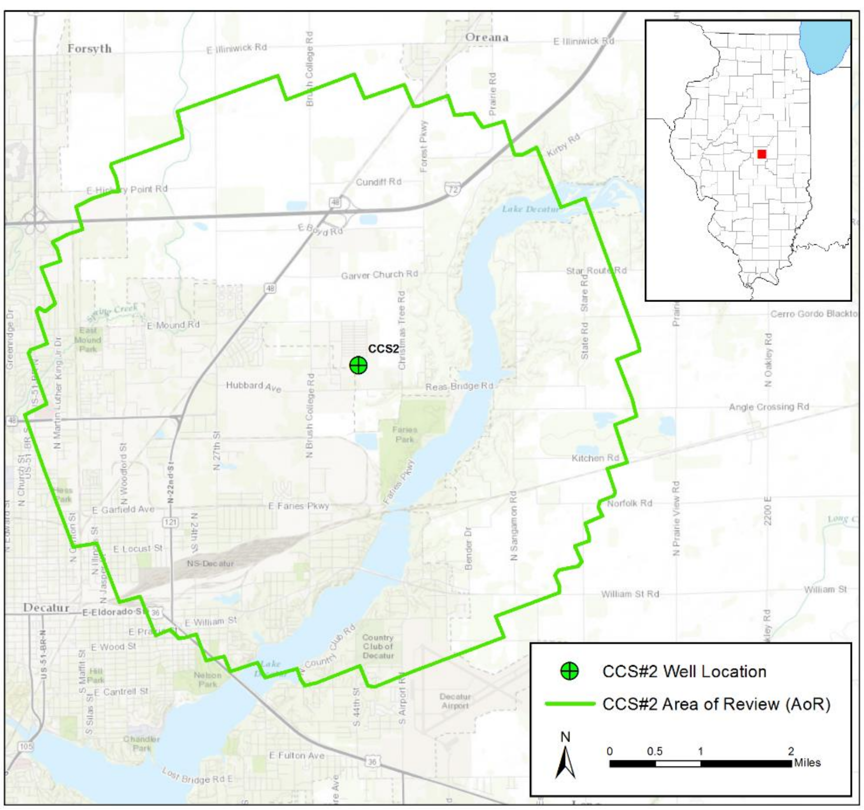
Administrative Record

The full administrative record, including all data submitted by Archer Daniels Midland Co., is available for public review at EPA's Chicago regional office. The office is open 9:00 a.m. – 4:00 p.m., weekdays. To review the administrative record or for additional information please contact Andrew Greenhagen at 312-353-7648 or greenhagen.andrew@epa.gov.

Legal Notice

To preserve your right to appeal any final permit decision, you must either participate in the public hearing or send in written comments on the draft modified permit decision by the end of the comment period.

The first appeal must be made to the Environmental Appeals Board; only after all agency review procedures have been exhausted may you file an action in the appropriate Circuit Court of Appeals.



This map shows the CCS#2 well location and Area of Review.

Archer Daniels Midland (ADM) of Decatur, Illinois has a U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program permit to inject carbon dioxide (CO_2) for geologic sequestration in a Class VI well (CCS#2).

ADM is capturing CO_2 generated from a fuel ethanol production unit at its agricultural and biofuels facility which, when injected underground, will support the goal of reducing carbon emissions to the atmosphere to help mitigate climate change.

Under the authority of Title 40 of the Code of Federal Regulations (40 CFR) Parts 144 and 146, EPA Class VI permits must specify conditions for the construction, operation, monitoring, reporting, plugging, post-injection site care and site closure of Class VI injection wells so as to prevent the movement of fluids into any USDW or unauthorized zones. General provisions for EPA UIC permit requirements are found at 40 CFR Parts 124, 144, 146 and 147.

EPA is proposing modifications to the Class VI permit for CCS#2 that address updated information about the site that ADM submitted pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 146.82(c). These changes relate to the size of the area of review, final injection and monitoring well construction, and injection start-up procedures. All other changes to the permit and attachments are editorial or clarifying in nature. EPA is retaining conditions related to completed activities (e.g., related to well construction and pre-operational formation testing activities) in the permit.

A number of changes are proposed in this draft major permit modification. The changes are categorized as formatting, administrative, and technical changes, and presented below:

- ***Formatting*** **-** A number of changes are proposed to ensure consistency of formatting throughout this document (e.g., capitalization, placement of table and figure headings, placement of footnotes and notes) and to support ease of review (e.g., reordering of tables or figures based on first reference, grammar and typo correction). For ease of review, these changes are not included in the table below.

- ***Administrative*** **-** Changes to operational dates and timeframes are proposed to conform to the updated permitting, operational and post-injection schedules. Additionally, limited wording edits were made for clarity. These changes are identified below.

- ***Technical*** **-** These changes are proposed to address new information collected and submitted to EPA in compliance with 40 CFR 146.82(c) (e.g., final well location coordinates, as-built well schematics, updated maps of the Area of Review, updated estimates of certain costs) following well construction and logging, and sampling and testing. These changes are identified and discussed below.

Throughout the tables below, page numbers refer to pages in the current version of the files.

In accordance with the conditions set forth in Title 40 of the Code of Federal Regulations (40 CFR) Parts 124.5, 144.39, and 146.82 the following permit conditions are proposed for modification:

Proposed Changes to the Permit

Page No.	Section/Topic	Description of Change	Justification
1	Authority	The coordinates of the CCS#2 injection well location, given in the first paragraph of this page, changed from 39º 53’ 08”, -89° 53’19” to 39º 53’ 09.32835”, -88° 53’16. 68306”.	This change reflects the final, as-drilled location of CCS#2.
1	Authority	The injection depths into the Mount Simon formation have changed from 5,545-7,051 feet to 5,553-7,043 feet.	This change reflects the final, as-constructed injection intervals at CC#2.
1	Authority	The Director of the Water Division has changed from Tinka G. Hyde to Christopher Korleski.	Administrative change.

Proposed Changes to Attachment A: Summary of Requirements

Page No.	Section/Topic	Description of Change	Justification
A1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
A1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53' 08", -89° 53'19" to 39º 53' 09.32835", -88° 53'16. 68306".	This change reflects the final, as-drilled location of CCS#2.
A1	Injection Well Operating Conditions	The word "minimum" was moved from the "Limitation or Permitted Value" column to the "Parameter/Condition" column to modify the second and third parameters/conditions, "Minimum Annulus Pressure" and "Minimum Annulus Pressure/Tubing Differential (directly above and across packer)."	Administrative change.
A1	Injection Well Operating Conditions – Parameter/Condition	The parenthetical "(directly above and across packer) was added at the end of the third parameter/condition that formerly read, "Minimum Annulus Pressure/Tubing Differential." The parameter/condition now reads, "Minimum Annulus Pressure/Tubing Differential (directly above and across packer)."	Administrative change.
A1	Injection Well Operating Conditions – Unit	The unit for the third parameter/condition, "Minimum Annulus Pressure/Tubing Differential (directly above and across packer)," was changed from "psig above surface injection pressure" to "psig."	This change was made for consistency with the Testing and Monitoring Plan.
A2 – A3	Start-up Monitoring and Reporting Procedures	This section was added to the Summary of Requirements.	This section was added to reflect the increased monitoring and reporting planned for the CCS#2 well during the start-up period and the first six months of the injection phase.

Proposed Changes to Attachment B: Area of Review (AoR) and Corrective Action Plan

Page No.	Section/Topic	Description of Change	Justification
B1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
B1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53’ 08”, -89° 53’19” to 39º 53’ 09.32835”, -88° 53’16. 68306”.	This change reflects the final, as-drilled location of CCS#2.
B2	Description of Model – Model Description	The second-to-last sentence of the last paragraph in this section was modified. The sentence formerly read, “Convergence is achieved once the model reaches the maximum tolerance ‘sufficiently small change’ for temperature and pressure calculation results on successive iterations,” and now reads, “Convergence is achieved once the model reaches the maximum tolerance where small changes of temperature and pressure calculation results occur on successive iterations.”	Administrative change (to provide clarity).
B2	Description of Model – Description of AoR Delineation Modeling Effort	The first sentence of the first paragraph in this section formerly read, “The 3D geologic model developed for the injection simulations is based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout the construction of the IBDP wells (CCS#1 and VW#1),” and now reads, “The 3D geologic model developed for the initial injection simulations was based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout the construction of the IBDP wells (CCS#1 and VW#1).”	Administrative change.
B2	Description of Model – Description of AoR Delineation Modeling Effort	The following sentence was inserted at the end of the first paragraph in this section: “Following the collection of testing and logging data during construction and pre-operational testing of CCS#2 and VW#2, the geologic model was updated pursuant to 40 CFR 146.82(c)(1).”	This change reflects the reservoir model update that occurred during construction and pre-operational logging and testing.
B2	Description of Model – Description of AoR Delineation Modeling Effort	The first sentence of the second paragraph in this section formerly read, “The model implements porosity and permeability well logs from CCS#1, VW#1, and VW#2,” and now reads, “The original, pre-construction phase model implemented porosity and permeability well logs from CCS#1, VW#1, and VW#2.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
B2 – B3	Description of Model – Description of AoR Delineation Modeling Effort	The following two sentences and list of seven steps were added to the end of the second paragraph of the section: "To update the reservoir model following pre-injection testing, logs from CCS#2 were used to update the 3D geologic model to reflect new information while remaining true to the original seismic property-driven distributions that did not require updates. The following steps were followed to incorporate CCS#2 well log data into the model domain permeability and porosity distributions: 1. Log (ELAN) permeability curves were upscaled into the static geologic model. 2. Permeability was log transformed. 3. General distribution was developed from log-permeability data. 4. The log permeability distribution was updated through co-simulation of VW#2 and CCS#2 log-permeability data with the existing 3D model log-permeability distribution and using the general log-permeability pdf developed from the data. The result honors the new log data at and near the wells and honors the seismic driven distribution as a trend away from VW#2 and CCS#2. 5. Permeability was inverse log transformed. 6. Steps 3 through 5 were done on a zone-by-zone basis. 7. The new permeability distribution was upscaled into a reservoir model grid and the existing permeability distribution for the CCS#2 injection zone was replaced with the newly computed permeability distribution within the CCS#2 injection zone across the entire lateral extent of the reservoir model grid."	This change reflects the most up-to-date reservoir model information submitted by ADM.
B3	Description of Model – Description of AoR Delineation Modeling Effort	The first sentence of the third full paragraph of this section was modified. The sentence formerly read, "In November 2011, injection of CO_2 into CCS#1 began and, as of January 2014, approximately 730,000 metric tons of CO_2 have been injected," and now reads, "In November 2011, injection of CO_2 into CCS#1 began and, as of project completion in November 2014, 999,215 metric tons of CO_2 had been injected."	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
B4	Model Inputs and Assumptions	The following sentence was added to the end of the first paragraph of this section: "The model update to meet requirements of 40 CFR 146.82(c)(1) simulates three years of injection in CCS#1, followed by five years of injection in CCS#2, followed by a 50-year post-injection period."	This change reflects the inputs used during the reservoir model update.
B4	Model Inputs and Assumptions – Site Geology and Hydrology	The following two sentences were added to the end of the first paragraph of this section: "Wireline log results from CCS#2 and VW#2 and core analyses from VW#2 were compared to data collected from CCS#1 and the ISGS database. The results show good agreement, validating the local site geology and hydrogeology as defined by data from CCS#1 and other nearby wells."	This change reflects the results of the additional VW#2 and CCS#2 well log data acquired during the pre-operational phase of the CCS#2 project.
B4	Model Inputs and Assumptions – Site Geology and Hydrology	The modifying phrase, "and verified from pre-injection testing on CCS#2 and VW#2" was added to a sentence in the second paragraph of this section. The sentence now reads, "However, based on core sample and log analysis from the CCS#1 well, and verified from pre-injection testing on CCS#2 and VW#2, the upper Mt. Simon is interpreted to have been deposited "in a tidally influenced system similar to the reservoirs used for natural gas storage in northern Illinois," while the basal 600 ft (the target injection zone) represents an "arkosic sandstone that was originally deposited in a braided river-alluvial fan system."	This change reflects the results of the additional VW#2 and CCS#2 well log data acquired during the pre-operational phase of the CCS#2 project.
B4	Model Inputs and Assumptions – Site Geology and Hydrology	The following sentence was added to the end of the third paragraph of this section: "Pre-injection testing in CCS#2 and VW#2 confirmed the absence of faults and folds based on the results of fracture finder logs."	This change reflects the results of the additional VW#2 and CCS#2 fracture finder logs completed during pre-operational testing for the CCS#2 project.
B5	Model Inputs and Assumptions – Site Geology and Hydrology	The following two sentences were moved from the end of the second full paragraph of the "Tabulation of Wells within the AoR – Wells within the AoR" section to the end of the fourth paragraph of this section: "Like other areas with humid climates (Freeze and Cherry, 1979), the water table in central Illinois is expected to reflect the elevation of the land surface. Steady-state ground water flow modeling for the IBDP site indicates that shallow ground water flows toward the east and southeast toward the Sangamon River and Lake Decatur."	Administrative change.
B6	Table 1 – Zone	The "Zone" information for the model domain changed from "Eastern" to "SPCS27-1201."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
B6	Table 1 – Coordinate of z_{min}	The coordinate of z_{min} changed from -6431.19 to -7113.19.	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B6	Table 1 – Coordinate of z_{max}	The coordinate of z_{max} changed from -4290.78 to -4272.78.	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B6	Porosity – Injection Zone Porosity	A former sentence in the first paragraph of the section that read, "For the injection interval of CCS#1 (-6,982 to -7,050 ft KB), the average effective porosity was found to be 21.0%," was replaced with two new sentences that read, "Pre-injection testing in CCS#2 identified an optimal injection interval of 6,630 to 6,825 ft KB, with multiple perforations of 6,630 – 6,670; 6,680 – 6,725; 6,735 – 6,775; and 6,781 – 6,825 (all in ft KB). The AoR was modeled using these perforation intervals, with an average effective porosity throughout the injection zone of 22%."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B6	Porosity – Injection Zone Porosity	In the second paragraph of the section, the average porosity of the lower zone of the Mt. Simon was changed from 16.8% to 22%.	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B6	Porosity – Injection Zone Porosity	The first sentence of the third paragraph of this section formerly read, "Based on the analysis of log results from CCS#1, ADM identified three porosity/permeability zones within the Mt. Simon," and now reads, "Based on the analysis of log results from CCS#2, ADM identified five porosity/permeability zones within the Mt. Simon."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B6	Porosity – Injection Zone Porosity	At the end of the third paragraph of this section, the following two sentences were replaced. The text had read, "The lower zone of the Mt. Simon, extending from the base of the formation at -6,367 MSL (-7,049 ft KB) to -5,738 ft MSL (-6,420 ft KB), is described as containing 'the highest average porosity and quite good permeability.' The middle zone, extending from -5,738 ft MSL (-6,420 ft KB) to -5,268 ft MSL (-5,950 ft KB), and the upper zone, extending from -5,268 ft MSL (-5,950 ft KB) to the top of the Mt. Simon at -4.862 ft MSL (-5,544 ft KB), have lower porosities and permeabilities." This text has been deleted and replaced with the following three sentences: "Pre-injection testing identified a	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
B6	Porosity – Injection Zone Porosity *(continued)*	high porosity/permeability region extending from the base of the Mt. Simon at 7,043 ft KB up to 6,427 ft KB; this overall interval included two sub-units with similar but varying porosity and permeability. The middle section of the Mt. Simon had lower porosity and permeability, extending from 6,427 to 5,907 ft KB. The upper unit from 5,907 to 5,553 ft KB also has high porosity and permeability, but was determined to be too close to the confining zone for injection."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B6	Porosity – Confining Zone Porosity	The following sentence was added to the end of the first paragraph in this section: "Pre-injection testing in CCS#2 and VW#2 indicated very small pore sizes based on CMR data, resulting in generally very low permeability (see "Confining Zone Permeability" below)."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B7	Figure 2	This figure has been modified to include the updated stratigraphic column. The previous figure is now on the left side of the composite figure under the heading "Original model," and the additional figure is on the right side under the heading "Updated model." The following changes were made to the original model to create the updated model: 1. Rock Type number labels were added adjacent to the right side of the stratigraphic column. The Mt. Simon Lower Zone is labeled "Rock Type 1 (intermittent layers of Rock Type 2)"; the Mt. Simon Middle Zone and the Mt. Simon Upper Zone are labeled "Rock Type 2"; and the Eau Claire is labeled "Rock Type 3." 2. The depth range of the Eau Claire formation was changed from 4545'-4862' to 4548'-4878'. 3. The following average porosity and permeability information was added for the Eau Claire, respectively: 4.7% and <<0.1 mD. 4. The depth range of the Mt. Simon Upper Zone was changed from 4862'-5268' to 4878-5232'. 5. The average porosity of the Mt. Simon Upper Zone changed from 10.6% to 11%, and its permeability changed from 66 mD to 95 mD.	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
B7	Figure 2 *(continued)*	6. The Mt. Simon Upper Zone was delineated as part of a five-part (Units A-E) delineation of all Mt. Simon zones. An identical stratigraphic column spanning the depths of all Mt. Simon zones is adjacent to the “Updated model” column. The Mt. Simon Upper Zone is Unit E in this column. 7. The depth range of the Mt. Simon Middle Zone was changed from 5268’-5738- to 5232’-5752’. 8. The Mt. Simon Middle Zone is delineated into two units in the second stratigraphic column of the updated model: Unit D, which spans a depth range of 5232’-5450’, has an average porosity of 9%, and an average permeability of 0.7 mD; and Unit C, which spans a depth range of 5450’-5752’, has an average porosity of 8%, and an average permeability of 0.22 mD. 9. The depth range of the Mt. Simon Lower Zone was changed from 5738’-6367’ to 5752’-6368’. 10. The Mt. Simon Lower Zone is delineated into two units in the second stratigraphic column of the updated model: Unit B, which spans a depth range of 5752’-5995’, has an average porosity of 16%, and an average permeability of 21 mD; and Unit A, which spans a depth range of 5995’-6368’, has an average porosity of 19%, and an average permeability of 25 mD (80 mD in perforated interval).	This change reflects the most up-to-date reservoir model information, updated to incorporate the project’s pre-operational logging and testing results.
B7	Figure 2	The following caption was added to Figure 2: “Reproduced layers of the geologic model and average porosity/permeability values, as identified by ADM based on log analysis, along with the approximate screened intervals of CCS #1 and CCS #2. The column on the left was produced during evaluation of the final AoR model prior to pre-injection testing; the right column incorporates the results of geophysical testing in CCS#2 and VW#2 during pre-injection testing. The updated column shows both the three primary rock types and the five rock types indicated by the wireline logs. Horizontal distances are not to scale, and the representation of layer thickness is approximate.”	This change reflects the most up-to-date reservoir model information, updated to incorporate the project’s pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
B7	Permeability – Injection Zone Permeability	The modifying phrase, "For the pre-construction modeling effort," was added to the beginning of the first sentence of this section. The sentence now reads, "For the pre-construction modeling effort, ADM determined intrinsic permeability for areas of the injection zone based on available core analyses and CCS#1 well testing results, and developed a core porosity-permeability transform based on grain size to estimate permeability over intervals without core samples."	Administrative change.
B8	Permeability – Injection Zone Permeability	The following two sentences were added to the end of the first paragraph of this section: "In the updated modeling effort following pre-operational testing and logging, ADM incorporated the logging and core analyses in CCS#2 and VW#2 using the methods described earlier in this plan. The well log data collected during pre-operational testing were simulated with the existing 3D permeability distribution to develop a new geological model."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B8	Permeability – Injection Zone Permeability	The last two sentences of the second paragraph of this section were deleted and replaced. The sentences had read, "ADM also directly calculated permeability for this interval from core samples and well log analyses, with a result of 182 mD. The CCS#1 well log reports an average permeability in the injection zone of 33 mD, though permeability in the perforated interval ranges from 60 mD to 'several hundred' mD (Figure 2)." The sentences now read, "ADM also directly calculated permeability for this interval from core samples and well log analyses, with a result of 80 mD in the perforated interval. Multiple regions in the perforated interval had much higher permeability (above 100mD), as shown in Figure 2."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B8	Permeability – Confining Zone Permeability	The following two sentences were added to the beginning of the first paragraph of this section: "During pre-operational testing, ADM collected 33 horizontal and 3 vertical whole core samples, and 2 rotary sidewall core samples, all from VW#2. These core samples were primarily used to validate and calibrate the ELAN petrophysical model based on well logs."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
B8	Permeability – Confining Zone Permeability	A modifying phrase, “and confirmed by well logs in CCS#2,” was added to the last sentence of the first paragraph in the section. The sentence now reads, “Based on the analysis of log results from CCS#1 and confirmed by well logs in CCS#2, the Eau Claire, extending from the top of the Mt. Simon to -4,545 ft MSL (-5,227 ft KB), is described as having “only a few small intervals of less than a few feet that have any permeability greater than 0.1 mD,” which do not appear to be continuous.”	This change reflects the most up-to-date reservoir model information, updated to incorporate the project’s pre-operational logging and testing results.
B9	Table 2	Table 2 and its caption were replaced. The table previously had the caption, “Operating details for CCS#1 and CCS#2,” and now has the caption, “Operating details for CCS#1 and CCS#2, as used in the model.”	This change reflects the most up-to-date reservoir model information, updated to incorporate the project’s pre-operational logging and testing results.
B10	Fracture Pressure and Fracture Gradient – Injection Zone	Maximum injection pressure values, corresponding elevations, and fracture gradients have been changed in the second paragraph of this section. The maximum injection pressure has changed from 4,500 psi at elevation -6,430 ft MSL to 4,266 psi at -6,630 ft MSL; the corresponding elevation for the maximum injection pressure for the top of the injection interval has changed from -6,020 ft MSL to -5,948 ft MSL; and the fracture gradient on which the maximum injection pressure is based has changed from 0.7 to 0.715.	This change reflects the most up-to-date reservoir model information, updated to incorporate the project’s pre-operational logging and testing results.
B10	Fracture Pressure and Fracture Gradient – Injection Zone	The last sentence of the second paragraph of this section formerly read, “These values are given in Table 3,” and now reads, “These values are given in Table 2 above.”	(The maximum injection pressure information for CCS#1 and CCS#2 in former Table 3 was incorporated into the current Table 2. Table 3, captioned “Maximum injection pressure for CCS#1 and CCS#2,” was deleted.)
B10	Fracture Pressure and Fracture Gradient – Injection Zone	A second paragraph was added to the end of this section. It reads: “It was determined that these values (calculated based on CCS#1 results) accurately represent the system and will continue to be used for the fracture gradient and fracture pressure for CCS#2, until and unless more accurate project-specific data are available. A step-rate test run after the construction of CCS#2 yielded results that do not contradict initial fracture pressure gradient estimates. Injection pressure limits based upon this fracture pressure gradient should not create new fractures or extend any existing fractures. However, additional precautions for initial injection operations and monitoring have been added to Attachment A of this permit.”	This change reflects the start-up procedures and associated monitoring/reporting protocols documented in Attachment A.

Page No.	Section/Topic	Description of Change	Justification
B10	Table 3	Table 3 was removed	Administrative change. (The maximum injection pressure information for CCS#1 and CCS#2 in former Table 3 was incorporated into the current Table 2. Table 3, captioned “Maximum injection pressure for CCS#1 and CCS#2,” was deleted.)
B10	Initial Conditions	The first sentence of this section has been modified. The sentence previously read, “Fluid sampling and testing were conducted in April 2009 at CCS#1, including in-situ measurements of formation pressure and temperature and the collection of eight fluid samples at five depths,” and now reads, “Fluid sampling and testing were conducted in August 2015 in VW#2, including in-situ measurements of formation pressure and temperature and the collection of eight fluid samples at five depths.”	This change reflects the most up-to-date fluid sampling and analysis conducted at the site.
B10	Initial Conditions	The following sentence was added to the first paragraph of this section: “A temperature log was run in CCS#2 in 2015.”	This change reflects the most up-to-date well testing conducted at the site.
B10	Initial Conditions	The initial conditions of the model have been updated. The former initial conditions of the model were as follows: • “Temperature ranged from 119.8°F at -5,772 ft KB to 125.8°F at -6,912 ft KB. • Formation pressure ranged from 2,583 psi at -5,772 ft KB to 3,206 psi at -7,045 ft KB. • Fluid density ranged from 1,090 g/L to 1,137 g/L, with an average of 1,119 g/L (of the five samples taken). TDS ranged from 164,500 ppm at -5,772 ft KB to 228,100 ppm at -7,045 ft KB, with an average of 196,700 ppm. For the initial conditions in the model, aqueous pressure was determined to be 3,205 psi at a reference elevation of -6,345 ft MSL. The initial temperature is 112°F at a reference elevation of -5,365 ft MSL, with a gradient of 1°F/100 ft. Salinity is spatially constant, at 200,000 ppm.”	This change reflects the most up-to-date reservoir model information, updated to incorporate the project’s pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
B10	Initial Conditions *(continued)*	The revised initial conditions of the model are as follows: • "Temperature increased consistently with depth from 60 °F at 50' to 100 °F at 6,950 KB with an average temperature gradient of 0.0058 °F/ft. • Formation pressure was 3,200 psi at 6,980 KB with a pressure gradient of 0.46 psi/ft. The pressure ranged from 2,626 psi at 5,848 KB to 3,211 psi at 7,041 KB. • Fluid density ranged from 1,101 g/L to 1,136 g/L, with an average of 1,124 g/L (of the four samples collected). • TDS ranged from 149,830 ppm at 5,848 KB to 199,950 ppm at 7,041 KB with an average of 184,053 ppm (of the four samples collected). The values presented above from pre-operational testing activities are consistent with the values presented in the initial permit application and pre-construction modeling effort."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B11	Boundary Conditions	The following sentence was added to the end of this section: "No changes were made to the boundary conditions following pre-operational testing."	This change reflects the most up-to-date reservoir model information, updated to incorporate the project's pre-operational logging and testing results.
B15	Computational Modeling Results	The first sentence of this section formerly read, "The map below presents the AoR based on the modeling results," and now reads, "The map below presents the AoR based on the modeling results (the maximum extent of the plume and pressure front), along with wells identified within the AoR."	This edit was made to improve clarity of the attachment.
B15	Figure 7	Figure 7 was replaced with an updated figure showing the updated AoR delineation and the updated inventory of wells in the AoR.	This change reflects the most up-to-date AoR delineation and well inventory information submitted by ADM.
B16	Computational Modeling Results	The following paragraph was added to the end of this section: "The surface area of the AoR is 34.17 square miles. The predicted evolution of the plume and pressure front relative to monitoring locations is shown in the Testing and Monitoring Plan (Attachment C to this permit) and the Post-Injection Site Care (PISC) and Site Closure Plan (Attachment E to this permit)."	This addition was made to improve the clarity of the attachment and reflects the most up-to-date AoR delineation information.

Page No.	Section/Topic	Description of Change	Justification
B16	Corrective Action Plan and Schedule	The first paragraph of this section was replaced. The paragraph formerly read, “An estimated 215 wells are located within the vicinity of the AoR and evaluated and submitted to EPA by ADM in February 2014.” The paragraph now reads, “Based on information from the Illinois State Geological Survey (ISGS) and the Illinois State Water Survey (ISWS) gathered in April 2016, ADM identified a total of 1,065 wells within the AoR. According to Illinois Department of Natural Resources (IDNR) drilling records (and confirmed by ISGS), no additional oil and gas wells were drilled in Macon County between April and September 2016. Except for the wells associated with the IBDP and IL-ICCS projects (as described below), no wells were identified that penetrate the confining zone within the AoR.”	This change reflects the most up-to-date well inventory information submitted by ADM.
B16	Corrective Action Plan and Schedule – Wells within the AoR	An addition was made to the first sentence of this section. The sentence formerly read, “The only existing wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are:” and now reads, “The only existing wells within the AoR which currently penetrate the caprock (Eau Claire Formation) are wells associated with the IBDP and IL-ICCS projects:”	Administrative change.
B16	Corrective Action Plan and Schedule – Wells within the AoR	The first bullet of this section, which names existing rocks penetrating the Eau Claire Formation, has been modified. The bullet formerly read, “The IBDP injection well,” and now reads, “The IBDP injection well, CCS#1 (which is currently permitted as a Class VI well in its post-injection phase and will be used as a monitoring well during the IL-ICCS project).”	Administrative change.
B16	Corrective Action Plan and Schedule – Wells within the AoR	The second bullet of this section, which names existing rocks penetrating the Eau Claire Formation, has been modified. The bullet formerly read, “IBDP verification well,” and now reads, “The IBDP verification well, VW#1 (which will continue to be used as a monitoring well during the IL-ICCS project).”	Administrative change.
B16	Corrective Action Plan and Schedule – Wells within the AoR	The following third bullet of this section, which names existing wells penetrating the Eau Claire Formation, has been added: “The IL-ICCS injection well, CCS#2.	Administrative change.
B16	Corrective Action Plan and Schedule – Wells within the AoR	The fourth bullet has been added: “The IL-ICCS verification well, VW#2.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
B16	Corrective Action Plan and Schedule – Wells within the AoR	The first sentence of the second paragraph in this section was modified. The sentence formerly read, “The latest estimate shows that a total of 215 wells are located within the vicinity of the proposed well,” and now reads, “The latest estimate shows that a total of 1,065 wells are located within the AoR.”	This change reflects the most up-to-date well inventory information submitted by ADM.
B16	Corrective Action Plan and Schedule – Wells within the AoR	The second sentence of the second paragraph in this section formerly read, “Water wells (157 of 215 wells) are the most common well type,” and now reads, “Water wells (725 of 1,065 wells) are the most common well type.”	This change reflects the most up-to-date well inventory information submitted by ADM.
B16	Corrective Action Plan and Schedule – Wells within the AoR	The word “generally” was added to the third sentence of the second paragraph in this section. The sentence now reads, “The domestic water wells generally have depths of less than 60 m (200 ft).”	Administrative change. (This addition was made to improve the clarity of the attachment.)
B16	Corrective Action Plan and Schedule – Wells within the AoR	The fourth sentence of the second paragraph in this section formerly read, “All wells within the 4 townships-area of the injection well site were also identified (total of 3,761 wells),” now reads, “As part of the original permit application, all wells within the 4 townships-area of the injection well site were also identified (total of 3,761 wells at that time).”	Administrative change.
B17	Corrective Action Plan and Schedule – Wells Penetrating the Confining Zone	The heading of this section was changed. The heading formerly read, “Wells Penetrating the Confining Zone [from Section 5.5.2]” and now reads, “Wells Penetrating the Confining Zone.”	Administrative change.
B17	Corrective Action Plan and Schedule – Wells Penetrating the Confining Zone	The last sentence of the first paragraph in this section was modified. The sentence formerly read, “Therefore, there are only three known wells that penetrate the uppermost injection zone.” The sentence now reads, “Therefore, there are only four known wells that penetrate into the uppermost injection zone: the IBDP wells CCS#1 and VW#1, and the IL-ICCS wells CCS#2 and VW#2.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
B17	Corrective Action Plan and Schedule – Wells Penetrating the Confining Zone	The following three bullets and sentence were deleted: • <u>Operating Wells</u>: Three wells penetrating the uppermost injection zone are known to be in use within the AoR. The IBDP wells (CCS#1 and VW#1) began injection operation in November 2011. The IL-ICCS verification well (VW#2) has been drilled and cased but not completed. • <u>Properly Plugged and Abandoned wells</u>: No wells deeper than -762 m KB (-2,500 ft KB) are known to have been plugged and abandoned within the AoR. • <u>Temporarily Abandoned Wells</u>: No wells deeper than -762 m KB (-2,500 ft KB) are known to have been temporarily abandoned within the AoR. No plugging affidavits are provided, as the IBDP wells are currently in use.	This change was made to improve clarity in the attachment by removing duplicative information.
B17	Corrective Action Plan and Schedule – Wells Penetrating the Confining Zone	The first sentence of the second paragraph in this section was modified. The sentence formerly read, "If any of these wells are taken out of service prior to initiating injection, ADM will provide information to EPA to confirm that they have been properly plugged to ensure USDW protection pursuant to requirements at 40 CFR Part 146," The sentence now reads, "If any of these wells are taken out of service during the life of the project, ADM will provide information to EPA to confirm that they have been properly plugged to ensure USDW protection pursuant to requirements at 40 CFR Part 146."	Administrative change.
B17	Corrective Action Plan and Schedule – Wells Penetrating the Confining Zone	The following sentence was added to the end of this section: "If any additional wells that penetrate the confining zone are identified (e.g., if the AoR is re-delineated to cover a larger area as the result of an AoR reevaluation), ADM will complete corrective action as needed pursuant to 40 CFR 146.849(d)."	This addition was made to improve the clarity of the attachment in reflecting the Class VI Rule requirements.
B17	Corrective Action Plan and Schedule – Plan for Site Access	This section formerly read, "Not applicable," and now reads, "This is not applicable because no corrective action is required."	This addition was made to improve the clarity of the attachment.
B17	Corrective Action Plan and Schedule – Justification of Phased Corrective Action	This section formerly read, "Not applicable," and now reads, "This is not applicable because no corrective action is required."	This addition was made to improve the clarity of the attachment.

Page No.	Section/Topic	Description of Change	Justification
B17	Area of Review Reevaluation Plan and Schedule	The following sentence was inserted following the second sentence of the first step in this section: “Monitoring activities to be conducted are described in the Testing and Monitoring Plan (Attachment C to this permit) and the PISC and Closure Plan (Attachment E to this permit).”	This addition was made to improve the clarity of the attachment.
B18	Area of Review Reevaluation Plan and Schedule	The second activity listed under the first step of the monitoring data review was modified. The sentence formerly read, “Also, limited 2D and 3D seismic surveys may be employed to determine the plume location at specific times.” The sentence now reads, “Also, 2D and 3D seismic surveys will be employed to determine the plume location as described in the Testing and Monitoring Plan and/or the PISC and Site Closure Plan (as applicable).”	This addition was made to improve the clarity of the attachment and reflects the most up-to-date content of Attachments C and E.
B19	Area of Review Reevaluation Plan and Schedule – AoR Reevaluation Cycle	The following two sentences were inserted following the first sentence of the second paragraph in this section: “Given anomalous results in the CCS#2 step-rate test, ADM will modify their monitoring and reporting schedule to collect and review data more regularly during the first six months of the injection phase. Specifically, pressure and seismic results will be reviewed on a monthly basis to identify any deviations from expected conditions (see Attachment A of this permit for more detail).”	This language was added to reflect the increased monitoring and reporting planned for the start-up period and the first six months of the injection phase, as documented in Attachment A.
B20	Area of Review Reevaluation Plan and Schedule – Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation	The last sentence of the “Exceeding Fracture Pressure Conditions” monitoring parameter bullet was modified. The sentence formerly read, “The Testing and Monitoring Plan provides discussion of pressure monitoring,” and now reads, “The Testing and Monitoring Plan (Attachment C to this permit) and the operating procedures in Attachment A to this permit provides discussion of pressure monitoring and specific procedures that will be completed during the injection start-up period.”	This language was added to reflect the increased monitoring and reporting planned for the start-up period and the first six months of the injection phase, as documented in Attachment A.
B20	Area of Review Reevaluation Plan and Schedule – Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation	The last sentence of the “Exceeding Established Baseline Hydrochemical/Physical Parameter Patterns” monitoring parameter bullet was modified. The sentence formerly read, “The Testing and Monitoring Plan provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.” The sentence now reads, “The Testing and Monitoring Plan (Attachment C to this permit) provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.”	This edit was made to improve the clarity of the attachment.

Proposed Changes to Attachment C: Testing and Monitoring Plan

Page No.	Section/Topic	Description of Change	Justification
C1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
C1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53’ 08”, -89° 53’19” to 39º 53’ 09.32835”, -88° 53’16. 68306”.	This change was made to reflect the final, as-drilled location of CCS#2.
C1	Facility Information – Quality Assurance Procedures	This section formerly read, “A quality assurance and surveillance plan (QASP) for all testing and monitoring activities pursuant to 146.90(k) is provided in Appendix A to this Testing and Monitoring Plan,” now reads, “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.”	Administrative change.
C3	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure	The last sentence of the second paragraph of this section was modified to include the acronym for distributed temperature sensing (DTS). The sentence now reads, “In addition there will be distributed temperature sensing (DTS) fibers in the injection well.”	Administrative change.
C3	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure	The second sentence of the third paragraph in this section was modified. The sentence formerly read, “Downhole gauges, in lieu of removing the injection tubing, 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,” and now reads, “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.”	Administrative change.
C3	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure	The following sentence was added to the end of the third paragraph of this section: “DTS sampling rate will be once per 10 seconds.”	This addition was made to improve the clarity of the attachment by including additional detail.
C3	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure	The first sentence of the fourth paragraph of this section was modified. The sentence formerly read, “Flow will be monitored with a coriolis mass flowmeter at the wellhead,” and now reads, “Flow will be monitored with a Coriolis mass flowmeter at the compression facility.”	This change reflects changes that have occurred at the ADM surface facility.

Page No.	Section/Topic	Description of Change	Justification
C4	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Injection Rate and Pressure Monitoring	The last sentence of this section was modified. The sentence formerly read, "ADM supervisors and operators will have the capability to monitor the status of the entire system site in two locations: the compression control room (near the main compressors), and the main Alcohol Department control room." The sentence now reads, "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 CO_2 collection and blower facility), and the phase 2 main compression control room."	This change reflects changes that have occurred at the ADM surface facility.
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The third procedure in this section was modified to change the set level of the injection tubing packer from 6,320 to 6,312 ft KB. The sentence now reads, "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."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The third full paragraph of this section formerly read, "Figure 1 shows an example of the injection well annulus protection system. The final design configuration of the annular monitoring system may differ from the example. The final design of the annular pressure system will be submitted to UIC Program Director with the construction completion report." The paragraph now reads, "Figure 1 shows the process instrument diagram for the injection well annulus protection system."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The first sentence of the fourth full paragraph in this section formerly read, "The annular monitoring system will consist of a continuous annular pressure gauge, a brine water storage reservoir, a low-volume/high-pressure pump, a control box, fluid volume measurement device, fluid, and electrical connections." The sentence now reads, "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."	This change reflects the most up-to-date information about the CCS#2 monitoring equipment.

Page No.	Section/Topic	Description of Change	Justification
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The second part of the fourth full paragraph in this section formerly read, "The control box will receive pressure data from an annular pressure gauge and will be programmed to operate the pump as needed to maintain approximately 400 psi (or greater) on the annulus. A means to monitor the volume of fluid pumped into the annulus will be incorporated into the system by use of a tank fluid level gauge, flow meter, pump stroke counter or other appropriate devices." This section has been replaced with one sentence, which reads, "The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen or CO_2."	This change reflects the most up-to-date information about the CCS#2 monitoring equipment.
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The first sentence of the fifth full paragraph in this section formerly read, "Pressure will be monitored by the ADM control system gauges," and now reads "The annulus pressure will be maintained between approximately 425-525 psi and monitored by the ADM control system gauges."	This addition was made to improve the clarity of the attachment by including additional detail.
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The second sentence of the fifth full paragraph in this section formerly read, "The pump will be controlled by two pressure switches—one for low pressure to engage the pump and the other for high pressure to shut the pump down." The sentence now reads, "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 CO_2 and the other to relieve pressure above 525 psi by venting gas off the annulus head tank."	This change reflects the most up-to-date information about the CCS#2 monitoring equipment.
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The following sentence was deleted from the end of the fifth full paragraph in this section: "Anticipated range on the switches would be 400 psi or higher for the low pressure set point and 500 psi or higher for the high pressure set point."	This change reflects the most up-to-date information about the CCS#2 monitoring equipment.

Page No.	Section/Topic	Description of Change	Justification
C5	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The following four sentences were deleted from the beginning of the sixth full paragraph in this section: "Annulus pressure will be monitored at the ADM data control system. A brine storage tank will be connected to the suction inlet of the pump. A hydrostatic tank level gauge will be installed in the brine storage tank with data fed into the ADM monitoring system. The brine in the storage tank will be similar to the brine in the annulus."	This change reflects the most up-to-date information about the CCS#2 monitoring equipment.
C6	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The first sentence of the seventh full paragraph in this section formerly read, "Average annular pressure and fluid volume changes will be recorded daily," and now reads, "Average annular pressure and annulus tank fluid level will be recorded daily."	This edit was made to improve the clarity of the attachment.
C6	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Continuous Monitoring of Annular Pressure	The following sentence was added to the end of the seventh full paragraph in this section: "The volume of fluid added or removed from the system will be recorded."	This addition was made to improve the clarity of the attachment by including additional detail.
C6	Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure – Casing-Tubing Pressure Monitoring	The second sentence of the second paragraph in this section was modified to change the range of surface pressure of the casing-tubing annulus from 400-700 psi to 425-525 psi. The sentence now reads, "Surface pressure of the casing-tubing annulus is anticipated to be from 425 to 525 psi."	This change reflects the most up-to-date information about the CCS#2 monitoring equipment.
C7	Table 5	Note 4, a footnote attached to the "Minimum sampling frequency: once every" column header, was added to the table. The note reads, "DTS sampling frequency is once every 10 seconds and recorded on an hourly basis."	This addition was made to improve the clarity of the attachment by including additional detail.
C7	Corrosion Monitoring – Sample Description	The last sentence of the first paragraph in this section was modified. The sentence formerly read, "Each coupon will be weighed, measured, and photographed prior to initial exposure (see "Sample Monitoring" section for measurement data)." The sentence now reads, "Each coupon will be weighed, measured, and photographed prior to initial exposure (see "Sample Handling and Monitoring" below)."	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
C9	Groundwater Quality Monitoring	The third bulleted zone of focus in the groundwater monitoring plan was modified. The bullet formerly read, "The Ironton-Galesville Sandstone—the zone above the confining Eau Claire cap rock," and now reads, "The Ironton-Galesville Sandstone – the zone above the Eau Claire confining zone."	This edit was made to improve the clarity of the attachment.
C9	Figure 3	The caption of Figure 3 has been modified. The caption formerly read, "Location of existing shallow groundwater monitoring wells and planned deep wells," and now reads, "Location of shallow groundwater monitoring wells and deep monitoring wells."	This change reflects the most up-to-date information since construction of the CCS#2 well was completed.
C10	Table 7	The spatial coverage for the CCS#2 DTS monitoring in the Quaternary and/or Pennsylvanian strata has changed from "1 point location, distributed measurement to 6325 KB/5631 MSL" to "1 point location, distributed measurement to 6211 KB/5520 MSL."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.
C10	Table 7	The spatial coverage for the GM#2 fluid sampling in the St. Peter formation has changed from "1 point location, 1 interval: 3300 KB/2606 MSL" to "1 point location, 1 interval: 3450 KB/2759 MSL."	This change reflects the most up-to-date well information since construction of the GM#2 well was completed.
C10	Table 7	The spatial coverage for the GM#2 pressure/temperature monitoring in the St. Peter formation has changed from "1 point location, 1 interval: 3450 KB/2756 MSL" to "1 point location, 1 interval: 3450 KB/2759 MSL."	This change reflects the most up-to-date well information since construction of the GM#2 well was completed.
C10	Table 7	The spatial coverage for the CCS#2 DTS monitoring in the St. Peter formation has changed from "1 point location, distributed measurement to 6325 KB/5631 MSL" to "1 point location, distributed measurement to 6211 KB/5520 MSL."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.
C10	Table 7	The spatial coverage for the VW#2 fluid sampling in the Ironton-Galesville formation has changed from "1 point location, 1 interval: 5000 KB/4918 MSL" to "1 point location, 1 interval: 5010 KB/4307 MSL."	This change reflects the most up-to-date well information since construction of the VW#2 well was completed.
C10	Table 7	The spatial coverage for the CCS#2 DTS monitoring in the Ironton-Galesville formation has changed from "1 point location, distributed measurement to 6325 KB/5631 MSL" to "1 point location, distributed measurement to 6211 KB/5520 MSL."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.

Page No.	Section/Topic	Description of Change	Justification
C11	Table 8	The monitoring activity "RST" was defined as "Reservoir Saturation Tool (RST) logs" in the first row in which it appears in Table 8. That data cell now reads, "Pulse Neutron Logging/ Reservoir Saturation Tool (RST) logs."	Administrative change.
C13	Table 9	Former Note 1, which reads, "An equivalent method may be employed with the prior approval of the Director," was incorporated into the end of the current Note 1, which includes the former Table 9 footnote.	Administrative change.
C13	External Mechanical Integrity Tests (MITs)	The title of this section was changed from "External Mechanical Integrity Testing" to "External Mechanical Integrity Tests."	Administrative change.
C17	Pressure Fall-Off Testing – Pressure Fall-off Test Procedure	The third sentence of this section was modified to change the normal injection rate from 3,000 MT/day to 2,750 MT/day. The sentence now reads, "The normal injection rate is estimated to be 2,750 MT/day (the last 3 years of the planned 5-year injection period)."	This change reflects an update to ADM's planned injection parameters.
C18	Table 11	The spatial coverage for the VW#2 fluid sampling for the Mt. Simon formation has changed from "1 point location, 3 intervals: 6800, 6300, 5800 KB; 6106, 5606, 5106 MSL" to "1 point location, 3 intervals: 6710, 6500, 5810 KB; 6007, 5797, 5107 MSL"	This change reflects the most up-to-date well information since construction of the VW#2 well was completed.
C19	Table 11	The frequency of the full coverage 3D surface seismic survey monitoring for the Mt. Simon formation changed from "Baseline, Year 2 (2018)" to "Baseline, Year 2 (2019)."	This edit was made to capture the anticipated numerical year of Year 2 of the CCS#2 operational phase.
C19	Table 12	The spatial coverage for the VW#2 pressure/temperature monitoring in the Mt. Simon formation has changed from "1 point location, 4 intervals: 7000, 6800, 6300, 5800 KB; 6306, 6106, 5606, 5106 MSL" to "1 point location, 4 intervals: 7041, 6681, 6524, 5848 KB; 6338, 5978, 5821, 5145 MSL."	This change reflects the most up-to-date well information since construction of the VW#2 well was completed.
C19	Table 12	The spatial coverage for the CCS#2 pressure/temperature monitoring in the Mt. Simon formation has changed from "1 point location, 1 interval: PT @ 6325 KB/5631 MSL; Perfs @ 6718 - 6881 KB, 6024 - 6187 MSL" to "1 point location, 1 interval: PT @ 6270 KB/5579 MSL; Perfs @ 6630 - 6825 KB, 5939 - 6134 MSL."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.
C19	Table 12	The spatial coverage for the CCS#2 DTS monitoring in the Mt. Simon formation has changed from "1 point location, distributed measurement to 6325 KB/5631 MSL" to "1 point location, distributed measurement to 6211 KB/5520 MSL."	This change reflects the most up-to-date well information since construction of the CCS#2 well was completed.

Page No.	Section/Topic	Description of Change	Justification
C20	Table 13	Former Note 1, which reads, “An equivalent method may be employed with the prior approval of the Director,” was incorporated into the end of the current Note 1, which includes the former Table 13 footnote.	Administrative change.
C20	Carbon Dioxide Plume and Pressure Front Tracking	The following paragraph was added following Table 13 on page C20: “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 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.”	Model predictions were included in the attachment to facilitate comparison with testing and monitoring results.
C21	Figure 4	Figure 4 was added.	These changes reflects the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C21	Figure 4	The following caption was added to Figure 4: “Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the commencement of injection for CCS #2.”	This caption reflects the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results.
C22	Figure 5	Figure 5 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C22	Figure 5	The following caption was added to Figure 5: “Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 1 year of injection at CCS #2.”	This caption reflects the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
C23	Figure 6	Figure 6 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C23	Figure 6	The following caption was added to Figure 6: “Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 2 years of injection at CCS #2.”	This caption reflects the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results.
C24	Figure 7	Figure 7 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C24	Figure 7	The following caption was added to Figure 7: “Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 3 years of injection at CCS #2.”	This caption reflects the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results.
C25	Figure 8	Figure 8 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C25	Figure 8	The following caption was added to Figure 8: “Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 4 years of injection at CCS #2.”	This caption reflects the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
C26	Figure 9	Figure 9 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C26	Figure 9	The following caption was added to Figure 9: "Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, after 5 years of injection at CCS #2."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.
C27	Figure 10	Figure 10 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C27	Figure 10	The following caption was added to Figure 10: "Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.
C27	Figure 11	Figure 11 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C27	Figure 11	The following caption was added to Figure 11: "Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
C28	Figure 12	Figure 12 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
C28	Figure 12	The following caption was added to Figure 12: "Predicted CO_2 phase distribution, simulated for 50 years after the commencement of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.

Proposed Changes to Attachment D: Injection Well Plugging Plan

Page No.	Section/Topic	Description of Change	Justification
D1	Introduction	A two-sentence introduction, which read, "The Permittee will submit a final injection well plugging plan using the as-built well construction schematics. This will be submitted with the injection well completion report," was deleted.	Administrative change.
D1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
D1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53' 08", -89° 53'19" to 39º 53' 09.32835", -88° 53'16. 68306".	This change was made to reflect the final, as-drilled location of CCS#2.
D1	Facility Information	The sentence that formerly read, "Injection well plugging and abandonment will be conducted according to the procedures below, which are based on information submitted by ADM in November 2013," now reads "Injection well plugging and abandonment will be conducted according to the procedures below, which are based on information submitted by ADM in May of 2016."	Administrative change.
D1	Facility Information	The sentence that formerly read, "If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with the plugging operations," now reads, "If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding with the plugging operations."	Administrative change.
D2	Information on Plugs	The first sentence of this section that read, "The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction," was deleted.	This sentence served as a placeholder for the plugs' volume and depth data that were subject to change prior to construction. Because construction has been completed, the data were updated and the placeholder was deleted.
D2	Information on Plugs – Plug #1	The "Depth to Bottom of Tubing or Drill Pipe (ft)" data for Plug #1 was changed from 7000 to 7100.	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.
D2	Information on Plugs – Plug #1	The "Sacks of Cement to be Used (each plug)" data for Plug #1 was changed from 1333 to 1378.	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.

Page No.	Section/Topic	Description of Change	Justification
D2	Information on Plugs – Plug #1	The “Slurry Volume to be Pumped (cu. ft)” data for Plug #1 was changed from 1480 to 1530.	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.
D2	Information on Plugs – Plug #1	The “Bottom of Plug (ft)” data was changed from 7000 to 7100.	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.
D4	Narrative Description of Plugging Procedures – Notifications, Permits, and Inspections	The Plug #1 data was changed in item #11, which describes the depth parameters of the plugging plan. The first two sentences that formerly read, “The lower section of the well will be plugged using CO_2 resistant cement from TD around 7000ft to around 1000ft above the top of the Eau Claire formation (to approximately 4000 ft). This will be accomplished by placing plugs in 500 ft incremental lifts. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 1333 sacks of cement will be required,” have been modified and now reads, “The lower section of the well will be plugged using CO_2 resistant cement from TD around 7100ft to around 1000ft above the top of the Eau Claire formation (to approximately 4000 ft). This will be accomplished by placing plugs in 500 ft incremental lifts. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 1378 sacks of cement will be required.” The last sentence of item #11 that formerly read, “(Calculations: Assume 47 lb/ft casing for this interval 3000ft x .4110 cu ft/ft x 1.20/ 1.11 cu ft/sk = 1333 sacks,)” now reads, “(Calculations: Assume 47 lb/ft casing for this interval 3100ft x .4110 cu ft/ft x 1.20/ 1.11 cu ft/sk = 1378 sacks.)”	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.
D5	Narrative Description of Plugging Procedures – Figure 1	Figure 1 was revised in the following ways: 1. The column labeled, “FORMATION TOPS MD” formerly listed formations as follows, in order of increasing depth: RKB, Limestone, Logan Shale, Renault Ls, St. Louis Ls/Anhyd, Borden Ss, Burlington Ls, New Albany Sh, Silurian Ls, Maquoketa Sh, Galena Ls, Platteville Ls, St. Peter Ss, Shakopee Dol, Oneota Dol, Gunter Ss, Eminence Dol, Potosi Dol, Ironton Ss, Eau Claire, Eau Claire Ls, Eau Claire Sh, Upper Mt. Simon Ss, Lower Mt. Simon Ss, Precambrian. The formations were updated, and are now listed as follows: RKB, Limestone, Renault Ls, St. Louis Ls/Anhyd,	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.

Page No.	Section/Topic	Description of Change	Justification
D5	Narrative Description of Plugging Procedures – Figure 1 *(continued)*	Burlington Ls, New Albany Sh, Silurian Ls, Maquoketa Sh, Galena Ls, Platteville Ls, St. Peter Ss, Shakopee Dol, Oneota Dol, Gunter Ss, Eminence Dol, Potosi Dol, Ironton Ss, Eau Claire,M. Simon E, M. Simon D, M. Simon C, M. Simon B, M. Simon A, Argenta, Precambrian. 2. The hole size from the surface to the depth of the surface casing has changed from 24 inches to 26 inches; 3. The surface casing label that read, "Surface casing 20 94# J55" was removed; 4. A duplicate lift, Lift 13 (Class A/H), was removed; 5. A note adjacent to Lift 9 that read, "Well filled with cement in 500 foot lifts using balanced plug method," was removed; 6. A labeled arrow that read, "Bottom of plug #2 = 4,000 ft" adjacent to the interface of Lifts 6 and 7 was removed; 7. A label that read, "13-3/8 csg Stage tool at ~3850'" adjacent to Lift 7 was removed; 8. A label that reads, "Top of EverCRETE Plug ~4000 ft" was added adjacent to the interface of Lifts 6 and 7; 9. A label that read, "Intermediate Csg 13-3/8" 54.5# J55 from __ to 13-3/8" 61# J55 from __ to 5350' Two stage cement job planned" adjacent to the interface between Lifts 3 and 4 was removed; 10. A labeled arrow that read, "Bottom of plug #1 = 7,000 ft" adjacent to the bottom of Lift 1 was removed; 11. A label that read, "Injection Zone (approx) adjacent to Lift 1 was removed. 12. A label that read, "Long String Casing 9-5/8" 40# N80 Surf to 5250' 9-5/8" 47# 13CRL80 5250 to 7200'" adjacent to the bottom of Lift 1 was removed; 13. A label that reads, "Btm of EverCRETE Plug ~7100 ft" adjacent to the bottom of Lift 1 was added; 14. A label that read, "Perforations ~6700' to 6800'" adjacent to the top of Lift 1 was replaced with a label that reads, "Injection Zone Perforations: 6630'-6670' 6680'-6725' 6735'-6775' 6787'-6825' adjacent to the interface between Lifts 1 and 2. 15. A label that reads, "80 ft cement at bottom of casing" adjacent to the bottom of Lift 1 was added;	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.

Page No.	Section/Topic	Description of Change	Justification
D5	Narrative Description of Plugging Procedures – Figure 1 *(continued)*	16. Two sentences were removed from the note at the bottom of the figure. The note formerly read, “Plugs to be set usin [sic] balanced plug method in 500 feet lifts. All casings to be cemented to surface. CO2 resistant Evercrete to be used for tall cement on long string job,” was revised and now reads, “All casings to be cemented to surface.” 17. From Figure 1 Title, “Perforation zone(s) are estimated.” was deleted.	This change reflects the most up-to-date plugging information, based on the as-built construction of CCS#2.

Proposed Changes to Attachment E: PISC and Site Closure Plan

Page No.	Section/Topic	Description of Change	Justification
E1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
E1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53’ 08”, -89° 53’19” to 39º 53’ 09.32835”, -88° 53’16. 68306”.	This change was made to reflect the final, as-drilled location of CCS#2.
E1	Facility Information	A sentence in this paragraph was modified to change the phrase “UIC Program Director” to “Director.”	Administrative change.
E1	Predicted Position of the CO2 Plume and Associated Pressure Front at Site Closure	The second sentence in this section that read, “This map is based on the final AoR delineation modeling results submitted in January 2014, per 40 CFR 146.84,” now reads, “This map is based on the final AoR delineation modeling results submitted in May 2016, per 40 CFR 146.84.”	Administrative change.
E2	Figure 1	Figure 1 was replaced and its caption was modified. The previous caption read, “Predicted Extent of the CO_2 plume and pressure front at site closure,” and the current caption reads, “Predicted extent of the CO_2 plume 10 years after the cessation of injection (Est Yr 2031). Pressure front (DPif = 62.2 psi) not shown because pressure is expected to decrease below that level at site closure.”	These changes reflect the most up-to-date AoR model information, updated to incorporate the project’s pre-operational logging and testing results.
E3	Table 1	Note 2 was revised to change the phrase “UIC Program Director” to “Director.”	Administrative change.
E4	Table 2	Note 1 was revised to change the phrase “UIC Program Director” to “Director.”	Administrative change.
E4	Table 3	The Table 3 caption was modified. The caption previously read, “Indirect Summary of analytical and field parameters for groundwater samples,” and now reads, “Summary of Analytical and Field Parameters for Groundwater Samples.”	Administrative change. (This change was made to correct an error in the previous version of the plan.)
E5	Table 3	Note 1 was modified. The second sentence of the note formerly read, “An equivalent method may be employed with prior approval of the UIC Program Director,” and now reads, “An equivalent method may be employed with prior approval of the Director.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
E6	Figure 2	The caption of Figure 2 was modified. The caption formerly read, “Location of existing shallow groundwater monitoring wells and planned deep wells,” and now reads, “Location of shallow groundwater monitoring wells and deep monitoring wells.”	This change reflects the most up-to-date information since construction of the CCS#2 well and associated monitoring wells was completed.
E7	Groundwater Quality Monitoring	The following paragraph was added prior to Table 4: Collection and recording of continuous monitoring data will occur at the frequencies described in Table 4.	Administrative change.
E7	Table 4	The content of the previous Table 4 “Note” was changed to the current Table 4 “Note 1” footnote attached to the second column header, “Minimum sampling frequency: once every.”	Administrative change.
E7	Table 4	The Table 4 “Note 2” was added. The footnote is attached to the third column header, “Minimum recording frequency: once every.” Note 2 reads, “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.”	Administrative change.
E7	Table 4	The former Table 4 “1” footnote is now “Note 3.” This footnote is still attached to the “5 minutes” data cell, the minimum recording frequency for continuous monitoring of the injection well.	Administrative change.
E7	Table 4	The Table 4 “Note 4” was added. The footnote is attached to the second and third column header, “Minimum recording frequency: once every.” Note 4 reads, “DTS sampling frequency is once every 10 seconds and recorded on an hourly basis.”	This addition was made to improve the clarity of the attachment by including additional detail.
E7 – E8	Table 5	Notes 1 and 2 were revised to change the phrase “UIC Program Director” to “Director.”	Administrative change.
E8	Table 6	Former Note 1, which reads, “An equivalent method may be employed with the prior approval of the Director,” was revised to change the phrase “UIC Program Director” to “Director.” The note was also incorporated into the end of the current Note 1, which includes the former Table 6 footnote.	Administrative change.
E9	Table 7	Note 2 was revised to change the phrase “UIC Program Director” to “Director.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
E9	Carbon Dioxide Plume and Pressure Front Tracking	The following paragraph was added following Table 7: "Monitoring locations relative to the predicted location of the CO_2 plume and pressure front at 5-year intervals throughout the post-injection phase are shown in Figure 3 through Figure 5. Predicted pressure profiles at the top of the injection interval and bottom-hole pressure at CCS#2 for 50 years after the commencement of injection are shown in Figure 6 and Figure 7. The predicted amount of CO_2 in the mobile gas, trapped gas, and dissolved (aqueous) phases for 50 years after the commencement of injection is shown in Figure 8."	Model predictions were added to this attachment to facilitate comparison with testing and monitoring results.
E10	Figure 3	Figure 3 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
E10	Figure 3	The following caption was added to Figure 3: "Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the beginning of the post-injection phase."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.
E11	Figure 4	Figure 4 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
E11	Figure 4	The following caption was added to Figure 4: "Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the end of 5 years after the cessation of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.

Page No.	Section/Topic	Description of Change	Justification
E12	Figure 5	Figure 5 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
E12	Figure 5	The following caption was added to Figure 5: "Predicted extent of the CO_2 plume and pressure front (DPif = 62.2 psi) relative to monitoring locations, at the end of 10 years after the cessation of injection (predicted time of site closure)."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.
E13	Figure 6	Figure 6 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
E13	Figure 6	The following caption was added to Figure 6: "Predicted pressure profile at the top of the CCS#2 injection interval, simulated for 50 years after the commencement of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.
E13	Figure 7	Figure 7 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
E13	Figure 7	The following caption was added to Figure 7: "Figure 7. Predicted CCS#2 bottom-hole pressure profile, simulated for 50 years after the commencement of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.

Page No.	Section/Topic	Description of Change	Justification
E14	Figure 8	Figure 8 was added.	These changes reflect the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results. The model predictions were included to facilitate comparison with testing and monitoring results.
E14	Figure 8	The following caption was added to Figure 8: "Predicted CO_2 phase distribution, simulated for 50 years after the commencement of injection."	This caption reflects the most up-to-date AoR model information, updated to incorporate the project's pre-operational logging and testing results.
E14	Schedule for Submitting Post-Injection Monitoring Results	The first paragraph of this section was revised to change the phrase "UIC Program Director" to "Director."	Administrative change.
E15	Non-Endangerment Demonstration Criteria	The first sentence of this section was revised. The previous sentence read, "Prior to approval of the end of the PISC period, the operator will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) or (3)," and the current sentence reads, "Prior to authorization of site closure, ADM will submit a demonstration of non-endangerment of USDWs to the Director, per 40 CFR 146.93(b)(2) or (3). "	This edit was made to improve clarity of the attachment.
E15	Non-Endangerment Demonstration Criteria	The first sentence of the second paragraph of this section was revised. The previous sentence read, "The operator will issue a report to the UIC Program Director," and the current sentence reads, "To make the non-endangerment demonstration, ADM will issue a report to the Director."	This edit was made to improve clarity of the attachment.
E15	Non-Endangerment Demonstration Criteria	The word "evaluation" was removed from the third sentence of the second paragraph in this section. The previous sentence read, "The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment." The revised sentence now reads, "The report will detail how the non-endangerment demonstration uses site-specific conditions to confirm and demonstrate non-endangerment."	This edit was made to improve clarity of the attachment.

Page No.	Section/Topic	Description of Change	Justification
E15	Non-Endangerment Demonstration Criteria	The parenthetical "(or appropriately reference)" was added to the fourth sentence of the second paragraph in this section. Additionally, this sentence was revised to change the phrase "UIC Program Director" to "Director." The previous sentence read, "The report will include: all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis." The current sentence now reads, "The report will include (or appropriately reference): all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Director to review the analysis."	This edit was made to improve clarity of the attachment and to reflect the most up-to-date EPA guidance on Class VI reporting.
E15	Non-Endangerment Demonstration Criteria	The final fragmented sentence of the second paragraph in this section, which introduces subsequent sections and ends with a colon, was revised to change the word "sections" to "components." The previous fragment read, "The report will include the following sections:" and the current fragment reads, "The report will include the following components:"	Administrative change.
E15	Non-Endangerment Demonstration Criteria – Summary of Existing Monitoring Data	The second sentence of this section was revised to change the phrase "UIC Program Director" to "Director."	Administrative change.
E15	Non-Endangerment Demonstration Criteria – Comparison of Monitoring Data and Model Predictions and Model Documentation	The second sentence of this section was revised. The previous sentence read, "The data will include time-lapse temperature, pressure, ground water analysis, passive seismic, and geophysical surveys (i.e. logging, operating-phase VSP, and 3D surface seismic surveys) used to update the computational model and to monitor the site." The revised sentence reads, "The data will include the results of time-lapse temperature and pressure monitoring, groundwater quality analysis, passive seismic monitoring, and geophysical surveys (i.e. logging, operating-phase VSP, and 3D surface seismic surveys) used to update the computational model and to monitor the site."	This edit was made to improve clarity of the attachment.

Page No.	Section/Topic	Description of Change	Justification
E16	Non-Endangerment Demonstration Criteria – Evaluation of Carbon Dioxide Plume	The word “potentially” was removed from the first sentence of the paragraph. The sentence previously read, “The operator will use a combination of time-lapse RST logs, time-lapse VSP surveys, and potentially other seismic methods (2D or 3D surveys) to locate and track the extent of the CO2 plume.” and now reads “The operator will use a combination of time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (2D or 3D surveys) to locate and track the extent of the CO2 plume.”	This change reflects the most up-to-date monitoring program for CCS#2.
E16	Non-Endangerment Demonstration Criteria – Evaluation of Carbon Dioxide Plume	The sixth sentence of this section that previously read, “Also, limited 2D and 3D seismic surveys may be employed to determine the plume location at specific times,” now reads, “Also, limited 2D and 3D seismic surveys will be employed to determine the plume location at specific times.”	This change clarifies the planned use of 2D and 3D seismic surveys during the CCS#2 PISC period.
E18	Non-Endangerment Demonstration Criteria – Evaluation of Carbon Dioxide Plume	The second sentence of the second paragraph in this section was modified to change the word “site” to “interval.” The previous sentence read, “The storage site (Mt. Simon) is considered to be an open reservoir system with a regional dip oriented NW (up-dip) to SE (down-dip) and having excellent porosity (20%) and permeability (120 mD),” and the sentence now reads, “The storage interval (Mt. Simon) is considered to be an open reservoir system with a regional dip oriented NW (up-dip) to SE (down-dip) and having excellent porosity (20%) and permeability (120 mD).”	This edit was made to improve clarity of the attachment.
E20	Figure 13	Figure 13, formerly Figure 7, was replaced with an updated figure that parenthetically captures the numerical years associated with years into the PISC phase. “Year 0” was changed to “Year 0 (2016),” “Year 5” was changed to “Year 5 (2021),” “Year 10” was changed to “Year 10 (2026),” and “Year 15” was changed to “Year 15 (2031).”	Administrative change.
E20	Figure 13	The caption of Figure 13 was modified to change the end of Year 10 in the PISC period from 2030 to 2031. The caption now reads, “Illustration of Verification Well #2 comparison of actual dP versus the predicted monitoring interval dP during PISC period through year 2031.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
E21	Evaluation of Reservoir Pressure	The second sentence of the third paragraph in this section was revised. The previous sentence read, “Figure 8 shows the differential reservoir pressure predicted for three years after injection ceases, relative to original static reservoir pressure.” The new sentence now reads, “Figure 14 shows an illustrative example of differential reservoir pressure predicted for three years after injection ceases, relative to original static reservoir pressure.”	This edit was made to improve clarity of the attachment.
E21	Figure 14	The caption of Figure 14 was modified. The caption previously read, “Direct pressure measurements at CCS#1, CCS#2, & VW#2 will support the 10 psi differential pressure contour as predicted by the flow model (inside red circle), shown at January 1, 2023,” and now reads, “Example of how direct pressure measurements at CCS#1, CCS#2, & VW#2 will support the 10 psi differential pressure contour as predicted by the flow model (inside red circle), shown at April 1, 2024.”	This edit was made to improve clarity of the attachment.
E22	Non-Endangerment Demonstration Criteria – Evaluation of Potential Conduits for Fluid Movement	The first sentence of this section was modified. The sentence previously read, “As shown in the alternative PISC timeframe demonstration, other than the project wells, there are no potential conduits for fluid movement or leakage pathways within the AoR,” and now reads, “Other than the project wells, there are no identified potential conduits for fluid movement or leakage pathways within the AoR.”	This edit was made to improve clarity of the attachment.
E22	Non-Endangerment Demonstration Criteria – Evaluation of Potential Conduits for Fluid Movement	The second sentence of this section was modified. The sentence previously read, “As shown in Figure 9, the closest penetration of the seal formation is approximately 17 miles from the injection well,” and now reads, “As shown in Figure 15, the closest penetration of the confining zone is approximately 17 miles from the injection well.”	This edit was made to improve clarity of the attachment.
E23	Site Closure Plan	The third sentence of this section was modified to change “EPA” to “the Director.” The sentence previously read, “Once the permitting agency has approved closure of the site, ADM will plug the verification well(s) and geophysical well(s); restore the site and move out all equipment; and submit a site closure report to EPA,” and now reads, “Once the permitting agency has approved closure of the site, ADM will plug the verification well(s) and geophysical well(s); restore the site and move out all equipment; and submit a site closure report to the Director.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
E24	Site Closure Plan – Type and Quantity of Plugging Materials, Depth Intervals	The following sentence was deleted from the beginning of this section: “The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction.”	This change reflects the most up-to-date plugging information since construction of the VW#2 well was completed.
E25	Site Closure Plan – Plugging and Abandonment Procedure	The first sentence of the 10th item in the procedure was modified. The sentence formerly read, “The lower section of the well will be plugged using CO_2 resistant cement from TD around 7000ft to around 1000ft above the top of the Eau Claire formation (to approximately 4000 ft).” The sentence now reads, “The lower section of the well will be plugged using CO_2 resistant cement from TD around 7150ft to around 800ft above the top of the Eau Claire formation (to approximately 4200 ft).”	These changes reflect the most up-to-date plugging information according to the as-built VW#2 construction dimensions.
E25	Site Closure Plan – Plugging and Abandonment Procedure	The first sentence of the 15th item in the procedure was modified. The sentence formerly read, “Finish filling well with cement from the surface if needed. Total of approximately 442 sacks total cement used in all remaining plugs above 4000 feet (4000 ft X .1305 cu ft/ft / 1.18 cu ft/sk = 442 sks).” The sentence now reads, “Finish filling well with cement from the surface if needed. Total of approximately 464 sacks total cement used in all remaining plugs above 4200 feet (4200 ft X .1305 cu ft/ft / 1.18 cu ft/sk = 464 sks).”	These changes reflect the most up-to-date plugging information according to the as-built VW#2 construction dimensions.
E26	Site Closure Plan – Plugging and Abandonment Procedure	The final two parenthetical sentences of the final paragraph on page E26 were deleted. The previous paragraph read, “See the figure below for a plugging schematic. (Perforation zone(s) are estimated. Well plugging plan will be updated and submitted with the well completion report.)” The current paragraph reads, “See Figure 17 below for a plugging schematic.”	This change reflects the most up-to-date plugging information since construction of the VW#2 well was completed.

Proposed Changes to Attachment F: Emergency and Remedial Response Plan

Page No.	Section/Topic	Description of Change	Justification
F1	Introduction	The second sentence of the introductory section previously read "As steps to prevent unexpected carbon dioxide (CO2) movement have already been undertaken in accordance with risk analysis, this plan is about actions to be taken, and to be prepared to take, if unexpected movement or any other emergency events occur" and now reads "As steps to prevent unexpected carbon dioxide (CO2) movement have already been undertaken in accordance with risk analysis, this plan is about actions to be taken, and to be prepared to take, if unexpected fluid movement or any other emergency events occur."	Administrative change.
F1	Injection Well Location	The coordinates of the CCS#2 injection well location changed from 39º 53' 08", -89° 53'19" to 39º 53' 09.32835", -88° 53'16. 68306".	This change was made to reflect the final, as-drilled location of CCS#2.
F1	ERRP Overview	The second full paragraph of the first page previously read, "This emergency and remedial response plan (ERRP) describes actions that the owner / operator (ADM) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during construction, operation, or post-injection site care periods," now reads, "This emergency and remedial response plan (ERRP) describes actions that the owner / operator (ADM) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the operation or post-injection site care periods."	Administrative change.
F2	Part 3: Emergency Identification and Response Actions	The second paragraph under Part 3 previously read, "In the event of an emergency requiring outside assistance, the project contact lead shall call the ADM Security Dispatch at (217) 424-4444 and ADM Corporate Communications at (217) 424-5413" and now reads, "In the event of an emergency requiring outside assistance, the lead project contact shall call the ADM Security Dispatch at (217) 424-4444 and ADM Corporate Communications at (217) 424-5413."	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
F5	Potential Brine or CO_2 Leakage to USDW	The bullet point under the "Response Actions" heading of this section formerly read, "If the presence of indicator parameters are confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:" now reads, "If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:".	Administrative change.
F12	Part 4: Response Personnel and Equipment	The phone number of the UIC Program Director (US EPA Region V) has changed from 312-886-6234 to 312-353-7648.	Administrative change.
F15	Figure F-2	The caption for Figure F-2 has been modified. The caption formerly read, "Local area map for the IL-ICCS project. Emergency & remedial response activities will most likely be within the "area of review" highlighted on the map. Source: ISGS and ISWS well databases, current as of May 10, 2011," and now reads, "Local area map for the IL-ICCS project. Emergency & remedial response activities will most likely be within the "area of review" highlighted on the map. Source: ISGS and ISWS well databases, current as of September 1, 2016."	This change reflects the updated AoR delineation and the most up-to-date information on activities/structures in the AoR as submitted by ADM.

Proposed Changes to Attachment G: Construction Details

Page No.	Section/Topic	Description of Change	Justification
G1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
G1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53’ 08”, -89° 53’19” to 39º 53’ 09.32835”, -88° 53’16. 68306”.	This change was made to reflect the final, as-drilled location of CCS#2.
G1	Open hole diameters and intervals – Surface	The depth interval data for the surface casing changed from 0 – 450 ft to 0 – 347 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Open hole diameters and intervals – Intermediate	The depth interval data for the intermediate casing changed from 450 – 5,300 ft to 347 – 5,234 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Open hole diameters and intervals – Long	The depth interval data for the long string casing changed from 5,300 – 7,250 ft to 5,234 – 7,190 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Surface	The depth interval data for the surface casing changed from 0 – 450 ft to 0 – 347 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Surface	The grade (API) for the surface casing changed from H40 to J55.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Surface	The first two sentences of the note for surface casing (Note 1) were modified. The note previously read, “Surface casing will be 450 ft of 20 inch casing. After drilling a 26” hole to 450’ true vertical depth (TVD), 20”, 94 ppf, H40, short thread and coupling (STC) casing will be set and cemented to surface.” The note now reads, “Surface casing is 347 ft of 20 inch casing. After drilling a 26" hole to 347' true vertical depth (TVD), 20", 94 ppf, J55, short thread and coupling (STC) casing was set and cemented to surface.”	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Intermediate	The depth interval for the intermediate casing changed from 0 – 5,300 ft to 0 – 5,234 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Intermediate	The grade (API) for the intermediate casing changed from K55 or J55 to J55.	This change was made to reflect the final, as-drilled construction details for CCS#2.

Page No.	Section/Topic	Description of Change	Justification
G1	Casing specifications – Intermediate	The first three sentences of the note for intermediate casing (Note 2) were modified. The note previously read, “Intermediate casing: 5,300 ft of 13 3/8 inch casing. After a shoe test or formation integrity test (FIT) is performed, a 17 ½” hole will be drilled to approximately 5,300’ TVD. 13-3/8”, 61 ppf, J55, long thread and coupling (LTC) or buttress thread and coupling (BTC) will be cemented to surface.” The note now reads, “Intermediate casing: 5,234 ft of 13 3/8 inch casing. After a shoe test or formation integrity test (FIT) was performed, a 17 1/2" hole was drilled to 5,234' TVD. 13-3/8", 61 ppf, J55, long thread and coupling (LTC) or buttress thread and coupling (BTC) was cemented to surface.”	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Long (carbon)	The depth interval data for the carbon long strong casing changed from 0 – ~5,000 ft to 0 – 4,818 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Long (carbon)	The grade (API) for the carbon long string casing changed from N80 to L80-HC.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Long (chrome)	The depth interval data for the chrome long string casing changed from ~5,000 – ~7250 ft to 4,818 – 7,190 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Long (chrome)	The grade (API) for the chrome long string casing changed from “Chrome alloy” to 13CR80.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G1	Casing specifications – Long (chrome) and (carbon)	The note for both carbon and chrome long string casing (Note 3) was modified. The note previously read, “Long string casing: 0-5,000 ft of 9 5/8 inch, N80 casing; 5,000’ – ~7250’ of 9 5/8 inch, chrome alloy (e.g., 13CrL80). After a shoe test is performed and the integrity of the casing is tested, a 12 ¼” hole will be drilled to approximately 7500’ TVD or through the Mt Simon, where the long string casing will be run and specially cemented. Coupling outside diameter is 10 5/8 inches for N-80 and 10.485 inches for the chrome alloy (e.g., 13Cr80).” The note now reads, “Long string casing: 0-4,818 ft of 9 ⅝ inch, L80-HC casing; 4,818' – 7,190' of 9 ⅝ inch, 13CR80. After a shoe test was performed and the integrity of the casing was tested, a 12 ¼" hole was drilled to 7190' TVD or through the Mt. Simon, where the long string casing was run and specially cemented. Coupling outside diameter is 10 ⅝ inches for L80-HC and 10.485 inches for the 13CR80.”	This change was made to reflect the final, as-drilled construction details for CCS#2.

Page No.	Section/Topic	Description of Change	Justification
G2	Tubing specifications – Injection tubing	Former Note 1 was deleted. The note had read, “The tubing length will be finalized after the location of the perforations are selected and the packer location determined. The final tubing design may change subject to availability and/or pending results of reservoir analysis.”	Administrative change.
G2	Tubing specifications – Injection tubing	The depth interval data for the injection tubing changed from 0 – 7,000 ft to 0 – 6,350 ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G2	Tubing specifications – Injection tubing	The outside diameter of the injection tubing changed from 4 ½ in to 5 ½ in.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G2	Tubing specifications – Injection tubing	The weight of the injection tubing changed from 12.6 lb/ft to 17 lb/ft.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G2	Tubing specifications – Injection tubing	The grade (API) of the injection tubing changed from “Chrome alloy” to 13CR80.	This change was made to reflect the final, as-drilled construction details for CCS#2.
G2	Tubing specifications – Injection tubing	A note for injection tubing (previously Note 1) was deleted. The note previously read, “The tubing length will be finalized after the location of the perforations are selected and the packer location determined. The final tubing design may change subject to availability and/or pending results of reservoir analysis.” This was previously one note of four, and now there are three notes.	Administrative change.
G2	Tubing specifications – Injection tubing	A note for injection tubing (previously Note 3, now Note 2) was modified. The note previously read, “Weight of injection tubing string (axial load) in air (dead weight) will be 88,200 lbs,” now reads, “Weight of injection tubing string (axial load) in air (dead weight) is 88,200 lbs.”	Administrative change.
G2	Tubing specifications – Injection tubing	A note for injection tubing (previously Note 4, now Note 3) was modified. The note previously read, “Thermal conductivity of tubing @ 77°F will be 16 BTU / ft.hr.°F.” The note now reads, “Thermal conductivity of tubing @ 77°F is 16 BTU / ft.hr.°F.”	Administrative change.

Page No.	Section/Topic	Description of Change	Justification
G2	Tubing specifications	Two sentences describing the specifications of the injection tubing have been modified. The original paragraph read, "The injection well will be plugged back from the bottom with at least 80 feet of cement or a greater amount sufficient to prevent the injection fluid from coming in contact with the Precambrian granite basement. The figure on the following page is a well construction schematic for CCS#2." The paragraph now reads, "The injection well has approximately 80 feet of cement above the casing shoe to prevent the injection fluid from coming in contact with the Precambrian granite basement. The figure on the following page is the "as built" well construction schematic for CCS#2."	Administrative change.
G3	IL-ICCS CCS #2 Well Schematic	The depth and site elevation parameters for CCS#2 above the well schematic figure were modified. The parameters formerly read, "(depths are reference to the Kelley bushing = 694 ft above MSL) KB = 17 ft above ground, site elevation = 677 ft above MSL." The parameters now read, "Depths are reference to Kelly Bushing = 691.2 ft. above MSL**.** KB = 15.5 ft. above ground, site elevation = 675.7 ft. above MSL."	This change was made to reflect the final, as-drilled construction details for CCS#2.
G3	IL-ICCS CCS #2 Well Schematic	The IL-ICCS CCS #2 Well Schematic was revised in the following ways: 1. The column labeled, "FORMATION TOPS MD" formerly listed formations as follows, in order of increasing depth: RKB, Limestone, Logan Shale, Renault Ls, St. Louis Ls/Anhyd, Borden Ss, Burlington Ls, New Albany Sh, Silurian Ls, Maquoketa Sh, Galena Ls, Platteville Ls, St. Peter Ss, Shakopee Dol, Oneota Dol, Gunter Ss, Eminence Dol, Potosi Dol, Ironton Ss, Eau Claire, Eau Claire Ls, Eau Claire Sh, Upper Mt. Simon Ss, Lower Mt. Simon Ss, Precambrian. The formations were updated, and are now listed as follows: RKB, Limestone, Renault Ls, St. Louis Ls/Anhyd, Burlington Ls, New Albany Sh, Silurian Ls, Maquoketa Sh, Galena Ls, Platteville Ls, St. Peter Ss, Shakopee Dol, Oneota Dol, Gunter Ss, Eminence Dol, Potosi Dol, Ironton Ss, Eau Claire, M. Simon E, M. Simon D, M. Simon C, M. Simon B, M. Simon A, Argenta, Precambrian. 2. Depth interval data was added to the surface casing label; the label now reads, "Surface Casing 20" 94# J55 = 0' to 347'"; 3. The hole size corresponding to the surface casing was changed from 24" to 26"; 4. A label that read, "13-3/8 csg Stage tool at ~ 3850'" adjacent to the top of the intermediate casing was deleted;	This change was made to reflect the final, as-drilled construction details for CCS#2.

Page No.	Section/Topic	Description of Change	Justification
G3	IL-ICCS CCS #2 Well Schematic *(continued)*	5. A label that read, “Intermediate Csg 13-3/8” 54.5# J55 from __ to __ 13-3/8” 61# J55 from __ to __ 5350’. Two stage cement job planned,” adjacent to the bottom of the intermediate casing now reads, “Intermediate Casing 13-3/8” 61# J55 = 0’ to 5234’. Two stage cement job”; 6. A label that read, “Injection Packer, set at ~6320’” adjacent to the packer was deleted; 7. A label that read, “Injection Tubing 5-1/2” 17# 13CR80 SMLS BEAR R3 Surface to 6350’” adjacent to the completion assembly was deleted; 8. A label that read, “Injection Zone (*approx*) was replaced with a label adjacent to the base of the production casing that reads, “Production Casing 9-5/8” 40# L80-HC = 0’ to 4818’ 9-5/8” 47# 13CR80 = 4818’ to 7190’. Two stage cement job, CO2 resistant EverCRETE used for tail cement,”; 9. A label that read, “Tubing Pressure Temperature ~6,325 ft” with an arrow pointing to the ‘PT’ indication near the completion assembly was deleted; 10. A label that read, “Pressure Temp Gage installed at packer” adjacent to the completion assembly was deleted; 11. A label that read, “Perf Zone ~6700-6,900” was deleted; 12. A label that reads, “Injection Zone Perforations: 6630’-6670’ 6680’-6725’ 6735’-6775’ 6787-6825’” was inserted adjacent to the completion assembly; 13. A note was added to the bottom of the figure, which reads, “All casings to be cemented to surface.”	This change was made to reflect the final, as-drilled construction details for CCS#2.

Proposed Changes to Attachment H: Financial Assurance Demonstration

Page No.	Section/Topic	Description of Change	Justification
H1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
H1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53' 08", -89° 53'19" to 39º 53' 09.32835", -88° 53'16. 68306".	This change reflects the final, as-drilled location of CCS#2.
H1	Facility Information	The second full paragraph of this section has been modified. The paragraph formerly read, "The estimated costs of each of these activities, as provided in "Cost Estimate to Demonstrate Financial Responsibility for Class VI UIC Permit" (Patrick Engineering, March 13, 2014), are presented in Table 1:." The paragraph now reads, "The updated costs of each of these activities, submitted pursuant to 40 CFR 146.82(c) on October 25, 2016, are presented in Table :"	This change reflects the updated cost estimates submitted by ADM.
H1	Table 1	The column header formerly called "Total Cost ($)" has been changed. The column header is now called "Total Cost (in Millions of $)."	This edit was made to improve the clarity of the attachment.
H1	Table 1	The total cost for the activity "Performing Corrective Action on Wells in AoR" has changed from $231,800 to $0.25 million.	This change reflects the updated cost estimates submitted by ADM.
H1	Table 1	The total cost for the activity "Plugging Injection Wells" has changed from $594,120 to $0.65 million.	This change reflects the updated cost estimates submitted by ADM.
H1	Table 1	The total cost for the activity "Post-Injection Site Care" has changed from $6,434,500 to $7.80 million.	This change reflects the updated cost estimates submitted by ADM.
H1	Table 1	The total cost for the activity "Site Closure" has changed from $535,300 to $0.59 million.	This change reflects the updated cost estimates submitted by ADM.
H1	Table 1	The total cost for the activity "Emergency and Remedial Response" changed from $30,792,000 to $33.81 million.	This change reflects the updated cost estimates submitted by ADM.
H2	Chief Financial Officer (CFO) letter	The previous letter from the ADM CFO, dated April 9, 2014, has been replaced.	This letter was replaced with an updated CFO letter, dated March 11, 2016.

Proposed Changes to Attachment I: Stimulation Program

Page No.	Section/Topic	Description of Change	Justification
I1	Facility Information – Facility contact	The facility contact/Plant Manager of the ADM CCS#2 well changed from Mr. Mark Burau to Mr. Steve Merritt and the facility contact email changed from mark.burau@adm.com to steve.merritt@adm.com.	Administrative change.
I1	Facility Information – Well location	The coordinates of the CCS#2 injection well location changed from 39º 53' 08", -89° 53'19" to 39º 53' 09.32835", -88° 53'16. 68306".	This change reflects the final, as-drilled location of CCS#2.
I1	Attachment I	The second sentence of the only paragraph in this attachment was deleted. The sentence had read, "The need for stimulation will be determined once the characterization data from the CO_2 injection wells are available and have been evaluated (i.e., results of geophysical logs, core analyses, hydrogeologic testing)." The paragraph now reads, "The need for stimulation to enhance the injectivity potential of the Mount Simon Sandstone is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 5 for review and approval prior to conducting any stimulation."	Administrative change.

Proposed Changes to Quality Assurance and Surveillance Plan (QASP)

Page No.	Section/Topic	Description of Change	Justification
Cover page	Date	The date changed from April 2014 to October 2016.	Administrative change.
vii	Distribution List	Two ADM points of contact were replaced. The primary point of contact has changed from Mark Burau to Steve Merritt and one point of contact changed from Sean Stidham to Ed Taylor.	Administrative change.
vii	Distribution List – Facilities Contact	The ADM Facilities Contact changed from Mr. Mark Burau to Mr. Steve Merritt.	Administrative change.
7	Table 1	The 5-year frequency of Time lapse 3D indirect CO2 plume tracking during the operation period changed from “Year 2 (2018)” to “Year 2 (2019).”	Administrative change.
8	Table 2	The data collection location for the CCS#2 DTS in the operational period changed from “Distributed measurement to 6325 KB/5631 MSL” to “Distributed measurement to 6211 KB/5520 MSL.”	This change reflects the most up-to-date well specification data since construction of the CCS#2 well was completed.
8	Table 2	The data collection location for the CCS#2 DTS in the PISC period changed from “Distributed measurement to 6325 KB/5631 MSL” to “Distributed measurement to 6211 KB/5520 MSL.”	This change reflects the most up-to-date well specification data since construction of the CCS#2 well was completed.
8	Table 2	The data collection location for the CCS#2 temperature and pressure in the Mt. Simon formation in the operational period changed from “T, P @ 6325 KB/5631 MSL Perfs @ 6718–6881 KB 6024–6187 MSL” to “1 point location, 1 interval: PT @ 6270 KB/5579 MSL; Perfs @ 6630 - 6825 KB, 5939 - 6134 MSL.”	This change reflects the most up-to-date well specification data since construction of the CCS#2 well was completed.
8	Table 2	The data collection location for the CCS#2 temperature and pressure in the Mt. Simon formation in the PISC period changed from “1 interval T, P @ 6325 KB/5631 MSL Perfs @ 6718–6881 KB 6024–6187 MSL” to “1 point location, 1 interval: PT @ 6270 KB/5579 MSL; Perfs @ 6630 - 6825 KB, 5939 -6134 MSL.”	This change reflects the most up-to-date well specification data since construction of the CCS#2 well was completed.
9	Table 2	The data collection location for the VW#2 temperature and pressure in the Ironton-Galesville formation in the operational period changed from “1 interval 5000 KB 4918 MSL” to “1 point location, 1 interval: 4902 KB/4199 MSL.”	This change reflects the most up-to-date well specification data since construction of the VW#2 well was completed.

Page No.	Section/Topic	Description of Change	Justification
9	Table 2	The data collection location for the VW#2 temperature and pressure in the Ironton-Galesville formation in the PISC period changed from "1 interval 5000 KB 4918 MSL" to "1 point location, 1 interval: 4902 KB/4199 MSL."	This change reflects the most up-to-date well specification data since construction of the VW#2 well was completed.
9	Table 2	The data collection location for the VW#2 temperature and pressure in the Mt. Simon formation in the operational period changed from "4 intervals 7000, 6800, 6300, 5800 KB 6306, 6106, 5606, 5106 MSL" to "1 point location, 4 intervals: 7041, 6681, 6524, 5848 KB; 6338, 5978, 5821, 5145 MSL."	This change reflects the most up-to-date well specification data since construction of the VW#2 well was completed.
9	Table 2	The data collection location for the VW#2 temperature and pressure in the Mt. Simon formation in the PISC period changed from "4 intervals 7000, 6800, 6300, 5800 KB 6306, 6106, 5606, 5106 MSL" to "1 point location, 4 intervals: 7041, 6681, 6524, 5848 KB; 6338, 5978, 5821, 5145 MSL."	This change reflects the most up-to-date well specification data since construction of the VW#2 well was completed.
9	Table 2	The data collection location for the GM#2 temperature and pressure in the operational period changed from "1 interval 3300 KB 2606 MSL" to "1 point location, 1 interval: 3450 KB/2759 MSL."	This change reflects the most up-to-date well specification data since construction of the GM#2 well was completed.
9	Table 2	The data collection location for the GM#2 DTS in the PISC period changed from "1 interval 3300 KB 2606 MSL" to "1 point location, 1 interval: 3450 KB/2759 MSL."	This change reflects the most up-to-date well specification data since construction of the GM#2 well was completed.
10	Table 3	The 5-year frequency of 3D surface seismic surveying during the operation period changed from "Year 2 (2018)" to "Year 2 (2019)."	This edit was made to capture the anticipated numerical year of Year 2 of the CCS#2 operational phase.
11	Figure 2	Figure 2 was replaced with an updated figure.	This change reflects the most up-to-date information since well construction was completed.
11	Figure 2	The Figure 2 caption was revised. The former caption read, "IL-ICCS Project area showing location of existing shallow groundwater monitoring wells and planned deep wells." The current caption reads, "IL-ICCS Project area showing location of shallow groundwater monitoring wells and deep monitoring wells."	This change reflects the most up-to-date information since well construction was completed.

Page No.	Section/Topic	Description of Change	Justification
25	Design Strategy – VW#2 Sampling	The third sentence of this section has been modified. The sentence formerly read, "VW#2 will be equipped with a multilevel pressure and temperature monitoring system with fluid sampling capability at four (4) intervals (perforation intervals 2-5; 6800, 6300, 5800, 5000 KB)," and now reads, "VW#2 will be equipped with a multilevel pressure and temperature monitoring system with fluid sampling capability at four (4) intervals."	This change reflects the most up-to-date information since well construction was completed.
25	Design Strategy – VW#2 Sampling	The fifth sentence of this section has been modified. The sentence formerly read, "Pressure and temperature will be continuously monitored and recorded in each of the five (5) perforation intervals (perforation intervals 1-5; 7000, 6800, 6300, 5800, 5000 KB)," and now reads, "Pressure and temperature will be continuously monitored and recorded in each of the five (5) perforation intervals."	This change reflects the most up-to-date information since well construction was completed.