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-137-6A-0001
Facility Name: FutureGen Industrial Alliance, Inc.

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,

FutureGen Industrial Alliance, Inc. of Jacksonville, Illinois

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of Illinois, Morgan County, Township 16N, Range 9W, Section 26, latitude 39.80111°N and longitude 90.07491°W, for injection of the carbon dioxide (CO_2) stream generated by an oxy-combustion power plant in Meredosia, Illinois and as characterized in the permit application and the administrative record as a liquid, supercritical fluid, or gas into the Mount Simon and Eau Claire Formations at depths between 3785 feet and 4432 feet below ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection well is identified as the upper part of the Eau Claire Formation formed by the upper part of the Lombard Member and the Proviso Member. 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 OCT 1 4 2014, 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: August 29, 2014

Tinka G. Hyde
Tinka G. Hyde
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. **<u>Modification, Revocation and Reissuance, and Termination</u>** – 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. **<u>Minor Modifications</u>** – 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. **<u>Transfer of Permits</u>** – 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 mechanisms are 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 as necessary to provide information about the injection and confining zones to allow determination or calculation of the 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 A 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. **<u>Pressure Fall-Off Test</u>** – 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. **<u>Plume and Pressure Front Tracking</u>** –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. **<u>Surface Air and/or Soil Gas Monitoring</u>** – 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. **<u>Additional Monitoring</u>** – 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. **<u>Electronic Reporting</u>** – 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. **<u>Semi-Annual Reports</u>** – 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(6)(d) 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(6)(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 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: FutureGen 2.0 Morgan County CO_2 Storage Site
IL-137-6A-0001 (Well #1)

Facility Contacts: Kenneth Humphreys, Chief Executive Officer,
FutureGen Industrial Alliance, Inc., Morgan County Office,
73 Central Park Plaza East, Jacksonville, IL 62650, 217-243-8215

Location of Injection Well: Morgan County, IL; 26–16N–9W; 39.80111°N and 90.07491°W

Injection Well Operating Conditions:

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE	UNIT
Maximum Injection Pressure		
Surface	1,171	psig
Downhole	2,237	psig
Annulus Pressure	100 minimum	psig
Annulus Pressure/Tubing Differential	100 above surface injection pressure	psig

The *downhole gauge* for injection pressure monitoring is located at: 3,850 feet below ground surface.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined using the following formula/methodology:

- For *maximum injection pressure using a downhole pressure gauge,* the maximum pressure is calculated as follows: 90% of fracture pressure of the injection zone. Therefore, the maximum injection pressure using downhole pressure gauge is 2,252 psia or 2,252-14.7 = **2,237 psig**.

- For *surface maximum wellhead injection pressure*, this limitation was calculated using the following formula: [{90% of fracture gradient-(0.433psi/ft)(specific gravity)} X upper depth of perforated interval] - atmospheric pressure. The maximum wellhead injection pressure is: [{0.585-(0.433)(0.64)}3850] -14.7 = **1,171psig**.

If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited to the calculated surface pressure until the downhole pressure gauge is repaired or replaced.

Shutdown Procedure:

The permittee has not developed procedures for implementing a gradual well shutdown.

Therefore, unless and until other procedures are developed and approved, every situation that warrants shutting down the well (from routine maintenance to emergency conditions) will require an immediate shutdown.

Summary of 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.

Summary of 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.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Facility Information

Facility Name: FutureGen 2.0 Morgan County CO_2 Storage Site
IL-137-6A-0001 (Well #1)

Facility Contacts: Kenneth Humphreys, Chief Executive Officer,
FutureGen Industrial Alliance, Inc., Morgan County Office,
73 Central Park Plaza East, Jacksonville, IL 62650, 217-243-8215

Location of Injection Well: Morgan County, IL; 26–16N–9W; 39.80111°N and 90.07491°W

Computational Modeling

Model Name: STOMP-CO2 (Subsurface Transport Over Multiple Phases-CO2) simulator

Model Authors/Institution: White et al. 2013; White and Oostrom 2006; White and McGrail 2005/Pacific Northwest National Laboratory (PNNL)

Description of Model:

The simulations conducted for this investigation were executed using the STOMP-CO2 simulator (White et al. 2013; White and Oostrom 2006; White and Oostrom 2000). STOMP-CO2 was verified against other codes used for simulation of geologic disposal of CO_2 as part of the GeoSeq code intercomparison study (Pruess et al. 2002).

Partial differential conservation equations for fluid mass, energy, and salt mass compose the fundamental equations for STOMP-CO2. Coefficients within the fundamental equations are related to the primary variables through a set of constitutive relationships. The salt transport equations are solved simultaneously with the component mass and energy conservation equations. The solute and reactive species transport equations are solved sequentially after the coupled flow and transport equations. The fundamental coupled flow equations are solved using an integral volume finite-difference approach with the nonlinearities in the discretized equations resolved through Newton-Raphson iteration. The dominant nonlinear functions within the STOMP-CO2 simulator are the relative permeability-saturation-capillary pressure (k-s-p) relationships.

The STOMP-CO2 simulator allows the user to specify these relationships through a large variety of popular and classic functions. Two-phase (gas-aqueous) k-s-p relationships can be specified with hysteretic or nonhysteretic functions or nonhysteretic tabular data. Entrapment of CO_2 with imbibing water conditions can be modeled with the hysteretic two-phase k-s-p functions. Two-phase k-s-p relationships span both saturated and unsaturated conditions. The aqueous phase is assumed to never completely disappear through extensions to the s-p function below the residual saturation and a vapor pressure lowering scheme. Supercritical CO_2 has the function of a gas in these two-phase k-s-p relationships.

For the range of temperature and pressure conditions present in deep saline reservoirs, four phases are possible: 1) water-rich liquid (aqueous), 2) CO_2-rich vapor (gas), 3) CO_2-rich liquid (liquid-CO_2), and 4) crystalline salt (precipitated salt). The equations of state express 1) the existence of phases given the temperature, pressure, and water, CO_2, and salt concentration; 2) the partitioning of components among existing phases; and 3) the density of the existing phases. Thermodynamic properties for CO_2 are computed via interpolation from a property data table stored in an external file. The property table was developed from the equation of state for CO_2 published by Span and Wagner (1996). Phase equilibria calculations in STOMP-CO2 use the formulations of Spycher et al. (2003) for temperatures below 100°C and Spycher and Pruess (2010) for temperatures above 100°C, with corrections for dissolved salt provided in Spycher and Pruess (2010). The Spycher formulations are based on the Redlich-Kwong equation of state with parameters fitted from published experimental data for CO_2-H2O systems. Additional details regarding the equations of state used in STOMP-CO2 can be found in the guide by White et al. (2013).

A well model is defined as a type of source term that extends over multiple grid cells, where the well diameter is smaller than the grid cell. A fully coupled well model in STOMP-CO2 was used to simulate the injection of supercritical CO_2 ($scCO_2$) under a specified mass injection rate, subject to a pressure limit. When the mass injection rate can be met without exceeding the specified pressure limit, the well is considered to be flow controlled. Conversely, when the mass injection rate cannot be met without exceeding the specified pressure limit, the well is considered to be pressure controlled and the mass injection rate is determined based on the injection pressure. The well model assumes a constant pressure gradient within the well and calculates the injection pressure at each cell in the well. The CO_2 injection rate is proportional to the pressure gradient between the well and surrounding formation in each grid cell. By fully integrating the well equations into the reservoir field equations, the numerical convergence of the nonlinear conservation and constitutive equations is greatly enhanced.

Model Inputs and Assumptions:

Conceptual Model

Site Stratigraphy

The regional geology of Illinois is well known from wells and borings drilled in conjunction with hydrocarbon exploration, aquifer development and use, and coal and commercial mineral exploration. Related data are largely publicly available through the Illinois State Geological Survey (ISGS)[1] and the U.S. Geological Survey.[2] In addition, the U.S. Department of Energy has sponsored a number of studies by the Midwest Geologic Sequestration Consortium[3] to evaluate subsurface strata in Illinois and adjacent states as possible targets for the containment of anthropogenic CO_2.

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[1] http://www.isgs.uiuc.edu/

[2] http://www.usgs.gov/

[3] http://sequestration.org/

To support the evaluation of the Morgan County site as a potential carbon storage site, a deep stratigraphic well was drilled and extensively characterized. The FutureGen 2.0 stratigraphic well, located at longitude 90.05298W, latitude 39.80681N, is approximately 1.24 mi (2 km) northeast of the planned injection site. The stratigraphic well reached a total depth of 4,826 ft (1,471 m) below ground surface (bgs) within the Precambrian basement (Figure 1). The well penetrated 479 ft (146 m) of the Eau Claire Formation and 512 ft (156 m) of the Mount Simon Sandstone. The stratigraphic well was extensively characterized, sampled, and geophysically logged during drilling. A total of 177 ft of whole core were collected from the lower Eau Claire Formation and upper Mount Simon Sandstone and 34 ft were collected from lower Mount Simon Sandstone and Precambrian basement interval. In addition to whole drill core, a total of 130 side-wall core plugs were obtained from the combined interval of the Eau Claire Formation, Mount Simon Sandstone, and the Precambrian basement. In Figure 2, cored intervals are indicated with red bars; rotary side-wall core and core-plug locations are indicated to the left of the lithology panel. Standard gamma ray and resistivity curves are shown in the second panel.

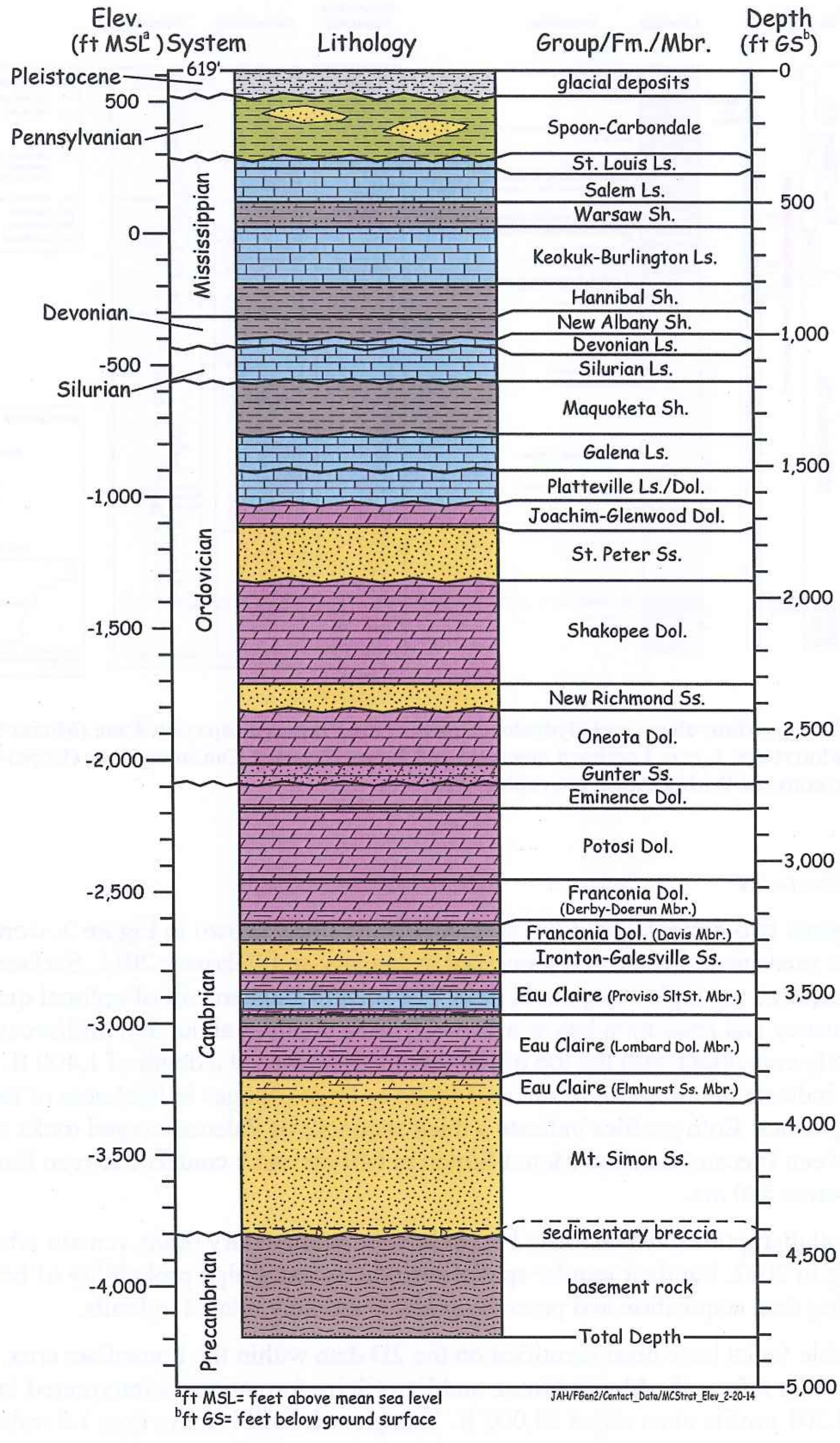


Figure 1. Stratigraphic Column of FutureGen 2.0 Stratigraphic Well

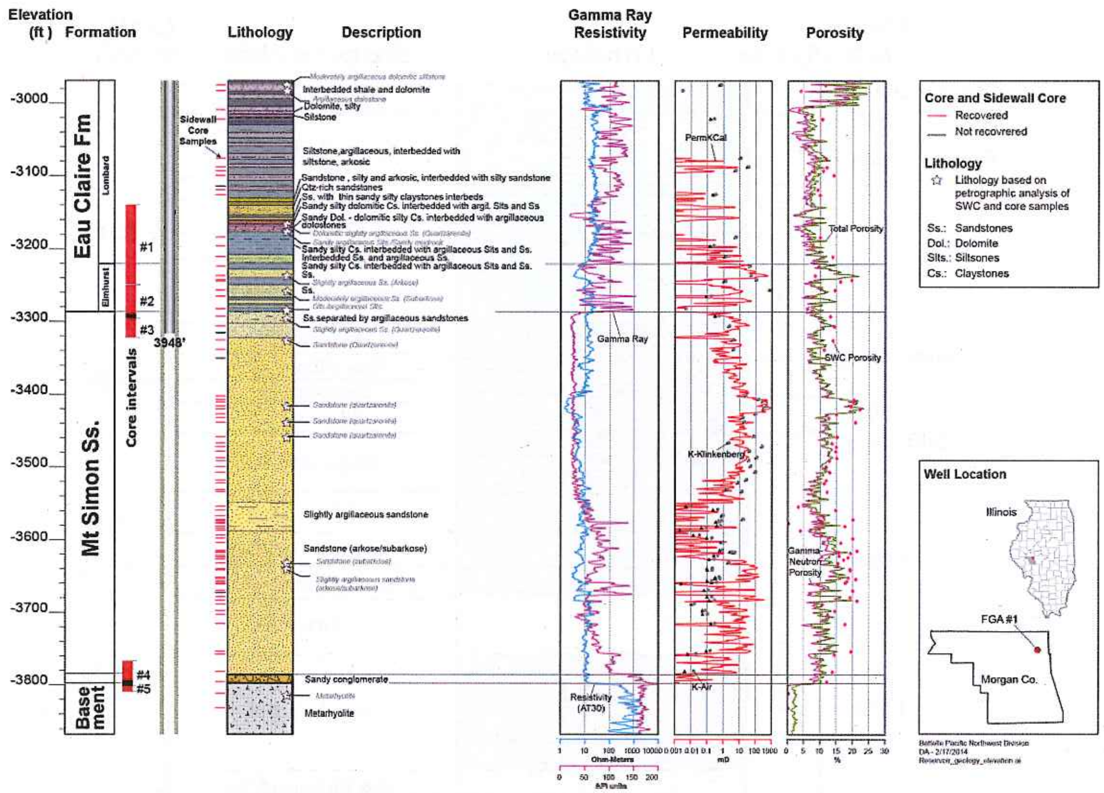


Figure 2. Lithology, Mineralogy, and Hydrologic Units of the Proposed Injection Zone (Mount Simon, Elmhurst and Lower Lombard member) and Lower Primary Confining Zone (Upper Lombard), as Encountered Within the Stratigraphic Well

Geologic Structures

Two orthogonal two-dimensional (2D) surface seismic lines, shown in Figure 3, were acquired along public roads near the site and processed in January and February 2011. Surface seismic data were acquired as single-component data. The seismic data are not of optimal quality due to loss of frequency and resolution below a two-way time depth of about 300 milliseconds (ms), approximately coincident with the top of the Galena limestone at a depth of 1,400 ft. However, they do not indicate the presence of obvious faults or large changes in thickness of the injection or confining zones. Both profiles indicate a thick sequence of Paleozoic-aged rocks with a contact between Precambrian and Mount Simon at 640 ms and a contact between Eau Claire and Mount Simon at 580 ms.

Some vertical disruptions, which extend far below the sedimentary basin, remain after reprocessing in 2012, but their regular spatial periodicity has a high probability of being an artifact during data acquisition and processing and is unlikely related to faults.

No discernable faults have been identified on the 2D data within the immediate area. A small growth fault that affects the Mount Simon and Eau Claire formations is interpreted in the eastern part of the L201 profile at an offset 28,000 ft. This growth fault is more than 1.5 miles away from the outermost edge of the CO_2 plume and does not extend far upward in the overburden. For these reasons, it is highly unlikely that it could affect the integrity of the injection zone.

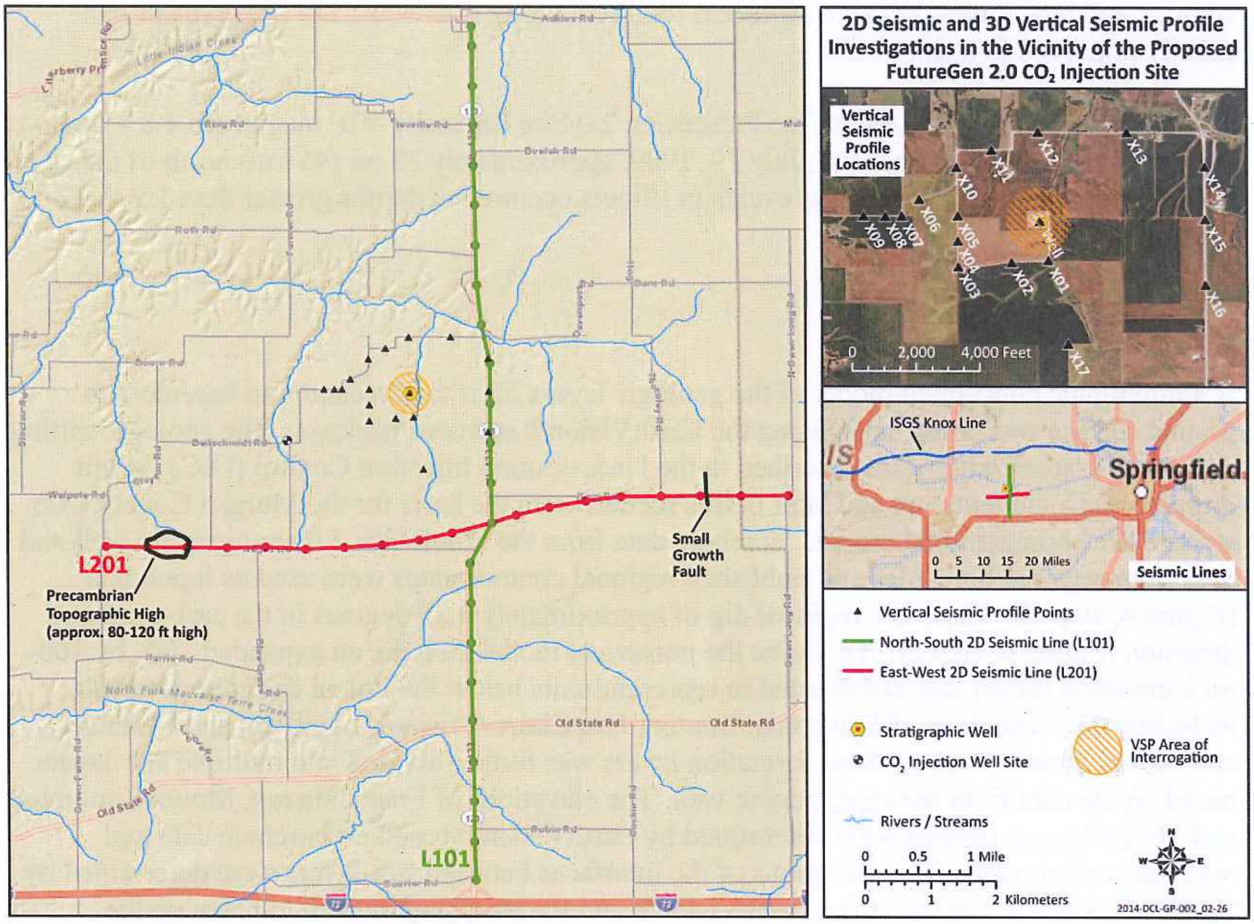


Figure 3. Locations of Two 2D Seismic Survey Lines, L101 and L201, Vertical Seismic Profile Locations, and the Knox Line Near the Proposed Morgan County CO_2 Storage Site

A three-component vertical seismic profiling (VSP) data set (Figure 3) was acquired in the FutureGen stratigraphic well in March 2013, and processed by Schlumberger Carbon Services. No discernable faults are present in the 15 short 2D seismic lines formed by the offset VSP locations. These lines represent a lateral interrogation extent of 800−1600 ft radially from the stratigraphic well. The high-resolution, low-noise VSP data also do not contain the vertical disruptions observed in the 2D surface seismic profiles (Hardage 2013[4]).

The ISGS recently shot a 120-mi long seismic reflection survey (the Knox Line) across central Illinois as part of a Department of Energy-sponsored research project to characterize rock units for geologic storage of CO_2. The continuous east-west line extends from Meredosia to southwestern Champaign County (Figure 3). FutureGen Industrial Alliance, Inc., (FutureGen Alliance) acquired these data from the ISGS with the intention of reprocessing the data, if needed, to identify regional faults that might impact the proposed FutureGen 2.0 Morgan County CO_2 Storage Site (FutureGen 2.0 Site). A review of the data by a geophysical expert on Illinois reflection seismic data[5], indicated that there was no discernable faulting west of Ashland,

[4] Bob Hardage. Personal Communication with Charlotte Sullivan, August 1, 2013.
[5] John McBride. Personal Communication with Charlotte Sullivan, October 29, 2013.

Illinois; and that current plans to reprocess the ISGS Knox line would not likely result in a greatly improved image.

The closest known earthquake to the FutureGen 2.0 Site (Intensity VII, magnitude 4.8 – non-instrumented record) occurred on July 19, 1909, approximately 28 mi (45 km) north of the site; it caused slight damage. Most of the events in Illinois occurred at depths greater than 1.9 mi (3 km).

Conceptual Model Domain

A stratigraphic conceptual model of the geologic layers from the Precambrian basement to ground surface was constructed using the EarthVision® software package. The geologic setting and site characterization data described in the Underground Injection Control (UIC) Permit Supporting Documentation and later in this section were the basis for the Morgan County CO_2 storage site computational model. Borehole data from the FutureGen 2.0 stratigraphic well and data from regional boreholes and published regional contour maps were used as input data (Figure 4, step 1). There is a regional dip of approximately 0.25 degrees in the east-southeast direction (Figure 4, step 2). To define the numerical model domain, an expanded 100- by 100-mi conceptual model was constructed to represent units below the Potosi dolomite interval, including the formations of Franconia, Ironton, Eau Claire (Proviso, Lombard, and Elmhurst), and Mount Simon. Each of these formation layers was further divided into multiple sub-layers based on the data from the stratigraphic well. The elevations of Franconia top, Mount Simon top, and Mount Simon Bottom were determined by EarthVision® based on borehole data and regional contour maps. The elevations of the interfaces between sub-layers were determined by the three bounding surfaces from EarthVision® and the stratigraphic well to make up the boundary-fitted stratigraphic layers of the computational model. The numerical model grid in the horizontal directions was designed to have constant grid spacing with higher resolution in the area influenced by the CO_2 injection (3-mi by 3-mi area), with increasingly larger grid spacing moving out toward the domain boundaries. The conceptual model hydrogeologic layers were defined for each stratigraphic layer based on zones of similar hydrologic properties. The hydrologic properties (permeability, porosity) were deduced from geophysical well logs and side-wall cores. The lithology, deduced from wireline logs and core data, was also used to subdivide each stratigraphic layer of the model. Based on these data, the Mount Simon Sandstone was subdivided into 17 layers, and the Elmhurst Sandstone (member of the Eau Claire Formation) was subdivided into 7 layers (Figure 4). The Lombard and Proviso members of the Eau Claire Formation were subdivided respectively into 14 and 5 layers. The Ironton Sandstone was divided into four layers, the Davis Dolomite into three layers, and the Franconia Formation into one layer. Some layers ("split" label in Figure 4, step 2) have similar properties but have been subdivided to maintain a reasonable thickness of layers within the injection zone as represented in the computational model. The thickness of the layers varies from 4 to 172 ft, with an average of 26 ft.

Based on knowledge of the regional and local geology, the Mount Simon Sandstone and the Elmhurst form the main part of the injection zone. However, the computational model results indicate that the Model Layer "Lombard 5" is the top unit containing a fraction of injected CO_2 during the 100-year simulation. Based on these results, the lower part of the Lombard (layers Lombard 1 to 5 of the Computational Model), is considered to be part of the injection zone

(Figure 4). The top of the injection zone is set at 3,785 ft bgs (-3,153 ft elevation MSL) in the stratigraphic well. The upper part of the Lombard and the Proviso members form the primary confining zone.

Figure 4, step 3, shows the numerical model grid for the entire 100- by 100-mi domain and also for the 3- by 3-mi area with higher grid resolution and uniform grid spacing of 200 ft by 200 ft. The model grid contains 125 nodes in the x-direction, 125 nodes in the y-direction, and 51 nodes in the z-direction for a total number of nodes equal to 796,875. The expanded geologic model was queried at the node locations of the numerical model to determine the elevation of each surface for the stratigraphic units at the numerical model grid cell centers (nodes) and cell edges. Then each of those layers was subdivided into the model layers by scaling the thickness to preserve the total thickness of each stratigraphic unit. Once the vertical layering was defined, material properties were mapped to each node in the model.

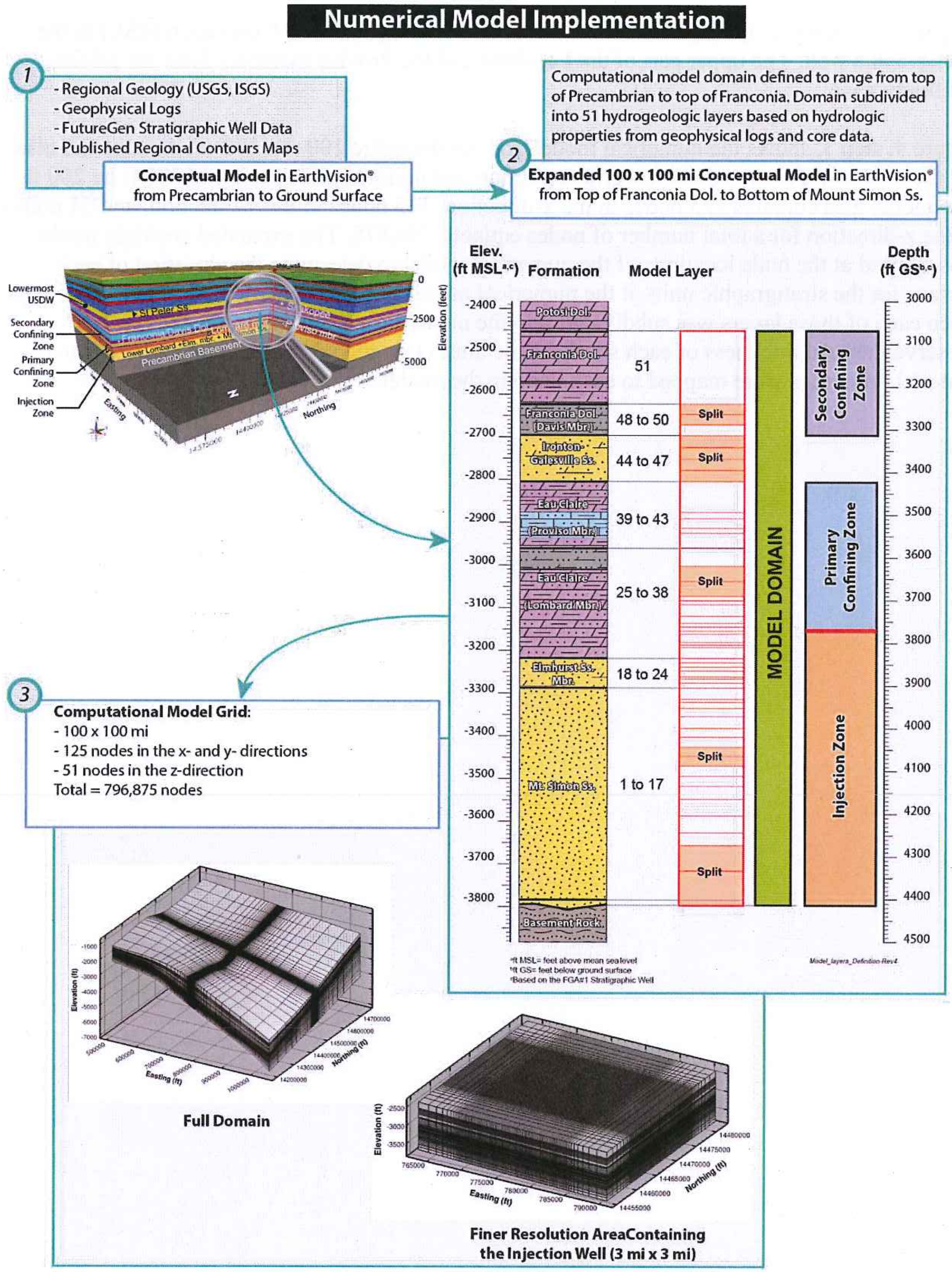


Figure 4. Implementation of the Numerical Model: From the Geological Conceptual Model to the Numerical Model

Processes Modeled

Physical processes modeled in the reservoir simulations included isothermal multi-fluid flow and transport for a number of components (e.g., water, salt, and CO_2) and phases (e.g., aqueous and gas). Isothermal conditions were modeled because it was assumed that the temperature of the injected CO_2 will be similar to the formation temperature. Formation salinity is considered because salt precipitation can occur near the injection well in higher permeability layers as the rock dries out during CO_2 injection. Porosity reduction due to salt precipitation is considered in the model. However, permeability reduction was not modeled because the salinity is relatively low in the injection formations at this site, resulting in low levels of salt precipitation.

Injected CO_2 partitions in the injection zone between the free (or mobile) gas, entrapped gas, and aqueous phases. Sequestering CO_2 in deep saline formations occurs through four mechanisms: 1) structural trapping; 2) aqueous dissolution; 3) hydraulic trapping; and 4) mineralization. Structural trapping is the long-term retention of the buoyant gas phase in the pore space of the permeable formation rock held beneath one or more impermeable or near impermeable confining zones. Aqueous dissolution occurs when CO_2 dissolves in the brine resulting in an aqueous-phase density greater than the ambient conditions. Hydraulic trapping is the pinch-off trapping of the gas phase in pores as the brine re-enters pore spaces previously occupied by the gas phase. Generally, hydraulic trapping only occurs upon the cessation of CO_2 injection. Mineralization is the chemical reaction that transforms formation minerals to carbonate minerals. In the Mount Simon Sandstone, the most likely precipitation reaction is the formation of iron carbonate precipitates. A likely reaction between CO_2 and shale is the dewatering of clays. Laboratory investigations are currently quantifying the importance of these reactions at the Morgan County CO_2 storage site. Based on its experiments, the FutureGen Alliance expects to see a small mass of precipitates (KCl, NaCl) forming near the injection well from the $scCO_2$ displacement of water, and does not expect to see the formation of any significant carbonate precipitates in the year (or years) time scale. Iron does precipitate, but concentrations are too low (<0.6 mmol/L) relative to carbonate mass to be a precipitate issue. Simulations by others (White et al. 2005) of $scCO_2$ injection in a similar sandstone (also containing iron oxides) shows that over significantly longer time scales (1000+ years), alumino silicate dissolution and alumino silicate precipitation incorporating significant carbonate (dawsonite) is predicted, as well as precipitation of some calcite. That predicted mineral trapping did permanently sequester 21 percent of the carbonate mass, thus decreasing $scCO_2$ transport risk. Therefore, the simulations described here did not include mineralization reactions. However, the STOMP-CO2 simulator does account for precipitation of salt during CO_2 injection. The CO_2 stream provided by the plant to the storage site is no less than 97 percent dry basis CO_2. Because the amount of impurities is small, for the purposes of modeling the CO_2 injection and redistribution for this project, it was assumed that the injectate was pure CO_2.

Rock Properties

Intrinsic Permeability

<u>*Site Characterization Data*</u>

Permeability in the sandstones, as measured in rotary side-wall cores and plugs from whole core, appears to be dominantly related to grain size and abundance of clay. In Figure 2, ELAN (Elemental Log Analysis)-calculated permeability (red curve) is in the third panel, along with two different lab measurements of permeability for each rotary side-wall core. Horizontal permeability (K_h) data in the stratigraphic well outnumber vertical permeability (K_v) data, because K_v could not be determined from rotary side-wall cores. However, K_v/K_h ratios were successfully determined for 20 vertical/horizontal siliciclastic core-plug pairs cut from intervals of whole core. Within the Mount Simon Sandstone, the horizontal permeabilities of the lower Mount Simon alluvial fan lithofacies range from 0.005 to 0.006 mD and average ratios of vertical to horizontal permeabilities range from 0.635 to 0.722 (at the 4,304 to 4,374 ft bgs depth or the elevation of -3,685 to -3,755 ft, Figure 2). Horizontal core-plug permeabilities range from 0.032 to 2.34 mD at the 3,838 to 3,904 ft bgs depth (elevation of -3,219 to -3,285 ft); K_v/K_h ratios for these same samples range from 0.081 to 0.833.

The computed lithology track for the primary confining zone indicates the upward decrease in quartz silt and increase in carbonate in the Proviso member, along with a decrease in permeability. The permeabilities of the rotary side-wall cores in the Proviso range from 0.000005 mD to 1 mD. Permeabilities in the Lombard member range from 0.001 mD to 28 mD, reflecting the greater abundance of siltstone in this interval, particularly in the lowermost part of the member. Whole core plugs and associated vertical permeabilities are available only from the lowermost part of the Lombard. Thin (few inches/centimeters), high-permeability sandstone streaks resemble the underlying Elmhurst; low-permeability siltstone and mudstone lithofacies have vertical permeabilities of 0.0004 to 0.465 mD, and K_v/K_h ratios of <0.0001 to 0.17. The ELAN geophysical logs indicated permeabilities are generally less than the wireline tool limit of 0.01 mD throughout the secondary confining zone. Two rotary side-wall cores were taken from the Franconia, and three side-wall cores were cut in the Davis member. Laboratory-measured rotary side-wall core (horizontal) permeabilities are very low (0.000005 to 0.001 mD). The permeabilities of the two Franconia samples were measured with a special pulse decay permeameter; the sample from 3,140 ft bgs (-2521 ft elevation) has a permeability less than the lower instrument limit of 0.000005 mD. Vertical core plugs are required for directly determining vertical permeability and there are no data from the stratigraphic well for vertical permeability or for determining vertical permeability anisotropy in the secondary confining zone. However, K_v/K_h ratios of 0.007 have been reported elsewhere for Paleozoic carbonate mudstones (Saller et al. 2004).

Model Parameters

Intrinsic permeability data sources for the FutureGen 2.0 stratigraphic well include computed geophysical wireline surveys (CMR and ELAN logs), and where available, laboratory measurements of rotary side-wall cores (SWC), core plugs from the whole core intervals, hydrologic tests (including wireline [MDT]), and packer tests. For the Mount Simon and Elmhurst Sandstones model layers (3,838 to 4,418 ft bgs depth or elevation of -3219 to -3799 ft at the stratigraphic well), wireline ELAN permeability model permKCal produced by Schlumberger (red curve on Figure 2) was used. This model, calibrated by rotary side-wall and core-plug permeabilities, provides a continuous permeability estimate over the entire injection zone. This calibrated permeability response was then slightly adjusted, or scaled, to match the composite results obtained from the hydrologic packer tests over uncased intervals. For injection zone model layers within the cased well portion of the model, no hydrologic test data are available, and core-calibrated ELAN log response was used directly in assigning average model layer permeabilities.

The hydraulic packer tests were conducted in two zones of the Mount Simon portion of the injection zone. The Upper Zone (3,934 ft to 4,180 ft bgs depth or -3,315 to -3,561 ft elevation) equates to layers 6 through 17 of the model, while the Lower Zone (4,186 ft to 4,498 ft bgs depth or -3,567 to -3,879 ft elevation) equates to layers 1 through 5. The most recent ELAN-based permeability-thickness product values are 9,524 mD-ft for the 246-ft-thick section of the upper Mount Simon corresponding to the Upper Zone and 3,139 mD-ft for the 312-ft-thick section of the lower Mount Simon corresponding to the Lower Zone. The total permeability-thickness product for the open borehole Mount Simon is 12,663 mD-ft, based on the ELAN logs. Results of the field hydraulic tests suggest that the upper Mount Simon permeability-thickness product is 9,040 mD-ft and the lower Mount Simon interval permeability-thickness product is 775 mD-ft. By simple direct comparison, the packer test for the upper Mount Simon is nearly equivalent (~95 percent) to the ELAN-predicted value, while the lower Mount Simon represents only ~25 percent of the ELAN-predicted value.

Because no hydrologic test has been conducted in the Elmhurst Sandstone interval of the injection zone, a conservative scaling factor of 1 has been assigned to this interval, based on ELAN PermKCal data (The permeabilities used for this formation were the ELAN PermKCal values without applying a scaling factor). The sources of data for confining zones (Franconia to Upper part of the Lombard Formations) and the Upper part of the Injection zone (Lower part of the Lombard) are similar to those for the injection zone, with the exception that no hydrologic or MDT test data are available. ELAN log-derived permeabilities are unreliable below about 0.01 mD (personal communication from Bob Butsch, Schlumberger, 2012). Because the average log-derived permeabilities (permKCal wireline from ELAN log) for most of the confining zone layers are at or below 0.01 mD, an alternate approach was applied. For each model layer the core data were reviewed, and a simple average of the available horizontal Klinkenburg permeabilities was then calculated for each layer. Core samples that were noted as having potential cracks and/or were very small were eliminated if the results appeared to be unreasonable based on the sampled lithology. If no core samples were available and the arithmetic mean of the PermKCal was below 0.01 mD, a default value of 0.01 mD was applied (Lombard9 is the only layer with a 0.01-mD default value). Because the sandstone intervals of the Ironton-Galesville Sandstone have higher permeabilities that are similar in magnitude to the modeled injection zone layers, the Ironton-Galesville Sandstone model layer permeabilities were derived from the arithmetic mean of the PermKCal permeability curve. Because no hydraulic test has been conducted in the primary confining zone and the Upper part of the injection zone (Elmhurst Sandstone layers and lower part of the Lombard – Lombard 1 to Lombard 5), the scaling factor was assigned to be 100 percent in this interval and the overburden formations. Figure 5 shows the depth profile of the horizontal permeability assigned to each layer of the model and actual values assigned are listed in Table 1. Figure 6 shows the distribution of horizontal and vertical permeability as it was assigned to the numerical model layers.

Because the anisotropy of the model layers is not likely to be represented by the sparse data from the stratigraphic well, the lithology-specific permeability anisotropy averages from literature studies representing larger sample sizes were used for the model layers (Table 2 and Table 3).

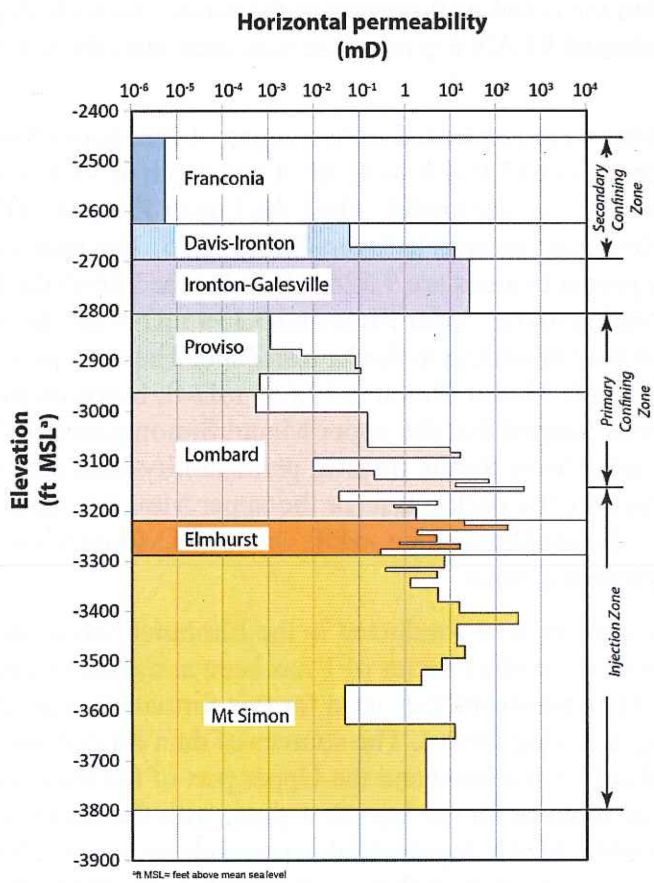
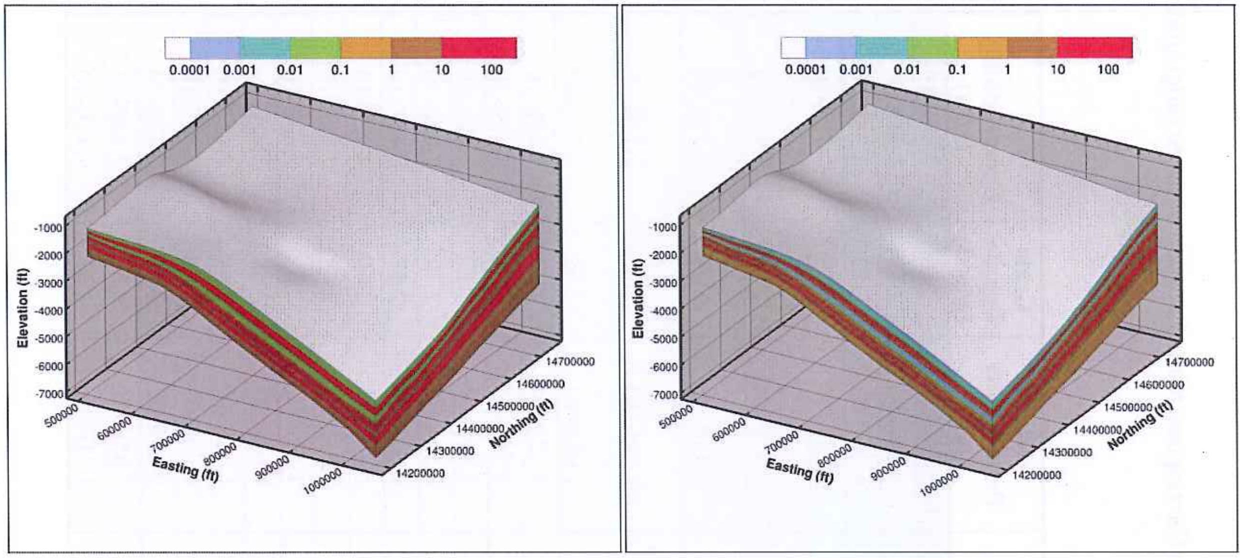


Figure 5. Vertical Distribution of the Horizontal Permeability in the Model Layers at the Stratigraphic Well Location



(a) **(b)**

Figure 6. Permeability Assigned to Numerical Model 1) Horizontal Permeability; b) Vertical Permeability

Table 1. Summary of the Hydrologic Properties Assigned to Each Model Layer. Depths and Elevations Correspond to the Location of the Stratigraphic Well

Simulation - CM22

Zone	Model Layer	Top Depth (ft bgs)	Top Elevation (ft MSL)	Bottom Elevation (ft MSL)	Thickness (ft)	Porosity	Horizontal Permeability (mD)	Vertical Permeability (mD)	Grain Density (g/cm3)	Compresibility (1/Pa)
Secondary Conf. Zone	Franconia	3072.00	-2453	-2625	172	0.0358	5.50E-06	3.85E-08	2.82	7.42E-10
	Davis-Ironton3	3244.00	-2625	-2649	24	0.0367	6.26E-02	6.26E-03	2.73	3.71E-10
	Davis-Ironton2	3268.00	-2649	-2673	24	0.0367	6.26E-02	6.26E-03	2.73	3.71E-10
	Davis-Ironton1	3292.00	-2673	-2697	24	0.0218	1.25E+01	1.25E+00	2.73	3.71E-10
	Ironton-Galesville4	3316.00	-2697	-2725	28	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
	Ironton-Galesville3	3344.00	-2725	-2752	27	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
	Ironton-Galesville2	3371.00	-2752	-2779	27	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
	Ironton-Galesville1	3398.00	-2779	-2806	27	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
Primary Confining Zone	Proviso5	3425.00	-2806	-2877	71	0.0972	1.12E-03	1.12E-04	2.72	7.42E-10
	Proviso4	3496.00	-2877	-2891	14	0.0786	5.50E-03	5.50E-04	2.72	7.42E-10
	Proviso3	3510.00	-2891	-2916	25	0.0745	8.18E-02	5.73E-04	2.77	7.42E-10
	Proviso2	3534.50	-2916	-2926	10	0.0431	1.08E-01	7.56E-04	2.77	7.42E-10
	Proviso1	3544.50	-2926	-2963	38	0.0361	6.46E-04	4.52E-06	2.77	7.42E-10
	Lombard14	3582.00	-2963	-3003	40	0.1754	5.26E-04	5.26E-05	2.68	7.42E-10
	Lombard13	3622.00	-3003	-3038	35	0.0638	1.53E-01	1.53E-02	2.68	7.42E-10
	Lombard12	3657.00	-3038	-3073	35	0.0638	1.53E-01	1.53E-02	2.68	7.42E-10
	Lombard11	3692.00	-3073	-3084	11	0.0878	9.91E+00	9.91E-01	2.68	7.42E-10
	Lombard10	3703.00	-3084	-3094	10	0.0851	1.66E+01	1.66E+00	2.68	7.42E-10
	Lombard9	3713.00	-3094	-3121	27	0.0721	1.00E-02	1.00E-03	2.68	7.42E-10
	Lombard8	3739.50	-3121	-3138	17	0.0663	2.13E-01	2.13E-02	2.68	7.42E-10
	Lombard7	3756.50	-3138	-3145	8	0.0859	7.05E+01	7.05E+00	2.68	7.42E-10
	Lombard6	3764.00	-3145	-3153	8	0.0459	1.31E+01	1.31E+00	2.68	7.42E-10

Table 1. (contd)

	Model Layer	Top Depth (ft bgs)	Top Elevation (ft MSL)	Bottom Elevation (ft MSL)	Thickness (ft)	Porosity	Horizontal Permeability (mD)	Vertical Permeability (mD)	Grain Density (g/cm3)	Compresibility (1/Pa)
Injection Zone	Lombard5	3771.50	-3153	-3161	9	0.0760	4.24E+02	4.24E+01	2.68	7.42E-10
	Lombard4	3780.00	-3161	-3181	20	0.0604	3.56E-02	3.56E-03	2.68	7.42E-10
	Lombard3	3800.00	-3181	-3189	8	0.0799	5.19E+00	5.19E-01	2.68	7.42E-10
	Lombard2	3807.50	-3189	-3194	5	0.0631	5.71E-01	5.71E-02	2.68	7.42E-10
	Lombard1	3812.50	-3194	-3219	26	0.0900	1.77E+00	1.77E-01	2.68	7.42E-10
	Elmhurst7	3838.00	-3219	-3229	10	0.1595	2.04E+01	8.17E+00	2.64	3.71E-10
	Elmhurst6	3848.00	-3229	-3239	10	0.1981	1.84E+02	7.38E+01	2.64	3.71E-10
	Elmhurst5	3858.00	-3239	-3249	10	0.0822	1.87E+00	1.87E-01	2.64	3.71E-10
	Elmhurst4	3868.00	-3249	-3263	14	0.1105	4.97E+00	1.99E+00	2.64	3.71E-10
	Elmhurst3	3882.00	-3263	-3267	4	0.0768	7.52E-01	7.52E-02	2.64	3.71E-10
	Elmhurst2	3886.00	-3267	-3277	10	0.1291	1.63E+01	6.53E+00	2.64	3.71E-10
	Elmhurst1	3896.00	-3277	-3289	12	0.0830	2.90E-01	2.90E-02	2.64	3.71E-10
	MtSimon17	3908.00	-3289	-3315	26	0.1297	7.26E+00	2.91E+00	2.65	3.71E-10
	MtSimon16	3934.00	-3315	-3322	7	0.1084	3.78E-01	3.78E-02	2.65	3.71E-10
	MtSimon15	3941.00	-3322	-3335	13	0.1276	5.08E+00	2.03E+00	2.65	3.71E-10
	MtSimon14	3954.00	-3335	-3355	20	0.1082	1.33E+00	5.33E-01	2.65	3.71E-10
	MtSimon13	3974.00	-3355	-3383	28	0.1278	5.33E+00	2.13E+00	2.65	3.71E-10
	MtSimon12	4002.00	-3383	-3404	21	0.1473	1.59E+01	6.34E+00	2.65	3.71E-10
	MtSimon11	4023.00	-3404	-3427	23	0.2042	3.10E+02	1.55E+02	2.65	3.71E-10
	MtSimon10	4046.00	-3427	-3449	22	0.1434	1.39E+01	4.18E+00	2.65	3.71E-10
	MtSimon9	4068.00	-3449	-3471	22	0.1434	1.39E+01	4.18E+00	2.65	3.71E-10
	MtSimon8	4090.00	-3471	-3495	24	0.1503	2.10E+01	6.29E+00	2.65	3.71E-10
	MtSimon7	4114.00	-3495	-3518	23	0.1311	6.51E+00	1.95E+00	2.65	3.71E-10
	MtSimon6	4137.00	-3518	-3549	31	0.1052	2.26E+00	6.78E-01	2.65	3.71E-10
	MtSimon5	4168.00	-3549	-3588	39	0.1105	4.83E-02	4.83E-03	2.65	3.71E-10
	MtSimon4	4207.00	-3588	-3627	39	0.1105	4.83E-02	4.83E-03	2.65	3.71E-10
	MtSimon3	4246.00	-3627	-3657	30	0.1727	1.25E+01	1.25E+00	2.65	3.71E-10
	MtSimon2	4276.00	-3657	-3717	60	0.1157	2.87E+00	2.87E-01	2.65	3.71E-10
	MtSimon1	4336.00	-3717	-3799	82	0.1157	2.87E+00	2.87E-01	2.65	3.71E-10

Table 2. Lithology-Specific Permeability Anisotropy Averages from Literature

Facies or Lithology	Kv/Kh	Reference
1. Heterolithic, laminated shale/mudstone/siltstone/sandstone	0.1	Meyer and Krause (2006)
2. Herringbone cross-stratified sandstone. Strat dips to 18 degrees	0.4	Meyer and Krause (2006)
3. Paleo weathered sandstone (coastal flat)	0.4	Meyer and Krause (2006)
4. Accretionary channel bar sandstones with minor shale laminations	0.5	Ringrose et al. (2005); Meyer and Krause (2006)
6. Alluvial fan, alluvial braided stream plain to shallow marine sandstones, low clay content	0.3	Kerr et al. (1999)
7. Alluvial fan, alluvial plain sandstones, sheet floods, paleosols, higher clay content	0.1	Hornung and Aigner (1999)
8. Dolomite mudstone	0.007	Saller et al. (2004)

Table 3. Summary of the K_v/K_h Ratios Applied to Model Layers

Model Layer	Kv/Kh Applied to Model Layers[a]*	Kv/Kh Determined from Core Pairs[b]	Successfully Analyzed Core Pairs
Franconia carbonate	0.007	ND	ND
Davis-Ironton	0.1	ND	ND
Ironton-Galesville	0.4	ND	ND
Proviso (Layers 4 and 5)	0.1	ND	ND
Proviso ([carbonate] Layers 1 to 3)	0.007	ND	ND
Lombard Total Interval	0.1	0.029	12
Lombard (Layer 7)	0.1	.098	2
Lombard (Layer 6)	0.1	0.003	2
Lombard (Layer 5)	0.1	ND	ND
Lombard (Layer 4)	0.1	0.016	2
Lombard (Layer 3)	0.1	0.064	2
Lombard (Layer 2)	0.1	0.009	1
Lombard (Layer 1)	0.1	0.104	3
Elmhurst Total Interval	0.4	0.06	4
Elmhurst (Layer 7)	0.4	ND	ND
Elmhurst (Layer 6)	0.4	0.023	1
Elmhurst (Layer 5)	0.1	ND	ND
Elmhurst (Layer 4)	0.4	0.902	1
Elmhurst (Layer 3)	0.1	ND	ND
Elmhurst (Layer 2)	0.4	0.022	1
Elmhurst (Layer 1)	0.1	0.037	1
Mt. Simon (Layer 17)	0.4	0.233	2
Mt. Simon (Layer 16)	0.1	ND	ND
Mt. Simon (layer 13)	0.4	0.643	2
Mt. Simon (Layers 12, 14, and 15)	0.4	ND	ND
Mt. Simon (Layer 11, Injection) zone)	0.5	ND	ND
Mt. Simon (Layers 6, 7, 8, 9, 10)	0.3	ND	ND
Mt. Simon (Layers 1, 2, 3, 4, 5)	0.1	ND	ND

(a) Value from literature, referenced in the Supporting Documentation of the UIC permit application
(b) Geometric mean of successful core pairs.

Porosity

Total (or absolute) porosity is the ratio of void space to the volume of whole rock. Effective porosity is the ratio of interconnected void space to the volume of the whole rock. As a first step in assigning porosity values for the FutureGen 2.0 numerical model layers, Schlumberger ELAN porosity log results were compared with laboratory measurements of porosity as determined from SWC and core plugs for specific sampling depth within the Mount Simon. The Schlumberger ELAN porosity logs examined include PIGN (Gamma-Neutron Porosity), PHIT (Total Porosity), and PIGE (Effective Porosity). The PIGN and PIGE wireline log surveys use different algorithms to identify clay- or mineral-bound fluid/porosity in calculating an effective porosity value. SWC porosity measurements are listed as "total porosity," but their measurement can be considered to be determinations of "effective porosity," because the measurement technique (weight measurements of heated/oven-dried core samples) primarily measures the amount of "free" or connected pore liquid contained within the SWC sample as produced by the heating process. It should be noted that the SWC porosity measurements were determined under ambient pressure conditions.

In Figure 2, neutron- and density-crossplot porosity is shown in the fourth panel, along with lab-measured porosity for core plugs and rotary SWC. An available porosity measurement data set for a conventional Mount Simon Sandstone core-plug sample taken near the top of the formation (depth of 3,912 ft bgs or elevation of -3,293 ft) indicates only minor changes in porosity for measurements taken over a wide range in pressure (i.e., ambient to 1,730 psi). This suggests that ambient SWC porosity measurements of the Mount Simon may be representative of in situ formation pore pressure conditions. The ELAN porosity log results generally underestimate the SWC porosity measured values. As a result of the poor visual correlation of the PIGE survey results with SWC measurements, this ELAN log was omitted from subsequent correlation evaluations. To aid in the correlations, the gamma ray survey log (GR) was used as a screening tool for development of linear-regression correlation relationships between ELAN log responses and SWC porosity measurements. This helps account for the shale or clay content that can cause the inclusion of "bound water" porosity. To assign model layer porosities, the regression model relationships used to calibrate the ELAN measurement results (Figure 7) were applied to the ELAN survey results over the formational depths represented by the Mount Simon (3,904 to 4,416 ft bgs depth or -3,285 to -3,797 ft elevation) and overlying Eau Claire-Elmhurst member (3,838 to 3,904 ft bgs depth or -3,219 to -3,285 ft elevation) based on the gamma response criteria. The ELAN survey results are reported at 0.5-ft depth intervals. For stratigraphic units above the Elmhurst and/or depth intervals exhibiting gamma readings >64 API units, the un-calibrated, average ELAN log result for that depth interval was used. An average porosity was then assigned to the model layer based on the average of the calibrated ELAN values within the model layer depth range. Figure 8 shows the depth profile of the assigned model layer porosities based on the average of the calibrated ELAN values. The actual values assigned for each layer are listed in Table 1.

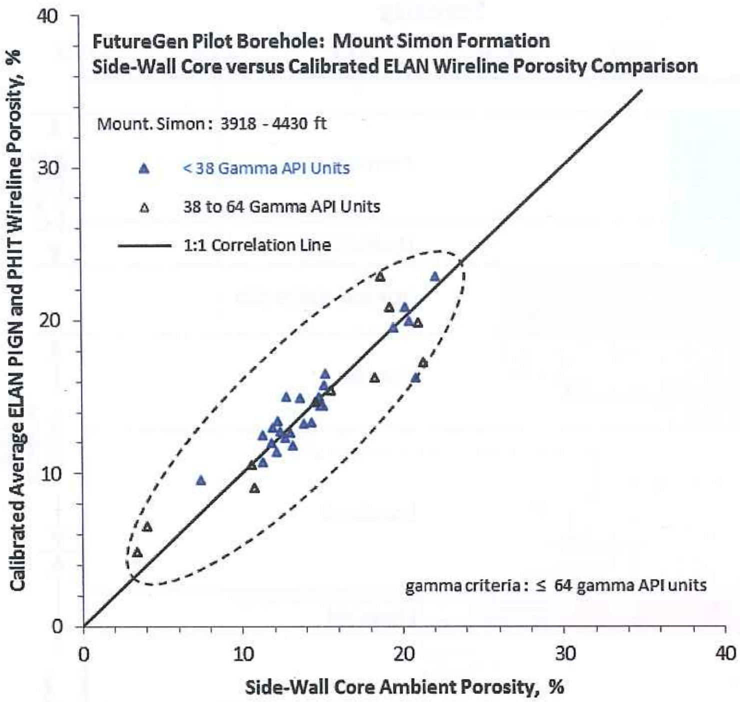


Figure 7. Comparison of SWC Porosity Measurements and Regression-Calibrated ELAN Log Porosities: ≤64 Gamma API Units

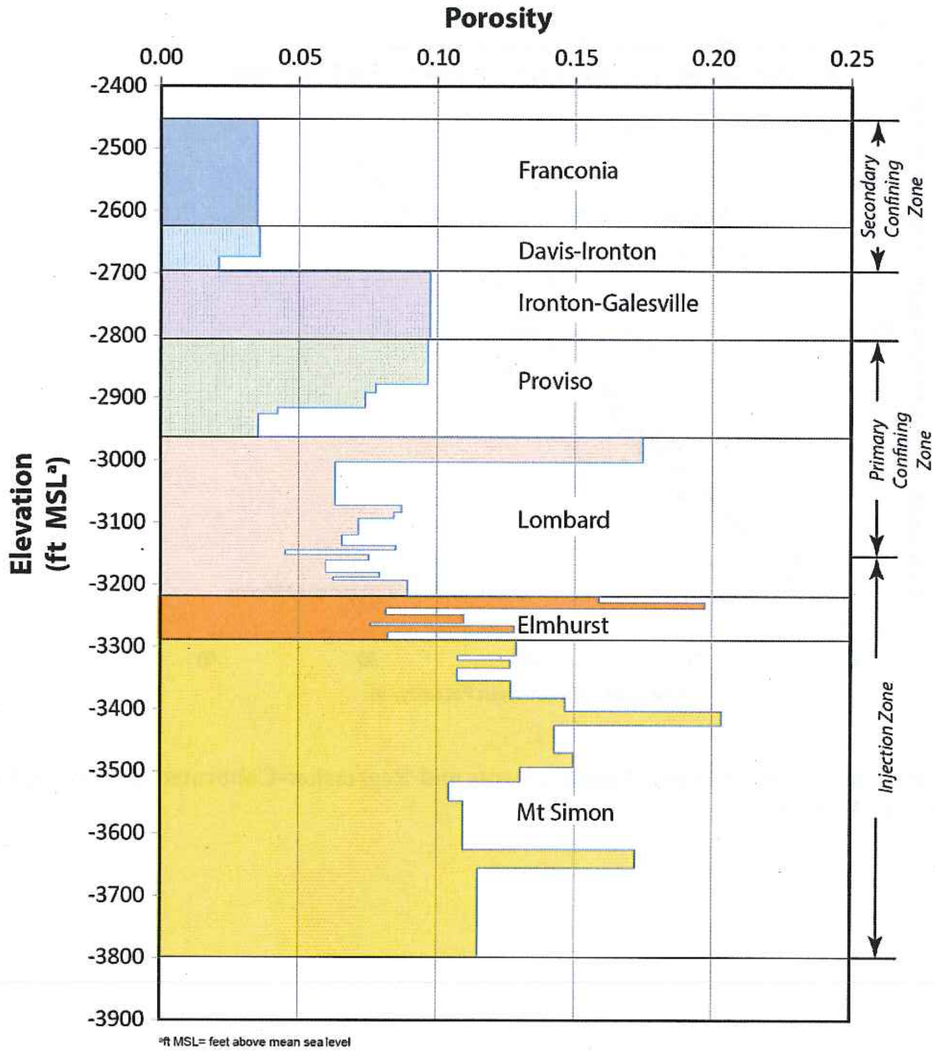


Figure 8. Vertical Distribution of Porosity in the Model Layers at the Stratigraphic Well Location

Rock (Bulk) Density and Grain Density

Grain density data were calculated from laboratory measurements of SWCs. The data were then averaged (arithmetic mean) for each main stratigraphic layer in the model. Only the Proviso member (Eau Claire Formation) has been divided in two sublayers to be consistent with the lithology changes. Figure 9 shows the calculated grain density with depth. The actual values assigned to each layer of the model are listed in Table 1. Grain density is the input parameter specified in the simulation input file, and STOMP-CO2 calculates the bulk density from the grain density and porosity for each model layer.

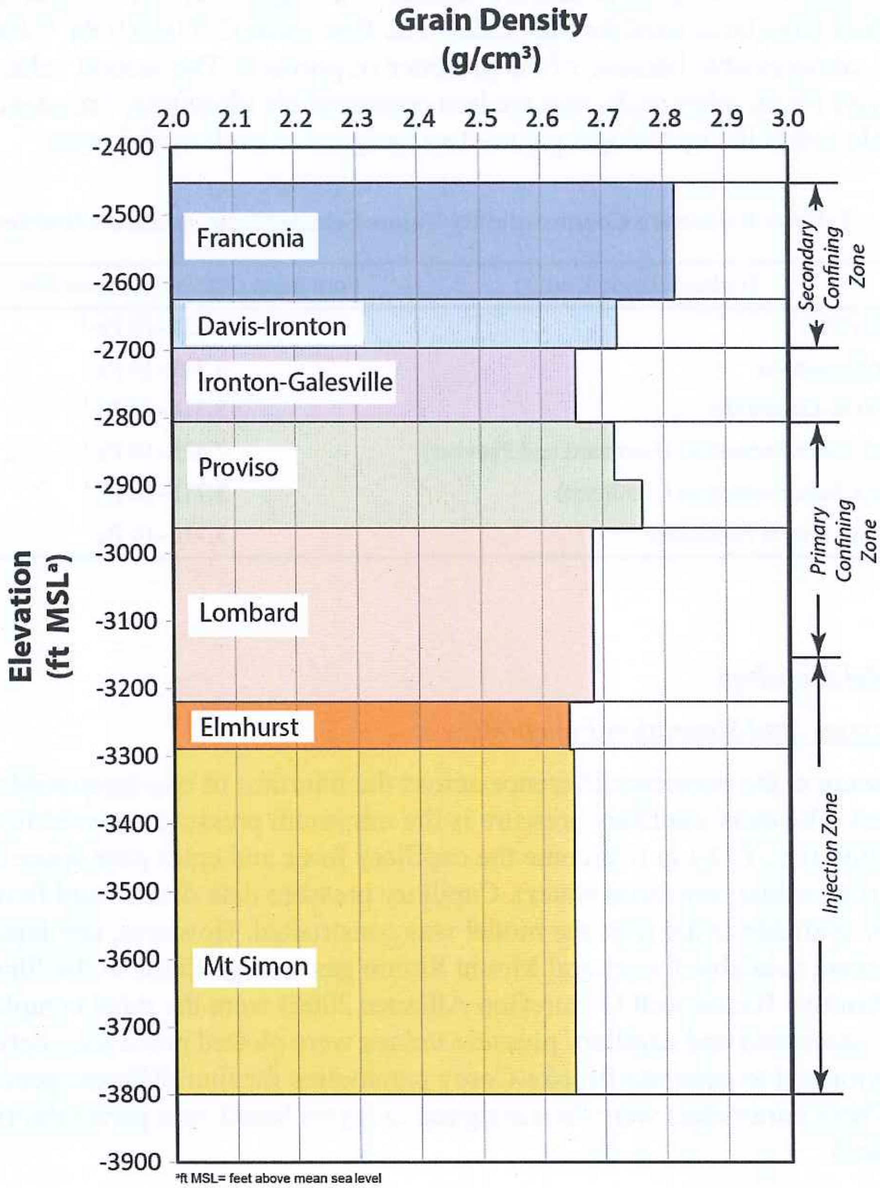


Figure 9. Vertical Distribution of the Grain Density in the Model Layer at the Stratigraphic Well Location

Formation Compressibility

Limited information about formation (pore) compressibility estimates is available. The best estimate for the Mount Simon Sandstone (Table 4) is that back-calculated by Birkholzer et al. (2008) from a pumping test at the Hudson Field natural-gas storage site, found 80 mi (129 km) northeast of the Morgan County CO_2 storage site. The back-calculated pore-compressibility estimate for the Mount Simon Sandstone of 3.71E−10 Pa^{-1} was used as a spatially constant value for their basin-scale simulations. In other simulations, Birkholzer et al. (2008) assumed a pore-compressibility value of 4.5E−10 Pa^{-1} for aquifers and 9.0E−10 Pa^{-1} for aquitards. Zhou et al. (2010) in a later publication used a pore-compressibility value of 7.42E−10 Pa^{-1} for both the Eau Claire Formation and Precambrian granite, which were also used for these initial simulations

(Table 4). Because the site-specific data are limited to a single reservoir sample, only these two published values have been used for the model. The first value (3.71E-10 Pa^{-1}) has been used for sands that are compressible because of the presence of porosity. The second value (7.42E-10 Pa^{-1}) is assigned for all other rocks that are less compressible (dolomite, limestone, shale, and rhyolite). Table 1 lists the hydrologic parameters assigned to each model layer.

Table 4. Formation Compressibility Values Selected from Available Sources

Hydrogeologic Unit	Formation (Pore) Compressibility, Pa^{-1}
Franconia	7.42E-10 Pa^{-1}
Davis-Ironton	3.71E-10 Pa^{-1}
Ironton-Galesville	3.71E-10 Pa^{-1}
Eau Claire Formation (Lombard and Proviso)	7.42E-10 Pa^{-1}
Eau Claire Formation (Elmhurst)	3.71E-10 Pa^{-1}
Mount Simon Sandstone	3.71E-10 Pa^{-1}

Constitutive Relationships

<u>*Capillary Pressure and Saturation Functions*</u>

Capillary pressure is the pressure difference across the interface of two immiscible fluids (e.g., CO_2 and water). The entry capillary pressure is the minimum pressure required for an immiscible non-wetting fluid (i.e., CO_2) to overcome the capillary force and enter pore space containing the wetting fluid (i.e., saline formation water). Capillary pressure data determined from site-specific cores were not available at the time the model was constructed. However, tabulated capillary pressure data were available for several Mount Simon gas storage fields in the Illinois Basin. The data for the Manlove Hazen well (FutureGen Alliance 2006) were the most complete. Therefore, these aqueous saturation and capillary pressure values were plotted and a user-defined curve fitting was performed to generate Brooks-Corey parameters for four different permeabilities (Figure 10). These parameters were then assigned to layers based on a permeability range as shown in Table 5.

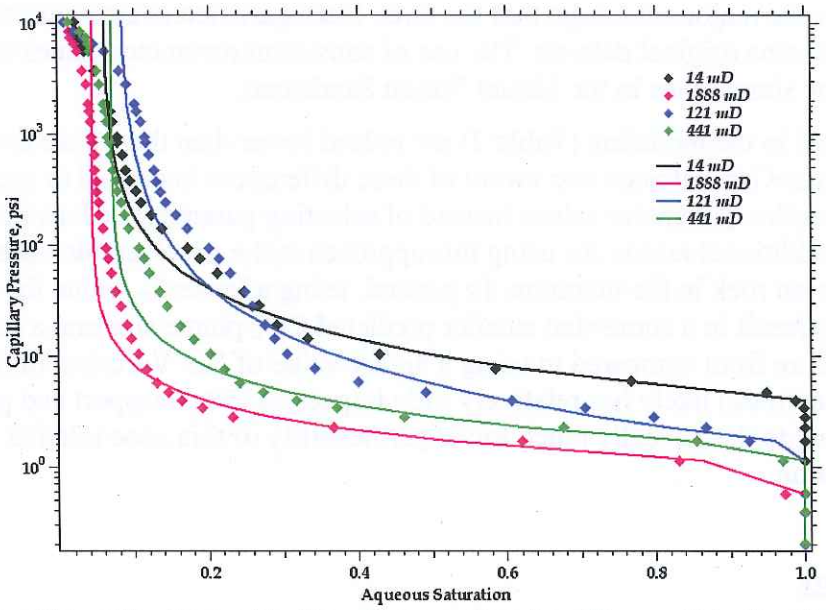


Figure 10. Aqueous Saturation Versus Capillary Pressure Based on Mercury Injection Data from the Hazen No. 5 Well at the Manlove Gas Field in Champagne County, Illinois

Table 5. Permeability Ranges Used to Assign Brooks-Corey Parameters to Model Layers

Permeability (mD)	Psi	Lambda (λ)	Residual Aqueous Saturation
< 41.16	4.116	0.83113	0.059705
41.16 to 231	1.573	0.62146	0.081005
231 to 912.47	1.450	1.1663	0.070762
> 912.47	1.008	1.3532	0.044002

The Brooks-Corey (1964) saturation function is given as

$$S_{ew} = \begin{cases} (P_e / P_c)^{\lambda} & \text{if} \quad P_c > P_e \\ 1 & \text{otherwise} \end{cases}$$

where S_{ew} is effective aqueous saturation, P_c is capillary pressure, P_e is gas entry pressure, and λ is the pore-size distribution parameter. Combined with the Burdine (1953) relative permeability model, the relative permeability for the aqueous phase, k_{rw}, and that for the non-aqueous phase, k_{rn}, are

$$K_{rw} = (S_{ew})^{3+2/\lambda}$$

$$K_{rn} = (1 - S_{ew})^2 (1 - S_{ew}{}^{1+2/\lambda})$$

Values for the residual aqueous saturation (S_{rw}) and the two other parameters used in the Brooks-Corey capillary pressure-saturation function (i.e., the non-wetting fluid entry pressure and a pore-size distribution parameter) were all obtained by fitting mercury (Hg) intrusion-capillary pressure data from the Manlove gas storage site in Champaign County. The fitting was applied after scaling the capillary pressures to account for the differences in interfacial tensions and contact angles for the brine-CO_2 fluid pair, relative to vapor-liquid Hg used in the measurements.

This approach has the major advantage that the three fitted parameters are consistent as they are obtained from the same original data set. The use of consistent parameter values is not the norm for brine-CO_2 flow simulations in the Mount Simon Sandstone.

The S_{rw} values used in the modeling (Table 2) are indeed lower than the values found in the literature. The FutureGen Alliance was aware of these differences but opted to use a consistent data set for all retention parameter values instead of selecting parameter values from different data sources. An additional reason for using this approach is the considerable uncertainty in S_{rw} values for Mt. Simon rock in the literature. In general, using a lower S_{rw} value for the injection zone will possibly result in a somewhat smaller predicted CO_2 plume size and a smaller spatial extent of the pressure front compared to using a higher value of S_{rw}. Variation of S_{rw} in the confining zone (cap rock) likely has relatively little impact on CO_2 transport and pressure development owing to the typically much lower permeability of this zone relative to the underlying formation.

Gas Entry Pressure

No site-specific data were available for gas entry pressure; therefore, this parameter was estimated using the Davies (1991) developed empirical relationships between air entry pressure, *Pe*, and intrinsic permeability, *k*, for different types of rock:

$$Pe = a\,k^b$$

where *Pe* takes the units of MPa and *k* the units of m^2, *a* and *b* are constants and are summarized below for shale, sandstone, and carbonate (Davies 1991; Table 3). The dolomite found at the Morgan County site is categorized as a carbonate. The *Pe* for the air-water system is further converted to that for the CO_2-brine system by multiplying the interfacial tension ratio of a CO_2-brine system β_{cb} to an air-water system β_{aw}. An approximate value of 30 mN/m was used for β_{cb} and 72 mN/m for β_{aw}.

Table 6. Values for Constants a and b for Different Lithologies

	Shale	Sandstone	Carbonate
a	7.60E-07	2.50E-07	8.70E-07
b	-0.344	-0.369	-0.336

CO_2 Entrapment

The entrapment option available in STOMP-CO2 was used to allow for entrapment of CO_2 when the aqueous phase is on an imbibition path (i.e., increasing aqueous saturation). Gas saturation can be free or trapped:

$$s_g = 1 - s_l = s_{gf} + s_{gt}$$

where the trapped gas is assumed to be in the form of aqueous occluded ganglia and immobile. The potential effective trapped gas saturation varies between zero and the effective maximum trapped gas saturation as a function of the historical minimum value of the apparent aqueous saturation. No site-specific data were available for the maximum trapped gas saturation, so this value was taken from the literature. Suekane et al. (2009) used micro-focused x-ray CT to image a chip of Berea Sandstone to measure the distribution of trapped gas bubbles after injection of $scCO_2$ and then water, under reservoir conditions. Based on results presented in the literature, a value of 0.2 was used in the model, representing the low end of measured values for the maximum trapped gas saturation in core samples.

Formation Properties

Fluid Pressure

An initial fluid sampling event from the Mount Simon formation was conducted on December 14, 2011, in the stratigraphic well during the course of conducting open-hole logging. Sampling was attempted at 22 discrete depths using the MDT tool in the Quicksilver Probe configuration and from one location using the conventional (dual-packer) configuration. Pressure data were obtained at 7 of the 23 attempted sampling points, including one duplicated measurement at a depth of 4,034 ft bgs or elevation of -3415 ft (Table 7).

Figure 11 shows the available regional potentiometric surfaces for the Mount Simon Sandstone. The figure contains pre-development hydraulic head measurements (e.g., before widespread pumping from the Mount Simon Sandstone, particularly in Northern Illinois) and simulation results for predicting the post-development (i.e., 1980) potentiometric surface. As shown in Figure 11, data are sparse around the area of the FutureGen 2.0 Site, and it is situated in an area where the regional gradients are very low and the flow directions are not constrained (pre- or post-development). For these reasons, a regional horizontal flux for the Mount Simon Sandstone was not specified in the computational model.

Vertical flow potential at the FutureGen 2.0 Site was evaluated based on an analysis of discrete pressure/depth measurements obtained within the pilot characterization borehole over the depth interval of 1,134 to 4,249 ft bgs depth (-515 to -3,630 ft elevation). The results indicate that there is a positive head difference in the Mount Simon that ranges from 47.8 to 61.6 ft above the calculated St. Peter observed static hydraulic head condition (i.e., 491.1 ft above MSL). This positive head difference suggests a natural vertical flow potential from the Mount Simon to the overlying St. Peter if hydraulic communication is afforded (e.g., an open communicative well). It should also be noted, however, that the higher head within the unconsolidated Quaternary aquifer (~611 ft above MSL), indicates a downward vertical flow potential from this surficial aquifer to both the underlying St. Peter and Mount Simon bedrock aquifers. The disparity in the calculated hydraulic head measurements (together with the significant differences in formation fluid salinity) also suggests that groundwater within the St. Peter and Mount Simon bedrock aquifers is physically isolated from one another. This is an indication that there are no significant conduits (open well bores or fracturing) between these two formations and that the Eau Claire forms an effective confining layer.

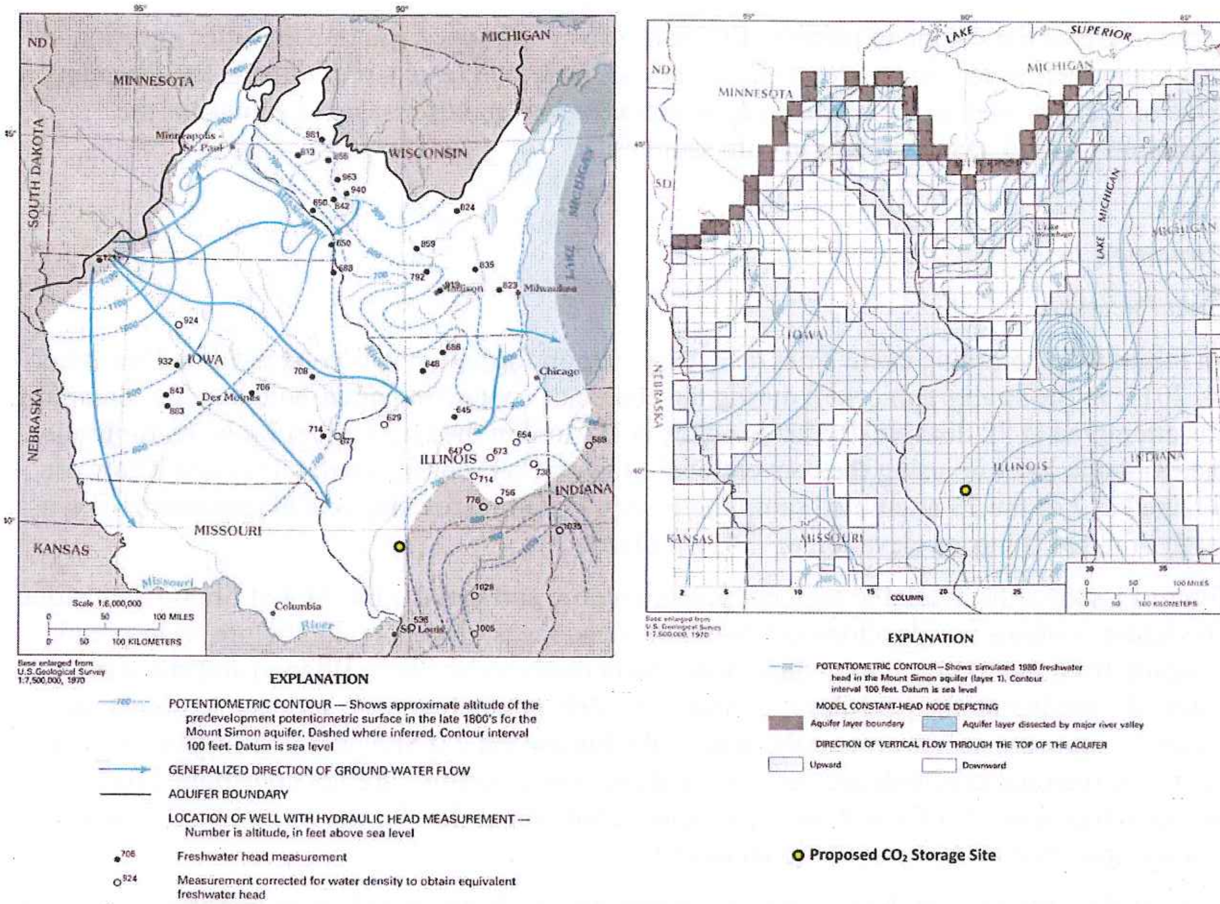


Figure 11. Approximate Pre-Development Potentiometric Surface (a) for the Mount Simon Aquifer (from Young 1992, modified from Mandel and Kontis 1992) and (b) Simulated 1980 Freshwater Head in the Mount Simon Aquifer showing Impact of Withdrawals in Northern portion of Illinois (Mandel and Kontis 1992)

Table 7. Pressure Data Obtained from the Mount Simon Formation Using the MDT Tool Where the Red Line Delimits the Samples Within the Injection Zone

Sample Number	Sample Depth (ft bgs)	Absolute Pressure (psia)
7	4,116	1,828
8	4,117	1,827.7
9	4,096.5	1,818.3
11	**4,034**	**1,790.2**
17	**4,034 (duplicated)**	**1,790.3**
21	4,234.5	1,889.2
22	4,232	1,908.8
23	4,249	1,896.5[(a)]

(a) Sample affected by drilling fluids (not representative)

Temperature

The best fluid temperature depth profile was performed on February 9, 2012, as part of the static borehole flow meter/fluid temperature survey that was conducted prior to the constant-rate injection flow meter surveys. Two confirmatory discrete probe depth measurements that were taken prior to the active injection phase (using colder brine) corroborate the survey results. The discrete static measurement for the depth of 3,698 ft bgs (elevation of -3,079 ft) was 95.9°F. The second discrete static probe temperature measurement is from the MDT probe for the successful sampling interval of 4,034 ft bgs depth (elevation of -3,415 ft). A linear-regression temperature/depth relationship was developed for use by modeling. The regression data set analyzed was for temperature data over the depth interval of 1,286 to 4,533 ft bgs (elevation of -667 to -3,914 ft). Based on this regression, a projected temperature for the reference datum at the top of the Mount Simon (3,904 ft bgs depth or -3,285 ft elevation) of 96.60°F is indicated. A slope (gradient) of 6.72×10^{-3} °F/ft and intercept of 70.27°F is also calculated from the regression analysis.

Brine Density

Although this parameter is determined by the simulator using pressure, temperature, and salinity, based on the upper and lower Mount Simon injection zone tests, the calculated in situ injection zone fluid density is 1.0315 g/cm^3.

Salinity and Water Quality

During the process of drilling the well, fluid samples were obtained from discrete-depth intervals in the St. Peter Formation and the Mount Simon Formation using wireline-deployed sampling tools (MDTs) on December 14, 2011. After the well had been drilled, additional fluid samples were obtained from the open borehole section of the Mount Simon Formation by extensive pumping using a submersible pump. The assigned salinity value for the Mount Simon (upper zone) 47,500 ppm is as indicated by both the MDT sample (depth 4,034 ft bgs or elevation of -

3,415 ft) and the multiple samples collected during extensive composite pumping of the open borehole section.

A total of 20 groundwater samples were collected between October 25 and November 10, 2011, including duplicate samples and blanks (Dey et al. in press as of 2013). General water-quality parameters were measured along with organic and major inorganic constituents. Values of pH ranged from 7.08 to 7.66. Values for specific conductance ranged from 545 to 1,164 μS/cm, with an average of 773 μS/cm. Values of Eh ranged from 105 to 532 mV with an average of 411 mV. Values of dissolved oxygen (DO) ranged from below detection limit to 3.3 mg/L O_2. Most dissolved inorganic constituent concentrations are within primary and secondary drinking water standards. However, the constituent concentration in water is elevated with respect to iron (Fe), manganese (Mn), nitrate (NO3), and the total dissolved salt (TDS). In some cases these constituents exceed the U.S. Environmental Protection Agency (EPA) secondary standards.

Fracture Pressure in the Injection Zone

At the time the computational model was developed, no site-specific hydraulic fracturing tests had been conducted in the stratigraphic well and no site-specific fracture pressure values were available for the confining zone and the injection zone. Other approaches (listed below) have thus been chosen to determine an appropriate value for the fracture pressure.

- Triaxial tests were conducted on eight samples from the stratigraphic well. Samples 3 to 7 are located within the injection zone. Fracture gradients were estimated to range from 0.647 to 0.682 psi/ft, which cannot directly be compared to the fracture pressure gradient required for the permit. Triaxial tests alone cannot provide accurate measurement of fracture pressure.
- Existing regional values. Similar carbon storage projects elsewhere in Illinois (in Macon and Christian counties) provide data for fracture pressure in a comparable geological context. In Macon County (CCS#1 well at Decatur), about 65 mi east of the FutureGen 2.0 Site, a fracture pressure gradient of 0.715 psi/ft was obtained at the base of the Mount Simon Sandstone Formation using a step-rate injection test (EPA 2011a). In Christian County, a "conservative" pressure gradient of 0.65 psi/ft was used for the same injection zone (EPA 2011b). No site-specific data were available.
- Last, the regulation relating to the "Determination of Maximum Injection Pressure for Class I Wells" in EPA Region 5 is based on the fracture closure pressure, which has been chosen to be 0.57 psi/ft for the Mount Simon Sandstone (EPA 1994).

Based on these considerations, a fracture pressure gradient of 0.65 psi/ft was chosen. The EPA Geologic Sequestration Rule requires that "Except during stimulation, the owner or operator 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)…" Therefore, a value of 0.585 psi/ft (90 percent of 0.65 psi/ft) was used in the model to calculate the maximum injection pressure permitted.

In November and December 2013, hydraulic tests were conducted in the Mount Simon Sandstone and in the Precambrian basement. The first results of these tests verify that the fracture gradient used in the model for the injection zone remains conservative and appropriate.

Site Evaluation of Mineral Resources

Other subsurface geochemical considerations include the potential for mineral or hydrocarbon resources beneath the proposed CO_2 storage site. While no significant mineral deposits are known to exist within Morgan County, natural gas has been recovered in the region, including at the Prentice and Jacksonville fields located within several miles of the stratigraphic well. ISGS oil and gas website data indicate that the Prentice Field contained more than 25 wells drilled during the 1950s; re-exploration occurred in the 1980s. Both oil and gas have been produced from small stratigraphic traps in the shallow Pennsylvanian targets, at depths of 250 to 350 ft (75 to 105 m) bgs. It is important to note that gas produced from these wells may contain around 16 percent CO_2 (Meents 1981). More than 75 wells have been drilled in the Jacksonville Field. Gas was discovered in the Jacksonville Field as early as 1890 (Bell 1927), but most oil and gas production from the Prentice and Jacksonville fields occurred between the late 1920s and late 1980s. The most productive formations in the Illinois Basin (lower Pennsylvanian and Mississippian siliciclastics and Silurian reefs) are not present in Morgan County. Only two boreholes in the vicinity of the Prentice Field and five boreholes near the Jacksonville Field penetrate through the New Albany Shale into Devonian and Silurian limestone. Cumulative production from the Prentice and Jacksonville fields is not available, and both fields are largely abandoned. The Waverly Storage Field natural-gas storage site in the southeast corner of Morgan County originally produced oil from Silurian carbonates. This field no longer actively produces oil, but since 1954 it has been successfully used for natural-gas storage in the St. Peter and the Galesville/Ironton Sandstone formations (Buschbach and Bond 1974).

The nearest active coal mine is approximately 10 mi (16 km) away in Menard County and does not penetrate more than 200 ft (61 m) bgs (ISGS 2012). A review of the known coal geology within a 5-mi (8-km) radius of the proposed drilling site indicates that the Pennsylvanian coals, the Herrin, Springfield, and Colchester coals, are very thin or are absent from the project area (ISGS 2010, 2011; Hatch and Affolter 2008). During continuous coring of a shallow groundwater monitoring well located immediately adjacent to the stratigraphic well, only a single thin (5-ft [1.5-m]) coal seam was encountered at about 200 ft (61 m) depth.

Initial Conditions

The injection zone is assumed to be under hydrostatic conditions with no regional or local flow conditions. Therefore the hydrologic flow system is assumed to be at steady state until the start of injection. To achieve this with the STOMP-CO2 simulator one can either run an initial simulation (executed for a very long time period until steady-state conditions are achieved) to generate the initial distribution of pressure, temperature, and salinity conditions in the model from an initial guess, or one can specify the initial conditions at a reference depth using the hydrostatic option in the STOMP-CO2 input file, allowing the simulator to calculate and assign the initial conditions to all the model nodes. Site-specific data were available for pressure, temperature, and salinity, and therefore the hydrostatic option was used to assign initial conditions. A temperature gradient was specified based on the geothermal gradient, but the initial salinity was considered to be constant for the entire domain. A summary of the initial conditions is presented in Table 8.

Table 8. Summary of Initial Conditions

Parameter	Reference Depth (ft bgs)	Elevation (ft)	Value
Reservoir Pressure	4,034	-3,415	1,790.2 psi
Aqueous Saturation			1.0
Reservoir Temperature	3,904	-3,285	96.6 °F
Temperature Gradient			0.00672 °F/ft
Salinity			47,500 ppm

Boundary Conditions

Boundary conditions were established with the assumption that the injection zone and confining zone are continuous throughout the region and that the underlying Precambrian unit is impermeable. Therefore, the bottom boundary was set as a no-flow boundary for aqueous fluids and for the CO_2-rich phase. The lateral and top boundary conditions were set to hydrostatic pressure using the initial condition with the assumption that each of these boundaries is distant enough from the injection zone to have minimal to no effect on the CO_2 plume migration and pressure distribution.

Wells within the Survey Area

A detailed survey was completed over a 25 mi^2 (65 km^2) area, termed the "Survey Area." This area is centered on the proposed injection location (labeled as "Injection Site") and encompasses the predicted maximum extent of the CO_2 plume (Figure 12). Wells, surface bodies of water and other pertinent surface features, administrative boundaries, and roads within the Survey Area are shown in Figure 12. There are no subsurface cleanup sites, mines, quarries, or Tribal lands within this area. The Survey Area is near the center of the AoR (Figure 15).

A total of 129 wells are located within the Survey Area. However, no well but the FutureGen Alliance's stratigraphic well penetrates the injection zone (Mount Simon Sandstone and the lower Eau Claire [Elmhurst Sandstone Member and lower portion of the Lombard Member]), the confining zone (Upper portion of Lombard Member and Proviso Member of the Eau Claire Formation), or the secondary confining zone (Franconia Dolomite).

Shallow domestic water wells with depths of less than 50 ft (15 m) are the most common well type within the Survey Area. Five slightly deeper water wells were identified that range in depths from 110 ft (33 m) to 405 ft (123 m). Other wells include stratigraphic test holes, coal test holes, and oil and gas wells.

Twenty four of the 129 wells in the Survey Area are identified with only a general location (center of a section) in the ISWS database. These wells are included in Table 9 but are not shown on the map.

A general survey of the AoR outside the Survey Area was conducted by reference of publicly available information. Maps of existing water wells, oil and gas wells, miscellaneous wells, coal mines, surface water, and geologic structures were submitted to complete the permit requirements.

There are 4,386 water wells and 740 oil and gas wells within the AoR, but only two of these penetrate the confining zone. These two wells identified in the AoR are approximately 16 miles from the injection site, but they are adequately plugged.

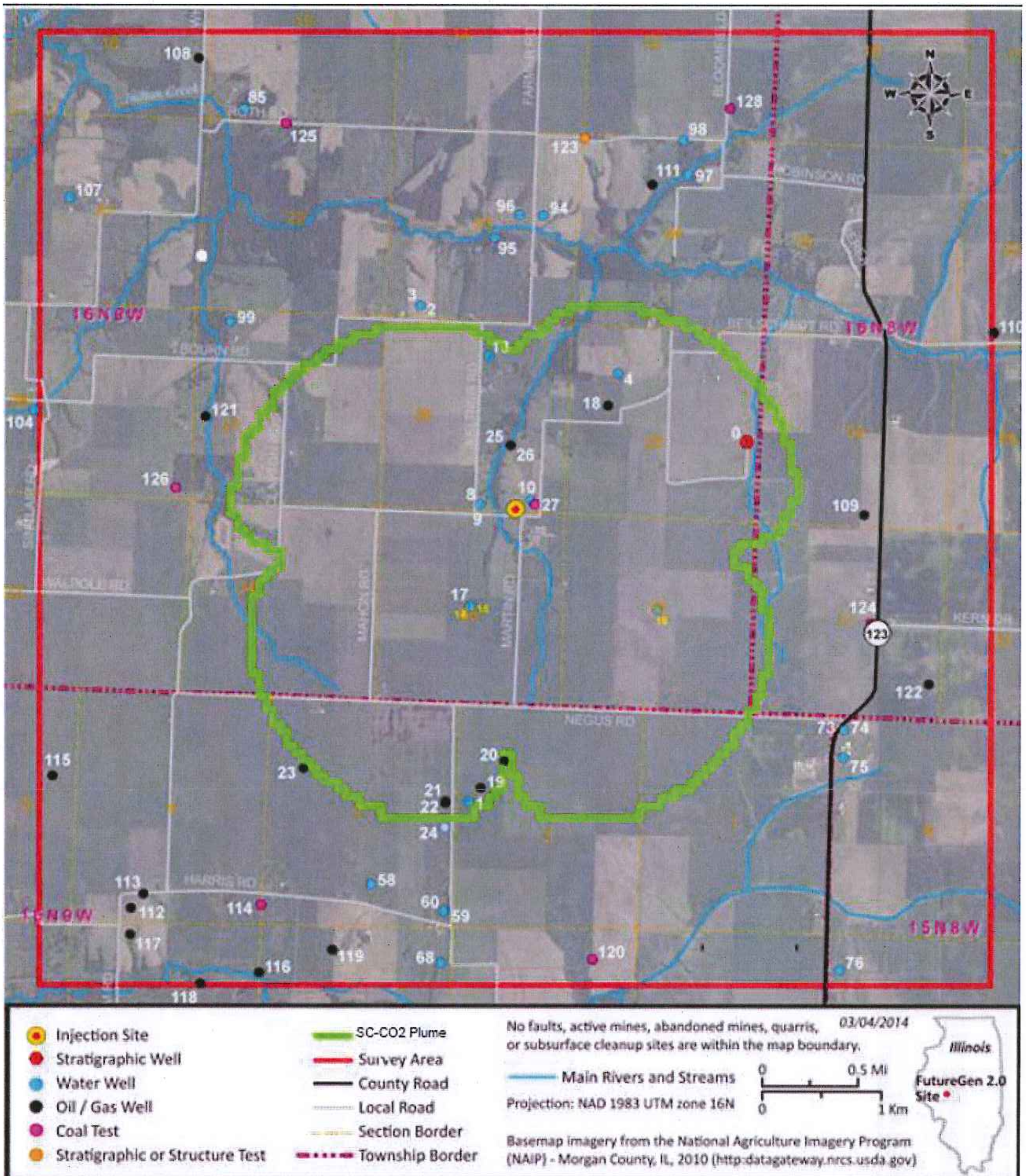
Survey Area

Latitude NAD1983	Longitude NAD1983	Public Land Survey System	Total Depth ft	Elev ft	Completion Date	Owner	Well Num	Well Type	Status
39.806064	-90.052919	T16n,R9w,Sec 25	4812	633	TBD	FutureGen Industrial Alliance, Inc.	1	Monitoring	Active
39.778074	-90.078443	T15N,R9W,Sec 2	25		19780712	A.A. Negus Estate	1	Water	Private Water Well
39.811025	-90.065241	T16N,R9W,Sec 25	115			Beilschmidt, William H.		Water	
39.800661	-90.078386	T16N,R9W,Sec 26	127		1950	Martin, L. E.	1	Water	
39.800661	-90.078386	T16N,R9W,Sec 26	127			Martin, L. E.		Water	
39.801129	-90.07342	T16N,R9W,Sec 26	25		19781213	Martin, Marvin & Jean	1	Water	Private Water Well
39.792894	-90.078875	T16N,R9W,Sec 35	28			E Clemons		Water	
39.792894	-90.078875	T16N,R9W,Sec 35	25			B Sister		Water	
39.792837	-90.060294	T16N,R9W,Sec 36	35			J M Dunlap		Water	
39.792893	-90.078984	T16N,R9W,Sec 35	1056	643		O'Rear, Judge	1	Oil & Gas / Water	
39.808545	-90.06614	T16N,R9W,Sec 25	1530	630	19391001	Beilschmidt, Wm.	1	Oil & Gas	Dry and Abandoned, No Sh
39.779153	-90.077325	T15N,R9W,Sec 2	338	644	19231101	Conklin	1	Oil & Gas	Dry and Abandoned, No Sh
39.781298	-90.075082	T15N,R9W,Sec 2	348	646	19231101	Conklin	2	Oil & Gas	Dry and Abandoned, No Sh
39.778057	-90.080754	T15N,R9W,Sec 3	342	645	19231001	Harris, A. J.	1	Oil & Gas	Gas Producer
39.7779	-90.080756	T15N,R9W,Sec 3	334	644	19231107	Harris, A. J.	3	Oil & Gas	Gas Producer
39.805251	-90.075597	T16N,R9W,Sec 26	1205		19670330	Martin	1	Oil & Gas	Dry and Abandoned, No Sh
39.805251	-90.075597	T16N,R9W,Sec 26	1400		19731029	Martin	1	Oil & Gas	Junked and Abandoned, Plu
39.800861	-90.073017	T16N,R9W,Sec 26	302	630				Coal Test	
39.807386	-90.060378	T16N,R9W,Sec 25	27			Beilschmidt, William H.		Water	
39.807386	-90.060378	T16N,R9W,Sec 25	30			W R Fowler		Water	
39.807386	-90.060378	T16N,R9W,Sec 25	28			Mason		Water	
39.807478	-90.079049	T16N,R9W,Sec 26	25			C H Matin		Water	
39.807478	-90.079049	T16N,R9W,Sec 26	22			T Gondall		Water	
39.807193	-90.041413	T16N,R8W,Sec 30	19		1930	R Allison		Water	
39.792765	-90.041512	T16N,R8W,Sec 31	28			W J Huston		Water	
39.792765	-90.041512	T16N,R8W,Sec 31	28			E Robinson		Water	
39.777005	-90.052023	T15N,R9W,Sec 1	25			A Harris		Water	
39.776968	-90.070521	T15N,R9W,Sec 2	32			A Harris		Water	
39.776968	-90.070521	T15N,R9W,Sec 2	22			W R Conklin		Water	
39.776968	-90.070521	T15N,R9W,Sec 2	30			B Negus		Water	
39.77688	-90.088996	T15N,R9W,Sec 3	28			C Negus		Water	
39.77688	-90.088996	T15N,R9W,Sec 3	30			L B Trotter		Water	
39.821881	-90.078925	T16N,R9W,Sec 23	30			D Flinn		Water	
39.821881	-90.078925	T16N,R9W,Sec 23	30			Hazel Dell School		Water	
39.821881	-90.078925	T16N,R9W,Sec 23	35			K Haneline		Water	
39.821811	-90.060168	T16N,R9W,Sec 24	30			J L Icenagle		Water	
39.821811	-90.060168	T16N,R9W,Sec 24	30			G Lewis		Water	
39.821811	-90.060168	T16N,R9W,Sec 24	200		1944	E C Lewis		Water	
39.807531	-90.097566	T16N,R9W,Sec 27	23			J Stewart		Water	

WS ID	(NAD 83)	(NAD 83)	(PLSS)	(ft)	(ft)	Date	Owner	Well #	Well Type	
37387	39.815638	-90.084967	T16N,R9W,Sec 23	41		19920313	Nickel, Gerald	1	Water	Pri
00966	39.815638	-90.084967	T16N,R9W,Sec 23	46		19971104	Nickel, Gerald & Diane	1	Water	Pri
97871	39.811987	-90.07805	T16N,R9W,Sec 26	37		19960213	Keltner, Dale		Water	Pri
	39.780186	-90.094859	T15N,R9W,Sec 3	402	642	19230101	Trotter, L.B.	1	Oil & Gas	Dry and
	39.776078	-90.080727	T15N,R9W,Sec 3	327	632	0	Harris		Unknown / other	Un
15642	39.82166	-90.041238	T16N,R8W,Sec 19	25		1870	W W Robertson		Water	
16456	39.776761	-90.107843	T15N,R9W,Sec 4	30			Rayburn		Water	
16457	39.776761	-90.107843	T15N,R9W,Sec 4	32			Greene		Water	
15725	39.821959	-90.097446	T16N,R9W,Sec 22	18			K Brown		Water	
15726	39.821959	-90.097446	T16N,R9W,Sec 22	30			E C Trotter		Water	
15640	39.836203	-90.022343	T16N,R8W,Sec 17	25			J H Hubbs		Water	
15641	39.83617	-90.041154	T16N,R8W,Sec 18	32		1850	H Robinson		Water	
15643	39.821671	-90.022214	T16N,R8W,Sec 20	26		1900	S Weinfeldt		Water	
15644	39.821671	-90.022214	T16N,R8W,Sec 20	30		1904	Robinson		Water	
15649	39.807149	-90.022402	T16N,R8W,Sec 29	26			M Walbaum		Water	
15653	39.793	-90.022	T16N,R8W,Sec 32	18			Beggs		Water	
16522	39.77156	-90.0878	T15N,R9W,Sec 3	50		19770320	Linebarger, David		Water	
16520	39.769673	-90.080523	T15N,R9W,Sec 3	42			Harris, Frank R.		Water	Pri
16521	39.769673	-90.080523	T15N,R9W,Sec 3	40			harris F R		Water	
16458	39.777	-90.126	T15N,R9W,Sec 5	30			Gary S. B.		Water	
16464	39.761	-90.126	T15N,R9W,Sec 8	30			Cleray W		Water	
16465	39.761	-90.126	T15N,R9W,Sec 8	40			Coons A		Water	
16466	39.761	-90.107	T15N,R9W,Sec 9	30			Wallbaum W M		Water	
16467	39.761	-90.107	T15N,R9W,Sec 9	35			Trotter l B		Water	
27314	39.761	-90.107	T15N,R9W,Sec 9	40			Carl Shinnall #1		Water	
16468	39.761	-90.089	T15N,R9W,Sec 10	30			Orear R		Water	
16525	39.765755	-90.080645	T15N,R9W,Sec 10	40			Linebarger D		Water	
16469	39.761	-90.07	T15N,R9W,Sec 11	30			Collins W		Water	
16470	39.761	-90.07	T15N,R9W,Sec 11	32			Lockhart G		Water	
16393	39.776799	-90.032936	T15N,R8W,Sec 6	25		1923			Water	
16394	39.776799	-90.032936	T15N,R8W,Sec 6	28			C Smith		Water	
16436	39.784526	-90.041604	T15N,R8W,Sec 6	54		19770226	Becker, Carl J.	1	Water	Livest
16435	39.784526	-90.041604	T15N,R8W,Sec 6	43		19781010	Becker, Carl J.	1	Water	Pri
16434	39.782453	-90.041567	T15N,R8W,Sec 6	27		19761213	Smith, Lloyd E.	1	Water	Livest
	39.766277	-90.041266	T15N,R8W,Sec 7	26			Walpole, Ron		Water	
16395	39.763	-90.033	T15N,R8W,Sec 7	30					Water	
15696	39.836221	-90.059875	T16N,R9W,Sec 13	25			V R Mc Clure		Water	

S ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	
697	39.836221	-90.059875	T16N,R9W,Sec 13	27			U B Fox		Water	
698	39.836221	-90.059875	T16N,R9W,Sec 13	27			G W Lewis		Water	
699	39.836362	-90.078662	T16N,R9W,Sec 14	30			J Parrat		Water	
700	39.836362	-90.078662	T16N,R9W,Sec 14	28			C W Lewis		Water	
701	39.836362	-90.078662	T16N,R9W,Sec 14	28			J W Parrat		Water	
702	39.836362	-90.078662	T16N,R9W,Sec 14	32			J Hodgeson		Water	
742	39.830101	-90.102984	T16N,R9W,Sec 15	47		20030910	Lomar Hager Construction		Water	Pri
703	39.836486	-90.097369	T16N,R9W,Sec 15	24			G Noulty		Water	
704	39.836486	-90.097369	T16N,R9W,Sec 15	30			L Lamkaular		Water	
705	39.836486	-90.097369	T16N,R9W,Sec 15	35			E E Hart		Water	
706	39.8365	-90.116151	T16N,R9W,Sec 16	23			S Jumper		Water	
707	39.8365	-90.116151	T16N,R9W,Sec 16	25			H Wester		Water	
722	39.821967	-90.116263	T16N,R9W,Sec 21	30			T J Ward		Water	
724	39.821967	-90.116263	T16N,R9W,Sec 21	30			C Trotter		Water	
249	39.821967	-90.116263	T16N,R9W,Sec 21	28		1934	Wm Noulty		Water	
	39.822767	-90.073164	T16N,R9W,Sec 23	405		19540301	Keltner	1	Water	
377	39.820978	-90.077895	T16N,R9W,Sec 23	42		19920414	Allen, John D.	1	Water	Pri
042	39.822764	-90.075515	T16N,R9W,Sec 23	46		20040715	Burton, Larry		Water	Pri
776	39.826288	-90.058992	T16N,R9W,Sec 24	40		19760220	Robinson, Leroy A.	1	Water	Pri
777	39.828869	-90.059535	T16N,R9W,Sec 24	37		19781214	Romine, Buddy	1	Water	Pri
169	39.813876	-90.103667	T16N,R9W,Sec 27	35		20060809	Donnan, Jeff		Water	Pri
744	39.807541	-90.116512	T16N,R9W,Sec 28	110			Noah B Fox		Water	
745	39.807541	-90.116512	T16N,R9W,Sec 28	28			Noah B Fox		Water	
746	39.807541	-90.116512	T16N,R9W,Sec 28	30			C Holdbrook		Water	
723	39.807541	-90.116512	T16N,R9W,Sec 28	28			W Noulty		Water	
692	39.806645	-90.122622	T16N,R9W,Sec 28	42			Kendra Swain		Water	
759	39.792956	-90.116724	T16N,R9W,Sec 33	30			H Swain		Water	
760	39.792956	-90.116724	T16N,R9W,Sec 33	28			L L Hart		Water	
	39.822856	-90.119949	T16N,R9W,Sec 21				Spradlin, Jack		Water	
	39.833775	-90.10777	T16N,R9W,Sec 16	385	616	19551101	Wolfe, Eliz	1	Oil & Gas	Dry and Aban
	39.80091	-90.040421	T16N,R8W,Sec 30	420	635	19560101	Beilschmidt	1	Oil & Gas	Dry and Aban
	39.815108	-90.028322	T16N,R8W,Sec 20	365	610	19551201	Robinson, Howard	1	Oil & Gas	Dry and Aban
	39.825408	-90.062536	T16N,R9W,Sec 24	200		19440101	Lewis, E. C.		Oil & Gas	
	39.769077	-90.111454	T15N,R9W,Sec 4	580			Rayborn	1	Oil & Gas	(
	39.770193	-90.110273	T15N,R9W,Sec 4	350			Rayburn	1	Oil & Gas	(
	39.769679	-90.098565	T15N,R9W,Sec 4	301					Coal Test	
	39.778927	-90.119618	T15N,R9W,Sec 5	423			Green, Laura & Effie	1	Oil & Gas	(
	39.764523	-90.098492	T15N,R9W,Sec 9	293			Baxter	2	Oil & Gas	Dry and A
	39.767065	-90.11144	T15N,R9W,Sec 9	325			Beilschmidt	1	Oil&Gas	Temp
	39.763524	-90.104346	T15N,R9W,Sec 9				Leinberger	2	Oil&Gas	Perm
	39.766464	-90.091366	T15N,R9W,Sec 10	295			Dunlap	8	Oil & Gas	(
	39.766422	-90.065678	T15N,R9W,Sec 11	243					Coal Test	

/S ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	
	39.828772	-90.06935	T16N,R9W,Sec 24	814	624	19700701	#MA-3		Stratigraphic or Structure Test	Struct
	39.792709	-90.039363	T16N,R8W,Sec 31	142	641	19700518	Flynn, Robert		Coal Test	
	39.829096	-90.098826	T16N,R9W,Sec 22	318	621	0			Coal Test	
	39.801122	-90.108499	T16N,R9W,Sec 28	301	621	0			Coal Test	
	39.814431	-90.023514	T16N,R8W,Sec 20	130	610	19700507	Newberry, Lucille		Coal Test	
	39.83138	-90.055009	T16N,R9W,Sec 13	301	619	0			Coal Test	



Several water wells are identified only with a general location (section, township and range) in the ISWS database. Those wells are not shown on the map, but are included in Table 9. Wells outside the Survey Area are not shown. The well ID number next to the well symbol on the map refers to the Map ID in Table 9.

Figure 12. Wells Located Within the Survey Area

Proposed Operating Data (Operational Information)

Figure 13 and Figure 14 show the well design for the representative case for the refined area of the model domain in plan view, in 3D view, and in cross section view, respectively. Injection into four lateral wells with a well-bore radius of 4.5 in. was modeled with the lateral leg of each well located within the best layer of the injection zone to maximize injectivity. Only the non-cased open sections of the wells are specified in the model input file because only those sections are delivering CO_2 to the formation. The well design modeled in this case is the open borehole design [6], therefore part of the curved portion of each well is open and thereby represented in the model in addition to the lateral legs. The orientation and lateral length of the wells, as well as CO_2 mass injection rates, were chosen so that the resulting modeled CO_2 plume would avoid sensitive areas. The coordinates of the screened portion of the injection wells are shown in Table 10. The injection rate was assigned to each well according to the values in Table 11 for a total injection rate of 1.1 MMT/yr for 20 years. A maximum injection pressure of 2,252.3 psi (2,237.6 psig) was assigned at the top of the open interval (depth of 3,850 ft bgs or an elevation of -3,220 ft), based on 90 percent of the fracture gradient described in Section 3.5 (0.65 psi/ft).

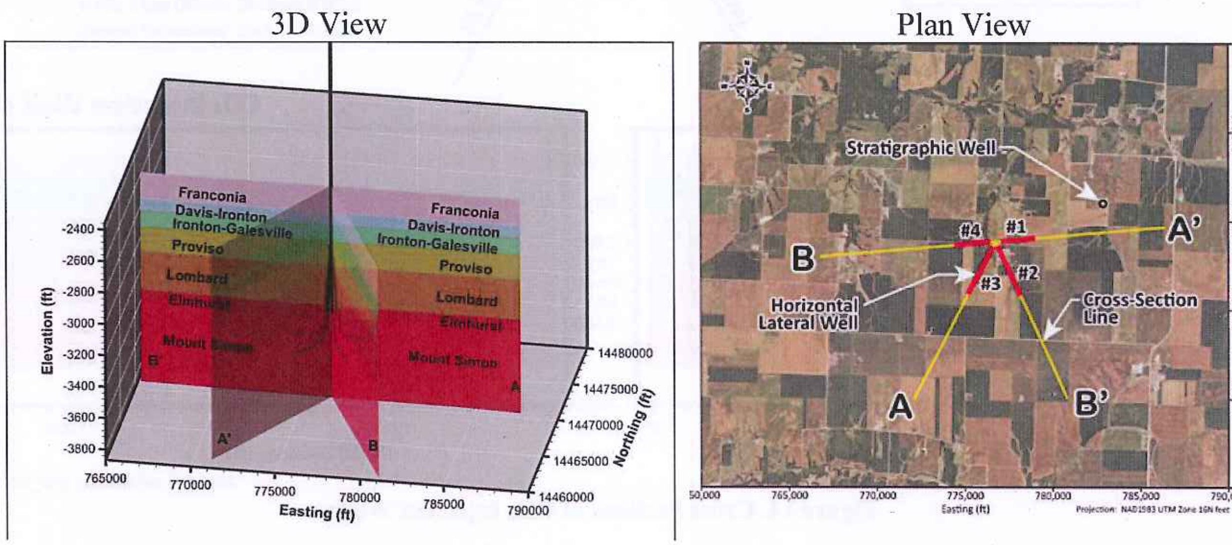


Figure 13. Operational Well Design for Representative Case Scenario as Implemented in the Numerical Model (with lateral legs of the injection wells shown in red and the cross section lines shown in yellow)

[6] Despite the models use of an open-hole design, the actual proposed construction is a cased hole with perforations.

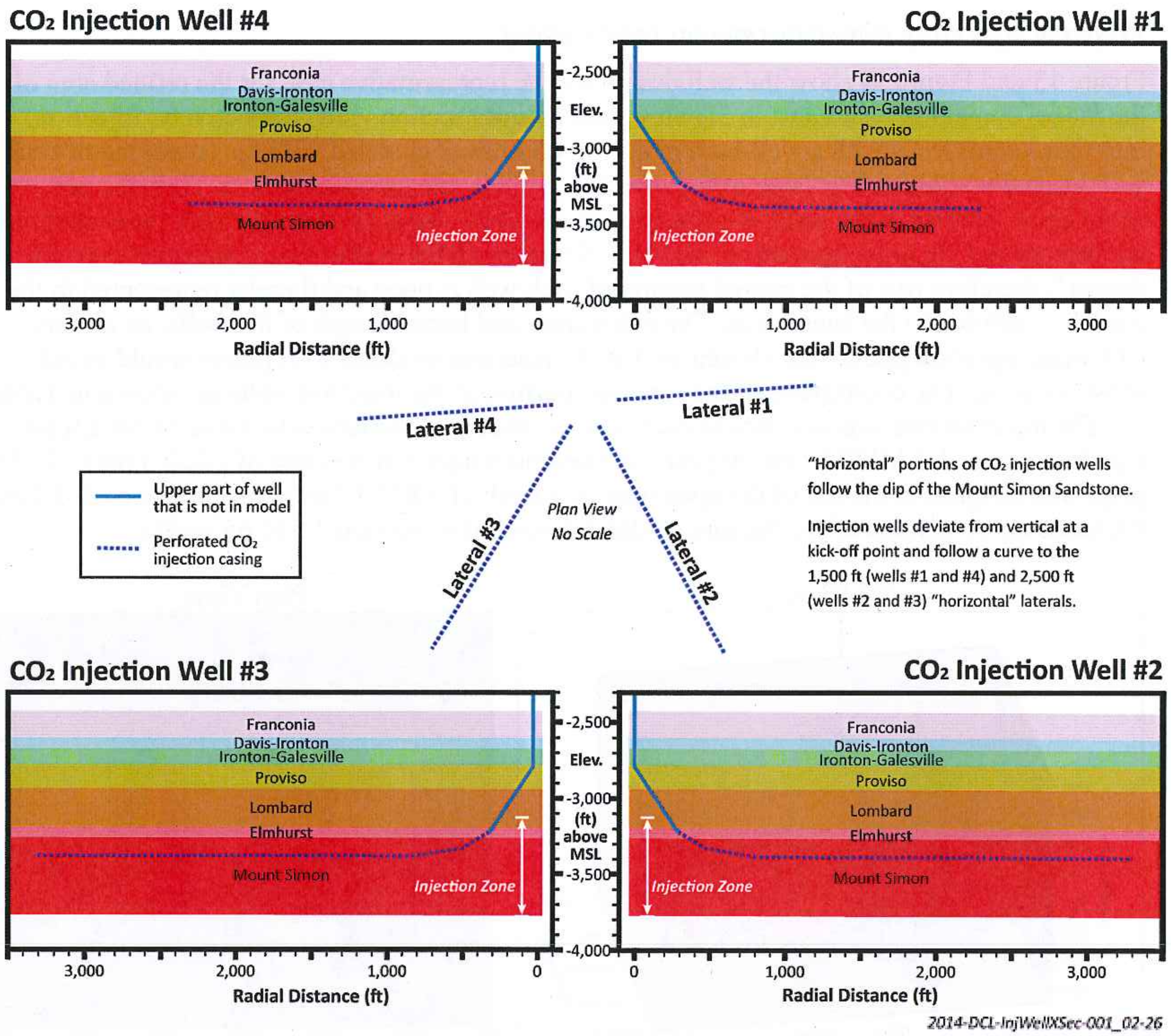


Figure 14. Cross Sections of CO_2 Injection Wells

Table 10. Coordinates (NAD1983 UTM Zone 16N) of Open Portions of the Injection Wells

	Coordinate 1(ft)			Coordinate 2(ft)			Coordinate 3(ft)			Coordinate 4(ft)		
	x	y	z	x	y	z	x	y	z	x	y	z
Well1	777079	14468885	-3220	777263	14468901	-3330	777592	14468929	-3387	779086	14469060	-3394
Well2	776898	14468571	-3220	776976	14468404	-3330	777116	14468105	-3388	778172	14465839	-3396
Well3	776617	14468578	-3220	776530	14468416	-3330	776375	14468124	-3382	775202	14465917	-3377
Well4	776451	14468829	-3220	776267	14468813	-3330	775938	14468785	-3377	774444	14468654	-3368

Table 11. Mass Rate of CO_2 Injection for Each of the Four Lateral Injection Wells

Well	Length of Lateral leg (ft)	Mass Rate of CO_2 Injection (MMT/yr)
Injection well #1	1,500	0.2063
Injection well #2	2,500	0.3541
Injection well #3	2,500	0.3541
Injection well #4	1,500	0.1856

Computational Modeling Results

At the end of the simulation period, 100 years, most of the CO_2 mass occurs in the CO_2 -rich (or separate) phase, with 20 percent occurring in the dissolved phase. Note that residual trapping begins to take place once injection ceases, resulting in about 15 percent of the total CO_2 mass being immobile at the end of 100 years. The CO_2 plume forms a cloverleaf pattern as a result of the four lateral injection-well design. The plume grows both laterally and vertically as injection continues. Most of the CO_2 resides in the Mount Simon Sandstone. A small amount of CO_2 enters into the Elmhurst and the lower part of the Lombard. When injection ceases at 20 years, the lateral growth becomes negligible but the plume continues to move slowly, primarily upward. Once CO_2 reaches the low-permeability zone in the upper Mount Simon it begins to move laterally. There is no CO_2 entering the confining zone. The maximum extent of the CO_2 plume, at 22 years, is in the center of Figure 15.

Pressure Front Delineation

As shown in Figure 16, the calculated hydraulic heads from the pressures and fluid densities measured in the Mount Simon Sandstone during drilling of the stratigraphic well range from 47.8 to 61.6 ft higher than the calculated hydraulic head in the lowermost USDW (St. Peter Sandstone). Based on these measurements, it was expected that the equation 1 suggested in the EPA AoR Guidance document (EPA 2013) for determination of the pressure front AoR would not be applicable for the FutureGen 2.0 Site since it would be in the "over-pressured" category. Thus alternative methods for assessment of the impacts of the pressure front would be needed for the "over-pressured" case at the FutureGen 2.0 Site.

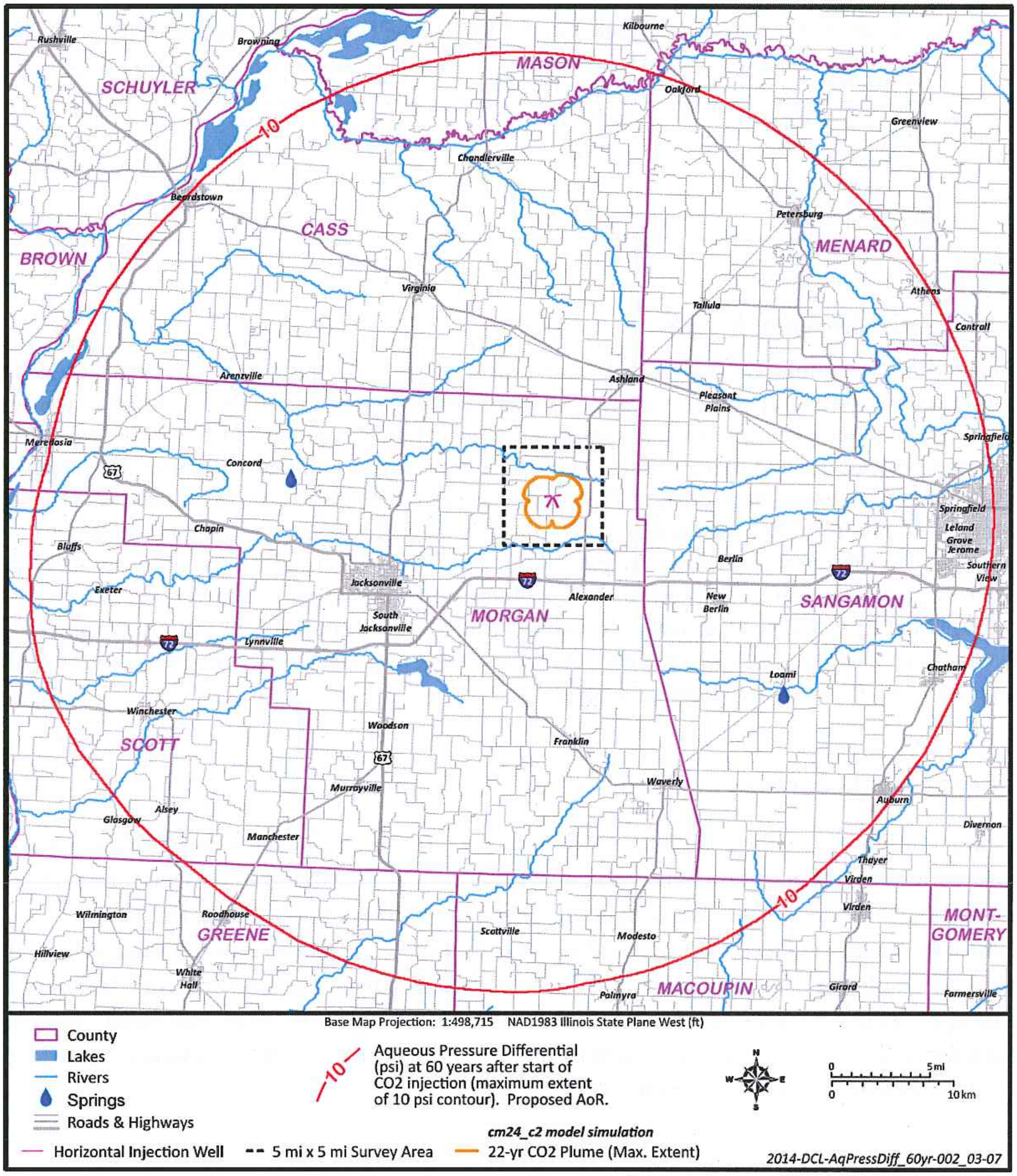


Figure 15. FutureGen Area of Review inclusive of the CO_2 plume and the area of elevated pressure delineated as the 10 psi contour at 60 years