ATTACHMENT 34

AR # 594

U.S. EPA, Underground Injection Control Permit, Class VI

(Excerpts)

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 14 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
Director, Water Division

PERMIT CONDITIONS

A. EFFECT OF PERMIT

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

B. PERMIT ACTIONS

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

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

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

C. SEVERABILITY

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

D. CONFIDENTIALITY

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

1. The name and address of the permittee; and

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

E. DEFINITION

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

F. DUTIES AND REQUIREMENTS

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

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

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

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

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

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and

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

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

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

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

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

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

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

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

G. AREA OF REVIEW AND CORRECTIVE ACTION

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

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

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

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The approved financial assurance 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. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

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

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

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

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

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

N. REPORTING AND RECORDKEEPING

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

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

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

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

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

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

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

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

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

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

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

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

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

3. **24-Hour Reporting** –

(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 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; 39.80111ºN and 90.07491ºW

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.

[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.

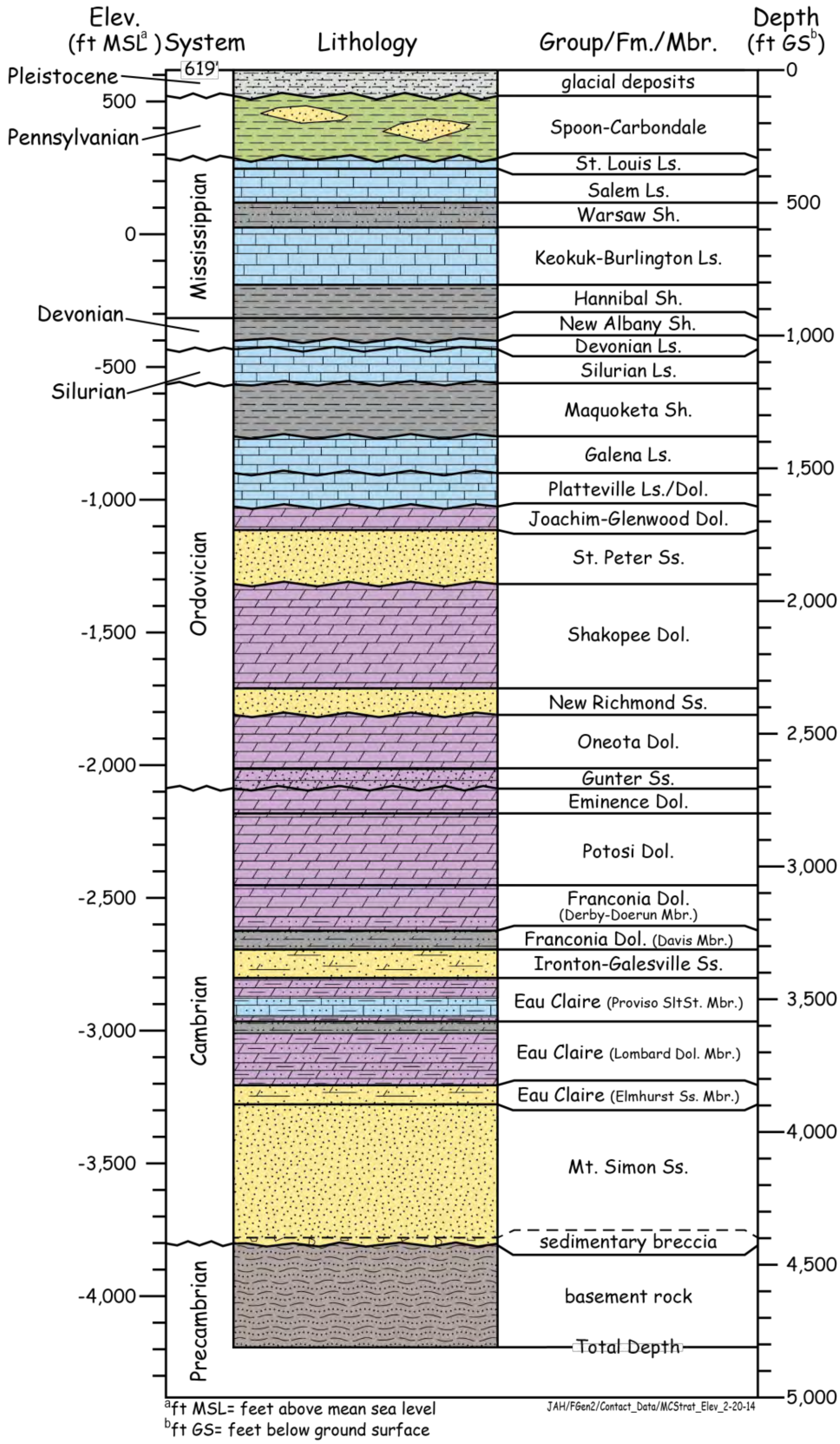


Figure 1. Stratigraphic Column of FutureGen 2.0 Stratigraphic Well

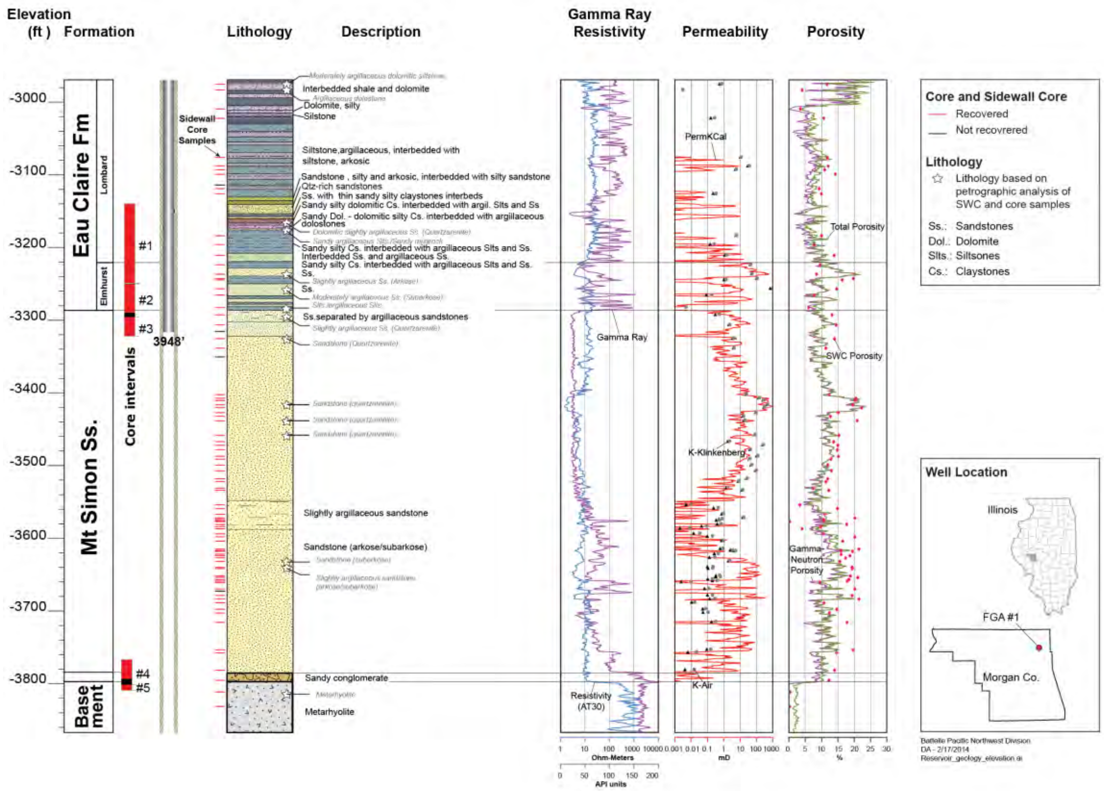


Figure 2. Lithology, Mineralogy, and Hydrologic Units of the Proposed Injection Zone (Mount Simon, Elmhurst and Lower Lombard member) and Lower Primary Confining Zone (Upper Lombard), as Encountered Within the Stratigraphic Well

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.

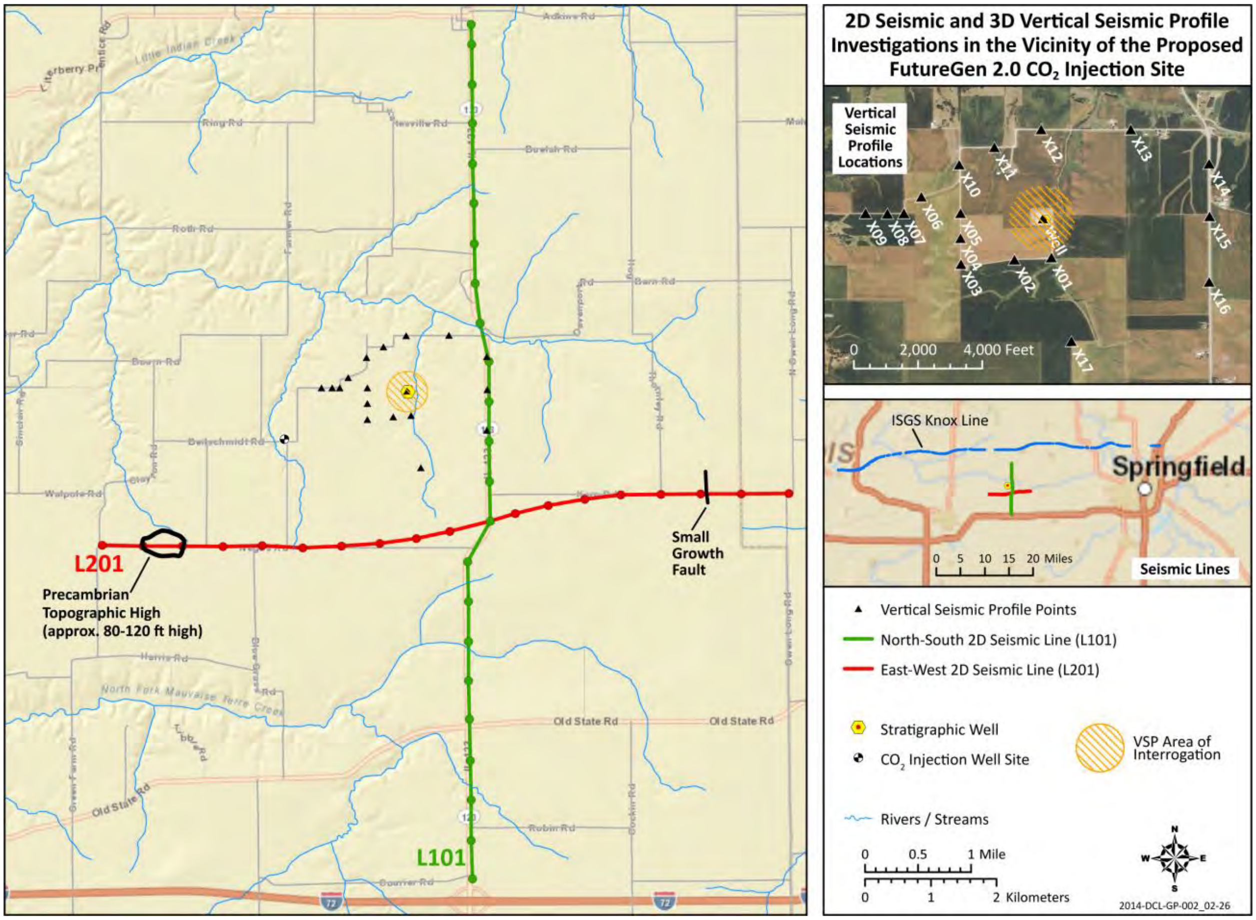


Figure 3. Locations of Two 2D Seismic Survey Lines, L101 and L201, Vertical Seismic Profile Locations, and the Knox Line Near the Proposed Morgan County CO_2 Storage Site

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.

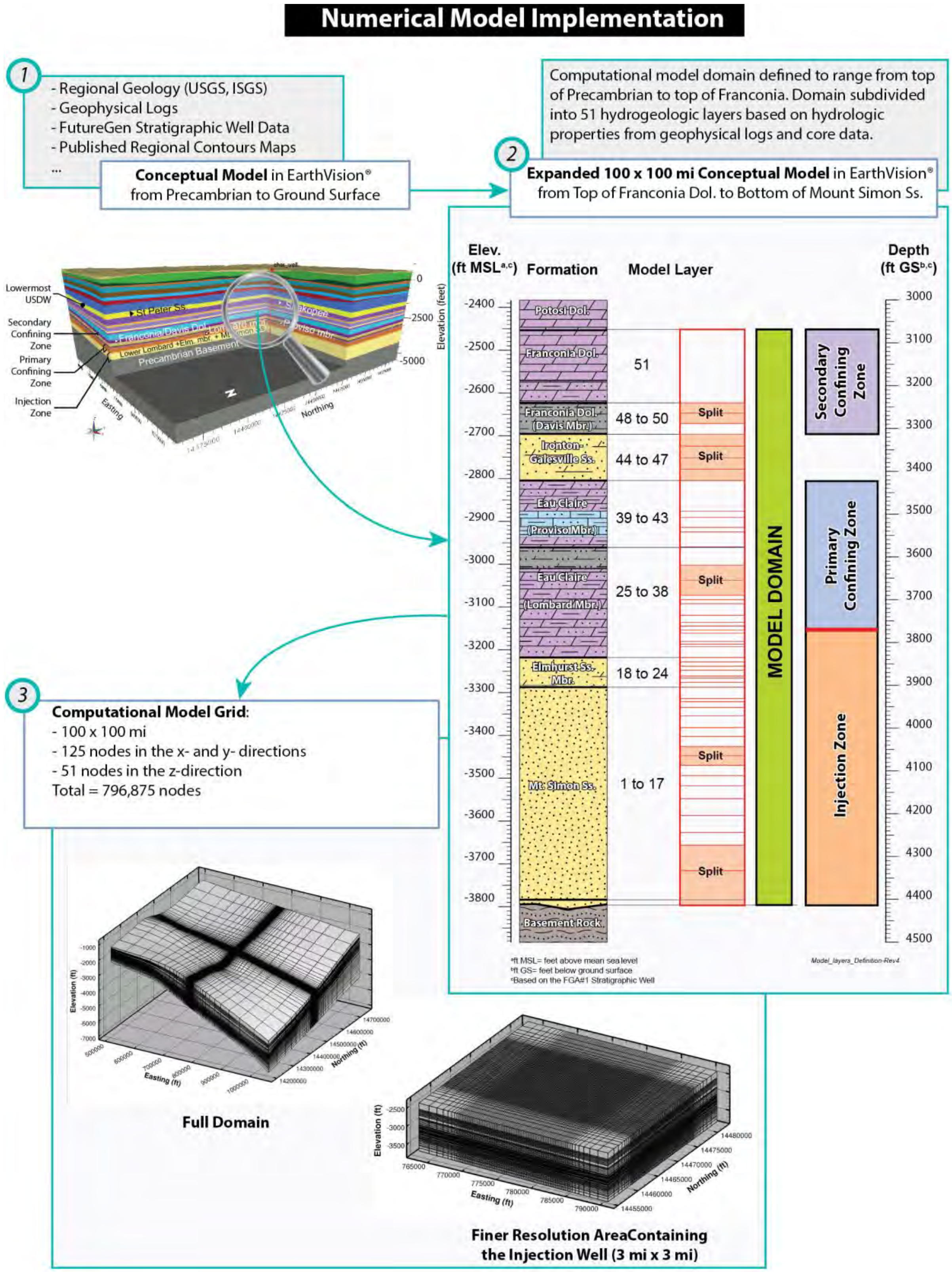


Figure 4. Implementation of the Numerical Model: From the Geological Conceptual Model to the Numerical Model

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).

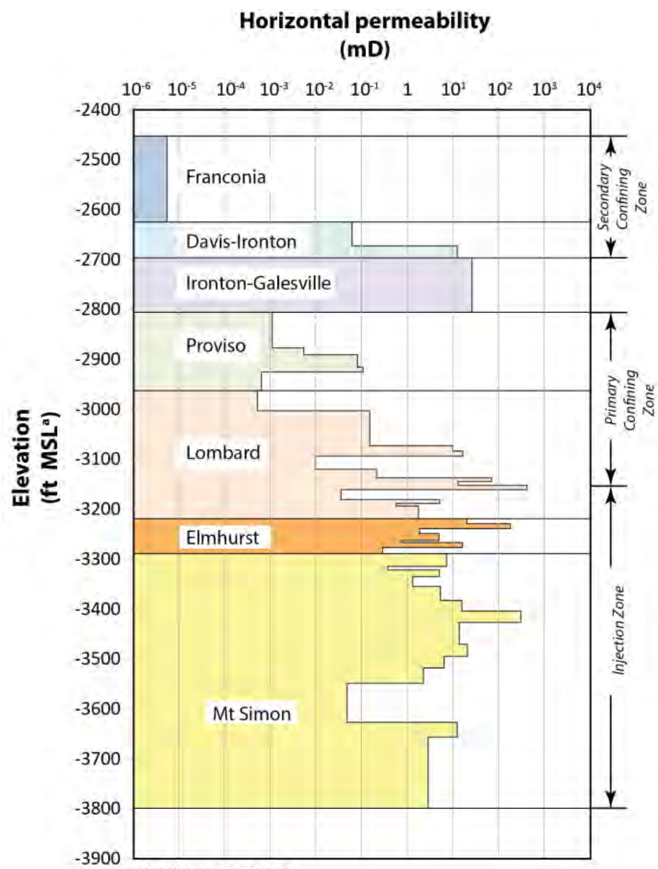
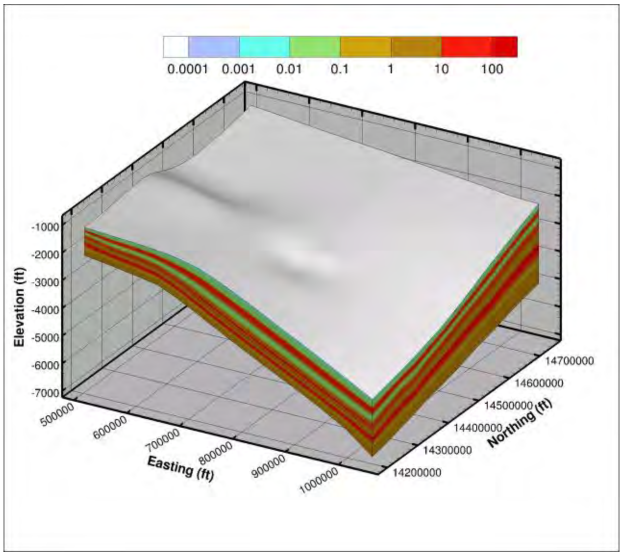
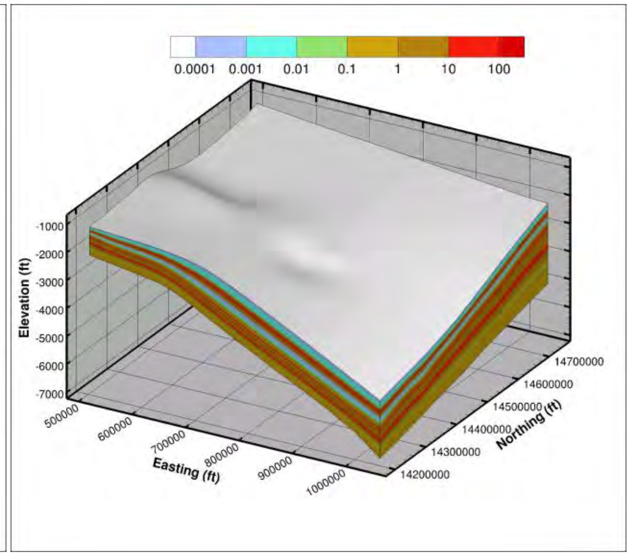


Figure 5. Vertical Distribution of the Horizontal Permeability in the Model Layers at the Stratigraphic Well Location



(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

	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.

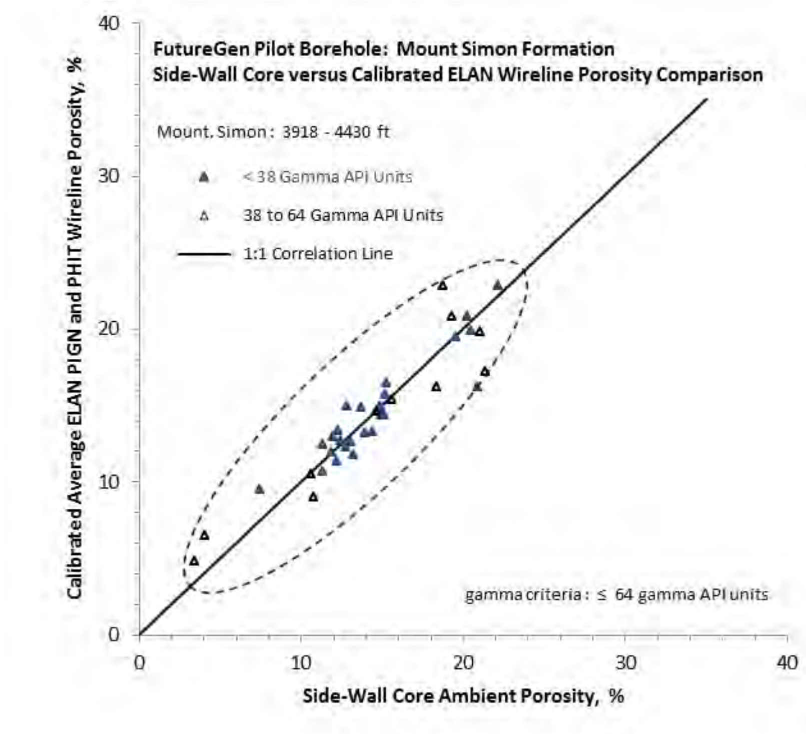


Figure 7. Comparison of SWC Porosity Measurements and Regression-Calibrated ELAN Log Porosities: ≤64 Gamma API Units

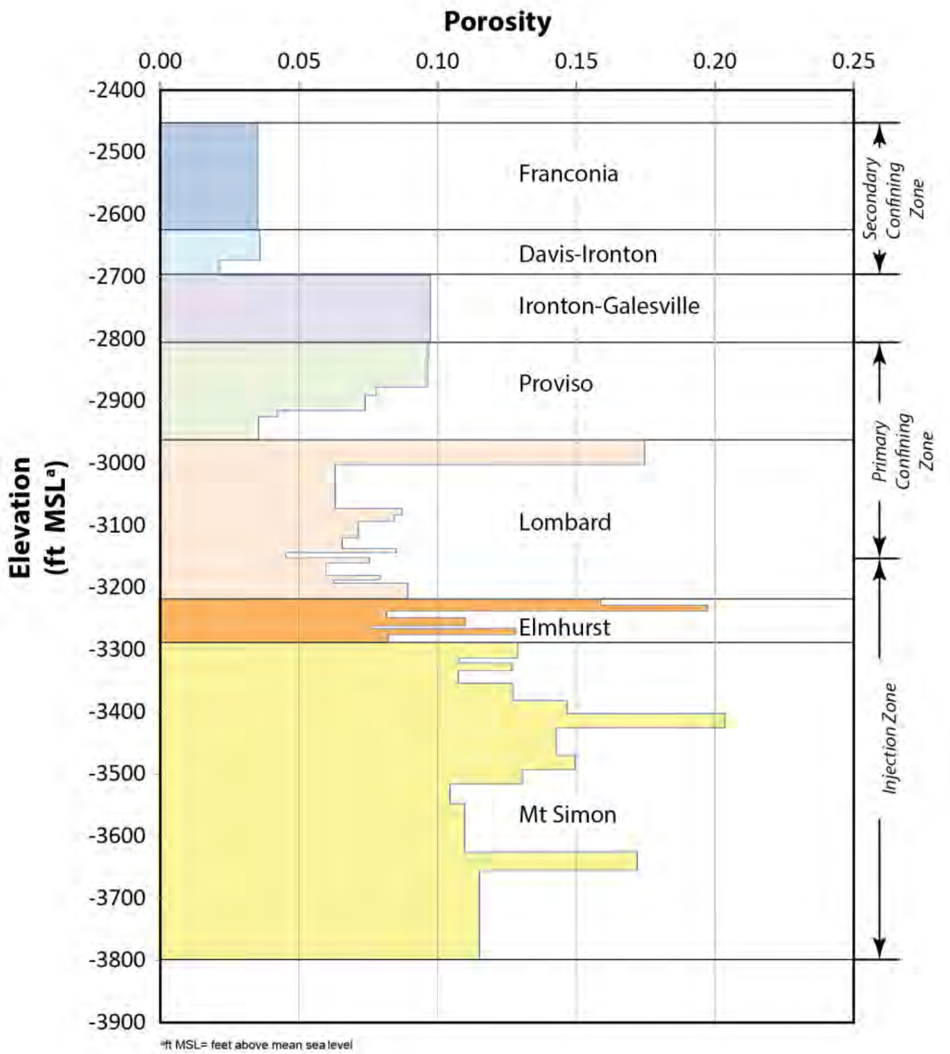


Figure 8. Vertical Distribution of Porosity in the Model Layers at the Stratigraphic Well Location

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.

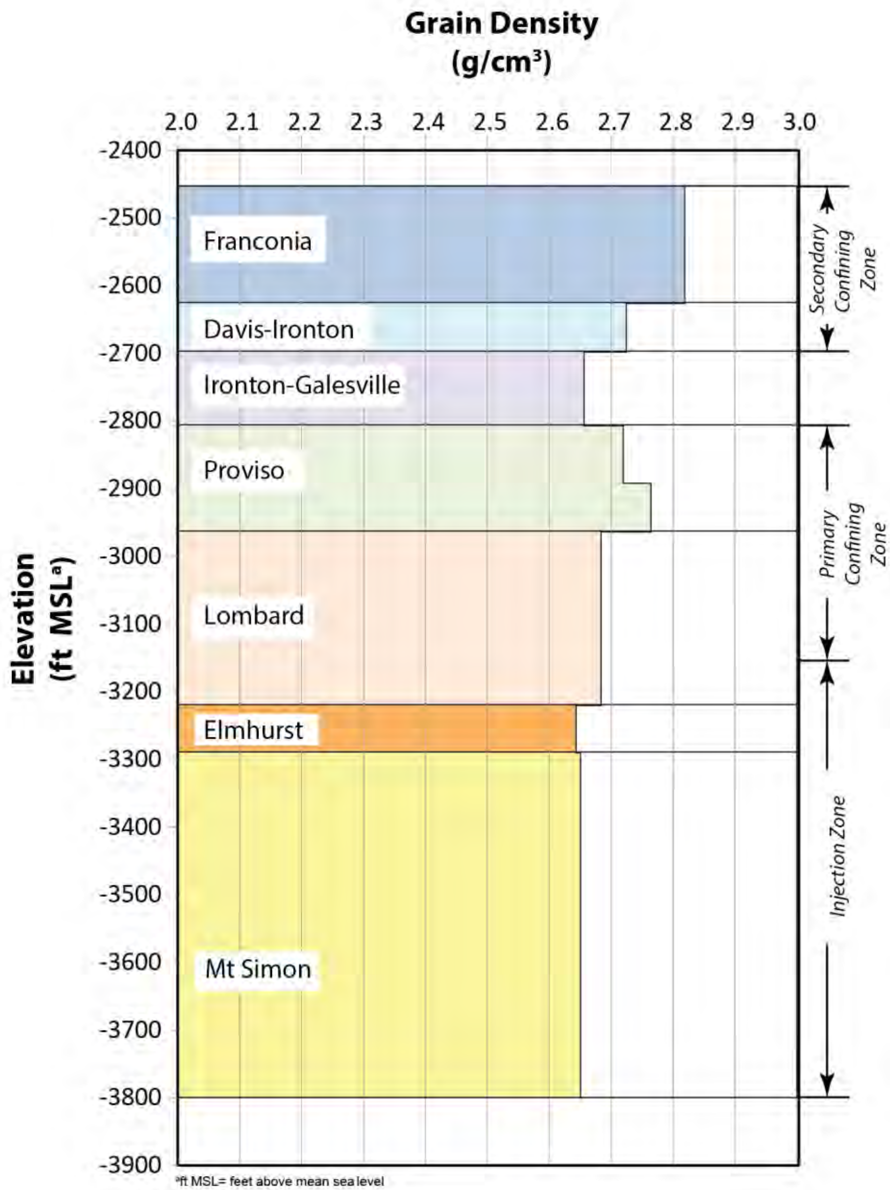


Figure 9. Vertical Distribution of the Grain Density in the Model Layer at the Stratigraphic Well Location

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

Capillary Pressure and Saturation Functions

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.

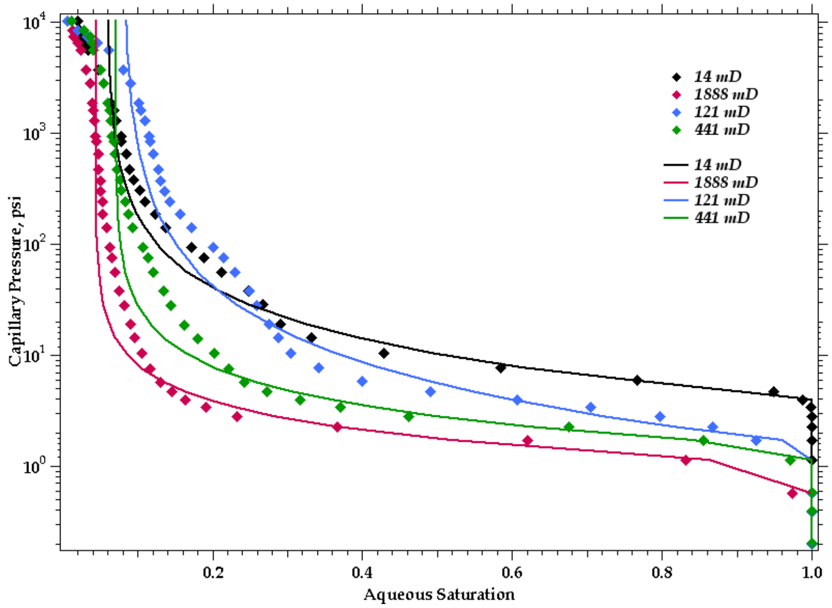


Figure 10. Aqueous Saturation Versus Capillary Pressure Based on Mercury Injection Data from the Hazen No. 5 Well at the Manlove Gas Field in Champagne County, Illinois

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

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

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.

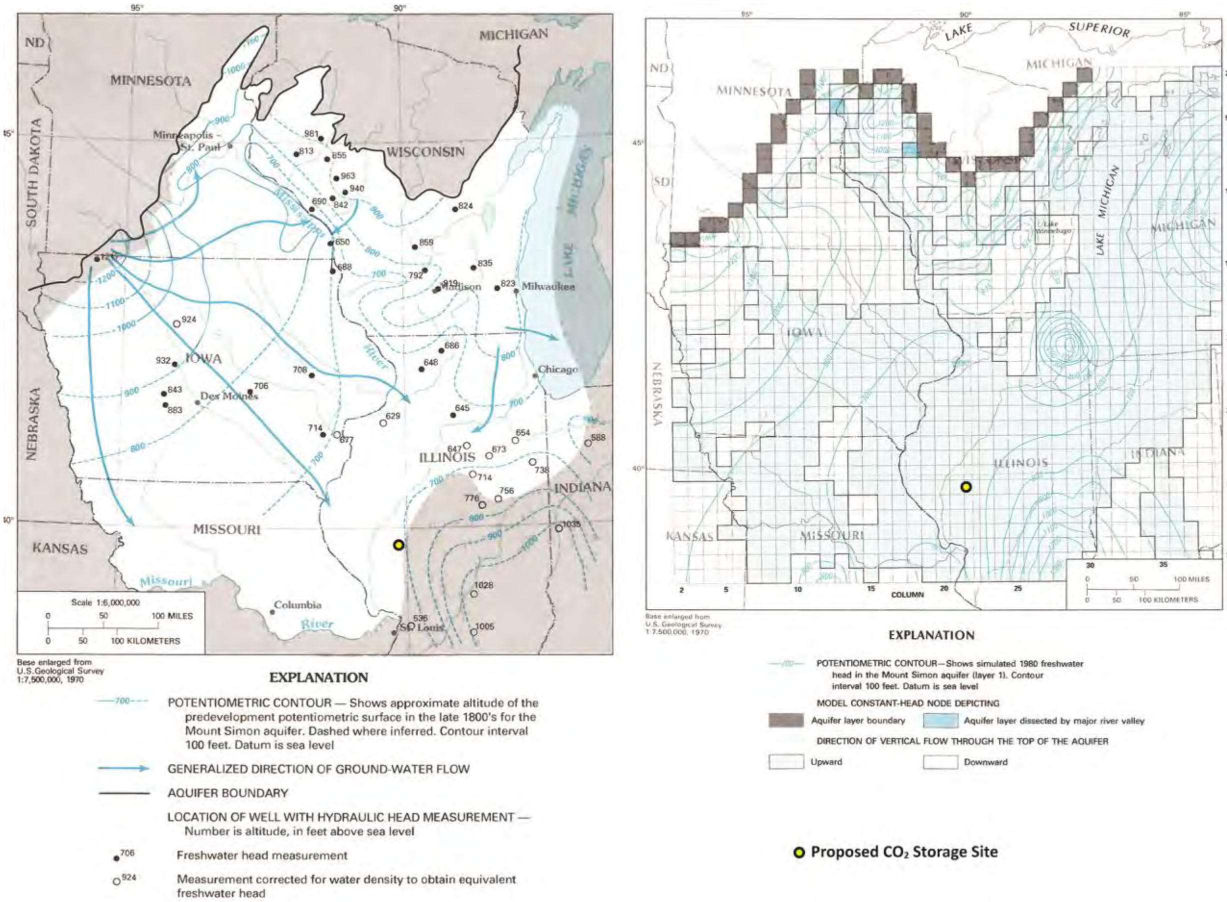


Figure 11. Approximate Pre-Development Potentiometric Surface (a) for the Mount Simon Aquifer (from Young 1992, modified from Mandel and Kontis 1992) and (b) Simulated 1980 Freshwater Head in the Mount Simon Aquifer showing Impact of Withdrawals in Northern portion of Illinois (Mandel and Kontis 1992)

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.

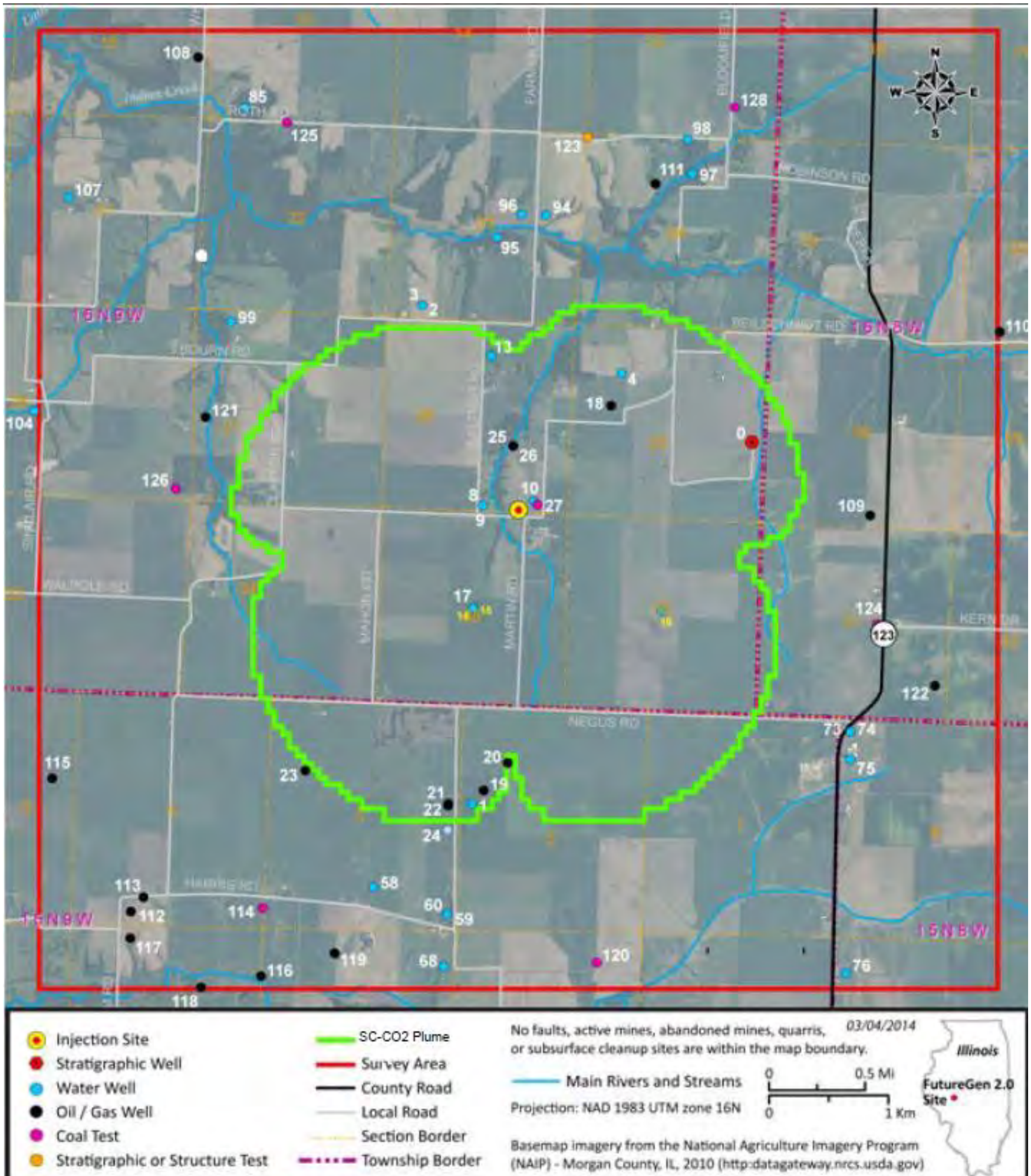
Table 9. List of Wells Located Within the Survey Area

Map ID	API Number	ISWS ID	Latitude NAD1983	Longitude NAD1983	Public Land Survey System	Total Depth ft	Elev ft	Completion Date	Owner	Well Num	Well Type	Status	Confining Zone Penetration Well
0	121372213200		39.806064	-90.052919	T16n,R9w,Sec 25	4812	633	TBD	FutureGen Industrial Alliance, Inc.	1	Monitoring	Active	Yes
1	121372118200	116519	39.778074	-90.078443	T15N,R9W,Sec 2	25		19780712	A.A. Negus Estate	1	Water	Private Water Well	No
4	121370018700	115778	39.811025	-90.065241	T16N,R9W,Sec 25	115			Beilschmidt, William H.		Water		No
8	121370028500	115740	39.800661	-90.078386	T16N,R9W,Sec 26	127		1950	Martin, L. E.	1	Water		No
9		115741	39.800661	-90.078386	T16N,R9W,Sec 26	127			Martin, L. E.		Water		No
10	121372128600	115779	39.801129	-90.07342	T16N,R9W,Sec 26	25		19781213	Martin, Marvin & Jean	1	Water	Private Water Well	No
14		115763	39.792894	-90.078875	T16N,R9W,Sec 35	28			E Clemons		Water		No
15		115764	39.792894	-90.078875	T16N,R9W,Sec 35	25			B Sister		Water		No
16		115765	39.792837	-90.060294	T16N,R9W,Sec 36	35			J M Dunlap		Water		No
17	121370051100		39.792893	-90.078984	T16N,R9W,Sec 35	1056	643		O'Rear, Judge	1	Oil & Gas / Water		No
18	121370009900		39.808545	-90.06614	T16N,R9W,Sec 25	1530	630	19391001	Beilschmidt, Wm.	1	Oil & Gas	Dry and Abandoned, No Shows	No
19	121370023500		39.779153	-90.077325	T15N,R9W,Sec 2	338	644	19231101	Conklin	1	Oil & Gas	Dry and Abandoned, No Shows	No
20	121370023600		39.781298	-90.075082	T15N,R9W,Sec 2	348	646	19231101	Conklin	2	Oil & Gas	Dry and Abandoned, No Shows	No
21	121370023700		39.778057	-90.080754	T15N,R9W,Sec 3	342	645	19231001	Harris, A. J.	1	Oil & Gas	Gas Producer	No
22	121370023900		39.7779	-90.080756	T15N,R9W,Sec 3	334	644	19231107	Harris, A. J.	3	Oil & Gas	Gas Producer	No
25	121370036300		39.805251	-90.075597	T16N,R9W,Sec 26	1205		19670330	Martin	1	Oil & Gas	Dry and Abandoned, No Shows	No
26	121370036301		39.805251	-90.075597	T16N,R9W,Sec 26	1400		19731029	Martin	1	Oil & Gas	Junked and Abandoned, Plugged	No
27	121372088500		39.800861	-90.073017	T16N,R9W,Sec 26	302	630				Coal Test		No
		115735	39.807386	-90.060378	T16N,R9W,Sec 25	27			Beilschmidt, William H.		Water		No
		115736	39.807386	-90.060378	T16N,R9W,Sec 25	30			W R Fowler		Water		No
		115737	39.807386	-90.060378	T16N,R9W,Sec 25	28			Mason		Water		No
		115739	39.807478	-90.079049	T16N,R9W,Sec 26	25			C H Matin		Water		No
		115738	39.807478	-90.079049	T16N,R9W,Sec 26	22			T Gondall		Water		No
		115650	39.807193	-90.041413	T16N,R8W,Sec 30	19		1930	R Allison		Water		No
		115651	39.792765	-90.041512	T16N,R8W,Sec 31	28			W J Huston		Water		No
		115652	39.792765	-90.041512	T16N,R8W,Sec 31	28			E Robinson		Water		No
		116450	39.777005	-90.052023	T15N,R9W,Sec 1	25			A Harris		Water		No
		116453	39.776968	-90.070521	T15N,R9W,Sec 2	32			A Harris		Water		No
		116451	39.776968	-90.070521	T15N,R9W,Sec 2	22			W R Conklin		Water		No
		116452	39.776968	-90.070521	T15N,R9W,Sec 2	30			B Negus		Water		No
		116454	39.77688	-90.088996	T15N,R9W,Sec 3	28			C Negus		Water		No
		116455	39.77688	-90.088996	T15N,R9W,Sec 3	30			L B Trotter		Water		No
		115727	39.821881	-90.078925	T16N,R9W,Sec 23	30			D Flinn		Water		No
		115728	39.821881	-90.078925	T16N,R9W,Sec 23	30			Hazel Dell School		Water		No
		115729	39.821881	-90.078925	T16N,R9W,Sec 23	35			K Haneline		Water		No
		115733	39.821811	-90.060168	T16N,R9W,Sec 24	30			J L Icenagle		Water		No
		115734	39.821811	-90.060168	T16N,R9W,Sec 24	30			G Lewis		Water		No
		115775	39.821811	-90.060168	T16N,R9W,Sec 24	200		1944	E C Lewis		Water		No
		115742	39.807531	-90.097566	T16N,R9W,Sec 27	23			J Stewart		Water		No
		115743	39.807531	-90.097566	T16N,R9W,Sec 27	23			l J Stewart		Water		No
		115761	39.792917	-90.097513	T16N,R9W,Sec 34	28			T Harrison		Water		No
		115762	39.792917	-90.097513	T16N,R9W,Sec 34	30			J Mahon		Water		No

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
2	121372155200	237387	39.815638	-90.084967	T16N,R9W,Sec 23	41		19920313	Nickel, Gerald	1	Water	Private Water Well	No
3	121372182100	300966	39.815638	-90.084967	T16N,R9W,Sec 23	46		19971104	Nickel, Gerald & Diane	1	Water	Private Water Well	No
13	121372173400	297871	39.811987	-90.07805	T16N,R9W,Sec 26	37		19960213	Keltner, Dale		Water	Private Water Well	No
23	121370024000		39.780186	-90.094859	T15N,R9W,Sec 3	402	642	19230101	Trotter, L.B.	1	Oil & Gas	Dry and Abandoned, No Shows	No
24	121372097800		39.776078	-90.080727	T15N,R9W,Sec 3	327	632	0	Harris		Unknown / other	Unknown, Plugged	No
28		115642	39.82166	-90.041238	T16N,R8W,Sec 19	25		1870	W W Robertson		Water		No
38		116456	39.776761	-90.107843	T15N,R9W,Sec 4	30			Rayburn		Water		No
39		116457	39.776761	-90.107843	T15N,R9W,Sec 4	32			Greene		Water		No
40		115725	39.821959	-90.097446	T16N,R9W,Sec 22	18			K Brown		Water		No
41		115726	39.821959	-90.097446	T16N,R9W,Sec 22	30			E C Trotter		Water		No
52		115640	39.836203	-90.022343	T16N,R8W,Sec 17	25			J H Hubbs		Water		No
53		115641	39.83617	-90.041154	T16N,R8W,Sec 18	32		1850	H Robinson		Water		No
54		115643	39.821671	-90.022214	T16N,R8W,Sec 20	26		1900	S Weinfeldt		Water		No
55		115644	39.821671	-90.022214	T16N,R8W,Sec 20	30		1904	Robinson		Water		No
56		115649	39.807149	-90.022402	T16N,R8W,Sec 29	26			M Walbaum		Water		No
57		115653	39.793	-90.022	T16N,R8W,Sec 32	18			Beggs		Water		No
58	121372070800	116522	39.77156	-90.0878	T15N,R9W,Sec 3	50		19770320	Linebarger, David		Water		No
59	121372118300	116520	39.769673	-90.080523	T15N,R9W,Sec 3	42			Harris, Frank R.		Water	Private Water Well	No
60	121372070700	116521	39.769673	-90.080523	T15N,R9W,Sec 3	40			harris F R		Water		No
61		116458	39.777	-90.126	T15N,R9W,Sec 5	30			Gary S. B.		Water		No
62		116464	39.761	-90.126	T15N,R9W,Sec 8	30			Cleray W		Water		No
63		116465	39.761	-90.126	T15N,R9W,Sec 8	40			Coons A		Water		No
64		116466	39.761	-90.107	T15N,R9W,Sec 9	30			Wallbaum W M		Water		No
65		116467	39.761	-90.107	T15N,R9W,Sec 9	35			Trotter l B		Water		No
66		227314	39.761	-90.107	T15N,R9W,Sec 9	40			Carl Shinnall #1		Water		No
67		116468	39.761	-90.089	T15N,R9W,Sec 10	30			Orear R		Water		No
68	121372070900	116525	39.765755	-90.080645	T15N,R9W,Sec 10	40			Linebarger D		Water		No
69		116469	39.761	-90.07	T15N,R9W,Sec 11	30			Collins W		Water		No
70		116470	39.761	-90.07	T15N,R9W,Sec 11	32			Lockhart G		Water		No
71		116393	39.776799	-90.032936	T15N,R8W,Sec 6	25		1923			Water		No
72		116394	39.776799	-90.032936	T15N,R8W,Sec 6	28			C Smith		Water		No
73	121372116800	116436	39.784526	-90.041604	T15N,R8W,Sec 6	54		19770226	Becker, Carl J.	1	Water	Livestock Watering Well	No
74	121372116900	116435	39.784526	-90.041604	T15N,R8W,Sec 6	43		19781010	Becker, Carl J.	1	Water	Private Water Well	No
75	121372117000	116434	39.782453	-90.041567	T15N,R8W,Sec 6	27		19761213	Smith, Lloyd E.	1	Water	Livestock Watering Well	No
76	121372161900		39.766277	-90.041266	T15N,R8W,Sec 7	26			Walpole, Ron		Water		No
77		116395	39.763	-90.033	T15N,R8W,Sec 7	30					Water		No
78		115696	39.836221	-90.059875	T16N,R9W,Sec 13	25			V R Mc Clure		Water		No

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
79		115697	39.836221	-90.059875	T16N,R9W,Sec 13	27			U B Fox		Water		No
80		115698	39.836221	-90.059875	T16N,R9W,Sec 13	27			G W Lewis		Water		No
81		115699	39.836362	-90.078662	T16N,R9W,Sec 14	30			J Parrat		Water		No
82		115700	39.836362	-90.078662	T16N,R9W,Sec 14	28			C W Lewis		Water		No
83		115701	39.836362	-90.078662	T16N,R9W,Sec 14	28			J W Parrat		Water		No
84		115702	39.836362	-90.078662	T16N,R9W,Sec 14	32			J Hodgeson		Water		No
85	121372203900	356742	39.830101	-90.102984	T16N,R9W,Sec 15	47		20030910	Lomar Hager Construction		Water	Private Water Well	No
86		115703	39.836486	-90.097369	T16N,R9W,Sec 15	24			G Noulty		Water		No
87		115704	39.836486	-90.097369	T16N,R9W,Sec 15	30			L Lamkaular		Water		No
88		115705	39.836486	-90.097369	T16N,R9W,Sec 15	35			E E Hart		Water		No
89		115706	39.8365	-90.116151	T16N,R9W,Sec 16	23			S Jumper		Water		No
90		115707	39.8365	-90.116151	T16N,R9W,Sec 16	25			H Wester		Water		No
91		115722	39.821967	-90.116263	T16N,R9W,Sec 21	30			T J Ward		Water		No
92		115724	39.821967	-90.116263	T16N,R9W,Sec 21	30			C Trotter		Water		No
93		216249	39.821967	-90.116263	T16N,R9W,Sec 21	28		1934	Wm Noulty		Water		No
94	121370028400		39.822767	-90.073164	T16N,R9W,Sec 23	405		19540301	Keltner	1	Water		No
95	121372155100	237377	39.820978	-90.077895	T16N,R9W,Sec 23	42		19920414	Allen, John D.	1	Water	Private Water Well	No
96	121372207600	365042	39.822764	-90.075515	T16N,R9W,Sec 23	46		20040715	Burton, Larry		Water	Private Water Well	No
97	121372128400	115776	39.826288	-90.058992	T16N,R9W,Sec 24	40		19760220	Robinson, Leroy A.	1	Water	Private Water Well	No
98	121372128500	115777	39.828869	-90.059535	T16N,R9W,Sec 24	37		19781214	Romine, Buddy	1	Water	Private Water Well	No
99	121372211600	420169	39.813876	-90.103667	T16N,R9W,Sec 27	35		20060809	Donnan, Jeff		Water	Private Water Well	No
100		115744	39.807541	-90.116512	T16N,R9W,Sec 28	110			Noah B Fox		Water		No
101		115745	39.807541	-90.116512	T16N,R9W,Sec 28	28			Noah B Fox		Water		No
102		115746	39.807541	-90.116512	T16N,R9W,Sec 28	30			C Holdbrook		Water		No
103		115723	39.807541	-90.116512	T16N,R9W,Sec 28	28			W Noulty		Water		No
104	121372203000	348692	39.806645	-90.122622	T16N,R9W,Sec 28	42			Kendra Swain		Water		No
105		115759	39.792956	-90.116724	T16N,R9W,Sec 33	30			H Swain		Water		No
106		115760	39.792956	-90.116724	T16N,R9W,Sec 33	28			L L Hart		Water		No
107	121372155000		39.822856	-90.119949	T16N,R9W,Sec 21				Spradlin, Jack		Water		No
108	121370011400		39.833775	-90.10777	T16N,R9W,Sec 16	385	616	19551101	Wolfe, Eliz	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
109	121370011500		39.80091	-90.040421	T16N,R8W,Sec 30	420	635	19560101	Beilschmidt	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
110	121370011600		39.815108	-90.028322	T16N,R8W,Sec 20	365	610	19551201	Robinson, Howard	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
111	121370018900		39.825408	-90.062536	T16N,R9W,Sec 24	200		19440101	Lewis, E. C.		Oil & Gas	Dry Hole	No
112	121370024100		39.769077	-90.111454	T15N,R9W,Sec 4	580			Rayborn	1	Oil & Gas	Gas Producer	No
113	121370044200		39.770193	-90.110273	T15N,R9W,Sec 4	350			Rayburn	1	Oil & Gas	Gas Producer	No
114	121372086900		39.769679	-90.098565	T15N,R9W,Sec 4	301					Coal Test		No
115	121370024200		39.778927	-90.119618	T15N,R9W,Sec 5	423			Green, Laura & Effie	1	Oil & Gas	Gas Producer	No
116	121370024600		39.764523	-90.098492	T15N,R9W,Sec 9	293			Baxter	2	Oil & Gas	Dry and Abandoned, Gas Shows	No
117	121372094800		39.767065	-90.11144	T15N,R9W,Sec 9	325			Beilschmidt	1	Oil&Gas	Temporarily Abandoned	No
118	121372105200		39.763524	-90.104346	T15N,R9W,Sec 9				Leinberger	2	Oil&Gas	Permit to Drill Issued	No
119	121370007900		39.766464	-90.091366	T15N,R9W,Sec 10	295			Dunlap	8	Oil & Gas	Gas Producer	No
120	121372084800		39.766422	-90.065678	T15N,R9W,Sec 11	243					Coal Test		No
121	121370030900		39.806625	-90.105838	T16N,R9W,Sec 27	324	610	19591001	Fox, Lyman	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
122	121370033200		39.788212	-90.03349	T16N,R8W,Sec 31	323	641	19271001	Corrington	1	Oil & Gas	Dry and Abandoned, No Shows	No

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
123	121370062300		39.828772	-90.06935	T16N,R9W,Sec 24	814	624	19700701	#MA-3		Stratigraphic or Structure Test	Structure Test, Plugged	No
124	121372068000		39.792709	-90.039363	T16N,R8W,Sec 31	142	641	19700518	Flynn, Robert		Coal Test		No
125	121372088400		39.829096	-90.098826	T16N,R9W,Sec 22	318	621	0			Coal Test		No
126	121372088600		39.801122	-90.108499	T16N,R9W,Sec 28	301	621	0			Coal Test		No
127	121372067800		39.814431	-90.023514	T16N,R8W,Sec 20	130	610	19700507	Newberry, Lucille		Coal Test		No
128	121372086000		39.83138	-90.055009	T16N,R9W,Sec 13	301	619	0			Coal Test		No



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).

3D View — Plan View

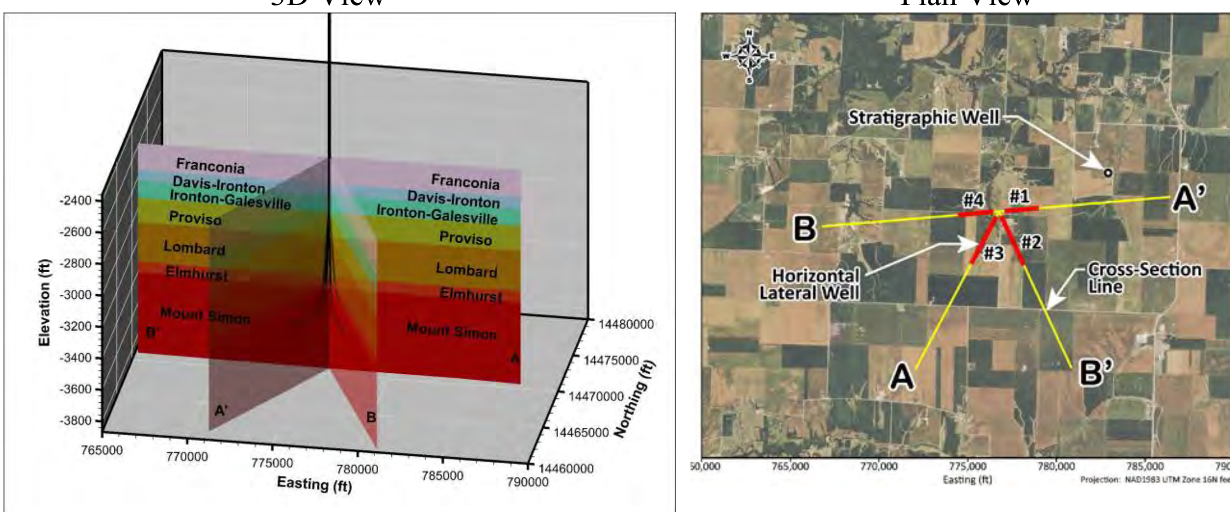


Figure 13. Operational Well Design for Representative Case Scenario as Implemented in the Numerical Model (with lateral legs of the injection wells shown in red and the cross section lines shown in yellow)

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

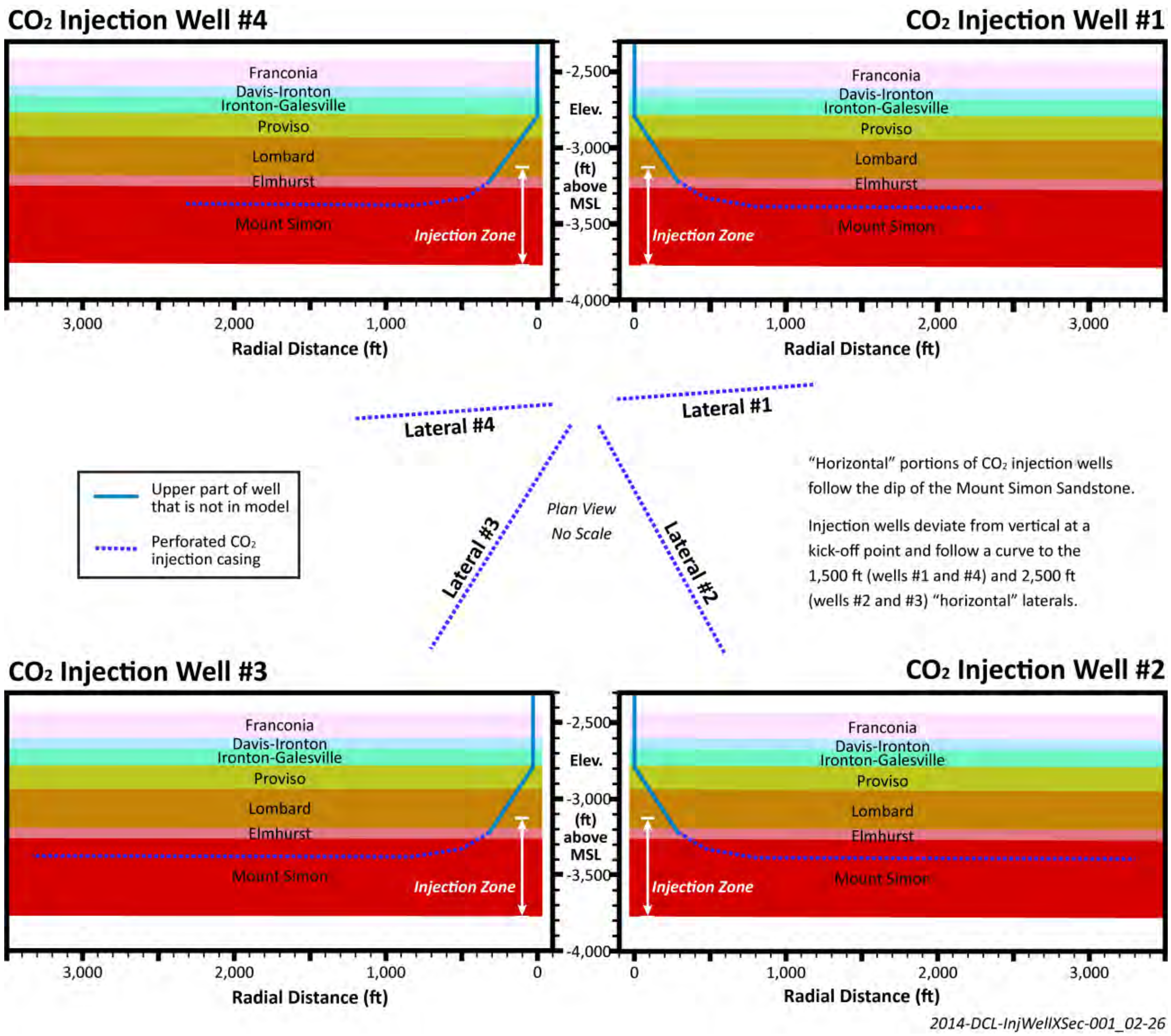


Figure 14. Cross Sections of CO_2 Injection Wells

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.

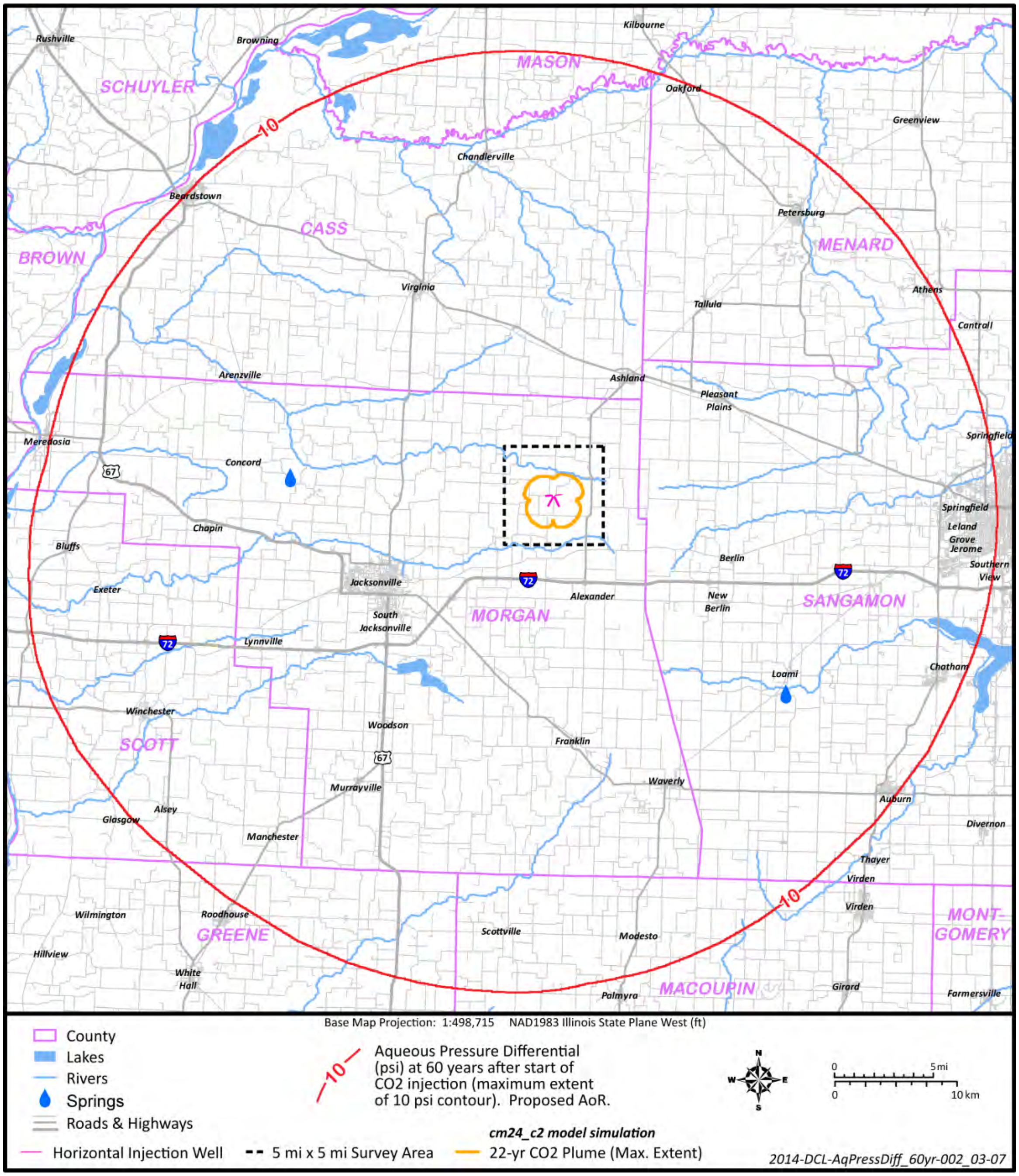


Figure 15. FutureGen Area of Review inclusive of the CO_2 plume and the area of elevated pressure delineated as the 10 psi contour at 60 years

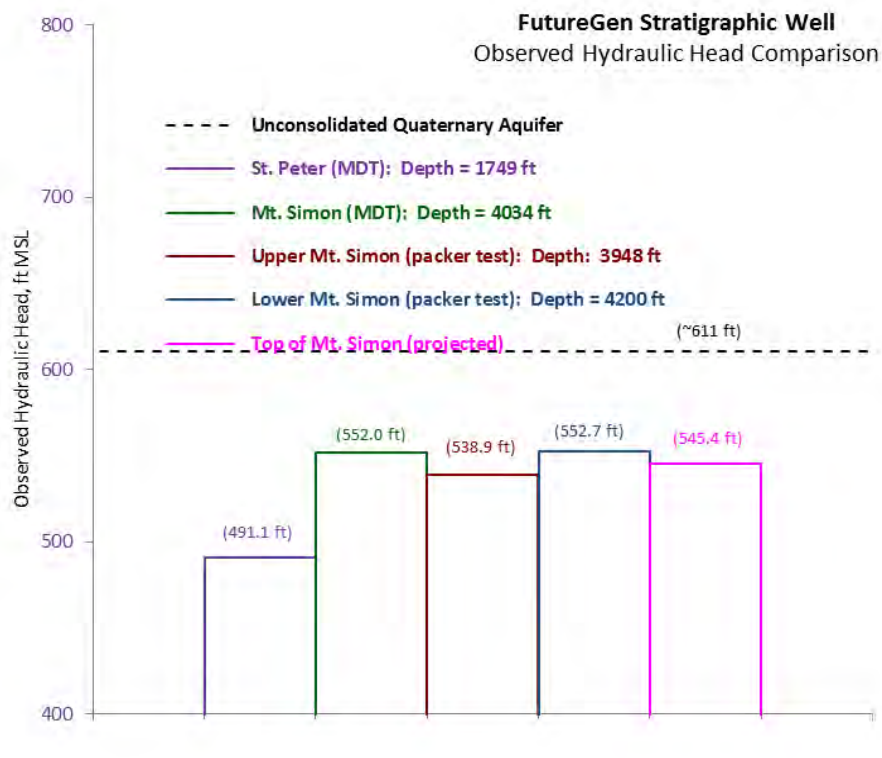


Figure 16. Observed Hydraulic Head Comparison between the Unconsolidated Quaternary Aquifer, St. Peter Sandstone, and Mount Simon Sandstone within the FutureGen Stratigraphic Well

Alternative approaches considered for delineation of an AoR inclusive of an area of elevated pressure

The FutureGen Alliance considered the applicability of and evaluated the project using an analytical solution (Cihan et al., 2011; 2013) and a range of other approaches (Table 13). The objective of these analyses was to assess, calculate, and account for critical pressure, which is the pressure great enough to mobilize fluids up an open conduit (i.e., an artificial penetration, fault, or fracture) from the injection zone into the overlying USDW. Methods evaluated are presented in Table 13.

Table 13. Methods Evaluated for Pressure Front Delineation

Approach	Results
AoR Guidance Equation 1	Not applicable
Nicot (2008)	13.76 psi
Birkholzer (2011)	9.65 psi
Cihan (2011): Assuming thief zones	Plume-sized AoR
Cihan (2011) Conservative: Assuming no thief zones	Large AoR

Pressure delineated AoR

Each of the pressure front analysis methodologies evaluated by the FutureGen Alliance (Table 13) are mathematical approximations applicable under prescribed conditions and subjected to simplifying assumptions. The simplified critical pressure calculations based on the open conduit concept are not applicable under site conditions because the ambient conditions in the lowermost USDW at the FutureGen site are under-pressured relative to the reservoir. Although the open conduit approaches are not strictly applicable under FutureGen site conditions, results from these conservative and protective approaches were used by EPA to delineate the pressure front AoR as the maximum extent of the 10 psi contour *of pressure differential* during the life of the project, which occurs 60 years after injection commences and is shown in Figure 15.

Corrective Action Plan and Schedule

No wells have been identified within the AoR that require corrective action.

Area of Review Reevaluation Plan and Schedule

Reevaluation Cycle

The FutureGen Alliance will reevaluate the AoR on an annual basis for the first 5 years following the initiation of injection operations (Figure 17). After the fifth year of injection, the AoR will be updated at a minimum of every 5 years as required by 40 CFR 146.84(b)(2)(i). An annual reevaluation in the first 5 years is intended to account for any operational variation during the startup period.

Some conditions will warrant reevaluation prior to the next scheduled cycle. To meet the intent of the regulations and protect USDWs, the following six conditions will warrant reevaluation of the AoR:

1. **Exceeding Fracture Pressure Conditions:** Pressure in any of the injection or monitoring wells exceeding 90 percent of the geologic formation fracture pressure at the point of measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan provides discussion of pressure monitoring.

   Action: The computational model will be calibrated to match measured pressures. Model outputs that calculate the change in AoR will be provided to EPA.

2. **Exceeding Established Baseline Hydrochemical/Physical Parameter Patterns:** A statistically significant difference between observed and baseline hydrochemical/physical parameter patterns (e.g., fluid conductivity, pressure, temperature) within the Ironton Formation immediately above the confining zone (ACZ1 and ACZ2 wells). The Student's t-test statistical procedure will be used to compare background (baseline) with observed

results. The Testing and Monitoring Plan provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored within the Ironton Formation.

Action: In the event that hydrochemical/physical parameter trends suggest that leakage may be occurring, either the computational model or other models will be used to understand the observational parameter behavior.

3. **Compromise in Injection Well Mechanical Integrity:** A significant change in pressure within the protective annular pressurization system surrounding each injection well that indicates a loss of mechanical integrity at an injection well.

   Action: Injection wells suspected of mechanical integrity issues will be shut down and the cause of the pressure deviation determined. Mechanical integrity testing will be conducted and the computational model will be updated with mechanical integrity results to determine the severity and extent of the loss of containment. The Testing and Monitoring Plan provides extended information about the mechanical integrity tests that will be conducted in the injection wells.

4. **Departure in Anticipated Surface Deformation Conditions:** Surface deformation measurements that indicate an asymmetric or otherwise heterogeneous evolution of the injection zone pressure front, resulting in larger than predicted surface deformation outside the CO_2 plume. Areal surface deformation will be monitored using several technologies including differential synthetic aperture radar interferometry (DInSAR), which is a radar-based method that can measure very small changes in ground-surface elevation linked to pressure variations at depth. The area surveyed will extend beyond the predicted maximum extent of the CO_2 plume. If a measurable rise in the ground surface occurs outside the predicted extent, the AoR will be re-evaluated. The Testing and Monitoring Plan provides extended information about surface deformation monitoring.

   Action: The computational model will be calibrated to match observed pressures if they vary from the predicted deformation/pressure calculations.

5. **Seismic Monitoring Identification of Subsurface Structural Features:** Seismic monitoring data indicate the possible presence of a fault or fracture near the CO_2 injection zone in the sedimentary cover or in the basement (concentration of microearthquakes of $M<<1$ in elongated clusters). The Testing and Monitoring Plan provides extended information about the microseismic monitoring network.

   Action: The cause of the indicated microseismicity patterns will be evaluated. In conjunction, various operational parameters will be tested using the computational model to determine if the microseismic activity can be controlled to acceptable levels

6. **Seismic Monitoring Identification of Unexpected Plume Pattern:** Seismic monitoring data indicate a CO_2 plume migration outside the predicted extent. The observation of microearthquakes ($M<<1$) may also help define the actual shape of the maximum pressure field associated with the plume extensions.

Action: The computational model will be calibrated to match the location of observed microseismicity patterns indicative of plume extensions.

7. **Other triggers for reevaluation may include:** facility operating changes; new injection activities or other deep wells added in the AoR; new owner/operators; new site characterization data; a seismic event or other emergency; and unexpected changes in rate, direction, and extent of plume/pressure front movement.

Reevaluation Strategy

If any of these conditions occurs, the FutureGen Alliance will reevaluate the AoR to comply with requirements at 40 CFR 146.84 as described below. Ongoing direct and indirect monitoring data, which provide relevant information for understanding the development and evolution of the CO_2 plume, will be used to support reevaluation of the AoR. These data include: 1) the chemical and physical characteristics of the CO_2 injection stream based on sampling and analysis; 2) continuous monitoring of injection mass flow rate, pressure, temperature, and fluid volume; 3) measurements of pressure response at all site monitoring wells; and 4) CO_2 arrival and transport response at all site monitoring wells based on direct aqueous measurements and selected indirect monitoring method(s). The FutureGen Alliance will compare these observational data with predicted responses from the computational model and if significant discrepancies between the observed and predicted responses exist, the monitoring data will be used to recalibrate the model (Figure 17). In cases where the observed monitoring data agree with model predictions, an AoR reevaluation will consist of a demonstration that monitoring data are consistent with modeled predictions. As additional characterization data are collected, the site conceptual model will be revised and the modeling steps described above will be repeated to incorporate new knowledge about the site.

The FutureGen Alliance will submit a report notifying the UIC Program Director of the results of this reevaluation within 90 days of detection. At that time, the FutureGen Alliance will either: 1) submit the monitoring data and modeling results to demonstrate that no adjustment to the AoR is required; or 2) modify its Corrective Action, Emergency and Remedial Response, and other plans to account for the revised AoR. All modeling inputs and data used to support AoR reevaluations will be retained by the FutureGen Alliance for the period of the project.

To the extent that the reevaluated AoR is different from the one identified in this supporting documentation, the FutureGen Alliance will identify all active and abandoned wells and underground mines that penetrate the confining zone (the Eau Claire Formation) in the reevaluated AoR and will perform corrective actions on those wells. As needed, the FutureGen Alliance will revise all other plans, such as the Emergency and Remedial Response Plan, to take into account the reevaluated AoR and will submit those plans to the UIC Program Director for review and approval.

Note that seismic events are covered under the Emergency and Remedial Response Plan. A tiered approach to responding to seismic events will be based on magnitude and location. A notification procedure is provided in that plan.

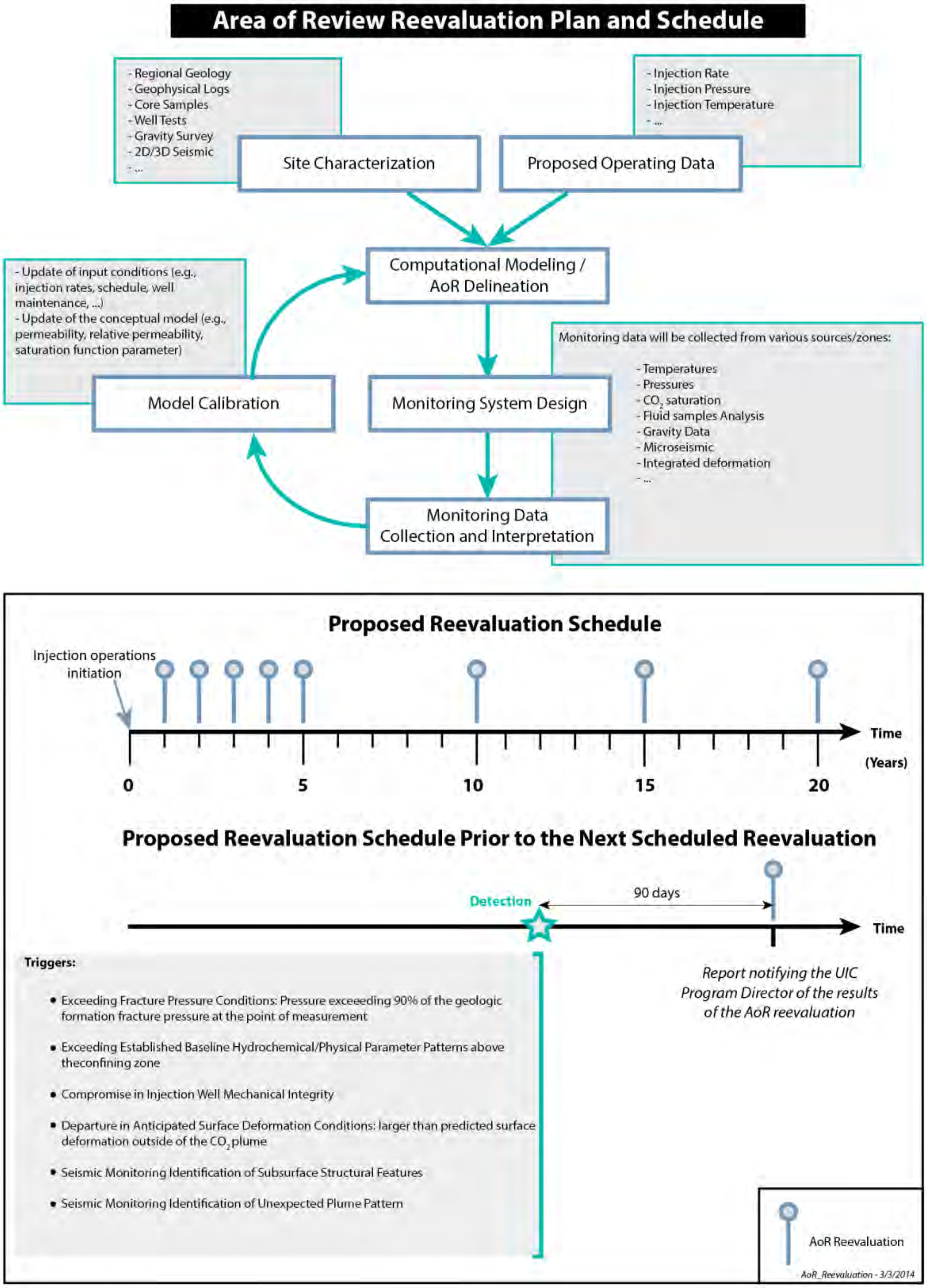


Figure 17. AoR Correction Action Plan Flowchart

ATTACHMENT C: TESTING AND MONITORING 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; 39.80111ºN and 90.07491ºW

Approach and Strategy of the Monitoring Network

This Testing and Monitoring Plan describes how the FutureGen Alliance will monitor the site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to underground sources of drinking water (USDWs), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the injection zone to support AoR reevaluations and a non-endangerment demonstration.

The monitoring network (Figure 1) is a comprehensive network designed to detect unforeseen CO_2 and brine leakage out of the injection zone and for the protection of USDWs. Central to this monitoring strategy is the measurement of CO_2 saturation within the reservoir using three reservoir access tubes (RATs) extending through the base of the Mount Simon Formation and into the Precambrian basement. The CO_2 saturation will be measured using pulsed-neutron capture (PNC) logging across the injection zone and primary confining zone. The three wells have been placed at increasing radial distances from the injection site to provide measures of CO_2 saturation at locations within the outer edges of the predicted 1-, 2- and 4-year CO_2 plumes, respectively. The three RAT installations have also been distributed across three different azimuthal directions, providing CO_2 arrival information for three of the four predicted lobes of the CO_2 plume.

The monitoring network will also include two Single-Level in-Reservoir (SLR) wells, completed across the planned injection interval within the Mount Simon Formation to continuously and directly measure for pressure, temperature, and specific conductance (P/T/SpC) over the injection and post-injection monitoring periods. Pressure at these locations will be compared with numerical model predictions and used to calibrate the model as necessary. These wells will initially be sampled for aqueous chemistry. However, once supercritical CO_2 ($scCO_2$) breakthrough occurs, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

Another central component of the monitoring strategy is to monitor for any unforeseen leakage from the reservoir as early as possible. This will be accomplished by monitoring for CO_2 and brine intrusion immediately above the confining zone. These two "early-detection" wells will be completed in the first permeable unit above the Eau Claire caprock, within the Ironton Sandstone. These wells will be continuously monitored for P/T/SpC, and periodically sampled to characterize aqueous chemistry. Leakage detected at the Above Confining Zone (ACZ) wells would most likely be identified based on pressure response, but it may also result in changes in aqueous chemistry.

The monitoring network will also include one well located in the lowermost USDW, the St. Peter Sandstone. This well will be instrumented to monitor continuously for P/T/SpC, and periodically samples will be collected for characterizing aqueous chemistry. This USDW well is co-located with the ACZ well located closest to the injection well site.

Comparison of observed and simulated arrival responses at the early-detection wells and shallower monitoring locations will be continued throughout the life of the project and will be used to calibrate and verify the model, and improve its predictive capability for confirming CO_2 containment and/or assessing the long-term environmental impacts of any CO_2 leakage. If deep early-detection monitoring locations indicate that primary confining zone leakage has occurred, a comprehensive near-surface-monitoring program will be activated to fully assess environmental impacts relative to baseline conditions.

Beyond the direct measures of the monitoring well network, two indirect monitoring techniques—deformation monitoring and microseismic monitoring—will be used to detect the development of the pressure front, which results from the injection of CO_2. The objective of the deformation monitoring is to provide a means to detect the development of an asymmetric plume that would be different from the predicted plume shape. The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of 1) addressing public and stakeholder concerns related to induced seismicity, 2) estimating the spatial extent of the pressure front from the distribution of seismic events, and 3) identifying features that may indicate areas of caprock failure and possible containment loss.

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

Specifically, as part of this adaptive monitoring approach, a pressure-monitoring well will be constructed within 5 years of the start of injection. The final placement/location of this well will be informed by any observed asymmetry in pressure front development during the early years of injection and will be located outside the CO_2 plume extent. The distance from the plume boundary will be based on the monitoring objective of providing information that will be useful for both leakage detection and model calibration within the early years of project operation. It is estimated that the well will be located less than 5 miles from the predicted plume extent in order to provide an intermediate-field pressure monitoring capability that would benefit leak detection capabilities and meet the requirement for direct pressure monitoring of the pressure front (i.e., outside the CO_2 plume area).

A second but less desirable approach would be to locate the well at a more distal location (e.g., 15-20 miles) so that there is time to install the well prior to pressure front arrival (at Waverley it is predicted to take 4 to 5 years). This location would have very limited benefit from a leak detection perspective, but it would be useful for calibrating the reservoir model.

<u>Quality assurance and surveillance measures:</u>

Data quality assurance and surveillance protocols adopted by the project have been designed to facilitate compliance with the requirements specified in 40 CFR 146.90(k). Quality Assurance (QA) requirements for direct measurements within the injection zone, above the confining zone, and within the shallow USDW aquifer that are critical to the Testing and Monitoring program (e.g., pressure and aqueous concentration measurements) are described in the Quality Assurance and Surveillance Plan (QASP) that is attached to this Testing and Monitoring Plan. These measurements will be performed based on best industry practices and the QA protocols recommended by the geophysical services contractors selected to perform the work. The QASP is presented in Appendix G of this Plan.

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

Table 1. Sampling and Recording Frequencies for Continuous Monitoring.

Well Condition	**Minimum sampling frequency: once every**	**Minimum recording frequency: once every**
For operating injection wells that are required to monitor continuously:	5 seconds	5 minutes [1]
For injection wells that are shut-in:	4 hours	4 hours
For monitoring wells (USDW, ACZ, SLR):	30 minutes	2 hours
[1] This can be an average of the sampled readings* over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified over that recording interval		
Notes: Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory. Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every minute.		

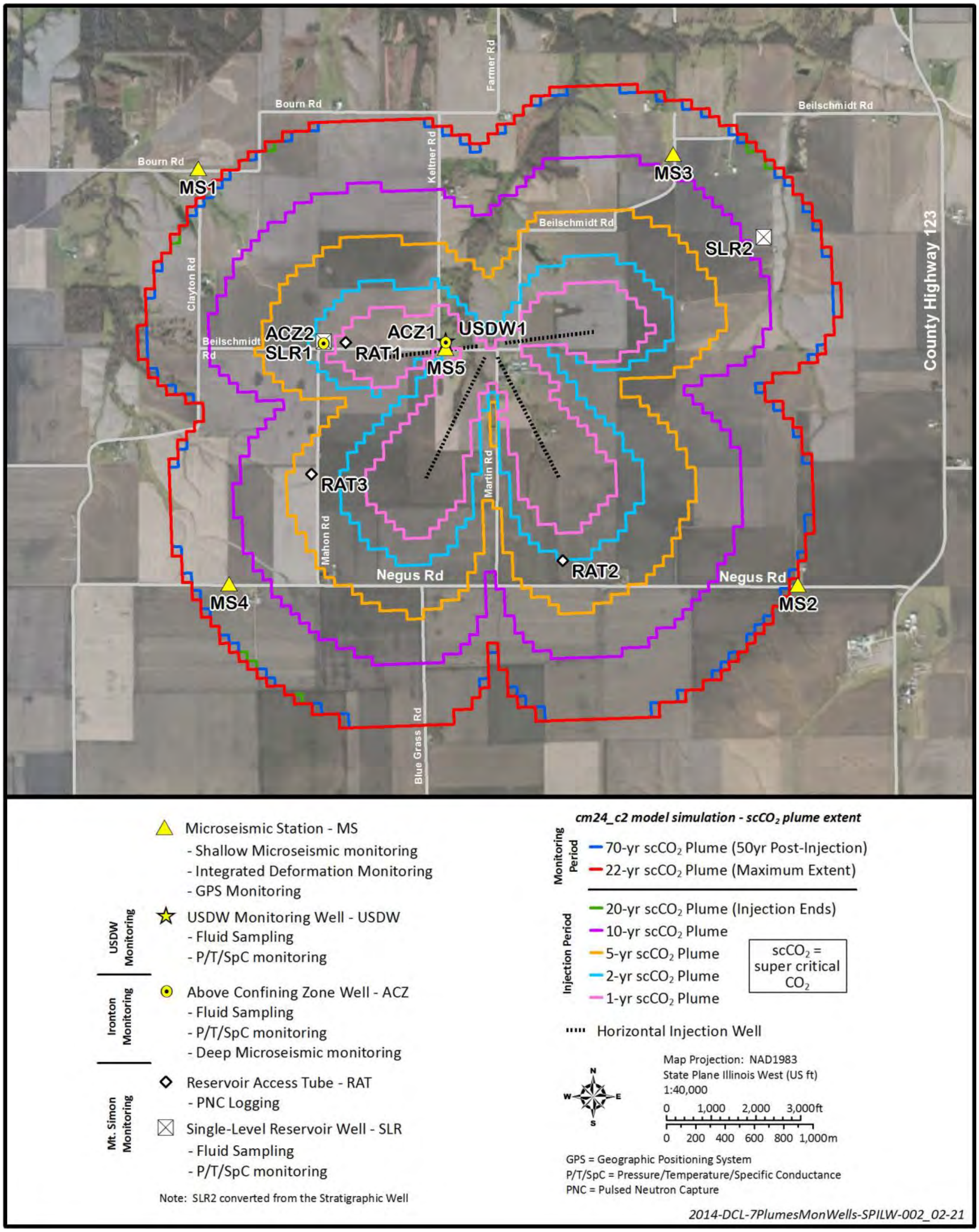


Figure 1. Monitoring Network Layout and Predicted Plume Extents at Multiple Time Intervals.

Carbon Dioxide Stream Analysis

FutureGen will conduct injection stream analysis to meet the requirements of 40 CFR 146.90(a), as described below.

Samples of the CO2 stream will be collected regularly (e.g., quarterly) for chemical analysis of the parameters listed in Table 2. Continuous monitoring is described in Table 1 of this plan.

Table 2. Parameters and Frequency for CO_2 Stream Analysis.

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
CO_2 (%)	quarterly
Water (lb/mmscf)	quarterly
Oxygen (ppm)	quarterly
Sulfur (ppm)	quarterly
Arsenic (ppm)	quarterly
Selenium (ppm)	quarterly
Mercury (ppm)	quarterly
Argon (%)	quarterly
Hydrogen Sulfide (ppm)	quarterly

Sampling methods:

Grab samples of the CO_2 stream will be obtained for analysis of gases, including CO_2, O_2, H2S, Ar, and water moisture. Samples of the CO_2 stream will be collected from the CO_2 pipeline at a location where the material is representative of injection conditions. A sampling station will be installed in the ground or on a structure close to the pipeline and connected to the pipeline via a sampling manifold with pressure and temperature (P/T) instrumentation to accommodate double-sided constant pressure sampling cylinders that will be used to collect the samples. The collection procedure is designed to collect and preserve representative CO_2 fluid samples from the pipeline to maintain pressure, phase, and constituent integrity and facilitate sample transport for analysis.

Analytical techniques:

See Section B.1.4 of the FutureGen QASP for analytical techniques for indirect CO_2 measurement.

Laboratory to be used/chain-of-custody procedures:

See Sections B.1.4 through B.1.7 of the FutureGen QASP for laboratory quality and Section B.1.3 for sample handling and custody.

Quality assurance and surveillance measures:

See the FutureGen QASP, including Sections B.14 for data management, B.1 for CO_2 sampling and analysis, and B.1.3 and B.14 for analytical techniques and chain of custody procedures.

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

FutureGen will conduct continuous monitoring of injection parameters to meet the requirements of 40 CFR 146.90(b), as described below.

Continuous Recording of Injection Mass Flow Rate

The mass flow rate of CO_2 injected into the well field will be measured by a flow meter skid with a Coriolis mass flow transmitter for each well. Each meter will have an analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). A total of six flow meters will be supplied, providing for two spare flow meters to allow for flow meter servicing and calibration. The flow meters will be connected to the main CO_2 storage site SCADA system for continuous monitoring and control of the CO_2 injection rate into each well.

Continuous Recording of Injection Pressure

The pressure of the injected CO_2 will be continuously measured for each well at a regular frequency by an electronic pressure transmitter with analog output mounted on the CO_2 line associated with each injection well at a location near the wellhead. The transmitter will be connected to the annulus pressurization system (APS) programmable logic controller (PLC) located in the Control Building adjacent to the injection well pad.

Continuous Recording of Injection Temperature

The temperature of the injected CO_2 will be continuously measured for each well at a regular frequency by an electronic temperature transmitter. The temperature transmitter will be mounted in a temperature well in the CO_2 line at a location close to the pressure transmitter near the wellhead. The transmitter will be connected to the APS PLC located in the Control Building adjacent to the injection well pad.

Instruments for measuring surface injection pressure and temperature will be calibrated initially before commencing injection and recalibrated periodically as needed based on regular (e.g., quarterly) instrument checks. These instruments for measuring surface injection pressure and temperature will be recalibrated annually.

Bottomhole Pressure and Temperature

An optical or electronic P/T gauge will be installed on the outside of the tubing string, approximately 30 ft above the packer, and ported into the tubing to continuously measure CO_2 injection P/T inside the tubing at this depth. In addition, injection P/T will be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead.

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow, as part of the instrumentation and control systems for the FutureGen CO_2 Pipeline and Storage Project. The P/T will also be monitored within each injection well at a position located immediately above the injection zone at the end of the injection tubing. The downhole sensor will be the point of compliance for maintaining injection pressure below 90%

of formation fracture pressure. If the downhole probe goes out between scheduled maintenance events then the surface pressure limitation noted in Attachment A of this permit will be used as a backup until the downhole probe/gauge is repaired or replaced.

Corrosion Monitoring

FutureGen will conduct corrosion monitoring of well materials quarterly to meet the requirements of 40 CFR 146.90(c), as described below.

Corrosion of well materials will be monitored using the corrosion coupon method. Corrosion monitoring of well casing and tubing materials will be conducted using coupons placed in the CO_2 pipeline. The coupons will be made of the same material as the long string casing and the injection tubing. The coupons will be removed quarterly and assessed for corrosion using the ASTM International (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed.

The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

Casing and tubing will also be evaluated periodically for corrosion throughout the life of the injection well by running wireline casing inspection logs (CILs). The frequency of running these tubing and casing inspection logs will be determined based on site-specific parameters and well performance. Wireline tools will be lowered into the well to directly measure properties of the well tubulars that indicate corrosion. The tools (described in Table 3), which may be used to monitor the condition of well tubing and casing, include:

- Mechanical casing evaluation tools, referred to as calipers, which have multiple “fingers” that measure the inner diameter of the tubular as the tool is raised or lowered through the well.

- Ultrasonic tools, which are capable of measuring wall thickness in addition to the inner diameter (radius) of the well tubular and can also provide information about the outer surface of the casing or tubing.

- Electromagnetic tools, which are able to distinguish between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated. These tools are able to provide mapped (circumferential) images with high resolution such that pitting depths, due to corrosion, can often be accurately measured.

Table 3. Wireline Tools for Monitoring Corrosion of Casing and Tubing.

Tool Name	Mechanical	Ultrasonic	Electromagnetic
	Multifinger Imaging Tool[a]	**Ultrasonic Imager Tool[a]**	**High-Resolution Vertilog[b]**
Parameter(s) Measured	Internal radius; does not measure wall thickness	Inner diameter, wall thickness, acoustic impedance, cement bonding to casing Up to 180 measurements per revolution	Magnetic flux leakage (internal and external) Full 360-degree borehole coverage
Tool OD (in.)	1.6875, 2.75, 4 (multiple versions available)	3.41 to 8.625	2.2 to 8.25
Tubular Size That Can Be Measured Min/Max (in.)	2/4.5, 3/7, 5/10 (multiple versions available)	4.5/13.375	4.5/9.625
Comments, limitations, special requirements, etc.	Typically run on memory using slickline. Can also be run in surface real-time mode.	Can detect evidence of defects/corrosion on casing walls (internal/external), quality of cement bond to pipe, and channels in cement. Moderate logging speed (30 ft/min) is possible.	Can distinguish between general corrosion, pitting, and perforations. Can measure pipe thickness. High logging speed (200 ft/min) is possible. Cannot evaluate multiple strings of tubular simultaneously.

(a) Schlumberger Limited

(b) Baker Hughes, Inc.

Groundwater Quality Monitoring

FutureGen will conduct groundwater quality/geochemical monitoring above the confining zone to meet the requirements of 40 CFR 146.90(d).

FutureGen will conduct periodic fluid sampling throughout the injection phase in three wells constructed for the purpose of this project: two ACZ monitoring wells in the Ironton Sandstone (the first permeable unit above the confining zone) and a lowermost USDW well in the St. Peter Sandstone. Details about these wells are in Table 4, and Figure 1 is a map with the well locations. The coordinates (in decimal degrees) of the wells are in Appendix A of this plan. Well construction information and well schematics are in Appendix B of this plan.

Table 4. Monitoring Wells to Be Used for GroundWater/Geochemical Sampling Above the Confining Zone.

	Above Confining Zone (ACZ)	USDW
Number of Wells	2	1
Total Depth (ft)	3,470	2,000
Lat/Long (WGS84)	ACZ1: 39°48'01.24"N, 90°04'41.87"W ACZ2: 39°48'01.06"N, 90°05'16.84"W	USDW1: 39°48'01.73"N, 90°04'41.87"W
Monitored Zone	Ironton Sandstone	St. Peter Sandstone
Monitoring Instrumentation	Fiber-optic (microseismic) cable cemented in annulus; P/T/SpC probe in monitored interval*	P/T/SpC probe in monitored interval*

* The P/T/SpC (pressure, temperature, specific conductance) probe is an electronic downhole multi-parameter probe incorporating sensors for measuring fluid P/T/SpC within the monitored interval. The probe is installed inside the tubing string, which is perforated (slotted) over the monitoring interval. Sensor signals are multiplexed to a surface data logger through a single conductor wireline cable.

FutureGen will also conduct baseline sampling in the shallow, semi-consolidated glacial sediments that make up the surficial aquifer. This sampling will use nine private water wells and one shallow monitoring well that has been drilled for the project (Figure 2). The locations of the surficial aquifer monitoring wells are tabulated in Appendix C of this plan.

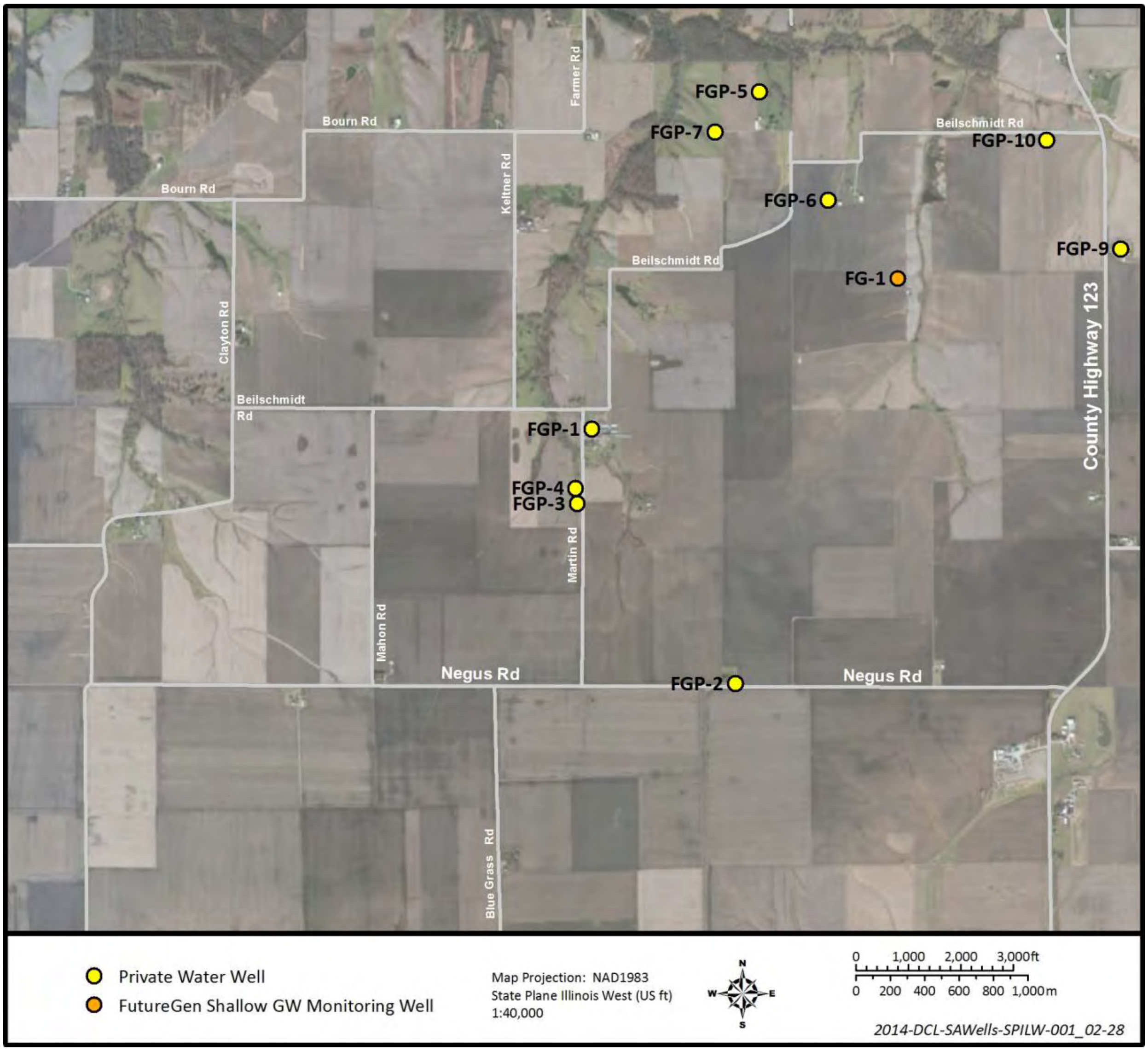


Figure 2. Surficial Aquifer Monitoring Well Locations. Well FG-1 is a dedicated well drilled for the purposes of the FutureGen 2.0 Project. FGP-1 through FGP-10 are local landowners' wells.

The tables below list the parameters that will be measured and the sampling frequencies. They include both dissolved gas compositional analysis (including CO_2) and measurements of dissolved inorganic carbon and pH. Continuous monitoring is described in Table 1 of this plan.

Table 5. Sampling Schedule for Surficial Aquifer Monitoring Wells.

Monitoring well name/location/map reference: Surficial aquifer monitoring wells (Figure 2) **Well depth/formation(s) sampled:** Shallow glacial sediments (approx. 17 ft – 49 ft)		
Parameter/Analyte	**Frequency (Baseline)**	**Frequency (Injection Phase)**
Dissolved or separate-phase CO_2	At least 3 sampling events	None planned
Water-level	At least 3 sampling events	None planned
Temperature	At least 3 sampling events	None planned
Other parameters, including total dissolved solids, pH, specific conductivity, major cations and anions, trace metals, dissolved inorganic carbon, total organic carbon, carbon and water isotopes, and radon	At least 3 sampling events	None planned

Table 6. Sampling Schedule for the USDW Monitoring Well.

Monitoring well name/location/map reference: One USDW monitoring well (see Figure 1) **Well depth/formation(s) sampled:** St. Peter Sandstone (2,000 ft)		
Parameter/Analyte	**Frequency (Baseline)**	**Frequency (Injection Phase)**
Dissolved or separate-phase CO_2	At least 3 sampling events	Quarterly for 3 years, then semi-annually for 2 years and annually thereafter
Pressure	Continuous, 1 year minimum	Continuous
Temperature	Continuous, 1 year minimum	Continuous
Other parameters, including total dissolved solids, pH, specific conductivity, major cations and anions, trace metals, dissolved inorganic carbon, total organic carbon, carbon and water isotopes, and radon	At least 3 sampling events	Quarterly for 3 years, then semi-annually for 2 years and annually thereafter
Note: For details and information on continuous monitoring, see Table 1.		

Table 7. Sampling Schedule for ACZ Monitoring Wells

Monitoring well name/location/map reference: Two ACZ monitoring wells (see Figure 1) **Well depth/formation(s) sampled:** Ironton Sandstone (3,470 ft)		
Parameter/Analyte	**Frequency (Baseline)**	**Frequency (Injection Phase)**
Dissolved or separate-phase CO_2	At least 3 sampling events	Quarterly for 3 years, then semi-annually for 2 years and annually thereafter
Pressure	Continuous, 1 year minimum	Continuous
Temperature	Continuous, 1 year minimum	Continuous
Other parameters, including total dissolved solids, pH, specific conductivity, major cations and anions, trace metals, dissolved inorganic carbon, total organic carbon, carbon and water isotopes, and radon	At least 3 sampling events	Quarterly for 3 years, then semi-annually for 2 years and annually thereafter
Note: For details and information on continuous monitoring, see Table 1.		

Sampling methods:

Sampling and analytical requirements for target parameters are given in Tables 8 and 9, respectively. A comprehensive suite of geochemical and isotopic analyses will be performed on collected fluid samples and analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Selection of this initial analyte list was based on relevance for detecting the presence of fugitive brine and CO_2.

During all groundwater sampling, field parameters (pH, specific conductance, and temperature) will be monitored for stability and used as an indicator of adequate well purging (i.e., parameter stabilization provides indication that a representative sample has been obtained). Calibration of field probes will follow the manufacturer's instructions using standard calibration solutions. A comprehensive list of target analytes under consideration and groundwater sample collection requirements is provided in Table 8.

All sampling and analytical measurements will be performed in accordance with project quality assurance requirements, samples will be tracked using appropriately formatted chain-of-custody forms, and analytical results will be managed in accordance with a project-specific data management plan.

The relative benefit of each analytical measurement will be evaluated throughout the design and initial injection testing phase of the project to identify the analytes best suited to meeting project monitoring objectives under site-specific conditions. If some analytical measurements are shown to be of limited use, they will be removed from the analyte list and not carried forward through the operational phases of the project. This selection process will consider the uniqueness and signature strength of each potential analyte and whether their characteristics provide for a high-value leak-detection capability. Any modification to the parameter list in Table 8 will be made in consultation with the UIC Program Director. Modifications to the parameter list will also require modifications to the permits through the process described in 40 C.F.R. Part 144.

Table 8. Aqueous Sampling Requirements for Target Parameters.

Parameter	Volume/Container	Preservation	Holding Time
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	20-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	60 days
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	20-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	60 days
Cyanide (CN-)	250-mL plastic vial	NaOH to pH > 12, 0.6 g ascorbic acid Cool 4°C,	14 days
Mercury	250-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	28 days
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	125-mL plastic vial	Filtered (0.45 µm), Cool 4°C	45 days
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	100-mL HDPE	Filtered (0.45 µm), Cool 4°C	14 days
Gravimetric Total Dissolved Solids (TDS)	250-mL plastic vial	Filtered (0.45 µm), no preservation, Cool 4°C	7 days
Water Density	100-mL plastic vial	No preservation, Cool 4°C	
Total Inorganic Carbon (TIC)	250-mL plastic vial	H_2SO_4 to pH <2, Cool 4°C	28 days
Dissolved Inorganic Carbon (DIC)	250-mL plastic vial	Filtered (0.45 µm), H_2SO_4 to pH <2, Cool 4°C	28 days
Total Organic Carbon (TOC)	250-mL amber glass	Unfiltered, H_2SO_4 to pH <2, Cool 4°C	28 days
Dissolved Organic Carbon (DOC)	125-mL plastic vial	Filtered (0.45 µm), H_2SO_4 to pH <2, Cool 4°C	28 days
Volatile Organic Analysis (VOA)	Bottle set 1: 3-40-mL sterile clear glass vials Bottle set 2: 3-40-mL sterile amber glass vials	Zero headspace, Cool <6 °C, Clear glass vials will be UV-irradiated for additional sterilization	7 days
Methane	Bottle set 1: 3-40-mL sterile clear glass vials Bottle set 2: 3-40-mL sterile amber glass vials	Zero headspace, Cool <6 °C, Clear glass vials (bottle set 1) will be UV-irradiated for additional sterilization	7 days
Stable Carbon Isotopes $^{13/12}C$ ($\delta^{13}C$) of DIC in Water	60-mL plastic or glass	Filtered (0.45 µm), Cool 4°C	14 days
Radiocarbon ^{14}C of DIC in Water	60-mL plastic or glass	Filtered (0.45 µm), Cool 4°C	14 days
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δD) and $^{18/16}O$ ($\delta^{18}O$) of Water	60-mL plastic or glass	Filtered (0.45 µm), Cool 4°C	45 days
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	1-L dissolved gas bottle or flask	Benzalkonium chloride capsule, Cool 4°C	90 days
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	1-L dissolved gas bottle or flask	Benzalkonium chloride capsule, Cool 4°C	90 days
Radon (^{222}Rn)	1.25-L PETE	Pre-concentrate into 20-mL scintillation cocktail. Maintain groundwater temperature prior to pre-concentration	1 day
pH	Field parameter	None	<1 h
Specific Conductance	Field parameter	None	<1 h

HDPE = high-density polyethylene; PETE = polyethylene terephthalate.

Table 9. Analytical Requirements.

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	ICP-AES, EPA Method 6010B or similar	1 to 80 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP-MS, EPA Method 6020 or similar	0.1 to 2 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Cyanide (CN-)	SW846 9012A/B	5 µg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Mercury	CVAA SW846 7470A	0.2 µg/L	±20%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	Ion Chromatography, EPA Method 300.0A or similar	33 to 133 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B	1 mg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Gravimetric Total Dissolved Solids (TDS	Gravimetric Method Standard Methods 2540C	10 mg/L	±10%	Balance calibration, duplicate samples
Water Density	ASTM D5057	0.01 g/mL	±10%	Balance calibration, duplicate samples
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of TIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of DIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Total Organic Carbon (TOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent Purge and Trap GC/MS	0.3 to 15 µg/L	±20%	Blanks, LCS, spike, spike duplicates per batch of 20
Methane	RSK 175 Mod Headspace GC/FID	10 µg/L	±20%	Blanks, LCS, spike, spike duplicates per batch of 20
Stable Carbon Isotopes $^{13/12}C$ ($1^{13}C$) of DIC in Water	Gas Bench for $^{13/12}C$	50 ppm of DIC	±0.2p	Duplicates and working standards at 10%

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Radiocarbon ^{14}C of DIC in Water	AMS for ^{14}C	Range: 0 i 200 pMC	±0.5 pMC	Duplicates and working standards at 10%
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ ($1^{18}O$) of Water	CRDS H_2O Laser	Range: -500‰ to 200‰ vs. VSMOW	$^{2/1}H$: ±2.0‰ $^{18/16}O$: ±0.3‰	Duplicates and working standards at 10%
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C	^{14}C Range: 0 & DupMC	^{14}C: ±0.5pMC ^{13}C: ±0.2‰ $^{2/1}H$: ±4.0‰	Duplicates and working standards at 10%
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	Modified ASTM 1945D	1 to 100 ppm (analyte dependent)	Varies by compon-ent	Duplicates and working standards at 10%
Radon (^{222}Rn)	Liquid scintillation after pre-concentration	5 mBq/L	±10%	Triplicate analyses
pH	pH electrode	2 to 12 pH units	±0.2 pH unit For indication only	User calibrate, follow manufacturer recommendations
Specific Conductance	Electrode	0 to 100 mS/cm	±1% of reading For indication only	User calibrate, follow manufacturer recommendations

ICP-AES = inductively coupled plasma atomic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; LC-MS = liquid chromatography-mass spectrometry; ECD = electron capture detector

Laboratory to be used/chain-of-custody procedures:

Samples will be tracked using appropriately formatted chain-of-custody forms. See Sections B.4.3 thru B.4.7 of the FutureGen QASP (Appendix G of this plan) for additional information.

Plan for guaranteeing access to all monitoring locations:

The land on which the ACZ and USDW wells are located will either be purchased or leased for the life of the project, so access will be secured.

Access to the surficial aquifer wells will not be required over the lifetime of the project. Access to wells for baseline sampling has been on a voluntary basis by the well owner. Nine local landowners agreed to have their surficial aquifer wells sampled. See Figure 2 for well locations.

Mechanical Integrity Testing

FutureGen will conduct external mechanical integrity testing (MIT) annually to meet the requirements of 40 CFR 146.90(e), as described below. The following MITs will be performed:

- **Pulsed-neutron capture (PNC) logging** to quantify the flow of water in or around the borehole. Following a baseline PNC log prior to the start of CO_2 injection, subsequent runs will be compared to the baseline to determine changing fluid flow conditions adjacent to the well bore (i.e., formation of channels or other fluid isolation concerns related to the well).

- **Temperature logging** to identify fluid movement along channels adjacent to the well bore. In addition to identifying injection-related flows behind casing, temperature logs can often locate small casing leaks.

To satisfy the annual MIT requirement, a PNC logging tool will be run in each injection well once per year to look for evidence of upward CO_2 migration out of the CO_2 storage zone. The PNC logging tool will be run twice during each event: once in the gas-view mode to detect CO_2 and once in the oxygen-activation mode to detect water.

A temperature log will also be collected in conjunction with each PNC logging run. Because the primary purpose of the external MIT is to demonstrate that there is no upward leakage of fluid out of the storage zone, the PNC logging tool will be run to a depth greater than the bottom of the caprock. Because the injection tubing will extend to a depth below the caprock, the PNC logs will be run inside the tubing; therefore, it will not be necessary to remove the injection tubing to conduct the PNC logging. A preliminary schedule for the annual well maintenance event is provided in Table 10.

Table 10. Schedule for Annual Injection Well Maintenance (per Well).

Activity	Work Days	Cum. Days
Shut down injection, isolate surface system	1	1
Allow well to sit undisturbed for 24 hours	1	2
Conduct PNC logging (external MIT)	2	4
Kill well	2	6
Slickline set plug in tubing above packer	0.5	6.5
Disconnect CO_2 pipeline, instruments, and other lines; remove Christmas tree valves for maintenance or replacement	0.5	7
Reinstall Christmas tree valves, re-connect CO_2 pipeline, instruments, and other lines	1	7
Slickline pull plug from packer	1	9
Perform annular pressure test, internal MIT	1	10
Return well to service	1	10

MIT = mechanical integrity test; PNC = pulsed-neutron capture.

MITs are also required to demonstrate that there are no significant leaks in the casing, tubing, or packer. This requirement will be met by continuously monitoring injection pressure on the annulus between tubing and long-string casing and annulus fluid volume. These functions will be provided by the Annular Pressurization System (APS), which is discussed in the Section of this document on "Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure."

All monitoring wells required under this permit will establish and maintain mechanical integrity. After construction, each monitoring well must establish Internal and External mechanical integrity. Wells that do not have a tubing and packer shall perform a pressure test on the casing. Each monitoring well that reaches the Eau Claire (the confining zone) shall establish mechanical integrity after construction, shall conduct an Internal mechanical integrity test at least every five years or continuously monitor the annulus, and shall conduct an External mechanical integrity test at least every five years. The testing of monitoring wells that reach the Eau Claire shall continue until they are plugged.It is also anticipated that it will be necessary to replace selected well components throughout the 20-year injection period, although the identity of the components and their frequency of replacement cannot be determined in advance. However, the components most likely to require replacement include the wellhead valves (selected portions), the tubing string, the packer, and the bottom-hole P/T gauge and associated cable. A preliminary schedule for the 5-year well maintenance event is provided in Table 11.

Table 11. Schedule for 5-Year Injection Well Maintenance Events (per Well).

Activity	Work Days	Cum. Days
Shut down injection, disassemble surface system	1	1
Arrive onsite with equipment rig-up/set-up	3	4
Conduct PNC logging (external MIT)	2	6
Kill well	2	8
Slickline set plug in tubing above packer	0.5	8.5
Disconnect CO_2 pipeline, instruments, and other lines; remove Christmas tree valves for maintenance or replacement	0.5	9
Pull tubing and P/T gauge and cable	1.5	10.5
Trip back in to pull packer	0.5	11
Pull packer	0.5	11.5
Reinstall new packer w/ plug, trip out to get P/T gauge and cable	1.5	13
Reinstall new P/T gauge and cable and injection tubing	1.5	14.5
Reinstall Christmas tree valves, re-connect CO_2 pipeline, instruments, and other lines.	1.5	16
Slickline pull plug from packer	1	17
Rig down and demobilize	3	20
Perform annular pressure test, internal MIT	1	21
Return well to service	1	22

Pressure Fall-Off Testing

FutureGen will conduct annual pressure fall-off testing to meet the requirements of 40 CFR 146.90(f), as described below. Pressure fall-off tests will provide the following information:

- Confirmation of hydrogeologic reservoir properties;
- Long-term pressure buildup in the injection reservoir(s) due to CO_2 injection over time;
- Average reservoir pressure, which can be compared to modeled predictions of reservoir pressure to verify that the operation is responding as modeled/predicted and identify the need for recalibration of the AoR model in the event that the monitoring results do not match expectations; and
- Formation damage (skin) near the well bore, which can be used to diagnose the need for well remediation/rehabilitation.

In the pressure fall-off test, flow is maintained at a steady rate for a period of time, then injection is stopped, the well is shut-in, and bottom-hole pressure is monitored and recorded for a period of time sufficient to make a valid observation of the pressure fall-off curve. Downhole or surface pressure gauges will be used to record bottom-hole pressures during the injection period and the fall-off period. Pressure gauges that are used for the purpose of the fall-off test shall have been calibrated no more than one year prior to the date of the fall-off test with current calibration certificates provided with the test results to EPA. In lieu of removing the injection tubing, the calibration of downhole pressure gauges will demonstrate accuracy by using a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on annual calibration checks (using the second calibrated pressure gauge) developed for the downhole gauge, can be used for the purpose of the fall-off test. If used, these calibration curves (showing all historic pressure deviations) will accompany the fall-off test data submitted to EPA. Pressures will be measured at a frequency that is sufficient to measure the changes in bottom-hole pressure throughout the test period, including rapidly changing pressures immediately following cessation of injection. The fall-off period will continue until radial flow conditions are observed, as indicated by stabilization of pressure and leveling off of the pressure derivative curve. The fall-off test may also be truncated if boundary effects are encountered, which would be indicated as a change in the slope of the derivative curve, or if radial flow conditions are not observed. In addition to the radial flow regime, other flow regimes may be observed from the fall-off test, including spherical flow, linear flow, and fracture flow. Analysis of pressure fall-off test data will be done using transient-pressure analysis techniques that are consistent with EPA guidance for conducting pressure fall-off tests (EPA 1998, 2002).

See Section B.6 of the FutureGen QASP for details on pressure fall-off testing.

Carbon Dioxide Plume and Pressure-Front Tracking

FutureGen will conduct direct and indirect CO_2 plume and pressure-front monitoring to meet the requirements of 40 CFR 146.90(g).

The following describes FutureGen's planned monitoring well network for plume and pressure-front monitoring (monitoring wells used for monitoring above the confining zone are described above in the Groundwater Quality Monitoring section).

The design to be used for plume and pressure-front monitoring in the injection zone is as follows:

- **Two SLR wells** (one of which is a reconfiguration of the previously drilled stratigraphic well). These wells will be used to monitor within the injection zone beyond the east and west ends of the horizontal CO_2-injection laterals.

  Monitored parameters: pressure, temperature, and hydrogeochemical indicators of CO_2. To meet permit requirements for pressure front monitoring, at least one additional SLR well will be installed outside the lateral extent of the CO_2 plume but within the lateral extent of the defined pressure front AoR. This well will be installed within 5 years of the start of injection.

- **Three RAT wells.** These are fully cased wells, which support PNC logging. The wells will not be perforated to preclude CO_2 flooding of the borehole, which can distort the CO_2 saturation measurements.

  Monitored parameters: quantification of CO2 saturation across the reservoir and caprock.

Details about these wells are provided in Table 12 (the well locations are presented in Figure 1). The coordinates (in decimal degrees) of the wells are provided in Appendix A of this plan. Well construction information and well schematics are provided in Appendix B of this plan.

Table 12. Monitoring Wells to Be Used for Plume and Pressure-Front Monitoring.

	Single-Level In-Reservoir (SLR)	Reservoir Access Tube (RAT)
Number of Wells	2	3
Total Depth (ft)	4,150	4,465
Lat/Long (WGS84)	SLR1: 39°48'01.56"N, 90°05'16.84"W SLR2: 39°48'24.51"N, 90°03'10.73"W	RAT1: 39°48'01.28"N, 90°05'10.59"W RAT2: 39°47'13.09"N, 90°04'08.50"W RAT3: 39°47'32.25"N, 90°05'20.46"W
Monitored Zone	Mount Simon Sandstone	Mount Simon Sandstone
Monitoring Instrumentation	Fiber-optic P/T (tubing conveyed)* P/T/SpC probe in monitored interval**	Pulsed-neutron capture logging equipment

* Fiber-optic cable attached to the outside of the tubing string, in the annular space between the tubing and casing.
** The P/T/SpC (pressure, temperature, specific conductance) probe is an electronic downhole multi-parameter probe incorporating sensors for measuring fluid P/T/SpC within the monitored interval. The probe is installed inside the tubing string, which is perforated (slotted) over the monitoring interval. Sensor signals are multiplexed to a surface data logger through a single conductor wireline cable.

Direct Pressure Monitoring

FutureGen will conduct direct pressure-front monitoring to meet the requirements of 40 CFR 146.90(g)(1).

Continuous monitoring of injection zone P/T will be performed with sensors installed in wells that are completed in the injection zone. P/T monitoring in the injection well and all monitoring wells will be performed using a real-time monitoring system with surface readout capabilities so that pressure gauges do not have to be removed from the well to retrieve data.

The following measures will be taken to ensure that the pressure gauges are providing accurate information on an ongoing basis:

- High-quality (high-accuracy, high-resolution) gauges with low drift characteristics will be used.
- Gauge components (gauge, cable head, cable) will be manufactured of materials designed to provide a long life expectancy for the anticipated downhole conditions.
- Upon acquisition, a calibration certificate will be obtained for every pressure gauge. The calibration certificate will provide the manufacturer's specifications for range, accuracy (% full scale), resolution (% full scale), drift (< psi per year), and calibration results for each parameter. The calibration certificate will also provide the date that the gauge was calibrated and the methods and standards used.
- P/T gauges will be installed in the injection wells above any packers so they can be removed if necessary by removing the tubing string without pulling the packer. P/T gauges will be installed either above or below the packer in the SLR monitoring wells that will have tubing and packer. Redundant gauges may be run on the same cable to provide confirmation of downhole P/T.
- Upon installation, all gauges will be tested to verify they are functioning (reading/transmitting) correctly.

- Pressure gauges that are used for the purpose of direct pressure monitoring will be calibrated on an annual basis with current annual calibration certificates kept on file with the monitoring data. In lieu of removing the injection tubing, the calibration of downhole pressure gauges will demonstrate accuracy by using a pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on all annual calibration checks (using the second calibrated gauge method described above) developed for the downhole gauge, may be used for the purpose of direct pressure monitoring. If used, these calibration curves, showing all historic pressure deviations, will be kept on file with the monitoring data.
- Gauges will be pulled and recalibrated whenever a workover occurs that involves removal of tubing. A new calibration certificate will be obtained whenever a gauge is recalibrated.

Injection P/T will also be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead. The surface instruments will be checked, and if necessary, recalibrated or replaced on a regular basis (e.g., semi-annually) to ensure they are providing accurate data.

Direct pressure monitoring in the injection zone will take place as indicated in Table 13. Continuous monitoring is described in Table 1 of this plan.

Table 13. Monitoring Schedule for Direct Pressure-Front Tracking.

Well Location/Map Reference	Depth(s)/Formation(s)	Frequency (Baseline)	Frequency (Injection Phase)
Injection Well 1	Mount Simon/4,030 ft.	Continuous	Continuous
Injection Well 2	Mount Simon/4,030 ft.	Continuous	Continuous
Injection Well 3	Mount Simon/4,030 ft.	Continuous	Continuous
Injection Well 4	Mount Simon/4,030 ft.	Continuous	Continuous
Two single-level monitoring wells (SLR Wells 1 and 2)	Mount Simon/4,150 ft.	Continuous	Continuous
Note: For details and information on continuous monitoring, see Table 1.			

See Section B.7 of the FutureGen QASP for further discussion of pressure monitoring.

<u>Plan for guaranteeing access to all monitoring locations:</u>

The land on which these wells are located will either be purchased or leased for the life of the project, so access will be secured.

Direct Geochemical Plume Monitoring

FutureGen will conduct direct CO_2 plume monitoring to meet the requirements of 40 CFR 146.90(g)(1).

Fluid samples will be collected from monitoring wells completed in the injection zone before, during, and after CO_2 injection. The samples will be analyzed for chemical parameter changes that are indicators of the presence of CO_2 and/or reactions caused by the presence of CO_2. Direct fluid sampling in the injection zone will take place as indicated in Table 14. Continuous monitoring is described in Table 1 of this plan.

Table 14. Monitoring Schedule for Direct Geochemical Plume Monitoring.

Monitoring well name/location/map reference: Two SLR monitoring wells (see Figure 1) **Well depth/formation(s) sampled:** Mount Simon Sandstone (4,150 ft)		
Parameter/Analyte	**Frequency (Baseline)**	**Frequency (Injection Phase)**
Dissolved or separate-phase CO_2	At least 3 sampling events	Quarterly for 3 years, then semi-annually for 2 years and annually thereafter
Pressure	Continuous, 1 year minimum	Continuous
Temperature	Continuous, 1 year minimum	Continuous
Other parameters, including major cations and anions, selected metals, general water-quality parameters (pH, alkalinity, total dissolved solids, specific gravity), and any tracers added to the CO_2 stream	At least 3 sampling events	Quarterly for 3 years, then semi-annually for 2 years and annually thereafter
Note: For details and information on continuous monitoring, see Table 1.		

<u>Sampling methods:</u>

Periodically, fluid samples will be collected from the monitoring wells completed in the injection zone. Fluid samples will be collected using an appropriate method to preserve the fluid sample at injection zone temperature and pressure conditions. Examples of appropriate methods include using a bomb-type sampler (e.g., Kuster sampler) after pumped or swabbed purging of the sampling interval, using a Westbay sampler, or using a pressurized U-tube sampler (Freifeld et al. 2005).

Fluid samples will be analyzed for parameters that are indicators of CO_2 dissolution (Table 15), including major cations and anions, selected metals, and general water-quality parameters (pH, alkalinity, total dissolved solids [TDS], specific gravity). Changes in major ion and trace element geochemistry are expected in the injection zone. Analysis of carbon and oxygen isotopes in injection zone fluids and the injection stream ($^{13/12}C$, $^{18/16}O$) provides another potential supplemental measure of CO_2 migration. Where stable isotopes are included as an analyte, data quality and detectability will be reviewed throughout the active injection phase and discontinued if these analyses provide limited benefit. Sampling and analytical requirements for target parameters are given in Tables 15 and 16 respectively.

The relative benefit of each analytical measurement will be evaluated throughout the design and initial injection testing phase of the project to identify the analytes best suited to meeting project monitoring objectives under site-specific conditions. If some analytical measurements are shown to be of limited use, they will be removed from the analyte list and not carried forward through the operational phases of the project. This selection process will consider the uniqueness and signature strength of each potential analyte and whether their characteristics provide for a high-value leak-detection capability. Any modification to the parameter list in Table 8 will be made in consultation with the UIC Program Director. Modifications to the parameter list will also require modifications to the permits through the process described in 40 C.F.R. Part 144.

Table 15. Aqueous Sampling Requirements for Target Injection Zone Parameters.

Parameter	Volume/Container	Preservation	Holding Time
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	20-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	60 days
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	20-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	60 days
Cyanide (CN-)	250-mL plastic vial	NaOH to pH > 12, 0.6 g ascorbic acid Cool 4°C,	14 days
Mercury	250-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	28 days
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	125-mL plastic vial	Filtered (0.45 µm), Cool 4°C	45 days
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	100-mL HDPE	Filtered (0.45 µm), Cool 4°C	14 days
Gravimetric Total Dissolved Solids (TDS)	250-mL plastic vial	Filtered (0.45 µm), no preservation, Cool 4°C	7 days
Water Density	100 mL plastic vial	No preservation, Cool 4°C	
Total Inorganic Carbon (TIC)	250-mL plastic vial	H_2SO_4 to pH <2, Cool 4°C	28 days
Dissolved Inorganic Carbon (DIC)	250-mL plastic vial	Filtered (0.45 µm), H_2SO_4 to pH <2, Cool 4°C	28 days
Total Organic Carbon (TOC)	250-mL amber glass	Unfiltered, H_2SO_4 to pH <2, Cool 4°C	28 days
Dissolved Organic Carbon (DOC)	125-mL plastic vial	Filtered (0.45 µm), H_2SO_4 to pH <2, Cool 4°C	28 days
Volatile Organic Analysis (VOA)	Bottle set 1: 3-40-mL sterile clear glass vials Bottle set 2: 3-40-mL sterile amber glass vials	Zero headspace, Cool <6 °C, Clear glass vials will be UV-irradiated for additional sterilization	7 days
Methane	Bottle set 1: 3-40-mL sterile clear glass vials Bottle set 2: 3-40 mL sterile amber glass vials	Zero headspace, Cool <6 °C, Clear glass vials (bottle set 1) will be UV-irradiated for additional sterilization	7 days
Stable Carbon Isotopes $^{13/12}C$ ($\delta^{13}C$) of DIC in Water	60-mL plastic or glass	Filtered (0.45 µm), Cool 4°C	14 days
Radiocarbon ^{14}C of DIC in Water	60-mL plastic or glass	Filtered (0.45µm), Cool 4°C	14 days
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δD) and $^{18/16}O$ ($\delta^{18}O$) of Water	60-mL plastic or glass	Filtered (0.45µm), Cool 4°C	45 days
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	1-L dissolved gas bottle or flask	Benzalkonium chloride capsule, Cool 4°C	90 days
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	1-L dissolved gas bottle or flask	Benzalkonium chloride capsule, Cool 4°C	90 days
Radon (^{222}Rn)	1.25-L PETE	Pre-concentrate into 20-mL scintillation cocktail. Maintain groundwater temperature prior to pre-concentration	1 day
pH	Field parameter	None	<1 h

Parameter	Volume/Container	Preservation	Holding Time
Specific Conductance	Field parameter	None	<1 h

HDPE = high-density polyethylene; PETE = polyethylene terephthalate.

Table 16. Analytical Requirements.

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	ICP-AES, EPA Method 6010B or similar	1 to 80 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP-MS, EPA Method 6020 or similar	0.1 to 2 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Cyanide (CN-)	SW846 9012A/B	5 µg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Mercury	CVAA SW846 7470A	0.2 µg/L	±20%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	Ion Chromatography, EPA Method 300.0A or similar	33 to 133 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B	1 mg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Gravimetric Total Dissolved Solids (TDS	Gravimetric Method Standard Methods 2540C	10 mg/L	±10%	Balance calibration, duplicate samples
Water Density	ASTM D5057	0.01 g/mL	±10%	Balance calibration, duplicate samples
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of TIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of DIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Total Organic Carbon (TOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent Purge and Trap GC/MS	0.3 to 15 µg/L	±20%	Blanks, LCS, spike, spike duplicates per batch of 20
Methane	RSK 175 Mod Headspace GC/FID	10 µg/L	±20%	Blanks, LCS, spike, spike duplicates per batch of 20
Stable Carbon Isotopes $^{13/12}C$ ($1^{13}C$) of DIC in Water	Gas Bench for $^{13/12}C$	50 ppm of DIC	±0.2p	Duplicates and working standards at 10%

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Radiocarbon ^{14}C of DIC in Water	AMS for ^{14}C	Range: 0 i 200 pMC	±0.5 pMC	Duplicates and working standards at 10%
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ ($1^{18}O$) of Water	CRDS H_2O Laser	Range: - 500‰ to 200‰ vs. VSMOW	$^{2/1}H$: ±2.0‰ $^{18/16}O$: ±0.3‰	Duplicates and working standards at 10%
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C	^{14}C Range: 0 & DupMC	^{14}C: ±0.5pMC ^{13}C: ±0.2‰ $^{2/1}H$: ±4.0‰	Duplicates and working standards at 10%
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	Modified ASTM 1945D	1 to 100 ppm (analyte dependent)	Varies by compon-ent	Duplicates and working standards at 10%
Radon (^{222}Rn)	Liquid scintillation after pre-concentration	5 mBq/L	±10%	Triplicate analyses
pH	pH electrode	2 to 12 pH units	±0.2 pH unit For indication only	User calibrate, follow manufacturer recommendations
Specific Conductance	Electrode	0 to 100 mS/cm	±1% of reading For indication only	User calibrate, follow manufacturer recommendations

ICP-AES = inductively coupled plasma atomic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; LC-MS = liquid chromatography-mass spectrometry; ECD = electron capture detector

Laboratory to be used/chain-of-custody procedures:

See Section B.4 of the FutureGen QASP for groundwater and brine sampling, analysis, chain-of-custody procedures. Additionally, see Section B.7 of the FutureGen QASP for protocols for plume and pressure-front tracking.

Plan for guaranteeing access to all monitoring locations:

The land on which these wells are located will either be purchased or leased for the life of the project, so access will be secured.

Indirect Carbon Dioxide Plume and Pressure-Front Tracking

FutureGen will conduct indirect plume and pressure-front monitoring to meet the requirements of 40 CFR 146.90(g)(2).

The screening of the indirect monitoring approaches was conducted as part of the Front End Engineering Design process. The selected indirect technologies will include the following:

- PNC logging for determination of reservoir CO_2 saturation;
- Integrated deformation monitoring;
- Time-lapse gravity; and
- Microseismic monitoring.

The monitoring schedule for these techniques is provided in Table 17. Continuous monitoring is described in Table 1 of this plan. The sections below describe these indirect methods.

Table 17. Monitoring Schedule for Indirect Plume and Pressure-Front Monitoring.

Monitoring Technique	Location	Frequency (Baseline)	Frequency (Injection Phase)
Pulsed-neutron capture logging	RAT Wells 1, 2, and 3	3 events	Quarterly for 5 years and annually thereafter
Integrated deformation monitoring	5 locations (see Figure 1)	1 year minimum	Continuous
Time-lapse gravity monitoring	46 locations (see Figure 3)	3 events	Annually
Passive seismic monitoring (microseismicity)	Surface measurements (see Figure 1) plus downhole sensor arrays at ACZ Wells 1 and 2	1 year minimum	Continuous (1 scene per month)
Note: For details and information on continuous monitoring, see Table 1.			

Pulsed-neutron capture logging

Once the reservoir model has been refined based on site-specific information from the injection site, predictive simulations of CO_2 arrival response will be generated for each RAT installation. These predicted responses will be compared with monitoring results throughout the operational phase of the project and significant deviation in observed response would result in further action, including a detailed evaluation of the observed response, calibration/refinement of the numerical model, and possible modification to the monitoring approach and/or storage site operations.

The coordinates (in decimal degrees) of the RAT wells are in Appendix A of this plan. Well construction information and well schematics are in Appendix B of this plan.

Integrated deformation monitoring

Integrated deformation monitoring (see Figure 1 for locations) integrates ground data from permanent Global Positioning System (GPS) stations, tiltmeters, supplemented with annual Differential GPS (DGPS) surveys, and larger-scale Differential Interferometric Synthetic

Aperture Radar (DInSAR) surveys to detect and map temporal ground-surface deformation. These data reflect the dynamic geomechanical behavior of the subsurface in response to CO_2 injection. These measurements will provide useful information about the evolution and symmetry of the pressure front. These results will be compared with model predictions throughout the operational phase of the project and significant deviation in observed response would result in further action, including a detailed evaluation of the observed response, calibration/refinement of the numerical model, and possible modification to the monitoring approach and/or storage site operations.

Orbital SAR data will be systematically acquired and processed over the storage site with at least 1 scene per month to obtain advanced InSAR time series. These data will come from X-band TerraSAR-X, C-band Radarsat-2, X-Band Cosmo-Skymed or any other satellite instrument that will be available at the time of data collection.

Widespread overall temporal decorrelation is anticipated except in developed areas (e.g., roads, infrastructure at the site, and the neighboring towns) and for the six corner cubes reflectors that will be deployed on site. These isolated coherent pixels will be exploited to measure deformation over time and different algorithms (e.g., persistent scatters, small baseline subsets, etc.) will be used to determine the best approach for the site.

Data from 5 permanent tiltmeters and GPS stations will be collected continuously (MS1-MS5 locations in Figure 1). In addition, annual geodetic surveys will be conducted using the Real-Time Kinematic (RTK) technique where a single reference station gives the real-time corrections, providing centimeter-level or better accuracy. Deformations will be measured at permanent locations chosen to measure the extent of the predicted deformation in the AoR and also used by the gravity surveys (see time-lapse gravity monitoring).

To establish a comprehensive geophysical and geomechanical understanding of the FutureGen site, InSAR and field deformation measurements will be integrated and processed with other monitoring data collected at the site: microseismicity, gravity, pressure and temperature. This unique and complete geophysical data set will then be inverted to constrain the CO_2 plume shape, extension and migration in the subsurface.

Time-lapse gravity monitoring

The objective of gravity monitoring is to observe changes in density distribution in the subsurface caused by the migration of fluids, which could potentially help define the areal extent of the CO_2 plume or detect leakage.

FutureGen will use a network of forty six permanent stations that were established in 2011 during a gravity survey for the purpose of future reoccupation surveys. Approximately 35 complementary stations will be established for a total of 81 stations. A map of the gravity stations is provided in

Figure 3. The coordinates (in decimal degrees) of the stations are provided in Appendix D.

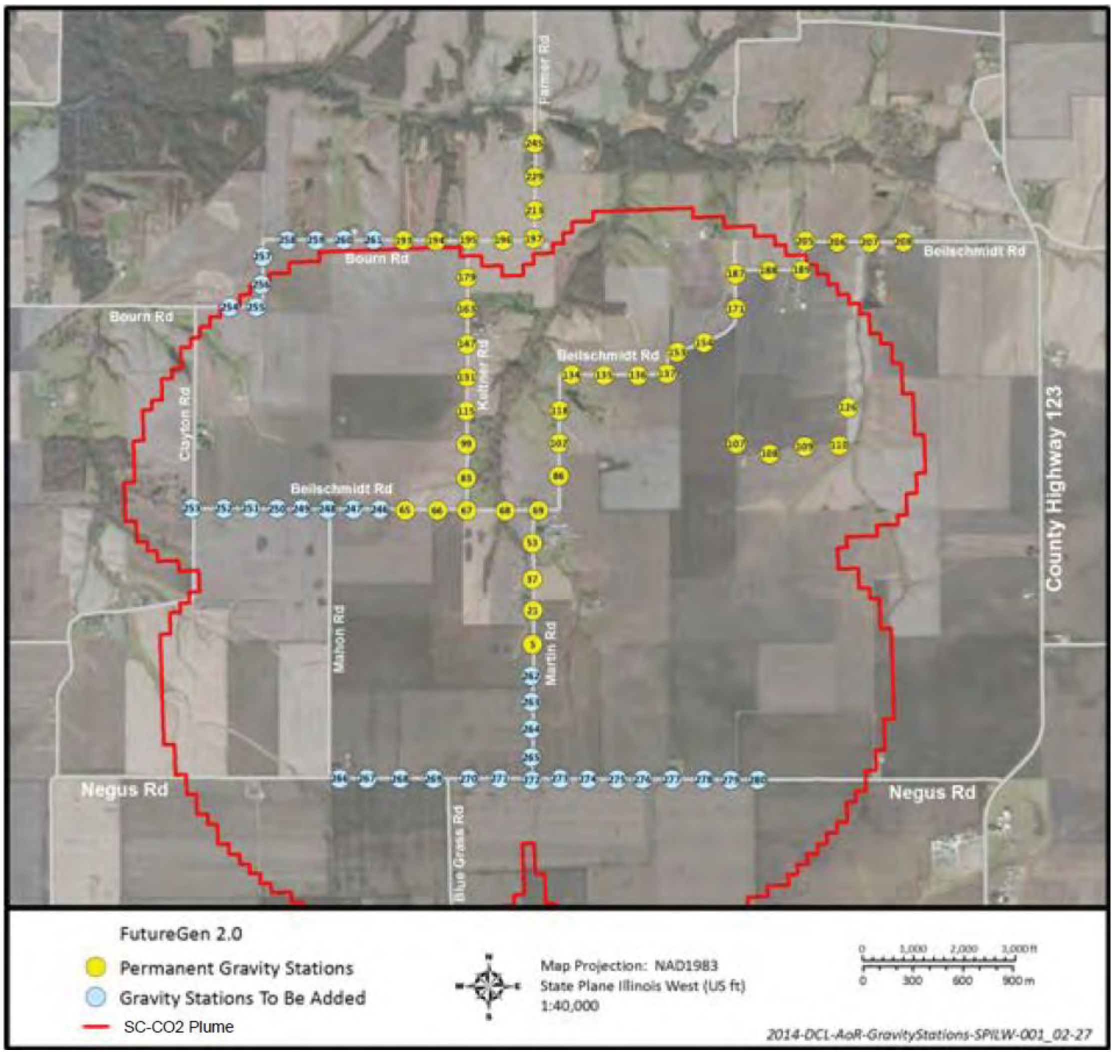


Figure 3. Permanent Gravity Station Locations (with supplemental DGPS).

Passive seismic monitoring (microseismicity)

The microseismic monitoring network (see Figure 1; downhole arrays will also be installed at the two ACZ wells) will be used to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of 1) addressing public and stakeholder concerns related to induced seismicity, 2) estimating the spatial extent of the pressure front from the distribution of seismic events, and 3) identifying features that may indicate areas of caprock failure and possible containment loss. Seismic monitoring considerations are also addressed in the Emergency and Remedial Response Plan (Attachment F of this permit).

Testing & Monitoring Techniques and Procedures

The techniques and procedures in the Testing & Monitoring Plan may be revised to incorporate best practices that develop over time. Such revisions will be governed under Section B of this permit “PERMIT ACTIONS.”

APPENDIX A: Deep Monitoring Wells Coordinates

Well ID	Well Type	Latitude (WGS84)	Longitude (WGS84)
ACZ1	Above Confining Zone 1	39.80034315	-90.07829648
ACZ2	Above Confining Zone 2	39.80029543	-90.08801028
USDW1	Underground Source of Drinking Water	39.80048042	-90.0782963
SLR1	Single-Level in-Reservoir 1	39.8004327	-90.08801013
SLR2	Single-Level in-Reservoir 2	39.80680878	-90.05298062
RAT1	Reservoir Access Tube 1	39.80035565	-90.08627478
RAT2	Reservoir Access Tube 2	39.78696855	-90.06902677
RAT3	Reservoir Access Tube 3	39.79229199	-90.08901656

APPENDIX B: Monitoring Well Construction and Schematics

- **ACZ Well Construction and Drilling Information**
- **USDW Well Construction and Drilling Information**
- **SLR1 Well Construction and Drilling Information**
- **SLR2 Well Construction and Drilling Information**
- **RAT Well Construction and Drilling Information**

ACZ Well Construction and Drilling Information

Construction detail for the Above Confining Zone (ACZ) wells is provided in Figure B-1. One of the ACZ wells will be located approximately 1,000 ft west of the injection well site, within the region of highest pressure buildup. The other ACZ well will be located approximately 0.75 mi west of the injection site on the same drill pad as single-level in-reservoir well 1 (SLR1). These selected ACZ locations focus early-detection monitoring within the region of elevated pressure and are proximal to six of nine project-related caprock penetrations (four injection wells, two reservoir wells, and three reservoir access tubes [RATs]). The ACZ wells will be used to collect fluid samples and for continuous pressure, temperature, specific conductance (P/T/SpC) and microseismic monitoring. A fiber-optic cable with integral geophones for microseismic monitoring will be secured to the outside of the casing and cemented in place. This design will permit unobstructed access to the inside of the casing and screen for planned sampling and monitoring activities.

To begin, a 30-in. borehole will be drilled and 24-in.-OD conductor casing will be installed to near the contact with Pennsylvanian bedrock (150 ft) (Figure B-1). Next, the boring will step down to a 20-in. borehole and 16-in. casing to approximately 600 ft. Below 600 ft, the hole will step down to a 14-3/4-in. hole lined with 10-3/4-in. casing to below the base of the Potosi Dolomite. Casing to the base of the Potosi Dolomite (~3,100 ft) is needed to case off the karstic lost-circulation zone encountered while drilling the stratigraphic well. After cementing the 10-3/4-in. casing in place a 9-1/2-in. borehole will be drilled into the top of the underlying confining zone. The base of the Ironton Sandstone in the stratigraphic well was 3,425 ft bgs. The bottom of the ACZ wells should be drilled a bit further (to ~3,470-ft depth) into the top of the Eau Claire Formation to positively identify the Ironton/Eau Claire contact and to create sufficient borehole to accommodate a 50-ft-long section of blank 5-1/2-in. casing below the well screen. If the ongoing modeling effort focused on evaluating early-detection capabilities in the ACZ wells indicates that detection is improved by moving the screen to near the top of the Ironton Formation, then the borehole will be plugged back prior to well completion.

After the 9-1/2-in. borehole has been drilled to total depth, the borehole will be developed to remove mud cake, cuttings, and drill fluids via circulation. Development will continue until all drilling mud has been effectively removed from the borehole wall. After the borehole has been circulated clean, a final casing string will be installed. The final casing string will be 5-1/2-in. OD and will include a ~20-ft-long stainless-steel well screen installed across the selected monitoring interval. A 50-ft-long section of blank casing will be attached below the screen to provide a sump for collecting any debris that may enter the well over time. A swellable packer may be placed immediately above and below the screened interval to help ensure zonal isolation (see Figure B-2). The annulus casing packer (ACP) and a stage-cement tool will be placed above the well screen to isolate and keep cement away from the screen. In addition to the stainless-steel well screen, the lowermost 200 ft of the 5-1/2-in. casing string (including the section that spans the Ironton Sandstone [3,286−3,425 ft bgs]) will be a corrosion-resistant alloy material (e.g., S13Cr110). The remainder of the 5-1/2-in. casing string will be carbon steel. Corrosion-resistant cement will be used to cement the final casing string up to ~3,100-ft depth. Regular cement will be used to seal the remainder of the 5-1/2-in. casing to ground surface. All other casing strings will be cemented with standard well cement. A summary of the borehole and casing program for the ACZ wells is in figure B.1.

Table B.1. Casing and Borehole Program for the ACZ Monitoring Wells.

Section	Borehole Depth (ft)	Borehole Diam. (in.)	Casing OD (in.)	Casing Grade	Casing weight (lb/ft)	Casing Connection
Conductor Casing	150	30 (min.)	24	B	140	PEB
Surface Casing	600	20	16	K-55	84	BTC
Intermediate Casing	3,100	14-3/4	10-3/4	K-55	51	BTC
Long Casing (with a 20-ft-long screened section)	3,470	9-1/2	5-1/2	J-55 (0-3,100 ft); S13Cr110 (3,100−3,470 ft)	17	LTC (J-55); Vam Top or similar (S13Cr110)

Grade B is equivalent to line pipe; BTC = buttress thread connection; Cr = chromium; LTC = long thread connection; PEB = plain end beveled.
Notes:
Actual casing grades and weights may differ based on material available at the time of construction.
All depths are approximate and may be adjusted based on information obtained when the well is drilled.

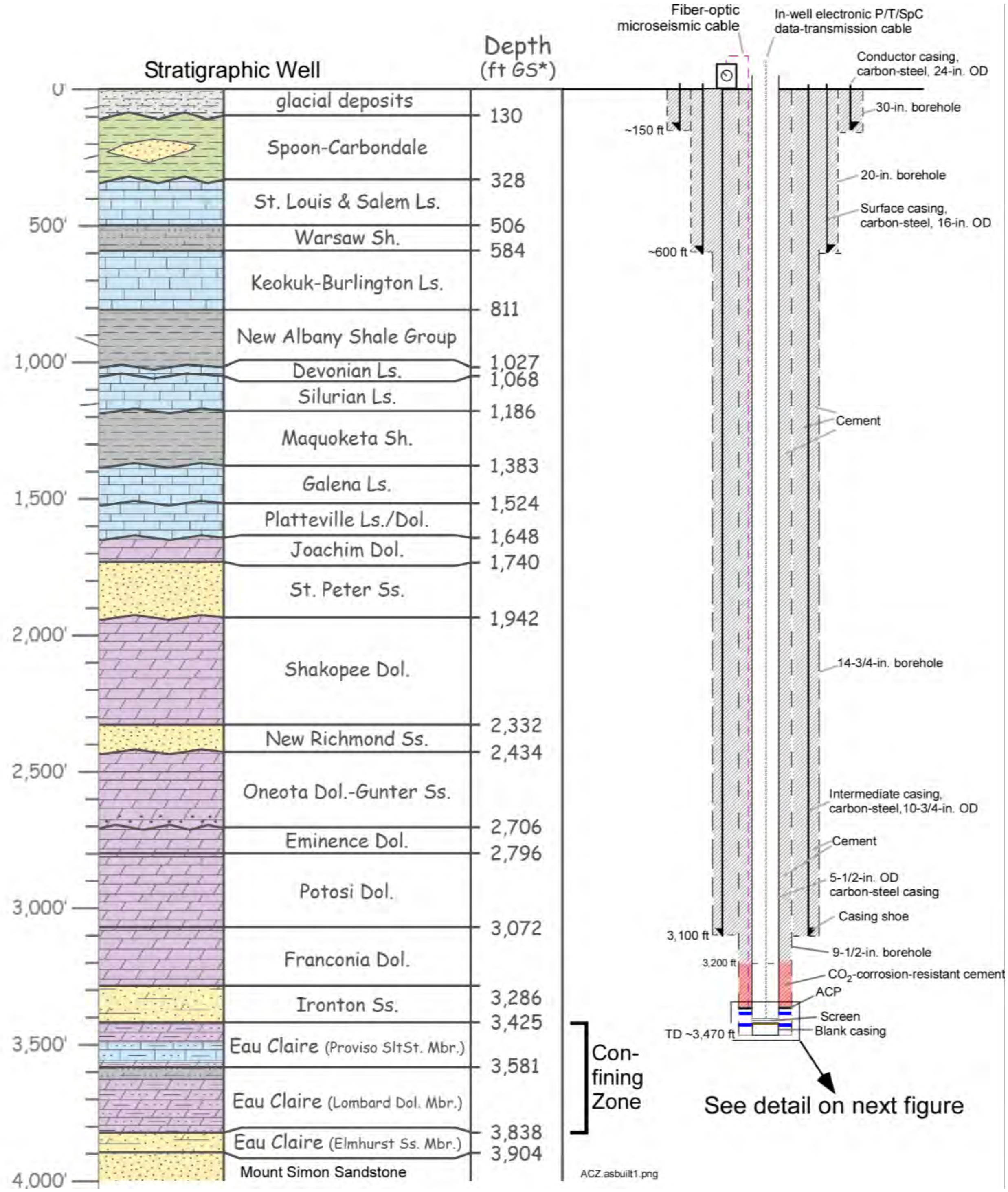


Figure B-1. Well Construction Diagram for the ACZ Monitoring Wells.

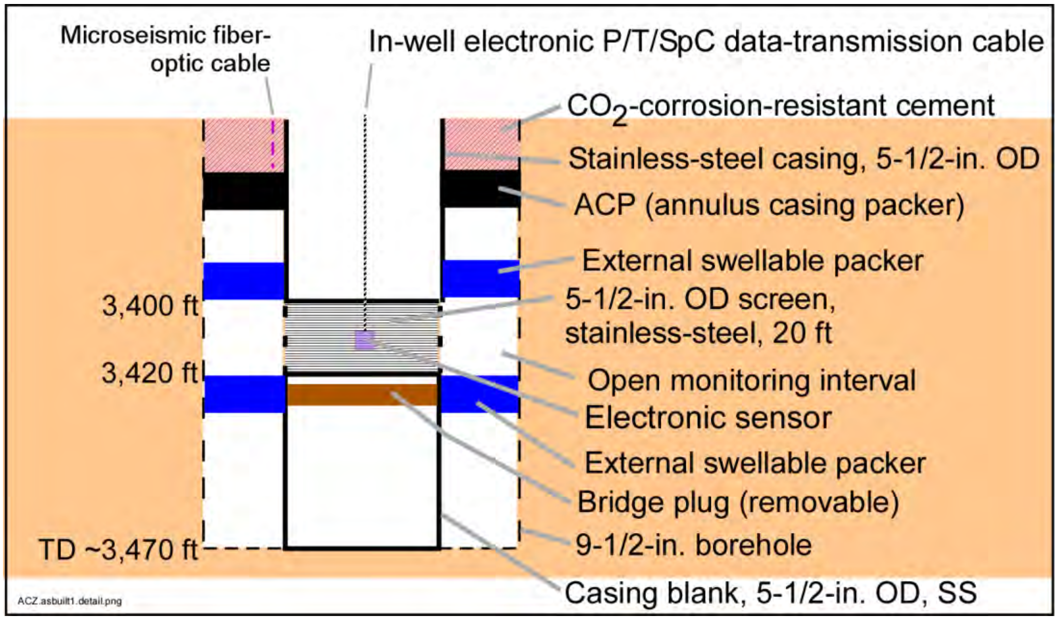


Figure B-2. Construction Detail for ACZ Monitoring Wells.

USDW Well Construction and Drilling Information

A single monitoring well (USDW1) will be installed in the Ordovician St. Peter Sandstone, the lowermost underground sources of drinking water (USDW) above the FutureGen injection reservoir. The St. Peter Sandstone is considered the lowermost USDW, because the measured total dissolved solids (TDS) content from this unit at the FutureGen stratigraphic well was 3,700 mg/L, which is below the regulatory limit of 10,000 mg/L for designation as a potential USDW. A single regulatory compliance well will be installed within this lowermost USDW aquifer, on the same drill pad with the ACZ1 early-detection monitoring well, which is within the region of highest pressure buildup.

The USDW1 well will be a 5-1/2-in.-OD well with a 20-ft-long, stainless-steel screen section placed across the monitoring interval (estimated at 1,930 to 1,950 ft). An evaluation of monitoring requirements for this well indicates that a 5-1/2-in.-OD casing string will be sufficient to meet project objectives (i.e., allow access for fluid sampling and installation of downhole P/T/SpC probes. The current plan calls for free hanging the P/T/SpC probes by wireline within the 5-1/2-in. casing; however, the design may be revised to include tubing and packer to secure the probe. A well schematic is shown in Figure B-3.

To begin, a 20-in. borehole will be drilled and 16-in. conductor casing will be installed to near the contact with Pennsylvanian bedrock (Figure B-3). Next, the boring will step down to a 14-3/4-in. borehole and 10-3/4-in. casing to approximately 600 ft. After cementing the 10-3/4-in. casing in place, a 9-1/2-in. borehole will be drilled to a short distance below the base of the USDW (St. Peter Sandstone) (to ~2,000-ft depth) to positively identify the St. Peter Sandstone/Shakopee Dolomite contact. After the 9-1/2-in. borehole has been drilled to total depth, the borehole will be developed to remove mud cake, cuttings, and drill fluids via circulation. Development will continue until all drilling mud has been effectively removed from the borehole wall. After the borehole has been circulated clean, a final casing string will be installed. The final casing string will be 5-1/2-in. OD and will include a ~20-ft-long stainless-steel well screen near the bottom (see screened interval construction detail for USDW1 in Figure B-4).

Stainless-steel casing (e.g., 13Cr), 5-1/2-in. OD, will be used in the lower 300 ft of the well including the entire St. Peter Sandstone. Standard carbon-steel casing will be used above depths of ~1,700 ft. A 20-ft-long, 5-1/2-in.-OD stainless-steel well screen will be incorporated into the final casing string and positioned to span the desired monitoring interval. Approximately 50 ft of blank casing will extend from immediately below the screen to the bottom of the well (Figure B-3). External swellable packers may be placed above and below the screened interval to help ensure zonal isolation (see Figure B-4). A removable bridge plug may be installed just below the screen to isolate it from the rat hole below. Standard well cement will be used to cement all casing strings.

A summary of the borehole and casing program for the USDW1 well is provided in Table B-2.

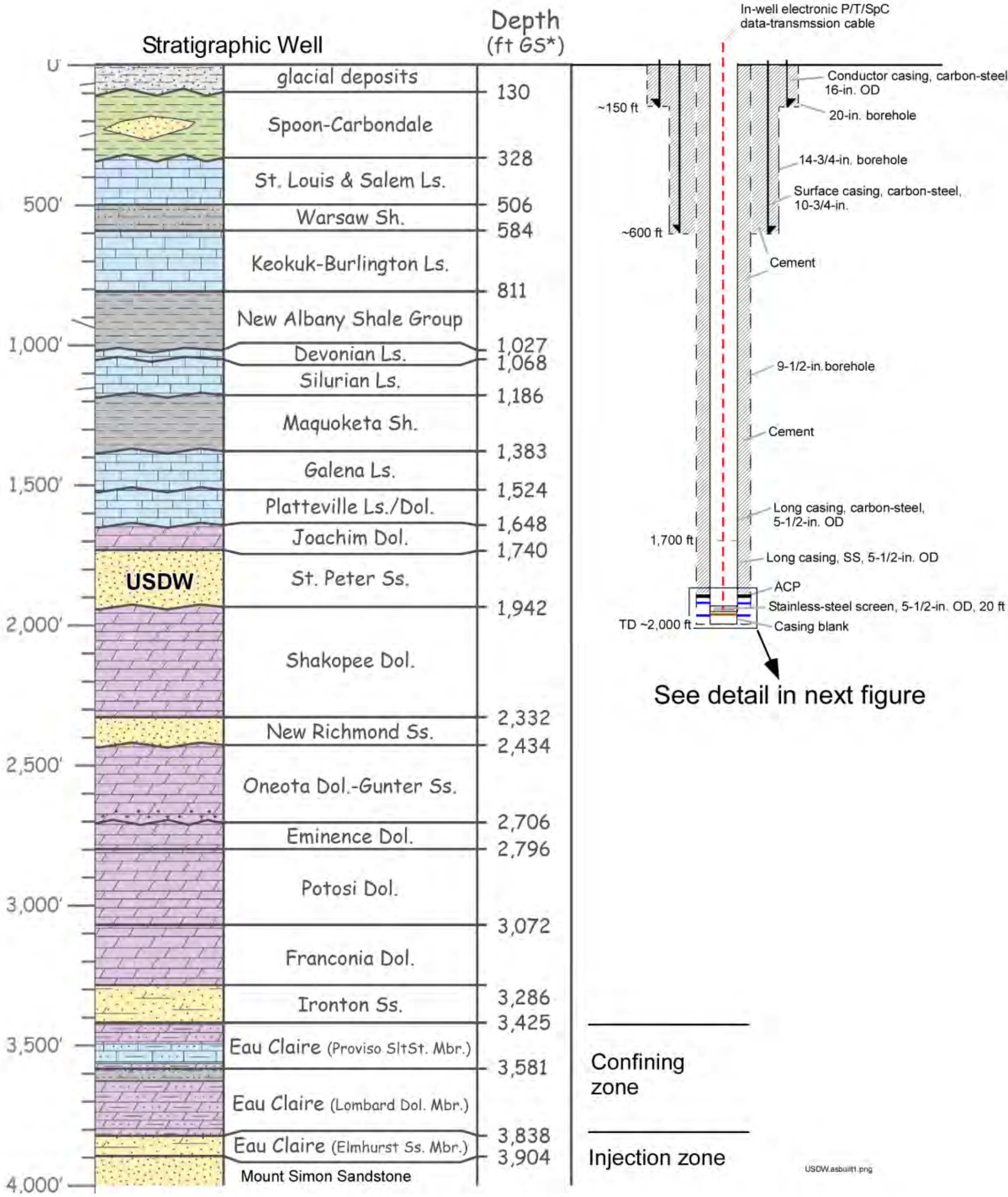


Figure B-3. Well Construction Diagram for the USDW1 Monitoring Well.

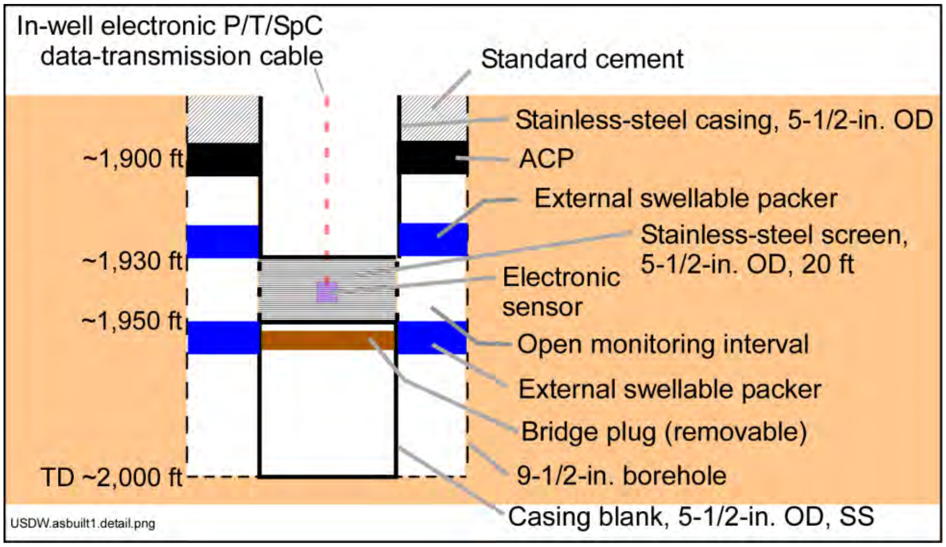


Figure B-4. Construction Detail for USDW1.

Table B-2. Casing and Borehole Program for the USDW Monitoring Well.

Section	Borehole Depth (ft)	Borehole Diam. (in.)	Casing OD (in.)	Casing Grade	Casing weight (lb/ft)	Casing Connection
Conductor Casing	150	20	16	B	55	PEB
Surface Casing	600	14-3/4	10-3/4	J-55	40.5	BTC
Intermediate Casing	NA	NA	NA	NA	NA	NA
Long Casing (with 20-ft-long screened section)	2,000	9-1/2	5-1/2	J-55 (0-1,700 ft); S13Cr110 (1,700−2,000 ft)	17	LTC (J-55); Vam Top or similar (S13Cr110)

Grade B is equivalent to line pipe; BTC = buttress thread connection; Cr = chromium; LTC = long thread connection; PEB = plain end beveled.
Notes:
Actual casing grades and weights may differ based on material available at the time of construction.
All depths are approximate and may be adjusted based on information obtained when the well is drilled.

As discussed above, the well will be developed by air lift prior to installing the downhole P/T/SpC probe. If necessary, further development via air lift or pumping may be conducted after the well has been completed. During development activities, groundwater samples will be collected and tested for turbidity and other field parameters to ensure adequate development.

SLR1 Well Construction and Drilling Information

As illustrated in Figure B-5, a 20-in.-diameter conductor casing within a 26- to 30-in. hole will be installed into the Pennsylvanian bedrock to 150 ft bgs. This will be followed by a 17-1/2-in. hole lined with 13-3/8-in. casing to ~600 ft before drilling a 12-1/4-in. hole lined with 9-5/8-in. intermediate casing into the top of the confining zone (Proviso member) to a depth of approximately 3,450 ft bgs. Next, cement grout will be emplaced, under pressure, in the annular space behind the 9-5/8-in. casing and around the casing shoe until it rises to the surface. This will be followed by a downhole cement bond log and pressure testing to ensure there are no leakage pathways behind the 9-5/8-in. casing or shoe. After testing the seal integrity of the 9-5/8-in. casing, an uncased 7-7/8-in. to 8-1/2-in. open borehole will be drilled to ~4,150 ft bgs. Once at total depth, the open portion of the borehole will be developed to remove all cuttings and drill fluids via circulation and pumping of formation water. Development will continue until all drilling mud has been effectively removed from the borehole wall and pumped water is clear of particulates. Following development, a final 5-1/2-in.-OD casing string will be installed and cemented in place. Once the casing installation is complete, the 5-1/2-in. casing and surrounding cement will be perforated over the interval between 4,000 and 4,100 ft bgs, creating a 100-ft monitoring interval within the injection zone.

The portion of the 5-1/2-in. casing that penetrates the reservoir and the Eau Claire caprock (from total depth to ~3,450 ft bgs) will be composed of corrosion-resistant alloy material (e.g., S13Cr110) (Figure B-6). Corrosion-resistant cement will be used to cement the final casing string across this same interval. This specially formulated type of cement is more finely ground than regular cement and thus resists CO_2 infiltration into the more-reactive cement pores. Above the caprock and overlying the CO_2 reservoir, regular cement will be used to seal the remainder of the 5-1/2-in. casing (i.e., above 3,450 ft). All other casing strings will be cemented with standard well cement. A summary of the borehole and casing program for the SLR1 well is provided in Table B-3.

Table B-3. Casing and Borehole Program for the SLR1 Monitoring Well.

Section	Borehole Depth (ft)	Borehole Diam. (in.)	Casing OD (in.)	Casing Grade	Casing weight (lb/ft)	Casing Connection
Conductor casing	150	26 to 30	20	B	94	PEB
Surface casing	600	17-1/2	13-3/8	J-55	61	BTC
Intermediate casing	3,450	12-1/4	9-5/8	J-55	36	STC
Long casing (with 100-ft perforated section)	4,150	7-7/8 or 8-1/2	5 -1/2	J-55 (0-3,450 ft); S13Cr110 (3,450-4,150 ft)	17	LTC (J-55); Vam Top or similar (S13Cr110)
Tubing	4,100	NA	2-7/8	13Cr80	6.5	EUE

Grade B is equivalent to line pipe; BTC = buttress thread connection; Cr = chromium; EUE = externally upset end; LTC = long thread connection; PEB = plain end beveled; STC = short thread connection.
Notes:
Actual casing grades and weights may differ based on material available at the time of construction.
All depths are approximate and may be adjusted based on information obtained when the well is drilled.

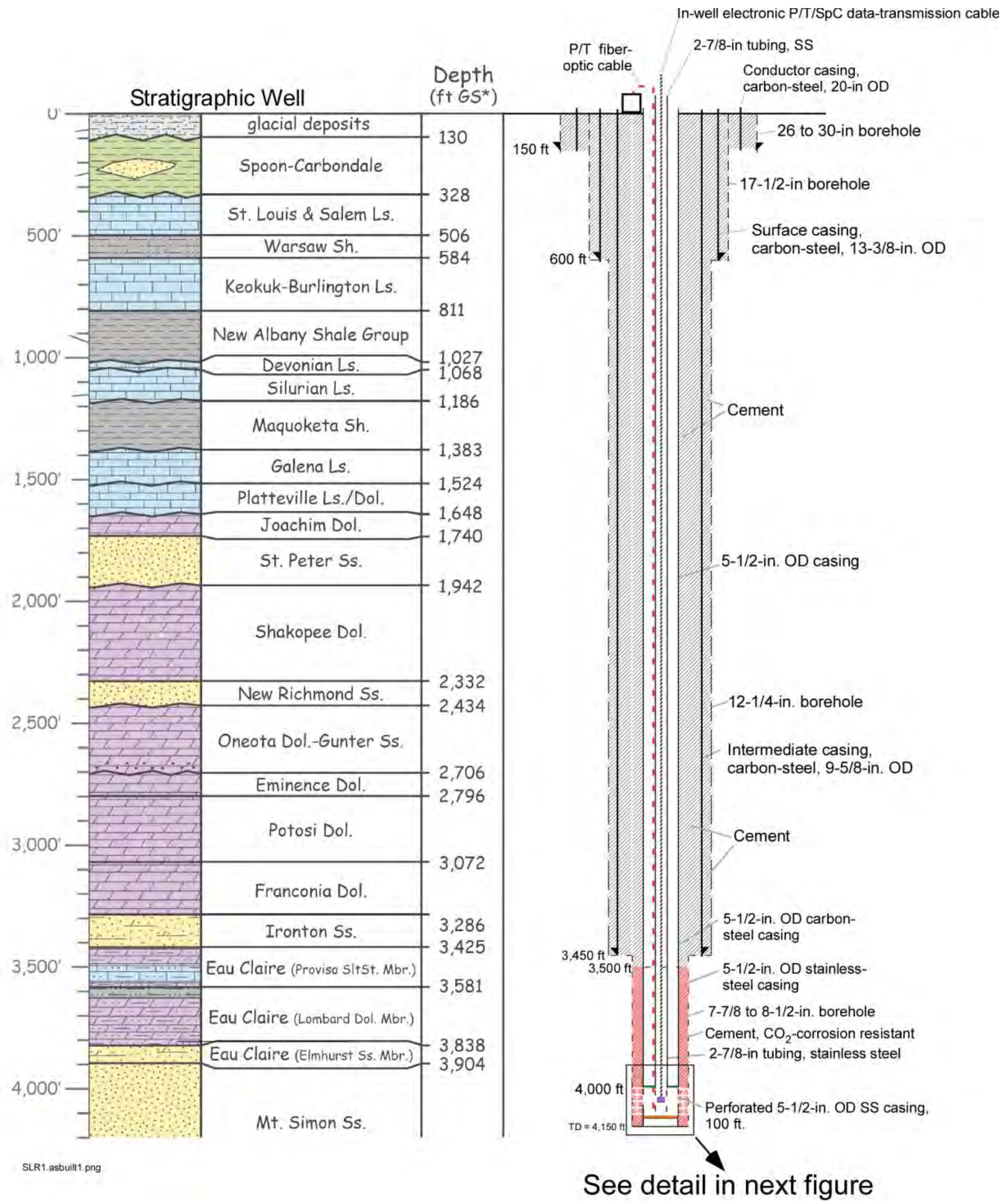


Figure B-5 Construction Diagram for the New Single-Level in-Reservoir Monitoring Well (SLR1).

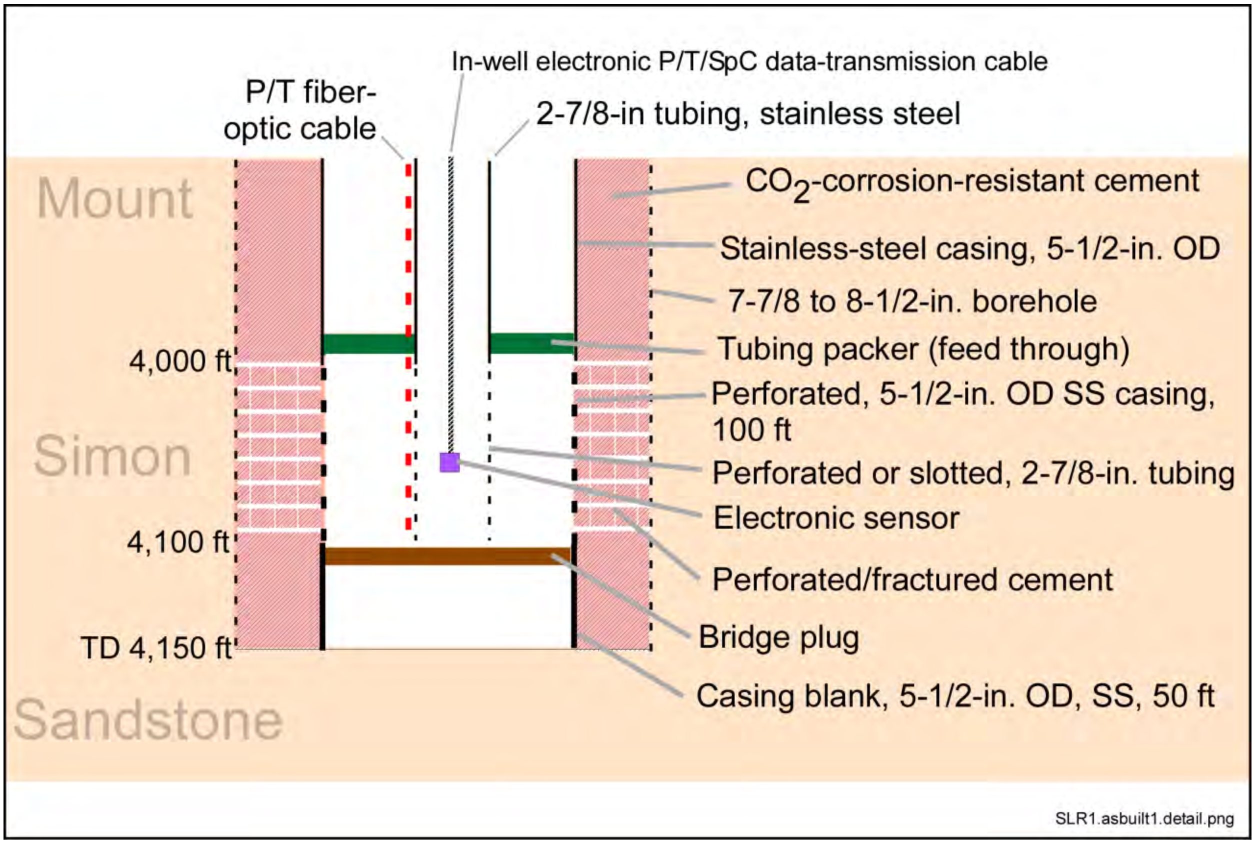


Figure B-6. Construction Detail for SLR1

SLR2 Well Construction and Drilling Information

Currently, the stratigraphic well is cased to 3,948 ft with 10-3/4-in. casing to below the top of the Mount Simon Sandstone (Figure). Below this is a 14-3/4-in. open borehole to a depth of 4,018 ft, then a 9-1/2-in. borehole to a total depth of 4,812 ft, which extends approximately 400 ft into Precambrian basement rock. The borehole below the intermediate casing is currently uncased. The planned design for the reconfigured stratigraphic well (SLR2) includes backfilling the bottom 660 ft of the borehole with CO_2-resistant cement to ~4,150 ft (Figure B-8) before installing a 7-in.-OD casing string to 4,150 ft bgs. The 7-in casing will then be cemented in place using CO_2-resistant cement to near the top of the caprock (3,450 ft) followed by regular cement to the surface. The 7-in. well will be constructed using 7-in stainless steel (S13Cr110) casing to a depth of approximately 4,000 ft. Above this depth, carbon-steel casing will be used. After the cement job has been completed, the 7-in. casing and cement will be perforated to construct a 100-ft-long Mount Simon Sandstone monitoring interval between the depths of 4,000 and 4,100 ft. Following perforation and well development activities, a removable bridge plug may be installed just below the perforated interval to isolate it from the rathole below. A 2-7/8-in.-OD tubing string will then be run inside the 7-in. casing to near the bottom of the perforated interval. The installed tubing will be perforated (slotted) across the 4,000- to 4,100-ft-depth interval and isolated to this zone via a tubing packer above (Figure B-8). A summary of the borehole and casing program for the SLR2 well is provided in Table B-4.

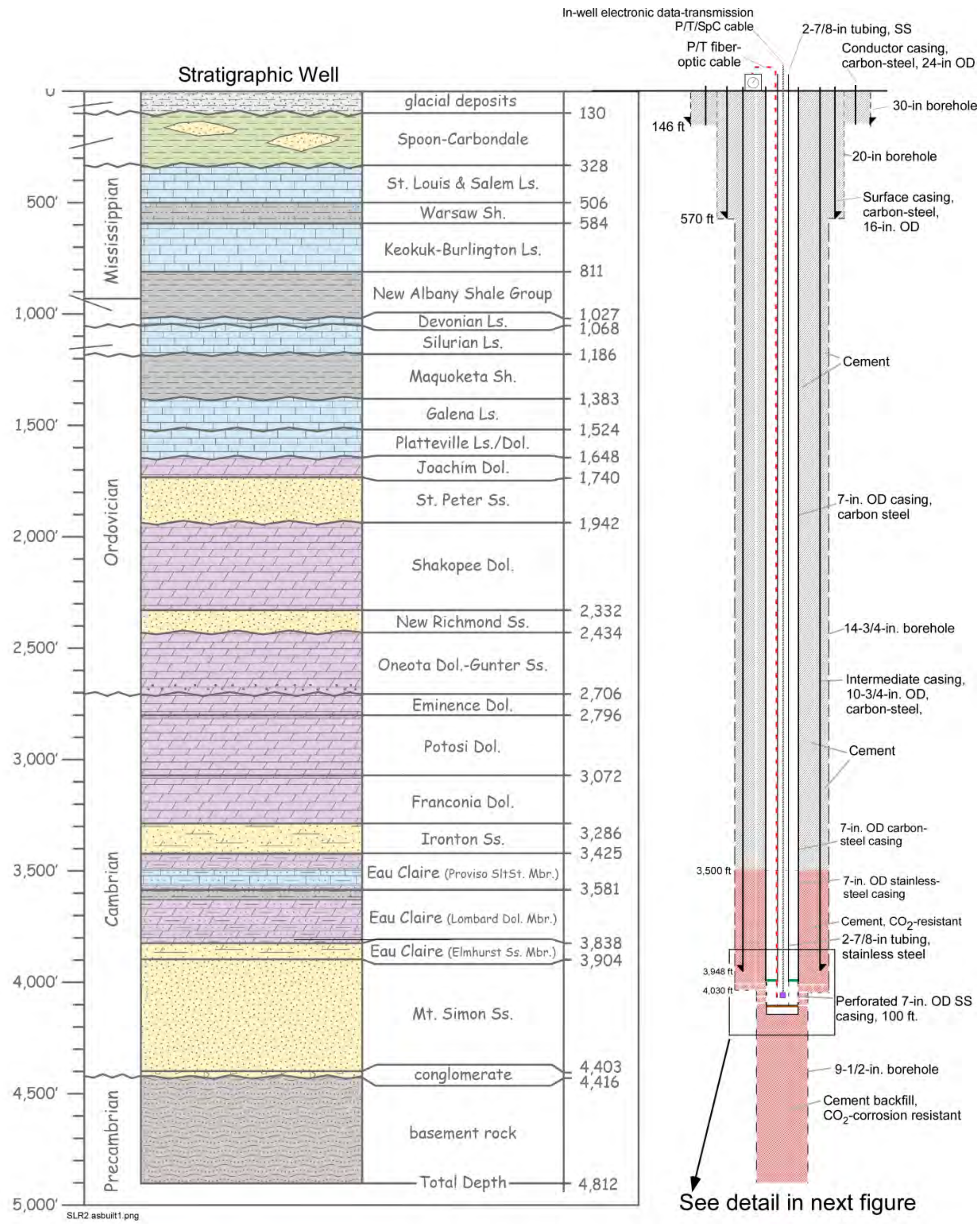


Figure B-7. Construction Diagram for the Stratigraphic Well Reconfigured as a Single-Level in-Reservoir Monitoring Well (SLR2).

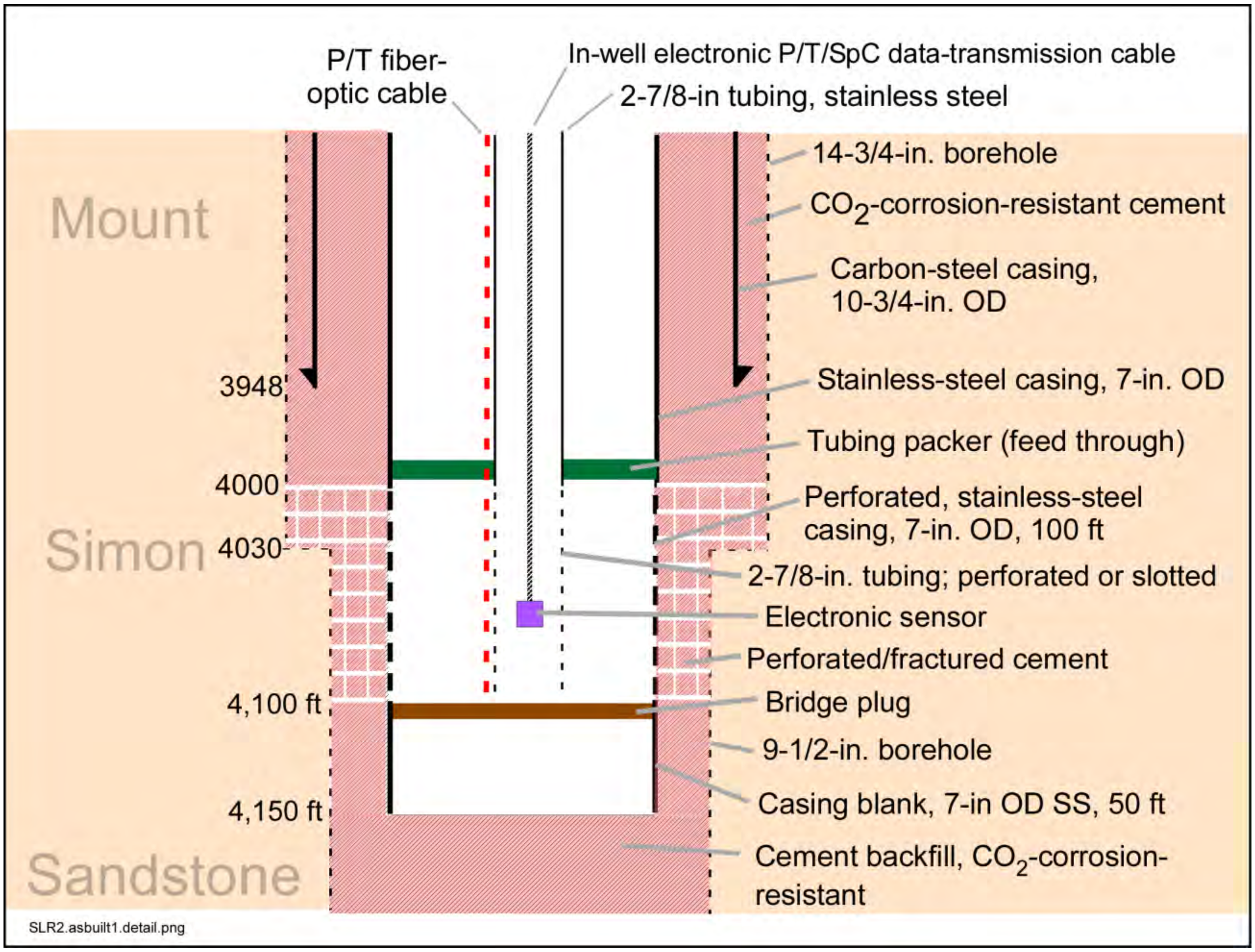


Figure B-8. Construction Detail for SLR2

Table B-4. Casing and Borehole Program for the SLR2 Monitoring Well

Section	Borehole Depth (ft)	Borehole Diam (in.)	Casing OD (in.)	Casing Grade	Casing weight (lb/ft)	Casing Connection
Conductor casing	132	30	24	PEB	140	Welded
Surface casing	556	20	16	J-55	84	BTC
Intermediate casing	3,948	14-3/4	10-3/4	N-80	51	BTC
Long casing (with 100-ft perforated section)	4,150	9-1/2 to 14-3/4	7	N-80 (0-3,500): S13Cr110 (3,500-TD)	29	LTC (N-80); VAM TOP (S13Cr110)
Tubing	4,100	NA	2-7/8	13Cr80	6.5	EUE

BTC = buttress thread connection; Cr = chromium; EUE = externally upset end; LTC = long thread connection; PEB = plain end beveled.
Note: Actual casing grades and weights may differ based on material available at the time of construction.

RAT Well Construction and Drilling Information

The monitoring network will also include three RAT installations (Figure B-9). These monitoring points will be located within the predicted lateral extent of the 1- to 3-year CO_2 plume based on numerical simulations of injected CO_2 movement. The RAT locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume. The RAT installations are planned for the collection of pulsed-neutron capture logs of the FutureGen CO_2 reservoir—the Mount Simon and Eau Claire formations. Design and construction requirements for the RAT installations are discussed in the following paragraphs.

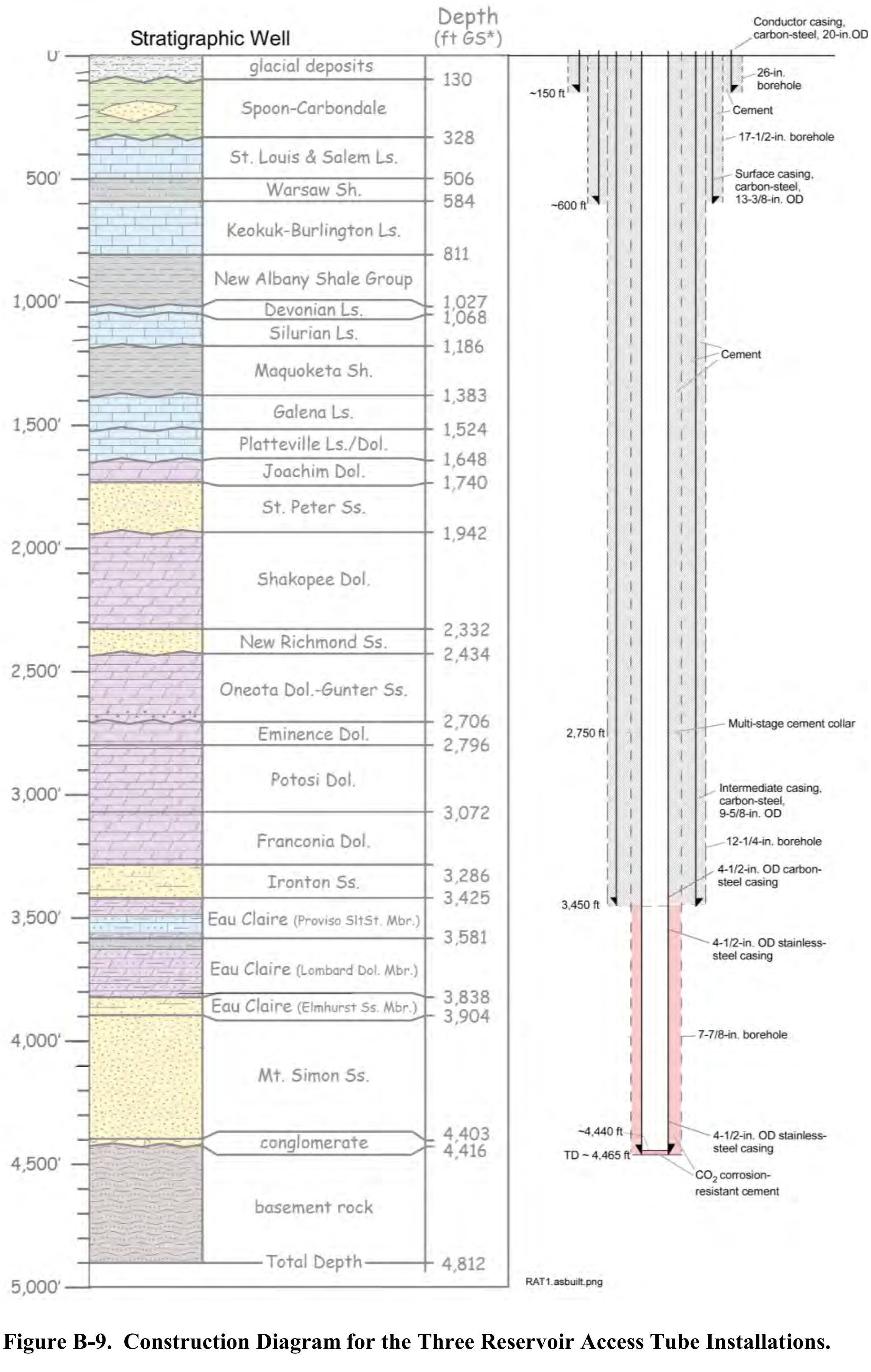


Figure B-9. Construction Diagram for the Three Reservoir Access Tube Installations.

To begin, a 26-in. borehole will be drilled and 20-in.-OD conductor casing will be installed to near the contact with Pennsylvanian bedrock (150 ft) (Figure B-9). Next, the boring will step down to a 17-1/2-in. borehole and 13-3/8-in. casing to approximately 600 ft. Below 600 ft, the hole will step down to a 12-1/4-in. hole lined with 9-5/8-in. casing down to the top of the confining unit (~3,450 ft) into the Proviso member. After cementing the 9-5/8-in. casing in place a 7-7/8-in. borehole will be drilled into the Precambrian basement rock (~4,465 ft). Next, a 4-1/2-in. stainless-steel casing will be lowered to the bottom of the hole and surrounded by CO_2-resistant cement, which will be allowed to rise 25 ft up inside the bottom of the 4-1/2-in. casing. Because these access tubes are designed for geophysical monitoring, no open interval will exist for direct measurement or collection of water samples or parameters. See Table B-5 for the RAT casing and borehole program details.

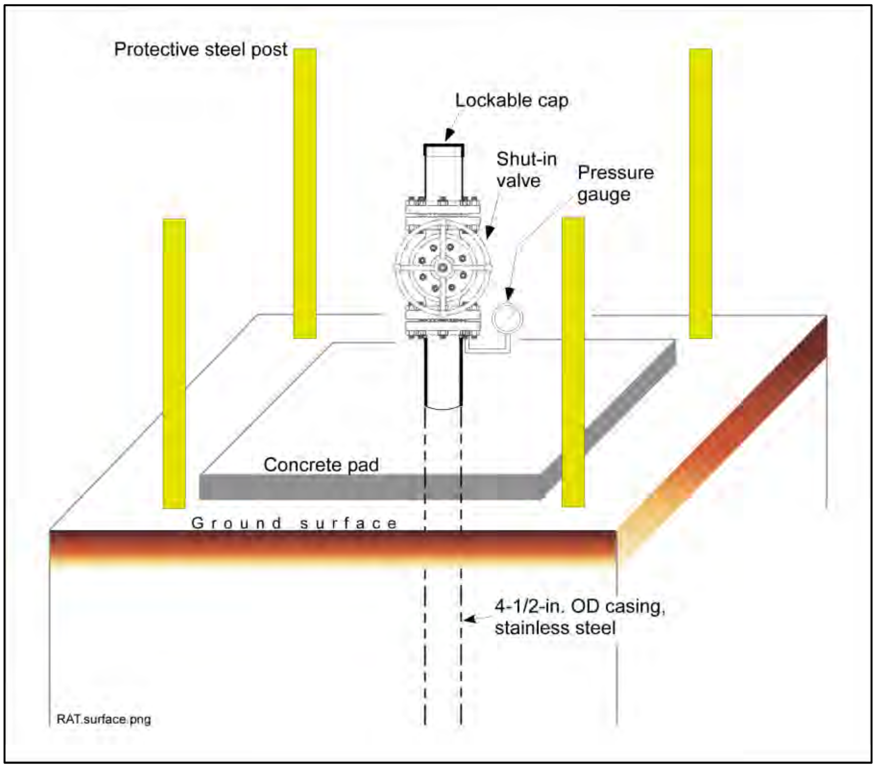


Figure B-10. Surface Completion Diagram for Reservoir Access Tube Installations.

The surface completion for the RAT installations will consist of a wellhead centered over a concrete pad. The wellhead will include a main shut-in valve and pressure gauge. The top of the access tube will be secured with a lockable cap along with four removeable steel protective posts outside each corner of the concrete pad (Figure B-10).

Table B-5. Casing and Borehole Program for the Reservoir Access Tubes.

Section	Borehole Depth (ft)	Borehole Diameter (in.)	Casing OD (in.)	Casing Grade	Casing weight (lb/ft)	Casing Connection
Conductor Casing	150	26 to 30	20	B	94	PEB
Surface Casing	600	17 1/2	13 3/8	J-55	61	BTC
Intermediate Casing	~3,450	12 1/4	9 5/8	J-55	36	STC
Long Casing	~4,465	7 7/88 to 8 1/2	4 1/2	J-55 (0-3,500 ft); S13Cr110 (3,500-4,465 ft.)	10.5	STC

Grade B is equivalent to line pipe; BTC = buttress thread connection; Cr = chromium; LTC = long thread connection; PEB = plain end beveled.
Notes:
Actual casing grades and weights may differ based on material available at the time of construction.
All depths are approximate and may be adjusted based on information obtained when the well is drilled.

APPENDIX C: Surficial Aquifer Monitoring Well Locations

Well ID	Well Type	Latitude	Longitude
FG-1	FutureGen Shallow Monitoring Well	39.80675	-90.05283
FGP-1	Private Well	39.79888	-90.0736
FGP-2	Private Well	39.78554	-90.0639
FGP-3	Private Well	39.79497	-90.0746
FGP-4	Private Well	39.79579	-90.0747
FGP-5	Private Well	39.81655	-90.0622
FGP-6	Private Well	39.81086	-90.057560
FGP-7	Private Well	39.81444	-90.065241
FGP-9	Private Well	39.80829	-90.0377
FGP-10	Private Well	39.81398	-90.0427

APPENDIX D: Permanent Gravity Station Locations

Station#	Latitude	Longitude	
0	39.73424	-90.22926	= NGS PID#KC0540, monument at Central Plaza Park, Jacksonville - point tied to 137 on 11/10/11 - this will be the reference used in future surveys.
5	39.79266	-90.07426	Nailed Permanent Stations
21	39.79449	-90.07424	
37	39.79617	-90.07425	
53	39.79814	-90.07427	
65	39.79991	-90.08316	
66	39.79990	-90.08090	
67	39.79989	-90.07886	
68	39.79988	-90.07616	
69	39.79989	-90.07384	
83	39.80164	-90.07889	
86	39.80176	-90.07240	
99	39.80349	-90.07888	
102	39.80352	-90.07239	
107	39.80348	-90.05998	
108	39.80295	-90.05766	
109	39.80332	-90.05519	
110	39.80339	-90.05277	
115	39.80526	-90.07887	
118	39.80529	-90.07237	
126	39.80544	-90.05216	
131	39.80710	-90.07886	
134	39.80721	-90.07154	
135	39.80720	-90.06922	
136	39.80720	-90.06687	
137	39.80727	-90.06485	
147	39.80888	-90.07885	
153	39.80842	-90.06413	
154	39.80894	-90.06224	
163	39.81078	-90.07885	
171	39.81077	-90.06002	
179	39.81248	-90.07884	
187	39.81265	-90.05999	
188	39.81283	-90.05770	
189	39.81286	-90.05538	
193	39.81447	-90.08326	
194	39.81447	-90.08103	
195	39.81451	-90.07870	
196	39.81449	-90.07629	
197	39.81457	-90.07419	
205	39.81443	-90.05513	
206	39.81436	-90.05287	
207	39.81435	-90.05064	
208	39.81437	-90.04825	
213	39.81609	-90.07408	
229	39.81790	-90.07408	

Station#	Latitude	Longitude	
245	39.81971	-90.07407	
246	39.79996722210	-90.08494295	Permanent Stations to be added prior to commencing injection.
247	39.79997642140	-90.08680687	
248	39.79998533330	-90.08861842	
249	39.79999393550	-90.09043265	
250	39.80000198450	-90.09213566	
251	39.80001079270	-90.09400542	
252	39.80001951540	-90.09586339	
253	39.80003000000	-90.09810508	
254	39.81088084490	-90.09544073	
255	39.81088937800	-90.09358759	
256	39.81211009600	-90.0932439	
257	39.81361707930	-90.0931657	
258	39.81450582940	-90.09142522	
259	39.81450590850	-90.08939647	
260	39.81450595100	-90.08745444	
261	39.81450596010	-90.0853458	
262	39.79094794920	-90.07434558	
263	39.78955807990	-90.07434813	
264	39.78808280800	-90.07435083	
265	39.78655838880	-90.07435362	
266	39.78543344990	-90.08777897	
267	39.78542392910	-90.08587085	
268	39.78541218410	-90.0835256	
269	39.78540044900	-90.08119175	
270	39.78540873070	-90.07875712	
271	39.78542609070	-90.07656216	
272	39.78533023230	-90.07434254	
273	39.78541496330	-90.07234073	
274	39.78538771320	-90.07041894	
275	39.78537326690	-90.06835921	
276	39.78537180190	-90.06658679	
277	39.78537006050	-90.06452139	
278	39.78536811720	-90.06226638	
279	39.78533703980	-90.06040206	
280	39.78532614220	-90.05850696	

APPENDIX E: Microseismic Monitoring and Integrated Deformation Station Locations

Well ID/Station ID	Well / Station Type	Latitude (WGS84)	Longitude (WGS84)
MS1	· Microseismic monitoring Station 1(shallow borehole) · Integrated deformation monitoring station	39.8110768	-90.09797015
MS2	· Microseismic monitoring Station 2 (shallow borehole) · Integrated deformation monitoring station	39.78547402	-90.05028403
MS3	· Microseismic monitoring Station 3 (shallow borehole) · Integrated deformation monitoring station	39.81193502	-90.06016279
MS4	· Microseismic monitoring Station 4 (shallow borehole) · Integrated deformation monitoring station	39.78558513	-90.09557015
MS5	· Microseismic monitoring Station 5 (shallow borehole) · Integrated deformation monitoring station	39.80000524	-90.07830287
ACZ1	· Deep microseismic station (deep borehole)	39.80034315	-90.07829648
ACZ2	· Deep microseismic station (deep borehole)	39.80029543	-90.08801028

APPENDIX F: Injection Well Continuous Monitoring Device Locations

Sampling Locations for Continuous Monitoring	
Test Description	**Location**
Annular Pressure Monitoring	Surface
Injection Pressure Monitoring	Surface
Injection Pressure Monitoring - primary	Reservoir - 3,850 feet below ground surface
Injection Rate Monitoring	Surface
Injection Volume Monitoring	Surface
Temperature Monitoring - primary	Surface
Temperature Monitoring	Reservoir - 3,850 feet below ground surface

APPENDIX G: Quality Assurance and Surveillance Plan

FutureGen 2.0 –
CO_2 Pipeline and Storage Project

Quality Assurance and Surveillance Plan

Revision 1

FutureGen Industrial Alliance, Inc.
1101 Pennsylvania Ave., Sixth Floor
Washington, DC 20004

August 2014

A. Project Management

A.1 Title and Approval Sheet

FutureGen 2.0 –
CO_2 Pipeline and Storage Project

Quality Assurance and Surveillance Plan

Revision 1

FutureGen Industrial Alliance, Inc.
1101 Pennsylvania Ave., Sixth Floor
Washington, DC 20004

Approvals:

Project Manager Battelle	______________________ Tyler J Gilmore	__________ Date
Monitoring, Verification, and Accounting Task Lead Battelle	______________________ Vince R. Vermeul	__________ Date
Project Quality Engineer Battelle	______________________ William C. Dey	__________ Date

A.2 Table of Contents

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Acronyms and Abbreviations

3D	three-dimensional
4D	four-dimensional
ACP	annulus casing packer
ACZ	above confining zone
AMS	accelerator mass spectrometry
AoR	Area of Review
API	American Petroleum Institute
APS	Annulus Pressurization System
ASTM	ASTM International (formerly the American Society for Testing and Materials)
bgs	below ground surface
CCS	carbon capture and storage
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CMP	Configuration Management Plan
CO_2	carbon dioxide
CVAA	cold vapor atomic absorption
DGPS	Differential Global Positioning System
DIC	dissolved inorganic carbon
DInSAR	Differential Interferometric Synthetic Aperture Radar
DOC	dissolved organic carbon
ECD	electron capture detector
EPA	U.S. Environmental Protection Agency
GC	gas chromatography
GC/FID	gas chromatography with flame ionization detector
GC/HID	gas chromatography with helium ionization detector
GC/MS	gas chromatography-mass spectrometry
GC/SCD	gas chromatograph with sulfur chemiluminescence detector
GPS	Global Positioning System
GS	Geologic Sequestration
HDI	How Do I…? (Pacific Northwest National Laboratory's web-based system for deploying requirements and procedures to staff)
IARF	infinite-acting radial flow
ICP	inductively coupled plasma
ICP-AES	inductively coupled plasma atomic emission mass spectrometry
ICP-MS	inductively coupled plasma mass spectrometry
IRMS	isotope ratio mass spectrometry
ISBT	International Society of Beverage Technologists
LC-MS	liquid chromatography-mass spectrometry
LCS	laboratory control sample

MIT	mechanical integrity testing
MMT	million metric tons
MS	mass spectrometry
MVA	Monitoring, Verification, and Accounting
NA	not applicable
OD	outside diameter
OES	optical emission spectrometry
P	pressure
P/T	pressure-and-temperature
P/T/SpC	pressure, temperature, and specific conductance
PDMP	Project Data Management Plan
PFT	perfluorocarbon tracer
PLC	programmable logic controller
PM	Project Manager
PNC	pulsed-neutron capture
PNWD	Battelle Pacific Northwest Division
QA	quality assurance
QASP	Quality Assurance and Surveillance Plan
QC	quality control
QE	Quality Engineer
RAT	reservoir access tube
RTD	resistance temperature detector
RTK	Real-Time Kinematic
RTU	remote terminal unit
SAR	Synthetic Aperture Radar
SCADA	Supervisory Control and Data Acquisition
$scCO_2$	supercritical carbon dioxide
SLR	single-level in-reservoir
SME	subject matter expert
SNR	signal-to-noise ratio
SpC	specific conductance
T	temperature
TC	thermocouple
TCD	thermal conductivity detector
TDMP	Technical Data Management Plan
TIC	total inorganic carbon
TOC	total organic carbon
UIC	Underground Injection Control
USDW	underground source of drinking water
VOA	Volatile Organic Analysis
WS-CRDS	wavelength scanned cavity ring-down spectroscopy

Definitions

Injection interval: The open (e.g., perforated) section of the injection well, through which the carbon dioxide (CO_2) is injected.

Injection zone: A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project.

Prover: A device that verifies the accuracy of a gas meter.

Reservoir: A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids (Schlumberger Oilfield Glossary). Used interchangeably with injection zone.

Sigma: A measure of the decay rate of thermal neutrons as they are captured.

A.3 Distribution List

Table A.1 lists the individuals that should receive a copy of the approved Quality Assurance and Surveillance Plan (QASP) and any subsequent revisions.

Table A.1. Distribution List

Name	Organization	Project Role(s)	Contact Information (telephone / email)
K. Humphreys	FutureGen Industrial Alliance, Inc.	Chief Executive Officer	202-756-2492 Khumphreys@futgen.org
T. J. Gilmore	Battelle PNWD	Project Manager	509-371-7171 Tyler.Gilmore@pnnl.gov
W. C. Dey	Battelle PNWD	Quality Engineer	509-371-7515 William.Dey@pnnl.gov
V. R. Vermeul	Battelle PNWD	Task Lead – Monitoring, Verification, and Accounting; Groundwater Quality Monitoring; CO_2 Plume and Pressure-Front Tracking	509-371-7170 Vince.Vermeul@pnnl.gov
M. E. Kelley	Battelle Columbus	Task Lead – CO_2 Injection Stream Monitoring; Corrosion Monitoring; External Well Integrity Testing	614-424-3704 kelleym@battelle.org
A. Bonneville	Battelle PNWD	Task Lead – Indirect Geophysical Monitoring	509-371-7263 Alain.Bonneville@pnnl.gov
R. D. Mackley	Battelle PNWD	Task Lead – USDW Groundwater Geochemical Monitoring, and Indicator Parameter Monitoring	509-371-7178 rdm@pnnl.gov
F. A. Spane	Battelle PNWD	Task Lead – Hydrologic Testing; Pressure Fall-Off Testing	509-371-7087 Frank.Spane@pnnl.gov

A.4 Project/Task Organization

The high-level project organizational structure for the FutureGen 2.0 CO_2 Pipeline and Storage Project is shown in Figure A.1 (Alliance 2013a).

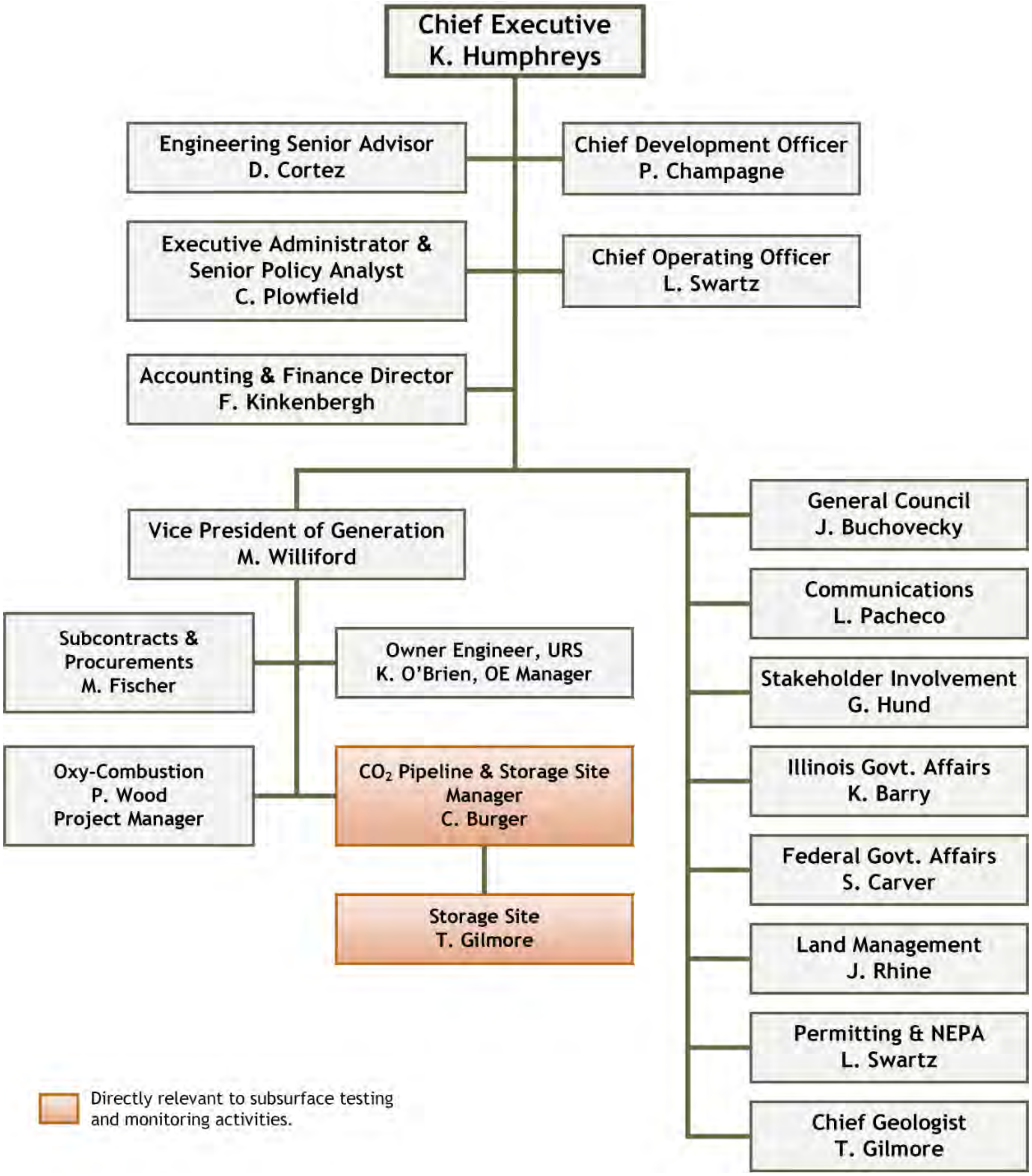

Figure A.1. CO_2 Pipeline and Storage Project Structure (after Alliance 2013a)

The organizational structure specific to well testing and monitoring is shown in Figure A.2.

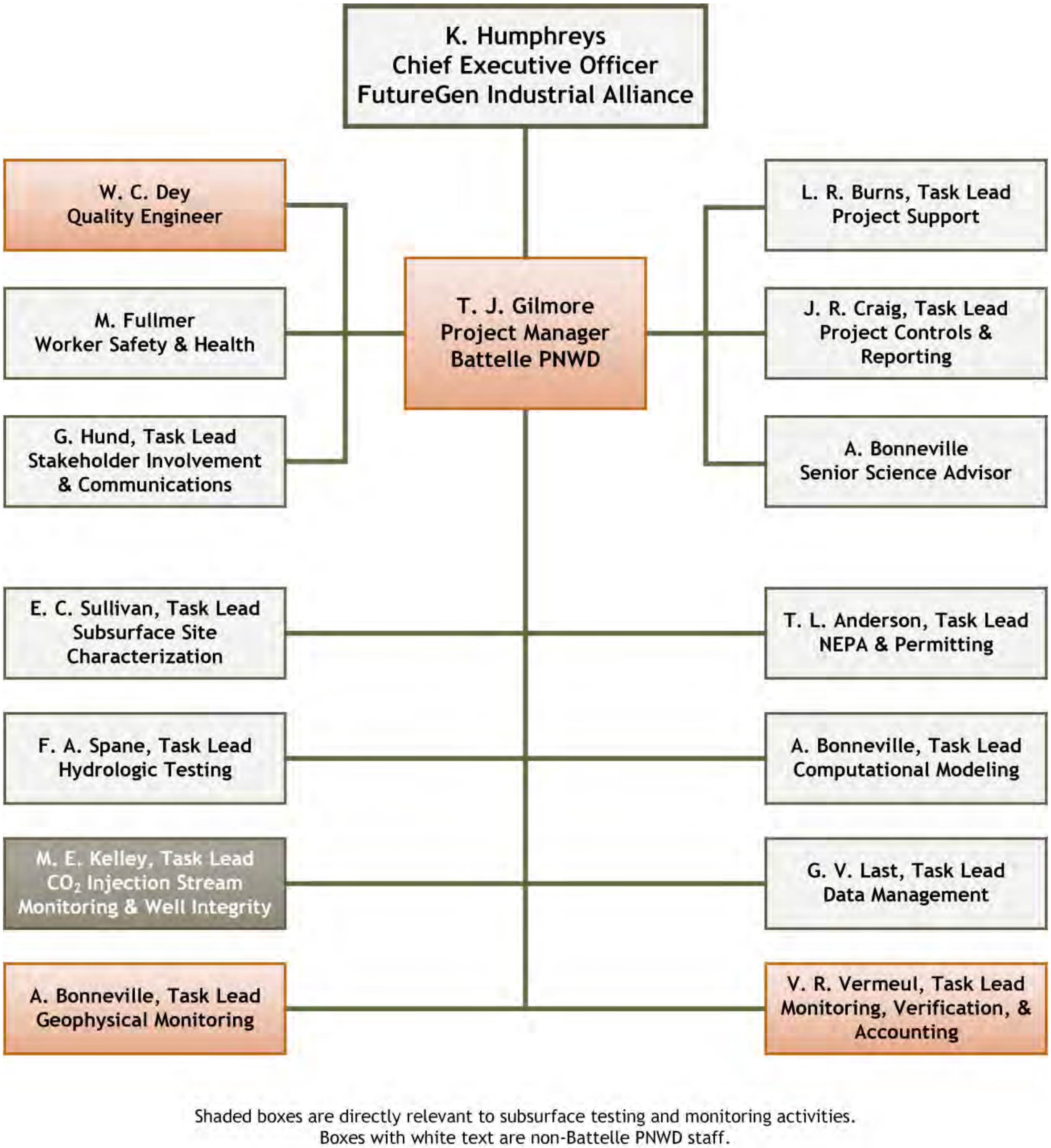

Figure A.2. Task Level Project Organization Relevant to Well Testing and Monitoring

A.4.1 Alliance Chief Executive Officer

The FutureGen 2.0 CO_2 Pipeline and Storage Project is led by the Chief Executive Officer (CEO) of the FutureGen Industrial Alliance, Inc. (Alliance), who is responsible on a day-to-day basis for the project. The Alliance CEO reports to a board of directors composed of industry executives (one executive for each company contributing funds on an equal basis to the Alliance).

A.4.2 Project Manager

The Project Manager (PM) plays a central role in the implementation of all data gathering and analysis for the CO_2 Pipeline and Storage Project and provides overall coordination and responsibility for all organizational and administrative aspects. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans and ensure that project participants adhere to the plan.

A.4.3 Quality Engineer

The role of the Quality Engineer (QE) is to identify quality-affecting processes and to monitor compliance with project requirements. The QE is responsible for establishing and maintaining the project quality assurance plans and monitoring project staff compliance with them. The QE is responsible for ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements.

A.4.4 Monitoring, Verification, and Accounting Task Lead

Well testing and monitoring activities are the responsibility of the Monitoring, Verification, and Accounting (MVA) Task Lead. The MVA Task Lead is responsible for developing, maintaining, and updating all well testing and monitoring plans, including this QASP.

A.4.5 Subject Matter Experts/Subtask Task Leads

Well Testing and Monitoring Subject Matter Experts (SMEs) and Task Leads comprise both internal (Battelle Pacific Northwest Division [PNWD]) and external (Battelle Columbus and other subcontractors) geologists, hydrologists, chemists, atmospheric scientists, ecologists, etc. The role of these SMEs is to develop testing and monitoring plans, to collect environmental data specified in those plans using best practices, and to maintain and update those plans as needed.

The SMEs, assisted by the MVA Task Lead, are responsible for planning, collecting, and ensuring the quality of testing and monitoring data and managing all necessary metadata and provenance for these data. The SMEs are also often responsible for data analysis and data products (e.g., publications), and acquisition of independent data quality/peer reviews.

A.5 Problem Definition/Background

A.5.1 Purpose and Objectives

The FutureGen CO_2 Pipeline and Storage Project is part of the larger FutureGen 2.0 Project aimed at demonstrating the technical feasibility of oxy-combustion technology as an approach to implementing carbon capture and storage (CCS) from new and existing coal-fueled energy facilities. The advancement of CCS technology is critically important to addressing CO_2 emissions and global climate change concerns associated with coal-fueled energy. The objective of this project is to design, build, and operate a commercial-scale CCS system capable of capturing, treating, and storing the CO_2 off-gas from a oxy-combustion coal-fueled power plant located in Meredosia, Morgan County, Illinois. Using safe and proven pipeline technology, the CO_2 will be transported to a nearby storage site, located near Jacksonville, Illinois, where it will be injected into the Mount Simon and Eau Claire formations at a rate of 1.1 million metric tons (MMT) of CO_2 each year, for a planned duration of at least 20 years.

The objective of the CO_2 Pipeline and Storage project is to demonstrate utility-scale integration of transport and permanent storage of captured CO_2 in a deep geologic formation (a.k.a. geologic sequestration) and to demonstrate that this can be done safely and ensure that the injected CO_2 is retained within the intended storage reservoir.

A.5.2 Background

The U.S. Environmental Protection Agency (EPA) established requirements for CO_2 geologic sequestration under the Underground Injection Control (UIC) Program for Geologic Sequestration (GS) Class VI Wells. These federal requirements (codified in the U.S. Code of Federal Regulations [40 CFR 146.81 et seq.], known as the Class VI Rule) set minimum technical criteria for CO_2 injection wells for the purposes of protecting underground sources of drinking water (USDWs). Testing and Monitoring Requirements (40 CFR 146.90) under the Class VI Rule require owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan that includes injectate monitoring; corrosion monitoring of the well's tubular, mechanical, and cement components; pressure fall-off testing; groundwater quality monitoring; and CO_2 plume and pressure-front tracking. These requirements (40 CFR 146.90[k]) also require owners and operators to submit a QASP for all testing and monitoring requirements.

This QASP details all aspects of the testing and monitoring activities that will be conducted, and ensures that they are verifiable, including the technologies, methodologies, frequencies, and procedures involved. As the project evolves, this QASP will be updated in concert with the Testing and Monitoring Plan.

A.6 Project/Task Description

The FutureGen CO_2 Pipeline and Storage Project will undertake testing and monitoring as part of its MVA program to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The MVA program includes operational CO_2 injection stream monitoring, well corrosion and mechanical integrity testing, geochemical and indicator parameter monitoring of both the reservoir and shallow USDWs, and indirect geophysical monitoring, for characterizing the complex fate and transport processes associated with CO_2 injection. Table A.2 summarizes the general Testing and Monitoring tasks, methods, and frequencies.

Table A.2. Monitoring Tasks, Methods, and Frequencies by Project Phase

Monitoring Category	Monitoring Method	Baseline 3 yr	Injection (startup) ~3 yr	Injection ~2 yr	Injection ~15 yr	Post-Injection 50 yr
CO_2 Stream Analysis	Grab sampling and analysis	3 events, during commissioning	Quarterly	Quarterly	Quarterly	NA
Continuous Recording of Injection Pressure, Rate, and Annulus Pressure	Continuous monitoring of injection process (injection rate, pressure, and temperature; annulus pressure and volume)	NA	Continuous	Continuous	Continuous	NA
Corrosion Monitoring	Corrosion coupon monitoring of Injection Well Materials	NA	Quarterly	Quarterly	Quarterly	NA
Groundwater Quality Monitoring	Fluid sample collection and analysis in all ACZ and USDW monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	Electronic P/T/SpC probes installed in ACZ and USDW wells	1 yr min	Continuous	Continuous	Continuous	Continuous
External Well Mechanical Integrity Testing	PNC and Temperature logging	Once after well completion	Annual	Annual	Annual	Annual until wells plugged
	Cement-evaluation and casing inspection logging	Once after well completion	During well workovers	During well workovers	During well workovers	NA
Pressure Fall-Off Testing	Injection well pressure fall-off testing	NA	Every 5 yr	Every 5 yr	Every 5 yr	NA
Direct CO_2 Plume and Pressure-Front Monitoring	Fluid sample collection and analysis in SLR monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	Electronic P/T/SpC probes installed in SLR wells	1 yr min	Continuous	Continuous	Continuous	Continuous
Indirect CO_2 Plume and Pressure-Front Monitoring	Passive seismic monitoring (microseismicity)	1 yr min	Continuous	Continuous	Continuous	Continuous
	Integrated deformation monitoring	1 yr min	Continuous	Continuous	Continuous	Continuous
	Time-lapse gravity	3 events	Annual	Annual	Annual	NA
	PNC logging of RAT wells	3 events	Quarterly	Quarterly	Annual	Annual

ACZ = above confining zone; NA = not applicable; PNC = pulsed-neutron capture; P/T/SpC = pressure, temperature, and specific conductance; RAT = reservoir access tube; SLR = single-level in-reservoir; USDW = underground source of drinking water.

A.6.1 CO_2 Injection Stream and Corrosion/Well Integrity Monitoring

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow, as part of the instrumentation and control systems for the FutureGen 2.0 CO_2 Pipeline and Storage Project. Periodic grab samples will also be collected and analyzed to track CO_2 composition and purity.

The pressure and temperature will be monitoring within each injection well at a position located immediately above the injection zone at the end of the injection tubing. The downhole sensor will be the point of compliance for maintaining injection pressure below 90 percent of formation fracture pressure.

CO_2 Stream Analysis

The composition and purity of the CO_2 injection stream will be monitored through the periodic collection and analysis of grab samples.

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

Pressure monitoring of the CO_2 stream at elevated pressure will be done using local analog gauges, pressure transmitters, or pressure transmitters with local digital readouts. Flow monitoring will be conducted using Coriolis mass type meters. Normal temperature measurements will be made using thermocouples (TCs) or resistance temperature detectors (RTDs). A Supervisory Control and Data Acquisition (SCADA) system will be used to transmit operational power plant, pipeline, and injection well data long distances (~30 mi) for the pipeline and storage project.

Corrosion Monitoring

Samples of injection well materials (coupons) will be periodically monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs.

External Well Mechanical Integrity Testing

Wireline logging, including pulsed-neutron capture (PNC) logs (both in the gas-view and oxygen-activation modes) and temperature logs, and cement-evaluation and casing inspection logging, will be conducted to verify the absence of significant fluid movement through potential channels adjacent to the injection well bore and/or to determine the need for well repairs.

A.6.2 Storage Site Monitoring

The objective of the storage site monitoring program is to select and implement a suite of monitoring technologies that are both technically robust and cost-effective and provide an effective means of 1) evaluating CO_2 mass balance (i.e., verify that the site is operating as permitted) and 2) detecting any unforeseen containment loss (i.e., verify that the site is not endangering any USDWs). Both direct and indirect measurements will be used collaboratively with numerical models of the injection process to verify that the storage site is operating as predicted and that CO_2 is effectively sequestered within the targeted deep geologic formation and is fully accounted for. The approach is based in part on reservoir-monitoring wells, pressure fall-off testing, and indirect (e.g., geophysical) methods. Early-detection monitoring wells will target regions of increased leakage potential (e.g., proximal to wells that penetrate the caprock). During baseline monitoring, a comprehensive suite of geochemical and isotopic analyses will be performed on fluid samples collected from the reservoir and overlying monitoring intervals.

These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Selection of this initial analyte list was based on relevance for detecting the presence of fugitive brine and CO_2. The results for this comprehensive set of analytes will be evaluated and a determination made regarding which analytes to carry forward through the operational phases of the project. This selection process will consider the uniqueness and signature strength of each potential analyte and whether its characteristics provide for a high-value leak-detection capability. Indicator parameters will be used to inform the monitoring program. Once baseline conditions and early CO_2 arrival responses have been established, observed relationships between analytical measurements and indicator parameters will be used to guide less-frequent aqueous sample collection and reduced analytical parameters in later years.

Monitoring Well Network (Geochemical and Indicator Parameter Monitoring)

The monitoring well network will address transport uncertainties by using an "adaptive" or "observational" approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring results).

Two aquifers above the primary confining zone will be monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone. These include the aquifer immediately above the confining zone (Ironton Sandstone, monitored with above confining zone [ACZ] wells) and the St. Peter Sandstone, which is separated from the Ironton by several carbonate and sandstone formations and is considered to be the lowermost USDW. In addition to directly monitoring for CO_2, wells will initially be monitored for changes in geochemical and isotopic signatures that may provide indication of CO_2 leakage. Wells will also be instrumented to detect changes in the stress regime (via pressure in all wells and microseismicity in selected wells) to avoid over-pressurization within the injection or confining zones that could compromise sequestration performance (e.g., caprock fracturing). Table A.3 describes the planned monitoring well network for geochemical and indicator parameter monitoring. Figure A.3 illustrates the nominal monitoring well layout.

Table A.3. Planned Monitoring Wells in the Network

	Single-Level In-Reservoir (SLR)	Above Confining Zone (ACZ)	USDW
Number of Wells	2	2	1
Total Depth (ft)	4,150	3,470	2,000
Monitored Zone	Mount Simon SS	Ironton SS	St. Peter SS
Monitoring Instrumentation	P/T/SpC probe in monitored interval[a]	Fiber-optic (microseismic) cable cemented in annulus; P/T/SpC probe in monitored interval[a]	P/T/SpC probe in monitored interval[a]

(a) The P/T/SpC probe is an electronic downhole multi-parameter probe incorporating sensors for measuring fluid pressure (P), temperature (T), and specific conductance (SpC) within the monitored interval. The probe will be installed inside a tubing string, which is perforated (slotted) over the monitoring interval. Measurements will be recorded with a data logger at each well location and also transmitted to the MVA data center in the control building.

SS = sandstone.

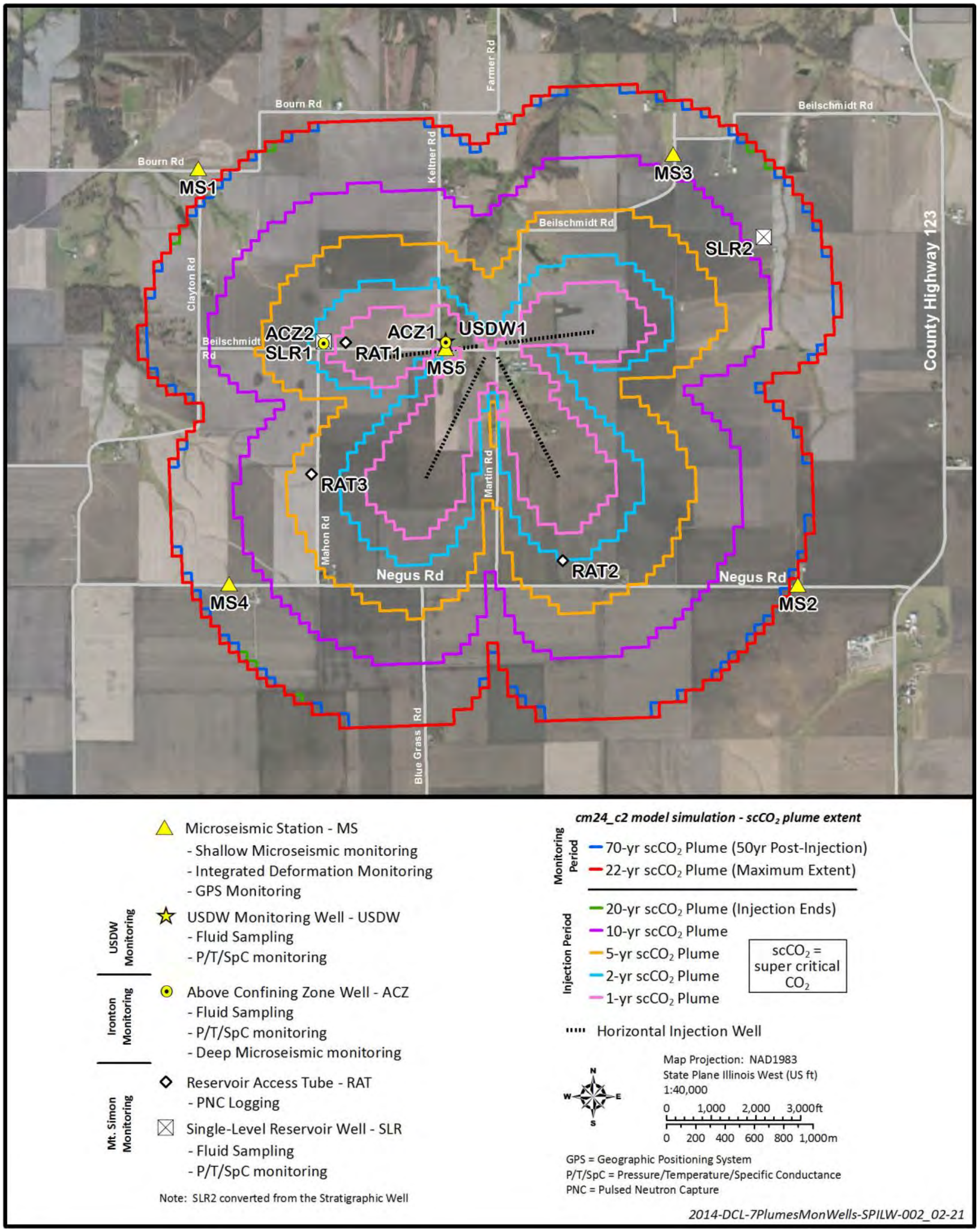

Figure A.3. Nominal Monitoring Well Layout and Modeled Supercritical CO_2 ($scCO_2$) Plume at different times. Note that the monitoring well locations are approximate and subject to landowner approval.

Groundwater Quality Monitoring

Fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at each ACZ and USDW monitoring well.

Indicator Parameter Monitoring – Fluid pressure, temperature, and specific conductance (P/T/SpC) will be monitored continuously. These are the most important parameters to be measured in real time within the monitoring interval of each well. These are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

In addition, in the two ACZ wells, a fiber-optic cable with integral geophones (fiber Bragg grating optical accelerometer) will extend from ground surface to the monitoring interval (i.e., to the annulus casing packer [ACP] just above the monitoring interval); this cable will be strapped to the outside of the casing and permanently cemented in place to support the microseismic monitoring program. Data from the fiber-optic sensors will be transmitted back to the MVA data center via a local-area fiber-optic network where the data-acquisition system will be located.

Geochemical Monitoring – Aqueous samples will be collected from each ACZ and USDW well, initially on a quarterly basis and decreasing in frequency as the system stabilizes over time, to determine the hydrochemistry in the monitoring interval fluids.

CO_2 Plume and Pressure-Front Tracking

Fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at each single-level in-reservoir (SLR) monitoring well.

Indicator Parameter Monitoring – Fluid P/T/SpC will be monitored continuously. They are the most important parameters to be measured in real time within the monitoring interval of each well. They are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

Geochemical Monitoring – Aqueous samples will be collected from each SLR well, initially on a quarterly basis and decreasing in frequency as the system stabilizes over time, to determine the hydrochemistry in the monitoring interval fluids. Aqueous sampling will not be used to assess CO_2 saturation levels. Once supercritical carbon dioxide ($scCO_2$) arrives, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

Indirect CO_2 Plume and Pressure-Front Tracking

The primary objectives of indirect (e.g., geophysical) monitoring are 1) tracking CO_2 plume evolution and CO_2 saturation levels; 2) tracking development of the pressure front; and 3) identifying or mapping areas of induced microseismicity, including evaluating the potential for slip along any faults or fractures identified by microseismic monitoring. Table A.4 summarizes potential geophysical monitoring technologies and identifies those included in the Testing and Monitoring Plan.

Pulsed-Neutron Capture Logging – The monitoring network will also include three reservoir access tube (RAT) installations designed for the collection of PNC logs to indirectly quantify CO_2 saturations within the Mount Simon injection zone or reservoir (Muller et al. 2007). PNC logging will serve as the primary measure for CO_2 saturation changes that occur within the injection zone. These monitoring points will be located within the predicted lateral extent of the 1- to 3-year CO_2 plume based on numerical simulations of injected CO_2 movement. The RAT locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume.

Geophysical Monitoring

Table A.4. Monitoring Technologies and Decision to Include in Monitoring Plans

Technology	Purpose	Analysis & Limitations
Pulsed-Neutron Capture Logging	Monitors CO_2 saturation changes along boreholes. Used for reservoir model calibration and leak detection.	Will provide quantitative CO_2 saturations. Sensitive only to region around the borehole.
Integrated Surface Deformation Monitoring	Monitors subtle changes in the Earth's surface due to geomechanical response to injection.	Will be able to measure expected deformation. Monitor for anomalies in pressure-front development. DInSAR can be difficult in vegetated areas.
Passive Microseismic	For locating fracture opening and slip along fractures or faults; may indicate location of the pressure front.	Can accurately detect seismic events. Not likely to detect limit of CO_2 plume.
Time-Lapse Gravity	Monitors changes in density distribution in the subsurface, caused by the migration of fluids. Relatively inexpensive.	Non-unique solution, must be used in conjunction with integrated surface deformation monitoring.

Passive Microseismic Monitoring – The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of 1) addressing public and stakeholder concerns related to induced seismicity; 2) estimating the spatial extent of the pressure front from the distribution of seismic events; and 3) identifying features that may indicate areas of caprock failure and possible containment loss. The proposed seismic monitoring network consists of five shallow borehole stations, surface stations, and two deep borehole stations. The shallow borehole stations will be drilled to at least the uppermost competent bedrock (~100 m). Actual noise levels and sensor magnitude detection limits at the stations will not be determined until after the sensors have been emplaced and monitored for a period of time. The results of this preliminary evaluation will guide the location of a small number (fewer than five) of additional surface stations.

Deep borehole sensors will be clamped to the outside of the casing of the two ACZ monitoring wells and cemented in place. A 24-level three-component borehole array will be installed in each well. The use of 24-level arrays results in a slight improvement in event location, but more importantly offers redundant sensors in case of failure. Optical three-component accelerometers are technically optimal due to their designed long-term performance characteristics.

Time-Lapse Gravity – The objective of this technique is to estimate the areal extent of the CO_2 plume, based on observed changes in density distribution in the subsurface, caused by the migration of fluids. Gravity changes at the surface are expected to be small but averaging many measurements and/or analysis of long-term trends may allow for tracking of the CO_2 plume. The solution is non-unique and is most useful when combined with Differential Global Positioning System (DGPS) surveys and other integrated surface deformation methods and/or seismic surveys. The locations of permanent and proposed permanent station monuments are shown in Figure A.4.

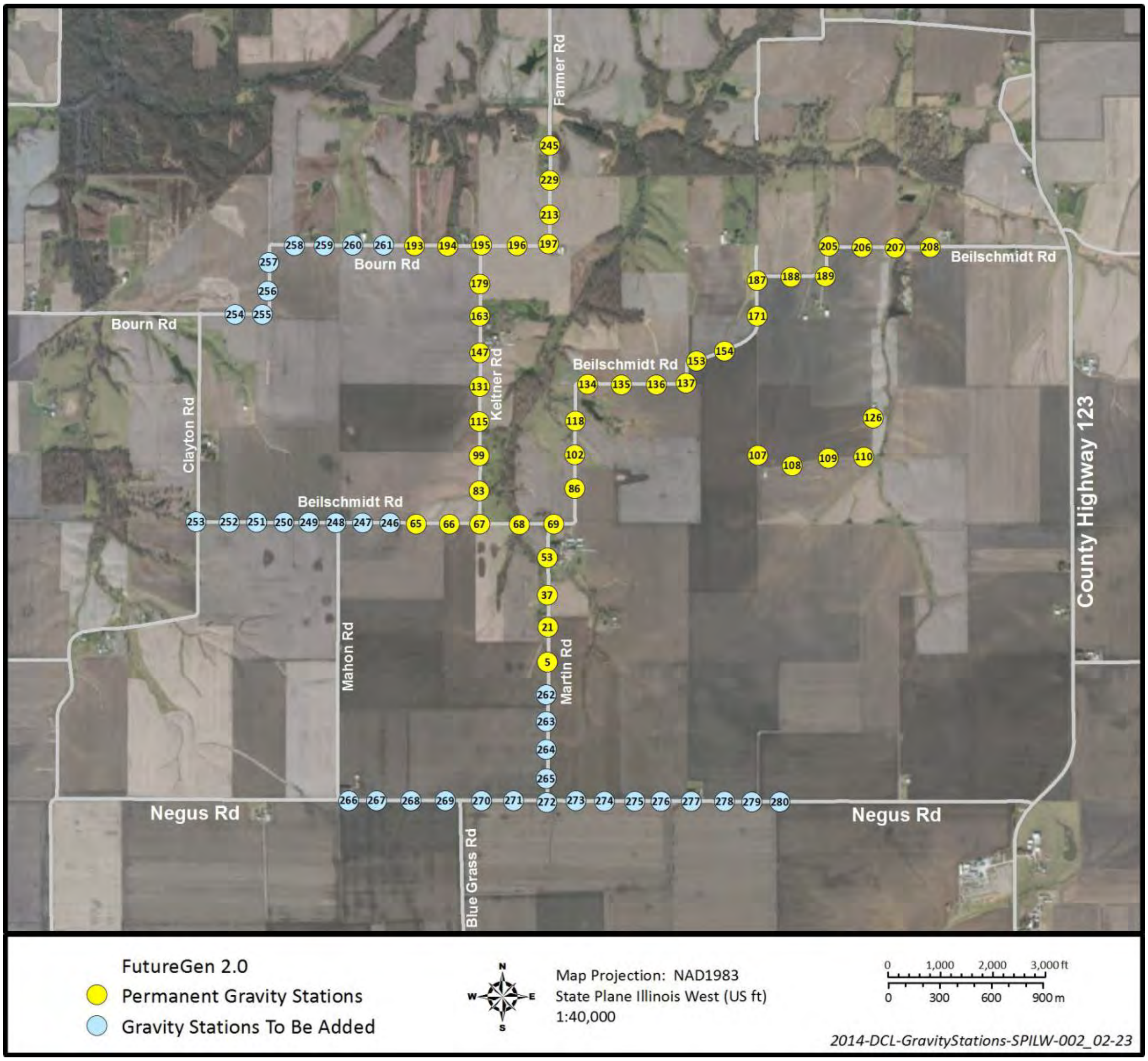

Figure A.4. Locations of Permanent and Proposed Permanent Gravity and Supplemental DGPS Stations

Integrated Deformation Monitoring – Integrated deformation monitoring integrates ground-surface data from permanent Global Positioning System (GPS) stations and tiltmeters, supplemented with annual DGPS surveys and larger-scale Differential Interferometric Synthetic Aperture Radar (DInSAR) surveys to detect and map temporal ground-surface deformation. The DInSAR and proposed GPS network are expected to resolve sub-centimeter surface changes and accurately measure the anticipated injection-induced surface deformation. Permanent GPS and tiltmeter stations will be co-located with the shallow microseismic locations and are expected to have the spatial coverage needed to characterize the overall shape and evolution of the geomechanical changes that occur as a result of CO_2 injection.

A.7 Quality Objectives and Criteria for Measurement Data

The primary goal of testing and monitoring activities is to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)).

A.7.1 Quality Objectives

The overall Quality Assurance (QA) objective for testing and monitoring is to provide results, interpretation, and reporting that provide reasonable assurance that decision errors regarding compliance with permitting and protection of USDWs are unlikely. The EPA (2013 EPA 816-R-13-001 – Testing and Monitoring Guidance) provides a number of recommendations that can be used as qualitative measures/criteria against which the testing and monitoring results can be compared to evaluate compliance.

Mechanical Integrity Testing

Demonstrating and maintaining the mechanical integrity of a well is a key aspect of protecting USDWs from possible endangerment and a specific requirement for Class VI wells in the UIC Program. The Class VI Rule requires mechanical integrity testing (MIT) to be conducted prior to injection (40 CFR 146.87(a)(4)), during the injection phase (40 CFR 146.89), and prior to well plugging after injection has ceased (40 CFR 146.92(a)). The EPA further identified a number of acceptable MIT methods.

A Class VI well can be demonstrated to have mechanical integrity if there is no significant leak (i.e., fluid movement) in the injection tubing, packer, or casing (40 CFR 146.89(a)(1)), and if there is no significant fluid movement through channels adjacent to the injection well bore (40 CFR 146.89(a)(2)). Note that the UIC Program Director will evaluate the results and interpretations of MIT to independently assess the integrity of the injection wells.

Operational Testing and Monitoring During Injection

The Class VI Rule requires owners or operators to monitor injectate properties, injection rate, pressure, volume, corrosion of well materials, and perform pressure fall-off testing (40 CFR 146.90(a), (b), (c), and (f)), to indicate possible deviation from planned project operations, verify compliance with permit conditions, and to inform Area of Review (AoR) reevaluations. The results are expected to be interpreted with respect to regulatory requirements and past results. Note the UIC Program Director will evaluate the results to ensure that the composition of the injected stream is consistent with permit conditions and that it does not result in the injectate being classified as a hazardous waste.

Plume and Pressure-Front Tracking

The EPA (2013 EPA 816-R-13-001 – Testing and Monitoring Guidance) indicates that identification of the position of the injected CO_2 plume and the presence or absence of elevated pressure (i.e., the pressure front) are integral for verifying the storage reservoir is behaving as predicted, informing the reevaluation of the AoR, and protecting the USDWs. The temporal changes will be analyzed by comparing the new data to previously collected data, and time-series graphs will be developed and interpreted for each well, taking into consideration the injection rate and well location. Spatial patterns will also be analyzed by constructing maps that present contours of pressure and/or hydraulic head. Increases in pressure in wells above the confining zone may be indicative of fluid leakage. Increases in pressure within the injection zone will be compared to modeling predictions to determine whether the AoR is consistent with monitoring results. Pressure increases at a monitoring well location greater than predicted by the current site AoR model, or increases at a greater rate, may indicate that the model needs to be revised.

Geochemical Monitoring

The results of groundwater monitoring will be compared to baseline geochemical data collected during site characterization (40 CFR 146.82(a)(6)) to obtain evidence of fluid movement that may affect USDWs. The EPA (2013 EPA 816-R-13-001 – Testing and Monitoring Guidance) suggests that trends in groundwater concentrations may be indicative of fluid leakage—such as changes in total dissolved solids, major cations and anions, increasing CO_2 concentrations, decreasing pH, increasing concentration of injectate impurities, increasing concentration of leached constituents, and/or increased reservoir pressure and/or static water levels. The EPA also suggests that geochemical data be compared to results from rock-water-CO_2 experiments or geochemical modeling.

Note that the UIC Program Director will evaluate the groundwater monitoring data to independently assess data quality, constituent concentrations (including potential contaminants), and the resulting interpretation to determine if there are any indications of fluid leakage and/or plume migration and whether any action is necessary to protect USDWs (EPA 2013 EPA 816-R-13-001 – Testing and Monitoring Guidance).

A.7.2 Measurement Performance/Acceptance Criteria

The qualitative and quantitative design objective of the FutureGen CO_2 Pipeline and Storage Project's testing and monitoring activities is to monitor the performance of the storage reservoir relative to permit and USDW protection requirements. The design of these activities is intended to provide reasonable assurance that decision errors regarding compliance with the permit and/or protection of the USDW are unlikely. In accordance with EPA 2013 EPA 816-R-13-001 – Testing and Monitoring Guidance, the well testing and monitoring program includes operational CO_2 injection stream monitoring, well MIT, geochemical and indicator parameter monitoring of both the reservoir and lowermost USDWs, and indirect geophysical monitoring. Table A.5 lists the field and laboratory analytical parameters, methods, and performance criteria for CO_2 injection stream monitoring. Table A.6 shows the MIT parameters, methods, and performance criteria. Table A.7 lists the groundwater geochemical and indicator parameters, methods, and performance criteria. Table A.8 lists the performance criteria for continuously recorded parameter measurements. Table A.9 lists the indirect geophysical parameters, methods, and performance criteria.

Table A.5. CO_2 Injectate Monitoring Requirements

Analytical Parameter	Analytical Method #	Detection Limit or (Range)	Typical Precision/Accuracy	QC Requirements
Pressure	Analog gauges, pressure transmitters	0-2500 psi	Accuracy: ±0.065% of span	CO_2 Pressure Transmitter, Mfg: Rosemount Part No: 3051TG4A2B21AS5M5Q4
Temperature	Thermocouples, or resistance temperature detectors	0-150 °F	Accuracy: ±0.03% of span	CO_2 Temperature Transmitter Mfg: Rosemount Part No: 644HANAXAJ6M5F6Q4
Flow	Coriolis mass meter	Range spanning maximum anticipated injection rate per well	±0.5 %	A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter.
CO_2	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
O_2	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
Total sulfur	ISBT 14.0 (GC/SCD)	0.01 µL/L to 50 µL/L (ppmv) dilution dependent	± 10%	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Arsenic	ICP-MS, EPA Method 6020	1 ng/m^3 (filtered volume)	±10%	Daily calibration
Selenium	ICP-MS, EPA Method 6020	5 ng/m^3 (filtered volume)	±10%	Daily calibration
Mercury (Hg)	Cold vapor atomic absorption (CVAA)	0.25 $\mu g/m^3$	± 10%	Daily calibration
H_2S	ISBT 14.0 (GC/SCD)	0.01 µL/L to 50 µL/L (ppmv) dilution dependent	± 10%	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Ar	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
Water vapor (moisture)	GC/HID*	< 100 ppm	± 10%	Replicate analyses within 10% of each other

GC/TCD – gas chromatography with a thermal conductivity detector
ISBT – International Society of Beverage Technologists
GC/SCD – gas chromatography with a sulfur chemiluminescence detector
GC/HID - gas chromatography with helium Ionization detector
* Andrawes (1983) or equivalent. Method subject to change in subsequent revisions.

Table A.6. Mechanical Integrity Testing and Corrosion Requirements

Analytical Parameter	Analytical Method #	QC Requirements
Corrosion of Well Tubulars		
Corrosion of well casing and tubing	Corrosion coupon monitoring (visual, weight, and size); U.S. EPA SW846 Method 1110A – "Corrosivity Toward Steel" (or a similar standard method).	Proper preparation of coupons per ASTM G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens. Refer to SW846 Method 1110A for measurement QC requirements.
Corrosion of well casing (internal radius, wall thickness; general corrosion, pitting, and perforations)	Wireline logging (mechanical, ultrasonic, electromagnetic); casing evaluation would only be done during well workovers that require removal of tubing string.	Vendor calibration of well logging tool(s) per manufacturer recommendations.
Well cement corrosion (quality of cement bond to pipe, and channels in cement)	Wireline logging (acoustic, ultrasonic); casing evaluation would only be done during well workovers that require removal of tubing string.	Baseline cement evaluation logs prior to start of injection. Vendor calibration of well logging tool(s) per manufacturer recommendations
External Mechanical Integrity		
Temperature adjacent to the well	Temperature logging to identify fluid movement adjacent to well bore	Baseline temperature log prior to start of injection. Vendor calibration of well logging tool(s) per manufacturer recommendations
Fluid composition adjacent to the well; fluid movement	Pulsed-neutron logging in oxygen activation mode and thermal capture cross-section (sigma) mode	Baseline log prior to start of injection. Tool calibration per manufacturer recommendations
Internal Mechanical Integrity		
Continuous measurement of fluid pressure and fluid volume in annulus between tubing and long casing string during injection	Pressure and fluid volumes will be measured and logged automatically using electronic pressure sensors and fluid level indicators that are incorporated into the annulus pressurization system (APS).	Initial and ongoing calibration of pressure and fluid level sensors will be done as part of the Annulus Pressurization System Operations and Maintenance program.
Initial annulus pressure test prior to start of injection and following workovers that involve removing tubing and/or packer.	Annular pressure test per EPA UIC requirements	
Pressure Fall-Off Testing		
Well pressure; CO_2 injection rate-history.	Pressure transient analysis methods will be used to analyze pressure fall-off test data to assess well condition (skin) that could indicate need for well rehabilitation.	Initial and ongoing calibration of in-well pressure sensors. Initial and ongoing calibration (proving) of CO_2 flow-rate meters.

Table A.7. Groundwater Geochemical and Indicator Parameter Requirements

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	ICP-AES, EPA Method 6010B or similar	1 to 80 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP-MS, EPA Method 6020 or similar	0.1 to 2 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Cyanide (CN-)	SW846 9012A/B	5 µg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Mercury	CVAA SW846 7470A	0.2 µg/L	±20%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	Ion Chromatography, EPA Method 300.0A or similar	33 to 133 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B	1 mg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C	10 mg/L	±10%	Balance calibration, duplicate samples
Water Density	ASTM D5057	0.01 g/mL	±10%	Balance calibration, duplicate samples
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of TIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of DIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Total Organic Carbon (TOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent Purge and Trap GC/MS	0.3 to 15 µg/L	±20%	Blanks, LCS, spike, spike 1 duplicate per batch of 20
Methane	RSK 175 Mod Headspace GC/FID	10 µg/L	±20%	Blanks, LCS, spike, spike 1 duplicate per batch of 20
Stable Carbon Isotopes $^{13/12}C$ ($1^{13}C$) of DIC in Water	Gas Bench for $^{13/12}C$	50 ppm of DIC	±0.2p	Duplicates and working standards at 10%

Table A.7. (contd)

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Radiocarbon ^{14}C of DIC in Water	AMS for ^{14}C	Range: 0 to 200 pMC	±0.5 pMC	Duplicates and working standards at 10%
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ ($1^{18}O$) of Water	CRDS H_2O Laser	Range: -500‰ to 200‰ vs. VSMOW	$^{2/1}H$: ±2.0‰ $^{18/16}O$: ±0.3‰	Duplicates and working standards at 10%
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C	^{14}C Range: 0 & DupMC	^{14}C: ±0.5pMC ^{13}C: ±0.2‰ $^{2/1}H$: ±4.0‰	Duplicates and working standards at 10%
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	Modified ASTM 1945D	1 to 100 ppm (analyte dependent)	Varies by component	Duplicates and working standards at 10%
Radon (^{222}Rn)	Liquid scintillation after pre-concentration	5 mBq/L	±10%	Triplicate analyses
pH	pH electrode	2 to 12 pH units	±0.2 pH unit *For indication only*	User calibrate, follow manufacturer recommendations
Specific Conductance	Electrode	0 to 100 mS/cm	±1% of reading *For indication only*	User calibrate, follow manufacturer recommendations

ICP-AES = inductively coupled plasma atomic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; LC-MS = liquid chromatography-mass spectrometry; ECD = electron capture detector

Table A.8. Required Minimum Specifications for Real-Time Parameter Measurements

Parameter	Range	Resolution	Accuracy	Additional Requirements
Pressure	0 – 2000 psi	0.05 psi	±2 psi	Calibration per manufacturer recommendations
Temperature	50 – 120 °F	0.1 °F	±2 °F	Calibration per manufacturer recommendations
Specific Conductance	0 – 85 mS/cm	0.002 mS/cm	±0.01 mS/cm	Calibration during sampling events

Table A.9. Indirect Geophysical Monitoring Requirements

Analytical Parameter	Analytical Method #	Detection Limit or (Range)	Typical Precision/Accuracy	QC Requirements
Sigma neutron capture cross section	PNC	Dependent on formation and well completion. Salinity >40 Kppm; porosity >0.10	0.5 c.u.	Manufacturer calibration and periodic recalibration
Carbon/Oxygen inelastic	PNC	Dependent on formation and well completion. Porosity >0.15;	Dependent on log time. Requires slow (5−8 ft/min) logging speed	Manufacturer calibration and periodic recalibration
Temperature	Temperature logging	0-350 °F	0.2 °F	Manufacturer calibration and periodic recalibration
Gamma	Gamma-ray logging	NA	1 count/API	Manufacturer calibration and periodic recalibration
Velocity	Passive seismic: geophone	145 dB; 1−350 Hz	10^{-7} m/s	Manufacturer calibration and periodic recalibration
Velocity	Passive seismic: seismometer	165dB ; 0.01−150 Hz	10^{-9} m/s	Manufacturer calibration and periodic recalibration
Acceleration	Passive seismic: force balance accelerometer	155 dB; DC-200 Hz	10^{-6} m/s^2	Manufacturer calibration and periodic recalibration
Acceleration	Passive seismic: fiber-optic accelerometer	0.01−2000 Hz	< 5. 10^{-7} m/s^2 / √Hz	Manufacturer calibration
Position	Integrated deformation: GPS	NA	5 mm+1 ppm horiz.; 10 mm +1 ppm vert.	Manufacturer calibration and periodic recalibration
Deformation	Integrated deformation: DInSAR	NA	<10 mm	Space Agency calibration
Acceleration	Time-lapse gravity	NA	10^{-8} m/s^2 (10^{-6} Gal)	Manufacturer calibration and periodic recalibration

A.8 Special Training/Certifications

Wireline logging, indirect geophysical methods, and some non-routine sampling will be performed by trained, qualified, and certified personnel, according to the service company’s requirements. The subsequent data will be processed and analyzed according to industry standards (Appendix A).

Routine injectate and groundwater sampling will be performed by trained personnel; no specialized certifications are required. Some special training will be required for project personal, particularly in the areas of PNC logging, certain geophysical methods, certain data-acquisition/transmission systems, and certain sampling technologies.

Training of project staff will be conducted by existing project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

A.9 Documentation and Records

The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)). These reports will follow the format and content requirement specified in the final permit, including required electronic data formats.

All data are managed according to the Project Data Management Plan (Bryce et al. 2013). All project records are managed according to the project records management requirements. All data and project records will be stored electronically on secure servers and routinely backed-up.

The FutureGen CO_2 Pipeline and Storage Facility PM (assisted by the QEngineer) will be responsible for ensuring that all affected project staff (as identified in the distribution list) have access to the current version of the approved QASP.

B. Data Generation and Acquisition

The primary goal of testing and monitoring activities is to verify that the Morgan County carbon dioxide (CO_2) storage site is operating as permitted and is not endangering any underground sources of drinking water (USDWs). To this end, the primary objectives of the testing and monitoring program are to track the lateral extent of supercritical carbon dioxide ($scCO_2$) within the target reservoir; characterize any geochemical or geomechanical changes that occur within the reservoir, caprock, and overlying aquifers; monitor any change in land-surface elevation associated with CO_2 injection; determine whether the injected CO_2 is effectively contained within the reservoir; and detect any adverse impact on USDWs.

This element of the Quality Assurance and Surveillance Plan (QASP) addresses data-generation and data-management activities, including experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to each testing and monitoring method. It should be noted that not all of these QASP aspects are applicable to all testing and monitoring methods. Other QASP aspects, such as inspection/acceptance of supplies and consumables (Section B.12), non-direct measurements (e.g., existing data) (Section B.13), and data management (Section B.14), are applicable to all techniques and are discussed separately.

Well testing and monitoring activities are broken into eight main categories/subtasks, as listed below.

1. CO_2 Injection Stream Analysis – includes CO_2 injection stream gas sampling and chemical analyses. See Section B.1.
2. Continuous Recording of Injection Pressure, Rate, and Volume, and Annulus Pressure. See Section B.2.
3. Corrosion Monitoring – includes sampling and analysis of corrosion coupons. See Section B.3.
4. Groundwater Quality Monitoring – includes formation fluid sampling within the Ironton Sandstone (Above Confining Zone) and St. Peter Sandstone (lowermost USDW) and subsequent geochemical analyses, as well as continuous monitoring of indicator parameters. See Section B.4.
5. External Mechanical Integrity Testing – includes temperature logging and pulsed-neutron capture (PNC) logging (both gas-view and oxygen-activation mode), as well as cement-evaluation and casing inspection logging. See Section B.5.
6. Pressure Fall-Off Testing. See Section B.6.
7. Direct CO_2 Plume and Pressure-Front Tracking − includes all formation fluid sampling within the Mount Simon Sandstone, as well as continuous monitoring of pressure, temperature, and fluid specific conductance. See Section B.7.
8. Indirect CO_2 Plume and Pressure-Front Tracking – includes PNC logging, passive seismic monitoring, integrated deformation monitoring, and time-lapse gravity. Optional supplementary methods may include three-dimensional (3D) multicomponent surface seismic, and multicomponent vertical seismic profiling. See Sections B.8 through B.11.

B.1 Carbon Dioxide Stream Analysis

The Alliance will conduct injection stream analysis to meet the requirements of 40 CFR 146.90(a). This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to CO_2 stream analysis monitoring activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.1.1 Sampling Process Design (Experimental Design)

Based on the anticipated composition of the CO_2 stream, a list of parameters has been identified for analysis. Samples of the CO_2 stream will be collected regularly (e.g., quarterly) for chemical analysis.

Table B.1. Parameters and Frequency for CO_2 Stream Analysis

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
CO_2 (%)	quarterly
Water (lb/mmscf)	quarterly
Oxygen (ppm)	quarterly
Sulfur (ppm)	quarterly
Arsenic (ppm)	quarterly
Selenium (ppm)	quarterly
Mercury (ppm)	quarterly
Argon (%)	quarterly
Hydrogen Sulfide (ppm)	quarterly

B.1.2 Sampling Methods

Grab samples of the CO_2 stream will be obtained for analysis of gases, including CO_2, O_2, H_2S, Ar, and water moisture. Samples of the CO_2 stream will be collected from the CO_2 pipeline at a location where the material is representative of injection conditions. A sampling station will be installed in the ground or on a structure close to the pipeline and connected to the pipeline via small-diameter stainless steel tubing to accommodate sampling cylinders that will be used to collect the samples. A pressure regulator will be used to reduce the pressure of the CO_2 to approximately 250 psi so that the CO_2 is collected in the gas state rather than as a supercritical liquid. Cylinders will be purged with sample gas (i.e., CO_2) prior to sample collection to remove laboratory-added helium gas and ensure a representative sample.

B.1.3 Sample Handling and Custody

Samples will be transported to the Monitoring, Verification, and Accounting (MVA) laboratory space in the control building for processing, packaging, and shipment to the contracted laboratory, following standard sample handling and chain-of-custody guidance (EPA 540-R-09-03, or equivalent).

B.1.4 Analytical Methods

Analytical methods are listed in Table A.5

B.1.5 Quality Control

A wide variety of monitoring data will be collected specifically for this project, under appropriate quality assurance (QA) protocols. Data QA and surveillance protocols will be designed to facilitate compliance with requirements specified in 40 CFR 146.90(k).

B.1.6 Instrument/Equipment Testing, Inspection, and Maintenance

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

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.1.7 Instrument/Equipment Calibration and Frequency

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.2 Continuous Recording of Injection Pressure, Rate, Volume, and Annulus Pressure

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to continuous monitoring of injection parameters. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.2.1 Sampling Process Design (Experimental Design)

The Alliance will conduct continuous monitoring of injection parameters to meet the requirements of 40 CFR 146.90(b). These activities include continuous recording of injection pressure, temperature, flow rate, and volume, as well as the annulus pressure.

B.2.2 Sampling Methods

Continuous Recording of Injection Pressure and Temperature

An electronic P/T gauge will be installed on the outside of the tubing string, approximately 30 ft above the packer, and ported into the tubing to continuously measure CO_2 injection P/T inside the tubing at this depth. Mechanical strain gauges and thermocouples will be the primary monitoring devices for pressure and temperature.

Injection P/T will also be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead. The P/T of the injected CO_2 will be continuously measured for each well. The pressure will be measured by electronic pressure transmitter with analog output mounted on the CO_2 line associated with each injection well. The temperature will be measured by an electronic temperature transmitter mounted in the CO_2 line at a location near the pressure transmitter, and both transmitters will be located near the wellhead. The transmitters will be connected to the Annulus Pressurization System (APS) programmable logic controller (PLC) located in the Control Building adjacent to the injection well pad.

Continuous Recording of Injection Mass Flow Rate

The mass flow rate of CO_2 injected into the well field will be measured by a flow meter skid with a Coriolis mass flow transmitter for each well. Each meter will have analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). A total of six flow meters will be supplied, providing for two spare flow meters to allow for flow meter servicing and calibration. Valving will be installed to select flow meters for measurement and for calibration. A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter. The flow transmitters will each be connected to a remote terminal unit (RTU) on the flow meter skid.

The flow meters will be connected to the main CO_2 storage site SCADA system for continuous monitoring and control of the CO_2 injection rate into each well. The flow rate into each well will be controlled using a flow-control valve located in the CO_2 pipeline associated with each well. The control system will be programmed to provide the desired flow rate into three of the four injection wells, with the fourth well receiving the balance of the total flow rate.

B.2.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Electronic sensor data (e.g., pressure data) will be networked through the local-area fiber-optic network using Ethernet network interfaces back to data-acquisition systems located in the MVA data center.

Electronic data and field records will be transferred to laptop and/or desktop computers and/or backed-up on secured servers at least quarterly, as well as scanned copies of all pertinent hardcopy field records/notes.

B.2.4 Analytical Methods

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements. Trend analysis will also help evaluate the performance (e.g., drift) of the instruments, suggesting the need for maintenance or calibration.

B.2.5 Quality Control

Continuous monitoring equipment will be calibrated according to the manufacturers' recommendations. If trends or other unexplained variability in the data are observed that might indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

B.2.6 Instrument/Equipment Testing, Inspection, and Maintenance

The surface instruments will be maintained according to manufacturers' recommendations; however, if data trends indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

B.2.7 Instrument/Equipment Calibration and Frequency

Because the bottom-hole P/T gauge will be attached to the tubing string, the gauge will be recalibrated or replaced only when the injection well tubing string is pulled, which would occur only if warranted by a downhole issue that can only be addressed by performing a well workover. The surface P/T instruments will be calibrated according to manufacturers' recommendations.

B.3 Corrosion Monitoring

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to corrosion-monitoring activities. Refer to Sections B.12 through B.14 for general description of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.3.1 Sampling Process Design (Experimental Design)

The Alliance will conduct corrosion monitoring of well materials to meet the requirements of 40 CFR 146.90(c). Corrosion-monitoring activities are designed to monitor the integrity of the injection wells throughout the operational period. This includes using corrosion coupons as well as periodic cement-evaluation and casing inspection logs when tubing is removed from the well (i.e., during well workovers). Corrosion coupons will be made of the same materials as the long string of casing and the injection tubing, and will be placed in the CO_2 pipeline for ease of access.

B.3.2 Sampling Methods

Corrosion monitoring will include corrosion coupons as well as periodic cement-evaluation and casing inspection logs.

Corrosion Coupon Monitoring

Corrosion coupons will be made of the same material as the long string of casing and the injection tubing and placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using the ASTM International (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

Cement-evaluation and Casing Inspection Logging

Cement-evaluation and casing inspection logs will be run periodically, on an opportunistic basis, whenever tubing is removed from the well (i.e., during well workovers). See Section B.5 on external mechanical integrity testing.

B.3.3 Sample Handling and Custody

Corrosion monitoring will include corrosion coupons as well as periodic cement-evaluation and casing inspection logs. No specialized sample handling or chain-of-custody procedures are needed. The coupons will be removed from the pipeline, then taken to the nearby mobile lab (field trailer) where they will be cleaned, inspected, weighed, and measured. They will be immediately returned to the pipeline. Cement-evaluation and casing inspection log data will be handled using best management practices. See Section B.5 on external mechanical integrity testing.

B.3.4 Analytical Methods

The corrosion coupons will be cleaned, inspected visually for evidence of corrosion (e.g., pitting), weighed, and measured each time they are removed (ASTM G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens). The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

See Section B.5 on external mechanical integrity testing for cement-evaluation and casing inspection logging analytical methods.

B.3.5 Quality Control

Two groups of four replicate corrosion coupons of each material type will be placed in proximity to each other within two different locations within the CO_2 injection pipeline. A third group of four replicate samples of each material type will placed in proximity to each other within a simulated injection pipeline as a control (not exposed to CO_2). All samples will be removed quarterly and subjected to the same visual and measurement methodologies. This approach will allow an evaluation of the potential spatial variability in corrosion rates within the injection tubing, as well as the natural variability between coupon samples. Corrosion rates (calculated as the weight loss during the exposure period divided by the duration, i.e., weight loss method) and statistical analyses (e.g., t-test) will be independently reviewed and documented.

See Section B.5 on external mechanical integrity testing for cement-evaluation and casing inspection logging quality control methods.

B.3.6 Instrument/Equipment Testing, Inspection, and Maintenance

Equipment and instrumentation for visual inspection and measurement of the corrosion coupons will consist of materials to clean corrosion products off the coupons as well as equipment and instrumentation for visual inspection and measurement in accordance with ASTM G1-03. Key inspection and measurement equipment may include calipers, an analytical balance (e.g., electronic scale), and a low-power microscope or hand lens (e.g., 7X to 30X). The analytical balance should be able to measure to with + or -0.2 to 0.02 mg. Calipers should be able to measure to about 1% of the area measured (ASTM G1-03).

Maintenance (e.g., charging, batteries, etc.) and instrument checks will be performed quarterly, prior to each sampling event. All equipment and materials will be visually inspected for damage, calibration dates, battery life, etc. prior to use. Fresh batteries and backup equipment/instrumentation will be stored in the mobile lab/field trailer.

See Section B.5 on external mechanical integrity testing for instrumentation and equipment testing, inspection, and maintenance relative to cement-evaluation and casing inspection logging.

B.3.7 Instrument/Equipment Calibration and Frequency

Calipers, analytical balances, and other measuring and testing instrumentation will be calibrated by the manufacturer, according to its recommended procedures and frequencies. See Section B.5 on external mechanical integrity testing for instrumentation and equipment calibration relative to cement-evaluation and casing inspection logging.

B.4 Groundwater Quality Monitoring (ACZ and USDW wells)

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to groundwater quality monitoring activities. Refer to Sections B.12 through B.14 for general description of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.4.1 Sampling Process Design (Experimental Design)

The Alliance will conduct ground-water-quality/geochemical monitoring above the confining zone to meet the requirements of 40 CFR 146.90(d).

The planned groundwater quality monitoring well network layout, number of wells, well design, and sampling regimen are based upon site-specific characterization data, and consider structural dip, the locations of existing wells, expected ambient flow conditions, and the potential for heterogeneities or horizontal/vertical anisotropy within the overburden materials (see also Section A.6.2). The planned monitoring network consists of two wells within the first permeable interval immediately above the primary confining zone (Ironton Sandstone), and one well within the lowermost USDW (St. Peter Sandstone) (Figure A.3). The above confining zone (ACZ) wells will be completed in the Ironton Sandstone and monitor for changes in pressure, groundwater chemistry, indicator parameters, and microseismicity. The ACZ monitoring interval is located immediately above the primary confining zone. One of these wells will be located ~1,000 ft west of the injection site adjacent to the western injection lateral; the other will be located ~1,500 ft west of the western injection lateral terminus. The USDW well (USDW1) will be installed at the base of the St. Peter Sandstone to monitor the groundwater quality of the lowermost USDW.

The Alliance plans to conduct periodic fluid sampling as well as continuous pressure, temperature, and specific conductance (P/T/SpC) monitoring throughout the injection phase in the two ACZ monitoring wells and the USDW well. (Table A.3 lists the parameters and instrumentation that will be used at each of the ACZ and USDW monitoring wells. Minimum specifications for the planned continuous measurements are listed in Table A.8.)

The Alliance will also conduct baseline surficial aquifer sampling in the shallow, semi-consolidated glacial sediments, using approximately nine local landowner wells and one well drilled for the project. Because near-surface environmental impacts are not expected, surficial aquifer (<100 ft bgs) monitoring will only be conducted for a sufficient duration to establish baseline conditions (minimum of three sampling events). Surficial aquifer monitoring is not planned during the injection phase; however, the need for additional surficial aquifer monitoring will be continually evaluated throughout the operational phases of the project, and may be reinstituted if conditions warrant.

B.4.2 Sampling Methods

Fluid samples will be collected at monitored formation depths and maintained at formation pressures within a closed pressurized sample container to prevent the escape of dissolved gases. Access to the monitored intervals at the ACZ and USDW monitoring wells will be through the 5-1/2-in. casing that is cemented into the borehole.

Aqueous samples will be collected from each monitoring well, initially on a quarterly basis and later less frequently, to determine the concentration of CO_2 and other constituents in the monitoring interval fluids. The fluid samples will be collected within the open interval of each monitoring well using a flow-through sampler with a 950-cc (or larger) sample chamber. The samples will be maintained at formation pressure within a closed sample container to prevent the escape of dissolved gases. Prior to sampling, the P/T/SpC probe will be monitored as the well is purged (up to three times the volume of the well-screen section will be discharged from the well before collecting the sample). The probe will then be removed from the well and the sampler will be run into the borehole on the same wireline cable to collect the pressurized fluid sample. Additional purging may be conducted just prior to collection of the pressurized fluid sample if mixing between the fluid column and sampling interval during insertion of the sampler is a concern.

B.4.3 Sample Handling and Custody

After removing the sampler from the well, the closed and pressurized sample container(s) will be transported to the MVA laboratory space in the control building for processing following standard chain-of-custody procedures.

B.4.4 Analytical Methods

The analytical methods for groundwater quality monitoring in the ACZ and USDW wells are summarized in Table A.7.. Where possible, methods are based on standard protocols from EPA or Standard Methods for the Examination of Water and Wastewater (American Public Health Association, American Water Works Association, Water Environment Federation, 19th edition or later, Washington, D.C.). Laboratories shall have standard operating procedures for the analytical methods performed.

B.4.5 Quality Control

The quality control (QC) elements in this section are used to help evaluate whether groundwater samples are free of contamination and whether the laboratories performed the analyses within acceptable accuracy and precision requirements. Several types of field and laboratory QC samples are used to assess and enhance data quality (Table B.2)

Table B.2. Quality Control Samples

	Field QC	
Sample Type	Primary Characteristic Evaluated	Frequency
Trip Blank	Contamination from containers or transportation	1 per sampling event
Field Duplicates	Reproducibility	1 per sampling event
	Laboratory QC	
Sample Type	Primary Characteristic Evaluated	Frequency
Method Blank	Laboratory contamination	1 per batch
Lab Duplicate	Laboratory reproducibility	(a)
Matrix Spike	Matrix effects and laboratory accuracy	(a)
Matrix Spike Duplicate	Laboratory reproducibility/accuracy	(a)
Laboratory Control Sample	Method accuracy	1 per batch

(a) As defined in the laboratory contract and analysis procedures (typically 1 per 10 samples).

Field QC samples consist of trip blanks and duplicate samples. Trip blanks are preserved sample bottles that are filled with deionized water and transported unopened to the field in the same storage container that will be used for samples collected that day. Trip blanks evaluate bottle cleanliness, preservative purity, equipment decontamination, and proper storage and transport of samples. The frequency of collection for trip blanks is one per sampling event. Field duplicates are replicate samples that are collected at the same well. After each type of bottle is filled, a second, identical bottle is filled for each type of analysis. Both sets of samples are stored and transported together. Field duplicates provide information about sampling and analysis reproducibility. The collection frequency for field duplicates is one per sampling event.

Laboratory QC samples include method blanks, laboratory duplicates, matrix spikes, matrix spike duplicates, and laboratory control samples (defined below). These samples are generally required by EPA method protocols. Frequencies of analysis are specified in Table B.2 and in the laboratories' standard operating procedures.

- **Method blank** – an analyte-free matrix to which all reagents are added in the same volumes or proportions as used in sample processing. The method blank is carried through the complete preparation and analysis process. Method blanks are used to quantify contamination from the analytical process.
- **Laboratory duplicate** – an intra-laboratory split sample that is used to evaluate the precision of a method in a given sample matrix.
- **Matrix spike** – an aliquot of a sample that is spiked with a known concentration of target analytes(s). The matrix spike is used to assess the bias of a method in a given sample matrix. Spiking occurs prior to sample preparation and analysis.
- **Matrix spike duplicate** – a replicate spiked aliquot of a sample that is subjected to the entire sample preparation and analytical process. Matrix spike duplicate results are used to determine the bias and precision of a method in a given sample matrix.
- **Laboratory control sample** – a control matrix (typically deionized water) spiked with analytes representative of the target analytes or a certified reference material that is used to evaluate laboratory accuracy.

Besides these measures, the laboratories maintain internal QA programs and are subject to internal and external audits.

B.4.6 Instrument/Equipment Testing, Inspection, and Maintenance

For groundwater sampling, field equipment will be maintained, serviced, and calibrated according to the manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.4.7 Instrument/Equipment Calibration and Frequency

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.5 External Mechanical Integrity Testing

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to external mechanical integrity testing (MIT) activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.5.1 Sampling Process Design (Experimental Design)

The Alliance will conduct external MIT to meet the requirements of 40 CFR 146.90(e). These tests are designed to include temperature logging, PNC logging, and cement-evaluation logging. An initial (baseline) temperature and PNC logs will be run on the well after well construction but prior to commencing CO_2 injection. These baseline log(s) will serve as a reference for comparing future temperature and PNC logs for evaluating external mechanical integrity.

Temperature Logging

Temperature logs can be used to identify fluid movement along channels adjacent to the well bore. In addition to identifying injection-related flows behind casing, temperature logs can often locate small casing leaks. Injection of CO_2 will have a cooling or heating effect on the natural temperature in the storage reservoirs, depending on the temperature of the injected CO_2 and other factors. Once injection starts, the flowing temperature will stabilize quickly (assuming conditions remain steady).

When an injection well is shut-in for temperature logging, the well bore fluid begins to revert toward ambient conditions. Zones that have taken injectate, either by design or not, will exhibit a “storage” signature on shut-in temperature surveys (storage signatures are normally cold anomalies in deeper wells, but may be cool or hot depending on the temperature contrast between the injectate and the reservoir). Losses behind pipe from the injection zone can be detected on both flowing and shut-in temperature surveys and exhibit a “loss” signature.

For temperature logging to be effective for detecting fluid leaks, there should be a contrast in the temperature of the injected CO_2 and the reservoir temperature. The greater the contrast in the CO_2 when it reaches the injection zone and the ambient reservoir temperature, the easier it will be to detect temperature anomalies due to leakage behind casing. Based on data from the stratigraphic well, ambient bottom-hole temperatures in the Mount Simon Sandstone are expected to be approximately 100°F; the temperature of the injected CO_2 is anticipated to be on the order of 72°F to 90°at the surface (depending on time of year) but will undergo some additional heating as it travels down the well. After the baseline (i.e., prior to injection) temperature log has been run to determine ambient reservoir temperature in each well, it will be possible to determine whether there will be sufficient temperature contrast to make the temperature log an effective method for evaluating external mechanical integrity.

The Alliance will consult the EPA Region 5 guidance for conducting temperature logging (EPA 2008) when performing this test.

Oxygen-Activation Logging

Oxygen activation is a geophysical logging technique that uses a PNC tool to quantify the flow of water in or around a borehole. For purposes of demonstrating external mechanical integrity, a baseline oxygen activation will be run prior to the start of CO_2 injection and compared to later runs to determine changing fluid flow conditions adjacent to the well bore (i.e., formation of channels or other fluid isolation concerns related to the well).

The PNC tool emits high-energy neutrons that interact with water molecules present in the casing-formation annular space, among others. This temporarily activates oxygen (^{16}O) to produce an isotope of nitrogen (^{16}N) that decays back to oxygen with a half-life of 7.1 seconds and emits an easily detected gamma ray. Typical PNC tools have two or three gamma-ray detectors (above and below the neutron source) to detect the movement of the activated molecules, from which water velocity can then be calculated. The depth of investigation for oxygen-activation logging is typically less than 1 ft; therefore, this log type provides information immediately adjacent to the well bore.

Repeat runs will be made under conditions that mimic baseline conditions (e.g., similar logging speeds and tool coefficients) as closely as possible to ensure comparability between baseline and repeat data.

The Alliance will consult the EPA Region 5 guidance for conducting the oxygen-activation logging (EPA 2008) when performing this test.

In addition to oxygen activation logging, the PNC tool will also be run in thermal capture cross-section (sigma) mode to detect the presence of CO_2 outside the casing.

PNC logging will be the primary method used to evaluate the external mechanical integrity of the injection wells.

Cement-Evaluation Logging

Cement evaluation beyond the preliminary cement-bond log is not required for Class VI wells under MIT or corrosion monitoring (40 CFR 146.89 and 146.90). However, it is recognized that cement integrity over time can influence the mechanical integrity of an injection well. Therefore, cement-evaluation logs will be run when tubing is removed from the well (i.e., during well workovers that involve removing the tubing string). Some cement-evaluation logs are also capable of providing information about the condition of the casing string, such as wall thickness and inside diameter (e.g., Schlumberger isolation scanner tool).

B.5.2 Sampling Methods

PNC logging will be the primary method used to evaluate the external mechanical integrity of the injection wells (EPA requires annual MIT demonstrations). PNC and temperature logging will be conducted on an opportunistic basis, for example, when each well is taken out of service. Temperature and PNC logging will be performed through the tubing and therefore will not require removal of the tubing and packer from the well. However, the cement-evaluation and casing-evaluation logging will be conducted only when tubing is removed from the well as this cannot be performed through tubing.

B.5.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Logging data will be recorded on a computer located in the wireline logging truck. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up on secure servers at the conclusion of each logging event, as will scanned copies of all pertinent hardcopy field records/notes.

B.5.4 Analytical Methods

Wireline log data will be processed following industry best practices and coordinated with the borehole-logging operator to optimize data-collection parameters. Modeling can be done to simulate near-borehole interferences and remove their effects from the signal. Modeling is a recommended procedure and requires knowledge of the target formations and fluids that must be obtained from cores and additional logging data. Each logging result will be compared for each well to the baseline or previous survey, as applicable, to determine changes.

B.5.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and are reproducible. Third-party logging and processing for a subset of boreholes and logging events can be used as part of the validation procedure. Failure of tool performance in the field or unreproducible "repeat sections" will result in non-acceptance of the data, and may trigger a return of the wireline tool to the manufacturer for recalibration or replacement. Off-normal results/comparisons to baseline will trigger additional evaluation and possible new logging runs.

B.5.6 Instrument/Equipment Testing, Inspection, and Maintenance

Examples of industry-published guidelines for calibration and field operation of the pulsed-neutron capture (PNC) wireline log hardware and data-collection software are provided in Appendix A.

B.5.7 Instrument/Equipment Calibration and Frequency

To ensure data acquisition quality, each logging tool will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All tools and field operation software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, tool recalibration will be performed monthly and both prior to and after each logging event following the manufacturer's guidelines. Examples of industry-published guidelines for calibration and field operation of wireline log hardware and data-collection software are provided in Appendix B.

B.6 Pressure Fall-Off Testing

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to pressure fall-off testing activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.6.1 Sampling Process Design (Experimental Design)

Pressure fall-off testing will be conducted upon completion of the injection wells to characterize reservoir hydrogeologic properties and aquifer response model characteristics (e.g., nonleaky vs. leaky reservoir; homogeneous vs. fractured media) as well as changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior in accordance with 40 CFR 146.87(e)(1). Pressure fall-off testing will also be conducted at least once every five (5) years after injection operations begin, or more frequently if required by the UIC Program Director (40 CFR 146.90 (f)). Specifically, the objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect well/reservoir performance (e.g., well injectivity, anomalous reservoir pressure behavior). Detailed descriptions for conducting and analyzing pressure fall-off tests are provided by the EPA (2002, 2003, and 2012). These guidelines will be followed when conducting pressure fall-off tests for the FutureGen 2.0 CO_2 Pipeline and Storage Project.

B.6.2 Sampling Methods

Controlled pressure fall-off tests are conducted by terminating injection for a designed period/duration of time. The pressure fall-off test is initiated by terminating injection, shutting-in the well by closing the surface wellhead valve(s), and maintaining continuous monitoring the surface and downhole pressure recovery within the well/test interval system during the fall-off/recovery period. The designed duration of the pressure fall-off recovery test is a function of a number of factors, including the exhibited pre-operational injection reservoir test response characteristics, the injection well history prior to termination (i.e., injection duration, rate history), and potential pressure interference effects imposed by any surrounding injection wells completed within the same reservoir. Because of the potential impact of injection-rate variability on early-time pressure fall-off recovery behavior, the EPA (2012) recommends that injection rates and pressures be uniform and held relatively constant prior to initiating a pressure fall-off test.

Upon shutting-in the well, in-well pressure measurements are monitored continuously in real time, both downhole (within or in proximity to the injection reservoir) and at the surface wellhead location. The EPA (2012) recommends the use of two pressure probes at each location, with one serving as a verification source and the other as a backup/replacement sensor if the primary pressure transducer becomes unreliable or inoperative. The duration of the shut-in period used in conducting the pressure fall-off test should be extended sufficiently beyond wellbore storage effects and when the pressure recovery is indicative of infinite-acting radial flow (IARF) conditions. The establishment of IARF conditions is best determined by using pressure derivative diagnostic analysis plots (Bourdet et al. 1989; Spane 1993; Spane and Wurstner 1993), and is indicated when the log-log pressure derivative/recovery time plot, plots as a horizontal line. When IARF pressure fall-off conditions are indicated, the pressure response vs. log of fall-off/recovery time plots as a straight line on a standard semi-log plot. The EPA (2012) recommends a general rule-of-thumb of extending pressure fall-off tests a factor of three to five beyond the time required to reach radial flow conditions, while Earlougher (1977) suggests extending recovery periods between 1 to 1.5 log cycles beyond when the pressure response starts to deviate from purely wellbore storage response characteristics (i.e., a unit slope, 1:1 on a standard log-log pressure fall-off recovery plot).

For projects like FutureGen 2.0 that will use multiple injection wells completed within the same reservoir zone, the EPA (2012) recommends special considerations to be used for pressure fall-off testing to minimize the pressure response impacts from neighboring injection wells on the pressure fall-off test well recovery response. For the neighboring injection wells (i.e., those not being tested), the EPA (2012) recommends that injection at these wells either should be terminated prior to initiating the pressure fall-off test for a duration exceeding the planned shut-in period, or that injection rates at the neighboring injection wells be held constant and continuously recorded prior to and during the fall-off recovery test. After completion of the fall-off test, additional large-scale areal reservoir hydraulic/storativity characterization information may be derived for the injection reservoir by implementing a stepped-pulse pressure interference signal (by significantly increasing and/or decreasing injection rates) initiated from the neighboring injection wells. The arrival of the observed pulsed pressure signal at the fall-off test well provides information (i.e., due to arrival time and attenuation of the pressure pulse signal) about inter-well reservoir conditions (e.g., hydraulic diffusivity, directional lateral extent of injected CO_2), particularly if compared to pre-injection interference test response characteristics.

B.6.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Electronic sensor data (e.g., pressure data) will be recorded on data loggers. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up on secure servers at the conclusion of each test, as well as scanned copies of all pertinent hardcopy field records/notes.

B.6.4 Analytical Methods

Quantitative analysis of the pressure fall-off test response recorded following termination of injection for the test well provides the basis for assessing near well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots established prior to operational injection of CO_2 and periodic fall-off tests conducted during operational injection phases can be used to determine whether significant changes in well or injection reservoir conditions have occurred. Diagnostic derivative plot analysis (Bourdet et al. 1989; Spane 1993; Spane and Wurstner 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

The EPA (2002, 2003) provides a detailed discussion on the use of standard semi-log and log-log diagnostic and analysis procedures for pressure fall-off test interpretation. The plotting of downhole temperature concurrent with the observed fall-off test pressure is also useful diagnostically for assessing any observed anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, as noted by the EPA (2012), if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures responding differently than registered within the probe sensor), erroneous fall-off pressure response results maybe be derived. As previously discussed, concurrent plotting of downhole temperature and pressure fall-off responses is commonly useful for assessing when temperature anomalies may be affecting pressure fall-off/recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log-log and semi-log plots of observed pressure change and/or pressure derivative plots versus recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity, etc.) based on characteristic diagnostic fall-off pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard et al. (2009).

As discussed by the EPA (2002), early pressure fall-off recovery response corresponds to flow conditions within and in proximity to the well bore, while later fall-off recovery response is reflective of progressively more distant reservoir conditions from the injection well location. Significant divergence in pressure fall-off response patterns from previous pressure fall-off tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure fall-off tests for discerning possible changes to well and reservoir conditions is presented by the EPA (2002, 2003).

As indicated by the EPA (2012), quantitative analysis of the pressure fall-off test data can be used to determine formation hydraulic property characteristics (e.g., permeability, transmissivity), and well skin factor (additional pressure change effects due to altering the permeability/storativity conditions of the reservoir/well injection interval boundary). Determination of well skin is a standard result for pressure fall-off test analysis and is described in standard well-test analysis texts such as that by Earlougher (1977). Software programs are also commercially available (e.g., Duffield 2007, 2009) for analyzing pressure fall-off tests. Significant changes in well and reservoir property characteristics (as determined from pressure fall-off analysis), compared to those used in site computational modeling and AoR delineation, may signify a reevaluation of the AoR, as may be required by the UIC Program Director, as noted by the EPA (2012).

B.6.5 Quality Control

Periodic QC checks will be routinely made in the field, and on occasion, where permanent pressure gauges are used, a second pressure gauge with current certified calibration will be lowered into the well to the same depth as the permanent downhole gauge.

B.6.6 Instrument/Equipment Testing, Inspection, and Maintenance

All field equipment will be visually inspected and tested prior to use. Spare instruments, batteries, etc. will be stored in the field support trailer.

B.6.7 Instrument/Equipment Calibration and Frequency

Pressure gauges that are used to conduct fall-off tests will be calibrated in accordance with manufacturers' recommendations, and current calibration certificates will be provided with test results to the EPA. In lieu of removing the injection tubing to regularly recalibrate the downhole pressure gauges, their accuracy will be demonstrated by comparison to a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on annual calibration checks (using the second calibrated pressure gauge) developed for the downhole gauge, can be used for the purpose of the fall-off test. If used, these calibration curves (showing all historic pressure deviations) will accompany the fall-off test data submitted to the EPA.

B.7 Carbon Dioxide Plume and Pressure-Front Tracking

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to CO_2 plume and pressure-front tracking activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.7.1 Sampling Process Design (Experimental Design)

The Alliance will conduct direct and indirect CO_2 plume and pressure-front monitoring to meet the requirements of 40 CFR 146.90(g). The planned reservoir-monitoring well network design is based on the Alliance's current conceptual understanding of the site and predictive simulations of injected CO_2 fate and transport. The number, layout, design, and sampling regimen of the monitoring wells are based upon site-specific characterization data collected from the stratigraphic well, as well as structural dip, expected ambient flow conditions, and potential for heterogeneities or horizontal/vertical anisotropy within the injection zone and model predictions.

The planned monitoring well network for direct plume and pressure-front monitoring consists of two sets of monitoring wells: single-level in-reservoir (SLR) wells and reservoir access tube (RAT) wells (Figure

A.3). Two SLR wells will monitor the injection zone beyond the east and west ends of the horizontal CO_2-injection laterals. One of the SLR wells (SLR2; reconfigured stratigraphic well) will be located to the east-northeast of the injection well pad between the projected 10- to 20-year plume boundaries and the other well (SLR1) will be located to the west of the injection well pad within the projected 2-year plume boundary. An additional SLR well will be constructed within 5 years from the start of injection. The location will be informed by any observed asymmetry in pressure front development and will be located outside the CO2 plume extent. The distance from the plume boundary will be based on the monitoring objective of providing information that will be useful for both leakage detection and model calibration within the early years of operation. It is estimated that the well will be located less than 5 miles from the projected plume extent in order to provide an intermediate-field pressure monitoring capability that would benefit leak detection capabilities and meet the EPA requirement for pressure monitoring outside the CO_2 plume.

Three RAT wells will be installed within the boundaries of the projected 1- to 3-year CO_2 plume. The RAT well locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume. The RATs will be completed with nonperforated, cemented casings and will be used to monitor CO_2 arrival and quantify saturation levels via downhole PNC (geophysical logging across the reservoir and confining zone).

The reservoir-monitoring network will address transport uncertainties by using an “adaptive” or “observational” approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring and updated modeling results). It is recognized that additional contingency wells may be required in out-years to monitor evolution of the CO_2 plume and fully account for the injected CO_2 mass.

Direct Pressure Monitoring

Continuous monitoring of P/T/SpC will be conducted in the SLR monitoring wells to track the pressure front and inform the monitoring and modeling programs.

Instruments will be installed at each SLR monitoring well to facilitate near-continuous monitoring of indicator parameters of CO_2 arrival and/or changes in brine composition. (Tables A.3 and A.8 list the parameters and instrumentation that will be used in the SLR wells.)

Fluid P/T/SpC are the most important parameters to be measured in real time within the monitoring interval of each well. These are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. In addition, pH and Eh (oxidation potential) measurements may be useful for detecting dissolved CO_2 and assessing water chemistry changes in the monitored interval. An initial evaluation of probes that are capable of measuring the desired parameters will assess the measurement accuracy, resolution, and stability for each parameter prior to selection and procurement of sensors for the full monitoring well network.

Pressure is expected to increase at the SLR monitoring wells installed within the injection reservoir soon after the start of injection and before the arrival of CO_2 because of the pressurization of the reservoir. Pressure will also be monitored to ensure that pressure within the injection interval does not exceed design specifications and to determine whether any observed pressure changes above the primary confining zone could be associated with a leakage response. Changes in other parameters are expected to occur later in time than the initial increase of pressure.

Direct Geochemical Plume Monitoring

Fluid samples will be collected from the SLR monitoring wells before, during, and after CO_2 injection. The samples will be analyzed for chemical parameter changes that are indicators of the presence of CO_2 and/or reactions caused by the presence of CO_2. Baseline monitoring will involve collection and analysis of a minimum of three rounds of aqueous samples from each well completed in the targeted injection zone prior to initiation of CO_2 injection. A comprehensive suite of geochemical and isotopic analyses will be performed on fluid samples collected from the reservoir. These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Aqueous sampling will not be used to assess CO_2 saturation levels. Once $scCO_2$ arrives, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

B.7.2 Sampling Methods

Direct Pressure Monitoring

A single probe incorporating electronic sensors that will monitor indicator parameters (P/T/SpC) will be placed at reservoir depth in each monitored well. Each parameter will be measured at a 10-minute sampling interval and will be transmitted to the surface via the wireline cable. Additional sensors may be installed at the wellhead for measuring parameters such as wellhead pressure, barometric pressure, and ambient surface temperature. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

Direct Geochemical Plume Monitoring

Fluid samples will be collected at monitored formation depths and maintained at formation pressures within a closed pressurized sample container to prevent the escape of dissolved gases. Access to the monitored interval at the SLR wells will be through an inner 2-7/8-in. tubing string extending to the monitoring interval and packed-off just above the screen.

Fluid samples will be collected within the open interval of each monitoring well using a flow-through sampler with a 950-cc (or larger) sample chamber. The samples will be maintained at formation pressure within a closed sample container to prevent the escape of dissolved gases. Prior to sampling, the P/T/SpC probe will be monitored as the well is purged (up to three times the volume of the well-screen section will be discharged from the well before collecting the sample). The probe will then be removed from the well and the sampler will be run into the borehole on the same wireline cable to collect the pressurized fluid sample. Additional purging may be conducted just prior to collection of the pressurized fluid sample if mixing between the fluid column and sampling interval during insertion of the sampler is a concern.

B.7.3 Sample Handling and Custody

Direct Pressure Monitoring

P/T/SpC measurements will be recorded by a data logger at each well site and also transmitted to data-acquisition systems located in the MVA data center.

Electronic data and field records will be transferred to laptop and/or desktop computers and/or backed-up on secured servers at least quarterly, as well as scanned copies of all pertinent hardcopy field records/notes.

Direct Geochemical Plume Monitoring

After removing the aqueous sampler from the well, the closed and pressurized sample container(s) will be transported to the MVA laboratory space in the control building for processing using standard chain-of-custody procedures.

B.7.4 Analytical Methods

Table A.7 summarizes the analytical methods for groundwater quality monitoring in the SLR wells. Where possible, methods are based on standard protocols from the EPA or Standard Methods for the Examination of Water and Wastewater (American Public Health Association, American Water Works Association, Water Environment Federation, 19th ed. or later, Washington, D.C.). Laboratories shall be required to have standard operating procedures for the analytical methods performed.

B.7.5 Quality Control

Direct P/T/SpC and other continuous monitoring equipment will be calibrated according to manufacturers' recommendations. If trends or other unexplained variability in the data are observed that might indicate a suspect response, instruments will be evaluated and, if required, recalibrated, or replaced.

The QC practices for groundwater monitoring of the geochemical plume are the same as those specified for groundwater monitoring above the confining zone (Section B.4.5). Field QC samples include field blanks and field duplicates; a minimum of one of each type of sample shall be collected at each sampling event. Laboratory QC samples include method blanks, laboratory duplicates, matrix spikes, matrix spike duplicates, and laboratory control samples. The frequencies of these samples will be determined by the laboratory contract and standard method protocols. Typically, method blanks and laboratory control samples are analyzed with every analytical batch, while the remaining QC samples are run at a frequency of 1 per 10 samples. Table A.8 lists additional, method-specific requirements.

B.7.6 Instrument/Equipment Testing, Inspection, and Maintenance

High-quality (high-accuracy, high-resolution) gauges with low drift characteristics will be used.

- Gauge components (gauge, cable head, cable) will be manufactured of materials designed to provide a long life expectancy for the anticipated downhole conditions.
- Upon acquisition, a calibration certificate will be obtained for every pressure gauge. The calibration certificate will provide the manufacturer's specifications for range, accuracy (% full scale), resolution (% full scale), and drift (< psi per year), and calibration results for each parameter. The calibration certificate will also provide the date that the gauge was calibrated, the methods and standards used, and the date calibration will expire.
- Gauges will be installed above any packers so they can be removed if necessary for recalibration by removing the tubing string. Redundant gauges may be run on the same cable to provide confirmation of downhole pressure and temperature.
- Upon installation, all gauges will be tested to verify that they are functioning (reading/transmitting) correctly.

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

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program. The laboratory's QA program will be reviewed by the Alliance prior to submission of samples for analysis.

B.7.7 Instrument/Equipment Calibration and Frequency

Pressure gauges that are used for direct pressure monitoring will be calibrated according to manufacturers' recommendations, and current calibration certificates will be kept on file with the monitoring data.

B.8 Pulsed-Neutron Capture Logging

PNC wireline logs will be used to quantify CO_2 saturation relative to depth in each of three monitoring RAT wells. These indirect measurements of CO_2 saturation will be used to detect and quantify CO_2 levels over the entire logged interval. The PNC logging data will be used for calibration of reservoir models and to identify any unforeseen occurrences of CO_2 leakage across the primary confining zone. Numerical modeling will be used to predict the CO_2 plume growth and migration over time by integrating the calculated CO_2 saturations in the three RAT wells with the geologic model and other monitoring data.

B.8.1 Sampling Process Design (Experimental Design)

PNC logs operate by generating a pulse of high-energy neutrons and subsequently measuring the neutron decay over time and across a wide energy spectrum. PNC logs can measure specific energy bins or a composite of energies, the latter of which is termed the thermal capture cross-section (sigma) operational mode. In sigma mode, all elements that capture and slow neutrons contribute to the measurement rather than just the characteristic energy levels associated with specific elements. Both measurement modes are useful for determining CO_2 saturation from PNC logs and will be simultaneously acquired.

PNC logging has been successfully implemented at a number carbon sequestration sites and while the PNC method has been shown to work quite well, problems associated with CO_2 flooding the casing and perforation zones have been identified. PNC logs are only sensitive to a localized region surrounding the borehole (15−30 cm) and are therefore susceptible to interference from features very near the borehole, such as changing borehole fluids, poor cement, or invaded drilling fluids. The monitoring RAT wells are designed with small-diameter, nonperforated casings to minimize near-borehole interference effects. Borehole effects will also be accounted for by analyzing response times from multiple detectors in the tool. Porosities within the reservoir at the FutureGen 2.0 storage site are moderate and the PNC logs are expected to adequately quantify CO_2 saturation along the RAT boreholes in order to calibrate reservoir models as well as identify possible leakage through the sealing layers.

B.8.2 Sampling Methods

Quarterly PNC logging will be conducted in RAT wells 1, 2, and 3. The locations of the RAT wells was chosen to sample various stages of the CO_2 plume migration, with the emphasis on the areas with large expected changes in the first five (5) years. Downhole repeatability of the tool performance will be verified by conducting a "repeat section" of the logging run. Repeatability is used to validate the measurement acquired during the main logging pass, as well as to identify anomalies that may arise during the survey for re-logging. Measurement depth is of critical importance in all borehole logs. Depth will be measured with respect to a fixed reference throughout the lifetime of the project. Verification of proper tool operation will be performed prior to each logging event following the manufacturer's recommended procedure. Elastic cable stretch and slippage will be automatically compensated. Repeatability of logging depths will also be checked by repeat gamma-ray depth location of key strata or drill collar locators and can be used to correct depth measurements after logging is complete.

B.8.3 Sample Handling and Custody

No specialized sample-/data-handling procedures are required. PNC tool readings will be recorded on a computer located in the wireline logging truck. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up, on secure servers at the conclusion of each logging event, as will scanned copies of all pertinent hardcopy field records/notes.

B.8.4 Analytical Methods

PNC log data will be processed following industry best practices and coordinated with the borehole-logging operator to optimize data-collection parameters. Modeling can be done to simulate near-borehole interferences and remove their effects from the signal. Modeling is a recommended procedure and requires knowledge of the target formations and fluids that must be obtained from cores and additional logging data. Each logging result will be compared for each RAT well to the baseline or previous survey, as applicable, to determine changes in saturation.

B.8.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and that calculations of CO_2 saturations are reproducible. Third-party PNC logging and processing for a subset of boreholes and logging events can be used as part of the validation procedure. Failure of tool performance in the field or unreproducible "repeat sections" will result in non-acceptance of the data and may trigger a return of the PNC tool to the manufacturer for recalibration or replacement. Off-normal CO_2 saturation calculations will trigger additional evaluation and possible new logging runs.

B.8.6 Instrument/Equipment Testing, Inspection, and Maintenance

Examples of industry-published guidelines for calibration and field operation of the PNC wireline log hardware and data-collection software are provided in Appendix B.

B.8.7 Instrument/Equipment Calibration and Frequency

To ensure data-acquisition quality, the logging tool will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All tools and field operation software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, PNC tool recalibration will be performed monthly and both prior to and after each logging event using an onsite calibration vessel following the manufacturer's guidelines. Examples of industry-published guidelines for calibration and field operation of the PNC wireline log hardware and data-collection software are provided in Appendix B.

B.9 Integrated Deformation Monitoring

B.9.1 Sampling Process Design (Experimental Design)

The deformation monitoring will include orbital DInSAR data (X-band TerraSAR-X, C-band Radarsat-2, X-Band Cosmo-Skymed, or any other satellite data that will be available at the time of data collection) and a field survey validation using permanent Global Positioning System (GPS) stations, permanent tiltmeters, and annual Differential Global Positioning System (DGPS) surveys. This approach will be used for the baseline before the injection and during the injection phase with modifications based on the experience gained during the two-year baseline-monitoring period.

Differential Synthetic Aperture Radar (SAR) Interferometry (DInSAR) is a method of generating surface displacement maps from two images acquired by radar aboard a satellite at distinct times. Specific and complex processing is applied to obtain time series of displacements of the ground surface. All DInSAR deformation measurements are corrupted by spatiotemporal variations in the atmosphere and surface scattering properties. Advanced DInSAR time-series analyses exploit a subset of pixels in a stack of many SAR images to reduce atmospheric artifacts and decorrelation effects. These pixels exhibit high phase stability through time. The output products from these advanced techniques include a pixel average velocity accurate to 1−2 mm/yr and a pixel time series showing cumulative deformation accurate to 5−10 mm for each of the SAR acquisition times. It should be noted that accuracy improves with time as the time series becomes larger.

B.9.2 Sampling Methods

Orbital SAR data will be systematically acquired and processed over the storage site with at least one scene per month to obtain an advanced DInSAR time series. These data will be obtained from the available orbital instruments available at the time of collection. It should be noted that the existing TerraSAR-X, Radarsat-2 and Cosmo-Skymed systems provide frequent systematic revisits of 11, 24, and 4 days, respectively.

Widespread overall temporal decorrelation is anticipated except in developed areas (e.g., roads, infrastructure at the site, and the neighboring towns) and for the six corner cube reflectors that will be deployed on site. These isolated coherent pixels will be exploited to measure deformation over time, and different algorithms (e.g., persistent scatters, small baseline subsets, etc.) will be used to determine the best approach for the site.

Data from five permanent tiltmeters and GPS stations will be collected continuously. In addition, annual geodetic surveys will be conducted using the Real-Time Kinematic (RTK) technique where a single reference station gives the real-time corrections, providing centimeter-level or better accuracy. Deformations will be measured at permanent locations chosen to measure the extent of the predicted deformation in the AoR and also used by the gravity surveys (see Section B.10).

B.9.3 Sample Handling and Custody

DInSAR data will be acquired, processed, and archived by the vendor. Displacement maps and deformation time series will be archived on digital media by the Alliance.

Permanent GPS and tiltmeter data will be collected in real time by the Alliance and stored on digital media on site. Differential GPS (DGPS) survey data will be archived on digital media by the Alliance.

B.9.4 Analytical Methods

To establish a more comprehensive geophysical and geomechanical understanding of the FutureGen 2.0 site, DInSAR and field deformation measurements will be integrated and processed with other monitoring data collected at the site: microseismicity, gravity, pressure, and temperature. This unique and complete geophysical data set will then be inverted to constrain the CO_2 plume shape, extension, and migration in the subsurface.

B.9.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and results reproducible.

B.9.6 Instrument/Equipment Testing, Inspection, and Maintenance

Testing of the whole DInSAR chain acquisition is routinely conducted by the space agencies.

Permanent tiltmeters and GPS instruments installed onsite will be checked annually.

The Trimble R8 receivers used for the annual DGPS surveys will be checked annually.

B.9.7 Instrument/Equipment Calibration and Frequency

Calibration of DInSAR chain acquisition is routinely conducted by the space agencies and the results will be compared to field measurements.

Tiltmeters and GPS instruments installed onsite will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. The Trimble R8 receivers used for the annual DGPS surveys will also be calibrated and verified by the manufacturer.

All equipment and software will be provided by the manufacturer with an auditable verification record to ensure traceability.

B.10 Time-Lapse Gravity Monitoring

B.10.1 Sampling Process Design (Experimental Design)

Four-dimensional (4D or time-lapse) microgravimetry—the temporal change of gravity at the microGal scale (1 μGal = 10^{-6} m/s^2)—is a cost-effective and relatively rapid means of observing changes in density distribution in the subsurface, particularly those caused by the migration of fluids.

Time-lapse gravity monitoring is accomplished using repetitive annual surveys at a series of points located at the ground surface (permanent stations). Changes in gravity anomaly with time are determined and then interpreted in terms of changes in subsurface densities. These changes could be linked for example to replacement of water by CO_2. providing an indirect method of tracing the displacement of the CO_2 plume at depth. Due to the non-uniqueness of the solution, this monitoring method could rarely be used alone and gives the best results when used with other methods (deformation or seismic).

B.10.2 Sampling Methods

Permanent station locations were established in November 2011 for the purpose of future reoccupation surveys (Figure A.4). These stations are located on the roadways inside the survey area, the reference being the KC0540 station (Central Plaza Park monument, Jacksonville, Illinois). The emplacement of each permanent station on the roadway is designated by a marker. Markers are approximately half-inch-diameter nails with a three-quarter-inch heads to provide good visibility from the surface.

Because all the gravity measurements are relative, a tie to a gravity station outside the surveyed area must be made. This reference is station NGS# KC0540, a monument located in Central Plaza Park in Jacksonville, Illinois, which was tied to the absolute gravity station NGS# KC0319 located in Hannibal, Missouri.

To compensate for the instrumental drift, measurements are taken on a 2-hour cycle at a local reference station at the center of the surveyed area (station 137) and at an offsite location (station KC0540) twice a day.

B.10.3 Sample Handling and Custody

Data will be archived on a digital media by the Alliance.

B.10.4 Analytical Methods

Data reduction will be performed using the standardized methods to obtain Free Air and Bouguer anomalies. These anomalies will then be interpreted in terms of subsurface density anomalies by gravity direct or inverse modeling using the commercial software ENcom Model Vision™ 12.0.

B.10.5 Quality Control

Repeat measurements at the same field point is the only way to evaluate their quality. At least three measurements for each point will be recorded.

B.10.6 Instrument/Equipment Testing, Inspection, and Maintenance

The gravity meter used will be a LaCoste & Romberg Model D belonging to Pacific Northwest National Laboratory. It is a steel mechanism, "zero length" spring meter with a worldwide range that is less prone to drift than quartz meters. The instrument is thermostatically controlled to approximately 50°C during the duration of the surveys. A full maintenance and inspection of the instrument needs to be completed every 10 years at the LaCoste and Romberg factory; the next one is scheduled in 2021.

B.10.7 Instrument/Equipment Calibration and Frequency

No calibration of the instrument is required.

B.11 Microseismic Monitoring

Elevated pressures in the reservoir due to injection of CO_2 have the potential to induce seismic events. The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of seismic events.

B.11.1 Sampling Process Design (Experimental Design)

A microseismic monitoring system must be able to detect a seismic event at a number of monitoring stations and use the signals to accurately determine the event location and understand the brittle failure mechanisms responsible for the event. The monitoring network consists of an array of seismic sensors placed either at the near-surface or within deeper monitoring boreholes. The accuracy of the network is dependent on both the geometry of the sensor array and the signal-to-noise ratio (SNR) at each of the sensor locations. The number and spatial distribution of sensors in a microseismic monitoring network must be designed to minimize the errors in estimating event location and origin times. The subsurface seismic velocity model also has a large influence on the predicted data and must be estimated as accurately as possible using borehole logs and data from vertical seismic profiling. Sensors need to have high sensitivity, flat response over the intended frequency range, a low noise floor, and stable performance over time.

External noise sources often occur at the surface or from nearby subsurface activities such as drilling. Surface noise attenuates with distance below the surface and it is therefore advantageous to emplace surface sensors within shallow boreholes in order to reduce external noise to an acceptable level. Surface or shallow borehole sensors provide multiple sensing azimuths and offsets, but surface sensors typically suffer from lower SNRs. Shallow borehole installations, however, can achieve a noise floor approaching that of sensors located in deep boreholes. Deep borehole monitoring can provide a higher SNR if the microseismic event occurs close enough to the array, but precise event location can be difficult due to geometric constraints on the array.

B.11.2 Sampling Methods

The microseismic network will consist of an array of near-surface shallow borehole sensors in addition two deep borehole sensor arrays installed within the ACZ wells. The network incorporates the benefits of both array types to improve the overall performance of the system and is expected to perform well for monitoring seismic events that occur in the AoR.

Commonly used sensors for seismic applications include moving coil geophones that that have frequency bandwidths from 5−400 Hz. These devices are often built with signal conditioning and digitizer circuitry located on the sensor to improve the electrical performance; however, because of the complexity of their assembly, their long-term deployment in a deep borehole environment results in reduced lifetimes. Permanent emplacement of standard moving coil geophones within a deep borehole would not be expected to last the lifetime of the FutureGen 2.0 project. Geophones will be placed in the shallow borehole stations and are expected to perform well in that environment, particularly for higher-frequency signals.

Surface sensors also require higher sensitivities and lower noise floors than sensors placed in deep boreholes because the distance from the event to the surface is often much greater. High-quality broadband seismometers exhibit much higher sensitivity and extremely low noise floors compared to standard geophones. These seismometers have long working lifetimes and an excellent frequency response from 1 mHz to 200Hz. Seismometers will also be installed in each shallow borehole along with a borehole geophone. To minimize signal attenuation and site noise, the boreholes will be drilled to at least the uppermost bedrock unit, and the casing will be sealed and pumped dry prior to sensor emplacement.

Fiber-optic-based seismic sensors use backscattered light from a laser pulse that has been introduced into an optical fiber to measure the movement of a sensing element. The fiber can be coupled to a device to mechanically amplify the strain on the fiber and produce a sensor with performance as good as, or better than, standard geophones. A key feature of these sensors is that because they have no electronics located within a borehole they are extremely robust; their lifetimes and performance stability are designed to last several decades. Due to their superior sensitivity and expected longevity, an array of fiber-optic accelerometers will be installed within two, deep ACZ wells. Optical cables will be extended from each of the wells back to a central control building that will house the data-acquisition and storage systems.

B.11.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Microseismic signals from the shallow boreholes will be continuously recorded on a data logger located at each of the stations. All electronic data will be continuously transferred to a data storage and processing system located at a central control building. Digital copies of all pertinent hardcopy field records/notes will also be transferred to the central data server.

B.11.4 Analytical Methods

Microseismic data will be processed and stored following industry best practices.

B.11.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and that determinations of event locations and focal mechanisms are accurate.

B.11.6 Instrument/Equipment Testing, Inspection, and Maintenance

Regular maintenance and testing of the seismic hardware and data-collection software are critical to ensuring high-quality results. All hardware will be maintained in accordance with manufacturer recommendations. Software updates will be incorporated as they are released by the manufacturer.

B.11.7 Instrument/Equipment Calibration and Frequency

All microseismic equipment will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All equipment and software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, seismometers and geophones will be periodically recalibrated following the manufacturers' guidelines. In the event that damage is identified, it will be immediately reported and the equipment removed and replaced.

B.12 Inspection/Acceptance of Supplies and Consumables

Testing and monitoring supplies and consumables that may affect the quality of the results will be procured, inspected, and accepted in accordance with the Alliance representative's administrative procedures (e.g., Pacific Northwest National Laboratory's HDI Workflows and Work Controls).

Critical items and responsible personnel will be identified in task-specific sampling and analysis plans, as appropriate.

B.13 Non-direct Measurements (e.g., existing data)

Existing data, including literature files and historic data from surrounding areas and previous onsite characterization, testing, and monitoring activities, have been used to guide the design of the testing and monitoring program. However, these data are only ancillary to the well testing and monitoring program described here. These existing data will be used primarily for qualitative comparison to newly collected data.

All data will continue to be evaluated for their acceptability to meet project needs, that is, that the results, interpretation, and reports provide reasonable assurance that the project is operating as permitted and is not endangering any USDWs.

B.14 Data Management

All project data, record keeping, and reporting will be conducted to meet the requirements of 40 CFR 146.91(f).

B.14.1 Data Management Process

Project data will be managed in accordance with the Project Data Management Plan (Bryce et al. 2013). Management of all monitoring data is controlled by the subtier Monitoring Data Management Plan (Vermeul et al. 2014; not publicly available). Management of well MIT data is controlled by the subtier Well Construction Data Management Plan (Lanigan et al. 2013; not publicly available). All data will be managed by Alliance representatives throughout the duration of the project plus at least 10 years.

B.14.2 Recordkeeping Procedures

Project records will be managed according to project record management requirements and Alliance representatives' internal records management procedures.

B.14.3 Data Handling Equipment and Procedures

All data will be managed in a centralized electronic data management system. The underlying electronic servers will be routinely maintained, updated, and backed-up to ensure the long-term preservation of the data and records.

The centralized data-management system acts as a "data hub" to support collaborative analyses, enabling a diverse spectrum of experts—including geologists, hydrologists, numerical modelers, model developers, and others—to share data, tools, expertise, and computational models. This data-management system also acts as a "turn-key" data-management system that can be transferred to any future Alliance representatives or storage site operators.

B.14.4 Configuration Management and Change Control

The project's Configuration Management Plan (Alliance 2013b) identifies configuration-management requirements and establishes the methodology for configuration identification and control of releases and changes to configuration items. Each Alliance contractor is required to use configuration management to establish document control and to implement, account for, and record changes to various components of the project under its responsibility. The project's data configuration process is detailed in the Project Data Management Plan (Bryce et al. 2013) and its subsequent subtier data management plans. This data configuration process controls how changes are made should errors or loss of data be detected during the course of routine data quality and readiness review checks and/or peer reviews.

QC mechanisms, checklists, forms, etc. used to detect errors are highly data-specific, but generally rely on spot-checks against field and laboratory records, as well as manual calculations to validate electronic manipulation of the data.

C. Assessment and Oversight

C.1 Assessments and Response Actions

As described in Section A.6 and detailed in Table A.2, the Monitoring, Verification, and Accounting (MVA) program for the FutureGen 2.0 CO_2 Pipeline and Storage Project includes numerous categories, methods, and frequencies of monitoring the performance of the CO_2 storage site. FutureGen staff responsible for the associated technical element or discipline will analyze the monitoring data and initiate any needed responses or corrective actions. Management will have ready access to performance data and will receive monitoring and performance reports on a regular basis.

In addition to the activities covered by the MVA program, data quality assessments will be performed to evaluate the state of configuration-controlled technical information in the FutureGen technical data repository to ensure that the appropriate data, analyses, and supporting information are collected, maintained, and protected from damage, deterioration, harm, or loss. These data quality assessments will be performed by a team consisting of the FutureGen 2.0 Data Manager, Project Quality Engineer, Subject Matter Experts, and additional knowledgeable and trained staff as appropriate for the scope and nature of the assessment. Assessments will be scheduled to occur at logical points in the project lifecycle, such as after completion and submission of a major deliverable that incorporates controlled technical information. Assessment results will be reported to management; deficiencies, weaknesses, opportunities for improvement, and noteworthy practices will be identified in the assessment reports. Assessment results will also be communicated to affected parties. Management will assign responsible staff to correct deficiencies and other nonconforming conditions and will ensure that corrective actions are implemented and verified in a timely manner. The Project Quality Engineer and FutureGen Data Manager will conduct follow-up surveillances to verify and document completion of corrective actions and to evaluate effectiveness.

C.2 Reports to Management

Management will be informed of the project status via the regular monitoring and performance reports generated by the MVA program, as well as reports of assessments conducted to verify data quality and surveillances performed to verify completed corrective actions. These reports are described in Section C.1; additional periodic reporting is not anticipated at this time. However, as directed by FutureGen management, targeted assessments by the Data Manager, Project Quality Engineer, or others will be conducted and reported to apprise management of project performance in areas of particular interest or concern.

D. Data Validation and Usability

D.1 Data Review, Verification, and Validation

The FutureGen 2.0 CO_2 Pipeline and Storage Support Project has established a Project Data Management Plan (PDMP) (Bryce et al. 2013) to identify how information and data collected or generated for the project will be stored, organized, and accessed to support all phases of the project. The PDMP describes the institutional responsibilities and requirements for managing all relevant data, including the intended uses and level of quality assurance needed for the data, the types of data to be acquired, and how the data will be managed and made available to prospective users. In addition to the PDMP, the FutureGen 2.0 project has issued discipline-specific subtier Technical Data Management Plans (TDMPs) to tailor data management processes to the needs of specific technical elements (e.g., computational modeling, geophysical, monitoring, site characterization). The PDMP and each TDMP define several categories of data, or Data Levels (consistent among all of the Data Management Plans), with corresponding data management, review, verification, validation, and configuration control requirements. The PDMP and TDMPs establish roles (e.g., Data Manager, Data Steward, Data Reviewer, Subject Matter Expert) and responsibilities for key participants in the data management process; project management assigns appropriate staff members to each role. Project staff who generate, review, verify, validate, or manage data are trained to the requirements of one or more Data Management Plans. Raw data (resulting from the use of a procedure or technology), defined as Level 1, are put under configuration control in the data management system at the time of upload to the system. Data defined at other Data Levels are put under configuration control when the data become reportable or decision-affecting. The procedures used to verify, validate, process, transform, interpret, and report data at each Data Level are documented and captured as part of the data management process.

D.2 Verification and Validation Methods

The Data Management Plans described in Section D.1 require that data packages undergo rigorous peer reviews. These reviews both *validate* the data—confirm that the appropriate types of data were collected using appropriate instruments and methods—and *verify* that the collected data are reasonable, were processed and analyzed correctly, and are free of errors. Data that have not undergone the peer-review process and are not yet under configuration control can be provided as preliminary information when accompanied by a disclaimer that clearly states that data are 1) preliminary and have not been reviewed in accordance with FutureGen's quality assurance practices, 2) considered "For Information Only", and 3) not to be used for reporting purposes nor as the basis for project management decisions. Once data are placed under configuration control, any changes must be approved using robust configuration-management processes described in the Data Management Plans. The peer-review and configuration-management processes include methods for tracking chain-of-custody for data, ensuring that custody is managed and control is maintained throughout the life of the project.

If issues are identified during a peer review, they are addressed and corrected by the data owner and peer reviewer (involving others, as necessary) as part of the peer-review process. These unreviewed data will not have been used in any formal work product nor as the basis for project management decisions, so the impacts of data errors will be minimal. If an error is identified in data under configuration control, in addition to correcting the error, affected work products and management decisions will be identified, affected users will be notified, and corrective actions will be coordinated to ensure that the extent of the error's impact is fully addressed.

D.3 Reconciliation with User Requirements

During the course of a long-duration project such as the FutureGen 2.0 CO_2 Pipeline and Storage Project, personnel changes over time can result in loss of institutional memory about the organization's data, thereby reducing the value of the data. New project staff may have little understanding of the content, intended uses, and pedigree of existing data sets. Metadata can help protect the organization's investment in data by providing context and pedigree, as well as describing interrelationships between various data sets. The Data Management Plans described in Section D.1 provide for Subject Matter Experts (SMEs) to establish and document metadata requirements for the data sets created by the FutureGen 2.0 project. Complete metadata will support data interpretation, provide confidence in the data, and encourage appropriate use of the data. To establish meaningful metadata requirements, SMEs must understand how data users and decision-makers will use the data. By adhering to metadata requirements when loading data into the project data repository, project staff ensure that user requirements addressed by the metadata are satisfied.

Data reviews, identification and resolution of data issues, and limitations on data use are discussed in Section D.2.

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40 CFR 146. Code of Federal Regulation, Title 40, Protection of Environment, Part 146, Underground Injection Control Program: Criteria and Standards.

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Appendix A

Quality Assurance for Logging and Vendor Processing of Pulsed-Neutron Capture (PNC) Logs

This appendix contains wireline logging, indirect geophysical methods, and some non-routine sampling data processing and analysis industry standards.

Example of Vendor QA for Pulsed-Neutron Capture Logging: Schlumberger registered brand name RST

Reference: Schlumberger Wireline Log Quality Reference Manual accessed January 2014 http://www.slb.com/resources/publications/books/lqcrm.aspx.

The sigma mode of PNC logs will also be used both for monitoring carbon dioxide transport and for mechanical integrity tests.

Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed†	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation‡	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

† See Tool Planner application for advice on logging speed.
‡ Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2 1/4 in [5.72 cm]	2 7/8 in [7.30 cm]
Borehole size—max.	9 5/8 in [24.45 cm] With flask: 9 5/8 in [24.45 cm]	9 5/8 in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

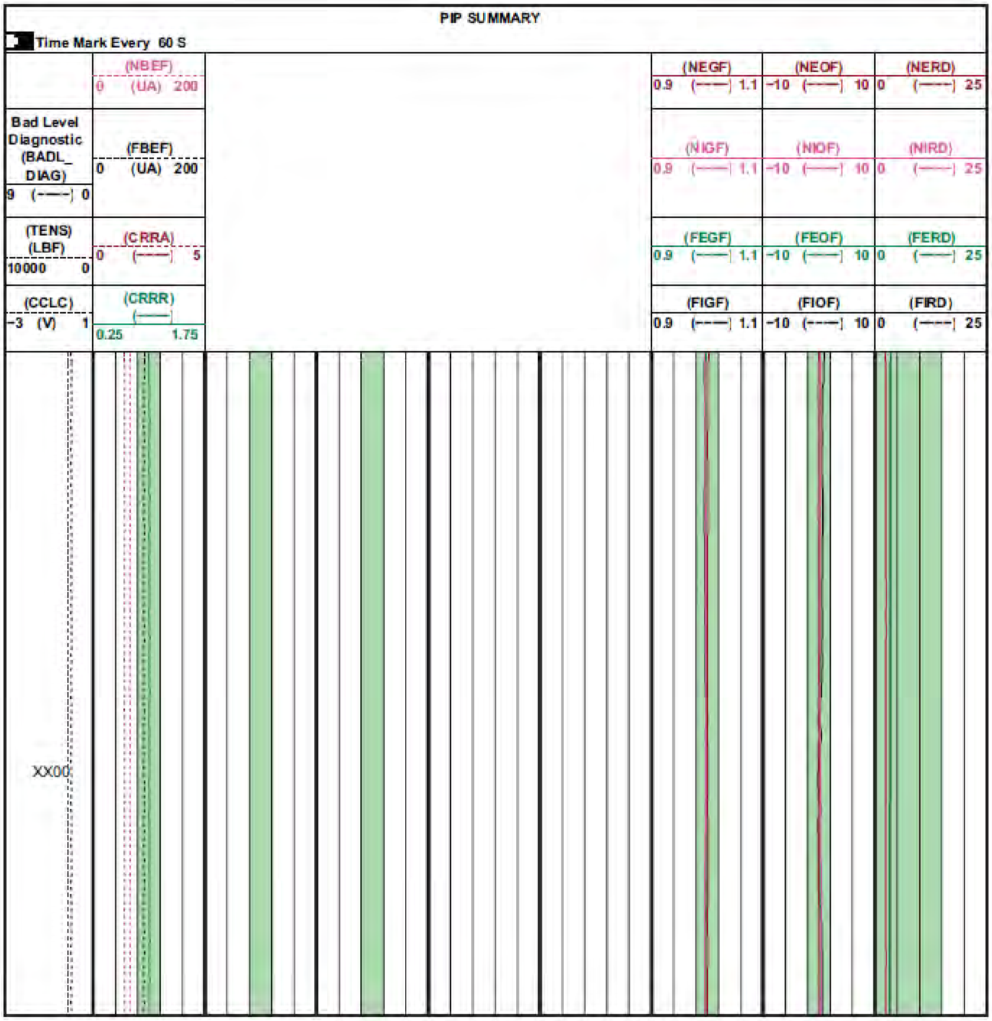


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

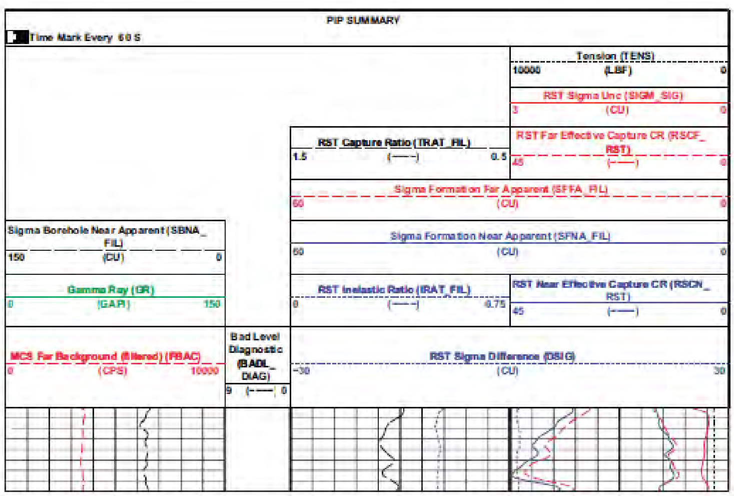


Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Quality Control in Processing Pulsed-Neutron Capture Logs

The following is an example from one vendor.

Reference: Albertin, I. et al., 1996, Many Facets of Pulsed Neutron Cased Hole Logging: Schlumberger Oilfield Review Summer 1996. Available at:
http://www.slb.com/~/media/Files/resources/oilfield_review/ors96/sum96/06962841.pdf

Additional information about the PNC tool is available at:
http://www.slb.com/~/media/PremiumContent/evaluation/petrophysics/porosity/rst_client_book.pdf

The Schlumberger Environmental Effects Calibration Facility, Houston, Texas, USA. Over 4000 measurements were made in more than thirty formations of differing lithology and porosity, with different combinations of formation salinities, borehole salinities, and completions to produce the sigma data base.

EUROPA facility, Aberdeen, Scotland.

Diffusion, borehole and lithology effects must be considered when transforming raw pulsed neutron capture measurements to actual physical quantities. These effects are difficult to account for in direct analytical approaches across the entire range of oilfield conditions. Therefore, an extensive data base of laboratory measurements is used to correct for these effects in real time.[1]

Over several years, the data base was acquired for the RST-A, RST-B and TDT-P logging tools at the Schlumberger Environmental Effects Calibration Facility (EECF), Houston, Texas *(above and right)*. This enables raw tool measurements to be referenced to calibrated values of formation sigma, borehole salinity and formation porosity for a variety of environmental conditions. Each tool was run in over 30 formations of different lithologies and porosities. Formation and borehole fluid salinities were varied and different completions were introduced into the borehole representing different casing sizes and cement thicknesses.

Altogether more than 1000 formation-borehole combinations were measured for each tool. Modeling was used to extend the range of available sandstone formations. To date, the data base contains over 4000 points.

The sigma values of the database formations are calculated classically

$$\Sigma = (1-\Phi)\,\Sigma_{ma} + \Phi\, S_{fl}\Sigma_{fl}$$

where Φ is the formation porosity, Σ_{ma} is matrix sigma, S_{fl} is the formation fluid saturation and Σ_{fl} is fluid sigma.

Porosity of the EECF tank formations was determined by carefully measuring all weights and volumes of the rocks, fluids and tanks used. CNL Compensated Neutron Log measurements verified the porosity values and the homogeneity of the formations.

Matrix sigma values were determined by gross macroscopic cross-section measurements provided by commercial reactor facilities and by processing complete elemental analyses through Schlumberger Nuclear Parameter (SNUPAR) cross-section tables.[2]

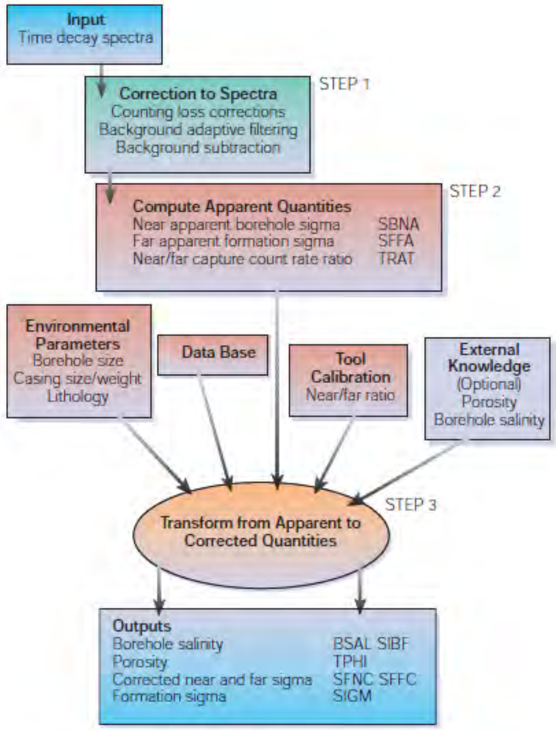
Water salinity was determined by a calibrated titration procedure and then converted into fluid sigma again using SNUPAR cross-section tables.

Algorithm—RST Sigma Processing

A three-step sequence is performed to translate raw log measurements into borehole salinity, porosity, corrected near and far sigma and formation sigma *(next page, top)*.

The first step is to correct the near and far detector time-decay spectra for losses in the detection and counting system, and for back-

1. Plasek RE et al, reference 3, main text.
2. McKeon DC and Scott HD: "SNUPAR—A Nuclear Parameter Code for Nuclear Geophysics Applications," *Nuclear Physics* 2, no. 4 (1988): 215-230.



□Simplified RST sigma processing.

ground radiation. Typically the background is averaged to improve statistics.

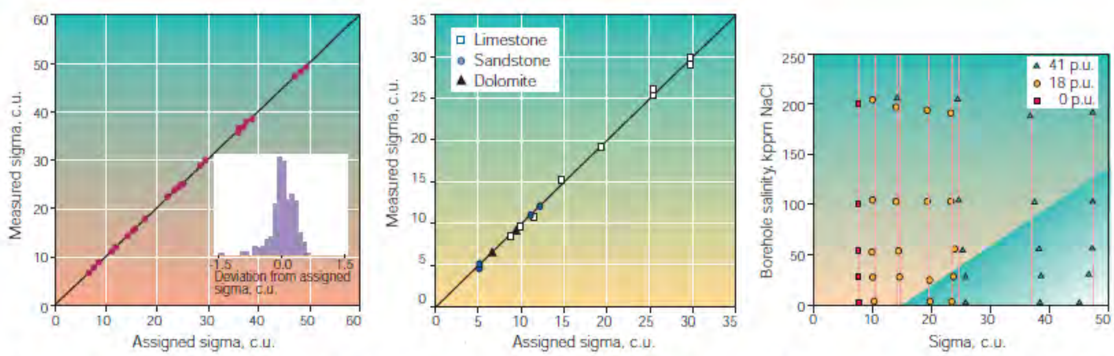
The next step is to generate the apparent quantities from the spectra, such as near and far apparent formation sigmas. These quantities are not environmentally corrected.

The third step is to apply transforms and environmental corrections to the apparent tool quantities to arrive at borehole salinity, porosity and formation sigma. The technique uses dynamic database parameterization that handles both the transformation and environmental corrections.

Accuracy

A series of benchmark measurements has been made to assess the accuracy of the algorithm used with the data base to compute borehole salinity, porosity and formation sigma *(below)*. These benchmark measurements include reprocessing the entire data base as well as logging in industry standard facilities such as the EUROPA sigma facility in Aberdeen, Scotland *(previous page, top right)* and the API porosity test pit, at the University of Houston, in Texas.

Database points were reprocessed with the dynamic parameterization algorithm and the results were compared with the assigned values.



□Processing accuracy. Benchmark measurements were made to assess the accuracy of the algorithm in computing formation and borehole sigma, porosity and borehole salinity. Sigma measured with the RST-A tool versus assigned database sigma *(left)* shows average errors are small—0.22 c.u. Sigma measured at the EUROPA facility in Aberdeen *(middle)* again shows excellent agreement with the assigned values. Comparison of RST-A tool sigma *(right)* versus borehole salinity shows that corrected sigma is independent of borehole salinity—vital for time-lapse surveys or log-inject-log operations. In the crossover region *(shaded area)*, formation sigma approaches or even exceeds borehole sigma. Historically, pulsed neutron capture tools erroneously identify the borehole decay as formation sigma and formation decay as borehole sigma in this region. However, the RST dynamic parameterization method solves this long-standing problem, correctly distinguishing between formation and borehole sigma components.

The algorithm does exceptionally well in matching the assigned values. For example, the average errors for formation sigma were 0.22 capture units (c.u.) for the RST-A tool and 0.20 c.u. for the RST-B tool.

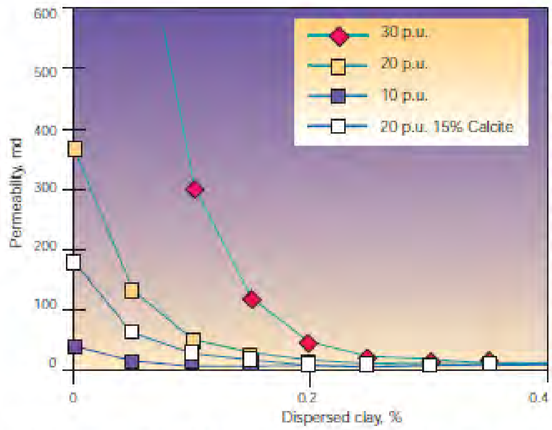
The EUROPA facility is an independent sigma calibration facility partially funded by the UK Atomic Energy Authority with major support from a consortium of 15 oil companies and government agencies. The RST-A tool was run in all the openhole formations and several cased-hole formations. A smaller number of measurements were made with the RST-B tool. Both tools read the true formation sigma over a wide range of lithologies, porosities, formation and borehole fluids, borehole sizes and completions. Even in the difficult crossover region, where formation sigma approaches or exceeds borehole sigma, the errors are small and the tool does not lock on to the wrong sigma component.

Both EUROPA and the University of Houston API pits were used to check porosity readings. The agreement between the two sets of porosities was excellent.

Precision

Key to time-lapse monitoring techniques is repeatability or precision. Time-lapse uses differences in measured quantities to monitor, for example, the progress of waterflooding, the expansion of gas caps and the depletion of reservoirs. The RST tool has been benchmarked to log nearly three times faster than previous generation tools for the same level of precision.[3]

3. For examples of repeatability—precision—see: Plasek et al, reference 3, main text.



Effect of clay and calcite on permeability. A small percentage of clay has a dramatic effect on permeability. Calcite also reduces permeability. So to determine a well's producibility or the cause of any formation damage, it is important to understand the mineralogy.

techniques, which by definition look at differences from one log to another over a period of several months. RST data can be gathered at logging speeds nearly three times those of previous-generation tools for the same precision.[4]

Lithology

Assessing reservoir deliverability and enhancing zone productivity rely on a thorough understanding of the rock matrix. For example, clay content dramatically affects permeability (*above*).[5] Elemental yields derived from RST spectroscopy measurements provide the input to determine clay and other mineral content and hence improve understanding of the rock matrix.

Elemental yields—Neutrons interact with the formation in several ways. Inelastic and capture interactions produce spontaneous release of gamma radiation at energy levels that depend on the elements involved. Measurement of the gamma ray spectra produced by these interactions can then be used to quantify the abundance of elements in the formation. Elemental yields are often used in various combinations or ratios to aid complex lithology interpretation, to determine shale volume or to augment incomplete openhole data (see "Making Full Use of RST Data in China," *page 36*).

At high neutron energies, inelastic interactions dominate. After a few collisions, neutron energy is reduced below the threshold for inelastic events. The probability of an inelastic interaction occurring is also reasonably constant for all major elements.

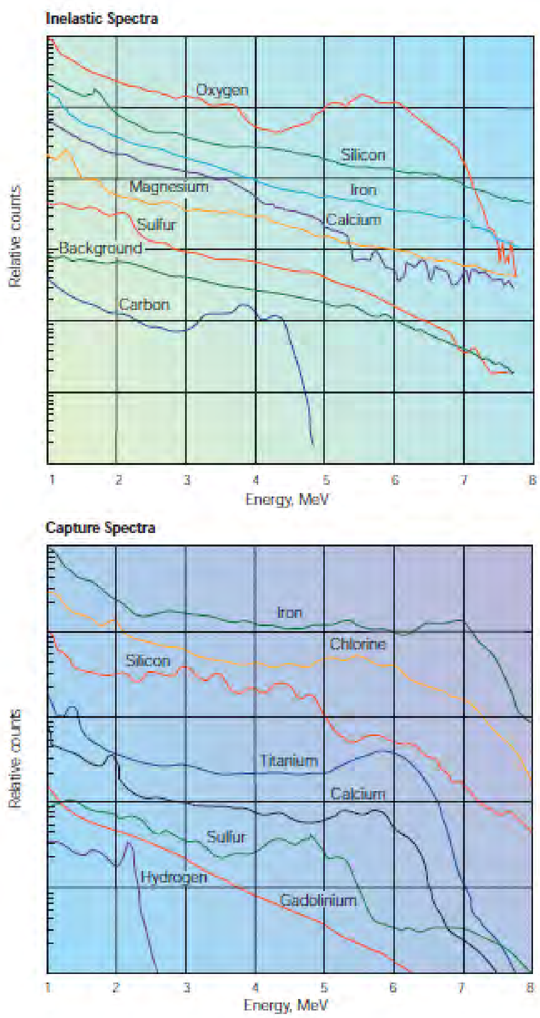
As neutrons slow to thermal energy levels, capture interactions dominate. Some elements are more likely to capture neutrons than others and so contribute more to the capture gamma ray spectrum.

Inelastic and capture gamma ray spectra are recorded by opening counting windows at the appropriate time after a neutron burst from the RST neutron generator. Tool design allows not only for much higher gamma ray count rates than previous generation tools, but also for gain stabilization that enables lower gamma ray energy levels to be recorded for both inelastic and capture measurements. A major advantage of this is the inclusion of the inelastic gamma ray peaks on the spectrum at 1.37 MeV for magnesium and at 1.24 MeV and 1.33 MeV for iron.[6]

A library of standard elemental spectra, measured in the laboratory for each type of tool, is used to determine individual elemental contributions (*next page*).

SpectroLith interpretation—SpectroLith processing is a quantitative mineral-based

4. For more details on time-lapse monitoring see sections on precision and auxiliary measurements: Plasek RE et al, reference 3.
5. Herron M: "Estimating the Intrinsic Permeability of Clastic Sediments from Geochemical Data," *Transactions of the SPWLA 28th Annual Logging Symposium*, London, England, June 29-July 2, 1987, paper HH.
6. Roscoe B, Grau J, Cao Minh C and Freeman D: "Non-Conventional Applications of Through-Tubing Carbon-Oxygen Logging Tools," *Transactions of the SPWLA 36th Annual Logging Symposium*, Paris, France, June 26-29, 1995, paper QQ.
7. Herron SL and Herron MM: "Quantitative Lithology: An Application for Open and Cased Hole Spectroscopy," *Transactions of the SPWLA 37th Annual Logging Symposium*, New Orleans, Louisiana, USA, June 16-19, 1996, paper E.
8. See Roscoe B et al, reference 6.



□*Elemental standards for the RST-A tool. Lower gamma ray energy levels are recorded by the RST tools than by previous generation pulsed neutron tools. This allows measurement of elemental contributions from elements such as magnesium and iron. Elemental yields are processed from standard spectra obtained using laboratory measurements. Shown are the standards for inelastic* (top) *and capture* (bottom) *spectra for the $1^{11}/_{16}$-in. RST-A tool.*

lithology interpretation derived from elemental yields. Traditional lithology interpretation relied on measurements of elements such as aluminum and potassium to determine clay content. Aluminum, especially, is difficult to measure and requires a combination of logging tools; the interpretation is also complex.

A recent detailed study of cores showed that a linear relationship exists between aluminum and total clay concentration. Of more importance, it also showed that silicon, calcium and iron can be used to produce an accurate estimation of clay without knowledge of the aluminum concentration.[7] The concentrations of these three elements can be obtained from RST spectroscopy measurements.

In addition, carbonate concentrations—defined as calcite plus dolomite—can be determined from the calcium concentration alone with the remainder of the formation being composed of quartz, feldspar and mica minerals.

SpectroLith interpretation involves three steps:

- production of elemental yields from gamma ray spectra
- transformation of yields into concentration logs
- conversion of concentration logs into fractions of clay, carbonate and framework minerals.

Borehole Fluid

The producing wellbore environment may include a combination of oil, water and gas phases in the borehole as well as flow behind casing. Borehole fluid interpretation is primarily based on fluid velocities and borehole holdup. The RST equipment makes these measurements using several independent methods, with enough redundancy to provide a quality control cross check:

- The WFL Water Flow Log measures water velocity and water flow rate using the principle of oxygen activation. This method detects water flowing inside and outside pipe, and in up and down flow.
- The Phase Velocity Log (PVL) measures oil and water velocities separately by injecting a marker fluid, which mixes and travels with the specified phase. This method may be applied to up and down flow, but only fluids in the pipe are marked and therefore detected.
- Two-phase—oil and water—borehole holdup may be measured in continuous logging mode with the RST-B tool.[8]
- Three-phase—oil, water and gas—borehole holdup is currently an RST-A station measurement based on a combination of C/O and inelastic count rate ratio data.
- Borehole salinity is one of the computations made as part of the sigma and porosity log and may be used to compute a borehole water holdup with either the RST-A or the RST-B tool.

(continued on page 39)

Appendix B

Quality Assurance for Wireline Logs Used in Mechanical Integrity Tests

This appendix contains examples of vendor quality assurance (QA) on the following tools:

- Ultrasonic Cement Evaluation tool: Example shown here is Schlumberger's Isolation Scanner (registered trademark)
- Cement Bond Log tool: Example shown is Schlumberger's Cement Bond Tool (CBT) registered trademark
- Cement Bond Logging QA
- Cased hole temperature log
- Cased hole gamma log
- NOTE: Pulsed-neutron capture (PNC) logs are covered in Appendix A

Reference: Schlumberger Wireline Log Quality Reference Manual accessed January 2014 at http://www.slb.com/resources/publications/books/lqcrm.aspx.

Schlumberger

Isolation Scanner

Overview

Isolation Scanner* cement evaluation service combines the classic pulse-echo technology of the USI* ultrasonic imager with a new ultrasonic technique—flexural wave imaging—to accurately evaluate any type of cement, from traditional slurries and heavy cements to lightweight cements.

In addition to confirming the effectiveness of a cement job for zonal isolation, Isolation Scanner service pinpoints any channels in the cement. The tool's azimuthal and radial coverage readily differentiates low-density solids from liquids to distinguish lightweight cements from contaminated cement and liquids. The service also provides detailed images of casing centralization and identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing.

Flexural wave imaging is used by Isolation Scanner service as a significant complement to pulse-echo acoustic impedance measurement. It relies on the pulsed excitation and propagation of a casing flexural mode, which leaks deep-penetrating acoustic bulk waves into the annulus. Attenuation of the first casing arrival, estimated at two receivers, is used to unambiguously determine the state of the material coupled to the casing as solid, liquid, or gas (SLG). Third-interface reflection echoes arising from the annulus/formation interface yield additional characterization of the cased hole environment:

- acoustic velocity (P or S) of the annulus material
- position of the casing within the borehole or a second casing string
- geometrical shape of the wellbore.

Because acoustic impedance and flexural attenuation are independent measurements, their combined analysis provides borehole fluid properties without requiring a separate fluid-property measurement.

Specifications

Measurement Specifications	
Output†	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Logging speed	Standard resolution: 2,700 ft/h [823 m/h] High resolution: 563 ft/h [172 m/h]
Range of measurement	Min. casing thickness: 0.15 in [0.38 cm] Max. casing thickness: 0.79 in [2.01 cm]
Vertical resolution	High resolution: 0.6 in [1.52 cm] High speed: 6 in [15.24 cm]
Accuracy	Acoustic impedance:‡ 0 to 10 Mrayl (range); 0.2 Mrayl (resolution); 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% (accuracy) Flexural attenuation:§ 0 to 2 dB/cm (range), 0.05 dB/cm (resolution), ±0.01 dB/cm (accuracy)
Depth of investigation	Casing and annulus up to 3 in [7.62 cm]
Mud type or weight limitations††	Conditions simulated before logging

† Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including a Variable Density* log of the annulus waveform and polar movies in AVI format.

‡ Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 Mrayl between the fluid behind the casing and a solid.

§ For 0.3-in [8-mm] casing thickness

†† Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.†	4½ in (min. pass-through restriction: 4 in [10.16 cm])
Casing size—max.†	9⅝ in
Outside diameter	IBCS-A: 3.375 in [8.57 cm] IBCS-B: 4.472 in [11.36] IBCS-C: 6.657 in [16.91 cm]
Length	Without sub: 19.73 ft [6.01 m] IBCS-A sub: 2.01 ft [0.61 m] IBCS-B sub: 1.98 ft [0.60 m] IBCS-C sub: 1.98 ft [0.60 m]
Weight	Without sub: 333 lbm [151 kg] IBCS-A sub: 16.75 lbm [7.59 kg] IBCS-B sub: 20.64 lbm [9.36 kg] IBCS-C sub: 23.66 lbm [10.73 kg]
Sub max. tension	2,250 lbf [10,000 N]
Sub max. compression	12,250 lbf [50,000 N]

† Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine)

Calibration

A master calibration of the near and far flexural transducers to identical sensitivities is required to avoid introducing a bias in the attenuation measurements. Within a pressurized sleeve filled with de-aired water, the tool is calibrated to an accurately machined stainless-steel target mounted relative to it to minimize any eccentering effects.

Tool quality control

Standard curves

Isolation Scanner standard curves are listed in Table 1.

Operation

The Isolation Scanner tool must be run centralized in the borehole. It is highly recommended to run the GPIT* general purpose inclinometry tool in combination for image orientation in a nonvertical well.

The Isolation Scanner tool planner must be run before the job with the following inputs: casing diameter, casing weight, logging fluid, and bit size. This is necessarily to obtain the transducer angle and job set-up parameters.

Table 1. Isolation Scanner Standard Curves

Output Mnemonic	Output Name	Output Mnemonic	Output Name
AGMA	Maximum allowed USI ultrasonic imager electronic programmable gain	THAV	Average thickness
AWAV	Average amplitude	THMN	Minimum thickness
AWBK	Amplitude of echo minus maximum	THMX	Maximum thickness
AWMN	Minimum amplitude	UFAI	USI fluid acoustic impedance (inverted)
AWMX	Maximum amplitude	UFDX	USI far maximum waveform delay
AZEC	Azimuth of eccentering	UFGA	USI far maximum allowed UPGA
CCLU	Casing collar locator from ultrasonic	UFGI	USI far minimum allowed UPGA
CFVL	Computed fluid velocity	UFGN	USI far minimum value of UPGA
CS	Cable speed	UFGX	USI far maximum value of UPGA
CZMD	Computed acoustic impedance of fluid	UFLG	USI processing flag
DFAI	USI discretized fluid acoustic impedance (inverted)	UFSL	USI fluid slowness (inverted)
ECCE	Eccentralization	UFWB	USI far window begin
ERAV	External radius average	UFWE	USI far window end
ERMN	Minimum external radius	UFZQ	USI inverted fluid acoustic impedance quality control
ERMX	Maximum external radius	UNDX	USI near window maximum delay
FSOD	Fluid slowness fitting casing outside diameter (parameter: 0 = off, 2 = use feedback on velocity and acoustic impedance, 5 = use feedback on velocity only, fixed or zoned impedance)	UNGA	USI near maximum allowed UPGA
GNMN	USI minimum value of programmable gain amplitude of waves (UPGA)	UNGI	USI near minimum allowed UPGA
GNMX	USI maximum value of UPGA	UNGN	USI near minimum value of UPGA
HPKF	USI histogram of far peaks	UNGX	USI near maximum value of UPGA
HPKN	USI histogram of near peaks	UNWB	USI near window begin
HRTF	USI histogram of far transit time	UNWE	USI near window end
HRTN	USI histogram of near transit time	UPGA	USI programmable gain amplitude of waves
HRTT	USI histogram of raw transit time	WDMA	USI waveform delay window end
IRAV	Internal radius average	WDMI	USI waveform delay window begin
IRMN	Internal radius minimum	WDMN	USI minimum waveform delay
IRMX	Internal radius maximum	WDMX	USI maximum waveform delay
RSAV	Motor resolution sub average velocity	WPKA	USI peak histogram

Formats

The format in Fig. 1 is used mainly for quality control of Isolation Scanner signals, enabling a quick view of the component USI, near, and far waveforms and arrival peak detection with histograms.

- Track 1
  - CS is the speed at which the cable is moving.
  - RSAV is the motor rotational velocity. It is important for confirming motor rotation during acquisition.
  - CCLU spikes in front of casing collars and is used for correlation.
- Track 2
  - The WPKA histogram is a distribution of the amplitude of the waveform measured by the USI transducer. The image scale and color represent the number of samples and their corresponding peak amplitude in binary bits.
- Track 3
  - GNMX and GNMN represent the minimum and maximum gains, respectively, of the amplifier responsible for image acquisition. The gain should be kept between 0 and 10 dB. If the gain is above 10 dB, the signal from the transducer is too small and the power should be increased by the engineer. If the gain is below 0 dB, the situation is reversed.
- Track 4
  - HRTT should be centered as shown in Fig. 2.
- Track 5
  - WDMN and WDMX should be close to each other. Depending on the sensor-to-casing standoff, the window in which the tool may locate the peak of the echo has to be set.
- Tracks 6 through 13
  - The log quality control concepts listed for Tracks 2 through 5 also apply in these tracks for the near and far transducers.

The purpose of the format in Fig. 3 is to check the quality of the fluid properties measurement (velocity and acoustic impedance) inversion.

- Track 1
  - ECCE decreases the signal-to-noise ratio of the ultrasonic measurements, resulting in the appearance of dark vertical bands on the amplitude map. ECCE should remain low throughout the logging interval represented in this figure.
- Track 2
  - The UFLG flags represent a diagnostic for processing. In normal cases, this track should be free of flags except at collars, which interrupt the model fitting by flagging.
- Track 3
  - The AWBK image track presents the reflectivity of the internal face of the casing. It corresponds to internal casing roughness and is also a good indicator of excessive eccentering. The color scale is in decibels, with black meaning low signal and white meaning high signal.
- Track 4
  - U-USIT_UFSL is the fluid slowness calculated assuming that the averaged outer casing OD is constant.
  - U-USIT_DFSL is the quantized value of UFSL. It compares the slowness between the current and previous depths and selects which will be used for processing.
  - CSVL is the actual fluid velocity input for processing. It may be equal to the discretized fluid slowness (DFSL) or the default fluid velocity (DFVL) depending on the software parameter setting of FSOD.
- Track 5
  - ERAV, IRAV, IRMX, and IRMN provide a view of the pipe.
- Track 6
  - U-USIT_UFAI is inverted from the flexural attenuation (UFAK) and the raw acoustic impedance (AIBK).
  - U-USIT_DFAI is a quantized value from the inverted fluid acoustic impedance.
  - CZMD is the acoustic impedance used in the processing. Its value depends on the software parameter setting of FSOD.
- Track 6
  - U-USIT_UFZQ is proportional to the number of points below the critical impedance that are considered liquid. Below a low threshold of 20%, it is flagged with red, and above a high threshold of 50%, it is flagged as green.

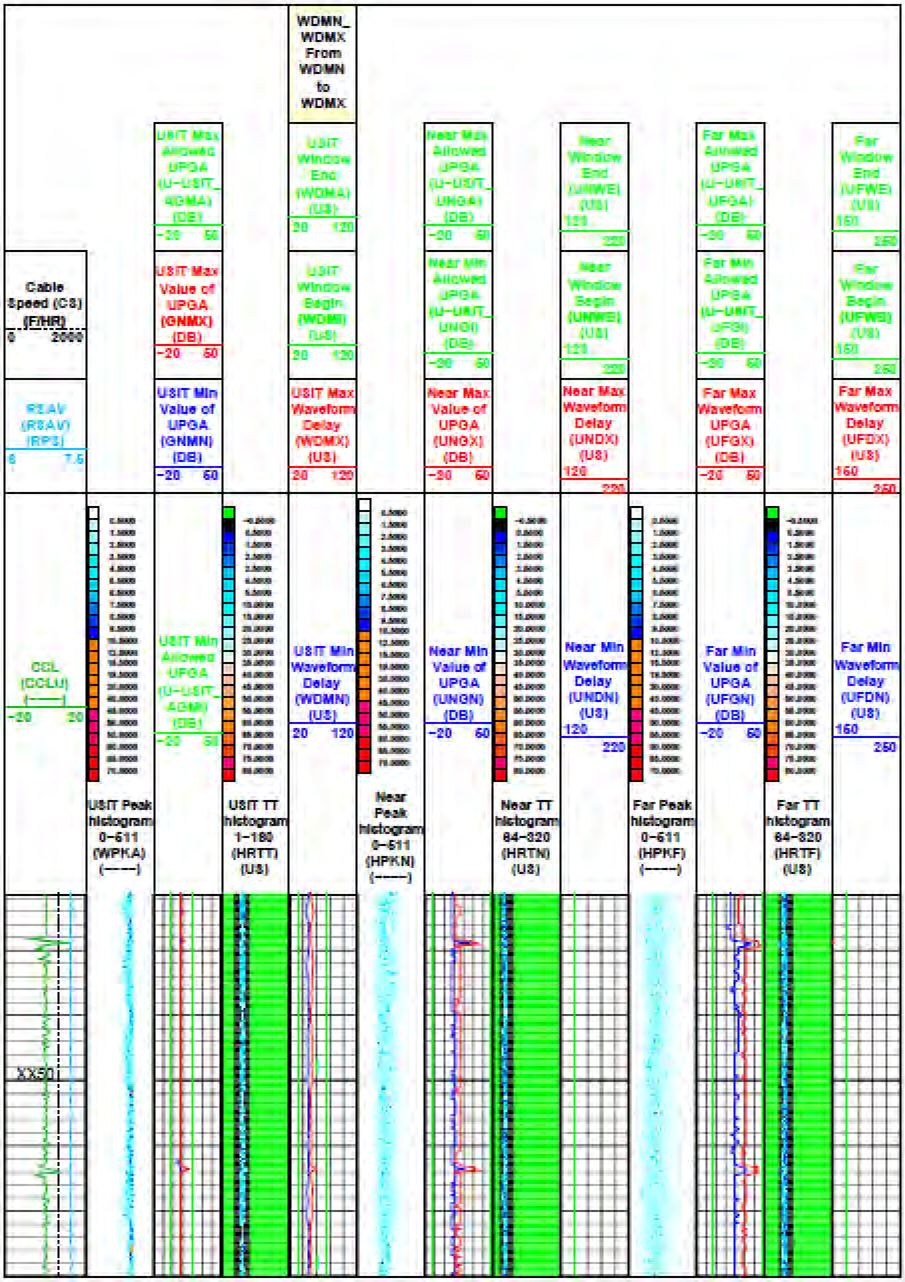


Figure 1. Isolation Scanner signal and waveforms quality control format.

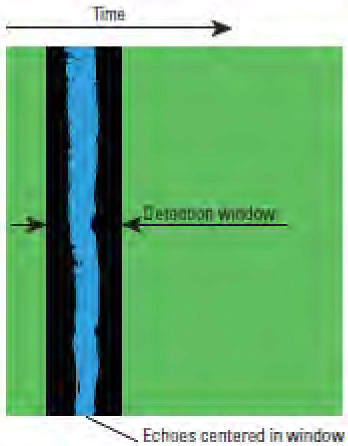


Figure 2. The USI transit-time histogram should be centered in the detection window.

Response in known conditions

The fluid slowness (DFSL) is checked for consistency with expected values in Table 2.

Table 2. Typical Isolation Scanner Fluid Slowness Ranges in Known Conditions

Fluid	DFSL, us/ft	Velocity, mm/us
Oil, oil-base, or heavy water-base mud	218 to 254	1.2 to 1.4
Water, light brine, or light water-base mud	184 to 218	1.4 to 1.65
Brine	160 to 184	1.65 to 1.9

The median internal radius is checked that it is reasonably close to what is expected from the casing size (±0.07 in [±2 mm]) to the casing inside diameter in noncorroded casing.

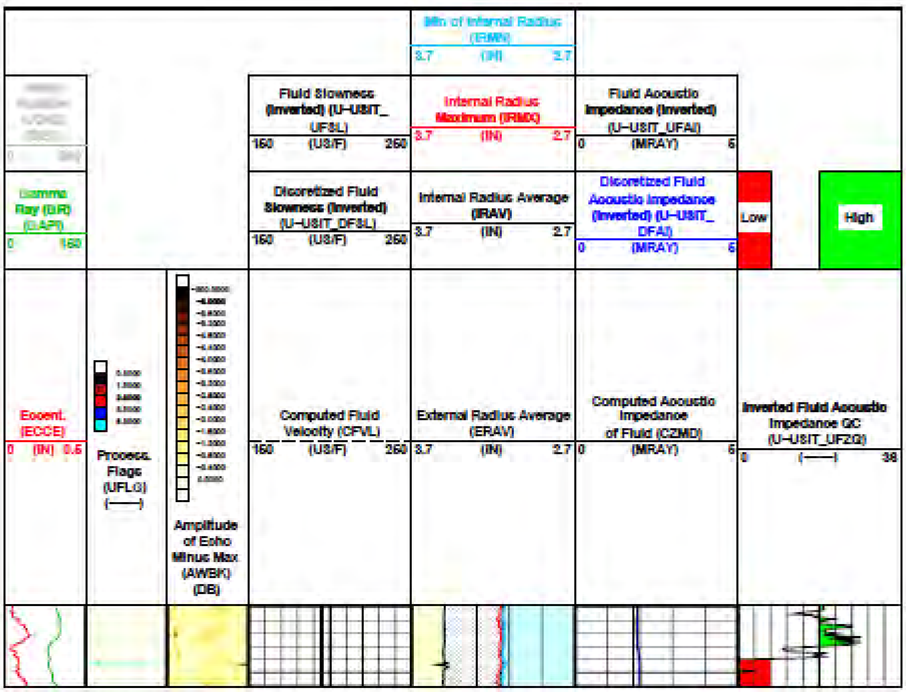


Figure 3. Isolation Scanner fluid property measurement quality control format.

Cement Bond

The example shown below is the QA for the sonic-based Schlumberger Cement Bond Tool (CBT) registered trademark.

Reference : Schlumberger Wireline Log Quality Reference Manual accessed January 2014 http://www.slb.com/resources/publications/books/lqcrm.aspx.

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h][†]
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

[†] Speed can be reduced depending on data quality

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation[†]
SBI	Short bond index[†]
SCBL	Short synthetic CBL[†]
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

[†] In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

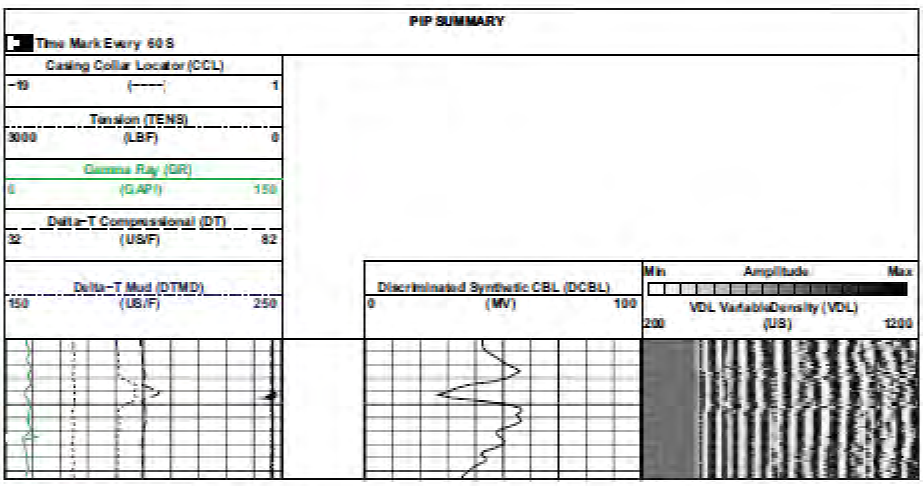


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

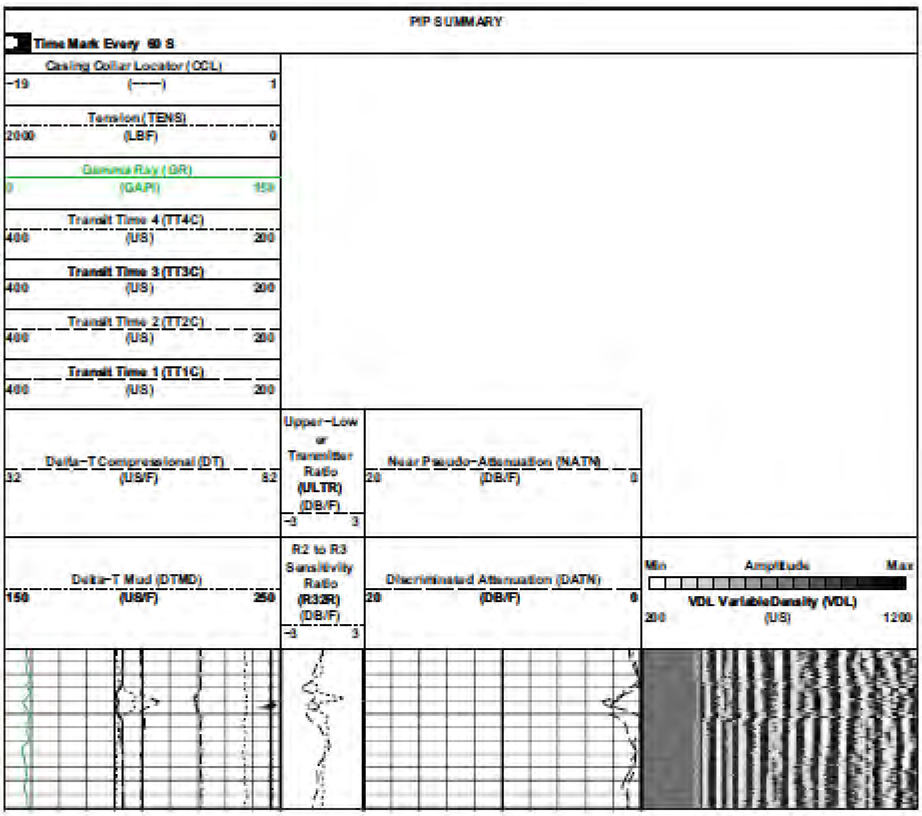


Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40†	52 ± 5	329	272	NM‡

† Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals when casings of 9⅝ in and larger are logged.
‡ NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)
Output	SLS-C, SLS-D, SLS-W, and SLS-E[†] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[†] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

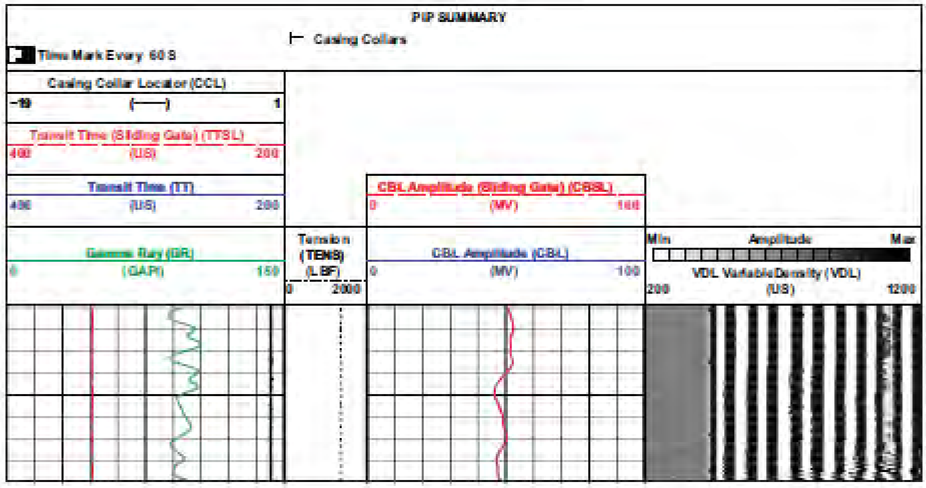


Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

Cased Hole Temperature Logging

Cased hole temperature logging tools are often run as part of a multi-tool tool string, as described in the following Schlumberger example.

Platform Basic Measurement Sonde

Overview

Platform Basic Measurement Sonde (PBMS) of the PS Platform* integrated production services system houses the gamma ray and casing collar locator (CCL) for correlation and also measures well pressure and temperature.

Specifications

Measurement Specifications	
Output	Wellbore pressure, wellbore temperature, gamma ray, casing collar locator
Logging speed	Recommended for accurate gamma ray response: 1,800 ft/h [549 m/h] Typically logged at 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	Sapphire* gauge: 1,000 to 10,000 psi [6.9 to 69 MPa] CQG* gauge: 4.5 to 15,000 psi [0.1 to 103 MPa] Temperature: Ambient to 302 degF [150 degC]
Vertical resolution	Point of measurement
Accuracy	Sapphire gauge: ±6 psi [±41,370 Pa] (accuracy), 0.1 psi [689 Pa] at 1-s gate time (resolution) CQG gauge: ±(1 psi [6,894 Pa] + 0.01% of reading) (accuracy), 0.01 psi [69 Pa] at 1-s gate time (resolution) Temperature: ±1.8 degF[±1 degC] (accuracy), 0.018 degF [0.01 degC] (resolution)
Depth of investigation	Borehole
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	302 degF [150 degC] PBMS-E: 347 degF [175 degC] HBMS: 392 degF [200 degC] for a limited time
Pressure rating	Sapphire gauge: 10,000 psi [69 MPa] CQG gauge: 15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	No limit
Outside diameter	1.6875 in [4.29 cm] HBMS: 2.125 in [5.4 cm]
Length	8.27 ft [2.52 m]
Weight	38.3 lbm [17.4 kg]

Calibration

The PBMS requires calibration for two sensors: the temperature sensor and the pressure sensor. Both calibrations are performed at the same time but cannot be done at the wellsite or field operating locations because of the equipment and personnel required. The sonde alone is placed in a bath of oil for thermal inertia effects and various pressures are applied at various temperatures. The measurements are then used to build a mathematical model that models the tool response.

The gamma ray sensor of the PBMS does not require calibration because the detector is hardwired to operate at the correct settings for the high voltage.

Tool quality control

Standard curves

The PBMS standard curves are listed in Table 1.

Table 1. PBMS Standard Curves

Output Mnemonic	Output Name
CCLD	Discriminated casing collar locator
GR	Gamma ray
MWFD	Pressure gradient derived density
WPRE	Well pressure
WTEP	Well temperature

Operation

The tool can be run centered, eccentered, or tilted.

Response in known conditions

Casing collars should be observed approximately 30 ft [9 m] apart in tubing and 41 ft [12.5 m] apart in casing. Pressure and temperature should increase with true vertical depth in a shut-in well without cross flow. Gamma ray logs should repeat from pass to pass.

Cased Hole Gamma-Ray Logging

Schlumberger

Gamma Ray Tools

Overview

Gamma ray tools record naturally occurring gamma rays in the formations adjacent to the wellbore. This nuclear measurement indicates the radioactive content of the formations. Effective in any environment, gamma ray tools are the standard devices used for the correlation of logs in cased and open holes.

Calibration

The calibration area for gamma ray tools must be free from outside nuclear interference. Background and plus calibrations are typically performed at the wellsite with the radioactive sources removed from the area so that no contribution is made to the signal. The background measurement is made first, and then a plus measurement is made by wrapping the calibration jig around the tool housing and positioning the jig on the knurled section of the gamma ray tool.

Specifications

Measurement Specifications

	Highly Integrated Gamma Neutron Sonde (HGNS)	Hostile Environment Telemetry and Gamma Ray Cartridge (HTGC)	Scintillation Gamma Ray Tool (SGT)	Slim Telemetry and Gamma Ray Cartridge (STGC)	SlimXtreme* Telemetry and Gamma Ray Cartridge (QTGC)	Combinable Gamma Ray Sonde (CGRS)
Output	Formation gamma ray	Formation gamma ray	Formation gamma ray	Formation gamma ray	Formation gamma ray	Gamma ray activity
Logging speed	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	Up to 3,600 ft/h [1,097 m/h]
Range of measurement	0 to 1,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI
Vertical resolution	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]
Accuracy	±5%	±7%	±7%	±7%	±7%	±5%
Depth of investigation	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]
Mud type or weight limitations	None	None	None	None	None	None
Combinability	Part of Platform Express* integrated system	Combinable with most tools	Combinable with most tools	Combinable with most tools	Combinable with most tools	Combinable with most tools
Special applications						H_2S service

Mechanical Specifications

	HNGS	HTGC	SGT	STGC	QTGC	CGRS
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	350 degF [177 degC]	302 degF [150 degC]	500 degF [260 degC]	350 degF [177 degC]
Pressure rating	15,000 psi [103 MPa]	25,000 psi [172 MPa]	20,000 psi [138 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]	20,000 psi [138 MPa]
Borehole size—min.	4½ in [11.43 cm]	4⅞ in [12.38 cm]	4⅞ in [12.38 cm]	3⅜ in [8.57 cm]	3⅞ in [9.84 cm]	1¹³⁄₁₆-in [4.61-cm] seating nipple
Borehole size—max.	No limit	No limit	No limit	No limit	No limit	No limit
Outside diameter	3.375 in [8.57 cm]	3.75 in [9.53 cm]	3.375 in [8.57 cm]	2.5 in [6.35 cm]	3.0 in [7.62 cm]	1.6875 in [4.29 cm]
Length	10.85 ft [3.31 m]	10.7 ft [3.26 m]	5.5 ft [1.68 m]	7.70 ft [2.34 m]	10.67 ft [3.25 m]	3.2 ft [0.97 m]
Weight	171.7 lbm [78 kg]	312 lbm [142 kg]	83 lbm [38 kg]	68 lbm [31kg]	180 lbm [82 kg]	16 lbm [7 kg]
Tension	50,000 lbf [222,410 N]	120,000 lbf [533,790 N]	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]	120,000 lbf [533,790 N]	10,000 lbf [44,480 N]
Compression	37,000 lbf [164,580 N]	28,000 lbf [124,550 N]	23,000 lbf [103,210 N]	17,000 lbf [75,620 N]	13,000 lbf [57,830 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The gamma ray tool standard curves are listed in Table 1.

Table 1. Gamma Ray Tool Standard Curves

Output Mnemonic	Output Name
ECGR	Gamma ray environmentally corrected
GR	Gamma ray

Operation

The tool can be run centered or eccentered.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

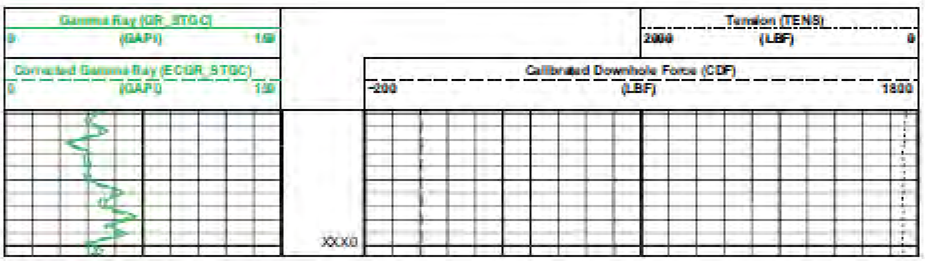


Figure 1. Gamma ray standard format.

Response in known conditions

- In shales, the gamma ray reading tends to be relatively high.
- In sands, the gamma ray reading tends to be relatively low.
- Gamma ray logs recorded in wells that have been on production may exhibit very high readings in the producing interval compared with the original logs recorded when the well was drilled. Mud additives such as potassium chloride and loss-control material can affect log readings.

ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION

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; 39.80111ºN and 90.07491ºW

The FutureGen Alliance is providing financial responsibility pursuant to 40 CFR 146.85. FutureGen is using a **trust fund** to cover the costs of: corrective action, emergency and remedial response, injection well plugging, and post-injection site care and site closure.

The estimated costs of each of these activities, as provided in FutureGen's permit application, are presented in Table 1:

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

Activity	Estimated Cost (Millions, 2012$)
Performing Corrective Action on Deficient Wells in AoR	$0.62
Plugging Injection Wells	$2.7
Post-Injection Site Care	$18.3
Site Closure	$3.4
Emergency and Remedial Response	$26.7
Note: Values in this table are rounded. For exact costs used to determine the value of the Trust Fund, refer to Table 2.	

The instrument values included in this document are based on cost estimates provided during the permit application and review process. These values are subject to change during the course of the project to account for inflation of costs and any changes to the project that affect the cost of the covered activities. If the cost estimates change, FutureGen will adjust the value of the financial instruments.

Trust Fund

The Permittee is providing financial responsibility for the cost of corrective action (as described in Attachment B of this permit), injection well plugging (per Attachment D of this permit), and post-injection site care and site closure (per Attachment E), and Emergency and Remedial Response (per Attachment F) via a trust fund valued at $51.7 million and established through the attached Trust Agreement. The U.S. Bank National Association is the Trustee of the trust fund. The trust fund will be funded in a “phased approach” to account for the fact that certain covered activities will not be incurred until injection begins. For example, resources to cover the cost of plugging the well need to be in place prior to when drilling commences; however certain activities (e.g., corrective action that is performed on a phased basis, post-injection site care and monitoring, and site closure) will not need to be covered until closer to when injection begins.

Table 2 breaks down the activities and estimated costs according to when the payments would be required (i.e., at least 7 days after final permit issuance, at the start of the “Pre-Injection” phase, and within 1 year of final permit issuance or at least 7 days prior to the start of the “Injection and Post-Injection Phase,” whichever comes earlier), within two years of final permit issuance.

Table 2. Payment Schedule for Trust Fund

Funding	Activities	Costs (millions of dollars)	Amount to be Added Before Start of Phase (millions of dollars)
Pre-Injection (*within 7 days of final permit issuance*)	Plugging Injection and Monitoring Wells	2.723	2.723
	Emergency and Remedial Response	6.1	6.1
Injection and Post-Injection (*within 1 year of final permit issuance, or at least 7 days prior to injection, whichever comes first*)	AoR and Corrective Action	0.623	22.345
	Post-Injection Site Care (Includes Monitoring)	18.32	
	Closure	3.402	
Injection and Post-Injection (*within 2 years of final permit issuance*)	Emergency and Remedial Response	20.6	20.6

AMENDED AND RESTATED TRUST AGREEEMENT

Amended and Revised Trust Agreement (Agreement), entered into as of March 28, 2014, by and between the FutureGen Industrial Alliance, Inc. (Alliance), a non-profit 501(c)(3) corporation organized under the laws of the State of Delaware, the Grantor, and U.S. Bank National Association, a national banking association, the Trustee.

Whereas, the United States Environmental Protection Agency (EPA), an agency of the United States Government, has established certain regulations applicable to the Grantor requiring that an owner or operator of an injection well shall provide assurance that funds will be available when needed for corrective actions, injection well plugging, post-injection site care and site closure, or emergency and/or remedial response of the FutureGen 2.0 Class VI (carbon dioxide [CO_2] geologic sequestration) injection wells,

Whereas, the Grantor has elected to establish a trust to provide all or part of such financial assurance for the facilities identified herein,

Whereas, the Grantor, acting through its duly authorized officers, has selected the Trustee to be the trustee under this agreement, and the Trustee is willing to act as trustee,

Now, therefore, the Grantor and the Trustee agree as follows:

Section 1. Definitions as used in this Agreement:

(A) The term "Grantor" means the owner or operator who enters into this Agreement and any successors or assigns of the Grantor.

(B) The term "Trustee" means the Trustee who enters into this Agreement and any successor Trustee.

(C) "Facility" or "activity" means any underground injection well or any other facility or activity that is subject to regulation under the Underground Injection Control Program.

(D) EPA Water Division Director means the EPA Regional Water Division Director for Region V or an authorized representative.

Section 2. Identification of Facilities and Cost Estimates. This Agreement pertains to the facilities and cost estimates identified on attached Schedule A.

Section 3. Establishment of Fund. The Grantor and the Trustee hereby establish a CO_2 Storage Trust Fund (Fund) to satisfy the financial responsibility demonstration under the Class VI Underground Injection Control (UIC) regulations (40 CFR §§ 146.81 – 146.95) for the FutureGen 2.0 Project.. The Grantor and the Trustee acknowledge that the purpose of the Fund is to fulfill the Grantor's corrective action, injection well plugging, post-injection site care and site closure, and emergency and/or remedial response obligations described at 40 CFR §§ 146.84 (Area of review and corrective action), 146.92 (Injection well plugging), 146.93 (Post-injection site care and site closure), and 146.94 (Emergency and remedial response), respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of EPA. The Grantor and the Trustee intend that no independent third-party have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, IN TRUST, as hereinafter provided. The Trustee shall not be responsible nor shall it undertake any responsibility for the amount or adequacy of, nor any duty to collect from the Grantor, any payments necessary to discharge any responsibilities of the Grantor established by EPA regulations.

Section 4. Payment for Corrective Action, Injection Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and/or Remedial Response. The Trustee shall make payments from the Fund only as the EPA Water Division Director shall direct, in writing, to provide for the payment of the costs of corrective actions, injection well plugging, post-injection site care and site closure, and/or emergency and remedial response of the injection wells covered by this Agreement. The Trustee shall use the Fund to reimburse the Grantor or other persons selected by the Grantor to perform work when the EPA Water Division Director advises in writing that the work will be or was necessary for the fulfillment of the Grantor's corrective actions, injection well plugging, post-injection site care and site closure, and/or emergency and remedial response obligations described at 40 CFR 146.84, 146.92, 146.93, and 146.94, respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of EPA, as the Agency is not a beneficiary of the Trust. The EPA Water Division Director may advise the Trustee that amounts in the Fund are no longer necessary to fulfill the Grantor's obligations under 40 CFR 146.85 and that the Trustee may refund the remaining funds to the Grantor. Upon refund, such funds shall no longer constitute part of the Fund as defined herein.

Section 5. Payments Comprising the Fund. Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee. Schedule C provides the amounts and timing of the Alliance payments (i.e., the pay-in periods).

Section 6. Trustee Management. The Trustee shall invest and reinvest the principal and income of the Fund and keep the Fund invested as a single fund, without distinction between principal and income, in accordance with general investment policies and guidelines which the Grantor may communicate in writing to the Trustee from time to time, subject, however, to the provisions of this Section. In investing, reinvesting, exchanging, selling, and managing the Fund, the Trustee shall discharge its duties with respect to the trust fund solely in the interest of the Grantor and with the care, skill, prudence, and diligence under the circumstances then prevailing which persons of prudence, acting in a like capacity and familiar with such matters, would use in the conduct of an enterprise of a like character and with like aims; *except that:*

(A) Securities or other obligations of the Grantor, or any other owner or operator of the facilities, or any of their affiliates as defined in the Investment Company Act of 1940, as amended, 15 U.S.C. 80a–2.(a), shall not be acquired or held, unless they are securities or other obligations of the federal or a state government;

(B) The Trustee is authorized to invest the Fund in time or demand deposits of the Trustee, to the extent insured by an agency of the federal or state government; and

(C) The Trustee is authorized to hold cash awaiting investment or distribution un-invested for a reasonable time and without liability for the payment of interest thereon.

Section 7. Commingling and Investment. The Trustee is expressly authorized in its discretion:

(A) To transfer from time to time any or all of the assets of the Fund to any common, commingled, or collective trust fund created by the Trustee in which the Fund is eligible to participate, subject to all of the provisions thereof, to be commingled with the assets of other trusts participating therein; and

(B) To purchase shares in any investment company, except as specified in writing by the owner or operator, registered under the Investment Company Act of 1940, 15 U.S.C. 80a–1 *et seq.,* including one which may be created, managed, underwritten, or to which investment advice is rendered or the shares of which are sold by the Trustee. The Trustee may vote shares in its discretion.

Section 8. Express Powers of Trustee. Without in any way limiting the powers and discretions conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered:

(A) To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition;

(B) To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted;

(C) To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depositary with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve bank, but the books and records of the Trustee shall at all times show that all such securities are part of the Fund;

(D) To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the federal or state government; and

(E) To compromise or otherwise adjust all claims in favor of or against the Fund.

Section 9. Taxes and Expenses. All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and all other proper charges and disbursements of the Trustee shall be paid from the Fund.

Section 10. Annual Valuation. The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the EPA Water Division Director a statement confirming the value of the Trust. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund. The failure of the Grantor to object in writing to the Trustee within 90 days after the statement has been furnished to the Grantor and the EPA Water Division Director shall constitute a conclusively binding assent by the Grantor, barring the Grantor from asserting any claim or liability against the Trustee with respect to matters disclosed in the statement.

Section 11. Advice of Counsel. The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any question arising as to the construction of this Agreement of any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

Section 12. Trustee Compensation. The Trustee shall be entitled to reasonable compensation for its services as agreed upon in writing from time to time with the Grantor.

Section 13. Successor Trustee. The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor trustee and this successor accepts the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall specify the date on which it assumes administration of the trust in a writing sent to the Grantor, the EPA Water Division Director, and the present Trustee by certified mail 10 days before such change becomes effective. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

Section 14. Instructions to the Trustee. All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by such persons as are designated in the attached Exhibit A or such other designees as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the EPA Water Division Director to the Trustee shall be in writing, signed by the EPA Water Division Director, and the Trustee may rely on these instructions to the extent permissible by law. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or a termination of the authority of any person to act on behalf of the Grantor or EPA hereunder has occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or EPA, except as provided for herein.

Section 15. Notice of Nonpayment. The Trustee shall notify the Grantor and the EPA Water Division Director, by certified mail within 10 days following the expiration of the 30-day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period. After the pay-in period is completed, the Trustee shall not be required to send a notice of nonpayment.

Section 16. Amendment of Agreement. This Agreement may be amended by an instrument in writing executed by the Grantor, the Trustee, with the concurrence of the EPA Water Division Director, or by the Trustee and the EPA Water Division Director if the Grantor ceases to exist. Provided, however, that EPA may not be named as a beneficiary of the Trust, receive funds from the Trust, or direct that Trust funds be paid to a particular entity selected by EPA.

Section 17. Cancelation, Irrevocability and Termination. Subject to the right of the parties to amend this Agreement as provided in Section 16, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor, the Trustee, with the concurrence of the EPA Water Division Director, or by the Trustee and the EPA Water Division Director if the Grantor ceases to exist. Upon termination of the Trust, all remaining trust property, less final trust administration expenses, shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the EPA.

Section 18. Immunity and Indemnification. The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any directions by the Grantor issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Trust Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all expenses reasonably incurred in its defense in the event the Grantor fails to provide such defense. EPA does not indemnify either the Grantor or the Trustee due to the restrictions imposed by the Anti-Deficiency Act, 31 U.S.C. 1341. Rather, any claims against EPA are subject to the Federal Tort Claims Act, 28 U.S.C. 2671, 2680.

Section 19. Choice of Law. This Agreement shall be administered, construed, and enforced according to the laws of the State of Illinois with regard to claims by the Grantor or Trustee. Claims involving EPA are subject to federal law.

Section 20. Interpretation. As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

Section 21. Integration. This Agreement supersedes the previously executed Trust Agreement between the parties hereto dated March 20, 2014.

In Witness Whereof the parties have caused this Agreement to be executed by their respective officers duly authorized and attested as of the date first above written.

Signature of Grantor's Authorized Representative: Kenneth K. Humphreys Jr.
Name of Grantor's Authorized Representative: Kenneth K. Humphreys, Jr.
Title: Chief Executive Officer

Attest:

Signature: Carole Plowfield
Name of Attester: Carole Plowfield
Title of Attester: Executive Administrator

Certification of Acknowledgement of Notary:

MATITA A. GREEN NOTARY PUBLIC DISTRICT OF COLUMBIA MY COMMISSION EXPIRES 3 31 2018

District of Columbia : SS
Subscribed and Sworn to before me
this 27th day of March, 2014
Notary Public, D.C.
My commission expires 3/31/2018

Signature of Trustee's Authorized Representative:
Name of Trustee's Authorized Representative: Thomas S. Maple III
Title: Vice President

Attest:

Signature: Judith L. Foley
Name of Attester: Judith L. Foley
Title of Attester: Vice President

Certification of Acknowledgement of Notary:

JASON ADAM FELIX
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2016

Jason A. Felix

Schedule A: Facilities and Cost Estimates to Which the Trust Agreement Applies

Because the four injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad, the CO_2 injected through the four wells will form one co-mingled CO_2 plume. Therefore, funds noted in the table below apply to all four injection wells as one integrated facility.

Facility	Corrective Action ($ million)	Injection Well Plugging ($ million)	Post-injection Site Care and Site Closure ($ million)	Emergency and Remedial Response ($ million)
EPA Identification Number IL-137-6A-0001 Morgan County Class VI UIC Well #1 73 Central Park Plaza E Jacksonville, IL 62650	$0.623	$2.723	$21.722	$26.7
EPA Identification IL-137-6A-0002 Morgan County Class VI UIC Well #2 73 Central Park Plaza E Jacksonville, IL 62650				
EPA Identification Number IL-137-6A-0003 Morgan County Class VI UIC Well #3 73 Central Park Plaza E Jacksonville, IL 62650				
EPA Identification Number IL-137-6A-0004 Morgan County Class VI UIC Well #4 73 Central Park Plaza E Jacksonville, IL 62650				

Schedule B: Trust Fund Property

Because the four injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad, the CO_2 injected through the four wells will form one co-mingled CO_2 plume. Therefore, funds noted in the table below apply to all four injection wells as one integrated facility.

Facility	Funding Value for Activities
EPA Identification Number IL-137-6A-0001 Morgan County Class VI UIC Well #1 73 Central Park Plaza E Jacksonville, IL 62650	$51,768,000.00
EPA Identification Number IL-137-6A-0002 Morgan County Class VI UIC Well #2 73 Central Park Plaza E Jacksonville, IL 62650	
EPA Identification Number IL-137-6A-0003 Morgan County Class VI UIC Well #3 73 Central Park Plaza E Jacksonville, IL 62650	
EPA Identification Number IL-137-6A-0004 Morgan County Class VI UIC Well #4 73 Central Park Plaza E Jacksonville, IL 62650	

Schedule C: Pay-in Periods

The CO_2 Trust Fund will be funded according to when the financial risks are incurred on the FutureGen 2.0 Project in four distinct activities:

- **Pre-Injection:** Once an injection or monitoring well is drilled, plugging costs will eventually need to be incurred. Therefore, the trust account will be funded with the cost of plugging injection and monitoring wells prior to drilling the wells. The Alliance's estimated cost of this activity is $2.723 million.
- **Injection:** As soon as injection of CO_2 begins in the Class VI well(s), certain activities will necessarily need to occur (corrective action that is performed on a phased basis, post-injection site care and monitoring, and site closure). Therefore, the trust account should be funded with the costs associated with these activities. The Alliance's estimated cost of this activity is $22.345 million.
- **Post-Injection:** While all costs must be covered at the start of the post-injection phase, the trust account may phase out these costs as the activities are completed (with approval from the EPA Water Division Director). For example, once wells have been plugged, their corresponding plugging costs may be subtracted from the total value of the trust account.
- **Emergency and remedial response:** Prior to authorization from EPA to begin injecting CO_2 under the Class VI well permit(s), the Alliance must be prepared to undertake any emergency or remedial response actions, although such actions are unlikely to be needed. The Alliance estimated the cost of the most severe incident to be $6.1 million, which is the amount that will be placed into the trust fund prior to drilling the injection well(s). However, to ensure that sufficient funds will be available in the highly unlikely event that multiple incidents occurred over the entire period of injection and post-injection operations, the Alliance will add $20.6 million to the trust fund for emergency and remedial response (for a total of $26.7 million) prior to EPA's authorization of the start of CO_2 injection.

Within seven calendar days after the issuance of final Class VI UIC permits for the Morgan County injection wells, the Alliance will ensure that $2.723 million is in the CO_2 Trust Fund to cover the cost of plugging injection and monitoring wells in the Pre-Injection Period. In addition, the Alliance will ensure that $6.1 million is in the CO_2 Trust Fund to cover the cost of emergency and remedial response during the construction period and prior to the start of CO_2 injection.

On or before the one-year anniversary of the issuance of the final Class VI UIC permits for the Morgan County injection wells, and at least seven calendar days prior to EPA authorization for the start of CO_2 injection in any of the wells (whichever is earlier), the Alliance will ensure that an additional $22.345 million is in the CO_2 Trust Fund to cover the costs of the Injection and Post-Injection Periods. The total value of the trust at the beginning of the Injection Period will be

$31.168 million. An additional $20.6 million will be added on or before the two-year anniversary of the issuance of the final Class VI UIC permit(s) for the Morgan County injection well(s), completing the phase-in of financial responsibility payments for emergency and remedial response. The Alliance may also elect to substitute another mechanism to demonstrate financial responsibility for emergency and remedial response for the injection and post-injection phases. If EPA approves such a substitution, this Agreement will be amended accordingly.

These amounts are based on the third-party cost estimate submitted by the Alliance in its *Supporting Documentation: Underground Injection Control Class VI Injection Well Permit Applications for FutureGen 2.0 Morgan County Wells 1, 2, 3, and 4,* dated March 2013 (Appendix C) and on EPA's independent evaluation of the cost estimates. These costs are subject to review and approval by EPA and may be adjusted for inflation or any change to the cost estimate in accordance with 40 CFR § 146.85(c)(2).

Table 1 shows the activities and estimated costs according to when the payments would be required (i.e., at the start of the "Pre-Injection" phase or at the start of the "Injection and Post-Injection Phase").

Table 1: Payment Schedule

Funding	**Activities**	**Costs (millions of dollars)**	**Amount to be Added Before Start of Phase (millions of dollars)**
Pre-Injection (*within 7 days of final permit issuance*)	Plugging Injection and Monitoring Wells	2.723	2.723
	Emergency and Remedial Response	6.1	6.1
Injection and Post-Injection (*within 1 year of final permit issuance, or at least 7 days prior to injection, whichever comes first*)	AoR and Corrective Action	0.623	22.345
	Post-Injection Site Care (Includes Monitoring)	18.32	
	Closure	3.402	
Injection and Post-Injection (*within 2 years of final permit issuance*)	Emergency and Remedial Response	20.6	20.6

Exhibit A FutureGen Industrial Alliance, Inc. Designee Authorized to Instruct Trustee

Kenneth K. Humphreys, Jr.
Chief Executive Officer
FutureGen Industrial Alliance, Inc.
73 Central Park Plaza East
Jacksonville, Illinois 62650
217/243-8215

The FutureGen Industrial Alliance, Inc., as Grantor, may designate other designees by amendment to this Exhibit.