U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 5
UNDERGROUND INJECTION CONTROL
CLASS VI PERMIT

PERMIT ID: IL-155-6A-0001

ISSUED TO:
MARQUIS CARBON INJECTION LLC
10000 MARQUIS DRIVE, HENNEPIN, ILLINOIS 61327

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LIST OF ATTACHMENTS

PERMIT AUTHORIZATION

Under the authority of the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 C.F.R.) Parts 124, 144, 146, and 147, and according to the terms of this permit, hereinafter referred to as "Permit," EPA hereby authorizes the company listed below, hereinafter referred to as the "Permittee," to engage in underground injection activities as described herein. This Permit incorporates all attachments to this Permit as enforceable conditions.

PERMITTEE NAME AND ADDRESS
MARQUIS CARBON INJECTION LLC
10000 MARQUIS DRIVE, HENNEPIN, ILLINOIS 61327

The Permittee is authorized, upon the express condition that the Permittee meets the restrictions of this Permit, to construct and operate the Class VI injection well listed below for injection of the carbon dioxide stream generated by MARQUIS CARBON INJECTION LLC ("Marquis", "Marquis Carbon", or "MCI") for the Marquis Biocarbon Project and as characterized in the permit application and the administrative record as a liquid, supercritical fluid, or gas below the ground surface. The authorized injection zone is the Mount Simon Sandstone formation at depths between 3,094 and 4,854 feet.

WELL NAME AND LOCATION
MCI CC3
ILLINOIS, PUTNAM COUNTY
S2 T32N R2W
Latitude: 41.27026520° N
Longitude: 89.30939322° W

Any underground injection activity not authorized by this Permit or by rule is prohibited. All references to 40 C.F.R. are to the regulations in effect on the date that this Permit is effective and, should renumbering occur, their subsequent equivalent. The following attachments are incorporated into this permit as enforceable conditions: A, B, C, D, E, F, G, H, I, J, and K. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the SDWA or any other law governing protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all applicable UIC regulations.

This Permit becomes effective on the date listed below and remains in full force and effect during the operating life of the injection well, the post-injection site care period, and until site closure is authorized and completed, unless this Permit is revoked and reissued, terminated, or modified pursuant to 40 C.F.R. §§ 124.5, 144.12, 144.39, 144.40, or 144.41. This Permit shall be reviewed at least once every five years to determine if action is required under 40 C.F.R. § 144.36(a). Upon delegation of primary enforcement responsibility to a new entity, this Permit remains in effect until such time as the new entity issues its own permit to the Permittee or the new entity chooses to adopt this Permit as its permit. The permit will expire in two years from its effective date if the permittee fails to commence well construction, unless a written request in an electronic format for an extension of this two-year period has been approved by the Director. The Permittee shall submit such requests prior to the permit expiration or extension deadline, whichever is applicable. Requests for extension must state delay causality, an estimated well completion date, and list additional wells that penetrate the designated confining zone within the area of review (AOR) which were not included in the initial permit application, including well construction diagrams, cement records, and cement bond logs for any new AOR wells. A maximum of two, two-year extensions are allowed. If the construction of the well has not commenced during the maximum period of six years from the effective date, the permit expires and may not be extended. The permittee may request an expiration date sooner than the two-year period, provided no construction on the well has commenced.

Authorization Signed By:

4/10/2026

X

Tera L. Fong
Director, Water Division
Signed by: TERA FONG

EFFECTIVE DATE OF PERMIT: May 14, 2026

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 must 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 geologic zones. The objective of this Permit is to prevent the movement of fluids into or between USDWs or into any unauthorized geologic zones consistent with the requirements at 40 C.F.R. §§ 146.86(a) and 144.12(a) and (b). Any underground injection activity not specifically authorized in this Permit is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege (40 C.F.R. § 144.51(g)); 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, or Termination – The Director of the Water Division of Region 5 of the EPA, hereinafter, the Director, may, for cause or upon request by the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 C.F.R. §§ 124.5, 144.12, 146.86(a), 144.39, and 144.40, and 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 condition of this Permit. (40 C.F.R. § 144.51(f)). The Permittee shall notify the Director at least 30 days in advance of any modification for approval. 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 C.F.R. § 144.41.

2. Transfer of Permit – The Permittee may transfer this Permit in accordance with 40 C.F.R. § 144.38(a) only when the Director has modified or revoked and reissued the Permit into the name of the new owner/operator. The Permittee shall provide written notice (EPA Form 7520-7 or its equivalent) to the Director at least 30 days in advance of the proposed transfer date. Such notice shall include a written agreement between the existing and proposed new Permittees containing a specific date for transfer of permit responsibility, coverage, and liability between them, and shall demonstrate that the financial responsibility requirements of 40 C.F.R. § 144.52(a)(7) have been met by the proposed new Permittee. This permit is only transferable after approval by the Director.

3. Permittee Change of Name or Address – The Permittee shall notify the Director at least 30 days in advance of changes in the Permittee legal name or address or address where

records are kept. The Permit may be subject to a modification in accordance with item (1) of this section.

4. Injection Well Conversion – The Permittee shall notify the Director at least 30 days in advance of planned well conversion to another type of injection or non-injection well. The notice shall include the type of well to which the existing well will be converted and a completed 7520-19 form or its equivalent. Such notice shall also include demonstration that the existing injection well has internal and external mechanical integrity (MI) and documentation that the agency with regulatory authority over the new well type has been notified. The Permittee shall not begin conversion of the well without written approval from the Director that the requirements of this Permit have been met nor without a proper UIC permit/authorization if the well is being converted to a different type of injection well. Upon conversion, the Permittee shall convert the well(s) in a manner which will not allow the movement of fluids into or between USDWs. The Permittee shall also ensure that the conversion meets any and all applicable federal, state, and local requirements. The Permittee must continue to meet all permit requirements until the permit expires unless the Permittee receives written approval from the Director waiving such requirements.

5. Permit Expiration – Once the permit has expired, the Permittee must reapply for a new injection well permit and restart the complete permit process, including opportunity for public comment, before injection can occur. If authorization to inject has not been provided once construction has commenced, the Permittee is subject to the conditions for wells not actively injecting.

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 C.F.R. Part 2 (Public Information) and 40 C.F.R. § 144.5, any information submitted to EPA under this Permit may be claimed as containing trade secret, proprietary, or confidential business information (collectively PBI) by the submitter. Any such claim must be asserted at the time of submission by clearly marking the words "proprietary 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 treated in accordance with the procedures in 40 C.F.R. 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. DEFINITIONS

All terms used in this Permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 C.F.R. parts 124, 144, 146, and 147.

F. DUTIES AND REQUIREMENTS

1. Prohibition of Movement of Fluid into a USDW – The Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any injection activity for the wells covered by this Permit in a manner that allows the movement of a fluid containing any contaminant into USDWs. If any water quality monitoring of a USDW indicates that a well covered by this permit may have caused the movement of any contaminant into the USDW, the Permittee shall initiate actions the Director may prescribe and as are necessary to remediate and prevent such movement.

2. Duty to Comply – The Permittee must 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 except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration as such noncompliance is authorized in an emergency permit under 40 C.F.R. §§ 144.34 and 144.51(a)).

3. Duty to Reapply – If the Permittee wishes to continue an activity regulated by this Permit after its expiration, the Permittee must apply for and obtain a new permit. (40 C.F.R. § 144.51(b))

4. 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.

5. 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. (40 C.F.R. § 144.51(c))

6. 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. (40 C.F.R. § 144.51(d))

7. 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. (40 C.F.R. § 144.51(e))

8. Duty to Provide Information – The Permittee shall furnish to the Director in electronic format, within the time specified by the type of submittal or as defined by the Director, 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. The Permittee shall also comply with all reporting requirements of this Permit, as specified in Section O, and as required by 40 C.F.R. § 144.32 and 144.51(h)).

9. 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 records which are required to be retained under the conditions of this Permit are kept;

    (b) Have access to and copy, at reasonable times, any records which are required to be 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. (40 C.F.R. § 144.51(i)).

10. Signatory and Certification Requirements – All reports, notifications, or any other information, required to be submitted by this Permit or requested by the Director shall be signed and certified in accordance with 40 C.F.R. § 144.32. The Permittee shall ensure that all signed documents include the following certification statement: "*I certify under penalty*

of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations." (40 C.F.R. § 144.51(k))

G. AREA OF REVIEW AND CORRECTIVE ACTION

The Permittee shall maintain and comply with the approved Area of Review (AoR) and Corrective Action Plan (CAP) included as Attachment B and shall meet the requirements of 40 C.F.R. § 146.84. In accordance with this Permit and UIC regulations, the Permittee shall do the following:

1. Every 5 years as specified in the AoR and CAP, 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 C.F.R. § 146.84 and update the AoR and CAP or demonstrate to the Director that no update is needed. Reevaluation of the AoR and CAP must meet the requirements of 40 C.F.R. § 146.84(e) and must include a new survey of wells within the existing or modified AoR; and

2. Following each AoR reevaluation or a demonstration that no evaluation is needed, the Permittee must submit a report of the resultant information the Director for review and approval (per 40 C.F.R. § 146.84) in an electronic format. Once approved by the Director, the revised AoR and CAP become enforceable conditions of this Permit.

3. The Permittee must update the AOR when requesting extensions to permit expiration due to delayed construction.

H. FINANCIAL RESPONSIBILITY

The Permittee must demonstrate and maintain financial responsibility in accordance with 40 C.F.R. § 146.85 to cover estimated costs. The approved financial responsibility documents and estimated costs for this Permit are found in Attachment I of this Permit. The Permittee must submit qualifying financial responsibility instrument(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. When Financial Statement Coverage is used as the financial mechanism, such coverage shall be updated on an annual basis. The Permittee must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration. The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.

1. Cost Estimate Updates and Adjustments – During the life of the geologic sequestration (GS) project, the Permittee shall maintain a current and detailed written cost estimate to reflect adjustments for inflation costs and any amendments made to the Project Plans included as Attachments of this Permit. The Permittee shall submit updates, adjustments, and amendments to the cost estimates as follows:

    (a) Annually, within 60 days prior to the anniversary date of the establishment of the financial instrument.

    (b) Within 60 days of any amendment to the area of review and corrective action plan (40 C.F.R. § 146.84), the injection well plugging plan (40 C.F.R. § 146.92), the post-injection site care and site closure plan (40 C.F.R. § 146.93), and the emergency and remedial response plan (40 C.F.R. § 146.94).

    (c) No later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (40 C.F.R. § 146.84), the injection well plugging plan (40 C.F.R. § 146.92), the post-injection site care and site closure plan (40 C.F.R. § 146.93), and the emergency and response plan (40 C.F.R. § 146.94), if the change in the plan increases the cost.

    (d) Within 60 days of notification from the Director that the most recent demonstration is no longer adequate to cover the current estimated costs.

    (e) Cost estimates must be based on costs of hiring a third party that is independent from the corporate structure of the Permittee to perform the required activities.

    (f) The Permittee must obtain approval from the Director for any new or updated cost estimate or revised financial instrument. The Permittee shall submit qualifying revised financial responsibility instrument(s) that cover the new or updated costs within 60 days of any amendment(s).

    (g) The Permittee must obtain approval from the Director to decrease the value of the financial assurance instrument or withdraw funds if a change to the plans decreases the cost.

2. Adverse Financial Conditions Notification (40 C.F.R. §§ 146.85(c)(4), 146.85(d)) – The Permittee shall notify the Director by certified mail and by email of adverse financial conditions that may affect the ability to cover current cost estimates.

    (a) Bankruptcy and/or Insolvency of the Permittee – In the event that the Permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the Permittee shall notify the Director within 10 days after commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the Permittee as debtor. 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.

(b) Bankruptcy, Insolvency, Suspension, or Loss of Authority of an Issuing Financial Institution – In the event of insolvency or bankruptcy of the trustee or issuing institution of the financial mechanism; the suspension or revocation of the authority of the trustee institution to act as trustee; or the issuing institution's losing its authority to issue such an instrument: The Permittee must notify the Director within 10 business days of the Permittee receiving notice of such event. See 40 C.F.R. §§ 144.28(d)(5) and 144.64(a). A Permittee who obtains a letter of credit, surety bond, or insurance policy will be deemed to be without the required FR or liability coverage in the event of bankruptcy, insolvency, or a suspension or revocation of the license or charter of the issuing institution. The owner or operator must establish other financial responsibility or liability coverage acceptable to the Director, within 60 calendar days after such an event. See 40 C.F.R. §§ 144.28(d)(6) and 144.64(b).

3. Changes in Coverage – Whenever a cost estimate increases to an amount greater than the face amount of a controlling financial instrument, 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 qualifying financial responsibility instruments to cover the increase. Whenever a current cost estimate decreases to an amount less than the face amount of a controlling financial instrument, 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. (40 C.F.R. § 146.85(c)(4)).

I. WELL CONSTRUCTION

The requirements listed in this section outline the approved construction standards. A more detailed EPA-approved design and specifications for the injection well, injection zone monitoring wells, confining zone monitoring wells, and the groundwater monitoring wells that are the subject of this Permit are included in Attachment H of this Permit. Changes to the approved construction plan must be approved through permit modification by the Director, prior to operation.

1. Injection Well Construction – The well must be constructed in accordance with 40 C.F.R § 146.86. The design and construction must allow continuous monitoring of the annulus between the long string casing and the injection tubing and accommodate testing devices and workover tools. During construction, the Permittee may make changes to the design of the injection well consistent with the conditions of this Permit. If changes are made to the design of the well before construction, notification must be made to EPA and

the construction changes must be provided for review and approval by the Director before installation. Once the construction of the well is completed, and prior to authorization to inject, the Permittee must submit the final, as-built construction specifications and diagrams within 30 days for review and approval by the Director. Any deviations from the proposed design and as-built construction of the well must be noted. If the changes in well design are significant, the Director may require this Permit to be modified.

2. Siting – The well must be sited in an area with a suitable geologic setting in accordance with the requirements at 40 C.F.R. § 146.83.

3. Casing and Cementing – The well must be cased and cemented per 40 C.F.R. §§ 146.22 and 146.86. Casing, cement, or other materials used in the construction of the well must have sufficient structural strength for the life of the GS 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 well must be cased and cemented to prevent the movement of fluids into or between USDWs for the expected duration of the GS project in accordance with 40 C.F.R. § 146.86.

4. Injection Tubing and Packer – The tubing and packer design must meet the requirements of 40 C.F.R. § 146.86(c). 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. Injection must only take place through the tubing, with a packer set in the long string casing within or below the nearest cemented and impermeable confining system no more than 100 feet above the injection zone.

5. Sampling and Monitoring Devices – The Permittee must install and maintain in good condition all devices required to measure, monitor, and record the data and parameters required by Attachment A and C of this Permit. The Permittee must ensure that the devices installed and methods used are sufficient to represent the activity being measured, monitored, or recorded. For required continuous monitoring, the Permittee must use devices capable of monitoring the required activity. Calculated flow data or periodic monitoring are not acceptable for required continuous monitoring except as a back-up system if the primary continuous monitoring devices malfunction or become inoperable. The Permittee must notify EPA of such occurrences, and continuous monitoring devices must be repaired or replaced as soon as practicable. If this length of time is extensive in the opinion of the Director, injection activities must cease until such time that normal monitoring is restored. The Permittee must ensure the well's construction and near-wellhead design is appropriate for the collecting of samples and fulfilling of all monitoring requirements of this Permit. The Permittee must ensure adequate well diameter to

accommodate appropriate tools for well development, aquifer testing equipment, and water quality sampling devices. The Permittee must ensure all gauges used for monitoring and testing are properly calibrated.

6. Monitoring Well Construction– 40 C.F.R. §§ 146.84 and 146.90(g) require monitoring of the carbon dioxide plume and pressure front of the confining and injection zones and 40 C.F.R. § 146.90(d) requires monitoring of groundwater located above the injection zone. These sections are incorporated by reference into this permit. Groundwater, confining zone, and injection zone monitoring wells must be constructed in the manner depicted in Attachment C of this Permit using materials that are compatible with the injected fluids. All monitoring wells must be constructed in a manner to provide representative samples that can be analyzed for the monitoring parameters required by this Permit. Once the construction of the monitoring wells has been completed, the as-built construction diagrams must be included in the Pre- injection Testing Report to be submitted to the Director per Section J of this Permit.

J. PRE-INJECTION TESTING

Testing is required during the construction of the well per 40 C.F.R. § 146.87. This testing is required to verify the geology of the well site to ensure compliance with the well construction requirements per 40 C.F.R. § 146.86 and to test viability of the well to meet the stipulated operational requirements. All testing must be conducted in accordance with 40 C.F.R. § 146.87. The pre-injection testing plan is included as Attachment G of this Permit.

1. Prior to receiving authorization to commence injection, the Permittee must perform all pre-injection logging, sampling, and testing specified at 40 C.F.R. § 146.87. This testing must 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 must include:

      (i) Deviation checks that meet the requirements of 40 C.F.R. § 146.87(a)(1);

      (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 C.F.R. § 146.87(a)(2);

      (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 C.F.R. § 146.87(a)(3);

      (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 C.F.R. § 146.87(a)(4); and

(v) Any alternative methods that are required by and/or approved by the Director pursuant to 40 C.F.R. § 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 C.F.R. § 146.87(b).

(c) Documentation of the measured fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 C.F.R. § 146.87(c).

(d) Tests to determine well-specific data regarding the injection and confining zones. These tests must determine 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 C.F.R. § 146.87(d).

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 C.F.R. § 146.87(e), including:

(i) A pressure fall-off test; and

(ii) A pumping test or injectivity tests.

2. The Permittee must submit to the Director for approval in an electronic format a schedule for pre-operational 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 with the opportunity to witness all logging, sampling, and testing required under this Section.

K. INJECTION WELL OPERATION

1. Outermost Casing Injection Prohibition – Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. Injection Pressure Limitation – Except at specific times as approved by the Director, the Permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) and does not initiate new fractures or propagate existing fractures in the injection zone(s). Under no circumstance 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 of this Permit.

3. Stimulation Program – The Permittee must obtain prior approval from the Director to conduct stimulation activities. The Permittee must carry out the Stimulation Program in accordance with Attachment J of this Permit.

4. Additional Injection Limitations – No injection fluid other than that identified on Page 1 of this Permit may be injected except fluids used for stimulation, rework, and well tests as approved by the Director. Injection must occur within the injection tubing.

5. 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.

6. Annulus/Tubing Pressure Differential – Except during workovers or times of annulus maintenance, the Permittee must maintain pressure on the annulus 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.

7. Automatic Alarms and Automatic Shut-off System

   (a) The Permittee must:

      (i) Install, continuously operate, and maintain an automatic alarm and 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.

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 O of this Permit.

8. Precautions to Prevent Well Blowouts – Except at specific times as approved by the Director, the Permittee must 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 fluid of sufficient specific gravity during workovers to maintain a positive (downward) pressure 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 must 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.

9. <u>Circumstances Under Which Injection Must Cease</u> – Injection must 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;

   (f) Circumstances dictated in the Emergency Remedial and Response Plan (Attachment F of this Permit)

   (g) Conditions described in Section M, Seismic Event Response of this Permit occur; or

   (h) The Director determines that the Permittee is unable to maintain compliance with any condition of this Permit or regulatory requirement and the Director determines that injection should cease.

L. MECHANICAL INTEGRITY

The Permittee must ensure that the injection well and all other wells covered by this permit have both internal (no significant leaks in the casing, tubing and packer) and external (no significant fluid movement outside of the injection zone) mechanical integrity for the operational life of the well. The approved tests and test procedures for mechanical integrity (MI) are found in Attachment C of this Permit.

1. <u>Standards</u> – Other than during periods of well workover (repair or 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 C.F.R. § 146.89, and 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 C.F.R. §§ 146.88(e) and 146.89(b). The Permittee must demonstrate MI using the approved tests and test procedures found in Attachment C of this Permit. The Permittee must also conduct any additional testing as the Director may require to make this determination. The determination of whether the injection well has mechanical integrity is at the discretion of the Director.

2. MI Demonstration Requirements and Schedule

   (a) The Permittee must demonstrate mechanical integrity as follows:

      (i) Any time upon written request from the Director.

      (ii) Annually for external mechanical integrity.

      (iii) After any loss or suspected loss of MI.

      (iv) After any well alteration, repair, or workover that may compromise the internal mechanical integrity of the well including well stimulation.

      (v) Prior to plugging the well.

      (vi) After a seismic event as outlined in Section M of this Permit.

      (vii) After well construction is completed.

   (b) The Permittee must obtain written authorization from the Director prior to commencing/resuming injection in any of the circumstances listed in Section L(2) above.

3. Monitoring Wells – Mechanical integrity tests and procedures for the confining zone and injection zone monitoring wells are outlined in Attachment C, Testing and Monitoring Plan and K, Quality Assurance and Surveillance Plan of this Permit. Internal and external testing and demonstration of monitoring wells must be conducted annually. Other tests and/or procedures including but not limited to corrosion monitoring, pressure tests, and televising casing integrity will be considered by the Director for approval and are outlined in Attachment C.

4. Alternative MI Tests and Procedures – The Permittee must submit any proposed alternative tests and/or procedures not listed in this plan to EPA for approval prior to using them to demonstrate MI.

5. EPA Witnessing of MI Tests – MI tests 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 unwitnessed test. To conduct testing without an EPA witness, the Permittee must adhere to the following procedures:

   (a) Submit prior notice in an electronic format within the time period specified within this section and Section O of this Permit, including the information that no EPA representative is available, and receive permission from EPA to proceed;

   (b) Perform the test in accordance with the Testing and Monitoring Plan found in Attachment C of this Permit and document the test using either a mechanical or digital device that records the value of the parameter of interest; and

   (c) Submit a final report including any additional interpretation necessary for evaluation of the testing, including a test record and gauge certification in electronic format to the Director for approval within the time period specified in Section O of this Permit.

6. Gauge and Meter Calibration – Prior to testing, the Permittee must ensure proper calibration of all gauges used in mechanical integrity demonstrations and other monitoring required by this Permit. All equipment must be calibrated in the manner and frequency recommended by the manufacturer and at least within one year prior to each required test. The date of the most recent calibration must be noted on or near the gauge or meter. A copy of the calibration certificate must be submitted to the Director in an electronic format with the report of the test. All recordings must read to an accuracy of no more than 0.5 percent of full scale for mechanical gauges. Pressure gauge resolution must be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and must be identified in the procedure submitted to the Director prior to the test.

7. Notification Prior to Testing and Reporting

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

   (b) The Permittee must notify the Director of any loss or suspected loss of MI as outlined within this Permit in accordance with Section O of this Permit.

   (c) The Permittee must report in an electronic format the results of a mechanical integrity demonstration as soon as possible but no later than 30 days after the demonstration is complete. Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst.

8. Loss of Mechanical Integrity – If the Permittee or the Director finds that the injection well and/or monitoring well(s) fail to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation or monitoring, or that a loss of mechanical integrity as defined by 40 C.F.R. § 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:

   (a) Cease injection immediately;

   (b) 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.

   (c) Implement the steps in the Emergency and Remedial Response Plan (Attachment F of this Permit);

   (d) Within 24 hours of the event, notify the Director of the circumstances surrounding the event in accordance with Section I.11(e);

   (e) Notify the Director in an electronic format when injection can be expected to resume and submit a projected plan for reestablishing MI or plugging the well.

   (f) Follow any other applicable reporting requirements as directed in Section O of this Permit;

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

   (h) If an automatic 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 investigation, the well appears to be lacking mechanical integrity, or if the required monitoring 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).

   (i) 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.

   (j) The well(s) must remain shut-in until the Permittee receives written approval from the Director to commence/resume injection.

M. SEISMIC EVENT RESPONSE

The Permittee must implement the response actions for seismic events as described in the Emergency and Remedial Response Plan (Attachment F) of this Permit.

N. TESTING AND MONITORING REQUIREMENTS

The specific measurement and reporting frequencies are listed in Attachment C.

1. Testing and Monitoring Plan

   (a) The Permittee must maintain and comply with the approved Testing and Monitoring Plan included as Attachment C of this Permit and with the requirements at 40 C.F.R. §§ 144.51(j), 146.88(e), and 146.90, and any modifications required by the Director after the effective date of this Permit. Samples and measurements taken for the purpose of monitoring must 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 if they plan to deviate from the procedures outlined in the Testing and Monitoring Plan in Attachment C of this Permit. 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 by 40 C.F.R. § 146.90(j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G of this Permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration must 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 must 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 must analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics at least annually, as described in the Testing and Monitoring Plan and to meet the requirements of 40 C.F.R. § 146.90(a).

3. Continuous Monitoring – The Permittee must install and use continuous recording devices to monitor: the injection pressure (at surface and directly above the packer), injection flow rate, injection mass, pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature (at surface and directly above the packer). This monitoring must be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 C.F.R. § 146.90(b). The Permittee must 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. Groundwater Monitoring Above the Confining Zone – The Permittee shall monitor groundwater quality and geochemical changes above the confining zone that may be a result of carbon dioxide movement through the confining zone and additional identified geologic units. All monitoring conducted must be performed for the parameters identified in the approved Testing and Monitoring Plan in accordance with the plan in Attachment C at the locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 C.F.R. § 146.90(d).

5. Carbon Dioxide Plume and Pressure Front Tracking – The Permittee must track the extent of the carbon dioxide plume and pressure front using direct and indirect monitoring methods as described in the approved Testing and Monitoring Plan with criteria outlined in Attachment C and in accordance with 40 C.F.R. § 146.90(g). The Permittee is required to conduct this monitoring in order to detect and locate the carbon dioxide pressure front and the dissolved carbon dioxide plume and the data will be used to calibrate the AoR model to determine whether modifications to the AoR need to be made. The data collected will be used to monitor the location of the plume and pressure front, evaluate its movement through time, and to compare to the plume and pressure front predictions of the AoR model.

   (a) Direct Methods – The Permittee must use the deep monitoring point to continuously record the pressure and temperature of the injection zone formation to track the position of the carbon dioxide pressure front and to collect fluid samples from the injection zone formation to track the position of the carbon dioxide plume described in the approved Testing and Monitoring Plan with criteria outlined in Attachments B, C and K to meet the requirements of 40 C.F.R. § 146.90(g)(1).

   (b) Indirect Methods – The Permittee must use the indirect monitoring methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan with criteria outlined in Attachments B, C and K and to meet the requirements of 40 C.F.R. § 146.90(g)(2).

6. Corrosion Monitoring – The Permittee must perform corrosion monitoring of the injection well and monitoring well(s) construction 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 with criteria outlined in Attachments B, C, and H and in accordance with 40 C.F.R. § 146.90(c). This ensures that the well components meet the minimum standards for material strength and performance set forth in 40 C.F.R. 146.86(b).

7. External Mechanical Integrity Testing – The Permittee must demonstrate external mechanical integrity annually as described in the approved Testing and Monitoring Plan with criteria outlined in Attachment C and must comply with Section L of this Permit in order to meet the requirements of 40 C.F.R. §§ 146.89 and 146.90.

8. 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 C.F.R. § 146.90(f).

9. Surface Air and/or Soil Gas Monitoring – In addition to the testing and monitoring outlined in this Permit and in the applicable regulations, the Director may require surface air monitoring and/or soil gas monitoring to detect potential movement of carbon dioxide that could endanger a USDW. Should the Director deem this monitoring necessary, the Testing and Monitoring Plan must be amended to be reflective of the frequency and locations the Director requires and must meet the requirements of 40 C.F.R. § 146.90(h).

10. Casing Inspection Logs – Casing inspection logs shall be run for both Injection and Monitoring Wells as follows:

    (a) Injection Well whenever the owner or operator conducts a workover in which the injection string is pulled, unless the Director waives this requirement due to well construction or other factors which limit the test's reliability or based upon the satisfactory results of a casing inspection log run within the previous five years.

    (b) Monitoring Wells whenever the owner or operator conducts a workover of the well of any kind, unless the Director waives this requirement due to well construction or other factors which limit the test's reliability or based upon the satisfactory results of a casing inspection log run within the previous five years.

    (c) The Director may require that a casing inspection log be run at a minimum of every five years, if the Director has reason to believe that the integrity of any well(s) may be adversely affected by naturally occurring or human-induced events.

11. Additional Monitoring – If required by the Director as provided in 40 C.F.R. § 146.90(i), the Permittee must perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 C.F.R. § 146.84(c) and to determine compliance with standards under 40 C.F.R. §§ 144.12 or 146.86(a). This monitoring must be performed as described in a modification to the

following Plan Attachments B, C and K of this Permit.

O. REPORTING AND RECORDKEEPING

The Permittee must submit reports at frequencies described in the approved Testing and Monitoring Plan, and as required by this Permit. Reports must contain all the data and information required to be monitored, gathered and reported by this Permit and meet the requirements of 40 C.F.R. §§ 144.17, 144.51(l), 144.54(c), and 146.91.

1. Electronic Reporting – All reports, submittals, notifications, correspondence to the EPA, and records made and maintained by the Permittee under this Permit must be in an electronic format. The Permittee must electronically submit all required reports to an address or location as determined by the Director.

2. Semi-Annual Reports – The Permittee must submit reports on a semi-annual basis in accordance with 40 C.F.R. § 146.91(a). The reporting period for semi-annual reports will be from January 1 through June 30 and from July 1 through December 31. Reports must be submitted within 30 days of the end of each reporting period. Semi-annual reports must include all data collected on a continuous, daily, monthly, quarterly and semi-annual basis as described in the approved Testing and Monitoring Plan. The second semi-annual report for each year must include all data collected on an annual basis as described in the approved Testing and Monitoring Plan. Reports must contain the following information and data, as well as all other information and data collected not listed below, but as described in the approved Testing and Monitoring Plan:

    (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 this Permit;

    (d) A description of any event which triggers the shut-off systems required in Section K of this Permit pursuant to 40 C.F.R. § 146.88(e), and the response taken;

    (e) The monthly mass of the carbon dioxide stream injected over the reporting period and the 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 N 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 mass of injectate, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and

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

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

3. 24 Hour Reporting

(a) The Permittee must report to the Director any permit noncompliance that may endanger human health or the environment and any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this Permit). Any information must be provided orally within 24 hours from the time the Permittee becomes aware of the circumstances. Such verbal reports must include, but need 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 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 C.F.R. § 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 must 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 O of this Permit. The submission must contain a description of the noncompliance or emergency, or remedial response and its cause; the period of noncompliance, emergency, or remedial response, 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 or emergency or condition requiring remedial response.

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. Advanced Notice Reporting

(a) Well Tests – The Permittee must 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 must give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted facility. An analysis of any new injection fluid must 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 must 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. <u>Additional Reports</u>

   (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 must 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 C.F.R. § 144.38(a) have been met. Pursuant to requirements at 40 C.F.R. § 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. All FR cost estimates, documentation, and instruments as required by 40 C.F.R. § 146.85 and by Section H of this Permit must be updated and provided to the Director by any new owner of the well.

   (c) Other Noncompliance – The Permittee must report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports must contain the information listed in Section O 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 must submit such facts or corrected information in an electronic format within 10 days of discovery in accordance with 40 C.F.R. § 144.51(l)(8).

   (e) Report on Permit Review – Within 30 days of receipt of this Permit, the Permittee must 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. <u>Records and Record Retention</u>

   (a) The Permittee must 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 must maintain records of all data required to complete the permit application for this Permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 C.F.R. §§ 144.27, 144.31, 144.39, and 144.41 until least 10 years after site closure.

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

(d) The retention periods specified in Section O of this Permit may be extended by request of the Director at any time. The Permittee must continue to retain records after the retention period specified this Section of the 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 must 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.

P. <u>WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE</u>

The Permittee must maintain and comply with the approved Well Plugging Plan (Attachment D) and the approved Post Injection Site Care and Site Closure Plan (Attachment E) and must comply with the requirements of 40 C.F.R. §§ 146.92 and 146.93. The Well Plugging Plan and the Post-Injection Site Care and Site Closure Plan are enforceable conditions of this Permit.

1. <u>Well Plugging Plan Revisions</u> – If data indicates and the Permittee deems it necessary, or if the Director requires the approved plans in Attachments C and D of this Permit to be modified, revised plan(s) must be submitted in an electronic format to the Director for review and written approval. Any amendments to the Well Plugging Plan and/or the Post-Injection Site Care and Site Closure plan must be approved by the Director and must be incorporated into the permit and are subject to the permit modification requirements at 40 C.F.R. §§ 144.39 and/or 144.41.

2. Required Activities Prior to Plugging – The Permittee must flush the well with an inert buffer fluid, determine the post-injection bottom hole pressure, and perform final internal and external mechanical integrity tests prior to injection well plugging. The internal and external mechanical integrity tests must be performed as required by Section L of this Permit.

3. Notice of Plugging and Abandonment – The Permittee must notify the Director in writing in an electronic format pursuant to 40 C.F.R. § 146.92(c), at least 60 days before plugging, conversion or abandonment of the well. A shorter notice period may be allowed at the discretion of the Director.

4. Plugging and Abandonment Approval and Report

    (a) The Permittee must receive written approval from the Director before plugging the well and must plug and abandon the well as required by 40 C.F.R. § 146.92, as described in the approved 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 signed and certified by the Permittee per 40 C.F.R. § 144.32 and by the person who performed the plugging operation (if other than the Permittee.) The Permittee must 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 approved Well Plugging Plan (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 must replug the well as required by the Director.

5. Temporary Abandonment – After any 24 consecutive month period of no injection, the well is considered to be in a temporarily abandoned status, and the Permittee must plug and abandon the well in accordance with the approved Well Plugging Plan, 40 C.F.R. §§ 144.52 (a)(6) and 146.92 or make a demonstration of non-endangerment of this well that is satisfactory to the Director while it is in temporary abandonment status. Temporary abandonment status includes instances where well construction/conversion has begun but no authorization to commence injection has been approved by the Director. During any periods of temporary abandonment or disuse, the Permittee must continue to comply with the conditions of this Permit, including all monitoring and reporting requirements in

compliance with all of the requirements of this Permit and all applicable regulations. The Permittee of a well that has been temporarily abandoned must notify the Director prior to resuming operation of the well.

6. Post-Injection Site Care and Site Closure Plan – The Permittee must maintain and comply with the Post-Injection Site Care and Site Closure Plan in Attachment E of this Permit and comply with the requirements of 40 C.F.R. § 146.93. The Post-Injection Site Care period is the length of time anticipated to demonstrate that the carbon dioxide injection poses no threat to USDWs and is an enforceable condition of this Permit.

   (a) Upon cessation of injection, the Permittee must either submit in 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.

   (b) 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 per 40 C.F.R. § 146.93(a)(3). 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 C.F.R. § 146.93(c)(1).

   (c) The monitoring as outlined in the approved Post-Injection Site Care and Site Closure Plan must define the position of the carbon dioxide plume and pressure front, provide a comparison of data collected to the predictions made by the AoR model, and demonstrate that USDWs are not being endangered per 40 C.F.R. §§ 146.90 and 146.93.

   (d) Prior to authorization for site closure, the Permittee must submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section P 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 C.F.R. § 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including an extension of the monitoring period) if there is a concern that USDWs are at risk of endangerment.

   (e) The Permittee must 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 must submit a revised plan.

(f) After the Director has authorized site closure, the Permittee must plug all monitoring wells as specified in Attachments D and E of this Permit in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The Permittee must also restore the site to its pre-injection condition.

(g) The Permittee must 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 C.F.R. § 146.93(f).

(h) The Permittee must 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 C.F.R. § 146.93(g). The Permittee must 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 C.F.R. § 146.91(f)(4). The Permittee must deliver the records in an electronic format to the Director at the conclusion of the retention period.

Q. EMERGENCY AND REMEDIAL RESPONSE

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 must 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 C.F.R. § 146.94.

1. If the data collected indicates evidence that the carbon dioxide plume and or pressure front may cause endangerment to a USDW, the Permittee must:

   (a) Cease injection in accordance with Section K and Attachments C and/or F of this Permit;

   (b) Take all reasonable steps necessary to identify and characterize any release from the underground injection system;

   (c) Notify the Director within 24 hours; and

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

2. At the frequency specified in the Emergency and Remedial Response Plan (Attachment F of this Permit) and 40 C.F.R. § 146.94(d), the Permittee must review the Emergency and Remedial Response Plan and submit an amended Emergency and Remedial Response Plan

or demonstrate to the Director that no amended is needed, as required at 40 C.F.R. § 146.94(d).The amended Emergency and Remedial Response Plan or demonstration must be submitted to the Director in an electronic format at least once every five years , within one year of an AoR reevaluation, following any significant changes to the facility such as the addition of injection or monitoring wells, within six months following the occurrence of an emergency event under the Emergency and Remedial Response Plan, or when required by the Director. If the amendments to the Emergency and Remedial Response Plan cause the cost estimates to change, then new Financial Responsibility must be submitted for review and approval by the Director in accordance with Section H of this Permit.

3. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the Permittee must 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.

R. 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 C.F.R. § 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 C.F.R. § 146.89(a)(1) and (2), and in accordance with Section L 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 C.F.R. § 146.84;

4. All requirements at 40 C.F.R. § 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 C.F.R. § 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 of this Permit; and

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

ATTACHMENTS

This Part includes, but is not limited to, permit conditions and plans concerning operating procedures, monitoring, and reporting, as required by 40 C.F.R. Parts 144 and 146. The Permittee must comply with these conditions and adhere to these plans as they are approved by the Director by their incorporation into this Permit.

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. WELL PLUGGING PLANS

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. PRE-INJECTION TESTING PLAN

H. WELL CONSTRUCTION DETAILS

I. FINANCIAL ASSURANCE DEMONSTRATION

J. STIMULATION PROGRAM

K. QUALITY ASSURANCE AND SURVEILLANCE PLAN

ATTACHMENT A: SUMMARY OF REQUIREMENTS

OPERATING AND REPORTING CONDITIONS

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Dr.
Hennepin, IL 61327

Well location: S2 T32N R2W
41.27026520°N, 89.30939322°W

Injection Well Operating Conditions, Parameters, and Limits:

Table 1: Summary of operating parameters.

PARAMETER/CONDITION	LIMITATION	UNIT
Maximum Injection Pressure - Surface	1,555	psig
Maximum Injection Pressure - Injection Zone at the top perforation	2,206	psig
Minimum Annulus Pressure	100	psig
Minimum Annulus Pressure/Tubing Differential (directly above and across packer)	100	psig
Carbon Dioxide Purity	>99%	percent
Maximum Injection Rate	1,500,000	metric tons/year

During the 12-year operational period, the injection pressure will be measured at the wellhead and at the injection interval.

The maximum injection pressure of the injection zone, which serves to prevent confining-formation fracturing, was determined using a fracture gradient of 0.76 psi/ft calculated from Minifrac tests performed at the MCI MW 1 characterization well. The injection zone maximum injection pressure is calculated as 90% of the depth to the top of the injection zone multiplied by the fracture gradient. The surface maximum injection pressure is the injection zone maximum injection pressure minus the static head.

After the well is constructed, the Maximum Injection Pressure (MIP) will be recalculated, the MIP limit in the table above will be revised, using a fracture gradient measured from step rate tests that will be conducted in the injection well and the actual depth of the top of the injection zone.

Summary of Measurement, Assessment or Update, and Reporting Frequencies

Table 2: Summary of monitoring activities.

ACTIVITY	MINIMUM RECORDING FREQUENCY	MINIMUM REPORTING FREQUENCY
CO_2 stream characterization	Quarterly and/or Continuous	Semi-annually
Flow rate, mass, annulus pressure, annulus fluid level, and temperature	Continuous	Semi-annually
Injection Pressure at the wellhead	Continuous	Semi-annually
Injection Pressure at the Injection Zone	Continuous	Semi-annually
Injection Zone Fluid Monitoring	Annually	Annually
Corrosion monitoring	Quarterly	Semi-annually
External MIT	Annually	Annually
Fall-off Test	Every 5 years	Every 5 years
Above Confining Zone Plume Monitoring – Galesville Sandstone	Quarterly for first 2 years of operation; semi-annually thereafter	Annually
Above Confining Zone Plume Monitoring–Gunter Sandstone	Annually	Annually
Above Confining Zone Plume Monitoring- Gunter Sandstone– Pulse Neutron Logging	Annually	Annually
Area of Review/Corrective Action Plan Assessment and Financial Responsibility Update	NA	Annually

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

The report submittal schedule is (determined on a calendar basis):

- Semiannual Reports due on or before July 31st for first reporting period and January 31st for second reporting period
- Annual Reports due on or before January 31st
- 5-year reports due on or before February 15th of the end of the 5-year reporting

cycle (from January 1st year 1 to December 31st year 5)

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Dr.
Hennepin, IL 61327

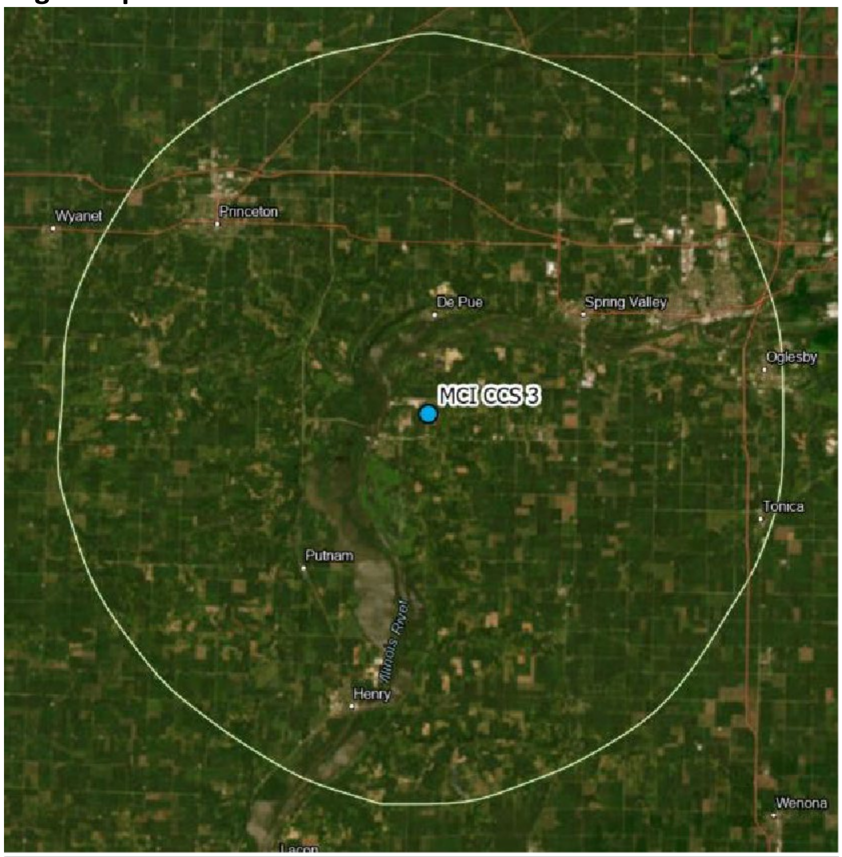
Well location: S2 T32N R2W
41.27026520°N, 89.30939322°W

Introduction

As a condition of the permit and as required by EPA's regulations set forth at 40 C.F.R. § 146.84, Marquis Carbon Injection LLC (Marquis) must maintain and implement an approved plan to delineate the Area of Review (AoR) for a proposed geologic sequestration project, periodically reevaluate the delineation, and a perform corrective action on all wells in the AoR needing corrective action as determined by the Director.

This attachment to the Permit delineates the AoR, which is the region surrounding the geologic sequestration project where Underground Sources of Drinking Water (USDWs) may be endangered by the injection activity. This attachment also details Marquis' approved plan for how wells within this area will be assessed and addressed by Marquis to ensure containment and corrective action. The map in Figure 1 below presents the AoR based on the approved modeling performed by Marquis.

Figure 1: Map showing Marquis' AoR.



Computational Modeling Approach

The AoR for a Class VI injection project must be delineated using a model that accounts for the physical and chemical properties of all phases of the injected carbon dioxide. 40 C.F.R. § 146.84(a).

Marquis used two models in its Class VI application: a 7x7 mile (mi) model for the CO_2 plume and a 100x100 mi model to assess the AoR. The 100x100 mi AoR model is an expansion of the 7x7 mi plume model. That is, it utilized similar parameters. The models were static earth models (SEM) run by Battelle on the Schlumberger Petrel® modeling software. The SEM serves as the framework for Dynamic Reservoir Modeling (DRM) of CO_2 injection. The injection of carbon dioxide into a saline aquifer was modeled using the flow simulator CMG-GEM, 2016. Marquis used site-specific data for the modeling. The model simulation used a closed boundary, resulting in a 29-mile diameter AoR 35 miles from the model's edges on each side. A second simulation was run under multiplier boundary conditions (constant pressure boundary) to further confirm the observations that the dynamic reservoir modeling boundary conditions do not significantly impact the AoR size. Model resolution increased near the injection well. Within 500 feet (ft) of MCI CCS 3, cell size was 62.25 ft x 62.25 ft. This increased to 100 ft x 100 ft within 3,960 ft, and beyond this, 500 ft x 500 ft.

<u>Figure 2</u>: Map showing the modeled CO2 plume footprint, and existing and proposed project.

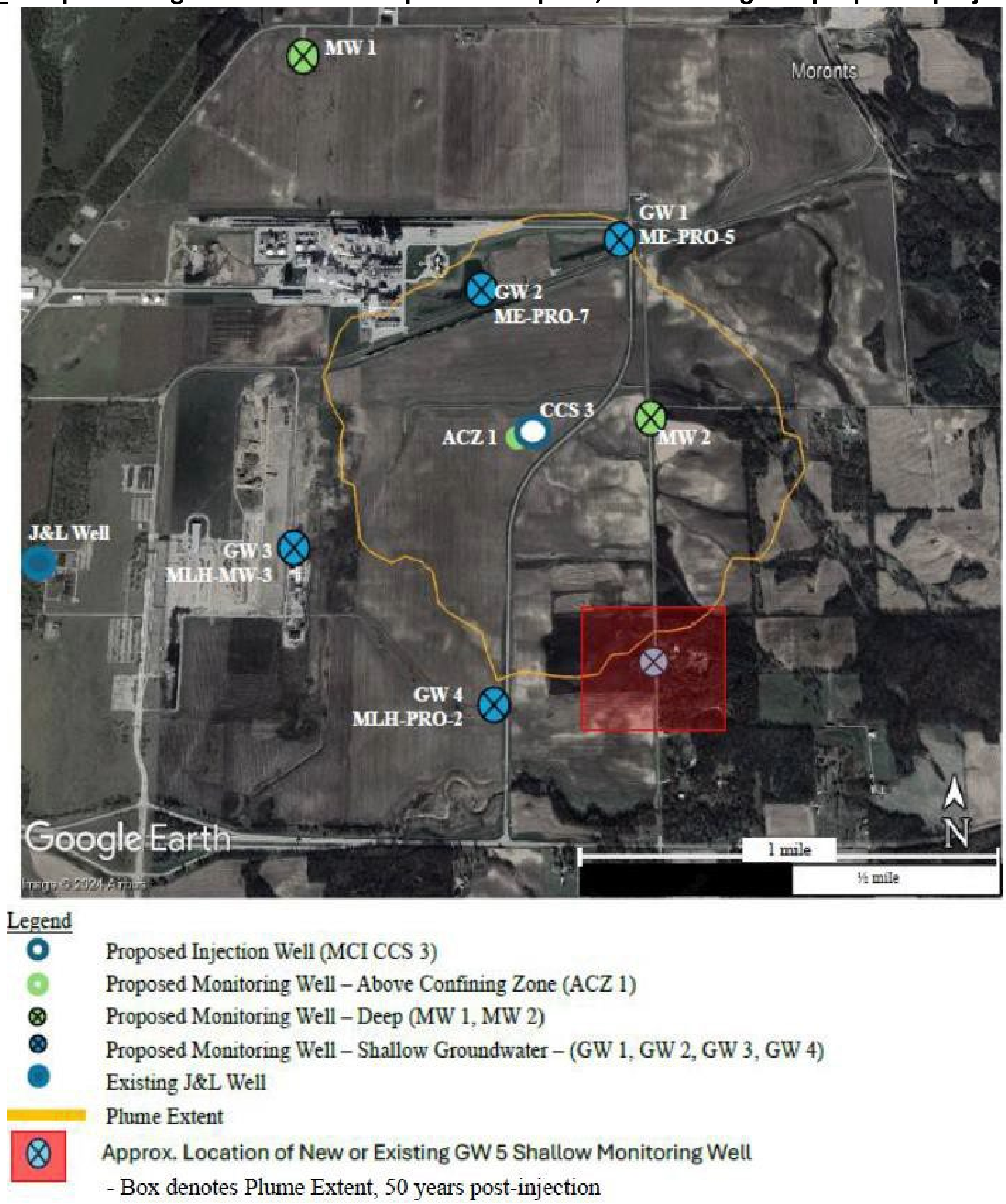


Figure 3: Stratigraphic column with lithology and hydrostratigraphy for the Marquis site based on data from the characterization well, MCI MW 1.

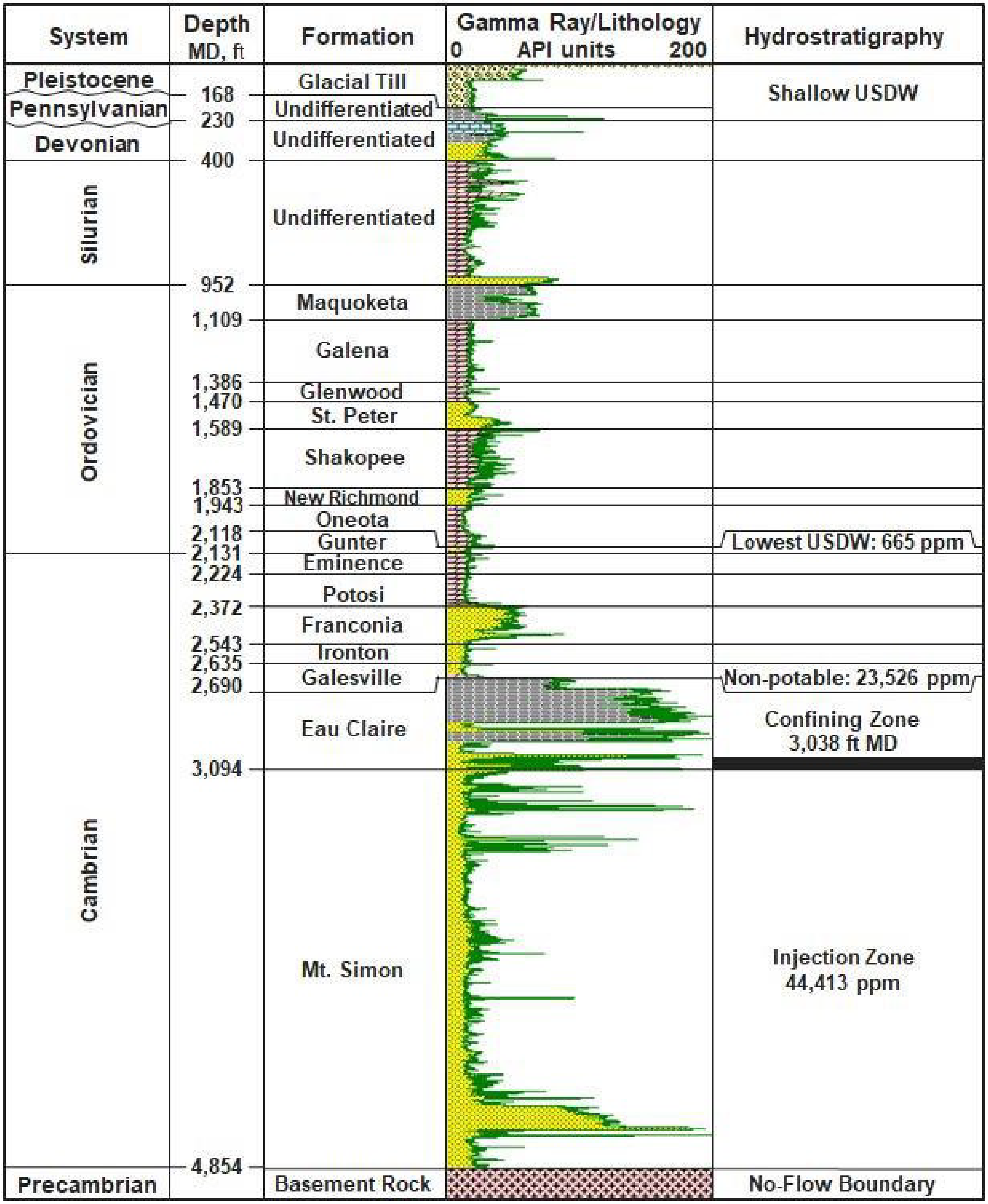


Table 1: Proposed zone for injection reservoir at the Marquis project area, as identified in the MCI MW 1.

Injection zone	Formation Thickness (ft)	Depth (ft)	Avg. Porosity (%)	Avg. Permeability (mD)
Mt. Simon Sandstone	1,760	3,094	7.9	79.9

Table 2: Model domain information.

Coordinate System	NAD 1983 BLM Zone 16N ft US		
Horizontal Datum	NAD83		
Coordinate System Units	Field = feet		
Zone	UTC -06:00 Central Time (US & Canada)		
FIPSZONE	1202	**ADSZONE**	3801
Coordinate of X min	735761.96	**Coordinate of X max**	14729359.72
Coordinate of Y min	1274438.25	**Coordinate of Y max**	15267988.58
Elevation of top of domain	-4851.12	**Elevation of bottom of domain**	-1903.17

Table 3: Initial Modeled Conditions.

Parameter	**Value or Range**	**Units**	**Corresponding Elevation (ft MSL)**	**Data Source**
Temperature	81.5 83.34 92.6	F	Top Eau Claire: 2,699 Top Mt. Simon: 3,068 Base Mt. Simon: 4,912	Temperature Log
Formation pressure	0.44	psi/ft	2,699 – 4,912	Drill Stem Testing
Fluid density	0.029	lb/ft^3	2,699 – 4,912	CMG Reservoir Simulator Calculation
Salinity	45000	ppm	2,699 – 4,912	Drill Stem Testing

Table 4: Modeled Operating Parameters.

Operating Information		**MCI CCS 3**
Location (global coordinates)	X Y	41.27026520° -89.30939322°
Model coordinates (ft)	X Y	987293.52° 14979542.23°
No. of perforated intervals		5
Perforated interval (ft MSL)	Z Top Z Bottom	3225 – 3383 3445 – 3488 3519 – 4137 4268 – 4290 4411 – 4791
Wellbore diameter (in)		9 5/8
Planned injection period	Start End	
Injection duration (years)		6
Maximum injection rate (million tonnes (MT)/year)		1.5

Table 5: Parameters and values used as input in the critical pressure calculation.

Parameter	**Value**	**Units**	**Source**
Pressure at the base of the lowermost USDW	895.99	psi	MCI MW 1
Depth to base of lowermost USDW	2,140	ft	MCI MW 1
Depth to top of injection zone	3,054	ft	MCI MW 1
Hydrostatic injection zone pressure	1,343.15	psi	MCI MW 1
Fluid density within the injection zone	1,051.48	kg/m^3	MCI MW 1

Corrective Action Plan and Area of Review Re-evaluation

This Corrective Action Plan and Area of Review Re-evaluation describes how Marquis will comply with the plan requirements at the Permit CCS Project site pursuant to 40 C.F.R. § 146.84 and per Section G of this permit. Data from MCI MW 1 indicates that the top of the confining zone at the project site is 2,690 ft MD (Figure 1). There are 6 wells within the AoR not associated with the Marquis project that partially penetrate the local confining zone depth (i.e., 2,690 ft MD), and a seventh non-project well approximately 1.25 mi from the injection well that penetrates the entire confining zone: the J&L well. The J&L well was properly plugged and abandoned in 2013 using cement suitable for contact with brine and acid. Data collected as part of the Testing and Monitoring Plan (See attachment C of this permit) will be evaluated to assess the prohibition of fluid movement and protection of USDWs. The Corrective Action Plan will be re-evaluated in accordance with this permit and all applicable regulations.

Monitoring well MCI MW-2 is predicted to come into contact with the injected CO_2 per this permit's computational modeling. Should the subsurface CO_2 plume interact with any additional well(s) or be predicted to interact with any additional well(s) per a revision to the project's computational modeling, such wells interacting or predicted to interact with the subsurface CO_2 plume will be evaluated for proper construction materials for the environment to which the wells will be exposed. The results of the well construction materials evaluation must be submitted to the Director within 14 days of the permittee learning of the interaction or predicted interaction. Within 45 days of the permittee learning of the interaction or predicted interaction, the permittee must submit a corrective action plan to address any construction deficiencies and must complete any corrective actions within a timeframe acceptable to the Director.

Reevaluation of CAP: Schedule and Criteria

Marquis will take the following steps to evaluate project data and, if necessary, reevaluate the AoR. AoR reevaluations will be performed during the injection and post-injection phases at least every 5 years. Marquis will:

1) Review available monitoring data and compare it to the model predictions. Marquis will analyze monitoring and operational data from the injection well, the formation monitoring wells and confinement monitor wells, and other sources to assess whether the predicted carbon dioxide plume migration is consistent with actual data. Monitoring activities to be conducted are described in the Testing and Monitoring Plan and the Post Injection Site Care (PISC) and Closure Plan. Specific steps of this review include:

    a) Reviewing available data on the position of the carbon dioxide plume and pressure front.
        i) Both direct and indirect methods will be used to monitor the carbon dioxide plume and pressure front. See Attachments C, E, and K for more information.

b) Reviewing groundwater chemistry monitoring data taken in the Gunter Sandstone, Galesville Sandstone, and Mt. Simon Sandstone to verify that there is no evidence of excursion of carbon dioxide or brines that represent an endangerment to any USDWs.

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

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

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

3) If the information reviewed is consistent with, or is unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of the plume and pressure front movement, Marquis will prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AoR is needed. The report will be submitted to the Director within 30-days of its review of the data and will include the data and results demonstrating that no changes are necessary. Marquis will review all data within 90-days of the commencement of Marquis 5-year review process.

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

a) Revise the site conceptual model based on new site characterization, operational, or monitoring data.
    i. Reevaluation of the AoR and CAP must meet the requirements of 40 C.F.R. § 146.84(e) and must include a new survey of wells within the existing or modified AoR.

b) Calibrate the model in order to minimize the differences between monitoring data and model simulations.

c) Perform the AoR delineation as described in the Computational Modeling section of the AoR and Corrective Action Plan.

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

a) Identifying any new wells within the AoR that penetrate the confining zone and provide a description of each well type, location, depth, and date of plugging/completion.

b) Performing corrective action on all deficient wells that penetrate the primary confining zone using methods designed to prevent the movement of fluid into USDWs.

6) Prepare an annual report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to EPA per the schedule for submitting annual reports in this permit. The report will include maps that highlight the similarities and differences in comparison with previous AoR delineations.

AoR Reevaluation Cycle

Upon commencement of injection, Marquis will reevaluate the above described AoR at least once every 5 years during the injection and post-injection phases. More frequent reviews may occur if any of the events described in the next section occur or at the discretion of the Director. Marquis will also review this AoR and corrective action plan following any AoR reevaluation and submit an amended plan or demonstrate to the Director that no amendment to the AoR and corrective action plan is needed. Marquis must retain all modeling inputs and data used to support AoR reevaluations for 10 years.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled reevaluation of the AoR will be based on quantitative changes of the monitoring parameters in the deep monitoring wells, including unexpected changes in pressure, temperature, neutron saturation, and deep groundwater constituent concentrations indicating that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes may include but are not limited to:

1) **Pressure:** Changes in pressure that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.

2) **Pressure front arrival**: If the arrival time of the pressure front at the deep monitoring well differs significantly from the model projections (2 standard variations) or if the pressure and plume data recorded at the well differs materially from expectations, an AoR reevaluation will be performed.

3) **Change in pressure front not seen in monitoring well**: A reevaluation of the AoR will be triggered in the event that a secondary means of pressure front and/or plume distribution is detected (such as through seismic observation).

4) **AoR interaction:** Potential interaction of AoRs from different wells: Future modeling could indicate possible interactions of AoRs from different injection wells in the same injection zone. This has the potential to change the evaluation schedule (i.e., cause an unscheduled AoR reevaluation) to assess the possible impact of such an occurrence.

5) **Temperature:** Changes in temperature that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.

6) **RST saturation:** Increases in carbon dioxide saturation that indicate the movement of the carbon dioxide into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. Marquis must investigate and address any well integrity issues pursuant to 40 C.F.R. § 146.88(d) and (f).

7) **Deep groundwater constituent concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of the carbon dioxide or brines into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. Marquis must investigate and address any well integrity issues pursuant to 40 C.F.R. § 146.88(d) and (f).

8) **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 the measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan and the operating procedures in the Narrative provides a discussion of pressure monitoring and specific procedures that will be completed during the injection start-up period and continuing operations.

9) **Exceeding established baseline hydrochemical/physical parameter patterns:** A statistically significant difference between observed and baseline hydrochemical/physical parameter patterns (e.g., fluid conductivity, pressure, temperature) immediately above the confining zone. The Testing and Monitoring Plan provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.

10) **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.

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

1) Seismic event greater than M_w 3.5 within 100 km the injection well.

2) If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected); or

3) If new site characterization data changes the computational model to such an extent that the predicted plume or pressure front exceeds, or is expected to exceed, vertically or horizontally beyond the predicted AoR.

Marquis will discuss any such events with the Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, Marquis will reevaluate the AoR in accordance with the regulations.

Table 6: Observed changes in monitoring data that may trigger an AoR re-evaluation.

Observed Change	Monitoring Technology
Significantly larger pressure increases in the Mt. Simon Sandstone in the monitor well than were predicted by the model	Pressure sensors
Early breakthrough of CO_2 at the monitoring well	Fluid sampling Pulsed neutron logging
CO_2 plume expands at a rate inconsistent with what the model predicted	Time-lapse surface seismic data
Sustained pressure increases observed in above confining zone in the MCI ACZ 1 monitoring well intervals	Pressure sensors
Geochemical changes in the MCI ACZ 1 monitoring intervals indicate potential CO_2 or brine migrations above the confining layer	Fluid sampling
CO_2 accumulations identified in the MCI ACZ 1 intervals	Pulsed neutron logging Time-lapse surface seismic data

ATTACHMENT C: TESTING AND MONITORING PLAN

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Dr.
Hennepin, IL 61327

Well location: S2 T32N R2W
41.27026520°N, 89.30939322°W

This Testing and Monitoring Plan describes how Marquis will monitor the Marquis Biocarbon Project site pursuant to 40 C.F.R. § 146.90 and per Section N of this permit. The Marquis Biocarbon Project will utilize one injection well to achieve the required annual injection rate. The Testing and Monitoring plan includes activities related to the injection well and the associated carbon dioxide plume. Marquis will use the monitoring data to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and there is no endangerment to underground sources of drinking water (USDWs). Marquis will also use the monitoring data to validate and adjust the geological models used to predict the distribution of the carbon dioxide within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may require Marquis to take action as described in the Emergency and Remedial Response Plan in Attachment F of this permit.

Testing and Monitoring Schedule of Sampling

All testing and monitoring will be conducted in accordance with the requirements of this permit, and the procedures will meet the requirements of the Quality Assurance and Surveillance Plan (QASP) in Attachment K of this permit.

The schedule of sampling is as follows:

1) Continuous: Data is continuously sampled and recorded per the frequencies presented in Table 2 of this attachment.
2) Quarterly: Sampling will take place within 30 days before the following dates each year: March 31st, June 30th, September 30th, December 31st.
3) Semi-annual: Sampling will take place within 30 days before June 30th and December 31st.
4) Annual: Sampling will take place within 45 days before January 1st of each year.
5) 5 Year: Sampling will take place every 5 years within 45 days before January 1st during injection and PISC periods (i.e., 5, 10, 15, etc. years after commencement of injection until site closure).

Measurement, Monitoring and Verification (MMV) Technologies

Two key objectives of any risk assessment evaluation and the development of a viable MMV plan are to:

1) Ensure Conformance by demonstrating that storage performance aligns with expectations regarding injectivity, capacity, and carbon dioxide behavior inside the geologic storage reservoir; and
2) Ensure Containment, which demonstrates security of carbon dioxide storage to protect human health, groundwater resources, hydrocarbon resources (if present), and the environment, and meets regulatory requirements.

Reporting procedures

Marquis will report the results of all testing and monitoring activities to the EPA in compliance with this attachment, the requirements under 40 C.F.R. § 146.91, and Section O of this permit.

Carbon Dioxide Stream Analysis

Marquis will analyze the carbon dioxide stream during the operation period with sufficient frequency to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 C.F.R. § 146.90(a). Sampling will take place continuously via permanently installed field analysis equipment, with the exception of total hydrocarbons, methane, and hydrogen sulfide which will be sampled quarterly. Marquis will sample and analyze the carbon dioxide stream as presented below.

Analytical Parameters

Marquis will employ continuous monitoring of the carbon dioxide stream with in-situ analysis at the Permit facility. Samples of the injection stream will be collected for chemical analysis. The CO_2 compression system that will be used to inject the off gases into the MCI CCS 3 well has been selected. The compressor design includes the use of a triethylene glycol (TEG) gas dehydration system to remove moisture from the gas stream. The carbon dioxide will be sampled for the following parameters:

Table 1: CO_2 Stream Analytical Parameters.

Parameter	**Analytical Method(s)**
Oxygen	Mass Spectrometer
Nitrogen	Mass Spectrometer
Total Hydrocarbons	Lab Analysis
Methane	Lab Analysis
Hydrogen Sulfide	Lab Analysis
Carbon Dioxide Purity	Mass Spectrometer
Moisture	Hygrometer

If at any time this monitoring reveals a substantive change from expected for the carbon dioxide stream, process troubleshooting will begin to determine the root cause of the carbon dioxide quality deviation. If carbon dioxide purity falls below 99% causes will be investigated and AoR re-modeling will be initiated, if appropriate.

Continuous Recording of Operational Parameters

As required by 40 C.F.R. § 146.90(b), Marquis will install and use continuous recording devices to monitor injection pressure, rate, and mass; the pressure on the annulus between the tubing and the long string casing; the fluid volume added to or produced from the annulus; and the temperature of the carbon dioxide stream.

System Operation Monitoring

Marquis will perform the activities identified here and in the QASP in Attachment K to continuously monitor operational parameters listed in Appendix A and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table below.

Table 2: Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection Pressure at Wellhead	Pressure Transducer	Wellhead	Every 1 min.	Every 1 min.
Injection Pressure at Formation (downhole)	Pressure Transducer	Tubing string above injection packer	Every 1 min.	Every 1 min.
Mass Injection Rate	Coriolis Flow Meter	After Compressor before wellhead (Pre- Wellhead)	Every 10 sec.	Every 10 sec.
Annular Surface Pressure	Pressure Transducer	Wellhead Annulus Monitoring System (WAMS) Surface Skid	Every 1 min.	Every 1 min.
Annular Downhole Pressure	Pressure Transducer	Above Injection Packer	Every 1 min.	Every 1 min.
Annulus Fluid Volume Added	Volume Level Instrument	WAMS Surface Skid	Every 1 min.	Every 1 min.
CO_2 Stream Temperature (surface injection)	Thermocouple	Wellhead	Every 1 min.	Every 1 min.
CO_2 Stream Temperature (downhole)	Thermocouple	Tubing string above packer	Every 1 min.	Every 1 min.
Wellbore Temperature Profile	Distributed Temperature Sensing (DTS) Fiber Optic	Distributed Temperature Sensing (DTS) Fiber Optic	Annual	Annual

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). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

System Monitoring details

The monitoring of the injection operations will be conducted through a distributed control system (DCS), and the computerized system will collect data from the sensors and record that data. The DCS system will also use alarms that will notify if the injection system is out of a specified range of operational parameters detailed in Attachment A, and if the operational parameters are exceeded, the DCS will shut down the system. The managers, supervisors, and operators will have the capability to monitor the injection system from Marquis' control centers.

Any pressure anomalies outside of the normal operating specifications may indicate that an issue has occurred with the well, such as a loss of mechanical integrity or blockage in the tubing or a change in injection flowrate. Anomalous pressure measurements would trigger the need for further investigation of the cause of the change (40 C.F.R. § 146.89(b)).

The temperature of the CO_2 injection stream will be continuously measured using an electronic thermocouple. The thermocouple will be mounted in a temperature thermowell in the CO_2 injection stream at a location close to the pressure transmitter near the wellhead. The transmitter will be electronically connected to the DCS system. The transmitter will be calibrated prior to the start of injection operations and calibrated annually per manufacturer's instructions.

The wellhead pressure of the injected CO_2 will be continuously measured by an electronic pressure transducer located after the compression system and before the wellhead with the MCI CCS 3 well. The transmitter will be electronically connected to the DCS system located in the Control Building, which can shut down the system or change the flowrate depending on the pressures measured at the wellhead. The transducer will be calibrated prior to the start of injection operations, and as recommended by the manufacturer thereafter.

The pressure on the annulus between the injection tubing and the long-string casing will be measured by an electronic pressure transducer with output, such as a Foxboro I/A Series® IAP20 or similar, that is mounted on the wing valve/annular fluid line connected to the wellhead of the MCI CCS 3 well. The transmitter will be connected to the well control system and the DCS system to regulate the annular pressure.

The volume of the annulus fluid between the injection tubing and the long-string casing will be measured using the brine reservoir level on the well annular control system. The brine reservoir level will be measured using a level transmitter (Rosemont 3051CD2A22A1AE5M5 or equivalent). The transmitters will be connected to the DCS system to regulate the annular pressure.

Annular pressure in MCI CCS 3 is expected to vary up to 20% during normal operations due to atmospheric and CO_2 stream temperature fluctuations. The annular pressure gauge will be calibrated annually, and the transducer will be recalibrated according to the manufacturer's recommendations. Annular pressure between the casing and tubing string in the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells will be monitored using a simple pressure gauge at the wellhead checked weekly.

Pressure and temperature data will be recorded from MCI CCS3 continuously on surface and in down hole before and after injection. The pressure and temperature will be measured using a pressure transducer and thermocouple, respectively. The surface and down hole pressure and temperature equipment will be calibrated over the full operational range according to manufacturers' specifications or recognized industry standards.

In accordance with the AoR recalculation schedule, the data collected during the monitoring program will be analyzed and interpreted annually. The data will then be integrated into the static and dynamic models every 5 years or 4 million tons whichever is earlier, incorporating the data collected in the storage formation. The pressure, temperature, and CO_2 plume data will be crucial to the AoR update. If there is confirmed anomalous data that could affect the AoR or CO_2 plume development, the static and dynamic models will be updated to show the effect of the data on the modeling results. AoR will then be re-established, and any necessary corrective actions will be taken.

Injection Rate and Pressure Monitoring

The Surface Facility Equipment and Control System will limit the bottomhole pressure to the maximum injection pressure (MIP) listed in Attachment A of this permit. NOTE: The injection pressure limit may be changed if the Fracture Gradient is significantly different during subsequent well testing during the drilling of the injection well(s). All injection operations will be continuously monitored and controlled by Marquis operations staff using the DCS system. This system will continuously monitor, control, record, and will alarm and shutdown if specified control parameters, identified in Attachment A, exceed their normal operating range.

These set points may need to be adjusted after the injection well is constructed and the startup testing has been conducted. The final alarm set points will be included in the startup report submitted to EPA.

More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system. Operators will monitor the status of the entire system from the main operations control room.

Calculation of Injection Volumes

The mass flowrate of CO_2 injected into the well will be measured by a Coriolis mass flow meter.

This flow meter will be placed in the CO_2 delivery line between the final compressor and the well. The Coriolis mass flow meter flow transmitter will have an output for instantaneous flow rates and density values along with a pulse output for totalization values (Micro Motion Elite Coriolis mass flow and density meter or similar). The Coriolis meter flow transmitter and P/T compensation transmitters will all be connected to the Measurement RTU flow computer system (Fisher FB 3000) for continuous monitoring and control of the CO_2 injection rate into the well. A hardwired signal will be connected from the Measurement RTU flow computer to the main DCS control panel via PROFINET. Two Coriolis mass flow meters will be supplied; this will provide one spare flow meter to allow for flow meter servicing and calibration. The mass flow meters will be calibrated annually.

Continuous Monitoring of Annular Pressure

Marquis will use the procedures below to monitor annular pressure. The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus:

1) The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity and a density that meets the requirements of the downhole conditions. The final values will be determined after the construction of the injection well.
2) The surface annulus pressure will be kept at a minimum of 100 pounds per square inch (psi) during injection (This is subject to changes based upon actual conditions encountered at the injection site).
3) During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer set at 3,000’ MD depth.
4) The pressure within the annular space, over the interval above the packer to the confining layer, will be greater than the pressure of the injection zone formation at all times.
5) The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

Casing-Tubing Pressure Monitoring

Marquis will monitor the casing-tubing pressure on a continuous basis. During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. Surface pressure of the casing-tubing annulus is anticipated to be 956 psi. As detailed in the Emergency and Remedial Response Plan in Attachment F, significant changes in the casing-tubing annular pressure will be investigated.

Corrosion Monitoring

To meet the requirements of 40 C.F.R. § 146.90(c) and Section N(6) of this permit, Marquis must monitor well materials during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 C.F.R. § 146.86(b).

Monitoring Location and Frequency

This monitoring will occur quarterly, in accordance with Section N and Attachment A of this permit. Marquis will monitor corrosion using Corrosion Coupon Method and collect samples according to the description below.

Sample Description

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the carbon dioxide stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 3 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see "Sample Handling" below).

Table 3: List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel Alloy
Long String Casing	25Cr Steel Alloy/ 13Cr Steel Alloy
Injection Tubing	25Cr Steel Alloy
Wellhead	Carbon Steel Alloy
Packers	25Cr Steel Alloy Corrosion resistant material

Monitoring details

Marquis will include the following elements in the monitoring program: continuous recording of injection pressure; continuous recording of injection mass flowrate; dynamic modeling; continuous recording of annular pressure; continuous recording of annulus fluid volume; continuous recording of CO_2 stream temperature; and down hole pressure and temperature. See "System Monitoring details" above for further discussion.

A bailer system will be used to collect the fluid samples to evaluate geochemical changes in groundwater fluids. Samples will be analyzed for field constituents using a calibrated water quality meter (Horiba U-53, or similar). The geochemical analyses will be performed by a qualified laboratory. The isotopic analyses will be performed by a qualified laboratory.

Sample Handling

A nationally accredited environmental laboratory will analyze the CO_2 stream samples. The third-party laboratory will follow standard sample handling and chain-of-custody guidance (EPA 540-R-09-03, or equivalent).

Sample holding times will be consistent with standard methods, identified in Attachment K. After collection and any necessary preservation, samples will be placed in ice chests in the field and maintained thereafter at approximately 4 degrees Celsius (°C) until analysis. The samples will be maintained at their preservation temperature and sent to the designated laboratory within 24 hours.

Above Confining Zone Groundwater Monitoring

Marquis will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 C.F.R. § 146.90(d) and Section N(4) of this permit.

Monitoring Location and Frequency

Table 4: Monitoring of groundwater quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Gunter Sandstone	Pressure/ Temperature	MCI ACZ 1	1 sample point @2,118 ft	Continuous (Every minute)
Gunter Sandstone	Groundwater Geochemistry	MCI ACZ 1	1 sample point @2,118 ft	Twice / year (Note 1)
	Stable Isotopes			Twice / year
Galesville Sandstone	Pressure/ Temperature	MCI ACZ 1	1 sample point @2,635 ft	Continuous (Every minute)
Galesville Sandstone	Groundwater Geochemistry	MCI ACZ 1	1 sample point @2,635 ft	Twice / year (Note 1)
	Stable Isotopes			Twice / year

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Formations shallower than 300 ft below ground surface (bgs)	Shallow groundwater monitoring	MCI GW 1-5	Above 300 ft bgs	Twice/year
Formations shallower than 300 ft bgs	Isotope Analysis	MCI GW 1-5	Above 300 ft bgs	Twice/year
Note: (1) For establishing baseline, sampling of the deep wells will occur during well drilling and prior to start of injection.				

Analytical Parameters

Table 5: Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods
Formation: Galesville Sandstone and Gunter Sandstone	
Cations (Sodium (Na), Calcium (Ca), Magnesium (Mg), Barium (Ba), Iron (Fe), Potassium (K), Strontium (Sr))	ASTM D1976 EPA Method 6020
Anions (Chloride (Cl), Bromide (Br), Sulfate (SO_4))	ASTM D4327 EPA Method 300
Dissolved Inorganic Carbon	ASTM D513-11 SM 5310C EPA Method 9060
Density	ASTM D4052 SM 2710F
Total Dissolved Solids	ASTM D5907 SM 2540C
Alkalinity	ASTM D3875 SM 2320B
pH	ASTM D1293 Standard Method (SM) 4500H
Conductivity/Resistivity	ASTM D1125 SM 2510B
Stable Isotopes of Carbon (C), Oxygen (O), and Hydrogen (H)	CRDS Laser H Isotopes Ratio Mass Spectrometry (IRMS) for C (Note 1)

Carbon-14	Accelerator Mass Spectrometer (AMS) (Note 1)
Temperature (field)	Thermocouple
Specific Conductance (field)	APHA 2510
pH (field)	EPA Method 150.1
(Note 1): If an alternative analytical method(s) is considered, Marquis must obtain prior approval from the UIC Director.	

Sampling methods

Sampling will be performed as described in Section B.2 of the QASP (Attachment K), which describes the groundwater sampling methods to be employed, including sampling SOPs (Section B.2.1) and sample preservation (Section B.2.6).

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

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

Laboratory to be Used/Chain of Custody Procedures

The laboratory selected will meet all requirements set forth here and in the QASP (Attachment K). The Chain-of-Custody procedures will follow the requirements of Section B.3.5 of the QASP.

Section A.4. of the QASP, Quality Objectives and Criteria, provides the detection limits and analytical methods to be employed during the Testing and Monitoring of all critical parameters of the project.

External Mechanical Integrity Testing

Marquis will conduct at least one of the external mechanical integrity tests (Temperature Measurements or Oxygen Activation Log) presented in Table 6 during the injection and post-injection phase to verify external mechanical integrity (MI) as required by 40 C.F.R. §§ 146.89(c) and 146.90(e) and Sections L and N(7) of this permit.

Table 6: Mechanical Integrity Tests.

Test Description	Location/ Depth Range (ft, MD)	Frequency
Annular Pressure MIT	MCI CCS 3, MCI MW 2, and MCI MW1/ Upper Mt. Simon (3,000)	After Completion of Workover
Annular Pressure Monitoring	MCI CCS 3, MCI MW 2, and MCI MW1/ Upper Mt. Simon (3,000)	Continuous
Temperature Measurements	MCI CCS 3, MCI MW 2, and MCI MW1/ Upper Mt. Simon (0-3,100)	Continuous
Oxygen Activation Log	MCI CCS 3, MCI MW 2, and MCI MW1/ Upper Mt. Simon (0-3,100)	Annually

Test Procedures

The following procedures are approved by use by the Director per Section L of this permit. Any deviation from the methods and procedures below will require approval by the Director at least 30 days prior to conducting the test and must comply with the witnessing requirements of Section L(5) of this permit.

Temperature Logging Using Wireline

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. The following procedures will be employed for temperature logging.

1) To conduct a static temperature log, the well must be shut in for at least 36 hours, or longer if temperature stabilization based on previous logs requires more time.
2) If the well cannot be shut in for 36 hours, shut in for as long as possible and run two logs at least six hours apart.
3) Calibrate the temperature tool in a bucket of ambient temperature water and a bucket of ice water immediately prior to conducting the test.
4) Log from the top of the well to the bottom, recording both temperature and natural gamma ray activity.
5) Record log data at least once per foot.
6) Logging speed shall not exceed 30 feet per minute. Reduce speed to 20 feet per minute in air-filled well bores.
7) The test shall include a written report by a knowledgeable log analyst. Such report must explain any anomalies shown in the results.
8) The test report shall include an up-to-date well schematic, digital logging data in a spreadsheet format, and a plot of the logging activity.
9) The test report shall include a tabulation of values for the following background parameters: EPA permit number, long string casing length (ft), tubing and/or tail pipe

lowermost depth (ft), top of open hole or uppermost perforation (ft), well total depth (ft), plugged back total depth or top of fill depth (ft), Kelly bushing elevation (ft), depth to top of confining zone (ft), and depth to top of permitted injection zone (ft). The test report shall also include a tabulation of values for the following test specific parameters: test date, depth reference (Kelly bushing or ground level), date of last injection, temperature of last injected fluid (F), elapsed time since last injection (hr), volume injected into the well in the past year (gal), names and depths of any other injection formations used at the site, temperatures logged by the tool and thermometer during calibration (F), depth to fluid level in the tubing (ft), depth to top of receptive strata (ft), and depth to bottom of receptive strata (ft).

10) The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.

Temperature Logging Using DTS Fiber Optic Line

The injection well will be equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DTS line is used for real-time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DTS for well mechanical integrity is as follows:

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

Oxygen Activation (OA) Logging

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

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

NOTE: Marquis will run one or more of the listed logging tests to verify external mechanical integrity and confirm that there is no upward flow behind casing above the injection zone. It is not anticipated that conducting more than one of the listed logging tests will be necessary to confirm external mechanical integrity; however additional testing may be necessary in some circumstances; for example, when there are temperature log inconsistencies.

The range, precision, and QC requirements of the different gauges used for MIT testing are presented in section A.4. of the QASP.

Pressure Fall-Off Testing

Marquis will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 C.F.R. § 146.90(f) and with Section N(8) of this permit. Pressure fall-off testing will be performed during system operation every 5 years and at the end of system operation.

Pressure Fall-off Test Procedure

1) Injection of normal injectate at the normal rate is preferred.
2) The injection period should be at least 50% longer than the planned shut-in time, or at minimum as long as operationally possible. During this time injection at a constant rate (+/- 10%) should be attempted.
3) The pressure gauge utilized for the pressure transient test shall have been calibrated no more than one year prior to the test date.
4) Place the pressure gauge downhole at approximately the top of the permitted injection zone at least one hour prior to ceasing injection.
5) Following at least one hour of pressure data collection during injection, shut-in the well as quickly as possible.
6) Collect data at a frequency of at least one data point every 10 seconds for at least the first five minutes after shut-in; between five and 30 minutes at no less than one reading every 30 seconds; and the operator can reduce frequency as required after 30 minutes.
7) End pressure measurements when pressure is relatively stable, when operational necessity dictates, when sufficient radial flow dominated data has been collected to allow evaluation of Henry's law constant (kh) and extrapolation of pressure to infinite shut-in time is possible, or if boundary effects are observed.
8) The test shall include a written report by a knowledgeable well test analyst. Such report must explain any anomalies shown in the results.
9) The test report shall include an up-to-date well schematic, a copy of the dated calibration certificate for the gauge utilized, and digital pressure data in a spreadsheet format.
10) The test report shall include a tabulation of values for the following background parameters: EPA permit number, porosity, net thickness (ft), viscosity (cp), formation compressibility (per psi), long string casing inner diameter (in), open hole diameter (in), and Kelly bushing elevation (ft). The test report shall also include a tabulation of values for the following test specific parameters: test start date/time, test end date/time, test length (hr), depth reference (Kelly bushing or ground level), specific gravity of test fluid, test fluid compressibility (per psi), gauge depth (ft), gauge calibration date, pressure required to maintain tubing fluid to the surface (psi), final tubing fluid level (ft), final flow rate immediately prior to shut-in (gpm), cumulative volume injected since last pressure equalization (gal), permeability- thickness (md-ft), skin factor, radius of investigation (ft), final measured flowing pressure (psi), final measured shut-in pressure (psi), and p* pressure (psi). Pressure gauge units (psia or psig) shall be specified.

11) The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.

Carbon Dioxide Plume and Pressure Front Tracking

Marquis will employ direct and indirect methods (listed in Table 7) to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 C.F.R. § 146.90(g) and Section N(5) of this permit. The primary location for direct tracking of the carbon dioxide plume and pressure front will be Galesville, Gunter, Eau Claire, and Mt. Simon Formations at MCI MW2 and MCI ACZ1. The primary location for indirect tracking of the carbon dioxide plume and pressure front will be the entire formation from surface to total depth via time-lapse 3D seismic taken at the surface covering the entire AoR. MCI MW2 is roughly 1500 ft east of MCI CCS3, and MCI ACZ1 is less than 500 ft west of MCI CCS3. Periodic fluid samples will be analyzed for the presence of carbon dioxide to further refine plume tracking. Pressure and temperature sensors in the deep monitoring well (MCI MW 2) will be used to measure variations in the storage formation in the pre-operational, injection, and post-injection phases of the project (40 C.F.R. § 146.90(g)). These sensors will continuously record data. This deep monitoring well will also be used to collect fluid samples from the storage formation to monitor for changes in the water chemistry over time and verify when the leading edge of the CO_2 plume reaches the MCI MW 2 well.

Plume monitoring location and frequency

Marquis will conduct fluid sampling and analysis to detect changes in formation fluids in order to directly monitor the carbon dioxide plume. The parameters to be analyzed as part of fluid sampling in the injection zone are listed in Table 8. Marquis will deploy pressure/temperature monitors and DTS to directly monitor the position of the pressure front. Indirect plume monitoring will be employed using pulsed neutron capture/RST logs to monitor carbon dioxide saturation. 3D seismic profiles will be used to image the developing carbon dioxide plume for indirect plume monitoring. The seismic survey will be acquired at regular intervals (every 5 years or 4 million metric tons injected), immediately preceding the cessation of injection and prior to the post-injection control period, and at the 5 and 10-year post-injection control period.

Plume monitoring details

For information concerning the type and specification of gauges used for the continuous monitoring of the Plume, please see the QASP in Attachment K.

Table 7: Plume monitoring activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
Upper Mt. Simon	Fluid sampling	MCI MW2	3,225 ft	Annual
Upper Mt. Simon	Isotope analysis	MCI MW2	3,225 ft	Annual
INDIRECT PLUME MONITORING				
Entire formation (0-TD)	Time- lapse 3D seismic	Surface	3.72 mi^2 baseline survey area	Every five years or 4 million metric tons of CO_2 injection, whichever occurs first
Galesville, Gunter, Eau Claire and Mt. Simon Formations	PNC logging	MCI MW2 and MCI ACZ 1	2,118- TD ft 2,118- TD ft	Annual

Table 8: Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods (Note 1)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Na, Ca, Mg, Ba, Sr, Fe, K	ASTM D1976	<1 to 8 mg/L (analyte, dilution, and matrix dependent)	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions: Cl, Br, SO4	ASTM D4327	0.03 to 0.13 mg/L (analyte, dilution, and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved Inorganic Carbon	EPA 9060	0.2 mg/L	±20%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	ASTM D5907	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	ASTM D3875	1 mg/L	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
pH	ASTM D1293	1 to 13 pH units	0/2 pH unit	
Density	ASTM D4052	0.01 g/mL	±10%	
Conductivity/Resistivity	ASTM D1125	0 to 100	±1%	
Stable C, H, O Isotopes	CRDS Laser H IRMS for C	200 to 500‰ 50 ppm of DIC	±4‰ ±0.2‰	Duplicates, working standards at 10%
Radiocarbon	AMS	0 to 200 pMC	±0.5 pMC%	
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

Note:

1. An equivalent method may be utilized with the prior approval of the UIC Program Director.

Pressure-front monitoring location and frequency

Table 9 presents the methods that Marquis will use to monitor the position of the pressure front, including the activities, locations, and frequencies Marquis will employ. Quality assurance procedures for these methods are presented in the QASP in Attachment K.

Pressure-front monitoring details

Pressure-front monitoring will occur via continuous monitoring of conditions in the injection zone at Mt. Simon Formation at 3,225 ft of MCI MW2. For information concerning the type and specification of gauges used for the continuous monitoring of the pressure front, please see the QASP.

Marquis must collect baseline data from surface stations in the Eau Claire and Mt. Simon Formations and Precambrian Basement before the start of injection activities. Marquis must record microseismic data from a near surface-based network of sensors on a continuous basis. These data will be sent to a cloud-based service via a cellular connection for data processing and archive. Marquis must collect baseline microseismic data for four to six months prior to the start of injection operations. This baseline data will be used to generate comparative data between the baseline case of the predictive model and expected rate of change in the formation conditions. As measured pressures and temperatures change, the data will be compared to the predicted data from the model. As appropriate, Marquis must conduct re-evaluation of the model, or further investigation of the downhole conditions, to ensure that no major deviation from the expected behavior of the pressure front occurs.

Table 9: Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PRESSURE-FRONT MONITORING				
Mt. Simon Sandstone	Pressure Monitoring	MCI MW2	3,225 ft	Continuous
INDIRECT PRESSURE- FRONT MONITORING				
Eau Claire and Mt. Simon Formations, Precambrian Basement	Microseismic Monitoring	5 Surface Stations	~1-mile radius from MCI CCS 3 (See Figure 1, below)	Continuous

Figure 1: Pressure-front monitoring activities (taken from Figure 7-10 of the application).

ATTACHMENT D: WELL PLUGGING PLANS

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Dr
Hennepin, IL 61327

Well location: S2 T32N R2W
41.27026520°N, 89.30939322°W

The Underground Injection Control regulations for Class VI wells require the owner or operator of a Class VI well to prepare, maintain, and comply with a plan that is acceptable to the EPA under 40 C.F.R. § 146.92(b). The owner or operator's maintenance and implementation of an approved plan is directly enforceable regardless of whether the requirement is a permit condition per 40 C.F.R. § 146.92(b). Marquis will conduct injection well plugging and abandonment according to the approved procedures below and in accordance with 40 C.F.R. § 146.92 and Section P of this permit.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Bottom-hole pressure measurements will be used to determine the pressure required to squeeze the cement from the well casing into the injection reservoir. In addition, these data will be used to determine the need for well control equipment. The weight of brine required to prevent the well from flowing (under balanced) will be calculated using this information. The pressure measurements will also be used to determine the formulation of cement to be used to plug the well.

During injection well operation, there will be in-formation pressure devices continuously monitoring the reservoir pressure. After cessation of injection activities these gauges will be used to obtain the final measurements of pressure in the injection zone. In the event that the originally installed gauges are not functioning properly after cessation of injection, bottom hole injection zone pressure and temperature will be obtained by running gauges in hole via wireline.

Verification of external mechanical integrity will be done by a temperature log and an oxygen activation log. For monitoring well plugging details, including the additional information required under 40 C.F.R. § 146.92(b), see Attachment E of this permit.

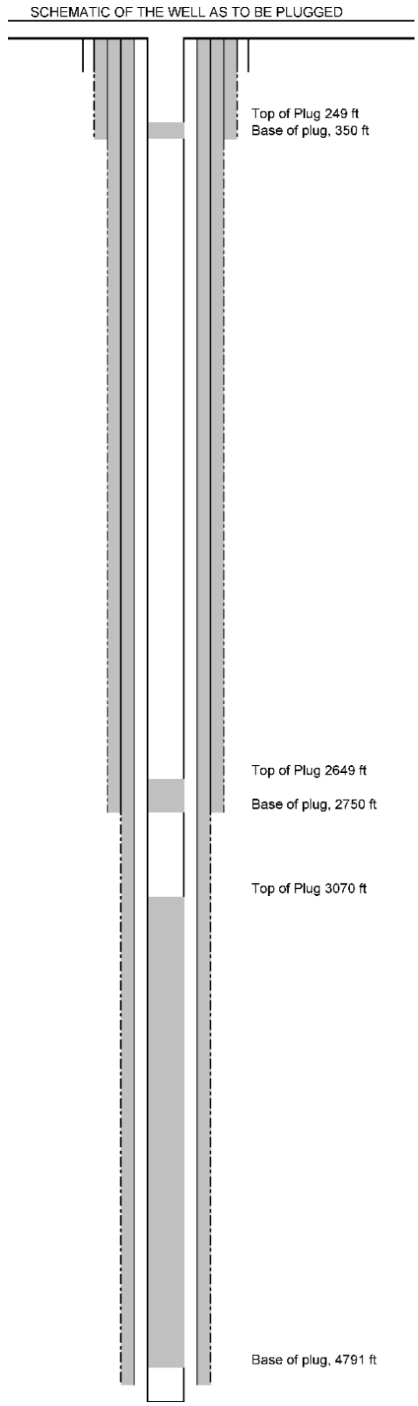
Table 1: Injection Well Planned MITs.

Test Description	Location
Temperature Log	Well Casing
Oxygen Activation Log	Well Casing

Table 2: Injection Well Plugging details.

Plug Information	Plug #1	Plug #2	Plug #3
Outer Diameter of casing in which plug will be placed (in.)	8.681	8.681	8.681
Depth to bottom of tubing or drill pipe (ft)	4,791	2,750	350
Sacks of cement to be used (each plug)	661	35	35
Slurry volume to be pumped (ft^3)	708	41	41
Slurry weight (lb./gal)	15.2	15.9	15.9
Calculated top of plug (ft)	3,070	2,649	249
Bottom of plug (ft)	4,791	2,750	350
Type of cement or other material	CO_2-Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balance	Balance

Figure 1: Injection Well Plugging Diagram



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

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Dr
Hennepin, IL 61327

Well location: S2 T32N R2W
41.27026520°N, 89.30939322°W

The Post-Injection Site Care (PISC) and Site Closure period of this permit is 12 years after cessation of injection and system operation. The PISC and Site Closure plan describes the activities that Marquis will perform to meet the requirements of 40 C.F.R. § 146.93 and Section P of this permit. Marquis will monitor groundwater quality and track the position of the carbon dioxide plume and pressure front for the duration of the 12-year PISC period. Marquis may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the Director pursuant to 40 C.F.R. § 146.93(b)(3). Following approval for site closure, Marquis will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Post-Injection Monitoring Plan

Marquis will perform groundwater monitoring, USDW monitoring, injection formation pressure and temperature monitoring, and 2D/3D seismic monitoring as described in the following sections during the post-injection phase. The results of all post-injection phase testing and monitoring will be submitted to the Director annually on or before February 15.

For the PISC plan, the following definitions apply for the frequencies given for the different testing protocols described.

1) Continuous: Data is continuously sampled and recorded.
2) Quarterly: Sampling will take place within 30 days before the following dates each year: March 31st, June 30th, September 30th, December 31st.
3) Semi-annual: Sampling will take place within 30 days before June 30th and December 31st.
4) Annual: Sampling will take place within 45 days before January 1st of each year.

5) Year: Sampling will take place every 5 years within 45 days before January 1st during injection and PISC periods (i.e., 5, 10, 15, etc. years after commencement of injection until site closure).

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored, and the analytical methods Marquis will employ.

Table 1: Monitoring of groundwater quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Shallow Groundwater	Groundwater geochemistry and stable isotopes	GW-1, 2, 3, 4 existing wells and GW-5 existing or new well within AoR	Within 300 feet below ground surface	Q2/year after injection ceases
Gunter Sandstone	Groundwater geochemistry and stable isotopes	MCI ACZ-1	~2,118 ft	Q2/year after injection ceases
Galesville Sandstone	Groundwater geochemistry and stable isotopes	MCI ACZ-1	~2,635 ft, MD	Q2/year after injection ceases
Galesville to Gunter Sandstones	PNC Logging	MCI ACZ-1	2,100 – 2,700 ft MD	Q2/year after injection ceases

Table 2: Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods	Alternate Analytical Method (Note 1)
Cations: Na, Ca, Mg, Ba, Sr, Fe, and K	ASTM D1976	EPA Method 6020
Cations: Sr	ASTM D1976	EPA Method 6010
Anions: Cl, Br, SO_4	ASTM D4327	EPA Method 300
pH	ASTM D1293	Standard Method (SM) 4500H
Alkalinity	ASTM D3875	SM 2320B
Total Dissolved Solids (TDS)	ASTM D5907	SM 2540C
Density	ASTM D4052	SM 2710F
Dissolved Inorganic Carbon	ASTM D513-11	SM 5310C
Conductivity/Resistivity	ASTM D1125	SM 2510B
Stable Isotopes of C, O, and H	CRDS Laser H Isotope Ratio Mass Spectrometry (IRMS) for C	(Note 1)
Carbon-14	Accelerator Mass Spectrometry (AMS)	(Note 1)

Note:
1. If another alternative analytical method(s) is considered, prior approval will be obtained from the UIC Director.

Table 3: Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Pressure	Pressure Gauge	Gunter Sandstone Galesville Sandstone	Every 1 min.	Every 1 min.
Temperature	Temperature Gauge	Gunter Sandstone Galesville Sandstone	Every 1 min.	Every 1 min.

Note:
- 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). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Table 4: Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
Mt. Simon Sandstone	Fluid sampling	MCI MW 2	3,225 ft MD (Note 1)	Annual
Galesville	Isotope analysis	MCI MW 2 MCI ACZ 1	2,635 ft MD	Semi-Annual
INDIRECT PLUME MONITORING				
Entire Formation (0 ft – TD)	Time-lapse 3D Surface Seismic Data	3.72 mi^2 (2022 baseline survey area)	Surface	Every 5 years and as required
Galesville, Eau Claire Shale, and Mt. Simon Formations	Pulsed Neutron Logging	MCI MW 2 well	2,118 – TD	Continuous

Notes:
1. The upper Mt. Simon at 3,225 ft is the estimated location of the first perforation of the topmost injection zone.
2. Frequency of sampling may be adjusted after post drilling model updates to attempt to detect fluid mixing front as it passes the well.
3. 2022 baseline survey area depicted in Figure 1 of Attachment C to this permit.

<u>Table 5</u>: Summary of laboratory analytical and field parameters for the Gunter Sandstone (lowermost USDW), Galesville Sandstone, and Mt. Simon Sandstone groundwater samples.

Parameters	Analytical Methods (Note 1)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Na, Ca, Mg, Ba, Sr, Fe, K	ASTM D1976	<1 to 8 mg/L (analyte, dilution, and matrix dependent)	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions: Cl, Br, SO_4	ASTM D4327	0.03 to 0.13 mg/L (analyte, dilution, and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved Inorganic Carbon	EPA 9060	0.2 mg/L	±20%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	ASTM D5907	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	ASTM D3875	1 mg/L	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
pH	ASTM D1293	1 to 13 pH units	0/2 pH unit	
Density	ASTM D4052	0.01 g/mL	±10%	
Conductivity/Resistivity	ASTM D1125	0 to 100	±1%	
Stable C, H, O Isotopes	CRDS Laser H IRMS for C	200 to 500‰ 50 ppm of DIC	±4‰ ±0.2‰	Duplicates, working standards at 10%
Radiocarbon	AMS	0 to 200 pMC	±0.5 pMC%	
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

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

Table 6: Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PRESSURE-FRONT MONITORING				
Upper Mt. Simon Sandstone	Pressure monitoring	MCI MW 2	~3,225 ft, MD Exact TBD	Continuous
Top Mt. Simon Sandstone	Pressure monitoring	MCI CCS 3 well	~3,100 ft, MD	Continuous
INDIRECT PRESSURE-FRONT MONITORING				
Eau Claire and Mt. Simon Formations, and Precambrian Basement	Microseismic Monitoring	5 Surface Stations	~1-mile radius from MCI CCS 3; See Figure 1, Attachment C	Continuous

Schedule for Submitting Post-Injection Monitoring Results

All post-injection site care monitoring data and monitoring results (i.e., resulting from the groundwater monitoring and plume and pressure front tracking described above) will be submitted to the Director in annual reports. These reports will be submitted each year by February 15.

Site Closure Plan

Marquis will conduct site closure activities to meet the requirements of 40 C.F.R. § 146.93(e) as described below. Marquis will submit a final Site Closure Plan and notify the Director at least 120 days prior of its intent to close the site per 40 C.F.R. § 146.93(d). Once the Director has approved closure of the site, Marquis will plug the monitoring wells and submit a site closure report. The activities, as described below, represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the Director for approval with the notification of the intent to close the site.

Plugging Monitoring Wells (MCI MW 1, MCI MW 2, and MCI ACZ 1)

Each well (MCI MW 1, MCI MW 2, and MCI ACZ 1) will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. A final external mechanical integrity test (MIT) will be conducted to ensure mechanical integrity. Detailed plugging procedures are provided below. All casing in each well will be cemented to surface and will not be retrievable at abandonment. After injection ceases and after the appropriate post-injection monitoring period is finished, the completion equipment will be removed from the well.

The perforated zone of each well will be plugged using a retainer method and the upper portions of the well will be cemented with a balance method. In addition, the portion of the casing within the storage formation in the deep MCI MW 1 and MCI MW 2 well and the upper portion of MCI MW 2 will be plugged using CO_2-resistant cement. All the wells will have the casing cut off 5 ft below grade and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification (ID) number and the date of plugging and abandonment inscribed on it.

Table 7: Intervals to be plugged and methods used when plugging the MCI MW 1 well.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Perforated Interval	Various between 3,165−4,050	Mt. Simon Sandstone	Retainer	CO_2-Resistant	132 sacks
5-1/2-in. Casing Column	~200-300	Pennsylvanian	Balance	Class A	12 sacks
5-1/2-in. Casing Column	~0-100	Pleistocene Drift	Balance	Class A	12 sacks

Table 8: Intervals to be plugged and methods used when plugging the MCI MW 2 well.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Perforated Interval	Various between 3,165−4,050	Mt. Simon Sandstone	Retainer	CO_2-Resistant	132 sacks
5-1/2-in. Casing Column	~200-300	Pennsylvanian	Balance	CO_2-Resistant	13 sacks
5-1/2-in. Casing Column	~0-100	Pleistocene Drift	Balance	CO_2-Resistant	13 sacks

Table 9: Intervals to be plugged and methods used when plugging the MCI ACZ 1 well.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Galesville Perforated Interval	2,409-2,579	Galesville Sandstone	Retainer	Class A	37 sacks
Deepest USDW Interval	1,321-1,466	Deepest USDW	Retainer	Class A	33 sacks
5-1/2-in. Casing Column	~200-300	Pennsylvanian	Balance	Class A	12 sacks
5-1/2-in. Casing Column	~0-100	Pleistocene Drift	Balance	Class A	12 sacks

Table 10: Materials used for plugging the MCI MW 1 well.

Plug Information	Plug #1	Plug #2	Plug #3
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft, MD)	~3,065	~300	~100
Sacks of cement to be used (each plug)	132	12	12
Slurry volume to be pumped (ft^3)	142	13.1	13.1
Slurry weight (lb./gal)	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.18	1.18
Calculated top of plug (ft, MD)	~3,065	~200	~0
Bottom of plug (ft, MD)	~4,050	~300	~100
Type of cement or other material	CO_2-Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balance	Balance

<u>Table 11</u>: Materials used for plugging the MCI MW 2 well.

Plug Information	Plug #1	Plug #2	Plug #3
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft, MD)	~3,065	~300	~100
Sacks of cement to be used (each plug)	132	13	13
Slurry volume to be pumped (ft^3)	142	13.9	13.9
Slurry weight (lb./gal)	15.2	15.2	15.2
Slurry Yield (ft^3/sack)	1.07	1.07	1.07
Calculated top of plug (ft, MD)	~3,065	~200	~0
Bottom of plug (ft, MD)	~4,050	~300	~100
Type of cement or other material	CO_2-Resistant	CO_2-Resistant	CO_2-Resistant
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balance	Balance

<u>Table 12</u>: Materials used for plugging the MCI ACZ 1 well.

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft, MD)	~2,309	~1,221	~300	~100
Sacks of cement to be used (each plug)	54	50	18	18
Slurry volume to be pumped (ft^3)	58	53	21.5	21.5
Slurry weight (lb./gal)	15.2	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.07	1.18	1.18
Calculated top of plug (ft, MD)	~2,309	~1,221	~200	~0
Bottom of plug (ft, MD)	~2,579	~1,466	~300	~100
Type of cement or other material	CO_2-Resistant	CO_2-Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Retainer	Balance	Balance

Volume Calculations

Volumes will be calculated for specific abandonment wellbore environments based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1) Choose the following:
   a) Length of the cement plug desired.
   b) Desired setting depth of base of plug.
   c) Amount of spacer to be pumped ahead of the slurry.
2) Determine the following:
   a) Number of sacks of cement required.
   b) Volume of spacer to be pumped behind the slurry to balance the plug.
   c) Plug length before the pipe is withdrawn.
   d) Length of mud freefall in drill pipe.
   e) Displacement volume required to spot the plug.
3) Field cementing and wellsite supervisor will both review calculations prior to spotting any plug.

Plugging and Abandonment Procedure

A detailed procedure follows:

1) Notify EPA 60 days in advance of plugging via letter of intent and 48 hours prior to commencing operations. Ensure proper notifications have been given to all regulatory agencies for rig move.

2) Make sure Marquis has written permission from U.S. EPA to proceed with planned ultimate P&A procedure.

3) Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks, and ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.

4) Have copies of the injection well permit prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.

5) Make sure all necessary safety forms are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.

Plugging Procedures for Injection Well

1) Conduct and document a safety meeting.

2) Conduct bottom hole pressures and MITs.
3) Move-in (MI) rig and ancillary equipment onto MCI CCS 3 well site and rig up (RU). Nipple up and test BOPs, pressure test equipment and ensure proper operation.
4) Check wellhead tubing and casing pressures.
5) Record bottom-hole pressure from downhole gauge (if final pressure has not already been determined) and calculate kill fluid density.
6) Fill tubing with kill weight brine as determined by the final pressure measurement. Inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. Release from packer with tubing string and circulate one hole volume with kill weight brine.
    a) If the well is not dead or the pressure cannot be bled off of tubing, RU slickline and set plug in lower profile nipple below packer. Pick on tubing to remove tubing seals from packer and circulate tubing and annulus with kill weight fluid.
7) Release packer and pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are at least two well control barriers in place at all times.
8) Trip into hole with work string with 9-5/8 inch cement retainer to a depth of 3,225 ft and set retainer to cement the perforated portion of the well, and prepare for cement plugging operations. Pump 661 sacks of CO_2-resistant cement (slurry weight of 15.2 pounds per gallon [lb/gal] through the retainer while maintaining bottom-hole pressure below fracture pressure). If it appears that the injection pressure will exceed the fracture pressure and the total amount of cement has not been pumped into the injection zone, cement pumping will cease. After allowing the pressure to reduce to an acceptable level, cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or plug.
9) Trip tubing string out of well and remove stinger from end of tubing.
10) Trip tubing string to a depth of 2,750 ft and prepare to set second cement plug. Pump 35 sacks of Class A cement with 50% POZ (slurry weight of 14.7 lb/gal) using a balance method to cement between a depth of 2,650 and 2,750 ft.
11) Trip tubing string to a depth of 350 ft and prepare to set third cement plug. Pump approximately 35 sacks of Class A cement to fill the casing from a depth of 350 to 250 ft.
12) Cut the casing string off at 5 ft below grade and weld a steel plate, (with well ID, permit number, and date of abandonment on it) to the casing strings.
13) Backfill the excavation.
14) Rig down and move off service rig and any remaining equipment.

The procedures described above are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect USDWs. Any significant modifications due to unforeseen circumstances will be described in the Plugging Report. The Plugging Report will be submitted to the EPA within 60 days after plugging is completed (40 C.F.R. § 146.92 (d)).

Plugging Procedures for the Monitoring Well(s)

1) Conduct and document a safety meeting.
2) Move-in (MI) rig and ancillary equipment onto well site and rig up (RU). Nipple up and test blow out preventors (BOPs), pressure test equipment and ensure proper operation.
3) Check wellhead tubing and casing pressures.
4) Record bottom-hole pressure from downhole gauge (if final pressure has not already been determined) and calculate kill fluid density.
5) Fill tubing with kill weight brine as determined by the final pressure measurement. Inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour.
6) If the well is not dead or the pressure cannot be bled off the tubing, rig up slickline and set plug in lower profile nipple below packer. Disconnect the tubing and circulate tubing and annulus with kill weight fluid until well is dead.
7) Release packer and pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are always at least two well control barriers in place.
8) Trip into hole with work string with 5-1/2-inch cement retainer to approximately 100 ft above the top perforation, set retainer to cement the perforated portion of the well, and prepare for cement plugging operations. Pump the specified number of sacks of cement through the retainer while maintaining bottom-hole pressure below fracture pressure. If it appears that the injection pressure will exceed the fracture pressure and the total amount of cement has not been pumped into the injection zone, cement pumping will cease. After allowing the pressure to reduce to an acceptable level, cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or plug.
9) If a second perforated zone is present in the well, repeat Step 8 for upper perforated zone.
10) Trip tubing string out of well and remove stinger from end of tubing.
11) Trip tubing string to a depth of approximately 300 ft and prepare to set second cement plug. Pump 12 sacks of Class A cement (slurry weight of 15.9 pounds per gallon [lb/gal]) using a balance method to cement between a depth of 200 and 300 ft.
12) Trip tubing string to a depth of 100 ft and prepare to set third cement plug. Pump approximately 12 sacks of Class A cement to fill the casing from a depth of 100 ft to near surface.
13) Cut the casing string off at 5 ft below grade and weld a steel plate, (with well ID, permit number, and date of abandonment on it) to the casing strings.
14) Backfill the excavation.
15) Rig down and move off service rig and any remaining equipment.

Planned Remedial/Site Restoration Activities

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

Site Closure Report

A site closure report will be prepared and submitted to the Director within 90 days following site closure per 40 C.F.R. § 146.93(f) and Section P(6) of this permit. The report will document the following:

1) Plugging of the verification and geophysical wells (and the injection well if it has not previously been plugged),
2) Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
3) Notifications to state and local authorities as required at 40 C.F.R. § 146.93(f)(2),
4) Records regarding the nature, composition, and volume of the injected carbon dioxide,
5) Post-injection monitoring records, and
6) Any other information required by the Director.

Marquis will record a notation to applicable property deeds per 40 C.F.R. § 146.93(g) documenting the following:

1) That the property was used for carbon dioxide sequestration,
2) The name of the local agency to which a plat of survey with injection well location was submitted,
3) The volume of fluid injected,
4) The formation into which the fluid was injected, and
5) The period over which the injection occurred.

The site closure report will be submitted to the Director and maintained by the owner or operator for a period of 10 years following site closure per 40 C.F.R. § 146.93(h). Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the Director.

10. EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

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10.0 Emergency and Remedial Response Plan

10.1 Introduction

This Emergency and Remedial Response Plan (ERRP) describes actions that Marquis Carbon Injection LLC (MCI or Marquis) shall take to address and remediate events that could allow for movement of the injected carbon dioxide (CO_2) stream (injection fluid), annulus fluid, brine, or formation fluid including but not limited to any movement of fluid into a Underground Source of Drinking Water (USDW) or any other unauthorized zones during the construction, operation, or post-injection site care (PISC) periods for the injection well.

The Marquis Biocarbon Project (Project) includes three wells that penetrate through the confining zone into the injection zone, as well as one above confining zone monitoring well and five shallow groundwater monitoring wells, as follows:

- MCI CCS 3 – CO_2 Injection Well.
- MCI MW 1 – Deep monitoring well located approximately 1.2 miles from MCI CCS3 and will be used for extended field monitoring under a backup contingency plan.
- MCI MW 2 – Deep monitoring well located adjacent to MCI CCS 3 that will be used to measure variations in the storage formation.
- MCI ACZ 1 – Above confining zone monitoring well to monitoring the Galesville Sandstone and the lowermost USDW, the Gunter Sandstone.
- MCI GW 1-5 – Shallow groundwater monitoring wells.

The comprehensive Sections of the UIC Application summarized below are considered in evaluating the potential risks associated with the Project. The risk-based management elements and response to emergency events are presented in this ERRP.

Section 1 of the UIC Application describes the geological setting for the Project site. The location is favorable to sequester CO_2 because of the existence of the Mt. Simon injection zone and the Eau Claire confining zone, as well as other site-specific factors as summarized below.

Section 2 details the modeling conducted to identify the CO_2 plume and pressure front within the injection zone, the Area of Review (AoR), steps for managing the pressure front, collecting baseline data pre-injection (e.g., aquifer samples from various geologic formations, shallow groundwater samples and seismic stations), and corrective action measures to protect USDWs within the AoR.

Section 4 details the construction design for the injection well and operational controls to maintain the mechanical integrity and pressure control within the well and prevent the movement of injection and formation fluids into the USDW or an unauthorized area. The construction plan includes:

- The well design;
- The drilling plan and contingencies, formations, casing depths and perforation strategy;
- State-of-the-art corrosion-resistant materials to be used;
- Pressure testing and logging to confirm proper installation prior to operation; and
- Well operational controls for continuous monitoring of the annular fluid, pressure and temperature.

Section 5 details the injection and monitoring wells' pre-operational test plan for the pre-operational formation testing that serves as baseline information for evaluation of any geochemical changes identified during operation and post-injection.

Section 6 details the injection and deep monitoring wells' operational design, preventive measures, and procedures, including monitoring systems, process and shutdown alarms, and process interlocks. The elements of the plan focus on safely maintaining: (1) the delivery and storage of CO_2 within the Mt. Simon; (2) the mechanical integrity of the wells; and (3) to prevent endangerment of the USDW or unauthorized zones.

Section 7 details the testing and monitoring plan for the injection well, above-confining zone monitoring well, two deep monitoring wells, and shallow monitoring wells. Section 7A includes the quality assurance components for the testing and monitoring plan implementation. As outlined in the Testing & Monitoring Plan, testing and monitoring data is evaluated utilizing EPA accepted statistical evaluation approaches, baseline and prior data monitoring or testing events, and predicted dynamic modeling results. An anomaly, outlier, or discrepancy (e.g., between electronic indicators and manual gauge monitoring) are further evaluated to determine if potential risks to endangerment of a USDW or an unauthorized zone are present.

Section 8 is the injection well plugging plan that details the methods and materials used to plug and abandon the injection well to prevent migration of injection or formation fluids above the confining zone.

Section 9 is the post-closure plan for the Project after the cessation of injections to monitor CO2 plume and pressure front stabilization and to demonstrate the Project poses no endangerment to USDWs.

While the below information does not negate or decrease the necessity of this ERRP or the utility of preparedness for emergency response, MCI includes this information to identify preventive measures it is taking to try to lessen the likelihood of some of the response scenarios occuring.

> MCI has taken steps regarding its site location, well drilling and construction materials, and preventive monitoring measures to lessen the likelihood of the occurrence of an emergency response. The potential for a CO_2 release from the injection or monitoring wells is diminished due to the corrosion-resistant well construction materials and well design. The injection well and two deep monitoring wells will be constructed with Super Chrome 25 casing and tubing material across the confining zone and within the Mt. Simon Sandstone. The Super Chrome material grade, which is a Super Duplex stainless steel has increased pitting and corrosion resistance. The injection well and nearby deep monitoring wells will be constructed with Chrome 13 long string casing material in the upper portion of the well (from the surface to the Eau Claire Shale caprock). The effectiveness of the mitigation strategy is monitored and reviewed through periodic corrosion coupon monitoring, as well as multi-finger caliper logging or an ultrasonic casing evaluation. Marquis' well design and monitoring approach substantially reduces the potential risk of an emergency event resulting from pitting and corrosion within the well. Marquis' monitoring wells do not utilize a nested-well design (e.g., installation of two or more well casings within the same borehole) further reducing the possibility of brine, annulus fluid, formation fluid, or CO_2 leakage or migration within the well bores.

In accordance with 40 C.F.R. § 146.94(b), if Marquis obtains evidence that the injected CO_2 stream and associated pressure front may cause an endangerment of a USDW. Marquis must perform the following actions:

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

Below in the ERRP, some of the scenarios where there may be evidence that the project may cause an endangerment of a USDW are identified along with the scope of response actions that will be taken as a result. The identified response actions must be implemented absent approval of an alternative by EPA in an emergency event.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed:

> MCI will immediately cease injection, unless MCI determines, in consultation with the Director, that gradual cessation of injection is necessary for safety. If a non-emergency shutdown of the CO_2 injection system is required, the operator will complete the shutdown in a stepwise approach to prevent over- pressure situations and/or damage to the equipment. Efforts will also be made to maintain the CO_2 in the injection stream in a supercritical phase to prevent special operations during the restart of the system. Also, the override of certain relays may be required to properly and safely shutdown the

system.

As used in this ERRP, the term "wells" unless otherwise specified, refers to the injection well and all monitoring/verification wells. As used in this ERRP, the term "Area of Review" or "AoR" unless otherwise specified, refers to the AoR as defined in the permit.

As used in this ERRP, the term "unauthorized zone", unless otherwise specified, refers to any geologic unit other than the injection zone formation as defined in the Permit.

10.2 Local Resources and Infrastructure

10.2.1 Local Resources

Local resources in the vicinity of the Marquis BioCarbon Project that may be impacted due to an emergency event at the Project include:

- Underground Sources of Drinking Water (USDWs);
- Four existing groundwater wells within ¼ mile of the CO_2 plume;
- The Illinois River and tributaries to the River;
- Donnelley State Fish and Wildlife Area;
- Hennepin Lake and Hopper Lake; and
- Dixon Waterfowl Refuge (The Wetlands Initiative).

The base of the lowermost USDW in the AoR is the Gunter Sandstone (2,118-2,131 ft MD). The AoR and Corrective Action Plan provides further details about the USDWs in the project area.

See **Figure 10-1** (Aerial of Local Resources and Wells); and **Figure 10-2** (Aerial Depicting the CO_2 Plume and AoR).

Two major aquifer systems serve as the primary public water supply in Putnam County and vicinity: the Quaternary and Pennsylvania aquifers. The village of Hennepin obtains its groundwater supply at depths up to 135 feet [ft]. The Quaternary aquifer system consists of shallow, glacial deposits overlying the bedrock. The Pennsylvanian aquifer system, up to 250 ft deep in the project area, contains variable water quality that is generally utilized when the Quaternary aquifer supplies are insufficient.

Within the vicinity, there is the Hennepin community water supply well. However, the Hennepin community well is not at a depth that penetrates through the confining zone (Eau Claire). The confining zone provides a barrier to prevent the migration of CO_2 from the injection zone (Mt. Simon) into a USDW.

There is also a plugged and abandoned deep injection well (J & L Well) located approximately 1.5 miles southwest of the MCI CCS 3 well. The J&L well was abandoned and closed, and final approval was received from the Illinois EPA in 2013. The well was closed in accordance with the standards of 35 Illinois Administrative Code (IAC) 730.171. See **Appendix W**.

(ArcelorMittal Permit No. UIC-004-W1-JL confirming proper plugging and abandonment of the J&L Well, Condition D.4). Based on the distance and certified closure of the J&L Well, this well is not expected to be impacted by an emergency at the MCI CCS 3 well.

Within the AoR that extends in a 14.5 mile radius, there are 2,537 community and non-community water wells. Of the community wells, none are within the CO2 plume or extend through the confining zone. The two closest to the CO_2 plume are shallow wells (less than 150 feet) owned by Village Hennepin. The non-community wells are less than 600 feet in depth. See **Figure 10 - 3** Community and Non-Community Wells Nearby MCI CCS 3. For a Complete List of all Wells within the AoR see **Appendix V7**. The community and non-community water wells are not expected to be impacted by an emergency at the MCI CCS 3 well because the confining zone is a barrier to prevent migration of CO_2 from the injection zone into those wells.

Nearby surface-water features in the vicinity include the Illinois River to the west and north and unnamed northern tributaries to Coffee Creek, and Hennepin Lake and Hopper Lake southwest of the Marquis Biocarbon Project. Groundwater supply wells within the vicinity of the project are scattered across the area, with depths typically shallower than 300 ft. More details are provided in Permit **Section 2.5** of the Area of Review (AoR) and Corrective Action Plan.

The land in the vicinity of the project consists primarily of cropland with a parcel to the northwest that is the site of an ethanol production facility.

10.2.2 Infrastructure

Infrastructure in the vicinity of Marquis BioCarbon Project that may be impacted due to an emergency at the project site includes:

- MCI CCS 3 wellhead;
- CO_2 compression facility that will house the CCS 3 compressors, steam generating units, and dehydration units; and
- Industrial buildings associated with the ethanol production facility location 0.5 miles to the north.

There are no public buildings, such as schools or hospitals in the vicinity of the MCI CCS 3 well.

The AoR encompasses portions of the counties of Putnam, Bureau, LaSalle, and Marshall. Hennepin, the town closest to the MCI CCS 3 site, is located approximately 1.5 miles southwest of the MCI CCS 3 well. Hennepin has residential areas, commercial properties, and recreational facilities. There is also a closed electrical coal-fired facility to the north, an open pit quarry to the northeast, and an abrasive grains and industrial fused mineral manufacturer north of the project site. However, these developed areas are not expected to be impacted due to an emergency at the MCI CCS 3 well.

At the end of this plan, figures are included identifying the following:

- **Figure 10 - 1**: Aerial of the site resources and infrastructure in the Vicinity of MCI CCS 3.
- **Figure 10-2**: Aerial Identifying Counties Within the AoR (i.e., 14.5- mile radius / 29-mile diameter)
- **Figure 10 - 2**: MCI CCS 3 CO2 Plume and AoR
- **Figure 10 - 3** Community and Non-Community Wells Nearby MCI CCS 3. For a Complete List of all Wells within the AoR see **Appendix V7.**
- **Figure 10 - 4**: Present Locations of Microseismic Stations Around Injection Site

10.3 Potential Risk Scenarios

The following events related to the Marquis BioCarbon Project that could potentially result in an emergency response are included in **Table 10-1**. This table lists the types of potential adverse incidents that will trigger response actions to protect USDWs and prevent injection fluid, brines, annulus fluid, or formation fluid migration into any unauthorized zones if the incidents occur during the construction, injection, or post-injection site care periods. Marquis will undertake emergency or remedial actions in response to these incidents.

This is a non-exhaustive list of potential risk scenario events:

Construction/Pre-Injection Period

• Well construction event during drilling or completion with loss of containment.
• Evidence suggesting leakage to a USDW or other Unauthorized Zone (including the surface). For example, evidence suggesting a leakage may include:
  ◦ Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting potential fluid leakage into a USDW or other Unauthorized Zone (including the surface), including elevated concentrations of indicator parameter(s) in groundwater sample(s) from the MCI ACZ 1 well or increased pressures in the MCI ACZ 1 well.
  ◦ Evidence of migration of brines, annulus fluid, or formation fluid related to unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
  ◦ Evidence of migration of brines, annulus fluid, or formation fluid between formations through injection, monitoring/verification, or water withdrawal well bores.
  ◦ Evidence of migration of brines, annulus fluid, or formation fluid from the Injection Zone through plugged and abandoned (P&Aed) wells or undocumented wells in the AoR.
  ◦ Evidence of migration of brines, annulus fluid, or formation fluid from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment).
  ◦ Evidence of migration of brines, annulus fluid, or formation fluid outside the AoR.
• Severe weather disaster (e.g., tornado, hurricane, lightning strike).
• Seismic event (e.g., natural or induced).

Injection Period

• Mechanical integrity failure, for example:
  ◦ Loss of internal mechanical integrity due to tubing, packer, or casing leak in injection or monitoring/verification wells.
  ◦ Loss of external mechanical well integrity due to fluid movement through vertical channels adjacent to well bores.
  ◦ Loss of external mechanical well integrity from metal leaching or corrosion due to prolonged wetted CO_2 exposure.
• Evidence suggesting leakage to a USDW or other unauthorized zone (including the surface), for example, evidence suggesting a leakage may include:
  ◦ Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting potential fluid leakage into a USDW or other Unauthorized Zone (including the surface), including elevated concentrations of indicator parameter(s) in groundwater sample(s) from the MCI ACZ 1 well or increased pressures in the MCI ACZ 1 well.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Project related to unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid between formations through injection, monitoring/verification, or water withdrawal well bores.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Injection Zone through plugged and abandoned (P&Aed) wells or undocumented wells in the AoR.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment).
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the injection zone, including due to metal leaching or corrosion due to prolonged wetted CO_2 exposure.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid outside the AoR.
• Well monitoring equipment failure or malfunction (e.g., all valves and gauges, pressure and temperature sensors downhole and at the wellheads, etc).
• Severe weather disaster (e.g., tornado, hurricane, lightning strike).
• Seismic event (e.g., natural or induced).

Post-Injection Site Care Period

• Mechanical integrity failure, for e.g.:
  ◦ Loss of internal mechanical integrity due to tubing, packer, or casing leak in monitoring/verification wells.
  ◦ Loss of external mechanical well integrity due to fluid movement through vertical channels adjacent to the well bores.
• Evidence suggesting leakage to a USDW or other unauthorized zone (including the surface), for example, evidence suggesting a leakage may include:
  ◦ Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting potential fluid leakage into a USDW or other Unauthorized Zone (including the surface), including elevated concentrations of indicator parameter(s) in groundwater sample(s) from the MCI ACZ 1 well or increased pressures in the MCI ACZ 1 well.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Project related to an unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid between formations through injection, monitoring/verification, or water withdrawal well bores.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Injection Zone through P&Aed wells or undocumented wells in the AoR.
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment).
  ◦ Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the injection zone, including due to metal leaching or corrosion due to prolonged wetted CO_2 exposure.

- ◦ Migration of injection fluid, brines, annulus fluid, or formation fluid outside of the AoR.
- Well monitoring equipment failure or malfunction (e.g., all valves and gauges, pressure and temperature sensors downhole and at the wellheads, etc.).
- Severe weather disaster (e.g., tornado, hurricane, lightning strike).
- Seismic event. (e.g., natural or induced).

Table 10-1: Potential Emergency Events.

In addition to the potential risk scenarios listed above a Feature, Event, and Process (FEP) risk assessment has been undertaken. Through the FEP risk assessment process, the response actions were developed.

10.4 Emergency Identification and Response Actions

Marquis must report to the Director within 24 hours if any evidence is obtained that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW (40 C.F.R. § 146.91(c)(1)); any noncompliance with a Permit Condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs (40 C.F.R. § 146.91(c)(2)); any triggering of a shut-off system (i.e. down-hole or at the surface (40 C.F.R. § 146.91(c)(3)); and any failure to maintain mechanical integrity (40 C.F.R. § 146.91(c)(4)). If required by the Director, any release of CO_2 to the atmosphere or biosphere must also be reported within 24 hours (40 C.F.R. § 146.91(c)(5)).

The purpose of the ERRP is to ensure that appropriate actions are taken in an emergency or USDW endangerment situation. Steps to identify and characterize an emergency event will be dependent on the specific issue identified and the severity of the event. The avoidance, detection, and response actions for the potential risk scenarios are detailed below.[1] Detection methods include a process where evidence that may indicate a release is evaluated and confirmed, as detailed in the Testing and Monitoring Plan of the Permit. The confirmation procedures include, but are not limited to, statistical analysis, additional sampling, monitoring, or testing. Regardless what detection methods (including those that may not be listed) are utilized, listed response actions must be implemented as identified in each emergency event scenario that calls for their employment.

10.4.1 Well Construction Event

Loss of containment could occur during drilling and completion operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well.

Timing of event: Construction/Pre-Injection

Avoidance measures: Include but are not limited to well control training, blowout prevention (BOP) equipment, kill fluid, BOP testing protocol, kick drill, lubricators for wireline operations.

Detection methods: Include but are not limited to flow sensor, pressure sensor, tank level indicator,

[1] Avoidance and detection measures identified throughout this ERRP do not replace or supersede any terms or conditions of the permit.

tripping displacement practices, mud weight control.

Response actions include but are not limited to:

- Notify the Director about the emergency event within 24 hours.
- Stop operation.
- Close Blow Out Prevention.
- Clear floor and secure area.
- Execute well control procedure.
- Evaluate drilling parameters and identify root cause.

10.4.2 Mechanical Integrity Failure

Loss of integrity in MCI CCS 3, monitoring/verification wells or water withdrawal well(s) may endanger USDWs, including endangerment due to the movement of injection fluid, brines, annulus fluid, or formation fluid into an unauthorized zone. Integrity loss may have occurred if the following events occur (note, this is not an exhaustive list):

- Automatic shutdown devices will be activated:
    - Wellhead pressure exceeds the maximum injection pressure (the shutdown point) specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
- Mechanical integrity test results identify a potential loss of mechanical integrity.
    - Loss of mechanical integrity due to a tubing or packer leak in all project site wells
    - Loss of mechanical integrity due to a casing leak in MCI CCS 3, monitoring/verification wells, or water withdrawal well(s).

Timing of event: Injection or Post-Injection

Avoidance measures:

- Use of corrosion resistant cement and corrosion resistant materials in the long string casing and tubing.
- Routine inspection of the well casing to determine corrosion rate using corrosion coupons.
- Corrosion evaluation using multi-finger caliper logging or ultrasonic casing evaluation.
- Continuous pressure monitoring and CO_2 stream injection monitoring.
- If high level pressure alarm triggers indicating maximum injection pressure (90% of fracture pressure), injection ceases.

Detection methods: Include but are not limited to:

- Well integrity issue is identified during internal mechanical integrity testing;
- Deficiency identified during pressure fall off testing,
- Exceedance of the maximum well injection pressure as specified in the permit;

- Inconsistencies confirmed of fluid flow behind casing resulting from annual evaluation of continuous temperature measurements using the Distributed Temperature Sensing (DTS) fiber optic sensor collection system.
- Exceedance of the annular pressure based on the variability from baseline conditions when correlating injection stream temperature and annular pressure.
- Change in annular fluid volume tank level indicator greater than 20% from baseline conditions.
- CO_2 plume and pressure tracking from above the confining zone shows a pressure change greater than 10% above baseline.
- Fluid samples from above the confining zone and USDW indicate a statistically significant change in conditions.
- Corrosion coupon evaluation indicates corrosion rate above acceptable industry standards and multi-finger caliper logging confirms well structural integrity issue.

Response actions include but are not limited to those detailed below in **Table 10 - 2**: Response actions to an emergency associated with mechanical integrity failure.

Wells	Response Action and Notification Procedures – Mechanical Integrity Failure
All	If a loss of mechanical integrity has occurred, then: • Notify the Marquis Carbon Injection LLC Environmental Manager and CCS Operations Manager immediately. • Notify the Director within 24 hours of the emergency event, per 40 C.F.R. § 146.91(c) and 40 C.F.R. § 146.94(b)(3). • After an initial assessment, the Environmental Manager and/or the CCS Operations Manager will notify other Project Management and Operational Personnel.

MCI CCS 3 and deep monitoring/ verification wells (MCI MW-1 and MCI MW-2)	• Initiate shutdown plan:
	  o Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the compressors to the atmosphere.
	  o Check wind direction.
	  o Mark an exclusion zone around the affected area/well to limit access to authorized personnel only.
	  o Notify plant safety personnel that well has been shut down.
	  o Vent excess CO_2 from surface lines and well, as necessary, to reduce pressures and clear lines.
	  o Notify local authorities and plant personnel, as necessary.
	  o Limit access to wellhead and surface facilities to authorized personnel only.
	  o If evacuation plan must be implemented, notify all surrounding businesses and offices, and local authorities.
	  o Reset or repair automatic shutdown devices, if necessary.
	  o Monitor the well conditions, including pressures, temperatures, and annulus pressure, and perform diagnostics to verify integrity loss and determine the nature or cause and extent of any failure, as well as any additional steps in the emergency procedure.
	• Provide Director with a report within 5 days from date MCI became aware of mechanical integrity failure that contains a description of the circumstance, and if situation has been corrected, and if situation has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the circumstance.
	• Identify and implement appropriate remedial actions to restore well integrity (in consultation with the Director).
	• If the loss of mechanical integrity has resulted in a failure or malfunction of monitoring equipment, implement Response Actions from Section 10.4.3.
	• Collect fluid samples from ACZ-1 and conduct a statistical evaluation of results with baseline and previous monitoring data. If there is evidence suggesting fluid leakage into a USDW or other Unauthorized Zone, implement Response Actions from Section 10.4.4.
	• Upon completing of steps to restore well integrity, perform mechanical integrity test prior to bringing the well back online and resumption of injection, and within 30 days of receipt of test results, provide a report of mechanical integrity test findings to the Director for review and approval.

Wells	Response Action and Notification Procedures – <u>Mechanical Integrity Failure</u>
All other monitoring/ verification well (MCI-ACZ- 1)	• Identify and implement appropriate remedial actions to repair the well (in consultation with the Director). Within 30 days of the event, inform Director of the plan and schedule for repairs. • Identify and implement appropriate remedial actions (in consultation with the Director). • Within 30 days after well repair completion, provide a report to the Director detailing the repairs that were made.

Table 10 - 2: Response actions to an emergency associated with mechanical integrity failure.

10.4.3 Well Monitoring Equipment Failure or Malfunction

The failure or malfunction of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure, including a malfunctioning monitoring/verification well, may indicate a problem that could pose a risk of endangerment to USDWs.

This subsection covers the remedial response and procedures to be followed should confirmation that the failure of one (or more) of the monitoring sensors/equipment for wellhead pressure, temperature, and/or annulus pressure fail. Note in the event of failure or malfunction of monitoring equipment, manual gauges are used to monitor well operations. The failure or malfunction of electronic equipment, when using manual gauges, along with an evaluation of other available information that demonstrates well integrity has not been impacted, is not considered an emergency event.

Timing of event: Injection or Post-Injection

Avoidance measures:

- Inspection and maintenance of monitoring equipment to prevent, detect, and correct potential equipment malfunctions or failures that could result in integrity issues.
- Routine inspection and calibration of monitoring equipment based on manufacturer's recommendations.
- Fluid sampling in ACZ-1 to identify a release above the confining zone.
- Surface pressure and temperature monitoring in ACZ-1 to identify pressure changes.
- Continuous and redundant pressure and temperature measurements at the surface and in the injection zone to ensure compliance with operational parameters in the permit.
- Continuous temperature measurements in injection well and deep monitoring wells using the DTS fiber optic sensor collection system

Detection methods:

- Failure or malfunction of monitoring equipment confirmed through use of redundant manual gauges. Once equipment is repaired, calibrated equipment evaluated for consistency with manual gauge information and other available monitoring data reviewed to confirm well integrity has not been impacted.
- Pressure and rate monitoring anomalies, pressure falloff tests, CO_2 plume and pressure tracking.
- Fluid and confirmation sampling in ACZ-1 to identify a statistically significant change in conditions that potentially indicates a release above the confining zone.

The response actions to an emergency associated with well monitoring equipment failures or malfunctions for all wells, except shallow groundwater wells, include but are not limited to the actions detailed below in **Table 10 - 3**: Response actions to an emergency associated with well monitoring equipment failure or malfunction.

Wells	**Response Action and Notification Procedures – Monitoring Equipment**

All, except Shallow Groundwater Monitoring Wells	If evidence indicates a failure or malfunction of monitoring equipment poses a risk to a USDW, then MCI will:
	• Notify the MCI Environmental Manager and CCS Operations Manager immediately.
	• Notify the Director within 24 hours of the emergency event, per 40 C.F.R. § 146.91(c) and 40 C.F.R. § 146.94(b)(3).
	• After an initial assessment, the Environmental Manager and/or the CCS Operations Manager will notify other Project Management and Operational Personnel.
	• Determine the impact of the event, based on the information available, within 24 hours of the event occurring. At this time, assess the impact of the loss of monitoring equipment and determine and implement a viable alternative monitoring method. Report this information to the Director. Note: A viable alternative monitoring method is not a substitution for any permit condition, including compliance with the Testing and Monitoring Plan.
	• If there has been a loss mechanical integrity, implement Response Actions from Section 10.4.2.
	• Identify and implement appropriate remedial actions to repair the well (in consultation with the Director).
	• Assess whether there is evidence suggesting potential fluid leakage into a USDW or Unauthorized Zone, and if there is such evidence, implement Response Actions from Section 10.4.4.
	• Assess the cause of the equipment failure and report the details to the Director within 30 days.
	• Repair or replace monitoring equipment that failed and utilize and record data from manual gauges in the interim. Repair or replacement of equipment (if needed) should be done as soon as is feasible based on operational conditions and suitability of the alternative method of monitoring.
	• Assess (in consultation with the Director) whether monitoring capabilities at the project are sufficient to ensure non-endangerment to USDWs. If monitoring capabilities are not sufficient, identify and implement (in consultation with the Director) alternative or redundant monitoring capabilities. If alternative or redundant monitoring capabilities are not sufficient, treat the event as an immediate risk and see Response Actions immediately below.
	• If the event poses an immediate or near-term risk to human health, USDWs, or infrastructure, implement the following Response Actions:
	  o Initiate shutdown plan
	    • Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the compressors to the atmosphere.
	    • Check wind direction.
	    • Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines.
	    • Mark an exclusion zone around the affected area/well to limit access to authorized personnel only.
	    • Notify plant safety personnel that well has been shut down.
	    • Notify local authorities and plant personnel, as necessary.
	    • Limit access to wellhead and surface facilities to authorized personnel only.
	    • If evacuation plan must be implemented, notify all surrounding businesses and offices, and local authorities.
	    • Reset or repair automatic shutdown devices, if necessary.
	    • Monitor the well conditions, including pressures, temperatures, and annulus pressure, to determine nature or cause and extent of failure or malfunction, as well as any additional steps in the emergency procedure.
	• Identify and, if necessary, implement appropriate remedial actions (in consultation with

	the UIC Program Director).
Shallow Groundwater monitoring wells	If evidence indicates a failure or malfunction of monitoring equipment poses a risk to a USDW, then MCI will: • Notify the Director about the event within one week; • Identify an alternative monitoring method as appropriate (in consultation with the Director)

Table 10 - 3: Response actions to an emergency associated with well monitoring equipment failure or malfunction.

10.4.4 Evidence Suggesting Potential Fluid Leakage to a USDW or Other Unauthorized Zone (including the Surface)

Potential injection fluid, brines, annulus fluid, or formation fluid leakage to the USDW or other unauthorized zone may endanger USDWs. This scenario includes but is not limited to:

- Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence suggesting fluid leakage into a USDW or other Unauthorized Zone (including the surface), including elevated concentrations of indicator parameter(s) in groundwater sample(s) from the MCI AZI well based on the Testing and Monitoring Plan (Attachment C) and Quality Assurance & Surveillance Plan (Attachment K) or increased pressures in the MCI ACZ1 well above 10%.
- A sudden, significant decrease in injection pressure (assuming constant injection rate) that might indicate a breach of confinement.
- Monitoring/Verification Well down hole pressure measurement deviating from expected within any overlying layers.
- Monitoring/Verification Well down hole temperature measurement deviating from expected within any overlying layers.
- Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Project related to an unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
- Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid between formations through the injection, monitoring/verification, or water withdrawal well bores.
- Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the Injection Zone through plugged and abandoned wells or undocumented wells in the AoR.
- Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the injection zone through failure of the confining zone, faults, and fractures (loss of containment).

- Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid from the injection zone, including metal leaching or corrosion due to prolonged wetted CO2 exposure.

- Evidence of migration of injection fluid, brines, annulus fluid, or formation fluid outside of the AoR.

Timing of event: Construction/Pre-Injection, Injection or Post-Injection

Avoidance measures:

- The use of corrosion-resistant well materials.
- Compliance with Testing and Monitoring Plan of the UIC Permit. For example,
  - Continuous monitoring of CO_2 injection flow.
  - Continuous pressure and temperature measurements at the surface and in the injection zone.
  - Monitoring of annulus pressures in injection and monitoring wells (except shallow groundwater wells), and annulus volume in injection well.
  - Fluid sampling in ACZ-1 to assess potential movement of injection zone fluids above the confining zone.
  - Pressure and temperature monitoring in ACZ-1 to confirm no pressure and temperature changes which indicate fluid leakage above the confining zone.
  - Continuous temperature measurements in injection well and deep monitoring wells using the DTS fiber optic sensor collection system to monitor temperature changes along the entire length of the fiber optic cable to confirm no leaks are detected.

Detection methods:

- Corrosion monitoring.
- Redundant monitoring of pressures, temperatures, and injectate flow.
- Redundant monitoring of annulus system (monitoring and annular fluid volumes) and annulus surface monitoring,
- Fluid sampling of water chemistry and statistical evaluation of data.
- Mechanical integrity testing.
- Pressure falloff testing.
- Oxygen activation logs over DTS zones to confirm anomalies.

Response actions to evidence suggesting fluid leakage to a USDW or other unauthorized zone include but are not limited to the actions detailed below in **Table 10-4**. If there is evidence of potential injection fluid, brines, annulus fluid, or formation fluid leakage to a USDW or other unauthorized zone, MCI must perform the following actions in **Table 10-4.**

Response Action and Notification Procedures – Fluid Leakage to USDW or Unauthorized Zone
If MCI obtains evidence of potential injection fluid, brines, annulus fluid, or formation fluid leakage to a USDW or other unauthorized zone, MCI must perform the following actions: • Notify the MCI Environmental Manager and CCS Operations Manager immediately. • After an initial assessment, the Environmental Manager and/or the CCS Operations Manager will notify other Project Management and Operational Personnel. • Notify the Director within 24 hours of the emergency event, per 40 C.F.R § 146.91(c) and 40 C.F.R. § 146.94(b)(3). • Initiate shutdown plan o Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the compressors to the atmosphere. o Check wind direction. o Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. o Mark an exclusion zone around the affected area/well to limit access to affected area to authorized personnel only. o Notify plan safety personnel that well has been shut down. o Notify local authorities and plant personnel, as necessary. o Limit access to wellhead and surface facilities to authorized personnel only. o If evacuation plan must be implemented, notify all surrounding businesses and offices, and local authorities. o Reset or repair automatic shutdown devices, if necessary. o Monitor the well conditions, including pressures, temperatures, and geochemical parameters to determine the nature or cause and extent of any failure or fluid migration, as well as additional steps in the emergency procedure. • Take all steps reasonably necessary to identify and characterize any release within 24 hours (40 C.F.R. § 146.94(b)(2)), including o Collection of confirmation sample(s) of USDWs, groundwater, or any other potentially relevant formation(s) (in consultation with the Director) and performance of constituent analysis for abnormal indicator parameters. See Table 7-6 of the Testing and Monitoring Plan. • If presence of leaked fluid or other contamination is confirmed in a USDW or other unauthorized zone, MCI will perform the following response actions: o Identify and implement (in consultation with the Director) a case-specific remediation plan as soon as possible and no later than 30 days of the emergency event. The plan will include, but not be limited to: • Installing additional groundwater monitoring points to delineate the extent of impact; and • Remediating the affected USDW or unauthorized zone to mitigate potential endangerment of or adverse impacts to USDWs. Examples of methods that may be applicable include: • A system to intercept and extract non-native fluid or CO_2; or • A pump-and-treat type system to aerate the water contaminated with CO_2 to purge the CO_2 from the water. o Arrange for an alternate potable water supply if the USDW was being utilized as a drinking water source and the contamination has caused an exceedance of drinking water standards. o Continue remediation and monitoring on a frequent basis (in consultation with the Director) until potential endangerment of or adverse impacts to USDWs have been fully addressed.

Table 10 - 4: Response actions to evidence suggesting potential fluid leakage to a USDW or other unauthorized zone

10.4.5 Severe Weather Disaster

Well problems (integrity loss, leakage, or malfunction) may arise because of a natural disaster affecting the normal operation of the MCI CCS 3 well. Weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities. The Marquis Carbon Injection facility lies outside the Federal Emergency Management Agency Adverse Effects (FEMA AE) Zone for floodplains.

Timing of event: Construction/Pre-Injection, Injection, and Post-injection

Response actions to an emergency associated with a natural disaster include but are not limited to the actions detailed below in
Table 10-5.

Wells	Response Action and Notification Procedures – Severe Weather Disaster
All	• Notify the MCI Environmental Manager and CCS Operations Manager immediately. • The Environmental Manager and/or the CCS Operations Manager or their designee will notify other Project Management and Operational Personnel. • Trigger alarm by the monitoring system or monitoring personnel. • If appropriate, contact the field supervisor to activate emergency evacuation and secure the location. • Notify the Director within 24 hours of the emergency event, per 40 C.F.R. § 146.94(b)(3), and 40 C.F.R. § 146.91(c) and (e). • If there has been a loss of mechanical integrity, implement Response Actions from Section 10.4.2. • Determine if all monitoring equipment remains functional. If there has been a failure or malfunctioning of monitoring equipment, implement Response Actions from Section 10.4.3. • Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or Unauthorized Zone. If there is such evidence, implement Response Actions from Section 10.4.4. • Assess potential impact to the project and the Local Resources and Infrastructure. • Identify and implement appropriate remedial actions (in consultation with the Director).

Table 10 - 5: Response actions to an emergency associated with a severe weather disaster.

10.4.6 Seismic Events

A major natural seismic event may disturb the surface or subsurface facilities. There is also a possibility that injection operations may cause induced seismicity. This portion of the response plan is developed for any seismic event with an epicenter within a 100-kilometer (62.14-mile) radius of the MCI CCS 3 well.[2] Refer to **Table 10-6** below for response actions based on Moment magnitude (Mw) thresholds and potential damage.

The Marquis BioCarbon Project is in a seismically stable region. To monitor the AoR for any potential seismic activity, MCI will maintain a network of surface seismological stations continuously record background seismic activity. MCI has installed microseismic surface monitors to collect background data prior to injection. The location of individual stations within

[2] The midpoint between the surface-hole and bottom-hole locations shall be used as the center of the circle.

this network are shown on **Figure 10 - 4**: Present Locations of Microseismic Stations Around Injection Site, and those stations can be adjusted as required in response to monitoring results or future AoR re-evaluations. Baseline microseismic data is being acquired prior to the start of injection operations. As of August 2024, no seismic activity has been identified within the modeled MCI CCS 3 CO_2 plume extent. However, should seismic activity occur, triggered MCI will process the seismic event data to provide seismic moment magnitude and precise location and depth information on a real-time basis and reported daily.

Upon issuance of a final permit, Marquis must subscribe to the U.S. Geological Survey (USGS) Earthquake Notification Service to receive notification of seismic events (both natural and induced) within 100 kilometers from the well. Based on the periodic analysis of the monitoring data, observed level of seismic activity, the USGS notification system, and local reporting of felt events, the site is assigned an operating state based on the protocol described in **Table 10 - 6**: Seismicity Monitoring System and Protocol for seismic events for Seismic Events >Moment Magnitude (Mw) 1.0 with an Epicenter Within a 100-Kilometer Radius of MCI CCS 3. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

Timing of event: Construction/pre-injection, injection and post-injection

Operating State	Threshold Condition, Movement Magnitude (Mw)[3][4]	Response Actions include but are not limited to:
Green	Seismic events within a 14.5-mile radius less than or equal to Mw 1.5	• Continue normal operation within permitted levels.
Yellow	Five (5) or more seismic events within a 14.5-mile radius within a 30- day period having a magnitude greater than Mw 1.5 but less than or equal to Mw 2.0	• Continue normal operation within permitted levels. • Within 24 hours of the fifth event, notify the Director of the operating status of the well. • Review seismic and operational data to determine the cause
Orange	Seismic event within a 14.5-mile radius greater than Mw 1.5 and local observation or felt report Seismic event within a 14.5-mile radius greater than Mw 2.0 and no felt report	• Continue normal operation within permitted levels. • Within 24 hours of the incident, notify the Director of the operating status of the well. • Review seismic and operational data to determine the cause. • Report findings to the Director and identify and implement appropriate remedial actions (in consultation with the Director).
Magenta	Seismic event within a 14.5-mile radius greater than Mw 2.0 and local observation or report	• Initiate rate reduction plan (in consultation with the Director) • Within 24 hours of the incident, notify the Director of the operating status of the well. • Limit access to wellhead to authorized personnel only. • Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. • Review seismic and operational data to determine the cause of the event. • Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • Report findings to the Director and identify and implement appropriate remedial actions (in consultation with the Director). • If there has been a loss mechanical integrity at any of the wells, implement Response Actions from Section 10.4.2. • Determine if all monitoring equipment remains functional. If there has been a failure or malfunctioning of monitoring equipment, implement Response Actions from Section 10.4.3. • Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or Unauthorized Zone. If there is such evidence, implement Response Actions from Section 10.4.4.
	Seismic event within a 14.5-mile radius greater than Mw 2.0, and local observation or report, and local report and confirmation of damage at the project site	• Monitor well pressure, temperature, and annulus pressure to assess if well operation is within permitted operational parameters. • Review seismic data from seismic stations around the project site.

[3] Specified magnitudes refer to magnitudes determined by USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[4] "Felt report" and "local observation or report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

Red	Seismic event greater than Mw 3.5 within a 14.5-mile radius	• If seismic stations indicate, based on USGS *Modified Mercalli Intensity Scale* (Fig. 10-5), an instrumental intensity in the project area of VII or above, Initiate shutdown plan (40 C.F.R. § 146.94(b)(1)).
		  ○ Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the compressors to the atmosphere.
		  ○ Check wind direction.
		  ○ Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines.
		  ○ Mark an exclusion zone around the affected area/well to limit access to affected area to authorized personnel only.
		  ○ Notify plan safety personnel that well has been shut down.
		  ○ Notify local authorities and plant personnel, as necessary.
		  ○ Limit access to wellhead and surface facilities to authorized personnel only.
		  ○ If evacuation plan must be implemented, notify all surrounding businesses and offices, and local authorities.
		  ○ Reset or repair automatic shutdown devices, if necessary.
		• Within 24 hours of the incident, notify the Director of the operating status of the well and about the emergency (40 C.F.R. § 146.94(b)(3)), including information on the status of the injection site.
		• Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.
		• Review seismic and operational data to determine the cause of the event.
		• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure.
		• Report findings to the Director and identify and implement appropriate remedial actions (in consultation with the Director).
		• Within 48 hours of the incident, evaluate the mechanical integrity of the well in accordance with Section 10.4.2 of the ERRP. If there has been a loss of mechanical integrity, implement Response Actions from Section 10.4.2. If there is a loss of mechanical integrity or other problems with the system that might impact a USDW, consult the Director prior to recommencing injection.
		• Determine if all monitoring equipment remains functional. If there has been a failure or malfunctioning of monitoring equipment, implement Response Actions from Section 10.4.3.
		• Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or Unauthorized Zone. If there is such evidence, implement Response Actions from Section 10.4.4.

Red	Seismic event greater than Mw 3.5 outside of 14.5-mile radius but within 100-kilometer radius	• Within 24 hours of the incident, notify the Director of the operating status of the well and about the emergency (40 C.F.R. § 146.94(b)(3)), including information on the status of the injection site. • Within 30 days of the incident, evaluate the mechanical integrity of the well. If there has been a loss in mechanical integrity, implement Response Actions from Section 10.4.2. If there is a loss of mechanical integrity or evidence of other problems with the system that may endanger a USDW, consult the Director prior to recommencing injection.

Red	Seismic event equal to or greater than Mw 5.0 within a 100-kilometer radius, and local observation or report, and local report and confirmation of damage to the project site	• Monitor well pressure, temperature, and annulus pressure to assess if well operation is within permitted operational parameters.
		• Review seismic data from seismic stations around the project site.
		• If seismic stations indicate, based on USGS *Modified Mercalli Intensity Scale* (Fig. 10-5), an instrumental intensity in the project area of VII or above, Initiate shutdown plan (40 C.F.R. § 146.94(b)(1)).
		  ○ Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the compressors to the atmosphere.
		  ○ Check wind direction.
		  ○ Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines.
		  ○ Mark an exclusion zone around the affected area/well to limit access to affected area to authorized personnel only.
		  ○ Notify plan safety personnel that well has been shut down.
		  ○ Notify local authorities and plant personnel, as necessary.
		  ○ Limit access to wellhead and surface facilities to authorized personnel only.
		  ○ If evacuation plan must be implemented, notify all surrounding businesses and offices, and local authorities.
		  ○ Reset or repair automatic shutdown devices, if necessary.
		• Within 24 hours of the incident, notify the Director of the event, operating status of the well and about the emergency (40 C.F.R. § 146.94(b)(3)), including information on the status of the injection well system.
		• Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.
		• Review seismic and operational data to determine the cause of the event.
		• Within 48 hours of the incident, evaluate the internal and external mechanical integrity of the injection well in accordance with Section L(2) of the Permit. If there is a loss of mechanical integrity or other problems with the system that might impact a USDW, the injection well must remain shut-in and MCI must submit a report in electronic format as soon as possible but no later than 30 days from the time MCI becomes aware of the circumstances
		  ○ The report shall contain a description of failure and if the failure has not been corrected, the anticipated time it is expected to continue and any steps taken or planned to reduce, eliminate, and prevent recurrence of the failure.
		  ○ Upon completion of the steps to ensure mechanical integrity and the subsequent mechanical integrity demonstration, MCI shall submit the results and any other required documentation to the Director.
		• Determine if all monitoring equipment remains functional. If there has been a failure or malfunctioning of monitoring equipment, implement Response Actions from Section 10.4.3.
		• Conduct assessment to determine if there is evidence suggesting potential fluid leakage into a USDW or Unauthorized Zone. If there is such evidence, implement Response Actions from Section 10.4.4.
		• If the well has been shut-in, consult the Director prior to recommencing injection.

Table 10 - 6: Seismicity monitoring system and protocol for seismic events > Mw1.0 with an epicenter within a 100-kilometer radius of MCI CCS3.

10.5 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. The injection well is located in Putnam outside of any city limits. Therefore, County emergency responders (as well as State agencies) will need to be notified in the event of an emergency.

A site-specific emergency contact list will be developed and maintained during the life of the project. The contact list will identify the site personnel, and their phone numbers, to be notified, in addition to the Director. This site-specific emergency contact list will be maintained during the life of the Project. MCI will provide the current site-specific emergency contact list to the Director.

Name	Title	Telephone Number
Jason Marquis	Chief Operating Officer	Office: (815) 925-7300 – Ext. 1128
Alex Tarmann	Emergency Preparedness & Response Advisor	Office: (815) 925-7300 – Ext. 2213
Dustin Marquis	Senior Vice-President – Government Relations & Corporate Communications	Office: (815) 925-7300 – Ext. 1121

Table 10-7: Contact Information of MCI Emergency Authorities

Key local, state, and other authority's emergency contact list is provided in **Table 10-8** and will also be maintained during the life of the project.

Agency	Phone Number
Local police (Hennepin Police)	815-925-7084
Illinois State police (LaSalle office, IL)	815-224-1171
Putnam County Sheriff	815-925-7015
Hennepin Fire Department	815-925-7225 or 911

Illinois Emergency Management Agency	800-782-7860
Environmental Services Contractor	Clean Harbors 1-800-645-8265
EPA National Response Center (24-Hours)	(800) 424-8802
UIC Director US EPA Region V	312-353-7648

Table 10 - 8: Key local, state, and other authority's emergency contact list.

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

10.6 Emergency Communications Plan

MCI will communicate to the public and relevant authorities about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental health or safety concerns in consultation with the Director. Based on the emergency event, MCI will determine the amount of information, timing, and communications method(s) that will be appropriate to the event. This information may include potential severity, impacts to drinking water, any impacts to the surrounding community, actions taken or planned to address the emergency event, and other information to protect the public during the event.

For responses that occur over the long-term (e.g., ongoing cleanups), MCI will provide periodic updates on the progress of the response action(s).

If required, MCI will also communicate with other entities who may need to be informed about or act in response to the event, including local water utilities, CO_2 source(s) and pipeline operators, landowners, Regional Response Teams (as part of the National Response Team), and other departments or authorities as guided by the UIC Program Director.

A designated MCI representative will be the first contact during an emergency event, and that representative will communicate with the relevant public authorities. The MCI representative and any designees will contact the agencies/departments on the emergency contact list (Table 10-7).

The MCI representative assigned the emergency response communications duties will be available 24-hours a day in the event of an emergency.

10.7 Plan Review

In accordance with 40 C.F.R. § 146.94(d), MCI shall periodically review the ERRP. Based on this review, MCI shall submit an amended ERRP or a demonstration to the Director that no amendment is needed. Any amendments to the ERRP must be approved by the Director to be effective, and if approved, will be incorporated into the Permit. Amended plans or demonstrations shall be submitted to the Director as follows:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review re-evaluation;
- Following any significant changes to the facility, such as an addition of injection or monitoring/verification wells, on a schedule determined by the Director;
- Within six (6) months following the occurrence of an emergency event under this ERRP; or
- When required by the Director.

10.8 Staff Training and Exercise Procedures

MCI will integrate this ERRP into the project-specific standard operating procedures and training program. Periodic training will be provided, not less than annually, to well operators, CO_2 scrubber operators, project safety and environmental personnel, plant technology manager, project manager, Carbon Capture Plant operations supervisor, and corporate communications. The training plan will document that the above listed personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

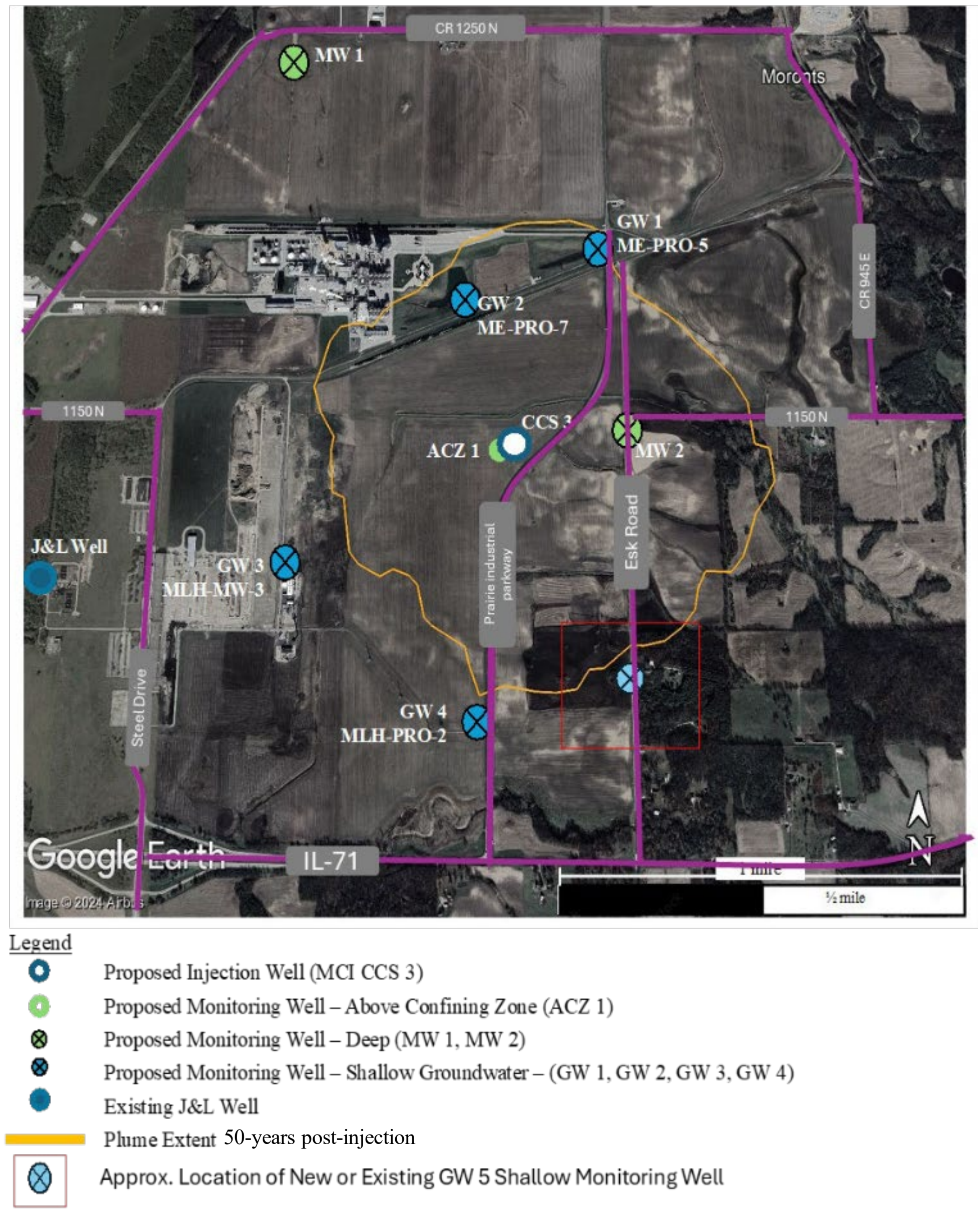


Figure 10 - 1: Aerial of the site resources and infrastructure in the vicinity of MCI CCS 3.

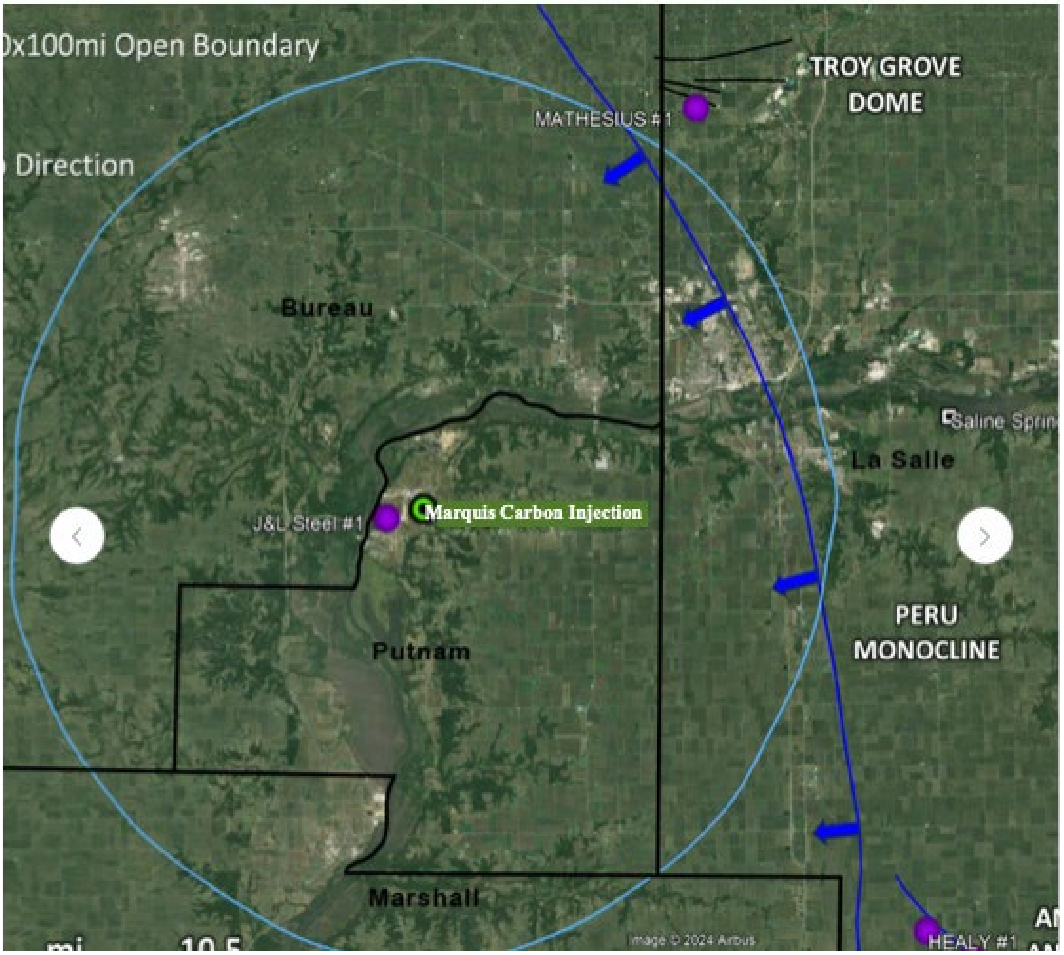


Figure 10 - 2: MCI CCS 3 CO_2 Plume and AoR

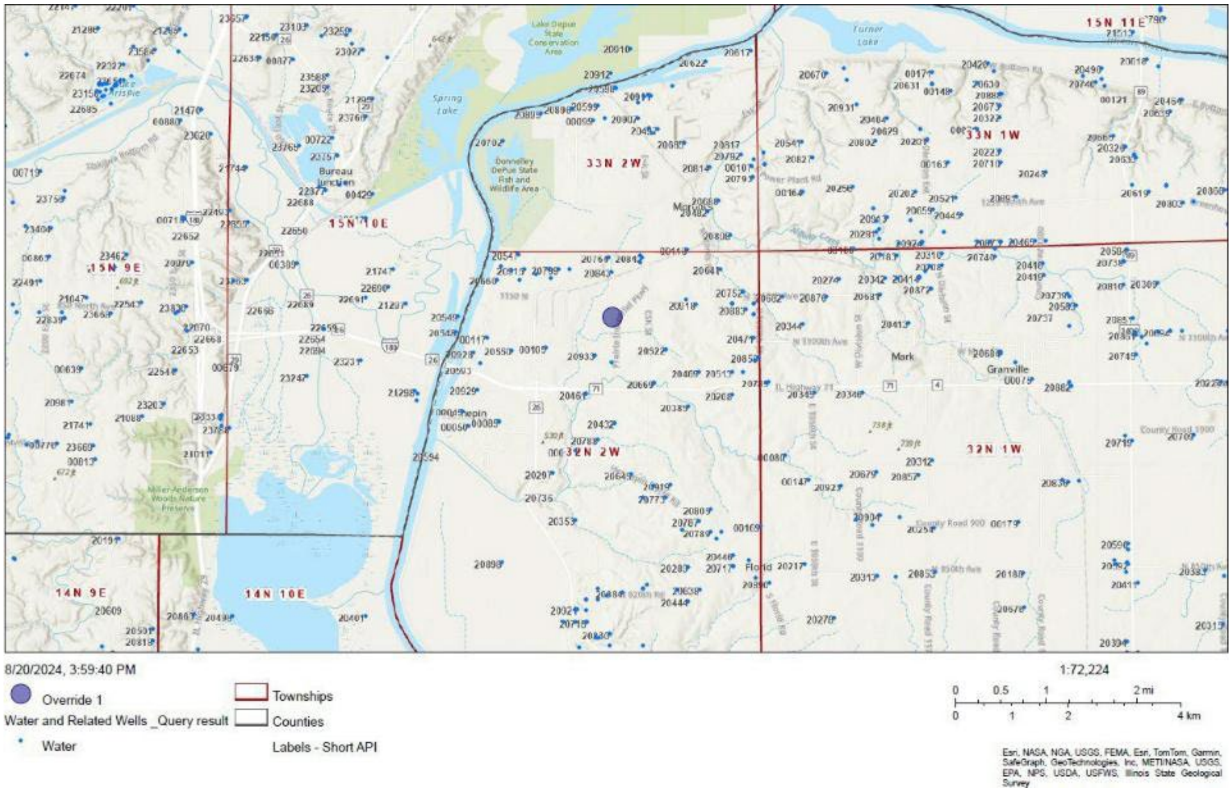


Figure 10 - 3 Community and Non-Community Wells Nearby MCI CCS 3. For a Complete List of all Wells within the AoR see **Appendix V7.**

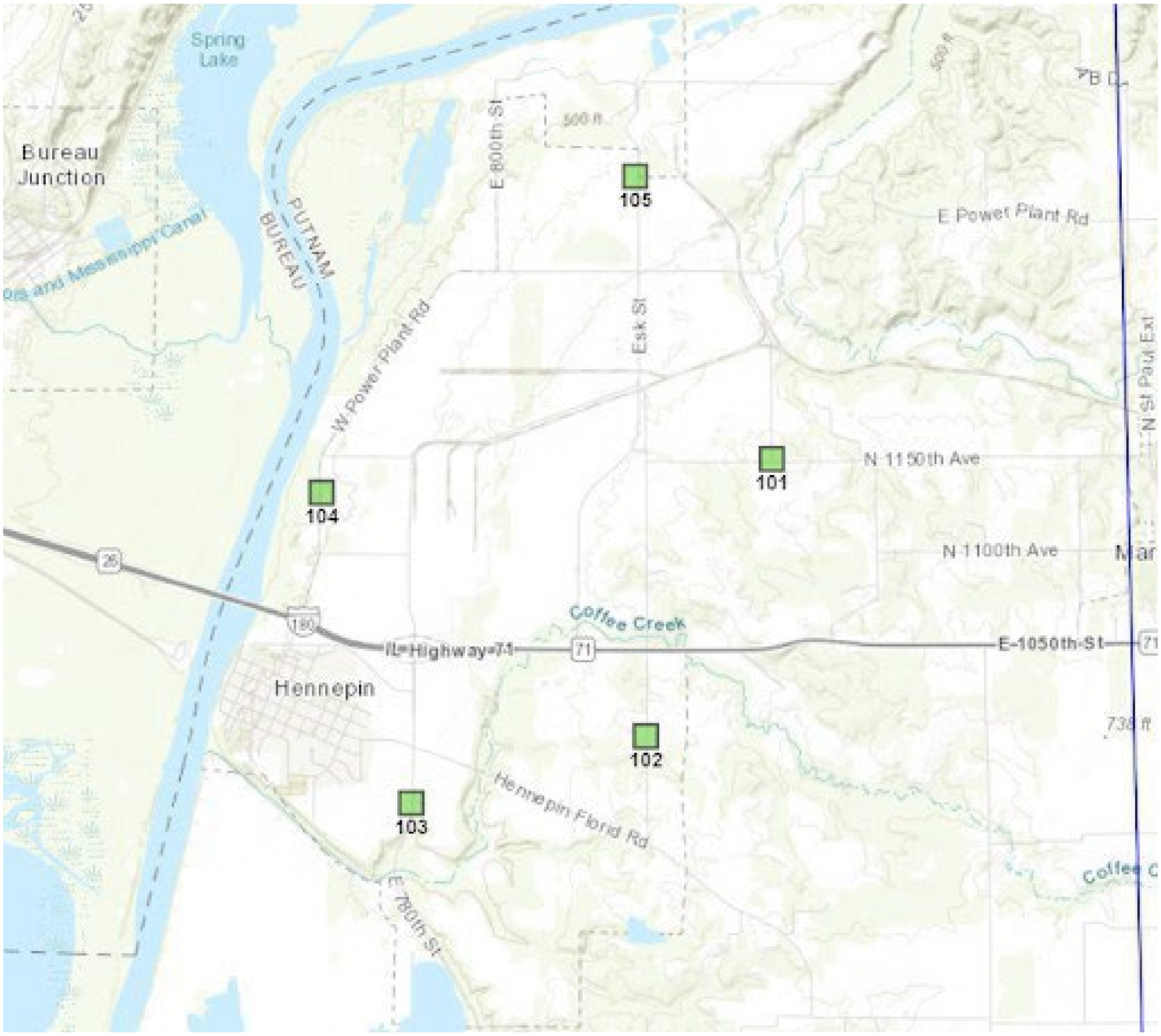


Figure 10 - 4: Present Locations of Microseismic Stations Around Injection Site

PERCEIVED SHAKING	Not felt	Weak	Light	Moderate	Strong	Very strong	Severe	Violent	Extreme
POTENTIAL DAMAGE	none	none	none	Very light	Light	Moderate	Moderate/Heavy	Heavy	Very Heavy
PEAK ACC.(%g)	<.17	.17-1.4	1.4-3.9	3.9-9.2	9.2-18	18-34	34-65	65-124	>124
PEAK VEL. (cm/s)	<0.1	0.1-1.1	1.1-3.4	3.4-8.1	8.1-16	16-31	31-60	60-116	>116
INSTRUMENTAL INTENSITY	I	II-III	IV	V	VI	VII	VIII	IX	X+

Figure 10 - 5: USGS Modified Mercalli Intensity Scale

ATTACHMENT G: PRE-INJECTION TESTING PLAN

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Drive, Hennepin, IL 61327

Well location: S2, T32N, R2W
41.27026520° N, 89.30939322° W

As per 40 CFR § 146.87:

> During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared.

The following Pre-Operational Testing Plan describes how the requirements of 40 C.F.R. § 146.87 and 40 C.F.R. § 146.86 will be fulfilled.

Marquis will be constructing a new well, MCI CCS 3, for the injection of CO_2 into the Mount Simon Sandstone of the Illinois Basin at ~3,094 ft MD. Prior to this construction, Marquis has completed the drilling and investigation of a stratigraphic test well, MCI MW 1, and included investigation of the geologic column to a depth of 4,854 ft MD. Data acquired during drilling and testing from MCI MW 1 will be used for comparison purposes while interpreting the data that will be obtained during the drilling and completion of MCI CCS 3.

Whole and side wall cores were collected from MCI MW 1. Analyses of these cores will be used as the primary geologic characterization of the injection site. Either whole core or sidewall core samples must be obtained from the confining zone and injection zone from MCI CCS 3 in accordance with 40 C.F.R. § 146.87(b).

The pre-operational testing will be performed in sequence with the well construction activities. As each portion of the well is constructed, a different suite of tests will be performed based on the bore hole conditions (open hole vs cased hole). This plan is broken into sections that will cover each major portion of the injection well and testing associated with each major section.

Table 1 provides the primary sections of the well along with estimated depths. The actual depths will be determined during the drilling operations based on input from well logs, geologist's inputs, and surrounding well data.

After the well has been completed, a cement bond log – variable density log (CBL-VDL) and advanced ultrasonic cement evaluation log will be run along the entire depth of the long casing string shortly after completion of the MCI CCS 3 well to confirm that the casing string was properly cemented. A baseline temperature measurement will also be acquired from surface to total depth (TD) to provide initial temperature conditions over the well.

Table 1: Major Well Sections/Casing Details.

Casing String	Casing Depth (MD feet)	Borehole Diameter (inches)	Casing Diameter (OD-inches)	Wall Thickness (inches)	Casing Material	String Weight (lb/ft)
Conductor	80	±36	30	0.375	X-42	118
Surface	350	26	20	0.438	J/K-55	94
Intermediate	2,735	17.5	13.375	0.38	J/K-55	68
Long String	2,690	12.25	9.625	0.482	13Cr80	47
Long String	4,854	12.25	9.625	0.482	25Cr80C	

Conductor

The bore hole for the conductor will be drilled to a depth of approximately 80 ft MD. Once the bore is established, the 30-inch conductor will be set and cemented to surface. Due to the shallow nature of the conductor section no pre-operational testing is proposed. Industry standards for cement setting time will be followed.

Surface Section

Surface casing will be set from 0 ft to 30 ft within the conductor and then from 30 ft to 350 ft in a 26-inch bore hole to ensure coverage of groundwater. Open hole well logs will be acquired prior to setting the surface casing. Table 2 shows all open hole testing planned for the surface casing section before the casing is installed and cemented. Additional cased well logs will be acquired for the surface casing section after the surface casing has been set and cemented. Table 3 shows all testing planned for the surface casing section after the casing is installed and cemented.

Table 2: Surface Section Open Hole Testing.

Test Performed	Purpose/Comments
Gamma Ray (GR)	Lithology
Density	Porosity, Density
Neutron Porosity	Porosity
Spontaneous Potential (SP)	Permeability
Resistivity	Fluid Saturation, Permeability
Caliper	Borehole Diameter, Stress
Dipole Shear Sonic-Delta-T Compressional (DTC)	Used to Compare to 3D Seismic Data
Delta-T Shear (DTS)	Used to Compare to 3D Seismic Data

Table 3: Surface Section Cased Hole Testing.

Test Performed	Purpose/Comments
Cement Bond Log – Variable Density Log (CBL-VDL)	Cement Integrity
Pulse Neutron Log (PNL)	Lithology, Fluid Saturation, Porosity

Intermediate Section

The intermediate section will be from approximately 350 ft to 2,750 ft MD. The intermediate casing will be set from 0 ft to 350 ft within the surface casing and then from 350 ft to 2,735 ft in a 17.5-inch bore hole. Open hole well logs will be acquired in the intermediate section of the well from a depth of approximately 350 ft to 2,750 ft. Table 4 shows all open hole testing planned for the intermediate section before the casing is installed and cemented.

Table 4: Intermediate Section Open Hole Testing.

Test Performed	Purpose/Comments
Gamma Ray (GR)	Lithology
Density	Porosity, Density
Neutron Porosity	Porosity
Spontaneous Potential (SP)	Permeability
Resistivity	Fluid Saturation, Permeability
Caliper	Borehole Diameter, Stress
Dipole Shear Sonic-Delta-T Compressional (DTC)	Used to Compare to 3D Seismic Data
Delta-T Shear (DTS)	Used to Compare to 3D Seismic Data

After completion of the open hole logging, the intermediate casing will be set and cemented. Additional cased well logs will then be acquired for the intermediate section to evaluate the cement integrity and to ensure the protection of USDWs is maintained. Table 5 shows all testing planned for the intermediate section after the casing is installed and cemented.

Table 5: Intermediate Section Cased Hole Testing.

Test Performed	Purpose/Comments
Cement Bond Log – Variable Density Log (CBL-VDL)	Cement Integrity
Ultrasonic Cement Evaluation	Cement Integrity

Long String Section

The long string section will be from approximately 2,750 to 5,000 ft MD. The upper portion of the long string casing will be set from 0 ft to 2,690 ft within the intermediate casing. The lower portion of the long string casing will be set from 2,690 ft to 2,735 ft within the intermediate casing and 2,735 ft to 4,854 ft in a 12.25-inch bore hole. Open hole well logs will be acquired in the long string section of the well from a depth of approximately 2,750 ft to 5,000 ft. Table 6 shows all open hole testing planned for the long string section before the casing is installed and cemented.

Table 6: Long String Open Hole Testing.

Test Performed	Purpose/Comments
Gamma Ray (GR)	Lithology
Density	Porosity, Density
Neutron Porosity	Porosity
Spontaneous Potential (SP)	Permeability
Resistivity	Fluid Saturation, Permeability
Caliper	Borehole Diameter, Stress
Dipole Shear Sonic-Delta-T Compressional (DTC)	Used to Compare to 3D Seismic Data
Delta-T Shear (DTS)	Used to Compare to 3D Seismic Data

After completion of the open hole logging, the long string casing will be set and cemented. Additional cased well logs will then be acquired for the long string section to evaluate the cement integrity and to provide baseline data for external well integrity. The pulsed neutron capture log and temperature log will be performed after drilling muds are no longer present near the well and the temperature has stabilized to ensure accurate results from the logging effort. Table 7 shows all testing planned for the long string section after the casing is installed and cemented.

After cased hole logs in the long string sections are acquired, the dipole shear sonic log from the MCI CCS 3 well will be examined to determine if any faults or fractures are present. Any formations with fractures will be compared to similar formations from the MCI MW 1 well to determine consistency of findings. Any indication of faulting or fracture networks that may compromise the seal will be tied to the 3D seismic analysis to determine if they impact the integrity of the seal or may lead to heterogeneities in the injection zone that could affect plume development.

Table 7: Long String Cased Hole Testing.

Test Performed	Purpose/Comments
Cement Bond Log – Variable Density Log (CBL-VDL)	Cement Integrity
Ultrasonic Cement Evaluation	Cement Integrity
Temperature Log	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations
Pulse Neutron Log (PNL)	Lithology, Fluid Saturation, Porosity

After the packer, tubing, and downhole equipment have been installed, and the tubing/casing annulus of each well has been filled with a corrosion-inhibited fluid, a mechanical integrity test (MIT) will be conducted on the annular space of all the deep wells to ensure that there are no leaks in the tubing, casing, or packer. The MIT will be performed by pumping additional annular fluid into the annulus to increase the pressure to the maximum allowable injection pressure at the surface. The annular pressure will be monitored for 60 minutes to measure pressure loss. A pressure loss of less than 3% of the initial value would indicate proper internal mechanical integrity. If a pressure loss greater than 3% is observed, the test will be repeated, and if it fails again, the cause of the poor mechanical integrity will be identified and corrected.

Formation Testing

After all casing is set the lowermost interval will be perforated to allow for injection into the desired section of the Mount Simon Sandstone. After the casing is perforated a series of injectivity tests and formation fluid tests will be performed. Table 8 includes the testing planned before the commencement of operation of the injection well.

Drill stem tests (DSTs) will be performed on potential USDWs in the MCI CCS 3 well. Starting at the St. Peter, each major water-bearing sandstone formation will be sampled and tested. Once a non-USDW formation is found, one formation deeper will be sampled and tested to confirm non-USDW status. Field testing of TDS/salinity will be the indicator of USDW status. Water samples will then be sent to a lab for further analysis. These results will be compared to the analyses done at MCI MW 1 to confirm consistency of the USDWs and other water bearing zones across the project site. As a final step, a petrophysical analysis will be performed to tie the water salinity to key log measurements such as resistivity, porosity, and elemental analysis.

Table 8: Formation Testing.

Test Performed	Purpose/Comments
Pump Test or Injectivity Test	Verification of the injectivity rates used in the Plume and AOR simulations
Fluid Temperature	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations
Fluid pH	Provide baseline of formation pH for reference to future samples
Fluid Conductivity	Provide baseline of formation conductivity for reference to future samples
Fluid Total Dissolved Solids/Salinity	Starting at the St. Peter Sandstone, each major water-bearing sandstone formation will be tested to determine USDW status. Once a non-USDW formation is found, one formation deeper will be sampled and tested to confirm non-USDW status.
Reservoir Pressure	Provide baseline of formation pressure for comparison during injection activities and CO_2 plume monitoring
Deviation Survey	Determine wellbore path and verticality from surface to total depth
Pressure Fall Off Test	Verification of connectivity of sequestration field
Static Fluid Level	Determination of bottomhole pressure

Injectivity testing is planned for the MCI CCS 3 well to confirm the flow of fluid into zones within the Mt. Simon Sandstone during injection. This data will be used to determine the best perforation strategy for the MCI CCS 3 well. The flowmeter testing will be performed by injecting brine into the open borehole after it has been drilled to TD and running a flowmeter tool across the open hole interval. Two flowmeter tests are planned for the MCI CCS 3 well. One test will examine the flow conditions across the entire open borehole (below the intermediate casing) and the other will focus on the Mt. Simon Sandstone by setting a packer at the base of the Elmhurst Formation.

Once the well is completed and perforated, a set of hydrogeologic tests will be performed. These include a pressure fall-off test and a pump test or injectivity test.

Data Analysis and Reporting

Marquis Carbon Injection will submit to the Director a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. Data will be presented in the pre-injection testing report submitted to the Director per Permit Section J.

ATTACHMENT H: WELL CONSTRUCTION DETAILS

Facility Information

Facility name:	Marquis Biocarbon Project MCI CCS 3
Facility address:	10000 Marquis Dr Hennepin, IL 61327
Well location:	S2 T32N R2W 41.27026520°N, 89.30939322°W

Figure 1: **Injection Well Construction Diagram (MCI CCS 3).**

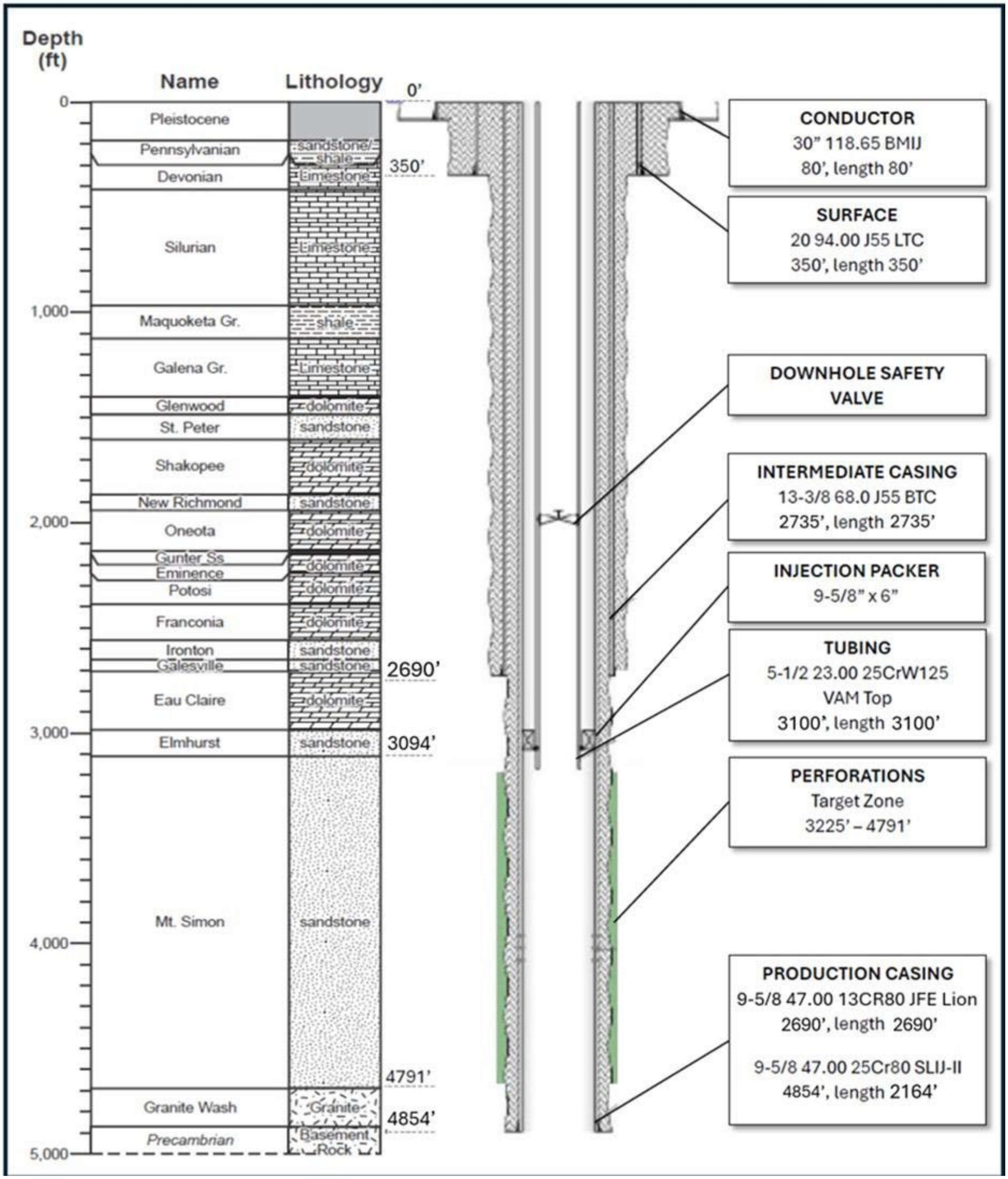
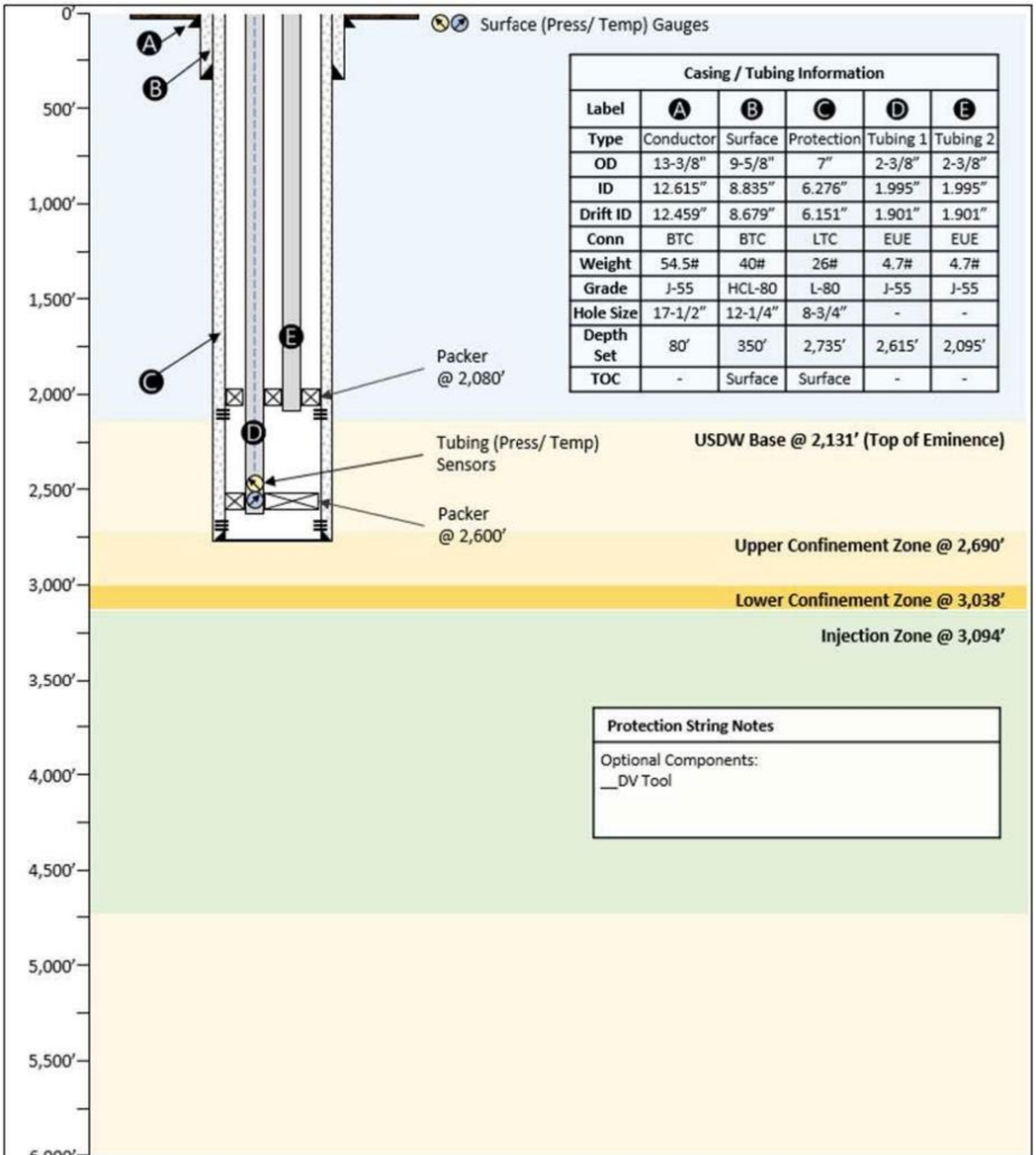


Figure 2: Groundwater Monitoring Well Construction Diagram (MCI ACZ 1).



Casing / Tubing Information

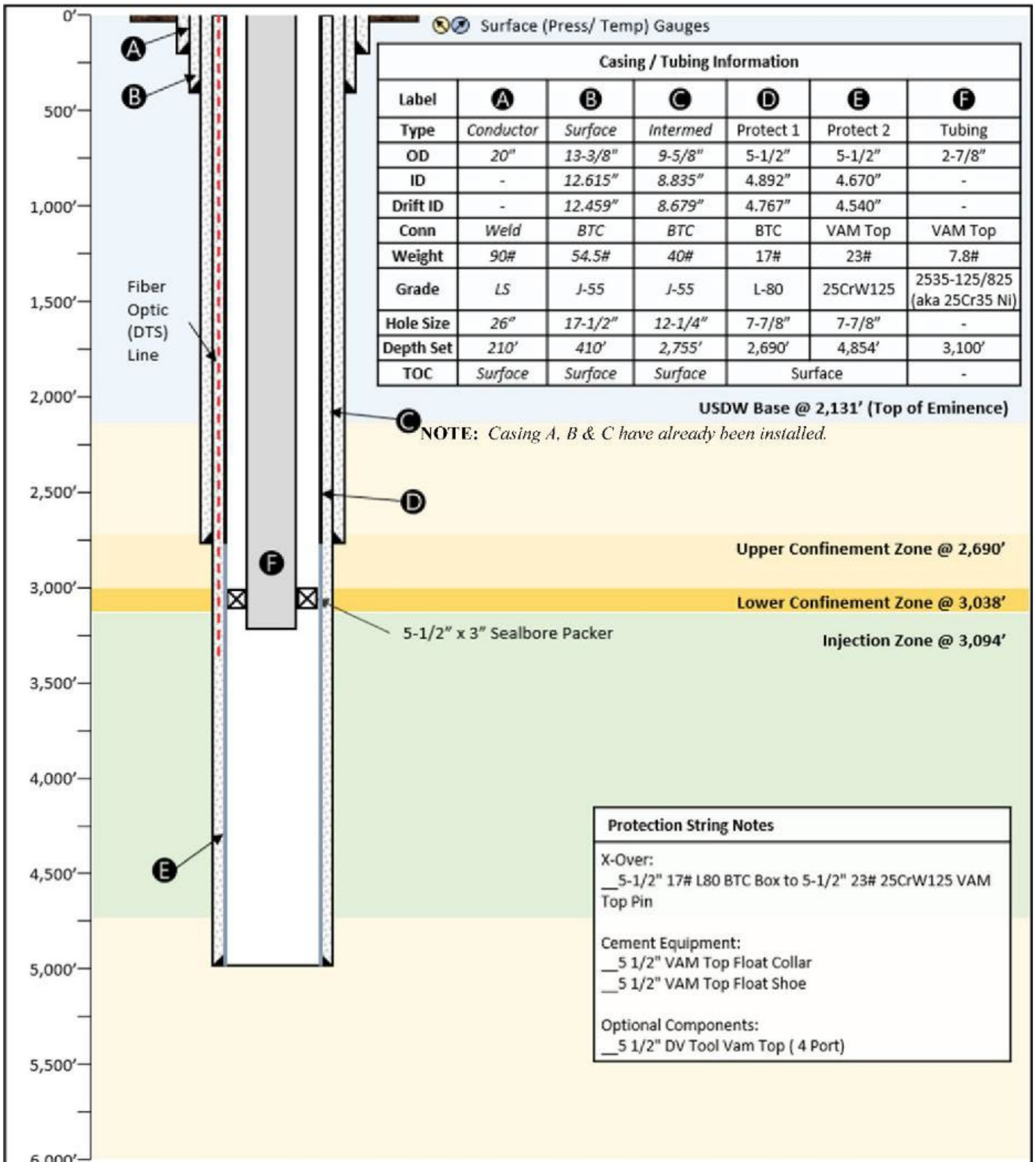
Label	A	B	C	D	E
Type	Conductor	Surface	Protection	Tubing 1	Tubing 2
OD	13-3/8"	9-5/8"	7"	2-3/8"	2-3/8"
ID	12.615"	8.835"	6.276"	1.995"	1.995"
Drift ID	12.459"	8.679"	6.151"	1.901"	1.901"
Conn	BTC	BTC	LTC	EUE	EUE
Weight	54.5#	40#	26#	4.7#	4.7#
Grade	J-55	HCL-80	L-80	J-55	J-55
Hole Size	17-1/2"	12-1/4"	8-3/4"	-	-
Depth Set	80'	350'	2,735'	2,615'	2,095'
TOC	-	Surface	Surface	-	-

Protection String Notes

Optional Components:
__DV Tool

TRES MANAGEMENT	Marquis Carbon Injection LLC – Biocarbon Project		MCI ACZ 1
	Company Rep: **Jared Walker**	State/Province: **Illinois**	County/Parish: **Putnam**
	API:	Well Type/Status: **Monitor**	Prospect: **Mt Simon**
	Location: **S-2, T-32N, R-2W**	Lat: **41.28..°**	Long: **-89.32..°**
	Drilling Engr: **Eric Burnett**	Completions: **Garrett Elsener**	Geology: **Sharon Minor**
Notes: Not drawn to scale.			Date: **1/22/25 - JEB**

<u>Figure 3</u>: Injection Zone Monitoring Well Construction Diagram (MCI MW 1).



Casing / Tubing Information

Label	A	B	C	D	E	F
Type	*Conductor*	*Surface*	*Intermed*	Protect 1	Protect 2	Tubing
OD	*20"*	*13-3/8"*	*9-5/8"*	5-1/2"	5-1/2"	2-7/8"
ID	-	*12.615"*	*8.835"*	4.892"	4.670"	-
Drift ID	-	*12.459"*	*8.679"*	4.767"	4.540"	-
Conn	*Weld*	*BTC*	*BTC*	BTC	VAM Top	VAM Top
Weight	*90#*	*54.5#*	*40#*	17#	23#	7.8#
Grade	*LS*	*J-55*	*J-55*	L-80	25CrW125	2535-125/825 (aka 25Cr35 Ni)
Hole Size	*26"*	*17-1/2"*	*12-1/4"*	7-7/8"	7-7/8"	-
Depth Set	*210'*	*410'*	*2,755'*	2,690'	4,854'	3,100'
TOC	*Surface*	*Surface*	*Surface*	Surface		-

Protection String Notes

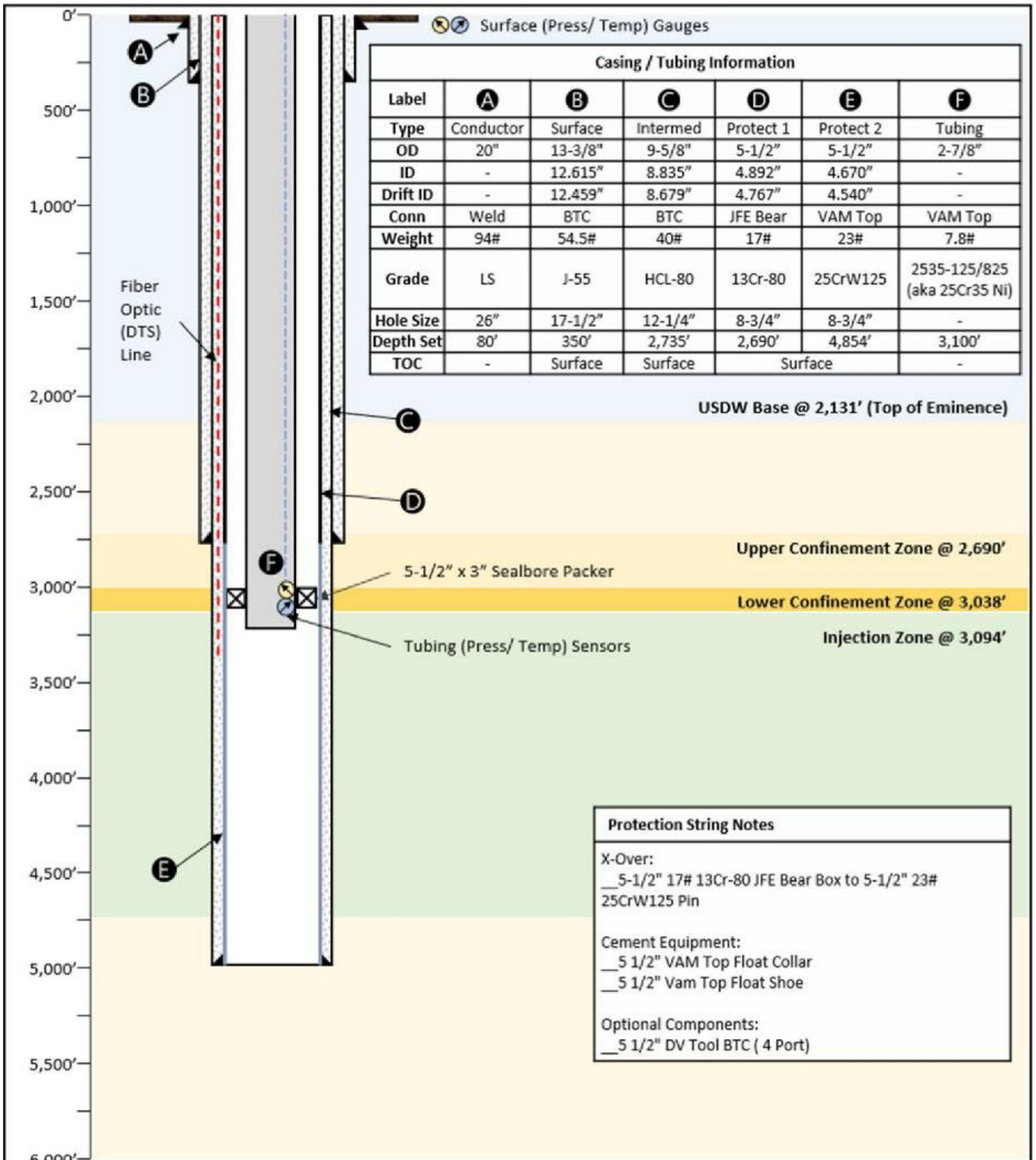
X-Over:
__5-1/2" 17# L80 BTC Box to 5-1/2" 23# 25CrW125 VAM Top Pin

Cement Equipment:
__5 1/2" VAM Top Float Collar
__5 1/2" VAM Top Float Shoe

Optional Components:
__5 1/2" DV Tool Vam Top (4 Port)

TRES MANAGEMENT	Marquis Carbon Injection LLC – Biocarbon Project		MCI MW 1
	Company Rep: **Jared Walker**	State/Province: **Illinois**	County/Parish: **Putnam**
	API:	Well Type/Status: **Monitor**	Prospect: **Mt Simon**
	Location: **S-2, T-32N, R-2W**	Lat: **41.28458°**	Long: **-89.32201°**
	Drilling Engr: **Eric Burnett**	Completions: **Garrett Elsener**	Geology: **Sharon Minor**
Notes: Not drawn to scale; *Italic text indicates pre-existing components.*			Date: **2/4/25 - JEB**

Figure 4: **Injection Zone Monitoring Well Construction Diagram (MCI MW 2).**



Casing / Tubing Information

Label	A	B	C	D	E	F
Type	Conductor	Surface	Intermed	Protect 1	Protect 2	Tubing
OD	20"	13-3/8"	9-5/8"	5-1/2"	5-1/2"	2-7/8"
ID	-	12.615"	8.835"	4.892"	4.670"	-
Drift ID	-	12.459"	8.679"	4.767"	4.540"	-
Conn	Weld	BTC	BTC	JFE Bear	VAM Top	VAM Top
Weight	94#	54.5#	40#	17#	23#	7.8#
Grade	LS	J-55	HCL-80	13Cr-80	25CrW125	2535-125/825 (aka 25Cr35 Ni)
Hole Size	26"	17-1/2"	12-1/4"	8-3/4"	8-3/4"	-
Depth Set	80'	350'	2,735'	2,690'	4,854'	3,100'
TOC	-	Surface	Surface	Surface		-

Protection String Notes

X-Over:
__5-1/2" 17# 13Cr-80 JFE Bear Box to 5-1/2" 23# 25CrW125 Pin

Cement Equipment:
__5 1/2" VAM Top Float Collar
__5 1/2" Vam Top Float Shoe

Optional Components:
__5 1/2" DV Tool BTC (4 Port)

TRES MANAGEMENT	Marquis Carbon Injection LLC – Biocarbon Project		MCI MW 2
	Company Rep: **Jared Walker**	State/Province: **Illinois**	County/Parish: **Putnam**
	API:	Well Type/Status: **Monitor**	Prospect: **Mt Simon**
	Location: **S-2, T-32N, R-2W**	Lat: **41.28..°**	Long: **-89.32..°**
	Drilling Engr: **Eric Burnett**	Completions: **Garrett Elsener**	Geology: **Sharon Minor**
Notes: Not drawn to scale.			Date: **2/4/25 - JEB**

ATTACHMENT I: FINANCIAL RESPONSIBILITY COST ESTIMATE AND DOCUMENTS

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Drive
Hennepin, IL 61327

Well location: S2, T32N, R2W
41.27026520° N, 89.30939322° W

Pursuant to the requirements in 40 C.F.R. § 146.85, Marquis has demonstrated adequate financial responsibility to cover the costs of the four geologic sequestration activities included in 40 C.F.R. § 146.85(a)(2), as determined by third-party estimates, using financial instruments as listed in 40 C.F.R. § 146.85(a)(1). The standby trust, letter of credit, and third-party insurance are part of the Administrative Record for this permit.

FINANCIAL RESPONSIBILITY SCHEDULE

Funding provided to the trust account through the letter of credit and the assurance provided by the third-party insurance will be adjusted according to when the financial risks are incurred on the Marquis Project. At the time of the following activities, Marquis will provide the adjustments stated below:

1. Pre-Injection: Costs associated with injection well plugging are covered by a letter of credit and standby trust. Once an injection or monitoring well is drilled, plugging cost will eventually be incurred. Therefore, the trust account will be funded with the cost of plugging injection and monitoring wells prior to drilling the wells.

2. Injection: Costs associated with post-injection site care and site closure are covered by a letter of credit and standby trust. As soon as injection of CO_2 begins in the Class VI well, certain activities related to post-injection site care and site closure will necessarily need to occur. Therefore, the trust account will be funded with the costs associated with these activities. Marquis estimates the cost of these activities at $8,727,806.

3. Post-Injection: For the reason stated above, post-injection site care and site closure will be funded by Marquis by the start of the injection phase. The trust account may phase out these costs as the activities are completed (with approval from the Director). For example, once wells have been plugged, their corresponding plugging costs may be

subtracted from the total value of the trust account.

4. Emergency and Remedial Response: Costs associated with emergency and remedial response activities are covered by a third-party insurance policy. Prior to well construction must be prepared to undertake any emergency or remedial response actions, although such actions are unlikely to be needed.

Within seven calendar days after the effective date of the final Class VI UIC permit for the Marquis Project, Marquis will ensure that $642,364 is in the trust fund to cover the cost of plugging injection and monitoring wells in the Pre-Injection Period. In addition, Marquis will ensure that there is an active third-party insurance policy valued at $7,342,390 to cover the cost of Emergency and Remedial response prior to well construction

On or before the one-year anniversary of the effective date of the final Class VI UIC permit for the Marquis Project, and at least seven calendar days prior to EPA authorization for the start of the CO_2 injection in the well (whichever is earlier), Marquis will ensure that an additional $8,727,806 is in the trust fund to cover the costs of the Post-Injection Site Care tasks. The total value of the trust at the beginning of the Injection Period will be $9,370,170.

As specified under 40 C.F.R. § 146.85(b)(1), Marquis will maintain financial responsibility until the EPA approves the completed Post-Injection Site Care and Site Closure Plan and approves site closure. Marquis must certify to the EPA that all geologic sequestration activities have been completed in accordance with the Post-Injection Site Care and Site Closure Plan.

Table 1: Total Financial Responsibility Cost Estimates.

Financial Responsibility Element	Cost Estimate	When Funded	Financial Instrument
Injection Well Plugging	$344,503	Prior to well construction	Letter of Credit
Total Cost	**$344,503**		
PISC and Site Closure			
Monitoring Wells Plugging	$297,861	Prior to well construction	Letter of Credit
PISC Testing & Monitoring	$6,776,819	Prior to authorization to inject	Letter of Credit
Site Closure (Seismic Data Acquisition, Updated Modeling, and Reporting)	$1,917,987		
Monitoring Well O&M during PISC	$33,000		
Total Cost	**$9,370,170**		
Emergency and Remedial Response – Site Remediation/Restoration	$6,840,000	Prior to well construction	Third-Party Insurance
Emergency and Remedial Response – Other	$502,390		
Total Cost	**$7,342,390**		
Total Financial Responsibility	**$16,723,057**		

Table 2: Breakdown of Cost Elements.

Injection Well Plugging		
Item	Contractor	Cost
Flush injection well with a buffer fluid	Drilling Contractor	Included in plugging costs below
Tests to measure bottomhole reservoir pressure	Third Party Service Provider	Included in project testing and monitoring costs
Final external mechanical integrity test to evaluate the integrity of the existing casing and cement that will remain after the well is plugged		
Plug injection well (CCS 3) - Mobilization of drill rig and demobilization	Drilling Contractor- Mobilization of drill rig and demobilization	$82,817.28
Plug injection well (CCS 3) - $12.5k per day for 7 days	Drilling Contractor	$90,581.40
Cement/gel	Haliburton cement provider	$156,611.00
Plugging oversight & report preparation	$200 per hour for 7 days at 10 hours per day	$14,493.02
Total		$344,502.70

Table 3a: PISC Cost Breakout – Post Injection Site Care.

PISC Time Period Years	12

Post-Injection Site Care		
Event	Frequency	Total Cost over PISC Duration
5 Shallow Groundwater Wells Sampling & Isotope Analysis	Annually for 12 years	$208,000
Annular Pressure Analysis & Fluid Volume of injection well (CCS 3)	Continuous	$22,361
Annular Pressure Analysis of deep monitoring well MW-2	Weekly	$22,361
Pressure-Temperature Sensors in Injection Well (CCS 3) Upper Mt. Simon Formation and ACZ-1 Monitoring Well in Gunter & Galesville Formations	Continuous	$89,443
Temperature Profile of Storage Formation of injection well (CCS 3), and deep monitoring wells – MW-1 and MW-2 (Distributed Temperature Sensing (DTS) System-Fiber Optic)	Annually	$124,226
Fluid sampling and isotope analysis of ACZ 1 monitoring well in Gunter & Galesville Formations, and deep monitoring well. MW-2 in Upper Mt. Simon Formation	Annually = 12 sampling/analysis events	$268,328
Pulsed Neutron Capture (PNC) Logging of ACZ-1 monitoring well and deep monitor well MW-2	Once per year	$447,213
Data Analysis/Updated CO_2 Plume/AoR Dynamic Modeling	Every 5 years	$144,102
Microseismic Monitoring of 5 Surface Stations	Continuous	$15,901
Time-Lapse 3D Surface Seismic Data of Surface	Every 5 years	$5,031,150
PISC Monitoring Reports to US EPA	Semi-Annual for 1st Year and Annually for Remaining 11	$403,734

	Years = 13 Reports @ 150 hours/ $30,000 per report	
Wellhead Valve Greasing	Annually	$9,000
Painting Well Heads	Annually	$4,000
Well Pad Maintenance	Annually	$4,000
Calibration of Temperature & Pressure Gauges	Annually	$6,000
Rebuilding Valves (8)	Once during PISC Period	$10,000
Total PISC Costs		**$6,809,819**

Table 3b: PISC Cost Breakout – Site Closure.

Site Closure		
Item	Contractor	Cost
Prior to plugging wells, check external integrity by temperature & PNC logging	Third Party	See oversight cost estimate below
Plug ACZ-1 Well and Deep Monitoring Wells – MW-1 and MW-2 (Service Rig Mobilization & Demobilization)	Drilling Contractor	$62,113
Plug ACZ-1 Well and Deep Monitoring Wells MW1 and MW-2 (Service Rig & pump)	Drilling Contractor	$85,405
Plug ACZ-1 Well and Deep Monitoring Wells MW-1 and MW-2 (Cement/gel)	Drilling Contractor	$123,013
Plugging Oversight & Remove above ground infrastructure (e.g., wellheads and monitoring equipment)	Third Party (44 hours per well @ $200 per hour = 132 hours)	$27,330
Time-Lapse 3D Surface Seismic Data of Surface (Once)		$1,677,050
Corrosion Monitoring – Multi-Finger Caliper Logging or Ultrasonic Casing Evaluation – Injection Well (CCS 3) 25Cr Casing & Tubing	Every 6 years after Start of Post-Closure Period Until Well is Closed (Baker Hughes 2025)	$184,000
Data Analysis/ Updated Modeling (Once - Following well closure)		$41,409
Site Closure Report to US EPA	Third Party	$15,528
Total		**$2,215,848**

Table 3c: Emergency and Remedial Response.

Emergency and Remedial Response		
Item	Contractor	Cost
Implement Shutdown (Alarm DCS System)		[no cost]
Conduct Site / Cause of Emergency Review	Third Party with Marquis	$8,282
Mechanical Integrity Concern	Service Rig	$323,298
Equipment Failure	Third Party	$155,282
Report of Corrective Action to US EPA	Third Party	$15,528
USDW Remediation – Total Costs: (*Breakdown of costs is below in italics)*		$6,840,000
Leak Investigation / Hydrogeological Study/ 10 Well Installation/Conversion	Third Party	*$2,000,000*
Extraction Well Installation/Conversion (4 wells) & Pump Installation & Electrical Connection to Onsite Electric Service	Third Party	*$1,960,000*
Electrical Service to 4 Existing Onsite Water Wells & Existing Building Housing Treatment System	Marquis	*$50,000*
Onsite Groundwater Treatment System & Media Change Out	Third Party	*$255,000*
Trenching and Piping from Existing Water wells to CO_2 Leakage Area & Electrical (Using Onsite Trenching Equipment)	Third Party & Onsite Trenching Equipment	*$130,000*

Permitting & Project Planning	Third Party and Marquis	*$760,000*
Operational & Maintenance Period	Third Party (2.25 Years)	*$1,400,000*
Close Out / Removal of Treatment System	Third Party	*$285,000*
Total		**$7,342,390**

ATTACHMENT J: STIMULATION PROGRAM

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Drive
Hennepin, IL 61327

Well location: S2, T32N, R2W
41.27026520° N, 89.30939322° W

Stimulation to enhance the injectivity potential of the injection zone may be necessary. Stimulation may involve but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection formation. Advance notice of all proposed stimulation activities must be provided to the Director, as detailed below, prior to conducting the stimulation. The permittee must describe any fluids to be utilized for stimulation activities and the permittee must demonstrate that the stimulation will not interfere with containment. The permittee must submit proposed procedures for all stimulation activities to the Director in writing at least 30 days in advance, per 40 C.F.R. § 146.91(d)(2). Within the 30-day notice period, EPA may: deny the stimulation; approve the stimulation as proposed; or approve the stimulation with conditions. The permittee must carry out the stimulation procedures, including any conditions, as approved or set forth by EPA.

ATTACHMENT K: QUALITY ASSURANCE AND SURVEILLANCE PLAN

Facility Information

Facility name: Marquis Biocarbon Project
MCI CCS 3

Facility address: 10000 Marquis Drive
Hennepin, IL 61327

Well location: S2, T32N, R2W
41.27026520° N, 89.30939322° W

This Quality Assurance and Surveillance Plan (QASP) describes the methods used to perform the activities listed in the Testing and Monitoring Plan (Attachment C) by Marquis Carbon Injection LLC for the Marquis Biocarbon Project site pursuant to 40 C.F.R. § 146.90(k) and per Section L and N of this permit. The performance of the Testing and Monitoring Plan will be shared between MCI and its designated subcontractor.

Results of the QASP activities described herein may trigger action according to the Emergency and Remedial Response Plan in Attachment F of this permit.

APPENDIX 7.A
QUALITY ASSURANCE AND SURVEILLANCE PLAN

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name: MARQUIS BIOCARBON PROJECT

Facility contact: ELIZABETH STEINHOUR
DIRECTOR OF ENVIRONMENTAL AFFAIRS
10000 MARQUIS DRIVE, HENNEPIN, IL 61327
815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM

Well name: MCI CCS 3

Well location: PUTNAM COUNTY, ILLINOIS
S2 T32N R2W
Latitude: 41.27026520 N, Longitude: 89.30939322 W

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at Marquis Biocarbon Project. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

______________________________ ____________
Signature Date

ELIZABETH STEINHOUR
DIRECTOR OF ENVIRONMENTAL AFFAIRS

______________________________ ____________

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Distribution List

The following project participants (**Table 7A-1**) will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project. The Marquis Carbon Injection LLC Director of Environmental Affairs will be responsible for ensuring that all of those on the distribution list receive the most current copy of the approved QASP. Names in bold are the primary points of contact with addresses listed below.

Name	Organization	Project Role (s)	Contact Information (email / telephone)
Elizabeth Steinhour	Marquis	Director of Environmental Affairs - Lead for Environmental and Quality personnel	bethsteinhour@marquisinc.com 815-925-7300
Trevor Davis	Marquis	Lead for Project Manager and MVA Task	trevordavis@marquisinc.com 217-440-7401

Table 7A-1: Distribution list.

A Project Management

A.1. Project/Task Organization

A.1.1 Key Individuals and Responsibilities

The project will be led by Marquis Carbon Injection LLC (MCI). MCI will retain the services of qualified subcontractors. The performance of the Testing and Monitoring Plan will be shared between MCI and our designated subcontractor. This QASP describes the methods used to perform the activities listed in the Testing and Monitoring Plan.

The key roles and responsibilities of the personnel involved in implementation of the Testing and Monitoring Plan are listed in **Table 7A-2**.

Role	Responsibility
Project Manager	The Project Manager (PM) plays a central role in the implementation of all data gathering and analysis for the 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.
Quality Representative	The role of the Quality Representative (QR) is to identify quality-affecting processes and to monitor compliance with project requirements. The QR is responsible for establishing and maintaining the project quality assurance plans and monitoring project staff compliance with them. The QR is responsible for ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements.
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.
Subject Matter Experts (SMEs) /Subtask Task Leads	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, data products and acquisition of independent data quality/peer reviews. The SMEs will be involved in the project as needed. They will be qualified third party individuals.

Table 7A-2: Key individuals and responsibilities.

A.1.2 Independence from Project QA Manager and Data Gathering

To ensure quality assurance, the sample collection process, data analysis and processing will be performed or witnessed by independent third parties outside the management structure in most cases.

A.1.3 QA Project Plan Responsibility

MCI will be responsible for maintaining and distributing the official, approved QASP. MCI will periodically review this QASP and consult with EPA when changes to the plan are required.

A.1.4 Organizational Chart for Key Project Personnel

Figure 7A-1: Marquis Carbon Injection LLC project organization structure is set out below. As depicted, the figure shows the organizational structure of the Marquis BioCarbon project. MCI will provide a contact list of individuals fulfilling these roles to the UIC Program Director, if required. The project manager and Monitoring, Verification, and Accounting (MVA) task lead are part of the Project Development team, and the Environmental and Quality representatives are part of the Environmental team.

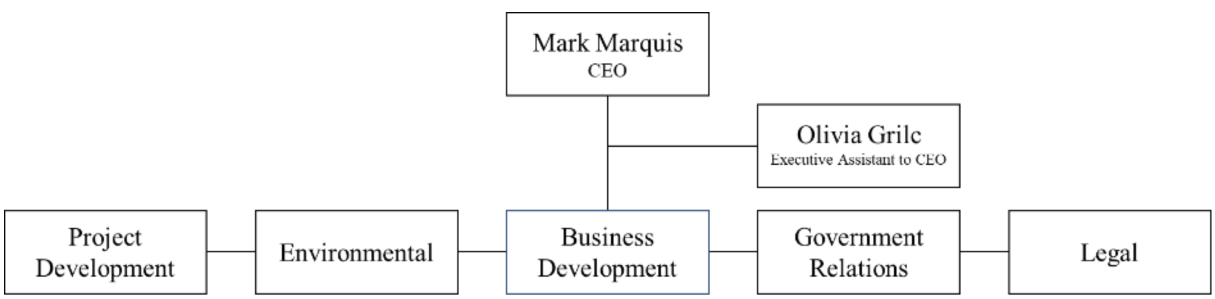

Figure 7A-1: Marquis Carbon Injection LLC project organization structure.

A.2. Problem Definition/Background

A.2.1 Reasoning

The goals of the Testing and Monitoring Plan (Permit Section 7.0) include:

- Protecting Underground Sources of Drinking Water (USDWs);
- Meeting the regulatory requirements of 40 Code of Federal Regulations (CFR) 146.90;
- Ensuring that the injection well is operating as planned;
- Providing data to validate and calibrate the geological and dynamic models used to predict the distribution of carbon dioxide (CO_2) within the injection zone; and

- Support Area of Review (AoR) re-evaluations over the course of the project.

These objectives will be met through the collection of pressure/temperature data within and above the storage formation, the collection of groundwater and fluid samples from shallow and deep monitoring wells, wireline logging techniques, pressure/temperature measurements in the tubing and annular space of the injection well and deep monitoring wells, sample collection/analysis of the injection stream, and geophysical monitoring.

This QASP was developed to ensure the quality standards of the Testing and Monitoring Plan to meet the requirements of the EPA Underground Injection Control (UIC) Program for Class VI wells.

A.2.2 Reasons for Initiating the Project

The objective of the Marquis BioCarbon Project is to safely and permanently store injected CO_2 in the Mt. Simon Sandstone. The Testing and Monitoring Plan for this project has been designed to confirm the safe and permanent storage of the CO_2 within the intended storage reservoir.

A.2.3 Regulatory Information, Applicable Criteria, Action Limits

US EPA regulation 40 CFR 146 Subpart H requires owners or operators of Class VI wells to monitor several parameters over the life of the project to ensure that:

- Mechanical integrity of the injection well is maintained;
- Fluid migration and the extent of pressure elevation are within the limits described in the permit application; and
- USDWs are not endangered.

Monitoring activities include mechanical integrity tests (MITs), pressure fall-off (PFO) tests during the injection phase of the project, monitoring of shallow and deep groundwater quality, and development of the CO_2 plume and associated pressure front. This document details the measurements that will be required as well as the steps used to ensure that the quality of all data is such that it can be used in the decision-making process over the life of the project.

A.3. Project/Task Description

A.3.1 Summary of Work to be Performed and Work Schedule

Tables 7A-3 and **7A-4** provide a summary of the testing and monitoring tasks, purpose of those tasks, responsible parties, locations, and the testing frequency.

Activity	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
CO_2 stream analysis	Post-Compressor	Direct sampling	N/A	Quarterly	None	Laboratory analysis	TBD	Monitor injectate
CO_2 stream analysis, including N_2, H_2O and O_2	CO_2 Delivery Plant Piping to Wellhead	Direct sampling	N/A	Quarterly (Note 3)	None	Gas Chromatograph	N/A	Monitor gas stream
CO_2 Injection mass rate	Post-Compressor	Coriolis Flow meter	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injection rate
Injection pressure	Injection Wellhead	Pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injection pressure
Injection temperature	Injection Wellhead	Temperature gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injection temperature
Down hole pressure/temperature monitoring (Note 1)	MCI CCS 3	Downhole transducer and thermocouple	Continuous from installation through CO_2 injection	Continuous	N/A	Direct measurement	N/A	Monitor storage formation
Annular pressure	Wellhead Annulus Monitoring System (WAMS) Skid	Pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Wellbore integrity – Annular fluid monitoring of differential pressure across the packing surface to downhole
Annulus Fluid Volume Added		Annulus Fluid Tank Level Indicator						

Activity	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
Annulus pressure	MCI MW 1, MCI MW 2, & MCI ACZ 1	Surface gauge	N/A	Weekly	Weekly while wells are open	Direct measurement	N/A	Wellbore integrity - Monitor annular pressure between casing and tubing string
Down hole pressure/temperature	MCI MW 2 & MCI ACZ 1	Downhole gauge	N/A	Continuous	Continuous while wells are open	Direct measurement	N/A	Monitor storage and ACZ formations
Wellbore Temperature Profile (storage formation) (Distributed Temperature Sensing) (DTS Fiber Optic System	MCI CCS 3, MCI MW 1, and MCI MW 2 – within the cement behind the borehole casing from the surface to downhole	DTS Fiber Optic Cable	Once	Annually	N/A	Direct measurement	N/A	Monitor storage formation – Obtain temperature profile for entire fiber length throughout the well
Corrosion monitoring	Pipe	Coupon	N/A	Quarterly	N/A	Chemical analysis	TBD	Wellbore integrity
	MCI CCS 3	Multi-Finger Caliper Logging or Ultrasonic Casing Evaluation Tool	N/A	Every 6 years after beginning of injection	Every 6 years through end of post-closure period	Downhole Direct measurement	TBD	25Cr Casing and tubing corrosion (integrity)
	MCI CCS 3	Logging	Once	N/A	N/A	Direct measurement	N/A	CO_2 plume development/baseline

Activity	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
Pulsed Neutron Capture	MCI MW 2 & ACZ 1	Logging	Once	Annually	Annually while wells are open	Direct measurement	N/A	CO_2 plume development, well Integrity
Pressure fall-off testing	Injection Well (MCI CCS3)	Pressure gauge	Once	Every 5 years	N/A	Direct measurement	N/A	Reservoir evaluation
Microseismic monitoring	Surface monitoring stations	Seismometer stations	Continuous starting 4-6 months prior to injection	Continuous	Continuous	Indirect measurement	N/A	Pressure plume development, confining zone integrity
Time-Lapse 3D Surface Seismic data	Surface	Geophones and seismic sources	Once	Every 5 years or 4 Million Tonnes of Injection, whichever occurs first (Note 2)	Year 5, Year 10 (Note 2)	Indirect measurement	N/A	CO_2 plume development, verify containment

Notes:

(1) Injection pressure at the storage formation is collected from a transducer downhole in the CCS3 well. Data will be collected on a continuous basis and pressure recorded to the distributed control system. See **Section 7.3.2.1**.

(2) A seismic survey will be conducted no more than 1 year prior to shutting down the injection well and prior to entering post-closure care.

(3) After initial startup of the well and during the first quarter, continuous CO_2 stream analysis will be conducted by a dedicated real time Gas Chromatograph (GC). After the first quarter, continuous analysis will be collected by the GC for a 7-day period each quarter during the injection phase.

Table 7A-3: Summary of testing and monitoring.

Level	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
Shallow groundwater monitoring & Isotope analysis - (Quaternary)	MCI GW 1 thru MCI GW 5	Dedicated Pump	Quarterly	Semi-Annually	Annually	Laboratory analyses	Table 7A-5: Summary of analytical and field parameters for shallow Quaternary Groundwater Samples.	Detection of changes in groundwater quality for a shallow USDW
Fluid sampling & Isotope analysis - Deepest USDW (Gunter Sandstone)	MCI ACZ 1	Bailer	Semi-Annually (Note 2)	Semi-Annually	Annually	Laboratory analyses	Table 7A-6: Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples.	Detection of changes in quality in the deepest USDW compared to baseline

Level	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
Fluid sampling & Isotope analysis – (Galesville Sandstone)	MCI ACZ 1	Bailer	Semi-Annually(2)	Semi-Annually	Annually	Laboratory analyses	Table 7A-6: Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples.	Detection of changes in quality in the ACZ aquifer compared to baseline.
In-zone monitoring Fluid sampling & Isotope analysis - (Mt. Simon Sandstone) (Note 1)	MCI MW 2	Bailer	Semi-Annually (Note 2)	Semi-Annually	None	Laboratory analyses	Table 7A-6: Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples.	Detection of changes in quality, geochemistry and CO_2 detection in storage formation compared to baseline

Level	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			

Notes:

(1) Sampling will occur in the upper Mt. Simon at 3,225 ft is the location of the first perforation of the top most injection zone. Sampling frequency may be adjusted once model is updated post drilling to try and detect CO_2 fluid mixing front as it passes by the well.

(2) For establishing baseline, sampling of the deep wells will occur during well drilling and prior to start of injection.

Table 7A-4: Summary of direct geochemical measurements.

A.3.2 Geographic Location

Figure 7A-2 identifies the Marquis BioCarbon Project site and monitoring infrastructure.

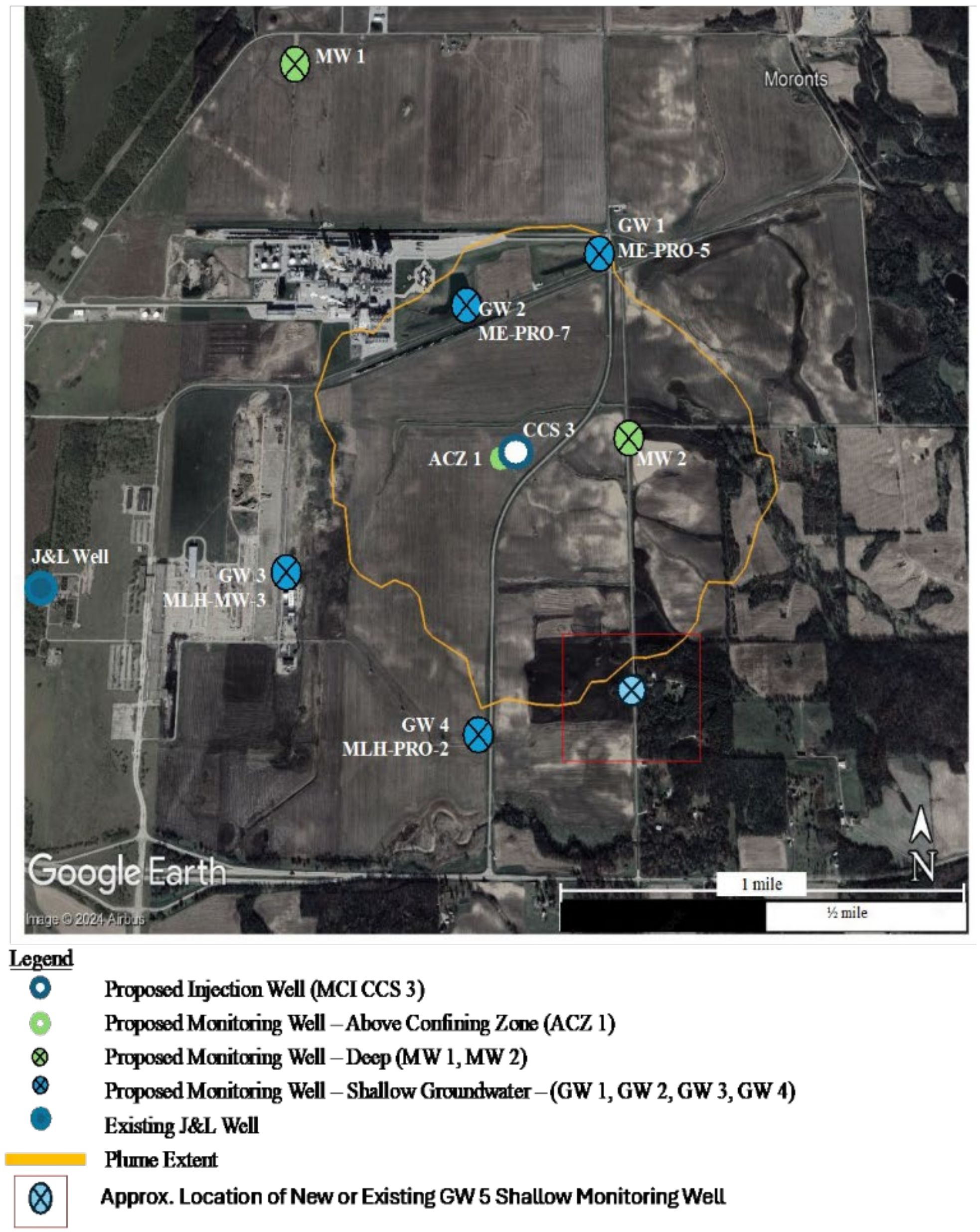

Figure 7A-2: Marquis Carbon Injection Project area showing location of the injection, deep, above confining zone (ACZ), and shallow groundwater monitoring wells.

A.3.3 Resource and Time Constraints

MCI proposes a 12-year post injection site care (PISC) phase and will continue PISC monitoring for 12 years. See Permit **Section 2.2.2** that details current modeling results on plume stability.

Computer Modelling Group (CMG-GEM) simulations will be run throughout the project and matched with actual field data collected under the Testing and Monitoring Plan. The simulations and field testing will confirm that plume stability modeling will be accurate beyond the 12-year period. However, no resource and time constraints have been identified for the Testing and Monitoring Plan beyond the 12-year PISC funding levels.

A.4. Quality Objectives and Criteria

A.4.1 Performance/Measurement Criteria

The overall quality assurance (QA) objective for the testing and monitoring plan is to develop and implement procedures to monitor the CO_2 injection system, development of the CO_2 plume and associated pressure front, and to confirm that CO_2 or other fluids have not migrated beyond the confining layer. This objective will be accomplished through the implementation of the methods provided in **Tables 7A-3** and **7A-4** (Summary of Direct Geochemical Measurements). The Tables below **(Tables 7A-5** to **Table 7A-15**) detail the specific performance and measurement criteria for each testing and monitoring output.

Parameters	Analytical Methods (Notes 1-5)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations (Na, Ca, Mg, Ba, Sr, Fe, K)	ASTM D1976 (Note 2)	<1 to 8 mg/L (analyte, dilution, and matrix dependent)	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions (Cl, Br, SO_4)	ASTM D4327	0.03 to 0.13 mg/L (analyte, dilution, and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved Inorganic Carbon	EPA 9060	0.2 mg/L	±20%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	ASTM D5907	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	ASTM D3875	1 mg/L	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
pH	ASTM D1293	1 to 13 pH units	0/2 pH unit	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Density	ASTM D4052	0.01 g/mL	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Conductivity/Resistivity	ASTM D1125	0 to 100	±1%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Stable C, H, O Isotopes	CRDS Laser H Isotope Ratio Mass Spectrometry (IRMS) for C	200 to 500‰ 50 ppm of DIC	±4‰ ±0.2‰	Duplicates, working standards at 10%
Radiocarbon (Carbon-14)	Accelerator Mass Spectrometry (AMS)	0 to 200 pMC	±0.5 pMC%	Duplicates, working standards at 10%
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation

Parameters	Analytical Methods (Notes 1-5)	Detection Limit/Range	Typical Precisions	QC Requirements
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

Notes:

(1) An equivalent method may be utilized with prior approval of the UIC Program Director.

(2) An alternate method for cations may be used. EPA Method 6020 for each constituent, except Strontium. EPA Method 6010 for Strontium.

(3) An alternate method for anions may be used. EPA Method 300.

(4) An alternate standard method (SM) 4500H may be used for pH.

(5) An alternate SM 2320B for alkalinity, SM2540C for Total Dissolved Solids, SM 2710F for Density, SM 5310C for Dissolved Inorganic Carbon, and SM2510B for Conductivity/Resistivity.

Table 7A-5: Summary of analytical and field parameters for shallow Quaternary Groundwater Samples.

Parameters	Analytical Methods (*)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Na, Ca, Mg, Ba, Sr, Fe, K	ASTM D1976	<1 to 8 mg/L (analyte, dilution, and matrix dependent)	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions: Cl, Br, SO_4	ASTM D4327	0.03 to 0.13 mg/L (analyte, dilution, and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved Inorganic Carbon	EPA 9060	0.2 mg/L	±20%	Duplicate measurement; standards at10% or greater frequency
Total Dissolved Solids	ASTM D5907	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	ASTM D3875	1 mg/L	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
pH	ASTM D1293	1 to 13 pH units	0/2 pH unit	
Density	ASTM D4052	0.01 g/mL	±10%	
Conductivity/Resistivity	ASTM D1125	0 to 100	±1%	
Stable C, H, O Isotopes	CRDS Laser H IRMS for C	200 to 500‰ 50 ppm of DIC	±4‰ ±0.2‰	Duplicates, working standards at 10%
Radiocarbon	AMS	0 to 200 pMC	±0.5 pMC%	Duplicates, working standards at 10%
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

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

Table 7A-6: Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples.

Parameters	Analytical Methods (Note 1)	Detection Limit/Range	Typical Precisions	QC Requirements
CO_2 Purity	GC/TCD	0.1-100%	±10 % across range	Standard with every sample, duplicate analysis within 10 % of each other
Oxygen	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	Daily standard within 10 % of calibration, secondary standard after calibration
Nitrogen	ISBT 4.0 GC/DID	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	Daily standard within 10 % of calibration, secondary standard after calibration
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Water Content	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Total Hydrocarbons	ISBT 10.0 THA (FID)	1 uL/L to 10,000 uL/L (ppm by volume)	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Ethanol	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Acetaldehyde	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Methane	ISBT 10.1 (GC/FID)	0.1 uL/L to 1,000 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration

Note:
(1) An equivalent method may be utilized with the prior approval of the UIC Program Director.
All analysis will be performed by a certified third-party laboratory.

Table 7A-7: Summary of analytical parameters for CO_2 gas stream.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2005	0.005mg	+/-2%	Annual Calibration of Scale (3rd Party Aldinger Co. – Cert #664896F)
Thickness	NACE RP0775-2005	0.001mm	+/-005mm	Factory calibration

Table 7A-8: Summary of analytical parameters for corrosion coupons.

Parameters	Detection Limit/Range
Calibrated working flow rate range	Normal process parameters are 118,224 to 386,353 lb/hr and 24.48 MMSCFD to 80 MMSCFD. Coriolis meter range 8″ body x 6″1,100 to 600,000 lb/hr.
Mass flow rate accuracy	< 0.2% Coriolis meter Accuracy ±0.10% of rate, Repeatability 0.05% of rate
Mass flow rate resolution	2.6 MT/day
Mass flow rate drift stability	To be determined after first year

Table 7A-9: Mass Flow Rate Field Gauge— CO_2 Mass Flow Rate.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Compressor discharge pressure HP CO_2 Discharge Header & Wellhead Line pressure	ANSI/NCSL Z540-1-1994	+/- 0.001 psig / 0-4000 psig	± 0.04% of span	Calibration range 0-3000psig
Wellhead Injection Tubing Temperature	ANSI/NCSL Z540-1-1994	+/- 0.001 F / 0-500 F	+/- 0.01 F	Calibrated per manufacturer specification
Annulus Pressure	ANSI/NCSL Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Calibrated per manufacturer specification
Wellhead Injection Tubing Pressure	ANSI/NCSL Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Calibrated per manufacturer specification

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Injection Mass Flow Rate	API MPMS	+/- 0.1000% of rate / 5-5,000 MT/day	+/- 0.01 lbs./hr.	Calibrated per manufacturer specification
Reservoir Pressures Silicon-sapphire	UNKNOWN	+/-0 0.03 psi / 0-6000 PSI	+/- 0.1 psi	Calibrated by manufacturer

Table 7A-10: Summary of measurement parameters for field gauges.

Parameters	Detection Limit/Range
Calibrated working pressure range	0 to 3,000 psi and 4–20 mA
Initial pressure accuracy	< 0.04375%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	To be determined after first year

Table 7A-11: Pressure Field Gauge —Injection tubing, annulus, pipeline.

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

Table 7A-12: Temperature Field Gauge —Injection tubing, annulus, pipeline.

Parameters	Detection Limit/Range
Calibrated working pressure range	Atmospheric to 6,000 psi
Initial pressure accuracy	<+/-0.03 psi over full scale
Pressure resolution	0.0003% psi over full scale
Pressure drift stability	<3 psi per year over full scale
Calibrated working temperature range	257°F
Initial temperature accuracy	<+/-0.9°F
Temperature resolution	0.009°F
Temperature drift stability	<+/-0.1°F per year
Max temperature	257°F

Table 7A-13: Pressure and temperature—bottomhole gauge specifications (PPS25).

Table 7A-15 presents the monitoring methods that will require additional testing or monitoring if exceedances or variances are observed. In the table, the routine measurement method is followed by the additional monitoring that would occur if an exceedance were measured.

Method	PNC	CBL	USI	Isolation Scanner
Logging speed	1,800 ft/hr.	3,600 ft/hr.	Standard resolution: 2,700 ft/hr. High resolution: 563 ft/hr.	Standard resolution: 2,700 ft/hr. High resolution: 563 ft/hr.
Vertical resolution	15 inches	3 ft	Standard resolution: 0.6 in High speed: 6 in	High resolution: 0.6 in. High speed: 6 in

Method	PNC	CBL	USI	Isolation Scanner
Investigation	Formation	Casing, annulus, and formation	Casing and annulus	Casing and annulus
Temperature rating	302°F	350°F	350°F	350°F
Pressure rating	15,000 psi	20,000 psi	20,000 psi	20,000 psi

Table 7A-14: Representative logging tool specifications. Actual tools used will be comparable.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
MIT—PNC	Action taken when PNC indicates CO_2 outside of expected range	+/- 0.5 SIGMA	Brine saturated ~ 60 CO_2 saturated ~ 8
Temperature Measurement – External Mechanical Integrity	Action taken when temperature measurement displays deflection that varies from baseline logs	+/- 1 °F	Continuous increasing gradient with depth
Internal Mechanical Integrity—Annular Pressure/ Fluid Volume Gauges	>5% pressure loss over 1hour	Refer to Table 7A-10	<5% pressure loss over 1 hour
Surface and downhole pressure gauges	Action will be taken when pressure outside of modeled/expected range	Refer to Table 7A-11 for surface gauges and Table 7A-13 for downhole gauge	Within storage formation: <90% fracture propagation pressure (2,207 psi at 3,226 ft)
Groundwater Chemical Data	Action will be taken if there is analytical evidence that CO_2 has migrated out of the injection zone or AOR	Refer to Table 7A-5 and Table 7A-6.	No presence of CO_2 or chemical indicators of CO_2 outside the injection zone or AoR.
Time-lapse surface seismic data	Detected CO_2 outside the baseline survey area or above the confining zone	Dependent on fluid saturation and formation velocities	CO_2 plume migration similar to modeled outcome

Table 7A-15: Actionable testing and monitoring outputs.

A.4.2 Precision

The specification and precision of each monitoring method is detailed in the tables above. For groundwater sampling, the accuracy of the data will be assessed by the collection and analysis of field blanks to test sampling procedures and matrix spikes to test lab procedures. Field blanks will be taken no less than one per sampling event to determine if the sample bottle is contaminated. Laboratory assessment of analytical precision will be the responsibility of the individual laboratories per their standard operating procedures.

A.4.3 Bias

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

A.4.4 Representativeness

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

A.4.5 Completeness

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

A.4.6 Comparability

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be very comparable to future data sets because of the use of standard methods and the level of quality assurance/quality control (QA/QC) effort. Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained baseline data sets or project data.

A.5. Special Training/Certifications

A.5.1 Specialized Training and Certifications

The geophysical survey equipment and wireline logging tools will be operated by trained, qualified, and certified personnel, according to the service company which provides the equipment. The subsequent data will be processed and analyzed according to industry standards. Examples of these are shown in **Attachment 1**.

No specialized certifications are required for personnel conducting groundwater sampling, but field sampling will be conducted by trained personnel. Groundwater sampling will be conducted by personnel trained to understand and follow the project-specific sampling procedures.

Upon request, the Agency will be provided with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the in-house samples will be trained on the SOP developed for each standard method. The technician's training certification will be included with the biannual report. Certifications will not be included for technicians conducting sample analysis from an accredited laboratory. Laboratory accreditation information will be provided upon request.

A.5.2 Training Provider and Responsibility

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

A.6. Documentation and Records

A.6.1 Report Format and Package Information

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

A.6.2 Other Project Documents, Records, and Electronic Files

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

A.6.3 Data Storage and Duration

Maquis Carbon Injection LLC or a designated contractor will maintain the required project data as provided elsewhere in the permit.

A.6.4 QASP Distribution Responsibility

The Marquis Carbon Injection LLC Manager will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design (Pre-Injection Phase)

During the pre-injection phase, fluid samples will be collected and analyzed for geochemical parameters listed in **Table 7A-5** and **Table 7A-6** to establish baseline conditions of the fluids within the target formations. Regular sampling will be performed during the injection and post-injection phases of the project to track the migration of CO_2 through the storage formation and to confirm that CO_2 and other fluids of interest have not migrated out of the storage formation. Analytes will include selected constituents that are:

- Primary and secondary EPA drinking water contaminants.
- Those most responsive in the interaction of CO_2 with the formation fluids and minerals; and
- Those needed for Quality Control.

The full set of selected parameters for each sampling interval is given in **Table 7A-5** (Summary of analytical and field parameters for shallow Quaternary Groundwater Samples) and **Table 7A-6** (Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples).

All samples will be analyzed using a laboratory that meets the requirements under the EPA Environmental Laboratory Accreditation Program. Isotopic analysis will be conducted using established methods. The pressure, temperature, and flowrate of the CO_2 injection stream will be monitored on a continuous basis using instrumentation located in the flowline between the final compression stage and the wellhead. In addition, samples of the injection stream will be collected on a quarterly basis for analysis. The sampling and analysis will be completed to ensure compliance with the approved Class VI permit.

B.1.1 Design Strategy

CO_2 Stream Monitoring Strategy

Continuous analysis through the gas chromatograph and regular sampling of the CO_2 stream provides an evaluation of the potential interactions of the CO_2 and other constituents of the injection stream with mineral components and fluids within the storage formation. It can also identify increases in trace components, such as water content, that could accelerate well corrosion and negatively impact well integrity. Minor variation (<5%) is expected in the composition of the injected CO_2 stream which will pass through at least one scrubber prior to entering the compressor and the pipeline. As a result, quarterly sampling of the CO_2 injection stream will be sufficient to accurately track the composition of the stream. An initial calibration and validation of the instruments will be performed by the manufacturers and will be verified by the project on a regular basis.

Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to assess the mechanical integrity of the well components that are in contact with the CO_2. The coupons will be assessed for signs of corrosion and any loss of mass thickness, cracking, pitting, and other signs of corrosion that could be indicative of future well integrity issues. The analysis will be in accordance with National Association of Corrosion Engineers (NACE) Standard RP-0775 (or similar) to determine and document corrosion wear rates.

Every 6 years after the beginning of injection through the end of the post-closure period, the MCI CCS 3 well itself will be assessed for signs of corrosion using well logging techniques such as multi-finger caliper logging or an ultrasonic casing evaluation tool. A 6-year period for enhanced corrosion monitoring was selected based on the limited time period for actual injection and plume migration and the corrosion modeling results. Marquis' corrosion modeling conducted by Viking projected a corrosion rate of 0.05% per year based on the thickness of the pipe. See **Appendix Y**. The multi-finger caliper is a downhole logging tool that can accurately detect penetration variations as small as 0.6% in pipes with a nominal thickness of 0.408 in. Prior to a 6-year period, a measurable amount of corrosion could not be detected, and conducting the monitoring would not provide meaningful results.

Shallow Groundwater Monitoring Strategy

Five dedicated shallow groundwater wells in the AoR will be used for shallow groundwater monitoring (**Figure 7A-2**). These wells penetrate the Quaternary-age deposits to depths less than 300 feet (ft) below ground surface, which is deeper than any drinking water well in the area. Baseline groundwater samples will be acquired from these wells at a minimum of once per quarter to obtain baseline data for the water quality within the AoR prior to the start of CO_2 injection. These groundwater samples will also have their geochemistry and stable isotopes analyzed by a qualified laboratory. Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry and isotope analyses will be compared to the baseline conditions for any indication of CO_2 or brine migration into the shallow groundwater aquifer.

Deep Groundwater Monitoring Strategy

A deep, above confining zone (ACZ 1) groundwater well will be drilled for the project (40 CFR 146.90 (d)). MCI ACZ 1 will be near the injection well to monitor the aquifers immediately above the confining layer in the event that there is CO_2 or brine migration out of the storage formation along the injection wellbore (**Figure 7A-2**). This well will allow for pressure and temperature monitoring as well as periodic fluid sampling in the Galesville Sandstone and Gunter Sandstone, the deepest USDW. The well will be equipped with continuous pressure and temperature gauges. A bailer system will be used to collect the fluid samples to evaluate geochemical changes in groundwater fluids. Samples will be analyzed for field constituents using a calibrated water quality meter (Horiba U-53, or similar). The geochemical analyses will be performed by a qualified laboratory. The isotopic analyses will be performed by a qualified laboratory.

CO_2 or brine migration into the Galesville or Gunter Sandstone will most likely be first identified through pressure changes in the formation. The presence of CO_2 or brine in the overlying aquifers can be further confirmed through aqueous geochemistry data and analysis of isotopes. If deep early-detection monitoring data indicate that CO_2 has migrated out of the primary storage formation, it will trigger external well integrity testing of the injection and deep monitoring wells. It may also trigger a time-lapse three-dimensional (3D) surface seismic survey earlier than initially planned.

Storage Formation Monitoring Strategy

The storage formation will be monitored through pressure and temperature sensors, fluid sampling and analysis, pulsed neutron capture (PNC) logging, time-lapse 3D surface seismic data, and microseismic monitoring to characterize the development of the CO_2 and pressure plumes over the injection and PISC phases of the project. Fluid samples will be collected from the deep monitor well on a biannual basis until the well becomes saturated with CO_2, while the pressure/temperature gauges will be retrieved for data download. PNC logging will be used to determine the CO_2 saturation adjacent to the deep monitoring well. The PNC logging will also confirm that CO_2 has not migrated above the confining layer.

Deep Monitoring Well (MCI MW 2) Sampling Strategy

The deep monitoring well (MCI MW 2) will be used to monitor the pressure and CO_2 plume development in the storage formation through the injection phase of the project. Fluid samples will be collected on a semi-annual basis from the Mt. Simon Sandstone to monitor aqueous geochemistry changes within the formation. The well will be swabbed to produce representative formation fluid in the well. During the swabbing process, the swab water will be analyzed in the field using a calibrated water quality meter (Horiba U-53, or similar). After swabbing the well, fluid samples will be collected using a bailer-style system. Samples will be analyzed for constituents that can be used to measure changes in chemistry that would be caused by interaction with the injected CO_2. See Table 7A-6 for list of analytes. Analysis will be conducted by an accredited laboratory. For example, Isotech or a similar laboratory will perform the isotopic analyses. A set of memory-style pressure and temperature gauges (Petrotech PPS25 or similar) will also be placed in the deep monitoring well to track the pressure response due to CO_2 injection. These gauges will be programmed to collect data every 60 seconds.

Deep Monitoring Well (MCI MW 1) Sampling Strategy

This deep well will be used for extended field monitoring. It will be used as a contingency in the monitoring plan. Should the need arise for cross-well measurements or downhole measurements, like Vertical Seismic Profile (VSP), this well will be employed as an additional data point to confirm pressure front or CO_2 plume movement.

B.1.2 Type and Number of Samples/Test Runs

The types, frequencies, and additional details of the sampling and monitoring methods are provided in (**Table 7A-3**) of this document.

B.1.3 Site/Sampling Locations

Five shallow groundwater wells (MCI GW 1-5), a deep groundwater monitoring well (MCI MW 2), and a monitoring well above the confining zone (MCI ACZ 1) will be installed and geochemical and isotope analysis will be conducted. See **Figure 7A-2** and **Table 7A-2**.

The chemical composition, pressure and temperature, and mass flowrates of the CO_2 injection stream will be monitored downstream of the last stage of compression and upstream of the injection well. At the injection well, the wellhead and storage formation pressure and temperature will be measured along with the annular pressure and volume. In addition, corrosion monitoring will be completed in the CO_2 pipe between the compressor and the injection well.

PNC logging will be performed in the ACZ 1 well and the deep monitoring well (MCI MW 2) to monitor the CO_2 plume development in the storage formation as well as for potential migration of CO_2 above the confining layer. Temperature measurements will be acquired in the injection and wells (MCI ACZ 1 and MCI MW 2) on an annual basis to confirm external mechanical integrity.

B.1.4 Sampling Site Contingency

The shallow groundwater, MCI ACZ 1, and deep monitoring wells (MCI MW 1 and MCI MW 2) are all located on Marquis property where the Marquis BioCarbon Project is located. Access to the wells is not anticipated to be a problem over the course of the project. The wells are all located on flat farmland, accessible, and not on any rough terrain. If inclement weather makes site access difficult, sampling schedules will be reviewed, and alternative dates may be selected that would still meet permit-related conditions.

B.1.5 Activity Schedule

Table 7A-3 provides the schedules for the sampling and monitoring activities along with other pertinent details regarding the techniques.

B.1.6 Critical/Informational Data

During data acquisition for the testing and monitoring activities, field and laboratory information will be documented in detail. Information will be recorded in field and laboratory forms and notebooks. Critical information will include the time and date of activity, person(s) performing activity, location of the activity or instrument, field or laboratory instrument calibration data, and field parameter values. For laboratory analyses, much of the critical data will be generated during the analysis and provided to the project in digital and printed formats. Noncritical data may include the appearance and problems with the wells or sampling/monitoring equipment, and weather conditions.

B.1.7 Sources of Variability

Potential sources of variability related to monitoring activities include:

- Natural variations in fluid geochemistry, formation pressure and temperature, and seismic activity;
- Variation in fluid geochemistry, formation pressure and temperature, and seismic activity due to project operations;
- Changes in groundwater recharge due to rainfall, drought, and snowfall;
- Changes in instrument calibration during sampling or analytical activity;
- Variations in the staff collecting or analyzing samples;
- Differences in environmental conditions during field activities;
- Changes in analytical data quality during life of project; and
- Data entry errors related to maintaining project database.

Activities to eliminate, reduce, or reconcile variability related to monitoring activities include:

- Collection of long-term baseline data to observe and document natural variation in monitoring parameters;
- Evaluation of data in timely manner after collection to observe anomalies in data that can be addressed through resampling;
- Conducting statistical analysis of monitoring data to determine whether variability in a data set is the result of project activities or natural variation;
- Checking instrument calibration before, during and after sampling or sample analysis
- Staff training;
- The use of standard operating procedures to describe testing and monitoring activities;
- Use of accredited laboratory and chain of custody procedures; and

- Conducting laboratory QA checks using third party reference materials, and/or blind and/or replicate sample checks.

B.2. Sampling Methods

Well logging, geophysical monitoring, and pressure/temperature monitoring do not apply to this section.

B.2.1 Sampling SOPs

B.2.1.1 Shallow Groundwater Wells

Groundwater samples will be collected from the shallow groundwater wells using a low-flow sampling method consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow-through cell is not used, field parameters will be measured in grab samples. Groundwater wells will be purged to ensure samples are representative of formation water quality. Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities begin. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells. The pH, temperature, specific conductance, and dissolved oxygen of the purge water will be monitored in the field using portable probes and a flow-through cell consistent with standard methods given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in **Table 7A-16**.

Field Parameter	Stabilization Criteria
pH	+/- 0.2 units
Temperature	+/- 1°C
Specific Conductance	+/- 3% of reading in µS/cm
Dissolved Oxygen	+/- 10% of reading or 0.3 mg/L whichever is greater

Table 7A-16: Stabilization criteria of water quality parameters during shallow well purging

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

B.2.1.2 Deep Monitoring Wells and ACZ 1 Well

Samples will be collected from the MCI ACZ 1 and deep monitoring well MCI MW2 using a bailer system lowered into the wells via slickline. Prior to sample collection, the well will be purged by swabbing the well to remove stagnant fluids and to ensure representative formation fluids are present in the well. During drilling of the wells, extensive infiltration of drilling fluids during construction and development activities will occur. Therefore, prior to sampling, each discrete zone interval where samples are being collected will be purged to ensure the samples are representative of site conditions. The pH, temperature, specific conductance, and dissolved oxygen of the swabbed water will be monitored every swab run in the field using portable probes until the parameters stabilize for three successive runs, and grab samples will be used to collect the samples. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions.

After the well has been swabbed, the bailer system will be lowered into the well to collect sufficient volume of the fluid to complete the analyses. The samples will be transferred to the appropriate bottles for each analytical method. Samples that require filtering will be filtered through a 0.45 µm cartridge filter per the procedure.

B.2.1.3. CO_2 Gas Stream

For the CO_2 stream, samples will be collected from a sampling port located between the final compression stage and the wellhead where the injectate is representative of the stream being injected into the well. The samples will be collected in Department of Transportation (DOT)-rated pressure cylinders that can be sent to an accredited analytical laboratory for analysis. A pressure regulator will reduce the pressure of the CO_2 to approximately 250 pounds per square inch (psi) so that the CO_2 is in the gaseous state when collected rather than a super-critical liquid. Cylinders will be purged with sample gas (i.e., CO_2) at least five times prior to sample collection to remove laboratory-added helium gas and ensure a representative sample. During purging, the outlet of the sample cylinder will be connected to a ventilation line and vented to the atmosphere. Appropriate sampling technique is critical for any gas analysis program. Therefore, great care will be taken to ensure that the cylinder is not contaminated by atmospheric gas, and the sample is representative of the CO_2 in the pipeline.

B.2.2 In-Situ Monitoring

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

B.2.3 Continuous Monitoring

The pressure and temperature in the deep monitoring wells will be continuously monitored using downhole pressure/temperature gauges.

B.2.4 Sample Homogenization, Composition, Filtration

Sample homogenization, composition, and filtrations is described in **Section B.2.1**.

B.2.5 Sample Containers and Volumes

For CO_2 stream monitoring, samples will be collected in a clean sample cylinder rated for the appropriate collection pressure provided by a laboratory such as Atlantic Analytical Laboratory.

CO_2 quarterly gas analysis will include:

- CO_2 Purity (% volume [v]/v, gas chromatograph [GC])
- Oxygen (O_2, parts per million [ppm] v/v)
- Nitrogen (N_2, ppm v/v)
- Hydrogen Sulfide (H_2S ppm v/v)
- Potential Trace Contaminants – See Table 7A-7

For shallow and deep fluid samples, all sample bottles will be new. Sample bottles for analytes will be used as received from the vendor or contract analytical laboratory for the analyte of interest. A summary of sample containers is presented in **Table 7A-17** (Preservation, Containers, and Holding Times for Aqueous Samples).

B.2.6 Sample Preservation

For groundwater and other aqueous samples, the preservation methods provided in **Table 7A-17** will be used.

Parameters	Preservation/Preparation	Container	Holding Time
Total Metals by ICP Na, Ca, Mg, Ba, Sr, Fe, K	HNO_3 to pH<2, Filter 4-µm	1.5 L Poly	6 months
Anions (Cl, Br, SO_4)	Cool, 4±2°C, no chemical preservation	1 L Poly	28 days
pH	Cool, 4±2°C, no chemical preservation	1 L Poly	None
Alkalinity	Cool, 4±2°C, no chemical preservation	1 L Poly	28 days
Total Dissolved Solids	Cool, 4±2°C, no chemical preservation	1 L Poly	7 days
Specific Gravity	None	1 L Poly	None
Dissolved Inorganic Carbon	None	1 L Poly	7 days
H and O Stable Isotopes	None	50-mLGlass	1 year
C Stable Isotope	Cool, 4±2°C, no chemical preservation	150 mL Poly	14 days
Carbon-14	Cool, 4±2°C, no chemical preservation	150 mL Poly	6 months

Table 7A-17: Preservation, containers, and hold times for aqueous samples.

No preservation will be required for the CO_2 injection stream samples, additional details for the gas sampling are provided in Table 7A-7 and Table 7A-18..

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding time(max)
CO_2 gas stream	300-ml cylinder	NA	5 Days

Table 7A-18: Preservation, containers, and hold times for aqueous samples.

Corrosion coupon sampling requires that the coupons be physically separated (e.g., sleeves, baggies) during transportation to prevent physical abrasion.

B.2.7 Cleaning/Decontamination of Sampling Equipment

Dedicated pumps (e.g., bladder pumps) will be installed in each shallow groundwater monitoring well to minimize potential cross contamination between wells. These pumps will remain in each well throughout the project period except for maintenance. Prior to installation, the pumps will be cleaned on the outside with a non-phosphate detergent. Pumps will be rinsed a minimum of three times with deionized water and a minimum of 1 liter (L) of deionized water will be pumped through the pump and sample tubing. Individual cleaned pumps and tubing will be placed in plastic bags for transport to the field for installation. All field glassware (pipets, beakers, filter holders, etc.) will be cleaned with tap water to remove any loose dirt and rinsed three times with deionized water before use. CO_2 gas stream sampling cylinders will be decontaminated by the analytical lab, and no sampling equipment will be utilized with the corrosion coupons or annual field gauge calibrations.

B.2.8 Support Facilities

Field activities are usually completed in mobile laboratory vehicles or trailers located on site. Fluid sampling may require the use of an air compressor, vacuum pump, generator, filters, and analytical meters (pH, specific conductance, etc.). Sample tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers. Sampling will occur within the CO_2 compression building or at the wellsite building prior to injection. Similarly, corrosion coupons will be removed from the CO_2 injection line.

B.2.9 Corrective Action, Personnel, and Documentation

Field staff will be responsible for testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then equipment will be returned to the manufacturer for repair or replacement. Significant corrective actions that occur during the sampling and data collection activities that affect analytical results will be documented in field notes.

B.3. Sample Handling and Custody

Well logging, geophysical monitoring, and pressure and temperature monitoring do not apply to this section and are omitted.

Sample holding times will be consistent with standard methods. After collection and any necessary preservation, samples will be placed in ice chests in the field and maintained thereafter at approximately 4 degrees Celsius (°C) until analysis. The samples will be maintained at their preservation temperature and sent to the designated laboratory within 24 hours. Analysis of the samples will be completed within the holding time listed in **Table 7A-17**. See **Table 7A-17** (Preservation, Containers and Hold Times for Aqueous Samples).

As appropriate, alternative sample containers and preservation techniques approved by the UIC Program Director will be used to meet analytical requirements.

B.3.1 Maximum Hold Time/Time Before Retrieval

See **Table 7A-17** (Preservation, Containers and Hold Times for Aqueous Samples).

B.3.2 Sample Transportation

See description in **Section B.2.**

B.3.3 Sampling Documentation

Field notes will be collected for all groundwater samples collected. These forms will be retained and archived as reference. The sample documentation is the responsibility of groundwater sampling personnel. A chain-of-custody form will be provided with each CO_2 gas stream sample or fluid sample provided for analysis as shown in **Figure 7A-4** (Example of chain-of-custody form for the CO2 injection stream gas analysis).

B.3.4 Sample Identification

All sample bottles will have waterproof labels with information denoting project, sampling date, sampling location, sample identification number, fluid sample, sample type, analyte, volume, filtration used (if any), and preservative used (if any). See **Figure 7A-3**: (Example label for groundwater sample bottles)

MarquisCI CS-1 10-16-2022
Metals, 60ml, filtered, HNO_3

Figure 7A-3: Example label for groundwater sample bottles.

B.3.5 Sample Chain-of-Custody

For CO_2 stream analysis, a chain-of-custody form will accompany the sample to the laboratory. As example of the form is provided in **Figure 7A-4**. The chain-of-custody form will include sample identification (ID), sample collection date/time, sample pressure, and analytical requirements. A chain-of-custody form will accompany the sample through the analytical process. Copies of the chain-of-custody forms will be retained in the monitoring files.

For groundwater samples, the chain-of-custody will be documented using a standardized form. A typical form is shown in **Figure 7A-5** (Example chain-of-custody form for the fluid sample analysis). Copies of the chain-of-custody forms will be provided to the person or lab receiving the samples as well as the person or lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain-of -custody form and record keeping is the responsibility of groundwater sampling personnel.

B.4. Analytical Methods

Well logging, geophysical monitoring, and pressure and temperature monitoring do not apply to this section and are omitted.

B.4.1 Analytical SOPs

Analytical methods are referenced in **Table 7A-5** (Summary of analytical and field parameters for shallow Quaternary Samples) and **Table 7A-6** (Summary of laboratory analytical and field parameters for deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples). Upon request, Marquis Carbon Injection LLC will provide the EPA with all laboratory SOPs developed for the specific parameter using the appropriate standard method.

B.4.2 Equipment/Instrumentation Needed

Equipment and instrumentation are specified in the individual analytical methods referenced in **Table 7A-5** (Summary of analytical and field parameters for shallow Quaternary Groundwater Samples) and **Table 7A-6** (Summary of analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples).

B.4.3 Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.4 Analytical Failure

Each laboratory conducting the analyses in **Table 7A-5** through **7A-8** will be responsible for appropriately addressing analytical failure according to their individual SOPs.

B.4.5 Sample Disposal

Each laboratory conducting the analyses in **Table 7A-5** through **7A-6** will be responsible for appropriate sample disposal according to their individual SOPs.

B.4.6 Laboratory Turnaround

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

B.4.7 Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project.

ATLANTIC ANALYTICAL LABORATORY, LLC
291 Route 22 East
Salem Industrial Park – Building #2
Lebanon, NJ 08833
(908) 534-5600

The Gold Standard for Gas Analysis

CHAIN OF CUSTODY FORM

CUSTOMER NAME:	PROJECT LOCATION:	COMMENTS:
SAMPLER SIGNATURE:	CUSTOMER SIGNATURE:	

SAMPLING			CUSTOMER CYLINDER NUMBER	SAMPLE IDENTIFICATION (Lot Number, Batch Number, Receiving Number, Part Number, etc.)	ANALYSIS REQUIRED	ON-SITE ANALYSIS
DATE / TIME	CYLINDER NUMBER	CYLINDER SIZE				

Relinquished By:	Date:	Time:	Received By:	Date:	Time:	Comments:
Relinquished By:	Date:	Time:	Received By:	Date:	Time:	Comments:
Relinquished By:	Date:	Time:	Received By:	Date:	Time:	Comments:

Page_______of_______ Form AALCOC Rev 6 25 Jun 2020

Figure 7A-4: Example of chain-of-custody form for the CO_2 injection stream gas analyses.

Intertek

Office:_____________
• Job Order Number:__________________

NON COMMERCIAL BILL OF LADING

CHAIN OF CUSTODY O **SAMPLE TRANSPORTATION RECORD** O **SAMPLE DISTRIBUTION RECORD** O **SAMPLE RECEIPT** 0

Point of Origin	**Intermediary**	Destination
Full Name And Address:		
Relinquished By:	Received By:	Received By:
Print:	Print:	Print:
Date:	Date:	Date:
Time:	Time:	Time:

* I hereby declare that the contents of this consignment are fully and accurately described below by the correct technical name(s) (Proper Shipping Name[s]), and are classified, packaged, marked and labeled/placarded, and are in all respects in proper condition for transport according to applicable international and national government regulations.

Delivered By: Intertek / Commercial carrier (circle one)

Inspector/ Driver: ____________________
Carrier: ____________________
Air Bill Number: ____________________
Date Shipped: ____________________

Customer Product Description
Product 1 :____________________
Product 2:____________________
Product 3 :____________________
Product 4:____________________

Note: All volumes must be in Metric units

UN NUMBER	PROPER SHIPPING NAME	HAZARDOUS CLASS NUMBER	PACKING GROUP	PRODUCT NUMBER	NUMBEROF SAMPLES	CONTAINER SIZE	SAMPLE SOURCE	SEAL NUMBER(S)

Figure 7A-5: Example chain-of-custody form for the fluid sample analyses.

B.5. Quality Control

Geophysical monitoring and pressure/temperature monitoring do not apply to this section and are omitted. For wireline log QC, please refer to **Section 7A-Attachment 1**.

B.5.1 QC Activities

Blanks

For shallow and deep groundwater/brine sampling, a field blank will be collected and analyzed for the inorganic analytes in **Table 7A-5** and **7A-6** at a frequency of no less than one blank for field event. Field blanks will be exposed to the same field and transport conditions as the groundwater samples. Field blanks will be used to detect contamination resulting from the collection and transportation process.

No field blanks will be collected for the injection stream sampling. Contamination and representative sampling will be determined through the concentrations of nitrogen and helium (that have been spiked into the cylinder) in the sample.

Duplicates

For each fluid sampling round, at least one duplicate sample will be collected from a well. Duplicate samples will be collected from the same source immediately after the original sample in different sample containers and processed in the same manner as all other samples. Duplicate samples will be used to assess sample heterogeneity and analytical precision.

B.5.2 Exceeding Control Limits

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

B.5.3 Calculating Applicable QC Statistics

Charge Balance

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

$$\%\ dddddddddddddddddddd = 100\frac{\sum ddccccddccddcc - \sum ccddddccddcc}{\sum ddccccddccddcc + \sum ccddddccddcc},$$ (Equation

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

Mass Balance

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

$$1.0 < \frac{mmddccccmmddddd\ d\ TTTTT\ T}{ddccccddmmcccccdddd\ \ TTTTTT} < 1.2\ ,$$ (Equation

where the anticipated values are between 1.0 and 1.2.

Outliers

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

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

Logging tool equipment will be maintained as per wireline industry best practices (**Section 7A-Attachment 1**).

All pressure, temperature, and mass flow measurement equipment will be maintained per the manufacturer's specifications. Any necessary calibrations or repairs will also be performed per the manufacturer's specification or by the manufacturer of the equipment.

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

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per standard practice, method-specific protocol, or National Environmental Laboratory Accreditation Program (NELAP) requirement.

B.7. Instrument/Equipment Calibration and Frequency

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

B.7.1 Calibration and Frequency of Calibration

Pressure and temperature gauge calibration information will be performed annually. Logging tool calibration will be at the discretion of the service company providing the equipment and following standard industry practices noted in **Section 7A-Attachment 1**.

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

B.7.2 Calibration Methodology

Logging tool calibration methodology will follow standard industry practices in **Section 7A-Attachment 1**.

The pressure, temperature, and mass flow meters will be calibrated annually.

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

B.7.3 Calibration Resolution and Documentation

Logging tool calibration resolution and documentation will follow standard industry practices in **Section 7A-Attachment 1**.

Manufacturers of the pressure, temperature, and mass flow equipment will provide calibration certifications for their equipment. If calibration cannot be achieved with the equipment, this piece of equipment will be replaced with a new or calibrated piece of equipment.

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

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.1 Supplies, Consumables, and Responsibilities

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

B.9. Non-direct Measurements

B.9.1 Seismic Monitoring Methods

Data Sources

3D seismic surveys will be conducted at regular intervals during and after CO_2 injection. Each of these surveys will be compared to the baseline survey which was acquired before the start of CO_2 injection. It is important that the only difference between the surveys is the change in acoustic properties of the injection formation caused by the presence of CO_2. Consequently, repeatability of source and receiver types and spacing, source size, and other acquisition parameters between surveys is paramount for an accurate comparison.

Relevance to Project

Time-lapse 3D seismic surveys will be used to track changes in the CO_2 plume in the subsurface. A modeling exercise has been completed to confirm that the planned injected volumes of CO_2 will result in sufficient change in the rock properties of the Mt. Simon to be measured with 3D seismic.

Processing and comparing subsequent surveys to a baseline survey will allow the project to monitor plume growth as well as to ensure that the plume does not migrate beyond the confining layer. Computational modeling will be used to predict the CO_2 plume growth and migration over time by combining the processed seismic data with the existing geologic model.

Acceptance Criteria

To ensure survey repeatability, consistent acquisition geometry (receiver line spacing, source line spacing, line direction) is required. The seismic sources (vibroseis trucks) should be the same for each survey, including the number of trucks, their specifications, and the characteristics (sweep parameters) of the seismic energy they generate.

Data processing for each survey should be the same and the baseline seismic survey should be reprocessed alongside each additional repeat seismic survey to ensure consistency.

Resources/Facilities Needed

Marquis Carbon Injection LLC will subcontract all necessary resources and facilities for the seismic monitoring, in-zone pressure monitoring, and groundwater sampling.

Validity Limits and Operating Conditions

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

B.10. Data Management

B.10.1 Data Management Scheme

Marquis Carbon Injection LLC, or a designated contractor, will maintain the project data required in the permit. Data will be backed up in electronic format and/or held on secure servers. A separate Data Management Plan will be developed to track and store project data.

B.10.2 Record-keeping and Tracking Practices

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

B.10.3 Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper industry techniques and/or manufacturer's requirements.

B.10.4 Responsibility

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

B.10.5 Data Archival and Retrieval

All data will be held by Marquis Carbon Injection LLC. These data will be maintained and stored for auditing purposes as described in **Section B.10.1**.

B.10.6 Hardware and Software Configurations

All Marquis Carbon Injection LLC and vendor hardware and software configurations will be appropriately interfaced.

B.10.7 Checklists and Forms

Checklists and forms will be procured and generated as necessary.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.1 Activities to be Conducted

Groundwater quality data will be collected at the frequency outlined in **Table 7A-4**. After completion of sample analysis, results will be reviewed for QC criteria, as noted in **Section B.5**. If the data quality fails to meet criteria set in **Section B.5**, samples will be reanalyzed, if still within holding time criteria. If outside of holding time criteria or at the operator's choosing, additional samples may be collected, or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the EPA 2009 Unified Guidance (EPA, 2009).

C.1.2 Responsibility for Conducting Assessments

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

C.1.3 Assessment Reporting

All assessment information should be reported to the individual organizations project manager outlined in Section A.1.1.F.

C.1.4 Corrective Action

All corrective action affecting only an individual organization's data collection responsibility should be addressed, verified, and documented by the individual project managers and communicated to the other project managers as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the distribution list for the QASP. Assessments may require integration of information from multiple monitoring sources across organizations (operational, in-zone monitoring, above-zone monitoring) to determine whether correction actions are required and/or the most cost-efficient and effective action to implement. Marquis Carbon Injection LLC will coordinate multiorganization assessments and corrective actions as warranted based on the severity of the event as described in the Emergency and Remedial Response Plan (Permit Section 10.0).

C.2. Reports to Management

C.2.1 QA Status Reports

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

D. <u>Data Validation and Usability</u>

D.1. Data Review, Verification, and Validation

D.1.1 Criteria for Accepting, Rejecting, or Qualifying Data

The groundwater/brine and injection stream analytical data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All analytical results will be entered into a database or spreadsheet with periodic data review and analysis. Marquis Carbon Injection LLC will retain copies of the laboratory analytical test results and/or reports. Analytical results will be reported on a frequency based on the approved UIC permit conditions. In the periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general system operations and variability with time.

D.2. Verification and Validation Methods

D.2.1 Data Verification and Validation Processes

See **Sections D.1.1**. and **B.5** for data verification and validation processes.

Appropriate statistical software will be used to determine data consistency.

D.2.2 Data Verification and Validation Responsibility

Marquis Carbon Injection LLC or its designated subcontractor will verify and validate the injection stream and groundwater analytical data.

D.2.3 Issue Resolution Process and Responsibility

Marquis Carbon Injection LLC or its designated coordinator will provide an overview of the injection stream and groundwater data handling, management, and assessment process. Staff involved in these processes will consult with the coordinator to determine actions that are required to resolve issues.

D.2.4 Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet permit requirements.

D.3. Reconciliation with User Requirements

D.3.1 Evaluation of Data Uncertainty

Statistical software will be used to determine groundwater data consistency.

D.3.2 Data Limitations Reporting

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

Marquis Carbon Injection LLC will use the current operating procedure for the use, sharing, and presentation of results and/or data for the Marquis BioCarbon Project. This procedure has been developed to ensure quality, internal consistency and facilitate tracking and record keeping of data end-users and associated publications.

References

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