U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 8
UNDERGROUND INJECTION CONTROL
CLASS VI DRAFT PERMIT

PERMIT ID: CO62455-12770

ISSUED TO:

Carbon Storage Solutions, LLC
31375 Great Western Drive
Windsor, Colorado 80550

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<u>LIST OF ATTACHMENTS</u>

PERMIT AUTHORIZATION

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this permit, hereinafter referred to as "Permit," EPA hereby authorizes the owner or operator listed below, hereinafter referred to as the "Permittee," to engage in underground injection activities as described herein.

<u>PERMITTEE NAME AND ADDRESS</u>
Carbon Storage Solutions, LLC
31375 Great Western Drive
Windsor, Colorado 80550

In accordance with this Permit, the Permittee is authorized to construct and operate the injection well listed below for injection of the carbon dioxide stream generated by Front Range Energy, LLC (hereinafter "Injection Well" or "Project"):

Well Name: Front Range 1-1
Latitude: 40.454962
Longitude: -104.859761

Bottom Hole Location
Latitude: 40.449494
Longitude: -104.852200

This Permit is based on representations made by the Permittee and other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit, and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

Any underground injection activity not authorized by this Permit is prohibited. All references to Title 40 of the Code of Federal Regulations are to the regulations in effect on the date that this Permit is effective.

This Permit becomes effective on the date listed below and remains in full force and effect during the operating life of the injection well, during 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 CFR 124.5, 144.12, 144.39, 144.40, or 144.41.

Upon authorization of primary enforcement responsibility to a state or tribe, this Permit remains in effect until such time as the authorized state or tribe issues its own permit to the Permittee or the new entity adopts this Permit as its permit.

Issued Date ______**DRAFT**_______ Effective Date _______**DRAFT**_______

Authorization Signed by:

DRAFT

Douglas Minter, Manager
Safe Drinking Water Branch
Water Division

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee 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. Any underground injection activity not specifically authorized in this Permit is prohibited. For purposes of enforcement, compliance with this Permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense of any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA.

B. CHANGES TO PERMIT

B.1 - Modification, Revocation and Reissuance, or Termination— The Director may, for cause or upon request by the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, 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.

B.2 - Transfer of Permit— The Permittee may transfer this Permit in accordance with 40 CFR 144.38(a) only when the Director has modified or revoked and reissued the Permit to identify the new Permittee and incorporate such other requirements as may be necessary under SDWA. The Permittee must 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 must include a written agreement between the existing and proposed new Permittee containing a specific date for transfer of permit responsibility, coverage, and liability between them, all subject to approval by the Director, and must demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) have been met by the proposed new Permittee. All financial responsibility cost estimates, documentation, and instruments as required by 40 CFR 146.85 and by Section F of this Permit must be updated and provided to the Director for review and approval by any new owner or operator of the well.

B.3 - Permittee Change of Name or Address—The Permittee must notify the Director at least 30 days in advance of changes in the Permittee's legal name or address or address where records are kept. The Permit may be subject to modification in accordance with the Modification, Revocation and Reissuance, or Termination, section B.1, of this Permit.

B.4 - Injection Well Conversion— The Permittee must notify the Director at least 30 days in advance of planned well conversion to another type of injection or non-injection well. The notice must include the type of well to which the existing well will be converted and a completed 7520-19 form or its equivalent. Such notice must 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 must 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. The Permittee must convert the well(s) in a manner which will not allow the movement of fluids into or between USDWs.

B.5 - Permit Expiration— The Permit will expire in two years from its effective date if the Permittee fails to commence well construction unless a written request for an extension of this two-year period has been submitted and approved by the Director. The Permittee must submit such requests prior to the Permit's expiration deadline. Each request must explain the reason for the delay, give an estimated well completion date, and list any additional wells that penetrate the designated confining zone within the area of review (AoR) that were not included in the initial permit application, including well construction diagrams, cement records, and cement bond logs. If the construction of the well has not commenced for six years from the effective date, the Permit expires and may not be extended. The Permittee may request an expiration of the permit at any time, provided no construction on the well has commenced. Prior to permit expiration, any monitoring wells and equipment must be plugged and abandoned and/or removed.

C. CONFIDENTIALITY

In accordance with 40 CFR Part 2, Subpart B and 40 CFR 144.5, any information submitted to EPA under this Permit may be claimed as a trade secret or confidential business information (collectively Proprietary Business Information or PBI). 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. Information covered by a PBI claim will be disclosed by EPA only to the extent, and by means of the procedures, set forth in 40 CFR Part 2, Subpart B. If no claim is made at the time of submission, EPA may make the information available to the public without further notice to the Permittee.

Claims of confidentiality for the following information will be denied: the name and address of the Permittee; and information which deals with the existence, absence, or level of contaminants in drinking water.

D. DEFINITIONS

All terms used in this Permit that are defined in the UIC regulations specified at 40 CFR parts 2, 124, 144, 146, and 147 will have the definition in the regulations as they exist on the day this Permit becomes effective. Unless specifically stated otherwise, all references to "days" in this Permit should be interpreted as calendar days.

E. DUTIES AND REQUIREMENTS

E.1 - Prohibition of Movement of Fluid into a USDW—The Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity for the injection well covered by this Permit and associated monitoring wells in a manner that allows the movement of a fluid containing any contaminant into USDWs. If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, the Permittee must report this to the Director within 24 hours and execute the Emergency Remedial and Response Plan (See Attachment F). The Director will prescribe additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection or monitoring well(s)) as are necessary to remediate and prevent such movement. The Director may also take enforcement actions for violations of 40 CFR 144.12(a) and (b) and may take emergency actions consistent with 40 CFR 144.12(e).

E.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, or modification except that the Permittee need not comply with the provisions of this Permit to the extent that, such noncompliance is authorized in an emergency under 40 CFR 144.34.

E.3 - Penalties for Violations of Permit Conditions—The Permittee may be subject to penalties, criminal prosecution, and/or other enforcement action under the SDWA, 42 USC 300h-2, for violating the requirements and conditions of this Permit, the SDWA, and regulations promulgated under the SDWA.

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

E.5 - Duty to Mitigate—The Permittee must take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

E.6 - Actions Not Authorized—Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of state or local laws or regulations.

E.7 – Enforceability During Modification—The filing of a request for a permit modification, revocation and reissuance, termination, 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.

E.8 - Proper Operation and Maintenance—The Permittee must at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances that are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance include but is not limited to: 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 backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

E.9 - Duty to Provide Information—The Permittee must furnish to the Director within the time specified, unless otherwise specified 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. The Permittee must also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this Permit.

E.10 - Inspection and Entry—The Permittee must 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 must be kept under the conditions of this Permit;

(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.

E.11 - Monitoring and Records – Samples and measurements taken for the purpose of monitoring must be representative of the monitoring activity. The Permittee must maintain complete and accurate monitoring records, calibration certificates, testing reports, and corrective action documentation. Record retention requirements are provided in Section O.7 of this permit. Records must be readily available for inspection and submitted to the Director upon request in accordance with 40 CFR 144.51(j)(1)(2), (3) and (4).

E.12 - Signatory and Certification Requirements — All reports, notifications, or any other information required to be submitted by this Permit or requested by the Director must be signed and certified in accordance with 40 CFR 144.32. The Permittee must 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*"

E.13 - Reporting Requirements – Copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Section E.11- *Signatory and Certification Requirements* of this Permit and submitted in a manner approved by the Director. All correspondence must reference the well name, well location, and EPA Permit number.

Reports and notifications required by this Permit should follow the Procedures for Submitting Required Reports and Notifications found at: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#contact.

(e) Sampling and Monitoring Reports. Sampling and monitoring results must be reported at the intervals specified in Attachment C.

(f) Planned changes. The Permittee must give notice to the Director as soon as possible of any planned changes, physical alterations, or additions to the permitted well, and prior to commencing such changes.

(g) Anticipated noncompliance. The Permittee must give at least 14 days' advance written notice to the Director of any planned changes in the permitted facility or activity that may result in noncompliance with Permit requirements.

(h) 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 no later than 30 calendar days following each schedule date.

(i) Twenty-four-hour reporting. The Permittee must report to the Director any circumstance that may endanger human health or the environment, including:

  (i) any monitoring or other information indicating that any contaminant may cause an endangerment to a USDW, including any loss or suspected loss of MI; or

  (ii) any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between USDWs.

  (iii) See Section O.3 for additional requirements.

(j) Other Noncompliance. The Permittee must report all instances of noncompliance not reported under paragraphs (a), (d), or (e) of this section at the time that monitoring reports are submitted.

(k) Other information. Where the Permittee becomes aware of a failure to submit any relevant facts in a permit application, submitted incorrect information in a permit application, or submitted incorrect information in any report to the Director, the Permittee must promptly submit such facts and information to the Director.

(l) Oil Spill and Chemical Release Reporting. The Permittee must comply with all reporting requirements related to the occurrence of oil spills and chemical releases that may endanger USDWs by contacting the National Response Center (NRC) at (800) 424-8802 or NRC@uscg.mil.

F. AREA OF REVIEW AND CORRECTIVE ACTION

The Permittee must maintain and comply with the approved Area of Review (AoR) and Corrective Action Plan included as Attachment B of this Permit. In accordance with this Permit and UIC regulations, the Permittee must do the following:

F.1 - Reevaluation of Area of Review and Corrective Action Plan—At a minimum frequency not to exceed every five years as specified in the AoR and Corrective Action Plan, or more frequently when monitoring and operational conditions warrant and as specified in the AoR and Corrective Action Plan, the Permittee must reevaluate the delineation of the AoR and perform corrective action in the manner specified in the AoR and Corrective Action Plan. Reevaluation of the AoR and Corrective Action Plan must include a new survey of wells within the existing or modified AoR.

Following each AoR reevaluation, the Permittee must submit an amended AoR and Corrective Action Plan or demonstrate to the Director through monitoring data and modeling results that no amendment is needed. A revised AoR and Corrective Action Plan must be approved by the Director, incorporated into the Permit, and are subject to the permit modification requirements. Once approved, the AoR and Corrective Action Plan become an enforceable condition of this Permit. If the Director disapproves the revised AoR and Corrective Action Plan, the Permittee must cease injection operations, or if the well is not currently injecting, the Permittee must not resume injection until a revised AoR and Corrective Action Plan are approved.

F.2 - Requirements for Corrective Action—At least 60 days prior to commencing corrective action, the Permittee must submit proposed procedures for performing corrective action on the identified deficient wells within the AoR and not commence any corrective action until the procedures are approved by the Director. Corrective action on all deficient wells in the AoR must be complete, and approved in writing by the Director, before the Permittee may commence injection, unless the Director has approved a phased corrective action plan.

G. FINANCIAL RESPONSIBILITY

The Permittee must demonstrate and maintain financial responsibility in accordance with 40 CFR 146.85 to cover estimated costs. The approved financial responsibility documents and estimated costs are found in Attachment H of this Permit. 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.

The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit. The Permittee must maintain financial responsibility and resources until the Director receives and approves the completed Post-injection Site Care and Site Closure Plan (Attachment E) and the Director approves site closure. The Permittee may be released from a financial instrument in the following circumstances: the Permittee has completed the phase of the Project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of Project, if required; or the Permittee has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the Permittee from the previous financial instrument.

The Permittee must provide updated information related to their financial responsibility instrument(s) on an annual basis, and if there are any changes, the Director must evaluate the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The Permittee must maintain financial responsibility requirements regardless of the status of the Director's review.

Compliance with the financial responsibility requirements, including the applicable duration, described in this Permit does not relieve the Permittee from complying with any other applicable federal, state, and local financial responsibility requirements.

G.1 - Cost Estimate Updates and Adjustments—During the life of the geologic sequestration project the Permittee must maintain a current, detailed written cost estimate to reflect adjustments for inflationary costs and any amendments made to the Project Plans included as attachments of this Permit. The Permittee must 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. The Permittee must also provide written update adjustments to the cost estimate within 60 days of any amendment to the AoR and Corrective Action Plan, the Injection Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, or the Emergency and Remedial Response Plan.

(b) No later than 60 days after the Director has approved a request to modify the AoR and Corrective Action Plan, the Injection Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, or the Emergency and Remedial Response Plan, if the change in the plan significantly increases the cost, as determined by the Director.

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

Cost estimates must be based on costs to the regulatory agency of hiring a third-party to perform the required activities. A third party is a party who is not within the corporate structure of the Permittee.

G.2 - Changes in Coverage— The Permittee must obtain approval from the Director for any new or updated cost estimate or revised financial instrument(s).

Whenever a cost estimate increases to an amount greater than the face amount of a controlling financial instrument(s), 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 instrument(s) 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.

G.3 - Adverse Financial Conditions Notification—The Permittee must notify the Director by certified mail and by email of adverse financial conditions that may affect the ability to cover current cost estimates.

(a) In the event that the Permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the Permittee must notify the Director within 10 days after commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy) of the U.S. Code, naming the Permittee as debtor. A guarantor of a corporate guarantee must make such notification if they are named as debtor, as required under the terms of the guarantee.

(b) 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. A Permittee who obtains a letter of credit, surety bond, or insurance policy will be deemed to be without the required financial responsibility 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 assurance meeting the requirements in 40 CFR 146.85, within 60 calendar days after such an event.

H. WELL CONSTRUCTION

The EPA-approved design and specifications for the injection well, injection zone monitoring well, groundwater monitoring wells that are the subject of this Permit are included in Attachment G of this Permit. Changes to the approved construction plan must be approved through permit modification by the Director, prior to implementation of any changes.

H.1. - Injection Well Construction – The well must be constructed in accordance with 40 CFR 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.

H.2. - Casing and Cementing—Casing, cement, and other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by the American Petroleum Institute (API) or ASTM International, or comparable standards acceptable to the Director. The well must be cased and cemented to prevent the movement of fluids into any unauthorized zones for the duration of the geologic sequestration project in accordance with 40 CFR 146.95(f)(ii).

H.3. - Injection Tubing and Packer—The tubing and packer design must meet the requirements of 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 API or ASTM International, or comparable standards acceptable to the Director. The tubing-packer system must be set in the long string casing within or below the nearest cemented and impermeable confining system no more than 100 feet above the top of the injection zone.

H.4.- Sampling and Monitoring Devices— The design and construction must allow continuous monitoring of the annulus between the long string casing and the injection tubing and accommodate testing and sampling devices and workover tools.

The Permittee must install and maintain in good condition all devices required to measure, monitor, and record the data and parameters required by Attachment 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 backup 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 greater than 72 hours, injection activities must cease until such time that continuous monitoring is restored.

The Permittee must ensure all gauges used for monitoring and testing are properly calibrated and maintained as described in Quality Assurance and Surveillance Plan (QASP) in Attachment I.

H.5. - Monitoring Well Construction— 40 CFR 146.90(g) and 146.95(f)(3) require monitoring of the carbon dioxide plume and pressure front of the injection zone, and 40 CFR 146.90(d) requires monitoring of groundwater located above the injection zone. These sections are incorporated by reference into this Permit. Casing, cement, and other materials used in the construction of the monitoring wells, including monitoring wells present in the injection zone, must be compatible with all fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by the API or ASTM International, or comparable standards acceptable to the Director. The injection zone monitoring well must be constructed in the manner depicted in Attachment G of this Permit using materials that are compatible with the injected fluids, formation fluids and a mix of both. 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.

I. PRE-OPERATIONAL REQUIREMENTS

Before the Director issues written authorization to commence injection, the Permittee must complete and submit documentation of preoperational requirements as required below. The Permittee is prohibited from injection until after the Director reviews and approves these results, along with any required plan updates, and issues written authorization to commence injection.

I.1. - Mechanical integrity demonstration (40 CFR 146.87

(a) Demonstrate no significant leak in the casing/tubing/packer via pressure testing.

(b) Demonstrate no fluid movement through the cemented annulus via cement evaluation logs (and other Director approved methods).

(c) Conduct tests with Director witnessing if required; submit plans/results per permit reporting.

I.2. - Injectivity and formation testing; operating limits (40 CFR 146.87(e))

(a) Establish baseline reservoir pressure and temperature in the injection zone (and confining zone, if applicable).

(b) Confirm maximum allowable injection pressure (MAIP) remains below fracture pressure; adjust to a lower value if required by subsequent testing or Director determination.

I.3. - Instrumentation, alarms, automatic shutoff, and emergency shutdown readiness (40 CFR 146.89)

(a) Install and calibrate continuous recording devices (pressure, rate, temperature as applicable); retain calibration certificates.

(b) Configure alarm and automatic shutoff/emergency shutdown (ESD) setpoints and logic with sufficient margin to prevent approaching/exceeding MAIP.

(c) Complete the preoperational functional demonstration of alarms, automatic shutoff, and ESD systems per Attachment C (e.g., Section C.15); obtain Director approval.

I.4. - Annulus fluid and packer verification (40 CFR 146.86)

(a) Fill annulus with approved noncorrosive fluid (add tracer if required); confirm stability.

(b) Verify tubing/packer differential pressure behavior consistent with design.

(c) Pressure test packer set and seal performance.

I.5. - Baseline sampling and CO_2 stream characterization (40 CFR 146.89)

(a) Characterize the CO_2 stream (composition/impurities) and submit documentation.

(b) Collect baseline groundwater quality in monitoring wells per the Testing and Monitoring Plan.

(c) Acquire baseline geochemical and pressure data.

I.6 - Area of Review (AoR) and corrective action completion (40 CFR 146.84)

(a) Complete corrective actions for wells in the AoR and submit verification.

(b) Update AoR delineation when new data or model updates materially change the projected CO_2 plume or pressure front.

(c) Submit updated AoR materials with the next report or earlier if directed.

I.7. - Emergency and remedial response readiness (40 CFR 146.92)

(a) Confirm the Emergency and Remedial Response Plan is current and ready for implementation.

(b) Verify ESD triggers and procedures are integrated into emergency response.

(c) Ensure personnel training and documentation are in place.

J. COMMENCING INJECTION

The Permittee cannot commence injection until all of the following requirements have been met:

J.1 – Review and Approval of Results of Pre-Operational Requirements - The Permittee has submitted the results of the Pre-Operational Requirements as specified in Section I of this Permit to the Director for review and approval;

J.2 – Notice of Completed Construction - Construction is complete and the Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 and required attachments or its equivalent. If the well construction is different than the approved construction found in Attachment G, the Permittee must also provide a revised well diagram and a description of the previously approved modification to the well construction;

J.3– Determination of Compliance with Permit Conditions - The Director has inspected the injection well and reviewed all submitted information in J.1 and J.2 and finds it complies with the conditions of the Permit. The inspection is waived if the Permittee has not received notice from the Director of intent to inspect the injection well within 13 days of the date of the notice provided in paragraph J.2 above; and

J.4 – Written Authorization to Commence Injection - The Director has provided the Permittee written authorization to commence injection.

K. INJECTION WELL OPERATION

K.1 - Outermost Casing Injection Prohibition—The Permittee must only inject the CO_2 stream into the injection zone through the injection tubing. Injection between the outermost casing protecting USDWs and the wellbore is prohibited.

K.2 - Injection Zone and Fluid Movement

Injection zone means "a geological formation, group of formations, or part of a formation receiving fluids through a well." Injection must only occur within the authorized injection zone specified in Attachment A, Section 1, and injected fluids must remain within the injection zone.

If monitoring or test results indicate the movement of fluids from the injection zone, the Permittee must notify the Director within twenty-four (24) hours (Sections E.12(e) or O.3(a)) and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

For perforated casing completions, additional injection perforations may be added if: (1) they are made within the approved injection zone, (2) fracture gradient data is submitted and representative of the portion of the injection zone to be perforated, and (3) the Permittee provides notice and reports to the Director in accordance with Sections O.4 & O.5. The Permittee must also follow the requirements found in Section I.3 that may result in a change to the permitted downhole MAIP.

K.3 - Injection Fluids Limitation— Approved Injection fluids are limited to those fluids described in Attachment A, Section 1. The Permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by the Director. An analysis of any proposed new injection fluid, including the chemical and physical characteristics, must be submitted to the Director for review and written approval prior to commencing injection of proposed injection fluid. This may require corrosion modeling, modifications to well design, and if approved, will result in a permit modification (either a "minor modification" pursuant 40 CFR 144.41 or a major modification pursuant to 40 CFR 144.39).

K.4 - Injection Pressure Limitation— Except during stimulation at specific times as approved by the Director, the Permittee must ensure that injection pressure does not exceed 90% 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 downhole MAIP at the depth of the injection zone is listed in Attachment A, Section1 of this Permit.

K.5 - Stimulation Program—The Permittee must obtain prior approval from the Director to conduct stimulation activities, at least 30 days in advance, and may be subject to the permit modification requirement. In no case may injection pressure initiate fractures in the confining zones or cause the movement of formation fluids that endanger a USDW.

K.6 - 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.

K.7 - Annulus/Tubing Pressure Differential— Except during workovers, the Permittee must maintain a pressure on the tubing-casing annulus as specified in Attachment A Section 1, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

K.8 - Maintenance of Mechanical Integrity—Other than during periods of well workover or annulus maintenance, approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the Permittee must always maintain mechanical integrity.

K.9 - Continuous Recording Devices, Automatic Alarms, and Automatic Shutoff System

The Permittee must:

(a) Install and use continuous recording devices to monitor the injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume;

(b) Install, continuously operate, and maintain an automatic alarm and automatic shutoff system or downhole shutoff systems; and

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

Well-specific thresholds for activating the shutoff system are identified in Attachment A.1. Shutoff thresholds must be below the maximum limits established in the Permit and manufacturer-recommended operating conditions.

Testing under this section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or their representative unless the Director authorizes an unwitnessed test in advance. The Permittee must provide notice 30 days prior to running the test and must provide the Director or their representative with the opportunity to attend. The test must be documented using either a mechanical or a 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 to the Director within the time period specified in Section N of this Permit.

K.10 - Precautions to Prevent Well Blowouts—Except at specific times as approved by the Director, the Permittee must maintain on the injection well a pressure which will prevent the return of the injected carbon dioxide stream to the surface. The wellbore must be filled with a fluid of sufficient specific gravity during workovers to maintain a positive (downward) pressure gradient and/or a plug must 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 the procedures below to ensure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injected carbon dioxide stream; and

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

K.11 - Circumstances Under Which Injection Must Cease—Injection must cease immediately when any of the following circumstances occur:

(a) The injection well fails to pass a mechanical integrity test;

(b) An injection zone monitoring well fails to pass a mechanical integrity test;

(c) There is a loss of mechanical integrity during operation;

(d) The automatic alarm or automatic shutoff system is triggered;

(e) There is an unexpected change in the annulus or injection pressure;

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

(g) Movement of injection or formation fluids into a USDW or other unauthorized formation is detected;

(h) Circumstances in Attachment F Emergency Remedial and Response Plan that require Permittee to "initiate shutdown plan"; or

(i) The Director determines that continued injection may result in endangerment of USDWs based on new data or information (e.g. AoR reevaluation, site is no longer suitable based on new site geology information).

In all instances where injection is required to cease, the Permittee must immediately cease injection and initiate the shutdown plan as outlined in Attachment F, Section 1.2, of this Permit. The Permittee must obtain written approval from the Director to resume injection.

If an automatic shutdown (i.e., downhole or at the surface) is triggered, the Permittee must immediately investigate and, as expeditiously as possible, identify the cause of the shutdown. If, upon investigation, the well appears to lack mechanical integrity, or if the required monitoring of data from continuous recording devices or automatic shutoff systems indicates that the well may lack mechanical integrity, the Permittee must take the actions listed below in Section L.7 Loss of Mechanical Integrity and in Attachment F Emergency and Remedial Response Plan.

L. MECHANICAL INTEGRITY

The Permittee must ensure that the Front Range 1-1 injection well and Front Range 2-1 monitoring well that penetrate the upper confining zone have both internal and external mechanical integrity for the operational life of the well. The approved tests, test procedures and schedule for mechanical integrity demonstration are found in Attachment C of this Permit. The Permittee may propose alternative tests and/or procedures not listed in the Testing and Monitoring Plan to be considered by the Director for approval and incorporated into Attachment C of this Permit as part of a permit modification. Any alternative tests and/or procedures must receive prior approval before they can be implemented.

L.1 – Requirement to Maintain Mechanical Integrity—The Permittee is required to ensure that injection well mechanical integrity is always maintained. Injection into a well that lacks mechanical integrity is prohibited. An injection well must satisfy both internal and external mechanical integrity:

Internal Mechanical Integrity - There is no significant leak in the casing, tubing, or packer; and

External Mechanical Integrity - There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

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 in accordance with 40 CFR 146.89.

L.2 - Mechanical Integrity Demonstration Requirements and Schedule

The Permittee must demonstrate mechanical integrity of the injection well(s) as follows:

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

(b) Continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume, as specified in 40 CFR 146.89(b).

(c) Annually for external mechanical integrity using a method listed in 40 CFR 146.89(c).

(d) After any loss or suspected loss of mechanical integrity.

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

(f) For external mechanical integrity, prior to plugging the well pursuant to 40 CFR 146.92(a) and as listed in Attachment D of this Permit.

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

(h) Prior to authorization to inject.

L.3 - Monitoring Wells—All monitoring wells must maintain internal and external mechanical integrity for the entire period of their operation. The Permittee must take corrective action if there are leaks in the casing. The Director has the discretion to determine whether the monitoring well has mechanical integrity in accordance with 40 CFR 146.89(a). Mechanical integrity is determined through testing and test procedures approved by the Director. Mechanical integrity tests and procedures for the confining zone and injection zone monitoring wells are specified in the Testing and Monitoring Plan in Attachment C of this Permit. Mechanical integrity testing for groundwater monitoring wells shall include periodic televising of the well casing. Testing and demonstration of monitoring wells must be conducted on the same schedule as the injection well. Other tests and/or procedures not listed in this plan may be considered by the Director for approval and incorporated into Attachment C of this Permit as part of a permit modification, as appropriate.

L.4 - Notification Prior to Testing and Reporting

(a) The Permittee must notify the Director 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 mechanical integrity tests and procedures are listed in Attachment C of this Permit. If the Permittee wishes to use tests and procedures not listed, such tests and procedures must be approved by the Director in advance of the testing.

(c) The Permittee must report the results of a mechanical integrity demonstration no later than 30 days after the demonstration is complete. Testing reports on a mechanical integrity demonstration must include a description of the test and the methods used. Any demonstration which includes logs, must include an interpretation of results by a knowledgeable log analyst.

L.5 - EPA Witnessing of Mechanical Integrity Tests—Mechanical integrity tests for the injection well and monitoring wells 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. If approval has been granted, to conduct testing without an EPA witness, the Permittee must adhere to the following procedures:

(a) Submit prior notice within the time period specified within this section and Section O.5 of this Permit, and receive written 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

(c) Submit a final report including any additional interpretation necessary for evaluation of the testing, including a test record and gauge certification to the Director within the time period specified in Section O.4 of this Permit.

L.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 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 with the report on the test. All recordings must read to an accuracy of no more than 0.5% of full scale for mechanical gauges. Pressure gauge resolution is not to exceed five pounds per square inch. When the Director determines that mechanical integrity or other testing requires greater accuracy, the Permittee must identify the alternative procedure and submit it to the Director prior to the test.

L.7 - Loss of Mechanical Integrity

(a) If the Permittee or the Director finds that: 1) the injection well and/or monitoring well(s) fails to demonstrate mechanical integrity during a test, 2) the well fails to maintain mechanical integrity during operation, or 3) a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) during operation has likely occurred (such as a significant unexpected change in the annulus or injection pressure), the Permittee must:

(i) Cease injection immediately;

(ii) Take all reasonable measures necessary to determine whether there may have been a release or is evidence of a potential leak of the injected carbon dioxide stream or formation fluids into any unauthorized zone;

(iii) Implement the steps in the Emergency and Remedial Response Plan (Attachment F, Section 4.2 of this Permit);

(iv) Within 24 hours of the event, notify the Director of the circumstances surrounding the event in accordance with Section O.3;

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

(vi) Notify the Director when injection can be expected to resume and submit a projected plan for reestablishing mechanical integrity or plugging the well; and

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

(b) If an automatic shutdown (i.e., downhole 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 injection well appears to be lacking mechanical integrity, or if the required monitoring indicates that the injection well may be lacking mechanical integrity, the Permittee must take the actions listed above in Section L.7 Loss of Mechanical Integrity.

(c) The injection well and/or monitoring well(s) must remain shut in until the Permittee receives written approval from the Director to commence/resume injection.

L.8 - Alternative Mechanical Integrity Tests and Procedures — The Permittee must submit any proposed alternative tests and/or procedures not listed in the Testing and Monitoring Plan to the Director for approval prior to using them to demonstrate mechanical integrity per 40 CFR 146.89(e). Any such approval will be in accordance with the UIC regulations at 40 CFR 146.89(e); if any proposed alternatives are not listed in 40 CFR 146.89, they will require approval by the EPA Administrator.

M. SEISMIC EVENT REQUIREMENTS

M.1 – Seismic Event Notification Service – The Permittee must subscribe to the U.S. Geological Survey Earthquake Notification Service to receive notification of seismic events (both natural and induced) within 5.6 miles from the injection well.

M.2 – Notice of Seismic Arrays –The Permittee must provide the Director with specific details of any obtained or reasonably available seismic arrays available to the Permittee prior to injection and shall make available the collected data and information to the Director

M.3 – Requirements for Seismic Activity – The Permittee must closely monitor seismic activity and cease operations or reduce injection rate, should analysis indicate a causal relationship between injection operations and detected seismicity. Specifically, the Permittee must perform response actions in accordance with Section 4.6, Table 2 in Attachment F Emergency Remedial and Response Plan.

N. TESTING AND MONITORING REQUIREMENTS

The Permittee must maintain and comply with the approved Testing and Monitoring Plan included as Attachment C of this Permit. Samples and measurements taken for the purpose of monitoring must be representative of the monitored activity. If an alternative test is proposed that deviates from the procedures outlined in the Testing and Monitoring Plan in Attachment C of this Permit, the Permittee must submit it to the Director and obtain approval prior to conducting the test.

The Permittee must review the Testing and Monitoring Plan periodically to incorporate monitoring data collected under this subpart, operational data collected under 40 CFR 146.88, and the most recent area of review reevaluation performed under Section F of this Permit and 40 CFR 146.84(e). In no case shall the Permittee review the testing and monitoring plan less often than every five years. Based on this review, the Permittee must submit an amended Testing and Monitoring Plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. The amended Testing and

Monitoring Plan or demonstration must be submitted to the Director for review and approval 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. Any amendments to the Testing and Monitoring plan must be incorporated into this Permit and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, if applicable.

N.1 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 quarterly, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR § 146.90(a).

N.2 - Continuous Monitoring – The Permittee must install and use continuous recording devices to monitor: the injection pressure (at surface and at injection interval), 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 at injection interval). This monitoring must be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR § 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.

N.3 - Groundwater Monitoring Above and Below the Injection Zone – The Permittee must monitor groundwater quality and any geochemical changes above and below the upper and lower confining zone, respectively, 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 Attachment C in accordance with the plan and at the locations and depths, and at frequencies described in the plan to meet the requirements of 40 CFR § 146.90(d).

N.4 - 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 CFR § 146.90(g). The Permittee is required to conduct this monitoring in order to detect and locate the carbon dioxide pressure front and the carbon dioxide plume. 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 FR 2-1 monitoring well 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 baseline 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 C and E and to meet the requirements of 40 CFR § 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 C and E to meet the requirements of 40 CFR § 146.90(g)(2).

N.5 - 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 C and in accordance with 40 CFR § 146.90(c). This ensures that wellbore components meet the minimum standards for material strength and performance set forth in 40 CFR § 146.86(b).

N.6 - 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 Attachments C and must comply with Section L of this Permit in order to meet the requirements of 40 CFR §§ 146.89 and 146.90.

N.7 - Pressure Fall-Off Test – The Permittee must 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 must be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR § 146.90(f).

N.8 - 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 CFR § 146.90(h).

N.9 - Casing Inspection Logs - Casing inspection logs must be run 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. The Director may require that a casing inspection log be run every five years, if the Director has reason to believe that the integrity of the long string casing of the well may be adversely affected by naturally occurring or human-induced events. Casing inspection logs must also 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.

N.10 - Additional Monitoring – If required by the Director as provided in 40 CFR § 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 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 146.86(a). This monitoring must be performed as described in a modification to 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 in Attachment C, and as otherwise required by this Permit. Reports must contain all the data and information required to be monitored, gathered and reported by this Permit, in accordance with 40 CFR 144.51(l) and 146.91.

O.1 - Electronic Reporting - All reports, submittals, notifications, correspondence to the Director, 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.

O.2 - Semiannual Reports—The Permittee must submit reports on a semi-annual basis. 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 as described in the approved Testing and Monitoring Plan. The second semi-annual report for each year must include all data that is required to be collected on an annual basis as described in the approved Testing and Monitoring Plan in Attachment C. 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 in Attachment C:

(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, 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 O 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 or 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.

   Results of any additional monitoring identified in the Testing and Monitoring Plan in Attachment C and described in Section O of this Permit

<u>O.3 - 24-Hour Reporting Requirements</u>

(a) Within 24 hours from the time the Permittee becomes aware of any of the circumstances listed below, Section E.13(e), or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F) including the release of the injected carbon dioxide stream or formation fluids into any unauthorized zone, the Permittee must notify the Director:

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

   (ii) Any triggering of the shutoff system required in Section J.9. (i.e., downhole or at the surface);

   (iii) Any failure to maintain mechanical integrity in the injection well or injection zone monitoring wells;

   (iv) Any release of carbon dioxide to the atmosphere or subsurface, including results from surface air/soil gas monitoring pursuant to 40 CFR 146.90(h);

   (v) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F); and

(b) Information must be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting the EPA Region 8 UIC Program SDWA Enforcement Supervisor, or by contacting EPA Region 8 Emergency Operations Center at (303) 293-1788.

(c) A written submission must be provided to the Director within five days of the time the Permittee becomes aware of the circumstances described in Section O.3 (a) above. The submission must contain a description of the noncompliance, 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); and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance or emergency or condition requiring remedial response.

O.4 - Reports on Well Tests and Workovers—The Permittee must report, within 30 days, the results of:

(a) Any mechanical integrity test required by this Permit;

(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.

O.5 - Advance Notice Reporting

(a) *Well Tests*—The Permittee must give at least 30 days advance written notice to the Director of any planned workover, stimulation, or other well test.

(b) *Planned Changes*— See Section E.12(b). In addition, an analysis of any fluid proposed for injection that is not authorized under this Permit 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*—See Section E.12(c).

O.6 - Additional Reports

(a) *Compliance Schedules*— See Section E.12(d)

(b) *Other Noncompliance*—See Section E.12(f). The reports must include any monitoring or other information which indicates that any injected carbon dioxide stream or injection zone fluid has moved into any unauthorized zone, or that any contaminant may cause an endangerment to a USDW, or any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into any unauthorized zone or into or between USDWs.

(c) *Other Information*—See Section E.12(g)

(d) *Report on Permit Review*—Within 30 days of receipt of this Permit, the Permittee must certify to the Director that they have read and are personally familiar with all terms and conditions of this Permit.

O.7 - Records and Record Retention

(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 form for this Permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, Plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 until at 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. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period.

(d) The retention periods may be extended by the Director at any time. In these cases, the Permittee must continue to retain records after the retention period specified in this section of the Permit or any Director extension thereof 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. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

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. The Well Plugging Plan and the Post-Injection Site Care and Site Closure Plan are enforceable conditions of this Permit.

P.1 - Injection Well Plugging Plan Revisions—Any amendments to the Injection Well Plugging Plan (Attachment D) or the Post-Injection Site Care and Site Closure Plan (Attachment E) must be approved by the Director and must be incorporated into the Permit and are subject to the permit modification requirements.

P.2 - Required Activities Prior to Plugging—The Permittee must flush the injection well with an inert buffer fluid, determine the post-injection bottomhole 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.

P.3 - Notice of Plugging and Abandonment—The Permittee must notify the Director in writing at least 60 days before plugging, conversion, or abandonment of the injection well, and must provide the Director or their representative the opportunity to attend. A shorter notice period may be allowed at the discretion of the Director.

P.4 - Plugging and Abandonment Approval and Report

(a) The Permittee must receive written approval from the Director before plugging the injection well and must plug and abandon the well as described in the approved Injection Well Plugging Plan (Attachment D).

(b) Within 60 days after plugging, the Permittee must submit a plugging report to the Director. The report must be signed and certified by the Permittee in accordance with 40 CFR 144.32 and by the person who performed the plugging operation (if other than the Permittee). The Permittee must retain the well plugging report for 10 years following site closure. The report must include:

(i) A statement that the injection well was plugged in accordance with the approved Injection Well Plugging Plan (Attachment D);

(ii) If the Director determines that a deviation from the plan incorporated in this Permit may endanger USDWs, to the extent that the determination does not give rise to an independent cause of action for enforcement, the Permittee must remediate the well plugging as required by the Director.

P.5 - Temporary Abandonment—After any 24-consecutive-month period of no injection, the injection well is considered to be in a temporarily abandoned status, and the Permittee must plug and abandon the injection well in accordance with the approved Injection Well Plugging Plan (Attachment D) or make a demonstration of non-endangerment of this injection well that is satisfactory to the Director while it is in temporary abandonment status. Such demonstration of non-endangerment to remain in temporary abandonment status must not be available to the Permittee after a period of ten consecutive years during which there is no injection. The Permittee must notify the Director within 30 days of temporary abandonment. A non-endangerment plan must be approved if the injection well will not be plugged. Temporary abandonment status includes instances where well construction/conversion has begun or been completed but no authorization to commence injection has been approved by the Director. During any periods of temporary abandonment, the Permittee must continue to comply with the conditions of this Permit, including all monitoring and reporting requirements and all applicable regulations. The Permittee of an injection well that has been temporarily abandoned must notify the Director prior to resuming operation of the injection well.

P.6 - Post-Injection Site Care and Site Closure Plan

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). The Well Plugging Plan and the Post-Injection Site Care and Site Closure Plan are enforceable conditions for this Permit.

(a) The Permittee must either submit an amended Post-Injection Site Care and Site Closure Plan (Attachment E of this Permit) for the Director's approval 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 geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.

(c) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.

(d) Prior to authorization for site closure, the Permittee must submit to the Director for review and approval, a demonstration, based on information collected pursuant to Section O of this Permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). If this demonstration cannot be made or if the Director does not approve the demonstration, the Permittee must submit to the Director an amended Post-Injection Site Care and Site Closure Plan (subject to Director approval) to continue post-injection site care until a demonstration can be made and approved by the Director. 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 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 for Director approval.

(f) After the Director has authorized site closure, the Permittee must plug all monitoring wells and any injection wells that remain unplugged as specified in Attachments D and E of this Permit in a manner, which will prevent 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 to the Director within 90 days of site closure. The report must include the information specified at Attachment 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 with the following information consistent with 40 CFR 146.93(g):

(i) The fact that land has been used to sequester carbon dioxide;

(ii) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(iii) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(i) The Permittee must retain, for 10 years following site closure, an electronic copy of the site closure report and records collected during the post-injection site care period, including well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, The Permittee must deliver the records to the Director at the conclusion of the retention period.

Q. EMERGENCY AND REMEDIAL RESPONSE

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

Q.1 Emergency and Remedial Response Plan Requirements

If the Permittee obtains evidence that the injected carbon dioxide stream and associated pressure front may cause endangerment to a USDW, the Permittee must:

(a) Immediately cease injection in accordance with Section L and Attachment F of this Permit;

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

(c) Notify the Director within 24 hours; and

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

Q.2 – Frequency of Emergency and Remedial Response Plan Amendments

The Permittee must periodically review the Emergency and Remedial Response Plan. In no case shall the owner or operator review the Emergency and Remedial Response Plan less often than once every five years. Based on this review, the Permittee must submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the Emergency and Remedial Response Plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate. Amended plans or demonstrations must be submitted to the Director as follows:

(a) Within one year of an AoR reevaluation;

(b) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or

(c) When required by the Director.

Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the Permittee must submit the result to the Director for review.

If the amendments to the Emergency and Remedial Response Plan cause the cost estimates to change, then a new financial responsibility demonstration must be submitted for review and approval by the Director in accordance with Section G.1. of this Permit.

ATTACHMENTS

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

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. INJECTION WELL PLUGGING PLAN

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. CONSTRUCTION DETAILS

H. FINANCIAL ASSURANCE DEMONSTRATION

I. QUALITY ASSURANCE AND SURVAILLANCE PLAN

ATTACHMENT A: SUMMARY OF OPERATING REQUIREMENTS

Facility Information

Facility name:	Front Range Storage Complex
Well Name:	Front Range 1-1
Well location:	Weld County, Colorado Surface Township, Range, Section: T6N, R67W, Sec 26 Bottomhole Township, Range, Section: T6N, R67W, Sec 35 Surface Latitude: 40.454962 Longitude: -104.859761 Bottomhole Latitude: 40.449494 Longitude: -104.852200

1.0 Operational Limits - Table 1 below contains permit conditions related to injection well operation. The Permittee must comply with the limits as indicated.

Table 1: Injection Well Operating Conditions, Parameters, and Limits

PARAMETER/CONDITION*	LIMITATION	UNIT
Downhole Maximum Allowable Injection Pressure at the Lyons Sandstone	5,560	psi
Minimum Annulus Pressure at all times	100	psi
Minimum Annulus Pressure above Tubing Differential (during injection)	100	psi
Carbon Dioxide Purity (minimum)	99	percent volume
Maximum Injection Rate	127,800	metric tons/year
Maximum cumulative mass of injected CO_2	1,540,000	metric tons

*See Attachment C, Table 2 Devices, location and frequencies for monitoring location.

Permittee is required by 40 CFR 146.89 to install and calibrate continuous recording devices (pressure, rate, temperature as applicable). Permittee must configure alarm and automatic shutoff/emergency shutdown (ESD) setpoints and logic with sufficient margin to prevent exceeding the downhole MAIP. The emergency shutdown points are listed in Table 2.

Table 2: Operational emergency shut down set points

ALARM TYPE		SET POINT	UNIT
Downhole Maximum Injection Pressure at the Lyons Sandstone	Shutdown point: 95% of downhole maximum allowable injection pressure	5,282	psi

Annulus Pressure (during injection)	Shutdown point: Minimum	100	psi
	Shutdown point: Less than minimum allowable annulus over tubing differential	100	psi

Downhole Maximum Allowable Injection Pressure

To meet EPA requirements at 40 CFR 146.88(a), the downhole maximum allowable injection pressure (MAIP) for the Front Range 1-1 well is 90% of the fracture pressure of the Lyons Sandstone injection zone, measured using a downhole pressure gauge placed within 20 ft. of the top perforation of the Front Range 1-1 well. The fracture gradient of the Lyons Sandstone was determined by a step rate test performed at the Front Range 1-1 as 0.695 psi/ft, and the corresponding fracture pressure of the Lyons Sandstone at the depth of the top perforation in the Front Range 1-1 well (8,889 ft. true vertical depth) is 6,178 psi. The initial downhole MAIP for this permit is therefore set to 90% of 6,178 psi, or 5,560 psi. If the downhole pressure gauge is placed at a depth other than 8,889 ft., the downhole MAIP must be recalculated as:

$$MAIP = FG * D, \text{ where}$$

MAIP is the downhole maximum allowable injection pressure (psi)

FG is the fracture gradient of the Lyons Sandstone (psi/ft), and

D is the true vertical depth of the gauge used to measure the downhole pressure (ft)

The downhole MAIP may be updated throughout the life of the well when testing or monitoring data indicate the formation fracture pressure differs from the current value. The recalculated downhole MAIP becomes effective and enforceable upon written correspondence from the Director. The Director may also determine that a permit modification is needed to implement the change.

1.1 Injection Zone

Injection must only occur into the authorized injection zone listed in the table below.

Formation Name or Stratigraphic Unit	Top (ft. TVD)	Bottom (ft. TVD)
Lyons Sandstone Formation	8,876	8,958

(TVD, true vertical depth)

1.2 Injection Fluid Limitation

Injected fluids are limited to CO_2 produced by the Front Range Energy, LLC ethanol production facility. As specified in Table 1 above, this injectate must consist of at least 99 percent by volume carbon dioxide. Written approval must be obtained from the Director prior to injection of any other fluids or source of CO_2.

2.0 Startup Procedures

The procedures related to the startup of operations, as well as monitoring and reporting during startup, are specified in this section. The injection rates must be gradually increased to the planned average rate over a period of six (6) days.

The procedures detailed below describe the requirements to initiate injection and conduct startup-specific monitoring of the injection well.

The multistage (injection rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup must follow Attachment C (Testing and Monitoring Plan) of this Permit.

(a) This procedure can be performed using the existing surface and downhole pressure and temperature gauges in the injection well.

(b) During the startup period, the Permittee must submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the Permittee may be required to schedule a daily conference call to discuss this information.

(c) A series of successively higher injection rates must be applied, as shown in Table 3 below. The elapsed time and pressure values must be read and recorded for each rate and timestep.

(d) The planned injection rates are shown in Table 3.

Table 3: Planned Injection Rates During Startup

Rate (metric tons per day)	Duration (hours)	Percent of Average Daily Injection Rate
144	24	40
180	24	50
216	24	60
252	24	70
288	24	80
324	24	90

(e) The injection rates must be measured and recorded.

(f) Surface and downhole pressures and temperatures must be measured and recorded.

(g) During the startup period, a graph of injection rates and their corresponding stabilized pressure values must be reviewed for evidence of anomalous pressure behavior and presented to the Director.

(h) If during the startup period any anomalous pressure behavior is observed, additional logging and modification of the injection rate program may be required by the Director to characterize the anomaly and determine whether formation fracturing is indicated. If fracturing is identified, the Permittee must cease injection and follow the steps below:

(i) Measure the instantaneous shut-in pressure (ISIP).

(ii) Notify the Director within 24 hours of the determination.

(iii) Consult with the Director before initiating any further injection.

3.0 Operations After Startup

Automatic alarms and automatic shutoff systems must be installed and maintained. Successful function of the alarm system and shutoff system must be demonstrated prior to injection and once annually thereafter.

At all times, pressure must be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug must be installed that 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 cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

1.0 Introduction

Pursuant to 40 CFR 146.84, this attachment includes the Area of Review (AoR) and Corrective Action Plan for wells that require corrective action. As a condition of the permit and as required by the EPA's regulations set forth at 40 CFR 146.84, the Permittee must maintain, implement, and comply with an approved plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action on all wells in the AoR needing corrective action as determined by the Director.

1.1 Injection Zone, Confining Zones, and Lowermost Underground Sources of Drinking Water

The Lyons Sandstone interval shown in Table 1 is the allowable injection zone. The upper confining zone consists of the Lykins Formation with primary confinement provided by the Opeche Shale and Blaine Evaporite Members, which comprise the lower part of the formation. The Lower Satanka (Owl Canyon) Formation is the underlying confining unit beneath the Lyons Sandstone. The lowermost underground source of drinking water (USDW) was identified as the Ingleside Formation, which is below the Lyons injection zone. The lowermost USDW above the Lyons injection zone is the Entrada Sandstone. In accordance with Section E.1 of this Permit, the Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity for the Front Range 1-1 injection well and associated monitoring wells in a manner that allows the movement of a fluid containing any contaminant into USDWs.

Table 1: Summary of Injection Zone, Confining Zones, and Lowermost Underground Sources of Drinking Water at the Front Range 1-1 well (USDW, underground source of drinking water; TVD, true vertical depth; MD, measured depth; *, estimated; NA, not applicable).

Formation	Description	Top (ft TVD)	Bottom (ft TVD)	Top (ft MD)	Bottom (ft MD)	Total Dissolved Solids (mg/L)
Entrada Sandstone	USDW	8,175	8,268	8,870	8,966	8,376
Lykins Formation (Blaine and Opeche Members)	Upper confining zone	8,792	8,876	9,494	9,524	NA
Lyons Sandstone	Injection zone	8,876	8,958	9,579	9,660	34,076
Lower Satanka (Owl Canyon) Formation	Lower confining zone	8,958	9,189*	9,660	9,758*	NA
Ingleside Formation	USDW	9,189*	9,737*	NA	NA	3,388

1.2 AoR Delineation

The AoR for the Front Range 1-1 well is shown in Figure 1. The AoR was delineated by using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide (CO_2) stream and is based on available site characterization data prior to receiving authorization to inject. The AoR has an area of about 6.4 square miles surrounding the bottomhole location of the Front Range 1-1. The AoR was determined as the union of the maximum extent of the simulated pressure front and the CO_2 plume, where the pressure front is defined by the critical pressure (3,865 psi) needed to move fluids from the injection zone into the Entrada USDW and the plume extent is defined by where the CO_2 concentration is greater than 1%. The critical pressure was calculated by using equation 1 of EPA, 2013 (Guidance 816-R-13-005):

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

where P_u is the initial fluid pressure in the USDW, ρ_i is the injection-zone fluid density, g is the acceleration due to gravity, z_u is the representative elevation of the USDW, and z_i is the representative elevation of the injection zone.

Because the simulated maximum extent of the CO_2 plume exceeded the maximum extent of the pressure front, the AoR effectively is delineated by the maximum CO_2 plume extent, which occurs in year 32 (20 years after injection ceases). Computational modeling predicts the CO_2 plume will reach the Front Range 2-1 deep-zone monitoring well between years 5 and 8 and that the pressure front does not extend to this well at any time during the life of the project.

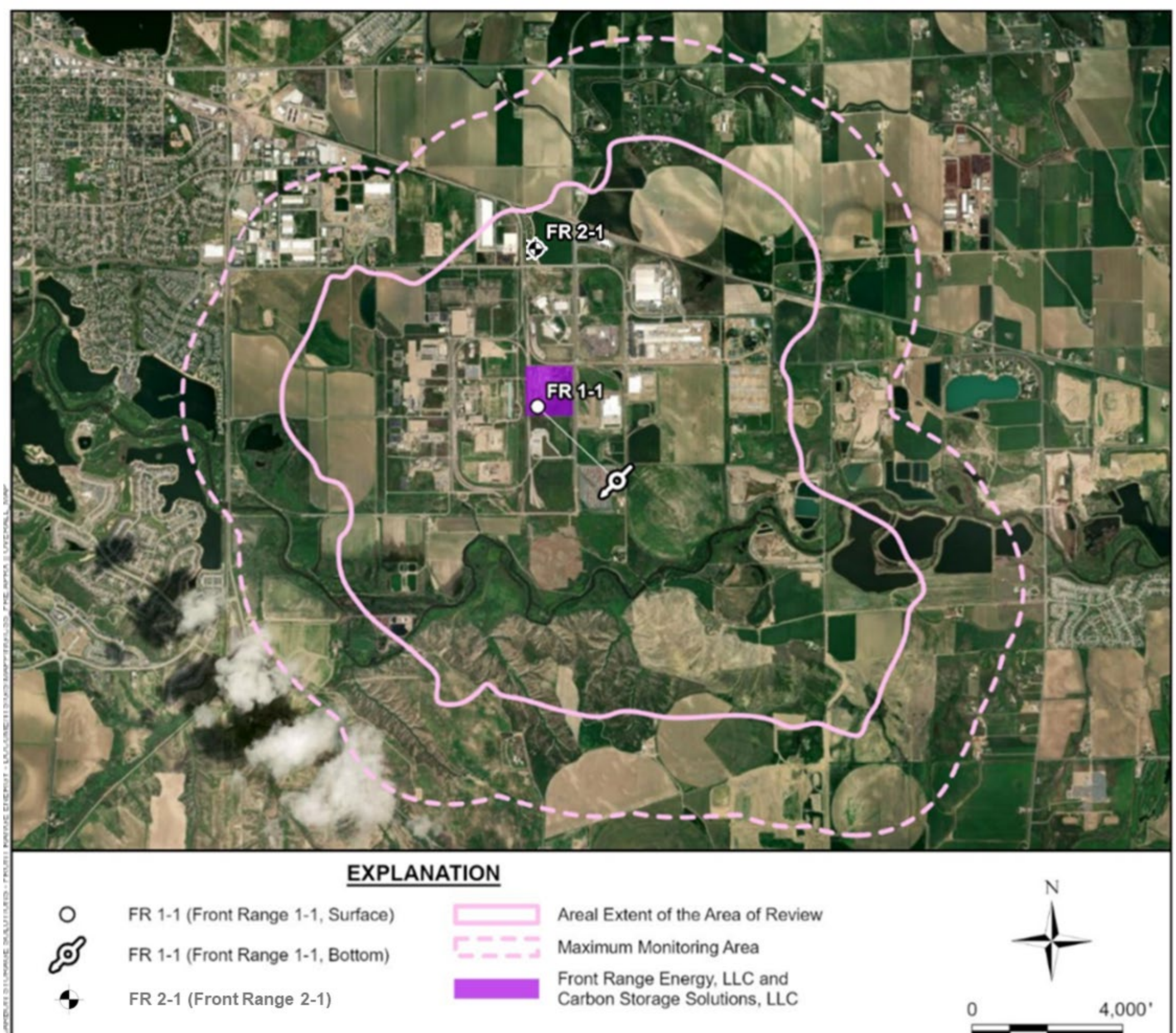


Figure 1: Area of review for the Front Range 1-1 well, delineated by using computational modeling based on available site characterization data. Location of Front Range 2-1 monitoring well is shown in the AoR.

1.3 Corrective Action Plan

Other than the Front Range 1-1 injection well, the only current penetration of the confining zones within the AoR is the Front Range 2-1 deep-zone monitoring well. This well has been properly constructed to Class VI standards to prevent movement of CO_2 or formation fluids out of the injection zone. No other artificial penetrations of the confining zones were identified within the AoR. Therefore, no corrective action is required.

1.4 AoR Reevaluation

The Permittee must reevaluate the AoR at a fixed frequency of five years from the commencement of injection activities throughout the injection and post-injection site care periods, or more frequently when monitoring and operational conditions warrant. Activities to be performed during reevaluation must include the following:

(A) Review data collected as required by Attachment C (Testing and Monitoring Plan) and Attachment E (Post-Injection Site Care and Site Closure Plan) of this Permit since the previous AoR evaluation. Specifically:

(1) Review temperature, pressure, and pulsed neutron log data collected at the Front Range 1-1 and Front Range 2-1 wells for the Lyons Sandstone injection zone, the Entrada Sandstone USDW, and the Ingleside Formation USDW.

(2) Review operating data, including injection rates, volumes, and pressures, and the composition of the CO_2 stream.

(3) Review groundwater and dissolved gas chemistry data collected at the Front Range 1-1 and Front Range 2-1 wells for the Lyons Sandstone injection zone, the Entrada Sandstone USDW, and the Ingleside Formation USDW.

(4) Review groundwater and dissolved gas chemistry data collected from shallow monitoring wells completed in near-surface aquifers.

(5) Review soil gas data collected at soil gas monitoring stations.

(6) Review results of vertical seismic profiles.

(B) Compare data to the current AoR delineation

(1) If the monitoring and operating data indicate subsurface and operating conditions are consistent with inputs used in the current AoR delineation model, the pressure front and CO_2 plume are moving as predicted or are smaller than predicted, and there is no evidence of CO_2 or fluid movement into USDWs, then no amendment to the AoR is required. The Permittee must submit a report to the Director within 90 days of the reevaluation that demonstrates, based on monitoring data and modeling results, that no amendment to the AoR and corrective action plan is needed.

(2) If monitoring or operating data indicate subsurface or operating conditions are substantially different from those used in the current AoR delineation model, the pressure front or CO_2 plume may extend beyond the current

AoR, or there is evidence of CO_2 or fluid movement into USDWs, the AoR must be delineated in the manner specified in 40 CFR 146.84(c). Steps to delineate the AoR include the following:

(a) Revise the site conceptual model based on the new monitoring data.

(b) Use computational modeling to simulate the projected lateral and vertical migration of the CO_2 plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases or until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present.

(c) Calibrate the computational model to minimize the differences between monitoring data and model simulations.

(d) Identify all wells that fall within the AoR. Evaluate the status and records of wells that were not previously evaluated and provide a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion.

(e) Determine which wells in the newly delineated AoR are plugged in a manner that prevents movement of CO_2 or other fluids that may endanger USDWs.

(f) Perform corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with CO_2.

(g) Submit a report to the Director documenting the AoR reevaluation process, data evaluated, computational modeling results, the revised AoR, any corrective actions determined to be necessary, and status of corrective action or a schedule for any corrective actions to be performed. The report must be submitted to the EPA within 90 days of the reevaluation and include maps that highlight similarities and differences between the current AoR delineation and previous AoR delineations.

(h) Within 90 days of the reevaluation, update the AoR and Corrective Action Plan to reflect the revised AoR, along with a description of how site access will be guaranteed for any needed corrective action, and submit to the Director. Any amendments to the AoR and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

(i) Update the Testing and Monitoring Plan, Post-Injection Site Care and Site Closure Plan, Emergency and Response Plan, and demonstration of financial responsibility to account for the revised AoR as required by the Director.

(j) Retain all modeling inputs and data used to support the AoR reevaluation for 10 years.

(C) Conditions Warranting AoR Reevaluation Prior to Scheduled Reevaluation

Monitoring and operational conditions that warrant an unscheduled reevaluation of the AoR include:

(1) Significant changes in site operations that may alter model predictions and the AoR delineation. Specifically, an unscheduled AoR reevaluation may be required when the limits shown in Table 1 of Attachment A of this Permit are exceeded for injection zone pressure, injection rate, or cumulative mass of injected CO_2 if those exceedances could result in the pressure front or CO_2 plume reaching the current AoR boundary prior to the next scheduled AoR reevaluation.

(2) Monitoring data indicate the pressure front or CO_2 plume may reach the current AoR boundary prior to the next scheduled AoR reevaluation.

(3) New site characterization data are acquired that indicate the pressure front or CO_2 plume may reach the current AoR boundary prior to the next schedule AoR reevaluation.

(4) Monitoring data indicate that CO_2 or other fluids have moved into a USDW, unless the movement is related to well integrity.

If any of these circumstances occur, the Permittee must notify the Director and perform the steps described in Section 1.4(B) above.

ATTACHMENT C: TESTING AND MONITORING PLAN

This Testing and Monitoring Plan describes the requirements for the Permittee pursuant to 40 CFR 146.90 and per Section N of this Permit. The monitoring data will be used to demonstrate that the well is operating as planned, the CO_2 plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs). The Permittee will also use monitoring data to evaluate the computational model to predict the distribution of the CO_2 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 trigger action according to the Emergency and Remedial Response Plan in Attachment F of this permit.

1.0 Carbon Dioxide Stream Analysis

The Permittee must analyze the CO_2 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 CFR 146.90(a). The Permittee must sample and analyze the carbon dioxide stream as presented below.

1.1 Sampling Location and Frequency

The Permittee must collect samples of the CO_2 stream at quarterly intervals. CO_2 stream will be obtained to analyze the constituents present in the injection stream. Samples of the CO_2 stream must be collected at a location in the system where the fluid is representative of the fluid injected (i.e., between the compression system and the Front Range 1-1 (FR 1-1) well), using a sampling port in the flowline.

1.2 Analytical Parameters

The CO_2 must be analyzed for the constituents identified in Table 1, which lists the specifications of the injected CO_2 stream. This analysis will ensure that the CO_2 stream composition entering the injection well is consistent with the expected composition.

Table 1: CO_2 Stream Analytical Parameters

Parameter	Analytical Method
CO_2 Purity	ISBT 2.0
Water (H2O)	ISBT 3.0
Total Hydrocarbons as Methane	ISBT 10.0
Total Non-Methane Hydrocarbon (TNMHC)	ISBT 10.1
Carbon Monoxide (CO)	ISBT 5.0
Ammonia (NH_3)	ISBT 6.0
Oxides of Nitrogen (NO_x)	ISBT 7.0
Nitrogen Dioxide (NO_2)	ISBT 7.1
Nitric Oxide (NO)	ISBT 7.2

Non-Condensable Gases:	
Nitrogen (N_2)	ISBT 4.0
Oxygen (O_2)	ISBT 4.0
Argon (Ar)	ISBT 4.0
Hydrogen (H_2)	ISBT 4.0
Helium (He)	ISBT 4.0

2.0 Continuous Recording of Operational Parameters

The Permittee must install and use continuous recording devices at the FR 1-1 to monitor wellhead and downhole formation injection pressure, mass flow rate, and volume (calculated); pressure on the annulus between the tubing and the long string casing; annulus fluid level; CO_2 stream temperature, and downhole formation temperature. (40 CFR 146.90(b), 146.88(e)(1), and 146.89(b)).

2.1 Monitoring Location and Frequency

Injection operations must be continuously monitored and controlled by the Permittee utilizing a process control system. The system must continuously monitor, control, record, and alarm for critical system parameters of pressure, temperature, and injection flow rate. The system must initiate a shutdown if specified control parameters deviate from the intended operating range and must allow for remote shutdown under emergency conditions. Trend analysis will be used in evaluating the performance (e.g., drift) of the instruments, indicating the need for maintenance or recalibration. Monitoring methods and frequencies are summarized in Table 2.

Table 2: Devices, locations, and frequencies for continuous monitoring

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection Pressure at Wellhead	Pressure Gauge	Wellhead	Every 10 sec.	Every 10 sec.
Injection Rate	Orifice Meter	Wellhead	Every 10 sec.	Every 10 sec.
Injection Volume (calculated)	Volumetric Flow meter & Flow computer	CO_2 Delivery Flowline	Every 10 sec.	Every 10 sec.
Annular Pressure	Pressure Gauge	Wellhead	Every 10 sec.	Every 10 sec.
Annulus Fluid Level	Level Transmitter	Wellhead	Every 1 min.	Every 1 min.
CO_2 Stream Temperature	Electronic Thermocouple	Wellhead	Every 10 sec.	Every 10 sec.
CO_2 Stream Temperature	Distributed thermal sensing system	Along outside of tubing	Every 10 sec.	Every 10 sec.
Injection Pressure at Formation	Pressure Gauge	Downhole gauge within 20 ft of top perforation	Every 10 sec.	Every 10 sec.

Temperature at Formation	Temperature Sensor	Downhole sensor within 20 ft of top perforation	Every 10 sec.	Every 10 sec.
Notes: • Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. • Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive).				

2.2 System Monitoring details

Injection operations parameters recorded on a continuous basis in Table 1 must be connected to the main facility through a supervisory control and data acquisition (SCADA) system to record the operations data, control injection rates, or initiate system shutdown, if needed.

Continuous recording devices must monitor wellhead injection pressure, temperature, and mass flow rate (40 CFR 146.90(b)). The injection flow rate will be directly measured at the surface to calculate the cumulative mass of injected CO_2 and ensure compliance with the permit injection limits. The injection volume will be calculated using the mass flow rate combined with the pressure and temperature conditions in the injection zone. The calculated injection volumes will, in turn, be used to update the computational models at regular intervals throughout the injection phase of the project as detailed in Attachment B.

The tubing – casing annular (TCA) pressure between the tubing and the injection casing string as well as the annular fluid volumes must also be monitored on a continuous basis (40 CFR 146.90(b)). The volume of the annulus fluid between the injection tubing and the long-string casing will be measured using the accumulator levels and the brine reservoir level on the well-control system. The accumulator and brine reservoir levels will be measured using a level transmitter. The transmitters will be connected to the well-control system and to the SCADA system. A significant change in the fluid volume in the accumulator or brine reservoir (i.e., fluid is being pumped from the reservoir to the annulus or fluid being pushed out of the annular space) during routine injection operations may be an indication of well integrity problems, as the fluid volumes would normally remain relatively constant, and will require further investigation.

Pressure differential between the annulus and the tubing at the depth of the packer will be calculated by the Permittee.

2.3 Injection Rate and Pressure Monitoring

The CO_2 injection pressure will be monitored on a continuous basis at the wellhead and downhole at the depth of the Lyons Sandstone Formation. If the downhole injection pressure exceeds 95% of the downhole maximum allowable injection pressure at any point, then the injection process will be automatically shut down per Attachments A and F of the Permit.

Any anomalies outside of the normal operating specifications may indicate that an issue has occurred within the well, such as a loss of mechanical integrity or blockage in the tubing or may be caused by a change in injection flow rate. Anomalous pressure measurements will trigger further investigation by the Permittee of the cause of the change. The downhole injection pressures will also be used to calibrate the computational modeling throughout the injection phase and PISC phase of the project.

The SCADA system will limit the downhole pressure to the MAIP listed in Attachment A of this permit. All injection operations will be continuously monitored and controlled by the Permittee using the SCADA system. This system must continuously monitor, control, record, and will alarm and shutdown if specified control parameters exceed their normal operating range. The operating conditions, parameters, limits, and alarm set points are found in Attachment A, Tables 1 and 2.

2.4 Calculation of Injection Volumes

The injection volume into the reservoir will be calculated on a continuous basis based on the injection mass and the pressure and temperature conditions in the injection zone. The volumetric flow rate of CO_2 injected into the well will be measured by a volumetric flow meter and flow computer. The flow computer will have digital output. The flow meter must be connected to the SCADA system for continuous monitoring and control of the CO_2 injection rate into the well. The flow meter will be calibrated at the frequency recommended by the manufacturer. The volume of CO_2 injected will be calculated from the mass flow rate obtained from the volumetric flow meter and flow computer. The mass flow rate will be calculated based on the pressure differential, temperature, and pressure data. This flow meter will be placed on the CO_2 delivery line downstream of the compressor.

2.5 Continuous Monitoring of Annular Pressure

The Permittee must 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 tubing casing annulus (TCA) will be filled with brine. The brine will have a specific gravity and a density that meets the requirements of the downhole conditions.
2. The TCA pressure, as measured at the wellhead, must be kept at a minimum of 100 pounds per square inch (psi) at all times. During injection, as measured at the wellhead, the TCA pressure must maintain a minimum of 100 above the tubing pressure. See Attachment A, Table 1.
3. 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.
4. 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.

After the initial standard annulus pressure test (SAPT), the annular pressure will be continuously monitored throughout the operational period in conjunction with the annular pressure monitoring and control system. The pressure on the annulus between the injection tubing and the long-string casing will be measured by an electronic pressure transducer with analog output that is mounted on the wing valve/annular fluid line connected to the wellhead of FR 1-1. The transmitter will be connected to the well control system and the SCADA system to regulate the annular pressure.

Sudden changes in the annular pressure during routine injection operations are a sign of potential tubing or tubing packer integrity issues that will trigger further investigation through mechanical integrity testing. As detailed in the Emergency and Remedial Response Plan, significant changes in the casing-tubing annular pressure will be investigated.

3.0 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), the Permittee 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.

3.1 Monitoring location and frequency

Monitoring must occur using corrosion coupons collected on a quarterly basis during the injection period and sent for analysis in accordance with NACE (National Association of Corrosion Engineers) Standard SP-0775-2023.

In addition to using corrosion coupons, the Permittee will conduct visual inspections of the well and evaluate monitoring data for potential fluid movement that could result from corrosion. Monitoring results will be documented and submitted to EPA as per 40 CFR 146.91(a)(7) and, if appropriate, 40 CFR 146.91(c).

Casing inspection logging will be conducted during planned well maintenance operations to evaluate downhole conditions and confirm absence of corrosion. Table 6 provides a summary of corrosion monitoring methods.

3.2 Sample description

Samples of material used in the construction of the compression equipment, flowline, FR 1-1 injection well, and FR 2-1 deep-zone monitoring 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 and Monitoring" below).

Table 3: List of equipment coupon with material of construction

Equipment Coupon	Material of Construction
Flowline	Stainless Steel
Long String Casing	13Cr85 Steel Alloy
Injection Tubing	13Cr95
Wellhead	Xylan coated iron

Packer	Permanent Nickel Alloy 925

3.3 Monitoring details

Samples of well construction materials (coupons) and monitoring well materials will be exposed to the injected CO_2 stream and monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs. Representative materials will be weighed, measured, and photographed prior to installation. Coupons will be analyzed in accordance with NACE Standard SP-0775- 2023 to determine and document corrosion wear rates based on mass loss. A summary of coupon parameters is shown in Table 4.

Table 4: Summary of Analytical Parameters for Corrosion Coupons.

Parameter	Analytical Method
Mass	NACE SP0775-2023[a]
Thickness	NACE SP0775-2023[a]

[a] NACE SP0775-2023: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations.

3.4 Casing Inspection Logs

Permittee will perform casing inspection logging (CIL) during planned well maintenance. Between planned maintenance events, Permittee may conduct CIL if corrosion coupon data indicates potential loss of material strength or performance inconsistent with operating standards.

3.5 Surface Detection Methods

The Permittee must visit the location on a routine basis, at least weekly, to make observations of surface equipment, identify potential leaks, and verify that equipment is operating within design limits. The Permittee will provide field personnel with handheld equipment to identify the presence of CO_2 as part of the safety requirements for the site.

The Permittee will perform additional optical analysis using OGI cameras quarterly during the injection period. OGI cameras use infrared images to detect gas leaks and will be used during the inspection of facilities and pipelines connected to the Class VI wells, and well locations.

4.0 Above and Below Injection Zone Groundwater Monitoring

The Permittee must monitor USDW groundwater quality and geochemical changes above and below the upper and lower confining zones, respectively, during the operation period to meet the requirements of 40 CFR 146.90(d). The Permittee must also monitor groundwater quality and geochemical changes in the USDWs (Entrada Formation and Ingleside Formation) adjacent to the injection zone and shallow groundwater wells, as well as pressure in these USDWs. Front Range 2-1 (FR 2-1) will be used to take fluid samples and monitor pressure changes in the Entrada and Ingleside Formation.

Pressure in the adjacent monitoring zones will be monitored from the wellhead. The gauge will record and transmit data to the SCADA system continuously.

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

Pressures in the FR 2-1 monitoring interval will be monitored at the wellhead. Migration of CO_2 or brine into the monitored formation would likely first be identified through pressure changes in the formation. An increasing pressure trend in the monitored zones would suggest that fluid movement across the confining zone has occurred. Any increasing trend in pressure will be evaluated, and an increase in pressure that deviates more than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid movement out of the injection zone. Such a change in pressure will initiate more frequent fluid sampling and analysis for aqueous geochemistry from the monitoring zones as well as additional external well integrity investigations for FR 2-1. Anomalous pressure or geochemical changes may trigger the need for additional well integrity testing for FR 2-1. Anomalous changes adjacent to the confining zone may also trigger the emergency response actions found in the Emergency and Remedial Response Plan in Attachment F.

If anomalous changes in aqueous geochemistry, such as pH, alkalinity, or dissolved solids, are observed in the monitoring interval, the Permittee must obtain new samples from the affected formation to verify the changes. Changes of greater than 25% in the value of the above parameters, not attributable to natural or seasonal fluctuations, will require the Permittee to acquire new samples. Changes in these parameters may also trigger the need for analyses of isotopic compositions.

4.1 Monitoring location and frequency

The shallow groundwater monitoring program will use nine shallow groundwater wells spatially distributed at six locations within the AoR in near surface groundwater aquifers, and the FR 2-1 is the dedicated groundwater monitoring well that has been drilled into the lowermost USDW (40 CFR 146.90(d)).

Baseline shallow groundwater quality samples has been collected from existing shallow groundwater wells within the AoR to characterize the seasonal variations in groundwater quality within the AoR. The project will have surface access rights to the land to sample the shallow groundwater wells as part of the landowner leases for the project.

Front Range 2-1 is monitoring well for the Lyons Sandstone injection interval and USDWs immediately above and below the injection zone. The well will provide direct measurements of pressure and fluid composition in the Lyons and in the first USDWs above (Entrada) and below (Ingleside), as well as indirect geophysical measurements of the CO_2 plume. Its location is between the modeled Year 5 and Year 8 plume perimeters and outside the Year 12 pressure front, allowing early plume detection while minimizing pressure-driven risk to USDWs.

Table 5 lists all groundwater sampling well locations and Figure 2 shows the distribution of the groundwater wells within the AoR including the location of Front Range 2-1.

Table 5: Groundwater sample wells

Target Formations	Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
Alluvial aquifer (water table aquifer), Upper Pierre (Commonly used USDW)	Groundwater Quality	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3, DMW-3 SMW-4 SMW-5 SMW-6	Grid of single point measurements within the AoR/MMA and vicinity	Pre-Injection	Continuous
				Injection	Continuous
				PISC	Initial: Continuous Maintenance: Data Loggers Only
Alluvial aquifer (water table aquifer), Upper Pierre (Commonly used USDW)	Geochemical Monitoring	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3, DMW-3 SMW-4 SMW-5 SMW-6	Grid of single point measurements within the AoR/MMA and vicinity	Pre-Injection	Quarterly
				Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annual
				PISC	Initial: Annual Maintenance: Every 5 years
Entrada Sandstone (First USDW above injection zone), Ingleside (First potential USDW below injection zone)	Geochemical Monitoring	Front Range 2-1	Single point measurements	Pre-Injection	Quarterly
				Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annual
				PISC	Initial: Annual Maintenance: Every 5 years

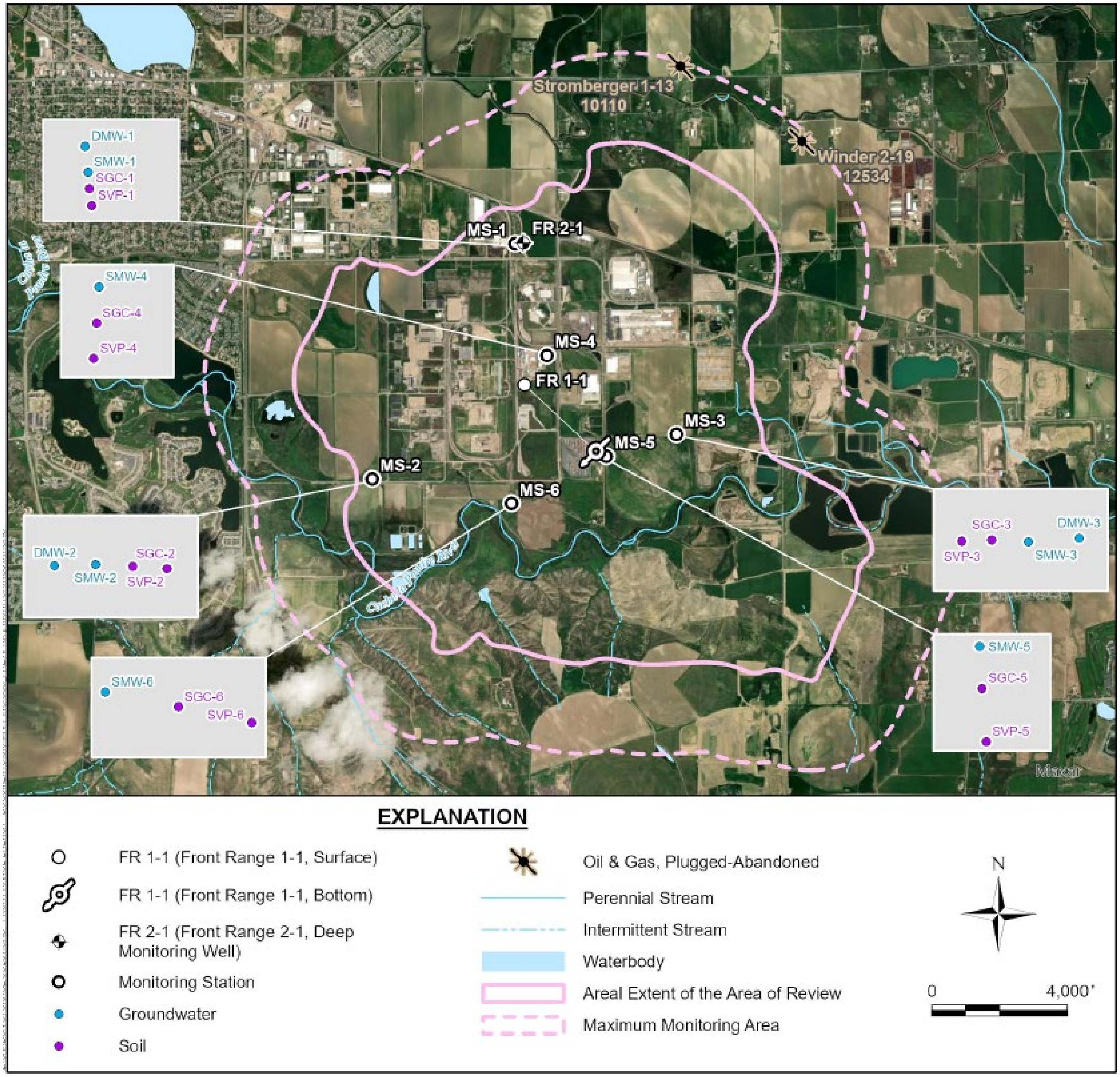


Figure 2. Front Range 1-1 monitoring well and shallow groundwater wells within the AoR.

4.2 Groundwater sampling

Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry analyses will be compared to the baseline conditions for any indication of CO_2 or formation fluid migration into the shallow groundwater aquifers or a USDW. If indications of CO_2 or brine are found in the shallow groundwater aquifer, it will trigger the emergency response actions found in the Emergency and Remedial Response Plan in Attachment F. If collected water samples during monitoring show anomalous changes in geochemical parameters, such as pH, alkalinity, or dissolved solids, the samples will be further analyzed for a change in isotopic composition.

4.2.1 Sampling Schedule

During the injection phase of the project, fluids from these wells will be sampled according to the frequency found in Table 5 to identify any changes to parameters for aqueous geochemistry.

The schedule of sampling is as follows:

1. Continuous: Data is continuously sampled and recorded per the frequencies presented in this attachment.
2. Quarterly: Sampling will take place within 5 days before the following dates each year: March 31st, June 30th, September 30th, December 31st.
3. Semi-annual: Sampling will take place within 5 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 the PISC period.

4.2.2 Sampling and analytical methods

During pre-operational testing, the carbon isotopic composition of the CO_2 stream, the USDWs, and the fluids of the monitored zones, will be measured to determine baseline values.

Groundwater monitoring samples will be collected according to Section E.I.2.2 of the QASP of the permit application. Prior to sample collection the well will be flushed to remove stagnant water from the well and ensure representative water is collected from the formation. The fluid removed from the well will be monitored for the field parameters listed in Table 8. Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Sample handling and custody will be performed as described in Section E.I.2.3 of the QASP. Quality Control (QC) will be ensured using the methods described in Section E.I.2.5 of the QASP.

Table 6: Summary of parameters and analytical methods for groundwater samples

Parameters	Analytical Methods
Formation: Pierre Shale	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K,v Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric Titration

Parameters	Analytical Methods
	ASTM D513-11
Total Dissolved Solids	Gravimetry APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Formation: Entrada	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric Titration
	ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Formation: Ingleside	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B

Parameters	Analytical Methods
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric Titration ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Once the project has established baseline conditions, the Permittee may submit a request to the Director to reduce monitoring to a subset of analytes that are most likely to change as a result of interactions with CO_2. Upon the Director's approval, that subset of analytes supplants the analytes listed in Table 6.

4.2.3 Laboratory to be used/chain of custody procedures

Final laboratory selection has not been made at this time. The laboratory selected will meet all requirements set forth in the Testing and Monitoring Plan and the QASP. The Chain-of-Custody procedures will follow the requirements of Section E.I.2.3 of the QASP.

4.3 Monitoring Summary of Monitoring Well Requirements

Table 7 provides a summary of the groundwater and soil/gas monitoring wells and their monitoring requirements and frequencies.

Table 7: Front Range Storage Complex Groundwater Monitoring Wells

Well Type	Objective	Method	Frequency
Front Range 2-1	Direct monitoring of CO_2 plume	Downhole saturation/resistivity logs (pulsed neutron, RST); time-lapse logging in the injection interval	Annually

	Direct monitoring of the pressure front	Downhole pressure gauges; pressure transient analysis (falloff/buildup); fiber-optic distributed thermal sensing	Continuous
	Direct measurement of fluids to detect CO_2	Downhole/fluid sampling; PVT and geochemical analysis	Attachment C- Table 5
	Internal mechanical integrity	Mechanical Integrity Tests (MIT), annulus pressure monitoring, casing/tubing leak tests, packer seal verification	Continuous
	External mechanical integrity	Cement bond logs, ultrasonic imaging, temperature/noise logs, radioactive tracer logs	Annual
	Corrosion monitoring	Corrosion coupons/probes	Quarterly
		Fluid corrosivity testing (pH, chloride, O2); inhibitor performance tracking	Continuous
Groundwater Monitoring Wells (SMW and DMW Wells)	Groundwater Analysis		
	Geochemical and isotopic monitoring to detect CO2	Groundwater sampling for pH, alkalinity, conductivity, major ions, DIC, dissolved gases; isotopes (e.g., δ13C)	Attachment C – Table 5
Soil Gas Monitoring Wells; Surface Air Monitoring Wells	Surface leak detection	Soil gas sampling/continuous CO_2 sensors; flux chambers; open-path laser/infrared for CO_2	Attachment C – Table 10
Seismic Monitoring Well	Indirect monitoring of CO_2 plume	Time-lapse 3D/4D seismic;	Attachment C – Table 9
	Indirect monitoring of CO_2 presence above the Injection Zone	Time-lapse seismic and EM to detect any CO_2 above caprock; crosswell surveys across confining unit	Attachment C – Table 9

<u>Reporting procedures</u>

The Permittee must report the results of all testing and monitoring activities to the EPA in compliance with this attachment, the requirements under 40 CFR 146.91, and Section O of this Permit.

5.0 Internal and External Mechanical Integrity Testing

Permittee must conduct tests to verify the internal and external mechanical integrity of the injection well and the FR 2-1 monitoring well before and during the injection phase pursuant to 40 CFR 146.87(a)(4), 40 CFR 146.89, 40 CFR 146.90(e), and 40 CFR 146.92(a).

The purpose of internal mechanical integrity testing is to confirm the absence of significant fluid movement within the injection tubing, casing, or packers (40 CFR 146.89(a)(1)). Continuous monitoring of injection pressure and pressure will be used to demonstrate internal mechanical integrity. In addition, annulus pressure tests will be conducted at the frequencies listed in Table 8 to demonstrate internal mechanical integrity.

The purpose of external mechanical integrity testing is to confirm the absence of significant fluid movement or fluid movement outside of the casing into or between USDWs (40 CFR 146.89(a)(2)). Permittee will conduct logging using an approved MIT-2 method in the injection well and deep monitoring well on an annual basis to demonstrate external mechanical integrity. Permittee may choose which logging and testing to demonstrate mechanical integrity but must continuous to use that same test for the remainder of the project.

Well logs and tests must be performed according to EPA approved procedures. It is the responsibility of the Permittee to obtain and use these procedures prior to conducting any well logging or test required as a condition of this Permit. These procedures can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy. Well logging and testing procedures must be submitted to the Director prior to conducting any well log or test.

Well logs and test results must be submitted to the Director within 30 calendar days of the logging or testing activity completion and must include a report describing the methods used during logging or testing and an interpretation of the log or test results by a knowledgeable log analyst. When applicable, the interpretative report must also include detailed analysis of: (1) USDWs and adjacent confining zone(s) and (2) the injection zone and adjacent confining zone(s).

5.1 Mechanical Integrity Testing Location and Frequency

The tables below provide a summary of the internal and external mechanical integrity monitoring methods and MIT plans in the injection well and monitoring well (Table 8).

To demonstrate internal mechanical integrity of the injection well(s), the Permittee will perform annulus pressure tests during well construction, prior to injection, and after any well maintenance operations which affects the tubing, packer, or casing. Annulus pressure monitoring will be performed on well(s) during construction and continuously thereafter. Additional testing will be conducted if the pressure or temperature data collected from gauges indicate a potential loss in mechanical integrity as determined by the Director.

The Permittee must demonstrate external mechanical integrity on the injection well, at a minimum on an annual basis, using an approved test such as an oxygen-activation, temperature or noise log (40 CFR 146.98).

Table 8: Mechanical Integrity Test and Monitoring Descriptions, Location, and Frequency

Test Description	Well	Measurement Location	Frequency
Standard Annulus Pressure Test (SAPT)	FR 1-1 Wellhead		Prior to Authorization to Inject & after workover and loss of MI
	FR 2-1 Wellhead		
Annular Pressure and Temperature Monitoring	FR 1-1	Surface	Continuous
	FR 2-1	Surface	Continuous
Temp/Noise/OA [1]	FR 1-1		Annually [2]
	FR 2-1		Annually [2]

[1] Permittee can determine the MIT-2 test, but must continue to use the same test for the remainder of the project life.
[2]At least once every 12 months after last successful test

5.2 Mechanical Integrity Test Procedures

The following testing procedures are testing protocols expected to be used by the Permittee. The following procedures are approved by the Director for use 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.

Description of Methods

Internal Mechanical Integrity Using Annulus Pressure Tests

An annulus pressure test is a common method to demonstrate internal mechanical integrity. The test assumes that pressure applied to fluids in the annulus space should be constant unless there are significant changes in temperature or a fluid leak.

The steps in the annulus pressure test procedure are as follows:

- Shut in the well to stabilize the pressures.
- Connect the testing equipment to the annulus valves and test surface lines to 1,500 psi above the testing pressure.

- Ensure there are no surface leaks from the pumping unit to the wellhead valve.
- Bleed any air in the system. If necessary, fill the annulus space with packer fluid and corrosion inhibitor.
- Record the initial tubing and casing pressure. The well's casing will be tested to at minimum 200 psi in the annulus space, and the pressure should not decrease more than 5% in 30 minutes.
- Monitor the tubing and casing pressures continuously. Record the final tubing and casing pressure, then bleed the pressure and volume. If the pressure decreases more than 5%, bleed the pressure, test the surface connection, and repeat the test. If there is an indication of mechanical failure, the Permittee must notify the Director within 24 hours.

External Mechanical Integrity Testing Using Logging Tools

Permittee will use logging tools such as oxygen-activation log; or a temperature or noise log (see 40 CFR 146.89(c)). These tools will be used to demonstrate external mechanical integrity.

6.0 Pressure Fall-Off Testing

A pressure fall-off test (PFOT) will be conducted in the Lyons Sandstone Formation in FR 1-1 after it is drilled to establish the hydrogeologic characteristics of the injection zone (see Attachment G). Permittee will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f). Pressure fall-off testing will be performed on FR 1-1 during system operation at least every 5 years. The formation characteristics obtained through the PFOT will be compared to the results from previous tests to identify any changes over time, and they will be used to calibrate the computational models.

6.1 Pressure Fall-off Test Procedure

1. Injection of characteristic 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 will be at a rate that is representative of the injection rate for normal operations, at a constant rate ±5%.
3. The pressure gauge utilized for the pressure transient test must have been calibrated no more than one year prior to the test date.
4. The permanent downhole pressure gauges set above the packer will be used for the PFOT. Surface monitoring equipment will be used to monitor injection data for the test.
5. Following at least one hour of pressure data collection during injection, the well will be shut-in at the wellhead, 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 kh and extrapolation of pressure to infinite shut-in time is possible, or if boundary effects are observed.
8. The test must include a written report by a knowledgeable well test analyst. Such report must explain any anomalies shown in the results and comparison to the previous tests.
9. The test report must include an up-to-date well schematic, a copy of the dated calibration certificate for the gauge utilized, and digital pressure data on CD/flash drive/email in a spreadsheet format.
10. The test report must 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 must also include a tabulation of values for the following test specific parameters: test start date/time, test end date/time, test length (hrs), 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) must be specified.
11. The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.

7.0 Carbon Dioxide Plume and Pressure Front Tracking

Permittee will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure throughout the life of the project to meet the requirements of 40 CFR 146.90(g)(1) and (2). A summary of the methods used for CO_2 and pressure front tracking is provided in Table 9 below.

7.1 Monitoring Location and Frequency

The Lyons Formation Injection Zone will be directly monitored using Front Range 2-1 monitoring well. The monitoring well was drilled prior to the commencement of CO_2 injection and is located within the Area of Review.

The tracking methods are summarized below, and Table 9 describes how the monitoring methods will be utilized throughout the Project. Quality assurance procedures for these methods are presented in the QASP.

Direct tracking methods include:

- Geochemical monitoring of fluids in the Injection Zone and shallow fluids and gases.

- Pressure and temperature measurements from the Injection Zone and the first permeable layer above the confining zone.

Transducers placed in the injection zone behind casing.

- Direct measurement of fluid depth in the well.

- Indirect tracking methods include:
- Estimation of CO_2 saturation using Pulsed Neutron Logging in the monitoring well(s).
- Calibration of the computational model for the AoR re-evaluation.

Table 9: Direct and Indirect Methods and Sampling Frequencies for Tracking the CO_2 Plume and Pressure Front.

Direct Methods				
Objective	**Method**	**Frequency Pre-Injection**	**Frequency Injection**	**Frequency Post-Injection**
Measure geochemical composition of the Injection Zone	Fluid and dissolved gas sampling in FR 2-1 well	Sampling to establish baseline	Quarterly/ Semi-Annual/ Annual (See Att C, Table 5)	Every 5 years
Measure P/T of the Injection Zone	P/T using gauges in injection and monitoring wells	Measurement to establish baseline	Continuous	Continuous
Measure geochemical composition above and below the confining zone	Fluid and dissolved gas sampling in FR 2-1 well	Sampling to establish baseline	Quarterly/ Semi-Annual/ Annual (See Att C, Table 5)	Every 5 years
Indirect Methods				
Objective	**Method**	**Frequency Pre-Injection**	**Frequency Injection**	**Frequency Post-Injection**
Estimate CO_2 saturation in the Injection Zone	Pulsed Neutron	Logging for baseline	Yearly	Every 5 years
Estimate CO_2 plume and pressure extent in the Injection Zone	Vertical Seismic Profile	Once	Every 5 years, plus once at the end of phase	Every 5 years plus once at the end of phase

7.2 Description of Methods

The direct and indirect tracking methods described in this document meet and/or exceed the requirements of the Testing and Monitoring Plan established in the UIC Class VI Rule. Additional new technologies may be considered in coordination with the Director and may be added to the Plan if approved. Any amendments to the Plan must be approved by the Director and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

Fluid and dissolved gas sampling will be conducted to constitute a baseline. These samples will be analyzed for their geochemical composition and isotopic characterization. If anomalous pressure and/or temperature changes are observed in an injection and monitoring wells during injection or post-injection, fluid samples and/or dissolved gas samples will be obtained for geochemical and isotopic analysis and compared with pre-injection samples.

Downhole and surface gauges for pressure and temperature are installed in the Front Range 2-1 well.

7.2.1 Geochemical Monitoring

Geochemical monitoring will be employed in Front Range 2-1 monitoring well to monitor the injection zone and adjacent USDWs above and below. These data will be compared with the pre-injection geochemical and isotopic characterization to evaluate whether changes are observed. If changes are measured, then Permittee will assess whether the compositional changes are likely to be the result of naturally occurring biological processes or another source. If sampling results indicate a potential migration of the CO_2 stream or formation fluids from the injection zone into a USDW, or other unauthorized zone, the Permittee must notify the Director within 24 hours.

7.2.2 Pressure and Temperature Monitoring

Pressure and temperature gauges will be deployed on the tubing above and below the injection packer to monitor downhole conditions in real time. In the Front Range 2-1 well, the gauges and cables will be selected to withstand CO_2 service conditions as determined by the Permittee or Director. Permittee will routinely evaluate the data and interpret the results. If a sudden change in pressure or temperature is recorded, Permittee will immediately cease injection, notify the Director within 24 hours, and evaluate and identify the cause of the change. Additional details on downhole gauge instrumentation are described in the QASP.

7.2.3 Saturation Detection Tool Method

Pulsed neutron logging (PNL) will be run in FR 2-1 to monitor CO_2 saturations and vertical plume development adjacent to the wellbore annually. The PNL data will be used to verify when the leading edge of the CO2 plume reaches the observation well. This logging can also be used to identify the presence of CO2 above the confining zone should there be fluid movement along the wellbore.

7.3 Seismic Methods

Permittee will use time-lapse Vertical Seismic Profiling (VSP) as the indirect geophysical method to image CO_2 plume evolution in the Lyons Sandstone. Fiberoptic sensors deployed in the wellbore provide dense, high-fidelity measurements close to the reservoir, and two semipermanent seismic sources (SensorEra helical pile sources) installed on accessible surface locations will generate repeatable signals for timelapse acquisition. Baseline data are processed to build a reference model; repeat surveys are then differenced against the baseline to track amplitude, frequency, phase, and time delay changes indicative of fluid substitution in the reservoir. Modeling and raytracing show that with sources ~5,500 ft from the injection well, the plume can be imaged for at least five years to the northwest and northeast from the injection well fiber, with additional coverage achievable by leveraging fiber in the monitoring well; coverage is more limited to the southeast and southwest due to well deviation. The VSP program is designed to provide early time plume delineation and support history matching the reservoir model as injection proceeds across the MMA and vicinity.

7.3.1 Timing of Baseline and Repeat Seismic Acquisition

- Baseline: Acquire a single pre-injection baseline VSP over the MMA and vicinity to establish the reference seismic state prior to CO2 injection.
- Injection period repeats: The Testing and Monitoring Plan schedules time-lapse VSP every five years during injection, plus one survey at the end of the injection period. Appendix E-1 also notes that acquisitions could be performed annually during the first three years of injection to identify which seismic attributes best highlight the plume front and early expansion; after this early evaluation period, the frequency can be adjusted to align with the observed plume expansion rate. Where operational coordination is helpful, repeat campaigns can be aligned with the project's annual CO2 supply outage to minimize interference with injection operations
- PISC repeats: Continue time-lapse VSP every five years during PISC, with one survey at the end of PISC to confirm stability prior to site closure, consistent with the plan's schedule .

8.0 Near-Surface Soil and Soil Gas Sampling *[40 CFR 146.90(h)]*

The primary objectives of near-surface soil and soil gas monitoring are to confirm containment of CO_2 within the Lyons Formation, and to provide early detection of anomalous conditions indicative of potential fluid movement of CO_2 or brine migration, for the ultimate objective of detecting fluid movement that could endanger a USDW.

8.1 Monitoring Location and Frequency

Subsurface soil gas probes will be installed at approximately six (6) representative locations throughout the AoR shown in Table 10.

The Permittee will collect and analyze soil gas samples for gas and isotopic parameters prior to CO_2 injection to determine a characteristic profile for the site. During the injection phase, soil gas will be monitored for gas composition between year one and 32 thereafter. If anomalous pressure and/or temperature changes are observed in the nearby Front Range 1-1 or injection zone monitoring well(s), or there is any indication of fluid movement through the injection well, additional soil gas samples will be collected for gas composition and/or isotopic analysis and comparison to pre-injection sample results.

Table 10: Soil Gas Monitoring Locations and Frequency

Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
Monitor soil gas CO_2 across a network of stations	SCSW-1 SCSW-2 SCSW-3 SCSW-4 SCSW-5 SCSW-6	Single point measurements within AoR/MMA and vicinity	Pre-Injection	Continuous(1)
			Injection	Continuous(1)
			PISC	Initial: Continuous(1) Maintenance: Continuous(1) (data logger only)
Laboratory Analysis of Samples from Network of Stations	SVP-1 SVP-2 SVP-3 SVP-4 SVP-5 SVP-6	Single point measurements within AoR/MMA and vicinity	Pre-Injection	Quarterly
			Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annually
			PISC	Initial: Annually Maintenance: Every 5 years
CO_2 Efflux Measurements at Each Station	MS-1, MS-2, MS-3, MS-4, MS-5, MS-6	4x4 grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Quarterly
			Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annually
			PISC	Initial: Annually Maintenance: Every 5 years

Note 1: Continuous is defined as measurements taken at 30-minute intervals, with a 6-hour averaged reading recorded

8.2 Description of Methods

Soil gas in the near-surface and groundwater composition in shallow wells have considerable variation due to natural processes. Monitoring both soil gas and fluid composition at multiple subsurface levels is a more reliable leak monitoring method. Analytes and analytical methods to derive them are listed in Table 11.

Table 11: Summary of analytes and methods for soil gas samples

Analyte	Analytical Method
Argon	ASTM D1945 modified or similar/equivalent
Oxygen	ASTM D1945 modified or similar/equivalent
Nitrogen	ASTM D1945 modified or similar/equivalent
Carbon Dioxide	ASTM D1945 modified or similar/equivalent
Methane	ASTM D1945 modified or similar/equivalent
δ^{13} C of CO_2	SRI 8610C
Methane - field	Field meter (Landtec - GM500 or equivalent) - dual wavelength infrared cell with reference channel
Carbon Dioxide - field	Field meter (Landtec - GM500 or equivalent) - dual wavelength infrared cell with reference channel
Oxygen - field	Field meter (Landtec - GM500 or equivalent) - internal electrochemical cell
Carbon Monoxide - field	Field meter (Landtec - GM500 or equivalent) - internal electrochemical cell
Hydrogen Sulfide - field	Field meter (Landtec - GM500 or equivalent) - internal electrochemical cell

9.0 Seismicity and Fault Monitoring

9.1 Monitoring for Natural and Induced Seismicity

Based on information available from the United States Geological Survey (USGS) seismic monitoring network, the Front Range Storage Complex Project area does not show high seismic activity that could endanger the containment of the CO_2 in the storage complex. Seismic history is discussed in more detail in the AoR and Corrective Action Plan (Attachment B of this Permit).

The Permittee will monitor the site with a seismic monitoring system for the duration of the Project through site closure to ensure the protection of USDWs, while also ensuring the safe operation of both the storage facility and adjacent infrastructure in the area. The seismic monitoring will be conducted with a surface array deployed to ensure detection of events above Moment magnitude (Mw) 1.0, with epicentral locations within 100 miles of Front Range 1-1.

If an event is detected, the Permittee will implement the response plan defined below to eliminate or reduce the magnitude and/or frequency of seismic events. Refer to the Emergency and Remedial Response Plan (Attachment F of this Permit) for action thresholds and specific steps.

9.2 Seismicity Monitoring Network

Permittee will implement a seismic monitoring plan to identify seismic risks and use the results of the seismic monitoring program to guide the respond to seismic events as described in Section H.4.5 of the Emergency and Remedial Response Plan. The monitoring and response plans are both aligned with seismic action plan used by the State of Colorado for the regulation of Class II wells.

The United States Geological Survey (USGS) network will be continuously monitored during Injection for validated triggering events. A triggering event is defined as a seismic event of greater than 2.5 local magnitude (ML) with an epicenter within 2.5-miles of Front Range 1-1. A validated triggering event is a triggering event that has been validated by USGS staff and added to their seismic event database. The response to triggering and validated triggering events is defined in Attachment F, Section 4.6 of the Emergency and Remedial Response Plan.

10.0 Reporting Requirements

The Permittee must report to the Director all testing and monitoring performed pursuant to this Permit and 40 CFR 146.90 and 146.91, in the manner and on the schedule specified in Table 12. Unless otherwise specified, discrete test results (e.g., mechanical integrity tests, injectate analyses, tracer tests) must be submitted within thirty (30) calendar days of completion of the test, including supporting data, methods, calibrations, and interpretations sufficient for Director review.

Table 12: Summary of Monitoring Activity and Reporting Frequencies

ACTIVITY	REPORTING FREQUENCY
CO2 stream characterization	Semi Annual
Flow rate, mass, annulus pressure, annulus fluid level, and temperature	Semi Annual
Injection Pressure at the Wellhead	Semi Annual
Injection Pressure at the Injection Zone	Semi Annual
Injection Zone Fluid Monitoring	Semi Annual
Corrosion monitoring	Semi Annual
External MIT	Semi Annual
Pressure Fall-off Test	Semi Annual
Pulse Neutron Logging	Semi Annual

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 D: WELL PLUGGING PLAN

This attachment includes the enforceable well plugging plan required by 40 CFR 146.92 and requirements for plugging all monitoring wells, in accordance with CFR 146.93(e). The Front Range 1-1 injection well will transition to a monitoring well after the 12 years of injection. After the Director has approved the site closure request from the permittee, all monitoring wells must be plugged and abandoned.

1.0 Tests or Measures to Determine Downhole Reservoir Pressure

1. Casing in the Front Range 1-1 injection well and Front Range 2-1 monitoring well have been cemented to the surface and will not be retrievable upon abandonment. After injection has permanently ceased, the injection tubing and packer must be removed.
2. Before beginning the plugging process, the pressure needed to conduct cementing will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as weighted displacement fluids, must be over-balanced to ensure that no reservoir fluids will enter the wellbore during cementing operations.
3. The wells must be flushed with kill fluid. Kill fluids must be 10 pounds per gallon sodium chloride (NaCl) brine. A minimum of three tubing volumes must be injected without exceeding the formation fracture pressure.
4. Downhole pressure measurements must be taken using downhole gauges. In the event installed gauges are not functioning properly, the Permittee must run a pressure gauge during the plugging and abandonment process.

2.0 Mechanical Integrity Tests

The Permittee must conduct final external mechanical integrity tests (MIT) prior to plugging as required by Section L.2(f) of this Permit and by 40 CFR 146.92(a). A temperature survey, noise log, or another approved external MIT log (Table) must be run over the entire depth.

Table 1: External Mechanical Integrity Tests

Test Description	Location
Temperature Log (external MIT)	Injection and Deep-Zone Monitoring Well
Pulse neutron log (external MIT)	Injection and Deep-Zone Monitoring Well
Noise log (external MIT)	Injection and Deep-Zone Monitoring Well
Annulus pressure test (internal MIT)	Injection and Deep-Zone Monitoring Well

If a failure in the long string casing is identified, the Permittee must repair the issue before plugging for Director review and approval.

3.0 Information on Plugs

1. Permittee must use the materials and methods listed in Table 2. the Injection Well. The cement formulated for plugging must be compatible with the CO_2 stream. The cement formulation, including details of all proposed additives and their quantities (%, wt-wt, wt-vol, etc.), and required certification documents will be submitted to the Director with the Injection Well Plugging Plan. The Permittee must report the wet density and will retain duplicate samples of the cement used for each plug.

2. In plugging procedures, no more than 2 plugs will be placed before a period of time is allowed for cement to cure. The curing time for the CO_2-resistant plugs will be determined at time of operation via laboratory testing in compliance with API 10B2 (Testing of Oilwell Cements). Permittee utilizes industry-recognized thresholds of 50-psi compressive strength to pressure test and 500-psi compressive strength for physically tagging. Compressive strength of 500 psi (or greater) will be achieved for plugging slurries and will be reached in <48 hours after placement. All plug mud will be 10 ppg NaCl brine with lime added at 1.0 ppb (pounds per barrel) to raise the pH to >10.5 to combat corrosion, H_2S, and CO_2 contamination. Xanthan gel will be added to the mud so that the viscosity is >50 sec/qt.

3. A standard Portland cement blend will be designed with a minimum 1,000-psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G Portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. The wells will have this cement placed as detailed in Table , and any portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud.

Table 2: Plugging Details

Plug Information	Squeeze Cement	Plug #1 (Lifts 1-6)	Casing Cement	Plug #2 (Lifts 8 – 19)
Diameter of boring in which plug will be placed, inches	6.184	6.184	8.835	6.184
Depth to bottom of tubing or drill pipe, feet	9,746	9,746	9,398	9,746
Sacks of cement to be used	60	576	831	1,053
Slurry volume to be pumped, cubic feet	75	757	954	1,208
Slurry weight, pounds per gallon	15	15	15.8	15.8
Calculated top of plug, feet	9,370	6,030	0	0
Bottom of plug, feet	9,660	9,370	5,990	5,990
Calculated top of plug, Elevation ft above MSL	-4,618	-1,278	4,752	4,752
Bottom of plug, Elevation ft above MSL	-4,908	-4,618	-1,238	-1,238
Type of cement or other material	CORROSACEM (CO_2 Resistant)	CORROSACEM (CO_2 Resistant)	HALCEM	HALCEM
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Squeeze Cement	Balanced Plug	Retainer	Balanced Plug

ft above MSL = feet above mean sea level elevation referenced to the North American Datum of 1983

Note:. The plugging procedure will be updated as required by 40 CFR 146.92(b).

4.0 Narrative Description of Plugging Procedures

4.1 Notifications, Permits, and Inspections

In accordance with 40 CFR 146.92(c) and Permit Section O.3, Permittee must notify the Director in writing at least 60 days before plugging Front Range 1-1 and Front Range 2-1 and provide a revised Injection Well Plugging Plan, if applicable. Once plugging is completed, Permittee must submit to the Director a final plugging report for each well plugged and retain the report for 10 years following site closure (40 CFR 145.92(d)).

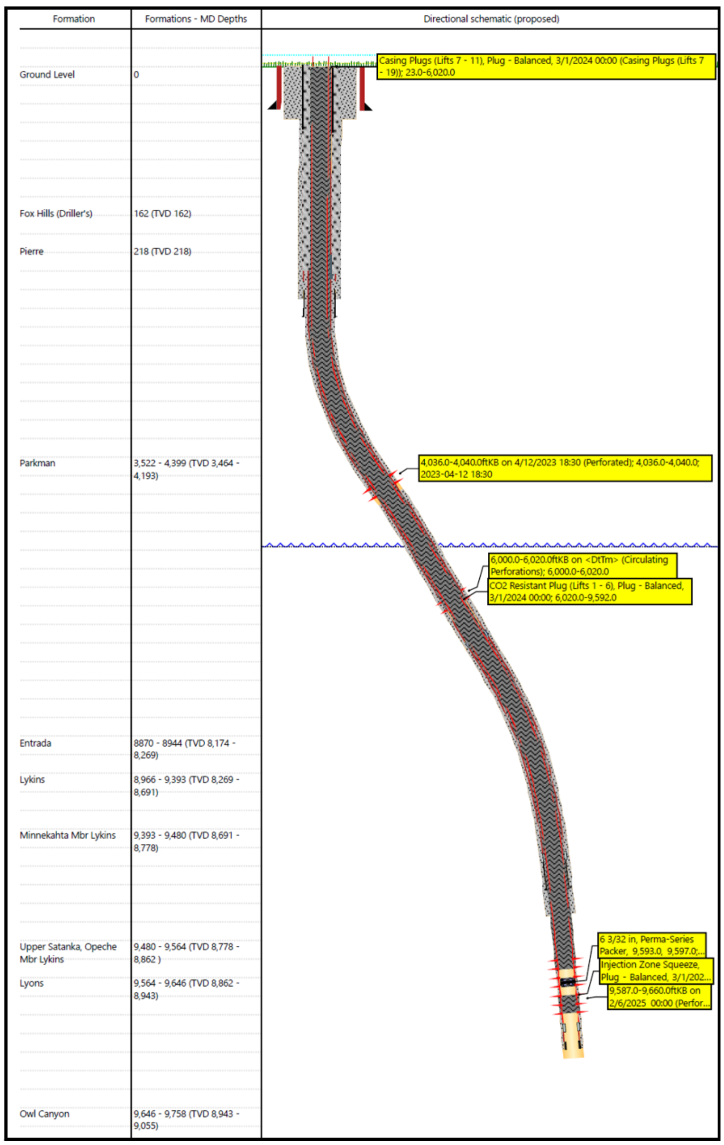
4.2 Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all equipment is removed. The plug placement method may vary depending on the type of service equipment used.

1. Notify the regulatory agency at least 60 days before plugging the well and provide an updated plugging plan if applicable.
2. Move-in (MI) rig onto Front Range 1-1 and rig up (RU). Ensure all CO2 pipelines are marked and noted with the rig supervisor prior to MI.
3. Conduct and document a safety meeting.
4. Record bottom hole pressure from downhole gauge and calculate kill fluid density.
5. Open all valves on the vertical run of the tree and check pressures.
6. Test the pump and line to 5,000 psig. Fill tubing with kill weight brine (10.1 ppg or as determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system.
7. Test casing annulus to 500 psig and monitor as in the annual mechanical integrity test (MIT). Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).
8. If the well is not dead or pressure cannot be bled off of the tubing, rig up (RU) slickline and set plug in lower profile nipple below the packer, then bleed off pressure.
9. Flush well with a kill weight brine fluid without exceeding formation fracture pressure.
10. Perform bottom hole pressure measurements and log and pressure test the well to ensure mechanical integrity. If mechanical integrity is lost, make repairs prior to continuing plugging activities.
11. Remove internal tubing as part of abandonment.
12. Use squeeze cements, casing circulations, and balanced plugs to plug the well.
13. Use CO2-resistant cement for the squeeze cementing of the injection interval and subsequent lifts. After abandoning the bottom interval, perforate the 7-inch casing and circulate cement to surface in the annular space.
14. Cement the rest of the 7-inch casing to the surface.
15. Top off the well with cement from the surface.

16. Nipple down (ND) blowout preventers (BOPs) and cut all casing strings below the plow line (minimum 3 feet below ground level or per local policies/standards).
17. Clean the cellar to allow a plate with the well name to be welded onto the lowest casing string at a depth of roughly 3 feet, or as per permitting agency directive.
18. Submit the completed plugging forms with charts and all lab information to the regulatory agency as required by the permit. The plugging report must be certified accurate by Permittee and the plugging contractor and submitted within 60 days after plugging is completed.

Figure 1: Front Range 1-1 well plugging schematic



5.0 Plugging Plan for Front Range 2-1 Monitoring Well

The permittee must plug the Front Range 2-1 monitoring well in accordance with the approved monitoring Well Plugging Plan and the requirements of 40 CFR §§146.92 and 146.93. Plugging operations must be conducted in a manner that prevents the movement of fluids into or between underground sources of drinking water (USDWs) and ensures long-term isolation of the injection zone and other permeable formations penetrated by the wellbore.

Prior to plugging, the permittee must stabilize the well and verify that formation pressures have been controlled. Tubing, packers, and other completion equipment must be removed to allow proper placement of cement plugs. The permittee must evaluate the mechanical integrity prior to placement of cement plugs.

Cement plugs and squeeze cementing operations must be placed at appropriate intervals to isolate the injection zone and other permeable formations encountered by the well. Cement used in the lower portion of the well (approximately the bottom 1,500 feet) must be formulated to resist corrosive conditions associated with carbon dioxide, including exposure to CO_2 and carbonic acid. The remaining portions of the well can be plugged using Class G cement suitable for well abandonment.

The final plugging configuration and procedures may be modified based on information obtained during well operations, logging, and testing. Following completion of plugging activities, the permittee must submit a final plugging report to the Director

Table 3. Plugging plan for Front Range 2-1.

Plug Information	Plug #1 (Lift & Squeeze)	Plug #2 (Lift & Squeeze)	Plug #3 (Lift & Squeeze)	Plugs #4 - #16
Diameter of boring in which plug will be placed, inches	6.18	6.18	6.18	6.18
Depth to bottom of tubing or drill pipe, feet	9,380	9,380	9,380	9,380
Sacks of cement to be used	104	187	82	1937
Slurry volume to be pumped, cubic feet	142	282	124	2,925
Slurry weight, pounds per gallon	14.5	14.5	14.5	14.5
Calculated top of plug, feet	8,890	8,230	7,800	0
Bottom of plug, feet	9,380	8,890	8,230	7,800
Calculated top of plug, Elevation ft NGVD	1,046	386	-44	-,7,844
Bottom of plug, Elevation ft NGVD	1,536	1,046	386	-44
Type of cement or other material	CO_2 Resistant	CO_2 Resistant	CO_2 Resistant	Neat Cement Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Squeeze & Balanced Plug	Squeeze & Balanced Plug	Squeeze & Balanced Plug	Balanced Plug

ft NGVD = feet elevation referenced to the National Geodetic Vertical Datum of 1929

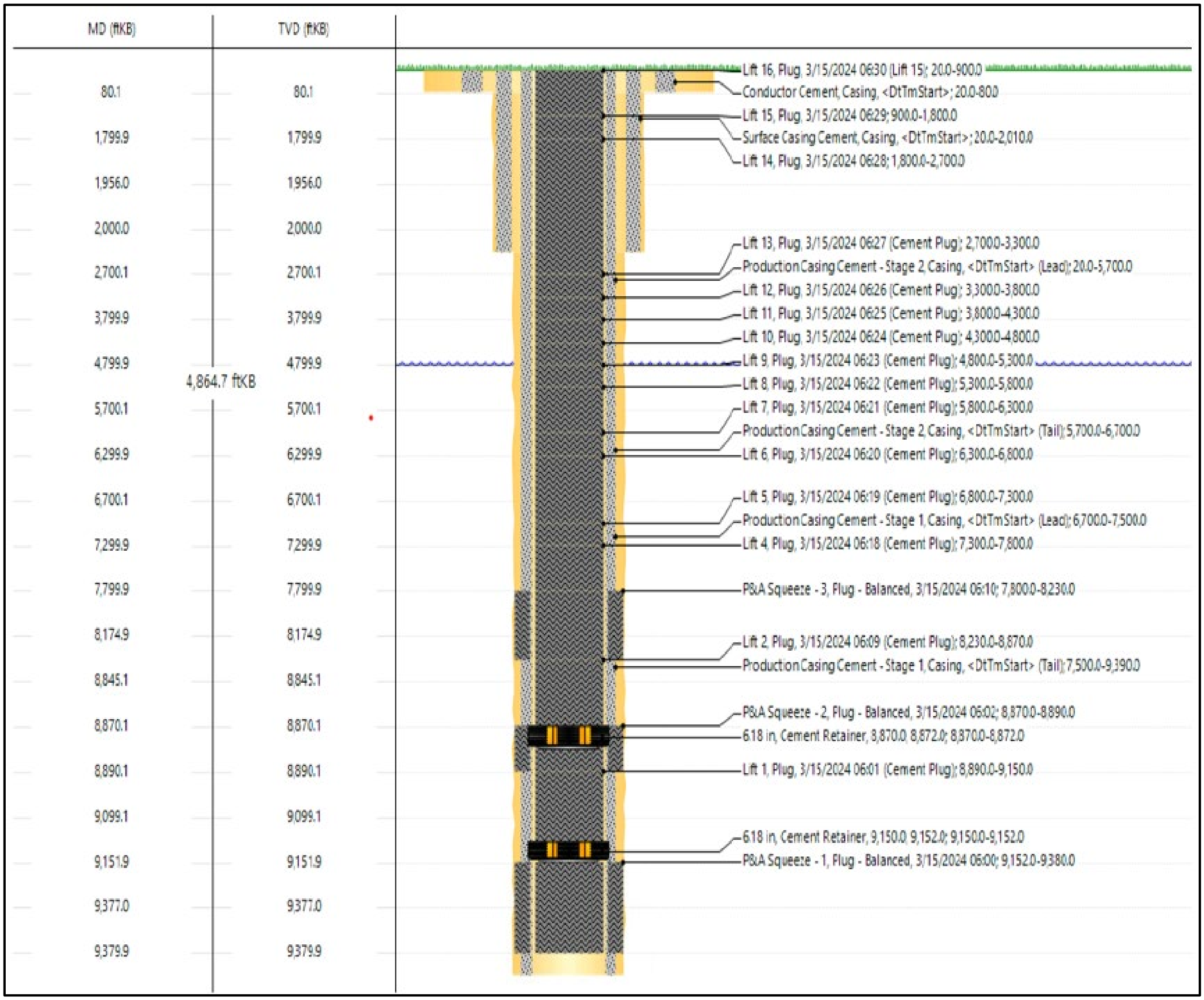
5.1 Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all equipment is removed. The plug placement method may vary depending on the type of service equipment used.

1. Notify the regulatory agency at least 60 days before plugging the well and provide an updated plugging plan if applicable.
2. Move-in (MI) rig onto Front Range 2-1 and rig up (RU). Ensure all CO2 pipelines are marked and noted with the rig supervisor prior to MI.
3. Conduct and document a safety meeting.
4. Record bottom hole pressure from downhole gauge and calculate kill fluid density.
5. Open all valves on the vertical run of the tree and check pressures.
6. Test the pump and line to 5,000 psig. Fill tubing with kill weight brine (10.1 ppg or as determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system.
7. Test casing annulus to 500 psig and monitor as in the annual mechanical integrity test (MIT). Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).
8. If the well is not dead or pressure cannot be bled off of the tubing, rig up (RU) slickline and set plug in lower profile nipple below the packer, then bleed off pressure.
9. Flush well with a kill weight brine fluid without exceeding formation fracture pressure.
10. Perform bottom hole pressure measurements and log and pressure test the well to ensure mechanical integrity. If mechanical integrity is lost, make repairs prior to continuing plugging activities.
11. Remove internal tubing as part of abandonment.
12. Use squeeze cements, casing circulations, and balanced plugs to plug the well.
13. Use CO2-resistant cement for the squeeze cementing of the injection interval and subsequent lifts. After abandoning the bottom interval, perforate the 7-inch casing and circulate cement to surface in the annular space.
14. Cement the rest of the 7-inch casing to the surface.
15. Top off the well with cement from the surface.
16. Nipple down (ND) blowout preventers (BOPs) and cut all casing strings below the plow line (minimum 3 feet below ground level or per local policies/standards).
17. Clean the cellar to allow a plate with the well name to be welded onto the lowest casing string at a depth of roughly 3 feet, or as per permitting agency directive.

18. Submit the completed plugging forms with charts and all lab information to the regulatory agency as required by the permit. The plugging report must be certified accurate by Permittee and the plugging contractor and submitted within 60 days after plugging is completed.

Figure 2: Front Range 1-1 well plugging schematic



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

1.0 Plan Overview

This attachment includes the enforceable post-injection site care (PISC) and site closure plan requirements consistent with 40 CFR 146.93.

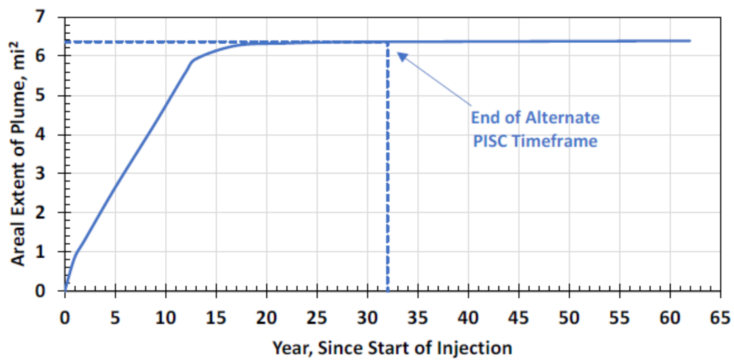
1. The Permittee must monitor groundwater quality and track the position of the CO2 plume and pressure front for twenty (20) years, or for another approved alternative timeframe approved by the UIC Program Director in accordance with 40 CFR 146.93(b)(2).
2. The Permittee must continue post-injection site care until the Director approves cessation of monitoring and site closure under 40 CFR 146.93.
3. Following approval for site closure, the Permittee must plug the all monitoring wells and submit a site closure report with all required documentation.

2.0 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR §146.93(a)(2)(ii)]

Computational modeling indicates that after injection ceases, the predicted CO_2 plume remains within the Lyons Formation, and the area does not expand over time. The colored area in Figure 1 shows the CO_2 plume extent in Year 32, as defined by the global mole fraction of CO_2. Figure 2 shows cross-section of the Lyons Formation with the CO_2 global mole fraction at the end of the injection period at Year 32. There is some minor vertical migration of CO_2 to upper portions of the Injection Zone due to buoyancy forces. The AoR is defined by the plume shape and size in Year 12 (end of injection period) because this is the time with the largest differential pressure and CO_2 plume. All pressure is predicted to have been reduced to levels below the level of endangerment to USDWs by Year 32. Therefore, Year 32 (20 years post-injection) is predicted to be the site closure date.

The map in Figure 1 is based on the final AoR delineation modeling results submitted pursuant to 40 CFR §146.84.

Year, Since Start of Injection	Areal Extent of Plume, mi^2	Rate of Expansion, mi^2/yr
0	0.00	-
1	0.86	0.86
2	1.31	0.45
5	2.64	0.44
9	4.30	0.41
12	5.59	0.43
13	5.93	0.34
17	6.27	0.09
22	6.33	0.01
27	6.36	0.01
32	***6.37***	***0.00***
62	6.39	0.00



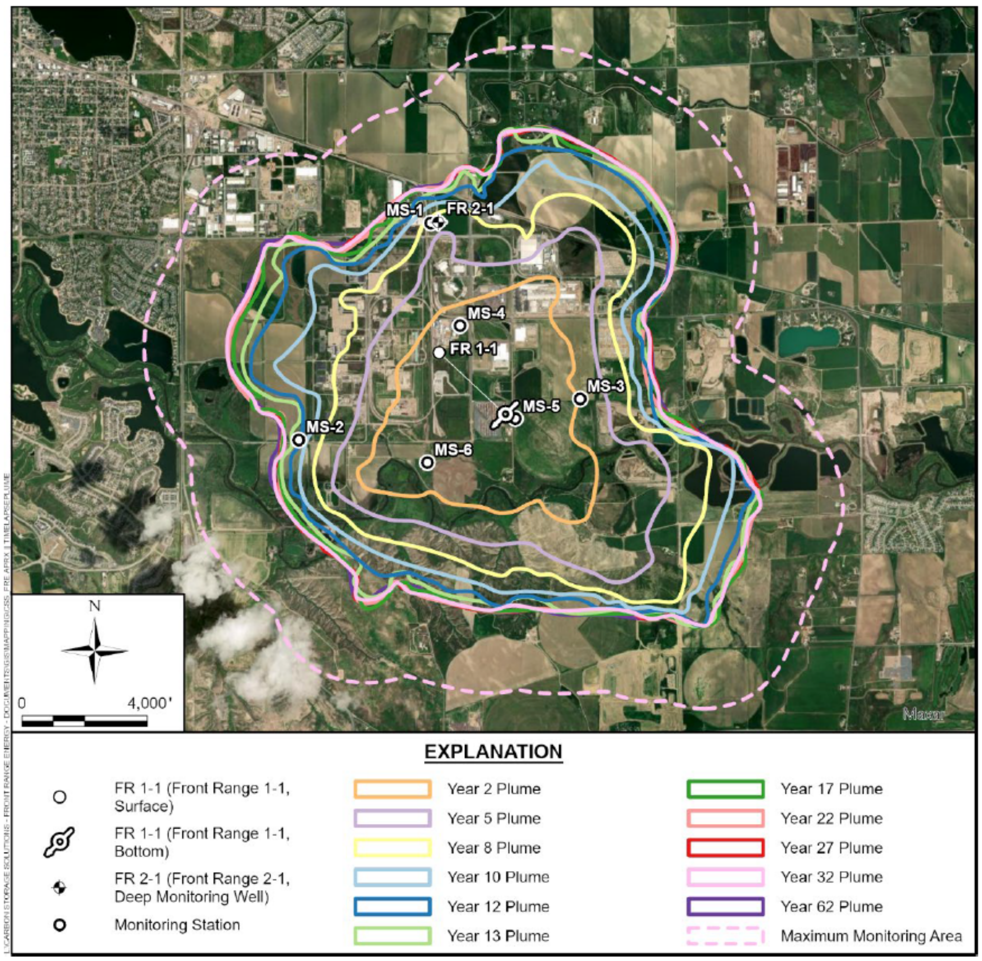


Figure 1: Areal extent of the CO_2 plume at site closure in Year 32 since start of CO_2 injection. graph of Areal, in mi^2, shows plume expansion ends in year 32.

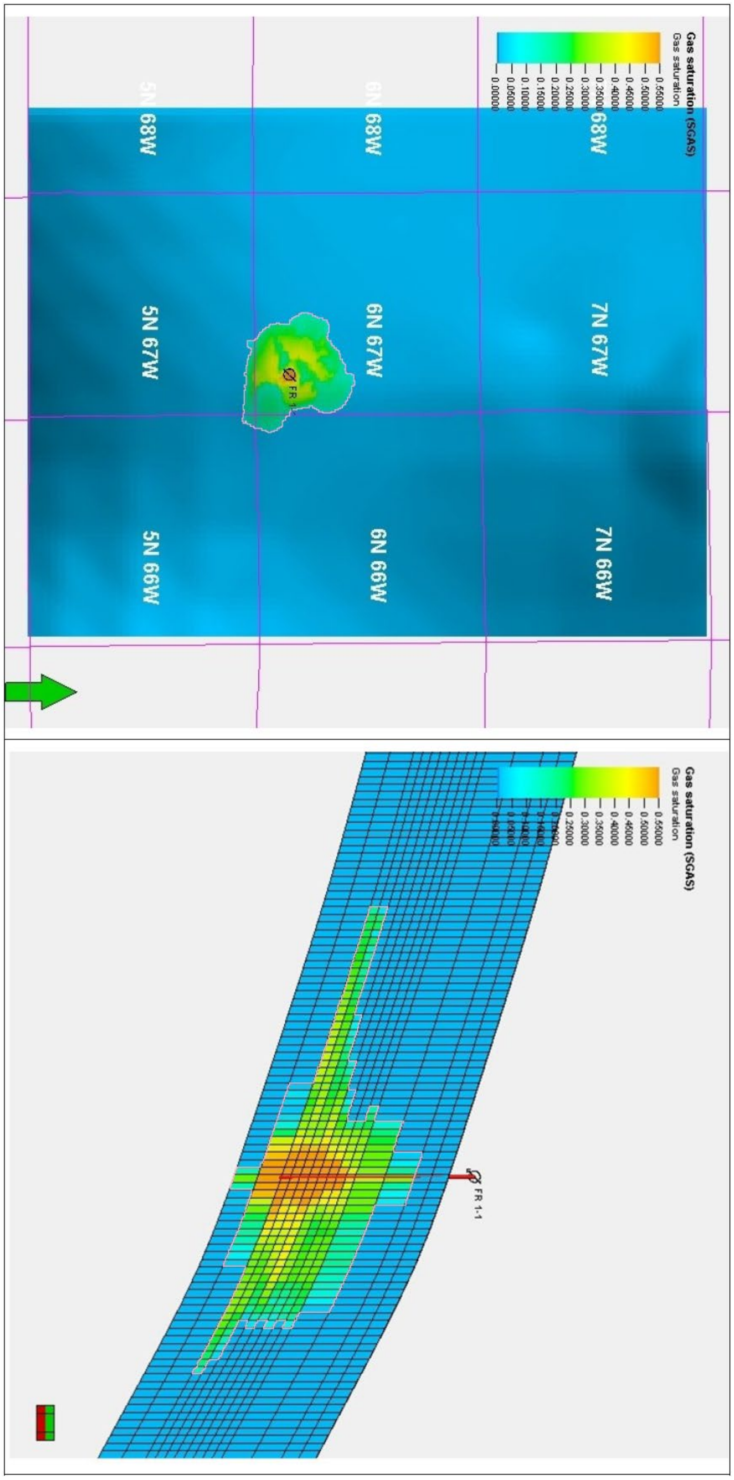


Figure 2: Vertical extent of the CO_2 plume at site closure in Year 32 since start of CO_2 injection. CO_2 plume remains in the Lyons Formation.

3.0 Post-Injection Monitoring Plan [40 CFR §146.93(a)(2)(iii)]

As described in the following sections, groundwater quality monitoring and plume and pressure-front tracking during the post-injection phase must meet the requirements of 40 CFR §146.93(b)(1).

The results of all post-injection phase testing and monitoring must be submitted annually, with the first submission within 60 days of the anniversary of the date that injection ceases, as described below under Section 3.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR §146.93(a)(2)(iv)].

The Permittee must perform the following requirements:

1. After the injection ceases, the Injector well must be converted to a monitoring well.
2. The first 10 years after the cessation of injection, direct measurements of pressure and temperature in the Injection Zone must be obtained from the FR 1-1 and FR 2-1 monitoring wells that have not yet been plugged. Fluid samples must be collected if pressure or temperature indicate a change in fluid encountered by the wellbore. If pressure and temperature data are consistent with lack of continued CO_2 migration, pressure and temperature monitoring in the Injection Zone must be continued annually after 10 years until plugging.
3. 10 years following the cessation of injection operations, the Permittee must annually collect and analyze the geochemistry of fluids and dissolved gasses from the FR 2-1 well for the Entrada and Ingleside Formation. These data will confirm the integrity of the Upper and Lower Confining Zone. Measurements will be event-driven thereafter (changes in temperature and/or pressure. If geochemistry data of fluids and dissolved gasses in the adjacent USDW are consistent with the absence of introduced Injection Zone brine or CO_2 injectate into the USDW, this monitoring method will be discontinued after 10 years.
4. If pressure or temperature data in the monitoring wells indicates a change in the Injection Zone that could indicate migration of CO_2 plume out of the storage complex, soil gas analysis must be conducted. If changes in soil gas are detected, an attribution study must be performed.
5. Annual saturation logging will be conducted in FR 1-1 and FR 2-1 wells until plugging.
6. Time-lapse vertical seismic profile (VSP) data must be collected in selected wells that have DAS fiber once every five-year period until plugging.

<u>3.1</u> ***<u>Monitoring Above and Below the Injection Zone</u>***

The required monitoring methods, locations, and frequencies for monitoring above the upper and lower Confining Zone are included in Table 1 below.

Table 1: Post-Injection Monitoring Techniques in/above the Confining Zone

Location	Objective	Method	Monitoring Post-Injection
USDWs above and below the confining zone monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Event-driven*, until plugging
Vadose Zone, Near surface	Isotopic analysis and chemical evaluation to detect changes from expected vadose zone chemistry	Isotopic analysis and chemical evaluation at a minimum of 15 locations	Event-driven*, triggered by P/T data in FR 1-1 and FR 2-1 wells and fluids sample results
FR 1-1 and FR 2-1	Confirming integrity of the Upper and Lower Confining Zone	Saturation logging (pulsed neutron logging)	Event-driven*, until plugging
		Distributed thermal sensing	Continuously for the first 10 years, pending an approved PISC plan

*The Permittee must monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, the Permittee must obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples must be obtained to confirm the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

3.2 *Carbon Dioxide Plume and Pressure Front Tracking [40 CFR §146.93(b)(1) and 146.95(f)(4)]*

The Permittee must employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure. Table 2 presents the direct and indirect methods that the Permittee will use to monitor the CO_2 plume, including the activities, locations, and frequencies. Fluid sampling, sampling handling and custody, quality control, and quality assurance will be performed as described in the QASP.

Table 2: Post-Injection Monitoring Techniques Plume and Pressure Front Tracking

Location	Objective	Method	Monitoring Post-Injection
FR 1-1 FR 2-1	Fluid and dissolved gas chemistry	Fluid and dissolved gas sampling via wireline	Event-driven* until plugging
	Direct monitoring of pressure and temperature to ensure seal integrity	Pressure and temperature gauges or distributed thermal sensing	Continuously
	Indirect monitoring of CO_2 concentration	Pulsed neutron log	Annually until plugging
	Plume and pressure extent over time	Vertical seismic profile	Once every five-year period until plugging or plume stabilization
	External mechanical integrity	Pressure and temperature gauges; external MIT	MIT log once every five-year period and before plugging
	Surface leak detection	Visual inspection at wellhead, optical gas imaging, cameras, surface sensors	Continuous surface monitoring and quarterly visual inspection until site closure
	Indirect monitoring of CO_2 presence above the Injection Zone	Pulsed neutron log	Event-driven* until plugging
	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Annually for first 10 years post injection; event-driven*, triggered by P/T data or soil gas chemistry
Vadose Zone, Near surface	Isotopic analysis and chemical evaluation to detect changes from expected vadose zone chemistry	Isotopic analysis and chemical evaluation at a minimum of 15 locations	Event-driven*, triggered by P/T data or fluid sample results

*The Permittee must monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, the Permittee must obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils must be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples must be obtained to confirm the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

3.3 *Schedule for Submitting Post-Injection Monitoring Results [40 CFR §146.93(a)(2)(iv)]*

During the PISC period, monitoring reports must be prepared and submitted to EPA once per year in accordance with Section 3 above. These reports must contain the information established pursuant to Sections 3(1) and 3(2) of this Plan.

Permittee must reevaluate the AoR at a minimum fixed frequency not to exceed five years during the post-injection phase. Permittee may be required to review the AoR earlier than the established fixed frequency when warranted by certain monitoring and operational conditions (40 CFR 146.84(b)(2)(ii)) during the injection and post-injection phases. The PISC and Site Closure Plan must be reviewed at a minimum fixed frequency not to exceed five years during the PISC period. Results of the plan review must be included in the PISC monitoring reports to the Director.

Permittee must submit an update to the PISC plan to the Director:

(a) as necessary to address new information collected during the logging and testing of the well and the formation prior to authorization to inject;

(b) during the operation of the well(s) if warranted in light of the review of the AoR that is mandated every five years based on monitoring data generated during operation;

(c) at the cessation of injection, Permittee must either submit an amended PISC or demonstrate to EPA through monitoring data and modeling results that no amendment to the plan is needed; and

(d) In the case of monitoring results that indicate a need for proposed changes to the PISC plan, Permittee will submit a modified plan to EPA for approval within 30 days of receipt such data results.

Prior to authorization for site closure, Permittee must submit a demonstration based on monitoring and other site-specific data that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.

The operational and monitoring results must be reviewed by the Permittee for adequacy in relation to the objectives of the PISC. The monitoring locations, methods, and schedule must be analyzed in relation to the size of the CO_2 Injection Zone, pressure front, and protection of USDWs.

4.0 Non-Endangerment Demonstration Criteria (40 CFR 146.93(b)(3)

Prior to authorization for site closure, the Permittee must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the Front Range Storage Complex does not pose an endangerment to USDWs. The Permittee must submit a report to the Director that will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the Front Range Storage Complex computational model. The report must detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report must include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Director to review the analysis. The report must contain all of the elements listed below:

4.1 Summary of Existing Monitoring Data

The required report must summarize all previous monitoring data collected pursuant to this PISC and Site Closure Plan and explain how it supports a non-endangerment demonstration. Data should be compared with baseline data collected during site characterization (40 CFR 146.82(a)(6) and 146.87(d)(3)).

4.2 Summary of Computational Modeling History

The report must compare the computational modeling results used for the AoR delineation with the monitoring data collected during the operational and PISC periods. Monitoring data must also be compared with baseline data collected during the site characterization required under 40 CFR §146.82(a)(6) and §146.87(d)(3).

The data must be used to update the computational model and monitor the site and must include both direct and indirect geophysical methods. Direct methods include measurements of pressure, temperature, fluid and dissolved gas chemistry. Indirect methods include Vertical Seismic Profile (VSP) and 2D seismic, and saturation logging using Pulsed Neutron (PNL).

Data generated during the PISC period must be used to show that the computational model accurately represents the storage site and can be used as a process to determine the plume's properties and size.

The Permittee must demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods must be employed to correlate the data and confirm the model's ability to represent the storage site accurately. The validation of the computational model with the large quantity of measured data will be a significant element to support the non-endangerment demonstration. Further, the validation of the complete model over the entire area, and at the points where direct data collection has taken place, will ensure confidence in the model for those areas with no direct observation wells where the surface infrastructure precludes geophysical data collection.

4.3 Evaluation of Reservoir Pressure

The report must demonstrate non-endangerment to USDWs by showing that the pressure within the Injection Zone will rapidly decrease to levels near its pre-injection static reservoir pressure during the PISC period. Because increased pressure is the primary driving force for fluid movement that could endanger a USDW, the decay in the pressure differential provides strong justification that the injectate will no longer pose a risk to any USDWs.

The Permittee must monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared with the pressure predicted by the computational model, which was previously shown in Figure 1 and Figure 2. Agreement between the actual and predicted values will validate the accuracy of the model and further demonstrate non-endangerment.

4.4 Evaluation of Carbon Dioxide Plume

The report must use a combination of monitoring data, logs, geophysical surveys, and seismic methods to locate and track the movement of the CO_2 plume. The data produced by these activities must be compared with the modeled predictions (previously shown in Figure 1 and 2) using statistical methods to validate the model's ability to represent the storage site accurately. PISC monitoring data must be used to show the stabilization of the CO_2 plume as the reservoir pressure returns to its near-pre-injection state. The risk to USDWs will decrease when the extent of pure-phase CO_2 ceases to grow either laterally or vertically. The stabilization of the CO_2 plume combined with the lack of unmitigated Artificial Penetrations in the confining formation will be significant factors in the Project's demonstration of non-endangerment.

Fluids and dissolved gases collected from monitoring wells or soil or soil gas samples may be used to determine aqueous-phase CO_2 concentrations and mobilized constituents to assess USDW endangerment. If a demonstration can be made that the majority of the CO_2 has been immobilized via trapping mechanisms, then there is strong evidence that the risk to USDWs posed by the CO_2 plume has decreased. Modeling results, including sensitivity analyses, may also be used to demonstrate that plume migration rates are negligible based on available site characterization, monitoring, and operational data.

4.5 Evaluation of Emergencies or Other Events

In addition to the CO_2 plume, mobilized fluids may also pose a risk to USDWs, as the reservoir fluids include brines that are high in total dissolved solids (TDS) and contain hydrogen sulfide. The geochemical data collected from monitoring wells must be used to demonstrate that no mobilized fluids have moved above the Upper Confining Zone and therefore would not pose a risk to USDWs after the PISC period. Monitoring data indicating steady or decreasing trends of potential drinking water contaminants below actionable levels (e.g., secondary, and maximum contaminant levels) will be used for this demonstration.

To demonstrate non-endangerment, the Permittee must compare the operational and PISC period fluid and dissolved gas samples from the lowermost USDW with the pre-injection baseline samples. This comparison is expected to show chemical similarity to baseline samples. Changes in chemistry must be evaluated to demonstrate attribution. This work must demonstrate the absence of CO_2 injectate or brine forced from the Injection Zone into the lowermost USDW.

Corrective action must be performed on artificial penetrations identified to be potential leak pathways. Based on this information, the potential for fluid movement through artificial penetrations of the confining formation does not present a risk of endangerment to any USDWs.

5.0 Site Closure Plan

The Permittee must conduct site closure activities to meet the requirements of 40 CFR §146.93(e) as described below. The Permittee must submit a final Site Closure Plan and notify the permitting agency at least 120 days in advance of its intent to close the site. Once the permitting agency has approved closure of the site, the Permittee must plug the monitoring wells and submit a site closure report to EPA within 90 days of site closure. The activities 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 UIC Program Director for approval with the notification of the intent to close the site.

5.1 Plugging Monitoring Wells (40 CFR 146.93(e))

Upon receiving authorization for site closure from the Director, all monitoring wells must be plugged within 90 days of site closure in accordance with Attachment D. All Injection Zone monitoring wells at the site must be plugged and abandoned using best practices to prevent any upward migration of the CO_2 or communication of fluids between the Injection Zone and USDWs. The deep monitoring wells in the Injection Zone have a direct connection between the injection formation and the ground surface; therefore, the well plugging program is specifically designed to prevent communication between the Injection Zone and USDWs. Details of the plugging program are found in the Attachment D.

Before the well is plugged, the internal and external mechanical integrity of the well must be confirmed by conducting a pressure test and a cement and casing inspection log. The results of this logging and testing will be reviewed and approved by the appropriate regulatory agencies before plugging the wells.

Infrastructure removal and site restoration efforts will comply with applicable state and local requirements.

5.2 Site Closure Report (40 CFR 146.93(f))

A Site Closure Report (SCR) must be prepared and submitted to the Director within 90 days after site closure. The SCR must document the following aspects of the site closure process:

(a) Plugging of all injection and monitoring wells as required at 40 CFR 146.92 and 146.93 (e);

(b) Details of site restoration activities;

(c) Location of the sealed injection well on a survey plat submitted to the local zoning authority, a copy of which will be sent to the Regional Administrator for EPA Region 8. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks

(d) Notifications sent to state and local authorities as required at 40 CFR 146.93(f)(2);

(e) Records reflecting the nature, composition, and volume of CO_2 injected;

(f) Records of pre-injection, injection, and post-injection monitoring;

(g) Certifications that all injection and storage activities have been completed; and

(h) A demonstration that the Permittee has met the deed notation requirements in Section 5.3 of this attachment.

(i) The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection site care period for a period of 10 years after which these records will be delivered to the UIC Program Director.

5.3 Notation of Deed

The Permittee must record a notation on the deed of the property on which the injection well was located, which must include the following:

(a) The fact that the property was used for carbon dioxide sequestration;
(b) The name of the local agency with which the survey plat was filed as well as the address of the EPA regional office to which it was submitted;
(c) The volume of fluid injected;

(d) The Injection Zone or zones into which the fluid was injected; and

(e) The period over which the injection occurred.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN (ERRP)

1.0 Plan Overview

This Attachment includes the permit requirements to address and remediate events that could allow for movement of the injected carbon dioxide (CO_2) stream, annulus fluid, or formation fluid including, but not limited to, any movement of fluid into an Underground Source of Drinking Water (USDW) or any other unauthorized zones during the operation or post-injection site care (PISC) periods for the injection well.

1.1 Endangerment Requirements - In accordance with 40 CFR 146.94(b), if the Permittee obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, the Permittee must perform the following actions:

(a) Initiate the shutdown plan for the injection well.
(b) Take all steps reasonably necessary to identify and characterize any release.
(c) Notify the permitting agency Underground Injection Control (UIC) Program Director of the emergency event within 24 hours.
(d) Implement applicable portions of the approved ERRP.

1.2 Shutdown Plan Initiation - Where the phrase "initiate shutdown plan" is used, the following protocol must be employed:

(a) Permittee must immediately cease injection, unless gradual cessation of injection is necessary for safety.
(b) Shut in the well (all necessary valves closed and locked out).
(c) Vent CO_2 from surface lines and facility as necessary.
(d) Limit access to wellhead and surface facilities to only those authorized (caution tape and/or rope may be used to limit access to the well and facility).

As used in this ERRP, the term "wells," unless otherwise specified, refers to the injection well and all monitoring 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.

2.0 Local Resources and Infrastructure

The infrastructure integral to the project includes the injection well Front Range 1-1, the deep zone monitoring well Front Range 2-1, and multiple monitoring stations labeled MS-1 through MS-6. Additionally, surface facilities are located at the Carbon Storage Solutions, LLC site, where the injection well is located, and the adjacent Front Range Energy, LLC site, where the CO_2 is produced

Land resources in the region are varied, comprising grasslands, herbaceous lands, pasture/hay lands, and cultivated crop lands, as identified by the United States National Land Cover Database for 2021. While public lands are present, indicated by black hatch marks on maps, there are no nature preserves within or near the geologic sequestration site. The built environment is mixed-use development and includes multiple industrial and residential buildings.

Surface water resources include the Cache de la Poudre River, unnamed tributaries, and several surface ponds. The AoR and Corrective Action Plan (Attachment B of this Permit) provides further details about the USDWs in the project area. Resources and infrastructure addressed in this plan are shown in Figure 1.

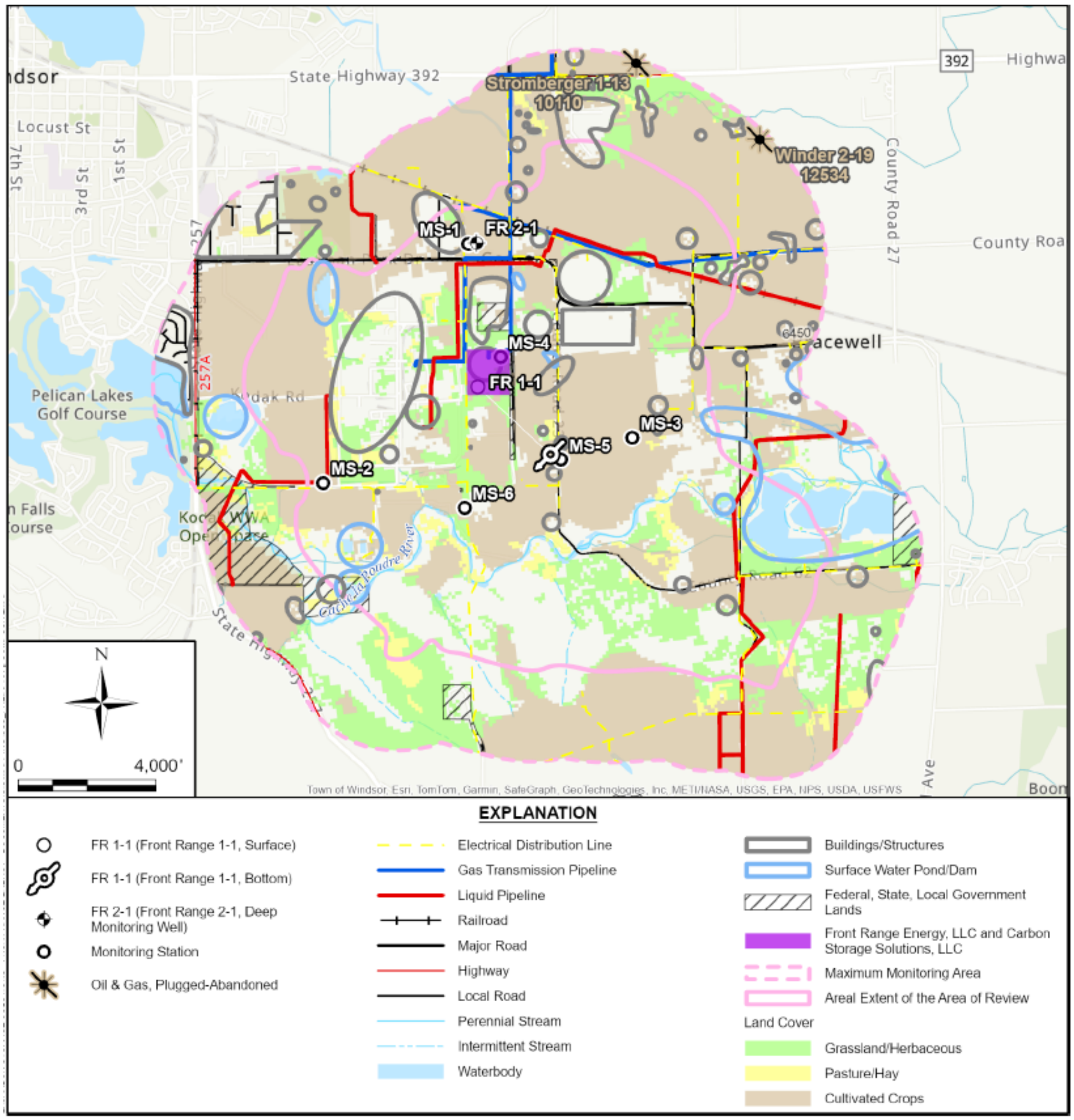


Figure 1: Map of surface features within the area of review (current as of February 28, 2026)

3.0 Potential Risk Scenarios

The following events related to the Project that could potentially result in an emergency response are included in Table 1. This table lists the types of potential adverse incidents that will trigger response actions to protect USDWs and prevent injected CO_2 stream, annulus fluid, or formation fluid migration into any unauthorized zones if the incidents occur during the injection through post-injection site care periods. The Permittee must undertake emergency or remedial actions in response to these incidents. This is a non-exhaustive list of potential risk scenario events.

Table 1: Potential Emergency Events

Injection Period

• Well integrity failure
  ○ Loss of mechanical well integrity due to casing, tubing or packer leak in injection well
  ○ Loss of mechanical well integrity due to casing leak in the monitoring wells
  ○ Loss of external mechanical well integrity from metal leaching or corrosion due to prolonged wetted CO_2 exposure in injection or monitoring wells
• Well control event during well rework with loss of containment
• Potential fluid movement to USDW
  ○ Vertical migration of fluids from the Injection Zone through plugged and abandoned (P&A'd) or undocumented wells
  ○ Vertical migration of fluids from the Injection Zone through failure of the confining zone and/or faults, and fractures (loss of containment)
• Well monitoring equipment failure or malfunction (e.g., shutoff valve or pressure gauge)

Post-Injection Site Care Period

• Well control event during plugging and abandonment with loss of containment
• Well integrity failure
  ○ Loss of mechanical well integrity due to casing leak in the monitoring wells
• Potential fluid movement to USDW
  ○ Vertical migration of fluids from the Injection Zone through plugged and abandoned (P&A'd) or undocumented wells
  ○ Vertical migration of fluids from the Injection Zone through failure of the confining zone and/or faults, and fractures (loss of containment)

Throughout the Life of the Project
• Severe weather disaster (e.g., tornado, hurricane, lightning strike) • Seismic event other than a microseismic event • Other emergency at or near the wellsite (e.g. pipeline rupture).

4.0 Emergency Identification and Response Actions

The Permittee must report to the Director within 24 hours if there is any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW; any noncompliance with a Permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs; any triggering of a shut-off system (i.e. down-hole or at the surface; any failure to maintain mechanical integrity; or surface air/soil gas monitoring detection that indicates CO_2 may have been released into the shallow subsurface and/or atmosphere.

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. Emergency identification and response actions for the potential risk scenarios identified in Table 1 are detailed below.

In accordance with Permit section K.11, the Permittee must obtain written approval to resume injection after any cease injection event.

4.1 Well Mechanical Integrity Failure

Loss of mechanical integrity in the injection and/or monitoring wells may endanger USDWs, including endangerment due to the movement of the injected CO_2 stream, 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 are activated.
  - Wellhead pressure exceeds the shutdown pressure specified in the Permit.
  - Annulus pressure indicates a loss of well containment.
- Mechanical integrity test results identify a loss of mechanical integrity.
  - Loss of mechanical integrity due to a casing, tubing or packer leak in the injection well.
  - Loss of mechanical integrity due to a casing leak in the monitoring wells.

4.1.1 If there is a loss of mechanical integrity for the Front Range 1-1 or Front Range 2-1 wells, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Initiate shutdown plan.

(c) Monitor tubing and annulus pressures and temperature, as is feasible. This information should be used to assess and determine the nature or cause and extent of the mechanical integrity failure.

(d) Identify and implement appropriate remedial actions to repair damage to the well in consultation with the Director.

(e) If the loss of mechanical integrity has resulted in a failure of monitoring equipment, implement Response Actions.

(f) If there is evidence suggesting potential fluid movement into a USDW or unauthorized zone, implement Response Actions

(g) Perform mechanical integrity test.

(h) Perform any other appropriate response actions.

4.1.2 If there is a loss of mechanical integrity for any other monitoring wells than those listed in 4.1.1, the Permittee must:

(a) Notify the Director within 24 hours of the emergency event.

(b) Identify and implement appropriate remedial actions to repair the well in consultation with the Director. Within 30 days of the event, inform Director of schedule for repairs.

(c) Identify and implement appropriate remedial actions in consultation with the Director.

(d) Perform any other appropriate response actions.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors

4.2 Well Control Event

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

If there is a well control event, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Cease injection.

(c) Close blow off prevention.

(d) Limit access to wellhead and surface facilities to only those authorized (caution tape and/or rope may be used to limit access to the well and facility) Execute well control procedure.

(e) Perform any other appropriate response actions.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors.

4.3 Well Monitoring Equipment Failure or Malfunction

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

This subsection covers the response and procedures that must be followed should one (or more) of the following monitoring sensors fail:

- Injection Well
    - Injection pressure and temperature gauge
    - Annulus pressure
    - Annulus fluid volume
    - Injection flow rate
- Deep Monitoring Wells

    - Annulus pressure
    - Annulus fluid volume
    - Formation pressure
    - Formation temperature
- Shallow Monitoring Wells
    - Groundwater samples

4.3.1 If there is a failure or malfunction of well monitoring equipment, including malfunctioning of the Front Range 2-1 monitoring well, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Determine the impact of the event, based on the information available, within 24 hours of the event occurring. Assess the impact of the loss of monitoring equipment and determine and implement a viable alternative monitoring method in consultation with the Director.

(c) If there has been a loss of mechanical integrity, implement Response Actions from Section 4.1.

(d) Assess whether there is evidence suggesting potential fluid movement into a USDW or unauthorized zone, and if there is such evidence, implement Response Actions from Section 4.4.

(e) In consultation with the Director, assess whether monitoring capabilities at the project are sufficient to ensure non-endangerment to USDWs. If monitoring capabilities are not sufficient, treat the event as an immediate risk. If the event poses an immediate or near-term risk to human health, resources (including USDWs), or infrastructure, the Permittee must initiate shutdown plan in Section 1.2 of this attachment..

(f) Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information should be used to assess and determine the nature or cause and extent of the failure.

(g) Replace equipment (if needed) as soon as is feasible based on operational conditions and suitability of the alternative method of monitoring.

(h) Identify and implement appropriate remedial actions to repair the well in consultation with the Director. Perform any other appropriate response actions.

4.3.2 If there is a failure or malfunction of well monitoring equipment at any of the shallow groundwater wells, the Permittee must:

(a) Notify the Director about the event within one week.

(b) Identify an alternative monitoring method as appropriate in consultation with the Director.

(c) Perform any other appropriate response actions.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors

4.4 Evidence Suggesting Potential Fluid Movement into a USDW or Other Unauthorized Zone (including the Surface)

Potential injected CO_2 stream, annulus fluid, or formation fluid fluid movement into a USDW or other unauthorized zones may endanger USDWs. This scenario includes but is not limited to:

- Elevated concentrations CO_2 in groundwater sample(s) or other evidence suggesting potential fluid movement into a USDW or other unauthorized zone (including the surface).
- Unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
- Evidence of migration of injected CO_2 stream, annulus fluid, or formation fluid between formations through the injection, and/or monitoring wells, including due to metal leaching or corrosion due to prolonged wetted CO_2 exposure.
- Evidence of migration of injected CO_2 stream, annulus fluid, or formation fluid from the Injection Zone through plugged and abandoned wells or undocumented wells in the AoR.
- Evidence of migration of injected CO_2 stream, annulus fluid, or formation fluid from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment).

4.4.1 If the Permittee obtains evidence of potential injected CO_2 stream, annulus fluid, or formation fluid movement into a USDW or other unauthorized zone, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Initiate shutdown plan if the event poses an immediate or near-term risk to human health, resources (including USDWs), or infrastructure.

(c) Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information must be used to assess and determine the nature or cause and extent of the failure.

(d) Take all steps reasonably necessary to identify and characterize any release.

(e) Collect confirmation samples from USDWs or any other potentially relevant formation(s) and analyze the sample to determine elevated analytes parameters.

4.4.2 If the presence of leaked fluid or other contamination is confirmed in a USDW or other unauthorized zone, the Permittee must:

(a) Identify and begin implementing a remediation plan in consultation with the Director, as soon as possible and no later than 30 days of the emergency event.

(b) Arrange for an alternate potable water supply within 24 hours if the USDW was being utilized for water supply and the contamination has caused an exceedance of drinking water standards.

(c) Continue USDW monitoring on a frequent basis in consultation with the Director, until potential endangerment of or adverse impacts to USDWs have been fully addressed.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors

4.5 Severe Weather Disaster

Well problems (mechanical integrity loss, fluid movement, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Weather-related disasters (e.g. tornado, hurricane or lightning strike) may affect project facilities.

If there is a severe weather event affecting the project facilities, the Permittee must:

(a) Notify the Director within 24 hours.

(b) Trigger alarm by the monitoring system or monitoring personnel.

(c) If appropriate, contact the field superintendent to activate emergency evacuation and secure the location.

(d) Determine if there has been a loss of mechanical integrity. If there has been a loss of mechanical integrity, implement Response Actions from Section 4.1.

(e) Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3.

(f) Conduct assessment to determine if there is evidence suggesting potential fluid fluid movement into a USDW or unauthorized zone. If there is such evidence, implement Response Actions from Section 4.4.

(g) Assess potential impact to the Project, local resources and infrastructure.

(h) Identify and implement appropriate remedial actions in consultation with the Director.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors.

4.6 Seismic Events

The Permittee must implement the response action in Table 2 below is based on Moment magnitude (Mw) thresholds and potential damage:

Table 2: Seismic Monitoring System, for Seismic Events >Mw 1.0

Operational Status	Moment Magnitude (Mw)[a,b]	Responses[c]
Green	Seismic events where Mw <= 1.5	1. Continue normal operation within permitted levels.
Yellow	Five or more seismic events within a 30-day period where 1.5 < Mw <= 2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the Director of the operating status of the well. 3. Review seismic and operational data to determine the cause.
Orange	Seismic event where Mw > 1.5 and local observation or felt report Seismic event where	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the Director of the operating status of the well. 3. Review seismic and operational data to determine the cause.

	Mw > 2.0 and no felt report	4. Report findings to the Director and identify and implement appropriate remedial actions in consultation with the Director.
Magenta	Seismic event where Mw > 2.0 and local observation or felt report	1. Initiate rate reduction plan in consultation with the Director. 2. Within 24 hours of the event, notify the Director of the operating status of the well. 3. Limit access to wellhead to authorized personnel only. 4. Communicate with facility personnel and local authorities to initiate evacuation plans, if necessary. 5. Review seismic and operational data to determine the cause of the event. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the extent of any failure. 7. Report findings to the Director and identify and implement appropriate actions in consultation with the Director. 8. If there has been a loss mechanical integrity at any of the wells, implement Response Actions from Section 4.1. 9. Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3. 10. Conduct assessment to determine if there is evidence suggesting potential fluid fluid movement into a USDW or unauthorized zone. If there is such evidence, implement Response Actions from Section 4.4.
Red	Seismic event where Mw > 2.0, and local report and confirmation of damage Seismic event where Mw > 3.5	1. Initiate shutdown plan. 2. Within 24 hours of the incident, notify the Director of the situation. 3. Limit access to wellhead to authorized personnel only. 4. Communicate with facility personnel and local authorities to initiate evacuation plans. 5. Review seismic and operational data to determine the cause of the event. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the extent of any failure. 7. Report findings to the Director and identify and implement appropriate remedial actions in consultation with the Director. 8. If there has been a loss of mechanical integrity, implement Response Actions from Section 4.1. 9. Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3. 10. Conduct assessment to determine if there is evidence suggesting potential fluid movement into a USDW or unauthorized zone. If there is such evidence, implement Response Actions from Section 4.4.

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

[b] "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.

[c] Remedial action will occur within 5 days.

5.0 Response Personnel and Equipment

Site and project personnel will be relied upon to implement this ERRP. It is the Permittee's responsibility to ensure appropriate personnel will implement the ERRP and that local authorities will be engaged by personnel in an appropriate and timely manner to manage emergencies. It is the responsibility of the Permittee to ensure all identified personnel are familiar with the procedures of the ERRP. Emergency drills should be conducted annually and include participation of the local authorities.

A site-specific emergency contact list must be developed and maintained during the life of the project and at a minimum, annually updated. Table 3 identifies the key contacts and their phone numbers.

Table 3: Contact Information for Key Local, State, and Other Authorities

Entity	Phone Number
Police	
Emergency	911
Main – Windsor Police Department (non-emergency)	(970) 686-7476
Fire	
Emergency	911
Main – Windsor Severance City (non-emergency)	(970) 686-9594 or (970) 686-2626
Weld County Emergency Planning Commission Dispatch	(970) 356-4015 ext. 2700
Colorado State Emergency Response Commission Greg Stasinos (CEPC Co-Chair)	(303) 692-3023
Colorado Department of Public Health & Environment 24-Hour Spill Hotline	(877) 518-5608
Colorado Division of Oil and Public Safety	(303) 318-8547
Colorado Energy and Carbon Management Commission	(888) 235-1101
Colorado/Occupational Safety and Health Administration	(303) 844-5285
US EPA National Response Center (24-hour)	(800) 424-8802
US EPA Region 8	
UIC Enforcement Supervisor – Tiffany Cantor	(303) 312-6521
Emergency Operations Center	(303) 293-1788, or (800) 227-8917

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

6.0 Emergency Communications Plan

The Permittee must communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

The Permittee must describe what happened, impacts to the environment or other local resources, how the event was investigated, what response actions were taken, and the status of the response. For responses that occur over the long term (e.g., ongoing cleanups), the Permittee must provide periodic updates on the progress of the response action(s).

The Permittee must communicate with entities who need to be informed about or act in response to the event, including local water systems, CO_2 source(s), pipeline operators, landowners, and regional response teams (as part of the National Response Team).

7.0 Plan Review

In accordance with 40 CFR 146.94(d), the Permittee must periodically review the ERRP. Based on this review, the Permittee must 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 by modification. Amended plans or demonstrations must be submitted to the Director as follows:

a. At least once every five (5) years following its approval by the permitting agency,

b. Within one (1) year of an area of review re-evaluation

c. Following any significant changes to the facility, such as an addition of injection or monitoring wells, on a schedule determined by the Director; or

d. Within six (6) months following the occurrence of an emergency event under this ERRP, and

e. When required by the Director.

8.0 Staff Training and Exercise Procedures

The Permittee must integrate the ERRP into the plant-specific standard operating procedures and training program. All operations employees, well operators, project safety and environmental personnel, the project manager, plant operations supervisor, and corporate communications must receive training related to health and safety, operational procedures, and emergency response according to the roles and responsibilities of their work assignments. Initial training must be conducted by, or under the supervision of, the operations manager or a designated representative. Trainers must be thoroughly familiar with the Operations Plan and ERRP.

Refresher training must be conducted at least annually. New personnel must be instructed before beginning their work. Monthly briefings must be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

A record including the person's name, date of training, and instructor's signature will be maintained. These records may be requested by EPA and made available upon request.

ATTACHMENT G: CONSTRUCTION DETAILS

1.0 Introduction

The construction details for the injection well are described in this attachment and include construction requirements, injection intervals, casing, tubing, packer and cement specifications. The design parameters and materials selection are to ensure sufficient structural strength and mechanical integrity for the life of the Project.

2.0 Injection Well Design

Front Range 1-1 is a directionally drilled well whose surface and bottomhole locations are shown in Figure 1.

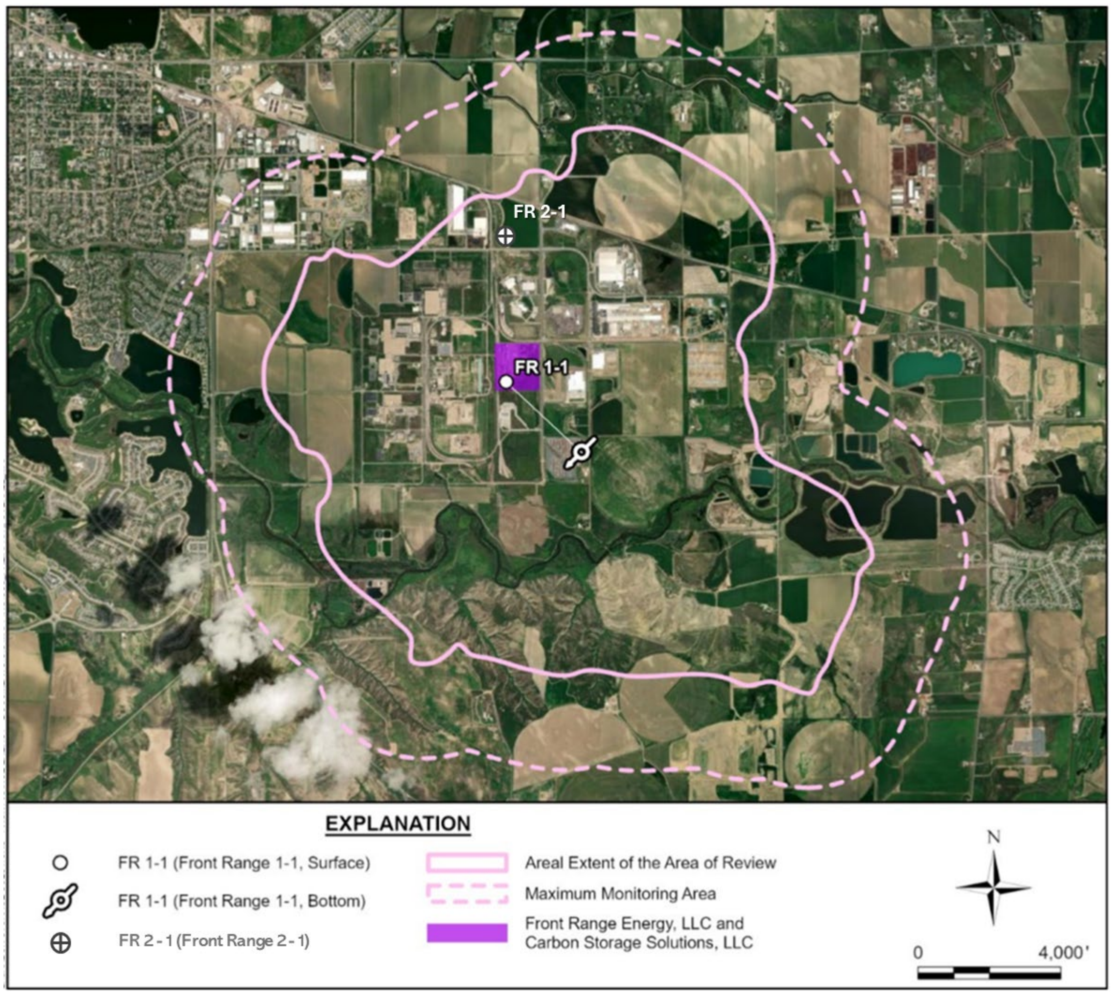


Figure 1: Surface and Bottomhole Location of Front Range 1-1

The well design includes three casing sections in addition to the conductor casing: 1) surface casing to protect shallow USDW while drilling to the injection zone, 2) intermediate section, and 3) a long string section from the injection zone to the surface. Figure 2 presents the directional wellbore schematic. Figure 3 shows the wellbore construction schematic in detail without deviation.

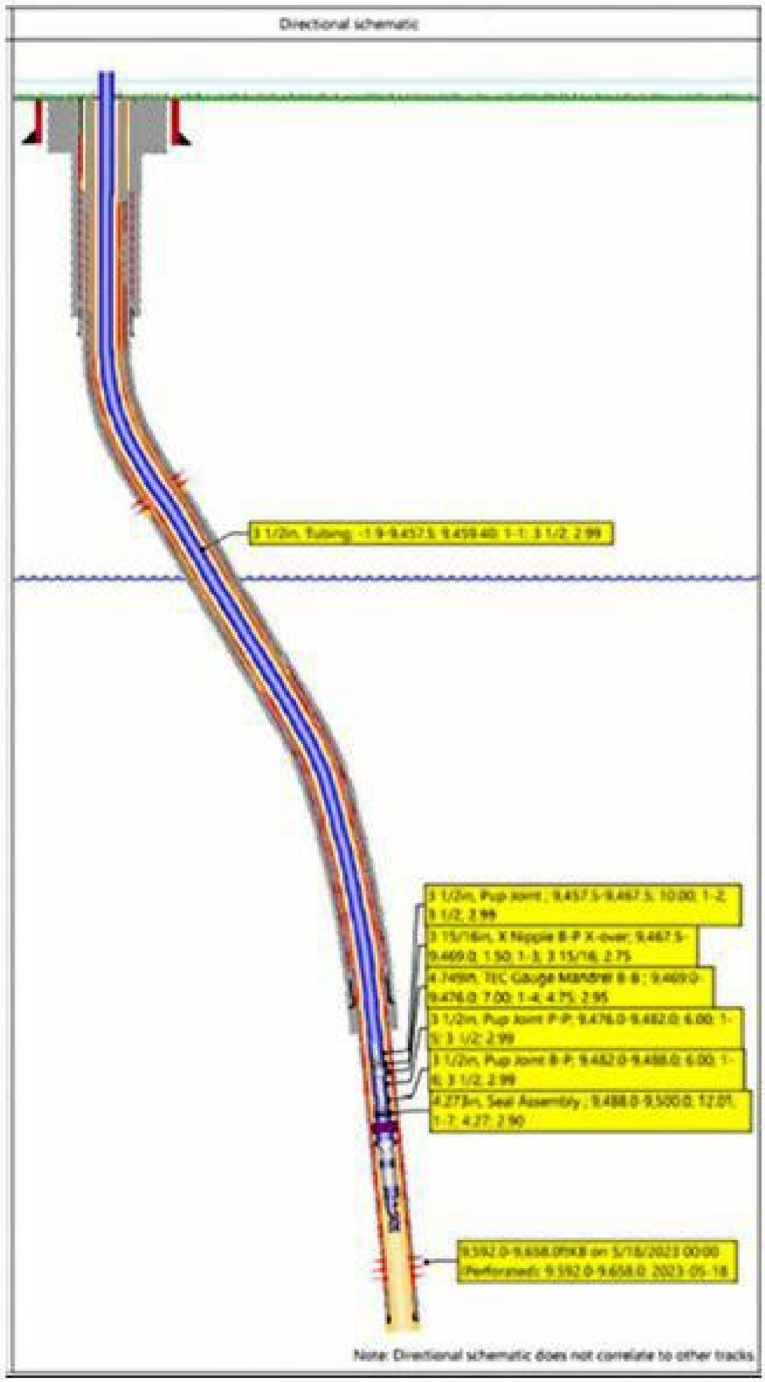


Figure 2: Directional Wellbore Schematic for Front Range 1-1

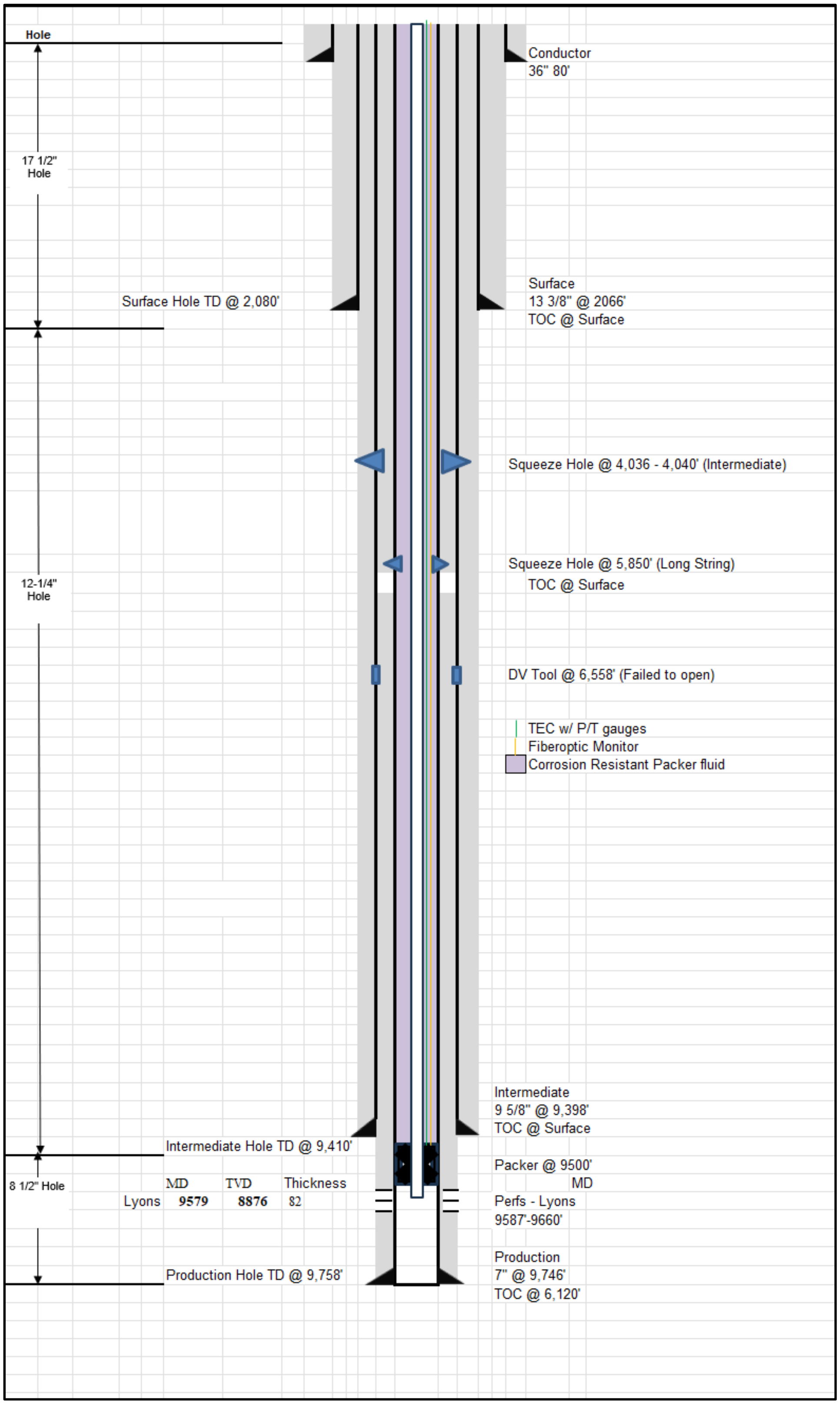


Figure 3: Wellbore Construction Schematic for Front Range 1-1 (Deviation not shown).

Details of well design are provided in the following tables. Table 1 contains the open hole diameters of each section, Table 2 lists the casing specifications, and Table 3 details the casing material properties. In addition, Table 4 contains the tubing and safety valve specifications, and Table 5 shows the packer material properties.

Table 1: Open Hole Diameters and Intervals

Open Holes	Depth Interval [ft]	Open Hole Diameter [inches]
Conductor	103	36
Surface	2,080	17 1/2
Intermediate String	9,410	12 1/4
Long String	9,758	8 1/2

Table 2: Casing Specifications

String	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Rating [psig]	Collapse Resistance [psig]
Conductor	103	20	19.5	52.78	A53B	NA	NA	NA
Surface	2066	13 3/8	12.615	54.5	J-55	BTC	2,730	1,130
Intermediate String	9398	9 5/8	8.835	40	HCL-80	BTC	5,750	4,230
Long String	9,746	7	6.184	29	13CR-80	VAM TOP	8,160	7030

ft = feet
lb/ft = pounds per foot
psig = pound-force per square inch, gauge
13 Chrome (CR) 80
NA = not applicable

Table 3: Casing Material Properties

Casing	Weight [lb/ft]	Grade [API]	Coupling	Joint Yield Strength (Lbs)	Body Yield Strength (Lbs)
Conductor	52.78	A53B	STC	60,000	35,000
Surface	54.5	J-55	BTC	909,000	853,000
Intermediate String	40	HCL-80	BTC	837,000	916,000
Long String	29	13CR-80	VAM TOP	676,000	676,000

Table 4: Tubing and Subsurface Safety Valve Specifications

Name	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Strength [psig]	Collapse Strength [psig]	Tensile Strength [Lbs]
Injection Tubing	9,495	3 1/2	2.99	9.2	13-CR95	JFEBEAR-CR T&C R2	12,070	12,080	207,000
Subsurface Safety Valve	9,498.7	2 3/4	1.33	NA	Inc 925	12 Otis SLB	11,000	11,000	NA

Table 5: Packer Material Properties

Packer								Casing Interface		
Type and Material	Setting Depth [ft]	Length [ft]	Outer Diameter [inches]	Inner Diameter [inches]	Tensile Rating [Lbs]	Burst Rating [psig]	Collapse Rating [psig]	Nominal Weight [lb]	Max Inner Diameter [inches]	Min Inner Diameter [inches]
Permanent Nickel Alloy 925	9,500	4	5.875	4	232,800	10,410	9,940	NA	4	2.5

The annulus space between the long string casing and injection tubing must be filled with fluid.

The completion fluid must be treated with a corrosion inhibitor that is compatible with the wellbore environment and bottomhole temperatures to prevent the internal corrosion of the long string casing and the external corrosion of the injection tubing.

3.0 Injection Well Cement Requirements and Details

The Permittee must ensure that the surface casing extends to the base of the lowermost USDW and is cemented to surface, consistent with 40 CFR 146.86(b)(2). All cement utilized in the well construction is corrosion resistant cement for use in CO_2 projects, as shown in Table 6.

This was accomplished by multiple strings of casing (surface and intermediate) and cement.

Table 6: Cement used during Front Range 1-1 Construction

Surface Section

Cement Type	Depth Interval (ft)	Description
Class G Cement	0 to 2,043	Cemented to surface, standard cement selection for contact with formation fluids

Intermediate Section

First Stage – 9,375 ft MD

Cement Type	Depth Interval (ft)	Description
Litepoz 3 (Lead Slurry)	2,043 to 9,375	Density of 13.5 ppg, yield of 1.64 ft^3/sk
EverCRETE (Tail Slurry)	9,375 to 9,387	Density of 14.8 ppg, yield of 1.21 ft^3/sk

Second Stage – Perforations at 4,040 ft MD

Cement Type	Depth Interval (ft)	Description
Litepoz 3 (Lead Slurry)	470 – 4,040	Density of 12 ppg, yield of 1.8 ft^3/sk
CemFIT Heal (Tail Slurry)	470 – 4,040	Density of 13.5 ppg, yield of 1.64 ft^3/sk

Production Section – 9,746 ft MD

Cement Type	Depth Interval (ft)	Description
CemFIT Heal Slurry	0 to 3,905	Lead cement with a density of 12.0 ppg and a yield of 1.80 ft3/sk
MidLead Slurry	3,905 to 8,127	Intermediate cement with a density of 12.0 ppg and a yield of 2.01 ft3/sk
EverCRETE Slurry	8,127 to 9,746	Tail cement with a density of 14.80 ppg and a yield of 2.01 ft3/sk, recommended for CO2 resistance

During construction verification, the EPA determined that the long string cement job only emplaced cement to approximately 6150 ft MD. The regulations at 40 CFR 146.86 requires one long string of casing extending from the injection zone to surface and must be cemented from the injection zone to surface.

<u>Front Range 1-1 Remediation Cement Job</u>

To remediate the well, the Permittee perforated and squeezed at 5850 feet MD and pumped 206 bbls cement and cement returns to surface. The Permittee used CO_2 resistant cement as required by the construction requirements at 40 CFR 146.86.

<u>4.0 Monitoring Well Design</u>

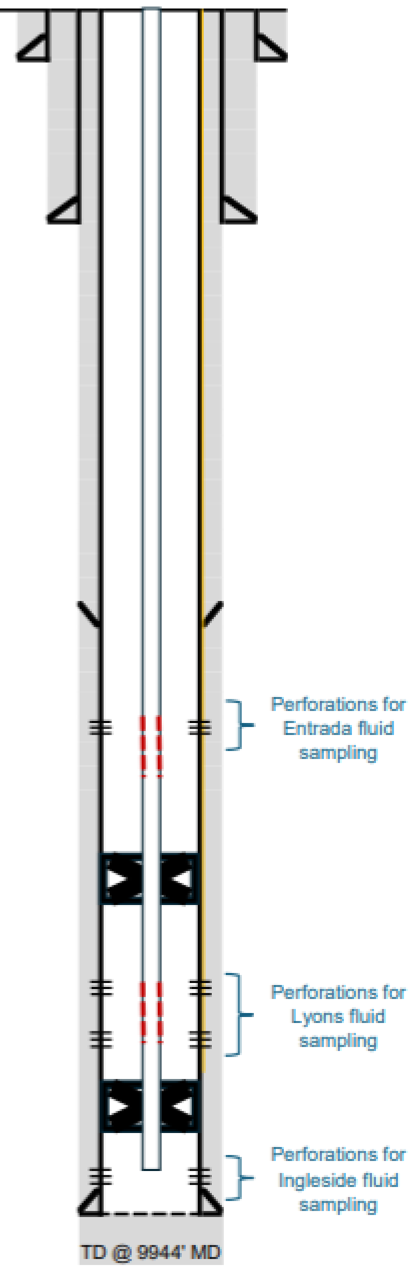
Front Range 2-1 is a vertically drilled well whose surface hole locations are shown in Attachment B, Figure 1. The well design includes three casing sections in addition to the conductor casing:
1) surface casing to protect shallow USDW while drilling to the injection zone, 2) intermediate section, and 3) a long string section from the injection zone to the surface. Figure 4 shows the wellbore construction schematic in detail.

Figure 4: Wellbore Schematic for Front Range 2-1

Front Range 2-1 Wellbore Diagram - Vertical Well

API: 05-123-52656

Formation Name	Top (MD)	Bottom (MD)	Hydrogeologic Role
Fox Hills	173'	226'	USDW
Richard	2,393'	2,584'	
Parkman	3,518'	3,827'	
Sussex	4,215'	4,287'	
Shannon	4,599'	4,720'	
Sharon Springs	6,804'	6,842'	
Niobrara	6,842'	7,137'	
Fort Hays	7,137'	7,158'	
Codell	7,158'	7,363'	
Greenhorn	7,363'	7,447'	
Graneros	7,447'	7,589'	
D Sand	7,589'	7,604'	
Huntsman/Mowry	7,604'	7,631'	
Muddy (Dakota J)	7,631'	7,724'	
Skull Creek	7,724'	7,859'	
Inyan Kara (Dakota / Cheyenne	7,859'	7,987'	
Morrison	7,987'	8,197'	
Ralston Creek	8,197'	8,227'	
Entrada	8,227'	8,319'	USDW
Lykins	8,578'	8,578'	Upper Secondary Confining Zone
Freezeout Shale (Member Lykii	8,692'	8,698'	
Forelle (Member Lykins)	8,698'	8,772'	
Glendo (Member Lykins)	8,772'	8,872'	
Opeche Mbr (Up. Satanka)	8,872'	8,902'	Primary Upper Confining Zone
Blaine Evaporite Mbr (Up. Sata	8,902'	8,952'	
Lyons	8,952'	9,027'	Sequestration Zone
Owl Canyon (Lower Satanka)	9,027'	9,256'	Lower Confining Zone
Ingleside	9,256'	9,804'	USDW
Fountain	9,804'	TD	



*Wellbore diagram not to scale

Details of well design are provided in the following tables. Table 7 contains the open hole diameters of each section, Table 8 lists the casing specifications, and Table 9 details the casing material properties. In addition, Table 10 contains the tubing and safety valve specifications, and Table 11 shows the packer material properties.

Table 7: Open Hole Diameters and Intervals

Open Holes	Depth Interval [ft]	Open Hole Diameter [inches]
Conductor	80	26
Surface	2,010	13 1/2
Long String	9,390	8 1/2

Table 8: Casing Specifications

String	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Rating [psig]	Collapse Resistance [psig]	Tensile Strength [Lbs]
Conductor	0 - 80	16	15.01	84	J-55	EUE	2,980	1,410	1,326,000
Surface	0 - 2,010	10 3/4	10.05	40.5	J-55	Buttress Thread	3,130	1,580	629,000
Long String	0 - 6,700	7	6.18	29	HCL-80	Buttress Thread	8,160	7,020	676,000
Long String	6,700 – 9,390	7	6.18	29	13-CR80	Vallourec VAM	8,160	7,020	676,000

Table 9: Casing Material Properties

Casing	Weight [lb/ft]	Grade [API]	Coupling	Joint Strength (Lbs)	Yield Strength (Lbs)
Conductor	84	J-55	EUE	817,00	1,326,000
Surface	10-3/4	J-55	Butress	420,000	629,000
Long String	7	HCL-80	Buttress	780,000	676,000
Long String	7	13-CR80	VAM	676,000	676,000

Table 10: Tubing and Subsurface Safety Valve Specifications

Name	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Strength [psig]	Collapse Strength [psig]
Tubing	0 - 8,758	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
Sliding Sleeve	8,758 – 8,761	2.875	2.31	NA	L-80	EUE	10,400.00	8,946.00
Tubing	8,761 –9,381	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
X Nipple	9,381 – 9,382	2.875	2.31	NA	L-80	EUE	10,570.00	11,170.00
7" AHR Packer	9,382 – 9,386	6.13	2.38	NA	INC 925	EUE	8,710.00	8,400.00
Tubing	9,386 –9,454	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160.00
Sliding Sleeve	9,454 – 9,458	2.875	2.31	NA	Inc 925	EUE	14,300.00	12,300.00
Tubing	9,458 –9,557	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160.00
X Nipple	9,557 – 9,558	2.875	2.31	NA	Inc 925	EUE	14,530.00	14,550.00
7" AHR Packer	9,558 – 9,563	6.13	2.38	NA	INC 925	EUE	8,710.00	8,400.00
Tubing	9,563 – 9,569	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
X Nipple	9,569 – 9,570	2.875	2.31	NA	L-80	EUE	10,570.00	11,170.00
Tubing	9,570 – 9,576	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
XN Nipple	9,576 – 9,577	2.875	2.21	NA	L-80	EUE	10,570.00	11,170.00

Table 11: Packer Material Properties

Packer								Casing Interface		
Type and Material	Setting Depth [ft]	Length [ft]	Outer Diameter [inches]	Inner Diameter [inches]	Tensile Rating [Lbs]	Burst Rating [psig]	Collapse Rating [psig]	Nominal Weight [lb]	Max Inner Diameter [inches]	Min Inner Diameter [inches]
Hydraulic Set Perma-Latch Packer – Inc 925	8,896 – 8,901	5	6.013	2.38	145,000	8,710	8,400	NA	6.0	2.377
Hydraulic Set Perma-Latch Packer – Inc 925	9,063 – 9,068	5	6.013	2.38	145,000	8,710	8,400	NA	6.0	2.377

The annulus space between the long string casing and injection tubing must be filled with fluid.

The completion fluid must be treated with a corrosion inhibitor that is compatible with the wellbore environment and bottomhole temperatures to prevent the internal corrosion of the long string casing and the external corrosion of the injection tubing.

5.0 Monitoring Well Cement Requirements and Details

The Permittee must ensure that the surface casing extends to the base of the lowermost USDW and is cemented to surface, consistent with 40 CFR 146.86(b)(2). All cement utilized in the well construction is corrosion resistant cement for using in CO_2 projects, as shown in Table 12.

This was accomplished by multiple strings of casing (surface and intermediate) and cement.

Table 12: Cement used during Front Range 2-1 Construction by Section

String	Depth Interval	Cement Type
Conductor Casing	Surface – 80 ft	Class G
Surface Casing	Surface – 2,000 ft	Class G
Long String (Upper Stage)	0 - 8,319 ft	VersaCem
Long String (Lower Stage)	8,319 - 9,380 ft	CorrosaLock

ATTACHMENT H: FINANCIAL RESPONSIBILITY DEMONSTRATION

1.0 Financial Assurance

The Permittee must demonstrate and maintain financial responsibility, and the demonstration must be approved by the Director pursuant to 40 CFR 146.85. The Director may disapprove the use of a financial instrument if it is determined to be insufficient to meet financial assurance requirements. Financial instrument(s) must be from the following list of qualifying instruments:

- Trust Funds
- Surety Bonds
- Letters of Credit
- Insurance
- Self Insurance (i.e. Financial Test and Corporate Guarantee)
- Escrow Account
- Any other instrument(s) satisfactory to the Director

The Permittee may demonstrate financial responsibility by using one or multiple qualifying instruments for specific phases of the Project in accordance with 40 CFR 146.85(a)(6)(i)-(vii). The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.

The financial responsibility instruments must be sufficient to address endangerment of underground sources of drinking water (USDWs) and comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass bond rating when applicable.

When Self Insurance (i.e., Financial Test and Corporate Guarantee) is used as the financial mechanism, the Permittee must update such coverage on an annual basis.

2.0 Activities Requiring Financial Assurance

Pursuant to 40 CFR 146.85, the Permittee is required to demonstrate financial ability to successfully complete all the tasks associated with performing corrective action, plugging injection and monitoring wells, post-injection site care, site closure, and implementation of an emergency remedial response. The estimated costs of these activities, as provided by Permittee and approved by the Director, are presented in Table 1.

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

Activity	Instrument	Cost (million $US)
Corrective action	Not Applicable	Not Applicable
Plugging injection well	Front Range 1-1: $456,000 Front Range 2-1: $342,000	Surety Bond
Post-injection site care	$6,000,000	Surety Bond
Site closure	$290,000	Surety Bond
Emergency and remedial response	$15,000,000	Third Party Insurance

If needed, the cost estimates will be reevaluated prior to the commencement of injection operations.

3.0 Activities Covered by Financial Responsibility

3.1 *Plugging Injection Wells*

The Well Plugging Plan is found in Attachment D of this Permit.

3.2 *Post-Injection Site Care and Site Closure*

Details of the post-injection site care plan are found in Attachment E of this Permit. Post-injection site care costs were estimated from cessation of injection to site closure and account for seismic studies at five-year intervals, maintenance of the wells until closure, and monitoring the site to ensure protection of USDWs. Site closure costs include plugging monitoring wells, removal of surface facilities, and reclamation of the site.

3.3 *Emergency and Remedial Response*

The Emergency and Remedial Response Plan is found in Attachment F of this Permit.

ATTACHMENT I: QUALITY ASSURANCE AND SURVEILLANCE PLAN

The Permittee must adhere to the Quality Assurance and Surveillance Plan (QASP) submitted as part of the permit application. The QASP establishes the quality assurance and quality control (QA/QC) procedures applicable to all sampling, testing, monitoring, laboratory analysis, data management, and reporting activities conducted to demonstrate compliance with the requirements of the Underground Injection Control (UIC) Class VI program under 40 CFR Part 146.90(k).

The QASP specifies the procedures and standards necessary to ensure that all data generated for the project are of known and documented quality and are suitable for regulatory compliance determinations. The plan includes requirements for standard operating procedures, instrument calibration and maintenance, analytical methods, chain-of-custody procedures, data verification and validation, and corrective actions.

The Permittee must conduct all monitoring, sampling, testing, and reporting activities associated with the pre-injection, injection, and post-injection site care periods in accordance with the approved QASP. Any material modifications to the QASP must be approved by the Director prior to implementation.