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EPA Region 8

Underground Injection Control (UIC) Program

Response to Public Comments
Class VI Permit No. CO62455-12770

Issued to:

Carbon Storage Solutions

31375 Great Western Dr,

Windsor, CO 80550

Final Permit Issuance: July 29, 2026

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Introduction

Background

EPA Region 8's Underground Injection Control (UIC) Program is issuing a Safe Drinking Water Act Class VI Permit (Permit) to Carbon Storage Solutions, LLC (CSS) for geologic sequestration of carbon dioxide (CO_2) at the Front Range Storage Complex, Front Range 1-1 well, near Windsor in Weld County, Colorado. The project will inject a purified CO_2 stream captured from the adjacent Front Range Energy ethanol facility, at a maximum rate of 140,000 metric tons per year and up to 1.54 million metric tons over a projected 12-year injection period; the injectate must be at least 99 percent CO_2.

CO_2 will be injected into the Lyons Sandstone at approximately 8,876–8,958 feet below ground surface. The Lyons is an ~82-foot sandstone with suitable porosity and permeability for storage and total dissolved solids of ~34,076 mg/L at the well, indicating it is not an underground source of drinking water (USDW). Confinement is provided by the overlying Lykins Formation (notably the Opeche Shale and Blaine Evaporite members) and the underlying Lower Satanka (Owl Canyon) Formation; within the Area of Review (AoR) these confining zones are free of known transmissive faults or fractures.

The AoR was delineated using numerical modeling as the union of the maximum pressure front at Year 12 (end of injection) and the maximum CO_2 plume at Year 32 (end of the proposed alternative post-injection site care period). Because the modeled plume extends farther than the pressure front, the AoR is effectively defined by the Year-32 plume extent; the modeled AoR covers approximately 6.4 square miles.

As part of the application process, CSS submitted a request for an Injection Depth Waiver. The request was submitted because the proposed injection zone, the Lyons Sandstone, lies above the lowermost USDW, the Ingleside Formation, and Class VI regulations require injection below the lowermost USDW unless a waiver is approved. The waiver process requires a demonstration that injecting above the lowermost USDW will not endanger USDWs above or below the injection formation. *See* 40 C.F.R. § 146.95. As part of the regulatory process, EPA documented its evaluation of the applicant's submittal in a report. EPA's administrative record notes that the Lyons Sandstone is a deep, confined interval with thick low-permeability confining units above and below it, which support containment of the injected CO_2 and pressure front.

Public Review Process

On March 27, 2026, the UIC program provided a 30-day public notice of the draft Permit for conversion of the existing Class V injection well to a Class VI carbon sequestration well (Front Range 1-1) on regulations.gov docket # EPA-R08-OW-2026-1915 and on EPA's Region 8's UIC websites website: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#public-notices.

In addition to the public notice on EPA Region 8's UIC Program website, EPA published notices of the draft UIC Permit in the *Loveland Herald, Greeley Tribune, and the Fort Collins Coloradoan.* All notices directed readers to regulations.gov and EPA Region 8's UIC Program website, which contained links to the relevant documents for the proposed actions. These documents included the draft Permit, fact sheet, injection depth waiver, and complete application.

The EPA held a virtual public hearing on Monday April 27, 2026, from the EPA Region 8 headquarters, from 5:00 p.m. to 8:00 p.m. The public hearing was attended by 6 people. Attendees included representatives from CSS, a member of Wyoming's Department of Environmental Quality and one member of the public. Dan Sanders, CEO of Carbon Storage Solutions, provided comment on the draft Permit, and the one other speaker relinquished their time to Dan Sanders. EPA also received written comments from the applicant and several private citizens.

CHANGES TO THE FINAL PERMIT

Pursuant to the Permitting regulations at 40 CFR § 124.17, this section of the Response to Comments specifies which provisions of the draft Permit have been changed in the final Permit decision and provides a reason for each change.

1. Section E.13(e), Twenty-four-hour reporting requirements

Draft language:

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

Final language:

> **Twenty-four-hour reporting-** The Permittee must report to the Director within 24 hours of discovery any circumstance that may endanger human health or the environment, including:
>
> (iii) 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
>
> (iii) 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.

Reason for change: CSS commented that the subsection title is "Twenty-four-hour reporting," but the requirement for 24-hr reporting is not explicitly re-stated in the supporting subsection text. Furthermore, the text is unclear whether 24-hr deadline is tied to the time of the incident or tied to the time of discovery. The EPA agrees with the commenter that this reporting requirement is vague and is clarified by the addition of within 24 hours of discovery. This language was clarified throughout the permit where 24-hr reporting is required.

2. **Within 24 hours of discovery, changes made throughout the Permit attachments**
   Draft Language: "must report to the Director"

   Final Language: "must report to the Director within 24 hours of discovery"

   Impacted Sections: Permit Attachments: Testing and Monitoring Plan Section 7.2.1Testing and Monitoring Plan Section 7.2.2; Emergency and Remedial Response Plan Section 1.1(c); Emergency and Remedial Response Plan Section 4.0; Emergency and Remedial Response Plan Section 4.1.1; Emergency and Remedial Response Plan Section 4.2(a); Emergency and Remedial Response Plan Section 4.3.1(a); Emergency and Remedial Response Plan Section 4.3.1(b); Emergency and Remedial Response Plan Section 4.4.1; Emergency and Remedial Response Plan Section 4.4.2(b), Emergency and Remedial Response Plan Section 4.5(a), and Emergency and Remedial Response Plan Table 2.

   Reason for change: CSS commented that this requirement was unclear. The EPA agrees with the commenter that this reporting requirement is vague and is clarified by the addition of within 24 hours of discovery.

3. **Section F.1 Reevaluation of Area of Review (AoR) and Corrective Action**

Draft Language:

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.

Final Language:

At a minimum frequency not to exceed every four 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.

Reason for Change: A commenter expressed concern about the default 5-year time frame for review of the AoR, given that the injection period is only 12 years and would therefore require reevaluation only twice during injection. The commenter asserted that reevaluation should occur every 3 years. EPA agrees that, given the 12-year injection period, 5-year reevaluation intervals could potentially miss valuable indicators of how the project is maturing. EPA determined that decreasing the timeframe for reevaluation of the AoR is appropriate; however, EPA is decreasing the requirement to 4 years for the following reasons:

- Shortening the AoR re-evaluation interval from five to four years increases responsiveness to potential changes in subsurface conditions that may be needed since the Class VI well is in an active oil and gas field (e.g., new nearby wells, operational changes). Decreasing the interval improves timely detection of any need to adjust the AoR. The four-year timeframe requires re-evaluation of the AoR three times during the proposed injection period instead of two.
- A four-year interval is a reasonable exercise of EPA's discretion because it provides more frequent oversight than the regulatory minimum, aligns reevaluation with the project's 12-year injection period, and ensures review before the Post-Injection Site Care period begins. The Permit retains the adaptive triggers from the UIC regulations. Out of cycle AoR reevaluation will still occur if monitoring indicates plume or pressure behavior deviates from predictions, ensuring protection beyond the periodic schedule.

4. Section G.1(a) Cost Estimates Updates and Adjustments

Draft language:
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 Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, or the Emergency and Remedial Response Plan.

Final language:
Annually, by March 1 for every year of the Permit life. 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 Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan, or the Emergency and Remedial Response Plan.

Reason for change: CSS requested that all financial instruments reflect the updated March 1 deadlines. EPA agrees with this request because it provides greater clarity without changing the annual requirement, and reduces the administrative burden associated with tracking the one-year anniversary date. EPA recognizes that this revision will simplify the reporting of updates, adjustments, and amendments and will allow for complete review of financial documents.

5. Section I.5. Annulus fluid and packer verification

Draft Language:

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

Final Language:

(a) Fill annulus with approved noncorrosive fluid;

Reason for change:

CSS commented that the draft language defined the annulus fluid as an approved noncorrosive fluid but left unclear whether a tracer was required and how stability would be confirmed. CSS also explained that 40 CFR section 146.88(c) and the Class VI Well Construction guidance do not specify tracer use or methods for confirming stability, and proposed using a ~50:50 volume mixture of ethylene glycol and water with a corrosion inhibitor package as the annulus fluid. EPA agrees that this is reasonable because the draft Permit requirement regarding addition of tracer was ambiguous, and the EPA recognizes that there are other Permit requirements that achieve the same goal of identifying leaks due to external MI loss. These requirements include: distributed temperature surveys, well construction, and continuous monitoring of pressure and temperature. The final Permit now removes the tracer requirement and the stability-confirmation language, while retaining the requirement that the annulus be filled with an approved noncorrosive fluid.

6. Section I.6 (e) Baseline sampling and CO_2 stream characterization

Draft Language:

(e) Submit list of laboratories to the director for approval.

Final Language:

(e) For baseline data collected prior to issuance of this Permit, submissions must include laboratory qualifications/accreditation, Standard Operating Procedures, Method Detection Limits / Quantitation Limits, calibration/ Quality Assurance / Quality Control results, chains of custody, and a comparability/bridging memo demonstrating that methods, detection limits, and holding times meet or exceed current Permit requirements. For all future testing, submit list of laboratories to the Director for approval.

Reason for change: CSS commented that it had already collected several years of samples and requested that previously completed work be grandfathered. EPA will recognize prior baseline data collected by qualified laboratories, provided the data quality objectives are met and documented, to avoid duplicative sampling while maintaining data integrity. The final Permit now allows EPA to accept the existing baseline data, but CSS must still submit a list of laboratories to the Director for approval for all future testing. This approach is consistent with 40 C.F.R. §§ 146.87 and 146.90(a).

7. Section Q.2 Frequency of Emergency and Remedial Response Plan Amendments

Draft Language:
Ten years following the cessation of injection operations, the Permittee must annually collect and analyze the geochemistry of fluids and dissolved gases 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.

Final Language:

Deleted

Reason for change: This draft Permit language was a remnant of the Class VI Permit template that was inadvertently included in this permit section; it does not appear anywhere else in this Permit or the Attachments. Requirements for monitoring USDW groundwater quality and geochemical changes in the injection zone and above and below the upper and lower confining zones remain in the Final Permit, Attachment C.

8. Section O.3 24-Hour Reporting Requirements

Section O.3 24-Hour Reporting Requirements has been moved to Attachment F: Emergency and Remedial Response Plan Section 1.3.

Reason for Change:

CSS requested that Section O.3 be moved to Attachment F Emergency and Remedial Response Plan so that all emergency response-related provisions can be found in one place in the Permit. EPA agrees this is a reasonable request. The final Permit at section O.3 and references throughout the permit and attachments now refers to Attachment F to find 24-Hour reporting requirements, and a new section 1.3 has been added to Attachment F that includes the content that was formerly in section O.3.

9. Changed "psi" to "psig" throughout the Permit attachments

Draft Language: Permit used pounds per square inch (psi) throughout the Permit.

Final Language: Replaced pounds per square inch (psi) with pounds per square inch – gauge (psig).

Reason for change: This revision provides clarity to the CSS when recording measurements of pressure for the project.

10. Attachment A: Summary of Operating Requirements Table 1 Injection Well Operating Conditions, Parameters, and Limits

Draft Language:

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

PARAMETER/CONDITION*	LIMITATION	UNIT
Downhole Maximum Allowable Injection Pressure at the Lyons Sandstone	4,640	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.

Final Language:

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

Parameter/Condition*	Limitation	Unit
Downhole Maximum Allowable Injection Pressure at Gauge Proximate to Packer	4,653	psig
Minimum Annulus Pressure above Tubing Differential (during injection only)**	100	psig
Carbon Dioxide Purity (minimum)	99	percent volume
Maximum cumulative mass injected in any 12-month period***	140,000	metric tons/year
Maximum cumulative mass of injected CO_2 over the project life	1,540,000	metric tons

* See Attachment C, Table 2 Devices, location and frequencies for monitoring location.
** The minimum annulus pressure requirement applies only during injection operations and does not apply during approved maintenance or other non-injection periods.
*** The maximum injection limit in this table is an annual cumulative mass limit, not an instantaneous injection rate.

Reason For Change: CSS requested clarification of the pressure units used in Table 1 and throughout Attachment A and that the annulus pressure requirement be revised to allow exceptions during maintenance and other non-injection periods. CSS also requested clarification of whether the annual injection limit is intended to be a cumulative annual mass limit or an instantaneous injection rate, and if it is an annual limit, that it be raised by ~10% to 140,000 metric ton/yr to provide headroom for uncertainty in current CO_2 supply and future incremental expansions in CO_2 supply from increased ethanol production. EPA agrees that the pressure units and operating limits should be clearly stated to avoid ambiguity and better reflect operational conditions. EPA also agrees that the annulus pressure requirement should be limited to injection operations and that the annual injection limit should be expressed as a cumulative mass limit to clarify compliance expectations.

Table 1 was revised to use specific pressure units expressed in psig and the maximum injection limit was revised to state a maximum cumulative mass injected in any 12-month period of 140,000 metric tons/year to allow for uncertainty in CO_2 supply and potential future incremental expansions. The maximum cumulative mass of injected CO_2 over the injection period remains unchanged at 1,540,000 metric tons. The corresponding footnotes were also added to clarify the scope of the annulus pressure requirement.

Row 1 of Table 1 also was revised to reference the downhole MAIP to the gauge proximate to packer rather than at the Lyons Sandstone to be consistent with the changes to Table 2 and Section 2.3 in Attachment C. To be consistent with changes to Section 1.0 of Attachment A, the MAIP in Row 1 was revised to reflect the value recalculated using an updated gauge depth and an approach that accounts for density differences between the step rate test fluid (fresh water) and the supercritical CO_2 injectate.

11. Attachment A: Downhole maximum injection pressure emergency shutdown point

Draft Language:

Table 2: Operational emergency shut down set points

ALARM TYPE		SET POINT	UNIT
Downhole Maximum Injection Pressure at the Lyons Sandstone	Shutdown point: At least 95% of downhole maximum allowable injection pressure	4,408	psig
Annulus Pressure (during injection)	Shutdown point: Minimum	100	psigg
	Shutdown point: Less than minimum allowable annulus over tubing differential	100	psigg

Final Language:

Table 2: Operational emergency shut down set points

ALARM TYPE		SET POINT	UNIT
Annulus Pressure (during injection)	Shutdown point*: Minimum	100	psig
	Shutdown point*: Less than minimum allowable annulus over tubing differential	100	psig

* The operational emergency shut down points for annulus pressure apply only during injection operations and do not apply during approved maintenance or other non-injection periods.

Reason for Change: CSS requested that injection operations be shut down at the maximum allowable injection pressure (MAIP), rather than at 95% of MAIP. EPA agrees that the Permit should not require shutdown at a downhole pressure below the MAIP. EPA had this requirement in the Permit previously when the MAIP was based on the fracture initiation pressure from the step rate test. When the EPA adjusted the MAIP to be based on the fracture propagation pressure, this requirement was not removed as intended. The Permit establishes the MAIP using the site-specific step-rate test (fracture propagation pressure) and includes an explicit 10% safety margin, consistent with 40 CFR section 146.88(a). This approach ensures injection pressures will not initiate or propagate fractures or endanger USDWs. Additional reductions are not required and would not materially increase protectiveness given existing safeguards, including downhole pressure alarms and automatic shutdowns, continuous pressure monitoring, MITs, and adaptive management.

CSS also requested that the annulus pressure shutdown points in Table 2 be deleted because they are redundant to requirements listed previously in Table 1 or that EPA add a footnote or other text to allow for exceptions during well maintenance and other non-injection periods. EPA added a footnote to further clarify that annulus pressure shutdown points apply only during injection.

12. Attachment A, Section 2 Startup Procedures

Draft Language:

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.

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

(a) 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.

(b) 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.

(c) 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

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

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

(f) 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.

(g) 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.

Final Language:

2.0 Startup Procedures

This section establishes standards for initial startup. The Permittee must design and execute an injection ramp up procedure that protects USDWs and complies with pressure limits and monitoring requirements.

2.1 Startup Ramp Plan (SRP)

At least 7 days before initial injection, the Permittee must submit an SRP to the Director for approval. The SRP must:

- Define stepwise rate increases (number of steps, target rates, and minimum step durations).
- Set criteria (e.g., pressure stabilization) for advancement to next step and for pausing or rolling back injection.
- Identify instrumentation used for control (Coriolis meter; downhole pressure/temperature proximate to the packer; wellhead and annulus pressures).
- Describe alarms/shutdowns and communication/reporting during startup.

2.2 Performance standards

Maintain downhole pressure below MAIP at all times (use the downhole gauge proximate to the packer), consistent with 40 CFR 146.88(a).

- Increase in discrete steps; each step must be ≥12 hours unless otherwise approved.
- Do not advance a step until pressure is stable as defined in the approved SRP.

Monitoring during startup

- Continuously measure and record: mass injection rate, downhole and wellhead , annulus pressure, and annulus fluid additions/removals.
- Maintain alarm setpoints and automatic shutdowns per Attachment C and Section I.4; base overpressure alarms on the downhole MAIP.

Reporting during startup

- Provide a daily summary to the Director including:

- Step timeline; target and actual injection rates; plots of injection rate vs. downhole pressure.

- Downhole and wellhead pressures and temperatures; changes in annulus pressure and fluid volume added.

2.3 Anomalies and required actions

Indicators of anomalous behavior include, but are not limited to:

- Disproportionate pressure response to modest rate increases, sudden injectivity changes not attributable to temperature/viscosity, sustained annulus pressure rise (>50 psig) or loss of annulus fluid, repeated alarms/shutdowns, or other evidence suggesting fracturing or loss of integrity.

If anomalous behavior occurs: (i) Immediately hold or reduce the rate; if integrity loss or fracturing is suspected, cease injection and shut-in the well (ii) Measure and record the instantaneous shut-in pressure (ISIP). (iii) Notify the Director within 24 hours of discovery. (iv) Submit a diagnostic plan (e.g., pressure falloff, MIT, Casing Inspection Log, additional surveillance) and a revised SRP if needed; do not resume higher rates without Director's approval.

2.4 Transition to normal operations

Startup ends after the well sustains the planned average rate with stable pressures for ≥48 consecutive hours (or as specified in the approved SRP). Thereafter, monitoring and reporting revert to Attachment C (Testing and Monitoring Plan).

Permittee must submit written notification to the Director that Start up Ramp is complete and Permittee is transitioning to normal operations.

2.5 Director authority

The Director may require modifications to the SRP, additional diagnostics, or alternative step sizes/durations based on observed well response.

Reason for Change: CSS requested that Attachment A: Summary of Requirements, Section 2.0 be revised to allow flexibility in implementing the six-level stair-step injection profile in Table 3, so that the rate and duration of each step can be adjusted based on well response and other field conditions, rather than following a rigid and potentially overaggressive schedule that could overpressure the well. CSS also requested that the plan include a provision requiring the Permittee to provide written notification to EPA when the start-up period has ended and normal operations have begun. EPA agrees with these requests because startup behavior is inherently well- and site-specific, and a performance-based Startup Ramp Plan (SRP) provides equal or greater protection than a fixed six-step, six-day schedule by allowing the Permittee to adjust the ramp based on observed well conditions while still maintaining strong safeguards. The revised Permit therefore replaces the prescriptive ramp with an SRP to be submitted for approval at least 7 days before startup, including step increases, criteria for advancing or rolling back steps, required instrumentation, alarm and shutdown triggers, and communication procedures, while preserving continuous monitoring, daily startup reporting, anomaly response requirements, and Director oversight. This approach is protective because it keeps the binding downhole MAIP, requires immediate investigation and notification if anomalous conditions occur, and gives EPA the ability to review and modify the plan as needed, thereby improving fracture-risk and well-integrity control without changing other protective limits such as cumulative volume or MAIP.

13. Attachment C: Testing and Monitoring Plan, Section 1.2 Analytical Parameters and Table 1 Draft Language:

1.6 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 required composition of 99% carbon dioxide.

Table 1: CO_2 stream analytical methods for constituent composition.

Parameter	Frequency of Analysis	Analytical Method
Isotopes: $\delta^{13}C$ of DIC	Every 5 years	Isotope ratio mass spectrometry
CO_2 Purity	Quarterly	ISBT 2.0
Water (H_2O)		ISBT 3.0
Hydrogen Sulfide		ISBT 14.0
Total Sulfur		ISBT 13.0
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) Oxygen (O_2) Argon (Ar) Hydrogen (H_2) Helium (He)		ISBT 4.0

Final Language:

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 required composition of 99% carbon dioxide.

During baseline sampling required by the Permit in section I.6(a), or for any proposed new source in section K.3, the Permittee must sample the CO_2 stream for all analytes listed below. If an analyte is not detected in the baseline or initial sample for a specific source, then the Permittee will not be required to sample for it in future sampling and analysis events for that specific source.

Table 1: **CO_2** stream analytical methods for constituent composition.

Parameter	Frequency of Analysis	Analytical Method
Isotopes: $\delta^{13}C$ of DIC	Every 5 years	Isotope ratio mass spectrometry
CO_2 Purity	Quarterly	ISBT 2.0 or approved equivalent method
Water (H_2O)		ISBT 3.0 or approved equivalent method
Hydrogen Sulfide		ISBT 14.0 or approved equivalent method
Total Sulfur		ISBT 13.0 or approved equivalent method
Total Hydrocarbons as Methane		ISBT 10.0 or approved equivalent method
Total Non-Methane Hydrocarbon (TNMHC)		ISBT 10.1 or approved equivalent method
Carbon Monoxide (CO)		ISBT 5.0 or approved equivalent method
Ammonia (NH_3)		ISBT 6.0 or approved equivalent method
Oxides of Nitrogen (NO_x)		ISBT 7.0 or approved equivalent method
Nitrogen Dioxide (NO_2)		ISBT 7.1 or approved equivalent method
Nitric Oxide (NO)		ISBT 7.2 or approved equivalent method
<u>Non-Condensable Gases:</u> Nitrogen (N_2) Oxygen (O_2) Argon (Ar) Hydrogen (H_2)		ISBT 4.0 or approved equivalent method

Helium (He)		

Reason for Change: The Permittee requested removal of routine testing requirements for analytes that are not reasonably anticipated to be present in the CO_2 stream, based on the facility design, process configuration, and baseline injectate characterization. EPA agrees that routine monitoring should be limited to constituents reasonably expected to be present in the injectate, consistent with 40 C.F.R. § 146.90(a), and that requiring routine analysis of analytes not supported by the process chemistry or available data is not necessary. Therefore, the Permittee will be required to sample each source for all analytes initially to determine whether it is expected to be present in the injectate. If an analyte is not detected in the baseline or initial sample and analysis, then future sampling of that source will not need to include the non-detected analyte.

CSS's carbon capture and liquefaction operations include multiple purification steps intended to remove water, sulfur compounds, trace organics, and other potential contaminants prior to injection. In addition, CSS has commissioned the system and obtained a representative baseline injectate sample analyzed by an independent laboratory using the ISBT methods specified in the Permit. That characterization demonstrated that the injectate consists of highly purified CO_2, with only trace concentrations of water vapor and non-condensable gases and other analytes below detection limits. EPA finds that this information provides a sufficient technical basis to limit routine analyte testing to constituents reasonably anticipated to be present in the stream.

EPA further notes that the Permit includes multiple provisions that ensure continued protectiveness. First, startup characterization of the injectate across the approved analyte list establishes the initial chemical profile of the stream. Second, the Permit retains Director approval authority over analytical laboratories and methods, ensuring that monitoring is conducted using scientifically valid and defensible procedures. Third, the Permittee is required to notify the Director and obtain approval prior to any change in CO_2 supply, capture configuration, or treatment process that could affect injectate composition. Should such a change occur, the Permittee must submit a new analyte demonstration and conduct quarterly monitoring of the Table 1 constituents, as well as any additional analytes the Director determines are necessary based on the revised stream composition. EPA also agrees that allowing approved equivalent analytical methods, rather than limiting analysis to a single ISBT method for each analyte, is appropriate where the alternative methods are scientifically sound and capable of producing reliable results. This approach provides operational flexibility, expands access to qualified laboratories, and reduces the potential for monitoring delays associated with limited laboratory availability, while maintaining data quality and regulatory oversight.

Accordingly, EPA is revising Table 1 to limit routine analyte monitoring to those constituents reasonably expected to be present in the injectate and to allow the use of approved equivalent analytical methods, while retaining the safeguards necessary to ensure the CO_2 stream remains protective for geologic sequestration.

14. **Attachment C, Testing and Monitoring, 2.0 Monitoring Locations and Frequency and Table 2: Devices, Locations, and Frequencies for monitoring on Front Range 1-1**

Draft Language:

<u>2.0 Continuous Recording of Operational Parameters</u>

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)).

Table 2: Devices, locations, and frequencies for monitoring at Front Range 1-1

Parameter	Device(s)	Location	Sampling Frequency	Recording Frequency	Reporting Frequency	Reporting Parameter
Injection Pressure at Wellhead (psi)	Pressure Gauge	Wellhead	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Injection Rate (bbl/day)	Orifice Meter	Wellhead	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Injection Volume (calculated) (bbl)	Volumetric Flow meter & computer	CO_2 Delivery Flowline	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Cumulative Injection Volume (bbl)	Volumetric Flow meter & Flow computer	CO_2 Delivery Flowline	Continuous (min every 10 sec)	Monthly	Semi-Annual	Lifetime Cumulative
Annular Pressures (psi)	Pressure Gauges	Wellhead and bottom hole above packer	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Annulus Fluid Volume (bbl)	Volumetric measurement	Wellhead	As needed	Monthly	Semi-Annual	Monthly Total
CO_2 Stream Temperature (deg F)	Electronic Thermocouple	Wellhead	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
CO_2 Stream Temperature (deg F)	Distributed thermal sensing system	Temperature profile along entire well	Continuous (min every 10 sec)	Monthly	Semi-Annual	Single monthly profile measured while injecting
Injection Pressure at Formation (psi)	Pressure Gauge	Downhole gauge within 20 ft of top perforation	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Temperature at Formation (deg F)	Temperature Sensor	Downhole sensor within 20 ft of top perforation	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum

Final Language:

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 volume added; and CO_2 stream temperature (40 CFR 146.90(b), 146.88(e)(1), and 146.89(b)).

Table 2: Devices, locations, and frequencies for monitoring at Front Range 1-1

Parameter	Device(s)	Location	Sampling Frequency	Recording Frequency	Reporting Frequency	Reporting Parameter
Injection Pressure at Wellhead (psi)	Pressure Gauge	Wellhead	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum
Injection Rate (metric ton/day)	Coriolis flow meter & flow computer	CO_2 Delivery Flowline	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum
Injection Volume bbl[standard]/day	Coriolis flow meter & flow computer	CO_2 Delivery Flowline	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum
Cumulative Injection Volume bbl[standard]	Coriolis flow meter and flow computer	CO_2 Delivery Flowline	Continuous (min every 15 min)	Monthly	Semi-Annual	Lifetime Cumulative
Annular Pressures (psig)	Pressure Gauges	Wellhead and bottom hole above packer	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum
Annulus Fluid Volume Added (gal)	Annulus Fluid Added to System (gal)	Annulus Fluid System	As needed	Monthly	Semi-Annual	Monthly Total
CO_2 Stream Temperature (deg F)	Temperature Sensor	CO_2 Delivery Flowline	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum

Downhole Pressure (psig)	Pressure Gauge	Downhole gauge located proximate to the packer	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum
Downhole Temperature (deg F)	Temperature Sensor	Downhole sensor proximate to the packer	Continuous (min every 15 min)	Monthly	Semi-Annual	Average, Minimum, Maximum

Notes:

1) Primary injection rate reporting is on a mass basis (metric tons). Where volumetric flow and injection volume are reported, bbl[standard] uses CO_2 bubble-point at 60°F as the standard condition.
2) A sampling frequency of no greater than every 15 minutes satisfies the continuous recording requirement at 40 CFR 146.88(e)(1) and 146.90(b).

Reason for Change: CSS requested revisions to Attachment C: Testing and Monitoring Plan, Table 2 to clarify monitoring terminology, align units and instrument descriptions with project-specific instrumentation, and improve consistency with operational reporting practices. EPA agrees that several of the requested revisions are appropriate to enhance clarity, reduce ambiguity, and better reflect the approved monitoring configuration for the facility, provided the revised language continues to satisfy the requirements of the Class VI program.

With respect to the injection monitoring entries in Table 2, Rows 2 through 4, EPA agrees that use of a Coriolis flow meter is acceptable where the device is installed, maintained, and calibrated in accordance with the approved quality assurance and surveillance plan and is capable of accurately measuring the applicable injection parameters. EPA also agrees that the monitoring language should reflect the actual approved location of the injection flow measurement instrumentation on the CO_2 delivery flowline, rather than at the wellhead, where such location is supported by the facility design and monitoring system. In addition, EPA agrees that reporting injection rate and cumulative injection volume on a mass basis is appropriate where consistent with the Permit's operational limits and reporting framework. Furthermore, CSS could not accommodate the amount of injection data that would result from sampling every 10 seconds, as this requirement was added without a full understanding of how CSS would store the data; therefore, the 15-minute sampling interval reduces the load on data storage while still providing appropriate operational oversight and safety.

Regarding Table 2, Row 6, EPA agrees that the annulus monitoring provision should be revised to more accurately describe the monitored parameter as fluid added to the annulus system, rather than annulus fluid volume, to better align with the Class VI regulations and the intended protective function of the monitoring requirement. EPA further agrees that identifying the monitored location as the annulus fluid system is more precise than referencing the wellhead, provided the revised language continues to ensure that changes in annulus fluid inventory are adequately tracked as an indicator of well integrity.

With respect to Table 2, Row 7, EPA agrees that the temperature monitoring provision should be revised to use a broader term such as temperature sensor rather than limiting the Permit to a specific sensor type, where the selected instrument is approved, calibrated, and capable of meeting Permit requirements. EPA also agrees that locating the temperature measurement on the CO_2

delivery flowline is acceptable where it reflects the approved system configuration and supports consistent monitoring of the injectate conditions.

EPA also deleted Row 8, because CSS demonstrated that the distributed thermal sensing system requirement was not necessary for the approved monitoring program and requested its removal. EPA determined that the remaining monitoring provisions are sufficient to support the approved external mechanical integrity framework and overall protectiveness of the permit. For Table 2, Rows 9 and 10, EPA agrees that the monitoring language should be revised to more accurately reflect the parameters being measured and the approved locations of the downhole monitoring devices. The Permit should distinguish between downhole pressure and downhole temperature, rather than referencing formation pressure or formation temperature, where the approved instrumentation is located proximate to the packer and is intended to monitor conditions in the injection string or associated downhole environment. EPA also agrees that the device location should be described as proximate to the packer rather than within a fixed distance from the top perforation, where such terminology better reflects the as-built monitoring design and remains protective of underground sources of drinking water.

Accordingly, EPA is revising Attachment C, Table 2 to improve consistency with the approved monitoring configuration, clarify units and terminology, and ensure that the Permit accurately reflects the facility's monitoring system, while retaining all requirements necessary to ensure compliance with the Class VI program and to protect human health and the environment. Section K.4 of the Permit also was revised to reference pressure at the downhole gauge rather than at the depth of the formation for consistency within the Permit.

15. Attachment C, Testing and Monitoring, 2.2 System Monitoring Details

Draft Language:

<u>2.2 System Monitoring Details</u>

Injection operations parameters recorded on a continuous basis in Table 2 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 must 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 must be calculated using the mass flow rate combined with the pressure and temperature conditions in the injection zone. The calculated injection volumes must, 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 annulus (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 must be measured using the accumulator levels and the brine reservoir level on the well-control system. The accumulator and brine reservoir levels must be measured using a level transmitter. The transmitters must 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 must require further investigation.

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

Final Language:

2.2 System Monitoring Details

Injection operations parameters recorded on a continuous basis in Table 2 must be connected to the main facility through a supervisory control and data acquisition (SCADA) system, or an equivalent programmable logic controller (PLC) approved by the Director, to record 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 amounts must be calculated on a mass basis and used to update the computational model 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 volume of annulus fluid added, must be monitored continuously in accordance with 40 CFR 146.90(b). The annulus fluid system must include level instrumentation configured to notify the Permittee when the system approaches a loss of level. A Low-Level Alarm (LAL) must trigger prompt investigation. Variations in annulus fluid level during non-steady-state operations, including startup, shutdown, or changes in CO_2 rate or temperature, do not by themselves constitute an anomaly. If investigation determines that the LAL is attributable to a loss of internal mechanical integrity, the Permittee must immediately cease injection and follow the shutdown and notification procedures in Attachment F (Emergency and Remedial Response Plan).

The pressure differential between the annulus and the tubing at the depth of the packer must be calculated by the Permittee.

Reason for Change:

CSS requested that Section 2.2 of Attachment C be revised to better reflect the approved monitoring configuration and the Class VI regulatory framework by: using a mass-based approach for tracking injection quantities and updating the computational model; clarifying that annulus monitoring applies to the amount of annulus fluid added, rather than continuous measurement of annulus fluid volume; removing any implication that a specific two-tank configuration is required; allowing an independent PLC-based monitoring and alarm system in lieu of a direct SCADA connection, provided the Control Room has access to the data; and requiring a Low-Level Alarm and follow-up investigation, with immediate cessation of injection and implementation of Attachment F procedures if a loss of internal mechanical integrity is identified.

EPA agrees with the comment because these revisions improve clarity, align the Permit more closely with the Permittee's approved system design, and better reflect the applicable Class VI regulations while maintaining the level of protection needed to detect and respond to potential mechanical integrity issues. EPA revised Section 2.2 accordingly to require mass-based injection accounting and computational model updates, clarify that annulus monitoring concerns the amount of fluid added to the annulus system, remove any requirement for a specific two-tank configuration, allow an independent PLC-based monitoring and alarm system with Control Room access, and require a Low-Level Alarm, prompt investigation, and shutdown and notification procedures if internal mechanical integrity is compromised. This revised language also removes the implication that annulus fluid levels remain constant during normal operations and instead focuses on alarm conditions and operational responses that are protective and enforceable.

16. Attachment C, Testing and Monitoring, 2.3 Injection Rate and Pressure Monitoring

Draft Language:
The CO_2 injection pressure must 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 must 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 must be continuously monitored and controlled by the Permittee using the SCADA system. This system must continuously monitor, control, record, and must 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.

Final Language:

The CO_2 injection pressure must be monitored continuously at the wellhead and downhole proximate to the packer, as specified in Attachment C, Table 2. If the downhole pressure reaches the downhole maximum allowable injection pressure, the well must automatically shut down in accordance with Attachments A and F.

Any pressure anomalies outside normal operating specifications may indicate an issue within the well, such as loss of mechanical integrity or a tubing restriction, and must be investigated by the Permittee to determine the cause and corrective action. Downhole pressure data will be used to calibrate the computational model throughout the injection and PISC phases.

The SCADA/well-control system must limit downhole pressure to the MAIP listed in Attachment A and must continuously monitor, control, record, alarm, and execute shutdowns if specified control parameters exceed their allowable ranges. Operating conditions, parameters, limits, and alarm setpoints are provided in Attachment A, Tables 1 and 2.

Reason for Change: CSS requested removal of language stating that changes in downhole pressure may be caused by changes in injection flow rate, because the CO_2 supply for the project is fermentation off-gas from an ethanol production facility and the injection rate is expected to vary by approximately ±16 percent over a 12-hour period during normal operations. CSS explained that, under these operating conditions, routine fluctuations in injection rate are an expected characteristic of the supply source and should not be described in a manner that could be interpreted as indicating an abnormal pressure condition.

EPA agrees that the proposed revision improves clarity by distinguishing anticipated operational variability from conditions that may indicate a concern for well or formation integrity. The referenced language could imply that normal, expected injection-rate variability is itself a potential cause of pressure anomalies, which may create unnecessary confusion for operators and reviewers and could lead to nuisance alarms or unwarranted follow-up actions. Removing that language more accurately reflects the project's supply characteristics and control philosophy, while maintaining the focus of monitoring on indicators relevant to protectiveness.

EPA concludes that the change is protective because the Permit retains the requirement to monitor downhole pressure at the appropriate monitoring location and to use that information to identify conditions that could affect mechanical integrity, over pressurization, or formation containment. The Permit also continues to require a response to pressure excursions and other anomalous operating conditions through established alarm and shutdown provisions. Accordingly, deleting the phrase, *or may be caused by a change in injection flow rate,* does not reduce oversight or compromise protectiveness; rather, it prevents normal operational variability from being mischaracterized as an abnormal condition while preserving the monitoring and response framework necessary to protect USDWs.

CSS also requested that the language be changed to indicate that downhole injection pressure must be monitored at a gauge proximate to the packer, rather than at the depth of the Lyons Sandstone Formation, to be consistent with the requested change to row 9 of Table 2 in Attachment C. EPA agrees with this change to maintain consistency throughout the Permit. CSS further requested that the text be revised to indicate that alarms and shutdown points are based on measurements from the downhole pressure gauge with a hydrostatic head adjustment for any difference between the depths of the downhole pressure gauge and the top the Lyons Sandstone Formation. EPA revised the text to indicate that the well must automatically shut down when the downhole pressure reaches the downhole maximum allowable injection pressure (rather than 95% of the downhole MAIP) to be consistent with revisions to Attachment A, Section 1.0.

17. Attachment C, Testing and Monitoring, 2.4 Calculation of Injection Volumes

Draft Language:

The injection volume into the reservoir must 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 must be measured by a volumetric flow meter and flow computer. The flow computer must 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 must be calibrated at the frequency recommended by the manufacturer. The volume of CO_2 injected must be calculated from the mass flow rate obtained from the volumetric flow meter and flow computer. The mass flow rate must be calculated based on the pressure differential, temperature, and pressure data. This flow meter must be placed on the CO_2 delivery line downstream of the compressor.

Final Language:

The injected volume must be calculated on a continuous basis from the measured CO_2 mass flow rate and the pressure and temperature conditions in the injection zone. The CO_2 mass flow rate must be measured by a Coriolis mass flow meter with a flow computer installed on the CO_2 delivery flowline downstream of the compressor. The flow computer must have digital output and be connected to the SCADA system or equivalent PLC for continuous monitoring and control of the CO_2 injection rate into the well. Injection rate data must be recorded at intervals no greater than every 15 minutes and summarized daily (average, minimum, and maximum). The cumulative injected mass and the calculated injected reservoir volume must be recorded and archived with time stamps.

Reason for Change:

CSS requested that the paragraph in Attachment C: Testing and Monitoring Plan, Section 2.4, Pages 15–16 be revised to align with changes made in #14 by identifying the Coriolis mass flow meter with the flow computer as the primary instrument, requiring data acquisition at intervals of no greater than 15 minutes with daily summaries of average, minimum, and maximum values, requiring semiannual calibration or verification in accordance with manufacturer recommendations, and confirming SCADA connectivity with digital outputs for continuous monitoring and control. EPA agrees with this request because it harmonizes the narrative with Table 2, removes the conflicting prescriptive requirement to use a volumetric flow meter and associated volumetric-to-mass conversions, and better reflects the technical realities of dense-phase CO_2 measurement, where direct mass flow measurement is more accurate due to the variability of CO_2 density with pressure and temperature. In addition, CSS could not accommodate the amount of injection data that would result from sampling every 10 seconds, as this requirement was added without a full understanding of how CSS would store the data; therefore, the 15-minute sampling interval reduces the load on data storage while still providing appropriate operational oversight and safety. This revision is protective because it improves measurement accuracy, reduces conversion error, aligns the monitoring method with the compliance unit of metric tons per day, supports trend analysis and anomaly detection through frequent recording and daily summaries, maintains instrument traceability through regular calibration or verification, and enables reliable real-time monitoring, control, and alarm response through SCADA or equivalent PLC connectivity.

18. Attachment C, Testing and Monitoring, Section 2.5 Continuous Monitoring of Annular Pressure

Draft Language:

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

1. The tubing casing annulus (TCA) must be filled with corrosion resistant fluid. The fluid must 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 surface, the TCA pressure must maintain a minimum of 100 above the tubing pressure. See Attachment A, Table 1.
3. The pressure in the annular space directly above the packer must 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 must 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 must 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 must 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.

Final Language:

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

1. The tubing casing annulus (TCA) must be filled with corrosion resistant fluid. The fluid must have a specific gravity and a density that meets the requirements of the downhole conditions.
2. During injection, as measured at the surface, the TCA pressure must maintain a minimum of 100 psig above the tubing pressure, except during maintenance and other non-injection periods. See Attachment A, Table 2.

3. The pressure in the annular space directly above the packer must be maintained at least 100 psig higher than the adjacent tubing pressure during injection, except during maintenance and other non-injection periods.

After the initial standard annulus pressure test (SAPT), the annular pressure must 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 must 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 must be connected to the well control system to monitor the annulus pressure. Sudden, unexpected, and unexplained 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.

Reason for Change:

CSS asked EPA to revise Section 2.5 so that the TCA pressure requirement would apply only during injection, with exceptions for maintenance and other non-injection periods, to change the transmitter language so it only needed to connect to the well control system for monitoring rather than to both the well control system and SCADA, and to limit the pressure-change trigger to sudden, unexpected, and unexplained changes in annular pressure. EPA agrees these changes are reasonable because the blanket "100 psig at all times" requirement is not feasible during maintenance and shutdown periods, the 100-psig differential remains protective during injection, SCADA was unnecessarily prescriptive for this monitoring function, and not every annular pressure fluctuation should automatically trigger mechanical integrity testing if the change is expected or explainable. The final Permit deletes the standalone "100 psig at all times" language, retains the 100 psig differential pressure requirement only during injection with exceptions for maintenance and other non-injection periods, revises the transmitter sentence so it only requires connection to the well control system to monitor annulus pressure, and limits the trigger language to sudden, unexpected, and unexplained annular pressure changes that warrant further investigation.

19. Attachment C, Testing and Monitoring, Section 3.1 Monitoring location and Frequency

Draft Language:

Casing inspection logging must be conducted during planned well maintenance operations to evaluate downhole conditions and confirm absence of corrosion.

Final Language:

During planned well maintenance operations that involve removal of the wellhead and tubing, the Permittee must conduct casing inspection logging to evaluate downhole conditions and confirm the absence of corrosion.

Reason for Change:

CSS requested that the Permit language be revised so casing inspection logging would be required during planned maintenance only when that maintenance involves removal of the wellhead and tubing, rather than during every planned maintenance event. EPA agrees because the existing language could require intrusive logging during maintenance activities that do not provide the access needed to perform the log, while the revised language still ensures corrosion and downhole condition verification when the well is actually opened. The final Permit now requires casing inspection logging during planned maintenance operations whenever the planned maintenance operation involves removal of the wellhead and tubing.

20. Attachment C, Testing and Monitoring, Section 3.4 Casing Inspection Logs

Draft Language:

Permittee must perform casing inspection logging (CIL) during planned well maintenance on the FR 1-1 and FR 2-1, 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. Between planned maintenance events, Permittee may conduct CIL if corrosion coupon data indicates potential loss of material strength or performance inconsistent with operating standards. 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.

Final Language: Permittee must perform casing inspection logging (CIL) during planned well maintenance involving the removal of the wellhead and tubing on the FR 1-1 and FR 2-1, 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. Between planned maintenance events, Permittee may conduct CIL if corrosion coupon data indicates potential loss of material strength or performance inconsistent with operating standards. 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.

Reason for Change:

CSS requested that the Permit be revised so casing inspection logging would be required only during planned well maintenance involving removal of the wellhead and tubing, rather than during all planned well maintenance events. EPA agrees that this is reasonable because casing inspection logging requires access that is not always available during routine maintenance, and the revised language better reflects the conditions under which the test can be performed while still preserving EPA's ability to require CIL when needed to protect well integrity. The final Permit now states that Permittee must perform casing inspection logging during planned well maintenance involving the removal of the wellhead and tubing on FR 1-1 and FR 2-1, unless the Director waives that requirement due to well construction or other factors limiting the test's reliability, or based on satisfactory results from a casing inspection log run within the previous five years.

21. Attachment C, Testing and Monitoring, Section 3.5 Surface Detection Methods

Draft Language:

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 must provide field personnel with handheld equipment to identify the presence of CO_2 as part of the safety requirements for the site.

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

Final Language:

The Permittee must install, operate, and maintain fixed infrared open-path CO_2 detectors proximate to the Front Range 1-1 and Front Range 2-1 wellheads to continuously monitor ambient CO_2 concentrations during the injection period. The detectors must be integrated with the SCADA system or PLC for continuous monitoring and alarm notification, calibrated at least annually and after any maintenance or configuration changes in accordance with manufacturer recommendations, and configured to record and retain time-stamped concentration data and alarm events.

Reason for Change:

CSS requested that the draft leak detection language in Section 3.5 be deleted and replaced with a requirement for continuous CO_2 monitoring at the Front Range 1-1 and Front Range 2-1 wellheads using ambient air sensors, rather than weekly inspections, handheld detection equipment, and quarterly OGI camera surveys. EPA agrees that this is reasonable because continuous monitoring is more effective for detecting leaks early, is simpler to implement and maintain, and better aligns with the purpose of 40 CFR § 146.90(h), which allows surface air monitoring to detect CO_2 movement that could endanger a USDW. The final Permit now requires continuous ambient air CO_2 monitoring at the wellheads and removes the weekly inspection, handheld equipment, and quarterly OGI camera requirements, while also avoiding unnecessary coverage of pipelines and other features beyond the scope of Class VI well locations. EPA further updated the PISC monitoring framework to remove draft language and rely on the revised monitoring structure in Table 2.

22. Attachment C, Testing and Monitoring, Section 4.0 Groundwater Monitoring

Draft Language:

The Permittee must monitor USDW groundwater quality and geochemical changes in the injection zone and above and below the upper and lower confining zones, the Entrada Formation and Ingleside Formation, respectively, during the operation period to meet the requirements of 40 CFR 146.90(d) and 146.95(f). The Permittee must also monitor groundwater quality and geochemical changes in the shallow USDWs (Quarternary and Pierre Formation), as well as pressure. Front Range 2-1 (FR 2-1) will be used to take fluid samples and monitor pressure changes in the Entrada and Ingleside Formations.

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 must adhere to the Quality Assurance and Surveillance Plan (QASP) in Attachment I.

Pressures in the FR 2-1 monitoring well 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 must 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 as determined by the Director. Anomalous pressure or geochemical changes may trigger the need for additional well integrity testing for FR 2-1 as determined by the Director. These results may require an update to the Testing and Monitoring Plan. 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 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. Such changes in these parameters may also trigger the need for analyses of isotopic compositions.

Final Language:

The Permittee must monitor USDW groundwater quality and geochemical changes in the injection zone and above and below the upper and lower confining zones, the Entrada Formation and Ingleside Formation, respectively, during the operation period to meet the requirements of 40 CFR 146.90(d) and 146.95(f). The Permittee must also monitor groundwater quality and geochemical changes in the shallow USDWs (Quarternary and Pierre Formation), as well as pressure. Front Range 2-1 (FR 2-1) will be used to take fluid samples and monitor pressure changes in the Entrada and Ingleside Formations.

Pressure in the adjacent monitoring zones will be monitored from the wellhead of Front Range 2-1. Installed pressure gauge will record and transmit data continuously.

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

Pressures within the first USDW above the injection zone and the first USDW below the injection zone will be monitored in the FR 2-1 monitoring well at the wellhead. Migration of CO_2 or brine into these monitored formations would likely first be identified through pressure changes in the formation. An increasing pressure trend in these monitored zones would suggest that fluid movement across the confining zone has occurred. Any increasing trend in pressure in these monitored zones must 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 these monitoring zones as well as additional external well integrity investigations for FR 2-1 as determined by the Director. Anomalous pressure or geochemical changes in these monitored zones may trigger the need for additional well integrity testing for FR 2-1 as determined by the Director. These results may require an update to the Testing and Monitoring Plan. Anomalous changes in these monitored zones 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 are observed in the first USDW above the injection zone and the first USDW below the injection zone, the Permittee must obtain new samples from the affected formation(s) 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. Such changes in these parameters may also trigger the need for analyses of isotopic compositions.

Reason for Change:

CSS asked EPA to clarify the monitoring zones of concern by identifying them as the first USDW above and the first USDW below the injection zone, rather than using broader or less clear references to the injection zone and adjacent formations. EPA agrees that these changes make the monitoring scope clearer, focus pressure and geochemical response actions on the zones where migration would first be detected, and better align the Permit with the regulatory purpose of protecting USDWs under 40 CFR § 146.90(d) and § 146.95(f) and with FR 2-1's monitoring role. The final Permit now uses "first USDW above the injection zone" and "first USDW below the injection zone" as the monitored zones, applies the 5% pressure and 25% geochemical thresholds to those zones, and ties any follow-up sampling, inspection, or emergency-response actions to changes in those monitored zones rather than to the injection zone itself.

23. Attachment C, Testing and Monitoring, Table 6

Draft Language:

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

Parameters	Analytical Methods
Formation: Alluvial Aquifer and 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, NO3, and SO4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric Titration ASTM D513-11
Total Dissolved Solids	Gravimetry APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Formation: Entrada, 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
Anions: Br, Cl, F, NO3, and SO4	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

Parameters	Analytical Methods
	2510
Temperature (field)	Thermocouple
Formation: Lyons	
Cations: Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Ni, potassium, Se, SiO2, Si, Ag, Na, Sr, V, Zn	ICP EPA Method 6010
Anions: Br, Cl, F, NO3, nitrite, and SO4	Ion Chromatography EPA Method 300.0
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Ammonia, as N	EPA 350.1
Sodium Adsorption Ratio (SAR)	EPA 6010
Mercury	EPA 7470
Phenol	EPA 8270
Oil and grease	EPA 1664A
Ferric and ferrous iron	SM 3500
Total dissolved solids	SM 2540C
Alkalinity, Total (as CaCO3)	SM 2320B
pH	SM 4500
Total sulfide and sulfide as H2S	SM 4500
Total CO2 SM 4500	SM 4501
Cyanide SM 4500	SM 4502
Total organic carbon	SM 5310C

Final Language:

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

Parameters	Analytical Methods
Formation: Alluvium and Pierre Shale	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Tl	ICP-MS; EPA Method 6020
Cations: Ca, Fe, Mg, Na, Potassium, Si	ICP; EPA Method 6010B
Anions: Br, Cl, F, NO3, SO4	Ion Chromatography; EPA Method 300.0
Isotopes: δ13C of DIC	Isotope ratio mass spectrometry
Total dissolved solids	SM 2540C
Alkalinity, Total (as CaCO3)	SM 2320B
Alkalinity, Carbonate (as CaCO3)	SM 2320B

Parameters	Analytical Methods
pH (field)	Field Meter
Dissolved CO_2 (field)	Field Meter
Dissolved oxygen (field)	Field Meter
Turbidity (field)	Field Meter
Specific conductance (field)	Field Meter
Temperature (field)	Field Meter
Depth to water (field)	Field Meter
Water pressure/depth, temperature, conductivity/salinity (field)	See Continuous Monitoring of Groundwater Quality

Parameters	Analytical Methods
Formations: Entrada - Ingleside	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Tl	ICP-MS; EPA Method 6020
Cations: Ca, Fe, Mg, Na, Potassium, Si	ICP; EPA Method 6010B
Anions: Br, Cl, F, NO3, SO4	Ion Chromatography; EPA Method 300.0
Isotopes: δ13C of DIC	Isotope ratio mass spectrometry
Total dissolved solids	SM 2540C
Alkalinity, Total (as CaCO3)	SM 2320B
Alkalinity, Carbonate (as CaCO3)	SM 2320B
pH (field)	Field Meter
Dissolved CO_2 (field)	Field Meter
Dissolved oxygen (field)	Field Meter
Turbidity (field)	Field Meter
Temperature (downhole)	Downhole instruments; see Continuous Monitoring of Groundwater Quality
Pressure (downhole)	Downhole instruments; see Continuous Monitoring of Groundwater Quality

Parameters	Analytical Methods
Formation: Lyons	
Cations: Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Ni, Potassium, Se, SiO2, Si, Ag, Na, Sr, V, Zn	ICP; EPA Method 6010
Anions: Br, Cl, F, NO3, nitrite, SO4	Ion Chromatography; EPA Method 300.0
Isotopes: δ13C of DIC	Isotope ratio mass spectrometry
Ammonia, as N	EPA 350.1
Sodium Adsorption Ratio (SAR)	EPA 6010
Mercury	EPA 7470
Phenol	EPA 8270
Oil and grease	EPA 1664A
Ferric and ferrous iron	SM 3500
Total dissolved solids	SM 2540C
Alkalinity, Total (as CaCO3)	SM 2320B
pH	SM 4500
Total sulfide and sulfide as H2S	SM 4500
Total CO_2	SM 4500
Cyanide	SM 4500
Total organic carbon	SM 5310C

Reason for Change:

CSS requested that Table 6 be revised to align with its application and to improve clarity, consistency, and enforceability by matching the analyte lists and analytical methods used in Tables E.9-3 and E.10-2. EPA agrees that the revisions better reflect the approved monitoring design and reduce ambiguity across the Permit and application. EPA notes that this change is consistent with EPA's Class VI Guidance by requiring unstable analytes to be measured in the field, where appropriate, to reduce degassing artifacts and improve data quality. The final Permit now includes a "Formation(s)" row under each section to clearly tie parameters and methods to the target formations and monitoring locations. EPA further revised the table to remove the "Water Density (field)" requirement from the Entrada/Ingleside section as it is not specified in CSS's application and not necessary data to collect under this Permit. EPA also revised the table to specify downhole pressure and temperature for FR 2-1 consistent with the installed instrumentation and to correct the Lyons section method references by using SM 4500 for Total CO_2 and Cyanide and standardizing the ICP method references and parameter naming to eliminate drafting errors and support QA/QC.

24. Attachment C, Testing and Monitoring, Table 7

Draft Language:

Front Range 2-1				
Monitor annular pressure	Gauge at wellhead and down hole above packer	Continuous (minimum reading every 10 seconds)	Record Monthly Report Semi-annual	Average, Minimum, Maximum
Direct monitoring of pressure and temperature to detect CO_2	Downhole pressure and temperature gauge	Continuous (minimum reading every 10 seconds)	Record Monthly Report Semi-annual	Average, Minimum, Maximum
Direct monitoring of fluids to detect CO_2 in the Lyons, Entrada, and Ingleside	Geochemical analysis (Table 6, Attachment C)	Year 1-2: Annually; Year 3-8: Quarterly; Remainder: Annually	Year 1-2: Annually; Year 3-8: Quarterly; Remainder: Annually	Analytical Results
Indirect monitoring of CO_2 plume	Pulsed Neutron Log (PNL)	Annually	Annually	PNL
Indirect monitoring of CO_2 plume	Time-lapse Vertical Seismic Profile (VSP)	At least every five years, plus one at end of period	At least every five years, plus one at end of period	VSP surveys
Indirect monitoring of CO_2 presence above the Injection Zone	Time-lapse Vertical Seismic Profile (VSP)	At least every five years, plus one at end of period	At least every five years, plus one at end of period	VSP surveys
Internal mechanical integrity	Downhole pressure gauge	Continuous (minimum reading every 10 seconds)	Record Monthly Report Semi-annual	Average, Minimum, Maximum
	SAPT: See Table 8. Attachment C	See Table 8, Attachment C	Within 30 days of conducting test	MIT results
External mechanical integrity	See Table 8. Attachment C	Annually	Within 30 days of conducting test	MIT results
Corrosion monitoring	Fluid corrosivity testing (pH, chloride, O2)	Quarterly	Quarterly	Any changes from proposed operating data
Groundwater Monitoring Wells (SMW and DMW Wells)				
Groundwater Quality	Water level (pressure), temperature, conductivity, and salinity	Continuous (minimum reading every 30 minutes)	Year 1-2: Quarterly; Year 3-5: Semi-annually; Remainder: Annually	Average, Minimum, Maximum
Geochemical and isotopic monitoring to detect CO2	See Table 6. Attachment C	Year 1-2: Quarterly; Year 3-5: Semi-annually; Remainder: Annually	Year 1-2: Quarterly; Year 3-5: Semi-annually; Remainder: Annually	Analytical results
Soil Gas Monitoring Wells; Surface Air Monitoring Stations				
Surface leak detection	See Table 9 & 10 - Attachment C	See Table 9 - Attachment C	See Table 9 - Attachment C	Analytical results; Average, Minimum, Maximum

Final Language:

Objective	Method	Event Frequency	Record/Report Frequency/Requirement	Reporting Parameter
Front Range 2-1				
Monitor annular pressure	Gauge at wellhead and down hole above packer	<15 mins	Record Monthly; Report Semi-annual	Average, Minimum, Maximum
Direct monitoring of pressure and temperature to detect CO_2	Downhole pressure and temperature gauge	<15 mins	Record Monthly; Report Semi-annual	Average, Minimum, Maximum
Direct monitoring of fluids in surrounding USDWs (Entrada – first USDW above the injection zone; Ingleside – first USDW below the injection zone) to detect CO_2	Geochemical analysis (Table 6, Attachment C)	Year 1–4: Annually; Year 5+: Quarterly until plume passes the FR 2-1 injection zone; After plume passage: Annually	Year 1–4: Annually; Year 5+: Quarterly until plume passes the FR 2-1 injection zone; After plume passage: Annually	Analytical results
Direct monitoring of fluids in the injection zone (Lyons) to detect CO_2	Geochemical analysis (Table 6, Attachment C)	Year 1–4: Annually; Year 5+: Quarterly until plume passes the FR 2-1 injection zone; After plume passage: Cease monitoring	Year 1–4: Annually; Year 5+: Quarterly until plume passes the FR 2-1 injection zone; After plume passage: Cease reporting	Analytical results
Indirect monitoring of CO_2 plume	Time-lapse Vertical Seismic Profile (VSP)	At least every five years, plus one at end of period	At least every five years, plus one at end of period	VSP surveys
Indirect monitoring of CO_2 presence above the Injection Zone	Time-lapse Vertical Seismic Profile (VSP)	At least every five years, plus one at end of period	At least every five years, plus one at end of period	VSP surveys
Internal mechanical integrity	Downhole pressure gauge	<15 mins	Record Monthly; Report Semi-annual	Average, Minimum, Maximum
	SAPT: See Table 8, Attachment C		Within 30 days of conducting test	MIT results
External mechanical integrity	See Table 8, Attachment C	Annually	Within 30 days of conducting test	MIT results
Groundwater Monitoring Wells (SMW and DMW Wells)				
Groundwater Quality	Water level (pressure), temperature, conductivity, and salinity	Continuous (minimum reading every 30 minutes)	Year 1–2: Quarterly; Year 3–5: Semi-annually; Remainder: Annually	Average, Minimum, Maximum
Geochemical and isotopic monitoring to detect CO_2	See Table 6, Attachment C	Year 1–2: Quarterly; Year 3–5: Semi-annually; Remainder: Annually	Year 1–2: Quarterly; Year 3–5: Semi-annually; Remainder: Annually	Analytical results
Soil Gas Monitoring Wells; Surface Air Monitoring Stations				
Surface leak detection	See Table 9 & 10 – Attachment C	See Table 9 – Attachment C	See Table 9 – Attachment C	Analytical results; Average,

				Minimum, Maximum

Reason for Change:

CSS requested that the combined “direct monitoring of fluids” row be split into two separate rows—one for the surrounding USDWs, including the first USDW above and below the injection zone, and one for the injection zone—to better align the Permit with 40 CFR § 146.95(f)(3)(i) and (ii) and 40 CFR § 146.90(c)(2), clarify the distinct monitoring objectives, and make the requirements zone-specific and enforceable. EPA agrees that the revised structure better reflects the different risks and monitoring needs for the adjacent USDWs and the injection zone, and because the monitoring frequencies can be tailored to the modeled plume behavior at FR 2-1, with lower-frequency monitoring early in the project, quarterly monitoring as the plume approaches or passes FR 2-1, annual monitoring resuming after plume passage for the surrounding USDWs, and fluid sampling ceasing for the injection zone once the plume has passed because additional sampling would provide little new information and could increase operational risk without additional protectiveness.

CSS also requested that EPA delete the annual pulse neutron log (PNL) requirement because it was redundant and does not provide much additional insight above the direct fluid sampling and time-lapse VSP monitoring already included in the Permit. EPA agrees with CSS’s rationale regarding the PNL requirement prior to closure of the well because the PNL will not provide useful information until it reaches the monitoring well. However, during the post-injection site care phase, PNL data can provide valuable information on saturation percentages about pressure and plume dissipation. Therefore, EPA is removing the PNL requirement from Attachment B Area of Review and Corrective Action Plan Section 1.4 (A)(1) and Attachment C Testing and Monitoring Section 7.2.3 Saturation Detection Tools, but retaining the requirement at Attachment E: Post Injection Site Care and Site Closure Plan. EPA also revised the continuous recording minimum to less than 15 minutes to improve data management and maintain consistency with other continuous monitoring parameters.

CSS also requested removal of the quarterly “fluid corrosivity testing” row because it was not tied to a specific Class VI regulatory trigger. This proposed requirement in the draft Permit is duplicative of the corrosion coupon testing requirements described in Section 3 of Attachment C. To avoid confusion and ensure consistency across the permit conditions, this row has been removed in the final permit.

25. Attachment C, Testing and Monitoring, Section 5.0 Internal and External MITs

Draft Language:

Permittee may choose which logging and testing to demonstrate external mechanical integrity but must continue to use that same test for the remainder of the project.

Final Language:

Sentence is deleted.

Reason for Change:

CSS requested that EPA delete the sentence requiring the Permittee to continue using the same external mechanical integrity test for the remainder of the project and remove the related “must continue to use that same test” requirement from Table 8, because the restriction is overly prescriptive and limits flexibility in demonstrating external mechanical integrity. EPA agrees this change is reasonable because the Class VI regulations and guidance do not require the same external MIT method to be used throughout the project, and the Permit can still ensure protection of USDWs while allowing the Permittee to use an approved alternative method if the primary DTS-based method is unavailable or if a follow-up test is needed to investigate an anomaly. The final Permit now deletes the requirement that the same external MIT method must be used for the remainder of the project and allows flexibility in the method used, subject to approval and protectiveness requirements.

26. Attachment C, Testing and Monitoring, Section 7.0

Draft Language:

A summary of the methods used for CO_2 and pressure front tracking is provided in **Error! Reference source not found.**7.

Final Language:

A summary of the methods used for CO_2 and pressure front tracking is provided in Section 7 of Testing and Monitoring.

Reason for Change:

This language appeared in the Permit due to an error in a hyperlink. It has been changed to provide the correct reference.

27. Attachment C, Testing and Monitoring, Section 7.2.2

Draft Language:

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

Final Language:

Pressure and temperature gauges are deployed on the tubing above and below the packer that isolates to injection zone to monitor downhole conditions in real time. In the Front Range 2-1 well, the gauges and cables must be selected to withstand CO_2 service conditions as determined by the Director. Permittee must evaluate the data semiannually and interpret the results. If a sudden change in pressure or temperature is observed outside of well maintenance or direct sampling events, Permittee must immediately cease injection, notify the Director within 24 hours of discovery, and evaluate and identify the cause of the change.

Reason for Change:

CSS requested that the Permit language be revised so that sudden pressure or temperature changes observed during well maintenance or direct sampling at FR 2-1 would not automatically require immediate cessation of injection and notification, because such changes are expected during those controlled activities and would otherwise lead to nuisance shutdowns without improving protection. EPA agrees with this requested change because the revised language better focuses on unplanned anomalous conditions that are most indicative of potential integrity issues, while excluding known and controlled operational activities. The final Permit now requires immediate cessation of injection, 24-hour notification to the Director, and evaluation of the cause only when sudden changes occur outside of well maintenance or direct sampling events, which improves clarity and enforceability while maintaining protectiveness.

28. Attachment C, Testing and Monitoring, Table 9

Draft Language:

Table 9: Soil Gas Monitoring Locations and Frequency

Monitoring Activity	Monitoring Locations	Spatial Coverage	Sample Frequency	Record Frequency	Reporting 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[2] and vicinity	Continuous[1]	Monthly	Semi-annually
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[2] and vicinity	Quarterly	Quarterly	Semi-annually
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[2] and vicinity	Quarterly	Quarterly	Semi-annually

[1]Continuous is defined as measurements taken at 30-minute intervals, with a 6-hr averaged reading recorded
[2]Maximum Monitoring Area (MMA) equals AoR plus ½ mile.

Final Language:

Table 9: Soil Gas Monitoring Locations and Frequency (revised)

Monitoring Activity	Monitoring Locations	Spatial Coverage	Sample Frequency	Record Frequency	Reporting 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[2]	Continuous	Monthly (Min, Max, Average)	Semi-annually
Laboratory analysis of soil-gas samples from network of stations	SVP-1, SVP-2, SVP-3, SVP-4, SVP-5, SVP-6	Single-point measurements within AoR/MMA[2]	Annually	Quarterly (Min, Max, Average)	Annually
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[2]	Annually	Quarterly (Min, Max, Average)	Annually

Reason for Change:

CSS requested that the Permit retain continuous soil gas monitoring while reducing the frequency of confirmatory laboratory analysis of soil gas samples and CO_2 efflux measurements to annual, because 40 CFR § 146.90(h) does not require soil gas monitoring, and the Permit should reflect a risk-based approach that remains protective of USDWs. EPA agrees with this requested change because the likelihood of CO_2 or brine reaching the surface is very low given the thickness of competent rock above the injection interval, and the laboratory and efflux measurements function primarily as confirmatory checks on continuous monitoring rather than as the primary detection method. The final Permit now keeps continuous monitoring for timely anomaly detection, changes the confirmatory sampling and analysis frequencies to annual, adds clarity to record frequency by adding minimum, maximum, and average, reduces redundancy, and better aligns the Permit with CSS's monitoring program design and operating practices. CSS requested that the "record frequency" column be removed from this table or for EPA to clarify what data to record. EPA determined that this requirement is necessary and provided clarification in the table for CSS to record minimum, maximum, and average value.

29. Attachment E, Post Injection Site Care, Section 2.0

Draft Language:

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.

Final Language:

Computational modeling indicates that after injection ceases, the predicted CO_2 plume remains within the Lyons Formation and 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 a cross-section of the Lyons Formation with the CO_2 global mole fraction 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 was determined as the union of the maximum extent of the pressure front in Year 12 (end of injection period) and the maximum extent of the CO_2 plume at Year 32 (end of proposed alternate post-injection site care period). 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. 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.

Reason for Change:

CSS noted a discrepancy between the draft permit attachment and fact sheet regarding how the AoR was determined. The description in the fact sheet accurately described EPA's methodology. EPA is revising the language in Attachment E to make this correction.

30. Attachment E, Post Injection Site Care, Table 1

Draft Language:

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

Location	**Objective**	**Method**	**PISC Monitoring**	**Recording and Reporting Frequency**
USDWs above and below the confining zone monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Annual	Record: Annually Report: Annually
Soil Gas Monitoring	Monitor soil gas CO_2 across a network of stations	Single point measurements within AoR/MMA and vicinity	Continuous	Record: Monthly Average, Min, and Max Report: Semi Annually
FR 1-1 and FR 2-1	Confirming integrity of the Upper and Lower Confining Zone	Saturation logging (pulsed neutron logging)	Annual until plugging	Report: Annually
		Distributed thermal sensing	Continuous	Record: Single Monthly Profile Report: 6 monthly profiles Semi Annually

Final Language:

Location	**Objective**	**Method**	**PISC Monitoring**	**Recording and Reporting Frequency**
USDWs above and below the confining zone monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Every 5 years	Record: Every 5 years; Report: Every 5 years
Soil Gas	Monitor soil gas CO_2 across a network of	Single point measurements	Continuous	Record: Monthly Average, Min, and Max; Report: Semi

Location	Objective	Method	PISC Monitoring	Recording and Reporting Frequency
Monitoring	stations	within AoR/MMA and vicinity		Annually
FR 1-1 and FR 2-1	Confirming integrity of the Upper and Lower Confining Zone	Saturation logging (pulsed neutron logging)	Annual until plugging	Report: Annually

Reason for Change:

CSS requested the deletion of distributed thermal sensing monitoring from the PISC requirements and that the EPA removed references to "and/or DTS fiber" in the footnote to align with that deletion. EPA agrees that this change is reasonable because DTS is not required by the Class VI regulations for PISC, and integrity confirmation is addressed through external MITs and other specified monitoring methods. The final Permit now relies on the specified downhole gauges as the authoritative data source for daily pressure monitoring, while retaining the triggers for follow-up sampling and analysis of reservoir fluids, the lowermost USDW, and soil gas, as well as optional saturation logging if anomalies persist. This change improves clarity and enforceability, reduces unnecessary burden, and preserves protectiveness by maintaining effective monitoring for departures from reference pressure, temperature, and chemistry.

31. Attachment E, Post Injection Site Care, Table 2

Draft Language:

Location	Objective	Method	PISC Monitoring	Recording and Reporting Frequency
FR 1-1 FR 2-1	Fluid and dissolved gas chemistry	Fluid and dissolved gas sampling via wireline	Event-driven* until plugging	After any event, record and report to the Director
	Direct monitoring of pressure and temperature to ensure seal integrity	Pressure and temperature gauges or distributed thermal sensing	Continuously	Record: Monthly Average, Min, and Max Report: Semi Annually
	Indirect monitoring of CO_2 concentration	Pulsed neutron log	Annually until plugging	Report within 30 days of test
	Plume and pressure extent over time	Vertical seismic profile	At least every five-year, coincident with AoR Review until	Report after acquisition

			plugging or plume stabilization	
	External mechanical integrity	Pressure and temperature gauges; external MIT	MIT log at least every five-year period and before plugging	Report within 30 days of test
	Surface leak detection	Visual inspection at wellhead, optical gas imaging, cameras, surface sensors	Continuous surface monitoring and quarterly visual inspection until site closure	Record: Any leakage Report: Any leakage and submit quarterly inspection report
	Indirect monitoring of CO_2 presence above the Injection Zone	Pulsed neutron log	Event-driven* until plugging	After any event, record and report to the Director
	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Annually	Record: Annually Report: Annually
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	After any event, record and report to the Director

Final Language:

Location	Objective	Method	PISC Monitoring	Recording and Reporting Frequency
	Fluid and dissolved gas chemistry	Fluid and dissolved gas sampling via wireline	Event-driven* until plugging	After any event, record and report to the Director
	Direct monitoring of pressure and temperature to ensure seal integrity	Pressure and temperature gauges	Continuously	Record: Monthly Average, Min, and Max; Report: Semi Annually
	Indirect monitoring of CO_2 concentration	Pulsed neutron log	Annually until plugging	Report within 30 days of test
FR 1-1 FR 2-1	Plume and pressure extent over time	Vertical seismic profile	At least every five years, coincident with AoR Review until plugging or	Report after acquisition

Location	Objective	Method	PISC Monitoring	Recording and Reporting Frequency
			plume stabilization	
	External mechanical integrity	Pressure and temperature gauges; external MIT	MIT at least every five-year period and before plugging	Report within 30 days of test
	Surface leak detection	Visual inspection at wellhead, optical gas imaging, cameras, surface sensors	Continuous surface monitoring and quarterly visual inspection until site closure	Record: Any leakage; Report: Any leakage and submit quarterly inspection report
	Indirect monitoring of CO_2 presence above the Injection Zone	Pulsed neutron log	Event-driven* until plugging	After any event, record and report to the Director
Vadose Zone, Near surface	Isotopic analysis and chemical evaluation to detect changes from expected vadose zone chemistry	Isotopic analysis and chemical evaluation at installed soil gas monitoring wells	Event-driven*, triggered by P/T data or fluid sample results	After any event, record and report to the Director

Reason for Change:

CSS requested that the Permit language be revised to remove distributed thermal sensing and reference to “and/or DTS fiber” so that it is consistent with the revised PISC tables, which now reference downhole gauges only. EPA agrees with this change for the reason described in Change #30.

CSS stated that the yellow highlighting in the title of Attachment E, Table 2 appears to be a drafting leftover and requested that it be removed. EPA agrees that the highlighting is not substantive and appears to be an editorial artifact.

CSS requested deletion of Table 2, Row 8 because it overlaps with Row 1 and annual injection zone sampling during post-injection site care is unnecessary. EPA agrees that Row 8 duplicates the objectives addressed in Row 1, and the record supports retaining the event-driven monitoring approach rather than a separate annual requirement.

CSS requested that the phrase “at a minimum of 15 locations” be deleted from Table 2, Row 9 because its six installed soil gas wells are sufficient for the monitoring program. EPA agrees that the existing six soil gas wells provide adequate site coverage for vadose zone monitoring.

32. Attachment G, Well Construction, Section 3.0 Injection Well Cement Requirements and Details

Draft Language:

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.

Final Language:

The Permittee must ensure that the surface casing extends through the base of the nearest USDW directly above the injection zone and is cemented to surface, consistent with 40 CFR 146.95(f)(2)(iii). All cement utilized in the well construction is corrosion resistant cement for use in CO_2 projects, as shown in Table 6.

Reason For Change:

CSS commented that EPA included the wrong regulatory citation since this project includes an injection depth waiver. EPA agrees and revised the permit language to reflect the applicable regulatory citation for that circumstance. Specifically, EPA revised the surface casing requirement in Attachment G, Section 3.0, Page 63, so that the surface casing language is aligned with 40 CFR 146.95(f)(2)(iii) rather than 40 CFR 146.86(b)(2).

33. Attachment G, Well Construction, Table 4

Draft Language:

Name	Depth Interval (ft)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Coupling	Burst Strength (psigg)	Collapse Strength (psigg)
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	9,831 – 9,832	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
Sliding Sleeve	9,454 – 9,458	2.875	2.31	NA	INC 925	EUE	14,300.00	12,300.00
Tubing	9,458 – 9,577	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160.00
X Nipple	9,577 – 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

Final Language:

Name	Depth Interval ft	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	[API] Coupling	Burst Strength [psig]	Collapse Strength [psig]	Tensile Strength [Lbs]
Injection Tubing	9495	2.5	2.99	9.2	13Cr95	JFEBEAR-CR T&C R2	12,070	12,080	207,000
Subsurface Safety Valve	9498.7	2.75	1.33	N/A	INC 925	12 Otis SLB	11,000	11,000	N/A

Reason For Change:

CSS requested that Attachment G, Table 4 be revised to align with Table A.II.2-5 in the Well Construction Details document submitted with the application, noting that the draft permit version was overly restrictive and did not provide tangible benefit for reassembling well internals during a future workover. EPA agrees that the draft permit table did not match the application record and included information that was more restrictive than necessary. EPA therefore revised Attachment G, Table 4 to conform to Table A.II.2-5 in the application.

34. Attachment G, Well Construction, Table 10

Draft Language:

No Footnote

Final Language:

Added Footnote: *Minor changes in depth relative to the depths and mechanical details in Table 10 are allowable as long as the changes do not impact the functionality or mechanical integrity of the well.

Reason for Change:

CSS requested that EPA add a footnote to Table 10 stating that minor changes in depths and mechanical details are allowable so long as those changes do not affect well functionality. EPA agrees this revision is appropriate, as it provides the Permittee reasonable flexibility to make field adjustments to wellbore internals while maintaining the required level of protection for USDWs.

35. Attachment A, Summary of Operating Requirements, Section 1.0

Draft Language:

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 calculated as 0.58 psi/ft based on the fracture propagation pressure determined by a step rate test performed at the Front Range 1-1, 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 5,155 psi. The initial downhole MAIP for this Permit is therefore set to 90% of 5,155 psi, or 4,640 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 indicates the formation fracture pressure differs from the current value. The recalculated downhole MAIP becomes effective and enforceable upon written correspondence from the Director. A Permit modification is needed to implement a change to the MAIP.

Final Language:

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 percent of the fracture pressure of the Lyons Sandstone injection zone, measured at a downhole pressure gauge proximate to the packer in the Front Range 1-1 well. The fracture propagation pressure of the Lyons Sandstone was determined to be 5,155 psig at a true vertical gauge depth of 8,781 feet based on a step rate test performed at the Front Range 1-1. To account for density differences between the test fluid (fresh water) and the supercritical carbon dioxide injectate over the distance between the downhole gauge and the uppermost perforation (8,889 ft TVD), the MAIP is calculated using the equation below.

$$\mathbf{MAIP} = 0.90 * [\mathbf{FP} + 0.433 * (1 - \mathbf{SG} + \mathbf{SGFF}) * \Delta\, \mathbf{D}]$$

Where:

FP (psig) is the fracture pressure of the injection zone as measured at the downhole gauge. The fracture pressure must be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to determine the fracture pressure may be used, if approved by the Director,

SG (unitless) is the ratio of the maximum injection-fluid density to the density of water (at 4 degrees Celsius), where the maximum injection-fluid density is determined based on the range of operating conditions for pressure and temperature,

SGFF (unitless) is a fluctuation factor added to Specific Gravity to account for potential variations of the actual injected fluid specific gravity, and

Δ ***D*** (ft) is the true vertical distance between the downhole pressure gauge and the uppermost perforation.

The parameter values in the table below were used to calculate the initial authorized MAIP for this Permit. These parameters may be updated throughout the life of the well, pursuant to the conditions in Section K.4 of this Permit. Except during stimulation at specific times as approved by the Director, if a change in parameter values would result in pressure exceeding 90 percent of the injection zone fracture pressure, the downhole MAIP must be recalculated. The recalculated downhole MAIP becomes effective and enforceable upon written correspondence from the Director. A Permit modification is needed to implement a change to the MAIP.

Fracture Pressure (psig)	Specific Gravity	SG Fluctuation Factor	Δ Depth (ft)	Authorized MAIP (psig)
5,155	0.633*	0.05	108	4,653

*Specific gravity of the supercritical carbon dioxide is based on a density of 39.5 pounds per cubic foot (lb/ft^3) at a maximum operating pressure of 4,700 psig and minimum operating temperature of 240° F, divided by the density of fresh water (62.4 lb/ft^3).

Reason for Change:

The draft Permit calculated the initial MAIP based on the fracture gradient and a downhole pressure gauge placed at the top perforation in the Front Range 1-1 well. The draft Permit further stipulated that the gauge must be within 20 feet of the top perforation. This approach was used because the density of supercritical carbon dioxide varies greatly with pressure and temperature, and the approach would minimize concerns about the effects of variable density on the downhole pressure. CSS asked EPA to revise Attachment C, Testing and Monitoring, 2.0 Monitoring Locations and Frequency and Table 2: Devices, Locations, and Frequencies for monitoring on Front Range 1-1, because the draft Permit does not specify the monitoring depth within the Lyons, nor does it address any hydrostatic head differences between the depth of the downhole gauge and the required monitoring depth within the Lyons. In addition, CSS clarified that a permanent downhole pressure gauge is installed at 8,781 feet true vertical depth, rather than at the top perforation, and that the CO_2 injectate density would not vary greatly over the range of operating pressures and temperatures at the facility. EPA therefore determined that an approach to calculating the MAIP that accounts for density (hydrostatic head) differences between the step rate test fluid (fresh water) and the supercritical CO_2 injectate is appropriate, along with an accurate pressure gauge depth. Accordingly, the revised MAIP calculation provides a more accurate value for ensuring that fractures are not initiated or propagated within the injection zone.

See Change to Permit #14 for more information about location of pressure gauge.

RESPONSE TO COMMENTS

Geologic Characterization

1. **A commenter expressed concerns about the suitability of the proposed injection and confining zones. They note the complexity of Front Range geology, with pinch outs, faults, folds, undetected permeable zones, and thin beds, and assert that these formations outcrop along the Front Range to the west.**

   The commenter discussed the sources that CSS used and identifies what they allege is an inconsistency in CSS's geologic information: "they state 'The Front Range 1-1 CCS site is situated in the Denver-Julesburg (DJ) Basin, approximately 15 miles east of the Front Range mountains, in Weld County, Colorado' on page 33, which is a more accurate start to defining where the site is than, 'The Front Range 1-1 CCS Site, near Greeley, Colorado, is close to the basin axis, where sedimentary strata are deep' on page 34." The commenter also raises a concern about the Higley and Cox 2005 source, stating that "the publication's geology is overgeneralized and doesn't highlight the differences between the Northern and Southern Denver Basin, which other publications do (see the <u>FT-04-01 Guide to the Laramide Structures along the NE Flank of the Front Range</u> source)." The commenter alleges that "[s]uggesting that CSS have the greatest thickness of sedimentary rocks at their injection site in the northern region beyond the Greeley Arch is a distortion of the complicated geology in this region."

The commenter further identifies concerns with various maps and figures from the Permit application, claiming that the applicant's use of and modifications to these are either "sloppy work" or "purposely misleading."

The commenter expressed concerns about the quality of images in the application, asserting they preclude evaluation and are evidence that the applicant does not have the geologic expertise to perform the needed review.

Response:

EPA acknowledges the complexity of Front Range geology; however the proposed site was evaluated using all available information in the record, particularly extensive, site-specific data. This site-specific data in the record provides more accurate information than the generalized information that the commenter references. Based on review of the information in the record, EPA concluded the injection and confining zones are suitable for the proposed injection activity and protective of USDWs.

Injection and confining zones at the site are thoroughly characterized and protective of the adjacent USDWs. The record shows that the injection zone, the Lyons Sandstone, is approximately 82 feet thick, with an average porosity of 7.8% and an average permeability of 3.3 Millidarcy (mD). A laboratory analysis of a water sample collected from the Lyons indicated a TDS of 34,076 mg/L confirming it is not a USDW. Cross sections, maps, and seismic surveys show the reservoir is laterally extensive and the nearest outcrop is ~17 miles west of the site.

The confining layers are also low-permeability and protective, with average porosity less than 5% and average permeability less than 0.3 mD. The upper confining zone is the Lykins Formation, with primary confinement by the Opeche Shale (~29 ft; ~64% clay) and Blaine Evaporite (~55 ft; 88% anhydrite). Laboratory measurements indicate very low porosity and permeability, consistent with an effective seal. The lower confining zone is the lower Satanka (Owl Canyon) Formation; approximately 231 feet thick at the FR 1-1 well, with porosity ~2.8% and permeability ~0.0002 mD based on core tests, providing an effective lower seal.

EPA determined the confining zones above and below the injection zone are free of known transmissive faults or fractures within the area of review (AoR) and that the overall geologic setting will contain injected CO_2 and isolate it from USDWs, consistent with 40 CFR § 146.83.

EPA evaluated site-specific data in the record for faults, fractures, and seismicity. This evaluation noted regional wrench faults (e.g., Windsor and Johnstown); however, seismic interpretation near the well shows no large structures or faulting around the wellbore. A mapped fold ~4 miles south terminates below the injection zone, indicating movement predates deposition of confining layers. Image log analysis shows fractures at the wellbore are isolated and not transmissive across formations. EPA concluded there are no fluid migration pathways from the injection zone to USDWs within the AoR. The Permit requires ongoing seismic notifications and shutdown and assessment if a magnitude ≥3.5 event occurs within 50 miles, with corrective actions as needed, providing additional protection beyond siting requirements**.** Although the Lyons Formation does outcrop approximately 17 miles away along the Front Range, the geologic and hydrologic conditions at the site make westward migration of CO_2 to that outcrop implausible.

The commenter raises concerns about use of Higley and Cox 2005 and other sources. These sources were used for context, but as noted above, site-specific seismic, logs, core, and hydrogeologic data in the record provide more accurate information for evaluation at this site. Where generalized sources were cited, they were supplemented by local data and analyses to resolve formations, structures, and seal quality at the project footprint. Similarly, the commenter raised concerns about the application's descriptions of the basin setting, such as the DJ Basin near Windsor in Weld County. However, as explained above, while EPA considers all information in the record, the site-specific information provides greater accuracy in characterizing the site. Therefore, EPA based Permitting decisions on the site's measured properties, geologic structures, monitoring, and modeling results, rather than generalized basin descriptors, to determine suitability and protectiveness.

Finally, the commenter raises concerns about the quality of the application maps and figures, suggesting that they are evidence that the applicant does not have the geologic expertise to perform the needed reviews. EPA's evaluation of the information provided by the applicant found the information to be complete and appropriate in accordance with the UIC regulations. The administrative record contains the figures and their underlying analyses, including seismic sections and fracture reconstructions, which were reviewed for completeness and accuracy. The composite 2D line derived from a 3D volume shows continuity of reflectors and no large structures near the borehole; EPA's conclusions are supported by these data despite noted "moderate" resolution in one legacy line. The full technical basis is part of the docketed record for public review.

In sum, while the Front Range geology is complex regionally, EPA's decision is grounded in site-specific geologic and geophysical data, laboratory measurements, and vetted modeling that demonstrate the Lyons injection zone and over/underlying confining zones will safely contain injected CO_2 and protect USDWs.

2. **A commenter expressed concerns about the potential for geochemical reactions between the injected CO_2 and the injection and confining zones. They assert that minerals in the injection and confining zones will react with the CO_2 over time resulting in upward movement of the CO_2, dissolution of shallower formations, expansion of natural fractures, or liberation of trace metals that could contaminate USDWs.**

Response: The lithological, petrophysical, geomechanical, and geochemical properties of the upper and lower confining zones, along with an absence of faults or fractures (see EPA's responses to "Seismicity" comments below), indicate that these formations will provide a suitable trap to prevent the carbon dioxide from moving upward, thereby protecting USDWs, as required under 40 C.F.R. § 146.83.

EPA also recognizes that geochemical interactions between the CO_2 and formation fluids can cause porosity changes. For this reason, applicants must provide information on the compatibility of the formation fluids with the CO_2 injectate. This is required by regulation in 40 C.F.R. § 146.83(c)(3). In this case, CSS has already provided fluid samples from the injection zone and performed geochemical studies to identify any potential geochemical reactions that could affect injection operations. EPA reviewed water chemistry and data on the solids in the injection zone to evaluate whether geochemical reactions during injection (i.e., due to reactions with the injected CO_2) could alter CSS's ability to inject, affect the site's storage capacity (i.e., through changes in porosity and permeability), or cause the release of trace elements. The modeling results allowed the EPA to conclude that little diagenetic alteration will occur from CO_2 injection.

3. **A commenter expressed concern about the risk of a seismic event. Citing the complexity of fault geometries along the eastern flank of the Colorado Front Range, the commenter references faults in the area, including the Wrench Fault Zones (which, they assert, are not easily discerned and are known to cause earthquakes) and a minor fault at the base of the Blaine Formation.**

   The commenter expressed concerns about the potential for earthquakes, noting past events in Colorado due to the reactivation of pre-existing faults in response to injection. They expressed concerns about lack of active earthquake monitoring stations because the CU Boulder stations were shut down.

The commenter raised concerns about the potential for induced seismicity, asserting that the injection site is in an active oil and gas field, with salt water disposal wells nearby.

Response: EPA acknowledges concerns about the potential for induced seismicity, particularly in a region as geologically complex as the Colorado Front Range. EPA's technical review of the Permit application included an assessment of faults and fractures, existing (historic) seismicity in the area, and the probability of induced seismicity (earthquakes) due to injection activities as required by 40 C.F.R. § 146.82(a)(3)(v).

EPA also reviewed information provided by the Permittee to determine if any faults are present in the project area. Evaluation of faults, fractures, and seismic activity in the region of the Front Range 1-1 well location shows no fluid migration pathways from the injection zone to USDWs.

EPA acknowledges that the project is situated within the Denver-Julesburg Basin, a regional geologic feature spanning three states and characterized by a strike-slip stress regime. However, the permit record is based on site-specific information for the CSS project, which demonstrates that there are no mapped faults within the AoR or within or crossing the injection or confining zones in the project area, and no evidence of transmissive fractures that would provide a likely fluid migration pathway. Although regional tectonic conditions are considered in evaluating the broader geologic setting, the application data support EPA's conclusion that the likelihood of large-scale fluid migration pathways existing within the AoR is minimal.

While EPA acknowledges that the site is situated in the Denver-Julesburg Basin, a regional geologic feature spanning three states which is characterized by a strike-slip stress regime. Information in the application demonstrates that there are no faults in the AoR or within or crossing the injection or confining zones. and that the likelihood of large fluid migration pathways existing within the AoR is minimal. For example:

- Seismic reflector images provided by CSS and reviewed by EPA indicate there are no large structures or faulting around the wellbore. Approximately 4 miles south of the project area is a fault that is interpreted to terminate below the injection zone and therefore would not serve as a pathway for fluid movement or be affected by injection operations.
- Fracture Analysis Logs at the Front Range 1-1 well indicate that fractures are isolated and do not extend into adjacent formations, which suggests a low likelihood of fluid migration through fractures.
- Additional evidence shows the Lyons formation is isolated from surrounding formations with no evidence of communicating faults or fractures as provided by variations in total dissolved solids concentration and reservoir pressure, which indicate that the formations are not in hydraulic communication.

Recorded earthquakes serve as a general indicator of seismic activity and the potential existence of a stressed fault. A record of past earthquakes provides evidence of the presence of stressed faults in the area, a common criterion EPA considers when evaluating the potential for seismic activity and induced seismicity. The 2014 National Seismic Hazard Model for Colorado, which is based on seismicity and fault-slip rates and considers the frequency of earthquakes of various magnitudes, shows the CSS site is located in an area of less than a 10% risk.

EPA acknowledges that a linkage has been shown between injection activity in certain contexts and seismic events. Injection-related seismic activity is typically associated with an increase in subsurface pressure that activates stressed faults. As identified in EPA's 2015 report *Minimizing and Managing Potential Impacts of Injection-induced Seismicity from Class II Disposal Wells: Practical Approaches*, seismicity caused by injection wells is likely to occur only when all the following conditions are present: (1) there is a fault in a near-failure state of stress; (2) the fluid injected has a path of communication to the fault; and (3) the pressure exerted by the fluid is high enough and lasts long enough to allow movement along the fault line. The risk of pressure buildup is related to the volume and rate of injected fluids, and the likelihood of triggering a significant seismic event increases as the volume and rate of injection increase. Most examples of injection-induced seismicity occur in geological formations with low permeability and/or where the pressure or volume of fluid injected over time is quite large. Specifically, formations such as crystalline basement rock (deeper geological formations of igneous or metamorphic rock that underlie layers of sedimentary rock) have very low permeability. Where permeability is low, injected fluid cannot flow easily through the pores and therefore flow is oriented mainly through existing fractures or faults.

The Colorado Energy and Carbon Management Commission (ECMC) uses adaptive mitigation measures to manage induced seismicity. Their core measures include seismic monitoring, injection volume limits, and a "traffic light" system that requires operators to slow or halt pumping if seismic thresholds are exceeded. The Permit includes these best practices to reduce the impact of injection, as well as cementing the bottom of the wellbore to decrease direct flow pathways to the crystalline basement and maintaining injection pressures below fracture gradient. In addition, CSS performed a seismicity analysis, which includes identification of known faults. As described above, the Front Range 1-1 well is not located near any known faults and injection will be more than 1,500 feet above the basement, reducing risk of induced seismicity.

EPA acknowledges concerns about small magnitude seismic events that may not be felt or detected. However, EPA clarifies that such events would not affect the integrity of the well nor lead to movement of any faults that are miles away from the injection well.

While the potential for induced seismic activity near the injection well is low, several aspects of the project will mitigate the potential effects of any induced seismic activity:

- The injection well is constructed to withstand significant stresses, with multiple strings of casing that are cemented in place (per Part H of the Permit). The Permittee must continuously monitor the well during injection operations to identify any potential mechanical integrity concerns. In addition, the well is designed to automatically cease operation in the event the integrity of the well is compromised, including by a seismic event.
- The Testing and Monitoring Plan requires CSS to monitor seismicity around the project by monitoring the U.S. Geological Survey (USGS) earthquake network for all seismic events within 50 miles of the injection well. This information will be used to monitor for induced seismicity and allow adjustment of well operations as needed. If a seismic event with a moment magnitude greater than 3.5 occurs within 50 miles of the injection well, CSS must initiate shutdown, notify EPA, and monitor the well pressure, temperature, and annulus pressure of the injection well to verify well status and determine the extent of any failure. Furthermore, per Part L of the Permit, the Permittee must test the injection well to demonstrate external mechanical integrity before operations begin and annually throughout injection operations.

Any detected seismic activity would trigger the Emergency and Remedial Response Plan (Attachment F), and could result in cessation of injection operations depending on the magnitude, location and frequency of seismic events. If there has been a failure of monitoring equipment or a loss of mechanical integrity, CSS must implement the response actions listed in Attachment F of the Permit.

Concerns about USDWs

4. **A commenter expressed concerns about the safety of water supplies in the Town of Windsor near the injection project. They reference drought conditions in Colorado and assert that, since groundwater flow is to the north and east, a CO_2 leak could affect headwaters of Nebraska and Kansas aquifers and river systems. They suggest this possibility should be considered in the modeling.**

Response: EPA recognizes there are concerns about the safety of groundwater supplies. Based on CSS's AoR delineation modeling, the CO_2 plume is expected to extend over an area of 6.4 square miles around the injection well. Under no scenario would the CO_2 plume reach the headwaters of aquifer systems in Nebraska and Kansas.

The primary purpose of the Class VI rule requirements and the Permit conditions is to prevent endangerment to USDWs via proper siting, construction, operation, monitoring, and closure of CO_2 injection wells. This protection will be provided to all USDWs in the area regardless of whether they are used as drinking water supplies.

The Class VI requirements and CSS's Permit contain numerous provisions to ensure that fluids remain in the intended injection zone and USDWs are protected. These include the following:

- Suitable geology that meets the requirements of 40 C.F.R. § 146.83 to protect USDWs from endangerment with: (1) an injection zone that can receive the total volume of CO_2 that CSS will inject without fracturing; and (2) a competent confining zone, with no transmissive faults or fractures in the project area to prevent the CO_2 from moving upward.
- Well construction provisions (Part H of the Permit) to prevent the movement of fluids into or between USDWs including: materials that are compatible with the fluids in which they will come into contact, and mechanical strength to withstand operational stresses or stresses associated with seismicity.
- Operating conditions in Part K of the Permit ensure that injection pressure will not initiate fractures in the injection or confining zones. The injection well is equipped with an automatic surface shutoff system that would shut off the well if any Permitted operating parameters, such as injection pressure, exceed Permit limits.
- Extensive injection and post-injection phase testing and monitoring (per Parts N and P of the Permit) to verify that the CO_2 plume and pressure front are moving as predicted or to provide early indication if they are not. This includes CO_2 injectate monitoring, groundwater sampling, pressure fall-off testing, CO_2 plume and pressure front tracking, well testing (mechanical integrity testing, corrosion monitoring, and continuous monitoring), and seismic monitoring.
- Emergency and Remedial Response procedures (Part Q of the Permit) to address adverse events and facilitate expedient responses and prevent or mitigate harm to USDWs and the environment.
- Financial resources (Part G of the Permit) to perform all needed corrective action on wells in the AoR, plug the injection well, perform all required post-injection site care and close the site, and conduct any needed emergency and remedial response measures without using public/taxpayer money.

5. **A commenter expressed concerns about the risk of CO_2 contamination or migration due to future drilling into the Lyons Sandstone "for either injection or oil/gas production in 20, 30, 60, or 100 years." They suggested that these future operators will need information from this CO_2 project or will risk CO_2 and weak acids leaking into unauthorized formations and aquifers. They further asserted that the CO_2 and weak acids will continue corroding the construction wells, monitoring wells, as well as eroding the sealing layers.**

Response: EPA agrees future operators must have access to site information to prevent CO_2 contamination or migration as a result of drilling a well into the Lyons Sandstone. The Class VI program and this Permit address both: (1) well construction into CO_2 storage formation: CSS must record a deed notation and submit data to EPA's public Class VI Data Repository, ensuring future operators are informed; and (2) well integrity: wells are constructed and will be plugged with CO_2 compatible materials, subject to corrosion monitoring, mechanical-integrity testing, and corrective-action requirements. Together with demonstrated confining zones and ongoing monitoring, these measures prevent CO_2 or associated carbonic acid from migrating into unauthorized formations or aquifers and ensure USDWs remain protected.

Area of Review Modeling

6. **A commenter asserts that the AoR delineation modeling CSS performed was not sufficiently robust, was not based on site-specific inputs and assumptions, and do not reflect site heterogeneities. The commenter stated that the "AOR Plume Model needs to include more than the standard inputs of one depositional environment or an averaging of permeability and porosity parameters in both the horizontal and vertical planes because these lateral changes in rock lithology can significantly affect chemical compositions (dissolution of confining zone) or the pressure front (fracture of confining zone)."**

   The commenter also asserted that the model should incorporate the effects of saltwater disposal (SWD) and enhanced oil recovery (EOR) operations in the area and address the possibility of expanded oil and gas industry operations. The commenter states that "[a]ccording to H&K 2005 source, within the Greeley area oil is produced from the Permian Lyons Sandstone and the Cretaceous Terry Sandstone Member, where of the 187 wells in the region, 67 penetrate the Lyons Sandstone." The commenter further asserts there is a very real risk of fluid dynamics "from both oil production (because it pulls water and oil from the reservoir altering pressures and geochemistries) as well as injection (because this introduces a higher TDS than they have data for altering pressures and geochemistries)" that was not considered in the AOR model. They assert that even if these field operations are "miles away", they need to include petrophysics and reservoir modeling of the adjacent production and SWD wells, including those not in their projected "AOR" because these fields or injection sites are creating additional highly pressurized fronts that may already be near the fracture gradient of the confining zones.

   The commenter also requested additional sensitivity analyses with multiple scenarios, using minimum and maximum petrophysical data, including geochemical interactions, and how faults/fractures may alter their model.

   The commenter also requested that CSS review the AoR at least every 1 year because the injection period is only for 12 years and not wait for "triggers for AOR re-evaluation." While they requested a review of the AoR every 1 year, they suggested that a best practice is to update the model at least every 3 years during injection and every 5 years post-injection. They requested that the Testing and Monitoring Plan and Emergency and Remedial Response Plan be reviewed every year, at the same time as the AOR modeling.

EPA response: The AoR is the area surrounding a geologic sequestration project within which USDWs may be endangered by injection activity. 40 C.F.R. § 146.84. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of the injected carbon dioxide stream and is based on site characterization, monitoring, and operational data. *Id*.

In accordance with 40 C.F.R. § 146.84(c)(1), CSS delineated the AoR using a computational model that predicts the movement of the carbon dioxide plume and the critical pressure front based on available information regarding planned injection operations and the characteristics of the subsurface rock formations, including data collected during drilling of the Front Range 1-1 and Front Range 2-1 wells. The AoR for the injection well encompasses approximately 6.4 square miles. EPA reviewed CSS's computational modeling approach to ensure that it is appropriate for a complex AoR delineation. Specifically, CSS's AoR model uses the ECLIPSE 300® numerical simulator, which is designed to simulate multiphase flow and phase transitions of CO_2 and formation fluids under a range of subsurface conditions.

A central requirement of the modeling provisions in the Permit and the Class VI Rule is that the model be based on site-specific data. EPA disagrees with the commenter's assertion that the model relied on "standard inputs." As noted in Response #1 above, CSS collected extensive data regarding the properties of the injection and confining zones, and those data were incorporated into the model inputs and documented in the AoR and Corrective Action Plan Attachment of the Permit. The model inputs are based on data collected and testing conducted on the Front Range 1-1 and Front Range 2-1 wells, including core analysis and geochemical and geomechanical modeling. EPA evaluated the modeling inputs, including porosity and permeability, geomechanical properties, fluid chemistry, and related parameters for the injection and confining zones, and determined that they accurately reflect the site-specific geologic conditions described in the Permit application. The use of average porosity and permeability values is a standard modeling practice that allows for the development of a site-specific geomodel while accounting for computational limitations. CSS also conducted sensitivity analyses by varying these parameters to evaluate whether the average values used were reasonable.

EPA also considered site heterogeneity, including spatial variability in formation properties and structural features. The record includes evaluation of available seismic interpretation, well logs, and geologic mapping, which did not identify transmissive faults or fractures that would provide a pathway for fluid migration to USDWs. While the commenter suggests that additional lithologic variability, geochemical interactions, and fracture behavior should have been modeled in greater detail, EPA concludes that the permit record supports the selected modeling approach and demonstrates that the AoR delineation is protective.

With respect to the request for additional sensitivity analyses, EPA notes that variations in porosity and permeability are the principal factors used to assess the potential effects of undetected heterogeneity in the injection and confining zones. With respect to geochemical interactions and faults, EPA refers the commenter to the responses provided under Geologic Characterization and Faults and Seismicity, respectively.

EPA acknowledges the commenter's concerns regarding the potential effects of saltwater disposal and enhanced oil recovery (EOR) operations. EPA recognizes that such activities, if occurring within the AoR of a project, could affect predicted pressure changes. However, EPA evaluated the modeling results and determined that the CO_2 plume and pressure front are not expected to reach any other injection or production wells, including the oil and gas wells identified by the commenter. EPA reviewed the available information on regional activities and determined that the identified operations do not warrant expansion of the modeled AoR beyond the area established in the permit record. The commenter has not provided site-specific evidence showing that nearby production or injection operations create a likely pathway for CO_2 or pressure communication to USDWs at the project site. EPA notes that the Class VI permit is based on the project-specific conditions at the injection well and surrounding area, and the record does not support inclusion of speculative future operations or distant field activities that are not shown to affect the injection system or confining units.

In addition, pursuant to Part F.1 of the Permit, CSS must reevaluate the AoR over the life of the project by incorporating operational and monitoring data into the delineation model to confirm that the plume and pressure front are behaving as predicted. EPA disagrees that annual AoR reevaluations are necessary. The Class VI Rule requires AoR reevaluation at least every five years; however, EPA revised the Permit to require reevaluations every four years in light of the relatively short injection period. See Change # 3. This revised schedule provides more frequent oversight than the regulatory minimum and will result in three AoR reevaluations during the 12-year injection period. EPA concludes that this schedule is reasonable and does not impose significant additional burden on the operator.

EPA also clarifies that, if any of the triggers identified in the Permit occur, the primary response would be implementation of the Emergency and Remedial Response Plan. Out-of-schedule AoR modeling would then be used to evaluate whether changes to project operations are necessary to prevent recurrence. EPA further clarifies that the Permit requires that CSS update the Testing and

Monitoring Plan, the Emergency and Remedial Response Plan, and the financial responsibility demonstration at the same as every AoR reevaluation. .

In summary, EPA concludes that the AoR delineation modeling is sufficiently robust and site-specific, and that the permit requirements provide adequate protection against endangerment to USDWs.

7. **A commenter raises concerns about wells within the AOR that do not penetrate the confining or injection zones. They state that:**

> **The AOR includes existing wells that are made without CO_2 resistant steel or cement, and the time it takes for CO_2 pitting or corrosion to occur can be during or after the injection period. However, because these wells 'don't penetrate the injection or confining zones in the AOR', these wells will not be part of the monitoring program and remain as conduits to the USDWs and aquifers – especially with the lack of heterogeneity and scenarios run in their AOR Modeling. It is possible after geochemical alterations to the confining rock layers or interior corrosion to the casing, that CO_2 can enter "unauthorized" formations where neighboring wells are injecting saltwater or producing, both having disastrous affects to not only the USDWs, but also surface waters that CSS may not realize immediately, especially if the EPA Region 8 allows them the ability to stop monitoring after 20 years, rather than extending the monitoring for in perpetuity.**

The commenter additionally stated that the measurements need not be event driven, but must be continuously monitored for as long as there is risk to the USDW.

Response: EPA clarifies that shallow wells that do not penetrate the confining zone do not offer a pathway for fluid movement. The deepest well identified within the AoR is completed 400 feet above the upper confining layer, approximately 1000 ft above the injection zone. As described in EPA's responses to comments on geology and operations, EPA reviewed extensive geologic information submitted by CSS and determined that there is a competent confining layer that will prevent fluid movement (see responses to comments on "Geologic characterization") and injection operations will be limited so that no fractures will be created or propagated in the injection zone or confining layer (see responses to comments on "Operating conditions").

EPA agrees with the commenter about the importance of a robust monitoring program. The Testing and Monitoring Plan (Attachment C to the Permit) describes the rigorous testing and monitoring that CSS is required to perform pursuant to 40 C.F.R. § 146.90. The Permit contains monitoring requirements for all aspects of the Class VI injection project, including well mechanical integrity testing, CO_2 plume and pressure front tracking, corrosion monitoring, and water quality monitoring above the confining zone. This testing and monitoring is required to ensure that the injection system is operating within the limits of the Permit and demonstrate that USDWs are not being endangered.

EPA clarifies that not all monitoring requirements are event driven as the commenter asserts. Rather, CSS must perform monitoring throughout the injection and post injection phases as described in Testing and Monitoring Plan and PISC and Site Closure Plan. The event driven measurements to which the commenter refers are in addition to other monitoring, including continuous pressure and temperature monitoring to track the plume and pressure front and annual groundwater sampling and analysis to detect leakage above the confining zone. The frequencies of monitoring activities vary, but they must be performed at the frequencies set in the Permit. Should any monitoring or other information provide evidence that the project could pose a risk to USDWs, EPA would require CSS to cease injection, reevaluate the AoR, and modify the monitoring activities or schedule, as necessary. CSS must perform this monitoring throughout the life of the project until they can demonstrate, based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, per 40 C.F.R. § 146.93(b)(2). See EPA's responses to comments on "PISC and Site Closure" below in Response # 17.

See Response # 10 for additional response to comments on corrosion.

8. **A commenter requests that CSS update the search for oil and gas wells in their AoR to identify any new wells that may have been drilled since the AoR study was performed in 2024.**

Response: EPA acknowledges that abandoned wells can pose a significant threat for movement of CO_2 or other fluids that can contaminate USDWs. For this reason, the Class VI Rule requires applicants to perform a thorough search to identify wells in a project's AoR and perform corrective action on any deficient wells. During the Permit application review, EPA reviewed corrective action information submitted in the application (including wellbore diagrams and information on the wells' condition).

The only well identified within the AoR that penetrates the confining zones at the Front Range Storage Complex is the Front Range 2-1 deep-zone monitoring well, which is constructed in accordance with Class VI standards to prevent movement of CO_2 or formation fluids out of the injection zone.

EPA recognizes the commenter's concerns that additional oil and gas wells could have been drilled since the AoR study was performed. EPA has reviewed the AoR and any new wells that have been drilled up to August 2025, finding no new wells are in the AOR and no corrective action is required. Furthermore, there are no oil and gas target intervals into or below the Lyons formation for economic quantities.

Well Construction

9. **A commenter requested that EPA remove language from the Permit accepting perforated casing completions because this will be much harder to replace or remediate as corrosion sets into the casing.**

Response: EPA clarifies that the purpose of perforations is to facilitate movement of the CO_2 into the injection zone without excessive pressure buildup. The presence of perforations within the casing would not affect the performance of the well including its corrosion nor the decommissioning of the well at the end of injection operations. It is not clear why the commenter believes this would affect performance of the well.

10. **A commenter raised concerns about the well construction, asserting it does not have CO_2 resistance in the cement and casing and that 13Cr-80 should have been used in the casing throughout the well. They claim that formation waters mixing with CO_2 and rock layers may create weak acids leading to corrosion of the injection well.**

    The commenter further requests that the Permit language be updated to specify that the well and all its materials will not be removed at the end of the "geologic sequestration project" and thus all "casing, cement, and other materials used in the construction of the well" should have sufficient strength for as long as there is a USDW. They suggest monitoring in perpetuity, paid for by the Permittee. The commenter stated that these comments applied to the tubing and packer materials and the monitoring of well construction materials.

EPA Response: Contrary to the commenter's assertion, CSS constructed the injection well and monitoring well to the corrosion resistant standards in 40 C.F.R. § 146.86, by utilizing corrosion resistant casing 13Cr80 and corrosion resistant cement for cementing jobs that would potentially encounter products of CO_2-water mixtures**.** This requirement is specified in Attachment G, Sections 2.0 and 3.0 of the Permit.

EPA acknowledges that the compatibility between well materials and CO_2 and the products of CO_2-water mixtures is a critical element of maintaining the integrity of injection wells and preventing fluid movement that can endanger USDWs. For this reason, Class VI injection and monitoring wells must be designed and built to withstand the environment to which they will be exposed over the lifespan of the project until they are plugged.

EPA acknowledges concerns that the construction of the well needs to ensure protection of USDWs in perpetuity; however, EPA clarifies that many of the well construction provisions in the Class VI rule and the Permit consider the need to protect against the stresses imposed during injection operations. During these times, when CO_2 is flowing down the well, casing and cement are exposed to stresses. However, following completion of injection, CSS will plug the well using CO_2-resistant cement, which provides an even stronger barrier to fluid movement along the casing and tubing.

EPA reviewed extensive information about the construction of the Front Range 1-1 injection well to verify that it complies with Class VI regulations at 40 C.F.R. § 146.86, utilizing appropriate casing material and CO_2-resistant cement. This conclusion is based on geochemical modeling conducted by CSS, which indicates that the anhydrous CO_2 injectate stream will have minimal corrosion impacts on the tubing material, and the acidity of fluids potentially in contact with the long string casing will be minimal.

EPA also reviewed information about the construction of the well, including casing specifications (e.g., burst rating, collapse rating) and determined these to be suitable to withstand the stresses to which the well will be exposed during injection operations.

While the injection well was previously constructed, this in no way compromised the rigor of EPA's review nor the need to make changes to ensure USDW protection. On the contrary, following review EPA determined that, as originally constructed, the long string cement job only emplaced cement to approximately 6,150 ft measured depth (MD). Because 40 C.F.R. § 146.86 requires at least one long string of casing to extend from the injection zone and be cemented from the injection zone to the surface, EPA required CSS to remediate the well by perforating and squeezing at 5,850 feet MD and pumping 206 sacks of cement to achieve cement returning to surface. EPA reviewed a cement bond log to determine that cement was sufficiently emplaced in the annulus of the long string casing from the injection zone to the surface.

In addition to demonstrating proper construction of the well, CSS must perform extensive testing of the well during injection operations for signs of corrosion and demonstrate internal and external well integrity. This testing, described in Part N of the Permit and the Attachment C: Testing and Monitoring Plan, includes:

- CSS will perform corrosion monitoring of the injection and monitoring wells. CSS will expose coupons (i.e., pieces of steel made of the same materials used in the well's construction) to the carbon dioxide stream. On a quarterly basis, CSS will examine the coupons by photographing and weighing them to identify any loss of mass, thickness, cracking, pitting, or other signs of corrosion. If any such change occurs, CSS would evaluate the well itself (e.g. casing inspection log) and repair the well, if needed.
- During injection operations, CSS must continuously observe and record injection pressure, flow rate and volume, and the pressure on the annulus to detect the development of any leaks in the casing, tubing, or packer (to demonstrate internal mechanical integrity).

- In addition, CSS must demonstrate external mechanical integrity (i.e., no movement of fluid along the well behind the casing) prior to commencing injection and annually using a tracer survey (oxygen activation log), temperature, or noise log. This mechanical testing will provide early indication of any degradation of well materials due to contact with CO_2 in the presence of water.

In summary, the injection and monitoring well are constructed of corrosion resistant, CO_2-compatible materials that will contain the CO_2 in the injection zone and prevent upward fluid migration. This, in combination with frequent testing, will make leakage of CO_2 along the wellbore highly unlikely.

Pre-Operational Requirements

11. **Simulated failure conditions should not be unwitnessed. Someone should be there to ensure the system was subjected to failure, and the procedure of failure conditions was initiated.**

Response:

EPA and ECMC will be onsite to witness the simulated failure test. The test will intentionally induce the required failure conditions and verify that the system responds as designed including alarms, automatic shutdowns, and closure of the applicable valves/rams. Results will be documented and signed by the onsite observers.

Operating Conditions

12. **A commenter requested that the injection pressure limit be revised to not exceed 75% of the fracture pressure of the injection zone to ensure injection will not initiate new fractures or propagate existing fractures. The commenter further stated that: the Lyons Formations has a pressure gradient of 0.38 psi/ft, which is "under pressured relative to hydrostatic," (page 79), however CSS does not include that hydrostatic pressure is 0.43 psi/ft (Weimer 1996 – their source), thus at static conditions, Lyons is already at 75% hydrostatic pressure – so this isn't a huge barrier from under-pressured. The modeled fracture gradient for Lyons is between 0.66-0.9 psi/ft, where they plan to use 0.66 psi/ft to "not exceed 90% of the fracture pressure of the zone". Adding this pressure will push the pressure gradient to already more than half (56%) within the formation, and while may not affect the Lyons Formation at the wellbore (where core was taken), can re-active the fracture network further in the formation, causing a cascading effect of geochemical dissolution and pressurization.**

Response: EPA finds the Class VI regulations specifying a 90% limit (40 C.F.R. § 146.88(a)) is appropriate for this Permit. Furthermore, instead of the formation fracture pressure, the Permit applies the more conservative, site-specific, measured fracture propagation pressure. Geologic analyses and AoR modeling further demonstrate that pressures will remain below fracturing thresholds and the CO_2 plume will be contained within the Lyons Formation, ensuring USDW protection.

Further clarifying points:

- The Class VI rule specifies the appropriate standard: Except during stimulation, injection pressure may not exceed 90% of the fracture pressure of the injection zone. Attachment A of the Permit incorporates this requirement (it does not authorize operation up to 100%). See 40 C.F.R. § 146.88(a).
- Site-specific fracture pressure was measured: A step-rate test determined a fracture propagation pressure of 5,155 psig. The draft Permit set the downhole MAIP at 4,640 psig (90% of 5,155 psig) and required recalculation if gauge depth changes or new data indicate a different fracture pressure. In response to comments and clarifying information from the operator, the MAIP was recalculated to provide a more accurate value of 4,653 psig that will ensure fractures are not

initiated or propagated within the injection zone. In both cases, using fracture propagation pressure (rather than the higher "opening" pressure) is conservative and ensures a protective margin below fracture initiation/propagation thresholds.

- "Underpressure" vs. "fracture pressure": Being under pressured relative to hydrostatic does not mean the formation is close to fracturing. Fracture pressure reflects in-situ stresses and rock strength and is substantially higher than pore pressure; the Permit's MAIP is tied to the measured fracture limit, not a generic gradient calculation.
- Geomechanics and modeling address fracture/reactivation risk: Structural and image log analyses show no transmissive faults within the AoR and only isolated fractures at the wellbore, reducing pathways for upward migration. AoR modeling (reviewed by DOE) indicates pressures remain below thresholds that would fracture the injection zone or confining units and that the CO_2 plume remains in the Lyons Formation.
- Continuous monitoring and automatic shutoffs: The Permit requires continuous recording of injection and annulus pressures/temperatures and automatic surface shut-off if Permitted limits are approached or exceeded, providing operational safeguards beyond the MAIP setting.

13. **A commenter asserted that for Prior Notice and Reporting, where the Permit requires a knowledgeable log analyst to interpret the MIT results, the use of "knowledgeable" is too vague. The commenter requested the language to be changed to ensure that log analyst has a science degree in earth sciences, engineering, or environmental from an accredited college, who has worked in this type of role in oil and gas operations for at least 6 years.**

Response: Use of the term "knowledgeable log analyst" is consistent with the UIC regulations at 40 C.F.R. § 146.87(a). EPA clarifies that log analysts are typically trained engineers or geologists employed by operators or contracted service companies who are experienced and specialized in evaluating well logs and similar tests. The Permit requires CSS to submit a report describing how the test was performed and the results to EPA for review. If the report were to indicate any concern about the performance of the well or how the test was performed, EPA could request follow up information including (as necessary) additional or repeat testing. Additionally, if a well owner or operator knowingly submits inaccurate, incomplete, or false data, such action is punishable under law, as stated in the required certification of the monitoring report under 40 C.F.R. § 144.32(d).

14. **A commenter requested that Permit language be included to require that if the injection stops for more than 12 months, then the well should be shifted to plugged/abandoned.**

Response: EPA disagrees that if injection ceases for more than 12 months that well should be plugged/abandoned. The Permit requirement at Section P.5 Temporary Abandonment considers a well in temporary abandonment status after 24 months of no injection, consistent with 40 C.F.R. § 144.52(a)(6). This provision is intended to provide operators flexibility in operations while maintaining USDW protective measures. Section P.5 of the Permit requires that, during any such temporary abandonment status, CSS would be required to comply with all monitoring and reporting conditions, which would include annual MITs on the injection well, ensuring continued protection of USDWs.

Reporting and Recordkeeping

15. **A commenter requests that the Permittee provide Semi-Annual Reports for the Testing and Monitoring Plan and asks them to be publicly available.**

Response:

Section O.2 of the Permit requires semiannual submittals of Testing and Monitoring Plan data and analyses (see Attachment C tables). EPA will place nonconfidential Semi-Annual Reports in the Class VI Data Repository; any information claimed confidential will be handled and redacted consistent with 40 C.F.R. part 2. See Response #30 for more information on the Class VI Data Repository. This data may also be requested through the Freedom of Information Act.

16. **A commenter requests that the records should be retained for life and publicly accessible to prevent water / air contamination. The commenter asserts that records must be kept for longer than 10 years because the injected CO_2 will be in the injection zone in perpetuity, and any incoming companies will need to know that this subsurface has a concentration of CO_2. The well must be monitored in perpetuity, and those records should be publicized to protect the USDW from any CO_2 leak.**

Response: See Response #5. The Permit meets the record-keeping requirements in the UIC regulations.

Well Plugging, PISC, Site Closure

17. **A commenter stated that "PISC monitoring should extend continuously (+50 yrs) as mentioned above – the Permittee decided this was a green solution to reduce greenhouse gas emissions and that their model was robust enough to "permanently" sequester CO_2. The Permittee needs to hold this responsibility for as long as there are USDWs and thus will need to ensure that their CO_2 injected will never contaminate a USDW as required by this Permit. The Permittee needs to monitor this injection site, AOR Plume and Pressure Front in perpetuity."**

Response: EPA acknowledges the commenter's concern that the potential for endangerment to USDWs may extend beyond the injection phase of a project. Consistent with the Class VI regulatory requirements, the Permittee must monitor water quality above the confining zone and track the CO_2 plume and pressure front until they can demonstrate that the CO_2 plume and pressure front no longer poses a risk to USDWs. See 40 C.F.R. § 146.93 and Section P and Attachment E of the Permit. Before EPA will authorize CSS to stop monitoring and close the site, CSS must provide a non-endangerment demonstration based on monitoring and other site-specific data that the geologic sequestration project no longer poses an endangerment to USDWs, per 40 C.F.R. § 146.93(b)(2). The required post-injection monitoring must continue for as long as is needed to support the non-endangerment demonstration.

Emergency and Remedial Response (ERR)

18. **A commenter raised concerns about public notification of disasters. The commenter asserted that the Director and public need to be aware within a month to properly be informed aware in case of imminent disaster. The commenter also requested that the Permit language be updated to include a requirement of a public notification system to ensure people can get to safety in the case of a surface leak or be informed to not to drink/use the water in case of USDW contamination. The commenter stated that during an emergency event, notification to adjacent landowners and businesses should be faster than written communication and requested that an email/emergency text (like those alerts we get on our phones when a child is abducted or a volcano is erupting) and/or incorporating an alarm is necessary to allow people to remove themselves from a contaminated site as quickly as possible.**

Response: EPA acknowledges concerns about CO_2 leakage and the safety of the local community. The purpose of the Emergency and Remedial Response Plan (Attachment F of the Permit) is to identify potential scenarios based on understanding of the site geology, operations, and the local community, and have in place procedures that would be followed in the unlikely event of a leakage to ensure an expedient response. The plan addresses a variety of scenarios, including a well control event, well integrity failure, monitoring equipment failure, severe weather disaster, evidence suggesting potential leakage to a USDW or other unauthorized zone (including the surface), and seismic events. It identifies response actions that are suitable to and dependent upon the severity of the event.

As it developed the Class VI Rule and the recommended content of Emergency and Remedial Response Plan, EPA recognized that each emergency or unanticipated event will be unique, and the appropriate response will be specific to the nature of the event and any adverse effects that are detected. Therefore, CSS's Emergency and Remedial Response Plan describes potential response procedures and identifies specialty contractors who can have the skills to perform the necessary repairs.

EPA disagrees with the commenter that CSS should develop a text alert system to communicate emergencies to the public. In the event of imminent danger to the public, the Emergency and Remedial Response Plan states that CSS would communicate with local authorities to initiate evacuation plans, if necessary. Any such communications would be initiated via local authorities who would be familiar with the needs of the community and how to best communicate with the public.

Also, EPA clarifies that the goal of the Permit conditions is to prevent leakage or other emergency events via: the presence of a competent confining zone to prevent leakage of CO_2 or formation fluids; operations to prevent or mitigate the effects of induced seismicity; well construction and testing to ensure integrity; and testing and monitoring to detect indication that the project is not operating as planned.

19. **Before an emergency event, the EPA need to ensure CSS will have the required personnel training that is maintained on the same schedule as other safety training and PPE on-site for a CO_2 leak to atmosphere/aquifer. The commenter points out that this type of training is different than HSE and HAZWOPPER Training, as CO_2 leaks are especially dangerous because they often go unnoticed until someone experiences dizziness or shortness of breath. In the field, these symptoms can easily be mistaken for fatigue or dehydration. For I.8, please include language that the personnel, including CSS employees as well as emergency responders and police/firefighters, will have annual training regarding how to respond to CO_2 as a hazardous chemical and as a compressible gas as both a subsurface leak, and a surface leak.**

Response: EPA agrees with the commenter that training in emergency procedures is important. Per Section 8 of the Emergency and Remedial Response Plan, all staff (i.e., well operators, project safety and environmental personnel, the project manager, plant operations supervisor, and corporate communications staff) must receive training related to health and safety, operational procedures, and emergency response.

EPA acknowledges concerns that local first responders may not be able to address emergency events at the facility. For this reason, it would be the responsibility of CSS (or response contractors it hires), and not the local fire department/first responders, to respond to an emergency event at the project. This ensures that the community is not responsible for responding to an adverse event associated with CO_2 injection and that appropriately trained personnel and specialized equipment are deployed to make necessary repairs and mitigate or prevent contamination of an aquifer.

20. **A commenter requested that the final Permit include what the remedial actions (with assistance from the EPA UIC Program Director) will be if contamination is detected. They asked whether CSS will be trained to remediate and asked who their subcontractors are.**

Response: EPA agrees that clear remedial actions must be specified. As required by 40 C.F.R. § 146.94, the Permit at Attachment F (Emergency and Remedial Response Plan (ERRP)), the ERRP specifies remedial actions and defines triggers, actions, and roles. If monitoring indicates contamination, fluid migration, or loss of mechanical integrity, CSS must:

- Immediately cease injection, secure the well/site, and notify the UIC Director within 24 hours.
- Implement diagnostics and increased monitoring (e.g., MITs, pressure transient analysis, geochemical resampling) to identify the cause and extent.
- Execute Director approved corrective measures (e.g., bleed down/kill, packer reset, squeeze cement or plug back, recover fluids, and corrective action on any penetrations) and report results; resumption of injection requires authorization by the Director.

Training and capabilities: CSS must maintain personnel trained on Attachment F procedures; the plan includes 24/7 points of contact and coordination with ECMC and local responders.

Subcontractors: CSS is responsible for implementing all actions and must ensure the availability of qualified third party services (e.g., workover, wireline, cementing, laboratories). Because vendors can change, the plan maintains current contact lists rather than naming fixed firms; updated lists will be provided to EPA upon request.

21. **A commenter suggested that the ERR plan should always be amended with the AOR and Testing & Monitoring Plans to ensure congruency and an updated understanding of the risk level (from the AOR) and the mitigation practice (Testing & Monitoring). Additionally, if all/any of these reevaluations affect the financial responsibility demonstration, then that should be reviewed at the same time too. If there are any amendments to any/all of the plans, then they need to be made publicly available. People, including Permittee Employees, Police, Fire, Hospital personnel will need to be informed about updated versions of the ERR.**

Response: As explained in Response #6, CSS must update the Testing and Monitoring and Emergency and Remedial Response Plans and their financial responsibility demonstration following each AoR reevaluation. See Response #30 regarding public availability of records.

Oversight

22. **A commenter requested that the Director or authorized EPA representative should physically be on site for the duration of the construction of the injection well at the very least. This is a "best practice".**

Response: EPA clarifies that the Front Range 1-1 well has already been constructed to allow for formation injectivity testing. EPA visited the project site during the construction of the well, witnessed the formation testing, and reviewed the finalized well construction reports to verify that it met Class VI UIC requirements.

23. **A commenter requested that the Permit include a requirement to inform the Director as soon as the field lead on site recognizes there is an issue with movement of any contaminant into a USDW.**

Response: EPA agrees that immediate notification of any endangerment is important. If CSS obtains evidence of USDW endangerment, Section O.3 of the Permit requires CSS to: (1) immediately cease injection; (2) take all steps reasonably necessary to identify and characterize any release; (3) notify the Director within 24 hours; and (4) implement the approved Emergency and Remedial Response Plan (Attachment F) in coordination with the UIC Program Director.

24. **A commenter requested that EPA remove language from the Permit allowing the Permittee to conduct testing without an EPA representative. Furthermore, the commenter asserted that the Director should commit to physical follow-up visits to the site with publicly accessible reports or at the very least meetings with the people overseeing the daily operations with publicly accessible reports.**

Response: EPA acknowledges the importance of appropriate and accurate testing. For tests related to Mechanical Integrity (Permit Section L.5) or the Automatic Alarms and Shutoff System (Permit Section K.9), CSS must provide EPA the opportunity to witness the test. However, the Director may authorize unwitnessed tests in advance. EPA staff may be onsite for inspections or to witness applicable testing and verify that the system responds as designed. If approval for a mechanical integrity test 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 in this section and Section O.5 of this Permit, and receive written permission from the Director 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.

Self-monitoring and self-reporting are consistent with the SDWA and the UIC regulations. All documents reporting the results of tests and monitoring activities must be certified under penalty of law as complete, true, and accurate by the Permittee. See 40 CFR §§ 144.32(d) and 144.51(k). The required certification acknowledges that there are significant penalties for submitting false information**.**

25. **The Permit as a whole should be re-evaluated at least once every three years (for a total of four times) during injection and then at least once every 5 years during post-injection.**

Response: EPA acknowledges the need for review of the Permit throughout operation and the post-injection site care period. This will be done consistently with the required time frame in the UIC regulations. This requires that review occur "at least once every 5 years" 40 C.F.R. § 144.36(a). Additionally, the Permit requires CSS to reevaluate the Area of Review and Corrective Action Plan every four years, which has cascading effects to the Testing and Monitoring Plan, Emergency and Remedial Response Plan, and Financial Plan.

Financial Responsibility

26. **A commenter requested that any reports related to the financial adjustments to the cost estimate should also be posted with the information required by the Director in section Duties and Requirements – perhaps on the EPA Region 8 site where this Class VI project has the Permit details, and all reports/monitoring required by the Permit.**

Response: See Response #30 for details about information posted for the public. Any other information can also be requested under a Freedom of Information Act (FOIA) request. The process and access to the FOIA submittal request link can be found at https://www.epa.gov/foia/foia-request-process.

27. **A commenter suggested that even if the cost estimate decreases, the financial coverage should remain the same as it was the previous year because each year inflation increases, and circumstances of the site or ERR cannot be perfectly known. It is best to be overly cautious to protect the USDW.**

Response: EPA disagrees that financial coverage should remain the same if the cost estimate decreases. The purpose of the annual adjustments to the cost estimates required at 40 C.F.R. § 146.85(c)(2) and Part G.1.b of the Permit is to ensure that the resources available for implementing the covered events are based on current costs of those activities. Should the cost of any activity increase in the future, the financial coverage would be adjusted accordingly.

28. **A commenter stated that the Financial Insurance Plan needs to cover the costs of annual specialized training for CO_2 leaks and blowouts, just like there is specialty training for H2S. They pose similar threats, and thus CO_2 needs to be taken just as serious.**

    The commenter also asserted that the Permittee should be required to have all the finances required to cover not only ERR costs, but also employee, resident, or industry person's medical bills for at least a decade.

The financial responsibility requirements placed on owners and operators of Class VI wells at 40 C.F.R. § 146.85 are designed to ensure that resources are available to responsibly plug the injection well, conduct corrective action if needed, implement emergency responses, and properly restore and close the site. The aim is to ensure protection of USDWs in all eventualities. If an owner or operator is unable to meet their financial obligations under their Permit (e.g., as a result of bankruptcy or other financial difficulty), the financial instruments will provide the funding for EPA to implement necessary actions to ensure protection of USDWs.

The financial responsibility requirements are outlined in Part G of the Permit. The costs have been estimated, and approved by EPA, for the following aspects of the project:

- Corrective action (that meets 40 C.F.R. 146.84);
- Injection well plugging (that meets 40 C.F.R. § 146.92);
- Post-injection site care and site closure (that meets 40 C.F.R. § 146.93); and
- Emergency and remedial response (that meets 40 C.F.R. § 146.94).

The financial responsibility instrument must be sufficient to address endangerment of USDWs. 40 C.F.R. § 146.85(a)(3).

29. **A note on the time this application was submitted, and where we are now in the global market. Please have CSS update the financials on the cost of all these CO_2 resistant materials and equipment. The US tariffs on the industrial coatings market, which has impacted the oil and gas infrastructure and metal fabrication, and will affect the CCS infrastructure as well. The tariffs triggered cost escalation, and it's possible that the well construction is now cost prohibitive.**

Response: EPA acknowledges concerns about rising costs of construction and other materials. To ensure that sufficient resources are available over the duration of the project, CSS must, per Part G.1.a of the Permit, update the available funds annually to account for annual inflation or to address changes to any of the project plans, including changes that result from an AoR reevaluation. These enforceable financial responsibility provisions ensure that sufficient resources are available to perform these USDW-protective activities without using public funds.

Comments Regarding Requests for Public Notice

30. **A commenter requests the Permit require notification to public for the following:**
    - **If there is a modification, transfer, injection well conversion from the existing Permittee, then the Director or existing Permittee must inform the public. The original agreement was with the existing Permittee, and to have a "proposed new" Permittee take charge at any point of the process can be dangerous and is an unnecessary risk to the surrounding populus.**
    - **Anytime the Director requests information from the Permittee, that the public is informed and given access to the information.**
    - **When the Director or authorized representative visits, samples, or makes copies of the records required under the Permit form the regulated facility, the public is informed of the field site report, the sample results, or the monitored data requested to be in compliant with this Permit.**
    - **Commencing Initial Injection -update language that the public should be notified once injection is started.**
    - **In case of CO_2 movement, the Director or Permittee should also inform the public as soon as possible with a text message system; similar to that notifying of an amber or silver alert.**
    - **Any reason for immediate shutdown should be publicized and the report publicly available for review.**
    - **when the injection well is abandoned**

Response: EPA acknowledges the importance of sharing information about Class VI Permits with the public. For this reason, EPA developed the Class VI Data Repository, which can be found at https://udr.epa.gov/ords/uicdr/r/uicdr_ext/uicdr-pub/map. This data repository contains Class VI Permitting materials, such as Permit applications, draft and final Permits, testing and monitoring reports, and Permit violation notifications. The repository is updated regularly to ensure that the public has the most recent data available about any Class VI project.

Regarding Permit modifications, 40 C.F.R. § 124.5(c)(1) requires that any major modification to the Permit, including an amendment to the AoR and Corrective Action Plan, Testing and Monitoring Plan, Well Plugging Plan, PISC and Site Closure Plan, or Emergency and Remedial Response Plan, be subject to public notice and comment. In the event of such modification the Director will prepare a Permit modification and accompanying statement of basis or fact sheet and provide an opportunity for public notice and comment in a manner similar to how the initial Permit was issued.

While there are no requirements for public notification of minor modifications to the Permit, e.g., minor changes such as correcting typographical errors, requiring more frequent monitoring or reporting, clarifying a project plan, or other modifications that do not affect the operations of the project, EPA would post the revised Permit on the Data Repository. See 40 C.F.R. § 144.41.

EPA clarifies that, if the Permit is transferred, the new operator would be subject to the same conditions as are in the current Permit. See 40 C.F.R. § 144.38. Any modifications to the Permit under 40 C.F.R. § 144.39 would be subject to public notice and comment.

See Response #18 for response about the text messages.

Any other information can be requested under a Freedom of Information Act (FOIA) request. The process and access to the FOIA submittal request link can be found at https://www.epa.gov/foia/foia-request-process. If the commenter is interested in other future actions, they can request to be put on a mailing list for specific UIC Permits.

31. **A commenter requested that the Permit require the following data be made available to the public for review, possibly in a public database:**
    - **All data from pre-operational requirements**

- **Simulated failure conditions**
- **All data from testing and monitoring during and post injection**

Response: See Response #30.

Outside the Scope of the Action

Some of the comments provided raised issues that are outside the scope of factors that the EPA can consider in Permitting actions. The Safe Drinking Water Act and the UIC regulations provide the only requirements on which EPA may approve, deny, or condition Permits. The following comments do not relate to these factors.

A. Comments raising concern about carbon capture technology and requesting that EPA include Permit conditions requiring submittal of information about technology they plan to use, where it has been tested, and for how long.

Response A: This is not a requirement under the UIC regulations.

B. Comments requesting promulgation of additional regulations to protect the air, land and people's health.

Response B: This comment requests a rulemaking, which is outside the scope of this Permitting action.

C. Comments regarding generalized concerns about CO_2.

Response C: Generalized opposition is not a factor that EPA can consider in Permitting actions.

D. Comments requesting that the Permittee restore the land because they prepared the site for their construction through clearing, earthworks, and some construction. Considerations for site restoration is adding native seeds to Colorado Region to reduce soil runoff, flooding, or other issues associated with a cleared field. Additionally, the taxpayers should not have to pay for this restoration work.

Response D: The UIC regulations do not provide authority to include Permit conditions regarding site restoration. While Section P.6.f of the Permit requires CSS to plug all monitoring wells and restore the site to its pre-operational condition, requiring the Permittee to plant specific types of vegetation is beyond the UIC requirements which focus on protecting USDWs.

E. Comments that reference to the American Petroleum Institute (API) is a conflict of interest. Please update to another organization such as the Chemical/Materials Science, or Water (?) who can remain unbiased.

Response E: The UIC regulations specifically require well materials to meet or exceed standards developed for such materials by the API, ASTM International, or comparable. To the extent this comment seeks to challenge the regulation as being biased, this is outside the scope of this Permit action.

F. Comments about individual liability if the company ends up going bankrupt.

Response F: The UIC regulations provide financial responsibility requirements that have been met by the Permittee, as discussed in Response #27 above. Individual liability in the event of bankruptcy is outside of scope of factors EPA can consider in a Permitting action.

Table 1 – CSS Comments/Requests on Draft Permit

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Draft Permit, Section E.13(e), Page 7, and elsewhere throughout the Draft Permit and Draft Permit Attachments	"Twenty-four-hour reporting. The Permittee must report to the Director any circumstance that may endanger human health or the environment, including:..."	Background: The subsection title is "Twenty-four-hour reporting", but the requirement for 24-hr reporting is not explicitly re-stated in the supporting subsection text. Furthermore, the text is unclear whether 24-hr deadline is tied to the time of the incident or tied to the time of discovery. 1) CSS requests this language be re-worded to explicitly state Permittee must report within 24-hr of discovery. CSS suggests the following revision: "Twenty-four-hour reporting. The Permittee must report to the Director within 24-hr of discovery any circumstance that may endanger human health or the environment, including:..." 2) CSS requests the "24-hr of discovery" clause be propagated throughout the entire Draft Permit and Draft Permit Attachments. This includes but is not limited to changes at the following locations: a) Draft Permit: Section E.1 Page 5; Section K.2 Page 13; Section L.7 Page 18; Section O.3(a) Page 21; Section Q.1(c) Page 26 b) Draft Permit Attachments: Testing and Monitoring Plan Section 7.2.1 Page 27; Testing and Monitoring Plan Section 7.2.2 Page 28; Emergency and Remedial Response Plan Section 1.1(c) Page 48; Emergency and Remedial Response Plan Section 4.0 Page 50; Emergency and Remedial Response Plan Section 4.1.1 Page 51; Emergency and Remedial Response Plan Section 4.2(a) Page 52; Emergency and Remedial Response Plan Section 4.3.1(a) Page 52; Emergency and Remedial Response Plan Section 4.3.1(b) Page 52; Emergency and Remedial Response Plan Section 4.4.1 Page 54; Emergency and Remedial Response Plan Section 4.4.2(b) Page 54, Emergency and Remedial Response Plan Section 4.5(a) Page 54, Emergency and Remedial Response Plan Table 2 Pages 55-56 - four	**See Permit Change #1 and #2**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		occurrences	
Draft Permit, Section G.1(a), Page 9	"Annually, within 60 days prior to the anniversary date of the establishment of the financial instrument."	Background: The schedule for regular annual updates to the financial instruments are tied to the anniversary date of the establishment of the financial instrument. CSS is using multiple instruments for the Financial Responsibility Demonstration. Current language requires EPA and the Permittee to keep track of the anniversary date for multiple instruments which may have different anniversary dates. 1) CSS requests the language be changed to: "Annually, by March 1 for every year of the Permit life." This change will simplify compliance.	**See Permit Change #4**
Draft Permit, Section I.5(a), Page 12	"(a) Fill annulus with approved noncorrosive fluid (add tracer if required); confirm stability."	Background: The draft text defines the annulus fluid as an approved noncorrosive fluid, but the requirements on tracers and confirming stability are un-clear. The Class VI regulation [40 CFR 146.88(c)] and Class VI Guidance Document on Well Construction are silent on requirements and use of tracers, and are also silent on requirements and methods for confirming stability. CSS proposes using the following as the annulus fluid to meet the noncorrosive and stability requirements: a ~50:50 vol% mixture of ethylene glycol:water plus an industry standard corrosion inhibitor package to stabilize the mixture. 1) CSS requests the parenthetical phrase "(add tracer if required)" be deleted. 2) CSS requests the phrase "confirm stability." be deleted.	**See Permit Change #5**
Draft Permit,	"(e) Submit list of laboratories to the director for approval."	1) CSS requests the language more clearly define the scope of tests to be covered by the list (e.g., limit scope to tests on injectate composition, shallow groundwater & soil gas measurements, and	**See Permit Change #6**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Section I.6(e), Page 12		deep zone formation fluids from Front Range 2-1). 2) CSS has already collected several years of baseline data with laboratory analyses conducted by reputable laboratories. CSS requests a written waiver from EPA to grandfather work to date from the requirements of Section I.6(d).	
Draft Permit, Section K.5, Page 14	"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."	Background: CSS made representations in its application (submitted in May 2024) that CSS did not anticipate the need for injection zone stimulation at that time since the computational model predicted sufficient injectivity based on CSS's proposed MAIP=5,321 psig. Subsequently in April 2026, EPA proposed a materially lower value for MAIP in the Draft Permit, and an even lower pressure limit that triggers a halt to injection (see Tables 1 and 2 in Attachment A: Summary of Operating Requirements, Pages 2-3). The Draft Permit limitations on downhole pressure greatly increases the likelihood that CSS will make a future request to stimulate the injection zone. CSS understands any future requests for a stimulation program will need to go through the process described in Section K.5 of the Draft Permit. CSS does not have a request on this matter at this time.	The stimulation plan requirement remains in the final Permit. This requirement is necessary to ensure that any future stimulation activity is evaluated in advance for consistency with Permit conditions and protection of USDWs. Before conducting any stimulation activity, CSS must submit a stimulation plan to the Director for review and approval in accordance with Section K.5 of the Permit.
Draft Permit, Section L, Page 16	"The Permittee must ensure that the Front Range 1-1 injection well and Front Range 2-1 deep-zone monitoring well that penetrate the upper confining zone have both internal and external mechanical integrity for the operational life of the well."	Background: CSS understands the Class VI regulations on injection wells do not fully apply to deep zone monitoring wells. CSS is committed to the protection of USDWs regardless of well type. The design of Front Range 2-1 is protective of USDWs for its given function as a deep zone monitoring well. Front Range 2-1 uses a system of non-pressurized tubing, sliding doors, packers & plugs, and casing perforations to collect fluid samples from three aquifers as follows: a) the upper zone of Front Range 2-1 can be configured to collect swab fluid samples from the first USDW above the injection zone, b) the middle zone of Front Range 2-1 can be configured to collect swab fluid samples from the injection zone,	EPA did not change the final Permit language, and the requirement for CSS to maintain internal mechanical integrity for the Front Range 2-1 remains in place. This requirement is necessary to ensure protection of USDWs from potential fluid leaks from this well. CSS can use

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		and c) the lower zone of Front Range 2-1 can be configured to collect swab fluid samples from the first USDW below the injection zone. A set of two packers with plugs is used to isolate the three sampling intervals and thereby prevent fluid migration between aquifers. One packer/plug combination is placed between the first USDW above the injection zone and the injection zone, the second packer/plug combination is placed between the injection zone and first USDW below the injection zone. The annular spaces in the three zones are each open to their respective aquifers, so they are filled with their respective formation fluids.1) CSS requests the text be revised to delete the requirement for internal MITs on Front Range 2-1. Front Range 2-1 is not designed as an injection well.2) CSS requests the deletion of requirements for internal MITs on Front Range 2-1 be propagated throughout the Draft Permit and Draft Permit Attachments. This includes but is not limited to changes at the following locations : a) Draft Permit: Section I.2 Page 12; Section L Page 16; Section L.1 Page 16; Section L.2 Bullet (e) Page 17 b) Draft Permit Attachments: Testing and Monitoring Plan Table 7 Page 27; Testing and Monitoring Plan Section 5.0 Page 25; Testing and Monitoring Plan Table 8 Page 26	specific well design elements planned or in place to ensure mechanical integrity; specifically, the plugs and sliding sleeves provide MI and integrity will be monitored continuously through temperature and pressure monitoring in accordance with the Permit conditions.
Draft Permit, Section L.4 through L.5, Page 17	Both sections	Background: The draft text in these sections define the notification, witnessing, and reporting requirements for mechanical integrity testing. CSS has already conducted an internal MIT on Front Range 1-1. US EPA was pre-notified of the test and declined to send a witness. CSS conducted the test prior to issuance of the Draft Permit, thus CSS was unaware of a 30-day deadline for submitting MIT reports. 1) CSS requests a waiver for the 30-day deadline on report submission for the previously conducted internal MIT on Front Range 1-1. CSS will expeditiously submit the report for US EPA	EPA did not change the final Permit language. CSS must submit any required mechanical integrity test reports that have not previously been submitted within 30 days, and that requirement remains in the final Permit. This requirement is prescribed by the regulations at 40 C.F.R. §

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		review/approval.	146.91(b).
Draft Permit, Section M.1, Page 19	Entire sections	Background: The Class VI regulations and Class VI Guidance Documents are purposely vague with respect to seismic action plan requirements so that plans can be customized to the needs of each Class VI project. The seismic action plan is spread across parts of the Draft Permit/Draft Permit Attachment. The plan appears overly complex and will likely create many false positives leading to unnecessary rate reductions/emergency shutdowns. The plan uses a "five color stoplight" system with a 50-mi monitoring radius and one trigger level at 1.5 Mw, three trigger levels at 2.0 Mw, and one trigger level at 3.5 Mw. A "five color stoplight" is not an intuitive tool for communicating seismic risk (e.g., what does a magenta stoplight mean to the general public?). Information provided by the USGS network does not align with the Draft Permit requirements. The USGS network typically (but not always) reports event magnitudes as ML rather than Mw, and the USGS network has 2.0 ML as its lower limit of reporting. The mis-alignment between the Draft Permit requirements and the information provided by the USGS network will severely complicate CSS's ability to comply. Finally, CSS conducted a study using the USGS seismic catalog over the past 12-years prior to any injection at the Front Range 1-1 location. The study found the Draft Permit seismic action plan would have led to 19 false positive events that would have required either a reduction in injection rate or a halt to injection.1) CSS requests the seismic action plan be modified to align with the proposed ECMC Class VI seismic action plan requirements. The plan should use an intuitive "three color stoplight" system with a 12-mi monitoring radius and trigger levels at 2.7 ML and 5.0 ML. For comparison, CSS repeated the seismic event study using the USGS seismic catalog over the past 12-years and found a plan that meets the proposed ECMC requirements would have led to only 1 false positive that would have required Permittee action, which suggests the proposed ECMC requirements has adequate sensitivity to protect the GS project from seismic risks. EPA has adequate	EPA did not make the requested revisions. The seismic action plan was developed based on the site-specific record and reflects EPA's determination of the monitoring and response measures necessary to protect USDWs and address potential seismic risks associated with the project. EPA's approach is consistent with Region 8 practice for UIC permits. Accordingly, EPA did not modify the seismic action plan or revise the related Permit language.

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		latitude to adopt the ECMC requirements under its regulations and CSS urges adoption of a seismic action plan based on the proposed ECMC Class VI regulations.2) CSS requests the change to seismic action plan be propagated throughout the Draft Permit and Draft Permit Attachment. This includes but is not limited to changes at the following locations: a) Draft Permit Attachments: Testing and Monitoring Plan Section 9.2 First Paragraph Page 30; Emergency and Remedial Response Plan Section 4.6 Pages 55-56	
Draft Permit, Section O.3, Page 21	Entire section	Background: As currently drafted, some information needed by the emergency response team is located in Draft Permit Section O.3, and some information is located in Attachment F: Emergency and Remedial Response Plan. CSS requests the requirements located in Draft Permit Section O.3 be transferred to Attachment F: Emergency and Remedial Response Plan. This change would place all information needed by the response team into a single location, thereby making it easier to comply with Permit requirements during an emergency event.	**See Permit Change #8.**
Draft Permit, Section Q.2, Page 27	The text starting with "Ten years following the cessation of injection operations,..."	Background: This text appears to be un-intentional text left in the document during EPA drafting. 1) If this text is un-intentional, then CSS requests the text be deleted. If this text is intentional, then CSS requests EPA re-write/re-format the text. Furthermore, CSS request the revised text be aligned with the requirements in Attachment C: Testing and Monitoring Plan	**See Permit Change #7**
Attachment A: Summary of Operating Requirements, Table 1-Rows 1 through 3,	Pressure units are given as "psi"	Background: EPA specifies pressure units as "psi" in Table 1 and throughout the Draft Permit and Draft Permit Attachment. This unit is not well defined. 1) CSS requests Table 1 be revised to "psig" if referring to gauge pressure, "psia" if referring to absolute pressure, and either	**See Permit Change #9**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Page 2		retaining "psi" or using "psid" if referring to a differential pressure. Alternatively, CSS requests text be added somewhere in the Draft Permit to clarify EPA's definition of "psi". CSS requests the approach used in 1) for the handling of "psi" be propagated across the Draft Permit and Draft Permit Attachment.	
Attachment A: Summary of Operating Requirements, Table 1-Row 2, Page 2	Minimum Annulus Pressure at all times 100 psi	Background: Placing requirements on both annulus pressure (Row 2) and annulus pressure above Tubing Differential (Row 3) is confusing and somewhat redundant. Furthermore, the lack of exceptions during well maintenance and other non-injection periods is impractical. CSS requests Row 2 be deleted. If EPA elects to keep Row 2, then CSS requests a footnote or other text be added to allow for exceptions during well maintenance and other non-injection periods.	**See Permit Change #10**
Attachment A: Summary of Operating Requirements, Table 1-Row 4, Page 2	Maximum Injection Rate 127,800 metric tons/year	Background: It is unclear whether this requirement applies to the cumulative injection over the course of one year, or whether it applies to the instantaneous injection rate at any point in time. To clarify using a relevant numerical example, a cumulative injection of 127,800 metric ton/yr roughly corresponds to an average instantaneous injection rate of 360 metric ton/day=15 metric ton/hr=0.25 metric ton/min. Instantaneous rates can vary around at any point in time around a mean, yet the cumulative injection over a specified time period is set by the mean over the specified time period. 1) If the basis is the cumulative injection over the course of one year, then CSS requests a clarifying footnote and further requests the cumulative yearly injection limit be raised by ~10% to 140,000 metric ton/yr to provide headroom for uncertainty in current CO_2 supply and future incremental expansions in CO_2 supply from increased ethanol production. Making this change will not	**See Permit Change #10**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		materially impact the AoR and other predictions from the computational model. To be clear, CSS is not requesting a change to the maximum cumulative injection limit of 1,540,000 metric ton over the course of the Injection period (i.e., Table 1-Row 5 remains unchanged). If the basis is the instantaneous injection rate, then CSS requests a clarifying footnote and further requests the maximum instantaneous injection rate set at 420 metric ton/day - consistent with Table A.III.1- of Summary of Requirements in CSS's application. CSS prefers expressing instantaneous rates in metric ton/day rather than metric ton/yr. A maximum of 420 metric ton/day is ~16% higher than the expected average rate of 360 metric ton/day, which provides headroom for expected daily and seasonal variations in CO_2 supply. Making this change will not materially impact the AoR and other predictions from the computational model. To be clear, CSS is not requesting a change to the maximum cumulative injection limit of 1,540,000 metric ton over the course of the Injection period (i.e., Table 1-Row 5 remains unchanged).	
Attachment A: Summary of Operating Requirements, Table 2-Row 1, Page 3	Downhole Maximum Injection Pressure at the Lyons Sandstone Shutdown point: At least 95% of downhole maximum allowable injection pressure 4,408 psi	Background: EPA defined fracture pressure in Section 1.0 Page 3 as the fracture propagation pressure, which was measured at 5,155 psig by a step-rate test on Front Range 1-1. EPA set MAIP=4,640 psig by applying a 90% safety factor to the fracture pressure per Class VI rules. In Table 2-Row 1 EPA further limits the downhole pressure to 95% of the MAIP by requiring a forced shutdown if the downhole pressure exceeds 4,408 psig. To simplify terminology, CSS will call this second restriction on downhole pressure the Pressure Alarm High High (PAHH) level, so PAHH = 4,408 psig per Table 2. The Class VI regulations [40 CFR 146.88(a) and elsewhere] and the pertinent Class VI Guidance Documents do not explicitly contemplate PAHH restrictions. The Draft Permit Attachment only provides an explanation of how PAHH was determined, it does not provide a rationale for why a separate PAHH level below the MAIP is required. In addition to lacking a rationale, EPA's approach on this	**See Permit Change #11**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		matter appears to be unprecedented since CSS is unaware of other Class VI Permits requiring a PAHH level be set below the MAIP. CSS believes that doubling up on safety factors to require PAHH=4,408 psig is unnecessary to protect USDWs. 1) CSS requests the PAHH limit in Table 2 be deleted. This will leave MAIP=4,640 psig as the sole restriction on downhole pressure, which aligns with requirements in the Class VI regulation and pertinent Class VI guidance documents. 2) CSS requests the deletion of the PAHH limit be propagated throughout the Draft Permit and Draft Permit Attachments. This includes but is not limited to the following locations: a) Attachments: Testing and Monitoring Plan Section 2.3 First Paragraph Page 15	
Attachment A: Summary of Operating Requirements, Table 2- Combined Row 2, Page 3	Annulus Pressure (during injection)Shutdown point: Minimum 100 psi Shutdown point: Less than minimum allowable annulus over tubing differential 100 psi	CSS requests the combined Row 2 in Table 2 be deleted since these requirements are redundant to requirements listed previously in Table 1 on Page 2. If EPA keeps the combined Row 2 in Table 2, then CSS requests a footnote or other text be added to allow for exceptions during well maintenance and other non-injection periods.	**See Permit Change #11**
Attachment A: Summary of Requirements, Section 2.0	Entire section	Background: The start-up plan specifies a stair-step injection profile that is inflexible with respect to the magnitude of the rate for each step and the duration for each step. CSS believes the profile in Table 3 is too aggressive and will likely result in overpressuring the well if followed rigorously. Also, the start-up plan does not define a milestone demarking the end of start-up and transition to normal operations. 1) CSS requests the plan be revised to allow flexibility in executing the six level stair-step shown in Table 3. The basic framework of a	**See Permit Change #12**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		six level stair-step can be retained, but CSS requests flexibility to adjust the rate and duration for each step based on well response and other field considerations. CSS requests the plan be revised to include a provision that, at the appropriate time, CSS will provide EPA with written notification the start-up period has ended and it is proceeding into normal operations.	
Attachment C: Testing and Monitoring Plan, Section 1.6 and Table 1, Pages 12-13	Entire section including Table 1	Background: Table 1 requires CSS to test for twelve (12) different chemical analytes in the injectate and allows no flexibility to use any test method beyond the specified ISBT method for each chemical analyte. The carbon capture and CO2 liquefaction processes used by CSS are very similar to those used to product high-purity CO2 for sale into the food & beverage and dry ice industries. The raw gas prior to capture is 99+% purity CO2 (dry basis) that is saturated with water vapor at near ambient pressure and temperature, plus several trace impurities. The raw gas undergoes several purification steps in the capture and liquefactions processes (e.g., water washing to remove trace organics and sulfur compounds, bulk water vapor removal using multi-stage compression with interstage knockout drums, further removal of water vapor using molecular sieve drying). These processing steps are required to reduce troublesome contaminants to acceptable levels for the low temperature liquefaction process (i.e., H2S and water vapor must be reduced to trace levels to prevent freezing in the liquefaction unit). CSS recently commissioned and started its carbon capture and liquefaction processes, collected a representative baseline injectate sample in compliance with the Draft Permit Section I.6 Page 12, and analyzed the baseline sample using a qualified outside laboratory and the ISBT methods specified in Table 1. The reported results were: CO2 = 99.98+ mol%, water vapor = 110 ppmv, and Non-Condensable Gases = 55 ppmv (total), with the remaining nine (9) analytes	**See Permit Change #13**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		reported as below detection limit. 1) CSS requests all rows in Table 2 for chemical analytes be deleted except for CO2. This revision will align the isotope and chemical analytes in Table 2 with the isotope and chemical analytes in Table E.5-3 of the Testing and Monitoring Plan in CSS's application. CSS requests the allowable analytical test methods in Table 2 be revised to the list of methods provided in Table E.5-3 of the Testing and Monitoring Plan in CSS's application. There are only a few outside analytical laboratories in the US that are qualified to run the ISBT methods, none of which are located in Colorado to our knowledge. Expanding the list of allowable test methods will give CSS flexibility to use a qualified local laboratory, and also expand the slate of qualified alternate laboratories should a problem arise with a particular outside analytical lab.	
Attachment C: Testing and Monitoring Plan, Section 2.0, Page 13	"The Permittee must install and use continuous recording devices at the FR 1-1...and downhole formation temperature. (40 CFR 146.90(b), 146.88(e)(1), and 146.89(b))."	Background: None of the cited Class VI regulations (40 CFR 146.90(b), 146.88(e)(1), and 146.89(b)) contain a requirement to measure the downhole formation temperature at the injection well. CSS requests the requirement be deleted as it is difficult to design an injection well to also measure downhole formation temperature. Front Range 1-1 was not designed to make this measurement, and this design requirement was not communicated to CSS until the Draft Permit was issued in April 2026.	**See Permit Change #14**
Attachment C: Testing and Monitoring Plan, Table 2-Row 2, Page 14	Injection Rate (bbl/day) Orifice Meter Wellhead Continuous (min every 10 sec) Monthly	Background: Table 2-Row 2 specifies the injection flowmeter as an orifice meter installed on the wellhead, while Table E.I.1-11c in Attachment I: Quality Assurance and Surveillance Plan specifies the injection flowmeter (FIT-3001) as a Coriolis flowmeter installed on the flowline to the wellhead. Also, there are inconsistencies in the units for measuring flow throughout the Draft Permit. In some locations (e.g., Table 2-Row2 requires the flow rate be measured in	**See Permit Change #14**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
	Semi-Annual Average, Minimum, Maximum	bbl/day, while the operational limits in Table 1 of Attachment A: Summary of Operating Requirements requires injection to be monitored in metric tons). Injection flows for most regulatory and credit programs in the CCS industry (e.g., US EPA Greenhouse Gas Reporting Program, US Treasury 45Z program, US Treasury 45Q program, most state-level Low Carbon Fuel Standards, most voluntary credit standards) utilize a mass-basis with metric tons for primary reporting, with little consistency in units for secondary reporting on a volumetric basis. 1) CSS requests Table 2-Row 2 be revised to specify the injection flowmeter as a Coriolis flow meter. Coriolis flow meters are highly accurate and robust instruments that are commonly used throughout industry for custody transfer and other demanding applications. Coriolis meters simultaneously measure both instantaneous mass flow and instantaneous density of the stream as it passes through the meter. A SCADA system connected to a Coriolis meter can easily integrate the instantaneous mass flow when cumulative mass flow is needed, can easily perform the math to convert mass flow into standard volume flow on either an instantaneous or cumulative basis, and can combine the mass flow and density measurements into actual volumetric flow on either an instantaneous or cumulative basis. 2) CSS requests Table 2-Row 2 be revised to specify the injection flow meter be located on the CO2 Delivery Flowline rather than the wellhead. CSS requests Table 2-Row 2 be revised to specify the instantaneous injection rate be reported in metric ton/day. CSS further requests that mass reporting be standardized to "metric ton" and be propagated throughout the Draft Permit and Draft Permit Attachments. Standardizing on mass reporting in metric ton will greatly simplify CSS's reporting to the US EPA Class VI and other	

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		regulatory and credit programs.	
Attachment C: Testing and Monitoring Plan, Table 2-Row 3, Page 14	Injection Volume (calculated) (bbl) Volumetric Flow meter & computer CO2 Delivery Flowline Continuous (min every 10 sec) Monthly Semi-Annual Average, Minimum, Maximum	Background: Table 2-Row 3 specifies the instantaneous injection volumetric flow rate be measured in bbl without specifying the time basis or the reference conditions for the measurement. The Class VI regulations require the installation and use of continuous recording devices to monitor injection volume (§ 146.88(e)(1), § 146.90(b), and elsewhere), but the Class VI regulations and the Draft Permit are silent as to whether volumetric measurements are to be reported on an actual or standard basis. The density of CO2 can vary by 10X depending upon pressure and temperature, so specifying the "actual" or "standard" basis for volumetric measurements is required for clarity. Table 2-Row 3 also specifies a volumetric flow meter & computer. 1) CSS requests Table 2-Row 3 be revised so that the units of instantaneous volumetric flow be measured in bbl(standard)/day, where the standard reference conditions are the bubble point pressure of pure CO2 at 60 F. This set of standard reference conditions is a convention that has been widely adopted by the US industry for supercritical substances. REFPROP 10.0 (NIST's reference-grade property package) gives the density of pure CO2 as 50.94 lb/ft3 at the bubble point pressure of 747.8 psia and 60 F. CSS requests Table 2-Row 3 be revised to specify use of a Coriolis meter	**See Permit Change #14**
Attachment C: Testing and Monitoring Plan, Table 2-Row 4, Page 14	Cumulative Injection Volume (bbl) Volumetric Flow meter & Flow computer CO2 Delivery Flowline Continuous (min every 10 sec) Monthly	Background: See immediately previous entry. 1) CSS requests Table 2-Row 4 be revised so that the units of cumulative volume are bbl(standard), where the standard reference conditions are the bubble point pressure of pure CO2 at 60 F. CSS requests Table 2-Row 4 be revised to specify a Coriolis flow meter	**See Permit Change #14**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
	Semi-Annual		
Attachment C: Testing and Monitoring Plan, Table 2-Row 6, Page 14	Annulus Fluid Volume (bbl) Volumetric Measurement Wellhead As needed Monthly Semi-Annual Monthly Total	Background: Table 2-Row 6 requires the annulus fluid volume be measured at the wellhead in bbl. The Class VI regulations (§ 146.88(e)(1), § 146.90(b), and elsewhere) require measuring the volume of fluid added to the annulus fluid system rather than the annulus fluid volume - this distinction is significant. CSS designed the annulus fluid system so that the annulus space in Front Range 1-1 should be completely full of liquid during normal operations - See Figure A.II.2-4 in Well Construction Details in CSS's application. CSS specified the annulus fluid system as a skid (storage tank with level gauge, injection pump, and various other hardware) that injects fluid into the annulus when needed to increase pressure in the Front Range 1-1 annulus, and lets excess annulus fluid overflow into the skid storage tank when needed. CSS anticipates the level in the storage tank will rise/fall as the temperature and density changes in the annular space during normal injection operations, however the total amount of fluid in the system (on a mass basis) will remain constant assuming Front Range 1-1 maintains internal mechanical integrity. The Class VI regulation and Class VI Guidance Documents recognize that tracking the amount of fluid added to the system is a status indicator for the state of internal mechanical integrity for the injection well - frequent additions to the annulus system is an indication the injection well may have lost internal mechanical integrity. 1) CSS requests replacing "Annulus Fluid Volume (bbl)" with "Annulus Fluid Added to System (gal)" in Table 2-Row 6 to improve alignment with the Class VI regulations. This request also changes the units from "bbl" to "gal" since this unit is more appropriate for the expected amounts. CSS does not see a need to specify whether the volume is actual or standard since the two are very similar in this particular application. CSS requests replacing "Wellhead" with "Annulus Fluid System" in	**See Permit Change #14**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		Table 2-Row 6.	
Attachment C: Testing and Monitoring Plan, Table 2-Row 7, Page 14	CO_2 Stream Temperature (deg F) Electronic Thermocouple Wellhead Continuous (min every 10 sec) Monthly Semi-Annual Average, Minimum, Maximum	Background: Table 2-Row 7 requires the CO_2 stream temperature be measured with an electronic thermocouple located at the wellhead. There are several other types of comparable instruments capable of making this measurement. Also, it seems odd to specify different locations for the measurement of CO_2 flow and the measurement of CO_2 temperature. CSS designed its instrumentation system to make measurements of the above ground CO_2 properties (flow, pressure, temperature) at a single location - see Figure A.II.2-3 in Well Construction Details in CSS's application. 1) CSS requests "Electron Thermocouple" be replaced with "Temperature Sensor" in Table 2-Row 7. Using a generic specification in this table simplifies "Permit maintenance" by locating all of the details for the temperature sensor at one location in the QASP CSS requests "Wellhead" be replaced with "CO_2 Delivery Flowline" in Table 2-Row 7. This change allows CSS to locate the temperature measurement in close proximity to the injection flow meter.	**See Permit Change #14**
Attachment C: Testing and Monitoring Plan, Table 2-Row 8, Page 14	CO_2 Stream Temperature (deg F) Distributed thermal sensing system Temperature profile along entire well Continuous (min every 10 sec) Monthly Semi-Annual Single monthly profile measured while injecting	Background: Table 2-Row 8 requires use of a distributed thermal sensing system to continuously measure the CO_2 stream temperature profile along entire well. The Class VI regulations and the Class VI Guidance documents are silent with respect to requirements for continuous measurement of the CO_2 stream temperature profile down the injection tubing. CSS specified use of a DTS system at Front Range 1-1 as a time-efficient means to conduct high-quality external MITs vs. wireline methods. CSS designed Front Range 1-1 with a distributed temperature sensor (DTS) fiber attached to the exterior of the injection tubing along with a DTS interrogator to measure and record temperature along the DTS fiber. The DTS fiber has a spatial resolution of 1 m (See	**See Permit Change #14**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		Table E.I.1-15b in Attachment I: Quality Assurance and Surveillance Plan) so each measurement cycle with the DTS generates several thousand data points, thus extended continuous use of the DTS system generates enormous amounts of data. Using a temperature log to demonstrate external mechanical integrity for an injection well requires halting injection for a few days to allow temperatures to equilibrate between the well and the formations. The external MITs on Front Range 1-1 will be scheduled to occur during an annual 4-day planned outage of CO2 supply. The window for conducting an annual external MIT is brief, so efficient use of time during each annual CO2 supply outage is critical. CSS intends to run frequent DTS scans during each 4-day planned outage, and use the data to demonstrate the well and formation temperatures were equilibrated prior to taking the temperature log for the external MIT, thereby validating data quality of the temperature log. CSS requests Table 2-Row 8 be deleted.	
Attachment C: Testing and Monitoring Plan, Table 2-Row 9, Page 14	Injection Pressure at Formation (psi) Pressure Gauge Downhole gauge within 20 ft of top perforation Continuous (min every 10 sec) Monthly Semi-Annual Average, Minimum, Maximum	Background: Table 2-Row 9 requires measuring the injection pressure at formation using a downhole gauge placed within 20 ft of top perforation. Rather than measuring formation pressure, the Class VI regulations [§ 146.88(e)(1), § 146.90(b), and elsewhere] require the installation and use of continuous recording devices to monitor injection pressure, with no specification in the Class VI regulation on the location(s) of the instrument(s) used for monitoring injection pressure. CSS designed the instrumentation system to measure injection pressure at three locations for redundant compliance with the Class VI regulations: 1) at a surface location proximate to the injection flow meter, 2) at a surface location on the wellhead, and 3) at a downhole location using a gauge connected to the injectate stream at a depth proximate to the packer. See CSS Comment to Attachment C: Testing and Monitoring Plan Section 2.3 First Paragraph First Sentence Page 15 for more discussion on definition of the depth for monitoring the Lyons and adjustments for hydrostatic head differences between	**See Permit Change #14**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		downhole gauge location and required monitoring depth. 1) CSS requests Table 2-Row 9 be modified to replace "Injection Pressure at Formation (psi)" with "Downhole Pressure (psig)". CSS requests Table 2-Row 9 be modified to replace "Downhole gauge within 20 ft of top perforation" to "Downhole gauge located proximate to packer"	
Attachment C: Testing and Monitoring Plan, Table 2-Row 10, Page 14	Temperature at Formation (deg F) Temperature Sensor Downhole sensor within 20 ft of top perforation Continuous (min every 10 sec) Monthly Semi-Annual Average, Minimum, Maximum	Background: Table 2-Row 10 requires measuring the temperature at formation using a temperature sensor placed within 20 ft of top perforation. Rather than measuring formation temperature, the Class VI regulations [§ 146.88(e)(1), and elsewhere] require the installation and use of continuous recording devices to measure the temperature of the carbon dioxide stream, with no specification in the Class VI regulation on the location(s) of the instrument(s) used for monitoring CO2 temperature. CSS designed the instrumentation system to measure CO2 stream temperature at three locations for redundant compliance with the Class VI regulations: 1) at a surface location proximate to the injection flow meter, 2) at a surface location proximate to the wellhead, and 3) at a downhole location using a temperature sensor connected to the injectate stream at a depth proximate to the packer. 1) CSS requests Table 2-Row 10 be modified by replacing "Temperature at Formation (deg F)" with "Downhole Temperature (deg F)". CSS requests Table 2-Row 10 be modified by replacing "Downhole sensor within 20 ft of top perforation" with "Downhole sensor located proximate to packer".	**See Permit Change #14**
Attachment C: Testing and Monitoring Plan,	"The injection volume must be calculated using the mass flow rate combined with the pressure and temperature conditions in	Background: The Draft Permit text requires characterizing CO2 flow on a volumetric basis, and further requires use of a volumetric basis for updating the computational models. As discussed previously in the CSS Comment on Attachment C: Testing and Monitoring Plan	**See Permit Change #15**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Section 2.2, Second Paragraph, Pages 14-15	the injection zone. The calculated injection volumes must, in turn, be used to update the computational models at regular intervals throughout the injection phase of the project as detailed in Attachment B."	Table 2-Row 2, CSS prefers to use a primary basis of characterizing CO2 amounts in terms of mass since this standard is more widely used in the CCS industry, and use a secondary basis of characterizing CO2 amounts in terms of volume only when required by regulatory or other constraints. Furthermore, CSS currently maintains only one computational model for the project, and the computational model is set up to use a mass basis for CO2 amounts. 1) CSS requests these two sentences be revised to one as follows: "The injection amounts must, in turn, be used to update the computational model at regular intervals throughout the injection phase of the projection as detailed in Attachment B."	
Attachment C: Testing and Monitoring Plan, Section 2.2, First Full Paragraph-First Sentence on Page 15	"...as well as the annular fluid volumes must also be measured on a continuous basis (40 CFR 146.90(b))."	Background: The regulation cited in this phrase requires measuring the annulus fluid volume added to the annulus system, it does not require continuous measurement of the annular fluid volumes. See previous CSS Comment on Attachment C: Testing and Monitoring Plan Table 2-Row 6 for more discussion. 1) CSS requests this phrase be revised to: "...as well as the annulus fluid volume added (40 CFR 146.90(b))."	**See Permit Change #15**
Attachment C: Testing and Monitoring Plan, Section 2.2, First Full Paragraph, Page 15	Entire Paragraph	Background: The text in this paragraph specifies the use of a two tank system (accumulator, brine reservoir) for managing the annulus fluid. The text further asserts that tank level(s) would normally remain relatively constant during normal injection operations. The Class VI regulations do not specify a two tank system for managing the annulus fluid. CSS specified a one-tank system for managing the annulus fluid - see Figure A.II.2-4 in Well Construction Details in CSS's application. CSS's past experience with annulus fluid systems does not fully align with EPA's assertion that tank level(s) remain relatively constant during normal operations. CSS's experience is that levels in annulus fluid tanks can vary materially during non-steady state operations (e.g., start-up,	**See Permit Change #15**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		shutdown, normal variability in the operation of the upstream carbon capture and liquefaction systems) since the temperature and density of the annulus fluid will change with variations in the injection flow rate and injectate temperature, thus variation in annulus fluid tank level is normal. One of the main indicators for a potential loss of internal mechanical integrity is a complete loss of level in the annulus fluid tanks...which is why the Class VI regulations require tracking the amount of annulus fluid added to the system rather than monitoring tank levels. 1) CSS requests this paragraph be revised as follows: a) Remove the requirement for a two-tank system b) Require the tank level instrumentation system be configured with a Level Alarm Low (LAL) that notifies Operations the system is approaching a complete loss of level. Require further investigation whenever a LAL condition is reached. If a loss of internal mechanical integrity is identified as the cause for the LAL, then CSS must follow the shutdown and notification procedures in Attachment F: Emergency and Remedial Response Plan. c) Remove the requirement to connect to the SCADA system. CSS specified the annulus fluid skid to have an independent PLC with cloud storage, automated alarms, and an alarm notification system for Operations. The Control Room has access to the PLC for the annulus fluid system. Remove the discussion that asserts tank levels will remain relatively constant during normal operations.	
Attachment C: Testing and Monitoring Plan, Section 2.3, First	".....and downhole at the depth of the Lyons Sandstone Formation."	Background: The text requires the downhole pressure in the Lyons be monitored. The text does not specify the monitoring depth within the Lyons, nor does it address any hydrostatic head differences between the depth of the downhole gauge and the	**See Permit Change #16**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Paragraph, First Sentence, Page 15		required monitoring depth within the Lyons. 1) CSS requests this phrase be revised as shown below (see previous CSS Comment on Attachment C: Testing and Monitoring Plan Table 2-Row 9 for more background): "...and downhole proximate to the packer as required in Table 2. Well overpressure alarms and Well overpressure emergency shutdowns are to be based on measurements from the downhole pressure gauge with a hydrostatic head adjustment for any difference between the depths of the downhole pressure gauge and the top the Lyons Sandstone Formation."	
Attachment C: Testing and Monitoring Plan, Section 2.3, Second Paragraph, Page 15	"...or may be caused by a change in injection flow rate."	Background: The CO2 source for the GS project is fermentation offgas generated at a fuel ethanol production facility. CSS anticipates the CO2 injection rate will vary by +/-16% around a mean within any 12-hr period during regular operations. This variation is a consequence of the fermentor configuration in the upstream ethanol production facility. 1) CSS requests the paragraph be revised by deleting the phrase "...or may be caused by a change in injection flow rate.".	**See Permit Change #16**
Attachment C: Testing and Monitoring Plan, Section 2.4, Pages 15-16	Entire Paragraph	Background: Text requires use of a volumetric flow meter CSS requests this paragraph be revised to align with the previous CSS Comment on Attachment C: Testing and Monitoring Plan Table 2-Row 2 and the previous CSS Comment on Attachment C: Testing and Monitoring Plan Table 2-Row 3	**See Permit Change #17**
Attachment C: Testing and Monitoring Plan, Section 2.5, Bullet 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 surface, the TCA pressure	1) CSS requests the first sentence be deleted - see previous CSS Comment on Attachment A: Summary of Operating Requirements Table 1-Row 2 for further background. CSS requests the second sentence be amended with an exemption from this requirement during maintenance and other non-injection	**See Permit Change #18**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Page 16	must maintain a minimum of 100 above the tubing pressure. See Attachment A, Table 1."	periods.	
Attachment C: Testing and Monitoring Plan, Section 2.5, Bullet 2, Page 16	"The pressure in the annular space directly above the packer must be maintained at least 100 psi higher than the adjacent tubing pressure during injection."	CSS requests the text be amended with an exemption from this requirement during maintenance and other non-injection periods.	**See Permit Change #18**
Attachment C: Testing and Monitoring Plan, Section 2.5, Second Paragraph, Third Sentence, Page 16	"The transmitter must be connected to the well control system and the SCADA system to regulate the annular pressure."	CSS requests the first sentence be revised as shown below (see previous CSS Comment on Attachment C: Testing and Monitoring Plan Section 2.2, First Full Paragraph for further background): "The transmitter must be connected to the well control system to monitor the annulus pressure."	**See Permit Change #18**
Attachment C: Testing and Monitoring Plan, Section 2.5, Second Paragraph, Fourth Sentence, Page 16	"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."	Background: Any sudden change in annular pressure need not always be investigated using mechanical integrity testing since some changes in annular pressure are expected and easily explained. An immediate jump to mechanical integrity testing is not warranted for expected and easily explained changes in annular pressure. 1) CSS requests the text be revised to: "Sudden, un-expected, and un-explained changes in the annular pressure. "	**See Permit Change #18**
Attachment C: Testing and Monitoring Plan, Section 3.1, Last	"Casing inspection logging must be conducted during planned well maintenance operations to evaluate downhole conditions and confirm absence of	Background: Not all planned well maintenance operations can easily accommodate a casing inspection log. A casing inspection log requires (at a minimum) the removal of the wellhead and tubing. 1) CSS requests the sentence be revised to:	**See Permit Change #19**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Paragraph, Page 17	corrosion."	"Casing inspection logging must be conducted to evaluate downhole conditions and confirm absence of corrosion during planned maintenance operations, whenever the planned maintenance operation involves the removal of the wellhead and tubing."	
Attachment C: Testing and Monitoring Plan, Section 3.4, First Sentence, Page 18	"...during planned well maintenance..."	Background: See previous CSS Comment to Attachment C: Testing and Monitoring Plan Section 3.1 Last Paragraph Page 17 CSS requests the requirement to conduct CILs during planned well maintenance be limited to planned well maintenance operations involving the removal of the wellhead and tubing. CSS suggests the phase "...during planned well maintenance..." be revised to "...during planned well maintenance involving the removal of the wellhead and tubing..."	**See Permit Change #20**
Attachment C: Testing and Monitoring Plan, Section 3.5, Page 18	"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 must provide field personnel with handheld equipment to identify the presence of CO_2 as part of the safety requirements for the site. The Permittee must perform additional optical analysis using Optical Gas Imaging (OGI) cameras quarterly during the injection period. OGI cameras use infrared images to detect	Background: 40 CFR 146.90(h) states the Director may require surface air monitoring to detect movement of CO_2 that could endanger a USDW. The leak detection plan in the Draft Permit is ineffective since it requires waiting up to one week (or more) to detect a leak, appears to be overly complex to implement since it specifies use of both handheld instruments and an Optical gas imaging (OGI) camera, and its scope includes pipelines to the injection well over which the US EPA Class VI program likely does not have regulatory authority. Safety is a priority for CSS, so CSS voluntarily implemented surface air monitoring using infrared open-path detectors installed proximate to the Front Range 1-1 and Front Range 2-1 wellheads to continuously monitor CO_2 in the ambient air around each wellhead. CSS believes that continuous monitoring of ambient air at the wellheads is more effective than weekly or quarterly inspections. Infrared open-path detectors are easier to maintain compared to OGI cameras since the models CSS specified have been ruggedized for continuous exposure to ambient weather, and require less frequent re-calibrations (once a year)	**See Permit Change #21**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
	gas leaks and must be used during the inspection of facilities and pipelines connected to the Class VI wells, and well locations."	than OGI cameras (every six months). 1) CSS requests the current text in Section 3.5 be deleted in its entirety, and replaced with a new leak detection plan requiring the use of a sensor to continuously monitor CO2 concentrations in the ambient air at both the Front Range 1-1 wellhead and the Front Range 2-1 wellhead per the Background discussion. 2) CSS requests the above changes be propagated across the Draft Permit and Draft Permit Attachment. This includes but is not limited to changes at the following locations: a) Draft Permit Attachments: Post-Injection Site Care and Site Closure Plan Table 2 Page 42	
Attachment C: Testing and Monitoring Plan, Section 4.0, Second and Third Paragraphs on Page 19	Both paragraphs	Background: CSS believes the text in its current form is confusing since it does not clearly identify the monitoring zones of concern. CSS requests the paragraphs be revised to improve clarity. CSS suggests identifying the monitoring zones of concern as the first USDW above the injection zone and the first USDW below the injection zone, and further suggests modify the text at several places to indicate the action plan only applies to the monitoring zones of concern and not to the injection zone. These clarifications should be propagated throughout both paragraphs.	**See Permit Change #22**
Attachment C: Testing and Monitoring Plan, Table 6, Pages 22-23	Various entries in the upper and middle subsections of Table 6	Background: Table 6 summarizes the analytes and test methods for groundwater samples. Bullet 4 on page 65 of the Class VI Guidance Document on Testing and Monitoring states: "It is recommended that physically or chemically unstable analytes be measured in the field rather than in the laboratory. Examples include pH, redox potential, dissolved oxygen, temperature, and specific conductivity." Some groundwater samples may be actively de-gassing CO2 and thus considered unstable. 1) CSS requests several entries in the upper and middle	**See Permit Change #23**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		subsections of Table 6 be revised to align with Table E.9-3 of the Testing and Monitoring Plan in CSS's application and also align with the Guidance Document recommendation for unstable analytes. Specifically: a) The test method for Dissolved CO2 in the upper and middle subsections of Table 6 should be changed to "Field Meter". b) The test method for pH in the upper and middle subsections of Table 6 should be change to "Field Meter". c) The test method for Specific Conductance in the upper subsection of Table 6 should be changed to "Field Meter", and the row for Specific Conductance in the middle subsection of Table 6 should be deleted. The test method for Temperature in both the upper and middle subsections of Table 6 should be changed to "Field Meter"	
Attachment C: Testing and Monitoring Plan, Table 6, Middle Section, Row 8, Page 22	Water Density (field) Oscillating body method	Background: Requirements for field measurements of water density are inconsistent across the three sections of Table 6, and are inconsistent with CSS's application . The middle section (Formation: Entrada, Ingleside) requires a field measurement of water density, the other two sections of Table 6 (Formation: Alluvial Aquifer and Pierre Shale, Formation: Lyons) do not require a field measurement of water density. Table E.9-3 and Table 10.2 in the Testing and Monitoring Plan in CSS's application do not contain a requirement for field measurement of water density. CSS requests deleting the requirement to measure "Water Density (field)" in Table 6 Middle Section Row 8.	**See Permit Change #23**
Attachment C: Testing and Monitoring Plan,	Entries in the lower subsection of Table 6	Background: Several of the "SM 4500 series" entries on the analytical methods appear to be inadvertently auto-filled during EPA drafting, resulting in the wrong number for the test method.	**See Permit Change #23**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Table 6, Page 23		1) CSS requests entries in the lower subsection of Table 6 be revised to align with Table E.10-2 of the Testing and Monitoring Plan in CSS's application. Specifically: a) For the Total CO2 row, change the parameter from "Total CO2 SM 4500" to "Total CO2", and change the analytical method from "SM 4501" to "SM 4500" For the Cyanide row, change the parameter from "Cyanide SM 4500" to "Cyanide", and change the analytical method from "SM 4502" to "SM 4500"	
Attachment C: Testing and Monitoring Plan, Table 7, Front Range 2-1 Subsection, Row 3, Page 24	Direct monitoring of fluids to detect CO2 in the Lyons, Entrada, and Ingleside Geochemical analysis (Table 6, Attachment C) Year 1-2: Annually; Year 3-8: Quarterly; Remainder: Annually Year 1-2: Annually; Year 3-8: Quarterly; Remainder: Annually Analytical Results	Background: Per 40 CFR 146.95(f)(3)(i), projects with an injection depth waiver must follow a testing and monitoring plan that meets the requirements of § 146.90 with modifications that require monitoring both the first USDW above the injection zone and the first USDW below the injection zone. Per 40 CFR 146.95(f)(3)(ii), projects with an injection depth waiver must follow a testing and monitoring plan that meets the requirements of § 146.90 with direct and indirect methods to track the extent of the CO2 plume and the pressure front in the injection zone. Thus, the Class VI regulations divide the monitoring requirements into two parts: one part for the two USDWs surrounding the injection zone, the other part for the injection zone. Table 7, Front Range 2-1 Subsection, Row 3 combines requirements for direct monitoring of fluids for both the surrounding USDWs and the injection zone into a single row. 1) CSS requests Table 7, Front Range 2-1 Subsection, Row 3 be split into two rows (one for the surrounding USDWS, one for the injection), which is consistent with the separation in § 146.95(f)(3)(i) and (ii). Splitting the row into two allows tailoring of monitoring frequency to the needs of the two different types of zones.	**See Permit Change #24**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Attachment C: Testing and Monitoring Plan, Table 7, Front Range 2-1 Subsection, NEW-row for direct monitoring of fluids in the surrounding USDWs, Page 24	NEW-row for direct monitoring of fluids in the surrounding USDWs	Background: From a risk perspective, monitoring frequency should vary over time according to the relative locations of Front Range 2-1 and CO2 plume and pressure front. Section B.3.5 of the Area of Review and Corrective Action Plan in CSS's application show the computation model predicts the CO2 plume will pass Front Range 2-1 just prior to Year 8. The computational model predicts the pressure front will never reach Front Range 2-1 (where the pressure front is determined by the threshold pressure needed to force liquids from the injection zone into a USDW), so monitoring frequency considerations do not need to account for the location the pressure front. Lower monitoring frequencies are appropriate prior to passage of the CO2 plume across the Front Range 2-1 injection zone since the risk for unauthorized fluid migration into the surrounding USDWs is low, higher monitoring frequencies are appropriate during the period when the CO2 plume passes the Front Range 2-1 injection zone since this is when the risk for unauthorized fluid migration into the surrounding USDWs is greatest, and resumption of lower monitoring frequencies is appropriate once the plume has passed the Front Range 2-1 injection zone since the risk for unauthorized fluid migration into the surrounding USDWs has decreased. 1) CSS requests the Event Frequency and Record/Report Frequency/Requirement for the new row for direct monitoring of fluids in the surrounding USDWs be set as follows: Year 1-4: Annual Year 5+: Quarterly until plume passes the Front Range 2-1 injection zone After Plume Passage: Resume Annual Monitoring	**See Permit Change #24**
Attachment C: Testing and Monitoring Plan,	NEW-row for direct monitoring of fluids in the injection zone	Background: The previous discussion for the new row to handle monitoring frequencies in the surrounding USDWs also applies to injection zone monitoring for the time periods prior to and during plume passage at Front Range 2-1, but the time period after plume	**See Permit Change #24**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Table 7, Front Range 2-1 Subsection, NEW-row for direct monitoring of fluids in the injection zone, Page 24		passage should be handled differently. It is generally accepted in various engineering fields that transient laminar flow of fluids through porous media (e.g., reservoir engineering and CO2 injection into an injection zone) is accurately modeled using the wave equation, which is a partial differential equation that describes the space and time behavior of a wave using various parameters to describe the properties of the fluid and porous media (e.g., equations of state for fluid properties, permeability for porous media properties). At any given location and point in time, the concentration of the flowing fluid will fall into one of three categories: 1) zero for locations and times well before the passage of the wave, 2) between 0 and 100% of injectate concentration (assuming full saturation) for times during which the wave is passing a specific location, and 3) 100% of injectate concentration (assuming full saturation) for locations and times well after passage of the wave. The takeaway point is that there are no further changes in concentration once the wave has passed a specific location, in other words there is no additional information to be garnered from continued monitoring of the injection zone once the CO2 plume has passed Front Range 2-1. From a risk perspective, collecting fluid samples from the injection zone at Front Range 2-1 once the plume has passed will not provide any new information since there is no new information to be collected, and continued sampling may increase the risk of unauthorized fluid migration into the surrounding USDWs. 1) CSS requests the Event Frequency and Record/Report Frequency/Requirement be set as follows: Year 1-4: Annual Year 5+: Quarterly until plume passes the Front Range 2-1 injection zone, then cease monitoring	
Attachment C: Testing and	Indirect monitoring of CO2 plume Pulsed Neutron Log (PNL)	Background: Table 7 requires annual Pulsed Neutron Logging (PNL) at Front Range 2-1 as a method for indirect monitoring of the CO2 plume. The Class VI regulations [40 CFR 146.90(c)(2)] requires use	**See Permit Change #24**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Monitoring Plan, Table 7, Front Range 2-1 Subsection, Row 4, Page 24	Annually Annually PNL	of indirect methods to track the CO_2 plume but does not specify the method(s). Later in Table 7, the Draft Permit also requires use of time-lapse vertical seismic profiles (VSPs) to track the plume. CSS believes PNLs will provide little additional information on plume tracking beyond the information provided by direct monitoring of formation fluids at Front Range 2-1 and indirect monitoring using time-lapse VSPs. PNL is an advanced logging technique that uses a high energy neutron generator and a gamma ray detector to measure CO_2 saturations in the near wellbore region beyond the cement casing for a well. Generally, both the generator and the detector are mounted on a slickline tool to allow logging through any installed tubing in the well. PNL is only capable of measuring CO_2 saturations ~1 foot into the rock formation. Vertical resolution is typically 1.5' to 3' outside of perforation intervals, with poorer resolution across perforation intervals because of fluid mixing. Furthermore, PNL tools operating in sigma mode perform poorly when logging across intervals containing freshwater (e.g., the surrounding USDWs). 1) CSS requests the requirement in Table 7 to use PNL be deleted since: it a redundant indirect monitoring method for plume tracking that provides little additional information beyond the information provided by direct monitoring of formation fluids and indirect monitoring by time-lapse VSP, and may perform poorly when logging across the surrounding USDW intervals. 2) CSS requests the deletion of all requirements and references to PNL be propagated across the Draft Permit and Draft Permit Attachment. This includes but is not limited to changes at the following locations: a) Draft Permit Attachments: Area of Review and Corrective Action Plan Section 1.4(A)(1) Page 9; Testing and Monitoring Plan Section 7.2.3 Page 28; PISC and Site Closure Plan Section 3.0 Bullet 3 Page	

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		40; PISC and Site Closure Plan Table 1 Page 41, PISC and Site Closure Plan Table 2 Page 42 - two occurrences; PISC and Site Closure Plan Section 4.2 Page 44;	
Attachment C: Testing and Monitoring Plan, Table 7, Front Range 2-1 Subsection, Row 9, Page 24	Corrosion monitoring Fluid corrosivity testing (pH, chloride, O2) Quarterly Quarterly Any changes from proposed operating data	Background: It is unclear whether this row is referring to the corrosion coupon testing program discussed previously in Section 3 of Attachment C, or if this row is a new requirement for quarterly fluid corrosivity testing using measurements on injection zone fluid samples from Front Range 2-1 to quantify pH, chloride concentrations, and dissolved oxygen concentration. 1) If this row refers to the corrosion coupon testing program, then CSS requests this row be deleted since the requirements for corrosion coupon testing are described in Section 3 of Attachment C. 2) If this row refers to a new requirement for quarterly measurements on injection zone fluid samples from Front Range 2-1, then CSS requests this row be deleted. Such testing is not explicitly discussed in the Class VI regulations, the required event frequency does not align with the event frequency for direct monitoring of fluids to detect CO2 in the injection zone, and there is no supporting discussion of this new requirement in the Draft Permit or Draft Permit Attachment. If this row refers to some other requirement besides those in 1) and 2) above, then CSS requests this row be revised to improve clarity on the requirement.	**See Permit Change #24**
Attachment C: Testing and Monitoring Plan, Section 4.3.1, Page 25	All five bullet points	Background: The five bullets points define specific days for sampling events. Two of these dates will likely fall over a holiday weekend (Memorial Day, and Christmas/New Years). CSS requests the text be revised to allowing sampling up to +/- one month around the proposed dates to provide flexibility with respect	EPA did not grant the requested date flexibility. CSS may conduct the sampling before the specified dates, and EPA is retaining the final Permit

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		to scheduling of personnel, weather, holidays, weekends, etc.	language as drafted because the established schedule provides the intended monitoring frequency. The requested ±1 month window is unnecessary, and the Permit language remains unchanged.
Attachment C: Testing and Monitoring Plan, Section 5.0, Third Paragraph, Last Sentence, Page 25	"Permittee may choose which logging and testing to demonstrate external mechanical integrity but must continue to use that same test for the remainder of the project."	Background: The Draft Permit language restricts the method used for external MITs over the entire course of the project to the method selected by the Permittee for the first MIT. The Class VI regulations and Class VI Guidance Documents do not place a restriction that the same external MIT method be used over the entire course of a project. CSS's current intent is to use DTS-based temperature logs as the primary method for conducting external MITs on both Front Range 1-1 and Front Range 2-1. CSS purposely included multiple allowable external MIT methods in its application to provide flexibility to use a secondary method in the event of: 1) DTS system(s) are unable to perform the test at the required time (e.g., a secondary test would be used if one of the DTS systems is broken), or 2) a follow-up external MIT using a secondary method is needed to investigate an anomaly discovered by a DTS-based temperature log. 1) CSS requests the sentence be deleted. 2) CSS requests this change be propagated throughout the Draft Permit and Draft Permit Attachment. This includes but is not limited to changes at the following locations: a) Draft Permit Attachments: Testing and Monitoring Plan Table 8 Footnote Page 26	**See Permit Change #25**
Attachment C:	"At least once every 12 months	Background: The footnote provides little leeway in testing	EPA did not grant the

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Testing and Monitoring Plan, Table 8, Footnote 2, Page 26	after last successful test"	frequency. CSS intends to conduct annual external MITs on Front Range 1-1 during the planned annual 4-day outages of CO2 supply (see previous CSS Comment on Attachment C: Testing and Monitoring Plan Table 2-Row 8 for more background information). The annual CO2 supply outage typically occurs in August or September of each year, but the exact 4-day period within those two months varies from year to year. CSS does not have the same concern for the specified frequency for external MITs on Front Range 2-1. 1) CSS requests the footnote be revised to provide CSS with a two month window to conduct the annual external MIT on Front Range 1-1.	requested two-month window. The final Permit language is retained because the existing requirement ensures clear compliance tracking and allows Compliance Assurance to readily determine whether the external MIT was completed within the required annual timeframe.
Attachment C: Testing and Monitoring Plan, Section 7.0, Last Sentence, Page 27	"A summary of the methods used for CO2 and pressure front tracking is provided in Error! Reference source not found.7."	Background: There appears to be a broken hyperlink in the text 1) CSS requests the broken hyperlink be fixed.	**See Permit Change #26**
Attachment C: Testing and Monitoring Plan, Section 7.2.2, Last Sentence, Page 28	"If a sudden change in pressure or temperature is observed, Permittee must immediately cease injection, notify the Director within 24 hours, and evaluate and identify the cause of the change."	Background: Text requires immediately ceasing injection and notifying the Direct whenever a sudden change in pressure of temperature is observed at Front Range 2-1, regardless of whether the change was expected. CSS anticipates there will be "sudden changes in pressure and temperature" during well maintenance at Front Range 2-1, and also during direct sampling events at Front Range 2-1. These sudden changes are normal and do not indicate a well failure. 1) CSS requests the sentence be revised as follows: "If a sudden change in pressure or temperature is observed outside of well maintenance or direct sampling events, Permittee must immediately cease injection, notify the Director within 24 hours,	**See Permit Change #27**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
		and evaluate and identify the cause of the change."	
Attachment C: Testing and Monitoring Plan, Table 9, Page 29	Table 9	Background: Table 9 requires continuous soil gas monitoring, quarterly laboratory analysis of soil gas samples, and quarterly CO2 efflux measurements. 40 CFR 146.90(h) states that soil gas monitoring is not a mandatory requirement of the Class VI regulations. CSS voluntarily included a soil gas monitoring program in its application to assure that at least one year of baseline data was obtained far in advance of the start of injection. CSS designed a comprehensive soil gas monitoring program using the same three monitoring methods as Table 9. The primary purpose of continuous soil gas monitoring is to quickly identify a potential non-containment event, while the primary purpose of laboratory analysis of soil gas samples and CO2 efflux measurements are to confirm results from continuous monitoring. Finally, the Record Frequency column in Table 9 is confusing to CSS. 1) CSS requests the sample frequency and reporting frequency for laboratory analysis of soil gas samples and CO2 efflux measurements be revised to annual. CSS believes the quarterly/semi-annual requirements in Table 9 are unnecessary since: 1) these methods are primarily used to confirm results from continuous monitoring, and 2) CSS believes the risk of CO2 or formation fluids migrating from the GS project depth to the surface is highly unlikely since there is over 8,000' of competent rock separating these locations. CSS requests the Record Frequency column in Table 9 either be: a) deleted, or b) revised to improve clarity in which case the Record Frequency updated to align with sampling and reporting frequencies.	**See Permit Change #28**
Attachment D: Well Plugging Plan,	"An annulus pressure test must be conducted to determine internal MIT in accordance with	Background: Both 40 CFR 146.92(a) and the UIC Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance document state a final external MIT must be conducted on an	EPA did not grant the requested deletion. The final Permit retains the

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Section 1.0, Page 32	Section 5.0 of Attachment C."	injection well before it is plugged. Neither the Class VI regulations nor the corresponding Guidance Document contemplate a requirement to conduct a final annulus pressure test (internal MIT) before an injection well is plugged. 1) CSS requests deleting the requirement to conduct a final annulus pressure test before plugging.	requirement for a final annulus pressure test before plugging because CSS must demonstrate internal mechanical integrity in accordance with Attachment C and the approved plugging procedures, which is done using the annulus pressure test.
Attachment E: Post-Injection Site Care and Site Closure Plan, Section 2.0, Page 37	"The AoR is defined by the plume shape and size in Year 12 (end of injection period) because this is the time with largest differential pressure and CO_2 plume."	Background: The text in the Draft Permit appears to be incorrect. 1) CSS suggests the text be replaced with the following wording from Pages 12-13 of the Fact Sheet: "The AoR was determined as the union of the maximum extent of the pressure front in year 12 (end of injection period) and the maximum extent of the CO_2 plume at year 32 (end of proposed alternate post-injection site care period), 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."	**See Permit Change #29**
Attachment E: Post-Injection Site Care and Site Closure Plan, Section 2.0, Bullet 2, Page 40 Attachment E: Post-Injection Site Care and Site Closure Plan,	<u>Bullet 2.</u> 2. The first 10 years after the cessation of injection, direct measurements of pressure and temperature in the Injection Zone, the Entrada Formation, and Ingleside Formations must be obtained from the FR 1-1 and FR 2-1 monitoring wells that	Background: There appears to be an inconsistency with the PISC Monitoring Frequency for fluid sampling and geochemical/isotopic monitoring for the USDWs surrounding the injection zone. Bullet 2 on Page 40 states fluid samples must be collected every 5 years, while Table 1-Row 1 on Page 41 requires annual sampling. The Class VI regulations for wells with an injection depth waiver [40 CFR 146.95(d)(4)(i)] requires monitoring of the surrounding USDWs for geochemical changes during PISC but does not specify a monitoring frequency. The Class VI regulations for wells without an injection depth do not require monitoring for geochemical changes above	**See Permit Changes #29 and #30**

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Table 1-Row 1, Page 41	have not yet been plugged. Fluid samples must be collected every 5 years, and more frequent fluid samples must be collected if pressure or temperature indicate a change as determined by the Director. <u>Table 1-Row 1</u> USDWs above and below the confining zone monitoring Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry Fluid and dissolved gas sampling Annual Record: Annually Report: Annually	the upper confining zone during PISC, but Section 3.3.3 of the Class VI Guidance Document on Well Plugging, PISC, and Site Closure recommends continued monitoring for geochemical changes until the leakage potential is reduced through the declining pressure differential in the injection zone. Section B.3.3 of the Area of Review and Corrective Action Plan in CSS's application predicts the injection zone pressure differential at Front Range 1-1 falls below the minimum threshold that within one year after cessation injection, so the risk of unauthorized fluid migration out of the injection zone falls rapidly once injection is halted. CSS requests Table 1-Row 1 entries be changed from annual to every 5-years. The Class VI regulations, Class VI Guidance Documents, and the computational model all support a relatively low risk for unauthorized fluid migration during PISC.	
Attachment E: Post-Injection Site Care and Site Closure Plan, Table 1-Lower Portion of Combined Row 3, Page 41	FR 1-1 and FR 2-1 Confining integrity of the Upper and Lower Confining Zone Distributed thermal sensing Annual until plugging Record: Single Monthly Profile Report: 6 monthly profiles Semi Annually	Background: The Class VI regulation [146.90(e)] requires annual external MITs at least once per year until the injection well is plugged. The Class VI regulations do not apply to the same extent to deep zone monitoring wells, but CSS has adopted reasonable Class VI Guidance Document recommendations for its deep zone monitoring wells anyway. Front Range 1-1 and Front Range 2-1 will be deep zone monitoring wells during PISC. Table 1-Lower Portion of Combined Row 3 requires continuous DTS monitoring for both Front Range 1-1 and Front Range 2-1 with stated objective of "Confirming integrity of the Upper and Lower Confining Zone". See previous CSS Comment on Attachment C: Testing and Monitoring Plan Table 2-Row 8 Page 14 for additional discussion on why selected DTS systems for conducting external MITs on Front Range	**See Permit Change #30**

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		1-1 and Front Range 2-1. 1) CSS requests the requirement for DTS monitoring in Table 1, Lower Portion of Row 3 be deleted. CSS believes this requirement is unnecessary; the Class VI regulations, Class VI Guidance Documents, and the computational model all support a relatively low risk for unauthorized fluid migration during PISC. The stated objective of "Confirming integrity of the Upper and Lower Confining Zone" is handled through the external MIT requirements given in Table 2 on the next page. CSS requests the deletion of DTS monitoring be propagated into the Table 1 footnote by deleting the phrase "...and/or DTS fiber...".	
Attachment E. Post-Injection Site Care and Site Closure Plan, Table 2, Title, Page 42	"Table 2: Post-Injection Monitoring Techniques Plume and Pressure Front Tracking"	Background: Yellow highlighting of the table title appears to be a drafting leftover. CSS suggests the yellow highlight be removed	**See Permit Change #31**
Attachment E: Post-Injection Site Care and Site Closure Plan, Table 2, Row 2, Page 42	"...or distributed thermal sensing"	1) CSS requests the phrase "...or distributed thermal sensing" be deleted. CSS requests the deletion of DTS monitoring be propagated into the Table 2 footnote by deleting the phrase "...and/or DTS fiber...".	**See Permit Change #31**
Attachment E: Post-Injection Site Care and Site Closure Plan, Table 2, Row 8, Page 42	FR 1-1 FR 2-1 Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry Fluid and dissolved gas sampling	Background: Table 2 Row 8 and Table 2 Row 1 appear to be in conflict; They have similar objectives to monitor changes in the injection zone geochemistry and both require taking injection zone samples, however the PISC Monitoring and the Recording & Reporting Frequencies differ. Figure B.3-2 in the Area of Review and Corrective Action Plan in CSS's application provide the computational model time-lapse predictions on gas saturation in the injection zone vertical NW-SE cross-sections through Front	**See Permit Change #31**

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	Annually Record: Annually Report: Annually	Range 1-1 and the approximate location for Front Range 2-1. The computational model predicts very little change in gas saturation between Year 12 and Year 32, thus it will likely be difficult to track changes in geochemistry given the limitations of the sampling and analysis methods. 1) CSS requests keeping Table 2 Row 1 for the event-driven monitoring, and CSS requests deleting Table 2 Row 8 for annual monitoring. This request is based on the computational model predictions for very little change in gas saturation between Year 12 and Year 32. Event-driven monitoring during PISC can be used as needed for computational model calibration.	
Attachment E: Post-Injection Site Care and Site Closure Plan, Table 2, Row 9, Page 42	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 After any event, record and report to the Director	Background: Table 2 Row 9 specifies event-driven soil gas monitoring at a minimum of 15 locations during PISC. CSS has installed 6 soil gas wells across the areal extent of the GS project that are capable producing the required samples. 1) CSS requests the phrase "at a minimum of 15 locations" be deleted. CSS believes its 6 installed soil gas wells is more than adequate for project needs.	**See Permit Change #31**
Attachment F: Emergency and Remedial Response Plan, 24-Hour Reporting	-	Background: 24-Hour Reporting Requirements are defined in the Draft Permit rather than the Emergency and Remedial Response Plan. 1) See previous CSS Comment on Draft Permit, Section O.3, Page 21 that requests moving text from the Draft Permit to the Emergency	**See Permit Change #8**

Location(s)	Text in Draft Permit/Permit Attachment	CSS Comment	EPA Response
Requirements		and Remedial Response Plan.	
Attachment F: Emergency and Remedial Response Plan, Section 4.6 and Table 2, Pages 55-56	Entire section	Background: This section provides a portion of the seismic action plan for the Draft Permit/Draft Permit Attachment. 1) See previous CSS Comment on Draft Permit, Section M.1, Page 19 to revised the seismic action plan to align with the requirements of the proposed ECMC Class VI primacy application.	EPA did not make the requested revisions. The seismic action plan was developed based on the site-specific record and reflects EPA's determination of the monitoring and response measures necessary to protect USDWs and address potential seismic risks associated with the project. EPA's approach is consistent with Region 8 practice for UIC permits. Accordingly, EPA did not modify the seismic action plan or revise the related Permit language.
Attachment G: Well Construction, Table 4, Page 63	The entire contents of Table 4	Background: The contents of Table 4 were not contained in the A.II Well Construction Details document in CSS's application to EPA. 1) CSS requests Table 4 be revised to align with Table A.II.2-5 in the Well Construction Details document CSS submitted in its application to EPA. CSS believes the level of information in Table 4 is overly restrictive and without tangible benefit for reassembling well internals during a future workover.	**See Permit Change # 33**
Attachment G: Well Construction, Section 3.0, Page 63	"The Permittee must ensure that the surface casing extends to the base of the lowermost USDW...consistent with 40 CFR	Background: CSS has filed for an injection depth waiver, so the language for the extent of surface casing should be based upon 40 CFR 146.95(f)(2)(iii); it should not be based upon 40 CFR 146.86(b)(2).	**See Permit Change #32**

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	146.86(b)(2)"	1) CSS requests the language and citation be revised to align with 40 CFR 146.95(f)(2)(iii)	
Attachment G: Well Construction, Table 10, Page 67	The entire contents of Table 10	Background: This table is based on Table A.II.3-5 in the Well Construction Details document CSS submitted in its application to EPA. 1) CSS requests a footnote be added to Table 10 stating that minor changes in depths and mechanical details are allowable as long as these changes do not impact functionality of the well. This will allow CSS with some flexibility to make field adjustments during a future workover.	**See Permit Change #34**