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<u>Via Federal Express No. 7779 9943 5234</u>

Dr. Steven Cliff
Executive Officer - California Air Resources Board

Rajinder Sahota
Deputy Executive Officer - Climate Change and Research

Carolyn Lozo
Branch Chief - Oil and Gas and Greenhouse Gas Mitigation

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Updated Joint EDF and Oxy comments to Staff Presentations Provided at the Oct 14-15, 2020, Low Carbon Fuel Standard Workshop

Dear Dr. Cliff, Ms. Sahota and Ms. Lozo:

The Environmental Defense Fund (EDF) and Oxy Low Carbon Ventures LLC (OLCV) jointly provided comments to the California Air Resources Board (CARB) following an October 14-15, 2020, LCFS Public Workshop. Since then, we have been conducting further research into seismicity monitoring and have identified needed improvements to our previously submitted proposal. As a result of our work, we have developed proposed revisions to the CARB CCS Protocol provisions that we consider absolutely critical to ensuring that well qualified CCS Projects deploy and maintain a seismicity monitoring system to determine the presence or absence, magnitude, and the hypocenter of seismic activity within the vicinity of a storage complex.

We strongly believe that our comments providing proposed revisions to CARB's CCS Protocol, including the proposed revisions to seismicity monitoring, significantly strengthen the program. Our comments are the result of EDF's and OLCV's joint effort and identifies certain CCS Protocol provisions that could benefit from some relatively minor but significant revisions. If adopted, we believe that our proposed revisions will provide a number of benefits, including, further bolstering the CCS Protocol's environmental protections, helping ensure that qualified projects demonstrate permanence of stored CO_2, attracting greater participation from high quality sequestration projects and building greater public trust in carbon capture and storage.

As a courtesy, we resubmit our full comment package, including our newly drafted revisions to the seismicity monitoring requirements. Our attached comments are generally organized in the following format: first, the current CCS Protocol language is provided or cited, next, revised language is proposed, lastly, a brief discussion provides support for our proposed language. One general comment is provided as #7. Our list of comments focused on CCS Protocol improvements, include:

Comments for Improving the CCS Protocol Provisions Overview

1. A.2.(8): Definition of "Brine" (CCS Protocol page 8)
2. C.1.1.1: Third Party Review (p. 32)
3. C.2.4.3.(d): Corrective Action Requirements – (p. 62)
4. C.4.1.(a)(3) and C.4.3.1.4: Testing and Monitoring and Corrosion Monitoring and Casing Inspection – (pp. 77, 88)
5. C.4.3.2.3: Seismicity Monitoring – (p. 96)
6. C.9.c: Legal Understanding, Contracts, and Post-Closure Care – (p. 119)
7. Process for recognizing other state regulatory programs for LCFS purposes

We would also like to schedule a follow-up meeting to discuss our comments and solicit feedback from CARB. We believe that such a meeting would provide an opportunity for constructive conversations about the CCS Protocol and help develop a pathway forward to enable California to address the current climate crisis.

Best Regards,

Adam Peltz
Director and Senior Attorney, Energy
Environmental Defense Fund

Myles Culhane
Associate General Counsel
Oxy Low Carbon Ventures

cc: Liane Randolph, Board Chairperson, California Air Resources Board
Le-Quyen Nguyen, Deputy Secretary of Energy, California Natural Resources Agency

Comments for Improving the CCS Protocol Provisions

1. A.2.(8): Definition of "Brine"

"Brine" is water containing dissolved minerals and inorganic salts in solution, including sodium, calcium, or bromides. Water containing dissolved solids in excess of 100 g/L is classified as brine. Large quantities of brine are often produced along with oil and gas.

Brine Proposal

CARB should redefine brine as waters containing dissolved solids in excess of 10,000 ppm or 10 g/L TDS.

Discussion

The CCS Protocol rightly works to mitigate migration of brine leakage from the sequestration zone. Typically, drinking water regulatory programs aim to protect waters below 10,000 parts per million (ppm) Total Dissolved Solids (TDS), or 10 g/L, from contamination. The protocol uses the definition of brine to prescribe brine leakage (e.g., C.2.1(a)4, demonstration that the geologic system comprises "[a] confining system composed of a layered interval of low and moderate permeability rocks that will (1) dissipate any excess pressure caused by CO_2 injection, (2) impede vertical migration of CO_2 and/or brine above the storage complex, potentially to the surface and atmosphere via possible leakage paths, and (3) provide opportunities for monitoring, measurement, and verification of containment.")

By defining brine as 100 g/L or 100,000 ppm TDS, the protocol does not explicitly protect against the migration of saline fluids between 10,000 ppm TDS and 100,000 ppm TDS out of the storage complex and potentially into protected groundwater zones.

2. C.1.1.1: Third Party Review

C.1.1.1.(a) – (f) contain the provisions for third party review and are supplemented with LCFS Guidance 19-07.

Third-Party Review Proposal

To ensure that third party reviewers have the necessary expertise to meaningfully evaluate the totality of the Application for Site Sequestration (C.1.1.2(b)) and the Application for CCS Project Certification (C.1.1.2(d)), covering site-based risk assessment, risk management, storage complex delineation and corrective action, baseline testing and monitoring, well construction, testing and monitoring related to containment, well plugging and abandonment, post-injection site care and site closure, emergency response, financial responsibility, and legal understanding, we propose C.1.1.1(e) and C.1.1.1(f) be modified to allow third party evaluators with the appropriate substantive expertise, regardless of certification, to review relevant sections, whether singularly or in teams (the modification could include a requirement that at least one PE and one PG participate on the team conducting the reviews).

We further propose that the LCFS Guidance 19-07's Third Party Reviewer Competency Evaluation additionally require a submission demonstrating the proposed individual or team's competency on the subjects of site-based risk assessment, risk management planning, geologic evaluation, storage complex delineation and corrective action planning, baseline testing and monitoring, well construction, testing and monitoring, well plugging and abandonment, post-injection site care, site closure, financial responsibility, and legal understanding.. We also propose that, in the list of projects reviewers must submit, that saline sequestration projects, if any, be included in addition to CO_2-EOR projects.

Discussion

CARB has a laudable goal in requiring third party review of aspects of Carbon Capture and Sequestration projects. However, the third-party review program could use some tweaks to better tailor it to program goals and industry realities. In particular, we see room for improvement in articulating necessary competencies for various pieces of the third-party certification requirement, and how third-party expertise is evaluated.

The protocol requires third-party certification of the Application for Sequestration Site Certification (C.1.1.2(b)) and the Application for CCS Project Certification (C.1.1.2(d)), which together make up the Permanence Certification. These materials are comprised of the following:

- Site-Based Risk Assessment, including Risk Management Plan
- Geologic Evaluation
- Storage Complex Delineation and Corrective Action Plan
- Baseline Testing and Monitoring Plan
- Well Construction Plan
- Testing and Monitoring Plan including MIT, emissions monitoring, and MMV of containment
- Well Plugging and Abandonment Plan
- Post-Injection Site Care and Site Closure Plan
- Emergency Response Plan
- Financial responsibility demonstration
- Legal understanding demonstration
- Updates and as-built reports for each of these plans

The purpose of enumerating these materials is to demonstrate that a breadth of expertise is required to properly evaluate the truth, accuracy, completeness and robustness of these filings. This raises two points.

a) We question the efficacy of the requirement that the evaluation of the Application for Sequestration Site Certification be conducted by a Professional Geologist (PG) (C.1.1.1(e)) while the evaluation of the Application for CCS Project Certification be conducted by a Professional Engineer (PE) (C.1.1.1(f)). The scope of expertise required for each of these evaluations stretches beyond the expertise to be expected in either a PG or a PE and would usually best be accomplished by a team that includes both PGs and PEs, as well as other types of experts.

b) We are concerned that the Third-Party Reviewer Competency Evaluation articulated in LCFS Guidance 19-07 does not map to the myriad competencies required to effectuate the requirements of C.1.1.1(b) and C.1.1.2(d). As such, the Evaluation should require prospective third parties to provide their expertise on the subjects of site-based risk assessment, risk management planning, geologic evaluation, storage complex delineation and corrective action planning, baseline testing and monitoring, well construction, testing and monitoring, well plugging and abandonment, post-injection site care, site closure, financial responsibility, and legal understanding.

3. C.2.4.3.(d): Corrective Action Requirements

(d) Prior to CCS Project Certification, CCS Project Operators must perform corrective action on all wells that either penetrate the storage complex or are within the surface projection of the storage complex that require corrective action. In performing corrective action, CCS Project Operators must use methods designed to prevent the movement of fluid out of the storage complex into a shallower zone, including use of materials compatible with the CO_2 stream, where appropriate.

(1) A well requires plugging if:

(A) Records indicate that a well plug sufficient to prevent upward movement of fluids does not exist at a depth corresponding to the primary confining layer, or there are no well plugs below permeable formations that may exhibit cross flow of mobilized fluids along the wellbore or casing; or

(B) Field evaluations reveal cracks, channels, or annuli in the plug that would allow fluid migration or suggest the plug material may corrode in response to reactions with CO_2; or

(C) Field tests indicate the well is leaking gas or fluids.

(2) A well requires remedial cementing if records or field evaluations indicate that the cement surrounding the wellbore has failed or has cracks, channels, or annuli that could allow migration of CO_2, or if the well has not been cemented.

(3) Materials used for cementing of abandoned wells must be supplemented with or replaced by materials such as polymer gels and acrylic grouts, if required by the Executive Officer.

C. 2.4.3.(d)(2) Proposal

Modify (2) above to read:

(2) A well requires remedial cementing if records or field evaluations indicate that the cement surrounding the wellbore has failed or has cracks, channels, or annuli that could allow migration of CO_2, or if the well has not been cemented in a manner that would prevent the degradation of protected groundwater resources.

Discussion

- This proposal aligns the performance standard for corrective action with the performance standard for well construction, clarifying corrective action review for existing wells.
- The revised language provides the mechanism for the project proponent to demonstrate that existing wells will prevent the movement of fluids into or between formations and prevent the degradation of protected groundwater resources.
- Successfully operated CO_2-EOR projects often have long operated wells that demonstrate mechanical integrity and secure performance.
- Having this record of successful performance demonstrates the wells operate in a manner consistent with regulatory goals and do not leak CO_2.
- Reworking existing wells that demonstrate mechanical integrity risks compromising the wells without achieving a higher level of performance.
- Continuous monitoring can detect leakage at extremely low levels.

4. C.4.1.(a)(3) and C.4.3.1.4: Testing and Monitoring and Corrosion Monitoring and Casing Inspection

C.4.1.(a)(3) Corrosion monitoring of well materials, upon well completion and a minimum of once per every five years thereafter, for loss of mass, thickness, cracking, pitting, and other signs of corrosion, to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent, by:

- (A) Analyzing corrosion coupons of the well construction materials placed in contact with the CO_2 stream; or
- (B) Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop;
- (C) Performing casing inspection logs; or
- (D) Using an alternative method approved by the Executive Officer.

C.4.3.1.4 Corrosion Monitoring and Casing Inspection

- (a) CCS Project Operators must monitor well materials for corrosion at a frequency specified in the Testing and Monitoring Plan following subsection C.4.1, not to exceed once every five years.
- (b) Well components must be monitored for corrosion using at least one of the following methods:
  - a. Corrosion coupons or loops;
  - b. Casing inspection logs (CILs), such as caliper, electromagnetic phase-shift, electromagnetic flux test log, or ultrasonic test logs; or
  - c. An alternative method approved by the Executive Officer.
- (c) Well corrosion monitoring data must be reported annually to CARB including, including at a minimum, the following:
  - (1) A description of the techniques used for corrosion monitoring;
  - (2) Measurement of (mass and thickness/weight) loss from any corrosion coupons or loops used;
  - (3) Assessment of additional corrosion, including pitting, in any corrosion coupons or loops;
  - (4) Measurement of thickness loss or corrosion detected in any CILs;
  - (5) All measured CILs and comparison to previous logs;
  - (6) Identification and explanation of data gaps, if any; and
  - (7) Any identified necessary changes to the CCS project Testing and Monitoring Plan.

C.4.1.(a)(3) and C.4.3.1.4 Proposal

Reduce default corrosion monitoring frequency to two years for Class II wells while providing a mechanism in the Testing and Monitoring Plan to decrease that frequency if the operator can demonstrate through evidence that a less frequent monitoring schedule would not present a material risk to mechanical integrity; establish a default corrosion monitoring frequency of quarterly for Class VI wells; conform the corrosion monitoring reporting requirements as applicable.

Discussion

Corrosion monitoring is essential to ensure that wells maintain integrity despite being subject to corrosive materials as part of regular operation. The CCS Protocol recognizes this and calls for corrosion monitoring at least every five years, subject to the frequency specified in the Testing and Monitoring

Plan. However, there are both internal inconsistencies in the CCS Protocol and on this subject, as well as inconsistencies between the protocol and Class VI rules, and between the protocol and other well integrity corrosion rules in California.

First, the internal inconsistency: CARB allows corrosion monitoring every five years but requires an annual submission of corrosion monitoring data. It's possible that if the five-year protocol is applied on a rolling basis to a large population of wells, then some number of wells will have data to be reported as part of an annual submission. But there is still a disjunct between calling for monitoring to not exceed every five years coupled with annual reporting.

Second, conflict with Class VI. The Class VI rule requires *quarterly* evaluation for corrosion: "40 C.F.R. § 146.90(c)" Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:

(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or
(3) Using an alternative method approved by the Director

Not all wells covered under the protocol are Class VI, and the Testing and Monitoring Plan can be used to shorten the monitoring period for such wells from five years to three months to ensure compliance with Class VI rules. Nevertheless, this 20-fold difference is notable.

Third, conflict with other California rules on well integrity. Section 1726.6 in California's gas storage regulation provides the following on corrosion: "(2) A casing wall thickness inspection to estimate internal and external corrosion, employing such methods as magnetic flux or ultrasonic technologies, shall be performed at least once every 24 months to determine if there are possible issues with casing integrity. Logging shall include a repeat section of no less than 200 feet, preferably across intervals where anomalies are present. The results shall be compared against prior results and any other available data to determine the corrosion rate. If the casing wall thickness inspection indicates that within the next 24 months thinning of the casing will diminish the casing's ability to contain 115 percent of the well's maximum allowable operating pressure utilizing Barlow's equation or another, similarly effective method, then the well shall be remediated and shall not be used for injection or withdrawal without subsequent approval from the Division. The Division may approve a less frequent casing wall thickness inspection schedule for a well if the operator demonstrates that the well's corrosion rate is low enough that biennial inspection is not necessary."

Implementation of the changes we suggest would be similar to what CalGEM has done with its gas storage rule, which calls for corrosion inspection every two years with exceptions for operators who can demonstrate that such a frequency is unnecessary.

5. C.4.3.2.3.(a)(1)(2): Seismicity Monitoring

(a) The CCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system in order to determine the presence or absence of any induced micro-seismic activity associated with all wells and near any discontinuities, faults, or fractures in the subsurface

(1) The design of the array should consider the seismic risk. Location of small events can be helpful in risk reduction, but sufficient planning is needed to collect and analyze the data. Analysis of the micro seismicity must consider if the risk of triggering an earthquake of Richter magnitude 2.7,[10] or greater, is significantly increased by injection. If an increase in risk is detected and determined, mitigation of the risk is required; and

(2) The array should be calibrated with check-shots, preferably at depth.

C.4.3.2.3.(a)(1)(2)(3)(4) Proposal

(a) The CCS Project Operator must deploy and maintain a seismicity monitoring system in order to determine the presence or absence, magnitude, and the hypocenter location to the best of the operator's ability of seismic activity within the vicinity of the storage complex of at least Richter Magnitude 0.7 or such other magnitude as may be necessary to perform the risk analysis required by subsection C.4.3.2.3. If, based on project-specific risk analysis, the operator determines that seismic monitoring does not need to be permanent for a particular project, CARB may permit local seismicity monitoring to be discontinued, deferring instead to state and/or national arrays for long-term monitoring (e.g., USGS).

(1) The design of the array and analysis of the results should enable consideration of whether the risk of triggering an earthquake of Richter magnitude 2.7, or greater, is significantly increased by injection.

(2) The array should be designed with surface arrays and/or downhole arrays as required to meet minimum magnitude of completeness of 0.7, or an alternative site-appropriate minimum magnitude approved by the Executive Officer, and to appropriately calibrate event magnitudes and hypocenter locations.

(3) The array should be calibrated with check-shots, sonic logs or other local velocity information, preferably at depth.

(4) Seismicity and other relevant data must be analyzed to determine whether the risk of triggering an earthquake of Richter Magnitude 2.7 or greater is significantly increased by injection. If such an increase is determined, the Executive Officer must be notified within 30 days and mitigation is required.

Discussion

- Surface and near-surface based seismicity monitoring systems can provide equivalent accuracy and broader aerial coverage without creating additional penetrations into the reservoir.
- When surface and near-surface based arrays can be demonstrated as accurate, they may be a better option than downhole monitoring, which introduces new penetrations into the storage complex.
- A generally accepted guideline for statistical analysis of seismicity is to seek to measure events over a range of 2 magnitude units in order to estimate the linear relationship between frequency and magnitude. [1] Given that our magnitude of concern is magnitude 2.7, the array should be designed to detect events at or above magnitude 0.7. Detected events above magnitude 0.7, as and if they occur, can be used to update the risk of a magnitude of 2.7 or

larger, due to the relationship observed with seismic events that relates earthquake magnitude and earthquake frequency. [2]

Sources
[1] - Stumpf, M. P. H. and M. A. Porter, 2012, Critical truths about power laws: Science, 335 (6069) p. 665-666.
[2] - Gutenberg, B.; Richter, C. F. Seismicity of the Earth and Associated Phenomena, 2nd ed.; Princeton Univ. Press: Princeton, NJ, 1954

6. C.9.(c): Legal Understanding, Contracts, and Post-Closure Care

The CCS Project Operator must show proof that there is binding agreement among relevant parties that drilling or extraction that penetrate the storage complex are prohibited to ensure public safety and the permanence of stored CO_2.

C.9.(c) Proposal

(c) Before commencing injection and during the life of the CCS Project, the CCS Project Operator must demonstrate to CARB's satisfaction that there are sufficient safeguards in place to ensure public safety and the permanence of stored CO_2. These safeguards may include:
   (1) A binding agreement among relevant parties that drilling or extraction that penetrate the storage complex are prohibited; or
   (2) Enforceable regulatory or other legal mechanisms that require wells that penetrate the storage complex prevent unauthorized mixing or loss of fluids, including CO_2, from the sequestration zone and confining layer or layers to the atmosphere.
   (3) Should a project operator become aware of a new drilling or extraction that penetrates the storage complex, the project operator will review and make a determination whether or not the proposed penetration has an impact on the storage complex and take appropriate corrective action if needed.

Discussion

- It is common for productive oil and gas reservoirs to be stacked. These reservoirs offer a substantial secure CO_2 storage opportunity.
- Well established property law provides that those with a property interest in an estate that lies within the surface projection of a project seeking Permanence Certification have a legal right to access their property, it cannot be prevented.
- Long established state legal requirements and UIC rules provide adequate safeguards to prevent migration of fluids when drilling through multiple formations. Regulatory requirements ensure that construction and operating standards are upheld to prevent unauthorized mixing or contamination and are enforceable by a state regulatory agency with jurisdiction over the activity.

7. Process for recognizing other state regulatory programs for LCFS purposes

State Regulatory Program Recognition Proposal

Upon request of an applicant (or other stakeholder), CARB can elect to review the rules, enforcement and regulatory capacity of particular states, and if CARB determines that a state's program is sufficiently rigorous to be as protective as CARB's standards, CARB will specify what aspects of the state's regulatory program suffice for purposes of the CCS Protocol. This "comity" would apply for regulations and programs related to the following CCS Protocol sections: C.2.4.3(c) (Area of Review); C.3.1 (Well Construction); C.4.1.(a)3 and C.4.3.1.4 (Corrosion Monitoring); C.4.2 (Mechanical Integrity Testing); C.4.3.1.5 (Pressure Fall-off Tests); C.5.1 (Plugging); and C.9(c) (Storage Complex Penetration).

Discussion

The CCS Protocol raises interesting questions with respect to the rules and regulatory programs related to CCS activities in other states, especially in the EOR context. Many provisions of the protocol (area of review, corrective action, well construction, mechanical integrity testing, pressure fall off tests, plugging, storage complex penetration) have strong overlap with pre-existing regulatory programs in other states, and in fact already apply to existing projects in those states that may be eligible for participation in California's LCFS program. For the provisions listed above, the CCS Protocol has a combination of performance or prescriptive elements, along with mechanisms for pursuing variances to those elements. In some cases, the existing state rules may achieve the performance standards sought by CARB in different ways than elucidated in the protocol. Where another state's regulatory program adequately covers protocol requirements, CARB may find it efficacious to give credit to that state's standards and decision making.