Carbon Sequestration Council

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Hon. Mary D. Nichols, Chair
California Air Resources Board
Chairman's Office
P.O. Box 2815
Sacramento, CA 95812

RE: Comments on Draft Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under the LCFS (CCS Protocol)

Dear Ms. Nichols:

The Carbon Sequestration Council (CSC) is pleased to submit these comments to the California Air Resources Board (CARB) on the Draft Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration (CCS Protocol) under the Low Carbon Fuel Standard (LCFS). The CSC is a multi-industry association formed to provide a forum for inter-industry communication around key issues of carbon capture and sequestration (CCS) including policy, funding, and messaging. CSC facilitates information sharing and consensus building to more effectively promote policies, legislation and regulatory frameworks that foster the use of anthropogenic carbon dioxide (CO_2) for enhanced oil recovery (EOR) as well as the early use and commercial deployment of geologic sequestration (GS) as a means of addressing greenhouse gas mitigation.

The CCS Protocol would establish two sets of requirements – (1) "Accounting Requirements to calculate credits or carbon intensity reductions for CCS projects under LCFS and (2) "Permanence Requirements set[ing] forth criteria and standards that geologic carbon sequestration (GCS) projects must implement in order to acquire Permanence Certification." The Permanence Requirements should be reconsidered and redesigned because they would create administrative and compliance difficulties owing to overlapping and being inconsistent with the preexisting Class VI injection well requirements established by the U.S. Environmental Protection Agency (USEPA) for geologic sequestration under the underground injection control (UIC) Program of the Safe Drinking Water Act (SDWA).

The Permanence Protocol Largely and Unnecessarily Duplicates the Class VI UIC Rule.

Since USEPA promulgated the Class VI rule in December 2010, all wells that inject CO_2 for geologic sequestration in nonproducing reservoirs must comply with the Class VI rule and obtain a Class VI permit. The USEPA rule applies everywhere in the country until a state seeks to obtain primacy by adopting either the Class VI rule or Class VI UIC regulations that are just as stringent as the USEPA rule. To date, North Dakota is the only state actively seeking primacy for the Class VI rule.

The draft Permanence Requirements cover essentially the same requirements as the Class VI rule, using modified versions of that rule's provision in combination with provisions adopted from the California Division of Oil, Gas and Geothermal Resources (DOGGR) requirements for the storage of natural gas. Because the Class VI rule will apply to all geologic carbon sequestration (CGS) projects "sequestering [CO_2] in depleted oil and gas reservoirs (not meant for oil and gas production) and saline formations" that would be covered by the draft Permanence Requirement, there is no need to reinvent those requirements for these wells. The provisions of the Permanence Requirement would not supplant the Rule VI requirements either in California or anywhere else.

If California wanted to supplant the Class VI requirements for all wells located in California, it would be necessary for the Governor of California to apply for primacy over the Class VI UIC program by designating the appropriate agency to exercise primacy. Even if that agency were CARB, it would still be necessary for CARB to adopt UIC regulations that satisfy the requirements of 40 CFR Part 145, including requirements beyond those relating solely to geologic sequestration. Because California does not currently have primacy for UIC classes other than Class II, it would also be necessary for California to meet a number of additional UIC program requirements to obtain Class VI primacy. In addition, California would need to demonstrate that its Class VI requirements "establish requirements at least as stringent as the corresponding listed provisions" of the USEPA Class VI rule. Under current USEPA policy, this would necessitate completing the "Federal/State Regulation Comparison Crosswalk for a SDWA Section 1422 UIC Program Application" in Appendix B of USEPA's *Underground Injection Control (UIC) Program Class VI Primacy Manual for State Directors* (April 2014) (Attachment A to these Comments). Indeed, to avoid conflicting with the Class VI requirements, CARB should complete this process with USEPA concurrence before adopting detailed provisions of the type currently in the draft Permanence Requirement.

Absent California primacy for the Class VI UIC program, every GCS facility in California that is not injecting into a hydrocarbon producing reservoir would need to conduct its own comparison crosswalk of the Class VI rule with the Permanence Requirement and would potentially encounter inconsistent and conflicting requirements. Moreover, we understand that CARB would also apply the draft Permanence Requirement to GCS projects located in other states when those projects seek to demonstrate conformance with the LCFS. Accordingly, those projects would also be required to conduct a similar comparison crosswalk between the CARB requirements and the applicable Class VI requirements under the USEPA rule or under the applicable state rule if the state in which the project is located has obtained primacy for Class VI.

To Avoid Duplication and Inconsistency, CARB Should Apply the Class VI Rule for GCS Projects in Nonproducing Reservoirs.

Rather than seeking to reinvent the Class VI requirements for GCS projects that inject into reservoirs that are not producing hydrocarbons, CARB should accept compliance with the Class VI rule as a demonstration of permanence and then identify any gaps in that coverage that might need to be addressed in the accounting requirements.[1/] Because all such GCS projects operating within the United States will be required to obtain Class VI permits, the uniform application of these requirements is already guaranteed under the UIC program.[2/]

The Draft Permanence Requirement Is Not Adaptable to CO_2-EOR Projects.

The draft Permanence Requirement is neither designed for nor adaptable to projects where CO_2 is stored in association with CO_2 enhanced oil production (CO_2-EOR). For example, the site screening provisions are not applicable to EOR operations because site screening, selection, characterization and permitting for EOR projects are governed by standards and regulatory requirements applicable to oil and gas exploration and production operations under the purview of oil and gas regulatory authorities. The same is true for plugging and abandonment requirements, which are addressed by existing oil and gas regulatory requirements. In contrast, as documented in the literature, this is generally not the case for the geologic storage projects, which is why these topics are addressed by the Class VI rule.

1/ The identification of gaps should also take into account that all such GCS projects are also required to comply with the mandatory reporting requirements of Subpart RR of 40 CFR part 98, which already address many of the requirements addressed by the Accounting Requirement.

2/ The CSC has registered concerns that the USEPA Class VI regulations need to be revised to facilitate more effective implementation as well as the advancement of CCS technologies, and these concerns will be presented to USEPA for consideration in its promised review and updating of the Class VI regulations. Any revisions of the regulations would be automatically implemented if CARB takes the proposed approach of accepting Class VI compliance as the basis for meeting the Permanence Requirement.

Unlike the Class VI approach to geological storage that relies more heavily on modeling, the containment of CO_2 that achieves permanent storage in association with EOR is not always demonstrated on the basis of predictive modeling and history matching to confirm modeling results. Rather containment and the confirmation of containment are achieved through the operations management and engineering controls associated with the EOR flood management and the monitoring routinely conducted as part of that flood management. Nor is plume movement the same type of consideration in CO_2-EOR: the injected CO_2 in those operations does not exist in plume form (i.e., in "free phase") to the same extent as in a geologic storage operation because of its interaction with the oil to be produced. The CO_2 flood front is highly engineered and tracked to control the CO_2-EOR operation. In addition, the established historical containment of the hydrocarbons bounds the injected CO_2 that will be contained within the same project reservoir.

The most critical consideration for purposes of CO_2 storage associated with EOR is the containment of the CO_2 within the established CO_2-EOR complex, and any permanence requirement should be based on a demonstration of safe, long-term containment by geology and engineering systems as well as a continuation of containment assurance through EOR operations controls. Well infrastructure is already addressed by the applicable oil and gas standards and requirements that are absent in the case of geologic storage projects conducted in the absence of that preexisting regulatory regime. The regulation of injection operations for EOR is different from injection operations for geologic storage because these operations are already fully regulated by oil and gas production requirements. The absence of such pre-existing requirements for geologic storage is what necessitates the extensive specific requirements included in the Class VI rule.

Finally, monitoring for saline formation storage operations differs from CO_2-EOR operations because those operations lack the historical containment of the hydrocarbon resources that are being produced through EOR (unless conducted in depleted hydrocarbon reservoirs). The active EOR flood management and the monitoring integral to that management achieve the necessary steps because each of the multiple injection and production wells constitutes a monitoring and management point. Any permanence requirement should focus on filling any gaps necessary to assuring safe, long-term containment to achieve and account for the storage of CO_2 that is associated with EOR. The requirements following the cessation of injection for geologic storage or the termination of an EOR project can be essentially similar but need to be described within their respective operational and regulatory contexts because of the inherent differences that reflect the pressure profiles as well as the geologic context and operational differences applicable to each type of project (e.g., hydrocarbon production may be subject to different regulatory jurisdictions and timelines).

Thus, a CO_2-EOR project should be required to provide evidence of the integrity of the reservoir and confining system that supports a conclusion that the EOR complex is suitable for safe long-term containment of CO_2. This demonstration should include descriptions of wells penetrating the EOR complex with evidence that they have been constructed and/or plugged and abandoned in such a manner as to provide safe long-term containment of CO_2. This inventory should include injection, production, monitoring, temporarily abandoned, shut-in, plugged and abandoned wells. This containment assurance, or permanence demonstration, would identify and assess potential geologic, engineered, and engineering-affected pathways that might lead to loss of CO_2 from the EOR complex.

The permanence demonstration for EOR projects should include engineering data encompassing such items as the results of reservoir management practices, including injection-withdrawal ratio monitoring, well integrity monitoring, pressure monitoring, monitoring of pathways identified in the initial containment assurance and monitoring of pressure response within the boundary of the EOR complex and may include results from other monitoring. These results would be used in periodically providing evidence of containment, including the supporting rationale. Containment assurance and reservoir management should also be reviewed periodically and revised as necessary if changes occur that have the potential to adversely affect containment.

A monitoring program should be required to address the identified inventory of potential leakage pathways to assess which ones might be active or might activate as a basis for determining whether monitoring of potential leakage pathway should be conducted. But the monitoring requirement should not prescriptively require specific methodologies as the draft Permanence Requirement appears to do. Instead, there should be a performance standard that requires a monitoring strategy that describes the tools, methods, applicability, and frequency for detecting and quantifying losses of CO_2. Details of the monitoring program and data assessed (including relevant data prior to the accounting period) should also be provided.

In many cases the detailing of the monitoring strategy and program will primarily involve providing a tailored description of the monitoring already being carried out for management of the CO_2-EOR flood and production operations, including methods developed and implemented to comply with other state and federal voluntary or mandatory provisions.

There should be no requirement for a fixed one hundred year monitoring program, regardless of how minimal the requirements might be in the outlying years. Instead, the CO_2-EOR operation should be allowed to rely on CO_2 monitoring and operational information collected within the project to demonstrate proper termination by showing an absence of detectable leakage or open conduits to the surface out of the EOR complex; that the injected CO2 is, at the time of project termination, safely contained; compliance with all well decommissioning and plugging requirements; that wells do not allow fluid movement out of the EOR complex and that the CO_2-EOR project wells do not pose a leakage risk; and that the injected CO_2 is safely contained with sufficient documentation of the characteristics of the EOR complex and operational history of the CO_2-EOR project to demonstrate long-term stability and predictability of the associated storage of CO_2. Likewise, there should be no requirement for one hundred years of monitoring for any GCS projects. A discontinuation of monitoring should be allowed once a project has demonstrated that the injected or displaced fluids are not expected to migrate in the future in a manner likely to result in leakage.

The Draft Permanence Requirement Appears to Apply Solely to New Projects

As currently written, the draft Permanence Requirement appears designed to apply almost exclusively to new projects, beginning at the time of site selection and characterization. Although projects may sometimes seek LCFS compliance before development and construction, it seems equally likely that operators will want to qualify existing sites and projects, especially with respect to CO_2-EOR projects. Accordingly, the provisions for a revamped approach should recognize that applications will likely come from existing operations and should provide performance based requirements that will provide the flexibility and adaptability required to accommodate the recognition of those projects.

The CSC appreciates the opportunity to comment on this draft protocol and would be happy to provide additional information or to answer any questions to clarify our comments.

Respectfully submitted,

Robert F. Van Voorhees

Robert F. Van Voorhees
Executive Director

Attachment

cc: LCFSworkshop@arb.ca.gov